STONE & WEBSTER CANADA LIMITED

BRITISH COLUMBIA
HYDRO AND POWER AUTHORITY

HAT CREEK COAL UTILIZATION STUDY

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HAT CREEK COAL UTILIZATION STUDY

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BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Hat Creek Coal Utilization Study

1. - EXECUTIVE SUMMARY

1.1 This Study Report investigates the development of the Hat Creek coal deposit for uses which may provide technically and economically attractive alternatives to its development as a source for steam-electric power generation within the period 1980-2010.

1.2 The Terms of Reference (Appendix A) provided wide scope for investigating the possible technical utilization of Hat Creek coal. Similarly, it has been possible to investigate possible markets for upgraded Hat Creek coal products on provincial, continental and worldwide scales. The investigation of economic factors has been carried out within the constraints of a set of economic criteria, drawn up by B.C. Hydro and Power Authority in consultation with economists of the Department of Economic Development, Government of British Columbia. These economic criteria laid stress upon using opportunity costs as guiding principles in drawing economic comparisons.

1.3 The Study was organized to contain the following principle sections:

- Geography and Magnitude of the Hat Creek coal deposit.
- Properties of Hat Creek coal.
- Coal Conversion Potential.

The section describing Properties is devoted to an exhaustive examination of the properties of the coal and their bearing on possible methods of utilization. The section dealing with Conversion Potential includes consideration of coal processing methods, markets for upgraded coal products, economic comparisons within a generalized opportunity costs framework, and a description of environmental impact and environmental engineering factors.

The remaining section provides a description of those processes which were selected for detailed study based upon coal properties, coal processing, and marketing considerations. They fall into three natural divisions
- Principally Solid Products
- Principally Liquid Products
- Principally Gaseous Products.

1.4 The study team was international and included members from Canada, Germany and the United States. Technology, marketing and economics have encompassed the free-World and every effort has been made to state the position as it stands at January 1977.

1.5 In accordance with the agreed Scope of Work,the Study has been limited to consideration of processes producing one principal product plus by-products. During the course of the work it became clear that a strong case could be made for considering the design of process plants with built-in flexibility to produce two or more principal products plus by-products. Such an arrangement permits taking maximum advantage of changing market situations but it is emphasized that flexibility is bought only at increasing cost, eventually to the point of economic non-viability. The point of balance between competitiveness in the energy marketplace and a loss-making situation can best be determined by further study within a pre-determined and limited technical and economic framework. If the conclusions and recommendations of the present report are acceptable it is strongly urged that additional studies, along the lines suggested, be undertaken in order to refine further the balance of advantages between development of Hat Creek coal for upgraded coal processing products or for steam-electric power.

1.6 Summary and Conclusions

The known properties and their relevance to modern coal conversion technology of Hat Creek coal have been exhaustively considered. This analysis has been accompanied by an assessment of the marketing prospects for the potential coal conversion products against a provincial, continental and world scenario. The combined results from these exercises have provided a basis for an economic and financial analysis from which the following conclusions are drawn:

1. A plant to produce 7.14-8.57 million Nm^3 per day (250-300 MM SCFD) of Synthetic Natural Gas is a technically and economically viable use of Hat Creek coal.

2. The production of methanol, while technically feasible, faces an uncertain market situation. Any alteration in present usages of methanol, such as its use as a gasoline additive, will produce a vast increase in world demand and the use of Hat Creek coal for methanol production will provide an attractive alternative to its use for steam-electric power generation.

3. The production of ammonia and hence of nitrogenous fertilizers, while technically feasible, faces a very unsatisfactory world market situation in which ample capacity into the 1990's seems a certainty.

4. The production of coal liquids by any of the processes now becoming available, does not appear to be economically attractive.

5. The possible production of upgraded solid products from Hat Creek coal, such as metallurgical coke, form coke or activated carbons is not technically feasible because of the very high inherent ash. The complete absence of coking properties, while important, is secondary to this prime question of very high ash content.

6. In-situ gasification of Hat Creek coal has been briefly considered and rejected because of the lack of technically relevant information on the coal deposits and major uncertainties in the present technology. (B.C. Hydro's membership of the consortium supporting the Alberta Research Council's trials at Battle River, Alberta, during the summer of 1976, has provided better information on the possibilities than the authors' can provide at this stage.)

7. Evaluation of the environmental impact of the coal conversion processes recommended for Hat Creek, and indeed for other processes studied but not recommended, leads to a conclusion that emissions of particulates, sulphur dioxide, nitrogen oxides, carbon monoxide and hydrocarbons for normal operating conditions of coal conversion plant can be controlled to meet environmental regulations and guidelines.

8. The Report, in accordance with the agreed Scope of Work, has been confined tc the consideration of single principal products plus by-products. It has become clear that a need exists for extending the studies to include mixed principal products and consideration of this course by B.C. Hydro is strongly recommended.

9. Some areas of the study-work have been hampered by lack of necessary or of adequate information. This need is particularly noticeable because of the uniqueness of Hat Creek coal in terms of its low rank and grade, and the unusual ash characteristics. If the development of alternatives to steam-electric power production are to be pursued further, it is strongly recommended that the appropriate work of placing of required contracts, to obtain the necessary information be undertaken at an early date.

10. The very low rank and grade of Hat Creek coal are not considered to be serious obstacles to its development for coal conversion. The Report has demonstrated that coal deposits of lower rank and

grade are finding economic employment in other parts of the world and that production costs forecast for Hat Creek coal are economically viable.

11. The Report has been based, as far as Synthetic Natural Gas and coal liquids are concerned, upon a coal throughput of 18 million tons per annum. This is approximately equivalent to 6360 m^3 (40,000 bbl.) per day of synthetic crude oil; 7.14-8.57 million Nm^3 (250-300 million SCFD) of synthetic natural gas; or 3,000-3,500 MW of electric power. It should be observed that this depletion rate would exhaust the No. 1 Deposit at Hat Creek, at present estimates of mineable reserves, in 30 years. Production of say SNG and electric power in the quantities mentioned would deplete mineable reserves in the No. 1 Deposit in 15 years, or in No. 1 and No. 2 Deposits in 30 years. Therefore, until mining studies prove otherwise, it is strongly recommended that the Hat Creek deposit be regarded as a finite resource, capable of exhaustion by present technology within a half-century.

2. - INTRODUCTION

2.1 The studies reported below were performed by Stone & Webster Canada Limited in association with Stone & Webster Engineering Corporation, Boston, Massachusetts; Stone & Webster Management Consultants Incorporated, New York, N. Y.; and Montan Consulting GmbH, Essen, Germany.

2.2 The purpose of the studies were to identify and examine potential uses for Hat Creek coal which could be considered as alternatives to the production of electric power; to describe those processes and applications which appeared to offer technical and economic possibilities; and to indicate potential markets for the coal and its conversion products.

2.3 The ground base for the studies of alternate uses has been laid by earlier and by ongoing studies by other consultants. These studies included geology and exploration of the coal reserves at Hat Creek, preliminary environmental impact of development, conceptual mining schemes using openpit methods, coal washing and beneficiation investigations, advanced electric power generation techniques and coal gasification. Some of this work is continuing so that the present report presents the overall situation as it is understood to be in January 1977.

A list of the other consultants' reports considered is shown in Appendix 'B'.

2.4 The Terms of Reference for the work are shown in Appendix 'A'.

2.5 It is important to note that the studies reported here are based upon information and reports supplied by B.C. Hydro and Power Authority, literature reviews, interviews and enquiries. No fieldwork at Hat Creek and no laboratory, pilot or demonstration work has been undertaken. As will become clear below, the available information is insufficient in some important areas of the work and a number of laboratory and pilot investigations will be required before progress from the present conceptual-only stage can be made. Some suggestions for further work, defining subjects where more information is required and how such information may be obtained, is included in the technical reviews.

2.6 Attention is drawn to the following general remarks:

i) Technology

Because of the renewed recognition of coal as an important item in the world and North American energy budgets, efforts made in the development of coal conversion processes are more intensive at the present time than at any previous age. Major research and development work is being carried out in the United States, Germany, Great Britain and Australia. Substantial effort in the processing and utilization of low grade coals is also underway in certain other countries, e.g. India, South Africa. Every effort has been made to keep abreast of progress in these countries and to present the status as it exists at January 1977.

ii) Environmental Engineering

The Government of British Columbia has not yet issued regulations governing the operation of coal conversion plants other than for steam raising and steel production. In this circumstance the relevant regulations, issued by the American Environmental Protection Agency (EPA), have been employed additionally as guidelines when considering the environmental engineering requirements of the coal conversion processes described in the Report.

iii) Capital and Operating Costs

Except for coke oven and by-product plants, usually forming part of large, integrated iron and steel works, no major coal conversion plants have been constructed in North America since the end of World War II. While a number of cost studies have been undertaken in America during the past two to three years, mainly supported by funding provided by the Energy Research and Development Agency, the only major commercial costs estimates for which information has become available have been for SNG production by:

a) El Paso Natural Gas Company
b) Michigan Wisconsin Pipeline Company and American Natural Gas Company
c) Transwestern Pipeline Company, Transwestern Coal Gasification Company, Pacific Coal Gasification Company and Western Gasification Company.

Not one of these proposed projects has yet proceeded to a stage where construction can commence. In the meantime the original costs estimates have been increased by a factor of 2 - 3 times as a direct result of prevailing inflation rates (Table 2.1).

While the commercially oriented costs in the above studies have been carefully considered in preparing this Report, as have many of the results of costs studies undertaken as part of the ERDA and other programmes, it must be emphasized that the costs estimates are 'paper only'. This situation will only be corrected when major coal conversion project design, engineering, procurement, construction and operations can be undertaken.

TABLE 2.1

COST INDICES*1971-1975

YEAR	PRICE INDICES(a)				CONSTRUCTION COST INDICES					MISCELLANEOUS INDICES		
	Consumer	Whlsl Comm.	Total Chem & Allied	Ind'l Chem	Chem. Equipm.(b)	Process Plants(c)	Petro Ref.(d)	Gen'l Const. Cost(e)	Gen'l Bldg.	Plant Maint.(f)	Aug. Wkly Benefits(g)	Fringe Benefits(h)
1971	121.0	114.0	104.0	102.0	319.0	132.2	406.0	146.0	140.0	119.0	159.0	114.0
1972	125.3	119.1	104.2	101.2	329.7	137.2	438.5	163.04	155.18	125.5	175.98	-
1973	133.1	134.7	110.0	103.4	341.1	144.1	468.0	176.52	168.42	133.6	187.71	121.0
1974	147.7	160.1	146.8	151.7	400.5	165.4	522.7	187.99	178.31	164.2	201.7	-
1975	161.2	174.9	181.3	206.1	447.6	182.4	575.5	205.67	193.30	172.4	219.63	133.0

* Perry & Chilton "Chemical Engineers' Handbook", McGraw-Hill. 5th Edn. p. 5-25, updated

(a) U.S. Bureau of Labor Statistics, 1967 = 100
(b) Marshall & Stevens. Chem. Eng. 1926 = 100
(c) Chem. Eng. Index, 1957 - 1959 = 100
(d) Nelson. Oil & Gas.J. 1946 = 100
(e) Eng. News - Record 1967 = 100
(f) Factory J. 1968 = 100
(g) U.S. Dept. of Labor Data 1960 = 100
(h) U.S. Chamber of Commerce (Chem. & Allied Products) 1967 = 100

In Canada the only significant attempt to estimate costs of major coal conversion plant on a commercial basis appears to have been by Trans Canada Pipelines Ltd. For the present study detailed cost estimates have been generated for several coal conversion processes, but in addition published capital and operating costs from the technical and government press have been used.

iv) Financial and Economic Analysis

The Terms of Reference (Appendix 'A') require that Opportunity Costs be estimated for the potential uses of Hat Creek coal under investigation. Opportunity Cost, often better identified as "lost-opportunity cost", refers to the cost or values which are given up because a proposed investment is undertaken. Usually this will be the base investment which, for purposes of the present studies, is taken to be electric power generation.

In the present studies the possible frames of reference for the economic viability and opportunity cost could be on:

a) public utility works basis
b) public utility corporation basis
c) provincial basis
d) national basis.

It seemed clear, from the scale of possible operations envisioned for Hat Creek by the British Columbia Hydro and Power Authority, that a provincial basis was appropriate and following discussion, and upon advice, that course has been followed in this Report.

The introduction of a provincial frame of reference necessitated that an official view of the economic impact of development of the coal resource at Hat Creek be obtained. Joint discussions with economists, representing British Columbia Hydro and Power

Authority and British Columbia Department of Economic Development, have therefore been held at various times throughout the course of the studies and the outcome of these discussions are reflected in the financial and economic analysis reported.

v) Marketing Studies

British Columbia and its neighbouring western provinces of Alberta and Saskatchewan, collectively comprising Western Canada, is primarily a resource producing region. The total industrial manufacturing base of the entire region is as yet largely underdeveloped and, being sparsely populated, the domestic demand for manufactured products is correspondingly small. Thus, in considering coal conversion products it has been necessary to investigate potential markets, not only in the Province and Western Canada, but also in the neighbouring Pacific States of America, the Pacific rim countries, and the world as whole.

3. - GEOGRAPHY AND MAGNITUDE OF THE HAT CREEK DEPOSIT

3.1 Location

The Hat Creek coal deposit is located 200 kilometers northeast of Vancouver, B. C. and approximately 24 kilometers due west of the town of Lilloet. See Figure 3.1.

3.2 Rail Access

The B.C., CN and CP railroads pass close to the Hat Creek deposit (Figure 3.2). Connections with these railroads may be made by the construction of connecting links either at Clinton (for the B.C.R.) or at Anglesey for the CNR (Figure 3.3).

Direct connection between the deposit with both the Burrard Thermal Generating Station and the Vancouver area wharves would be possible via both rail links (Reference 3.2).

3.3 Water Supply

Large potential supplies of water are available at the Hat Creek deposit from either the Fraser or Thompson Rivers (Figure 3.3). In each case transport by pipeline for a distance of approximately 24 kilometers would be necessary. The Fraser and Thompson rivers have been reported to have mean annual discharges of 1865 m^3/s and 825 m^3/s respectively (Reference 3.1).

3.4 Proximity to Gas & Oil Pipelines

Both the petroleum and gas pipelines of Westcoast Transmission pass through Savona (Figure 3.4) at the lower end of Kamloops Lake (Figure 3.3) approximately 55 kilometers east of the Hat Creek deposit.

3.5 Proximity to Electric Power

The 500 KV transmission line from the northern hydroelectric generating stations passes close to Hat Creek and connections with this system at Kelly Lake, 30 kilometers to the north, are projected in the future (Figure 3.5, Reference 3.5).

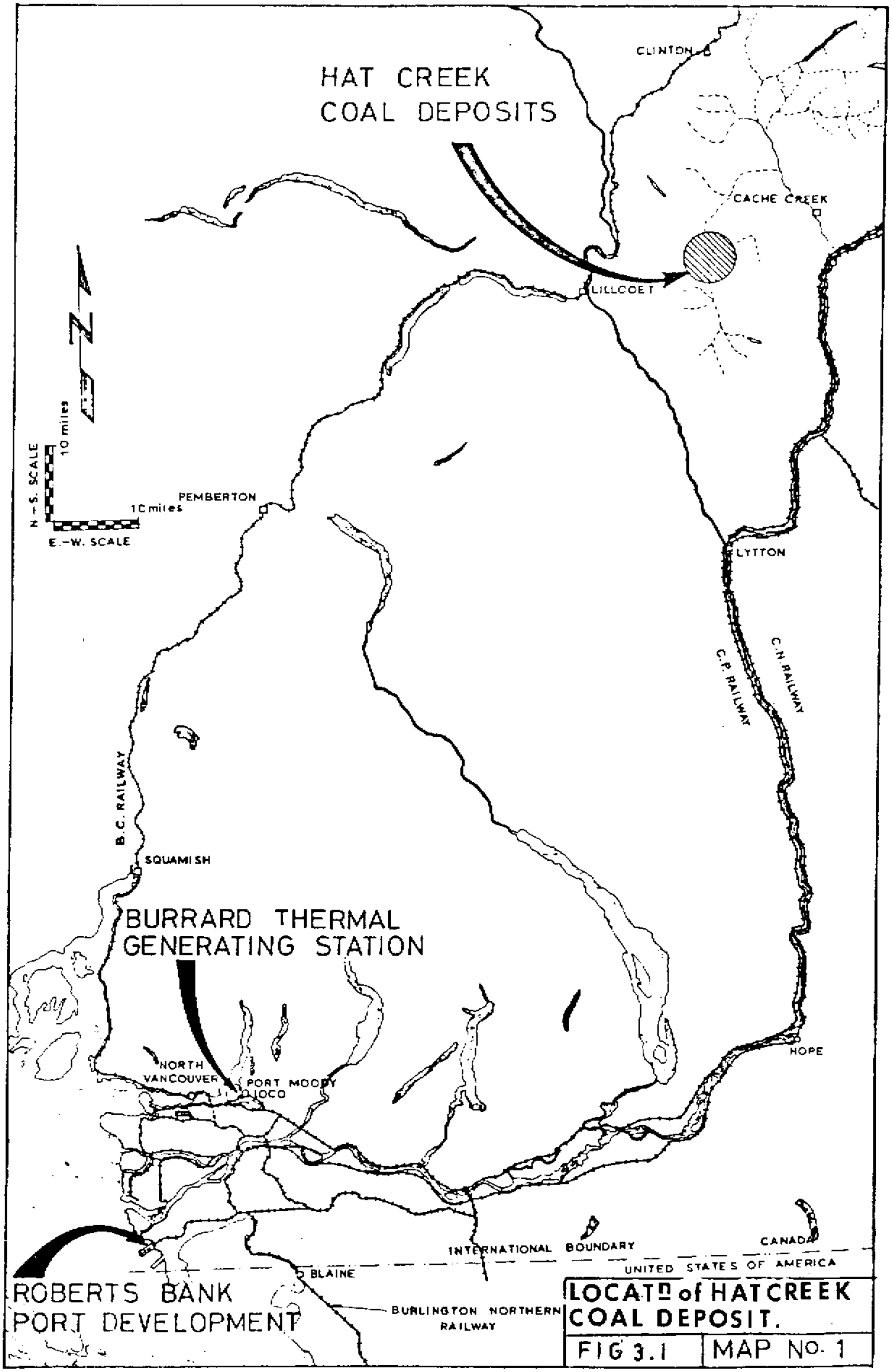
3.6 Magnitude of the Deposit

There are essentially two distinct deposits of coal in the Hat Creek Valley which for the purposes of exploitation have been designated Openpit No. 1 and Openpit No. 2 (References 3.3 & 3.4). Both pits have been stated to have similar geological and geotechnical environments (Reference 3.4).

The amount of coal obtainable from the No. 1 pit has been estimated at two levels depending on the depth of pit considered. With a 182 metres (600 feet) pit it is considered that "450 million tons of coal (insitu) (proved, probable and possible) will be available". With an extension of the pit depth to 457 metres (1500 feet) the total mineable reserves would become 910 million tons of coal. However, due to the formidable problem of predicting slope behaviour from borehole data it is impractical to design a pit deeper than 182 meters at this time.

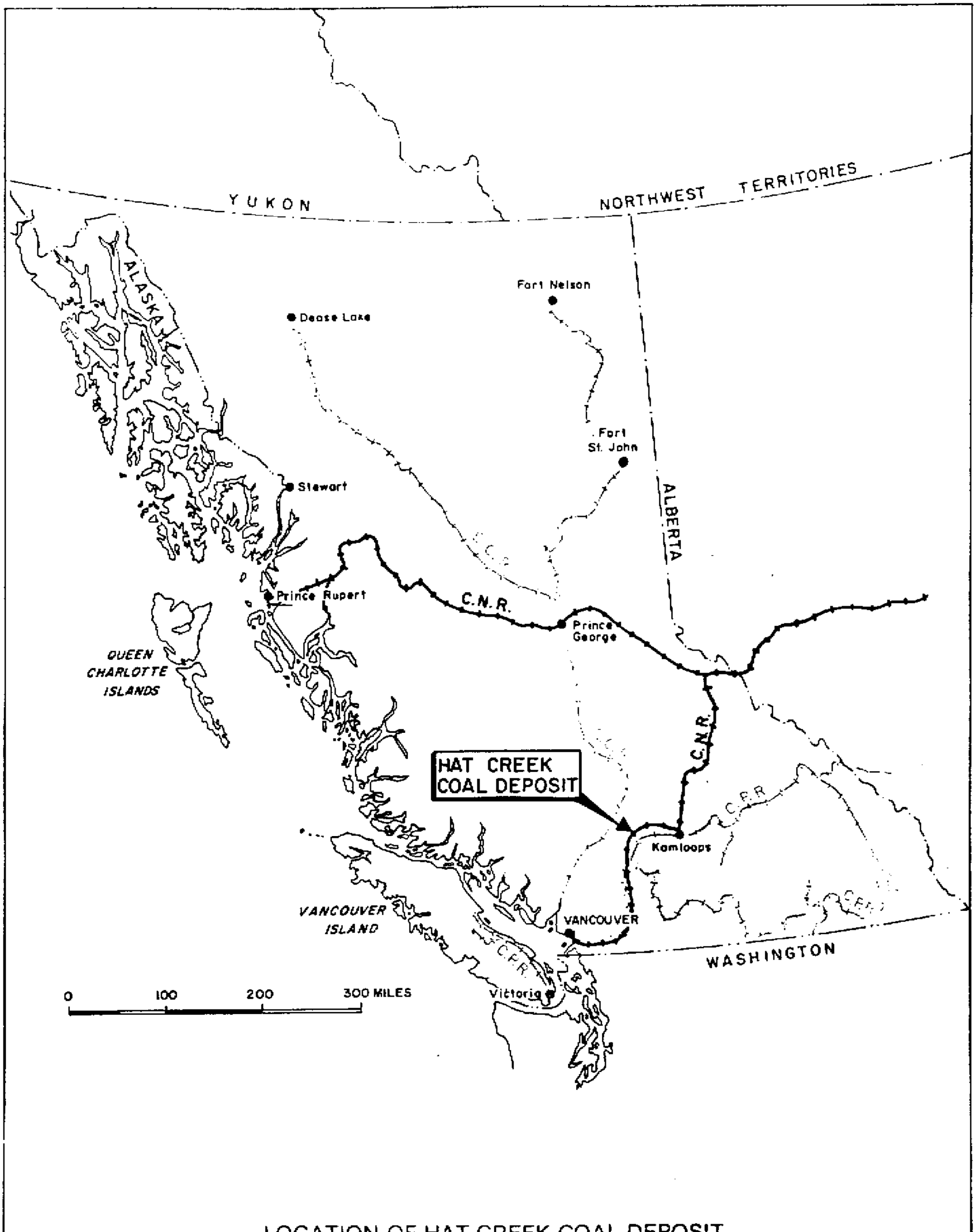
The extent of coal reserves that would be available in Openpit No. 2 has been conjectured to be 664 million tons with development to the 182 metres level. It has been estimated that a 457 metres pit would provide 3,397 million tons run of mine coal (Reference 3.4).

In both pits, but particularly Openpit No. 2, it can be seen that considerable coal reserves exist beyond the 182 metres level proposed for initial exploitation. It is stated that these reserves may not be economically mineable by surface mines, however, and that underground mining would be extremely difficult and also uneconomic at current price levels (Reference 3.4).



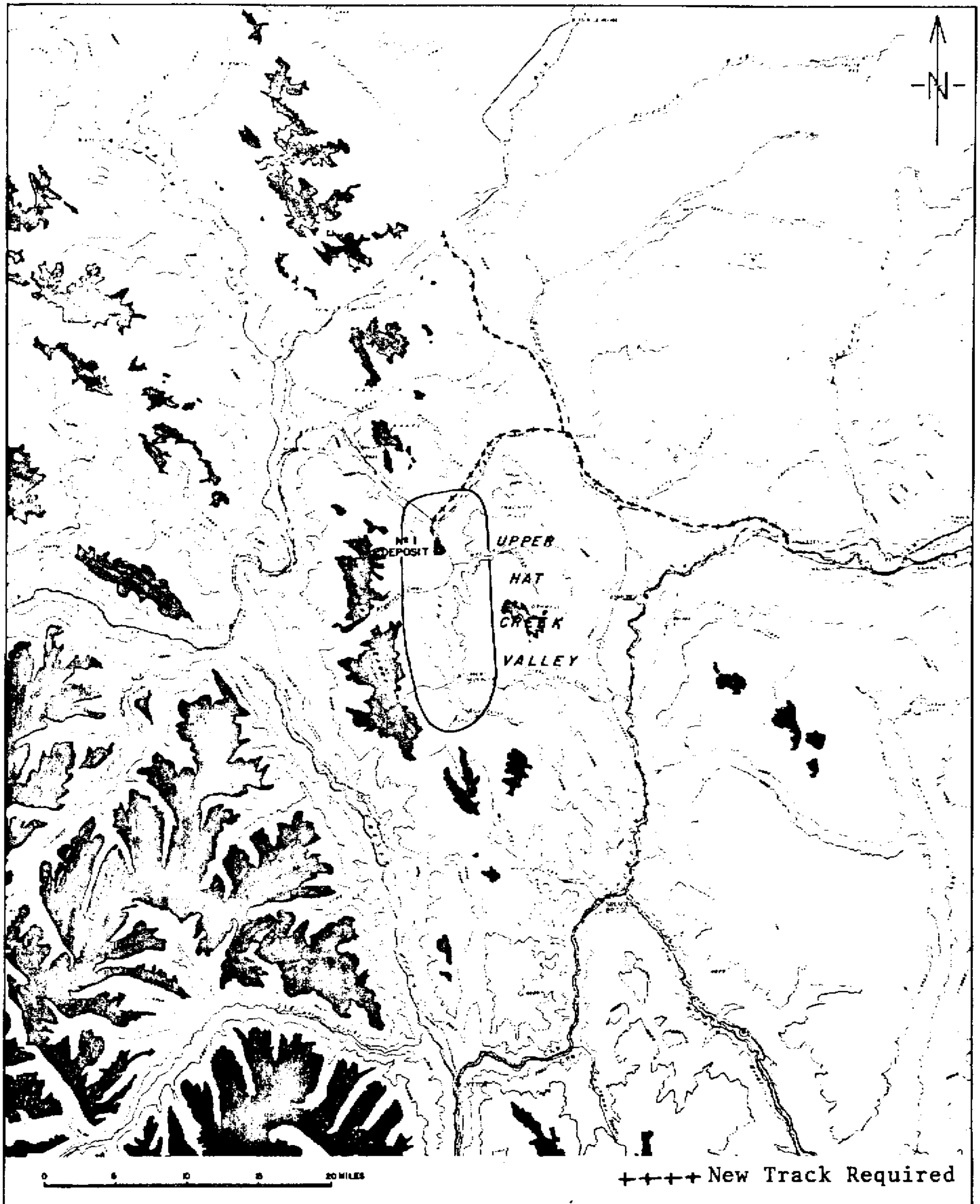
LOCAT$^{\underline{n}}$ of HATCREEK COAL DEPOSIT.

FIG 3.1 MAP NO. 1



LOCATION OF HAT CREEK COAL DEPOSIT
MAP No. 2

FIG 3.2



RELATION of RAILROADS to HAT CREEK.

FIG 3.3

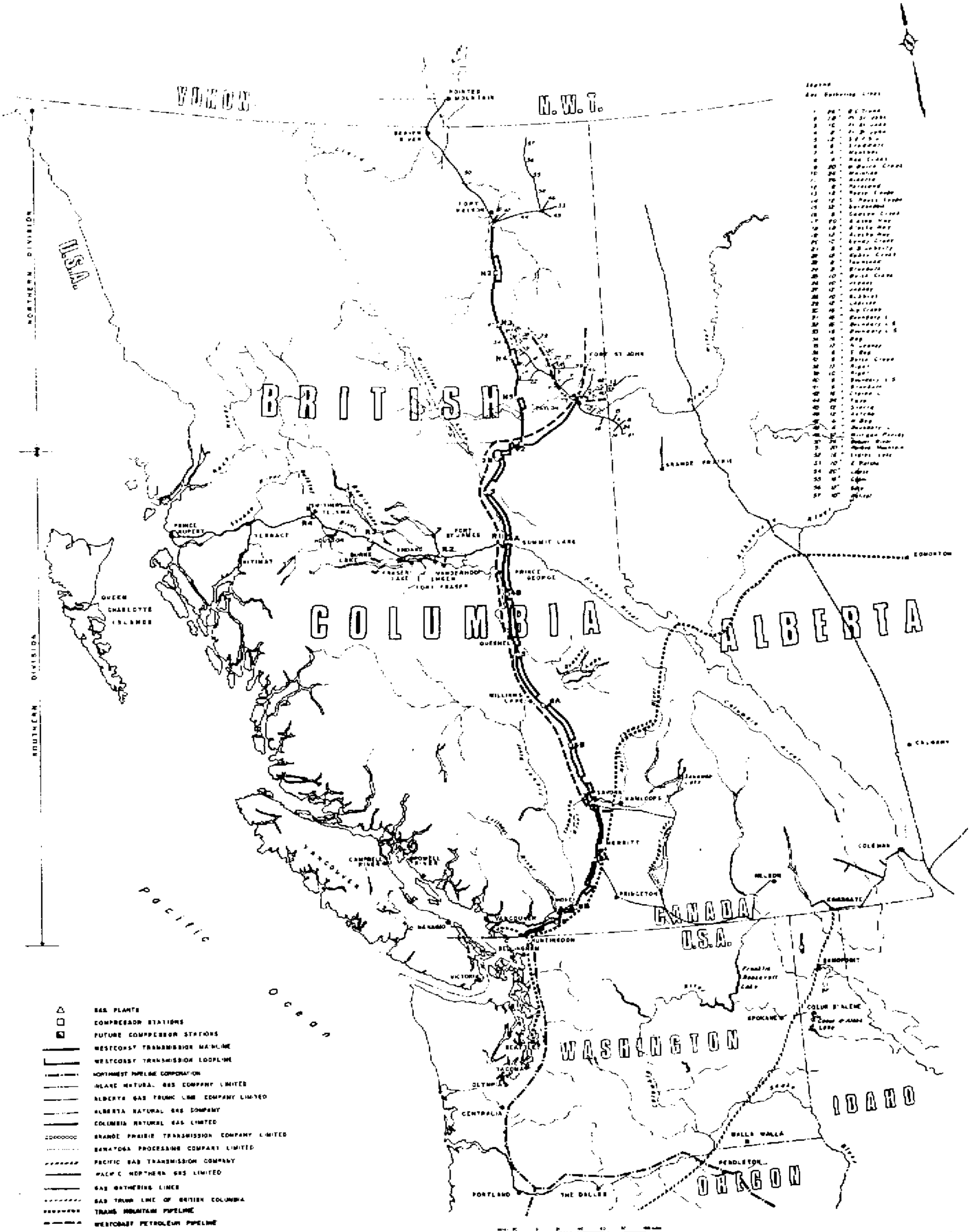


FIG 3.4

SOURCE: MAP COURTESY WEST COAST TRANSMISSION LTD

BRITISH COLUMBIA
PIPELINE SYSTEMS

LOCATION OF GENERATION, TRANSMISSION AND SUBSTATIONS ON B.C. HYDRO SYSTEM

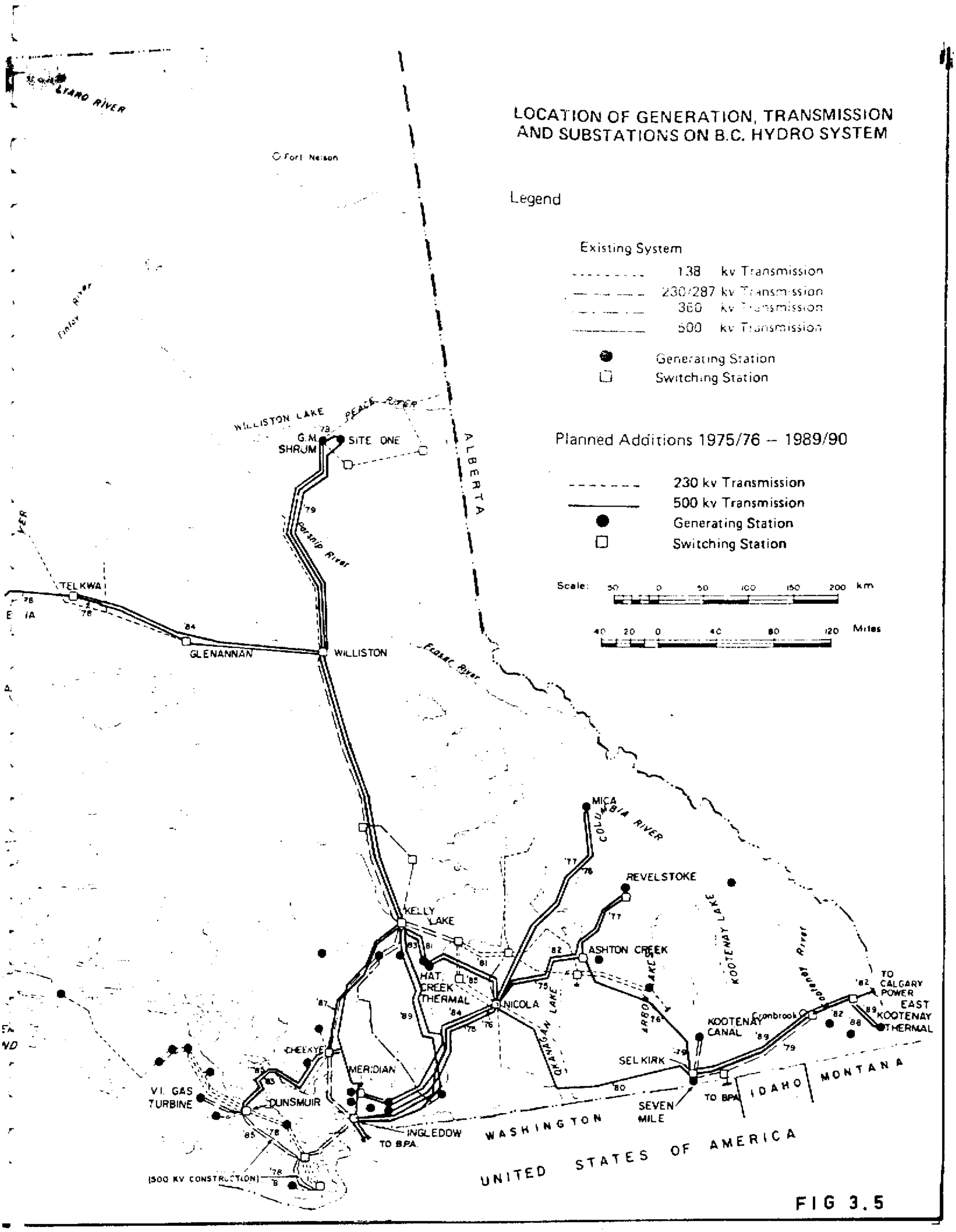


FIG 3.5

4. PROPERTIES OF HAT CREEK COAL

4.1 Introductory Note

4.1.1 The general use of the word COAL is misleading unless the singular is understood to include the plural. From the scientific and technical standpoint there are many different types of coal and the particular properties and characteristics exhibited by any coal are generally of crucial importance in the utilization, and usually in the design of processing equipment employed in the utilization of that coal.

4.1.2 One result of the energy problem has been the appearance of many technical articles in which coal, oil, gas and uranium resources are discussed only in terms of energy contents, with too little regard being paid to the real differences that exist in the means of exploiting and utilizing them. This simplistic approach can produce serious consequences, particularly in the case of coal, which is by far the most complex raw material among these resources. The history of coal production and utilization is littered with unsuccessful ventures, most of which might have been avoided by a better approach to the technical and economical problems involved. One essential element in such an approach is careful consideration of the chemical and physical properties of the coal in question and also of the many empirical tests that have been developed over many years to meet the requirements of particular industrial applications.

4.1.3 Basic coal substances are so complex that chemical analysis in terms of their elemental composition - carbon, hydrogen, oxygen, nitrogen, sulphur - are useless for predicting the behaviour of the material on heating, or on combustion, or towards gases like steam, carbon dioxide, hydrogen, etc., which play such an important role in all coal conversion processes. It is generally recognized that not all coal exhibits the coking and caking properties necessary for it to produce coke of metallurgical quality on heating but the fact that pulverized fuel boilers, designed to fire lignites, cannot operate successfully, or at all, on low volatile bituminous coals or anthracites is less well appreciated. A gasifier designed to operate on one coal feedstock may fail disastrously if required to accept a different coal. Characteristics which may determine that a coal has a very reactive combustion profile may have no bearing upon the carbon conversion or liquid yields which may result from subjecting the same coal to hydrogenation and liquefaction. The result of these differences has lead to the design and development of numerous empirical tests for the purpose of assessing and predicting the behaviour of the coal under a given set of processing conditions. Although empirical in nature these tests and analyses are usually precise, and reproducible, and lend themselves readily to standardization.

4.1.4 Two broad classifications of coal properties may be distinguished (Ref. 4.1)

Class 1

Properties having real values which are independent of the method of test employed in their determination, for example - elemental analysis, density, calorific value.

Class 2

Properties having values which are highly dependent upon the method of test employed in their determination. Examples include virtually all the empirical tests developed to meet particular coal processing applications such as determination of volatile contents, free swelling index, carbonization assays, combustion profiles, petrographic analysis, etc.

Class 2 properties are of greatest importance in considering the utilization of Hat Creek coal but it should be observed that they are, for the most part, based on laboratory scale tests on quantities of coals generally ranging from 1 - 50 g. Their use as a basis for large scale practice is therefore in terms only and does not eliminate the need for obtaining essential design data by further testing in process demonstration units (PDU) or test plant of appropriate scale.

4.2 Method of Reporting

4.2.1 Various descriptions are frequently encountered relating to coal analysis or properties. Some describe location or past history of the material described. Examples are in-situ run-of-mine; raw; washed or beneficiated; as received; and as charged. Others describe the condition of the coal corresponding to the analysis and include as received; air dry; dry; dry ash-free; moist, mineral matter-free; and dry, mineral matter-free.

4.2.2 For most processing applications the analyses reported on the as received basis (ARB) or dry basis (DB) are adequate and will be the only bases used as far as possible. However, in discussion of coal rank it will be necessary to employ values reported on the moist, mineral matter-free basis. The International Classification, National Coal Board, and ASTM Classification systems are employed and compared.

4.2.3 Most of the information relating to the analysis and tests of Hat Creek coal has been obtained from samples taken from diamond drill cores. The accuracy with which such samples represent the coal deposit depends upon a number of factors of which the most important is the degree of core recovery, e.g. soluble material and fine chips are lost in the drilling fluids, so may be clays. It is also impossible to prevent some contamination of drill cores by the drilling fluids and, of course, it is not possible to obtain accurate estimations of the in-situ (or seam) moisture contents.

Some of these defects were overcome when tonnage-scale bulk samples were obtained using large diameter augers. (B.C. Hydro Bulk Samples A, B and C)

4.2.4 Coal analyses and tests have been carried out by a number of laboratories, whose reports are listed in Appendix B. The major work of analysing the drill cores for proximate and ultimate analysis has been performed by Dolmage Campbell & Associates, while the other laboratories listed have provided supporting information on analyses and special tests. The average results for the laboratories are shown in Table B.1 Appendix B. The exploration work indicated that not only were wide variations in coal quality encountered between drill holes but also within drill holes with variation in depth. In particular Dolmage Campbell & Associates and Birtley Engineering have produced much evidence of variation in the basic quality parameters of ash contents and gross calorific values and both sources have produced the linear graphical correlation between these parameters which is normally expected.

4.2.5 An immediate difficulty arose in connection with the present study because of the need to establish a single quality description, expressed as a proximate analyses as received, which would represent the mean quality of coal supplied to process plant. While the question of washing and beneficiation will be dealt with later, it is also necessary to observe, at the present time, that while the washability characteristics of the coal were poor, a possibility of achieving some improvement in quality by washing to remove clay and shales, and hence reduce ash content, was a possibility to be considered. To resolve these questions, a meeting of all consultants engaged in current studies and of B.C. Hydro was requested. This meeting was held at Vancouver on July 26, 1976 at which the mean quality parameters shown in Table 4.1 were established.

Table 4.1 QUALITY OF RAW AND WASHED HAT CREEK COAL

		Raw		Washed	
		Mean	Range of Mean	Mean	Range of Mean
Moisture (ARB)	%	22.5	20 - 25	22.5	20 - 25
Ash (DB)	%	41.9	38.5 - 45	17.5	15 - 20
Calorific Value	kJ/kg	12790		17860	
	(BTU/1b)	(5500)		(7680)	

At the time of the meeting these values were taken to represent the average quality of recoverable coal in the Hat Creek No. 1 Deposit. (Ref. 3.3) The mining consultants PD-NCB Consultants Limited in association with Wright Engineers Ltd. and Golder Associates have since indicated that these values can also be taken to represent the mean quality of the Hat Creek No. 2 Deposit, which has not been so fully explored. (Ref. 3.4).

4.2.6 It is therefore suggested that the values shown in Table 4.1 can be taken to represent the quality of Hat Creek coal. The column headed Raw represents the mean quality which will be received by coal processing plants should washing or beneficiation not be practicable. Alternatively, the columns headed Washed represent what the as received quality will be if washing is demonstrated to be technically and economically feasible and it is introduced.

4.2.7 By taking these figures and applying them to average values of volatile matter content and ultimate analysis reported for all the diamond drill hole samples it is possible to obtain mean analyses values of sufficient accuracy for process applications. Similarly, the results of other tests can be corrected to the common moisture, ash and calorific values of Table 4.1. By this method, the properties shown in Table 4.2 have been derived and represent the results upon which this study is based.

Table 4.2 Proximate and Ultimate Analysis of Hat Creek Coal

ANALYSIS	RAW					WASHED				
Basis	A.R.	Dry	D.A.F.	DMMF(1)	M.MMF	A.R.	Dry	D.A.F.	DMMF(1)	M.MMF
Proximate:										
Moisture %	22.5 (M)				22.5(2)	22.5				22.5(2)
Ash %	32.5 (A)	41.9				13.6	17.5			
Volatile Matter %	23.8 (V)	30.7	52.9	49.9(V')	39.6	33.8	43.6	52.9	49.9	39.6
Fixed Carbon %	21.2 (F)	27.4	47.1	50.1(F')	37.9	30.1	38.9	47.1	50.1	37.9
	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Calorific Value										
Gross kJ/kg	11555	14910		22975	17805	14680	18945		22975	17805
Btu/lb	4970 (Q)	6410		9880	7655(Q')	6310	8145		9880	7655(Q')
Ultimate:										
Carbon	30.8	39.8	68.6			43.8	56.5	68.6		
Hydrogen	2.4	3.1	5.3			3.4	4.4	5.3		
Oxygen	10.6	13.7	23.6			15.1	19.5	23.6		
Nitrogen	0.8	1.0	1.7			1.1	1.4	1.7		
Sulphur	0.4 (S)	0.5	0.8			0.5	0.7	0.8		
Chlorine	0.1					0.1				

Notes (1) Parr Formulae

a) $F' = \dfrac{100(F - 0.155)}{100 - (M+1.08A+0.55S)}$

b) $V' = 100 - F'$

c) $Q' = \dfrac{100\ (Q - 50S)}{100 - (1.08A+0.55S)}$

(2) The moisture shown here should be the natural in-situ seam or bed moisture. This is not known. Dolmage Campbell Associates report an equilibrium moisture content of 23.3 percent (30°C, 95% Relative Humidity) and this value probably approximates to the natural seam moisture content. If this figure is assumed, the moist, mineral matter free calorific value is 17620 kJ/kg (7575 Btu/lb).

4.3 Proximate Analysis

4.3.1 The moisture content of the coal as mined is not known. Dolmage Campbell Associates reported an equilibrium moisture content of 23.3 percent and this is believed to approximate to that of the coal in-situ. A number of laboratories reported that the coal dries out, accompanied by some break-up, so that air dried moisture contents of laboratory samples were 9 - 12 percent. This observation may indicate behaviour of the coal under dry climatic conditions and given sufficient time. However, for large scale mining conditions (say around 15 million tons per year) the hourly coal production rates can be expected to average 1500 - 2000 tons or about 45,000 tons per day. A surge stockpile to handle 3 days production (150,000 - 200,000 tons) would require a large area and expensive high capacity stock out and reclaiming machines. If this operation is to be avoided, the coal consuming units must be designed to handle run-of-mine raw coal as produced. Drying capacity should therefore be designed for a minimum input moisture content of about 25 percent.

The moisture content level is typical of sub-bituminous coals and is less than that generally reported for North American lignites (30 - 40 percent) or European brown coals (50 - 70 percent).

4.3.2 Ash Content

The run-of-mine and inherent ash contents are high. This matter is dealt with in detail in the discussion of coal washing and beneficiation later, but it may be noted here that the mining consultants reports do not hold out much prospect for reducing and controlling ash levels by selective mining operations.

4.3.3 Total Inerts Content

The moisture plus ash contents of the raw coal as received total 55.0 percent and hence impose a heavy inert load on the materials handling systems. The corresponding inerts load for washed material is 36.1 percent and hence still comprises more than one third of the materials handling requirements.

4.3.4 Calorific Value

The correlation of ash contents with calorific values reported by Dolmage Campbell Associates and by Birtley Engineering indicate that the observed ash contents are appreciably less than the inert mineral matter actually present. The intercept of the straight line equations

$$A = 82.11 - 0.00269\ Q\ \%$$

$$Q = 30459 - 370.96\ A\ \text{kJ/kg}$$

where A and Q are the ash and calorific contents respectively on the dry basis, show that the observed ash content at zero calorific value (100 percent inert) corresponds to only 82.11 percent of the actual mineral matter present.

The approximately 18 percent of inert content that does not report in the ash figure is believed to consist of carbonates and combined water in the clay minerals present. The ratio of mineral matter to ash found by this method is 1.218 and is hence considerably higher than the 1.08 ratio assumed in the PARR FORMULAE. If the higher ratios apply at low ash contents, the calculated calorific values for the dry, mineral matter free (DMMF) and moist, mineral matter free (M.MMF) bases, shown in Table 4.2, are too low as the following comparison shows:

Table 4.3

COMPARISON OF CALORIFIC VALUES CALCULATED BY PARR FORMULAE & DOLMAGE CAMPBELL FORMULA

Calorific Value (Gross)

	DMMF		M.MMF	
	kJ/kg	Btu/lb	kJ/kg	Btu/lb
PARR BASIS	23690	10185	18360	7895
Dolmage Campbell	30435	13085	23585	10140

However, there is no reason to expect that the interference by the clay minerals persists to very low ash levels, although the point at which clay contamination ceases and more normal ash constituents prevail is not known.

For the time being, therefore, the calorific value of the inert-free coal substance cannot be stated with greater precision than the range represented in Table 4.3.

The range corresponds to coals falling in the lignitic/ sub-bituminous classes. The discussion of coal classification is found in para. 4.5.

The nature of the clay minerals have been investigated (Birtley) and are discussed below in conjunction with ash composition and characteristics (Para. 4.6).

4.3.5 Volatile Matter and Fixed Carbon

Fixed Carbon is what remains of the inerts-free coal substance after the volatile matter has been driven off. The volatile matter, apart from a minor correction for carbon-dioxide resulting from decomposition of carbonates in the mineral matter, normally represents the organic matter and gas liquor contents of the coal driven off by pyrolysis under standard laboratory conditions of heating rate, temperature and time. The result is a fair approximation of yields obtainable by high temperature (900°C) pyrolysis and carbonization under industrial conditions except that actual yields of volatile products are lower because some of the volatile matter cracks to produce more residual carbon. This cracked carbon rarely exceeds 5 percent under the heating conditions currently employed in high temperature pyrolysis and carbonization practices. Volatile yields from low-temperature (500-600°C) pyrolysis and carbonization processes are lower because thermal decomposition is not completed under these conditions. Generally, therefore, the reported volatile content indicates the maximum possible yields of volatile substances obtainable by thermal decomposition of the coal. The relative quantities of tar, liquor and gas evolved are not indicated by this test (see Carbonization Assay, para. 4.7).

Because of the presence of clays it has been suggested that the observed volatile contents of Hat Creek coal are affected by excess water of hydration (Dolmage Campbell Associates, Reports on No. 1 Openpit Deposit, Interim and Statistical Tables of Proximate Analysis Data) in a similar manner to the mineral matter/ash ratio and calorific value correlations. By applying the mineral matter/ash ratio in a Parr-type formula they report a reconstituted mean analysis for Hat Creek coal in which the 'fuel ratio' (Fixed Carbon/Combustible Volatile Matter) has a value of 1.29 and in which the uncombustible volatile matter accounts for 24 percent of the total volatile matter. However, Lurgi (Analytical Test Report No. 112/75), after correcting for carbonates present, report a proximate analysis in which the 'fuel ratio' is 1.28 based on total volatile content.

Table 4.4 COMPARISON OF 'CORRECTED' PROXIMATE ANALYSES REPORTED BY DOLMAGE CAMPBELL & LURGI MINERALOLTECHNIK GMBH

PROXIMATE ANALYSIS - ARB

	DCA (1974-1975)	Lurgi (corrected for carbonates)
Moisture	20.00	20.0
Ash	28.66	25.95
Total Volatile Matter (TVM)	25.96	23.74
Combustible Volatile Matter (CVM)	19.72	
Incombustible Volatile Matter (IVM)	6.24	
Fixed Carbon	25.38	30.30
Fuel Ratio		
a) FC/TVM	0.98	1.28
b) FC/CVM	1.29	---

The FC/TVM ratio reported by Dolmage Campbell for explorations conducted 1957-59 had a value of 0.813. The discrepancy was attributed to 'bias in the data ... (resulting) ... from the burning off of fixed carbon during the determination of volatile matter'. However, there is evidence to suggest that the 'fuel ratio' of 0.98 reported for the many hundreds of analyses carried out during 1974-1975 may still be too low. Thus fuel ratios calculated from average results reported by other laboratories are as follows:

Table 4.5 CALCULATED FUEL RATIOS

	Report Index (Appendix 'C')	Fuel Ratio (FC/TVM)
Dolmage Campbell	(a) (b) (c)	0.89
Babcock & Wilcox	d(i)	1.10
CE-SL	d(ii)	0.90
Birtley Engineering	d(iii)	1.15
Birtley Engineering		0.93
Loring Laboratories	(f)	1.01
Ebasco	(i)	1.17
Corex	(j)	1.03
Lurgi	(k)	1.28 (corrected for carbonates)
Dolmage Campbell	(l)	1.04

General experience is that the fuel ratio tends to be a fixed and relatively constant parameter for coal seams, increasing with the rank of coal as shown in Table 4.6.

Table 4.6 VARIATION OF FUEL RATIO WITH COAL RANK

	DMMF BASIS		
Coal Type	TVM	FC	FC/TVM
Lignites	45-50	50-55	1.0-1.2
Sub-bituminous	40-45	55-60	1.2-1.5
Bituminous High Vol.	30-40	60-70	1.5-2.3
Bituminous Med. Vol.	20-30	70-80	2.3-4.0
Bituminous Low Vol.	15-20	80-85	4.0-5.7
Anthracites	5-10	90-95	9-19

Interference by hydrated clays, as suggested by Dolmage Campbell, can only occur in the determination of volatile matter if this moisture is not expelled during the determinations of total moisture or inherent moisture because the experimented results are corrected for the moisture content of the analysis sample. The moisture determination is designed to cause dehydration of hydrated materials but the standard test methods were developed for bituminous coals for which the extent of clay contamination encountered with Hat Creek coal was not expected. (Similar difficulties have been experienced with other lignites and sub-bituminous coals, e.g. in Australia, and standard test methods modified to accommodate them).

If the interference is encountered, the result is that the volatile matter determined is too high, the fixed carbon (obtained by difference) is too low and the fuel ratio calculated is too low. It can be expected that these errors will increase as the ash content, and hence the clay content, of the sample increases. Some evidence that this does occur is found in results reported by Ebasco (Report on Sieve Analysis and Washability Data for Bulk Sample received May 21, 1976) as shown by the following Table 4.7 and Figure 4.1.

Table 4.7 Sieve and Proximate Analysis on Bulk Sample, May 21, 1976

Size Fraction	%	TVM	FC	FC/TVM	ASH
+2 in.	5.5	37.7	45.3	1.20	17.0
2 - 1 in.	14.3	35.3	42.7	1.21	22.0
1 - ½ in.	14.6	34.4	40.5	1.18	25.1
½ - ¼ in.	16.5	33.6	39.5	1.18	26.6
¼"- 28 mesh	33.0	31.0	36.9	1.19	32.1
28 - 48 mesh	7.1	28.8	30.5	1.06	40.7
48 -100 mesh	4.6	28.9	27.9	0.97	43.2
100- 0 mesh	4.4	28.1	28.4	1.01	43.5
	100.0	32.5	38.0	1.17	29.5

However, Dolmage Campbell have recently issued the results obtained on two series of drill holes sunk during 1976 to penetrate (and sample separately) the four major quality zones suggested by Ebasco-Integ to exist in the No. 1 openpit area. The results of these trials indicate a completely reverse relationship, i.e. the fuel ratio increasing with increasing ash content. Table 4.8 shows the summarized results.

Table 4.8 Combined Results of Drill Holes 76 - 135 and 76 - 136

ZONE	TVM	FC	FC/TVM	ASH
A	26.59	29.39	1.11	44.0
B	34.15	31.66	0.93	34.2
C	18.46	24.91	1.35	56.7
C	41.64	34.06	0.82	24.3
All	29.90	30.08	1.04	40.0

The opposition of these results to the expected trend is striking (see Fig. 4.1) and is difficult to explain.

