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GEOTHERMAL MINE AIR HEATING

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ABSTRACT

This study follows an earlier conceptual level investigation that examined the potential for geothermal heating of mine ventilation air in the Saskatchewan potash mining industry. That investigation showed geothermal heating to be technically simple and an economic means for reducing natural gas consumption and mine heating energy costs.

The findings confirmed the generally favourable technical and economic conditions for geothermal heating except for one important area relating to tax. This concerns the Provincial Resource Payment Agreement, or PRPA, a form of royalty payment to the provincial government that imposes a further level of tax on income. The graduated portion of the PRPA effectively limits retained savings, after-tax, to between 10 to 30¢ of each dollar saved rather than the 50 to 60¢ normally remaining after payment of conventional corporate taxes.

Cette étude suit une recherche au niveau conceptuel qui a examiné le potentiel d'utilisation de chaleur géothermique pour chauffer l'air de ventilation des mines de potasse en Saskatchewan. Les résultats confirment que des conditions existent pour le chauffage géothermique sauf pour un aspect majeur qui a trait aux impôts. Ceci est relié à l'Accord de Paiement de Ressource Provinciale ou "PRPRA", qui a un type de paiement de royauté au gouvernement provincial qui impose un niveau d'impôt accru sur le revenu. La partie graduée des PRPA limite la retenue d'économies, après impôt entre 10¢ et 30¢ pour chaque dollar épargné plûtot qu'aux 50¢ et 60¢ qui restent normalement après les impôts corporatifs conventionels.

GEOTHERMAL MINE AIR HEATING

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Cominco, Vanscoy Delisle
Central Canada Potash Div., Noranda, Colonsay
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Potash Corporation of Saskatchewan, Saskatoon

EXECUTIVE SUMMARY

This study follows an earlier conceptual level investigation that examined the potential for geothermal heating of mine ventilation air in the Saskatchewan potash mining industry. That investigation showed geothermal heating to be technically simple and an economic means for reducing natural gas consumption and mine heating energy costs.

The present study objectives included: visits to three mines to inspect existing facilities; evaluation of opportunities for recovering waste heat; and the identification and analysis of further mine uses of low temperature geothermal energy.

During the course of the visits, meetings were held with mine managers, financial officers and the engineers responsible for mineral processing and mine operations. The findings confirmed the generally favourable technical and economic conditions for geothermal heating except for one important area relating to tax. This concerns the Provincial Resource Payment Agreement, or PRPA, a form of royalty payment to the provincial government that imposes a further level of tax on income. The impact of the graduated portion of the PRPA was found to cause effective taxes on profits to approach as high as 90 percent, though 70 to 80 percent may be more common.

The PRPA tax was not included in earlier analyses. Effectively it limits retained savings, after-tax, to between 10 to 30¢ of each dollar saved rather than the 50 to 60¢ normally remaining after payment of conventional corporate taxes.

Economic opportunities for significant waste heat recovery at the mines appear to be minimal. There is an opportunity for further geothermal energy utilization involving heating the air used by potash product dryers. This air, presently drawn into

the process building, unheated, also includes a component that goes to cyclone-type, dust separators.

Other, more minor uses exist for geothermal heating including that of ventilation air and internal space heating for site offices, warehouses and shops. The cost effectiveness of building/equipment retrofits, and extensions to the heat distribution system to pick up these typically small space and domestic water heating demands, is considered to be in the marginal to uneconomic range in most cases.

Two mines, considered to be representative for the industry, were examined - Central Canada Potash, a Division of Noranda, at Colonsay, and the Potash Division of Cominco, at Vanscoy Delisle. Financial analysis of geothermal mine air heating (only) for the two mines shows real internal returns of 12 and 8 percent respectively. These values are well below those of the previous study by virtue of adjustments to the analysis that reflect the inclusion of the PRPA tax and more conservative gas price expectations.

Analysis of a combined geothermal heating case, involving both process building air and mine air heating, was undertaken for the Cominco mine. The results show a 3 to 4 point improvement in real returns to above 11 percent.

Expiry of the PRPA in 1986, and its replacement by a more equitable form of resource levy to the province, is understood to be a distinct possibility. Re-working of the Cominco combination case, with corporate tax a maximum at 50 percent, (i.e. excluding the PRPA tax) shows a further improvement in the return to 18 percent real.

The study concludes that the mine air and process building applications of geothermal heating are economic and should prove financially attractive given expiry of the PRPA. However, until a replacement for the PRPA is established, one found to avoid the latter's punitive tax provisions, the industry is likely to continue to avoid non-essential investments and to show little interest in pursuing the savings that geothermal energy certainly promises.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF 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

In 1984, a conceptual level study (1) examined the potential for geothermal heating of mine ventilation air. The work was undertaken for the National Research Council. The mines are the potash operations in Saskatchewan. The study showed there to be a significant practical, economic and financial potential for geothermal energy to displace natural gas currently used for heating ventilation air.

This present study has been commissioned to follow up on these findings. The objectives are to:

1) examine geothermal mine air heating potential in further detail, supplementing the questionnaire and telephone survey data base of the first study with site visits and discussions with plant personnel.

2) identify practical, operational, financial and other factors aiding or opposing geothermal development.

3) appraise present opportunities for heat recovery in the mine heating and potash processing operations.

4) select three candidate mines for feasibility-level investigation of heat recovery options and geothermal uses, including mine air heating.

During meetings at the sites with plant management and operations personnel, discussions revealed the existence of the provincial resource payment agreement (PRPA). This resource tax, reviewed in detail herein, is additional to conventional corporate business taxes. Its effect on geothermal energy after tax cost savings was foreseen to seriously threaten the favourable financial returns predicted by the conceptual study. In view of this finding, the study scope was modified, downgrading the fourth objective to cover only a prefeasibility study of one or two representative mines, and extending the financial analysis to include an assessment of impacts of the PRPA tax on geothermal and heat recovery type investments.

1.2 New Brunswick Potash Mine Heating Opportunities

During the mine visits the possibilities for geothermal heating at potash mines, in operation or under development in New Brunswick, was raised.

EMR has for a number of years been actively encouraging the study and exploration of geothermal resources and their potential in the Maritimes. Accordingly, the original scope was further amended to include: a survey of the New Brunswick potash mine operations and their mine air heating requirements; a summary of geothermal resource data in the mine areas; and assessment of geothermal heating opportunities.

The results of the survey and assessment of the practical and economic potential for geothermal mine air heating are presented in Appendix A of this report.

1.3 Detailed Resource Study

A companion study to this present work was to have been undertaken concurrently for the purpose of evaluating geothermal resource conditions at a greater level of detail than provided by the conceptual study (1). It has since been postponed to await justification on the basis of the results of this study. The results of the geothermal resource analysis undertaken in the conceptual study are used for present study purposes.

2.0 MINE AIR HEATING - BACKGROUND

2.1 Mine Ventilation

Potash is mined at depths of the order of 1 km below surface. Daily ranges for ore production are presently from 6000 to nearly 10,000 tonnes. In the typical case, two mine shafts connect to the mining levels. Ventilation air passes down one shaft, circulates through the mine and is expelled via the second. The shafts penetrate major aquifers such as the Blairmore Formation.

