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Geothermal Service of Canada

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STUDY OF MINE AIR HEATING WITH GEOTHERMAL ENERGY

Acres Consulting Services Limited
8th Floor - 800 West Pender Street
Vancouver, B.C.
V6C 2V6

Earth Physics Branch Open File Number 84-14
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ABSTRACT

This conceptual level study examines the technical and economic potential for employing geothermal energy to heat mine ventilation air at a number of potash mines in Saskatchewan.

A preliminary evaluation of the resource indicates that, conservatively, resource temperatures of 35-45°C should be achievable, a range for this application.

Most mines are presently using direct-fired natural gas to heat outside air from winter lows of around -35°C (and occasionally lower) to 10-25°C. Air volumes range from 325,000 m^3/h to a high, projected for one mine expansion, of over 750,000 m^3/h.

For a projected capital investment of approximately $2 million for the geothermal supply system and glycol/air coil recirculation system, before-tax lifetime unit energy cost savings of 25-40 percent relative to natural gas are predicted. An economic analysis on three selected mines indicates real internal returns of over 20 percent after tax.

RESUME

Cette étude conceptuelle examine le potentiel technique et économique de l'utilisation de l'énergie géothermique pour le chauffage de l'air ventilé à plusieurs mines de potasse du Saskatchewan.

Une évaluation préliminaire de cette ressource indique que des températures de réservoir de 35 à 45°C devraient être atteintes, températures raisonnables pour cette utilisation.

La plupart des mines utilise un feu continu de gaz naturel pour chauffer l'air extérieur, qui en hivers descend jusqu'à - 35°C (et même plus bas), jusqu'à 10-25°C. Le taux de réchauffement varie entre 325,000 m^3/h et 750,000 m^3/h, cette dernière valeur étant celle projetée pour l'expansion d'une mine.

On projette des dépenses d'investissement d'environ $2 millions pour un système géothermique d'alimentation et un système de recirculation avec serpentin glycol/air; ce qui representerait une épargne à vie, avant impôt, par unité d'énergie, de 25 à 40% en comparaison avec le gaz naturel.

Une analyse économique de trois mines indique un rendement effectif de plus de 20% après les impôts.

STUDY OF MINE AIR HEATING
WITH GEOTHERMAL ENERGY

Prepared for:
NATIONAL RESEARCH COUNCIL
Division of Energy Research
and Development

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PREFACE

This study was undertaken jointly by Acres Consulting Services Limited, acting as the principal consultant, and Nevin Sadlier-Brown Goodbrand Ltd., consulting geological engineers.

The assistance of the mining companies in providing information on their present operations and future plans is hereby acknowledged and greatly appreciated.

ABSTRACT

This conceptual level study examines the technical and economic potential for employing geothermal energy to heat mine ventilation air at a number of potash mines in Saskatchewan.

A preliminary evaluation of the resource indicates that, conservatively, resource temperatures of 35-45° C should be achievable, a range adequate for this application.

A telephone and questionnaire survey of design and operating conditions at a number of mines indicates that the majority are presently using direct-fired natural gas to heat outside air from winter lows of around -35° C (and occasionally lower) to 10-25° C. Air volumes range from 325,000 m3/h (190,000 acfm) to a high, projected for one mine expansion, of over 750,000 m3/h (430,000 acfm).

For a projected capital investment of approximately $2 million for the geothermal supply system and glycol/air coil recirculation system, before-tax lifetime unit energy cost savings of 25-40 percent, and over, relative to natural gas are predicted. An economic analysis on three selected mines indicates real internal returns of over 20 percent, after tax.

It is recommended that geothermal mine air heating be examined in further detail and that discussions be held with the mine companies to determine specific conditions at the mines and the interest in pursuing the savings potentially available with geothermal heating.

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LIST OF FIGURES AND TABLES

LIST OF ABBREVIATIONS & SYMBOLS

ATES - Aquifer thermal energy storage
MAH - Mine air heating
R_f - Ratio of primary to secondary circuit flows
TDF - Temperature drop factor
UF - Utilization factor
DDWD - Deadwood formation
PCMB - Precambrian formations

Thermal Load and Annual Delivered Energy - q (GJ/h) and Q (GJ/yr)

q_p , Q_p - process (mine air) demand
q_g , Q_g - geothermal system supply
q_1 , Q_1 - primary heat exchanger supply (geofluid circuit)
q_b , Q_b - peaking boiler supply (indirect fired system)

Annual Load Factor - LF

LF_p - process (mine air) demand load factor
LF_g - geothermal delivery system load factor

Heating System Temperatures - T (°C)

Primary Circuit (Geofluid):

T_1 - resource supply temperature
T_2 - resource injection temperature
T_{si} - reference geofluid sink injection temp.(0°C assumed)

Secondary Circuit (to air heaters):

T_s - hydronic supply
T_r - return to geofluid exchanger
T_p - supply process after boiler (indirect fired only)

Process Circuit:

T_i - air entering air coils
T_o - air leaving air coils
T_m - heater/bypass air stream mix
T_e - air entering mine shaft

Heating System Flows - F (m^3/h)

F_g - geofluid supply flow (primary circuit)
F_p - secondary circuit flow (hydronic system)
F_p/F_g - ratio R_f
F_{bp} - bypass air flow

Unit Energy Cost (Levelized) - Ø ($/GJ)

$Ø_g$ - geothermal supply system
$Ø_i$ - incremental system energy cost

Outdoor Temperatures - t (°C)

t_w - winter design (peak space load)
t_s - summer design (zero space load)
t_t - transition temperature (below which air bypass of heater is required)

1.0 INTRODUCTION

1.1 Study Objectives

The large potash mining operations found in central Saskatchewan process large quantities of fresh air for mine ventilation purposes. In the winter this air requires heating to a suitable temperature from winter levels of -35° C and very occasionally, -45° C. At the present time air is heated by natural gas which is frequently contracted on an interruptible basis. During supply interruptions diesel, heating oil or propane are used.

This study briefly examines the opportunities, design concepts, comparative costs and provisional economics of utilizing the low to medium grade geothermal resources of the underlying sedimentary basin for this air heating function. The work has been commissioned by the National Research Council as part of its on-going investigations program examining the geothermal potential in Canada.

1.2 Mine Survey

The primary operating mines in the Saskatchewan potash area were initially contacted by telephone. This was followed by a brief questionnaire, issued to each of the companies listed below, to obtain specific details covering local geology and technical aspects of the present ventilation systems:

- Cominco Ltd., Potash Operations, at Vanscoy Delisle;
- Central Canada Potash, Division of Noranda Mines Ltd., (CCP) at Colonsay;

- International Minerals and Chemicals Corporation (Canada) Ltd. (IMC), near Esterhazy; and,

- Potash Corporation of Saskatchewan (PCS), a Crown corporation of the Province of Saskatchewan that has since 1975 operated the Lanigan, Cory, Allan and Rocanville Divisions.

The Potash Company of America mine operation near Saskatoon was not contacted.

Data from these questionnaires are presented in Table 1-1. Presently, air flows are seen to range from about 300,000 to over 500,000 m^3/h, with the PCS-Lanigan mine air demand projected to increase to 765,000 m^3/h. Mine supply air temperatures range from 10°C to 25°C.

TABLE 1-1

GENERAL DATA SHEET - POTASH MINE OPERATIONS

COMPANY:	COMINCO	PCS M I N I N G				CENTRAL CANADA POTASH (NORANDA)	INTERNATIONAL MINERALS & CHEMICALS	
	1	2	3	4	5	6	7	8
MINE NAME/LOCATION:	VANSCOY - DELISLE	ROCANVILLE	LANIGAN	CORY	ALLAN	COLONSAY	ESTERHAZY K1	ESTERHAZY K2
Production Rate (KCL) - Present (tonnes/yr) - Projected (tonnes/yr)	1,014,000 (est.) -	1,728,000 -	1,010,000 2,928,000 (1986)	1,066,000 -	1,455,000 -	1,350,000 (est.)		
1. Ventilation Rate - Present ($1000m^3/h$) - Projected ($1000m^3/h$)	360 520 (1984)	431 -	426 765	360 480	426	265-375[3]	408	408
2. Supply Air Temp.[1]	13°C (55°F)	24°C (75°F)	10°C (50°F)	21°C (70°F)	25°C (70°F)	14°C[3] (57°F)	20°C(68°F)	20°C(68°F)
3. Fuel Source - Main - Alternate	Nat. Gas n/a	Nat. Gas n/a	Nat. Gas Propane(40MB/h) and oil	Nat. Gas Propane and Oil	Nat. Gas Prop. (36MB/h) and Oil	Nat. Gas -	Nat. Gas n/a	Nat. Gas n/a
4. Energy Transmission - direct fired - indirect heating	in progress[2]	X -	X -	- X (Glycol)	X -	- X (Glycol)[4]		
5. Formation Temp.	40°C (est.)	33°C (drill logs)	35°C (drill logs)	35-40°C	35°C (assumed)	Approx. 45°C		
6. Depth to Mining level (m)	1075	n/a	n/a	n/a	n/a	1025	958	958
7. Injection Formation	Deadwood	Winnipegosis & Interlake	Deadwood	Deadwood	Deadwood	Deadwood	Winnipegosis & Interlake	Winnipegosis & Interlake
8. Waste Brine Injection Rate (m^3/h)	108	n/a	n/a	n/a	112	250	110-130	110-130
9. Waste Brine Injection Pressure (psi)	90	n/a	n/a	n/a	500	750	800	800

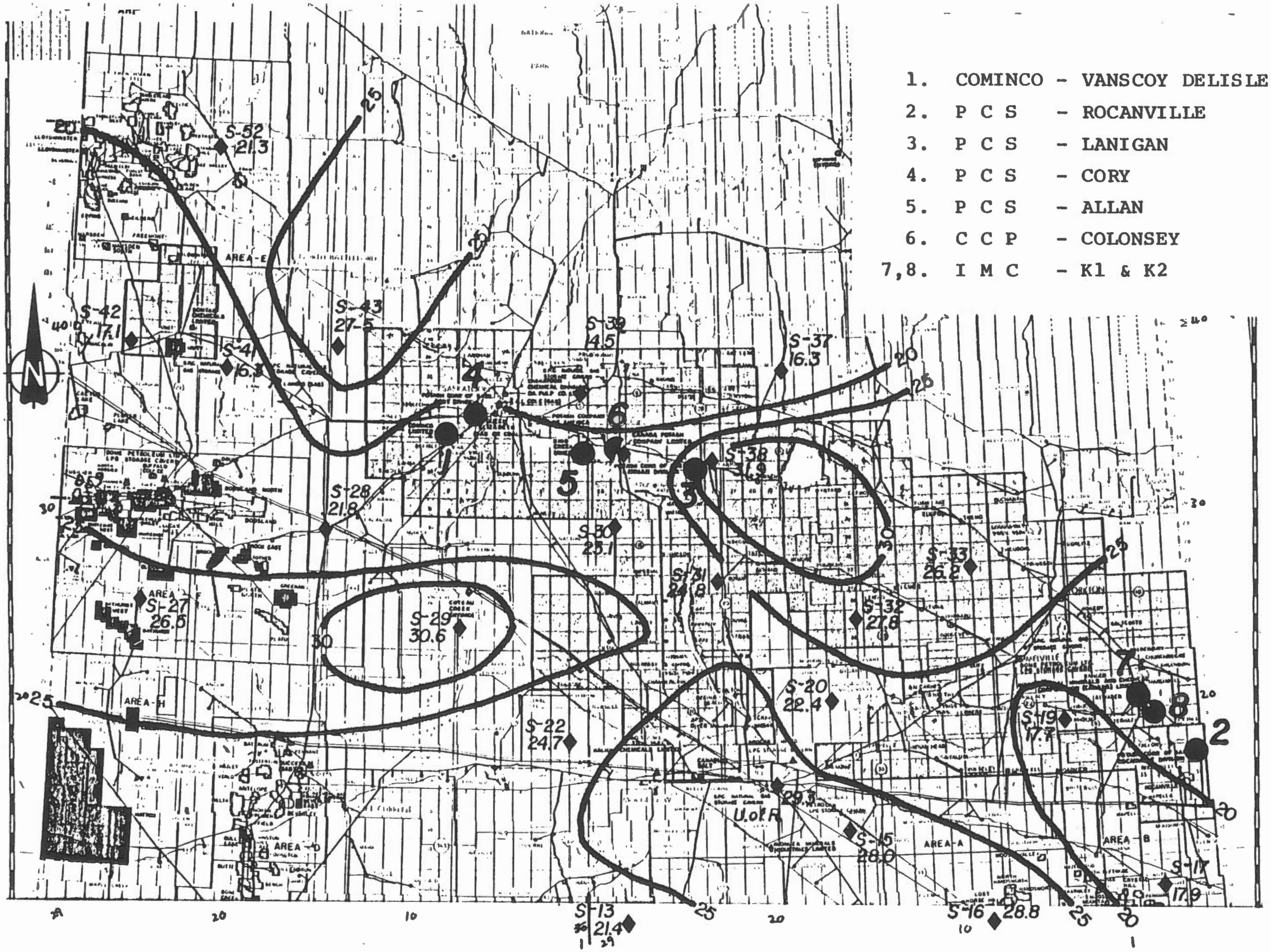
Notes
(1) Min. allowable temp. downshaft set to minimize expansion/contraction of shaft tubbing.
(2) Cominco to replace n/gas fired steam boilers in 1984 with gas direct firing to suit increase in air flow.
(3) CCP Air flow at -30°C limited by heating capacity to 175,000 acfm ($297,000m^3/h$); at 35°C, $260,000m^3/h$.
(4) CCP Steam to Glycol heating supply; (21 GJ/h) supply 10 Glycol/Air Coil HX's.

