Province of British Columbia
Ministry of Energy, Mines and Petroleum Resources

ERRATA

COAL IN BRITISH COLUMBIA
PAPER 1986 - 3

Page 5 - Table 1.2 - Representative value of British Columbia coal production 1978 - 1984. The Headings for the columns "THERMAL" and "METALLURGICAL" have been transposed.

Page 61 - Paragraph three -
"Typical coal strength__" should read "Typical coke strength__".

November 27, 1986

COAL IN BRITISH COLUMBIA

PAPER 1986—3

Ministry of Energy, Mines and Petroleum Resources
Hon. Jack Davis

VICTORIA
BRITISH COLUMBIA, CANADA

SEPTEMBER 1986

Canadian Cataloguing in Publication Data

Main entry under title:
Coal in British Columbia

(Paper, ISSN 0226-9430 ; 1986-3)

2nd ed. -- Foreword.
Previously issued by: British Columbia, Coal Task Force, Technical Committee.
Issued by Geological Survey Branch.
Bibliography: p.
ISBN 0-7718-8527-X

1. Coal - British Columbia. 2. Coal mines and mining - British Columbia. 3. Coal trade - British Columbia. I. British Columbia. Ministry of Energy, Mines and Petroleum Resources. II. British Columbia. Geological Survey Branch. III. British Columbia. Coal Task Force. Technical Committee. Coal in British Columbia. IV. Series: Paper (British Columbia. Ministry of Energy, Mines and Petroleum Resources) ; 1986-3.

HD9554.C33B75 1986 333.8'22'09711 C86-092153-0

FOREWORD

This is the second edition of the 1976 publication of *Coal in British Columbia.* It has taken a number of years to complete because of shifting priorities and constrained resources. Thus some sections may be somewhat dated as it goes to print, but overall we believe it to be a valuable production.

The Ministry wishes to thank those in government, industry, and university who contributed to this edition of *Coal in British Columbia.*

LORNE E. SIVERTSON
Assistant Deputy Minister
Mineral Resources Division

ACKNOWLEDGMENT

The Ministry of Energy, Mines and Petroleum Resources gratefully acknowledge the significant contributions of the following:

R. Gilchrist and J. Thompson
Ministry of Energy, Mines and Petroleum Resources

D. E. Pearson
David E. Pearson & Associates Ltd.

H. Dennis
Ministry of Energy, Mines and Petroleum Resources

P. L. Kitteridge
Associated Economic Consultants Ltd.

B. J. M. Parrot
Ministry of Industry and Small Business Development

E. T. Pietraszek
Ministry of Industry and Small Business Development

G. W. Scobie
Ministry of Industry and Small Business Development

J. D. McDonald
Ministry of Energy, Mines and Petroleum Resources

R. L. Crook
Ministry of Energy, Mines and Petroleum Resources

R. L. Evans
The University of British Columbia

Cynthia Hawksworth
Ministry of Municipal Affairs

and, in addition, the many individuals in the ministry who have assisted in the production of this volume.

A. MATHESON
Coordinator

Summary

This report outlines the coal resources of British Columbia, as currently known, and examines factors which might influence the development of the Province's coal industry over the next 20 years.

Coal was the major source of energy in the 19th century and the early years of the 20th century; coal mining in British Columbia grew, in response to energy demand, into a thriving industry during this period. However, with the discoveries of oil and gas, the industry here, as elsewhere, experienced a steady decline leading to near extinction by the late 1950's. The resurgence of the coal industry to its present position came with recognition of the excellent coking properties of much of the coal in the East Kootenays and the potential market for such coal in Japan for that country's rapidly expanding steel industry. Coal now accounts for \$500-\$600 million of the Province's mining revenues and now vies with copper for the position of the single most important mineral produced in the Province.

Escalating prices and forecasts of dwindling supplies of oil and natural gas have led, worldwide, to a renewal of interest in coal. Coal comprises almost 50 per cent of the planet's fossil fuel resource, and must assume greater importance in the future, not only in its traditional roles as a source of coke and thermal energy but as a raw material for synthetic fuels and for the organic and heavy chemicals industries. Already, several large-tonnage synthetic ammonia plants in various countries are based on the production of hydrogen from coal, and major plants for the production of substitute natural gas (SNG) from coal are in the planning stages in the United States. A preliminary review of the manufacture of substitute natural gas from a sub-bituminous British Columbia coal has been made and is discussed in this report.

Forecast demands for British Columbia coking or metallurgical coal over the next 20 years are considered to depend on a number of assumptions, including the ability of the United States to continue exporting large amounts of coal; continued growth of the world's, and particularly Japan's, steel industry; and continued requirements for such coal despite anticipated developments in iron-making and coke-making technology. In the latter regard it is concluded that the production of coke by advanced techniques, such as hot charging to conventional coke ovens, and by formcoking of coals traditionally regarded as non-coking, will assume growing importance in the period under review. British Columbia coals from both the Kootenay and Northeast regions are of such quality that their market potential is not likely to be affected significantly by modifications of conventional coking practices. Formcoking, however, will ultimately (beyond the period under review) cause the distinction between thermal and metallurgical coals to become blurred. Indications of this development are already apparent in the shipping of "oxidized" coal, normally considered a thermal coal, to Japan for use in one of the advanced coke-making techniques. Taking these factors into account, the potential demand for metallurgical coal is projected to grow from the current 18 million annual tonnes to 35 million annual tonnes by 1990.

The demand for thermal coal for the generation of electricity and gas may increase from the current 4 million annual tonnes to as much as 75 million annual tonnes. The development of such a demand is predicated on the assumptions that large amounts of electricity will be produced by the combustion of Hat Creek coal and also that the production of 23 million cubic metres per day of SNG will be achieved by gasifying 14 million annual tonnes of sub-bituminous coal.

The inferred and indicated resources of the Province are estimated at this time to be approximately 43 000 million tonnes. The **measured** reserves of coal have been calculated as 1500 million tonnes of metallurgical coal *in situ* and 1240 million tonnes of thermal coal *in situ*. Assuming an over-all clean (marketable) coal recovery of 60 per cent, the measured reserve of metallurgical coal in the Province is calculated 900 million tonnes. However, ongoing exploration programs continually increase these figures.

Currently four British Columbia shipping terminals, with a total nominal capacity of 40 million annual tonnes, handle coal exports: Roberts Bank on the Lower Mainland, Neptune Terminals in North Vancouver, Pacific Coast Terminals in Port Moody, and Ridley Island at Prince Rupert. The planned ultimate capacity of 24 million tonnes for Ridley Island will be more than adequate to handle the projected 12 million annual tonnes of coal produced in the Northeast by 1995.

Maximization of the recovery of the coal resource, particularly from underground mines, will require first the application and development of advanced mining technologies such as hydraulic mining. Previous experience with the difficult mining conditions encountered in the Rocky Mountain region indicates that major efforts will have to be made to obtain detailed knowledge of the geology of the coal deposits and to develop techniques for the early detection of roof instabilities and roof control. The second factor in maximizing recovery of the resource is concerned with the beneficiation of the raw coal to a marketable product. Most of the metallurgical coals in the Southeast and Northeast regions appear to beneficiate easily. However, Southeast coals tend to have a relatively high ash content at economic recovery levels. This topic is of considerable significance and it is noted that there is at present no active research or teaching activity in the Province in coal beneficiation. Maximization of the return on Provincial coals in the world market will require increased knowledge of their properties and of their position relative to those of other countries. Constant monitoring of the progress of coking technology will be required to verify that future markets develop as forecast. The developments in other areas of coal-utilization technology, such as gasification, also will require close attention to ensure that the production of gas from coal can be applied in British Columbia when the need arises. To this end the implementation of research and development in both gasification and carbonization at the Provincial level is suggested.

To meet future coal demand, large-scale coal mine developments must inevitably occur. These will have considerable impact on the natural, social, and economic conditions in their respective regions. In recognition of this consequence, a comprehensive set of guidelines has been prepared to assist coal companies in the preparation of environmental impact assessments of their proposed developments. These guidelines are described in the report.

TABLE OF CONTENTS

TABLE OF CONTENTS — *Continued*

TABLE OF CONTENTS — *Continued*

TABLE OF CONTENTS — *Continued*

APPENDICES

LIST OF ILLUSTRATIONS

LIST OF ILLUSTRATIONS — *Continued*

TABLES

COAL IN BRITISH COLUMBIA

I. INTRODUCTION

1.1 HISTORICAL

Coal, as is well known, was the energy raw material for the Industrial Revolution, generating steam for motive power, and coke for the production of pig iron. In North America, the revolution began in the 1860s, and with its coming, coal production increased dramatically. In the United States, for example, coal production grew from 18 million tonnes in 1860 to 450 million tonnes by 1910, to supply 90 per cent of the demands of the energy market. In 1950, coal still accounted for 40 per cent of the United States energy consumption, but by the 60s, coal's share had fallen to 23 per cent, and by 1972 to 17 per cent.

An essentially similar energy source growth pattern developed in Canada. The change in the relative position of coal as a source of energy in both countries has been due less to a decrease in the production of coal than to massive increases in the use of gas and oil. These latter fuels are not only cleaner in direct use but are better adapted to the major end uses—transportation, space heating, and industrial processing. The uses of coal have thus come to be confined principally to power generation and coke production.

For power generation, coal's long-term future is bright despite competition from nuclear fuels. Recent projections for the United States, for example have coal use in electricity generation increasing to the year 2000 by more than 50 per cent over current levels, at which point it will be supplying almost 60 per cent of all electricity produced. This compares to 22 per cent for electricity generated by nuclear power. In 1973 coal supplied 47 per cent of U.S. electricity production, nuclear 4 per cent. The increase in the use of nuclear fuels for power generation has been and will continue to be rapid in development projects underway in OECD (Organization of Economic Cooperation and Development) countries. Nevertheless, it is a fact that OECD coal use between now and the year 2000 will increase by virtually the same amount as that for nuclear use, in terms of energy generated in coal equivalent units.

Coal represents the largest fraction of the world's total fossil energy reserves and with the forecast shortfalls of gas and oil supplies, an expanding worldwide production of coal can be expected. Indeed, in Canada, production has been expanding since 1960. A steady decline from a peak in 1940 was reversed with the development of an export market for coking-coal, although it was not until 1966 that production reached the levels attained in 1911. There has been a steady growth in output ever since, to a current level of about 60 million tonnes annually.

In British Columbia, the earliest development of coal mining was on Vancouver Island, in response to the demands created by ships for fuel. Vancouver Island indeed has a lengthy history of coal mining dating back to the discovery of coal at Suquash near Port McNeill in 1835. Production from this coalfield and those at Nanaimo and Comox amounted to 65 million tonnes between 1849 and 1914. Most of this coal was used for thermal purposes, either for residential and commercial heating or for "bunkering" ships; uses which declined rapidly in the face of competition from oil. Small quantities of coal were carbonized in a plant consisting of 100 beehive coke ovens which operated until 1922. The coke produced here was partly consumed in two copper smelters operating on the Island.

Coal mining in the East Kootenay district of British Columbia also has a long history of production, dating from the period of construction of the railroads in western Canada and the northwest United States. Underground mines were established at Coal Creek, 8 kilometres east of Fernie, shortly after construction of the southern branch line of the Canadian Pacific Railway through the Crowsnest Pass. Subsequently, similar mines were developed at Michel in 1898 and at Morrissey in 1902. The pioneers of coal mining in this area recognized the coking qualities of the coal and, parallel with the mine development, batteries of beehive coke ovens were constructed at the minesites.

The problems of mining in the Rocky Mountain region were soon evident to these early miners when they encountered the alarming phenomenon known as "outbursts," in which huge volumes of methane gas were explosively released at the coal face. After several

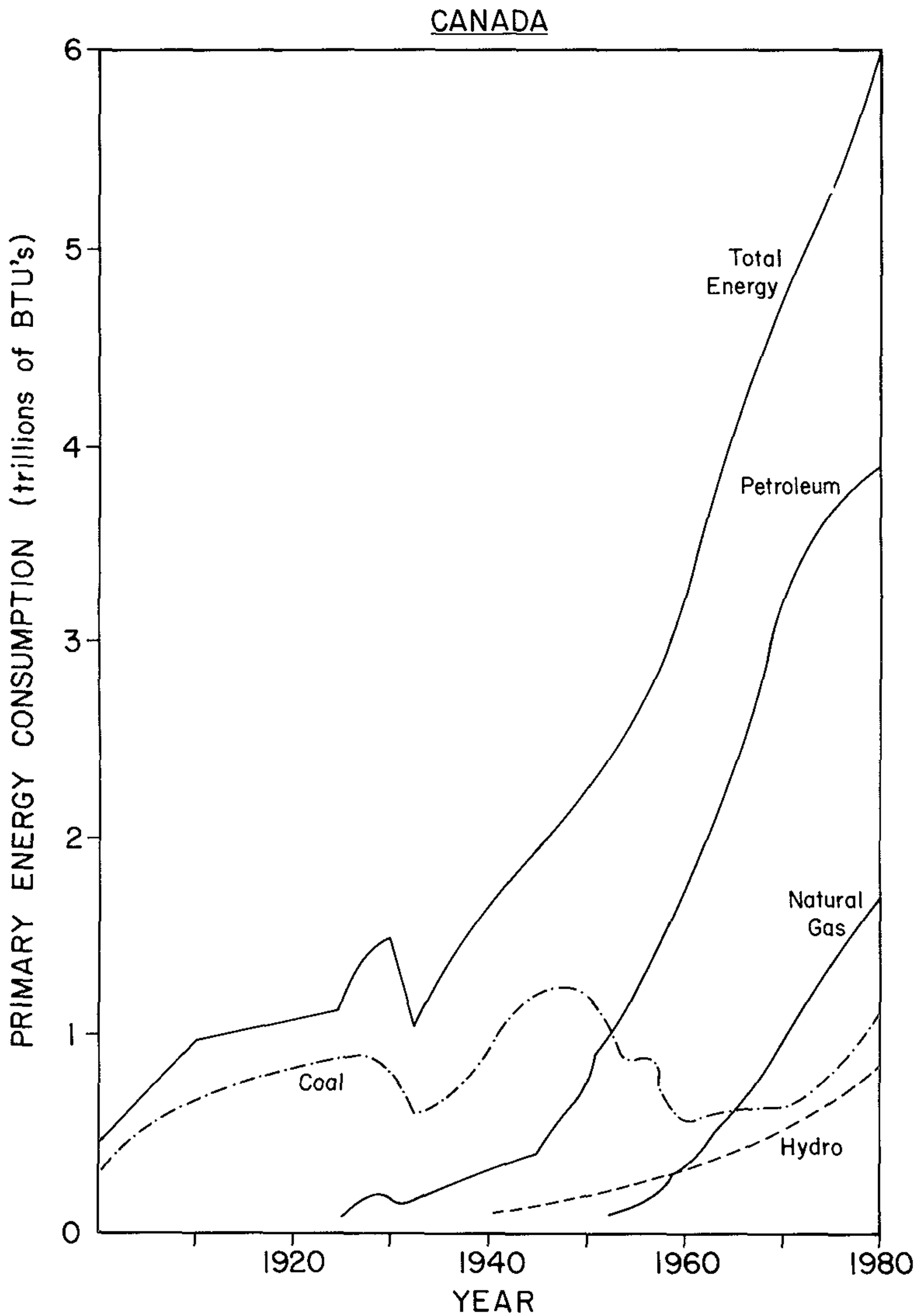


Figure 1.1 — Consumption of energy, 1900–1980.

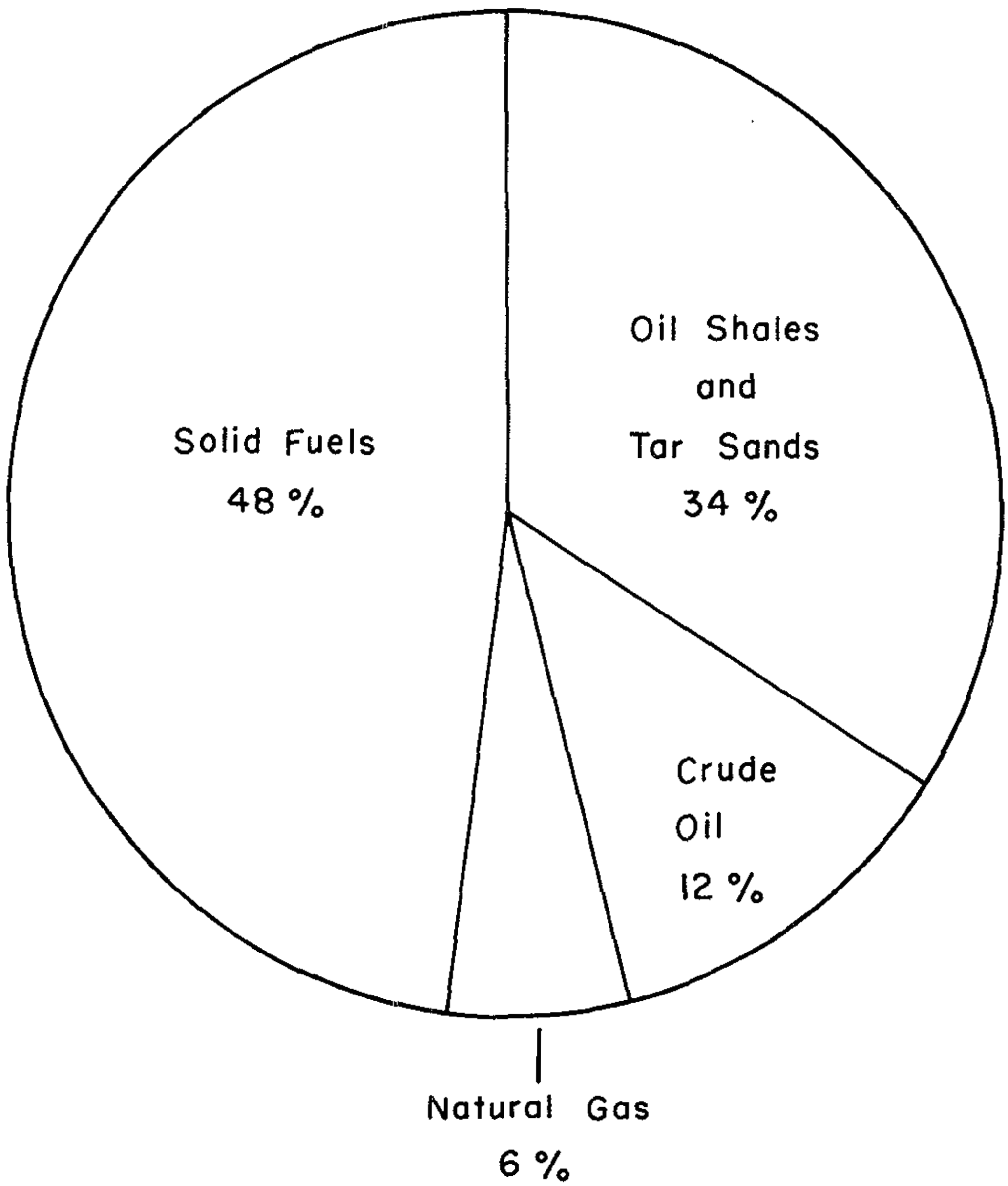


Figure 1.2 — World resources of fossil energy.

incidents of this type, accompanied by serious loss of life, the Morrissey mine in the Kootenays was closed in 1909.

The conversion of the railroads from coal to diesel fuel in the 1950s brought a virtual end to coal mining in this area until the development of the markets for metallurgical coal in Japan in the mid-1960s. Prior to the development of this market an aggregate of approximately 45 million tonnes of coal had been produced from the mines of the East Kootenays.

The Northeast region fared similarly to the other regions of the Province as regards coal development. However, in this region the development was more recent and the decline more rapid. Although first reported in 1879, the coal deposits in the Peace River were not exploited until shortly after the construction of the Alaska Highway in 1944. By 1950, three small mines were operating, and in that year approximately 12 thousand tonnes of coal were produced. No sooner had this infant coal-mining industry become established, however, when oil and natural gas were discovered in major amounts in the Northeast region. From this time on the *industry declined rapidly and the total production from the mines did not exceed 65 thousand* tonnes.

Another region of the Province where coal mining experienced a similar growth and recession is that including the Merritt, Tulameen, and Princeton coalfields. The mines in this region were *active from the early part of the century until the end of World War II, producing in that period* just over 6 million tonnes of coal.

By the late 1950s, in fact, the British Columbia coal industry faced virtual extinction, exposed as it was to the same forces of change as experienced on the rest of the continent. This decline can be ascribed to a number of causes. First, the Province had no heavy industry such as steelmaking which could provide a steady demand for coal. Second, there was abundant potential for hydro-electric power development. And finally, the production of coal was tied to the two uses most affected by alternative fuels—transport and home heating.

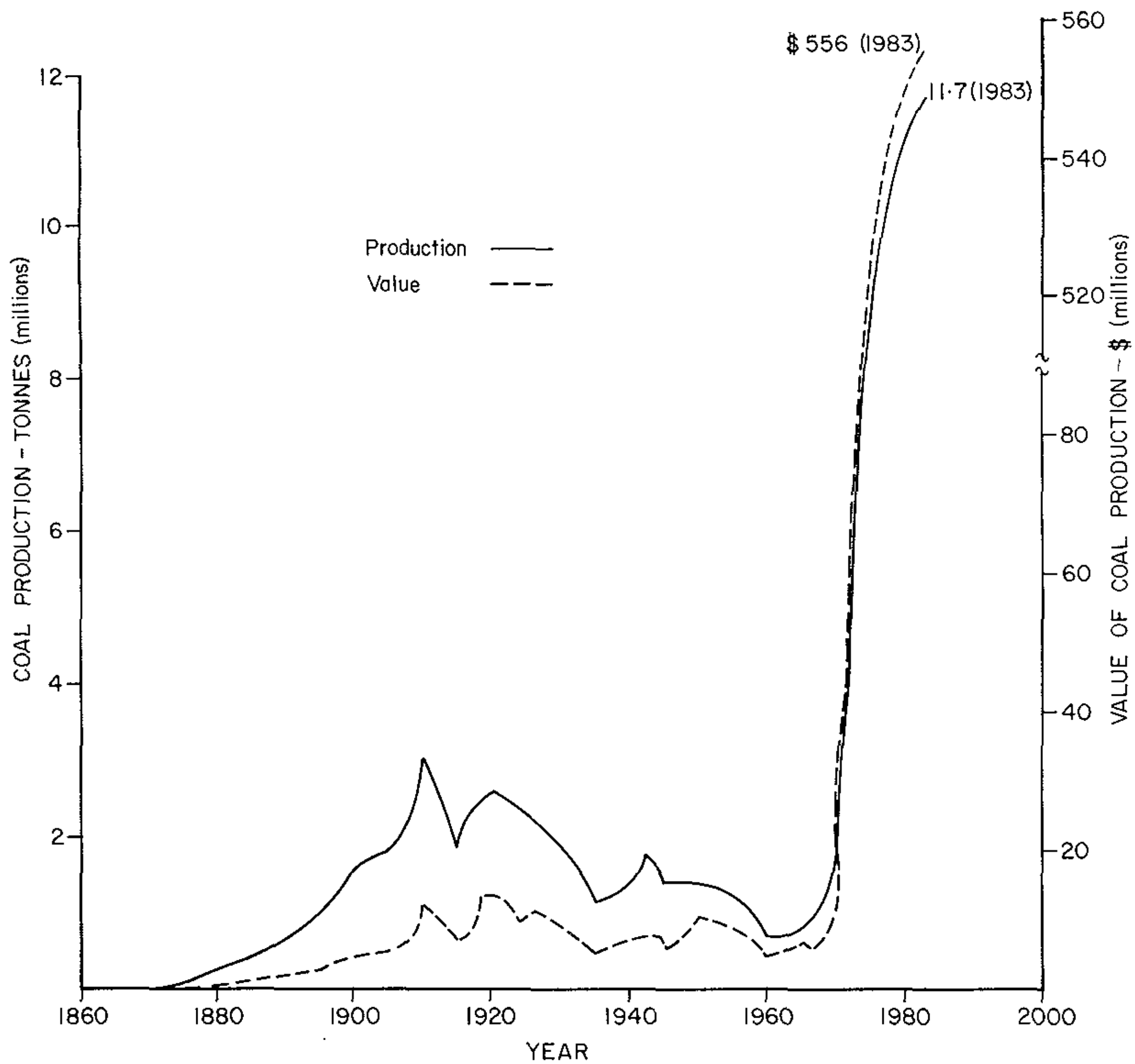


Figure 1.3 — Tonnage and value of coal production in British Columbia, 1960–1981.

The resurgence of the coal-mining industry in the Province occurred as a result of the development of an export market in Japan for metallurgical coal. The development of this market took considerable time and effort. In the initial stages, trial shipments of substantial tonnages were required to establish quality acceptability in the highly demanding steel industry of Japan, which was the only market offering any promise in the 1960s. During this period of development the Federal Government assisted with financial aid in maintaining the three remaining companies mining metallurgical coal in western Canada (at Fernie, Coleman, and Canmore) in existence.

Following acceptance of the coal by the Japanese steelmakers by the mid-1960s, short-term contracts (three years) were signed to provide a total export market for 1 million tonnes annually. By the late 1960s, large-volume long-term contracts could be negotiated. During this later stage of development the unit coal train was introduced, the Port of Roberts Banks constructed, and some of the Vancouver docks adapted for coal storage and handling.

The production of coal in the Province increased approximately 27 fold in the last 15 years, with the annual production amounting to almost 21 million tonnes in 1984. In constrast to the production in 1969 of which 90 per cent was obtained from underground mines, surface mining now accounts for virtually all production. This upsurge of activity was not without its problems. It was affected by the previous decades of depression, during which the industry lost much of its management expertise, skilled labour, and financial strength.

British Columbia mining revenues from 1978 to 1984 for all major minerals produced are shown in Table 1.1. In 1984, sales of coal amounted to $964 million, or approximately 30 per cent of the total value of British Columbia mineral production. Coal, which had vied with copper and natural gas for the position of the single most important mineral produced in the Province, since the mid-1970s, became the clear leader in 1984 following the doubling in coal output.

The average mine price of metallurgical and thermal coal since 1978 are shown in Table 1.2. In 1984, the average mine price of metallurgical coal was Cdn$ 52.18 per tonne, of thermal coal Cdn$ 25.31 per tonne. The average export price of British Columbia metallurgical coal, as of mid-1985, was Cdn$ 70.00 per tonne for hard coking coal from the southeast part of the Province, Cdn$ 90.00–92.00 per tonne for hard coking coal from northeast British Columbia, and Cdn$ 50.00 per tonne for thermal coal.

TABLE 1.1. Value of British Columbia Mineral Production ($ millions)

	1978	1979	1980	1981	1982	1983	1984
Coal	382	439	462	554	567	556	964
Natural gas	401	699	613	617	543	455	516
Copper	432	656	671	611	495	560	515
Crude oil	145	169	190	236	339	402	434
Silver	45	95	157	152	158	180	122
Gold	48	104	170	136	118	131	119
Zinc	52	62	49	67	64	80	113
Molybdenum	168	321	289	198	155	88	108
Asbestos	47	65	82	77	57	53	88
Combined other[1]	252	347	394	361	301	352	358
Total	1,972	2,957	3,077	3,009	2,797	2,857	3,337

[1] Includes lead, iron concentrates, sulphur, structural materials, and other minerals.

Source: Ministry of Energy, Mines and Petroleum Resourses, Summary of Operations 1978–1983; EMPR notification of release for 1984.

TABLE 1.2. Representative Value of British Columbia Coal Production 1978–1984 (Cdn$ FOB Mine)

Year	Thermal	Metallurgical
1987	42.35	22.11
1979	42.99	27.48
1980	43.83	32.81
1981	47.95	38.09
1982	57.98	35.56
1983	52.80	29.51
1984	52.18p	25.31p

p-Preliminary.

1.2 CLASSIFICATION OF COALS

Coal occurs as an integral part of geological successions and is indeed a rock. Like other rocks, it consists of aggregates of components. Some of these, such as quartz and pyrites, are true minerals, but most are of a coalified nature and are termed macerals. Macerals are in many respects analogous to minerals but differ in their chemistry and molecular structure. At present it is not easy to categorize macerals in terms of chemistry and structure, but microscopic observations of their brightness, shape, and internal structure can be used to identify and quantify their content in a given coal sample.

Coal ranges from brown coal through lignite, sub-bituminous and bituminous coal, to anthracite, according to the degree of conversion of the original organic remains which formed the deposit. The conversion is marked by a progressive change in the ratio of volatile matter to fixed carbon. The higher the fixed carbon content, the higher is the rank of the coal. Thus, the conversion to fixed carbon in anthracite may be almost complete and in any case is always over 90 per cent.

Numerous systems have been developed for the classification of coal, designed to satisfy the needs of producers, consumers, and technologists. For example, the ASTM system (Appendix 1.1), which is widely used in Canada and the United States, is essentially a broad indicator of the chemical composition and the heating value of the organic component of the coal.

In the application of coals for thermal use, detailed analysis of the coal organic component is in general not of major significance. However, for this and other uses, elementary information on the inorganic components, including the ash and sulphur contents and the ash softening temperature, can be of considerable significance. An ASTM system has been developed classifying these properties by number and letter (Appendix 1.2). It should be noted, however, that for coal gasification and possibly for carbonization more detailed data on the composition of the inorganic matter from the standpoint of such constituents as iron, magnesia, and lime can be of significance. These compounds can catalyse the gasification of the organic components of the coal, thus leading to enhanced rates of gas production which in carbonization may change the strength of the coke.

The International System of Classification of Hard Coals by Type (Appendix 1.3) is being used increasingly, particularly in Europe and Japan, for the identification of coals for both carbonization and thermal applications. This system is based on a numerical grouping with gross measurements of coking and caking properties as parameters in the classification, and thus the reason for its adoption is clear.

However, in recent years qualitative and quantitative data obtained by microscopic analysis on the maceral component of the coal, using essentially petrographic techniques, have come to be recognized as the most significant indicator of coking properties. These techniques have been speeded up to the point where it is possible to perform semi-automatically the tasks from sample collection to analysis and to combine the results with a computer system to estimate the strength of the coke product and set up coal-blending plans. In addition, the petrographic technique is considered to be a very effective tool in forecasting the value of a coal deposit for development when only small amounts of samples may be available.

Other analytical data, such as the Gray-King Assay (as used in the International Classification System) and chemical analysis, are of course useful for this purpose; but it is now accepted that identification of the type and quantity of the different macerals provides data which enables assessment of coal properties to be made with a greater degree of confidence than heretofore.

The Japanese have been particularly successful in developing a classification system for metallurgical coals by combining coal petrographic techniques, using, for example, measurement of the light reflectance of the coal maceral, as an indicator of rank, with other significant indicators of coking quality, such as coal fluidity measured at high temperature. The classification system of Miyazu (Appendix 1.4) uses this approach. It enables the position of coals relative to the field occupied by blends or individual coals to be clearly delineated. In addition, deviations from the broad correlations (indicated by the solid lines in Appendix 1.4), such as shown by some Canadian and Australian coals, are able to be explained by further application of coal petrography, it having been shown that these coals contain an abnormally high content of maceral components which are inert in the carbonization process.

The correlation diagram has been divided into four quadrants with reference to the lower limit of fluidity and the lower limit of mean reflectance (about 1.2) deemed necessary for the coal blend. Coals in quadrants I and IV are necessary for maintaining the mean rank of coalification of the blend, and only a few coals, but especially American and Canadian, belong to these categories. Coals falling in quadrants I and II are essential for maintaining the mean fluidity. Coals of quadrant III having low rank of coalification and fluidity can be regarded merely as sources of carbon in blending.

A glossary of coal classification terms has been included in this report (Appendix 1.5) for the convenience of the reader.

1.3 USES OF COAL

Coal can be a direct or indirect source of energy, a direct or indirect source of hydrogen, a source of carbon, and a direct or indirect source of chemical compounds (Fig. 1.4).

In common with the other fossil fuels, coal is a highly flexible source of energy. For example, it can be easily and cheaply stored and transported. Furthermore, it is capable of directly providing heat on small or large scales and at high or low intensities. Its well-known disadvantages are that, when combusted, its inorganic component remains as ash and its sulphur content is converted to sulphur dioxide (Appendix 1.6). Much of the effort in the technological development in combustion of coal in recent years has been devoted, therefore, to the removal of noxious solid and gaseous compounds from the combustion gases.

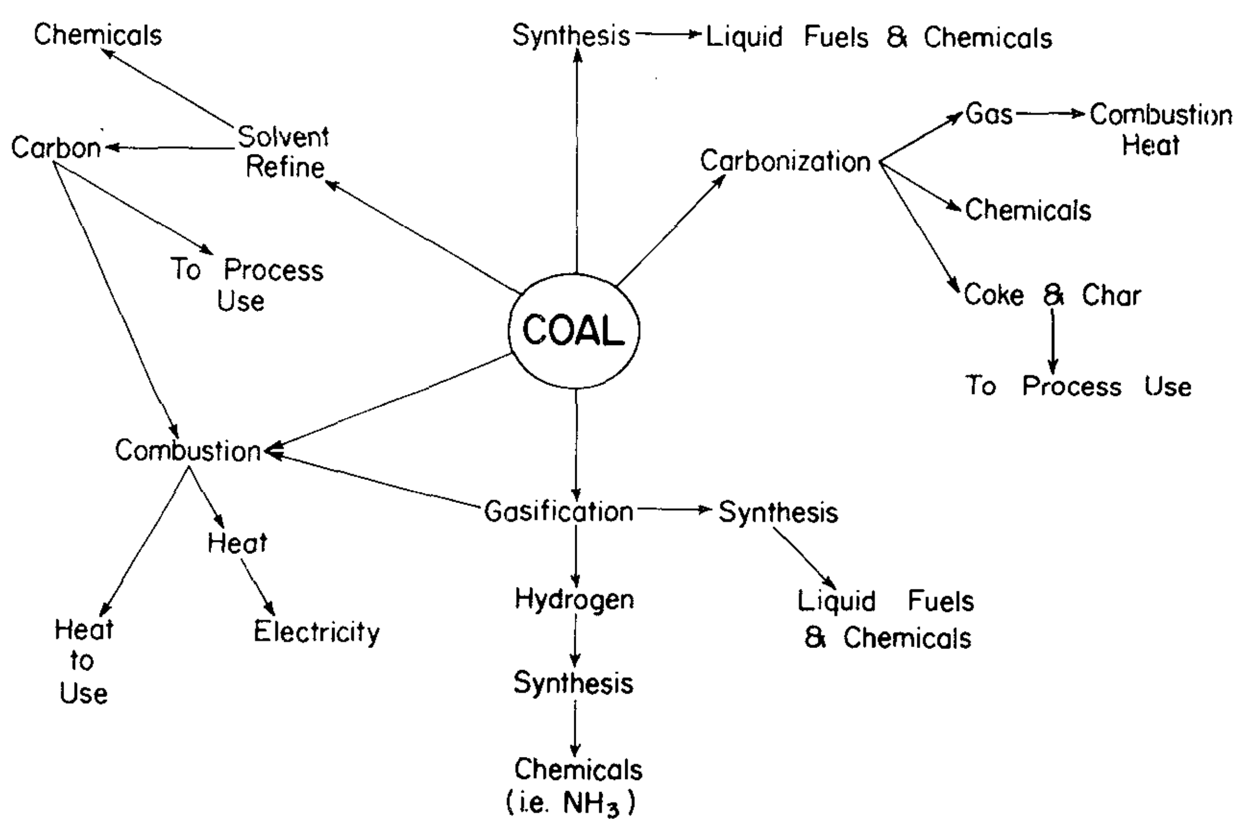


Figure 1.4 — Products obtainable from coal.

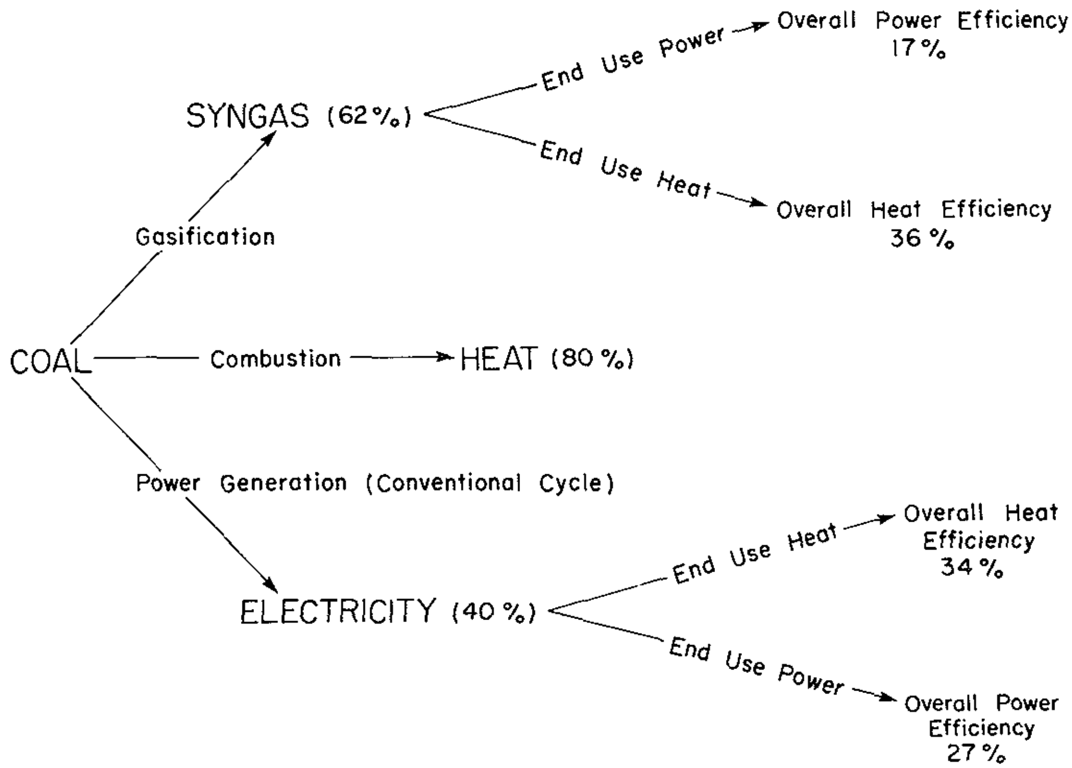


Figure 1.5 — Relative efficiencies of coal conversion processes.

A factor of potential significance, however, in considering coal as an energy source, is the overall efficiency of converting it to useful energy for heat or power. From Figure 1.5 it can be seen that the overall efficiencies of conversion of coal to heat via SNG and via electricity are similar, but changes in technology in either route could modify this observation.

In the 1960s, when very low contract prices (approximately 25 cents per million Btu*, CIF) were in effect for coal for thermal use, even at low conversion efficiencies coal could be the favoured energy source for electricity generation in many locations. Current prices, however, average at least nine times this amount on a CIF basis (equivalent to approximately $50 per tonne). Thus coal, in common with other fossil fuels, should not be considered any longer a cheap source of energy.

Particularly for purposes other than direct energy production by combustion, it is appropriate to consider coal as a hydrocarbon compound which, compared with oil or natural gas, has a deficiency of hydrogen (Appendix 1.7). The conversion of coal into liquid and gaseous hydrocarbons, therefore, requires either the addition of hydrogen (directly, as in liquefaction; or through a catalytic process following the reaction of coal with steam, as in gasification), or the removal of hydrogen-rich compounds, as in carbonization.

Paradoxically, despite coal's low hydrogen content, it is an excellent raw material for hydrogen production via its reaction with steam. Plants employing this technique of hydrogen generation for synthetic ammonia production are presently in operation in several locations around the world.

Gases (60 per cent hydrogen) are also the principal by-product of the carbonization of coal to coke and thus even this coal conversion process can be regarded as a gasification process. In

* Btu/lb. × .002326 = MJ/kg.

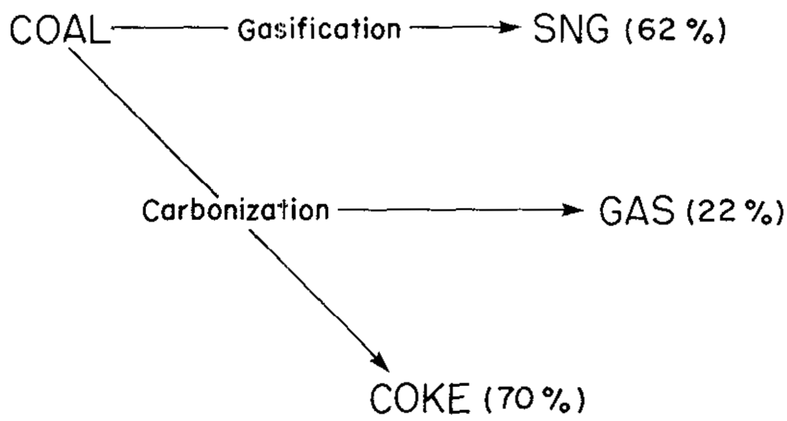


Figure 1.6 — Comparison of equivalent energy yields in gasification and carbonization.

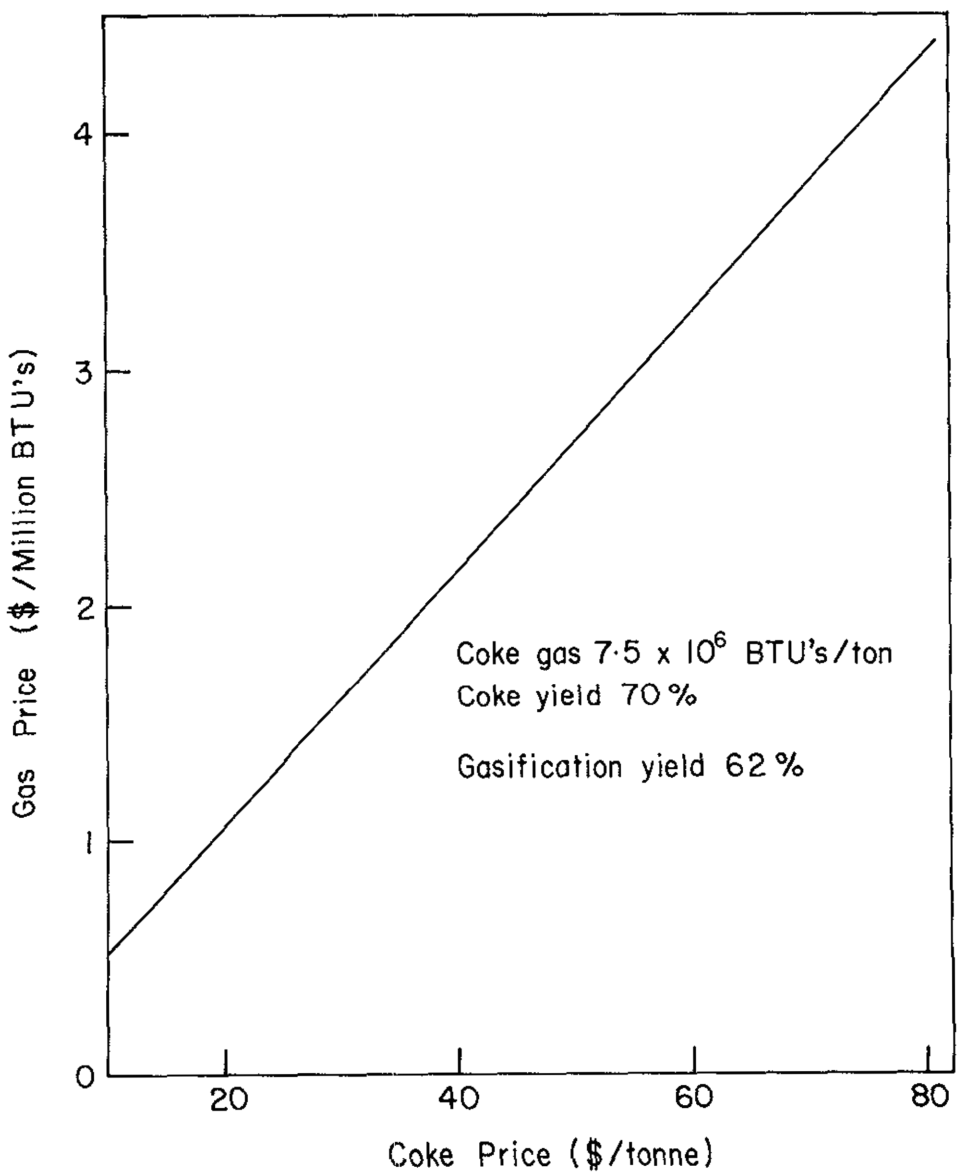


Figure 1.7 — Prices of gas and coke for equivalent value of products from equal amount of coal.

this case, the volatile matter and water contents of the coal are expelled by heating the coal in the absence of air to leave a coke as the residue. Historically, "gas works" based on carbonization and using gasometer storage of coke-oven-generated gas were a common feature of urban landscapes in many countries.

The yields in energy equivalent units of gas from direct gasification and carbonization are compared in Figure 1.6. A major advantage of coal gasification in an energy-producing sequence or as a first step in chemicals production is that several proven techniques exist for the removal of sulphur compounds from the product gases. Gasification from this standpoint is therefore ecologically a very desirable route of coal utilization.

Comparing the monetary value of the products obtained in gasification and carbonization (Fig. 1.7), it can be seen that, at present coke prices (in the range $100 to $120 per tonne), SNG from gasification would have to be priced at about $5 per million Btu's to provide a product of equivalent value to the gas and coke obtained in carbonization. The value of other chemical by-products has been assumed to be approximately the same in both carbonization and gasification. On this basis, the gasification of good coals with coking properties, such as occur in many of the British Columbia coal deposits, would not appear to be justified.

A further advantage of carbonization compared with gasification is that, from the standpoint of the long-term conservation of the world's resources, coal should be used in applications where its unique properties are exploited to the fullest. Coke production would seem to be an application of this type since coke is a reagent which currently has no equal in the large-scale production of iron, and the liquid by-products of coking are valuable materials for the chemical industry.

Logical extension of this reasoning would make coal liquefaction or solvent extraction an even more desirable coal treatment process. For example, approximately 80 per cent of the coal substance can be dissolved in a liquid solvent such as anthracene oil; the resulting solution is chemically similar to the original coal. Although unsuitable for direct use as a chemical feedstock, further processing of this solution can yield a remarkable range of products, including pitch and tar substitutes, electrode cokes, and carbon fibres. The main processing routes in such a treatment process are shown in Appendix 1.8.

Consideration of all the above principal alternatives in coal utilization is necessary so that the large coal resource which the Province possesses can be put to the best use, particularly in view of the fact that coal is a finite resource.

II. COAL RESERVES AND RESOURCES

2.1 INTRODUCTION

National compilations of coal reserves and resources have been made since the beginning of the century based on available data (*see* references). The reserve and resource data for coal must be used with caution as there are many uncertainties and limitations inherent in attempting to quantify complex geometric bodies on the basis of a limited number of observation points and data of varying accuracy. Furthermore, in calculating reserve and resource figures, the effect of complex technical and economic factors that control extraction and marketing cannot be accurately assessed. Different agencies, companies, and countries use various parameters for reserve and resource data which produce inconsistencies. Even the use of the same terms provides no assurance that the same parameters have been used.

The deposits of coal in British Columbia were most recently described in *Coal in B.C., A Technical Appraisal,* 1976. Only a few deposits have been discovered since, however, considerable development work has been done on the more promising properties. The British Columbia Ministry of Energy, Mines and Petroleum Resources has a continuing program of reserve and resource evaluation. Reserve figures have been updated to December 1981 for those properties which have had feasibility studies done. Resource figures are current for all areas but the Southeast and Northeast Coalfields which are in the process of being updated.

2.2 RESERVE AND RESOURCE DEVELOPMENT

The development of reserves and resources is dependent upon various factors as is illustrated in Figure 2.1. *Motivation* is market demand; the resultant *work* is exploration and associated studies. The *product* of the work is the delineation of a resource or a reserve; and finally, the *use* of these data is for planning.

Throughout the development of a coal resource, markets must be identifiable. In the initial stages of development, the demand or anticipated demand, is general. In order to justify continuing development, the demand must become more specific—marketable coal must be found and produced at an economic price. Eventually, it is necessary to match coal quality with a prospective buyer and proceed with negotiations.

Exploration work also goes through a number of phases during the development of a coal resource. It begins with reconnaissance mapping and seam measurement from which an inferred resource will be defined (*see* section 2.3.2). The next stage consists of detailed mapping and a sizeable drilling program. Indicated resources may be defined after this work is done (*see* section 2.3.2). The final stage includes dense enough drilling to establish a measured reserve (*see* section 2.3.2). Coal sampling at this stage also helps classify the coal. Feasibility studies are completed in this last phase.

All of the information derived is used for long-range and immediate planning. As illustrated in Figure 2.1, the general information is of use in making long-range plans on a provincial or national level. As more specific information becomes available the planning can become more detailed. Proposals on a regional basis can be made, and eventually, the economic viability of a deposit can be determined.

2.3 RESERVE AND RESOURCE CLASSIFICATION

Coal resources are defined as a natural concentration of coal in a form and place that makes economic extraction feasible. A number of classification schemes for reporting reserves and resources have been proposed or are currently in use. The British Columbia Ministry of Energy, Mines and Petroleum Resources has based its scheme on that proposed by the Federal Department of Energy, Mines and Resources*. A more liberal approach than the federal system has been taken by the Province as a compromise between the stringent standards set by the Department of Energy, Mines and Resources* and the constraints of companies' exploration work.

---

* *Energy, Mines and Resources Canada:* Report ER 79-9, Coal Resources and Reserves of Canada, Appendix B, pp. 35–37, December 1979.

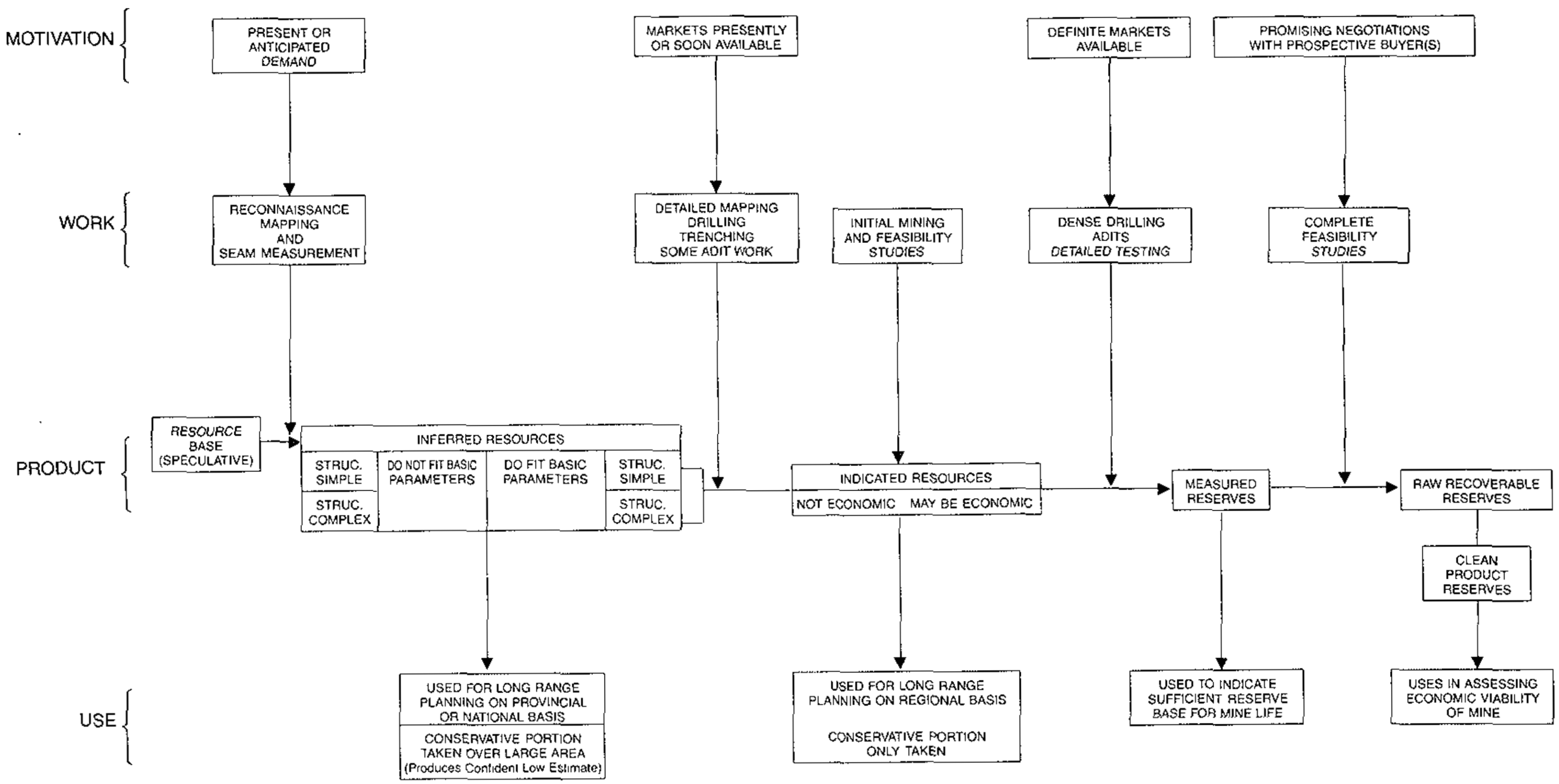
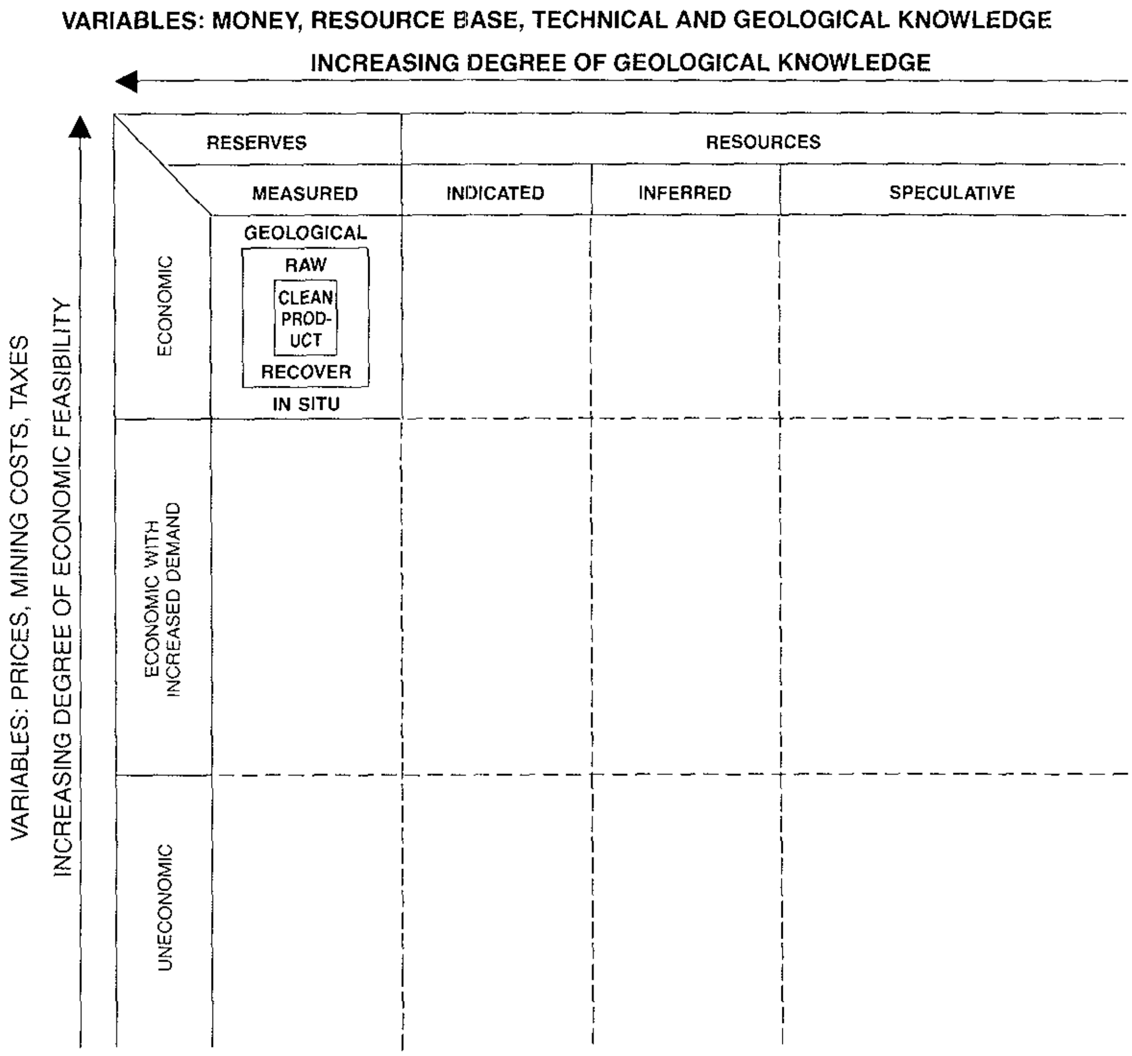


Figure 2.1 — Concept of reserves and resources for coal.

2.3.1 FEDERAL SYSTEM

The federal resource classification system consists of four main categories; it is based upon the degree of assurance as one parameter and economic feasibility of production as the other (Figure 2.2). The first category, measured reserves, includes tonnages computed from points of geological observation (outcrop, trenches, mine workings, and drill holes). For measured reserves data points have a maximum specified spacing of 300 metres in the Cordillera region, but 150 metres in severely contorted areas.

The second category, indicated resources, has tonnages computed from both specific measurements and projection of data over a reasonable distance, based on the geological evidence. The maximum spacing of the data points are 600 metres in the Cordillera region and 300 metres in structurally distorted areas.



Recover. = Recoverable

Figure 2.2 — Classification of coal reserves based on probability of existence and economic feasibility of production.

The third grouping, inferred resources, is based on a broad knowledge of the geological character of the region or bed. These quantitative estimates include few available measurements of coal seam thickness but are extrapolated on assumed geological continuity.

The fourth and final category in the federal system, the speculative resources, involves quantity estimates based on information from a few scattered occurrences only.

2.3.2 BRITISH COLUMBIA MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES SYSTEM

The classification system used by the British Columbia Ministry of Energy, Mines and Petroleum Resources recognizes three main categories: measured reserves, indicated resources, and inferred resources. The parameters for the classifications were derived after empirical investigation of the overall data density for the properties and taking into consideration the geological complexity. The main deviation from the federal system is the data-point spacing.

Several parameters affect all three categories. One parameter is acceptable data points, which are accurate physical measurements of seam thickness. These data points include boreholes (diamond, rotary, and Winkie), adits, and some trenches. Map sizes and scales are important parameters; for example, a 1:10 000-scale map is necessary for calculations. Another parameter applicable to all three categories is seam thickness—the minimum true stratigraphic seam thickness used is 1.5 metres. However, in an open pit, a rider or multiple seams of 1.0 metre are acceptable.

The first classification category, measured reserves, has a maximum data-point spacing of 375 metres (25 per cent greater than the federal system). Also, a feasibility study should be completed containing enough exploration information to do a detailed mine design and a cost analysis.

The second category, indicated resources, allows a maximum spacing of 750 metres between data points. Without a feasibility study a deposit will be considered an indicated resource even if it has a data-point spacing of 375 metres. Further, if the deposit has a feasibility study, but a data-point spacing of more than 375 metres, it will also be considered an indicated resource, as represented in Tables 2.1 through 2.4.

Inferred resources, the third category, has a data-point spacing of greater than 750 metres. A depth limit of 750 metres is imposed for the inferred resources, although in some cases economic coal seams may exist beyond this depth. Coal resources of less than one million tonnes are considered inferred even though the data-point spacing is within the indicated category. Basically, inferred resources are based on general knowledge of the region, as in the federal system.

The geological complexity of some deposits creates problems in applying the parameters. For example, in areas of extreme structural and/or stratigraphic complexity the data-point spacing must be closer than suggested by the parameters to ensure accurate geological interpretation.

2.4 RESERVE AND RESOURCE CALCULATIONS

The assessment of British Columbia's reserves and resources is underway. The initial stage of the study, measured reserves, has been completed and is presented herein. The reserves are restricted to those deposits considered to be economic, that is, those having complete feasibility studies with positive results.

Data submitted for credit purposes under the *Coal Act* are not accepted until they conform to the regulations, revised in 1974, and again in 1979. This represents the most comprehensive coal resource data file available. However, reserve and resource data are not mandatory under the *Coal Act*, although when submitted they have to follow the pattern stated in the regulations. This leads to incomplete and antiquated data which were augmented by information sent by the owners/operators upon this Ministry's request.

Coal data compiled from annual assessment reports are stored in a computer data-base. The nonconfidential information is available for public use.

The following estimates are based on the best data available in the coal files. Most of the information used dates from 1976 to 1981. When reserve and resource information was almost non-existent, the owners/operators sent in the 1981 exploration results, which were subsequently incorporated into the calculations. Some companies have not performed resource calculations for several years thus older reports were used.

Outdated figures were used for the Hat Creek property due to the unique computerized method used by British Columbia Hydro and Power Authority which does not coincide with the parameters set by this Ministry for the *in situ* reserve and resource calculations.

Listed in Tables 2.1, 2.2, and 2.3 are measured *in situ* coal reserves and some of the indicated resources of British Columbia as well as the probable mining method and possible end use of the coal for each property. The remaining indicated and the inferred resources of British Columbia are presented in Table 2.4. Resource figures are only as recent as 1977 because a proper study has not yet been completed. The figures are summarized for each coalfield due to the confidential nature of the sources.

Metallurgical or coking coal is differentiated from thermal or steam coal using ASTM (American Society for Testing and Materials) standards that are the basis for determining coal rank and quality as well. The metallurgical and thermal coals are separated in two columns on the tables but this does not necessarily quantify the end use of the coal. Present technology allows a blending of several, sometimes inferior coals to produce a different or superior rank of coal. The blending allows some metallurgical coals to be marketed as thermal coals and vice versa. It is usually dependent upon market availability, the cost of production, and other economic factors. The thermal coal category includes oxidized coal; oxidation causes the loss of coking properties.

TABLE 2.1. Reserves of Coal — Northeast Coalfield (Million Tonnes)

PROPERTY	GEOLOGICAL IN SITU COAL				COAL RANK	TYPE OF MINING
	Metallurgical Quality		Thermal Quality			
	Measured	Indicated	Measured	Indicated		
Carbon Creek					mvb—hvAb	open pit and underground
Burnt River					hvb—sa	open pit
Sukunka					lvb—mvb	underground
Bullmoose					mvb	open pit
Mount Spieker					lvb—mvb	open pit and underground
Quintette					mvb	open pit
Monkman					mvb	open pit
Saxon					mvb	open pit and underground
Total Geological In Situ Coal	470	290	110	7.8		
Total Run-of-Mine Coal	370	280	82	8.2		
Total Saleable Coal	280	160	77	6.5		

Key to Abbreviations:

an = anthracite	hvCb = high-volatile C bituminous
sa = semi-anthracite	subA = sub-bituminous A
lvb = low-volatile bituminous	subB = sub-bituminous B
mvb = medium-volatile bituminous	subC = sub-bituminous C
hvAb = high-volatile A bituminous	lig = lignite
hvBb = high-volatile B bituminous	

TABLE 2.2. Reserves of Coal — Southeast Coalfield
(Million Tonnes)

PROPERTY	GEOLOGICAL IN SITU COAL				COAL RANK	TYPE OF MINING
	Metallurgical Quality		Thermal Quality			
	Measured	Indicated	Measured	Indicated		
Elk River					lvb—hvb	open pit and underground
Fording River					mvb	open pit and underground
Greenhills (Westar *Mining)*					*mvb—hvAb*	*open pit*
Line Creek					lvb—mvb	open pit
Sparwood Area (Westar Mining)					lvb—hvb	open pit and underground
Hosmer Wheeler					mvb—hvb	underground
Corbin—Shell					*mvb*	*open pit*
—Esso					mvb	open pit
Sage Creek					mvb	open pit
Total Geological In Situ Coal	1030	44	160	0		
Total Run-of-Mine Coal	880	22	120	0		
Total Saleable Coal	*640*	*14*	*110*	*0*		

TABLE 2.3. Reserves of Coal — Other Coalfields
(Million Tonnes)

PROPERTY	GEOLOGICAL IN SITU COAL				COAL RANK	TYPE OF MINING
	Metallurgical Quality		Thermal Quality			
	Measured	Indicated	Measured	Indicated		
Hat Creek					lig—subB-C	open pit
Quinsam					hvAb	open pit
Tulameen					hvCb	open pit
Total Geological In Situ Coal			970	1000		
Total Run-of-Mine Coal			770	800		
Total Saleable Coal			690	720		

TABLE 2.4. Resources of Coal
(Million Tonnes)

COALFIELD	INDICATED AND INFERRED RESOURCES	COAL RANK	TYPE OF MINING
NORTHEAST			
Peace River	8 100	mvb—lvb	open pit and underground
SOUTHEAST			
Elk Valley, Crowsnest, Flathead	25 300	mvb	open pit and underground
GROUNDHOG	3 900	lvb—an	open pit and underground
TELKWA	88	hvBb	open pit and underground
BOWRON RIVER COAL DEPOSITS	20	hvBb	underground
HAT CREEK	1 720	lig—subB	open pit
MERRITT	18	hvBb	underground
SIMILKAMEEN	21	lig—hvCb	open pit and underground
COMOX	154	hvAb	open pit and underground
NANAIMO	7	hvBb	underground

The indicated column (Tables 2.1, 2.2, and 2.3) contains data only from deposits where positive feasibility studies have been completed and some of the property is measured. Not all coal of indicated status in the Province is included here.