In passing, it may be noted that the values for all results reported in Table 4.7, when corrected to 22.5 percent moisture content, give the following as received analysis:

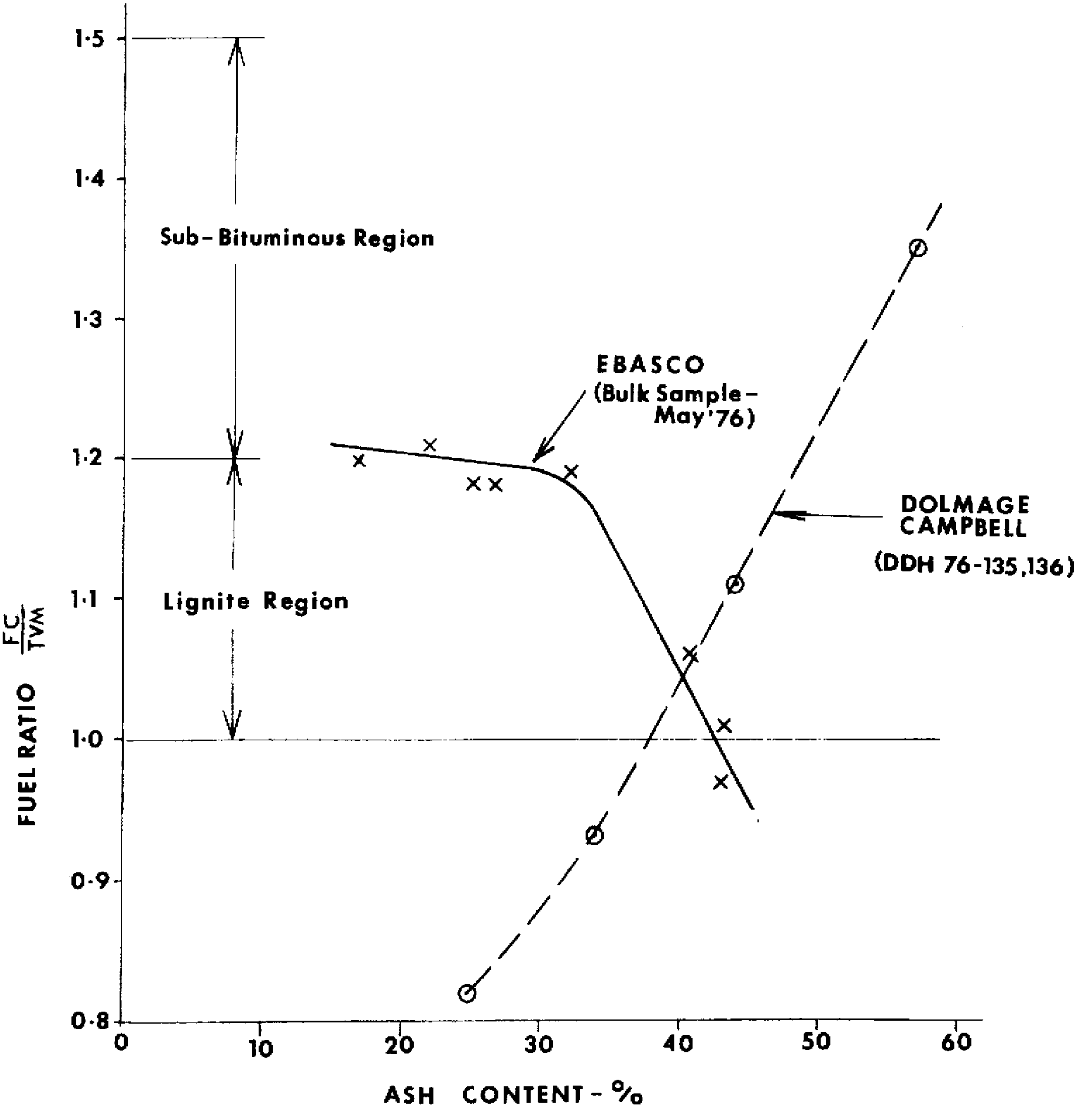
Moisture	22.5
Ash	31.0
Volatile Matter	23.2
Fixed Carbon	23.3

which, except for the noted difficulties regarding volatile and fixed carbon contents, agrees satisfactorily with the earlier estimates of coal quality in Hat Creek No. 1 and No. 2 Deposits.

From the discrepancies noted, it appears clear that difficulty in obtaining consistent proximate analysis has been encountered. The discrepancies may result from the nature of the contaminating minerals or may indicate that the coal substance of the Hat Creek deposits is itself variable. The latter observation lends emphasis to the borderline lignite/sub-bituminous character of the coal, but it should be observed that the fuel ratios determined are indicative, and are frequently lower than expected for lignites (cp. Table 4.6) See also the discussion of Coal Rank in para. 4.12.

4.4 Ultimate Analysis

Ultimate analysis is shown in Table 4.2, based on summarized results reported by Dolmage Campbell. The individual results reported by the laboratories are shown in Table B.1 (Appendix 'B'). It should be noted that agreement between the various reporting laboratories is good.



RELATIONSHIP OF FUEL RATIO AND ASH CONTENT

FIG 4.1

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE	B.C. HYDRO STONE & WEBSTER CANADA LIMITED Sheet / Cont. Sh. CJ 1381.000

4.4.1 Carbon. Lignites and sub-bituminous coals generally have carbon contents falling in a range of 73 - 83 percent. The carbon content of Hat Creek coal, at 68 percent therefore appears deficient and is attributed to the effect of the high oxygen content.

4.4.2 Hydrogen appears normal.

4.4.3 Oxygen. Reported as a 'difference' value in the analysis, the oxygen content appears to be abnormally high. (It is recommended that oxygen determinations are made by 'direct' methods which are now available to check the 'difference' values.) The high oxygen content can be expected to have several consequences during processing.

(a) Gas liquor produced by pyrolysis or carbonization will be higher and tar production lower
(b) Caking, coking and fluidity properties will be inhibited
(c) Hydrogen demand during coal hydrogenation will be higher
(d) Yields of gasification processes will be reduced
(e) Thermal efficiency and yields of coal liquids will be reduced.

All these effects reduce the utility value of the coal.

4.4.4 Nitrogen appears normal.

4.4.5 Sulphur

Sulphur contents reported by most laboratories are low, less than 0.5 percent, although there are exceptions, e.g. Ebasco reported values averaging 1.39 percent (dry basis) on a bulk sample tested in May 1976.

Although the sulphur contents appear low on a weight basis, because the calorific value of the coal is also low, the sulphur contents related to heating values are not low. Thus taking the heat value of dry raw coal to be 6410 Btu/lb at 0.5 percent sulphur, the corresponding weight of sulphur dioxide per million Btu is 1.56 lbs. This should be compared with the American Environmental Protection Agency requirement for new coal burning installations of 1.2 lbs SO_2 per million Btu. Even allowing for the fact that a small proportion of the sulphur is retained by the ash, the bulk of it reports to the flue gases so that Hat Creek coal is not a low-sulphur fuel within EPA definition.

The sulphur content is not high enough to have any deleterious effects on other coal processing applications.

Results of Float and Sink analysis, reported by several laboratories, show that the sulphur content is fairly evenly distributed throughout the specific gravity fractions corresponding to coal, but is markedly lower in sinks at specific gravities greater than 1.8. Therefore beneficiation or washing is likely to produce some net increase in sulphur content of the cleaned coal.

4.4.6 Forms of Sulphur

A few results reporting forms of sulphur are available. They tend to show

Organic sulphur	>70% of total sulphur content
Pyritic sulphur	<25% of total sulphur content
Sulphate sulphur	< 5% of total sulphur content

The bulk of the sulphur being organically combined can be expected to appear in the primary gaseous products of combustion and gasification, but the total sulphur present is such that loading of hydrogen sulphide scrubbers in gasification or liquefaction process plants will be low.

4.4.7 Chlorine

Chlorine contents reported are generally less than 0.15 percent and are not expected to cause fouling or corrosion problems in combustion or coal processing plant.

4.5 Petrographic Analysis and Palynology

4.5.1 The only petrographic and palynological analyses available to date are those reported by the British Corex Laboratories Ltd. on Borehole sample number 75-74. The results reported are as shown in Table 4.9.

Table 4.9 Petrographic Analysis of Hat Creek Coal
Borehole No. 75 - 74

Maceral Group & Mineral Composition	Maceral (Sub-Group)	Volume %
Huminite	Humotelinite/ Humocollinite	83.0
Exinite	Sporinite	0.4
	Resinite	2.4
Inertinite	Mainly Sclerotinite	0.6
Clays		13.4
Pyrites		0.2

Mean Maximum Reflectance of Huminite = 0.34 (at wavelength 546 Nm in oil of R.I. = 1.518)

The results are shown in the Internationally - adopted, modern Stopes-Heerlen system of nomenclature which differs from the Thiessen's - U.S. Bureau of Mines nomenclatural system commonly employed in North America. The approximate correlation between the two systems is shown in Table 4.10 (ref. 4.3) from which it may be seen that the bulk of the coal material consists of anthraxylon and translucent attritus as expected for lignites and sub-bituminous coals.

Table 4.10

Correlation of the Banded Components and Attrital Constituents of Thiessen's-Bureau of Mines Nomenclatural System with the Macerals and Maceral Groups of the Stopes-Heerlen Nomenclatural System.

Transmitted-Light-Thin-Section Examination			Reflected-Light-Polished-Surface Examination	
Banded Components	Constituents of Attritus		Macerals	Maceral Groups
Anthraxylon			Vitrinite with more than 14-u band width	Vitrinite
Attritus	Translucent attritus	Translucent humic matter	Vitrinite with less than 14-u band width	
		Spores, pollen, cuticles, algae	Sporinite, cutinite, alginite	Exinite
		Resinous and waxy substance	Resinite	
		Brown matter	Weak reflecting semi-fusinite, weak reflecting massive micrinite, weak reflecting sclerotinite, strong reflecting resinite	Inertinite
	Opaque attritus	Granular opaque matter	Granular micrinite	
		Amorphous (massive) opaque matter	Fusinite with less than 37-u band width strong reflecting massive micrinite strong reflecting sclerotinite	
Fusain			Fusinite and semi-fusinite with more than 37-u band width	

4.5.2 One notable feature is the low value recorded for mean maximum reflectance since this figure is expected to be between 0.5 - 0.8 for sub-bituminous coals. Here again there is evidence pointing towards low rank, lignite composition.

4.5.3 Palynological examination reported was indeterminate but this is of small consequence unless correlation of the Hat Creek deposits with other deposits may become important.

4.5.4 The clay minerals present were not identified, however evidence of clay minerals composition has been provided by Birtley Engineering Company following examination of clay build-up during pilot washing trials. The results of four such analyses are shown in Table 4.11.

Table 4.11 Minerals Analyses of Clays Associated with Hat Creek Coal

	Sample No.			
Mineral	1	2	3	4
Montmorillonite	10	13	16	7
Kaolinite	57	50	59	48
Quartz	14	18	16	25
Feldspar	9	9	8	20
Pyrite	6	5	1	Trace
Siderite	4	5	Trace	Trace

It may be noted that more than two thirds of the clays present consist of strongly swelling and gelling minerals. The extreme stickiness of these contaminants can be expected to cause difficulties in coal handling operations and severe difficulties in coal washing operation.

4.6 Ash Composition and Properties

4.6.1 Several consultants have reported ash analysis and fusion properties. The results are summarised in Table 4.12.

The table generally indicates good agreement between the various sources. The results show -

i) that the ash is uncommonly high in silica and alumina contents
ii) that the ash softening and fusion temperatures are high
iii) that alkali oxides are low
iv) that the basicity ratio is low.

The high fusion temperatures correspond to the low basicity. The alumina content, at around 30 percent, has lead to suggestions that the ash should be considered as a potentially useful alumina ore, and this has been the subject of a separate study by another consultant (Halvorson Associates).

The Lurgi report commented that the high ash fusion temperatures rendered the coal suitable for fixed bed, non-slagging gasification and commented on the similarity of the properties to those of the Sigma Mine at Sasolburg, South Africa. The properties of this ash were obtained and are shown, for comparison in the table.

The high ash fusion temperatures will have the following effects-

i) require design of dry-bottom pulverized coal boiler
ii) will permit fluidized bed combustion furnaces to operate at temperatures around 1100^{o}C instead of the more usual limit of 950 - 1010^{o}C

Table 4.12 Ash Composition and Fusion Temperatures of Hat Creek Coal

SOURCE	ASH COMPOSITION - %										ASH FUSION °C (Oxidizing Atmos.)		
	SiO_2	Fe_2O_3	MgO	CaO	Al_2O_3	TiO_2	Na_2O	K_2O	P_2O_5	SO_3	INITIAL	SOFTENING	FLUID
B & W	58.0	6.0	1.0	4.5	25.0	0.7	1.2	0.36	N.D.	2.2	1400	1543	1587
LORING	47.4	5.7	0.7	7.5	31.0	1.9	0.9	0.1	0.2	3.7	1450+	1450+	1450+
COREX	54.6	4.8	0.5	2.1	33.1	1.2	1.2	0.3	0.3	1.7	1450+	1450+	1450+
LURGI	54.3	4.5	1.0	1.6	34.0	1.2	1.0	0.3	0.1	0.4	1500	1500	1500
BIRTLEY 'A'	57.4	6.0	1.6	1.9	28.2	1.2	0.6	0.7	0.1	1.4	1284	1370	1455
'B'	52.1	8.4	1.7	4.4	27.2	1.1	0.5	0.5	0.2	3.6	1370	1455+	1455+
'C'	52.7	6.2	1.8	3.1	30.4	1.2	0.7	0.5	0.2	2.4	1455+	1455+	1455+
SASOL ASH	52.0	5.0	1.7	7.0	28.0	N.D.	0.7	0.5	0.3	0.2	1500+	1500+	1500+

iii) will permit high oxygen to steam ratios to be employed in total gasification processes e.g. Lurgi

iv) will cause difficulties in processes requiring slagging conditions e.g. cyclone - fired boilers, Koppers-Totzek gasifiers.

4.6.2 A further consequence of the ash composition, namely low alkalis content, in combination with the low sulphur content of the coal can lead to production during pulverized fuel combustion of fly ashes exhibiting very high values of electrical specific resistivity. This condition has been associated with inefficient electrostatic precipitator operation, even to the point where deliberate injection of sulphur trioxide into boiler flue gases or other treatments have been necessary for its correction. (Ref. 4.4)

4.7 Carbonization Assay and Coking Properties

4.7.1 A Fischer Carbonization Assay has been reported by Lurgi Mineralöltechnik GmbH, and the results of various coking tests by Lurgi, Corex Laboratories and Commercial Testing and Engineering Company. The results are summarized in Table 4.13.

Table 4.13 Carbonization Assay and Coking Properties of Hat Creek Coal

	ARB	DB	DAF	MMMF
CARBONIZATION ASSAY (FISCHER)				
Gas Liquor %	25.0	3.2	5.6	26.8
Tar %	3.1	3.9	6.8	5.3
Gas %	4.5	5.8	9.9	7.7
Char %	67.4	87.1	77.7	60.2
	100.0	100.0	100.0	100.0

COKING & CAKING INDICES:

Free Swelling Index	0
Gray-King Coke Type	A
Gieseler Plastometer	Non-fluid
Ruhr Dilatometer -	
Max Expansion	Nil
Contraction @ 500°C	10%

4.7.2 The results show-

i) that the coal possesses no measurable coking properties
ii) that the tar yield is very low.

4.7.3 The main consequences of these results are -

i) that the coal can find no application in conventional cokemaking practice.
ii) that the ash content of the char is 48 percent, which level is too high for considering employment of the char for briquetting or form coke processes.
iii) the low tar yield will reduce the production of oils irrespective of which type of pyrolysis process is considered.

The low tar yield is important in determining the rank of the coal and will be discussed in Section 4.12.

4.8 Gasification Tests

4.8.1 The results of the Pressure Reick Degasification tests and the Carbon dioxide reactivity test (Boudouard Reaction) have been reported by Lurgi. These tests are special experiments which provide information on the yield and composition of gas produced by de-volatilization of the coal under pressure which occurs in the top part of the Lurgi gasifier and the reactivity of the resulting char towards carbon dioxide, which is the most important gasification reaction taking place in the central and lower parts of the gasifier. While the results of these tests are used to predict composition of the raw gas exiting the gasifier, interpretation of the results is empirical and dependent upon previous experience. Lurgi has concluded that "the sample submitted (DH 74-38, 916-1036 ft.) makes an excellent feed stock for Lurgi gasification".

4.8.2 It is assumed that this conclusion by Lurgi applies to the 'dry-bottom' gasifiers. It is possible that the very high ash fusion temperatures may not be suitable for the high-capacity slagging gasifiers under development by the British Gas Council at Westfield (Ref. 4.5) for the consortium of North American utilities companies. This would require plant trials to establish.

4.8.3 Similarly, some doubt exists as to the suitability of Hat Creek coal for gasification by the Koppers - Totzek route, because this process requires an ash slag that runs freely out from the base of the gasifier chamber. The very high slag viscosities reported by Babcock - Wilcox for both oxidizing and reducing conditions is somewhat ominous as far as successful application of the K-T process is concerned. Difficulties with ash properties have been encountered at several K-T plants, including recent reports of troubles encountered at Modderfontein, South Africa.(Ref. 4.6)

4.8.4 The ash characteristics are not expected to cause difficulties in the Winkler process.

4.9 Combustion Tests and Grindability

4.9.1 Hardgrove indices of grindability have been determined and reported by most of the testing laboratories employed. The indices generally found lie between 35 - 50. The results show some dependence upon moisture and ash contents of the test sample, commonly experienced with lignitic/sub-bituminous coals. The results clearly show that the coal is difficult to grind and high-capacity mills will be required.

4.9.2 Combustion profiles (see Figures 4.2 and 4.3) determined by the differential thermo-gravimetric test method, have been reported by Babcock & Wilcox Canada Ltd. Comparisons with similarly determined profiles for bituminous coals and anthracites generally indicate (Ref. 4.7)

i) drying is completed before onset of coal decomposition with ignition

ii) ignition temperatures are low

iii) The maximum rates of sample burnout are lower than measured for bituminous coals and anthracites. This result can be attributed to the high inherent ash content.

A major consequence of these results is that the boiler must be designed to permit sufficient residence time for burnout to be completed.

4.9.3 Babcock & Wilcox also reported upon the slag viscosity against temperature relationships and found that the melts were frozen at 1425°C (2600°F). Figures 4.4 and 4.5. These results indicate that the Hat Creek coal is unsuitable for cyclone and slag-bottom furnaces for which it is generally recommended that a slag viscosity of 250 poise at 1425°C is required (Ref. 4.7). From Figures 4.4 and 4.5 it may be seen that temperatures exceeding 1540°C (2800°F) are required before the slag viscosity approaches this optimum.

4.9.4 Pilot pulverized combustion tests are being carried out on bulk samples of Hat Creek coal by the Combustion Research Laboratory, Department of Energy Mines and Resources, Ottawa. However, no results were available at time of preparation of this Report.

4.9.5 No results of tests to determine the behaviour of Hat Creek coal under fluidized combustion conditions have been reported. A previous study carried out for B.C. Hydro by Engineering and Power Development Consultants in Association with Combustion

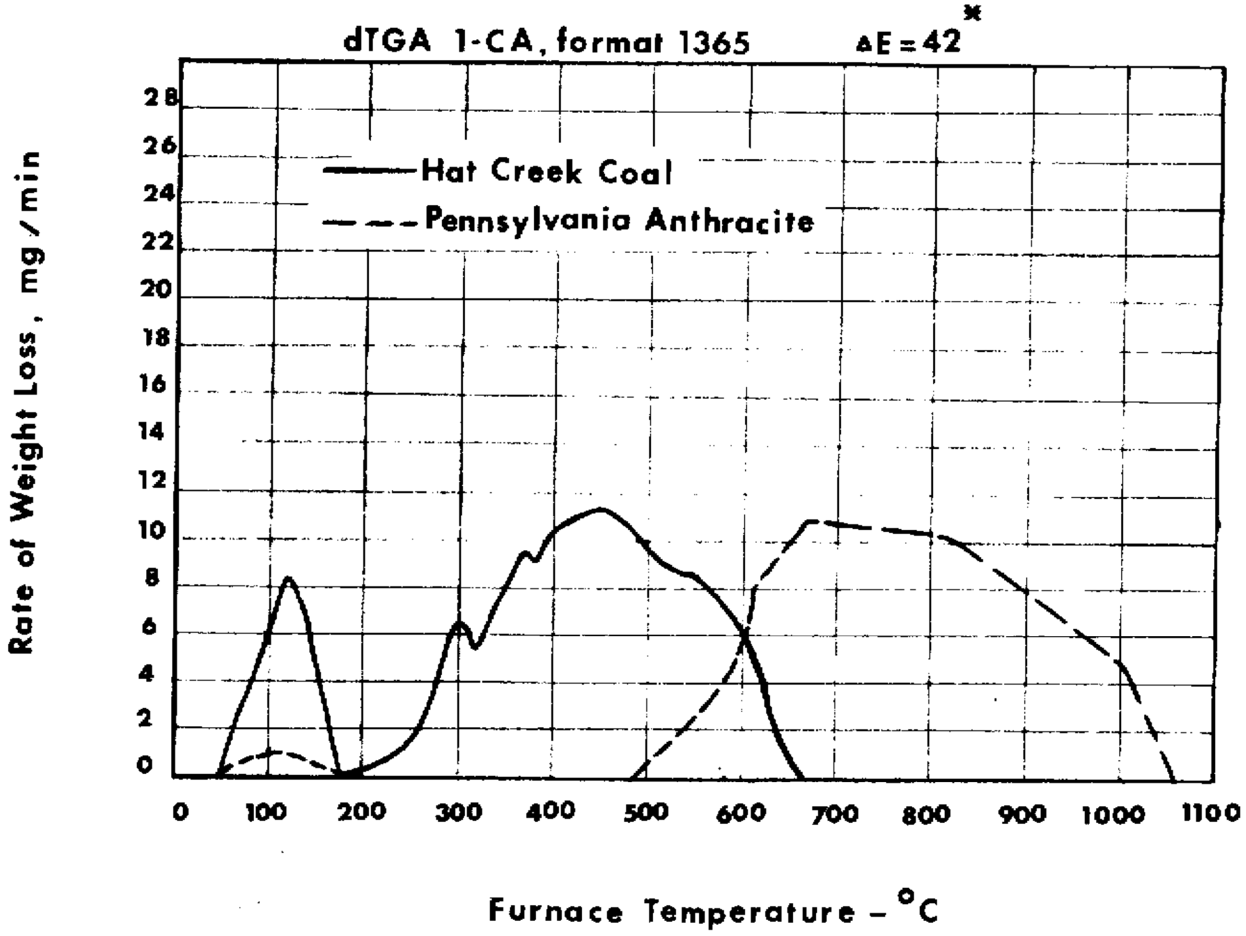
Systems Ltd. was based on an assumption that "consideration (of coal analysis and other data) has not revealed any characteristics of the coal that would preclude its use in fluidized combustions". While it is true that the ability of fluidized combustions to burn a variety of low grade fuels has been amply demonstrated, and that this fact arises naturally from the requirement that fluidized combustion only operates satisfactorily at very low levels, of fuel (carbon) concentration - one to five percent by weight of bed material - it must be appreciated that much of this work has been aimed primarily at disposal of the low grade feedstock rather than serious attempts to generate steam and power, particularly under load following conditions.

Fluidized combustion tests on colliery shales and tailings have been reported by several investigations (Ref. 4.9, 4.10) which have indicated that a minimum calorific value of about 5000 kJ/kg is necessary to produce self-sustaining combustion. (Fig. 4.6, Ref. 4.10) This condition of criticality corresponds to an ash content of 54 percent in Hat Creek Coal as received at 22.5 percent moisture. Borehole data shows that coal of this quality or lower is frequently encountered within the deposits and this fact must be considered in conjunction with the indicated difficulty of controlling "as mined" quality by selective mining procedures within the pits, reported by the mining consultants.

4.10 Hydrogenation and Liquefaction Tests

4.10.1 No test work to determine the behaviour of Hat Creek Coal on hydrogenation coupled with action of coal solvents has been reported. Modern techniques for coal liquefaction or hydrogasification involve relatively minor modifications to the Bergius Process (catalysed hydrogenation at elevated temperatures and pressures) and the Patt-Broche process (non-catalytic hydrogenation at lower temperatures and pressures.) For example, in the H - Coal process the homogeneous catalyst is replaced by a solid catalyst in an ebullating bed but a process change of this sort cannot be

HAT CREEK COAL



BURNING PROFILES OF HAT CREEK RAW COAL-SAMPLE C-14026 COMPARED WITH A PENNSYLVANIA ANTHRACITE

* A Description of Test Procedures is given in Ref. 4.7

(Ref–Babcock & Wilcox Canada Ltd.)

FIG 4.2

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER
CANADA LIMITED

Sheet
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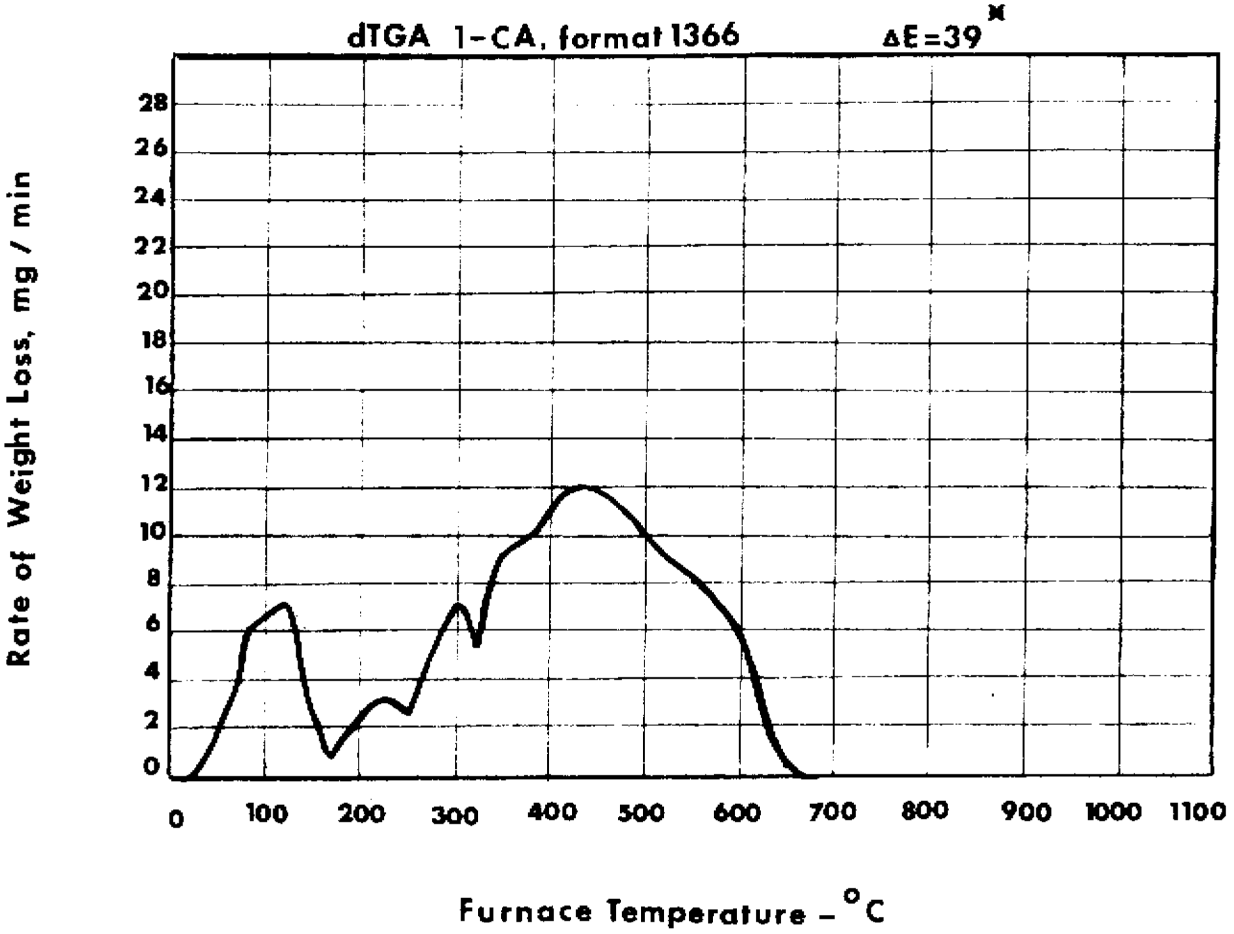
HAT CREEK COAL



BURNING PROFILE OF HAT CREEK COAL – SAMPLE C-14027
1.60 FLOAT COMPOSITE FROM B.C. HYDRO & POWER AUTHORITY 6716-08
DATED 6.12.75

* A Description of Test Procedures is given in Ref. 4.7
(Ref Babcock & Wilcox Canada Ltd)

FIG 4.3

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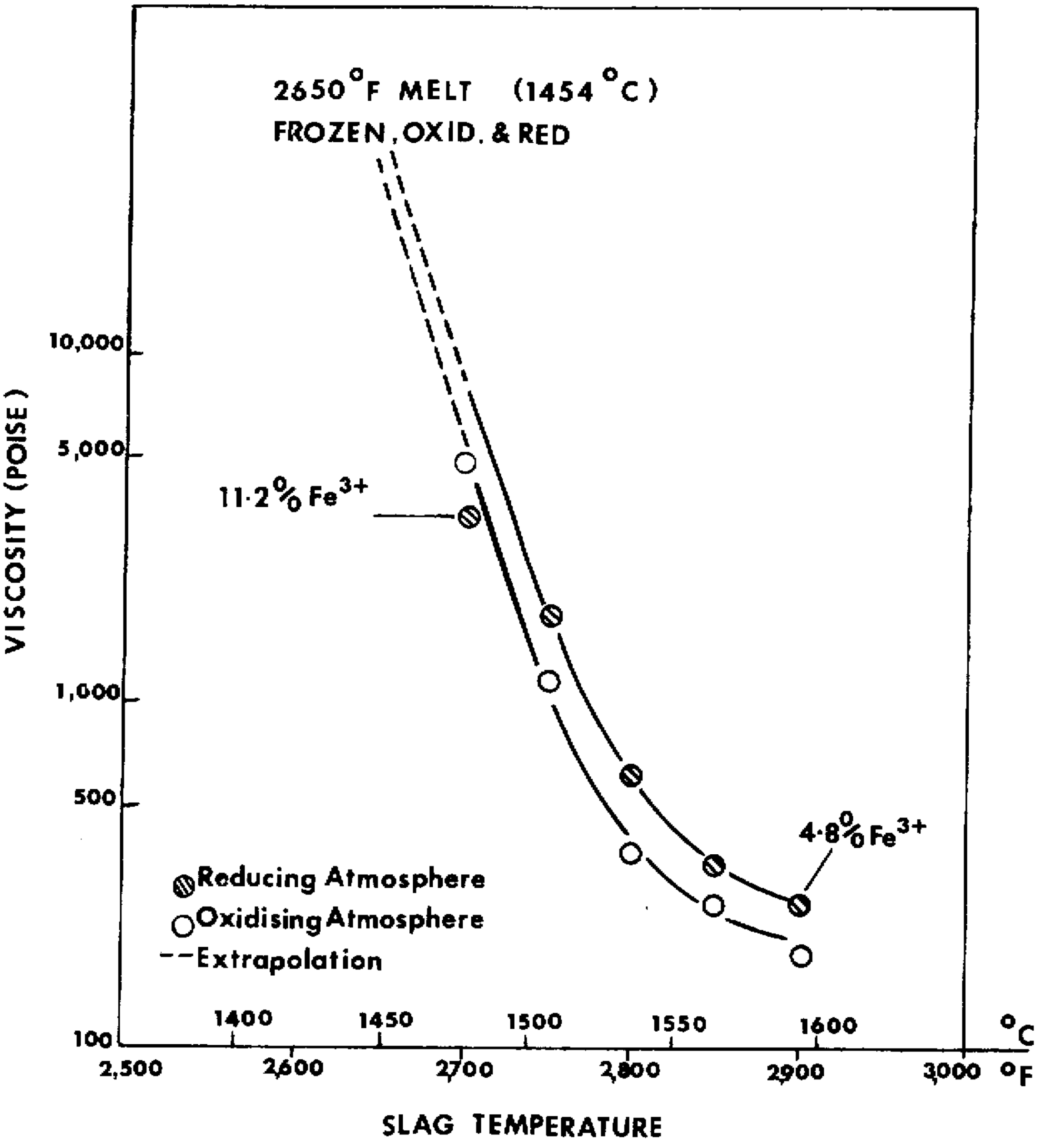

VISCOSITY-TEMPERATURE RELATIONSHIP
FOR ASH FROM COAL C-14026

(Ref – Babcock & Wilcox Canada Ltd.)

FIG 4.4

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

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STONE & WEBSTER
CANADA LIMITED

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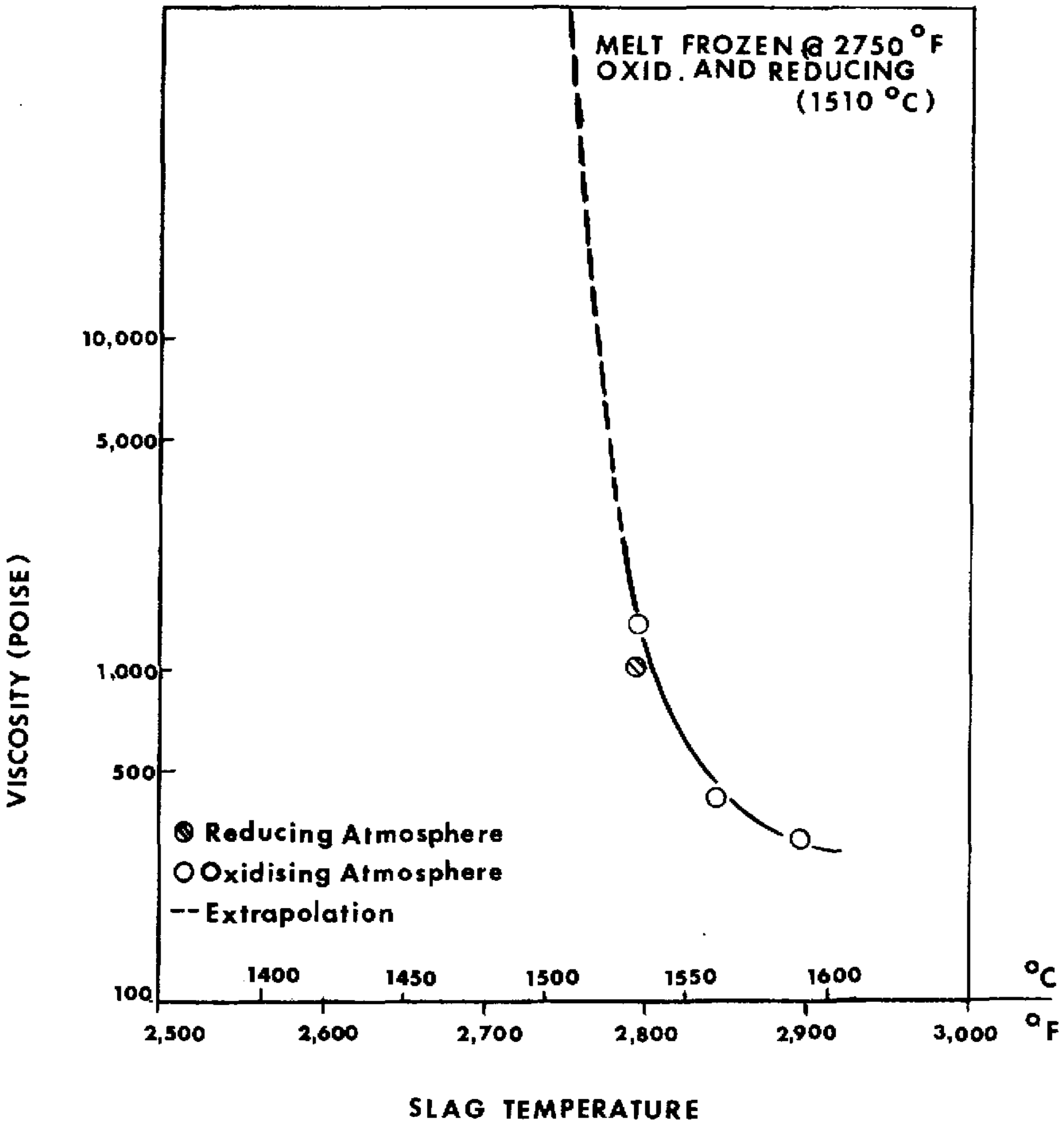

<u>VISCOSITY-TEMPERATURE RELATIONSHIP</u>
<u>FOR ASH FROM COAL C-14027</u>

(Ref Babcock & Wilcox Canada Ltd.)

FIG 4.5

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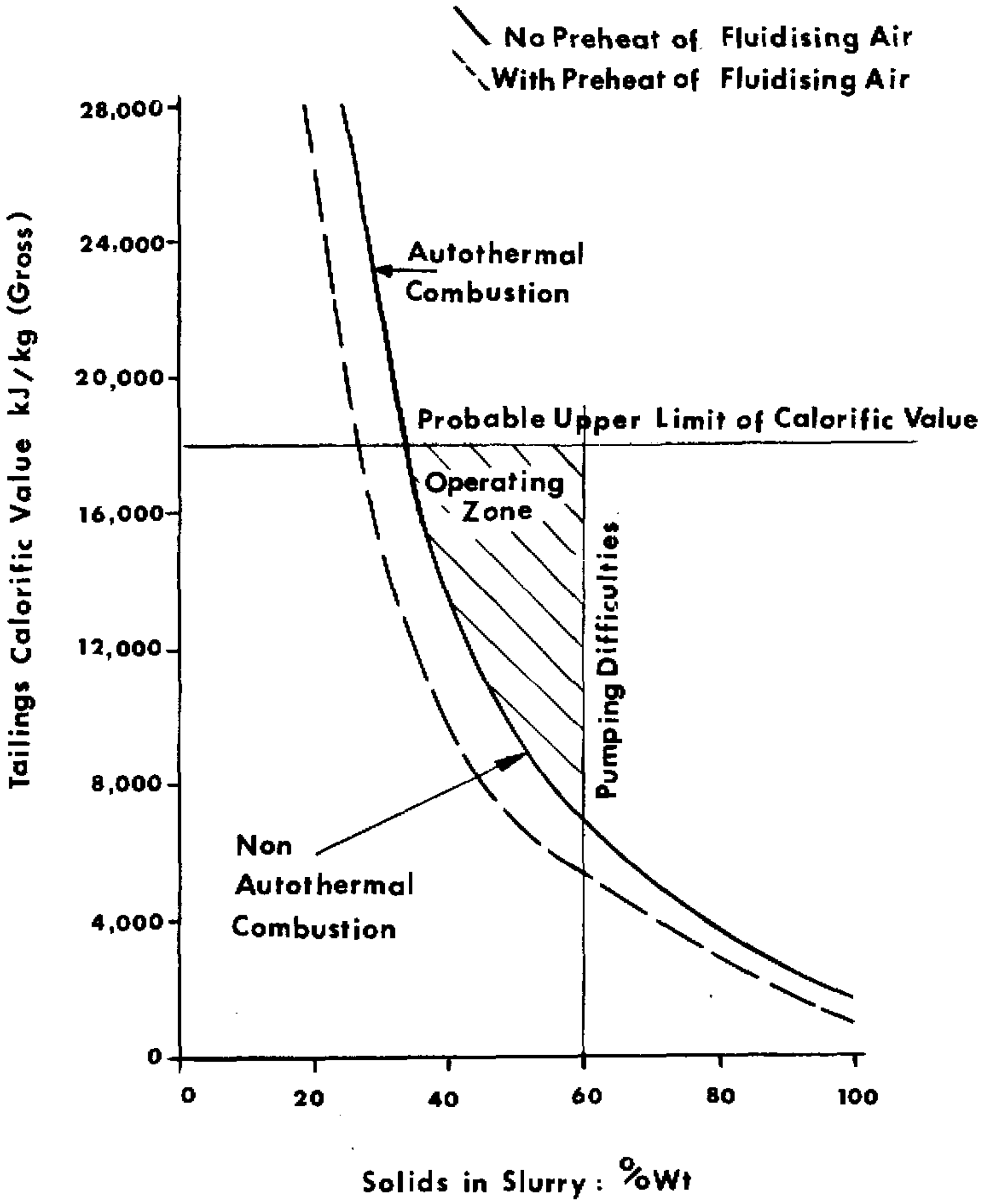

OPERATING ZONE FOR AUTOTHERMAL COMBUSTION

FIG 4.6

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expected to alter, by very much, the basic response of the coal to hydrogenation and liquefaction treatment.

4.10.2 In the absence of this information it has been necessary to base consideration of the suitability of Hat Creek coal for liquefaction and hydrogasification upon certain assumptions which are based on direct experience of the study team with other low-rank coal feedstocks.

4.11 Washability Characteristics

4.11.1 Washability characteristics, as determined by float and sink analysis, on small samples recovered from boreholes have been reported by several laboratories. Testing of bulk samples has also been reported by Ebasco (Float and Sink) and Birtley (Float, Sink and pilot washing tests).

4.11.2 A general interpretation of each of the individual reports indicates that the coal has high inherent ash and that control of any beneficiation process based upon gravity or pseudo-gravity separation would be difficult.

4.11.3 A comparison of the individual reports indicates a wide variation of ash content of product even for fixed conditions of separation. An average table of washability data was calculated from all the available reports and the results plotted to provide Figure 4.7. It may be seen that the average ash content of the raw coal found by this method is 42.4 percent, which compares favourably with 41.9 percent assumed for dry raw coal in this report. (See Table 4.2). Indicated washing yield is about 26 percent at 10 percent ash in clean product and is only 40 percent at 15 percent ash. It is noteworthy that even at this unacceptably high ash the product contains all material containing 30 percent and less (from Curve A, Fig. 4.7)

4.11.4 Figure 4.8 shows Curve B replotted to include all its constituent curves. It becomes very clear that at any given level of specific gravity cut, or at any yield cut-point, the variation of ash in product covers an inordinately high range. For example, from Fig. 4.7 at S.G. 1.6 the indicated yield is 47 percent and from Fig. 4.8 the range of ash at this yield is 8 to 28 percent. If the samples tested are reasonably indicative of the true variation of coal characteristics as mined then it would appear that it would not be possible to set washing plant control systems at pre-determined levels to guarantee anything like reasonable consistency of product ash.

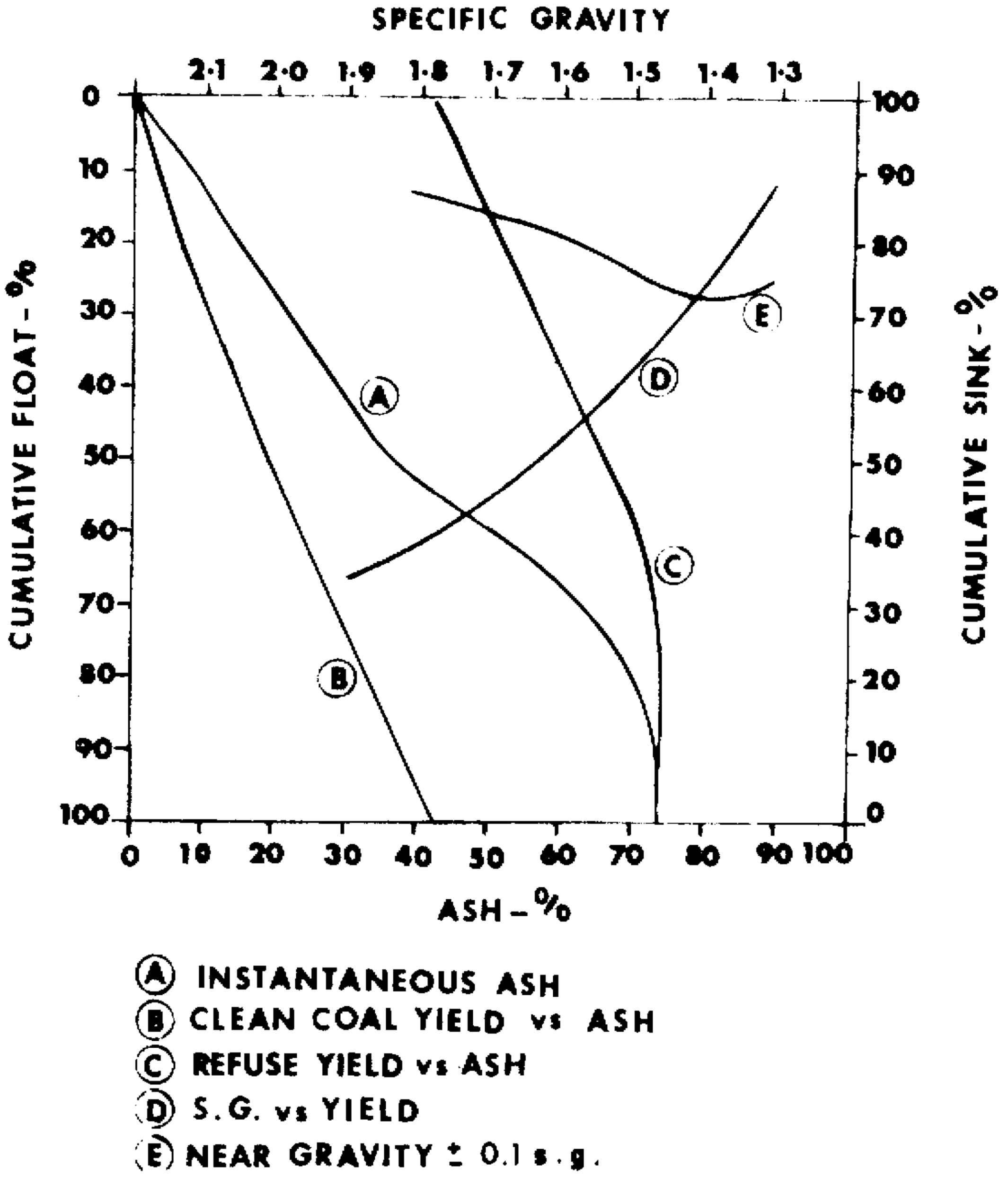
4.11.5 The difficulty of product quality control is confirmed by consideration of the Near Gravity (± 0.1 SG) Curve. Conventional interpretation of this curve is provided in Table 4.14.

Table 4.14 Significance of Amount of Near - Gravity Material

Amount of Near - Gravity Material		Estimate of Coal - Preparation Plant Cleaning Problem
Greater Than	Less Than	
0%	7%	Simple
7%	10%	Moderately Difficult
10%	15%	Difficult
15%	20%	Very Difficult
20%	25%	Exceedingly Difficult
25%		Formidable

(Ref. 4.11)

It should be noted that this table refers to coals which have reasonably consistent washability characteristics. In the case of Hat Creek the difficulty is compounded by the variation of washability characteristics throughout the deposit.



HAT CREEK COAL WASHABILITY
AVERAGE FOR 15 SAMPLES
(APPENDIX B1)

FIG 4.7

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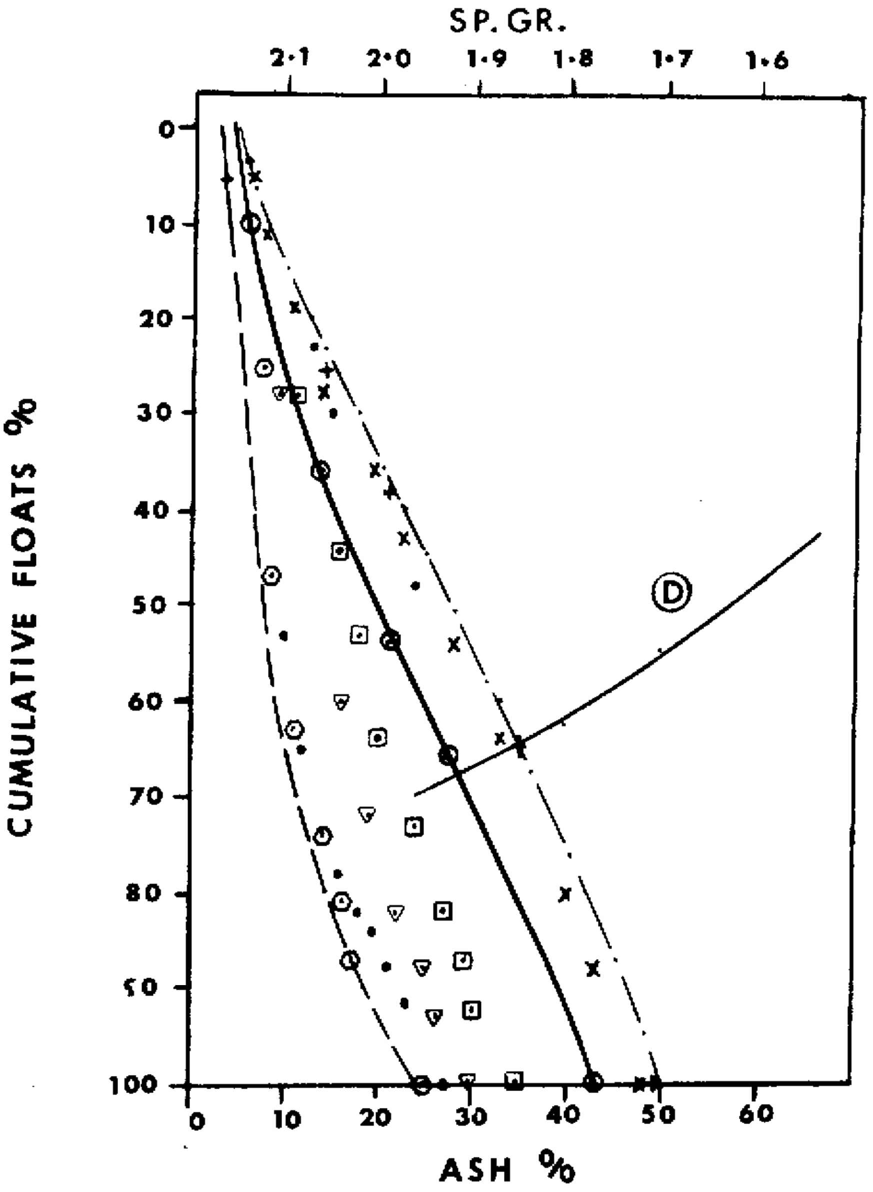

N. B.
Curves are averages calculated from laboratory reports summarised in appendix B.
(see para. 4.11.3.)

D = SPECIFIC GRAVITY

HAT CREEK COAL-CLEAN COAL YIELD vs ASH

FIG 4.8

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4.12 Coal Rank

4.12.1 Some confusion appears to exist in the factor we call RANK. Properly so-called, rank is a description of the degree of maturity of the coals or the position it occupies in the solid fuel series - peat, lignites, sub-bituminous coal, bituminous coal, anthracite.

4.12.2 No single coal property describes rank. Most coal classification systems employ a primary relationship between volatile matter and calorific value as a basis on which other properties, notably fusion and coking properties, are superimposed to provide class divisions. Carbon contents or carbon to hydrogen ratios are imperfect descriptions of rank.

4.12.3 It also follows that attributions of variation of rank based upon relationships between calorific and ash contents are not correct. (See DCA Report on DDH Nos. 76-135 and 136, Sept. 1976, page 2.)

4.12.4 Hat Creek coal has been variously described as ASTM Subbituminous B, as lignite, as NCB Coal Rank Code No. 902, as German DIN Standard Mattbraunkohle, and as ISO Classification Code 900. This range of classifications are not strictly comparable or identical and some, particularly the attribution to ISO 900, appears incorrect because of the tar yield and heating value. As determined by Fischer Carbonization Assay the tar yield of DAF coal is 6.8 percent and is considerably lower than the 10 percent required for classification as ISO 900 (heating value <10,260 Btu/lb., <570 Kcal/Kg) Also, the NCB Classification system is not designed to include very low rank coals of borderline lignites/sub-bituminous lignites/sub-bituminous character that Hat Creek coal indoubtedly is, so that the rank is lower than the NCB Code Rank No. 902.

4.12.5 After carefuly consideration of all the properties described above, the following Code numbers are assigned to Hat Creek coal:

International Classification:

Group	Code Number	Class Number
00	1200	12

ASTM Classification:

By Rank	Lignite A (50-77)
By Grade	Size ?, 77 - A20+ - F24 - S0.4

The standard tables from which these figures are derived are shown in Tables 4.15, 4.16 and 4.17. The corresponding analyses are drawn from Table 4.2 and the Fischer Carbonisation Assay (Table 4.13). A major factor supporting the lignitic character is the low mean maximum reflectance value (Ro) of 0.34 reported by Corex Laboratories Ltd.

4.12.6 Comments have been made about the very low rank and grade of Hat Creek coal and its possible utilization in an area which contains an abundance of very high grade bituminous coals. To this criticism, two answers may be made:

a) the utilization, in energy terms, is more dependent upon the cost per unit of energy at which the coal can be made available for use. This matter receives close attention in this study.

b) Coals of even lower rank and grade are finding economic use in other parts of the world, as may be clearly seen in Fig. 4.9 (Ref. 4.12), which depicts coals in terms of quality indicated by moisture and ash contents, and calorific value.