2.0 RESERVOIR EVALUATION

2.1 Temperature Gradients

The commercial potash area containing the candidate mines is illustrated in Figure 2-1. In order to evaluate the subsurface temperature regime within this area several sources of information were studied. Jones et al, (1982) compiled all of the known well temperatures in the provinces of Saskatchewan and Manitoba, keyed them to locations, and used computer means to plot and contour the temperature data. Unfortunately, temperatures measured during the course of typical oil and gas well drilling are rarely logged in a manner which can provide stable temperature estimates of the subsurface formations. Consequently, the data presented by Jones et al for the study area are misleading and largely unsuitable for the present application. However, in analyzing the data by sections, a generally decreasing gradient from west to east is observed. Whether this is a function of deeper drilling in the deeper basin to the west is not known.

In a study of subsurface mapping of geothermal potential, using the existing data, Sproule Associates Limited (1983) produced a more usable map by carefully selecting a relatively few wells with high quality data. The well points of relevance to this study are summarized in Table 2-1. Using Sproule's temperatures at the various depths noted, the geothermal temperature gradients of Table 2-1 are based on a mean surface temperature of 5°C and the assumption of linearity with depth. This 5°C temperature is supported by the plots of temperature versus depth presented by Jones et al (1982). To complement the Sproule data, gradients have been also calculated from the



WELL POINT DATA & GEOTHERMAL GRADIENT CONTOURS

FIGURE 2-1

TABLE 2-1

TEMPERATURES OF WELLS

	Depth	Temp.	Formation	Gradient*
S-13	2664	62°	DDWD	21.4
S-15	2361	71°	PCMB	28.0
S-16	1982	62°	PCMB	28.8
S-17	2121	43°	PCMB	17.9
S-19	1642	34°	PCMB	17.7
S-20	2007	50°	PCMB	22.4
S-22	2104	57°	DDWD	24.7
S-23	1738	48°	PCMB	24.7
S-27	2002	58°	DDWD	26.5
S-28	1976	48°	DDWD	21.8
S-29	1800	60°	DDWD	30.6
S-30	1861	48°	PCMB	23.1
S-31	1815	50°	PCMB	24.8
S-32	1833	56°	PCMB	27.8
S-33	1487	44°	PCMB	26.2
S-37	1349	27°	PCMB	16.3
S-38	1601	56°	PCMB	31.9
S-39	1650	29°	PCMB	14.5
S-41	1958	37°	PCMB	16.3
S-42	1988	39°	PCMB	17.1
S-43	1745	53°	DDWD	27.5
S-52	1503	37°	PCBM	21.3

* Gradient assumes a 5°C mean surface temperature.

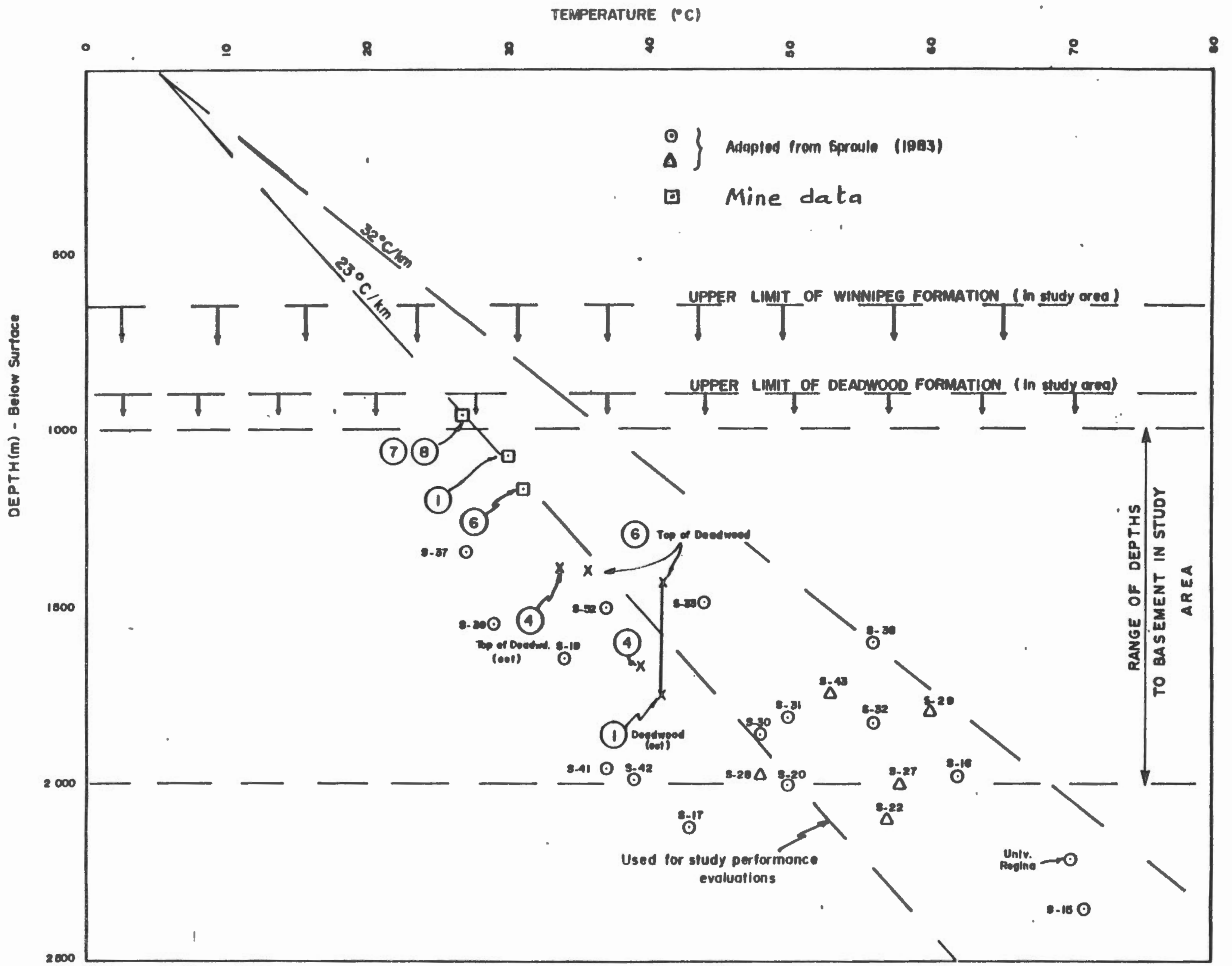
mine level temperatures provided by the mine companies, as well as temperature data presented by Vigrass et al (1979) for the University of Regina research well.

Figure 2-2 shows well temperature results plotted against depth. Although the reliability of the data is uncertain, it provides an initial interpretation for this study. Well points and estimated gradients are superimposed on the map, Figure 2-1, and gradient contours developed.

Regarding Figure 2-2, two distinct temperature regimes appear to exist in the area. Near the mining facilities a gradient of about 23°C/km is observed. Elsewhere zones of higher gradient, in the order of 30°C/km, appear to exist. It is not clear whether the lower gradient observed in the Saskatoon and Esterhazy areas is a real feature, perhaps caused by thermal refraction from an insulating layer of evaporites, or is an artifact of temperature measurements in disturbed environments, e.g. mining caverns and injection wells. Until further information has been acquired the conservative gradient value of approximately 23°C/km is considered the appropriate one to use for this prefeasibility study, particularly in estimating direct use performance and costs.

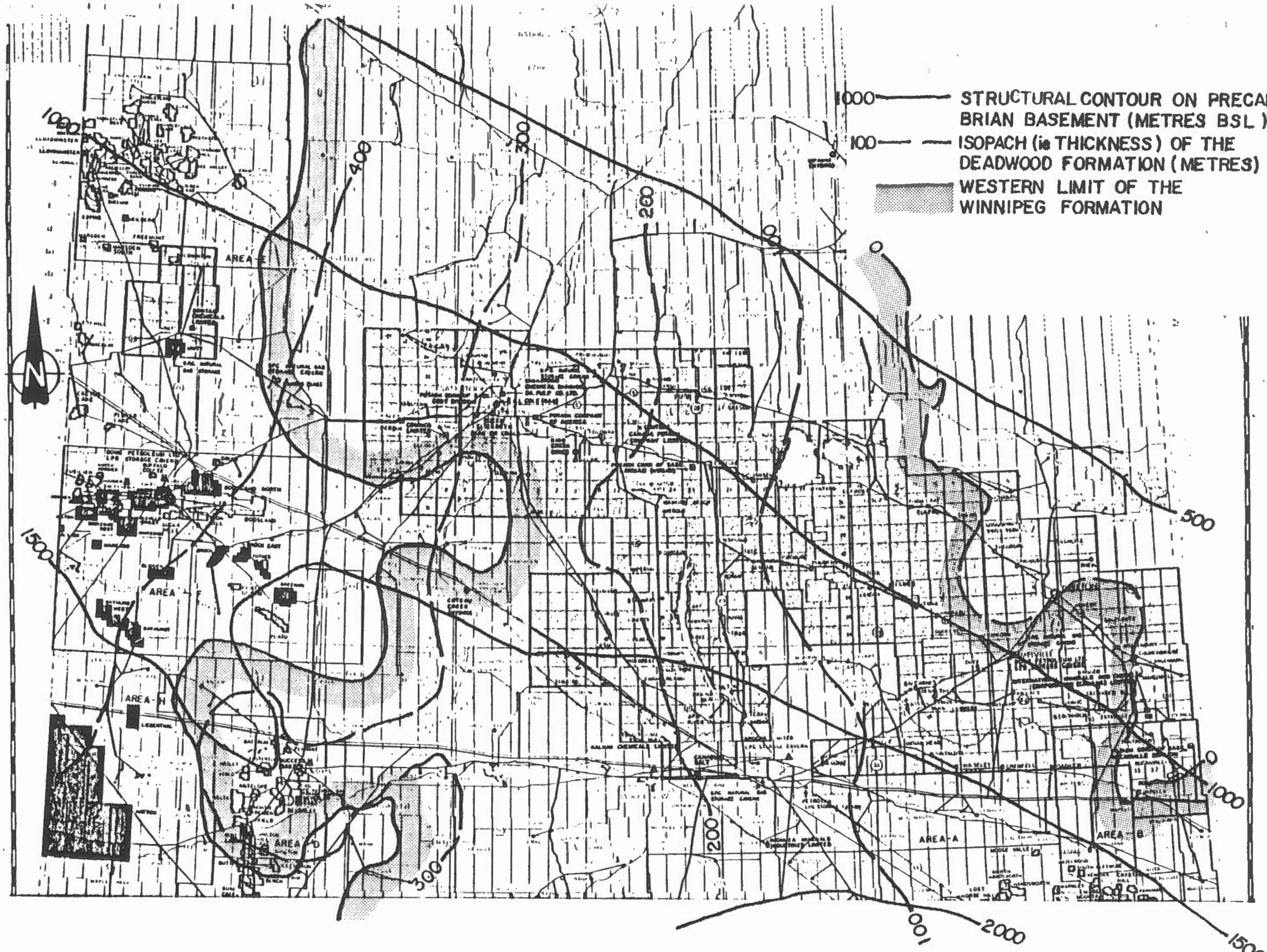
2.2 Reservoir Formations

The depth to the Precambrian surface is the maximum for geothermal drilling and, by inference, the maximum temperature in any specific area is limited. A structural contour map showing the Precambrian basement is presented in Figure 2-3. Here, the contours represent depth in metres below sea level (BSL) to the Precambrian basement



POTENTIAL RANGE OF GEOTHERMAL GRADIENTS FOR THE STUDY AREA

FIGURE: 2-2



BASEMENT STRUCTURE & RESERVOIR ISOPACHS

FIGURE 2 - 3

(PCMB). To a first order of approximation the average ground elevation above sea level in the region of interest may be taken to be 500 metres. In the absence of a detailed study of basement depth below each individual mine site it has been considered appropriate to determine an approximate basin depth in two areas. The 5 mines near Saskatoon (Figure 2-1) lie over a basement that is approximately 1800 metres below surface, while the remaining three mines near Esterhazy, at the eastern border with Manitoba, have a maximum basement depth of about 1500 metres. For a 23°C/km gradient this would suggest maximum temperatures of around 45°C near Saskatoon, and 40°C near Esterhazy. Since the producing formation(s) may not be immediately on the basin-basement contact, and production will occur over some length of open hole, lesser temperatures of 40°C and 35°C for the Saskatoon and Esterhazy mines, respectively, are assumed to be more appropriate for preliminary feasibility estimating purposes.

2.3 Permeability and Flow Considerations

In order to provide the quantity of geothermal fluid necessary for the processes under consideration, formations of reasonably high permeability will be required. Fortunately, throughout the potash mining area a generalized unit referred to as the Basal Clastic Division, which comprises the Winnipeg Formation underlain by the Deadwood Formation, lies on the basement. These two formations consist of interbedded shale and water-bearing sandstones. Although an evaluation of drill stem data is beyond the scope of this study, it is of note that the Winnipeg and Deadwood Formations are most commonly used for re-injection purposes for the disposal of potash waste brine. This implies that, as a minimum, permeabilities are moderate in these horizons. The development well penetrating the Winnipeg and Deadwood Formations beneath the University of Regina (located on the southern fringe of the potash mining area) encountered permeability sufficient to economically produce 100 to 150 m^3/h (Vigrass, 1979), this with a normal down-hole pumping system and moderate drawdown.

The shale horizons of both the Winnipeg and Deadwood Formations will be unsuitable for water production. Notwithstanding, it is reasonable to assume that in places where the formations are thick, allowing large open hole or multi zone completions, the potential for high fluid production is considerable. Figure 2-3 shows contours of equal thickness for the Deadwood Formation (isopach) as well as the western limit of the Winnipeg Formation. In the Saskatoon area both formations are available as targets with thicknesses in excess of 250 metres. On the eastern border of the province, the Deadwood Formation pinches out and the thickness of the Winnipeg Formation is about 30 metres. At the IMC K-1 and K-2 mines and the PCS - Rocanville Division mine, the Interlake and Winnipegosis Formations are being utilized for re-injection for reasons that have not been pursued in this study. It is likely that the Winnipeg Formation is available in this area as a potential geothermal reservoir unit.