The reserves and resources are listed (Tables 2.1, 2.2, and 2.3) using the particular coalfields as the basis of division: the Northeast, the Southeast, and others. The figures are presented as a total measure for each coalfield, not individually by property. The *in situ* reserve and resource figures are based on conservative calculations within this Ministry. Ideally it is to compare only coal seams between properties; excluding major partings which might bias the figures.

The *in situ* coal is defined as in-place underground coal which excludes the partings of greater than 10 centimetres in thickness. The *in situ* figures portray coal seams of greater than 1.5 metres in thickness and in some cases rider seams of 1.0 metre thick.

Recoverable or run-of-mine coal is in-place underground coal which excludes partings that can be selectively mined out at the pit site. This mining section may be more, or less, than the total coal seam thickness. It is determined by the type of equipment used in mining. Underground operations are often inflexible in seam thickness variations where, for example, portions of coal seams greater than 2.5 metres in thickness are left. Additionally coal may be left on the roof to strengthen incompetent roof material. The surface mining usually includes the full seam but thin ancillary seams are not always recovered.

Saleable or clean product coal is, in the case of metallurgical coal, that coal which is refined through the wash plant. Thermal coal may be cleaned for a partial refining but is not often processed through a wash plant. In many cases for thermal coal the run-of-mine coal is equivalent to the saleable coal.

The run-of-mine and saleable coal figures were obtained directly from the companies. Often the run-of-mine totals are larger than the *in situ* figures portrayed due to the inclusion of partings which cannot be selectively mined out.

The coal rank and type of mining are listed by property for each of the coalfields within the tables. For the most part the Northeast Coalfield has coal ranging from high-volatile bituminous to semi-anthracite with the metallurgical coals mainly of medium-volatile bituminous rank, according to the ASTM classification. The coals of the Southeast Coalfields are predominantly medium-volatile bituminous in rank as well. The other Coalfields, mainly thermal coals, range in rank from lignite to anthracite.

2.5 THE COALFIELDS OF BRITISH COLUMBIA

GEOLOGICAL SETTING

The principal coal-bearing formations in British Columbia are of Jurassic and younger age; the most extensive coal deposits are in Cretaceous and Tertiary rocks. Jurassic and Cretaceous coal-bearing formations form a continuous belt along the eastern side of the Rocky Mountains from the United States boundary northward to beyond latitude 56 degrees north. The central part of this belt lies in Alberta. Most Tertiary coal deposits are in the central part of the Province, occurring within relatively small isolated basins. Coal is found in Jurassic and Lower Cretaceous rocks of the Bowser Basin, north of the central part of the Province, and in the Cretaceous rocks of Vancouver Island. The extent of the coal-bearing formations has been delineated in only general terms by geological mapping and stratigraphic work. Detailed studies of many individual deposits have been made for mining purposes, but little is known of stratigraphic correlations between deposits and general conditions of sedimentation. Figure 2.3 (in pocket) summarizes the stratigraphy, names of the formations, and geological ages of the rocks in the principal coal basins of the Province.

The economic value of coal deposits depends on the sedimentary and tectonic conditions at the time they were deposited and on subsequent tectonic events. The thickness and continuity of seams, the nature of the roof and floor, the presence of shale or other impurities within the coal, and the maceral composition of the coal depend on the sedimentary conditions at the time of deposition. Characteristically, these conditions can change rapidly in coal basins—sandstone, for example, passing laterally into shale or shale into coal.

Changing tectonic conditions create variations and repetitions in rock types. In the Rocky Mountain belt, which underwent repeated emergence and submergence during the period of coal deposition, some seams extend over considerable areas, but many change laterally as the enclosing rocks change facies.

Correlations and projections of rock characteristics for engineering purposes may be made with confidence in some areas, but in others they cannot be made with certainty, even within areas the size of a mine property. In the Tertiary basins, projections are even more difficult than in the Rocky Mountains because sedimentary conditions changed more rapidly therefore are less predictable, and the formations contain fewer stratigraphic markers.

Depth of burial, metamorphism, deformation following deposition, and weathering related to the present surface have determined the rank, coking characteristics, volatile content of the coal, as well as the attitude and position of the seams. Most of the Rocky Mountain coals, which have been deeply buried and highly deformed, are low to medium-volatile bituminous in rank. In many of the smaller basins, the coal is sub-bituminous and lignitic. In the Bowser Basin, the coal is noncoking, low-volatile bituminous with localized pockets of higher rank.

Finally, most of the coal deposits in British Columbia are structurally deformed, and this, together with the generally high topographic relief, places major constraints upon mining. In all areas, major and minor faults and folds strongly influence both long-range mine planning and day-to-day mining operations. In the Rocky Mountains, coal-bearing strata in general are concentrically folded on axes trending parallel to the mountain ranges. The folds are upright to overturned with axial planes generally dipping to the west; they are complicated by various fold-related faults. The coal seams mainly have low to moderate dips, but may lie at any angle. The Tertiary basins are dominated by block faulting with associated local folds and lesser thrust faulting. Very few of the seams are flat lying; mining in the past was severly hampered by the complex, poorly understood structural geology.

The principal coalfields are the Northeast (Peace River), Southeast (East Kootenay), and Hat Creek. However, economically mineable deposits also occur in the Comox, Groundhog, and Similkameen Coalfields.

2.5.1 NORTHEAST (PEACE RIVER) COALFIELD

The coals of northeastern British Columbia are exposed along the Rocky Mountain foothills from the Alberta boundary in the south to the Prophet River in the north. The coal measures occur in the Bullhead and Fort St. John Groups, which are mainly alluvial-deltaic in origin, having been deposited in an elongate embayment of an Early Cretaceous sea. The Minnes Group also contains coal seams of potential interest, however, a concerted exploration effort is needed to determine the extent, quantity, and quality of the seams.

The Bullhead Group contains the Cadomin Formation which consists of massive pebbly sandstones deposited in a piedmont-alluvial plain environment. The Cadomin grades laterally into the overlying Gething Formation, a sequence of sandstone, carbonaceous shale, and coal. Several seams, well over 1.5 metres thick in some localities, occur just above the Cadomin and throughout the Gething. The Chamberlain and Skeeter seams in this formation are well developed on the Sukunka property. North of the Halfway River the coal becomes thin and lensy and the formation consists of sandstone formed on the delta front, and siltstone and shale deposited in the basin beyond it.

Overlying the Gething Formation is the Moosebar Formation, a marine shale deposited when the deltaic complex of the Gething was drowned by a trangressing sea. Rates of sedimentation exceeded subsidence and a second alluvial-deltaic complex, the Gates Formation, was formed. The lower part of the formation, informally known as the coal-bearing member, contains the major coal seams which are up to 12 metres in thickness. The coal-bearing member is developed from the Alberta border northward to the vicinity of Bullmoose Mountain where it pinches out.

Strata of the Northeast Coalfield are within the Rocky Mountain fold belt. They are highly folded into synclines and anticlines with axes trending to the northwest. Several large thrust faults extending over tens of kilometres repeat the strata and there is much minor faulting. Within this belt there are a few relatively large areas in which the strata have a uniform low dip. This resulted in early exploration for coal on the Sukunka and Quintette properties.

Potentially mineable coal seams vary considerably throughout the coalfield in both number and thickness. As many as 11 seams have been identified in the Gething Formation and at least six in the Gates. These seams vary in thickness from the minimum 1 metre presently considered mineable up to 10 metres or more. The classification of the coals is generally that of a medium-volatile bituminous, usually with a low sulphur content and high calorific value. Many of the coals have excellent coking qualities.

The properties in this coalfield that contain measured reserves are shown on Figure 2.4 (in pocket) and are described in detail in the following sections. Calculations for the indicated resources are in progress, only those completed have been shown on this figure.

2.5.1.1 Carbon Creek Property

Coal-bearing rocks in the Gething Formation are contained in the Carbon Creek Basin. The basin is a broad, relatively simple northwesterly trending syncline, 2.4 kilometres in width and 32 kilometres in length. The northern part of the basin is a simple syncline plunging gently to the southeast, whereas the southern part is more complex with several subsidiary folds and flexures. The Carbon Creek fault forms the eastern margin of the syncline.

The upper 270 metres of the section contain more than 50 coal beds of which only 12 are over 1.5 metres in thickness. These beds are irregular and lens out over relatively short distances. The principal seams are as much as 4 metres thick, but are known from only a few boreholes; they often contain shale partings. Total known thicknesses of mineable coal in any one locality do not exceed 15 metres.

Exploration for coal on the Carbon Creek property has been on the western limb of the syncline in the north and central sectors and on the eastern limb in the southeast sector. Drill holes in the north and central sectors have been most successful in discovering coal seams with economic potential.

2.5.1.2 Burnt River Property

Coal reserves in the Burnt River coal deposit lie in the Lower Cretaceous Gething Formation. Exposure is poor, the structure is complicated, and no younger rocks (with the exception of a small outlier of Moosebar) occur on the property.

The stratigraphy is not well known in the area, but the Gething Formation is believed to have a total thickness of 400 metres or more. To date, only three seams are deemed to be of economic interest, namely the Lower Seam, Upper Seam, and Seam 60. The Lower Seam varies considerably in thickness, from an average of 3.2 metres at the northern end of the deposit to an average of 6.2 metres at the southern end. The Upper Seam averages 3.2 metres in thickness, thins to the north, and is usually split by 30 to 60 centimetres of parting. Seam 60 is from 4.3 to 8.9 metres thick in the southwest portion of the deposit. The coal ranges from high-volatile bituminous to semi-anthracite in rank.

Reserves in the main deposit are contained within a gently undulating, relatively narrow monocline that trends northwest-southeast with a 10 to 20-degree southwest dip. The western margin of the deposit is believed to be delimited by a northwest-trending thrust fault. The northern half of the deposit is divided into two thrust sheets by an offshoot of the previously mentioned fault.

2.5.1.3 Sukunka Property

In the Sukunka area, coal is present in both the Gates Formation and the Gething Formation. No seams thicker than 1.5 metres are known in the Gates, hence, exploration has been concentrated on the Gething, which is approximately 240 metres thick. A non-coal-bearing marine band (Moosebar Formation tongue) divides the Gething into a lower and upper sequence. The continuity of the Gething Formation is broken to the north where the upper sequence pinches out and is replaced by marine units of the Moosebar Formation. Eight coal seams are known in the Gething, four of which are in the lower 45 metres of the formation. The upper two of these four seams are known as the "middle coals" and contain numerous claystone bands. The two major seams in the upper Gething are the lower and upper Chamberlain. They lie above the Moosebar Formation tongue approximately 180 and 187.5 metres respectively above the base of the Gething Formation. The Bird seam is in the uppermost 3 metres of the formation.

Gething strata on the Sukunka property are within a broad, relatively undeformed syncline that is bounded on the northeast by the Bullmoose fault complex, an extensively faulted major anticlinal structure. Within the syncline the gently dipping strata has been dislocated into three blocks or structural plates by a series of thrust faults. Gentle undulatory folds are also present; their axes are oriented southeasterly parallel to the thrust faults. The regional plunge is southeast in the northern part of the property and northwest in the southern part.

2.5.1.4 Bullmoose Property

The lower part of the Gates Formation occurs at shallow depth and with gentle dips in two areas on the Bullmoose property. The northern portion has been designated the "West Fork" area and the southern portion the "South Fork" area.

The potentially productive portion of the Gates Formation consists of about 80 metres of nonmarine sediments that includes five coal seams. This zone lies between the Torrens Member sandstone and the roof of the "E" seam.

In the South Fork area, the lower Gates strata form a platter-shaped outlier which dips gently to the north and is crudely concordant with the slope. Erosion has exposed the coal seams around the entire periphery of the area.

The West Fork area lies along the axial portion of the broad syncline and strata are generally flat lying for about 2 kilometres across the structure. Coal seams along the southern edge of the area have been exposed by erosion. To the north, the seams lie progressively deeper as surface elevations increase toward the high ridge west of Mount Chamberlain.

Five mineable seams have been identified and are designated in ascending order as "A", "B", "C", "D", and "E". They range from less than a metre to 5 metres in thickness and have an aggregate thickness of approximately 12 metres.

2.5.1.5 Mount Spieker Property

The strata have undergone a moderate amount of deformation on the property. The southwest portion is folded into a broad northwest-trending syncline with dips varying from zero to 60 degrees. The northeast portion is separated from the southwest by a local anticlinal structure but the area is generally flat to gently dipping with dips under 10 degrees. Coal of mineable thickness is present in both the Gething Formation and the Gates Formation. Within the Gething Formation, the Bird seam is well developed averaging 2.3 metres in thickness; however, the Skeeter seam is only 1.5 to 2.4 metres in the west and thins southeastward. The Chamberlain and Middle seams are very thin.

Coal seams within the Gates are more developed than those in the Gething, especially in the southeast. Four distinct seams exist, they have an average aggregate thickness of approximately 12 metres. Individual seam thicknesses up to 5.1 metres have been recorded. Only two of the proposed pits, EB-1 and Mount Spieker Ridge, contain measured reserves; all are in the Gates Formation.

2.5.1.6 Quintette Property

The Gates Formation and the Gething Formation both contain coal seams of mineable thickness on the Quintette property; however, the Gates contains all the reserves.

There are six seams of mineable thickness in the Babcock area, but three contain bands of rock or other impurities. The remaining three are relatively clean seams with thicknesses in excess of 3 metres; all are considered to be high quality metallurgical coking coals. The structure underlying the Babcock Mountain area includes an extensive area of gently dipping seams bounded on the southwest by the Waterfall Creek syncline, an upright fold with steeply dipping limbs. A considerable tonnage of coal recoverable by open-pit methods has been discovered on the Quintette property. In the Babcock area, two pits have been delineated, the Babcock and the Roman. The Babcock pit, on the east slope of Babcock Mountain, will exploit six seams in the nearly flat strata. The Roman pit is located within a fairly simple chevron fold at the southern end of the Murray syncline. Here five seams have an aggregate thickness of approximately 15 metres.

North of the Murray River in the Wolverine area, two more pits have been delineated. The McConkey (Sheriff) pit, which is located on Mast Ridge, is contained in a complex syncline overlying a large thrust fault. The Deputy pit is situated in a smaller syncline immediately to the southwest and is contiguous with the McConkey pit. Two seams totalling nearly 15 metres in thickness constitute the bulk of the reserves. The Frame pit, southwest of the McConkey pit, is located in the Mast syncline, an area of relatively minor faulting. Five seams are developed here but two seams are thinner, giving an aggregate thickness of 12 metres.

2.5.1.7 Monkman Property

The licences cover two narrow linear belts of Lower Cretaceous strata of the Bullhead and Fort St. John Groups that lie along the limbs of a broad northwesterly trending anticlinal structure. The two belts differ greatly in structural complexity. The southwestern belt, which extends from the Narraway River northwestward to Kinuseo Creek for a strike length of 70 kilometres, is relatively undeformed with dips in the order of 30 degrees to 50 degrees to the southwest. In the northwestern part of the belt, the strata have been folded into two doubly plunging northwest-trending synclines.

The northeastern belt is more deformed. It has folds trending northwest, cut by southwesterly dipping thrusts. It extends from Wapiti River to Kinuseo Creek, a strike length of 27 kilometres.

The Gates Formation, which has an average thickness of 300 metres, is the main coal-bearing sequence; however, coal seams of possible economic importance do occur in the Gething Formation and some coal seams may be of interest in the Minnes Group. In the southwestern belt, coal seams occur along the entire strike length in the Gates Formation. In the Mount Belcourt area, the member contains three seams that are over 1.4 metres in thickness, totalling 14 metres of coal. North of the Wapiti River there are six seams that exceed 1.5 metres in thickness and have an aggregate total of 18 metres of coal.

In the area of the two proposed pits with measured reserves (Duke and Honeymoon), the Gates Formation has an average thickness of 270 metres. Five seams averaging approximately 3, 4, 5, 5, and 3 metres each are developed in the area of the two pits.

Gates coals rank as medium-volatile bituminous coals. Gething coals have a reputed rank of high-volatile bituminous in some areas. Coals that occur in the Minnes Group are of a low-volatile bituminous rank.

The structure of the Duke area consists mainly of an anticline/syncline pair with a southeasterly axial trend. The anticline has a box fold configuration with several thrust faults; the syncline has a chevron form. The bedding in Duke pit generally dips between 30 degrees to 50 degrees to the east and is part of the eastern limb of the anticline. The hinge line has a very shallow and variable plunge. In the southeastern section of the pit there is a high-angle reverse fault running northwest to southeast and dipping between 40 degrees to 60 degrees to the east. This fault trends southeast and truncates the syncline and most of the anticline. The northern section of the pit is cut by three of the four main reverse faults. They dip at about 60 degrees to the south. These high-angle faults, trending west to east, are oblique to the general strike of the area.

The Honeymoon area is divided into two main pit areas. They occur west and east of a large, southeasterly plunging anticline. This anticline is characterized by a box fold with an axial plunge increasing from 12 degrees to 20 degrees in a southeasterly direction.

The structure of the Honeymoon West pit consists of the western limb of the anticline which has dips of 30 degrees to 35 degrees to the southwest. Some high-angle reverse faults are found trending northwest to southeast from the middle to the northern section of the west pit. These faults dip at approximately

55 degrees to 60 degrees to the southwest and narrow from two faults to one main fault in the northern section.

The Honeymoon East pit is further separated from the West pit by a smaller syncline/anticline pair to the east of the large anticline. The eastern limb of the anticline has dips from 40 degrees to 50 degrees to the northeast. In the southern end of the pit the dip angle decreases to approximately 20 degrees, eventually reaching the anticlinal nose of the fold within the pit. A low-angle reverse thrust fault occurs in the southern section of the property; it trends in a northwest to southeast direction.

2.5.1.8 Saxon Property

The Saxon property is underlain by a complex syncline or synclinorium which brings coal-bearing Gates Member strata to the surface at its edges. The Saxon East reserve area is found on the eastern limb of the major synclinorium where consistently steep dips are found in blocks which may be suitable for hydraulic mining. The Saxon South reserve area is located in the southwestern corner of the property where the Gates strata are faulted and folded into series of anticlines which provide coal reserves that are suitable for open-pit mining. In the Saxon East three Gates Member coal seams, numbered 1, 2, and 4 from the base up with respectively weighted average thicknesses of 5.5, 5.95, and 5 metres, can be considered for mining. In Saxon South, six mineable seams numbered 1 through 5 and 10 have respective thicknesses of 4, 5, 2, 8, 1.5, and 1.2 metres. Seams 1, 2, and 4 provide over 85 per cent of the reserves.

2.5.2 SOUTHEAST COALFIELDS

The Southeast Coalfields extend 175 kilometres from the International Boundary northward to the head of the Elk River, with a maximum width near Fernie of 35 kilometres. They consist of three structural areas: the Flathead Coalfield near the Boundary, the Crowsnest Coalfield east of Fernie, and the elongated Elk Valley Coalfield which lies *en echelon* and to the north of the Crowsnest Coalfield. The following section contains detailed descriptions of those properties containing measured reserves. Figure 2.5 (in pocket) is a map of the southeast area that outlines the measured reserves and those indicated resources which do not have the control in data-point spacing to be considered measured. The indicated resource calculations are still in progress.

The coal in all three basins is contained in the Mist Mountain Formation of the Jurassic-Cretaceous Kootenay Group. This formation averages 600 metres thick and consists of interbedded sandstone, shale, and coal. The latter comprises of seams varying from less than 1 metre to greater than 15 metres in thickness, forming an average of 8 to 12 per cent of the total thickness of the formation. In the Flathead Coalfield, the Mist Mountain Formation occurs only as scattered erosional remnants in various structural positions which, on a regional basis, are truncated by faults. The Crowsnest Coalfield, occupying the Fernie Basin, is broadly synclinal with fold axes trending west of north and which plunge northward in the southern part and southward in the northern part of the basin. Toward the centre of the basin the coal measures are thought to be gently dipping and broadly folded. Toward the edges, particularly the eastern edge, the dips are moderate to steep and the beds are folded and truncated by faults. In the Elk Valley Coalfield, the Mist Mountain Formation is within the Alexander Creek syncline that trends north-northwest. To the south only erosional remnants in the trough of this syncline are preserved. However, to the north the Mist Mountain Formation is present for almost 80 kilometres, though it is faulted and locally has complex folding.

With the exception of the northern end of the Elk Valley Coalfield and the Dominion Coal Blocks, all the area of the Kootenay Group is held under licence or freehold.

2.5.2.1 Elk River Property

This property is the northernmost property of the Elk Valley Coalfield containing measured reserves. The rocks of the Mist Mountain Formation and locally the Blairmore Group in the Elk River valley form the Alexander Creek syncline. This is a north to northwesterly trending asymmetric syncline with a westerly dipping axial plane. This structure is truncated on the western side of the valley by the north-trending, westerly dipping Borgeau thrust fault. Coal-bearing strata on the eastern side of the valley dip 35 to 40 degrees to the west, whereas exposed strata on the western side are vertical. The intervening structure is poorly understood, but the numbering and correlation of seams have been made on the assumption that the structure is a relatively simple syncline.

The measured reserves are mostly found east of the river, where the seams dip somewhat more steeply to the west than the slope. The northern limit of a proposed pit is 0.4 kilometre south of the junction of the Elk River and Cadrona Creek; the southern limit is 6.2 kilometres farther south. The average total thickness of mineable coal in the initial pit is 90 metres, comprised of 18 groups of seams. Another 11 metres is contained in five additional seams intersected by the ultimate pit. The rank ranges from low to high-volatile bituminous.

2.5.2.2 Fording River Property

The measured and indicated reserves are within and adjacent to the Fording mine. They underlie the mountains east of the Fording River between Henrietta and Kilmarnock Creeks, including Eagle Mountain and the lower slopes of the Greenhills Range west of the river.

The major structural features of the Fording River property are two northerly trending synclines. The Alexander Creek syncline to the east and the Greenhills syncline to the west of the Fording River are separated by the Erickson (Fording River) normal fault that is downthrown on the west. Several westerly dipping thrusts, and a few other normal faults further complicate the structure.

The Mist Mountain Formation is well over 600 metres thick on the Fording River property and contains at least 10 seams of significant thickness—the lowest of which overlies the basal sandstone. The No. 4 and B seams are identical, occurring east and west of the Fording River respectively. This seam, No. 4 or B, is the thickest on the property, having a mean thickness of 10 metres and reaching 18 metres in places. In the Greenhills area, total mean thickness of the mineable seams is approximately 55 metres; in the Clode Creek area, it is 50 metres. The coal rank is medium-volatile bituminous.

2.5.2.3 Greenhills Property

The Greenhills area is located at the southern end of the Greenhills Range situated between the Fording and Elk River valleys. The Greenhills syncline is an open syncline which plunges gently northward and dominates the geology of this area. The west limb has beds dipping between 20 degrees and 40 degrees to the east, whereas the beds on the east limb dip 20 degrees to 60 degrees to the west and are interrupted and offset by faulting that also dips to the west. Moderate to severe deformation in the form of dragfolds and minor thrust faults occurs in places throughout the length of the synclinal axis. This deformation decreases away from the axis of the syncline.

The largest of these faults is the Erickson (Fording River) normal fault. The western block of the fault was downthrown and displacement was over 600 metres. This fault bounds the northern section of the eastern pit limit.

The Greenhills fault occurs as an offshoot of the Erickson fault and defines the southern end of the eastern pit limit. It has a displacement of between 120 to 140 metres.

The western pit limit follows the general trend of the surface topography, travelling along a north-northeasterly direction it cuts into the western limb of the syncline. There are indications of minor, low-angle thrust faulting in this limb as well.

The coal-bearing member within the Kootenay Formation contains 29 known coal seams, however only a few of these are economic to mine. Seams 1, 7, 10, 16, and 20 are major seams. They are continuous throughout the property but are not consistent in thickness or in quality. They constitute about 68 per cent of the in-place coal reserves. The remaining percentage is found as discontinuous, lenticular seams in the upper half of the coal-bearing member.

Seams 1, 7, and 10 are coals of medium-volatile bituminous rank, whereas seams 16 and 20 are of high-volatile A bituminous rank.

2.5.2.4 Line Creek Property

The Line Creek property is situated on the west limb of the Alexander Creek syncline, near the south end of the Elk Valley Coalfield. Up to 550 metres of Mist Mountain Formation are preserved as a dip-slope on Line Creek Ridge. The relatively straightforward synclinal structure is complicated by bedding "rolls" and small-scale faults.

The Mist Mountain Formation contains seven coal seams that are thicker than 2.8 metres and have an aggregate thickness of up to 55 metres. Ninety per cent of the reserves are in the four lower seams, Nos. 8, 9, 10B, and 10A, which have an aggregate thickness of approximately 26 metres. The seams range from low to medium-volatile bituminous in rank.

2.5.2.5 Sparwood Property

Sparwood, Natal, and Harmer Ridge are at the north end of the Crowsnest Coalfield. The first is separated from the latter two by the valley of Michel Creek.

The area, consisting of the three ridges, has a sequence which is gently folded into a regional structure referred to as the Sparwood syncline. This is the fold that terminates the pear-shaped Fernie Basin (Crowsnest Coalfield). The western limb of the fold dips easterly at about 30 degrees, whereas the eastern limb dips westerly at about 20 degrees. Folding, especially on the eastern limb, has produced a number fo thrust surfaces of small displacement which locally repeat portions of the stratigraphic section.

The coal measures in the Sparwood area are about 610 metres thick and between 45 and 52 metres of coal are contained in 11 seams. The seams are identified in ascending order as 10, 9, 8, 7, 6, 5, 3 or 1, A, B, C, and D. Seam 3 on Natal Ridge is identical to Seam 1 on Sparwood Ridge. Current production is mainly from the number 10, or Balmer seam, which is mined by both underground hydraulic and conventional methods. The Harmer Ridge mine is an open-pit surface mine. The underground conventional mine is in the Harmer-Natal area whereas the hydraulic minesite is to the south at Sparwood. Natal Ridge, the former minesite, is again under exploration. The coal rank ranges between low to high-volatile bituminous. The upper seams tend to be high-volatile bituminous.

2.5.2.6 Hosmer-Wheeler Property

This property is found on the western edge of the Crowsnest Coalfield. Of the two ridges making up this property Wheeler Ridge is found east of Hosmer Ridge. The reserves are in part bounded to the north by the northern Dominion Coal Block.

The coal measures lie on the upper plate of the southwesterly dipping Dominion thrust fault. The structure of this area is dominated by a broad open syncline that plunges southwesterly at between 10 to 30 degrees. The axial trace of this fold continues into the northern Dominion Coal Block where it is terminated against the Natal Lookout thrust fault, a splay of the Dominion thrust fault. In general the strata on Hosmer Ridge dip southeasterly at 20 to 30 degrees while strata on Wheeler Ridge dip to the southwest at 10 to 45 degrees. South of the area, coal measures plunge beneath younger cover rocks.

The total thickness of coal measures on the Hosmer-Wheeler property is about 762 metres, of which 79 metres is coal.

Plans for a proposed mine at the Hosmer-Wheeler project are now in abeyance. Extraction was to have been from seven seams, namely Nos. 2, 3, 4, 8, 9, 10, and 11 with respective thickness ranges of 3.5 to 4.5 metres, 3.5 to 20 metres, 2.5 to 8 metres, 8 to 10 metres, 4 to 8 metres, 3.5 to 4 metres, and 4.25 to 4.5 metres. The seams range from medium to high-volatile bituminous in rank.

2.5.2.7 Corbin Properties

The Corbin properties are located on Coal Mountain which lies on the eastern edge of the Crowsnest Coalfield adjacent to the Alberta-British Columbia boundary. Two areas and two companies are involved. Byron Creek Collieries Ltd. produces coal from it's freehold land on the northern side of Coal Mountain. The southern side of Coal Mountain is leased and under exploration by Crows Nest Resources Ltd.

The Byron Creek area is structurally dominated by a double syncline plunging northward 15 to 30 degrees. Thrust faulting has modified the folds to some extent throughout.

The southern Coal Mountain area has four prominent synclinal folds, which plunge to the north about 20 degrees, and one anticline. The three western synclines are imbricately thrust faulted upon each other and separated from the fourth by the Coal Mountain anticline. A series of high-angle reverse faults dipping to the west are found west of the Coal Mountain anticline.

Little remains of the coal-bearing Mist Mountain Formation on the Corbin properties resulting in the occurrence of only one coal seam or zone. The "Mammoth" seam is intensely deformed and abnormally thickened in the cores of fold synclines. The coal is medium-volatile bituminous but will not coke because of extensive oxidation. At Byron Creek the "Mammoth" seam averages 30 metres in thickness and appears as one seam whereas at the southern side of Coal Mountain the "Mammoth" seam or zone has been divided. The "Lower Mammoth", not currently economic, has been found up to 58 metres thick with high ash and partings. The "Upper Mammoth" seam is considered economic with coal up to 35 metres thick and shale interbeds ranging from 0.5 centimetre to 4 metres.

Underground mining at Byron Creek, which was undertaken during the period 1908 to 1934, was generally unsuccessful because of structural problems and the susceptibility of the coal to spontaneous combustion. Production is now from three general pit areas representing separate structural blocks. The mine-run coal has a rather high ash content as the original rock partings are intimately mixed into the coal by the shearing which occurred during deformation.

2.5.2.8 Sage Creek Property

The Sage Creek property lies in the Flathead River valley. The coal measures of this deposit occur on the east flank of a monocline striking north to northeast and dipping to the east at about 30 degrees.

The deposit is structurally divided into two segments by the valley of Cabin Creek which is aligned at right angles to the strike of the strata. The South Hill deposit, south of Cabin Creek, is complicated by normal faulting which trends to the northwest and causes apparent down-dip repetition. The fault displacement ranges from 60 to 240 metres and usually drops the beds on the west side. This normal faulting has had the effect of preserving coal-bearing strata up-dip that otherwise would have been eroded. The North Hill deposit, north of Cabin Creek, has only a minor amount of faulting; it more closely approximates a dip slope than the South Hill deposit.

The coal-bearing section of the Kootenay Group in this area is approximately 185 metres thick. There are three major mineable seams present in this deposit of medium-volatile bituminous rank. The lowest, No. 5, has an average thickness of 10 metres and is split by a parting ranging from 1.0 to 2.5 metres in thickness. The middle seam, No. 4, is split by a parting from 1 to 12 metres in thickness that produces upper and lower benches with average thicknesses of 8 and 6 metres respectively. Seam 2, the highest economic seam in the section, has an average thickness of 3.3 metres.

2.5.3 HAT CREEK COALFIELD

The upper Hat Creek valley is underlain by Tertiary age strata containing coal, clastic sedimentary and volcanic formations. These strata rest unconformably on Cretaceous volcanic rocks and metamorphosed Paleozoic carbonate and greenstone basement rocks.

Much of the detailed stratigraphic information now available is the result of the 1974 to 1978 drilling program of British Columbia Hydro and Power Authority. This work shows that the coal-bearing unit, referred to as the Hat Creek Coal Formation, is almost everywhere succeeded by a thick claystone unit, the Medicine Creek Formation, which in turn is unconformably overlain by a volcaniclastic sequence known as the Finney Lake beds. The Finney Lake volcaniclastic rocks are assigned to the Kamloops Group.

Owing to the great stratigraphic thickness of the Tertiary rocks (more than 1 300 metres in the centre of the basin) few drill holes have penetrated to the base of the section. An equally thick succession of sandstones, conglomerates, and siltstones comprising the Coldwater beds is exposed mainly to the north and west of the drilling area. These rocks are largely fluvial in origin and are thought to partly underlie, and to be partly equivalent to, the Hat Creek Coal Formation.

The structure of the Hat Creek Basin is straightforward and simple in broad aspects. The central zone of the main valley, underlain mainly by the coal measures and associated sedimentary formations, has been downfaulted forming a graben. This has been achieved principally by movement on a series of north-south tension faults trending in the direction of maximum regional stress. Locally the walls of the graben, particularly at the northern and southern extremities of the basin, are offset somewhat by a series of northwest and northeast-striking conjugate shear faults. Easterly trending gravity faults in this area appear to be more recent in origin, being superimposed on the graben.

Other subparallel graben-like structures occur to the northeast, exposed along the lower course of Hat Creek and in the Trachyte Hills. In this area Upper Cretaceous (?) sandstones and conglomerates are tilted to the east and west in fault-bounded panels and are unconformably overlain by near horizontal dacite and rhyolite outliers of the Kamloops Group.

The Hat Creek Coal Formation is approximately 425 metres thick; consequently, it is estimated that between 1.66 and 2.5 million years were required to accumulate the coal measures. The complete sedimentary cycle, including an undetermined thickness of Coldwater beds below and approximately 300 metres of strata of the Medicine Creek Formation above, may represent an additional million years of deposition.

2.5.3.1 Hat Creek Property

The name Hat Creek Coal Formation is applied to the coal measures. The principal exposures are along a 400-metre section of Hat Creek about 1.5 kilometres south of Marble Canyon. This area, which includes the original coal discovery, is referred to as the No. 1 Reserve. A second coal deposit, the No. 2 Reserve, is centred about 8 kilometres south near the mid-point in the valley.

The general stratigraphy of the coal formation, especially in the area of No. 1 Reserve, is known from detailed studies of drill core. Three principal seams are recognized here. The coal formation, consisting of somewhat more than 425 metres of strata, maintains a more or less constant thickness although the "height" of clean coal varies markedly over short distances passing into shaly coal then coaly shale. The uppermost seam, about 160 metres thick, constitutes more than one-third of the total formation. It is a relatively impure sequence of alternating coal, seat earth, and siltstone and sandstone lenses. The middle and lower seams are comparatively thin, 50 metres and 70 metres thick respectively, and are separated by zones of sandy siltstone, conglomeratic sandstone, and a few thin coaly bands. The bottom half of the lowest seam has the largest apparent volume of clean coal at a thickness of about 30 metres. The coal rank according to the ASTM system is subbituminous B.

The structure of the No. 1 deposit consists of a southerly plunging trough with limbs dipping about 30 degrees to 70 degrees to the east and west. Several steeply dipping normal faults striking east, north-northeast, and northwest displace the coal beds.

The No. 2 deposit is elongated in a north-northwest direction. It is about 5 800 metres long and averages 760 metres in width and the coal beds generally dip to the west. The anticline limbs may be terminated or disrupted by steeply dipping faults. This area is not as extensively drilled as the No. 1 deposit and thus has only reached an indicated resource evaluation stage.

2.5.4 SIMILKAMEEN COALFIELD

Throughout the Interior Plateau region of southern British Columbia discontinuous, generally small areas of Tertiary rocks lie unconformably on most, if not all, the older rocks. While the bulk of these rocks are of volcanic origin, relatively thick sequences of sedimentary rocks mainly of fluvial and lacustrine origin are found interbedded with the volcanic rocks in many places. The Princeton and Tulameen Basins are two such areas which contain coal measures and have been commercially exploited in the past, although only the latter contains economic reserves today. In the Princeton Basin, four main coal zones are found in the lower 400 metres of the approximately 1 500-metre-thick Allenby Formation. A mid-Eocene age has been derived from K/Ar dating. The northern half of the basin has been folded into a very gentle open syncline about a gently plunging, easterly trending fold axis. The limbs of the syncline dip inward about 15 to 25 degrees, shallowing to the east (McMechan, 1981). The southern part of the coalfield appears as a large basin-like structure into which project three large anticlinal noses. The strata dip steeply (50 to 70 degrees) eastward along the western margin (Shaw, 1952).

2.5.4.1 Tulameen Property

The Tulameen Basin, centred 20 kilometres northwest of Princeton, is a possible volcano-tectonic sink with an elliptical 5.4 kilometre by 3.6-kilometre coal-bearing sedimentary core.

The basal Tertiary volcanic and sedimentary rocks rest unconformably on Triassic greenstones and metasedimentary rocks. They are overlain by young basaltic lavas and breccias. The age of the older sequence of lavas is placed near the boundary between Lower and Middle Eocene.

The Eocene beds are estimated to be 800 metres thick where best developed. The coal measures, about 30 metres thick in the southwestern part of the basin, are sandwiched between 200 metres of sandstone and shale below, and 60 metres of fissile shale above. An estimated thickness of 500 metres of quartzose sandstone and conglomerate forms the uppermost part of the sedimentary succession in the central part of the basin.

The Miocene basalt series ranges to about 100 metres thick. These rocks overlie the Eocene sedimentary pile in the south and west-central parts of the basin. Feeder dykes to these lavas cut older rocks in the area, including the coal beds north of Blakeburn pit. Here a large dyke, about 50 metres wide, intrudes a fault zone and divides the old mine workings.

The thickest and most continuous coal deposit is in the Blakeburn area at the site of the old mining operation. The original mining excavation followed a 2 to 4-metre thick seam with a strike length of 2.3 kilometres. Individual seams above and below the mine seam are separated by clay layers, rhyolite ash bands, or shaly partings. The coal is a high-volatile bituminous B and C variety.

Laterally the coal beds "shale out" as is typical of limnic deposits. The main coal zone has been traced 3 to 4 kilometres along strike northwest from the Blakeburn pit to where the measures are 15 to 20 metres thick. However, to the east and south the coal horizon diminishes to a few thin seams and impure carbonaceous beds.

The coal-bearing formation is subdivided into a lower sandstone unit of 100 to 150 metres thick. It is a coarse to fine-grained sandstone interbedded with mudstones and shales. The second division is the coal-bearing member found in the sedimentary rocks of Tertiary age. This member is approximately 130 metres thick on the western margin of the basin. It has been subdivided further into coal, mudstones, bentonitic clay, shales, and sandstones. The upper sandstone unit completes the formation and rests conformably on the coal member. This unit is divided into two sections: the first consisting of 3 to 6 metres of coarse to fine-grained sandstones interbedded with fissile shales, siltstones, and sandy shales and the second is a 600-metre section of granule conglomerates and coarse sandstones.

There are two major coal seams, one of which is economically important. The Main coal seam has a thickness ranging between 15 and 21 metres. The individual beds are well banded. The ratio of waste rock to coal increases from south to north in the drilling area. The coal is of a high-volatile bituminous C rank. The Lower coal seam is not of economic interest presently. It is a very dirty coal seam between 7.0 and 7.6 metres thick, interbedded with mudstones and bentonite.

The Tertiary sediments are structured in an asymmetric syncline which trends northwest. The southwestern limb has beds dipping about 20 to 25 degrees.

Northeast and along the northeastern limbs, the dips steepen from 55 to 80 degrees southwest. The area of potential economic reserves has dips increasing from 25 to 45 degrees northeast in the northern section.

At least four major faults trending northeast occur in the southwest, creating a vertical offset of about 152 metres. Numerous small-scale faults and dragfolds are found on the northern edge of the basin, but these do not cause major displacements.

2.5.5 *VANCOUVER ISLAND COALFIELDS*

The economic coal deposits of Vancouver Island occur in the Late Cretaceous Nanaimo Group, which rests unconformably on a basement of Paleozoic to Jurassic sedimentary, volcanic, and intrusive rocks. The coal measures consist of up to five depositional cycles. The coarse clastic nearshore sediments at the bottom of each cycle grade upward to the fine clastic offshore marine sediments (Muller and Atchison, 1971).

Significant coal is restricted to two major and one minor coalfields. The major ones are designated Nanaimo, centred around that city, and Comox, centred around Cumberland. The minor one is the Suquash, between Port McNeill and Port Hardy. Muller and Atchison (1971) concluded that the Nanaimo field is largely mined out. The Comox field is a composite, embracing several subfields or isolated areas. All production has come from the Cumberland and Tsable River areas. Preliminary exploration was done in several other areas at different times, including Cowie Creek, Anderson Lake, Quinsam, and Campbell River in 1976. Only one seam was found in the east area, and in 1977–78 grid drilling was done in the Quinsam area.

2.5.5.1 Quinsam Property

This property is bounded on the east by a ridge of Triassic Karmutsen basalt and on the north by Campbell Lake. On the west and south the erosional edge rests on the Quinsam stock and Middle Bonanza volcanic rocks. Outside the Iron River and a section of the Quinsam River valley natural exposures are scarce, and knowledge of the stratigraphy and structure has in part been pieced together from drill logs. The coal-bearing part of the property was systematically drilled at 152 and 76-metre (500 and 250-foot) centres using a solid bit for the most part. The cuttings were logged by the drillers and the logs were used in the seam correlations.

A discontinuous basal conglomerate is overlain by a recessive unit some 40 metres thick consisting mainly of shale and siltstone. It is in turn overlain by several hundred metres of sandstone containing sporadic thin layers of shale and siltstone. One discontinuous layer is as much as 8 metres thick and lies about 25 metres above the lower recessive unit.

The overall structure of the coalfield is a broad asymmetric syncline with an axis striking about 25 degrees west of north. On the shore of Campbell Lake the contact with the Karmutsen is clearly a fault, on which the Nanaimo beds have been relatively downthrown. Southward there are insufficient exposures to characterize the contact, but near the Iron River the geometry is compatible with an unfaulted, unconformable contact. A topographic lineament through Beavertail Lake and along Beavertail Creek coincides with a right hand offset of the contact with the Quinsam stock and probably marks a fault. South of Middle Quinsam Lake another strong lineament coincides with a contact between the stock and the Nanaimo beds and suggests a fault. However, the lineament ends abruptly eastward, and no more than 12 metres of throw could be determined from drill sections crossing the extension. Small faults are probably common. In the Iron River a steep normal fault has dropped the overlying sandstone down 2 or 3 metres against the coal.

As many as three coal seams are present, two of them in the lower recessive unit, respectively near the bottom and top, and the third in the shaly layer 25 metres above it. Generally the two lower seams are distinct, but from a borehole section near the Iron River they clearly coalesce southward. Thus only one thick seam is present in the river bed, and it thins out upstream to the southwest. The extent of the seam southeast of the Iron River is unknown. The lower seams also thin northward, and economic reserves on the east side of the coalfield are restricted. The lower seams occur extensively on the west side of the coalfield between Highway 28 and the southwest and south erosional edges, but over parts of the area thicknesses are sub-economic. The seams are commonly composite, containing one or more layers of carbonaceous shale as much as 1 metre thick.

2.5.6 TELKWA COAL DEPOSITS

The Telkwa coal deposits are found in west-central British Columbia, a few kilometres southwest of Telkwa and about 18 kilometres south of Smithers. The coal measures of the Telkwa basin occur within the Skeena Group which is of Cretaceous age. Intensive exploration has taken place over the last few years resulting in more details on structure and stratigraphy.

The Telkwa coal measures dip to the northeast or east between 5 and 15 degrees. Local variations in structure are caused by faulting, dragfolding or block tilting. The faults generally dip at high angles from 70 to 90 degrees and strike northwest, north-south, northeast or east-west. The coal basin has a horst and graben configuration consisting of two parallel, major grabens that contain coal measures separated by a central horst made up of Hazelton volcanic rocks.

Conglomerate, sandstone, mudstone, marl, and coal make up the Telkwa coal measures, generally averaging 400 metres in thickness. The measures consist of three stratigraphic units. The Lower unit attains a thickness of 15 to 120 metres, the Middle unit between 90 and 140 metres and the Upper unit usually consists of more than 330 metres.

The coal seams are found in the upper zone of the lower unit and the lower zone of the Upper unit. Four coal seams are located in the Lower unit ranging from 1 to 6 metres in thickness and achieving an aggregate thickness of 2 to 12 metres. The Upper unit contains 15 coal seams each averaging 1 to 5 metres thick and having an aggregate thickness of 26 metres. The coal ranges from medium to high-volatile bituminous in rank.

2.5.7 GROUNDHOG COAL DEPOSITS

The Groundhog coal deposits, somewhat over 260 kilometres in area, lie in the Skeena Mountains which are formed largely of folded sedimentary rocks of Late Jurassic and Early Cretaceous age. Folding is intense, but areas of relatively flat and gently dipping strata have been prospected. Several coal seams over 1.5 metres thick are recorded in the succession and may have considerable areal extent. Extraction would most likely be by underground methods, although some areas may be amenable to open-pit operations. The coal rank generally ranges from semi-anthracite to anthracite, and means that the coalification has proceeded to the extent that the coking and agglomerating properties of the coal are severely reduced. However, the coal has a relatively high heat content, that is, over 12,000 Btu/lb.* on a dry basis (ash included), or approximately 14,000 Btu/lb. on a dry mineral-matter-free basis. Ash content is generally quite low, as are the volatiles.

In recent years exploration activity has been concentrated on the Mount Klappan property in the northwestern part of the Groundhog Coalfield. The structure here shows open to tight folds that are almost vertical or are overturned to the northeast. The

* 1 Btu/lb. × .002326 = MJ/kg.

fold axes strike 30 to 60 degrees to the northwest and the axial planes dip from 25 to 85 degrees southwest. The folds are cut by thrust faults striking 20 to 40 degrees to the northwest and dipping 10 to 25 degrees southwest. The whole area is cut by younger high-angle faults trending northwest, north, or northeast. The coal measures have a minimum thickness of 350 metres and consist of conglomerate, sandstone, mudstone, marl, and coal seams. The coal seams occur in three units: the Lower, Middle, and Upper units. The Lower unit has six coal seams with an average thickness ranging between 1 and 5 metres and an aggregate total of 10 metres. There are 10 seams in the Middle unit averaging 1 to 5 metres in thickness and having an aggregate thickness of 7 metres. An aggregate thickness of 22 metres is found in the four seams making up the Upper unit and these average between 2 and 10 metres thick. Anthracite is the rank of the coal seams found here.

2.6 CONCLUSION

The reserves and resources presented herein are the best estimates available at the present time. The purpose of this study was to unify information on *in situ* coal across the Province and reach a plausible composite resource figure. The parameters were well defined to enable a more detailed procedure. The first section of this study, the calculation of measured reserves, has been completed up to the end of 1981 for the most part. The indicated and inferred resources have not been updated to that extent; this is currently underway.

There is no accurate way to estimate the effects of technical and economic factors which control the extraction and marketing of coal. The federal system from which our system has developed simply says: "the deposit must be economic". The British Columbia Ministry of Energy, Mines and Petroleum Resources has further defined economic as requiring a proper complete feasibility study with positive results.

The study of reserves and resources is a dynamic process as each year of exploration further defines the properties and coalfields. This in turn causes new resources to be included in the inferred category. As more exploration and drilling take place, portions of the inferred resources change to indicated; the indicated resources reach a measured status, and more mines are put into production. The mining techniques are not stagnant either. New methods, techniques, and better equipment evolve, allowing deposits that previously were uneconomic to become more attractive and feasible. The initial life of a coal mine is estimated for a certain number of years according to the measured or proven reserves. This mine life is generally extended by several years as continuing exploration proves up the indicated and inferred resources.

Exploration over the past decade has greatly improved knowledge of the coalfields in British Columbia. Interpretations of the structure and stratigraphy change and become more accurate with new data which will aid future mine planning. Geological descriptions for different coalfields and the properties in the Province, especially the Southeast and Northeast Coalfields, have been summarized to show presently accepted interpretations.

These reserve and resource figures are used only as a guide. The figures were simplified due to the information and time constraints. Although calculations were made as accurately as possible, other methods and parameters could have been incorporated.

Revised figures for measured reserves show the greatest change in the Peace River Coalfield. Over the past six years, exploration has been progressing rapidly in the northeast. The infrastructure is currently being constructed, although present restrictive monetary policies may curtail the development somewhat. A true comparison is not valid as previous figures were calculated using different parameters.

Subsequent to the writing of this manuscript several properties have achieved or nearly achieved a measured reserve status due to intense exploration activity. Four mines have come into production as well. In the northeast the Quintette and Bullmoose mines are operational and in the southeast the Line Creek and Greenhills mines have started production.

2.7 REFERENCES

Bielenstein, L. P. Chrismas, L. P., Latour, B. A., and Tibbetts, T. E. (1980): Coal Resources and Reserves of Canada, *Energy, Mines and Resources Canada,* Report ER 79-9.

B.C. Ministry of Energy, Mines and Petroleum Resources (1972): Geology, Exploration and Mining in British Columbia, 1972, pages 619–644.

——— (1976): Coal in British Columbia, A Technical Appraisal, *Coal Task Force,* November 1976 (second printing).

Coal Association of Canada, The (1980): Proceedings, 32nd Canadian Conference on Coal, September 14–16, 1980.

Dolmage, Campbell and Associates Ltd. (1975): Coal Resources of British Columbia, 1975.

Dowling, D. B. (1915): Coal Fields and Coal Resources of Canada, *Geological Survey of Canada,* 1915, Memoir 59, No. 55 Geological Series.

Energy, Mines and Resources Canada (1977): 1976 Assessment of Canada's Coal Resources and Reserves, 1977, Report EP 77-5, 20 pages.

Government of British Columbia (1977): Northeast Coal Study: Report on Coal Resource Evaluation Studies, January 1977, Resource Sub-Committee on Northeast Development, 126 pages.

Latour, B. A. and Chrismas, L. P. (1970): Preliminary Estimate of Measured Coal Resources Including Reassessment of Indicated and Inferred Resources in Western Canada, *Geological Survey of Canada,* 1970, Paper 70-58.

MacKay, B. R. (1935): Coal *in* Prospecting in Canada, Second Edition, *Geological Survey of Canada,* Economic Geology Series No. 7, 1935, pages 106–115.

McMechan, R. D. (1983): Geology of the Princeton Basin, *B.C. Ministry of Energy, Mines and Petroleum Resources,* Paper 1983-3.

Muller, J. E. and Atchison, M. E. (1971): Geology, History and Potential of Vancouver Island Coal Deposits, *Geological Survey of Canada,* Paper 70-53.

Shaw, W. S. (1952): The Princeton Coalfield, British Columbia, *Geological Survey of Canada,* Paper 52-12.

Wilson, Carroll (1980): Future Coal Prospects: Country and Regional Assessement, World Coal Study (WOCOL), *Ballinger Publishing Company,* Cambridge, Massachusetts.

——— (1980): Coal — Bridge to the Future, Report of the World Coal Study (WOCOL), *Ballinger Publishing Company,* Cambridge, Massachusetts.

III. THE QUALITY OF BRITISH COLUMBIA COALS

3.1 INTRODUCTION

There are three principal end uses for coals mined in the Province at this time; metallurgical coals are used to make coke for blast furnaces, thermal coals are used to raise steam for electric power generation, and coal may also be used to produce petrochemical feedstocks and gasoline. The diverse and varied nature of British Columbia's coal resources is reviewed in the context of these technologies.

3.2 COKING COAL QUALITY

Fundamental to any description of coking coal quality is a knowledge of two parameters: (1) rank and (2) maceral composition or coal type. These two independent variables together control the quality of coals and therefore influence utilization.

3.2.1 RANK OF COALS

Three principal methods of determining coal rank are currently being used by exploration companies and coal-producing companies in British Columbia. The most popular method uses the volatile-matter yield of a coal sample. In this standard American Society for Testing and Materials (ASTM) test, coal is heated in a closed crucible, and the weight lost (exclusive of moisture) is the volatile-matter yield of the sample.

Volatile-matter yield, converted to a dry, mineral-matter-free basis, is a principal parameter on which the ASTM "Classification of Coals by Rank" is based. In this system, agglomerating bituminous coals which possess less than 22 per cent volatile matter on a dry, mineral-matter-free basis (dmmf) [= 23 per cent volatile matter on a dry, ash-free basis (daf)] are of low-volatile rank, whereas those coals with less than 31 per cent volatile matter (dmmf) (= 32.5 per cent volatile matter daf basis) are medium-volatile in rank, and those with over 31 per cent volatile matter are high-volatile in rank.

For low-rank coals that do not agglomerate (non-coking coals) the calorific value on a moist mineral-matter-free basis is used to define rank in the ASTM classification.

The third method of determining rank employs reflected light microscopy and, although it is more precise, it is also more expensive, and is therefore less commonly used in routine exploration. In this test, a sample of ground coal ($<$20 mesh, $<$850 μm) is mounted in a thermo-plastic or cold-set resin, and polished. The maximum reflectance of the vitrinite maceral is then measured in oil at 546 μm on 100 grains and the mean of these values, $\bar{R}_o$ max, is taken as the rank of that coal sample. The advantage of this method is that it is very precise and no corrections are made to the determined values based on moisture or ash contents. It is therefore the superior method by which maturity, or rank, of coal can be established.

Reflectance determinations on vitrinite can be used to designate approximate ASTM rank groups as shown in Table 3.1

TABLE 3.1. Rank Categories Based on Reflectance

Reflectance ($\bar{R}_o$ max) per cent	Rank
0.50 — 1.12	High-volatile bituminous
1.12 — 1.51	Medium-volatile bituminous
1.51 — 1.92	Low-volatile bituminous
1.92 — 2.50	Semi-anthracite
$>$2.50	Anthracite

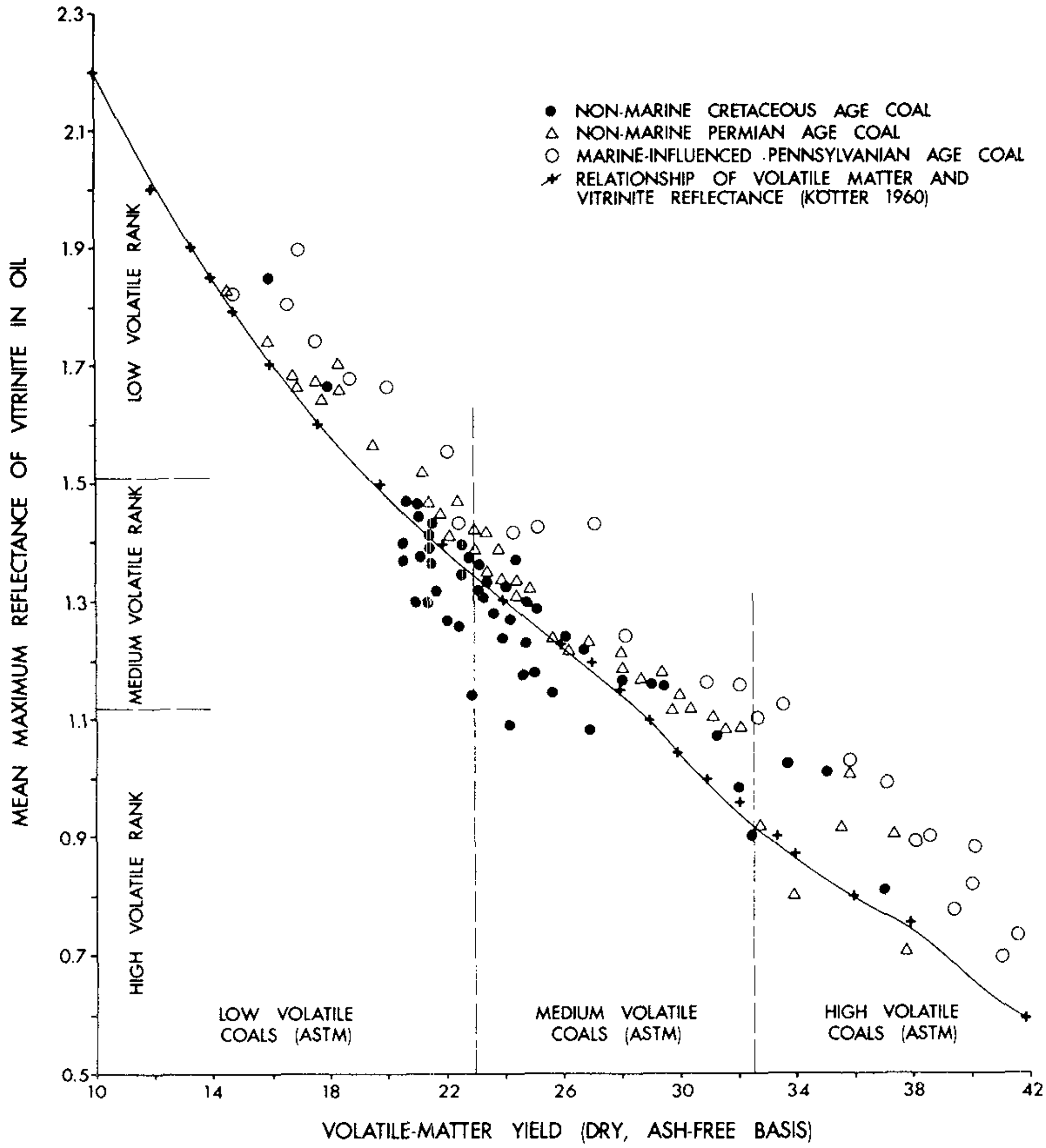


Figure 3.1 — Relationship between rank measured by vitrinite reflectance and rank measured by volatile-matter yield (corrected for ash and moisture).

Figure 3.1 shows rank as measured by the mean maximum reflectance of vitrinite in oil ($\bar{R}_o$) versus volatile-matter content (dry, ash-free basis) for coals from the non-marine Cretaceous age Southeast and Northeast Coalfields of British Columbia, from the non-marine Permian age German Creek seam of Queensland, and from some marine-influenced Pennsylvanian age coals in the United States. The diagram shows that the volatile-matter content of all coals decreases with increasing rank ($\bar{R}_o$). The continuous line shown on the diagram is the relationship between volatile matter and vitrinite reflectance for Pennsylvanian age coals from Europe. In general, the non-marine Cretaceous age coals possess lower volatile yields than both the non-marine Permian age coals and the marine-influenced coals of the same rank. In the rank range of $\bar{R}_o = 1.1–1.2$, for example, the variation between these different coals is about 11 per cent volatile yield. This variation is a consequence of compositional differences. Thus, British Columbia Rocky Mountain coking coals of non-marine origin and Cretaceous age which are characterized by relatively high inertinite contents have correspondingly lower volatile yields, whereas Pennsylvanian age, marine-influenced coals of similar maturity have higher volatile yields.

Because volatile-matter yield is dependent on both rank ($\bar{R}_o$) and maceral composition, analysis data on coals rich in the inertinite component are not indicative of true rank. This point is displayed in Figure 3.1 where coals with a dry, ash-free volatile yield of 23 per cent cover the range of $\bar{R}_o = 1.12–1.51$. This range of reflectance covers the entire medium-volatile bituminous rank range shown in Table 3.1 and shown on the ordinate on Figure 3.1.

3.2.2 MACERAL COMPOSITION OF COALS

Coal is composed of microscopically recognizable constituents, called macerals, which differ from one another in form and reflectance. Macerals are analogous to minerals of inorganic rocks. Three principal maceral groups are identified and these are, in increasing order of carbon content, exinite, vitrinite, and inertinite (Table 3.2).

TABLE 3.2. *Macerals Commonly Identified in Black Coals*

Group Macerals	Exinite	Vitrinite	Inertinite
Macerals	Sporinite	Telinite	Macrinite
	Cutinite	Collinite	Micrinite
	Resinite	Vitrodetrinite	Semifusinite
	Alginite		Fusinite
	Liptodetrinite		Sclerotinite
			Inertodetrinite

In a single coal, vitrinite, which is usually the most common maceral, has a higher reflectance than the associated exinite, but a lower reflectance than inertinite. There is, therefore, a correlation between carbon content and reflectance and this is used to precisely determine rank. Petrographers in Canada and many other countries use the mean maximum reflectance of vitrinite in oil ($\bar{R}_o$ max), at 546 μm, as the level of organic maturity, or rank, of a coal sample.

Vitrinite is thought to be derived mainly from the original woody tissue of trees in peat swamps. In Pennsylvanian age coals of Western Europe and the eastern United States, it often constitutes 60 to 80 per cent of the macerals, whereas in Permian age Gondwana coals of the southern hemisphere it rarely exceeds 80 per cent, and in some cases comprises less than 50 per cent of the total macerals.

Exinite, which is derived from pollen, spores, and leaf epidermis, is technologically important because, among other things, it enhances the fluidity of coal. Exinite contents of 1 per cent are common in Gondwana coals of the southern hemisphere, and 5 to 10 per cent in Pennsylvanian age coals. Both exinite and vitrinite are capable of yielding petroleum-type hydrocarbons.

The inertinite group of macerals is more or less nonreactive during the carbonization process. Whereas exinite and vitrinite melt, with an evolution of volatiles, inertinites generally remain intact. Inertinite is derived from fungal remains, charcoal and partly charred wood. Gondwana coals in general and many Lower Cretaceous Kootenay Formation coals of British Columbia and Alberta are enriched in inertinite macerals. For example, Lower Kootenay coals usually comprise 30 to 40 per cent inertinite; Pennsylvanian age coking coals generally consist of 5 to 20 per cent inertinite.

The maceral content and volatile-matter yield of a coal may be considerably influenced by the post-depositional chemical environment to which the normally acid peat is subjected. When the peat becomes covered by salt water, the maceral proportions remain unaffected but anaerobic bacteria flourish and promote advanced decomposition together with reduction of seawater sulphate to sulphide. This leads to development of per-hydrous coal which is rich in sulphur and has a higher volatile yield than normal. By contrast, in those cases where peats are generally covered by fresh water, but periodically exposed to oxidation, volatile-matter yields are reduced and the intertinite content may be increased at the expense of vitrinite and exinite.

In the East Kootenay (Southeast) Coalfields, roof strata and sulphur contents indicate that all seams formed under non-marine conditions, and in the Peace River (Northeast) Coalfield only two instances are known where marine strata form the seam roof. Thus, the influence of the post-depositional chemical environment probably explains why many Rocky Mountain coals are rich in inertinite macerals. Coals of the Comox Formation of Vancouver Island are often pyritic and may have marine roofs. They are also rich in the reactive macerals, exinite and vitrinite.

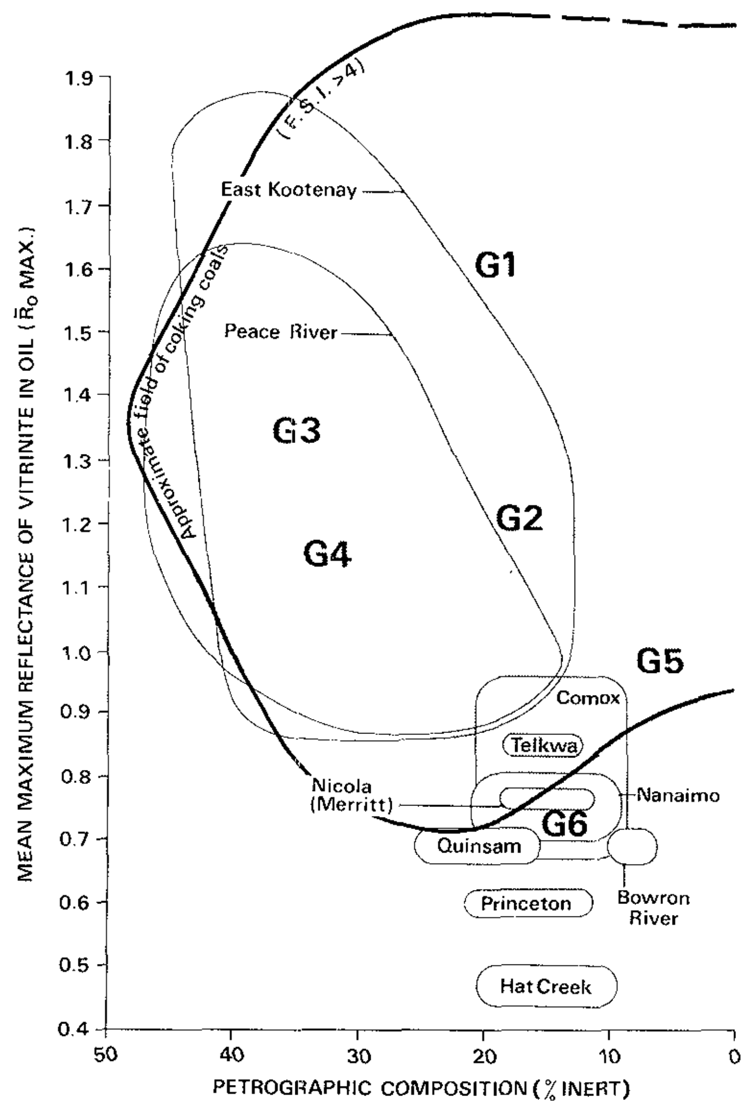


Figure 3.2 — British Columbia's coals displayed in terms of rank (vitrinite reflectance) and petrographic composition. Six international coking coal groups, G1–G6 are shown for reference. Group G6, soft coking coals, have FSI's less than 4, and for the purposes of this discussion are collectively regarded as thermal coals.

Figure 3.2 shows the petrographic composition (expressed as inerts or the percentage of inertinite macerals plus ash computed by the Parr formula) and rank (expressed as $\bar{R}_o$ max) of many of British Columbia's coals. Included in the diagram is the boundary line between coals regarded as coking and those which are thermal. The "optimum inert" line represents the optimum amount of inert components that would produce the strongest coke for each rank. Coal compositions to the left of the line are inertinite-rich, and those to the right are reactive-rich. It is apparent that most of British Columbia's currently exported coking coals are rich in inerts.