Table 4.15

International Classification of Coals
With a Gross Calorific Value Below 23,880 kJ/kg (5700 kcal/kg)
(Statistical Group)

Group Number	Tar Yield % (dry, ash-free)	Code Number					
40	25	1040	1140	1240	1340	1440	1540
30	20 - 25	1030	1130	1230	1330	1430	1530
20	15 - 20	1020	1120	1220	1320	1420	1520
10	10 - 15	1010	1110	1210	1310	1410	1510
00	10 and less	1000	1100	1200	1300	1400	1500
	Class Number	10	11	12	13	14	15
Class Parameter	Total Moisture % (ash-free)	20 and less	>20 to 30	>30 to 40	>40 to 50	>50 to 60	>60 to 70

Notes: The total moisture content refers to freshly mined coal.

For internal purposes, coals with a gross calorific value over 23,880 kJ/kg (5700 kcal/kg)*, considered in the country of origin as brown coals or lignites but classified as hard coals for international purposes, may be classified under this system, to ascertain, in particular, their suitability for processing.

When the total moisture content is over 30%, the gross calorific value is always below 23,880 kJ/kg (5700 kcal/kg).

* Moist, ash-free basis (30°C and 96% relative humidity).

RANGE of PROPERTIES of LOW RANK, LOW GRADE COALS & LIGNITES USED IN OTHER PARTS of THE WORLD WITH HAT CREEK VALUES SUPERIMPOSED.

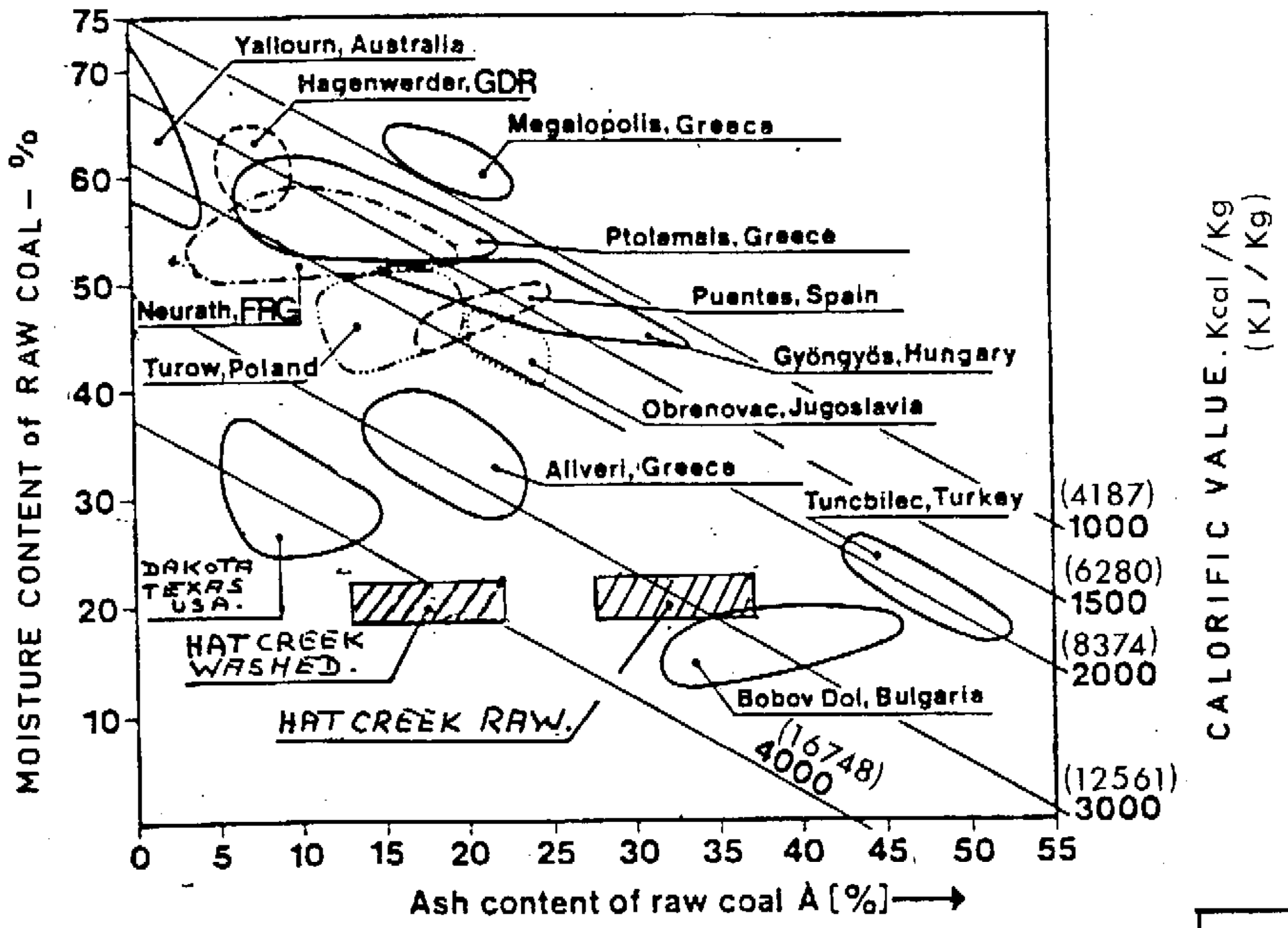

FIG 4.9

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Table 4.16

CLASSIFICATION OF COALS BY RANK ASTM D 388-66 (1972)

Class	Group	Fixed Carbon Limits, percent (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, percent (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu per pound (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	-	-	2	-	-	nonagglomerating
	2. Anthracite	92	98	2	8	-	-	
	3. Semianthracite[c]	86	92	8	14	-	-	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	-	-	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	-	-	
	3. High volatile A bituminous coal	-	69	31	-	14,000[d]	-	
	4. High volatile B bituminous coal	-	-	-	-	13,000[d]	14,000	
	5. High volatile C bituminous coal	-	-	-	-	11,500	13,000	
						10,500	11,500	agglomerating
III. Subbituminous	1. Subbituminous A coal	-	-	-	-	10,500	11,500	nonagglomerating
	2. Subbituminous B coal	-	-	-	-	9,500	10,500	
	3. Subbituminous C coal	-	-	-	-	8,300	9,500	
IV. Lignitic	1. Lignite A	-	-	-	-	6,300	8,300	
	2. Lignite B	-	-	-	-	-	6,300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

Table 4.17

Specifications For Classification of Coals By Grade (D 389 - 37)

Symbols For Grading Coal According to Ash, Softening Temperature of Ash, and Sulphur (Analyses Expressed on Basis of the Coal as Sampled).

Ash[a]		Softening Temperature of Ash[c]		Sulphur[a]	
Symbol	Percent[b] inclusive	Symbol	Deg Fahr, incl,	Symbol	Percent, inc
A 4	0.0 to 4.0	F 28	2800 and higher	S0.7	0.0 to 0.7
A 6	4.1 to 6.0	F 26	2600 to 2790	S1.0	0.8 to 1.0
A 8	6.1 to 8.0	F 24	2400 to 2590	S1.3	1.1 to 1.3
A 10	8.1 to 10.0	F 22	2200 to 2390	S1.6	1.4 to 1.6
A 12	10.1 to 12.0	F 20	2000 to 2190	S2.0	1.7 to 2.0
A 14	12.1 to 14.0	F 20 minus	less than 2000	S3.0	2.1 to 3.0
A 16	14.1 to 16.0			S5.0	3.1 to 5.0
A 18	16.1 to 18.0			S5.0 plus	5.1 and higher
A 20	18.1 to 20.0				
A 20 Plus	20.1 and Higher				

[a] Ash and sulphur shall be reported to the nearest 0.1 percent by dropping the second decimal figure when it is 0.01 to 0.04 inclusive, and by increasing the percentage by 0.1 percent when the second decimal figure is 0.05 to 0.09, inclusive. For example 4.85 to 4.94 percent, inclusive shall be considered to be 4.9 percent.

[b] For commercial grading of coals, ranges in the percentage of ash smaller than 2 percent are commonly used.

[c] Ash-softening temperatures shall be reported to the nearest 10 F. For example 2635 to 2644 F, inclusive, shall be considered to be 2640 F.

5. - COAL CONVERSION POTENTIAL

5.1 Review of Technology

5.1.1 General Remarks

The basic concept of coal conversion technology has been aptly described as "the representation of coal in acceptable socio-economic forms. To accomplish this, high-sulphur coals must be desulphurized, high-ash coals must be demineralized, and solid coal must be depolymerized into conventionally acceptable liquid and gaseous products". (Ref. 5.1.)

The composition and properties of Hat Creek coal are such that while sulphur content is not a serious problem, the exceptionally high inherent mineral content, low rank and heavy clay contamination compels consideration of some form of conversion to higher grade material, if some alternative use, other than combustion for steam/electric power generation, is to be found.

Demineralization cannot be accomplished by physical separation methods unless exceptional steps are taken to reduce the particle size of the coal to that of its macerals components, as in the proposed Ilok process*. However, this is not yet a demonstrated possibility. Washing by gravity separation methods or froth flotation cannot achieve more than partial reduction of mineral matter, usually at the expense of substantial reduction of yield and loss of useful coal in rejects. The washability characteristics of Hat Creek coal, described in para. 4.11, are such that substantial demineralization by physical methods are not possible.

The best methods available for demineralization involve depolymerization of the coal substance, invariably accompanied by

---

*Demineralization after grinding the coal to particle diameters smaller than that of the mineral matter present.

some hydrogenation so that the coal is liquefied, followed by some sort of mechanical or physical separation. Methods under development include filtration, sedimentation (centrifugation or hydroclones) and vacuum distillation. None of these methods have been successfully demonstrated in commercial scale operation and this demineralization step remains a very serious problem in coal liquefaction process development.

The very high inherent mineral content of Hat Creek coal must be regarded as a serious obstacle to its use as a feedstock for coal liquids production other than those produced by gaseous synthesis, and it is necessary to bear this in mind when considering potential application of Solvent Refining methods described in para. 6.2.

It is worth noting that, although demineralization is not of consequence in coal conversion processes involving total gasification as a first step because the mineral matter is automatically rejected during the change of state of coal substance, nevertheless the properties of the mineral matter can have an important influence upon the process conditions that can be employed. Thus coals having low ash fusion temperatures can cause serious difficulties in 'dry-bottom' gasifiers, whereas coals having high ash fusion temperatures will cause difficulties in slagging gasifiers.

Hat Creek coal has very high ash fusion temperatures and has been reported to be suitable for Lurgi Pressure Gasification in spite of the high ash content. The coal may not be suitable for Koppers-Totzek Gasification, which employs slagging conditions.

A range of possible coal conversion processes, applicable to Hat Creek coal, is shown in Figure 5.1. Many of these processes are, or have been, applied to low rank coals bearing similarities to Hat Creek coal in various parts of the world. Some of the coals shown in Figure 4.9 are feedstocks.

The three basic routes for coal conversion shown in Figure 5.1 are COKING/PYROLYSIS, HYDROGENATION WITH DISSOLUTION and GASIFICATION.

5.1.2 COKING/PYROLYSIS

i) Coking and pyrolysis are similar but not interchangeable terms. Both involve carbonization of the coal feedstock which may also be described as destructive distillation of the coal. However, coking is conventionally reserved for the carbonization of coals which possess coking properties and in which the general aim of the process is to maximize the production of coke as an upgraded carbon conversion product. Since Hat Creek coal possesses no measurable coking properties, the term COKING does not apply.

ii) Pyrolysis is commonly aimed at maximizing the production of liquid and gaseous products and employing the char as fuel by-product for generation of process steam and power. This is achieved by employing much higher rates of heating of the coal than can be achieved in conventional coking or gas retorts, and process equipment specially designed to achieve these higher heating rates is required.

iii) A general scheme for COAL PYROLYSIS is shown in Figure 5.2. At least 7 pyrolysis processes are currently under development -

UTILIZATION OF HAT CREEK COAL

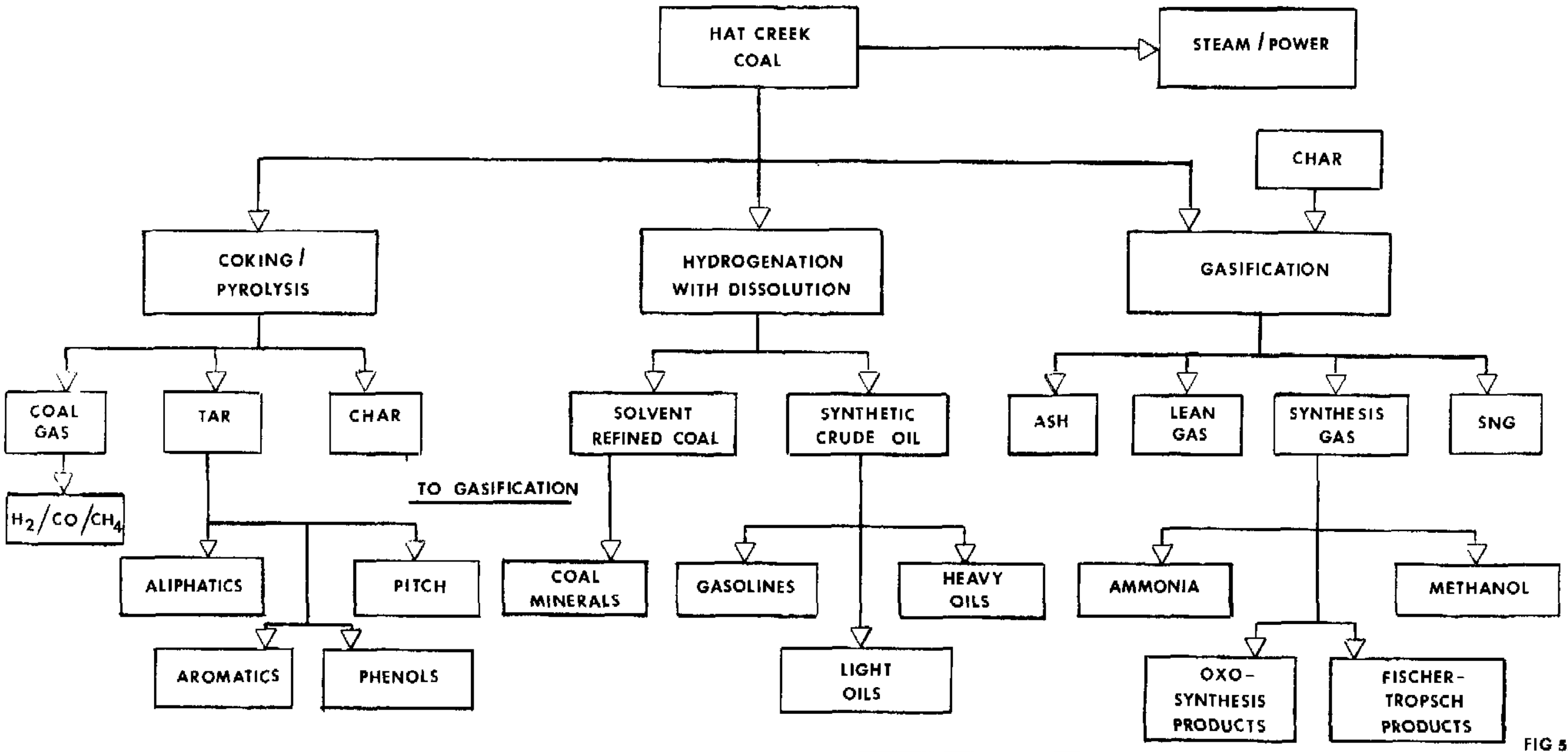

FIG 5.1

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COAL PYROLYSIS – GENERAL SCHEME

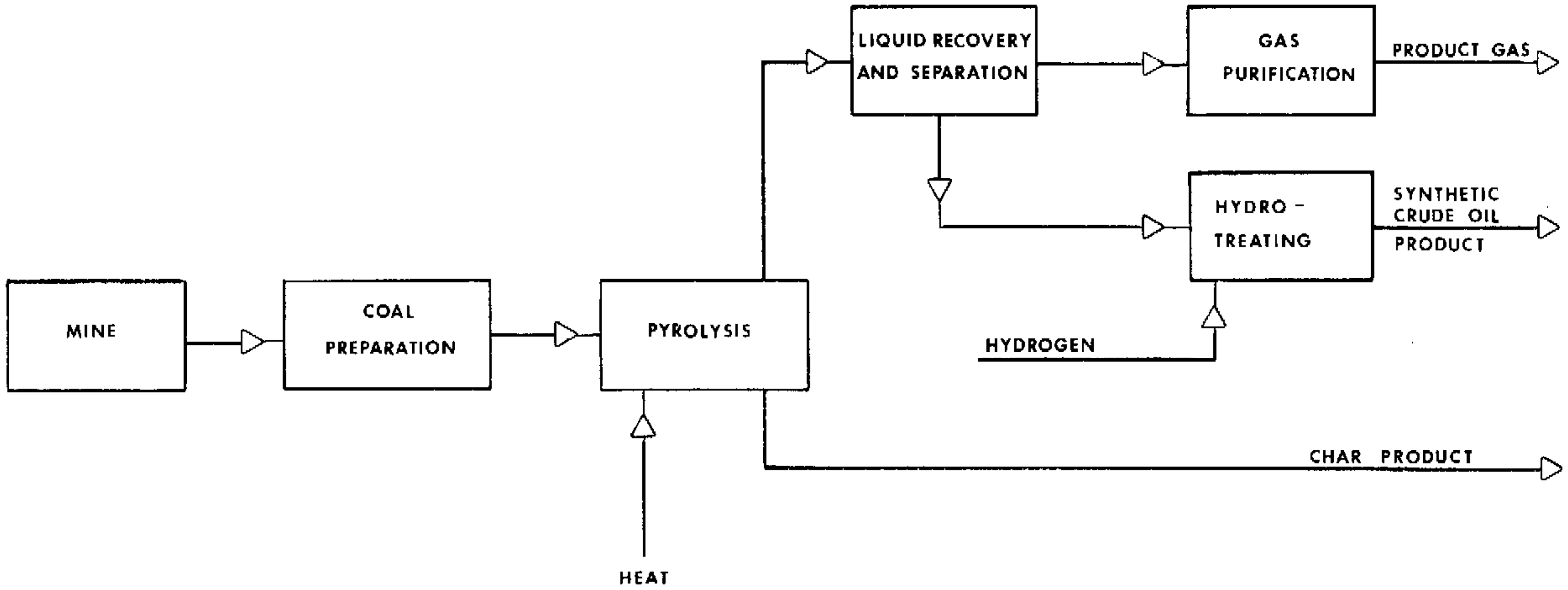

FIG 5.2

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CSF 405-18

Clean Coke Process - U.S. Steel Corp.
COED - FMC Corporation
COGAS - Joint Venture Consortium
Garrett's Coal Pyrolysis - Occidental Petroleum Corp.
Lurgi-Ruhrgas - Lurgi GmbH/Ruhrgas AG
Project Seacoke - ARCO Chemical Co.
Toscoal - The Oil Shale Corporation.

iv) The only fully commercial process is the LURGI-RUHRGAS process, the first commercial plant having been built in 1963 in Yugoslavia to process 1600 t/d of lignite. Since then numerous large scale plants have been erected. It is the process selected for the Hat Creek study as an example of a pyrolysis application.

5.1.3 HYDROGENATION WITH DISSOLUTION

i) This process is capable of producing a solid Solvent Refined Coal (SRC) or a coal liquid, depending upon the degree of hydrogenation achieved. A general process scheme is shown in Figure 5.3.

ii) Major products are -

SRC (SRC-1 is a solid. SRC-11 is a liquid)
Heavy Fuel Oil
Distillate Fuel Oil
Naphtha.

The latter two products being produced directly or by hydrogenation of primary pyrolysis products.

iii) The basic processes were originally developed by Bergius (Ref. 5.2) (high temp. (480^{0}C), high pressure (98 bar); and by Potte & Broche (Ref. 5.3) (lower temp. (435^{0}C), lower pressure (65 bar). Both processes found extensive application in Germany during

World War II. There are no known applications or development of the Bergius process in current operation. The Potte-Broche non-catalytic process forms the basis of the current SRC developments (PAMCO, C-E, MITSUI).

iv) Recent process development include H-COAL (catalytic, ebullated bed (Co/Mo) reaction at 455°C under 170 bar, hydrogen pressure) by Hydrocarbon Research Inc. and the EXXON LIQUEFACTION process (425°C/135 bar) recycling of catalytically regenerated hydrogen-donating solvent) by Exxon Research & Development Corp.

v) Current major development projects in coal liquefaction are summarized in Table 5.1.1 (Ref. 5.4).

vi) In terms of maximum practical yields and maximum thermal efficiencies there does not appear much to choose between any of these process developments. The Electric Power Research Institute has indicated the following maximum yields and efficiencies (Ref. 5.4).

COAL LIQUEFACTION – GENERAL SCHEME

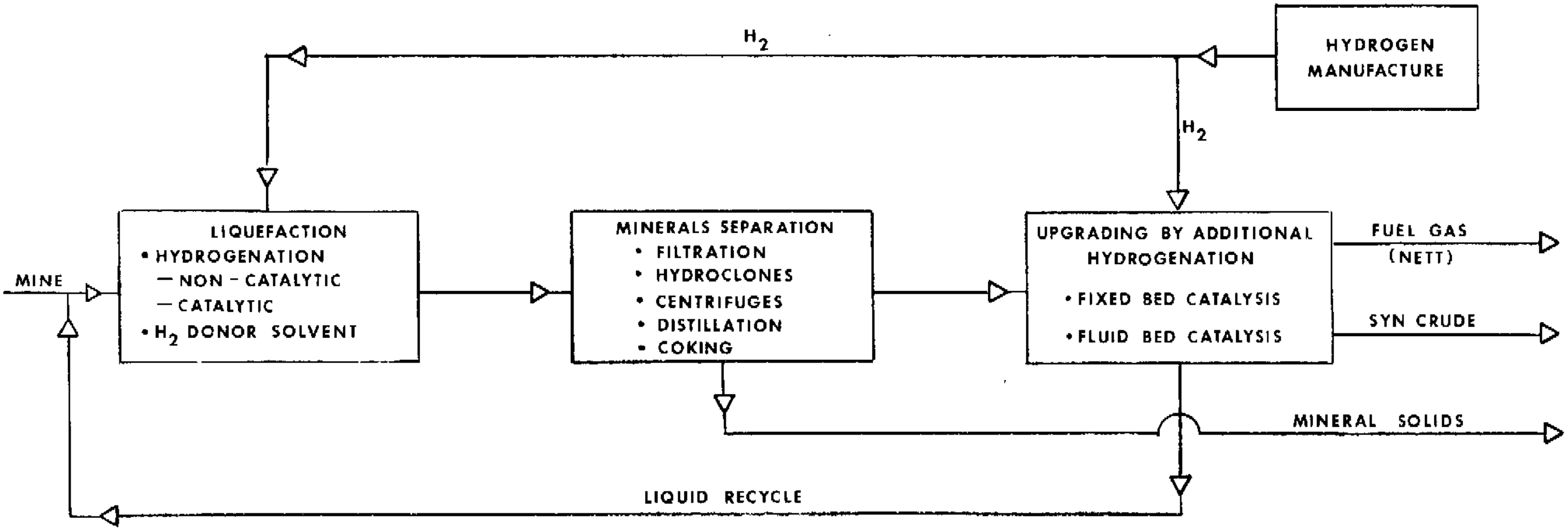

FIG 5.3

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Table 5.1.1

Major Projects in Coal Liquefaction

Process	Site	Capacity	Status
Catalytic			
H-Coal	Trenton, N.J.	3 T/D	Operational
	Catlettsburg, Ky.	600 T/D	Design Phase - Startup 1978
Synthoil	Bruceton, Pa.	8 T/D	Design Phase
Hydropyrolysis			
Coalcon		2,600 T/D	Conceptual Design
SRC			
	Tacoma, Washington	50 T/D	Operational
	Wilsonville, Ala	6 T/D	Operational
	Sheffield, Ala	2,000 T/D	Study Phase
	Western U.S.A.	500 T/D	Study Phase

Table 5.1.2

MAXIMUM PRACTICAL YIELDS
SELF-SUFFICIENT LIQUEFACTION PLANT

	% of Dry Coal Feed
Feed Coal Energy	100
Hydrogen Production	10 - 15
Process Heat and Power	15 - 20
Feed Energy Available for Liquids Production	65 - 75
Overall Process Efficiency %	65 - 75
Maximum Practical Liquid Yield %	46 - 54
Barrels/Ton	2.7 - 3.1

vi) It is unlikely that these yields and efficiency will be achieved in the earliest commercial plant, e.g. ERDA has recently published the following economic forecasts for an SRC plant charging a Wyoming sub-bituminous coal and a north-central coal (Ref. 5.5).

Table 5.1.3

ERDA - 76-55

"Preliminary Economic Analysis of SRC Liquid Fuels Process Producing 50,000 barrels per day of Liquid Fuels from Two Coal Seams: Wyodak and Illinois No. 6".

		Wyodak (Sub-Bitum.)	Illinois No. 6 (Bituminous)
Plant Size Bbls/day		50,000	50,000
Solid SRC produced		NIL	NIL
Unconverted COAL/CHAR disposal		H_2 production	H_2 production
Coal HHV	Btu/lb (kJ/kg)	8,048 (18,995)	12,861 (30,350)
Coal Feed	T/D	22,358	20,456
Products:			
Clean Boiler Fuel	Bbls	45,978	45,978
Naphtha	Bbls	4,022	4,022
Sulphur	T/D	2222	634
Electricity	MW	10	22
Thermal efficiency %		59.8	63.1
Economics			
Total Capital Investment $/MMBtu		710.6	700.6
Per Annual Bbl Liquid	$	42.52	42.46

vii) It should be noted that the quality of the Wyodak subbituminous coal, used in the above illustration, is considerably better than that of Hat Creek coal. The important properties affecting yields and thermal efficiency are ash, oxygen content and calorific value for coals of equivalent rank. Oxygen content is important because it both reduces the liquefaction yield and increases the hydrogen consumption. A comparison of these properties for Wyodak and Hat Creek coals is shown in Table 5.1.4.

Table 5.1.4 - Comparison of Wyodak (Sub-bituminous) and Hat Creek Coals

		% - DRY BASIS	
		Wyodak	Hat Creek
Ash		9.1	41.9
Calorific Value	kJ/kg	27,050	14,910
Carbon		66.76	54.9
Hydrogen		5.25	2.56
Oxygen		17.00	18.9

Assuming similar thermal conversion efficiencies, the yield of coal liquids produced per ton of dry coal charged is -

Barrels	
Wyodak	Hat Creek
2.25	1.0

viii) Comparison of coal liquids with petroleum residual oils reveals that the coal liquids have

- Lower hydrogen content
- Higher nitrogen and oxygen
- Higher aromaticity
- Higher asphaltenes
- Lower molecular weight.

Apart from their obvious applications as raw chemical feedstocks, it is expected that they will find ready applications as industrial fuel oils and peaking or intermediate fuel oils in electricity generation.

ix) After consideration of the status of developments of the major projects under development, the SRC (PAMCO) (Ref. 5.6) process was selected for process application of Hat Creek coal, with the addition of the H-OIL process to the SRC product as a method of producing light refinery liquids. These process descriptions are given in Section 6.2.

5.1.4 GASIFICATION

i) Until very recently the objectives of coal total gasification processes were aimed at producing either lean fuel gases (low and medium Btu) or synthesis gases. The synthesis gases could be employed for further conversion to ammonia, and hence synthetic fertilizers; to methanol, a valuable chemical intermediate; to hydrocarbons by Fischer-Pichler and Fischer-Tropsch processes; or to carbonyl compounds by OXO process. Quite rapid development in all these areas was brought to an abrupt halt after 1950 by very cheap energy availability resulting from the development of Middle Eastern oilfields and the utilization of natural gas in the U.S.A. Since that time coal gasification conversion technology has largely been confined to areas of the world having only coal and having strategic problems (South Africa) or poorly developed contries having cheap, readily accessible coal but little gas or oil resources. The oil embargo and other consequences, since the winter of 1973, has given fresh impetus to development in North America to coal-based conversion technologies.

ii) The most important result of renewed activity to date has been the successful demonstration of a capability of producing Synthetic Natural Gas (SNG) which is, in effect, pure methane from coal synthesis gases (Ref. 5.7, 5.8). The importance of this development is reinforced by a shortage of natural gas in North America that is accelerating. However, its practical application in large-scale commercial plants has been seriously delayed by

a) uncertainties over future oil and gas prices
b) severe inflationary effects on new plant costs
c) environmental regulatory factors affecting both coal mining and coal processing developments.

iii) In the meantime research and development activities to improve total gasification and crude gas upgrading processes has greatly expanded. An example of this is provided by the increased funding of these major projects by U.S. Energy Research and Development Agency, as shown in Table 5.1.5.

iv) Despite this activity, the old-established total gasification processes - Lurgi Pressure Gasification, Koppers-Totzek Gasification and Winkler Gasification - appear to have no serious competitors in the immediately foreseeable future and these processes, particularly Lurgi and Koppers-Totzek have evident scope for improvements, which might well counter competition from the third-generation concepts outlined in Table 5.1.5.

v) Improvements to the Lurgi process include development of
   a) much higher temperatures resulting in slagging conditions and complete re-design of the bottom sections of the gasifier (British Gas Council, Westfield) with increased gasifier outputs by factors of 4 or greater;
   b) increased gasifier sizes and hence reduction of units required for a given production. Some examples of this progress are illustrated in Figure 5.4 (Ref. 5.7);
   c) increased pressure of operation from the present 20-30 bars to 70 bars. This development is being conducted by Gesellschaft für Vergasung und Verflüssigung von Steinkohle mbH, an associate company of Montan-Consulting GmbH, and who have made major contributions to the studies included in the present Report. One expected result, if it is successful, will be to increase the calorific value of the crude gas to a stage where the methanation synthesis step

Table 5.1.5

ERDA-FUNDED COAL GASIFICATION PROJECTS

Process	Current Plant Phase	Obligations to 1/31/76 Government	Obligations to 1/31/76 Private	Total estimated cost Government	Total estimated cost Private	Anticipated Completion of Current Phase
		(000 omitted)				
High BTU:						
Hygas	75-ton-a-day pilot plant operating since October 1971	$34,251	$ 9,401	$38,511	$12,105	1977
Steam iron (hydrogen producing technique)	Pilot plant under construction; operation planned for October 1976	9,510	5,192	39,090	19,495	1978
Synthane	72-ton-a-day pilot plant is scheduled to start operation in May 1976	27,350	--	68,250	--	1978
Carbon dioxide acceptor	40-ton-a-day pilot plant operating since October 1972	29,199	7,330	37,720	12,080	1977
Bi-gas	120-ton-a-day pilot plant under construction; operation planned for June 1976	33,465	12,461	90,507	43,290	1978
Self agglomerating ash	25-ton-a-day process development unit starting operation May 1976	6,788	569	16,964	569	1978
Low BTU:						
Molten Salt	Contract is being renegotiated to reduce plant size to 24-ton-a-day	4,611	1,784	5,830	2,783	1979
Westinghouse fluidized bed	14-ton-a-day plant starting operations in March 1976 (note a)	15,696	4,167	b/22,794	b/6,726	Open
Morgantown Energy Research Center fixed bed	24-ton-a-day plant in operation since 1968	3,622	--	15,910	--	1977
Slagging fixed bed	25-ton-a-day pilot scale gasifier under construction. Operation is scheduled to start in September 1977	800	--	4,650	--	1979
Bituminous Coal Research fluidized bed	1-ton-a-day plant completed construction December 1975. Shake down operations are now underway	2,575	--	3,725	--	1977
Combustion Engineering entrained bed	120-ton-a-day plant under construction. Operation planned to start in June 1977	13,739	6,870	14,239	6,870	1979
Foster-Wheeler combined cycle	480-ton-a-day plant in design phase. Project to be discontinued at end of work on current contract	6,250	2,895	6,250	2,895	1976

a/ Only one section under operation. Complete plant operation scheduled for early 1978.

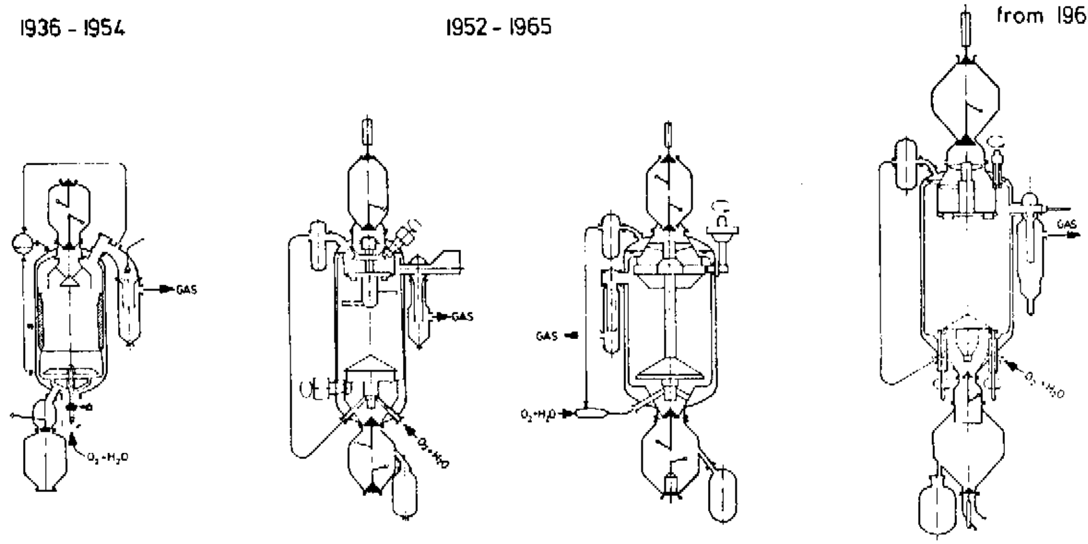
b/ Through fiscal year 1977, at which time a decision will be made on whether or not to continue the project.

Ref. SYNTHETIC FUELS, SEPTEMBER, 1976

may be reduced to much smaller dimensions, or even eliminated in producing a gas suitable for pipelining.

vi) Improvements to the Koppers-Totzek process have included introduction of 4- headed for the earlier 2- headed gasifiers and a 6- headed gasifier is at the conceptual stage. Other improvements include materials of construction developments to meet the more severe slagging conditions encountered with certain coals. This development is of particular interest in the case of Hat Creek coal because of the severe ash fusion characteristics that are expected. There are 15 plants, all of which are producing synthesis gas for ammonia production (See Table 5.1.6). A pressurized K-T gasifier is currently being tested in a development project conducted by a joint venture of Heinrick Koppers GmbH and Shell International Petroleum Maatschappij, The Hague, Netherlands, at the Dusseldorf Research Centre of Koppers-Essen (Ref. 5.9). The tests have been sufficiently successful to indicate that commercial operation at pressure is feasible.

STAGES OF GASIFIER DEVELOPMENT



	first generation	second generation		third generation
year	1936 - 1954	1952 - 1965		from 1969
coal grade	lignite	all coal grades	non-caking coals	all coal grades
capacity $\frac{\text{MM BTU coal input}}{\text{hr}}$	100	180-250	400-500	450-570

FIG 5.4

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ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER CANADA LIMITED

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Table 5.1.6

COAL BASED SYNTHETIC AMMONIA PLANTS

Customer and Location	Gasification Process and Ammonia Production (tons per day) Winkler	Lurgi	Koppers-Totzek	Construction Start
Azot Gorazde, Yugoslavia	50			1950
Empreso Nacional Calvo Sotelo, Puertolano, Spain	140			1950
Azot Sanayii, Kutahya, Turkey	120			1950
Typpi Oy, Oulu, Finland			60	1950
Nippon Suiso, Onahama, Japan			100	1954
Empreso Nacional Calvo Sotelo, Puentes, Spain			100	1954
Typpi Oy, Oulu, Finland Extension			60	1955
Daudhkel, Pakistan		60*		1956
Nitrogenous Fertilizer Ptolemais, Greece			300	1959
Neyveli, South Ascot, India	300			1960
Naju Fertilizer, Korea		150*		1962
Chemical Fertilizer Mae Moh, Lampang, Thailand			100	1963
Azot Sanayii, Kutahya, Turkey			250	1966
Industrial Development Corp., Kafue/Lusaka, Zambia			100	1966
Nitrogenous Fertilizer Ptolemais, Greece			75**	1969
Fertilizer Corp. of India Ramagundam, India			900	1969
Fertilizer Corp. of India Talcher Plant, India			900	1970
Nitrogenous Fertilizer Ptolemais, Greece			150	1970
Fertilizer Corp. of India Korba Plant, India			900	1972
AE & CI Ltd., Modderfontein, Republic of South Africa			1000	1972
Industrial Development Corp., Kafue/Lusaka, Zambia			100**	1974
TOTAL	610	210	5195 = 6015	
PERCENT OF PRODUCTION	10%	4%	86% = 100%	

* exact production rate unknown

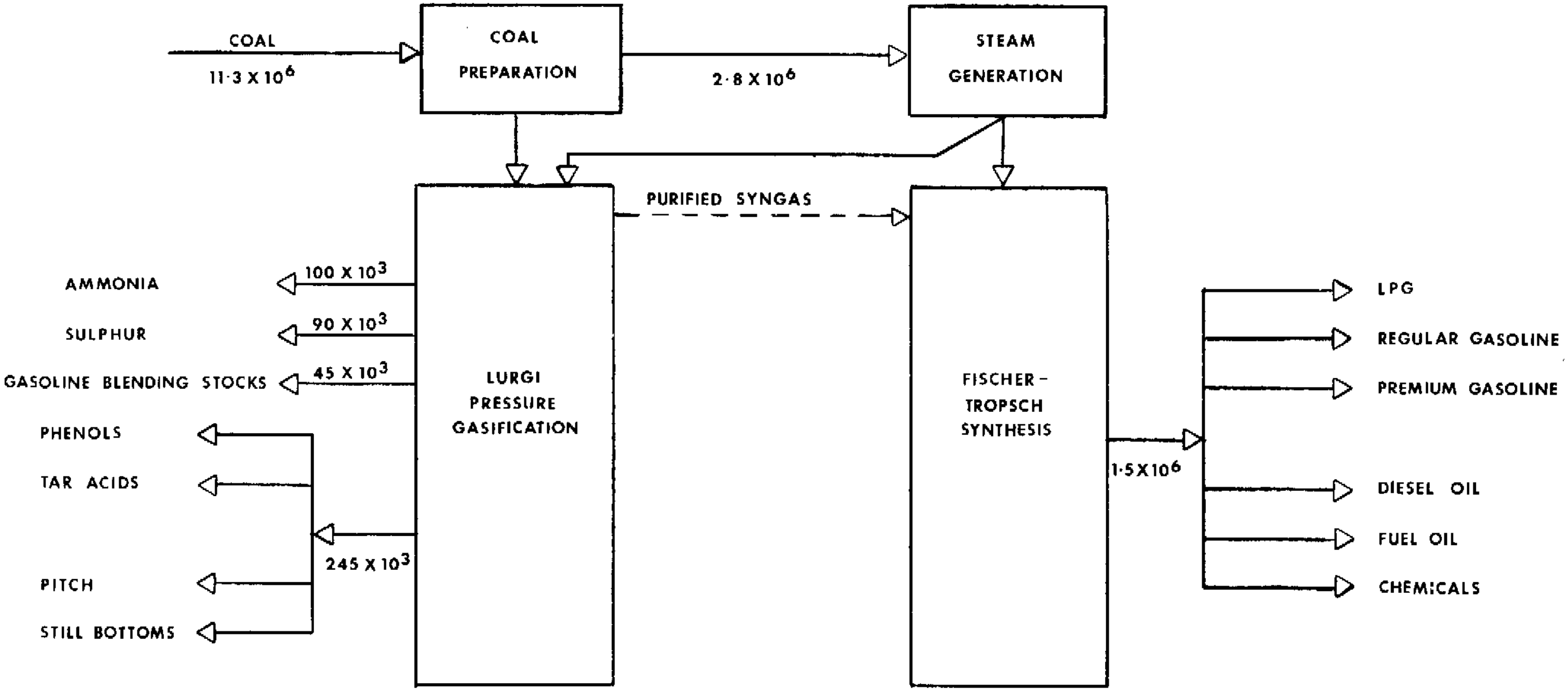
** ammonia production calculated from the increased synthesis gas production

vii) Although installation of Winkler units appears to have reduced greatly since 1960 more than 16 plants have been installed throughout the world and are all believed to be in operation at the present time. Davy Powergas Inc. is currently developing a high-pressure modification of the Winkler process which should increase the thermal efficiency.

viii) After considering the status of development of existing and future total gasification processes, it was decided to select the three existing commercial processes - Lurgi, Koppers-Totzek and Winkler - for application to Hat Creek coal, and to employ these processes both for coal conversion to SNG; and to ammonia and methanol.

The outstanding development of Fischer-Tropsch, Arge and Kellogg syntheses applied to synthesis gases produced by Lurgi gasification, which has been achieved since the early Fifties by the South African Oil & Gas Co. (SASOL) compels attention by coal processing technologists in spite of the very different politic/strategic situation which pertains to that country. In the case of Hat Creek, added interest arises from the general similarity of coal quality and ash characteristics to that of the Sigma mine at SASOL. At the present, SASOL is proceeding with a second installation which is double the size of the existing SASOL and is designed to produce greater yields of synthetic coal liquids and less fuel gas (Ref. 5.10). A flow sheet of SASOL-II is shown in Figure 5.5. Application of this process technology was selected for evaluation of Hat Creek coal and the mass/energy balances and costs are given in Section 6.2.

SASOL II - PROCESS FLOW DIAGRAM



TONS PER ANNUM

FIG 5.5

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER CANADA LIMITED

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5.2 Product Markets

A host of products can be manufactured in one or more of the coal conversion processes. Some of these products are sold in such large quantities that they can be referred to as principal coal conversion products. *An example is pipeline gas or Synthetic Natural Gas (SNG).*

Some of the products appear in lesser quantities and can be referred to as by-product. An example is coal tar.

In a case where the front end of a plant is capable of a coal gasification procedure, and where the same gas then can be either converted to ammonia or methanol, the plant can be referred to as a mixed plant. A mixed plant can be dedicated to the production of more than one principal product and the productions ratios can vary over a wide range. Such a mixed plant has not been examined in this Report.

*Thus in this Report, to confirm the contents, only single princi*pal products and their by-products are considered. The single principal products are both of an energy producing or a chemical nature. However, those by-products that are capable of being feedstocks for secondary industries are identified.

5.2.1 Principal Products

Principal products are closely associated with the commodities market where there is a universal and continuing demand for an item. Pipeline gas (SNG) and motor fuels are prime examples.

Secondary products are associated with both the feeds to *secondary industries and to commodities that are in lesser* demand. Examples are activated and electrograde carbon.

Below, the several products considered or reviewed in this Report are listed within the broad categories suggested.

Table 5.2.1

COAL CONVERSION PRODUCTS

Principal Products	By-Products	Secondary Products
Pipeline Gas (SNG)	Tars	
Ammonia	Tar Oils	Activated Carbon
Methanol	Naphtha	Electrograde Carbon
Motor Fuels	Phenols	Alumina
	Benzene	
Refinery Liquids	Sulphur	Low BTU gas
SRC Solids	LPG	CO_2
Coke		N_2
Power	Residue Cokes	Process Steam
	Heating Oils	
	Ash	

Under the classification of principal products, two of the eight listed have either been studied elsewhere or do not lend themselves to manufacture at Hat Creek. Power production has been amply studied by B.C. Hydro and is not examined here. Coke production has been dismissed because the Hat Creek coal demonstrates a complete lack of agglomerating properties. The remaining six principal products are examined in this Report.

The by-products are not examined by themselves, but are included in the economic analyses as those items that are generated in the manufacturing process and require marketing.

Secondary products can be manufactured from the several by-products. Activated and electrograde carbon can be derived from the residue cokes. Alumina may be derived from the ashes.

However, alumina has been examined by Halvorson and is not re-examined here. Low Btu gas and process steam are capable of satisfying a local market that could evolve if the Hat Creek complex becomes a reality. The gaseous CO_2 and N_2 will be waste streams unless secondary industries such as urea manufacture are established.

While the by-products and secondary products are of importance from a revenue point of view, the principal products are the core of the economics of Hat Creek coal conversion. These principal products are examined in the following order, first by their market potential and second their economic evaluation.

Market Location	Principal Products	Economic Evaluation Location
5.2.2	Pipeline Gas (SNG)	5.3.2
5.2.3	Ammonia	5.3.3
5.2.4	Methanol	5.3.4
5.2.5	Miscellaneous Hydrocarbon Products	5.3.5
5.2.6	Chemical Feedstocks	5.3.6
	Selected Process Evaluation	5.3.7

5.2.2 Pipeline Gas (SNG)

Canada has natural gas resources and an active market in the national consumption and export of the commodity. In 1974 Canadian production, consumption and exports were as follows:

Table 5.2.2

Canadian Natural Gas Flows - 1974

(Billions of cubic meters)

Production	- 73
Imports	- neg.
Exports	- 27
Apparent Consumption	- 46

The Canadian exports of 27 BCM per year are transmitted to the U.S. at several points along the common border. Should a plant be constructed at Hat Creek to manufacture SNG at the rate of 250,000,000 SCFD (7,000,000 Nm^3/d), the annual production would be about 2 to 3 billion cubic meters per year, a volume equal to about one tenth of the gas flow from Canada to the U.S.

In the discussions with Canadian natural gas producers, their appraisal of the volumes of this magnitude caused them to identify a potential SNG stream as incremental gas. As an incremental gas supply, Hat Creek SNG would be welcome by the pipeline gas transmission companies providing it was reasonably priced.

Their expression of acceptance reflected their concern over the future natural gas supplies from the Canadian Northwest. While Hat Creek SNG could not be expected to satisfy their base load requirements, it could help to provide an important energy material to the B.C. area even after the scheduled cessation of gas exports to the U.S.

This concern reflects the comparative size of the known natural gas reserves and the prospects of future supplies from the Canadian frontier areas. Currently, it is estimated that the recoverable producing areas contain some 3,250 billion cubic meters. These reserves are primarily in Alberta (2,600 BCM) and British Columbia (425 BCM), with a small fraction in the remainder of Canada.

At a future consumption rate of 100-125 BCM per year, Canada has reason for concern. However, the frontier areas are reported to contain over twice the conventional reserves. But the existence of reserves in such remote areas would have to be discounted somewhat due to the problem of delivering the volumes to the market.

The current natural gas problems in Canada are real. There is a long-term shortage in the Western Canadian transmission system and the shortage may continue beyond the U.S. supply contract termination date in the late 80's.

According to discussions held with the Westcoast Transmission Company Ltd., Canada still has 10 - 12 trillion cubic feet (about 312 BCM) to deliver at the rate of about 1 TCFY (about 30 BCM per year). An SNG plant at Hat Creek could help to alleviate the shortage both in the short and the long terms, particularly in the Westcoast Transmission System. Past 1985, this "supplemental" supply could be a welcome resource for the population of British Columbia.

The by-products of such a supplemental SNG supply would be tars, tar oils, naphtha, phenols, sulphur and ash. The whole range of by-products are of a type that could be readily sold in the northwest area. Their volumes are indicated below.

Table 5.2.3

SNG Plant Products

	Volume
SNG Pipeline Gas	2.8×10^9 Nm^3/a
Tars	189 MTPY
Tar Oils	189 MTPY
Naphtha	145 MTPY
Phenols	45 MTPY
Sulphur	34 MTPY

The estimated sum of the capital cost and the working capital total of an SNG plant of this size is $933,000,000*. This amount related to the annual revenues provides a capital ratio of 32 percent. The thermal efficiency of conversion is about 62 percent, a level generally higher than that experienced in most coal conversion processes.

In a later section, the comparative evaluation of SNG production will be presented.

5.2.3 Ammonia

Ammonia can be produced from Hat Creek coal. Whereas SNG production was based on a coal feed of 18,000,000 tons per year, the ammonia plant is considered only at a capacity related to a 3,000,000 ton per year coal input. It is to be noted that in as much as the potential plant size is at a one sixth level, the comparative economics are presented at the 18,000,000 tons per year coal feed level.

The 3,000,000 metric tons per year of Hat Creek coal would produce about 1,000,000 metric tons per year of ammonia on an equivalent nitrogen basis. This level of flow is compared to those flows in Canada, the U.S., and the world market, as indicated in Table 5.2.4.

* The total 1978 capital requirement is estimated to be $1,058,100,000 and is shown in detail on Table 5.3.12.

Table 5.2.4

Nitrogen Fertilizer Data*

(million metric tons of nitrogen)

	Canada	U.S.A.	World
1975 Data			
Supply	0.8	8.5	42.4
Consumption	0.5	7.8	38.8
Balance	0.3	0.7	3.6
Capacity	1.2	13.7	68.3
1980 Estimate			
Supply	1.3	11.0	66.8
Consumption	0.6	8.8	54.4
Balance	0.7	2.2	12.4
Capacity	2.2	17.7	107.8

	Combined U.S.A. and Canada	World
1990 Estimate of Consumption	10.4	77.5
2000 Estimate of Consumption	11.5	118.8
2010 Estimate of Consumption	12.7	195.0

Detailed ammonia data on capacity, production, consumption, and trade can be examined in Tables 5.2.5 to 5.2.11.

One million new tons of Hat Creek ammonia production would double current Canadian production. The tonnage, in proportion, is equal to one eighth of the current U.S. production.

* Data from the Tennessee Valley Authority, FAO-United Nations, and Stamford Research Institute.

Table 5.2.5

WORLD NITROGEN FERTILIZER PRODUCTION

(Thousand Metric Tons)

	1965	1970	1973	1974	1975	% Annual Growth
North America	4,805	8,234	9,205	9,961	9,421	7.0
Central & South America	520	739	845	873	1,009	6.9
Western Europe	5,827	7,841	8,949	9,355	9,690	5.2
Eastern Europe	1,345	3,250	4,152	4,373	4,773	13.5
U.S.S.R.	2,099	4,509	6,551	7,241	7,856	14.1
Africa	190	367	552	462	536	10.9
Asia	1,909	3,689	4,932	4,994	5,423	11.0
Communist Asia	752	1,392	2,475	3,031	3,340	16.1
Oceania	26	160	182	197	192	22.1
Grand Total	17,473	30,181	37,843	40,488	42,241	9.2

Table 5.2.6

WORLD NITROGEN FERTILIZER CONSUMPTION

	1965	1970	1973	1974	1975	% Annual Growth 1965-1975
			(Thousand Metric Tons)			
North America	4,379	7,037	7,935	8,820	8,306	6.6
Central & South America	683	1,180	1,629	1,718	1,924	10.9
Western Europe	4,275	6,005	6,990	7,413	7,230	5.4
Eastern Europe	1,551	3,057	3,675	3,791	4,005	10.0
U.S.S.R.	1,759	3,798	5,624	6,156	6,746	14.4
Africa	511	735	1,061	1,075	1,101	8.0
Asia	1,945	3,841	4,894	5,168	5,143	10.2
Communist Asia	1,196	2,851	3,696	4,281	4,197	13.4
Oceania	77	188	206	218	208	10.5
Grand Total	16,375	28,691	35,711	38,739	38,859	9.0

Table 5.2.7

NITROGEN FERTILIZER DEMAND/SUPPLY

	1975	1980	1990	2000	2010
	(Thousand Metric Tons)				
NORTH AMERICA					
Consumption	8,306	9,400	10,400	11,500	12,700
Capacity	14,959	19,857			
Supply	9,275	12,311			
CENTRAL AMERICA					
Consumption	1,924	3,200	5,600	9,700	16,800
Capacity	2,709	6,836			
Supply	1,680	4,238			
WESTERN EUROPE					
Consumption	7,230	8,200	9,100	10,000	11,000
Capacity	13,351	16,319			
Supply	8,278	10,118			
EASTERN EUROPE/U.S.S.R.					
Consumption	10,751	15,100	16,700	18,500	20,400
Capacity	18,362	27,558			
Supply	11,384	17,086			
AFRICA					
Consumption	1,101	1,800	4,100	9,500	22,100
Capacity	1,346	3,790			
Supply	835	2,350			
ASIA					
Consumption	9,340	16,400	21,100	58,900	110,900
Capacity	17,452	33,255			
Supply	10,820	20,618			
OCEANIA					
Consumption	208	300	500	700	1,100
Capacity	144	144			
Supply	89	89			
WORLD TOTAL					
Consumption	38,859	54,400	77,500	118,800	195,000
Capacity	68,323	107,759			
Supply	42,360	66,810			

Table 5.2.8

NITROGEN FERTILIZER MARKET - PACIFIC RIM

	1975	1980e
	(Thousand Metric Tons)	
CANADA		
Consumption	510	577
Capacity	1,231	2,176
Supply	763	1,349
UNITED STATES		
Consumption	7,796	8,820
Capacity	13,728	17,681
Supply	8,511	10,962
JAPAN		
Consumption	691	1,251
Capacity	5,040	5,266
Supply	3,125	3,265
PHILIPPINES		
Consumption	177	320
Capacity	109	109
Supply	68	69
INDONESIA		
Consumption	401	725
Capacity	302	1,363
Supply	187	845

Table 5.2.9

NITROGEN FERTILIZER CONSUMPTION, TRADE AND PRODUCTION

1971 - 1975

(Thousand Metric Tons)

	NORTH AMERICA	CENTRAL & SOUTH AMERICA	WESTERN EUROPE	EASTERN EUROPE	U.S.S.R.	AFRICA	ASIA	COMMUNIST ASIA	OCEANIA	TOTAL WORLD
1971										
Consumption	7,671	1,359	6,444	3,210	4,605	823	4,140	3,358	158	31,767
Net Trade(1)	537	-616	1,573	193	210	-354	267	-1,727	-4	78
Total	8,208	743	8,017	3,403	4,815	469	4,407	1,631	154	31,845
Production	8,887	749	8,107	3,670	5,423	403	3,957	1,631	145	32,972
Difference(2)	679	6	90	267	608	-66	-450	0	-9	1,127
1972										
Consumption	7,622	1,445	6,824	3,430	5,182	954	4,365	3,389	138	33,348
Net Trade(1)	594	-603	1,327	653	177	-547	35	-1,316	33	353
Total	8,216	842	8,151	4,083	5,359	407	4,400	2,073	171	33,701
Production	8,896	796	8,372	3,942	6,055	483	4,169	2,073	176	34,962
Difference(2)	680	46	221	-141	696	76	-231	0	5	1,261
1973										
Consumption	7,935	1,629	6,990	3,675	5,624	1,061	4,894	3,696	206	35,711
Net Trade(1)	761	-799	1,374	605	204	-624	116	-1,221	-25	391
Total	8,696	830	8,364	4,280	5,828	437	5,010	2,475	181	36,102
Production	9,204	845	8,949	4,152	6,551	552	4,932	2,475	182	37,843
Difference(2)	508	15	585	-128	723	115	-78	0	1	1,741
1974										
Consumption	8,820	1,718	7,413	3,791	6,256	1,075	5,167	4,281	218	38,739
Net Trade(1)	509	-875	1,031	654	369	-564	-495	-1,257	-29	143
Total	9,329	843	8,444	4,445	6,625	511	4,672	3,024	189	38,882
Production	9,961	873	9,355	4,373	7,241	462	4,994	3,031	197	40,488
Difference(2)	632	30	911	-72	616	-49	322	7	8	1,606
1975										
Consumption	8,306	1,924	7,230	4,005	6,746	1,101	5,143	4,197	208	38,859
Net Trade(1)	148	-958	1,808	735	470	-612	-811	-867	-10	-96
Total	8,454	966	9,038	4,740	7,216	489	4,332	3,330	198	38,763
Production	9,421	1,009	9,690	4,773	7,856	536	5,423	3,340	192	42,241
Difference(2)	967	43	652	-33	640	47	1,091	10	6	3,478

Note: (1)Net Trade = Exports less Imports; (2)Difference = Production less Consumption + Net Trade

Table 5.2.10

WORLD AMMONIA CAPACITY

	1973	1974	1975	1976e	1977e	1978e	1979e	1980e	% Annual Growth 1973-1980e
					(Thousand Metric Tons)				
North America	13,894	13,898	14,959	15,257	18,337	19,332	19,857	19,857	5.2
Central & South America	1,766	2,359	2,709	3,587	5,106	5,516	5,875	6,836	21.3
Western Europe	14,368	14,047	13,351	14,030	13,949	14,865	16,165	16,319	1.8
Eastern Europe	6,878	8,113	8,563	9,513	10,202	10,202	10,833	11,239	7.3
U.S.S.R.	8,159	8,800	9,799	10,263	11,003	11,879	12,619	16,319	13.1
Africa	917	1,065	1,346	1,450	1,829	3,141	3,736	3,790	22.4
Asia	11,396	12,047	12,796	13,197	14,055	18,263	23,016	24,023	11.3
Communist Asia	4,409	4,575	4,656	6,515	7,875	9,232	9,232	9,232	11.1
Oceania	144	144	144	144	144	144	144	144	0.0
Grand Total	61,931	65,048	68,323	73,956	82,500	92,574	101,477	107,759	8.2
World Supply Nitrogen Fertilizer(1)	43,351	45,534	47,826	51,769	57,750	64,802	71,034	75,431	8.2

Note: (1)Based on 62% average capacity utilization.

