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P. Dharma Rao and Daniel E. Walsh, Editors

Mineral Industry Research Laboratory
University of Alaska Fairbanks

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PREFACE

Alaskan coal, the principal source for power generation in interior Alaska, is also finding markets abroad. Alaska's huge coal resources can meet Alaska's future energy needs as well as those of Pacific Rim Nations.

This volume contains 20 of the 28 papers presented at the two-day conference, "Focus on Alaska's Coal '93," held in Anchorage at the Hotel Captain Cook on May 5-7, 1993. "Focus on Alaska's Coal '93" is the fourth in a series of conferences. "Focus on Alaska's Coal 1975" and "Focus on Alaska's Coal 1980" were held in Fairbanks, and "Focus on Alaska's Coal '86" was held in Anchorage. Their proceedings have been published.

The principal objective of the 1993 conference was to provide a forum for the review of knowledge gained on Alaska's coals since the 1986 conference. Highlighting developments during the past six years were:

1. Selection of the Healy Clean Coal Plant for funding by the U.S. Department of Energy.

2. Laboratory research into hot-water drying as a means of upgrading low-rank coal by the Mineral Industry Research Laboratory.

3. Pilot scale testing of hot-water drying and combustion tests of hot-water dried Usibelli, Beluga, and Little Tonzana coals by the University of North Dakota.

4. Evaluation of Deadfall Syncline coal as a source of fuel for Northern Alaska's villages and coal mine development by Arctic Slope Consulting Engineers.

5. Alaskan coal research efforts of the U.S.G.S., principally the efforts of Ron Affolter, Gary Stricker, and Romeo Flores.

In all, there has been a significant addition of new knowledge on Alaska's coals over the past seven years, as is evident from the contents of this volume.

Dr. Scott L. Huang, Acting Dean, School of Mineral Engineering, University of Alaska Fairbanks, welcomed the participants. Speakers at the opening ceremonies were Joan Wadlow, Chancellor, University of Alaska Fairbanks, Glenn Olds, Commissioner, State of Alaska, Department of Natural Resources, Paul Fuhs, Commissioner, State of Alaska, Department of Commerce and Economic Development. Dr. Victor Der, Director, Office of Advanced Technology Development, U.S. Department of Energy, Washington, D.C., presented the keynote address. Luncheon speakers were Samuel Dunway, who discussed land permitting, and Robert Stiles, who summarized developments in the Mental Health Trust Lands litigation. The banquet speaker was Jim Burling, Pacific Legal Foundation, Sacramento, CA.

The technical sessions were preceded on May 5th by a "Short Course on Small Scale Coal Combustion" taught by Mike Mann, EERC, University of North Dakota. The conference was sponsored by the University of Alaska's School of Mineral Engineering and Alaska Section of Society of Mining and Exploration of AIME.

Successful completion of this volume was made possible by many individuals. Special thanks are due to Carol Leaky and Nancy Mighells for their patience and word processing skills in painstakingly formatting these proceedings, and to Cathy Genaux for compiling the final manuscript. Our sincere appreciation is extended to the program committee members and to the speakers and participants for their valuable contributions to making "Focus on Alaska's Coal '93" a success.

The School of Mineral Engineering intends to organize another coal conference at an appropriate time, in the coming years, to review knowledge of future exploration, mining, and utilization of Alaska's coal resources.

July 1, 1994
Fairbanks, Alaska

P. Dharma Rao
Daniel E. Walsh

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MINING CHALLENGES AND OPPORTUNITIES AT THE DEADFALL SYNCLINE

Steve W. Denton
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ABSTRACT

ASCG, Incorporated, a subsidiary of Arctic Slope Regional Corporation (ASRC), has been conducting pilot scale mining and basin wide exploration on ASRC land in the Deadfall Syncline (DFS) area since 1984. This effort has identified the presence of a large deposit of high quality bituminous coal, with adequate measured reserves to support the development of a coal mine producing 1 to 2 million tons of clean coal per year. During the course of the exploration and mining activities, there has been an ongoing study of the engineering, environmental, infrastructure and market requirements for development of a major mine at the Deadfall Syncline. Although there are some obvious obstacles facing development at the DFS, there are positive aspects of the deposit which favor its development.

Coal seams identified by exploration drilling are consistent in quality and thickness over broad areas. Both underground and surface mining methods are being investigated for large scale production from the DFS. Many of the commonly regarded impediments to development in the Arctic, such as permafrost, weather and remoteness, are less severe and may even hold opportunities for improved efficiency in mining at the DFS. Permafrost, while making surface construction expensive on the Arctic Coastal Plain, is not a serious problem for surface activities in the dry foothills region where the DFS is located and may improve ground control for underground mining. Winter, though long, is moderated by proximity to the ocean and is less severe than found further inland, the effects of which can be further moderated by underground mining. Remoteness, while making transportation and project support more costly, does not carry with it the problems of proximity to National Parks, Preserves or critical habitat areas, which are common impediments to development in other remote areas of Alaska.

This paper will present a brief history of pilot scale mining activity that has occurred at the Deadfall Syncline coal deposit in Northwest Alaska since 1986 followed by a discussion of the engineering challenges and opportunities involved in large scale development of the deposit.

INTRODUCTION

The Deadfall Syncline (DFS) is located within the Western Arctic Coal Field in northern Alaska. The Western Arctic Coal Field (WACF) is bordered on the west by the Chukchi Sea, on the south by the Delong Mountains and extends eastward to include the Kukpowruk River drainage. Most of the potential coal resource within the WACF is located on lands owned by Arctic Slope Regional Corporation (ASRC). DFS has been identified as an area containing mineable reserves of high quality bituminous coal in close proximity to the Chukchi Sea. Geology and reserves are detailed in a paper by Teresa A. Imm and J.E. Callahan, presented at the Focus on Alaska's Coal '93 titled, *Coal Exploration and Reserve Evaluation, Western Arctic Alaska* (not submitted for publication).

HISTORY

The WACF has been studied at various times since the beginning of this century. Detailed evaluation of the resource began in 1982 with a State funded exploration and resource evaluation program, which identified the DFS as the most promising coal reserve for development to supply domestic and small commercial use throughout the Arctic and Western Alaska. Since then, exploration, pilot scale mining and preliminary feasibility analyses funded through a combination of State, North Slope Borough and ASRC sources has identified the DFS as a significant resource with potential to supply not only local needs but also large scale export markets.

Pilot scale mining was initiated in 1986, with a shallow underground test mine producing approximately 100 tons of coal for home heating in Arctic coastal communities. Pilot scale mining has grown and now produces approximately 400 tons annually along the west limb outcrop of the syncline, from DFS 4 seam, using mechanized surface mining techniques. Current mining activity is serviced by an airstrip, 20 person camp and equipment maintenance facilities. Pilot scale mining activities, though small and relatively inefficient, have provided invaluable experience and resulted in the conclusion that large scale mining, using high efficiency mining methods, should be feasible. The geologic, environmental and social aspects of mining in the DFS will provide many challenges to the potential developer, but also present some unique opportunities for mining in the area.

Exploration drilling at the DFS through the mid 1980's was targeted, primarily, at shallow auger and rotary borings near known coal outcrops. This data was used to develop a general geologic model for the syncline and identify prime targets for more detailed reserve drilling. Exploration drilling on a thick coal seam near the syncline axis was initiated in 1991 in an area dubbed the Kuchiak Block, after Kuchiak Creek, which roughly parallels the syncline axis. This two year drilling program identified a thick coal seam, K3 seam, of high quality coal apparently continuous along the syncline axis to a depth of at least 800 feet with good lateral extent. K3 seam is currently the focus of mine design and feasibility analysis.

QUALITY

Table 1 lists the average proximate analysis for DFS4 seam and K3 seam for 1991 exploration borehole samples (both core and cutting chip samples) taken from holes reaching below the surface weathering zone. The above analysis is typical of quality found in thick coal seams, which have been sampled by exploration drilling, near the lower part of the coal bearing formation. Channel samples taken of DFS4 seam from the active mine in 1987 and 1991 average 3.3 percent ash across the full depth of the seam. Therefore, actual quality of the coal is anticipated to be slightly better than indicated by exploration borehole samples. Samples taken in the southwest portion of the syncline indicate slightly lower rank and heating value as one progresses stratigraphically upward.

Grindability of the coal is good, with values of 50 to 60 typical of the samples tested. Slagging temperatures typically are below 2400 °F, which is lower than what is associated with similar coals mined in the contiguous United States and more in line with typical slagging temperatures of low rank coals. This could be a problem for boilers designed to burn coals with high slagging temperatures, but would be a beneficial char-

TABLE 1
Deadfall Syncline Proximate Analysis

Parameter	DFS4 Seam	K3 Seam
Equilibrium Moisture, %	3.68	4.19
Ash, %	8.78	9.06
Volatile Matter, %	31.48	32.81
Fixed Carbon, %	56.06	53.85
Heating Value, BTU/lb	12750	12602
kcal/kg	7080	7000
Total Sulfur, %	0.30	0.19

Source: Mineral Industry Research Laboratory Report No. 93(presently unpublished), April 1992, *Deadfall Syncline Coal: Quality and Reserves.*

acteristic for use in slagging type combustors. K3 seam exhibits free swelling indices of up to 5 with an average of 2.4. In general, the quality of DFS coals indicate they would be superior fuel for steam generation and may be attractive as blend coals for metallurgical coke production.

GEOLOGY

The DFS is a canoe shaped synclinal structure with bedding dip of approximately 8 degrees near the axis outcropping of K3 seam, at the northeast end of the syncline. Bedding dip at the outcrop increases as one progresses along the limbs of the syncline. The site of present mining activity is located approximately three miles along strike from the syncline axis, where bedding dip is 20 degrees.

At least 7 mineable coal seams, ranging from 4 to 18 feet thick, have been identified by drilling to date. Coal seams are typically separated by thick sections of sedimentary rock, up to several hundred feet thick. The stratigraphic thickness between seams and the moderate coal dip at outcrops limits the potential for large open pit mining. However, the long strike length of coal outcrop and a broad section of dip/slope oriented coal in K3 seam near the syncline axis provide a good potential for low ratio reserves amenable to surface mining at a rate of 1 to 2 million tons per year from multiple locations.

Coal dip and thickness are within the range typically encountered in high efficiency mechanized underground mining in the Western United States and other locations throughout the world. The thickness, absence of partings, apparent continuity and simple geology in the major coal seams provide favorable conditions for underground mining to produce a clean raw coal product without waste rock dilution. Based upon the geology and resources indicated at the DFS a mining rate of 4 to 5 million tons per year from combined surface and underground operations appears to be a reasonable expectation.

Overburden materials at DFS range from massive beds of well cemented sandstone, to poorly cemented clay and silt stones. Overburden bedding has been observed in the current open pit to be complex and lenticular, with beds pinching out over several hundred feet of strike length. A typical section, through the 40 foot highwall at DFS4 seam pit, would contain 10 to 15 beds of clay/silt stone, sandstone and coal pebble conglomerate from a few inches to several feet thick. This complex bedding should not present any serious impediment to surface mining. However, assuming the condition persists throughout the syncline, it is expected to complicate roof control for underground mining.

CLIMATE

A visit to the DFS in early spring, during start-up of the camp, drives home the most severe aspect of the climate quite vividly. The pit, camp and the interior of rooms and equipment cabs are all packed full of drifted snow. Although snow removal will be a constant headache for mine operation in the area, it will not represent quite such a formidable task when dealt with on a daily basis during year round operations. Use of good engineering practice, such as elevated roads without berms, can mitigate much of the difficulty resulting from the nearly constant wind and frequent ground blizzards of the area.

Temperatures at the DFS area are moderated by proximity to the ocean and temperatures less than -30 °F seldom occur. The average daily temperatures are below freezing for 9 months per year. This will increase operating costs for heating of mine facilities, but will decrease maintenance cost for haul roads. Both the Red Dog zinc and the Usibelli coal mines operate year round in temperatures as cold or colder than anticipated at DFS and thus temperatures are not expected to be a serious impediment to year round mining. Underground mining would be relatively immune to the effects of surface temperature. Activities requiring personnel to work outdoors, such as surveying, can be seriously hampered by the cold temperatures and windy conditions. However, modern surveying techniques like the Geodetic Positioning System can be used to greatly reduce the unpleasantness of such tasks.

Daylight extremes in the Arctic will necessitate provisions for extra area lighting capability in the winter. During the nearly 4 months of continuous summer daylight, productivity and efficiency of all surface operations will increase. Scheduling can be used to take advantage of increased summer productivity to yield savings in operations during the summer which benefit most from the long daylight, while minimizing the impact of lower productivity during the winter, when usable daylight is reduced to approximately 5 hours.

PERMAFROST

The most unique aspect of operations resulting from the climate will be dealing with permafrost, which is expected to extend to depths below 1000 feet. Fortunately, the majority of DFS is located in rolling hills adjacent to the Arctic coastal plains, where the effects of permafrost are minimized, with respect to construction of surface facilities. The area is characterized by frequent, dry hogback ridges, resulting from differential erosion of the sedimentary rocks. These rock rubble covered ridges are often continuous for several thousand feet at a time and wide enough for siting of roads and other surface facilities. Using the ridges for location of surface facilities should permit employment of conventional low cost construction methods.

Ice rich surface soils between the dry ridges are typically less than 20 feet deep, but will require special handling during surface mining operations. Because the volume will be small, ice rich materials could be buried under overburden during backfilling to prevent thawing or mixed into overburden without serious effect on spoil stability, even if it thaws. Ice rich surface soils will need to be stripped in advance of the highwall to prevent material from flowing into the pit during thawing conditions. Highwalls cut in the active mining pit have undergone several freeze/thaw cycles with no apparent reduction in highwall stability.

Blasting of the frozen overburden has been highly successful using small diameter boreholes, relatively confined conditions and a powder factor less than 1.0 pound per cubic yard. It is anticipated that large scale mining could achieve acceptable blasting with practices typical for mining in non-permafrost sedimentary formations. In general, the effect of permafrost on the cost of surface mining is expected to be negligible.

The permafrost, which is expected to have pockets of free water, will necessitate some changes over conventional techniques for underground mining. The use of water for dust control may not be practical for mining in permafrost and dry dust control methods may have to be utilized. Permafrost is expected to increase the strength of roof rock, which should be beneficial for roof control in conventional or continuous room and pillar mining, but could be a serious impediment to longwall mining. Permafrost materials, if they have significant ice content tend to behave plastically, which would promote creeping collapse of the roof behind a longwall face. This could result in excessive pressure on the face and shields and render long wall mining practically infeasible. However, the discontinuous nature of bedding may create adequate weakness in the roof rock to promote proper caving. In is probable that room and pillar mining will precede longwall mining until adequate knowledge of frozen rock behavior is gained.

REMOTENESS

Perhaps the greatest impact to cost of operations will be the remoteness of the DFS, which is located approximately 40 miles from Point Lay, the nearest community. Point Lay currently does not have any facilities designed for provision of services to industrial activities in the area. The mine will therefore need to be self sufficient. Spare part inventories will need to be large enough to remove reliance upon supply from traditional sources, which could be cut off completely during periods of inclement weather and at a minimum will need lead time for supply of even routine materials. Additional storage capacity for bulk commodities, such as explosives and fuel will need to be adequate to accommodate nearly a full year's requirements.

Camp facilities will need to be constructed with self sufficiency in mind. Facilities for personnel should include adequate recreational amenities to maintain employee moral and an airstrip adequate for large freight hauling aircraft.

The remote and relatively pristine nature of the area is expected to result in opposition to the mine during permitting. However, because of the mine's remoteness, it can be operated to minimize impact on local residents. The DFS is not located within any critical habitat, such as a caribou calving area, and is approximately 50 miles from the nearest wilderness area, the Noatak National Preserve. Use of the area offshore from DFS by beluga whales has been identified by local residents, who hunt the whales, as an area of major concern, which may necessitate timing restrictions on shipping, if the coal is taken offshore from DFS. In summary, although permitting a mine at DFS will likely face opposition and some significant hurdles, there do not appear to be any fatal flaws precluding permit procurement.

One of the key elements of maintaining efficiency in operations in remote mining operations is incorporation of flexibility in mining methods and equipment selection, which will be especially important at the DFS. Equipment currently used for mining, a large backhoe excavator and ripper dozer, provide a small equipment compliment capable of performing a wide variety of tasks, though perhaps not the most efficient equipment for all tasks.

The same principle should be employed when mining is expanded. It may be necessary to sacrifice some efficiency in mine design and equipment selection in order to provide flexibility. This could mean scheduling production to maintain large coal inventories to accommodate interruptions in new coal production, development of multiple production areas to mitigate unforeseen environmental or geologic conditions and standardization of equipment to be used for different tasks to provide interchange ability and avoid excessive reliance upon any single production unit.

PERSONNEL

The limited availability of labor skilled in the areas required for mining is commonly cited as an impediment to development in remote parts of Alaska. However, because of the need for self sufficiency and the experience gained through employment during trans-Alaska pipeline construction, there is a fairly high percentage of personnel with heavy equipment operating experience in the North Slope Borough. Therefore, finding qualified local personnel for surface mining operations is not anticipated to be a serious problem. Conversely, there is virtually no experience base in underground mining and the operator of an underground mine will need to institute an aggressive training program to develop a trained local work force.

Experience to date has shown that work at the mine is desirable for local residents and jobs at a DFS mine would be in high demand at local communities. Current mining activity experiences a high rate of turnover, which stems primarily from the short duration of the work and the inability to offer permanent positions to employees. Local residents also treasure subsistence activities as part of their lifestyle. A mine that offers permanent positions on a scheduled rotation, which would provide time off for subsistence activities, should find little difficulty attracting hard working local personnel for production and maintenance positions at the mine.

RECLAMATION

Mining has only recently progressed to the point where backfilling of open cuts could begin and rigorous investigation of revegetation techniques was possible on backfilled mine spoils. However, past areas used for camp sites have exhibited good natural invasion of native plants. Grass seed broadcast along the edge of the existing runway several years ago has survived and is doing well without subsequent maintenance. From this experience, it appears that reestablishment of vegetation on backfilled mine spoils is technically feasible and the test plots recently established should yield the information necessary to design a successful revegetation strategy.

The two other major areas of reclamation, backfilling and drainage control, are expected to be similar to methods employed at other mines and in many respects, may be less costly. Because of the low mean annual temperature, the permafrost condition of backfilled spoils is expected to be reestablished, which would promote long term backfill stability. Because much of the surface disturbance will be located on the rubble strewn ridges, which serves as the available topsoil in the area, the surface of backfilled areas is expected to be quite resistant to erosion and rill and gully formation.

The DFS is located within an area described as an Arctic desert, with rainfall at less than 10 inches per year. The permafrost condition, which tends to inhibit ground water flow, means volumes of water which must be handled by surface water treatment facilities will be small. Experience with water impounded in the active pit, shows quality of water pumped directly from the pit frequently meets discharge standards without treatment. This, coupled with the low quantity of rain and ground water anticipated, leads to the expectation that water collection and treatment can be performed at minimal cost.

TRANSPORTATION

The single greatest impediment to development of the coal resource at DFS is, most likely, transportation of the coal to market. Proximity of the area to the coast and favorable terrain for road construction lends itself to a wide range of transportation options from the mine to a marine loading terminal. However, the Chukchi Sea near DFS is ice free for less than 3 months per year and is shallow along the coast, requiring one to go offshore several miles before reaching water depths adequate to accommodate Panamax size vessels. Overland transportation through the Delong Mountains, to deeper water and longer ice free seasons, has been investigated but, as expected, very high production rates are required to justify investment in the infrastructure.

However, the potential for shipment from the coast near DFS has not yet been fully investigated. Detailed bathymetry is needed to conclusively determine the offshore distance which must be traversed and detailed studies of ice movement are necessary for design of any offshore structures. Ledyard Bay, which is located adjacent to DFS, does not exhibit the massive pressure ridging typical of other areas along the Arctic coast. This points to the possibility that conventional pile supported structures may be feasible for continuous offshore transport, which would reduce transfer terminal construction and operating costs and minimize impacts to beluga whales, an area of concern when considering lightering type of operations. The expanding use of ice breakers may provide an opportunity to extend shipping seasons to an acceptable length.

The long period during winter when the ground and ocean are frozen provide opportunities for some unique approaches to transportation, not yet fully investigated. The Arctic winter period is frequently used as the period for overland shipment of bulk commodities with minimal road construction cost and environmental disruption. This principle may also be applicable to offshore shipment of coal. An ice road across Ledyard Bay to an offshore island constructed for coal stockpiling and ship loading is an option deserving investigation for economic and technical feasibility, since it would virtually eliminate potential impact on whale migration. Furthermore, the annual maintenance cost of such a system would be the cost of ice road construction, a definable and low risk cost component.

CONCLUSION

The Deadfall Syncline coal basin contains mineable coal seams of adequate thickness, quality and tonnage to make it an attractive resource for energy consumers throughout the Pacific Rim and Western Alaska. The geology and geography of the area are favorable for large scale, high efficiency surface and underground mining with minimal impact on the environment. There are many environmental, social and economic factors challenging the resources and ingenuity of a potential developer of the deposit. Most of these factors have the potential to become assets in the design of coal mining operations at Deadfall Syncline. Using the knowledge gained from pilot scale mining at Deadfall Syncline and other successful mining operations under equally challenging conditions, the author is optimistic about the potential for economically viable production of coal from the Western Arctic Coal Field.

COAL EXPLORATION AT USIBELLI COAL MINE, INC.

Dan Graham
Usibelli Coal Mine, Inc., Healy, AK

WHERE IT ALL BEGINS...

Usibelli Coal Mine, Inc. operates two mine sites in the Nenana Coal Field. Both mines are located in the Hoseana Creek basin just north of Denali National Park near the town of Healy. They are supported by a shop/office facility located at the confluence of Hoseana Creek and the Nenana River.

All reserves on Usibelli leases lie within the Usibelli Group, which consists of 5 formations ranging in age from Upper Oligocene (33 MY) to mid-Upper Miocene (6 MY). The Gold Run Pass mine reserves are from the Healy Creek Formation, which is the basement formation in the Group. The Poker Flats mine reserves are in the Suntrana Formation, which holds the bulk of the reserves in the valley. The Sanctuary, Lignite and Grubstake formations contain no currently mineable reserves within the leases.

The deposits in this area have been structurally altered by two main events. The dominant event was the uplift of the Alaska Range, with more localized complexities caused by the igneous intrusion know as Jumbo Dome. The result has been a trend of east-west anticline/syncline structures plunging westward and associated faulting, both major (regional effects) and minor (limited to one or two properties).

SO WHY ALL OF THE EXPLORATION?

Since the inception of Usibelli Coal Mine in 1943, the dominant market for the coal produced has been interior Alaska. Current customers include the city of Fairbanks, Golden Valley Electric Association, the University of Alaska Fairbanks, and the military bases of Clear, Eilson and Fort Wainwright. Through the seventies and into the eighties, this lead to sales of between 600,000 and 800,000 tons per year (see Fig. 1). In 1986, UCM started shipments of coal to the Korean Power Company (KEPCO) via Suneel Shipping Company in Seward, which average roughly 700,000 tons per year. This increase in sales effectively reduced the mine's reserve life by one-half. This led to a "revitalized" exploration program starting in 1986, which continues today. The early years of this program included intense field programs, while the more recent years have been spent compiling this information and moving into mine planning and permitting.

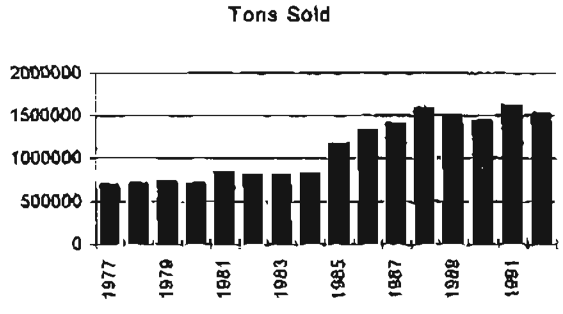

FIGURE 1 - Sales - 1977 through 1992

PROPERTY DEVELOPMENT PLANNING

The planning and development process used by the mine ranks properties or mining units into a 5 stage ladder, beginning with a literature search and concluding with a permitted property with respect to the Alaska DNR - Division of Mining's Surface Mining Control and Reclamation Act (SMCRA) program standards. The stages include (1) lease-wide or basin-wide literature search, (2) field mapping and confirmation, (3) broad-spaced drilling program(s), (4) fill-in or detailed drilling and data gathering, and (5) mine planning and permitting.[1] In the standard sequence of events, a property may take from 8 to 11 years to complete the process. The philosophy adopted by the engineering department is to keep future mine properties "spread-out" by holding the majority of properties in stage II and minimize the number of properties that are brought into the higher and more expensive stages, particularly stages IV and V, while maintaining enough permitted reserves to meet future sales. The details of each stage are discussed below.

Stage I

The literature search or regional appraisal portion of development an essential starting point for any development program that is to maintain integrity and proceed in an informed manner. In 1988, an appraisal was conducted on all of the Hoseanna Creek Leases held by UCM to better define the status of our reserves. All available information was compiled on each property. The level of development for each was determined and a reserve calculation was done using the data available and a uniform list of criteria. This took nearly 1 full year to complete with the results compiled into a single report.

Stage II

Once the office research is complete, the next and least expensive information available is field confirmation of data through mapping. This can include a variety of observations including mapping outcrops, formation contacts, measured sections with lithology definitions, strike/dip measurements and fault lineations. UCM contracted the services of a UAF Ph.D. candidate who spent several summers collecting geologic data (as well as other data related to his thesis) and compiled all geologic data on 1"=200' scale topography maps. These maps have proven to be an excellent tool for calculating initial reserve estimates and planning for drilling and/or geophysical programs at later stages. The total time involved for this stage is a function of climate, area to be covered and the number of geologists employed. As a general rule, 1 to 2 years should be expected, with the emphasis on two years as fewer geologists may take more time, but could result in more consistent data.

Stage III

The broad-spaced drilling program (and the potential for surface geophysical assistance) is the first stage at which major costs are incurred. Thus, wise use of information gathered in the first two stages can greatly reduce the risk and expense incurred at this stage. In some deposits, however, this may be the first stage at which any significant data can be gained, which may lead to higher costs and risks as more drilling may be needed.

There are rules and costs that apply to all deposits at this stage, while other costs are a function of the deposit. In general, drilling conducted at this stage does not have specific drill targets. Maximizing the depth of these initial holes can be highly beneficial, limited by either the physical limits of the drill or other limits deemed practical by the envisioned mining method. However, it has proven useful in the past to have preliminary holes extend several hundred feet below practical mining limits in an effort to better and more fully define the geologic structure. Good downhole geophysical logging is another must for drilling programs at this stage. Anyone who has tried to perform correlation exercises from a pure geometrical vantage point in a structurally complex region can testify as to how futile this can be. A natural or induced gamma log can define a seam signature that greatly aids correlation exercises. Fairly user-friendly and portable logging instruments are available for sale or lease, or the logging services can be contracted. Whichever method is chosen, the added cost greatly increases the usefulness of the drill information. Finally, depending on the drill method chosen, chip samples and/or core samples should be collected to give a preliminary indication of coal quality. Fifty million tons of 1:1 steam coal isn't worth much if it doesn't have good combustion characteristics.

Site-specific items that affect costs which need to be considered include access, transportation modes and living quarters for work crews. These costs are greatly reduced when activities are conducted near existing mine sites as opposed to remote locations. The time frame for all of the above activities will generally range from 1 to 2 years, including office time to compile data and generate updated reserve information.

Stage IV

Once a company has advanced to this stage of detailed drilling and data gathering, a strong commitment has been made. Once we bring a property to this point, we have basically committed the property to full development within a reasonable time frame. It is not cost effective to force properties into this stage of development just to have them wait in line for 10 or 15 years prior to starting a permit process. Costs incurred here may be viewed more as a development cost to be returned, rather than pure exploration costs that are sunk, in the final cash flow (barring any fatal flaws which have gone undetected).

Activities at this stage include specific drill targets with variable and fairly well defined depths to better define structure, a concentrated effort on coal quality gathering, potential geophysical work to help delineate limits and structural complexities (if applicable), and geotechnical and hydrological data gathering. An excellent method to achieve all of the above is reverse circulation drilling for a majority of the work, supplemented by some form of coring. In addition, test pits may be appropriate. The timeline for this work may again vary, but 1 and more likely 2 years should complete this stage of development. In the end, a final geologic model should be prepared and ready for mine planning. A major portion of baseline data needed for permitting should also have been collected in this stage.

Stage V

The final stage combines a multitude of professional skills to bring a property through the mine design stage and prepare a SMCRA permit application. (Other permits obviously apply, but the SMCRA permit from DOM tends to determine the critical path of the project.) This is the final stage for test pits to confirm drilling and product performance. Hydrologic and geotechnical studies are finalized, and a final mine plan is produced. From this mine plan, reclamation plans are produced and bonding amounts calculated. A bit of crystal-ball technology and voodoo science combine to predict and compare pre- to post-mining hydrology and vegetation conditions. If all goes well, it may take 2 years, several copier toner cartridges and a good supply of 4" 3-ring binders to produce a "complete" permit application.

After submitting a permit application to DOM, it takes on the average 2 years to receive a permit to mine on the property. This appears to be a fairly rigid average, with a standard deviation of only 1 to 2 months[2], regardless of the applicant history, property size or location. All totaled, this gives a range of 8 to 11 years from the time a property is first investigated to the time the first shipment of production coal is able to be removed.

THE NUTS & BOLTS OF PAST EXPLORATION

A gradual progression of exploration techniques has been used over the years on UCM leases. Stopping short of a churn drill, exploration has spanned from mud-rotary drilling through reverse circulation drilling and recently included beta site testing of NanoTEM (geophysical) as an exploration tool in coal exploration. Here is a brief description of what has and hasn't worked in the past.

Beginning with the early 1970's, extensive mud-rotary drilling was conducted throughout UCM leases. Although the drillers' logs from this drilling are, for the most part, worthless, downhole geophysical logs were conducted on all drillholes and have proven to be very valuable. The logs included gamma, density and resistivity logs, with the first two being the most useful for seam correlation. Several holes were twinned with core holes to obtain quality information, as no useable chip samples could be obtained from the mud-rotary drilling. Later in the 70's and into the early 80's, straight air-rotary drilling was conducted for fill-in drilling. These produced better defined drillers' logs, but produced no quality information and no geophysical logs were run. Correlations in complex areas can be frustrating without the aid of the geophysical logs, but some of these holes have helped aid surface geophysical work in complex areas and structural definition in "non-complex" regions.

Beginning with the 1986 program, reverse circulation (RC) drilling was used. Advantages of RC drilling includes excellent lithology pattern definition, accurate depth records of formation changes and contacts, representative quality data, and excellent production rates. For gathering quality data, the drill rig is stopped upon contacting a target coal seam and the cyclone and drill pipe are washed out. The process takes about 5 minutes. When drilling resumes, all cuttings are easily collected in 5 gallon pails. They are then run through a splitter, bagged, tagged and sent to the lab for a proximate analysis, giving representative quality data of the entire interval drilled. Reducing contamination from sloughing of the overburden greatly depends on the drill bit. Bits with little or no reaming cutters work best, if the formation allows it. After drilling, a portable logger is used with a radium source to produce simple gamma-gamma logs. The logs are run in either open-hole, through the drill steel, or, in areas of a weak top layer, a combination of the two. Once complete, the holes may be backfilled or used as piezometer installations if the hole stays open long enough to allow an installation.

To further improve coal quality information, some wireline diamond coring has been conducted in the late 80's/early 90's. However, the need for and amount of coring required has been greatly reduced by the RC drill data. It should be noted that there was a three-fold increase between the cost of RC drilling and coring during a recent program.

Additional techniques used for drilling to improve results while reducing costs include angle drilling, hinged drill beds and seasonal drill programs. Angle drilling has proven highly effective near a major fault area where the coal beds roll from a 7 degree dip to 80 degree dip over a relatively short (50') horizontal distance. Angle drilling has also been useful on ridge tops or ridge lines where making a drill pad down the outslope is not practical. When using this method, it is imperative that the driller or rig geologist be prepared to make several downhole measurements of the dip and direction of the hole for accurate data calculations. One major drawback of this method has been the inability to conduct geophysical logging in an angled hole. In other areas where the outslope makes drill pad construction marginal at best (specifically on north facing slopes), the use of a hinged leveling bed allow versatility in drill site location without the need for of dozer preparation and the often disastrous mistake of removing the tundra mat. The drill carrier parks facing downdip and the bed of the drill is leveled via rams mounted behind the carrier cab. We have set up on slopes up to 14 degrees with few problems encountered. Where access has been a problem, particularly in permafrost areas, seasonal programs may be required. Drilling in April has proven to greatly improve certain logistical problems. Temperatures reach marginal freezing to above freezing during the day while refreezing at night. It is also a good relief from the contour maps you have been staring at on the computer screen all winter.

A final drill technique used with good success in shallow holes has been auger coring. A 5 foot core barrel replaces the cutting head or plug bit in the center of the auger stem and is retrieved at the end of each auger run. An adjustable rod attaches to the core barrel to allow adjustment of the barrel with respect to the auger face. When used for geotechnical/hydrological field programs, soft soils had near 100% recovery, permafrost zones were cored with ice lenses in tact, and excellent coal/footwall interface samples were extracted. While drill rates were relatively slow, it has had the best record for extracting solid geotechnical samples and data that I have seen in sedimentary formations. After testing, the samples may also be used for chemical analysis of the different lithology packages.

Geophysical techniques have been reconsidered as of late as a more cost-effective way to perform better structural definition without spending big dollars on drilling or as a way to help reduce drilling costs. The first technique used in the recent past was a black-box technology that uses electrotellurics, or ET. This methodology, in short, reads transient currents set up in the earth by solar radiation, translates it to a "pitch" or sound for varying resistivities at depth, and is recorded by the geologist/geophysicist wearing headphones. The point data is treated as a drillhole in modeling. After being highly sold on the method and cost savings early on in the program, subsequent drilling on old ET sites has cast a gray cloud over the data that was collected. One big bonus for this method is that it only works on bright sunny days with little or no cloud cover. If only that were true for drilling, eh?

Another method that has been studied for use at UCM, but not yet tried, is VLF/EM. It has been used in coal mines in the western US to define faults and subcrops. It is a simple method, requiring little training and minimal ground preparation. The cost of purchasing the equipment is also relatively low. One catch to this method is the need to know the maintenance schedule of the transmitting sites in the area, namely Washington and Hawaii. Also, the data from VLF/EM is two dimensional in the horizontal with no ability to record the vertical depth of the change. We anticipate running a trial of this method sometime in 1994 or 1995 to help locate future drill targets.

A final geophysical method that was tried at the mine (as a beta site) was NanoTEM.[3] In short, it is a shallow transient electromagnetic method that maps resistive anomalies. It contains its own transmitter and receiver loops for creating and recording field decay. Although the initial trial had poor results, modifications to the system and retests performed during the spring and summer of 1993 showed great improvements and encouraging results in the first several hundred feet of the surface. Field work for NanoTEM is more involved than a VLF/EM survey. Two to three field hands are required as well as fairly flat terrain. Working in wooded areas is possible, but would be much more cumbersome than working on the open tundra. Another requirement is a fairly distinct difference in resistivities between the target and the host. Data produced is in section beneath the line of testing. The accuracy required will determine station spacing. A sample of the data produced in the final 1993 test is included in Figure

2. This shows an area where the coal has been faulted and a void zone exists.

CONCLUSION

The success and future survival of any company in production must include planning for the future. To make the most informed decisions, information must be compiled in a presentable and meaningful form. Methods of obtaining and adding to the information is constantly changing. To stay competitive, a company must keep up with the latest technology. Usibelli Coal Mine strives to meet all of these goals through and in its exploration program.

[1] These stages are adapted in part by those defined by Dell Adams, Consolidation Coal Company, whom the author wishes to thank.

[2] From a speech by Sam Dunaway, DOM Surface Mining Manager, 1993 Focus on Alaska Coal Conference

[3] NanoTEM is a method exclusively designed and used by Zonge Engineering of Tucson, Arizona.

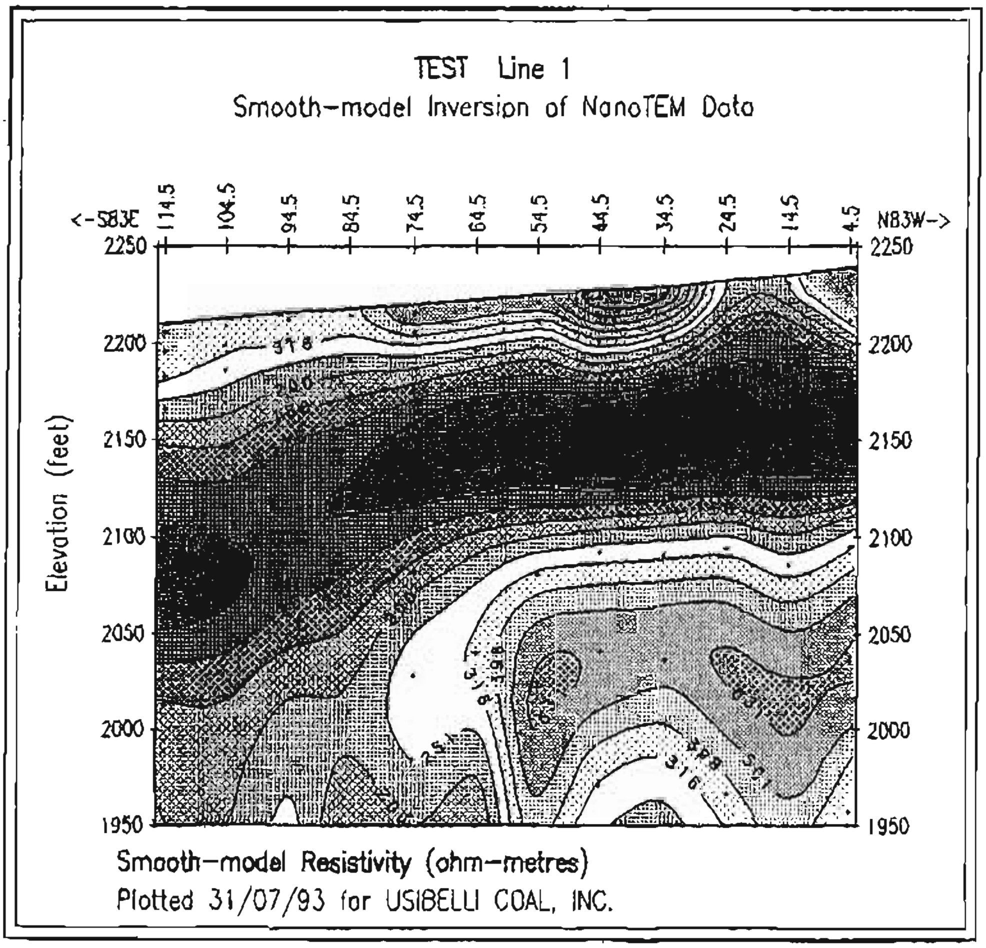

FIGURE 2 - Sample of NanoTEM data from Usibelli Coal Mine Exploration, 1993.

CAST BLASTING AND PRESPLITTING AT USIBELLI COAL MINE, INC.

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INTRODUCTION

This paper discusses cast blasting and presplitting at Usibelli Coal Mine, Inc. (UCM), with respect to the techniques used and design considerations. UCM is located within the Alaska Range near the town of Healy, about ten miles northeast of Denali National Park's main entrance.

UCM was founded in 1943 and produces ultra-low sulfur subbituminous coal for domestic and export markets. The domestic market consists of about 800,000 tons per year supplied to six interior Alaska power plants, and approximately 700,000 tons per year are shipped through the port of Seward to the Republic of Korea.

BLASTING GENERAL

Annually, UCM produces about 1.5 million tons of coal while excavating over 10 million bank cubic yards of spoil. Roughly 6.5 million lbs. of explosives are used to blast the overburden and coal.

A frozen gravel layer at the surface is drilled and blasted by conventional blasting methods and prestripped with a truck and shovel operation. This first lift usually averages 20 to 40 feet deep. Additional sandstone overburden is then blasted and also removed with trucks to achieve the desired bench volume for our dragline pit.

Once the prestripped material is removed, the cast blast pad is prepared. Each blast hole is staked by the blasting engineer so that the drill pattern matches the design. After a blast hole is drilled, the hole is dewatered by using a Legra blast hole dewatering pump. A 10 mil plastic blast hole liner, which is used to protect the explosive from getting desensitized by water, is lowered into the hole. Next, a one lb. cast primer with a 350 millisecond (m/s) insert delay is lowered to the midpoint of the blast hole. The explosive, which is 65% ANFO and 35% emulsion, is then bulk loaded into the blast hole. The final step is to stem the top of the drill hole with the desired amount of drill cuttings.

Once the pattern is drilled out and loaded, it is tied together with a surface delay system. The proper delay sequence is set up so that the material will cast in the intended direction.

The cast blasting technique is easy to explain. By overloading the blast area, relative to standard blasting, the material is cast across the pit into the desired location. If everything is done right, it is possible to achieve a 60 to 70% cast (60 to 70% of the material is removed by explosives instead of by machinery).

Presplitting is a method of highwall control that minimizes backbreak from the production cast blast. Basically, presplitting involves a single row of holes drilled along the back perimeter of the area to be excavated. The holes are spaced and loaded to achieve a blasted plane of broken rock and a split, which forms along the length of the presplit line. The presplit line is shot in before the production cast blast is even drilled. When the production shot takes place, it should break back to the presplit line leaving a safe and well defined highwall.

PRESPLITTING - SPECIFIC DESIGN CONSIDERATIONS AT UCM

We have tried many different combinations of hole spacing with varying amounts of powder. The best results, which we have achieved for our geology, will be discussed.

Drill spacing in our frozen ground is 15 feet on centers, and these holes are drilled at a 20 degree angle from the vertical. We use 18 feet spacing in our unfrozen material and these holes are usually drilled at a 15 degree angle; the drilling angle is based on geotechnical considerations. Drill holes are drilled with a 10 5/8 inch diameter bit.

We have found that using air gaps, with 180 lbs. of explosives at the bottom of the hole and a 75 lb. charge placed half way up the hole, works best.

We have tried not stemming the hole and found that all the explosive gases vented out and poor presplitting was accomplished. By using 16 ft. of stemming from our drill cutting, we get our best results. This appears to be proper confinement of the explosive gases, in that the gases can readily split to the adjacent hole rather than blow out the stemming.

Note that 180 lbs. of explosives in a 10 5/8 inch diameter hole only takes us a few feet of bore hole; the remainder of the drill hole is filled with air. The upper charge and the stemming are held in place by an inflated air bag. This is technically called air gap presplitting. Presplitting is thought to be a combination of the explosive's shock energy and the explosive's gas energy working together. As adjacent holes shoot, the shock waves start the cracking, but it is believed that the gas pressure from the explosives over come the compressive strength of the rock causing a split to occur along the path of least resistance, which should be the adjacent hole.

It works best to drill and shoot the presplit holes before the production portion of the shot is even drilled. This way, the presplit gases are not tempted to split in the undesired direction of the production shot.

Another observation that we have noted, which gives better results, is to not use delays between or in the presplit line. Wider cracks appear, hole to hole, when all are fired at the same time. It seems logical to visualize the gases from each hole going half the distance and meeting with the gases from the adjacent holes on both sides. When delays are used, the gases are expected to split all the way to the next hole, one after the other, which makes it easier for the powder to blow out the stemming. Also, by not using delays in a presplit shot, you minimize the cap scatter that is associated with m/s delays.

Presplitting is considered by many to be too costly and therefore not worth the effort. I'd challenge that. It can be economical when you consider what the presplitting adds to the production blast. The zone between the presplit line and the last row of production blast hole is added material that contributes in the total volume being blasted. It is also important to remember that we are dealing with highwalls that often exceed several hundred feet in height, and it's the rock fall from these highwalls that is the number one cause of fatal accidents in open pit mining. Presplitting will produce the safest highwalls possible.

CAST BLASTING - SPECIFIC DESIGN CONSIDERATIONS AT UCM

The first consideration that usually comes to mind when cast blasting is how much powder should be used. The amount of explosive will depend on rock type, but a typical powder factor range for cast blasting is 1.0 to 1.7 lb./cubic yard. By only looking at powder factors you do not consider the strength in a given explosive. A better measure is using energy factors. For example, when heavy ANFO is used in a mixture of 35% emulsion to 65% ANFO, you will have about 40% more energy by volume than straight ANFO. At UCM we use an energy factor of 470 Kcal/cubic yard. When casting it is also important to remember that the primary goal is to blast the rock across the pit; our secondary goal is to fragment the remaining rock that must be handled by equipment. It has been observed on high speed camera, that only the first three rows really cast rock; the remaining rows start to stack up. This suggests that we should use a high heaving explosive on the outside rows, and a high shock energy explosive capable of good fragmentation on the inner rows. ANFO happens to be a very good heaving explosive, but due to its light relative density a lot of extra drilling is needed to obtain the same energy factors. Due to limited angle drilling capability at UCM, we have compromised by using a higher shock energy explosive in order to spread out our drill patterns. In our front rows, we use a higher energy factor and decrease it towards the back rows near the presplit line.

At UCM we have found that midhole priming is giving us advantages over top or bottom priming. We think that having the powder column initiate from the middle of the hole helps the highwall face achieve maximum flex before the explosive gases have a chance to vent. This appears to help the middle of the highwall blow out first and then the top and bottom of the highwall is dragged along with it. Another slight advantage of midhole priming is that the powder column is completely initiated in half the time that it takes compared to top or bottom priming. This may allow the explosive gases to produce a better cast.

We use a 10 5/8 inch drill bit and drill at a 15 to 30 degree angle from vertical depending on the highwall geotechnical considerations. It becomes impractical to bulk load an angle hole greater than 30 degrees because the explosive will not slide down the drill hole. Our main drill is a Driltech D60K, which is capable of drilling up to a 30 degree angle hole. However, beyond 20 degrees there is a substantial decrease in drilling rate.

A staggered drill pattern has proven to be superior over a square pattern. The number of rows will vary from 5 to 7 depending on the overburden depth. In the front row we reduce the burden to 2/3 of the normal burden in order to assure that the toe of the highwall is displaced. If the toe of the cast blast does not move, then there is real trouble. Instead of the explosive energy casting the rock across the pit, it sends the energy wave in the wrong direction, causing it to crash through the presplit line and making a mess of the highwall. If there is a golden rule for cast blasting it is, "Thou shalt make sure that the toe in row one is sent flying across the pit!" The burden and spacing are adjusted to maintain the desired energy factor. We use a spacing to burden ratio of at least two. The geometry of the burden and spacing is important and will vary with your material.

It is crucial not to blast into our coal; we have found that we need to keep the bottom of our drill holes 10 to 15 feet above the hanging wall. In doing so, we have been able to properly fragment our overburden while leaving our coal seams virtually untouched.

Stemming is also a very important parameter in cast blasting. It is better to use a little too much stemming than not enough. If there isn't enough stemming the cast will tend to shoot up instead of out, which will result in a low casting percentage. In order to minimize pad preparation after the cast blast, we intentionally try to shoot in a flat blasted profile. This is done by varying the amount of stemming from row to row. We use 18 feet of stemming in the front row and increase it to 22 feet in the back row.

Timing is the key between a good and bad cast. We are still trying to optimize our timing sequence. The goal is to get the rock masses working together by taking advantage of inertia. If the timing is too slow between rows, energy will be lost as the first row is trying to break away (in tension) from the second row. If the timing is too fast, energy will be lost when the back row shoots into the front row before it has proper time to move. When the timing is just right the rock mass moves across the pit in perfect harmony. For a rough rule of thumb on time delays, from row to row, start out with 5 m/s per burden foot between rows one and two, and increase it up to 10 m/s per burden foot between the last two rows. At UCM, we generally have 130 m/s between rows one and two, and increase it to 200 m/s between the final back rows. Scaled distance laws will determine the number of holes you can shoot in an 8 m/s period. At UCM, we put a 9 m/s delay between each hole and each drill hole has a 350 m/s in-hole delay to prevent cutoffs.

CONCLUSION

At UCM we have been able to accomplish an effective cast blasting and presplitting program, which has proven to be a cost effective way to move material. When all the blasting parameters are correct and working together we achieve very satisfying results.

LONG-TERM REVEGETATION AT USIBELLI COAL MINE

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INTRODUCTION

Usibelli Coal Mine began reclaiming land in 1972, five years before it was required by the Surface Mining Control and Reclamation Act of 1977 (SMCRA). Every year since they have reclaimed land disturbed by themselves or prior mine operators. During the summers of 1985 and 1989 selected reclamation areas were surveyed to determine what has happened over time on several sites.

The short-term goal of Usibelli's reclamation is to stabilize the site while the long-term goal is the reestablishment of local species. The short-term stability goal is addressed by seeding with grass and legume seed mixes and fertilizing. Results of various grass trials in the early 1980's at Usibelli were reported by Mitchell (1987). Local woody species are being reestablished by transplanting of young plants from native vegetation (Jackson 1987) or by depending on natural seed dispersal. This study was intended to identify what species of the original seeded species survived, what local species were colonizing these sites, and what site characteristics were associated with these successes.

Some of the original seed mixes contained over 20 plant species until it could be learned what species would grow in the area. The major species included red fescues (Festuca rubra), other fescues (Festuca spp.), two bluegrasses (Poa spp.), Manchar smooth bromegrass (Bromus inermis), meadow foxtail (Alopecuris pratense), reed canarygrass (Phalaris arund inacea), timothy (Phleum pratense), crested wheatgrass (Agropyron cristatum), annual and perennial ryegrasses (Lolium spp.), alfalfas (Medicago spp.), clovers (Trifolium spp.), other legumes, and canola (Brassica campestris). The yellow-flowered canola is used as a marker to detect stripping in the aerial seeding. Over 45 cultivars of these species have been used at one time or another between 1972 and 1989. Reclamation at Usibelli Coal Mine preceded the release of most cultivars developed from Alaskan collections that are used in reclamation today.

It precedes much of the other reclamation work that has been performed in Alaska. Only a few of the original species in the seed mixes survived very long-red fescue, brome, foxtail, Kentucky bluegrass (Poa pratensis), and some alfalfa. The original reclamation work performed at Usibelli Coal Mine not only has helped Usibelli improve their reclamation but has provided background work for many other reclamation projects.

SITE DESCRIPTION

Usibelli Coal Mine is located near Healy, Alaska, and mine sites occupy the Healy Creek and Hoseanna Creek Valleys. Much of the parent material in the area consists of sandstones and gravels. Streams in the area are actively downcutting, which has resulted in unstable slopes. Reclamation in the area must stabilize slopes that nature has not yet stabilized . The area is windy and can be hot and dry, especially early in the growing season. Summer precipitation may include thunder showers and heavy downpours which result in gullies where slopes are not adequately protected by vegetative cover.

PROCESS

Reclamation takes place as soon as a pit is mined (Jackson 1987). The pit is backfilled, regraded, and aerially seeded and fertilized. Aerial seeding reduces compaction by heavy equipment on the site and facilitates seeding large areas in rough terrain. Many sites are furrowed across the slope to reduce runoff and soil erosion. Tracks of heavy machinery may also increase moisture catchment and increase seed germination and plant establishment (Jackson 1987). Another technique used in the past was to terrace the slopes, which resulted in more moisture at the base of the slope. This created wetter sites, which formed the habitat for species that would not be able to colonize drier sites.

Young individuals of woody plants such as alder (Alnus sinuata) and white spruce (Picea glauca) were obtained from nearby native vegetation and transplanted with their root ball to the reclaimed site. By transferring the soil with the plant, the workers were able to keep the soil microorganisms that help in nutrient absorption. Associated plants frequently came with the target plant. In recent years this program has been expanded to include paper birch (Betula papyrifera) seedlings. Unrooted cuttings and fresh catkins with seeds of willows such as feltleaf (Salix alaxensis) and others have been placed around ponds and other moist sites . The deeper root systems of woody plants help hold the soil in place like rebar while grasses and colonizing mosses stabilize the surface soils. Both grasses and woody plants are needed for stabilization.

RESULTS

Vegetative cover may be variable during the seeding year depending on rainfall and temperatures while plants are becoming established. In good moisture years, initial establishment may be lush in areas. During dry years with grasshoppers, some areas have had to be reseeded. Yellow flowers of canola dominate the seeded area during the establishment year, but this annual plant does not reseed itself. The second year may have a flush of growth, which is partly dependent on the initial fertilizer applications. After that living grass cover may decline, which permits increased native colonization. Litter and roots are still present from the initial flush of growth to bind the soil. The original seeded cover may lose much vigor, but native colonization becomes more noticeable during years 5 through 9 depending on site conditions and distance to native vegetation. Where the surface has been furrowed, better grass growth occurs in the troughs where the moisture is greater. Native colonization may occur either on the ridges of the furrows where there is less competition or it may occur in the troughs where moisture is better.

Some of the study areas included sites at Gold Run Pass dating back to the late 1970's. The Gold Run Pass area is near tree line, and nearby vegetation is dominated by glandular birch (Betula glandulosa) and ericaceous shrubs such as bog blueberry (Vaccinium uligi nosum) and Labrador tea (Ledum groenlandicum) as well as grasses and sedges. Over 30 native plant colonizing species have been identified in the Gold Run Pass area, including 25 on one site alone. Several of these have flowered and set fruit, an important step in establishing a self-sustaining community. Some of these are species associated with organic soils, but are colonizing these mineral soils; Labrador tea and bog blueberry. Several species of willow have been found, including some with catkins. Seedlings of four species of trees have been found including paper birch, balsam poplar (Populus balsamifera), aspen (Populus tremuloides), and white spruce. This is particularly interesting since none of the broadleaf trees (birch, poplar, aspen) occur in native vegetation above these sites. The seeds apparently are lofted from lower elevations by winds under particular weather conditions or carried by animals.

Many species of mosses usually associated with various successional stages have been found in the Gold Run Pass as well as other areas. The rhizoids (root-like structures) of mosses help stabilize surface soils. This binding is so strong that when mosses are dug up, a substantial amount of soil clings to the rhizoids.

These smaller plants colonize some of the sites where the grass cover is beginning to deteriorate. However, other plants may colonize the sites with tall, dense grass cover near the active areas on Poker Flats. Alder is found in many moist areas. Raspberry (Rubu s idaeus) and wild rhubarb (Polygonum alaskanum) are colonizing amidst tall grass cover on slopes at Poker Flats at a lower elevation than Gold Run Pass. The wild rhubarb has become particularly vigorous on many portions of the outslope.

A gravel cut on an access road to the Poker Flats area illustrated the effect of aspect on native plant species colonization. This was seeded with a grass mix in 1977 and young white spruce individuals from nearby native vegetation were transplanted at the same time. The site consisted of north- and south-facing slopes. Twelve years after planting the two slopes had dramatic differences in cover and species composition. The north-facing slope was covered with alder with some white spruce and Labrador tea. Labrador tea was present in nearby vegetation, but the adjacent vegetation was dominated by glandular birch, paper birch, and white spruce. Although Labrador tea usually occurs in relatively undisturbed communities, it can colonize recent disturbances as indicated by vegetation in this gravel cut and sites in Gold Run Pass.

The south-facing slope of the gravel cut was very open after 12 years with very little evidence of the initial grasses. Some white spruce transplants were still growing. Although other spruce had died, several of the native species that came in with the transplants were alive and expanding. These included lowbush cranberry (Vaccinium vitis-idaea), bearberry (Arctostaphylos spp.), Labrador tea, and the lichen, Stereocaulon paschale.

Not only has the aspect affected the native colonizers, it has affected the seeded species success. Different grass communities developed on different slopes and substrate s on a dump in the Poker Flats area, even though all sites were seeded with the same seed mix. Depending upon where mining is occurring, some of the overburden is sandstone while some is gravel, thus creating different growth media. Approximately five years after the site was first seeded, the south-facing slope on sandstone had somewhat open vegetation dominated by Manchar brome but Arctared red fescue, meadow foxtail, and Nugget Kentucky bluegrass were present. The north-facing slope on sandstone had very dense cover but was dominated by foxtail with some brome and red fescue. Both the south- and north-facing slopes on gravel were dominated by red fescue. Foxtail was not observed on the gravel substrate.

Some of the oldest and harshest sites occurred at Vitro in Healy Valley. Hot , dry winds blow off the Alaska Range during the summer. Not only do these winds make it difficult for plants to become established, but the loose sandy soil is eroded wherever grass cover is not protecting the soil. University research plots that had been seeded and fertilized in 1981 and half fertilized again in 1984 had been pictured in Figure 3 of Mitchell (1987). These plots were revisited in 1989. The once-fertilized portion was barely visible while the twice-fertilized portion had substantially more cover, although much of it had low vigor. This points out the need to use fertilizer to help grasses become established.

Not far from Vitro, but also in the Healy Valley, is one of the first reclamation projects by Usibelli Coal Mine. Portions of the site are barely discernible from the surrounding native vegetation 17 years after reclamation. Permafrost material had been pushed over the north-facing side of a slope in 1972 and the area seeded. Hence good moisture and seed source were present. Little evidence of grass remained on the slope 17 years later, although it was seeded like other areas. However, the seeded area could be distinguished at the base of the slope, but feltleaf willow was colonizing the site and was large enough to serve as moose browse. Grass seedings provide opportunities for wildlife diversity in an area dominated by woody vegetation, either forests or shrublands. The grasses provide extensive cover for voles, which can be food for raptors. Hence grass seeding may increase the raptors in an area (Elliott 1984). Ptarmigan and caribou are frequently seen in the Gold Run Pass area, moose are seen in the Poker Flats area, and bears and moose have been observed near the active mining.

Although grasses are the most visible part of reclamation in the short term at Usibelli Coal Mine, many native species are colonizing the area in the long term and the older sites are becoming more similar to native vegetation.

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HEALY COAL - AN ELECTRIC UTILITY PERSPECTIVE

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INTRODUCTION

This paper describes how Healy coal's physical and chemical characteristics influence the operation of a coal-fired power generating station. Golden Valley Electric Association (GVEA) operates Healy Unit #1, a 25 MW mine-mouth power plant. It consumes 160,000 tons of Healy coal each year generating electricity for interior Alaska. A 50 MW plant addition, the Healy Clean Coal Project (HCCP), is being designed now with anticipated operation by 1996. The Healy plant's existing coal handling system must be upgraded to serve both plants, and the new system will incorporate equipment changes to minimize past coal handling problems. Studies on Healy coal flowability were performed to optimize storage bunker design.

Healy Unit #1 has a boiler fueled with pulverized coal. GVEA installed a baghouse in 1979 to reduce the boiler's particulate emissions. Recent stack testing revealed relatively low emission rates of sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulates (TSP). In fact, there is evidence that some of the SO_2 is being absorbed by the coal ash.

Healy fly ash characteristics and marketing potential are also discussed in the paper. Today electric utilities are developing markets for fly ash to reduce its disposal cost. Fly ash is used throughout the world as a cement additive and in road foundations. Alaska is beginning to realize its potential uses. The recently completed Bradley Lake Hydro project used Healy fly ash as a pozzolan to reduce cement requirements. GVEA is also cooperating with the University of Alaska and the Alaska Department of Transportation to establish its value as a road sub-base material.

HEALY PLANT COAL HANDLING SYSTEM

GVEA's Healy #1 plant receives mine run coal from the Usibelli Coal Mine (UCM). Coal is delivered daily in 95 ton Dresser Model 325M HaulPak trucks and unloaded near the plant's coal crusher intake hopper. Figure 1 shows a diagram of the existing system.

A John Deere 850B dozer is used to spread, contour the coal pile, and push mine run coal into the intake hopper. This hopper has a slotted beam-bar sloped grizzly with six inch openings. Vibrating pan feeders at the base of the hopper feed the coal to the coal crushers. Jeffrey model 45FT crushers reduce the coal size to 3/4" minus and discharge it onto belt conveyor #1. This conveyor is 24 inches wide, equipped with 20 degree idlers, and is inclined at 14 degrees from horizontal. It spans a distance of over 415 feet to climb a height of 100 feet. The coal is discharged through chute work to the plant's storage bunker #1A or onto conveyor #2, an inclined belt, to feed into storage bunker #1B.

Each bunker has a design capacity of 195 tons. However, actual working capacity is only about 160 tons each, due to the coal's sloped cone at the top (each bunker has a single fill point). A Galigher coal sampling system is located between belt conveyors #1 and #2. The design capacity for the existing coal handling system is 200 tons/hour with both crushers operating. Only one crusher is normally operating with the other crusher as spare. The present coal handling system capacity is operated near 125 tons/hour, and Unit #1 burns 500 tons of coal daily. The plant bunkers can be filled within a 4 hour period. This schedule allows the coal crew sufficient time to perform routine maintenance and cleanup during a single work shift.

COAL HANDLING PROBLEMS

The existing coal handling system encounters operating problems primarily due to large chunks of mine run coal, the coal's high moisture content, and arctic weather conditions.

Mine run coal is delivered to the plant uncrushed and normally ranges in sizes from 36 inches to fines. The larger coal chunks are either broken up by the dozer or set aside to weather and break up into smaller pieces on their own. This sorting process is time consuming for the coal operator and increases the coal loading time. The large chunks that do pass through the grizzly will slow the crusher's output; since they operate best crushing 4 inch coal to 3/4" minus. Tramp iron from mine equipment and large rocks can also cause problems.

They can jam inside the crusher and cause internal damage, requiring downtime for repairs. This problem does not occur very often, but it is worth mentioning because of its impact on the coal handling equipment.

Healy's ambient temperatures range between +85 °F in the summer to -60 °F in the winter. Arctic sub-zero temperatures create severe operating conditions for the coal handling system. The coal's moisture content aggravates system operation, when the coal sticks and freezes to cold metal surfaces. Summer rains and winter snow storms also increase the coal's surface moisture. Snow falls in this area are usually followed by wind, which will drive the snow into the coal pile and create snow drifts in the storage yard.

The existing reclaim hopper has shallow angles; so the coal often freezes and sticks to the corners and sides of the cold steel hopper wall and then decreases flow to the crushers. This condition also occurs on the crusher's discharge chutes. The coal bridges across the hopper or crusher outlet unless it is manually removed, which can be time consuming and hard work. During snow, cold and wet coal conditions, the coal can bridge over in less than an hour of operating time. This coal flow problem seriously impacts the operating capacity and reliability of the entire coal handling system.

Coal flow is also a problem in the boiler's storage bunkers. The crushed coal freezes together inside the bunker, and then bridges across the bunker outlets. Coal also freezes to the metal walls of the bunker, hindering its flow downward though the bunker's discharge outlet. Vibrating thumpers are mounted on the walls of the bunker to keep the frozen coal flowing. These vibrators help to a degree; but they also tend to pack the coal tighter and increase the

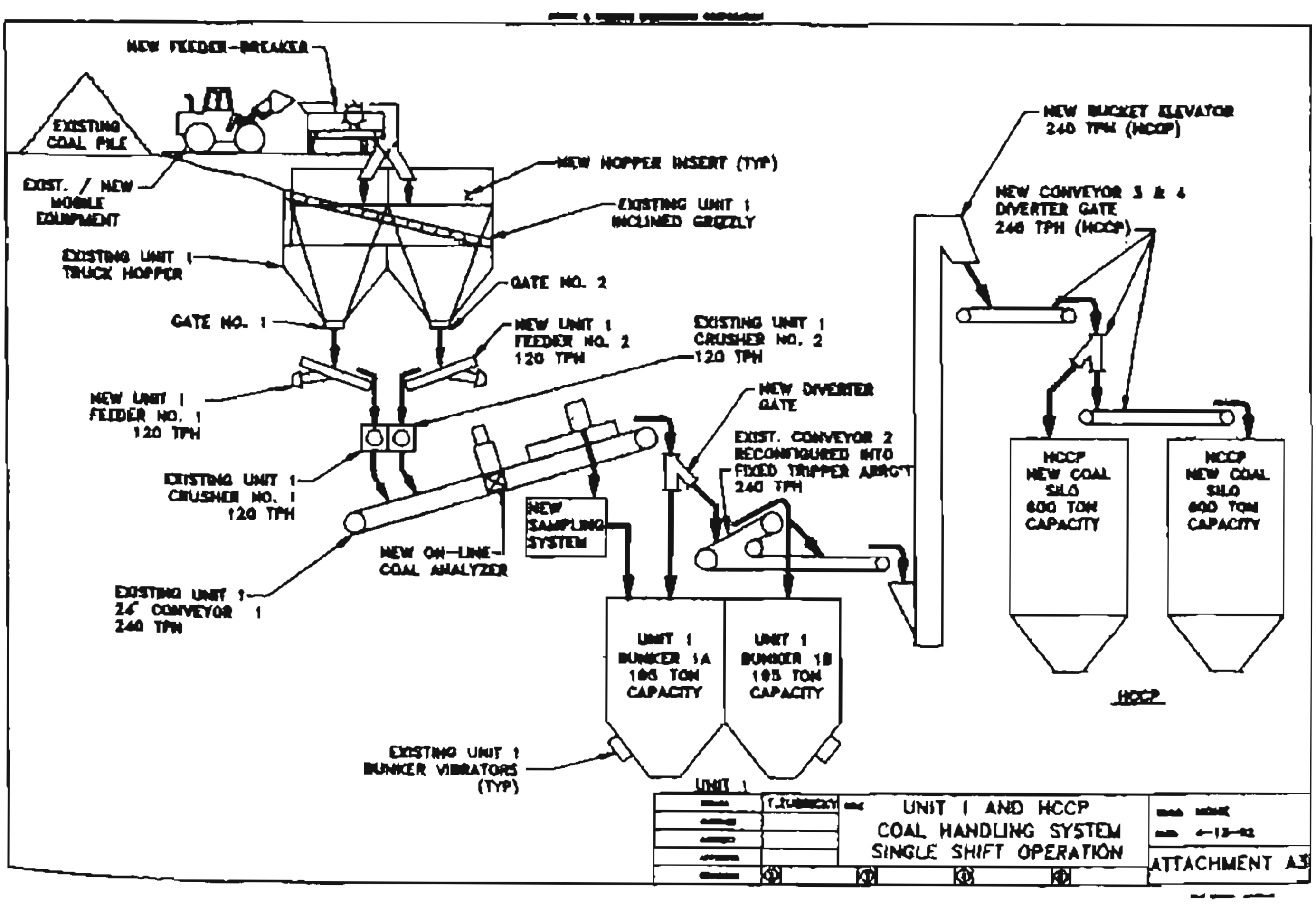

FIGURE 1
Diagram of Existing Healy Plant Coal Handling System

problem. Eventually, the coal must be manually dislodged by inserting steel rods and air lances through poke holes near the bunker's outlet. This work is physically demanding and requires quick action by the crew before the boiler runs out of coal.

PLANNED COAL HANDLING IMPROVEMENTS

The HCCP plant addition provides an opportunity to improve the existing coal handling system and minimize future coal handling problems. HCCP and Healy #1 will consume 1,800 tons/day of coal compared to Healy #1's 500 tons/day. The most cost effective system would utilize as much of the existing facilities as possible.

Stone & Webster Engineering Company (SWEC) began their investigation by defining the available capacity of the Healy #1 bunkers and HCCP coal silos. Healy #1's bunkers can hold approximately 320 tons of coal, which is enough to operate the boiler for about 15 hours at a burn rate of 21 tons/hour. The Healy #1 bunkers must be filled at the beginning of the day shift (8 AM) and then topped off by the end of the shift (6 PM) to keep the plant operating continuously overnight. HCCP's silos are being designed to store up to 22 hours of coal for its boiler; so they will only need to be filled once each day. To fill all the coal silos and bunkers in a single 10 hour shift, SWEC determined that the new conveying system would operate 9.25 hours per day. The mode of operation required double filling of the existing Healy #1 bunkers and a single filling of HCCP's coal silos. At the maximum combined coal burning rate of 75 tons/hour, a minimum conveying rate of 240 tons/hour would be required:

Coal Burned Daily: 75 tons/hr x 24 hrs/day = 1,800 tons

Coal Conveying Time: 1,800 tons / 240 tons/hr	
	= 7.50 hours
Startup/Shutdown/Cleanup	= 1.75 hours
Total Daily Coal Handling Time	9.25 hours

Major equipment maintenance could be performed after hours.

SWEC then reviewed the drawings and obtained field information on the Healy #1's existing equipment. They recommended the following modifications and component replacements to achieve the 240 tons/hour coal handling capacity:

* Install Pre-Crusher: Install a primary stage crusher in the coal yard to reduce the mine run coal to 4 inch before entering the existing crushers. This equipment addition could increase the existing crusher capacity from 150 ton/hour to 240 ton/hour. At present, the crushers are the bottleneck because too much size reduction is required. Field tests confirmed that presizing the coal could increase existing crusher capacity to at least 217 tons/hour. UCM is providing a Stamler feeder breaker as the primary crusher.

* Mobile Equipment: Use a front end loader to transfer coal from the yard stockpile to the primary crusher. The existing dozer would be used to maintain the stockpile area, not move coal to the crushers.

* Modify Yard Hopper: The new primary crusher discharge would elevate the coal enough to raise the hopper and make its sides a steeper angle. This change would reduce the coal buildup problem.

* Variable Belt Feeders: The existing vibrating pan feeders are each rated at 100 tons/hour. Vibrating feeders are very susceptible to slugging of the coal flow and can even cause plugging in the crushers. SWEC recommended replacing them with variable speed belt feeders. These feeders have superior flow control compared to vibrating pan feeders. This control is critical, when operating coal belt conveyors near design capacity.

* Install Magnets: Magnets above the hopper belt feeders would catch the tramp iron before it enters and damages the coal crushers.

* Upgrade Crusher Motors and Drive: Continuous operation of the existing crushers at higher flow rates requires increasing the crusher motor size from 100 HP to 150 HP and upgrading the drive belts and sheaves.

* Upgrade Belt Conveyor: The existing conveyor belt is designed to handle 200 tons/hour. Good engineering practice requires limiting capacity to less than 95% of a belt's maximum rated loading to account for surges in flow, belt misalignment, etc. SWEC's computer modeling identified three possible upgrades for conveyor #1 (see Table 1). Case #2 was selected as the best choice. It requires upgrading the conveyor belt strength, increasing the conveyor drive motor horsepower, increasing the gravity takeup counter weight, and increasing the angle of the existing 20°

TABLE 1
Healy Conveyor Belt Upgrade Options

Design Case	Base	#1	#2	#3
Troughing Angle (degrees)	20	20	35	35
Idler Diameter (inches)	5	5	5	5
Belt Speed (ft/min)	450	550	450	500
Length (feet)	416	416	416	416
Lift (feet)	100	100	100	100
Minimum Operating Temp. (°F)	30	30	30	30
Max. Capacity @100% (ton/hr)	216	264	274	305
Design Capacity @ 93% (ton/hr)	200	245	255	284
Brake Horsepower (100% load)	44	55	55	62
Motor Horsepower	50	75	75	75
Tight Side Tension T1 (lbs)	4566	4670	5780	5842
Slack Side Tension T2 (lbs)	1522	1557	1926	1947
Size of Gravity Takeup (lbs)	3044	3113	3853	3895

Note: Above design calculations based on Conveyor Equipment Manufacturers Association (CEMA) standards.

troughing idlers to 35°.

* Modify Galigher Coal Sampler: The existing sampler's cutter hopper outlet needs to be increased to allow 240 tons/hour flow rate.

* Install TIVAR Liners: Slick TIVAR liners on the metal walls of the crusher hopper, crusher discharge chute, and Galigher sampler chute would minimize the buildup of wet and frozen coal.

* Install Dust Suppression System: Dust control will be installed to capture coal dust at each transfer point. Baghouses at the crusher building and HCCP storage silo area will remove the coal dust from the ventilation system.

Figure 2 shows the proposed coal handling system for both plants. The system modification package was awarded to Mid-West Conveying Company. They have been released for engineering and detailed design; fabrication and installation of the new system will begin once all of the necessary permits are received for HCCP. The above changes can be accomplished in stages to minimize Healy Unit #1's downtime.

In an effort to minimize future coal flow problems, SWEC studied Healy coal's flow properties to optimize HCCP's coal silo design. Jenike & Johanson, material handling specialists, performed tests to determine silo discharge dimensions necessary to maintain flow. Wall friction angles were determined on different wall materials. The test results are shown below for a 3 ft. opening using stainless steel wall material and using a TIVAR coating:

Wall Material	Hopper Angle (max)
304 #2B finish stainless steel	19° to 23°
TIVAR-88	27° to 34°

TIVAR (an ultrahigh molecular weight polyethylene) allows the hopper to be 10 degrees less steep and still achieve mass flow. Its use also increases the silo's storage capacity without increasing height or outside dimension. The HCCP silos will have a 1/2" TIVAR liner on their discharge cone. This thickness is expected to have a ten year wear life. Its use should improve coal flow, and the large 3 ft. outlet should eliminate coal bridging problems experienced in Healy #1.

HEALY BOILER EXHAUST EMISSIONS

GVEA performed emissions source testing on Healy #1 boiler in 1990. It was required by the Alaska Department of Environmental Conservation as a condition of the plant's operating permit. The test measured the amounts of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates (TSP) exiting the stack. Test results verified that the boiler operates well within its permit:

Regulated Emissions (lbs/hour)

	Actual	Permitted
Particulate (TSP)	6	74
Sulfur Dioxide (SO_2)	76	199
Nitrogen Oxides (NO_x)	210	570

The baghouse on the boiler outlet is very efficient; it removes over 99% of the particulate before reaching the stack. Healy #1 does not have a scrubber to chemically remove SO_2 from the exhaust. All of the SO_2 gas produced inside the boiler is emitted, when the coal's sulfur oxidizes. Nitrogen oxides form in the high temperature zone of the flame. Healy #1's coal burners are the original equipment installed 25 years ago. Modern coal-fired boilers equipped with Low NO_x burners and sulfur scrubbers would have much lower SO_2 and NO_x emissions.

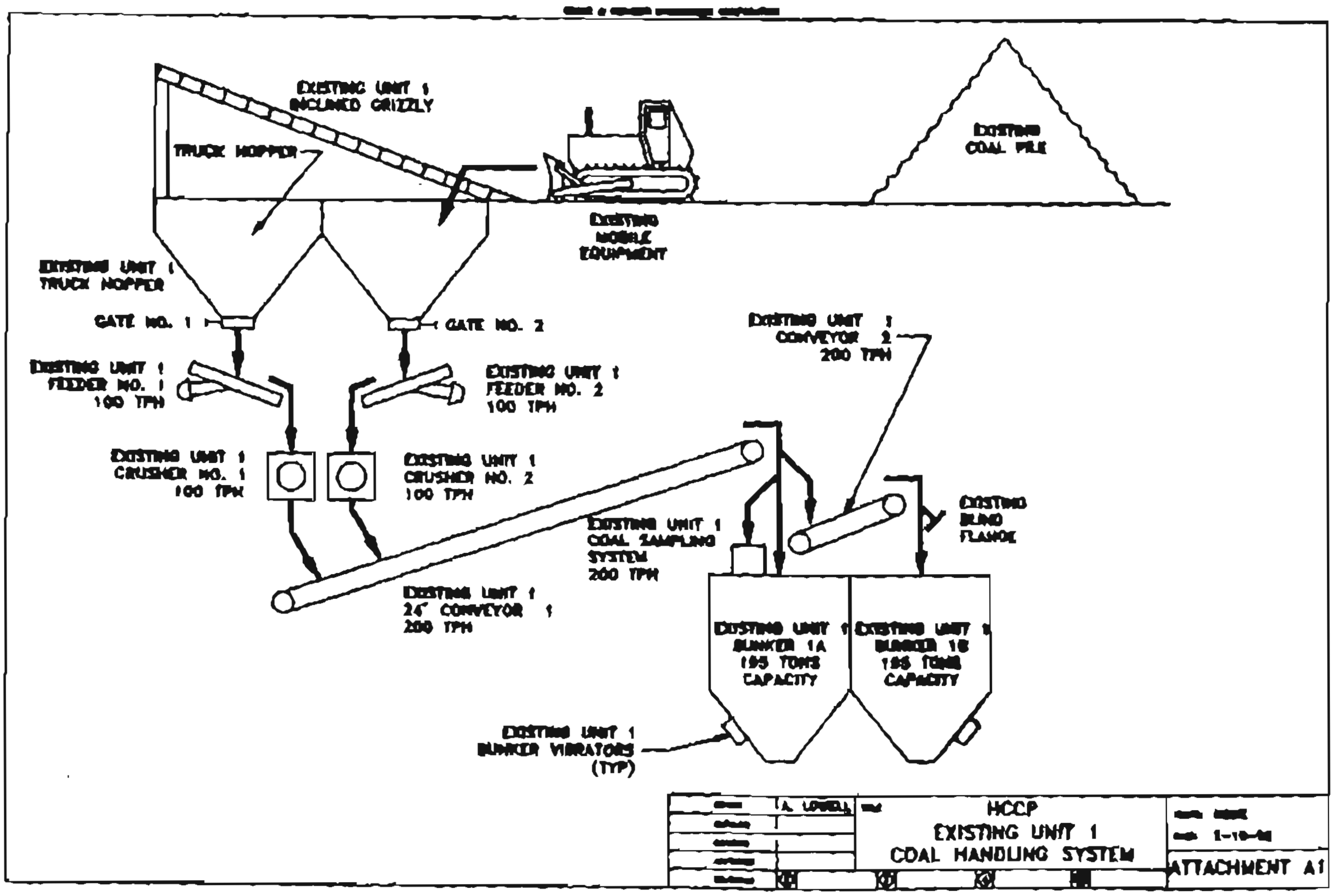

FIGURE 2
Diagram of Updated Healy Plant Coal Handling System

The emission source test results documented lower SO_2 emission rates in the stack than were expected. The SO_2 emissions should be directly related to the sulfur content of the coal. According to the test results, either the coal used during the test had a lower than normal sulfur content or sulfur compounds were retained somewhere inside the boiler. Healy coal has a very low sulfur content, ranging between 0.15% and 0.3% (as received). It also has a high percentage of calcium in its ash.

We suspected that the calcium rich flyash might be capturing some of the SO_2 gas as it passed through the dust covered filter bags in the baghouse. In August, 1992 a second source test was performed, and sufficient data was collected to construct a sulfur balance for the Healy #1 boiler. Emissions monitoring was performed by EMC Analytical, Inc. The coal and ash samples were analyzed by Hazen Research, Inc. SWEC prepared the test program and the final report. Table 2 shows the analysis of coal burned, Table 3 a typical fly ash analysis, and Figure 3 the actual and expected SO_2 emission levels during the tests.

A sulfur mass balance compared the coal's sulfur content to that found at the following boiler locations: a) SO_2 in the stack gas, b) sulfur products in the boiler bottom ash, and c) sulfur products in baghouse flyash. Table 4 summarizes this data.

The test verified that actual SO_2 emissions were less than expected. Only 91% of the available sulfur in the coal was emitted up the stack; the bottom ash and fly ash retained 9% of the sulfur. There was equal capture of the sulfur in the fly ash and bottom ash, indicating that the baghouse was not a major influence. Even though the calcium levels in the ash provides an alkali to sulfur molar ratio of 6 to 1, conditions needed to promote these reactions were not present.

FLY ASH UTILIZATION

Waste reduction and recycling are becoming priorities for electric utilities today. Even substances of seemingly little value can be candidates for recycling. For more than a decade, GVEA has promoted the use of fly ash as a resource in Alaska. In many other states, it is used as an aggregate to pave highways and airport runways, as an insulation in industrial buildings, and as an excellent concrete-like fill material for roadway foundation construction.

Healy #1 produces about 30 tons/day of fly ash. Pozzolanic, Inc. markets fly ash from plants in Alaska and the Northwest. They currently market Healy #1 fly ash as an industrial pozzolan; it has been approved by the U.S. Army Corps of Engineers as a qualified source of Class C structural grade fly ash. Table 5 shows its typical characteristics.

The University of Alaska Institute of Northern Engineering received a grant from the Alaska Science and Technology Foundation in 1990 to study fly ash. GVEA and the Alaska Department of Transportation are assisting the University by providing financial support, fly ash, and testing facilities. The project's objectives are to develop engineering criteria and design methodologies for utilizing Alaskan coal ash as a construction material. Their research will test fly ash as an admixture in concrete mixes to promote strength, durability and workability and as a source material that is stabilized with cement and used as a high strength, light-weight and insulating layer in roads. This research project should be completed this year.

Healy fly ash is beginning to gain acceptance as structural fill. Thousands of yards of Healy fly ash were mixed with concrete in the construction of Bradley Lake Hydro, which was recently built near Homer, Alaska. Pozzolanic, Inc. markets fly ash as a ready mixed flowable fill (RFF), which is a blend of cement, fly ash, sand and water. It is a low strength, flowable material requiring no subsequent vibration of tamping to fill excavations, such as backfilling sewer trenches, bridge abutments, building excavations, etc. RFF is a high density backfill and reduces costly maintenance of roadways due to settlement. It can also be re-excavated easily. Healy's fly ash is also being used on the North Slope oil field as a drill well cement.

SUMMARY

This paper has examined some the aspects of handling, burning, and ash disposal of Healy coal at GVEA's mine mouth power plant. Coal is plentiful in Alaska and the United States. It is competitively priced and can be purchased under stable, long term contracts. Healy coal has a very low sulfur content, so it requires less scrubbing to meet today's permitted SO_2 emission limits. However, coal-fired power plants are expensive to build today and require more labor and equipment for fuel processing and ash disposal. Material handling systems need to be designed efficiently to minimize

TABLE 2
Healy Coal Analysis (8/92)

Proximate (%)	As Received	Dry	Air Dry
Moisture	25.60	-	10.57
Ash	11.06	14.87	13.30
Volatile	34.72	46.67	41.74
Fixed Carbon	28.62	38.46	34.39
Total	100.00	100.00	100.00
Sulfur	0.22	0.30	0.27
Btu/lb	7,533	10,125	9,055
MMF Btu/lb	8,554	-	-
MAF Btu/lb	-	-	11,894
Air Dry Loss (%)	-	-	-
Ultimate (%)			
Moisture	25.60	-	10.57
Carbon	44.29	59.63	53.24
Hydrogen	3.49	4.69	4.20
Nitrogen	0.67	0.76	0.68
Sulfur	0.22	0.30	0.27
Ash	11.06	14.87	13.30
Oxygen	14.77	19.65	17.74
Total	100.00	100.00	100.00

TABLE 3
Healy Fly Ash Analysis (8/92)

Elemental Analysis of Ash (%)		Ash Viscosity Calculations	
SiO_2	53.14	Base Content (%)	26.84
Al_2O_3	14.16	Acid Content (%)	73.16
TiO_2	0.54	Dolomite Ratio	67.82
Fe_2O_3	6.28	Base/Acid Ratio	0.37
CaO	15.20	Silica/Alumina Ratio	3.75
MgO	1.68	T250 Temperature (°F)	2,448
NaO_2	0.51	Equivalent Silica Content (%)	69.65
K_2O	1.22	Ash Type	Lignite
P_2O_5	0.40		
SO_3	0.79		

operation and maintenance costs.

During the past twenty years, the United States has changed its position twice on fuel preference for electric utilities and industry, depending on global events. In the 1970's, it discouraged the use of oil, natural gas, and nuclear energy; coal was preferred. Then in the 1980's, it switched back to natural gas. Today, the utility industry burns coal to provide over 60% of U.S. electric energy demand. The Department of Energy's Clean Coal program should provide the technologies needed to make coal an acceptable fuel choice in the near future.

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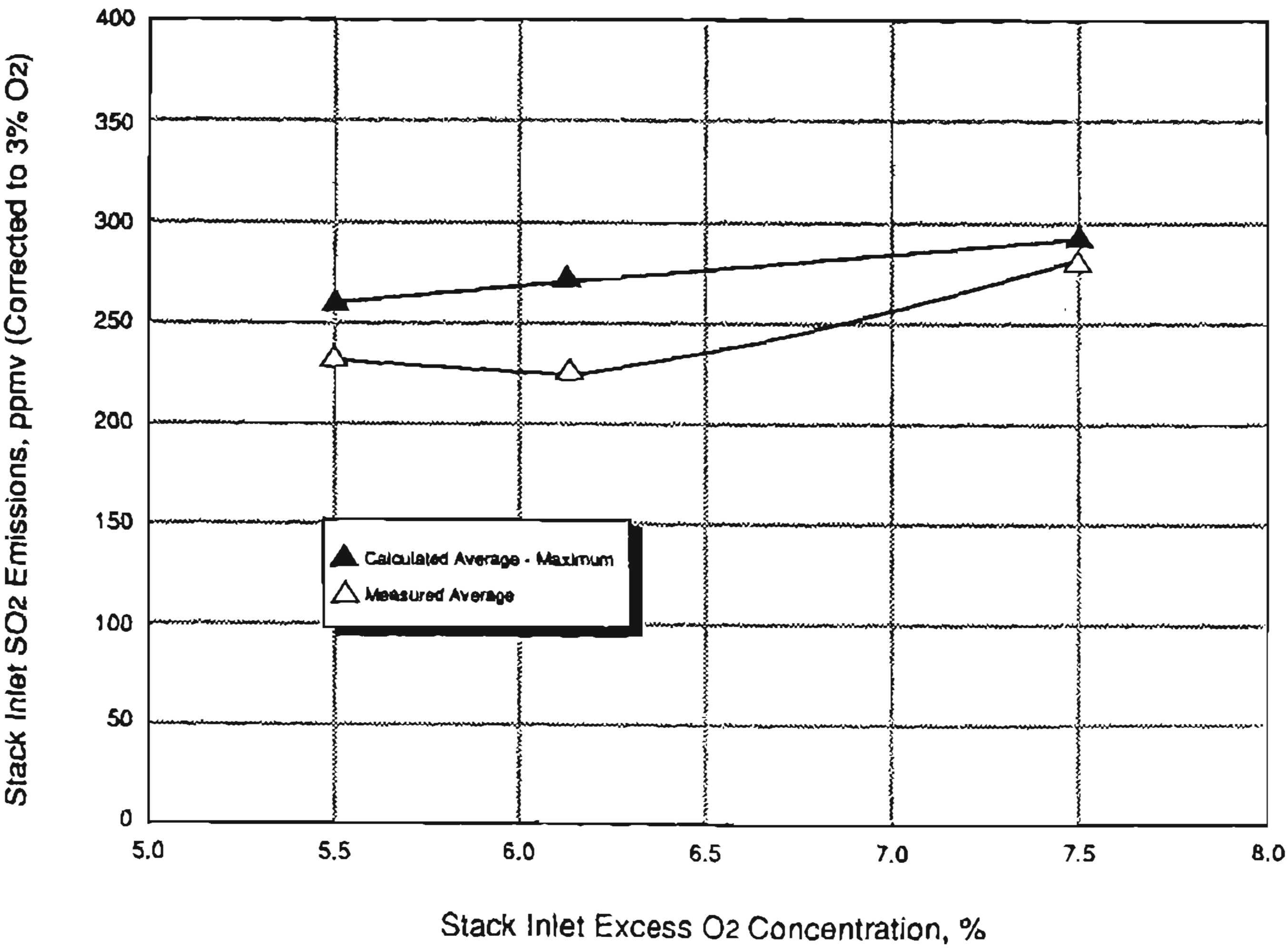

FIGURE 3
Healy #1 Boiler Sulfur Dioxide Emissions (8/92)

TABLE 4
Healy #1 Sulfur Balance (8/92)

Test #	#1	#2	#3	Average
Plant Load (MW)	25.1	25.0	24.8	25.0
Excess Air (%)	19.5	11.0	28.5	19.7
Sulfur In (Lb/Hr)				
- Coal Burned	77.52	73.15	80.00	76.89
Sulfur Out (Lb/Hr)				
- Stack Exhaust	70.69	72.48	85.14	76.10
- Baghouse Flyash	3.50	2.86	3.77	3.38
- Bottom Ash	3.25	4.33	4.55	4.04
Total	77.44	79.67	93.46	83.52
Sulfur Balance	100.2%	108.8%	116.7%	108.6%

TABLE 5
Healy #1 Fly Ash Pozzolan Characteristics

TEST PARAMETER	Healy #1 Fly Ash	ASTM C 618 Requirements Class F	Class C
Fineness: (max % retained on #25 sieve)	12.5	34	34
Pozzolanic Activity Index: (min % of control at 28 days)	108.8	75	75
Soundness: (max % expansion or contraction)	+.048	0.8	0.8
Chemical Composition:			
Silicon Dioxide SiO_2 (%)	38.12	-	-
Aluminum Oxide Al_2O_3 (%)	17.77	-	-
Iron Oxide Fe_2O_3 (%)	7.38	-	-
Total $SiO_2+Al_2O_3+Fe_2O_3$ (min %)	63.27	70	50
Sulfur Trioxide SO_3 (max %)	1.34	5.0	5.0
Moisture Content (max %)	0.08	3.0	3.0
Loss-on-Ignition (max %)	2.3	6.0	6.0
Specific Gravity	2.56	-	-

UTILIZATION TECHNOLOGY FOR THE HEALY CLEAN COAL PROJECT

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ABSTRACT

The Healy Clean Coal Project (HCCP) is a new 50 MWe nominal pulverized coal-fired power plant to be constructed near Healy, Alaska. Power plant technologies will include an entrained combustion system developed by TRW Applied Technologies Division in conjuction with an activated fly ash recycle flue gas desulfurization system developed by Joy Technologies Inc. The integration of these technologies is expected to result in significantly lower emissions of SO_2 and NO_X than previously achieved in conventional pulverized coal fired power plants. This paper will present a current description of the integrated technologies and status of the HCCP.

INTRODUCTION

In 1989, the Department of Energy (DOE) selected the Healy Clean Coal Project to participate in its Clean Coal Technology (CCT) Program. The CCT program is a government and industry co-funded technology development program aimed at demonstrating new and innovative coal utilization processes in a series of large scale showcase facilities. HCCP was selected for participation because the technologies being demonstrated have the potential to achieve significant reductions in emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X).

Key project participants include the DOE, providing about half the project funding, the Alaska Industrial Development and Export Authority, the plant owner, providing the remainder of the funding, and Golden Valley Electric Association, the plant operator. Usibelli Coal Mine will supply the coal. TRW Applied Technologies Division is the advanced coal combustion system developer. Joy Technologies is the advanced flue gas cleanup system developer. Stone and Webster Engineering Corporation prepared the proposal to the DOE and is providing project engineering and design services.

HCCP DEMONSTRATION GOALS

The primary goal of the HCCP is to demonstrate a new design featuring integration of an advanced combustion and heat recovery system coupled with both high and low temperature emission control processes. The HCCP technology suppliers believe the demonstration technology can achieve NO_X and SO_2 emission levels significantly below current New Source Performance Standards for new utility coal-fired units (Table 1). Control of these pollutants is expected to be achieved by integrating the TRW entrained slagging combustors with Joy Technologies' back end spray dryer absorber featuring a sorbent recycle system (Figure 1).

CONTROL OF OXIDES OF NITROGEN

To understand the NO_X reduction technologies being demonstrated it is important to understand the NO_X generation mechanisms.

Mechanisms of NO_X Formation

NO_X formed as a result of coal combustion is typically referred to as thermal NO_X, fuel NO_X, or prompt NO_X depending on the formation mechanism.

Thermal NO_X is produced when atmospheric nitrogen and oxygen combine at temperatures normally over 1700 degrees F. Production of thermal NO_X is an exponential function of flame temperature and a linear function of the time the combustion gas is at the flame temperature. The thermal NO_x mechanism follows the Zeldovich reactions:

(1) $N_2 + O \leftrightarrow NO + N$

(2) $N + O_2 \leftrightarrow NO + O$

(3) $N + OH \leftrightarrow NO + H$

At temperatures above about 3000 degrees F production of thermal NO_x becomes significant. The reverse reactions are not favored in the presence of molecular oxygen. In a typical combustion zone where excess air is present the NO formed is essentially fixed.

Fuel NO_x is produced by the oxidation of the chemically bound nitrogen present in the fuel. Significant factors governing this mechanism are the amounts of chemically bound nitrogen in the fuel and the degree the fuel is mixed with air in the early stages of combustion when fuel bound nitrogen is released. It is also governed by the amount of oxygen available during the combustion process.