Maintaining the integrity of the cast-iron (or steel) shaft lining, called tubbing, is critical. Careful sealing of shaft casings is essential to prevent leakage and serious interference to the mining operation. Exposure to significant seasonal temperature extremes can cause permanent deformation of the lead gaskets between tubbing sections, resulting in water leakage to the mine. To prevent this situation, the seasonal temperature extremes of the ventilation air supply are kept between fairly narrow limits.

Ventilation rates to each mine typically exceed 350,000 m^3/h. Depending on the particular mine and specific shaft construction details, minimum air temperatures in the ventilation supply (down) shaft range from 10° to 24°C. In Saskatchewan, with winter outdoor temperatures as low as minus 40°C, the cost of heating this air with natural gas exceeds $300,000 per year. The flow rate is based on the need to control dusting at the ore loading face, maintain a cooling air stream for the mine operators, and to transport fumes generated by diesel equipment. The deepest mine, Colonsay, experiences temperatures at the mining level of over 30°C. The tendency in the future is for ventilation rates to increase to further improve the working environment in the mines.

Heating the incoming air is presently accomplished either directly by open-flame, natural gas burners firing into the air stream or, indirectly, using gas fired steam boilers to heat glycol/water systems which, in turn, serve intake air heating coils. Indirect firing, presently being used by two of the mines, is less efficient. Boiler combustion and stack losses, of the order of 20 to 25 percent on an annual basis, increase air heating costs by a similar amount relative to direct heating.

Direct firing is straightforward and typically comprises a gas burner assembly, mounted in the air stream, and an induced draft fan downstream which delivers the heated air, via an air gallery, into the main shaft.

2.2 Geothermal Heating of Ventilation Air

Geothermal heating entails using warm, saline water at 35 to 40°C pumped from the 1500 m deep Winnipeg/Deadwood sedimentary rock formation to the surface. There, after its heat is transferred to a glycol/water secondary circuit supplying ventilation intake air heating coils, the saline geothermal fluid is returned back to the original formation. This geothermal energy supply, comprising a single supply and disposal well, has a useful life expectancy of 30 or 40 years and once installed the direct cost of operating is principally for well pumping power.

The heat load potential at a well flow rate of 100 m^3/h (440 usgpm) is around 15 GJ/h equivalent to 400 m^3/h (14 MCF/h) of natural gas, direct fired. Higher flow rates, obtained at the cost of additional pumping power, produce a corresponding increase in the heating load capability of a geothermal system.

The capital cost of geothermal heating is high but direct costs for operation and maintenance are, normally, relatively modest compared to those for conventional fuels (gas, oil). Geothermal heating is most economic when fullest use is made of its load supply capability. Mine air heating, with peak load demands of typically 20 to 30 GJ/h, is an ideal application for geothermal energy because heating is necessary for most of the year.

Further economic improvement can be obtained if geothermal is used to supply other large heat demands at the mines. Conversely, the economics of geothermal energy is weakened if heat from the mine discharge air is recovered by the intake air stream, reducing the heat demand.

Energy consumption for mine air heating is only one tenth of the total required, the other major uses being potash drying, building heating and crystalizer process heating.

Table 2-1 presents, for reference, general mine data applicable to eight of the nine mines previously investigated. The Potash Company of America mine, located near Saskatoon, was not included in the original study.

For the present study two mines are used as reference cases, the Cominco potash operation at Vanscoy Delisle and Noranda's Central Canada Potash (CCP) operation near

TABLE 2-1

GENERAL DATA SHEET - POTASH MINE OPERATIONS

COMPANY:	COMINCO	PCS MINING				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	950	950
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.

Colonsay. The location of these and the remaining seven mines is shown in Figure 2-1.

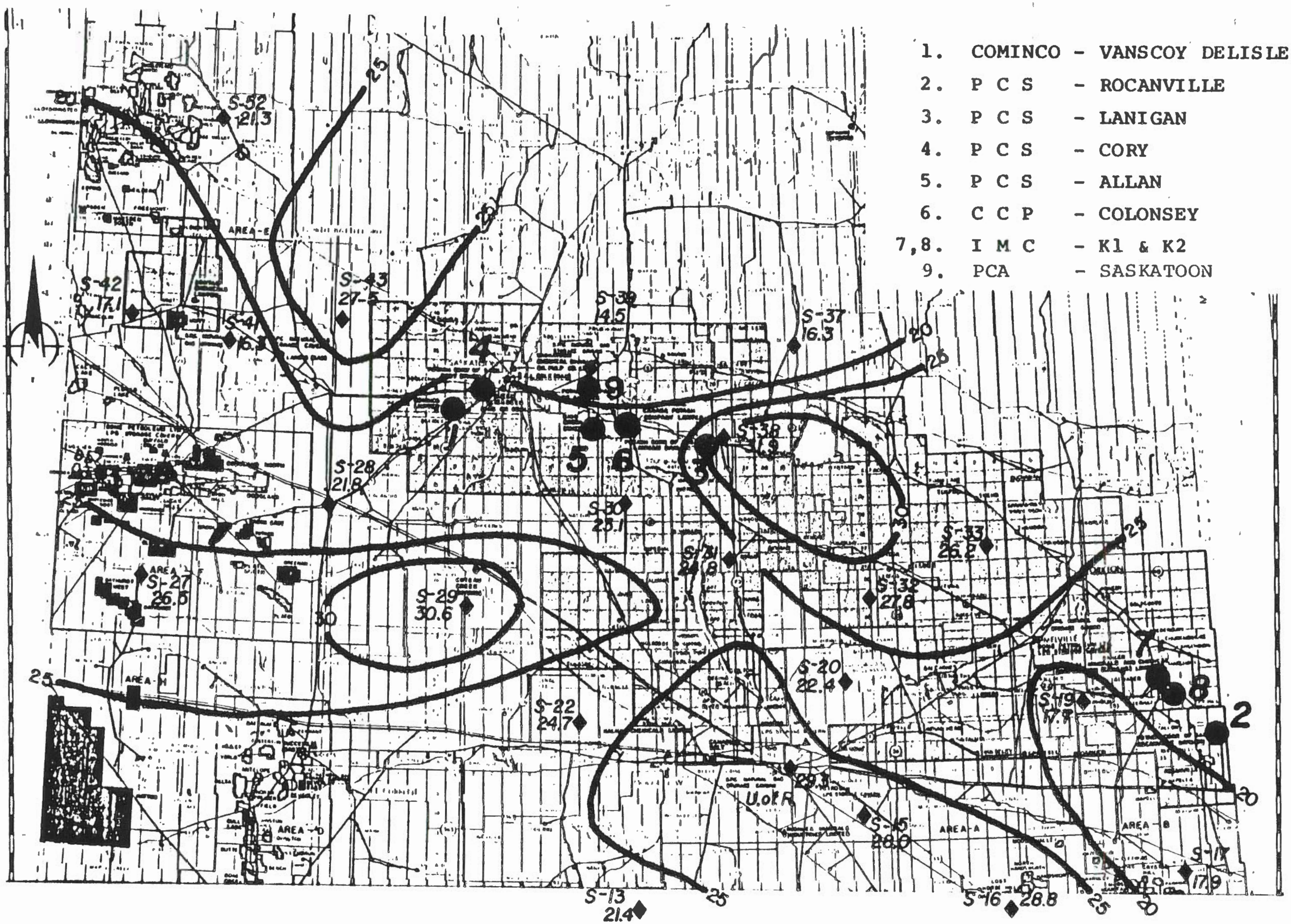
Cominco has recently completed conversion of its mine air heating system from indirect to direct gas firing. CCP maintains an indirect glycol heating system. Both plants have a nominal or reference annual potash production rate of roughly a million tonnes.