Table 5.2.11

NITROGEN FERTILIZER CONSUMPTION

1975 - 2010

	% Annual Growth 1965-1970	% Annual Growth 1970-1975	1975 (000M Tons)	% Annual Growth e 1975-1980	1980e (000M Tons)	Consumption per Capita 1975	Consumption per Capita 1980	1990 (Thousand Metric Tons)	2000	2010	% Annual Growth 1980-2010	Consumption per Capita 2010
North America	10.0	3.4	8,306	2.5	9,400	34	37	10,400	11,500	12,700	1.0	37
Central & South America	11.5	10.3	1,924	10.7	3,200	6	9	5,600	19,700	16,800	5.7	28
Western Europe	7.0	3.8	7,230	2.5	8,200	24	28	9,100	10,000	11,000	1.0	33
Eastern Europe	14.5	5.5	4,005	7.3	5,700			6,300	7,000	7,700	1.0	
U.S.S.R.	16.6	12.2	6,746	6.9	9,400	26	35	10,400	11,500	12,700	1.0	35
Africa	7.5	8.4	1,101	10.0	1,800	3	4	4,100	9,500	22,100	8.7	28
Asia	14.5	6.0	5,143	12.6	9,300	4	7	17,600	33,400	62,900	6.6	29
Communist Asia	19.0	8.0	4,197	11.1	7,100			13,500	25,500	48,000	6.6	
Oceania	19.5	2.0	208	7.6	300	10	13	500	700	1,100	4.4	30
World (Expected)	11.3	6.2	38,859	7.0	54,400	10	13	77,500	118,800	195,000	4.3	30
World (Potential)[1]				9.8	62,000[1]		15	85,000[1]	140,000[1]	195,000		

Note: [1] Potential world consumption based on sharply reducing grain deficits in developing countries by 1985.

The introduction of an additional flow of one million tons on to the world market would encounter an excess of some three million tons in todays global market and an expected 12 million tons in 1980. A sixth of this world excess is now being planned and constructed in neighbouring Alberta where the following plants are in the process of construction.

Table 5.2.12

Proposed Alberta Ammonia Plants

Principal	Locations	Status	Tons per Year Capacity
Esso Chemicals	Redwater	Planning	770,000
Cominco	Calgary	1977	400,000
Sherrit Gordon	Fort Saskatchewan	1977	495,000
CF Industries	Medicine Hat	1977	396,000
			2,061,000

If only one half of this Alberta capacity is realized, it would be equal to a Hat Creek product flow at the 3,000,000 tons per year coal feed rate. Thus both the Alberta and B.C. production volumes would encounter a Canadian limit of ammonia consumption of 600,000 tons per year by 1980.

This combined Alberta and B.C. production would require both U.S. and Pacific markets for their consumption. This western Canadian production may be satisfied in the continental market by 1990 if the restrictions of natural gas feed force the North American producers to convert to coal in place of natural gas feedstocks. As a matter of fact, Alberta has already announced that future applications of natural gas based ammonia plants will be denied in favour of coal based plants. This trend will undoubtedly spill over into the U.S. area.

In summary, coal based ammonia plants at the 3,000,000 tons per year of coal feed level would encounter both limited local and limited world markets, and would be impossible to sustain other than at greatly reduced production rate at the 18,000,000 coal feed level. Under this overwhelming set of conditions, ammonia is not recommended as a potential principal product. In a later section the economics of a large ammonia plant is presented, but only for comparative purposes.

5.2.4 Methanol

Methanol is unique as a multifaceted chemical. It is an energy commodity, an intermediate chemical, a hydrogen source, and a potential feed material for manufacture of protein.

Currently, the world demand for chemical methanol is of the order of 8 million metric tons, about two thirds of which are consumed equally by the U.S. and Western Europe, and the remainder divided between Japan and the rest of the world.

Currently Alberta Gas Chemicals is starting up a pair of 600 tons per day methanol units in Medicine Hat. With a license for an additional pair, AGC would be shipping close to one million tons to the Canadian coast for sale to the U.S. and the Pacific rim countries. Whereas the above plants are natural gas based, the tendency is to shift to coal feedstocks in future units.

The new world scale supplies could be absorbed in the world market when the projected demand of twice the current supply is realized in the early 1980's.

Methanol proponents are optimistic about future methanol demand. Under the proper economic conditions, the forecast for maximum potential demand soars past the doubling mark to a tenfold increase. The following data were presented at the recent Baghdad* conference.

Table 5.2.13

Potential Future Methanol World Market (1983)

(millions of metric tons)

	Low Estimate	High Estimate
Steel Industry	74	95
Motor Fuel	10	80
Fuel (Peak Shaving)	5	15
Ammonia Synthesis	4	5
Single-Cell Proteins	3	5
Chemical Intermediate	12	20
	108	220

In the steel industry, the future availability of traditional coke as a reducing agent is questionable because of its greatly expanded price structure. Methanol could provide the reducing hydrogen required if the price is competitive with other hydrocarbon sources such as petroleum.

The second largest use could be as a high-octane component for gasoline. Should the gasoline and automotive manufacturers solve their immediate problems, methanol can be useful in abating air pollution.

The current world gasoline market is of the order of 650 million metric tons. The introduction of methanol would be small to start with, but could mushroom if methanol is eventually accepted as a motor fuel additive in North America.

As an ammonia plant feedstock, it may develop that methanol can be transported over long distances relatively more cheaply than ammonia. This relationship could potentially allow for small ammonia plants to be operational at the point of use.

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* Oil and Gas Journal - June 14, 1976

In the long term world scene, protein will be in short supply. Imperial Chemical Industries* has found that it is possible to produce an excellent animal food by growing bacteria on methanol.

Under the right conditions, bacteria can double their mass in an hour. To quote Dr. Peter Reynolds*, "whereas a half-ton cow can synthesize a pound of protein in a day, a half-a-ton of bacteria could make a million tons". According to Reynolds, the amino-acid profile of the protein is excellent for animal nutrition and further, the animals love and thrive on it.

As a boiler feed material, methanol has proved to be a clean fuel for two reasons. In the New Orleans Public Utility tests** not only were the stack gases clean but the burning of only several thousand tons of methanol cleansed the boiler tubes and enhanced the heat transfer surfaces. However, extended use of methanol as a boiler feed requires experimentation to discover the results of the long term effects.

Methanol is also a potential feed to a turbo-generator. This use will also require research and development by equipment manufacturers.

As a chemical intermediate, methanol is the feedstock for plants that produce formaldehyde, dimethyl terephthalate, methyl halides, methyl methacrylate, acetic acid, methylamines, and glycol methyl ethers. The Hat Creek plant could conceivably be expanded to provide for the manufacture of some of these derivatives in secondary industries.

To consider methanol as a basic product for Hat Creek is to direct the attention to the production of a hydrogen carrier. Such a carrier could then be compared to other hydrogen

* Energy World - May 1975

** Personal observation

carriers. Current estimates of the cost of hydrogen from several carriers is as follows:

Methanol	\$3.19 - \$ 3.52 per MMBTU
Natural Gas	\$4.09 - \$ 4.41 per MMBTU
LNG	\$4.18 - \$ 4.52 per MMBTU
Naphtha	\$4.50 - \$ 4.92 per MMBTU
Electrolysis	\$7.87 - \$10.00 per MMBTU.

From the above concept a closer look at methanol may be required for Hat Creek coal.

Methanol as well as ammonia and SNG are ideal candidates for a mixed product plant. The three products lend themselves to the same front end equipment. However, the introduction of two or three downstream unit processes to convert synthesis gas to either methanol, ammonia or SNG may compromise the savings realized in using a common front end. The concept of a composite plant requires both consideration and analysis, but beyond the scope of this study.

The findings on the potential methanol markets do not project as clear a direction as is found in SNG and ammonia. There is an ample and continuing market for SNG and the level of Hat Creek potential production is only a small fraction of the current market. There is a limited tonnage market for large volumes of ammonia and its derivatives in both North America and the world. But in the case of methanol there is a large potential market but not an assured market.

Coke prices may not expand at their current accelerated levels. Alcohol motor fuels may fail to be adapted by the motor industry. Protein production may be found to be more acceptable in an ethanol media in preference to methanol. So consideration of large scale methanol production rests on a non-assured market and may require consideration of methanol as part of a mixed plant product rather than a principal plant product.

The assurance of a methanol market for Hat Creek would be greatly reduced should Middle East flare gas be converted in large quantities to methanol.

5.2.5 Miscellaneous Hydrocarbon Products

A range of hydrocarbon products can be produced from Hat Creek coal by several different processes. The following table identifies the principal product of the several processes under review.

Table 5.2.14

Hydrocarbon Products

Process	Principal Products
Fischer-Tropsch	Motor Fuel
Lurgi-Kellog	Motor Fuel
SRC-1 - Gulf	Coal Solids
SRC + H-Oil	Light Refinery Liquids
Lurgi-Ruhrgas	Tars and Power

The above principal products are all energy products. Should one of the above processes be considered at Hat Creek, the products would require a frame of reference that would extend beyond the local area.

The conversion of 18,000,000 tons of coal to various hydrocarbons would introduce commodities into a marketplace with an insatiable and increasing demand. A review of the Canadian hydrocarbon market as it relates to U.S. and world energy markets will demonstrate the comparative volumes.

Working with the latest United Nations statistical paper (Series J, No. 19)* the relationship of Canadian production, trade and consumption of commercial energy as compared to the U.S. and the world, can best be described in tabular form of coal equivalent as the reference unit. These data* follow:

* World Energy Supplies (1950-1974) United Nation Series J, No.19

Table 5.2.15

Energy Data - 1974

(millions metric tons of coal equivalent* or 29,300,000 KJ/MT)

Production	Canadian	U.S.A.	World
Total Primary Energy	282	2,105	8,641
Coal and Lignite	19	544	2,513
Crude Petroleum and Nat. Gas. Lig.	139	729	4,248
Natural Gas	98	781	1,675
Hydro & Nuclear Electricity	28	52	205
Imports	79	486	3,150
Exports	129	63	3,225
Bunkers	5	25	243
Consumption			
Aggregate	221	2,433	7,971
Solid Fuels	20	500	2,531
Liquid Fuels	113	1,068	3,567
Natural Gas	61	811	1,668
Hydro & Nuclear Electricity	26	53	205

On a total primary energy basis, Canadian energy production and consumption is small by comparison to U.S. and world totals. The relative percentages are noted below:

Table 5.2.16

Canadian Relationships

(in percentages)

	To U.S.A.	To World
Energy Production	16%	3%
Energy Consumption	9%	3%

These data suggest that suitable energy materials, that Canada would have for export, would not substantially effect either the U.S. or world markets. Conversely, in todays energy market, suitable Canadian hydrocarbons could find a ready market if priced reasonable.

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* Based on definition of coal equivalent as shown on page xviii of World Energy Supplies (1950-1974) United Nations Series J, No. 19.

Even in 1974, Canada exported some 55 to 60 million metric tons of coal equivalent of mixed hydrocarbons, providing a revenue of the order of 1 to 2 billion dollars. In todays energy situation, these revenues may not be expandable following the development of a Canadian national conservation policy.

Currently Canada's flows of solid fuels (primarily coal) are noted below:

Table 5.2.17

Canadian Solid Fuel Flows* (1974)

(millions of metric tons of coal equivalent or 29,300,000 kJ/MT)

Productions	19
Imports	13
Exports	11
Consumption	21

The bulk of the imports are from the U.S. Appalachian area for use in the Ontario steel mills and power plants. The bulk of the exports are shipments of western Canadian metallurgical coal bound for Japan. The Hat Creek coal is non-metallurgical and it is very unlikely that it could enter into these steel markets even with an expected doubling of Canadian metallurgical coal to Japan.

The liquid fuel flows are primarily crude petroleum and natural gas liquids. The flows shown below are given in terms of million metric tons of liquid and not coal equivalents.

Table 5.2.18

Canadian Liquid Fuel Flows* (1974)

(Millions of metric tons of liquid)

Natural Gas Liquid Production	11
Crude Petroleum Production	83
Imports of Liquids	41
Exports of Liquids	40
Stock Additions	-1
Apparent Supply to Refineries	84
Refining Capacity	101

* World Energy Supplies (1950-1974)
United Nations (Series J, No. 19)

These data indicate that Canada is presently self-suffient in hydrocarbon liquids and that imports and exports are exchanged to compensate for the wide geographic expanse of the nation. The bulk of the imports are generally directed to the eastern provinces in approximate exchange for Canadian crude to the western parts of the U.S.A.

Canada appears to have a reasonable supply of natural gas liquids available for petrochemical production. This flow as well as the flows to the refineries could readily be supplemented with liquids produced from Hat Creek coal. At a rough ratio of one barrel of liquid per ton of coal, the 18,000,000 annual barrels would translate into some 3 million metric tons, or equivalent to some 3 percent of current refining capacity. Should liquids be manufactured at Hat Creek, the flow would have a small impact on the Canadian liquid market.

However, the flow of the liquid by-products could have an effect on the non-energy Canadian petroleum products market because of the relatively small volumes involved. These are shown below:

Table 5.2.19

Canadian Non-Energy Petroleum Products*

(millions of metric tons)

Total Flows	4.434
Naphtha	0.513
Bitumen and Road Oils	2.993
Paraffin Wax	0.040
Petroleum Coke	0.263
Lubricating Oil	0.625

Were Hat Creek liquids to be directed at the petroleum energy markets, the small production would not be expected to effect the overall national liquid energy structure and the amount would probably be consumed in the local area. The data is noted below.

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* United Nations Reference

Table 5.2.20

Canadian Petroleum Energy Flows*
(millions of metric tons)

Major Product Aggregates	
Production	83
Imports	4
Exports	10
Bunkers	3
Apparent Consumption	73
Liquefied Petroleum Gases	
From Refineries	0.755
From Plants	4.419
Imports	0.006
Exports	3.128
Apparent Consumption	2.054
Fuel Oils	
Distillates	23
Residuals	21
Imports	3
Exports	6
Bunkers	3
Apparent Consumption	37

The importance of the above review is that hydrocarbon products, at the 18,000,000 ton coal feed level, would find ready markets at reasonable cost.

5.2.6 Chemical Feedstock

Two aromatic compounds are reviewed here as potential candidates to be considered as principal products. They are Benzene and Phenol.

* United Nations Reference

Historically, aromatic ring compounds were ever associated with coal tar chemicals, the coal itself being possessed of a wide mixture of ring compounds. In the coal gasification process, some of the products are ring compounds (phenols and other derivities of benzene) if the reaction temperatures are not extreme.

The question to be resolved in this section is the size of a potential market for these products. If the market is relatively small, the by-product production could satisfy the demand. Should the market be insatiable, the possibility of a benzene or toluene synthesis can be investigated.

In the production of 250,000,000 SCFD (7 x 10^6 Nm^3/day) of SNG some 45,000 metric tons per year of phenols are recovered as by-products.

Current U.S. consumption of phenols is of the order of 1.0 million metric tons and is expected to rise to 1.3 million metric tons by the 1980's. The potential Hat Creek by-product production would be of the order of 4-5% of U.S. consumption, small enough to be absorbed in the North American market.

Should the Hat Creek plant be dedicated to the production of benzenes and phenols, the combined production at the 3,000,000 tons per year coal input level would be about 400,000 metric tons. This volume approaches 50% of U.S. demand and would require a world market for its distribution. Therefore any consideration of a dedicated plant would require a reference to the world markets for benzene and phenol. However, before the world market is reviewed, the Canadian production is analyzed.

Eastern Canada now has a 400,000 metric tons of benzene capacity in the Sarnia area. Western Canada has proposals for 1 million metric tons, all in the Alberta area. The current and potential producers are shown below.

Table 5.2.21

Canadian Benzene Producers*

(thousand metric tons)

	Current	Under Construction	Proposed
Gulf Oil, Montreal	64		
Petrofina, P.A. Trembles	82		
Texaco, Port Credit	16		
Esso, Sarnia	100		
Polysar, Sarnia	68		
Shell, Sarnia	25		
Sun, Sarnia	38		
	393		
Shell, Sarnia		25	
Petrosar, Sarnia		375	
		400	
Petro-Alberta, Ft. Sask.			500
AGTL/AGC/Dow, Bruderheim			445
			945

The new Sarnia capacity will provide for the Canadian demand until 1980. The proposed Alberta capacity will probably move westward to the Pacific rim for part of the production and through the Panama Canal for the remainder. Should the proposed Alberta capacity become a reality, there would be little room for a Hat Creek benzene supply.

Whereas Canadian production is headed to a 2 million metric ton level, world demand is headed to 10 times this amount, one third of which will be consumed by the U.S. The data is show below.

* Canadian Petroleum - September 1976

Table 5.2.22

Benzene Supply/Demand*

(thousand metric tons)

	Canada	U.S.A.	World
Current (1977)	400	5,000	12,000
1977 - 1978	800	6,000	14,000
1978 - 1980	1,800	7,00	20,000

At the right world price, Canadian benzene could move into the world marketplace. This is to say that 400,000 M.T. additional B. C. production at the 3 million tons of coal level, could potentially find a market, but a mammoth dedicated plant at 6 times this production would be hard pressed to market its product.

Whereas world benzene capacity is of the order of 12,000,000 metric tons, world phenol is about one quarter of this volume and is expected to expand by 25% by the 1980's. The world data is shown below.

Table 5.2.23

Phenol Capacity*

(thousand metric tons)

	Current	1980
North America		
U.S. & Puerto Rico	1,266	1,563
Canada	50	61
Mexico	0	25
South America	62	128
Western Europe	1,048	1,233
Eastern Europe	220	220
Asia & Pacific	366	470
	3,012	3,700

* Stanford Research Institute data

Should 45,000 metric tons of phenol from a 7 x 10^6 Nm^3/day SNG plant at Hat Creek be introduced into the market place, it could find a market. However, whereas a dedicated plant producing 10 times this amount would have to scramble for markets (3,000,000 tons of coal), a larger plant (18,000,000 tons of coal), would produce a phenol stream about equal to world capacity. In short, neither phenol nor benzene should be seriously considered from a 3,000,000 tons per annum dedicated coal fed plant and never from an 18,000,000 tons per year coal fed Hat Creek plant.

5.3 Economic Evaluation

The economic evaluations in this Report are presented at two levels of detail. The lower level of detail is used to compare the overall economics of 14 coal conversion processes.

Once the overall economics are examined and a single recommended process is selected, a detailed economic analysis is presented for the one process. The process that is selected is chosen on both a market and an economic basis. In a subsequent section, the three additional factors of technology, process risk, and environmental impact are applied to the 14 processes to further confirm the process selection.

It is to be noted that the economic evaluations are all based on raw rather than washed coal.

Should a coal beneficiation plant have been considered, the dense medium systems would not cost less than \$10 per annual ton of raw coal throughput. The washing costs would add about \$2 - 4 per ton to the cost of the clean coal product. The economics of plant size for coal preparation plants is not appreciable for throughputs over 2-4 million tons per annum, and in the present case we are considering throughputs of 18,000,000 t.p.a. A cost of a beneficiation plant at this throughput would be of the order of \$180,000,000.

As seen from Table 4.1, the beneficiation plant would produce a final product containing 17.5% ash at 22.5% moisture content, i.e. 40% inerts. The washed product would exit with an ash content equal to or higher than the ash content of the input feedstocks in a conventional beneficiation plant.

The above considerations have lead to the conclusion that coal beneficiation of Hat Creek coal by washing is not feasible on technico-economic grounds.

It is to be noted that the effect of supplying washed coal to the several process units would be similar. That is, the extra yields on a proportionate basis would be about the same.

5.3.1 The Range of Processes

The processes under review manufacture gases, liquids and solids as principal products. The description of these processes is treated in Part 6 of this Report. The 14 processes mentioned above are listed below and their principal products are identified in the following table:

Table 5.3.1 Range of Processes

	Process	Principal Product
1.	Lurgi	Pipeline Gas (SNG)
2.	Koppers Totzek	Pipeline Gas (SNG)
3.	Winkler	Pipeline Gas (SNG)
4.	Lurgi	Ammonia
5.	Koppers-Lurgi	Ammonia
6.	Winkler	Ammonia
7.	Lurgi	Methanol
8.	Koppers	Methanol
9.	Winkler	Methanol
10.	Fischer Tropsch	Motor Fuel
11.	Lurgi-Kellogg	Motor Fuel
12.	SRC-1 - Gulf	Coal Solids
13.	SRC + H-Oil	Light Refinery Liquids
14.	Lurgi Ruhrgas	Tars and Power

The lower level of economic indication involves capital cost, working capital, production volumes, revenue analyses, and the thermal efficiency of conversion. The selection of the one process is made on the revenue/capital ratio and the percent efficiency derived from the above data.

5.3.2 Pipeline Gas (SNG)

The production of pipeline gas (970 - 1000 BTU/cu.ft.) by the three processes, Lurgi, Koppers-Totzek and Winkler, would generate 7×10^6 Nm^3/d in addition to the following liquid and solid products:

Table 5.3.2

By-Products of SNG Units
(thousand of metric tons per year)

	Lurgi	Koppers-Totzek	Winkler
Tar	189	-	-
Oil	189	-	-
Naphtha	145	-	-
Phenols	45	-	-
Sulphur	34	65	60
Power Generation		(~21 MW)	

The totals of the revenues from the by-products as well as the pipeline gas are listed below alongside the sum of the capital costs and working capital.

Table 5.3.3

SNG Plants Comparative Data (Current Costs)

	Lurgi	Koppers-Totzek	Winkler
Annual Revenues 10^6\$	303	228	217
Capital Cost & Working Capital 10^6\$	933	894	927
Revenue/Capital Ratio	0.32	0.26	0.23
Thermal Efficiency	61.9%	49.7%	50.8%

From the above data, the Lurgi route to SNG was selected, both from a consideration of the Revenue/Capital Ratio and the Thermal Efficiency.

5.3.3 Ammonia

The production of ammonia through the front ends of the Lurgi, Koppers-Totzek and Winkler units would be supplemented by the following by-products:

Table 5.3.4

Products of the Ammonia Plants

(thousand of metric tons per year)

	Lurgi	Koppers-Totzek	Winkler
Ammonia	479	756	740
SNG (Methanol)	$174 \times 10^6 M^3/a$	-	$46 \times 10^6 M^3/a$
Tar	29	-	-
Oils	29	-	-
Naphtha	23	-	-
Phenols	7	-	-
Sulphur	6	9	9

As in Section 5.3.2, the following comparative data is presented in a similar manner.

Table 5.3.5

Ammonia Plant Comparative Data (Current Costs)

	Lurgi	Koppers-Totzek	Winkler
Annual Revenues 10^6\$	600	677	737
Capital Cost & Working Capital 10^6\$	853	835	835
Revenue/Capital Ratio	0.70	0.81	0.88
Thermal Efficiency	58.5%	47.1%	50.2%

The revenue/capital ratios of ammonia production are over twice those of SNG production, but the thermal efficiencies are of the same order of magnitude. Were there an assured market for ammonia in such large quantities, ammonia production would be selected over SNG production. Since the reverse is the case, on the basis of 18,000,000 t/a, raw coal feed, SNG is favoured.

5.3.4 Methanol

For a third product the front ends of the Lurgi, Koppers-Totzek and Winkler processes are used to manufacture methanol. The products from the three routes are shown below.

Table 5.3.6

Production of the Methanol Plants
(thousand of metric tons per year)

	Lurgi	Koppers-Totzek	Winkler
Methanol	411	678	643
SNG	$186\times10^6 M^3/a$	$3.4\times10^6 M^3/a$	$50\times10^6 M^3/a$
Tar	31	-	-
Oil	31	-	-
Naphtha	24	-	-
Phenols	8	-	-
Sulphur	6	11	9

The above products revenues are compared to the total capital costs in the following table:

Table 5.3.7

Methanol Plant Comparative Data (Current Costs)

	Lurgi	Koppers-Totzek	Winkler
Annual Revenues 10^6\$	277	309	314
Capital Costs & Working Capital 10^6\$	664	737	737
Revenue/Capital Ratio	0.42	0.42	0.43
Thermal Efficiency	56.4%	42.4%	45.3%

The capital ratios are greater than those found in the SNG plant case while the efficiencies are lower. Here again the lack of assurance of a firm market for methanol subjugates its choice as the selected product in favour of SNG production. Nevertheless an analysis of revenues, operating costs and cash flows were developed for the years 1978 - 2010 and are shown in Table 5.3.15.

5.3.5 Miscellaneous Hydrocarbon Products

Here we relate the economics of 5 different processes that produce energy materials that can also be used as a petrochemical feedstock, thus the nomenclature, hydrocarbon products. The 5 processes with their products are shown below.

Table 5.3.8

Hydrocarbon Plant Products (From 18,000,000 tons coal)

(thousand of metric tons per year)

	Fischer Tropsch	Lurgi Kellogg	SRC-1 Gulf	SRC H-Oil	Lurgi Ruhrgas
SNG Pipeline Gas	-	-	-	-	$221 \times 10^6 M^3/a$
Tars	-	-	-	-	892
Phenols	-	-	-	-	27
Power*	-	-	-	-	13×10^6 MWH/a
Motor Fuel	1,495	1,267	-	-	25
F-T By-Products	169	237	-	-	-
Gasification By-Products	263	231	-	-	-
SRC-1 Solids	-	-	2,134	-	-
Light Refinery Liquids	-	-	525	1,780	-
LPG	-	-	151	277	-

*Produced from char.

The revenues from the above products would generate the following cash flows.

Table 5.3.9

Hydrocarbon Plant Comparative Data (Current Costs)

	Fischer Tropsch	Lurgi Kellogg	SRC-1 Gulf	SRC H-Oil	Lurgi Ruhrgas
Annual Revenues 10^6\$	380	352	144	276	379
Capital Costs & Working Capital 10^6\$	1,305	1,152	1,376	2,272	1,270
Revenue/Capital Ratio	0.29	0.31	0.10	0.12	0.30
Thermal Efficiency	38%	34%	52%	44%	40%

The revenue/capital ratios are generally less than those found in the SNG, ammonia, and methanol analyses. The thermal efficiencies are in the medium to low ranges.

Whereas the range of products are capable of being fully marketed, the selection of the SNG route is still favoured.

5.3.6 Chemical Feedstocks

Considerations of chemical feedstocks has resulted in the determination that the aromatic benzene and phenol are not principal but secondary products. For this reason, capital and revenue analyses were not prepared for comparison with the principal products.

5.3.7 Evaluation of the Selected Process

SNG production has been selected for production consideration at Hat Creek because of its ready marketability. Further, from the comparative data, SNG production is preferable, both on a revenue/capital ratio and efficiency basis.

At this juncture, it is appropriate to shift to a more intensive level of economic analyses of an SNG production facility.

The SNG plant capital cost is first presented in detail in terms of those dollars that would be spent during the construction years. This development is shown on Table 5.3.12.

The revenues, operating costs, and cash flows were developed for the years 1978-2010. The cash flows were calculated for SNG sales at $2.00 to $5.00 per 10^6 BTU in 1981 based on the suggested B. C. Hydro cost criteria. The development of the 1981 prices are shown below.

Table 5.3.10

SNG Price Development
(Dollars per million Btu's)

Year	Cost Criteria	Low	Probable	Medium	High
1976/77	Base Year	$1.43	$2.15	$2.86	$3.58
1977/78	11%	$1.59	$2.39	$3.17	$3.97
1978/79	9%	$1.73	$2.60	$3.46	$4.33
1979/80	8%	$1.89	$2.81	$3.74	$4.68
1980/81	7%	$2.00	$3.00	$4.00	$5.00
Beyond	5%				

The per ton coal costs were based on the B. C. Hydro suggested range of $5.50, $7.50, and $10.00 for 1976/77 and projected to $8.00, $11.00, and $14.68 for 1980/81 and at 5% per year additional for the years to 2010.

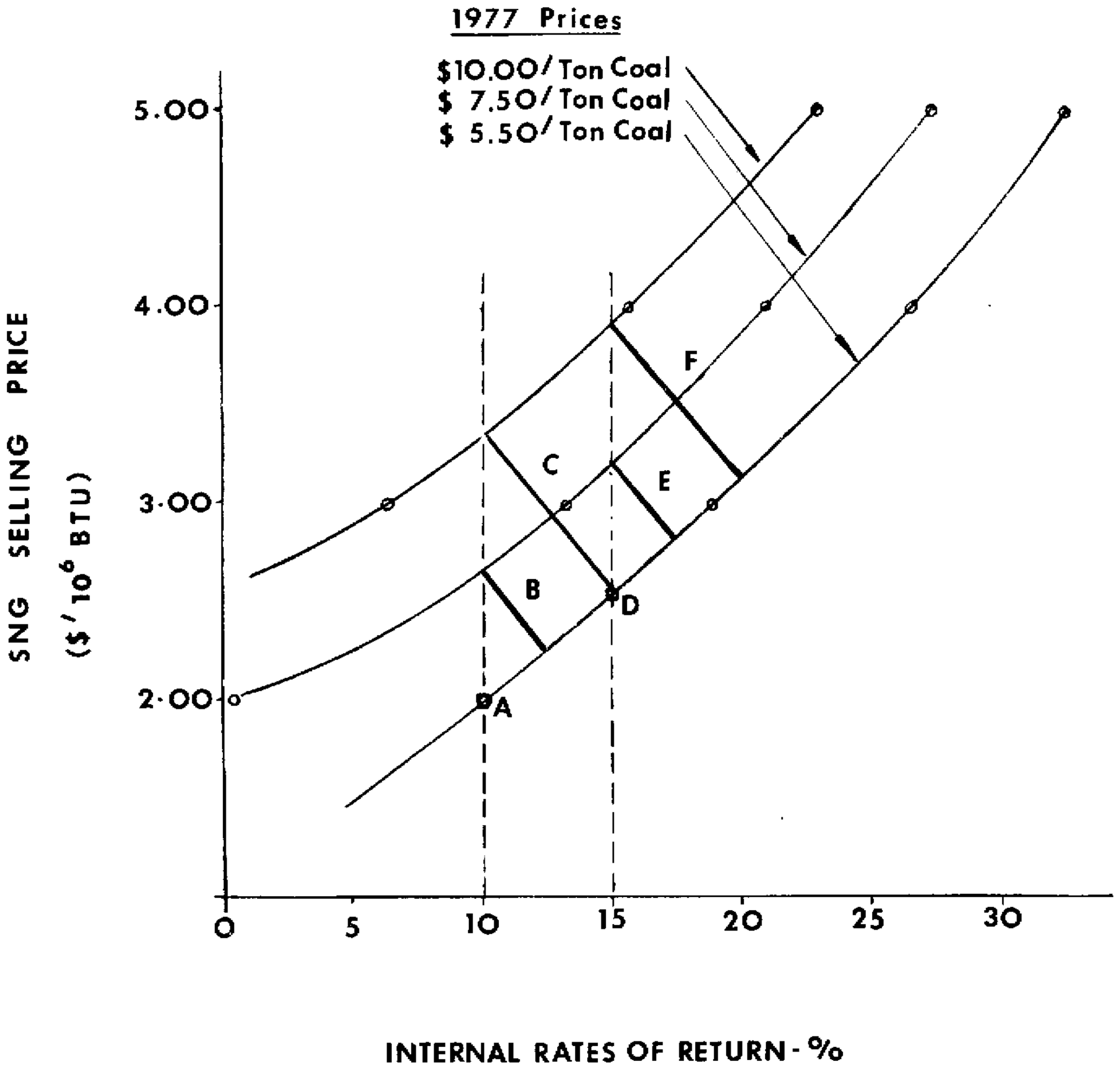
Within the above price and cost parameters and for the economic life of the plant of 30 years, the internal rates of return were calculated. The 30 year projections at the $3.00 SNG selling price and the $5.50 base year coal cost are detailed on Tables 5.3.13 to 5.3.14 and the results of the range of internal rates of return are summarized below.

Table 5.3.10A

Internal Rates of Return

	Base Year Coal Costs		
SNG Price/10^6 BTU	$5.50	$7.50	$10.00
$2.00	9.77%	0.97%	Negative
$3.00	18.32%	13.63%	5.95%
$4.00	25.15%	21.22%	15.90%
$5.00	31.18%	27.68%	23.07%

These data are plotted on Figure 5.6. By examining the graph, the management of Hat Creek can determine what the effect of the SNG selling price would have on the internal rate of return. In addition, the lost opportunity cost of relegating the 18,000,000 tons of coal annually to SNG production can be determined by further examination of the same graph.



RATE OF RETURN vs SNG SELLING PRICE

FIG 5.6

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER CANADA LIMITED

Sheet
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For example, should the SNG selling price be \$3.15 per 10^6 BTU in 1981, the lost opportunity cost would be about \$2.00 per ton at a 15 percent internal rate of return. The amount of this lost opportunity is represented by line E on the graph, the base line being the given \$5.50 coal price in 1977. Other estimates of lost opportunity costs at the various internal rates of return and SNG selling prices are shown by points A and D and lines B, C, E, and F. Their approximate values are shown in the following table.

Table 5.3.10B

Lost Opportunity Costs

	SNG Selling Price	Internal Rate of Return	Lost Opportunity Cost
Point A	\$2.00	10%	Zero
Line B	2.65	10%	\$2.00
Line C	3.35	10%	4.50
Point D	2.50	15%	Zero
Line E	3.15	15%	\$2.00
Line F	3.85	15%	4.50

By visualizing a curve for \$14.50 coal, and projecting the intersection of a \$5.00 SNG price and a 15 percent internal rate of return, a lost opportunity cost of some \$9.00 may be reasonable to imagine within the selected parameters.

Should future energy supplies continue to diminish, an SNG plant may be able to realize the higher lost opportunity costs from the Hat Creek coal reserve.

Table 5.3.11

INDICATION OF PROJECT RISK

(Millions of Dollars)

Basis - (18,000,000 T.P.A. Coal Feed) (Current Costs) (30 year plant life)

PRODUCTS	PRICES	Pipeline Gas (SNG)			Ammonia			Methanol			Synth. Liquids		Hydrogenation Products		Pyrolysis Products
		Lurgi	Koppers Totzek	Winkler	Lurgi	Koppers Lurgi	Winkler	Lurgi	Koppers	Winkler	Fischer Tropsch	Lurgi Kellogg	SRC-1 Gulf	SRC + H-Oil	Lurgi Ruhrgas
SNG Pipeline Gas	7.6¢/Nm^3	212	222	215	80		21	1	2	23					16
Tars	$ 84.00/M.T.	16			15			16							74
Tar Oils	$128.00/M.T.	24			22			24							
Naphtha	$161.00/M.T.	23			22			23							
Phenols	$600.00/M.T.	27			25			27							16
Sulphur	$ 25.00/M.T.	1	2	2	1	2	2	1	2	2					
Power	$ .02/KWH		4												269
Ammonia	$150.00/M.T.				435	675	714								
Methanol	$ 75.00/M.T.							185	305	289					
Motor Fuel	$167.00/M.T.										250	212			4
F-T By-Products	$300.00/M.T.										51	71			
Gasification By-Products	$300.00/M.T.										79	69			
SRC-1 Solids	$ 35.00/M.T.												75		
Light Refinery Liquids	$132.00/M.T.												46	234	
LPG	$150.00/M.T.												23	42	
Annual Revenues		303	228	217	600	677	737	277	309	314	380	352	144	276	379
Capital Cost & Working Capital		933	894	927	853	835	835	664	737	737	1,305	1,152	1,376	2,272	1,270
Revenue/Capital Ratio		0.32	0.26	0.23	0.70	0.81	0.88	0.42	0.42	0.43	0.29	0.31	0.10	0.12	0.30
Thermal Efficiency of* Conversion		61.9	49.7	50.8	58.5	47.1	50.2	56.4	42.4	45.3	38.0	34.0	52.0	43.5	40.1

* At plant gate. Comparisons of efficiencies in end use are complex undertakings and considerable disagreement exists between differing investigators. The conclusions for electricity as against SNG reported in "Studies of Advanced Electric Power Generation Techniques and Coal Gasification. Based on Hat Creek Coal" (Ref. 5.24) may be usefully contrasted with results of studies reported by Pacific Gas and Electric Company (Ref. 5.25).

Table 5.3.12

SNG PROCESS

Construction Cost

(Thousands of Dollars)

	ANG Study 1976 Dollars		1976 Total Cost	Inflated Cost as of January 1978		Total Cost*	Distribution				
	Material	Other		Material	Other		1978	1979	1980	1981	1982
Process Equipment											
Lurgi Gasification	$ 74,700	$ 37,000	$111,700	$ 83,000	$ 41,100	$124,100	-	$ 21,100	$ 63,300	$ 39,700	-
Shift Conversion	18,900	12,300	31,200	21,000	13,700	34,700	-	5,900	17,700	11,100	-
Tar Separation	7,400	6,500	13,900	8,200	7,200	15,400	-	2,600	7,900	4,900	-
Rectisol Unit	47,900	34,200	82,100	53,200	38,000	91,200		15,500	46,500	29,200	
Methonation	25,500	17,900	43,400	28,300	19,900	48,200	-	8,200	24,600	15,400	-
Phenosolvan Unit	22,700	20,700	43,400	25,200	22,900	48,100	-	8,200	24,500	15,400	-
Total	197,100	128,600	325,700	218,900	142,800	361,700		61,500	184,500	115,700	
Percentage Distribution							0	17%	51%	32%	
Supporting Facilities											
Cool prep. & Ash Disposal	29,900	23,100	53,000	33,200	25,600	58,800	-	10,000	30,000	18,800	-
Product Compression	7,400	5,000	12,400	8,200	5,500	13,700	-	2,300	7,000	4,400	-
Oxygen Plant	38,300	35,200	73,500	42,600	39,100	81,700	-	13,900	41,700	26,100	-
Sulphur Recovery Plant	14,900	12,900	27,800	16,500	14,300	30,800	-	5,200	15,700	9,900	-
Steam Generation & Scrubbing	79,100	42,000	121,100	87,900	46,700	134,600	-	22,900	68,600	43,100	-
Water Supply & Treatment System	24,200	17,700	41,900	26,800	19,700	46,500	-	23,300	23,200	-	-
Total	193,800	135,900	329,700	215,200	150,900	366,100	-	77,600	186,200	102,300	
Percentage Distribution (except Water)							0	17%	51%	32%	
Percentage Distribution - Waters							50%	50%			
General Facilities											
Power Distribution	3,400	7,800	11,200	3,800	18,700	12,500	5,000	5,000	1,200	1,300	-
Piping, Storage	6,100	10,100	16,200	6,800	11,200	18,000	7,200	7,200	1,800	1,800	-
Buildings, Land & Equip.	18,400	14,000	32,400	20,400	15,600	36,000	14,400	14,400	3,600	3,600	-
Miscellaneous	17,600	88,300	105,900	19,500	98,000	117,500	29,400	29,400	29,400	29,300	-
Total	45,500	120,200	165,700	50,500	133,500	184,000	56,000	56,000	36,000	36,000	
Subtotal	436,400	384,700	821,100	484,600	427,200	911,800	56,000	195,100	406,700	254,000	
Percentage Distribution (except Misc.)							40%	40%	10%	10%	
Percentage Distribution - Misc.							25%	25%	25%	25%	
Other Capitalized Outlays											
Startup and Training	-	-	31,200	-	-	34,600	-	-	-	17,300	17,300
Engineering Superv. & Inspect.	-	-	6,200	-	-	6,800	1,700	1,700	1,700	1,700	-
Admin. & General	-	-	12,300	-	-	13,700	3,500	3,400	3,400	3,400	-
Contingency Allowance - 10%	-	-	82,100	-	-	91,200	22,800	22,800	22,800	22,800	-
Grand Total			952,900			1,058,100	84,000	223,000	434,600	299,200	17,300
Percentage Distribution - Startup										50%	50%
Percentage Distribution - All Other							25%	25%	25%	25%	

* Fixed Cost Contract

Table 5.3.13

SNG PROCESS

Income and Expense 1978-1989

(Thousands of Dollars)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Revenue from Product Sales												
Pipeline Natural Gas ($3.00/MM BTU)	-	-	-	$ 68,438	$287,438	$301,809	$316,900	$332,745	$349,382	$366,851	$385,194	$404,453
By-Products	-	-	-	29,200	122,500	128,700	135,100	141,800	148,900	156,300	164,200	172,400
Total Revenues	-	-	-	97,638	409,938	430,509	452,000	474,545	498,282	523,151	549,394	576,853
Direct Operating Expenses												
Feedstock Coal (18.0 MM Tons)	-	-	-	36,000	151,200	158,800	166,700	175,000	183,800	193,000	202,600	212,800
Contract Maintenance Expenses	-	-	-	7,500	31,400	33,000	34,600	36,300	38,200	40,100	42,100	44,200
Production Salaries & Benefits	-	-	-	4,300	17,900	18,800	19,700	20,700	21,800	22,800	24,000	25,200
Electric Power System	-	-	-	3,300	13,700	14,400	15,100	15,900	16,700	17,500	18,400	19,300
Catalysts and Chemicals	-	-	-	2,100	8,900	9,300	9,800	10,300	10,800	11,400	11,900	12,500
Total Direct Operating Expenses	-	-	-	53,200	223,100	234,300	245,900	258,200	271,300	284,800	299,000	314,000
Administrative & General Expenses												
Office Salaries & Benefits	-	-	-	2,200	9,000	9,400	9,900	10,400	10,900	11,500	12,000	12,600
Property Ins., Injury & Damage	-	-	-	900	3,900	4,100	4,300	4,500	4,700	5,000	5,200	5,500
Office Supplies and Expenses	-	-	-	200	630	660	690	730	770	800	840	890
Miscellaneous General Expenses	-	-	-	25	105	110	120	120	130	130	140	150
Total Admin. & General Expenses	-	-	-	3,325	13,635	14,270	15,010	15,750	16,500	17,430	18,180	19,140
Total Expenses	-	-	-	56,525	236,735	248,570	260,910	273,950	287,800	302,230	317,180	333,140
Cash Generated from Operations	-	-	-	41,113	173,203	181,939	191,090	200,595	210,482	220,921	232,214	243,713
Less: Construction Outlays	84,000	223,000	434,600	299,200	17,300	-	-	-	-	-	-	-
Initial Working Capital	-	-	-	21,200	-	-	-	-	-	-	-	-
Cash Flow from Gasification	(84,000)	(223,000)	(434,600)	(279,287)	155,903	181,939	191,090	200,595	210,482	220,921	232,214	243,713

Note: Thirty year plant life.

Table 5.3.13 (Cont'd)

SNG PROCESS

Income and Expense 1990 - 2001

(Thousands of Dollars)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Revenue from Product Sales												
Pipeline Natural Gas	$424,676	$445,910	$468,205	$491,616	$516,196	$542,006	$569,106	$597,562	$627,440	$658,812	$691,752	$726,340
By-Products	181,000	190,100	199,600	209,600	220,000	231,000	242,600	254,700	267,400	280,800	294,900	309,600
Total Revenues	605,676	636,010	667,805	701,216	736,196	773,006	811,706	852,262	894,840	939,612	986,652	1,035,940
Direct Operating Expenses												
Feedstock Coal (18.0 MM Tons)	223,400	234,600	246,300	258,600	271,600	285,200	299,400	314,400	330,100	346,600	363,900	382,100
Contract Maintenance Expenses	46,400	48,700	51,200	53,700	56,400	59,200	62,200	65,300	68,600	72,000	75,600	79,400
Production Salaries & Benefits	26,500	27,800	29,200	30,600	32,200	33,800	35,500	37,200	39,100	41,000	43,100	45,300
Electric Power System	20,300	21,300	22,300	23,500	24,600	25,900	27,200	28,500	29,900	31,400	33,000	34,700
Catalysts and Chemicals	13,100	13,800	14,500	15,200	16,000	16,800	17,600	18,500	19,400	20,400	21,400	22,400
Total Direct Operating Expenses	329,700	346,200	363,500	381,600	400,800	420,900	441,900	463,900	487,100	511,400	537,000	563,900
Administrative & General Expenses												
Office Salaries and Benefits	13,200	13,900	14,600	15,300	16,100	16,900	17,700	18,600	19,500	20,500	21,600	22,600
Property Ins., Injury & Damage	5,800	6,100	6,400	6,700	7,000	7,400	7,700	8,100	8,500	9,000	9,400	9,900
Office Supplies and Expenses	930	980	1,030	1,080	1,140	1,190	1,250	1,300	1,380	1,450	1,520	1,600
Miscellaneous General Expenses	160	170	170	180	190	200	210	220	230	240	260	270
Total Administrative & General Expenses	20,090	21,150	22,200	23,260	24,430	25,690	26,860	28,220	29,610	31,190	32,780	34,370
Total Expenses	349,790	367,350	385,700	404,850	425,230	446,590	468,760	492,120	516,710	542,590	569,780	598,270
Cash Generated from Operations	255,866	268,660	282,105	296,356	310,966	326,416	342,946	360,142	378,130	397,022	416,872	437,670
Less: Construction Outlays	-	-	-	-	-	-	-	-	-	-	-	-
Initial Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow from Gasification	255,886	268,660	282,105	296,356	310,966	326,416	342,946	360,142	378,130	397,022	416,872	437,670

Table 5.3.13 (Cont'd)

SNG PROCESS

Income and Expense 2000-2010

(Thousands of Dollars)

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Revenue from Product Sales									
Pipeline Natural Gas	$ 762,657	$ 800,790	$ 840,829	$ 882,871	$ 927,014	$ 973,365	$1,022,033	$1,073,135	$1,126,792
By-Products	325,100	341,300	358,400	376,300	395,100	414,900	435,600	457,400	480,300
Total Revenues	1,087,757	1,142,090	1,199,229	1,259,171	1,322,114	1,388,265	1,457,633	1,530,535	1,607,092
Direct Operating Expenses									
Feedstock Coal (18.0 MM Tons)	401,200	421,300	442,300	464,400	487,700	512,000	537,600	564,500	592,800
Contract Maintenance Expenses	83,400	87,600	91,900	96,500	101,400	106,400	111,800	117,400	123,200
Production Salaries & Benefits	47,600	50,000	52,500	55,100	57,900	60,800	63,800	67,000	70,300
Electric Power System	36,400	38,200	40,100	42,100	44,200	46,500	48,800	51,200	53,800
Catalysts and Chemicals	23,500	24,700	25,900	27,200	28,600	30,000	31,500	33,100	34,700
Total Direct Operating Expenses	592,100	621,800	652,700	685,300	719,800	755,700	793,500	833,200	874,800
Administrative & General Expenses									
Office Salaries and Benefits	23,700	24,900	26,100	27,400	28,800	30,200	31,800	33,300	35,000
Property Ins., Injury & Damage	10,400	10,920	11,500	12,000	12,600	13,300	13,900	14,600	15,400
Office Supplies and Expenses	1,680	1,800	1,850	1,940	2,040	2,140	2,250	2,360	2,480
Miscellaneous General Expenses	280	300	310	320	340	360	380	400	420
Total Admin. & General Expenses	36,060	37,920	39,760	41,660	43,780	46,000	48,330	50,660	53,300
Total Expenses	628,160	659,720	692,460	726,960	763,580	801,700	841,830	883,860	928,100
Cash Generated from Operations	459,597	482,370	506,769	532,211	558,534	586,565	615,803	646,675	678,992
Less: Construction Outlays	-	-	-	-	-	-	-	-	-
Initial Working Capital	-	-	-	-	-	-	-	-	-
Cash Flow from Gasification	459,597	482,370	506,769	532,211	558,534	586,565	615,803	646,675	678,992

Table 5.3.14

SNG PROCESS

Net Cash Analysis

(Thousands of Dollars)

	Cash Flow Before Gas Sales	Gas Sales @ 3.00 MM BTU in 1981	Net Cash Flow @ 3.00 MM BTU	Gas Sales @ 4.00 MM BTU in 1981	Net Cash Flow @ 4.00 MM BTU	Gas Sales @ 5.00 MM BTU in 1981	Net Cash Flow @ 5.00 MM BTU
1978	$(84,000)	$ -	$(84,000)	$ -	$(84,000)	$ -	$(84,000)
1979	(223,000)	-	(223,000)	-	(223,000)	-	(223,000)
1980	(434,600)	-	(434,600)	-	(434,600)	-	(434,600)
1981	(347,725)	68,438	(279,287)	91,250	(256,475)	114,063	(233,662)
1982	(131,535)	287,438	155,903	383,250	251,715	479,063	347,528
1983	(119,870)	301,809	181,939	402,413	282,543	503,016	383,146
1984	(125,810)	316,900	191,090	422,533	296,723	528,166	402,356
1985	(132,150)	332,745	200,595	443,660	311,510	554,575	422,425
1986	(138,900)	349,382	210,482	465,843	326,943	582,303	443,403
1987	(145,930)	366,851	220,921	489,139	343,209	611,419	465,489
1988	(152,980)	385,194	232,214	513,592	360,612	641,990	489,010
1989	(160,740)	404,453	243,713	539,271	378,531	674,089	513,349
1990	(168,790)	424,676	255,886	566,235	397,445	707,793	539,003
1991	(177,250)	445,910	268,660	594,546	417,296	743,183	565,933
1992	(186,100)	468,205	282,105	624,274	438,174	780,342	594,242
1993	(195,260)	491,616	296,356	655,488	460,228	819,359	624,099
1994	(205,230)	516,196	310,966	688,262	483,032	860,327	655,097
1995	(215,590)	542,006	326,416	722,675	507,085	903,344	687,754
1996	(226,160)	569,106	342,946	758,809	532,649	948,511	722,351
1997	(237,420)	597,562	360,142	796,749	559,329	995,936	758,516
1998	(249,310)	627,440	378,130	836,587	587,277	1,045,733	796,423
1999	(261,790)	658,812	397,022	878,416	616,626	1,098,020	836,230
2000	(274,880)	691,752	416,872	922,337	647,457	1,152,921	878,041
2001	(288,670)	726,340	437,670	968,454	679,784	1,210,567	921,897
2002	(303,060)	762,657	459,597	1,016,876	713,816	1,271,095	968,035
2003	(318,420)	800,790	482,370	1,067,720	749,300	1,334,650	1,016,230
2004	(334,060)	840,829	506,769	1,121,106	787,046	1,401,383	1,067,323
2005	(350,660)	882,871	532,211	1,177,161	826,501	1,471,452	1,120,792
2006	(368,480)	927,014	558,534	1,236,019	867,539	1,545,024	1,176,544
2007	(386,800)	973,365	586,565	1,297,820	911,020	1,622,275	1,235,475
2008	(406,230)	1,022,033	615,803	1,362,711	956,481	1,703,389	1,297,159
2009	(426,460)	1,073,135	646,675	1,430,846	1,004,386	1,788,558	1,362,098
2010	(447,800)	1,126,792	678,992	1,502,389	1,054,589	1,877,986	1,430,186
Internal Rate of Return			18.32%		25.15%		31.18%

Notes: 1. Based on 1976/77 coal cost of $5.50.