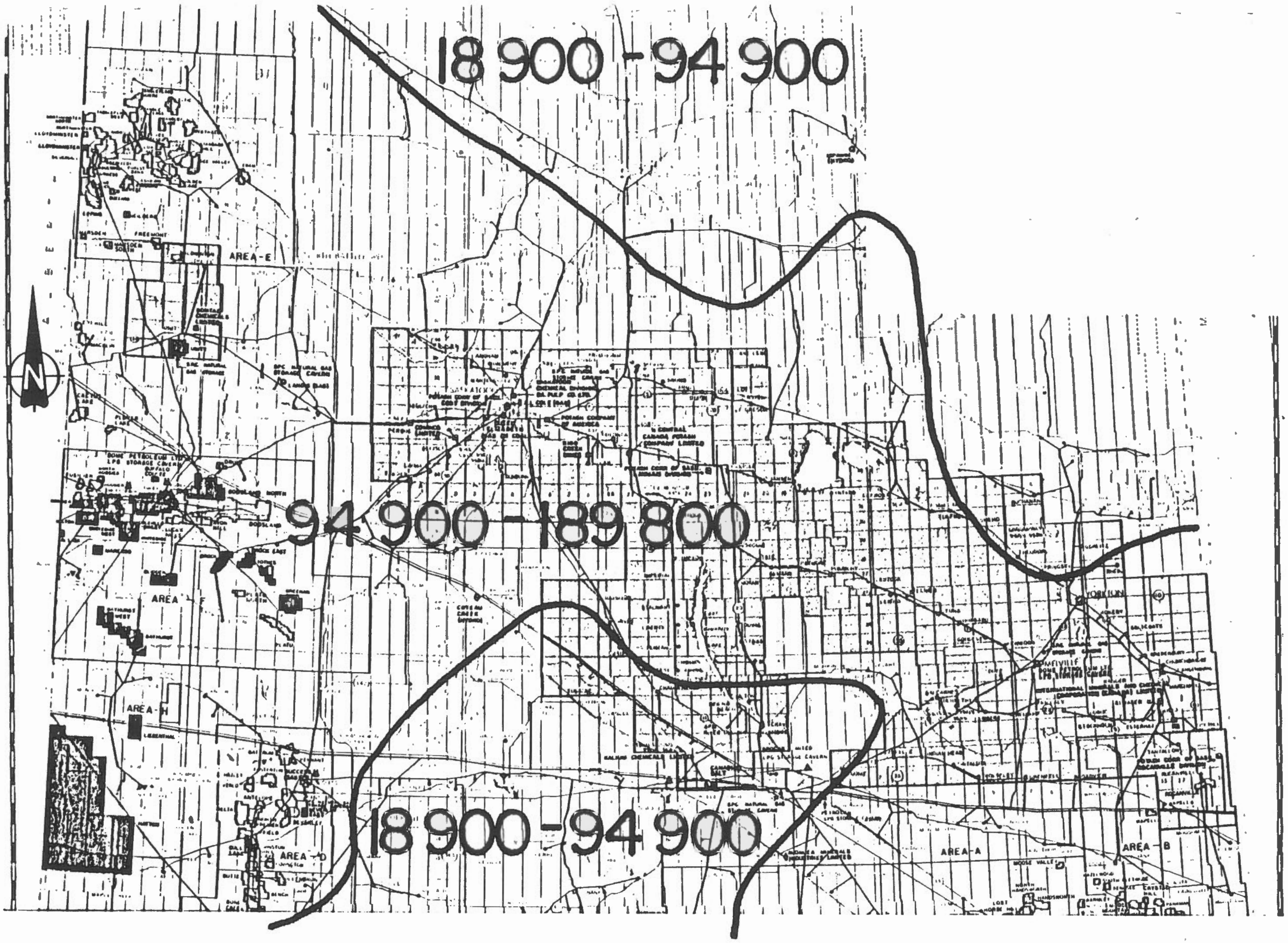
Information regarding waste brine injection volumes and pressures was provided by some mines, and is shown summarized in Table 1-1. Injection rates range from approximately 100 to 250 m^3/h at pressures from 600 to 5500 kPa (90 to 800 psi). Although these volumes are comparable with those required for economic geothermal fluid extraction they cannot be directly compared to formation production. Injection at high pressures commonly results in hydraulic fracturing of rock and the consequent channelling of injected fluids along fracture planes. The fact that the formations in question routinely accept large injected volumes of process brine without fracturing is nevertheless encouraging.

In summary, there should be every chance of success for penetrating formations near the basin-basement contact capable of sustaining fluid flows on the order of 100-150 cubic metres per hour.

2.4 Formation Fluids

Only limited data are available concerning the nature of formation fluids in the potash mining area. The chloride content of the basal clastic division has been estimated for the region (Simpson and Dennison, 1975). The results are presented on Figure 2-4. This information is sketchy at best so that it is probably more realistic to consider the findings of Vigrass et al (1979) at the University of Regina. There, the total dissolved solids ranged between 108,000 and 127,000 mg/L. More importantly, a significant concentration of dissolved hydrogen sulphide (at least 2 to 3 percent) was encountered in this well in the Winnipeg Formation. This gas is unpleasant and toxic and presents a significant corrosion problem for well casing and surface plant equipment.

Although the problems related to fluid chemistry in geothermal applications are important considerations, this aspect of resource exploitation is best addressed on a site-specific basis for which, at present, there is in-



RESERVOIR CHEMISTRY - CHLORIDE CONTENT CONTOURS (BASAL CLASTIC DIVISION)

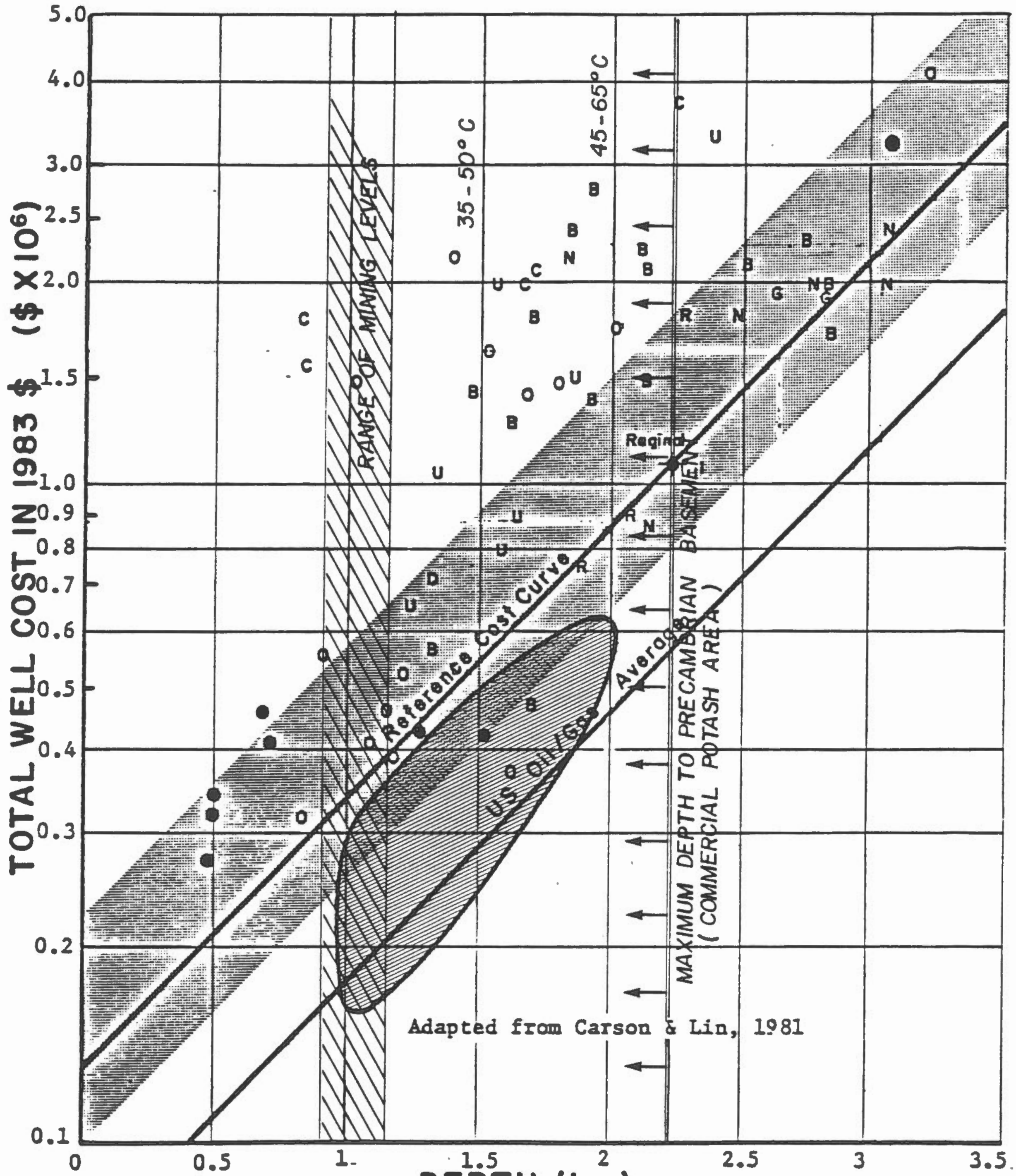
FIGURE 2 - 4

adequate data. Problems related to solids precipitation would have to be addressed during plant and process design at each site. It is probably best to assume relatively high completion costs during well drilling as a result of known dissolved hydrogen sulphide in formation waters. Surface plant of suitable steel grade and heat exchangers of titanium will probably be mandatory.

2.5 Well Costs

Generalized costs for the drilling of geothermal wells in the Western Sedimentary Basin were presented in a previous report (Acres, 1983). Some factors, unique to the potash mining region of Saskatchewan, narrow the range of expected cost. The maximum well depth in a potash producing area will be less than 2 kilometres. Although it is clear that any economic producing well will have to penetrate close to the basement contact, more importantly, a similar requirement exists with regard to injection wells which must be completed in horizons well below the potash mining level for safety reasons. For the purposes of analyzing production drilling costs for specific mine sites and formations, a graph of well cost (in 1983 dollars) versus depth is presented in Figure 2-5 adapted from Acres (1983). The reference cost curve is constructed through the University of Regina well cost point superimposed on the U.S. database.

For reference, Figure 2-5 also shows an irregular shaded area representing a range of costs obtained for typical potash waste brine injection wells from the Saskatchewan area. In general, it can be assumed that the costs of geothermal wells, both production and injection, will lie closer to the reference cost curve because drilling and



Key

G The Geysers
B Baca, New Mexico
C Cove Fort - Sulphurdale, Utah
I Imperial Valley
N Northern Nevada
R Roosevelt Hot Springs, Utah
U Industry Coupled, Utah/Nevada
● Direct Use
o Others

Range of costs for typical potash waste brine injection wells corrected to 1983 $ (after Simpson and Dennison 1975)

GEOTHERMAL WELL COSTS vs. DEPTH

FIGURE 2-5

completion practices will have to be more closely regulated, using better grades of steel and cement, than those of the typical waste injection well or, for that matter, the typical oil and gas well.

A typical well layout, suitable for servicing a single mine, could consist of a pair of wells (doublet), one of which produces from the target formation and the other which injects to the same formation. Due to the practice of mine brine waste injection in the vicinity of the mine shaft, often into formations of geothermal interest, the geothermal supply well may have to be set off a significant distance from the shaft. The potential for thermal degradation of the formation(s) due to existing injection practices, as well as the possibility of interfering with existing mine workings, will determine the required set off distance for the geothermal wells. This is site specific and will have to be analyzed on a mine-by-mine basis at a more detailed level of study.

In summary, it appears that the entire area with potash potential within central Saskatchewan is reasonably well situated with regard to exploitable geothermal low- to medium-grade resources. Suitable water-bearing formations exist immediately upon the Precambrian basement. Based on the conservative estimate of geothermal gradient 23°C/km in the vicinity of existing mines, it is appropriate to consider a minimum resource temperature of the order of 35°C. Due to the expected disturbed nature of temperature measurements upon which this analysis is based, higher temperatures will probably be encountered in practice.

The most favourable area with respect to existing mine sites lies in the region of Saskatoon. Here the reasonably deep basement and thick intersections of Deadwood Formation, overlying the basement, support minimum resource temperature estimates of the order of 40°C. Primarily because of the deeper reservoir formations and consequent higher temperatures in the Saskatoon area, this area might be a first priority for further investigation. Reported high temperatures in a drill hole near Lanigan suggest that the Lanigan Division mine may be favoured with higher geothermal supply temperatures than the 40°C credited to it in the performance and cost analysis section of this report.