3.2.3 BRITISH COLUMBIA'S COKING COALS

Upon beneficiation, unoxidized coking coals generally show improvement in their caking and coking capacity. Coal petrography allows the prediction of these parameters in both oxidized and unoxidized coals whether or not there are high ash contents in the coal sample. In other words, by determining the rank and maceral composition of a coal, assuming that it can be obtained unoxidized and then cleaned to a reasonable ash level, petrography can classify coal types. Therefore, in this chapter, quality of coals is determined initially by petrography as shown in the classification of coking coal quality by group (Table 3.3). However, as there is only a small overlap between groups, and because they remain mutually distinct even when other parameters are used to define them, coking coal quality groups can be recognized by dilatation, fluidity, and Free Swelling Index (FSI) if the rank ($\bar{R}_o$ max) is also known. A full description of the classification appears in Pearson (1980).

TABLE 3.3. Classification of Coking Coal Quality by Group (From Pearson, 1980)

Group Name	Group No.	Rank ($\bar{R}_o$ max %)	Inert Content (%)	Max. Dilatation (%)	Max. Fluidity (DDM)	FSI	Volatile Matter (%)	Coke Strength JIS D^{30}_{15}	Coke Strength ASTM 25 mm
Keystone	G1	>1.50	8–30	0 to 70	5–100	6–9	16–19	92–93.5	50–65
Pittston	G2	1.0–1.4	8–30	80 to 260	1500–30000	7–9+	22–34	91–94	48–65+
Balmer	G3	1.2–1.5	25–45	−10 to 100	3–1500	5–8	19–26	90.5–93.5	40–62
Moura	G4	0.9–1.2	25–45	−10 to 100	3–2500	5–8	25–32	90–92.5	45–57
Kellerman	G5	0.8–1.0	0–25	100 to 300	1500–>30000	7–9+	32–38	75–90.5	20–48
Big Ben	G6	<0.9	5–20	−10 to 100	3–1000	5–7	37–40	50–80	0–30

Figure 3.2 shows many of British Columbia's agglomerating coals plotted together with the relative positions of the six coking coal quality groups as defined in the classification of Table 3.3. The information which permitted accurate plotting and classification of the coals shown is from the confidential coal files of the Ministry, therefore individual seams are not identified. However, rank information has been published by the Ministry for the Peace River Coalfield (Karst and White, 1980) and for the East Kootenay Coalfields (Pearson and Grieve, 1979 and 1980), so a general discussion on coking coal quality of these areas is possible.

Coals on most of the properties southeast of the Pine River in the Peace River Coalfield have reflectances between 1.1 per cent and 1.5 per cent which conform to groups G3 and G4 in Table 3.3.

West of the Peace River Canyon and south of Williston Lake, most coals have reflectances of less than 1.1 per cent, however, only some of these high-volatile coals conform with the quality parameters of group G5, much of the coal is similar in quality to Witbank from South Africa. Such coal is marginal coking coal but excellent thermal coal.

There are three principal coal areas in the East Kootenays: the Crowsnest Coalfield, Elk Valley Coalfield, and the Flathead Coalfield.

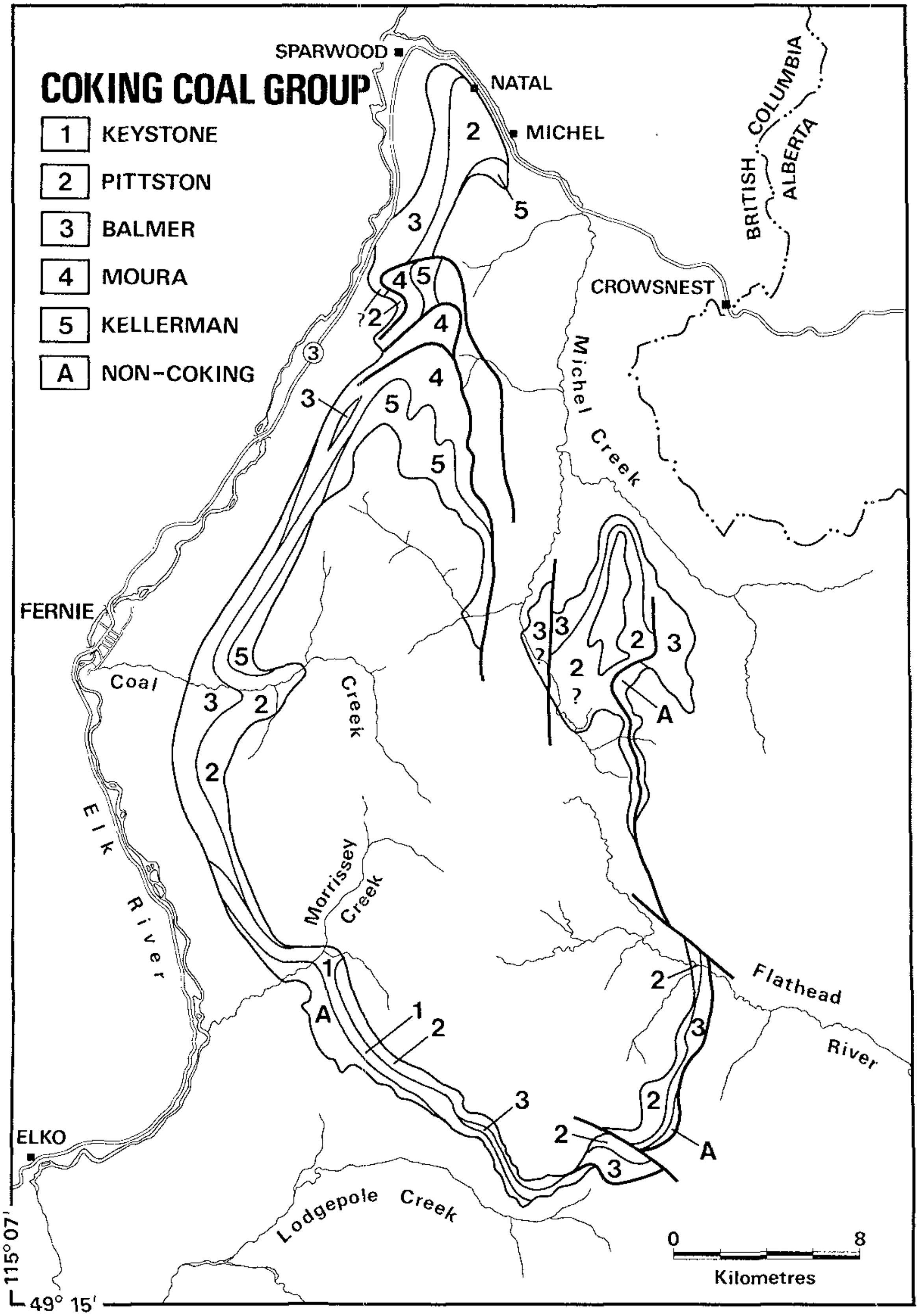


Figure 3.3 — Map showing the distribution of coking coal groups, G1–G5, in Crowsnest Coalfield.

In the Crowsnest Coalfield there are small areas of high rank coals with reflectances greater than 1.5 per cent, however, only some have qualities of group G1, the remainder are thermal coals. The majority of the coalfield is underlain by medium-volatile coals which conform to groups G2, G3, and part of G4. High-volatile areas, particularly around the north Dominion Coal Block, have reflectances less than 1.12 per cent and are of quality groups G5 and G4. The distribution of these groups is shown on Figure 3.3.

In the Elk Valley Coalfield, virtually all coals have reflectances less than 1.5 per cent, and large areas have reflectances less than 1.1 per cent. Thus the quality of the coals is principally of groups G3, G4, and G5.

On Vancouver Island, Comox Formation and Nanaimo Group coals have reflectances less than 1.1 per cent. Therefore all are of high-volatile rank. Coals from both areas have relatively low inert contents and conform with groups G5 and G6. The rank of coals in the Comox Formation decreases northward so that coals around Nanaimo are of G5 quality and have good coking capacity whereas those around Quinsam Lake are of G6 quality, have marginal caking capacity, and are regarded as thermal coals. Coal measures in the Nanaimo Group are stratigraphically higher than those of the Comox Formation. Despite the regional southward increase in rank, coals south of Nanaimo have qualities which conform to the parameters of group G6.

Coal measures around Telkwa and Merritt both contain coals which show caking capacities that conform with quality group G6.

3.3 THERMAL COAL QUALITY

The most important characteristics used to evaluate thermal coal qualities are calorific value, moisture, and ash. The calorific value of coal is reduced by both moisture and ash but the latter is particularly important because it influences boiler design and efficiency.

3.3.1 CALORIFIC VALUE

All coals burn, but there is a great variation in the level of heat emission. It depends on coal rank, maceral composition, ash content, moisture level, and the kind of combustion unit. Figure 3.4 shows the relationship between ash content and calorific value with reference to five varieties of British Columbia coal. The diagram shows that calorific value (expressed on a dry basis) increases with rank and decreases with higher ash contents. An inverse relationship also exists between calorific value and moisture content. Figure 3.5 shows approximate calorific values (on a dry, ash-free basis) as a function of rank and maceral composition for coals with vitrinite reflectances from 0.4 per cent to 1.9 per cent, inert contents of 0–50 per cent, and zero ash content. The diagram shows that at constant rank, inert-rich coals have lower calorific values than reactive-rich coals. Perhaps this reflects additional heat contributed by volatile gases during combustion of the reactive macerals. From this diagram it can be seen that the highest calorific values are obtained from high-rank coals and that these values decrease with both decreasing rank and increasing inert component. However, it should not be concluded that the most desirable coals are necessarily those of higher rank. Anthracites and semi-anthracites, for example, are difficult coals to ignite, whereas lower rank, high-volatile coals with their high gas contents, ignite easily.

3.3.2 MINERAL MATTER

In a general way, mineral matter in coals is dominated by two assemblages. Authigenic mineral formation is controlled by one of two end members that depend upon the pH of the peat swamp water, the alkali-availability, and the ion-exchange reactions that took place in the original peat swamp. Coal seams which developed from peat in anaerobic, low-pH environments where acid-leaching of alkalis takes place, have authigenic mineral parageneses characterized by alumina-rich clays (kaolinite) and quartz. In contrast, where peat swamps are invaded by marine waters, pH rises, bacterial activity increases, and ion-exchange reactions between sea water and either the peat or overlying marine silt results in nucleation of carbonates, iron sulphides, and alkali-rich clays (illites). Environmental factors result in many local variations to these two principal parageneses. Detrital minerals brought in by local river systems may, for example, change the physico-chemical conditions of the peat swamp. Nevertheless, the two end-member mineral-matter populations are depicted on Figure 3.6, which shows (1) marine-influenced Pennsylvanian age Illinois basin and Appalachian coals and (2) non-marine Cretaceous and Tertiary age Rocky Mountain coals and Permian age Australian Gondwana coals, in terms of their respective ash and sulphur contents.

3.3.3 ASH TYPES

Ash is the oxide residue that remains after combustion of coal. It results from thermal destruction of the mineral matter and is characterized chemically by oxide analysis. Whereas the mineral matter tends to be of geological interest, ash types can have considerable economic significance because of their environmental impact and potential for air and water pollution.

Figure 3.7 displays ash chemistry for some of British Columbia's coals on a ternary diagram. The approximate boundary between the two mineral-matter assemblages described above is indicated. Also shown are approximate ash fusion temperatures and a chemical cypher, the base/acid ratio. This ratio is useful in predicting slag viscosity and has a strong correlation with ash fusibility.

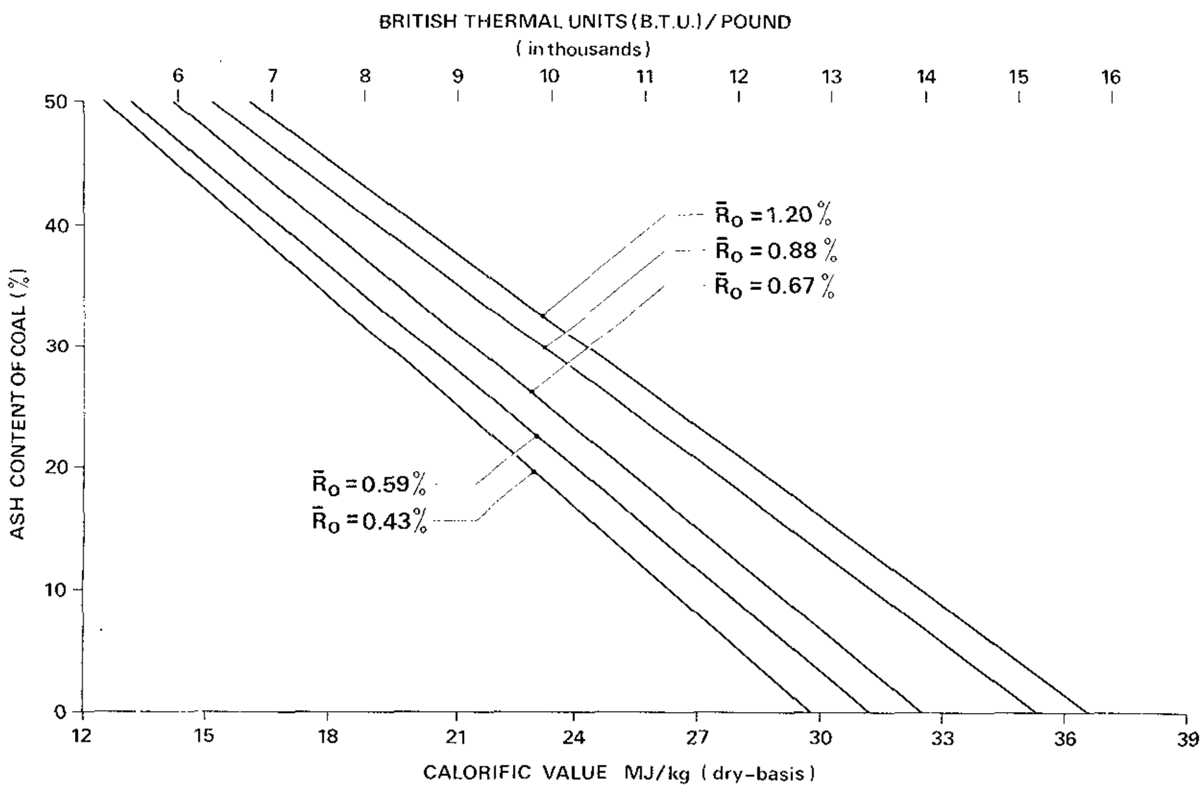


Figure 3.4 — Diagram relating calorific value to rank and ash content for five British Columbia coals.

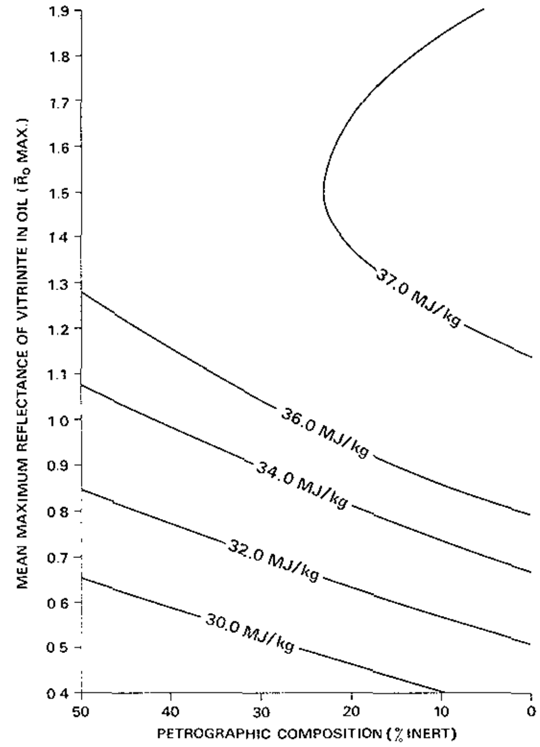


Figure 3.5 — Relationship between approximate calorific value, expressed as megajoules per kilogram on a dry, ash-free basis, rank (vitrinite reflectance), and petrographic composition.

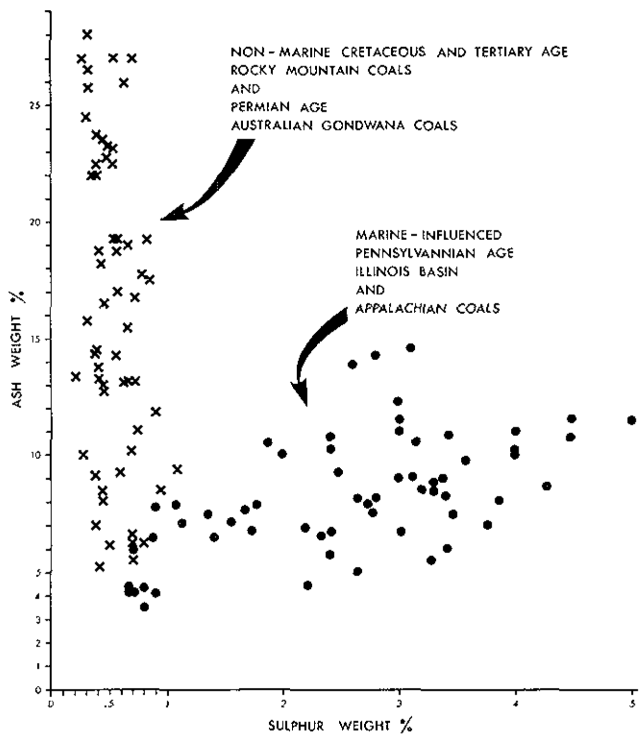


Figure 3.6 — Diagram displaying two different mineral matter populations in terms of ash and sulphur content. The nonmarine Cretaceous and Tertiary-age Rocky Mountain coals are kaolinite-quartz assemblages; the marine, influenced Pennsylvanian-age, Illinois Basin, and Appalachian coals are typical pyrite-illite-calcite assemblages.

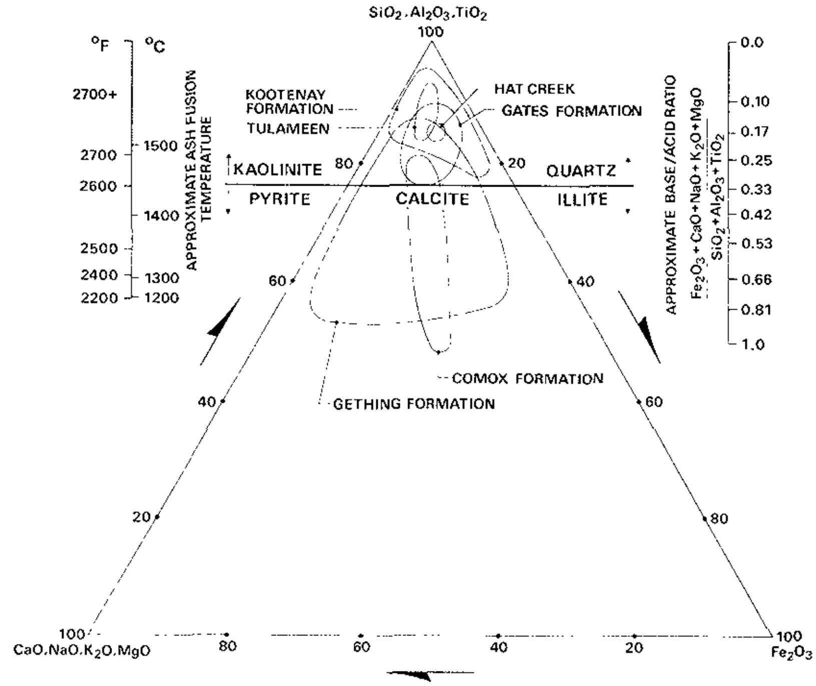


Figure 3.7 — Ternary diagram showing the chemistry of ash from some of British Columbia's coals, together with the approximate boundary for the two mineral-matter assemblages described in the text, the approximate base/acid ratio, and the approximate ash fusion temperatures.

The diagram shows that coal ash with low base/acid ratios (<0.25) has such an excess of refractory acidic oxides that high ash-fusion temperatures are common. The vast majority of Kootenay Group and Gates Member (Rocky Mountain) coals together with Hat Creek, some Vancouver Island, and some Gething Formation coals fall within this group. Such coals are characterized by the kaolinite-quartz mineral-matter assemblages. Utilization of such coals is relatively trouble-free. Coals which have illite-calcite-pyrite mineral-matter assemblages have proportionally more of the basic oxides (alkalis and ferric iron), and ash-fusion temperatures are correspondingly reduced. The primary problem with these coals, however, is sulphur in the pyrite. Sulphur is released as SO_2 and becomes an environmental pollutant. Although much pyrite is removed by beneficiation, some coals still possess high sulphur contents. Examples of illite-calcite-pyrite assemblage coals from British Columbia include some Gething Formation coals from the Peace River Coalfield, and some coals from the Comox Formation on Vancouver Island.

Ash fusibility is a recognized tool for predicting boiler deposit build-up and slagging performance of coals when used in steam-generating units. Ash particles arrive at heat-absorbing surfaces and, depending upon the temperature of that surface and the fusion temperature of the ash particles, they will either soften and bond weakly, settle-out as dust, or fuse and act as slag.

3.3.4 BRITISH COLUMBIA'S THERMAL COALS

There are four principal sources of thermal coal in the Province:

(1) non-coking coals,
(2) oxidized coking coals,
(3) coking coal-middlings from preparation plants, and
(4) coking coal-discards from preparation plants.

3.3.4.1 Non-Coking Coals and Oxidized Coking Coals

For the purposes of this discussion, non-coking coals are defined as those which possess free swelling indices of less than 4 and include, for all practical purposes, oxidized coking coals. Figure 3.8 shows a plot of predicted calorific value, on a dry-basis, for coals with an ash content of about 10 per cent. Inherent moisture will reduce these values by about 4 megajoules per kilogram (MJ/kg) in the higher rank coals and 7 MJ/kg among the lower rank coals. Included on the diagram are some of the approximate domains for British Columbia coals cleaned to meet this ash content. The diagram shows that the majority of Rocky Mountain coals have calorific values, on a dry-basis at 10 per cent ash, in excess of 30 MJ/kg with many greater than 32 MJ/kg. Such coals can be mined, processed, and shipped at a profit. Other coals, for example at Hat Creek, have dry calorific values at 10 per cent ash of about 26.5 MJ/kg but contain about 20 per cent moisture. Although they can be mined and perhaps processed profitably, the cleaned coal has a calorific value that makes transportation uneconomic. Therefore utilization of such coals has to be at the mine. Between these two cases there are a variety of coals, and the economic viability of individual situations is dependent upon the calorific value of the coal, the moisture level, and the yield upon processing.

Vancouver Island coals, on a dry-basis at 10 per cent ash, have calorific values of 29 to 32 MJ/kg. Interior coals are variable in rank and therefore moisture content. Tulameen, at 15 per cent ash content, has a dry calorific value of 26.5 MJ/kg; Hat Creek at 20 per cent ash, has a dry calorific value of 23 MJ/kg. Bowron River coals and those around Telkwa have dry, ash-free calorific values of 34 to 36 MJ/kg. The Groundhog Coalfield contains anthracite coal with a dry, ash-free calorific value of 31 to 36 MJ/kg.

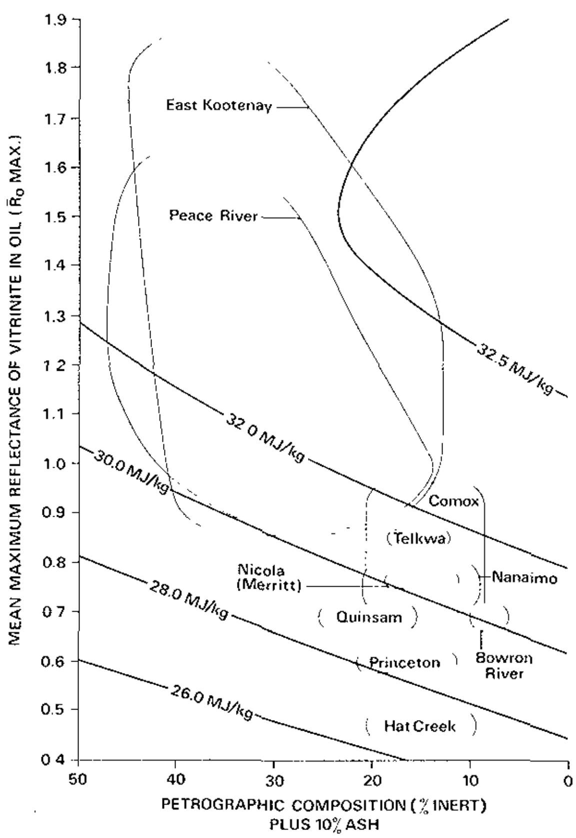


Figure 3.8 — Estimated calorific value of some of British Columbia's coals, dry, with ash contents of 10 per cent.

3.3.4.2 Middlings From Preparation Plants

When metallurgical coal is cleaned to meet a set of contract specifications, the yield from the preparation plant may be 80 per cent, which means 20 per cent of the mined coal is destined for the tailings dump. However, if the ash content of this material is only 50 per cent, it is theoretically possible in some cases to have a second circuit to produce a second or middlings product, and limit the discard or tailings to 10 per cent. Thus, the middlings would be a secondary product with an ash content of 25 to 35 per cent and a dry calorific value of 26 MJ/kg (23 MJ/kg @ 6 per cent moisture).

Only a few metallurgical coal deposits in British Columbia can produce middlings. Peace River coals typically have yield-ash characteristics which do not warrant middlings circuits but some Kootenay coals (for example, Balmer) could produce middlings in amounts equivalent to about 5 per cent of the raw coal feed.

3.3.4.3 Discards From Preparation Plants

Discard material from preparation plants in the Peace River and East Kootenay Coalfields amounts to about 10 per cent of the raw coal feed. This material, or tailings, has about 40 per cent ash and 20 per cent moisture with a moist calorific value of about 16 MJ/kg. Utilization of this coal for thermal generation requires local generating stations, the economics of which are beyond this discussion. To place this reject material in context, however, it should be realized that it has equivalent heat content to Hat Creek coal that has been cleaned to a 20 per cent ash level.

3.4 LIQUEFACTION OF BRITISH COLUMBIA COAL

There is renewed interest in utilization of coal for production of liquid hydrocarbon fuels. In this section, two different process types are discussed. These are: (1) direct liquefaction and (2) gasification and synthesis.

3.4.1 DIRECT LIQUEFACTION

This procedure involves the thermal dissociation of coal at high temperature in the presence of a process-derived oil and perhaps a catalyst, with or without high-pressure hydrogen.

Conventional thinking advocates the use of reactive-maceral-rich, high-volatile coking coals in such processes (Groups G6, G5, and G2 of Table 3.3), yet there are good reasons for believing that inertinite-rich coking coals (Groups G3 and G4 of Table 3.3) may be equally as good.

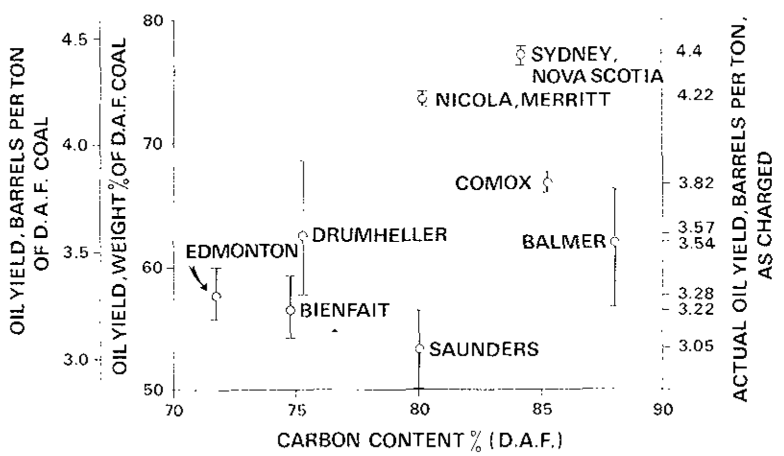


Figure 3.9 — Solubility of some Canadian coals in degrading solvents (from Warren, Bowles, and Gilmore, 1939).

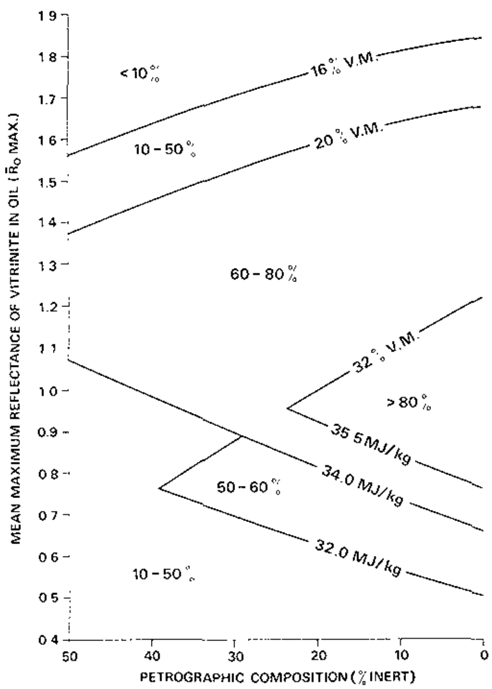


Figure 3.10 — Predicted yields in weight per cent, dry, ash-free, of different coals in degrading solvent liquefaction (modified from the National Coal Board).

Preliminary screening of suitable coals was performed many years ago (Warren, Bowles, and Gilmore, 1939), on Comox Group High-volatile A bituminous coal ($\bar{R}_o$ = 0.74 per cent); Middlesborough Colliery, Merritt, Nicola, high-volatile B bituminous coal ($\bar{R}_o$ = 0.7 per cent); and Kootenay Group, Balmer, Michel Colliery medium-volatile bituminous coal ($\bar{R}_o$ = 1.30 per cent). The results of these tests are shown on Figure 3.9. The tonnages of coal required in commercial coal liquefaction plants is large, so both Nicola Group and Comox Group coals possess inadequate reserve bases. However, very large reserves exist of coals of similar quality to Balmer coal used in these experiments, and potentially, at least, some of these coals may be suitable in future direct liquefaction.

Figure 3.10 shows the predicted solubility of various coals as a function of rank ($\bar{R}_o$) *and maceral composition (1). The diagram shows that coals which have a dry, ash-free* calorific value of >35.5 MJ/kg and volatile-matter yields (dry, ash-free basis) of >32 per cent, have the highest yields (>80 per cent). As well, it shows that coals with calorific values (daf) of >34 MJ/kg and volatile-matter yields (daf) of 20 to 32 per cent also have very high yields. It is this latter group that contains the bulk of the Rocky Mountain coking coals of the Peace River and East Kootenay Coalfields (compare Fig. 3.10 with Fig. 3.2). Such diagrams explain the unexpected results of the earlier experiments and add weight to the belief in the inherent viability of liquefaction of these inertinite-rich coals.

3.4.2 GASIFICATION AND SYNTHESIS

In this process, coal is first gasified to produce hydrogen, carbon monoxide, carbon dioxide, and methane. This product is then cleaned of contaminants to leave only carbon monoxide and hydrogen. This "synthesis gas" is then reacted with catalysts to produce a spectrum of products of various molecular weights from waxes to diesel fuels and low-octane gasoline. The process is utilized commercially at the SASOL plants in South Africa.

In South Africa coals used in this process are of low rank: Sigma Colliery — $\bar{R}_o = 0.58$ per cent, ash 36 per cent, 11 per cent moisture; Bosjesspruit Colliery — $\bar{R}_o = 0.68$ per cent, ash 20 per cent, 4 per cent moisture. Similar rank coals exist in British Columbia (Hat Creek—$\bar{R}_o = 0.43$ per cent, ash 10 to 50 per cent, moisture 22 per cent) in the quantities that would be necessary for a plant the size of the new SASOL 2 and 3 plants. Coal requirements are in the order of 13 million tonnes per annum.

Most lower and middle rank coals can be gasified so utilization of coals in this process is not limited to the poorer quality coals described above. This type of process is thermally inefficient because the coal must be broken into basic "building blocks" then rebuilt into other forms of hydrocarbon. This thermal inefficiency makes the process expensive, and the cost of the finished products may be too high to market at this time.

3.5 REFERENCES

Karst, R. H. and White, G. V. (1979): Coal Rank Distribution within the Bluesky-Gething Stratigraphic Horizon of Northeastern British Columbia, *B.C. Ministry of Energy, Mines & Pet. Res.,* Geological Fieldwork, 1979, Paper 1980-1, pp. 103–107.

Pearson, David E. (1980): The Quality of Western Canadian Coking Coal, Bulletin, *Can. Inst. Min. & Met.,* Vol. 73., No. 813, pp. 71–84.

Pearson, David E. and Grieve, D. A. (1978): Crowsnest Coalfield, *B.C. Ministry of Energy, Mines & Pet. Res.,* Geological Fieldwork, 1978, Paper 1979-1, pp. 61–65.

Pearson, David E. and Grieve, D. A. (1979): Elk Valley Coalfield, *B.C. Ministry of Energy, Mines & Pet. Res.,* Geological Fieldwork, 1979, Paper 1980-1, pp. 91–96.

Warren, T. E., Bowles, K. W. and Gilmore, R. E. (1939): Hydrogenation Tests on Canadian Coal, *Industrial & Engineering Chemistry,* Vol. 31, No. 8, pp. 1021–1025.

IV. TECHNOLOGY OF COAL PRODUCTION

4.1 INTRODUCTION

The mining of coal presents many of the same problems met in the mining of other bedded mineral deposits, in addition to problems unique to coal. Coal seams typically occur in a succession of sedimentary strata of moderate to low strength. The control of these relatively soft strata surrounding the mining excavation of underground coal is a much more formidable problem than that posed by the hard igneous rock in many metal mines. Indeed, roof control influences the system of coal mining, which in turn influences the amount of coal recovered from a deposit. This amount may be very low under adverse conditions.

Another problem arises from the relatively flat-lying nature of many coal seams compared with steeply dipping metalliferous deposits. This results in the workings extending far from the shafts or adit portals of an underground mine, requiring provision for hauling large tonnages of coal over considerable distances.

Finally, most coal seams, unless naturally drained, give off varying quantities of methane gas during mining. Methane gas is explosive when mixed with air in the proportions of 5 to 15 per cent. This hazard has to be met constantly by providing ample ventilation, regular monitoring, and the use of specialized equipment. Since coal is largely composed of carbonaceous materials, it is capable of catching fire, sometimes spontaneously. This problem demands yet another series of precautions.

For many years coal mining was not an attractive occupation and until quite recently in British Columbia, it was an uncertain means of livelihood. Coal mining presents a more hazardous working environment than many other vocations. This has resulted in close examination of coal-mining methods and mechanization throughout the world. New mining techniques have been developed and legislation has been modified in order to provide safer working conditions while producing the maximum recovery of the resource.

The application of machine technology to the problems of coal mining goes back many years. The steam engine and the railway originated from efforts to solve the pumping and transportation problems at coal mines in Northern England during the latter half of the 18th and the beginning of the 19th centuries. However, early efforts to apply machine technology were restricted to pumping, hoisting, and haulage. The actual mining of the coal continued to be carried out by hand (with some aid from explosives) until well into the present century.

After 1930, coal-face mechanization proceeded rapidly. Reliable conveyor systems were soon on the market, enabling large tonnages to be handled and making obsolete the time-consuming practice of bringing the coal cars to or near the face for hand-loading. In the late 1930's machines were designed which would actually load as well as cut the coal. These were improved and installed in large numbers after World War II, in conjunction with a flexible hauling system based on rubber-tired trackless vehicles. At the same time, the first steps were being taken in longwall mining towards a fully mechanized system based on hydraulic supports, a massive conveyor, and a plough, shearer or other machine to remove the coal from the face and direct it onto the conveyor.

Coal-face mechanization was introduced on a small scale in British Columbia coal mines at a relatively early date. Coal-cutting machines were used in the Newcastle seam at Nanaimo Colliery on Vancouver Island prior to 1909. Progress was quite slow until the 1930's when the thinner seams, being mined by longwall on Vancouver Island, were equipped with conveyor systems. In the East Kootenay (Southeast) Coalfields, coal-cutting machines and pneumatic picks were introduced in the 1930's, continuous miners and shuttle cars in 1961, and hydraulic mining in 1970.

Mining of coal by open-pit methods in British Columbia was readily adapted from the technology developed in large engineering projects and open-pit mining of other kinds of materials. Large-scale open-pit mining in British Columbia commenced in 1970, and the most modern equipment available was introduced from the start. Four out of the six operating coal mines and the three mines now under construction in British Columbia are open-pit surface mines.

Mechanization has greatly increased the productivity of those employed in the industry. In 1914 in British Columbia, the average productivity per man-shift for all employed was approximately 1.3 tonnes. In 1979, the productivity of the underground mines in the Province was 17 tonnes per man-shift, an exceptionally high figure resulting from the hydraulic operations. For surface mining, productivity rates vary from 24 to 37.6 tonnes per man-shift. Typical productivities are shown in Table 4.1.

TABLE 4.1. Productivity in U.S. Coal Mines*
(Tonnes/Employee Shift)

	1976	1977	1978	1979	1980	1981
Underground	9.4	9.1	7.7	8.5	10.5	9.7
Surface	25.2	24.8	22.6	23.4	25.4	26.9

* Injury Experience in Coal Mining, *U.S. Dept. of Labour.*

Preparation plants (*see* Section 4.3) are an essential part of all present metallurgical coal production operations in British Columbia. They will almost certainly be common to all future plants producing either metallurgical or thermal coal for export or shipment to eastern Canada. The coking coals of western Canada, found primarily along the eastern slopes of the Rocky Mountains, generally contain a large amount of inorganic impurities and unless beneficiated are unable to meet the specifications set out on these impurities by the consumers. The raw coal at Westar Mining Ltd.'s plant, for example, contains approximately 16 per cent ash; contract specifications for the Japanese metallurgical coal market require a content of 9.5 per cent ash. Coal for the Ontario thermal market may not exceed 10 per cent ash. These specifications are not particularly severe when considered from the standpoint of the maximum ash contents set by coke-makers for their blended coke-oven feeds. The Steel Company of Canada, for example, sets a maximum of 5.8 per cent ash for this purpose. Western Canadian coals present special problems which, even with today's technology, make it difficult to obtain the modestly low ash contents indicated above.

Transportation costs are a further reason for preparation plants. Minimizing the water content of coal prior to shipment lowers freight charges based on tonnages handled.

Unfortunately, beneficiation yields reject material. This material not only represents a loss to the mining company, but may also result in waste of a resource for the Province and pose an ecological problem in its disposal. In some instances, the reject materials may be further beneficiated to yield "middlings" and "tailings". Middlings may contain 20 to 30 per cent ash and be saleable as a thermal coal. The tailings currently remain as a waste product. For example, Westar Mining Ltd. at Sparwood currently produces approximately 265 tonnes per hour of tailings with 36.5 per cent ash. This material could be expected to possess a dry calorific value of approximately 8 800 Btu/lb. or 7 300 Btu/lb.** at a total moisture level of 20 per cent (mechanically dewatered). At the present time, cost of transportation would only allow such a low calorific value product to be used as a fuel at or near the minesite.

4.2 MINING

The methods of mining coal are divided into the following categories:

(1) Underground Mining:
  (i) Room and Pillar and its derivatives
  (ii) Longwall (advancing and retreating)

(2) Surface Mining:
  (i) Contour or Strip
  (ii) Open Pit (advancing and retreating)

** 1 Btu/lb. × .002326 = MJ/kg.

4.2.1 UNDERGROUND MINING

4.2.1.1 Room and Pillar

In room-and-pillar mining, a number of entries are driven through the coal seam and on the plane of the seam in such a pattern that the seam is split up into a series of pillars of regular size, the size being determined by the pattern of the entries. When the area of coal has been fully developed, the pillars of coal may then be extracted on a retreating basis. The actual mining is frequently done by a machine known as a "continuous miner" which cuts the coal and loads it into shuttle cars or onto flexible conveyors, which in turn transport the coal onto a main conveyor system. Today, continuous miners are available in various forms suitable for specific uses and conditions. These machines are equally versatile for both entry development and pillar extraction.

4.2.1.2 Longwall Mining

The longwall system of mining originated in Europe. Basically, in its "advancing" form it opens up a long, continuous length of coal face in the seam and then advances it steadily forward, allowing the overlying strata to subside behind the immediate working area of the coal face. Access to the face is by "roadways" which are established as the face advances and maintained through the mined-out area or "gob". The longwall faces are ventilated by circulating air through these roadways, which also act as passages for men, supplies, equipment, and coal removal.

Alternatively, longwall can be applied in a "retreating" form. In this case, development roadways are driven out to the deposit boundary through the solid coal. The long face is then opened up and mined out on the retreat using the roadways through the solid coal for access.

Mechanization of longwall mining has been made possible largely through the development of self-advancing hydraulic systems that control the roof immediately behind the advancing face. Protected by these hydraulic supports, a machine, frequently of the drum-shearer type, propels itself back and forth along the coal face, shearing off successive slices of coal on each trip. The coal falls onto a heavily armoured chain conveyer kept close to the coal face. Behind the strong line of supports, the overlying strata are induced to cave into the cavity left by removal of the coal seam, thus limiting pressure on the support system.

In recent years, a number of longwall installations have been made in the United States, and extremely high productivity has been attained. For example, at the No. 33 mine of Bethlehem Steel Company, a production of 5 000 tonnes per day was maintained for a month from a longwall face 183 metres long, and on one day 6 500 tonnes was produced.

4.2.1.3 System Comparisons

The detailed layout and design of these two basic mining systems vary considerably from one operation to another because the methods have to be adapted to the varied conditions in which the coal seams occur. Workable coal seams may range in thickness from 0.5 metre to more than 15 metres. The geological environment may present seams that are flat lying or they may be inclined to practically vertical. Sedimentary rocks immediately adjacent to seams may also vary greatly in their composition and physical properties. Finally, the coal seam itself may be strong and homogeneous or weak and friable. All of these factors have a bearing on the design of a successful mining method.

Both basic mining systems have been highly mechanized and are able to produce coal at comparable costs. The capital cost of a mechanized longwall installation is higher than that of room-and-pillar installation, but under the right conditions the former has the advantage of very high production from a relatively small area.

Underground mechanized mining systems in their "classic" form, as described above, have proved most successful in areas where strata are only very gently folded, resulting in flat-lying or slightly inclined coal seams; where adjacent strata are reasonably strong without being too hard and inelastic; where there is relative freedom from geological disturbances such as faults, or at least reasonable spacing between them; where the coal seams are within a uniform range of from 1 to 3 metres thick and free of interbedded rock or inferior coal; and where methane emission is moderate and underground water seepage is not severe. The costs and difficulties of mechanized mining increase as conditions deviate from the ideal.

Steeply dipping coal seams or very thick coal seams make application of highly mechanized mining methods particularly difficult. When both these conditions occur together, as they frequently do in the Rocky Mountain coalfields, the problems are compounded.

In the case of steeply inclined seams, the difficulty lies in manoeuvring and controlling heavy mining machines on steep gradients and in controlling the movement of coal. Some success has been achieved in thinner seams, but in thick seams only a small percentage of coal can be extracted by conventional mechanized methods.

In thick seams, the problem is to support the roof of an excavation which is too high to permit the use of conventional supports and to protect the miners from high and potentially dangerous "ribs" of coal which form the sides of the entries. In longwall mining, control of the roof becomes almost impossible; in room-and-pillar mining extraction of pillars becomes too dangerous to attempt. In thick seams that are relatively flat-lying, some success has been achieved by longwall mining in layers, either taking out the top layer first and mining the lower layers under the broken roof by means of steel mats and shield-type hydraulic supports, or by mining the bottom layer, after which the supports are moved forward, permitting the top layer to cave and be extracted from behind the supports. From the conservation point of view room-and-pillar mining in its conventional form remains an inefficient method for extracting a coal seam that is in excess of 6 metres thick.

Longwall mining has a number of other advantages over conventional room-and-pillar mining. The principal one is the very high rate of extraction attainable. Under favourable conditions, 85 to 90 per cent of the coal reserve in a given area can be recovered, compared to 60 to 75 per cent with conventional room-and-pillar methods under ideal conditions. Thin seams are more easily worked by longwall methods; at great depths, it is probably the only practical method of mining. In longwall mining, the working area is small, making ventilation less of a problem than when the room-and-pillar system is used for the same output. Methane drainage from mined out areas is also much simpler. Under bad roof conditions, longwall mining with hydraulic shield supports is likely to be safer and result in a far greater recovery of coal than room-and-pillar mining.

A disadvantage of longwall mining is that it is less adaptable to variable conditions, such as changes in the thickness or dip of the seam or the presence of faults or other geological disturbances. Since the success of mechanized longwall depends on regular caving of the roof behind the working area of the face, difficulties may be experienced in mining seams. Seams up to about 4 metres thick have been mined in a single slice, but this is probably the upper limit with present technology. Serious problems may also be experienced when mining under massive sandstone roofs which do not readily shear behind the back line of supports. Finally, the capital cost of a longwall installation is likely to be higher than room-and-pillar mining due to the elaborate hydraulic support systems and heavy armoured face conveyers. In western Canada, the number of people with experience in longwall mining is very limited and of those who do have experience, none have successfully operated under western Canadian conditions.

4.2.1.4 Longwall Mining in the Rocky Mountains

In general, strata in the Rocky Mountain coalfields have been subjected to severe tectonic stress, and the geological structure is characterized by numerous major folds and low-angle thrust faults. Seams change in dip and in many areas are steeply inclined. Very thick seams are common and, especially in the southern area, the coal tends to be intensely sheared and friable.

It would seem therefore, that longwall mining in its present form would be limited to areas where the seams are of moderate thickness (for example, less than about 3 metres) and gently dipping (less than 20 degrees). Such conditions may occur in the troughs of wide shallow syclines and on the crests of similar anticlines. Certainly there appear to be areas of relatively gentle dip and seams of moderate thickness in the vicinity of the Peace River, in the Babcock Mountain area of the Quintette property, and on the Sukunka property.

Possible areas for longwall mining are less evident in the southeastern coalfields, but there may be seams in some parts of the Crowsnest Basin where the method could be used to advantage.

So far, longwall mining in its fully mechanized form has been tried only by one company in western Canada. In 1970, McIntyre Porcupine installed longwall units in No. 4 seam at its Nos. 2 and 5 mines at Smoky River. The seam is 6 metres thick and it was proposed to mine only the top 3 metres. The supports used were new and untried and apparently insufficient information had been obtained about the mining conditions in No. 2 seam. Control of the weak and fractured overlying strata combined with a soft floor proved exceptionally difficult and the longwall method was abandoned in 1971.

4.2.1.5 Hydraulic Mining

A modified room-and-pillar system, somewhat similar to the sublevel caving technique used in metalliferous mining, has been successfully applied in a number of countries where suitable conditions exist. The system uses a high-pressure water jet as the primary excavating tool. The method was applied successfully at Sunagawa Colliery in Japan in a seam of moderate thickness dipping at 45 to 60 degrees. In 1970, the same system was applied in the Balmer seam of Kaiser Resources Ltd. (Westar Mining Ltd.) under conditions where it was exceptionally difficult to achieve high percentage extraction rates by conventional mechanized methods. The seam is approximately 15 metres thick and inclined at 30 degrees. Under conventional room-and-pillar mining little more than 10 to 15 per cent of the reserves were mined, but with the hydraulic method the extraction rate in a block is 70 per cent with an overall extraction rate of 55 per cent. This latter figure is lower than it might be owing to the need to mine the Balmer seam in separate "panels" surrounded by ribs of solid coal so that these can be rapidly sealed and isolated in the event of an outbreak of fire resulting from spontaneous combustion. In spite of the low extraction rate, it is considerably better than one could hope to achieve by any other method known at the present time.

The initial development consists of the driving of entries and sublevels. It is done by continuous miners. The mined coal is transported by water in semicircular steel flumes, so the layout of the workings must be very carefully planned beforehand to ensure the optimum gradients for water flow. Thus, in designing a hydraulic mine, the geological structure and configuration of the coal seams must be determined over a wide area. The operation of pillar extraction, which is done by hydraulic jets, is carried out on the retreat. The method has the advantage that no heavy electrically driven machinery is required for the actual mining of the coal. Also, the miners can operate from a protected position some distance back from the coal face. Although the presence of high-pressure water pipes calls for precautions, the transportation of the coal out of the mine by water results in less coal dust becoming airborne, helping to eliminate one of the gravest hazards in coal mining.

Hydraulic mining probably provides a means by which the many thick and steeply dipping coal seams of the Rocky Mountain coalfields may be profitably and economically mined with high recovery rates. However, a note of caution is necessary as the system has only been applied at one mine where the seam lies less than 550 metres below the surface. Regular caving of the overlying strata behind the retreating faces, which is vital to attaining high extraction rates in a thick seam, has occurred very satisfactorily so far in the Balmer hydraulic mine. It might not always occur, however, especially if the immediate overlying bed was a thick, hard sandstone. If regular caving did not take place and a huge rock mass came down, it could possibly result in a hazardous air blast. In such a case, the Inspection and Engineering Branch of the Ministry of Energy, Mines and Petroleum Resources might have to rule that systematic supporting pillars be left as a safety precaution reducing the percentage of extraction.

Problems of hydraulically mining seams that have heavy methane emission have not yet been encountered. Large reservoirs of methane gas could not be permitted to accumulate in the mined-out areas prior to sealing, and some effective means (for example, the use of bleeder return airways) would be necessary to ventilate these areas and drain off any accumulations of methane gas. The thicker the seam and the larger the excavations, the more formidable is this task.

There are other problems common to thick-seam mining and to mining in the Rocky Mountains generallly which might affect the profitability and extraction rate of hydraulic mining systems. These are: a soft floor which might "heave" and thus affect the gradient of the flume; local and unexpected changes in dip of the coal seam; presence of interbeds and rock in the seam; variability of seam thickness; and occasional occurrence of "bumps" and "blowouts". Nevertheless, in spite of some potential operating problems, modified room-and-pillar hydraulic mining techniques could play a significant part in the mining of Rocky Mountain coal resources.

4.2.1.6 Shortwall Mining

Another interesting development is the combination of room-and-pillar and longwall technology known as "shortwall" mining. In this method, a continuous miner cuts and loads from the open end of a rectangular pillar of coal while self-advancing roof supports provide protective cover.

The advantages of shortwall over longwall are:

(1) In a mine where development is done by a continuous miner, the same type of machine can be used for the shortwall mining operation. This machine can be fairly easily moved from one location to another.

(2) Since the working face is shorter, the system is more adaptable where faults and irregularities in the coal seam are likely to be met. One or

more shortwall faces may be held in reserve, in which case continuous production could be maintained even if it becomes necessary to stop one face temporarily.

(3) Control of airborne dust may be easier due to the fact that mining is unidirectional. If the air current is directed in the same direction as the mining, any dust will be carried away from the operator and crew.

Some of the disadvantages of shortwall as compared with longwall are:

(1) Productivity is usually greater in longwall due to longer faces, and the fact that the machines can shear or plough off the coal in two directions.

(2) In shortwall, the distance from the coal face to the back line of supports is greater due to the greater width of the continuous miner. This means that the cost of powered supports may be higher due to the need for special canopies to provide safe support.

(3) Shortwall would appear to be less adaptable where very friable roof conditions exist.

(4) The minimum operating height is greater in shortwall than in longwall (about 1.4 metres is the minimum operation height for shortwall).

(5) The continuous miner tends to cut "steps" in the floor which have to be negotiated by the supports as they are moved forward. Problems also arise where the floor is soft.

(6) There is a need for clean-up of spillage behind the continuous miner on a shortwall face.

(7) There is a tendency for transportation to be less continuous on a shortwall face where shuttle cars or extensible conveyers are used, whereas armoured conveyors on a longwall face are relatively continuous.

In British Columbia, while it is not possible to identify specific areas and seams where shortwall might be applicable, it is possible to indicate general situations where it might be considered as a more easily applied and more appropriate alternative to longwall. Such conditions would include coal seams of moderate dip and between 1.4 and 2.75 metres thick, where the overlying roof is such that complete pillar recovery by conventional room-and-pillar mining might be difficult or impossible. There is little doubt that this combination of conditions will be found to be quite widespread as underground mining expands. Shortwall mining might also be seriously considered in conditions generally suitable for longwall mining, except for the presence of a number of faults or other irregularities in the seam.

Finally, it can be speculated that in the crushed and friable coal seams of the Rocky Mountain coalfields, it may be possible to use the hydraulic monitor in place of the continuous miner in some areas of the shortwall systems. Such a combination of technologies might prove highly productive.

4.2.2 SURFACE MINING

4.2.2.1 Methods

Prior to 1970, several small-tonnage surface coal mines were operated in the Michel-Natal area of southeastern British Columbia. The mining methods used were similar to those used in metal-mine open pits; shovels and trucks were employed to mine the material in benches. These mines generally had low stripping ratios and operated sporadically.

In 1970, Kaiser Resources Ltd. (now Westar Mining Ltd.) brought their Harmer Ridge surface operation into production at a rate of 4.1 million tonnes per year, followed in 1972 by Fording Coal Ltd., at a production rate of 3.1

million tonnes per year. A feature common to the mining of both of these deposits, as well as the Tent Mountain and Race Horse deposits of Coleman Collieries Ltd. in Alberta, is the overlying sandstone and shale. This makes the drill-shovel-truck operation the popular system.

Four seams are currently being mined at the Westar Mining Ltd.'s operations where the overall stripping ratio is approximately 5.5 cubic metres per tonne of raw coal. The overlying rock is removed in 15-metre benches by 12 to 20-metre shovels and is transported by 180-tonne haulage trucks to waste dumps located outside the pit limits. Bulldozers are used to clean remaining rock from the hangingwall slope, which dips at 25 to 30 degrees. Front-end loaders, assisted by bulldozers, then load the coal into 91-tonne trucks for transport to the central breaker station from which coal is carried by an underground conveyer belt, a distance of approximately 1.6 kilometres to the coal preparation plant.

Ten seams are currently being mined by Fording Coal Ltd. at their Fording River Operations, using the following two systems for extraction:

(1) Front-end loaders, with assistance from bulldozers, load coal into 135-tonne trucks which haul it to the breaker station. Because the seams dip through the benches formed during mining, extreme care must be taken to clean off the waste rock prior to coal removal, so dilution is minimized.

(2) Loading by means of a 45-cubic-metre dragline with a 61-metre boom. This system is located in a shallow valley, necessitating a relatively small amount of preparation work by shovels and trucks in order to accommodate the dragline. Waste and coal are selectively mined. The waste is cast to one side for rehandling if necessary and the coal is stockpiled for loading into 135-tonne trucks for transport to the breaker station. The average stripping ratio in the Greenhills dragline pit is 6.5:1.

Once the mine plan has been initiated, the important factors in the efficiency of each large open-pit mine are the skillful deployment and availability of equipment.

Repairing and servicing of large equipment at coal-mining operations in the southeast of the Province is a demanding task as the open pits are located at elevations in excess of 1 500 metres and are subject to adverse weather conditions. Equipment maintenance facilities have been located close to the pits. In addition to truck and other equipment bays, wash bays, fabrication and welding shops are provided. Planned preventive maintenance is practised, as is close cooperation between production and maintenance personnel.

During 1979, over 45 million cubic metres of waste was stripped and disposed of from the open-pit coal mining operations in British Columbia. Such large volumes of waste pose unique haulage and disposal problems in mountainous terrain where the dump crest-to-toe heights have exceeded 185 metres. The stability of such dumps can very easily be aggravated by snow accumulations within the body of the dump and by rapid spring thaw or high precipitation.

4.2.2.2 Reclamation

The workings of a surface coal mine are generally more extensive than a metal-mine orebody of similar tonnage. As a result, much more land is affected by such coal mining.

Section 7 of the British Columbia *Mines Act* requires the "owner, agent, or manager" of a mine to submit and gain the approval of the Minister of Energy, Mines and Petroleum Resources for a program for the protection and reclamation of the land and watercourses affected by the mining operations. It is also required that when work on the property is discontinued the land and watercourses must be left in a condition satisfactory to the Minister. The performance of an approved reclamation program is secured by a bond which is retained until the reclamation work is completed.

The lands occupied by the open pits in southeastern British Columbia are located in mountainous terrain. Reclamation of these areas will no doubt be slower and more costly than operations of flatter lands at lower elevations.

Determined efforts have been made by the two major coal mining companies to progressively reclaim areas affected by coal extraction. Considerable knowledge has been built up regarding reclamation at high altitudes in mountain areas. Research is continuing to establish the best methods of reclaiming the affected land and the methods of mining which minimize the impact on the environment. Westar Mining Ltd. has also successfully undertaken the reclamation of land disturbed prior to 1970.

4.3 COAL PREPARATION

Coal, as already indicated, is a rock made up of organic (maceral) and inorganic components. As mined (run-of-mine coal), it usually contains these components in a wide range of sizes and in varying relative amounts. The aim of coal preparation or beneficiation is to convert this inconsistent run-of-mine coal into a product of consistent size and inorganic material content as required by the prescribed application. It is also generally necessary that the coal should not vary in quality over the period of supply.

Inorganic matter (ash) content is essentially the only characteristic of the coal that the producer can modify. Properties such as swelling index and volatile matter are innate to the seam from which the coal was derived.

The allowable amount of inorganic matter in the coal product will vary from as much as 30 per cent in a thermal coal for use at a minesite power station to as low as 5 to 6 per cent for a coal used for coking by Canadian steel companies. The practical means of achieving these ash values in British Columbia are examined in the following paragraphs.

The major property that is utilized to effect beneficiation of coal is the density difference which exists between its maceral and inorganic components. The former has a relative density of approximately 1.25 and the latter in excess of 2.3. However, although much of the inorganic material associated with the run-of-mine coal is in the form of discrete lumps, some proportion will occur in a finely divided state associated with the maceral components. Obviously, this could be released by crushing coal. Preparation of the resulting mass would be more costly. Consequently, most coal beneficiation processes compromise between crushing the coal to a size sufficient for separation of the higher ash content material as discard and making a product with some ash included. This compromise can obviously have serious economic implications if the proportion of discard becomes too large. The characterizations of the coal which determine how large the discard must be for a given ash content are shown clearly on the washability curve plots (*see* Appendix 4.1)

The coal cleaning methods which exploit the difference of density of maceral and inorganic components are classified under the headings in Table 4.1, depending upon equipment type and operation.

The metallurgical coals in the mountainous areas of southeastern British Columbia are porous and prone to oxidation. They tend to break down during mining and handling into material containing a high proportion of fine coal. In this respect they differ from coals in most of the developed fields throughout the world and also from the lower ranked coals of western Canada (Figure 4.1).

Operators, particularly in the East Kootenays, must wash coals that have a greater proportion of fines than those from the plains of Alberta, the eastern United States, or Australia.

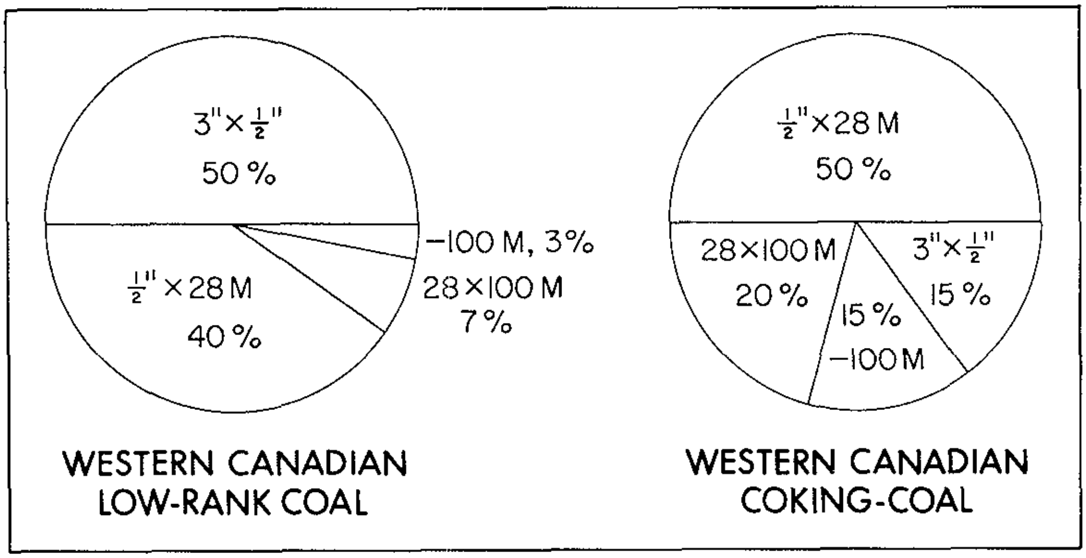


Figure 4.1 — Comparison of proportion of fines in western Canadian coking coal with western Canadian low-rank coal.

As can be seen from Table 4.2, the processes for coal preparation based on density difference are mostly effective on material above 28 mesh in size. The water-only cyclone is the only equipment capable of effectively treating coal in the 28 to 100 mesh range. Below the practical size limits of either 28 mesh or 100 mesh, whichever applies in a particular instance, the fine coal remaining can be cleaned by physiochemical techniques, that is, though differences in the surface properties of the raw fine coal particles.

TABLE 4.2. Coal Beneficiation Processes Exploiting Density Differences of Maceral and Inorganic Components

Dense Medium:		
1. Bath Type	Used on material +6 millimetres and up to 125 millimetres or more	Highest efficiency with 6 millimetres
2. Centrifugal Type (Cyclone)	Used on material from 25 mesh to 6 millimetres to 28 mesh (and *perhaps* to 200 mesh)	Lower limit in practice, 28 mesh with high efficiency
Jig Washers	Used on material down to 28 mesh	Less efficient than dense medium but works well on easy-to-clean coals, simple to operate
Water-only Cyclones	Used to treat material below 28 mesh and down medium cyclone to 100 mesh; may work down to 200 mesh	Less efficient than dense medium

NOTE: If beneficiation equipment works inefficiently, low-ash coal is lost to discard and high-ash material is put in with the clean coal. To restore the ash content to the value it should be, the machine must be set to operate at a lower relative density than that given by the washability curve. The actual yield, divided by the yield at the charted ash level, is a useful measure of the efficiency of a coal preparation plant; it is known as the "organic efficiency." An organic efficiency of 100 per cent means that the machine is making a theoretically perfect separation — values of 95 per cent should be attainable in practice. Note, however, that if the coal is not material near the required density of separation, then a high organic efficiency may be obtained even if the partition curve shows a poor separation.

The most common process is that of froth flotation, in which coal particle surfaces are conditioned by hydrocarbons to be hydrophobic (water repellent), transported by generated air bubbles to a liquid-air interface boundary, and removed as cleaned product. Reject particles cannot be conditioned in this way and appear as slurry effluent from the system. Froth flotation is a costly process and therefore is used only where density processes fail.

Other, less common, fine coal processes work on a similar physiochemical principle in conjunction with agglomeration. In these cases, cleaning is effected by separating agglomerated coal particles and nonagglomerated reject material. A major advantage of an agglomerating system that utilizes oil as the agglomerating medium is the reduction of product moisture. The economic viability of these techniques is in question at this time. Attendant problems of dewatering and drying fine coal products constitute the highest proportional cost of coal cleaning; consequently, alternative techniques are constantly under review.

Coal preparation in plants in British Columbia, because of the large amount of fines in the coal, tend to be complex and to incorporate flotation plants for fines treatment. The problem is further complicated by the fact that bentonite clay is frequently the inorganic component of the fines fraction. When mixed with water, the bentonite forms a gel-like suspension. The clay settles from the suspension very slowly and may impede the settlements of other fines, which causes difficulties in dewatering and tailings disposal.

4.4 SAFETY AND HEALTH PROBLEMS IN COAL MINING

Coal mining has an accident potential for unskilled or unwary workers. Unfortunately, because of inattention to these problems, underground coal mining has, over the years, developed a poor reputation in safety and health matters. This is changing with increased research. Engineering and training are being directed at making the workplace for coal miners more comparable to that of other industrial operations. Surface mining in mountainous terrain also has potential hazards and safe operation requires the constant attention of all members of any team. Some mines are now achieving years of accident-free operation.

Underground coal mining presents unique hazards. Consequently, governments have legislated a comprehensive series of safety provisions which regulate every aspect of operations—from the certification of mine managers for underground coal mines to such matters as the approval requirements for every type of electrical equipment used underground. In more recent years, attention has also been given to formulating equally detailed regulations to control the hazards of surface mining. These regulations are embodied in the *Coal Mine Regulation Act.* Responsibility for the enforcement of this Act is vested in the Chief Inspector of Mines and his Inspectors of Mines and Resident Engineers.

Most companies now have Safety Departments to monitor and advise upon hazardous or potentially hazardous conditions in any operation. This Department acts in most cases in support of joint Management-Union Committees which, in addition to investigating accidents or near-accidents, meet regularly to devise means of promoting safety in the operation and to formulate methods of overcoming potentially hazardous situations which may have developed.