Coal, when decomposed during combustion, releases fragments composed of hydrogen, carbon and

TABLE 1
HCCP Target Emission Levels

Pollutant	NSPS Limit	Proposed PSD Permit Limit	Target Emissions
NO_x	0.5 lb/MMBtu	0.35 lb/MMBtu	0.2 lb/MMBtu
SO_2	70% Removal	80% Removal	90% Removal
PM	0.03 lbs/MMBtu	0.02 lb/MMBtu	0.015 lb/MMBtu

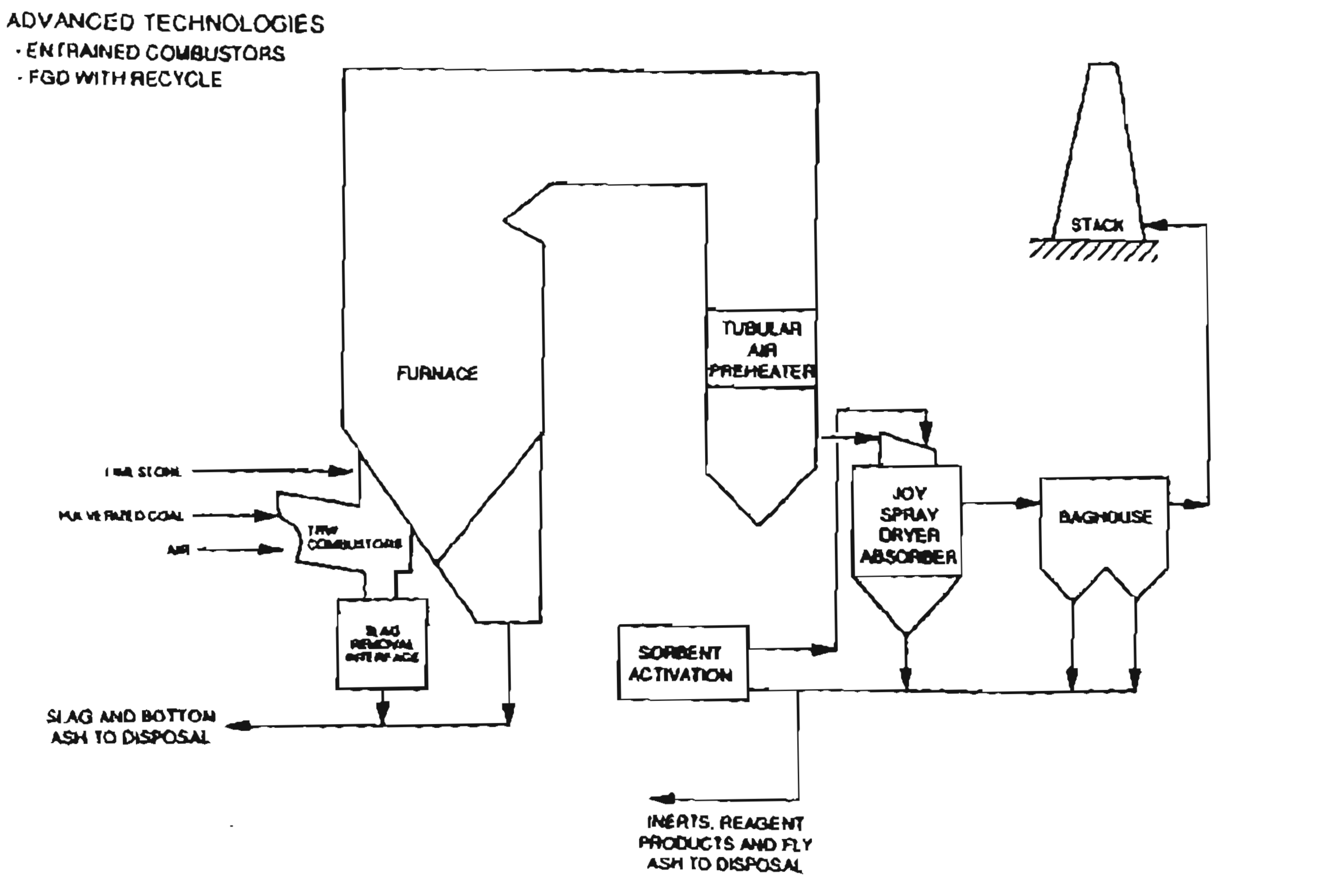

Figure 1: Process Flow Diagram

nitrogen substructures. In fuel rich combustion zones, gas phase nitrogen components react in several steps to various amine species: NH_i. Subsequent reaction of these amines is the most important aspect of NO_X control.

In a fuel rich environment where excess oxygen is scarce, the amines combine with NO or other amines in a reaction converting the fuel bound nitrogen to molecular nitrogen (N_2). In an excess air environment and with adequate mixing of fuel and oxygen, amines react with oxygen to form fuel NO_X.

Prompt NO_X is produced by the reaction of disassociated nitrogen, either from air or the fuel, combining with hydroxyl radicals from the fuel according to the mechanism proposed by Fenimore:

$$N + OH \leftrightarrow NO + H$$

A final set of reactions important in NO_X control are those leading to the destruction of NO. These reactions take place in a fuel rich environment and convert NO to other nitrogenous species.

Figure 2 excerpted from Song et al (1) summarizes five major reaction paths for fixed nitrogen formation and conversion in coal-air combustion.

To summarize, maintaining temperatures near or below 3000 degrees F during fuel-lean combustion or by operating under fuel rich conditions with little or no O_2 mitigates production of thermal NO_X. Fuel NO_X may also be reduced by burning coal under fuel rich conditions. Prompt NO_X is minimized by combustion in a fuel-lean atmosphere where hydroxyl radicals for the decomposition of the fuel are scarce. Finally, NO destruction to other nitrogenous species occurs in fuel rich environments.

HCCP Control Technology for NO_X

The TRW system uses a staged combustion process to establish environments unfavorable to the production of oxides of nitrogen. The process employs three main components including a precombustor stage, a main (slagging) combustor stage and a short slag recovery duct connecting the combined combustor stages to the boiler. Figure 3 shows the arrangement of the components.

Additional NO_X control takes place just downstream of the combustion system in the boiler furnace.

Precombustor Stage

The precombustor will burn approximately 20 - 50 percent of the total coal consumed by HCCP at substoichiometric conditions to boost the temperature of the combustion air supplied to the slagging combus-

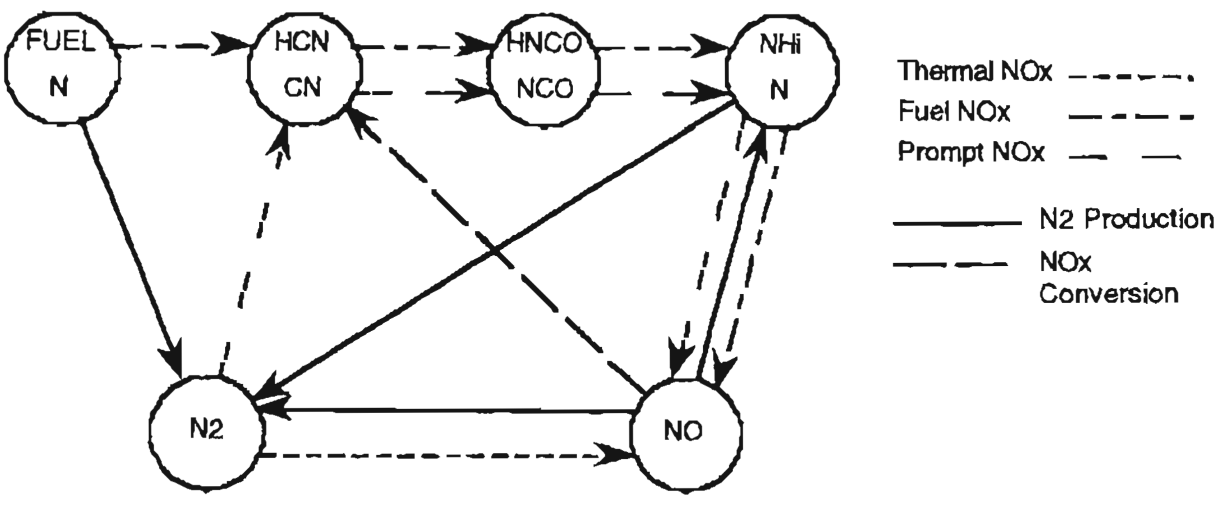

Figure 2: Reaction Paths For Fixed Nitrogen in Coal Combustion

tors well above the temperatures normally supplied by the combustion air heaters. The temperature of the air is increased to a value necessary to achieve optimum slagging performance of fuel in the main combustor stage.

Downstream of the burner, air is added in a mix annulus to produce a fuel-lean mixture of combustion products. This mixture is then ducted to the main (slagging) combustor stage.

TRW tests have measured very high NO_x levels in the combustion products stream. However, when additional fuel is combined with this combustion product stream in the main slagging combustor, a fuel-rich combustion environment conducive to NO_x destruction reactions is established. The resulting NO_x in the gas stream exiting the TRW combustion system to the furnace is negligible.

Main (Slagging) Combustor

The key component of the TRW Entrained Combustion system is the slagging combustor. It consists of a water-cooled cylinder with a tangential air inlet and a key slotted baffle located about two-thirds of the way down the combustors longitudinal axis. Preheated air enters the cylinder shaped main combustor tangentially imparting a swirling motion to the combustion products.

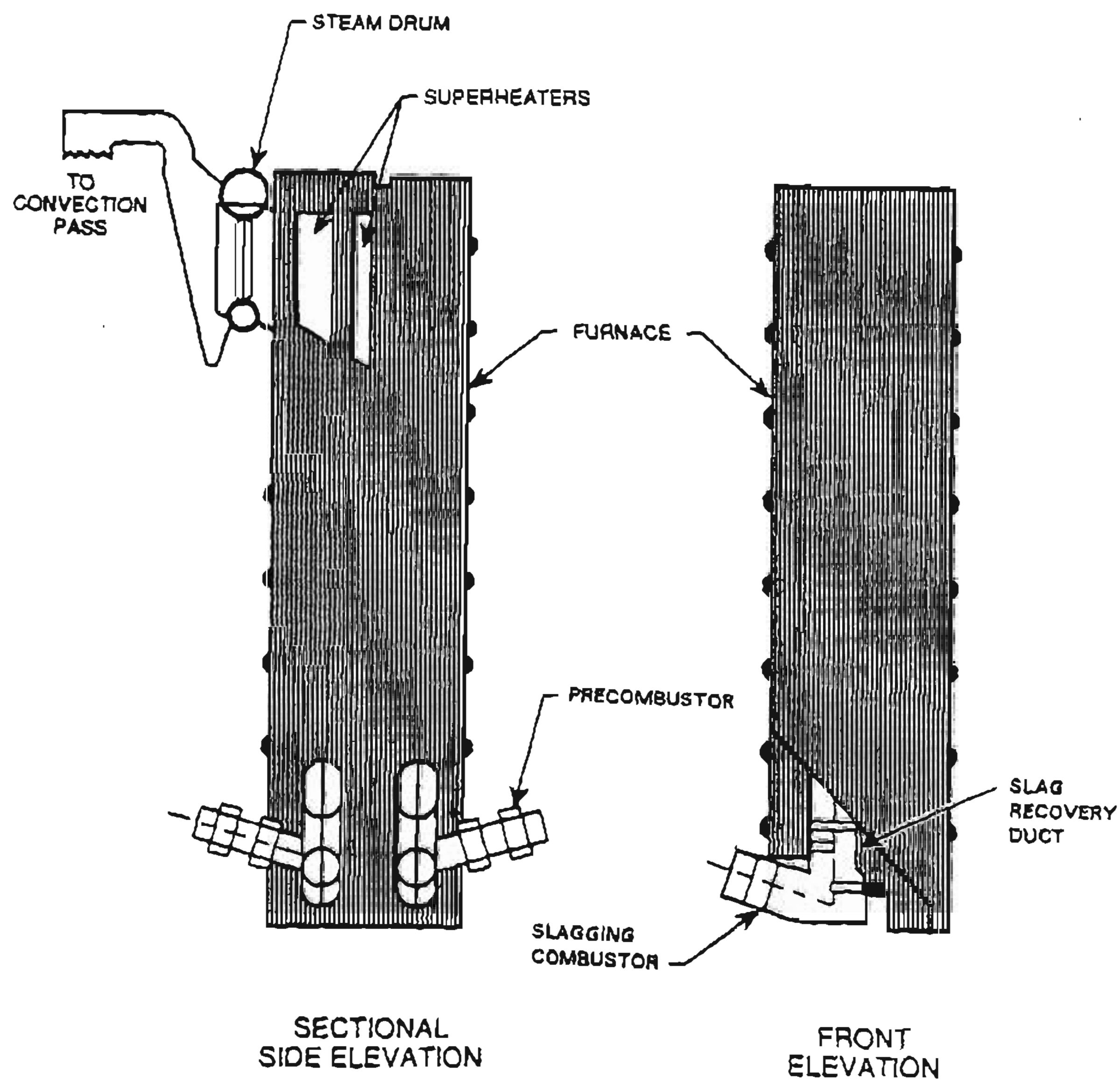

Figure 3: HCCP Boiler Arrangement and Entrained Combustor Installation

The portion of the pulverized coal not used in the precombustor stage is introduced axially through multiple ports into the main combustor stage where it is mixed with the preheated gas entering from the precombustion stage. Air inlet and baffle combination promotes efficient mixing/combustion reactions and internal slag flow patterns. The coal is burned at high temperatures and in a fuel-rich (substoichiometric) conditions.

Actual total air provided is nearly 90 percent of the theoretical air required for complete combustion. Ash contained in the coal is released in drops of molten slag as the coal particles burn. The swirling motion resulting from the tangential entrance of the precombustor exhaust gases causes the molten slag to collect on the walls of the main combustor. Slag removal at this stage accounts for about 80 percent of the total coal ash. The slag nearest the water cooled wall solidifies to protect the combustor walls from erosion and corrosion. Slag nearest the combustion zone remains fluid and flows by aerodynamic and gravitational forces through the key slot and into a slag tap located just downstream of the baffle into the slag recovery stage. Heat transferred to the combustor cooling system is recovered in the power generation cycle.

The main slagging combustor converts solid fuel components to a hot partially oxidized fuel gas in an environment conducive to destroying the complex organic fuel bound nitrogen compounds that could easily be oxidized to NO_X in the presence of excess oxygen.

<u>Slag Recovery Stage</u>

The slag recovery stage located beneath the slotted outlet of the main combustor directs the molten slag into a water-filled slag recovery tank for subsequent removal to disposal. The partially oxidized fuel gas is ducted into the furnace section of the boiler for final combustion.

<u>Final Combustion</u>

When the exhaust gases leave the slagging combustor, coal has been mixed with 70 to 90 percent of the theoretical air necessary to complete combustion. Hot swirling gas entering the furnace is rich in carbon monoxide (CO) and hydrogen (H_2).

The final stage of combustion takes place in the furnace section of the boiler as entering fuel gases mix with air added via the "NO_X ports" at a low section of the furnace.

Delaying addition of combustion air to the main combustor exhaust gases entering the furnace until the gases are sufficiently cooled (by radiation and convection to the furnace water walls) allows final combustion to occur at temperatures below the 3000 degrees F thermal NO_X threshold. This results in a second stage of NO_X reduction.

CONTROL OF SULFUR DIOXIDE

Mechanisms of Sulfur Dioxide Formation

Sulfur dioxide (SO_2) formation from coal combustion is solely dependant on the sulfur content in the fuel. Formation of SO_2 during the combustion process results from oxidation of sulfur or conversion of hydrogen sulfide (H_2S) in the fuel:

(1) $S + O_2 \rightarrow SO_2$

(2) $2H_2S + 3O_2 \rightarrow 2H_2O + 2SO_2$

HCCP Control Technology for SO_2

The SO_2 removal process at HCCP integrates SO_2 removal features of the entrained combustion system, a Joy spray dryer absorption system and a baghouse collector in a three stage process.

<u>First Stage SO_2 Control</u>

The first stage of SO_2 removal takes place in the furnace as flue gases pass through the furnace to the spray dryer absorber.

Reactive material needed for this process and the back-end SO_2 removal process (second stage removal) is produced by introducing pulverized limestone ($CaCO_3$) into the main combustion stage exhaust gas stream in the slag recovery duct. While passing into the furnace, most of the limestone decomposes to flash calcined lime:

$$CaCO_3 + heat \rightarrow CaO + CO_2$$

The mixture of lime (CaO) and ash (not removed by the combustors) is called Flash Calcined Material (FCM).

Reductions in the furnace are achieved by optimization of conditions under which SO_2 will absorb and react with FCM. Limestone calcination occurs at the outlet of the combustors where gas temperatures produce a soft burnt highly reactive finely divided flash calcined material. When limestone is added and flash calcined with the final air for combustion at the combustor furnace interface, the resulting FCM is thoroughly mixed with the hot products from the combustor. SO_2 removal is achieved by the thorough mixing of the highly reactive FCM with the flue gas stream.

Entrained particulates leaving the furnace contain a highly reactive FCM with minimum ash content and a high percentage of available calcium oxide and minimum dead burn of the limestone.

Second stage SO_2 Control

Second stage of SO_2 removal is accomplished in the Joy spray dryer absorber (SDA) using reactivated flash calcined material (FCM).

Flue gas exiting the boiler contains fly ash, FCM, NOx and SO_2. This gas enters the FGD system through connecting ductwork for secondary treatment.

Downstream fabric filters located in the baghouse remove fly ash and FCM from the flue gas stream. The particulate is periodically removed from the fabric filters and stored in a fly ash-FCM surge bin. Part of this material is transferred to the Joy FCM reactivation system for reactivation and used as a sorbent in the SDA. The remaining portion is transferred to a fly ash storage silo for disposal. Figure 4 depicts the flue gas desulfurization system.

FCM produced by flash calcining limestone contains unreacted lime, dead burned lime and calcium sulfate. The calcium sulfate reaction products form a hard deposit on the surface of the lime particles. The Joy FGD system reactivates the unreacted lime for subsequent use as a sorbent SDA.

A heated slurry of fly ash containing the FCM solids is prepared in a mixing tank. Heating the FCM slurry for a time causes a reaction between the slaked hydrated lime and the fly ash to occur increasing the total surface area and reactivity of the sorbent particles. This slurry is further activated by abrasive grinding in a vertical tower mill. This process provides conditions for slaking of the calcined lime and increases the surface area of the lime particles. The reactivated FCM slurry is transported to the SDA where the SO_2 removal process occurs.

Flue gas exiting the boiler at about 300 degrees F enters the top of the SDA and is distributed through scrolled dispersers. At the discharge of the dispersers, the flue gas is mixed with an atomized spray of the reactivated FCM. As a result of thorough mixing of the flue gas and slurry spray, SO_2 in the flue gas stream reacts with calcium hydroxide ($Ca(OH)_2$) to form hydrated calcium sulfite($CaSO_3$ $2H_20$) and hydrated calcium sulfate ($CaSO_4$ $2H_2O$). Simultaneously, the sensible heat of the gas causes the water in the slurry mist to evaporate leaving a dry particulate residue suspended in the treated gas stream. The gas stream exits through the angled bottom of the SDA vessel. The flue gas stream transports reaction products and FCM to the baghouse for collection and further reaction. Particulate fall out from the bottom of the SDA is collected and conveyed to the fly ash silo.

Third Stage of SO_2 Control

A third stage of SO_2 removal occurs in the baghouse as FCM deposited on the filter bag surfaces reacts with SO_2 in the flue gas stream.

The bags in the baghouse are periodically cleaned by pulses of low pressure air. Particles broken loose from the filter bags by a reverse flow of air fall into a lower compartment hopper and are subsequently conveyed to the fly ash silo.

CONTROL OF PARTICULATE MATTER

Particulate Matter (PM) emissions associated with the combustion process result from ash entrained and transported to the exhaust stack by the flue gas. PM emissions reduction at HCCP integrates features of the TRW entrained combustion system and the Joy flue gas desulfurization system. PM emissions are reduced as a result of the slagging design of the main combustor, which removes 80 percent of the ash in the coal as slag. The remaining ash is collected in conventional design fabric filter collectors located in the baghouse. Fly ash is also collected in the hoppers at the bottom of the furnace, boiler bank and the SDA.

HCCP PROJECT STATUS

Technology Testing

Prototype tests conducted at TRW's Cleveland Test Facility have confirmed operability and performance of a small scale slagging combustor unit. Design Verification Tests have confirmed performance of the full sized precombustor stage as well as the associated one-third scale direct coal feed system.

SO_2 removal tests using 200-mesh top size limestone, conducted by TRW have displayed SO_2 levels consistent with expectations. Pilot tests at Niro confirmed the reactivity of the FCM generated in the TRW combustors. Pilot tests demonstrated overall SO_2 removal exceeding 90% at atomizer feed solids rates up to 50% by weight

Engineering/ Design, Permitting, Construction

Engineering and design is approximately 75 percent complete. All major equipment procurements have been placed.

The Prevention of Significant Deteriorization Permit has been issued by the Alaska Department of Environmental Conservation (ADEC). Other permits are in the review process.

Construction is currently scheduled to begin in the Spring of 1994. Start of the demonstration phase is scheduled to begin September 1996. Commercial operation is schedule to begin after the demonstration test program.

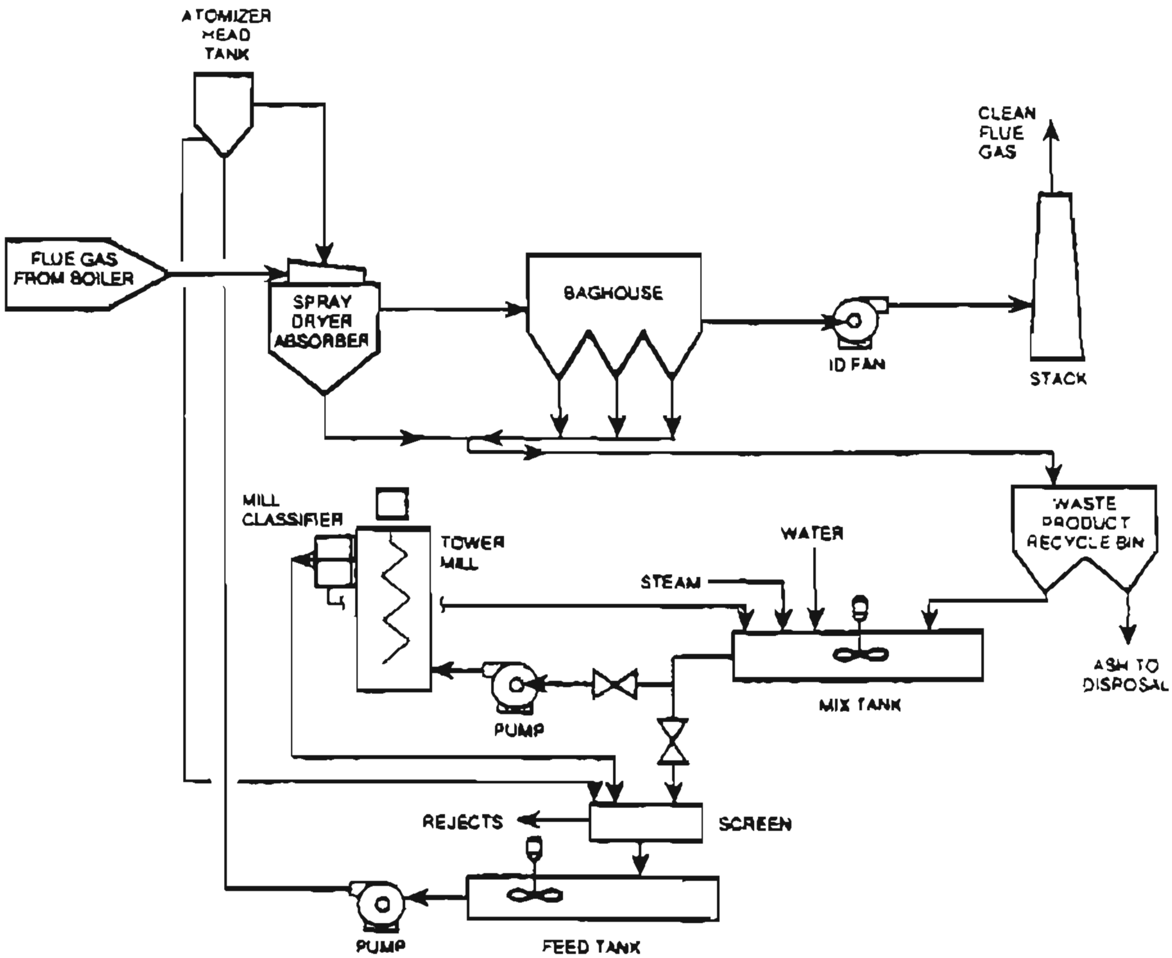

Figure 4: Joy Recycle/Reactivation SDA System

CONCLUSION

The HCCP team participants look forward to the successful operation of the project and expect the project to demonstrate:

Economical and environmentally acceptable commercial operation

Emissions significantly below the current New Source Performance Standard limits for new power plants

Economical use of limestone as a sorbent material.

Process will display SO_2 reduction by limestone injection into the furnace with coal containing wide ranges of sulfur.

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A STUDY OF NON-EVAPORATIVE, HOT WATER DRYING OF THREE ALASKAN LOW-RANK COALS

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ABSTRACT

Over a period of four years (1989-1993) the Mineral Industry Research Laboratory (MIRL) University of Alaska Fairbanks, has investigated the effects of temperature, residence time, and particle size on the degree of low-rank coal (LRC) upgrading for a non-evaporative drying process, hot water drying (HWD). Three Alaskan LRCs were used in this study: Usibelli coal (Seam No. 4) from the Nenana coal field, Little Tonzona coal from near McGrath, and Beluga coal from the Beluga-Yentna field on the west side of Cook Inlet. Replicated, factorial tests were conducted. The discussion is based on the results of analysis of variance (ANOVA) of the experimental data. Within the tested particle size range, there was no significant effect due to particle size and no interaction effects between the factors were significant. Experimental results indicate that most of the low-rank coal upgrading via HWD occurs rapidly within the first 10-20 minutes of residence time. Thereafter, the upgrading process slows down and over 100 minutes of additional residence time are required to produce similar percentage increases in coal properties to those achieved in the first 10-20 minutes. The properties of the hot water dried products were very sensitive to process temperature. Calorific value, carbon and oxygen contents, and equilibrium moisture level all appear to change linearly with temperature within the 275° C to 325° C range.

INTRODUCTION

Alaska, generally known for its oil wealth, also has large resources of coal. The most readily accessible, economically recoverable coals are of subbituminous 'C' rank. Usibelli Coal Mine, Alaska's only current operating coal mine, has an annual production of about 1.4 million (MM) metric tons (mt). Half of this is exported to Korea while the remainder supplies heat and power for interior Alaska. The Beluga coal field, adjacent to Cook Inlet, is readily accessible to ice-free tidewater. Both Placer Dome, Inc. and Diamond Alaska Coal Co. have been extensively drilling and evaluating this field and now await the availability of markets for the contained coal. The Little Tonzona coal deposit, which lies 80 miles east of McGrath on Doyon, Ltd. lands, is being considered for use in power generation at McGrath.

The U.S. Department of Energy, under the Clean Coal Technology Program, selected Healy, Alaska as the site for a cogeneration plant that will use about 300,000 tons of coal per year. It is envisioned that, by the turn of the century, process heat from this operation will be utilized to reduce the moisture of raw coal for export markets.

Coals from Usibelli Coal Mine and the Beluga field are of subbituminous 'C' rank and typically have calorific values of 8,000 Btu/lb. The moisture of these coals measures about 28%. Little Tonzona coal is also of subbituminous 'C' rank, but slightly more lignitic. The combination of high moisture and a low heating value has restricted most low-rank coal (LRC) usage worldwide to mine-mouth power generation, which, in turn, has limited export sales of Alaskan coal to only 0.75 MM tons per year. This comes at a time when Australian coal exports have topped 100 MM tons per year, and the steam coal market is expected to more than double in this decade. Given economic methods to reduce moisture and enhance quality, Alaskan LRCs can participate in the Pacific Rim coal market.

The most desirable qualities of Alaskan LRCs are their low sulfur (typically 0.2%), ash (about 8%), and sodium contents plus a relatively high calcium concentration within the ash that assists with reactive sulfur capture. Since the principal impediment to the export growth of these coals is their high moisture content, the thrust of current Alaskan coal drying research is to produce a stable product with low equilibrium moisture.

Conventional Drying

Numerous conventional, low-temperature, evaporative technologies are available.[1,2,3,4] Most of these use hot furnace gases or superheated steam to evaporate moisture. The final moisture content achieved in the product is dependent upon particle size and residence time. Typical driers utilized include fluidized bed driers, Parry driers and rotary driers. These processes are quite economical due to the low temperatures employed and are preferred when the dried coal is used immediately. LRC dried at such low temperature tends to reabsorb moisture, heat spontaneously and ignite, and can be very dusty. Such problems can be minimized by coating the dried coal with an agent such as residual oil or by briquetting. The AMAX drying plant near Gillette, Wyoming attempts to dry subbituminous coal to between 10% and 15% moisture, and stabilize the product by coating with residual fuel oil.

Moisture reabsorption tendencies can be prevented by drying coal at higher temperatures. Subjecting LRCs to a temperature exceeding 240° C results in changes in their basic chemical properties that induce decarboxylation, thereby reducing the coals' ability to bind water.[5,6] Product stability, especially with respect to spontaneous combustion and the production of fines, needs to be evaluated for candidate coals.

Several processes have been developed for high-temperature drying. Examples are the Koppleman, the DK, the Fleissner, the Evans Siemon, the University of North Dakota, the Bechtel hydrothermal, the Saskatchewan Power, and the Institute of Gas Technology processes. These operations use water or steam at higher temperatures, generally exceeding 230° C, and pressure. Other procedures, including the WECO process, utilize superheated steam and the Hitachi and Mitsubishi processes carbonize the coal at 400° to 450° C.

Hydrothermal Treatment of Coals

In 1921, Fischer and Schrader first studied hydrothermal treatment of coals. Their procedure involves subjecting coals, in the presence of water, to a temperature of 320° to 400° C in an autoclave. With Koppleman's process, utilized in the K-fuels system, LRCs are treated, under high pressure, at temperatures of 500° to 600° C; this operation liberates moisture as well as light hydrocarbon gases and liquids. The hot water drying process developed by the University of North Dakota and Bechtel employs temperatures under 400° C, and the gases liberated consist principally of CO_2.[7]

In cooperation with Dr. Warrack Willson (Manager, Fuel and Process Chemistry Research Institute, EERC, University of North Dakota), the Mineral Industry Research Laboratory (MIRL), University of Alaska Fairbanks, began conducting hydrothermal drying studies. Under Dr. Willson's direction, Li[7] studied hydrothermal treatment of LRCs from the Usibelli Coal Mine and the Beluga coal field. Much of his work focused on the preparation of coal-water fuels. Later, Rao, et al.[8] investigated the hydrothermal treatment of lump coals from Usibelli Coal Mine and the Beluga coal field to (1) determine the quality of product that can be prepared, and (2) delineate petrographic changes accompanying hydrothermal treatment that will eventually influence the mechanical properties, surface area and product reactivity. Both of these studies, Li[7] and Rao[8], utilized a 7.6 liter autoclave system for the hydrothermal drying studies, which investigated drying temperatures of 275° - 325° C. Though the autoclave system worked well, residence time at temperature was not controllable due to the long heat-up and cool-down times inherent to the system. Hence, the focus of this present study was to explore the effects of residence time on hydrothermal drying using a tubing reactor system.[9] The effects of feed coal particle size and process temperature were also studied.

PROJECT DESCRIPTION

The coals tested were subbituminous 'C' coals from Alaska; Usibelli coal (Seam No. 4) from the Nenana coal field, Little Tonzona coal from near McGrath, and Beluga coal from the Beluga-Yentna field on the west side of Cook Inlet. Bulk samples were collected at the sites and transported to MIRL where they were crushed and screened into size fractions. Prior to hot water drying (HWD) tests, raw coal analyses were run on each coal. These are shown in Table 1.

Hot water drying tests were conducted using a reactor system similar to the one designed by Youtcheff.[10] The system provides excellent isothermality and accurate residence time measurements. The reactor consists of three components: 1) a stainless steel tubing microreactor, 2) a fluidized sand bath used for heating the reactor, 3) an agitation device.

Two identical tubing bombs were used as microreactors. Each microreactor had a 75 ml capacity and was made of 28 mm outside diameter, stainless steel tubing. Two Swagelok threaded plugs capped the end fittings. A 6 mm hole was bored at the midpoint of the tube reactor and tubing was welded in a vertical position to support a tee-valve assembly and a 3,000 Psi Bourdon gauge. The tubing bomb fitted into a holder which was connected to a vertical oscillation device. The reactors could be removed from the holder quickly, so that a rapid quench was attainable.

The drying tests were arranged according to a randomized, replicated, factorial design (Table 2). The three factors were process temperature, particle size and process residence time. The three temperature levels of 275° C, 300° C, 325° C were chosen for this study. Residence times were chosen between 1-120 minutes according to different feed particle sizes. For Usibelli coal, the first coal studied, four particle size fractions were used; 6.4 mm x 4.8 mm, 4.8 mm x 2.4 mm, 2.4 mm x 1.2 mm, 1.2 mm x 0.6 mm. Based on the results of this particle size test series, only two size fractions of Beluga coal (4.8 x 2.4 mm and 1.2 x 0.6 mm) and one size fraction of Little Tonzona (L.T.) coal (4.8 x 2.4 mm) were studied.

The hydrothermal drying tests were conducted by charging the tubing reactor with 22-24 gm of raw coal. Deionized water was added until all the material was immersed in water. About 85% of the reactor volume was occupied by coal and water.

The fluidized sand bath was preheated to a level 20° C higher than the desired process temperature. By setting the temperature higher than the desired temperature, the reaction vessels reached their desired process temperature within a short time (average 4 mins), without decreasing the sand bath temperature below the desired process temperature.

The tubing reactor was immersed in the fluidized sand bath and the thermostat controller was reset to the desired process temperature setting. When the gauge pressure reading reached the saturated steam pressure corresponding to the desired process temperature, the clocking of residence time was begun. After the required residence time, the reactor was quickly taken out of the sand bath and quenched in water and the hydrothermally dried product was taken out of the tubing reactor and separated from the process water. The products were centrifuged to reduce surface moisture prior to analysis.

Table 1. Raw coal analyses of the three low-rank coals used in hydrothermal drying tests. (All data expressed on a dry, ash-free basis except for equilibrium moisture, which is expressed on a raw coal basis).[9, 11]

Coal	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	H, %	N, %	O, %	S, %
Usibelli	25.1	52.3	47.7	11730	69.9	5.1	1.0	23.8	0.2
Beluga	24.4	49.7	50.3	11930	68.9	6.1	1.0	23.8	0.2
Little Tonzona	27.4	56.0	44.0	11095	66.5	5.0	0.7	26.6	1.2

The feed and various product samples were analyzed for heating value, equilibrium moisture (EBM), proximate analysis, and ultimate analysis in accordance with standard ASTM methods. Improvements in product quality were evaluated on the basis of equilibrium moisture reduction and other characteristics, expressed on dry ash-free basis.

RESULTS AND DISCUSSIONS

Analysis of variance (ANOVA) techniques were applied to the data analysis in this study. The ANOVA results were used to determine the significance of factor levels at a 95% family level of confidence. The difference between factor levels was also determined at a

Table 2. Experimental designs.[9, 11]

Particle Size Fraction	TEMPERATURE=275°, 300° and 325°C Residence Time (minutes)					
6.4 mm x 4.8 mm	120	90	60		30	Usibelli
4.8 mm x 2.4 mm	80	60	40		20	Usibelli
2.4 mm x 1.2 mm	60	45	30		15	Usibelli
1.2 mm x 0.6 mm	40	30	20		10	Usibelli
4.8 mm x 2.4 mm	60	30	5		1	Beluga
1.2mm x 0.6mm	60	30	5		1	Beluga
4.8 mm x 2.4 mm	60	25	15	5	1	Little Tonzona

95% family level of confidence. SPSS[x] software (4.0/4.1 version) on the University of Alaska Vax computer network was used for the analysis of variance. Where a confounded nature of the experimental design existed, i.e. unequal sample sizes (not all particle sizes were processed at all residence times), a regression approach was used for analysis of variance.

According to the ANOVA results, no interaction effect among the three factors (particle size, process temperature and residence time) was significant, nor was there a significant effect due to particle size. Because of the non-significance of particle size, Tables 3-5 shows the average proximate and ultimate analyses of the hot water dried products calculated over particle size ranges for Usibelli and Beluga coals. While sulfur values of the hot water dried products were not measured in this study, previous work has shown that HWD does little to affect the low sulfur values of these raw coals.[7, 8, 11]

Effect of Particle Size

ANOVA results show that within the particle size ranges studied, particle size does not have a significant effect on the products' calorific value, total carbon content, oxygen content or equilibrium moisture content within the HWD design parameters tested. Particle size could possibly influence the product properties via heat transfer. Stanmore and Boyd[1] studied the thermal conductivity of Victorian coal. They stated that 3 mm coal particles require about 10-15 seconds for the core temperature to reach the surrounding temperature within a temperature range of 200° C to 225° C. Virtually all the resistance to heat transfer was found to be a function of conduction within the coal. With a decrease in coal particle size, the time required to bring the feed coal particle up to process temperature decreases.

Experimental results from this study indicate that for feed coal under 1/4 inch in size, heat transfer during HWD was not a determining factor within the tested particle size fractions. Because of the non-significance of particle size, this factor was dropped from the ANOVA regression model design and the ANOVAs were rerun as two factor models using only temperature and residence time.

Effect of Residence Time

The effect of residence time was determined over a range of 1 minute to 120 minutes. Figures 1-3 shows the influence of residence time, averaged over the different temperature levels, on the product properties of

Table 3. Averaged analyses of hot water dried 6.4 mm x 0.6 mm coal, No. 4 seam Usibelli Coal Mine. (All data expressed on dry, ash-free basis except equilibrium moisture, which is expressed on raw coal basis.[9]

Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
PROCESS TEMPERATURE=275° C						
120	13.1	47.0	53.0	12690	73.9	20.4
90	13.4	47.6	52.4	12570	73.4	20.8
80	13.2	47.6	52.4	12645	73.7	20.3
60	13.6	47.5	52.5	12560	73.0	21.1
45	14.0	50.5	50.5	12490	72.8	21.0
40	14.0	48.9	51.1	12515	72.7	21.4
30	14.2	49.5	50.5	12405	72.6	21.4
20	14.2	48.8	51.2	12335	72.1	22.1
15	14.8	51.4	48.6	12320	71.7	22.2
10	14.7	50.2	49.8	12270	71.8	22.2
5	16.5	52.1	47.9	12055	72.3	21.4
1	17.6	53.3	46.7	11805	71.1	22.8
PROCESS TEMPERATURE=300° C						
120	10.2	44.7	55.3	13050	75.9	18.1
90	10.6	45.1	54.9	12995	75.8	18.2
80	10.4	48.8	51.2	13065	75.3	18.4
60	11.4	47.9	52.1	12895	75.1	18.9
45	11.6	49.0	51.0	12875	74.9	18.9
40	12.0	47.6	52.4	12915	75.0	18.8
30	12.2	48.2	52.0	12765	74.4	19.8
20	12.6	49.4	50.6	12665	74.0	19.9
15	12.3	50.8	49.2	12620	73.8	20.2
10	12.1	49.4	50.6	12430	73.6	20.3
5	15.2	50.4	49.6	12210	73.0	20.8
1	17.3	51.5	48.5	11875	71.9	22.0
PROCESS TEMPERATURE=325° C						
120	8.5	43.5	56.5	13540	77.9	16.0
90	9.2	42.4	57.6	13305	77.9	16.1
80	8.4	46.5	53.5	13480	77.8	15.8
60	9.1	45.5	54.5	13355	77.2	16.6
45	9.2	45.7	54.3	13230	76.3	17.5
40	10.0	46.8	53.2	13275	77.3	16.4
30	9.7	46.0	54.0	13130	76.3	17.6
20	10.5	47.8	52.2	13100	76.1	17.9
15	10.9	47.6	52.4	13005	76.1	17.6
10	10.8	47.4	52.6	12885	75.3	18.5
5	13.9	48.7	51.3	12475	74.8	18.9
1	15.4	50.4	49.6	12230	73.2	20.6

Table 4. Averaged analyses of hot water dried 4.8 mm x 0.6 mm, Beluga Coal. (All data expressed on dry, ash-free basis except equilibrium moisture, which is expressed on a raw coal basis).

PROCESS TEMPERATURE=275° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	10.3	45.9	54.1	12690	74.7	18.7
30	11.4	47.3	52.7	12500	74.0	19.6
5	13.0	49.5	50.5	12280	72.5	21.0
1	14.6	50.7	49.3	12085	71.5	22.1

PROCESS TEMPERATURE=300° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	9.6	44.0	56.0	13070	76.9	16.6
30	9.6	44.9	55.1	12820	75.4	18.1
5	12.0	48.0	52.0	12445	73.9	19.7
1	13.5	50.8	49.2	12305	72.3	21.3

PROCESS TEMPERATURE=325° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	8.2	41.5	58.5	13605	78.8	14.6
30	8.6	44.3	55.7	13260	77.3	16.2
5	9.7	46.0	54.0	12720	75.0	18.6
1	12.2	47.8	52.2	12460	73.3	20.3

Table 5. Averaged analyses of hot water dried 4.8 mm x 2.4 mm, Little Tonzona Coal. (All data expressed on dry, ash-free basis except equilibrium moisture, which is expressed on a raw coal basis).[11]

PROCESS TEMPERATURE=275° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	18.2	47.5	52.5	12335	-	-
25	17.2	48.9	51.1	12280	72.3	21.0
15	19.2	50.4	49.6	12035	-	-
5	18.8	5137	48.3	11875	70.0	23.2
1	21.5	54.2	45.8	11440	68.1	25.2

PROCESS TEMPERATURE=300° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	15.4	44.6	55.4	12605	-	-
25	15.4	47.1	52.9	12500	73.8	19.5
15	17.4	47.2	52.8	12285	-	-
5	17.8	49.6	50.4	12170	71.7	21.6
1	19.8	52.6	47.4	11760	69.7	23.6

PROCESS TEMPERATURE=325° C						
Residence Time, minutes	Equilibrium Moisture %	Volatile Matter %	Fixed Carbon %	Calorific Value Btu/lb	C, %	O, %
60	15.1	42.8	57.2	12725	-	-
25	14.0	45.0	55.0	12665	75.6	17.8
15	15.7	45.5	54.5	12490	-	-
5	17.0	47.9	52.1	12415	73.6	19.5
1	18.0	50.1	49.9	12120	71.6	21.6

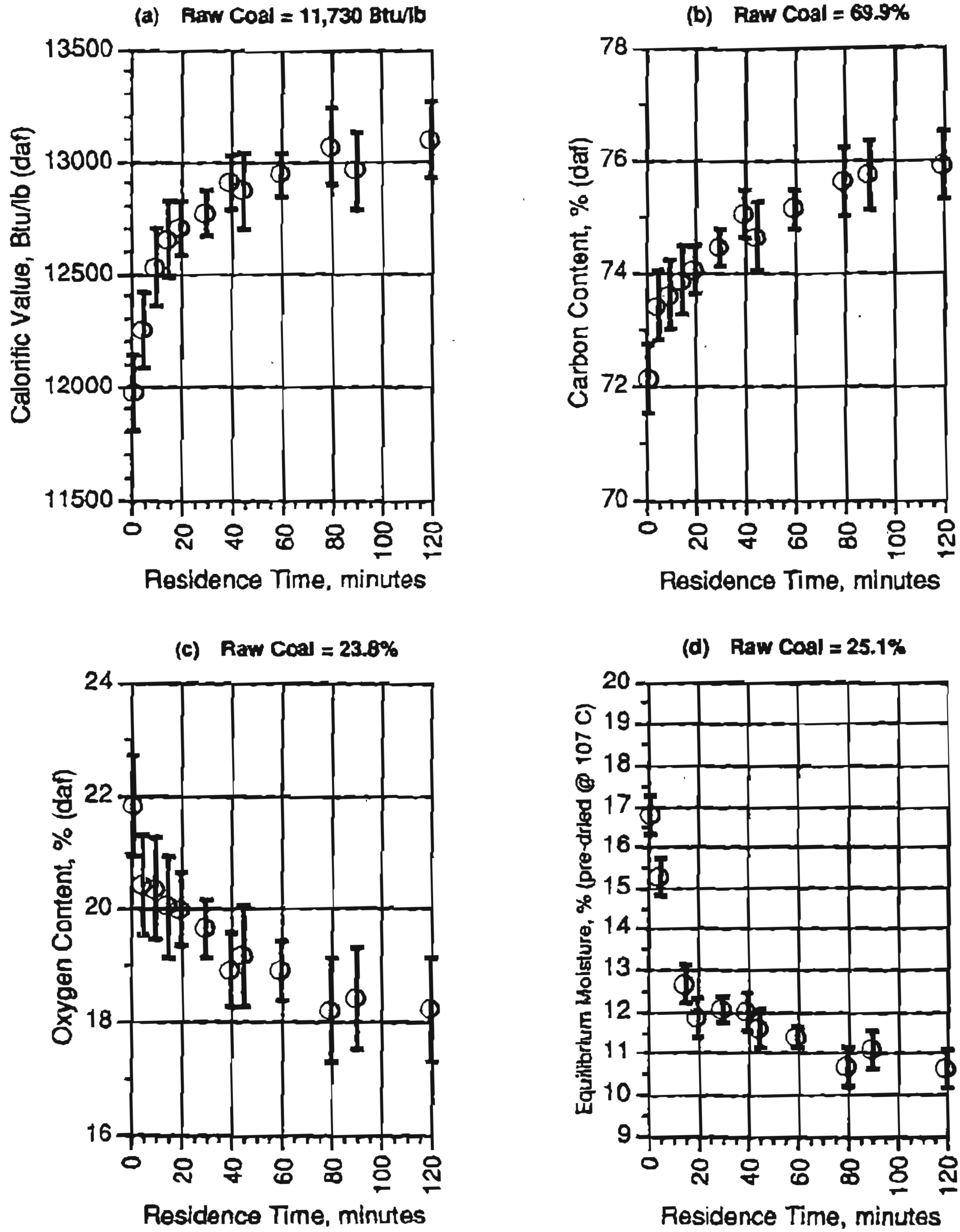

Figure 1. Hot water dried Usibelli coal parameters versus residence time; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over process temperatures and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

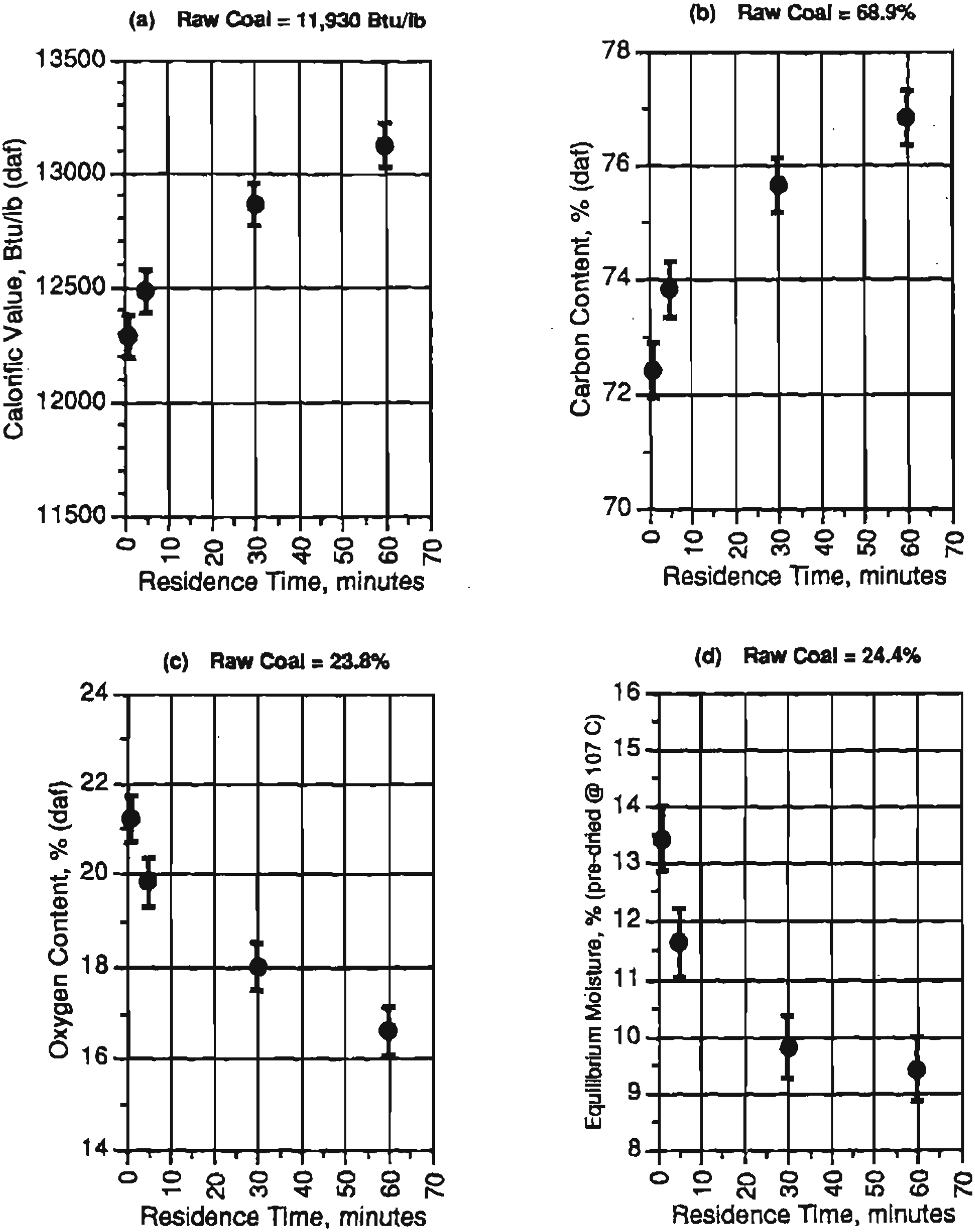

Figure 2. Hot water dried Beluga coal parameters versus residence time; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over process temperatures and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

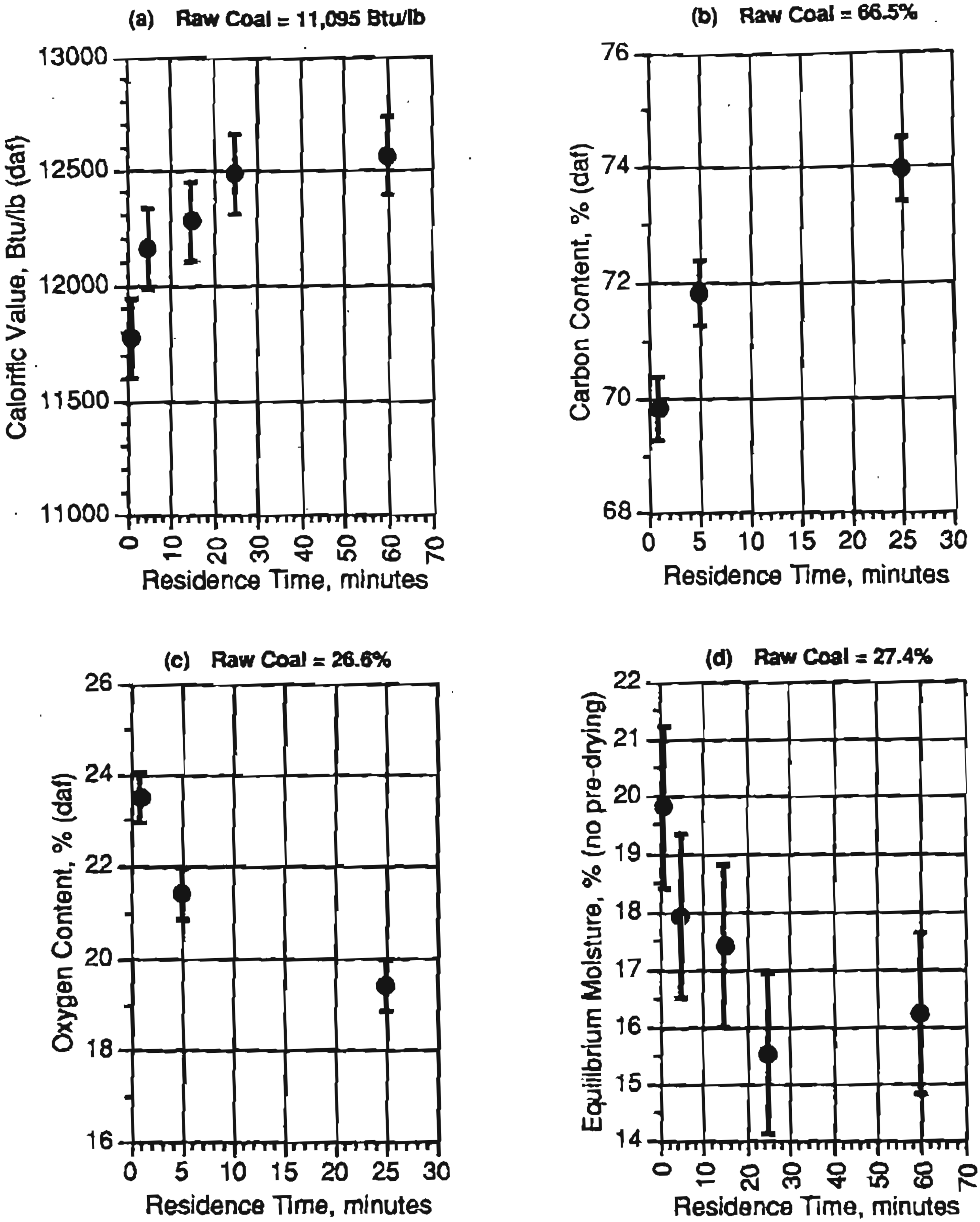

Figure 3. Hot water dried L.T. coal parameters versus residence time; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over process temperatures and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

calorific value, carbon content, oxygen content, and equilibrium moisture.

Since there was no interaction of temperature and residence time the change of coal properties at different process temperatures follows the same trend over residence time factor levels, although the curves shift upwards or downwards with increasing temperature. Experimental results indicate that upgrading reactions occur rapidly within the first 10-20 minutes of HWD. Thereafter, the upgrading process slows down, and over 100 minutes of additional residence time are required to produce similar percentage increases to those achieved in the first 10-20 minutes.

The various mechanisms of LRC upgrading have been noted by Stanmore and Boyd[1]:

1) shrinkage of the coal structure,

2) the differential thermal expansion of coal and water, coupled with a lowering of the viscosity of water at high temperatures,

3) the carbon dioxide evolved from decarboxylation forces water from the pores,

4) the surface nature of the coal changes from hydrophilic to hydrophobic above 250° C.

The thermal expansion of water and the coal shrinkage rate are controlled by the heat transfer rate. Because of the high heat transfer rate within the coal particle and lower water viscosity at high temperature, the effects of mechanisms (1) and (2) take place very rapidly at the beginning of process and then play a minor role with increasing residence time. Further slow and continuous improvement of coal properties is due to the increase of decarboxylation over longer residence times[4]. In other words, the upgrading of LRCs during the beginning of the HWD process is affected by all four mechanisms mentioned above. Later upgrading is most affected by mechanisms (3) and (4), and the rate of change in coal properties slows down, i.e. the curves of product properties versus residence time tend to level off.

Effect of Process Temperature

The properties of the products were very sensitive to the process temperature. The relationships between process temperature and the product properties are shown in Figures 4-6; plots of mean values for temperature factor levels averaged over residence times. All four properties appear to change linearly with temperature within the 275° C to 325° C range. For Usibelli coal, the calorific value was increased by 2-4%, for each 25° C increase between 275° C and 325° C. Similarly total carbon increased by approximately 2-3%, oxygen content decreased by roughly 8-13% and the equilibrium moisture level decreased by about 15-20%. Comparing the properties between raw coal and the 275° C products mean values shows that the calorific value increased by 6%, carbon content increased by 4%, oxygen content decreased by 12% and the equilibrium moisture level decreased by 45%. The other two low-rank coals show similar upgrading after HWD (Figures 7 and 8).

Process temperature has been found to be a significant factor controlling the shrinkage of coal structure and the differential thermal expansion of coal and water. With increasing process temperature, the effect of the thermal expansion of water and coal shrinkage increases, which undoubtedly will increase the water loss and assist the upgrading process. Higher temperatures also help to lower the water viscosity so that the resistance to the flow of water through the porous coal will decrease.

During the HWD process, the degree of decarboxylation increases with increasing process temperature. The following two points have been noted by Taoda, et al.[2], as coal quality changes believed to affect the calorific value of coal after heat treatment:

1) Elimination of oxygen from the coal. Oxygen escapes in the form of gases such as CO or CO_2; causing a calorific value decrease or increase respectively.

2) Elimination of hydrogen from the coal. Hydrogen escapes in the form of H_2 or hydrocarbon gas such as CH_4, causing reduction of the calorific value.

A significant decrease in the oxygen content and equilibrium moisture level was observed from experimental results. These are due to the loss of oxygen-containing functional groups such as carboxylic acid, and the degree of decarboxylation increases with increasing process temperature. No significant

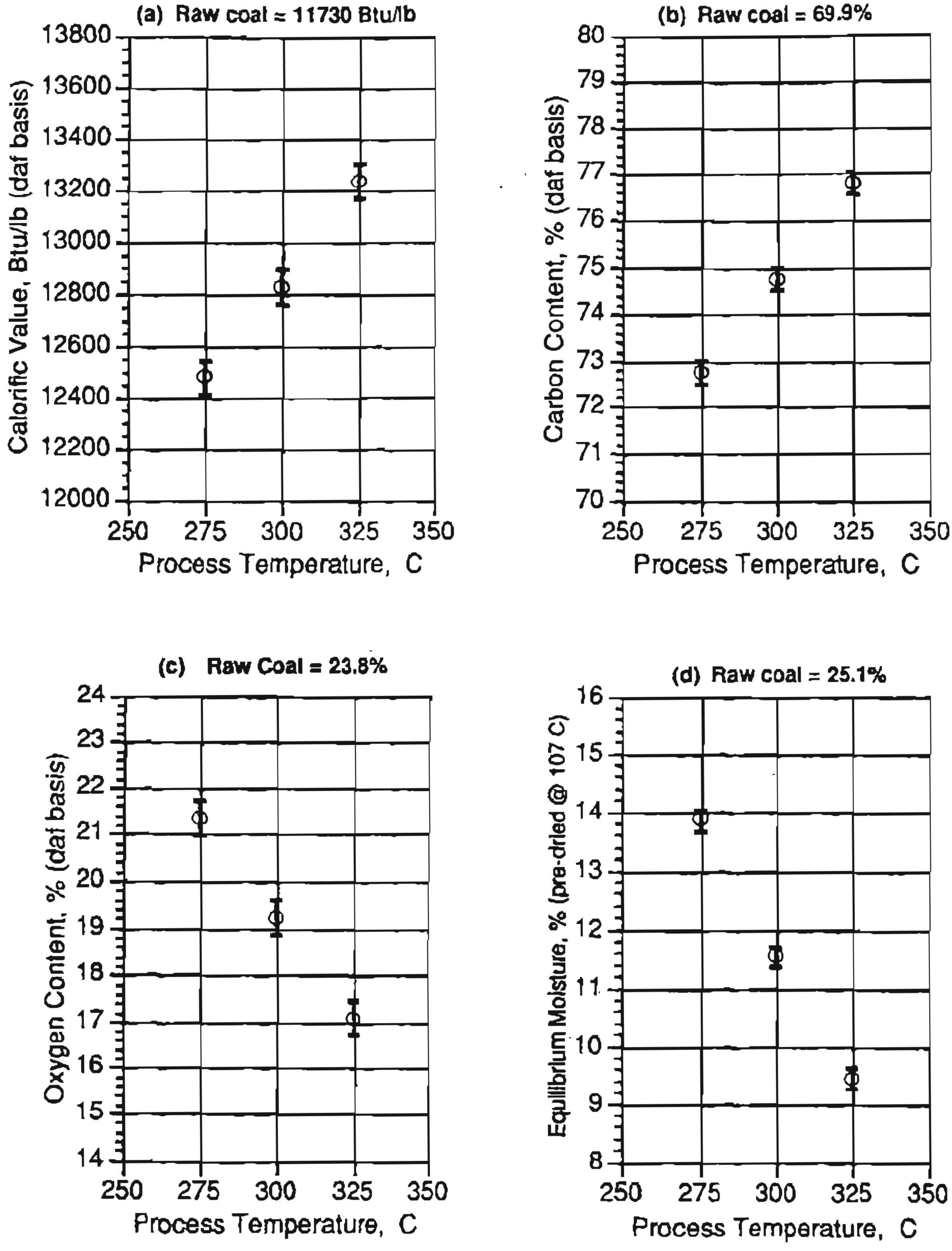

Figure 4. Hot water dried Usibelli coal parameters versus process temperature; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over residence times and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

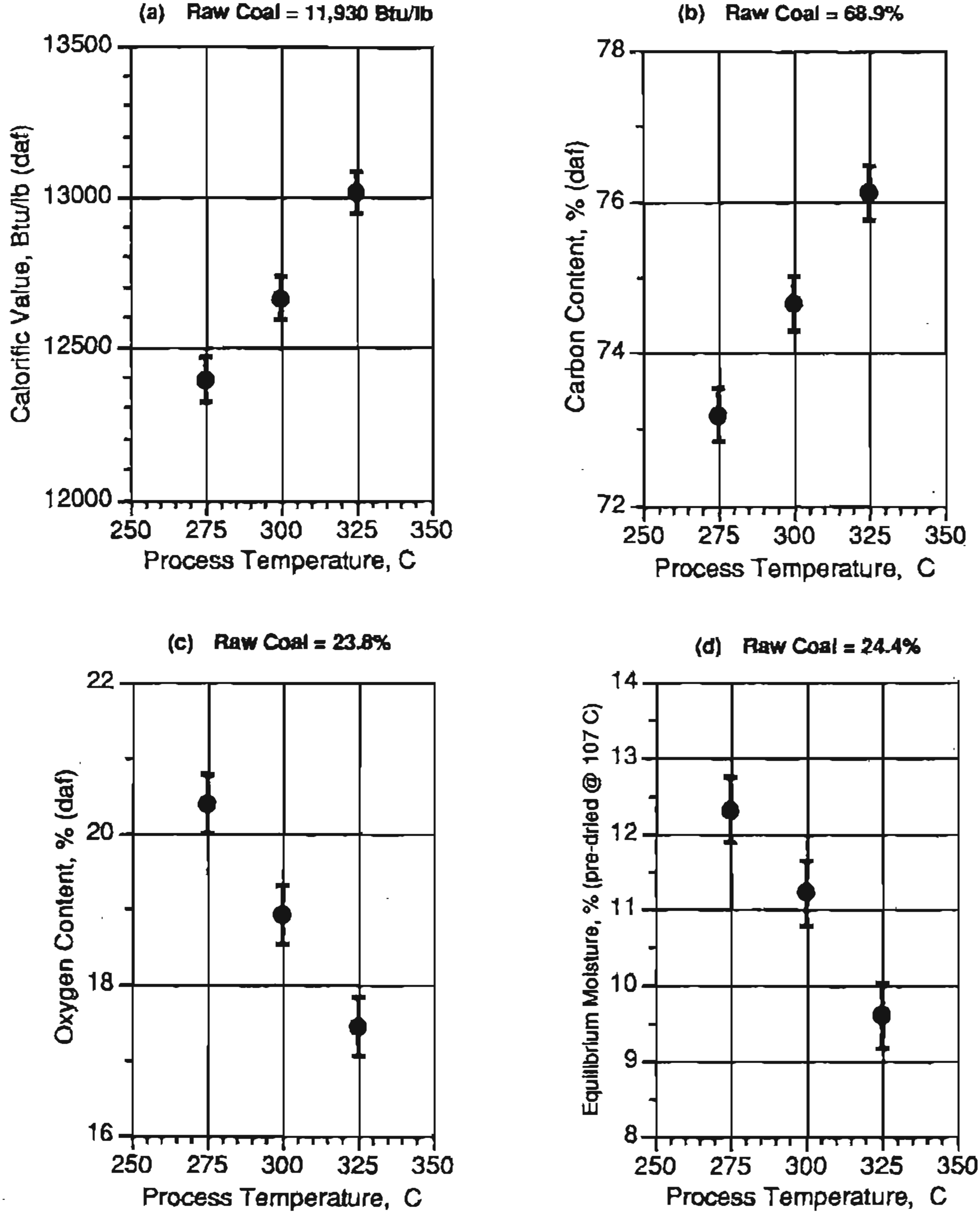

Figure 5. Hot water dried Beluga coal parameters versus process temperature; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over residence times and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

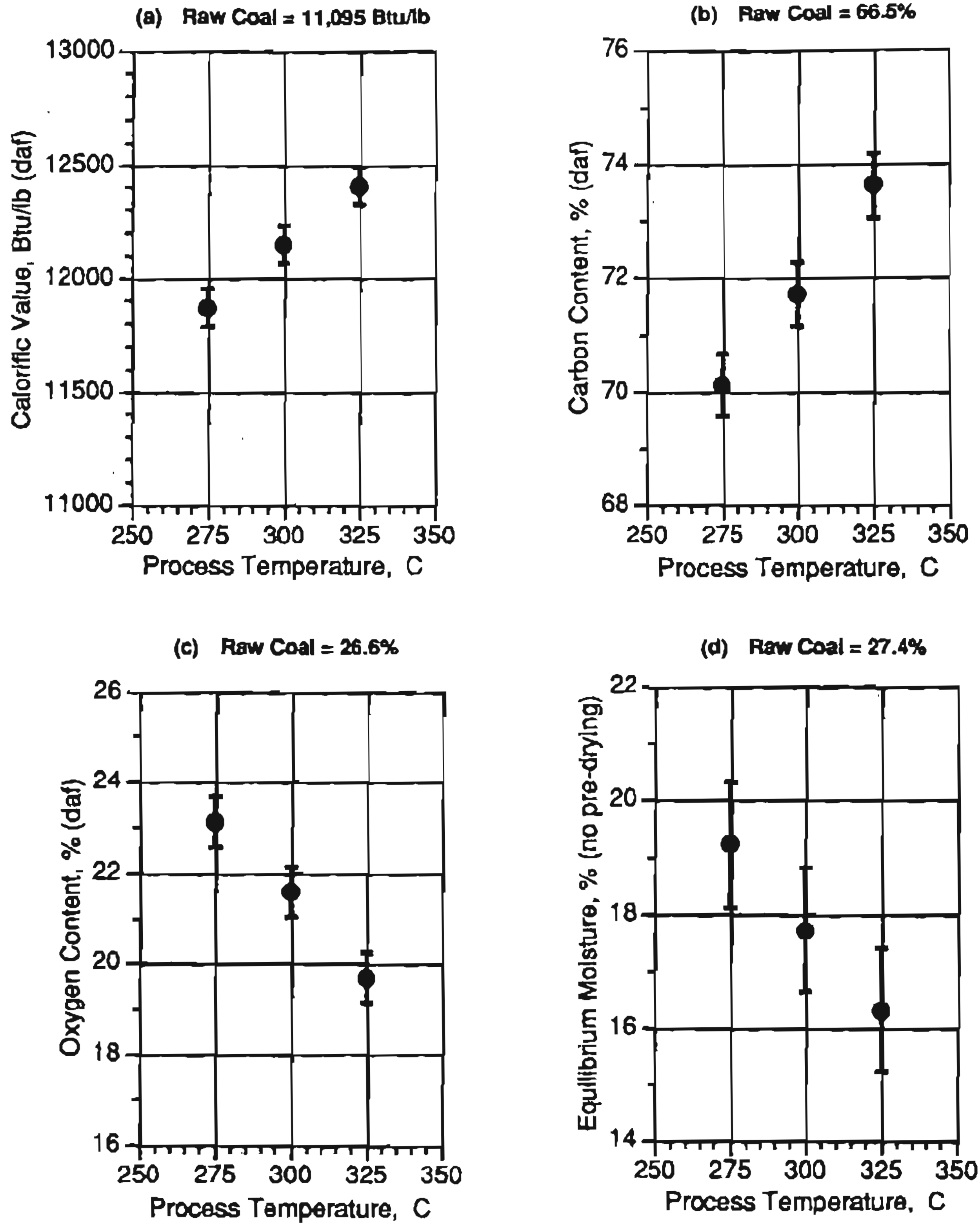

Figure 6. Hot water dried L.T. coal parameters versus process temperature; (a) Calorific value, (b) % Carbon, (c) % Oxygen, (d) Equilibrium moisture. Data are mean values averaged over residence times and error bars represent the 95% family confidence interval of the mean using the Scheffe' method.

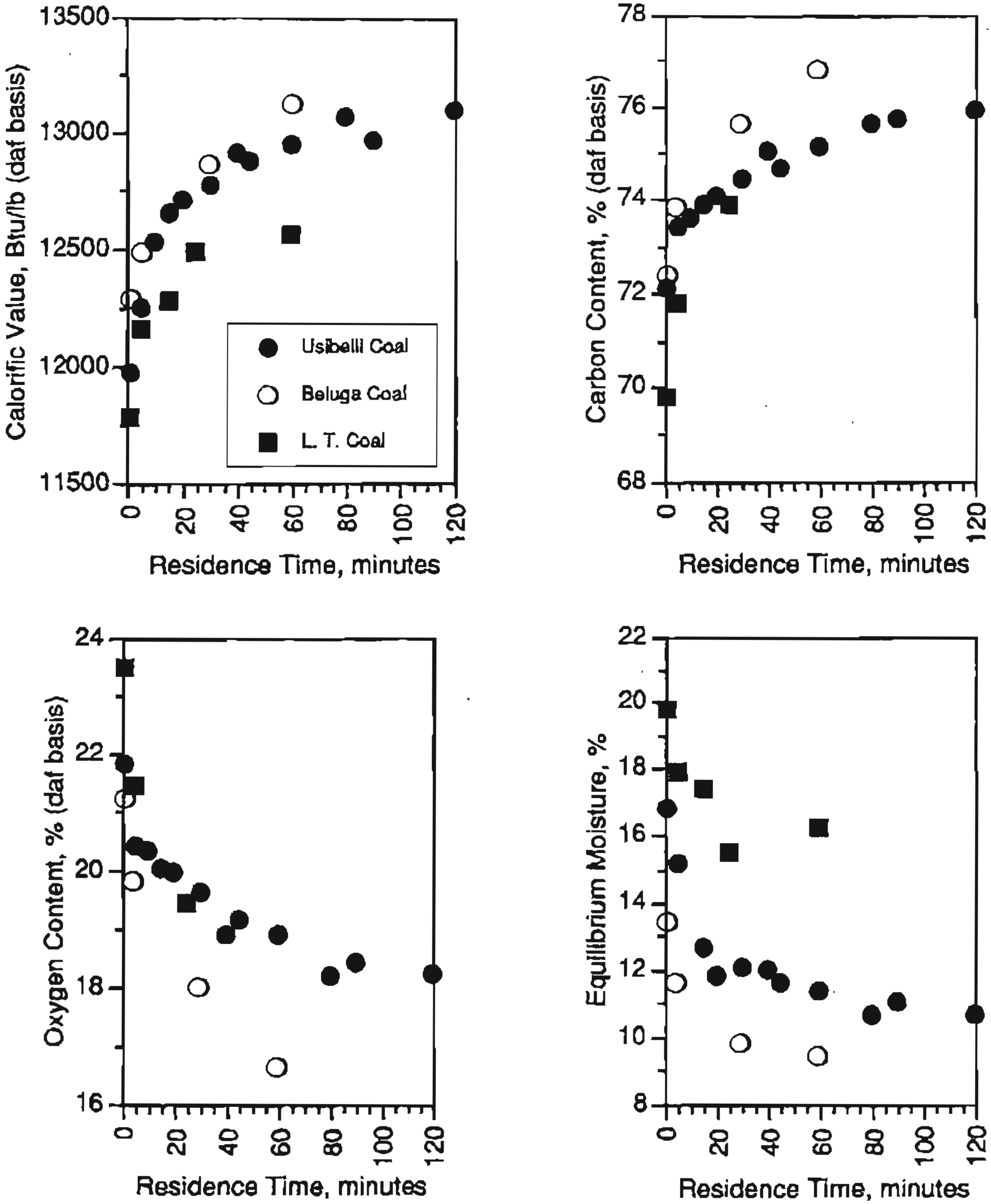

Figure 7. Comparison of hot water dried coals' parameters as a function of residence time for the three low-rank coals; Beluga, Usibelli and Little Tonzona. Data are the same as shown in figures 1-3, with error bars omitted.

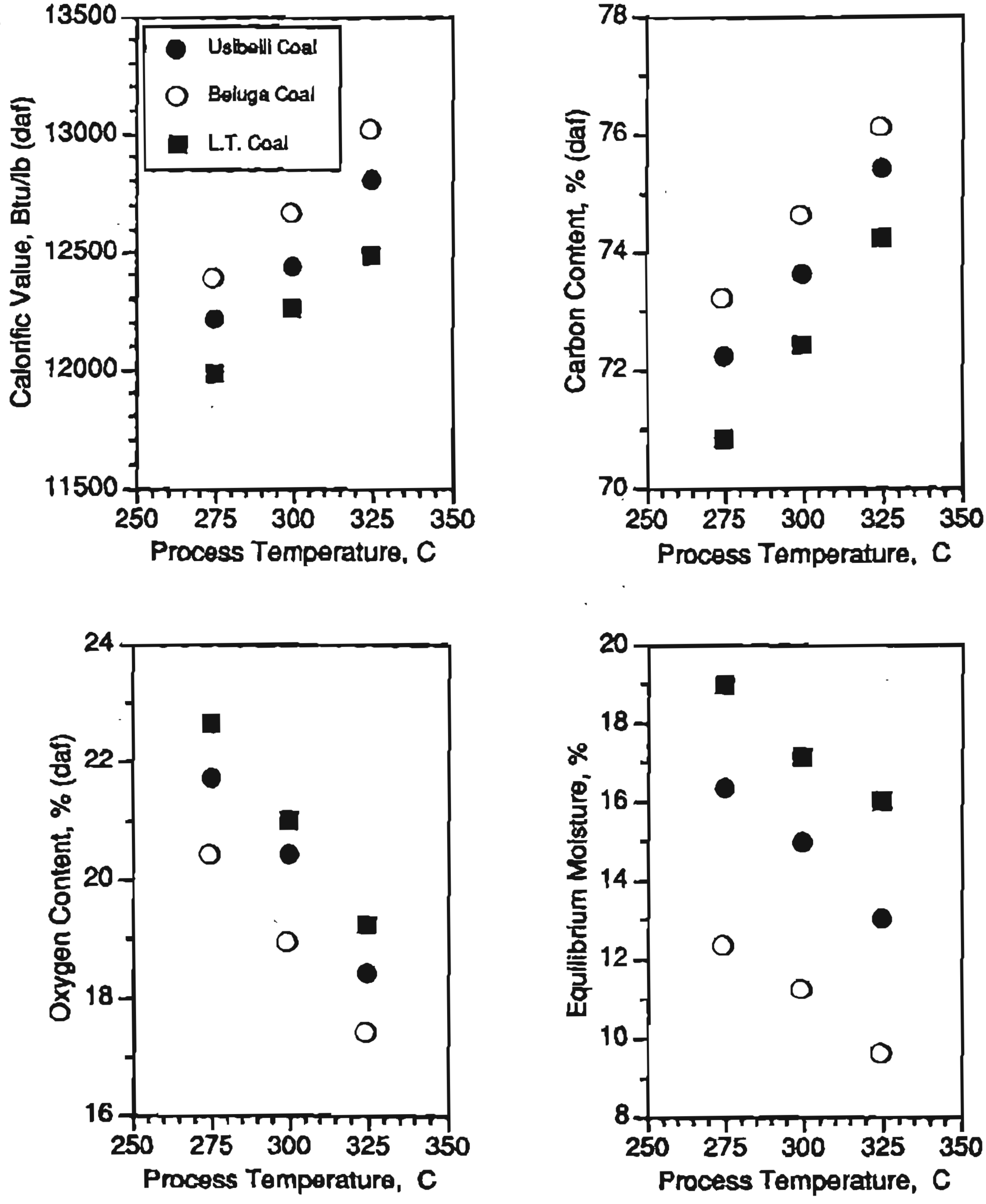

Figure 8. Comparison of hot water dried coals' parameters as a function of process temperature for the three low-rank coals; Usibelli, Beluga and Little Tonzona. Data are mean values averaged over common residence times (1,5,30 and 60 minutes).

change in hydrogen content was apparent from the product analyses.

Vitrinite Reflectance

Vitrinite material (ulminite, telecollinite, desmocollinite) in low rank coals is present in several forms as precursors to vitrinite in high rank coals. Ulminite is gelified plant tissue in which cell structure can be seen. Telecollinite is completely gelified structureless plant tissue. Both of these macerals can exist as thick bands. Desmocollinite is also a completely gelified structureless material but is found as a ground mass embedding other macerals such as exinites and inertinites. Desmocollinite is generally of lower reflectance than ulminite.

Although vitrinite reflectance is not the best indicator of rank for low rank coals, it is a very good indicator of structural changes accompanying thermal treatment of coals. In this study ulminite and telecollinite were chosen as indicators. Mean maximum reflectance was measured in oil. Ulminite reflectance values of the raw coals and the dried products are shown in Tables 6-8. Ulminite reflectance is found to be very sensitive to process conditions. Ulminite reflectance for Usibelli coal increased from 0.30% in raw coal to 0.72% for coal treated at 325° C for 40 minutes. These changes in ulminite reflectance are indicative of induced coalification, i.e. rank progression, by the HWD process. The HWD process accomplishes in minutes what requires million of years in the natural world. The data showed that reflectances for Usibelli coal of 0.48 can be achieved by a treatment time of 40 minutes at 275° C or 10 minutes at 300° C. Treatment times can therefore be dramatically reduced by increasing the temperature of treatment. The other two low-rank coals show similar reflectance changes. In Figure 9, the linear relationship that exists between dry, ash free carbon, and ulminite reflectance of the raw coals and their hot water dried products can be seen.

Equilibrium Moisture Determination

Over all of the three coals' hot water dried products, EBM values demonstrated a much larger variability than other measures of product quality. This suggested a larger degree of experimental error existed in determining EBM values and hence, the question was asked, "What impact does sample handling (i.e. evaporative drying at ambient or higher temperatures) have on EBM determination using ASTM procedures?"

A supplemental study was initiated to look more closely at EBM measurements. For each of the three coals, additional HWD tests were run on 4.8 x 2.4 mm and minus 0.21 mm size fractions. All tests were run at 300° C for 10 minutes residence times. EBMs were then determined for the products after the following pre-treatments:

1) Products stored moist,
2) Products air-dried at 20° C for 48 hours,
3) Products air-dried at 107° C for 1.5 hours.

Following pre-treatment, EBMs were run on:

1) 4.8 x 2.4 mm raw coal,
2) 4.8 x 2.4 mm hot water dried coal,
3) Size fractions of crushed, 4.8 x 2.4 mm hot water dried coal,
    a) 0.85 x 0.42 mm
    b) 0.42 x 0.21 mm,
    c) 0.21 x 0.11 mm,
    d) -0.11 mm.
4) 4.8 x 2.4 mm hot water dried coal pulverized to minus 0.21 mm,
5) Minus 0.21 mm, hot water dried coal.

Table 9 shows the results of this series of tests, and indicates that while air-drying at 20° C has little impact on EBM values compared to stored-moist products, 107° C drying displays a more noticable effect. Individual size fractions of crushed, 4.8 x 2.4 mm, hot water dried products, shows no significant differences, but minus 0.21 mm, hot water dried products appear to have decidedly lower EBMs than 4.8 x 2.4 mm products. This may indicate, that at smaller particle sizes than studied in the main body of this project, i.e. 1.2 x 0.6 mm coal, that particle size begins to have a significant impact on hot water dried product quality. More work is recommended in this area.

Hot Water Dried Product Quality

The previous discussion has described the effects of HWD residence time and temperature on the parameters of the coal products characterized in this study. However, no coal is marketed on a dry, ash-free basis. Marketed coals contain moisture and ash which

Table 6. Ulminite reflectance of 1.2 mm x 0.6 mm, raw and hot water dried Usibelli coal. [9]

Process Temperature °C	Residence Time Minutes	Ulminite Reflectance $\bar{R}_{max}$, oil
275	1	0.34
	5	0.37
	10	0.42
	40	0.48
300	1	0.39
	5	0.43
	10	0.48
	40	0.57
325	1	0.44
	5	0.47
	10	0.60
	40	0.72
Raw Coal		0.30

Table 7. Ulminite reflectance of 1.2 mm x 0.6 mm, raw and hot water dried Beluga coal.

Process Temperature °C	Residence Time Minutes	Ulminite Reflectance $\bar{R}_{max}$, oil
275	1	0.41
	5	0.48
	30	0.59
	60	0.64
300	1	0.51
	5	0.54
	30	0.70
	60	0.84
325	1	0.59
	5	0.71
	30	0.86
	60	0.94
Raw Coal		0.32

Table 8. Ulminite reflectance of 4.8 mm x 2.4 mm, raw and hot water dried Little Tonzona coal.[11]

Process Temperature °C	Residence Time Minutes	Ulminite Reflectance $\bar{R}_{max}$, oil
275	1	0.27
	5	0.35
	15	0.40
	25	0.43
	60	0.56
300	1	0.34
	5	0.40
	15	0.50
	25	0.63
	60	0.78
325	1	0.42
	5	0.52
	15	0.63
	25	0.63
	60	0.78
Raw Coal		0.18

determine their as-shipped calorific value and in the crudest sense their economic value, though contemporary environmental regulations will certainly cause sulfur values to have increasing pricing significance.

HWD, as investigated by this study, is seen to hold promise for permanently reducing the moisture levels of Alaskan LRCs and thereby increasing their marketability by:

1) reducing transportation costs,
2) increasing calorific values,
3) reducing moisture readsorption and the attendant spontaneous heating.

In some instances, HWD may also reduce boiler fouling ash levels by leaching alkali cations.[12]

HWD can be applied to low-rank coals to successfully reduce its equilibrium moisture level and increase their calorific value. Table 10 compares raw Usibelli coal to its hot water dried products produced at the various process temperatures at a 10 minute residence time.[9] After only a 10 minute residence time, a very significant improvement in coal quality was achieved. Ash levels remain essentially unchanged; the apparent increase in ash levels above that of the raw coal being due to the dramatic decrease in equilibrium moisture (42% - 57% decrease). Calorific values increased from 19% to 31% on an equilibrium moisture basis. After an initial increase above the raw coal level, volatile matter changed little, while there was a steady, gradual increase in fixed carbon levels. This leads to an increase in the fuel ratio (fixed carbon: volatile matter). The fuel ratio is an empirical ratio developed in Europe over 50 years ago as an indicator of the fuel's combustibility. Many coal users consult it when buying coal to assure high enough reactivity to achieve nearly complete carbon burnout. The higher the fuel ratio, the lower the volatile content, which is indicative of a material that is difficult to ignite and requires longer residence times for complete carbon burnout. It is important to note that, while the fuel ratio generally increases with increasing HWD temperature, even at

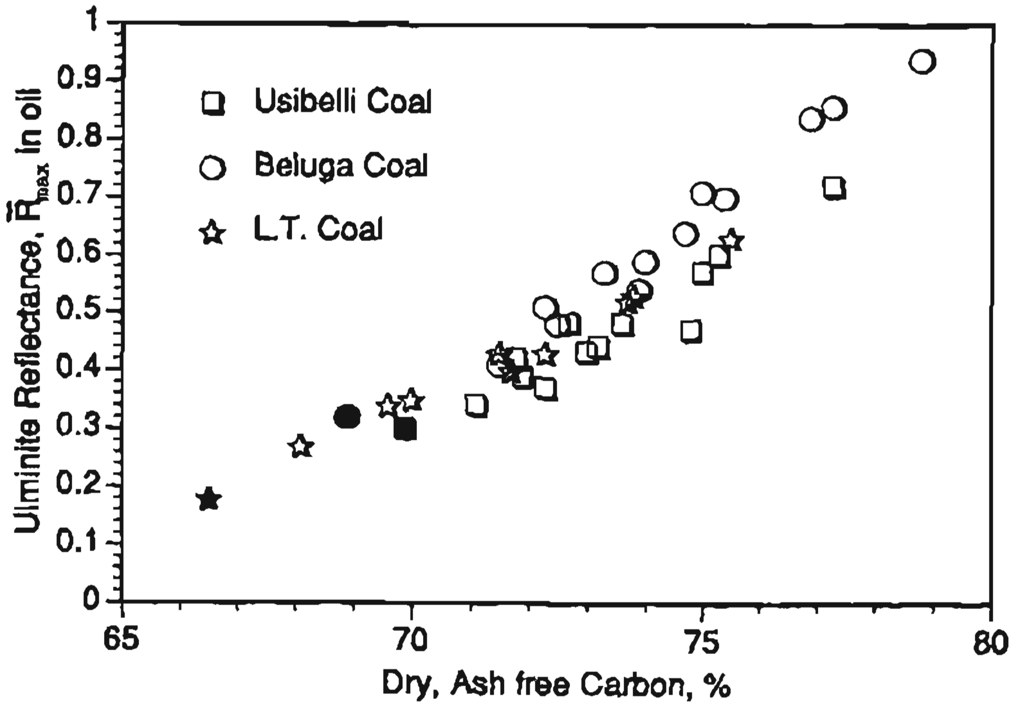

Figure 9. Relationship between ulminite reflectance and carbon content of raw and hydrothermally treated coals. Solid symbols indicate raw coal values.

the highest temperature tested, 325° C, it remained well below the nominal 1.6 suggested as a cut off point for many combustion applications.[12,13]

In contemplating the industrial scale production of hot water dried lump coal from raw Usibelli coal or other low-rank coals, a cost-benefit analysis of operating parameters versus product marketability would be helpful. While lower process temperatures would allow lower process pressures and enable lower capital costs to be realized, higher temperatures obviously produce a higher quality coal product. Process residence time and reactor volume would also need to be considered. Induced coalification is seen even at the lowest temperature (275° C) and a short residence time (10 minutes), yielding a hot water dried Usibelli product with a 42% lower equilibrium moisture level and a 19% higher calorific value. Detailed studies will be required to demonstrate that hot water dried lump coal has the physical and oxidative stability to withstand the rigors of transportation.

Finally, it is worth noting that microreactor HWD tests seem to predict pilot plant performance well. At EERC, University of North Dakota, a series of HWD tests were performed processing Beluga coal in a 200 kg/hr pilot plant.[12] At EERC, coal was ground to minus 420 microns, giving a mass mean diameter of about 90 microns. Ground coal was mixed with water to prepare a dilute feed slurry, with a solids content of around 40%, which was fed to heat exchangers by positive displacement pumps at pressures slightly above the saturated steam pressure at the selected temperature. The preheated slurry entered the top of a downflow reactor which was externally heated by electrical resistance heaters. The residence time at a nominal slurry flow rate of 200 kg/hr at reaction temperature was approximately 10 minutes in the pilot plant. Following pressure reduction, the hot water dried Beluga coal was physically dewatered using a continuous solid bowl centrifuge and concentrated to its final concentration in preparation for characterization, rheological analyses, and combustion testing as a coal water fuel.

Table 9. Comparison of equilibrium moisture values for the three low-rank coals given HWD feed size and post HWD treatment.

		USIBELLI COAL			BELUGA COAL			LITLE TONZONA COAL		
		Stored Moist	Air Dried at 20° C	Air Dried at 107° C	Stored Moist	Air Dried at 20° C	Air Dried at 107° C	Stored Moist	Air Dried at 20° C	Air Dried at 107° C
1.	Raw Coal									
	A. 4.8 x 2.4 mm	25.3	25.6	24.1	24.5	23.6	20.2	32.6	28.6	25.4
	B. -0.21 mm	-	-	-	-	-	-	30.9	28.4	25.4
2.	Hot Water Dried Coal									
	A. 4.8 x 2.4 mm feed	18.6	18.3	17.6	17.7	16.6	15.7	-	16.7	16.4
	B. Crushed 4.8 x 2.4 mm after HWD									
	1) 0.85 x 0.42 mm	20.8	19.8	19.5	17.5	16.9	15.9	-	18.4	17.2
	2) 0.42 x 0.21 mm	20.7	20.0	18.7	17.6	16.4	15.4	-	18.9	18.2
	3) 0.21 x 0.11 mm	19.8	19.0	18.8	16.6	16.2	15.2	-	18.0	17.8
	4) -0.11 mm	18.9	17.9	17.0	16.3	15.4	15.3	-	16.9	17.0
	C. Pulverized 4.8 x 2.4 mm after HWD (all -0.21 mm)	20.3	19.2	19.3	17.5	16.5	16.0	-	17.4	17.0
	D. -0.21 mm feed	18.4	18.1	18.3	14.3	14.3	13.4	-	17.5	17.1

Pilot plant results are shown in table 11. These results can be compared to those of Table 10, also for a 10 minute residence time, but from microreactor HWD tests at MIRL using Usibelli coal. Results indicate a good agreement between pilot plant and bench scale tests. Figures 7 and 8 indicate that Beluga coal may yield hot water dried products, which are more highly upgraded than those from Usibelli and Little Tonzona coals, at a given process temperature, especially at longer residence times. Li[7] previously noted this distinction between Usibelli and Beluga coals in his autoclave study of hot water drying.

SUMMARY AND CONCLUSIONS

The objective of this study was to determine the degree of upgrading experienced by three Alaskan low-rank coals as a function of particle size, residence time and process temperature during a non-evaporative drying process, hot water drying. The conclusions of this research are summarized below:

1) The particle size of the feed coal, within the range of 6.4 mm to 0.6 mm has no significant influence on the degree of upgrading for the temperatures and residence times evaluated.

2) There exists no significant interaction between process temperature and residence time.

3) The degree of upgrading with respect to calorific value, total carbon content, oxygen content, and the equilibrium moisture level is affected by both process temperature and residence time.

4) Process temperature has a greater influence than residence time on LRC upgrading.

5) The upgrading reactions take place rapidly. Most occur in the first 10-20 minutes of residence time, and the rate of upgrading decreases thereafter, although significant upgrading can still take place given long enough residence time.

6) Beyond 40-60 minutes, the curves of upgrading, response variables versus residence time tend to level off.

7) All four of the upgrading, response variables (calorific value, carbon content, oxygen content, and equilibrium moisture level) increase

Table 10. Improvement in Usibelli coal quality after hot water drying (equilibrium moisture basis).[9]

		HWD PROCESS TEMPERATURE, °C (10 minute residence time)		
Property	Raw Coal	275	300	325
Equilibrium moisture, %	25.3	14.7	12.1	10.8
Ash, %	4.7	6.0	5.9	5.9
Volatile matter, %	36.5	39.8	40.5	39.4
Fixed carbon, %	33.5	39.5	41.5	43.9
Fuel Ratio	0.9	1.0	1.0	1.1
Calorific Value, Btu/lb	8,200	9,730	10,190	10,730

or decrease linearly with process temperature within the temperature range of 275°C to 325°C.

8) Vitrinite reflectance increased significantly from the raw coal to the hot water dried products, indicating significant structural changes; i.e. induced coalification has occurred during the hydrothermal drying process.

9) Hot water drying holds promise for permanently reducing the moisture level of low-rank coals, thereby enhancing its marketability by reducing transportation costs, increasing its calorific value and reducing moisture reabsorption tendencies.

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Table 11. HWD pilot plant results for Beluga coal (equilibrium moisture basis).[12]

		HWD PROCESS TEMPERATURE, °C (10 minute residence time)		
Property	Raw Coal	270	285	300
Equilibrium moisture, %	25.0	17.1	15.0	14.0
Ash, %	5.0	5.4	6.0	6.3
Volatile matter, %	34.5	38.8	38.5	38.2
Fixed carbon, %	35.6	38.7	40.5	41.5
Fuel Ratio	1.0	1.0	1.0	1.0
Calorific Value, Btu/lb	8150	9580	9890	10110
Carbon, %	47.8	55.8	57.4	58.2
Hydrogen, %	6.4	6.1	5.8	5.8
Nitrogen, %	0.6	0.8	0.9	0.9
Oxygen, %	40.0	31.6	29.8	28.7
Sulfur, %	0.1	0.1	0.1	0.1
Mass Recovery, %	-	85	88	87
Calorific Recovery, %	-	87	90	91

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SUBSTITUTION OF COAL-WATER FUEL (CWF) FOR OIL-DERATING ISSUES

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BACKGROUND

Oil importing nations have grave concerns regarding the security of oil supply and the volatility of oil prices from OPEC. Many, like Japan and Korea, have included the reduction of the dependence on imported oil as a key objective of their long term national energy policy planning. Given the enormous quantities of heavy oil consumed by utilities alone, early retirement of oil-fired units and replacement with other generating options, i.e., coal, gas, and nuclear, are being considered.

Of all the coal-based alternative fuels, coal-water fuels (CWFs) appear the most promising. The use of bituminous coal-water fuels is being aggressively pursued in China, Italy, Japan, Korea and Russia to produce a low cost, more secure supply of quasi-liquid fuel that can be substituted for heavy oil in industrial and utility boilers.

The magnitude of the alternative oil market can be gauged by the consumption levels of heavy oil for the production of electricity in Japan, Korea and Taiwan alone. In 1990, the utilities in these countries consumed about 200 million barrels of oil, the equivalent of about 80 million tons of CWF.[1,2,3]

In some cases it may be possible to convert oil-designed boilers to dry bulk coal-firing. However, the cost for adding all the dry coal preparation and handling equipment and particulate controls is high. Consequently, despite the strong desire to reduce dependency on imported oil, the rapidly increasing energy requirements are likely to preclude retiring oil-fired capacity in the near future.

Replacement of imported oil with CWF would eliminate concerns over stability of price and supply, and provide a low-cost alternative to retirement of oil fired capacity. Retrofitting an oil-designed boiler to fire CWF will be far cheaper than converting the facility to dry bulk coal. CWF operation would use all the existing oil infrastructure, and apart from burners, which may have to be redesigned, only minor modifications would be necessary to the fuel handling system. The only requirement would be some sort of particulate control system, such as a baghouse or ESP. Thus, with minimal retrofitting CWF will provide low-cost life extensions for oil-fired boilers.

Perhaps the most attractive feature of CWF is that its price would be based upon relatively stable coal prices prevailing in the international steam-coal market and the cost of producing the fuel, not upon volatile international crude oil prices. Since the international steam coal market is served by major producers from around the world, consumers would not be subject to the high level of uncertainty regarding fuel cost and stability of supply, which exists in the OPEC dominated oil market.

Another attribute of CWF is that it is non-hazardous and would produce no long term negative environmental impacts should a major spill occur. There have been three major oil spills since December 1992, involving over 128 million gallons of oil, which have provoked a strong reaction from environmentalists to mandate improved tanker safety and which may lead to increased oil transportation costs.

Since CWF is simply coal dispersed in water, it is non-hazardous and represents no environmental threat in the event of a spill. Therefore, CWF can be transported in single hulled tankers likely to be retired from oil service when the requirement for double hulls is enforced. This should result in future transportation costs for CWFs becoming substantially lower than for oil.

BITUMINOUS CWF

Today's international coal-water fuel industry is based on the use of finely ground, high quality bituminous coals formulated into dense CWFs with solids content of around 69%. Because of their low inherent moisture, bituminous coals can be used directly without moisture reduction to prepare CWFs. However, due to their rheological properties at the high solids concentrations, bituminous CWFs require the use of costly, proprietary additives.