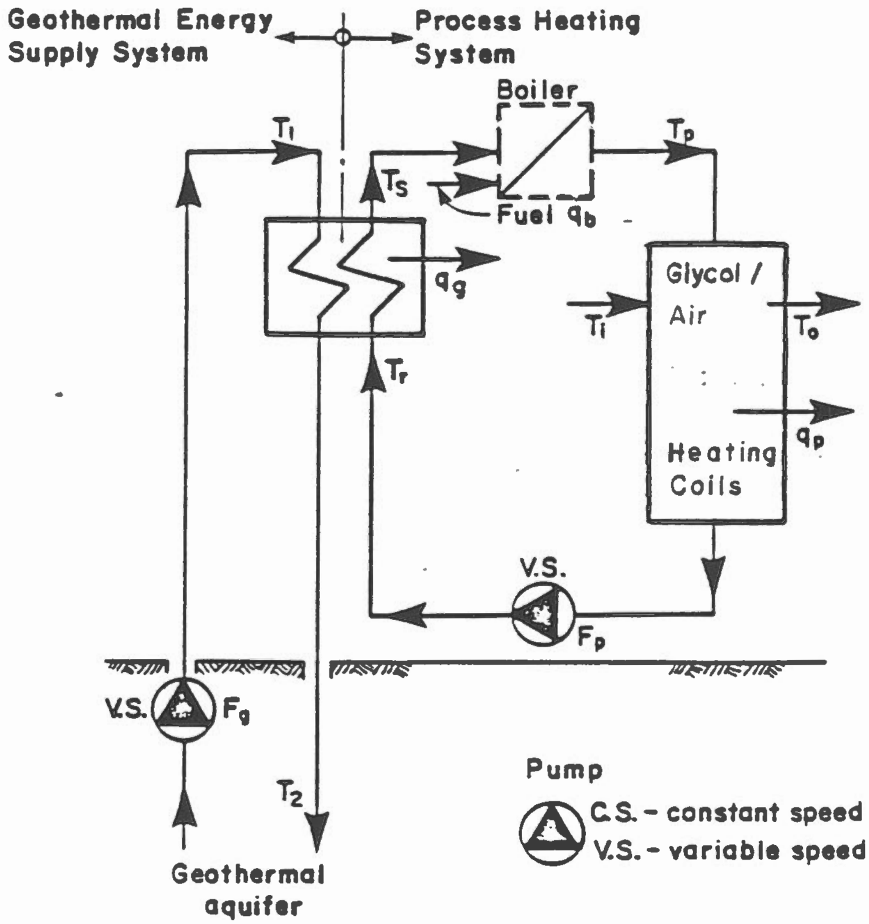
3.0 GEOTHERMAL SUPPLY SYSTEM

A geothermal doublet system is conceived for the mine air heating application comprising a single supply well, an injection well, interconnecting surface pipework and a primary plate-type heat exchanger. The schematic of Figure 3-1 illustrates the basic heating system arrangement of the primary geothermal supply and return well circuit, and also the glycol (secondary) recirculation system supplying the air heating coils. Where indirect gas fired air heating exists, the boiler (shown dotted) would be retained for standby/peak heating service. With direct fired gas heating systems, the direct fired gas heater (not shown) would be retained, located downstream of the heating coils in the air stream. (The schematic of Figure 4-2 illustrates this system in greater detail.)

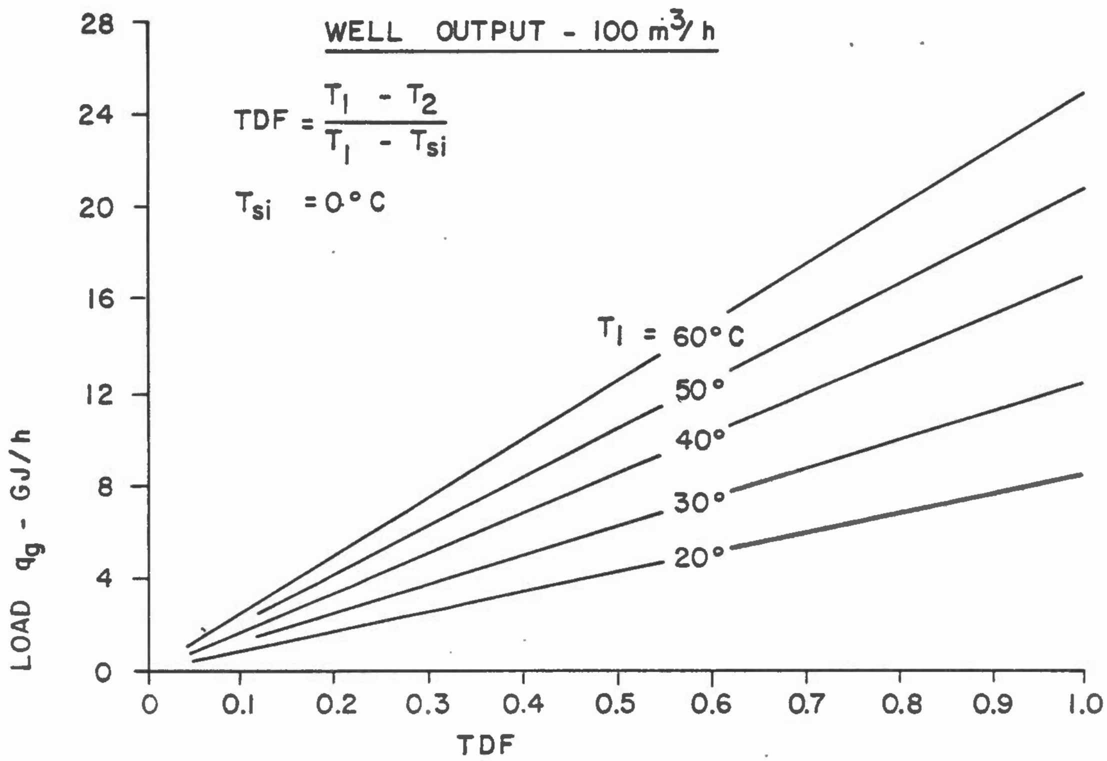
All but the CCP-Colonsey mine will be using direct gas firing by the end of 1984.

3.1 Geothermal System Load and Annual Energy

Figure 3-2 presents curves of supply load q_g (GJ/h) versus the temperature drop factor (TDF) for a doublet flow rate F_g of 100 m^3/h. Load is directly proportional to flow so that higher flows will result in a corresponding increase in output. The upper flow limit for a single doublet is in the order of 150-200 m^3/h, with actual values much influenced by downhole pumping requirements, system head losses and limits to downhole motor size.

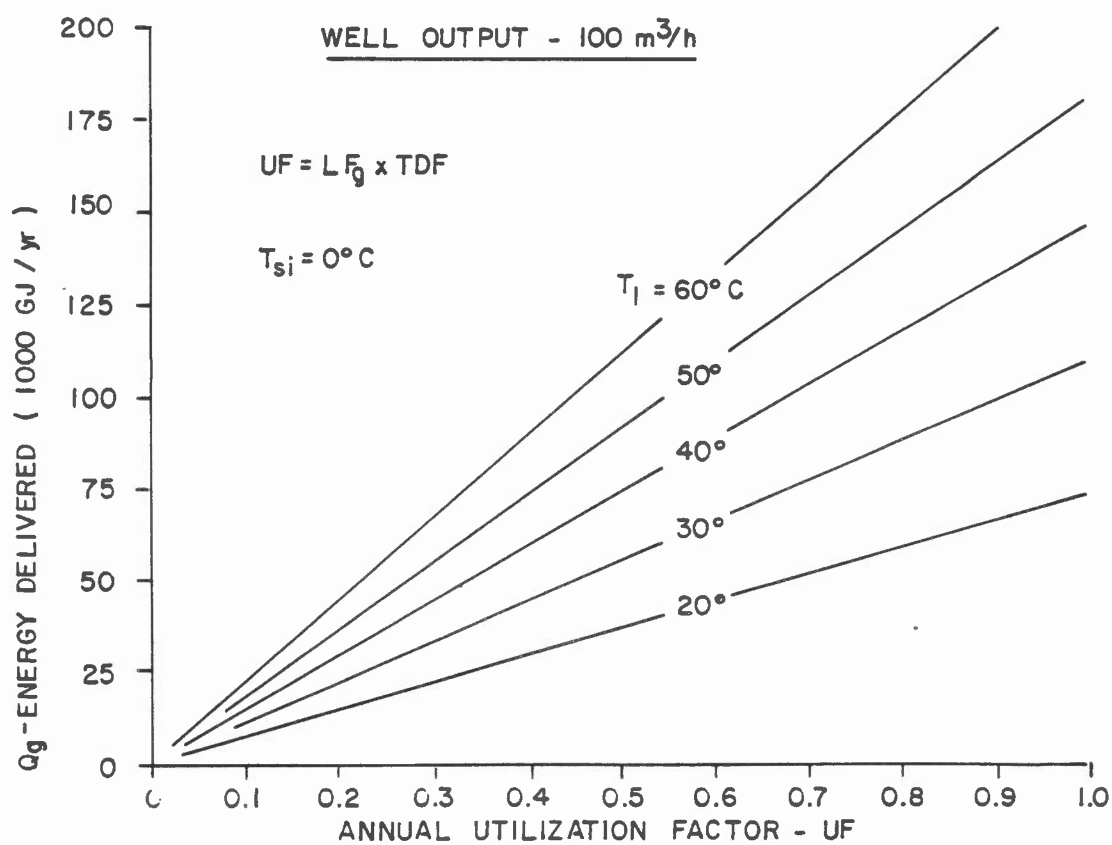


SCHEMATIC OF DIRECT COUPLED GEO - SYSTEM FIGURE 3 - 1



LOAD vs. TEMPERATURE DROP FACTOR

FIGURE 3-2



ENERGY DELIVERED vs. UTILIZATION FACTOR

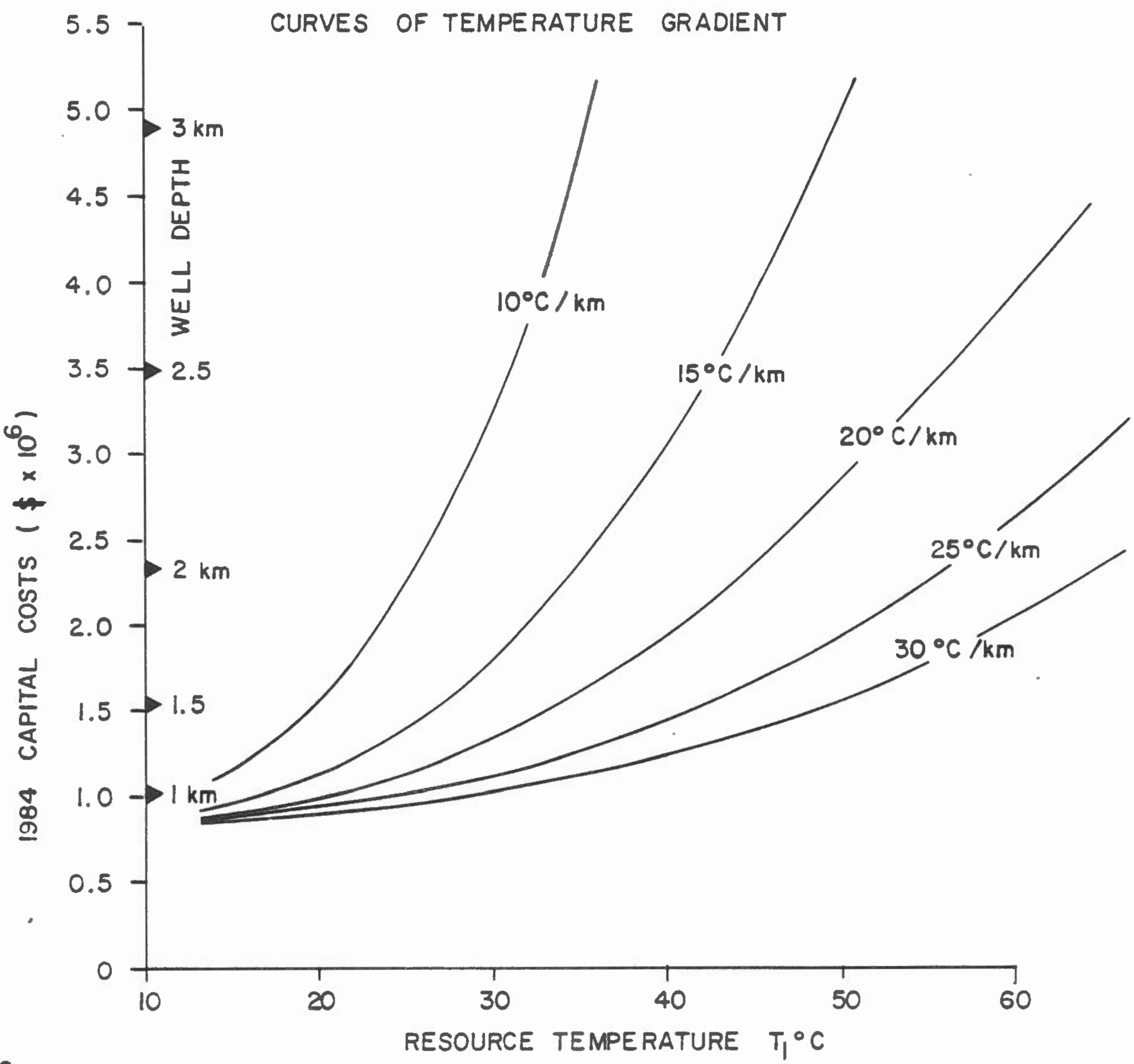
FIGURE 3-3

Figure 3-3 shows curves of annual energy delivered (Q_g) versus the utilization factor (UF), where UF is the product of load factor LF_g and TDF. Familiarity with the derivation and significance of TDF and UF concepts, and important load factor LF_g improvement considerations, is assumed (see Acres, 1983).

3.2 Geothermal System Costs

Figure 2-5, presented earlier, showed single well completion cost data versus well depth. This is incorporated in Figure 3-4 which is a plot of geothermal system capital costs versus geothermal gradient and resource temperatures T_1. As noted in Section 2.0, the potential T_1 range for the region under study is expected to vary from 35°C to around 50°C based on a conservative gradient estimate of 23°C/km. Above-ground equipment costs of $425,000 included in Figure 3-4 data correspond with a flow rate of 100 m^3/h, the use of titanium plate type heat exchangers employing a 2°C approach, and approximately 1100 m of buried insulated pipework separating supply and injection wells. An overground routing could diminish pipeline costs. For 150 m^3/h flow rate, above-ground system costs can be expected to increase by 30 percent or so while well costs (Figure 2-5) remain unchanged.

Figure 3-5 presents indicative geothermal unit energy cost curves for flow rates of 100 m^3/h and 150 m^3/h, and resource temperatures of 35°C and 40°C. They are based on the previously noted well system and above ground costs and a reference 23°C/km gradient.



