CONFIDENTIAL

GULF CANADA RESOURCES INC.

MOUNT KLAPPAN COAL PROJECT

1982

POWER STUDY

Coal Licence Number 7118 to 7177

7381 to 7392

and

7416 to 7432 inclusive

Cassiar Land District

NTS Map Number 104 H

Latitude Between 57°11' and 57°22'N
Longitude Between 128°39' and 129°05'W

BY

PHILLIPS BARRATT KAISER
Engineering Ltd.
Vancouver, B.C. Canada

DECEMBER 1982

PBK Project No. 82062

MOUNT KLAPPAN COAL PROJECT

Phillips Barratt Kaiser Engineering Ltd.

GULF CANADA RESOURCES INC.

Phillips Barratt Kaiser

MOUNT KLAPPAN COAL PROJECT LOCATION MAP

Phillips Barratt Kaiser

PBK

POWER STUDY

MOUNT KLAPPAN POWER STUDY

TABLE OF CONTENTS

INTRODUCTION

In November, 1982, Gulf Canada Resources Inc. commissioned Phillips Barratt Kaiser Engineering Ltd. to prepare a study of the size and costs of a coal-fired electric generating plant which would be located at a coal mine at Mount Klappan. The powerplant would provide power for the coal mine and power for sale to existing and potential mines and towns in the region.

The coal mine is the subject of a separate Mine Assessment Study prepared for the Mount Klappan Coal Project.

Capital and operating cost estimates, of order-of-magnitude accuracy, and design and construction schedules have been prepared for the various sizes of powerplant necessary to satisfy the power requirements identified, together with the high-voltage transmission systems to serve the local mines and towns. In addition, in order to provide comparative costs to prospective mines of generating their own power, estimates of capital and operating costs of diesel-generator plants have been prepared.

The information developed in this study contains the basic elements of unit costs and potential power requirements of mines and towns selected. It is emphasised that the size of powerplant necessary depends upon the assumptions made as to which mines may be developed and the relative start dates for same. Similarly, the size of boiler-turbine units which should be installed initially to correspond with the rate of load growth can vary with the assumptions made. To provide a means by which cost estimates can be made of powerplants of varying installed capacities and sizes of units, capital cost curves and adjustment factors have been prepared, and examples are given to illustrate their use.

Cost estimates have been prepared for two alternative powerplant development schemes which correspond to the following mine production levels:

Level A: 1 000 000 tonne per year. Coal supplied to the powerplant would be run-of-mine.

Level B: 5 000 000 tonne per year. Coal supplied to the powerplant would be washed product.

Power demands from Mount Klappan mine activity have been obtained from the separate Mine Assessment study.

Recommendations have been included regarding further areas of study which could affect significantly the assumptions made and cost estimates prepared in this study.

At this stage of preliminary evaluation, standard utility technology has been used as the basis for cost estimating. Later studies would investigate the most appropriate systems.

SUMMARY

1. An initial review of the power requirements and location of existing and potential mines and towns lead to a selection of ten major B.C. mines for study as potential load centres for servicing with electrical power from a powerplant at Mount Klappan. There are two major areas of concentration of load:

   - Kutcho Creek Area, 125 kilometers north of Mount Klappan, involving four of the potential mines on the transmission route;

   - Schaft Creek Area, 150 kilometers west of Mount Klappan, involving three of the potential mines on the transmission route.

   The four other mines are within a 400 kilometer radius.

2. Based upon an optimistic assumption as to anticipated start-up dates and sequence of development within the period 1987 through 2000, following are estimates of power demands of Mount Klappan coal mine operations and selected mineral mines:

   Level A, 1 million tonne per year of run-of-mine coal shipped as product:

	Mount Klappan MW	Mines MW	Total MW
- Kutcho Creek area	13	50	63
- Schaft Creek area	16	149	165
- All ten mines	18-20	172-220	190-240

   Level B, 5 million tonne per year of washed product coal:

	Mount Klappan MW	Mines MW	Total MW
- Kutcho Creek area	65	50	115
- Schaft Creek area	71	149	220
- All ten mines	72-74	173-221	245-295

3. Not included in the study are existing and potential mines in the Stewart/Kitsault area, the Yukon Territory and Alaska.

4. Information from various sources on reserves and production rates for potential mines as it related to power requirements was inconsistent. For this study, demand figures and start dates which had been provided to British Columbia Hydro and Power Authority (BCHPA) were adopted.

5. Capital cost estimates have been prepared for powerplants (constructed to utility standards) using coal with a 33% ash content (Level A), and with a 20% ash content (Level B). The costs per kilowatt of installed capacity are as follows:

Plant Size:	50 MW	100 MW	150 MW	200 MW	250 MW
Level A:	$ 2,800	2,250	2,120	2,000	1,900
Level B:	$ -	2,100	1,970	1,860	1,800

All costs are in 1982 Canadian dollars.

6. The total cost of a powerplant necessary to provide a given firm capacity can vary with the sizes of units adopted to suit the load buildup schedule and standby capacity. Curves and factors have been provided to calculate these estimated costs to suit various combinations of unit sizes and standby capacity. The same curves may be used to estimate unit costs using coals varying in ash content between 20% and 33%.

7. The operating cost estimates in cents per kilowatt hour of the powerplants studied, and the corresponding unit costs of coal assumed, are as follows:

Plant Size:	50 MW	100 MW	150 MW	200 MW	250 MW
Level A					
$25.00/tonne	2.44	2.17	2.02	1.99	1.93
$50.00/tonne	3.95	3.66	3.45	3.46	3.39
Level B					
$25.00/tonne	-	1.82	1.67	1.64	1.59
$50.00/tonne	-	3.03	2.80	2.82	2.75
$75.00/tonne	-	4.22	3.93	3.94	3.91

8. The capital and operating cost estimates of the high voltage transmission line systems were based upon discussions with BCHPA, who have performed route studies and cost studies for transmission systems from Mount Klappan to potential mine sites. Unit costs of 138 kV and 230 kV lines using wooden-pole H-frame construction, were estimated at $140,000/km and $160,000/km respectively. All systems are based upon a single line serving the selected mines, and no grid has been investigated to increase reliability of supply. The total cost of the transmission system required to serve the ten mines is $245 million.

9. Capital costs of diesel generating plants of 10 MW, 25 MW and 50 MW installed capacity are estimated at $820/kW, $775/kW and $755/kW respectively. Operating costs are estimated at 13.7¢/kWh, 13.4¢/kWh and 13.0¢/kWh respectively. Diesel fuel represents approximately 77% of the operating cost, assuming use of light diesel fuels.

10. Engineering and construction schedules, assuming that governmental approvals have been given, are as follows:

- coal-fired powerplants could be designed and constructed in four to six years depending upon the size of plant and boiler delivery times;

- for transmission lines, time required for land acquisition, and design and construction could be from three to four years;

- diesel plants could take about two to two and one-half years to design and construct, depending upon the size of station.

11. In order to refine some of the broad assumptions made for this study and to supplement the findings, the following recommendations for further study are made:

- identify potential site locations for a powerplant at Mount Klappan and establish their influence on costs;

- identify potential sources of raw water and relative cost and reliability of supply;

- identify potential cooling pond locations and construction, and compare costs of pond cooling with various tower cooling alternatives, including environmental considerations;

- study methods of ash disposal specifically related to the site, incorporating environmental considerations;

- in particular, prepare a study of environmetal and operational advantages of fluidized bed combustion boilers as applied specifically to Mount Klappan, and prepare cost estimates for same;

- identify locations and costs of mini-hydro sites, presently being studied by BCHPA and others, as alternatives for the generation of power for potential major mines.

- investigate the opportunities and advantages of district heating.

PART 1

EXISTING AND POTENTIAL LOADS

PART 1 - EXISTING AND POTENTIAL LOADS

CONTENTS

Table

Figure

Plate

1.1 INTRODUCTION

Major existing and potential mines have been identified for which it could be practical to have electric power provided from a coal-fired powerplant at Mount Klappan. A map indicating the location of the mines and Mount Klappan is provided in Plate 1.1.

For each mine, a potential electrical demand value has been assigned and load growth curves have been developed for various groupings of major mines. The load growth curves have been based upon an optimistic outlook for start-up of mines between 1987 and the year 2000. These curves include an allowance for power required for existing towns and settlements.

The power requirements to produce coal at Mount Klappan for sale have been obtained from the separate mine assessment study. The power requirements to produce coal to fuel the powerplants are developed herein.

1.2 INFORMATION SOURCES

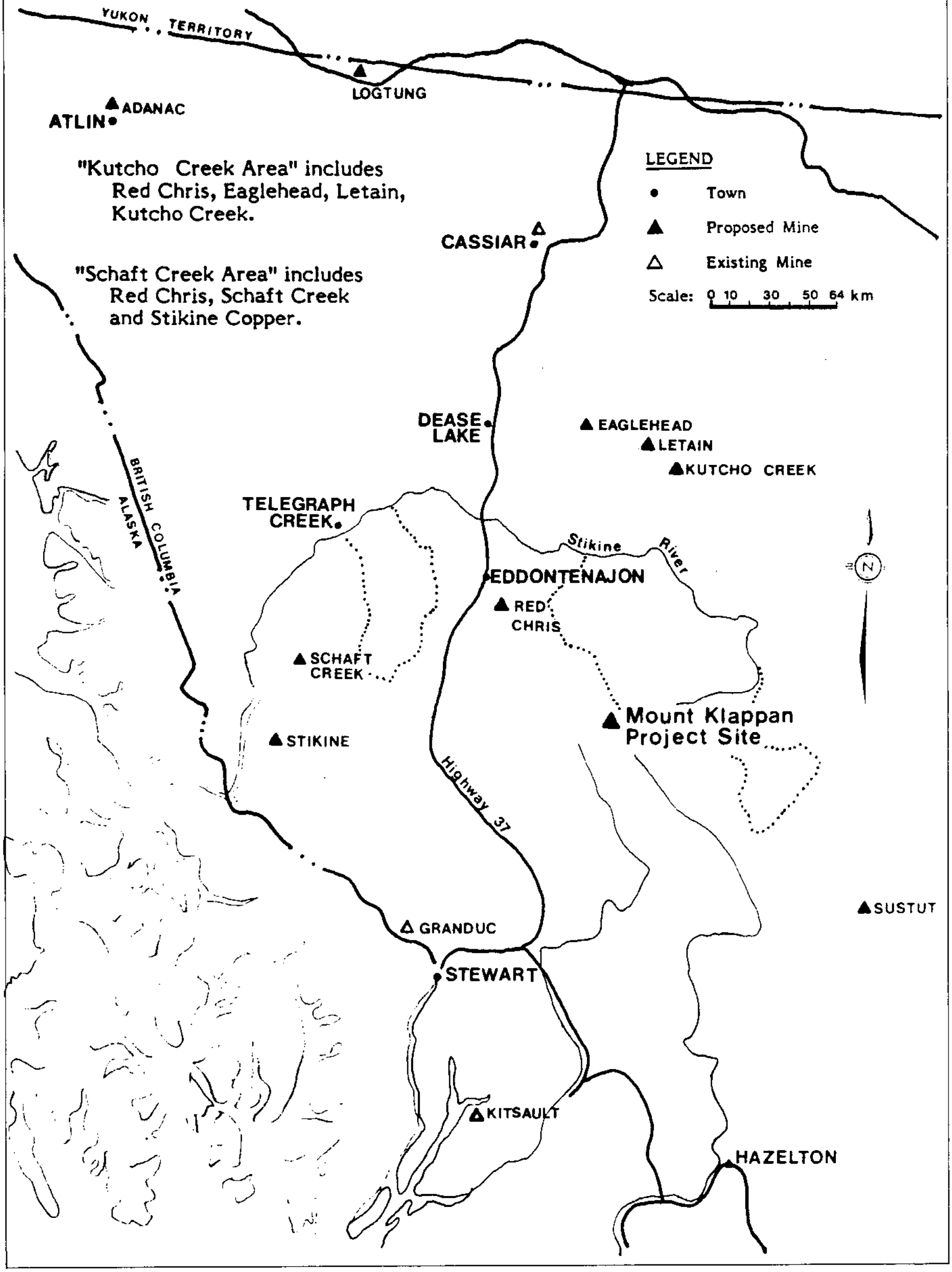
Information on the mines was sought from industry and government sources by telephone and in meetings, and from published reports and other data. Information varied and was often qualified.

The anticipated life of each of the major potential mines was based on Table 3.3 of the British Columbia Regional Economic Study 1982, "The Northwest Region", produced by the Ministry of Industry and Small Business Development of B.C., May 1982. The demands projected for each mine identified were obtained informally, and are believed to correspond to those used by the Provincial Government in their studies.

A location map showing existing mines and mining properties in British Columbia and the Yukon Territory (including part of the Northwest Territories) is included in Appendix A. This map has been produced by the British Columbia and Yukon Chamber of Mines and is Revised January 1983.

PLATE 1.1

MINE & TOWN LOCATIONS



1.3 LOAD ESTIMATES

131 MINES

The projected loads for the mines identified have been presented in Table 1.1. Also presented is an optimistic start date and expected life for each.

132 TOWNS

A listing of existing towns and settlements and potential towns is given in Table 1.2, together with estimated demands. (It may not be economical to service some existing towns: See Part 4.)

.1 Existing Towns

The towns in the region are quite small and, except for Cassiar, commercial and industrial loads are minimal. B.C. Hydro operates four diesel plants in the region as follows:

Town	Capacity (MW)
Atlin	1.75
Dease Lake	1.65
Eddontenajon (Iskut)	0.80
Telegraph Creek	1.15
Total	5.35

All four plants are multiple diesel-generator installations, some sets of which are mobile units. The loads served generally include only residential and small commercial customers. Typical corresponding reported populations served are:

Dease Lake - 130 families approximately
Eddontenajon - 300 persons
Telegraph Creek - 300 persons

The town of Cassiar is served by diesel generators owned by Brinco Ltd. (Cassiar Asbestos), with an installed capacity of about 12 MW. Brinco advised that the town has an approximate demand of 3 MW (with the mine requiring around 7 MW).

.2 Potential Towns

The estimated work force and electric demand at the mines are shown in Table 1.2. A load of 4.5 kW per worker has been assumed as a measure of peak demand from the towns.

TABLE 1.1

ELECTRICAL DEMAND FROM MAJOR MINES

Mine	Owner	Minerals	Optimistic Start Date	Expected Life-Years	Demand MW
Potential					
Adanac	Placer Development	Mo, W	1989	20	12
Eaglehead	Esso-Nuspar	Cu, Mo, Ag, Au	1995	15	13
Kutcho Creek	Esso-Sumitomo	Cu, Ag, Zn	1987	12	13
Letain	Brinco Ltd.	Asbestos	1990	15	10
Logtung	Amax	W, Mo	1990	15	13
Red Chris	Kidd Creek	Cu, Au	1990	20	7
Schaft Creek	Teck Corporation	Cu, Mo, Au, Ag	1992	25	80
Stikine Copper	Liard-Hudson Bay (?)	Cu, Ag, Au	2000	20	55
Sustut	Falconbridge	Cu	1996	8	10
				Sub-Total	213
Existing					
Cassiar	Brinco Ltd.	Asbestos	-	10	7

TABLE 1.2

ELECTRICAL DEMAND FROM MINING TOWNS

Mine-Town	Workforce	Demand (MW)
Adanac	350	1.6
Cassiar	500	3.0
Eaglehead	250	1.1
Kutcho Creek	150	0.7
Letain	350	1.6
Logtung	250	1.1
Red Chris	250	1.1
Schaft Creek	750	3.4
Stikine Copper	450	2.0
Sustut	300	1.4

133 MOUNT KLAPPAN OPERATIONS

The demand from the Mount Klappan operations arises from two main sources:

(1) Power necessary for the mine operation to produce coal for sale. This would include the townsite.

(2) Power necessary to produce sufficient coal to fuel the coal-fired powerplant.

The power requirements for coal for sale have been obtained from a separate study for the mine operations. These values have been prorated to obtain the required power for providing coal for electrical generation. The coal tonnages required for the powerplants are presented in Part 3 of this study.

A summary of the Mount Klappan power requirements are provided in the following Table 1.3.

TABLE 1.3

MOUNT KLAPPAN OPERATIONS - POWER REQUIREMENTS

		Level A 1 000 000 tpy					Level B 5 000 000 tpy			
Size of Powerplant (MW)		50	100	150	200	250	100	150	200	250
(1) Power to Produce Coal for Sale (MW)		9	9	9	9	9	60	60	60	60
(2) Power to Produce Coal for Powerplant (MW)		3	5	7	9	11	5	7	10	12
Total Requirement (MW)	=(1)+(2)	**12**	**14**	**16**	**18**	**20**	**65**	**67**	**70**	**72**

1.4 LOAD GROWTH

141 INTRODUCTION

Expected start dates for development of major potential mines are very difficult to predict. To illustrate a possible maximum load growth pattern, an optimistic outlook on development of mines has been taken which assumes that all identified mines will have been started by the year 2000. The sequence of start dates has been established from information obtained informally and is believed to correspond to an optimistic development pattern adopted by the Provincial Government for its planning for the northwest of B.C.

142 LOAD GROWTH CURVES

Three curves have been prepared to illustrate load development using the information in Tables 1.1 and 1.2. These curves are for the following load areas, which are shown on Figure 1.1:

- Kutcho Creek Area
- Schaft Creek Area
- All areas.

The demands at Mount Klappan for the production of coal are listed on Figure 1.1, for both production levels and for each size of powerplant. These demands must be added to the curves to obtain total demand on a powerplant.

.1 Kutcho Creek Area

The following mines and towns have been included in this area:

- Red Chris
- Eaglehead
- Letain
- Kutcho Creek
- Dease Lake Town

.2 Schaft Creek Area

The following mines and towns have been included in this area:

- Red Chris
- Schaft Creek
- Stikine Copper
- Eddontenajon and Telegraph Creek towns.

.3 All Areas

The following mines and towns have been included in these areas:

- Kutcho Creek area mines
- Schaft Creek area mines
- Dease Lake town
- Eddontenajon and Telegraph Creek towns
- Cassiar mine and town
- Adanac and Atlin town
- Logtung
- Sustut

1.5 YUKON AND ALASKA

Potential and existing mines in the Yukon and Alaska have not been included in this study. This decision was made following discussions with the B.C. and Yukon Chamber of Mines as to the potential for development in those areas compared with development in British Columbia.

In the Alaska panhandle, one prospect has been identified, but this is located on an island over 300 km from Mount Klappan. There are no large operating mines at present.

The exploration activity in the Yukon has involved expenditures of substantial amounts; nevertheless, development of substantial Yukon mines is not foreseen before the year 2000. The property of Amax/Logtung on the B.C./Yukon border has been included in the study.

Amax/Regional Resources have been actively exploring a number of lead-zinc deposits near Watson Lake (Midway deposits).

An area reported to have significant potential and exploration activity is around Macmillan Pass, however, this area is about 500 km north of Mount Klappan and straddles the Yukon/Northwest Territories border.

1.6 OTHER POTENTIAL MINES

The following areas or mines with identified potential have not been included in Table 1.1 but are mentioned here for reference.

161 WINDY-CRAGGY

This property is owned by Falconbridge Ltd. and Geddes Resources Ltd. The property is located in the extreme north-west of B.C. near the Alsek River, about 200 km west of Atlin (Adanac mine area). Recent public announcements say that the "drill-indicated" tonnage (12 holes) is "100 million tons grading at 2.8 percent copper and 0.09 percent cobalt. Inferred tonnage for the overall deposit -- is more than 334 million tons with a grade of 1.52 percent copper and 0.08 percent cobalt." (A second report says that the latter figures were based on 3 drill holes).

162 STEWART/KITSAULT AREA

At present the Canada Wide Mine (Granduc) north of Stewart has power provided by diesel-fired gas turbine generators using bunker C oil. The mine has reported an expected life through to 1988, but is recognised as having to overcome difficult mining conditions. The diesel-electrical installation at Stewart run by BCHPA has a rated capacity of 7.25 MW. Peak demand in 1983 was around 3 MW, and the town depends heavily on activity at Granduc. There are other potential mines in the area, however, the difficulties of mining and access are considerable. If adequate access is provided, it may be practical to extend the transmission line from Kitsault. Similarly, in addition to Amax Kitsault, there are large potential properties in the Kitsault/Alice Arm area. Disposal of tailings could present significant environmental problems. Should potential properties in both the Stewart and Alice Arm areas be developed reasonably concurrently, a good possibility may exist for extension of BCHPA service from Kitsault.

163 MISCELLANEOUS PROPERTIES

The following properties in the area studied have been reported on over the last five to ten years.

.1 New Jersey Zinc Exploration. Located near Cassiar, this property is reported as a potential producer. Reserves quoted in 1977 are 110 million tons with 0.115% Molybdenum. Expected life is approximately 15 years, based upon a 20,000 tpd production rate.

.2 Gnat Pass

This Hudson Bay property is between Red Chris and Dease Lake, and was reported in 1974 as being a potential open-pit copper operation with an expected life of 10 years. It is relatively low grade ore, however, and has not been included in the study.

1.7 PRECIOUS METAL MINES

For this study the potential loads from the precious metal mines have not been included. A brief discussion follows.