The high costs of additives and bituminous coal, when compared to the relatively low cost of fuel oil, have led to the decline of interest in CWF in North America. For instance, Canada, which was acknowledged as a world leader in CWF technology in the early 1980s, has no CWF producers today. However, in countries with few indigenous energy resources and a high dependency on imported oil there are concerns over security of oil supply and the drain on hard currency for imported oil. In these countries, notably Japan, a CWF industry is developing rapidly.

Japan, the world's largest coal importer, has closed its direct liquefaction project in Australia and is now concentrating on bituminous CWFs.[4] Significantly, Japan has reached an agreement with a number of Chinese firms to build several CWF production plants in China. A nominal 250,000 tpy plant in Yanzhou has been producing CWF for use in Japan since Fall of 1992.[5] The combined output from Japanese plants located abroad and those located in Japan using imported bituminous coal are expected to exceed 7 MM tpy before the turn of the century.[4-6] The bullish position taken by Japan, stems from extensive testing of CWFs in a 75 MWe unit and a 650 MWe unit at the Nakoso power station.[7] As a world leader in bituminous CWF technology, Japan has become the major player in an emerging CWF market. It is important to note, that Japan has initiated an R&D program for the use of low-rank coal upgraded by hydrothermal treatment as a CWF feedstock.[8]

An Italian firm, Snamprogetti, is the leading developer of bituminous CWF technology in Europe. Snamprogetti opened a 500,000 tpy CWF plant using its patented, "Reocarb" technology on Sardinia this year and is involved in the largest single CWF project to date in a joint venture with Russia.[9] When fully operational, 5 MM tpy of bituminous CWF will be produced in Belevo, Russia and transported 260 km by pipeline to Novosibirsk to power five 220 MWe generators.[9]

LOW-RANK COAL-WATER FUEL (LRCWF)

Until recently, the high inherent moisture in low-rank coals (LRCs) has precluded the use of these cheaper, more reactive coals to produce CWFs. To prepare concentrated LRCWFs, the inherent or equilibrium moisture must be reduced to levels similar to those for bituminous coals. Presently, the most promising method for effecting a permanent moisture reduction in LRCs is hydrothermal treatment, commonly called hot-water drying (HWD).[8,10,11] HWD is an advanced technology, developed at the Energy and Environmental Research Center (EERC) in Grand Forks, ND, USA. HWD features high-temperature/pressure, non-evaporative drying, which irreversibly removes much of the inherent moisture.[10,11] LRCWFs are non-toxic, easily transportable quasi-liquid fuels that avoid the stability problems of dust generation and spontaneous combustion normally associated with LRC in its dry bulk form.

HWD is accomplished by treating a slurry of pulverized LRC at high pressure and temperature in water. Sufficient residence time is provided to ensure that the interior of the largest particle reaches the desired temperature. Following HWD, the system pressure is reduced and excess water is removed by filtration or centrifugation leaving a LRCWF.[10,11] HWD is similar in many respects to pressure cooking, retaining most of the desirable characteristics of LRC.

Water is removed via expansion and expulsion by carbon dioxide (CO_2). Devolatilized tars and oils, being hydrophobic, are retained on the coal surface in the pressurized aqueous environment, giving a uniform tar distribution that seals most of the micropores minimizing water reabsorption.[11] By retaining most of the volatile matter in the form of tars, the high reactivity of LRCs, as well as most of the energy value, is preserved. HWD can be viewed as induced coalification which occurs in seconds rather than millenia required to convert LRC to bituminous coal in nature. However, since LRCs retain some of their oxygen functionality after HWD, they have significantly different properties than bituminous coals when slurried. Many hot-water dried LRCs are inherently stable and exhibit pseudo-plastic, shear thinning, rehology. Consequently, no stability enhancing or viscosity breaking additives are usually required. Typically the only additive recommended for LRCWFs is a biocide to prevent biological growth for fuel that is to be stored for some period of time before use. [10,11]

The technical feasibility of HWD has been demonstrated in a nominal 7.5 tpd pilot plant at the EERC.[11] The unit has operated for over a thousand hours with LRCs from around the world. As a general rule, the increases in energy density for LRCWFs versus coal water slurries prepared from untreated coals are 30% for subbituminous coals, about 50% for lignites, and well over 100% for brown coals, peat, and biomass.[8,10,11]

Derating of Oil-Designed Boilers for CWFs

In addition to costs for the conversion of oil-fired units to CWF, i.e., new atomizers/burners, additional soot blowers, and particle collection devices, a major concern of potential CWF users is the extent of any derating. In converting from oil to CWF-firing, it has been assumed that significant derating will occur. Derating is a complex phenomenon, dependant on coal, ash and CWF properties, as well as, boiler design. Until significant practical experience has been gained, there is little data to provide concrete examples of actual derating. Instead, there is a wealth of data generated from a variety of test combustors using bituminous CWFs exclusively that have been used to develop a number of derating models. While many of the models are proprietary, one developed by SAIC using the Burns and Roe boiler code has been widely reported.[12,13]

Derating factors include, fouling, slagging, carbon burnout and erosion. Fouling and slagging are determined by ash chemistry and maximum boiler temperatures. Carbon burnout is determined by coal reactivity, boiler temperature and residence time, atomization and agglomeration. Erosion, which is regarded as the most serious cause of derating, is a function of ash composition, ash particle size distribution (PSD), unburnt coal and velocity.[12,13]

In the SAIC code, the calculated derating is usually based on ash PSD and the resulting velocity limits. Ash PSD is more complex than just the maximum particle size determined by the size of the ground coal.[14,15] To achieve the current defacto standard CWF of around 69%, by weight, finely ground bituminous coal dispersed in water, costly, proprietary additives are required yielding a slurry that tends to be dilatent, i.e., shear thickening.[14] This characteristic has contributed to the need for significant expenditures to develop atomizers which will produce droplets ideally only slightly larger than the finely ground coal. However, since most bituminous coals go through a plastic stage when heated, they still tend to agglomerate producing particles many times larger than the ground coal.[14,15] Agglomerates lead to poor carbon-burnout and large ash particles, both of which contribute to lower boiler efficiency.[14]

The SAIC derating model suggests that if, in the absence of slagging or fouling, the ash composition and PSD allow a boiler to be operated at velocities used for oil firing, up to 120 ft/sec, derating should be less than 15%.[12,13] However, if ash properties indicate that velocities must be reduced by about third or more to avoid excessive erosion, derating will be from 20% to over 40%.[12,13] Obviously such severe derating will not encourage many boiler operators to switch from oil to CWF.

The perception that CWF applications in oil-fired boilers necessarily means a substantial derating is supported by recent tests in the U.S. using CWFs made from relatively unreactive bituminous coals. As an example, Penn State researchers have made extensive boiler tests with CWF made from a Pennsylvania bituminous coal with a fuel ratio of around 1.7 in their new 15,000 lb steam/hr, oil-designed boiler. To date no attempts to operate using CWF alone have been successful.[16] At least 23.7% natural gas is required to obtain acceptable performance, and even with this fuel support, the best carbon-burnout achieved to date is only about 95%.[16] Due to the fact that much of the funding and equipment used in these CWF tests comes from the State, Pennsylvania bituminous coals are the mandated feedstocks. Unfortunately, these coals usually lack the inherent reactivity to produce premium CWFs.

Another example of poor boiler performance is the recent testing performed for DOE and Jim Walter Resources by Energy and Environmental Research Corp. in a fire-tube boiler at the University of Alabama.[17] CWF was made from reject, low-volatile bituminous coal fines from the JWR coal preparation plant, and the results were similar to those at Penn State. The boiler could not be operated with CWF alone, but required natural gas assist. The maximum boiler load achieved was 80%, a 20% derating, even though the CWF accounted for only 62% of the energy input with the balance being natural gas.[17]

These examples imply that conversion from oil-firing to CWF-firing will require auxiliary fuel, yield carbon burnout of less than 95%, and result in deratings of over 20%. However, in reality, the poor performance was mainly due to the choice of the coal feedstock. Since, burning CWF is, in reality burning coal, the choice of a coal with low reactivity will inevitably result in poor performance in oil-designed boilers and advanced combustors. A more reactive coal, such as a high volatile bituminous coal, with a fuel ratio (fixed carbon/volatile matter) below 1.6 or virtually any LRC, all of which have high reactivity, should significantly improve combustion performance.

The most well documented, extensive test of CWF in an oil-designed boiler was the CWF demonstration at the Charlottetown power station, PEI, Canada, 1986-87.[15,16] The demonstration was a joint project of Energy, Mines and Resources Canada, Maritime Electric Co., Ltd., Cape Breton Development Corp. and the New Brunswick Electric Power Co. The Charlottetown boiler was a 20 MWe wall fired unit designed for oil with tube spacings of only 25 mm. The only modifications that were necessary were to add new burners, which could be operated with either oil or CWF, another soot blower and a baghouse.[18]

The CWF used in this tests was prepared by the Cape Breton Development Co. at their Victoria CWF Plant in Sydney, Nova Scotia. It was prepared from a beneficiated high volatile bituminous coal. CWF specifications were 69% solids, less than 4% ash, heating value of 10,500 Btu/lb and a viscosity below 1,000 cp.[18]

Two independent studies predicted that the unit would suffer nearly a 50% derating when it was switched from oil to CWF.[18] However, actual operation showed the unit could readily obtain 95% of the full load capacity of 20 MWe.[18] The maximum output obtained with CWF was 19.5 MWe with a boiler efficiency of 83.2%, compared with 85.4% on oil, a derating of less than 3%.[18] A key finding was that the bulk density of the ash produced with CWF was only about a third of that from fly ash produced from the same coal burned as a pulverized coal.[18]

LRCWFs do not require costly additives and have pseudoplastic flow behavior, which means that they are shear thinning and easily atomized.[10,11,14] In addition, LRCs have no tendency to agglomerate and, in fact, tend to blow apart when heated.[14] These characteristics produce a fuel that burns rapidly and completely. In all combustion tests, both at the EERC and at other combustion test facilities, LRCWFs burned significantly better than comparable bituminous CWFs.[14,19] Recent tests run in the GM Allison's coal-fired turbine simulator, with 5,000 gal. batches of LRCWF made from subbituminous coal hot-water dried in the EERC pilot plant, demonstrated the superiority of LRCWFs over commercial bituminous CWFs.[19] Carbon burnout obtained using a LRCWF with a mass mean diameter of about 15 microns was over 99% under all operating conditions. Carbon burnout obtained with commercial bituminous CWFs with similar PSDs, even under optimum operating conditions, was 4-5% lower.[19]

It is notable that with the correct choice of a feed coal, a CWF can be formulated that requires no auxiliary fuel, has carbon utilization at over 99% and results in a derating only a fraction of that calculated from mathematical models. This suggests that because of their higher reactivity and small ash size, CWFs produced from LRCs can be used in oil-fired boilers with little derating.

CWF Costs

Coal-water fuel costs are site and coal specific, especially for LRCWFs. Coal specificity determines the optimum HWD temperature for each LRC. As little as a 15 °C change in the temperature can cause as much as a 20% change in capital costs, due to the higher pressures.

The data used to develop CWF costs for a hot-water dried LRC were generated using EERC's HWD and combustion pilot plants using subbituminous coal from Placer Dome U.S. Inc.'s Beluga field west of Anchorage, Alaska.[11] This particular coal field is considered by many to be the world's largest and least expensive source of ultra low sulfur coal (less than 0.2% on a dry basis) near tidewater. Beluga LRC was treated by HWD and concentrated into a LRCWF with energy densities approaching 7000 Btu/lb.[11] It burned readily, giving over 99.8% carbon burnout with virtually no fouling; SO_2 emissions were far below compliance levels.[11]

Preliminary cost estimates to assess Beluga LRCWF competitiveness with heavy oil and bituminous CWF in Japan are presented in Table 1. HWD/

LRCWF costs have been estimated for Beluga LRC to range between $1.15 - $1.85 per MM Btus depending mainly on the size of the LRCWF production facility. With Beluga mining costs originally estimated at between $0.45 - $0.65 per MM Btus, and pipeline and marine transportation costs ranging from $0.88 to $1.04 per million Btus, the costs of a Beluga CWF are estimated to be between about $2.48 - $3.54 per MM Btus, CIF Japan.[11,20] Currently, this is well below the reported heavy oil price of $4.60 per MM Btus, and is competitive with bituminous CWF.[5,6,11,20] Comparable cost numbers were reported by Bechtel National, Inc., in a study for the North Dakota Lignite Energy Council on preparation and transportation of hot-water dried North Dakota lignite.[21]

CONCLUSIONS AND RECOMMENDATIONS

The following are a list of conclusions regarding the use of CWF produced from hot-water dried LRCs as an oil substitute:

- Too much attention has been placed on increasing the solids concentration of CWFs rather than focusing on combustion characteristics.
- Coal selection is critical in preparing CWFs with good combustion characteristics.
- A key to rapid ignition and carbon burnout is the reactivity of the feed coal, which is a function of the volatile matter content.
- As a general rule of thumb, coals with fuel ratios (Fixed Carbon/Volatile Matter) above 1.6 will not produce good CWFs.
- It has been shown via a commercial demonstration, that a high volatile bituminous coal can be formulated into a CWF that can be substituted for oil with a derating of less than 5%.
- Predicted derating of boilers converting from oil-firing to CWF-firing using current models are far to severe. With the proper coal selection, a derating of only a fraction of the calculated value is possible.
- CWFs are being produced in China and transported for use in Japan at prices well below those for heavy oil.
- It appears that LRCWFs can be produced in Alaska, by hot-water drying, and transported to Japan at prices comparable to or below those for bituminous CWFs.
- Due to the higher reactivity, low-rank coals are prime candidates to produce premium CWFs.
- A commercial demonstration of LRCWF in an oil-designed boiler is a critical need.

Based on the promising preliminary process economics and the enormous market potential for CWFs made from hot-water dried Alaskan coals, the next critical step in developing an Alaskan CWF industry is a

TABLE 1. Estimated costs for Beluga LRCWF made at the mine in a 1 MM tpy plant.

Operation	Cost Estimate ($/MM Btus) Low	High
Mining	0.45	0.65
HWD/LRCWF Production	1.15	1.85
Pipeline - Mono Buoy	0.24	0.24
Marine Transportation*	0.64	0.80
LRCWF Cost USD CIF Japan	2.48	3.54

*Shipping costs have decreased and, if new double hulled requirements are enacted for oil carriers, could be reduced further.

commercial-scale demonstration to instill confidence in potential users and enable them to develop their own economic analysis. Project sponsors have formed the Alaskan CWF Consortium to develop funding for the demonstration project. The Consortium consists of three principal organizations; Usibelli Coal Mine, Inc., Hobbs Industries, Inc., and the Energy and Environmental Research Center. Consortium affiliates include the Alaska Energy Authority, Cook Inlet Region, Inc., International Coal Preparation Consultants, Ltd., Major International Inc., Power Engineers, Placer Dome U.S. Inc., Tyonek Native Corp., and the University of Alaska Fairbanks.

There is a unique opportunity to demonstrate this technology in the dormant Knik Arm Power Plant owned by Hobbs Industries, Inc. near the Port of Anchorage, Alaska, USA, at a fraction of the time and cost it would take to build a new facility. This facility will be available as part of the overall cost share from the Alaskan CWF Consortium, which is seeking joint venture sponsorship for the three year, $25 MM demonstration project from the State of Alaska and the U.S. DOE.

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EXPORT MARKET POTENTIAL FOR ALASKAN LOW-RANK COAL-WATER FUEL

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ABSTRACT

Pacific Rim utility boilers in Japan, Taiwan and Korea consumed about 200 million barrels of high sulfur heavy oil in 1990. Low-Rank Coal-Water Fuel (LRCWF) is a product which is designed to replace heavy oil in utility and industrial boilers. Although heavy oil use is increasing in the Pacific Rim; there are plans in all three countries to gradually retire boilers which use heavy oil. A market can be developed for LRCWF by convincing the owners of the scheduled-to-be- retired boilers to convert them to use LRCWF. This would allow for a practical demonstration of the qualities of LRCWF while extending the life of the heavy oil boilers. Similar markets exist in Hawaii and Alaska. Rural Alaska also offers some opportunities to use LRCWF to replace diesel fuel. Alaska LRCWF faces competition in two major areas: the development by Japan of bituminous, or high rank, coal-water fuel, and a decision by the Japanese to begin to investigate LRCWF. A successful introduction of LRCWF could prompt users to assess the performance of Alaska low-rank coal in bulk form. A brief review of the steam-coal export market is given.

INTRODUCTION

Low-Rank Coal-Water Fuel (LRCWF) is relatively unique in world energy markets because it seeks to replace a petroleum product, heavy oil and/or diesel fuel, with a fuel developed from another energy source, coal. In order to clarify marketing goals, it should be noted at the onset, that LRCWF is not intended to compete with lump coals, either bituminous or subbituminous. LRCWF is designed to replace heavy oil and bituminous coal water fuels (CWFs) in existing oil-fired boilers. CWF is an attractive substitute for heavy oil primarily because it is based upon relatively stable coal prices and the cost of producing the fuel, not on volatile crude oil prices. In addition, the large and diverse number of established coal suppliers guarantees secure supplies.

THE MARKET

The first market comparison must be made between the expected cost of LRCWF and the current and expected export prices of crude oil and heavy oils. Prices for crude oil and residuals (heavy oil) are both important because although Japan uses residual fuels in its utility and industrial boilers, it also directly fires crude oil in some boilers. The price of LRCWF is site and coal specific but for Beluga coal, from the Beluga/ Yentna coal field, Alaska, it is estimated to range between \$2.48 and \$3.54 per million BTU, CIF Japan [1,2,3,4]. The high sulfur fuel oil market price in Japan, as cited by Nagata in September 1992, for example, was \$4.60 per million BTU with crude oil selling for \$17 per barrel [3]. The price of crude oil is expected to follow a trend of gradual increase while continuing to undergo fluctuations. The level is expected to edge up to between \$21-\$22 per barrel through 1995 and reach \$25-\$26 per barrel in 2000 [5]. Clearly, a market opportunity exists to replace heavy oil with LRCWF.

PACIFIC RIM MARKETS

The most likely large export market for an Alaskan LRCWF would be for Pacific Rim utility and industrial boilers. The magnitude of the potential market for CWF can be gauged by the consumption levels of heavy oil by utilities for the production of electricity in Japan, Taiwan, and Korea. In 1990, Japan required 141 million barrels of heavy oil for its oil-fired utility plants [6]. Taiwan's electric utility used 27 million barrels of heavy oil in 1990 and estimates this level of consumption of heavy oil will continue through the decade [7]. Korea's consumption of heavy oil for power generation in 1990 was 32 million barrels for a combined three-nation total of 200 million barrels [8]. The equivalent tonnage of CWF from low rank coal would be about 80 million tons per year. Capturing just 1 percent of that figure would more than double Alaska's current coal exports of about 750,000 tons per year (tpy).

The use of heavy oil in boilers is not limited to power utilities. While electric utility use of heavy oil in Korea in 1990 was 38 million barrels, total use was more than 122 million barrels [8], leaving an additional 84 million barrels of consumption, primarily in industrial boilers. Similarly, Japan has more than 2,000 industrial boilers operated with heavy oil [1], adding substantially to consumption totals.

THE CHALLENGE

The major marketing challenge facing LRCWF is to develop a way to offer owners of oil fired utility and industrial boilers an opportunity to test the fuel in a manner which does not detract from their current boiler use. Pacific Rim nations have developed long-term plans to reduce dependency on heavy oil by retiring oil-fired boilers and replacing them with other generating options such as coal, natural gas and nuclear [3,6,7,8,9]. However, oil-fired facilities continue to be added to meet increasing energy requirements. Heavy oil use in Korea has increased dramatically over the past several years. Oil use for Korea Electric Power Co. (KEPCO) rose from 32 million barrels in 1990 to 38 million barrels in 1991, and increased to 53 million barrels in 1992 [10]. KEPCO's heavy oil use is expected to peak in 1993 at 65 million barrels before gradually declining to 57 million barrels in 1995 [11].

A component of the LRCWF marketing effort should incorporate an effort to identify those oil-fired boilers which have been targeted for retirement. The owners of the boilers should then be approached with a proposal to test LRCWF in those boilers. A very attractive aspect of LRCWF would be that consumers would not have to retire their oil-fired plants, and could look toward low cost retrofitting for LRCWF-firing and extended life for the boilers. Reduced dependency on oil could be accomplished without the high cost of constructing new plants or retrofitting existing plants to utilize pulverized coal.

WESTERN HEMISPHERE MARKETS

Hawaii

Hawaii generates much of its electric power with heavy oil, and may be the first to feel the expected increases in fuel prices due to regulatory requirements, such as the use of double hulled tankers (Oil Pollution Act of 1990), as well as increased liability insurance requirements. Hawaii has initiated efforts to expand coal-fired power generation. Contacts with two utilities in Hawaii have demonstrated an interest in LRCWF. It is believed that marketing LRCWF to Hawaiian utilities can proceed at a pace faster than that with Pacific Rim countries because there are no language or cultural barriers to be overcome.

Mexico

Mexico is in the process of building new coal-fired generating capacity as rapidly as possible, particularly on its west coast. Since Mexican coals are so high in ash (38-50%), the current Mexican government philosophy is to avoid expanding or opening new domestic coal mines, but instead increase port capacity and import foreign coals. Contacts indicate Mexican power generation officials are interested in LRCWF as an oil substitute in existing units. LRCWF marketing efforts should continue to develop these contacts. At this point it is considered likely that Mexican utilities will want to test LRCWF once it is available in supplies large enough for meaningful tests.

MARKETING OPPORTUNITIES IN ALASKA

Virtually all of Alaska's more than 200 rural villages use diesel fuel for space heating and to generate electricity. Use of diesel for energy is both expensive and potentially hazardous. Since 1980, the State of Alaska, through a program now known as Power Cost Equalization (PCE), has provided financial assistance in the form of rate relief to rural utilities dependent on fuel oil as a means to generate electricity [12]. In FY 1991, the PCE program served 67,223 rural residents in 160 communities. Fuel oil consumed just by electrical utilities participating in the program was 23.5 million gallons at prices of up to $1.94 per gallon [13]. This does not account for heating use or industrial users such as mining, timber and fish processing. More than $19.6 million was spent by the State to subsidize rural electric rates in FY 1991 [13]. Until recent years, the PCE program was an adequate solution to assist rural communities. However, declining state oil revenues are threatening the program's future.

Rural Alaska also faces severe and immediate problems with bulk fuel storage facilities in many rural communities. These communities, primarily located in western and northern Alaska, are dependent on bulk fuel storage because the vast majority of fuel must be delivered by barge during a very brief ice-free shipping season and stored throughout the year [14].

A total of 44 communities were surveyed by the Alaska Energy Authority and consultants, and detailed engineering studies were prepared for 32 of the communities. The total estimated cost for complete repair and renovation of deficient diesel storage facilities in the 32 communities is $47 million [14]. The AEA has indicated it believes the cost to repair deficient facilities in rural communities statewide ranges from $200 million to $300 million. The cost of environmental remediation of extensive contamination was not included because it was not possible at the time to quantify the level of effort which may be required. In many instances, the remediation costs may far exceed repair costs [14].

The State of Alaska, through AEA, has a policy of diesel replacement wherever possible. There are many alternatives to oil, such as wind, hydro, solar, natural gas, and geothermal. However, detailed studies have shown in most cases those alternatives are not practical because of the surrounding environment or cost. CWF may be a viable alternative because it addresses both economic and environmental problems for rural Alaskan communities. The use of CWF could save from 25 percent to 35 percent in fuel costs alone. When considering increased operating efficiency and mitigation of environmental expenses, the savings become even greater.

In most rural applications, standard thermal power and heating equipment can be used in conjunction with existing fuel handling equipment to address power and heating needs using CWF. Although the capital cost is higher for thermal equipment than standard diesel equipment, thermal equipment has a much longer life, thus eliminating any disadvantage in a plant's life cycle cost. The ability to take advantage of standard equipment makes CWF very attractive from a maintenance and reliability stand point.

Research is underway to develop an internal combustion engine capable of running solely on CWF. LRCWF produced at EERC has proven that an internal combustion engine can run efficiently and cleanly on CWF. Tests of a low ash, LRCWF in a General Electric diesel engine gave equal or better carbon burnout than the commercial bituminous CWF [15].

TECHNOLOGY LICENSING

It is obvious that Alaska cannot begin to supply all the LRCWF that could be in demand if widespread oil substitution takes place. However, substantial revenues can still be generated through licensing the technology in areas where Alaskan LRCWFs are uneconomical. Licensing the technology presents a worldwide market opportunity. This opportunity may be most pronounced in developing nations where LRCs are the primary energy source.

COMPETITION

While resource-rich countries such as the United States, Canada, and Australia have no immediate need for the widespread use of alternative sources of energy, Pacific Rim countries such as Japan, Korea, and Taiwan, which have few natural energy resources, are actively pursuing the goal of reducing their dependence upon imported oil. To achieve that objective, the energy mix in those countries is being changed to include alternative fuels as an energy option to oil [3,6,7,8,9]. Of all the alternative coal-based fuels, coal water fuels are the most promising.

Today's coal-water fuel industry is based on the use of bituminous coals formulated into CWFs using costly, proprietary additives [3,4]. The high costs involved when coupled with the relatively low cost of fuel oil have led to a decreased interest in CWFs in North America. Canada, the world leader in CWF technology in the 1980s, has no bituminous CWF producers today [16]. However, in countries where fuel oil prices are much higher and where there are concerns over security of oil suppliers or the loss of hard currency for imported oil, a CWF industry is developing. Japan is aggressively pursuing the use of bituminous CWF as a direct replacement for oil. In addition to its own in-country CWF production capacity and plant construction programs, Japan is a joint venture partner in the ownership of CWF plants currently either in production or under construction in Mainland China [3,4]. Similarly, South Korea's largest oil refiner is investigating the construction of a CWF plant [8].

The estimated cost of Japan's bituminous CWF is $3.26 per million BTU; which is approximately in the middle of the cost estimate range for LRCWF [3,4]. The $3.26 figure should be viewed as a reasonable estimate of what Pacific Rim markets expect to pay for CWF, before adding any premium for such benefits as superior combustion, lower inherent sulfur and less boiler tube fouling.

To date, Pacific Rim countries have shown little interest in LRC because of perceived poor quality. Japan, in particular, appeared to place its initial dependence on bituminous coal for its CWF production, ignoring the superior combustion characteristics of LRC and LRCWF. This reliance, however, is in a state of change. A joint venture effort led by JGC Corporation surveyed processes to determine which was the most suitable to produce CWF from low-rank coal [17]. The joint venture selected the hot water drying (HWD) method developed by the Energy and Environmental Research Center of the University of North Dakota as the best and most appropriate low-rank coal up-grading process [17]. JGC Corporation has installed a bench scale test plant in its Kinuura Laboratory and is constructing a 1,100 pound-per-hour pilot plant in the Onahama Plant of its joint venture partner, Japan COM Company. The pilot plant is scheduled to begin operation in mid-1994. Assessment of a commercial scale plant is scheduled to begin in mid-1994 [17]. It would appear that the uncontested window of opportunity for Alaskan LRCWF has been defined.

Another competitor of LRCWF is a liquid fuel product called Orimulsion, which is also used as a substitute for heavy oil. Orimulsion is produced in Venezuela by emulsifying a natural occurring bitumen material rich in heavy hydrocarbons with 30% water [18]. In mid-1991, commercial contracts totaling 4 million tons per year had been signed with large utility and industrial users [18]. Additional boiler conversions to Orimulsion fuel are planned in the United Kingdom, Spain, Sweden, Japan, and Canada.

Compared to CWF, Orimulsion has a higher energy content and usually a lower ash content. However, Orimulsion has a very high sulfur content of 2.8 percent [18]; compared to a sulfur content of 0.1 percent in Alaskan LRCWF [19]. Initial use of Orimulsion in the United Kingdom has demonstrated higher emission levels of sulfur dioxide. The cost of emissions control equipment needed for air quality compliance can be a significant cost component in conversion to Orimulsion and may limit its use in many applications. Additionally, Orimulsion has significant heavy metals in its ash which may require that it be treated as hazardous waste, further limiting the attractiveness of the fuel [18].

Although viewed as a competitor, Orimulsion should also be recognized for the positive effect it may have on LRCWF because of its role in demonstrating that a coal-like liquid fuel can be used successfully in heavy oil boilers. LRCWF marketing efforts can point to the success of Orimulsion as a reason a utility or industrial user should consider the testing and use of LRCWF.

LRCWF'S ENVIRONMENTAL PREMIUM

The environmental impact of oil spills and the requirements of the Oil Pollution Act of 1990, including the requirement for double hulled tankers, will enhance the attractiveness and competitiveness of LRCWF.

Any marketing effort should stress the "environmentally benign" aspects of the fuel should a spill occur, whether on or offshore. With a spill on land, the coal could be reclaimed by hand tools or heavy equipment after the water has evaporated or been absorbed by the ground. Offshore or fresh water spills also pose no environmental threat. The coal particles will disperse with the current, settle out, and mix with bottom sediments. Since the coal is inert and the sulfur is insoluble in water, there is no acid leaching and no harm is posed to sea life of any kind.

ALASKAN LRCWF DEMONSTRATION PROJECT

A consortium led by Usibelli Coal Mine, Inc. and the University of North Dakota's Energy & Environmental Research Center is seeking public sector partial funding for a low rank coal water fuel commercial demonstration project in Anchorage. Other consortium members include Placer Dome US Inc., Cook Inlet Region Inc., International Coal Preparation Consultants Ltd., Major International, Environmental Services Ltd., and Tyonek Native Corp. Affiliates include the University of Alaska Fairbanks (Mineral Industry Research Laboratory) and the University of Alaska Anchorage (Center for International Business).

The LRCWF demonstration project will last 36 months. Prior to initiation of the project, it is the intent of the LRCWF Consortium to engage an end user as a consortium member. The extent of end user participation could range from an agreement to purchase LRCWF to equity participation in the project. The first 18 months will be devoted to completing design and permitting activities, receiving equipment and supplies, and completing construction or refurbishing. After a shakedown period, demonstration runs will begin with Usibelli coal and conclude with three months of test runs using Beluga and Little Tonzona coals. Marketing during the first 18 months will concentrate on developing agreements with potential users to test the fuel in their boilers and to purchase LRCWF upon completion of a successful demonstration project.

As soon as data are developed on the properties of the LRCWFs from each test coal, site specific process economics will be developed. Specific test data will include coal preparation steps, preferred HWD operating parameters, LRCWF rheology, all the combustion parameters, and emission control and waste disposal/utilization options. These results will be used with input from consulting engineers, Alaskan native corporations, DEC and other state agencies as required, and potential coal suppliers and LRCWF users to develop coal and site specific process economics.

In addition, pipeline, overland, and marine transportation issues will be addressed as part of the ongoing economic assessment for each coal. Site specific transportation alternatives, i.e., pipeline versus rail versus truck haulage where applicable, will be evaluated. The lowest cost option will be integrated with the process economics to determine required selling costs for both the export and Alaskan markets. These economic data will become the basis for marketing the technology, and developing the financial backing for a 1 million ton per year commercial LRCWF production facility in Alaska.

EDUCATIONAL AND TRAINING OPPORTUNITIES

It is the intent of the LRCWF Consortium to continue to operate the test facility upon completion of the demonstration project. Other Alaskan coals, as well as coals from around the world, could be tested for LRCWF applicability. In addition to the demonstration of the technical and economic feasibility of CWF production, the facility would offer many opportunities for University of Alaska involvement for teaching, training, and research. Teaching and training could cover a broad range of interests, from graduate education to non-degree technical training. Research activities would be more specifically directed at unit processes of HWD, combustion engineering, and international marketing.

On a graduate level, the University of Alaska's mineral preparation engineering (MPR) program would likely be the largest beneficiary of the CWF demonstration project. This program has in the past produced and continues to produce masters students with expertise in coal preparation, including coal drying. The facility would become a practical laboratory for MPR students, who could research both practical problems encountered during the demonstration project and longer term, basic research directed towards future LRCWF process development.

Likewise, undergraduate students from many disciplines could use the facility for field trips, senior projects and laboratory sessions. A very exciting aspect of the university's interaction with the demonstration project, as well as that of the Alaskan native corporations such as Doyon Ltd., is non-degree technical training in the areas of coal beneficiation and power plant operation and maintenance. This may become a more important part of the facility's educational function, should rural Alaska communities begin the transition from diesel/electric generator sets to coal-fired power generation.

STEAM (THERMAL) COAL EXPORT MARKET

Although LRCWF is intended as a substitute for heavy oil in existing oil-fired boilers, its successful use may prompt users to assess the performance of Alaska low-rank coal in bulk form. Therefore, a brief review of the steam coal export market is appropriate.

It is expected that the steam coal demand for Japan, Korea, and Taiwan alone will exceed 100 million tons per year by the end of this century (see Table A below [5, 6, 7, 8, 10]). However, within this predicted growth, representing tens of thousands of megawatts of new boiler capacity, currently there are concrete plans to design only two facilities for LRC firing.

Of the 29 new plants, representing more than 15,000 M, to be built in Korea by the year 2006, only two plan to use LRC [10]. These plants, Samchonpo #5 and #6, will generate 550 MW and will each consume about 1.2 million tpy of LRC.

Korean Electric Power Co. (KEPCO) will accommodate LRC in boilers designed to operate with coals containing between 7,700 to 10,300 BTU per pound, down from the usual range of 9,500 to 11,300 BTU per pound [10]. For Alaska to be successful in winning Samchonpo contracts, the bids must be competitive and will be based on the going Australian steam coal price. That price, as the basis for negotiation, will be decreased in direct proportion to the heat content of the coals.

KEPCO has indicated that Alaskan LRC should expect stiff competition from LRCs from China, Indonesia, and Russia [10]. However, Russia and China are not expected to become immediate competitors due to each country's infrastructure problems and overwhelming need for domestic power. The threat of Indonesian LRC is real, however, because that country is rapidly expanding its port and mining capacity. Indonesian coal may also have environmental qualities equal to or better than Alaskan LRCs. KEPCO has invested in at least on Indonesian LRC property. In any event, KEPCO indicates the expected share for Alaskan LRC would be around 40 percent, a figure which would double the size of Alaska coal exports [10].

TABLE A. Current and projected steam-coal imports

	1990	1995			2000		
	MM tons	MM tons	% Increase	% /year	MM tons	% Increase	% /year
Korea	10.1	24.0	137	19	36.9	265	14
Japan	34.7	51.5	49	8	74.8	116	8
Taiwan	13.0	21.6	16	11	27.4	110	8
Total	57.8	97.1	68	-	139.1	141	-

Without a significant change in the perception of LRCs by Pacific Rim coal importers, LRCs will largely be excluded from this rapidly expanding steam coal market. Demonstration of the economic viability of producing clean, low cost power from LRCWFs at a commercial scale will be the most effective method for moving Alaska decisively into the emerging international CWF trade. LRCWF represents the quickest way of significantly increasing the size of Alaskan coal exports. It also offers the prospect of overcoming the perception of many Pacific Rim coal importers that LRCs are low quality fuels. As LRCWF users become familiar with the superior combustion performance, they may want to assess LRC performance in dry bulk form. This, in turn, could lead to widespread acceptance and use of LRCs in the rapidly expanding steam-coal market.

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APPLICATION OF CORRELATION MODELS FOR PREDICTING HEAT CONTENT OF ALASKAN COALS

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ABSTRACT

This paper discusses the results of a study aimed at evaluating the reliability of some existing models derived from ultimate and proximate analyses data in predicting the heating value of Alaskan coals.

About 247 coal samples from the major coal mines in Alaska were used in the study. The proximate and ultimate analyses data obtained from previous studies were used. The reliability of these models were compared and constrasted with each other.

Models derived from ultimate analysis were better than that derived from proximate analysis in predicting the heating value of the Statewide, Northern, and Southern coals, while they were comparable in predicting the heating value of the Interior Alaska coals. In geneal, the heating value was predicted to within less than about 100 Cal/g.

INTRODUCTION

Alaska's coal resources account for about half of the United States coal resource base[1]. These coals are of Cretaceous and Tertiary age[2] and are mainly of subbituminous A to high volatile A bituminous ranks.

The bulk of Alaska's coals are found in the Northern Alaska basin where more than 4 trillion tons of coal are deposited[3]. Coals in the Northern Alaska are mainly subbituminous and bituminous[1]. The next largest coal deposits of Alaska are located in the Cook Inlet-Susitna Basin, with estimated reserves of over 1 trillion tons, most of which are low-rank[3].

Alaskan coals are generally very low in sulfur and moderately low in ash. They are therefore, excellent candidates for clean power generation. Low fouling/slagging potential is expected as a result of the low ash content. SO_x emissions are also expected to be below Environmental Protection Agency (EPA) acceptable limit of 0.4 lb. $SO_2/10^6$ Btu. In addition, Alaskan coals are very reactive and are, therefore, excellent feedstocks for utilization in gasifiers and other advanced coal utilization technologies.

Heat content, that is, the quantity of heat per unit mass of coal (which is commonly called calorific value or heating value) is an important parameter for assessing the economic value of coal. Price of coal is now commonly quoted in dollars/Btu ($/Btu). Coal buyers and users depend on calorific value in order to design and/or modify their plant for efficient operation. Calorific value is, therefore, an important measure of coal quality and is usually required along with other important properties of coal (such as elemental and proximate analyses) by respective coal buyers and users.

Calorific value, and these other coal properties are generally determined by analytical techniques. The advent of advanced instrumentation has made the proximate and ultimate analyses of coal quicker and cheaper to obtain than determining its heating value. In view of this, theoretical computation of heating value from the elemental composition appears to be economically justifiable. Many theoretical equations have been proposed for predicting the heating value of solid and liquid fuels[4-13]. Some of these equations are more or less empirical correlations and are most suitable for predicting the heating value of liquid fuels[6,8-11]. Mott and Spooner[5] proposed an equations for predicting the heating value of low-rank coals, that is, coals with more than 15% oxygen content on a dry, ash-free basis. This equation was later modified by Given and co-workers[4]. Equations have also been proposed for predicting heating value from the proximate analysis of coal[12]. While all these equations have been used for predicting heating value of coals from many parts of the world, including coals in the lower 48 states of the U.S.[4], Europe[10], South Africa[10], and Australia[10,13], they have not been applied to Alaskan coals. The Pennsylvania State University coal databank were used for the previous studies on U.S. coals. At the time those studies were conducted, Alaskan coals were not included in the Pennsylvania State University coal databank.

This paper presents the results of the first study to apply some existing correlation equations to Alaskan coals.

DATA COLLECTION AND ANALYSIS

Coal Samples and Data Used

The Mineral Industry Research Laboratory (MIRL), University of Alaska Fairbanks (UAF) has been actively involved in characterizing Alaskan coals for many years. The MIRL coal analysis databank was therefore used for this study. Coals ranging from lignite to high volatile bituminous were used in the study. These samples represent coals from the major Alaskan coal fields. For the purpose of this study, the coal fields were classified into three regions, Northern region, Interior region, and the Southern region. The Northern region can be considered to consist of coal fields north of the Brooks Range. The major fields in this region considered in this study include mainly the Deadfall Syncline coal field and the Cape Beaufort coal field. The Interior region coal fields include mainly the Nenana, Little Tonzona, and the Jarvis Creek coal fields. This region falls between south of the Brooks Range and north of the Alaska Range. The Southern region, which falls south of the Alaska Range, consists mainly of the Kenai, Beluga, Yetna and Susitna coal fields.

Data on about 247 well characterized samples from the various fields were obtained from MIRL databank. The data of importance to this project were the proximate and ultimate analyses, and heating value. The data were divided into two sets. Table 1 gives the ultimate analysis and the measured heating value, while Table 2 summarizes the proximate analysis and the measured heating value.

Application of Existing Correlation Equations Derived from Ultimate Analysis Data

The aim is to assess the suitability of existing correlation equations in predicting heating value of Alaskan coals from the ultimate analysis. The following equations, expressing the heating value, Q (Cal/g) in terms of the elemental compositions in weight percent on dry, ash-free (daf) basis was used.

$$Q = 80.8C + 345H + 22.5S - 43.1O \quad \text{[Eq. 1]}$$

$$Q = 80.3C + 339H + 22.5S - 34.7O \quad \text{[Eq. 2]}$$

$$Q = 80.3C + 339H + 22.5S - 36.6O + 0.172O^2 \quad \text{[Eq3]}$$

$$Q = 78.34C + 339H + 22.1S - 33.0O + 152 \quad \text{[Eq. 4]}$$

$$Q = 84.0C + 278H + 25.0S - 26.5O + 15.0N \quad \text{[Eq. 5]}$$

The first four equations are based on Dulong's law, which states that the heat generated by a fuel during combustion is approximately equal to the sum of the heats generated by its component elements. Equation 1, proposed by Francis and Lloyd(8), is one of the earliest expression of Dulong's law. Modifications of this equation by Mott and Spooner(5), who made empirical correlations for the finite enthalpy of decomposition of coal, yielded equations 2 and 3. Equation 3 was proposed to take care of low-rank coals with oxygen content greater than 15%. Equation 4 was proposed by Given and co-workers(4) who explicitly included ethalpy of decomposition as a separate term. Equation 5 is empirically derived by Boie(7) for solid and liquid fuels.

The value of Q was computed for all the samples listed in Table 1 using the above-listed equations. The predicted heating value in each case was then compared with the measured value given in Table 1. The closer the value of predicted heating value, Q to the corresponding measured value, Qm, the better is the equation.

Application of Existing Correlation Model Derived From Proximate Analysis

This approach is relatively newer than via ultimate analysis. The first equation relating heating value to components of the proximate analysis was proposed by Goutal (reported by Ernest & Fyans(14)) who expressed heating value Q (Cal/g) in terms of fixed carbon F and volatile matter V, contents in weight percent on moisture-free basis. This is written as:

$$Q = 82F + aV \quad \text{[Eq. 6]}$$

where a is a coefficient which varies with the volatile matter content of the coal. Variation of Goutal coefficient "a" with volatile matter content is illustrated in Table 3. The value of Goutal coefficient is obtained based on the dry ash-free volatile matter while the Goutal equation (Eq. 6) itself uses volatile matter and fixed carbon contents on moisture free basis. Goutal equation implies that a constant correlation of 82 calories per percent of fixed carbon exist [14]. However, the contribution of. volatile matter to the heating value depends on the volatile matter content since 'a' varies with volatile matter[14], stressing the empirical nature of the equation. Another observation from Goutal formulas is that the correlation is forced to pass through the origin ignoring the possibility that the natural correlation intercept could be higher.

The Goutal equation was applied to the proximate analysis data shown on Table 2 to obtain predicted heating value for each of the coal samples. The calculated value Q was again compared with corresponding measured value, Qm.

RESULTS AND DISCUSSIONS

Tables 1 and 2 illustrate the ultimate and proximate analyses and measured heating value of the coal samples used in this study. As mentioned earlier, Equations 1-5 were applied to the ultimate analysis data on Table 1 while Equation 6 was applied to the proximate analysis data on Table 2 to estimate the heating value of the coal samples. The performance of each equation in predicting the heating value of Alaskan coals was determined by subjecting the results to statistical analysis.

Prediction Using Ultimate Analysis Data

The five existing equations (Eq. 1-5) relating heating value with elemental compositions of coal (C, H, N, S, O) obtained via ultimate analysis yielded heating values that were compared with corresponding measured value.

Denoting the difference of the measured and calculated heating values for sample number i by $\delta_i = Q_{mi} - Q_i$, we define the mean of the absolute differences by

$$\Delta = \frac{1}{N} \sum_{i=1}^{N} |\delta_i| \qquad \text{[Eq. 7]}$$

and the mean of the absolute relative differences by

$$\Delta_r = \frac{1}{N} \sum_{i=1}^{N} |\delta_i|/Q_i \qquad \text{[Eq. 8]}$$

The statistics for the distribution of δ_i are the mean difference

$$\bar{\delta} = \frac{1}{N} \sum_{i=1}^{N} \delta \qquad \text{[Eq. 9]}$$

and and the standard deviation of the differences

$$\sigma_\delta = \left[\frac{1}{N} \sum_{i=1}^{N} (\delta_i - \bar{\delta})^2 \right]^{1/2} \qquad \text{[Eq.10]}$$

Table 4 summarizes the results obtained. The mean difference values in Table 4 show that the heating value of Alaskan coals can be predicted by Eq. 2, 3, and 4, to within the acceptable interlaboratory variation of measured heating value (55.5 Cal/g) recommended by American Society for Testing and Materials (ASTM). The value of mean difference obtained for Eq. 1 (due to Francis and Lloyd (δ)) and from the Boie empirical formula (Eq. 5) are higher than the the ASTM acceptable experimental difference. The results of the calculated mean difference o(δ,·), show that the heating value of all the Statewide samples can be predicted to within about 3.5 Cal/g by the theoretical formula derived by Mott and Spooner [5] for low rank coals (Eq. 3).

Considering only the mean of absolute relative difference values, shown in Table 4, it appears that Eq. 3 (proposed by Mott and Spooner[14]) is the best of all the equations (with Δr value of 1.10,%) in predicting the heating value of Alaskan coals. This is followed by Eq. 4 (proposed by Given et al.[4]). Eq. 1 is the poorest (with Δr value of 2.0%) in predicting the heating valuof the Statewide set of samples.

A comparison of the Δr value obtained for Equation 5 in this study with those reported by Boie, et al. [7] and Ringen, et al. [8] suggests that Eq. 5 better predicts the heating value of Alaskan coals than Wyoming coals. Ringer et al. [8] reported Δr value of 1.86% for 54 Wyoming coal samples when Eq. 5 (due to Boie, et al. [7]) was applied. This is higher than the 1.68%

obtained in this study for Alaskan coals. Also, application of Eq. 5 to western Canadian upgraded low rank coals by Friesen and Ogunsola[15] yielded a higher Δr value than obtained in the present study. Again, this implies that Eq. 5 gives a better prediction of Alaskan coals than it is of western Canadian coals and Wyoming coals. Similarly, Eqs. 1-4 predict the heating values of Alaskan coals better than those of western Canadian coals. Δr values for Eq. 1-3 were reported to be greater than 2% for western Canadian coals[15]. Results obtained by Given et al.[4] who applied Eq. 4 to 1004 coals from the lower 48 yield relatively poorer prediction for those coals than for Alaskan coals. The value of the mean difference reported by Given et al. [4] for coals from the various provinces in the U.S. as well as all the coals together varies from about 31.5 Cal/g for all lignite samples to about 62 Cal/g for all coal samples. Also, about 71 Cal/g was obtained for all coals from the Eastern province. These values are much higher than the 9.5 Cal/g obtained for Alaskan coals.

In order to evaluate the difference (if any) in the predictability of the heating value of coals from the different regions, the Statewide coal samples were separated into three groups based on the three different regions. Eq. 1-5 were then applied to the elemental analysis data set in each region. Table 4 shows values of the mean absolute difference, mean absolute relative difference (Δr), the mean difference (δ^-)), and the standard deviation of relative difference (σ_g) obtained by subjecting the measured and calculated heating values for each formula to statistical analysis.

From the results, it appears that the heating values of the Northern coal samples are better predicted by all the five equations than those of the Interior coals which in turn are better predicted than those of the Southern coals except for Eq. 1 and 2 which give a better prediction for of the Southern coals than the Interior coals. The reason for the better prediction of the heating value of the Northern region coals is probably because of the less variation in the elemental composition of these coals compared to the Interior and Southern coals. This is supported by the results obtained by Given and his co-workers[4] when Eq. 4 was applied to 10014 coal samples from the lower 48 states. In general, the performance of each of the five formulae in predicting the heating value of the Northern coals is about two times better as that of the Interior and Southern coals. The heating values of the statewide coal samples are even better predicted than for both the Interior and Southern coal samples (see Table 4). In summary, the order of predictability for the Northern coals, is:

$$\text{Eq. } 5 < \text{Eq. } 4 < \text{Eq. } 1 < \text{Eq. } 2 < \text{Eq. } 3$$

For the Interior coals, the order is:

$$\text{Eq. } 1 < \text{Eq. } 5 < \text{Eq. } 2 < \text{Eq. } 3 = \text{Eq. } 4$$

and for the Southern coals the order is:

$$\text{Eq. } 1 < \text{Eq. } 5 < \text{Eq. } 2 < \text{Eq. } 4 < \text{Eq. } 3$$

For the Statewide samples, the order is:

$$\text{Eq. } 1 < \text{Eq. } 5 < \text{Eq. } 2 < \text{Eq. } 4 < \text{Eq. } 3$$

Figures 1 and 2, which are plots of measured versus predicted heating value for Eq. 3 and 5, pictorially illustrates the superiority of Eq. 3 (the best) over Eq. 5 (the poorest). Although it appears that Eq. 3 (due to Mott and Spooner[5]), which was developed for low-rank coals (coals with >15% oxygen content), is better than most of the other formulae for predicting the heating value of low rank coals in the Interior and Southern Alaska. It is not as good as Eq. 4, proposed by Given et al.[4], particularly for the Interior Alaskan coals (see Figs. 1 and 3 and Table 4). The difference between measured and calculated heating value by Eq. 4 is pictorially illustrated in Fig. 3. Notice the difference in the degree of scatter in the data of the different sets of coal.

Predictions of Heating Value from Proximate Analysis Data

In order to evaluate the reliability of predicting the heating value of Alaskan coals from the proximate analysis data (fixed carbon, volatile matter, and ash contents), Goutal formula (Eq. 6), which utilizes fixed carbon and volatile matter, was applied. This equation was forced to pass through the origin, hence there is no intercept.

Table 5 shows the mean difference, mean of absolute relative difference, and average absolute difference Results presented on Tables 4 and 5 provide a basis for comparing and contrasting the use of existing equations derived from ultimate analysis and proximate analysis data for accurate prediction of the heating value of Alaskan coals. From the results on Tables 4 and 5, it is obvious that all the formulae derived from ultimate analysis data (Eq. 1-5) are better than the Goutal formula (Eq.6) derived from the proximate analysis data in predicting the heating value of the statewide coal samples used in this study. For example, the worst model (Eq. 1) obtained from the ultimate analysis, which predicts the heating value of the statewide samples to within 2%, is better than the Goutal formula (Eq.6). Hence, prediction of heating value of statewide sample set is more reliable using the formulae derived from ultimate analysis than from the proximate analysis. On regional basis, the formula derived from proximate analysis appears to predict the high rank coals of the Northern region better than it does for the lower rank coals of the Interior and Southern Alaska. The Northern coals can be predicted to within 6% while those of the Interior and Southern regions can respectively be predicted to 12% and 14%. Extent of predictability of Eq. 6 is pictorially illustrated in Figure 4.

Although, the results obtained in this study suggest that the heating value of Alaskan coals can better be estimated from the ultimate analysis than from the proximate analysis data, it is recommended that correlation models obtained from proximate analysis be used to estimate the heating value of coals, particularly from a new field. It is more economical to use equation involving proximate analysis to estimate the thermal quality of a new field during exploration since it is cheaper to obtain proximate analysis than ultimate analysis. Besides, proximate analysis of coal must be done before ultimate analysis and heating value can be reported on the conventional dry, ash-free basis. So, just obtaining the proximate analysis can reasonably (within less than 100 Cal/g) estimate the heating value on any basis of choice. Whereas, if you determine the heating value either experimentally or by calculation from the ultimate analysis, you still need to determine the proximate analysis.

CONCLUSIONS

The aim of this study has been application and evaluation of appropriate models for estimating the thermal quality of Alaskan coals from proximate and ultimate analyses data.

About 247 coal samples from the major coal fields in the Northern, Interior, and Southern Alaska were used in the study. The fields of study include those from the Deadfall Syncline, Nenana, Jarvis Creek, Little Tonzona, Beluga-Yetna, Kenai, Chicnuk, and Matanuska. Five existing formulae (Eq. 1-5) derived from ultimate analysis data and one derived from fixed carbon and volatile matter (Eq. 6) were applied to Alaskan coals to determine their reliability in predicting the heating value of these coals.

From the results, the heating value of Alaskan coals could generally be predicted to within 100 Cal/g of the average value by the existing formulae derived from ultimate analysis. The Goutal formula (Eq. 6), derived from proximate analysis was off by more than 10 percent. for the statewide, Interior, and Southern coals.

The accuracy of prediction was found to vary with equation and coal region. For example, the Northern coals were best predicted by all the models. However, Eq. 2 was the best for the Northern coals.

In spite of the relatively better accuracy exhibited by equations derived from the elemental analysis data over that derived from the proximate analysis in predicting the heating value of Alaskan coals, the Goutal formula (Eq. 6) obtained from fixed carbon and volatile matter can still be used to estimate the thermal quality of a new coal field.. This is because of the economic advantage that would be derived from using proximate analysis data over those of ultimate analysis. For example, proximate analysis has to be done in order to report ultimate analysis and/or heating value on the conventional dry, ash-free basis. This is particularly attractive for assessing the thermal quality of a new exploratory coalfield.

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Table 1: Ultimate Analysis and Measured Heating Value of Alaskan Coals Samples Used

Region	Dry, Ash Free C (wt.,%)	H (wt.,%)	N (wt.,%)	O (wt.,%)	Total Sulfur (wt.,%)	Heating Value Cal/g
Interior	68.68	5.18	0.89	25.07	0.18	6736
Interior	70.47	5.01	0.79	23.48	0.25	6771
Interior	70.38	5.23	0.88	23.05	0.46	6687
Interior	70.54	5.43	0.92	22.73	0.38	6655
Interior	69.81	5.34	1.74	22.60	0.51	6663
Interior	69.51	5.16	0.81	24.24	0.27	6526
Interior	69.67	5.16	0.89	24.03	0.25	6546
Interior	68.97	5.21	0.82	24.69	0.31	6495
Interior	66.21	4.93	0.45	27.55	0.87	6077
Interior	68.73	5.20	0.75	25.09	0.23	6486
Interior	70.29	5.45	0.90	22.96	0.40	6642
Interior	68.40	5.54	0.94	24.84	0.28	6574
Interior	69.54	5.60	0.93	23.37	0.56	6579
Interior	68.60	4.97	0.93	25.30	0.20	6529
Interior	72.90	5.56	1.15	20.18	0.21	7015
Interior	71.01	5.24	0.96	22.54	0.25	6769
Interior	70.69	5.15	0.81	23.06	0.29	6603
Interior	71.21	5.09	0.83	22.62	0.25	6623
Interior	70.77	5.13	0.78	23.08	0.23	6603
Interior	69.54	5.49	0.87	23.78	0.33	6584
Interior	69.63	5.56	0.90	23.44	0.46	6596
Interior	69.76	5.30	0.84	23.54	0.56	6652
Interior	69.59	5.12	0.83	24.18	0.27	6658
Interior	70.09	5.34	0.83	23.50	0.24	6643
Interior	70.39	5.44	0.89	22.84	0.44	6626
Interior	69.62	5.20	0.87	23.82	0.49	6636
Interior	70.64	5.22	0.85	22.96	0.33	6685
Interior	70.00	5.22	0.87	23.39	0.53	6731
Interior	70.35	5.16	0.90	23.00	0.59	6682
Interior	69.70	5.14	0.92	23.64	0.60	6672
Interior	70.67	5.01	0.94	22.97	0.41	6681
Interior	69.43	5.44	0.98	23.57	0.59	6623
Interior	68.49	5.15	0.85	25.19	0.32	6627
Interior	68.66	5.24	0.88	24.93	0.28	6653
Interior	70.11	5.17	0.85	23.59	0.29	6575
Interior	69.97	5.07	0.77	23.92	0.27	6556
Interior	69.69	5.33	0.87	23.63	0.49	6569
Interior	70.75	5.36	0.91	22.31	0.67	6619
Interior	69.85	5.42	0.89	23.53	0.32	6622

Table 1: (Cont.)

Region	C (wt.,%)	H (wt.,%)	N (wt.,%)	O (wt.,%)	Total Sulfur (wt.,%)	Heating Value Cal/g
	Dry, Ash Free					
Interior	69.25	5.30	0.85	24.36	0.25	6727
Interior	65.73	5.22	0.86	27.90	0.29	6659
Interior	69.29	5.43	0.88	24.11	0.28	6709
Interior	67.24	5.54	0.91	25.93	0.38	6016
Interior	73.81	4.19	1.14	20.43	0.43	6799
Interior	74.33	3.66	0.92	18.86	2.23	6818
Interior	71.09	4.82	0.59	22.01	1.49	6781
Interior	69.43	4.83	1.09	24.08	0.57	6693
Interior	71.73	3.42	0.76	21.30	3.21	6703
Interior	70.83	5.02	1.13	21.53	1.49	6906
Interior	73.17	4.72	0.55	21.23	0.33	7042
Northern	84.18	4.96	1.43	9.05	0.37	8123
Northern	84.15	4.76	1.57	9.12	0.40	8124
Northern	83.11	5.30	1.27	10.02	0.31	8112
Northern	83.13	5.29	1.50	9.74	0.34	8117
Northern	82.79	5.18	1.48	10.17	0.39	8129
Northern	82.82	5.36	1.57	9.88	0.37	8134
Northern	82.97	5.38	1.39	10.03	0.23	8134
Northern	83.15	5.25	1.48	9.82	0.30	8143
Northern	82.58	5.56	1.67	9.72	0.47	8136
Northern	83.70	5.04	1.53	9.54	0.20	8097
Northern	80.75	5.50	1.71	11.56	0.49	7932
Northern	80.64	5.32	1.51	12.01	0.53	7953
Northern	82.78	4.68	1.41	10.93	0.20	7862
Northern	80.41	5.34	1.61	12.19	0.46	7876
Northern	83.78	5.06	1.44	9.42	0.31	8058
Northern	82.93	5.20	1.78	9.79	0.30	8087
Northern	83.38	5.08	1.41	9.80	0.33	8092
Northern	83.19	5.04	1.50	10.04	0.24	8058
Northern	82.34	5.34	1.73	10.13	0.46	8061
Northern	82.81	5.46	1.52	9.85	0.36	8144
Northern	83.32	5.45	1.25	9.75	0.23	8221
Northern	83.29	5.55	1.23	9.65	0.28	8226
Northern	82.85	5.56	1.26	10.08	0.24	8199
Northern	82.86	5.52	1.17	10.26	0.20	8210
Northern	83.04	5.61	1.36	9.75	0.24	8229
Northern	83.54	5.75	1.48	9.01	0.21	8259
Northern	83.98	5.34	1.68	8.70	0.30	8259
Northern	83.45	5.52	1.74	8.98	0.31	8254
Northern	83.27	5.53	1.26	9.75	0.19	8257
Northern	83.45	5.46	1.38	9.49	0.21	8198
Northern	83.70	5.24	1.40	9.05	0.61	8172

Table 1: (Cont.)

	Dry, Ash Free					
Region	C (wt.,%)	H (wt.,%)	N (wt.,%)	O (wt.,%)	Total Sulfur (wt.,%)	Heating Value Cal/g
Northern	82.92	5.46	1.80	9.48	0.34	8177
Northern	83.28	5.29	1.30	9.76	0.38	8158
Northern	82.76	5.67	1.58	9.73	0.25	8169
Northern	81.83	5.60	1.75	10.60	0.22	8179
Northern	83.60	5.25	1.54	9.32	0.29	8188
Northern	83.94	5.31	1.47	8.95	0.32	8191
Northern	83.53	5.41	1.18	9.68	0.21	8181
Northern	82.91	5.70	1.58	9.36	0.45	8184
Northern	83.50	5.17	1.39	9.7	0.24	8053
Northern	83.77	5.14	1.44	9.19	0.46	8134
Northern	83.64	5.09	1.42	9.6	0.25	8115
Northern	84.76	5.38	1.43	8.13	0.29	8019
Northern	84.11	5.49	1.43	8.75	0.23	8259
Northern	83.99	5.36	1.42	8.98	0.26	8212
Northern	85.18	5.26	1.46	7.84	0.27	8179
Northern	83.44	5.38	1.28	9.66	0.23	8083
Northern	82.87	5.17	1.25	10.42	0.28	7945
Northern	83.24	4.94	1.17	10.37	0.28	7896
Northern	83.64	4.65	1.24	10.25	0.22	7858
Northern	83.43	5.41	1.19	9.73	0.25	8214
Northern	84.40	5.29	1.38	8.58	0.34	8151
Southern	70.48	5.38	1.04	22.91	0.19	6718
Southern	70.58	5.45	1.04	22.71	0.21	6759
Southern	71.22	5.32	0.97	22.29	0.20	6792
Southern	69.80	5.56	0.99	23.37	0.28	6674
Southern	67.59	5.11	0.79	26.35	0.16	6593
Southern	67.16	5.24	0.73	26.35	0.08	6576
Southern	70.77	5.42	1.07	22.55	0.20	6793
Southern	67.55	5.68	1.05	25.33	0.39	6556
Southern	71.38	5.06	1.25	21.88	0.43	6869
Southern	70.25	5.76	1.12	22.69	0.18	6733
Southern	72.05	5.34	1.08	21.36	0.18	6811
Southern	71.09	5.54	1.31	21.76	0.30	6866
Southern	69.11	5.11	0.91	24.53	0.34	6526
Southern	70.30	6.03	1.02	22.44	0.21	6787
Southern	68.40	5.51	1.16	24.65	0.28	6471
Southern	69.42	5.29	1.14	23.81	0.35	6477
Southern	70.40	5.16	1.09	23.09	0.27	6546
Southern	70.01	5.25	0.79	23.74	0.21	6751
Southern	70.08	5.09	0.73	23.74	0.26	6458
Southern	71.93	5.30	1.00	21.57	0.20	6924
Southern	69.40	5.49	1.28	23.57	0.26	6607

Table 1: (Cont.)

Region	C (wt.,%)	H (wt.,%)	N (wt.,%)	O (wt.,%)	Total Sulfur (wt.,%)	Heating Value Cal/g
	Dry, Ash Free					
Southern	69.79	5.56	1.13	23.27	0.25	6691
Southern	70.29	5.08	1.03	23.47	0.13	6700
Southern	70.39	5.32	1.21	22.77	0.30	6710
Southern	70.26	5.31	1.02	23.20	0.20	6661
Southern	70.79	5.35	1.09	22.61	0.16	6662
Southern	70.54	5.07	1.19	23.00	0.20	6674

Table 2: Proximate Analysis and Measured Heating Value of Alaskan Coal Samples Used

Region	Moisture Free Basis (wt.,%) Ash	Moisture Free Basis (wt.,%) Fixed Carbon	Moisture Free Basis (wt.,%) Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Dry, Ash Free (wt.,%) Volatile Matter	Heating Value (Cal/g,daf)
Interior	15.52	38.28	46.20	45.31	54.69	5549
Interior	8.97	40.94	50.09	44.97	55.03	5968
Interior	7.20	44.17	48.63	47.60	52.40	6027
Interior	12.26	41.00	46.75	46.73	53.27	5773
Interior	12.14	39.06	48.80	44.46	55.54	5795
Interior	10.25	42.81	46.94	47.70	52.30	6002
Interior	8.55	44.36	47.09	48.51	51.49	6152
Interior	4.19	42.90	52.90	44.78	55.22	5822
Interior	8.91	43.52	47.57	47.78	52.22	6036
Interior	7.85	41.47	50.68	45.00	55.00	5977
Interior	8.44	44.02	47.54	48.08	51.92	6092
Interior	8.01	44.01	47.98	47.84	52.16	6172
Interior	9.06	43.25	47.70	47.56	52.44	5988
Interior	17.26	36.37	46.37	43.96	56.04	5480
Interior	12.51	39.22	48.27	44.83	55.17	5924
Interior	13.18	43.30	43.52	49.87	50.13	5784
Interior	10.74	44.03	45.23	49.33	50.67	6042
Interior	9.77	44.38	45.85	49.19	50.81	6329
Interior	11.96	42.08	45.96	47.80	52.20	6096
Interior	9.60	42.16	48.24	46.64	53.36	5969
Interior	8.98	43.36	47.67	47.64	52.36	6058
Interior	10.15	42.84	47.01	47.68	52.32	5968
Interior	10.25	41.99	47.46	46.79	53.21	6046
Interior	13.95	40.14	45.91	46.65	53.35	5618
Interior	7.62	41.65	50.73	45.09	54.91	6100
Interior	7.96	43.50	48.54	47.26	52.74	6153
Interior	11.22	41.73	47.05	47.00	53.00	5976
Interior	12.56	43.23	44.22	49.44	50.56	5853
Interior	10.30	41.50	48.20	46.27	53.73	5939
Interior	8.09	40.97	50.94	44.58	55.42	6106
Interior	11.25	42.07	46.68	47.40	52.60	5931
Interior	7.72	48.45	43.73	52.50	47.50	6285
Interior	16.72	36.67	46.61	44.03	55.97	5647
Interior	11.41	43.01	45.58	48.55	51.45	6118
Interior	12.69	44.34	42.96	50.78	49.22	5853
Interior	4.08	48.65	47.28	50.72	49.28	6823
Interior	6.34	46.97	46.57	50.15	49.85	6596
Interior	11.70	41.77	46.53	47.30	52.70	5848
Interior	7.98	44.08	47.94	47.90	52.10	6023
Interior	9.48	43.02	47.51	47.53	52.47	5907

Table 2. (Cont.)

Region	Moisture Free Basis (wt.,%) Ash	Fixed Carbon	Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Volatile Matter	Heating Value (Cal/g,daf)
Interior	13.25	39.65	47.10	45.71	54.29	5742
Interior	8.44	42.59	48.98	46.52	53.48	6098
Interior	13.05	41.49	45.46	47.72	52.28	5717
Interior	11.07	40.98	47.94	46.08	53.92	5925
Interior	11.56	40.58	47.86	45.88	54.12	5901
Interior	9.87	42.95	47.18	47.65	52.35	6022
Interior	9.89	42.85	47.26	47.55	52.45	5971
Interior	12.09	41.45	46.46	47.15	52.85	5847
Interior	9.00	42.09	48.90	46.25	53.75	6059
Interior	11.00	40.75	48.25	45.79	54.21	5906
Northern	8.48	55.12	36.40	60.23	39.77	7490
Northern	9.33	56.27	34.40	62.06	37.94	7376
Northern	3.87	61.20	34.93	63.66	36.34	7828
Northern	4.93	62.39	32.68	65.63	34.37	7661
Northern	6.21	61.35	32.44	65.41	34.59	7589
Northern	2.42	62.96	34.63	64.52	35.48	7993
Northern	5.78	58.38	35.84	61.96	38.04	7647
Northern	7.10	58.77	34.14	63.26	36.74	7537
Northern	3.52	60.57	35.91	62.78	37.22	7893
Northern	2.79	59.91	37.30	61.63	38.37	7981
Northern	8.87	55.30	35.83	60.68	39.32	7413
Northern	4.11	59.42	36.47	61.97	38.03	7861
Northern	7.47	59.02	33.51	63.78	36.22	7522
Northern	2.70	62.20	35.10	63.93	36.07	7869
Northern	3.76	58.86	37.38	61.16	38.84	7869
Northern	4.98	62.24	32.78	65.50	34.50	7657
Northern	4.04	67.23	28.73	70.06	29.94	7796
Northern	2.53	62.62	34.84	64.25	35.75	8051
Northern	4.48	59.42	36.10	62.21	37.79	7884
Northern	6.39	64.12	29.49	67.77	32.23	7645
Northern	3.17	60.10	36.73	62.07	37.93	7701
Northern	4.31	60.76	34.93	63.50	36.50	7820
Northern	5.97	63.46	30.57	67.49	32.51	7638
Northern	3.85	63.24	32.91	65.77	34.23	7785
Northern	3.38	61.22	35.40	63.36	36.64	7911
Northern	5.69	58.93	35.38	62.49	37.51	7672
Northern	3.00	60.60	36.40	62.47	37.53	7978
Northern	3.58	60.17	36.25	62.40	37.60	7793
Northern	3.66	58.66	37.68	60.89	39.11	7914
Northern	3.38	62.34	34.27	64.52	35.48	7859
Northern	4.15	60.45	35.40	63.07	36.93	7813
Northern	14.11	52.92	32.97	61.61	38.39	6824

Table 2. (Cont.)

Region	Moisture Free Basis (wt.,%) Ash	Fixed Carbon	Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Volatile Matter	Heating Value (Cal/g,daf)
Northern	16.83	53.89	30.29	64.03	35.97	6646
Northern	15.64	52.94	31.42	62.75	37.25	6765
Northern	5.81	59.45	34.74	63.12	36.88	7704
Northern	3.13	60.30	36.57	62.25	37.75	7955
Northern	9.82	56.70	33.48	62.87	37.13	7263
Northern	13.48	58.69	27.83	67.83	32.17	6799
Northern	5.41	60.68	33.91	64.15	35.85	7676
Northern	3.53	58.33	38.13	60.46	39.54	7967
Northern	2.57	59.75	37.68	61.33	38.67	8044
Northern	4.04	58.43	37.54	60.89	39.11	7868
Northern	11.80	59.48	28.72	67.44	32.56	6934
Northern	6.27	59.34	34.39	63.31	36.69	7647
Northern	4.37	59.41	36.22	62.12	37.88	7862
Northern	3.20	58.91	37.89	60.86	39.14	7966
Northern	16.29	50.59	33.12	60.43	39.57	6818
Northern	4.95	56.53	38.52	59.47	40.53	7774
Northern	4.40	57.14	38.46	59.77	40.23	7896
Northern	6.70	57.73	35.57	61.88	38.12	7521
Northern	8.64	54.72	36.64	59.89	40.11	7463
Northern	13.43	52.65	33.92	60.82	39.18	6818
Northern	12.42	52.22	35.36	59.63	40.37	6947
Southern	6.07	41.92	52.01	44.63	55.37	6311
Southern	8.01	43.33	48.65	47.10	52.90	6217
Southern	9.63	46.68	43.68	51.65	48.35	6031
Southern	29.23	33.77	37.00	47.72	52.28	4676
Southern	14.21	42.92	42.87	50.03	49.97	5756
Southern	18.79	36.03	45.18	44.37	55.63	5512
Southern	13.67	41.14	45.19	47.65	52.35	5762
Southern	4.74	40.76	54.50	42.79	57.21	6286
Southern	6.58	45.67	47.75	48.89	51.11	6346
Southern	3.44	40.54	56.02	41.98	58.02	6349
Southern	16.63	42.47	40.90	50.94	49.06	5459
Southern	12.68	42.56	44.76	48.74	51.26	5816
Southern	11.23	42.29	46.28	47.64	52.36	5793
Southern	12.63	41.35	46.01	47.33	52.67	6002
Southern	17.37	35.42	47.21	42.87	57.13	5417
Southern	5.09	48.34	46.57	50.93	49.07	6464
Southern	21.56	37.85	40.58	48.25	51.75	5248
Southern	8.43	45.01	46.56	49.15	50.85	6100
Southern	6.36	47.04	46.60	50.23	49.77	6359
Southern	6.38	45.69	47.94	48.80	51.20	6273
Southern	8.25	43.59	48.16	47.51	52.49	6177

Table 2. (Cont.)

Region	Moisture Free Basis (wt.,%) Ash	Fixed Carbon	Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Volatile Matter	Heating Value (Cal/g.daf)
Southern	21.55	34.16	44.29	43.55	56.45	5441
Southern	14.50	40.84	44.66	47.77	52.23	5681
Southern	11.40	41.16	47.44	46.45	53.55	5867
Southern	18.32	35.99	45.69	44.06	55.94	5261
Southern	27.82	32.51	39.67	45.04	54.96	4610
Southern	24.91	32.08	43.01	42.72	57.28	4778
Southern	24.97	33.87	41.17	45.13	54.87	4778
Southern	7.59	44.54	47.87	48.20	51.80	6203
Southern	15.57	39.48	44.97	46.76	53.24	5446
Southern	13.17	36.35	50.48	41.86	58.14	5716
Southern	15.69	36.21	48.11	42.94	57.06	5733
Southern	18.26	36.66	45.07	44.86	55.14	5337
Southern	35.60	28.74	35.64	44.63	55.37	4133
Southern	28.31	34.94	36.75	48.74	51.26	4725
Southern	29.07	31.01	39.92	43.72	56.28	4804
Southern	18.78	37.34	43.88	45.98	54.02	5327
Southern	16.18	39.79	44.01	47.48	52.52	5561
Southern	13.06	40.37	46.56	46.43	53.57	5679
Southern	17.64	38.58	43.79	46.84	53.16	5314
Southern	37.28	35.14	32.29	56.03	43.97	4986
Southern	23.83	34.19	41.99	44.88	55.12	4999
Southern	20.10	35.86	44.05	44.88	55.12	5300
Southern	18.36	34.67	46.97	42.46	57.54	5728
Southern	9.56	43.09	47.33	47.65	52.35	5930
Southern	10.87	42.73	46.40	47.94	52.06	5932
Southern	7.14	40.51	52.35	43.62	56.38	6070
Southern	9.92	43.35	46.73	48.12	51.88	5926
Southern	12.39	42.53	45.08	48.55	51.45	5758
Southern	13.53	37.02	49.46	42.81	57.19	5868
Southern	9.75	44.80	45.45	49.64	50.36	5917
Southern	13.97	40.40	45.63	46.96	53.04	5746
Southern	8.45	40.76	50.79	44.52	55.48	5815
Southern	31.68	33.37	34.95	48.85	51.15	4595
Southern	29.94	34.31	35.75	48.98	51.02	4600
Southern	8.34	38.49	53.16	42.00	58.00	5754
Southern	10.51	41.34	48.15	46.20	53.80	5319
Southern	10.06	36.02	53.92	40.05	59.95	5395
Southern	11.63	39.06	49.31	44.20	55.80	5582
Southern	29.40	33.62	36.98	47.62	52.38	4666
Southern	16.44	41.32	42.24	49.45	50.55	5778
Southern	16.84	39.41	43.74	47.39	52.61	5791
Southern	10.10	43.61	46.29	48.51	51.49	6092

Table 2. (Cont.)

Region	Moisture Free Basis (wt.,%) Ash	Fixed Carbon	Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Volatile Matter	Heating Value (Cal/g,daf)
Southern	19.64	38.25	42.12	47.60	52.40	5502
Southern	23.47	37.07	39.46	48.44	51.56	4936
Southern	24.03	36.35	39.62	47.85	52.15	5045
Southern	23.46	36.55	39.99	47.76	52.24	5074
Southern	25.49	30.19	44.32	40.51	59.49	4512
Southern	25.10	29.70	45.20	39.65	60.35	4559
Southern	24.04	30.21	45.75	39.77	60.23	4655
Southern	25.75	29.10	45.15	39.20	60.80	4426
Southern	13.48	40.32	46.21	46.60	53.40	5868
Southern	35.15	27.11	37.74	41.80	58.20	4061
Southern	30.38	29.53	40.09	42.41	57.59	4365
Southern	24.33	29.61	46.04	39.13	60.87	4757
Southern	18.47	34.64	46.89	42.49	57.51	5076
Southern	20.75	35.74	43.49	45.10	54.90	5160
Southern	11.42	36.65	51.94	41.37	58.63	5171
Southern	21.18	31.54	47.28	40.01	59.99	5068
Southern	35.53	36.22	27.97	56.17	43.83	4923
Southern	17.44	35.11	47.44	42.53	57.47	4984
Southern	21.06	32.02	46.90	40.57	59.43	4986
Southern	25.00	35.40	39.61	47.20	52.80	4916
Southern	13.63	38.99	47.37	45.15	54.85	5671
Southern	7.76	40.76	51.48	44.19	55.81	5725
Southern	18.21	38.21	43.58	46.71	53.29	5917
Southern	13.15	39.62	47.23	45.62	54.38	5597
Southern	22.65	35.89	41.46	46.40	53.60	5287
Southern	20.13	38.99	40.86	48.82	51.18	5441
Southern	17.51	38.75	43.74	46.98	53.02	5509
Southern	8.10	43.31	48.59	47.13	52.87	5996
Southern	21.67	36.48	41.84	46.58	53.42	5077
Southern	20.57	37.01	42.41	46.59	53.41	5131
Southern	15.79	37.25	46.96	44.24	55.76	5262
Southern	25.11	33.48	41.42	44.70	55.30	4976
Southern	30.24	31.44	38.32	45.07	54.93	4514
Southern	32.43	29.54	38.04	43.71	56.29	4566
Southern	38.56	33.73	34.33	54.91	45.09	4737
Southern	16.26	39.61	44.14	47.30	52.70	5669
Southern	13.87	42.09	44.04	48.87	51.13	5744
Southern	8.53	42.53	48.94	46.50	53.50	5848
Southern	22.81	37.00	40.18	47.94	52.06	5076
Southern	14.75	34.93	50.42	40.97	59.03	5506
Southern	38.47	26.07	35.46	42.37	57.63	4254
Southern	10.23	43.67	46.10	48.65	51.35	6059

Table 2. (Cont.)

Region	Moisture Free Basis (wt.,%) Ash	Fixed Carbon	Volatile Matter	Dry, Ash Free (wt.,%) Fixed Carbon	Volatile Matter	Heating Value (Cal/g,daf)
Southern	18.85	41.30	39.85	50.89	49.11	5550
Southern	29.92	30.43	39.65	43.42	56.58	4705
Southern	28.10	34.41	37.49	47.86	52.14	4740
Southern	22.84	38.21	38.95	49.52	50.48	5077
Southern	32.34	31.04	36.62	45.88	54.12	4406
Southern	17.75	53.18	40.15	64.66	35.34	5820
Southern	39.02	28.32	32.66	46.45	53.55	3886
Southern	40.02	24.51	35.47	40.87	59.13	4080
Southern	19.49	37.64	42.88	46.76	53.24	5282
Southern	16.20	39.01	44.80	46.55	53.45	5585
Southern	10.08	42.15	47.78	46.87	53.13	5770
Southern	9.13	42.09	48.78	46.32	53.68	5854
Southern	7.39	43.22	49.39	46.67	53.33	5573
Southern	25.36	32.77	41.88	43.90	56.10	4791
Southern	18.10	38.24	43.66	46.69	53.31	5297
Southern	20.85	38.69	40.47	48.89	51.11	5325
Southern	11.53	45.79	42.68	51.76	48.24	5896
Southern	28.55	30.16	41.27	42.21	57.79	4644
Southern	27.86	30.82	41.32	42.72	57.28	4733
Southern	26.01	33.19	40.80	44.86	55.14	4808
Southern	36.87	27.96	35.17	44.28	55.72	4090
Southern	10.63	43.82	45.55	49.03	50.97	5905
Southern	7.84	43.41	48.75	47.10	52.90	5948
Southern	12.07	39.82	48.10	45.28	54.72	6027
Southern	16.68	40.96	42.36	49.16	50.84	5595
Southern	15.40	39.74	44.86	46.97	53.03	5612
Southern	16.89	38.47	44.63	46.29	53.71	5829
Southern	20.88	36.88	42.24	46.61	53.39	5589
Southern	21.41	37.23	41.36	47.37	52.63	5355
Southern	11.92	39.24	48.85	44.56	55.44	5527
Southern	7.70	44.68	47.63	48.41	51.59	5539
Southern	7.92	41.24	50.84	44.79	55.21	5839
Southern	30.97	30.30	38.75	43.89	56.11	4372
Southern	27.94	32.48	39.57	45.08	54.92	4626
Southern	28.05	33.67	38.29	46.79	53.21	4779
Southern	40.55	27.05	32.40	45.50	54.50	3817
Southern	10.47	41.42	48.11	46.26	53.74	5875
Southern	12.24	42.50	45.27	48.42	51.58	6004
Southern	8.10	43.02	48.88	46.82	53.18	6113

TABLE 3

Some Values of the Goutal Coefficient "a" for selected values of the volatile content (V')[14]

V' (%)	a (Calories/%)
5	145
10	130
15	117
20	109
25	103
30	98
35	94
38	85
40	80

NOTE: In anthracitic coals, a value of a = 82 is employed and is considered constant. For coke samples, the value of a ≈ 0 is recommended.

TABLE 4

Summary of Statistical Results for Predictability of Heating Value by Models Derived from Ultimate Analysis

Formula:		Eq. 1	Eq. 2	Eq. 3	Eq. 4	Eq. 5
	Northern Region					
Average Heating Value (Cal/g)	8123					
Mean Absolute Difference (Cal/g)		47.05	46.30	45.33	47.68	114.52
Mean of Absolute Relative Difference, Δr (%)		0.58	0.57	0.56	0.59	1.41
Mean Difference, δ (Cal/g)		-20.06	-28.24	-26.13	-34.07	-114.52
Standard Deviation of Relative Difference, σ		70.83	66.93	66.39	65.49	66.14
	Interior Region					
Average Heating Value (Cal/g)	6661					
Mean Absolute Difference, Δ (Cal/g)		211.91	111.63	98.99	98.84	112.53
Mean of Absolute Relative Difference, Δr (%)		3.17	1.66	1.48	1.48	1.70
Mean Difference, δ (Cal/g)		211.89	82.07	32.61	27.66	-69.96
Standard Deviation of Relative Difference		125.95	124.35	124.64	124.94	109.31
	Southern Region					
Average Heating Value (Cal/g)	6648					
Mean Absolute Difference, Δ (Cal/g)		172.10	95.83	96.42	99.72	142.96
Mean of Absolute Relative Difference, Δr (%)		2.59	1.46	1.48	1.53	1.79
Mean Difference, δ (Cal/g)		155.02	25.13	-25.24	-30.26	-114.33
Standard Deviation of Relative Difference		139.26	135.63	133.96	134.93	128.25
	Statewide Region					
Average Heating Value (Cal/g)	7252					
Mean Absolute Difference, Δ (Cal/g)		136.54	81.75	76.65	78.24	119.76
Mean of Absolute Relative Difference, Δr (%)		2.00	1.18	1.10	1.13	1.68
Mean Difference, δ (Cal/g)		105.66	25.25	-3.46	-9.63	-97.42
Standard Deviation of Relative Difference		153.18	118.40	111.12	111.46	101.43

TABLE 5

Summary of Statistical Results for Predictability of Heating Value by Model [Eq. 6] Derived from Proximate Analysis

Region		Northern Goutal	Interior	Southern	State-wide
Average Measured Heating Value (Cal/g)	7615	7615	5980	5364	5971
Mean Absolute Difference, Δ (Cal/g)		478	45	54	43
Mean Absolute Relative Difference Δr, (%)		6.32	0.60	0.72	0.58
Mean Difference, δ (Cal/g)		469	-0.02	0.14	-0.12
Standard Deviation of Relative Difference, σ		170.48	61.98	69.23	60.40

Fig. 1: Measured vs. Predicted Heating Value Derived from Ultimate Analysis of Alaskan Coals

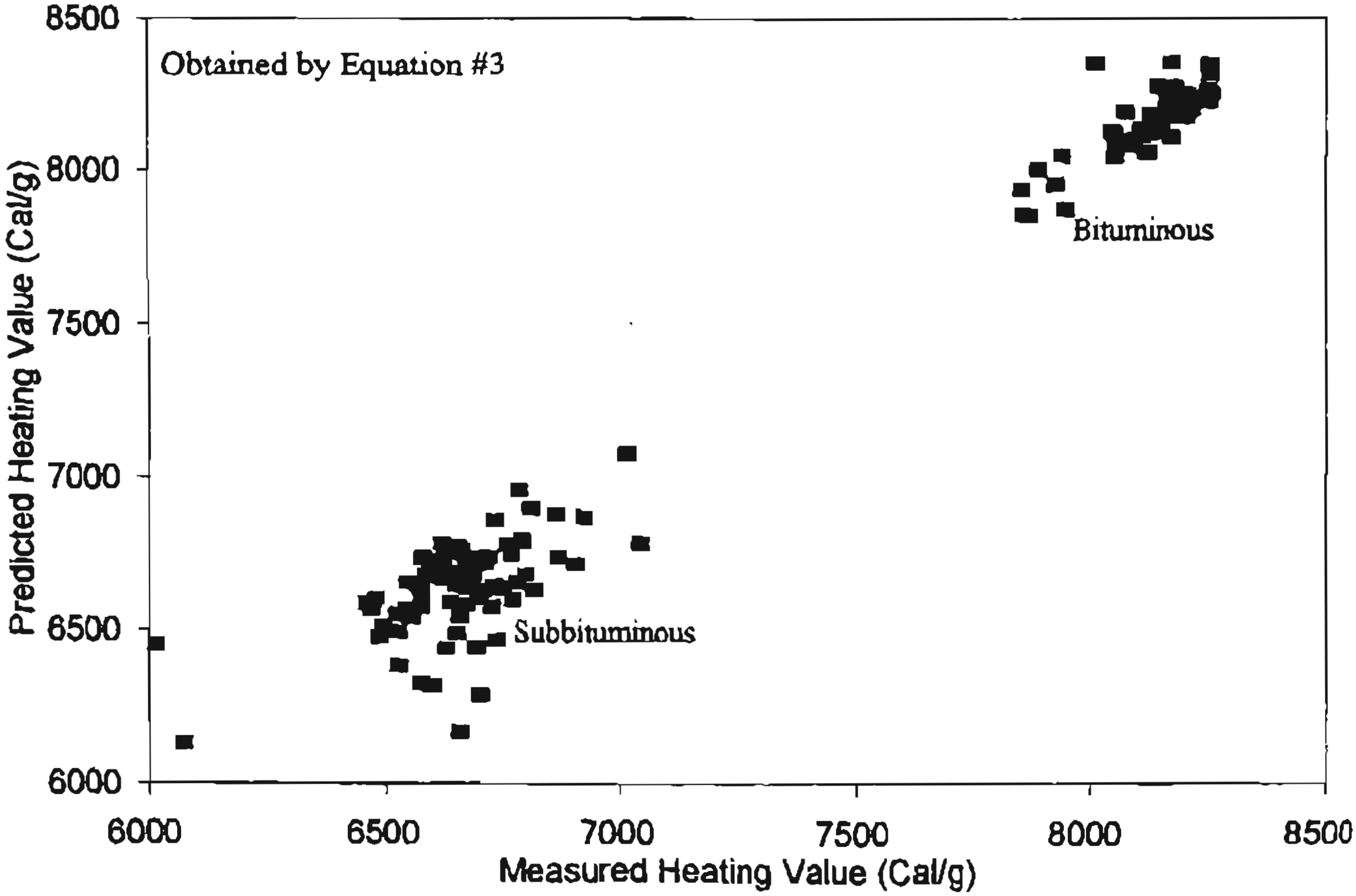


Fig. 2: Measured vs. Predicted Heating Value
Derived from Ultimate Analysis of Alaskan Coals

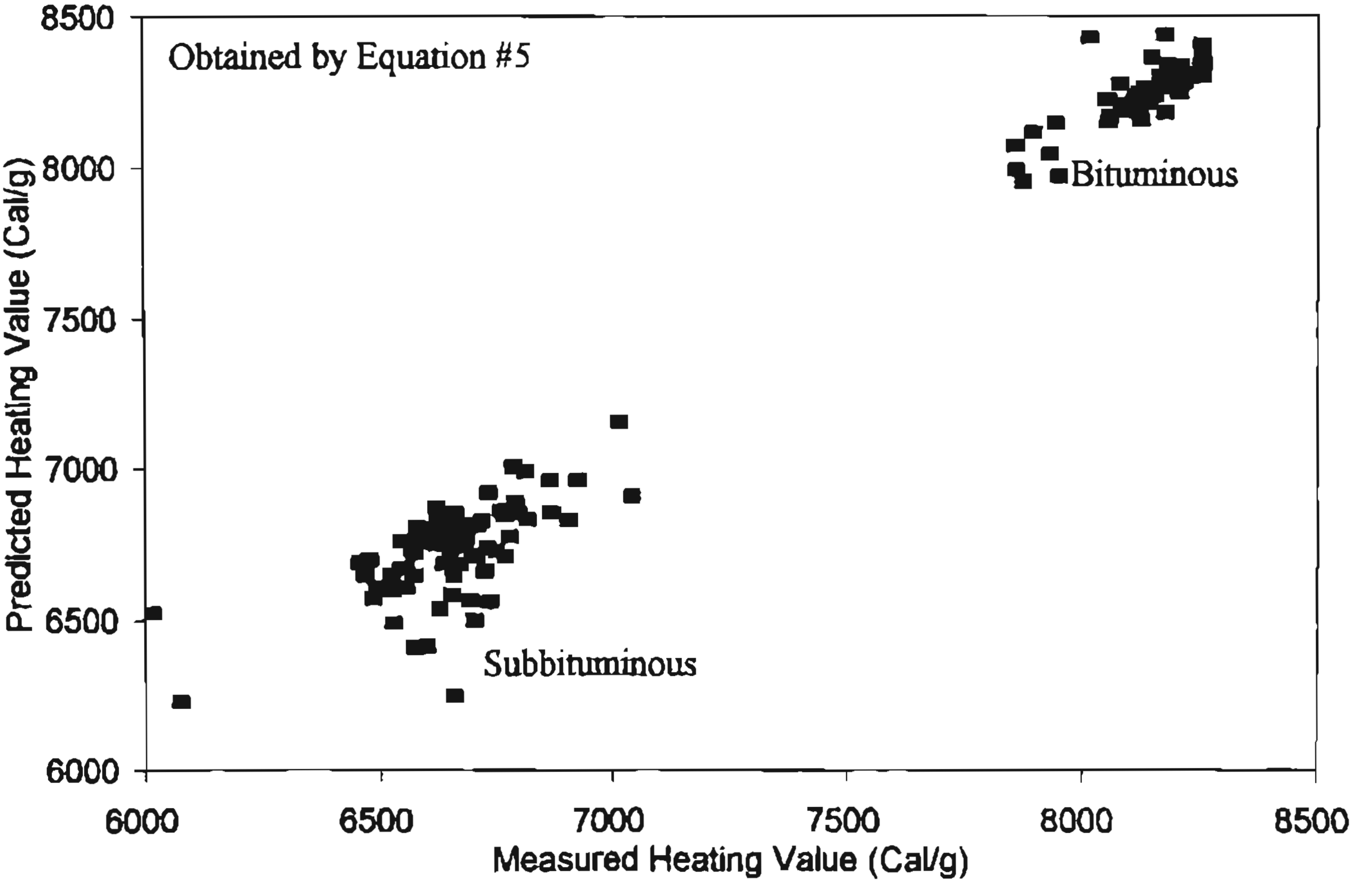


Fig. 3: Measured vs. Predicted Heating Value Derived from Ultimate Analysis of Alaskan Coals

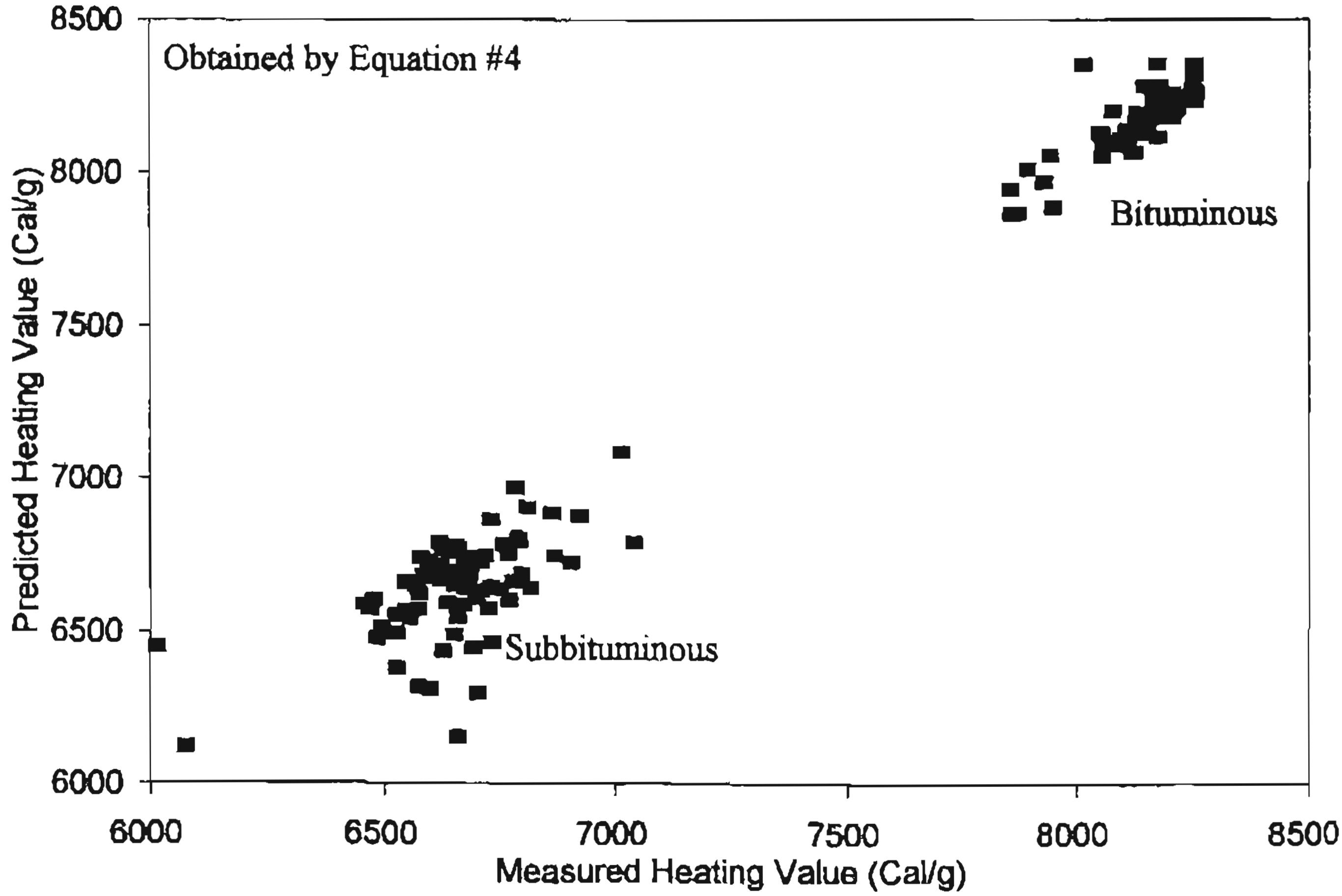
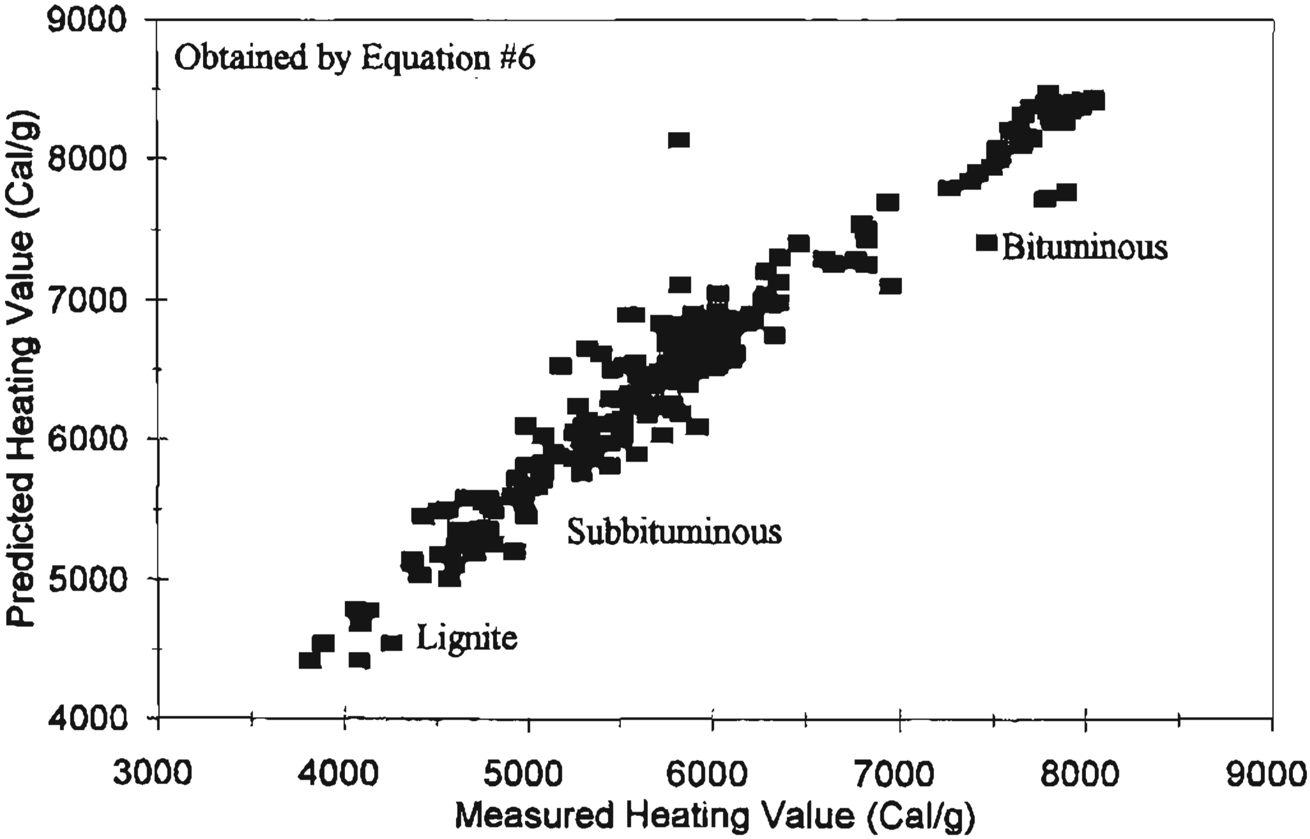


Fig. 4. Measured vs. Predicted Heating Value
Derived from Proximate Analysis of Alaskan Coals



CAN COAL REPLACE OIL IN RURAL ALASKA?