NOTES

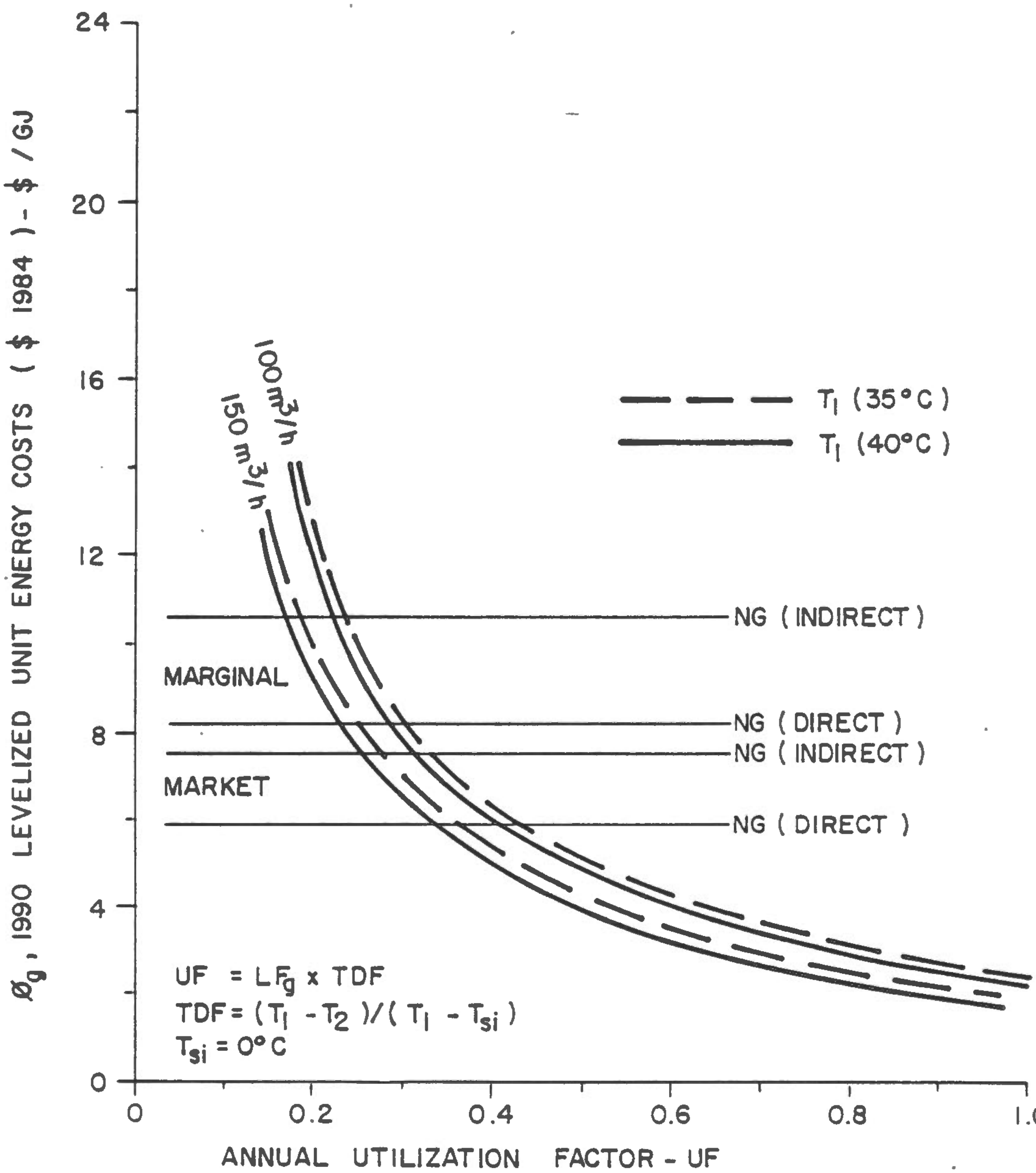
1 - MEAN SURFACE TEMPERATURE 5° C

2 - COSTS ARE BROADLY APPLICABLE TO SINGLE DOUBLET OUTPUTS OF 150 m^3/h AND LESS, WITH WELL COSTS BASED ON REFERENCE CURVE OF FIG. 2-5

3 - COSTS INCLUDE TWO WELLS, WELLHEAD EQUIPMENT & PRIMARY HEAT EXCHANGER.

GEOTHERMAL DOUBLET SYSTEM CAPITAL COSTS

FIGURE 3-4



NOTES:

1 - BASED ON 10% REAL OWNERSHIP COST OF CAPITAL , 30 YEAR LIFE
2 - GEOTHERMAL GRADIENT 23°C/km

GEOTHERMAL SYSTEM UNIT ENERGY COSTS

FIGURE 3 - 5

4.0 MINE AIR HEATING DESIGN & EVALUATION

4.1 General Considerations

The mines operate at depths in the order of 1 km below surface. Daily ranges for ore production are presently from 6000 to nearly 10,000 tonnes. To accommodate these volumes, vertical shafts of considerable dimensions must be sunk to the mine levels. Major water-bearing formations such as the Blairmore Formation are carefully sealed from the shaft interior to prevent flooding of the mine and shaft, a potentially disastrous situation.

Maintaining the integrity of the cast-iron (or steel) shaft lining, called tubbing, is critical. Exposure to significant seasonal temperature extremes can cause permanent deformation of the lead gaskets installed between tubbing sections; and water in-leakage to the shaft. To avoid this, the seasonal supply air temperature extremes are kept between fairly narrow limits. The PCS Lanigan mine uses a double shell, continuous steel lining with concrete fill in the annulus. This form of construction is less sensitive to temperature fluctuations, allowing the winter supply air design temperature (10°C) to be lower than that for other mines with consequent energy savings.

The following discussion centres on issues that may restrict use of formations local to the mine for geothermal purposes. The potash refining process produces considerable volumes of concentrated brine wastes. This brine is disposed of by injection in the subsurface formations. The evaporate (potash) ore deposit is highly soluble and mine safety considerations require that injection take place well below the mining level.

Furthermore, care must be exercised in the drilling of all wells in the mine vicinity lest communication between water-bearing formations and mining levels be established. These concerns would apply to all geothermal drilling in the mine area.

Typically, a 0.8 km diameter central core of rock is preserved to contain the mine shaft(s) and waste brine injection well(s). In the event that the geothermal target reservoir beneath the core is found to be unsuitable, perhaps because of permeability loss or thermal degradation caused by the injected brine, a sizeable step-out from the core may be considered necessary in order to avoid any risk of penetrating the mining level, or restricting future potash production plans.

4.2 Review of Present Heating Schemes and Load Requirements

Heating is presently accomplished through direct, open-flame, natural gas heaters or, alternatively, indirectly via natural gas fired steam boilers serving glycol recirculation systems. Indirect firing is presently being used by both the PCS-Cory and the CCP-Colonsay mines. It introduces boiler combustion energy losses of 20 percent or more. The CCP operation is planning to convert to direct gas firing in 1984 when airflow requirements are upgraded.

Direct firing is simple and typically comprises a damper-controlled air intake house, a burner assembly mounted in the air stream, and an induced draft fan downstream which blows the heated air, via an air galley, into the main shaft. Air is discharged to the surface via an adjacent shaft which is typically located 125 to 150 m away from the shaft conveying the supply air down to the mine.

The air heating load demand is a product of ventilation air flow rate F_a and temperature rise from intake temperature T_i, (directly, the outdoor air temperature, t) to supply air temperature T_e at entry to the shaft. Discussions with mining personnel were held to determine opportunities for reducing either T_e, F_a, or both, in order to conserve energy. The responses were generally as follows:

1. Ventilation rate is set by the need to control dusting at the ore loading face, to maintain a cooling flow of air for the mine operators, and to remove fumes generated by diesel equipment. (The deepest mine, Colonsey experiences a temperature of over 30°C.) If anything, the future tendency will be to increase air flow in order to improve working conditions for the operators, a trend which is in opposition to reducing flows for energy conservation reasons. Each electric powered ore loader, operating at the work face, is provided with a nominal 68,000 m^3/h (40,000 acfm) to control dusting (personal communication, M. Henningson of CPP).

2. Shaft entry temperature T_e is set by a combination of shaft lining design considerations modified by observed performance behaviour relating to tubbing gasket performance and leakage problems under summer/winter temperature cycling.

3. Typically, the amount of energy used for mine air heating represents around 10 percent of the total energy demand comprising product drying (200°C), building heating and crystallizer loads.

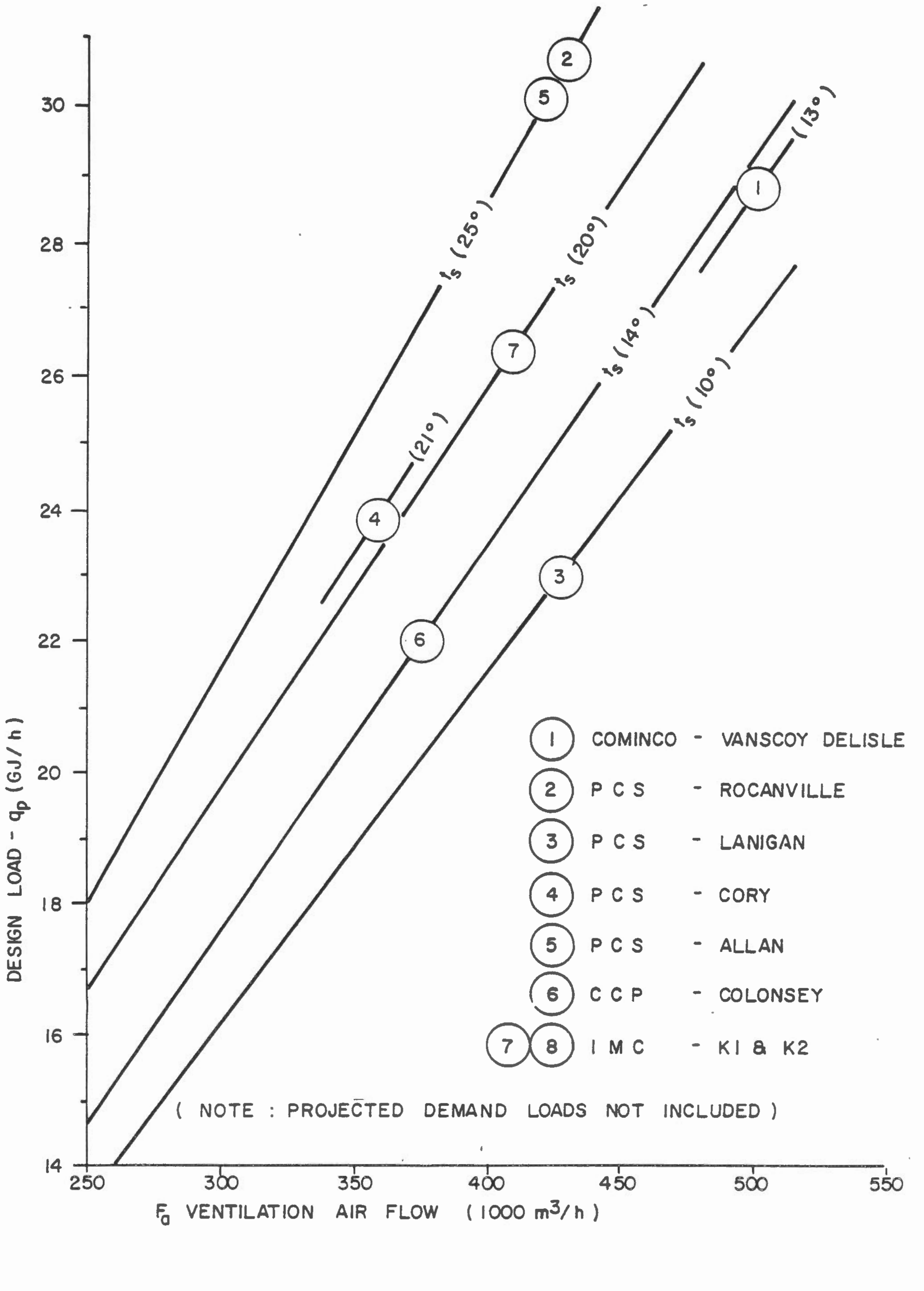
4. Some mines have examined heat recovery schemes for the higher temperature parts of the process. However, ventilation air heat recovery has not been seriously pursued.

It is provisionally concluded that data regarding air flow rates and entering temperatures of Table 1-1 is representative and indicative of continuing minimum load demands in the future.

Figure 4-1 presents curves of load demand q_p corresponding to the air flows F_a and supply air temperatures of Table 1-1; they are based on a winter ASHRAE design temperature t_w for the Saskatoon region of -35°C (1 percent non-exceedance value), though temperatures can occasionally be expected to dip to -45°C for short periods of time. The future loads projected for the PCS-Lanigan (air flow 765,000 m^3/h) and PCS-Cory mines (air flow 480,000 m^3/h) are not shown.