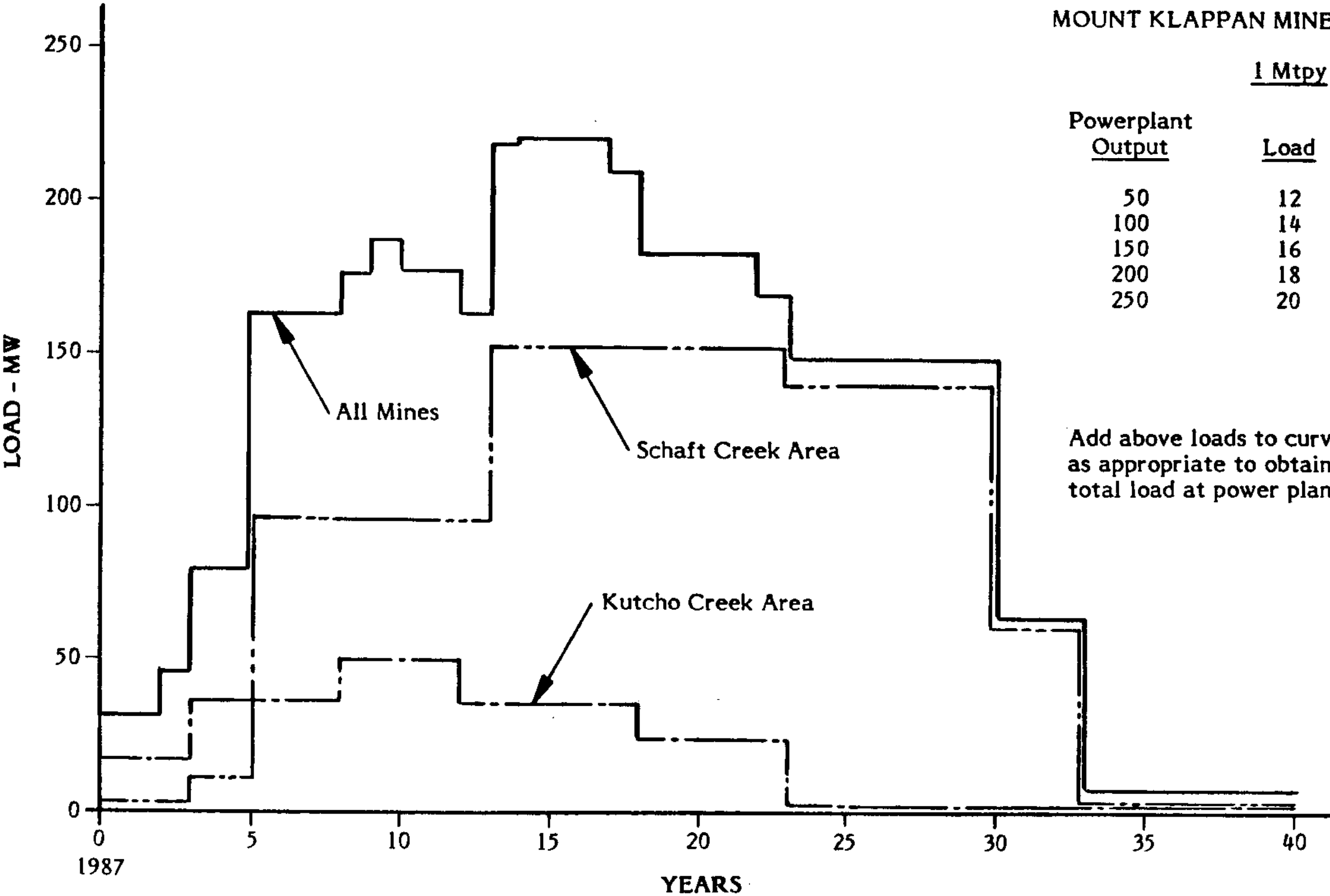
Existing small precious metal mines are reported to be served by diesel-generator sets, often mobile units. Both existing and potential precious metal mines in the vicinity of major existing or proposed mineral developments may have some potential as future loads to be serviced from Mount Klappan powerplant. One such group is in the Cassiar area.

Economic connection of such loads to the transmission line from Mount Klappan would depend upon the evaluation of the following:

- size of load and expected life of mine;
- anticipated continuity of production;
- distance from the major substation and substation and transmission line costs to the mine;
- increased transformer and switching costs to existing mines if voltage at the mine is presently generated at the required voltage by the diesel-generator set without transformation;
- sharing of capital and operating costs of the major transmission system built into the rate proposed;
- effect on the small mine of system stability problems with the major mine loads on line;
- reliability of supply should load-shedding on the system be required to service a major mine load.

FIGURE 1.1

LOAD GROWTH CURVES



MOUNT KLAPPAN MINE LOADS - MW

Powerplant Output	1 Mtpy Load	5 Mtpy Load
50	12	-
100	14	65
150	16	67
200	18	70
250	20	72

Add above loads to curves as appropriate to obtain total load at power plant.

PART 2

COAL-FIRED ELECTRIC GENERATING STATIONS
CAPITAL COST ESTIMATES

PART 2 - COAL-FIRED ELECTRIC GENERATING STATIONS
CAPITAL COST ESTIMATES

CONTENTS

2.1 INTRODUCTION

This part covers order-of-magnitude capital cost estimates for nine sizes of coal-fired electric generating stations, ranging from 50 MW to 250 MW installed capacity. The station would be located at Mount Klappan in the general vicinity of the coal mine operations. Likely sites for the generating stations have not been identified.

The estimates have been based upon use of coal with ash contents and specifications given below. Comments are provided on the order-of-magnitude effects of varying ash contents on capital costs.

In Figure 2.1, unit cost curves are provided which show the relationship between the unit cost per kilowatt of installed capacity, for both levels of coal quality. The unit costs shown are based upon twin-unit installations.

Factors have been provided in Section 2.6 which may be used with the cost curves to obtain cost estimates of stations employing various numbers and sizes of units. These combinations can be chosen to allow for variations in load buildup schedules and for variations in assumptions regarding standby units required for operation during periods of maintenance and down-time of other units.

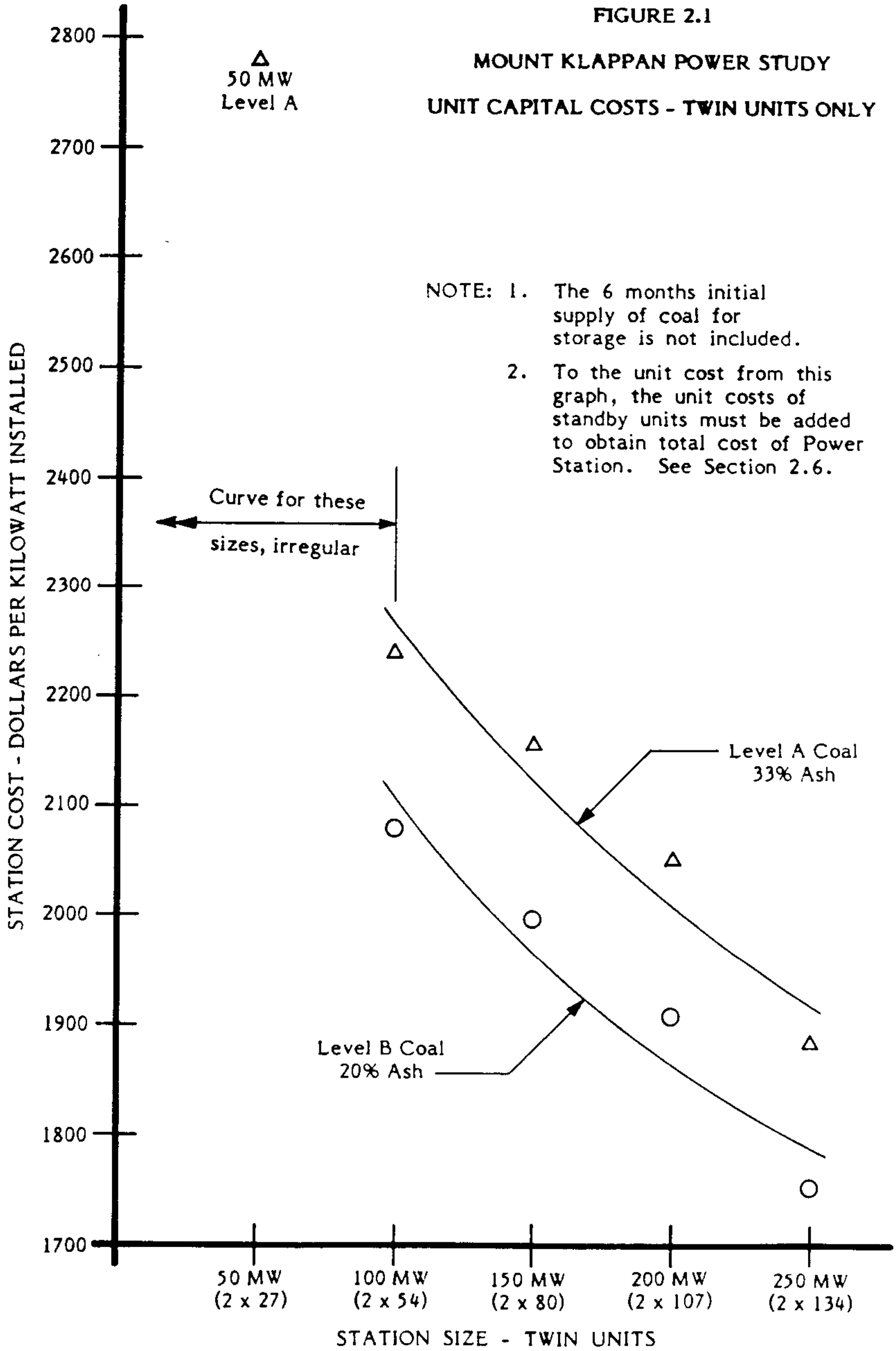
Comments are included on alternatives for cooling of condensate water, and relative cost figures are provided.

The matters of availability of water, means of ash disposal, and local environmental considerations can have a significant influence on the design of the associated facilities at the plant and their corresponding capital and operating costs. Investigation of these matters is beyond the scope of this study.

FIGURE 2.1

MOUNT KLAPPAN POWER STUDY

UNIT CAPITAL COSTS - TWIN UNITS ONLY



NOTE: 1. The 6 months initial supply of coal for storage is not included.

2. To the unit cost from this graph, the unit costs of standby units must be added to obtain total cost of Power Station. See Section 2.6.

2.2 SCOPE OF ESTIMATES

The estimates have been prepared for two levels of coal production, designated in this study as Level A and Level B, with two different ash contents, namely, 33% ash for Level A and 20% ash for Level B.

221

Level A: 1 000 000 tonnes per year of run-of-mine coal shipped as product. Powerplants would use run-of-mine coal which would be screened for oversize only prior to delivery to the plant. The sizes of the stations are:

- .1 50 MW net station output
- .2 100 MW net station output
- .3 150 MW net station output
- .4 200 MW net station output
- .5 250 MW net station output

222

Level B: 5 000 000 tonnes per year of washed product coal. Power plants would use washed coal from the coal preparation plant. The sizes of the stations are:

- .1 100 MW net station output
- .2 150 MW net station output
- .3 200 MW net station output
- .4 250 MW net station output

2.3 COAL QUALITY

231 SPECIFICATIONS USED

Following are the coal specifications adopted for this study:

.1 Level A - Proximate Analysis

Residual Moisture	-	1.5%
Ash	-	32.2%
Volatile Matter	-	6.6%
Fixed Carbon	-	59.7%
Total Sulphur	-	0.7%
HV	-	21.36 MJ/kg
	-	5116 kcal/kg

.2 Level B - Proximate Analysis

Residual Moisture	-	1.6%
Ash	-	19.0%
Volatile Matter	-	8.3%
Fixed Carbon	-	71.1%
Total Sulphur	-	0.6%
HV	-	27.2 MJ/kg
	-	6506 kcal/kg

2.4 EQUIPMENT

The following provides a brief description of the major components of the powerplant equipment.

241 BOILER PLANT EQUIPMENT

.1 Steam Generator

Type - indoor, pulverized coal, balanced draft. Pressure/Temperature - to match turbine generator requirement.

.2 Coal Handling System

The coal is to be transported from the coal mine to the powerplant site. The transportation system is not included. Coal delivery to the plant site is assumed to be daily except Saturday and Sunday. The coal distribution to stockpile is to be accomplished in one shift - 6 hours operation.

The conveying system will be complete with dry dust collection, wet dust suppression, sampling, crushing house, transfer tower, tramp iron magnets, belt scale, stationary trigger conveyor, feeders, hoppers, and boiler feed bins.

.3 Air Quality Control Systems

The boilers will be equipped with electrostatic precipitator for fly ash emission control and wet-type limestone scrubber for control of sulphur dioxide emissions.

.4 Ash and Sludge Disposal Systems

A pneumatic conveying system will remove ash from the boilers. Vacuum will be created by a mechanical exhauster. Ash will be stored in a silo and conditioned for dust control and unloaded at regular intervals. Sludge will be conditioned with fly-ash for ease of handling and removed at the regular intervals to the sludge disposal area.

242 TURBINE - GENERATOR AND RELATED SYSTEMS

.1 Turbine-Generators

The steam cycles assumed for the units are as follows:

- Twin Unit-27 MW (50 MW, net) - 1250 psig/950°F, four feedwater heaters 430°F feed temperature
- Twin Unit-54 MW (100 MW, net) - 1250 psig/950°F, four feedwater heaters, 430°F feed temperature
- Twin Unit-80 MW (150 MW, net) - 1800 psig/1000°F, five feedwater heaters, 450°F feed temperature
- Twin Unit-107 MW (200 MW, net) - 1800 psig/1000°F, six feedwater heaters, 450°F feed temperature
- Twin Unit-134 MW (250 MW, net) - 1800 psig/1000°F, six feedwater heaters, 450°F feed temperature

NOTE: A comment on the use of other size units or installing standby units for reliability of supply and the effect on the initial capital investment is presented in Section 2.5.

243 CONDENSER COOLING WATER SYSTEM

The system will employ evaporative type, mechanical draft cooling tower of wooden construction. A comment on the use of a cooling pond and other systems as alternatives to the cooling tower scheme is presented in Section 271. The source of raw water has not been identified for this study.

244 SWITCHYARD EQUIPMENT

The Switchyard will include all necessary equipment ready for connection of high voltage transmission lines.

2.5 CAPITAL COST ESTIMATES

A summary of the order-of-magnitude cost estimates for the various sizes of twin-unit powerplant for Level A and Level B are presented in Table 2.1. The range of costs have been presented in graphical form in Figure 2.1. As explained in Section 2.6, the graph and factors presented can be used to estimate the cost of a spare unit or units to provide a given firm station capacity for the load characteristics assumed.

251 WORK INCLUDED

Following are the major items of work included in the estimates:

.1 Boiler Plant Equipment and Related Systems: As outlined in Section 241.

.2 Turbine - Generators and Related Systems: As outlined in Section 242.

.3 Electrical Plant Systems and Equipment.

.4 Miscellaneous Powerplant Equipment, including spares, start-up oil and materials.

.5 Switchyard equipment complete ready for connection of high-voltage transmission lines.

.6 Buildings and structures, including main power building, administration building, warehouse and machine-shop, gate-house; stack.

.7 Raw Water Supply. An allowance has been included for this system. No work has been done, however, to identify the potential location, type and pumping systems necessary to supply raw water to the powerplants.

.8 On-Site Ground Improvements, including site for coal pile, clearing, excavation and fill, roads, fencing, drainage, sewage and fire and domestic water systems, yard lighting, all within the battery limits only. A reasonably level site has been assumed with no unusual foundation conditions.

.9 Sludge Disposal. The location and type of sludge disposal area depend upon a detailed study of site conditions and environmental requirements. An allowance only has been included for the disposal area, and it is emphasized that actual costs can vary widely.

.10 Camp Costs. An allowance has been made for camp costs during construction.

.11 Coal in Storage. An initial supply of coal in storage sufficient for 6 months operation has been included in the estimates.

252 WORK AND COSTS NOT INCLUDED

The following items have not been included in the cost estimates.

.1 Access. Road and rail access to the powerplant site have been assumed to be available.

.2 Land Costs.

.3 Offsite Improvements.

.4 Interest During Construction.

.5 Owner's Costs, both during construction and for housing of operating staff.

.6 Construction Model.

.7 Mobile Equipment for Coal Supply and Ash Disposal.

.8 District Heating for local town. Note: An opportunity exists at Mount Klappan for district heating and should be studied further.

.9 Escalation.

253 BASIS OF ESTIMATES

The cost estimates are based on 1982 costs in Canadian dollars. No drawings were prepared and no specific site location studies were conducted.

Costs contained in Table 2.1 are based upon the following elements.

.1 Labour

Labour costs include labour, payroll burden, travel costs, consumables and small tools, and contractor's overhead and profit. A 45 hour work week (37½ hours straight time and 7½ hours double time) has been assumed as an incentive to attract a skilled work force.

.2 Material

Material pricing was based on in-house information and experience on projects in British Columbia. All material costs are assumed to be F.O.B. jobsite.

.3 Equipment

For equipment pricing, budget telephone quotes were obtained for the steam generators, electrostatic precipitators, scrubbers, major pumps, turbine generators and condensers. Other equipment was priced from in-house data.

.4 Construction Equipment

Equipment usage is included in the unit cost and is the cost of construction equipment excluding operator and oiler.

.5 Taxes and Duty

An allowance of 5% has been included for these items.

.6 Contractor's Overhead and Profit

Contractor's overhead and profit is included in the unit prices.

.7 Indirect Costs

Other indirect costs such as professional services and construction management are calculated at 15% of construction cost plus spare parts and lube oil/start materials, etc.

254 CAPITAL COST CURVES

The Figure 2.1 curves show the order-of-magnitude relationship between station size for the unit combinations shown and the unit cost in dollars per kilowatt installed. Some particular comments follow.

.1 Station Size

The unit costs have been based upon installation of twin units of output shown. The installed capacities are shown in parentheses. The difference between the two corresponds to an assumed station service power requirement of 7%.

The curves are intended as an aid in determining the relative costs of twin coal-fired units when used in combination with other coal-fired units, or diesel electric units, for standby (necessary to provide the firm capacity of the station). The costs of the standby units can be added to the twin unit costs as explained in Section 2.6.

.2 Unit Costs

The unit costs of stations below the 100 MW capacity rise very rapidly, and the values can be quite irregular depending upon size combinations and specifications chosen. For this reason, the curves have not been drawn between values shown for stations sized below 100 MW. A rough unit cost for a 30 MW station would be $2,900 per kilowatt installed for Level A coal, assuming twin 16 MW units.

.3 Varying Ash Content of Coal

The two curves shown for Level A and Level B coals indicate the difference in unit costs for the two ash levels. Boiler manufacturers quoted a range of 10% to 15% increase in the boiler plant cost for a corresponding increase in coal ash content from 20% to 33%. The cost of the balance of the plant remains the same. Interpolation between these curves for ash contents between 20% and 33% will provide a reasonable unit cost estimate.

2.6 CHOICE OF UNIT SIZE

The cost estimates contained in Table 2.1 have been based upon the installation of twin units to provide the installed capacities shown.

These cost estimates of twin units have been prepared to form a basis or framework from which to estimate the costs of a powerplant in which various combinations of unit sizes are chosen to suit load assumptions, demand variations, and standby units required for operation during periods of overhaul and downtime on other units.

Example 1: For a firm capacity of 100 MW the powerplant could consist of 3-50 MW units installed capacity, with one unit as standby. Another choice may be 2-50 MW units and 2-25 MW units installed, which would provide more flexibility in operation to accommodate varying demands and downtime, and can afford more efficient operating ranges in the larger units by use of one of the smaller units at full load in place of a second larger unit at half load.

Order-of-magnitude comparisons can be made in the same way for powerplant sizes chosen to suit a given combination of mine loads, and adjustments can be made to assess the effects of differing demand levels from mines and various assumptions as to sequence of development and anticipated life of mines.

Similarly, order-of-magnitude comparisons can be made between smaller, coal-fired standby units and comparable diesel generator units, the costs of which are set out in Part 5.

For convenience, as explained in Section 254, the curves given in Figure 2.1 can be used to make these comparisons together with the application of the following factors which are based upon experience. This may be best illustrated by further examples, as follows:

Example 2: Three-Unit Installation, with one unit used as a standby.

To estimate the cost per kilowatt of the standby unit, obtain the cost per kilowatt installed (for twin units) from Figure 2.1, then multiply the result by 85%.

50 MW net firm station output.
Choose 3 x 27 MW units = 81 MW installed capacity, using one unit as a standby unit.

Twin Units - unit cost = \$2,790/kW installed
Spare Unit - unit cost = 0.85 x \$2,790
= \$2,370/kW installed

Total installed cost = \$2,790/kW x 54 x 10^3 kW + \$2,370/kW x 27 x 10^3 kW

= \$215 Million

÷ 81 MW = \$2,655/kW installed

Example 3:

Four-Unit Installation, with a diesel unit used as standby

To estimate the cost per kilowatt of four similar coal-fired units, obtain the cost per kilowatt installed (for two units) from Figure 2.1, then multiply the result by 95%.

100 MW net firm station output.
Choose 4 x 27 MW coal-fired units plus 25 MW diesel standby capacity = 133 MW installed capacity.

Four Units - unit cost = 0.95 x \$2,790/kW
= \$2,650/kW installed
Diesel Units - unit cost (Table 5.1) = \$775/kW installed

Total Installed Cost = \$2,650 x 108 x 10^3+ \$775 x 25 x 10^3
= \$305 Million

÷133 MW = \$2,295/kW installed

Use of unit costs of diesel units for standby capacity as given in Part 5 will result in a conservative estimate of overall cost because the coal-fired station costs include an allowance for black-start diesel capability.

The effect on the unit costs is not large and is within the order-of-magnitude of the estimates.

2.7 COMMENTS AND ALTERNATIVES

271 COOLING WATER ALTERNATIVES

No investigation was made in this study of potential sites and sources for obtaining raw water for the powerplants, and no investigation was made to identify potential sites for cooling ponds. Similarly, no attempt was made to evaluate possible environmental effects of various kinds of cooling towers or ponds.

.1 Mechanical Draft Cooling Towers

The cost estimates are based upon the use of this type of cooling tower. The approximate water requirement for domestic use, cooling tower makeup, boiler water makeup, and other miscellaneous services for both Level A and Level B are as follows:

Plant Size, MW	50	100	150	200	250
Water Requirement, US g.p.m.	2100	4100	5600	6700	8100

NOTE: Approximately 96% of the above water requirement is for cooling tower makeup.

The effects of possible formation of fog from the cooling tower must be evaluated for any site location and climatic conditions as to effects on the actual operations and on the environment in general.

.2 Cooling Pond

In general, the initial investment cost of a cooling pond could be expected to be about 150% higher than the cost of mechanical draft cooling towers. However, the operating costs associated with the cooling pond could be much lower and the pond aesthetically preferred over the cooling tower scheme. The difference in operating costs would depend upon the location of the pond. The environmental impact or effect of the cooling pond would also be less and contained in a smaller area than the cooling tower scheme. In addition, possibly the cooling pond could also be utilized for recreational purposes.

Based on climatological conditions at the site, the cooling pond area requirements for the units would be approximately 0.70 acre to 1.0 acre for each installed megawatt plant capacity or about 14 acre feet per MW.

.3 Natural Draft Cooling Towers

These are about twice as expensive to build as mechanical draft towers.

.4 Dry Type Radiator Systems

These air cooled systems (direct and indirect) cost about three and a half to four times as much to build as a mechanical cooling tower system and require large volumes of air for cooling. Potential acoustical problems must be considered with these systems.