As a result of these concerted efforts, Workers' Compensation Board of British Columbia reports show that the mining and smelting industry has one of the best accident records of any industrial group in British Columbia.

In underground mining the principal industrial health problem among coal miners arises from breathing substantial amounts of airborne dust over long periods of time. This results in a condition know as pneumoconiosis or "black lung" as it has come to be known in the United States. Initially, there is some loss of breathing capacity, but no serious disability. A more advanced stage of the disease may be reached (known as progressive massive fibrosis) in which infection plays a part. In this stage there is widespread and progressive destruction of the normal lung function, causing increasing disability and death.

A study of the incidence of pneumoconiosis among miners in many parts of the world shows a marked variation in the incidence of this disease either in its early or advanced form. Part of the variation results from differing methods of diagnosing and classifying pneumoconiosis, part from differing methods used in collecting mortality statistics.

Pneumoconiosis appears to be rare in many coal-mining areas, including British Columbia. It has, however, been a severe health and social problem in other areas, especially in the South Wales coalfield between 1925 and 1945. Even where pneumoconiosis has been an uncommon cause of disability, the social problems have been exacerbated by the reluctance of authorities to recognize the condition as a compensatable industrial disease. This problem has arisen partly because clear diagnosis in the earlier stages is difficult and can only be done by X-ray photographs.

Pneumoconiosis can largely be prevented by the control and suppression of airborne dust combined with regular X-ray examinations of employees.

4.5 CONCLUSIONS

The expected future demand for coal throughout the world gives British Columbia an opportunity to increase the production of coal in the remainder of this century. Two mines came into production at the end of 1983 in the Northeast Coalfield, namely the Quintette and Bullmoose projects, with a maximum annual output of 5 million tonnes of metallurgical coal and 1.5 million tonnes of thermal coal from the Quintette project and 1 million tonnes of metallurgical coal from the Bullmoose project. In the Southeast Coalfields two new mines, namely Westar Mining Ltd.'s Greenhills project and the Crows Nest Resources Ltd.'s Line Creek project, commenced production in 1982/83. The annual outputs from these mines will be 1.8 million tonnes and 2.7 million tonnes respectively.

Other underground and open-pit mines may be developed and existing mines may be expanded in the Province during the present decade and will produce both metallurgical and thermal coal.

For the industry to prosper mining companies and employees must work together under the safest possible conditions to provide the coal demanded. New mines will employ large numbers of persons at all levels who have not been previously employed in the mining industry, therefore, it will be necessary for companies to develop training programs that will enable these persons to work efficiently and safely.

4.6 REFERENCES

Horsfall, David: Coal Report, *Anglo-American Co.*, Johannesburg, South Africa.

James, A. R. C. (1975): Some Comments on Underground Coal Mining Technology with Particular Reference to the Rocky Mountain Coalfields in British Columbia, *B.C. Ministry of Energy, Mines and Petroleum Resources,* July, 1975.

Little, A. S., M. D. (1976): Coal Workers' Pneumoconiosis, *Workers' Compensation Board,* April, 1976.

McDonald, J. D. and Dick, J. (1973): Reclamation Guidelines for Exploration, *B.C. Ministry of Energy, Mines & Pet. Res.*

Symonds, D. F. (1975): Coal Preparation and Quality of Known Coal Deposits, A Report of the Province of British Columbia, Mineral Resources Branch, *Birtley Engineering (Canada) Ltd.,* July, 1975.

V. ECONOMIC OVERVIEW OF COAL PRODUCTION

5.1 INTRODUCTION

This chapter presents an overview of the economics of coal production in British Columbia. It examines the factors which determine the prices that coal producers will receive for their product and the factors which have an impact upon costs of coal production in British Columbia.

British Columbia coal producers do not set the prices they receive for their product; prices offered are the result of interaction between producers and consumers in the international coal market. British Columbia's location establishes the Pacific Rim nations as a natural market area. It also forces British Columbia to compete with Australian and other producers for the key industrial markets of Japan and Korea.

In these markets, as in other markets, the prices paid for coal vary considerably and are determined by the quality and the cost of coal supplied to the market, as well as by the demand for it. For British Columbia coal therefore, prices paid and hence revenues received can be said to be determined by market demand and by the quality and costs of coal produced. In this chapter, the influence of coal quality and other factors in determining ultimate prices are reviewed.

The economic viability of the development of new coal mines not only depends upon the prices received by the producers for their product but also upon certain technical and economic factors related to production. The impacts of these technical and economic factors upon capital and operating costs associated with the extraction and processing of the Province's coal resources are also examined in this chapter. These two major cost factors plus taxes, royalties, transportation costs, and profits approximate the f.o.b. price of coal, when expressed in "dollars per tonne" units.

The sensitivity of return on invested capital to changes in key cost elements is also reviewed.

The data presented are drawn from publicly available information on the financial structure of existing mining operations, and from cost estimates prepared for proposed new coal projects in British Columbia. Where possible, costs have been expressed in 1984 dollars, unless otherwise stated.

5.2 DETERMINANTS OF COAL PRICES

5.2.1 TECHNICAL DETERMINANTS

Prices offered for coal in international markets are affected by both the physical characteristics of the coal and by economic factors.

In the case of metallurgical coal, the different physical characteristics inherent in each type of coal determine the attractiveness of that coal to a steelmaker. In the manufacture of blast furnace pig iron, metallurgical coal, as one of three main raw material inputs into the blast furnace production process (the others being iron ore and limestone), is charged into the blast furnace in the form of coke where it serves: (1) as a source of fuel, (2) as a reducing agent, and (3) to maintain permeability in the blast furnace. It is this third role that is especially important to the steelmaker, because coke is the only solid present in the furnace shaft bottom and lower zone where the ore and flux soften and melt. In the blast furnace, the coke must be sufficiently strong to support the blast furnace charge and, at the same time, sufficiently permeable to permit gases to escape and molten metal and slag to flow. Permeability of coke is affected by porosity, which in turn, is affected by the strength and reactivity of the coke. Strength and reactivity are therefore two main standards used to evaluate the ability of coal to make good coke. In general, a good quality metallurgical coal should have a high fixed carbon content which provides heat and is related to coke strength, be low in impurities which affect steel quality, and be capable of producing a strong blast furnace coke.

The ability to produce a strong coke is very important. Generally, U.S. coals make stronger coke than Canadian, Australian or Japanese coals of the same rank (same fixed carbon content). U.S. coals are reactive rich; that is U.S. coals are high in organic substances that bind a coal when heated, and low in inerts or organic substances that add to the coke's basic structure. Reactives and inerts (together called macerals) combine at each coal rank to produce a range of coke strengths. In general, coke strength increases with coal rank and decreasing inert content or equivalently, with rank and fluidity levels.

Modern steel mills import and use as many as 80 brands of metallurgical coal, which has necessitated the development of coal blending that permits the combined use of numerous brands. This is done to ensure security and diversity of supply and to reduce raw material costs. Because of this, steelmakers have developed techniques to estimate coke strength, from a coal blend.

Typical coal strength indices and their combinations used, for example, in Japan are shown in Table 5.1. There are five common pairs of blending parameters used in Japan to evaluate coke strength. The blending parameters are classified as either coking properties or caking properties. The ability of coal to become coke of higher strength in conjunction with the caking property is referred to as the coking property. The softening and melting of a coal during carbonization to bring about intergranular union and solidification are termed the caking property.[1]

TABLE 5.1. Japanese Steel Industry Coal Blending Parameters

No.	Rank Parameter	Caking Property Parameter
1.	Volatile Matter Content (VM)	Caking Index (CI)
2.	Volatile Matter Content (VM)	Maximum Fluidity (MF)
3.	Volatile Matter Content (VM)	Total Dilatation (TD)
4.	Mean Refectance of Vitrinite ($\bar{R}_o$)	Maximum Fluidity (MF)
5.	Strength Index (SI)	Composition Balance Index (CBI)

Source: T. Miyazu, Nippon Kokan Ltd., 1978 and NSC, 1982.

Steelmakers in Japan differ regarding which qualities contribute most to making a good coking coal. Nevertheless, much of any debate over blending properties is somewhat academic because of the high degree of correlation within the rank parameters and within the caking parameters, which together help determine coke strength. The rank parameter, mean reflectance ($\bar{R}_o$), for example, correlates closely with fixed carbon content (hence volatile matter) and with strength index. The caking parameter, composition balance index, correlates closely, although not precisely, with fluidity and inert content.

The relationship between coking parameters, caking parameters and coke strength is illustrated in Figure 5.1. The coking parameter is measured by mean maximum reflectance or $\bar{R}_o$ (shown on the ordinate), caking parameter, measured by inert content (shown on the abscissa), and coke strength is determined from the isostrength lines.

The figure shows that, in general, coke strength increases with coal rank ($\bar{R}_o$ increase) in the medium and high volatile range to $\bar{R}_o = 1.4$) and coke strength increases with inert content in all volatile ranges until inert content reaches 20–30 per cent, at which point coke strength decreases. Optimum coke strengths fall in the range of 50–60 (JIS 92–93).

A typical target coke strength of modern steel industry blend, such as in Japan, is shown in Table 5.2.

[1] "Requirements for Coals in Japanese Coking Blends", H. Matsuoka, Nippon Steel Corporation, Paper presented to Australian I.M.M., 1975.

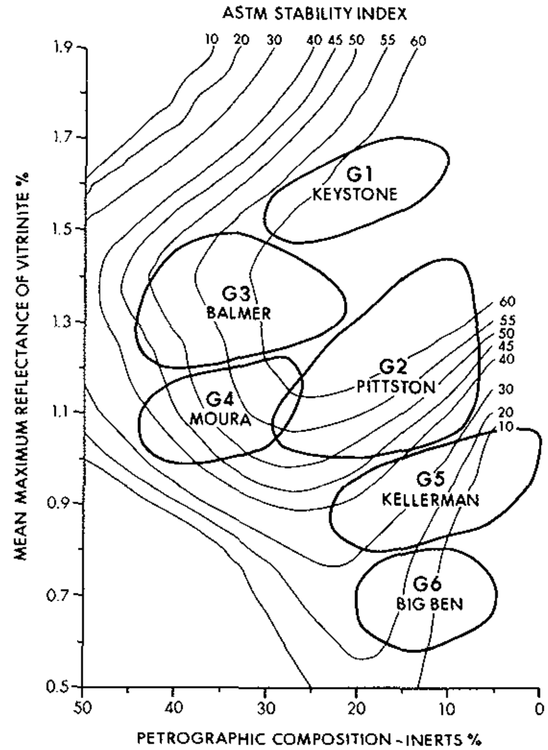


Figure 5.1 — Relationship between coal rank parameters, caking parameters and coke strength (*Source: David E. Pearson & Associates Ltd.*).

TABLE 5.2. Typical Coke Quality Used In the Japanese Steel Industry

Volatile Matter	26–30
Ash	11–12%
Sulphur	0.55–0.65%
$\bar{R}_o$	1.2–1.3
Fluidity (log ddpm)	1.9–3.0
Strength (DI 30/15)	Over 93.5%
(DI 150/15)	Over 81.5%
ASTM	56
Strength of coke reacted by CO_2	45–50
Mean Size	47–50
Range of Size	30–75

Most coals trading in the Japanese coking coal market fall into groups that have similar coke-making abilities. These groups, classified initially by Nippon Steel Corporation as G-groups 1 through 6, have been superimposed on the $\bar{R}_o$/Inert diagram of Figure 5.1. This diagram indicates that U.S. low volatile and medium volatile coals, those coals of the G1 and G2 groups, make generally stronger cokes. All the G1 coals and most of the G2 coals, however, are located outside the likely range of blended coals, those located in the centre of the diagram where G2 and G4 overlap. Many coals in the G3 (Canadian) and G4 (Australian) groups, however, have been found to make excellent cokes as well. Examples of typical coking coal blends at three Japanese steel works are shown in Table 5.3. As the table illustrates, the use of such a large number of coals provides the Japanese with tremendous purchasing flexibility.

Over time, since the development of new blending technology in Japan in the early 1970s, Japan has changed the source of its hard coking coals away from the U.S. to

Canada and Australia. This trend is illustrated in Figure 5.2. The motivation for this switch was the high cost of U.S. coal compared to Canadian and Australian coal. As recently as 1979 U.S. hard coking coals (low and medium volatile metallurgical coal) were selling at premiums of up to US$ 25.00 per tonne with the average being roughly US$ 20.00 per tonne. Turning to Figure 5.1, we can see that when the technical capability became available to do so (through advances in blending technology), it was a simple matter to substitute coals in the more expensive G1 and G2 (U.S.) groups with those in the appreciably cheaper G3 (Canadian) and G4 (Australian) groups.

Recent improvements in blending technology in Japan, namely in (1) briquetting, (2) preheated coal charging, (3) coal selective pulverization, and (4) pulverized coal injection have enabled the Japanese to increase their ability to substitute coals in the coal blending process. Improvements to date now permit them to utilize up to 35 per cent non-coking or poor coking coals. Briquetting involves briquetting a portion of coking coal prior to charging into the coke ovens and mixing the briquettes with the coal blend in amounts ranging from 15–35 per cent (usually 30 per cent) of the total charge. Roughly 65 per cent of the briquetted charge is made up of poor coking coals, so that the process permits the replacement of between 10–20 per cent hard coking with soft coking coal to produce coke of the same strength. At present, Japan has a capacity of 8.4 million tonnes of briquette production which, at current coking coal consumption rates of 65 million tonnes annually, represents a capability to utilize briquetting with about 42 million tonnes of coking coal or 65 per cent of total coal used.

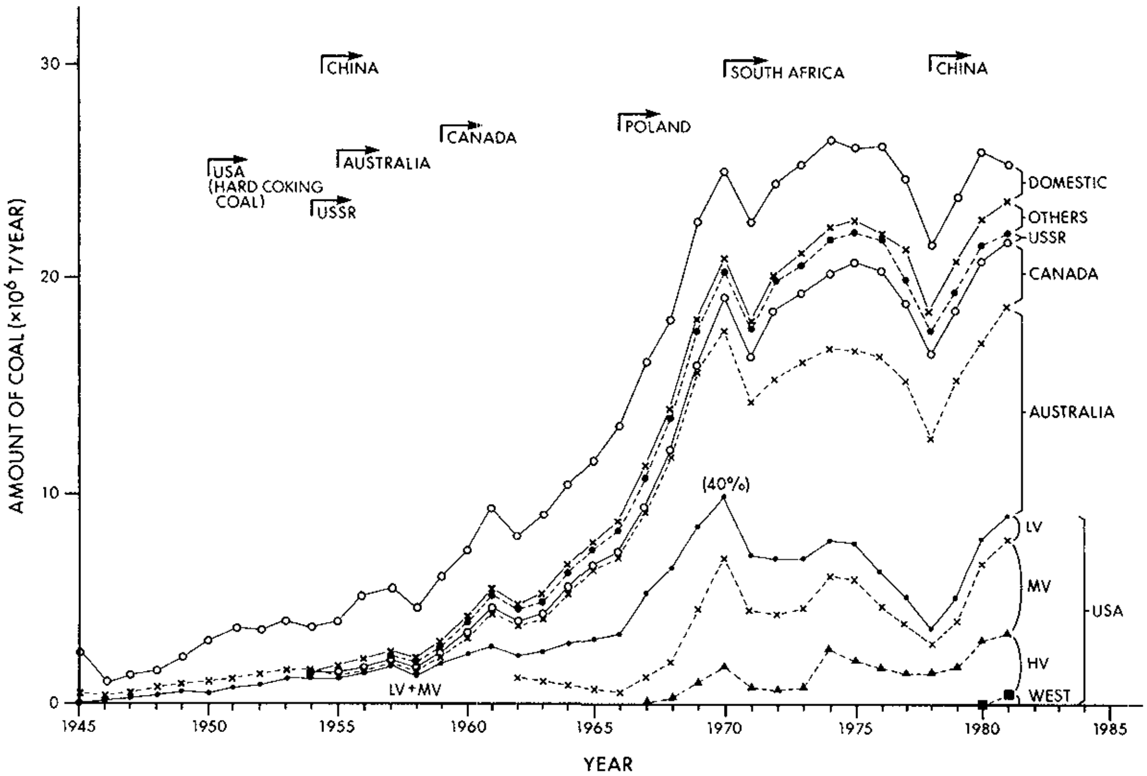


Figure 5.2 — Changes in consumption of coking coals (Nippon Steel) (Source: Y. Ishikawa, *ibid.*).

TABLE 5.3. Example of Coal Blends in Works Determined With Coal Allocation System

Coals \ Works		Yawata	Muroran	Nagoya
US	— LV	2	2	4
	— MV	11	5	10
	— HV	9	6	24
Australia	— LV	16	0	8
	— MV	24	0	15
	— HV	0	0	16
Canada	— LV	0	22	13
	— MV	0	15	10
China	— MV	4	0	0
	— HV	9	0	0
South Africa	— HV	6	13	0
Domestic (Hokkaido)		0	32	0
Domestic (Kyushu)		17	0	0
US—West		2	5	0
SI		3.92	3.66	4.10
CBI		1.21	1.26	1.21

Note: Yawata: Being equipped with briquette blend coking process
Muroran: Being equipped with preheated coal charging process
Nagoya: Conventional process

Source: "Technical Aspects of Coal Use In The Japanese Steel Industry", Y. Ishikawa, Nippon Steel Corporation, 1982.

Preheated coal charging means preheating the coal charge prior to charging in to the coke oven. Its use permits a 30–40 per cent rise in productivity and a reduction in the number of coke ovens necessary. It also enables the replacement of hard coking coal by up to 30 per cent soft coking coal and the use of non-coking and poor coking coals. However, this system requires drastic reconstruction of coke ovens and, with the extension of the life of most Japanese coke ovens to 2000, is it not likely to be implemented on a large scale until then and, even then, only if economics permit.

Coal selective pulverization enables better size control in crushing. This process avoids excessive pulverization of reactive rich coals and because it, thereby, improves coke strength, enables the replacement of up to 10 per cent hard coking coal with soft coking coal.

Pulverized coal injection is used to substitute for oil and tar injection in the blast furnace and is used to maintain stable blast furnace operation. Its use permits 10 per cent non-coking coal use.

On the distant horizon is the formed coke process which would allow the use of 70–80 per cent non-coking coal or poor coking coal. By this carbonizing process, coke is made with 100 per cent briquetted coal. Development of this process is underway in Japan, under joint sponsorship of the government and the steel industry. This technology, however, will not be in place on a significant scale until most of the current coke ovens are replaced, beginning around 2000.

As is the case with metallurgical coal, there are a number of inherent physical differences among thermal coals and these quality characteristics impact directly on the operating and capital costs of conventional coal-fired powerplants.

In order to generate electricity using coal, a coal-fired powerplant must be designed to achieve steam flow, pressure and temperature sufficient to drive electricity producing turbines. Plant design is directly affected by coal quality. Coals with difficult quality characteristics such as the tendency to form mineral deposits on furnace walls and other surfaces in the combustion zone of the boiler (slagging) and the tendency to form high temperature bonded deposits on the superheater and reheater tubes in the convective section of the boiler (fouling) can be compensated for by building larger units. To do so, however, is very expensive. Thus, the slagging and fouling tendencies of prospective powerplant coals are a major cost consideration for any powerplant.

Because it is not practical to design a boiler to accommodate every possible problem, coal quality characteristics can continue to seriously impact on both the operating and capital costs of powerplants. Difficult coals, those that slag and foul or are corrosive and abrasive or that create temperature imbalance in the boiler, can increase fuel costs or act to accelerate the physical depreciation of plant and equipment increasing unit capital and operating costs.

The combustion of coal in a boiler is very rapid taking two seconds or less. But during this short period complex chemical reactions occur primarily between the various mineral components of coal, collectively known as the ash content. How the coal reacts affects the powerplant performance expressed in terms of boiler efficiency and boiler availability. Boiler efficiency is the amount of heat consumed to produce a given quantity of steam while boiler availability is simply the time the boiler is available to generate steam when the boiler's operation is not reduced due to forced outage or partial outage.

The complex chemical reactions are extremely important because they affect the formation of chemical compounds that promote slagging, fouling, corrosion and, possibly, temperature imbalance. These are commonly the most troublesome problems caused by coal in a powerplant. For example, the most important chemical reactions are those affecting sodium and potassium, the alkali metal salts on superheater tubes. These salts are extremely corrosive and are the principal cause of damage to powerplant superheater tubes.

Such negative impacts can be compensated for in a number of ways. The coal can be washed to reduce the ash quantity or to reduce certain detrimental ash characteristics such as sulphur content, it can be blended with other coals, or have the quality variability reduced, or powerplant flue gases can be cleaned further, etc. The desirability of doing so however, depends on an analysis of the economics of how a change in coal quality will affect powerplant performance.

Recent studies conducted by the International Energy Agency[1] have shown, for example, the following economic impact of ash level on powerplant efficiency and availability: a 1% increase in ash (generally after passing the 10% ash level) results in a 1.2%–1.5% decrease in boiler availability and a decrease of 0.3% in boiler efficiency. At a capital cost of US$ 1000 per KW, the capital cost absorption penalty is US$ 0.95 per tonne and US$ 0.67 per tonne respectively per 1% ash content increase, disregarding all but boiler efficiency and availability factors. And this is only one half of the coin. The impact of ash chemistry, as opposed to ash quantity, is recognized as being even more significant.

[1] *Coal Quality and Ash Characteristics*, IEA Coal Advisory Board, Paris, January 1985.

There is also increasing evidence of the importance of consistency of coal quality and the need to have delivered coal quality that remains within the design parameters of the boiler. A 1983 study of utilities in NSW, Australia reports that a high forced outage rate of 7.2% over the preceding 3-year period was due primarily to ash content exceeding design levels and to inconsistency in coal quality. The reduced output resulted in increased fixed capital charges, operating and maintenance costs equivalent to A$ 6.80 per tonne of coal consumed and a production cost increase due to increased boiler wear of A$ 4.20 per tonne of coal consumed. The solution to this problem was to install a coal washery to reduce ash content and introduce more consistency in coal quality.

Recent technological developments, such as fluidized bed combustion and gasification will enable the use of poorer quality thermal coals. The qualitative characteristics that are currently of great significance to consumers of thermal coals, such as heat content, ash content, ash composition (slagging and fouling tendencies), volatility (an indication of the ability of the coal to burn efficiently in a boiler), sulphur levels and nitrogen levels (both contribute to pollution or require expensive stack emission control equipment), and moisture content will not be as important. This will result in an increased competitiveness among coals as the range of acceptable coals widens to include coals not used in conventional thermal boilers. Acceptable coals will likely include sub-bituminous coals (lower heat contents due to high inherent moisture contents) and lignites (very high moisture contents). These coals are available in large quantities worldwide, as are poor, higher sulphur, higher nitrogen heavy slagging or fouling bituminous coals.

Some thermal coal prices also are affected by the physical size of the coal provided. Anthracite, in particular, is standardized into 10 or more distinct sizes based upon the coal's inherent physical makeup. Price differences between sizes stem, in part, from the fact that the larger sizes genereally have higher heat content, but size requirements for particular industrial uses also affect the price levels.

5.2.2 ECONOMIC DETERMINANTS

While the inherent physical characteristics of coal determine the relative attractiveness of one coal to another from the perspective of the consumer, these differences serve only to separate the price of one coal from another at any market price level. For example, the fact that one thermal coal may have 7 000 kcal/kg (12 600 Btu/lb.) while another only has 6 000 kcal/kg (10 800 Btu/lb.), establishes that the market will be willing to pay a premium for the additional head content of the 7 000 kcal/kg coal. This premium is equal to the difference in heat content (1 000 kcal/kg) multiplied by the market value of 1 kcal/kg. The market price of an energy commodity, which in this case is thermal coal, is established by market forces and these change from day to day. In 1978, prior to the second energy shock, the value of this additional 1 000 kcals would have been US$ 2.86 at the shipping port compared to US$ 5.72 in 1981, following the doubling of export coal prices.

In general, the market price of coal traded in the international market is affected by five main factors: (1) the demand for coal; (2) the cost of producing, transporting and loading the coal on board ship; (3) the price of competing energy sources such as oil, natural gas, or hydro power; (4) exchange rates; and (5) the availability of coal. An additional factor, more difficult to anticipate, is the expectation of the future price of coal on the part of buyer and sellers. The panic buying or "coal fever" exhibited by Japan over thermal coal in 1980/81, following the second oil crisis in 1979 and the disruptions of Polish supply, is an example of the potential of this phenomenon. International thermal coal prices doubled over this period.

Another factor is the market power of the buyer or seller which has been evident especially in the metallurgical coal market in recent years. Japan is the world's largest single importer of metallurgical coal, buying 85% of all Pacific Region metallurgical coal imports and 45% of world imports. The presence of significant excess coal production capacity has given Japan, as the dominant purchaser, a significant influence on coal prices. Since coal is generally traded under long-term contracts, coal prices have tended to reflect the degree of flexibility in individual contracts for adjusting prices and volumes. Thus coal prices no longer strictly reflect coal quality characteristics.

In the case of metallurgical coal therefore, price is determined, in part, by the demand for steel as well as by these other factors. There is also some evidence that the price is also influenced by the length of the contract. Prices tend to be lower in longer contracts which shifts some risk from the seller to the buyer. This shift enables the seller to plan production more favourably, and to minimize inventory costs. The buyer acquires additional risks that may result in accumulation of unnecessary inventories during recessionary periods. However, with a long-term contract, the buyer benefits from reduced transaction costs, which can be substantial.

Export prices are also influenced by the transportation costs incurred in moving the coal from the port of supply to the buyer's plant. Transportation costs for Australian and Canadian coal producers selling to Japanese markets should be similar, as Western Canadian ports are nearly equidistant from Yokohama (about 7 000 kilometres). Prices offered to United States producers by Japanese steel mills should be lower, simply because shipping distances are substantially longer.

Prices offered for thermal coal will be affected similarly by these factors, but also will be heavily influenced by the prices of competing sources of thermal energy. In this regard, there is the recent evidence of dramatic downward revisions in 1982 and 1983 to projections of world demand for thermal coal. This change in outlook stems from the largely unanticipated adjustments of oil consumers to rising oil prices. Demand cutbacks have not yet been large enough to lower the prices of oil to a level where conversion of many oil-fired plants to coal would be uneconomic, or where construction of new coal-fired plants would be uneconomic but the threat of this happening overhangs the market. Even fairly recent projections of demand for thermal coal assumed larger increases in oil prices than are now expected. The volume of thermal coal demand and the price likely to be offered are both adversely affected by this development.

Prices for all types of export coal will be affected by exchange rates. As Table 5.4 shows, declines in the value of the Australian dollar and the South African rand of 25 per cent and 35 per cent respectively between January 1985 and July 1985 have not been matched by the 8 per cent decline in the value of the Canadian dollar over the same period. This has resulted in hardship for Canadian producers who have had to reduce their prices to stay competitive with their Australian and South African counterparts. While FOB port prices denominated in Canadian dollars have actually been reduced for Canadian producers, the export price received by Australian and South African exporters has risen in terms of their domestic currencies. As Figure 5.3 shows, since 1980 Canadian exporters have lost a considerable foreign exchange advantage over Australian and South Africa.

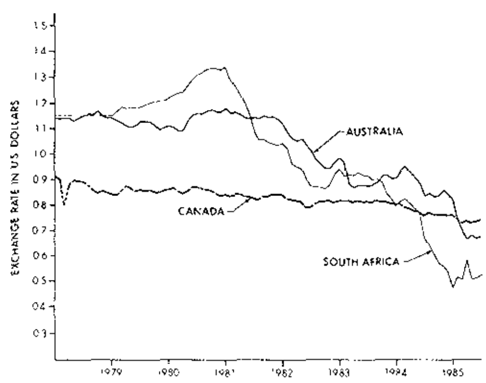


Figure 5.3 — Comparative exchange rates (Source: A.E.C. Ltd.).

TABLE 5.4. Exchange Rates[1] (in U.S. dollars)

		Australia	South Africa	Canada
January	1984	.9051	.7967	.8011
February	1984	.9359	.8132	.8013
March	1984	.951	.8225	.7874
April	1984	.9237	.8025	.7816
May	1984	.9054	.7836	.7723
June	1984	.8829	.766	.7670
July	1984	.8353	.6699	.7553
August	1984	.8462	.6359	.7672
September	1984	.8326	.6027	.7609
October	1984	.8357	.5669	.7583
November	1984	.8594	.5547	.7597
December	1984	.8419	.5295	.7575
January	1985	.8158	.4635	.7554
February	1985	.7416	.5093	.7391
March	1985	.6964	.5022	.7229
April	1985	.6593	.5176	.7327
May	1985	.6763	.5024	.7269
June[2]	1985	.6644	.5063	.7314
July[3]	1985	.6700	.5195	.7366

[1] Monthly Averages.
[2] Preliminary.
[3] As of July 5, 1985.

Source: IMF Financial Statistics (RM Series).

5.3 DETERMINANTS OF THE COST OF COAL PRODUCTION

The viability of British Columbia's coal industry depends upon its ability to extract, process, and transport the coal to export markets at a cost lower than the prices offered on international markets. Costs, like prices, obviously are subject to myriad influences, thereby making it hazardous to generalize about cost structures. However, various elements of the total costs of producing coal can be separated, and estimates of the relative magnitudes of these costs can be produced from records provided by existing mines and from plans submitted for new mines.

Costs of bringing coal to the point of export can be divided into four main elements. They are:

(1) Capital costs
(2) Operating costs; including:
  —costs of extraction
  —costs of beneficiation
  —administration costs
(3) Taxes and royalties
(4) Transportation costs; including:
  —costs of moving the coal to tidewater
  —loading costs

Direct taxes and royalties paid by coal mines in British Columbia are determined by legislation, and vary with both the profitability of the mining operation (which affects both the mining tax and corporate income taxes) and with changes in the mine-head value of the coal extracted (the basis of royalty payments). Costs of inputs also will influence total taxes paid through the various sales taxes.

5.3.1 CAPITAL COSTS

5.3.1.1 Capital Investments in Existing Facilities

Coal has been mined in British Columbia since the mid-1800's; large-scale contemporary coal mining started with the development of Kaiser Resources Ltd.'s Balmer mine near Sparwood in 1970. The capital costs incurred in bringing that mine into production were reported at $135 million (1972 dollars). Given the initial capacity of 5.2 million tonnes per year (MTPY*), that capital investment was equivalent to about $26 per tonne of annual output including financing costs.

In 1980 British Columbia Resources Investment Corporation (BCRIC) bought control of the (expanded) Balmer mine through the purchase of 67 per cent of Kaiser Resources for $672 million. This acquisition also included Westshore Terminals Ltd.'s bulk loading port facility at Roberts Bank, and various oil and gas properties, including the Brae Field properties in the North Sea. Westar Mining Ltd., a subsidiary of BCRIC, is now the operator of the Balmer and Greenhills mine.

Cominco Ltd.'s Fording mine near Elkford was the second large-scale coal operation in British Columbia. Completed in 1972 at a capital cost of $76 million (1972 dollars), this mine had an initial capacity of 3 MTPY. The unit capital cost was about $25 per annual tonne.

In 1974 the Byron Creek mine (now owned by Esso Resources Ltd.) was constructed at a capital cost of about $24 million (1974 dollars). This is a relatively small mine. Production capacity totalled 0.9 MTPY, making the unit capital cost for the mine about $27 per annual tonne.

5.3.1.2 Capital Investments in New Capacity

The capital costs per tonne of annual output for new coal mines in British Columbia range from $74 to $150 per tonne of annual capacity (excluding financing costs). Lower costs are possible for capacity increases achieved through expansion of existing mines, at least for limited percentage increases in capacity. Their costs will be lower than the costs associated with entirely new operations simply because of scale economies possible with the use of existing plant, equipment, and infrastructure.

Prior to the expansion of British Columbia's coal industry in the early 1980s, all export coal production came from the Crowsnest Coalfield in the southeastern corner of the Province. The coalfield's capacity was about 12 MTPY. With the addition of Westar Mining Ltd.'s new Greenhills mine (2.9 MTPY) and Crowsnest Resources Ltd.'s Line Creek mine (2.7 MTPY) in 1982 and 1983, along with expansions at Fording and Byron Creek, capacity increased to 20 MTPY by 1985.

The Greenhills mine reportedly cost $282 million to generate a production capacity of 1.8 MTPY of metallurgical coal and 1.1 MTPY of thermal coal. This represents a capital cost of about $97 per tonne of annual capacity. If financing costs of $53 million as calculated by the company are added to the capital cost, the cost per tonne rises to $115.

Capital costs for the Line Creek mine were projected to total $200 million. With an initial capacity of 2.7 MTPY, capital costs per annual tonne would be about $74. With the addition of estimated financing costs of $38 million, capital costs per annual tonne increase to $88.

By mid-1985 nearly one-third of British Columbia's coal capacity was originating from new mine developments in the Peace River Coalfield in the northeast

* MTPY = million tonnes per year.

sector of the Province. A study published by Price Waterhouse Associates in April 1981 detailed capital costs for the combined Denison and Teck coal operations as $1.65 billion in 1980 dollars or $2.89 billion spent dollars, including townsite, railway, and port costs. Since this study was completed, both mines have revised their capacity. Combined annual capacity has been increased from 7.7 MTPY to 8.4 MTPY, however no capital costs have been estimated for this new production level.

Denison Mines Ltd.'s Quintette mine has an annual capacity of 5 MTPY of metallurgical coal and an additional 1.3 MTPY of thermal coal. The Bullmoose mine owned by Teck Corp. has a capacity of 2.0 MTPY of metallurgical coal and 100 000 tonnes of thermal coal. The breakdown of the capital costs required to move the coal to tidewater is shown in Table 5.5. It should be noted that these data are estimates; they are based on an inflation charge of 12 per cent and a construction interest charge of 15 per cent. In addition, capital costs have been estimated using a capacity of 7.7 MTPY. On the basis of these numbers the average capital cost per annual tonne for these two mines is $89 in 1980 dollars, or $154 in spent dollars.

TABLE 5.5. Northeast Coal Project, April 1981 Estimates of Total Project Capital Costs

	Cost in *1980 dollars*	Period over *which spent*	Cost in "spent" dollars to the end of the construction *period*
By Component:	($ Million)		($ Million)
Mines	687	1981–1984	1 183
Railway	566	1981–1986	982
Port	139	1981–1983	197
Townsite, roads, and power	260	1981–1986	526
Total	1 652		2 888
By Sector:			
Private sector	911		1 625
Public sector	741		1 263
Total	1 652		2 888

Source: The Northeast Coal Project. An Assessment of Public Sector Investment and Job Creation Impacts, *Price Waterhouse Assoc.*, for Quintette Coal Ltd. and Teck Corp, April 1981.

5.3.2 OPERATING COSTS

The direct costs of mining and processing the coal extracted from British Columbia open-pit mines range from $20 to $34 per tonne of output.

The above-quoted study of the proposed Quintette and Bullmoose developments indicated that costs of administration, and of mining and processing the coal from these two mines would amount to $27 (1981 dollars) per tonne of coal produced. About $9 of these operating costs would arise from wages and salaries; the remaining $18 per tonne would be attributed to materials and supplies.

These operating costs are estimated based upon a total capacity of 7.7 MTPY. The added capacities of each mine and the change in mine plan at Quintette will result, of course, in a somewhat different level of costs.

5.3.3 BRITISH COLUMBIA'S COMPETITIVE POSITION

From the perspective of the world's buyers of British Columbia's coals, its costs of mining, transporting and loading coal on board ship for export were for the most part competitive as of the end of 1984. As Table 5.6 shows, breakeven costs of existing mines in British Columbia, at US$ 36–43 per tonne, compare favourably with the cost of coal coming from its two major competitors, Australia and the U.S. at US$ 38–47 and US$ 37–50 per tonne respectively. When compared to South Africa, none of these suppliers could match its breakeven cost of US$ 27–28 per tonne FOBT. However, South Africa does not compete in the hard coking coal export market and there are increasing limitations on the quantity of thermal coal it is likely to export.

British Columbia's new mines are also generally competitive with Australian and U.S. exporters, as of the end of 1984, with breakeven costs of US$ 42–52 per tonne compared to US$ 42–50 and US$ 45–55 per tonne respectively.

Over time it can be expected that the cost of producing coal worldwide will rise in real terms as coal deposits that are currently more expensive to mine are exploited. Taking world thermal coal as an example, it is most likely that by 1990, breakeven costs FOBT will rise from the 1984 levels of US$ 36–39 per tonne, at the low end of the cost range in Table 5.6 to roughly US$ 43–45 per tonne (in 1984 dollars), again at the low end of the range (excluding South Africa). Comparative cost of new bituminous coal production are also presented in Table 5.6. Costs are in 1984 U.S. dollars per tonne. These costs estimates include the costs of new projects currently being brought into production in Canada and Australia. Figure 5.4 illustrates the expected coal supply cost curve, FOBT, for world export thermal coal, again in 1984 dollars per tonne. The figure shows that Canada, as of year-end 1984, was expected to be a competitive supplier in the world export thermal coal trade.

A projection such as the foregoing 1990 world coal supply cost curve has a number of attendant risks associated with it. Factors such as unanticipated changes in real production costs, or transportation costs, or port charges, or government charges can make these forecasts questionable. In addition, variations in the exchange rates of exporters relative to the U.S., will have a significant impact on the continuing competitiveness of Canadian producers. For example, in the first six months of 1985 the Australian dollar fell 20 per cent relative to the U.S. dollar, while the Canadian dollar fell only 3 per cent. This differential fall in the Australian exchange relative to Canada had the effect of reducing the FOBT cost of much of Australia's metallurgical by US$ 5–9 per tonne. The Australian dollar is a volatile currency, however, that has in the past exhibited large swings in value, both up and down, depending on its net trade and capital account balances. More importantly, the current competitive disadvantage Canadian producers are experiencing may well disappear, if Australian devaluation leads to a faster rate of production cost increase in Australia or if the excess profits arising from devaluation are absorbed by Australian labour or governments in the form of higher wages or higher direct or indirect taxes.

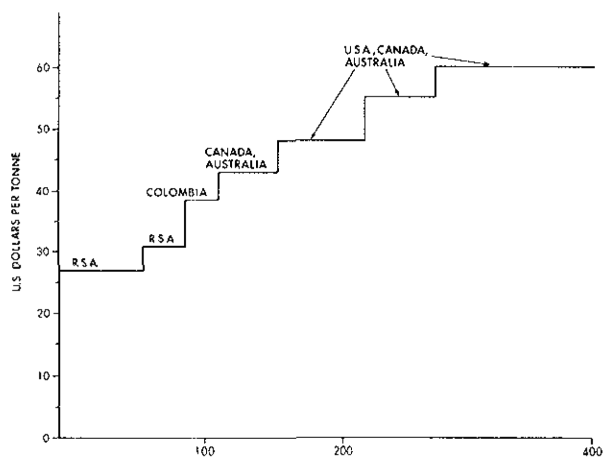


Figure 5.4 — World coal supply cost curve, 1990, F.O.B.T. cost (Source: A.E.C. Ltd.).

TABLE 5.6. Representative Costs of World Bituminous Export Coal (In 1984 US$ Per Tonne[1])

Source	Operating	Transp.	Port	Breakeven Costs	
				Existing Mines	New Mines
Canada					
B.C.	15–26	15–18	3	36–43	42–59
Alta.	19–21	16–17	3	39–43	45–52
United States					
West	17–23	22–24	5	46–50	46–50
East	20–26	14–18	3	37–48	45–55
Australia					
Qlnd.	19–25	7–15	3	39–47	47–50
NSW	19–21	10–14	5	38–42	42–48
South Africa	7–13	8	4	27–28	31–32
Colombia	13–15	5	5	28–43	—
Indonesia	—	—	—	—	36–40

[1] Converted at Cdn$ = US$ 0.77 and Aust$ = US$ 0.84

Source: A.E.C. Ltd.

5.3.4 TAXES AND ROYALTIES

Direct taxes paid by British Columbia coal mines are dependent upon the mine-head value of the coal, and upon the profitability of the operations involved.

The coal royalty imposed is equal to 3.5 per cent of the mine-head value of the output. When the British Columbia Mining Tax, land taxes, and income taxes are added to these royalties, the total burden of direct taxes could range from $4 to over $10 per tonne of output, depending upon the financial characteristics of the individual mine.

The mining industry also pays sales, property and other applicable taxes.

5.4 FACTORS AFFECTING COSTS OF PRODUCTION

5.4.1 TECHNICAL FACTORS

The costs cited so far have been based upon information for existing or proposed mines. In most instances, these costs are for the extraction and beneficiation of metallurgical coal from open-pit mines. Given this similarity, and the fact that these mines pass the economic test of providing revenues greater than costs, it is hardly surprising to find that the cost structures do not vary widely.

Costs associated with the extraction of coal from other sites could be much different than the costs reviewed. Geological, geographical, and other factors peculiar to the development of each coal reserve lead to unique cost structures for each potential mine.

The list of factors affecting capital or operating costs for new mines is quite extensive (*see* Table 5.7). Major cost differences appear between the two broad categories of mining techniques, open-pit mining and underground mining. However, even within each type of technology, costs can vary substantially with changes in key variables.

TABLE 5.7. Variables Affecting Capital and/or Operating Costs for New Coal Mines

Open Pit Mining
Geological structure of the reserves
Tonnage of the reserve that can be developed
Type of open-cast mining — dragline versus truck and shovel
Design of pit and pit slopes
Size of loading, transport, drilling, and other equipment
Volume and type of overburden
Haul distance of overburden
Haul distance of raw coal
Groundwater
Design and costs of reclamation and tailings containment
Availability and competence of labour
Prevailing weather conditions
Difficulty of drilling and blasting
Financing; debt: equity ratios and interest charges
Tax regime
Underground Mining
Geology, depth and attitude of reserves
Number and thickness of mineable coal seams
Competence of rock above and below coal seam
Mining method
Presence of gas in the mine
Plan of development — tunnelling and shafts
Financing; debt: equity ratios and interest charges
Tax regime
Preparation
Specifications of the clean coal sales contract
Washability curve (difficulty of separation)
Sizing character of raw coal, for example, fines
Organic efficiency of separation
Recoveries from the raw coal supply
Distance from coal mine and loading area
Blending requirements
Design of plant and equipment
Type and cost of fuel source
Townsite
Distance from existing facilities
Distance from mine
Desirability of area
Costs of construction
Amenities
Types and proportions of housing required
Services
Financing and support costs

5.4.1.1 Underground Mining

Underground mining methods can be divided into four techniques. Choice of technique—and therefore of cost patterns and levels—depends largely upon the physical characteristics of the coal.

The room-and-pillar technique requires flat-lying seams. A number of entries split the seam into pillars. These pillars are then extracted using continuous mining machines working along 7 to 9-metre faces. Pillars are reduced in size as much as possible consistent with leaving enough strength to support the roof. Coal recovery may be as low as 40 per cent, but under favourable conditions will reach 65 per cent to 70 per cent. This system is fairly flexible with respect to seams containing rock or areas of low quality coal. Seam thickness may range up to 6 metres, above which coal recovery rates become inordinately low using room-and-pillar techniques. This mining method generally has the lowest capital costs of the underground mining techniques, but higher operating costs make it the most costly underground technology per tonne of coal won.

The longwall system typically consists of two underground "roadways" reaching opposite ends of a single linear coal face, usually about 100 metres in length. The roof at the face is secured by powered supports which are moved as the coal is mined. A drum shearing machine moves back and forth across the coal face, removing successive slices of coal. Coal is removed from the face by a conveyer system. As the roof supports are moved to follow the face, the roof in the mined-out areas subsides. In advancing longwall mines the roadways approach the face through the mined-out area, or "gob". In retreating longwall mines the roadways are driven through the coal to the face by continuous mining machines.

Under favourable seam thickness and slope conditions, longwall recovery rates may reach 85–90 per cent. However, the system is limited to seams less than 4 metres thick, and is not very adaptable to changes in the thickness or dip of the seam, the presence of impurities, weak floor conditions, or faulting.

Capital investment required is high, but good recovery rates make this the least costly of the underground techniques per tonne of coal extracted.

Shortwall mining combines the flexibility of room and pillar with some of the enhanced productivity of the longwall technique. A continuous mining machine cuts and loads from a face (up to about 50 metres long) on a rectangular pillar of coal under the cover of self-advancing roof supports.

The system is more adaptable than longwall mining to faulted or irregular coal seams. Minimum seam thickness necessary for shortwall mining is about 1.5 metres versus 1 metre for longwall mining.

More than one shortwall face may be prepared so that continuous production can be maintained even when one face is down, but productivity does not match that of longwall mining. The use of armoured conveyor systems to remove the coal in longwall mining is more efficient than the mining carts or extensible conveyors common in shortwall operations. Furthermore, additional set-up time may be involved in the more frequent moving of roof supports in shortwall mining.

Capital investment in shortwall mining is the highest among the underground mining methods, but high productivity keeps total costs per tonne below those associated with room-and-pillar mining.

Hydraulic mining is considered to be an improvement on the traditional room-and-pillar techniques. It is particularly suited to thick, steeply sloping seams like those frequently found in Canadian Rocky Mountain deposits. For example, Westar's Balmer North seam is 14 to 18 metres thick and inclined at 30 degrees. Early attempts to mine this coal with traditional room-and-pillar techniques resulted in recovery rates of only 10 to 15 per cent, while hydraulic methods have resulted in 55–70 per cent recovery.

In this method, entries are driven through the seam using continuous mining machines. Pillar extraction is done on the retreat using a high-pressure water jet from a hydraulic monitor. Coal is washed away from the face in a coal-water slurry that is carried in metal flumes down the access tunnel. Careful preparation and much information on the geological structure of the seam is required to obtain optimum gradients for the slurry outflow.

Capital investment for hydraulic mining is high, but operating efficiencies generate total costs per tonne of output which compare favourably with either the room-and-pillar or shortwall methods.

5.4.1.2 Open-pit or Surface Mining

This technology generally is characterized by higher output per worker, higher reserve recovery rates, and lower overall mining costs than underground mining. However, open-pit mining is limited to areas where the ratio of overburden to coal (known as the stripping ratio) averages 12:1, or less, although in the first one or two years of a mine's operation, stripping ratios may reach 20:1. Choice of the method of removing the overburden and coal depends upon the physical characteristics of the deposits involved.

Truck and shovel methods are used in Rocky Mountain deposits that are covered by shale and sandstone. The overburden is drilled and blasted, and stripped away with power shovels of 13 to 21-cubic-metre capacity. Heavy trucks are used to carry the material to dumps outside the pit limits. Bulldozers are used to remove the remaining rock and to assist front-end loaders to load the coal into haulage trucks. The coal is delivered to a crusher and then moved into the wash plant.

In large open areas with fairly flat coal seams, a dragline may be used to strip away the overburden and to mine the coal. Waste is cast aside while coal is stockpiled for removal with front-end loaders and haulage trucks. If required, the waste may later be moved again by truck and shovel. Smaller shovels and bulldozers may be used to prepare benches from which the dragline can work.

Careful site preparation is necessary to maximize the dragline's potential. Stripping ratios are critical, because the efficiency of the operation may be lowered by the inability of other machines to remove waste from the vicinity of the dragline as quickly as it accumulates. Fording's dragline has been working only in areas where the stripping ratio averages about 2.5:1 or less.

Open-pit mining typically exhibits considerable scale economies as production per year rises. Costs per tonne may drop by as much as 12 per cent with a doubling of capacity from 1 to 2 MTPY. Smaller reductions are possible with further increases in capacity.

5.4.1.3 Beneficiation

As discussed in the previous section, the technology used to extract the coal has a direct relationship to mining costs. Similarly, the degree of processing or beneficiation directly affects the cost of producing coal and is related to the quality characteristics required by the purchaser.

Obviously some of the physical and chemical characteristics are determined by nature, and cannot be altered by the supplier. However, factors like the proportion of inorganic or inert rock matter, and the moisture content of the coal can be altered.

Depending upon the size of the coal particles after crushing, a number of washing techniques which exploit the different densities of coal and inorganic impurities, can be applied to pit run material to reduce the proportion of inorganic matter. However, because the coals from the mountainous areas of British Columbia oxidize readily and the crushed material tends to contain a high proportion of very fine particles, it must be cleaned by using physiochemical techniques which use differing surface qualities of fine coal particles to separate them from impurities. As a result, beneficiation plants in British Columbia tend to be complex, and the washing process is relatively costly. Output from the wash plants must be dried to meet moisture content requirements of export contracts.

Wash plants typically yield about 70 per cent of the mined material in southeast British Columbia.

5.4.2 ECONOMIC FACTORS

The mining techniques used and the degree of beneficiation required have a major impact upon the total cost per tonne of coal produced. The impact of different techniques upon cost components is uneven. One technology may have a greater impact on capital costs than on operating costs, whereas the reverse may be true using a different technology.

In order to assess the economic effects of changes in cost structures, the Ministries of Energy, Mines and Petroleum Resources and Industry and Small Business Development developed a model which simulates the economic linkages between mine revenues and mine costs.

The model incorporates price and volume of production assumptions to calculate gross revenues. Various elements of both capital and operating costs are then inputted to or calculated within the model, to derive net revenues. The model also provides summary measures of the economic viability of the simulated operation through calculation of rates of return on investment and on owners' equity, and through estimation of the payback period. Direct and indirect tax revenues of the simulated coal-mining operations also are calculated.

The structure of the model permits ready assessment of the effects of changes in taxation rates, interest rates, level of borrowing, production costs, capital costs, price, output, and several of the other inputs to the model.

The model has been used to compare the impact of changes in capital costs with the impact of changes in production costs for a typical open-pit coal mining operation in British Columbia. In the example capital costs are $280 million and operating costs are $25 per annual tonne, including $8 per annual tonne for costs of labour. Figure 5.5 shows percentage changes in the Rate of Return (R.O.R.) that arise from percentage changes in either capital investment or in production costs per tonne of output.

It is important to note that the graph reflects changes, rather than absolute levels of either costs or rates of return.

The line labelled "K" on Figure 5.5 represents percentage changes in R.O.R. that result from changes in capital invested per tonne of output. The line labelled "P" reflects the impacts on R.O.R. of changes in production costs.

In general, a given percentage increase in production costs elicits a greater decrease in the returns to investment. Also, returns to investment are more sensitive to changes in production costs than they are to changes in capital investment requirements (line P is steeper than line K).

Figure 5.6 illustrates one source of these differential responses to changes in cost components. This graph presents percentage changes in direct tax burdens that arise from percentage changes in capital investment or in production costs. Again, line K reflects changes in capital investment costs per tonne of output, and line P plots changes in production costs per tonne of output.

The tax load paid by the mining company depends upon the mine-head value of the coal, on the company's profitability, and upon the structure of its costs. As can be seen on Figure 5.6, taxes paid are relatively insensitive to changes in capital costs; a percentage increase in capital investment costs only reduces total direct taxes by about one-half of one per cent. In contrast, a percentage increase in production costs results in nearly twice as large a decrease in total direct taxes.

This sensitivity of taxes to production costs has a direct influence on the sensitivity of the rate of return to production costs; a reduced share to taxes translates into greater relative returns to investment.

This greater sensitivity of rates of return to production costs, rather than to capital investment requirements indicates that, other things being equal, mining technologies which offer higher output per man-hour (labour costs are one of the major production costs), even at the cost of higher capital investment, will be economically more attractive compared to those which offer lower capital costs, but higher production costs.

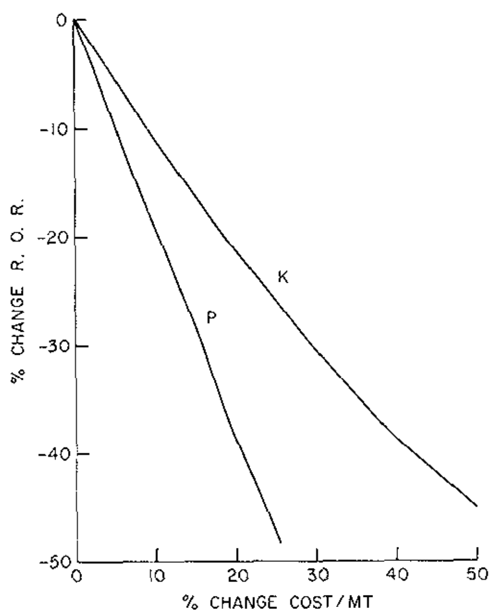


Figure 5.5 — Sensitivity of rate of return to changes in capital and operating costs.

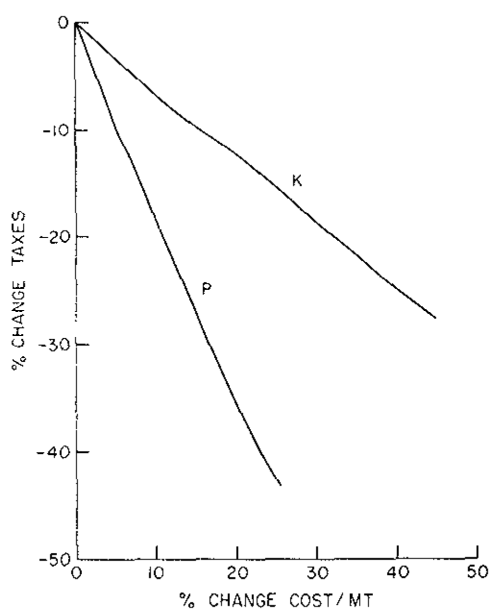


Figure 5.6 — Sensitivity of taxes to changes in capital and operating costs.

VI. ENVIRONMENTAL CONSIDERATIONS FOR COAL DEVELOPMENT IN BRITISH COLUMBIA

6.1 INTRODUCTION

Large-scale coal exploration and development activities may be accompanied by significant impacts on both the natural and socio-economic environments of British Columbia. Many of these impacts are beneficial, particularly those stemming from the regional economic boost which can accompany mine development. Nonetheless, it is important to recognize that many of the impacts can be negative, unless properly managed.

Chapter VI briefly reviews the environmental implications of exploration and mine development, while Chapter VII addresses socio-economic implications such as manpower considerations and community impacts.

6.2 SCOPE OF ENVIRONMENTAL IMPACTS

One logical approach, when considering environmental impacts, is to recognize two primary components of impact: firstly, impacts on the baseline conditions inherent to the natural environment; and secondly, impacts on resource utilization potential, resulting from changes in baseline conditions *and* disturbance of existing resource activities.

The resource utilization considerations have both biophysical and socio-economic ramifications, and the latter are mentioned in Chapter VII.

6.2.1 BASELINE BIOPHYSICAL ENVIRONMENT

6.2.1.1 Air

(a) *Climatology and Meteorology:* Exploration activities normally have virtually no impact on microclimates. Minor microclimatic changes are possible around a mine, although they are seldom considered significant, unless coal is used on-site for purposes such as thermal power generation. The latter may be associated with local (and even regional) impacts on both the temperature and the moisture content of the atmosphere.

(b) *Air Quality:* Both exploration and mining may result in potentially significant deterioration of baseline air quality through the generation of particulates. Gaseous substances may also be emitted around minesites.

Particulates include both coal dust and materials derived from surface soils, and may be generated by use of heavy equipment along haul roads and within a mine, and by coal preparation. Gaseous emissions are minor (for example, water vapour from coal drying), except when coal is used to fire power plants. Thermal power generation may be associated with major gaseous emissions, especially sulphur oxides (SO_x) and nitrogen oxides (NO_x).

6.2.1.2 Water

(a) *Water Quantity:* Groundwater and surface water volumes are not normally significantly affected by exploration. The local groundwater table, however, may be lowered as mine development proceeds. Both surface and underground mine workings may contribute to a significant reduction in surface flows. Considerable volumes of process water may be required for coal preparation and other uses. Particularly in smaller streams, volume reductions may significantly affect fisheries values or other water licence holders.

(b) *Water Quality:* Contamination of groundwater and surface waters may have downstream ramifications for a considerable distance from exploration and mining activities. Surface disturbance and waste dumping may increase sediment yields dramatically, causing excessive suspended solids concentrations in surface waters. Chemical toxicity problems in surface waters or groundwater are not normally associated with the exploration phase. Heavy metals and process chemicals in the tailings slurry, blasting compounds (which yield nutrients), and acid mine drainage are potential problems during mining operations.

6.2.1.3 Land

(a) *Physiography:* Excavation of surface mine pits and construction of overburden and waste rock dumps may dramatically affect on-site topography and the associated drainage pattern. Exploration activities may produce localized topographic disturbances (for example, in association with road construction or trenching).

(b) *Surface Soils:* Removal of overburden, movement of heavy equipment, and alteration of surface runoff patterns may contribute to the extensive loss of productive soil horizons during both exploration and mining operations.

6.2.1.4 Biota

(a) *Vegetation:* On-site removal of vegetation cover may be required for some types of exploration activity, or in preparation for mine construction and operation, and contributes to both soil erosion problems and possible disturbance of fish and wildlife habitats.

(b) *Aquatic Fauna:* Fish and other aquatic fauna (such as benthic invertebrates) may be adversely affected during mining operations by stream diversions, physical disruptions of spawning areas, or increases in the concentrations of suspended solids and certain chemical constituents. To a much lesser extent, similar impacts may occur during exploration activities also. Angling pressures may increase as access improves.

(c) *Terrestrial Wildlife:* Loss of key wildlife habitat and general surface disturbances (such as noise and barrier effects) may seriously reduce local wildlife populations, at least for the life of the exploration and mining programs, and possibly for much longer. Exploration disturbances may be felt over much larger areas than mining disturbances, but are usually more superficial and more temporary in nature. Exploration may contribute to improved regional access, and therefore to greater hunting pressures.

6.2.2 UTILIZATION OF NATURAL RESOURCES

Mine development may affect many resource activity sectors, each of which derives its potential to some extent from baseline biophysical conditions, although technology and the local economic situation are also factors which help determine the value of natural resources.

6.2.2.1 General Considerations

(a) *Land Use:* Both the minesite and its ancillary facilities (access road, railway, transmission line, port, camp or new town, etc.) may affect existing land uses, although such effects can often be minimized through careful project location. Exploration impacts are normally temporary and, in any event, are more minor.

(b) *Land Status:* The prior rights of both private landowners and Crown land and resource tenure holders may be compromised by exploration and mine development activities, often necessitating a negotiated re-allocation of rights. The allocation of coal rights may pre-empt or restrict the future tenure allocation options in other resources sectors, at least for the life of the coal tenures, and possibly for much longer.

(c) *Resource Management:* Exploration and, to a greater extent, mine development may impinge upon current resource management programs in other resource sectors. Some of these programs are entirely a private sector responsibility, but many are either implemented by, or supervised by, the Crown. It may be necessary to adjust the long-term management goals for other resource sectors in order to accommodate mine development realistically, although short-term exploration impacts may require no important long-term adjustments. Facets of a resource management program which may be affected include: ongoing inventory programs; capacity production capabilities; target production levels and production scheduling; policies and priorities for future resource allocation; present and future levels of resource utilization; and planned resource enhancement programs.

6.2.2.2 Resource Sectors

(a) *Coal, Minerals, Aggregates, Petroleum/Natural Gas:* Coal mining operations seldom sterilize other subsurface resources or disturb other subsurface activities since various siting options for mine components (such as dumps and tailings ponds) are usually available. Exploration activities have negligible long-term effects on other subsurface resources.

(b) *Agriculture:* Any disturbances of agricultural lands by exploration tend to be minor and short-term in nature. However, both mining and its associated infrastructure may encroach on agricultural lands which are being used (or which could be used) for grazing or crop production. Occasional longer-term problems may include loss of farmland and the disruption of farming operations associated with access through specific farm properties. Weed control problems are sometimes evident.

(c) *Forestry:* While exploration and mining activities often occur within Provincial Forests, there is usually considerable flexibility to minimize impacts on forest lands and existing or potential forestry operations through siting and layout options. Forestry operations often benefit from newly created mine access, although some forest land may be lost for the life of mining operations.

(d) *Water Use:* Diversion of water for use at various phases of mine operations may conflict with existing commitments to water licence holders, and it may be necessary to guarantee minimum flows in neighbouring streams. Exploration activities seldom, if ever, affect other water uses and users.

(e) *Waste Discharge Potential:* Mine-related discharges (emissions to air or effluents to water) must be in compliance with ambient objectives and point source standards for waste management. These are set on the basis of two factors: the volumes of contaminants and the dilution potential. The capacity of both air and water to absorb contaminants without exceeding predetermined concentration ceilings is finite. Problems are encountered if proposed mine discharges are inconsistent with allocations of the available dilution capacity to existing waste management permit holders, or if the available capacity, although unallocated, is small. Any waste management concerns during exploration are normally minor.

(f) *Fisheries:* During exploration, water quality contamination problems may occur locally. Occasionally, one important concern is the contribution which exploration may make to the improvement of access to large areas, bringing with it increased angling pressures. At the mining stage, the production potential of commercial fisheries may be diminished if contamination of water bodies (for example, siltation of spawning gravels) cannot be controlled. It may be necessary to impose bag limit reductions and other types of management restrictions if fisheries productivity is thereby reduced. Both the livelihoods of commercial fishermen and the recreational enjoyment of sports fishermen may be adversely affected.

(g) *Wildlife:* Concerns are similar to those for fisheries. Exploration activities may improve access to large areas, bringing with it increased hunting pressures, as well as causing direct habitat disturbances through road construction and other activities. If the populations of commercial wildlife species (for example, ungulates, bear, furbearers, and waterfowl) are reduced by exploration and mining activities, stricter hunting and trapping regulations may be necessary, affecting the hunting opportunity of recreational hunters and the livelihoods of guide/outfitters and trappers.

(h) *Outdoor Recreation:* In addition to effects on consumptive recreational activities such as hunting, trapping, and fishing, exploration and mining may disturb a variety of nonconsumptive activities and values, such as hiking, snowshoeing, crosscountry skiing, camping, swimming, wildlife viewing and photography, appreciation of landscape aesthetics, and enjoyment of wilderness areas.

6.2.3 IMPACTS BY COAL ACTIVITY — A SUMMARY

6.2.3.1 Exploration

Coal may be distributed over very large areas in association with other sedimentary rocks. Thus, coal exploration may be associated with widely distributed, although normally short-term, environmental impacts.

The major exploration impact concerns are land disturbances, vegetation removal and soil erosion, and the resultant damage to surface resource values in general, and to fish and wildlife habitat in particular. Also of concern are the potential wildlife disturbances and increased hunting and angling pressures associated with improved access, although much of this access is eliminated after exploration.

The impact of exploration roads on prime wildlife winter and summer ranges in both the Southeast and Northeast Coalfields (also know as the East Kootenay and Peace River Coalfields respectively) has been a priority concern for several years. A basic conflict exists, since the protection of wildlife habitats runs counter to the need to investigate the extent of coal resources.

6.2.3.2 Mine Development and Production

Open-pit mining is associated with a greater range of impacts than is underground mining, particularly with respect to land and water resources.

Open-pit mining necessitates the excavation of large amounts of waste material, and its subsequent deposition in waste dumps (or spoil piles). Thus, land and other surface resource values may be affected over a significant area, at least for the life of the mine.

Disturbances of natural drainage may have major downstream implications, unless carefully controlled. In addition to possible water volume reductions associated with diversions for mine-related water uses, there may be water quality deterioration problems. The most common mine-related water quality problem in British Columbia is the increase in suspended solids levels. Acid generation and leaching of heavy metals may also emerge as important issues, particularly where valuable fisheries are threatened adjacent to coals with a significant sulphur content. The problems which may be caused by nutrient loading associated with blasting are now also being given greater recognition.

6.2.3.3 Related Off-Site Developments

Off-site developments include any or all of the following:

(a) *Coal Transportation and Shipment Facilities:* Coal haul roads and railways, conveyor systems and coal slurry pipelines, and coal shipment facilities (for either barges or deep-sea vessels).

(b) *Site Access Facilities for Personnel:* Normally confined to road access, but may be supplemented by airport facilities for fly-in/fly-out workforces.

(c) *Power Supply:* Normally involving a transmission line hook-up from the integrated grid, although on-site diesel generation, local hydro-electric generation, and on-site thermal generation (using product coal) are also possible.

(d) *Housing:* Accommodation for the workforce and for the indirectly induced population expansion may range from an on-site camp for small mines to expansion of existing nearby communities, or even to new town development for large mines (when there is no sizeable community within daily commuting distances).

Particularly for the larger mines, the direct and indirect environmental impacts of ancillary infrastructural developments may be at least as significant as those of the minesites themselves.

The ultimate scope of the direct environmental impacts depends on the skills which are employed in environmental design. However, indirect impacts (those which result from the incidental improvement in regional access) are less amenable to management and control.

For example, access roads, like other linear developments, may traverse large areas, resulting in land and water disturbances which affect resource values and utilization potential in a direct sense. However, it is often the increased human presence and the resultant increase in the levels of natural resource use which are of greater concern as access is improved. It may be difficult to respond effectively to sudden increases in levels of hunting, angling, hiking, camping, logging pressures, and demands for Crown land tenures, cottage sites, etc.

New townsites (and to a lesser extent, expanded towns or large mining camps) may result in very high levels of indirect impact. Large population influxes may dramatically affect all aspects of the regional environment — the land, the wildlife, fisheries, recreational sites, wilderness values, etc.