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ABSTRACT

Before the discovery of major oil and gas reserves in Alaska, coal was of prime importance as a fuel source. The lower costs associated with oil and gas use spurred conversion, away from coal for power generation and heating, in locations where they were readily available. The low initial cost of diesel generating plants allowed the electrification of many remote villages.

Fuel cost has since become a major component of the cost of living for most Alaskans. The State of Alaska has recognized this overwhelming dependence on oil and is seeking price stable alternatives. Coal has been targeted as a replacement as it is Alaska's most abundant energy resource.

Many rural Alaskan communities are located in proximity to mineable coal deposits and most of Alaska's major communities are located along navigable waters, providing an economic means of transport. The environmental risks associated with shipping a solid fuel, such as coal, are lower than with liquid fuels.

Funding from the State of Alaska has allowed ASCG INC. to investigate the feasibility of coal-fired electric generating and heating plants at a number of western Alaskan communities. Funding from the North Slope Borough allows continuing demonstration of coal mining in the arctic,as well as for delivery of coal mined to nearby villages for domestic space heating.

Economic comparisons of the cost to generate electricity with coal in targeted western Alaska locations, using conventionally designed and constructed plants, has not shown the conversion from oil to be justified. Coal is being successfully mined in the arctic on a demonstration basis. The use of coal for domestic space heating in the villages has had measured acceptance.

HISTORY

Before the arrival of western man, Native Alaskans had already been using coal for heating in areas where it was readily available. Western man "discovered" coal in Alaska at Cape Beaufort in 1826. Initially, small amounts of Alaskan coal were mined for use by whalers and aboard ships. The gold rush created increased coal demand to power dredges and riverboats, thaw gravel, and heat buildings. The majority of this demand was imported from the Lower 48 and Canada, with some coal supplied from local sources.

The 1920's saw surveys of the National Petroleum Reserve No.4 (NPR4) and the western arctic region by the United States Geological Survey (USGS). During this same era, oil was discovered in California. Its availability began the conversion of mining equipment to gasoline power.

In the ensuing decades, numerous mapping and reconnaissance surveys were conducted by the USGS and the U.S. Bureau of Mines (USBM) to quantify the coal potential of the western arctic. One such survey was conducted in 1946 and 1947 to identify potential coal deposits for heating use in local villages. Local coal was to replace coal, which was being imported from the Lower 48 and supplied to villages under a program started by the Bureau of Indian Affairs (BIA) in the 1890's.

In the 1950's, while efforts to quantify the coal potential of Alaska by various agencies of the Federal Government were continuing, the BIA started installing bulk fuel oil tanks in schools and converting to oil heat. The availability of fuel oil in the villages prompted conversion to oil heating in homes, initiating the decline of residential coal use (Table 1).

The oil embargoes of the 1970's caused dramatic oil price increases that had large impacts on oil

TABLE 1
BIA Coal Shipments To Western Alaska

Year	Tons
1955	185
1966	36
1967	65
1968	90
1974	8

- A one time shipment of 1000 tons was made to St. Paul in 1963.
- Three tons were delivered to the Seward peninsula in polypropylene bags in 1986

dependent rural Alaska. Energy cost became an overwhelming part of the cost of living. The State of Alaska was driven to seek relief from oil price volatility by identifying alternative energy sources.

Beginning in 1980, the Alaska Power Authority (APA) commissioned a series of studies to assess alternative energy sources available to rural Alaskans. One such study for the City of Kotzebue (Arctic Slope Technical Services, et al., 1982) assessed the feasibility of wind, hydroelectric, geothermal, and coal as energy sources. Coal was identified as having the most potential as a replacement for oil in this particular location.

In order to tap the enormous potential of the western Alaskan coals, a number of APA studies concentrated on assessing the development of this resource. An early study, which focused on western Alaska (Dames & Moore, 1981), assessed the following:

(a) Resource Availability

The resource assessment identified three coal deposits with potential to serve the needs of western Alaska. These were the North Slope coals, the coals of the Seward Peninsula, and the coal deposits along the Kobuk River.

(b) Feasibility of Use for Heating and Electrical Generation

The feasibility assessment phase of the study compared:

1. Mining local coal deposits versus mining a single large deposit capable of supplying all the villages of the study area:
   The conclusions reached were that due to the quality of the coals and quantity of the reserves, a centrally located western arctic mine was most economic. The deposit should be surface mined, have reserves of 60,000 to 100,000 tons per year for 20 years, and the coal should have a heating value of 10,000 BTU/lb minimum.
2. Local and subregional versus regional utility companies:
   The local case provided independent plants in each village. The regional utility cases provided for larger centrally located plants interconnected via transmission lines. Small coal fired plants (less than 500 kW) were found to be uneconomic. The high cost of transmission lines made local power plants with interconnections no more than 30 miles long the best generation option.
3. Transportation modes:
   Roads from the local coal deposits versus barge transportation from a centrally located mine were considered. Barges were found to provide the most viable transportation option. The mine should be located within reasonable distance of the coast (20 miles).

(c) Marketability Study

The marketability study of western arctic coal focused on defining the market opportunities for this coal, estimating the cost of coal as a fuel in comparison to oil, and examining the social and environmental impacts which mining would have in the western arctic. The results of this phase were that the coal located at Cape Beaufort was the most economic source to serve western Alaska. Small scale mines serving a domestic market (100,000 tons/yr or less) were found to be only marginally economic. To be able to compete internationally, a mine must have a production level of at least 2,000,000 tons/yr.

RECENT DEVELOPMENT EFFORTS

Following these studies, the State of Alaska, the North Slope Borough, and the Arctic Slope Regional Corporation began a cooperative effort to demonstrate the potential of western arctic coal and at the same time serve a portion of the energy needs of western Alaska.

PROJECT	SPONSORS	TASK
Western Arctic Coal Development Project	Alaska Native Foundation & Department of Community and Regional Affairs	Determine feasibility of a western arctic coal industry
Western Arctic Coal Demonstration Project	North Slope Borough	Demonstrate feasibility of mining coal and its use for domestic heating
Atqasuk Coal Project	North Slope Borough	Demonstrate feasibility of mining coal and its use for domestic heating

Three projects were initiated; two of which opened demonstration mines to supply coal for domestic heating, and a third to determine the feasibility of developing of a full scale mining operation.

Western Arctic Coal Development Project

Phase I

This project consisted of three phases, beginning in 1984. Phase I evaluated the potential of two regional deposits to serve the power and heating needs of western Alaska. Of the Cape Beaufort and Deadfall Syncline coalfields, the latter was selected as the most promising minesite. This was concluded based on the higher quality and mineability of the Deadfall Syncline coal, despite Deadfall Syncline's location several miles from tidewater.

Phase II

The project's Phase II performed a market evaluation to identify potential end users of the coal. It also collected the field data and performed the necessary infrastructure and impact studies required to evaluate commercial feasibility of a mine at the Deadfall Syncline. This phase identified a potential instate market of 500,000 ton/yr, given conversion by the military, industry, and the 130 communities considered candidates for conversion. A base case 50,000 ton/yr mine was used to determine infrastructure requirements and transportation costs.

At the base case production level, cost of delivered coal was determined. Table 2 compares the delivered cost of coal and fuel oil in the listed communities for use in residential heating.

The large gap between coal and diesel costs, especially apparent in Nome and Kotzebue, provided the incentive for pursuing a conversion in those communities. Also apparent from the table, is the shrinking of the cost gap the more southerly the community. The incentive for conversions in communities located closer to the source, of oil and further from the coal source is reduced by the increase in the shipping costs for coal.

After comparing the costs of power generation and heating with both fuel types, it was concluded that coal fired generation and district heating could be justified in the larger communities. In smaller villages, those requiring less than 500 kW of generation, a central coal fired generating and heating plant was found to be uneconomic. However, the use of coal in stoves and furnaces for heat is advantageous in those smaller communities.

TABLE 2
Residential Heating Delivered Fuel Cost, 1986$

Community	Coal ($/MBTU)	Diesel ($/MBTU)
Kotzebue	4.5	11.6
Nome	4.71	10.95
Bethel	5.04	8.99
Dillingham	5.17	7.76
Dutch Harbor	5.21	5.73
Kodiak	5.71	5.37

Phase III

Phase III of the project tested coal stove performance and proceeded with conceptual engineering and cost estimates for power plants in three western Alaska locations. It also considered a number of other production scenarios at the Deadfall Syncline mine and calculated mining costs and delivered coal prices for these cases.

Coal Stoves

Testing of residential coal stoves found the units to be 64% efficient in converting the heating value of the coal into beneficial home heat. Given the low sulfur content of the coal being supplied for the coal stove program, the sulfur emissions from the coal stoves was found to be less than the emissions from a diesel fuel fired furnace. While oil produced 76.7 lbs of SO_2/yr, the coal stoves produced only 6.9 lbs/yr.

Power Plant Feasibility

To aid in determining viability of coal fired power plants supplied from the Deadfall Syncline, coal cost at various production rates were projected. These cost are shown graphically in Figure 1.

Conceptual plant designs and cost studies were performed for the cities of Kotzebue and Nome, and for the Red Dog mine. These locations were selected for their proximity to the Deadfall Syncline coal mine and for their large cost gaps between coal and oil. The size of the load base in these locations also fit the guidelines established in the previous studies.

Designs and cost estimates of conventional Rankine cycle, coal-fired, generating plants, with partial district heating systems were prepared (SFT Inc., 1992). The expected number of plant staff required the and level of operating and maintenance expenses were estimated. These are summarized in Table 3 and compared to similar data for existing oil fired plants.

The coal fired plant figures represent redundant boiler, single turbine plants with a capacity to meet existing as well as projected load growth over the 10 year study term. The data for diesel-fired power plants is based on costs to expand the existing diesel plants (Humphrey, 1993).

Additional diesel plant capacity costs are those incremental costs to replace retired units or add new units to an existing plant in order to meet the expected load growth. These projects usually involve a retrofit of an existing facility, which utilizes the existing infrastructure to the maximum extent.

The heat rates given show the efficiency advantage diesel generation has over a conventional steam cycle, coal plant. The diesel plants exhibit overall efficiencies in the 32% to 38% range, versus the calculated efficiencies of 21% for the coal fired plants. The simplicity of construction and operation of the diesel plants is reflected in the installed cost per kWh and in the number of operating staff required.

The coal plant staff includes four shifts of mechanical, electrical, and operating staff to provide 24 hour, seven day per week coverage. Five day per week supervisory and administrative staff positions are also included. Possible reductions in these numbers could be garnered through integration of the coal plant with the existing diesel plant.

Before an economic comparison could be carried out, the cost trend of diesel fuel was projected (Analysis North, 1991). The predicted prices of utility and residential oil are shown below in Table 4.

Figure 2 compares the projected trend in diesel fuel costs with expected coal costs in Kotzebue and Nome. The steady increase in oil price is accompanied by coal prices which drop over time. The reduc-

TABLE 3
Power Plants For Nome, Kotzebue, and Red Dog

Coal Plant	
Technology Selected:	Stoker Boiler Steam Cycle
Construction Method	On-Site, Stick-Build
Heat Rate:	16,250 BTU/kWh
Capital Costs:	3,300 to 5,400 $/kW
Staffing Levels:	22
Diesel Plant	
Additional Capacity:	740 to 1000 $/kW
Heat Rate:	8,900 to 10,500 BTU/kW
Staffing:	6 to 9

FIGURE 1. Mining and Transportation Cost of Deadfall Syncline Coal at Omalik Lagoon and Delivered to a Western Alaskan Community

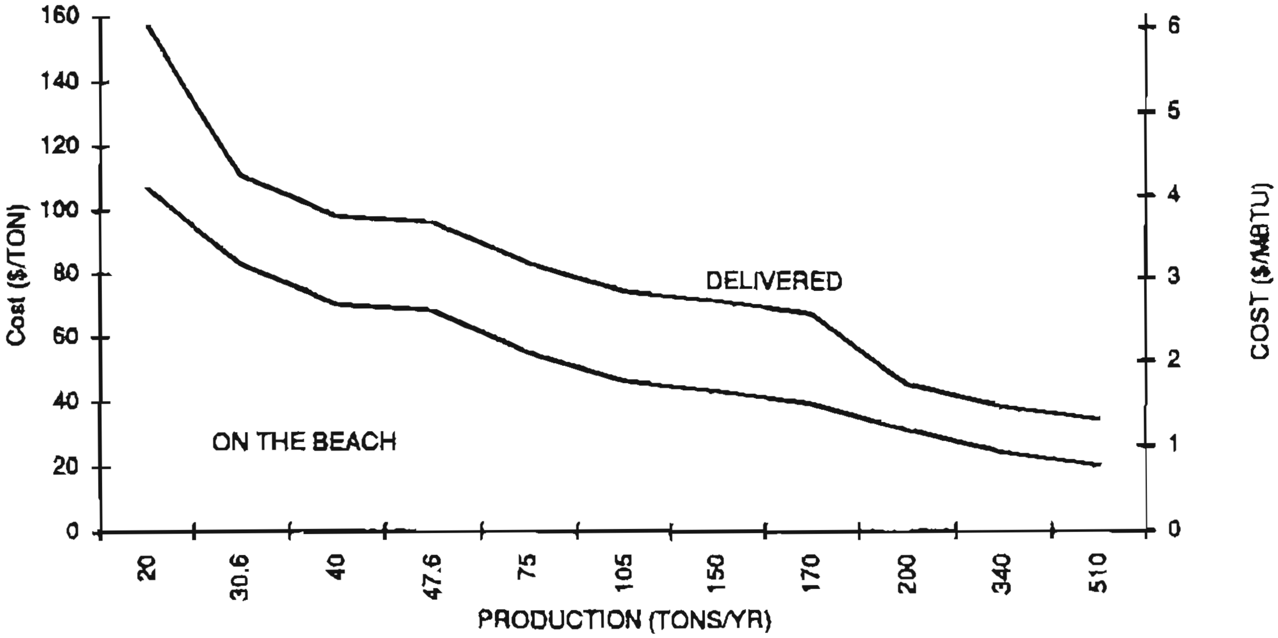

FIGURE 2. Diesel Versus Coal Cost at Kotzebue and Nome.

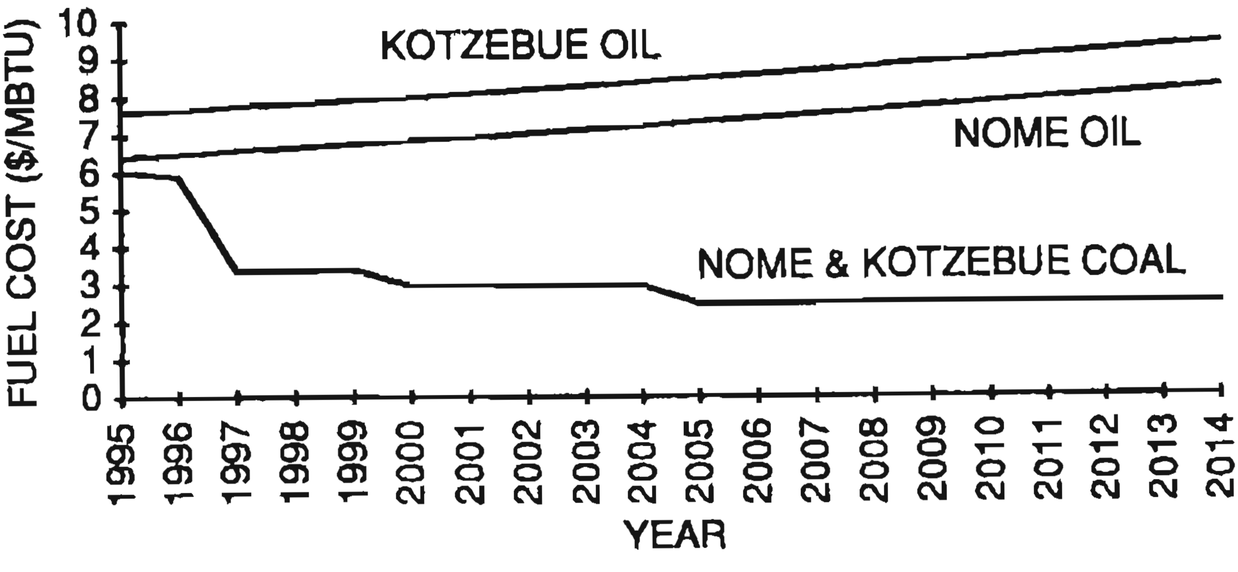

TABLE 4
Delivered Diesel Prices (1991$/Gallon)

Nome	1995	2000	2014	GROWTH
Utility	.89	.94	1.13	1.3%
Retail	1.67	1.72	1.91	.7%
Kotzebue				
Utility	1.05	1.1	1.29	1.1%
Retail	1.7	1.75	1.94	.7%

tion in coal price is due to predicted increases in mine production. Using these costs, an economic analysis of generating the electrical and heating needs of the study locations for the next 35 years was made. The present value of costs to supply the same amount of energy from coal, as compared to diesel, are reflected in Table 5.

The present value of fuel costs are positive, showing coal to have a long term fuel component cost

TABLE 5
Power Plant Economics

Present Values, 1991 M$

	Nome	Kotzebue	Red Dog
Fuel	14	15	44
Labor	-20	-23	-26
Capital	-27	-26	-53
Recovered Heat	0	-1	-6
Net Benefit	-33	-34	-41

advantage over diesel. The negative labor figures reflect the higher staffing level estimated for the coal plant. The capital numbers indicate the high cost of a complete new coal plant to meet the same load, which could be met by an incremental addition to the existing diesel plant.

The cost of recovered heat is negative in Kotzebue and at Red Dog due to the need to burn additional fuel to meet the heating needs over and above that which could be recovered from the condenser in the generation cycle. To meet the heating needs in these locations, steam would be extracted from the turbine before it has reached the final stages. This extraction requires additional fuel be burned to meet both the steam and electrical loads on the plant.

In considering the impact of each cost component, if one assumes that the labor deficit can be eliminated by refining the actual number of staff required to operate a coal plant, Table 5 still shows insufficient fuel savings accruing to recover the capital required to build the coal fired plant. Without a significant reduction in coal plant capital costs in conjunction with an increase in the fuel component savings from coal use, the use of coal will not offer the cost advantages to the investor and consumer necessary to warrant its construction.

The gap between coal and diesel fuel cost is initially small, and does not become significant until well in the future. The fact that a significant gap occurs later lessens the present value impact of the use of coal. Coal used in rural plants such as these must therefore be sourced from mines with sufficiently high production volume at the outset, to provide immediate cost savings.

Figure 3 relates the cost components of a diesel and coal generated kilowatt-hour (kWh) of electricity purchased by a typical western Alaskan consumer. The values are based on actual and estimated costs for the City of Nome projected to 1995.

In relative terms, the plot shows the effects of the lower efficiency and higher operating costs of a coal fired plant. Despite coal's lower raw energy cost, producing electrical energy with coal results in a higher net cost per kWh to the end user. Thus, a coal fired plant as conceived here would result in a net increase in Power Cost Equalization (PCE) payments by the State of Alaska.

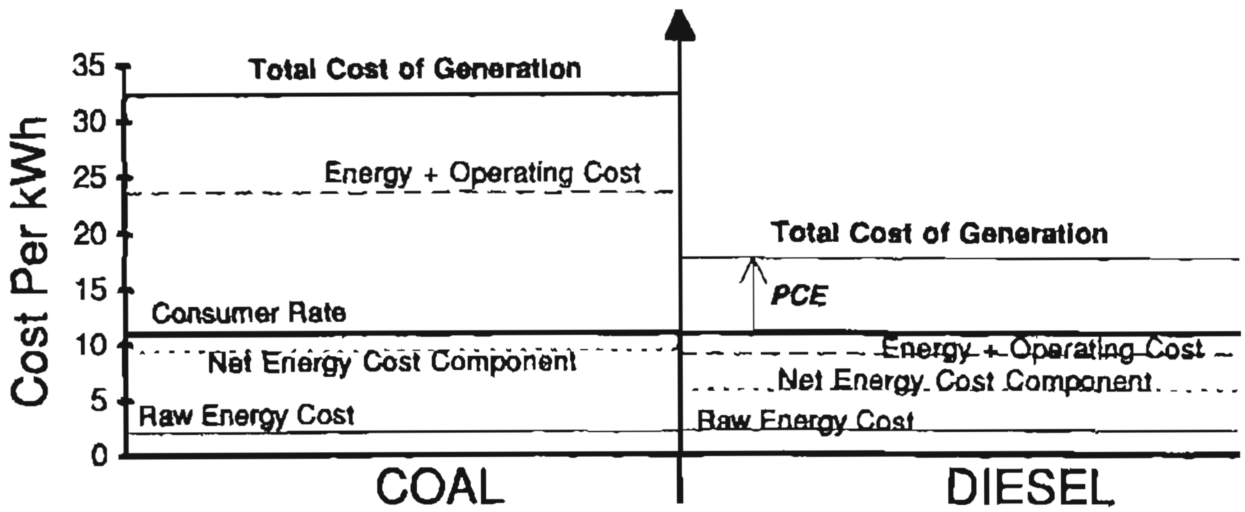

FIGURE 3. Cost Components of a Coal and Diesel Generated Kilowatt-hour of Electricity in a Typical Western Alaskan Community.

Viability of coal fired plants will require each of a number of cost factors to improve. Lower capital costs, higher plant efficiencies, and realistic staff levels must all be realized in order for coal to become Alaska's premier fuel resource.

Western Arctic Coal Demonstration Project

The Demonstration Project was initiated in 1986 by the North Slope Borough. Success of the project has prompted continuing yearly programs, and the project has progressed through eight phases. The purpose of the project is to promote the following:

- Demonstrate the feasibility of mining and transporting coal in the arctic
- Reaquaint the North Slope Villagers with the use of coal for home heating
- Provide a cost effective, alternative fuel source.

The project funding provides for a yearly, small scale, coal mining operation at Deadfall Syncline, with bagging and transporting of the coal to the villagers of Point Lay, Point Hope, and Wainwright. In addition to the mining, a number of coal stoves are installed in the homes of selected villagers each year. The funds for mining and transportation of the coal, as well as for the coal stove installation are provided by the North Slope Borough. Arctic Slope Regional Corporation, the regional native corporation and landowner of the coal resource, donates the coal to the project. From 1986-1991, the project has produced the statistics shown in Table 6.

TABLE 6
Statistics of the Western Arctic Coal Demonstration Project

Phase	Year	No. Stoves Installed	Coal Mined (Tons)	Cost ($/Ton)
I	1986	15	100	5550
II	1987	14	250	2910
III	1988	15	347	1559
IV	1989	11	380	1028
V	1990	7	400	1652
VI	1991	8	300	1336

Average Cost of Stove Installation: $3420

Coal Quality

Coal was initially mined using a combination of blasting and underground mining methods. This shallow depth coal resided in the freeze/thaw zone, and the coal produced fractured easily. The resulting coal was sized too small for effective use in stoves. In addition, coal was delivered to the villagers in 150 lb. bags. This size proved too large for household use. Acceptance of stove use by villagers was low as a result.

Changing the mining method, using different blasting techniques, and screening the coal at the minesite improved the size quality of the coal. A shallow surface operation using only heavy equipment, replaced earlier methods. These changes, along with packaging the coal in 60 lb. bags, improved coal acceptance.

By Phase II of the project, some villagers admitted to being totally dependant on coal for their heating needs. Average oil displacement has reached 100 gallons per home per month.

Transportation

A combination of cat train, flowtron vehicle, and helicopter was used in the initial phases to transport coal from the mine to the project villages. The most cost effective method of transport employed has been the cat train from the Deadfall Syncline mine to the coast at Omalik Lagoon, and barge transport from Omalik to the three participating villages.

Operating Season

Original mining and transportation operations were carried out in the late fall and winter. With the switch to barge transport, the later phases have adopted a spring mining and cat train operation. Barge transport from Omalik Lagoon to the villages occurs in the late summer.

Stove Use

Surveys are distributed by the project to the villagers involved to assess acceptance of the coal stoves. The results of these surveys indicate the acceptance of the stoves has grown over the life of the project. The later surveys show that of the people involved in the program:

> 33% use their stoves daily (a fire at least once per day)
> 20% use theirs periodically (fires 2 to 4 times per week)
> 21% supplementally (only during a power outage or oil shortage)
> 26% did not use theirs at all

Of those surveyed, 10% use their coal stoves for their total heating needs.

Atqasuk Coal Project

The Atqasuk coal project has similar goals to the Western Arctic Coal Demonstration Project in that a local coal source is mined and distributed to nearby homes for domestic heating needs. The project was initiated at the request of the village of Atqasuk, after they observed the benefits of the ongoing Western Arctic Project. The villagers of Atqasuk were also well aware of the resource potential they had within walking distance of their village.

In 1987, the North Slope Borough provided the funding for a demonstration mining operation using the Meade River coal mine as the resource. This mine had served as the coal source to Barrow, 70 mile to the north, in the 1940's. The mine lies within the NPRA, and the Bureau of Land Management is the resource owner. Existing statutes allow mining of up to 250 tons of coal per year for space heating by locals under a demonstration permit.

Coal stove installation and drilling and blasting operations are performed in conjunction with the Western Arctic Coal Demonstration Project. Due to the quantity mined and its proximity relative to the users (less than two miles), transportation of the coal is by Caterpillar DJB (articulated dump truck). Statistics for the Atqasuk project are shown in Table 7.

TABLE 7
Statistics for the Atquasak Coal Project

Phase	Year	No. Stoves Installed	Coal Mined (Tons)	Cost ($/Ton)
1	1987	10	132	616
2	1988	10	200	263
3	1989	10	250	182
4	1990	3	200	268
5	1991	3	200	248

Average Cost of Stove Installation: $2400

Coal is mined by surface methods, with blasting of the overburden and ripping the coal with a bulldozer to minimize fines production. Coal is transported to the village, where it is screened and stockpiled.

Coal is bulk delivered to each program resident by pickup truck, where it is stored in a coal crib constructed by the project. Acceptance of the coal has been similar to that by the villagers of the Western Arctic Coal Demonstration Project.

A coal stove complaint registered by the users in Atqasuk with the use of stoves has been that heat from the stove fails to reach throughout the entire house. Relocating the stove and fans have been proposed as solutions to improve heat distribution throughout the residence.

CONCLUSION

The use of coal has a historic precedence in Alaska. Large Alaskan coal resources and their widespread distribution would lead one to believe that its use could be expanded, even though coal use has been superseded by the convenience of imported oil and the economics of local gas.

Programs funded by the State of Alaska and the North Slope Borough are promoting the use of western arctic coal both as a local fuel and as an export commodity. These programs have demonstrated the ultimate feasibility of mining and transporting coal in the arctic and its use as a home heating fuel.

The replacement of oil fired generation in western Alaska with power plants fired with western arctic coal has been shown to be uneconomical using present technologies and construction practices. Although coal generation provides a cheaper energy component, its higher capital and operating costs combine to far outstrip any energy cost savings. The cost of coal generated power will have to be reduced below the price of PCE supported oil fired generation in order to attract investment in such conversions.

The work to date of the Western Arctic Coal Programs has been summarized here. Areas requiring further study have been identified by these programs and will be targeted in subsequent phases. The promise coal offers should guarantee the continuance of these programs and ensure that this very valuable Alaskan resource be utilized.

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BELUGA COAL, POSITIONED FOR THE 1990S?

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Placer Dome U.S. Inc. is not new to Alaska coal mining. The Company formerly operated the Evan Jones Coal Mine in the Matanuska Valley from 1956 to 1967. Placer Dome U.S., through its subsidiary, Beluga Coal Company, has held coal leases in the Beluga coal field since 1971.

Placer Dome U.S. remains convinced that Alaska coal will become an important fuel source for the world — but the realization of this has required patience. Recently, however, some developments have taken place which may amplify interest in Beluga coal. This paper will outline those developments — but first, a brief background of the project may be advantageous.

The Beluga coal field is located in south central Alaska, only about 60 miles west of Anchorage. One of the significant advantages of this coal field is that it is adjacent to tidewater, allowing unusual economies in the transportation of this fuel to its markets. In addition, infrastructure from previous timber operations can be utilized, including a 1475 foot pier capable of accommodating 40,000 Dwt ocean vessels.

The coal leases contain an estimated 500 million tons of surface-minable coal, which can be subdivided further into areas of very attractive strip ratios. Exploration and engineering activities have defined reserves that can be competitive at large production levels as well as at low levels - mainly due to the existing infrastructure.

The evolution of production from the property is envisioned to start with an initial long term contract of at least 1.5 million tonnes per year with production increasing to 5.0 million tonnes per year or more as dictated by the market. Traditionally, the marketing scope has been local and Pacific Rim utilities and industrial consumers. A study was also performed in the early 1980's to evaluate the feasibility of using this coal to produce methanol for consumption in Pacific Coast states for both power generation and vehicular fuels.

Developments in the political/environmental and technical domains have focused renewed interest in Beluga coal because of its unusually low sulphur content, and its marketability has thereby been enhanced.

Environmental concerns have resulted in important U.S. legislation. The Clean Air Act, which limits the SO_2 and NO_x emissions, has already affected fuel consumers and producers. As provisions of this legislation take effect over the next few years, there will be increasing need to provide fuels which are environmentally attractive.

SO_2 emissions are typically controlled by installing expensive scrubbers, fuel switching or fuel blending. Beluga coal averages less than 0.2% sulphur content — well below the SO_2 limits — making it an ideal blending source for other fuels. Blending with low sulphur coal has enabled plants to minimize derating while maintaining, to a considerable extent, their traditional fuel sources. In most instances, low sulfur subbituminous coals have been blended with bituminous coal to reduce the sulphur content of the mixture. However, in a recent development, subbituminous coals are scheduled to be blended with lignite.

The government has also installed an incentive program to further encourage emission reductions through credits. Holders of these credits can sell them to other fuel users which burn coal having higher emissions of SO_2.

Not only is the Beluga coal's total sulphur content unusually low, but it also contains inherent calcium. During combustion, this tends to tie-up what little sulphur there is in the ash, instead of emitting it to the atmosphere. Beluga coal is also low in nitrogen and burns at low temperature — both attractive factors in limiting NO_x emissions.

Testing has demonstrated that the coal performs well in conventional applications. It has excellent carbon burn-out and the ash has no problem trace elements; it is also characteristically low in sodium and has a high fusion temperature.

Additionally, other technologies are expanding which favor Beluga Coal. Coal water mixtures (CWMs) are moving into commercial status, most notably in Japan and in Russia. Japan is currently in the lead, with several separate industrial groups developing this technology. Recently a CWM has started to be imported by Japan from China. Its principal attraction can be viewed as an alternative for petroleum-based fuels, inasmuch as it is distributed and handled as a liquid fuel. CWMs made from upgraded low rank coals (LRCWM) may offer a particular opportunity to the subbituminous coals of the Cook Inlet area because the product could be loaded on ocean tankers close to the source of the coal. A paper given recently by the JGC Corporation of Japan, a principal developer of CWM fuels, reported on hot water drying methods for upgrading low-rank coals such as Beluga.

A coal-methanol fuel is another type of slurry which may be appropriate to produce in the Cook Inlet area. With the large supply of gas which is available, methanol can be easily produced and may serve as a carrier fuel for the particulate coal. A program to confirm the rheology and pumping characteristics of such a fuel is just now commencing.

SGI International, has recently performed a first phase test of Beluga coal in which a liquid fuel product was obtained as a by-product of char produced from the coal. A commercial demonstration plant was recently completed near Gillette, Wyoming and a number of subbituminous coals will be tested for these products. The high volatile content of Beluga coal is beneficial for such a process.

At some point in time, gasification of Beluga coal may become the preferred fuel source for a Beluga power plant if world gas prices rise sufficiently. Although coal gasification has not proceeded as rapidly as had been envisioned only a few years ago, gaseous hydrocarbon feedstocks are indeed produced from coal in a number of locations, including the U.S., Japan, Germany and South Africa.

While the above mentioned developments will bring Beluga coal closer to the marketplace, the timing of its development remains uncertain. However, it is clear that environmental concerns regarding combustion emissions are causing increased regulations in foreign nations as well as in the U.S. and that there are consistent growth projections for coal-fueled energy, especially in the Pacific Rim. As these events transpire and converge with emerging technologies, there is little doubt that Beluga coal is well positioned to respond to these international opportunities.

COAL OCCURRENCES ON NELSON ISLAND, SOUTHWEST ALASKA

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ABSTRACT

Lower Cretaceous coals crop out at several localities on Nelson Island within fluvial rocks of a nonmarine to marine siltstone-greywacke sequence. The coal beds range in thickness from thin coal stringers to a 40 cm thick seam (our observations) to a reported 76 cm thick coal seam occurrence on the north side of the island. Coal comprises less than 1.5% of our four measured stratigraphic sections and is generally poor in quality because of many observable ash partings. A sample collected from a 40-cm-thick coal bed on the south side of the island was analyzed and has an apparent coal rank of medium volatile bituminous with an ash content of 12%, 0.47% sulfur (on an equilibrium moisture basis) and a vitrinite reflectance of 0.97. The fluvial depositional setting of the coal-bearing section was apparently not conducive to the accumulation of thick, laterally continuous coal-forming peat swamps.

INTRODUCTION

In July 1992, geologists from Calista Corporation and the Alaska Division of Geological and Geophysical Surveys (ADGGS) conducted a reconnaissance field investigation on western Nelson Island to determine the extent and quality of the coal occurrences. Nelson Island is approximately 68 km long by 65 km wide and is located in southwestern Alaska northwest of the Kuskokwim River mouth. The island is separated from the mainland by the Kolavinarak and Ninglick Rivers and Baird Inlet. The investigation was based from the village of Toksook Bay and conducted by small power boat and on foot to explore the exposures along the coastline of the western end of the island for coal beds. Four sites containing coal were located and examined (fig. 1), three on the south side of Nelson Island on the north shore of Kangirlvar Bay (localities 1, 2 and 3) and one on the north side of Nelson Island east of the village of Tununak on Hazen Bay (locality 4). No coal beds thicker than 40 cm were located. A traverse by power boat was made along the west coast of Nelson Island from Toksook Bay around Cape Vancouver to Tununak (fig. 1). Rocks observed along this traverse are folded and faulted and appear to be predominantly marine shale and siltstone. No coal-bearing rocks were observed, although our distance from the coast varied from fifty to several hundred meters from shore. The brief reconnaissance nature of this examination did not allow for a detailed on-foot investigation of the entire western Nelson Island coastline. Additionally, significant remnant coastal snowpack on the north side of the island, east of the village of Tununak, prevented examination of a previously reported 76 cm thick coal occurrence (Spurr, 1900; Weber, 1944). The purpose of our paper is to provide additional information on the nature of the coal exposures on Nelson Island including proximate and ultimate analyses.

PREVIOUS INVESTIGATIONS

Reverend Kilbuck, a missionary from the southwest Alaska village of Bethel, first reported the occurence of lignitic coal beds to 76 cm at Kaluyak Point (Spurr, 1900). Kaluyak is the Yup'ik Eskimo language name for Nelson Island (spelled *Qaluyaaq*). This locality may be near the Kaluyut Mountains and our locality 4. In 1944, Nelson Island exposures of coal were examined by the U.S. Bureau of Mines in an effort to evaluate the potential of coal utilization at the village of Tununak (Weber, 1944). East of the village of Tununak six coal seams, including a 76 cm thick bed (same thickness reported by Spurr, 1900, and probably the same locality), were evaluated and a plan for mining 150 tons of coal annually was developed. The 76 cm coal seam was estimated to contain 550 tons of coal within the initial 30 meter strike interval, however the lateral continuity of the coal seam along strike was not tested (Weber, 1944). A few tons of coal were mined from this locality prior to a 1954 U.S. Geological Survey field examination (Coonrad, 1957) but the year(s) when this mining occurred is not known.

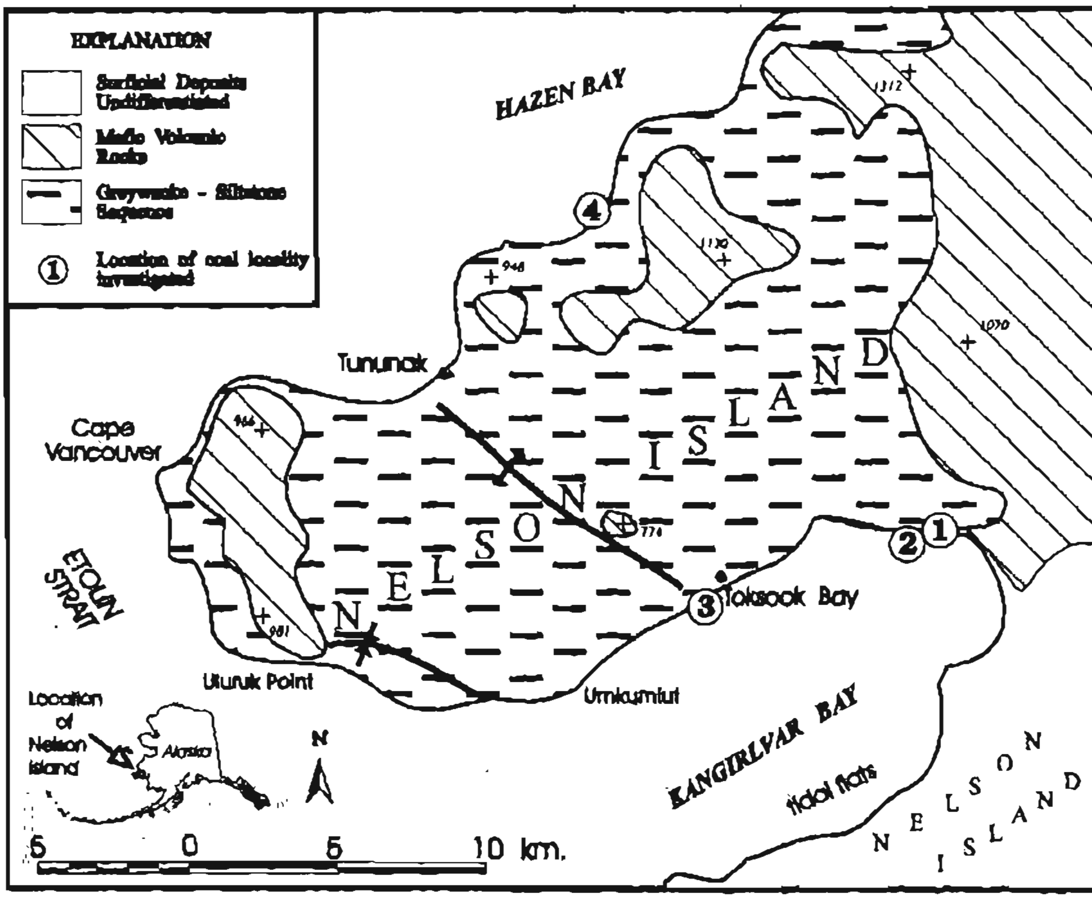


Figure 1. Locations of coal occurrences investigated (1-4) and generalized geology of western Nelson Island (geology modified from Coonrad, 1957).

Regional-scale (1:500,000) geologic mapping of the Yukon-Kuskokwim region by Coonrad (1957) described the geology of Nelson Island and provided two locations of coal outcrops on the island. Subsequent studies include two measured stratigraphic sections by Lyle and others (1982) and unpublished petroleum industry exploration work.

REGIONAL GEOLOGY

The western end of Nelson Island contains a Lower Cretaceous succession of unnamed graywacke-siltstone sedimentary rocks (Coonrad, 1957) which are well exposed along the coastline but poorly exposed in the interior of the island (fig. 1). This succession consists of marine to nonmarine sandstone, siltstone, calcareous siltstone, shale, claystone and thin coal beds. These rocks are estimated to be as much as 1500 m thick and are folded into broad N 70° W trending anticlinal synclinal structures (Coonrad, 1957). The Cretaceous sedimentary succession is overlain by up to 60 m of between 8 to 20 undeformed holocrystalline olivine basalt flows (Coonrad, 1957) (fig. 1). Similar sedimentary and basaltic rocks also crop out on Nunivak Island situated 32 km to the southwest across Etolin Straight where coal has also been reported (Coonrad, 1957). Radiometric-age dates for the basalt flows on Nunivak Island range from 6 Ma to Holocene (Hoare and others, 1968).

Coal-bearing section

The nonmarine coal-bearing rocks consist of: 1) thick intervals (m-scale) of crossbedded fine- to coarse-grained sandstone, with minor pebble conglomerate; 2) interbedded with thick intervals (m-scale) of claystone with locally abundant fossil leaf imprints and coalified plant debris; 3) thin laterally-discontinuous beds (cm-scale) of siltstone and very fine sandstone with various amounts of carbonaceous shale; and 4) thin coal beds as thick as 76 cm. Lyle and others (1982) report the presence of minor thin beds of bentonitic mudstone in the nonmarine section. Crossbedded sandstone represents deposition in a fluvial channel setting. This sandstone is poorly sorted and compositionally immature containing abundant angular to subangular quartz, chert, white mica, and volcanic lithic fragments suggesting proximity to a volcanic provenance (R.

Reifenstuhl, 1994, written communication). Lyle and others (1982) provide an Albian-age (Early Cretaceous), based on palynology, for the coal-bearing strata on Nelson Island. This age is similar to the coal-bearing fluvial-deltaic rocks of the Nanushuk Group, North Slope of Alaska, which contains economic deposits of bituminous and subbituminous coal (Stricker, 1991).

MEASURED STRATIGRAPHIC SECTIONS

Locality 1, Kangirlvar Bay

Kangirlvar Bay stratigraphic section at locality 1 (fig. 2) was measured on the gently dipping east limb of an anticlinal structure and consists of 33 meters of sandstone, claystone and minor coal. The sandstone is fairly well indurated and crossbedded whereas the claystone is poorly indurated and locally slumped and covered. Between 20-22.5 meters above the base a frost-disturbed claystone interval is interspersed with a highly weathered coal blossom to 30 cm thick. At 23 meters above the base, a 40 cm thick coal bed was sampled (sample 92-JC-303, discussed below). A very thin 6 cm thick coal stringer which pinches out laterally occurs at 27 meters above the base.

Locality 2, Kangirlvar Bay

Section 2 (fig. 3) at Kangirlvar Bay locality 2 (fig. 1), contains 5.6 m of poorly-indurated claystone. Within the claystone are a thin 10 cm thick horizon of high ash coal and two beds of carbonaceous claystone to carbonaceous siltstone which pinch-out laterally. A thin ripple-laminated fine-grained sandstone bed overlies the lowermost carbonaceous claystone bed. This section is on the same east limb of the anticline as locality 1 but is stratigraphically higher.

Locality 3, Toksook Bay

Locality 3 (fig. 1) is on the west limb of an anticline which is located immediately west of the village of Toksook Bay. The 53.5 m thick measured section contains a 24 cm thick coal bed at 34 m above the base (fig. 4). The sandstone beds in this section are fairly well indurated and are crossbedded and represent fluvial channels. Abundant leaf imprints and coalified

Figure 2. NELSON ISLAND LOCALITY 1
Kangirlvar Bay

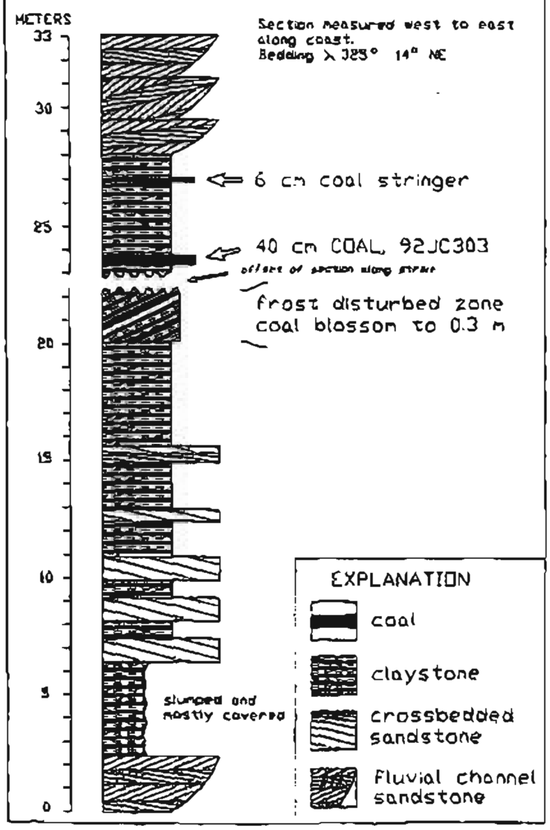
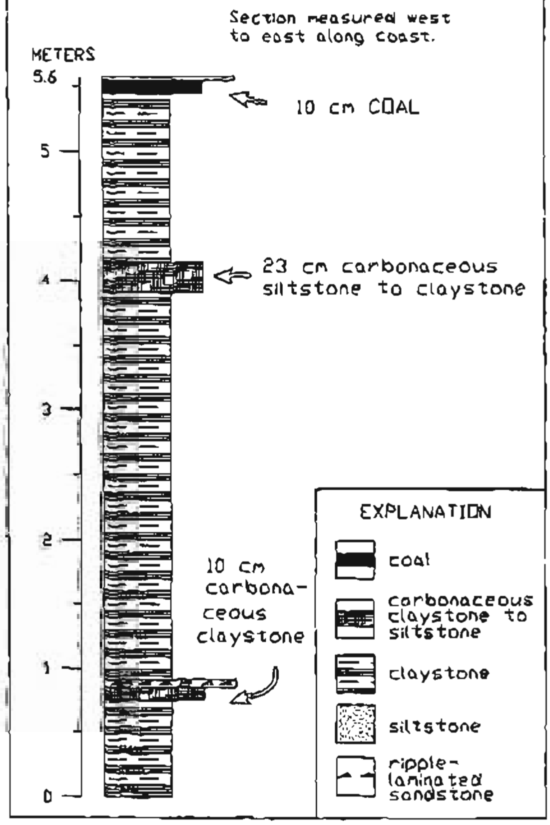


Figure 3. NELSON ISLAND LOCALITY 2
Kangirlvar Bay



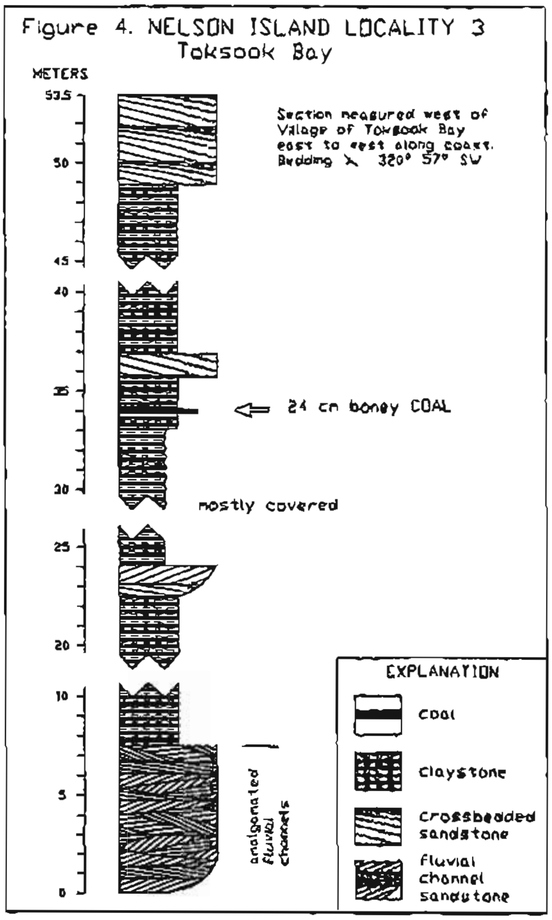


Figure 4. NELSON ISLAND LOCALITY 3
Toksook Bay

plant debris occur at the top of the sandstone beds and in the intervening claystone.

Locality 4, Hazen Bay

At Hazen Bay locality 4 (fig 1), about 18 m of southwest dipping section is exposed. This section contains 5 thin beds of coal ranging from discontinuous 5 cm thick coal stringers to 25 cm of coal (fig. 5). The coals are within a nonmarine succession of predominantly poorly indurated claystone with 0.5 to 1m thick beds of siltstone to very fine sandstone. Weathered claystone covers much of the coal and excavation is necessary to examine bed thickness and lateral extent (fig. 6). A 76 cm thick coal bed, reported by Weber (1944) to be east of our locality 4, was not located during our investigation. Coastal bluffs immediately east of our locality 4 were covered by snowpack at the time of our investigation obscuring this thick coal bed.

COAL QUALITY

A sample of coal (92-JC-303) collected from a 40 cm thick bed at locality 1 was submitted to the Mineral Industry Research Laboratory, University of Alaska Fairbanks for proximate and ultimate analyses (reported in table 1). The coal has a calorific value of 12,510 Btu/lb, 12.14% ash, 0.47% sulfur, 3.92% moisture (all values Equilibrium Moisture Basis), and a vitrinite reflectance value of 0.97. The analytical results indicate an apparent rank of medium-volatile bituminous coal using the Parr formula (ASTM designation D-388-77, 1978). The coal is agglomerating and therefore of coking quality.

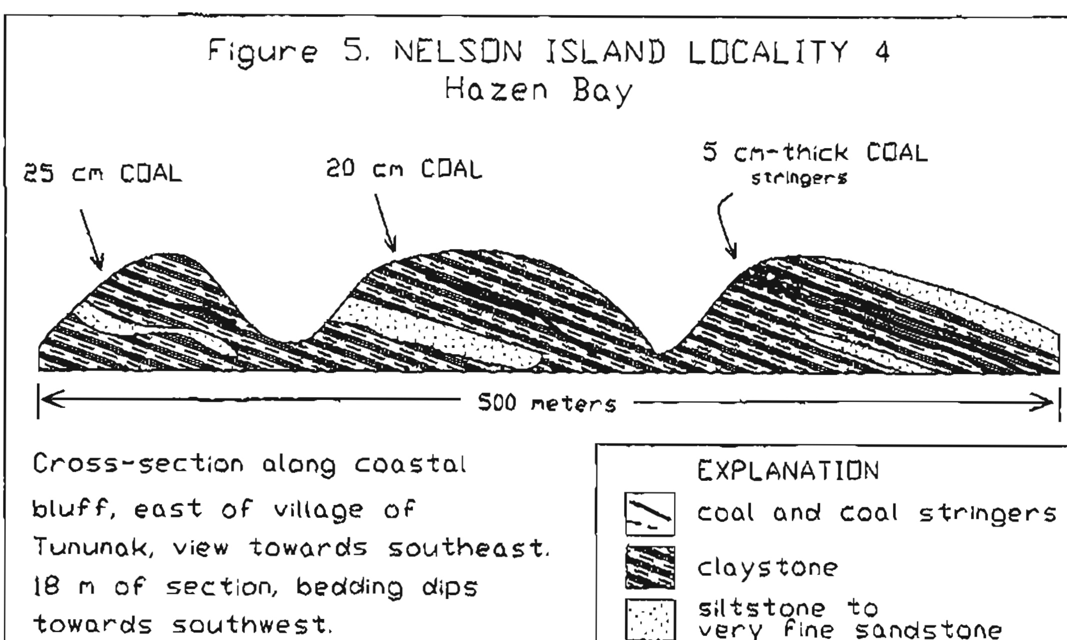


Figure 5. NELSON ISLAND LOCALITY 4
Hazen Bay

Cross-section along coastal bluff, east of village of Tununak, view towards southeast. 18 m of section, bedding dips towards southwest.

Figure 6. Excavation and sampling of 25 cm thick coal bed in coastal bluff at locality 4, east of village of Tununak, western Nelson Island.

A coal sample from Nelson Island submitted to the U.S. Bureau of Mines in 1925 for analytical testing yielded similar results: 12,930 Btu/lb heating value, 14.6% ash content, 0.5 % sulfur and 64.1% fixed carbon (Cooper and others, 1946). This compares well with our Basis 2 in Table 1. Warfield (1967, p. 20) analyzed four Nelson Island coal samples collected by the U.S. Geological Survey for coking quality and found all samples to be agglomerating; one fair caking, one good caking, and two firm agglomerate.

DISCUSSION

A total of 111 m of nonmarine stratigraphic section exposed along the coast of Nelson Island was examined in detail for coal. Nine thin coal seams of variable quality and extent occur in a fining-upward sequence consisting of crossbedded and channeled sandstone, overlain by claystone and then coal. Thin fine-grained sandstone, siltstone and carbonaceous claystone beds within these sequences represent small crevasse-splay and overbank deposits. Coals on Nelson Island comprise less than 1.5% of the measured nonmarine section and appear to have formed in small swamps marginal to meandering or braided streams. Thick intervals of channel sandstone and claystone with thin, laterally variable, seams of coal suggest the environment was not stable long enough to allow for the accumulation of thick coal-forming peat swamps, possibly due to tectonism and/or rapidly migrating fluvial systems (G. Stricker, 1994, oral communication). The high volcanic lithic content and immature nature of the sandstone [discussed above] indicates proximity to a volcanic provenance, further supporting an unstable tectonically-active setting. The apparent rank of medium-volatile bituminous coal determined for a single 40 cm thick coal bed (sample 92-JC-303) indicates the Lower Cretaceous sedimentary rocks on Nelson Island underwent sufficient pressure-temperature gradients during burial to form moderately high rank coal.

Table 1. Proximate and Ultimate Analyses of Nelson Island Coal Sample No. 92-JC-303

Basis	Moisture, %	Ash, %	Volatile Matter, %	Fixed Carbon, %	Heating Value Btu/lb	Sulfur, %	C, %	H, %	N, %	O, %
1	3.92	12.14	23.23	60.71	12,510	0.47	72.78	4.63	1.27	8.72
2		12.63	24.18	63.19	13,020	0.48	75.75	4.36	1.32	5.45
3			27.68	72.32	14,900	0.55	86.70	5.00	1.51	6.24
4			26.69	73.31						
5					14,410					

1. Equilibrium Moisture Basis
2. Moisture Free Basis
3. Dry Ash Free Basis
4. Dry mm Free
5. Moist, mm-free

The coal is agglomerating.
Vitrinite Reflectance $\bar{R}_{0\ max}$: 0.97

ACKNOWLEDGMENTS

We acknowledge the generous assistance of the people of Toksook Bay, particularly Peter Julius who was extremely helpful to us. Thanks also to Dr. P. Dharma Rao, Mineral Research Laboratory, University of Alaska Fairbanks, for analysis of a coal sample from Nelson Island; Dr. Gary D. Stricker, for discussions with the senior author on the Nelson Island coal-forming environment; and Rocky Reifenstuhl, Alaska Division of Geological and Geophysical Surveys, for petrography on thin-sections of Nelson Island fluvial sandstone. Our paper has benefited greatly from the thoughtful review by Dr. Gary D. Stricker and Mr. Ronald H. Affolter, U.S. Geological Survey, Denver.

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RESPONSES OF COAL SPLITTING AND ASSOCIATED DRAINAGE PATTERN TO SYNTECTONISM IN THE PALEOCENE AND EOCENE CHICKALOON FORMATION, MATANUSKA COAL FIELD, ALASKA

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INTRODUCTION

Coal splitting and associated drainage pattern are often results of non-uniform rates of sedimentation controlled by autocyclic processes of depositional environments. These autocyclic processes directly reflect rates of sediment influx, river discharge, and nature of topography of the depositional surfaces. The topography of the depositional surfaces, however, may be controlled by underlying tectonic conditions (e.g., faulting and subsidence). Thus, syntectonic conditions may influence the character of the contemporaneous depositional environments, which in turn affect the lithologic variations. Tectonic controls to sedimentation in coal-bearing sequences have been demonstrated by Ferm and Cavaroc (1969), Padgett and Ehrlich (1979), Flores (1984), Weisenfluh and Ferm (1986), and Fielding (1987). In all these studies, differential rates of subsidence have affected contemporaneous sedimentation either on a local or regional scale.

Tectonic controls, specifically contemporaneous growth faulting, affected sedimentation in the Paleocene and Eocene Chickaloon Formation at Matanuska coal field, Alaska (Flores and Stricker, 1993) (fig. 1). However, the most significant effect of contemporaneous syntectonism and deposition in the Chickaloon Formation is splitting and discontinuity of coal beds and coal zones. These observations are substantiated by cross sections constructed from 46 measured stratigraphic sections in the highwalls of the Evan Jones Coal Mine (fig. 2) and isopachous maps constructed from 9 drill holes for the strata near the mine. The objective of this study, therefore, is to record the effects of contemporaneous tectonism on coal splitting and drainage pattern in the Chickaloon Formation.

REGIONAL STRUCTURAL GEOLOGY

The Matanuska coal field is located on the western part of the Matanuska River valley (about 10 km wide and 70 km long) at the northeast head of the Cook Inlet. The coal field is bounded to the north by the high-angle Castle Mountain fault (Martin and Katz, 1912) and the Talkeetna uplift composed of Jurassic granitic and gneissic basement rocks. To the south, the coal field is bounded by the Chugach uplift, which contains Jurassic and Cretaceous greenstone, diorite, and interbedded slate and graywacke basement rocks (Barnes and Payne, 1956; Winkler, 1992). The Castle Mountain fault (figs. 1 and 2) was interpreted by Grantz (1966) to be a right-lateral, strike-slip fault during the Mesozoic through the early Tertiary and a steep reverse fault from Oligocene time to the present. Detterman and others (1976) indicated that the Castle Mountain fault was active for millions of years and have recorded at least several kilometers of net displacement. Lateral displacement along the Castle Mountain fault zone during the past few hundred thousand years has affected river channel diversion and capture, and the geomorphology of tributary streams of the Matanuska River (Detterman and others (1976).

Accumulation of a thick (greater than 2,000 m) interval of Tertiary strata (fig. 3) in the Matanuska River Valley prompted Payne (1955) to interpret the coal field to have formed in a larger, 50-km-wide, rapidly subsiding trough that extended beyond the present eastern and western boundaries of the valley. Mapping by Capps (1927), Barnes and Payne (1956), Grantz and Jones (1960), and Barnes (1962) in the Matanuska valley showed that Tertiary nonmarine clastic sedimentary rocks are mainly concentrated along the central part of the trough. Subordinate amounts of the Tertiary rocks consist of hypabyssal intrusives and volcanics (basalt flow). These Tertiary rocks are flanked to the north, south, and east by Jurassic and Cretaceous rocks, which are generally marine to nonmarine clastic sedimentary rocks intruded by volcanic and plutonic rocks.

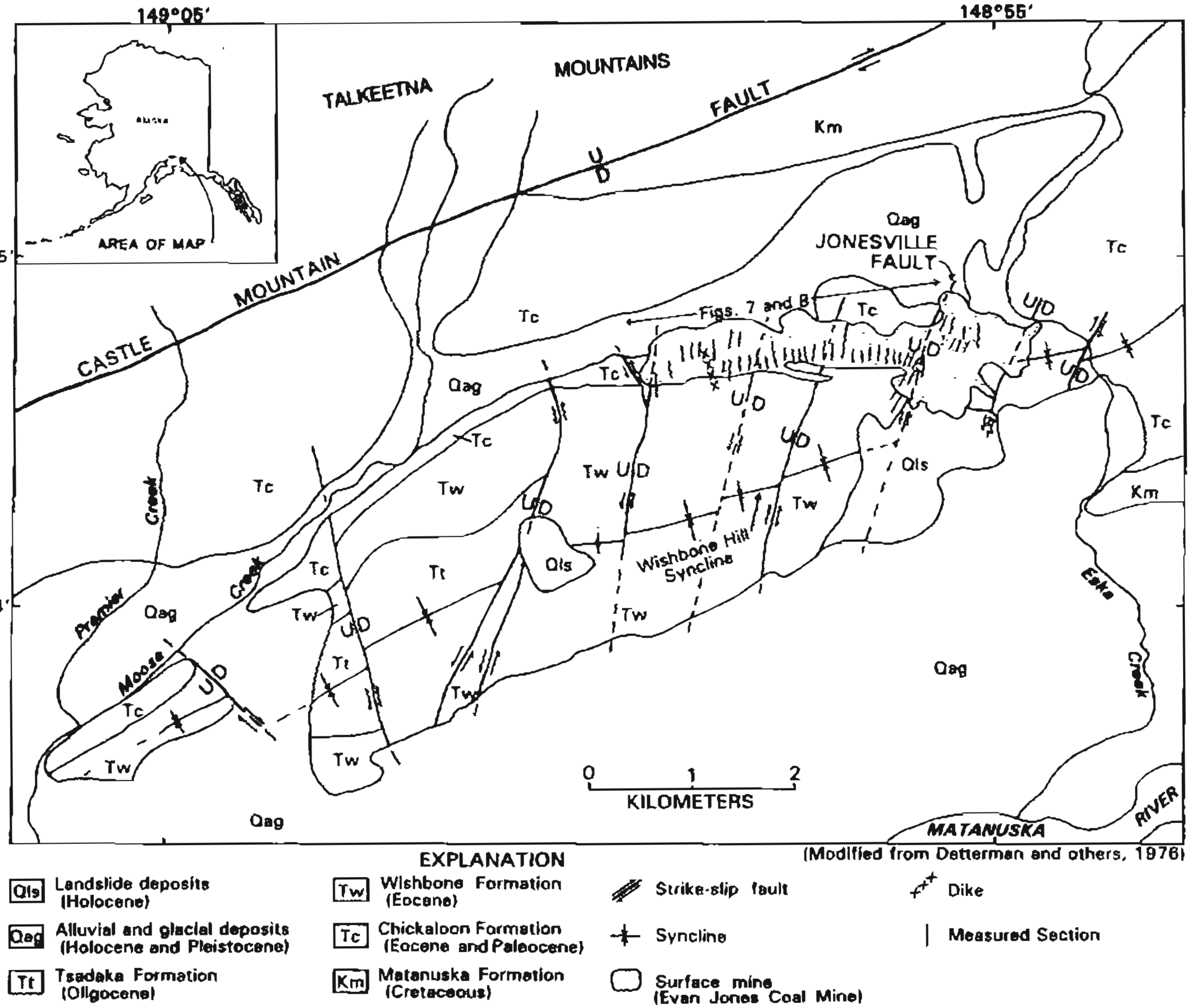

Figure 1- Location and generalized geology of the Matanuska coal field, Alaska. Modified from Grantz (1966).

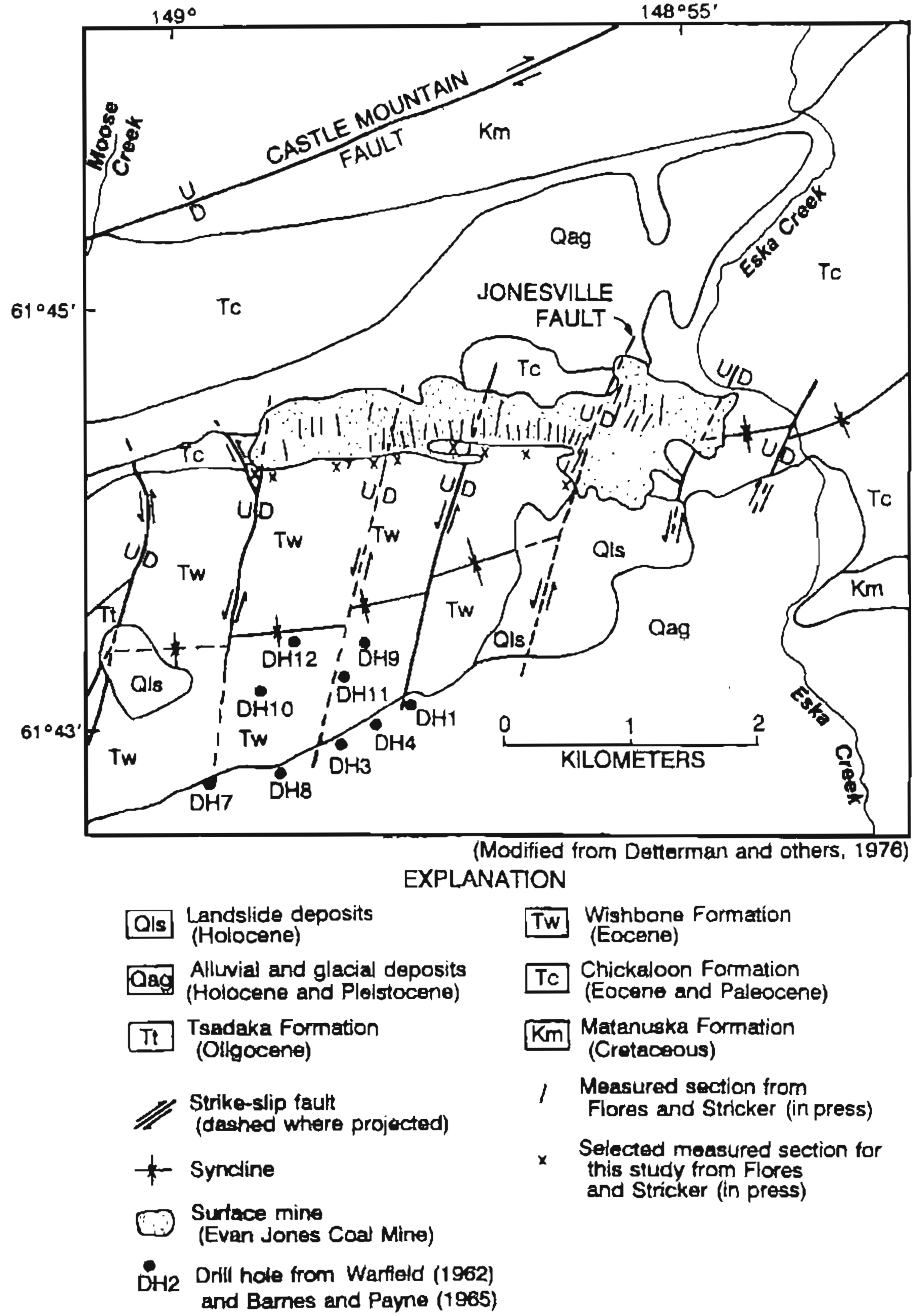

Figure 2- Geologic map of the study area in the Wishbone Hill district of the Matanuska coal field. Map shows locations of measured sections in the Evan Jones Coal Mine and drill data along the south limb of the Wishbone syncline (WS).

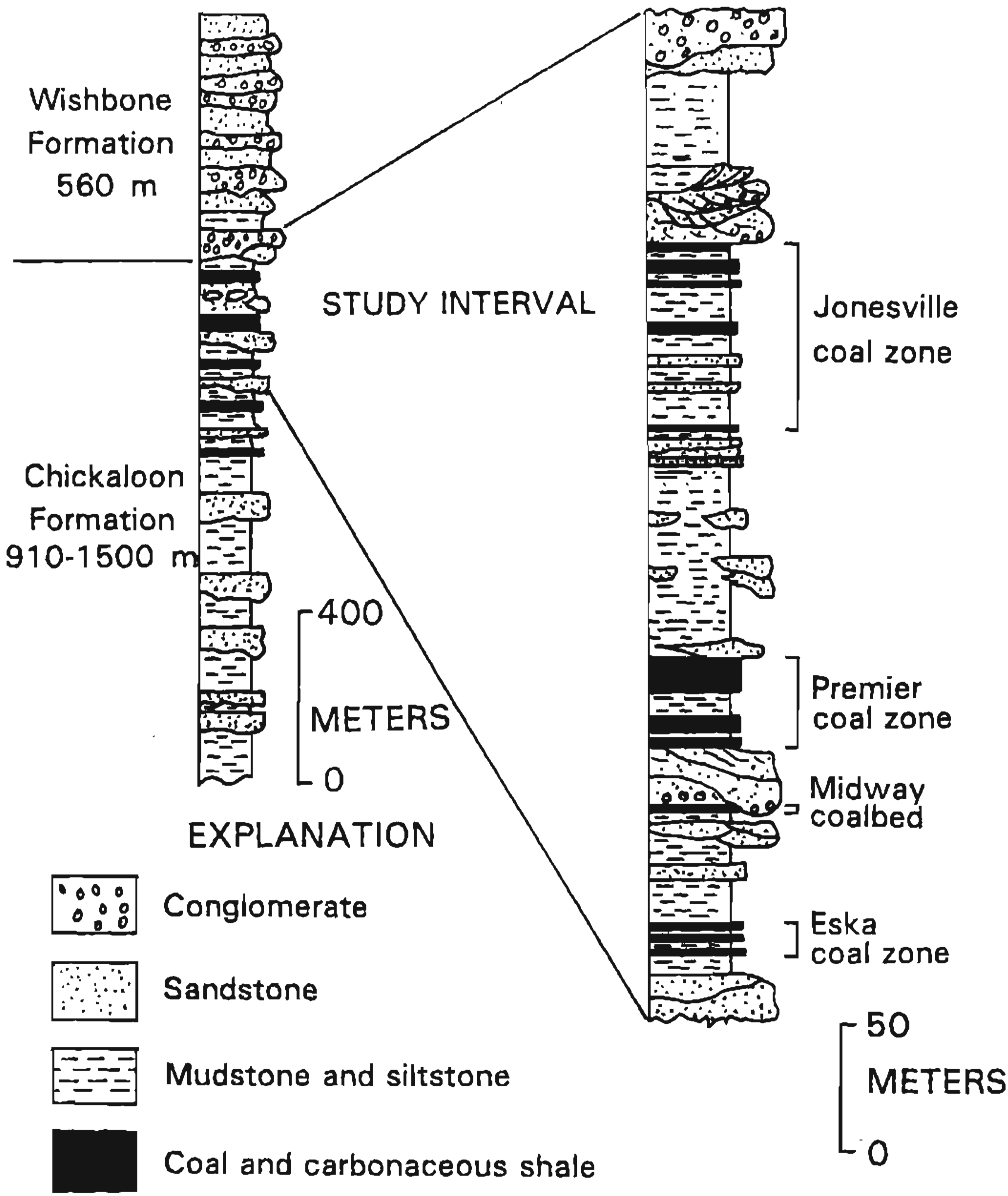

Figure 3- Generalized stratigraphic column of the Paleocene and Eocene Chickaloon Formation and overlying Eocene Wishbone Formation. Study interval is shown on the right.

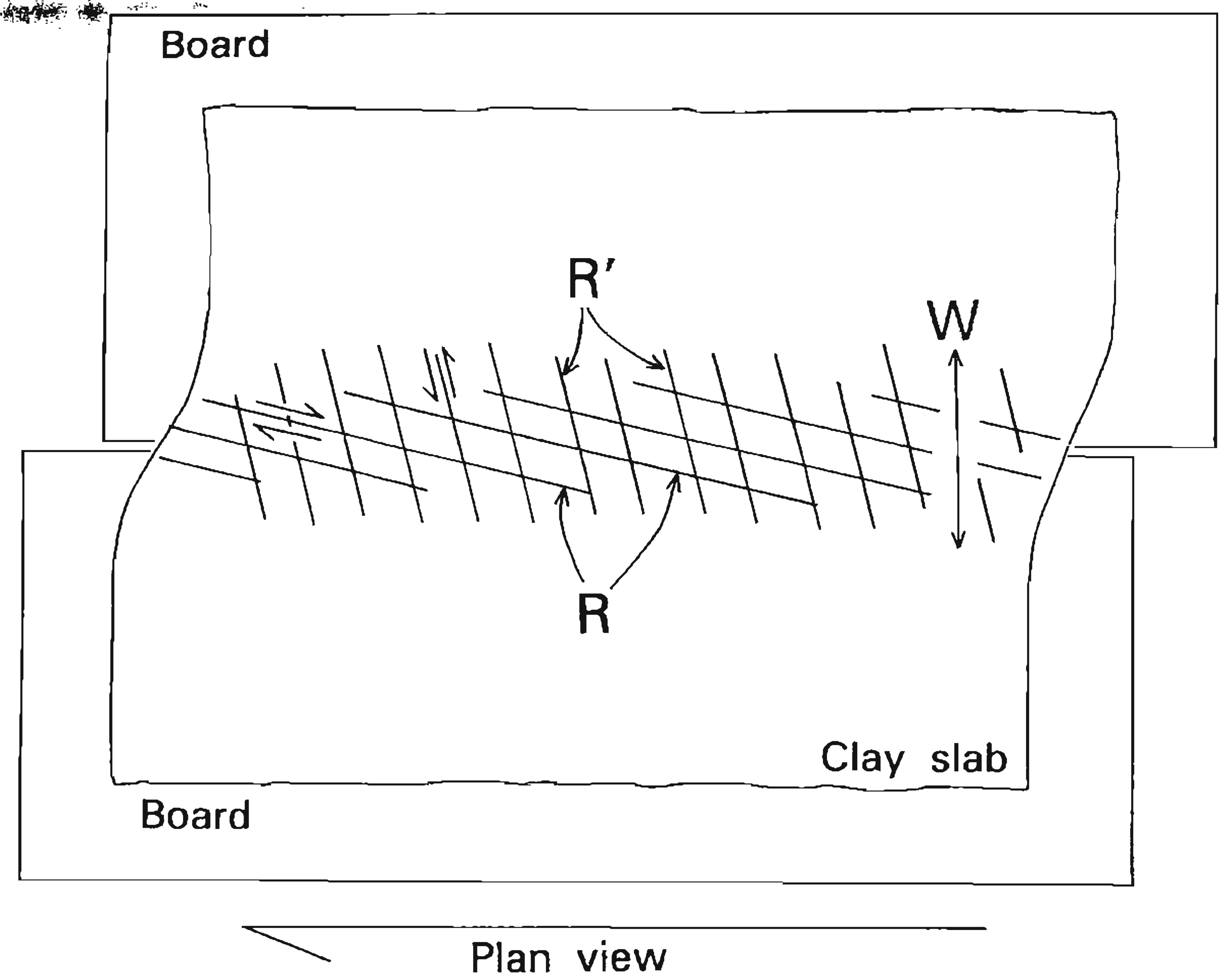

Figure 4- Structural model of deformation of Riedel experiment showing Riedel shear (R) and conjugate Riedel shear (R'). W, width of shear zone. Modified from Tchalenko (1970).

LOCAL GEOLOGY AND STRUCTURAL GEOLOGY IN STUDY AREA

The study area (fig. 2) in the Wishbone Hill coal district (Barnes, 1962) is marked by the presence of two major structural elements: a synclinal fold and oblique slip faults. The most prominent structural element in the coal district is the southwest-plunging, S 55°80°W- striking, asymmetrical, canoe-shaped Wishbone Hill syncline (Patsch, 1981). The Paleocene and Eocene Chickaloon Formation is mainly exposed along the northern and southern flanks of the syncline. The Eocene Wishbone Formation is exposed along the axis of the syncline. Northeast- striking left-lateral oblique-slip faults have offset the Wishbone Hill syncline. These faults, commonly with an up-to-the-west displacement component and steeply dipping to the east (75°-85°), can be seen in the highwall exposures of the Evan Jones coal mine along the northern limb of the syncline. Measured horizontal displacement components range from a few centimeters to 120 m and vertical-displacement components are as much as 15 m. In addition to these oblique-slip faults are subsidiary oblique-slip faults that splayed from them and served as avenues for a gabbroic dike (as thick as 7.5 m) (see fig. 1).

The left-lateral oblique-slip faults are located less than 2 km south of the Castle Mountain fault. Although previous surficial mapping did not extend these oblique-slip faults to the Castle Mountain fault, we interpret them as splays off the major fault in the subsurface. The orientation of these oblique-slip faults with respect to the Castle Mountain fault indicates that they probably represent oblique-slip faults rotated as much as 30° clockwise from the ideal R' Riedel shear orientation (Tchalenko, 1970) (fig. 4). The observed arrangement of the faults does not necessarily conform to those predicted by the Riedel model (developed on clay material). Because the rocks are heterogeneous, structures were developed sequentially rather than instantaneously, and early-formed structures were rotated during protracted deformation (Christie-Blick and Biddle, 1989). We suggest that the oblique-slip faults and/or their precursors were active during the early stages of deformation of the Castle Mountain fault from late Mesozoic through early Tertiary time when the Matanuska and Chickaloon Formations were deposited. Vertical components of movement along these faults probably produced differential subsidence and uplift of depositional surfaces, which in turn, affected localization and deflection of drainages as well as creation of stable areas un-encumbered by detrital influxes. Thickening of rock units on the downthrown sides of the faults and corresponding thinning of the same rock units on the upthrown sides of the fault as shown in figure 5 indicates that growth faulting occurred during deposition.

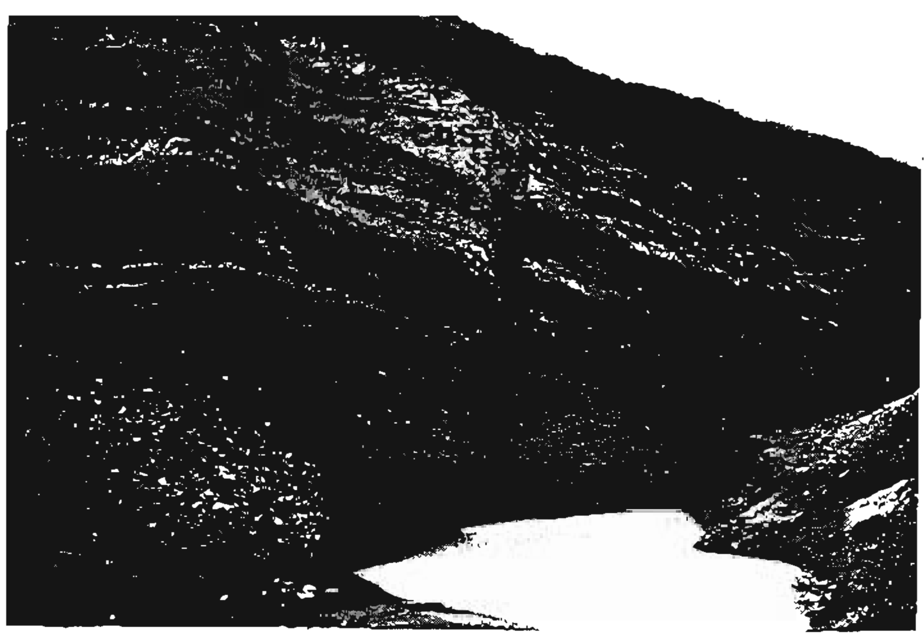

Figure 5- Photograph of the highwall in the Evan Jones coal mine showing an oblique-slip fault with up-on-the-west displacement component. Note overthickened units (ChS = channel sandstone) on the downthrown block of the fault and relatively thinned units on the upthrown block suggesting growth faulting.

In order to examine more closely the nature of coal splitting and pattern of associated drainages, these characteristics were examined in a small area (10 sq km) where data are abundant and rocks are best exposed. Six, nearly continuous highwalls in the Evan Jones Coal Mine were studied because at that location the Chickaloon Formation is approximately 100 percent exposed and nearby drill-hole data are available.

FACIES TYPES OF CHICKALOON FORMATION

Flores and Stricker (1993) described the facies types of the Chickaloon Formation to include fining-upward channel conglomeratic sandstones and sandstones, channel plug deposits, crevasse splay coarsening-upward mudstones, siltstones, and sandstones, floodplain mudstones and siltstones, and carbonaceous shale and coals formed in lowlying mires.

The channel sandstones represent deposits ranging from high- sinuosity (meandering) to low-sinuosity (slightly meandering) streams. The meandering channel sandstones are commonly amalgamated with channel plug (abandoned) deposits consisting of mudstones and siltstones. The meandering channel sandstones, which are multiscoured and multistory, are common in the intervals between Eska-Premier coal zones and Midway coalbed (fig. 6). This channel-sandstone architecture indicates that the river-channel processes were predominantly cutting and filling followed immediately by shifting. The meandering channel conglomeratic sandstones, which are amalgamated with channel plugs and are multiscoured and multilateral, are mainly found above the Jonesville coal zone (fig. 6). Amalgamation of the channel sandstones and channel plugs suggests that river-channel processes were dominated by infilling of channel cut-offs (channel plug deposits) and active channels by cutting, lateral filling, and shifting (channel sandstones). These channel sandstones are bounded by floodplain mudstones and siltstones and are commonly overlain by coal zones formed in raised mires. Although mires formed on topographically high meander-ridge belts, the high ash content (as much as 25 percent) and abundant carbonaceous shale interbeds of the coals suggest that the local base level must have been lowered probably by rapid subsidence and/or sediment autocompaction to permit flooding of the mires.

Crevasse splay sequences are abundant in the interval between the Premier and Jonesville coal zones (fig. 6). These sequences are thick and laterally juxtaposed to narrow, thick, coeval channel sandstones (thickness-to-width ratios as much as 1:30). The crevasse sandstones that cap the coarsening-upward sequences are tabular and commonly burrowed indicating deposition in subaqueous floodbasins and/or lakes. The channel sandstones are bounded by thick interbedded sandstones, siltstones, and mudstones that commonly contain upright tree trunks (as much as 6 m long) suggesting well-developed levees, which formed along the channel margins. The abundance of crevasse splay sequences juxtaposed to narrow, thick, coeval channel sandstones with well developed levees suggest deposition in an anastomosed fluvial system (Smith, 1983). Thus, the Jonesville coal zone above these fluvial deposits was probably formed on an abandoned, low-lying, subaqueous belt of the anastomosed fluvial system similar to that found in the Saskatchewan River (Smith, 1983).

Coal zones in the Chickaloon Formation are therefore interbedded with deposits of the meandering and anastomosed fluvial systems. The high ash content and abundant carbonaceous shale and mudstone interbeds associated with the coal zones indicate that they accumulated in lowlying or topogenous mires. Although mires formed in topographically high meander belts such as that below the Premier coal zone, base level must have been lowered periodically to permit drowning by detrital influxes. However, such influxes were probably short lived, allowing for the reestablishment of the mires, until a final sustained influx terminated peat accumulation. Flores and Stricker (1993) suggested that the lowering of local base level was due to either to autocompaction of sediments or tectonic subsidence. Thus, the vertical repetition of coal zones (see fig. 6) in the Chickaloon Formation reflects interaction of autocyclic and allocyclic (tectonic subsidence) processes. Syntectonism played an additional role, however, in lateral and vertical variations of the coal zones.

RELATIONSHIP OF COAL VARIATIONS TO SYNTECTONISM

Coal variations in the form of coal splits and thickening of intervening detrital deposits in the Chickaloon Formation (fig. 6) are well developed in the Premier coal zone and in the overlying interval beneath the Jonesville coal zone. In addition, merging of coal beds accompanied laterally by "stacking" of chan-

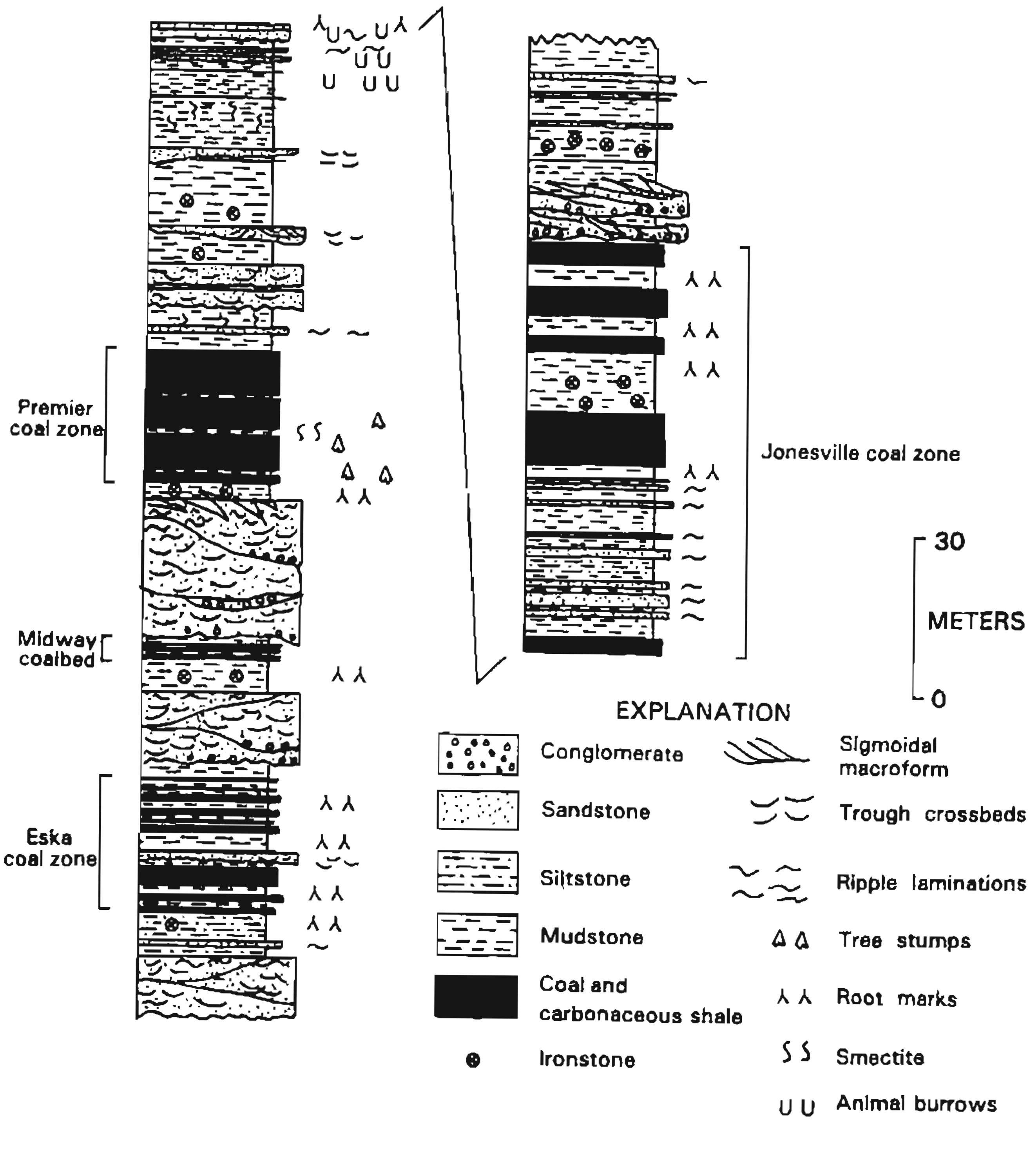

Figure 6- Composite vertical-facies association of the study interval in the Chickaloon Formation.

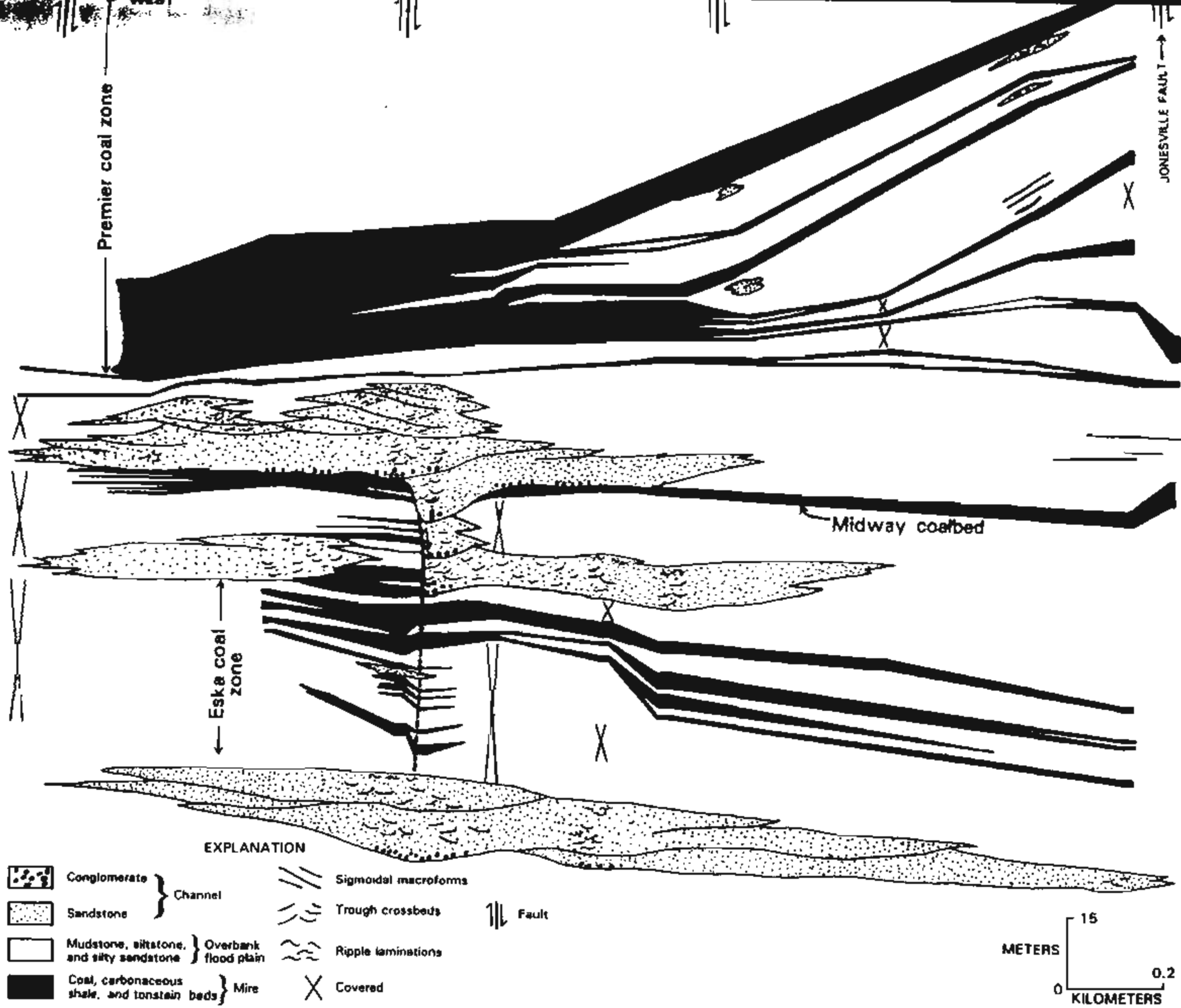

Figure 7 - Cross section (see location on fig. 1) showing splitting of the Premier coal zone and growth faulting that localized deposition of the stacked channel sandstones between the Eska coal zone and Midway coalbed.