.5 Wet/Dry Systems

The systems operate wet in summer (rely on water evaporation for cooling) and dry in winter. They cost about twice as much as the mechanical draft systems.

272 SLUDGE AND ASH DISPOSAL

No study has been made as to potential sludge and ash disposal sites. The environmental climatic and geological considerations can have a marked influence on the choice of a site and the type of disposal area and relationship to the mining operation, and must be studied in detail for each specific site. Disposal of sludge in winter presents substantial storage, transporting and disposal problems and, similarly, must be the subject of detailed study.

273 FLUIDIZED BED COMBUSTION (FBC)

Recent budget pricing information of an FBC boiler of the atmospheric type shows competitiveness with conventional boilers.

Some of the major advantages are as follows:

- Expected lower operating and maintenance costs.
- Elimination of energy requirements to operate flue gas desulphurization system (FGD).
- Sulphur dioxide (SO_2) removal efficiency is simply adjusted for different coals by changing the coal to limestone ratio.
- Lower production of oxides of nitrogen (NO_x) because of reduced combustion temperatures.

- Spent limestone is removed with the ash in a dry, easily stored form (unlike the large volumes of wet FGD sludge which are difficult to transport and store).
- Unburned carbon is passed through a carbon burn-up cell (CBC) for complete combustion to remove monoxide, unburned hydrocarbons and soot.

The potential advantages of the fluidized bed combustion system are so significant that it is strongly recommended a study be made of comparative capital and operating costs. Evaluation of the environmental advantages of the system should also be included in the study.

274 STIKINE COPPER AND SCHAFT CREEK MINES

The demands from both of these mines would be very high, and that from Stikine Copper would be higher than any existing open-pit mine in British Columbia. The influence of either one or both of these mines, and the expected start dates, on the sizes of units chosen in a powerplant would be most significant.

TABLE 2.1

CAPITAL COST ESTIMATE SUMMARY

COAL-FIRED ELECTRIC GENERATING STATIONS

($000 Cdn - 1982)

DESCRIPTION	LEVEL A - 1 Million Tonne Per Year				
	50 MW (2 x 27 MW)	100 MW (2 x 54 MW)	150 MW (2 x 80 MW)	200 MW (2 x 107 MW)	250 MW (2 x 134 MW)
ON-SITE FACILITIES					
On-site Ground Improvements	3,250	3,700	4,100	4,500	5,150
Buildings and Structures	14,700	15,350	17,700	20,800	24,200
Boiler Plant Equipment	47,400	87,100	131,900	159,250	184,250
Turbine Generator & Related Systems	17,700	27,200	37,000	57,800	65,200
Electrical Plant Systems & Equipment	6,800	11,000	16,100	20,650	23,750
Miscellaneous Power Plant Equipment	2,600	4,450	6,050	7,800	9,050
Switchyard	2,200	3,350	4,350	5,700	6,900
TOTAL DIRECT CONSTRUCTION COST	$ 94,650	152,150	217,200	276,500	318,500
Taxes and Duty	6,450	10,350	14,780	18,800	21,650
Spare Parts Allowance	960	1,500	2,150	2,710	3,140
Lube Oil/Start Materials etc.	40	50	70	90	110
SUB-TOTAL	$102,100	164,050	234,200	298,100	343,400
Professional Services Engineering Services and Procurement Construction Management	15,400	24,600	35,100	44,700	51,500
SUB-TOTAL	$117,500	188,650	269,300	342,800	394,900
Contingency	23,500	37,750	53,900	68,400	78,900
TOTAL ON-SITE COST	$141,000	226,400	323,200	411,200	473,800
OFF-SITE FACILITIES					
Camp Cost	6,600	10,650	15,200	19,350	22,300
Raw Water Supply	800	1,400	1,900	2,300	2,600
Ash/Sludge Disposal Area	500	800	1,000	1,200	1,400
SUB-TOTAL	$ 7,900	12,850	18,100	22,850	26,300
Contingency	1,600	2,550	3,600	4,550	5,300
TOTAL OFF-SITE COST	$ 9,500	15,400	21,700	27,400	31,600
TOTAL CAPITAL COST	**150,500**	**241,800**	**344,900**	**438,600**	**505,400**
Initial Coal Supply - 6 months	6,600	13,200	19,200	25,900	32,000

(Level A, $50.00/t. Level B, $75.00/t)

Caution: The above capital costs must be adjusted for costs of standby capacity. See Section 2.6.

TABLE 2.2

CAPITAL COST ESTIMATE SUMMARY

COAL-FIRED ELECTRIC GENERATING STATIONS

($000 Cdn - 1982)

DESCRIPTION	LEVEL B - 5 Million Tonne Per Year			
	100 MW (2 x 54 MW)	150 MW (2 x 80 MW)	200 MW (2 x 107 MW)	250 MW (2 x 134 MW)
ON-SITE FACILITIES				
On-site Ground Improvements	3,500	3,650	3,900	4,500
Buildings and Structures	13,600	15,800	18,600	21,650
Boiler Plant Equipment	78,500	118,050	142,650	164,950
Turbine Generator & Related Systems	27,200	37,000	57,800	65,200
Electrical Plant Systems & Equipment	11,000	17,000	20,650	23,750
Miscellaneous Power Plant Equipment	4,100	6,050	7,800	9,050
Switchyard	3,350	4,350	5,700	6,900
TOTAL DIRECT CONSTRUCTION COST	141,250	201,900	257,100	296,000
Taxes and Duty	9,600	13,650	17,500	20,100
Spare Parts Allowance	1,410	1,990	2,530	2,910
Lube Oil/Start Materials etc.	40	60	70	90
SUB-TOTAL	152,300	217,600	277,200	319,100
Professional Services Engineering Services and Procurement Construction Management	22,900	32,500	41,600	47,800
SUB-TOTAL	175,200	249,100	318,800	366,900
Contingency	35,000	49,800	63,800	73,400
TOTAL ON-SITE COST	210,200	298,900	382,600	440,300
OFF-SITE FACILITIES				
Camp Cost	9,900	14,050	18,000	20,700
Raw Water Supply	1,400	1,900	2,300	2,600
Ash/Sludge Disposal Area	600	800	1,000	1,100
SUB-TOTAL	11,900	16,750	21,300	24,400
Contingency	2,400	3,250	4,200	4,900
TOTAL OFF-SITE COST	14,300	20,000	25,500	29,300
TOTAL CAPITAL COST	**224,500**	**318,900**	**418,100**	**469,600**
Initial Coal Supply - 6 months	16,000	22,400	31,000	38,000

(Level A, $50.00/t. Level B, $75.00/t)

Caution: The above capital costs must be adjusted for costs of standby capacity. See Section 2.6.

PART 3

COAL-FIRED ELECTRIC GENERATING STATIONS

OPERATING COST ESTIMATES

PART 3 - COAL-FIRED ELECTRIC GENERATING STATIONS OPERATING COST ESTIMATES

CONTENTS

3.1 INTRODUCTION

The annual operating cost estimates for the nine coal-fired generating stations from 50 MW to 250 MW capacity are presented in Tables 3.1, 3.2 and 3.3. Each table is based upon different assumptions for cost of coal.

The costs shown include the cost of fuel, labour, plant management, operating and maintenance materials and services, and sludge/ash disposal.

For Level A, 1 000 000 tonne per year production of product coal, the operating costs have been based upon use of coal with a 33% ash content as discussed in Part 2.

The coal costs are based upon the tonnage required to produce the net output capacity assuming that 100% of the output would be required 100% of the time (8760 hours per year) using coal only as fuel.

The actual installed capacity necessary to provide this output would be larger and the spare or standby capacity necessary could be provided by coal-fired units or, more probably, by diesel generator sets or oil-fueled gas turbine-generator sets.

3.2 BASIS OF ESTIMATES

321 COST OF COAL

The required annual tonnage of coal is based upon coal providing 100% of the output. The unit costs per tonne have been assumed to be:

	Level A, 1 000 000 tpy	Level B, 5 000 000 tpy
Table 3.1	$50.00	$75.00
Table 3.2	$25.00	$25.00
Table 3.3	$50.00	$50.00

As can be seen from the tables, the operating costs per kWh are most sensitive to the price of coal for all assumed unit costs of coal.

322 SLUDGE/ASH REMOVAL

A unit cost of $2.00 per tonne has been assumed. As discussed in Part 2, the unit cost will depend upon actual site conditions and the effects of winter weather on storage, handling and transportation facilities.

323 OPERATING AND MAINTENANCE MATERIALS AND CHEMICALS

Estimates for these items have been based upon data available from similar installations.

324 OPERATING AND MAINTENANCE LABOUR

The numbers of operators and maintenance personnel required have been based upon data available from similar sized plants. The average cost per year has been taken as $47,000 per man, including fringe benefits.

325 MANAGEMENT AND SUPERVISION

The cost per year for these personnel for the numbers estimated has been based upon an annual salary cost of $65,000 per person, including fringe benefits.

326 INCREMENTAL COST OF FUEL OIL

Should oil-fueled diesel-generator or gas turbine-generator sets be used for standby service rather than a similar size coal-fired unit, it would be necessary to add to the operating costs shown in Table 3.1, 3.2 and 3.3, the incremental cost of fuel oil used.

The amount of fuel-oil used would depend upon the combination of unit sizes chosen for a given station capacity and the assumed station capacity factors for given load combinations. This amount of fuel oil would be in addition to that required for boiler start-up and for combustion stabilization when a unit may be operating at low load conditions.

An order-of-magnitude comparison of the fuel cost in cents per kWh is:

	Table 3.1	Table 3.2	Table 3.3
- Raw Coal:	3.0	1.5	3.0
- Washed Coal:	3.5	1.2	2.4
- Diesel Oil:	10.0	10.0	10.0

327 STATION CAPACITY FACTOR

In order to provide the firm power output on which the tables have been based, it probably would be more practical and economical to install oil-fueled gas turbine-generator or diesel generator sets rather than a similarly sized coal-fired unit for backup or standby service. The amount of fuel oil used would depend upon the assumed capacity factor of the station for servicing mine loads and the combination of sizes of units chosen to economically serve the system. For comparison, the typical lifetime capacity factor of utility type coal-fired powerplants of the unit sizes and technical features assumed in the study is approximately 70%. (This figure is based upon the Edison Electric Institute (EEI) annual survey of operating powerplants in the U.S.A.).

The expected overall economy of utilizing oil-fired standby units would result from lower capital costs of the sets compared with coal-fired units. The operating costs could be higher, however, this would depend upon the load levels at which the coal-fired units would be operating.

TABLE 3.1

TABLE 3.1

ANNUAL OPERATING COST ESTIMATES

COAL-FIRED ELECTRIC GENERATING STATIONS

($ 000 Cdn - 1982)

Coal Cost
Level A - $50.00/tonne
Level B - $75.00/tonne

DESCRIPTION	LEVEL A - 1 Mtpy 50 MW	100 MW	150 MW	200 MW	250 MW	LEVEL B - 5 Mtpy 100 MW	150 MW	200 MW	250 MW
Materials and Miscellaneous									
Coal Requirement-t/yr	(264,000)	(526,000)	(754,000)	(1,034,000)	(1,280,000)	(422,000)	(596,000)	(824,000)	(1,018,000)
Ash/Sludge Flow-t/yr	(130,000)	(260,000)	(375,000)	(510,000)	(625,000)	(125,000)	(175,000)	(240,000)	(295,000)
Coal Cost	13,200	26,300	37,700	51,700	64,000	31,600	44,700	61,800	76,300
Ash/Sludge Disposal	260	520	750	1,020	1,250	250	350	480	590
Operating Materials, Chemicals	190	260	320	380	450	250	300	350	400
Maintenance Materials, Services	550	1,000	1,500	2,000	2,500	900	1,350	1,870	2,300
Sub-Total	14,200	28,100	40,300	55,100	68,200	33,000	46,700	64,500	79,600
Labour									
Operating, Maintenance, Misc.	(57)	(75)	(95)	(105)	(115)	(75)	(95)	(105)	(115)
Cost @ $47,000/yr	2,680	3,520	4,470	4,930	5,400	3,520	4,470	4,930	5,400
Manager, Supervisory	(6)	(7)	(8)	(9)	(9)	(7)	(8)	(9)	(9)
Cost @ $65,000/yr	390	450	520	590	590	450	520	590	590
Sub-Total	3,100	4,000	5,000	5,500	6,000	4,000	5,000	5,500	6,000
TOTAL ANNUAL COST	17,300	32,100	45,300	60,600	74,200	37,000	51,700	69,000	85,600
Annual Energy Output-kWh x 10^6	438	876	1,314	1,752	2,190	876	1,314	1,752	2,190
Operating Cost-¢/kWh	3.95	3.66	3.45	3.46	3.39	4.22	3.93	3.94	3.91

Note: The annual operating cost estimates are based upon 100% load operation, 24 hours per day, 365 days per year = 8,760 kWh/year produced for each kW net output.
The unit cost per kWh energy output is very sensitive to assumed cost per tonne of coal.
Totals have been rounded.

TABLE 3.2

TABLE 3.2

ANNUAL OPERATING COST ESTIMATES

COAL-FIRED ELECTRIC GENERATING STATIONS

($ 000 Cdn - 1982)

Coal Cost
- $25.00/tonne

	LEVEL A - 1 Mtpy					LEVEL B - 5 Mtpy			
DESCRIPTION	50 MW	100 MW	150 MW	200 MW	250 MW	100 MW	150 MW	200 MW	250 MW
Materials and Miscellaneous									
Coal Requirement-t/yr	(264,000)	(526,000)	(754,000)	(1,034,000)	(1,280,000)	(422,000)	(596,000)	(824,000)	(1,018,000)
Ash/Sludge Flow-t/yr	(130,000)	(260,000)	(375,000)	(510,000)	(625,000)	(125,000)	(175,000)	(240,000)	(295,000)
Coal Cost @ $25.00/tonne	6,600	13,100	18,800	25,800	32,000	10,500	14,900	20,600	25,500
Ash/Sludge Disposal	260	520	750	1,020	1,250	250	350	480	590
Operating Materials, Chemicals	190	260	320	380	450	250	300	350	400
Maintenance Materials, Services	550	1,000	1,500	2,000	2,500	900	1,350	1,870	2,300
Sub-Total	7,600	15,000	21,500	29,300	36,200	11,900	16,900	23,300	28,800
Labour									
Operating, Maintenance, Misc.	(57)	(75)	(95)	(105)	(115)	(75)	(95)	(105)	(115)
Cost @ $47,000/yr	2,680	3,520	4,470	4,930	5,400	3,520	4,470	4,930	5,400
Manager, Supervisory	(6)	(7)	(8)	(9)	(9)	(7)	(8)	(9)	(9)
Cost @ $65,000/yr	390	450	520	590	590	450	520	590	590
Sub-Total	3,100	4,000	5,000	5,500	6,000	4,000	5,000	5,500	6,000
TOTAL ANNUAL COST	10,700	19,000	26,500	34,800	42,200	15,900	21,900	28,800	34,800
Annual Energy Output-kWh x 10^6	438	876	1,314	1,752	2,190	876	1,314	1,752	2,190
Operating Cost-¢/kWh	2.44	2.17	2.02	1.99	1.93	1.82	1.67	1.64	1.59

Note: The annual operating cost estimates are based upon 100% load operation, 24 hours per day, 365 days per year = 8,760 kWh/year produced for each kW net output.
The unit cost per kWh energy output is very sensitive to assumed cost per tonne of coal.
Totals have been rounded.

TABLE 3.3

TABLE 3.3

ANNUAL OPERATING COST ESTIMATES

COAL-FIRED ELECTRIC GENERATING STATIONS

($ 000 Cdn - 1982)

Coal Cost
- $50.00/tonne

	LEVEL A - 1 Mtpy					LEVEL B - 5 Mtpy			
DESCRIPTION	**50 MW**	**100 MW**	**150 MW**	**200 MW**	**250 MW**	**100 MW**	**150 MW**	**200 MW**	**250 MW**
Materials and Miscellaneous									
Coal Requirement-t/yr	(264,000)	(526,000)	(754,000)	(1,034,000)	(1,280,000)	(422,000)	(596,000)	(824,000)	(1,018,000)
Ash/Sludge Flow-t/yr	(130,000)	(260,000)	(375,000)	(510,000)	(625,000)	(125,000)	(175,000)	(240,000)	(295,000)
Coal Cost	13,200	26,300	37,700	51,700	64,000	21,100	29,800	41,200	50,900
Ash/Sludge Disposal	260	520	750	1,020	1,250	250	350	480	590
Operating Materials, Chemicals	190	260	320	380	450	250	300	350	400
Maintenance Materials, Services	550	1,000	1,500	2,000	2,500	900	1,350	1,870	2,300
Sub-Total	14,200	28,100	40,300	55,100	68,200	22,500	31,800	43,900	54,200
Labour									
Operating, Maintenance, Misc.	(57)	(75)	(95)	(105)	(115)	(75)	(95)	(105)	(115)
Cost @ $47,000/yr	2,680	3,520	4,470	4,930	5,400	3,520	4,470	4,930	5,400
Manager, Supervisory	(6)	(7)	(8)	(9)	(9)	(7)	(8)	(9)	(9)
Cost @ $65,000/yr	390	450	520	590	590	450	520	590	590
Sub-Total	3,100	4,000	5,000	5,500	6,000	4,000	5,000	5,500	6,000
TOTAL ANNUAL COST	17,300	32,100	45,300	60,600	74,200	26,500	36,800	49,400	60,200
Annual Energy Output-kWh x 10^6	438	876	1,314	1,752	2,190	876	1,314	1,752	2,190
Operating Cost-¢/kWh	3.95	3.66	3.45	3.46	3.39	3.03	2.80	2.82	2.75

Note: The annual operating cost estimates are based upon 100% load operation, 24 hours per day, 365 days per year = 8,760 kWh/year produced for each kW net output.
The unit cost per kWh energy output is very sensitive to assumed cost per tonne of coal.
Totals have been rounded.

PART 4

Table

Plate

4.1 INTRODUCTION

Estimates of capital costs of transmission line systems from Mount Klappan of 138 kV and 230 kV capacity, and of switching and distribution substations, are presented in Table 4.1 through Table 4.8. These systems would serve major potential loads from large mines and townships which have been identified in Part 1 and shown on Plate 1.1.

The operating cost estimates are presented in Table 4.9.

All systems have been based on the provision of single circuit transmission lines, and no grid has been assumed for any system.

Various alternative systems have been identified for preparation of cost estimates. These systems have been chosen to serve various groups of loads from major potential mines. The systems chosen are shown on Plates 4.1 through 4.8. The choice of voltage for the systems has been based upon empirical rules-of-thumb and discussions with BCHPA.

4.2 SYSTEM ALTERNATIVES

In order to provide comparisons between costs of various transmission and associated substation systems which could serve the major load areas identified, a series of alternative systems have been chosen to reflect the possible development of the two major load areas as occurring at significantly different times, namely, Kutcho Creek area and Schaft Creek area. Sufficient combinations are presented in the alternative systems studied to allow order-of-magnitude comparisons within parts or sections of various systems.

For convenience of reference, for each system a map is provided which shows the mines served and transmission route (Plates 4.1 through 4.8). A table which shows the components of the system and the capital cost estimate for same follows each map.

The systems chosen have been divided broadly into 138 kV and 230 kV systems. Following are the systems for which estimates have been made:

138 kV Systems

System 1 (Plate 4.1)	Mount Klappan to Red Chris Mine and Eddontenajon town, thence northeast to Eaglehead/Letain/Kutcho Creek mines.

System 2 (Plate 4.2)	Mount Klappan to Red Chris Mine, thence north to Dease Lake, and thence east to Eaglehead/Letain/Kutcho Creek mines.
System 3 (Plate 4.3)	System 2 plus Dease Lake to Cassiar and thence west to Atlin (Adanac Mine).
System 4 (Plate 4.4)	Mount Klappan to Sustut Mine to the southeast.

230 kV Systems

System 5 (Plate 4.5)	Mount Klappan to Red Chris Mine, Telegraph Creek and thence south to Stikine Copper and Schaft Creek Mines.
System 6 (Plate 4.6)	System 5 plus Dease Lake, Eaglehead/Letain/Kutcho Creek mines.
System 7 (Plate 4.7)	All loads.
System 8 (Plate 4.8)	Alternative route west to Stikine Copper and Schaft Creek Mines via Bob Quinn Lake.

4.3 CAPITAL COST ESTIMATES

431 BASIS OF ESTIMATES

The capital cost estimates have been based generally upon discussions with BCHPA who have made studies over the years on potential transmission corridors and have assessed the general physical conditions of the potential areas to be served.

432 ROUTE SELECTION

The routes for each of the system alternatives selected have been based upon information provided by BCHPA from their studies assuming Mount Klappan as the power source.

433 LINE LENGTH

Lengths of transmission lines have been estimated from small scale maps, and are of order-of-magnitude accuracy. Each system is based upon terminating the line at the mine named at the end of the system.

434 LINE COSTS

Unit costs for 128 kV and 230 kV line construction were based upon discussions with BCHPA who have performed route studies and cost studies for transmission systems in the area from Mount Klappan to potential mines. These prices were subsequently reviewed with a contractor experienced in line construction and labour productivity in remote areas of British Columbia.

Unit costs of 138 kV and 230 kV lines were estimated at $ 140,000/km and $ 160,000/km respectively. These costs include allowances for:

- right-of-way survey and land acquisition costs of $ 3,000/km
- clearing and access roads
- all pole line materials
- foundation and installation work
- camp costs
- engineering and site inspection
- contingency allowance of 15%.

Wooden pole H-frame construction has been assumed generally for both 138 and 230 kV lines. The poles would be buried direct in the ground with compacted backfill. Certain sections may require steel towers depending upon conditions.

435 MISCELLANEOUS

No consideration has been given to possible effects on routing due to Indian Reserves along the Stikine River or to Indian land claims.

No consideration has been given to possible conflict with routes which may be planned by BCHPA for the future. Such conflict could affect routing in areas of minimal land availability at reasonable cost, if such exist.

No allowance has been made for winter construction; it has been assumed that all line construction would be performed in summer.

A higher unit cost allowance has been made for System 8, based upon discussions with BCHPA as to type of terrain and effect of possible land reserves for hydro-electric development in the future at the More Creek site.