2. Plant life of 30 years.

Table 5.3.15

METHANOL PROCESS

Income and Expense 1978 - 1989

(In Thousands of Dollars)

Production of Methanol Based on Montan-Consulting Report.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Revenue from Product Sales												
Methanol (at $100/metric ton in 1977)	-	-	-	$13,590	$57,080	$59,900	$62,930	$66,100	$69,400	$72,850	$76,500	$80,300
By-Products	-	-	-	4,800	20,315	21,330	22,400	23,500	24,700	25,900	27,200	28,600
Revenues				18,390	77,395	81,230	85,330	89,600	94,100	98,750	103,700	108,900
Direct Operating Expenses												
Feed Coal (3 MM tons @ 7.50 in 1977)	-	-	-	8,300	34,700	36,400	38,300	40,200	42,200	44,300	46,500	48,800
Contract Maintenance (÷ 3.51)	-	-	-	2,100	9,000	9,450	9,920	10,420	10,940	11,500	12,100	12,700
Production Labour & Benefits (1÷4.7)				900	5,100	5,400	5,600	5,900	6,200	6,500	6,800	7,200
Electric Power System (1÷6)	-	-	-	600	2,300	2,400	2,550	2,600	2,800	2,900	3,080	3,200
Catalysts & Chemicals (given in M-C Report)	-	-	-	200	650	690	715	750	790	830	870	915
Total Operating Expenses				12,100	51,750	54,340	57,085	59,870	62,930	66,030	69,350	72,815
Administrative and General Expenses												
Office Salaries & Benefits (1÷4.7)	-	-	-	470	1,900	2,000	2,090	2,195	2,300	2,400	2,540	2,670
Insurance (Cost $^{Im}/I6$ = .202	-	-	-	180	790	830	871	915	960	1,000	1,060	1,110
Supplies, etc. (÷ 4.7)	-	-	-	40	135	140	150	160	165	170	180	190
Miscellaneous (÷ 4.7)	-	-	-	5	20	21	22	23	24	26	27	28
Total Admin. & General Expenses				695	2,845	2,991	3,133	3,293	3,449	3,596	3,807	3,998
Total Expenses	-	-	-	12,795	54,595	57,331	60,218	63,163	66,379	69,626	73,157	76,813
Cash Generated from Operations	-	-	-	5,595	22,800	23,899	25,112	26,437	27,721	29,124	30,543	32,087
Less: Construction Outlays	14,200	38,000	74,000	50,900	2,900	-	-	-	-	-	-	-
Working Capital Requirement	-	-	-	9,000	-	-	-	-	-	-	-	-
Cash Flow from Methanol Process (@ $100/metric ton as above)	(14,200)	(38,000)	(74,000)	(54,305)	19,900	23,899	25,112	26,437	27,721	29,124	30,543	32,087
Alternative #1												
Cash Flow from Methanol Process (at $75/metric ton in 1977)	(14,200)	(38,000)	(74,000)	(57,700)	(5,360)	8,924	9,380	9,912	10,371	10,912	11,418	12,000
Alternative #2												
Cash Flow from Methanol Process (at $125/metric ton in 1977)	(14,200)	(38,000)	(74,000)	(50,910)	34,170	38,874	40,845	42,962	45,070	47,335	49,700	52,200

Table 5.3.15 (Cont'd)

Production of Methanol Based on
Montan-Consulting Report.

METHANOL PROCESS

Income and Expense 1990 - 2001

(In Thousands of Dollars)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Revenue from Product Sales												
Methanol (at $100/metric ton in 1977)	$ 84,300	$ 88,500	$ 92,900	$ 97,600	$102,400	$107,600	$112,950	$118,600	$124,500	$130,750	$137,300	$144,200
By-Products	30,000	31,500	33,100	34,700	36,500	38,300	40,200	42,200	44,300	46,500	48,900	51,300
Revenues	114,300	120,000	126,000	132,300	138,900	145,900	153,150	160,800	168,800	177,250	186,200	195,500
Direct Operating Expenses												
Feed Coal (3 MM tons @ 7.50 in 1977)	51,200	53,800	56,500	59,300	62,300	65,400	68,700	72,100	75,700	79,500	83,500	87,600
Contract Maintenace (÷ 3.51)	13,300	14,000	14,700	15,400	16,200	17,000	17,900	18,800	19,700	20,700	21,700	22,800
Production Labour & Benefits (1÷4.7)	7,600	8,000	8,400	8,800	9,200	9,700	10,200	10,700	11,200	11,790	12,400	13,000
Electric Power System (1÷6)	3,400	3,600	3,700	3,900	4,100	4,300	4,600	4,800	5,000	5,300	5,500	5,800
Catalysts & Chemicals (given in M-C Report)	960	1,000	1,060	1,100	1,170	1,200	1,290	1,350	1,400	1,490	1,600	1,640
Total Operating Expenses	76,460	80,400	84,360	88,500	92,970	97,600	102,690	107,750	113,000	118,780	124,700	130,840
Administrative and General Expenses												
Office Salaries & Benefits (1÷4.7)	2,800	2,940	3,090	3,240	3,400	3,600	3,800	3,900	4,100	4,300	4,560	4,790
Insurance (Cost ^{Im}/1c = .202)	1,165	1,220	1,300	1,350	1,420	1,490	1,560	1,640	1,720	1,800	1,900	1,990
Supplies, etc. (÷ 4.7)	200	210	220	230	245	255	270	280	295	310	325	340
Miscellaneous (÷ 4.7)	30	32	33	35	36	38	40	42	44	47	49	51
Total Admin. & General Expenses	4,195	4,402	4,643	4,835	5,101	5,383	5,670	5,862	6,159	6,457	6,834	7,171
Total Expenses	80,655	84,802	89,003	93,335	98,071	102,983	108,360	113,612	119,159	125,237	131,534	138,011
Cash Generated from Operations	33,645	35,198	36,997	38,965	40,829	42,917	44,790	47,188	49,641	52,013	54,666	57,489
Less: Construction Outlays	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Requirements	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow from Methanol Process (@ $100/metric tons as above)	33,645	35,198	36,997	38,965	40,829	42,917	44,790	47,188	49,641	52,013	54,666	57,489
Alternative #1												
Cash Flow from Methanol Process (at $75/metric ton in 1977)	12,600	13,100	13,800	14,600	15,300	16,000	16,500	17,500	18,500	19,300	20,300	21,400
Alternative #2												
Cash Flow from Methanol Process (at $125/metric ton in 1977)	54,720	57,300	60,200	63,370	66,400	69,800	73,000	76,800	80,800	84,700	89,000	93,500

Table 5.3.15 (Cont'd)

METHANOL PROCESS

Income and Expense 2002 - 2010

(In Thousands of Dollars)

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Revenue from Product Sales									
Methanol (at $100/metric ton in 1977)	$151,400	$159,000	$166,900	$175,300	$184,000	$193,200	$202,900	$213,000	$223,700
By-Products	53,900	56,600	59,400	62,400	65,500	68,700	72,200	75,800	79,600
Revenues	205,300	215,600	226,300	237,700	249,500	261,900	275,100	288,800	303,300
Direct Operating Expenses									
Feed Coal (3 MM tons @ 7.50 in 1977)	92,000	96,600	101,400	106,500	111,800	117,400	123,300	129,500	135,900
Contract Maintenance (÷ 3.51)	23,900	25,100	26,300	27,700	29,100	30,500	32,000	33,600	35,300
Production Labour & Benefits (1÷4.7)	13,700	14,400	15,100	15,900	16,700	17,500	18,400	19,300	20,200
Electric Power System (1÷6)	6,100	6,400	6,700	7,100	7,400	7,800	8,200	8,600	9,000
Catalysts & Chemicals (given in M-C Report)	1,700	1,800	1,900	2,000	2,100	2,200	2,300	2,400	2,500
Total Operating Expenses	137,400	144,300	151,400	159,200	167,100	175,400	184,200	193,400	202,900
Administrative and General Expenses									
Office Salaries & Benefits (1÷4.7)	5,030	5,280	5,500	5,800	6,100	6,400	6,700	7,100	7,400
Insurance (Cost Im/Ic = .202)	2,090	2,200	2,300	2,400	2,540	2,700	2,800	2,940	3,090
Supplies, etc. (÷ 4.7)	360	380	400	420	440	460	480	500	530
Miscellaneous (÷ 4.7)	53	55	58	60	65	67	71	75	78
Total Admin. & General Expenses	7,533	7,915	8,258	8,680	9,145	9,627	10,051	10,615	11,098
Total Expenses	144,933	152,215	159,658	167,880	176,245	185,027	194,251	204,015	213,998
Cash Generated from Operations	60,367	63,385	66,642	69,820	73,255	76,873	80,849	84,785	89,302
Less: Construction Outlays	- -	-	-	-	-	-	-	-	-
Working Capital Requirement	-	-	-	-	-	-	-	-	-
Cash Flow from Methanol Process (@ $100/metric ton as above)	60,367	63,385	66,642	69,820	73,255	76,873	80,849	84,785	89,302
Alternative #1									
Cash Flow from Methanol Process (at $75/metric ton in 1977)	22,517	23,635	24,900	26,000	27,300	28,600	30,124	31,500	33,400
Alternative #2									
Cash Flow from Methanol Process (at $125/metric ton in 1977)	98,200	103,100	108,400	113,600	119,300	125,200	131,600	138,000	145,200

5.4 ENVIRONMENTAL CONSIDERATIONS

5.4.1 General Remarks

Coal conversion processes are faced with potential pollution problems that are common to coal burning power plants and with possible pollution problems which are peculiar to the conversion processes. Due to the relative lack of experimental data and full scale coal process plant operating experience, relative environmental impact of such processes compared with the impact produced by a coal fired power plant is difficult to assess. The very nature of most coal conversion systems assures the probability that some potential effluent streams will be reduced in size when compared to a power plant, however, the large numbers of chemical products and wastes produced by these systems provide potential for a variety of undesirable impacts which may require improvements in process design, construction, and operating methods.

Anticipated plant emissions for a number of conversion processes have been calculated on the basis of 40,000 t/day coal feed and are compared with the emissions of a coal fired power plant developed in the Preliminary Draft Environment Impact Statement prepared by Dolmage, Campbell and Associates, Ltd. Although these comparative emissions provide an instructive view of relative impacts in the vicinity of the plant, it is important to point out that consumption of the products of a coal conversion plant will occur in a much larger geographical area and will provide additional environmental impacts which will be significantly different from those associated with the consumption of electric power. Table 5.4.1 shows the annual emissions of several coal conversion processes compared with the emissions of a coal fired power plant on the basis of 40,000 t/day Hat Creek coal consumption. The values for coal conversion processes were interpolated from data published by the U.S. Energy Research and Development Agency (Ref 5.5, 5.11). The figures given for the

Table 5.4.1

TABLE I ANNUAL CONSUMPTION/EMISSIONS
METRIC TONS

Process	Coal-Fired Power Plant	Lurgi Hi-BTU Gasif.	Synthoil	SRC I	Fischer Tropsch
Coal Consumption Metric 10^6 Tons	10.4	18	18	18	18
Output (as shown)	2,000 MW	7.79 MMm^3/day (275 MMSCFD)	5,725 m^3/day (36,000 bbl/day)	5,087 m^3/day (32,000 bbl/day)	5,325 m^3/day (33,500 bbl/day)
SO_2	10,400	3,800	2,200	1,180	5,650
Fly Ash	3,200	4,700	1,200	800	7,900
Hydrocarbons	700	300	140	110	450
NO_x	39,000	12,500	3,600	2,900	20,000
Water Intake (m^3/min.) (excluding Scrubber)	25,000	4,000	6,600	750	12,300
T.D.S. in Discharge*	330 (0)	0	7,300 (0)	0	0
Suspended Solids* in Discharge	75 (0)	0	0.9 (0)	0	0
B.O.D. in Discharge	5 (0)	0	0.2 (0)	0	0
Solid Waste-Ash + Regenerative Scrub.	3,125,000	4,250,000	4,330,000	3,800,000	4,330,000
+ Non-Regenerative Scrub	3,560,000				

*Based on recirculating water to scrubber and cooling tower, amount of these discharges become zero.

Above values based on Ref. 5.11 and 90 percent capacity factor, except coal-fired power plant which is based on 70 percent capacity factor.

coal plant were based on information given in the Hat Creek EIS (Ref. 5.5, 5.12) and Stone & Webster experience.

5.4.2 Air Emissions and Regulations

Table 5.4.2 lists potentially applicable air emission regulations.

Level A in Table 5.4.2 is applicable to all new facilities constructed after 1974 and is the minimum desirable level for air quality. The Level A guidelines are based on best available control technology with emphasis placed on segregation of gaseous streams and recycling, where possible. Economic considerations provided coal conversion processes with the incentive to maximize recycling of streams and to segregate process products, thus assuring that best available control technology will be used.

Although none of the coal conversion processes is specifically described by the Pollution Control Objective guidelines of British Columbia, coal conversion processes are sufficiently similar to the chemical and petroleum industry that extrapolation of the objectives for those industries to the coal conversion industry is a reasonable approach. The Director of Pollution Control Branch (Director) may establish other minimum requirements, if it is determined that extrapolation is not deemed suitable. The five major processes which are easily extrapolated to the coal conversion industry are hydrogen sulfide recovery in Claus or Claus tail gas treatment plants, catalyst regeneration, petroleum storage, cooling towers, and waste gas incineration. Table 5.4.3 presents the air emission objectives which may be applicable to the coal conversion processes and coal fired power plant.

Emissions of particulate, sulphur dioxide, nitrogen oxides,

Table 5.4.2

Ambient Air-Quality Guidelines for the Petroleum and Chemical Industries

	Level A (a)	Level B (a)	Level C (a)	Monitoring
Sulphur Dioxide				
1-hour maximum	450 (0.17)	900 (0.34)	1,300 (0.5)	Continuous
24-hour maximum	160 (0.06)	260 (0.10)	360 (0.14)	Continuous
Annual arithmetic mean	25 (0.01)	50 (0.02)	80 (0.05)	Continuous
Hydrogen Sulphide				
1-hour maximum	7.5 (0.005)	45 (0.030)	45 (0.030)	Continuous
24-hour maximum	-	7.5 (0.005)	7.5 (0.005)	Continuous
Suspended Particulates				
24-hour maximum	150	200	260	
Annual geometric mean	60	70	75	
Dustfall				
Residential, tons/sq. mi/mon	15	20	20	Monthly
Other, tons/sq. mi/mon	25	30	35	

(a) Concentrations given in micrograms per cubic metre (20^{o}C, 760 mm Hg, dry basis), and in parentheses, ppm by volume, except where noted.

Source: Reference 5.22

carbon monoxide and hydrocarbons are expected to be significantly lower for normal operating conditions of coal conversion plants than for a coal fired power plant. With respect to the major pollutants, the relative air quality in the region of such conversion plants should be superior to that which would result from a power plant operation. Coal process plants may produce substances that have teratogenic and carcinogenic potential, however, and even small amounts of such hydrocarbon materials released to the environment continuously over long periods may result in detrimental health effects. On the basis of information now available, it would be as imprudent to assign undue concern to this particular aspect of coal conversion plant operations as it would be to judge a coal conversion plants' air quality impact to be more acceptable than that of a coal fired power plant. Table 5.4.4 describes major effluent streams to the atmosphere for several coal process systems based on the use of Hat Creek coal. No detailed analysis of these effluent streams is as yet available; however, several research programs have been initiated recently by U.S. EPA which should provide such data.

There appears to be no new technology development requirements to provide for control of air emissions at coal conversion plants to achieve objectives presented in Table 5.4.3. A power boiler would be required and therefore electrostatic precipitators and sulphur dioxide scrubbing equipment familiar to the power industry, would be required. The only air emission control process that would be used in coal conversion plants is the Claus process and a Claus tail gas treatment system used for producing sulphur or sulphuric acid from the hydrogen sulphide generated in the coal conversion process. The remainder of the plant equipment which serves to control air emissions is required for process system control and, therefore, cannot

Table 5.4.3

Objectives for Air Emissions Applicable to Coal Conversion Processes

	Level A
Sulphur Plant	
Sulphur recovery, % (a)	99+
Sulfur dioxide, mg/M^3 (ppm)	830 (300)
Overall Refinery	
Sulphur trioxide, mg/M^3 (gr/SCF)	25 (0.011)
FCCU Regenerator	
Particulate solids, mg/M^3 (gr/SCF)	115 (0.050)
Hydrocarbons (as Hexane) -	
mg/M^3 (ppm)	90 (25)
lb./1,000 bbl. cracking feed	20
Carbon monoxide, mg/M^3 (ppm)	2,400 (2,000)
Sulphur dioxide, mg/M^3 (ppm)	830 (300)
Steam Plant	
Particulate solids, mg/M^3 (gr/SCF) (c)	150 (0.065)
Sulphur dioxide, mg/M^3 (ppm)	830 (300)

(a) Total sulphur recovered from refinery fuel gases.
(b) Emission concentration objectives are not set for Levels B and C, but must be such as to maintain ambient air-quality guidelines given in Table VII.
(c) Corrected to 12 percent carbon dioxide

Sulphur Recovery	Level A
Acid gas CO_2/H_2S ratio lower than 10	99
Acid gas CO_2/H_2S ratio higher than 10(a)	95

(a) Individual assessment may be required.

Table 5.4.3 (Cont'd)

Trace Elements	Level A (a)
Acetaldehyde	3.8 (2.1)
Acrolein	2.5 (1.0)
Alkanolamines	60
Ammonia	180 (250)
Benzene	800 (250)
Carbon Monoxide	2,400 (2,000)
Cobalt	7.0 (0.003) (b)
Copper	7.0 (0.003) (b)
Cresol	220 (50)
Demethyl ether	190 (100)
Diphenyl	10 (2)
Formaldehyde	30 (20)
Formic acid	90 (50)
Hydrogen sulphide	7 (4.7)
Maleic anhydride	10 (2.5)
Mercaptans	(c)
Methanol	2,600 (2,000)
Methyl ethyl ketone (2-butanone)	900 (300)
MIBK (hexone)	2,050 (500)
Organic disulphides	4
Particulate solids--	
Total	230 (0.100) (b)
Organic chemical dust	115 (0.050) (b)
Phenol	100 (26)
Phthalic anhydride	120 (20)
Styrene	200 (47)
Toluene	3,750 (1,000)
Vinyl acetate	30 (10)

(a) Concentrations given in milligrams per cubic metre (20°C, 760 mm Hg, dry basis) and in parentheses, ppm by volume.
(b) Concentrations in parentheses are given in grains per standard cubic foot.
(c) Not detectable.

Table 5.4.4 - A

Air Emissions from H-Coal Plant (Ref. 5.13)
(40,000 t/d Coal Feed)

(All Values in Metric Tons/Day)

1. Vent Gas from Coal Dryer - 3,400, bag filter required for dust control
2. CO_2 Vent Gas from H_2 Shift Reactor - 6,900
3. Stack Gas from Utility Boiler - 19,500
4. Waste Nitrogen from Oxygen Plant - 8,500
5. Tail Gas from Sulphur Plant - 5,000
6. Air from Cooling Towers - 1,350,000 (includes 12,954 t/day H_2O)
7. Drift from Cooling Tower - 600
8. Evaporation from Ponds - potential odor problems
9. Hydrocarbons releases associated with storage and handling - possible odor problem
10. Sulphur Dioxide - 9
11. Particulate - 12

Based on U.S. EPA - 650/2-74 - 009
Evaluation of Pollution Control in Fossil Fuel Conversion Process
H-Coal Process.

Table 5.4.4 - B

Air Emissions from Lurgi, High-BTU (Ref. 5.14) Gasification Plant

(40,000 t/d Coal Feed)

(All Values in Metric Tons/Day)

1. From Coal Dryer - 3,400, bag filter required for dust control
2. Stack Gas from Utility Boiler - SO_2 = 6

   NO_2 = 8
3. Tail Gas from Sulphur Plant/Incinerator - Primarily CO_2 and nitrogen, but contains:

   SO_2 = 20

   COS = 5

   NO_2 = 2
4. Waste Nitrogen from O_2 Plant - 17,000
5. Water Vapor from Cooling Towers - 12,800
6. Drift from Cooling Tower - 600
7. Air from Cooling Tower - 13,500,000
8. Hydrocarbons released from Ponds, Storage and Handling - possible odor problems

Table 5.4.4 - C

Air Emissions from SRC I Plant (Ref. 5.15)
(40,000 t/d Coal Feed)

(All Values in Metric Tons/Day)

1. Vent Gas from Dryer - 3,400, bag filter required for dust control (collects 110 t/d)
2. Stack Gases from all Furnaces - 45,000 $SO_2 = 0.8$
3. Tail Gas from Claus Plant - Sulphur = 0.4
4. Nitrogen from O_2 Plant - 12,000
5. CO_2 rejected from Benfield Process - 1,300
6. Air from Cooling Tower - 1,300,000
7. Drift Loss from Cooling Tower - 600
8. Hydrocarbons released from Ponds, Storage and Handling - possible odor problems

be segregated as pollution control equipment. Air emission costs for a coal process plant and those of a coal fired power plant, therefore, cannot be compared meaningfully.

Because of the potential hazards associated with some of the products which may be produced, the most difficult air emission control problem may be the design of equipment to ensure minimal releases of hydrocarbons from the process plant, storage and handling areas. Storage areas will need to be equipped with vapor recovery systems which would either recondense and return to storage, material that vaporizes due to external temperature changes or which would remove such vapors to a flare or fuel line. Table 5.4.5 lists substances which may be present in coal conversion plant process streams. It must be pointed out that power plants are also suspected of emitting polycyclic hydrocarbons (Ref.5.16); however, it is unclear, as yet, to what extent air quality and health are affected by these relatively undefined emissions (Refs 5.17, 5.18).

The primary problems associated with the process plant will likely be accidental releases of product and waste gases from valves and heat exchange leakage. Small leaks of product into the cooling system could result in hydrocarbon materials being stripped from the cooling water and emitted to the atmosphere from the plant cooling towers. The circulating water is used to cool product oil, waste water, raw fuel gas, amines, and other compounds, and, therefore, heat exchanger failures may cause the cooling tower to become the source of a variety of air pollutants of unknown quantity and quality.

The sulphur plant is a potential source of considerable quantities of obnoxious emissions and, therefore, a tail gas clean up system is needed to assure acceptably low sulphur emissions.

Table 5.4.5

Potentially Hazardous Substances Suspected Present in Coal Conversion Plant Process Streams (Ref. 5.23).

Chemical Classification	Compound	Phase
Acids and Anhydrides	Maleic Acid	liquid
	Cresylic Acid	liquid
	Sulphuric Acid	liquid
	Anthraquinone Disulphuric Acid	liquid
Alcohols	Aliphatic Alcohols	liquid
	Aromatic Alcohols	liquid
Amines	Diethylamines	gas
	Methylethylamines	gas
	Ammonia	gas/liquid
Inorganic Salts	Ammonium Sulphate	liquid
Carbonyl Compounds	Ketones	gas/liquid
	Aldehydes	gas/liquid
Combustion Gases	Carbon Monoxide	gas
	Sulphur Oxides	gas
	Nitrogen Oxides	gas
Heterocyclics	Pyridines	gas/liquid
	Pyrroles	gas/liquid
	(Mono) Benzofurans	gas
Hydrocarbons	Benzene	gas/liquid
	Toluene	gas/liquid
	Xylene	gas/liquid
	Aliphatics	gas
	Olefins	gas
Phenols	Phenols	gas/liquid
	Dimethyl Phenol	liquid
	Cresols	gas/liquid
	Xylanols	gas/liquid
	Phenyl Phenols	gas
	Alkyl Phenols	gas
	Alkyl Cresols	gas

Continued...

Table 5.4.5 - Continued

Chemical Classification	Compound	Phase
Polynuclears	Anthracenes	gas
	Benzo(a)pyrene	gas
	Benzo(e)pyrene	gas
	Perylene	gas
	Benzo(g,h,i)perylene	gas
	Coronene	gas
	Phenanthrene	gas
	Fluranthrene	gas
	Chrysene	gas
	Benzo(a)anthracene	gas
	Acridine	gas
	Benzo(a)anthrone	gas
	Dibenzo(a,l)pyrene	gas
	Dibenao(a,n)pyrene	gas
	Dibenzo(a,i)pyrene	gas
	Methyl Pyrene	gas
	Indeno(1,2,3-c,d)pyrene	gas
	Benzoacridine	gas
Sulphur Compounds	Sulphides	liquid
	Sulphonates	liquid
	Mercaptans	gas
	Thiophenes	gas/liquid
	Hydrogen Sulphides	gas/liquid
	Methyl Mercaptans	gas/liquid
	Carbon Disulphides	gas
	Carbonyl Sulphide	gas
	Methyl Thiophene	gas
Trace Elements	Vanadium	gas/liquid
	Nickel	gas
	Lead	gas
	Cobalt	gas
	Molybdenum	gas
	Strontium	liquid
	Beryllium	gas
	Selenium	gas/liquid
	Cadmium	gas
	Mercury	gas
	Antimony	gas
	Arsenic	liquid
	Phosphorous	gas/liquid
	Manganese	liquid

Continued...

Table 5.4.5 - Concluded

Chemical Classification	Compound	Phase
Organo-metallics	Nickel Carbonyl	gas
	Cobalt Carbonyl	gas
Fine Particulates	Sulphur Particulates	gas
	Catalyst fines	gas
	Coke	gas
	Coal Dust	gas
Cyanides	Hydrogen Cyanide	liquid
	Ammonium Thiocyanate	liquid

A number of such processes with extensive commercial experience are available for use in this service. The tail gas treatment systems fall into two general categories. In one, the Claus plant effluent is treated to reduce all sulphur compounds to hydrogen sulphide which is then scrubbed by a conventional system such as an amine process, and the other groups of processes rely on catalytic reactions which first oxidize all sulphur compounds to sulphur dioxide which is then treated by processes similar to those used for stack gas clean up. In the event that a power boiler is used, there is some potential of integrating scrubber product sulphur dioxide with the process plant Claus unit, thereby reducing waste disposal and equipment requirements for sulphur dioxide removal.

The sulphur feed to a Claus plant in a coal conversion plant that uses 40,000 t/d of Hat Creek coal will be of the order of 200 t/d. Investment costs for a sulphur recovery system of this size will be in the range of $6-8 million depending to a great extent on the required concentration of sulphur compounds in final stack effluent. Such sulphur recovery plants can be utilized as steam generators and, therefore, operating costs assigned to a sulphur plant will be dependent upon the value of low pressure steam within the coal process plant and the current value of the sulphur product. This, in turn, is dependent on the detailed process design of the entire plant which will, of course, be optimized to produce lowest overall plant operating costs and not lowest sulphur recovery plant operating costs.

As mentioned previously, consumption of the products of coal processing facilities will have additional environmental impacts and therefore deserve some attention when comparing environmental impacts of such plants with coal-fired power plants. Low BTU gas and high BTU gas products consumption is unlikely to generate significantly different air quality impacts than are presently observed with the use of natural gas unless the low BTU gas is used as turbine fuel in a combined cycle generation plant. In this case, there is a potential for increased nitrogen oxides emissions especially if advanced high temperature turbines are considered. Use of light end distillate coal liquids, similarly would not be expected to generate a greater air quality impact than light petroleum fuels; however, there may be health risks associated with storage and handling.

The heavier liquid and solid fuels such as may be used in existing power and steam boilers and turbines may provide a number of operating problems and associated environmental impacts. In the case of SRC I sulphur levels may not be sufficiently low to meet some emission standards or air quality regulations, and preliminary combustion tests have indicated that burner modifications may be necessary to avoid increased nitrogen dioxide emissions compared with coal firing. Insufficient information is available to characterize precipitator performance on ash generated from SRC I; however, it can be anticipated that a finer particulate size distribution will result from SRC I combustion which could lead to increased emissions of fine particles.

Coal liquids, in general, are low sulphur, low ash, high BTU fuels, which share a potential problem of increased nitrogen oxides emissions in comparison to residual fuels.

Combustion tests have shown that burner design, atomizing air pressure, and excess air affect nitrogen oxides and smoke emissions. Each system using such fuels will require performance evaluations to determine minimum nitrogen oxides and particulate emissions. It may also be necessary to process the coal derived fuels to remove nitrogen which would increase the processing and product costs. Table 5.4.6 lists the properties of several coal liquids.

Based on present experience and the state-of-the-art of coal conversion processes and associated pollution control equipment,

Table 5.4.6 TYPICAL COAL LIQUIDS

	H-Coal* (Syn. crude)	H-Coal* (Ref. 5.19) Fuel Oil	Exxon Donor (Ref. 5.20) Solvent Hydrotreated	Gulf Catalytic Coal Liquids (Ref. 5.21) Full Range	No. 6 Fuel Oil
Parent Coal Sulphur wt %	5	5	3.5		
API Gravity (Density)	15(.966)	4.4(1.049)	8.6(1.01)	7.0(1.02)	17.5(0.950)
Hydrogen wt %	9.48	8.43	8.6	8.84	11.3
Sulphur wt %	0.19	0.43	.04	0.07	0.8
Nitrogen wt %	0.68	1.05	.24	0.51	0.10
Ash wt %				.01	.08
HHV, kJ/Kg	42,110				43,540
Na					29 ppm
Carbon			90.8	89.93	87.7
Vanadium					60 ppm

*H-Coal analyses shown represent samples obtained under different process operating conditions.

there should be no technical difficulty in meeting the air emission objectives and the air quality guidelines for the Province of British Columbia during construction and operation of either a coal conversion complex or a coal-fired power plant.

5.4.3 Water Discharges and Applicable Regulations

For liquid discharges there are seven major streams which must be controlled to meet the effluent-quality objectives and receiving-water quality guidelines. These streams are foul condensate and sour water, oily waters, amine filter washes, spent chemicals and scrubber wastes, boiler and cooling tower blowdown, domestic sewage wastes and storm runoff from coal liquids storage areas.

Potential water pollutants produced by a coal liquids plant include dissolved solids and suspended solids, mercaptans and other sulphur compounds, ammonia, oxygenated compounds, hydrocarbons, tars, oils, cyanides, sulphur, phosphates and trace elements reflecting those in raw coal. Sulphur compounds tend to form acids and decrease stream pH. Sulphur, phenols, amines and other compounds mentioned may cause odor and taste problems. Turbidity may be increased and tar and oils may have an undesirable impact on aquatic biota. Neither the fate nor the effects of trace elements are clearly understood but many appear to be toxic or carcinogenic to terrestrial and aquatic biota.

As with air emissions, the applicable effluent-quality objectives and receiving-water quality guidelines are established for three levels of compliance. Again, Level A standards must be met since that level is applicable to any plant built after 1974. The receiving-water quality guidelines are not applicable at the point of discharge but must be met within an initial dilution zone defined for rivers to extend 100 metres downstream from the point of discharge but not to exceed 25 percent of the river cross-sectional area. The total plant discharge should originate from a single, submerged outfall. Table 5.4.7 presents the water quality receiving stream guidelines.

As described in the previous section, the coal conversion processes are sufficiently similar to the chemical and petroleum industry that extrapolation of effluent objectives to the coal conversion industry is a reasonable approach. Table 5.4.8 presents the applicable effluent-quality objectives. These effluent standards are based upon maximum control of losses and reduction of wastes through recovery and recycling. Separate sewer systems should be maintained for uncontaminated and waste water streams. Cooling towers or air-fan coolers are strongly recommended for thermal pollution control.

Where plausible, effluent streams should be combined so that only a single discharge point is necessary. Overall, the waste treatment system should be designed to eliminate toxicity and reduce gross emissions. It should be noted that, whenever discharge objectives are set concurrent with receiving water quality objectives, the more restrictive requirements take precedence. Treatment of foul condensate, sour water, spent chemicals, and filter washes are waste water treatment components which are integral parts of coal conversion process plants and, as such, cannot be considered as add-on pollution control equipment.

The primary purpose of the waste water or sour water treatment system is to separate and recover ammonia and H_2S. In a conventional stripper, all dissolved gasses (NH_3, H_2S, CO_2) would be vaporized and would lead to problems in the Claus plant due to solid ammonia salts formation. A proprietary waste water treating system developed by Chevron avoids this problem and yields saleable ammonia by-product. The process separates ammonia as

Table 5.4.7 Receiving-water Quality Guidelines (Ref. 5.12)

Parameter	Marine Waters	Fresh Water
Dissolved oxygen	90 percent of seasonal value	90 percent of seasonal value
pH	No change	No change
Residual chlorine	Not detectable	Not detectable
Turbidity, APHA Units	+5 maximum	+5 maximum
Settleable solids mg/l	Negligible	Negligible
Floatable solids mg/l	Negligible	Negligible
Dissolved solids, mg/l	----	No measurable change
Heavy Metals mg/l	No measurable change	No measurable change
Phenol mg/l	0.001	0.001
Toxicity	Below detectable limit	Below detectable limit
Temperature increase, F maximum	+2	+2

Biological parameters which are not amenable to tabulation will also require consideration

Table 5.4.8

Effluent-quality Objectives for Chemical Industries Other Than Petroleum Refineries (Ref. 5.12A)

	Discharges to Marine Waters			Discharges to Fresh Waters			Monitoring
	Level A	Level B	Level C	Level A	Level B	Level C	
Oil, nonvolatile, mg/l (a)	-	10	15	-	10	15	Daily composite, once per week
Oil, total, mg/l	10	-	-	5	-	-	Daily composite, once per week
BOD, five-day, 20°C, mg/l	20	45	130	20	45	130	COD or TOC once per week, BOD checked quarterly
Ammonia, as N, mg/l	10	15	15	10	15	15	Daily composite, once per week
Nitrates, as N, mg/l	10	50	50	10	50	50	Daily composite, once per week
Total nitrogen, mg/l (kjeldahl)	15	25	25	15	25	25	Daily composite, once per week
Chlorate, mg/l	75	150	150	50	100	100	Daily composite, once per week
Chloride ion, mg/l (b)	-	-	-	-	-	-	Daily composite, once per week
Chlorine, residual, mg/l	0.2	0.5	1.0	0.2	0.5	1.0	Continuous
Fluoride, mg/l	2.5	10	15	2.5	10	15	Daily composite, once per week
Formaldehyde, mg/l	5	5	10	5	5	10	Daily composite, once per week
Metals (total) -							
Arsenic, trivalent, mg/l	0.05	0.05	0.08	0.05	0.05	0.05	Daily composite, once per month
Barium, mg/l	1.0	1.0	1.5	1.0	1.0	1.0	Daily composite, once per month
Boron, mg/l	15	15	15	10	10	10	Daily composite, once per month
Chromium, mg/l	0.2	0.2	0.2	0.2	0.2	0.2	Daily composite, once per month
Copper, mg/l	0.1	0.1	0.1	0.1	0.1	0.1	Daily composite, once per month
Lead, mg/l	0.2	0.2	0.2	0.2	0.2	0.2	Daily composite, once per month
Mercury, mg/l	0.002	0.050	0.050	0.002	0.050	0.050	Daily composite, once per month
Nickel, mg/l	0.2	0.2	0.2	0.2	0.2	0.2	Daily composite, once per month
Zinc, mg/l	0.2	0.2	0.3	0.2	0.2	0.2	Daily composite, once per month
Phenols, mg/l	0.2	0.3	1.0	0.2	0.3	1.0	Weekly grab
Phosphate, as P, mg/l	-	-	-	1.0	10	30	Daily composite, once per week
Sulphate, mg/l (b)	-	-	-	-	-	-	Daily composite, once per week
Urea, mg/l	2.0	2.0	2.0	1.0	1.0	1.0	Daily composite, once per week
Sulphides, mg/l	0.10	0.10	1.0	0.10	0.10	1.0	Weekly grab
Cyanide, mg/l	0.10	0.10	0.20	0.10	0.10	0.20	Weekly grab
Suspended solids, mg/l (c)	20	20	30	20	20	30	Daily composite, once per week
Settleable solids, mg/l (c)	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	Daily composite, once per week
Floatable solids	(d)	(d)	(d)	(d)	(d)	(d)	Daily observation
Total solids, mg/l (e)	3,000	3,000	3,000	1,500	1,500	1,500	Daily composite, once per week
Colour, Pt Co Units at pH 7	20	20	30	15	15	20	
Turbidity, JTU	15	15	25	10	10	15	
Temperature, $^{\circ}$F maximum	90	90	90	90	90	90	Continuous
pH	6.5-8.5	6.5-9.0	6.5-9.0	6.5-8.5	6.5-8.5	6.5-9.0	Continuous
Toxicity (f)	50	45	25	100	90	50	Quarterly

(a) For discharge of once-through cooling water used for indirect cooling (heat exchangers, bearings, etc.) the maximum permissible oil concentration is 2 mg/l above background.

(b) While the importance of these characteristics is recognized, no limits have been established at this time.

(c) Not applicable to discharges to exfiltration ponds.

(d) Negligible.

(e) Depends upon the nature of solids other than normal marine composition.

(f) 96 hour TLm Bioassay on salmonid species, expressed as per cent by volume of effluent in receiving-water which is required to give 50 per cent survival over 96 hours.

a dry liquid and hydrogen sulphide as a gas which is sent to a Claus plant. If phenols are present in amounts too large for biological oxidation systems, solvent extraction may be used to remove them from the waste water. Processes are under development to allow separation of the various types of phenol groups in order to enhance possible by-product value of these compounds.

Effluents from gas liquor/foul condensate treatment, sewage treatment plant wastes, storm water runoff, and oil water separator wastes are sent to aeration ponds for secondary treatment. This biological oxidation pond is the primary water pollution control system in any coal conversion complex. For a 40,000 metric ton per day coal conversion plant the secondary treatment pond would require approximately 162,000 m^2. The blowdown from this pond would range from 0.25 - 1.25 m^3/s and could be recycled to the plant makeup water system. The river makeup water requirements are on the order of 0.63 m^3/s with over 50 percent consumed as evaporation in the cooling towers. This is about 40 percent of the makeup water requirements (1.58 m^3/s) for a 2,000 Mw coal-fired power plant.

The cooling tower blowdown could be the only discharge stream from a coal conversion plant since all treatment effluents are discharged to the aeration pond. Since the cooling tower concentrates the chemical constituents in the circulating water system, either makeup water treatment such as lime softening, or blowdown treatment such as reverse osmosis, or evaporation may be required to meet effluent objectives or receiving-water quality guidelines. At a power plant, the blowdown would be similar to a coal conversion plant, since the largest effluent by far is the cooling tower blowdown. The major difference between the two complexes is that small quantities of oil and waste stream leakages may be contained in coal conversion plant cooling tower blowdown and may require special additional treatment. Table 5.4.9 compares the effluent quality from several coal conversion complexes (Refs. 5.3, 5.4, 5.5). As in the case of air emissions given in Table 5.4.4, these values were interpolated from information developed for the U.S. EPA by Exxon Research and Engineering.

For both a power and a coal conversion plant, a scrubber for the boiler stack gas could eliminate a waste water blowdown requirement, but additional by-product and waste handling systems would be needed.

Table 5.4.10 shows an analysis of plant effluent at the SASOL coal conversion complex.

When compared to Level A effluent quality objectives for fresh waters, only suspended solids, fluorine and cyanide concentrations are greater than the desired levels. These data suggest that commercial scale and coal conversion plant liquid effluent should easily achieve Level A effluent quality objectives. It is technically feasible to achieve a zero liquid effluent level for coal conversion systems just as can be achieved at a power plant by recycling all waste streams to the power boiler scrubber system where components of waste streams would become part of the scrubber solid wastes.

The optimum liquid waste treatment system will be dependent on the detailed design of the overall coal processing complex and the design of components, such as the ash handling system, scrubber type, the degree to which certain chemical wastes may have recycle or market value, makeup water quality and cost, and operating and maintenance practices which may become required for personnel safety. The cost of such systems will be highly variable and virtually indeterminate in the absence of a detailed process design. The cost of waste treatment

Table 5.4.9 - A

Liquid Discharges from H-Coal Plant
40,000 t/d Coal Feed

(All values in metric tons per day)

1. Cooling Tower Blowdown - 2,600
2. Treated Waste Water from Secondary Treatment Pond - 4,500; water is recycled to circulating water system.
3. Phenols may be recovered or sent to secondary treatment.
4. Ammonia recovered from sour water stripper and purified for sale - 200.
5. Demineralizer wastes, neutralized and sent to waste water treating.

Table 5.4.9 - B

Liquid Discharges from Lurgi, High-BTU Gasification

(All values in metric tons per day)

1. Cooling tower blowdown - 2,600.
2. Treated Waste Water from Secondary Treatment Pond to Reuse - 15,000.
3. Phenols from Waste Water Treatment - 110, recovered.
4. Ammonia (24.1 percent aqueous solution) recovered from gas liquor purification - 110.

Table 5.4.9 - C

Liquid Discharges from SRC I Plant

(All values in metric tons per day)

1. Cooling Tower Blowdown - 2,600.
2. Treated Waste Water from Secondary Treatment Pond - 10,200.
3. Demineralizer Wastes.
4. Chemical purge from Benfield to Waste Treating - 575.
5. Oil from API separator.
6. Phenols from Waste Water Treatment - returned to hydrogenerating unit.
7. NH_3 recovered from Waste Water Treatment - 65.

Table 5.4.10 Analysis of Coal Conversion Plant Effluent - SASOL

pH	8.5
Suspended Solids	3.0 mg/l
T.D.S.	959 mg/l
Free and Saline Ammonia (as N)	7.45 mg/l
Arsenic	0.05 mg/l
Chromium	0.01 mg/l
Copper	0.04 mg/l
Phenolic Compounds	0.03 mg/l
Lead	0.02 mg/l
Cyanides	0.11 mg/l
Fluorine	5.87 mg/l
Zinc	0.07 mg/l
Sodium	158 mg/l
Phosphates	0.29 mg/l
C.O.D.	82 mg/l

facilities for a 2,000 MW power plant will depend on raw water quality, design of plant grounds and fuel storage pile, and the ash handling system. Based on experience developed at a number of plants, waste water treatment equipment costs, exclusive of power plant flue gas scrubber system waste, would be on the order of 8 to 10 million dollars. We would anticipate the need for a somewhat more complex and therefore more costly system for a coal conversion plant; however, the waste treating facility would be a much more integral part of the overall plant. For example, the water treatment facilities at a Lurgi SNG gasification plant are quite extensive and would require a considerable investment but it is required as a consequence of process as well as environmental needs. Waste water treatment costs at a coal conversion plant, therefore, cannot be compared directly with those at a coal fired power plant.

5.4.4 Solid Wastes

There are no specific quidelines or objectives to control solid wastes originating either directly from a coal conversion plant process or from waste water treatment systems; however, there are general quidelines recommended for handling solid wastes. Where available and acceptable to a landfill operator, refuse and solid waste should be taken to a municipally/regionally-operated landfill. Industrial refuse (e.g., slag, ash, waste, rock, etc.) should be disposed of in a controlled access area, and adequate surface drainage should be ensured at onsite disposal area, such that groundwaters will not be contaminated. Cover material, cover frequency, compaction, and vegetative cover are required and specific details are left to the discretion of the Director. Sludges must be neutralized, dewatered and stabilized, where necessary.
Waste oils should be recycled; organic liquids recovery is

preferred, although incineration is acceptable.

Table 5.4.11 provides an indication of the general type and source of solid wastes generated by several types of coal conversion plants. The information was interpolated for Hat Creek Coal from data developed by Exxon. (Ref. 5.3, 5.4, 5.5) Land requirements for mining and plant operations will be approximately the same for a power plant or a coal conversion complex but will, of course, be dependent on the working life of the mine, the land reclamation plan and the degree to which waste products may find use as raw materials. If no processing of solid wastes for raw material consumption occurs, the land requirements and disposal techniques may be somewhat different due to the potentially complex nature of the wastes from coal conversion plants. The associated tars and soot material with coal conversion ashes may require special handling and disposal techniques to ensure against contamination of groundwaters and adjacent soils. If sulphur was produced at both a power plant or coal conversion complex, additional land would be required for sulphur storage.

Trace elements in coal conversion processes will be of concern as they are in coal-fired power plants. Although the reducing atmosphere present in coal conversion systems may form compounds such as hydrides, carbonyls or sulphides which may be relatively volatile, most of the trace elements will probably be associated with the solid residue. If the residue is disposed in a lined dump area, the potential problems due to trace metals could be effectively negated.

Trace metals emitted from a power plant, however, will have a tendency to escape through the stack unless an extremely efficient electrostatic precipitator is used. Several studies have been performed which indicate that several elements increase in concentration in the topsoil around coal-fired power

Table 5.4.11 - A - Solid Wastes Generated by H-Coal Plant (40,000 t/Day Coal Feed)

(All values in metric tons per day)

1. Coal Dust from Coal Dryer - collected by bag filters and sent to fly ash disposal system.
2. Spent Catalyst from Liquefaction Reactor - contains trace elements.
3. Spent Chemicals from Waste Treating System and Gas Cleaning Systems - primarily inorganics to waste water treating.
4. Sulphur from Claus Plant - 190, stored on site or sold.
5. Gasifier Ash - 10,800; disposed of in lined ponds or utilized in reclamation or raw material source.
6. Power Plant Bottom and Fly Ash - 1,200; disposed of with gasifier ash (No. 5 above).
7. Secondary Treatment Sludge - 100.
8. Water Treating Wastes - dependent upon makeup water quality.
9. Trace Metals.

Table 5.4.11 - B - Solid Wastes Generated by Lurgi, SNG Gasification Plant

(40,000 t/Day Coal Feed)

(All Values in metric tons per day)

1. Coal Dust from Coal Dryer - collected by bag filters and sent to fly ash disposal.
2. Spent Chemicals from Waste Treating and Gas Cleaning Systems.
3. Sulphur from Claus Plant - 180, stored on site or sold.
4. Wet Ash Disposal -

Water	16 percent
Ash	80 percent
Unused Coal	4 percent

   Total Weight = 15,000
5. Lime sludge from makeup water treating, dependent upon makeup water quality.
6. Trace Metals.

Table 5.4.11 - C - Solid Wastes Generated by SRC I Plant
(40,000 t/Day Coal Feed)

(All Values in metric tons per day)

1. Coal Dust from Coal Dryer - 200 collected by bag filters and sent to fly ash disposal.
2. Spent Chemicals from Waste Treating and Gas Cleaning Systems.
3. Sulphur from Sulphur Plant - 200.
4. Slag from Gasifier - 650.
5. Lime Sludge from Makeup Water Treatment.
6. Sludge from Secondary Treatment is Dewatered and Incinerated.
7. Trace Metals.

plants and that this could result in floral followed by faunal intake. Increased efficiency is available for dust collection at power boilers now, however, and it is not yet known if the potential trace metal problem can be effectively controlled in this manner. More information detailing potential impacts of trace metals is required as well as better understanding of trace metal balance over the power plant and coal conversion plant cycles.

Until recently, disposal of solid wastes in unlined landfills has been acceptable. Assuming a waste production of 12,000 metric tons per day, approx. 11.7×10^6 square meters of land with wastes at a depth of 10 m. would be required in 35 years. A typical operation if the landfill were adjacent to the plant site would include a 1,500 m. conveyor and the earthmoving equipment necessary to distribute the wastes throughout the landfill. Cost of disposal in such a landfill may be on the order of \$0.35 to \$0.45/ton, exclusive of land and indirect costs. Moving the landfill to a location at about eight miles from the plant site would increase the landfilling cost to about \$1.00 to \$1.20/ton range due to the increase in conveyor system costs.

Current environmental regulations may require that provision be made to protect surface and groundwaters from contamination by leachate and runoff from landfills. One method of providing this protection is to line and cap the landfill with bentonite clay. Cost of the landfilling operation described above, adjacent to the plant site, if provided with liner and cap, would be in the range of \$0.60 to \$0.70/ton and about \$1.20 to \$1.40/ton if the disposal site was about eight miles distant from the plant.

6. Descriptions of Selected Processes

6.1 Principally Solid Products

6.1.1 It was shown in Section 4, that in accordance with its rank, Hat Creek coal exhibits no coking or caking properties. It also has a very high ash content which cannot, even on washing, be reduced below 15-20 percent, and this only at the expense of an uneconomically low product yield. This combination of lack of coking power and very high inherent ash renders the coal unsuitable for processing to upgraded products. Its potential application to:

- Carbonization
- Form coke
- Smokeless solid fuels
- Activated carbons

has been carefully considered but no recommendations are made.

6.1.2 The possibility of producing low-grade nitrogenous fertilizers by direct ammoniation of the coal was considered. Such utilization has been employed in India, and has been studied, by the Alberta Research Council. No recommendation for further work is made.

6.1.3 The use of Hat Creek coal for effluent treatment, presumably based upon ion-exchange properties of coal, has recently been publicized in British Columbia and Alberta. Although it has been known for many years that coals, particularly the low rank coals, exhibit ion-exchange properties, the exchange capacities have been low compared with manufactured exchange resins.

No information on the ion-exchange characteristics of Hat Creek coal has been made available and hence no estimate of either the exchange capacity, or of the method and efficiency of regeneration can be made. The possibility of the coal finding wide use in water treatment or effluent purification is considered to be remote.

6.2 Principally Liquid Products

6.2.1 Production of Coal Liquids by the SRC-1 Process (PAMCO).

6.2.1.1 Process Developers:

i) The Pittsburgh and Midway Coal Mining Co., Ft. Lewis, Washington, a subsidiary of Gulf Oil Corporation.

ii) Southern Services - Catalytic Inc. - Edison Elec. Inst., Wilsonville, Alabama.

6.2.1.2 Sponsor:

U.S. ERDA

6.2.1.3 Description:

Raw coal is pulverized and mixed with a coal-derived solvent boiling in the general range 285-425^{0}C. Hydrogen, or a hydrogen-rich synthesis gas, is added to the coal-solvent slurry and passed through a preheater to a dissolver vessel. The dissolver is operated at 435^{0}C and 70 bar with an excess of hydrogen, and under these conditions approximately 90% of the D.A.F. coal is dissolved. The actual degree of dissolution of the coal depends on the "reactivity" of the particular coal feed. In addition to solution of the coal, several other major types of reactions occur. These are: (1) depolymerisation of the coal, necessarily accompanied by hydrogenation of the coal; (2) hydro-cracking of the solvent to lower molecular weight hydrocarbons ranging from light oil to methane; (3) removal of organic sulphur by hydrogenation of the sulphur to hydrogen sulphide.

The product stream from the dissolution-hydrogenation step consists of coal solution, unreacted coal (inerts), undissolved mineral matter (ash), light hydrocarbon gases (methane-rich) and excess hydrogen. The excess hydrogen and light hydrocarbon gases are separated from the product slurry. A portion of the hydrogen stream is recycled to the dissolution reactor and the remaining hydrogen, together with the light hydrocarbon gases are further processed for utilization as plant fuel or for sale as "town" gas (22360 KJ/m^3) or upgraded by methanation to pipeline-quality gas (37,000 kJ/m^3).

The product slurry is pumped to the filtration section where the undissolved coal solids are separated from the coal solution. The filtrate is sent to a vacuum-flash distillation step for removal of the solvent for recycle to the reactor. Experience at the Tacoma pilot plant has shown the filtration stage, to be unsatisfactory. Equipment availability was lower than 50 percent during an operating period from Sept. 1975 - November 1976. A process change substituting sedimentation for filtration is planned during 1977. The bottoms fraction from the vacuum-flash tower is a hot liquid with a solidification point of about 175°C. This is the major product of the process and is referred to as "Solvent-Refined Coal (S.R.C.)". This material can either be transported as a hot, molten liquid or solidified by cooling for shipment.

Alternatively, the process could be modified to produce products that are liquids at normal temperatures and pressures by subjecting the product slurry, after filtration and solvent recovery, to hydro-cracking and subsequent hydro-treatment. Hydro-cracking is employed firstly to product a lighter, hydrogen-enriched material and also effect bulk removal of hetero-atoms such as sulphur, nitrogen and oxygen which would increase costs in refinery operations. A tar by-product is obtained from this step and this tar may be mixed with the filter cake from the filtration step (which contains about 50% carbonaceous matter and 50% ash) and gasified in a commercially-available gasifier to produce the hydrogen for the process. The product liquid from the hydro-cracking step is further hydro-treated to produce light refinery liquids.

Off-gases from the hydro-cracking and hydro-treatment sections are combined with off-gases from the S.R.C. process and sent to acid-gas absorption for removal of CO_2 and H_2S prior to being sent to a hydrogen-methane cryogenic separation unit. The resultant hydrogen stream is recycled to the hydroconversion section and the methane is available for sale as pipeline gas.