The reference design ventilation rate for a million tonne output is 360,000 m^3/h (200,000 cfm). Values prefixed "reference" in this report relate to the above conditions of output and ventilation flow rate. Six of the nine operations conform quite closely to these reference conditions. Other things being equal, the mine ventilation rate is a function of the number of mining machines working the ore face, each of which requires 60,000 to 70,000 m^3/h for dust control.

2.3 Mine Visits and Data Collection

During the week of September 23, 1984, visits were made to four potash mining operations in Saskatchewan for discussions with engineering, operations and accounting staff. The purpose was to assess various technical and financial factors influencing geothermal air heating potential, including opportunities for energy conservation and waste heat recovery. The companies visited were:

Noranda Central Canada Potash (CCP) Division - Colonsay
Cominco - Vanscoy Delisle
Potash Company of America (PCA) - Saskatoon
Potash Corporation of Saskatchewan (PCS) - Head Office



S-29 Well Point Data

-25- Geothermal Gradient Contours

FIG. 2-1

GEOTHERMAL MINE AIR HEATING

MINE LOCATION MAP

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With the first three, site tours were arranged to inspect the mine air heating facilities and the surface plant process operations.

The visits confirmed the view of the earlier study, that implementation of geothermal mine air heating (MAH) is relatively straight forward. For the three sites visited, adequate space is available in existing MAH structures to accommodate pipework, pumps, primary heat exchanger and air heaters coil banks comprising the geothermal system. Routing of geothermal supply and disposal pipework from the supply to the injection wells is not foreseen to be a problem at the uncongested Cominco and CCP mine sites.

The findings from the inspections and discussions with mine personnel are presented in the report appropriate to the topics being addressed.

Further clarification of specific issues has been obtained by follow-up telephone calls to mine personnel, process engineering companies, and other reference sources. Personal communications are acknowledged in the report where applicable.

3.0 REVIEW OF PROCESS AND OTHER MINE ENERGY DEMANDS

The following briefly reviews the primary operations involved with processing the potash ore and identifies the principal heat input and energy transfer points.

3.1 Potash Process

Figure 3-1 presents a simplified process flow schematic showing the basic operations of ore crushing, screening, flotation separation of product and rejects, centrifuging of product for moisture removal, and final drying of the refined product prior to storage.

Product dryers are the principal gas consumers of the whole process operation, typically accounting for half of the mine consumption. In the dryers, the product is heated by direct gas combustion to temperatures close to the melting point of 350°C. Reference air input to the dryers is 280,000 m^3/h comprising primary combustion and secondary dilution air.

3.2 Brine System

Figure 3-2 illustrates brine flows around the crystalizer operation. From an energy use/recovery viewpoint the steam heater - hot thickener - crystalizer - condenser loop is of primary interest. The process of removing NaCl operates on the difference in relative water solubility of KCl and NaCl. Steam heats brine to about 100°C in the dissolver from where, product and brine are separated in the hot thickener. Product solution, on leaving the thickener, flows to a 4-stage crystalizer, each stage under increasing vacuum. Moisture is drawn off and