PLATE 4.1

TRANSMISSION SYSTEM 1

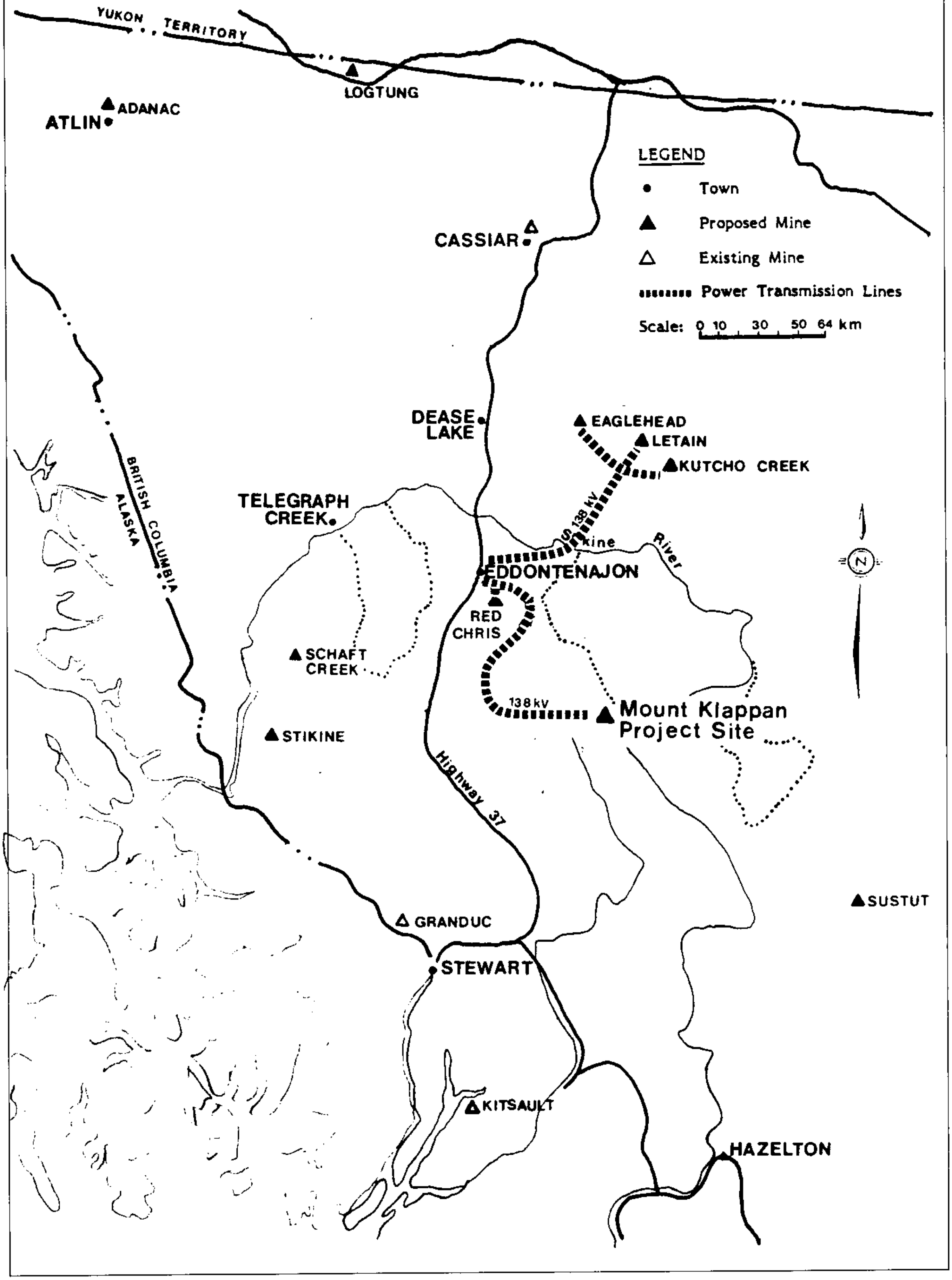


TABLE 4.1

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 1 - 138 kV

($000 Cdn - 1982)

Mount Klappan to Red Chris Substation	$
- 138 kV transmission line	23,700
- 25 kV line to mine	1,000
- 25 kV line to Eddontenajon	100
Substation, allow	2,700
Red Chris to Kutcho Creek area	
- 138 kV transmission line	18,600
- 69 kV line to Eaglehead	2,600
- 69 kV line to Letain	1,300
- 69 kV line to Kutcho	3,500
- 25 Kv line to townsite	300
Substation, allow	3,200
TOTAL	57,000

PLATE 4.2

TRANSMISSION SYSTEM 2

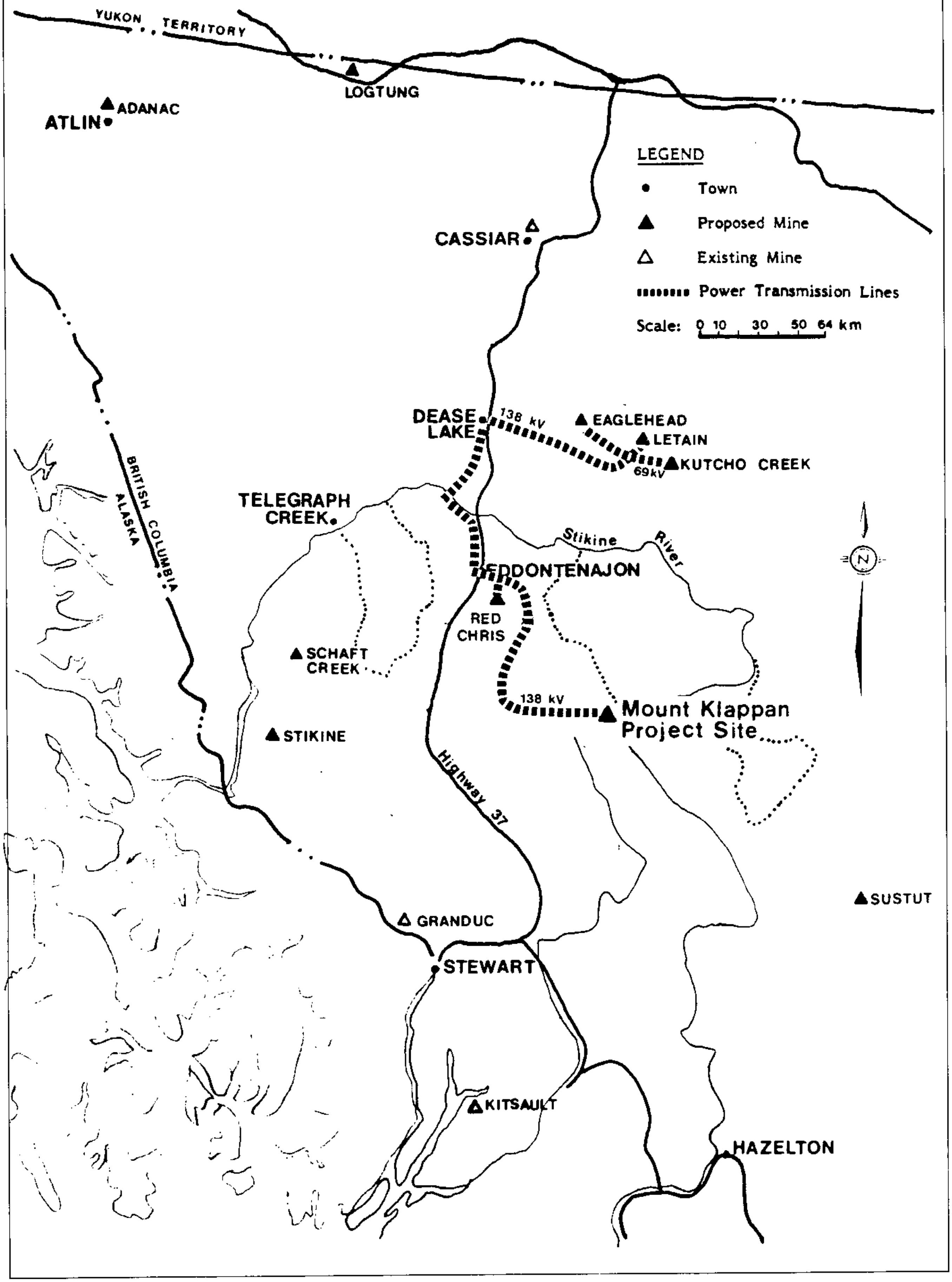


TABLE 4.2

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 2 - 138 kV

($000 Cdn - 1982)

Mount Klappan to Red Chris Substation	$
- 138 kV transmission line	23,500
- 25 kV line to mine	1,000
- 25 kV line to Eddontenajon	100
Substation, allow	2,900
Red Chris to Dease Lake area	
- 138 kV transmission line	18,600
- 25 kV line to Dease Lake	200
Substation, allow	3,100
Dease Lake to Kutcho Creek area	
- 138 kV transmission line	12,600
- 69 kV line to Eaglehead	2,600
- 69 kV line to Letain	1,300
- 69 kV line to Kutcho Creek	3,600
- 25 kV line to townsite	300
Substation, allow	3,200
TOTAL	73,000

PLATE 4.3

TRANSMISSION SYSTEM 3

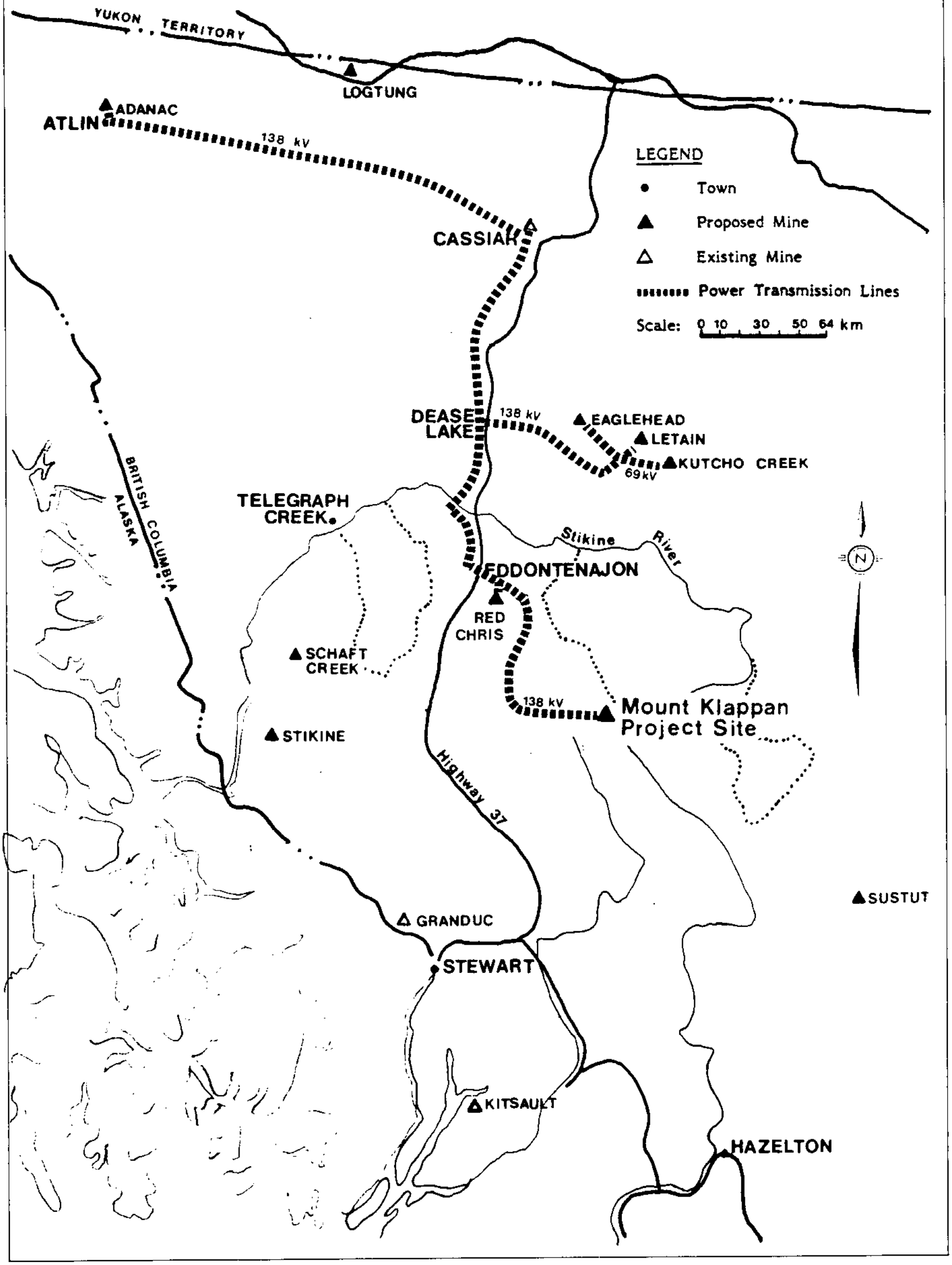


TABLE 4.3

CAPITAL COST ESTIMATE - 1982 $000's

TRANSMISSION SYSTEM 3 - 138 kV

		$
System 2		
-	138 kV serving Red Chris, Kutcho Creek area. Ref. Table 4.2	73,000
Dease Lake to Cassiar		
-	138 kV transmission line	15,300
-	69 kV to mine	400
-	69 kV to town	300
Substation, allow		2,900
Cassiar to Atlin (Adanac)		
-	138 kV transmission line	39,000
-	69 kV to mine	1,100
-	25 kV to town	500
Substation, allow		2,500
TOTAL		$135,000

PLATE 4.4
TRANSMISSION SYSTEM 4

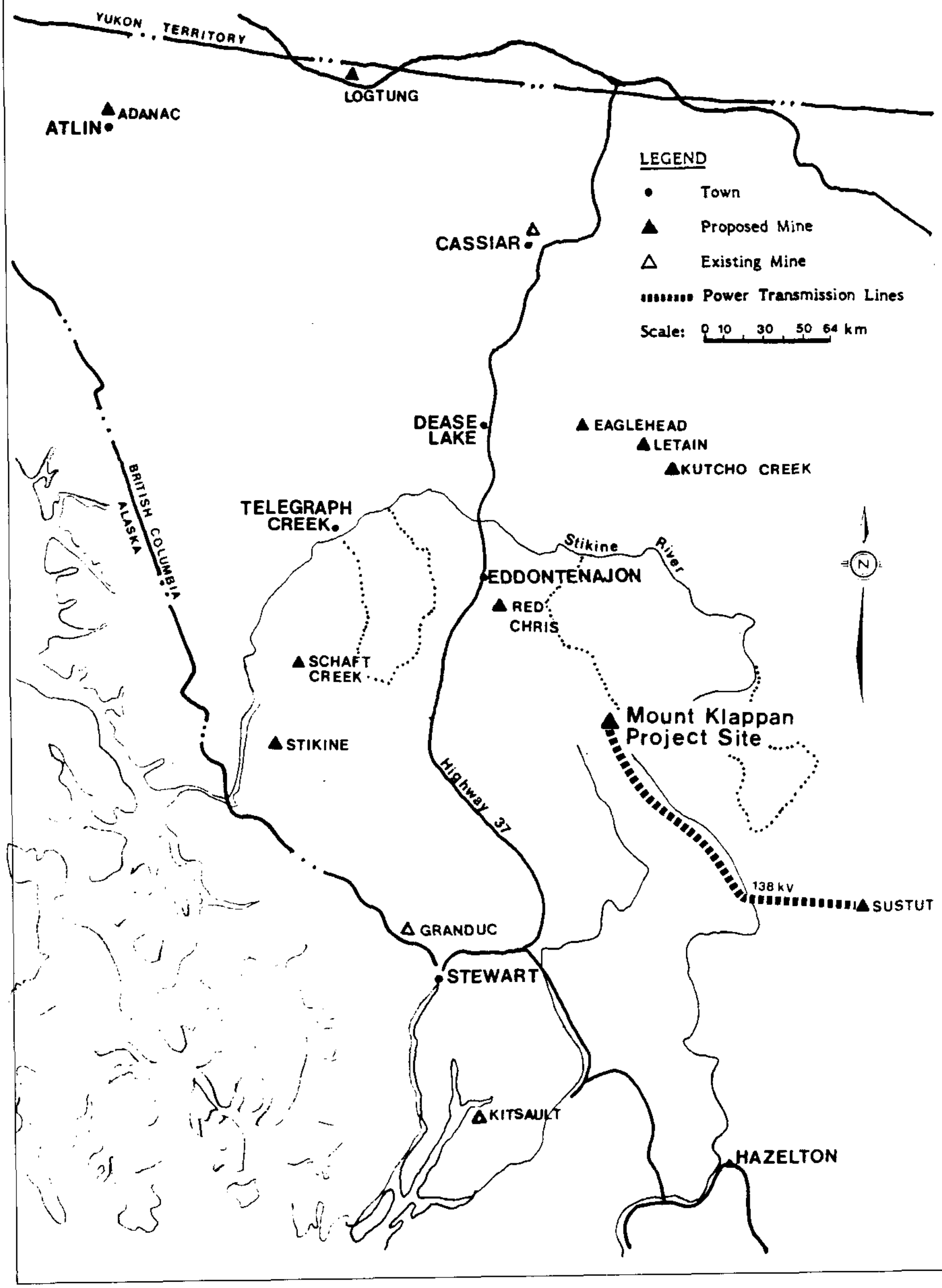


TABLE 4.4

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 4 - 138 kV

($000 Cdn - 1982)

Mount Klappan to Sustut Mine	$
- 138 kV transmission line	27,800
- 25 kV line to town/mine	200
Substation, allow	2,000
TOTAL	30,000

PART 4

HIGH VOLTAGE TRANSMISSION SYSTEMS

PART 4 - HIGH VOLTAGE TRANSMISSION SYSTEMS

CONTENTS

PLATE 4.5

TRANSMISSION SYSTEM 5

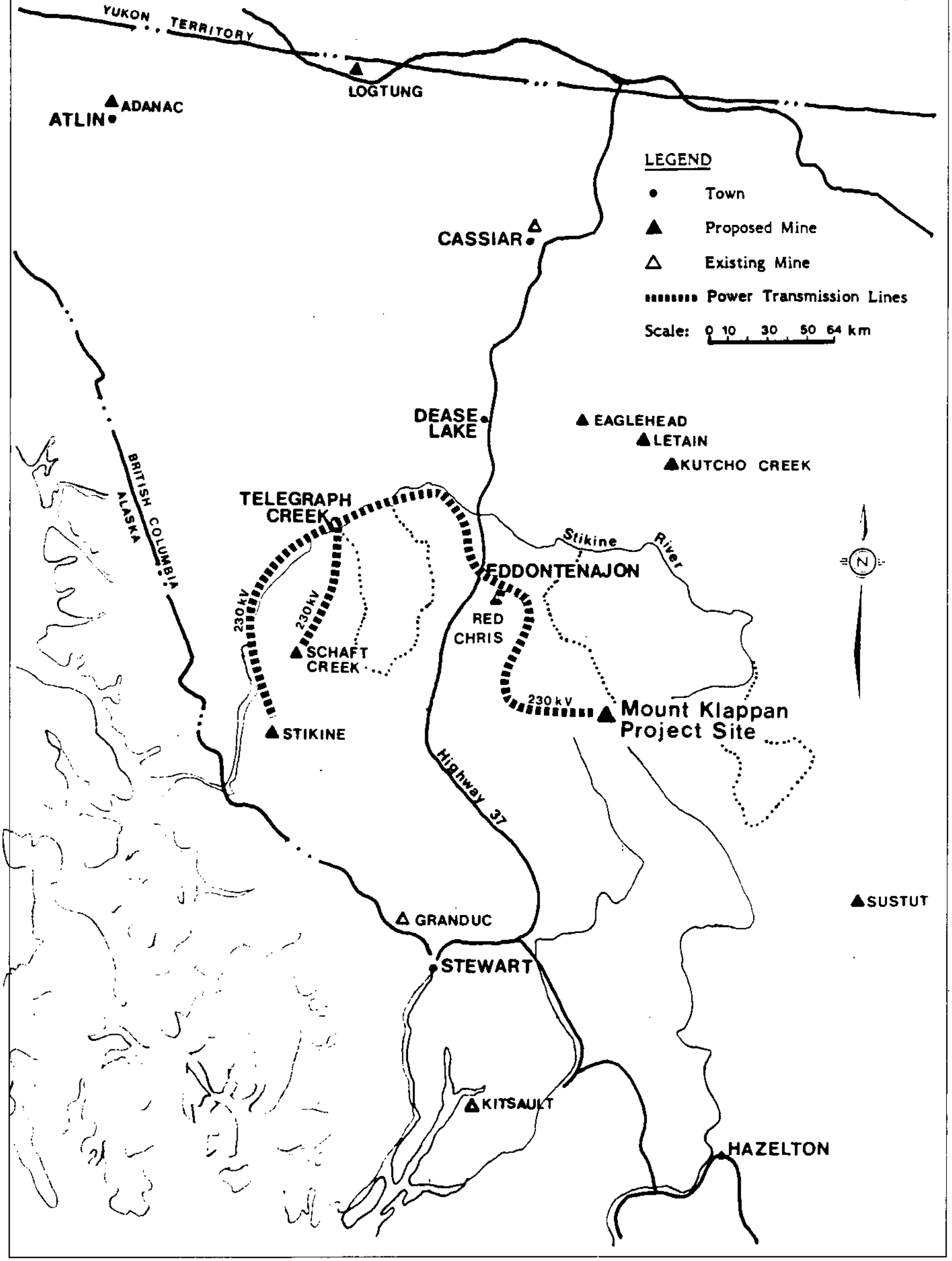


TABLE 4.5

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 5 - 230 kV

($000 Cdn - 1982)

Mount Klappan to Red Chris Substation	$
- 230 kV transmission line	25,300
- 25 kV line to mine	1,000
- 25 kV line to Eddontenajon	100
Substation, allow	3,100
Red Chris to Telegraph Creek	
- 230 kV transmission line	18,000
- 25 kV to Telegraph Creek	100
Substation, allow[(a)]	3,700
Telegraph Creek to Stikine Copper	
- 230 kV line	18,000
- Substation to 69 kV say, allow[(b)]	2,000
Telegraph Creek to Schaft Creek	
- 230 kV line	12,700
- Substation, to 69 kV say, allow	2,000
Townsite. Assume by mines	-
TOTAL	85,000

Note: (a) Cost of substation at Telegraph Creek if town of Telegraph Creek not served from 230 kV line would be about $2.5 million.

(b) Substation voltage would depend upon mine requirements and distribution systems proposed.