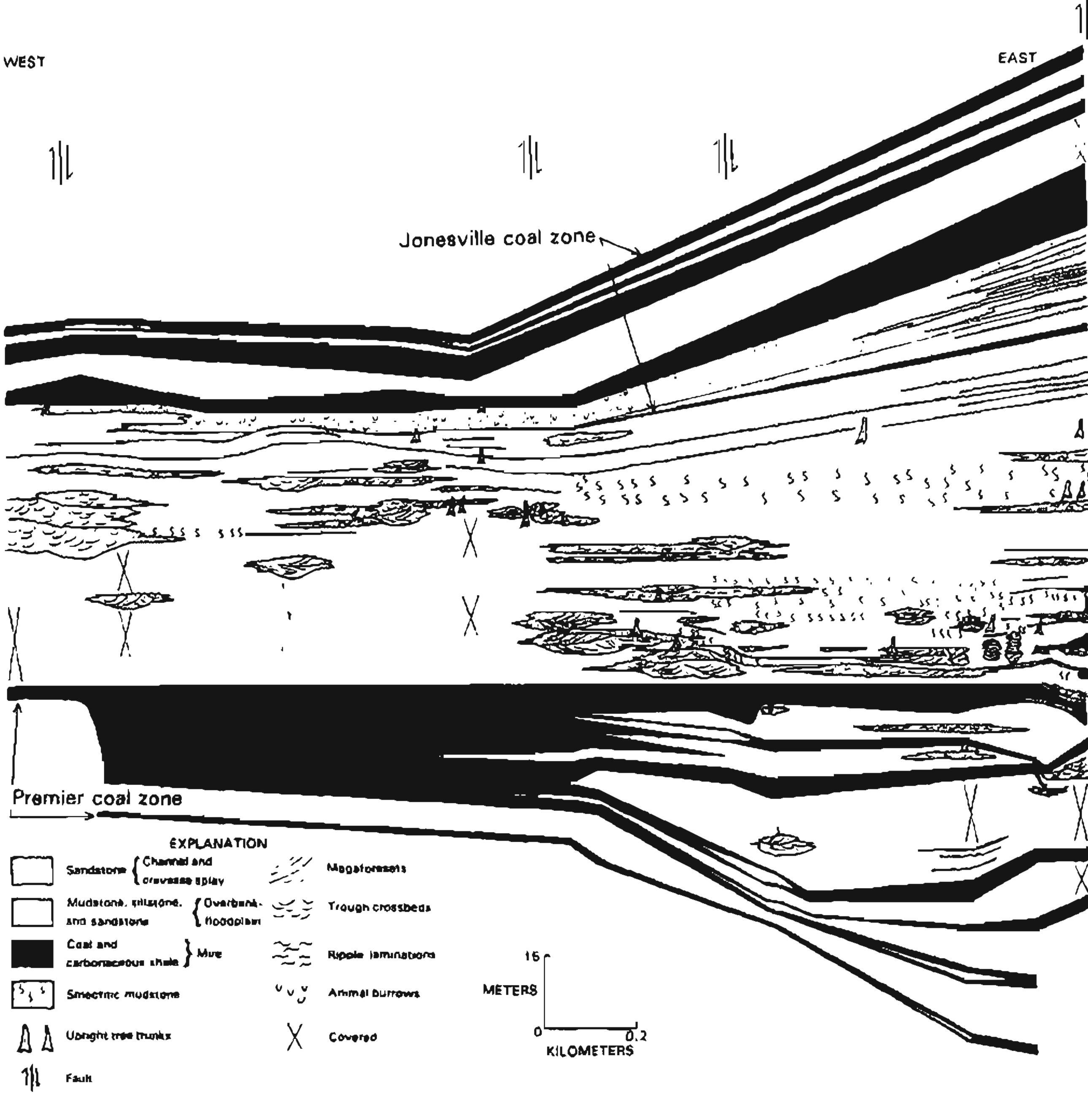

Figure 8 - Cross section (see location on fig. 1) showing splitting of the Premier and Jonesville coal zones and overthickening of the interval between the Premier and Jonesville coal zones. Cross section is restored from vertical components of displacement of oblique-slip faults shown at the top.

nel sandstones is clearly displayed in the intervals between the Eska coal zone and Midway coalbed. Precise nature of the thickness variations of the stratigraphic intervals between these coal zones along the Evan Jones Coal Mine highwalls are shown in figures 7-8. These cross sections are constructed by closely-spaced sections that are approximately 15 to 150 m apart.

Figure 7 shows that the Eska coal zone and Midway coalbed are thick and merged on the upthrown block (west side) of a oblique-slip fault. Here, the coal zones are as much as 45-m thick and include rock partings on the west or upthrown block and are immediately juxtaposed against thick, stacked channel sandstones on the east or downthrown block. The stacked channel sandstones on the downthrown block and merged coal zones on the upthrown block are shown on the sides of a 7-m-wide gap through which the oblique-slip fault developed (figs. 9 and 10). Figure 9 shows the thick (22 m), stacked channel sandstones underlain by the Eska coal zone and Midway coalbed in the downthrown block or on the east side of the gap. Figure 10 exhibits the merged Eska coal zone and Midway coalbed overlain by a channel sandstone complex in the upthrown block or on the west side of the gap. The stacked channel sandstones on the downthrown block are laterally juxtaposed to the upper part of the merged coal zone and coalbed in the upthrown block. The stacked channel sandstones on the downthrown block are vertically amalgamated with the overlying channel sandstones elsewhere above the Midway coalbed. This relationship of the merged coal zones juxtaposed against stacked channel sandstones reflect localization of channeling along the downthrown block resulting from contemporaneous subsidence enhanced by growth faulting.

Figures 7 and 8 are oriented normal to the contemporaneous oblique-slip faults and illustrate the differences in thickness of the detrital intervals within the Premier coal zone and between the Premier and Jonesville coal zones. The thick, merged Premier coal zone (fig. 11) is located on the upthrown fault blocks at the western part of the cross section. Eastward, on the downthrown the fault blocks, the Premier coal zone abruptly splits from the merged coal zone 25 m thick to an interval 67 m thick consisting as many as 6 coal beds that are separated by detrital sediments that range from 3 to 18 m thick. This rapid lateral splitting occurs within 0.8-km distance of the Jonesville fault. The sediments between coal-bed splits comprise fining-upward, channel sandstones and coarsening-upward crevasse splay sandstones; both facies types are interbedded with

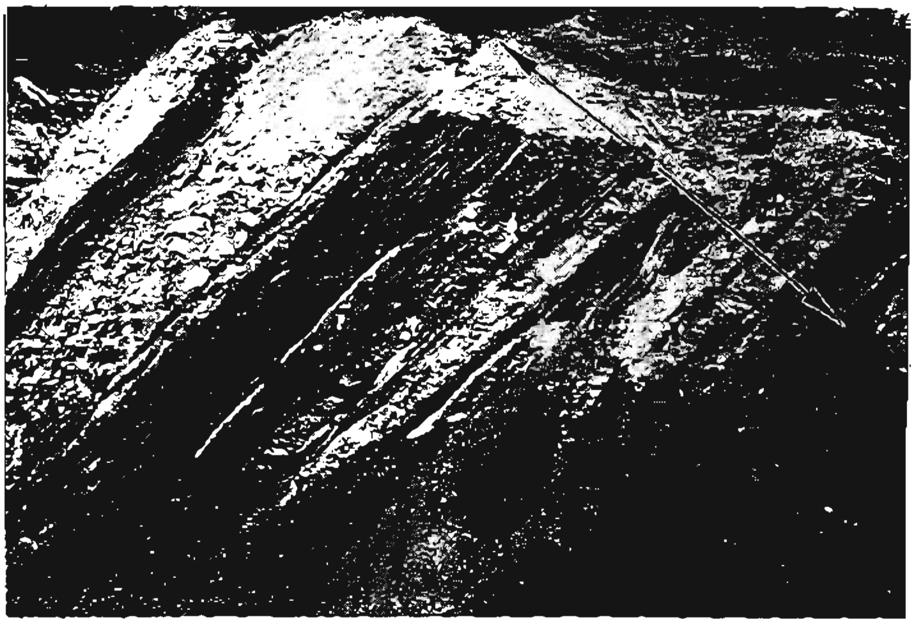

Figure 9 - A photograph of the outcrop of the Eska (E) coal zone and Midway (M) coalbed and associated channel sandstones on the downthrown side of the growth fault. Cross section is restored from vertical components of displacement of oblique-slip faults shown at the top.

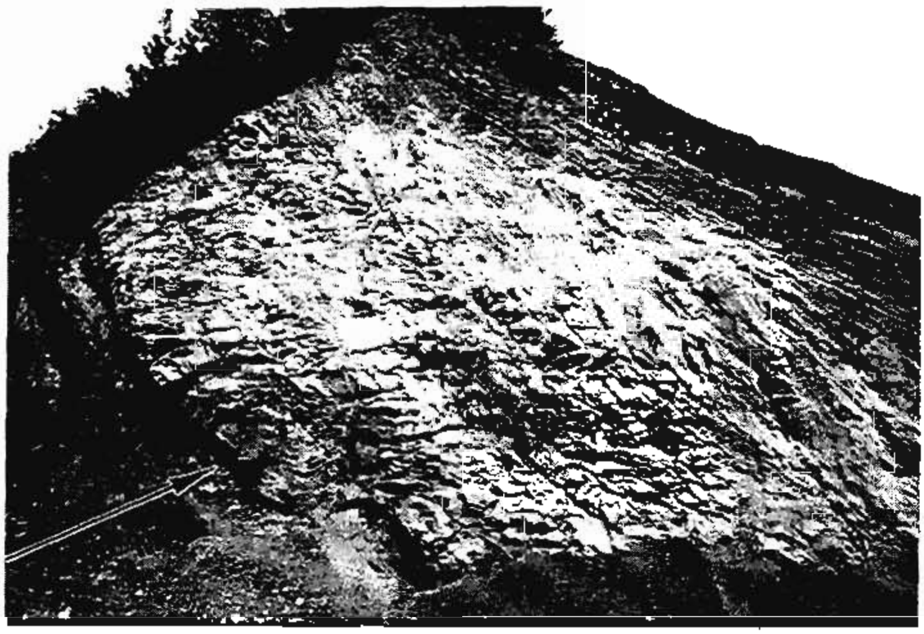

Figure 10 - A photograph of the outcrop of the merged Eska coal zone and Midway coalbed (E-M) and overlying channel sandstones on the upthrown side of the growth fault.

Figure 11 - A photograph of the outcrop of the thick, merged Premier (P) coal zone on the upthrown side of the growth fault.

floodplain mudstones and siltstones, which are the dominant facies type (fig. 12). Measurements (N=37) of trough crossbeds in the channel sandstones show a southwest direction of transport.

Figure 8, oriented normal to the contemporaneous oblique-slip faults, exhibits variation in thickness of the detrital interval between the Premier and Jonesville coal zones. The interval thickens eastward on the same downthrown block that affected splitting of the underlying Premier coal zone. The interval abruptly thickens from 25 m to 75 m within 0.8 km. The interval is dominated by fining-upward anastomosed fluvial channel sandstones bounded by thick crevasse splay mudstones, siltstones, and sandstones and thick, tree trunk-containing, overbank-floodplain sediments (fig 13). Measurements (N=56) of trough crossbeds in the channel sandstones exhibit a westerly direction of transport.

AREAL THICKNESS VARIATIONS OF COAL ZONES AND ASSOCIATED INTERVALS

Areal variations of the thickness of the Premier and Jonesville coal zones and intervening detrital splits and the interval between the Premier and Jonesville coal zones are shown in figures 14-16. Figure 14 shows the areal thickness distribution of the Premier coal splits and intervening detrital intervals. The thickest and most widespread coal splits are in the east-southeast, where the coal zone and intervening detrital intervals are as much as 75 m thick. The areal pattern confirms the data from the cross sections. The progressive thickening from 10 to 75 m of the Premier coal zone and intervening detritus to the east-southeast suggests that the series of oblique-slip faults (right-normal dip direction) developed generally active down-to-the-east displacement components during deposition of the coal zone. These displacement components, which formed from differential movements, created a local topographic low where rapid rate of fluvial channel-crevasse splay-floodplain sedimentation was diverted repeatedly to the southwest between pauses of slow rate of accumulation of peat in low-lying mires.

Figure 15 displays the areal thickness variation of the detrital interval between the Premier and Jonesville coal zones. The areal pattern indicates a general thickening to the east-northeast to greater than 60 m thick from less than 30 m to the west. Comparison of figures 14 and 15 illustrates varying degrees of control by the faults and differential accumulation of the sediments. A uniformly thick (average 55 m) accumulation of sediments by the westerly-flowing anastomosed fluvial system was concentrated along the northern tier. Conversely, thin (average 39 m) accumulation of sediments of the anastomosed fluvial system overlies the fluvial sediments of the Premier coal zone where the zone is thick (average 46 m). This inverse relationship suggests that the effects of continued subsidence due to net displacements of the growth faults were probably better recorded where the underlying sediments are thin as compared to where they are thick because movements may have been masked by greater differential compaction of the thicker sediments. Furthermore, while the Premier coal zone and associated detrital splits show general thickening to the east-southeast, the overlying interval exhibits thickening to the north and east, and thinking to the west.

Figure 16 shows the areal thickness variation of the detrital intervals between the coal splits of the Jonesville coal zone. The total thickness (as much as 51 m) of the detrital splits of the coal zone, like those of the Premier coal zone and the interval between the Premier and Jonesville coal zones, thickens to the east. However, the eastward thickening is not as rapid laterally as that of the underlying detrital intervals. In addition, variable thickening and thinking occur within the fault blocks.

DISCUSSIONS AND CONCLUSIONS

Our study shows that the lateral and vertical trends of thickening of the detrital intervals within and between coal zones of the Chickaloon Formation are best developed in the Premier coal zone and the interval between this coal zone and overlying Jonesville coal zone. Northeast-striking contemporaneous oblique-slip faults with down-on-the-east displacement components developed growth-fault movements. Differential net displacements along these subparallel faults caused intermittent subsidence and provided a topographic low on the downthrown blocks where fluvial sedimentation was diverted, resulting in coal splitting. Progressive and rapid thickening of detrital coal splits in the Premier coal zone to the east-southeast suggests increased net displacements in the direction of the topographic low. The western part of the study area is upthrown across these faults and was probably affected by least-net displacements, serving as a raised platform

Figure 12 - A photograph of the outcrop of the fluvial deposits that consist of the detrital splits (DS) of the Premier coal zone.

Figure 13- A photograph of the outcrop of the anastomosed fluvial deposits between the Premier and Jonesville coal zones. Cs = crevasse splay channel sandstones; F = floodplain deposits.

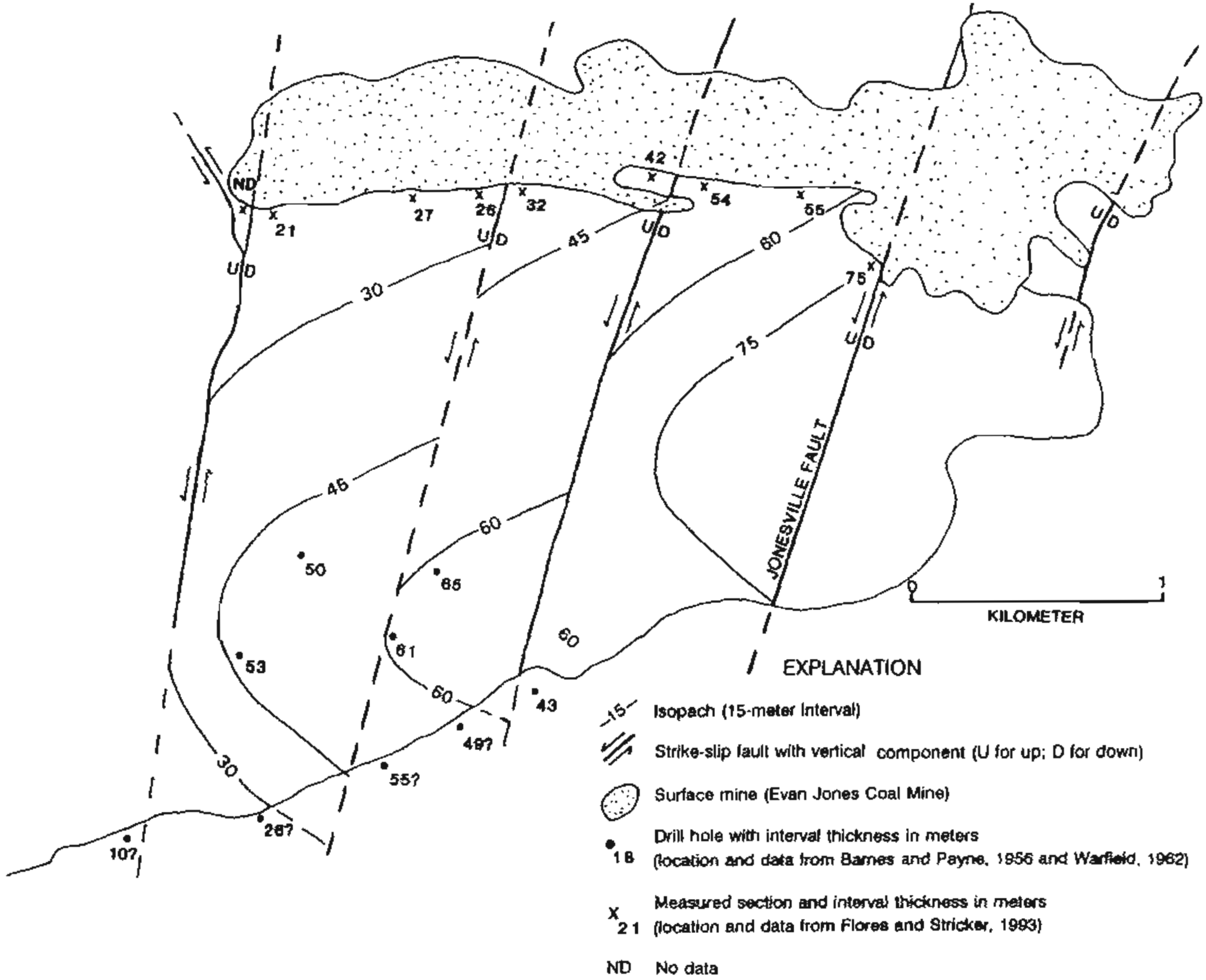

Figure 14- Isopachous map of the total thickness of the detrital splits of the Premier coal zone, Chickaloon Formation (Paleocene and Eocene). Contemporaneous oblique-slip faults are superimposed.

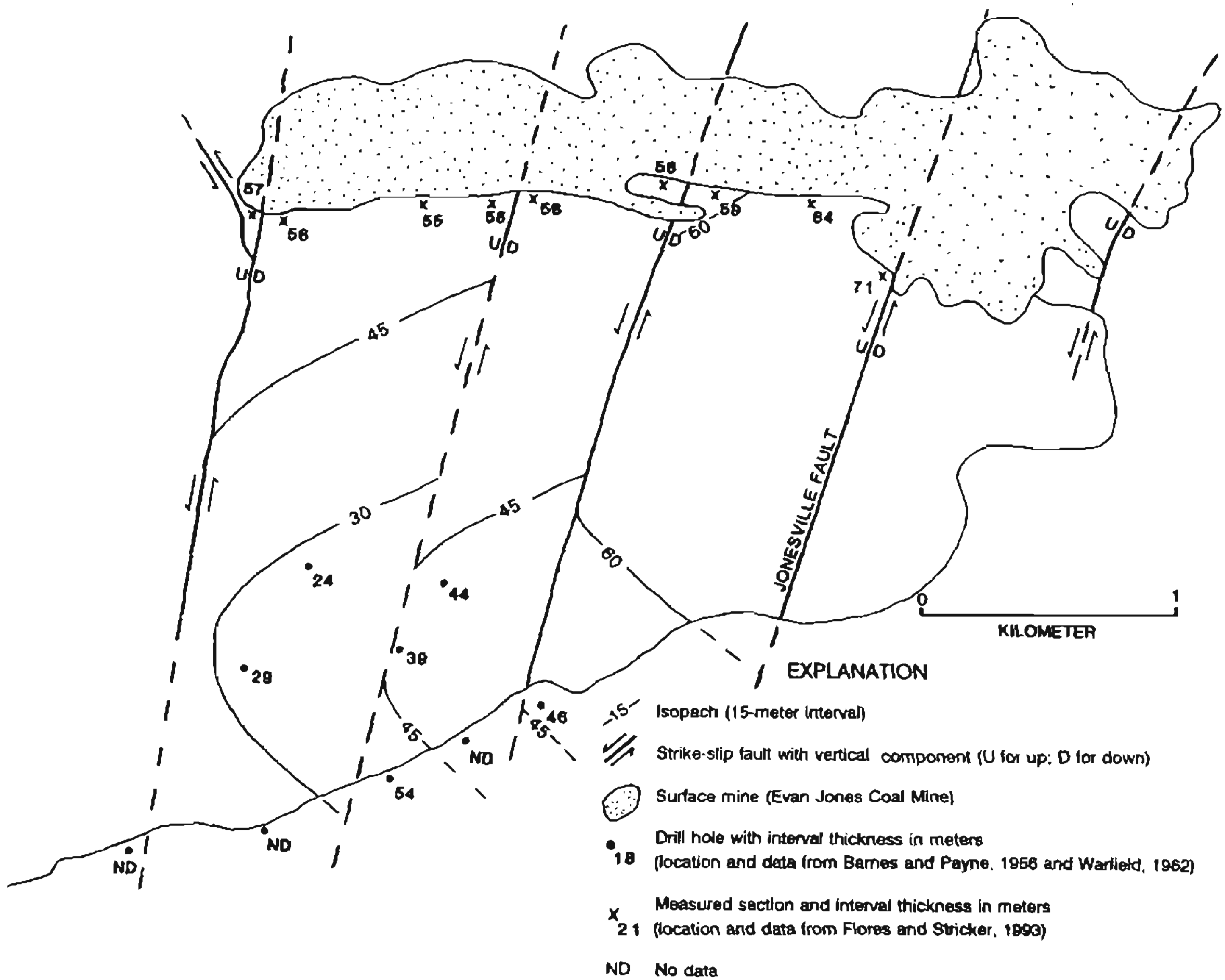

Figure 15- Isopachous map of the total thickness of the detrital interval between the Premier and Jonesville coal zones, Chickaloon Formation (Paleocene and Eocene). Contemporaneous oblique-slip faults are superimposed.

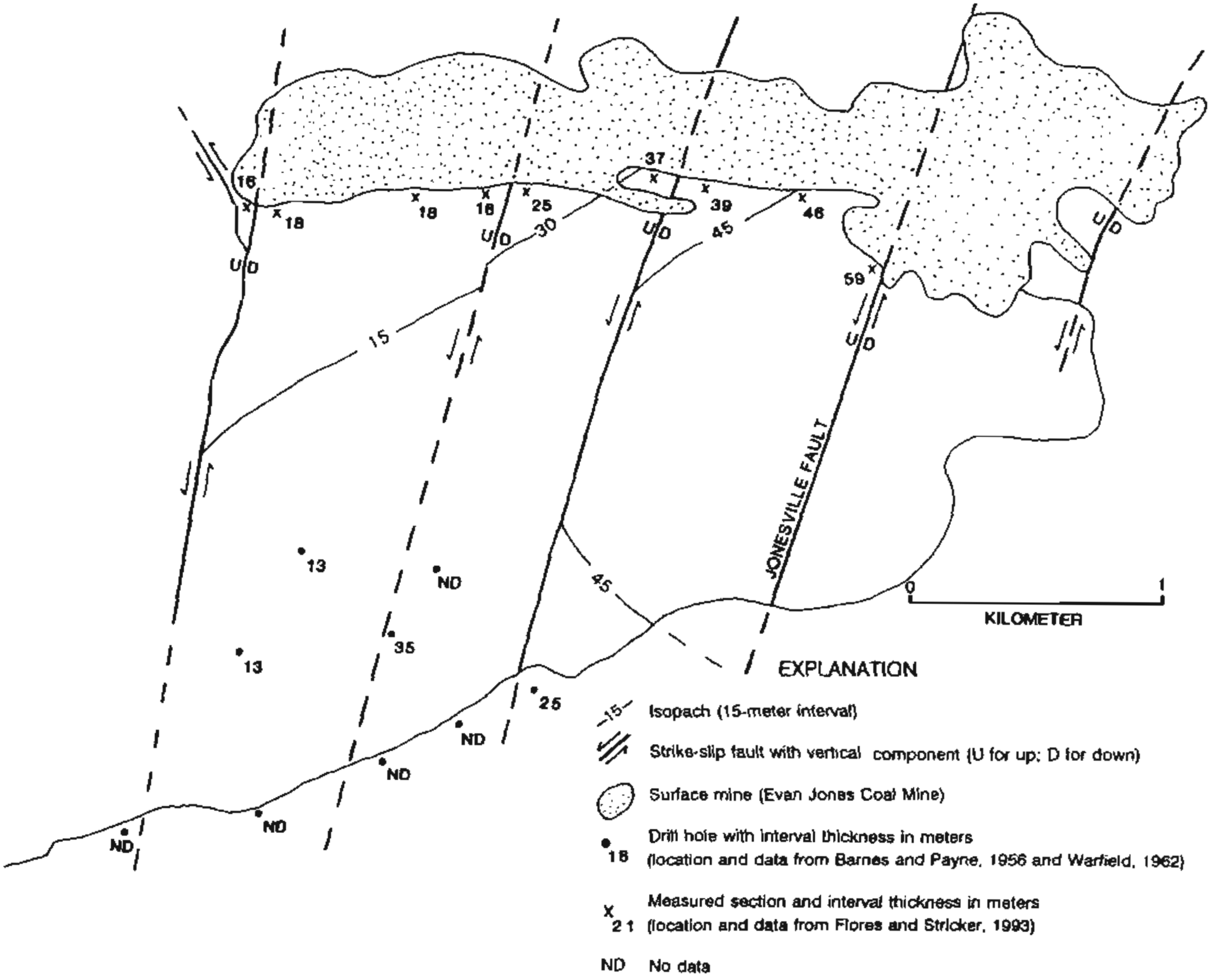

Figure 16 - Isopachous map of the total thickness of the detrital splits of the Jonesville coal zone, Chickaloon Formation (Paleocene and Eocene). Contemporaneous oblique-slip faults are superimposed.

where continuous peat accumulated and was unaffected by detrital influxes. Southwesterly-flowing fluvial-crevasse systems were repeatedly diverted into the topographic low, interrupting accumulation of peat in low-lying mires that were re-established during pauses of detrital sedimentation. The topographic low was maintained with continued increase net differential displacements of the faults on the north and east during deposition of the overlying detrital interval between the Premier and Jonesville coal zones. Deposits of this interval were formed in a westerly-flowing anastomosed fluvial system that mainly drained areas underlain by thin deposits of the underlying Premier coal splits; in this area, net displacements of the faults were not masked by underlying thick deposits. Differential growth toward the east-southeast during deposition of the Premier coal zone and overlying interval was reduced by a factor of 2 (from 65 to 38 m thick) suggesting waning tectonic subsidence through time.

Active differential growth along the oblique-slip faults during deposition of the Premier coal zone and overlying interval was followed by diminished effect of tectonic subsidence as expressed by less abrupt lateral variation of splitting of the Jonesville coal zone. Similar thickness variation (38 m) of the Jonesville coal zone and underlying interval indicates no differential growth along the oblique-slip faults towards the east-southeast. However, the variable thickening and thinning of the Jonesville coal zone and detrital splits within the fault blocks suggest that "scissor" components of movement developed following active growth faulting. Prior to active differential growth along the oblique-slip faults syntectonism was represented by localization of a fluvial channel along a downthrown fault block indicated by the channel sandstones in the interval between Eska coal zone and Midway coalbed.

Recognition of contemporaneous growth faulting in the interval between the Eska and Jonesville coal zones, therefore, suggests that syntectonism played an important role in the geomorphology of the depositional surface and nature of the underlying substrate. These characteristics, in turn, directly affected coal splitting and diversion and localization of associated drainages. Furthermore, the upthrown sides of the growth faults being topographically high were the most favorable sites for accumulation of thick, merged coal zones in the Chickaloon Formation.

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GEOLOGY, MINE DEVELOPMENT, AND MARKETING FOR EVAN JONES COAL

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INTRODUCTION

The Evan Jones mine is one of numerous past producing coal mines in the Wishbone Hill Coal District of the Matanuska Coal Field. The Matanuska coal field covers an area of about 200 square miles varying from 6 to 8 miles in width and extending about 40 miles in an east-west direction. The coal field is bisected by the Glenn Highway and its western end, at Palmer, is accessible by the Alaska Railroad.

The Wishbone Hill district lies on the north side of the Matanuska Valley, northeast of Palmer . The district takes its name from the prominent conglomerate-capped hill that rises to 2,300 feet with steep escarpments along its central part. This canoe-shaped hill, which slopes gently to the southwest, is approximately 8 miles long by 2 1/2 miles wide and extends from Moose Creek on the west to Eska Creek on the east. Access to the Evan Jones Mine within the Wishbone Hill district, is via the Jonesville road that exits the Glenn Highway at mile 61 in the village of Sutton. The mine is located 2 miles northwest of Sutton via this road and another short gravel road that exits to the west (Figure 1).

GENERAL GEOLOGY

The coal-bearing rocks in the Matanuska Valley belong to the Paleocene-age Chickaloon Formation which has been measured to be at least 3,000 feet thick. The main coal measures, however, occur within the upper 1,400 feet of this sequence. These coals are interbedded with moderately well indurated claystone, siltstone, shales, sandstones and thin conglomerates. The Matanuska Valley itself is a structural valley that is bounded on the north by the large-scale, high angle Castle Mountain Fault and the Talkeetna Mountains and on the south by many smaller faults and the Chugach Mountains. These two mountain systems are cored by Cretaceous and Tertiary-aged plutonics and volcanic rocks. Regional tectonic deformation in response to uplift due to these emplaced rocks and subsequent faulting has resulted in complex structures in the sedimentary Chickaloon Formation. These include strong folding and steeply dipping strata in many areas. Complicating this activity was the intrusion of late Tertiary hypabyssal igneous rocks (i.e. gabbro, diabase) along with some basalt into the already deformed sedimentary assemblages of the valley.

In general, the eastern part of the Matanuska Valley is more structurally complex and contains more intrusive activity than the western part. This increased deformation and thermal heating of the country rock is reflected in a general increase in coal rank as one progresses in an easterly direction up the Matanuska Valley (Merritt and Belowich, 1984)

The dominent structural feature of the Wishbone Hill district is the Wishbone Hill syncline. This canoe-shaped fold extends the full length of the district and is cut into segments by several northeast trending left lateral, oblique-slip faults (Flores and Stricker, 1993).

These faults result from shear related to movement along the nearby Castle Mountain fault system. The Wishbone Hill syncline is an open syncline that strikes S 55°-80° W and whose axis plunges 10° to 25° to the southwest (Patsch, 1981). Dip angles of the strata beneath Wishbone Hill range from about 20° to nearly vertical. In the vicinity of the Evan Jones mine, these dips average about 30°. Figure 2 illustrates in cross section the dipping structure of the syncline at the location of the new Evan Jones development.

COAL GEOLOGY

The coal measures of the Wishbone Hill district, as previously stated, occur in four main groups of three or more beds (Barnes and Payne, 1956). An additional laterally persistent bed that is not part of a group is also included. These coal units are separated by relatively thick sections of Chickaloon Formation strata composed mainly of interbedded sandstones, siltstones, claystones, carbonaceous shale and minor thin and discontinuous coal beds or stringers. The following names have been applied to the coal units, in order from oldest to youngest with average stratigraphic thicknesses of the group in parentheses: Burning Bed coal group (125'), Eska coal group (70'), Mid-

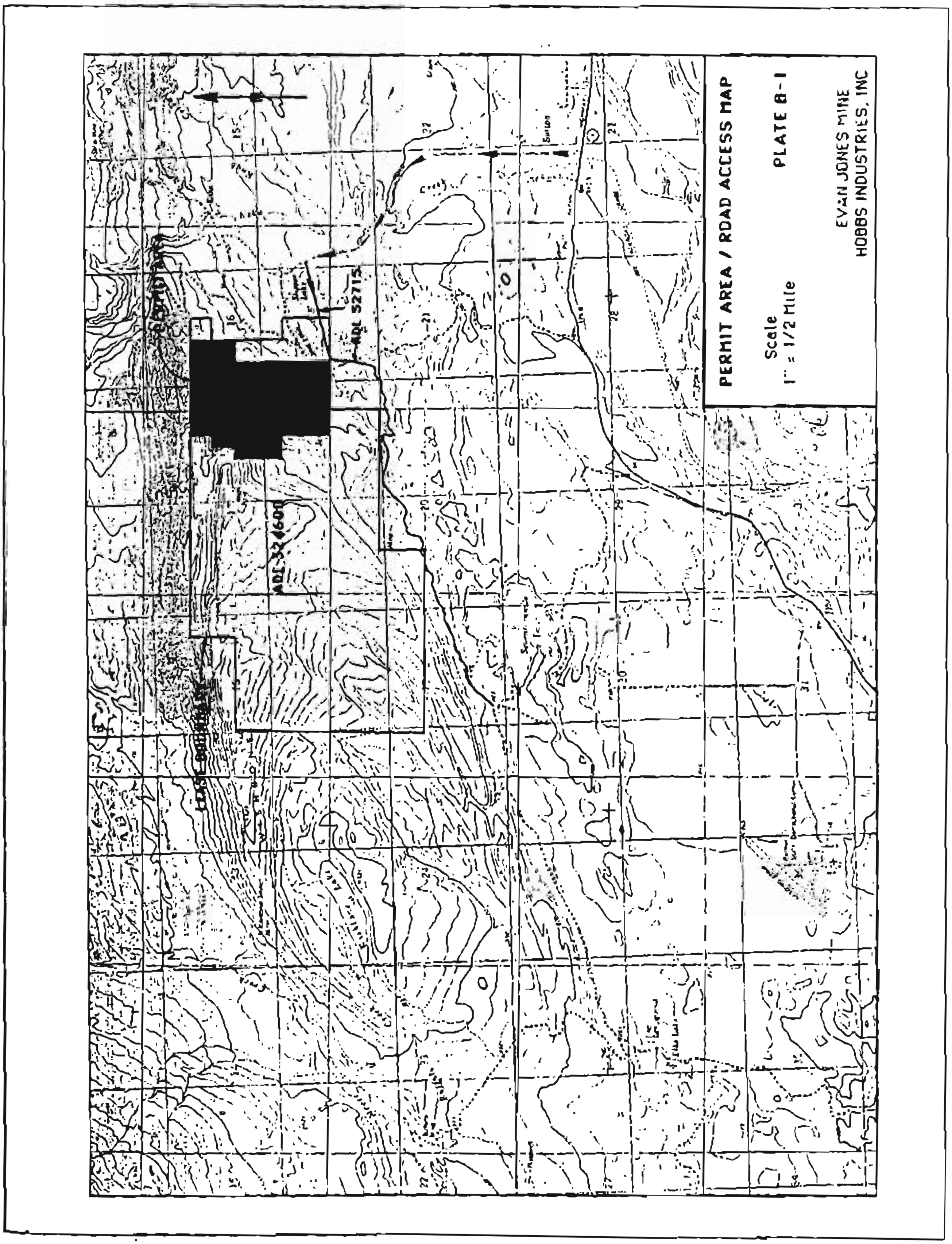
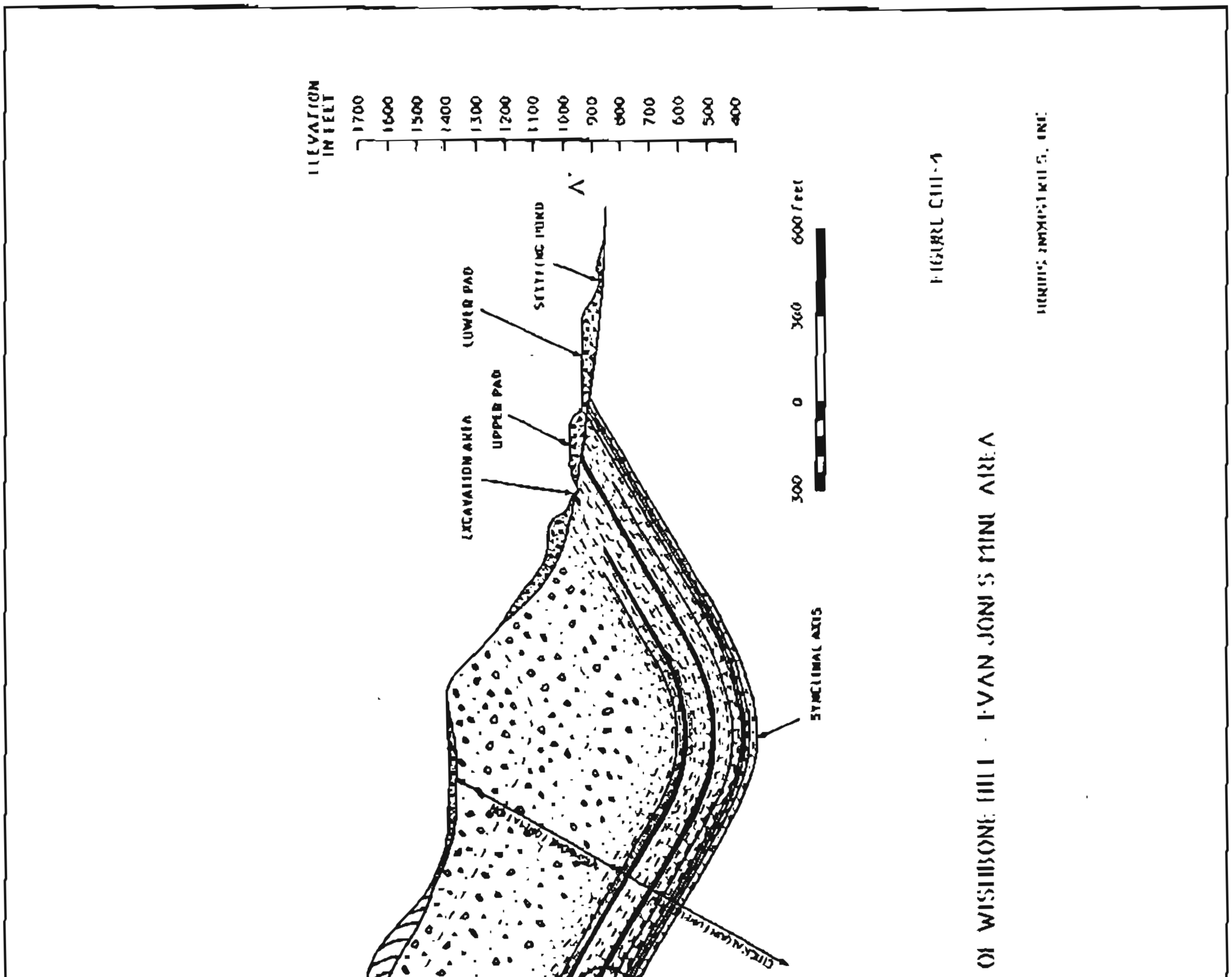

PERMIT AREA / ROAD ACCESS MAP
Scale
1" = 1/2 Mile
PLATE B-1
EVAN JONES MINE
HOBBS INDUSTRIES, INC
ADL 324601
ADL 52715

Figure 1



GENERALIZED GEOLOGIC CROSS SECTION OF WISHBONE HILL - EVAN JONES MINE AREA
LEGEND
MINE SPOILS
LANDSLIDE DEPOSITS
CONGLOMERATE
SANDSTONE
FINE-GRAINED DEPOSITS (SILTSTONE/CLAYSTONE)
COAL
ELEVATION IN FEET
1700
1600
1500
1400
1300
1200
1100
1000
900
800
700
600
500
400
SYNCLINAL AXIS
EXCAVATION AREA
UPPER PAD
LOWER PAD
SETTLING POND
STRIP PITS
PERMIT BOUNDARY
A
A'
300
0
300
600 Feet

Figure 2

way coal bed, Premier coal group (175'), and the Jonesville coal group (120'). Only one-fifth to one-third of the groups's thickness is coal due to included partings of sandstone, siltstone, claystone, carbonaceous shale and bone coal.

Over 20 coal seams with thicknesses in excess of three feet are known to occur in the Wishbone Hill district. Although seams to 23 feet are known, 8 feet is the average bed thickness. Thicker beds are composites of clean coal benches separated by claystone, coaly claystone and bony coal. In no instance has more than 12 feet of coal been mined from a single bed (Barnes and Payne, 1956). Thick mineable coal seams are located throughout the Wishbone Hill District. These thickened seams are generally located west of left lateral, oblique-slip faults which commonly bisect the district. Those areas exhibiting thickened coals are generally located on the upthrown sides of the fault, while areas to the east or downthrown sides exhibit overthickened packages of clastic rock assemblages and splitting of not only individual coals but entire coal groups (Flores and Stricker, 1993). These "growth" faults that characterize the environment of deposition of the coals were also responsible for determining the location of the numerous past-producing coal mines that targeted these thicker coal areas.

The coals of the Wishbone Hill District are characterized as high volatile B bituminous with heating values slightly higher in eastern portions of the district, which mimics the trend exhibited for the entire Matanuska Valley. Average quality parameters are as follows on an as-received basis: Moisture 4.0% - 6.0%; Ash 9% - 23%; Sulfur 0.3% - 0.4%; Volatile Matter 35% - 39%; Fixed Carbon 37% - 46%; Heating Value (BTU/lb) 10,400 - 12,000; Ash Fusion 2310°F - 2960° F; Hardgrove Grindability Index (HGI) 37-46 (air-dried); and Free Swelling Index (FSI) 1-3 (air-dried). It is a good steam coal and has been used extensively in the past for power generation. Ash contents, locally, can be high due to included claystone and bone partings and washing of these coals has in the past been necessary to produce a higher quality product.

In terms of coal resources for the district, the best estimate shows that 106 million tons remain in place after mining; 52 million tons indicated resources and 54 million tons inferred resources (Barnes and Payne, 1956). It is presently thought that about half of the remaining mineable resources of the district are contained in the old Evan Jones property now under lease by Placer Dome, U.S. Inc. As much as 18 million tons of coal, from the two predominant coal seams on the property (3 and 5 seams), are predicted to be recoverable on this lease.

PAST MINING

The presence of coal in the Matanuska Valley was first learned of by prospectors and trackers from natives in 1894. The first mining in the valley occurred in 1913 at Chickaloon when 1,000 tons was hauled out by sled for use by Navy steamships. This early coal discovery prompted the building of a railroad spur to the Chickaloon mine. In 1916, when the railroad reached the Moose Creek area, the first Wishbone Hill mine opened at the mouth of Moose creek. Completion of the railroad to Chickaloon in 1917 opened the way for development of the Wishbone Hill district. From 1917 until the last major Matanuska coal mine was closed in 1968, a total of nine separate mines were developed on Wishbone Hill, although no more than four operated at one time.

The Evan Jones Mine, named after the original prospector and first president of the company, was by far the district's largest and most consistent producer from 1920 until it closed in 1968. Out of approximately 7 million tons of coal produced from Wishbone Hill, 6 million tons came from the Evan Jones Mine. In its early years, 1920 to 1925, this mine produced coal from the south limb of the Wishbone Hill syncline. In 1925, a roughly 2,500 foot long crosscut tunnel was driven on the level to the north through the hill to reach the beds on the north limb of the syncline. It was from this northern limb of the syncline that all subsequent production came. The predominant mining method utilized by the Evan Jones Coal Company in their underground operations was conventional room and pillar. Some limited experimentation using mechanized mining methods was attempted (Tucker, 1968) In 1953, a surface strip mine that started with a small dragline, two bulldozers and a few haul trucks was opened up on the north side of Wishbone Hill on Evan Jones property to supplement production from their underground operation. Production came from the outcropping Jonesville and Premier Group coals that had been mined underground. These include No. 3 and 4 seams from the Jonesville group and No's 5,6,7, and 8 seams from the Premier Group. By 1959, production at the north strip pits was sufficient to warrant termination of the underground mine and it was closed.

For 40 years, Evan Jones coal was used by the Alaska Railroad, but with conversion of locomotives to diesel fuel in the mid-1950's, emphasis shifted to coal-fired electrical power generation on military bases near Anchorage. After the bases converted to natural gas in 1963, the domestic market was insufficient for the large Evan Jones Mine and it finally closed in 1968. Since 1934, the earliest date for which records are available, 2,300 different personnel have worked at the mine (Patsch, 1981). In 1956, Placer Amex, Inc., (now Placer Dome, U.S., Inc.) purchased an interest in the Evan Jones Coal Company. From 1959 to the closing of the mine in 1968, it was the managing joint venture partner of the property. The property still maintains one coal lease, which covers a natural mining block of the underground coal reserves. It is this lease that Hobbs Industries, Inc. subleased in August of 1990.

PRESENT DEVELOPMENT

Development of the new underground Evan Jones Mine was initiated in the summer of 1990 after a court injunction involving the state of Alaska's Mental Health lands blocked further development and permitting of the Hobbs Industries surface coal mine at Castle Mountain. Coal was needed from the Evan Jones Mine to fulfill contractual obligations to supply fuel for Slana Energy's Backscatter Radar Power Plant being constructed near Gulkana, Alaska. The site of the new mine is on the south limb of the Wishbone Hill syncline adjacent to but above the old abandoned crosscut tunnel portal. Instead of expensive and time-consuming rehabilitation of the existing underground entries or long distance entry development through old landslide gravels, it was decided to trench through the landslide gravels and place a portal into 5 seam of the Premier Group. Work to obtain an underground mine permit was also initiated at this time. After facing up in 5 seam in late 1990, development work was terminated due to a stop work order on Slana's Backscatter Power Plant project. Before portalling into 5 seam and subsequent backfilling over the proposed underground entries could be completed and land stabilized, an earthquake in April 1991 caused a landslide that partially buried the 5 seam development. Development work and permitting emphasis was then shifted to target the stratigraphically higher but partially mined No. 3 seam coal bed from the Jonesville Group. In July of 1991, 2 seam, the bed directly below 3 seam (8 - 10'), was reached. Portalling and underground development work into this seam commenced with the intention of flattening the entry to intersect the overlying and thicker 3 seam once the old workings from the early 1920s had been bypassed downdip. With the termination of the Backscatter project in June 1991, development work at the new Evan Jones Mine has slowed with no committed end-user for the coal. In January of 1992, the State of Alaska Division of Mining issued a decision approving the Evan Jones underground permit application that was submitted in late 1990. Issuance of the permit is contingent on submission of a reclamation bond for the project. In the meantime, the operation is being performed under an exploration permit.

Underground development to date is comprised of one 350 foot entry (16' by 8') in both rock and coal (2 seam). A 12 foot half round multiplate portal structure daylights this coal to the surface. With a seam dip of 32°, the entry is being developed at an angle to bedding to allow manuverability for the mechanized mining equipment used in the project. Mining equipment being utilized at the Evan Jones Mine includes a Joy 12CM5 continuous miner, a Joy 10SC-22 shuttle car, and a Lee Norse TD1-43 roofbolter. A Pemco power distribution center converts 480 volts from a 300KW generator into 120/230/480/1,000 volts and distributes these various voltages to run the underground electric mining equipment. Hookup with Matanuska Electric Association (MEA) power is slated for the future when the mine goes into production.

Surface facilities at the Evan Jones Mine include two working facility pads for equipment maintenence, parts/material storage and mine office, a settling pond for surface runoff and mine drainage treatment, a coal storage area, and connecting haul and access roads (Figure 3). The access road connects directly to a State maintained gravel road and the paved Jonesville road. The latter road terminates at Sutton where it intersects the Glenn Highway. Trucking to a rail loadout in Palmer via the Glenn Highway is the envisioned route of the Evan Jones coal to prospective end-users.

MINING PLANS

The Evan Jones Mine is envisioned to be a continuous miner operation unless market demand necessitates expansion and the use of longwall mining. Only continuous mining is envisioned within the present permit area. Figure 4 shows the proposed underground mine plan submitted by Hobbs Industries in its underground mining permit approved by the State of Alaska. Three entries into the underground reserve are depicted.

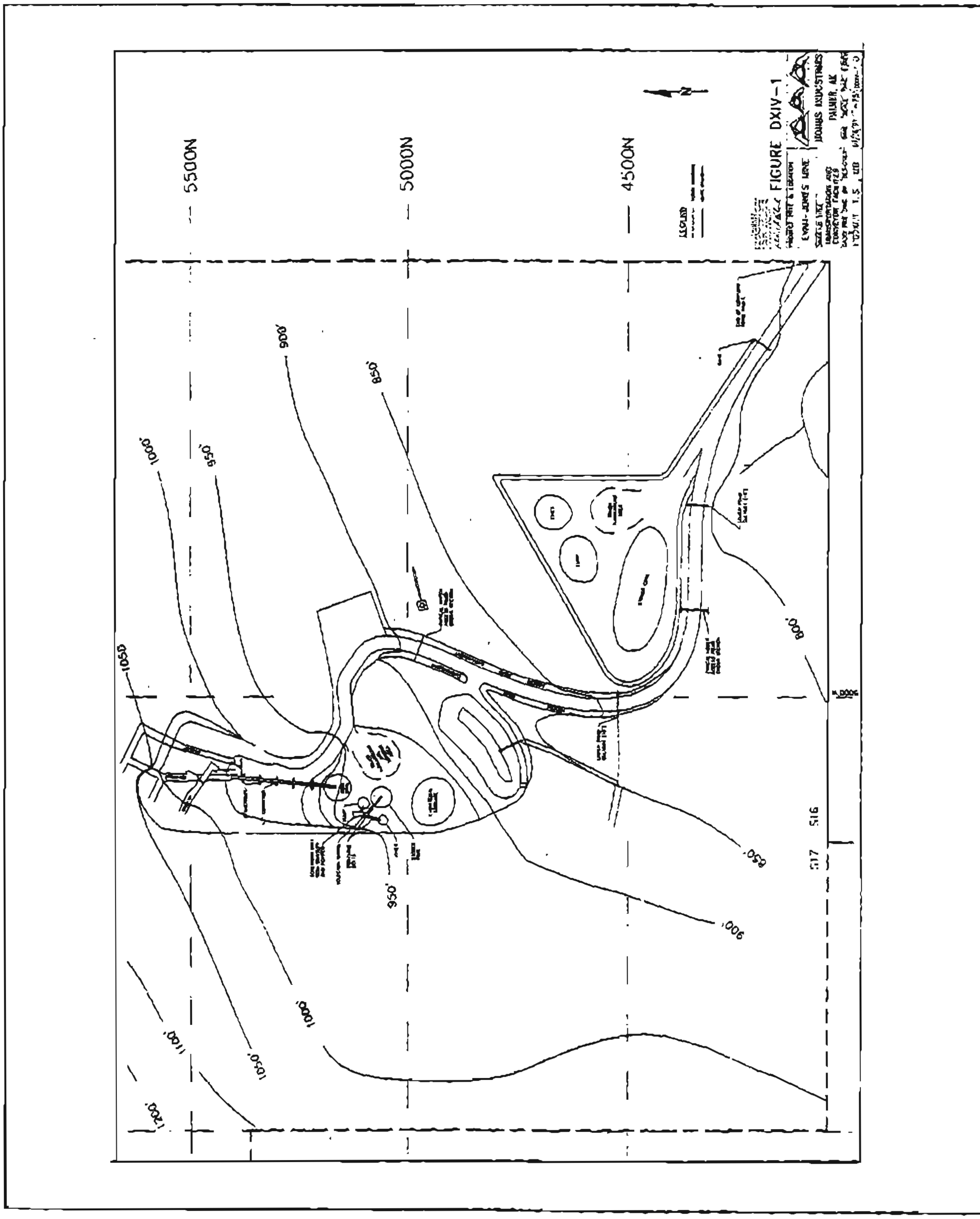


FIGURE DXIV-1
5500N
5000N
4500N
900'
850'
1000'
950'
1050
800'
516
517

Figure 3

These include an intake and return air entry and a conveyor belt haulage entry. There is presently ongoing discussion of rehabilitating the old crosscut tunnel for future use as the main haulage route, possibly with railcars. This change, however, would require a major revision to the mining permit and has not yet been submitted to the Alaska Division of Mining.

As mentioned previously, the continuous miner operation would utilize a Joy continuous miner to mine the coal with one or two Joy shuttle cars transporting the ROM coal to an advancing conveyor system. This system features a Stamler feeder breaker to downsize the ROM coal to 6 inch minus for belt haulage purposes. The mainline conveyor belt would then take the sized coal out of the mine, and after it was elevated above the upper development pad, it would drop into a conical storage pile on the lower pad. A loader would then take the crushed ROM coal and place it into another conveyor, which would load it into a combination crushing/screening plant. Lump, stoker, and fine coal would then result with each of these coals trucked separately to the coal storage area near the access road, for storage and transport to end-users. There is no washing plant contained within this initial mining scenario. With an increase in coal demand and concurrent production, a washing plant would receive the ROM coal directly and eliminate the lower pad screening unit.

Only one mining section is presently planned at the Evan Jones Mine, utilizing the continuous miner, shuttle cars and belt haulage. Roof control in the underground mine would consist of both conventional and resin-grouted roofbolts supplemented with matting, mesh and timbers, as needed. Given the steep operating conditions and off dip advancement of the entries, one operating shift is projected to result in a conservative daily production of 400 tons of coal. Annually, this will result in approximately 122,000 tons with 305 operating days per year; another conservative estimate. If mining conditions prove to be better than anticipated or if less maintenance and down periods are realized, this production could be increased. Market demand may also play a part in the determination of production. This may require additional equipment or working shifts. The proposed mine support facilities, including screening operations and storage facilities should be able to accommodate the base case mine production scenario of 122,000 tons per year. An additional continuous miner and two daily shifts could boost production to 500,000 tons per year, but this would probably require up-scaling the screening and storage capabilities of the mine. The addition of longwall mining, projected for the future on the west side of the Jonesville Fault, would easily boost daily production to 6,000 tons and annual production to about 1,320,000 tons.

MARKETING

Marketing of the Evan Jones coal should prove to be interesting and challenging. It can be safely assumed that when coal starts to be commercially produced at the Evan Jones Mine, the domestic, in-state market will be the first to utilize it. There are presently no bituminous coal producers in the State of Alaska. The high heating value, low moisture, and low sulfur characteristics of the Evan Jones coal will almost certainly make it a hit with local homeowners who still possess coal stoves left over from the old days or possess new coal-burning stoves and now must rely on low-rank coal or wood. Residences and businesses outside natural gas utilization areas may also become markets, since they must now resort to expensive heating oils for their heating needs. There also will be potential in these remote areas for the placement of small package coal heating systems and co-generation, coal-fired, power plants.

Marketing of the Evan Jones coal outside Alaska (i.e. Pacific Rim, Hawaii, Mexico) is possible but will require some infrastructure development and repeal of the Jones Act. Whatever advantage Evan Jones coal has, due to a local road network and rail haulage possibilities, it is tempered by the lack of a nearby shipping port. The cost of shipping coal to Seward has proven to be too expensive to compete on the world market (example - Wishbone Hill project). However, should a new coal shipping port be established in Anchorage or nearby Point MacKenzie, this export inhibitor will be erased and Evan Jones coal could then be economically exported. Only time will tell on this front, but in the meantime, Evan Jones coal should compete very effectively in in-state residential and business heating applications and coal-fired, co-generation, power plants.

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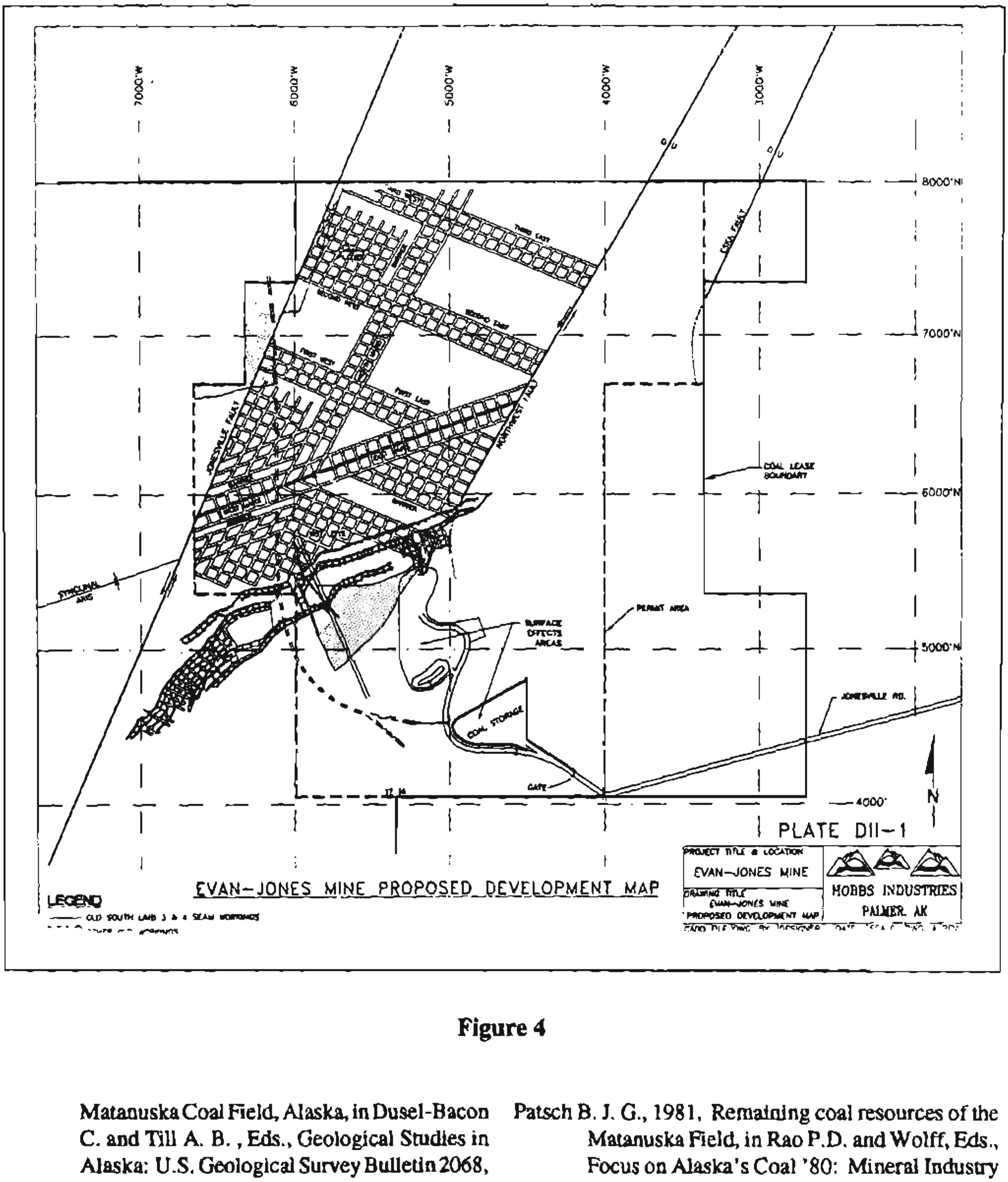

Figure 4

Matanuska Coal Field, Alaska, in Dusel-Bacon C. and Till A. B., Eds., Geological Studies in Alaska: U.S. Geological Survey Bulletin 2068, pp 101-117.

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INTERFLUVE-CHANNEL FACIES MODELS IN THE MIOCENE BELUGA FORMATION NEAR HOMER, SOUTH KENAI PENINSULA, ALASKA

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ABSTRACT

Interfluve-channel facies in the middle part of the Beluga Formation, near Homer, Alaska, contain coal beds that are presently considered a viable source of coal-bed methane gas and channel sandstones that are reservoirs for hydrocarbons in the onshore Kenai Peninsula and offshore Cook Inlet. Lithogenetic associations of the interfluve-channel facies of the Beluga Formation indicate that the Beluga alluvial plain was drained mainly by braided streams flanked by floodbasins. Floodbasins were initially drained by crevasse channels consisting of a type I channel sandstone (thickness to lateral extent ratio ranging from 1:50 to 1:200, suggesting oblate shape). Continued aggradation of crevasse sediments via feeder channels during repeated floods promoted further progradation of crevasse splays into the central floodbasins. Progradation caused feeder channels to merge and diverge and develop an anastomosed network. As major flow and sediment influx were concentrated along one of these channels due to stream capture, it was transformed into a youthful braided stream forming a type II channel sandstone (thickness to lateral extent ratio that ranges from 1:25 to 1:250, indicating lenticular shape). Prolonged lateral and vertical accretions of coarse detritus in this stream resulted in a mature, low-sinuosity, braided stream forming a type III channel sandstone (thickness to lateral extent ratio ranges to as much as 1:400, indicating elongate shape). Continued occupation of this braided stream promoted avulsion and abandonment of adjoining braidbelts, which in turn, were overrun by raised mires forming peat on elevated platforms.

INTRODUCTION

Interfluve-channel models for a rock unit (formation) have been frequently represented by vertical- and lateral-facies analysis of outcrop and subcrop localities. Data from these localities are often interpolated across long distances. The interpolations, in turn, are utilized to interpret the depositional setting for the purpose of basin analysis. Small-scale studies (Campbell, 1976; Rust, 1978; Stear, 1983; Lawrence and Williams, 1987) are limited in areal extent and provide only partial knowledge of basinal interfluve-channel models. Regional-scale investigations (Nilsen and Moore, 1982; Turner and Whateley, 1983; Melvin, 1987) require interpolation between data that are widely separated. The large gaps in data make basin wide interpretation and comparison of interfluve-channel models difficult. Both small-scale and regional investigations are especially disadvantageous in areas or basins where rapid stratigraphic variations (vertical and lateral) are present.

In this study, a regional assessment has been made during the past 3 years on essentially continuous, linear exposures along the beach cliffs of Cook Inlet and Kachemak Bay, for about 25 km, between Anchor Point and McNeil Canyon in the southern Kenai Peninsula (fig. 1). Here, exposures of the upper part of the Beluga Formation are oriented normal to subparallel of the axes of northeast-southwest trending anticlines and synclines and the Border Ranges fault (Merritt and others, 1987). These cliffs provide nearly 100 percent rock exposure and represent the most continuous and complete records of the upper part of the Beluga Formation in the Cook Inlet basin (see fig. 1). Our experience in the Cook Inlet basin, where less than 10 percent of the Tertiary rocks are exposed, suggest that examination and description of vertical and lateral sedimentologic variation and accurate identification of depositional patterns is the most productive method of investigation. The stratigraphic variations and depositional patterns can then be used to develop predictive models for analysis of the basin.

The focus of this investigation is on the economically important interfluve-channel deposits of the Cook Inlet basin. The interfluve deposits contain thick coal beds that were mined intermittently from the turn

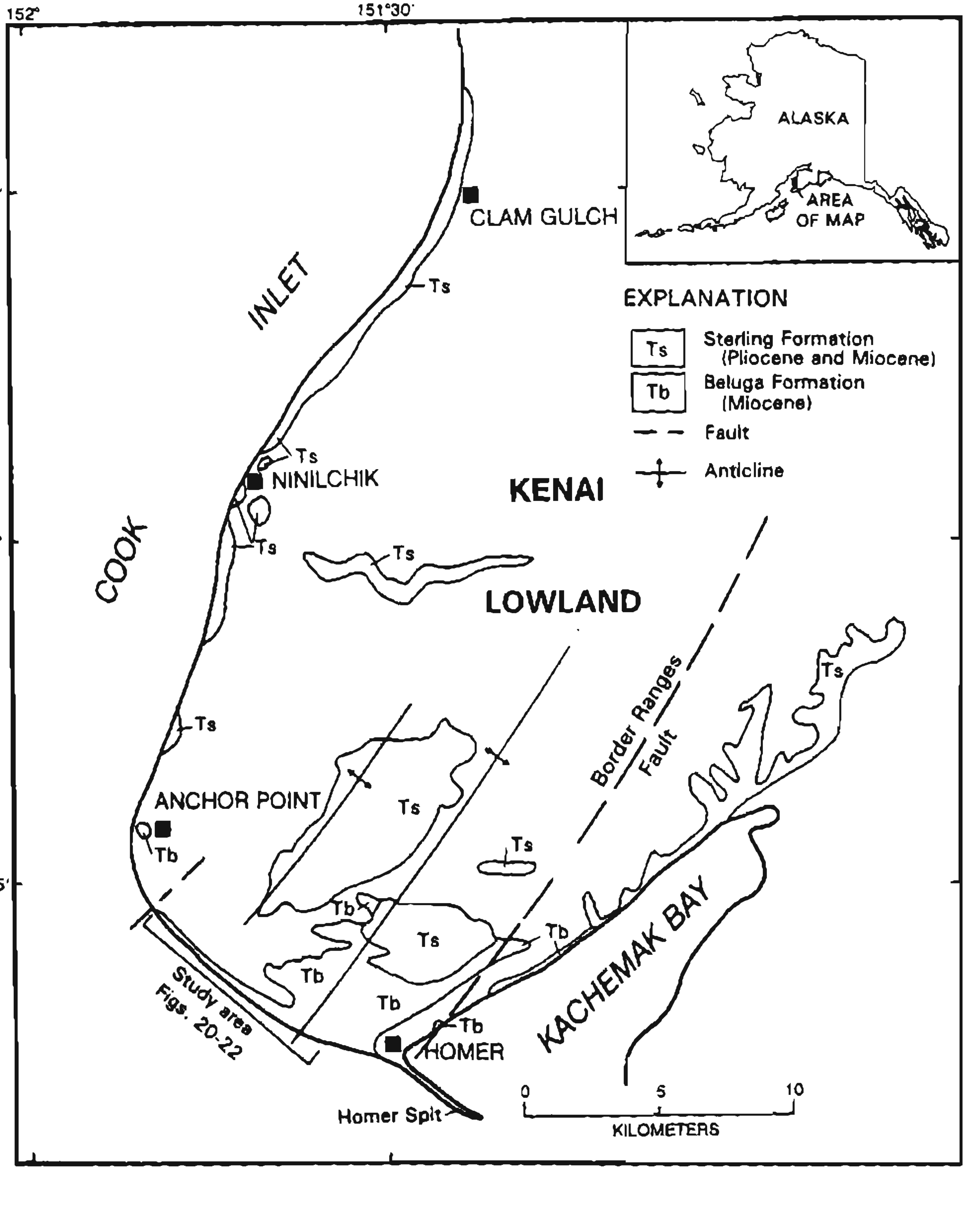

Figure 1. Locality map showing the study area along the beach cliffs west-northwest of Homer, Alaska. Homer coal district is located south of Clam Gulch on the Kenai lowland. Figures 19, 20, and 21 are lines of stratigraphic cross sections.

of the century to 1951 (Meyer, 1990, p. 309-320) and are presently considered as a viable source of coal-bed gas. In addition, the interfluve deposits are associated with channel sandstones that serve as reservoir rocks for coal-bed gas and hydrocarbons in the Cook Inlet basin (Kelly, 1963; 1968; Magoon and Anders, 1990). The main objective of this study is to characterize the interfluve-channel models of the Beluga Formation near Homer (see fig. 1) for the purpose of modeling the seal/source-reservoir facies of nearby oil and gas fields in the Cook Inlet basin (Flores and Stricker, 1993). Basic data for this study consist of 63 measured sections and continuous photomosaics between sections. Photomosaics are complemented by outcrop sketches to record the variabilities between measured sections. Measured sections are about 300 m apart on average; however, photomosaics and sketches between these measured sections permit a closer control and better correlation of facies types.

GEOLOGIC SETTING

The lowland of the Kenai Peninsula (see fig. 1) is made up of two coal districts: 1) Kenai district, which is located north of Clam Gulch and completely concealed by glacial and alluvial deposits and 2) Homer district, located south of Clam Gulch (Barnes and Cobb, 1959). The Homer district, includes an area of about 2849 sq km on the southern Kenai Peninsula. It is bounded by the Cook Inlet to the west, Kenai Mountains to the east, Kachemak Bay to the south, and the Kenai coal district to the north.

The Kenai lowland is the onshore part of the Cook Inlet forearc basin (Cook Inlet) of the Alaska-Aleutian Range (Kelley, 1985). Based on Bouguer gravity mapping, Barnes (1977) outlined a broad structural basin in the Kenai lowland with a west and northwest dipping paleoslope. Except for minor, gentle upwarping resulting from folding and vertical faulting (up to 24 m), the Beluga Formation is flat lying to gently dipping (Barnes, 1951; 1967). The horizontal beds of the Beluga Formation permit the tracing of marker beds over long distances.

Tertiary coal-bearing rock units (fig. 2) exposed in the Homer coal district include the middle and upper Miocene Beluga Formation and upper Miocene and Pliocene Sterling Formation (Barnes and Cobb, 1959; Wolfe and Tanai, 1980). Exposures of the upper part of the Beluga Formation (a few hundred meters thick) are mainly found along beach cliffs and valley walls of large streams (Barnes, 1967). In the subsurface the total thickness exceeds 1500 m (Hartman and others, 1972). Older Tertiary coal-bearing units are the Oligocene through middle Miocene Tyonek Formation and the Oligocene Hemlock Conglomerate. These two formations are present only in the subsurface in the study area (see fig. 2). The four coal-bearing formations make up the Kenai Group as modified by Fisher and Magoon (1978) from the stratigraphic work of Calderwood and Fackler (1972).

Early investigations of the Beluga Formation and its coal deposits (Dall and Harris, 1892; Dall 1896; Kirsopp, 1903; Atwood, 1909) focused on mapping, measuring, and sampling coal beds for resource analyses. Later works by Barnes and Cobb (1959), Calderwood and Fackler (1972), and Adkison and others (1975) established the stratigraphic framework and coal quality of the Beluga coals. Recent investigations of the Beluga Formation by Sisson (1985) and Merritt and others (1987) expanded on the geology of the Beluga Formation and resource characteristics of the associated coal deposits.

Environments of deposition of the Beluga Formation include braided and meandering fluvial settings and alluvial fans (Hayes and others, 1976; Hite, 1976; Rawlinson, 1984; Merritt, 1986). A recent study of the Beluga Formation by Flores and Stricker (1992) suggests deposition in an anastomosed fluvial system and proposed a direct relation between thick coals and mires formed in this fluvial setting. Paleocurrent analysis of the Beluga Formation by Rawlinson (1984) and Kremer and Stadnicky (1985) suggest a western transport direction of its sediments.

LITHOGENETIC ASSOCIATION OF THE UPPER PART OF THE BELUGA FORMATION

The upper part of the Beluga Formation in the Homer coal district is composed of interbedded sandstone, siltstone, mudstone, carbonaceous shale, and coal. Sandstone is the dominant lithic unit and the carbonaceous shale and coal are the least common units. These lithic units are drab-gray in color. The color of the Beluga Formation is used to distinguish it from the overlying buff to light-brown Sterling Formation (Barnes and Cobb, 1959; Wolfe and others, 1966; Merritt and others, 1987). However, we find sandstones of the Beluga Formation that exhibit buff-yellow color

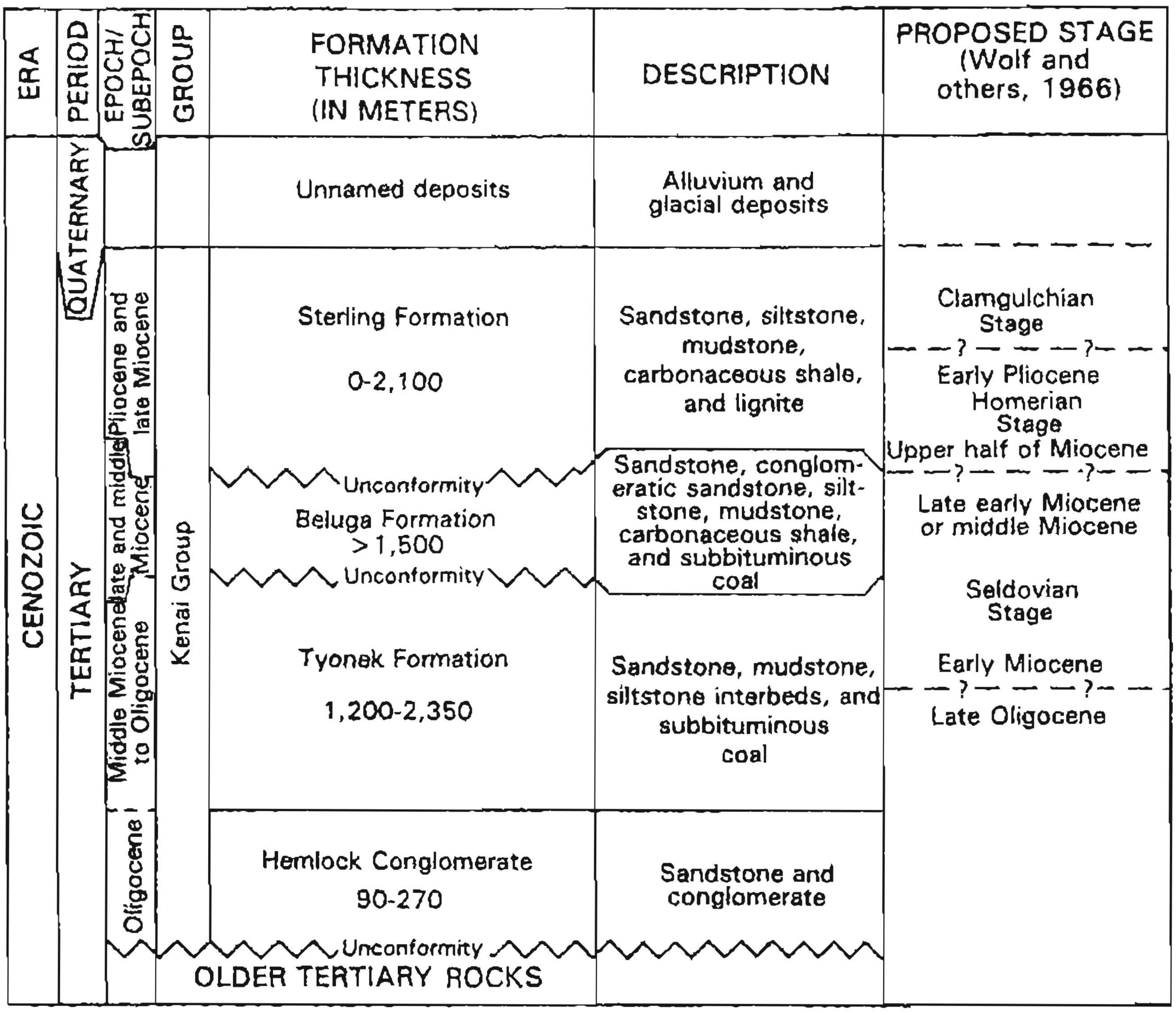

Figure 2. Composite stratigraphic column showing the coal-bearing formations of the Kenai Group and the study interval in the Kenai Peninsula.

similar to those of the Sterling Formation and therefore regard this criteria as unreliable.

The upper part of the Beluga Formation in the vicinity of the McNeil Canyon consists of fine-grained-rich (siltstones and mudstones) lithofacies (Flores and Stricker, 1992). In this area, the upper 110 m of the Beluga Formation is dominated by thick floodplain or interfluve lithofacies, which grade laterally into thin- to thick-, narrow-channel lithofacies. Flores and Stricker (1992) grouped the Beluga Formation into three lithogenetic associations (related rocks of the same origin); 1) a coarse-grained lithogenetic association, composed of medium- to very fine-grained sandstones; 2) a fine-grained interfluve lithogenetic association, consisting of mudstones, siltstones, and silty sandstones; and 3) an organic-rich mire lithogenetic association consisting of carbonaceous shales, coals, and associated tonstein partings. In this paper we will follow a similar scheme of lithogenetic associations but will lump the organic-rich lithogenetic association with the interfluve lithogenetic association because they are commonly interbedded. Thus, the upper part of the Beluga Formation will be divided into channel and interfluve lithogenetic associations.

CHANNEL LITHOGENETIC ASSOCIATION

Sandstones, which make up as much as 40 percent of the upper part of the Beluga Formation in the study area, comprise the channel lithogenetic association. The channel lithogenetic association may be classified into three types of erosional-based, fining-upward sandstones on the basis of grain size, nature of the basal contact, internal architecture (number of internal scour surfaces; interconnectedness of units or plumbing; vertical and lateral patterns of sedimentary structures within units; extent and hierarchical arrangement of internal bounding surfaces), and geometry (two dimensional).

Type I Channel Sandstone

Type I channel sandstone (fig. 3) is very fine to medium grained, 1.5 to 8 m thick, and as much as 150 m in lateral extent. One subtype of the type I channel sandstone ranges from 1.5 to 3 m thick and 15 to 30 m in lateral extent. Thus, this subtype has a height to width ratio of 1:5 to 1:20 (fig. 4). A thicker subtype of type I channel sandstone ranges from 75 to 900 m in lateral extent or a ratio of about 1:10 to 1: 200 (fig. 4). Type I channel sandstone (fig. 3) is oblate in shape and the body is depressed at its base and top. Type I channel sandstones are homogeneous bodies without internal scour surfaces. At their bases, they are marked by shallow to deep scour surfaces that are overlain by ripup mudstone and ferruginous clasts, and coal spars or a basal lag conglomerate (fig. 5).

The internal architecture of the type I channel sandstone is influenced by variations in grain size and sedimentary structures. Channel sandstones of type I are fining-upward bodies that display, from its base to top, either a gradational reduction upward in grain size or increase upward of the occurrence of fine grained interbeds (figs. 3 and 6). Similar variations in grain size are represented laterally. Sedimentary structures in the type I channel sandstone consist of trough crossbeds (a few centimeters to 0.6 m in height), convolute laminations (up to 1 m in height), and ripple laminations. A vertical profile of sedimentary structures of the type I channel sandstone consists of trough crossbeds that decrease in height upward. Convolute laminations accompany the trough crossbeds in its lower part of the profile, whereas ripple laminations are locally present in the uppermost part of the profile (fig. 7). Sedimentary structures of the type I channel sandstone grade laterally from trough crossbeds in the interior of sand bodies into ripple laminations in the margins of the body. Patterns of vertical and lateral variations of internal architecture occur in both the thin and thick type I channel sandstone bodies.

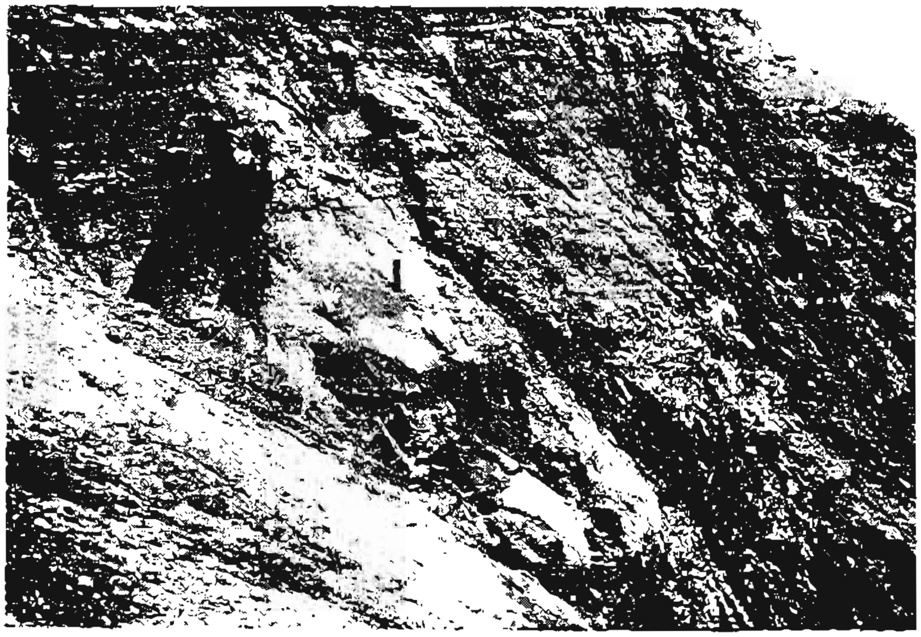

Figure 3. Type I channel sandstone (I) showing fining-upward characteristic and a thinning margin (TM).

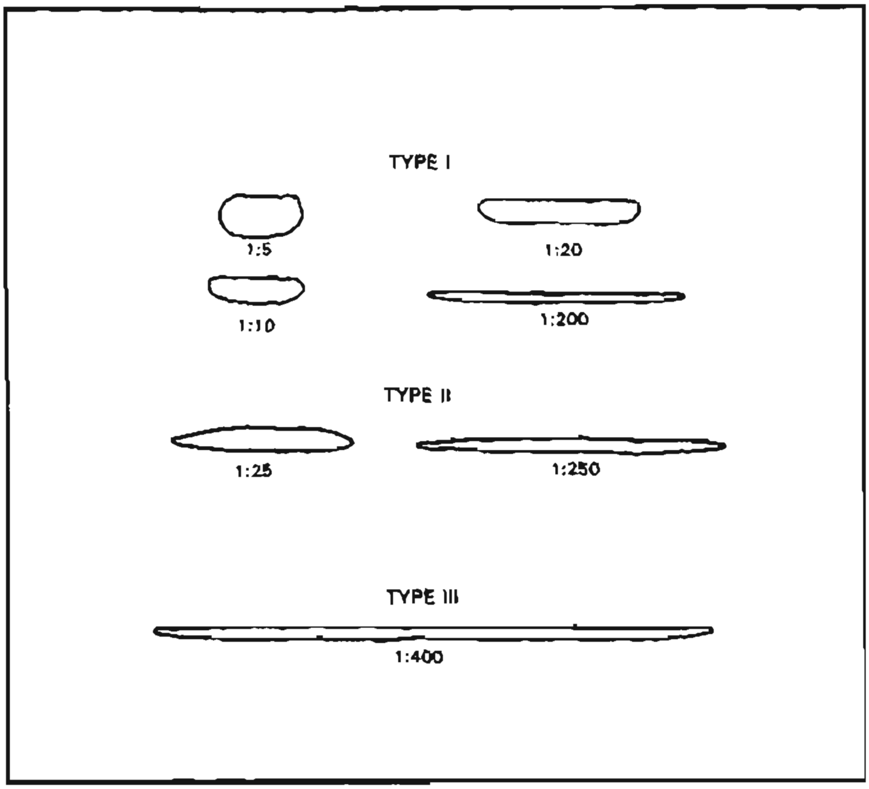

Figure 4. Diagrams of geometry of the type I, II, and III channel sandstones based on the thickness and lateral extent ratios.

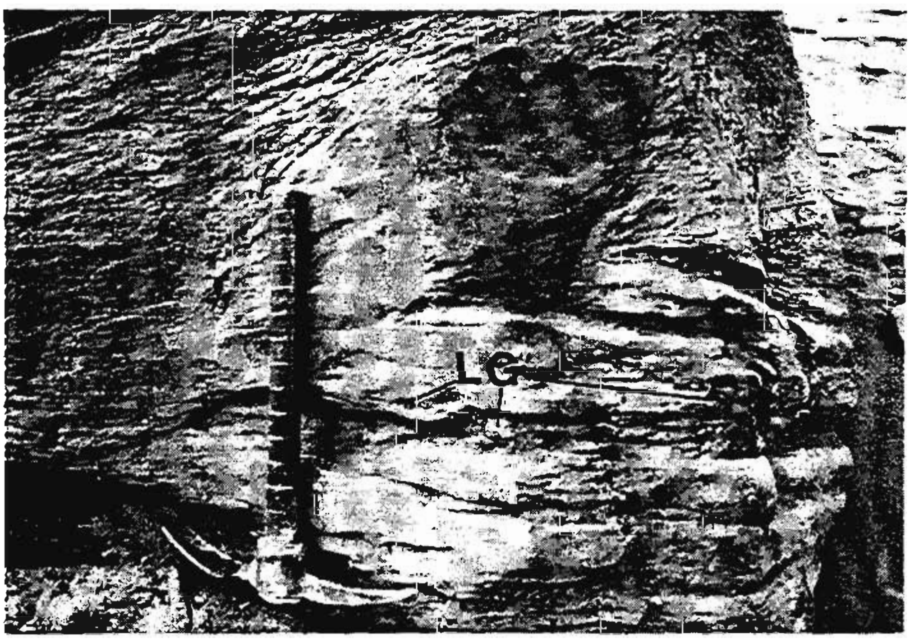

Figure 5. Lag conglomerate (LG) and basal scour surface of the type I channel sandstone. Conglomerate consists of ripup clasts. Handle of mattox is about 0.35 m long.

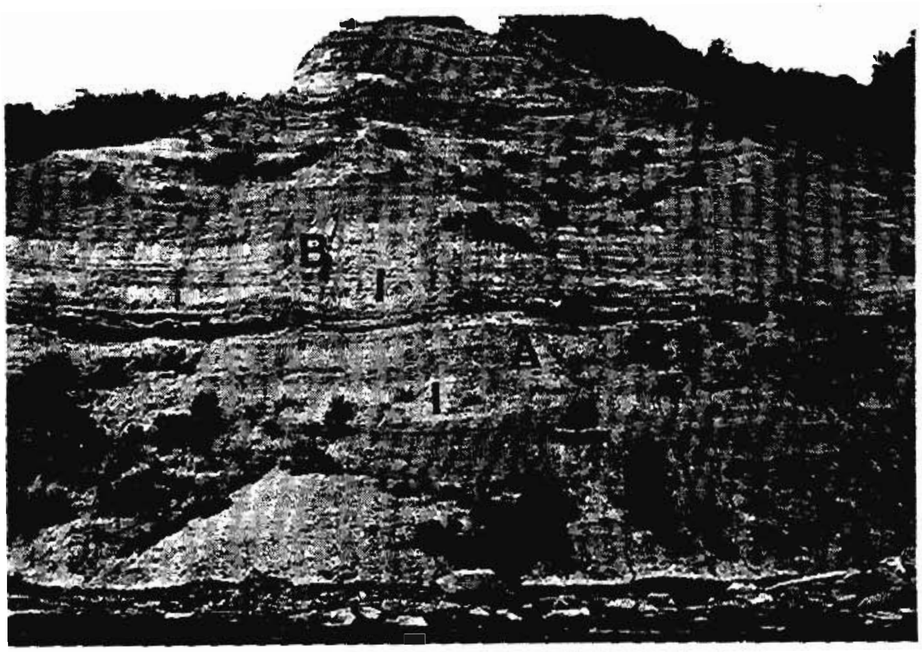

Figure 6. Uppermost part of the type I channel sandstones (I) showing gradational change of grain size (A) and upward increasing siltstone interbeds (B).

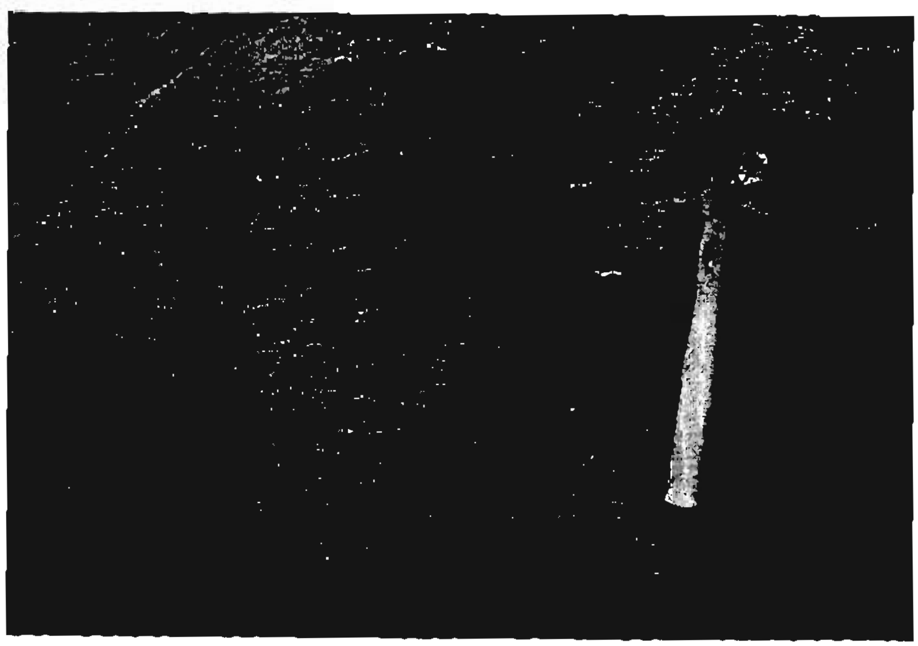

Figure 7. Ripple laminations (RL) and small-scale trough crossbeds (SCT) characterize the uppermost part of the type I channel sandstone. The handle of the hammer is about 0.3 m long.

Type II Channel Sandstone

Type II channel sandstone (fig. 8) is fine to coarse grained, 6 to 10 m thick, and 240 to 1,500 m in lateral extent. Thickness to lateral extent ratios of the type II channel sandstones, are lenticular-shaped bodies that range from 1:25 to 1:250 (fig. 4). The base of these sandstone bodies are shallow to deep concave-upward, whereas, the tops are either shallow concave-downward or asymmetrical, bi-convex in shape. The sandstones are heterogeneous bodies with one internal scour surface. Basal scour surfaces are marked by a basal-lag conglomerate like that of the type I channel sandstones. The type II channel sandstones may laterally grade into the type I channel sandstones.

Like the type I channel sandstones, the internal architecture of the type II channel sandstones is influenced by grain size, internal scour surface, sedimentary structures. Type II channel sandstones are generally fining-upward bodies; however, the upper part more often contains silty interbeds (see fig. 9) than mixed grain sizes. Silty interbeds are also formed along the margins of the sandstone body. In addition, partitioning of the type II channel sandstone by an internal scour surface (fig. 10) defines a couple of fining-upward sandstone subbodies. These scour surfaces (basal and internal scours) are overlain by basal-lag conglomerates. The internal scour surface may be as deep, but not as laterally extensive, as the basal scour surface. Also, this scour surface extends laterally into the margin and/or to the top of the type II channel sandstones, as well as into the basal scour surface.

Sedimentary structures of the type II channel sandstones are trough and planar crossbeds, convolute laminations, and ripple laminations. Trough crossbeds are common and range from a few centimeters to 1.2 m in height (fig. 11). Planar crossbeds are less common, as much as 0.6 m in height, and grade laterally into and overlie, trough crossbeds. Convolute laminations are as much as 1.5 m in height and commonly formed along steep foresets of trough crossbeds. Ripple laminations are present in the uppermost part of the sandstone body. Vertical profiles of the sedimentary structures contains a set of large-scale trough and planar crossbeds with convolute laminations in the lower part of the sandstone bodies. These convolute laminations are often truncated by the overlying internal scour surface. The scour surface, in turn, is overlain by another set of large- to small-scale (decreasing in height upward) trough crossbeds, which grade upward into ripple laminations in the upper part of the sandstone body. Margins of the sandstone body are also commonly ripple laminated.

Heterogeneity of the type II channel sandstones arises from the vertical stacking of dissimilar sets of

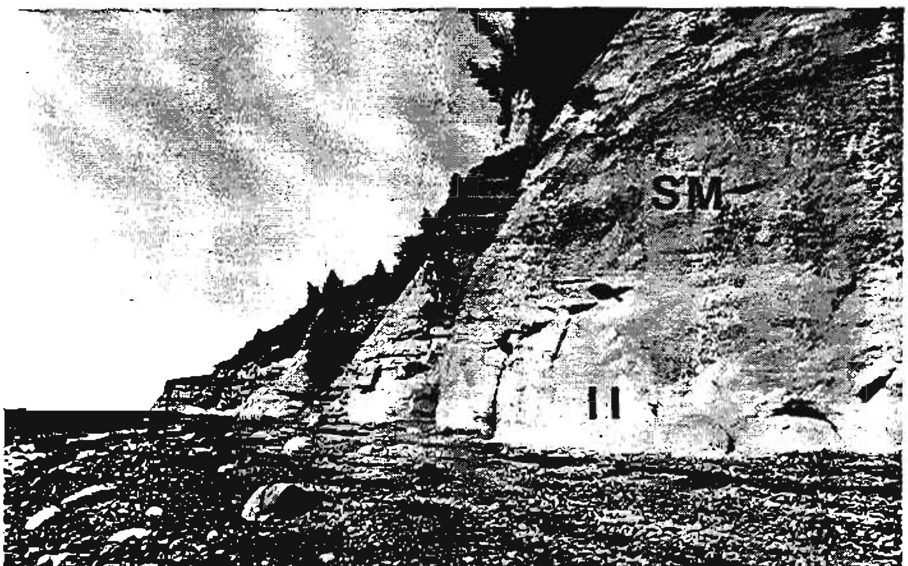

Figure 8. Type II channel sandstone (II) showing a fining-upward grain size with silty and muddy upper part (SM).

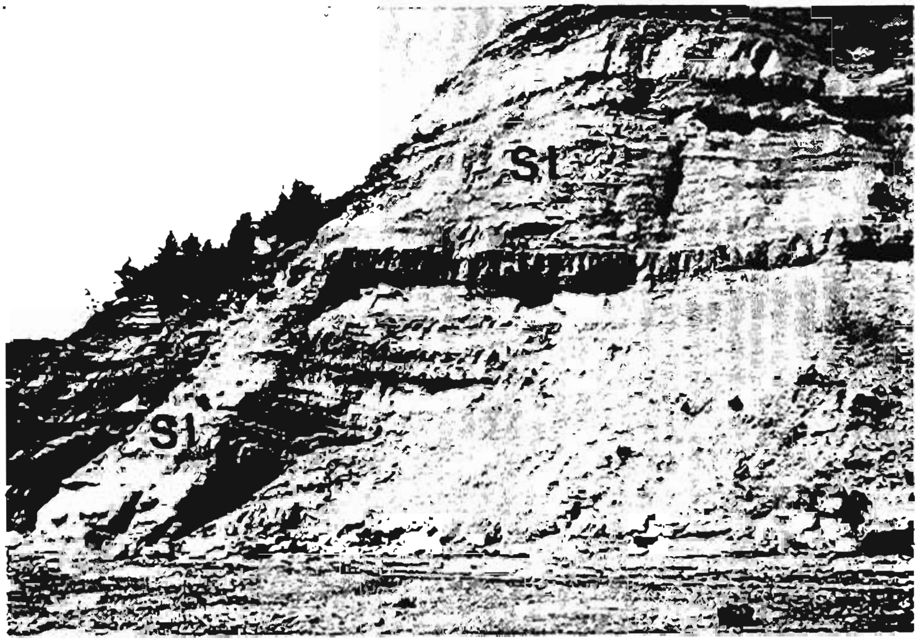

Figure 9. The upper part of the type II channel sandstone shows common siltstone interbeds (SI).