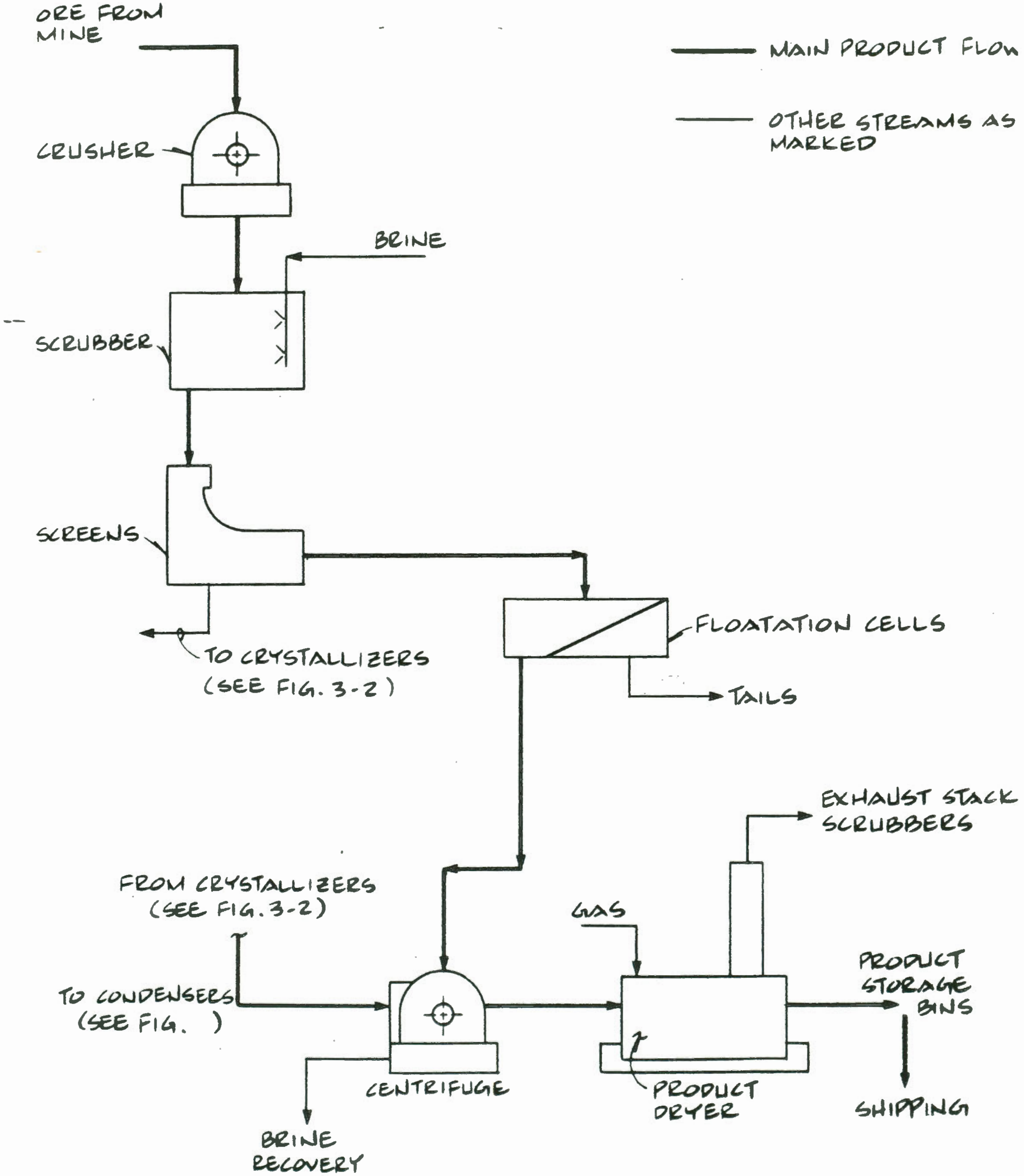

FIG. 5 –

GEOTHERMAL MINE AIR HEATING
POTASH PROCESS SCHEMATIC

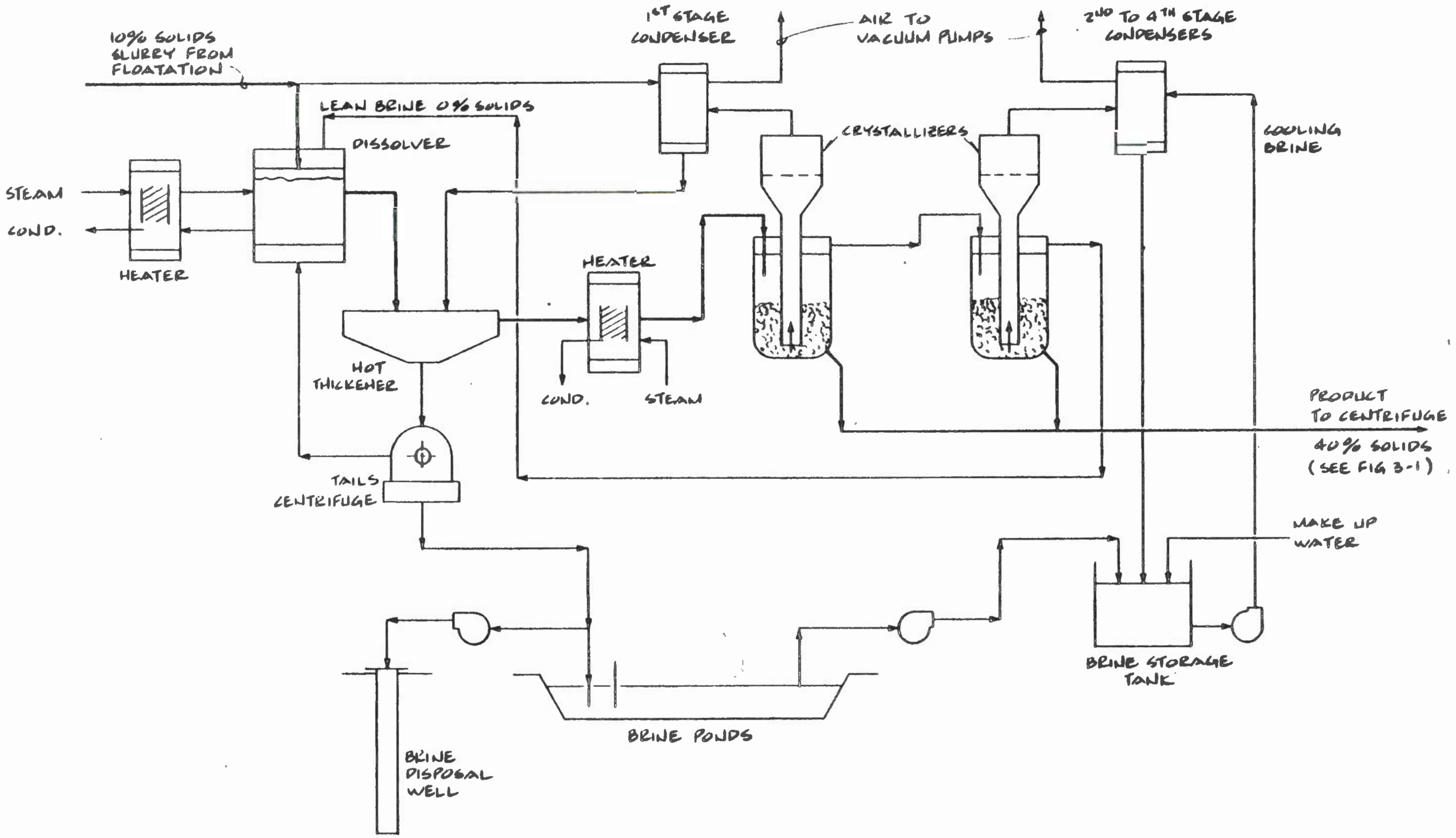

FIG. 3-2

GEOTHERMAL MINE AIR HEATING
CRYTALLIZER-BRINE SYSTEM SCHEMATIC

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condensed in four companion condenser stages. Product is crystalized and passed to the centrifuge for further moisture separation (Figure 3-1) before mixing with the main product stream for final drying.

An important part of the brine system is the brine disposal well. Brine generated by the process finds its way from various stream sources into the tailing ponds, where cooling and substantial evaporation of surplus water occurs. Should pond storage capacity be temporarily insufficient, as determined by the natural evaporation rate, the surplus is disposed of in the brine injection well which discharges to the Winnipeg/Deadwood formation.

3.3 Building Heating

At the surface, the mines comprise a number of individual buildings. The site plans, Figure 3-3 and 3-4 show typical facilities such as offices, process building, change rooms, shops and warehouse, boiler plant and others. At CCP Colonsay, a central boiler plant supplies steam for heating individual buildings. Distribution piping is run in buried concrete trenches. The Cominco mine, on the other hand, uses steam to heat a pumped glycol/water site distribution system.

At the PCA mine, there is no central heat distribution system. Gas is piped to individual buildings for use in unit heaters (shops and stores) or gas fired furnaces (office and administration buildings).

Potash processing buildings require a large amount of outside ventilation air to replace the air exhausted via cyclone dust collection system and product dryers. In the