PLATE 4.6

TRANSMISSION SYSTEM 6

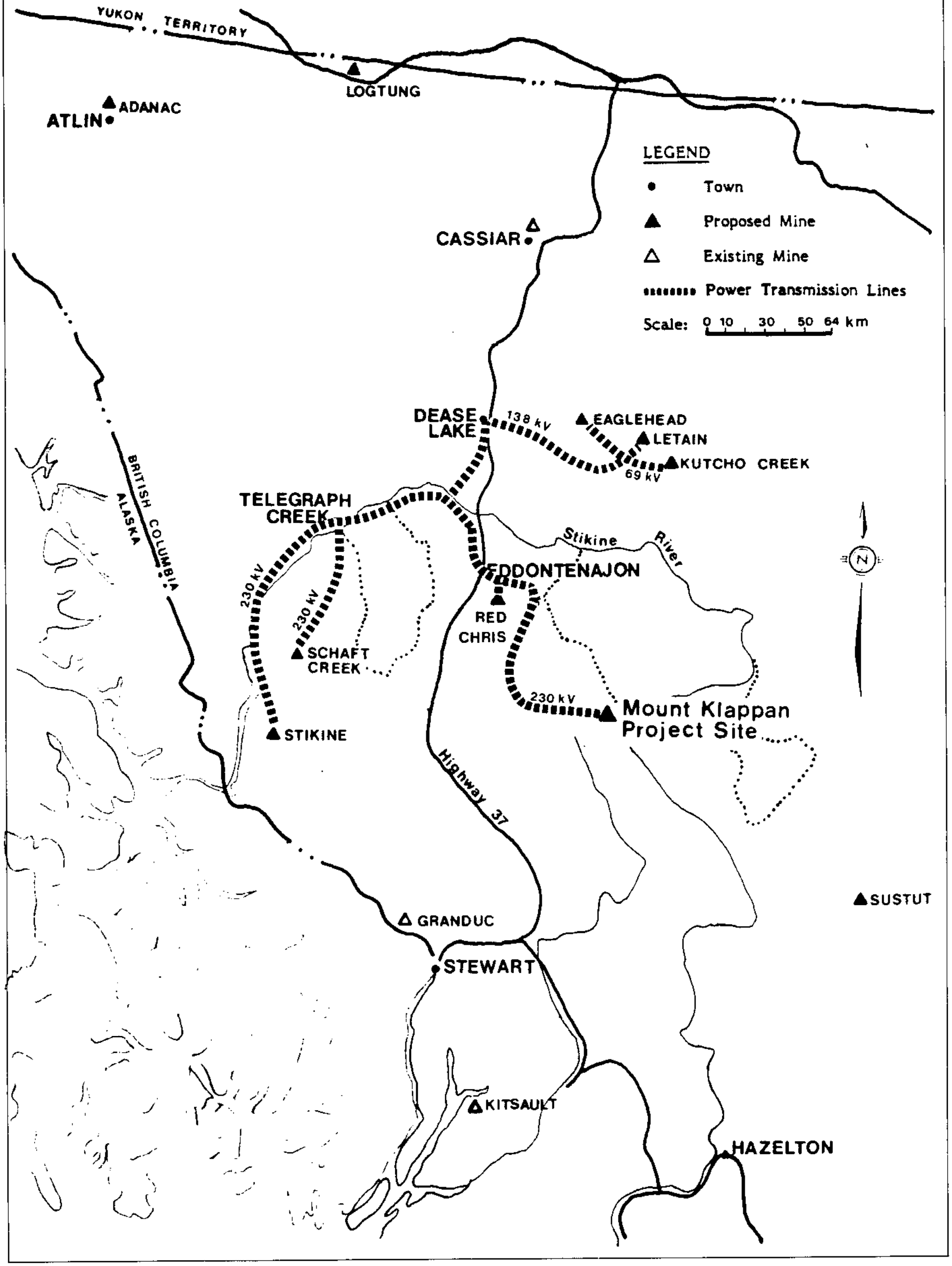


TABLE 4.6

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 6 - 230 kV/138 kV

($000 Cdn - 1982)

	$
System 5 - 230 kV serving Red Chris, Stikine Copper and Schaft Creek, Ref. Table 4.5.	85,000
Major switching substation on Stikine River for 230 kV/138 kV switching and transforming, located on 230 kV line about half way between Red Chris and Telegraph Creek.	10,000
Stikine substation to Dease Lake	
- 138 kV transmission line	11,000
- 25 kV line to Dease Lake	200
Substation at Dease Lake, allow	3,100
Dease Lake to Eaglehead/Letain/ Kutcho Creek, 138 kV, See Table 4.2.	23,700
TOTAL	133,000

PLATE 4.7

TRANSMISSION SYSTEM 7

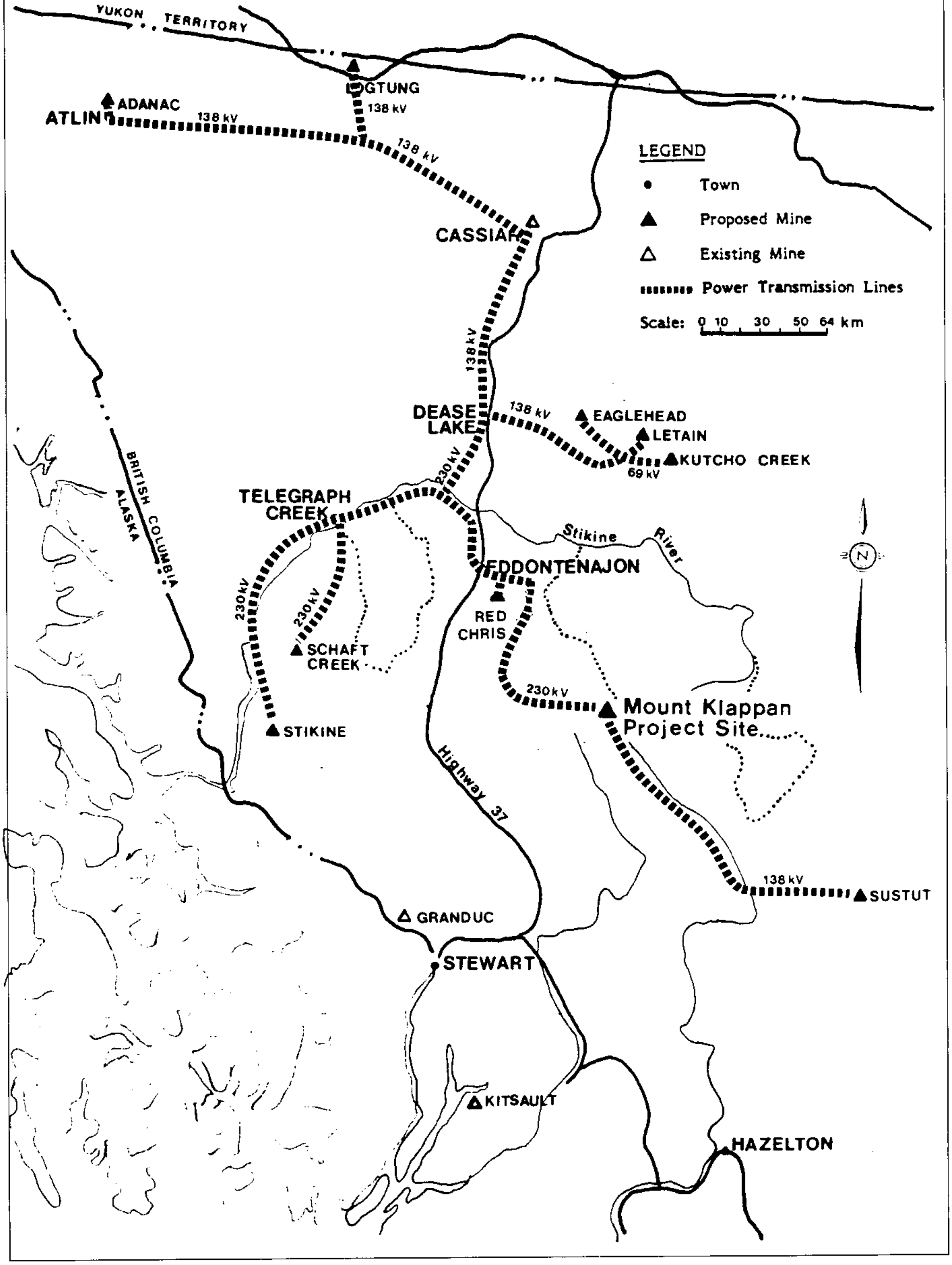


PLATE 4.8

TRANSMISSION SYSTEM 8

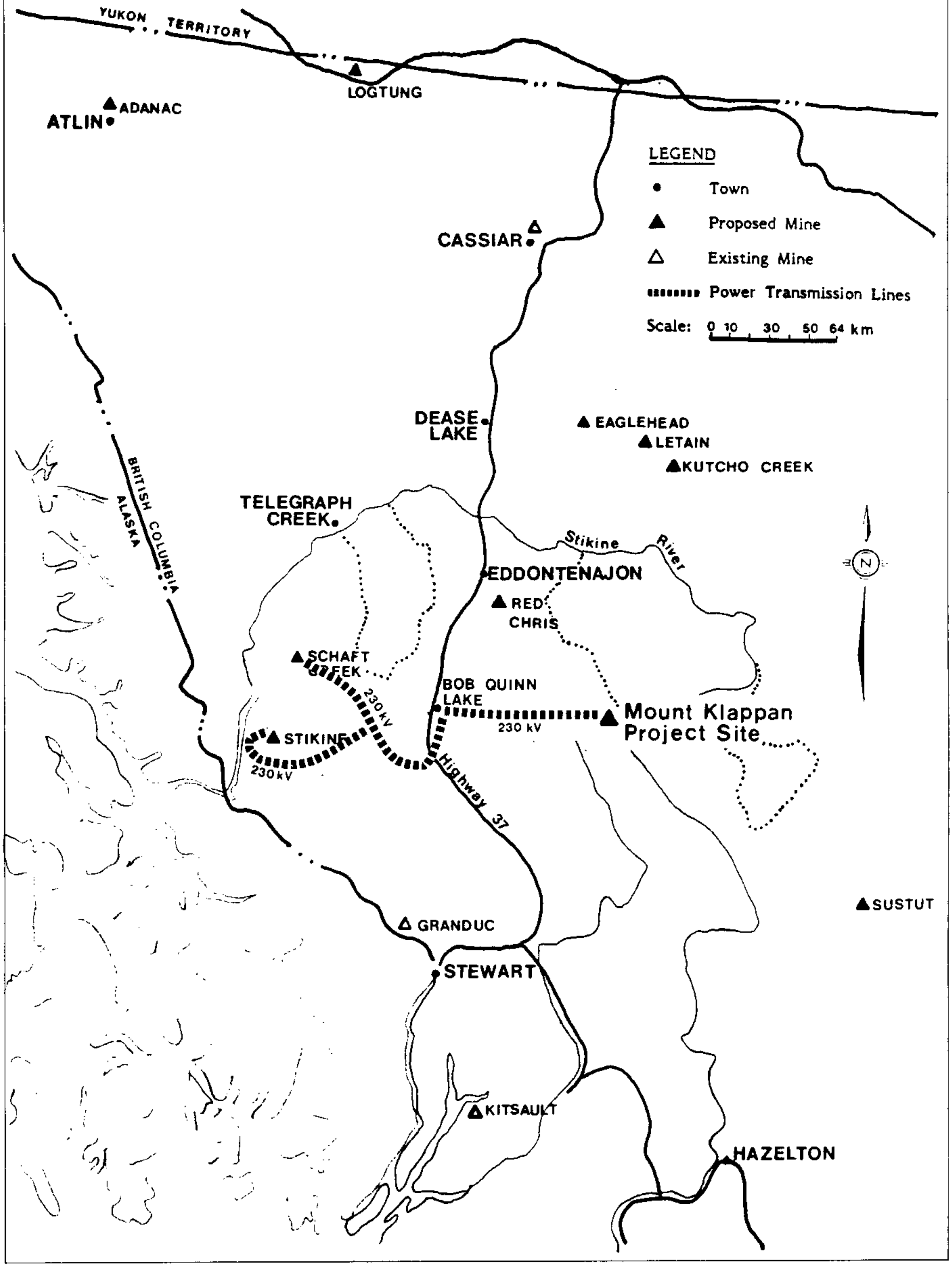


TABLE 4.8

CAPITAL COST ESTIMATE

TRANSMISSION SYSTEM 8 - 230 kV

($000 Cdn - 1982)

Mount Klappan to Bob Quinn area[a]	$
- 230 kV transmission line	18,000
- 25 kV to camp site [b]	Not incl.
Substation at Bob Quinn area, allow	2,800
Bob Quinn to switching station	
- 230 kV line	20,200
Switching station, allow	2,000
Switching station to Stikine Copper	
- 230 kV line	26,500
- 69 kV line to mine, say	300
- substation to 69 kV, say	1,700
Switching Station to Schaft Creek	
- 230 kV line	11,000
- 69 kV line to mine, say	500
- substation to 69 kV, say	2,000
Townsite supply. Assume by mines	-
TOTAL	85,000

Note: (a) There is doubt as to the practicability of this route.

(b) Load at Bob Quinn Camp assumed much too small for cost of transforming from 230 kV to 25 kV say.

(c) Substation voltage would depend upon mine requirements and distribution systems proposed.

4.4 OPERATING COST ESTIMATES

The operating cost estimates given in Table 4.9 have been based on a percentage of the capital costs of each system. The sub-stations are assumed to be un-manned. Crews for line-work maintenance and sub-station duties are assumed to be located at reasonably central points for each system.

TABLE 4.9

TRANSMISSION SYSTEMS

OPERATING COST ESTIMATES

($000 Cdn - 1982)

System		$ Annual Operating Cost
System 1 -	Red Chris, Eaglehead Letain, Kutcho Creek	1,500
System 2 -	Red Chris, Dease Lake, Eaglehead, Letain, Kutcho Creek	1,900
System 3 -	System 2 plus Cassiar, Atlin (Adanac)	3,800
System 4 -	Sustut	800
System 5 -	Red Chris, Telegraph Creek, Stikine Copper, Schaft Creek	2,400
System 6 -	Red Chris, Eaglehead, Letain, Kutcho Creek, Stikine Copper, Schaft Creek	3,900
System 7 -	All mines	6,800
System 8 -	Stikine Copper, Schaft Creek alternative	3,500

As noted in Part 1, the power losses in the transmission system have been assumed to be included in the estimated mine loads.

4.5 SYSTEM CHARACTERISTICS

The power carried by a system varies as the square of the voltage. The electrical stability of the system can be significantly improved by using higher voltages. These two major considerations must be studied in any system design with accompanying economic comparisons made of the additional costs of lines and substations.

One primary consideration in the selection of line voltage for the systems chosen has been the estimation of the potential capacity of the line for a voltage drop of from 10 to 15%. For a given conductor size, the relationship between voltage drop, as it may affect the capacity of a given system, and distance to the load source is not linear, and for shorter distances with higher loads may not be the governing technical design consideration.

A second consideration arises from the nature of mining operations in which large swings in short term power demand occur (such as from start-up of large motors and, more particularly, from operation of large electric shovels). These large demand swings of short term duration have considerable influence on the fault levels for which a system must be designed. The effect of these voltage fluctuations (flicker effect) due to these swings can be reduced substantially by increasing the primary transmission voltage.

Other matters which affect the voltage of the line chosen and conductor size include:

- load characteristics of the mine(s),
- location of the mine in the systems and the effects on other customers of the mine operations,
- design of the electrical system at each mine as to type and size of large motors, and the use of compensating equipment, reduced voltage starters, and so on to minimize instability in the system,
- ice and wind loadings as they affect strength requirements of the cable for economical spans between towers.

PART 5

DIESEL-POWERED ELECTRIC GENERATING STATIONS

PART 5 - DIESEL-POWERED ELECTRIC GENERATING STATIONS

CONTENTS Page

5.1 INTRODUCTION

Capital and operating cost estimates for three sizes of diesel-powered electric generating plants are presented in this Part. Estimates are provided for installed capacities of 12.5 MW, 25 MW, and 50 MW respectively. These order-of-magnitude estimates may be used to compare costs of diesel-powered electric generation at selected potential mine locations with the costs of generation and transmission of power from Mount Klappan. They may be used also to compare coal-fired power generation costs at Mount Klappan at the lower station capacities considered. Capital cost estimates are given in Table 5.1 and operating cost estimates in Table 5.2.

5.2 CAPITAL COSTS

521 ITEMS INCLUDED

General descriptions of the plants follow, together with some comments on the basis of the choice of sizes as they may affect the interpretation of the cost estimates given in this Section.

.1 Diesel-Generator Units

The numbers of units and installed capacities are representative of typical installations. The capacities stated are based upon continuous ratings of the diesel units, however, for the purposes of establishing firm capacity for each plant, at least one unit should be deducted from the total installed capacity to allow for downtime and major overhauls. For example:

- a 12.5 MW Plant could consist of five, 6-cylinder units @ 2,500 kW output each; the firm capacity would be a maximum of 10 MW;
- a 25 MW Plant could consist of six, 9-cylinder units @ 4,200 kW output each; the firm capacity would be a maximum of 21 MW;
- a 50 MW Plant could consist of seven, 16 cylinder units, (V-configuration) @ 7,500 kW output each; the firm capacity would be a maximum of 42.5 MW.

The diesel units would be the low-speed type designed for reliability and long life. For the purposes of the cost estimates, the use of No. 2 diesel oil has been assumed which would not require special heating or filtration treatment, although No. 1 oil may be necessary in mid-winter. Further discussion on the influence of the type of diesel oil is contained in Section 5.4.

The actual choice of size of the spare unit (or units) is dependent upon detailed study of the load characteristics of each installation, and consideration of such matters as spare parts, peak load variations and overall efficiencies. For example, the choice of two, 8-cylinder units rather than one, 16-cylinder as the spare unit(s) may prove better on detailed analysis for a particular installation.

.2 Auxiliaries

Auxiliaries would include an overhead crane, compressor systems, inside oil storage and pump facilities, heat exchangers, intake and exhaust systems, and so on.

.3 Site

A level site with no unusual foundation conditions has been assumed.

.4 Building

An insulated, metal-clad building designed for a bridge crane has been assumed, with concrete foundations on spread footings.

.5 Waste Heat, Recovery Portion

Recovery of a portion of the waste heat sufficient for operation of the plant within the building has been assumed.

.6 Commissioning

An allowance has been made for commissioning to be done by the manufacturer.

.7 Bulk Storage Facilities

The capacity of bulk storage tanks will depend upon the effects of winter, spring break-up conditions, and other such matters on deliveries of oil. An approximate allowance for about 30 days storage has been included, including cost of the oil to fill the tanks.

.8 Water Supply

An allowance has been made for the supply of raw water for cooling, makeup, and station requirements. Actual costs can vary considerably depending upon relative locations and reliability of the water supply.

.9 Housing

An allowance has been included for the cost of providing housing for the Superintendent and General Foreman. No attempt has been made to allow for possible subsidy plans or camp allowances for operators which can vary widely with specific site conditions.

.10 Spare Parts

An allowance has been included for an initial supply of spare parts.

522 ITEMS NOT INCLUDED

A listing of the main items which have not been included in the estimates is given in this section, together with a brief discussion on each item.

.1 Transmission Lines and Mine Substation

The transmission line voltage and length from the diesel plant are site-specific for any installation, as are the substation requirements at the point of delivery.

.2 Waste Heat Recovery, Remainder

Use of waste heat from the exhaust gases and cooling water for such purposes as space heating elsewhere and for ore drying can be economical depending upon the relative location of these facilities to the plant. Recovery of such heat can cause the overall plant efficiency to increase to above 90 percent.

.3 Access Roads

Access to the site and maintenance of the roads is not included in the estimate.

5.3 OPERATING COSTS

531 UNIT COSTS

.1 Oil

The fuel oil has been assumed to be normal diesel fuel, (No. 2) for this estimate.

The price of oil delivered, including provincial sales tax, has been assumed as $0.37 per litre, which reflects current cost experience in the area.

.2 Operating and Maintenance Costs

The operating and maintenance costs have been estimated based on ratios obtained from an existing installation.

.3 Interest and Depreciation

No allowance has been made for the cost of interest or depreciation.

5.4 TYPE OF OIL

Generally speaking, heavier (more viscous) oils are cheaper than the lighter oils and have a higher calorific value per litre. The diesel engines can be readily designed to accept heavy oils, however, the advantages of the cost of heavy oil must be weighed against the increased cost of handling, transportation, storage and treatment (before use) which is necessary when using these oils.

The use of the very light No. 1 Diesel oil in winter should present few problems, and, similarly use of No. 2 oil (commonly called "normal" diesel) in summer is very satisfactory from an operational viewpoint. As heavier oils are used, measures must be taken in colder weather to use heated barges, trucks and storage tanks and insulated pipe systems so that the oil is sufficiently fluid to handle. Further, in the diesel-powered electric generating station a treatment plant must be installed for removing sludge and tars from the heavy oil. (A typical capital cost of such treatment equipment is in the order of $350,000 to $400,000 for a 25 MW plant). The sludge must be stored until disposed of or used in summer for such purposes as dust control on roads. Disposal of sludge from heavy oils can present environmental problems.

The potential use of concentrate trucks for back-haul of diesel oil is also complicated by use of heavy oils for the reasons mentioned above. This should be studied, along with the volumes of light diesel fuels used by mobile equipment, for any particular location.

Use of heavy diesel may be practical in cases where the power plant is close to a primary delivery and major storage depot, where heating of large volumes of oil can be handled economically. For very large installations, the increased efficiencies obtained from larger diesel-powered electric generating units may be a significant factor in any comparison of fuel usage involving very large volumes.

The economics of use of plants located some distance from such a depot can only be established by detailed study of particular operations associated with the plant and the volumes and projected life of the plant concerned.

TABLE 5.1

CAPITAL COST ESTIMATE

DIESEL-POWERED ELECTRIC GENERATING PLANTS

($000 Cdn - 1982)

Installed Capacity	**12.5 MW**	**25 MW**	**50 MW**
Number of Units	5	6	7
	$	$	$
Building Site	900	1,200	1,350
Major Equipment, Supply	7,100	14,600	30,000
Auxiliaries, Supply	200	275	425
Installation	500	750	1,300
Commissioning	50	75	125
Spare Parts	100	150	200
Sub-total	8,850	16,950	33,400
Bulk Storage Tanks	325	500	725
Oil to fill storage tanks	660	1,325	2,600
Raw Water Supply, Allow	300	500	850
Owner's Costs and Housing, Allow	115	125	125
TOTAL	10,250	19,400	37,700
Unit Cost per kW installed	820/kW	775/kW	755/kW

Note: Engineering and Contingency included.