6.2.1.4 Operating Conditions:

Reactor	Temp. $^{\circ}$C	Press. Bar	Reactants	Product
Dissolver	435	70	Coal-Solvent-H_2	Solvent-Refined Coal (S.R.C.) Gas

6.2.1.5 A materials balance and overall thermal efficiency for raw coal feed is shown in Fig. 6.2.1.

About 52 percent of the coal is available for liquid conversion, the other 48 percent being required for production of hydrogen, fuel gas and power.

Liquid (and solid SRC-1) yield is about 15.6 percent.

Overall thermal efficiency is 52 percent.

6.2.1.6 A materials balance and overall thermal efficiency for washed coal feed is shown in Fig. 6.2.2.

About 54 percent of the coal is available for liquid conversion, the remainder being required for production of hydrogen, fuel gas and power.

Liquid (and solid SRC-1) yield is 21.7 percent.

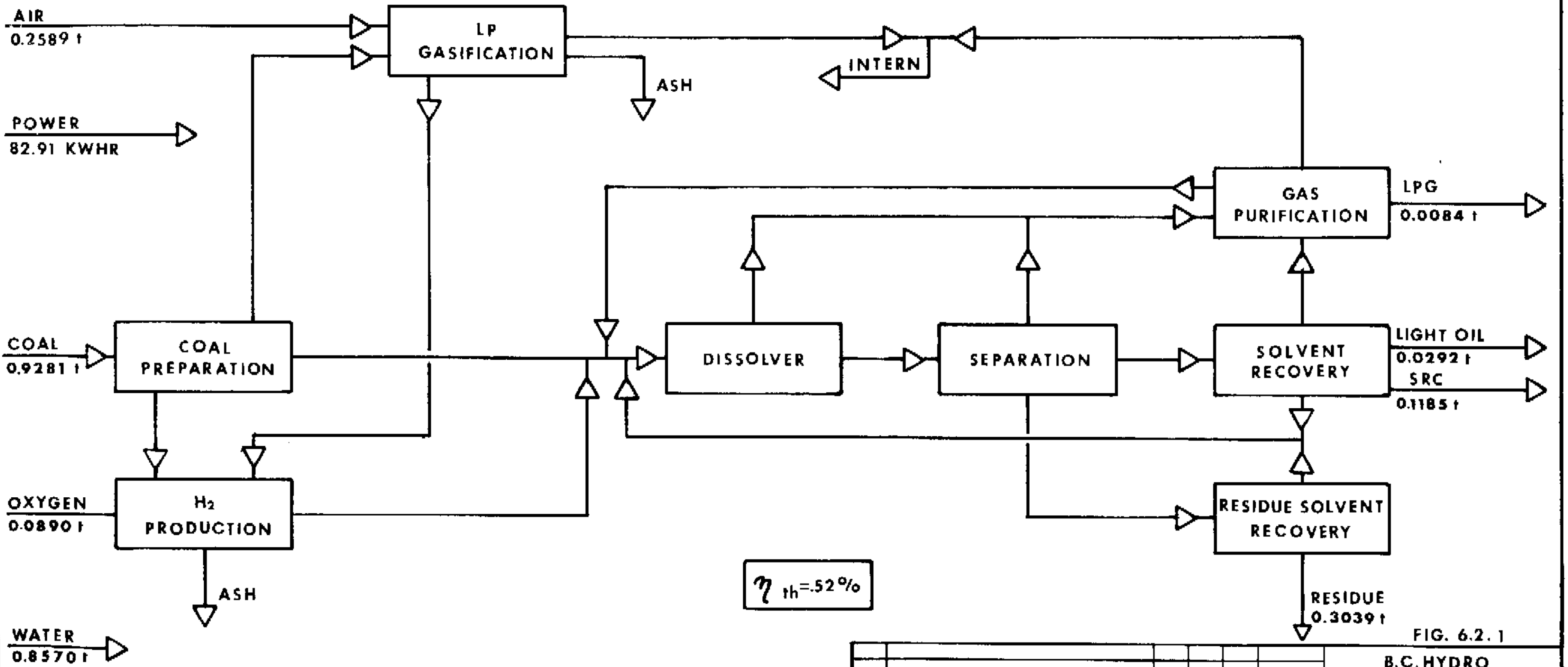
Overall thermal efficiency is 54 percent.

6.2.1.7 Commercial production plant

The coal feed rate of the commercial production plant should be 18,000,000 t/a of run-of-mine coal.

The on stream factor should be 330 d/a.
For such capacity the major primary process units are as follows:

COAL LIQUEFACTION
(SOLVENT REF. COAL SRC)
RAW COAL



η_{th}=.52%

FIG. 6.2.1

Drawn By
MONTAN CONSULTING GmbH

ISSUE | DESCRIPTION | BY | CHK'D | APP'D | DATE

B.C. HYDRO

STONE & WEBSTER
CANADA LIMITED

Sheet
Cont'd
C.J. 1381,000

COAL LIQUEFACTION
(SOLVENT REF. COAL SRC)
WASHED COAL

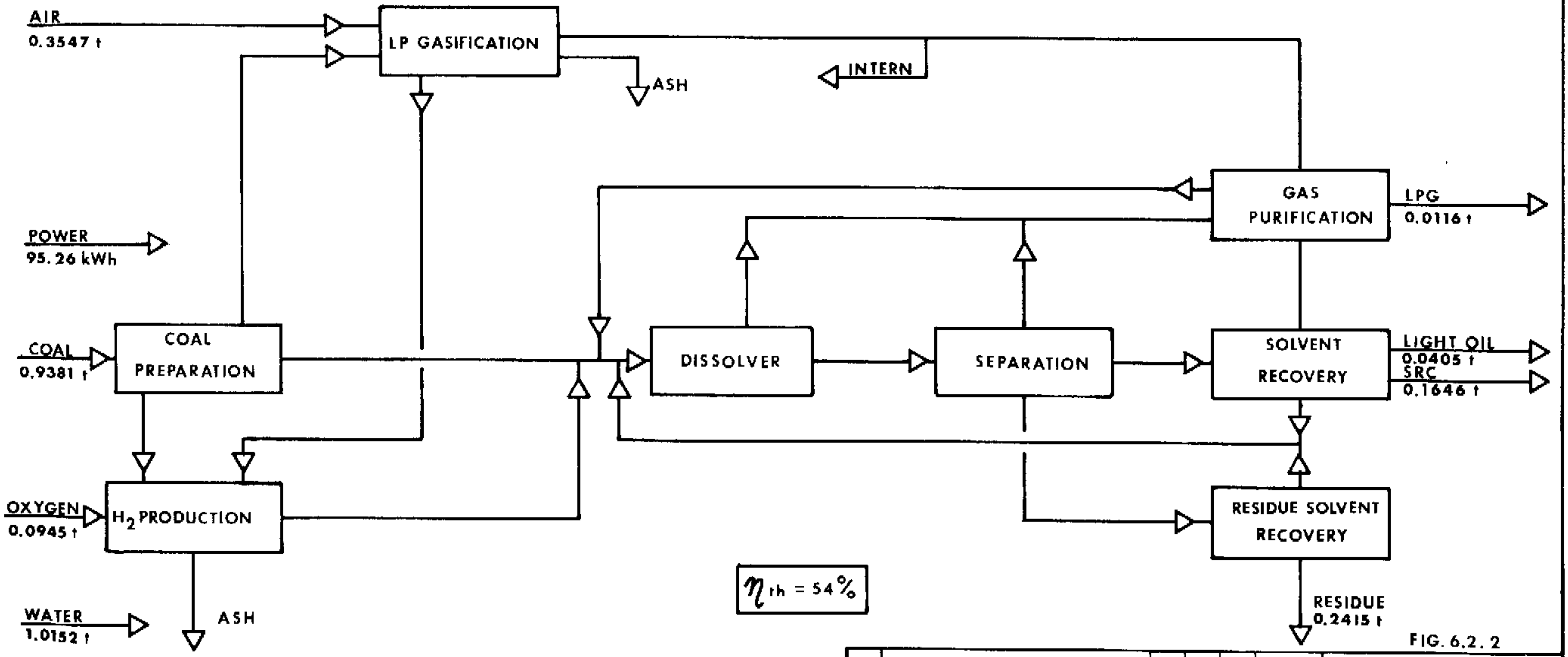


FIG. 6.2.2

Drawn By

MONTAN CONSULTING GmbH

ISSUE	DESCRIPTION	BY	CHKD	APP'D	DATE

B C HYDRO

STONE & WEBSTER
CANADA LIMITED

Sheet
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CJ 1381.000

CSF 405.18

- Coal preparation unit with 10 trains
- Dissolver unit with 10 trains
- Separation unit with 10 trains
- Solvent recovery unit with 7 trains
- Gas purification unit with 1 train
- Residue solvent recovery unit with 5 trains
- H_2 - production unit

In the H_2 - production unit are added the following units:

- Pressure gasification unit with 12 gasifiers
- CO shift conversion unit with 2 trains
- Rectisol purification unit with 2 trains

Secondary process units are included as follows:

- Phenols recovery
- Sulphur recovery and tail gas clean-up-units
- Oxygen unit
- Chemicals recovery unit
- Cooling water unit
- Water treatment unit
- Auxiliary steam and power generation unit
- Low pressure gasification unit
- Storage unit

Feed and products
Feed
18,000,000 t/a run-of-mine coal
15,425,000 t/a river water

Products

2,134,000 t/a SRC I
525,000 t/a Light Oil
151,000 t/a LPG

2,810,000 t/a total products

Table 6.1 Product Specification of SRC I and Light Oil Products

Value	Unit	SRC I	Light Oil
C	W.-%	89.21	82.92
H	"	5.07	11.33
N	"	2.49	0.58
O	"	2.78	5.16
S	"	0.45	0.01
Density	kg/m3	1070	850
HHV	kJ/kg	38,350	45,640
ash	W.-%	<0.05%	0.0
soft.point	°C	180...220	-

Capital costs

Investment cost : 1,290 . 10^6 CDN $
Working capital : 86 . 10^6 CDN $

Costs for chemicals and catalyst

Chemicals	: 2.75 . 10^6 CDN $ /a
Catalyst	: 0.55 . 10^6 CDN $ /a

Manpower requirements
420 employees

Land
1,500,000 m^2

6.2.2 Production of Light refinery liquids

This process is a combination of the SRC-process and the H-oil-process by HYDROCARBON RESEARCH INC. The H-Oil-process has been commercialized in the oil-industry for hydrocracking of crude oil residues.

The idea of hydrocracking of coal extracts was proposed firstly in Germany in the thirties and the H-Oil-process may be the best way today to do this.

6.2.2.1 Process Description

The feed coal is dried in the coal preparation unit to a residual moisture content of 3% by weight and reduced to a particle size of 3 mm. The predried and size-reduced coal is then mixed with solvent (anthracene oil) in a weight ratio 1:2 at a temperature of 180 - 200°C to produce a slurry which, after being subjected to a pressure of 75 - 80 bar and admixed with hydrogenation gas (H_2 = 95% by vol.) and recycle gas (H_2 = 75% by vol.), is heated in a preheater to 430 - 450°C.

This is followed by extraction of the mixture in a dissolver unit at a aforementioned pressure and temperature. In the gas separation unit succeeding the dissolver unit, the evolved gas is first separated at the same temperature and pressure. The slurry is then cooled down to 280 - 300°C and subjected to stepwise flash evaporation at 35 - 37 bar and at 11 - 12 bar, after which it is passed to the separation unit.

In the mechanical separation stage the slurry is separated into a high-solids fraction and a low-solids fraction.

The low-solids fraction is passed to the solvent recovery unit, where it is subjected to vacuum distillation at 0.2 bar and from which SRC I is withdrawn as bottom product and transferred to the hydroconversion unit.

The condensed top product is reprocessed in a further distillation stage at a pressure of 2.5 bar into solvents as bottom product which is returned for slurrying the prepared coal, and into a condensed top product which, after condensation, is passed to a hydrotreating unit.

Since the high-solids fraction contains a considerable amount of solvent, it is fed into a residue solvent recovery unit. The solvent recovered in this unit is reused for slurrying the prepared coal and the residue is sent to the dump.

The solvent recovery unit and the residue solvent recovery unit are included in the separation stage shown in the block diagram and are not shown separately.

The SRC I formed is brought to a pressure of 200 - 240 bar, admixed with recycle gas heated to 320 - 360°C and fed into a hydroconversion reactor. The liquid-gas mixture leaving the hydroconversion reactor is separated and a light-oil fraction is recovered from the gas. The liquid product is distilled at various pressure stages and temperatures.

The top product of the distillation units together with light oil recovered from the gas fraction and the light oil from the SRC I process are brought up again to a pressure of 200 - 240 bar and, after being mixed with make-up hydrogen and heated to a reaction temperature of 400 - 450°C, fed into a refining unit. The refined product leaving this unit is flash evaporated in steps and then distilled. The bottom product of this distillation is Light refinery liquid which is withdrawn and passed to the storage tanks.

The gases evolving in the various process stages are fed into a gas purification unit where the recycle gas is removed and the remaining purified gases following separation of the LPG fraction, is utilized together with the lean gas from the low-pressure gasification unit for generating the heat required for the process.

The make-up hydrogen required in the dissolver unit and refining unit has a purity of 95% by vol. It is produced in the hydrogen production unit by pressure gasification of the residue from the hydroconversion unit, the tar from the low-pressure gasification unit and of raw coal, then converted in a CO shift conversion unit and then purified in the gas purification unit.

The CO shift conversion unit and the gas purification unit are included in the hydrogen production unit.

6.2.2.2 A material balance and calculated overall thermal efficiency is shown in Fig. 6.2.3 for raw coal feed.

About 45 percent of the coal feed is available for liquids conversion, the remainder being required for hydrogen production, fuel for and power generators.

Liquid yield is 11.4 percent of total coal feed.

Overall thermal efficiency is 43.5 percent.

COAL LIQUEFACTION (LIGHT REF. LIQUIDS)
RAW COAL

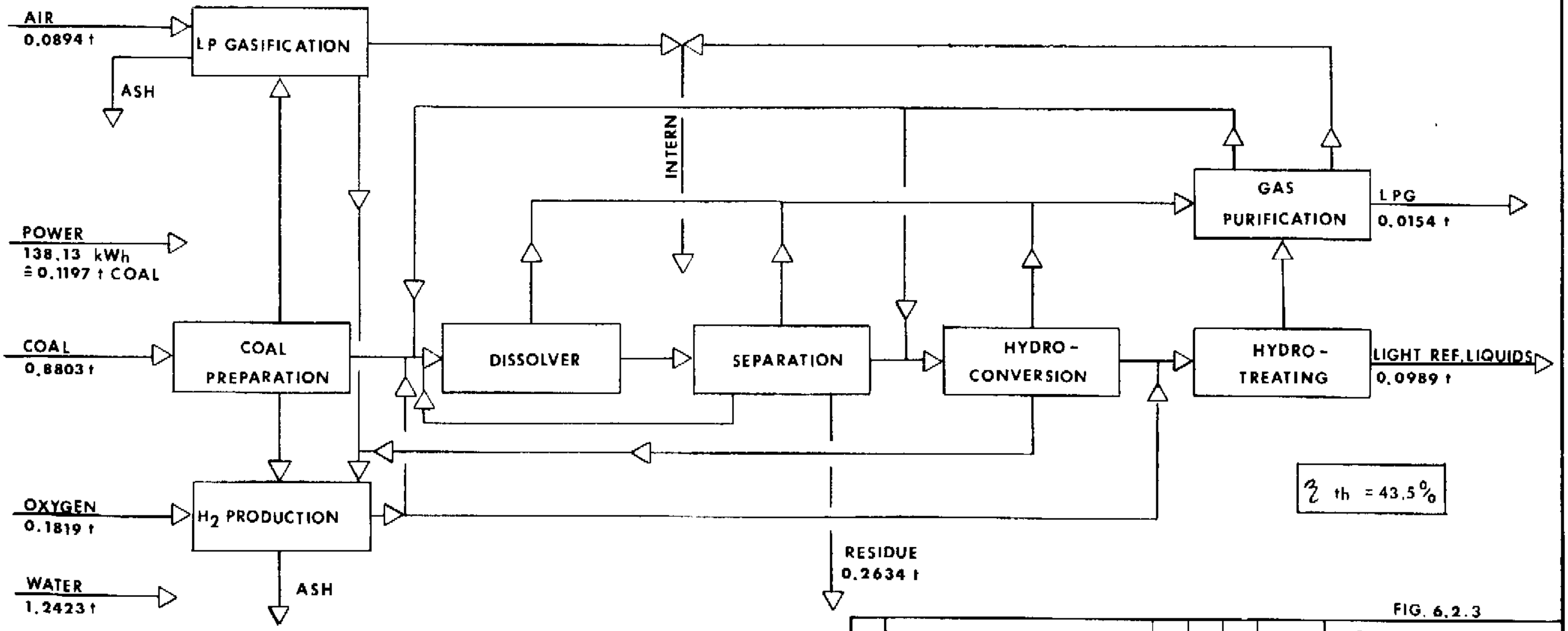

FIG. 6.2.3

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6.2.2.3 A materials balance and overall thermal efficiency is shown in Fig. 6.2.4 for washed coal feed.

About 48 percent of the coal feed is available for liquids conversion, the remainder being required for hydrogen production, fuel for and power generation.

Liquid field is 16.2 percent.

Overall thermal efficiency is 46.5 percent.

6.2.2.4 Commercial production plant

The coal feed rate of the commercial production plant should be 18,000,000 t/a of run of mine coal.

The on stream factor should be 330 d/a. For such capacity the major primary process units are as follows:

- Coal preparation unit with 9 trains
- Dissolver unit with 9 trains
- Separation unit
- Hydroconversion unit with 9 trains
- Hydrotreating unit with 9 trains
- Gas purification unit with 2 trains
- H_2 -production unit

In the separation unit and in the H_2 -production unit are added the following units:

- Separation unit
  - Separation unit with 9 trains
  - Solvent recovery unit with 7 trains
  - Residue solvent recovery unit with 5 trains

- H_2 -production unit
  - Pressure gasification unit with 24 gasifiers
  - CO shift conversion unit with 4 trains
  - Rectisol purification unit with 4 trains

Secondary process units are included as follows:

- Phenols recovery
- Sulphur recovery and tail gas clean-up units
- Oxygen unit
- Chemicals recovery unit
- Cooling water unit
- Water treatment unit
- Auxiliary steam and power generation unit
- Low pressure gasification unit
- Storage unit

Feed and products

Feed

18,000,000 t/a	run of mine coal
22,361,000 t/a	river water

Products

1,780,000 t/a	Light refinery liquids
277,000 t/a	LPG
2,057,000 t/a	total products

Product specification of Light refinery liquids is shown in Table 6.2.

COAL LIQUEFACTION (LIGHT REF. LIQUIDS)
WASHED COAL

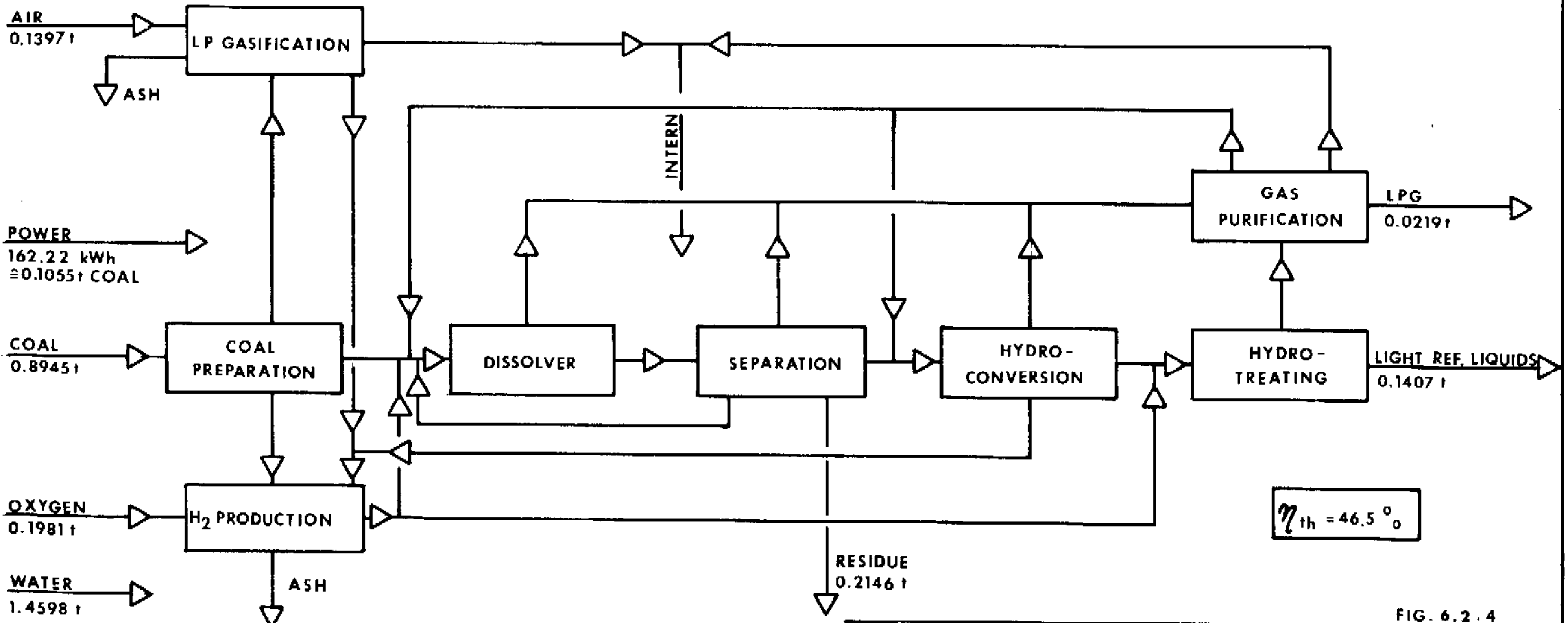

FIG. 6.2.4

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Table 6.2

PRODUCTION SPECIFICATION OF LIGHT REFINERY LIQUIDS

Light refinery liquid		Total	Fraction		
Value	Unit	C5...343°C	C5...93°C	93°C...204°C	204°C...343°C
Volume	Vol. %	100	10	26	64
Weight	W.-%	100	8	24	68
Density	kg/m3	861	692	824	903
S	W.-%	--	--	--	--
N	"	0.07	0.01	0.06	0.08
O	"	0.04	0.005	0.02	0.05
Paraffins	"		50	20	
Olefines	"		--	--	
Naphthenes	"		47	65	
Aromatics	"		3	15	
Ash	"	0.05			
HHV	KJ/Kg	14020	-	-	-

6.2.2.5 Capital costs

Investment cost : 2,130 . 10^6 CDN \$
Working capital : 142 . 10^6 CDN \$

6.2.2.6 Costs for chemicals and catalyst

Chemicals : 5.6 . 10^6 CDN \$ /a
Catalyst :16.1 . 10^6 CDN \$ /a

6.2.2.7 Manpower requirements

510 employees

6.2.2.8 Land

2,000,000 m^2

6.2.3 Production of Liquids by the LURGI-RUHRGAS Process

6.2.3.1 Process Developers:

Lurgi GmbH, a subsidiary of Metallgesellschaft AG, Frankfurt, and Ruhrgas AG.

6.2.3.2 Description:

Feed coal and a heat carrier consisting of hot char are continuously supplied to a mechanical mixer which ensures a uniform mixing of the two components as well as a very rapid equalization of temperature between the char and coal so that a major part of the carbonization occurs at the end of the mixer. The resultant pyrolysis gas and vapours are withdrawn at the end of the mixer, passed through a cyclone for dust removal, and then sent to a condensing unit.

The tar is subjected to dust removal and hydrogenation in the hydro-treatment section to produce a range of liquid products. The gas, after cleaning, has a heating value of 26,100 - 31,670 kJ/Nm^3. This gas may be used as a source of hydrogen for the tar-hydrogenation steps or methanated to pipeline quality.

The char which has been used as a heat carrier and newly-formed char, fall into the carbonizer shaft where additional temperature equalization between the heat carrier and fresh distillation residue takes place so that a subsequent degasification can occur. The char leaves the carbonizer shaft at the lower end and flows to a lift pipe where it is raised by comubstion gases and heated simultaneously.

The combustion gases are produced in the lift pipe itself, into which preheated air is blown to cause partial combustion of the char. Char and combustion gases are separated and the gases, after cleaning, are exhausted.

The hot char is collected in a bin and then recirculated to the mixer to complete the cycle. The continuous production of fresh char results in a surplus of circulating char. This surplus is continuously withdrawn and used for steam and electricity production.

The close intermixing of coal and hot char in the mixer avoids the formation of agglomerates so that coking coals can be treated.

6.2.3.3 Operating Conditions:

Reactor	Temp.°C	Pressure	Reactants	Products
Carbonizer	595	Atmospheric	Coal-Hot Char	Char,Tar,Gas

6.2.3.4 A materials balance and calculated overall thermal efficiency is shown in Fig. 6.2 5 for raw coal.

Liquid product yield is 16.5 percent. Gas yield is 2 percent.

Electric power as coal equivalent (gross calorific value basis) is 21.6 percent.

Overall thermal efficiency is 40.1 percent.

BASE SCHEME FOR LURGI - RUHRGAS PROCESS
ROM - COAL

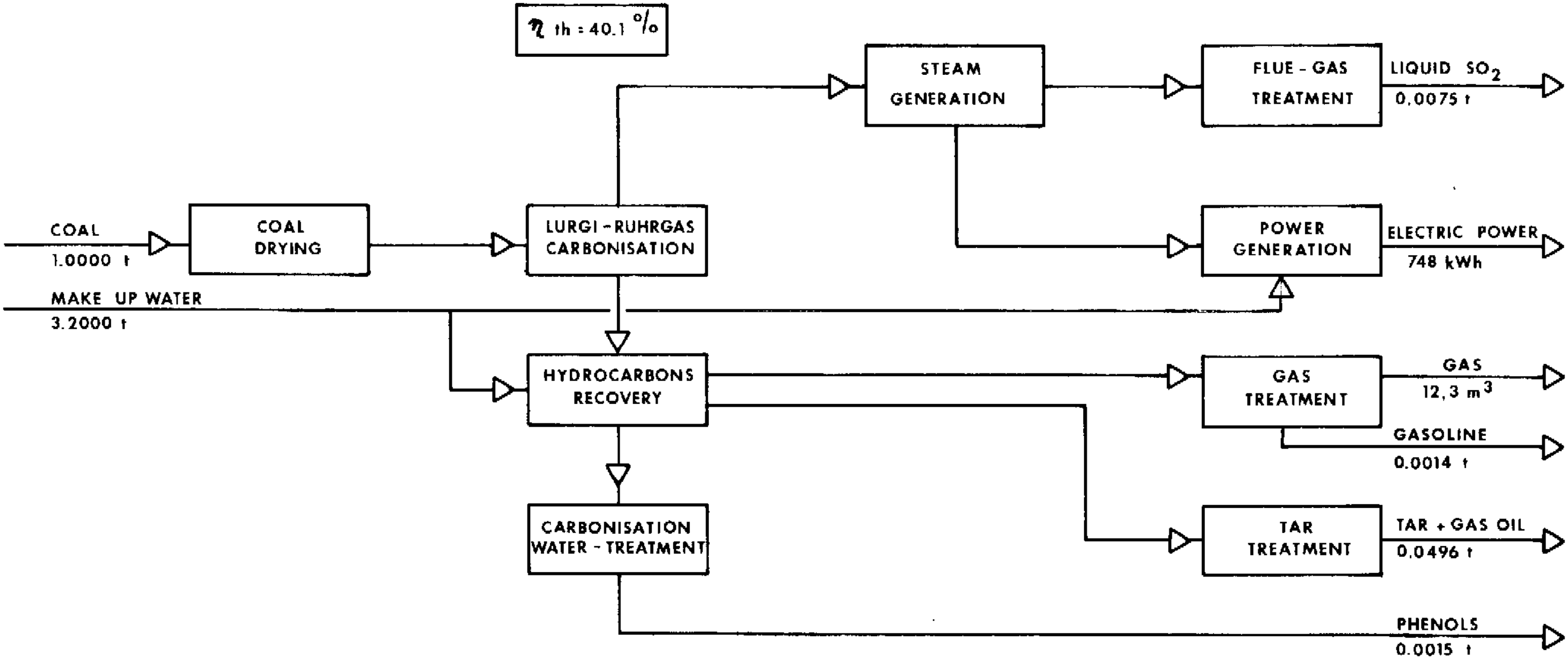

FIG. 6.2. 5

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6.2.3.5 A materials balance and calculated overall thermal efficiency is shown in Fig. 6.2.6 for washed coal.

Liquid product yield is 16.6 percent. Gas yield is 2.0 percent.

Electric power as coal equivalent (gross calorific value basis) is 22.3 percent.

Overall thermal efficiency is 40.9 percent.

6.2.3.6 Commercial production plant

The coal feed for the L-R plant should be 3.10^6 t/a run-of-mine coal. The on stream factor is fixed to 330 days/a.

For this capacity the major primary units are as follows:

- coal-drying unit
- LURGI-RUHRGAS carbonization-unit with 2 carbonizers including quench- and waste-heat systems
- hydrocarbons recovery with gas treatment, tar treatment and carbonization-water treatment.

Secondary process units:
- Power- and steam plant
- Flue-gas treatment
- Make-up water unit
- Cooling water unit

Feeds and products

Feeds

Coal for carbonization	3	. 10^6 t/a
Make-up water	9.6	. 10^6 t/a

Products

Gas	36.90	. 10^6 m^3/a
Tar and gas oil	128.96	. 10^3 t/a
Gasoline	24.02	. 10^3 t/a
Phenols	4.49	. 10^3 t/a
Electric power	2.23	. 10^6 KWH/a

Capital costs

Investment cost:	310	. 10^6 CDN$
Working capital:	15.5	. 10^6 CDN$

Costs for chemicals and catalyst

Chemicals:	4.2	. 10^6 CDN $/a

Manpower requirements

177 employees

Land

300,000 m^2

BASE SCHEME FOR LURGI - RUHRGAS PROCESS
BENEFICIATED COAL

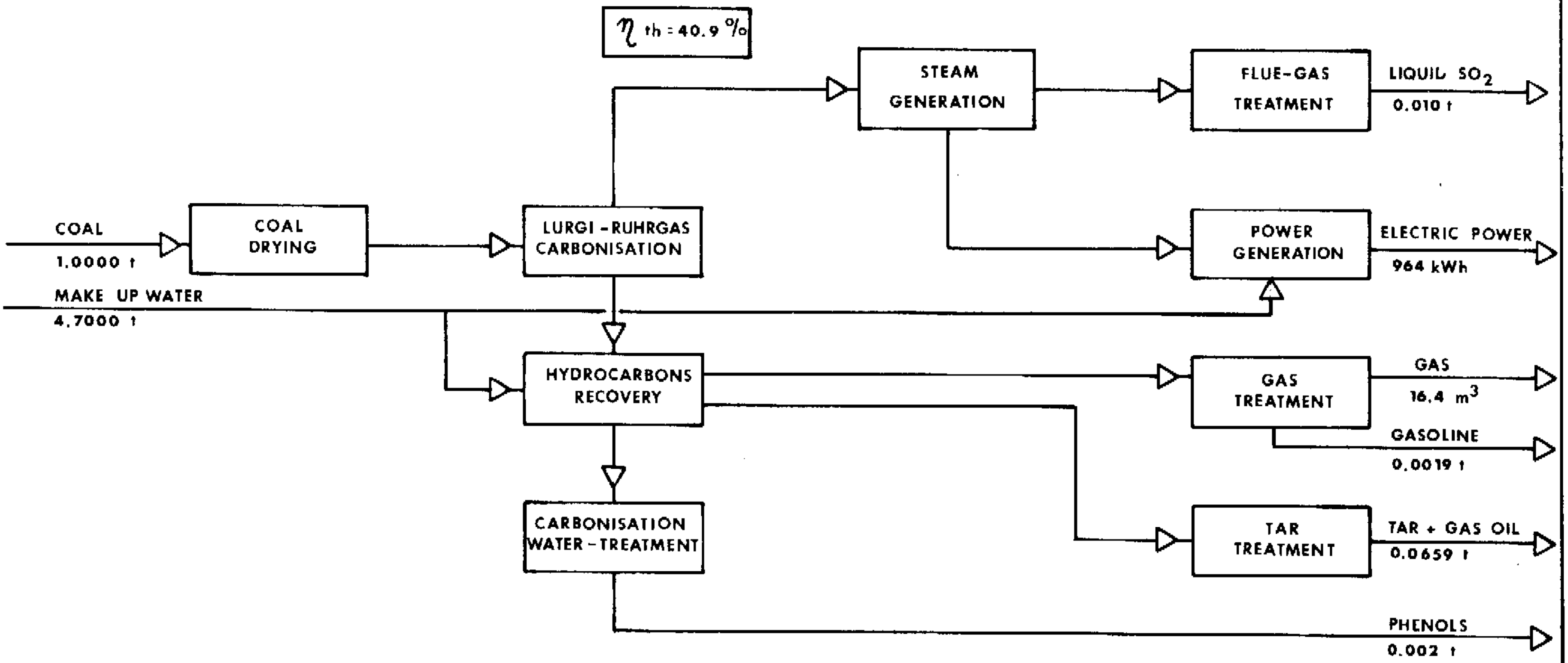

FIG. 6.2.6

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6.2.4 Liquid Production by Lurgi Gasification combined with FISCHER-TROPSCH-synthesis

6.2.4.1 Process Developers:

Fischer and Tropsch (Germany) M.W. Kellogg Co.
(Synthol Process, SASOL)
Arge-Arbeit Gemeinschaft Lurgi and Ruhrchemie
(Arge Synthesis, SASOL)

6.2.4.2 Description:

The F-T-synthesis process basically converts carbon monoxide and hydrogen to liquid hydrocarbons. By gasification of coal the synthesis gas can be produced in an earlier step.

The combination of both processes means an indirect coal liquefaction. The reaction of the gasification process is endothermic and needs heat under a high temperature level. The reaction of the F-T-synthesis process is exothermic and delivers waste heat under a low temperature level. Following this the overall plant efficiency is significantly lower than for direct liquefaction processes. Typical products from the F-T-synthesis process are Middle- and Light-distillates like oils similar to motor gasoline and diesel fuel. But a wide range of organic chemicals are produced, which must be sold if the process is to be even marginally acceptable from a cost stand point.

As only one commercial plant, SASOL in South Africa is currently in operation to produce liquid hydrocarbons from coal-derived synthesis gas via Fischer-Tropsch Synthesis, the following description is for that plant:

Coal is gasified in a battery of 13 Lurgi high-pressure, steam-oxygen gasifiers to produce a gas consisting essentially of carbon monoxide and hydrogen, with a proportion of other gases, tar and oil. The gas stream from the gasifiers is quenched to remove tar and oil and purified by the Rectisol (Lurgi) process which uses a single solvent (methanol) to remove the last traces of tar and oil, carbon dioxide, hydrogen sulphide, organic sulphur, ammonia and phenol. The purified synthesis gas stream is partitioned and a part of the gas is passed through a fixed-bed catalytic reactor (Arge synthesis). Feed gas has a H_2/CO ratio of about 2:1 and synthesis occurs under conditions of $220^{o}C$ and 24.8 bar

The products of the Arge synthesis are straight-chain, high-boiling hydrocarbons, with some medium-boiling oils, diesel oil, L.P.G., and oxygenated compounds such as alcohols.

The portion of the synthesis gas which was not sent to the Arge unit goes to the Synthol plant (Kellogg synthesis) which is a fluidized-bed catalytic (iron) reactor. In this reactor, catalyst is circulated along with the synthesis gas. Gas and catalyst leaving the reactor are separated in cyclones and the catalyst is recycled. Operating conditions are 315^{o}-$330^{o}C$ and 22.5 bar

A portion of the Synthol plant tail gas is reformed with steam to increase the H_2/CO ratio to about 3:1, and is mixed with the fresh synthesis gas.

Reactor effluent gas is quenched in a scrubbing tower where the remaining catalyst dust is removed and returned to the reaction zone in the form of a heavy slurry oil.

The raw products from the synthesis require certain treatment and then final purification to make the specification products. From the gas phase, valuable hydrocarbon and chemical products are scrubbed out and recovered. The oil phase is treated catalytically to remove dissolved oxygenates and then distilled into gasoline and fuel oil fractions. The remaining liquor is distilled and fractionated to produce chemical products. Heavy alcohols to pentanol are also recovered.

A portion of tail gas from the Arge and Synthol synthesis plants is removed and used for utility gas.

6.2.4.3 Operating Conditions:

Synthesis Process	Catalyst	Temp. °C	Press bar	Products
Arge Fixed Bed	Iron/Cobalt	230	24.8	Petrol, L.P.G., Oil Wax, Gas
Kellogg Fluidized Bed	Iron	325	22.8	Petrol, Alcohol, Oil Gas

6.2.4.4 A materials balance and calculated overall thermal efficiency for raw coal is shown in Fig. 6.2.7.

About 85 percent of the coal is available for production of synthesis gas, the remainder being consumed in production of process heat and electric power.

Liquid product yield is 11.3 percent.

Overall thermal efficiency is 38 percent.

6.2.4.5 A materials balance and calculated overall thermal efficiency for washed coal is shown in Fig. 6.2.8.

About 86 percent of the coal is available for production of synthesis gas, the remainder being consumed in production of process heat and electric power.

Liquid product yield is 15.5 percent.

Overall thermal efficiency is 39 percent.

6.2.4.6 Commercial Production plant

The coal feed rate of the commercial production plant should be 18,000,000 t/a of run of mine coal.

The on stream factor should be 330 d/a. For such capacity the major primary process units are as follows:

LURGI GASIFICATION / FISCHER TROPSCH SYNTHESIS 1
RAW COAL

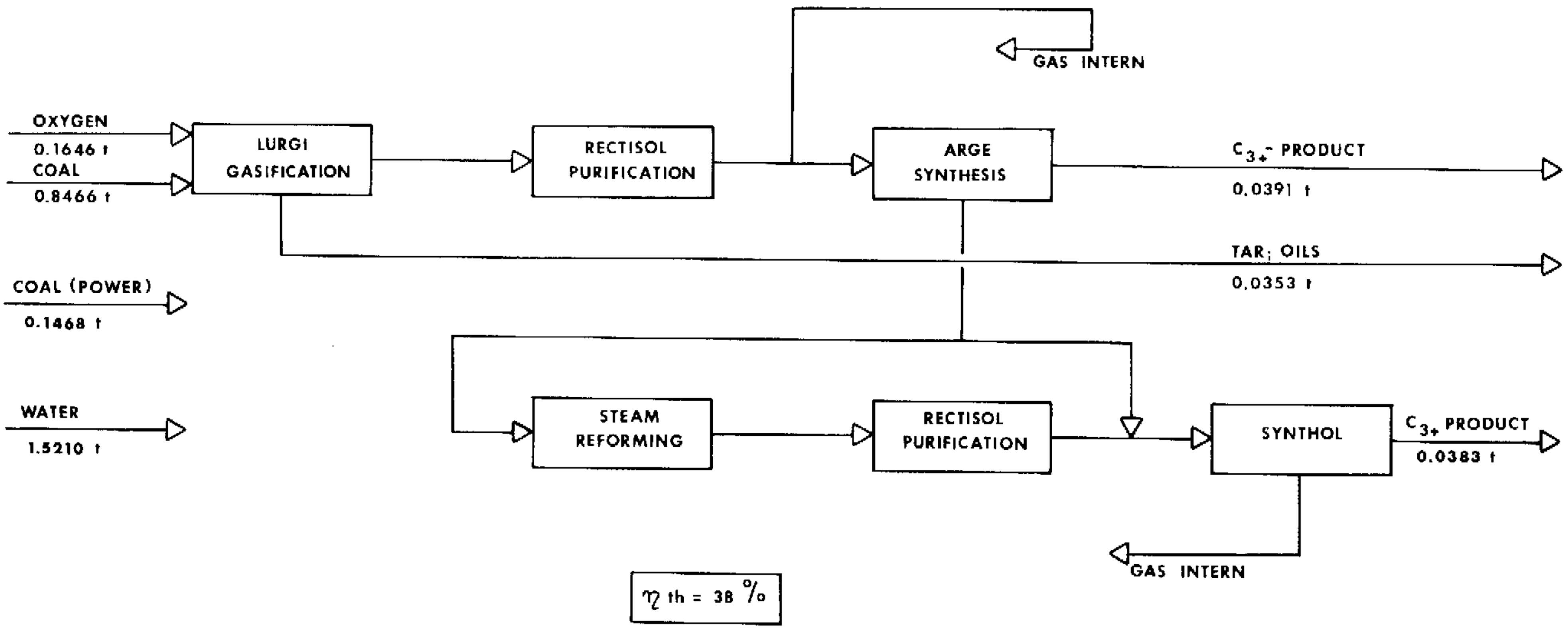

FIG. 6.2.7

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LURGI GASIFICATION / FISCHER-TROPSCH SYNTHESIS 1
WASHED COAL

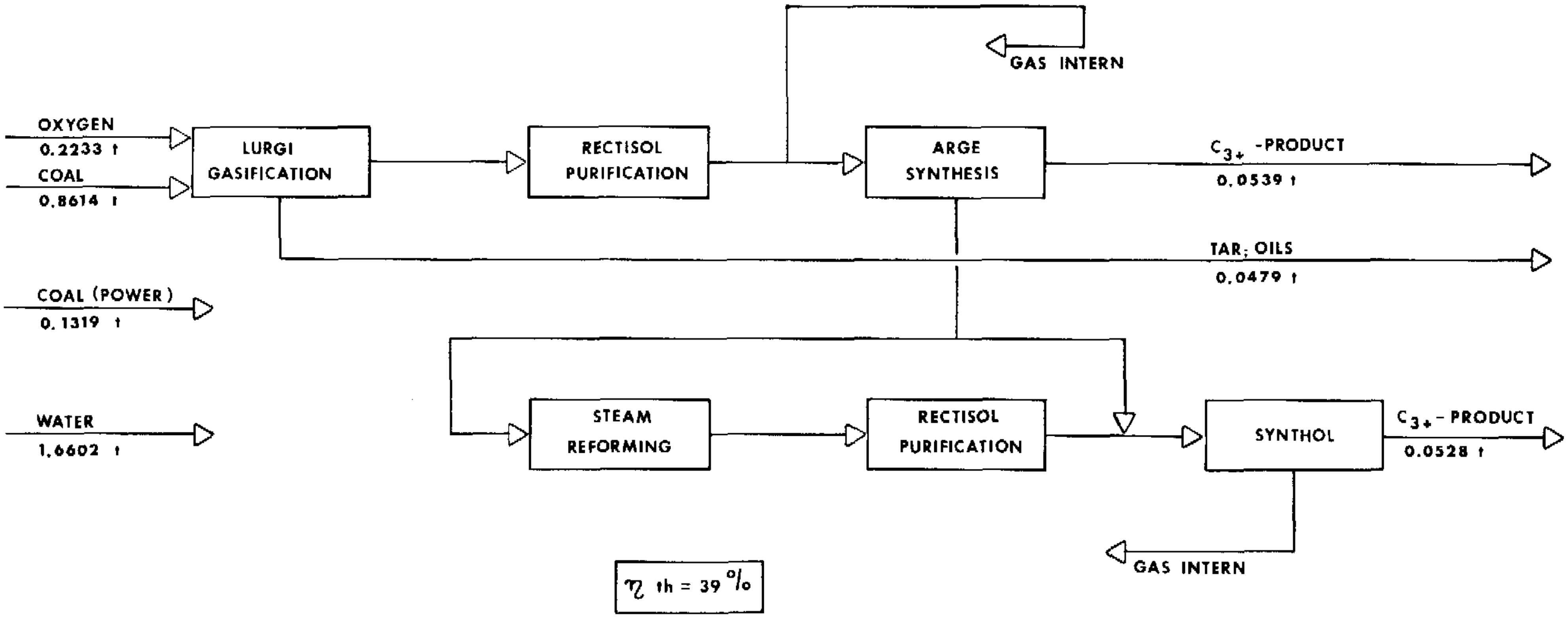

FIG. 6.2.8

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- LURGI gasification unit with 40 gasifiers
- Rectisol purification unit with 5 trains
- ARGE synthesis unit with 45 reactors
- KELLOG synthesis unit with 5 reactors
- STEAM reforming unit with 8 trains

Other primary process units are:

- Units for processing gas by-products
- Units for processing primary F-T-synthesis products to motor fuels and F-T by-products.

Secondary process units are:

- Sulphur recovery and tail gas clean-up units
- Oxygen unit
- Chemicals recovery unit
- Cooling water unit
- Water treatment unit
- Auxiliary steam and power generation unit
- Storage unit

Feed and products

Feed

18,000,000	t/a run of mine coal
36,500,000	t/a river water

Primary products

703,600 t/a C_3^+ - ARGE-Products

699,200 t/a C_3^+ - KELLOGG-Products

635,800 t/a Tar and Oils

2,038,600 t/a liquid products

Products

1,495,400 t/a motor fuel

168,900 t/a F-T by-products

262,600 t/a gasification by-products

1,926,900 t/a total products

Capital costs

Investment cost: 1225 . 10^6 CDN \$

Working capital: 80 . 10^6 CDN \$

Costs for chemicals and catalyst

Chemicals : 11.2 . 10^6 CDN \$/a

Catalyst : 0.8 . 10^6 CDN \$/a

Manpower requirements

930 employees

Land

3,500,000 m^2.

6.2.4.7 Liquids products by LURGI - gasification combined with Kellog-synthesis.

The process description was given in para 6.2.4.2.

6.2.4.8 A material balance and calculated overall thermal efficiency is shown in Fig. 6.2.9 for raw coal.

About 75 percent of the coal is available for production of Synthesis gas, the remainder being required for fuel gas and power generation.

Liquid products yield is 9.9 percent of raw coal feed.

Overall thermal efficiency is 34 percent.

6.2.4.9 A material balance and calculated overall thermal efficiency is shown in Fig. 6.2.10 for washed coal.

About 76 percent of the coal is available for production of Synthesis gas, the remainder being required for fuel gas and power generation.

Liquid products yield is 13.6 percent of washed coal feed.

Overall thermal efficiency is 35 percent.

6.2.4.10 Commercial production plant
The coal feed rate of the commercial production plant is taken to be 18,000,000 t/a of run of mine coal.

On stream factor is 330 d/a. For this capacity the major primary process units are:

- LURGI gasification unit with 36 gasifiers
- CO shift conversion unit with 10 trains
- Rectisol purification unit with 4 trains
- KELLOG synthesis unit with 9 reactors
- Steam reforming unit with 7 trains

Other primary process units are:

- Units for processing gas by-products
- Units for processing primary F-T-synthesis products to motor fuels and F-T by-products.

Secondary process units included are:

- Sulphur recovery and tail gas clean-up-units
- Oxygen unit
- Chemicals recovery unit
- Cooling water unit
- Water treatment unit
- Auxiliary steam and power generation unit
- Low pressure gasification unit
- Storage unit

Feed and products

Feed
18,000,000 t/a run of mine coal
31,920,000 t/a river water

LURGI GASIFICATION
FISCHER-TROPSCH-SYNTHESIS II
RAW COAL

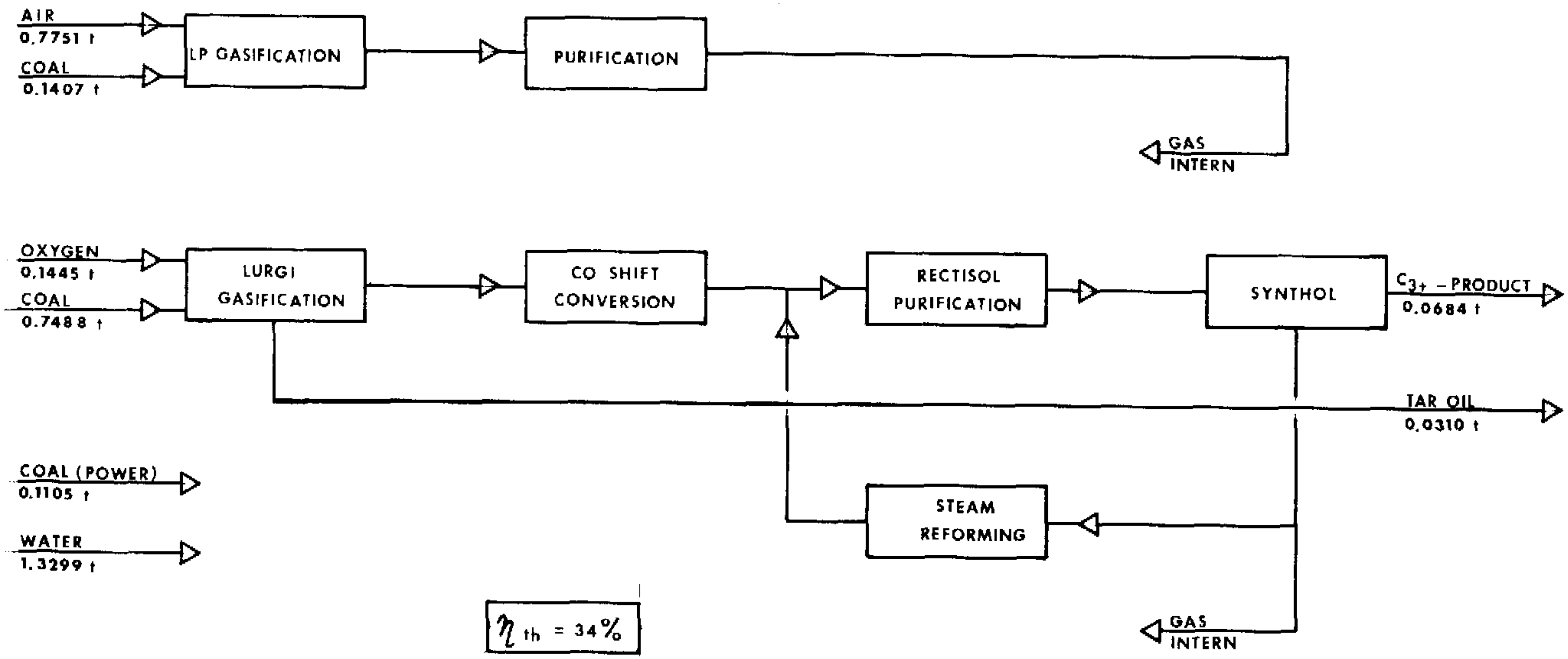

FIG. 6.2.9

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LURGI GASIFICATION
FISCHER - TROPSCH - SYNTHESIS II
WASHED COAL

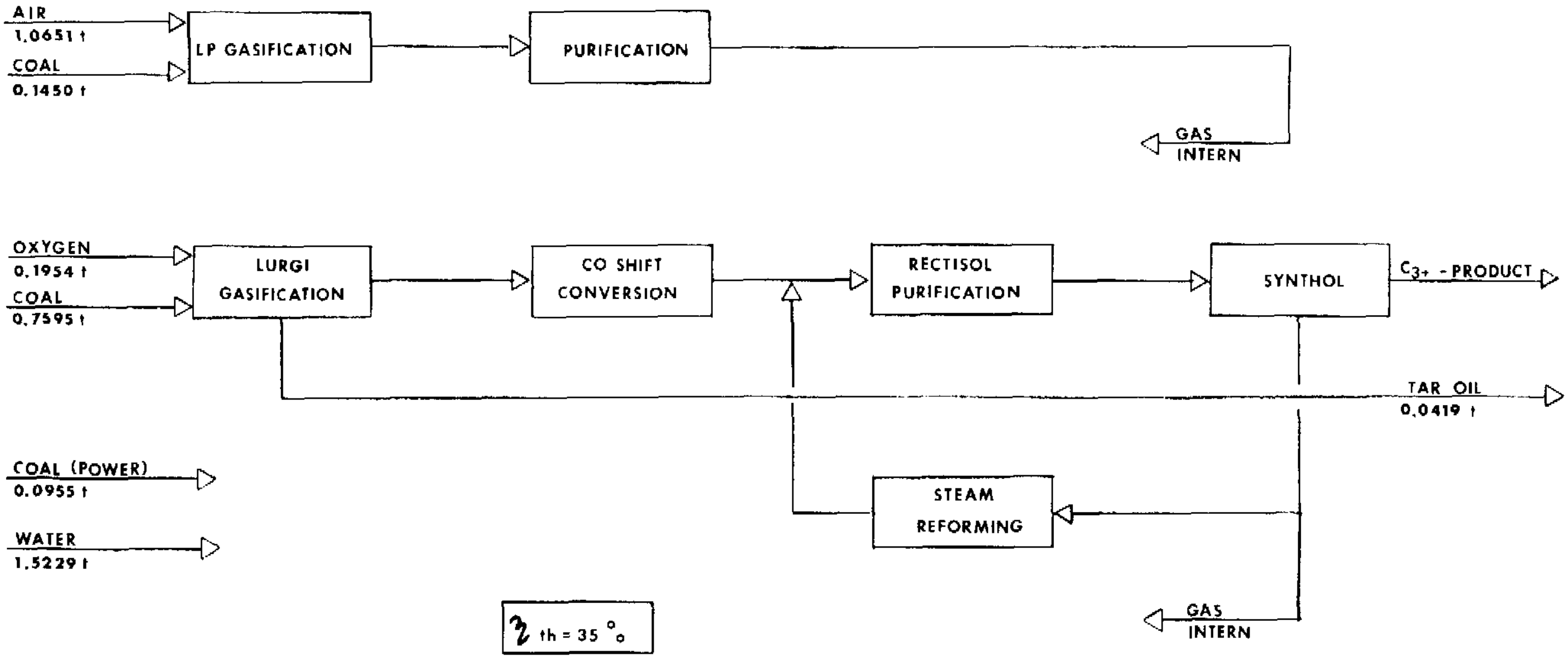

FIG. 6.2.10

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Primary products

1,230,500 t/a	C_3^+ -KELLOG-products
558,000 t/a	Tar and Oils
1,788,500 t/a	liquid products

Final products

1,267,200 t/a	motor fuel
236,700 t/a	F-T by-products
230,500 t/a	gasification by-products
1,734,400 t/a	

Capital costs

Investment cost: 1080 . 10^6 CDN $

Working capital: 72 . 10^6 CDN $

Costs for chemicals and catalysts

Chemicals: 10 . 10^6 CDN $/a

Catalysts: 0.8 . 10^6 CDN $/a

Manpower requirements

860 employees

Land

3,200,000 m^2

6.2.5 Production of Methanol

6.2.5.1 Methanol Synthesis

Methanol can be synthesized by the catalytic reaction of synthesis gas produced by any one of a number of commercially-available coal gasification processes which produce CO/H_2 mixtures. Suitable gas for the catalytic production of methanol utilizing conventional zinc-chromium (high pressure) or copper-zinc-chromium (low to moderate pressures) catalysts is produced by passing the raw gas from the gasifier through a conventional water-gas shift conversion to adjust the H_2:CO ratio in the gas to 2:1. After purification, this $2H_2$:1CO gas is sent to the catalytic reactor operating at about 260°C and 52-310 bar (depending on the catalyst) where methanol is formed by the following reactions:

$$CO + 2H_2 = CH_3OH \text{ (methanol)}$$
$$CO_2 + 3H_2 = CH_3OH + H_2O$$

Methanol formed in the catalytic converter is condensed and recycle gas is separated for return to the converter. The raw methanol is distilled for purification and higher alcohols (through pentanol) are recovered as residue together with other organic compounds.