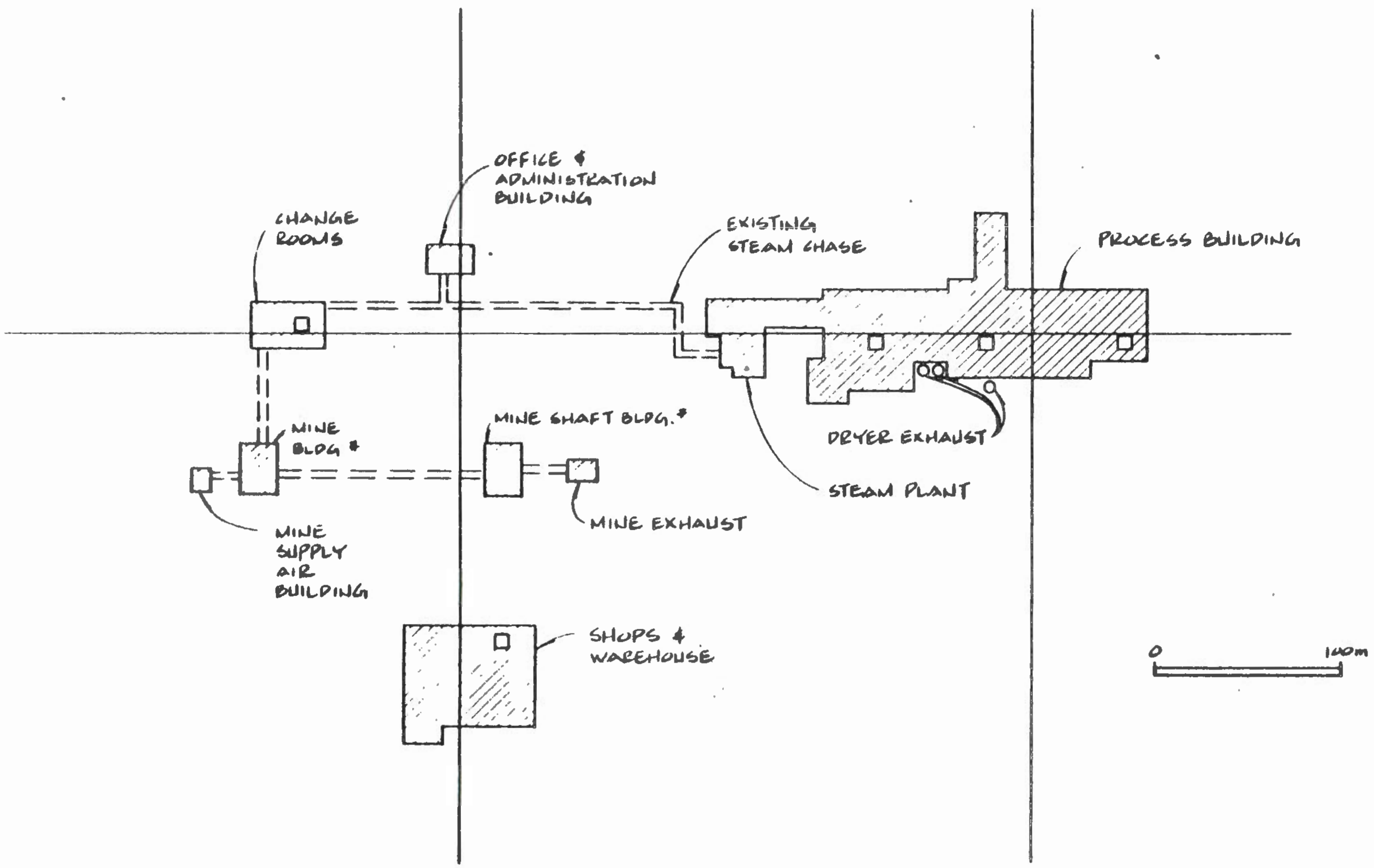

FIG. 3-3

GEOTHERMAL MINE AIR HEATING
SITE PLAN-CCP

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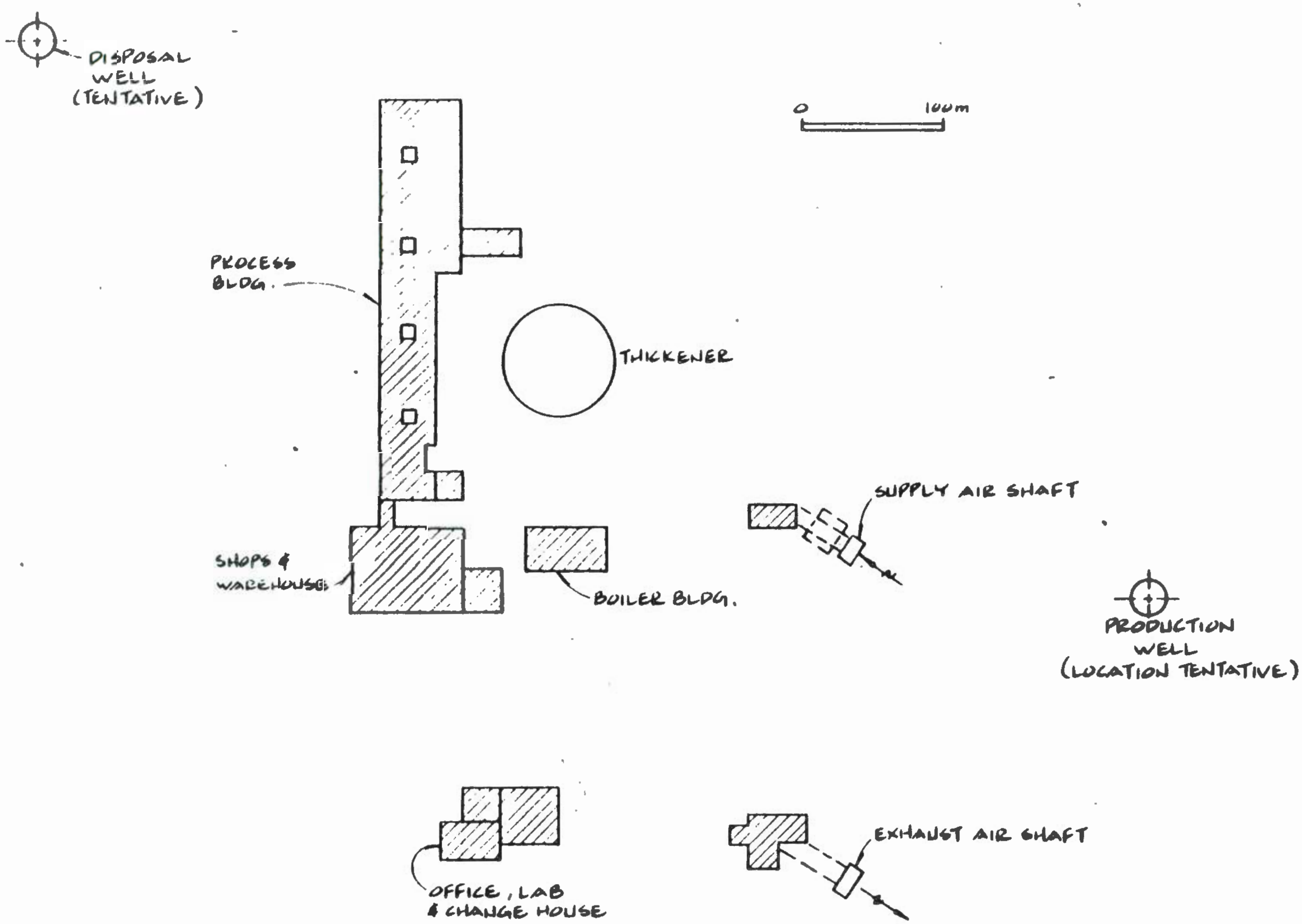

FIG. 3-4

GEOTHERMAL MINE AIR HEATING
SITE PLAN-COMINCO

Cominco plant, the process building total air intake is 530,000 m^3/hr which is comparable to mine ventilation flow (personal communication, A. Cormode, Cominco). Additional ventilation required for shops, change rooms and other buildings is estimated to total a further 70,000 m^3/hr.

At present in the process buildings, no attempt is made to supply (or heat) the intake air. Most commonly, air is allowed to infiltrate through wall openings, resulting often in pipe freezing.

3.4 Domestic Hot Water

The principal hot water requirement is for showers. For the reference case, approximately 120 showers are taken daily in total by the day and night shift crews returning from underground.