TABLE 5.2

OPERATING COSTS PER ANNUM

DIESEL-POWERED ELECTRIC GENERATING PLANTS

AT 70 % CAPACITY FACTOR

($000 Cdn - 1982)

Installed Capacity	**12.5 MW**	**25 MW**	**50 MW**
Number of Units	5	6	7
	$	$	$
Oil, 70% Capacity Factor	7,950	15,900	31,000
Lubricating Oil	250	500	1,000
Operation and Maintenance	2,200	4,000	7,800
Supervision, Allow	70	100	100
TOTAL	10,520	20,500	39,900
Electrical output	76.65 MWh	153.3 MWh	306.6 MWh
Unit cost/kWh	13.7 ¢/kWh	13.4 ¢/kWh	13.0 ¢/kWh

PART 6

ENGINEERING AND CONSTRUCTION SCHEDULES

PART 6 - ENGINEERING AND CONSTRUCTION SCHEDULES

CONTENTS

6.1 INTRODUCTION

Engineering and construction schedules are briefly presented in this part for coal-fired generating stations, transmission line construction, and diesel-powered electric generating stations. Assuming that approvals are given by governing bodies, generally it can be said that:

- coal-fired stations could be designed and constructed in four to six years depending upon the size of plant and boiler delivery times;
- transmission line land acquisition, and design and construction could take from three to four years;
- diesel-powered plants could take about two to two and one-half years, depending on the size of the station.

6.2 COAL-FIRED POWERPLANTS

621 GENERAL

The major critical item in scheduling coal-fired stations is the delivery and erection of the boilers. Depending upon the size of the units and business activity of boiler manufacturers, delivery times are typically from eighteen months to thirty months. Erection can take from eighteen to twenty-four months, including ancillaries and turbine installation. Start-up and commissioning can take six months. For multiple-unit installations, it is advisable to stage start-up of the second and following units from three to six months later depending upon the load committments. Erection time can be reduced by working two shifts or by duplicating erection crews on two or more units, however, the procedure is not expected to be as cost-efficient as for single-shift erection.

622 50 MW TO 150 MW STATIONS

Engineering and construction for the 50 MW, 100 MW and 150 MW stations would normally take approximately four to five years.

623 200 MW and 250 MW STATIONS

The larger stations, 200 MW and 250 MW, would take approximately five to six years to design and build.

6.3 HIGH VOLTAGE TRANSMISSION LINES

Time required for preliminary route surveys and land acquisition can vary with the amount of time required for government approvals, and the extent of governments support for proposed developments can be expected to have significant influence on the time required. Clearing activity depends upon such matters as logging regulations required by the Forest Ministry for scheduling of commercial log recovery, watercourse protection, land stability and requirements for brush clearing and grubbing.

Assuming that engineering and procurement would proceed during these early activities, construction of the lines and substations would take from one to two years. To avoid winter work as much as possible on line construction, sections of the line could be broken into smaller contracts to ensure completion in summer months.

In summary, depending upon the extent of government support, it could be expected that the average transmission line and substation system considered in this study would take from a minimum of three to a probable four years to complete.

6.4 DIESEL-POWERED ELECTRIC GENERATING PLANTS

Engineering and construction of the diesel-powered electric generating plants would take about two years. The delivery and installation schedule for the larger stations of 40 to 50 MW capacity would depend largely upon the capacity of the manufacturing company to deliver the units in nine to twelve months.

APPENDICES

CONFIDENTIAL

GULF CANADA RESOURCES INC.

MOUNT KLAPPAN COAL PROJECT

1982

MINE ASSESSMENT

VOLUME 1

SUMMARY

Coal Licence Number 7118 to 7177

7381 to 7392

and

7416 to 7432 inclusive

Cassiar Land District

NTS Map Number 104 H

Latitude Between 57°11' and 57°22'N
Longitude Between 128°39' and 129°05'W

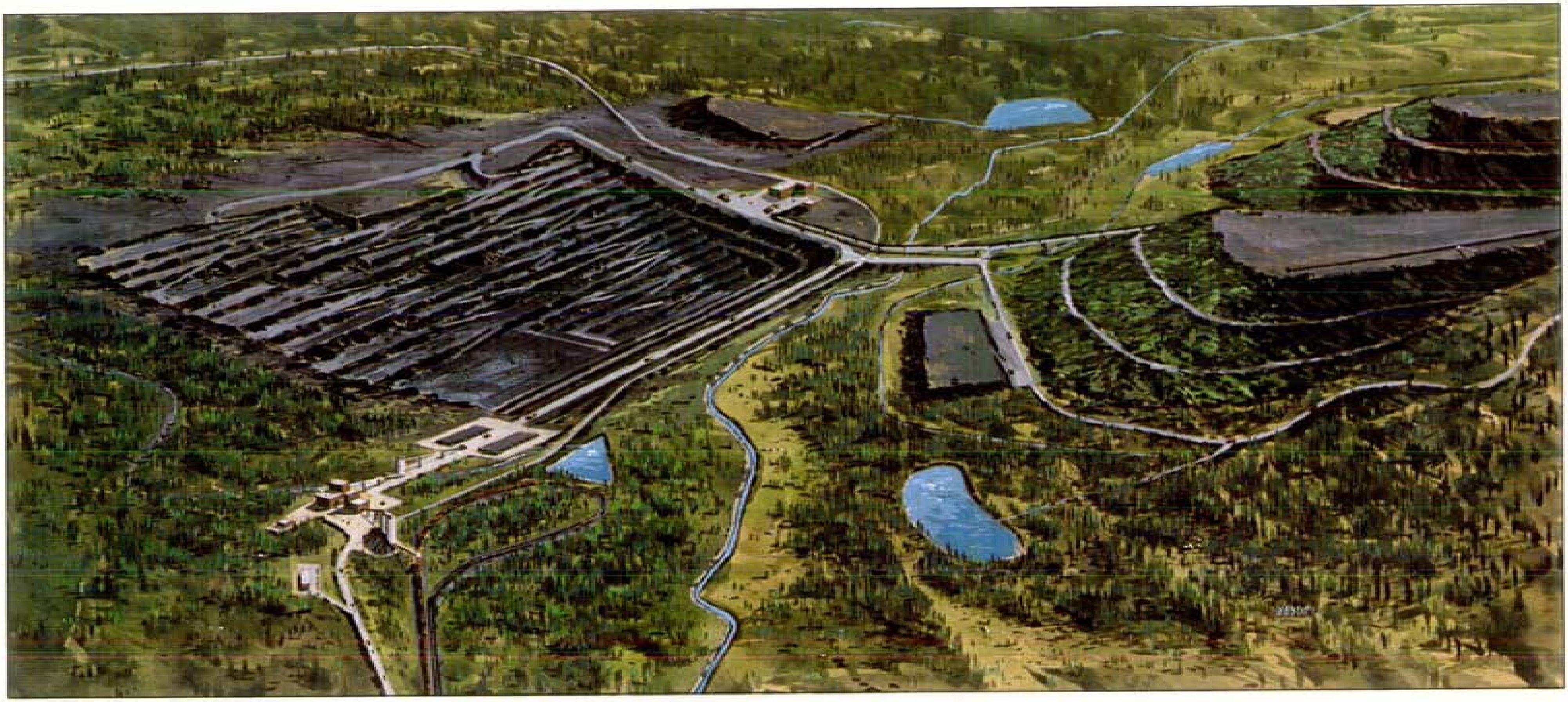
BY

PHILLIPS BARRATT KAISER
Engineering Ltd.
Vancouver, B.C. Canada

DECEMBER 1982

PBK Project No. 82054

00110 (4)



MOUNT KLAPPAN COAL PROJECT

Phillips Barratt Kaiser Engineering Ltd.

GULF CANADA RESOURCES INC.

Phillips Barratt Kaiser

MOUNT KLAPPAN COAL PROJECT LOCATION MAP

Phillips Barratt Kaiser

PBK

MOUNT KLAPPAN COAL PROJECT

MINE ASSESSMENT

▷ VOLUME 1 SUMMARY

VOLUME 2 GEOLOGY

VOLUME 3 MINING

VOLUME 4 COAL PREPARATION FACILITIES

VOLUME 5 INFRASTRUCTURE

VOLUME 1

SUMMARY

CONCLUSIONS

Bearing in mind the preliminary nature of the geological exploration of the Mount Klappan property, the conclusions of Phillips Barratt Kaiser Engineering Ltd. are:

1. A resource of anthracite of commercial importance exists at the Mount Klappan project site.

2. Mining the property by open pit methods using conventional truck and shovel equipment appears feasible.

3. Washing and upgrading the coal using a jig, water-only cyclone and flotation circuit to produce a product anthracite of 20% ash appears feasible.

4. The laying of 85 km of track on a partially completed railway subgrade will complete the connection to Ridley Island Terminal.

5. With the completion of rail access to the property, unit trains of coal can be moved to the port.

6. The rail distance to the port can be shortened by approximately 800 km (from 1400 to 600 km) by the construction of 176 km of new line connecting the British Columbia Railway to the Canadian National Railway.

7. The large coal resource base, favourable stripping ratios for open pit mining and a potentially favourable rail haulage distance combine to offer the prospect of a successful mining operation.

MOUNT KLAPPAN COAL PROJECT

VOLUME 1

SUMMARY

TABLE OF CONTENTS

PART 1

EXECUTIVE SUMMARY

PART 1 - EXECUTIVE SUMMARY

CONTENTS

1.1 BACKGROUND

The Mount Klappan property is located in northwestern British Columbia some 336 km northeast of the Ridley Island Coal Terminal now under construction. Gulf Canada Resources Inc. owns 89 whole and partial coal licenses covering some 22 000 hectares with applications pending for further licenses covering approximately 16 000 more hectares.

Preliminary geological exploration work by Gulf in 1981 and 1982 indicates an area covering less than 10% of the property to be underlain by nine anthracite seams with a combined average thickness of 21.75 metres. This area contains an inferred in situ resource of 620 million tonnes. Low sulphur clean coal products could be produced having ash contents ranging from 5% - 20%.

Phillips Barratt Kaiser Engineering Ltd. were retained in September, 1982 to carry out a mine assessment. The requirements were to develop conceptual engineering plans for two alternative mining operations and to investigate the infrastructure needed to produce and ship the product coal.

Two conceptual mine plans were developed:

- A mine to produce 5 million tonnes per year of anthracite washed to a 20% ash level. The coal preparation plant has a nominal yield of 70%. The product stripping ratio is 8.8 m^3/t of product coal.

- An alternative mine to produce and ship 1 million tonnes per year of run-of-mine coal. The product stripping ratio is 7.4 m^3/t.

1.2 ASSESSMENT FINDINGS

Phillips Barratt Kaiser's assessment of the mining and coal processing requirements of the Mount Klappan coal property, as presently defined, shows that open pit mining appears technically feasible and coal washing requirements can be met using conventional equipment.

In both cases, open pit bench mining was proposed using conventional truck/shovel/equipment. Waste will be transferred to external dumps by overland conveyor; dumps will be constructed by slewing stackers traversing transfer conveyors.

The coal preparation plant circuit consists of jig, water-only cyclone and flotation washing equipment.

Transportation to the Ridley Island port could begin following the laying of 85 km of track on the partially completed subgrade already extending to the minesite along the British Columbia Railway (BCR) right-of-way. This line connects with the Canadian National Railway (CNR) at Prince George. The total distance from the mine to the port is approximately 1 400 km. Construction of a new section of railway line to connect the BCR to the CNR near Hazelton would reduce the distance to approximately 600 km.

The new coal port at Ridley Island, scheduled for completion in 1983, will have a planned capacity of 12 million tonnes per year, approximately 4 million tonnes per year more than the tonnage proposed from the two coal projects now under construction in northeastern British Columbia. Design of the present Ridley Island Terminal allows for an expansion to handle 15 to 16 million tonnes per year.

PART 2

INTRODUCTION

PART 2 - INTRODUCTION

CONTENTS

2.1 BACKGROUND

The coal occurrences of the Bowser Basin have attracted interest for more than one hundred years. However, only in the last few years has serious attention been directed to the search for anthracite in the northern portion of the basin.

Since 1979 Gulf Canada Resources Inc. has been engaged in exploration of the northern portion of the Bowser Basin. This work resulted in the acquisition of the Mount Klappan coal property in 1981.

211 COAL LICENCES

As a result of the 1981 programme Gulf Canada Resources Inc. now owns 89 whole and partial British Columbia coal licences. These licences cover a total of 22 371 hectares of land.

Following the 1982 geological field programme, an application was filed for 53 coal licences covering 15 901 hectares.

Gulf Canada Resources Inc. has also reapplied for approximately 1 000 hectares or land bordering the Spatsizi Plateau Wilderness Park. This additional area brings the total area either currently held by licences or under application to 38 272 hectares.

212 STUDY ASSIGNMENT

In September 1982, Gulf Canada Resources Inc. retained Phillips Barratt Kaiser Engineering Ltd. to carry out a mine assessment. PBK was retained to prepare a conceptual engineering study for the mining and washing of anthracite coal and to investigate the regional infrastructure required. Examination of two levels of production was called for:

- 5 million tonnes per year of product shipped as anthracite washed to a 20% ash content; and,

- 1 million tonnes per year of product shipped as run of mine anthracite.

213 SUBSEQUENT STUDIES

In December 1982, Phillips Barratt Kaiser Engineering Ltd. was asked to perform additional studies to assess the feasibility of mining and washing anthracite coal to obtain product coals with ash contents at the 5% and the 10% levels.

214 QUALITY OF PRODUCT COALS

The 5 million tonnes per year of anthracite washed to a 20% ash content and the 1 million tonnes per year of run-of-mine anthracite are intended for use as briquetting coal.

The 5% and 10% ash level coals, which are the subject of subsequent studies, would be considered for purposes other than as briquetting coal.

2.2 CONSULTANTS EMPLOYED

Phillips Barratt Kaiser Engineering Ltd. (PBK) has acted as the prime consultant for this study and has evaluated the mining, coal preparation and the regional infrastructure requirements of rail and road access.

Other services have been provided by the following consultants:

- Environmental Management Associates - environmental assessment.
- Price Waterhouse Associates Ltd. - socio-economic assessment.

2.3 BASIC DATA PROVIDED BY GULF CANADA RESOURCES INC.

The basic geological data, geological cross sections and coal quality data were supplied by Gulf Canada Resources Inc.

2.4 SITE DESCRIPTION

The Mount Klappan coal project site at latitude 57° 15' N and 128° 50' W lies some 336 km. northeast of Prince Rupert in northern British Columbia. A British Columbia Railway (BCR) right-of-way connecting to Prince George runs through the project site. At present, the rail track laid from Prince George stops 85 km to the south of the Mount Klappan project site.

The topography is characterized by broad, open subalpine valleys and generally subdued mountains with elevations ranging from 1100 to 2000 m. The licence area is located in the headwaters of the Little Klappan and Spatsizi Rivers.

Present site access is by air to a 1000 m airstrip on the property. Road access could be established from Highway 37 (Stewart-Cassiar) via the Ealue Lake road and then the BCR subgrade south to the project site. Bridges for one river crossing and two stream crossings would have to be completed.

2.5 ACKNOWLEDGEMENTS

We wish to acknowledge the assistance, encouragement and support of the Coal Department staff of Gulf Canada Resources Inc. in this assessment.

PART 3

PROJECT DESCRIPTION

PART 3 - PROJECT DESCRIPTION

CONTENTS

Table

Figure

Plate

3.1 INTRODUCTION

Two alternative mining concepts were called for:

- 5 million tonnes per year (5 Mtpy Case) of anthracite, washed to a 20% ash level and then shipped as the product; and
- 1 million tonnes per year (1 Mtpy Case) of run-of-mine anthracite shipped as the product.

The mining assessment performed by Phillips Barratt Kaiser Engineering Ltd. is based on the geological data and geological cross sections provided by Gulf Canada Resources Inc. This data was obtained from field programmes conducted in 1981 and 1982.

3.2 GEOLOGY AND COAL QUALITY

321 FIELD PROGRAMMES

The following field programmes were conducted:

1981 Programme

An initial geological assessment consisting of mapping, trenching and surface sample collection was made in the late summer and early fall of 1981. Data gathered from this work guided the design of the 1982 exploration programme.

1982 Programme

Based on the 1981 results, a programme of geological mapping, trenching and diamond drilling was conducted during the summer of 1982. 50 hand trenches, with an aggregate length of over 285 metres, were dug in coal exposures and 7 diamond drill holes were drilled for a total of 1223 metres. Coal samples taken during the coring programme were subjected to detailed analytical testing and washability studies.

322 GENERAL GEOLOGY

.1 Geological Setting:

The Mount Klappan coal property is underlain by the coal bearing Upper Jurassic to Lower Cretaceous Klappan Sequence. Twelve seams with a cumulative average thickness of 25.2 metres exist within the 300 to 350 metre interval of the Middle Klappan Sequence.

.2 Resources

.21 Quantity

The property is estimated to have a resource potential of 3 billion tonnes of coal of which 890 million tonnes is calculated to be in the inferred resource category. This inferred category comprises:

Resource Area	Million Tonnes
Hobbit-Broatch	620
Lost-Fox	240
Summit	30
Total	890

The Hobbit-Broatch Resource Area is the portion of the property which was evaluated in this assessment. Thirty-four trenches have been excavated in coal outcrops, and 5 diamond drill holes have been completed in the area.

Coal seams A to K were intersected by the drill holes. Seams C and D were excluded from the resource calculations because they have weighted average thicknesses less than 0.5 metres. The weighted average thickness of the 9 seams used in the resource calculation is 21.75 metres.

.22 Quality

The raw coal analysis for the Hobbit-Broatch Resource Area, on an air dried basis is:

Proximate Analysis		
Residual Moisture	1.42	%
Ash	30.87	%
Volatile Matter	8.36	%
Fixed Carbon	59.35	%
Total Sulphur	0.88	%
Thermal Value	5238	kcal/kg
	2.19	MJ/kg
Hardgrove Grindability Index	54	

323 MINING AREA GEOLOGY

.1 Description

Four of the five Hobbit-Broatch Resource Area diamond drill holes influence the mining area selected. These are DDH-82001, 82002, 82003 and 82004.

Only seams E through K were included in this evaluation because seams A through D are below the depth of the diamond drill holes which influence the mining area selected.

.2 Resources

.21 Quantity

For production scheduling and mine planning purposes, a block model approach was adopted to determine the quantities and qualities of coal available in the mining area selected. A standard grid was established based on the geological cross sections available. The grid dimensions were:

- vertical (indexed to the cross section elevations) - 50 metres;
- width (along the cross section axis) - 200 metres;
- length (perpendicular to the cross section - 250 metres on each side) - 500 metres.

The volume of coal in each block was estimated by actual measurement of the width dimension on the cross sections and multiplication of this number by the block length of 500 metres and by the seam thickness.

The total estimated quantity of run of mine coal required for the life of the mine used in this assessment is 146 550 000 tonnes in the 5 Mtpy Case.

.22 Quality

The composite raw coal quality analysis (calculated by PBK) on an air dried basis for the mine area selected is:

Residual Moisture	1.50 %
Ash	29.85 %
Volatile Matter	6.82 %
Fixed Carbon	61.83 %
Total Sulphur	0.74 %
Thermal Value	22.26 MJ/kg
	5325 kcal/kg

3.3 5 Mtpy CASE

331 MINING

The development of a conceptual mine plan has followed the approach of selecting the low stripping ratio areas for the 5 million tonne per year level of production.

The mining concept has not been optimized, however, engineering judgement has been exercised to incorporate improvements where appropriate.

The mining system is an open pit benching approach with waste disposal to waste dumps. Transfer of waste from the mine to the waste dump is by trucks to a hopper and then by surface conveyor to the dump. Coal transportation to the coal preparation plant is by truck.

Plate 3.1 presents the general arrangement of the 5 Mtpy case minesite and illustrates the mining and dump areas as well as mine limits.

The conceptual design is an open pit benching operation with the box cut sited in the southern part of the Hobbit-Broatch Area. The mining progresses in a northerly direction, with benches running east-west.

Key to developing a workable concept was the handling of the mine waste rock. A waste dump is necessary for the nine years required to complete the box cut. By Year 9, some capacity is available for waste backfilling, however, this capacity is limited because the pit bottom is rising, and the use of the external waste dumps will be necessary until Year 15. At this point, there is sufficient space in the mined out area to dispose of all mine waste by backfilling. Also, the material balance is such that this can be accomplished without purchasing additional mine trucks.

The waste rock (which has been blasted) is hauled by end dump trucks to a conveyor hopper sited close to the mine crest.

A 2 134 mm belt elevates the rock to the mountainside waste dump. Rock passes over a transfer belt to a lateral conveyor which runs on top of the dump. The lateral conveyors are traversed by stackers with 50 m slewing booms. A system of lateral conveyor extension and radial slewing is used to build the dump. Two waste dump wings provide for continuity of disposal.

Over the life of the mine, a total of 944 x 10^6 m^3 of waste has to be removed. Up to Year 15, the waste conveyors handle 538 x 10^6 m^3. The remaining 406 x 10^6 m^3 is backfilled into the mined-out area. Table 3.1 presents the material movement schedule for the 5 Mtpy case.

Conventional mining equipment such as drills, shovels and end dump trucks have been used as the basis for the capital and operating cost estimates.

A total of 106 x 10^6 t of product coal is shipped, to give a product stripping ratio of 8.8 (m^3/t). Run-of-mine (R.O.M) coal delivered to the preparation facilities is 147 x10^6 t for an R.O.M. stripping ratio of 6.3 (m^3/t).

332 COAL PREPARATION FACILITIES

The estimated product quality and preliminary flowsheet design presented are based on producing the following:

- 5,000,000 tonnes of product coal per year having:
  - an ash content of 20% (dry basis) and
  - a maximum total moisture (residual + surface moisture) of 8%.

Several preparation plant processing circuits were analyzed to assess the clean coal recovery options. A design consisting of jig, water only cyclones and flotation equipment was selected to meet the product criteria specified. Figure 3.1 presents a simplified preparation plant flow sheet. The preparation facility consists of:

- a raw coal handling system including a truck dump, rotary breaker and a 10 000 tonne raw coal silo;
- a 1 100 tph preparation plant;
- two fluid bed thermal dryers each capable of a 25 tph moisture evaporation rate;
- clean coal handling including two 10 000 tonne capacity clean coal silos;
- ground storage and a unit train loading system.