The commercial-scale production of methanol via the catalytic synthesis of coal-derived synthesis gas has been practiced in many countries for a great many years, primarily based on Koppers-Totzek, Lurgi and Winkler gasifiers.

6.2.5.2 Using Lurgi gasification

A materials balance and overall thermal efficiency is shown in Fig. 6.2.11 for raw coal.

About 77 percent of the raw coal feed is available for synthesis gas production.

Methanol yield is 0.137t/t raw coal feed.
Methane yield is 62 m^3/t raw coal feed.

Overall thermal efficiency is 56 percent.

6.2.5.3 A materials balance and overall thermal efficiency is shown in Fig. 6.2.12 for washed coal. About 78 percent of the coal feed is available for synthesis gas production.
Methanol yield is 0.188 t/t of washed coal feed.
Methane yield is 85m^3/t of washed coal feed.
Overall thermal efficiency is 58 percent of washed coal feed.

6.2.5.4 Commercial production plant

The coal-feed for the methanol production plant should be 3 . 10^6 t/ a run-of-mine coal. The on-stream factor is fixed at 330 days/ a.

For this capacity the major primary units are as follows:

- LURGI-gasification-unit with 6 gasifiers including quench- and waste-heat systems,

- CO-shift conversion-unit
- Rectisol purification with 2 trains
- Methanol-synthesis

Secondary process-units

- Oxygen-plant
- Power- and steam plant
- Make-up water unit
- Cooling water unit
- Sulphur-recovery
- Gas-water treatment
- Synthesis-gas compression

Feed and Products

Feed

Coal	3.0	. 10^6 t/a
Steam	1.557	. 10^6 "
Oxygen	0.455	. 10^6 "

Products

Methanol	411	x 10^3 t/a
SNG (methane)	186	. 10^3 m3/a
Tar	31.2	. 10^3 t/a
Oil	31.2	. 10^3 "
Naphtha	24	. 10^3 "
Phenols	7.5	. 10^3 "
Sulphur	5.7	. 10^3 "

BASE SCHEME FOR METHANOL PRODUCTION
LURGI - PROCESS RAW COAL

η = 56.38%

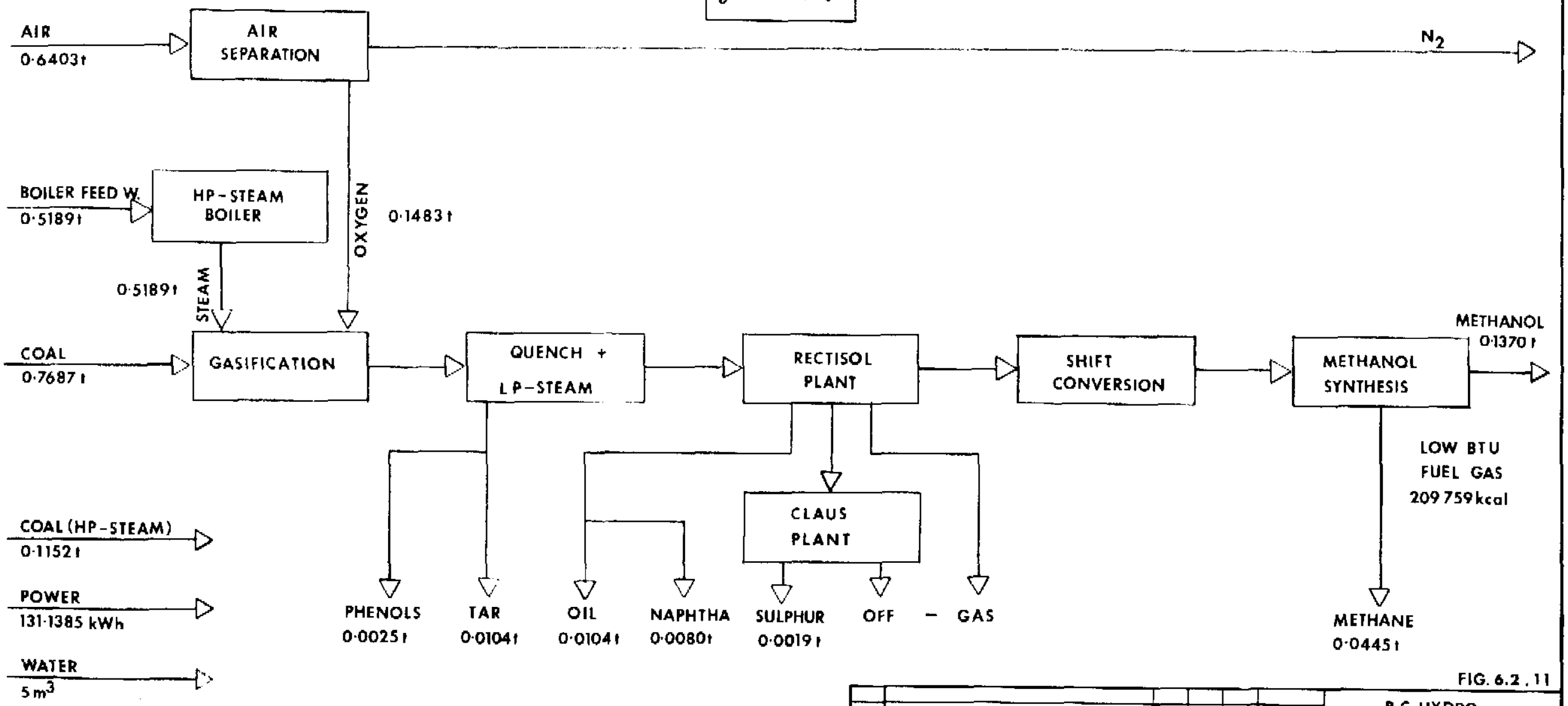

FIG. 6.2.11

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BASE SCHEME FOR METHANOL PRODUCTION
LURGI - PROCESS WASHED COAL

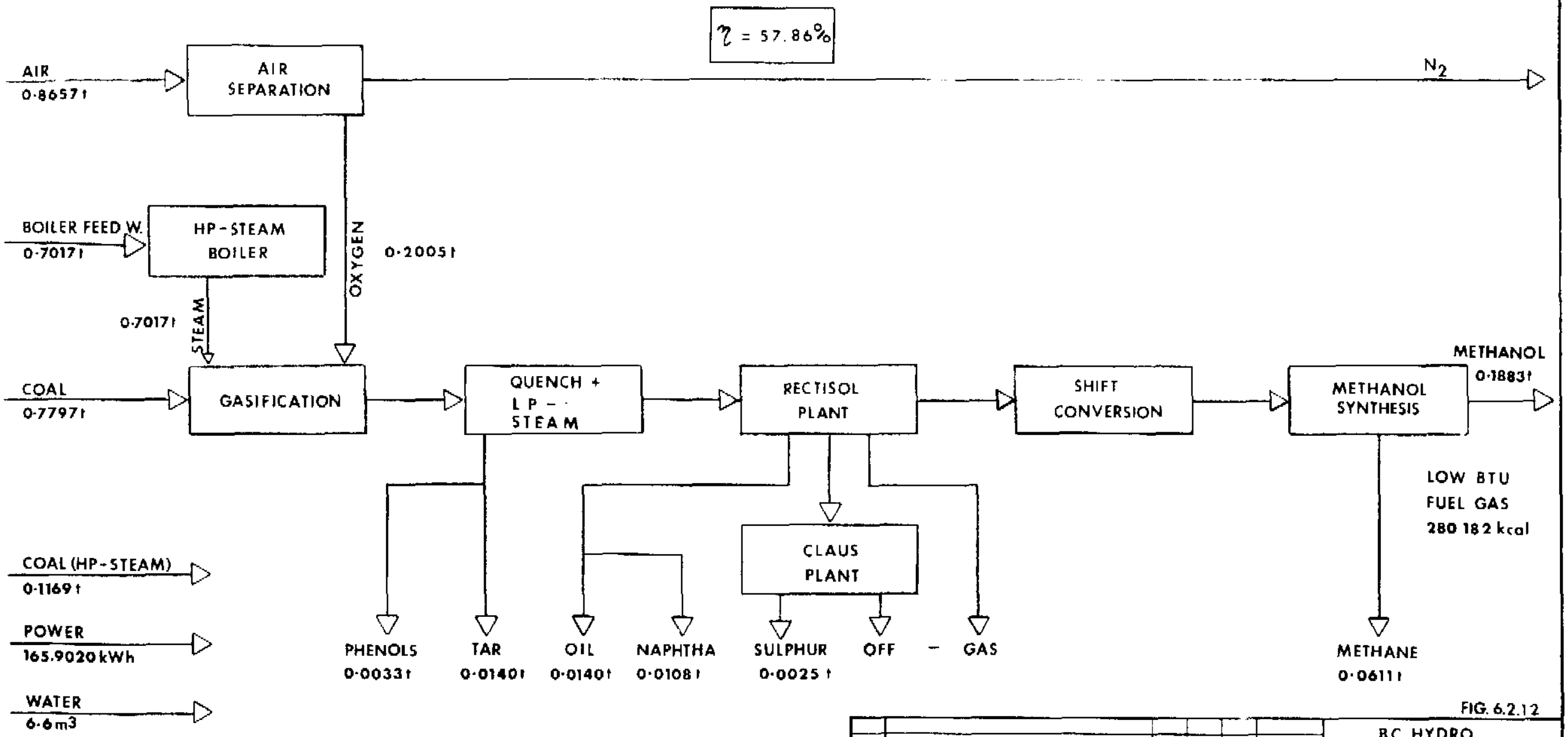

FIG. 6.2.12

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Capital costs

Investment cost:	$180 \cdot 10^6$ CDN $
Working capital:	$9 \cdot 10^6$ CDN $

Costs for chemicals and catalysts

Chemicals and catalysts	$0.62 \cdot 10^6$ CDN $

Manpower requirements

Operators	100

Land

Plant area required	$0.75 \cdot 10^6$ m^2

6.2.5.5 Using Koppers-Totzek gasification

A material balance and calculation of thermal efficiency for raw coal is shown in Fig. 6.2.13.

About 99 percent of the coal is available for producing synthesis gas.

Methanol yield is 0.226 t/t raw coal feed.
Methane yield is 113 m^3/t raw coal feed.

Overall thermal efficiency is 42 percent.

6.2.5.6 A material balance and calculation of thermal efficiency for washed coal is shown in Fig. 6.2.14.

All the coal is available for production synthesis gas.

Methanol yield is 0.338 t/t washed coal feed.
Methane yield 85 m3/t washed coal feed.

Overall thermal efficiency is 47 percent.

6.2.5.7 Commercial production plant

The coal-feed for the methanol production plant should be 3 . 10^6 t/ a run-of-mine coal. The on-stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- KOPPERS-gasification-unit with 8 gasifiers

- CO-shift conversion-unit
- Rectisol purification with 2 trains
- Methanol-synthesis

Secondary process-units
- Oxygen-plant
- Power- and steam plant
- Make-up water unit
- Cooling water unit
- Sulphur-recovery
- Gas-water treatment
- Synthesis-gas compression

BASE SCHEME FOR METHANOL PRODUCTION

KOPPERS-TOTZEK PROCESS RUN-OF-MINE COAL

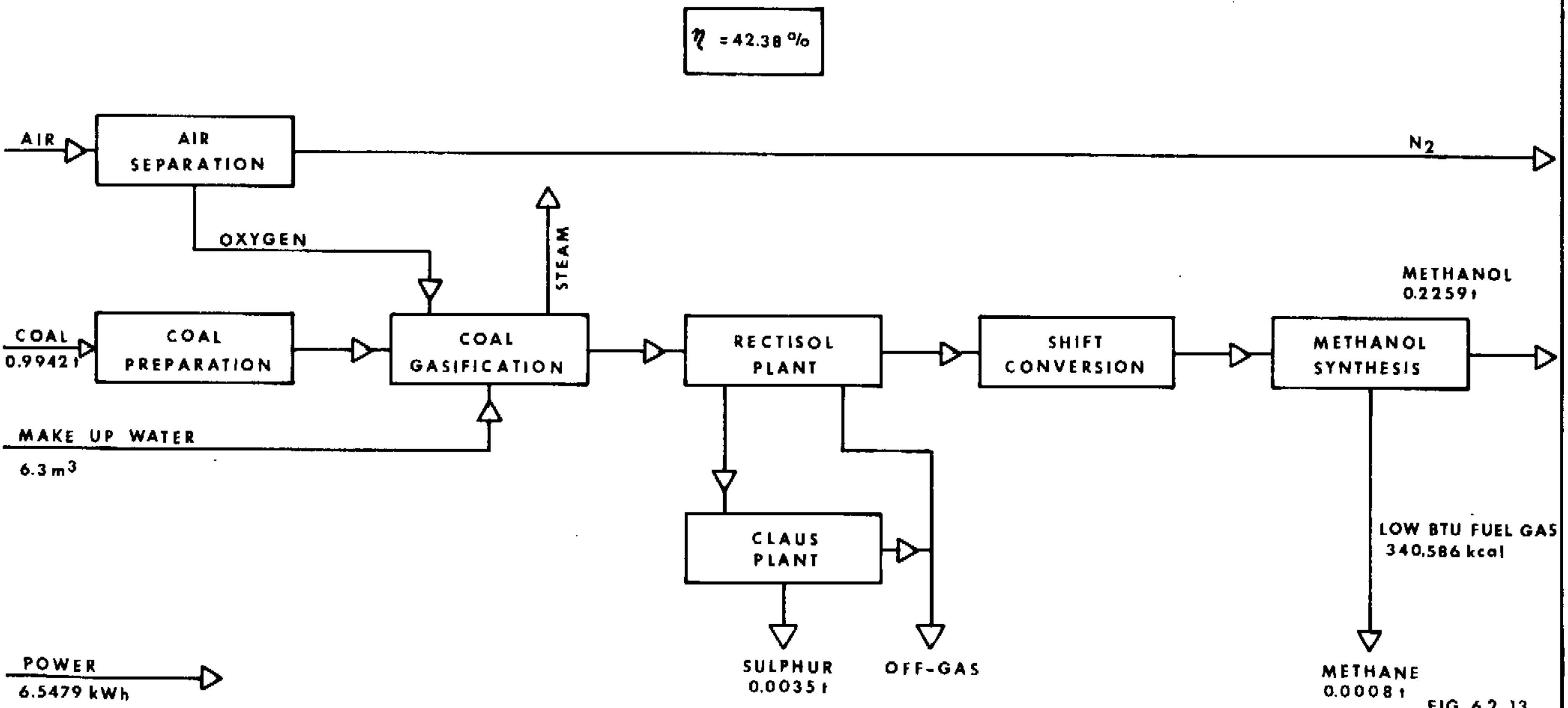

FIG. 6.2.13

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BASE SCHEME FOR METHANOL PRODUCTION
KOPPERS-TOTZEK PROCESS BENEFICIATED COAL

η = 47,37 %

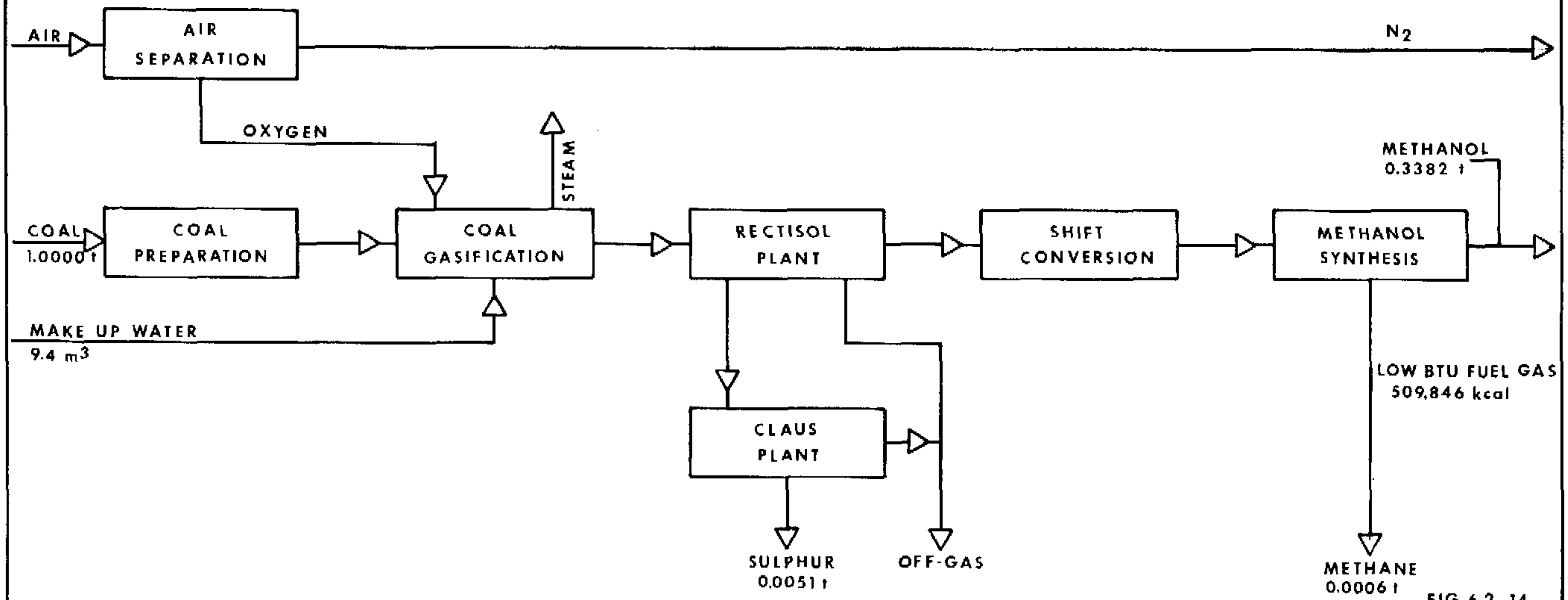

FIG. 6.2.14

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6.2.5.8 Feed and products

Feed

Coal for gasification	$2.9826 . 10^6$ t/a
Coal for power generation	$0.0174 . 10^6$ t/a

Products

Methanol	$0.6777 . 10^6$ t/a
Sulphur	$10.500 . 10^3$ t/a
Methane	$3.348 . 10^6$ m^3

Capital costs

Investment cost:	$200 . 10^6$ CDN \$
Working capital:	$10 . 10^6$ CDN \$

Costs for chemicals and catalysts

Chemicals and catalysts:	$1.0 . 10^6$ CDN \$/a

Manpower requirements

operators	100

Land

plant area required $0.75 . 10^6$ m^2

6.2.5.9 Using WINKLER gasification

A materials balance and calculation of overall thermal efficiency is shown in Fig. 6.2.15 for raw coal.

About 93 percent of the raw coal is available for synthesis for production.

Methanol yield is 0.214 t/t raw coal
Methane yield is 16 m^3/t raw coal

Overall thermal efficiency is 45 percent.

6.2.5.10 A materials balance and calculation of overall thermal efficiency is shown in Fig. 6.2.16 for washed coal.

About 94 percent of the washed coal is available for synthesis for production.

Methanol yield is 0.308 t/t washed coal
Methane yield is 21 m^3/t washed coal

Overall thermal efficiency is 48 percent.

6.2.5.11 Commercial production plant

The coal-feed for the methanol production plant should be 3 . 10^6 t/a run-of-mine coal. The on-stream factor is fixed at 330 days/a.

BASE SCHEME FOR METHANOL PRODUCTION
WINKLER-PROCESS RUN-OF-MINE-COAL

$\eta = 45.28\,\%$

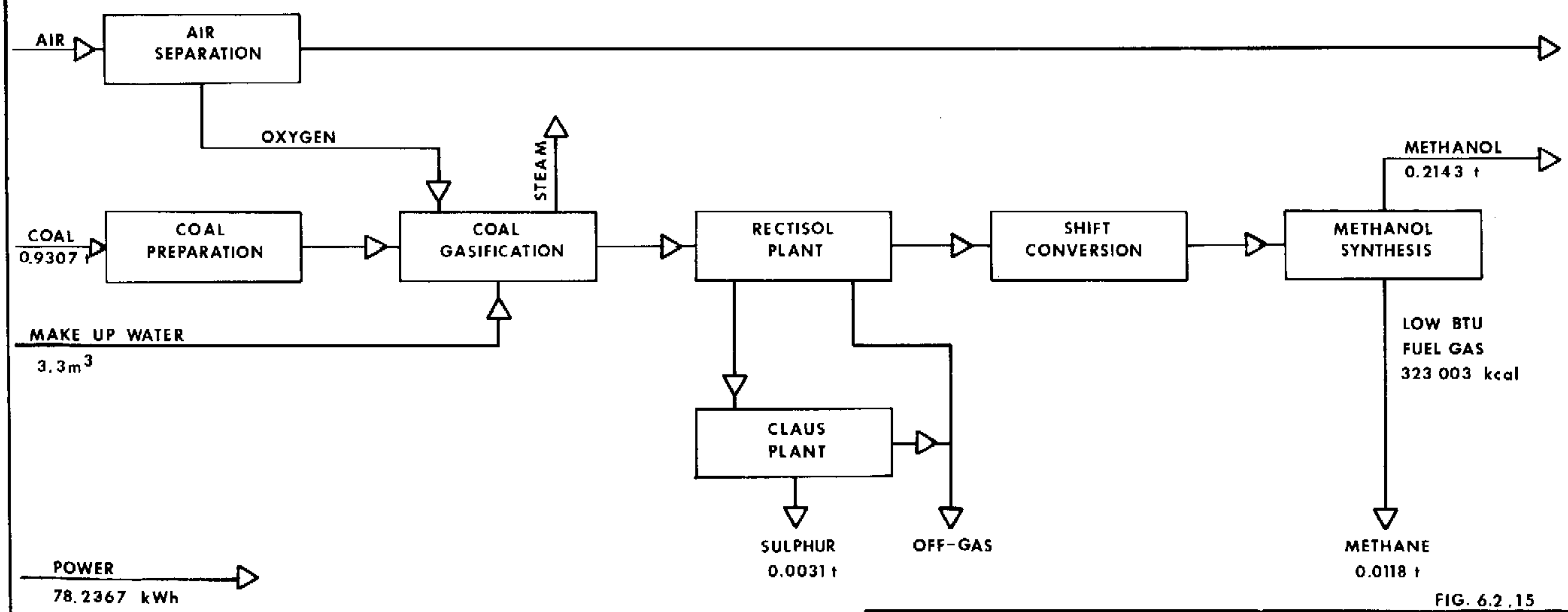

FIG. 6.2.15

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BASE SCHEME FOR METHANOL PRODUCTION
WINKLER PROCESS - BENEFICATED COAL

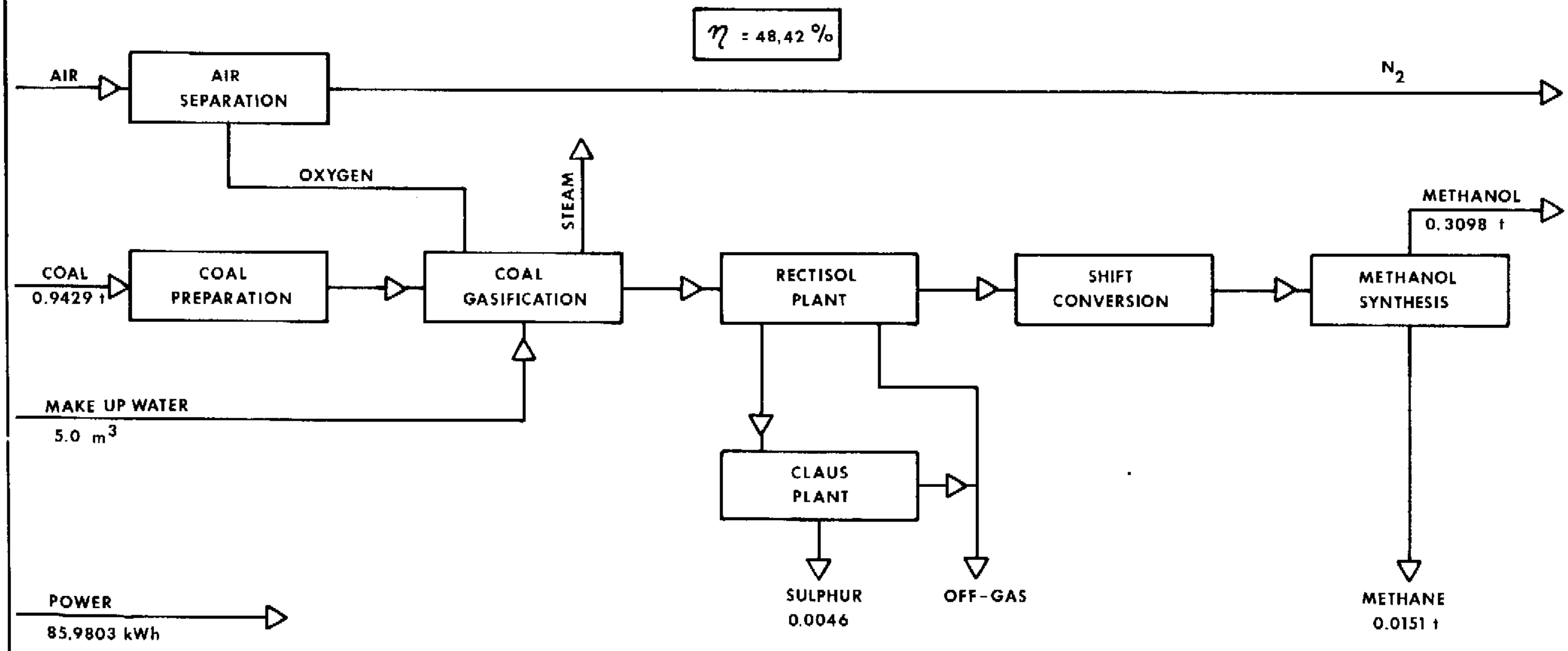

FIG. 6.2.16

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For this capacity the major primary units are as follows:

- WINKLER-gasification-unit with 8 gasifiers

- CO-shift conversion-unit
- Rectisol purification with 2 trains
- Methanol-synthesis

Secondary process-units

- Oxygen-plant
- Power- and steam plant
- Make-up water unit
- Cooling water unit
- Sulphur-recovery
- Gas-water treatment
- Synthesis-gas compression

Feeds and products

Feeds

Coal for gasification	2.792 . 10^6 t/a
Coal for power-generation	0.208 . 10^6 t/a
total	3.000 . 10^6 t/a

Products

Methanol	642.900 . 10^3 t/a
Sulphur	9.300 t/a
Methane	49.386 . 10^6 m^3/a

Capital costs

Investment cost: 200 . 10^6 CDN \$

Working capital: 10 . 10^6 CDN \$

Costs for chemicals and catalysts

Chemicals and

Catalysts: 0.9 . 10^6 CDN \$/a

Manpower requirements

operators 100

Land

plant area required 0.75 . 10^6 m^2

6.3 PRINCIPALLY GASEOUS PRODUCTS

6.3.1 SNG Production by the Lurgi Pressure Gasification Route

6.3.1.1 Process Developer:

Lurgi Gesellschaft für Wärme- und Chemotechnik mbh, Frankfurt, West Germany.

6.3.1.2 Licensor:

Lurgi Mineraloltechnik GmbH.

Note: The Lurgi group of companies are subsidiaries of Metallgesellschaft AG of Frankfurt (Main), West Germany.

6.3.1.3 Description:

Crushed and dried coal is fed to a moving-bed gasifier where gasification of coal takes place at 24 - 31 bar. Initial devolatisation occurs accompanied by gasification in the temperature range of 615 to 760^{0}C. Residence time is about one hour. Steam is the source of hydrogen. Combustion of a portion of the char with oxygen supplies the necessary heat. A revolving grate at the base of the reactor supports the fuel bed, removes the ash, and introduces the steam and oxygen mixture. Crude gas leaving the gasifier at temperatures between 370 and 595^{0}C (depending on type of coal) contains tar, oil, naphtha, phenols, ammonia, plus coal and ash particulates. Quenching with oil removes tar and oil. Part of the gas passes through a shift converter. Gas from the shift converter is washed to remove naphtha and unsaturated hydrocarbons. Then CO_2, H_2S and COS are removed. The gas is methanated and pipeline gas is produced by final CO_2 removal and dehydration.

Methanation of Lurgi synthesis gas, using Lurgi's "Hot Gas Recycle (H.G.R.) Process" catalytic methanators, has been performed on a commercial scale at plants at Westfield, Scotland, Sasolburg, South Africa and at a Lurgi test plant in Austria*.

Synthesis gas from the gasifier is suitable for use as town gas, synthesis gas for ammonia, methanol, Oxo, and Fischer-Tropsch synthesis for high-purity hydrogen. The SASOL plant in South Africa utilising 13 gasifier units, has been operating commercially since 1954 and plans are in hand for expansion. The U.S. Bureau of Mines has a Lurgi-gasification pilot plant at Grand Forks, N. D. and the Office of Coal Research - American Gas Association sponsors "Lurgi Studies" as part of its R & D programme.

6.3.1.4 Operating Conditions:
Reactor - Fixed bed
Temperature $^{\circ}C$ - 615-760
Press bar - 24-31
Reactants - Coal-steam-O_2
Product (off gas) - 16,765 kJ/m^3

6.3.1.5 A materials balance and overall thermal efficiency for raw coal is shown in Fig. 6.3.1 based on 1t of raw coal feed.

About 78 percent of the feed is available for gasification and SNG production, the remainder being required for HP steam and power production.

The calculated methane yield is 152 m^3/t. Calculated overall thermal efficiency is 62 percent.

* Note: Conoco Methanation Co. is testing a fixed-bed catalytic methanator at Westfield, Scotland and Catalysts and Chemicals, Inc., is also developing fixed-bed methanation in a pilot plant at Louisville, Kentucky.

BASE SCHEME FOR SNG PRODUCTION
LURGI - PROCESS
RAW COAL

η = 61.89 %

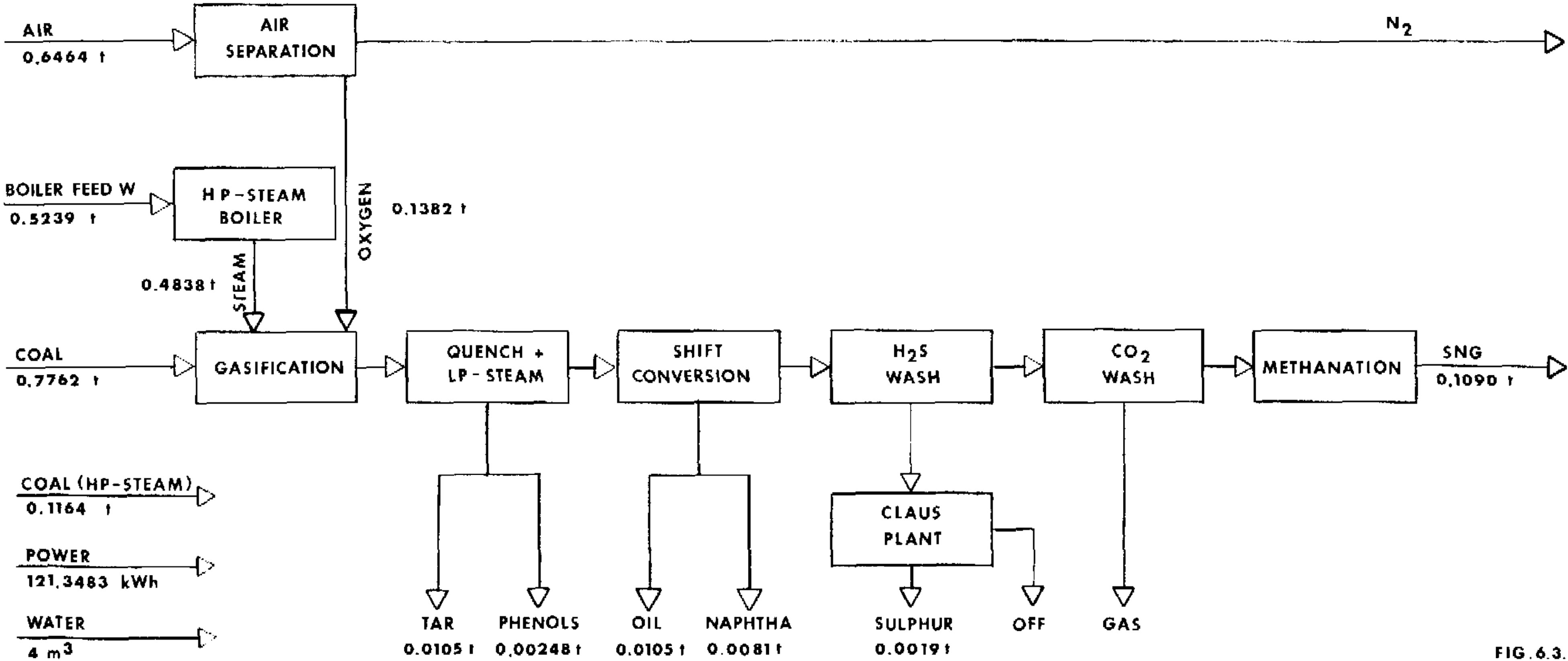

FIG. 6.3.1

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6.3.1.6 A materials balance and overall thermal efficiency for washed coal is shown in Fig. 6.3.2 based on 1t of raw coal feed.

The calculated methane yield is 209 m^3/t. Calculated overall thermal efficiency is 64 percent.

6.3.1.7 Commercial Production Plant

The coal feed for the SNG plant should be 18 . 10^6 t/a run-of-mine coal. The on stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- LURGI gasification-unit with 30 gasifiers* including quench-and waste-heat-systems
- CO-shift conversion unit with 3 trains including waste-heat recovery
- Rectisol purification with 3 trains
- Methanation unit with 5 trains
- Units for processing gas by-products

Secondary process units:

- Oxygen unit
- Power and steam plant
- Make-up water unit
- Cooling water unit
- Sulphur-recovery
- Gas-water treatment

* 5 metre diameter gasifiers currently under test at Sasolburg, South Africa.

Feeds and Products

Feeds	
coal for gasification	13.972 . 10^6 t/a
coal for HP-steam	2.095 . 10^6 t/a
coal for power-generation	1.933 . 10^6 t/a
Total	18.000 . 10^6 t/a
Steam	9,430 . 10^6 t/a
Oxygen	2,695 . 10^6 t/a
Products	
SNG (calculated as methane)	2,785 . 10^9 m3/a
Tar	189 . 10^3 t/a
Oil	189 . 10^3 t/a
Naphtha	145 . 10^3 t/a
Phenols	45 . 10^3 t/a
Sulphur	34 . 10^3 t/a

BASE SCHEME FOR SNG - PRODUCTION
LURGI - PROCESS
WASHED COAL

η - 63,55 %

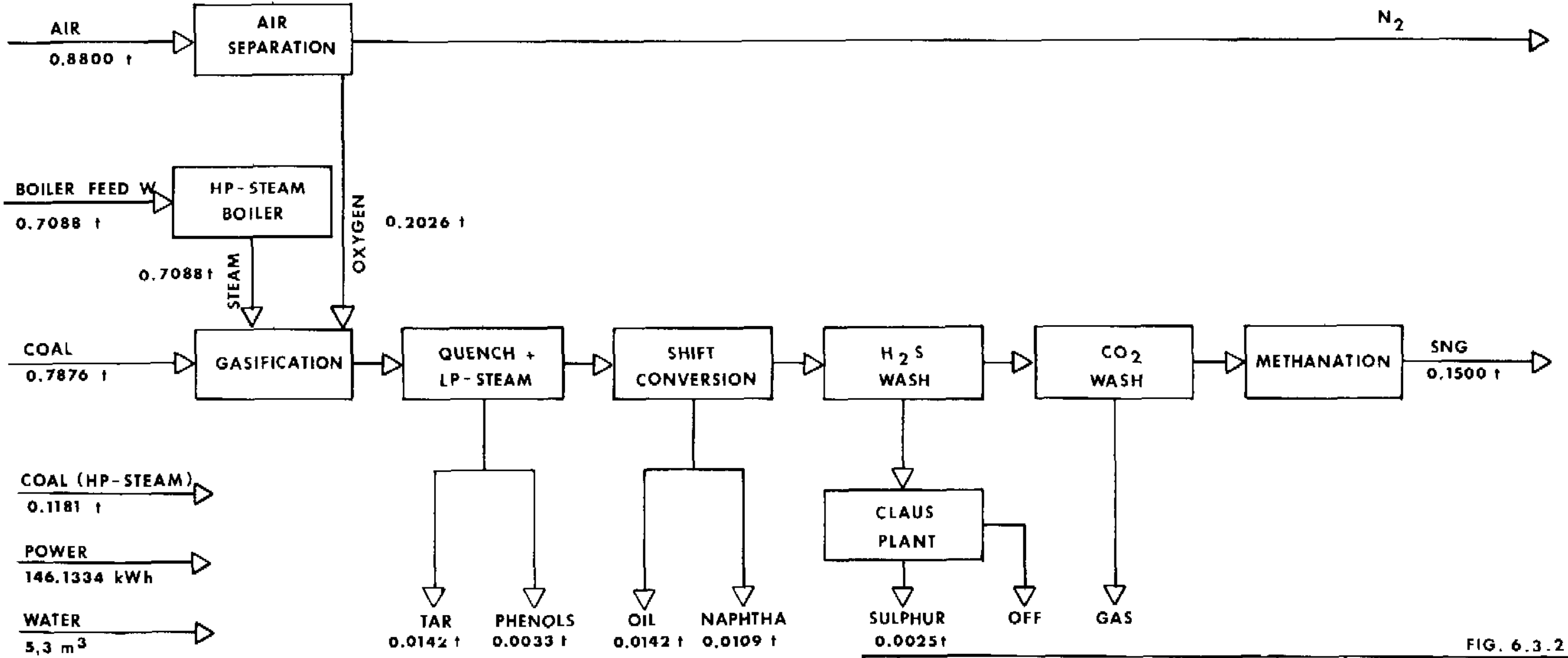

FIG. 6.3.2

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Capital costs

Investment cost: $\$\ 889 \times 10^{6}$ CDN

Working capital: $\$\ 44 \times 10^{6}$ CDN

Costs for chemicals and catalysts

Chemicals: $\$3.058 \times 10^{6}$ CDN

Catalysts: $\$2.255 \times 10^{6}$ CDN

Manpower requirements

470 employees

Land

Plant area required $2.6 \times 10^{6}\ m^{2}$

6.3.2 SNG by the Koppers-Totzek Gasification Route

6.3.2.1 Process Developer:

Heinrich Koppers GmbH, Essen, West Germany.

6.3.2.2 Sponsor:

Federal Government of the Republic of West Germany.

6.3.2.3 Description:

The gasifier is a refractory-lined, horizontal, cylindrical vessel with conical ends. Oxygen, steam and coal react at about atmospheric pressure and 1,815^{o}C. Fixed carbon and volatile matter are gasified to produce offgas containing carbon monoxide and hydrogen. Coal ash is converted into molten slag a proportion of which drops into a water-quench tank, the remainder carried by the gas. Low-pressure steam is circulated around burners and refractory to cool them as well as producing process steam. Gas leaving the gasifier is quenched with water to solidify entrained molten ash. After passing through a waste-heat boiler, the gas is scrubbed to remove entrained solids. Scrubbed gas is compressed to 31 bar, hydrogen sulphide and a controlled quantity of carbon dioxide is removed by purification. The purified gas is then shifted and methanated, the methanated gas dehydrated and purified to remove carbon dioxide. Dry, pulverised coal of any type may be used.

6.3.2.4 Operating Conditions:

Reactor type - Entrained fuel
Temperature ^{o}C - 1,815
Pressure - Atmospheric
Reactants - Coal-steam-O_2
Product (raw gas) - 11,178 KJ/m^3

6.3.2.5 A materials balance and overall thermal efficiency, for raw coal is shown in Fig. 6.3.3 based on 1t of raw coal feed.

The calculated methane yield is 149 m^3/t. Overall thermal efficiency is calculated to be 49.7 percent.

6.3.2.6 A materials balance and overall thermal efficiency for washed coal is shown in Fig. 6.3.4 based on 1t of washed coal feed.

The calculated methane yield is 220 m^3/t. Overall thermal efficiency is 54.3 percent.

6.3.2.7 Commercial Production Plant

The coal feed for the SNG plant should be $18 \cdot 10^6$ t/a run-of-mine coal. The on stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- KOPPERS-TOTZEK gasification-unit with 48 gasifiers including quench-and waste-heat-systems
- Raw gas desulphuration unit
- CO-shift methanisation unit including waste-heat recovery

Secondary process units:

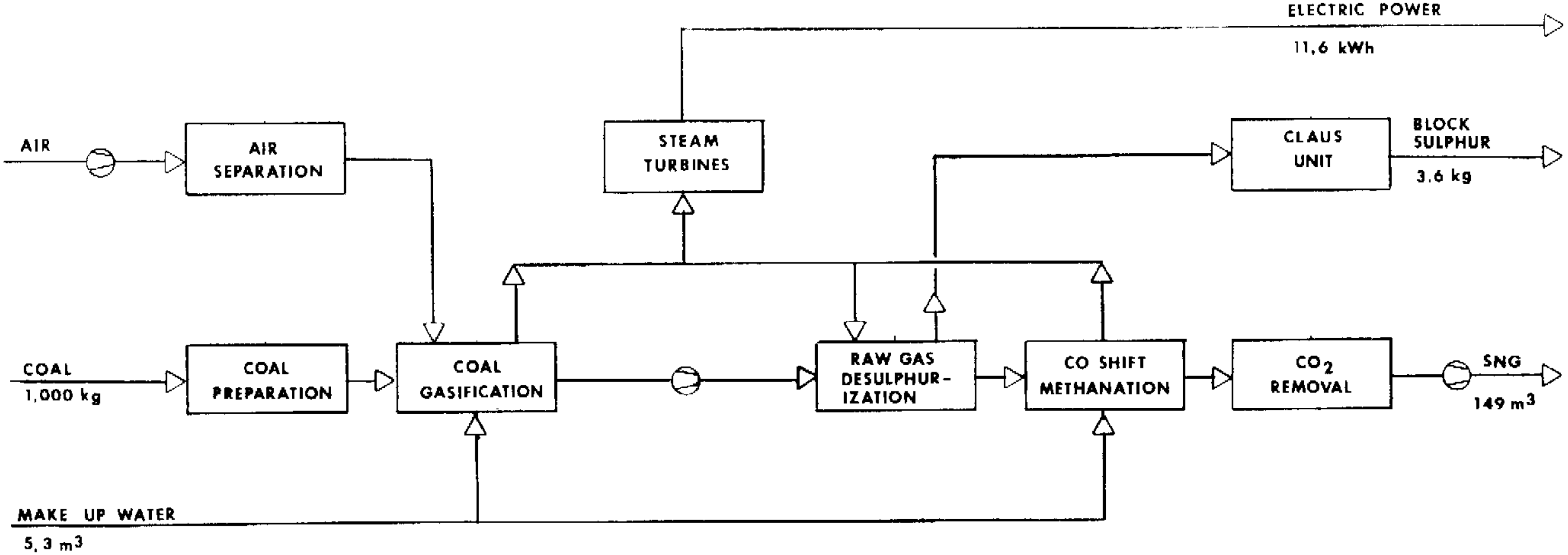
- Oxygen unit
- Power and steam plant
- Make-up water unit
- Cooling water unit
- Sulphur-recovery

Feeds and Products

Feeds	
Coal for gasification	18,000 . 10^6 t/a
Oxygen	8,460 . 10^6 t/a
Make-up water	95,400 . 10^6 m^3/a

Products	
SNG (calculated as methane)	2.920 . 10^9 m^3/a
Sulphur	64.8 . 10^3 t/a
Power-generation	208.8 . 10^6 kWh/a

BASE SCHEME FOR SNG PRODUCTION
KOPPERS-TOTZEK PROCESS RAW COAL



$\eta_{TH} = 49.7\ \%$

FIG. 6.3.3

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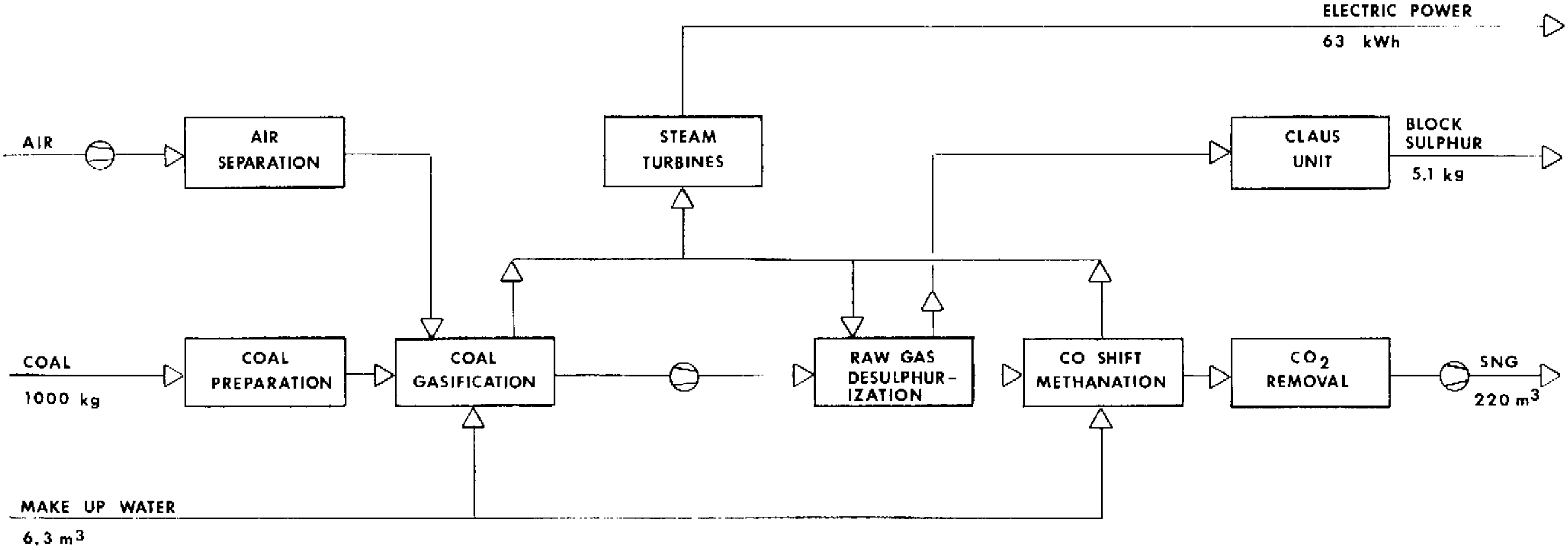
BASE SCHEME FOR SNG PRODUCTION
KOPPERS - TOTZEK PROCESS BENEFICATED COAL



$\eta_{TH} = 54.3\ \%$

FIG. 6.3.4

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6.3.3 SNG by the Winkler Gasification Route

6.3.3.1 Process Developers: Davy Powergas, Inc., Lakeland, Florida, a subsidiary of Davy International Ltd., London, and its affiliate, Bamag Verfahrens-Technik GmbH, (W. Germany.)

6.3.3.2 Description: Crushed coal is dried and fed to a fluidized bed gasifier through a variable-speed screw feeder. Coal reacts with oxygen and steam to produce offgas rich in carbon monoxide and hydrogen Because of the high temperatures, all tars and heavy hydrocarbons are reacted. About 70% of the ash is carried over by the gas and 30% is removed from the bottom of the gasifier by the ash screw. Unreacted carbon carried over by gas is converted by secondary steam and oxygen in the space above the fluidized bed. As a result, maximum temperature occurs above the fluidized bed. To prevent ash particles from melting and forming deposits in the exit duct, gas is cooled by a radiant boiler section before it leaves the gasifier. Raw gas leaving the gasifier is passed through a further waste-heat recovery section. Fly-ash is removed by cyclones, wet scrubbers and an electrostatic precipitator. Gas is then compressed and shifted. Gas from the shift converter is purified, methanated, dehydrated and compressed to pipeline quality. Thermal efficiency is 75%.

6.3.3.3

Gasifier Type	Temp. ^{o}C	Pressure	Reactants	Products
Fluidized Bed	815-980	Atmospheric	Coal-steam-O_2	10,245 KJ/m^3*

* Raw gas from gasifier up-graded by methanation to 35,770 KJ/m^3

Capital costs

Investment cost: $ 868 X 10^6 CDN
Working capital: 26 X 10^6 CDN

Costs for chemicals and catalyst

Chemicals and Catalyst: 0.8 X 10^6 CDN

Manpower requirements
350 operators

Land
900,000 m^2

6.3.3.4 A materials balance and overall thermal efficiency for raw coal is shown in Fig. 6.3.5, based on 1 t of raw coal feed.

Calculated methane yield is 157.4 m^3/t.

Calculated overall thermal efficiency is 50.8 percent. About 6 percent of coal feed is required for power generation.

6.3.3.5 A materials balance and overall thermal efficiency for washed coal is shown in Fig. 6.3.6, based on 1 t of washed coal feed.

Calculated methane yield is 225.1 m^3/t.

Calculated overall thermal efficiency is 55.2 percent. About 4 percent of the coal feed is required for power generation.

6.3.3.6 Commercial Production Plant

The coal feed for the SNG plant should be 18 . 10^6 t/a run-of-mine coal. The on stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- WINKLER gasification-unit with 46 gasifiers including quench- and waste-heat-systems;
- Raw gas desulphurization unit;
- CO-shift methanation unit including waste-heat recovery.

Secondary process-units:
- Oxygen unit
- Power- and steam plant
- Make-up mwater unit
- Cooling water unit
- Sulphur recovery.