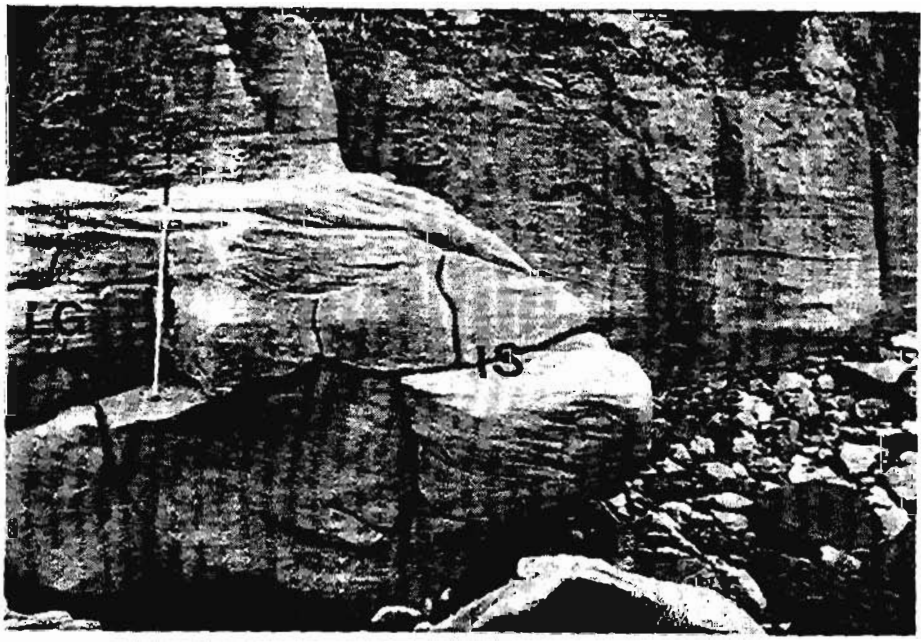

Figure 10. Internal scour surface (IS) defined by a basal lag conglomerate (LG) in a type II channel sandstone. The Jacob staff is about 1 m long.

Figure 11. Stacked trough crossbeds above and below an internal scour surface (IS) in a type II channel sandstone. The Jacob staff is about 1 m long.

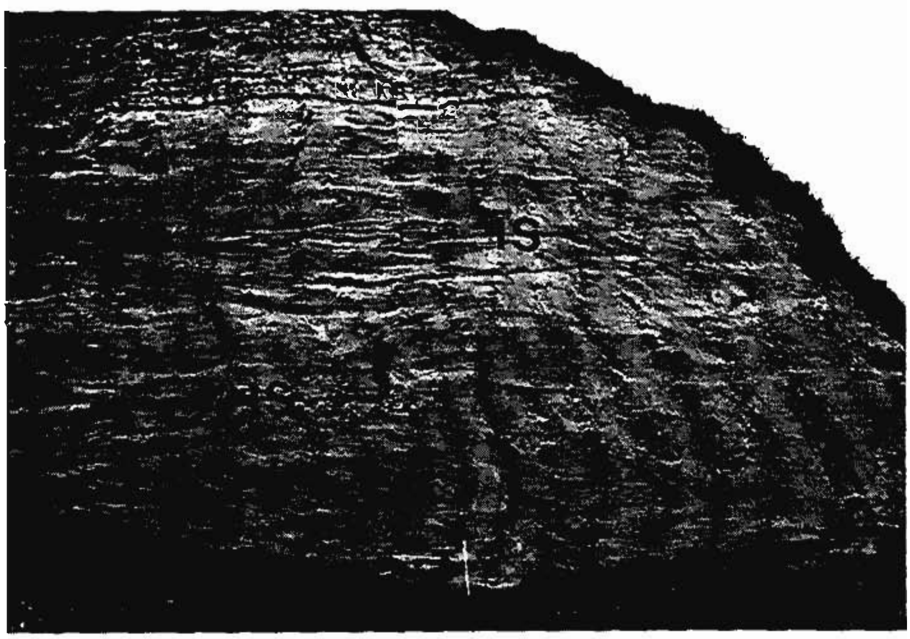

Figure 12. Type III channel sandstone characterized by internal scour surfaces (IS) and a fining-upward grain size. Jacob staff at the bottom (middle) of the photo is about 1.5 m long.

sedimentary structures above and below the internal scour surface. In addition, the internal scour surface, which displays an uneven relief on the underlying cross set, causes random juxtaposition of various crossbeds different in types and scales. Stacking of fining-upward sandstone subbodies also imparts textural heterogeneity of the type II channel sandstone.

Type III Channel Sandstone

Type III channel sandstone (Fig. 12) is fine to coarse grained, 7.5 to 15 m thick, and 1.5 km to 3 km in lateral extent. Thus, the thickness to lateral extent ratio is as much as 1:400 (fig. 4), and it may be described as a elongate-shape body. This type of sandstone body has a flat to concave up base and has a flattened top compared to type I and II channel sandstones. Type III channel sandstone laterally grades into type II channel sandstone.

Internal heterogeneity of type III channel sandstones is controlled by the grain size, continuity and interconnectedness of the internal scour surface, and sedimentary structures. Although type III channel sandstones are, in general fining-upward, they are partitioned by internal scour surfaces into smaller subbodies that are fining-upward. The internal scour surfaces may be locally overlain by a basal conglomerate, particularly in deepest parts of the scour sets. Overall, this imparts an apparent random arrangement of conglomeratic lenses.

Numerous (3 or more) internal scour surfaces are present in the type III channel sandstones. These internal scour surfaces are less extensive than the basal scour surface. Internal scour surfaces are truncated by adjoining and overlying internal scour surfaces. That is, the length of an internal scour surface may be shortened by cutting of a succeeding (younger) scour surface(s). Thus, an internal scour surface overlies as well as laterally offsets other scour surfaces. This pattern of development of the internal scour surfaces, in turn, affects interconnectedness of sandstone subbodies. Increased interconnectedness reflects heterogeneous plumbing of the type III channel sandstone due to more compartmentalization of sandstone subbodies.

Sedimentary structures of the type III channel sandstone consist mainly of trough and planar crossbeds (fig. 13), as much as 1.5 and 3 m in height, respectively. Tabular to wedge shape planar crossbeds are more common in type III channel sandstones than in type I and II channel sandstones. However, like the previous channel sandstone types, convolute (as much as 1.5 m in height) and ripple laminations are also locally present. Sedimentary structures of type III channel sandstones consist dominantly of trough and planar crossbed sets except for local lenses of ripple laminations lateral to, and above these crossbed sets. Internal scour surfaces divide or compartmentalize the sandstone body into subbodies (fig. 14). The subbodies are repeated successions containing vertically and laterally

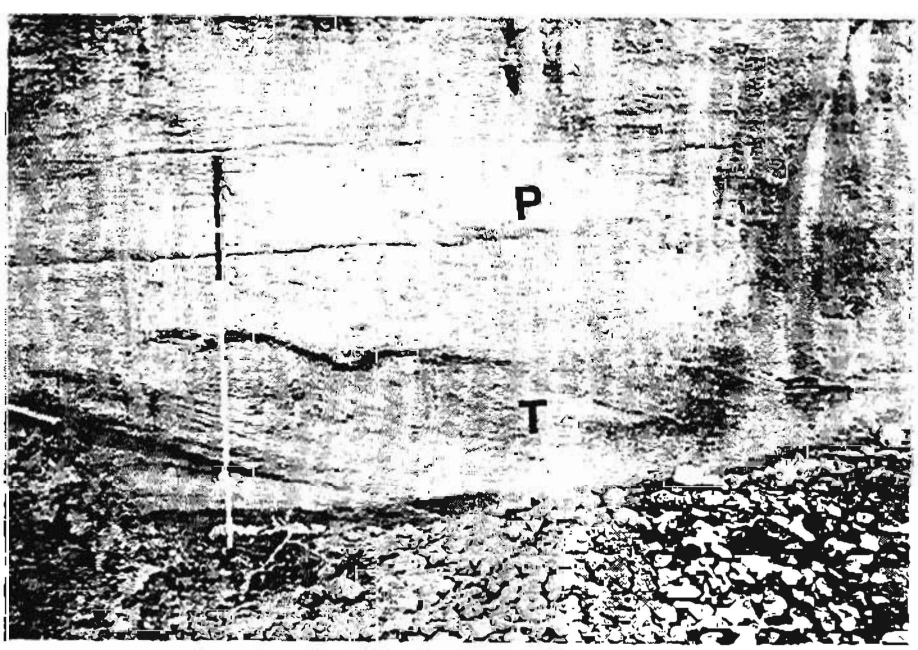

Figure 13. A large-scale trough (T) and planar (P) crossbeds of a type III channel sandstone. Jacob staff is about 1.5 m long.

arranged large- to small-scale crossbed sets separated by ripple laminations and some convolute laminations.

Type III channel sandstone is more heterogeneous than the other channel sandstone types. This results from juxtaposition of various types of crossbed sets resulting in multiple interconnectedness by the internal scour surfaces. Crossbed sets, which are bounded by numerous overlying and laterally truncated internal scour surfaces, produce an apparent random pattern of sedimentary structures. These characteristics of the sedimentary structures and internal scour surfaces are

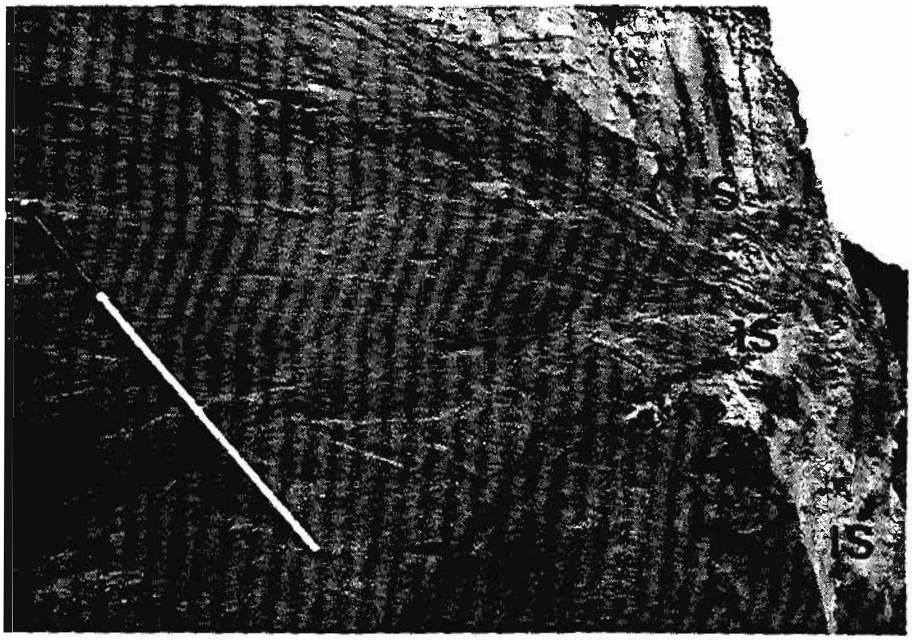

Figure 14. Compartmentalization of type III channel sandstone into three sandstone subbodies by three internal scour surfaces (IS). Jacob staff is about 1 m long.

Figure 15. Thick-bedded, smectitic, heavily-rooted (R) mudstone-dominated subtype of the clastic lithogenetic association. Handle of the hammer is about 0.3 m long.

overprinted by textural variations adding to the heterogeneity of the type III channel sandstone.

INTERFLUVE LITHOGENETIC ASSOCIATION

The interfluve lithogenetic association of the Beluga Formation is composed mainly of clastic and subordinate organic lithogenetic associations. These associations are compose as much as 55 percent of the total rock volume. The clastic lithogenetic association consists of mudstones, siltstones, and silty sandstones. The organic lithogenetic association, which may be as much as 5 percent of the total rock volume of the Beluga Formation, consists of coal and carbonaceous shale.

Clastic Lithogenetic Association

The clastic lithogenetic association may be subdivided into subtypes based on dominant lithotype and vertical sequential arrangement of the rock types. One subtype of the clastic lithogenetic association is dominated by mudstone with subordinate siltstone interbeds (fig. 15). The second subtype of the clastic lithogenetic association is dominated by silty sandstone with minor mudstone and siltstone interbeds (fig. 16).

The mudstone-dominated subtype is the most common subtype of the clastic lithogenetic association. This subtype may occur as sequences comprising: 1) entirely mudstone, 2) mudstone with unorganized siltstone interbeds, or 3) mudstone with organized siltstone interbeds. These sequences may grade vertically and laterally into each other.

The sequence of entirely mudstone ranges from gray to dark gray, has a massive texture, and is smectitic (weathers with popcorn texture) in composition. Darkness of color varies in proportion to the organic content, mainly macerated plant fragments, of the mudstone. Organic-marked roots and rootlets, carbonized large leaves and stems, and petrified tree trunks and stumps are present in this subtype. Mottled structures, formed in association with plant roots and rootlets, are rare. Horizontal and vertical animal burrows are common and range from pinstripe to tubule shape. Some crude thin- to thick-horizontal bedding is defined by laminae of finely macerated plant fragments and micaceous minerals. Spherical- to irregular-shaped (10 mm to greater than 0.3 m in diameter) nodules and concre-

Figure 16. Silty sandstone interbedded with subordinate siltstones and mudstones. Jacob staff is about 1.5 m long.

tions are common diagenetic sedimentary structures present in the mudstone dominated subtype. The nodules and concretions are composed mainly of siderite, hematite, and limonite; and many contain nuclei of plant fossils.

The mudstone-dominated subtype locally contains siltstone interbeds that are unorganized within the subtype. Siltstone interbeds are thin to thick (less than an 20 mm to more than 0.3 m), and both grade vertically into, or are in sharp contact with mudstone beds. Sedimentary structures of the siltstone range from ripple laminations to small-scale (less than 75 mm in height) trough crossbeds. Horizontal and vertical animal burrows are rarely present. The sedimentary structures may be destroyed by large trunk-root and rootlet penetrations, both of which are abundant. Small leaves and twigs are common along bedding planes of the siltstone. The mudstone-dominated subtype is characterized by the unorganized nature of siltstone interbeds in vertical profile.

The silty sandstone-dominated subtype is the least common subtype of the clastic lithogenetic association. The silty sandstone subtype comprises both fining- and coarsening-upward sequences. Fining-upward silty sandstone sequences (fig. 17) consist of fine-grained sandstone in their lower parts and grade upward into very fine-grained sandstone in the upper parts. These sequences are sharp at the base and gradational at the top and range from 0.3 to 1 m in thickness. The fining-upward silty sandstone sequences contain trough crossbeds (less than 150 mm in height) in their lower parts and climbing ripple laminations in their upper parts. The sedimentary structures are commonly destroyed by root penetrations.

Coarsening-upward silty sandstone sequences (see figs. 17 and 18) consist of very fine to silty mudstone in their lower parts and fine grained sandstone in their upper parts. The coarsening upward sandstone sequences have gradational top and bottom, and range from a few centimeters to 3 m in thickness. The upper part of these sequences locally contain scour surfaces that are overlain by muddy, fine-grained sandstone. The muddy fine-grained sandstones comprise both single and amalgamated bodies (see fig. 19). The coarsening upward silty sandstone sequences are ripple laminated (wavy to symmetric ripple laminations that are rarely draped by mudstone) and burrowed in their lower parts. The sequences are scoured in their upper parts, and capped by trough crossbedded (up to 150 mm in height) and ripple laminated sandstones. The upper parts of the coarsening upward sequences contain sedimentary

Figure 17. A thin, fining-upward, sharp-based silty sandstone (FU) eroding into an underlying coarsening-upward (CU) mudstone, siltstone (with ironstone concretion - FE), and silty sandstone. Handle of the hammer is about 0.2 m long.

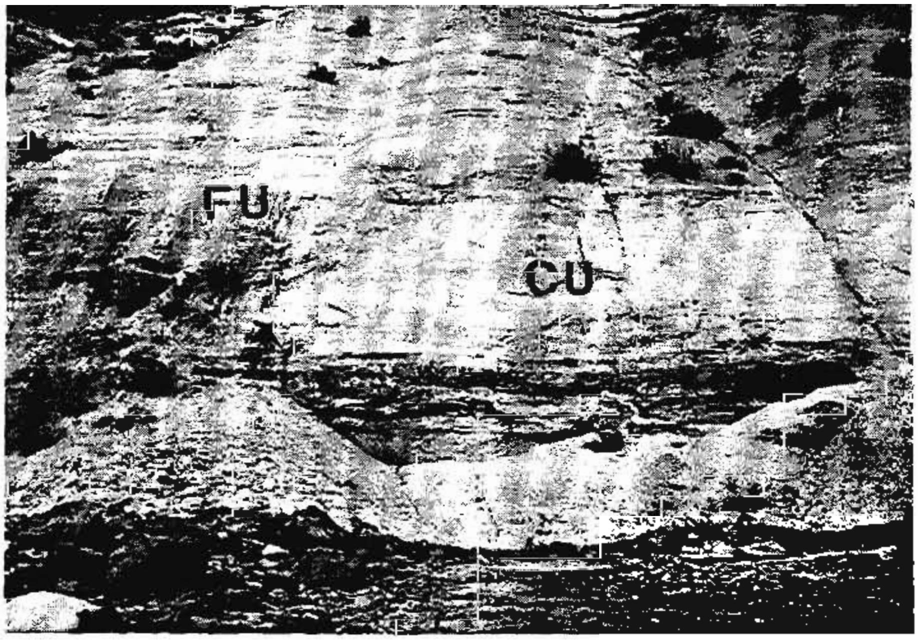

Figure 18. A thick (5 m) coarsening-upward (CU) silty sandstone locally eroded by a fining-upward silty sandstone (FU).

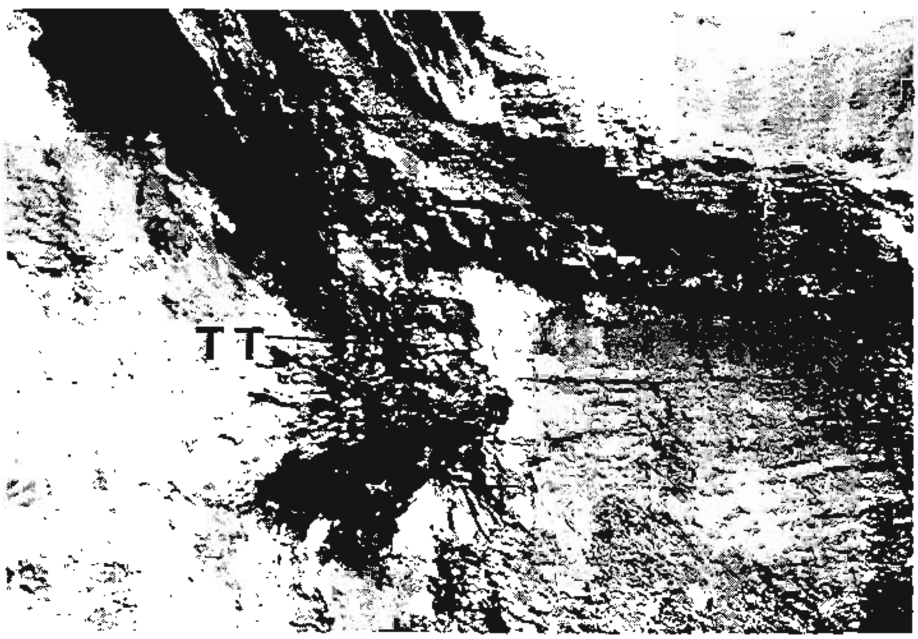

Figure 19. An upright coalified tree trunk (TT), about 2 m high, bounded by mudstones, siltstones, and silty sandstones.

structures, large roots and rootlets, and upright tree trunks and stumps (see fig. 19).

The silty sandstone-dominated subtype is commonly interbedded with the mudstone-dominated subtype with siltstone interbeds. This silty sandstone is tabular in shape that can be laterally traced in outcrops for as much as 100 m.

Organic Lithogenetic Association

Economically, the most important part of the Beluga Formation is the organic lithogenetic association, however, it is the least common interfluve lithogenetic association. This lithogenetic association may be subdivided into coal-dominated and coal-poor subtypes. The coal-dominated subtype consists of coal beds (see fig. 20), which occur as a single coaly unit or as a stack of coaly units. These coal beds are interbedded with strata of coal-poor subtype, which consists of carbonaceous shales, carbonaceous mudstones, and tonsteins.

Coal beds in the coal-dominated subtype are dull black in color, with numerous bright, lustrous vitrain bands. The coal beds are woody, consisting mainly of flattened coalified tree stumps, trunks, and limbs that have retained the original woody grain texture Barnes and Cobb (1959). The woody texture impart platy partings that are parallel to bedding. Coals of the Beluga Formation in the Homer coal district range in apparent rank from lignite to subbituminous B (typically C) (Barnes, 1967), although they increase in apparent rank (subbituminous to high volatile bituminous) with depth. Vitrinite reflectance (% $R_{o\ max}$) analysis of coals from outcrop yield values ranging from 0.36 to 0.42 percent and average about 0.37 percent by (Merritt and others, 1987). Analysis of Beluga coal beds in the Homer coal district, on an as-received basis (ASTM, 1991), yield ash content of 3.2 to 22.6 percent and sulfur content of 0.1 to 0.7 percent (Barnes and Cobb, 1959).

Barnes and Cobb (1959) reported that coal beds in the Homer coal district are lenticular in shape with at least 30 coal beds as thick as 1 to 2 m. Our study shows that Beluga coal beds range from a few centimeters to 2.5 m in thickness and have an average thickness near 1 m. Thin coal beds (a few centimeters to less 30 centimeters) are traceable laterally from a few tens to hundreds of meters. Thicker beds (greater than 0.6 m) are traceable laterally up to at least a few km. The thickness to length ratio, of coal beds we measured, ranges from lenticular (1:9) to elongate (1:1,000 to >3,000).

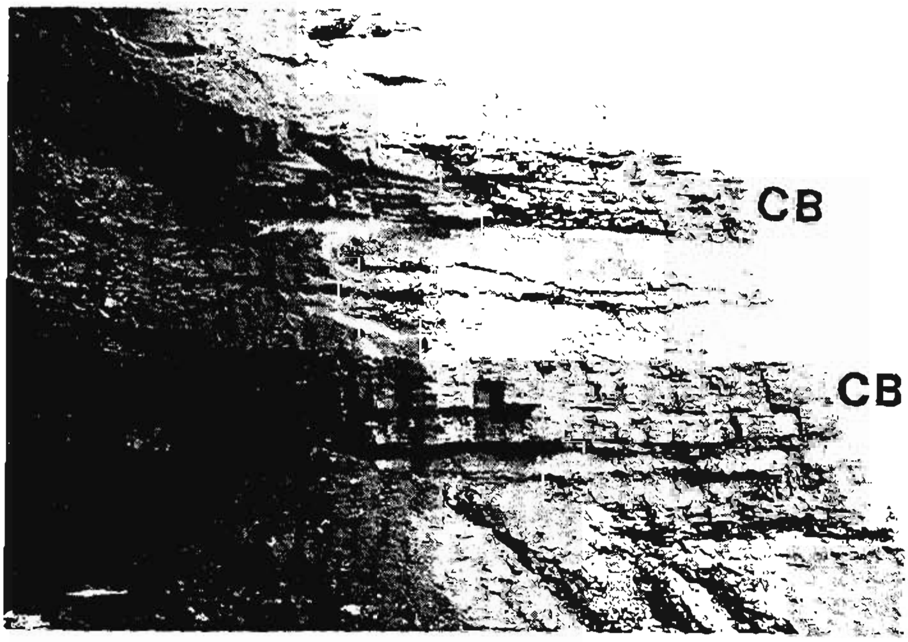

Figure 20. Thick (average about 1.7 m thick) coal beds (CB) interbedded with mudstones, siltstones, and silty sandstones.

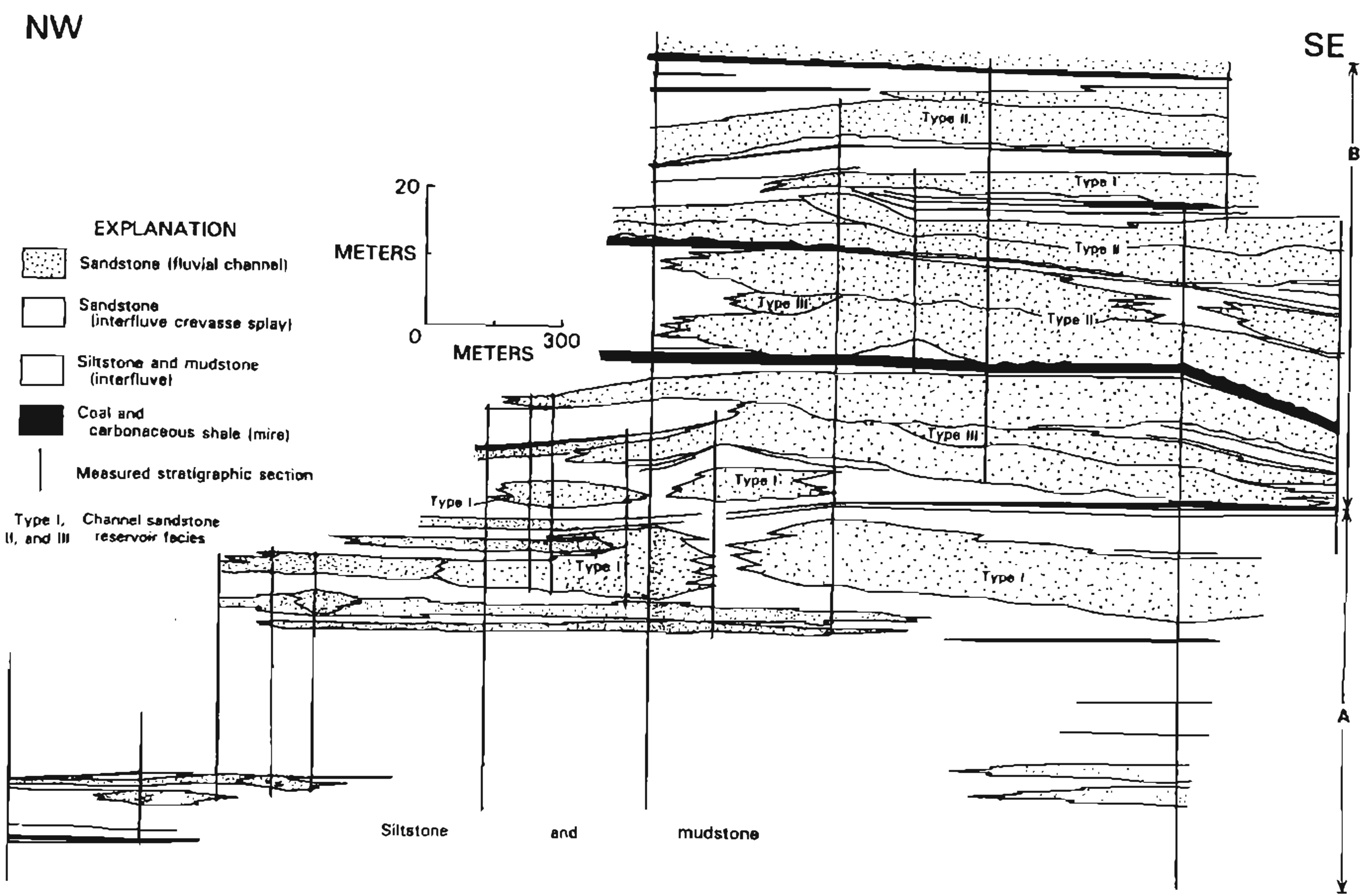

Figure 21. A cross section south of the mouth of Diamond Gulch showing the stratigraphic framework variations of the upper study interval in the Beluga Formation. A=lower interval; B=upper interval.

More than two thirds of the total rock volume of the organic lithologic association consists of carbonaceous shale (mud mixed with finely macerated plant fragments). Laminae loaded with plant leaf and stem fragments impart fissility to the shale. Carbonaceous shale beds range from a few centimeters to 0.3 m in thickness and are commonly interbedded with and grade laterally into the coal beds.

Carbonaceous mudstone, in comparison to the carbonaceous shale, contains less organic matter, lacks fissility, and is less commonly interbedded with coaly units. Carbonaceous mudstone units are commonly penetrated by roots. Tonsteins are the least common interbeds in the coaly units and consist of airborne volcanic ash (Reinink-Smith, 1990) up to 15 cm in thickness. Tonsteins are laterally extensive.

FRAMEWORK ARCHITECTURE OF RESERVOIR AND SEAL/SOURCE FACIES

In the Beluga Formation, the lithogenetic associations of channel-sandstone types (I-III) serve as reservoir facies for hydrocarbons. The interfluve clastic and organic deposits serve as seal facies for hydrocarbons and source facies for coal-bed methane gas, respectively. Framework architecture of these facies within the Beluga Formation is characterized by their: 1) coarse- and fine-grain size ratio and 2) vertical and lateral relationships to each other. This concept follows that of Allen's (1978) alluvial architecture, which refers to a large-scale distribution of alluvial sandstone bodies within a finer grained sediments and their mutual relationships.

A 3-km-long, continuous outcrop between the mouth of Diamond Gulch and Point Bluff (shown in fig. 21) illustrates the framework architecture of the middle part of the Beluga Formation. This outcrop is dominated by the channel sandstone reservoir facies. The upper part of the study interval consists mainly of at least four distinct channel sandstone bodies of types II and III, which average 10 m thick, and make up the reservoir facies (see interval B, fig. 21). Type II channel sandstone bodies are as much as 12 m thick and are laterally extensive for more than 1.2 km. Type III channel sandstone bodies are as much as 15 m thick but are more laterally extensive (>1.5 km) than the type II channel sandstones (see interval B, fig. 21). These channel sandstone bodies that comprise the reservoir, are multistorey or vertically stacked in which, from bottom to top, two type I channel sandstone reservoirs in the lower part is overlain by a type III channel sandstone reservoir, three type II channel sandstone reservoir, and a type I channel sandstone reservoir in the upper part (see interval B, fig. 21).

Interfluve seal and source facies, which separate and bound the sandstone reservoirs (see interval B, fig. 21), are subordinate member sediments in this interval of the Beluga Formation. The seal facies immediately below and above the multistorey channel sandstone reservoirs is composed of mudstone, siltstone, and silty sandstone that range from 3 to 4.5 m in thickness. This intervening seal facies is up to a meter in thickness. The source facies (see coal beds in interval B, fig. 21), which consists mainly of coal and carbonaceous shale, below and above the multistorey channel sandstone reservoirs, ranges from 7.5 to 45 cm in thickness and occurs in zones (coal beds that are interbedded with thin to thick mudstone, siltstone, and silty sandstone). This intervening source facies ranges from 12 cm to 2.5 m in thickness.

Lateral variation of the reservoir facies is well displayed by type I, II, and III channel sandstones at their northern margins (see upper part of interval A and lower part of interval B, fig. 21). Here the upper channel sandstone reservoir facies grades immediately into interfluvial mudstone, siltstone, silty sandstone, and carbonaceous shale. The interfluvial sequence, from its bottom to top, consists of rippled silty sandstone grading upward into rooted mudstone overlain by carbonaceous shale and rooted mudstone and silty mudstone. Overall the units may be grouped into fining- and coarsening-upward sequences below and above the carbonaceous shale. However, successively to the north, the fining-upward sequence is alternately replaced by a coarsening-upward sequence capped by rippled-rooted silty sandstone and a fining-upward sequence immediately below the carbonaceous shale, which is thicker and coaly at this locality. In contrast and in the same quence above the carbonaceous shale is locally replaced by a small type I channel sandstone. Type II and III channel sandstone reservoirs laterally grade into coarsening-upward sequences of mudstone, interbedded siltstone, and mudstone capped by a rippled silty sandstone, which in turn is overlain by rooted mudstone and siltstone. These sequences are continuous northward except that thin, discontinuous coal and carbonaceous shale beds begin to occur below and above the rippled sandstone and pinch into the sandstone reservoirs.

The lower part of the study interval (see interval A, fig. 21) of the Beluga Formation between the mouth of Diamond Gulch and Point Bluff depicts a high proportion of interfluve seal/source facies. Mudstone is the most abundant interfluve seal facies and is as much as 20 m thick and is commonly interbedded with coarsening-upward siltstone and silty sandstone and subordinately with fining-upward silty sandstone and siltstone. These interfluve seal facies are interbedded with coal and carbonaceous shale (source facies) that are as much as 0.6 m thick. Overall, the interfluve seal and source facies complex is encased in two tiers of isolated laterally equivalent type I channel sandstone reservoirs (see upper part of interval A, fig. 21). These reservoirs are as much as 10 m thick and >1000 m in lateral extent. The upper tier of the type I channel sandstone reservoir is internally homogeneous, comprising mainly trough crossbeds. This reservoir is as much as 7 m thick and 300 m in lateral extent. The lower tier of the type I sandstone reservoir is internally heterogeneous. The lower 3 to 6 m of this reservoir consists of trough crossbeds, whereas, the upper 3 to 4.5 m thick is ripple laminated. In addition, this sandstone reservoir is flanked on both margins by a sharp-based rippled sandstone imparting a winged appearance; however, the rippled sandstone at the northern margin is split by mudstone that thickens northward (see upper part of interval A, fig. 21).

Figures 22 and 23 are cross sections constructed along a 7.4-km-long, continuous outcrop north of the mouth of Diamond Gulch. The stratigraphic interval is immediately below the interval illustrated in figure 21. This part of the Beluga Formation is an interfluve-dominated interval in which the seal and source facies are abundant. Mudstone, which is as much as 12 m thick, is the seal facies. Subordinate siltstone and silty sandstone occur either as unorganized interbeds or as coarsening-upward sequences in the mudstone. A tabular-shaped silty sandstone caps the coarsening-upward sequence. The source facies consists of coaly units as much as 1.2-m-thick single beds or 2.5-m-thick multiple beds with numerous carbonaceous mudstone and shale, and tonstein partings. These interfluve seal/source facies are commonly repeated in cycles vertically and uninterrupted by channel sandstone reservoir facies (see uppermost part of fig. 23).

Where the reservoir facies is encountered along the outcrop (see figs. 22 and 23), it is distributed as isolated, discontinuous channel sandstone bodies that are vertically and laterally bounded by thick interfluve seal/source facies. The reservoir facies is composed of type I, II and III channel sandstones. Type I channel sandstone (see upper part of fig. 22) ranges from 1 to 12 m thick and 6 to 950 m wide. Small sandstone reservoir laterally merges with the tabular silty sandstone of the interfluve coarsening-upward sequences. A large type III channel sandstone reservoir (see lower left of fig. 23) laterally pinches out southward into rooted mudstone and siltstone. Type I channel sandstone (see upper center of fig. 23) is as much as 2 m thick; however, it grades laterally into type II channel sandstone that is as much as 8 m thick. These channel sandstone types combined are as much as 1.5 km in lateral extent. Their margins merge with thick, rooted mudstone and siltstone interbedded with thin coal and carbonaceous shale (see upper center of fig. 23).

In general, the outcrop collectively represented in figures 22 and 23 may be grouped into lower, middle, and upper intervals based on the grouping of the channel sandstone reservoir facies and relationships of the seal/source and reservoir facies. The lower interval (see lower part of fig. 22) is dominated by seal/source facies and encased mainly type II and III channel sandstone reservoir facies that are randomly distributed. The middle interval (see upper part of fig. 22 and lower part of fig. 23) is characterized by abundant seal/source facies that surrounds mainly isolated type I channel sandstone reservoir facies. Discontinuous sandstone reservoir facies is commonly distributed contemporaneous with each other, but laterally separated by the seal/source facies. In addition, the source facies (coal beds) are thicker in the lower interval than in the upper interval (see lower part of fig. 22 and upper part of fig. 23). These seal/source and reservoir facies relationships are similar to those described by Flores and Stricker (1992) of the uppermost part of the Beluga Formation in the McNeil Canyon area along the northern coast of the Kachemak Bay.

DISCUSSIONS, INTERPRETATIONS, AND SUMMARY

Lithogenetic associations and framework architecture of the Beluga Formation in the beach-cliff outcrops north and south of Diamond Gulch, west of Homer, significantly contribute to our understanding of the reservoir, seal, and source facies relationships and their origin. In this area, the general pattern or alluvial architecture of these facies in the middle part

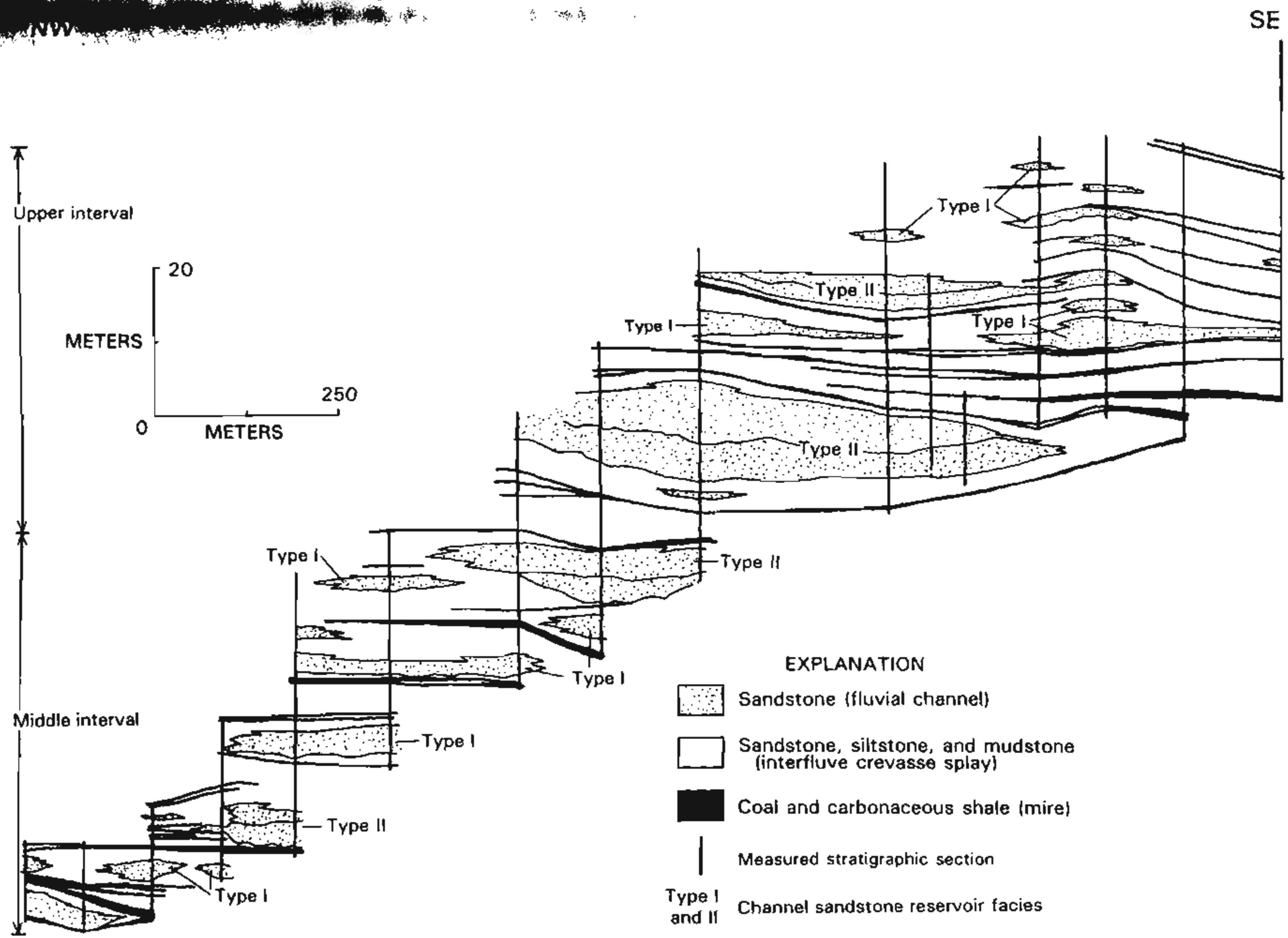

Figure 22. A cross section north of the mouth of Diamond Gulch showing the stratigraphic framework variations of the middle study interval in the Beluga Formation.

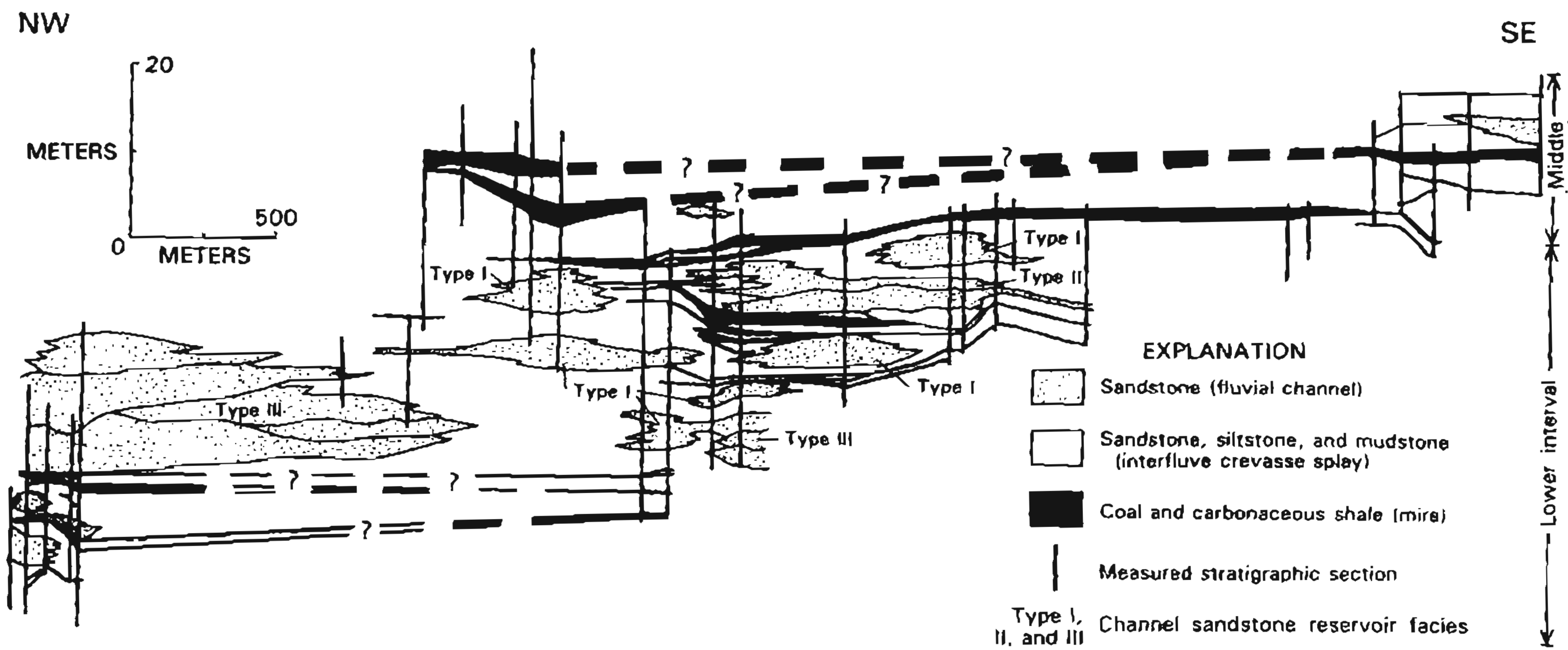

Figure 23. A cross section immediately north of Figure 21 showing the stratigraphic framework variations of the lower part of the study interval in the Beluga Formation.

of the Beluga Formation are illustrated in figure 24. Vertically, the sandstone reservoir facies displays a nested pattern in which type II and III channel sandstone reservoir facies are concentrated in the lower and upper parts of the study interval. Type I channel sandstone reservoir facies is distributed mainly in the middle part (see fig. 24).

Variations in the thickness, width and/or lateral extent, and internal homogeneity/heterogeneity of these channel sandstone types reflect the framework morphology of fluvial pathways that drained the alluvial plain during deposition of the Beluga Formation. In addition, the relationship of these channel sandstone types to adjoining interfluve deposits indicates the areal arrangement of floodbasin/mires settings that separate fluvial pathways in the alluvial plain.

As shown in figure 24, type I channel sandstone in the middle part of the study interval represents two morphological styles: 1) thin and narrow, and 2) moderately thick and wide fluvial channel sandstone bodies. Differences in the morphology of the fluvial channel sandstone bodies reflect the size, mobility, and behavior (Friend, 1983) of the channelized flow that formed them. Thin and narrow sandstone (type I) represents deposits of small, straight, and fixed fluvial channels. The moderately thick and wide sandstone (type I) suggests a deposit of a slightly larger, straight, and fixed fluvial channel. Close association of these sandstones with interfluve coarsening-upward sequences suggests deposition in crevasse splays common in fluvial floodplains or floodbasins (Ferm and Cavaroc, 1968; Smith and Smith, 1980; Flores, 1981, 1986; Smith, 1983). Thus, type I channel sandstone represents floodbasin fluvial channels that were either ephemeral (thin and narrow) or perennial (moderately thick and wide). The ephemeral fluvial channels probably formed as feeder channels of crevasse splays that broke through levees and spilled into the floodbasins during floods. During progradation of a crevasse splay, a proximal feeder channel is transformed into a deeper and larger channel as it served as a major conduit of the splay. Continued occupation of this channel created a perennial fluvial channel. Where contemporaneous feeder channels are transformed into major conduits, anastomosed streams are developed as they merged and diverged. This process of anastomosis results from crevasse-splay progradation and development of smaller floodbasins between merged crevasse splay channels (Flores, 1986; Flores and Stricker (1992).

Figure 24 shows that type II and III channel sandstones in the lower and upper parts of the Beluga study interval may be grouped respectively into: 1) moderately thick and wide and 2) very thick and laterally extensive fluvial channel sandstone bodies. Collectively, both fluvial channel sandstone bodies suggest prolonged development in more mobile channels along a sinuous fluvial belt. However, the moderately thick and wide fluvial channel sandstone represents deposition in a less stable fluvial channel as evidenced by its scattered distribution in dominantly fine-grained interfluve deposits. In contrast, the very thick and laterally extensive fluvial sandstone indicates prolonged occupation of the same part of the alluvial plain, as evidence by their multistorey characteristics. The internal multiscour nature of type II and III channel sandstones suggests deposition in a relatively low-sinuosity cut and fill channels. This mode of channelized-flow aggradation is typical of braided streams (Smith, 1970 1971; Schwartz, 1978; Blodgett and Stanley, 1980; Friend, 1983).

Interfluve facies interbedded with the various fluvial channel sandstone types differs in the thickness of associated coal and carbonaceous shale beds. Thick (greater than 1 m) coal and carbonaceous shale beds are commonly interbedded with type II and III fluvial channel sandstones (see interval A, fig. 21). Thin (less than 0.6 m) coal and carbonaceous shale beds are commonly interbedded with type I fluvial channel sandstones (see fig. 22). Thick coal and carbonaceous shale beds were formed in mires on abandoned, wide fluvial belts of the braided streams. These abandoned alluvial ridges of braided streams permitted prolonged accumulation of peat in mires on raised platforms during periods of fluvial avulsion (rerouting of active fluvial channels). Moreover, accumulation of peat deposits on abandoned, topographically-elevated fluvial belts allowed continuous organic deposition interrupted by detrital influxes. In contrast, the thin coal and carbonaceous shale beds were deposited in low-lying mires of floodbasins drained by crevasse and anastomosed streams. Here the rapid rate of vertical accretion of sediments and frequent lateral aggradation by crevasse splays into the low-lying mires, resulted in abbreviated accumulation of peat. However, longer peat accumulation may occur on mires formed in large, stable platforms formed on an abandoned crevasse splay-anastomosed stream complex as typified by those in the uppermost part of the Beluga Formation (Flores and Stricker, 1992).

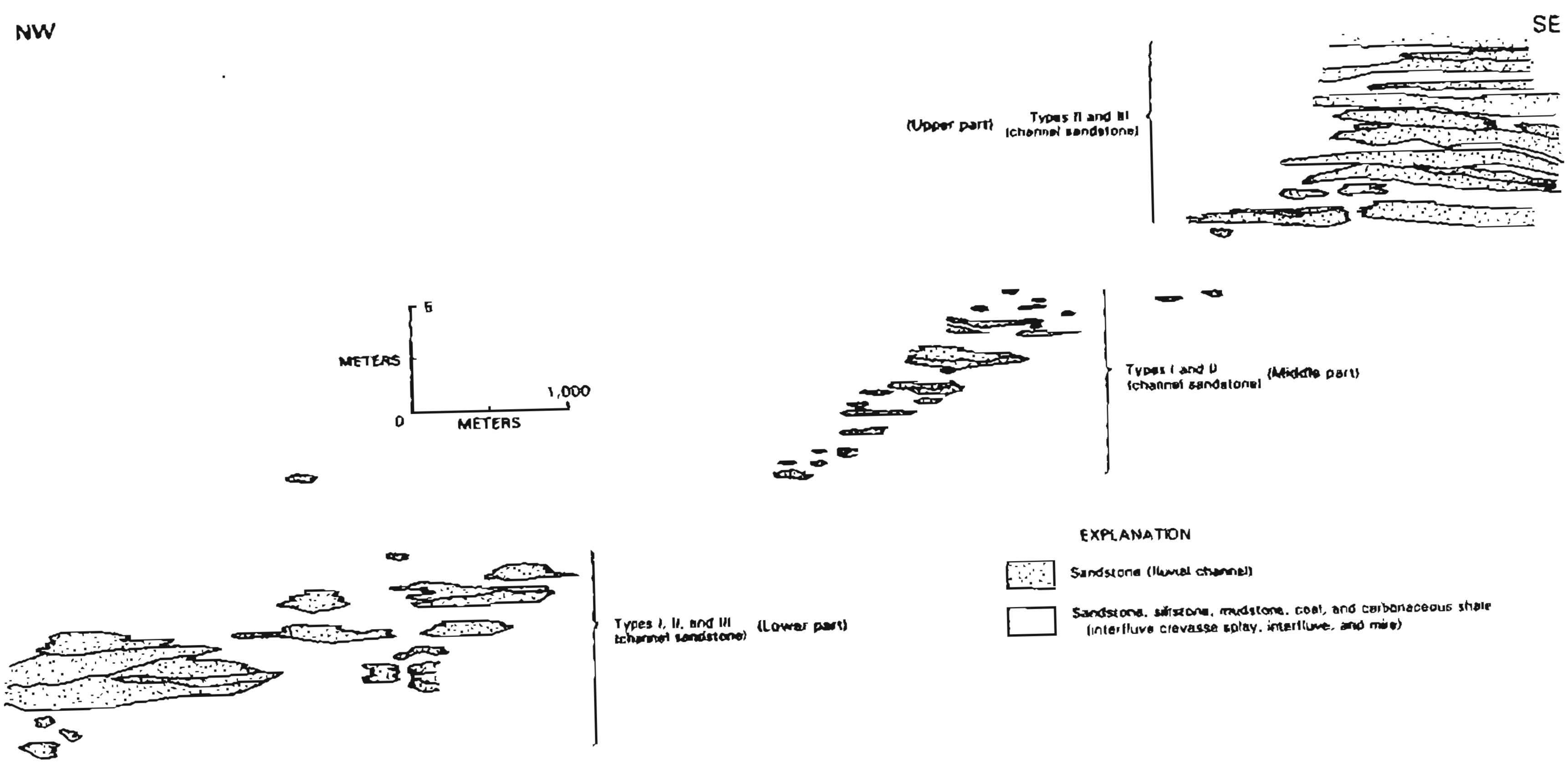

Figure 24. A diagrammatic cross section condensed from Figures 21-23 showing the differences in vertical patterns and geometry of the type I, II, and III channel sandstones in the study interval in the Beluga Formation.

Overprinting of local stratigraphic variations on the interfluve-channel lithogenetic associations of the Beluga Formation, is the regional stratigraphic difference attributed to fluvial depositional changes and effects of local or regional subsidence. This aspect is illustrated in figure 24, in which the Beluga Formation may have been deposited, in large part, by braided streams as indicated in the lower and upper parts of the study interval. These braided streams alternated in draining the Beluga alluvial plain with crevasse splay-anastomosed streams as indicated in the middle part of the study interval (see fig. 24). The fact that braided streams can change morphology, as well as in the mode of aggradation, is indicated by variations in the thickness and lateral extent/width of type II and III channel sandstones (see figs. 21 to 23). For example, type I and III channel sandstones in the lower (A) and upper (B) parts of the interval in figure 21, represent a change from youthful to mature fluvial belts, respectively. This youthful fluvial belt gives rise to the mature belt through time as may be controlled by subsidence either due to tectonism (regional) or autocompaction of sediments (local). Subsidence permits prolonged occupation of low-sinuosity fluvial belts and vertical stacking of their deposits. The type I channel sandstone (see A in fig. 21), which was deposited by crevasse splay and anastomosed streams, represents transient drainages in floodbasins. However, stream capture may transform some of these transient drainages into youthful braided streams.

Considering the overall interfluve-channel facies variations of the Beluga study interval, the evolution of types of streams in the alluvial plain is shown in figure 25. The Beluga alluvial plain was drained mainly by low-sinuosity braided streams flanked by floodbasins (fig. 25A-C). Floodbasins were initially drained by crevasse splay-channel systems. This resulted in breaching of levees of the braided stream during floods. Crevassing may have been developed areally either as isolated or multiple breakouts along stream margins. Continued aggradation of the crevasse sediments via feeder channels by repeated flooding promoted progradation of the splays into the central floodbasins (fig. 25A). Progradation caused merging and diverging of feeder channels and developed an anastomosed network. Some feeder channels along the floodbasin margins deepened and widened into straight

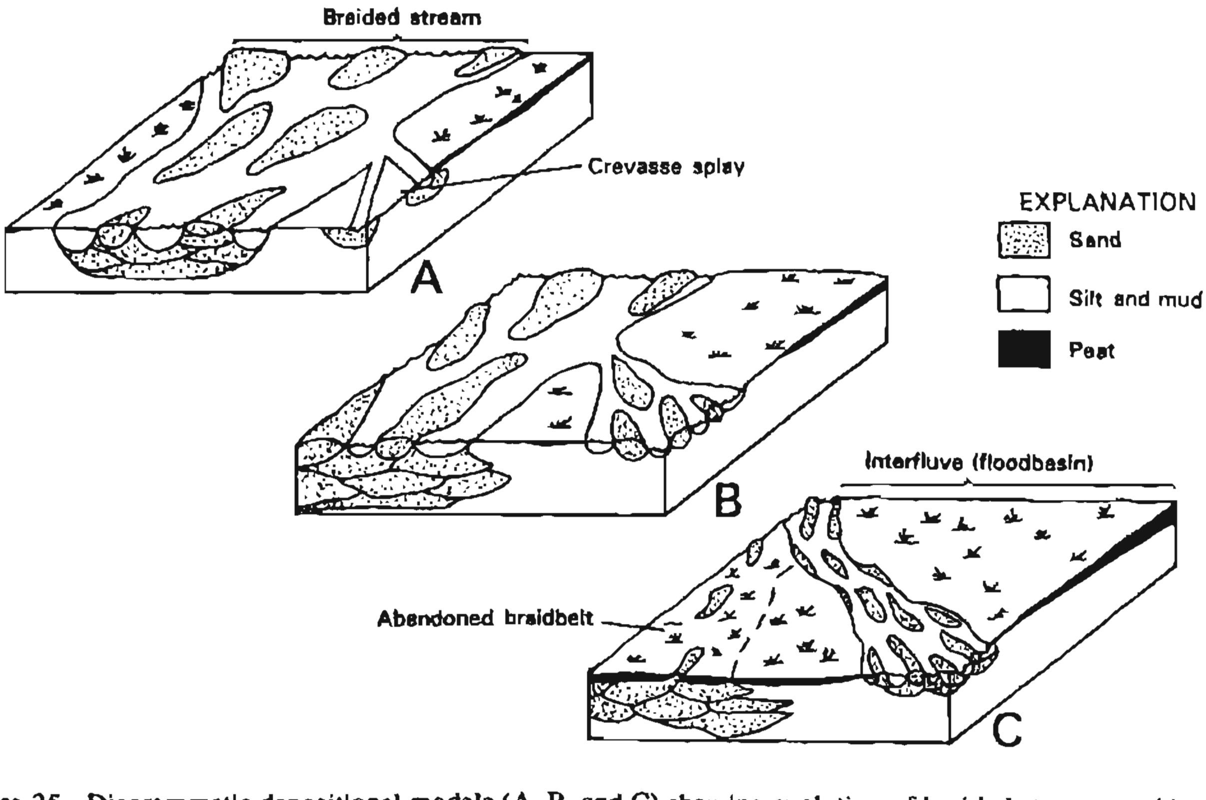

Figure 25. Diagrammatic depositional models (A, B, and C) showing evolution of braided streams and interfluves from the lower to the upper study intervals in the Beluga Formation.

to slightly sinuous streams as they became major conduits. As major flow and sediment input were concentrated along one of these channels due to stream capture, it was transformed into a youthful braided stream (fig. 25B) while the other channels were gradually abandoned and capped by peat-forming mires. Prolonged lateral and vertical accretions of coarse detritus in this stream resulted in a mature, low-sinuosity braided stream (fig. 25C). This was accompanied by avulsion in which the original braided stream was abandoned and covered by peat-forming mires. The succeeding cycle of anastomosis followed by braiding, occurred during the next stream avulsion via crevassing into a new floodbasin where the fluvial process was repeated.

Reviewed by Dwight C. Bradley, James G. Clough, Thomas E. Moore, and Allison B. Till.

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GEOCHEMICAL EVALUATION OF COAL FROM THE TERTIARY USIBELLI GROUP, USIBELLI COAL MINE, ALASKA - ONE OF THE LOWEST SULFUR COALS MINED IN THE UNITED STATES

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ABSTRACT

The Nenana coal basin extends 240 km in length and 1.5-50 km in width along the northern foothills of the Alaska Range in central Alaska. Located at the western end of the Nenana basin is the Usibelli Coal Mine, approximately 120 km southwest of Fairbanks. The Tertiary Usibelli Group consists of coal-bearing fluvial and lacustrine sedimentary deposits that were derived from the Yukon-Tanana Upland area located northeast of the present mine site. To evaluate changes in major-, minor-, and trace-element distributions, we collected 65 samples from the No. 3 bed from 5 different locations and 128 samples from the No. 4 bed from 6 different locations.

When compared to other western U.S. Tertiary coals, the No. 3 bed is higher in concentrations of Ca, Cr, F, Mn, Ni, Sb, Sc, Sr, V, Y, and Zr and lower in total sulfur, organic sulfur, pyritic sulfur, sulfate sulfur, ash, and the concentrations of Si, Mg, Na, Fe, Ti, Ag, B, Cd, Ce, Ga, Hg, La, Li, Nb, Nd, P, Th, U, and Zn. The No. 4 bed is higher in Si, Al, Ca, K, Cr, Cu, F, Mn, Ni, Pb, Sb, Sc, V, Yb, and Zr and lower in total sulfur, organic sulfur, pyritic sulfur, sulfate sulfur, and the concentrations of Mg, Na, Fe, Ag, B, Be, Cd, Ge, Hg, Li, Nb, Nd, P, U, and Zn.

The No. 4 bed shows a higher concentration of elements in the upper part of the bed and a lower concentration near the bottom. Over 60% of all analyzed elements are statistically higher in the upper part of the bed. The No. 3 bed shows a high concentration at the top and bottom and lower concentration in the middle part of the bed. This elemental distribution appears to be directly related to tectonic changes that occurred in the Yukon-Tanana Upland area during the development of the mire. These tectonic changes also altered subsidence patterns increasing the influx of clastic material and changing the ground water pattern in the mires, thereby enriching the elemental concentrations in the upper or lower parts of these beds.

INTRODUCTION

More than half the total coal mined in Alaska has been produced from the Nenana coal basin. The rest has been mined from the presently inactive Matanuska coal field (Meyer, 1990). Resource estimations for the Nenana basin are: 7.2 billion metric tons identified and 12.7 billion metric tons hypothetical (Merritt and Hawley, 1986). Resource estimates for the two major fields in this basin are 910 million metric tons identified and 1.8 billion hypothetical for the Healy Creek field and 4.4 billion metric tons identified and 6.3 billion metric tons hypothetical for the Lignite Creek field.

The Usibelli Coal Mine is located at the western end of the Nenana basin and currently supplies fuel to a 25-megawatt coal-fired power plant. This power plant supplies over half the electrical demand for the northern Alaskan railbelt. This mine also supplies coal to several cogeneration power plants in Alaska (Fairbanks Municipal Utilities, University of Alaska Fairbanks, Fort Wainwright Army base, Eielson Air Force Base, and Clear Air Force Station) (Anonymous, 1993). It also exports coal to Korea (Bohn and Schneider, 1992) and could become a significant exporter to Pacific Rim countries. Mine production has grown from 9,050 metric tons in 1943 to 1.36 million metric tons of coal per year in 1993.

The Usibelli Coal Mine produces a low-ash and one of the lowest sulfur coals in the U.S. (Affolter and Stricker, 1987) and in the world (Anonymous, 1993). The apparent rank of these coals ranges from lignite A to subbituminous B with a mode of subbituminous C. Mean heat-of-combustion (Btu/lb) is 8,030 with a range of 6,130 to 9,210 (Affolter and others, 1981).

This paper presents a preliminary evaluation of the concentrations of major-, minor- and trace-elements of the No. 3 and No. 4 beds from the Usibelli Coal Mine. These coals are statistically compared to Tertiary coals of equivalent age from the western United States to characterize the potential of these Alaskan coals in relation to other minable U.S. coals. Elements of environmental concern, according to the 1990 Clean Air Act Amendment, are also summarized and compared to relative concentrations for other U.S. coals. Vertical changes in chemical composition and bulk mineralogical determinations were also evaluated on selected samples.

GEOLOGICAL SETTING

The Nenana coal basin consists of ten coal fields partially or completely separated by erosion. This basin extends about 200 km along the northern foothills of the Alaska Range and include, from west to east, the Western Nenana, Healy Creek, Lignite Creek, Rex Creek, Tatlanika Creek, Mystic Creek, Wood River, West Delta, East Delta, and Jarvis Creek coal fields (fig. 1). These coal fields are located north of the Alaska Range and appear to lie in areas where tributaries of a major paleoriver system draining central Alaska flowed across subsiding basins prior to the uplift of the Alaska Range (Wahrhaftig and others, 1994). Coal is found in the Usibelli Group (Wahrhaftig, 1987), a sequence of five formations of poorly consolidated continental sedimentary rocks of late Eocene and early to late Miocene age (fig. 2). Some of these coal-bearing formations have been identified in all the coal fields in the Nenana coal basin.

The oldest stratigraphic unit in the Usibelli Group is the Healy Creek Formation (fig. 2). This formation consists of a fluvial sequence of poorly-sorted and basally-scoured lenticular sandstone, conglomerate, siltstone, and claystone with coals that thicken, split, and pinch out abruptly. These sedimentary materials were deposited by laterally migrating braided streams (Stanley and others, 1989). Because the Healy Creek Formation was deposited on a surface having a few hundred meters of relief in a slowly subsiding basin,

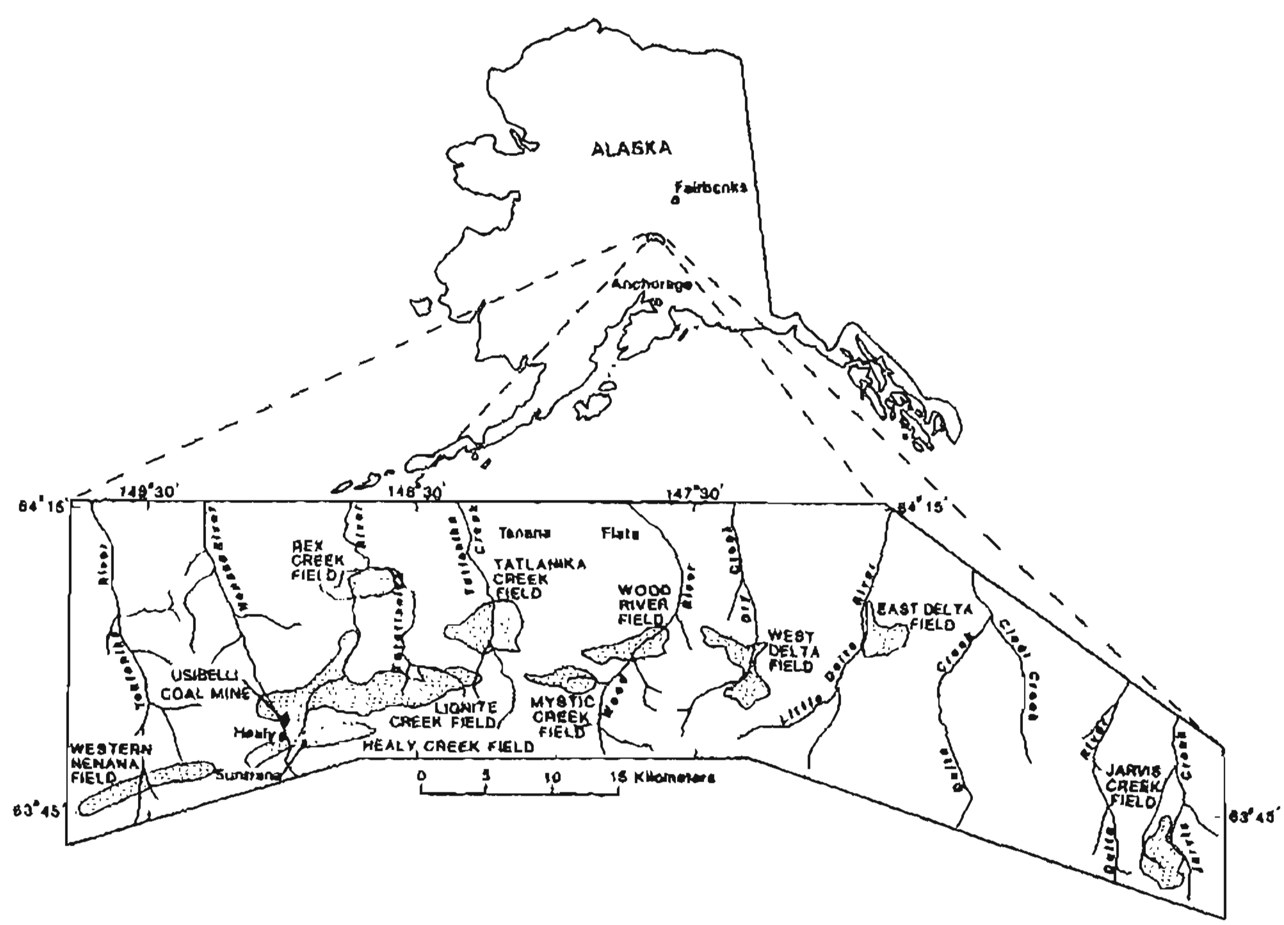

Figure 1. Location of the Nenana basin and Usibelli Coal Mine in central Alaska and the distribution of the coal fields within the basin.

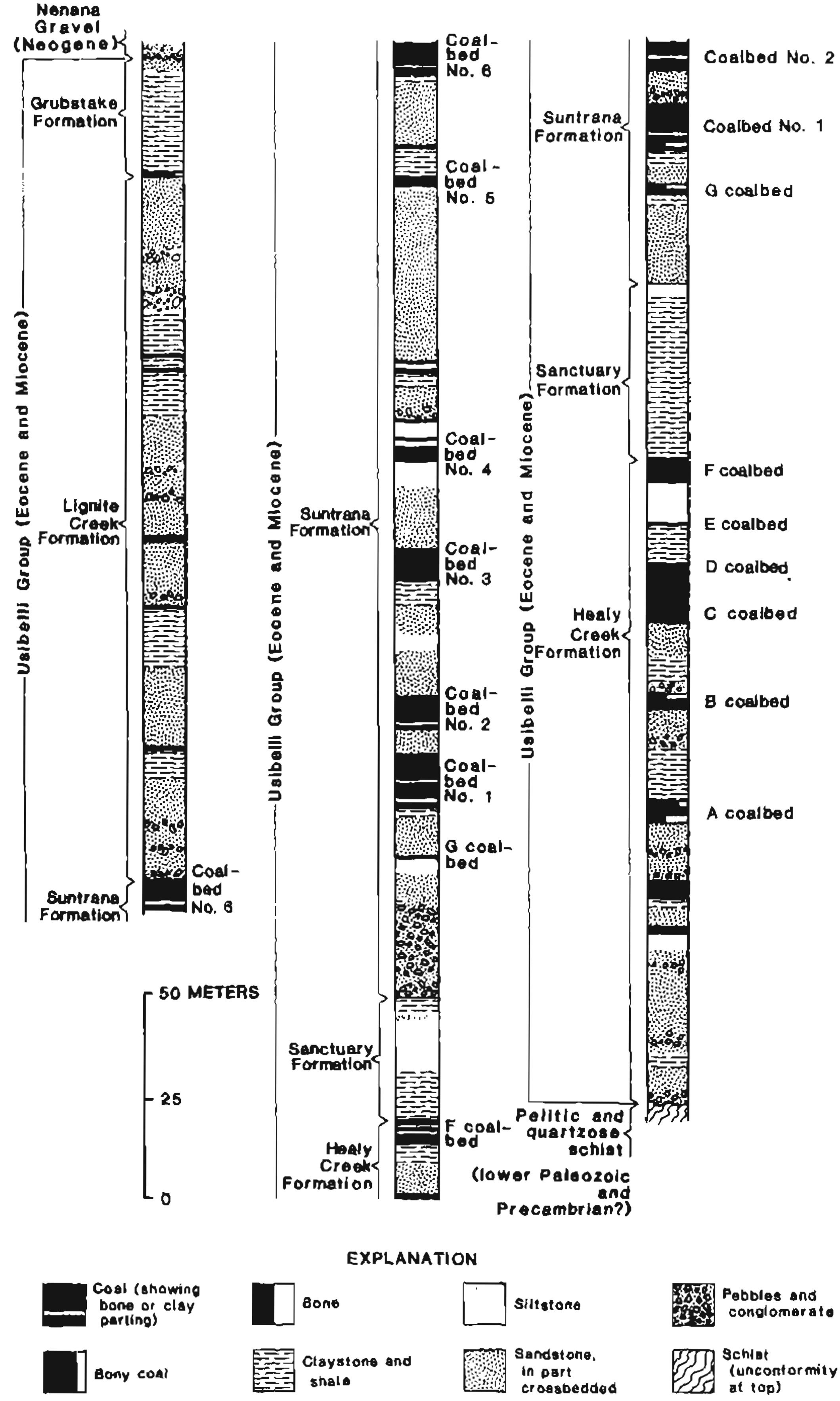

Figure 2. Generalized stratigraphy of the coal-bearing units and related rocks in the Nenana basin.

the thickness of the formation as well as the number of coal beds varies markedly. The peats accumulated in mires developed on abandoned-braidbelt sandstones. Coals are as thick as 20 m, and have been mined extensively in underground and surface mines.

Overlying the Healy Creek Formation is the Sanctuary Formation (fig. 2), a thinly laminated shale (possibly varved) 40 m thick. This non-coal-bearing unit, which is assigned to the middle Miocene (Wolfe and Tanai, 1980), accumulated in a large shallow lake (Wahrhaftig, 1987).

The overlying Suntrana Formation, of middle Miocene age (Wolfe and Tanai, 1980), is as thick as 400 m and consists of 6-12 fining-upward sequences. These sequences consist of basal conglomerates and fining-upward cross-stratified sandstones, which are overlain by mudstones and commonly are capped by coals as thick as 20 m. Stanley and others (1989), have interpreted the coarse clastic materials as having been deposited in braided to meandering fluvial channels and the mudstones as having been deposited in flood plains, crevasse splays, and abandoned channels. Coals in the Suntrana Formation are thicker and more laterally persistent than coals in the underlying Healy Creek Formation. Peats accumulated in mires that formed on abandoned braid and meander belts as evidenced by thick beds directly lying above the fluvial-channel sandstones.

Overlying the Suntrana Formation is the Lignite Creek Formation of middle and late Miocene age (fig. 2). This unit, 150-240 m thick, is a multi-cycled fining-upward sequence, similar to the underlying Suntrana Formation. The Lignite Creek Formation differs from the Suntrana by its sandstone, which was primarily deposited in a meandering fluvial system; mudstone, which was primarily deposited in a floodplain and crevasse-splay environment; and coal, which is thinner (typically less than 1.5 m) and less laterally persistent. The peats accumulated in mires that developed on the floodplains and abandoned meander belts.

The uppermost formation assigned to the Usibelli Group is the non-coal-bearing Grubstake Formation. This dark-gray, laminated shale and claystone sequence is interpreted to have accumulated in a lake formed by the damming of south-flowing streams caused by uplift of the Alaska Range (Wahrhaftig, 1987).

The Usibelli Coal Mine is currently mining in the Lignite Creek coal field, Poker Flats area, which is located 4 miles north of the town of Healy (fig. 1). Near the mine, the coal-bearing Suntrana Formation consists of sandstone, siltstone, claystone, shale, and several coal beds. The coal beds, which are subbituminous C in apparent rank, are designated (bottom to top) by numbers one through six (Wahrhaftig and others, 1969) (fig. 2). In the study area, the No. 3 and No. 4 coal beds are each overlain by a poorly consolidated fluvial sandstone unit and underlain by a carbonaceous shale and siltstone unit.

METHODS

Sampling was accomplished over several field seasons and from various localities within the Usibelli Coal Mine. In most cases, coal samples were collected from the active face of each bed and were selected to be as fresh and as unweathered as possible. Individual bench channel samples were collected for both the No. 3 and No. 4 coal beds. Within the mine area the No. 3 bed ranges from 4.9 to 5.5 m thick (mean=5.2 m) and the No. 4 bed ranges from 5.8 to 6.7 m thick (mean=6.7 m). Samples were collected in vertical succession from the top of the bed to its bottom in 30-cm increments or less, depending on megascopic observations. The thickness of each sample was recorded and all partings were sampled and identified. Samples were also taken of the rocks overlying and underlying the coals. Therefore, each face channel that was sampled represents a vertical profile (top to bottom) through the individual coal bed. Samples collected consist of 65 samples taken from the No. 3 bed from 5 different locations in the mine, and 128 samples taken from the No. 4 bed from 6 different locations in the mine. The No. 4 bed was more easily sampled than the No. 3 bed because of mining conditions that allowed better access to the No. 4 bed. This easier access resulted in the collection of more detailed samples and an increased sample density for the No. 4 bed.

Forms-of-sulfur determinations are reported on the as-received-basis and were determined either by the U.S. Bureau of Mines, the U.S. Department of Energy, or by Geochemical Testing, Pittsburgh, PA. Analyses of ash content and major-, minor-, and trace-elements were done by the U.S. Geological Survey, Denver CO. Descriptions of the analytical techniques and procedures used by the U.S. Geological Survey can be found in Swanson and Huffman (1976), Baedecker (1987), and Golightly and Simon (1989). Only samples with less than 50% ash content were selected for the summary tables and statistical comparisons. A common problem in statistical summaries of trace-element data arises when the element content of one or more of the samples is below the limit of analytical detection. This results in a censored distribution. In order to compute unbiased estimates of censored data, all less than values were reduced by 50% when summary statistics were calculated. Accuracy of analytical values is reported to two significant figures for elements and to two decimal places for forms-of-sulfur. In order to make all of our comparisons consistent and to reflect the true nature of the chemistry of these coals, all major-,minor-, and trace-elements are calculated to a whole coal basis and are presented in percent or as parts per million (ppm).

Selected Usibelli coal samples were ground to pass 80 mesh and were then ashed in an International Plasma Corporation low temperature asher for 160 hours at temperatures no greater than 150°C. This low-temperature-asher (LTA) method oxidizes and removes organic material without altering the inherent mineral matter in the raw coal (for more information, see Gluskoter, 1965; Frazer and Belcher, 1973; Rao and Gluskoter, 1973; and, Miller and others, 1979). The LTA coal ash was ground and loaded into cavity-mount specimen holders and then X-rayed.

STATISTICAL COMPARISONS

Three statistical comparisons (student's t test, 95% confidence level) were made for coal from the Usibelli Coal Mine (No. 3 and No. 4 beds). The first comparison was made between the No. 3 and No. 4 beds to show the main difference between these two beds. The next two comparisons were made comparing the No. 3 bed and No. 4 bed to western U.S. Tertiary coals. The reason for this comparison is that western U.S. Tertiary coals are representative of most coals mined in the western U.S. and give a good idea of how coal from the Usibelli Coal Mine would compare in quality to other proven areas of marketable U.S. coals. Western U.S. coals chemical summaries used in the comparisons are from Affolter and Hatch (1984, 1993).

1) Comparison between the No. 3 bed and No. 4 bed

A statistical comparison between the No. 3 bed (table 1 and table 2) and the No. 4 bed (table 3 and table 4) shows that the No. 3 bed is significantly higher in Na, Ba, Be, Cr, Ge, and Sr and that the No. 4 bed is significantly higher in total sulfur, pyritic sulfur, organic sulfur, ash, Si, Al, Mg, K, Fe, Ti, As, Cd, Ce, Cu, F, Ga, La, Li, Mo, P, Pb, Sb, Se, Th, U, and Zn. Contents of sulfate sulfur, Ca, Ag, B, Co, Hg, Mn, Nb, Nd, Ni, Sc, Sn, V, Y, Yb, and Zr are similar for both of the beds.

2) Comparison between the No. 3 bed and western U.S. Tertiary coals

A statistical comparison between the No. 3 bed and western U.S. Tertiary coals shows that the No. 3 bed is significantly higher in Ca, Cr, F, Mn, Ni, Sb, Sc, Sr, V, Y, and Zr and significantly lower in total sulfur, organic sulfur, pyritic sulfur, sulfate sulfur, ash, Si, Mg, Na, Fe, Ti, Ag, B, Cd, Ce, Ga, Hg, La, Li, Nb, Nd, P, Th, U, and Zn. Contents of Al, K, As, Ba, Be, Co, Cu, Ge, Mo, Pb, Se, and Yb are similar for both the No. 3 bed and western U.S. Tertiary coals.

3) Comparison between the No. 4 bed and western U.S. Tertiary coals

A statistical comparison between the No. 4 bed and western U.S. Tertiary coals shows that the No. 4 bed is significantly higher in Si, Al, Ca, K, Cr, Cu, F, Mn, Ni, Pb, Sb, Sc, V, Yb, and Zr and significantly lower in total sulfur, organic sulfur, pyritic sulfur, sulfate sulfur, Mg, Na, Fe, Ag, B, Be, Cd, Ge, Hg, Li, Nb, Nd, P, U, and Zn. The contents of ash, Ti, As, Ba, Co, Ga, La, Mo, Se, Sr, Th, and Yb and similar for both the No. 4 bed and western U.S. Tertiary coals.

ELEMENTS OF ENVIRONMENTAL CONCERN

As utilization of both high and low sulfur coal increases, more research will be needed to deal with the stricter environmental regulations and the problems of increased coal use. Problems such as increased SO_2 emissions, potential greenhouse conditions, and the effects of acid rain will all have to be addressed with future increases in coal utilization. Alaskan coals have the lowest reported sulfur contents of any coal in the United States (Affolter and others, 1981; Affolter and Stricker, 1984; Stricker, 1992). The sulfur content for the No. 3 bed (table 2) ranges from 0.03% to 0.32% with a mean of 0.14% and the sulfur content for the No. 4 bed (table 4) ranges from 0.01% to 1.0% with a mean of 0.31%. When compared to western U.S. Tertiary coals the average sulfur content from the Usibelli Coal Mine is 5.5 times lower for the No. 3 bed and 2.5 times lower for the No. 4 bed.

Table 1. Number of samples, range, arithmetic mean, and standard deviation of ash and 41 elements in coal from the Usibelli Coal Mine, No. 3 bed. (All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.)

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Percent					
Ash	57	4.9	24.5	8.60	4.4
Si	57	0.12	7.1	1.20	1.5
Al	57	0.13	2.8	0.66	0.59
Ca	57	1.3	2.0	1.60	0.17
Mg	57	0.065	0.19	0.13	0.04
Na	57	0.003	0.32	0.074	0.06
K	57	0.006	0.33	0.050	0.07
Fe	57	0.26	0.56	0.35	0.06
Ti	57	0.002	0.18	0.030	0.04
Parts per million					
As	57	0.63	7.9	2.3	1.5
B	57	14L	51	28	7.1
Ba	57	160	960	550	180
Be	57	0.05	6.8	1.2	1.8
Cd	57	0.006	0.073	0.019	0.010
Ce	57	0.47	24	6.4	5.9
Co	57	0.58	24	3.5	3.6
Cr	57	0.71	570	47	120
Cu	57	0.31	39	11	10
F	57	10	500	170	140
Ga	57	0.05L	15	2.0	2.8
Ge	57	0.22L	26	1.8	4.8
Hg	57	0.002	0.13	0.020	0.04
La	57	0.31	16	3.7	3.5
Li	57	0.29	14	1.9	2.1
Mn	57	43	800	120	170
Mo	57	0.50	3.0	1.4	0.72
Nb	57	0.05L	6.9	1.4	1.7
Nd	41	3.0L	22	6.2	4.0
Ni	57	6.2	35	10	4.9
P	57	22	92	47	25
Pb	57	0.29	13	3.5	3.0
Sb	57	0.04L	4.7	0.88	1.1
Sc	57	0.15	26	4.3	6.3
Se	57	0.10L	1.5	.54	0.37
Sr	57	73	890	410	140
Th	57	0.04L	6.5	1.3	1.6
U	57	0.15L	2.3	0.60	0.55
V	57	1.3	110	24	28
Y	57	0.36	37	8.3	9.8
Yb	57	0.050	3.5	0.74	0.96
Zn	57	0.48	11	3.0	1.9
Zr	57	2.5	90	26	23

Table 2. Number of samples, range, arithmetic mean, and standard deviation of total sulfur, and forms-of-sulfur from the No. 3 bed, Usibelli Coal Mine (All values are in percent, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Total sulfur	57	0.030	0.32	0.14	0.084
Sulfate sulfur	57	0.002L	0.058	0.013	0.011
Pyritic sulfur	57	0.01L	0.050	0.013	0.008
Organic sulfur	57	0.01L	0.29	0.013	0.079

Table 3. Number of samples, range, arithmetic mean, and standard deviation of ash and 41 elements in coal from the Usibelli Coal Mine, No. 4 bed. (All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.)

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	116	5.0	47.0	12.1	7.5
Si	116	0.14	13	2.2	2.3
Al	116	0.080	6.1	1.3	1.1
Ca	116	0.23	2.7	1.6	0.29
Mg	116	0.066	0.41	0.16	0.050
Na	116	0.001L	.077	.015	0.020
K	116	0.005	0.98	0.12	0.16
Fe	116	0.25	0.91	0.43	0.10
Ti	116	0.002	0.28	0.055	0.050
		Parts per million			
As	116	0.38	16	4.7	3.8
B	116	5.3	63	28	11
Ba	116	240	1300	460	170
Be	113	0.050	4.2	0.69	0.79
Cd	116	0.005	0.47	0.051	0.06
Ce	111	0.58	50	13	12
Co	116	0.61	21	3.9	3.3
Cr	116	0.1L	70	15	14
Cu	116	2.0	95	25	22
F	116	10	1100	270	260
Ga	116	0.076L	28	3.6	4.3
Ge	110	0.23L	2.6	0.33	0.32
Hg	116	0.005L	0.14	0.022	0.030
La	110	0.40	30	7.3	6.7
Li	116	0.27	28	3.9	4.5
Mn	116	42	330	100	44
Mo	116	0.39	6.5	2.1	1.4
Nb	114	0.061L	10	1.7	1.7
Nd	107	2.1L	55	9.1	9.2
Ni	116	4.7	49	12	7.1
P	116	21	430	71	70
Pb	116	0.30	22	6.0	4.7
Sb	116	0.035	5.6	1.5	1.4
Sc	116	0.15	14	3.8	3.1
Se	116	0.1L	2.5	0.72	0.54
Sr	116	73	460	240	90
Th	115	0.056	9.7	2.5	2.5
U	116	0.075	5.1	1.2	1.4
V	116	1.2	140	28	27
Y	116	0.74	33	8.0	6.9
Yb	116	0.10	2.4	0.75	0.61
Zn	116	0.54	72	11	15
Zr	116	2.9	140	26	23

Table 4. Number of samples, range, arithmetic mean, and standard deviation of total sulfur, and forms-of-sulfur from the No. 4 bed, Usibelli Coal Mine (All values are in percent, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
Total sulfur	116	0.014	1.00	0.31	0.25
Sulfate sulfur	116	.002L	0.030	0.012	0.008
Pyritic sulfur	116	.01L	0.36	0.054	0.091
Organic sulfur	116	.01L	0.90	0.24	0.23

Environmental concerns over stack emissions from the combustion of coal may also be affected by the Clean Air Act Amendment of 1990, which has identified several potentially hazardous air pollutants (HAP). These elements are listed in table 5 along with mean values for the No. 3 bed, No. 4 bed, western U.S. Tertiary coals and Interior Province Pennsylvanian coals (Affolter and Hatch, 1984). When the No. 3 and No. 4 beds are compared to western U.S. Tertiary coals, the contents of Cr, Mn, Ni, and Sb show slight increases; however, when compared to Interior Province Pennsylvanian coals, then only the Cr content from the No. 3 bed is significantly higher. The contents of Mn, Ni and Sb are slightly elevated in the Usibelli coals, however, no mineral forms have been identified for these three elements and at present we do not have enough information as to why these elements are higher in Usibelli coals. Cr content for the No. 3 bed ranges from .71 ppm to 570 ppm. Mean Cr content for the No. 3 bed is 47 ppm, which is 3 times greater than the No. 4 bed, 4.7 times greater than western U.S. Tertiary coals, and 3 times greater than Interior Province Pennsylvanian coals. Most of the Cr content from the No. 3 bed is found in the uppermost meter of the coal bed (fig. 3). Average Cr content in table 6 for selected coals and rocks indicate that this value is the second highest for U.S. coals. Brownfield and others (1991) report that high-Cr content in coals from the Glacier area, Washington may be the direct result of detrital chromium-bearing grains incorporated into the inorganic fraction of the coal from nearby dismembered ophiolite bodies. A mineralogical examination of the No. 3 bed so far has not identified any Cr-bearing minerals. At this time we are not able to identify the source of the high Cr content.

The distribution of Cr within Alaskan coals (fig. 4) shows that high Cr concentrations in Alaskan coals are not unusual. Alaskan coals generally show high values of Co, Cr, Mn, Ni, and Pb (Affolter and Stricker, this volume). Limited work has been done on some of these elements, but recent studies on Alaskan North Slope coals indicates that the high values may be related to the source areas for the coal-bearing sedimentary deposits. Provenance for some of the clastic material in the coal bearing units of the central and eastern North Slope is believed to be located to the south in the central Brooks Range plutonic belt (Bartsch-Winkler, 1985; Bartsch-Winkler and Huffman, 1988; Affolter and others, 1992), which probably served as a possible source for the higher contents of Co, Cr, Mn, and Ni, and Pb in these coals. In the case of the Nenana coals, the source area is related to the Yukon-Tanana Upland and the Alaska Range, which may have affected

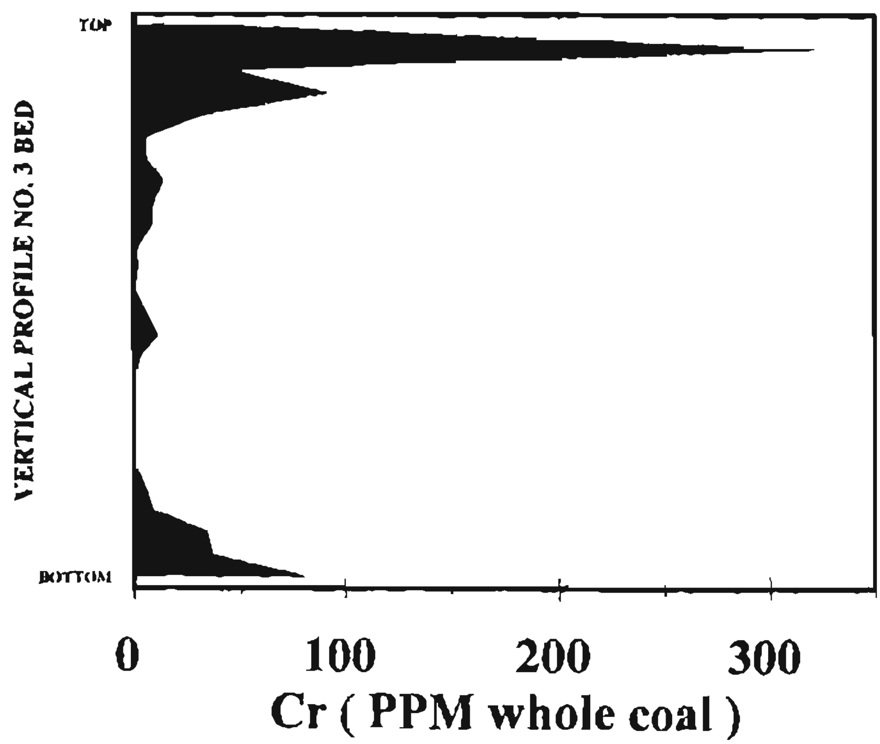

Figure 3. Vertical profile of Cr concentration from a selected bench channel of the No. 3 bed. The No. 3 bed is 5.2 m thick.

Table 5. Comparision of mean element contents for elements that have been classified as hazardous air pollutants (HAPs) by the 1990 Clean Air Act Amendment. Comparisions are made for the No. 3 bed and No. 4 bed with Alaskan Tertiary and Western U.S. Tertiary coals. The mean values for Interior Province Pennsylvanian age coals are included for comparision. (All element contents are in parts per million and are presented on the whole coal basis).

Element	No. 3 bed, Usibelli Coal Mine[1]	No. 4 bed, Usibelli Coal Mine[1]	Alaskan Tertiary Mean[2]	Western U.S. Tertiary Mean[3]	Interior Province Pennsylvanian Mean[4]
As	2.3	4.7	4.6	7.4	12
Be	1.2	0.69	0.84	1.1	2.0
Cd	0.019	0.051	0.12	0.10	.61
Co	3.5	3.9	5.9	3.5	6.7
Cr	47	15	22	10	15
Hg	0.020	0.022	0.038	0.12	0.15
Mn	120	100	120	62	100
Ni	10	12	20	4.6	25
Pb	3.5	6.0	4.9	4.2	42
Se	0.54	0.72	0.99	0.72	3.4
Sb	0.88	1.5	0.97	0.63	1.3

[1] This Report

[2] Affolter and Stricker, this volume

[3] Affolter and Hatch, 1993

[4] Affolter and Hatch, 1984

Table 6. Comparison of chromium contents for Usibelli coals with other coals and mafic, intermediate, and felsic rocks.

Description	Chromium content (ppm whole coal)
NW Washington coal[1]	100
No 3 Bed Usibelli Mine	47
Svea Bed, Spitzbergen[2]	38
Average U.S. coal[3]	15
No 4 Bed Usibelli Mine	15
Western U.S. Tertiary Coal[4]	10
Nova Scotia coal[2]	5
Ultramafic rocks[5]	2,000
Mafic rocks[5]	200
Intermediate rocks[5]	50
Felsic rocks[5]	25

[1]Brownfield and others, 1991

[2]Nicholls, 1968

[3]Swanson and others, 1976

[4]Affolter and Hatch, 1993

[5]Krauskopf, 1979

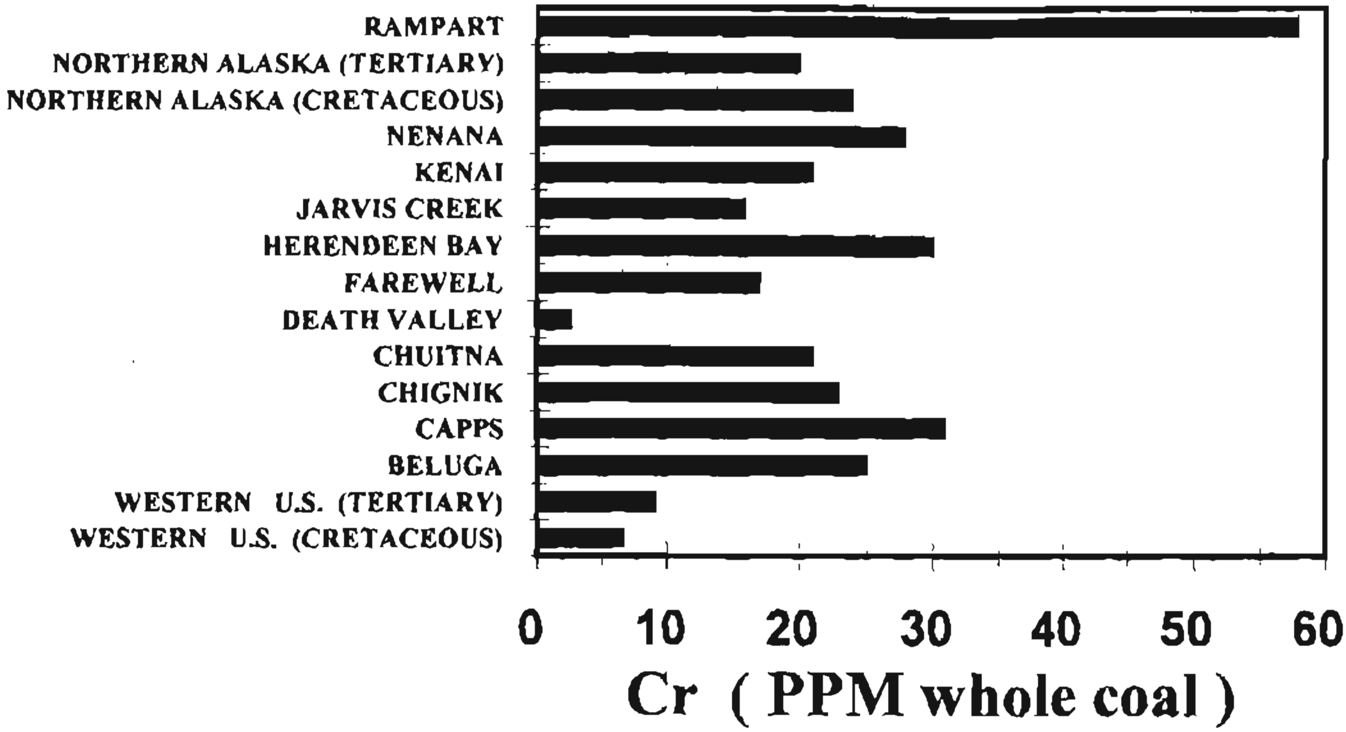

Figure 4. Distribution of mean Cr concentrations for most Alaskan coal fields and western U.S. Cretaceous and Tertiary coals.

the amount and type of clastic material introduced into the mire.