The proposed concept incorporates industry-proven circuitry for efficient operation and minimum down time.

The following product coal specification will be met:

		Run-of-Mine*		Product	
		Air Dried Basis	As Rec'd Basis	Air Dried Basis	As Rec'd Basis
Moisture	%	1.5	5.0	1.5	7.50
Ash	%	32.20	31.07	19.70	18.50
Volatile Matter	%	6.58	6.35	7.80	7.33
Fixed Carbon	%	59.70	57.58	71.00	66.67
Sulphur	%	0.74	0.71	0.74	0.69
Thermal value	MJ/kg	21.36	20.61	26.74	25.11
	kcal/kg	5116	4933	6398	6008
Yield		-	-	70.0	71.9

* Includes out-of-seam dilution

333 ADMINISTRATION

Appropriate minesite facilities will be provided. An organization chart is presented in Figure 3.2.

3.4 1 Mtpy CASE

341 MINING

The development of a conceptual mine plan for the run-of-mine coal to be shipped as product has followed the approach of selecting the low stripping ratio areas. The 1 Mtpy Case low stripping ratio area was restricted to the portion of the Hobbit-Broatch Resource Area totally within the influence of drill hole DDH 82-001. Drill core data indicates this area to have the lowest in-seam ash levels.

The mining concept has not been optimized, however, engineering judgement has been exercised to incorporate improvements, where appropriate.

The mining system is an open pit benching approach with waste disposal to waste dumps. Transfer of waste from the mine to the waste dump is by trucks to a hopper and then by surface conveyor to the dump. Coal transportation to the coal preparation plant is by truck.

Plate 3.2 presents the general arrangement of the mine site for the 1 Mtpy Case. The pit crest limit is shown and also the size of the waste dump after 20 years of operation.

As in the 5 Mtpy Case, the concept developed is an open pit benching operation. Mining progresses in a northerly direction from a box cut and the benches run east-west. Blasted waste rock is hauled out of the pit by truck to a conveyor hopper. A 1 066 mm conveyor belt transfers and elevates the waste to the mountainside. The same concept of waste disposal is employed as in the 5 Mtpy Case. All mine waste (148 x 10^6 m^3) must be transferred to the waste dumps because seams of coal remain below the bottom of the pit. Table 3.2 presents the material movement schedule for the 1 Mtpy Case.

Conventional mining equipment (as is in the 5 Mtpy Case), was used in developing the concepts and forms the basis for cost estimating.

A total of 20 x 10^6 t of anthracite coal is shipped. The product stripping ratio is 7.4 (m^3/t).

342 COAL HANDLING

No coal preparation facilities are called for in this mining case. Run-of-mine coal will be transferred directly to the coal silos after passing through a rotary breaker. The coal handling system incorporates:

- truck drump and rotary breaker station;
- a 10 000 tonne raw coal silo;
- ground storage and a unit train loadout system.

The estimated quality of coal shipped (R.O.M. coal, no dilution) is:

(This analysis is from DDH 82-001, which totally influences the 1 Mtpy Case mining area).

		Air Dried Basis	As Rec'd Basis
Moisture	%	1.5	5.0
Ash	%	27.3	31.07
Volatile Matter	%	7.2	6.8
Fixed Carbon	%	65.1	61.8
Sulphur	%	0.75	0.71
Thermal value	MJ/kg	24.7	23.5
	kcal/kg	5904	5618

343 ADMINISTRATION

For this fly-in case appropriate facilities will be provided at the minesite. Some staff will work in an office in Smithers. The organization chart in Figure 3.3 records the work locations.

3.5 RECLAMATION

For this assessment PBK has adopted a conventional reclamation approach.

Topsoil and root zone material will be stripped and stockpiled for future use in reclamation. Once the mine cycle has progressed sufficiently, soil spreading can be carried out to facilitate revegetation on waste dumps, roads, etc. During later years in the mine life, topsoil can be stripped and taken directly to the reclamation area.

5 Mtpy CASE

TABLE 3.1

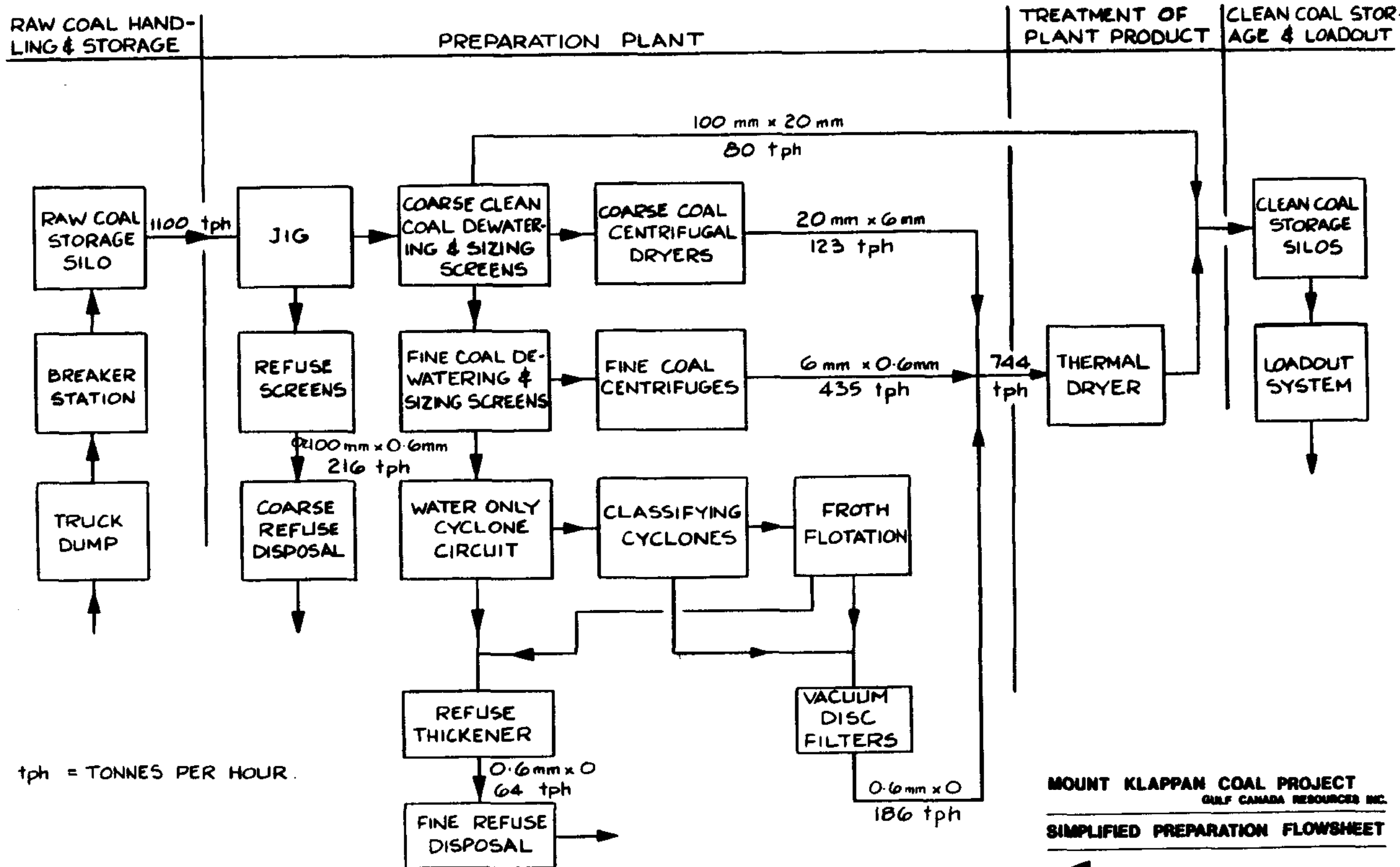
MATERIAL MOVEMENT SCHEDULE - 5 Mtpy Case

	Units* x 10^3	-4	-3	-2	-1	1	2	YEARS 3	4	5	6-10	11-15	16-20	21-23	Total
Product															
Shipped	t	-	-	-	500	3 000	5000	5 000	5 000	5 000	25 000	25 000	25 000	7 379	105 879
Mine															
Waste															
Mine	m^3	-	-	-	3 030	20 382	39 471	38 508	38 270	40 806	237 423	229 630	215 675	66 575	929 770
Coal															
ROM	t	-	-	-	692	4 152	6 921	6 921	6 921	6 921	34 603	34 603	34 603	10 213	146 550
Statistics															
Strip Ratio (ROM)	m^3/t	-	-	-	4.4	4.9	5.7	5.6	5.5	5.9	6.9	6.6	6.2	6.5	6.3
Mine Construction															
Roads	m^3	-	160	139	11	11	11	11	11	11	102	114	114	-	69803
Ditches	m^3	-	-	115	-	-	-	-	-	-	-	-	-	-	115
Pond Topsoil	m^3	-	-	294	-	-	-	-	-	-	-	-	-	-	294
Waste Disposition															
Waste from Prep Plt	m^3	-	-	-	67	402	671	671	671	671	3 356	3 356	3 356	989	14 211
Waste to Dump	m^3	-	-	-	3 097	20 784	40 142	39 179	38 941	41 477	240 779	113 903	-	-	538 303
Waste to Pit	m^3	-	-	-	-	-	-	-	-	-	-	119 083	219 031	67 564	405 678
Reclamation															
Topsoil Excavated															
Mine Area	m^3	-	-	352	352	352	352	352	352	352	503.	503.	403	-	3 878
Waste Dump Area	m^3	-	-	302	302	302	302	302	176	176	880	528	-	-	3 270
Topsoil Rehandled	m^3	-	-	-	-	-	-	-	362	362	1 813	935	478	529	4 481
Topsoil Spread	m^3	-	-	-	-	-	-	-	538	538	2 693	1 967	882	529	7 148

All volumes in bank equivalents

Decimal places in the above table have been rounded out for clarity of presentation.

* Does not apply to the stripping ratio.



MOUNT KLAPPAN COAL PROJECT
GULF CANADA RESOURCES INC.

SIMPLIFIED PREPARATION FLOWSHEET

Phillips Barratt Kaiser Engineering Ltd

Figure 3.1

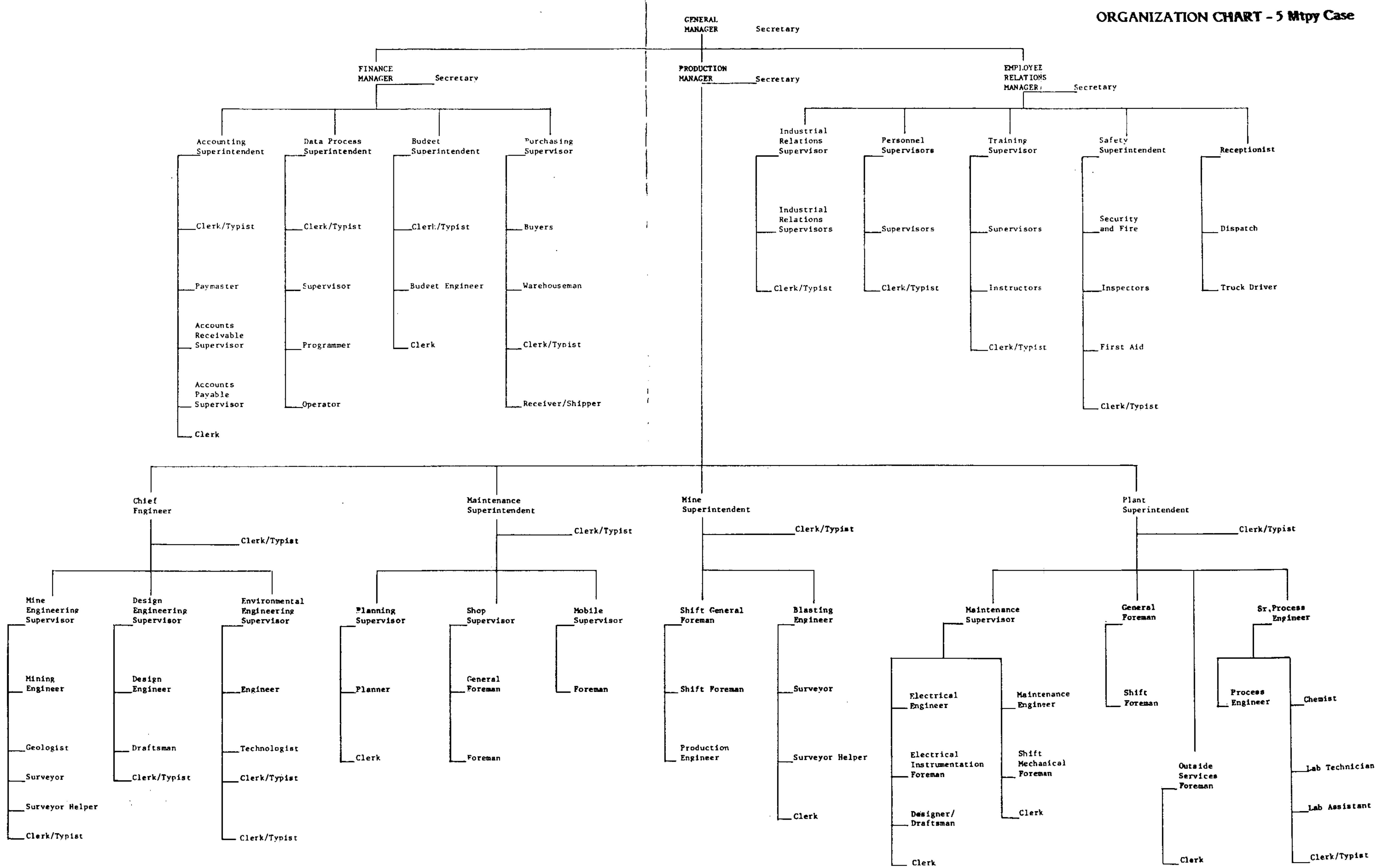
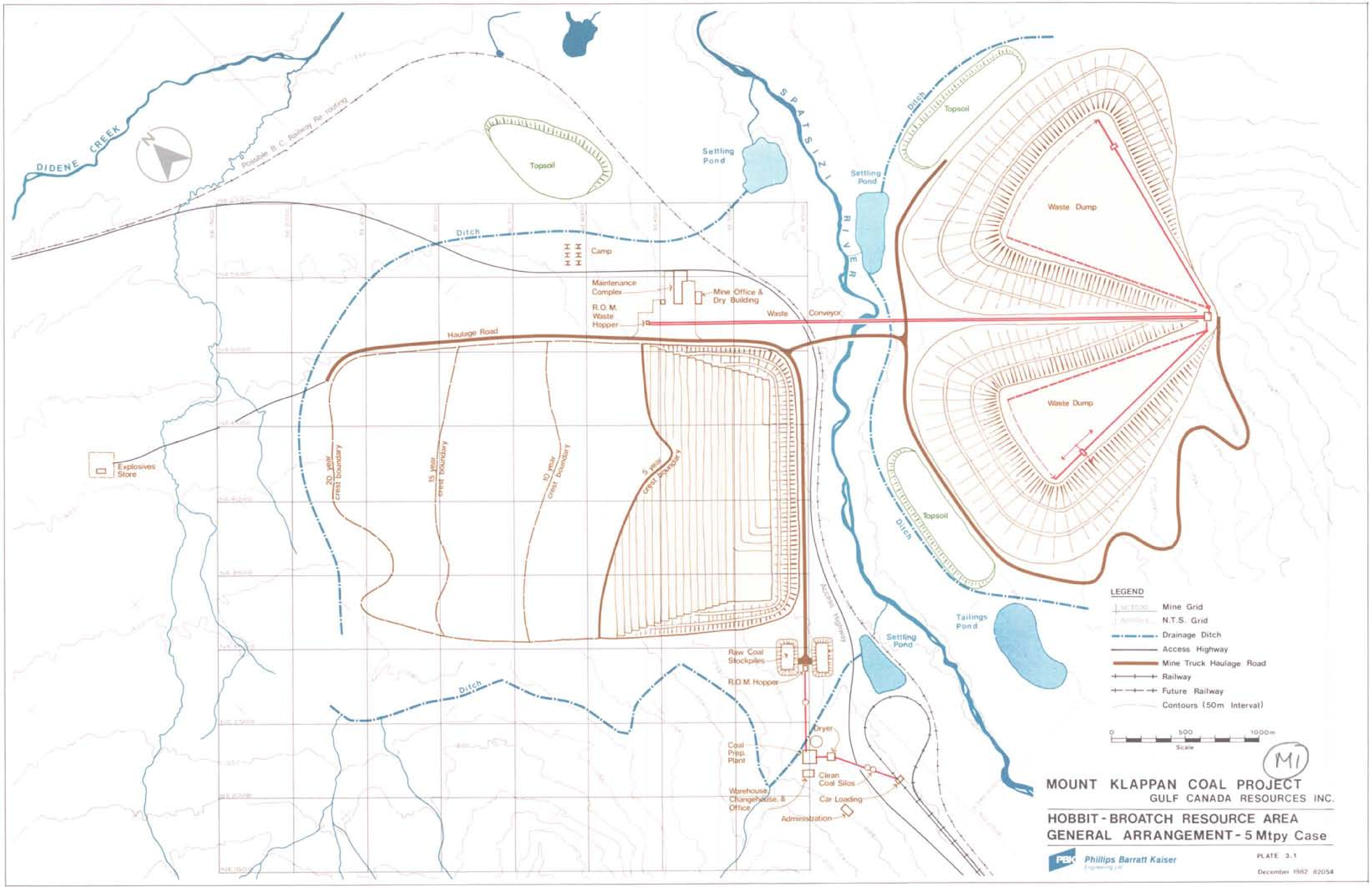


FIGURE 3.2

ORGANIZATION CHART - 5 Mtpy Case



DIDENE CREEK
Possible B.C. Railway Re-routing
Topsoil
Settling Pond
SPATSIZI RIVER
Ditch
Topsoil
Settling Pond
Waste Dump
Camp
Maintenance Complex
Mine Office & Dry Building
R.O.M. Waste Hopper
Waste Conveyor
Haulage Road
Waste Dump
Explosives Store
20 year crest boundary
15 year crest boundary
10 year crest boundary
5 year crest boundary
Topsoil
Ditch
Access Highway
Tailings Pond
Settling Pond
Raw Coal Stockpiles
R.O.M. Hopper
Ditch
Dryer
Coal Prep. Plant
Clean Coal Silos
Warehouse, Changehouse, & Office
Car Loading
Administration
LEGEND
Mine Grid
N.T.S. Grid
Drainage Ditch
Access Highway
Mine Truck Haulage Road
Railway
Future Railway
Contours (50m Interval)
0
500
1000m
Scale
M1
MOUNT KLAPPAN COAL PROJECT
GULF CANADA RESOURCES INC.
HOBBIT - BROATCH RESOURCE AREA
GENERAL ARRANGEMENT - 5 Mtpy Case
Phillips Barratt Kaiser
PLATE 3.1
December 1982 82054

1 Mtpy CASE

TABLE 3.2

MATERIAL MOVEMENT SCHEDULE - 1 Mtpy Case

	Units* x 10³	YEARS -4	-3	-2	-1	1	2	3	4	5	6-10	11-15	16-20	21-23	Total
Product															
Shipped		-	-	-	-	502	1 00C	1 000	1 000	1 000	5 000	5 000	5 000	508	20 010
Mine															
Waste															
Mine	m^3	-	-	-	-	7 533	10 555	8 421	8 176	7 871	37 228	33 512	32 046	3 405	148 747
Coal															
ROM	t	-	-	-	-	502	1 000	1 000	1 000	1 000	5 000	5 000	5 000	508	20 010
Statistics															
Strip Ratio (ROM)	m^3/t	-	-	-	-	15	10	8.4	8.2	7.9	7.4	6.7	6.4	6.7	7.4
Mine Construction															
Roads	m^3	-	-	10	224	9	9	6	6	6	32	6.0	-	-	331
Ditches	m^3	-	-	-	89	-	-	-	-	-	-	-	-	-	89
Pond Topsoil	m^3	-	-	-	143	-	-	-	-	-	-	-	-	-	143.5
Reclamation															
Topsoil Excavated															
Mine Area	m^3	-	-	-	454	82	82	42	42	42	126	-	-	-	871
Waste Dump Area	m^3	-	-	-	51	50	49	48	47	46	179	150	120	-	740
Topsoil Rehandled	m^3	-	-	-	-	-	-	-	-	-	76	15	45	265	401
Topsoil Spread	m^3	-	-	-	-	-	-	-	-	-	255	165	165	265	850

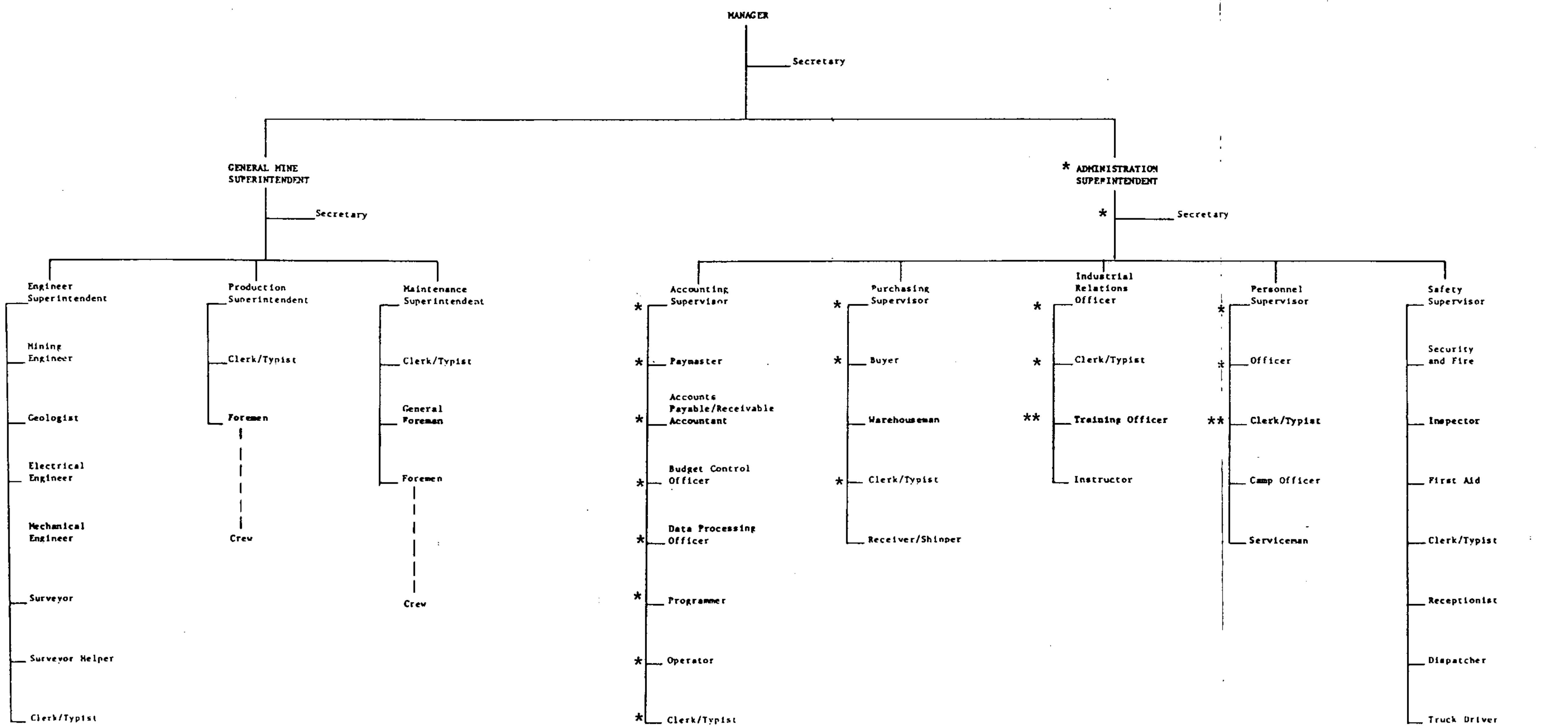
All volumes in bank equivalents

Decimal places in the above table have been rounded out for clarity of presentation.