Feeds and products

Feeds

Coal for gasification	$16.953 \cdot 10^6$ t/a
Coal for power generation	$1.047 \cdot 10^6$ t/a
Total	$18.000 \cdot 10^6$ t/a
Oxygen	$5.893 \cdot 10^6$ t/a
Make-up water	$34.585 \cdot 10^6$ t/a

Products

SNG (calculated as methane)	$2.833 \cdot 10^9$ m^3/a
Sulphur	$60 \cdot 10^3$ t/a

Capital costs

Investment cost - $900 \cdot 10^6$ CDN $

Working capital - $27 \cdot 10^6$ CDN $

Costs for chemicals and catalyst

Chemicals and
Catalyst - $0.85 \cdot 10^6$ CND $/a

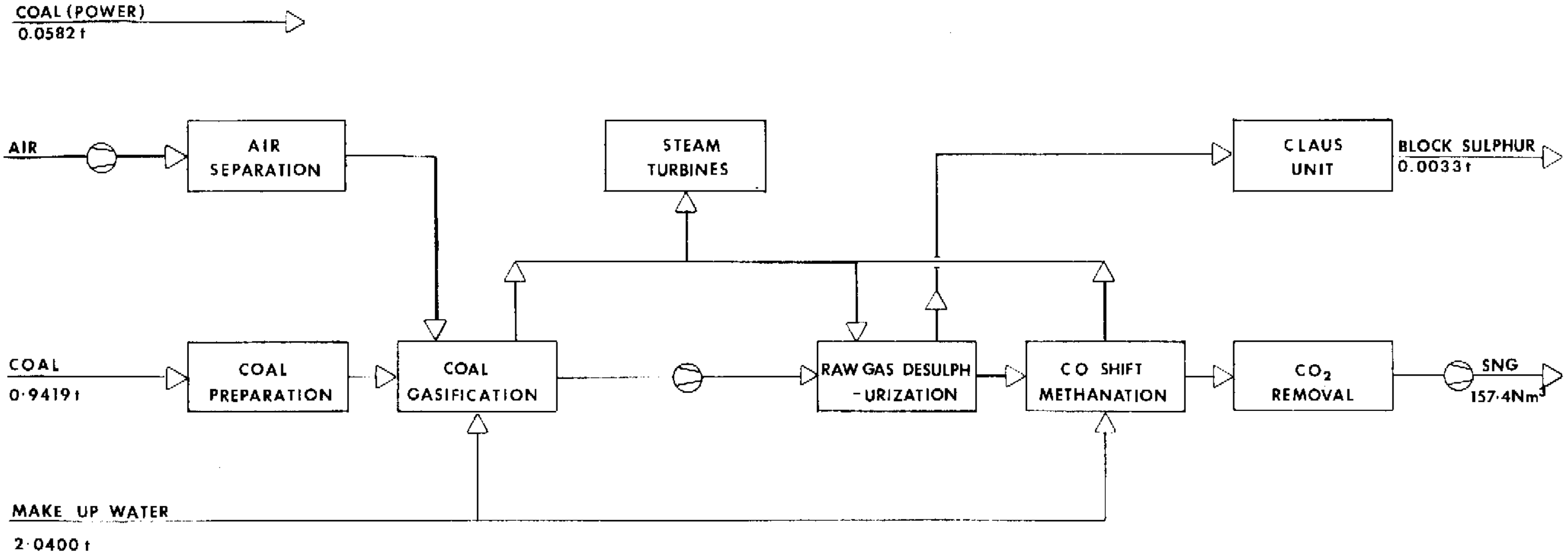
Manpower requirements

360 employees

Land

950,000 m^2

BASE SCHEME FOR SNG PRODUCTION
WINKLER PROCESS ROM COAL



$\eta_{TH} = 50{\cdot}8\ \%$

FIG 6.3.5

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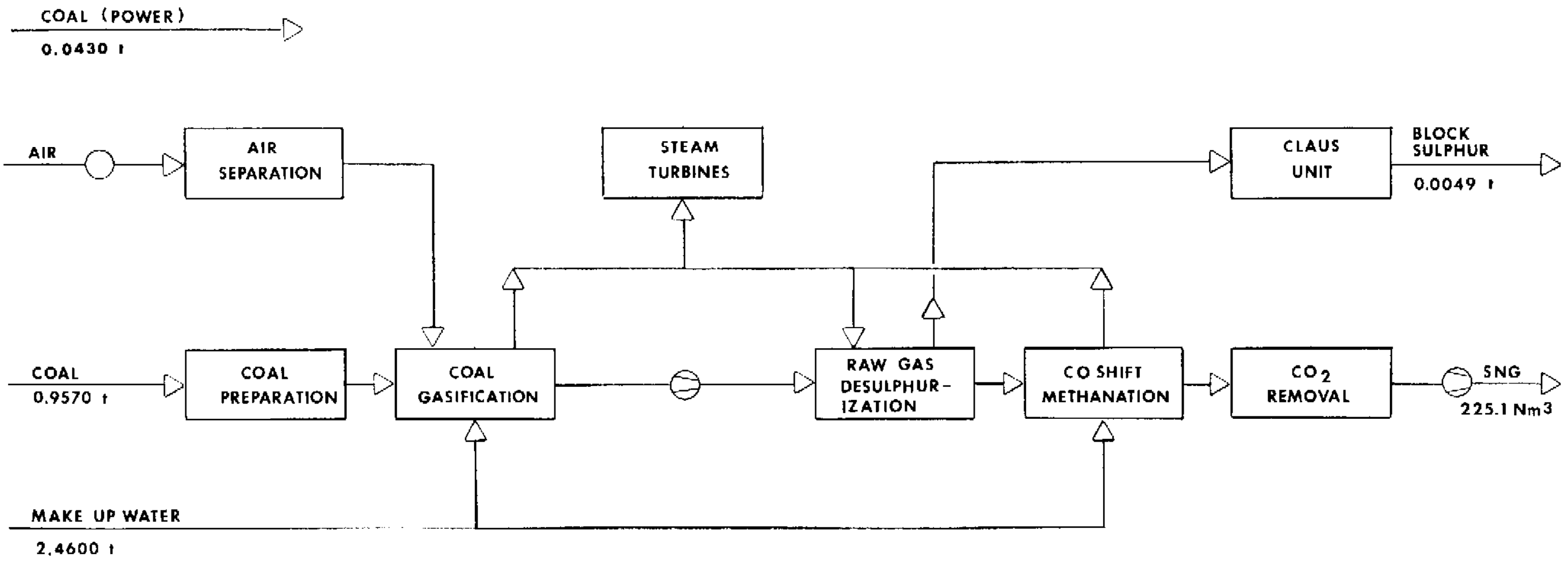
BASE SCHEME FOR SNG PRODUCTION
WINKLER – PROCESS BENEFICIATED COAL



$\eta_{TH} = 55.2\ \%$

FIG. 6.3.6.

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6.3.4 Production of Ammonia

6.3.4.1 Production of Ammonia using Lurgi Pressure Gasification

Process Description: The gasification step has been described in para. 6.3.1.3, omitting the methanation step.

The naturally formed methane is separated by a liquid nitrogen wash. The additional production of synthesis gas by reforming the methane was not investigated.

6.3.4.2 A materials balance and overall thermal efficiency for raw coal feed is shown in Fig. 6.3.7.

About 72 percent of the coal is available for synthesis gas production

Ammonia production is 0.159 t/t coal feed
Methane production is 58 m^3/t coal feed.

Calculated overall thermal efficiency is 59 percent.

6.3.4.3 A materials balance and overall thermal efficiency for washed coal feed is shown in Fig. 6.3.8.

About 73 percent of the coal is available for synthesis gas production.

Ammonia production is 0.2187 t/t coal feed
Methane production is 79 m^3/t coal feed.

Calculated overall thermal efficiency is 60 percent.

6.3.4.4 Commercial Production Plant

The coal feed for the ammonia synthesis plant should be 3 . 10^6 t/a run-of-mine coal. The on-stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- Lurgi gasification unit with 6 gasifiers including quench and waste heat systems
- CO-shift conversion unit with 2 trains including waste heat recovery
- rectisol purification with 2 trains
- liquid nitrogen wash, single train
- ammonia synthesis, single train.

Secondary process units:

- oxygen unit
- power and steam plant
- make-up water unit
- cooling water unit
- sulphur recovery
- gas water treatment
- synthesis gas compression.

Feed and products

Feed	
Coal for gasification	2.1504 . 10^6 t/a
Coal for HP steam	0.3222 . 10^6 t/a
Coal for power generation	0.5274 . 10^6 t/a
Total	3.000 . 10^6 t/a
Steam	1.4514 . 10^6 t/a
Oxygen	0.4146 . 10^6 t/a

BASE SCHEME FOR AMMONIA PRODUCTION
LURGI - PROCESS
RAW COAL

η = 58,52 %

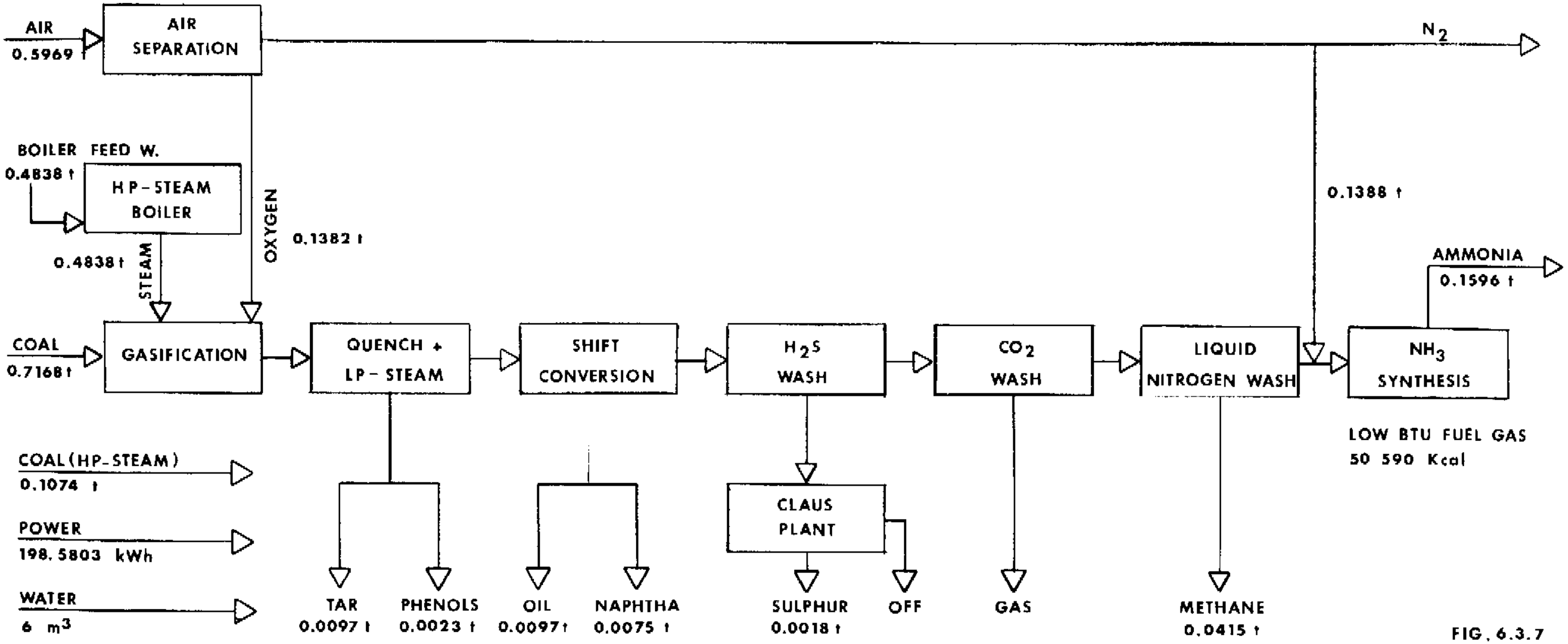

FIG. 6.3.7

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BASE SCHEME FOR AMMONIA PRODUCTION
LURGI - PROCESS
WASHED COAL

$\boxed{\eta = 59.95\,\%}$

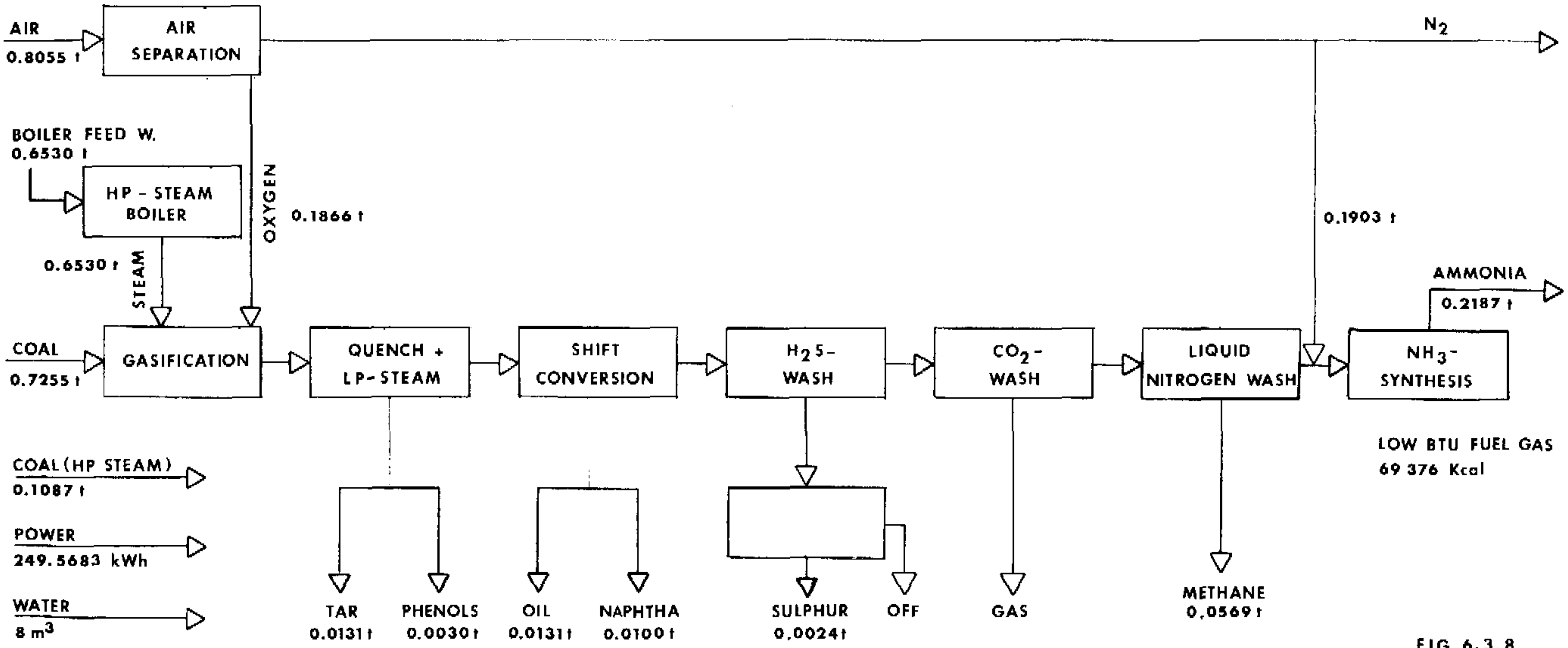

FIG. 6.3.8

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Products		
Ammonia	479	. 10^3 t/a
SNG (Methane)	173.689	. 10^6 m3/a
Tar	29.100	. 10^3 t/a
Oils	29.100	. 10^3 t/a
Naphtha	22.500	. 10^3 t/a
Phenols	6.900	. 10^3 t/a
Sulphur	5.400	. 10^3 t/a

Capital Costs	
Investment costs	228 . 10^6 CDN $
Working capital	15 . 10^6 CDN $

Costs for chemicals and catalysts	0.91 . 10^6 CDN $

Manpower requirements	
Operators	120

Land	
Plant area required	0.8 . 10^6 m^2

6.3.4.5 Production of ammonia using Koppers-Totzek gasification.

Process Description: Synthesis gas is produced as described in para. 6.3.2.3, omitting the methanation step.

6.3.4.6 A materials balance and overall thermal efficiency for raw coal feed is shown in Fig. 6.3.9.

About 89 percent of coal feed is available for synthesis gas production.

Ammonia yield is 0.252 t/t raw coal feed.

Overall thermal efficiency is 47 percent.

6.3.4.7 A materials balance and overall thermal efficiency for washed coal feed is shown in Fig. 6.3.10.

About 90 percent of the coal is available for synthesis gas production.

Ammonia yield is 0.380 t/t washed coal feed.

Overall thermal efficiency is 53 percent.

6.3.4.8 Commercial Production Plant

The coal feed for the ammonia synthesis plant should be 3 . 10^6 t/a run-of-mine coal. The on-stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:

- Koppers gasification unit with 8 gasifiers
- CO-shift conversion unit with 2 trains including waste heat recovery
- rectisol purification with 2 trains
- liquid nitrogen wash, single train
- ammonia synthesis, single train.

Secondary process units:

- oxygen unit
- power and steam plant
- make-up water unit
- cooling water unit
- sulphur recovery
- gas water treatment
- synthesis gas compression.

BASE SCHEME FOR AMMONIA PRODUCTION
KOPPERS-TOTZEK PROCESS ROM COAL

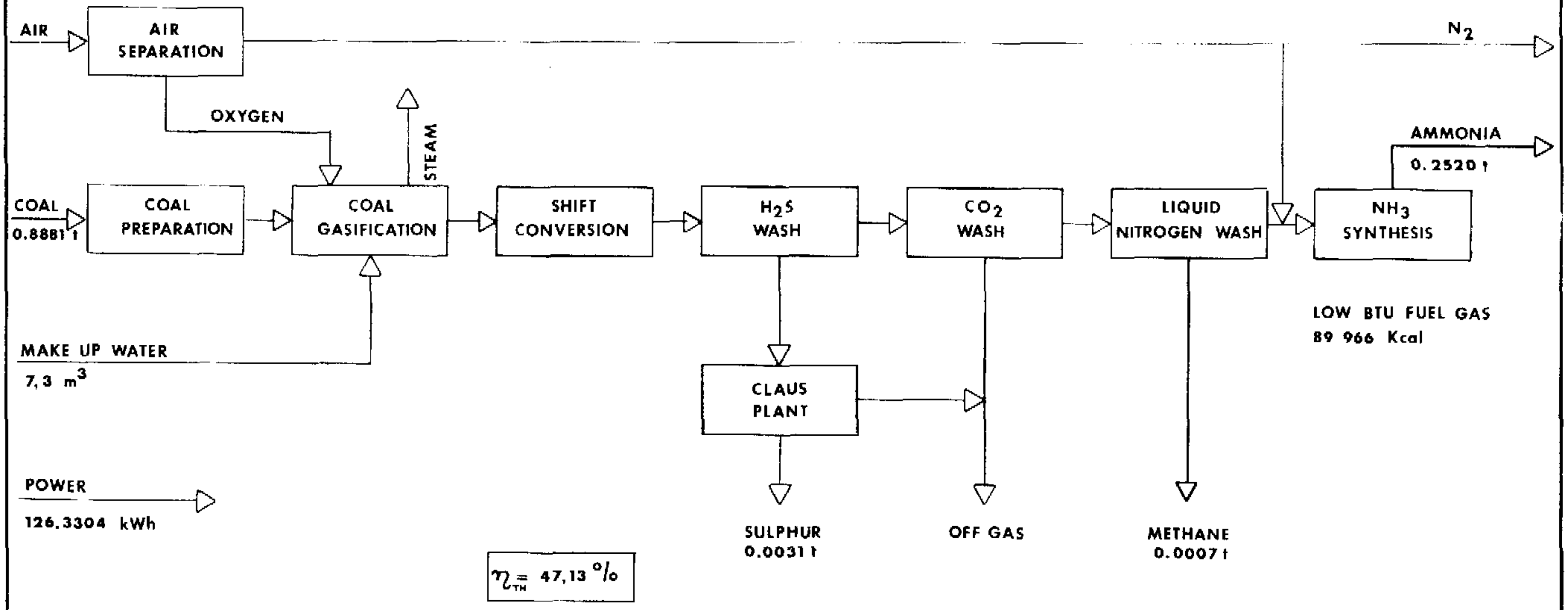

FIG. 6.3.9

B.C. HYDRO

STONE & WEBSTER
CANADA LIMITED

Drawn By
MONTAN CONSULTING GmbH

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

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BASE SCHEME FOR AMMONIA PRODUCTION KOPPERS-TOTZEK PROCESS BENEFICIATED COAL

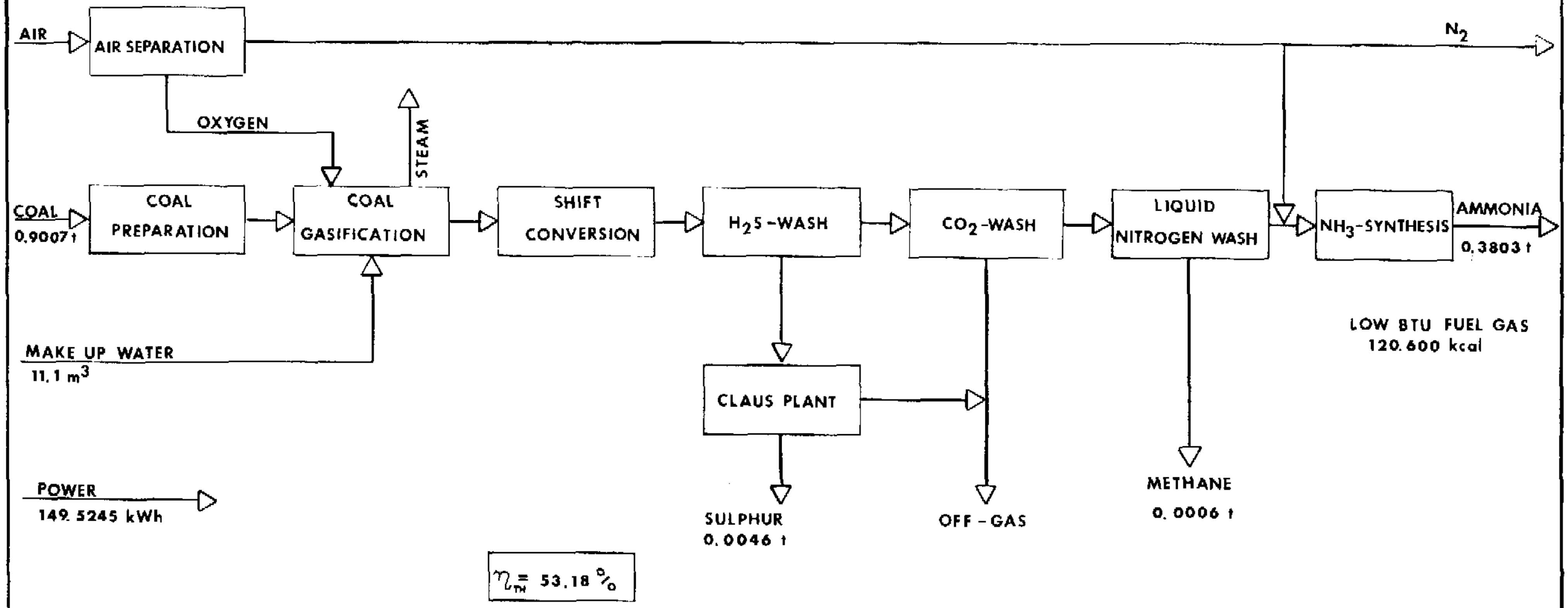

FIG. 6.3. 10

Drawn By
MONTAN CONSULTING GmbH

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B C HYDRO
STONE & WEBSTER CANADA LIMITED
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CJ 1381.000

CSF 405.18

Feeds and products

Feeds

Coal for gasification	$2.664 \cdot 10^6$ t/a
Coal for power generation	$0.336 \cdot 10^6$ t/a
Total	$3.000 \cdot 10^6$ t/a

Products

Ammonia	$756 \cdot 10^3$ t/a
Sulphur	9.300 t/a

Capital Costs

Investment cost	$224 \cdot 10^6$ CDN $
Working capital	$14 \cdot 10^6$ CDN $

Costs for chemicals and catalysts

Chemicals and catalysts	$1.4 \cdot 10^6$ CDN $/a

Manpower requirements

Operators	120

Land

Plant area required	$0.8 \cdot 10^6$ m^2

6.3.4.9 Production of Ammonia by Winkler Gasification

Process Description: Synthesis gas is produced as described in para 6.3.3.2, omitting a methanation step. Methane naturally formed is removed by liquid nitrogen wash. Additional production of synthesis gas by reforming methane recovered has not been considered.

6.3.4.10 A materials balance and overall thermal efficiency for raw coal feed is shown in Fig. 6.3.11.

About 83 percent of the coal is available for synthesis gas production.

Ammonia production is 0.246 t/t raw coal feed.
Methane production is 15 m^3/t raw coal feed.

Overall thermal efficiency is 50 percent.

6.3.4.11 A materials balance and overall thermal efficiency for washed coal feed is shown in Fig. 6.3.12.

About 83 percent of the coal is available for synthesis gas production.

Ammonia production is 0.3423 t/t washed coal feed.
Methane production is 19 m^3/t washed coal feed.

Overall thermal efficiency is 52 percent.

6.3.4.12 Commercial Production Plant
The coal feed for the ammonia synthesis plant should be $3 \cdot 10^6$ t/a run-of-mine coal. The on-stream factor is fixed at 330 days/a.

For this capacity the major primary units are as follows:
- Winkler gasification unit with 8 gasifiers including quench and waste heat systems
- CO-shift conversion unit with 2 trains including waste heat recovery
- rectisol purification with 2 trains
- liquid nitrogen wash, single train
- ammonia synthesis, single train.

BASE SCHEME FOR AMMONIA PRODUCTION
WINKLER PROCESS ROM COAL

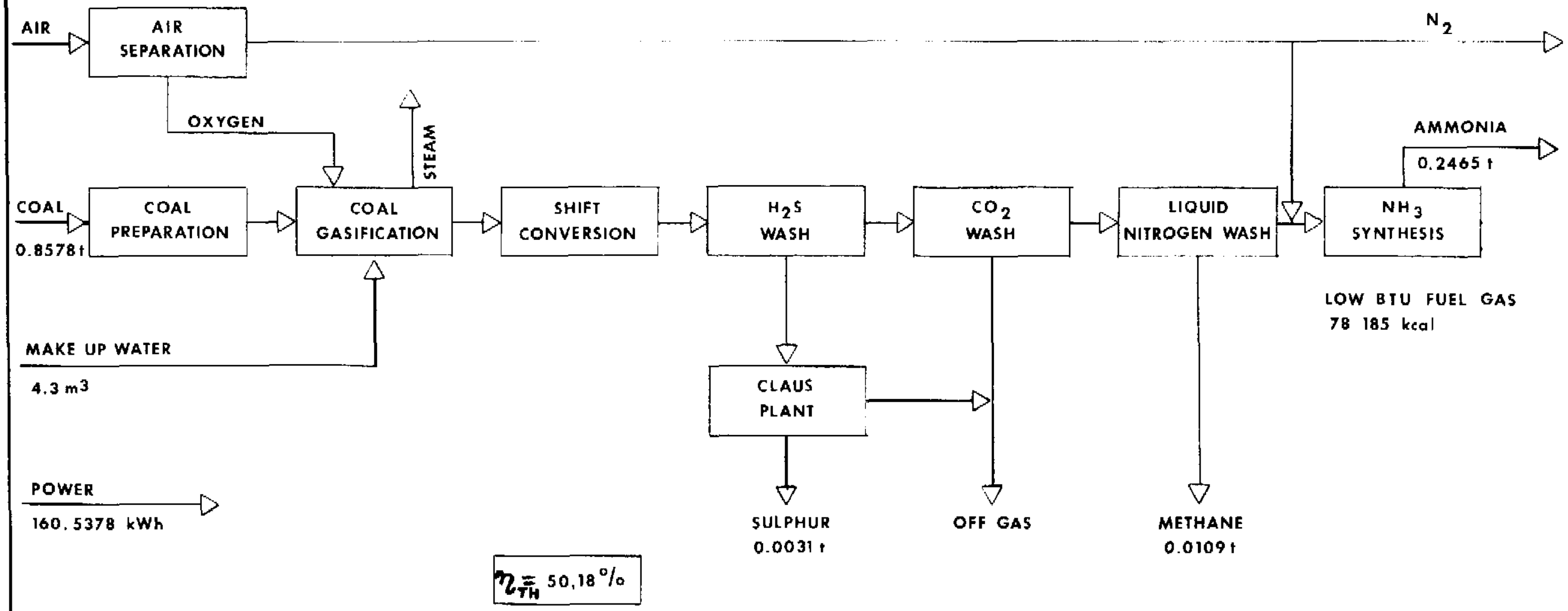

FIG. 6.3.11

Drawn By
MONTAN CONSULTING GmbH

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER CANADA LIMITED

Sheet
Cont. Sh.

CJ 1381.000

CSF 405.18

BASE SCHEME FOR AMMONIA PRODUCTION WINKLER PROCESS BENEFICIATED COAL

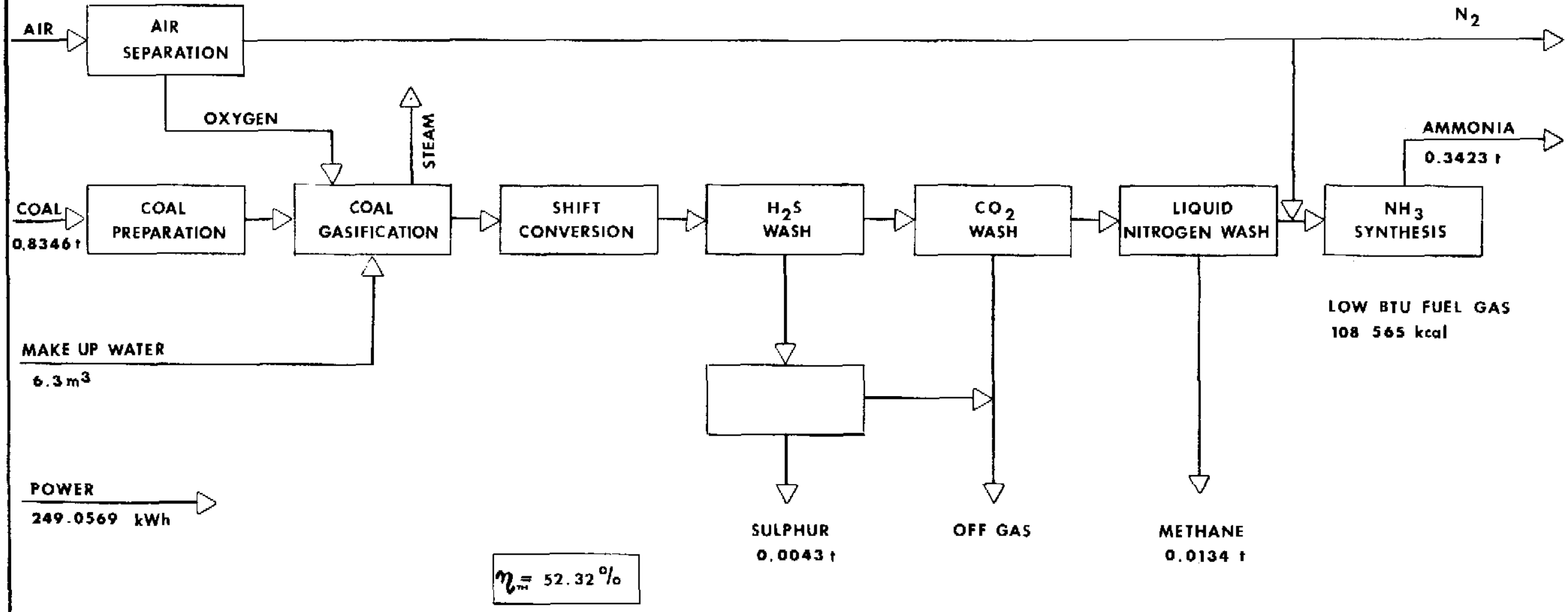

FIG. 6.3.12

ISSUE	DESCRIPTION	BY	CHK'D	APP'D	DATE

B.C. HYDRO

STONE & WEBSTER CANADA LIMITED

Sheet Cont. on

CJ 1381.000

Drawn By
MONTAN CONSULTANTS GmbH

CSF 405 1B

Secondary process unit:
- oxygen unit
- power and steam plant
- make-up water unit
- cooling water unit
- sulphur recovery
- gas water treatment
- synthesis gas compression.

Feeds and products

Feeds	
Coal for gasification	2.573 . 10^6 t/a
Coal for power generation	0.427 . 10^6 t/a
Total	3.000 . 10^6 t/a
Products	
Ammonia	739.500 . 10^3 t/a
Sulphur	9.300 . 10^3 t/a
Methane	45.600 . 10^6 t/a
Capital Costs	
Investment cost	224 . 10^6 CDN \$
Working capital	14 . 10^6 CDN \$
Costs for chemicals and catalysts	
Chemicals and catalysts	1.4 . 10^6 CDN \$/a
Manpower requirements	
Operators	120
Land	
Plant area required	0.8 . 10^6 m^2

7 - SUMMARY AND CONCLUSIONS

The known properties and their relevance to modern coal conversion technology of Hat Creek coal have been exhaustively considered. This analysis has been accompanied by an assessment of the marketing prospects for the potential coal conversion products against a provincial, continental and world scenario. The combined results from these exercises have provided a basis for an economic and financial analysis from which the following conclusions are drawn:

1. A plant to produce 7.14-8.57 million Nm^3 per day (250-300 MM SCFD) of Synthetic Natural Gas is a technically and economically viable use of Hat Creek coal.

2. The production of methanol, while technically feasible, faces an uncertain market situation. Any alteration in present usages of methanol, such as its use as a gasoline additive, will produce a vast increase in world demand and the use of Hat Creek coal for methanol production will provide an attractive alternative to its use for steam-electric power generation.

3. The production of ammonia and hence of nitrogenous fertilizers, while technically feasible, faces a very unsatisfactory world market situation in which ample capacity into the 1990's seems a certainty.

4. The production of coal liquids by any of the processes now becoming available, does not appear to be economically attractive.

5. The possible production of upgraded solid products from Hat Creek coal, such as metallurgical coke, form coke, or activated carbons is not technically feasible because of the very high inherent ash. The complete absence of coking properties, while important, is secondary to this prime question of very high ash content.

6. In-situ gasification of Hat Creek coal has been briefly considered and rejected because of the lack of technically relevant information on the coal deposits and major uncertainties in the present technology. (B.C. Hydro's membership of the consortium supporting the Alberta Research Council's trials at Battle River, Alberta, during the summer of 1976, has provided better information on the possibilities than the authors' can provide at this stage.)

7. Evaluation of the environmental impact of the coal conversion processes, recommended for Hat Creek, and indeed for other processes studied but not recommended, leads to a conclusion that emissions of particulates, sulphur dioxide, nitrogen oxides, carbon monoxide and hydrocarbons for normal operating conditions of coal conversion plants can be controlled to meet environmental regulations and guidelines.

8. The Report, in accordance with the agreed Scope of Work, has been confined to the consideration of single principal products plus by-products. It has become clear that a need exists for extending the studies to include mixed principal products and consideration of this course by B.C. Hydro is strongly recommended.

9. Some areas of the study-work has been hampered by lack of necessary or of adequate information. This need is particularly noticeable because of the uniqueness of Hat Creek coal in terms of its low rank and grade, and the unusual ash characteristics. If the development of alternatives to steam-electric power production are to be pursued further, it is strongly recommended that the appropriate work on the placing of required contracts, to obtain the necessary information be undertaken at an early date.

10. The very low rank and grade of Hat Creek coal are not considered to be serious obstacles to its development for coal conversion. The Report has demonstrated that coal deposits of lower rank and

grade are finding economic employment in other parts of the world and that production costs forecast for Hat Creek coal are economically viable.

11. The Report has been based, as far as Synthetic Natural Gas and coal liquids are concerned, upon a coal throughput of 18 million tons per annum. This is approximately equivalent to 6,360 m^3 (40,000) barrels per day of synthetic crude oil; 7.14 - 8.57 million Nm^3 (250-300 million SCFD) of synthetic natural gas; or 3,000-3,500 MW of electric power. It should be observed that this depletion rate would exhaust the No. 1 Deposit at Hat Creek, at present estimates of mineable reserves, in 30 years. Production of say SNG and electric power in the quantities mentioned would deplete mineable reserves in the No. 1 Deposit in 15 years, or in No. 1 and No. 2 Deposits in 30 years. Therefore, until mining studies prove otherwise, it is strongly recommended that the Hat Creek deposit be regarded as a finite resource, capable of exhaustion by present technology within a half-century.

8. - RECOMMENDATIONS

During the course of the study reported here it appeared evident that certain important areas of the work were hampered by a shortage, or absence, of necessary information on the properties and behaviour of Hat Creek coal for certain utilization methods. Specific examples have been mentioned in the text as they occurred. These areas include fluidized combustion, hydrogenation and liquefaction, and gasification processes. If the decision by B.C. Hydro and Power Authority is favourable towards the continuation of the work of evaluation of alternative processes described in this report it is recommended that test, pilot or full-scale trial programmes be initiated as soon as possible in order to provide the information necessary for the remaining stages of the work.

9. - BIBLIOGRAPHY

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Preliminary Environmental Impact Study of the
Proposed Hat Creek Development (1975)
B.C. Research, Dolmage Campbell & Associates Ltd.

Ref. 3.2 - British Columbia Hydro & Power Authority
Proposed Hat Creek Development Transportation Study
Project No. 3297
June 1976
Swan Wooster Engineering Co. Ltd.

Ref. 3.3 - PD - NCB Consultants Limited
in association with
Wright Engineers Ltd. & Golder Associates
Report No. 2
Preliminary Report on Hat Creek Openpit No. 1
Volume 1
to
British Columbia Hydro and Power Authority
March 1976

Ref. 3.4 - PD - NCB Consultants Limited
in association with
Wright Engineers Ltd. & Golder Associates
Report No. 3
Preliminary Report on Hat Creek Openpit No. 2
Volume 1
to
British Columbia Hydro and Power Authority
March 1976

Ref. 3.5 - British Columbia Hydro & Power Authority
Alternatives 1975 to 1990
Report of the Task Force on Future Generation and
Transmission Requirements
May 1975

Ref. 4.1 - Williams, D.G. "Assessment of the Properties of Coking Blends" Yearbook of the Coke Oven Managers Association (G.B.) 1971 278 - 314

Ref. 4.2 - International Committee for Coal Petrology Glossary of terms used in Coal Petrology Paris C.N.R.S. 1957

Ref. 4.3 - Chemistry of Coal Utilization Supp. Vol. H.H. Lowry (Ed). J. Wiley and Sons 1963

Ref. 4.4 - Southern Research Institute, Birmingham, Albama. Report No. A1231 - 2865 - I June 1972

Ref. 4.5 - "The Fixed-bed Slagging Gasifier Programme" See "The Westfield Story", British Gas Corporation, Washington 1975.

Ref. 4.6 - Sharpe, R.A. " Gasifying Coal for SynGas Production". Hydrocarbon Processing. Nov. 1976. 171 - 175

Ref. 4.7 - Wagoner, C.L., and Duzy, A. F., "Burning Profiles for Solid Fuels", ASME 1967

Ref. 4.8 - Rowland, W.H. and Kispert, E.G., Mech. Eng. 82 No. 4 103 (1960)

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Ref. 4.10 - Cooke, J.J. & Hodgkihson, N. "Fluidized Combustion of Low Grade Materials" (Institute of Fuel, London) No. 7 (1975) Proc. Vol. 1. Paper C - 2

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Ref. 4.12 - "Brown Coal Utilization Research & Developement" Rheinische Braunkohlenwerke AG., Cologne 1976

Ref. 5.1 - Howard-Smith I., and Werner G.J., "Coal Conversion Technology" Noyes Data Corp. 1976

Ref. 5.2 - Bergius, F. " The Use of High Pressure in Chemical Reactions" (1913)

Ref. 5.3 - Pott, A. and Broche, H. Brit. Pat. 293808 (1927) , French Pat. 657409 (1928), U.S. Pat. 2308247 (1943)

Ref. 5.4 - Wolk R.H. "EPRI Clean Solid and Liquid Fuels Programme" Electric Power Research Institute, 1976.

Ref. 5.5 - "Preliminary Economic Analysis of SRC Liquid Fuels Process Producing 50,000 barrels per day of Liquid Fuels from Two Coal Seams; Wyodak and Illinois No. 6" ERDA - 76 -55

Ref. 5.6 - Pittsburgh and Midway Coal Mining Comapny, Fort Lewis, Washington (Subsidiary of Gulf Oil Corporation).

Ref. 5.7 - Rudolph, P.F.H., " The Lurgi Process The Route to SNG from Coal" Proc. Forth Syn. Pipeline Gas Symp., Amer. Gas Assoc. 1972 p.177 - 197

Ref. 5.8 - Landers, J.E. "Coal Methanation Demonstration in Scotland", AICRome CEP (1975)

Ref. 5.9 - Wintrell, R. "Synthetic Gas Production in the Chemical & Fertilizer Industries", A I Chem. E. National Meeting Salt Lake City, 1974

Ref. 5.10 - Kronseder J.G., "SASOL - II, A Progress Report", EIC Western Region Conference, 12th May, 1976.

Ref. 5.11 - Synthetic Fuels Commercialization Program, Draft Environmental Statement, Volume IV, December 1975, U.S. ERDA.

Ref. 5.12 - Hat Creek Development, Preliminary Environmental Impact Study prepared by B.C. Research and Dolmage Campbell and Associates, Ltd., August, 1975.

Ref. 5.12A- Department of Lands, Forests, and Water Resources; Water Resources Service, Victoria, B.C. - Report on Pollution Control Objectives for The Chemical and Petroleum Industries of British Columbia, Issued March 1974. (Page 35)

Ref. 5.13 - Evaluation of Pollution Control in Fossil Fuel Conversion Processes Liquefaction: Section 3, H-Coal Process EPA - 650/ 2-74-009-m, October 1975.

Ref. 5.14 - Evaluation of Pollution Control in Fossil Fuel Conversion Processes Gasification: Section 1; Lurgi Process EPA 650/2-74-009-c, July, 1974

Ref. 5.15 - Evaluation of Pollution Control in Fossil Fuel Conversion Processes Liquefaction: Section 2; SRC Process EPA-650/3-74-009-f, March 1975

Ref. 5.16 - Particulate Polycyclic Organic Matter, National Academy of Sciences, Washington, D.C., 1972.

Ref. 5.17 - Health Implications of Oil to Coal Conversion in New England Power Plants, J. Gruhl, Report Mass. Inst. of Technology, El. 76-013WP, April, 1976

Ref. 5.18 - Energy and the Environment, Council on Environmental Quality, U.S. Govt. Printing Office, August, 1973.

Ref. 5.19 - Johnson, C.A. and J.Y. Livingston, "H-Coal; How Near to Commercialization," Presented at Univ. of Pitts. School of Eng. Symposium, August 6-8, 1974.

Ref. 5.20 - Furlong, L.E., E. Efforn, L.W. Vernon, and F.L. Wilson, "Coal Liquefaction by the Exxon Donor Solvent Process," Presented November 18, 1975, Nat. AICHE Meeting, Los Angeles.

Ref. 5.21 - Haebig, J.E., B.E. Davis, and E.R. Dzura, "Preliminary *Small-Scale Combustion Tests of Coal Liquids*," Environmental Science and Technology, pp. 243-247, March, 1976.

Ref. 5.22 - "Pollution Control Objectives for The Chemical and Petroleum Industires of British Columbia," Water Resources Service, Department of Lands, Forests, and Water Resources March 1974.

Ref. 5.23 - Caranough, G. et al. " Potentially Hazardous Emissions from the Extraction & Processing of Coal & Oil", EPA - 605/2-75-038, U.S. Environmental Protection Agency, Washington D.C., April 1975

Ref. 5.24 - "Studies of Advanced Electric Power Generation Techniques and Coal Gasification". B.C. Hydro and Power Authority, 1976. Vol. 1. (at page 40).

Ref. 5.25 - Harral, J. K. A. "A Fossil Fuel Choice - To Manufacture Gas or Generate Electricity". AIME. 1976.

APPENDIX A

10. - TERMS OF REFERENCE

1. The purpose of this study is to identify and evaluate major uses of Hat Creek coal. The study shall include but not be limited to a comparative analysis of the following areas:-

   (a) Principally solid products
   - direct sales
   - combustion for heat generation
   - high and low temperature carbonization and recovery of coal chemicals
   - delayed coking of coal tar pitch
   - form coking
   - solvent refining
   - carbon activation
   - fertilizers

   (b) Principally liquid products
   - pyrolysis
   - solution and hydrogenation of coal and tar
   - synthesis

   (c) Principally gaseous products
   - commercially proven processes
   - "second generation" processes

   Information on thermal-electric generation and gasification will be provided from existing studies and included to provide a comparative evaluation report.

2. For each of the selected process applications, material and energy balances per unit of feed material (one tonne) shall be developed. Material and energy flows per unit of time (one hour) shall be presented on flow diagrams showing the thermodynamic states of reactants and products.

3. Capital investment and operating costs for each selected process shall be identified.

4. In considering alternate uses of the resource, a market forecast within the time frame 1990 - 2010 shall be developed for these uses based on:-

   (a) supply of Hat Creek coal as a raw material for export;
   (b) chemical products (identified under 1.) manufactured at Hat Creek and supplied to meet market demands;
   (c) potential development of secondary industry in the Province using the products from (b).

   Data relating to existing or anticipated future productive capacity, supply and demand for individual products should be accumulated and forecasts of probable future markets should be prepared. The evaluations shall include estimates of probable selling prices at selected locations, the costs involved in delivering products from Hat Creek to those areas, an indication of the profitability of serving the principal markets from Hat Creek, and a resulting evaluation of whether a given product will be economically viable.

5. The study shall derive opportunity costs (or values in alternative uses) based on alternate uses of Hat Creek coal. A framework within which the opportunity costs will be evaluated shall be agreed upon by B.C. Hydro.

6. The economic evaluation shall develop cash flow projections showing costs, potential sales dollars and resulting net income and cash generation.

7. The cost and feasibility of installing the required chemical or carbonization plant at Hat Creek shall be determined. Electricity, steam, land and water requirements associated with various plant sizes shall be clearly identified.

8. Environmental considerations associated with various processes shall be described. In particular, material balances should be carried out on the basis of uncontrolled processes (without special pollution control devices) indicating all wastes such as

hydrocarbons, sulphur compounds, etc. released into the environment. Further, the best practical technology available to reduce the uncontrolled emissions to stringent levels should be outlined including costs.

9. The manpower requirements for construction and operation of the various processes shall be identified.

10. Economic criteria for the study shall be provided by B.C. Hydro.

11. The study is to be controlled and co-ordinated on behalf of B.C. Hydro by the Assistant General Manager of the Engineering Group or his appointee.

12. Draft report shall be submitted to B.C. Hydro for review by 3 December 1976 and final report by 28 January 1977.

NOTE:-

(i) International system of units (S.I. units) should be used throughout the report. Conventional American or English units should be put in brackets following the S.I. units.

(ii) All calculations and use of formulas should be clearly presented for easy reading.

(iii) Sources of information used in report should be documented.

(iv) All tables and figures in the report should have descriptive titles.

(v) The report should have a table of contents and an index of tables and figures.

APPENDIX B

List of Consultants' Reports provided by B.C. Hydro and Power Authority and by Department of Economic Development, Government of British Columbia used in the course of the study.

MINING

- *PD-NCB Consultants Limited in association with Wright* Engineers Ltd. & Golden Associates
- Preliminary Report on Hat Creek Open Pit No. 1
- Preliminary Report on Hat Creek Open Pit No. 2 March 1976

COAL PROPERTIES

1. Dolmage Campbell & Associates Limited:-
    - Interim Report on Coal Analysis No. 1 Deposit June 27, 1975
    -
    - Addendum July 31, 1975
    -
    - Hat Creek Deposits Proposed No. 1 Open Pit - Statistical Tables of Proximate Analyses Data July 15, 1975
    - Ash - Calorific Value Linear Regression Graphs and Statistical Tables of Proximate Analysis Data Sept. 1976
    - Hat Creek Development DDH NOC 76-135 and 136 Proximate Data Sept. 17, 1976
2. B.C. Hydro & Power Authority:-
    - Compilation of Analyses on Composite Coal Sample RH-75-4, 125' - 450' Hat Creek Coal Deposit Sept. 25, 1975
        - (i) Analysis by Babcock & Wilcox Canada Ltd.
        - (ii) Analysis by Combustion Engineering - Superheater Ltd.
        - (iii) Analysis by Birtley Engineering (Canada) Ltd.
    - Hat Creek Coal Deposit, Field Specific Gravity Tests DH 75 - 68
    - Coal Resources of British Columbia (Dolmage Campbell & Associates Ltd.) 1975

3. Loring Laboratories Ltd.:-	
- Analysis Reports No. 10634, 10635, 10636 - Float and Sink Analysis	Oct. 20, 1975
- Analysis Report No. 10464, DDH 75-4 (PD-NCB Appendix G)	Oct. 1, 1975
- Analysis of Sample from	Oct. 1, 1975
4. Commercial Testing and Engineering Co.:-	
- Reports Nos. 67 - 4767; -4769 Spectographic Analysis	Dec. 26, 1974
- Reports Nos. 67 - 6023, -6024, -6027 Spectographic Analysis	Jan. 27, 1975
- Reports Nos. 64 - 11237 - 11242, Float & Sink Analysis	Nov. 3, 1975
- Reports Nos. 64 - 11243 - 11248 Float & Sink Analysis	Nov. 3, 1975
- Reports Nos. 64 - 11249 - 11254 Float & Sink Analysis	Nov. 3, 1975
- Reports Nos. 67 - 7356 Free Swelling Index	Jan. 30, 1975
5. Ebasco NYK:-	
- Sieve Analysis & Washability Data for Bulk Samples Received 21/5/76	May 27, 1976
6. Corex Laboratories Limited:-	March 1976
- Examination of Hat Creek Coal - British Columbia C.L. 5	
7. Lurgi Mineraloltechnik GmbH:-	
- Examination of Hat Creek Coal, drill holes No. 74 - 38, 916 - 1036 feet	July 1975
- Analytical Test Report No. 112/75, BGD 50-3910	

STEAM ELECTRIC POWER GENERATION

B.C. Hydro and Power Authority:-

- Alternatives 1975 to 1990	May 1975
- Report of the Task Force on Future Generation and Transmission Requirements	
- Studies of Advanced Electric Power Generation Techniques and Coal Gasification (Based on the use of Hat Creek Coal) Intercontinental Engineering E.D.P. Consultants Shawinigan Engineering Company The Lummus Co. Canada Ltd.	1976

TRANSPORTATION

Swan Wooster Engineering Co. Ltd.:-

- Proposed Hat Creek Development Transportation Study Project No. 3297	June 1976

ENVIRONMENT

B.C. Hydro & Power Authority:-

- Preliminary Environmental Impact Study of the Proposed Hat Creek Development B.C. Research Dolmage Campbell & Associates Ltd.	1975

ECONOMICS

The Department of Economic Development, Government of British Columbia:-

- "A Summary Report on Development Possibilities in the North East Region of British Columbia"	June 1975
- "A Summary Report on Development Possibilities in the Central Region of British Columbia"	Jan. 1976
- "Hat Creek Coal, A Critical Assessment of Development Options"	April 1976

Strong,Hall and Associates Ltd.:-

- "Hat Creek, Regional Economic Impacts" March 1976

Table B.1(A)

PROXIMATE ANALYSIS - DRY BASIS

Laboratory Reference	(a)(b)(c)	d(i)	d(ii)	d(iii)	(f)		(g)	·	(i)	(j)+	(k) Lurgi#	SASOL I(Sigma)	II
Ash	35.9	22.0	21.4	21.3	28.14	52.3	49.0	44.7	29.5	25.1	32.44	35.9	27
Volatile Matter	33.9*	37.2	41.4	36.7	35.72	-	-	-	32.5	36.9	29.68	22.3	25
Fixed Carbon	30.2	40.8	37.2	42.0	36.14	-	-	-	38.0	38.0	37.88	41.8	48
	100.0	100.0	100.0	100.0	100.00				100.0	100.0	100.00	100.0	100
Fuel Ratio	0.89	1.1	0.90	1.14					1.17	1.03			
Calorific Value - KJ/kg	16,251	21,868	21,014	21,622	19,505	10,999	12,231	13,729	18,735	20,444	18,022	18,559	
Sulphur	0.49	0.30	0.35	0.38	0.80	0.46	0.65	0.55	1.39	0.77	0.39		

* Combustible Volatile = 24.7; + (j) is No. 2 Deposit; # (Corrected for Carbonates)

Dry Ash Free Basis

Dry Ash Free Basis	(a)(b)(c)	d(i)	d(ii)	d(iii)	(f)		(g)	·	(i)	(j)+	(k) Lurgi#	SASOL I(Sigma)	II
Volatile Matter	52.9	47.7	52.7	46.6	49.71	-	-	-	46.1	49.3	43.9		
Fixed Carbon	47.1	52.3	47.3	53.4	50.29	-	-	-	53.9	50.7	56.1		
Ratio FC/VM	0.890	1.096	0.898	1.146	1.07	-	-	-	1.169	1.028	1.278		
Sulphur	0.76	0.38	0.45	0.48	-	0.96	1.27	0.99	1.97	1.03	0.58		
Calorific Value - KJ/kg	25,356	28,039	26,743	27,480	-	23,076	23,992	24,820	26,586	27,302	26,675	28,554	

Table B.1(B)

ULTIMATE ANALYSIS - DRY BASIS

Laboratory Reference	(a)	d(i)	d(ii)	(f)+	(j)+	(k) Lurgi#
Carbon	43.50	56.4	55.3	51.0	53.20	45.95
Hydrogen	3.39	4.2	4.0	4.8	4.11	3.77
Chlorine	0.03	N/A	N/A	N/A	0.03	0.03
Nitrogen	1.06	0.7	0.5	1.0	1.01	0.89
Sulphur	0.51	0.3	0.3	0.8	0.77	0.39
Ash	36.59	22.0	21.4	28.1	25.14	32.45
Oxygen (by Difference)	14.92	16.4	18.5	14.3	15.74	16.52
	100.00	100.0	100.0	100.0	100.00	100.00

+ (f) and (j) are No. 2 Deposit; # (Corrected for Carbonates)

Dry Ash Free Basis

Dry Ash Free Basis	(a)	d(i)	d(ii)	(f)+	(j)+	(k) Lurgi#
Carbon	68.6	72.3	70.4	71.0	71.1	68.0
Hydrogen	5.3	5.4	5.1	6.7	5.5	5.6
Oxygen	23.6	21.0	23.5	19.8	21.0	24.5
Nitrogen	1.7	0.9	0.6	1.4	1.4	1.3
Sulphur	0.8	0.4	0.4	1.1	1.0	0.6
Chlorine	Tr	-	-	-	-	Tr
	100.0	100.0	100.0	100.0	100.0	100.0

Laboratory References for Tables B.1(A) and (B)

(a)(b)(c)	- Dolmage Campbell & Associates
d(i)	- M. H. French - Analyses by Babcock & Wilcox Canada Ltd.
d(ii)	- M. H. French - Analyses by Combustion Engineering-Superheater Ltd.
d(iii)	- M. H. French - Analyses by Birtley Engineering (Canada) Ltd.
(f)	- Loring Laboratories Ltd.
(g)	- Commercial Testing & Engineering Co.
(i)	- Ebasco NYK
(j)	- Corex Laboratories Ltd.
(k)	- Lurgi Mineraloltechnik GmbH