6.3 ENVIRONMENTAL IMPACT MANAGEMENT

6.3.1 BACKGROUND

Before the introduction of legislated reclamation requirements in 1969, little consideration was given to such issues as soil erosion, water quality deterioration, and wildlife impacts. This inattention resulted in considerable environmental damage, especially in the Southeast Coalfields of British Columbia.

During the early 1970s, major coal exploration programs were initiated in the Northeast Coalfield, concurrent with the ongoing exploration and mining activity in the Southeast Coalfields. As a result of these exploration and mining activities, much knowledge has been gained, not only about the extent of coal resources and reserves, but also about the minimizing of environmental disturbances. This bodes well for the effective control of any environmental disturbances associated with the exploration and development activities which have now been initiated elsewhere in the Province, such as on Vancouver Island and, most recently, in northwestern British Columbia.

As a result of the geological knowledge gained to date, it is reasonable to expect that, during the 1980s, exploration and development activity will tend to be more localized, focussing on areas of greatest economic potential. Moreover, environmental impact management programs will become more effective as experience accumulates.

6.3.2 RECLAMATION

Initially, impact management tended to be considered synonymous with reclamation activity at the minesite, and it is in the field of reclamation that some of the most obvious improvements in environmental protection have been noted to date. As regulated pursuant to the *Mines Act,* reclamation normally involves the restoration of directly disturbed lands and water bodies to a mutually agreed use (or standard) following exploration and/or mining.

Reclamation permits specify requirements for the seeding and fertilization of reclaimed land, the restoration of water courses, and the dismantling of buildings and other structures. To provide a technical framework for sound reclamation planning, the Ministry of Energy, Mines and Petroleum Resources has published coal exploration guidelines since the mid-1970s. The latest edition was published in August of 1981.

The costs of reclamation may vary from as little as $1 000 per hectare to as high as $20 000 per hectare where considerable site preparation is required. It is important, therefore, that every exploration road, pit, and dump be located at the outset with ultimate restoration of the landscape in mind. Reclamation planning, as part of overall mine planning, attempts to minimize original disturbance and to maximize the productivity of the final landscape (for example, as demonstrated by recent mining company research into wildlife usage of restored vegetation cover in the Southeast Coalfields, in particular, in the Crowsnest portion of these fields).

On a provincial basis, the pace of reclamation has increased spectacularly in the last 15 years. Prior to 1969, when regulatory reclamation requirements were introduced in British Columbia, most disturbed coal lands were not reclaimed. By the early 1980s, the ratio of reclaimed to disturbed lands had risen to between 20 per cent and 30 per cent, although fluctuating from year to year. The ratio tends to fall in years when new mines commence construction since this involves large new disturbances which it may not be possible to reclaim for some years. However, overall, reclamation is now keeping pace with, and not falling behind, disturbances.

In the Northeast Coalfield, exploration disturbances began to be more localized by the late 1970s, as knowledge of *in situ* resources became more definite. During 1979, 120 hectares of land were disturbed by exploration, whereas by 1980, this figure had been reduced to 70 hectares. Part of this reduction was attributable to use of helicopters and portable drills to minimize exploration access disturbances. Moreover, in 1980, 90 per cent of all exploration activity was reclaimed, as compared to around 30 per cent in previous years. Finally, acceptability of the reclamation work (in conformity with the provincial reclamation guidelines) rose from a low of 45 per cent in 1976 to 94 per cent by 1980.

The rate of reclamation in the Southeast Coalfields has also accelerated. For example, the Fording Coal Project near Elkford had disturbed 977 hectares of land by the end of 1978, and an additional 59 hectares in 1979. Reclaimed areas totalled 108 hectares at the end of 1978, and a further 93 hectares were reclaimed in 1979. In fact, in that year, the area reclaimed exceeded the area newly disturbed, and this progress has been maintained into the early 1980s.

Thus, the record of on-site reclamation in British Columbia is now a source of comparative satisfaction, both to the mining industry and to government agencies.

6.3.3 OTHER ASPECTS OF IMPACT MANAGEMENT

Concurrent with the improvement in reclamation performance, there has been a broadening of perceptions of environmental impact, and a noteworthy refinement of many other aspects of environmental impact management. Many principles in addition to the need for on-site reclamation are now gaining a wider acceptance.

For example, it is now appreciated that the impacts of all components of a mine development, including off-site ancillary facilities, should be considered. It is also generally agreed that some impacts at the minesite itself may extend for a considerable distance off-site (for example, downstream impacts on water quality and fisheries). Another sign of progress is the willingness to consider off-site measures in cases where it is technically very difficult or too costly to redress an on-site impact directly (for example, replacement of disturbed wildlife habitat at the minesite in part through off-site habitat enhancement programs).

Perhaps the most important improvements have been made in the environmental design of exploration programs and mining projects, based on the underlying principle that prevention is better than cure. Thus, there has been an impressive increase in the collaboration of engineering and environmental personnel in the designing of mining programs in recent years. Of course, obvious problems remain. It may be difficult to predict some types of impact in advance, perhaps because of inadequate baseline data or an imperfect understanding of ecosystem mechanics. In such cases, a greater reliance may be placed on operational and post-operational monitoring programs rather than on questionable predictions to ensure that problems are resolved if and when they arise.

Another problem relates to the evaluation of impacts on intangible environmental values, such as those associated with fish and wildlife, recreation features, wilderness, and aesthetics. It may never be possible to compare such values with the tangible costs and benefits of mining development in a completely objective manner. Nowhere is this more in evidence than in the Southeast Coalfields, where the preservation of recreational and other environmental values is an increasing challenge in the face of the rapid pace of recent resource development.

A typical impact management program for a new mining project now contains numerous components, including some or all of the following:

- a reclamation program, as established in a reclamation permit pursuant to the *Mines Act;*
- a water management program, as established in water licences pursuant to the *Water Act,* and covering such items as water uses and water diversions;
- a waste management program, as established in waste management permits pursuant to the *Waste Management Act,* and covering all waste discharges (emissions to air, effluents to water, and refuse to land);
- ambient (receiving environment) objectives for air quality and water quality, employed as a context for the setting of waste discharge standards;
- a fisheries impact management program, including measures to protect (and even to replace) existing commercial populations and important fish habitat in adjacent and downstream reaches;
- a wildlife impact management program, including measures to protect (or replace) existing commercial populations and important wildlife habitat in the surrounding area;

- miscellaneous other impact management measures (for example, those designed to minimize disturbance of farming or forestry operations, or encroachment on natural recreation features, recreation facilities, and aesthetics); and
- detailed construction and operational monitoring programs for water, air, fish, and wildlife.

This listing reflects the greater emphasis which is now placed on environmental design in advance of operations, in addition to that already placed on post-operational restoration of former resource values.

6.3.4 COAL MINING COMPANY RESPONSIBILITIES

In British Columbia, developers such as mining companies are considered generally responsible for management of direct environmental impacts, that is, those impacts which are normally experienced on-site or in the immediate vicinity of project sites. A broad spectrum of direct project impacts may be identified, as noted in section 6.2. These may include terrain or aquatic disturbances, loss of land and other direct encroachments on the natural resource base, creation of barrier effects (inhibiting, for example, wildlife migrations or farm operations), waste discharges, noise, and visual disturbances.

Mining companies are expected to implement mitigation measures to reduce potential direct impacts to acceptable levels. Normally, appropriate mitigation measures are *mutually agreed on the basis of negotiations between the companies and Provincial* agencies, held under the auspices of the Mine Development Review Process in general (*see* section 6.3.5), and the individual permitting processes in particular.

British Columbia's insistence on reclamation and other types of impact management applies to all coal mining projects, even when the overall benefit/cost ratio for projects is strongly positive. The rationale is that impact mitigation must be equitable as well as economically efficient. Those interests which are adversely affected by a project are not necessarily those which also benefit from project development in a direct sense.

During negotiations, various mitigation options may be discussed, and tradeoffs may be made on both sides. If there is serious doubt about the economic viability and/or utility of the various options for managing potentially serious impacts, negotiations may be conducted within a rigorous economic evaluation framework (such as the *Guidelines for Benefit-Cost Analysis,* which were published by the Environment and Land Use Committee in June, 1977).

It should be noted that, in the past, the appropriate provincial resource agencies have tended to assume primary responsibility for the management of indirect environmental impacts resulting from improved access and a population influx. Often, however, this has not been the case with respect to socio-economic impacts. Mining companies are normally involved to some extent in the upgrading of overloaded community and social services, although a component of the overloading problems reflects indirectly induced population growth, and cannot be solely ascribed to the direct workforce.

6.3.5 MINE DEVELOPMENT REVIEW PROCESS

6.3.5.1 History

Concern for the protection of environmental resources, uses, and sensitivities in areas of proposed coal mining led to the approval of the *Guidelines for Coal Development,* a comprehensive review procedure, by the Environment and Land Use Committee of Cabinet in March, 1976.

These guidelines are about to be superseded by the *Guidelines for Mine Development,* which will likely be published during 1987, following finalization of the details of the revised procedure. The new guidelines embrace both coal and metal mines (other than placer operations), and have been improved and streamlined on the basis of operating experience since 1976.

6.3.5.2 Goal and Objectives

The primary goal of the Mine Development Review Process (as it was for its predecessor) will be to facilitate and expedite sound, acceptable mining ventures in British Columbia. The process strives to meet this goal by pursuing various specific objectives:

(a) It provides a "one-window" contact point for mining companies, that is, the Mine Development Steering Committee, chaired by the Ministry of Energy, Mines and Petroleum Resources.

(b) It sponsors a comprehensive, credible, and widely understood review process to examine the major environmental, social, and economic implications of mine development.

(c) It ensures expedient and efficient coordination of project reviews and arranges for a realistic staging of company/government consultations, involving all appropriate government Ministries at each phase of project planning.

(d) The final outcome of the review process is an agreement between mining companies and government agencies with respect to the means by which environmental, social, and economic impacts will be managed when projects proceed.

(e) The review process is structured to ensure that all major policy and technical issues have been resolved to a satisfactory extent prior to project approval-in-principle. When granted, approval-in-principle indicates that a project is acceptable to the Province in principle, subject to compliance with regulatory requirements and any other conditions.

(f) Project proponents are expected to undertake extensive consultations with regional districts, municipalities, local interest groups, and the public at large in order to ensure that local and regional concerns are recognized and addressed during project planning.

6.3.5.3 Scope of Review Process

The guidelines are applied when sufficient exploration has been completed to demonstrate that economically mineable coal reserves may be present. Thus, the exploration phase generally precedes application of the guidelines. Once a coal company has developed an initial conceptual mining plan, a prospectus is filed, initiating the Mine Development Review Process, which then functions until all approvals have been granted and construction can commence.

As noted in subsection 6.3.5.2, the guidelines are broad in scope, and address the major economic, social, and natural environmental implications of project development. Coal developments are expected to conform to broad principles of integrated resource planning, principles which seek a balance between economic, social, and environmental goals. Thus, the net economic benefits of coal development must be carefully weighed against the environmental and social costs before final decisions are made.

It should be noted that the guidelines cover all related components of the coal development program, including not only the coal mine, waste dump areas, processing plants, etc., but also off-site facilities such as new transportation networks, shipping terminals, community development, power sources and power supply corridors, and any ancillary industrial activity generated in the region as a result of the coal development impetus.

Thus, the environmental impact assessment process should not be perceived as a set of narrowly based studies of the impacts of coal development on the natural environment, prepared late in the engineering feasibility study process. Rather, it should be viewed as a planning tool which shapes the whole development program from its inception, so as to be responsive to the economic, social, and environmental goals of the region of development. In a few cases, environmental and social costs may outweigh the economic gains and the development may not proceed. Where a project does contribute positively to the overall social well being of a region, the assessment process tailors the development to fit smoothly into the regional planning goals of the development area.

6.3.5.4 Legislative Framework

The *Guidelines for Mine Development* will be published under the authority of the Environment and Land Use Committee, a Cabinet Committee of the Government of British Columbia. The Environment and Land Use Committee comprises eight Ministers representing eight Ministries which are responsible for resource use and economic development, as well as for matters dealing with major public facilities such as highways and settlement. Under the *Environment and Land Use Act,* the committee is responsible for integrated land and resource use planning in the Province, and for ensuring that the environmental impacts of all major resource developments are fully assessed. The *Guidelines for Mine Development* are implemented as a working policy of this statutory committee.

Although the *Environment and Land Use Act* supersedes other provincial resource legislation, various Ministries retain their responsibility for individual statutes relating to specific aspects of coal development. Coal companies are required to apply for approvals for exploration, development, and reclamation (under the *Mines Act* and the *Coal Mines Regulation*). These regulations are quite specific regarding the engineering safety of the mine, the provision of environmental safeguards at the minesite, and the program of minesite reclamation required during and following development.

In addition, coal companies must obtain permits for discharges of liquid, solid, and gaseous wastes from the Waste Management Branch, and licences for water use from the Water Management Branch. There are also procedures and regulations governing such matters as use of Crown Lands for transportation routes, settlements, and other facilities, resource uses other than mining, the establishment of communities, and the provision of housing and services. In other words, existing regulatory procedures remain in effect.

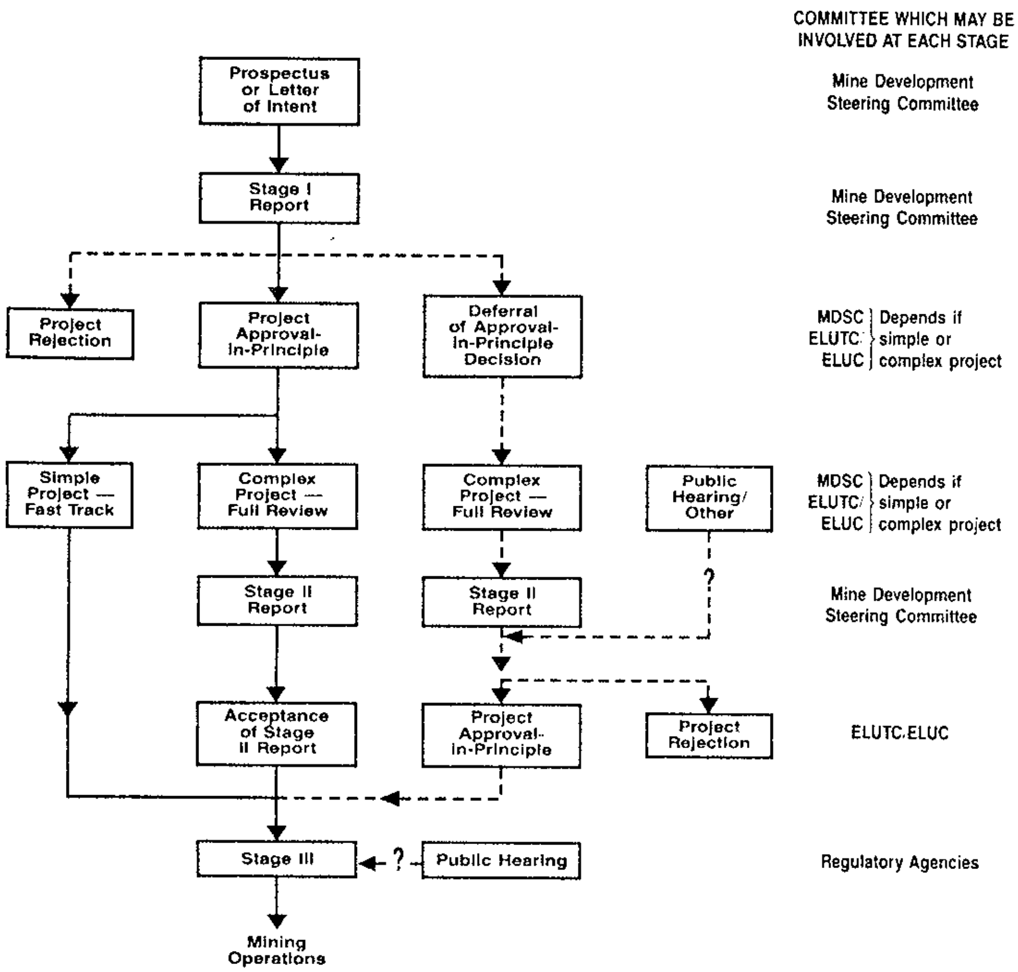
The regional and municipal levels of government have well-defined interests in major coal developments, and coal projects should strive to conform to regional plans and municipal zoning policies.

The review process is predicated on the need to address a wide variety of issues and concerns, both legislative and non-legislative, and to ensure that they are systematically considered. As noted above, it is not intended that the guidelines replace existing regulatory procedures, or add another layer of legalized approvals to the existing legislative framework, but rather to address a broad range of complex issues (only some of which are regulatory in nature) in the most efficient manner. The alternative, which is to expect companies to work with individual Ministries, local governments, and local interest groups in an unstructured "one-on-one" manner in order to obtain approvals and endorsements, would be highly inefficient and time-consuming.

6.3.5.5 Staging of Review Process (*see* Table 6.1)

The revised staging resembles the earlier staging for the review process in many respects, although there are some important differences. As in the past, the process involves a prospectus stage, Stage I, Stage II (now optional), and

TABLE 6.1. Mine Development Review Process



Stage III. The review process progresses systematically from a broad conceptual overview to final site-specific detail.

(a) *Prospectus:* The prospectus, when filed by a coal company, initiates the review process. It contains a conceptual description of all components of the proposed project. The government review determines which Ministries will remain involved in the later stages of review, and also generates the terms of reference for the Stage I report which must be filed by the company at the next stage.

(b) *Stage I:* In the revised review system, the Stage I submission is of greater importance than in the past since, on the basis of the Stage I review, a decision will be made on whether or not the coal project should receive approval-in-principle (formerly decided at the end of Stage II). The required level of detail for the Stage I report remains preliminary, as before, but its focus is altered somewhat. As in the past, the Stage I report should provide a preliminary project description. Largely on the basis of existing information, it should also present an overview of baseline biophysical and socio-economic conditions, identify data gaps, outline the major categories of impact, and make preliminary mitigation suggestions.

However, since the Stage I report is the basis of an approval-in-principle decision, the Stage I terms of reference which are generated by the prospectus review must focus on any major policy or technical concerns. Before approval-in-principle can be granted at the end of Stage I, any policy concerns must be resolved, while technical concerns must be known to be manageable by economic means, even if a detailed management strategy has yet to be worked out at Stages II and III. If these conditions are satisfied, project approval-in-principle will be issued, either by the Environment and Land Use Committee (for complex projects) or at the working level (for simple projects).

(c) *Stage II:* In a few rare instances, the conditions for approval-in-principle may not have been satisfied by the end of Stage I. In such circumstances, the Environment and Land Use Committee may decide to defer a decision on approval-in-principle, pending the filing of a Stage II submission. More frequently, it may issue an approval-in-principle subject to the condition that a Stage II submission be filed. This would occur in cases where, although the project is acceptable in principle, the level of information in the Stage I report is insufficient to permit a smooth passage to Stage III (the licencing stage).

A Stage II submission, if required, would be firmly focussed on key issues on the basis of the Stage I agency review comments, and would not be based on a broad, lengthy, standard checklist, as in the past. For the issues of outstanding concern, detailed evaluation and impact assessment would typically be required, leading to detailed impact management strategies.

(d) *Stage III:* At this stage, mining companies complete final engineering design and file detailed company permit applications, leading ultimately to the issuance of all licences, permits, and other approvals necessary for mine construction and operation. Much of the groundwork for the regulatory approvals processes will already have been completed at earlier stages. Where possible, companies may actually have filed permit applications prior to Stage III, although approvals cannot be issued before Stage III. Any outstanding non-regulatory matters may also be resolved at Stage III.

(e) *Mine Construction and Operation:* Formerly termed "Stage IV", this stage witnesses the actual implementation of the environmental and socio-economic impact management measures which have been agreed. Monitoring programs are undertaken in order to ensure that impacts, if any, are maintained at acceptably low levels.

6.3.5.6 Government Participants in Review Process

(a) *Mine Development Steering Committee:* This inter-Ministry committee is responsible for the day-to-day working level administration of the review process. In particular, it is responsible for major procedural decisions, and may also make recommendations on procedures to more senior levels, such as whether or not a Stage II submission is warranted for a project. The committee functions as the primary government contact for mining companies. It also distributes mining company submissions to government agencies for review, and compiles the results of the reviews. It is chaired by the Ministry of Energy, Mines and Petroleum Resources.

(b) *Mining and Environmental Technical Committee:* While its roles and responsibilities under the revised system have yet to be finalized, this inter-Ministry committee will continue to be responsible for advice on technical and biophysical aspects of mine development. In this capacity, it may review environmental impact reports, recommend further studies, identify all required regulatory approvals, etc. It reports to the steering committee, and is currently chaired by the Ministry of Energy, Mines and Petroleum Resources.

(c) *Socio-Economic Technical Committee:* This inter-Ministry committee was set up in 1979 as a standing committee to coordinate the socio-economic reviews of all types of major development in British Columbia. For mine reviews, it performs this service for the Mine Development Steering Committee (in the same manner as does the Mining and Environmental Technical Committee for technical and biophysical matters). The committee is currently chaired by the Ministry of Municipal Affairs.

(d) *Environment and Land Use Technical Committee:* This committee is chaired by the Deputy Minister of Environment, and consists of all Deputy Ministers of Ministers on the Environment and Land Use Committee. It may make major procedural and technical decisions, based on briefings by the Mine Development Steering Committee, or it may refer matters to the Environment and Land Use Committee for resolution.

(e) *Environment and Land Use Committee:* This committee of eight Ministers is chaired by the Minister of Environment, and makes the primary approval-in-principle decisions for complex or controversial mining projects. The committee is ultimately responsible for the Mine Development Review Process, as noted in item 6.3.5.4.

(f) *Provincial Government Ministries:* Although committees organize much of the review process, ultimately all government inputs originate as individual Ministry positions, whether filed directly with the steering committee or through its two technical advisory committees. The review of the prospectus helps to determine which of the numerous potential provincial review agencies will be involved in each project review. Only those with significant program or legislative interests participate in the subsequent stages of review.

(g) *Federal Government:* In the past, three federal departments (Environment Canada, Fisheries and Oceans Canada, and Indian and Northern Affairs Canada) have shown a regular interest in mine reviews. By working arrangement, federal departments participate in the provincial review process, rather than administering a separate federal review process.

(h) *Local Governments:* All regional districts and municipalities near a proposed mine receive mining company submissions. Their review comments (if any) are relayed to the steering committee by the Ministry of Municipal Affairs, which maintains close contacts with local governments during project reviews.

6.3.5.7 Public Involvement

As in the past, public consultation will remain primarily the responsibility of project proponents under the new system. Companies are expected to liaise with local governments and all interested elements of the local communities.

All formal company submissions to the Mine Development Steering Committee (prospectuses and Stage I and II reports) are considered to be public documents, although they remain confidential during a short initial screening phase. The public also has access to the consolidated compendia of government review comments after the approval-in-principle decision (whether the latter is affirmative, negative, or a decision deferral).

The Environment and Land Use Committee may exercise its prerogative to order a public inquiry, either prior to or after approval-in-principle, in cases where a full airing of public concerns is deemed to be warranted.

6.3.6 MANAGING IMPACTS IN THE FIELD

Considerable strides have been made in the development of technical solutions to potential impact problems in recent years. Selection of a preferred approach in a particular situation may depend on such factors as economic feasibility (from the standpoint of companies) and effectiveness (from the standpoint of government agencies).

6.3.6.1 Exploration

Exploration activities have relatively little impact on microclimate. Dust suppression can normally be achieved by such measures as wetting road surfaces or applying a chemical to fix the loose surface.

Impacts on water quality, topography, vegetation, and soils may be reduced by careful design of roads, drilling sites, trenches, and adits, and by subsequent rehabilitation and reclamation of all surface disturbances according to the procedures outlined in the *Guidelines for Coal Exploration* (published in its latest form in August, 1981 by the Ministry of Energy, Mines and Petroleum Resources).

Obvious design measures include avoiding sensitive areas, fitting roads to topography, avoiding steep slopes adjacent to watercourses, minimizing road grades, minimizing cleared areas, ensuring proper road drainage, and avoiding any type of in-stream activity. In areas of unusual environmental sensitivity, surface disturbances during exploration have been significantly reduced in some instances by using helicopters to transfer equipment to drilling sites.

Hunting and fishing restrictions may help to prevent excessive hunting or angling in normally inaccessible areas which are temporarily accessed for exploration purposes.

6.3.6.2 Mining

During mining operations, particularly where open-pit methods are used, major topographic disturbances are unavoidable, leading to disruption of surface resource values and aesthetics.

Some measures are available to help blend the newly emerging topography with surrounding areas, both during and after operations. In British Columbia, for example, it is normal to expect 35-degree waste dump slopes to be resloped to perhaps 26 degrees to facilitate the permanent re-establishment of a vegetation cover. Some coal seam configurations may even make possible a mining plan which provides for ongoing backfilling of worked-out areas of the pit. This has the dual advantage of infilling the pit while at the same time avoiding the need to use land outside the pit for waste dumping. Where pit development must be essentially vertical rather than horizontal, this approach would not be possible without twice moving the overburden, thus effectively doubling the stripping ratio (almost always an uneconomic proposition).

As during exploration, road dusting can be controlled by wetting or the application of fixing chemicals. At the minesite and around any coal stockpiles, continuous wetting, sweeping, and cleaning may be necessary to control coal dust.

This is essential for the health of mine personnel as well as being environmentally desirable. A latex or other compounds may be applied to stockpiles or to coal loaded into trucks or trains in order to control dusting. On-site thermal generation may necessitate the use of fluidized bed combustion, stack scrubbing or other (sometimes costly) technologies to control emissions of particulates, primarily SO_x and NO_x.

Impacts on groundwater and surface water volumes can normally be reduced to acceptable levels by means of recycling. For example, it is common for process water to be recycled in a largely closed system in the coal preparation plant.

Water quality and fisheries protection requirements may necessitate elaborate water and waste management planning. Measures may include ditching to divert uncontaminated runoff around the minesite, and the installation of ditches and settling ponds to capture suspended solids from both contaminated and uncontaminated runoff, perhaps with the aid of flocculants. It may be necessary to apply chemical treatments before discharge to natural drainages where chemical contamination has occurred (for example, excessive nutrient loading associated with blasting compounds).

Fortunately, the coals in eastern British Columbia have a generally low sulphur content, and acid generation problems such as those experienced in the southeastern United States are unknown here to date. The potential for acid generation associated with coal activities in northwestern British Columbia and on Vancouver Island is now receiving detailed attention. Reclamation planning, and in particular the sealing of potentially acid-producing materials from air and/or water, is important to successful prevention.

Where water quality is protected, direct impacts on fisheries can normally be minimized. In the past, fish productivities have been reduced by such problems as siltation of food-producing and spawning gravels. Effective on-site water and waste management, preservation of vegetation along stream banks, and successful restoration of disturbed vegetation cover after operations are all key measures which contribute to the minimizing of direct impacts. Indirect impacts such as overfishing may be more difficult to control in remote areas where access is suddenly improved. Some mountain lakes and streams are not highly productive and the equilibrium of fish populations may be rapidly undermined by even relatively small increases in fishing pressures. Minimizing of needless access and enforcement of fishing regulations are partial answers to these problems.

Coal mining can be associated with some difficult wildlife impact management problems. In British Columbia, most of the coal exploration and production activities presently occur in terrain which includes extensive alpine areas, some of which constitute high quality wildlife habitat. Mountain goat, mountain caribou, bighorn sheep, and grizzly bear are four of the many species which may be influenced by mine development in alpine areas. It is possible to recreate a productive landscape when mining activity ceases, but it is not yet clear that these four species will repopulate the reclaimed alpine areas.

Moose, elk, deer, and black bear tend to pose lesser impact management problems. They have demonstrated a greater ability to co-exist with mining operations. Moreover, their greater reliance on lower elevation habitat places them beyond the range of many minesite activities, although ancillary facilities (such as access roads and other linear developments) may nevertheless disturb major floodplains and other important low-elevation habitats. On the positive side, elk and deer are now making heavy use of reclaimed areas of the Southeast Coalfields.

Mining companies and wildlife managers are now working on the critical problem of preserving vulnerable bighorn sheep populations, especially in the Southeast Coalfields. Techniques which are under study for the management of this and other species include animal capture and reintroduction, fertilization of grazing and browsing areas to increase productivity, location of migration routes, and hunting moratoria (for sheep, elk, and grizzly bear) in key areas.

Impacts on levels of fish and wildlife utilization are one component of the broader issue of recreation resource impacts. Except for some aesthetic design and possible screening, there may be little that can be done to ameliorate impacts on wilderness values in remote areas while the mine is in operation. Restriction of off-site road development and proper "putting to bed" of all workings and disturbances after use are constructive measures, pending overall mine abandonment and site rehabilitation.

6.4 CONCLUSION

The purpose of Chapter VI has been to review briefly the types of environmental impact which may occur as a result of coal exploration and production, and to outline some of the steps which are taken by mining companies and government agencies to minimize adverse environmental impacts.

Impact management is a high priority in British Columbia, and there has been a record of considerable progress in this area during the last 15 years. Mining companies accept an obligation to minimize impacts, and are able to do so using rapidly improving techniques. For their part, government agencies, as stewards of public resources, work toward impact management success through effective regulation, project review, and consultation with companies.

VII. SOCIAL AND COMMUNITY CONSIDERATIONS

7.1 INTRODUCTION

The social impacts of coal mining projects depend on a variety of factors. The most important variable influencing the magnitude of the impact is the size of the project. The larger the project, the greater will be the workforce required, not only for the construction and operation of the mine itself but also for the related transportation and support services. A second factor influencing the size of the workforce required is the nature of the mining operation (that is, surface or underground) and the type of technology available.

The extent to which a project, of whatever size, results in regional population in-migration depends on two main factors. The first is the availability and occupational mix of the regional workforce. If there is relatively high unemployment, the potential for recruiting a proportion of the workforce locally is enhanced. It is important, however, that the unemployed possess characteristics required by the prospective employer. In most cases, this will require an investment in training and skill-improvement programs. If this is not provided, regional residents may find themselves unemployed while more highly skilled in-migrants obtain work. Thus, the degree of population influx into a region depends upon the number of unemployed residents whose characteristics match those desired by the mining companies. An intervening factor is the implicit or explicit hiring policies of the developer. The characteristics the developer requires may include more than those essential to the task. Therefore, in some cases, a greater percentage of the workforce could be obtained locally by lowering unnecessarily stringent hiring standards.

Any increase in local population, resulting from the growth in demand for labour, will place increased demands on such things as housing, infrastructure, and public services (for example, health, education). In addition to expanded public facilities, a larger population will also require the creation or expansion of indoor cultural and recreational facilities, retail shopping, and recreational land use in the area. Of course, the degree of change this growth in demand necessitates will depend primarily on the size of the existing community and its degree of isolation. The larger the community, the more likely that already established facilities could be utilized and expanded if necessary.

The duration of a coal project is also an important factor in determining the social impact of the development. While a long-term project can promote a certain degree of economic security for residents and contribute to community stability, a short-term, but relatively large, mine operation could actually be destabilizing by stimulating rapid growth of the local economy to levels which cannot be sustained without the project. This "boom and bust" influence is also characteristic of a region whose economy is dependent on a single resource.

Social impacts can result, as well, from conflicts between the economic base of the community and coal development. For example, a coal mine could threaten agricultural activities or disrupt traditional land use by native Indians.

7.2 LABOUR REQUIREMENTS

The current development of several new minesites in the northeast and southeast areas of British Columbia and possible coal developments on Vancouver Island and in the northwest should augment the demand for workers in the coal mining industry during the 1980s.

Predicting the labour requirements for the coal-mining sector, however, is difficult. First, development is contingent upon approval of all aspects of the project by provincial government reviewing agencies. Second, the production of coal depends upon securing markets at prices which make the development of coal mines profitable. Finally, the labour requirements depend on several technical considerations such as mining methods, coal recovery rates, and types of technology available.

Prior to 1983, all operating coal mines in British Columbia were located in the southeast. As indicated in Table 7.1, a total of 3 963 people were employed in the provincial coal-mining workforce (including administrative and supervisory staff) in 1982. Table 7.2 lists new coal

TABLE 7.1. Operating Coal Mines, 1982

	CLEAN COAL PRODUCTION (million tonnes/year) Metallurgical	Thermal	AVERAGE 1982 WORKFORCE
Balmer (Westar)	5.6	0.07	2 221
Fording (Fording Coal)	6.3	0.1	1 562
Byron Creek (Esso Resources)	—	1.2	180
TOTAL	11.9	1.37	3 963

TABLE 7.2. Coal Mines Under Construction, 1982/83

	POTENTIAL CLEAN COAL PRODUCTION (million tonnes/year) Metallurgical	Thermal	POTENTIAL OPERATING WORKFORCE
Southeast			
Fording Expansion	1.3	0.2	—
Greenhills (Westar)	1.8	1.0	500
Line Creek (Shell)	1.0	0.75	640
Northeast			
Quintette (Denison Mines)	5.0	1.5	1 460
Bullmoose (Teck)	1.7	—	530
TOTAL	10.8	3.45	3 065

TABLE 7.3. Proposed Coal Mines for the Next Decade

	POTENTIAL CLEAN COAL PRODUCTION (million tonnes/year) Metallurgical	Thermal	POTENTIAL OPERATING WORKFORCE
Southeast			
Byron Creek Expansion	—	2.6	330
Sage Creek (Sage Creek Coal)	—	2.2	480
Line Creek Expansion	0.3	0.95	300
Northeast			
Monkman (PetroCan)	3.3	—	925
Carbon Creek (Utah Mines)	—	1.75	490
Cinnabar (Cinnabar Peak Mines)	—	1.0	525
Burnt River (Teck)	—	0.75	265
Willow Creek (David Resources)	—	0.6	85
Vancouver Island			
Quinsam (Weldwood/Brinco)	—	0.9	245
Wolf Mountain	—	0.2	35
Northwest			
Klappan (Gulf Resources)	—	1.0–5.0	250–1 200
Telkwa (Crows Nest Resources)	—	1.0–1.5	350–380
TOTAL	3.6	12.95–17.45	4 280–5 260

NOTE: Proposed coal mines listed in Table 7.3 are those projects that were under the Provincial Government *Mine Development Review Process* as of February 1984. Some of these projects are currently dormant, however, due to depressed coal markets.

mines and expansions which were under construction in 1982/83. Table 7.3 presents a number of proposed and possible coal projects for which construction has or will potentially begin in the next decade. Whether developers actually proceed with the proposed or planned projects listed in Table 7.3 depends on their success in obtaining markets for coal, the economics of coal production, and the ability of proponents to conform to the standards of the provincial *Guidelines for Mine Development.*

The capacity exists to increase production of coal in the Province to at least 40 million tonnes in the next decade. Over 50 per cent of the potential for expanded production is in the northeastern region of the Province. As a consequence, the demand for workers in the British Columbia coal-mining industry will probably double and could possibly more than triple during the period 1981–1995, with the heaviest demand emanating from proposed mines in the Peace River Coalfield.

7.3 LABOUR FORCE AVAILABILITY AND TRAINING

During this decade, the demand for labour in the coal-mining industry should increase despite the recent economic recession. If we assume that Table 7.3 is an accurate reflection of future projects, the total demand for operations stage workers in British Columbia coal projects would exceed 10 000 by the early 1990s. Increased requirements for skilled workers have been forecast in other sectors of the British Columbia economy as well, particularly in the forest products, metal mining, and construction industries. This indicates that the coal industry will have to compete with other sectors to obtain skilled tradesmen. The coal-mining industry, however, has historically experienced difficulties in attracting and retaining skilled workers. The primary reasons for this are that working conditions in coal mining have in the past tended not to be as pleasant as those in other industries, and that the locations and facilities of mining communities have in many cases not been particularly attractive to a predominantly southern/urban labour force.

In order to obtain a stable workforce, coal-mining companies usually utilize a strategy of hiring a "core group" of workers—people with a number of characteristics which have been shown to be related to their affinity for long-term employment. Usually, companies hire young married males from the area and then rely upon this "core group" to attract friends and/or relatives into the company's workforce. Any shortages of specialized skills have then traditionally been supplemented by recruiting from other parts of the country or, more commonly, from abroad.

There are indications, however, that the foreign supply of skilled tradesmen is diminishing. This factor, coupled with the consideration that a goal of both the federal and provincial governments is to provide employment opportunities for Canadians, especially for those inhabiting regions of new resource developments, has diminished the practice of hiring from abroad.

The extent to which future worker requirements in the British Columbia coal-mining industry can be met with provincial or regional labour is dependent upon:

1. The number of unemployed and/or underemployed workers in the Province or regions.
2. The extent to which these workers possess the skills required by the industry (or the extent to which these workers can acquire skills).
3. The willingness of these workers to work in coal mines.

The most comprehensive regional analysis of manpower supply within British Columbia in relation to the coal-mining industry was the *Report of the B.C. Manpower Sub-committee on N.E. Coal Development.* Information compiled in this study indicated that a significant pool of underutilized labour (unemployed or underemployed) existed in the northeast in 1976. The Sub-committee estimated that there were more than 2 000 unemployed experienced workers in the northeast, and that 75 per cent of these were in the Dawson Creek, Chetwynd, and Fort St. John areas. (Indications are that during the economic recession in 1982 and 1983, these numbers almost doubled.) The report also noted that a significant source of potential labour existed among women in the northeast who had past work experience but were no longer in the workforce. The authors speculated that if only 25 per cent of the latter re-entered the labour force, it would increase the number of potential workers by 1 300 in the northeast in general, and by 1 000 in the region closest to proposed coal developments (including Fort St. John and Hudson Hope).[1] The Sub-committee emphasized increasing the participation rate of women as an important means of supplementing the regional labour pool.

The report mentioned, as well, a number of other potential sources of mine workers. These include the underemployed sector of the farming population, graduates of local secondary schools, underemployed native Indians, and working age in-migrants to the region. These groups could all contribute to the local mining workforce if recruitment policies and training programs are successful in encouraging them to pursue mining occupations.

Although evidence indicates, in the case of northeast British Columbia, that the supply of local and regional labour is adequate to meet the increase in demand as a result of proposed coal developments, the skill and occupational mix of the labour force is not immediately suited to the needs of coal mining. In an "average" open-pit mine, approximately 21 per cent of the total mine workforce is comprised of journeymen and apprentices, 30 per cent of highly skilled equipment and plant operators, and another 10 per cent of supervisory and technical staff.

A *Critical Skills/Trade Inventory* (conducted by the Provincial Ministries of Labour and Education in 1980) revealed shortages of heavy-duty mechanics and industrial electricians across all industries and an anticipated shortage of millwrights.[2] These three trades make up the largest part of the maintenance workforce in any coal-mining operation. Given that 20 to 25 per cent of any coal-mining workforce consists of skilled journeymen and apprentices, the inclusion of the new coal mines cited in Table 7.3 would substantially increase the expected shortage of tradesmen throughout the Province.

Training efforts in the 1980s have been aimed at expanding in-house apprenticeship training and improving the skills of journeymen for employment in coal mines, as well as increasing the training capacity of the Province for those trades which will be in short supply.

7.4 IMPLICATIONS FOR WOMEN

Special problems are faced by women in mining communities. The communities tend to be situated in geographically isolated areas and the mining companies, frequently the area's single dominant employers, have in the past tended not to hire women in non-clerical positions. In recent years, however, the trend has been for coal-mining companies to hire progressively more women in "non-traditional" occupations.

Female interest in non-traditional mine employment has been confirmed in many mining towns. In a 1976 survey of women in Elkford, it was found that 27 per cent of the non-working women in the community were actively interested in full or part-time employment, and another 39 per cent felt they might seek employment in the future.[3] One-third of all women (employed and unemployed) were interested in taking training leading to a non-traditional occupation at the local coal mine (that is, non-office and non-administrative). One study revealed that less than 10 per cent of the total hourly workforce in the mining industry was comprised of women hired in non-traditional jobs and that these were limited to the lower skilled, lower paying positions.[4]

There are several barriers to the employment of women in non-traditional mining jobs. Women have less experience than men in industrial work, and therefore are less likely to be hired. There is an extremely low participation rate of women in apprenticeship training, which only compounds the problem. Also, in some cases attitudes of mining supervisory staff have been cited in the literature as a constraint to non-traditional female employment. This is especially salient to the extent that attitudes carry over into company hiring practices.[5]

---

[1] Report of the B.C. Manpower Sub-committee on N.E. Coal Development, *Ministry of Economic Development*, November 1976.

[2] *Province of British Columbia*, Phase I Report of the Critical Skills/Trade Inventory, 1980.

[3] Langin, S., The attitudes and perceptions of women concerning the quality of life in the new resource town of Elkford, B.C., M. A. Thesis, Unpublished, cited in *Women in Mining: An Exploratory Study*, October, 1976.

[4] Women in Mining, An Exploratory Study: *Suzanne Veit and Associates*, October, 1976.

[5] *Northern British Columbia Women's Task Force Report on Single Industry Resource Communities*, 1977.

Alternative employment opportunities for women in mining towns are usually limited to retail trade and service industries which support the mine employee population. These jobs are low-paying compared to mine wages. They are also the most insecure and require the least skill. Therefore, women are very vulnerable to any cyclical changes in economic conditions.

Finally, inadequate support services and facilities can act as a barrier to women pursuing non-traditional occupations in the mining industry. For example, child-care services are necessary for many women who might potentially enter the labour force.

There are costs and benefits associated with women in non-traditional mining positions. The employment of women serves to augment the male labour force, and could help alleviate any labour supply bottlenecks in future coal developments. It would also serve to employ the regional labour force more fully, thereby contributing to increases in family and per capita incomes. Associated costs would include training facilities and instruction in order to improve the level of skills of the female labour force.

In terms of benefits to mining companies, to the extent that the women employed are spouses of male mine employees, the requirements for company-supplied accommodation will be reduced. The presence of women in the mine workforce may contribute to a reduction in turnover and absenteeism rates. Interviews with company officials of mines employing women in non-traditional positions indicate that women tend to be more conscientious than men regarding safety procedures and equipment maintenance. Associated costs included providing washroom facilities for women at minesites and the cost of filling vacancies during maternity leaves.

The benefits and costs of the employment of women in non-traditional mining occupations, however, must be viewed in the light of social policy objectives. The elimination of barriers to the employment of women in mining will contribute to employment advances for the residents of coal-mining regions and enhanced employment prospects for those suffering from disadvantages in relation to job market opportunities.

7.5 IMPLICATIONS FOR NATIVE INDIANS

Future coal developments in British Columbia will have many potential social and economic impacts on Indians living in these regions. These include threats to traditional economic activities, negative social impacts due to the increase in numbers of in-migrants, and indeterminate impacts on the employment levels of status and non-status Indians. For example, the proposed coal developments in the northeast could have impacts on the hunting, trapping, and fishing territories of the Saulteau and West Moberly Lake Bands. Indian residents state that the fish and game stocks supporting these activities have already been reduced by pipelines, hydro-electric projects, roads, transmission lines, logging activity, and non-Indian recreation use.[6]

Although coal developments in northeast British Columbia could add to the pressures already placed on fish and game stocks in the region, they also have the potential of offering native Indians employment opportunities. The Manpower Sub-committee on Northeast Coal Development reported that the regional population of status and non-status Indians could potentially supply an estimated 500 employable individuals to the northeast coal-mining workforce.

However, the Sub-committee also pointed out that incorporating significant numbers of native Indians into the coal-mining labour force would be contingent upon overcoming several barriers to Indian employment. The six reserves in the southern portion of the northeast region have poor road links to towns and coal minesites. Few Indians residing on these reserves have driver's licences, therefore commuting to work is difficult or impossible.

Another barrier often cited is the education system's low level of success in delivering education to Indian people. As a result, Indian students face linguistic and cultural obstacles in school which reduce their prospects for a high level of education. Adult education programs have had problems in adapting to the particular needs of native Indians. For those who have

[6] Alaska Highway Gas Pipeline: British Columbia Public Hearings, *Northern Pipeline Agency,* Volume 7, 1979.

completed training in a trade, difficulties in obtaining employment related to their training have reinforced a pessimistic view among Indians as to the usefulness of these programs.

Employment policies of industry, which have tended to establish inflated educational and experience levels as job requirements, also act as barriers to the employment of Indians. In the same way, the educational and experience requirements for apprenticeship training effectively close off this avenue for most native Indians. As previously noted in the case of women, the tendency for companies involved in resource development to import workers and to operate with limited training programs also reduces employment opportunities for Indians.

7.6 REGIONAL DEVELOPMENT AND COMMUNITY STABILITY

It is provincial government policy that the development of the coal resources of the Province be consistent with overall regional development and social objectives. These objectives include the encouragement of balanced regional development.[7] Balanced regional development depends upon the degree to which the economic benefits which accrue from new resource projects are "captured" by the region involved. The ability of a region to capture these benefits arises from the extent to which the incomes directly created by a resource project are spent within the region and in turn, generate further "induced" incomes and successive rounds of spending. In addition, indirect incomes generated by construction, manufacturing, or service firms in the region supplying inputs to the resource industry (backward linkages) or by firms that further process or handle outputs (forward linkages) contribute to a region's ability to capture benefits.

The development of a primary resource project such as a coal mine does not necessarily result in economic benefits for those residents of the region who are not directly employed in the resource industry. Construction contracts may go to large firms outside the region, and union hiring halls may be located in larger urban centres. Likewise, materials may be purchased from suppliers in major centres that are some distance from the region. In order to address some of these problems, the Government of British Columbia has developed a procurement policy which is designed to assist developers of major projects in gaining the maximum possible exposure to local supply capabilities and potential. In certain circumstances, it will be expected that developers will establish local procurement or engineering offices.

The employment opportunities generated by a new resource development in a particular region will initially attract people from outside the region. The greater the ability of the region to capture the economic benefits of development, the more likely that the resource communities within the region will be successful in retaining any already established population as well as attracting new residents who will develop a long-term commitment to the locality. In this respect, several aspects of company and government actions with regard to proposed or planned coal projects in the Province have serious consequences for the stability of communities in development regions.

A report on labour turnover and community stability prepared for the Federal/Provincial Manpower Subcommittee on N.E. Coal Development gives a working definition of community stability as:

> . . . a stage of community development in resource towns that is characterized by the presence of an established core population, a sound economic base, a network of social services programs and facilities, a low rate of criminal activity, and citizen participation in community affairs.[8]

The stability of communities impacted by coal developments will be affected by several factors, most of which are related to the task of retaining a core population. A number of studies have concluded that a necessary requirement for the stability of a resource community is a diversified economic base. This is because the cyclical nature of international

[7] British Columbia Coal Policy, *Ministry of Energy, Mines and Petroleum Resources.*, June 1977.

[8] Labour Turnover and Community Stability, *Suzanne Veit and Associates*, for Department of Regional Economic Expansion, Employment and Immigration Canada and Ministry of Economic Development, Ministry of Labour, February, 1978.

markets for primary products can affect the production levels of, or even shut down, resource extraction operations. Non-renewable resource industries such as coal mining are also limited to the lifespan of recoverable reserves. A resource community dependent on only one industry for its economic viability is consequently most susceptible to a "boom and bust" development cycle which reflects the fortunes of the single industry. The large number of ghost towns in British Columbia are a testimony to the legacy of the single-industry town. The diversification of the economic base of future and developing resource communities is desirable because it provides the residents of the community with alternative economic activities in the event of a production slowdown or closure of one resource industry.

The new coal mines and expansion projects that are planned in the southeast corner of the Province will result in the growth of communities such as Fernie, Sparwood, and Elkford. Although the area is dominated by the coal-mining industry, it also supports some logging and sawmilling activities which are likely to become increasingly important. However, the economic viability of the communities in this area can be expected to continue to rely heavily upon the coal-mining industry.

The economy of communities close to coal developments in the northeast of the Province is based on agriculture, forestry, and the oil and gas industry. The mining of coal reserves south of Chetwynd and Dawson Creek offers alternative employment to residents of the region. However, it also involves the development of a new community at Tumbler Ridge to accommodate the mine workforce. A *Preliminary Feasibility Report on Townsite/Community Development for Northeast Coal* took into consideration the provincial government policy of discouraging the creation of new single industry resource towns. It considered the alternatives of the mine workforce commuting from either Chetwynd or Dawson Creek as well as the possibility of minesite bunkhouse camps with families in Chetwynd and Dawson Creek. It was concluded, however, that because of the size of the potential workforces and the commuting distance involved, both of these alternatives would be impractical. As a result, Tumbler Ridge will become a community with a population of over 5 000 by 1985. The possibility of this new resource town growing to become a stable community, as defined above, will depend upon the time duration of coal developments as well as the possibilities for expanding the town's economic base.

In order to avoid the many social problems that have been associated with new resource communities, it has been necessary for planners to attempt to anticipate the needs of the residents. The provision of certain key community services and facilities has a determining influence on the stability of resource communities. The populations of new resource towns tend to be younger than the average Canadian community and as a consequence, heavy demands are placed on health and education services. The potential for inadequate provision of these services as well as other cultural and recreational facilities is high in new or rapidly expanding communities. Because of a tendency for higher rates of mental illness and alcoholism in resource communities, a major social concern is the need for psychiatric and marital or family counselling services. In addition, unemployed women who are newcomers to the mining town tend to be subjected to a high degree of physical and social isolation and consequently experience intense feelings of loneliness. Agencies would be required to provide self-help programs, home care services in times of illness, financial and legal aid, and opportunities for the social development of children. It has been suggested by women already living in resource towns that a permanently funded women's centre and transition house would help to mitigate some of the pressures experienced by women in this type of community.[9]

7.7 ACCOMMODATION OF MINE WORKFORCE AND COMMUNITY IMPACTS

As noted in Section 7.6, the attraction and retention of a stable workforce during the operation of a mine produces significant benefits for mining companies in increased productivity and lower costs. A stable housing market, a high level of services and a community not unduly burdened with debt or high taxes are all factors which contribute to labour force stability.

[9] Northern British Columbia Women's Task Force Report on Single Industry Resource Communities, 1977.

However, the population changes associated with a mining operation can have major impacts on the local housing market and community services and finances.

The responsibility for management of the community impacts of the mine workforce is shared by the mining company, respective local governments and the provincial government (in particular the Ministry of Municipal Affairs). Coordination among these three parties during the planning and development of the mine is essential.

As planning for a mining project proceeds, the company provides information on such matters as manpower and population projections, the expected distribution of population within a region, housing demand and impacts on municipal infrastructure, as well as company policies on such matters as housing subsidies, transportation of employees and company investment in community facilities, as part of submissions required under the provincial government's *Guidelines for Mine Development.* Provincial government agencies use this information to assess impacts on such provincial services as education, health and policing to ensure that additional requirements for these services can be met. Similarly, this information is employed by local government, with the assistance of the Ministry of Municipal Affairs, to respond with land, servicing (e.g., sewer, water, road network) and facilities required to accommodate the mine employees.

The planning activities undertaken by the mining company, the Province, and local government relating to accommodation of the mine workforce may identify potential problems in the provision of required housing and services. For example, it may be identified that there will be a substantial increase in serviced land required when the mine comes into operation but the timing of mine start-up is uncertain, leading to a risk that the population and tax assessment of the municipality may be insufficient to support the cost of the new services. In such instances, the mining company and government will negotiate an agreement on actions which will be taken by each to resolve the problem. In most cases, this agreement is informal and involves the exchange of letters at the time of approval-in-principle of the project under the *Guidelines for Mine Development.* In some cases, however, where the problems are most complex or critical, a more formal development agreement may be required between the company and the Province (e.g., as in the case of the development of Tumbler Ridge, a new community to serve the northeast coal project).

In recent years, most mining projects initiated in British Columbia have been the subject of discussions between the Province, local government and the mining company with respect to possible municipal taxation and, sometimes, tax-sharing arrangements between municipalities. It is to be expected that future mine proposals in the Province will also be considered for municipal taxation. It has been the practice of the provincial government to decide on the possible municipal taxation of each mining proposal on a case-by-case basis with regard to the impact of the mine on local government finances.

7.8 HERITAGE RESOURCES

Occasionally, coal exploration and mining activities may come into conflict with archaeological or historical resources. Although these tend to be uncommon in alpine areas, preconstruction surveys and construction activities may reveal artifacts.

Heritage resources in British Columbia are currently managed by the Heritage Conservation Branch of the Ministry of Provincial Secretary and Government Services, pursuant to the *Heritage Conservation Act.* Most management actvities are reactive, with surveys being undertaken if and when developments such as mines are proposed. The Heritage Conservation Branch participates in the *Guidelines for Mine Development* project review process, and may request surveys of historical, architectural, archaeological, palaeontological and related scenic resources.

Through mining company/government consultations, it is almost always possible to minimize impacts on heritage resources, and the past record in British Columbia has been very satisfactory. In the rare case where avoidance has been impossible, salvage has instead been undertaken. A good example is the removal and preservation of petroglyphs along the access road to the Line Creek coal mine north of Sparwood.

7.9 CONCLUSIONS

Proposals submitted by potential mine developers indicate that the demand for workers in British Columbia coal mines could exceed 10 000 by the early 1990s. A large share of this demand will emanate from the northeast region of the Province. Indications are that a significant pool of under-utilized labour continues to exist within the region. This included from 3 000 to 4 000 unemployed experienced workers in 1982. In 1976 it was found that there was also a large number of women who had past work experience but had since left the labour force. A significant number of these were interested in pursuing non-traditional mining occupations. Other potential sources of labour include underemployed Indians and agricultural workers as well as young people coming out of local secondary schools. However, the skills and occupational mix of the northeast region's labour force are not immediately suited to the requirements of the coal-mining industry. In particular, there is a lack of skilled tradesmen in this region as is the case for the Province as a whole.

In order for the labour requirements of future coal-mining developments in the Province to be met by British Columbians, and in particular by the residents of coal-mining regions, it will be necessary to expand training programs in the Province to provide more people with the opportunity to acquire industrial skills. The larger the proportion of established local residents in a mine workforce, the more likely that labour force turnover will be minimized. To this end, it will be necessary to enhance the employment prospects of groups that traditionally have been disadvantaged in relation to the job market, by reducing or eliminating a number of barriers to their employment, especially as these pertain to women and native Indians.

The degree of community stability in coal-mining towns will depend upon the extent to which these communities can retain the economic benefits from coal development within the region, primarily by developing trade and service sectors in order to maximize local consumer, as well as producer, spending. Stability will also be enhanced to the degree that communities in coal-mining areas develop a diversified economic base.

Population growth associated with a new mining development may have major impacts on the housing market, services and local government finances in an adjacent community. These factors in turn can have significant impacts on the mining company's efforts to attract and retain a stable workforce. In British Columbia, the responsibility for identifying and resolving any potential problems is shared by the mining company, the Province and local government through the exchange of information at the mine planning stage, negotiation of agreements on actions to be taken by each during construction and operation of the mine, and the review of and decision on municipal taxation.

Communities directly affected or created by coal developments will need to provide adequate housing, retail shopping, and health, educational, cultural, and recreational services and facilities to attract and retain a long-term stable workforce for coal mining. In addition, to minimize social problems usually associated with new resource towns, it will be necessary to provide a number of specialized facilities and services such as family counselling, child care, a women's centre and transition house, to mention only a few.

VIII. COAL TRANSPORTATION ROUTES, TECHNOLOGY, AND COSTS

8.1 INTRODUCTION

In British Columbia few coal-producing regions are located adjacent to export points or coal-consuming facilities. As a result, coal transportation is an essential part of the overall system of coal production and utilization. In fact, since the majority of British Columbia's coal-producing regions are several hundreds of kilometres from tidewater or consuming centres, transportation costs can represent a significant portion of the total coal production cost.

8.2 TRADITIONAL TRANSPORTATION TECHNOLOGY

Throughout North America coal is moved by a variety of transportation modes, including rail, river barge, Great Lakes carriers, truck, pipeline, and conveyor belt systems. Rail carries most coal, followed by river and lake barges. In British Columbia, where distances are great and suitable river systems do not exist, rail is almost the exclusive mode of transport. Trucks are used where distances are short and the volumes being moved do not justify new rail spurs.

There are four types of train movement, including single car, multiple car, trainload, and unit train operations. Since the overwhelming majority of British Columbia's coal is destined for export through major coal terminals, unit train operations have developed as the most economical form of train movement. Unit-train operations are those which involve an integral movement of one commodity from a single origin to a single destination, moving on a regularly scheduled basis and utilizing both specialized rolling stock and specialized loading and unloading equipment.[1]

Coal unit trains are usually in the order of 100 cars, each capable of carrying 90 tonnes with a total load capacity of 9 000 tonnes. The steel gondola cars are loaded, profiled, and sprayed with chemical binders in approximately 4 hours at coal preparation plants and are moved to their destination by 4 to 6 locomotives each of about 3 000 horsepower*. All cars are equipped with rotary couplings which enables them to be rotated 360 degrees for unloading at coal ports. This permits a train to remain completely intact while being mechanically moved through unloaders in approximately 2 to 6 hours, depending on the capacity of the unloader. Rail distances from British Columbia's Rocky Mountain coalfields to tidewater are in the order of 1 000 to 1 200 kilometres and a return trip requires up to 7 days.

8.2.1 EXISTING EXPORT ROUTES

8.2.1.1 Rail

As noted above, the principal mode of transport for British Columbia coal is rail and dependence on this mode is expected to continue due to the inherent scale economies for volume movements over long distances. Principal rail export routes in British Columbia are shown on Figure 8.1. Canadian Pacific Rail (CPR) moves all British Columbia's coal from southeastern British Columbia. Coal loaded at Fording and Sparwood for delivery to Roberts Bank moves through Elko to Fort Steele. From Fort Steele on the Cranbrook Subdivision, the route joins the CPR mainline at Golden. From there the route passes through Revelstoke, Kamloops and Mission. From Mission a brief stretch of Canadian National Rail (CNR) mainline is used to connect to the British Columbia Hydro and Power Authority Railway (BCHPAR). It then carries on to a point in Cloverdale where the BCHPAR and the British Columbia Harbours Board Railway[2] interconnect. The British Columbia Harbours Board Railway, built to provide common rail access to Westshore Terminals at Roberts Bank, is used to complete the route.

---

[1] *Swan Wooster Engineering Co. Ltd.*, Background Report on Coal Transportation in Western Canada, prepared for Canada West Foundation, Calgary, p. 29.

* 1 horsepower = 746 watts.

[2] As of October 31, 1983 all of the railway assets of the British Columbia Harbours Board were transferred to the British Columbia Railway (BCR).

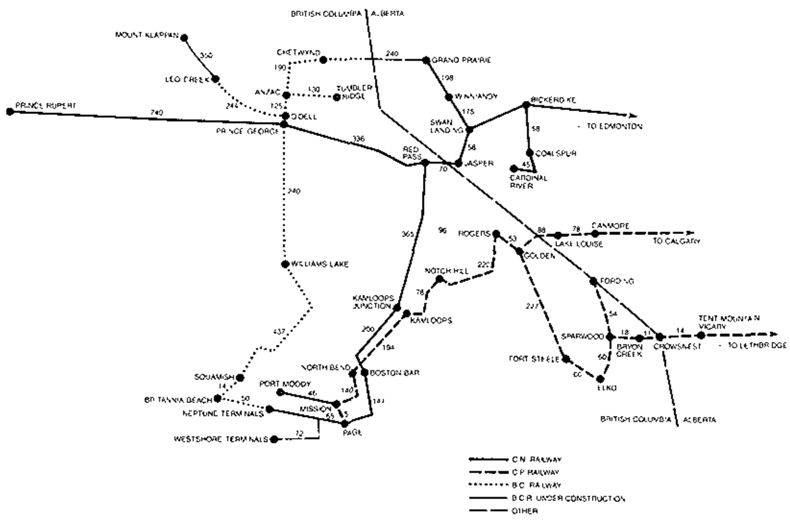


Figure 8.1 — Schematic rail network export coal routes.

This route was a single track line with passing sidings spaced every 12 to 16 kilometres on average. CP has recently completed portions of a double tracking program on the mainline section between Revelstoke and Kamloops in order to increase speed and capacity.

Since the Burlington Northern Railway passes within about 35 kilometres of CP's Elko station, a link between the two railways has been discussed. A connection of this sort would enable coal to be transported from southeastern British Columbia over U.S. rail routes to the east or to Roberts Bank via Seattle thereby creating a second route from the southeast and additional capacity. This routing, however, would involve foreign carriers moving Canadian commodities.

The newest rail export route is the BCR/CNR route which serves the Peace River coalfields in northeastern British Columbia. This route follows a newly constructed 130-kilometre branchline from the new town of Tumbler Ridge to Anzac on BCR's mainline, 125 kilometres north of Prince George. From Anzac the route then follows BCR's mainline to Prince George where coal trains are switched to CNR's northern mainline running 700 kilometres to the new coal terminal at Ridley Island. Shipments over this route began in late 1983.

A major innovation on this route is that the newly constructed 130-kilometre branchline is electrified. Using a 50-kilovolt (kv) system, electric locomotives haul the coal trains from the mines to Anzac where they are then switched out for diesel locomotives for the remainder of the route. This avoids the need for expensive ventilation systems in the two major tunnels on the branchline.

This route will also likely serve future potential developments in the Peace River coalfields such as Petro-Canada's Monkman property. Other promising coal properties to the north (for example, Willow Creek) will connect to the BCR at or near Chetwynd and then move coal via the BCR/CNR system to Ridley Island.

Other coal carried on the Canadian National Railway originates in northwestern and central Alberta and is moved through British Columbia for export. The coal moves on CN's mainline south from Red Pass junction, through Kamloops to the Port Mann yards. The route then crosses to Vancouver's north shore for access to Neptune Terminals. CN also has access to Pacific Coast Terminals at Port Moody and can access the coal terminal at Roberts Bank.

Coal shipped east to central Canada (including southwestern Alberta coal) moves either in trainloads directly to the destination or in unit trains to Thunder Bay, where a major Great Lakes coal-loading port is located. Unit trains connecting with "lakers" at Thunder Bay provide a rail-water intermodal system into central Canada.

8.2.2 POTENTIAL EXPORT ROUTES

8.2.2.1 Rail

The recently discovered Mount Klappan anthracite coal property in northwestern British Columbia could possibly be accessed by BCR's Dease Lake extension. One option would be to upgrade the existing railway and extend the track to Mount Klappan. Anthracite would then be hauled southeast along the Dease Lake extension to O'Dell, on BCR's mainline, just north of Prince George. A switch to CN track would be made in Prince George and from there the route could then follow the CN northern mainline to Prince Rupert. This route would entail a total distance of some 1 420 kilometres. However, if sufficient tonnage can be developed and marketed from the Mount Klappan property a new, shorter rail route would likely be warranted. A number of options may be considered including a connection between the BCR and the CN which could reduce the total distance to Ridley Island by half and a railroad between the mine and Stewart.

8.2.2.2 Pipelines

The feasibility of a coal slurry pipeline route through British Columbia was studied by the Province of Alberta[3]. Consultants designed a preliminary pipeline system originating in Alberta to carry thermal coal from the Hinton area. Such a pipeline would run 1 032 kilometres following the Yellowhead Highway from the Alberta border to Terrace. From Terrace it would head south to the Kitimat area where a coal slurry shipping terminal with a dewatering plant would be required.

8.2.2.3 Road

Revived interest in coal mining on Vancouver Island has led to a number of proposals to truck coal from mines to small tidewater barge terminals where coal would be trans-shipped by tug and barge to markets on the coast (for example, cement or forest product plants) or to a major shipping terminal for export. The Quinsam coal project near Campbell River would use existing forestry roads to haul coal about 35 kilometres to a tidewater terminal at Middle Point. Another proposal to mine coal at Wolf Mountain near Nanaimo includes a plan to truck coal to existing barge-loading facilities at Nanaimo during a limited production phase while a site is chosen to load coal when full production is achieved.

8.2.3 EXISTING TERMINALS

There are operating coal terminals on British Columbia's coast. Table 8.1 summarizes the capabilities of these terminals. Two terminals are dedicated exclusively to coal. The other two handle bulk materials as well as coal.

---

[3] *Fluor Canada Ltd.,* Coal Slurry Pipeline Feasibility Study 1981, for the Province of Alberta, Edmonton, 1981.

TABLE 8.1. Existing and Planned British Columbia Coal Loading Facilities

Port/ Terminal	Operator	1984 Annual Throughout Capacity	Loading Facilities	Restrictions	Expansion Plans
Roberts Bank	Westshore Terminals (Westar Mining)	22 MMT	— tandem rotary rail car dumper — one travelling ship-loader of 7 000 tonnes/hour capacity — 2 ship berths — dual quadrant loaders with 6 000 MT/hour capacity — 2 stacker reclaimers	23.0-metre draft; 250,000 DWT vessel size	Expansion to 30 MMT when required.
Neptune Terminals	Neptune Terminals Incorporated	7 MMT	reclaiming/loading capacity of 4 500 MT/hour	15-metre draft; 120,000 DWT vessel size	Expansion to 9 MMT being considered.
Port Moody	Pacific Coast Terminals Ltd.	1.5 MMT	2 loaders: 1 at 2 000 MT/hour, 1 at up to 1 450 MT/hour	13.7-metre draft; 65,000 DWT vessel size	
Ridley Island	Ridley Terminals Incorporated	10–12 MMT	— dual quadrant loaders with capacity of 8 000 MT/hour — tandem rotary rail car dumper — one ship berth	250,000 DWT vessel size	Potential expansion could exceed 24 MMT/ year.