4.3 Injection Temperature and Geothermal System Load

For this study the resource temperature is conservatively set at 35°C and 40°C for the two principal mine areas. The geothermal system supply load q_g depends on the injection temperature and geofluid flow rate. With air intake temperatures to -35°C, it is conceivably possible to cool and re-inject the geofluid brine at a few degrees below freezing. The French have raised concerns regarding the possibility of damaging the resource if too low injection temperatures are employed. This aspect should be explored in some detail to determine the basis of these concerns. An injection temperature of 5°C is assumed for



DESIGN LOAD q_p Vs MINE AIR FLOW AND TEMPERATURE

FIGURE 4-1

this study. Accordingly, the geothermal system supply load potential is as follows, determined from Figure 3-2:

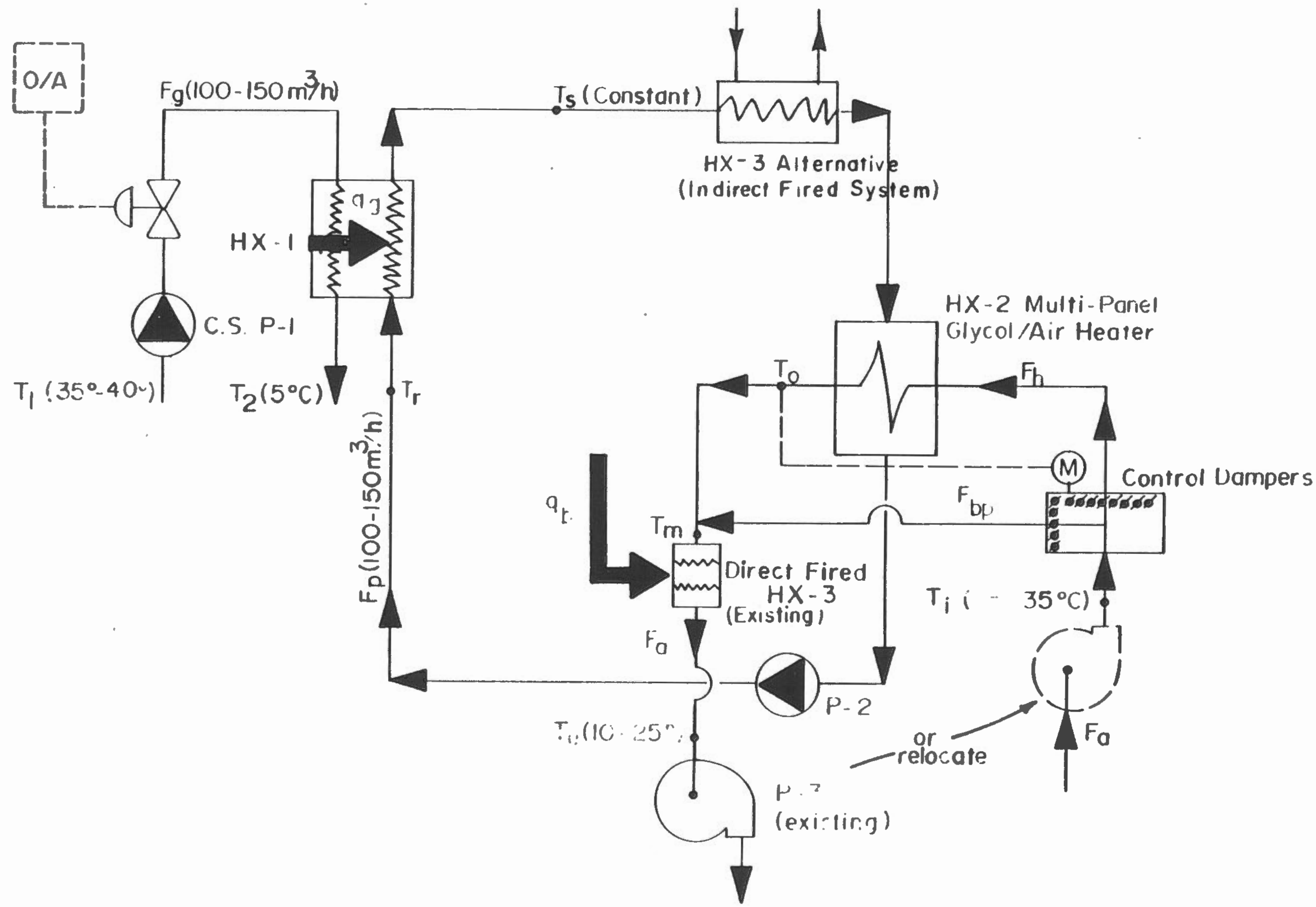
For resource temperatures T_1:	35°C	40°C
TDF (T_{si} = 0°C)	0.86	0.88
supply loads (GJ/h) are:		
q_g (100 m^3/h)	13.0	15.1
q_g (150 m^3/h)	19.5	22.6

In comparing with the demand loads (q_p) shown in Figure 4-1 it is seen that, except for two mines, the supply load capability of a single geothermal doublet is less then demand by a considerable margin even at flow rates of 150 m^3/h.

4.4 Heating System Design and Operating Features

Figure 4-2 illustrates a schematic arrangement of the mine air heating system. The system comprises primary geothermal, secondary recirculation, and air heating and bypass elements. Operating requirements for each elementis described below.

Geothermal: The downhole pump P-1 is assumed to be a constant speed unit supplying to the primary exchange HX-1. Given favourable pump flow/power characteristics, control valve V-1 operates to throttle flows between certain set limits. The objective is to reduce power requirements during partial/no-load periods of system operation. V-1 is sensitive to outdoor air and T_s. Alternatively, variable speed pumps are available though expensive.



TYPICAL MINE AIR HEATING SYSTEM SCHEMATIC

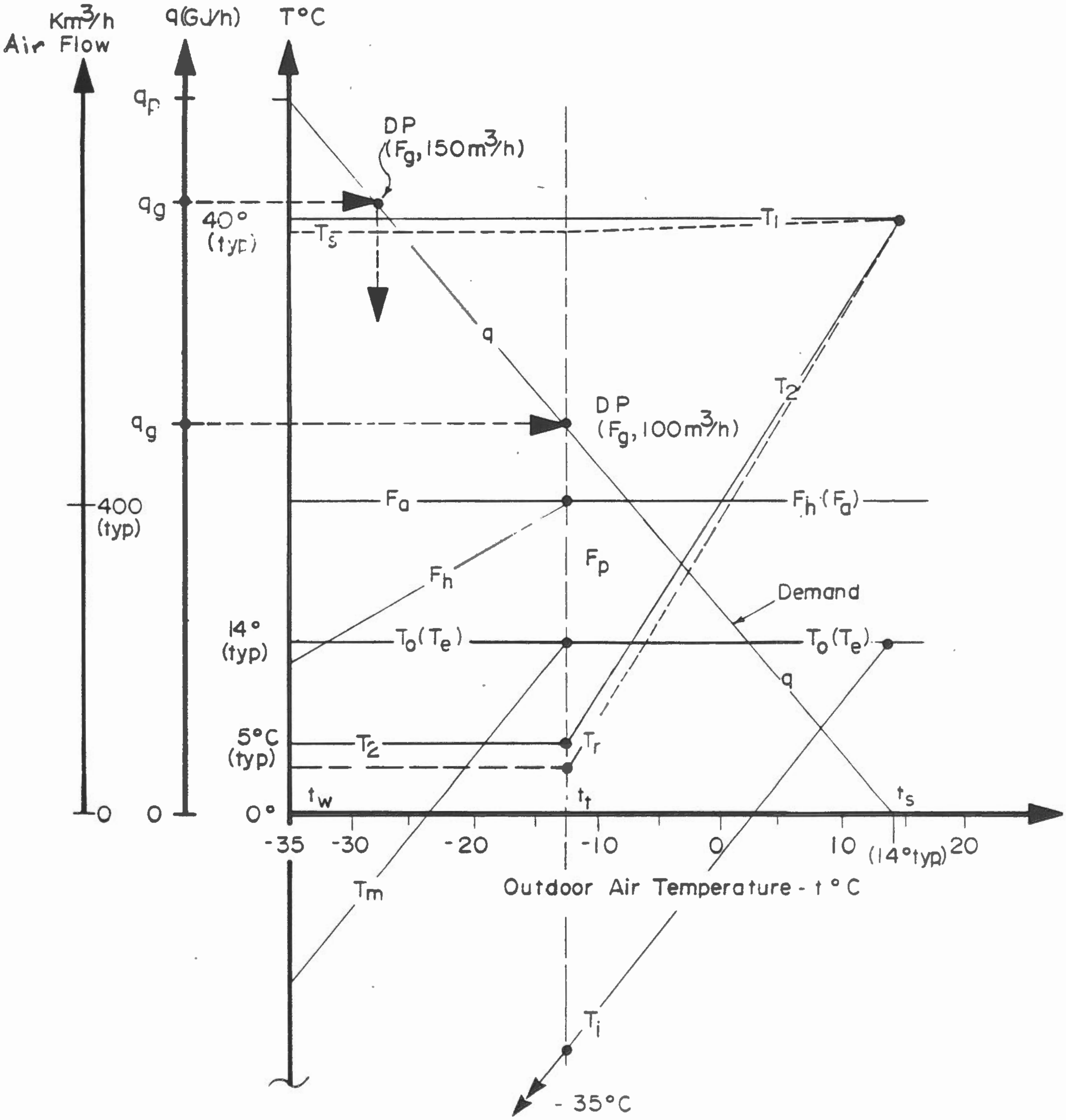
FIGURE: 4-2

Secondary Recirculation Loop: A glycol-water solution is employed for freeze prevention. Variable speed recirculation pump P-2 is responsive to HX-2 air side leaving temperature T_o and regulates flow F_p according to demand. Flow increases linearly with load i.e. falling outdoor air temperature t, to a maximum at t_t the transition outdoor air temperature. Thereafter, flow is constant.

Air System: When t is less than T_e, outside air is heated to T_o which is held constant and equal to T_e. Below the transition temperature t_t corresponding to the maximum capability of the geothermal supply, the ganged control dampers operate to restrict air supply to heater HX-2. Bypass dampers operate to bypass air around HX-2. Flows F_h and F_{bp} re-mix, prior to entry to the direct fired gas heater HX-3; the gas supply is regulated to maintain T_e constant at entry to the mine shaft.

The system is technically simple and straightforward. Modification of the existing systems to install the heating coils HX-2 is expected to be uncomplicated. Additional fan motor capacity may be necessary to allow for air heater pressure drop.

Figure 4-3 illustrates typical trends in major heating system parameters with outdoor air temperature. Demand load q is directly proportional to outdoor temperature for a constant ventilation air flow. Transition point temperature t_t, the point at which partial bypassing of the heating coils begins, is defined by the geothermal system load capability.



HEATING SYSTEM PARAMETERS
vs OUTDOOR TEMPERATURE

FIGURE: 4 - 3

Two heating system design points are shown corresponding to geothermal flows of 100 m^3/h and 150 m^3/h. The greater is q_g, the lower is the transition temperature and flow F_{bp} bypassing the heating coils.

4.5 Incremental System Costs

Integration of geothermal mine air heating with existing direct fired systems will entail the following:

- Modification of present air intake house structures to fit heating coil panels, and main and bypass dampers.
- The possible addition of a simple small structure to the air intake house to contain the primary heat exchangers, glycol recirculation pumps, storage tanks and limited pipework connecting the primary and air heat exchangers.
- The possible relocation of present air supply fans depending whether they are currently providing induced air or forced air service. Forced air service, forcing the flow through the heaters, will be preferable if the heater (HX-2) air-side pressure drop is high. Induced draft units placed downstream, however, greatly simplify the intake ductwork and bypass damper arrangement.
- Miscellaneous services, e.g. electricity supplies (power, light) and instrumentation control air.

Budget estimates were developed for the above items based on simplifying assumptions concerning proximity to existing services, ready access for pipework via existing pipe bridges, etc., and similarly for power cables and miscellaneous services. Discussions with heater air coil suppliers have resulted in indicated prices for heaters (supply only) in the order of \$50,000. The order-of-magnitude cost estimate for the 100 m^3/h, 15 GJ/h glycol/air heating system is in the range of \$250,000 to \$300,000 installed. The component included for the heat exchange building depends greatly on the type of construction adopted and the extent to which the existing intake houses might be able to accommodate the primary exchangers, glycol pumps and storage tanks. If space permits, a separate building would be avoided. The issues are site-specific.

On the basis of:

- a 10 percent real return on money;
- the limited operation and maintenance requirements provided by existing mine forces; and
- miscellaneous charges for other factors at 2 percent of total cost;

an annual fixed-charge rate of 12 percent of the investment is considered appropriate. Accordingly, the annualized cost of the incremental systems (direct fired) is set at \$35,000 (100 m^3/h) and \$45,000 (150 m^3/h).

Significant savings would be possible concerning implementation into the existing indirect fired system (CPP-Colonsey). Here, it is necessary to introduce only the primary exchanger into the secondary heating circuit.

The existing glycol/air heater system remains otherwise unaffected.

The unit energy cost addition $\emptyset_i$, corresponding to the system annualized cost increment, is determined thus:

$$\emptyset_i = \frac{\text{Annualized Cost (\$/GJ)}}{\text{Annual Energy Delivered, } Q_g}$$

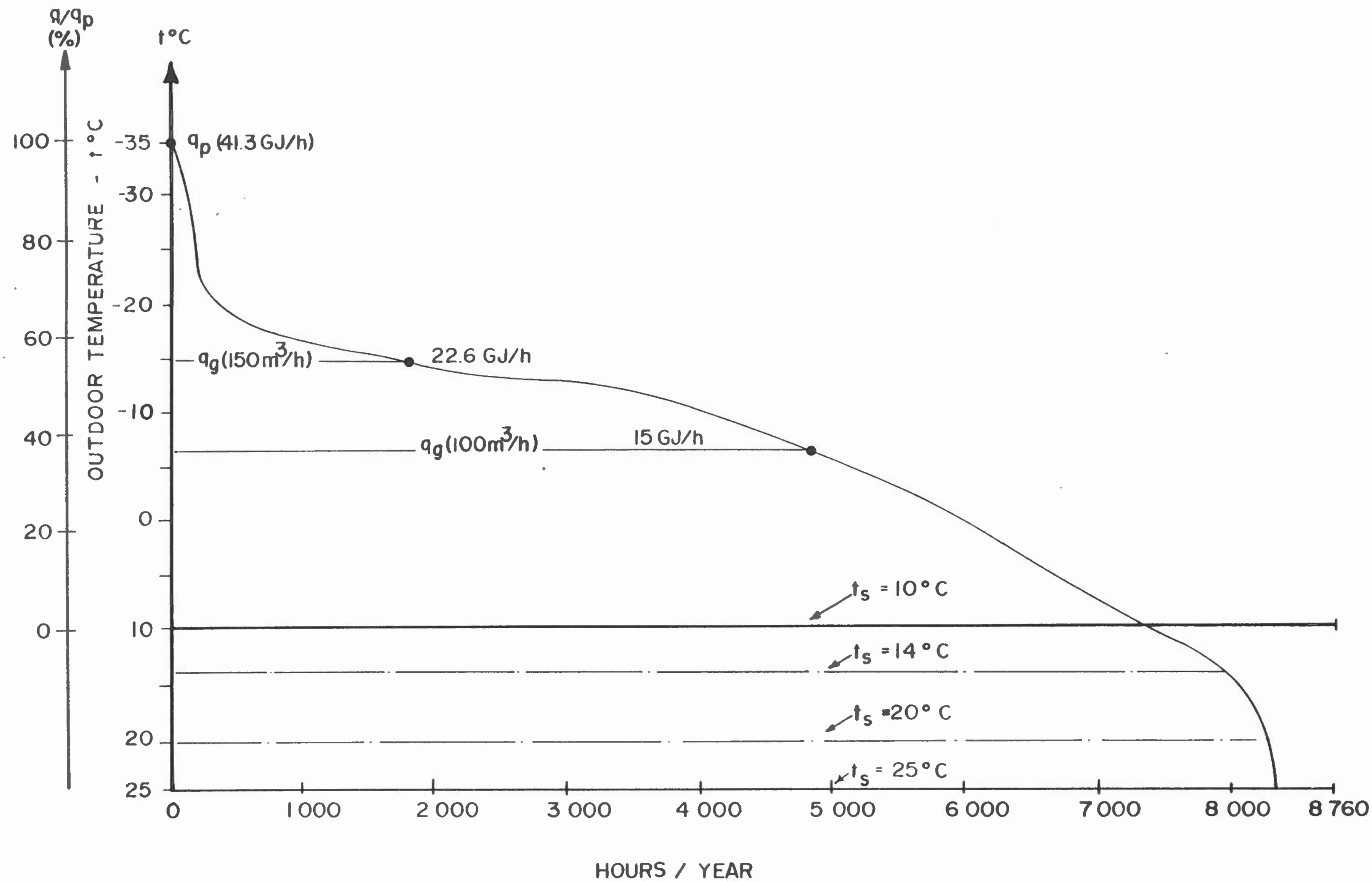
For Q_g at 100,000 GJ/yr, $\emptyset_i$ varies between 35¢ and 45¢/GJ.