3.5 Summary of Energy Requirements & Annual Usage

The tabulation below lists reference peak load demands and annual gas consumptions by function.

	Peak Loads	Gas Consumption	
	(GJ/h)	(M m^3/y)	% Total
Process			
- Product dryers	91	17	48
- Brine heating	40	12	34
Surface Buildings			
- Ventilation air	30	2.5	7
- Space heating	12	1.0	3
- DHW	18	0.05	neg.
Mine			
- Ventilation air	25	2.8	8
Totals	216	35.3	100

The total annual gas consumption figure accords closely with the annual total of monthly consumption data obtained from Cominco.

The high peakload, limited annual energy consumed for DHW heating is evident from the tabulation.

4.0 PRESENT HEAT RECOVERY AND FUTURE OPPORTUNITIES

4.1 Mine Air Heating

The ventilation air leaving the mine is warmer than the supply and carries considerable moisture and dust, picked up from the mining face. At PCA during winter, the condensation, pooling and freezing of released moisture in the vicinity of the discharge fans is a problem.

The ore dust carried by the air stream combines with the moisture to produce a sticky product which adheres thickly to surfaces with which it comes in contact. Outlet grills, fans, motor drives, etcetera in the exhaust air building at the CCP-Colonsay mine provide witness to this problem.

In addressing methods of heat recovery from mine discharge air, finding means to deal with the dust/moisture combination must be regarded as a fairly formidable challenge, one requiring the design and development of an effective, self-cleaning or on-line, washable type of heat exchanger.

Air-Air Heat Recovery

Field trials of a novel form of heat exchanger are being conducted at the present time at CPP-Colonsay. This research level project is being conducted by the University of Saskatchewan. The experimental air-to-air, crossflow exchanger uses a plastic fabric material. Preliminary results show the 2.5 m x 7.5 m x 5 m long exchanger to be capable of heating incoming air from -35°C to -5°C. It is reported that the exchanger exhibits a self-cleaning action, particularly during the winter, with airborne moisture condensing and washing dust from the exchanger surfaces. During the summer, natural flexing of the fabric could assist to keep surfaces clean.

The use of commercial air-to-air heat exchange equipment in this application is problematic and uncertain. Such a system requires ducting, about 3 m x 3 m in section, connecting between mine shafts. For CCP and Cominco mines, the length required is about 150 and 200 m respectively. The cost of such an installation including heat exchanger, is estimated to be of the order of $500,000.

ASHRAE recommends the installation of preheat coils where freezing temperatures could cause ice formation. Preheating significantly limits maximum energy recovery, annual gas savings and overall cost effectiveness.

Applying practical criteria of trouble-free and reliable operation, considerable further development is necessary to overcome some of the operational limitations foreseen and to identify an annual savings potential large enough to justify the capital expenditure.

Air-Water-Air Heat Recovery

Perhaps the more practical and cost effective method of heat recovery from mine exhaust is through the use of an air/glycol coils mounted in the supply and discharge duct. A pumped glycol/water solution connecting the two provides the intermediary means for heat conveyance. Such a system avoids the visual bulk associated with interconnecting ductwork between mine shafts, and the cost of installation is estimated to be about 50 percent or so of air-to-air systems.

One manufacturer, supplying heat recovery make-up units to Alberta industries, claims to achieve annual energy savings of 40 percent or so with smaller sized installations, operating under similar temperature regimes. Glycol coils preheat incoming outdoor air while depressing exhaust air to within 1°C of freezing.

For the mine air application, preventing ice and dust build-ups from fouling exchanger surfaces is a priority consideration that requires development and testing of prototype designs to fully identify and resolve.

4.2 Product Dryers

At Cominco, secondary (dilution) air to the dryers infiltrates unheated into the process building and is partially tempered by incidental heat emissions from equipment and hot product storage bins. Some small assistance is provided by unit heaters strategically located to avoid localized freezing. Combustion air is ducted directly from outside during winter and from within the process building in the summertime (personal communications. A. Cormode, Cominco.)

The PCS Rocanville operation is reported to preheat dryer air by ducting past hot product storage bins downstream of the dryers (personal communications B. Fairburn, Kilborn Engineering).

At the PCA mine, the combustion air ducts leading from outside the building would appear to be rendered ineffective by the removal of the large duct inspection doors (this might be a summer provision only to increase the cooling air flow through the building). It is understood that the full air requirements to the product dryer (and cyclone separators, etc.) are met by natural infiltration through wall and door openings. Incidental preheating is obtained from equipment emissions within the building. The impression is that this situation is not satisfactory. Operating personnel report incidences of pipe freezing, notwithstanding local unit heater support.

Dryer Stack Gas Heat Recovery

Product dryers have brine scrubbers fitted to the exhausts to recover airborne product and to meet atmospheric emission regulations. Some heat from the stack gases is recovered by the brine though this is not the primary intent.

The expectation of achieving further useful heat recovery by this means is regarded as minimal. There is the risk of undercooling exhaust gases with adverse affect on plume buoyancy. (Also, the emission of moisture-saturated plumes tends to create fogging and the potential for ice build-up on surrounding buildings during winter operation.)

4.3 Brine Circuit

The primary heat energy inputs to the brine circuit occur in the product dryer stack gas scrubber and in the brine heater ahead of the hot thickener. Heat energy is removed from the first stage condenser of the 4-stage crystalizing process and transported to the brine heater for recirculation at 90°C to the hot thickener. The remaining three condenser stages are cooled by reclaim brine pumped from the tailings ponds. This first stage brine flow of 90 to 100 m^3/h (perhaps higher in some cases), at a temperature of 50 to 60°C, offers significant energy potential for recovery and possible utilization for heating mine air, site buildings and other purposes. However, in discussion with plant operations (D.A. Cormode, Cominco) and process designers (B. Fairbairn, Kilborn Engineers) there is a concern for potential salt precipitation from the highly saturated brine stream if subjected to significant cooling with adverse impact on the process. At present there appears to be little interest in recovering energy from this source.

4.4 Summary of Heat Recovery Potential

Heat recovery from the process is minimal and principally restricted to that picked up by the brine used in the stack-gas scubbing process. Incidental heating of air infiltrating into the process building is a random, uncontrolled approach to recovery, but does provide partial tempering of air prior to entry to the dryers.

A major capacity expansion is currently in progress at the PCS mine at Lanigan. It is understood there is no intention to implement energy conservation techniques in either the processing plant or mine ventilation system though, apparently, various opportunities were looked at including cooling of the final potash product for heat recovery purposes.

Retrofitting recovery systems is expensive and not necessarily simple to implement successfully. The contaminated condition of various fluid streams incurs the risk of heat exchanger fouling and increases operation surveillance and maintenance problems. Retrofitting causes plant operating complications and is disruptive to production during the construction phase. All of these factors carry their own cost burdens.

Recovering mine air discharge heat is technically feasible and appears to be the most practical using an air-glycol-air system in preference to air-air. However, the potential for both freezing and fouling remains indeterminate in the absence of extensive field testing and development trials.