MMT = million tonnes
MT = metric tonnes

The largest coal terminal on the coast is located at Roberts Bank, south of the mouth of The Fraser River in the Strait of Georgia. This terminal is operated by Westshore Terminals, a division of Westar Mining Ltd., and has a design throughput capacity of about 22 million tonnes per year.

Expansion at Roberts Bank from 12 million tonnes capacity to some 22 million tonnes capacity was scheduled to be completed in early 1984. The expanded terminal includes a tandem rotary rail-car dumper capable of unloading 45 cars per hour, two stacker reclaimers, dual quadrant shiploaders, a new travelling shiploader capable of loading ships at a rate of 7 000 tonnes per hour, and two berths, one of which is capable of handling 250 000 DWT (dead weight) vessels.

An additional expansion is proposed which could add another 10 million tonnes of throughput capacity. This expansion is dependent upon market conditions.

Neptune Terminals is located on the northern shore of Burrard Inlet and is served by CN. Additional equipment was added in the early 1980s giving the terminal a handling capacity in the order of 7 million tonnes per year. Further expansion at Neptune is constrained by land availability. However, by reconstructing rail access and adding more equipment the terminal capacity could be increased to around 9 million tonnes per year.

The other terminal available for coal shipments is Pacific Coast Terminals at Port Moody. The throughput capacity for coal is currently around 1.5 million tonnes per year.

Finally, the newest coal terminal in British Columbia, completed at the end of 1983, is located near Prince Rupert in northwestern British Columbia. The new terminal was constructed by Ridley Terminal Inc., a joint venture between the National Harbours Board and Federal Commerce and Navigation. The terminal is designed to receive and unload unit trains using a tandem rotary rail-car dumper system. Ships of up to 250 000 DWT can be loaded by dual quadrant loaders at a rate of up to 8 000 tonnes per hour. Throughput capacity is 12 million tonnes per year and the terminal can be expanded to handle 24 million tonnes per year in the future.

8.3 COAL MOVEMENTS AND CAPACITY RESTRAINTS

In 1978 a computer analysis of the major coal export routes was conducted by Swan Wooster Engineering Co. Ltd. to determine rail capabilities with respect to coal movements.[4] Coal terminal capacities were also assessed in another study.[5] The rail analysis showed that in the late 70s, limited additional capacity existed for coal exports, given reasonable projections of other traffic. The assessment of coal terminal capacity was similar. Since these reports were published, however, the railways have undertaken improvements in an attempt to increase rail capacity and coal terminal expansions have been completed.

8.3.1 RAIL

8.3.1.1 Southeastern Movements

Fording Coal Ltd., Westar Mining Ltd., Crows Nest Resources Ltd., and Byron Creek Collieries Ltd. make shipments via the CP to Roberts Bank for export. Some Alberta producers also use CP's southern line to move coal to lower mainland export points. In the peak year of 1981 shipments over this route totalled nearly 12 million tonnes which was close to taxing the capacity of the Fort Steele-Golden link. However, shipments declined slightly in the following 2 years and improvements to this section including decreasing average siding spacing to 12 kilometres, introduction of centralized traffic control signals, and upgrading the track to allow faster travel were undertaken to alleviate capacity constraints.

In conjunction with these improvements the upgrading of CP's mainline has also been undertaken. By adding two relatively short sections of double track between Revelstoke and Kamloops the mainline capacity was improved. Other track improvements between Rogers and Glacier, most notably a 14.5-kilometre tunnel, will improve capacity even further. This work is part of a $600 million project to reduce the grade from Beaver River valley to Rogers Pass.

With respect to the Fraser Canyon, the present capability appears to be sufficient for existing requirements and "recent studies show that, based on recent traffic projections, the Canyon will present no serious capacity problems for the foreseeable future."[6]

Finally, an assessment of the capability of the Lower Mainland rail network to serve Roberts Bank showed that "the present route is adequate for handling current and future levels of traffic to and from Roberts Bank."[7]

8.3.1.2 Northeast and Alberta Movements

The Swan Wooster analysis of the CN system indicated that it is in a more favourable position than CP with respect to available capacity. In 1978 Swan Wooster stated the CN could accommodate an additional 15 million tonnes of coal before upgrading work would be required. Since 1978 the CN has not significantly increased the tonnages moving to lower mainland export points from the Luscar and McIntyre mines in Alberta. With new coal shipments from Alberta and increased shipments of grain and other commodities, the CN is planning to double track the entire mainline from Red Pass junction to Vancouver by the late 1980s thereby providing ample capacity over its system.

With respect to the BCR/CN route from Tumbler Ridge to Prince Rupert, the route has been designed so that it will be capable of carrying the anticipated export volumes of coal for the entire Peace River Coalfield.

---

[4] *Swan Wooster Engineering Co. Ltd.,* for the Transportation Sub-Committee on North East Coal Development, and reported in Rail Systems Operation/Cost Model of Coal Unit Trains, Southeastern British Columbia and Western Alberta Coal, Vancouver, B.C., February, 1978.

[5] *Acres Consulting Services Ltd.,* Lower Mainland Port Economic Study, Vancouver, B.C. 1980.

[6] *Swan Wooster Engineering Co. Ltd.,* Background Report on Coal Transportation in Western Canada, Fall, 1979.

[7] *Swan Wooster Engineering Co. Ltd.,* An Assessment of the Effects of Traffic Growth on the Railway System Serving Roberts Bank, for Roberts Bank Expansion Committtee, December, 1982.

8.3.2 TERMINALS

With the addition of the Ridley Island coal terminal and the expansion of Westshore Terminal's capacity at Roberts Bank, terminal throughput capacity in British Columbia should exceed 40 million tonnes in 1984 and have the potential to exceed 60 million tonnes as demand warrants. Other than these major terminal expansions, new terminal capacity may be required at a site or sites on Vancouver Island to serve the thermal deposits on the Island.

8.4 FUTURE TECHNOLOGIES

The discussion so far has centred on conventional rail and unit train operations. A new development for unit train operations is the electrification of the Tumbler Ridge branchline. An increased demand for thermal coal and a rekindled interest in Vancouver Island coal could create a need for other new and advanced transportation technologies.

8.4.1 RAIL ELECTRIFICATION

During the construction of the Tumbler Ridge branchline, a decision to electrify that portion of the route was made. Using a 50-kilovolt (kv) system, electric locomotives haul coal for the first 130 kilometres of the route to Anzac where they are switched out for diesel locomotives for the remainder of the route. This is the second 50-kilovolt rail system in North America used to haul coal and only the third in the world. Unlike 25-kilovolt electric train systems in Europe and eastern North America, a 50-kilovolt system requires limited connections to the existing hydro grid, thus it is suitable for remote locations such as the northeast. Electric locomotive power also has greater tractive efficiency than diesel power and therefore is more energy efficient, making it an attractive energy alternative. In the case of the Tumbler Ridge branchline, electrification eliminates the need to ventilate the major tunnels. This electrification project is being closely monitored by the national railways to see if electrification would be a viable alternative to diesel on their systems, particularly through the Rocky Mountains.

8.4.2 COAL SLURRY PIPELINES

Coal slurry pipelines using water as the carrier medium are not an entirely new idea but the first pipeline was not built until 1957 when a 25-centimetre pipe was built between Cadiz and Cleveland in Ohio. It was operational for only 6 years when unit train operations began, resulting in lower freight rates which made the pipeline uneconomic. A second, 45-centimetre coal pipeline was built in 1970, over 430 kilometres from the Black Mesa mine in Arizona to the Mohave power plant in Nevada. It is the only industrial scale pipeline presently in operation.

Both these pipelines were constructed for thermal coal shipments and no metallurgical coal has successfully been shipped by pipeline to date. The major problem, which research is attempting to overcome, is that metallurgical coal, in slurry form, breaks down to a great extent, creating fines and destroying coking capabilities. Although with present technology the use of slurry pipelines for moving metallurgical coal is not viable, proposals for transporting thermal coal by pipeline are becoming more prominent.

One drawback to pipeline technology is the dewatering aspect. Various methods for disposing of the water are being investigated, but in a coastal setting the options are limited. Another drawback is that once in place, pipelines restrict the volume that can be moved. That is, they become fixed and do not provide the flexibility that a railway does.

The 1980 study on coal slurry pipelines commissioned by the Province of Alberta examined the feasibility of constructing a pipeline to move thermal coal from west central Alberta through to tidewater in British Columbia. The study indicates that a pipeline capable of delivering 10 million tonnes a year of thermal coal to a coal-loading terminal in northern British Columbia would be technically feasible. The possibility of using methanol as a carrier was also briefly addressed and was determined to be technically feasible. A methanol medium would avoid any dewatering problems and would increase the total unit value of the commodity being transported.

8.5 COAL TRANSPORTATION COSTS

As noted at the outset, due to great distances to tidewater, transportation costs make up a major portion of the total cost of getting British Columbia coal to markets. Rail costs and tariffs originally decreased with the introduction of unit trains but in the latter part of the 1970s unit trains have run into higher operating costs than were originally expected. "Partly as a consequence of these higher costs, rail tariffs have sometimes moved upward out of sequence with coal prices."[8]

Another transportation cost is the handling charge at coal terminals. However, as a portion of total transport costs, this has not yet become significant.

8.5.1 RAIL COSTS

Tariffs presumably represent the capital and operating costs of providing rail service from mine to destination. Thus a brief discussion of rail capital and operating costs is appropriate. The most recent experience of capital construction costs is that of the Tumbler Ridge branchline.

The inplace capital cost of the 130-kilometre Tumbler Ridge branchline was expected to be $455 million including escalation during construction. Of that total, the construction of about 16 kilometres of tunnel costs $165.5 million and the 14 bridges cost $20.6 million. Thus, the inplace cost of the Tumbler Ridge branchline, including escalation during construction, is estimated to be $3.5 million per kilometre. Upgrading is also a major capital cost item. For the BCR the upgrading costs for the 125-kilometre section of track from Anzac to Prince George are expected to be $50 million. The CN will incur costs of $265 million to the end of 1984 to upgrade the track from Prince George to Prince Rupert and add track into the terminal at Ridley Island. CN expects to spend over $500 million upgrading this track between 1981 and 1989. The track between Prince George and Prince Rupert will be used for both coal and grain shipments as well as other commodities.

The other major portion of railway costs are operating costs which are divided into two components: variable and fixed costs. Variable costs are functions of distance, topography, and type of train configuration. Fixed operating costs reflect the fixed costs associated with maintaining the integrity of the rail no matter how many trains pass over the route.

The April 1983 tariff for shipping Northeast coal to Prince Rupert including the capital recovery surcharge is estimated to be about 2.2 cents per tonne kilometre. For the southeast in mid-1983 the tariff for shipping coal was around 1.8 cents per tonne kilometre.

8.5.2 TERMINAL COSTS

Another transportation cost that should be considered is terminal costs. The estimated throughput charge at Westshore Terminals for a tonne of coal in 1983 was in the order of $3.00 per tonne. For a new terminal, however, the capital costs are higher and therefore the throughput charge should be higher. The charge at Ridley Island terminal *for the first two users* will be based on a $3.00 per tonne charge in 1980 to be escalated at 80 per cent of the Consumer Price Index (CPI) for the first 5 years.

8.5.3 TRUCKING COSTS

Trucking costs for an on-highway truck capable of carrying 35 tonnes were estimated to be around 5 to 6 cents per tonne kilometre in 1983 depending on terrain. This would include a capital charge for the tractor and trailer which would cost around $160 000.

[8] *Energy, Mines and Resources Canada,* Discussion Paper on Coal, Ottawa, 1980.

8.5.4 SLURRY PIPELINE COSTS

The most recent analysis on the costs of coal slurry pipeline was made by a consultant for the Province of Alberta. The study was done to determine the feasibility of transporting thermal coal in a water slurry form from northwest Alberta to a tidewater in northern British Columbia. A system capable of transporting about 10 million tonnes a year was conceptually designed assuming that coal would be fed into the system from 5 feeder coal mines. The total capital cost of the system was estimated to be around $1.7 billion (1981 dollars) and the annual operating costs were estimated to be between $40 million and $60 million (1981 dollars). Further analysis suggests that 1982 tariffs for such a pipeline would be in the order of $30.00 per tonne.[9]

8.5.5 OCEAN SHIPPING COSTS

Although British Columbia's export coal is sold on an f.o.b. basis (which does not include ocean shipping costs), ocean shipping is an important aspect of the landed price for coal at the demand centre. From a number of cost estimates it is quite clear that economies of scale are derived as the ship size gets larger. It appears though that economies of scale drop off at around 120 000 to 150 000 DWT and this is likely to be the most predominant bulk coal carrier over the next few decades. The estimated cost per tonne of coal shipped in ships of this size on a long-term charter basis from British Columbia to Japan is around $12.00 to $15.00 per tonne[10] although spot rates have decreased dramatically from this long run equilibrium level due to world-wide recession and an excess of dry bulk tonnage.

8.6 SUMMARY

Due to the great distances to tidewater from most British Columbia coal mines, transportation costs make up a significant portion of the f.o.b. selling price of coal. For British Columbia's coals to remain competitive in the world market the continued efficiency of the transportation system is necessary.

New capacity on British Columbia's north coast, additional port capacity on the lower mainland, expansion and upgrading of the BCR/CN route serving the Peace River coalfields, and added capacity on the CP mainline should ensure that an efficient transportation system is maintained. With these improvements in place, British Columbia is well situated to handle increased demands for all types of British Columbia coal.

---

[9] J. D. Robb and R. C. Bassett, Coal Slurry Transportation System, *Alberta Economic Development*, November 17, 1982.
[10] Ministry of Industry and Small Business Development Estimate, 1983.

IX. UTILIZATION TECHNOLOGY

9.1 INTRODUCTION

Until recently the technology of coal utilization has lagged markedly behind that of other energy sources. However, with the renewed interest in coal as a source of energy and as a chemical feedstock, this trend has reversed. There are now many laboratories around the world conducting research ranging from basic coal chemistry to the production of liquid transport fuels from coal. Coal will undoubtedly play a leading role as a source of hydrocarbons for energy and chemicals in the decades ahead.

Although British Columbia has large reserves of coal and is a major coal producer, only negligible amounts of coal are currently used in the Province. This has largely been because other, more convenient, and less expensive energy sources have been readily available. British Columbia is richly endowed with hydroelectric power potential, and this has largely been the basis for our electrical generation requirements. Similarly, natural gas is a major provincial energy resource and crude oil has been readily available from Alberta.

However, with substantial cost increases being projected for other energy sources, particularly crude oil, and the uncertain long-term availability of crude oil, coal will undoubtedly play a major role in the future as a domestic source of energy in British Columbia. This chapter provides an overview of coal utilization technologies which will likely be employed in British Columbia in the coming decades.

9.2 CARBONIZATION

9.2.1 COKE UTILIZATION

Carbonization is the process in which swelling or coking coal is converted into metallurgical coke in coke ovens. The production of coke is done by pyrolysis, or the heating of coal in the absence of oxygen. In this process the volatile portion of the coal is driven off as "coke-oven gas", resulting in a hard material high in carbon content (usually 90 per cent) known as coke. The coke is then used primarily for the reduction of metallic ores in blast furnaces.

Currently, the world's iron blast furnaces consume an average of approximately 500 kilograms of coke per tonne of pig iron produced. In turn, 1.43 tonnes of coal are estimated to be consumed for each tonne of metallurgical coke produced. The major portion of this coal will be carbonized to coke in coke ovens.

While there has been little change in coke oven technology until recently, there have been major advances over the past two decades in the technology of metallurgical coke production from blends of coals thought earlier to be unsuitable. In recent years the combined influences of greatly increased prices for coking coal, the prospect of diminishing supplies of the hard coking coals, the environmental problems presented by operation of conventional coke ovens, and the increasing demand for steel have given impetus to:

(1) improvements in the technology of the conventional coke oven;
(2) alternatives to the conventional coke-oven technique of making coke.

Any modification or alternative to conventional coke-oven design and practice must clearly meet the primary requirement of producing metallurgical coke with the properties demanded by blast furnace operators (*see* Table 9.1).

TABLE 9.1. Properties Required of Metallurgical Coke

	B.S.C.	CANADA	JAPAN
Moisture	$\not> 3\%$		$\cong 4\%$
Shatter 1·5″	$>90\%$	$>90\%$	
Micum M 40 Index	$>75\%$		
ASTM Stability		min. 55·0	
D.I. 30/15			$>93{\cdot}5$
Micum M 10 Index	$<7\%$		
ASTM Hardness		70·0	
D.I. 150/15			$>81{\cdot}5$
Ash	$\not> 8\%$	$\not> 8\%$	$\cong 11$–12%
Sulphur	$\not> 0{\cdot}6\%$	$\not> 0{\cdot}7\%$	0·55–0·65%
Volatile Matter	$\cong 0{\cdot}8\%$	$\cong 0{\cdot}7\%$	$\cong 0{\cdot}7\%$
Size Range	20–65 mm	13–65 mm	30–75 mm

NOTE—Micum 10 and 40 Indices, ASTM stability and hardness, and D.I. 30/15 and D.I. 150/15 values are derived from similar tests. In the D.I. test, for example, plus 50-mm samples of coke are given 150 revolutions in a standard drum, after which the coke is screened through 15-mm screens and the weight remaining in the screen is the D.I. 150/15 index. The coke remaining on a similar screen after 30 revolutions is the D.I. 30/15 index.

9.2.2 IMPROVEMENTS IN THE TECHNOLOGY OF CONVENTIONAL COKE PRODUCTION

The major improvements in conventional coke-oven technology are mainly in the areas of:

(1) larger oven size;
(2) higher carbonization temperatures;
(3) preheating of coal charged to the coke oven;
(4) stamp or briquette charging of coal to the coke oven;
(5) improved pollution control;
(6) better exploitation of byproducts.

Preheating combined with pipeline charging of the coal has been particularly effective in decreasing the pollution problems associated with conventional practice in which coal is charged from cars on top of the oven. In addition, preheating has been found to widen the range of coals which can be carbonized to yield a coke with the required properties and also to decrease the time for carbonization. This technique is beginning to be adopted by the coking industry and will have the effect of decreasing the amount of low-volatile coking coal required in coking.

"Stamp charging," in which a large single slab of compacted coal is charged to the oven, is of considerable interest in extending the range of coals which can be carbonized to metallurgical coke in a conventional coke oven. The proportion of "inerts" (coal substances with a swelling index of <1) in the coal charge can be as high as 30 per cent with this technique.

A technique which is allied to that of stamp charging has been developed by Nippon Steel. In this process briquettes of coal are fed along with particulate coal into a conventional coke oven. It has been claimed that this enables the low-volatile coking coal component of the Nippon blend to be decreased to 4 per cent or less compared with the present minimum of 10 per cent. Also, up to 20 per cent of the coal used in the blend can be noncoking coal, which was considered previously to be unsuitable.

Stamp, or briquette charging, although expanding the range of coals for coking, is unlikely to prove to be as efficient a technique as pipeline charging for suppression of pollution. This is unfortunate because a coke-oven plant can be a disagreeable neighbour, and in the present world climate of growing recognition for the need to eliminate environmental pollution, coke ovens are the target for severe attack. Pollution from coke ovens arises in a number of ways:

(1) A black cloud of coal dust and gas arising when ovens are charged in the normal way.
(2) Similar clouds of coke dust and smoke when an oven charge is pushed.
(3) The production of clouds of steam laden with dust and odiferous gases when the incandescent coke is quenched. Pollution is aggravated when, as in the past, aqueous effluent is used for quenching.
(4) The discharge of SO_2 from stack gases.
(5) A general disagreeable odour in the area of coke oven plants caused mainly by leaks of sulphur-bearing gases from doors and vents, but also from byproduct treatment where it is difficult to achieve complete tightness. This form of pollution can be much reduced (but never entirely eliminated) by ensuring good maintenance standards.
(6) The toxic and contaminated liquid effluent from gas purification and byproduct plants.

The first three are the major sources of pollution and can be seen to be directly associated with coke-oven plant design. Assuming that pipeline charging and preheating are used on the input side of the oven, then the major problems become those of eliminating the push-cycle and quench-station emissions.

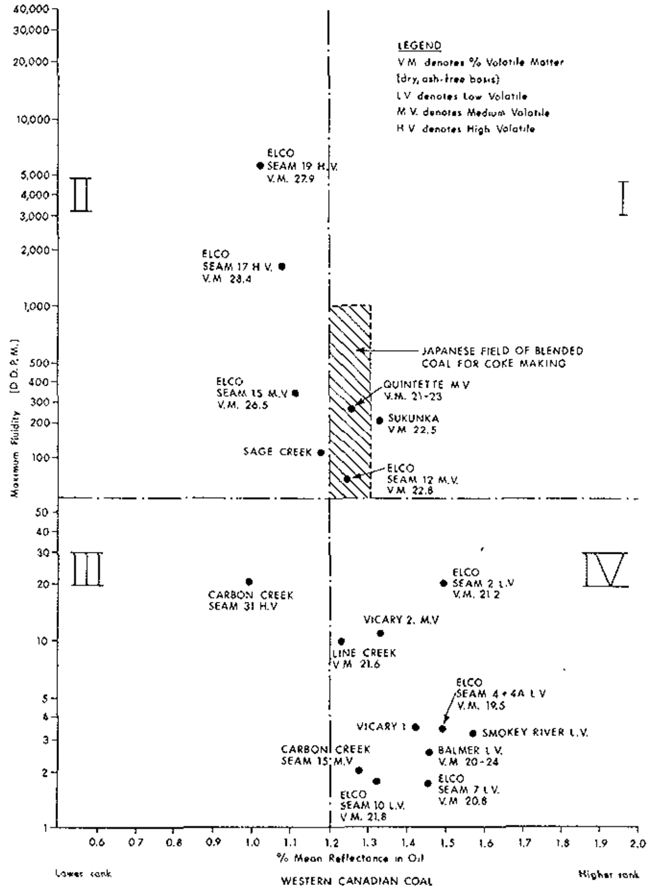


Figure 9.1 — Relationship between maximum fluidity and mean maximum reflectance of some Rocky Mountain coals.

Considerable attention has been devoted to the former problem and plants are now operating with a variety of dust-suppression systems installed. The quench-station pollution can be very effectively suppressed by use of the dry-quench technique, using cold inert gas. Dry cooling units were first built in the 1930s but it is the Soviets who have realized the full potential for these units by not only eliminating pollution but also by improving the quality of the coke produced.

The moisture content of the coke is decreased from about 3–0.3 per cent, but more importantly the M40 micum index is increased by 6 per cent and the M10 micum index by 0.5–1 per cent. The effect of these latter gains is, as with preheating, to extend the range of coals that can be blended to produce an acceptable metallurgical coke.

Several of the individual coals from the Rocky Mountain region of British Columbia have properties essentially the same as those in Japanese coal blends (*see* Fig. 9.1) and thus would be expected to yield coke of suitable quality for Japanese blast furnaces. Using preheating and possibly by quenching techniques, Quintette and Sukunka coals should give excellent quality coke. Further, in view of the ability of these coals to be economically treated to low ash (5 per cent), they would appear to be prime candidates for consideration if a provincial conventional coke plant were contemplated.

The sulphur contents of the coals from the Rocky Mountain Region are in general very low (Westar washed coal = 0.3 per cent) and can easily produce coke having sulphur contents well below the maximum limit (*see* Table 9.1).

9.2.3 ALTERNATIVES TO CONVENTIONAL COKE-MAKING TECHNIQUES

In these processes a formed coke is produced (formcoke) by the carbonization or partial carbonization of coal briquettes which have been shaped mechanically and heated beyond the decomposition temperature of the coal during manufacture. A typical sequence of operations is shown on Figure 9.2 which depicts the F.M.C. (Food Machinery Corp.) process. Formcoke has the following potential advantages over conventional coke:

(1) The size and shape of the briquettes can be varied to achieve optimum performance in the blast furnace.
(2) Relatively cheap, indigenous, low-rank, noncoking coals could be used for metallurgical purposes.
(3) Atmospheric pollution could be more stringently controlled and working conditions improved.

In addition, the coke briquettes produced from a formcoke plant would be strong and without the irregular shape of conventional coke, and show less tendency to degradation in transport. Having only 70 per cent of the weight of the coal from which they were produced, formcoke should show a saving in transport costs, although their bulk density being lower than coal might detract somewhat from this saving.

The known processes for formcoke production can be classified into three main types (*see* Table 9.2):

(1) Coal or charbonded with tar or pitch.
(2) Hot charbonded with coking coal.
(3) Coal or charbonded with pressure alone.

Currently, in formcoke technology, several of the processes are being scaled up or operated to produce sufficient coke for extended blast-furnace trials. These trials will establish the necessary production technology to produce coke that can replace conventional coke completely. It is already clear from early short-term tests that at least 50 per cent formcoke can be used in the blast furnace burden.

It has been estimated that the capital cost of a formcoke plant should be no more and probably less than a conventional coking plant equipped with the latest pollution

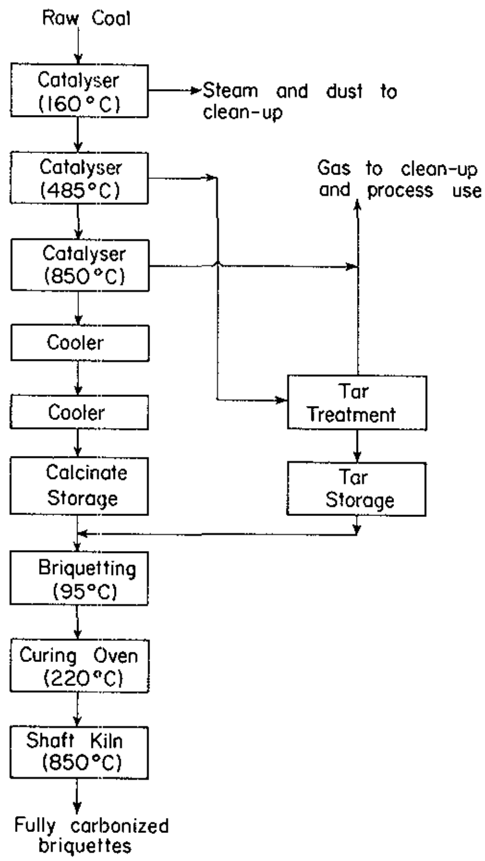


Figure 9.2 — The F.M.C. process for formcoke production.

TABLE 9.2. Some of the Formcoke Processes Currently Under Development

Name of Process	Type[1]	Origin Country	Current Capacity
			Tpd
Ancit Eschweiler Bergwertsverein	(b)	Germany	250
B.B.F.L. (Bergbau-Forschung-Lurgi)	(b)	Germany	600[2]
F.M.C. (Food Machinery Corp.)	(a)	U.S.A.	230
Consol — B.N.R. (Consolidation Coal, Bethlehem, National, and Republic Steel)	(b)	U.S.A.	500
H.B.N.P.C. (Houilleries du Basin du Nord et du Pas-de-Calais)	(a)	France	160
I.N.I.E.X. (National Institute of Extractive Industries)	(a)	Belgium	110
AUSCOKE (Broken Hill Proprietary Limited)	(a)	Australia	110
Sapozhnikov	(c)	U.S.S.R.	1 370[3]
D.K.S. (Didler, Keihan Rentan, Sumitomo)	(a)	Germany, Japan	130

[1] (a) Coal or char bonded with tar or pitch; (b) hot char bonded with coking-coal; (c) coal or char bonded with pressure alone.
[2] Building in United Kingdom.
[3] Building.

control systems [formcoke plants of the B.B.F.L. (Bergbau-Forschung-Lurgi) and F.M.C. (Food Machinery Corp.) type use completely enclosed vessels in their processing steps and thus are environmentally more satisfactory than conventional coking plants]. The byproducts obtained from a B.B.F.L. plant producing char for formcoking and from a coke oven are compared in Table 9.3. Gas from the B.B.F.L. plant being produced at 750°C instead of 1 100°C as in the conventional plant would be expected to have a relatively higher methane content. The gas from either plant could be used for a variety of purposes, including that as a reducing agent for a direct-reduction iron plant (*see* section 9.2.4).

In this case, the gas from a conventional coking plant might be preferred because of its more desirable composition.

Formcoking almost certainly represents the direction which coke production technology will take. Ultimately, processes similar to that being developed by U.S. Steel will be preferred. These processes aim to optimize energy and materials recovery from coal. The U.S. Steel process (*see* Fig. 9.3) would produce annually from 4.5 to 5.5 million tonnes of coal the following products: 2.0 million tonnes of coke pellets, 1 million kg of chemicals, 30 million litres of liquid fuel, and 6 300 megajoules of fuel gas. Operation of this process has been so far at the 225 kilograms per day scale; scale up to 220 tonnes per day is planned.

Formcoking could be applied to coal from the northeast region of British Columbia, from the Kootenays, and to the sub-bituminous coal from Hat Creek if its ash content could be sufficiently reduced. Alberta sub-bituminous coals would also be well suited to formcoking.

9.2.4 DIRECT REDUCTION OF IRON ORES

The blast furnace will probably remain the major iron producer, wherever steel is produced in large tonnages, for a long time in the future. This is not only because of the high thermal efficiency of the blast furnace (80 to 95 per cent) and the major improvements still being made in blast-furnace practice, but because projections of future energy resources point to coal as the long-term primary source of carbon as a reducing agent.

Nevertheless, considerable efforts have been made during the past two decades to develop alternative processes to the blast furnace. These efforts have been successful to the extent that some of the alternatives clearly will have an important role in the production of iron in specific locations. One of the most significant factors influencing the selection of a direct reduction process route to steelmaking is the scale of operation. At the 500 000-tonne-per-year level of steel output and starting from raw materials, direct reduction is considered to be the only economic choice, with an integrated blast furnace BOF complex not being competitive until approximately the 1.8-million tonne-per-year output is required.

There are basically two process alternatives possible in a direct reduction operation. The first, which has been most successful to date and accounts for the major proportion of the direct reduction installed capacity, uses a gaseous mixture of hydrogen and carbon monoxide derived from natural gas as the reducing agent. Typical examples of this type of process are the Midrex, the Armco, and FIOR requiring 12 700 to 13 400 megajoules of energy per tonne of metallized product. A Midrex plant is operating in Canada at the Sidbec-Dosco facility at Contrecoeur, Quebec, with a present installed capacity of 360 000 tonnes per year.

The growing shortage and increasing price of natural gas in North America has led to consideration of alternative sources of gaseous reducing agents for these processes. Low-cost crude or fuel oil, LPG (liquefied petroleum gas) or naphtha can be converted to a favourable reducing gas by any number of well-proven partial oxidation processes familiar to the petroleum industry. High-sulphur oils can be considered if the sulphur is removed from the gas after partial oxidation. The flexibility of the processes to alter-

TABLE 9.3. Comparison of By-products From Conventional Coke Ovens and Low-temperature Char (B.B.F.L.) Coke Process

PRODUCTS FROM 1 TONNE COAL

	B.B.F.L.	Conventional
Coal gas	150–180 m³	300–360 m³
Calorific value	6 000–8 000 kcal/m³	5 000 kcal/m³
Coke	620 kg	600–700 kg
Coke breeze	—	50–100 kg
Tar	70–90 kg	50–70 kg
Light oil and benzine	33–50 kg	11–18 kg
Ammonium sulphate	very small	10–14 kg
Ammonia liquor	very small	75–175 l

NOTE — The sulphur in the coal is distributed among the carbonization products, usually in the following proportions:

	Per Cent
Coke	50–65
Gas (as H_2S)	25–30
(As CS_2 and etc.)	1–1.5

Tar and ammonia liquor balance.

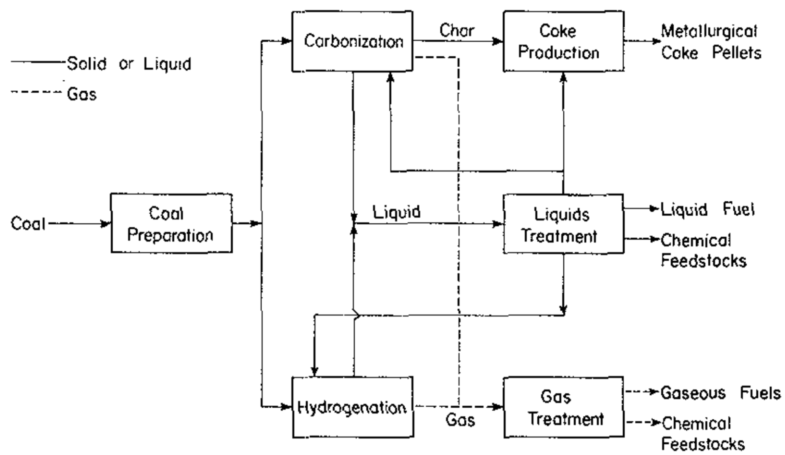


Figure 9.3 — U.S. Steel clean coke process.

native reducing gas feedstocks has already been demonstrated—the 4.5-tonne-per-day FIOR plant, for example, used catalytic steam reforming of natural gas, whereas the 275-tonne-per-day demonstration plant was operated with gas produced by the partial oxidation of butane.

The second basic process alternative in direct reduction is to use coal directly as a reducing agent. The two currently available commercial processes which employ this technique are the Krupp and the SL/RN. Both of these processes have had long and checkered histories of development.

Currently the world steel producers are awaiting with great interest the proving of the largest SL/RN facility constructed to date, at the Steel Co. of Canada's Griffith mine at Red Lake, Ontario. This plant has a rated capacity of 320 000 tonnes per year of metallized product and uses Alberta sub-bituminous coal from the Forestburg mine as a reducing agent (the energy consumption of the process is approximately 16 300-megajoule-per-tonne of product). Test runs (*see* Table 9.4) indicated that the maximum ore throughput rate with maximum metallization of the product was obtained with this coal.

TABLE 9.4. Variation of Throughput and Degree of Metallization With Rank of Coal in SL/RN Tests

Coal	Dry Ore Rate MT/Day	Coal/Ore Ratio (Wet)	Average Kiln Temp.	+9/16-in. Sponges Metallization	Fixed Carbon Consumption Charged FC/Fe	Discharged FC/Fe
			°F	Per Cent		
Anthracite	140.3	0.50	2110	91.5	0.56	0.22
Bituminous (Calora)	139.9	0.52	2016	72.8	0.41	0.05
Bituminous (Boich)	125.6	0.37	2000	59.3	0.58	0.02
Sub-bituminous	191.1	0.66	1960	90.2	0.40	0.06
Lignite	173.8	0.77	1874	90.7	0.40	0.40

In addition to requiring coal of the correct rank, it has also been found by the developers of the process that the fusion temperature of the coal's ash content should be as high as possible to obtain maximum and constant throughput. If the SL/RN process were to be adopted, then sub-bituminous coal similar to Forestburg would be required. Sub-bituminous coals with similar properties occur in the Tulameen and Princeton Basins and at Hat Creek, although in all cases the ash contents are higher than the Forestburg coal. Imperial Metals Corporation have had tests performed with the Tulameen coal for the SL/RN process which were reported to be successful. The quantities of coal required for 450 000 tonnes per year direct-reduction plants employing syngas or coal would be 0.9–1.1 million tonnes per year.

9.3 THERMAL POWER GENERATION

9.3.1 CONVENTIONAL COMBUSTION

Nearly all large coal-fired power stations operating in the world today utilize suspension firing of pulverized coal. In this technique the coal is ground into a fine powder in pulverizers and then blown into the furnace where it is mixed with combustion air and heated to ignition temperature. Experience has shown that this system of firing has several advantages over techniques which involve combustion on static or moving grates. Suspension firing enables virtually any type of coal to be used, and there is no practical upper limit to the unit size. However, the milling process used to prepare the coal is expensive and requires precise quality control on the grading and sizing of the coal.

Suspension firing does have some problems with respect to combustion products. Because the coal is burned in suspension, as much as 80 per cent of the ash content leaves the furnace as fly ash. The removal of fly ash and other particulate matter from the flue gases requires the use of highly efficient electrostatic precipitators.

Another problem is the emission of sulphur dioxide and oxides of nitrogen, both of which are more difficult to control. If the sulphur content of the coal is less than about 0.5 per cent, then sulphur dioxide emission may not pose a serious problem and flue gas treatment for sulphur dioxide removal is unlikely to be necessary. However, if the sulphur content is greater than about 0.5 per cent, gas-scrubbing equipment could be necessary to remove the sulphur dioxide in order to meet pollution control requirements. The cost of gas-scrubbing equipment for a generating station would be in the range of $250 to $300 per kilowatts of installed capacity.

The production of nitrogen oxides (NO_x) in a furnace depends on the flame temperature, the excess oxygen available after coal combustion and the residence time of the gas in the furnace. The amount of the fuel nitrogen is also important to the over all amount of NO_x produced. NO_x emissions can be controlled by furnace design which would reduce the flame temperature and excess air in the furnace and the residence time at temperature.

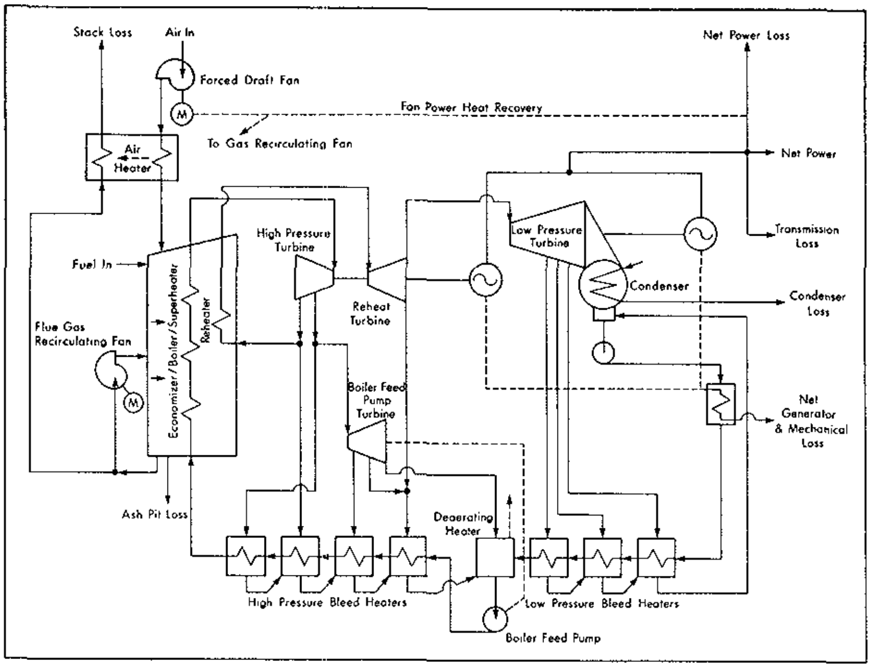


Figure 9.4 — Power cycle diagram for a modern steam power plant.

With pulverized coal combustion very large boiler unit sizes are possible, and boilers capable of providing 660 megawatts (MW) of electrical output are now commonly in service. Steam conditions in these boilers, limited by boiler tube metallurgical consideration, are usually 16.5 megapascals (MPa) and 565°C with reheat to 565°C. This results in an overall thermal efficiency of the power generating cycle of just under 40 per cent based on the fuel higher heating value (HHV). Figure 9.4 shows a typical power cycle diagram for a modern coal-fired power plant.

New combustion techniques are currently under development. They are designed to use lower grade fuels while at the same time meeting more stringent pollution control standards. The techniques which show the most potential in this regard and which also offer the promise of higher efficiency employ fluidized bed combustion or gasification followed by combustion.

9.3.2 FLUIDIZED BED COMBUSTION

The fluidized bed concept has been used in the chemical industry for many years as a convenient vehicle for chemical reactions. A fluidized bed combustor consists basically of a vessel which contains a bed of fine inert particles such as sand or ash. Air is blown in from beneath the bed at such a rate as to cause the bed material to be lifted into suspension, at which point the bed is said to be "fluidized" and takes on the properties of a fluid. Combustion is started by first heating the bed and then introducing finely crushed coal which mixes with the fluidizing air and burns within the bed. If boiler tubes are immersed in the bed, the rapid turbulent motion of the particles in the bed results in a high heat transfer rate to the tubes. Ash particles accumulate near the top of the bed as the coal particles burn out while moving up the bed. An ash overflow outlet then removes excess ash from near the top of the bed, while fresh coal is added just above the air distributor plate at the bottom. Some fly ash is also carried over with the hot flue gases, and is usually collected in a series of cyclones. A schematic diagram of a fluidized bed combustor is shown on Figure 9.5.

The principal advantage of fluidized bed combustion, and the reason that intense development work is being pursued around the world, are that pollutant emissions can be substantially reduced. With the addition of limestone into the bed, the sulphur in the

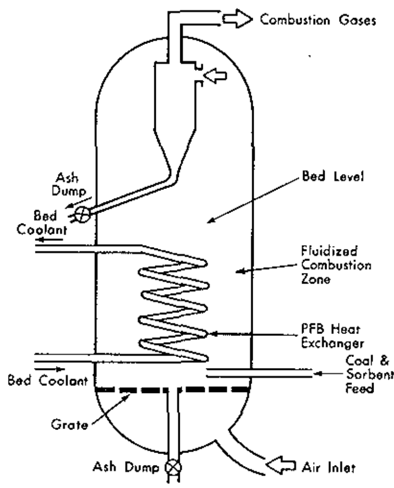


Figure 9.5 — Schematic of a fluidized bed combuster.

coal reacts with the calcium carbonate during combustion to form calcium sulphate which can be removed with the ash. A reduction of over 90 per cent in SO_2 emissions can be achieved by the addition of limestone or dolomite to the bed in this manner, eliminating the need for costly and inefficient flue-gas "scrubbers". The low combustion temperature, around 900°C, in a fluidized bed also minimizes the production of nitrogen oxides (NO_x) which are responsible for the production of photochemical smog. Additional advantages of fluidized bed combustion are due to the rapid turbulent mixing motion of the bed. This enables coals of different particle size and varying ash content to be burned in the same combustor, and also results in a high heat transfer rate from the bed. This latter characteristic results in a smaller heat transfer surface area and a more compact boiler than with conventional combustion.

Fluidized bed combustors can be operated at either atmospheric pressure or at elevated pressure. Atmospheric pressure fluidized bed boilers have been commercially demonstrated at up to 10 MW thermal output size, and several are now in operation at industrial establishments in the United States. These are primarily used for generating process steam and for space heating and are based on designs developed by the United Kingdom National Coal Board. For power generation, much larger sizes are required, and these are currently in the advanced development stage. At Rivesville, West Virginia, a 100-MW thermal output boiler developed by Foster Wheeler and sponsored by the United States Department of Energy is currently in operation. This unit will be used as the basis for a design to generate 200 MW of electrical power. Conventional Rankine steam cycles are used to generate power utilizing atmospheric fluidized boilers.

Operation of a fluidized bed combustor at elevated pressure offers several potential advantages. Emissions of SO_2 and NO_x can be further reduced compared to atmospheric operation, and high density of the combustion gases means that more energy can be released in a given volume. This results in a significant reduction in the physical size of a pressurized fluid-bed combustor compared to an atmospheric unit of the same capacity, with a consequent reduction in capital costs. Some of the reduction in the capital cost will however be offset by the increased complexity of the pressurized unit, and the requirement for a pressure shell. A general impression of the expected size advantage of a pressurized fluid-bed boiler can be obtained from Figure 9.6.

Finally, a key advantage of pressurized fluidized bed combustion is the opportunity for increased power generation efficiency[1]. This increased efficiency is obtained by generating power in a "combined cycle", using both a gas turbine and a steam turbine. The pressurized hot combustion gases are used to run a gas turbine, while steam tubes in the bed provide steam for the steam turbine. In addition, exhaust gases from the gas

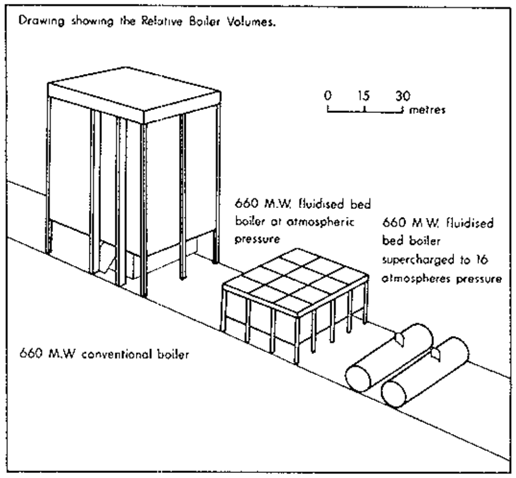


Figure 9.6 — Size advantage of fluidized bed combustion.

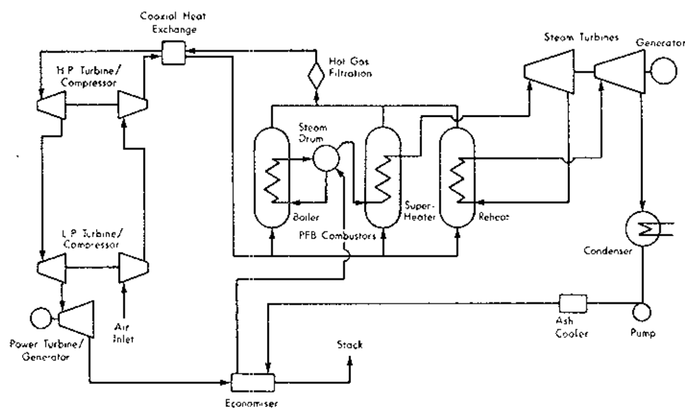


Figure 9.7 — Schematic of a combined cycle power generation system using pressurized fluidized bed combustion.

turbine are further used to help generate steam before being exhausted to atmosphere. A schematic of a combined cycle power generation system using pressurized fluidized bed combustion is shown in Figure 9.7.

A variation on this cycle, the so-called "air heater" cycle uses the tubes immersed in the bed to heat air which is then mixed with the combustion gases and used to drive the gas turbine. Gas turbine exhaust gases are used to generate steam for the steam turbine in a waste heat boiler. Using either appproach, the overall power generation efficiency can be raised from around 38 per cent for a conventional power station to approximately 40 per cent.

Pressurized fluidized bed combustion was pioneered in the United Kingdom by the National Coal Board and is currently at an advanced development stage. An experimental pressurized combustor of about 2 MW thermal output operating at up to 6 bar has been in operation since 1969 at the National Coal Boards Coal Utilization Research Laboratory (CURL) in Leatherhead, Surrey. A much larger 80 MW thermal output unit sponsored by the United Kingdom, the United States and West Germany under the auspices of the International Energy Agency is now being commissioned at Grimethorpe, Yorkshire in the United Kingdom. This unit will be used to obtain design data for full-scale commercial units. In the United States, the Curtiss-Wright Corporation is constructing a 40-MW thermal output unit based on the air-heater cycle in cooperation with the United States Department of Energy.

9.3.3 GASIFICATION/COMBINED CYCLE

Another approach to environmentally acceptable power generation from coal and higher efficiency is the gasification/combined cycle approach. In this method coal is first converted to a low or medium calorific-value gas, which is then used to fire a gas turbine and generate steam for combined cycle power generation. Several companies have been developing this approach, but the only large-scale installation to date is the Kellerman plant at Lunen in West Germany operated by STEAG, the German utility and engineering firm.

A diagrammatic representation of the Lunen Plant is shown on Figure 9.8. The plant utilizes Lurgi pressurized gasifiers and "supercharged" boilers to generate steam. These boilers operate with the combustion chambers under pressure, so that the flue gases can then be used to fire the gas turbine portion of the cycle. At the Lunen plant 74 MW is generated by the gas turbine, and 96 MW by the steam turbine. The main advantages of the gasification/combined cycle are increased efficiency and reduction of sulphur emissions by removing H_2S from the fuel gas which is formed during gasification.

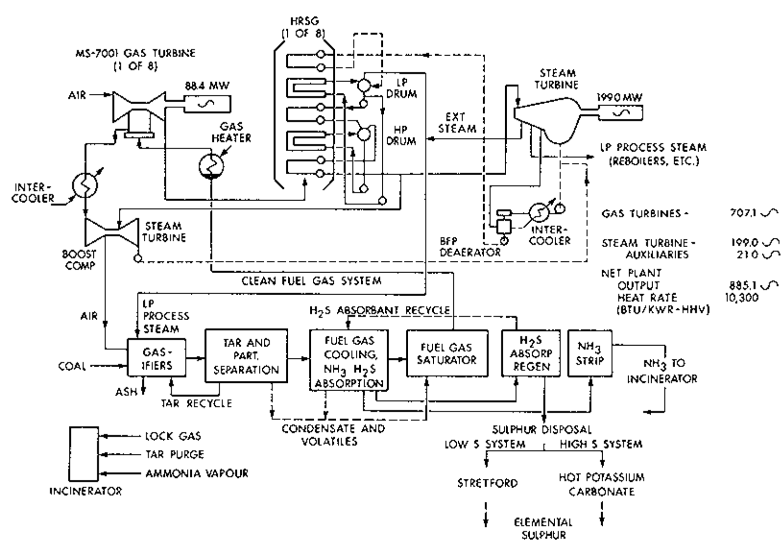


Figure 9.8 — Integrated gasification combined cycle plant.

9.4 COAL GASIFICATION

9.4.1 FUNDAMENTALS OF GASIFICATION

Combustion of a solid fuel may be simply described as a two-part process—in the first part, the solid carbonaceous material is gasified; in the second, the combustible gas so formed is burned with oxygen to produce heat. In normal combustion of solid fuel the speed of these reactions is such that they are virtually inseparable. The separation of the reactions, however, can clearly lead to a far more flexible use of the solid fuel, although loss in efficiency would result when converting to power or heat energy end-use. Gasification of coal as a separate process essentially involves the controlled addition of oxygen and hydrogen using steam and air or pure oxygen as reagents. Depending upon the conditions under which this reaction is performed, the gas produced contains various proportions of hydrogen, carbon monoxide, carbon dioxide, and methane. The content of the last component is relatively low in all, and virtually absent in some processes, with the result that the gas has a low heating value relative to natural gas. Product gas from an "air-blown" gasifier contains 50 per cent nitrogen and has a calorific value between 3.7 and 7.4 MJ/m^3. If pure oxygen is used, the calorific value may be raised to between 11 and 17 MJ/m^3.

Since the gasifier product contains both carbon monoxide and hydrogen, it is both a highly toxic gas and one with wide limits of inflammability, dangerous for its explosive characteristics. It is therefore not a desirable domestic fuel but can be utilized for industry; indeed, so-called "gas producers" have been used for many years to produce relatively small amounts of gas to furnish fuel for all types of furnaces.

Generated on a large scale, low and medium heating value gas can be considered as a fuel for the generation of electric power, as in the STEAG combined cycle technology, and as a raw material feed for the production of ammonia or of SNG (synthetic natural gas). Three commercially proven processes are available for the large-scale production of low and medium heating value gas. The operational characteristics and the products obtained with these processes are shown in Table 9.5.

In considering the applicability of gasification to British Columbia coals, however, it is important to note that the metallurgical coals of the Rocky Mountain region, being strongly caking, are less than ideal for current Lurgi or Koppers-Totzek reactor designs.

In addition to the above high-capacity gasifiers, there are modern versions of the old producer gas units suited to the daily production of the low heating value gas (6–7 MJ/m^3) in the 300 000 m^3/day range.

The Wellman gasifier is typical of this type and a range of standard sizes of them is in use. The largest gasifiers consume 90 to 110 tonnes of coal per day and yield 1.85 to 2.37 million megajoules per day as gas. Multiple gasifier installations are also normal, with a common gas purification section and with plant sizes ranging from 1 million to 32 million megajoules per day. Because of their small output and simplicity of operation, they are ideally suited to use by small steel plants, brick or ceramic ware manufacturers, and paper mills.

The coal for these small gasifiers must be noncaking or weakly caking and preferably in the size range 1.3–5 centimetres. Also, the ash fusion temperature of the coal should be above 1 200°C.

9.4.2 GASIFIER CONFIGURATIONS

Coal gasifiers may be grouped into three main categories according to the type of reactor configuration chosen. In a fixed bed gasifier, coal in lump size (approximately 5 cm) is introduced into the top of the gasifier while steam and air are introduced through the bottom of the vessel. The coal charge passes downward in the reactor passing successively through zones of devolatilization, endothermic gasification and finally combustion, which provides the heat of reaction for the process. The product gas moves up the reactor vessel and leaves from the top of the gasifier. Fixed bed gasifiers are characterized by low exit gas temperatures, high carbon conversion, and a high tar content in the product gas. The best known example of this type of gasifier is the Lurgi unit which operates at a pressure of up to 20 bar.

Fluidized bed gasifiers operate using finely crushed coal which is "fluidized" by the air or oxygen and steam entering the bottom of the reactor. These units usually produce less tar, but have a higher dust loading in the product gases than do fixed-bed gasifiers. The Winkler gasifier is a commercially proven unit of this type which operates at atmospheric pressure.

In the entrained bed gasifier both the coal and air or oxygen and steam enter the reactor from the bottom. The coal charge along with increasing amounts of product gas moves upwards in the reactor, so that the product gas is at a much higher temperature than in the other two gasifier types, which results in a very low tar production. The product gas dust loading can, however, be quite high, and small variations in coal quality can lead to wide variations in product gas composition. The Koppers-Totzek

TABLE 9.5. Characteristics of Three Commercially Proven Gasifiers

	Lurgi	Koppers-Totzek	Winkler
Developers and sponsors	Lurgi Gmb H	Koppers Gmb H	Winkler
Pilot plants	To date has built 14 commercial plants utilizing their gasifiers	Commercial, 16 plants since 1952	Commercial, 16 plants in operation
Future plans for process	Presently engineering four plants for the United States	Engineering studies being performed now for industrial application	Engineering studies in preparation for commercial units
Feedstocks	Flexible and capable of handling all types, except strongly caking coals	All ranks of coal, tar, pitch, coke, and other carbonaceous materials	Most ranks of coal can be used
Products	Pipeline gas, by-product oils, and sulphur	Synthesis gas and sulphur	Synthesis gas and sulphur
Process advantages	Only gasifiers that have long-term commercial operation	(1) No by-products other than slag and sulphur (2) Wide range of feed (3) Quick turn-down ratio (4) Feed can be charged	(1) H.C. liquors can be added during coal operation (2) No tars or oils produced
Process disadvantages	(1) Requires O_2 plant (2) Requires compression of product gas (3) Requires sized coal	(1) Low pressure-atmospheric (2) Requires O_2 plant (3) High-temperature gasifier operation, 3 000°F (4) High methanation requirements as 0% CH_1 produced (5) High compression requirements for pipeline gas	(1) Requires O_2 plant for high Btu gas (2) Low pressure-atmospheric (3) Coal drying may be required (4) 70 per cent of ash overhead (5) Reactor brick-lined (6) High methanation requirements as only 2% CH_1 produced (7) High compression required for pipeline gas requirements
Typical gasifier section Outlet composition	Mol. per cent (H_2O free)	Mol. per cent (H_2O free)	Mol. per cent (H_2O free)
CH_4	10	0	2
H_2	38	36	35
CO	24	56	48
CO_2	28	6	15
H_2S	—	—	—
Proposed gasifier requirements for a 250 MM scfd commercial plant	Gasifier section would consist of 25–30 fixed-bed reactors designed to operate at 400–450 psi	Gasifier can handle 850 t/d coal each; 18–20 gasifiers required	10–20 gasifiers required

gasifier is a commercially proven entrained bed gasifier which has been widely used around the world.

At present, there are many gasifiers under development with a view to increasing the unit size, efficiency, and flexibility of operation. Table 9.6 lists most of the gasifiers either now available or under development, broken down by gasifier type, operating pressure, and whether they are air or oxygen blown.

TABLE 9.6. **Characteristics of Some Gasifiers Commercially Available or Under Development**

Name	Developer	Reactor Type	Operating Pressure Range	Oxidant
	COMMERCIAL PROCESSES			
Koppers-Totzek	Koppers Co.	Entrained Flow	Atmospheric	Oxygen
Lurgi	Lurgi Gmb H	Moving Bed	Medium	Air/Oxygen
Wellman-Galusha	Wellman Engineering Co.	Moving Bed	Atmospheric	Air
Winkler	Winkler Co.	Fluidized Bed	Atmospheric	Air/Oxygen
	DEVELOPING PROCESSES			
Slagging Lurgi	British Gas/Lurgi Gmb H	Moving Bed	Medium	Oxygen
Shell-Koppers	Shell Research	Entrained Flow	Low	Oxygen
Texaco	Texaco Development Corp.	Entrained Flow	Medium	Air/Oxygen
Bi-Gas	Bituminous Coal Research Inc.	Entrained Flow	High	Air/Oxygen
CO_2 Acceptor	Conoco Coal Development Co.	Fluidized Bed	—	Air
COGAS	Consortium	—	Low	Air
GEGAS	G.E.	Moving Bed	Medium	Air/Oxygen
Hydrane	Pittsburgh Energy Research Centre	Fluidized Bed	High	Oxygen
Hygas	I.G.T.	Fluidized Bed	High	Oxygen
Rockgas	Rockwell International Corp.	Molten Salt	Medium	Air
Synthane	Pittsburgh Energy Research Centre	Fluidized Bed	High	Oxygen
Union Carbide-Battelle	Union Carbide/Battelle	Fluidized Bed	Medium	Air
Westinghouse	Westinghouse Research	Fluidized Bed	Medium	Air

9.4.3 IN SITU GASIFICATION

In situ gasification is a process whereby coal is converted into gaseous products in the ground by partial oxidation of the coal seam. This promises to offer economic advantages, as it eliminates the need for mining the coal, but trials to date have resulted in low gas yields and somewhat erratic operating reliability.

The technique of *in situ* gasification was first suggested in 1868 and since that time a number of countries have experimented with the process. The first significant production of gas from *in situ* gasification was in the Soviet Union during the 1930s. The technique developed in the Soviet Union was known as the "percolation" method—two boreholes were drilled into a coal deposit and the coal between the bottom of the two boreholes was made porous by hydraulic or air fracturing. The coal in the vicinity of one borehole was ignited and an air-steam mixture was injected into the second borehole. This mixture percolated through the fractured coal and gasified the coal near the combustion zone. The gas so produced was then collected through the first borehole.

The gas produced by this technique had a heating value of about 3.7 MJ/m^3 and was used primarily for electric power generation. A number of semi-commercial gasification plants using this method were constructed during the period 1936–65, and as much as 1.25 million m^3 per day were produced at a single plant. The results of the Soviet experiments showed that the heating value and the gas production rates tended to deteriorate fairly rapidly with time. In addition, it was found that the resource recovery was low since about 30 per cent of gas produced was lost underground and over half the coal was burned to carbon dioxide and water. As a result, the estimated energy recovery from the coal was only about 20 per cent.

Several *in situ* gasification experiments were conducted in the United States during the 1950s and 1960s, using basically the same technology as that developed in the Soviet Union. The results of these experiments generally confirmed the Soviet results that gas production and quality tended to deteriorate with time.

Since 1970, two major research programs in the United States have been initiated to determine the technical and economic feasibility of *in situ* gasification, using Wyoming coal.

(1) United States Bureau of Mines Experiment: Hanna, Wyoming

Gas production in this project started in March 1973. The percolation method of gasification was used to produce a low heating value gas at an average rate of 45 000 m^3 per day with an average heating value of 4.7 MJ/m^3. During the five and one-half-month period from mid-September 1973 to February 1974, relatively stable gas production rates and heating values were maintained. The energy recovery efficiency for this experimental program has been reported as about 50 per cent compared to 20 per cent for the Soviet experiments. Also, it is expected that efficiency could be increased to about 55 per cent with more efficient compressors and process control equipment.

(2) Lawrence Livermore Laboratory Experiment: Hemmer, Wyoming

A new technique for *in situ* gasification has been suggested by Higgins of the Lawrence Livermore Laboratory. This method involves the use of chemical explosives to fracture an underground coal zone to prepare it for gasification. Several collection wells are drilled to the bottom of the fractured zone and some of the wells are re-entered to gain access to the top of the zone. Oxygen is then injected into the top of the coal zone and combustion is initiated. The injection of oxygen is replaced by a mixture of oxygen and steam in order to gasify the coal. Gas collection takes place through the collection wells at the bottom of the fractured zone.

This system represents an underground packed bed reactor which should achieve more complete mixing between the reactant gases and the coal than the percolation method. As a result, it should be possible to gasify almost all of the coal in the fractured zone. Also, the impermeable region surrounding the fractured zone should prevent leakage of reactant gases and improve product gas recovery.

In April 1975 the Alberta Research Council presented plans for an *in situ* gasification program. This program consists of combined laboratory and field tests which are directed toward achieving sustained production of a low heating value industrial fuel gas for on-site steam raising and/or generation of electrical energy. The gasification process which is used in the program is similar to the percolation process; initially an air-steam gasifying mixture is used to produce a gas with a heating value of about 4.5 MJ/m^3. Consideration is also being given to using a gasifying mixture of oxygen and steam to produce a synthesis gas (syngas) composed primarily of carbon monoxide and hydrogen which could be used in the production of SNG, ammonia, methanol, and synthetic liquid hydrocarbons. The Alberta Research Council has conducted field trials at a site near Drumheller, Alberta and are continuing with laboratory studies.

9.5 COAL LIQUEFACTION

9.5.1 FUNDAMENTALS OF LIQUEFACTION

The production of liquid hydrocarbon fuels from coal involves increasing the hydrogen to carbon atomic ratio of the coal from approximately 0.8 to an average ratio of 1.5. This can be done by either adding hydrogen to the coal or by removing carbon, or by a combination of both. The production of gaseous products requires the hydrogen/carbon ratio to be increased still further. Two main process routes have been developed for the production of liquids from coal, both having their origin in Germany prior to World War II. In the so-called indirect liquefaction route, coal is first gasified and broken down into the basic chemical building blocks of carbon monoxide and hydrogen. These basic constituents are then synthesized into liquid products using a catalyst.

In direct liquefaction processes, coal is converted directly to liquid hydrocarbons by the application of heat and pressure and with the addition of hydrogen. A catalyst may be employed, depending on the product slate required and the particular process route chosen. This route involves less degradation of the original coal material than the indirect route, and theoretically results in a a higher thermal efficiency. Pyrolysis, the destructive decomposition of coal without the addition of hydrogen or oxygen, may be considered as an intermediate form of direct liquefaction. It results in a range of gaseous, liquid, and solid products which may be varied depending on the process conditions chosen. Although the liquid yield from pyrolysis is less than for direct or indirect liquefaction, it may prove to be an attractive option if an economic use can be found for all the products.

In Germany during World War II, there were 12 direct liquefaction plants producing 3 million tonnes per year of oil products and 8 indirect Fischer-Tropsch synthesis plants producing some 500 000 tonnes per year. These plants produced 90 per cent of the German aviation gasoline requirements, as well as a quantity of diesel fuel for the war effort. Most of these plants were destroyed toward the end of the war, although three of the synthesis plants were subsequently rebuilt. After the war, however, the ready availability of crude petroleum supplies resulted in a decreased interest in coal liquefaction, and the three rebuilt plants were shut down in 1962. The lack of interest in liquefaction continued until recent years, when the concern over the availability of crude oil resulted in a renewed interest in coal liquefaction.

9.5.2. INDIRECT LIQUEFACTION PROCESS DEVELOPMENTS

The only commercial coal liquefaction plants operating today are in South Africa and are based on the Fischer-Tropsch synthesis indirect liquefaction process. The SASOL I plant at Sasolburg was commissioned in 1955 and currently produces some 250 000 tonnes per year of liquid fuels from approximately 3.5 million tonnes per year of coal. This plant uses Lurgi fixed-bed gasifiers and two different types of synthesis reactors. The original reactors are Arge fixed-bed reactors while the newer units are Synthol fluidized-bed units, which maximize the production of transport fuels.

A second, much larger plant, SASOL II, has been constructed at Secunda, South Africa and the plant is now in full production. This plant consumes some 40 000 tonnes per day of coal and produces approximately 50 000 barrels per day of liquid transport fuels. This plant uses 36 Lurgi Mark IV gasifiers and 7 Synthol fluidized-bed synthesis reactors. It is designed to maximize production of transport fuels, but some chemical by-products including ethylene and alcohols are also produced. A duplicate plant, known as SASOL III, has recently been completed next to SASOL II. The two plants produce a total of some 100 000 barrels per day of transport fuels, equivalent to approximately two-thirds of the current British Columbia consumption of crude oil.

The Province of British Columbia has recently completed a pre-feasibility study to examine the technical and economic viability of a SASOL-type coal liquefaction plant at Hat Creek[3]. The plant design was based on SASOL II, with a product slate designed to maximize the production of gasoline. The plant was sited near the proposed British Columbia Hydro and Power Authority 2 000-MW power plant and it was assumed that the mine, water supply, ash disposal, and certain other facilities would be common to both plants. Earlier tests conducted by Lurgi for B.C. Hydro indicated that Hat Creek coal is a good feedstock for gasification, so that no technical difficulties were expected. A block flow diagram for the liquefaction plant is shown on Figure 9.9.