4.6 Performance and Cost Evaluations

4.6.1 Histogram Annual Load Profiles

Figure 4-4 presents the typical load demand profile for mine air heating under Saskatchewan conditions. It is based on an outside air temperature variation from t_w (-35°C) in winter to a summer no- load temperature t_s, which ranges for the candidate mines from 10°C to 25°C. As t_s increases, the total area below the curve (representing the annual energy demand Q_p), is increased also. The figure illustrates the PCS-Lanigan mine load conditions for the projected air flow of 726,000 m^3/h.

Geothermal system design loads, corresponding to flow rates of 100 and 150 m^3/h and a resource temperature of 40°C, are shown superimposed. In accordance with an earlier analysis (Acres, 1983) load factor LF_g improves as the load ratio q_g/q_p diminishes. Generally, ratios of 0.6 or lower offer load factor improvements that are substantial. By inspection of the histogram, both geothermal design loads are seen to imply favourable load



TYPICAL HISTOGRAM - PCS LANIGAN (PROJECTED DEMAND) ILLUSTRATED

FIGURE: 4 - 4

factors with load ratios of 0.36 and 0.55 respectively. It should be noted that the lower the geothermal design load, the higher is its load factor, a feature that helps to compensate for a lower air flow and hence load.

A gradient of 30°C/km, manifesting as a higher than expected resource temperature, will improve the TDF, load q_g and annual energy delivered Q_g. However, for a fixed MAH system demand, load factor LF_g will be reduced, thus partially nullifying improvements in UF and unit energy costs normally associated with an increase in TDF.

4.6.2 Performance Cost Tabulations

Table 4-1 presents the results of the performance and cost evaluations conducted for each candidate mine at its present demand and projected demand. It includes the following data:

- a summary of the mine air supply design parameters;
- resource conditions;
- geothermal system performance parameters at 100 and 150 m^3/h;
- system unit energy cost $Ø_s$ at 100 m^3/h and 150 m^3/h, comparisons with market natural gas, and annual and lifetime energy cost savings; and,
- glycol/air heater design parameters (transition temperature and winter design flow and bypass requirements).

Delivered energy Q_g was derived from individual histograms, similar to Figure 4-4, containing specific q_g and t_s values appropriate to each case. The values Q_g were obtained by planimeter measurement of areas

TABLE 4-1

PERFORMANCE AND UNIT ENERGY COST EVALUATIONS

(Page 1 of 2)

MINE IDENTIFICATION		VANSCOY DELISLE	PCS-ROCANVILLE	PCS-LANIGAN	PCS-LANIGAN	PCS-CORY
Mine Supply				PRESENT	PROJECTED	PRESENT
Winter Design t_w	(°C)	-35	-35	-35	-35	-35
Air Flow F_a	(1000 m^3/h)	520	431	360	765	360
Air Temp. T_e	(°C)	13	24	10	10	21
Demand q_p	GJ/h	30	30	23.0	41.3	23.8
Natural Gas System		conversion to direct in 1984	direct	direct	direct	direct
Resource						
Gradient	(°C/km)	23	23	23	23	23
Depth	(km)	1.5	1.3	1.5	1.5	1.5
Supply Temp.	(°C)	40	35	40	40	40
Injection Temp.	(°C)	5	5	5	5	5
TDF (T_{si}=0°C)		0.875	0.857	0.875	0.875	0.875

		VANSCOY DELISLE		PCS-ROCANVILLE		PCS-LANIGAN (PRESENT)		PCS-LANIGAN (PROJECTED)		PCS-CORY (PRESENT)	
Heating System											
Geothermal Flow F_g	(m^3/h)	100	150	100	150	100	150	100	150	100	150
Supply Load q_g	(GJ/h)	15	22.6	13	19.5	15	22.6	15	22.6	15	22.6
Annual Energy Q_g	(1000 GJ)	86.9	102.5	89.7	125.6	67.6	69.9	85	118.8	91.3	93.8
Load Factor LF_g		0.66	0.52	0.79	0.52	0.52	0.35	0.65	0.6	0.69	0.47
Annual Utilization UF		0.58	0.46	0.68	0.46	0.45	0.31	0.57	0.53		
Unit Energy Costs (Lev)	($/GJ)										
- Geothermal System ϕ_g		4	4.4	3.8	3.0	5.5	7.5	4.2	3.7	3.5	2.7
- Incremental ϕ_i		0.4	0.4	0.4	0.35	0.5	0.6	0.4	0.35	3.9	3.15
- Total Geothermal ϕ_s		4.4	4.8	4.2	3.35	6.0	8.1	4.6	4.05	6.0	6.0
- Natural Gas		6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
- Difference		1.6	1.2	1.8	2.65	0	-2.1	1.4	2.05	2.1	1.2
Lifetime Energy Cost Savings	(%)	24	20	30	44	-	-	23	35	35	20
Heater Design											
Transition O/A temp. t_t	(°C)	-11	-23	-1.5	-14	-19.5	-34.2	-6.5	-14.5	-15.3	-32
Heater Air Flow F_h @ t_w	(1000 m^3/h)	260	390	185	276	277	418	275	421	227	347
Bypass Air Flow $F_{b/p}$	(1000 m^3/h)	260	130	246	155	149	8	489	344	133	133

TABLE 4-1

PERFORMANCE AND UNIT ENERGY COST EVALUATIONS

(Page 2 of 2)

MINE IDENTIFICATION		PCS-CORY		PCS-ALLAN		CCP-COLONSEY		IMC - K1 & K2	
Mine Supply		PROJECTED				PRESENT		PROJECTED	
Winter Design t_w	(°C)	-35		-35		-35		-35	
Air Flow F_a	(1000 m^3/h)	480		426		375		408	
Air Temp. T_a	(°C)	21		25		10		20	
Demand q_p	GJ/h	31.7		30.3		22		26.3	
Natural Gas System		direct		direct		indirect		n/a	
Resource									
Gradient	(°C/km)	23		23		23		23	
Depth	(km)	1.5		1.3		1.5		1.5	
Supply Temp.	(°C)	40		35		40		40	
Injection Temp.	(°C)	5		5		5		5	
TDF (T_{si}=0°C)		0.875		0.857		0.875		0.875	
Heating System									
Geothermal Flow F_g	(m^3/h)	100	150	100	150	100	150	100	150
Supply Load q_g	(GJ/h)	15	22.6	15	22.6	15	22.6	13	22.6
Annual Energy Q_g	(1000 GJ)	96.6	123.2	103.7	129	75.2	76	85.8	103.0
Load Factor LF_g		0.73	0.62	0.79	0.65	0.57	0.38	0.75	0.62
Annual Utilization UF		0.64	0.54	0.69	0.57	0.5	0.33	0.64	0.53
Unit Energy Costs (Lev)	($/GJ)								
- Geothermal System ϕ_g		3.6	3.5	3.5	3.5	5.0	5.8	5.5	3.7
- Incremental ϕ_i		0.35	0.35	0.35	0.35	0.1	0.1	0.4	0.4
- Total Geothermal ϕ_s		3.95	3.85	3.85	3.85	5.1	5.9	5.9	4.1
- Natural Gas		6.0	6.0	6.0	6.0	7.5	7.5	6.0	6.0
- Difference		2.05	2.15	2.15	2.15	2.4	1.6	0	1.9
Lifetime Energy Cost Savings	(%)	35	36	36	36	33	21	-	32
Heater Design									
Transition O/A temp. t_t	(°C)	-5.5	-19	-5	-20	-22	-35	-7.5	-21
Heater Air Flow F_h @ t_w	(1000 m^3/h)	227	341	213	320	255	375	204	306
Bypass Air Flow $F_{b/p}$	(1000 m^3/h)	253	139	213	106	120	-	204	102

above the abscissa t_s (10°C, 14°C, etc.) and within the q_g horizontals (100 and 150 m^3/h).

Unit energy cost $Ø_g$ was derived from Figure 3-5 according to calculated UF values. Examining the unit energy costs of Table 4-1 there are a number of instances where, at 150 m^3/h, the unit energy cost is higher than at the 100 m^3/h flow. This is due to worsened load factor. It will be recalled that when the load ratio q_g/q_p exceeds about 60 percent, the load factor LF_g diminishes markedly. In short, the small gain in annual energy delivered by the 150 m^3/h system does not justify the additional capital and operating (pumping) expenses.

The incremental system unit energy cost included in the table is derived from the relationship of Section 4.5. In the case of the indirect fired system of the CPP-Colonsey mine, a nominal value is assumed since the work involves mainly installation of the primary exchanger into the existing glycol system, the addition of bypass lines and some isolation valving.

4.7 Appraisal of Seasonal Storage Potential

Seasonal storage of thermal energy using shallow aquifers or some other means can, under the right circumstances, provide considerable improvement to LF_g, the geothermal system load factor. At process load factors (LF_p) of around 0.2 to 0.3, aquifer thermal energy storage (ATES) can achieve LF_g values ranging from 0.65 to 0.8, depending on the energy recovery factor (Acres, 1983). However, a considerable increase in overall costs is incurred principally for initial exploration and the installation and pumping demands for the shallow supply, injection and recovery wells. Well flow rates are proportional to the magnitude of improvement in load factors so that pump related costs are considerable.

For the mine air heating application, three factors oppose the adoption of ATES or similar such scheme:

- load factor LF_g for many of the candidate cases is already high, particularly for these requiring mine air supply temperatures of 20°C and above;

- the capital cost of storage of between $0.5 and $1 million or more, depending on depth of aquifers could, with pumping costs, impose an uncompetitive surcharge on the total geothermal heating system;

- improvement in LF_g, would not provide a good fit of storage system load capability and process demand.

Storage is therefore discounted as a necessary or viable option for this application.

4.8 Geothermal System Financial Assessment

To indicate the financial viability of geothermal systems for mine air heating, discounted cash flow analysis methods were used to examine three of the potential projects discussed in this study: Vanscoy-Delisle, CCP-Colonsey and PCS-Allan.

For all cases, the investment criteria and economic assumptions utilized were adapted from a previous report on geothermal applications (Acres, 1983). Specifically, projects were expected to have an operations start-up date of 1990 and an economic life of 30 years. The annual fuel cost savings, which represent the cash inflows in the analysis, are predicated on an assumed 1990 price for natural gas of $6/GJ. For the Vanscoy and PCS cases, where direct firing of the gas is employed, no adjustment is required for combustion losses. At the CCP mine, however, the gas is used indirectly such that the end-use cost of the natural gas, adjusted for an assumed combustion efficiency of 75 percent, is $8/GJ.

The geothermal gradient assumption of 23.5°C/km results in an estimated $1,075,000 cost for drilling and well development; a further $425,000 is allocated for well-head inter-well piping, primary heat exchanger and pumping equipment. Land is estimated at $100,000. Exploration and drilling costs for the first production well are are expensed in the initial year. Well completion and drilling of the injection well are capitalized in the second year of development. Capital cost allowances are taken assuming that Class 34 deductions on energy conservation equipment would be allowed. The classification provides a 25 percent write-off in the year of purchase, 50 percent in the second year and the remainder in the third year. Capital replacements of pumps and well-heat equipment are allowed for every 5 years and 10 years respectively, through the projects life.

A system cost increment included in the capital costs for integration of the geothermal system with the existing mine air heating system is $300,000 for the Cominco Vanscoy and PCS-Cory direct fired cases. For CCP, the increment is $50,000.

Income taxes are taken at 40 percent in the Cominco and CCP cases while it is assumed that taxes and CCA's do not apply for the PCS as a crown corporation. All cash flows are estimated in terms of "real" prices, thus, the returns should be evaluated in terms of "real" discount rates, excluding any allowance for inflation.

Analysis Results

All three projects appear to be very attractive investments on these bases with internal rates of return ranging from 18 percent to 24 percent "real". These values would be well in excess of most corporate investment opportunities. When it is considered that if inflation is running at approximately 6 percent, then the nominal returns represented here range from 24 percent to 30 percent.