In any future heat recovery plans, it appears that the more cost-effective approach will be for process plant sources to use their own recovered energy locally and similarly for mine ventilation. This approach entails minimum interconnecting piping and ductwork.

Regarding mine air heat recovery, Cominco's involvement with the experimental air/air heat exchanger is one of the more positive indications of the industry's interest in furthering energy conservation opportunities. However, heat recovery can only achieve a certain percentage savings in conventional energy consumption at an installed cost that is frequently high. Geothermal, on the other hand, is capable of displacing up to perhaps 90 percent of conventional energy given the kind of conditions represented by mine air heating.

Overall, heat recovery is not seen to pose a significant challenge to geothermal heating opportunities at the mines. Rather, as is shown later, this review suggests that the extension of geothermal into areas such as pre-heating of product dryer air, building ventilation air, and domestic hot water offers the opportunity to improve the load, load factor and unit cost of geothermal energy while incurring only a small increase in capital cost. This is based on the fact that up to the output limit of one supply and return well - a limit that is mainly set by increasing pumping costs - the principal cost of geothermal energy is fixed and relatively insensitive to output. With such a cost structure, the greater the energy usage the lower becomes the cost of geothermal energy and the higher the annual savings from displacing consumption of natural gas.

5.0 GEOTHERMAL HEATING POTENTIAL

To add further heating loads to the basic geothermal mine air heating system, proposed in the previous study, requires extending the secondary glycol loop to distribute heat to the site buildings. The above-ground primary system of heat exchanger and supply and disposal piping becomes appropriately larger to suit an increase in the supply well flow rate (F_g). A flow of 150 m^3/h or higher could be necessary depending on the economic balance between the incremental cost for connecting to and retrofitting each building (or process) and the present worth benefits of future gas savings.

A conservative value for the geothermal resource of 40°C, as previously determined, is assumed to remain valid for this study.

5.1 Heating Load Demands

Building Make-Up Air - Total ventilation air flow requirements for all site buildings is of the same order of magnitude as the mine ventilation air flow. Air to the process building (for dryer and cyclone separators) represents 75 to 80 percent of the total building make-up flow. The 40°C resource condition is suitable for both building and mine air heating duties.

Examination of the economics of retrofitting make-up air heating systems to displace gas useage in the smaller buildings does not indicate a particularly favourable economic payback at the present time. This applies generally to buildings such as offices, stores and warehouses.

Building Space Heating - Space heating is at present supplied by 90-100°C hydronic (or steam) systems typically supplying perimeter convector coils in office and administration buildings, and to fan coil unit heaters in the open indoor areas found in the stores and warehouse buildings. Retrofitting equipment designs suited to the 40°C supply, even with temperature boosting under peak load conditions, is not expected to be particularly practical or cost effective.

Domestic Hot Water - The estimated one hour peak demand of 18 GJ/h corresponds to 100 showers, the useage that occurs following completion of the day shift. With a 40°C supply temperature the geothermal based system might supply perhaps 50 percent of the total DHW heating load. The total annual energy consumed in heating DHW, however, is small overall (see tabulation of energy consumptions, Section 3.5). This, combined with quite substantial retrofit costs (for heat exchanger and the large capacity DHW storage facilities necessary to "level" the supply rate) can be expected to make geothermal heating of DHW uneconomic.

Summary

At this level of study it is provisionally proposed to extend the geothermal mine air heating system to include only the process building. This involves retrofitting the building to accommodate roof-mounted fan coil units and supply distribution pipework.

As is addressed in the following section, the combined demand of these two loads is very adequate for the expected capability of a single geothermal well doublet supply. There is little justification to connect up other buildings to further increase system demand to simply benefit geothermal utilization.

The following tabulation presents provisional air flows, peak loads and other design conditions relevant to the combined mine air and process building air heating demands.

MINE		COMINCO	CPP
Air Flow			
- Mine ventilation	(m^3/h)	520	375
- Process building	(m^3/h)	525	525
- Totals	(m^3/h)	1045	900
Winter outdoor temp - t_w	(°C)	-35	-35
Ventilation supply temp - t_e	(°C)	13	14
Peak load demand - q_p	(GJ/h)	60	53

5.2 Geothermal Supply and Disposal

Resource Conditions

The postponed companion resource study to this was to have investigated the resource and formation conditions in considerable detail sufficient to identify potential productivity index values for the formation, hydrostatic heads and so forth from which drawdowns, flow rates, pumping heads and power requirements could be closely established. In the absence of such data, regional resource conditions are assumed. Concerning the geofluid chemistry, salinities ranging from 100,000 to 150,000 NaCl are predicted, levels sufficient to avoid freezing at temperatures as low as minus 18°C.

Disposal Temperature

The winter design geofluid disposal temperature selected in the earlier study was limited to 5°C. With well flow rates set at 100 and 150 m^3/h, this resulted in a geothermal supply load potential of 15 GJ/h and 22.5 GJ/h respectively.

Currently at some mines, brine flows surplus to the process are being injected to the Winnipeg/Deadwood at temperatures that range seasonally from minus 18 to plus 25°C (and at rates of up to 250 m^3/h). Noting the successful experience of the mines in pumping process brines at these low injection temperatures, the effects of lower design geofluid disposal temperatures were studied. Lowering the geothermal disposal temperature is a direct means of increasing the geothermal supply load capacity. It results in an increase in geofluid viscosity and disposal well pump power, but does not affect the wells, pipe sizes or cost of supply and disposal system.

Examination of annual ambient temperature variations and heat exchanger operation over the load range, shows a pinch point condition occurring as T_2 and outdoor temperature t fall. This condition is alleviated somewhat at higher flow rates (F_g) such that the higher the flow the lower can be the minimum temperature T_2. Thus, the geothermal supply load potential - a function of flow and (T_1-T_2) - benefits doubly from higher flow rates (F_g).

The following tabulation presents comparative design conditions corresponding to the flow and disposal temperatures indicated.

		Well Flows m^3/h	
		100	150
Disposal Temperature T_2	(°C)	0	-5
Geothermal Supply Load q_g	(GJ/h)	17	29
Improvement in Load	(%)	14	30

The percentage improvement in load (compared to the previous study disposal temperature of 5°C) is illustrated i.e. at -5°C, the geothermal load capability is improved by 30 percent.

Design and Peak Loads

Comparison of the above geothermal supply loads with the tabulated load demand values of page 5-3, corresponding to combined process building and mine air heating, shows that the geothermal supply alone cannot meet the peak demand so that supplementary heating, using gas or other means, is needed.

Figure 5-1 shows a simple schematic of the proposed geothermal system. Referring to the figure, peak heating of mine air at Cominco would be achieved by operating the direct fired gas burners to bring up the temperature of the supply air leaving the glycol/air heaters to the required set point. At CCP-Colonsay, the existing steam/glycol exchangers would be used to increase the secondary circuit supply temperature (T_s) at peak times.