VERTICAL VARIATIONS

The vertical variations within the No. 3 and No. 4 beds were studied for 41 elements, ash, and total sulfur, sulfate sulfur, pyritic sulfur, and organic sulfur. Generally, most of the high element concentrations are concentrated at the tops or bottoms of these beds; however, these trends vary slightly for each bed. All eleven locations (No. 3 bed, 5 locations and No. 4 bed, 6 locations) within the Usibelli Coal Mine were evaluated, and the vertical profiles of elemental distributions are generalized by dividing each bed into three equal parts in order to show the basic trends described below.

Number 4 bed (figures 5-6)

A generalized vertical profile of this coal bed shows a higher concentration at the top of the bed and a lower concentration at the bottom of the bed for most elements. Over 60% of all analyzed elements are statistically higher in the upper part (upper 2.2 m) of No. 4 bed, many are 2-6 times higher in the upper part than in the lower part. Over 90% of the elements are statistically higher in the upper 1.5 m. Sulfur content is 0.62% in the top 2.2 m and 0.14% in the bottom part (2.2 m).

Number 3 bed (figures 7-8)

A generalized vertical profile of this coal bed shows a higher concentration at the top (1.7 m) and bottom (1 .7 m) and lower concentration in the middle part (1.7 m) of the bed for most elements. Over 51% of the elements are statistically higher in the upper and lower 1.7 m. Over 50% of the elements are statistically lower in the middle part of the bed than at either the top or bottom. Statistical comparisons of elemental concentrations between the top 1.7 m and bottom 1.7 m of the bed shows no significant differences. Sulfur content is only .07% in the middle part compared to .20% in the top and .12% in the lower part. (see fig 7)

The reasons for the differences observed in these beds may be directly related to tectonic changes that occurred in the Yukon-Tanana Upland and Alaska Range during the time of accumulation of the No. 3 and No. 4 beds. We believe that tectonic changes altered erosional patterns by exposing different rocks, which changed both stream flows and accompanying

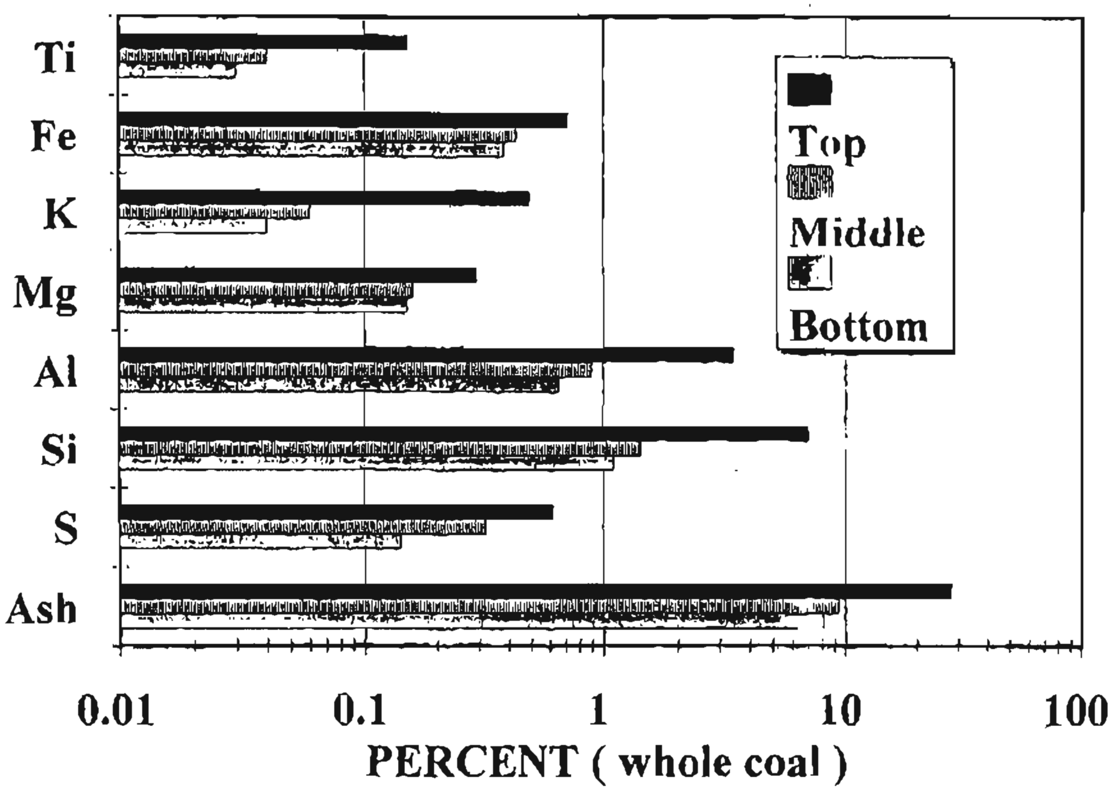

Figure 5. Variation between top, middle, and bottom of the No. 4 bed for selected elements.

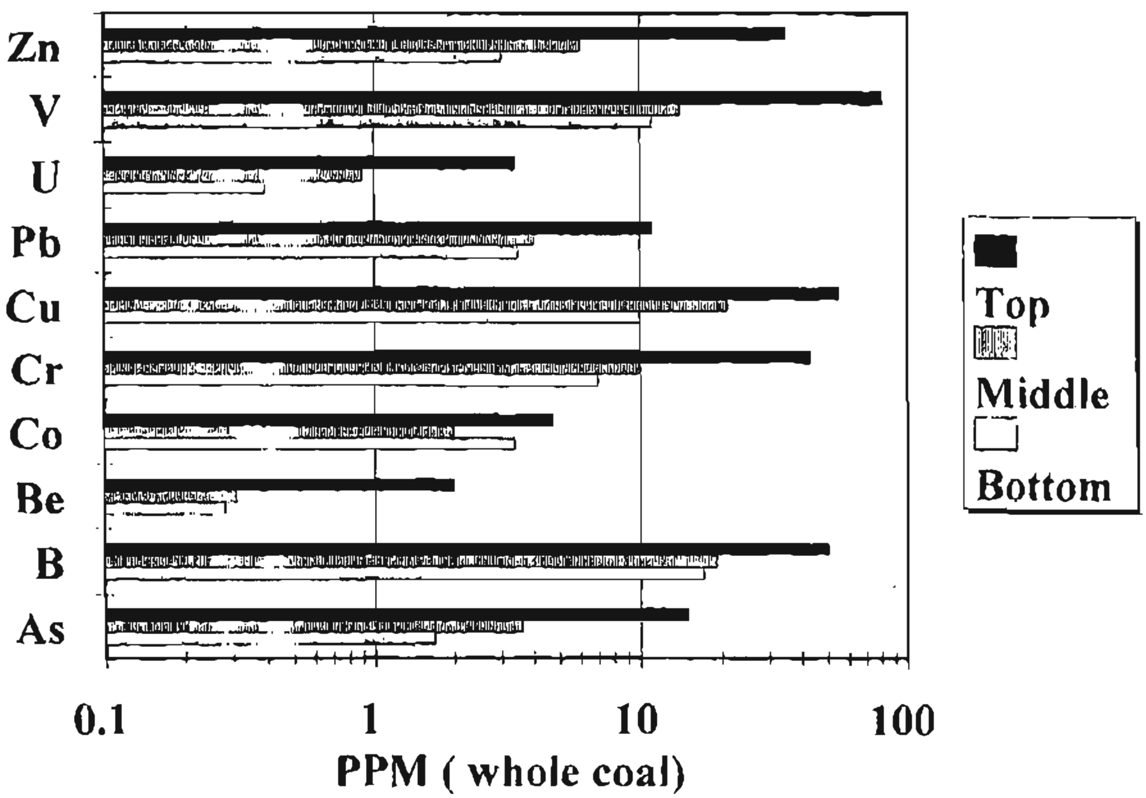

Figure 6. Variation between top, middle, and bottom of the No. 4 bed for selected elements.

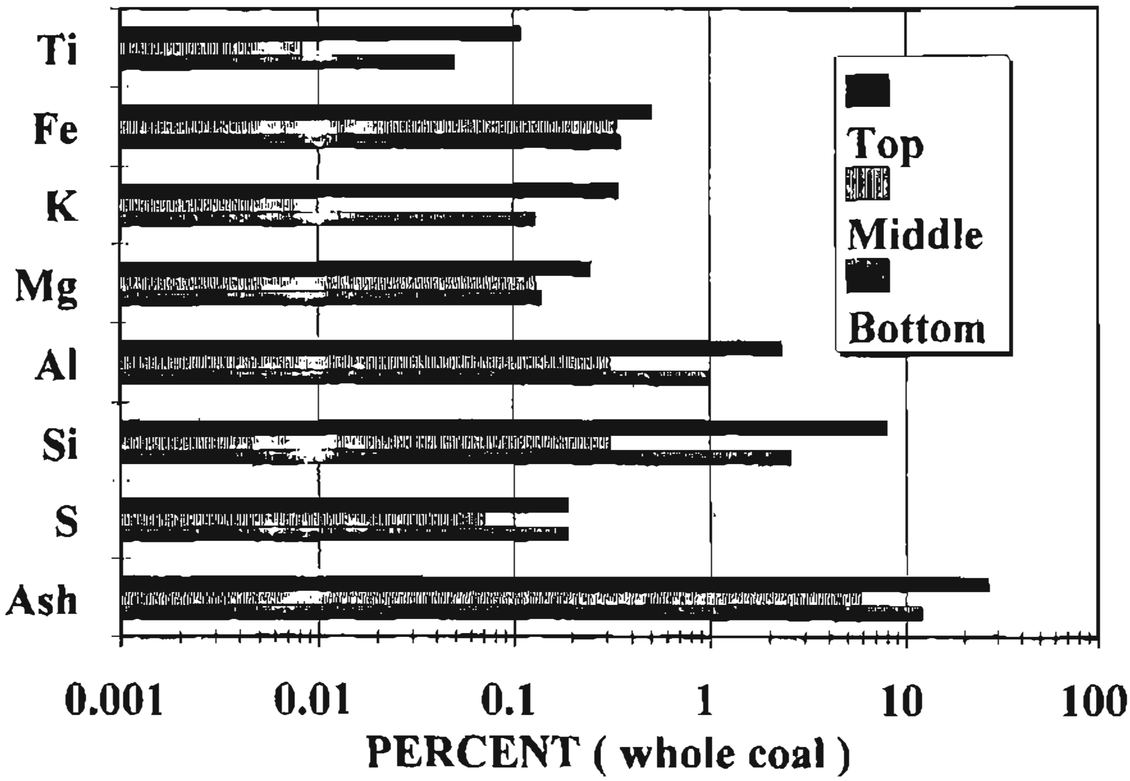

Figure 7. Variation between top, middle, and bottom of the No. 3 bed for selected elements.

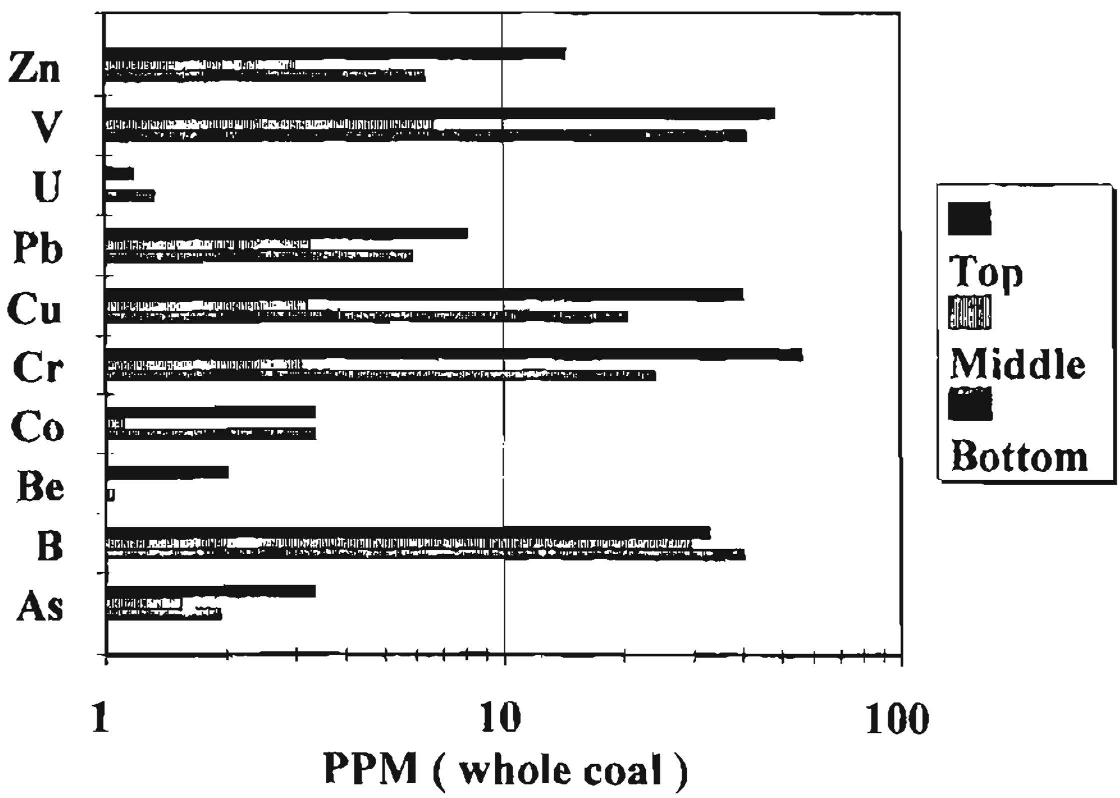

Figure 8. Variation between top, middle, and bottom of the No. 3 bed for selected elements.

sediment loads to the Nenana basin. Tectonic changes also altered subsidence patterns increasing the influx of clastic material and changing ground water patterns in the mires (Stanley and others, 1992).

MINERALOGY

Bulk-mineralogy determinations indicate the presence of quartz, kaolinite, and varying amounts of mica-type clays and feldspars in both the No. 3 and No. 4 beds. X-ray diffractograms of the No. 4 bed also show indications of a possible Crandallite group mineral (figure 9). Even though P, Ba, and Sr element values were high, they were not as high as found in other Alaskan coals. Based on previous studies of Alaskan coals, the presence of high concentrations of P, Ba, and Sr commonly indicates the presence of Crandallite group minerals and, therefore, indicates possible volcanic influences (Brownfield and others, 1987; Stricker and others, 1986; and, Affolter and others, 1992). They suggest that the enrichment of phosphate may be due to the alteration of apatite-bearing air-fall tuffs that were deposited into the reducing environment of a mire and that the Crandallite group minerals formed early during diagenesis of the peat and were localized in the kaolinitic-altered ash partings. These Crandallite group minerals are difficult to differentiate by X-ray diffraction alone since they are members of a solid-solution series that includes:

Crandallite (Ca end-member)
$(CaAl_3(PO_4)_2(OH)_5{\cdot}H_2O)$,
Goyazite (Sr end-member)
$(SrAl_3(PO_4)_2(OH)_5{\cdot}H_2O)$
Gorceixite (Ba end-member)
$(BaAl_3(PO_4)_2(OH)_5{\cdot}H_2O)$.

Vertical plots of the concentrations of P, Ba, and Sr were made for one bench channel of the No. 4 bed (fig. 10). At several locations within the bed, high concentrations of P, Ba, and Sr were observed. At one location near the middle part of the bed, P content was 2.4 times greater (170 ppm), Sr 1.4 times greater (350 ppm), and Ba 1.4 times greater (660 ppm) than the average for this bed. These associations were later seen in several other bench channels of the No. 4 bed. Semiquantitative X-ray diffraction methods, based on the reference-intensity-ratio method of Snyder and Bish (1989), were made on several of these samples. These studies indicated the presence of quartz, kaolinite, feldspar, bassanite (an artifact of the LTA procedure formed by extended ashing), and an unknown Ca-phosphate mineral (table 7). Analyses using a scanning electron microscope (SEM) were not available, which made mineral identification difficult. At present, we have tentatively identified this mineral as an unspecified Crandallite group mineral, based on the high values of P, Ba, and Sr and the X-ray diffraction results. If this

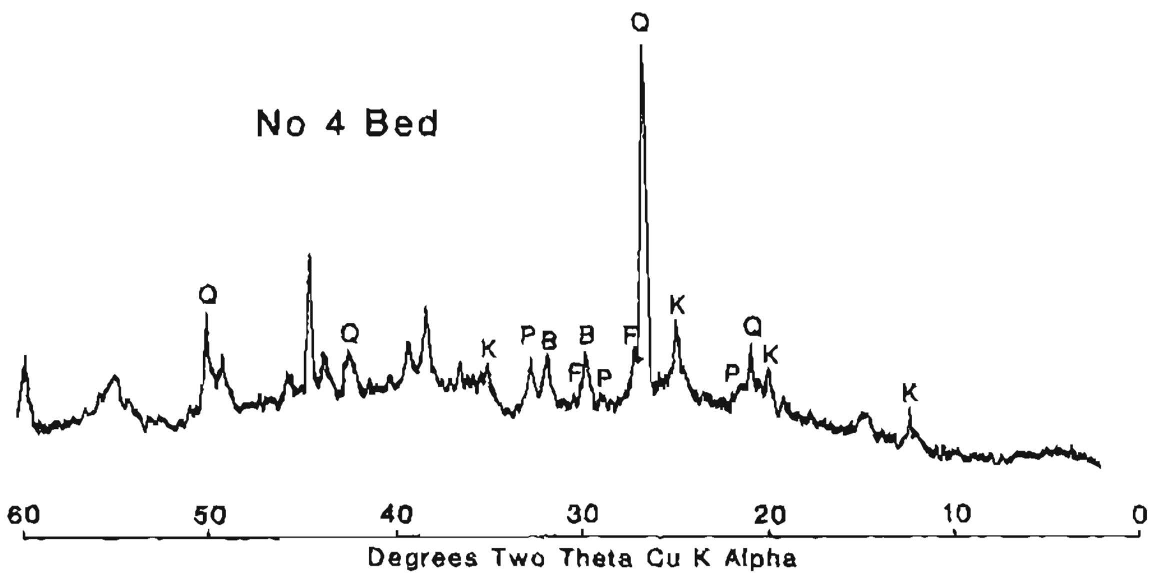

Figure 9. X-ray diffractogram, which indicates the presence of an unidentified Crandallite group mineral. (Q=quartz, K=kaolinite, F=feldspar, P=Ca Phosphate mineral, B=bassanite).

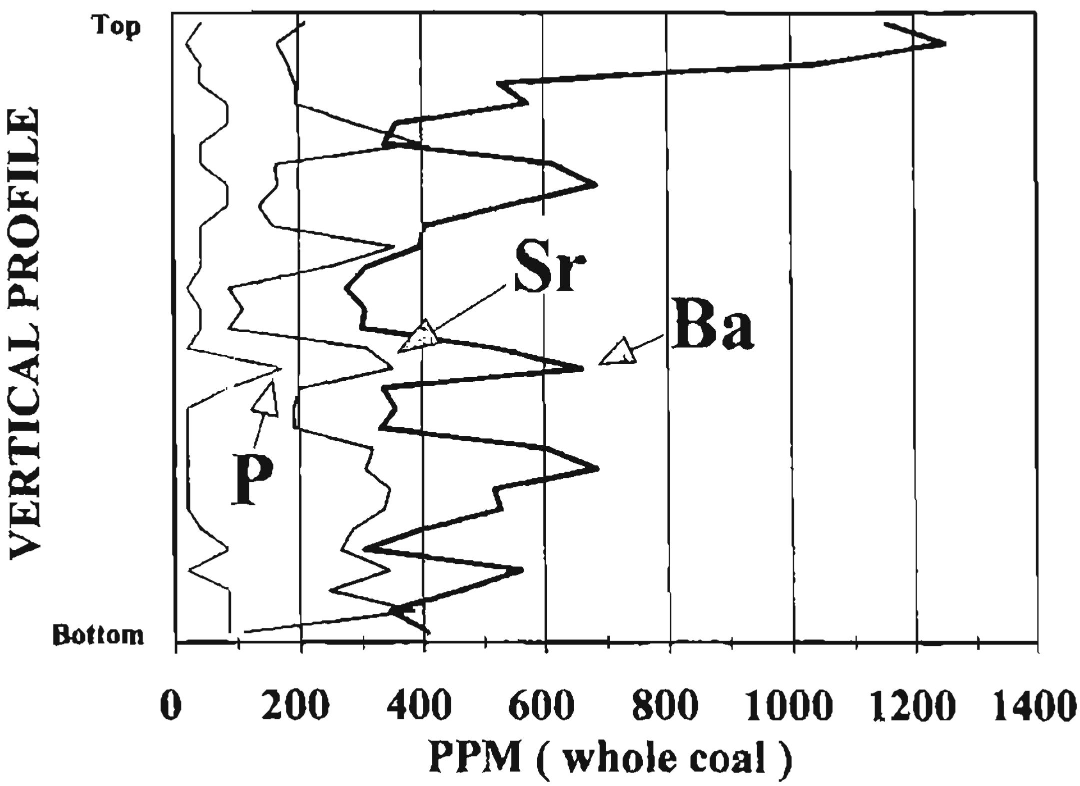

Figure 10. Vertical profile of Sr, Ba, and P from a selected bench channel of the No. 4 bed show where the high values coincide.

Table 7. Mineralogy of the No. 4 bed using semi-quantitative x-ray methods based on the reference intensity ratio method of Snyder and Bish (1989). [All values are in percent]

Mineral	Minimum	Maximum	Mean
Quartz	17	54	32
Kaolinite	19	60	38
Feldspar	9	17	12
Ca-Phosphate	12	43	19
Bassanite	9	32	20

interpretation is verified in future studies, this would be the first time that volcanic ash partings have been identified in these beds.

SUMMARY

Based on the data from this study, Usibelli coal compares favorably with other western U.S. Tertiary coals. Greater than 65% of the analyzed elements from Usibelli coals are lower or similar in concentration to other western U.S. Tertiary coals. However, some elements of environmental concern, such as Cr, Mn, Ni, and Sb, are slightly higher in concentration in Usibelli coal than in other U.S. coals and require further studies to determine their modes of occurrence. The mean sulfur content for the No. 3 bed (mean= 0.14%) is 5.5 times lower than other western U.S. Tertiary coals and the No. 4 bed (mean= 0.31%) is 2.5 times lower, thus making these coals some of the lowest sulfur coals mined in the United States. Possible volcanic ash partings in the No. 4 bed may add information to the depositional history of these coals and should be studied to further our understanding of the effects of how volcanic activity may have affected the elemental chemistry and distributions in the coals of the Usibelli Coal Mine.

Alaska's onshore coal resources are estimated to be 5.3 trillion short tons (Merritt and Hawley, 1986;

Stricker, 1991). More than half the total coal mined in Alaska has been produced from the Nenana coal basin. Within this basin, the Usibelli Coal Mine is now the only active mine in Alaska and supplies most of Alaska's coal power plants. The mining and utilization of this coal will continue to have a large impact on the entire state of Alaska for many years. Soon a new 50-megawatt power plant will be built adjacent to the present 25-megawatt power plant. When this new plant is operational, it will have the potential to become one of the cleanest coal-fired power plants in the world. With increasing attention for elements of environmental concern (Clean Air Act Amendment of 1990), more information on the chemistry of Usibelli coals should be collected and evaluated. Future studies should focus on detailed mineralogical and petrological studies of the coals, partings, overburden, and underburden and to their relationships with respect to coal-quality issues.

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SELF-HEATING CHARACTERISTICS OF ALASKAN COALS

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ABSTRACT

This paper presents a brief description of the three methods (adiabatic calorimetry, oxygen sorption, and thermogravimetry) available at the Mineral Industry Research Laboratory (MIRL) for evaluating the self-heating characteristics of coal and the preliminary results obtained from an on-going experimental study aimed at assessing the self-heating behavior of Alaskan coal.

For the experimental study, the self-heating characteristics of four Alaskan coals (Deadfall Syncline, Usibelli, Beluga, and Little Tonzona) were investigated using the adiabatic coal oxidation calorimetry method. A 1 kg, 16 x 50 mesh, coal sample was charged into the calorimeter, then heated and maintained at 50 °C in nitrogen for about 16 hours. The gas was then switched to oxygen and temperature rise in the coal, as a result of oxidative reactions, was monitored for 30 hours to obtain a temperature-time profile. The maximum heating rate, a measure of self-heating, was obtained from the characteristic temperature-time curve. It was found that the Deadfall Syncline coal was significantly less susceptible to self-heating than the other three lower rank coals. Usibelli and Beluga coals exhibited comparable degrees of self-heating susceptibility, and showed more susceptibility than the Little Tonzona coal, a coal of similar rank and comparable properties.

INTRODUCTION

Many factors, both intrinsic and extrinsic, are responsible for the self-heating propensity of a given coal. Some of the intrinsic factors are oxygen and moisture contents and distribution of oxygen-bearing polar groups. Exposure of coal to an oxidizing atmosphere, even at ambient conditions, can cause exothermic oxidative reactions, which may release heat. [1] Such heat release, if not removed, can cause temperature rise, which eventually may lead to spontaneous combustion. [2] Therefore, coals prone to oxidation, such as low-rank coals, are more liable to self heating than higher rank coals.

Most of the accessible coals in Alaska are low-rank coals. With increasing interest in expanding Alaskan coal markets (domestic and foreign), thermal upgrading is important. Upgrading of low-rank coals most often results into a product with reduced oxygen and moisture contents, but with increased moisture readsorption and self-heating propensity. Hence, accurate assessment of the self-heating behavior of Alaskan coals is essential.

Many methods, reviewed by others, [3,5] have been utilized for assessing the self-heating characteristics of coal. Three of these methods are currently available at MIRL for evaluating self-heating behavior of Alaskan coals. These methods are: (1) adiabatic calorimetric, (2) oxygen absorption, and (3) thermogravimetric analysis (TGA). This paper presents a brief description of the three methods available at MIRL and preliminary results obtained from one of these; the adiabatic calorimetric method.

DESCRIPTION OF THE METHODS USED AT MIRL

Adiabatic Calorimetric Method

This is the method that best simulates actual coal stockpile conditions. The adiabatic system at MIRL is a coal oxidation calorimeter (COC) developed by Broken Hill Proprietary (BHP) Research in Australia. The COC is designed to determine the self-heating characteristics of coal in a controlled, adiabatic environment.

The COC system (Figure 1) consists of a furnace, temperature, and gas (nitrogen and oxygen) flow monitor and control systems, water bath/humidifier, controller and an IBM compatible personal computer. The computer, with custom menu driven software, controls the COC.

The furnace assembly, clearly illustrated in Figure 2, consists of an outer casing, insulation, outer block, and the inner block. The inner block has 16 sample compartments, which hold the coal sample. The sample compartments are separated from each other to ensure consistent heating and temperature monitoring. There is an air gap between the inner and outer block for temperature isolation. A stainless steel gauze at the bottom of the inner block allows the gas to pass upward through the coal sample. Both the inner and outer blocks have precision RTD thermometers to control and monitor the block temperatures. The cylindrical sample compartments can hold about 1 kg of sample altogether. The outer block is wound with a heater element which, in conjunction with a computer proportional controller, raises the temperature of the outer shell to match the temperature rise being generated by the oxidation of the coal sample contained in the inner block. This adiabatic system controls the coal environment to 0.01°C. The temperature of the two calorimeter blocks is measured by highly sensitive and accurately calibrated thermistors. A second, larger heater, is also contained within the inner block to enable the sample temperature to be raised quickly to its initial temperature, typically 50°C.

The oxidizing gas is passed into the inner block via a manifold, down through the coal and out an exhaust manifold. The gas is heated to the temperature of the coal before entering the block to eliminate cooling affects. The flow rate of the oxidizing gas is monitored continually.

Oxygen Sorption Method

This method involves the measurement of pressure drop and the concentrations of oxygen, carbon dioxide, and carbon monoxide in the head gas of a sealed flask containing 50 g coal (initially at one atmosphere of oxygen), kept at constant temperature for 7-10 days. The volume of oxygen absorbed by the coal and associated production of carbon monoxide and/or carbon dioxide at the end of the test are a relative measure of the coal's liability to spontaneous combustion. The pressure drop is monitored daily. From oxygen pressure drop measurement only, it is not possible to determine if the changes are due to oxidative reactions or simply to sorption of oxygen on the coal surface.

The oxygen sorption method, which has been used to evaluate spontaneous combustion characteristics of some naturally occurring and upgraded coals, [3, 6-8] complements the liability index obtained from crossing point and calorimetric methods. Chakravorty Kar [6] reported that high rank coals absorbed little o oxygen and that the emission of carbon monoxide the coals correlated with oxygen sorption.

The method now routinely used at MIRL performed under static conditions and is similar to t used by the U.S. Bureau of Mines. [8] It is a simple a versatile method that can be taken to the field. T pressure drop in a sealed jar containing 50g of 16 x mesh coal is monitored daily by a pressure transduc Six jars containing six different samples, or replicat can be connected to a single pressure readout. T oxygen, CO and CO_2 concentration of the gas in the j can also be monitored.

Thermogravimetric Analysis (TGA) Method

TGA is another method used in evaluating self heating characteristics of coal. TGA measures th weight change in a small amount of coal as it is heated If the coal sample is heated in an oxidative atmosphere one can sometimes detect a weight increase as the coal chemisorbs oxygen, followed by a weight drop as the coal burns. When one combines this with evolved gas analysis (TG-EGA) one can obtain data necessary to follow the oxidative reactions that occur in the coal. At MIRL, Perkin-Elmer TGA Models TGS2 and TGS7 are used. Typical TG/DTG (thermogravimetric/differental thermogravimetric) curves are shown in Figure 3. From these curves, kinetic data and reactivity of the coal can be computed. The higher the reactivity, the higher the liability to self-heating. The difficulty with this method is that it involves extensive interpretation of data. It requires only small quantities of material and hence, raises question of sample heterogeneity and representation. The reactions observed (at temperatures of 300° C and higher) may not be similar to those occurring during spontaneous combustion under stockpile conditions. It is possible, however, to do DTG and TG in an isothermal mode at more appropriate temperatures. In differential thermal analysis, the amount of energy released at these lower temperatures, when held in an oxidative atmosphere, may correlate with spontaneous combustion propensity. Isothermal TG-EGA provides data similar to the oxygen sorption technique discussed earlier. It has the advantage of directly monitoring weight gains and weight losses of the coal as well as simultaneously analyzing the evolved gases.

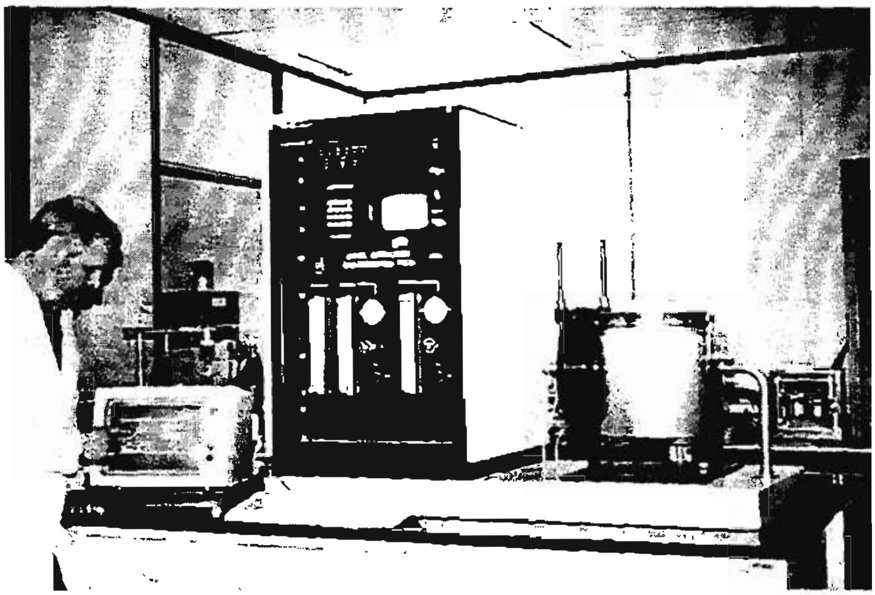

Figure 1. Adiabatic Coal Oxidation Calorimeter

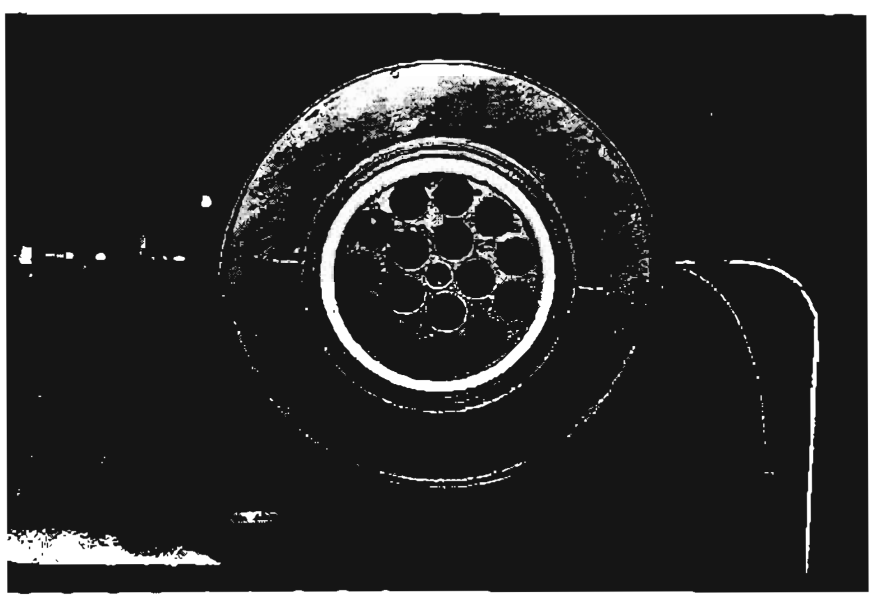

Figure 2. Furnace Showing the Sample Compartments

EXPERIMENTAL

Samples And Their Preparation

Preliminary experimental work on the self-heating characteristics of Alaskan coals was conducted using the adiabatic calorimetric method. Four Alaskan coals (Usibelli, Beluga, Little Tonzona, and Deadfall Syncline) were used for this study. The bulk coal samples collected from the various mines were taken to MIRL. A representative split of each sample was stage-crushed to 16 x 50 mesh. The crushed samples were then divided into 1 kg splits. Table 1 summarizes the properties of the four feed coal samples.

Test Procedure

About 60 g of the 16 x 50 mesh coal samples were charged into each of the 16 sample compartments shown in Figure 2. The sample was first heated in nitrogen and maintained at 50° C for 16 hours. The gas was then automatically switched to oxygen. The temperature rise in the coal bed, which occurs as a result of the oxidative reaction between the coal and oxygen, was continuously monitored. From the temperature-time data obtained, the maximum heating rate was determined. The maximum heating rate is a measure of the coal's liability to spontaneous combustion. The higher the maximum heating rate exhibited by a coal, the more susceptible the coal is to self-heating.

RESULTS AND DISCUSSIONS

The temperature-time profiles for Usibelli, Beluga, Little Tonzona, and Deadfall Syncline coals are shown in Figure 4. In general, a steady increase in the coal bed temperature, as a function of time, could be seen for all four coals. This rise in temperature is attributed to oxidative reactions occurring between coal and oxygen. However, Beluga and Usibelli coals showed similar characteristic temperature-time history that is quite different from the other two Alaskan coals studied. While a maximum temperature of about 93° C was reached at about 12.5 hours, followed by a plateau for the Usibelli coal, for example (Fig. 4), no such maximum was observed for Little Tonzona and Deadfall Syncline coals.

Although Figure 4 shows a steady rise in temperature with time for all four coals, the rate of temperature rise (heating rate) was found to be different for the coals. This difference is more obvious when comparing the maximum heating rates. Table 2 shows the maximum heating rates for all four coals. The maximum

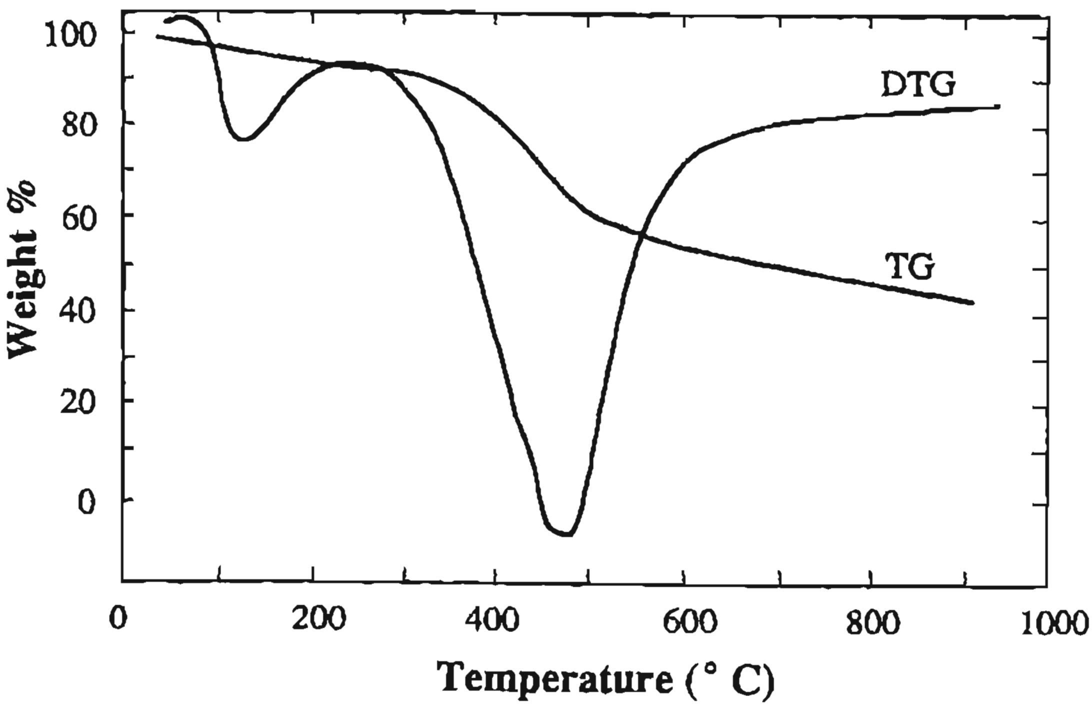

Figure 3. Typical Thermogravimetric and Differential Thermogravimetric Curves of an Alaskan Coal

Table 1. Characteristics of Four Alaskan Coals Used in the Preliminary Spontaneous Heating Study

	Beluga	Usibelli	Little Tonzona	Deadfall Syncline
Proximate analysis (wt%, ASTM equilibrium moisture basis)				
Moisture	24.4	27.3	27.4	4.2
Ash	7.7	4.0	4.5	8.7
Volatile matter	33.7	35.9	38.1	33.3
Fixed carbon	34.2	32.8	29.9	53.8
Ultimate analysis (wt%, ASTM equilibrium moisture basis)				
Carbon	46.7	47.2	45.4	72.7
Hydrogen	6.9	7.1	6.5	5.1
Nitrogen	0.7	0.5	0.5	1.1
Sulfur	0.2	0.1	0.8	0.2
Oxygen	37.8	41.0	42.4	12.2
Heating value (cal/g)	4500	4531	4195	7078
Vitrinite Reflectance %	0.32	0.30	0.18	0.74

Table 2. Maximum Heating Rates of Four Alaskan Coals Used in the Preliminary Spontaneous Heating Study

COAL	Maximum Heating Rate (°C/hr)		
	Replicate 1	Replicate 2	Average
Beluga	2.78	2.56	2.67
Usibelli	2.69	2.66	2.68
Little Tonzona	1.22	1.24	1.23
Deadfall Syncline	0.23	-	0.23

heating rate (MHR) obtained from temperature-time profiles generated by the adiabatic coal oxidation calorimeter, has been reported to be a reliable measure of coal's susceptibility to self-heating. [10, 11] The higher the maximum heating rate, the more susceptible the coal is to spontaneous combustion and self-heating.

The results of Table 2, clearly indicate that the Deadfall Syncline coal from Northwest Alaska is significantly less susceptible to self-heating than the other three Alaskan coals examined in this study. This is not surprising because the Deadfall Syncline coal is of a higher rank (high volatile A bituminous) than the other three coals, which are subbituminous. Generally, high rank coals are less susceptible to self-heating and spontaneous combustion than lower rank coals. This is because of the low oxygen and moisture contents in high rank coals relative to coals of lower rank. [1-7]

In addition to the moisture and oxygen contents, there are other numerous factors and coal properties that alter coal's susceptibility to self-heating and spontaneous combustion. Some of the other intrinsic factors include, sulfur and material content and type and distribution of oxygen functional groups. [1-3, 6] Furthermore, the effect of some of the factors/coal properties differ in different coals. [1, 2] For example, pyrite has been found to increase susceptibility of some coals to self-heating, while some high pyrite-containing coals have been shown to have low susceptibility . [1, 6] It has also been found that susceptibility increases with increasing moisture content, only up to a point, beyond which the effect is reversed. [6, 12] This complex dependence of susceptibility to self-heating on coal properties may explain the difference in the results obtained for the Little Tonzona coal, a coal of similar rank and comparable properties to the other two subbituminous coals (Beluga and Usibelli, Tables 1 and 2). Beluga and Usibelli coals exhibited comparable susceptibility to self-heating, but a significantly higher susceptibility than the Little Tonzona coal.

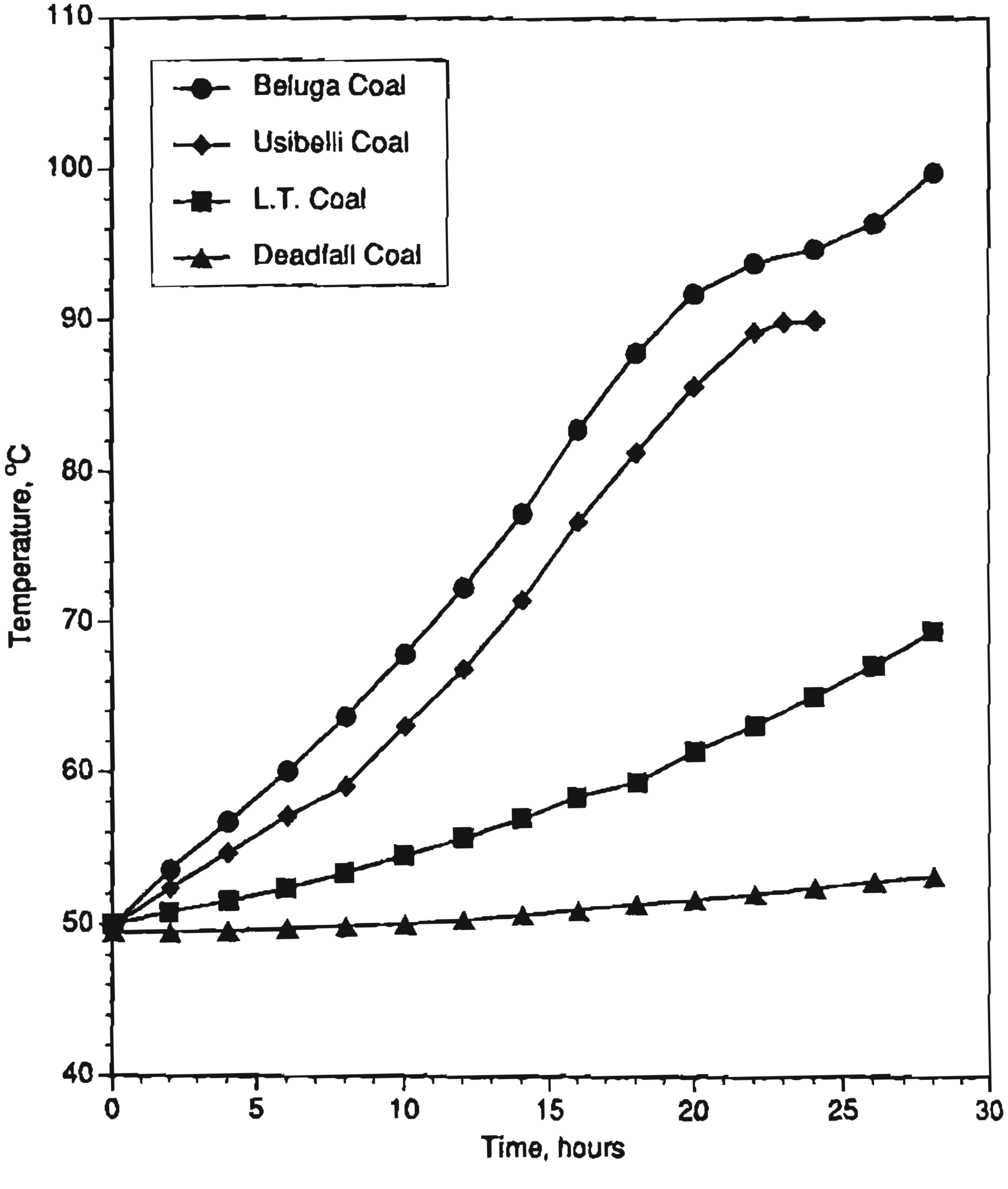

Figure 4. Temperature-time Profile for the Four Coals

CONCLUSIONS

Three methods (oxygen absorption, thermogravimetric analysis, and adiabatic coal oxidation calorimetry) available at MIRL for determining the self-heating characteristics of coal have been described briefly in this paper. The three methods not only provide accurate determination of the spontaneous combustion characteristics of coal, but can also used to evaluate the oxidation potential and reactivity of other carbonaceous materials.

From the preliminary experimental study conducted in order to assess the self-heating characteristics of Alaskan coals using the adiabatic coal oxidation calorimetric method, the following conclusions can be drawn:

(a) The high rank coal (Deadfall Syncline) is significantly less susceptible to self-heating than the lower rank coals (Usibelli, Beluga, and Little Tonzona).

(b) Beluga and Usibelli coals appear to have comparable susceptibility to spontaneous combustion.

(c) Little Tonzona coal, although of similar rank and properties to Beluga and Usibelli coals, showed less susceptibility to self-heating.

(d) A coal's susceptibility to self-heating is a complex function of coal rank and properties.

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QUALITY OF ALASKAN COAL— A STATEWIDE SUMMARY

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ABSTRACT

In 1974 the U.S. Geological Survey began a limited sampling program and collected 56 outcrop samples of Alaskan coal from the Kenai, Herendeen Bay, and Nenana coal fields. Since then, the U.S. Geological Survey, with the help of state and federal agencies, the coal mining industry and various colleges and universities, has collected and analyzed over 670 coal samples throughout Alaska. These samples represent most major coal bearing areas in Alaska and consist of stratigraphic and chemical data from drill core, drill cuttings, face channel mine, and outcrops. Information on these samples is currently stored in the U.S. Geological Survey's National Coal Resources Data System (NCRDS).

A statistical comparison of Alaskan coals to western U.S. coals of similar age and rank shows that Alaska Cretaceous and Tertiary coals collectively are significantly lower (95% confidence level) in total sulfur, organic sulfur, pyritic sulfur, sulfate sulfur, and contents of B, Nb, and Nd. Cretaceous Alaskan coals are significantly lower in Si, Ca, Cu, Pb, and Se and Tertiary Alaskan coals are significantly lower in Mg, Na, Be, Ge, Hg, Sr, and U. When compared to western U.S. coal both Cretaceous and Tertiary Alaskan coals are higher in Ba, Co, Cr, Ni, P, Sc, Yb, and Zr. Cretaceous Alaska coals are higher in Na, K, As, Sr, and Th and Tertiary Alaskan coals are higher in Si, Al, Ca, Cu, Pb, and Se.

Alaskan coals have the lowest average sulfur content of any U.S. coal. However, there is concern that some elements that have been classified as hazardous air pollutants (HAPs) by the Clean Air Act Amendment (1990), such as As, Be, Cd, Cr, Co, Hg, Ni, Pb, Sb, and Se, may be higher in some coal fields in Alaska. Because of this, more work must be done to adequately evaluate the quality of all Alaskan coals.

INTRODUCTION

Since 1971, the U.S. Geological Survey has been involved in a comprehensive program to obtain coal quality data from major coal basins in the conterminous United States. The goals of this program are to collect and analyze United States coals using standardized methods for chemical evaluation (Swanson and Huffman, 1976). In 1974, the U.S. Geological Survey began a limited sampling program in Alaska and collected 56 outcrop samples of Alaskan coal from the Kenai, Herendeen Bay, and Nenana coal fields. From 1974 to 1993, with the help of state and federal agencies, the coal mining industry, and various colleges and universities, the U.S. Geological Survey has collected and analyzed over 670 samples throughout the state of Alaska. These samples represent most major coal-bearing areas in Alaska and consist of stratigraphic and chemical data from drill core (65 samples), drill cuttings (8 samples), face channel mine (521 samples), and outcrops (76 samples). These data are stored in the U.S. Geological Survey's National Coal Resources Data System (NCRDS).

Hatch and Swanson (1977) list the following four reasons why coal quality data are necessary for the proper evaluation and utilization of United States coal. These include:

(1) Evaluation of the environmental impacts of mining and combustion of coal.
(2) Evaluation of the best and most effective technological use of coal (combustion, liquefaction, gasification, etc.).
(3) Deciding the economical aspects of extracting elements such as Ge, Se, U, V, and Zn from coal.
(4) Development of geological and geochemical models to help interpret and predict coal quality and also relating these factors to the stratigraphic and sedimentological framework.

Coal quality data are also an essential component of the U.S. Geological Survey's resource classification system (Wood and others, 1983). Any evaluation of coal resource potential must consider quality as well as quantity. The chemical composition of coal will become more of a concern in the future during the mining, coal cleaning, and reclamation stages. Environmental concern over stack emissions from the combustion of coal may also be affected by the Clean Air Act Amendment of 1990, which has identified several hazardous air pollutants (HAP). Problems will also arise for the proper disposal of the bottom ash and fly ash that will be generated by these power plants. With this increasing emphasis on environmental concerns, the quality of coal (sulfur content, heat-of-combustion, major-, minor-, and trace-element content) will become almost as important as the resource itself.

The main purpose of this paper is to summarize the chemical data that have been collected and to statistically compare these data with western United States coal of similar age and rank. This is done to provide a better understanding of the quality and chemical composition of Alaskan coal in relationship to other United States coal.

METHODS

Chemical Analyses

Proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperature determinations are reported on the as-received-basis and were done either by the U.S. Bureau of Mines, the U.S. Department of Energy, or by Geochemical Testing, Pittsburgh, Pa. Analyses of ash content and major-, minor-, and trace-elements were done by the U.S. Geological Survey (Denver Co). Analytical procedures used for chemical analyses have changed several times during the last 20 years. Detailed descriptions of analytical techniques and procedures used by the U.S. Geological Survey can be found in Swanson and Huffman (1976), Baedecker (1987), and Golightly and Simon (1989).

Only samples with less than 50% ash content were selected for the summary tables and statistical comparisons. Most of the proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperature determinations were made on composite samples, whereas the ash content and major-, minor-, and trace-elements were run on single samples. Accuracy of analytical values is reported to two significant figures for elements and to two decimal places for proximate and ultimate analyses and forms-of-sulfur. Heat-of-combustion and ash-fusion-temperatures are rounded to the nearest tenth. In order to make all of our comparisons consistent and to reflect the true nature of the chemistry of these coals, all elements are calculated to a whole coal basis and are presented in percent or as parts per million (ppm).

Statistical Comparisons

In order to distinguish between Alaskan coal and other U.S. coals, statistical comparisons were made for Alaskan Cretaceous and Tertiary coals with similar-aged western U.S. coals of the Northern Great Plains and Rocky Mountain Provinces (Affolter and Hatch, 1984, 1993). We choose these coals for comparison because these groups make up the majority of western mined coal and would aid in characterizing Alaskan coal with other proven areas of marketable coal. Three statistical comparisons (student's t test, 95% confidence level) are made with the Alaskan coal data. The first comparison is made between Alaskan Cretaceous and Tertiary coals. The second comparison is made between Alaskan Tertiary coal and western Tertiary U.S. coal. The last comparison is made between Alaskan Cretaceous coal and western Cretaceous U.S. coal. All proximate and ultimate analyses, forms-of-sulfur, and heat-of-combustion were compared on an as-received-basis. All major-, minor-, and trace-elements were compared on a whole-coal basis.

RESULTS

Summary Tables

Sample distributions of Cretaceous and Tertiary coal are divided into Regions (Table 1), coal fields and formations (Table 2, Figure 1). Mississippian age coal and coal from the Susitna field were not statically evaluated in this paper because of the limited amount of

Table 1--Distribution of Alaskan coal samples by region

Coal Region	Total number of samples	Cretaceous samples	Tertiary samples
Alaska Peninsula	13	12	1
Central Alaska	259	--	259
Cook Inlet Susitna	98	--	98
Northern Alaska	296	132	162
Seward Peninsula	6	--	6

samples, however, Mississippian coals are included in the summary tables. Summary tables (Tables 3-15) of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperature, as well as major-, minor- and trace-element data (Tables 16-29) are included for each coal field. Distributions by coal field for ash content, total sulfur, and heat-of-combustion are shown in Figures 2-4. Graphic comparisons of 32 major-, minor-, and trace-elements for Alaskan Cretaceous and Tertiary coals to western U.S. coals are shown in Figures 5-8 (Cretaceous) and Figures 9-12 (Tertiary).

Alaskan Cretaceous Coal Verses Alaskan Tertiary Coal

Statistical comparisons between Alaskan Cretaceous and Tertiary coals show that Cretaceous coals are higher in fixed C, C, N, heat-of-combustion, Na, B, Ba, Ce, Ga, Ge, Hg, La, Li, Nb, Nd, P, Th, U, and Zr. Tertiary coals are higher in moisture, volatile matter, H, O, Ca, Mg, Fe, As, Cr, Cu, F, Mn, Mo, and Sb. The contents of total S, sulfate S, pyritic S, organic S, ash, Si, Al, K, Ti, Be, Cd, Co, Ni, Pb, Sc, Se, Sr, V, Y, Yb, and Zn are similar for both Cretaceous and Tertiary coals.

Table 2--Distribution of Alaskan coal samples by coal field and formation

Coal Field	Formation	Cretaceous samples	Tertiary samples
Beluga	Tyonek	--	19
Capps	Tyonek	--	15
Chignik	Chignik	7	--
Chuitna	Tyonek	--	16
Death Valley	Unnamed	--	6
Farewell	Unnamed	--	18
Herendeen bay	Bear Lake	--	1
	Chignik	5	--
Jarvis Creek	Suntrana	--	2
	Healy Creek	--	6
Kenai	Sterling	--	29
	Beluga	--	20
Nenana	Suntrana	--	217
	Healy Creek	--	3
	Cantwell	--	8
Northern AK	Sagavanirktok	--	162
	Prince Creek	5	--
	Chandler	27	--
	Corwin	100	--
Rampart	Suntrana	--	3
Susitna	Beluga	--	1

Alaskan Tertiary Coal Verses Western U.S. Tertiary Coal

Statistical comparisons between Alaskan Tertiary coals and western U.S. Tertiary coals show that Alaskan coals are higher in volatile matter, N, Ash, Si, Al, Ca, K, Ti, Ba, Co, Cr, Cu, F, Mn, Ni, P, Pb, Sb, Sc, Se, V, Y, Yb, and Zr, and lower in moisture, fixed C, H, O, total S, sulfate S, pyritic S, organic S, Mg, Na, As, B, Be, Ce, Ge, Hg, La, Li, Nb, Nd, Sr, and U. The contents of C, heat-of-combustion, Fe, Cd, Ga, Mo, Th, and Zn, are similar for both Alaskan Tertiary and western U.S. Tertiary coal.

Alaskan Cretaceous Coal Verses Western U.S. Cretaceous Coal

Statistical comparisons between Alaskan Cretaceous coals and western U.S. Cretaceous coals show that Alaskan Cretaceous coals are higher in fixed C, O, Na, K, As, Ba, Co, Cr, Hg, Ni, P, Sc, Sr, Th, V, Yb, and Zr and lower in volatile matter, H, total S, sulfate S, pyritic S, organic S, heat-of-combustion, Si, Ca, B, Cu, Nb, Nd, Pb, and Se. The contents of moisture, C, N, ash, Al, Mg, Fe, Ti, Be, Cd, Ce, F, Ga, Ge, La, Li, Mn, Mo, Sb, U, Y, and Zn are similar for both Alaskan Cretaceous and western U.S. Cretaceous coal.

DISCUSSION

Differences in the composition of coal ashes and the elemental contents of coal result from variations in the total and relative amounts of inorganic minerals, the elemental composition of these minerals, and the total and relative amounts of any organically bound elements. The chemical form and distribution of a given element are dependent on the geological history of the coal bed. A partial listing of the geologic factors that influence element distributions would include chemical composition of original plants; amounts and compositions of the various detrital, diagenetic, and epigenetic minerals; chemical characteristics of the ground waters that come in contact with the bed; temperature and pressures during burial; and extent of weathering. Few evaluations of all of these factors have been made for most Alaskan coal deposits. However, the following generalizations about Alaskan Cretaceous and Tertiary coals can be made:

1) Alaskan coals have the lowest reported mean total sulfur, sulfate sulfur, organic sulfur, and pyritic sulfur content of any known U.S. coal (Affolter and

others, 1981; Affolter and Stricker, 1984; and Stricker, 1992). Mean total sulfur content for Tertiary Alaskan coal is .30% verses .79% for western U.S. Tertiary coal. Mean total sulfur content for Cretaceous Alaskan coal is .34% verses .77% for western U.S. Cretaceous coal. Affolter and Stricker (1989) suggest that one of the reasons for low sulfur content in Alaskan coals may be related to the the latitude at which the original swamp developed. They suggest that lower temperatures at higher latitudes (Alaskan coals formed at latitudes greater than 60 degrees) affected the rate of microbiological activity therefore inhibiting sulfate reduction. This would then supress the amount of reduced sulfur available for incorporation in the peat as organic sulfur, which would also limit pyrite and other sulfur minerals.

2) Over 50% of all the elements analyzed for Cretaceous and Tertiary Alaskan coals are lower or similar in content when compared to western U.S. coals. Alaskan coal is generally lower than other western U.S. coals in B, Nb, and Nd content and higher in Ba, Co, Cr, Ni, P, Pb, Sc, V, Yb, and Zr content. The contents of ash, Fe, Ti, Ga, Mo, and Zn are not significantly different.

3) Over 70% of the highest mean-element contents are from the following four Alaskan coal fields (Table 30):
   a) Rampart - Si, Al, Mg, Fe, Ti, Cu, La, Nb, Y, and Yb, and Zr;
   b) Chignik - B, Li, Pb, Th, and Zn;
   c) Farewell - K, Ba, Cd, Cr, Ga, Ge, Ni, Sb, Sc, Se, V; and
   d) Death Valley- As, Be, Hg, Mo, Nd, and U.

4) Over 60% of the lowest mean-element contents are from the following three Alaskan coal fields (Table 31):
   a) Death Valley -Ash, Si, Al, Ca, Ti, Cd, Ce, Co, Cr, Cu, Ga, La, Ni, Pb, Sc, Sr, and V;
   b) Chuitna -Mo, Nd, and Y; and
   c) Jarvis Creek -Mg, Na, B, U.

5) X-ray diffraction analysis of low temperature ash (LTA) from selected coal fields demonstrate that the average bulk mineralogy of these coals is basically quartz, kaolinite, with traces of mica-type clays, which is similar to other western U.S. coals.

6) Some of the highest reported values of Ba, P, and Sr for any U.S. coal (Figures 13-15) are found in Cretaceous and Tertiary Alaskan coals. For example, ten out of the thirteen coal fields summarized in this report have higher P content than Cretaceous and Tertiary western U.S. coals. High values of phosphorus (9,000 ppm, whole coal) are 127 times higher, barium values (24,000 ppm whole coal) are 48 times higher, and strontium values (4,400 ppm, whole coal) are 18 times higher in North Slope coals than conterminous U.S. coals (Affolter and Others, 1992). High values for Ca range from 2.7% to 3.1% for Alaskan coals. X-ray diffraction of the low temperature ash of coals with high Ba, Ca, Sr and P has confirmed the presence of authigenic phosphate minerals of the crandallite group. The crandallite minerals are difficult to differentiate by X-ray diffraction since they are members of a solid solution series that includes:

   crandallite ($CaAl_3(PO_4)_2(OH)_5\_H_2O$)
   goyazite ($SrAl_3(PO_4)_2(OH)_5\_H_2O$)
   gorceixite ($BaAl_3(PO_4)_2(OH)_5\_H_2O$)

   Many Alaskan coals with high P content display variable Ba and Sr contents. This relationship can be further demonstrated by the plot of Ba+Sr versus P for most North Slope Cretaceous and Tertiary Alaskan coals (Figure 16). The enrichment of phosphate is believed to be the result of the alteration of apatite-bearing air-fall tuffs that were deposited into the reducing environment of the coal mire (Brownfield and others, 1987). The crandallite group minerals that formed early during diagenesis of the peat mires help document that volcanic activity during the development of these coals was instrumental in affecting their final chemical composition.

7) Some elements that have been classified as hazardous air pollutants (HAPs) by the Clean Air Act Amendment (1990), which includes As, Be, Cr, Co, Hg, Ni, Pb, and Sb, Se, are higher in some Alaskan coals. Table 32 shows mean contents of elements of environmental concern for Cretaceous and Tertiary Alaskan coal compared to western U.S. coal and Pennsylvanian coal. Statistically, when compared to western U.S. coals, Tertiary Alaskan coals are higher in Co, Cr, Mn, Ni, Pb, Se, and Sb. Cretaceous Alaskan coals are higher in As, Co, Cr,

Hg, and Ni. However, most of the higher values are actually from Alaskan coal fields that are not currently being mined or that will probably not be mined in the future. When compared to Pennsylvanian Interior Province coals, only Cr and Mn are higher in Alaskan Tertiary coals. Recent studies on North Slope Tertiary coals have indicated that high values for these elements can be related to source areas for some of the coal-bearing sediments. Provenance for some of the clastic material in the coal-bearing units of the central and eastern North slope coals is believed to be located to the south in the central Brooks Range plutonic belt (Bartsch-Winkler, 1985; Bartsch-Winkler and Huffman, 1988; Affolter and others, 1992), Major chemical differences between Cretaceous and Tertiary North Slope coals are the result of changes in the source areas for the coal bearing sediments. During Cretaceous time, the source area consisted of pre-Jurassic clastic rocks to the west, whereas during the Tertiary, the source area was to the south in the central Brooks Range plutonic belt, which probably served as a possible source for the higher contents of Co, Cr, Mn, and Ni, and Pb in these coals (Affolter and others, 1993).

SUMMARY

Alaska's onshore coal resources are estimated to be 5.3 trillion short tons (Merritt and Hawley, 1986; Stricker, 1991). This estimate includes coals which range in age from Mississippian to Tertiary and in rank from lignite to anthracite (Barnes, 1961). The majority of Alaskan coal resources are Cretaceous (3.2 trillion short tons) and Tertiary (2.1 trillion short tons) in age. If offshore coal is also considered, there would be an additional 6 trillion metric tons of undiscovered coal resources from the continental shelf of Alaska (Affolter and Stricker, 1987).

Presently, the only active coal mine is the Usibelli Coal Mine, Inc. in Healy, Alaska. This mine produces 1.5 million short tons per year, half of which is exported to Korea (Bohn and Schneider, 1992, p. 32-35). Even though Alaska is endowed with large resources of low-sulfur coal, many of these coals may be difficult to develop because of 1) remote locations and lack of infrastructure, 2) inhospitable climate, and 3) long overland and overseas distances to potential markets. The major constraint on the utilization of Alaskan coal deposits is economic. The conterminous United States has vast developed and known but undeveloped coal deposits that are currently minable by today's technology. And because of the easy access to western U.S. coal deposits, it is not as economical to explore or utilize the majority of Alaskan coal. Present coal production in Alaska likely will not change in the near future and the large resources of low-sulfur coal will not be utilized, unless some major changes take place in the world energy picture or in global environmental concerns.

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Table 3. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Beluga field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	19	16.78	27.49	22.42	2.93
Volatile matter	19	27.27	41.17	35.91	3.48
Fixed carbon	19	22.12	35.20	29.91	3.55
Ash	19	3.59	29.87	11.76	7.57
Hydrogen	19	5.08	6.74	6.14	0.50
Carbon	19	33.99	52.39	46.15	4.80
Nitrogen	19	0.60	0.95	0.74	0.13
Oxygen	19	29.54	39.09	35.06	2.81
Sulfur	19	0.08	0.32	0.15	0.07
Heat-of-combustion					
Btu/lb	19	5,750	8,980	7,920	850
Forms-of-sulfur					
Sulfate	19	0.01	0.03	0.02	0.01
Pyritic	19	0.01L	0.02	0.01	0.01
Organic	19	0.06	0.30	0.14	0.07
Ash-fusion-temperatures °F					
Initial deformation	19	2,140	2,490	2,310	100
Softening temperature	19	2,180	2,600	2,370	110
Fluid temperature	19	2,260	2,730	2,450	120

Table 4. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Capps field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	15	4.80	26.05	17.93	7.19
Volatile matter	15	9.05	41.20	31.03	7.28
Fixed carbon	15	16.65	59.95	29.01	9.57
Ash	15	9.31	40.30	22.03	9.74
Hydrogen	15	1.89	6.43	5.18	1.21
Carbon	15	27.47	64.67	43.03	8.53
Nitrogen	15	0.40	0.66	0.56	0.08
Oxygen	15	6.58	36.82	28.98	7.94
Sulfur	15	0.12	0.33	0.22	0.07
Heat-of-combustion					
Btu/lb	15	4,640	9,850	7,310	1,300
Forms-of-sulfur					
Sulfate	15	0.01L	0.05	0.02	0.02
Pyritic	15	0.01	0.09	0.02	0.02
Organic	15	0.07	0.32	0.18	0.07
Ash-fusion-temperatures °F					
Initial deformation	15	2,330	2,600	2,460	90
Softening temperature	15	2,420	2,700	2,560	100
Fluid temperature	15	2,450	2,770	2,610	110

Table 5. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Chignik field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. G, greater than than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Proximate and ultimate analyses			
Moisture	3	2.20	2.30	2.23	0.06
Volatile matter	3	32.10	33.70	33.17	0.92
Fixed carbon	3	36.80	41.10	39.67	2.48
Ash	3	23.00	28.80	24.93	3.35
Hydrogen	3	4.30	4.80	4.63	0.29
Carbon	3	52.30	56.90	55.37	2.66
Nitrogen	3	0.50	0.50	0.50	0.00
Oxygen	3	13.00	13.50	13.33	0.29
Sulfur	3	1.10	1.30	1.23	0.12
		Heat-of-combustion			
Btu/lb	3	9,130	10,090	9,770	550
		Forms-of-sulfur			
Sulfate	3	0.02	0.02	0.02	0.00
Pyritic	3	0.57	0.57	0.57	0.00
Organic	3	0.49	0.76	0.67	0.16
		Ash-fusion-temperatures °F			
Initial deformation	3	2,580	2,800G	2,730	130
Softening temperature	3	2,690	2,800G	2,760	70
Fluid temperature	3	2,770	2,800G	2,790	20

Table 6. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Chuitna field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Proximate and ultimate analyses			
Moisture	16	19.19	26.15	23.83	1.69
Volatile matter	16	24.91	38.55	33.44	3.76
Fixed carbon	16	17.23	34.40	30.11	4.39
Ash	16	4.83	38.67	12.62	9.08
Hydrogen	16	4.70	6.83	6.24	0.56
Carbon	16	28.91	50.37	45.21	6.00
Nitrogen	16	0.57	0.88	0.73	0.08
Oxygen	16	26.98	37.38	35.08	2.64
Sulfur	16	0.08	0.18	0.13	0.03
		Heat-of-combustion			
Btu/lb	16	4,960	8,750	7,840	1,070
		Forms-of-sulfur			
Sulfate	16	0.01L	0.03	0.01	0.01
Pyritic	16	0.01	0.01	0.01	0.00
Organic	16	0.06	0.17	0.11	0.04
		Ash-fusion-temperatures °F			
Initial deformation	16	2,070	2,620	2,350	160
Softening temperature	16	2,200	2,750	2,470	150
Fluid temperature	16	2,290	2,790	2,530	150

Table 7. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Death Valley field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
Proximate and ultimate analyses					
Moisture	6	23.86	44.63	35.31	7.50
Volatile matter	6	14.39	24.51	21.24	3.74
Fixed carbon	6	31.34	45.48	39.59	5.63
Ash	6	1.75	6.15	3.87	1.62
Hydrogen	6	6.18	7.52	6.82	0.46
Carbon	6	38.99	54.66	47.03	6.18
Nitrogen	6	0.53	0.77	0.67	0.10
Oxygen	6	31.75	49.24	41.11	6.53
Sulfur	6	0.30	1.16	0.51	0.33
Heat-of-combustion					
Btu/lb	6	6,520	9,420	7,970	1,120
Forms-of-sulfur					
Sulfate	6	0.01L	0.09	0.03	0.03
Pyritic	6	0.04	0.41	0.11	0.15
Organic	6	0.25	0.66	0.37	0.15
Ash-fusion-temperatures °F					
Initial deformation	6	2,230	2,390	2,330	60
Softening temperature	6	2,330	2,460	2,410	40
Fluid temperature	6	2,500	2,770	2,640	100

Table 8. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Herendeen Bay field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. G, greater than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
Proximate and ultimate analyses					
Moisture	3	2.50	4.10	3.57	.92
Volatile matter	3	23.50	33.40	30.10	5.72
Fixed carbon	3	25.20	45.20	38.53	11.54
Ash	3	17.30	48.80	27.80	18.19
Hydrogen	3	3.40	4.90	4.40	.87
Carbon	3	36.80	60.20	52.40	13.51
Nitrogen	3	0.20	0.70	.53	.29
Oxygen	3	10.20	16.60	14.47	3.70
Sulfur	3	0.30	0.60	.40	.17
Heat-of-combustion					
Btu/lb	3	6,360	10,370	9,030	2,320
Forms-of-sulfur					
Sulfate	3	0.02	0.02	0.02	0.00
Pyritic	3	0.05	0.42	0.17	0.21
Organic	3	0.16	0.23	0.21	0.04
Ash-fusion-temperatures °F					
Initial deformation	3	2,170	2,800G	2,590	370
Softening temperature	3	2,250	2,800G	2,620	320
Fluid temperature	3	2,330	2,800G	2,640	270

Table 9. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Jarvis Creek field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Proximate and ultimate analyses			
Moisture	8	18.00	26.17	22.49	3.29
Volatile matter	8	32.97	36.20	34.54	1.24
Fixed carbon	8	25.41	35.68	33.15	3.30
Ash	8	5.81	19.30	9.83	4.42
Hydrogen	8	5.80	6.54	6.20	0.31
Carbon	8	43.72	51.17	48.84	2.33
Nitrogen	8	0.70	0.84	0.76	0.07
Oxygen	8	29.90	36.35	33.50	2.48
Sulfur	8	0.42	1.47	0.88	0.30
		Heat-of-combustion			
Btu/lb	8	7,720	8,660	8,350	320
		Forms-of-sulfur			
Sulfate	8	0.01	0.03	0.02	0.01
Pyritic	8	0.02	0.54	0.17	0.19
Organic	8	0.39	0.90	0.70	0.17
		Ash-fusion-temperatures °F			
Initial deformation	8	2,100	2,480	2,300	120
Softening temperature	8	2,300	2,610	2,450	140
Fluid temperature	8	2,360	2,670	2,520	140

Table 10. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Kenai field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Proximate and ultimate analyses			
Moisture	16	11.00	26.50	19.66	4.10
Volatile matter	16	30.00	43.20	37.85	4.16
Fixed carbon	16	20.50	33.10	28.18	4.08
Ash	16	4.80	26.90	14.31	7.16
Hydrogen	16	5.20	6.60	5.94	0.40
Carbon	16	35.40	50.40	44.34	5.24
Nitrogen	16	0.60	1.10	0.88	0.17
Oxygen	16	24.60	40.20	34.16	3.90
Sulfur	16	0.20	1.30	0.38	0.25
		Heat-of-combustion			
Btu/lb	16	6,170	8,610	7,620	870
		Forms-of-sulfur			
Sulfate	16	0.01L	0.03	0.02	0.01
Pyritic	16	0.01	0.12	0.04	0.04
Organic	16	0.16	1.29	0.32	0.27
		Ash-fusion-temperatures °F			
Initial deformation	10	1,870	2,270	2,050	120
Softening temperature	10	1,910	2,350	2,160	120
Fluid temperature	10	1,950	2,450	2,260	130

Table 11. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Lisburne field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. G, greater than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	2	12.80	16.10	14.45	2.33
Volatile matter	2	9.40	12.80	11.10	2.40
Fixed carbon	2	48.40	68.90	58.65	14.50
Ash	2	5.60	26.00	15.80	14.43
Hydrogen	2	3.80	4.60	4.20	0.57
Carbon	2	49.70	70.60	60.15	14.78
Nitrogen	2	0.80	1.00	0.90	0.14
Oxygen	2	17.70	18.40	18.05	0.50
Sulfur	2	0.50	1.30	0.90	0.57
Heat-of-combustion					
Btu/lb	2	8,330	11,640	9,990	2,340
Forms-of-sulfur					
Sulfate	2	0.02	0.02	0.02	0.00
Pyritic	2	0.05	0.23	0.14	0.13
Organic	2	0.47	1.07	0.77	0.42
Ash-fusion-temperatures °F					
Initial deformation	2	2,500	2,630	2,560	90
Softening temperature	2	2,600	2,740	2,670	100
Fluid temperature	2	2,710	2,800G	2,750	70

Table 12. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Nenana field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	30	14.80	32.70	24.70	4.97
Volatile matter	30	27.30	40.10	35.89	2.82
Fixed carbon	30	23.10	34.10	29.52	3.23
Ash	30	5.20	34.50	9.89	5.49
Hydrogen	30	4.60	6.90	6.11	0.58
Carbon	30	35.60	52.40	45.58	4.63
Nitrogen	30	0.50	1.00	0.67	0.12
Oxygen	30	24.50	44.60	37.48	4.73
Sulfur	206	0.01	1.49	0.27	0.24
Heat-of-combustion					
Btu/lb	30	6,130	9,210	7,780	910
Forms-of-sulfur					
Sulfate	206	0.01L	0.14	0.01	0.01
Pyritic	206	0.01L	0.55	0.05	0.08
Organic	206	0.01L	0.90	0.21	0.21
Ash-fusion-temperatures °F					
Initial deformation	22	1,970	2,320	2,170	100
Softening temperature	22	2,050	2,420	2,250	120
Fluid temperature	22	2,150	2,530	2,330	130

Table 13. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Northern Cretaceous field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis. L, less than value shown. G, greater than value shown.).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	68	1.80	33.10	12.52	7.12
Volatile matter	68	22.10	40.00	30.07	3.72
Fixed carbon	68	24.50	60.20	47.13	7.87
Ash	68	2.30	37.20	10.28	7.82
Hydrogen	52	3.82	6.25	5.24	0.48
Carbon	52	43.92	72.50	60.96	8.54
Nitrogen	52	0.72	1.80	1.29	0.30
Oxygen	52	11.30	39.33	23.73	6.58
Sulfur	73	0.10	2.00	0.31	0.23
Heat-of-combustion					
Btu/lb	68	5,610	13,820	10,140	1,810
Forms-of-sulfur					
Sulfate	37	0.01L	0.04	0.01	0.01
Pyritic	37	0.01L	0.06	0.01	0.01
Organic	37	0.05	0.55	0.28	0.12
Ash-fusion-temperatures °F					
Initial deformation	51	2,180	2,910G	2,540	200
Softening temperature	51	2,130	2,910G	2,410	200
Fluid temperature	51	2,030	2,910G	2,300	200

Table 14. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Northern Tertiary field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	68	18.44	35.97	27.04	3.85
Volatile matter	68	23.78	36.09	30.16	2.73
Fixed carbon	68	25.05	42.35	34.65	4.35
Ash	68	1.16	25.46	8.15	6.24
Hydrogen	68	5.11	7.12	6.19	0.42
Carbon	68	35.07	55.11	46.22	4.94
Nitrogen	62	0.59	1.70	1.04	0.22
Oxygen	68	30.09	49.21	38.16	3.86
Sulfur	160	0.06	1.65	0.31	0.33
Heat-of-combustion					
Btu/lb	68	5,930	9,330	7,770	860
Forms-of-sulfur					
Sulfate	160	0.01L	0.23	0.03	0.03
Pyritic	160	0.01L	0.24	0.03	0.03
Organic	160	0.01L	1.54	0.26	0.31
Ash-fusion-temperatures °F					
Initial deformation	69	2,070	2,800G	2,460	240
Softening temperature	69	1,930	2,800G	2,360	240
Fluid temperature	69	1,890	2,800G	2,240	230

Table 15. Number of samples, range, arithmetic mean, and standard deviation of proximate and ultimate analyses, heat-of-combustion, forms-of-sulfur, and ash-fusion-temperatures of coal from the Rampart field (All values are in percent except Btu/lb and ash-fusion-temperatures, and are reported on the as-received basis).

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Proximate and ultimate analyses					
Moisture	3	25.80	34.50	28.83	4.91
Volatile matter	3	27.90	34.60	31.37	3.36
Fixed carbon	3	24.00	32.70	28.00	4.39
Ash	3	6.50	22.30	11.80	9.09
Hydrogen	3	4.90	5.80	5.43	0.47
Carbon	3	33.10	43.90	38.17	5.43
Nitrogen	3	0.80	1.30	1.03	0.25
Oxygen	3	38.30	49.00	43.20	5.41
Sulfur	3	0.40	6.60	2.53	3.52
Heat-of-combustion					
Btu/lb	3	5,020	6,900	5,840	960
Forms-of-sulfur					
Sulfate	3	0.01	0.01	0.01	0.00
Pyritic	3	0.05	0.12	0.08	0.04
Organic	3	0.15	0.51	0.32	0.18
Ash-fusion-temperatures °F					
Initial deformation	3	2,120	2,540	2,260	240
Softening temperature	3	2,210	2,620	2,340	230
Fluid temperature	3	2,310	2,720	2,450	230

Table 16. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Beluga field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Percent					
Ash	19	4.7	34.7	13.7	8.9
Si	19	0.12	8.9	2.7	2.7
Al	19	0.15	4.2	1.6	1.2
Ca	19	0.48	1.2	0.89	0.20
Mg	19	0.055	0.69	0.26	0.13
Na	19	0.007	0.19	0.064	0.059
K	19	0.009	0.75	0.21	0.21
Fe	19	0.10	1.2	0.43	0.25
Ti	19	0.005	0.20	0.077	0.058
Parts per million					
As	19	1.8	7.5	4.5	1.9
B	19	5.1	50	20	14
Ba	19	290	1,500	690	340
Be	19	0.061L	1.8	0.59	0.59
Cd	19	0.015	0.13	0.04	0.033
Ce	12	2	40	13	12
Co	19	0.5	9.0	3.9	2.4
Cr	19	1.9	68	25	22
Cs	12	0.10L	4.4	1.4	1.5
Cu	19	4.7	42	16	12
F	19	20	480	190	140
Ga	19	0.67	16	5.2	4.4
Gd	12	0.71L	10	2.6	3.6
Ge	12	0.22L	0.80	0.33	0.24
Hg	19	0.02	0.16	0.059	0.038
La	18	1	23	8.9	6.7
Li	19	0.23	20	5.8	6
Mn	19	8.6	110	40	27
Mo	16	0.22	34	3.5	8.2
Nb	19	0.42L	4.5	1.8	1.4
Nd	12	4	16	9	3.1
Ni	19	4.4	38	11	7.7
P	19	87	1,800	440	410
Pb	19	0.24	14	4.1	3.6
Sb	19	0.2	3.1	1.0	0.75
Sc	19	0.62	11	4.5	3.3
Se	19	0.10L	2.5	0.46	0.56
Sr	19	73	430	180	98
Th	15	0.3	6.5	2.8	2.1
U	19	0.2	3.3	1.2	0.83
V	19	2.6	160	43	42
Y	19	1.9	23	7.3	5.9
Yb	19	0.2	2.3	0.99	0.70
Zn	19	3.5	42	13	9.6
Zr	19	3.4	36	18	9.4

Table 17. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Capps field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	15	11.6	45.6	26.2	10
Si	15	1.9	13	6.6	3.3
Al	15	1.6	5.5	3.3	1.2
Ca	15	0.83	1.8	1.1	0.20
Mg	15	0.077	0.35	0.19	0.082
Na	15	0.009	0.28	0.077	0.084
K	15	0.053	1.1	0.50	0.28
Fe	15	0.34	1.5	0.75	0.32
Ti	15	0.053	0.26	0.13	0.055
		Parts per million			
As	15	2.8	50	9.9	11
B	15	4.3	57	20	13
Ba	15	150	430	280	75
Be	15	0.39	2.2	0.94	0.52
Cd	15	0.088	0.33	0.19	0.06
Ce	15	7.2L	50	28	14
Co	15	3.6	11	5.9	2.1
Cr	15	8.4	61	31	15
Cs	—	—	—	—	—
Cu	15	6.8	40	21	8.5
F	15	35	230	130	53
Ga	15	2.3	11	7.3	2.7
Gd	15	1.7L	11	4.7	4.0
Ge	15	0.53L	1.1	0.60	0.24
Hg	15	0.03	0.24	0.10	0.058
La	15	5.9	19	12	4.0
Li	15	4.3	18	10	4.7
Mn	15	24	170	84	43
Mo	15	0.36L	3.7	1.1	0.97
Nb	15	0.90L	3.6	2.1	1.1
Nd	15	3.7L	14	5.4	3.3
Ni	15	6.4	32	15	6.8
P	15	43	1,100	430	310
Pb	15	1.5	13	6.0	3.1
Sb	15	0.65	2.6	1.6	0.57
Sc	15	3.1	9.3	6.4	2.1
Se	1	—	—	—	—
Sr	15	170	590	320	110
Th	15	1.3	4.8	3.1	1.2
U	15	0.65	3.0	1.7	0.72
V	15	17	90	54	23
Y	15	5.3	20	11	3.9
Yb	15	0.76	3.0	1.5	0.61
Zn	15	14	83	39	16
Zr	15	17	61	37	12

Table 18. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Chignik field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	7	9.9	32.3	20.2	9.2
Si	7	1.5	7.0	4.2	2.5
Al	7	1.0	6.0	2.9	2.1
Ca	7	0.12	1.6	0.78	0.50
Mg	7	0.06	0.34	0.24	0.087
Na	7	0.007	0.04	0.022	0.014
K	7	0.029	0.16	0.09	0.052
Fe	7	0.44	1.2	0.79	0.24
Ti	7	0.057	0.19	0.11	0.055
		Parts per million			
As	7	3.0	5.0	4.4	0.98
B	7	65	220	110	49
Ba	7	20	150	79	41
Be	5	0.38	1.5	0.79	0.46
Cd	7	0.1L	0.16	0.10	0.046
Ce	—	—	—	—	—
Co	7	1.08	4.8	2.6	1.7
Cr	7	4	22	11	6.4
Cs	—	—	—	—	—
Cu	7	9.4	26	16	6.6
F	7	40	110	55	25
Ga	7	2.6	10	6.5	3.3
Gd	—	—	—	—	—
Ge	—	—	—	—	—
Hg	3	0.07	0.12	0.087	0.029
La	2	6.9	16	12	6.5
Li	7	11	81	36	28
Mn	7	32	110	72	29
Mo	7	0.90	2.3	1.8	0.55
Nb	5	1.3	6.5	3.5	2.1
Nd	—	—	—	—	—
Ni	7	2.6	9.7	5.1	2.3
P	7	47	710	300	280
Pb	7	3.2L	13	6.7	4.4
Sb	7	0.2	8.2	2.9	3.5
Sc	7	3.9	15	6.7	3.9
Se	7	0.3	4.4	1.3	1.5
Sr	7	19	130	63	38
Th	3	4.2	6.4	5.3	1.1
U	7	0.41	1.6	0.91	0.43
V	7	19	65	33	18
Y	7	6.5	22	14	5.0
Yb	6	0.9	3.2	1.8	0.83
Zn	7	12	440	79	157
Zr	7	19	97	43	28

Table 19. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Chuitna field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	16	6.0	46.5	15.	11.
Si	16	0.70	14	3.4	3.4
Al	16	0.66	5.9	1.9	1.4
Ca	16	0.56	1.1	0.84	0.15
Mg	16	0.082	0.46	0.19	0.10
Na	16	0.007	0.54	0.18	0.21
K	16	0.044	0.76	0.21	0.20
Fe	16	0.19	0.9	0.41	0.21
Ti	16	0.023	0.32	0.086	0.075
		Parts per million			
As	16	1.7	4.1	2.5	0.65
B	16	5.1	36	17	9.1
Ba	16	140	560	280	130
Be	16	0.13	1.3	0.49	0.41
Cd	16	0.043	0.20	0.095	0.052
Ce	16	7.0	43	18	11
Co	16	1.5	12	5.2	3.1
Cr	16	6.1	66	21	17.3
Cs	—	—	—	—	—
Cu	16	5.0	29	12	6.9
F	16	32	260	110	66
Ga	16	1.7	16	4.7	3.7
Gd	16	0.96L	10	3.8	2.9
Ge	16	0.14	1.1	0.34	0.25
Hg	16	0.28L	0.12	0.027	0.027
La	16	4.2	25	9.6	6.0
Li	16	1.1	18	5.2	4.6
Mn	16	7.5	57	28	16
Mo	16	0.21	2.9	0.86	0.67
Nb	16	0.5	6.5	2.0	1.7
Nd	16	1.9L	11	3.3	3.0
Ni	16	4.5	32	14	7.8
P	16	8	4,100	580	970
Pb	16	1.7	8.6	3.3	2.0
Sb	16	0.37	1.9	0.95	0.53
Sc	16	1.6	9.3	3.7	2.3
Se	2	0.25	0.29	0.27	0.032
Sr	16	150	1,400	370	300
Th	16	1.0	5.6	2.3	1.4
U	16	0.59	2.7	1.1	0.69
V	16	7.6	100	32	28
Y	16	2.6	13	6.0	3.4
Yb	16	0.29	2	0.80	0.53
Zn	16	6	29	15	8.6
Zr	16	10	60	23	13

Table 20. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Death Valley field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range: Minimum	Range: Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	6	3.9	8.2	6.0	2.0
Si	6	0.64	1.3	0.93	0.27
Al	6	0.49	0.93	0.70	0.19
Ca	6	0.13	0.57	0.33	0.18
Mg	6	0.082	0.27	0.16	0.066
Na	6	0.008	0.043	0.019	0.014
K	6	0.006	0.13	0.047	0.054
Fe	6	0.21	1.1	0.43	0.36
Ti	6	0.021	0.071	0.043	0.019
		Parts per million			
As	6	10	59	22	19
B	6	25	80	46	18
Ba	6	35	170	91	48
Be	6	0.77	4.8	1.7	1.5
Cd	6	0.028	0.043	0.032	0.006
Ce	6	5.4	9.4	7.2	1.6
Co	6	0.7	2	1.2	0.56
Cr	6	1.7	4	2.6	1.0
Cs	6	0.17	1.8	0.64	0.59
Cu	6	3.9	9.0	5.5	2.0
F	6	40	120	70	30
Ga	6	0.99	2.9	2.1	0.70
Gd	—	—	—	—	—
Ge	6	0.66	9.6	3.5	3.3
Hg	6	0.05	0.5	0.24	0.2
La	6	2.2	3.9	2.9	0.7
Li	6	1.0	5.9	2.3	1.8
Mn	6	21	140	63	44
Mo	6	8.8	16	12	2.8
Nb	6	1.2	4.4	2.2	1.2
Nd	6	5.5	32	13	10
Ni	6	1.1	5.8	2.6	1.6
P	—	—	—	—	—
Pb	6	1.3	2.7	1.7	0.53
Sb	6	0.22	1.1	0.53	0.31
Sc	6	1.6	4.4	3.1	1.1
Se	6	0.41	0.98	0.57	0.21
Sr	6	26	98	53	35
Th	6	0.89	1.8	1.2	0.38
U	6	1.2	37	14	12
V	6	7.3	19	13	4.9
Y	6	4.7	8	6.4	1.1
Yb	6	0.74	1.4	1.0	0.25
Zn	6	7.1	12	9.3	2.0
Zr	6	21.1	36	27	5.8

Table 21. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Farewell field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	15	7.2	49.5	22.9	17.7
Si	15	0.12	14	5.3	6.1
Al	15	0.23	6.4	2.6	2.6
Ca	15	0.10	2.2	1.2	0.88
Mg	15	0.11	0.44	0.25	0.10
Na	15	0.003	0.05	0.021	0.019
K	15	0.007	1.6	0.55	0.67
Fe	15	0.18	1.8	0.64	0.40
Ti	15	0.008	0.33	0.13	0.13
		Parts per million			
As	9	2.0	23	13	7.8
B	15	17	86	38	22
Ba	15	370	2,300	1,300	590
Be	7	0.22	0.92	0.58	0.26
Cd	9	0.073	13	2.6	4.1
Ce	—	—	—	—	—
Co	15	3.4	30	8.4	6.6
Cr	15	8.6	220	63	67
Cs	—	—	—	—	—
Cu	9	8.8	72	34	22
F	9	35	190	100	51
Ga	15	1.4	43	12	12
Gd	—	—	—	—	—
Ge	2	1.7	8.7	5.2	4.9
Hg	9	0.11	0.81	0.23	0.22
La	—	—	—	—	—
Li	9	0.72L	6.0	2.0	1.8
Mn	15	8.2	150	45	47
Mo	14	1.5	44	8.8	11
Nb	7	1.5L	5.0	3.8	1.5
Nd	—	—	—	—	—
Ni	15	7.3	98	47	32
P	15	22	1,300	400	430
Pb	9	0.91	5.6	2.7	1.7
Sb	9	0.69	7.4	3.5	2.3
Sc	15	1.7	37	12	8.7
Se	9	2.0	43	15	12
Sr	15	37	300	130	73
Th	9	0.28	1.4	0.81	0.36
U	9	0.93	8.5	3.3	2.2
V	15	2.2	350	160	120
Y	15	5.1	65	18	14
Yb	15	0.51	6.5	1.8	1.5
Zn	9	2.8	190	63	56
Zr	15	4.4	150	51	58

Table 22. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Herendeen Bay field [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (—) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
Percent					
Ash	4	13.2	27.7	18.6	6.53
Si	4	1.8	6.2	3.7	1.8
Al	4	1.3	5.6	2.9	1.9
Ca	4	0.09	3.1	0.86	1.5
Mg	4	0.03	0.62	0.20	0.28
Na	4	0.01	0.04	0.02	0.011
K	4	0.03	0.05	0.04	0.01
Fe	4	0.17	0.43	0.27	0.12
Ti	4	0.09	0.31	0.16	0.11
Parts per million					
As	4	2.0	8.5	3.9	3.1
B	4	28	66	48	17
Ba	4	56	290	170	100
Be	4	0.44	2	1.1	0.66
Cd	4	0.15L	0.73	0.26	0.31
Ce	—	—	—	—	—
Co	4	7.2L	26	15	8.0
Cr	4	2.8	4.4	3.9	0.70
Cs	—	—	—	—	—
Cu	4	8.6	24	16	7.9
F	4	30	65	41	17
Ga	4	2.8	8.3	5.5	2.4
Gd	—	—	—	—	—
Ge	—	—	—	—	—
Hg	3	0.03	0.04	0.04	0.006
La	2	7.3	9.2	8.3	1.4
Li	4	8.2	36	19	13
Mn	4	5.8	44	17	18
Mo	3	0.92	3.7	2.2	1.4
Nb	3	2.9L	5.5	3	2.2
Nd	—	—	—	—	—
Ni	4	5.6	14	11	3.8
P	4	58L	610	340	240
Pb	4	5.8	19	10	6.3
Sb	4	0.4	1.8	1.1	0.68
Sc	4	3.7	9.2	6.4	2.8
Se	4	0.20	0.80	0.58	0.26
Sr	4	42	220	110	79
Th	—	—	—	—	—
U	4	0.68	2.7	1.2	0.97
V	4	13	42	26	12
Y	4	10	40	21	13
Yb	4	0.56	2.6	1.5	0.93
Zn	4	21	120	54	43
Zr	4	20	140	58	55

Table 23. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Jarvis Creek field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
		Percent			
Ash	8	7.5	22.7	11.5	4.93
Si	8	0.61	5.3	1.6	1.6
Al	8	0.53	3.2	1.2	0.89
Ca	8	1.1	1.5	1.3	0.12
Mg	8	0.064	0.15	0.094	0.031
Na	8	0.003	0.025	0.009	0.007
K	8	0.008	0.40	0.073	0.13
Fe	8	0.42	1.2	0.70	0.24
Ti	8	0.025	0.15	0.074	0.05
		Parts per million			
As	8	3.7	18	7.5	4.3
B	8	4.9	27	12	6.8
Ba	8	690	1,500	1,100	240
Be	7	0.17	2.7	0.86	0.95
Cd	8	0.037	0.094	0.062	0.023
Ce	6	3.1	30	10	10
Co	8	2	11	4.2	3
Cr	8	2.2	35	12	12
Cs	6	0.2L	2.3	0.52	0.88
Cu	8	3.8	44	18	14
F	8	10	310	95	100
Ga	8	0.62	6.8	2.3	2.1
Gd	—	—	—	—	—
Ge	6	0.35L	1.0	0.39	0.34
Hg	8	0.01	0.17	0.063	0.053
La	6	1.7	15	5.1	4.9
Li	8	1.7	10	4.1	2.6
Mn	8	38	90	56	22
Mo	8	3.8	14	6.8	3.2
Nb	8	0.57	5.4	2.0	1.6
Nd	6	4.6	13	7.9	3.8
Ni	8	6.8	35	14	9.5
P	8	44L	310	150	110
Pb	8	2.5L	13	5.5	3.7
Sb	8	0.36	3.7	1.2	1.2
Sc	8	1.3	9.3	3.7	2.8
Se	8	1.0	9.8	3.4	2.8
Sr	8	91	250	160	58
Th	6	0.33	6.1	1.5	2.3
U	8	0.16L	2.6	0.87	0.79
V	8	7.9	61	28	18
Y	8	3.7	20	8.1	5.6
Yb	8	0.23	1.6	0.66	0.46
Zn	8	8.3	44	19	16
Zr	8	15	55	32	15

Table 24. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Kenai field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range: Minimum	Range: Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	44	5.8	49.1	15.2	9.38
Si	44	0.46	11.	3.0	2.5
Al	44	0.31	6.3	1.6	1.3
Ca	44	0.32	1.6	1.1	0.23
Mg	44	0.061	0.57	0.21	0.14
Na	44	0.018	0.68	0.19	0.17
K	44	0.02	1.3	0.23	0.24
Fe	44	0.21	2.4	0.58	0.38
Ti	44	0.014	0.25	0.073	0.055
		Parts per million			
As	44	2.0	25	7.4	5.2
B	44	5.5	75	24	16
Ba	44	160	980	500	180
Be	36	0.18	1.5	0.54	0.32
Cd	44	0.029L	0.25	0.076	0.047
Ce	—	—	—	—	—
Co	44	2.1	12	5.5	2.1
Cr	44	2.4	74	21	16
Cs	—	—	—	—	—
Cu	44	7.1	86	22	16
F	44	10	290	63	56
Ga	43	0.9	15	4.2	3.2
Gd	—	—	—	—	—
Ge	12	1.2L	11	2.3	2.8
Hg	44	0.01	0.40	0.084	0.063
La	12	4.2	29	8.6	6.7
Li	44	0.31	26	6.0	6.3
Mn	44	40	290	110	60
Mo	42	0.47	14	2.2	2.2
Nb	39	1.2L	7.7	2.3	1.8
Nd	—	—	—	—	—
Ni	44	3.9	20	9.5	4.2
P	44	26L	1,300	460	340
Pb	44	1.5L	11	3.1	2.3
Sb	44	0.20	3.7	1.0	0.69
Sc	44	1.1	15	4.2	3.0
Se	44	0.1L	2.1	0.62	0.69
Sr	44	42	520	220	110
Th	—	—	—	—	—
U	44	0.20	3.1	0.77	0.58
V	44	9.0	200	56	42
Y	44	2.1	20	6.6	4.5
Yb	44	0.21	2.0	0.73	0.51
Zn	44	2.1	113	12	20
Zr	44	5.8	82	23	18

Table 25. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Lisburne field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
		Percent			
Ash	2	5.0	27.8	16.4	16.1
Si	2	0.98	7.1	4.1	4.4
Al	2	0.69	3.5	2.1	2.0
Ca	2	0.040	0.09	0.065	0.035
Mg	2	0.022	0.12	0.069	0.067
Na	2	0.016	0.17	0.095	0.11
K	2	0.067	0.49	0.28	0.30
Fe	2	0.29	1.2	0.75	0.64
Ti	2	0.033	0.18	0.11	0.11
		Parts per million			
As	2	3.5	21	12	12
B	2	15	56	35	29
Ba	2	100	280	190	130.
Be	2	3.5	4.2	3.8	0.47
Cd	2	0.075	0.14	0.11	0.045
Ce	1	—	—	—	—
Co	2	2.8L	15	8.2	9.6
Cr	2	25	83	54	41
Cs	—	—	—	—	—
Cu	2	16	45	30	21
F	2	40	120	80	57
Ga	2	7.5	28	18	14
Gd	—	—	—	—	—
Ge	2	1.5	19	10	13
Hg	2	0.01	0.27	0.14	0.18
La	2	25	28	26	2
Li	2	34	210	120	120
Mn	2	11	30	20	13
Mo	2	3.5	28	16	17
Nb	2	2.5	14	8.2	8.1
Nd	—	—	—	—	—
Ni	2	19	75	47	39
P	2	220L	610	360	350
Pb	2	22	92	57	50
Sb	2	1.3	2.1	1.7	0.57
Sc	2	8.3	10	9.2	1.2
Se	2	1.4	1.8	1.6	0.28
Sr	2	56	100	78	31
Th	—	—	—	—	—
U	—	—	—	—	—
V	2	75	280	180	140
Y	2	14	15	14	0.78
Yb	2	1.5	1.9	1.7	0.32
Zn	2	49	130	90	59
Zr	2	15	56	35	29

Table 26. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Nenana field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	206	4.9	47	11.4	7.19
Si	206	0.12	13	2.0	2.3
Al	206	0.080	6.1	1.1	1.0
Ca	206	0.15	2.7	1.5	0.37
Mg	206	0.054	0.48	0.16	0.065
Na	206	0.001L	0.32	0.033	0.042
K	206	0.005	0.98	0.11	0.16
Fe	206	0.12	1.4	0.41	0.15
Ti	206	0.002	0.28	0.051	0.050
		Parts per million			
As	206	0.38	43	4.1	4.3
B	206	4.4	100	30	15
Ba	206	150	1,500	510	230
Be	197	0.045	6.80	0.87	1.2
Cd	206	0.005	0.56	0.053	0.078
Ce	190	0.47	94	12	13
Co	206	0.58	24	3.8	3.3
Cr	206	0.1L	570	25	63
Cs	176	0.015	6.1	0.73	1.1
Cu	206	0.31	95	20	19
F	206	10	1,100	240	240
Ga	206	0.049L	28	3.3	4.0
Gd	181	1.1L	7.9	1.6	1.2
Ge	181	0.23L	26	0.84	2.8
Hg	206	0.005L	0.3	0.028	0.042
La	195	0.31	30	6.4	6.1
Li	206	0.27	35	3.9	5.3
Mn	206	6.1	800	110	98
Mo	204	0.39	12	2.0	1.6
Nb	203	0.051L	10	1.7	1.7
Nd	167	1.1	55	8.5	8.0
Ni	206	4.6	49	11	6.8
P	206	22	530	76	85
Pb	206	0.3	22	5.2	4.2
Sb	206	0.02	8.1	1.4	1.4
Sc	206	0.15	26	4.0	4.2
Se	206	0.10L	11	0.80	0.94
Sr	206	39	890	270	140
Th	199	0.04L	18	2.4	2.6
U	206	0.15L	5.2	1.0	1.2
V	206	1.2	140	28	28
Y	206	0.37	37	8.0	7.6
Yb	205	0.05	3.5	0.77	0.74
Zn	206	0.48	75	9.0	13
Zr	206	2.5	140	26	23

Table 27. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Northern Cretaceous field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
		Percent			
Ash	127	2.0	38.9	10.7	7.94
Si	106	0.030	11	1.9	2.1
Al	106	0.13	6.4	1.2	1.1
Ca	106	0.040	2.2	0.41	0.30
Mg	106	0.020	0.72	0.15	0.11
Na	106	0.015	0.85	0.15	0.13
K	106	0.003	2.4	0.16	0.31
Fe	106	0.040	3.0	0.35	0.36
Ti	106	0.004	0.52	0.07	0.077
		Parts per million			
As	97	0.1L	8.7	2.4	1.7
B	127	17	190	59	33
Ba	127	140	25,000	1,100	2,300
Be	122	0.032	12	0.96	1.4
Cd	97	0.008	0.61	0.10	0.13
Ce	68	2.0	120	23	24
Co	127	0.40	58	6.6	8.0
Cr	127	0.1L	59	11	14
Cs	37	0.050	3.1	0.49	0.70
Cu	97	0.99	32	6.1	6.1
F	97	10	400	83	78
Ga	123	0.25	19	4.9	4.4
Gd	37	0.51L	11	2.0	2.3
Ge	56	0.064	55	3.5	8.7
Hg	97	0.13L	0.50	0.10	0.12
La	111	1.1	65	10	11
Li	97	0.44	84	12	12
Mn	106	1.8L	390	33	51
Mo	75	0.07	5.9	1.0	1.1
Nb	124	0.20	17	2.5	2.9
Nd	69	2.6	90	11	12
Ni	127	1.0	83	18	16
P	106	22	9,000	670	1,000
Pb	97	0.17	26	4.1	4.4
Sb	97	0.02	2.3	0.25	0.39
Sc	127	0.19	25	4.0	4.0
Se	97	0.05	2.0	0.45	0.32
Sr	127	16	4,400	230	450
Th	102	0.1L	37	3.8	5.5
U	80	0.23L	11	2.0	1.9
V	127	1.2	370	35	52
Y	127	0.42	28	7.3	5.8
Yb	127	0.063	2.7	0.8	0.64
Zn	97	1.7	67	9.1	10
Zr	127	1.3	540	50	73

Table 28. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Northern Tertiary field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown.]