The Hat Creek liquefaction plant would consume approximately 54 000 tonnes per day of coal and produce 54 000 barrels per day of transport fuels, of which some 32 000 barrels per day would be gasoline. In addition, some 1 000 tonnes per day of chemical by-products, principally ethylene, would be produced. Table 9.7 shows the design product slate. In addition to the coal input, the liquefaction plant would have a power demand of approximatley 447 MW. With the product slate shown on Table 9.7 the calculated overall thermal efficiency of the plant was 43.7 per cent.

A new and promising development in indirect liquefaction is the Mobil MTG (methanol to gasoline) process which converts methanol directly to gasoline. This process has only been operated on a small pilot plant scale, but a 12 500-barrel-per-day plant is being proposed for New Zealand, using natural gas as the feedstock for production of methanol. It may be that synthesis of methanol from coal, followed by the MTG process would be a more effective way to produce gasoline than Fischer-Tropsch synthesis. This remains to be proven, however, and several feasibility studies are currently being conducted around the world. An interesting possibility for British Columbia would be the production of gasoline with the MTG process using natural gas initially as the feedstock, switching to coal when that appears to be more economic or a surplus of gas no longer exists.

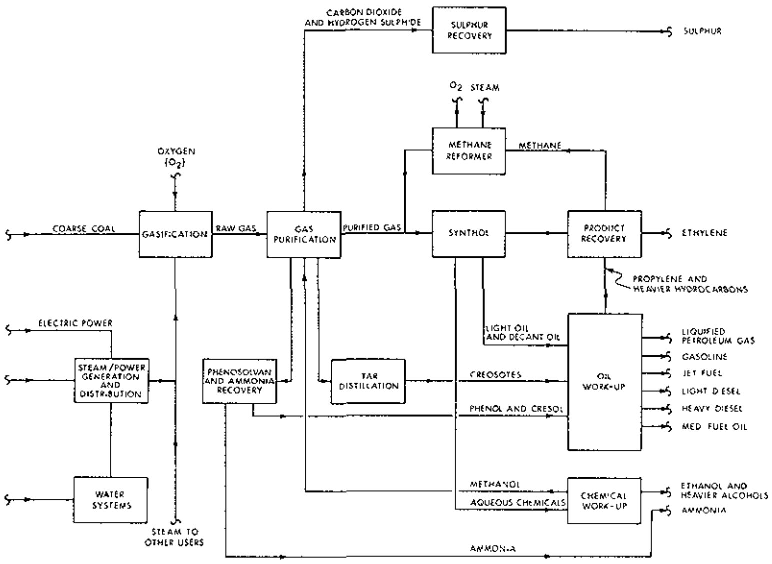


Figure 9.9 — Block flow diagram for a Hat Creek coal liquefaction plant.

TABLE 9.7. Product Slate — Hat Creek Coal Liquefaction Project

Product	(Tonnes per d)	Per cent of Production (%)	Fuel Equivalent (m³/d)	Fuel Equivalent (U.S. bbl/d)
Gasoline	3 569	46	5 105	32 110
Jet fuel	978	13	1 262	7 940
Diesel fuel	1 277	16	1 540	9 685
Medium fuel oil	106	1	119	750
Mixed alcohols	465	6	583	3 665
Ethylene	705	9	—	—
Ammonia	307	4	—	—
Sulphur	155	2	—	—
Liquefied petroleum gas (LPG)	194	3	—	—
	7 756	100	8 609	54 150

9.5.3 DIRECT LIQUEFACTION PROCESS DEVELOPMENTS

There are currently no commercial direct coal liquefaction plants in operation, although there is a great deal of development activity worldwide. In addition to many process-development units operating in the several hundred kilogram per day range, there are several large-scale pilot plants operating in the range of 10 to 600 tonnes per day. Most of these processes are based loosely on the original I. G. Farben direct liquefaction process developed prior to World War II. The new developments seek to improve the product yield and process efficiency and to reduce the severity of the operating conditions. The high level of interest in direct liquefaction processes reflects the fact that, at least in theory, they should provide a higher yield of transport fuels and higher overall thermal efficiency than indirect processes. Table 9.8 lists the process characteristics and present development status of a number of major direct coal liquefaction processes around the world. This table has been adopted from the United Kingdom National Coal Board report, "Liquid Fuels from Coal".

The various direct liquefaction processes currently operating at the large pilot plant scale differ in reactor configuration, catalyst addition, and the way in which hydrogen is added to the process. In the U.S. there are currently three processes which have been developed to the large pilot-plant scale, and each is unique, although they naturally show some common characteristics. As these three processes are currently the most advanced in the world, from the point of view of proximity to commercial development, a brief description of each will be given.

Solvent Refined Coal (SRC-II) Process

The initial concept of the SRC process was to use solvent refining to produce a de-ashed, low sulphur solid boiler fuel. This material was simply called solvent refined coal, or SRC, and was to be used primarily to generate electricity with significantly reduced emissions. With the increased world concern about availability of liquid petroleum products, a subsequent development of the process was undertaken to produce synthetic liquid fuels from coal. The original process to develop a clean solid boiler fuel was termed SRC-I, while the all-liquid products process was referred to as SRC-II. Most of the recent development has been concentrated on the SRC-II process.

A simplified flowsheet for the SRC-II process is shown on Figure 9.10. Pulverized coal is mixed with recycled coal/oil slurry and together with hydrogen pumped through a preheater to the main reactor. In the reactor coal is combined with the hydrogen and dissolved in the recycle oil. From the reactor, products pass first to a separator where gaseous materials are separated from the liquid and solid products, and then to a two-stage fractionation process. The atmospheric and vacuum fractionation towers produce the final naphtha and fuel oil products as well as a recycle slurry and heavy vacuum bottoms. The vacuum bottoms are sent to a gasifier which produces make-up hydrogen for the process and ash.

The SRC-II process is a non-catalytic process and relies on sulphur and minerals in the ash for some catalytic action. The process has been developed primarily for high-sulphur eastern bituminous coals, and early tests indicate that performance with low sulphur western coals is poor. The Gulf Oil Corporation, through its subsidiary Pittsburgh and Midway Coal Mining Co., has been operating a 50-tonne-per-day pilot plant at Fort Lewis, Washington, since 1974. The results from this pilot plant are currently being used to provide data for design of a commercial-scale 5 500-tonne-per-day plant.

Exxon Donor Solvent Process (EDS)

The Exxon Donor Solvent Process (EDS) has been developed by Exxon Research and Engineering Co. A one-tonne-per-day process development unit has been in operation since 1974, and a 425-tonne-per-day pilot plant is now in operation in Texas. A simplified flowsheet for the EDS process is shown on Figure 9.11.

TABLE 9.8. Characteristics of Some Direct Coal Liquefaction Processes

Process	Agency	Development Stage	Process Details	Reactor Conditions	Liquefaction Products
I. UNITED STATES					
Clean Fuel From Coal (CFFC)	C-E Lummus Company (Combustion Engineering Incorporated subsidiary)	Present process demonstration unit work under government contract is to be followed by project evaluation and pilot plant construction. Conceptual design of commercial size (11 400 t/d) CFFC plant has been prepared	Pulverized coal is slurried and partially digested in presence of aromatic recycle solvent. This is then hydrogenated in presence of catalyst. The Lummus antisolvent (e.g. straight-run kerosene distillates) de-ashing technique is applied to gravity separation of ash. Rotary filters, centrifuges, etc. are therefore not required.	In mixing zone and gravity settler, 260°C; 4 bar. In reactor, 415-438°C; 148 bar.	Fuel oil.
Exxon Hydrogen Donor Solvent	Exxon Corporation	Exxon operating a 1 t/d pilot plant at Baytown, Texas. Construction of 250 t/d pilot plant started. Total cost of project to be $240 million. Government paying half, Carter Oil, EPRI and Phillips Petroleum the rest. Carter Oil will operate the 250 t/d plant from 1980 to 1982.	Coal is heated with hydroaromatic solvent. Liquid products can be upgraded by catalytic hydrogenation. No filters or centrifuges for solids separation are required. The hydrogenation unit is separate from the liquefaction vessel.	370-480°C; 102-136 bar.	Naphtha blending stock for gasoline and fuel oil. Yield expected to be 0.3 to 0.4 t/t coal. Heavy materials go to fluid coking process such as Exxon Flexicoker.
H-Coal	Hydrocarbon Research Incorporated (Dynalectron Corporation subsidiary)	3 t/d process demonstration unit operating at Trenton, N.J. 250 t/d pilot plant being built under co-sponsorship of government, EPRI and several oil companies at Catlettsburg, Kentucky, adjacent to Ashland Oil Company refinery; operation planned Sept. 1978. (Original proposal was for 600 t/d capacity.) Montana State University, Universal Oil Products Company, and Chevron Research Company are studying upgrading of Syncrude to clean distillable fuel, and Dow Chemicals the use of Syncrude as source of petrochemicals.	Pulverized coal is slurried with coal-derived, recycled oil, mixed with H_2 and fed into ebullated bed with cobalt molybdate catalyst. Lummus to install its "anti-solvent" de-ashing technique.	454°C; 150-180 bar.	Syncrude, or low-sulphur fuel oil; 0.3 to 0.4 t/t.

PAMCO SRC	Pittsburgh & Midway Coal Mining Company (PAMCO) (Gulf Oil subsidiary)	50 t/d pilot plant at Fort Lewis, Tacoma, Washington operating since Sept. 1974. Process developed by PAMCO and Rust Engineering Company (Wheelabrator-Frye subsidiary) under government sponsorship. A 3 000-tonne test burn of SRC I in a power station in Georgia has been successfully completed. The plant has been altered to make all-liquid product (SRC II). Refining of SRC to liquid fuels is being studied by Air Products & Chemicals Incorporated, Universal Oil Products Company, Cities Service R&D, Chevron Research Company and Montana State University with government support. Government-supported Dow Chemical Company is studying SRC as source of petrochemicals. Wheelabrator-Frye Incorporated are designing a 1 000 t/d SRC I plant for Kentucky; the SRC to be consumed in Southern Company power plant. The SRC plant may later be extended to commercial scale of 15 000 t/d. Gulf seeks to commercialize SRC process in Japan and Germany, where it has patent rights. No rights in US to this process. Ralph M. Parsons Company, under government contract, designed 1 000 t/d demonstration plant using combined SRC-BIGAS gasification process; however, design not detailed enough for actual construction. Gulf Oil Corporation has proposed building 600 t/d demonstration plant for SRC II.	Pulverized coal is mixed with coal-derived anthracene oil and the slurry combined with H_2, sent through a preheater and then pumped to a dissolver; here, nearly 90% of the coal is dissolved under pressure and at elevated temperature. The coal solution is pumped to a rotary filter where, after removal of undissolved coal, it is washed with light solvent. Filtrate then goes to separator for vacuum flash distillation to remove solvent. Final SRC product is cooled and solidified. Filtration problems occurred on the 50 t/d plant and the SRC did not meet the EPA 90% SO_2 removal requirement. Changeover to SRC II eliminated solids removal problem and EPA standard could be met. Lummus may install their "anti-solvent" de-ashing technique to help overcome solids separation problems with SRC I.	454°C; 105 bar.	SRC (60% by wt. of feed coal). Black, brittle pitch-like solid (equivalent to some 3 bbl/t) to be tested as boiler fuel and molten as gas turbine fuel. SRC II product approximates No. 6 fuel oil. Sulphur content 0.4%, pour point 10°C.

Process	Agency	Development Stage	Process Details	Reactor Conditions	Liquefaction Products
II. UNITED KINGDOM					
Solvent extraction/ hydrogenation	National Coal Board, Coal Research Establishment, Cheltenham	2-litre stirred autoclave work. A 0.75 t/d extraction plant and a 0.025 t/d hydrogenation plant are operational. A 25 t/d plant is proposed. NCB/BP carrying out two-year study on coal liquefaction processes. Intend to build pilot plant to produce 20 t/d of liquids. Proposals for £25 million pilot plant put to Department of Energy.	Crushed coal is slurrried with anthracene oil and pumped to a digester operating at 370-450°C. Up to 85% of the coal dissolves. After filtering and solvent-stripping, the resulting liquid is fed to a hydrogenation reactor, employing cobalt/molybdenum catalyst. In the conceptual million t/a coal plant a solvent extraction stage would be followed by two hydrogenation stages; liquid hydro-treating and vapour-phase hydrocracking.	Hydrogenation reactor conditions: 400-480°C; 200-340 bar.	Light oil, middle oil, heavy oil (for recycling). Light and middle oils gave the following product yields: Petrol up to 0.15 t/t coal, 0.25 t/t distillate oil for gas turbine fuel and chemical feedstock.
Solvent extraction by supercritical gases	National Coal Board, Coal Research Establishment, Cheltenham	Batch extraction followed by semi-continuous work. A 0.1 t/d plant is operational. Pilot plant of 25 t/d envisaged. Final development stage seen as demonstration plant with throughout of say 2 500 t/d. Commercial plant is then envisaged as 4-stream operation processing some 3 million t/a coal. Economic study for such a plant has been carried out by Air Products & Chemicals Incorporated USA. ECSC support.	A stream of supercritical gas (e.g. toluene vapour) at 200-270 bar and 300-400°C is passed into heated bed of coal in extraction vessel. Coal constituents pass into gas phase leaving involatile residue of char and mineral matter. The gas phase containing the dissolved constituents is transferred to a vessel at atmospheric pressure, causing coal extract to precipitate and separate from the extracting gas.		Extract yields up to 50% can be converted to chemical feedstocks and liquid fuels.

Process	Agency	Project Details
III. WEST GERMANY		
Hydrogenation	Bergbau-Forschung Gmb H, Essen	0.25 to 0.5 t/unit to test feasibility of producing heavy and medium oil. Also examining possible catalytic effect of mineral matter in coal liquefaction.
	Chemisches Institut der Universitat, Tübingen	Carrying out literature study on liquefaction of coal using atomic hydrogen.
	Ruhrkohle AG, Essen (Sub-contractor STEAG)	Evaluating Stearns-Roger design study for construction of 6 000 t/d demonstration plant based on SRC II process.
	Saarbergwerke AG, Saarbrucken	Production of refinery products from bituminous coal by extraction and/or hydrogenation in laboratory apparatus. 6 t/d pilot plant planned to operate by 1979 using disposable iron catalyst.
	Technical University of Aachen	Development of cheap base-metal homogeneous catalysts.
	Technical University of Hanover	Autoclave work on hydrogenation of coal-in-water slurry at 380°C with H_2 or $CO+H_2$ and no catalyst.

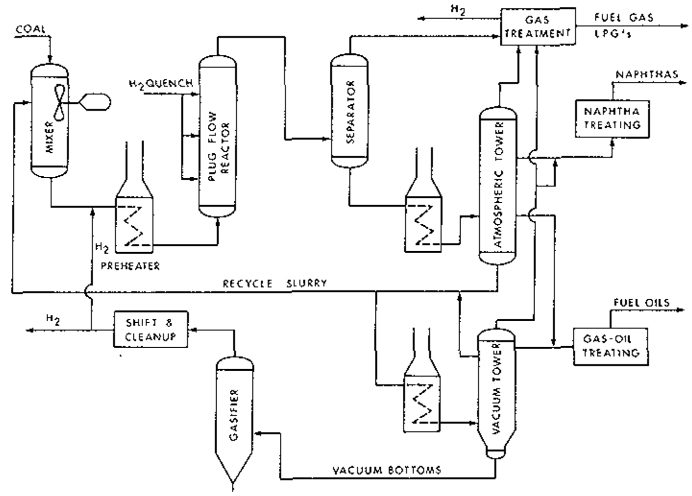


Figure 9.10 — Simplified flowsheet — SRC-II process.

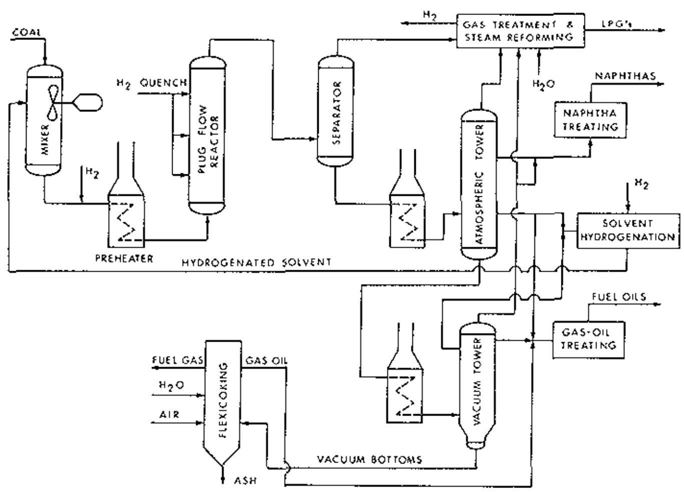


Figure 9.11 — Simplified flowsheet — EDS process.

Comparison of the EDS flowsheet with that for the SRC-II process indicates that the two processes are very similar in nature. The main difference is that the EDS process utilizes hydrogenated solvent for slurry preparation rather than slurry recycle. Catalytic hydrogenation of the solvent takes place as a separate step, and the "donor solvent" then provides the necessary hydrogen make-up for the liquefaction reactions. This separate solvent catalytic hydrogenation step means that the process is more flexible than SRC-II and can be applied to a wider range of coals. Another difference is that the EDS process uses a flexicoker to produce fuel gas and gas oil from the vacuum bottoms, while the hydrogen from the process is provided by steam-reforming the reactor gas products.

With operation of the 225-tonne-per-day pilot plant just beginning, process development is not as far advanced as for SRC-II. However, it is hoped that after two years operation at this scale, sufficient data should be available to design a commercial-scale plant with some confidence.

H-Coal Process

The H-Coal process has been developed by Hydrocarbon Research Inc. (HRI) as an extension of the H-Oil process used to upgrade residual oil. The process has been developed in a 2.5-tonne-per-day process development unit at Trenton, New Jersey and in a pilot plant at Catlettsburg, Kentucky. The process can be operated to maximize the production of heavy fuel oil, in which case the pilot plant has a nominal capacity of 600 tonnes per day, or to maximize the production of light distillate products, in which case there is a much higher recycle of solvent and the capacity is 250 tonnes per day.

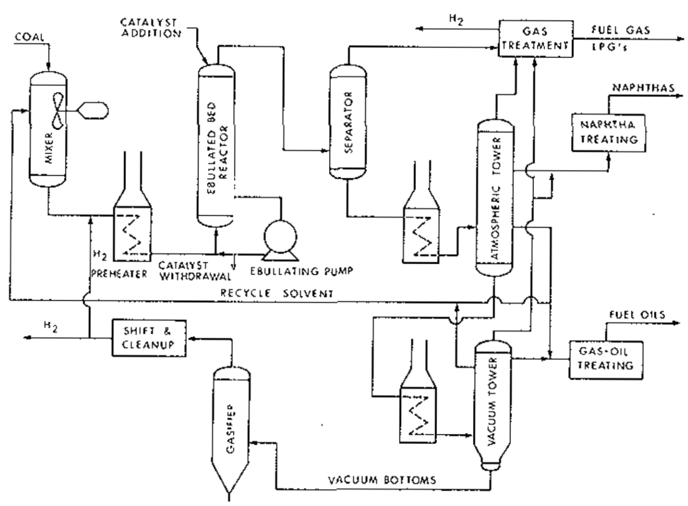


Figure 9.12 — Simplified flowsheet — H-Coal process.

A simplified flowsheet of the H-Coal process is shown on Figure 9.12. The main feature of the process is the so-called "ebullated-bed" reactor through which catalyst is continuously circulated with fresh catalyst being added during process operation. The ebullated-bed configuration is a three-phase fluidized bed in which gas, liquid, and solids are mixed and reacted. This design provides favourable conditions for the reaction of hydrogen, recycle solvent and coal in the presence of a catalyst. The rest of the process is very similar to the SRC-II process, with hydrogen being provided by gasification of vacuum bottoms in the commercial design. For the pilot plant at Catlettsburg, however, hydrogen is obtained from the neighbouring refinery in order to simplify the process.

Extensive testing at the process development unit scale has shown the H-Coal process to be capable of processing a wide range of coals. Some of the mechanical problems associated with all of the direct liquefaction processes will be examined during operation of the large pilot plant. Data from operation of this pilot plant will be used for design of a proposed 10 000-tonne-per-day commercial plant in Kentucky.

9.6 CONCLUSIONS

There are several coal utilization technologies currently under development which are of particular interest to British Columbia. With B.C. Hydro planning the first coal-fired power plant for the Province, combustion technologies are of immediate interest. Coal liquefaction is also important since the Province currently produces less than 10 per cent of its crude oil requirements from provincial resources. With strong reserves of natural gas, coal gasification is unlikely to be of interest for some time. Further, development of a substantial carbonization industry is unlikely unless a steel mill is built in the Province.

B.C. Hydro's proposed 2 000-MW power plant at Hat Creek will use conventional combustion technology, but there is a good possibility that an advanced technology could be utilized if a second plant were built. Pressurized fluidized-bed combustion is being examined by B.C. Hydro, with a view toward possible construction of a 180-MW combined-cycle pilot plant. If this pilot project does go ahead, it could provide British Columbia with a lead in producing power from coal with a minimum of environmental damage.

In many ways, coal liquefaction seems to be a natural technology for British Columbia. The only major energy resource in which the Province is not self-sufficient is crude oil. With abundant coal reserves, of widely differing characteristics, coal liquefaction could play a major role in making British Columbia energy self-sufficient and in reducing oil imports into Canada. Indirect liquefaction may be suitable in the near future, particularly at the large low-grade Hat Creek deposit, and this has been the subject of a study by the provincial government. In the longer term, direct liquefaction may provide higher yields and prove to be better suited to the higher quality coals. By utilizing natural gas as a source of hydrogen, British Columbia may even have an economic advantage in the production of liquid fuels from coal.

9.7 REFERENCES

B.C. Ministry of Energy, Mines & Petroleum Resources (1984): Hat Creek Coal Liquefaction Project, Steering Committee Report.

Evans, R.L., and Anastasiou, R. (1985): On the performance of pressurized fluidized bed combined cycles for power generation, Proceedings. *I. Mech. E.*, vol. 199, No. A1.

Science Council of British Columbia (1980): Opportunities for Coal Liquefaction Research in British Columbia.

U.K. National Coal Board (1978): Liquid Fuels from Coal.

X. COAL MARKETS

10.1 INTRODUCTION

British Columbia's coal markets lie almost entirely outside the Province's boundaries and in most cases are outside Canada's national boundaries as well. This is in sharp contrast to earlier coal-mining days, when much of British Columbia's coal production was used as a fuel for the transportation industry and for domestic and commercial heating. The coal industry grew vigorously in the early half of the century, based on the use of coal as a primary source of energy in Canada. Subsequently coal production declined sharply from levels of 2 to 3 million tonnes per year to 0.7 million tonnes in the 1950s and 1960s as the use of petroleum increased. However, as export markets for metallurgical coal developed, British Columbia's coal industry recovered and production rose steadily during the 1970s. This trend continued in the early 1980s when demand for export metallurgical coal rose sharply and when export markets for thermal coal also developed. By 1984, as Table 10.1 shows, British Columbia had become the third largest exporter of metallurgical coal in the world. With the development of recently discovered high quality anthracite underway, British Columbia has the potential of becoming a major anthracite exporter as well.

This chapter examines British Columbia's current and future coal markets. The structure of existing markets is described, followed by discussion of expected demand during the remainder of the decade. Domestic and export markets for metallurgical and thermal bituminous coal and for anthracite are covered in this review.

TABLE 10.1. World Seaborne Bituminous Coal Exports — 1984[1]
(Million Tonnes)

Country	Thermal	Coking	Total Coal
Australia	28.9	47.0	75.9
U.S.A.	10.3	44.7	55.0
S. Africa	30.6	4.8	35.4
Canada	4.0	21.1	25.1
(B.C.)	(3.5)	(16.3)	19.8
(Alta.)	(0.5)	(4.3)	(4.8)
(N.S.)	(—)	(0.5)	(0.5)
Poland	17.7	7.0	24.7
Other[2]	8.0	6.5	14.5
World Total	99.5	131.1	230.6

[1] Estimate
[2] Includes USSR, PRC, UK, FRG, and others.

10.2 STRUCTURE OF MARKETS

Table 10.2 lists the destinations and types of coal shipped by British Columbia's producers since the development of metallurgical export markets in 1968. As the table indicates, metallurgical coal currently accounts for the bulk of British Columbia's coal shipments, representing 80 per cent of sales in 1984. Since 1982, however, thermal coal shipments have increased sharply, doubling their share of total coal shipments to 20 per cent.

10.2.1 METALLURGICAL COAL

As Table 10.2 illustrates, metallurgical coal shipments increased dramatically in 1984, rising by 75 per cent to 16.3 million tonnes, after averaging 9.5 million tonnes over the preceding five years. This large increase was caused by the build-up of output from four new mines — Quintette, Bullmoose, Greenhills and Line Creek, which commenced production in 1982 and 1983. These mines, representing an additional metallurgical capacity of 10 million tonnes, were brought into production

TABLE 10.2. British Columbia Bituminous Coal Sold and Used (1968–1984)
(Thousand Tonnes)

	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Japan																	
metallurgical	408	296	1621	3687	5166	6625	6922	7621	6297	6804	6910	7839	7449	7357	6322	6359	11745
thermal	–	–	–	–	–	–	–	86	132	61	109	72	219	136	300	275	964
South Korea																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	798	980	1696	1305	1586	1955
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	691	431	1266
Taiwan																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	57	211	274	520	564	573
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	27	173
Hong Kong																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	177	189	192
Other Asia																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	24	105	147	143	159
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	70	47
Brazil																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	255	289	430	–	361	589
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Other Amer.[1]																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	109	163	489	83	133	241
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	45	67	158	259
Denmark																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
thermal	–	–	–	–	–	–	–	–	–	–	–	133	252	319	330	346	330
Sweden																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	49	49	164	–	99	216
thermal	–	–	–	–	–	–	–	–	–	–	–	–	35	–	–	–	–
France																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	224
thermal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	111
Other Europe[2]																	
metallurgical	–	34	127	188	46	–	123	239	361	657	1321	319	348	–	–	51	566
thermal	–	–	–	–	–	–	319	243	280	434	360	–	–	109	–	–	200
TOTAL EXPORTS																	
metallurgical	408	330	1748	3875	5212	6625	7045	7860	6658	7461	8231	9426	9514	10515	8377	9296	16270
thermal	–	–	–	–	–	–	319	329	412	495	469	205	508	611	1564	1496	3542
DOMESTIC																	
British Columbia																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	7	35	–	16	16
thermal	79	85	107	67	65	68	43	55	67	64	62	59	50	27	43	68	64
Canada																	
metallurgical	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	16
thermal	155	134	286	–	–	–	134	436	234	249	402	714	611	303	639	599	831
Total Coal Sold & Used																	
metallurgical	408	330	1748	3875	5212	6625	7045	7860	6658	7461	8231	9426	9521	10550	8377	9317	16302
thermal	234	219	393	67	65	71	496	820	713	808	933	978	1169	941	2246	2163	4437
GRAND TOTAL	642	549	2141	3942	5277	6696	7541	8680	7371	8269	9164	10404	10690	11491	10623	11480	20739

[1] Includes U.S., Mexico and other Latin America.
[2] Includes Eastern Europe and North Africa.
From 1968–1978 all exports, including Japan.

following the signing of export contracts with Japan and South Korea between 1980 and 1981. Total metallurgical capacity now stands at 21 million tonnes. Details regarding the current capacity of each producer are given in Table 10.3.

Shipments continue to increase in 1985 due largely to the build-up of production at these new mines. By year-end, metallurgical coal exports are likely to total 19 million tonnes. At this level of shipments, British Columbia will supply 12 per cent of world *metallurgical coal imports in 1985. This would represent 80 per cent of Canada's* projected 1985 metallurgical coal exports of 24 million tonnes.

Additional coal production capacity in Canada (and Australia) has come at a difficult time for Japan which contracted for 18 million tonnes of additional production from these sources in the early 1980s in anticipation of growing steel demand. The decline in Japan's steel production has resulted in Japan having a contracted overcommitment of 18 million tonnes of metallurgical coal or 30 per cent of total steel industry coal consumption. To compensate for this the Japanese steel industry has reduced metallurgical coal purchases from their established coal producers worldwide. In British Columbia's case, Westar's and Fording's shipments to Japan have been reduced by 30 per cent of contracted volumes since 1983. These volume cuts (and related price cuts) have been consistent with those received by coal producers in other countries. Acting to offset their hard coking coal tonnage loss, coal producers have begun to sell semi-soft coking coal to Japan's steel mills.

TABLE 10.3. Current British Columbia Coal Production Capacity (Million Tonnes)

Producer	Metallurgical	Thermal	Total Capacity
Westar — Balmer	6.0	1.0	7.0
— Greenhills	1.8	1.1	2.9
Fording	5.0[1]	—[1]	5.0
Byron Creek	—	1.3	1.3
Line Creek	1.3	1.7	3.0
Quintette	5.0	1.3	6.3
Bullmoose	2.0	0.1	2.1
Wolf Mtn.	—	0.1	0.1
Total	21.1	6.6	27.7

[1] Fording produces less than 10 per cent oxidized metallurgical coal as a thermal product.

Despite reductions in purchases from individual mines by the Japanese steel industry, Japan remains by far the largest consumer of British Columbia's metallurgical coal. Japan took almost 12 million tonnes or 72 per cent of British Columbia's metallurgical coal shipments in 1984. Its share of total shipments, however, has fallen steadily since 1973 when it took 100 per cent of all metallurgical coal production. The growth of export opportunities in South Korea, Taiwan, other Asia, Latin America, Europe and Africa is expected to further reduce Japan's market share.

South Korea is British Columbia's next largest customer, taking 2 million tonnes or 12 per cent of metallurgical coal shipments in 1984, followed by smaller shipments to European countries of 1.0 million tonnes, 0.8 million tonnes to Latin America, and 0.7 million tonnes to other Asian countries.

10.2.2 THERMAL COAL

Thermal coal shipments from British Columbia increased significantly in 1984 reflecting the trend in many countries to substitute thermal coal for oil. At 4.5 million tonnes, thermal coal shipments in 1984 were double the level of the previous year. The increase in production was largely due to the continuing buildup of shipments from three new mines — Quintette, Greenhills and Line Creek, and the expansion of Byron Creek. South Korea represented the largest export market for thermal coal in 1984, taking 1.3 million tonnes for the country's electricity generating and cement industries. The second largest market was Japan's cement and steel industries. At 1 million tonnes, exports to Japan were only slightly larger than the 0.9 million tonnes of domestic shipments, most of which were used to generate electricity in Ontario. Europe took 0.6 million tonnes, followed by other Asian countries at 0.4 million tonnes and Latin America, 0.3 million tonnes.

In both the thermal and metallurgical coal markets, British Columbia faces competition from a number of coal-producing regions, including, in Canada, Alberta and to a smaller extent Nova Scotia. Alberta competes with similar quality metallurgical and thermal coals but Nova Scotia's high fluidity, low ash metallurgical coal is so unique in Canada that, although it is high volatile coal, it has totally different blending characteristics to British Columbia's low fluidity, moderate ash coal and does not compete directly. In the markets served by British Columbia, the principal foreign competitors are Australia and the United States. South Africa, China and the U.S.S.R. have also provided increasing amounts of competition in recent years. The large number of suppliers in most markets reflects the fact that coal importers like to diversify their supply sources. This may be attributed to the technical advantages of blending coal from different sources and a desire to increase security of supply.

10.3 FUTURE METALLURGICAL COAL MARKET

10.3.1 DOMESTIC METALLURGICAL COAL MARKETS

As shown in Table 10.2, the Canadian market for metallurgical coal is not a factor in British Columbia's coal industry. The major domestic market for metallurgical coal consists of steel mills in Eastern Canada. Here coal producers in Western Canada are at a transportation cost disadvantage relative to mines in the Eastern United States.

Studies of the Canadian metallurgical coal market show minimal potential in the domestic market for British Columbia producers[1]. The Steel Company of Canada Limited (STELCO) is involved in the proposed property in Southeast British Columbia. Development of this project could result in a significant shipment of metallurgical coal to Ontario. However, this mine was not under active consideration for development as of 1985.

It should be noted that, technically, it is possible to produce good quality coke in British Columbia from Canadian coal. However, construction of a major coking operation in British Columbia is not expected in the near future, unless a steel complex is built as well. The feasibility of building a blast furnace steel mill in British Columbia was examined in the mid 1970s[2] but the studies undertaken were not able to justify such an operation on economic grounds.

10.3.2 EXPORT MARKETS FOR METALLURGICAL COAL

Due to British Columbia's location with respect to the major steel-producing regions, the Pacific Rim is the predominant market for the Province's metallurgical coal. Within this region, Japan is by far the major consumer. Consequently, the Japanese and non-Japanese coal markets are reviewed separately.

10.3.2.1 Japanese Metallurgical Coal Markets

Japan has approximately 155 million tonnes of annual crude steel production capacity. Actual production in 1984 was only 106 million tonnes. This was 6 per cent more than that of the previous year and represented a continuation of the recovery begun two years earlier, following a three-year, 17-million-tonne (15 per cent) decline in Japanese crude steel output from 1980 to 1982. Table 10.4 shows how the industry has performed in recent years.

---

[1] Canadian Energy Research Institute, Development Options for British Columbia Coal, 1983.

[2] Nippon Kokan KK, Summary Report — B.C./NKK Steel Mill Feasibility Study Report, Volume I, Phase II, 1976.

TABLE 10.4. Japanese Crude Steel Production[1] (Million Tonnes)

1966	51.9	1976	108.3
1967	63.8	1977	100.6
1968	69.0	1978	105.1
1969	87.0	1979	113.0
1970	92.4	1980	107.4
1971	88.4	1981	103.0
1972	103.0	1982	96.3
1973	120.0	1983	100.2
1974	114.0	1984	106.5
1975	101.6		

[1] Fiscal Year Basis.

The cyclical pattern in Japanese crude steel production since 1980 has been similar to that experienced by other world producers. As Figure 10.1 and Table 10.5 illustrate, a serious decline in world steel production, which began in 1980 and which saw world production fall 102 million tonnes or almost 15 per cent, ended only in 1983 with a recovery in U.S. production, followed in 1984 by strong recoveries in the EEC and Japan. A continued increase is likely in 1985, albeit somewhat smaller, due to a general slowdown in many of the world's economies.

Recent forecasts of crude steel production in Japan are considerably reduced from those which prevailed in the mid-1970s, when many observers (including the Japanese Steel Industry) believed that Japan would be producing between 170 and 200 million tonnes of steel by 1985. There are a number of reasons for substantially lower growth rates in the Japanese steel industry. First, the energy shocks of 1973 and 1979 significantly affected the growth of the domestic economy and the economies of the countries which provided markets for Japanese steel exports. Second, the Japanese steel industry has faced increased competition in steel and steel products from newly emerging less-developed countries. Third, Japan is experiencing increasing problems in access to markets in the United States and in Europe, as these countries have raised tariff and non-tariff barriers to protect their domestic industries. Fourth, because of pollution and land use problems in Japan the expansion of steel and heavy industry has become more difficult.

In addition to the above conventional cyclical demand explanations, an increasing number of observers believe that major structural changes in world steel markets have been underway since the mid-1970s. From this point of view the steel intensities[1] of the U.S., the EEC and Japan, peaked in the 1950s, 1960s and 1970s, respectively. Steel intensity, it is contended, generally follows a four-stage development process comprising pre-growth, strong growth, maturation and slow decline phases. On this basis Japan's crude steel consumption is expected to decline along with the U.S. and the EEC. At the same time, consumption in developing countries that are in the strong growth stage, such as South Korea, China, Taiwan, and Brazil, would increase rapidly.

With the rapid rise in energy and other costs, Japanese industry, including the steel industry, has found it increasingly difficult to compete in international markets and there is little doubt that a structural shift away from energy intensive heavy industry has occurred. As far as steel is con-

[1] The ratio of steel consumption to Real Gross National or Domestic Product.

cerned, these adjustments have included the switch to less capital intensive investments, steel substitution and steel process technological shifts (increased use of continuous casting and electric steel mini-plants), and steel product mix changes (a shift to lighter, high quality specialty steels) which have all had the effect of reducing blast furnace crude steel output.

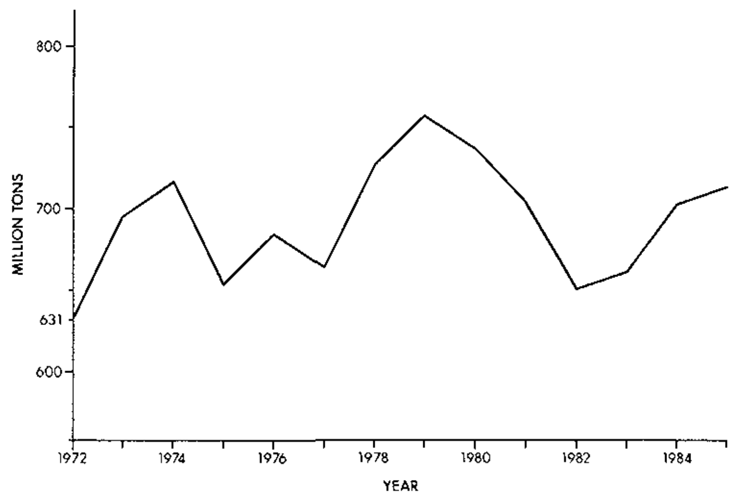


Figure 10.1 — World crude steel production [Source: Eurostat, Iron and Steel, 1952–1982; The Steel Market in 1983, OECD; ITSI, 1983(1), 1985(8)].

TABLE 10.5. World Crude Steel Production (Million Tonnes)

	1973	1977	1979	1982	1983	1984	1985
U.S.A.	136.8	113.7	123.7	67.7	76.8	84.5	80.6
Canada	13.4	13.6	16.1	11.9	12.8	14.7	14.2
EEC (9)	150.1	126.1	140.2	(110.5)			
EEC (10)	150.8	126.7	141.2	111.4	109.5	121.2	120.0
Other West. Europe	29.1	29.0	33.5	32.9	34.2	35.6	35.8
Japan	119.3	102.4	111.7	99.5	97.2	105.6	106.5
Australia and New Zealand							
OECD	456.6	392.4	433.6	330.1	336.3	367.0	363.5
South Africa	5.7	7.3	8.9	8.2	7.0	7.8	8.2
Latin America	16.7	22.0	27.5	27.1	28.9	31.9	33.3
Other Africa	0.9	1.4	1.4	1.5	1.9	2.1	2.1
Middle East	0.9	2.5	2.9	2.9	3.3	3.6	3.6
India	6.9	10.0	10.1	11.0	10.3	10.5	10.9
Other Asia	3.1	8.3	12.9	18.1	19.4	21.0	21.4
Total	28.5	44.2	54.8	60.7	63.8	69.1	113
Western World	490.8	443.9	497.3	398.9	407.1	443.9	443
Eastern Europe (including U.S.S.R.)	178.3	204.2	209.4	203.5	210.8	215.0	215
China and N. Korea	28.1	27.7	39.9	42.9	45.8	48.0	52
World	697.2	675.8	746.6	645.3	663.7	706.9	710

Source: OECD. World Steel Markets.

Nevertheless, it must be pointed out that an explanation relying solely on a steel intensity analysis, is not substantiated by evidence. Such an approach, in the case of Japan, is simply one particular interpretation of the unprecedented world economic disorder that has occurred since 1973. As if to underscore this uncertainty, the steel intensities of the U.S., the EEC and Japan have all risen since the end of the worldwide 1981-1982 recession.

An alternate approach often used to assess trends in world steel consumption is per capita steel consumption. Figure 10.2 shows U.S., EEC and Japanese per capita steel consumption between 1952 and 1982. On this basis, Japanese steel consumption would be expected to increase in line with population increases, following completion of any steel adjustment process. This approach suggests crude steel production in Japan will increase by roughly 1 million tonnes per year.

In the 1980-1981 period, when contracts for Northeast coal were signed, most forecasts predicted that Japanese crude steel production would be about 125 million tonnes in 1985 and 135 million tonnes in 1990 compared, to 103 million tonnes in 1981. However, steel production has only risen 3 million tonnes since 1981 as the Japanese steel industry has faced limited domestic and foreign demand and growing competition from developing countries. By 1984, Japan itself was importing 6 million tonnes of steel from developing countries, an increase of almost 5 million tonnes since 1981. Structural changes within the Japanese steel industry have also caused a decline in the demand for metallurgical coal. Since 1981, electric furnace production has increased by 15 million tonnes, to 30 million tonnes in 1984. The increase has been caused largely by the availability of cheap steel scrap which has been in oversupply during the period. The increase in the industry's coke rate (kg of coke per tonne of pig iron) which stood at 804 in 1984, following the introduction of pulverized coal injection to replace oil/tar additives in blast furnace operations over this period, has only been a marginal 5–7 kg.

Problems of limited domestic and export demand are expected to continue into the medium term. As a result most forecasts, as of the middle of 1985, predict that Japanese crude steel production will range between 95 and 110 million tonnes for the rest of the 1980s.

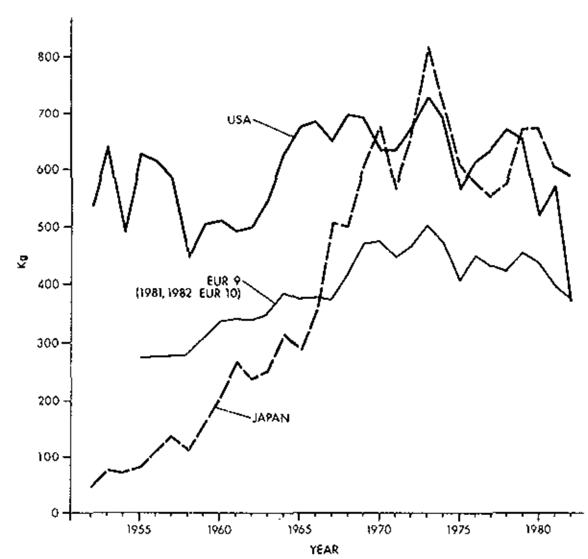


Figure 10.2 — Steel consumption per capita (ECSC and non-ECSC steel) (Source: Iron and Steel, 1952–1982, Eurostat, Luxembourg, 1983).

Table 10.6 shows the sources of Japanese metallurgical coal imports in recent years. Canada is Japan's second largest supplier, accounting for 16.4 million tonnes or 24 per cent of the market in 1984. Of this amount, British Columbia provided approximately 72 per cent. Metallurgical coal imports are mostly used by the steel industry. The gas and coke industries as well as other small users consume 5 to 6 million tonnes of imported metallurgical coal as well. The Japanese demand for metallurgical coal is partially met by domestic coal mines, which supply 3 million tonnes per year.

TABLE 10.6. Japanese Metallurgical Coal Imports[1]
(Million Tonnes)

Source	1984	1983	1982	1981	1980
Australia	29.8	28.5	27.1	27.3	26.5
Canada	16.4	11.4	9.4	9.3	11.2
South Africa	4.6	3.6	3.0	3.1	2.9
U.S.A.	14.2	15.4	19.8	23.7	20.8
U.S.S.R.	1.5	1.5	1.2	1.0	2.0
Other	1.6	1.8	1.7	1.5	1.4
TOTAL	68.1	62.2	62.2	65.9	64.8

[1] Fiscal Year Basis.

As a result of the Japanese steel industry's contractural commitments, signed in the early 1980s, to develop new sources of metallurgical coal from new operations at Greenhills and Line Creek in Southeast British Columbia and Quintette and Bullmoose in the Northeast part of the Province, British Columbia's share of the Japanese metallurgical coal market will double from 11 per cent in 1981 to 22 per cent or 15 million tonnes in 1985. Canada's share in 1985 is likely to be 26 per cent of expected total imports of 69 million tonnes or 18 million tonnes.

10.3.2.2 Other Foreign Metallurgical Coal Markets

British Columbia's metallurgical coal export markets outside Japan are also expected to be concentrated in the Pacific Rim during the remainder of the decade. South Korea will remain the major member of this group. Taiwan, possibly India and Latin American countries such as Brazil and Chile, may also provide a regular market for British Columbia coal. These countries represent areas where steel production growth is expected to occur during this decade. Shipments to Europe which increased dramatically to 1 million tonnes in 1984 will continue to represent an important market.

South Korea became a significant market for British Columbia coal producers with the establishment of an integrated steel facility by the Pohang Iron and Steel Company (POSCO) in the early 1970s. Since it began operations, POSCO has expanded production capacity from 1.0 million tonnes per year to 9.1 million tonnes per year. POSCO has for the most part been able to operate at close to full capacity even when most other steel producers have been forced to operate at much lower capacity utilization ratios. POSCO has begun construction of a second mill at Gwangyang. Stage 1 start-up is scheduled for 1987 and Stage 2 for 1989. Both stages are intended to produce 2.7 million tonnes each giving POSCO a capacity of 14.5 million tonnes by 1989.

Canadian producers have been very successful in supplying Korea's metallurgical needs, with 30 per cent or 2.3 million tonnes of POSCO's total 1984 coal requirement of 7.6 million tonnes coming from Canada. British Columbia accounts for the majority of these shipments. As POSCO's annual coal requirements are expected to increase to 12 million tonnes by the end of the decade, there is potential for increased sales from British Columbia. POSCO's 20 per cent ownership of the Greenhills mine operated by Westar Mining indicates Korea's long-term commitment to British Columbia's coal industry.

Taiwan purchases coal through the China Steel Company. China Steel has signed long-term contracts with producers in British Columbia that call for shipments of over 600,000 tonnes per year into the next decade, representing 25 per cent of Taiwan's current metallurgical coal demand. As Taiwan's requirements are expected to grow from 2.5 million tonnes per year to 4 million tonnes by the end of the decade, opportunities for further shipments will likely develop.

Although India has not been a market for British Columbia coal, it has the potential to become a regular customer. The Indian steel industry is engaged in a major expansion and modernization program which calls for upgrading of existing plants and the construction of three new mills, the first to be completed by 1986. Although planned Indian coal supply capacity should meet the demand from the steel industry, the low quality of Indian coal plus low operating rates in Indian coal mines result in a demand for foreign coal for blending with domestic coal. Annual imports may reach 2 to 3 million tonnes during this decade. British Columbia's coal meets the quality requirements of the Indian steel industry and has a good chance of acceptance in this market.

Pakistan has a contract with a British Columbia producer for 0.3 million tonnes annually or 30 per cent of current demand. Future steel industry expansion is likely to utilize natural gas in a direct reduction process rather than coal.

Latin America is expected to show growth in metallurgical coal consumption during this decade, particularly in Brazil. Metallurgical coal imports in Latin America could go from 8 million tonnes in 1984 to in excess of 12 million tonnes by 1990. British Columbia producers have signed long-term contracts with Mexico, Chile, and Brazil. Exports to Latin American countries totalled 0.8 million tonnes in 1984 and British Columbia producers will likely more than double exports to this market by 1990.

It has always been difficult for British Columbia producers to sell metallurgical coal in European markets due to locational disadvantages relative to suppliers in the Eastern U.S. and Poland. This disadvantage has been partly overcome since 1981, however, with the general 50-per-cent decline in ocean-shipping charges. Into Europe, Canada's freight disadvantage has been reduced to U.S. $4.00–6.00 tonnes for Panamax cargoes. The European Steel industry is currently rationalizing, reducing capacity and cutting subsidies on production. The result will be an increase in steel imports and, in some cases, a reduction in coking coal demand. At the same time the European coal industry, which is heavily subsidized, is being rationalized. On balance, current expectations hold that metallurgical coal imports will increase, possibly strongly. The most likely markets for British Columbia coal are countries which do not face severe rationalization of their steel industries or which face rationalization of their coal industries, for example, the U.K., Belgium, France or Turkey. British Columbia producers have been successful in signing at least one long-term contract that will see up to 165 000 tonnes per year being shipped to Swedish producers over a 5-year period.

In addition to the above shipments which are expected on the basis of long-term contracts, there will continue to be spot market sales to countries such as Algeria, Egypt and Yugoslavia. These account for only a small portion of British Columbia's coal sales.

10.4 FUTURE THERMAL COAL MARKETS

10.4.1 DOMESTIC THERMAL COAL MARKETS

The primary use of thermal coal in Canada is expected to be for the generation of electricity. However, while coal will be an important source of energy in Eastern Canada and the Prairie provinces, no coal-fired electrical capacity is forecast for British Columbia during this decade. Plans had been made by B.C. Hydro for a 2 000 megawatt plant consuming 10.0 million tonnes of coal annually to be in place at Hat Creek in the late 1980s. However, falling demand forecasts and rising cost estimates resulted in the project first being reduced in size and then postponed indefinitely. A potential coal-fired plant using reject coal in the East Kootenay area has been considered as well but this has also been placed on hold.

Coal-fired electrical production is expected to increase on the Prairies, particularly in Alberta and Saskatchewan. However, local coal resources will be available for this purpose. The only domestic electrical market for British Columbia thermal coal will come from Ontario Hydro. However, Ontario Hydro's immediate plans call for increased use of nuclear energy and reduced coal purchases. Therefore, shipments to this market are expected to remain at or below current levels, until the 1990s.

Conversion to coal for energy generation is an option for a number of producers in the Province. Cement, lime and coal producers commenced conversion in 1984, and some pulp and paper manufacturers are currently testing coal as a substitute for oil in their boilers. As Table 10.7 shows, plans already in place call for a total industrial coal demand in British Columbia of 0.5 million tonnes by 1986, up from less than 0.1 million tonnes in 1983. Including conversion in the pulp and paper industry demand could exceed 1 million tonnes by 1990. The timing of conversion will depend mostly upon the relative prices of coal and natural gas. Currently, as Table 10.8 shows, industrial natural gas is 60–100 per cent more expensive than coal. Natural gas deregulation can be expected to reduce this price trade-off only moderately.

10.4.2 FOREIGN THERMAL COAL MARKETS

Projections made at the beginning of the 1980s called for enormous growth in world thermal coal demand during the rest of the decade. These projections were later reduced as the long-term demand for electricity and for products which involve the use of thermal coal was thought to have radically declined. Recent recoveries in electricity demand worldwide have seen some upward adjustments in these earlier forecasts. Although sustained low world oil prices would affect the rate of growth in thermal coal demand, on balance there are good prospects for significant demand growth.

10.4.2.1 Japanese Thermal Coal Markets

As a result of increases in the price of oil during the 1970s, Japan like other countries, began converting to other forms of energy, including thermal coal. Targets set by the Japanese government call for petroleum's share of the country's energy supplies to fall from 75 per cent in 1977 to slightly more than 50 per cent by 1990. The share provided by imported thermal coal is expected to exceed 5 per cent by 1990 and to total 10 per cent by 2000.

Thermal coal imports have grown very rapidly in Japan. Such imports were less than 1 million tonnes before 1978 but by 1984 they had grown to 19.4 million tonnes. Table 10.9 shows the sources of thermal coal imports in recent years. Australia has become the dominant supplier in the market, providing over 60 per cent of thermal coal imports. Canada's share is slightly less than 5 per cent of which the major portion has recently been from British Columbia.

TABLE 10.7. B.C. Industrial Coal Demand, 1983–1990
(Thousand Tonnes)

	1983	1984	1985	1986	1987–1990
COAL MINES					
Quintette	—	66	102	207–237	252–287
Bullmoose	—	—	—	—	—
Westar					
— Elkview	—	—	—	—	—
— Greenhills	—	—	—	—	—
Fording	—	—	—	—	—
SMELTERS	50	50	50	50	50
CEMENT	—	15	30	150–230	150–230
LIME (2)	—	10	15	20	20
TAR and GRAVEL	—	1	5	5	5
PULP and PAPER					
(Power Boilers)	—	—	1	—	(500+)[1]
(Lime Kilns)[2]	—	—	—	—	—
OTHER INDUSTRIES	28	30	30	50	(50+)
TOTAL DEMAND	78	172	233	482–592	1,027–1,142

[1] Bracketed figures indicate estimate.
[2] Lime kilns primarily use petroleum coke due to its low ash content.

TABLE 10.8. Comparative Fuel Prices
B.C. Industrial Market

Fuel	$/Common Unit	$/GJ **	$/GJ *** (Burner Tip)
Electricity	3.2 C/KWH	8.89	8.89
Natural Gas*	2.88–3.14/GJ	2.88–3.14	3.60–3.99
Heavy Fuel Oil	27.50–31.00/BBL	4.15–4.68	5.19–5.85
Hog Fuel	10.00–22.00/Gravity Packed Unit	.70–1.55	1.08–2.39
Thermal Coal	40–55.00 MT	1.43–1.97	1.79–2.46

* Price range corresponds to schedule 12 (interruptable) gas rates on the Inland Natural Gas and B.C. Hydro systems respectively.

** Energy content per fuel is taken to be: heavy fuel oil 6.63 GJ/barrel; hog fuel 14.2GJ/unit; coal 27.9GJ/tonnes. (12 000 Btu coal); electricity 0.0036GJ/KWH.

*** Burner tip prices were calculated on the following furnace efficiencies: natural gas and heavy fuel oil 80%; hog fuel 65%; coal 80%; electricity 100%.

TABLE 10.9. Japanese Thermal Coal Imports[1]
(Million Tonnes)

Source	1980	1981	1982	1983	1984
Australia	4.5	5.4	7.0	8.3	11.8
Canada	0.6	1.1	1.3	0.5	0.8
China	0.7	1.3	1.6	2.2	2.3
South Africa	0.5	1.9	2.2	2.9	2.9
U.S.A.	0.6	2.3	1.4	0.8	0.5
U.S.S.R.	0.2	0.3	0.2	0.6	0.8
Other	0.1	—	—	0.2	0.3
TOTAL	7.2	12.3	13.7	15.5	19.4

[1] Fiscal Year Basis.

Table 10.10 shows the users of imported thermal coal in Japan. Initially the cement industry had been the largest user of imported thermal coal, but since 1983 the power companies have consumed more coal in total, including domestic supplies. The cement industry converted to thermal coal rapidly, since conversion is a relatively simple process in this sector. In addition, waste products from coal use are themselves useful as part of the cement production process.

TABLE 10.10. Uses of Imported Thermal Coal in Japan[1]
(Million Tonnes)

	1981	1982	1983	1984
Pulp and Paper Industry	0.14	0.35	0.51	0.73
Chemical Industry	0.33	0.76	0.97	2.05
Ceramics (Cement, etc.)	8.13	7.68	6.21	5.75
Power Companies	3.57	5.12	7.50	10.42
Others	0.20	0.18	0.31	0.38
TOTAL	12.37	14.09	15.50	19.33

[1] Fiscal Year Basis.

With conversion to coal essentially complete in the cement industry, the demand for coal in this sector is now dependent only on cement production. However cement production, which peaked in 1979 at an all-time high of 92 million tonnes, has declined for 5 straight years and stood at only 81 million tonnes in 1984. Production in the first six months of 1985 has declined to an annual rate of 75 million tonnes and is not expected to increase by very much, if at all during the rest of the decade. Coal demand by the cement sector is therefore expected to stay at or below 9 million tonnes through to 1990, with imports accounting for 6–8 million tonnes.

Electric power companies have become the largest importers of thermal coal in Japan. However, coal demand in this sector will build up over a long period of time compared to the cement industry. The number of existing stations remaining to be converted to coal is small so that additional demand will come from the construction of new coal-fired units. There are plans to construct a number of plants but there is uncertainty as to how fast they will be built. This is largely due to reduced expectations of electricity demand growth. Optimistic electricity demand forecasts presented by the Electricity Planning Board in 1980, which called for an electricity demand growth of 6 per cent per year, have been halved and the 1985 forecast projects a 3.0 per cent annual growth to 1994. This may be a conservative projection given the 1983 and 1984 growth rates of 6.3 and 4.9 per cent and the historic growth rate of 4.2 per cent between 1973 and 1979. Current plans call for coal to supply 15 per cent of Japan's total electricity supply by 1990 and 20 per cent by 2000, compared to 8 per cent in 1978. A total of 4 600 megawatts of additional coal-fired capacity will be built in the five years to fiscal 1990, inclusive. Because of frequent revisions in Japan's long-term energy plan, uncertainty remains regarding the number and timing of additional coal-fired units beyond 1990.

This uncertainty is compounded by competition from other fuels. Nuclear power is marginally less expensive than thermal coal and LNG is seen in Japan as being more acceptable from an environmental point of view. Furthermore, the weakness in the ability of OPEC to maintain production controls has many analysts speculating a break-up of the oil cartel has begun, to be followed in 1986 by a collapse of oil prices. This is a very real possibility and the question that follows from it is how low will oil prices go, for how long and what will coal demand do. One recent study[1] suggests that a natural resistance barrier to lower oil prices occurs when oil is priced in the low U.S. $20s per barrel. At this point oil demand will increase rapidly as people find it cheaper to consume oil than conserve it. Another barrier would be around U.S. $18.00 per barrel, where utilities find themselves indifferent to burning oil and coal.

Despite these problems, Japan's power companies are expected to significantly increase their consumption of thermal coal during the 1980s. Projections call for demand of about 30 million tonnes a year by 1990, of which approximately 20 million tonnes would be imported. This is much less than many earlier forecasts which predicted imports in 1990 of over 40 million tonnes by electric utilities. Still, the revised projections predict an increase in thermal coal demand in this sector of about 10 million tonnes between 1984 and 1990, almost all of which is expected to be imported. The newer forecasts reflect postponement of new coal-fired plants, but increased use of coal due to completion of almost all conversions of existing oil-fired plants. They also project some increase in thermal coal use by the industrial sector (pulp and paper, textile manufacturers, etc.). Japan's demand for imported coal from all sources is expected to be in the range of 30 to 35 million tonnes per year by 1990. Most of the incremental demand will come from the electric utilities.

British Columbia coal producers have provided relatively small amounts of the thermal coal imported by Japan in recent years. British Columbia's share of this market has been increased by a long-term contract signed with the Quintette property calling for delivery of 1.3 million tonnes per year of thermal coal. Properties under development such as Quinsam and Telkwa may also be attractive to Japanese buyers because of their quality specifications (that is, high volatile matter content). Mines producing coal with lower volatility may increase sales when new power plants that will accept a broader range of coals are in operation in Japan.

10.4.2.2 Other Thermal Coal Export Markets

Although Japan is the largest importer of thermal coal in the Pacific Rim, other foreign markets have proved to be more important to British Columbia's coal producers. The leading markets in this group are also in the Pacific Rim. European markets are expected to continue to play a smaller role, with sales being mainly to give the buyer greater diversity of supply.

---

[1] "Future World Oil Prices and Their Implications for the Price of Coal", Paper presented to the thirty-sixth Canadian Conference on Coal by J. P. Prince, Global Energy and Minerals Group, Royal Bank of Canada, September 1985.

South Korea has become an important market for British Columbia thermal coal as a result of activity in the electric power and cement industries. Korea Electric Power Company (KEPCO), the national power utility, has constructed power plants at Samcheonpo and Poryeong (formerly Gojeong) which run on thermal coal. The country's cement industry has almost completely converted to the use of thermal coal. Since Korea's domestic coal is low-grade anthracite, the above-mentioned coal demand is being satisfied by imports. Canadian producers have been successful in this market and will likely continue to supply between one-quarter and one-fifth of these coal requirements. British Columbia producers have signed long-term contracts to increase thermal coal shipments to almost 2 million tonnes per year to the power and cement industries, compared to 1.3 million tonnes in 1984.

KEPCO's additional power demand will be met mostly by nuclear energy, although its ambitious nuclear program has recently been slowed. Under the new 1985 plan, KEPCO's next coal-fired plants are planned for commissioning in 1991 and 1992. Each will have a capacity of 500 megawatts. In addition, conversion of two oil-fired plants totalling 500 megawatts will be completed by 1992. On this basis, KEPCO's thermal coal demand should remain at about 6 million tonnes to 1990 and then increase to 10 million tonnes by 1992. Between now and 1990, the addition of cement industry demand will raise imports to 10 million tonnes. Demand in the industrial boiler market may grow significantly during this decade. Korean government plans continue to call for over 1 million tonnes a year to be used by this sector by 1990 compared to a few hundred thousand tonnes in 1984.

Until recently Hong Kong did not import coal. However, like many countries responding to high oil prices, it began to import thermal coal for the use of power utilities and cement producers. Hong Kong's two major utilities, China Light and Power and Hong Kong Electric, both constructed coal-fired generating stations and have plans to increase their capacity. China Cement, Hong Kong's only integrated cement producer, also uses thermal coal, but its requirements total less than 300 000 tonnes annually. Depending on demand for power and cement, Hong Kong's thermal coal requirements could reach 9 to 10 million tonnes per year by 1990. British Columbia producers have been successful in signing contracts for part of the cement company's and China Light and Power's coal requirements. Planned shipments under these contracts will reach 600 000 tonnes per year by the late 1980s or 6 per cent of the market.

Taiwan is expected to increase its steam coal imports significantly during the 1980s. In 1984, imports were 5 million tonnes and of this amount British Columbia supplied 0.2 million tonnes. By 1990 they are expected to be in the range of 10 to 14 million tonnes, with most of the requirements coming from Taipower, the national electric utility.

Malaysia and the Phillipines are other potential long-term consumers of British Columbia thermal coal. Malaysia's imports are expected to be about 500 000 tonnes a year in 1985 and approximately 2-3 million tonnes in 1990. Phillipine thermal coal imports could be close to 3 million tonnes by 1990.

Exports to Latin America totalled 259 000 tonnes in 1984. Coal-fired development plans in Mexico offer a natural market opportunity should development proceed.

The European market differs from the Pacific Rim, in that large amounts of thermal coal were being imported prior to the 1980s. Nevertheless substantial growth has been predicted for European thermal coal imports, although this has been tempered by uncertainty about future economic conditions and changes in the oil/coal price ratio. Canada has been and will continue to be a minor supplier in the market, which is dominated by the United States, South Africa, and Poland. In 1984, Canada's exports totalled 900 000 tonnes, of which 641 000 tonnes or 70 per cent came from British Columbia. Nevertheless, some shipments to Europe from British Columbia are expected, largely for the purpose of diversity of supply. Long-term contracts have been signed to export 400 000 tonnes a year from British Columbia to power producers in Denmark.

A recent development has been the shipment of thermal coal to the U.S. One British Columbia producer has moved several shiploads to New England Power (NEPCO) through the Panama Canal and has been very competitive. This has been possible because of a low ocean freight rate and lower production costs.

10.5 ANTHRACITE MARKETS

Anthracite markets are of interest to the Province as large resources exist in the Groundhog coalfield in Northwest British Columbia. Studies indicate that one property in the area, known as Mount Klappan, could produce up to 5 million tonnes per year of anthracite for an extended period. A semi-anthracite coal deposit is also proposed for development at the Burnt River property in Northeast British Columbia.

Markets exist for anthracite in Japan, South Korea, and Europe. Major uses include home-heating and cooking in Asia, for which anthracite is formed into briquettes, and domestic heating in Europe; industrial applications such as the blending with thermal coal in cement making, for sintering ores, for ferro-nickel processing, lime production, and carbide and electrode manufacturing; and some thermal power generation.

Different quality specifications are required for these differing end uses. High quality anthracite having high fixed carbon content, low volatile matter content and ash values of 5 to 6 per cent is sold in the industrial market for specialized uses where high heat content and low impurity levels bring a premium price. The European home-heating market also uses such premium quality coals. Briquetted coal has less fixed carbon than premium anthracite, and ash content of around 18 per cent. This coal tends to have less heat content and therefore obtains a lower price. This type of coal is preferred in the Korean domestic market because of its burning characteristics and convenient disposal.

In the European market, anthracite consumption is around 20 million tonnes but most supplies are from domestic mines. The main suppliers of the coal that is imported are the Soviet Union, the United States, and South Africa. The existing producers in Europe are facing increasingly high production costs and if high quality anthracite can be landed in Europe at lower prices than those of domestic producers there would be an opportunity for market penetration.

In the Pacific market the primary suppliers of anthracite have been Vietnam, the People's Republic of China, the United States, and to a lesser extent South Africa and the Soviet Union. Japan imports anthracite primarily for industrial purposes. Quantities totalled 1.2 million tonnes in 1984. The Korean market imported 0.8 million tonnes in 1984 in addition to the domestic product of 21 million tonnes. This represented the second year imports had totalled less than 1 million tonnes. Korea started importing anthracite in 1979 when domestic demand began to exceed production and, up until 1983, imports have ranged from 2.1 to 4.3 million tonnes annually. The 1983 and 1984 decline was almost entirely due to two unusually mild winters in 1981 and 1982 which saw the buildup of large stockpiles. For 1985, Korea's import target has been raised to 2.7 million tonnes due to (1) a severe depletion of stockpiles following the return to more normal winters in 1983 and 1984, and (2) to the continuing decline in the calorific value of Korean coal, which forced a doubling of the amount of foreign coal mixed in the household Yontan briquette to 13 per cent.

The major use of anthracite in Korea is for household heating and cooking, which accounts for 75 per cent of home use. With lower oil prices, the large increase in the number of people living in oil-heated apartments and government plans to import LNG for city gas, anthracite consumption is not projected to increase significantly. Nevertheless, Daehan Coal Corp., the state coal agency, projects a record anthracite consumption of almost 25 million tonnes in 1985. This compares to 24 million tonnes in 1984. An attempt by the government to raise the price of the household briquette last winter was sharply rebuked by consumers for whom the Yontan briquette is considered a staple. The government's long-term energy policy calls for the enhancement of anthracite as a home heating fuel. In addition, the government is encouraging the use of anthracite boilers under their off-oil policy. At the same time, the government is anticipating an increase in the use of LPG, instead of anthracite, for cooking.