Table 4-2 summarizes key elements of the financial analysis, and print outs of the cash flow model runs are included in the Appendix.

Determination of appropriate hurdle rates for investments of this type is beyond the scope of work for this study. However, if current corporate borrowing rates of around 12 percent to 14 percent nominal are taken as an indication of the cost of capital and if inflation is 6 percent, then real returns of about 7 percent after tax would be considered the minimum requirement necessary to recover the invested capital and cover the interest costs. Table 4-2 indicates, for illustration purposes, the NPV's of the three projects at selected discount, or hurdle, rates of 6, 9, 12 and 15 percent. As can been seen, the present values of all three projects are comfortably positive even

TABLE 4-2

MINE AIR HEATING SYSTEM FINANCIAL ASSESSMENT

	Project		
	Vanscoy Delisle	CCP Colonsey	PCS - Allen
System Supply (TJ/yr.)	86.9	75.2	103.7
Total Capital and Drilling Costs ($1000's)	1900	1650	1900
Year 1 Fuel Cost Savings ($1000's)	521	602	622
Year 1 Operating Costs ($1000's)	158	158	158
Internal Rate of Return	18%	24%	24%
NPV @ 6% Discount Rate	2029	2855	4881
NPV @ 9% Discount Rate	1079	1689	2851
NPV @ 12% Discount Rate	717	1230	1677
NPV @ 15% Discount Rate	531	998	959

at the 15 percent hurdle rate level, indicating that the internal rate of return for each is in excess of 15 percent. Depending on the investor company's actual after-tax cost of capital, and assessment of the riskiness of these projects, the NPV's indicated represent the economic returns to the company over and above the invested capital and interest costs. For example, if Cominco determines that a project of this type at its Colonsey mine should have a hurdle rate of 9 percent real, then the economic gain available from the project is $1,689,000.

The internal rates of return calculated for the three projects are also indicated on Table 4-2. For the Vanscoy project, the IRR is 18 percent while for the other two projects it is 24 percent. Provided the required after-tax, real hurdle rate is less than these values, the projects are attractive investments.

Pages 1, 2 and 3 of the Appendix to this report provide computer printouts for the cash flow analysis of these projects over the initial 14 years of the project life. The data on Table 4-2 is taken from these printouts. Page 4 of the Appendix indicates the cash flows arising from the PCS-Allen project using marginal prices for the estimated fuel cost savings. Marginal fossil fuel prices are assumed to be 20 percent greater than market prices for fuel oil. Marginal prices are appropriate for evaluating the social returns of avoiding the next increment of conventional energy consumption. This higher value reflects the notion that fossil fuels are not renewable, are scarce resources, and at the margin, are represented by imported oil which causes a negative impact on the Canadian economy.

From the perspective of Canadian society as a whole, then, a project which displaces conventional energy consumption will have better returns than a project based solely on market prices. Therefore, the social rate of return on the Allen project is calculated as 33 percent as opposed to 24 percent using market prices. The difference arises because the public benefit is added to the benefit available to the company alone.

Study constraints have precluded a more detailed analysis of the financial viability of mine air heating system. Important considerations which should be investigated include the impact of earlier project start-up dates, the sensitivity to lower or higher natural gas prices, the implications of exploration risks for total capital costs and the required rates of return for investments of this type.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

By inspection of the levelized energy cost savings it is seen that all candidates, with the exception of PCS-Lanigan at its present capacity, offer an attractive potential with savings varying from about 25 to 44 percent depending on flow. Clearly, cases where the 150 m^3/h capability causes an increase in unit energy cost would not be pursued. Perhaps, with the exception indicated, none of the cases can be excluded at this point. Further site-specific investigation could well uncover both practical and cost saving features which could substantially improve the competitive position of a specific case. For example, pending plans for mine development, or modifications to the existing air heating (delivery system), a particularly enthusiastic response that the operator may show to reducing conventional energy consumption by geothermal means, all of these could influence the selection and/or development potential of each candidate site.

An improved gradient may be only marginally beneficial. The target reservoir is expected to be at or close to contact with the Precambrian Basement, so that the drilling depth and hence actual cost is largely independent of gradient. What is potentially affected, of course, is the TDF; relative to a fixed injection temperature T_2 of 5°C, an improvement in T_1 from 35°C to 45°C only improves TDF from 0.86 to 0.89, or 3.5 percent. LF_g will worsen to some degree, dependent on the application, due to the 30 percent improvement in g_g with T_1, so that the UF may remain essentially the same with only a minor change to unit cost from the small Q_g increase. The hope for further improvement against competition from direct fired natural gas lies in achieving well cost savings, i.e. costs lower than predicted by the reference cost curve, relative to predicted values. Re-injection pumping power is one area where annual savings of 25¢ to 50¢/GJ may be realizable. Reduced surface pipework distances less than the 1100 m allowed for could help to save a few cents per GJ. The most dramatic improvement would be achieved if gas price growth trends exceed the indicated real growth trends of 0-0.5 percent to 1990, 1 percent to 2000, and 2 percent to 2020, as used herein.

The CPP-Colonsey operation could prove to be a particularly favourable candidate in that the present heating system is direct fired and also experiencing a deficiency in the energy supply system capacity. Adoption of geothermal energy would introduce a minimum of disruption and modification to the present heating system or buildings, and also potentially overcome the capacity deficiency and allow full winter flows to be re-instated.

5.2 Recommendations

It is recommended that schemes for mine air heating using geothermal energy be taken to a feasibility level of examination for two or perhaps three candidate mines. Discussions with all mining companies are appropriate to appraise them of the results of this conceptual study and determine the level of interest in pursuing the subject to the next phase of investigation.

In summary, the work of the next phase should include:

- site visits and meetings with the mine companies to determine present plans, and technical and economic features of mine air heating designs;

- a comprehensive evaluation of resource conditions and assessment of potential local effects from the current practice of brine injection on in-site resource conditions, particularly temperature;

- examination of geothermal injection pressures, pumping requirements, and problems particularly any that may be caused by injection of the geofluid at temperatures down to 5°C or so;

- a pre-feasibility design of the primary and secondary heating circuits and buildings, examination of corrosion issues, and identification of materials selection of principal equipment and preparation of preliminary capital cost estimates;

- a further examination of system performance and economics, using financial criteria considered acceptable to the mine companies;

- an evaluation of land acquisition and right-of-way costs; and

- detailed evaluation of design features and cost of production and injection wells and specification of drilling methods.

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APPENDIX

FINANCIAL ANALYSIS - CASH FLOW MODEL

GEOTHERMAL ENERGY SYSTEM
CASH FLOW ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5
HOLE DEPTH: (KM)	1.4894
SYSTEM SUPPLY (TJ/YR):	103.7
HEAT PUMP CAPACITY: (GJ/H)	0
HP WORK ENERGY (TJ/YR)	0

POTASH CORP-ALLAN
MINE AIR HEATING
DIRECT GAS FIRED

MARKET PRICE ANALYSIS

C A S H F L O W S	Y E A R 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		536												
Above-Ground Equipment		425												
Low Temp System Increment		300												
Heat Pump System		0			0									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	1261	0	0	0	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	622.2	628.4	628.4	634.7	641.1	647.5	653.9	660.5	667.1	673.8	680.5	694.1
OPERATING COSTS														
Exploration Drilling Costs	480	60												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Energy			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING COSTS	480.0	59.5	158.0	158.7	159.5	160.2	161.0	161.7	162.5	163.3	164.1	164.9	165.8	167.3
NET OPERATING INCOME	-480.0	-59.5	464.2	469.7	469.0	474.5	480.1	485.7	491.4	497.2	503.0	508.8	514.7	526.8
NET CASH FLOW (NOI-T-C)	-580	-1320	464	470	469	474	480	436	491	497	503	509	425	527

NET PRESENT VALUE @ 3%	8626
NET PRESENT VALUE @ 6%	4881
NET PRESENT VALUE @ 9%	2851
NET PRESENT VALUE @ 12%	1677
NET PRESENT VALUE @ 15%	959
NET PRESENT VALUE @ 18%	497
@ 25%	-83
@ 30%	-289

GEOTHERMAL ENERGY SYSTEM
CASH FLOW ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5
HOLE DEPTH: (KM)	1.4894
SYSTEM SUPPLY (TJ/YR):	86.9
HEAT PUMP CAPACITY: (GJ/H)	0
HP WORK ENERGY (TJ/YR)	0

VANSCOY DELISLE
MINE AIR HEATING
DIRECT FIRED GAS

<u>MARKET PRICE ANALYSIS</u>

C A S H F L O W S	Y E A R 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		536												
Above-Ground Equipment		425												
System Increment		300												
Heat Pump System		0			0									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	1261	0	0	0	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	521.4	526.6	526.6	531.9	537.2	542.6	548.0	553.5	559.0	564.6	570.2	581.7
OPERATING COSTS														
Exploration Drilling Costs	480	60												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Energy			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING COSTS	480.0	59.5	158.0	158.7	159.5	160.2	161.0	161.7	162.5	163.3	164.1	164.9	165.8	167.3
NET OPERATING INCOME	-480.0	-59.5	363.4	367.9	367.2	371.7	376.2	380.8	385.5	390.2	394.9	399.7	404.5	414.3
CAPITAL COST ALLOWANCES														
Class 34 @ 50%	25.0	365.1	655.3	315.1	0.0	0.0	0.0	12.5	25.0	12.5	0.0	0.0	22.5	45.0
LOSSES CARRIED FORWARD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAXABLE INCOME	-505.0	-425	-292	53	367	372	376	368	360	378	395	400	382	369
TAXES @ 40%	-202	-170	-117	21	147	149	150	147	144	151	158	160	153	148
NET INCOME	-303	-254.8	-175.1	31.658	220.29	223	225.74	221	216.28	226.59	236.93	239.79	229.18	221.58
NET CASH FLOW (NOI-T-C)	-378	-1150	480	347	220	223	226	183	241	239	237	240	162	267

NET PRESENT VALUE @ 3%	3784
NET PRESENT VALUE @ 6%	2029
NET PRESENT VALUE @ 9%	1079
NET PRESENT VALUE @ 10.8%	717
NET PRESENT VALUE @ 12%	531
NET PRESENT VALUE @ 15%	197
NET PRESENT VALUE @ 18%	-16

GEOTHERMAL ENERGY SYSTEM
CASH FLOW ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5
HOLE DEPTH: (KM)	1.4894
SYSTEM SUPPLY (TJ/YR):	75.2
HEAT PUMP CAPACITY: (GJ/H)	0
HP WORK ENERGY (TJ/YR)	0

CCP COLONSEY
MINE AIR HEATING
INDIRECT FIRED GAS

MARKET PRICE ANALYSIS

CASH FLOWS	YEAR 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		536												
Above-Ground Equipment		425												
System Increment		50												
Heat Pump System		0			0									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	1011	0	0	0	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	601.6	607.6	607.6	613.7	619.8	626.0	632.3	638.6	645.0	651.4	658.0	671.1
OPERATING COSTS														
Exploration Drilling Costs	480	60												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Energy			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING COSTS	480.0	59.5	158.0	158.7	159.5	160.2	161.0	161.7	162.5	163.3	164.1	164.9	165.8	167.3
NET OPERATING INCOME	-480.0	-59.5	443.6	448.9	448.2	453.5	458.9	464.3	469.8	475.3	480.9	486.5	492.2	503.8
CAPITAL COST ALLOWANCES														
Class 34 @ 50%	25.0	302.6	530.3	252.6	0.0	0.0	0.0	12.5	25.0	12.5	0.0	0.0	22.5	45.0
LOSSES CARRIED FORWARD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAXABLE INCOME	-505.0	-362	-87	196	448	453	459	452	445	463	481	486	470	459
TAXES @ 40%	-202	-145	-35	79	179	181	184	181	178	185	192	195	188	184
NET INCOME	-303	-217.3	-51.99	117.76	268.89	272.09	275.32	271.07	266.86	277.67	288.52	291.9	281.81	275.26
NET CASH FLOW (NOI-T-C)	-378	-925	478	370	269	272	275	234	292	290	289	292	214	320

NET PRESENT VALUE @ 3%	5013
NET PRESENT VALUE @ 6%	2855
NET PRESENT VALUE @ 9%	1681
NET PRESENT VALUE @ 10.8%	1230
NET PRESENT VALUE @ 12%	998
NET PRESENT VALUE @ 15%	577
NET PRESENT VALUE @ 18%	304
@ 24%	-9

GEOTHERMAL ENERGY SYSTEM
CASH FLOW ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5
HOLE DEPTH: (KM)	1.4894
SYSTEM SUPPLY (TJ/YR):	103.7
HEAT PUMP CAPACITY: (GJ/H)	0
HP WORK ENERGY (TJ/YR)	0

POTASH CORP-ALLAN
MINE AIR HEATING
DIRECT GAS FIRED

MARGINAL PRICE ANALYSIS

C A S H F L O W S	Y E A R 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		536												
Above-Ground Equipment		425												
Low Temp System Increment		300												
Heat Pump System		0			0									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	1261	0	0	0	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	829.6	837.9	837.9	846.3	854.7	863.3	871.9	880.6	889.4	898.3	907.3	925.5
OPERATING COSTS														
Exploration Drilling Costs	480	60												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Energy			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING COSTS	480.0	59.5	158.0	158.7	159.5	160.2	161.0	161.7	162.5	163.3	164.1	164.9	165.8	167.3
NET OPERATING INCOME	-480.0	-59.5	671.6	679.2	678.4	686.1	693.8	701.5	709.4	717.3	725.3	733.4	741.5	758.1
NET CASH FLOW (NOI-T-C)	-580	-1320	672	679	678	686	694	652	709	717	725	733	652	758

NET PRESENT VALUE @ 3%	13300
NET PRESENT VALUE @ 6%	7847
NET PRESENT VALUE @ 9%	4873
NET PRESENT VALUE @ 12%	3140
NET PRESENT VALUE @ 15%	2068
NET PRESENT VALUE @ 18%	1369
@ 33%	-5