	Number of samples	Range Minimum	Range Maximum	Arithmetic mean	Standard deviation
		Percent			
Ash	160	1.3	47.8	11.8	10
Si	158	0.070	14	2.3	2.9
Al	158	0.060	6.3	1.4	1.5
Ca	158	0.020	1.5	0.6	0.30
Mg	160	0.001	0.67	0.19	0.16
Na	158	0.001	0.12	0.025	0.028
K	158	0.002	1.2	0.19	0.26
Fe	158	0.14	10	1.1	1.4
Ti	158	0.002	0.37	0.067	0.08
		Parts per million			
As	160	0.35	29	2.9	4.0
B	160	9.0	130	50	33
Ba	160	18	4,700	1,200	1,000
Be	160	0.058	4.1	0.90	0.79
Cd	160	0.011L	0.27	0.075	0.063
Ce	160	0.67	67	12	12
Co	160	0.49	94	8.9	13
Cr	160	0.35	69	16	17
Cs	160	0.04L	7.2	1.0	1.5
Cu	159	1.1	170	16	22
F	160	20L	700	110	150
Ga	151	0.063L	33	4.8	5.4
Gd	160	0.29L	7.4	1.6	1.5
Ge	160	0.074L	3.8	0.42	0.56
Hg	160	0.005L	0.11	0.01	0.020
La	160	0.35	33	6.6	6.7
Li	160	0.080	61	5.3	7.7
Mn	160	2.1	1,600	160	230
Mo	151	0.1L	8.2	2.1	1.4
Nb	160	0.065	25	1.9	2.6
Nd	146	0.7L	43	9.1	8.5
Ni	160	5.9	760	34	67
P	160	22	5,400	740	1,100
Pb	160	0.20	27	5.4	5.6
Sb	160	0.004L	1.8	0.28	0.30
Sc	160	0.15	26	4.5	4.5
Se	160	0.08L	2.9	0.60	0.49
Sr	160	0.82	1,000	190	240
Th	160	0.03	6.8	1.7	1.70
U	160	0.13L	5.7	0.84	0.94
V	160	0.51	190	30	37
Y	159	0.3L	39	8.8	7.0
Yb	160	0.05L	3.9	0.78	0.69
Zn	160	2.0	150	23	25
Zr	160	0.57L	880	35	74

Table 29. Number of samples, range, arithmetic mean, and standard deviation of ash and 43 elements in coal from the Rampart field. [All analyses are in percent or parts per million and are reported on a whole coal basis. L, less than value shown. Leaders (---) indicate means could not be calculated owing to an insufficient number of analyses above the lower detection limit]

	Number of samples	Range		Arithmetic mean	Standard deviation
		Minimum	Maximum		
		Percent			
Ash	3	18.5	43.8	29.8	12.9
Si	3	4.0	11.	7.1	3.3
Al	3	2.1	5.8	3.7	1.9
Ca	3	1.1	1.7	1.4	0.33
Mg	3	0.17	0.40	0.26	0.12
Na	3	0.043	0.19	0.10	0.075
K	3	0.23	0.45	0.32	0.11
Fe	3	0.85	1.6	1.2	0.37
Ti	3	0.17	0.29	0.22	0.062
		Parts per million			
As	3	1.9	2.7	2.3	0.4
B	3	56	81	67	13
Ba	3	440	1,300	850	430
Be	2	0.93	1.4	1.1	0.31
Cd	3	0.14	3.1	1.1	1.7
Ce	—	—	—	—	—
Co	3	5.6	6.9	6.1	0.72
Cr	3	45	77	58	17
Cs	—	—	—	—	—
Cu	3	39	69	50	16
F	3	150	160	150	5.8
Ga	3	5.6	13	8.9	3.9
Gd	—	—	—	—	—
Ge	—	—	—	—	—
Hg	3	0.06	0.22	0.12	0.087
La	3	13	31	21	9.0
Li	3	12	29	20	8.7
Mn	3	15	140	74	64
Mo	2	2.7	2.8	2.7	0.053
Nb	3	3.7	8.8	5.9	2.6
Nd	—	—	—	—	—
Ni	3	19	31	26	6.1
P	—	—	—	—	—
Pb	3	4.6L	13	6.3	6.0
Sb	3	0.7	0.8	0.77	0.058
Sc	3	8.1	13	10	2.6
Se	3	0.1L	0.10	0.10	0
Sr	3	66	190	150	70
Th	3	3.4	6	4.4	1.4
U	3	2.2	4.1	3	0.99
V	3	56	88	75	17
Y	3	19	31	26	6.1
Yb	3	2.7	4.4	3.3	0.95
Zn	3	27	47	39	11
Zr	3	37	130	74	50

Table 30. Distribution by coal field of the highest mean values for ash and 43 elements.

Element	Mean	Coal Field
	Percent	
Ash	29.8	Rampart
Si	7.1	Rampart
Al	3.7	Rampart
Ca	1.5	Nenana
Mg	0.26	Rampart/Beluga
Na	0.19	Kenai
K	0.55	Farewell
Fe	1.2	Rampart
Ti	0.22	Rampart
	Parts per million	
As	22	Death Valley
B	110	Chignik
Ba	1300	Farewell
Be	1.7	Death Valley
Cd	2.6	Farewell
Ce	28	Capps
Co	15	Herendeen Bay
Cr	63	Farewell
Cs	1.4	Beluga
Cu	50	Rampart
F	240	Nenana
Ga	12	Farewell
Gd	4.7	Capps
Ge	5.2	Farewell
Hg	0.24	Death Valley
La	21	Rampart
Li	36	Chignik
Mn	160	Northern Alaska (Tertiary)
Mo	12	Death Valley
Nb	5.9	Rampart
Nd	13	Death Valley
Ni	47	Farewell
P	740	Northern Alaska (Tertiary)
Pb	6.7	Chignik
Sb	3.5	Farewell
Sc	12	Farewell
Se	15	Farewell
Sr	370	Chuitna
Th	5.3	Chignik
U	14	Death Valley
V	160	Farewell
Y	26	Rampart
Yb	3.3	Rampart
Zn	79	Chignik
Zr	74	Rampart

Table 31. Distribution by coal field of the lowest mean values for ash and 43 elements.

Element	Mean	Coal Field
	Percent	
Ash	6.0	Death Valley
Si	0.93	Death Valley
Al	0.70	Death Valley
Ca	0.33	Death Valley
Mg	0.094	Jarvis Creek
Na	0.009	Jarvis Creek
K	0.04	Herendeen Bay
Fe	0.27	Herendeen Bay
Ti	0.043	Death Valley
	Parts per million	
As	2.3	Rampart
B	12	Jarvis Creek
Ba	79	Chignik
Be	0.54	Kenai
Cd	0.032	Death Valley
Ce	7.2	Death Valley
Co	1.2	Death Valley
Cr	2.6	Death Valley
Cs	0.49	Northern Alaska (Cretaceous)
Cu	5.5	Death Valley
F	41	Herendeen Bay
Ga	2.1	Death Valley
Gd	1.6	Northern Alaska (Tertiary)/ Nenana
Ge	0.33	Beluga
Hg	0.01	Northern Alaska (Tertiary)
La	2.9	Death Valley
Li	2.0	Farewell
Mn	17	Herendeen Bay
Mo	0.86	Chuitna
Nb	1.7	Nenana
Nd	3.3	Chuitna
Ni	2.6	Death Valley
P	76	Nenana
Pb	1.7	Death Valley
Sb	0.25	Northern Alaska (Cretaceous)
Sc	3.1	Death Valley
Se	0.10	Rampart
Sr	53	Death Valley
Th	0.81	Farewell
U	0.77	Kenai
V	13	Death Valley
Y	6.0	Chuitna
Yb	0.66	Jarvis Creek
Zn	9.0	Nenana
Zr	18	Beluga

Table 32. Comparision of mean element contents for elements of environmental concern according to the 1990 Clean Air Act. Comparisions are made between Cretaceous and Tertiary Alaskan coals and Western U.S. Cretaceous and Tertiary coals. The mean values for Interior Province Pennsylvanian coals is included for comparision. (All element contents are in parts per million and are presented on the whole coal basis).

Element	Alaskan Cretaceous Mean[1]	Western U.S. Cretaceous Mean[2]	Alaskan Tertiary Mean[1]	Western U.S. Tertiary Mean[2]	Interior Province Pennsylvanian Mean[3]
As	2.6	1.70	4.6	7.4	12
Be	0.96	1.2	0.84	1.1	2
Cd	0.10	0.10	0.12	0.10	.61
Co	6.7	1.9	5.9	3.5	6.7
Cr	11	7.1	22	10	15
Hg	0.10	0.07	0.038	0.12	0.15
Mn	35	29	120	62	100
Ni	17	4.3	20	4.6	25
Pb	4.4	6.1	4.9	4.2	42
Se	0.51	1.4	0.99	0.72	3.4
Sb	0.46	0.44	0.97	0.63	1.3

[1] This Report

[2] Affolter and Hatch, 1993

[3] Affolter and Hatch, 1984

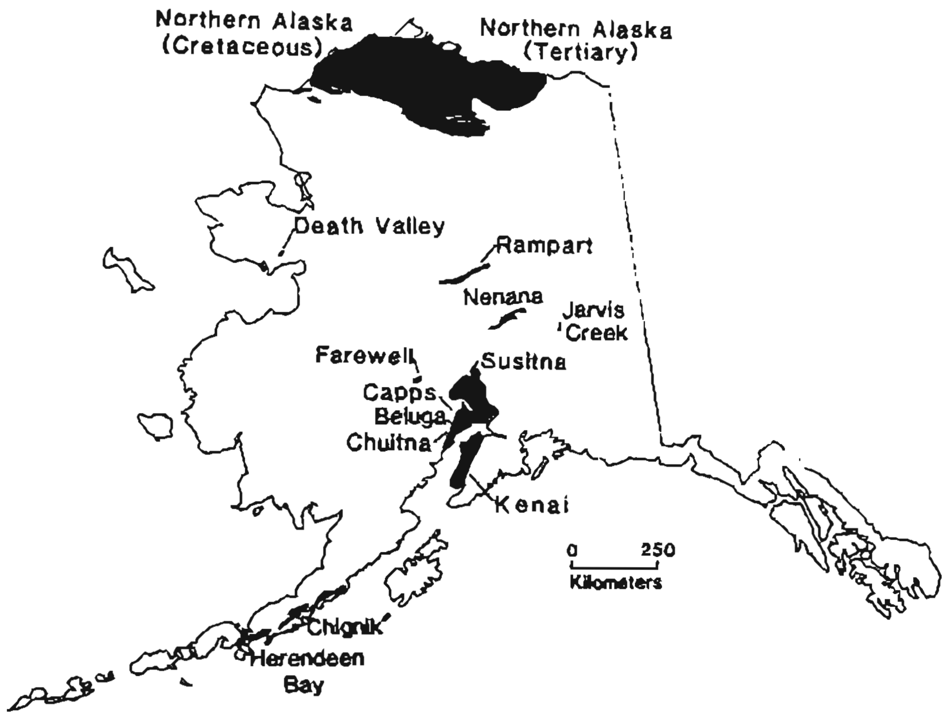

Figure 1. Location of Alaskan coal fields summarized in this paper.

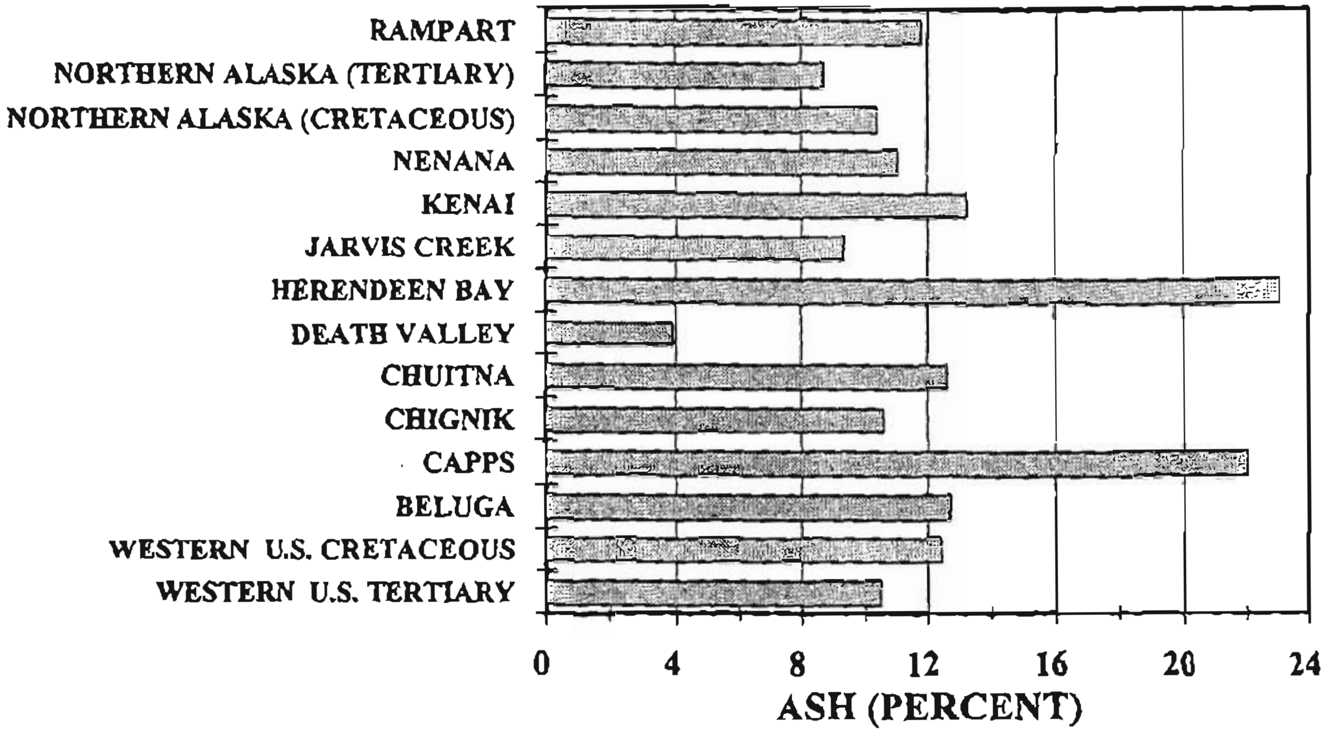

Figure 2. Distribution of mean ash contents by coal field.

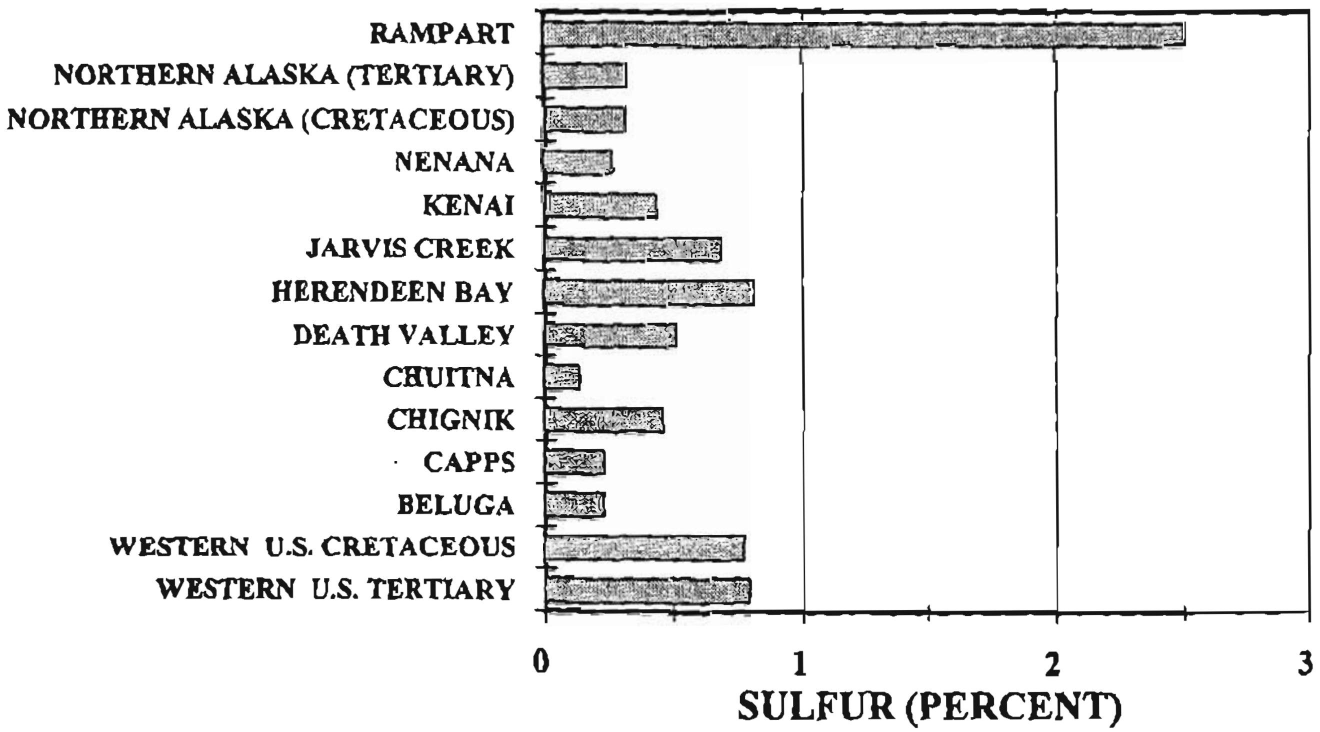

Figure 3. Distribution of mean sulfur contents by coal field.

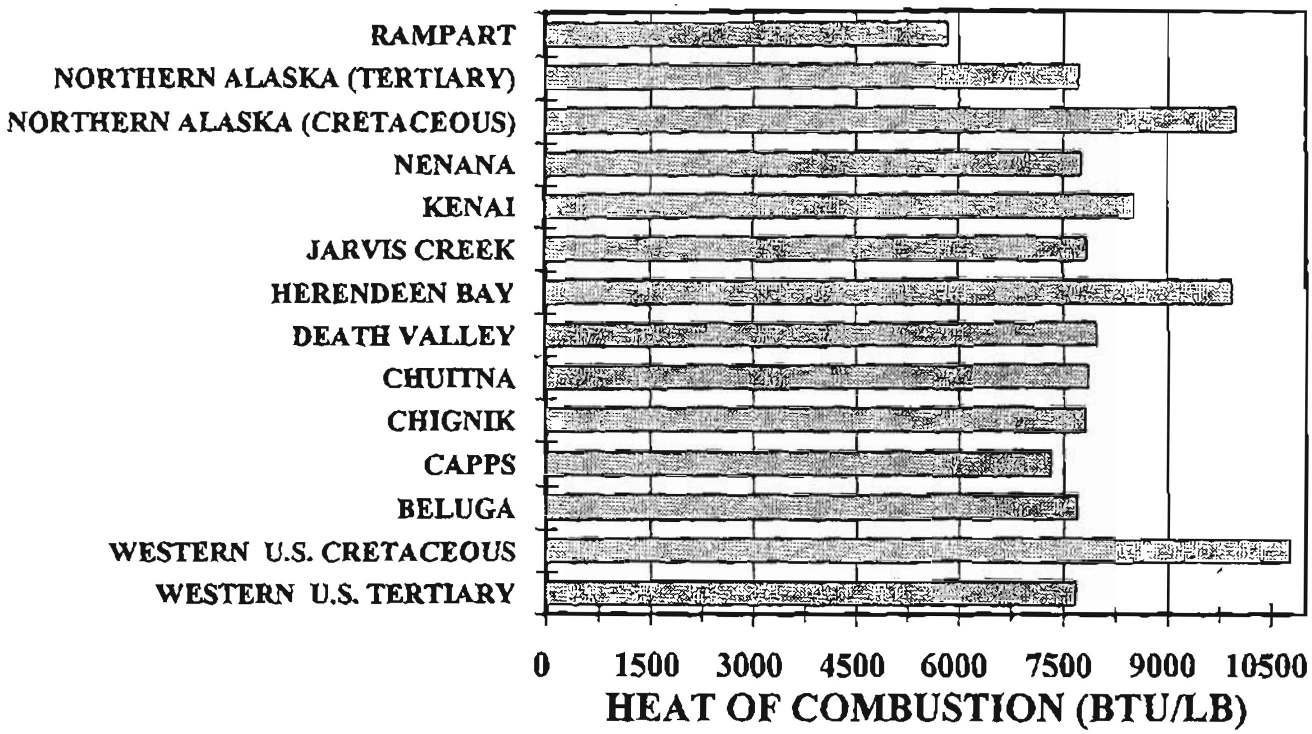

Figure 4. Distribution of mean heat-of-combustion contents by coal field.

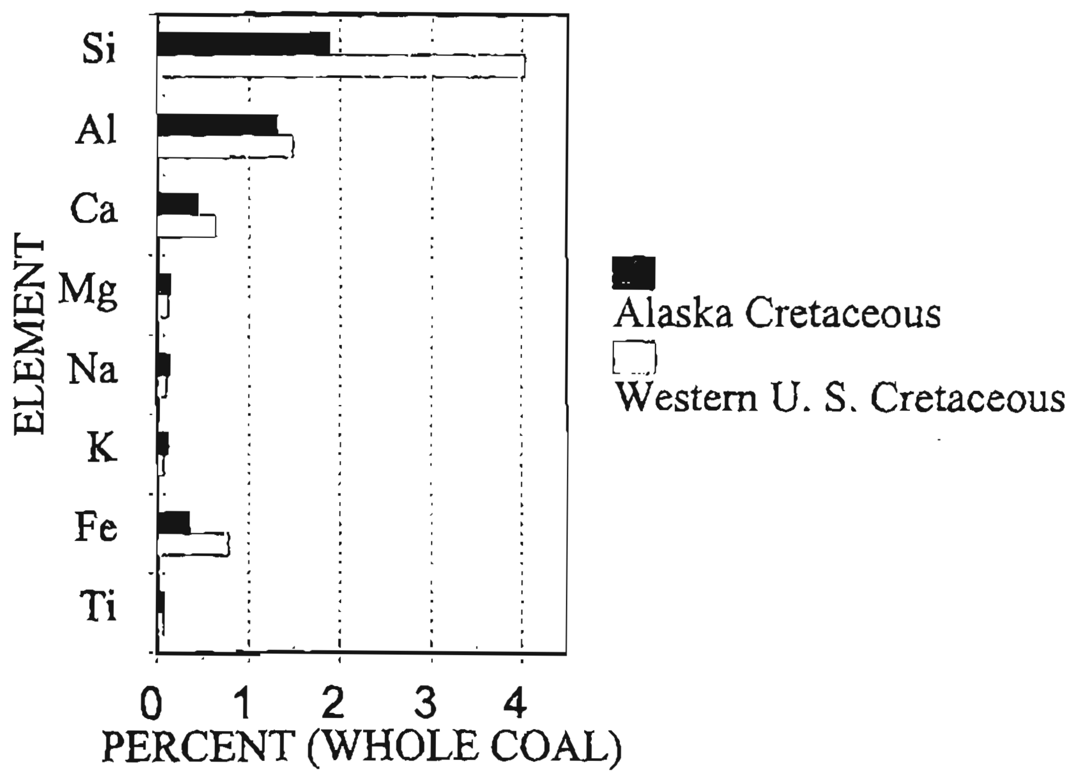

Figure 5. Comparison of mean element contents of Si, Al, Ca, Mg, Na, K, Fe, and Ti for Alaskan Cretaceous coal to western U.S. Cretaceous coal.

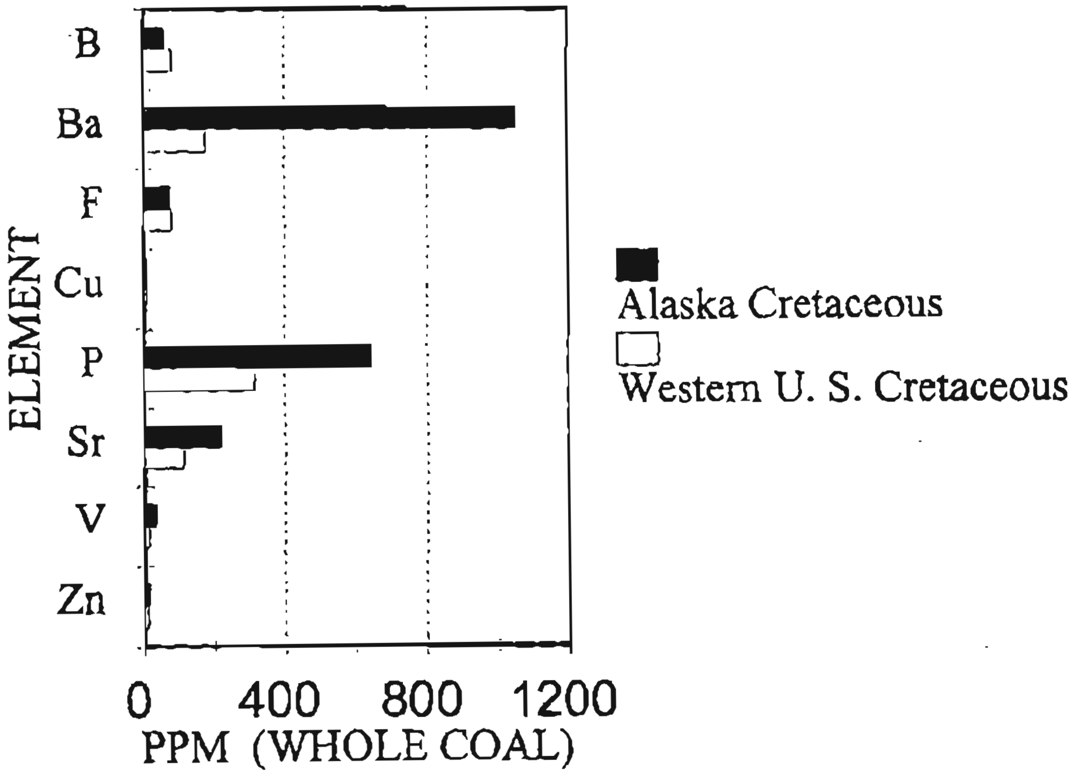

Figure 6. Comparison of mean element contents of B, Ba, F, Cu, P, Sr, V, and Zn for Alaskan Cretaceous coal to western U.S. Cretaceous coal.

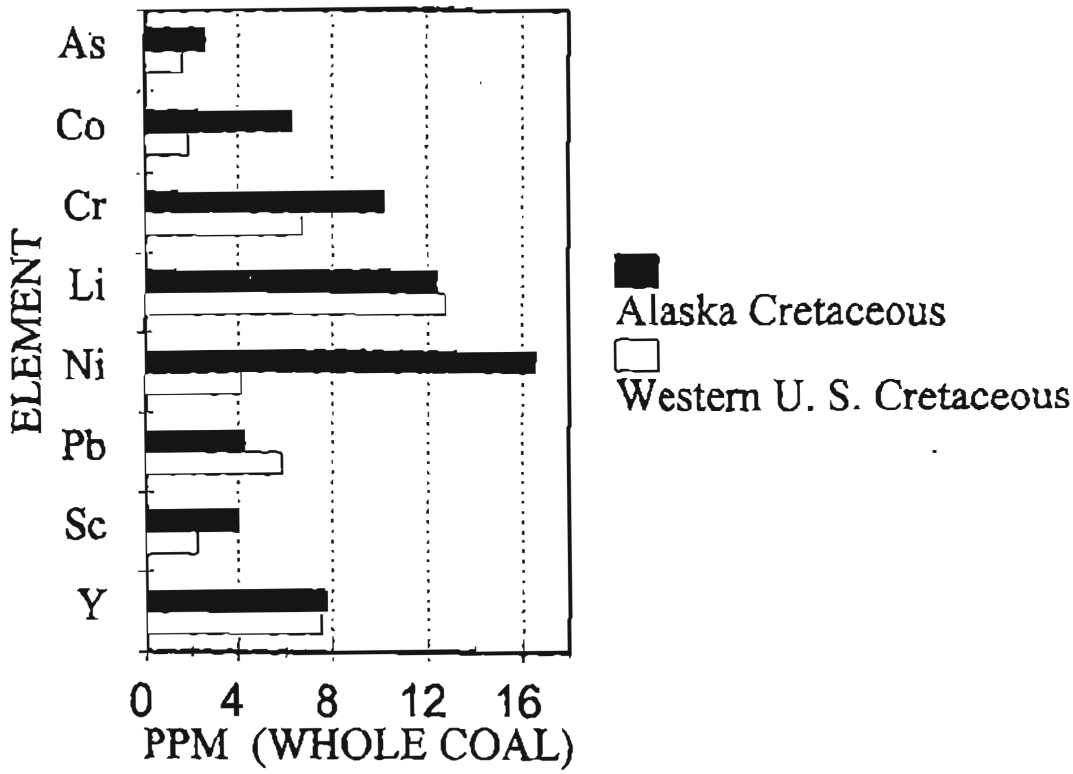

Figure 7. Comparison of mean element contents of As, Co, Cr, Li, Ni, Pb, Sc, and Y for Alaskan Cretaceous coal to western U.S. Cretaceous coal.

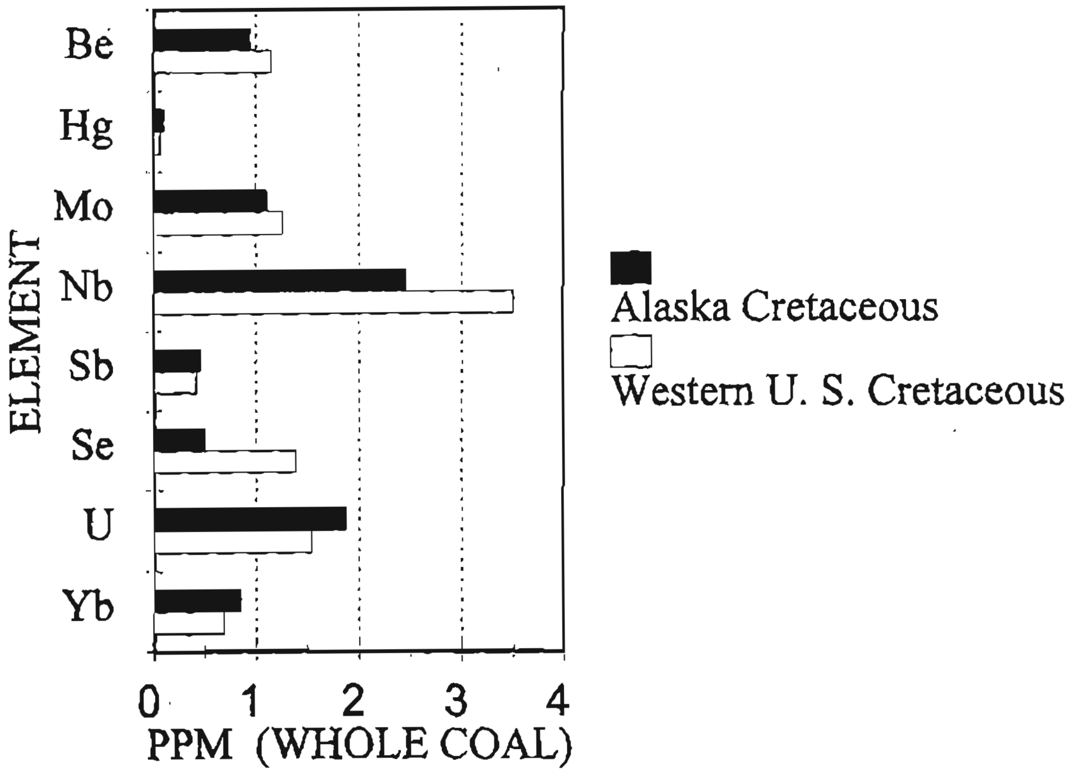

Figure 8. Comparison of mean element contents of Be, Hg, Mo, Nb, Sb, Se, U, and Yb for Alaskan Cretaceous coal to western U.S. Cretaceous coal.

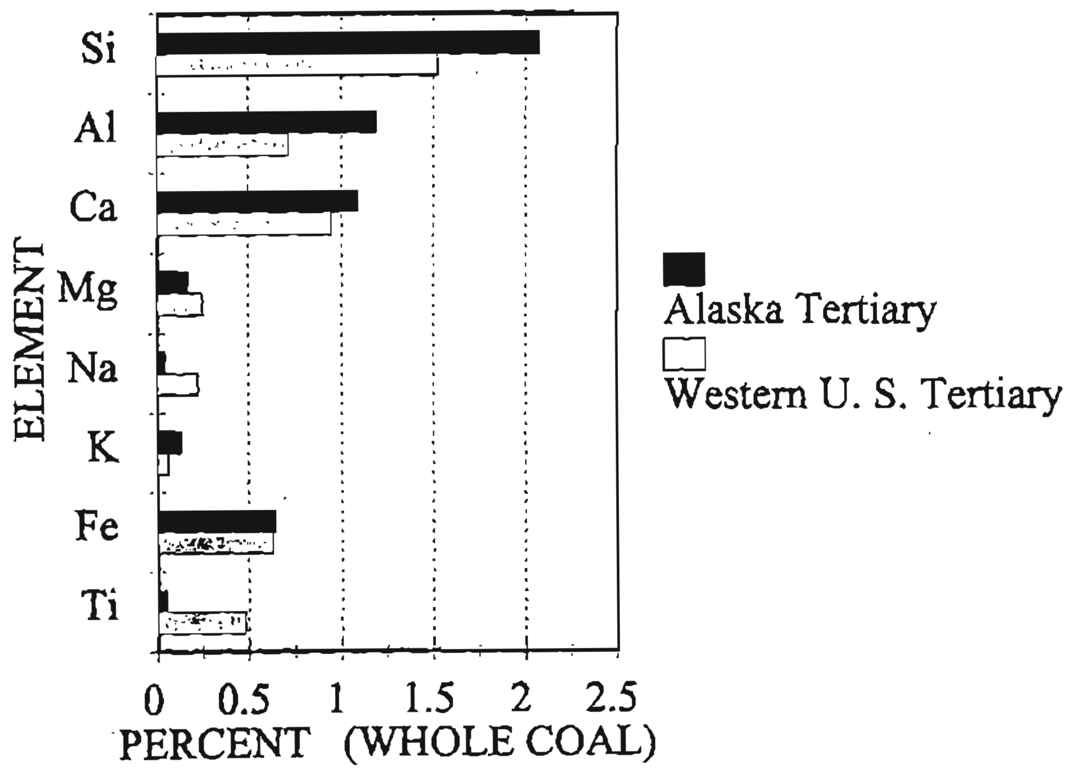

Figure 9. Comparison of mean element contents of Si, Al, Ca, Mg, Na, K, Fe, and Ti for Alaskan Tertiary coal to western U.S. Tertiary coal.

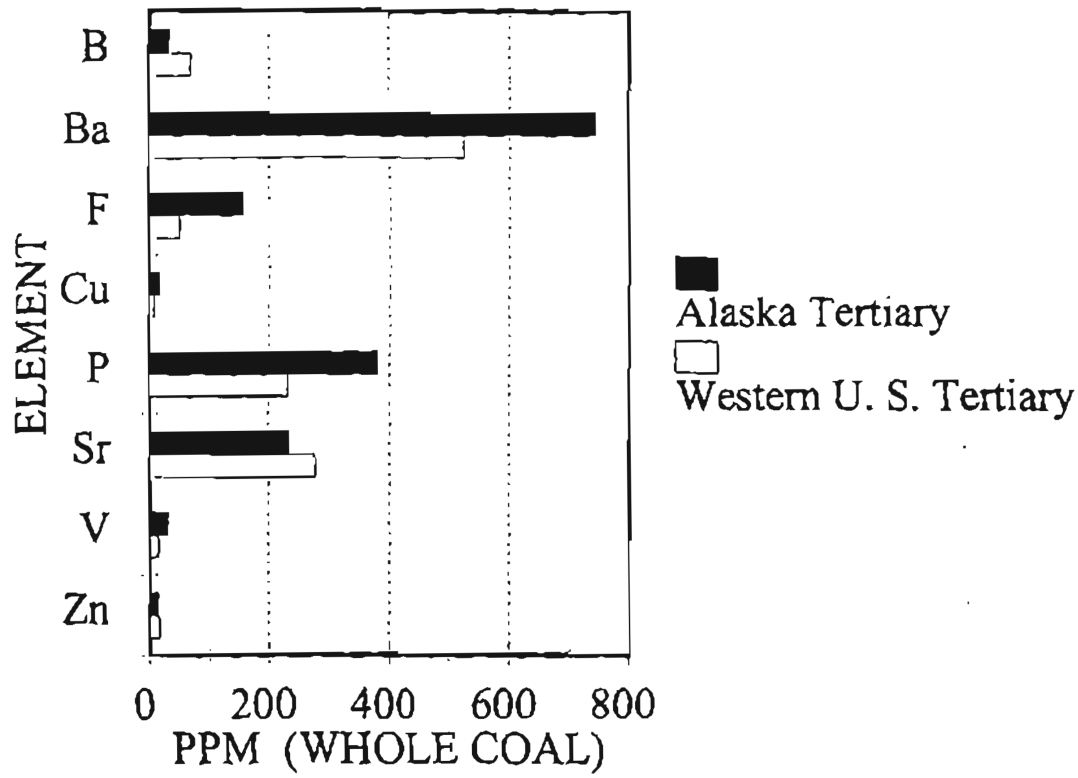

Figure 10. Comparison of mean element contents of B, Ba, F, Cu, P, Sr, V, and Zn for Alaskan Tertiary coal to western U.S. Tertiary coal.

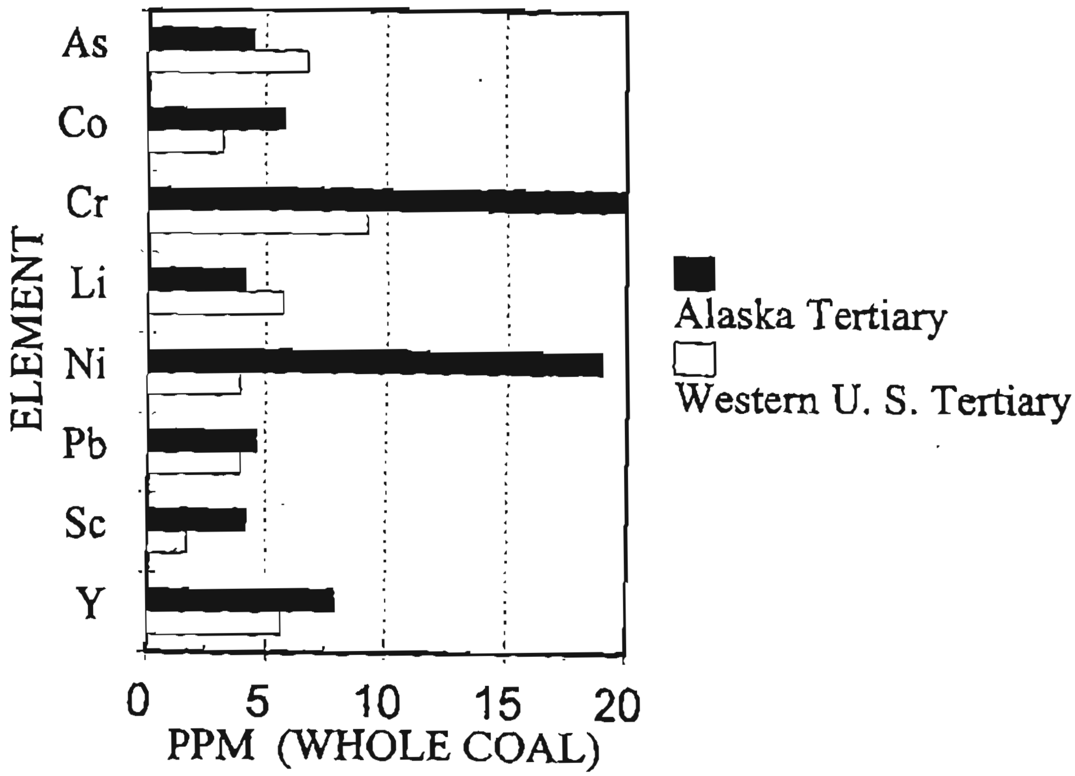

Figure 11. Comparison of mean element contents of As, Co, Cr, Li, Ni, Pb, Sc, and Y for Alaskan Tertiary coal to western U.S. Tertiary coal.

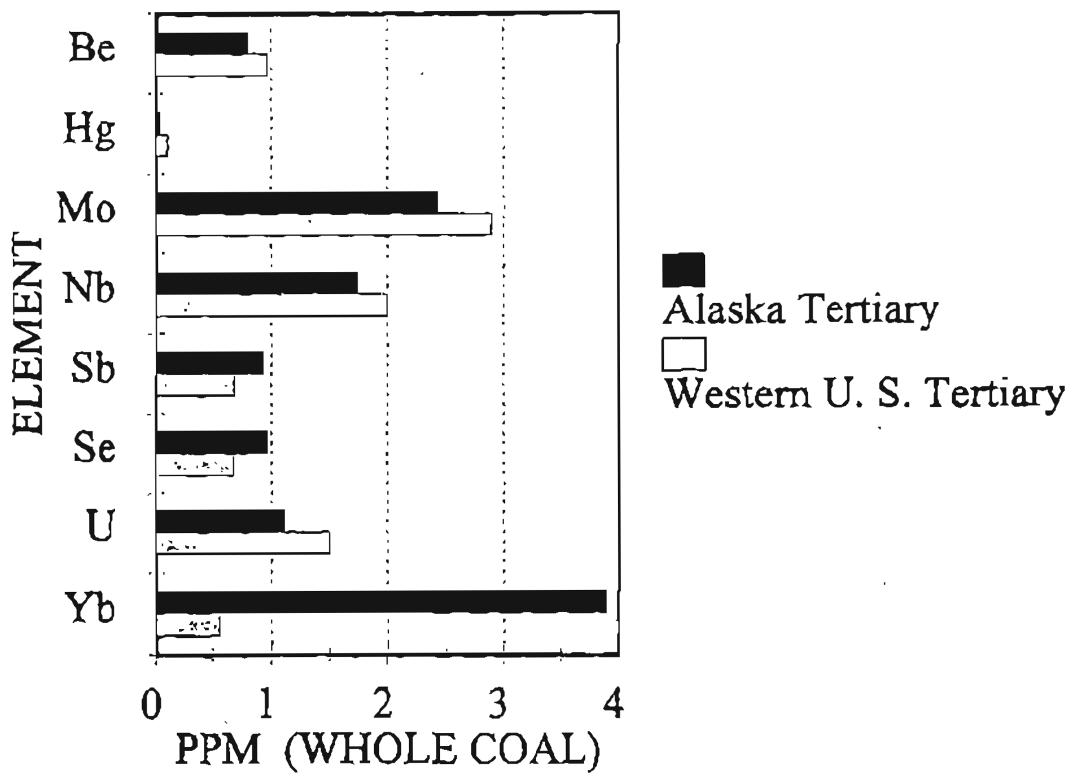

Figure 12. Comparison of mean element contents of Be, Hg, Mo, Nb, Sb, Se, U, and Yb for Alaskan Tertiary coal to western U.S. Tertiary coal.

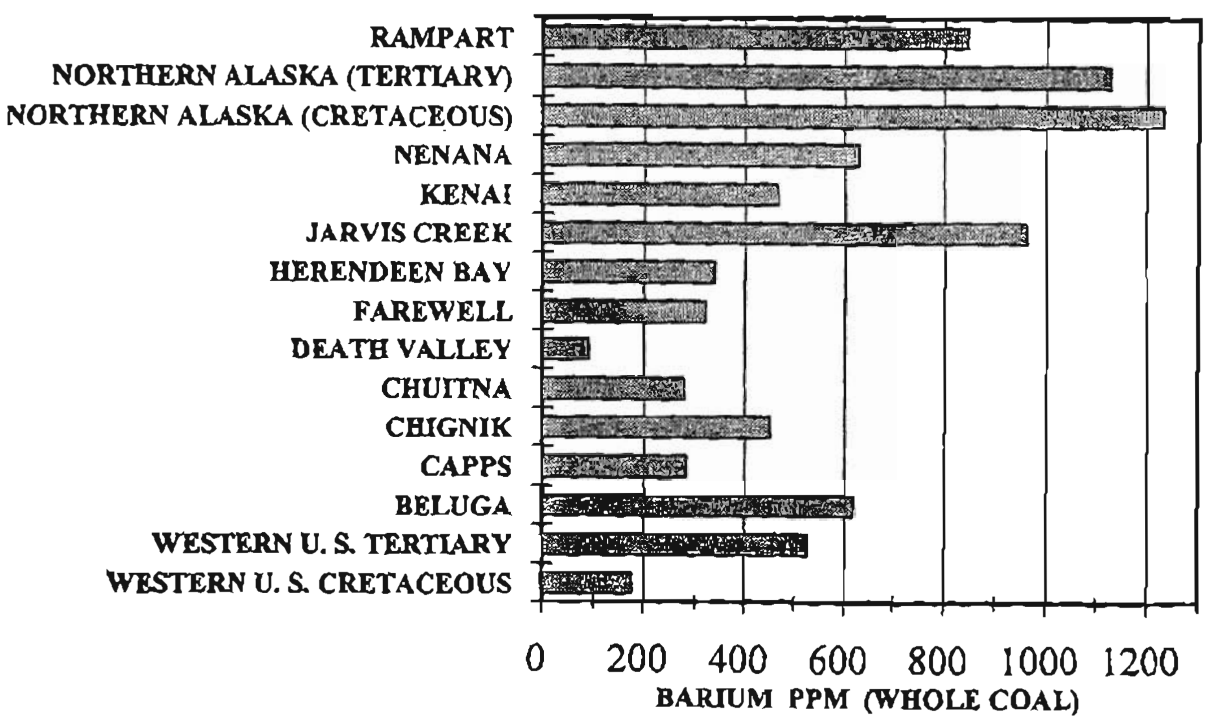

Figure 13. Distribution of mean Barium contents by coal field.

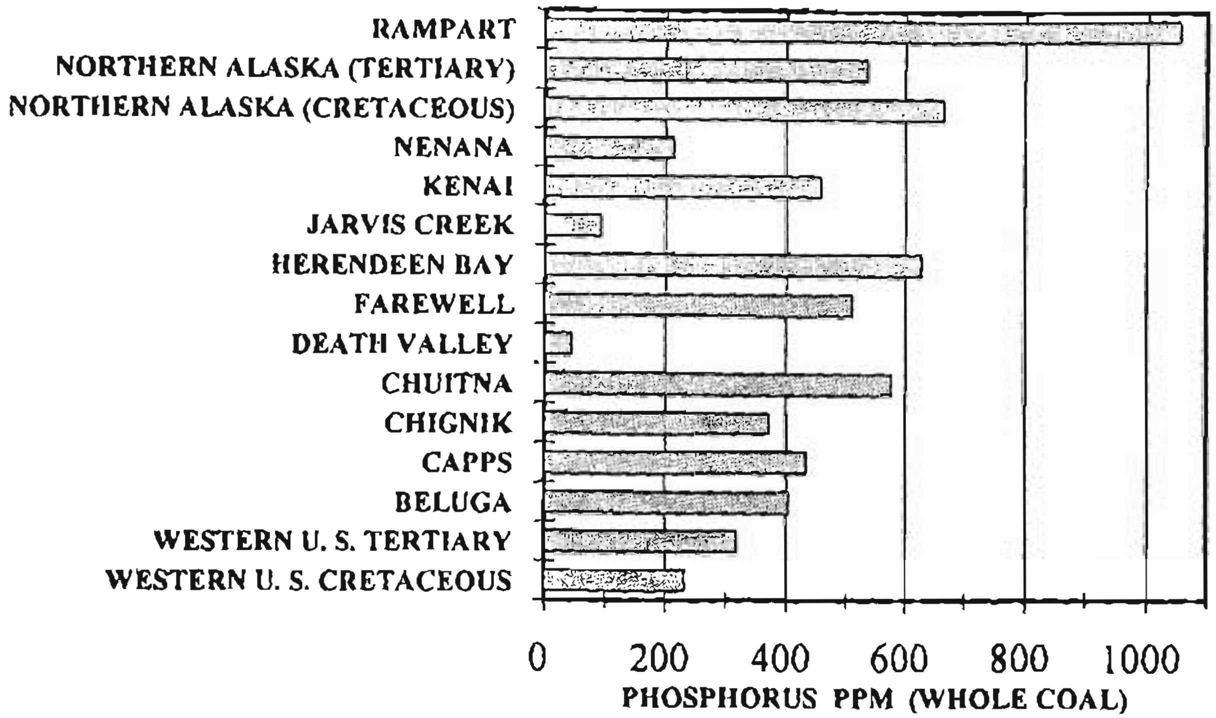

Figure 14. Distribution of mean Phosphorus contents by coal field.

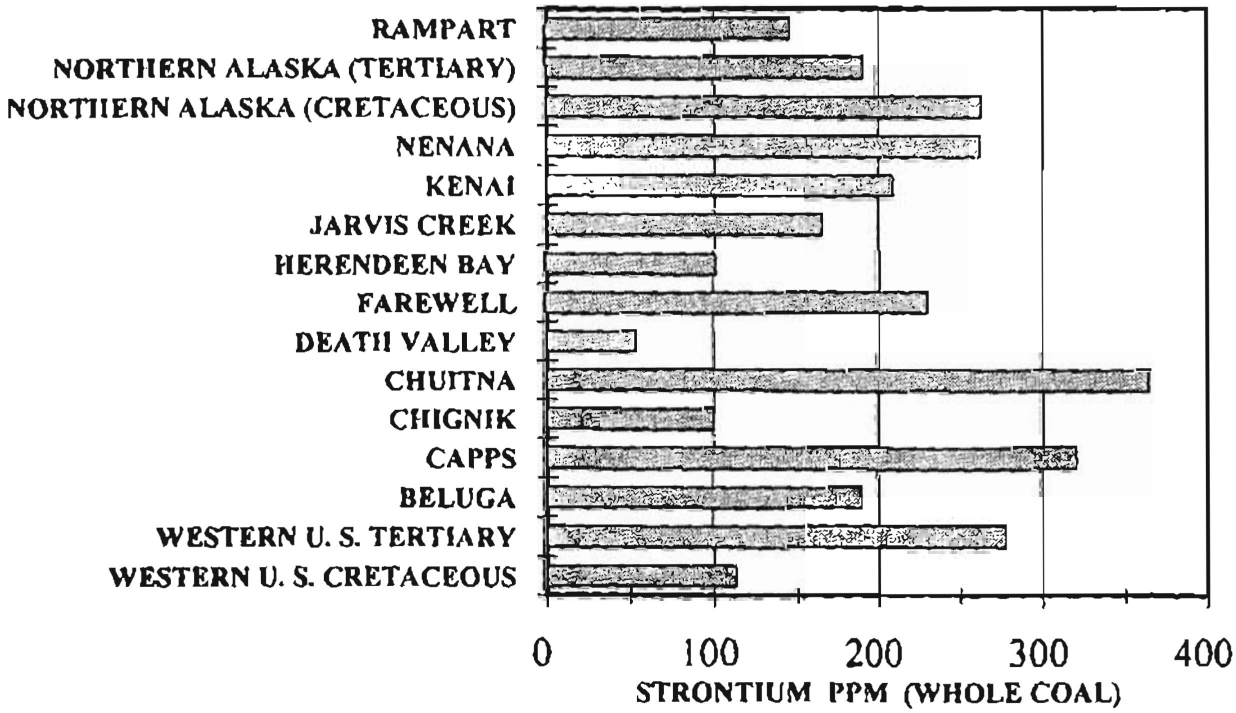

Figure 15. Distribution of mean Strontium contents by coal field.

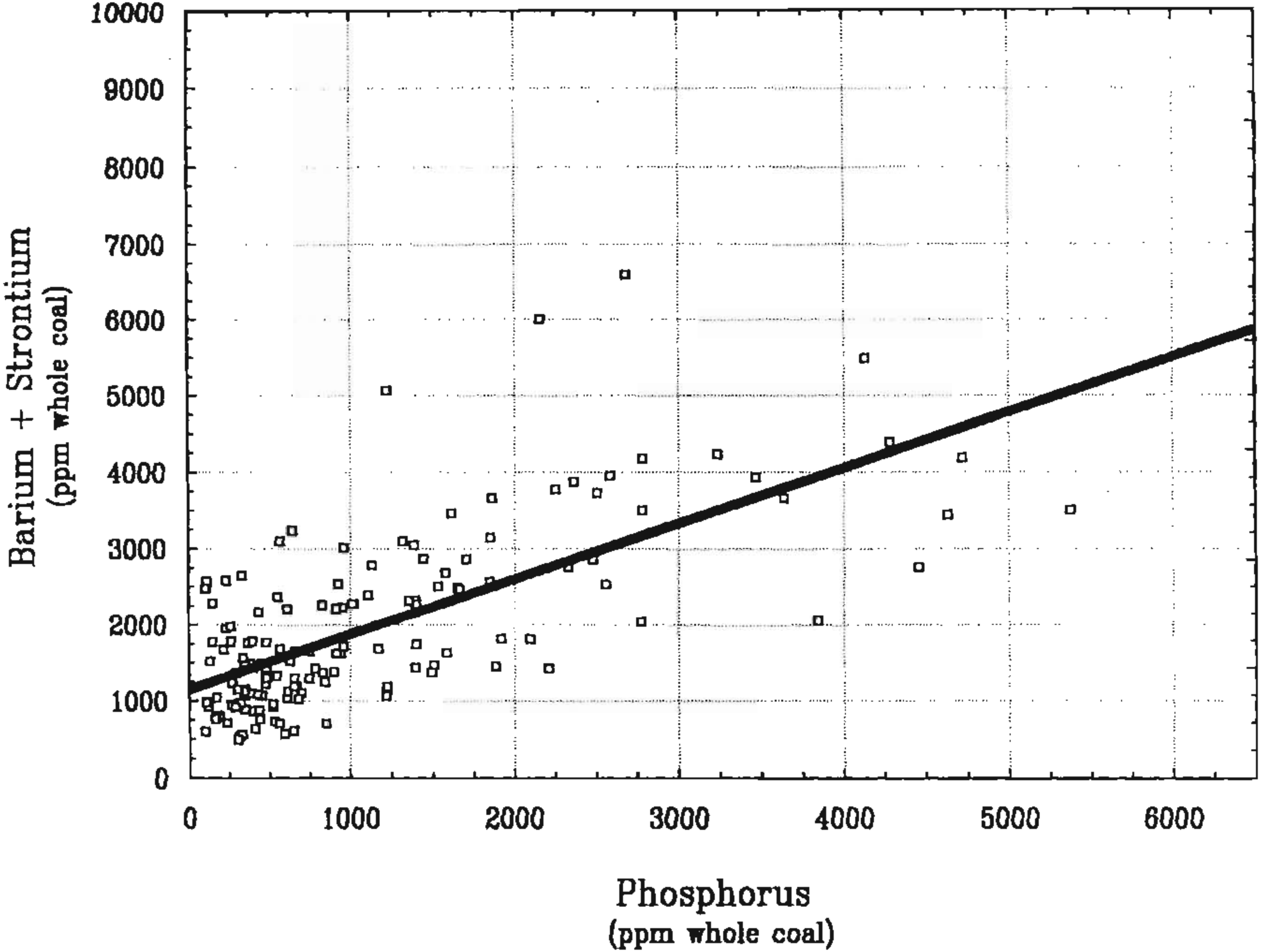

Figure 16. Distribution of Barium + Strontium versus Phosphorus for Cretaceous and Tertiary North Slope coals.

APPLICATION OF PFBC'S IN RURAL LOCATIONS

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ABSTRACT

The high cost of providing power in remote regions of Alaska through the traditional use of diesel electric generator sets has prompted the Alaska Energy Authority (AEA) to evaluate Pressurized Fluidized-Bed Combustors (PFBC's) as a replacement technology. The Morgantown Energy Technology Center (METC) of the U.S. Department of Energy (DOE) has been supplying AEA with data to further their analysis of the application of PFBC technology to power generation on village-scale systems. Starting with the results from studies managed by METC, a review of how modular PFBC construction could be applied to remote villages was undertaken. Results of this study have applications to remote micro-grid village sites in Alaska as well as to off-grid located in other regions of the world.

INTRODUCTION

PFBC plants provide a coal-fired, high-efficiency, combined-cycle system for the generation of electricity and steam. Coal is the most available source of fossil energy in Alaska and the world. PFBC's have demonstrated fuel flexibility, especially in the firing of low-rank coals. PFBC's use lime (calcium) based sorbents to obtain environmental air quality standards without back-end flue gas desulfurization. This form of emission control yields a dry waste product, which may be utilized as a construction material. There are additional environmental benefits, such as reduced nitrogen oxide (NO_x) emissions and reduced emissions of carbon dioxide due to increases in plant efficiency. These same increases in plant efficiency result in lower coal usage and, therefore, lower operating costs.

In remote, rural locations like many villages in Alaska, the use of local coal supplies could greatly reduce the cost of power, both electrical and thermal. Current power generation is based upon diesel generation sets. Cost of fuel oil in some remote location approaches \$1.32/liter (\$5.00/gal). Most of the fuel cost is due to transportation expense. The reduced fuel costs along with reduced size of PFBC components due to pressurization, modular construction, high-efficiency, and quick field erection can be extremely beneficial in remote locations.

Second-generation PFBC plants integrate a coal carbonizer (partial gasifier) with a PFBC. The carbonizer produces char and low-heat value fuel gas. The char with or without additional coal is burned in the PFBC. The flue gas from the PFBC and the low-Btu fuel gas from the carbonizer are combined and burned in a topping combustor to achieve high gas turbine inlet temperatures compatible with modern commercially available machines. Utility size second-generation PFBC systems will be capable of high-cycle efficiencies (45 percent, HHV) while burning coal in an environmentally acceptable manner.

DOE studies indicate that second-generation PFBC's can be competitive in sizes greater than 20 MWe where the cost of electricity exceeds \$0.07 per kWh. This same set of studies also showed that a 8.5-MWe one and one-half generation PFBC could be competitive with conventional power generation systems depending on site-specific conditions.

Alaskan Profile

Alaska is the largest of the 50 states which comprise the United States of America. The land mass is equal to the area covered by the entire area of the 16 east and gulf coast states, excluding Texas. The actual land area is 1,478,458 square kilometers and about a third is located above the Arctic Circle.

FIGURE 1

This large state has a small population of approximately 550,000 people. Two large cities, Anchorage and Fairbanks, account for one-half of the population; the rest is located in smaller cities and towns and in more than 350 remote villages. Village sizes range from tens to several thousands of inhabitants and tend to be situated along the state's many rivers. Much of the state territory has been set aside for national parks and wildlife refuges, which cover an area equal to 13 of the northeastern states from Maine to West Virginia as shown in Figure 1. In general, there are few developed land transportation networks. Alaska has limited roads, railroads, and has seasonally limited water transportation. A well-developed system of air transportation is used to move a considerable amount of goods and services used in the remote villages.

The remote communities suffer high electricity and/or power costs due to the high cost of delivered finished petroleum products. While Alaska has large remote crude oil reserves, it has a small refining capacity. This limited refining capacity is directed at transportation fuels, especially aircraft fuels. Refined fuel oil to operate remote village diesel generator sets must travel thousands of miles before reaching its final destination.

In addition to the high fuel costs, the remote villages encounter extremely high cost for field fabricated equipment or systems. The need to import skilled labor adds to the cost of field construction along with the remoteness of the villages and lack of land transportation. These high construction costs are similar to those found in many underdeveloped countries.

The remote rural communities cannot be economically connected into a large power grid or single large power station. Therefore, each village represents

TABLE 1. Alaska Energy Authority FY90 PCE Program Facts

Utilities served	96	Tariffs	
Communities served	165	(Residential up to 500kwh/month)	
Population	69,000	St. Paul	32.0
Customers served (total)	28,100	Arctic Village	70.0
residential	22,000	Tatitlek	100.0
commercial	5,000	AVEC (49 communities)	40.4
community facilities	1,100	McGrath	34.9
PCE payments	$16,000,000	Gwitchyaa Zhee Utility	31.8
		Mountain Village	40.4
MWH sold	293,000	Galena	28.0
Fuel used, liters	94,625,000	Kotzebue	18.7
cost	$23,000,000	Bethel	19.3
Non-fuel O&M costs	$41,000,000	Nome	17.8

Note: During this year fuel was flown into Akutan at $0.94 / liter a "micro-grid" electrical system, similar to those found in underdeveloped countries.

The AEA currently administers subsidy programs to defray the high cost of electricity in the rural villages. These subsidies are tied to Alaska's decreasing oil revenues. Therefore, the AEA is interested in electrical power generating systems which are not linked to the high cost of fuel oil. Coal-fired advanced power generation systems could prove to be a viable option to diesel-based power generation.

Many of Alaska's rural villages are close to known shallow coal deposits. In general, if coal is not found locally, a regional source near water transportation can be identified. The 1,440 billion metric ton coal resource of Alaska represents over 40 percent of the U.S. estimated coal resource. Only a small fraction of this abundant resource has been developed for use. The major portion of Alaska's reserve is subbituminous coal. Large deposits of bituminous coal have also been found. Generally geological surveys indicate that Alaskan coal reserves contain less than 0.5 percent sulfur.

PFBC System for Alaska

DOE/METC is chartered to study and further the commercial development of fossil fueled, advanced energy systems. METC's initial discussions with the AEA reviewed a number of advanced coal-fired technologies. The fluidized-bed combustor's (FBC's) ability to control sulfur dioxide (SO_2) and NO_x emissions without scrubbers while producing a dry ash focused further discussions on atmospheric fluidized-bed combustors (AFBC's) and PFBC's. Fuel flexibility and possible construction use of the dry ash further enhanced FBC's acceptance.

PFBC's high-efficiency combined-cycle operation results in lower overall emissions per unit of power produced. This not only causes reductions in sulfur and nitrogen emissions but also reduces the amount of carbon dioxide emitted. Based upon efficiency and environmental concerns, PFBC's would be the preferred technology as shown by the comparison of utility size (300 MWe) systems in Table 2.

Predicted capital costs of PFBC's are compared to other technologies in Figure 2. This presentation indicates that PFBC's have a cost advantage over other technologies. Natural gas fired, combined-cycle, gas turbines were not considered in this analysis based upon the assumption that it was not available, not available

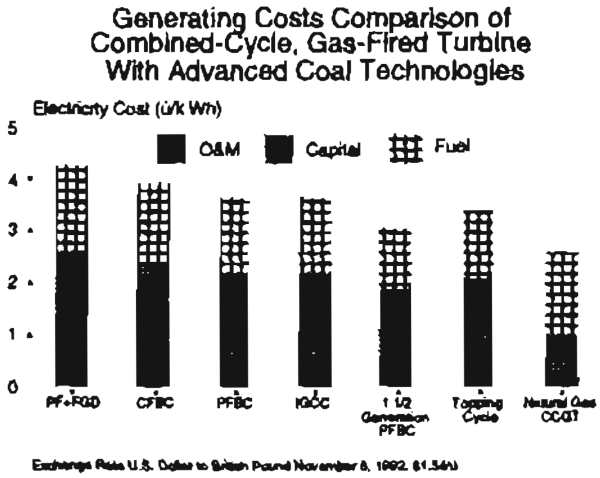


FIGURE 2

TABLE 2
***PC/FGD plant matched to NSPS—2/90.**

Performance Summary for PFBC Systems	PC/FGD*	Self-Generation PFBC	First-Generation PFBC	1-1/2 Generation PFBC	Second-Generation PFBC
Net Efficiency, %	~36	~36	~40	~46	~45
Power Output Gas Turbine, %	0	0	~22	44 to 79	40 to 60
Power Output Steam Turbine, %	100	100	~78	21 to 56	60 to 40
Gas Turbine Inlet Temperature, °C	N/A	~454	~871	1,149 to 1,288	1,149 to 1,288
Ca/S Molar Ratio	1.6	1.6	1.75	1.75	1.75
Sulfur Retention, %	90	90 to 98	90 to 95	95	90 to 95
NO_x Emission, gm/MM joules	0.26	<0.49	0.04 to 0.12	0.04 to 0.12	0.04 to 0.12
Particulate Emission, gm/MM joules	0.013	<0.013	0.004 to 0.013	0.002 to 0.009	0.004 to 0.013
Excess Air, %	20	15 to 30	25	96	25 to 124
Fluid-Bed Temperature, °C	N/A	~871	~871	~871	~871

in large quantities, or the cost was not favorable. METC and AEA reviewed both first- and second-generation PFBC systems as defined below.

First-Generation PFBC

First-generation PFBC is an extension of the atmospheric fluidized-bed concept that operates at pressures between 7 and 14 atm. At these higher pressure levels, expansion of the boiler flue gases across the gas turbine provides not only the energy needed to drive the compressor but an additional amount that can be used to generate electricity.

In this concept, steam production is split between in-bed PFBC heat transfer surface and economizer located after the gas turbine as shown in Figure 3. While the fluidized bed operates at ~1,600 °F, flue gases are not cooled before entering the hot gas cleanup system or turbine. The higher gas temperature increases gas turbine output and thus becomes a net electrical power generator. This 1,600 °F gas at a higher gas pressure increases the potential for hot gas cleanup system problems and turbine fouling.

TABLE 3. Comparison of System Efficiencies for Small Power Plants

Plant	Fuel	HHV Efficiency
Conventional Boiler	Coal	20-25 percent
Gas Turbine	Oil/Gas	18-28 percent
1-1/2 Generation PFBC	Coal + Oil/Gas	25-30 percent

The first-generation concept is approaching commercialization with plants being constructed worldwide. The American Electric Power's Ohio Power Company is operating the 79-MWe Tidd demonstration plant at Brilliant, Ohio. DOE is supplying a portion of the funds for the Tidd demonstration plant under the Clean Coal Technologies program.

Second-Generation PFBC

METC is actively involved with the development of the second-generation PFBC. This concept attempts to utilize the full power producing potential

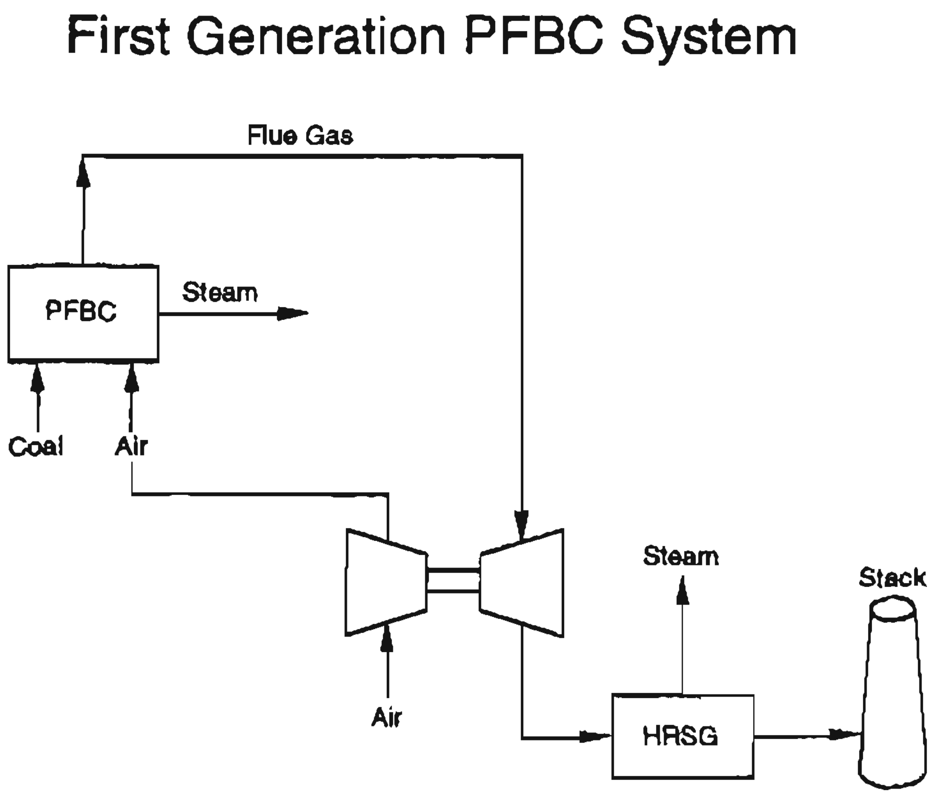


FIGURE 3

Second Generation PFBC System

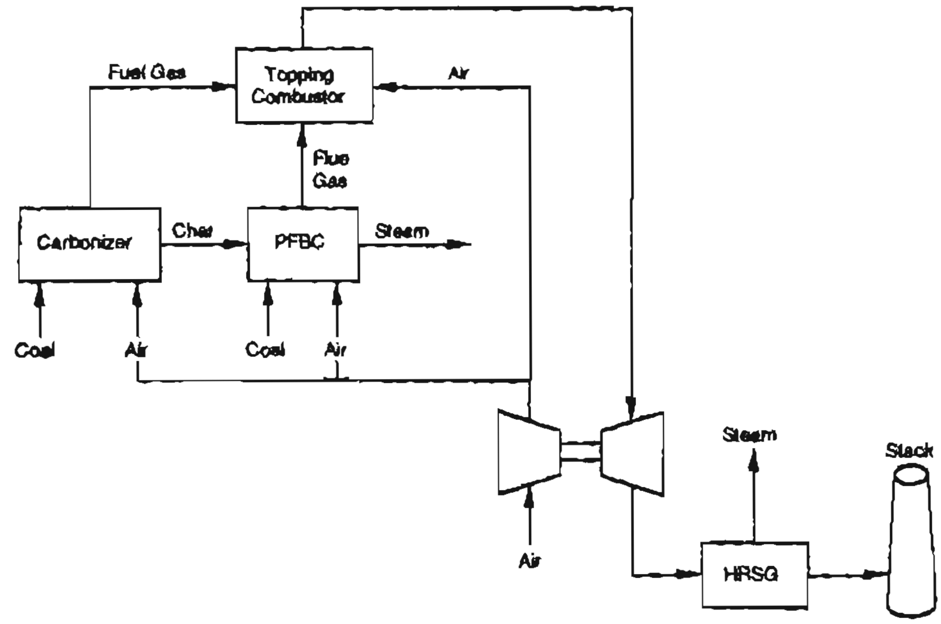


FIGURE 4

of modern gas and steam turbines in coal-fired, combined-cycle plants. This is accomplished by increasing the temperature of the gases entering the gas turbine via a topping combustor as shown in Figure 4.

Coal is fed to a pressurized fluidized-bed partial gasifier that produces a low-Btu gas and char. Char is then burned in a PFBC, and the flue gas is cleaned of particulate and sent to the topping combustor. Low-Btu fuel gas from the partial gasifier is also cleaned and piped to the topping combustor. In the topping combustor, any air required to complete combustion is mixed with the fuel gas and the flue gases. The topping combustors in second-generation systems are designed to achieve turbine inlet temperatures of 2,100 to 2,500 °F, consistent with the high power output of modern gas turbines.

Steam is produced from heat transfer surfaces located in the PFBC and a heat recovery steam generator (HRSG).

Second-generation studies by both Foster Wheeler Development Company (FWDC) and the M.W. Kellogg Company have shown that the coupling of partial gasification and char combustion makes an optimum balance between the steam and gas turbine cycles possible. From this, system efficiencies approaching 45 percent on a higher heating value basis result. FWDC is continuing work on their second-generation concept through pilot plant component and integrated system test programs.

The first- and second-generation PFBC's can function successfully as power generating systems in Alaska. However, the AEA believed the second-generation system was too advanced at this time. A first-generation system could be used, but there were concerns about its ability to approach the load following capabilities of the diesel generator sets currently in use. Because of the remoteness of Alaskan villages and the severe weather conditions, the AEA wanted dual-fuel operating capability and some duplication of generating capacity. A one and one-half generation PFBC could meet the AEA's needs.

A one and one-half generation PFBC system substitutes a premium fuel such as oil or natural gas in place of the low energy fuel gas generated by the carbonizer in the second-generation system. This substitution of premium fuel negatively impacts operating costs while reducing capital costs. The substitution of premium fuel should increase the load following capabilities of the one and one-half generation PFBC to approximate those of a diesel generator set. In emergency situations, both gas turbine and the PFBC could be fired on oil. If necessary, the gas turbine could be uncoupled from the PFBC and fired on oil thus giving the plant internal equipment redundancy. Alone the gas turbine could generate between one-third and one-half of the plant's normal power output.

1 1/2 Generation PFBC System

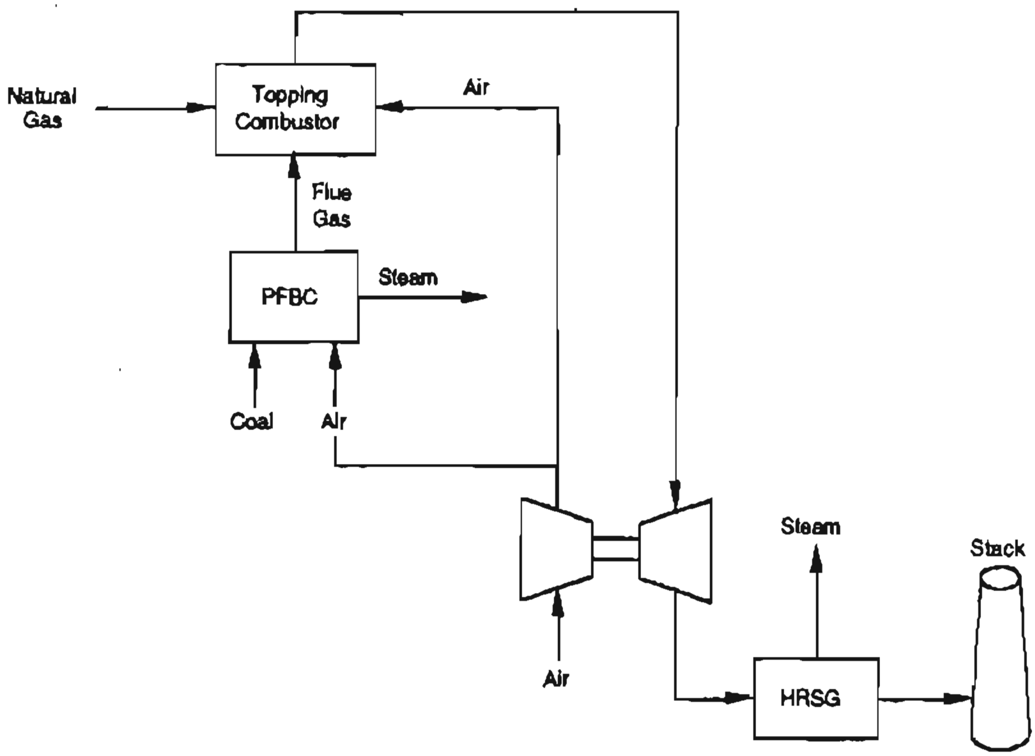


FIGURE 5

To ensure the load following potential, a circulating one and one-half generation PFBC system shown in Figure 6 was selected.

4-MWe Plant

The AEA indicated that a plant having an output of approximately 5 MWe was of interest. Based on available gas turbines and using information from previous studies, equipment components for a 4-MWe system were sized as shown in Figure 7.

Again, using information developed by the U.S. DOE, two other small, advanced PFBC power systems were configured. The cost summary shown in Table 4 was then prepared based upon these system configurations.

Transportation of PFBC Modules

Alaska's remote villages suffer extremely high field erection cost due to imported labor. Modular construction methods used to fabricate PFBC's will reduce field erection costs. Further modular construction of PFBC components will help overcome transportation problems. Alaska's lack of roads, railroads, and seasonally limited, as well as, shallow draft water transportation creates major challenges. The use of aircraft to move the PFBC modules could resolve the transportation challenge. Figure 8 illustrates that the components required for the 4-MWe second-generation PFBC plant can be airlifted to remote villages. Limited calculations indicated that PFBC plants up to 30 MWe may be airlifted if necessary.

TABLE 4
Cost Summary k$, 4 MW Plant

Cost Item	First Generation PFBC	Second Generation PFBC	1-1/2 Generation PFBC
Equipment	$8,900	$8,636	$7,708
Material	$2,250	$1,702	$1,553
Direct Labor	$3,007	$3,653	$3,244
Indirect Labor	$233	$255	$247
Bare Erected Cost	$16,543	$14,249	$13,028
Process Contingencies	$852	$873	$666
Project Contingencies	$2,302	$2,503	$2,269
Total Plant Cost	$23,131	$19,194	$17,398
TPC, $/kW	6,608	6,398	4,093

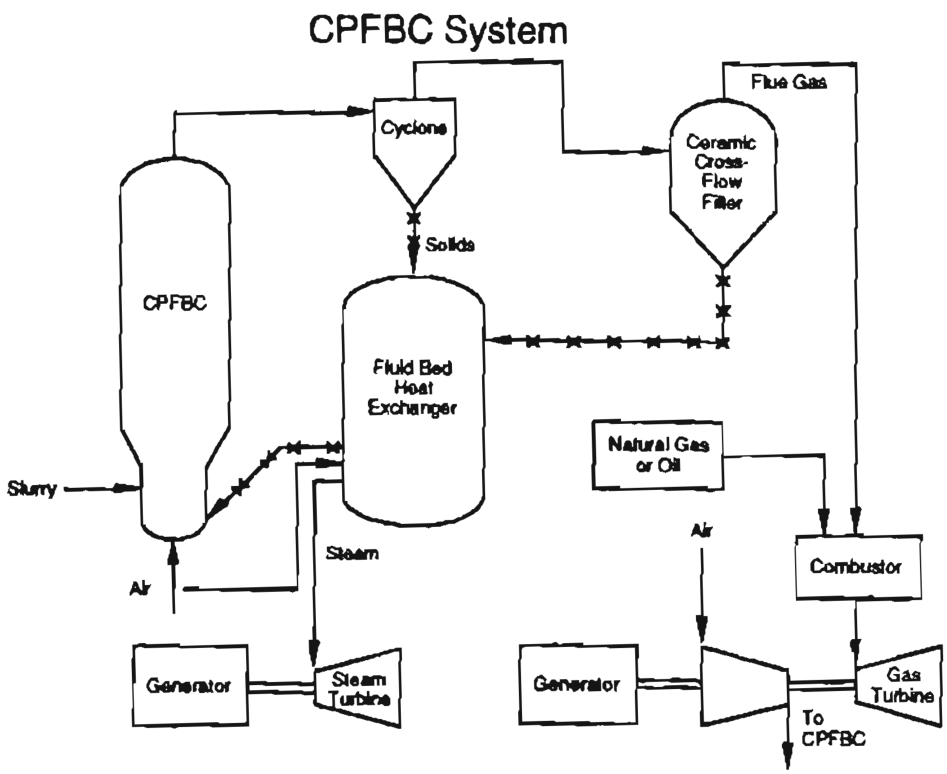


FIGURE 6

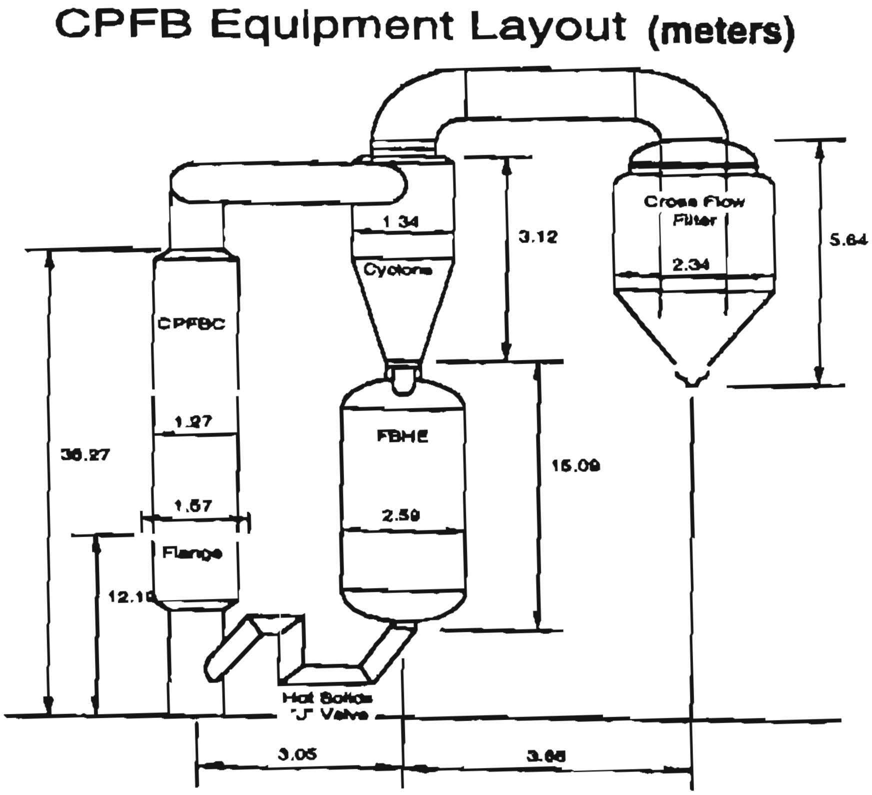
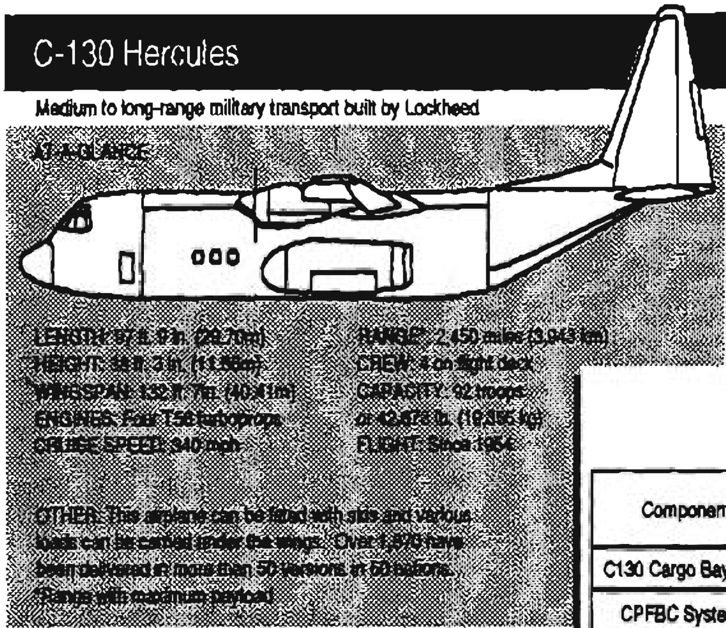


FIGURE 7

Airlifted PFBC's



Shipping Requirements

Component	Length (m)	Width (m)	Height (m)
C130 Cargo Bay	12.5	3.14	2.74
CPFBC System			
CPFBC	36.27 [1]	1.58 O.D.	
Cyclone	3.12	1.34 O.D.	
Filter	5.64	2.39 O.D.	
FBHE	15.09 [2]	2.59 O.D.	
Carbonizer System			
Carbonizer	13.66 [2]	1.93 O.D.	
Cyclone	3.66	1.77 O.D.	
Filter	5.1	2.2 O.D.	

[1] CPFBC to be shipped in three sections of 12.2 m each

[2] Head will be removed to reduce length to within limit

FIGURE 8

CONCLUSIONS

PFBC's provide the small remote rural village micro grids with the same benefits as the large-grid utility. Both large and small grids can obtain PFBC capital and operating cost saving from the following:

- Use of local coal resources and fuel flexibility.
- Emission control of NO_x and SO_2 without scrubbers.
- Dry sulfur waste product, as $CaSO_4$.
- High-efficiency combined-cycle operation, reduced CO_2 emissions.
- Reduced size, modular construction, quick field erection.

The airlifting of PFBC components probably has limited application, but the possibility demonstrates that modular advanced coal-fired PFBC's can be transported into remote locations. Shallow draft barge transportation is probably the most practical method for moving PFBC parts. Whether the remote village is in Alaska or Somalia, the modularity of PFBC components makes environmentally acceptable coal-fired power generation available worldwide.

Site conditions, especially the size of the village or micro grid will dictate the type of PFBC to be installed, but the one and one-half generation plant appears to have advantages in the areas of load following and increased availability via internal equipment redundancy. The one and one-half generation PFBC's major disadvantage is that it does not fully remove the small village's dependency on imported oil.

The small PFBC will not suffer from scale-up uncertainties like the large utility units. The small system needed in Alaska and other micro-grid locations around the world closely match the size of the major PFBC test facilities.

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