The outlook for future anthracite demand, according to a recent forecast by the Korean Institute of Energy and Resources is for anthracite use to peak in 1986/87 near present levels and then drop back to about 21 million tonnes by 2001. The amount of imports are projected at around 2-3 million tonnes annually, but these will depend greatly upon domestic production. Since domestic production is expected to decline due to increasing mining costs and decreasing quality, imports of anthracite have a good probability of increasing.

10.6 SUMMARY

The basis of the British Columbia coal industry since the early 1970s has been exports of metallurgical coal to Japanese steel mills. This will continue to be the case through the 1980s, although markets for the Province's coal have become increasingly diversified. Korea, Europe, Brazil and to a lesser extent Taiwan have become important customers of metallurgical coal, and a number of other markets are served as well. Thermal coal sales have also helped diversify markets, beginning in the early 1980s. Markets for this type of coal are more evenly distributed than for metallurgical coal, with the majority of shipments going to non-Japanese markets.

British Columbia coal producers signed a number of long-term sales contracts in the early 1980s which led to a significant increase in supply capacity. By the latter part of the 1980s, metallurgical coal shipments are expected to be approximately 21 million tonnes per year. Thermal coal shipments can be expected to reach at least 6 to 7 million tonnes by 1990. At these shipment levels bituminous coal sales will total 27-28 million tonnes per year by 1990, an increase of forty per cent from the 1984 export level of 19.8 million tonnes. In addition to these expected sales of bituminous coal, by 1990 British Columbia may have a significant anthracite operation, producing between 1 and 3 million tonnes a year for export markets.

APPENDICES

Appendix 1.1 ASTM Classification of Coals by Rank[1]

Class	Group	Limits of Fixed Carbon or Btu, Mineral-matter-free Basis	Requisite Physical Properties
I. Anthracite	1. Meta-anthracite	Dry FC, 98% or more (dry VM, 2% or less)	
	2. Anthracite	Dry FC, 92% or more and less than 98% (dry VM, 8% or less and more than 2%)	
	3. Semi-anthracite	Dry FC, 86% or more and less than 92% (dry VM, 14% or less and more than 8%)	Nonagglomerating.[2]
II. Bituminous[3]	1. Low-volatile bituminous coal	Dry FC, 78% or more and less than 86% (dry VM, 22% or less and more than 14%)	
	2. Medium-volatile bituminous coal	Dry FC, 69% or more and less than 78% (dry VM, 31% or less and more than 22%)	
	3. High-volatile A bituminous coal	Dry FC, less than 69% (dry VM, more than 31%) and moist[4] Btu, 14,000[4,5] or more	
	4. High volatile B bituminous coal	Moist[4] Btu, 13,000 or more and less than 14,000[4]	
	5. High-volatile C bituminous coal	Moist Btu, 11,000 or more and less than 13,000[4]	Either agglomerating or nonweathering.[6]
III. Sub-bituminous	1. Sub-bituminous A coal	Moist Btu, 11,000 or more and less than 13,000	Both weathering and nonagglomerating.
	2. Sub-bituminous B coal	Moist Btu, 9,500 or more and less than 11,000	
	3. Sub-bituminous C coal	Moist Btu, 8,300 or more and less than 9,500	
IV. Lignitic	1. Lignite	Moist Btu, less than 8,300	Consolidated.
	2. Brown coal	Moist Btu, less than 8,300	Unconsolidated.

Source: ASTM D388-38 (ref. 1).

FC = fixed carbon; VM = volatile matter; Btu = British thermal units.

[1] This classification does not include a few coals that have unusual physical and chemical properties and that come within the limits of fixed carbon or Btu of the high-volatile bituminous and sub-bituminous ranks. All of these coals either contain less than 48 per cent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free Btu.

[2] If agglomerating, classify in low-volatile group of the bituminous class.

[3] It is recognized that there may be noncaking varieties in each group of the bituminous class.

[4] Moist Btu refers to coal containing its natural bed moisture but not including visible water on the surface of the coal.

[5] Coals having 69 per cent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of Btu.

[6] There are three varieties of coal in the high-volatile C bituminous coal group—Variety 1, agglomerating and nonweathering; Variety 2, agglomerating and weathering; Variety 3, nonagglomerating and nonweathering.

Appendix 1.2 Symbols for Grading Coals According to Ash, Softening Temperature of Ash, and Sulphur

Ash[1]		Softening Temperature of Ash[2]		Sulphur	
Symbol	Amount,[3] Per Cent Inclusive	Symbol	Temp., °F Inclusive	Symbol	Amount, Per Cent Inclusive
A4	0.0– 4.0	F28	2,800 and higher	S0.7	0.0–0.7
A6	4.1– 6.0	F26	2,600–2,790	S1.0	0.8–1.0
A8	6.1– 8.0	F24	2,400–2,590	S1.3	1.1–1.3
A10	8.1–10.0	F22	2,200–2,390	S1.6	1.4–1.6
A12	10.1–12.0	F20	2,000–2,190	S2.0	1.7–2.0
A14	12.1–14.0	F20 minus	Less than 2,000	S3.0	2.1–3.0
A16	14.1–16.0	—	—	S5.0	3.1–5.0
A18	16.1–18.0	—	—	S5.0 plus	5.1 and higher
A20	18.1–20.0	—	—	—	—
A20 plus	20.0 and higher	—	—	—	—

Source: ASTM D389-37 (ref. 1).

[1] Ash and sulphur shall be reported to the nearest 0.1 per cent by dropping the second decimal figure when it is 0.01–0.04, inclusive, and by increasing the percentage by 0.1 per cent when the second decimal figure is 0.05–0.09, inclusive. For example, 4.85–4.94 per cent, inclusive, shall be considered 4.9 per cent.

[2] Ash-softening temperatures shall be reported to the nearest 10°F. For example, 2,635–2,644°F, inclusive, shall be considered to be 2,640°F.

[3] For commercial grading of coals, ranges in the percentage of ash smaller than 2 per cent are commonly used.

Appendix 1.3 International Classification System of Hard Coals by Type

GROUPS — GROUPES (determined by caking properties) (déterminés d'après le pouvoir agglutinant)			CODE NUMBERS — NOMBRES CONVENTIONNELS										SUB-GROUPS — SOUS-GROUPES (determined by coking properties) (déterminés d'après le pouvoir cokéfiant)		
Group number / Nº du groupe	Alternative group parameters / Paramètre de détermination du groupe (au choix): Crucible-swelling number / Indice du gonflement au creuset	Roga index / Indice Roga	The first figure of the code number indicates the class of the coal, determined by volatile matter content up to 33% V.M. and by calorific parameter above 33% V.M. The second figure indicates the group of coal, determined by caking properties. The third figure indicates the sub-group, determined by coking properties. / Le premier chiffre du nombre conventionnel indique la classe, déterminée d'après l'indice M.V. (Charbons contenant jusqu'à 33% de M.V.) ou par paramètre du pouvoir calorifique (charbons contenant plus de 33% M.V.) Le deuxième chiffre indique le groupe, déterminé d'après le pouvoir agglutinant. Le troisième chiffre indique le sous-groupe, déterminé d'après le pouvoir cokéfiant.										Sub-group number / Nº du sous-groupe	Alternative sub-group parameters / Paramètre de détermination du sous-groupe (au choix): Dilatometer / Essai dilatométrique	Gray-King / Essai Gray-King
							435	535	635				5	>140	>G8
						334	434	534	634				4	>50 – 140	G5 – G8
3	>4	>45				333	433	533	633	733			3	>0 – 50	G1 – G4
						332 a / 332 b	432	532	632	732	832		2	≤0	E – G
						323	423	523	623	723	823		3	>0 – 50	G1 – G4
2	2½ – 4	>20 – 45				322	422	522	622	722	822		2	≤0	E – G
						321	421	521	621	721	821		1	Contraction only / Contraction seulement	B – D
1	1 – 2	>5 – 20			212	312	412	512	612	712	812		2	≤0	E – G
					211	311	411	511	611	711	811		1	Contraction only / Contraction seulement	B – D
0	0 – ½	0 – 5		100 (A / B)	200	300	400	500	600	700	800	900	0	Non-softening / Ne se ramollissant pas	A
Class number — Nº de la classe →			0	1	2	3	4	5	6	7	8	9	As an indication, the following classes have an approximate volatile matter content of: Class 6 ..... 33 – 41 %; 7 ..... 33 – 44 %; 8 ..... 35 – 50 %; 9 ... 42 – 50 %	A titre d'indication, les classes ci-après ont environ l'indice M.V. (matières volatiles) suivant: Classe 6; 7; 8; 9	
Class parameters / Paramètre de détermination de la classe	Volatile matter (d.a.f.) / Matières volatiles (produit sec exempt de cendres) →		0 – 3	>3 – 10 (A: >3 – 6.5; B: >6.5 – 10)	>10 – 14	>14 – 20	>20 – 28	>28 – 33	>33	>33	>33	>33			
	Calorific parameter[a] / Paramètre du pouvoir calorifique[a] (Produit humide exempt de cendres) →		–	–	–	–	–	–	>7 750	>7 200 – 7 750	>6 100 – 7 200	>5 700 – 6 100			

CLASSES

(determined by volatile matter up to 33% V.M. and by calorific parameter above 33% V.M.) — (déterminées d'après l'indice de matières volatiles (charbons contenant jusqu'à 33% de M.V.) ou par paramètre de pouvoir calorifique (charbons contenant plus de 33% de M.V.)

NOTE. — (i) Where the ash content of coal is too high to allow classification according to the present systems, it must be reduced by laboratory float-and-sink method (or any other appropriate means). The specific gravity selected for flotation should allow a maximum yield of coal with 5 to 10% of ash.

(ii) 332a ... > 14-16% V.M.
332b ... > 16-20% V.M.

[a] Gross calorific value on moist, ash-free basis (30° C, 96% humidity) kcal/kg.

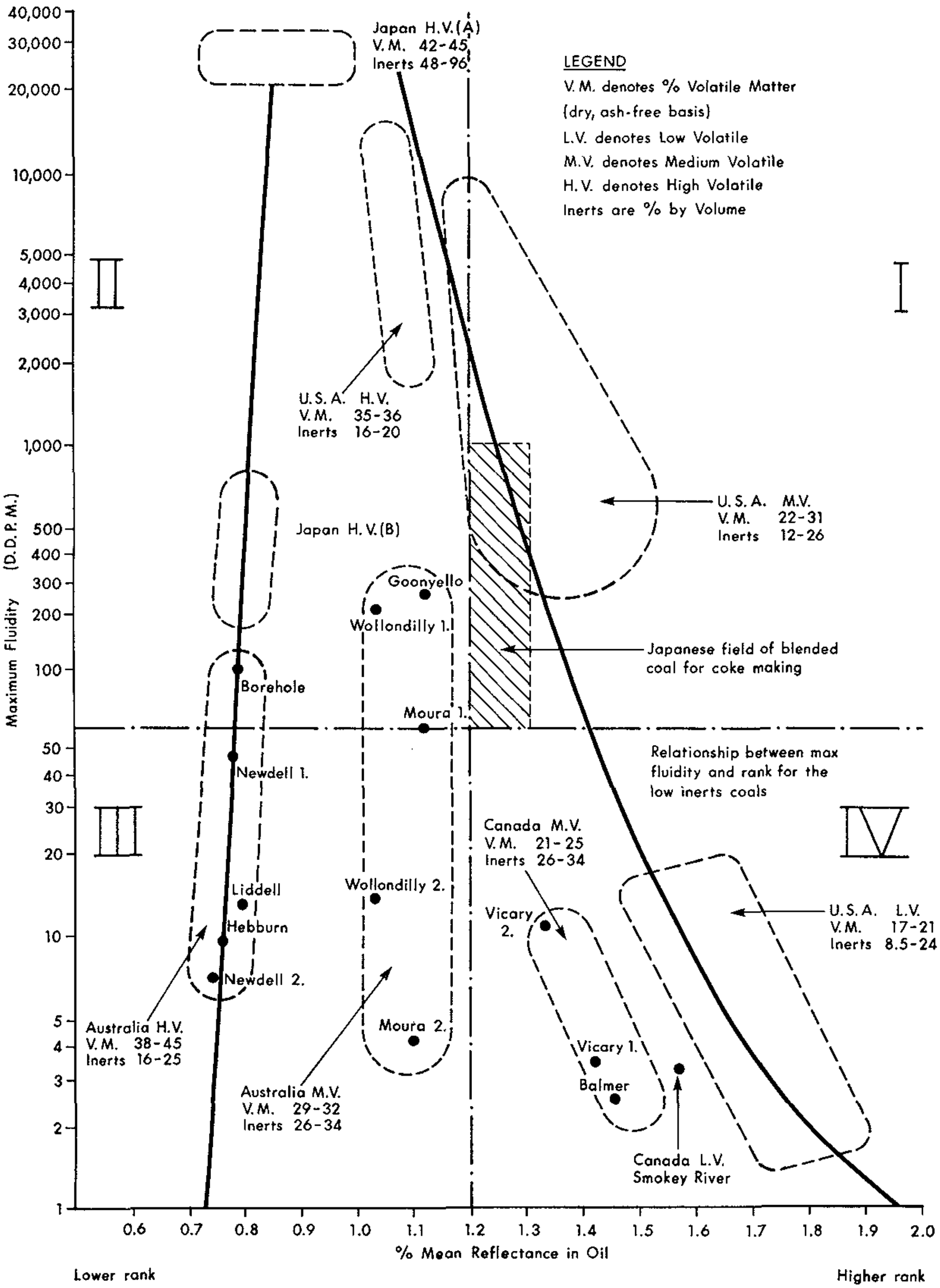
NOTE. — (i) Lorsque la teneur en cendres du charbon est trop élevée pour que sa classification soit effectuée selon les principes de la méthode, cette teneur en cendres doit être réduite, au laboratoire, par traitement aux liqueurs denses (ou tout autre traitement approprié). La densité de coupure devra être choisie de manière à assurer le rendement maximum en charbon d'une teneur en cendres comprise entre 5 et 10 %.

(ii) 332a ... >14-16 % M.V.
332b ... >16-20 % M.V.

[a] Pouvoir calorifique supérieur de produit humide, exempt de cendres en kcal/kg. Humidité correspondant à l'eau de rétention dans une atmosphère à 30 °C et 96 % d'humidité.

Source: *International Classification of Hard Coals by Type*, United Nations, Geneva, August 1956.

Appendix 1.4 Relationship Between Maximum Fluidity and Mean Maximum Reflectance



Appendix 1.5 Glossary of Coal Classification Terms

1. In the International Classification System, the first subdivision is based on *caking* property, which in broad terms reflects the behaviour of coal when heated rapidly, i.e., during combustion. The crucible-swelling test (Free Swelling Index) and the Roga tests can be used alternatively for measuring caking property.

(a) Free Swelling Index (F.S.I.)

This is the simplest and most well-known test to assess the swelling properties of the coal. A 1-gram sample of pulverized coal is heated in a covered crucible of fixed dimensions. After the coal has swelled, its profile is compared against a series of standard profiles labelled in half units from 0–9. Since the test is quick and easy, and uses small samples of coal, it is most commonly used on drill hole samples and by the coal producer for a rapid appraisal of his coal (often to detect oxidation). A value of less than 4 *indicates* that a coal would produce a poor-quality coke. On the other hand, a value of 9 is not necessarily better than a value of 6. The following more detailed tests would enable a better judgment to be made.

(b) Roga Index

The test is conducted by carbonizing a mixture of 1 gram of coal and 5 grams of a standard anthracite at 850°C for 15 minutes. The mechanical strength of the resulting coke button is measured by an abrasion test in a special rotating drum. At the end of the tumbling period, the residue is screened on a sieve with 1-millimetre round openings and the oversize weighed. The tumbling and screening of the oversize is repeated two additional times. The index is calculated *from the results of the screening test by the following formula:*

$$\text{Roga Index} = \frac{100}{3Q}\left\{\frac{a+d}{2}+b+c\right\}$$

Where: Q = total weight of residue after carbonization;
a = weight of oversize before first screening;
b = weight of oversize after first screening;
c = weight of oversize after second screening; and
d = weight of oversize after third screening.

2. In the International Classification System, the second subdivision is based on *coking* property, which reflects the behaviour of coal when heated slowly, as in carbonization. The Ruhr Dilatometer Test and the Gray-King Assay can be used alternatively for measuring coking property.

(a) Gray-King Coke-type Test

The test is conducted by carbonizing a 20-gram sample of coal progressively to 600°C in a horizontal tube furnace. The carbonized residue is classified as to volume, coherence, fissuring, and hardness by comparing it with a series of residues. For coals that form residues that range from pulverulent to hard cokes occupying the same volume as the original coal (standard coke), the type of residue is assigned letters ranging from A to G. For coals that swell to fill the cross-section of the tube, electrode carbon is mixed with the coal to obtain a strong, hard coke of the same volume as the original coal-electrode carbon mixture. The coke type is indicated by the letter G with a subscript figure, that is, G_4, G_3, etc. The subscript shows number of parts of electrode carbon needed in the mixture with coal to give a G-type (standard) coke.

(b) Ruhr Dilatometer

The German steel companies (and to a lesser extent the British Steel Corporation) make great use of this test and, since they are becoming involved in British Columbia coal properties, a mention of its use would be appropriate.

The dilation test produces a curve based on the changing of the length of a coal pencil with progressive heating, under controlled conditions. From the dilation test, the coking propensities of coking-coal and blends are characterized by the following: Contraction, dilation, softening temperature, solidification temperature, and plastic range. Contraction is the decrease in length that the coal pencil undergoes during the heating cycle within the tube, i.e., as the coal melts.

3. *Mean Maximum Reflectance* ($\bar{R}_o$) In this case, a sample of pulverized coal is set with resin into a mould, the surface of the coal is then polished and viewed under a microscope, the tip of which is immersed in an oil film on the coal surface. The operator then focuses the microscope on a vitrinite component and the maximum reflectance value is recorded. The procedure is repeated for a statistically representative number of vitrinite macerals and the mean maximum reflectance value is determined.

It is interesting to note that $\bar{R}_o$ values are a more precise guide to the rank of a coal, in the coking range, than the determination of volatile content. The use of petrographic techniques, such as $\bar{R}_o$ values, is becoming more prevalent, particularly in Japan.

4. *Gieseler Fluidity* This is a test performed to determine the viscosity or fluidity of a coal during the plastic stage of coke formation. A sample of pulverized coal is packed around a stirrer to which a constant torque is applied. The coal is then heated at a given rate and the following temperatures are measured: Initial softening temperature, temperature at maximum fluidity, final temperature, and melting range. A measurement of the maximum fluidity in terms of dial divisions per minute is also made.

British Columbia coals generally exhibit low ddpm values (less than 500) as do the low volatile eastern United States coals, which are generally regarded as "prime" coking-coals. The coals of northeastern British Columbia are generally more fluid than those of the south.

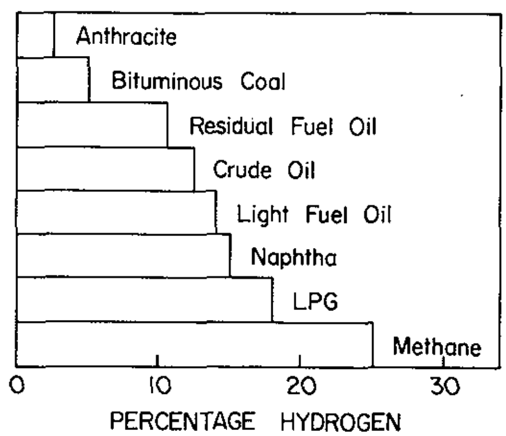
Gieseler tests are frequently performed in North America and Japan, but rarely in Europe.

Appendix 1.6 Combustion Products of Coal[1, 2]

Combustion Products	(lb./10^6 Btu)
CO_2	219.6
CO	.09231
NO	.4455
SO_2	.5385[3]
SO_3	.01346
Particulates[4]	7.422
95 per cent ash removal	.3711
97 per cent ash removal	.2226

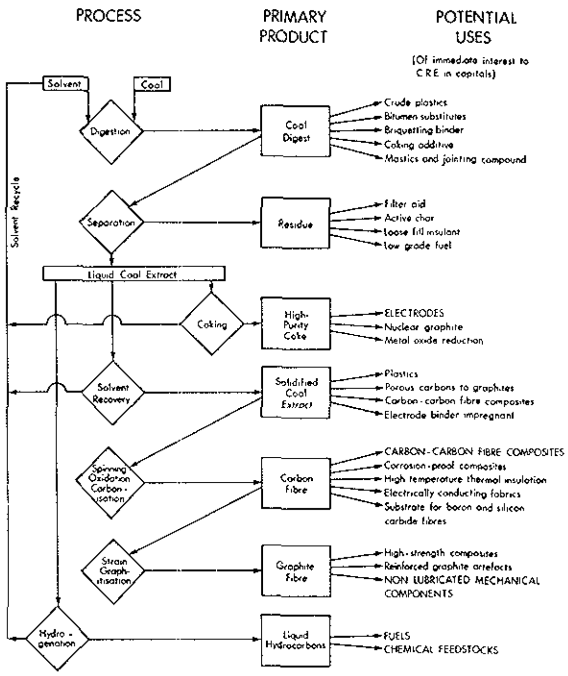
[1] This table does not consider the emissions of minor elements that might be present in a given coal.
[2] Western Canadian Bituminous Coal (0.7% S).
[3] Assuming 50 per cent S in coal is neutralized by cations in the ash.
[4] Particulates include C_xH_y, flyash, and soot.

Appendix 1.7 Hydrogen Content of Organic Materials*



* The Robens Coal Science Lecture 1974: *Coal into the Twenty-first Century*, L. Grainger, London, October 1974.

Appendix 1.8 Potential Products of the Solvent Refining of Coal*



* The Robens Coal Science Lecture 1974: *Coal into the Twenty-first Century,* L. Grainger, London, October 1974.

Appendix 4.1 Washability Curves: Glossary of Terms and Examples

Washability curves are used to describe the yield and properties of material that floats when raw coal is immersed in a liquid of particular relative density. The curves are established by laboratory testing of the coal, using liquids of different relative densities to effect the separations. The results are cumulated so that, by graphing them, it is possible to determine the yield and ash content of a float coal (and discard) at any density within the range tested. Appendices 4.1a and 4.1b show a set of washability curves. They are as follows:

(a) Primary curve (characteristic curve): This is a graph of the ash content of the dirtiest particle present in a particular yield of clean coal; hence it is read against the ash/cum per cent weight floats axes.

(b) *Clean coal curve (cumulative floats): The cumulative (average) ash of coal floats at any* yield may be read from this curve; hence it, too, is read on the cumulative per cent of floats/ash content axes.

(c) Discard curve (cumulative sinks): This is simply the ash content of the discards obtained at a particular yield of floats. It is read on the cumulative per cent sinks/ash content axes.

(d) *Specific gravity yield curve (densimetric curve): This shows the percentage material* floating at any given relative density; hence the yield of floats is read against the relative density (specific gravity) scale.

(e) Distribution curve: This is a graph of the amount of material in the range ±0.1 of the particular relative density being considered. It is an expression of the ease with which a coal may be cleaned, as the more material which is in the region of the density at which the coal is being washed, the more precise must be the control of the washing operation and hence the more difficult the coal is to clean. The following classification has been suggested:

0–7 per cent near density—simple separation
7–10 per cent near density—moderately difficult
10–15 per cent near density—difficult
15–20 per cent near density—very difficult
20–25 per cent near density—exceedingly difficult
over 25 per cent near density—formidable.

For most coals considered in this report, the near density is under 10 per cent. Separations in other countries are being carried out involving 70–80 per cent near density material.

Appendix 4.1b shows a coal that is fairly difficult to clean. To show the use of the curves, if it is desired to make a coal of 10 per cent ash, curve B tells us that the yield will be 63 per cent, and D shows that the relative density of washing must be 1.52. The ash in the discard (C) is 44 per cent (yield 56 per cent) and the dirtiest particle present has an ash of about 24 per cent. The per cent near density is some 30 per cent. Increasing the ash in the clean coal to 15 per cent brings the yield up to 83 per cent, the discard ash increases to 62 per cent, ash of dirtiest particle is 37 per cent, washing density 1.75, and the near density material is down to 10 per cent. Not only has the yield materially increased, the coal has actually become easier to clean by increasing the ash content, with a consequent increase in the range of equipment that could be used (and a possible reduction in cost). Appendices 4.1c and 4.1d show an exceptionally easy coal; note the low percentage of near density material over quite a wide range of washing densities. In deciding the ash content that can economically be produced, it is important to take both yield and effect on washing characteristics into account: if the separation has to be carried out in a region where there is much near density material, then increases in ash and losses in yield can occur unless the process is capable of being closely controlled. As pointed out, coals currently being considered in British Columbia have near density under 10 per cent, and high yields at the required ash content. This immediately suggests that simple and cheap preparation methods may be used in many cases to attain the required ash, with more costly equipment being used only to re-treat the discards from the first separation. This can apply to coarser coals, but is more generally applicable to the smaller sizes, say under one-half inch.* It should be noted that the smaller the size of coal, the greater the liberation of the organic material from associated inorganic. Hence, the smaller sizes may be washed at higher densities to give the same ash as the coarser sizes washed at lower densities. This is also accompanied by a diminution in the amount of near density material, making the coals easier to clean.

Coal from Mine A (Appendices 4.1e and f) can be taken as an example of one of the coals of the Province that should be able to be beneficiated to a yield of 80 per cent with an ash content slightly over 4 per cent, with a low order of control precision required at the plant. Coal from Mine B, on the other hand, in the size range 4″ × 28 mesh would only give a yield of 25 per cent at approximately 4 per cent ash (Appendices 4.1g and h). If the material is below 28-mesh size (i.e., smaller and therefore showing better liberation of maceral and inorganic material), then a 70-per-cent yield at 5 per cent is theoretically possible with highly precise control from the washability curves (Appendices 4.1i and j). In practice, the operator has been able to obtain contracts for coal from carbonization with ash contents of approximately 9 per cent; yields of 70 per cent are possible at this ash from the 4″ × 28-mesh size fraction. This ash content should be obtainable with a low order of control because of the shape of the distribution curve.

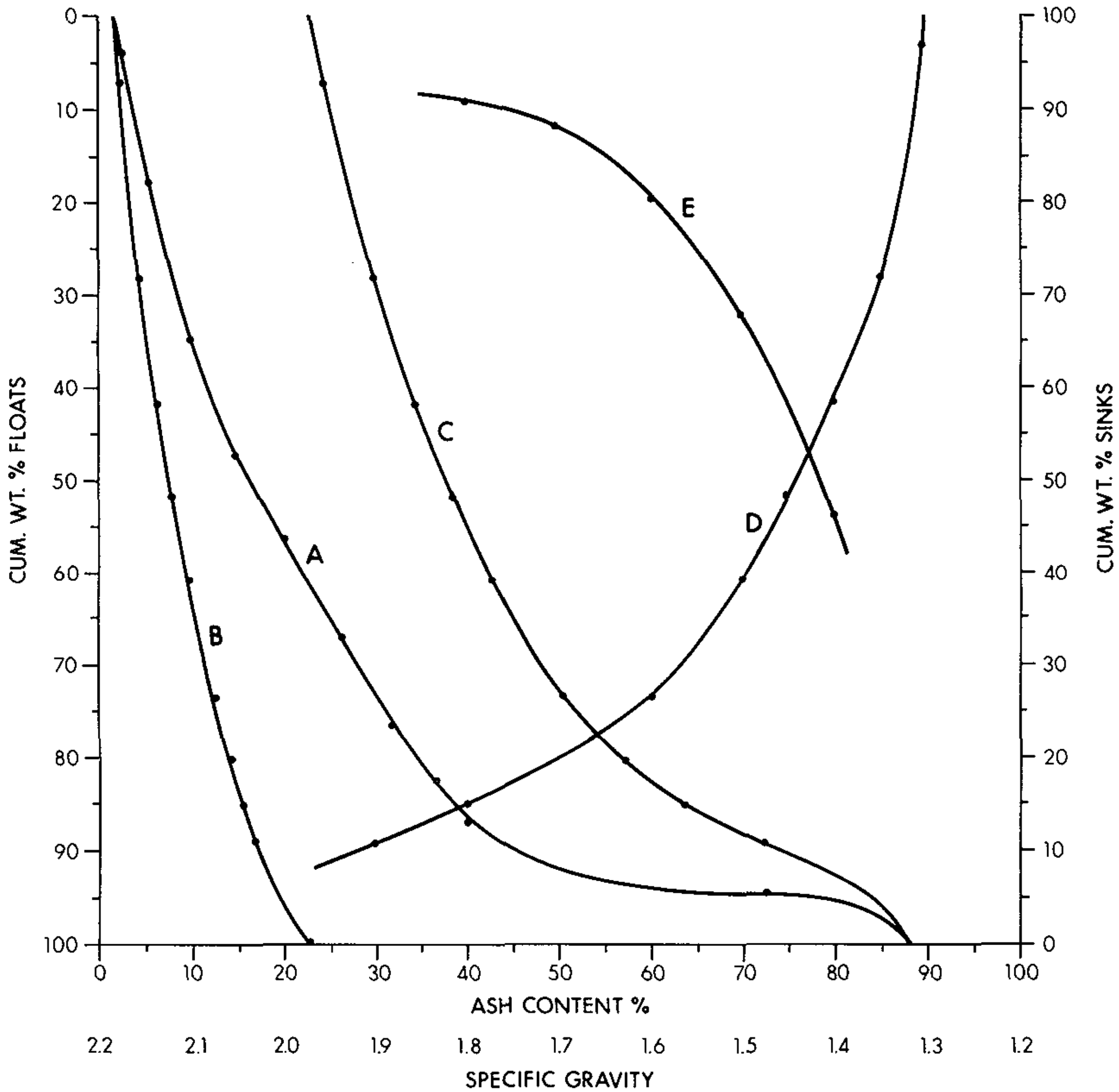
* 1 inch = 2.54 centimetres.

Appendix 4.1a

Client: B.C. Coal Task Force.
Sample identification: Seam B.

Specific Gravity	Direct		Weight of Ash of Total	Cum Weight of Ash	Cum Floats		Sink Weight of Ash	Cum Sinks		+0.1 S.G. Distribution	
	Weight	Ash			Weight	Ash		Weight	Ash	S.G.	Weight
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	%	%	%	%	%	%	%	%	%	%	%
−1.30	7.1	2.6	0.18	0.18	7.1	2.6	22.77	92.9	24.51	....	....
1.30–1.35	20.9	5.4	1.13	1.31	28.0	4.7	21.64	72.0	30.06	....	....
1.35–1.40	13.3	10.1	1.34	2.65	41.3	6.4	20.30	58.7	34.58	1.40	53.3
1.40–1.45	10.2	15.1	1.54	4.19	51.5	8.1	18.76	48.5	38.68	....	....
1.45–1.50	8.9	20.3	1.81	6.00	60.4	9.9	16.95	39.6	42.80	1.50	31.9
1.50–1.60	12.8	26.6	3.40	9.40	73.2	12.9	13.55	26.8	50.56	1.60	19.8
1.60–1.70	7.0	31.8	2.23	11.63	80.2	14.5	11.32	19.8	57.17	1.70	11.6
1.70–1.80	4.6	36.7	1.69	13.32	84.8	15.7	9.63	15.2	63.36	1.80	8.8
1.80–1.90	4.2	40.0	1.68	15.00	89.0	16.9	7.95	11.0	72.27	....	....
+1.90	11.0	72.3	7.95	22.95	100.0	23.0	....	....	....	....	....
	100.0	....	22.95	....	....	....	....	....	....	....	....

Appendix 4.1b



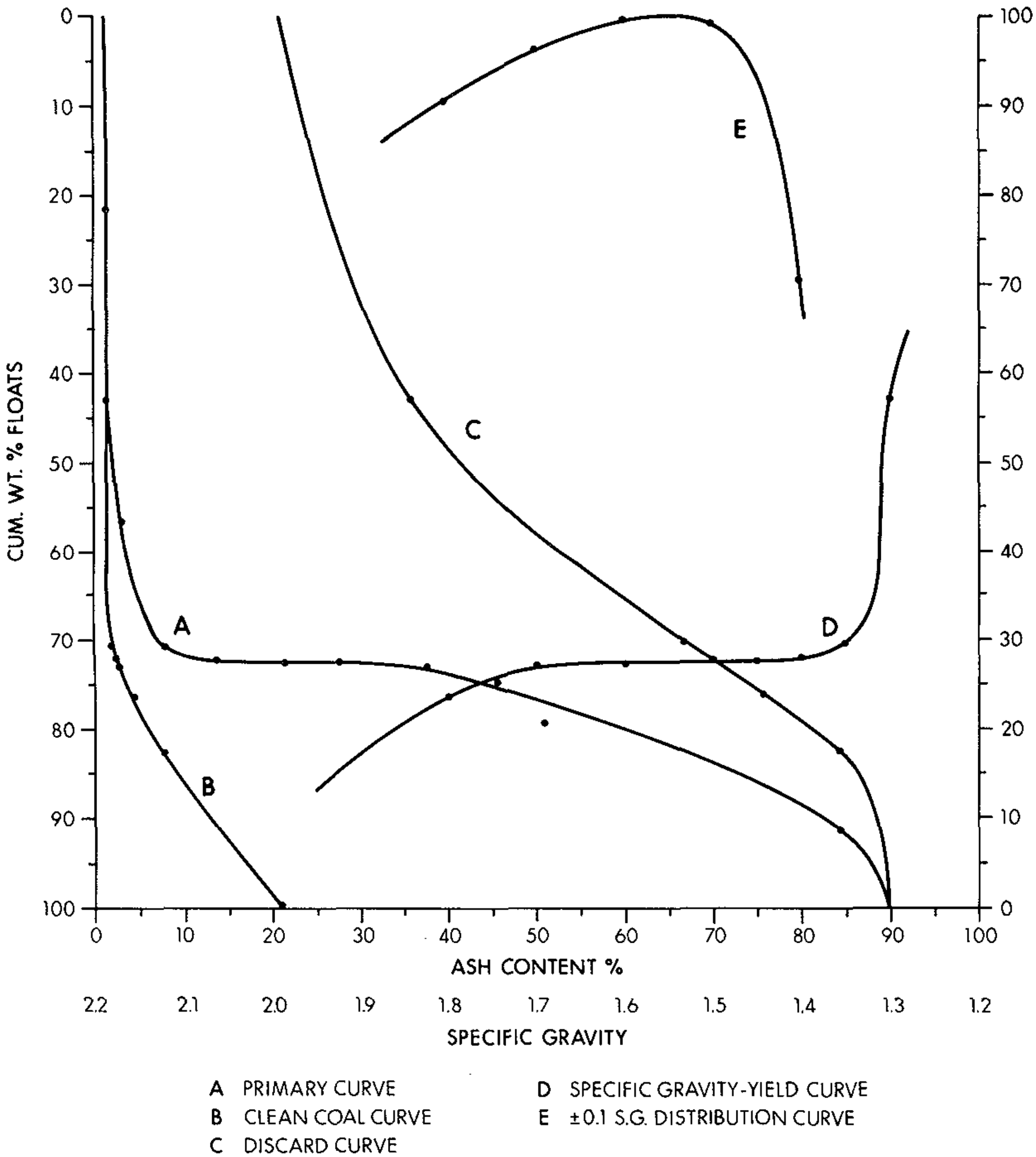
A PRIMARY CURVE
B CLEAN COAL CURVE
C DISCARD CURVE
D SPECIFIC GRAVITY-YIELD CURVE
E ±0.1 S.G. DISTRIBUTION CURVE

Appendix 4.1c

Client: B.C. Coal Task Force.
Sample identification: Seam A.

Specific Gravity	*Direct*		Weight of Ash of Total	*Cum* Weight of Ash	*Cum Floats*		*Sink* Weight of Ash	*Cum Sinks*		+0.1 S.G. Distribution	
	Weight	Ash			Weight	Ash		Weight	Ash	S.G.	Weight
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	%	%	%	%	%	%	%	%	%	%	%
−1.30	43.1	1.6	0.69	0.69	43.1	1.6	20.46	56.9	35.96	....	....
1.30–1.35	27.3	3.0	0.82	1.51	70.4	2.1	19.64	29.6	66.35	....	....
1.35–1.40	1.8	8.1	0.15	1.66	72.2	2.3	19.49	27.8	70.11	1.40	29.7
1.40–1.45	0.4	13.4	0.05	1.71	72.6	2.4	19.44	27.4	70.95	....	....
1.45–1.50	0.2	21.3	0.04	1.75	72.8	2.4	19.40	27.2	71.32	1.50	0.8
1.50–1.60	0.2	27.6	0.06	1.81	73.0	2.5	19.34	27.0	71.63	1.60	0.4
1.60–1.70	0.2	37.7	0.08	1.89	73.2	2.6	19.26	26.8	71.87	1.70	3.4
1.70–1.80	3.2	45.3	1.45	3.34	76.4	4.4	17.81	23.6	75.47	1.80	9.5
1.80–1.90	6.3	51.0	3.21	6.55	82.7	7.9	14.60	17.3	84.39	....	....
+1.90	17.3	84.4	14.60	21.15	100.0	21.1	....	....	....	....	....
	100.0	....	21.15	....	....	....	....	....	....	....	....

Appendix 4.1d

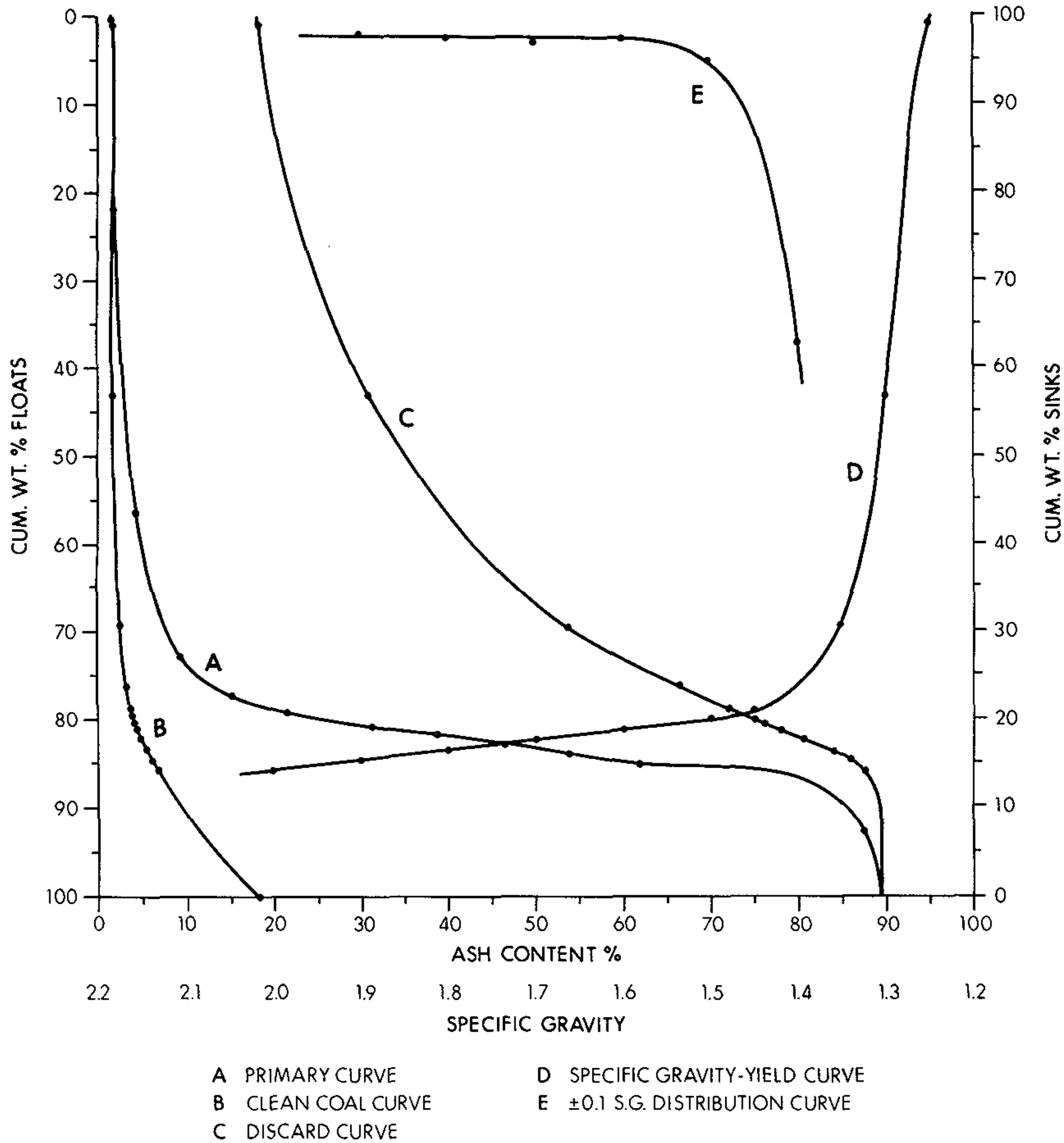


Appendix 4.1e

Client: British Columbia Coal Mine "A."
Sample identification: Raw coal.
Size fraction: Plus 28-mesh composite.

Specific Gravity	Direct		Weight of Ash of Total	Cum Weight of Ash	Cum Floats		Sink Weight of Ash	Cum Sinks		+0.1 S.G. Distribution	
	Weight	Ash			Weight	Ash		Weight	Ash	S.G.	Weight
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	%	%	%	%	%	%	%	%	%	%	%
−1.25	0.72	1.34	0.01	0.01	0.72	1.34	18.60	99.28	18.73	...	...
1.25–1.30	42.05	1.82	0.77	0.78	42.77	1.81	17.83	57.23	31.15	...	...
1.30–1.35	26.12	4.38	1.14	1.92	68.89	2.79	16.69	31.11	53.65	...	...
1.35–1.40	7.03	9.70	0.68	2.60	75.92	3.43	16.01	24.08	66.49	1.40	36.75
1.40–1.45	2.40	15.30	0.37	2.97	78.32	3.79	15.64	21.68	72.14	...	...
1.45–1.50	1.20	21.35	0.26	3.23	79.52	4.05	15.38	20.48	75.10	1.50	4.90
1.50–1.55	0.70	25.27	0.18	3.41	80.22	4.24	15.20	19.78	76.85	...	...
1.55–1.60	0.60	31.34	0.19	3.60	80.82	4.44	15.01	19.18	78.26	1.60	2.46
1.60–1.70	1.16	38.89	0.45	4.05	81.98	4.93	14.56	18.02	80.80	1.70	2.71
1.70–1.80	1.55	46.60	0.72	4.77	83.53	5.70	13.84	16.47	84.03	1.80	2.46
1.80–1.90	0.91	53.78	0.49	5.26	84.44	6.22	13.35	15.56	85.80	1.90	1.86
1.90–2.00	0.95	61.43	0.58	5.84	85.39	6.83	12.77	14.61	87.41	...	...
+2.00	14.61	87.40	12.77	18.61	100.00	18.60	...	...	...	...	...
	100.00	...	18.61	...	...	...	...	...	...	...	...

Appendix 4.1f

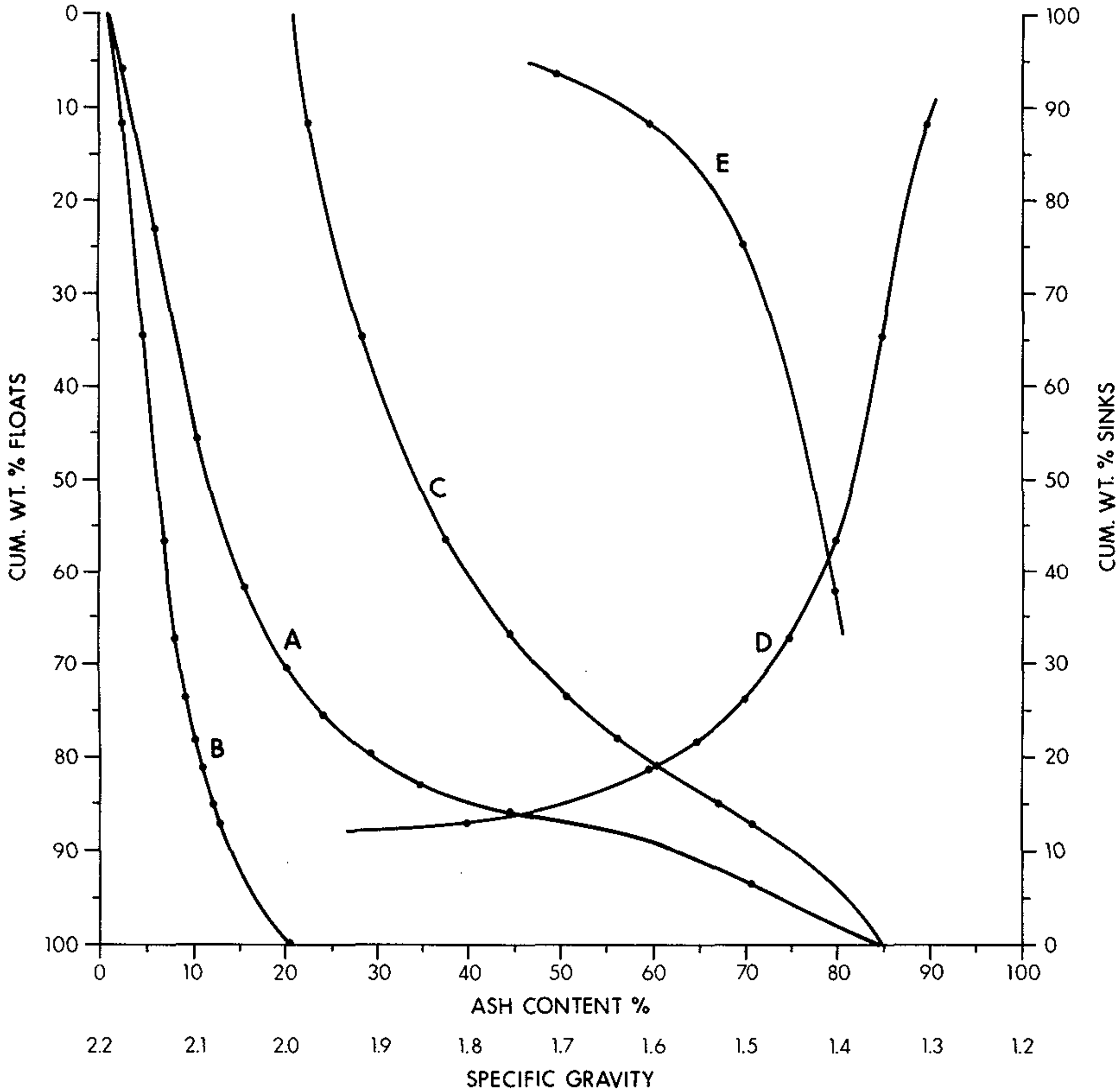


Appendix 4.1g

Client: British Columbia Coal Mine "B."
Sample identification: Raw coal.
Size fraction: 4″×28M.

Specific Gravity	Direct		Weight of Ash of Total	Cum Weight of Ash	Cum Floats		Sink Weight of Ash	Cum Sinks		+0.1 S.G. Distribution	
	Weight	Ash			Weight	Ash		Weight	Ash	S.G.	Weight
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	%	%	%	%	%	%	%	%	%	%	%
1.30	11.43	2.71	0.31	0.31	11.43	2.71	20.35	88.57	22.98	....	....
1.35	23.08	6.24	1.44	1.75	34.51	5.07	18.91	65.49	28.87	....	....
1.40	21.84	10.95	2.39	4.14	56.35	7.35	16.52	43.65	37.85	1.40	62.05
1.45	10.69	15.97	1.71	5.85	67.04	8.72	14.81	32.96	44.93	....	....
1.50	6.44	20.66	1.33	7.18	73.48	9.77	13.48	26.52	50.83	1.50	24.75
1.55	4.52	24.48	1.11	8.29	78.00	10.62	12.37	22.00	56.23	....	....
1.60	3.10	29.85	0.93	9.22	81.10	11.36	11.44	18.90	60.69	1.60	11.58
1.70	3.96	35.06	1.39	10.61	85.06	12.46	10.05	14.94	67.27	1.70	6.05
1.80	2.10	44.60	0.94	11.55	87.16	13.24	9.11	12.84	70.95	....	....
+1.80	12.84	70.93	9.11	20.66	100.00	20.64	....	....	....	....	....

Appendix 4.1h



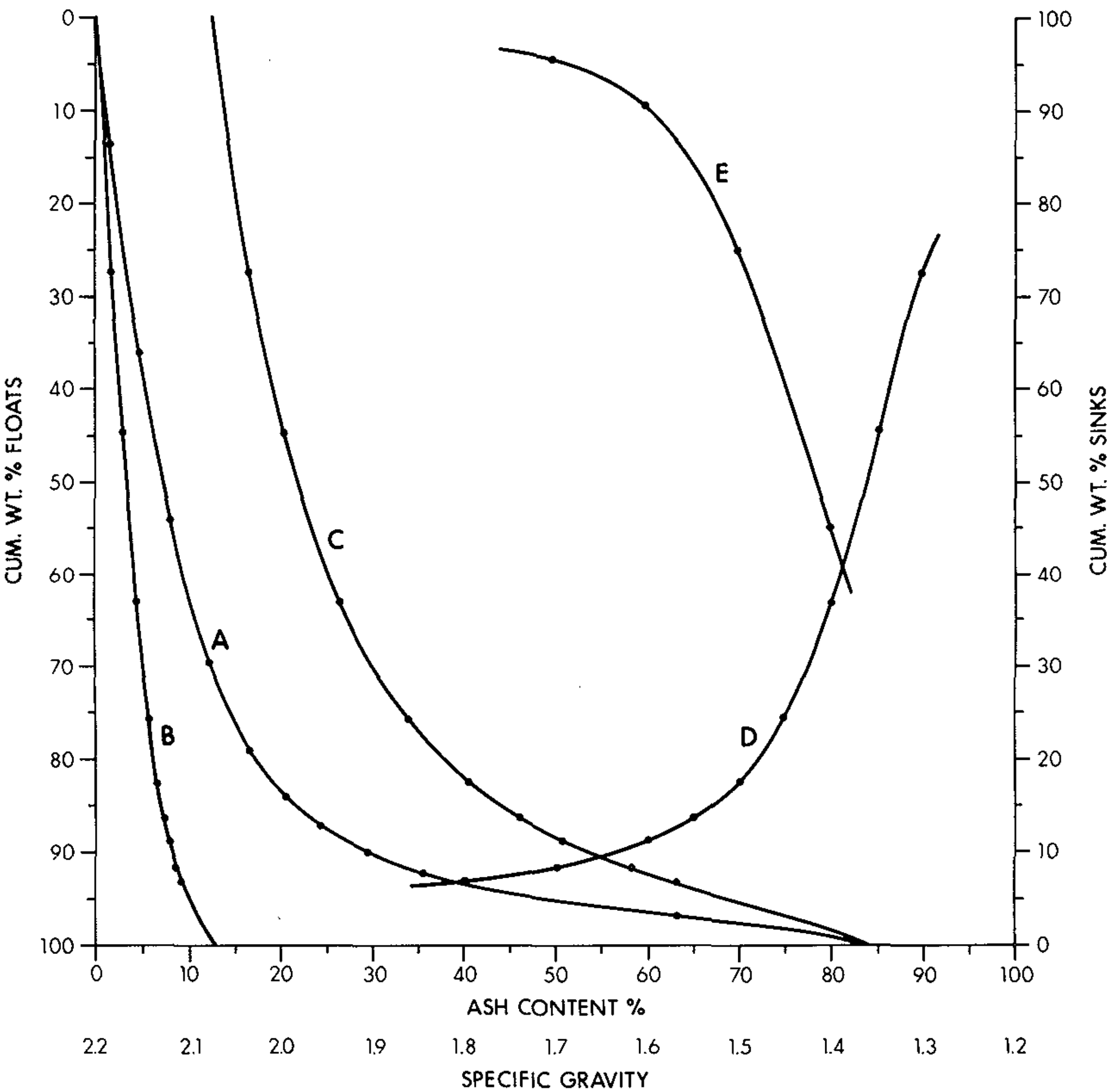
A PRIMARY CURVE
B CLEAN COAL CURVE
C DISCARD CURVE
D SPECIFIC GRAVITY-YIELD CURVE
E ±0.1 S.G. DISTRIBUTION CURVE

Appendix 4.1i

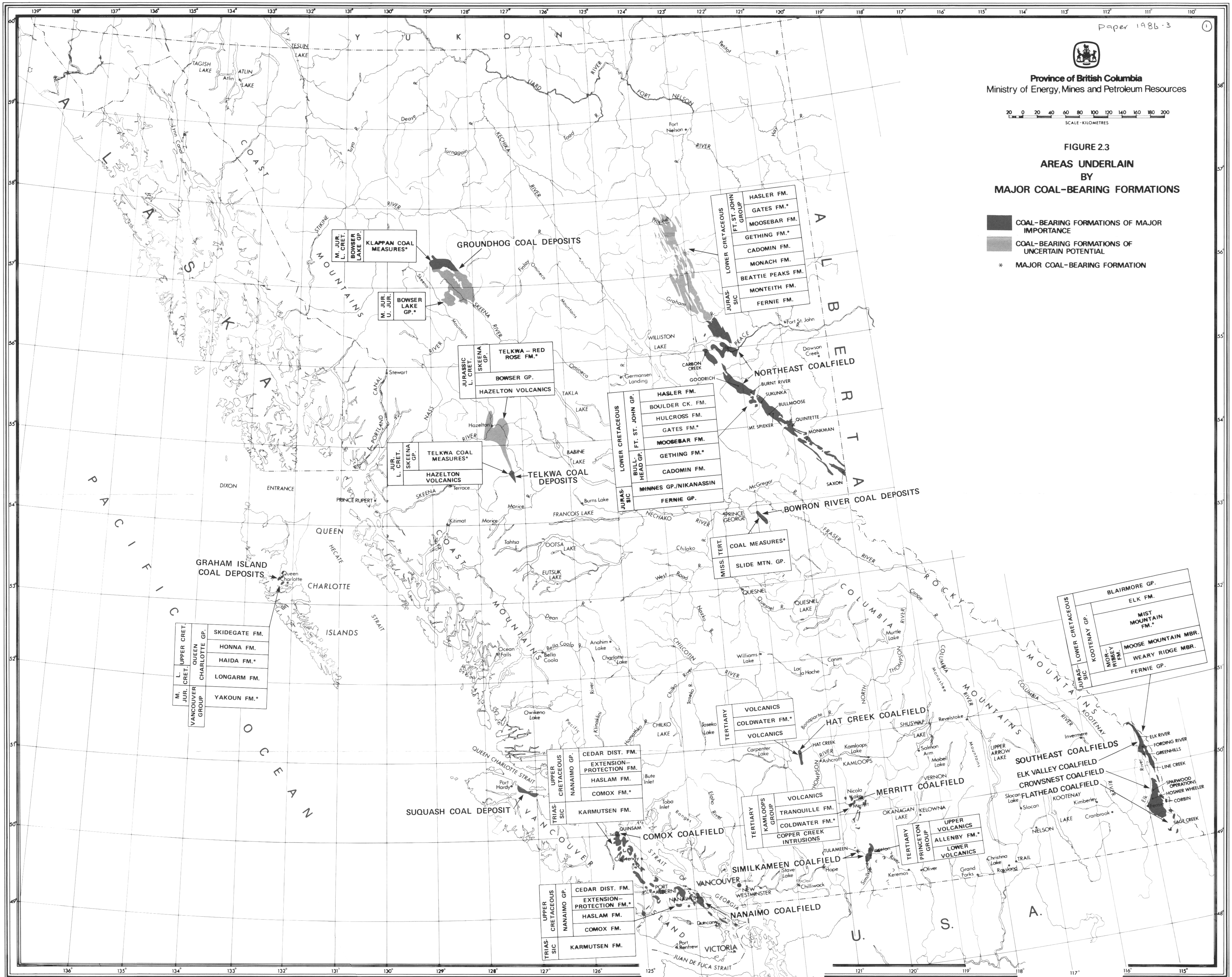
Client: British Columbia Coal Mine "B."
Sample identification: Raw coal.
Size fraction: 28M × 100M.

Specific Gravity	Direct		Weight of Ash of Total	Cum Weight of Ash	Cum Floats		Sink Weight of Ash	Cum Sinks		+0.1 S.G. Distribution	
	Weight	Ash			Weight	Ash		Weight	Ash	S.G.	Weight
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	%	%	%	%	%	%	%	%	%	%	%
1.30	27.4	1.7	0.47	0.47	27.4	1.7	12.22	72.6	16.83	...	...
1.35	17.3	4.9	0.85	1.32	44.7	2.9	11.37	55.3	20.56	...	...
1.40	18.5	8.2	1.52	2.84	63.2	4.5	9.85	36.8	26.77	1.40	54.8
1.45	12.4	12.2	1.51	4.35	75.6	5.7	8.34	24.4	34.18	...	...
1.50	6.6	16.6	1.10	5.45	82.2	6.6	7.24	17.8	40.67	1.50	25.2
1.55	3.8	20.5	0.78	6.23	86.0	7.2	6.46	14.0	46.14	...	...
1.60	2.4	24.2	0.58	6.81	88.4	7.7	5.88	11.6	50.69	1.60	9.2
1.70	3.0	29.3	0.88	7.69	91.4	8.4	5.00	8.6	58.14	1.70	4.5
1.80	1.5	35.6	0.53	8.22	92.9	8.8	4.47	7.1	62.96	...	...
+1.80	7.1	62.9	4.47	12.69	100.0	12.7	...	...	...	...	...
	100.0	...	12.69	...	...	...	...	...	...	...	...

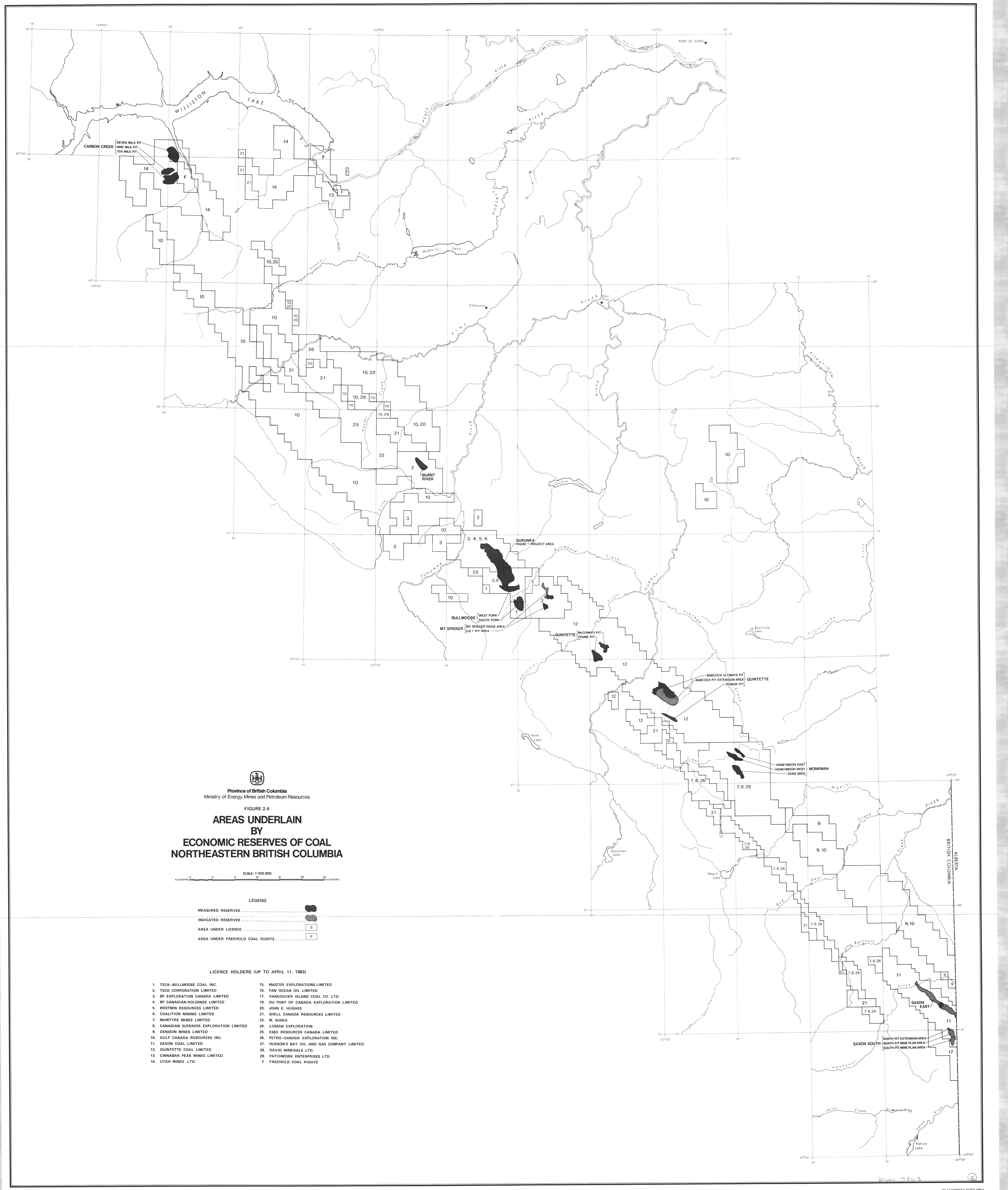
Appendix 4.1j



A PRIMARY CURVE
B CLEAN COAL CURVE
C DISCARD CURVE
D SPECIFIC GRAVITY-YIELD CURVE
E ±0.1 S.G. DISTRIBUTION CURVE



TO ACCOMPANY PAPER 1986-3



Province of British Columbia
Ministry of Energy, Mines and Petroleum Resources
FIGURE 2.4
AREAS UNDERLAIN BY ECONOMIC RESERVES OF COAL NORTHEASTERN BRITISH COLUMBIA
SCALE - 1: 250 000
KILOMETRES 5 0 5 10 15 20 25 KILOMETRES
LEGEND
MEASURED RESERVES
INDICATED RESERVES
AREA UNDER LICENCE
AREA UNDER FREEHOLD COAL RIGHTS
LICENCE HOLDERS (UP TO APRIL 11, 1983)
1. TECK–BULLMOOSE COAL INC.
2. TECK CORPORATION LIMITED
3. BP EXPLORATION CANADA LIMITED
4. BP CANADIAN HOLDINGS LIMITED
5. WESTMIN RESOURCES LIMITED
6. COALITION MINING LIMITED
7. McINTYRE MINES LIMITED
8. CANADIAN SUPERIOR EXPLORATION LIMITED
9. DENISON MINES LIMITED
10. GULF CANADA RESOURCES INC.
11. SAXON COAL LIMITED
12. QUINTETTE COAL LIMITED
13. CINNABAR PEAK MINES LIMITED
14. UTAH MINES LTD.
15. MASTER EXPLORATIONS LIMITED
16. PAN OCEAN OIL LIMITED
17. VANCOUVER ISLAND COAL CO. LTD.
19. DU PONT OF CANADA EXPLORATION LIMITED
20. JOHN E. HUGHES
21. SHELL CANADA RESOURCES LIMITED
23. M. SUSKA
24. LOSSAN EXPLORATION
25. ESSO RESOURCES CANADA LIMITED
26. PETRO–CANADA EXPLORATION INC.
27. HUDSON'S BAY OIL AND GAS COMPANY LIMITED
28. DAVID MINERALS LTD.
29. PATCHWORK ENTERPRISES LTD.
F FREEHOLD COAL RIGHTS
WILLISTON LAKE
CARBON CREEK
SEVEN MILE PIT
NINE MILE PIT
TEN MILE PIT
PEACE RIVER
FORT ST. JOHN
MOBERLY RIVER
Moberly Lake
Chetwynd
East Pine
PINE RIVER
BURNT RIVER
SUKUNKA
PHASE 1 PROJECT AREA
BULLMOOSE
WEST FORK
SOUTH FORK
MT. SPIEKER
MT. SPIEKER RIDGE AREA
E.B.1 PIT AREA
QUINTETTE
McCONKEY PIT
FRAME PIT
BABCOCK ULTIMATE PIT
BABCOCK PIT EXTENSION AREA
ROMAN PIT
MONKMAN
HONEYMOON EAST
HONEYMOON WEST
DUKE AREA
MURRAY
KISKATINAW RIVER
Gwillim Lake
Bearhole Lake
Hook Lake
Monkman Lake
Wapiti Lake
WAPITI RIVER
Belcourt
SAXON EAST
SAXON SOUTH
NORTH PIT EXTENSION AREA
NORTH PIT MINE PLAN AREA
SOUTH PIT MINE PLAN AREA
Kakwa Lake
ALBERTA
BRITISH COLUMBIA
TO ACCOMPANY PAPER 1986-3

TO ACCOMPANY PAPER 1986-3