* Does not apply to the stripping ratio.

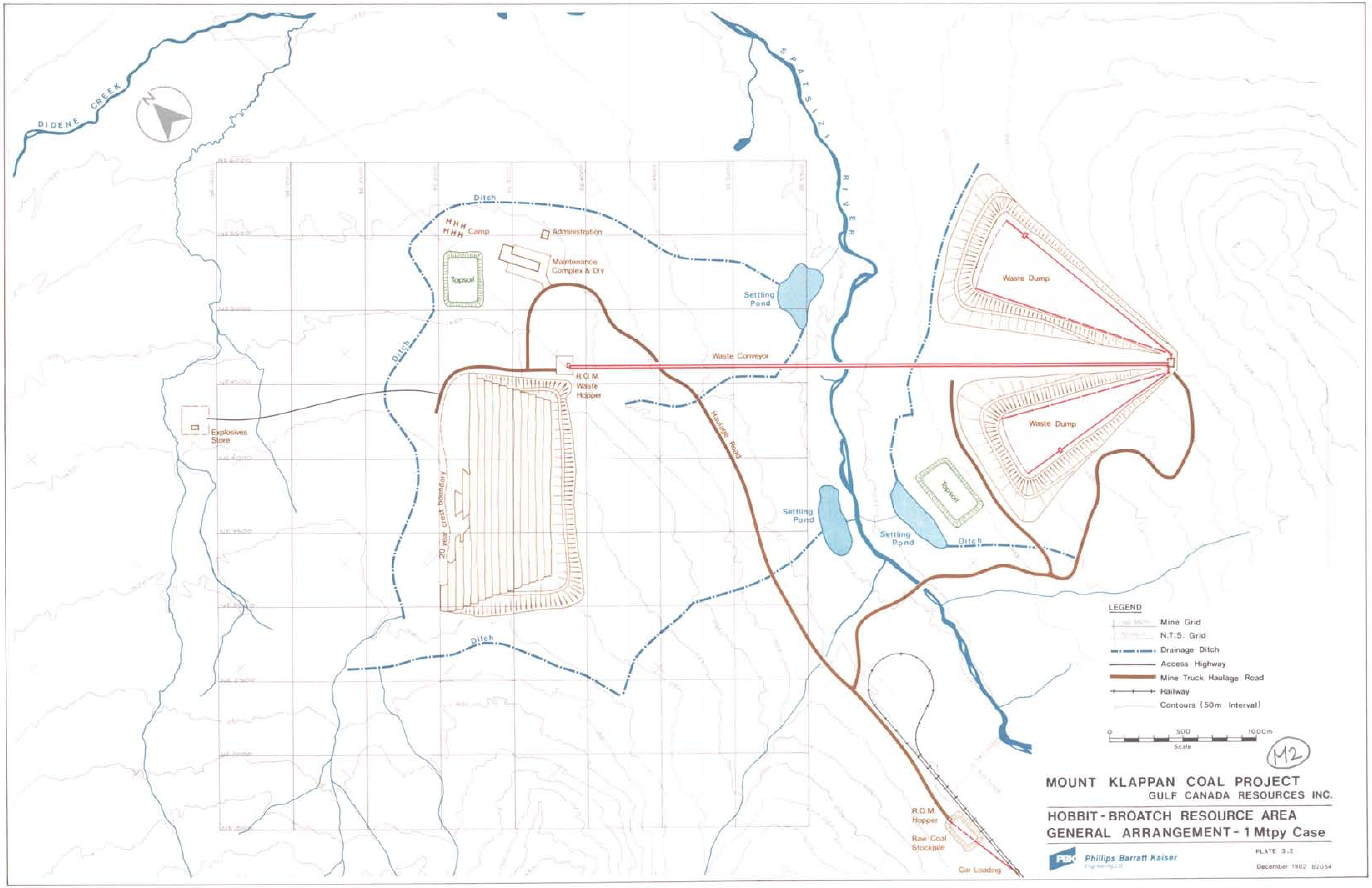
FIGURE 3.3

ORGANIZATION CHART 1 Mtpy Case



* These positions will be located in the Smithers office

** These positions will be in both Smithers office and Mine.



DIDENE CREEK
SPATSIZI RIVER
Ditch
Camp
Administration
Maintenance Complex & Dry
Topsoil
Settling Pond
Waste Conveyor
R.O.M. Waste Hopper
Explosives Store
Haulage Road
20 year crest boundary
Waste Dump
Waste Dump
Topsoil
Settling Pond
Settling Pond
R.O.M. Hopper
Raw Coal Stockpile
Car Loading
LEGEND
Mine Grid
N.T.S. Grid
Drainage Ditch
Access Highway
Mine Truck Haulage Road
Railway
Contours (50m Interval)
0
500
1000m
Scale
M2
MOUNT KLAPPAN COAL PROJECT
GULF CANADA RESOURCES INC.
HOBBIT-BROATCH RESOURCE AREA
GENERAL ARRANGEMENT - 1 Mtpy Case
PLATE 3.2
Phillips Barratt Kaiser
December 1982

PART 4

LABOUR AND MAJOR EQUIPMENT REQUIREMENTS

PART 4 - LABOUR AND MAJOR EQUIPMENT REQUIREMENTS

CONTENTS

Table

4.1 INTRODUCTION

PBK has developed plans for mining and coal preparation which incorporate present day technology and utilize standard equipment.

4.2 5 Mtpy CASE

421 MAJOR EQUIPMENT REQUIREMENTS

.1 Mining

Table 4.1 presents a summary listing of the major units of mining equipment needed for the 5 Mtpy Case.

422 LABOUR REQUIREMENTS

.1 Construction

For this assessment, the following levels of construction labour have been estimated.

	Year -3	Year -2	Year -1	Year 1	Total Man Years
5 Mtpy	150	900	1200	250	2500

.2 Operations

Table 4.2 presents a summary of total operations labour requirements for the 5 Mtpy Case.

4.3 1 Mtpy Case

431 MAJOR EQUIPMENT REQUIREMENTS

.1 Mining

Table 4.3 presents a summary listing of the major units of mining equipment needed for the 1 Mtpy Case.

432 LABOUR REQUIREMENTS

.1 Construction

For this assessment, the following levels of construction labour have been estimated.

	Year -2	Year -1	Year 1	Total Man Years
1 Mtpy	250	450	175	875

.2 Operations

Table 4.4 presents a summary of total operations labour requirements for the 1 Mtpy Case.

5 Mtpy CASE

TABLE 4.1

MAJOR MINING EQUIPMENT LIST

5 Mtpy Case

This sample listing is for year 5.

Mining Equipment	Number Of Units	kW Total
Shovel - 24.5 m^3	5	4 000
Shovel - Hyd.	3	-
Truck 154 t	45	-
OB Drill BE-55R	4	640
OB Drill BE-2450	2	-
F.E.L. L-800	1	-
Dozer D9L	13	-
Dozer 834	1	-

Conveyor System

Crusher System	1
Overland Conveyors	1
Transfer Conveyor	2
Travelling Stacker	2

TABLE 4.2

SUMMARY OF LABOUR - 5 Mtpy Case

	YEARS										
	-1	1	2	3	4	5	6-10	11-15	16-20	21	22
Mining											
Non-supervisory	139	353	549	521	546	489	783	787	736	788	485
Supervisory	92	92	92	92	92	92	92	92	92	92	58
Preparation											
Non-supervisory	88	88	88	88	88	88	88	88	88	88	88
Supervisory	36	36	36	36	36	36	36	36	36	36	36
Administration											
Staff	102	102	102	102	102	102	102	102	102	102	63
TOTAL	457	671	867	839	864	807	1101	1105	1054	1106	730

1 Mtpy CASE

TABLE 4.3

MAJOR MINING EQUIPMENT LIST

1 Mtpy CASE

This sample listing is for year 5.

Mining Equipment	Number of Units	kW (Total)
Shovel - 24.5 m^3	1	800
Shovel - hyd.	1	-
Truck - 154 t	11	-
OB Drill BE-55R	1	160
OB Drill BE-2450	1	-
FEL L-800	1	-
Dozer D8L	6	-
Dozer 834	1	-
Conveyor System		
Crusher System	1	
Overland Conveyor	1	
Transfer Conveyor	2	
Traveling Stacker	2	

TABLE 4.4

SUMMARY OF LABOUR - 1 Mtpy Case

	YEARS								
	1	2	3	4	5	6-10	11-15	16-20	21
Mining									
Non-supervisory	186	234	210	213	211	211	208	212	166
Supervisory	35	35	35	35	35	35	35	35	30
Handling									
Non-supervisory	20	20	20	20	20	20	20	20	20
Supervisory	9	9	9	9	9	9	9	9	9
Administration									
Supervisory	59	59	59	59	59	59	59	59	31
TOTAL	309	357	333	336	334	334	331	335	256

PART 5

INFRASTRUCTURE

PART 5 - INFRASTRUCTURE

CONTENTS

5.1 INTRODUCTION

Volume 5 of this mine assessment report for the Mount Klappan project includes the regional and site infrastructure. The components of this infrastructure are railway, pipeline, road, port, electrical power, water and townsite requirements. Plate 1.1 (Regional Access Map) shows the locations of the alternative rail and road routes investigated.

The soci-economic and environmental parts of this volume were provided by consultants retained directly by Gulf Canada Resources Inc.

5.2 RAILWAY

The system considered for transportation of the coal from the minesite to the port is by rail.

The railway evaluation consists of the following items:

- the completion of the existing British Columbia Railway (BCR) line from Chipmunk to the Mount Klappan property. The distance is 85 km;

- an investigation into four possible cutoff routes (varying from 176 to 196 km) to connect the BCR line to the Canadian National Railway (CNR) line near Hazelton. Any one of these cutoffs would reduce the total haulage distance by approximately 50% of the rail distance via Prince George, which is approximately 1,400 km; and,

- the preparation of preliminary capital cost estimates for the main line completion and for three of the four alternative cutoffs investigated.

The shortest cutoff distance (176 km) along the Skeena River (Railway Route No. 2) is the preferred route. This gives a total rail haul distance of approximately 600 km to Ridley Island.

5.3 PORT

The shipping port chosen for this evaluation is the coal terminal at Ridley Island, now under construction to handle the coal which will be produced in northeastern British Columbia.

No evaluation was made as to the capability of this facility to handle the tonnage being considered for the Mount Klappan project. However, when completed in 1983, the planned capacity of this terminal will be 12 million tonnes per year, approximately 4 million tonnes per year more than the tonnage proposed from the Quintette and Bullmoose Coal Projects now under construction in the northeast. The Ridley Island Coal Terminal can be expanded to handle 15 to 16 million tonnes per year as the demand increases.

5.4 SLURRY PIPELINE

The possibility of pumping coal in slurry form from Mount Klappan to the port of Stewart has been considered as an alternative to railway transportation. Preliminary estimates put the length at some 225 km.

Construction and operation of a pipline handling fine coal should not present a problem. A detailed investigation into this option was not made, however, because the final coal markets have not been identified and, therefore, the size specifications of the shipped products is not known.

5.5 ROAD ACCESS

An investigation was made to determine the feasibility of building a road link between the existing Stewart-Cassiar Highway (Highway 37) and the Mount Klappan property. Two possible routes were studied and the lengths of the new roads required were 146 km and 226 km. Capital cost estimates were prepared for each of these alternatives.

In addition, an estimate was made for the cost of completing a temporary access road from Tatogga Lake on the Stewart-Cassiar Highway, southeast along the Little Klappan River using the existing BCR roadbed. This road would provide access during the project construction, and until a permanent access road is available.

The preferred route is the 146 km Highway Route 1, which joins Highway No. 37 at Bowser Lake.

5.6 ACCOMMODATION

Two assumptions were made for the living accommodation for the mine employees for the two mine cases considered. These are:

- the total number of personnel estimated for the 5 million tonne operation in a typical year is 1 100. It is assumed that they will be resident in a public townsite which will be constructed near the mine property.

  A cost allowance per employee has been included in the capital cost estimate for assistance in developing the townsite.

- the 1 million tonne per year operation is designed for a fly-in operation. The total number of on-site personnel in a typical year is 155. Employees will be air-lifted to the site from Smithers on a routine scheduled basis to cover the operation, and will live in camp accommodation while at the mine. In addition, there will be a support staff of 24 people in Smithers performing functions which do not require full-time coverage at the mine. Total personnel, in a typical year, will be 335.

5.7 ELECTRICAL POWER

This mine assessment was developed on the assumption that a source of 138 kV power will be available at the property line at current B.C. Hydro charges for power consumed.

5.8 WATER

An investigation into the availability of a source of fresh water has not been made. However, the assumption has been made that sufficient water can be obtained from the numerous water sources available in the area.

5.9 SOCIO - ECONOMIC IMPACT

The basic finding of this investigation is that no socio-economic impact was found which precludes the development of the Mount Klappan coal project. Some of the positive impacts are:

5 Mtpy Case

- up to 1 100 direct and 500 indirect new jobs in the area
- regional income increased by $40 million per year
- total provincial employment increased by 2 750 and provincial income by $50 million per year
- some 2 500 man years of construction labour to develop the mine and build the support facilities.

1 Mtpy Case

- 338 direct and 100 indirect new jobs created in the area
- regional income increased by some $10 million per year
- total provincial employment increased by 676 and provincial income by some $12 million per year
- more than 800 man-years of labour to develop the mine and construct the site support facilities.

5.10 ENVIRONMENT

The basic finding of this investigation is that no environmental factor was found which precludes development of the Mount Klappan coal project. Environmental impacts will occur as a result of project development, but proper planning, design, construction, operation and reclamation will reduce the significance of these impacts. The most significant environmental issue relates to the project's proximity to Spatsizi Plateau Wilderness Park, however, the presence of a permanent townsite would result in increased recreational use of the park, which can be viewed as a positive impact.


YUKON
N.W.TERRITORIES
BRITISH COLUMBIA
BRITISH COLUMBIA
ALASKA
BRITISH COLUMBIA
ALBERTA
CASSIAR
DEASE LAKE
FORT NELSON
Preliminary
Access Road
Stikine River
SPATSIZI
PLATEAU
PROVINCIAL
PARK
37
Mount Klappan
Project Site
Route 1
Route 2
Route 2
Route 1
STEWART
HAZELTON
BCR
FORT
ST JOHN
DAWSON
CREEK
NE COAL AREA
97
SMITHERS
TERRACE
PRINCE RUPERT
RIDLEY ISLAND
KITIMAT
FORT
ST JAMES
CNR
16
PRINCE
GEORGE
LEGEND
Existing Railways
Proposed Railways
BCR British Columbia Railway
CNR Canadian National Railway
Existing Highways
Proposed Roads
Air Strips
Existing Mines
SCALE 0 10 50 100 KM
MOUNT KLAPPAN COAL PROJECT
GULF CANADA RESOURCES INC.
REGIONAL ACCESS MAP
M3
PBK Phillips Barratt Kaiser
PLATE 1.1
December 1982 / 82054

VOLUME 2

GEOLOGY

MOUNT KLAPPAN COAL PROJECT

VOLUME 2

GEOLOGY

TABLE OF CONTENTS

PART 1 - INTRODUCTION

CONTENTS

PART 2 - PROPERTY HISTORY

CONTENTS

PART 3 - EXPLORATION

CONTENTS

Table

Plate

PART 4 - GEOLOGY

CONTENTS

Table

Plate

PART 5 - RESOURCES

CONTENTS

Table

Plate

PART 6 - COAL QUALITY

CONTENTS

APPENDICES

GEOLOGY

CONTENTS

VOLUME 3

MINING

MOUNT KLAPPAN COAL PROJECT

VOLUME 3

MINING

TABLE OF CONTENTS

PART 1 - INTRODUCTION

CONTENTS

PART 2 - GEOLOGICAL SETTING

CONTENTS

PART 3 - MINING SYSTEMS

CONTENTS

Table

Figure

Plate

PART 4 - MINESITE INFRASTRUCTURE

CONTENTS

Table

Figure

PART 5 - ASSESSMENT PARAMETERS

MINING

CONTENTS

Page

Table

VOLUME 3

APPENDIX A

CONTENTS

VOLUME 4

COAL PREPARATION FACILITIES

MOUNT KLAPPAN COAL PROJECT

VOLUME 4

COAL PREPARATION FACILITIES

TABLE OF CONTENTS

PART

PART 1 - INTRODUCTION

CONTENTS

PART 2 - DESIGN CRITERIA

CONTENTS

PART 3 - PREPARATION FACILITY - 5 Mtpy CASE

CONTENTS

Figure

Plate

PART 4 - RAW COAL HANDLING FACILITY - 1 Mtpy CASE

CONTENTS

Table

APPENDICES

TABLE OF CONTENTS

APPENDIX

VOLUME 5

INFRASTRUCTURE

MOUNT KLAPPAN COAL PROJECT

VOLUME 5

INFRASTRUCTURE

TABLE OF CONTENTS

PART

PART 1 - INTRODUCTION

CONTENTS

PART 2 - COAL TRANSPORTATION

CONTENTS

Plate

PART 3 - ROAD ACCESS

CONTENTS

PART 4 - SERVICES

CONTENTS

PART 5 - SOCIO-ECONOMIC IMPACT

CONTENTS

Table

Plate

PART 6 - ENVIRONMENT

CONTENTS

Table

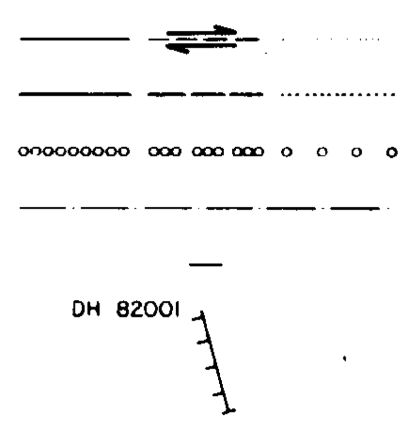
APPENDIX A

GEOLOGICAL CROSS SECTION

APPENDIX A

CONTENTS

Legend



- COAL SEAM TRACE (DEFINED, APPROXIMATE, INFERRED)
- FAULT TRACE (DEFINED, APPROXIMATE, INFERRED)
- CONGLOMERATE UNIT (DEFINED, APPROXIMATE, INFERRED)
- STRUCTURAL TRACE
- ATTITUDE CONTROL POINT
- DIAMOND DRILL HOLE WITH ATTITUDE CONTROL

PBK ADDITION:

- MINING AREA - 5 Mtpy Case

GULF CANADA RESOURCES INC.
Coal Division
CALGARY ALBERTA

Northwestern British Columbia

MT. KLAPPAN COAL PROPERTY

GEOLOGICAL CROSS-SECTION

4500 S (EAST) (M4)

PREPARED BY: G. SEVE		SCALE 1:10,000
APPROVED BY:	DATE: SEPT. 82	FIGURE A-3

APPENDIX B

REGIONAL MAP

APPENDIX B

CONTENTS

Produced jointly by GULF CANADA DRAFTING DEPT. and HARDY ASSOC. (1978) LTD., MAPPING SECTION.

Revised to January, 1983.

LEGEND

- Highway
- Road, proposed
- Road, alternate
- Railway
- Proposed Railway cut-off
- Alternate Railway cut-off
- Pipeline, possible
- Proposed Dam Site
- Gulf Property
- Proposed Pit, Mt. Klappan property
- Proposed Townsite, Mt. Klappan property
- Boundary, Park or Reserve
- Boundary, International
- Spot Elevation (feet above sea level) · 6750
- Contours (1000 Foot Interval) 2000
- Producing Mine (see separate list) 4
- Prospect
- City, Town

GULF CANADA RESOURCES INC.

NORTHWEST BRITISH COLUMBIA

REFERENCE NOTE

Producing Mines: from The Northwest Region — B.C. Regional Economic Study, 1982.

Prospects: from Kitimat-Stikine Regional District — 1:500,000 Regional Resource Map, 1981.

Base Map: from Dept. of Energy, Mines and Resources, Surveys and Mapping Branch, current N.T.S. series maps.

SCALE 1: 500,000

Kilometres 10 5 0 10 20 30 40 50 Kilometres

Miles 5 0 10 20 30 Miles

M5

PRODUCING MINES

1 DOME MOUNTAIN — Ag, Pb, Zn
2 DUTHIE — Ag, Pb, Zn, Au, Cd, Cu
3 SILVER STANDARD — Ag, Pb, Zn, Au, Cu
4 KITSAULT — Mo
5 SCOTTIE GOLD — Au, Ag
6 GRANDUC — Cu, Ag, Au

KEY MAP

110