With respect to meeting the peak ventilation loads of the process building, the simplest approach is not to attempt

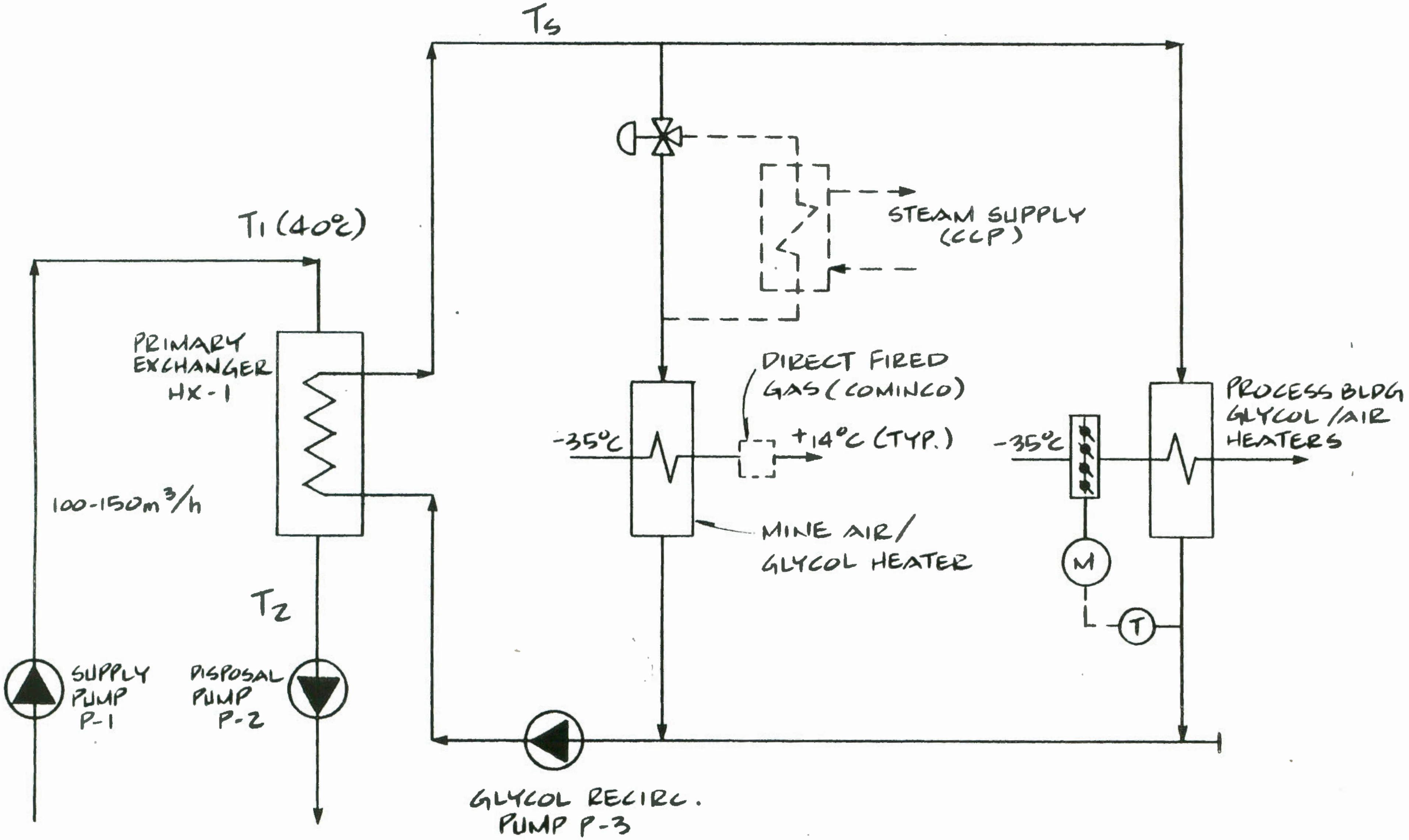

FIG. 5-1

GEOTHERMAL MINE AIR HEATING
MINE HEATING SYSTEM SCHEMATIC

to meet peak levels. Instead, automatic regulation of air intake dampers incorporated with the roof-mounted air heaters would restrict air flow to suit a selected minimum glycol leaving temperature. Considerable heating of the outdoor air is still achieved. Compensation for building supply air deficiency can be achieved by existing means such as from induced infiltration. Alternatively, attempting to meet peak heating demands would require some form of supplemental heating in the geothermal central heat plant to raise the supply temperature T_S by the required amount.

The above briefly outlines possible approaches to operating the geothermal/central heat system under peak demand conditions where the geothermal system capacity is not sufficient for the demand. There are others. The relative merits of each can be readily addressed and resolved at a later detailed stage. For the present, control is foreseen to be simple.

The previous study provided, in some detail, information on the operation of the geothermal mine air heating system. A diagram was included to illustrate trends in the heating and air system parameters in accordance with seasonal changes in outdoor temperature i.e. heating load. For brevity this is not repeated. It is sufficient to observe that control of the geothermal heat supply is obtained by controlling the geo-fluid supply flow either by throttling or regulation of pump speed, P-1 (Figure 5-1).

5.3 Annual Energy Supply

The profiles of annual heating demand (histogram) for the mine air and the process building air are assumed to be similar since both involve heating outdoor air from winter conditions to temperatures of about 15°C. Where combustion air is ducted separately to the dryers, it would be possible, by providing air heaters in the intake duct(s) to heat to higher than 15°C.

Figure 5-2 shows the combined heating demand (process and mine air) histogram for the two mines. Geothermal supply loads are superimposed, corresponding to 100 and 150 m^3/h. Annual energy Q_g supplied by the geothermal system was obtained from planimetre measurement of the area under the histogram curve. This and other performance data is presented in Table 5-1 which is applicable to the combined heating case and also the mine air only case: the latter data is reproduced from the earlier report. Comparison shows that for the same well flow rate (F_g) of 100 m^3/h, the addition of process building heating improves annual energy Q_g by 14 percent (Cominco) and 27 percent (CCP). Some of this improvement is due to the lower disposal temperature.

The main benefit to combining process and mine heating comes with higher well flow rates. At 150 m^3/h, for example, the annual energy Q_g is increased by 65 percent (Cominco) and 110 percent (CCP); again, some of this is due to the lowered disposal temperature. The reason the increase for the Cominco case is less pronounced is because that mine's air flow is substantially higher than CCP's in the first place, providing an inherently better base load condition, load factor and annual utilization potential for the geothermal supply system.

TABLE 5-1

GEOTHERMAL PERFORMANCE DATA

PROCESS BUILDING & MINE AIR HEATING

MINE		COMINCO		CPP	
General					
Winter design t_w	(°C)	-35		-35	
Total air flow F_a	($1000m^3/h$)	1045		900	
Ventilation supply temp. T_e	(°C)	13		14	
Peak demand q_p	(GJ/h)	60		53	
Natural gas heating		Direct		Indirect	
Resource					
Gradient	(°C/km)	23		23	
Depth	(km)	1.5		1.5	
Supply temperature T_1	(°C)	40		40	
Geothermal flow F_g	(m^3/h)	100	150	100	150
Injection temperature T_2	(°C)	0	-5	0	-5
TDF (T_{si} = 0°C)		1.0	1.13	1.0	1.13
Heating System (Process & Mine Air)					
Supply load q_g	(GJ/h)	16.5	28	16.5	28
Annual energy Q_g	(TJ/yr)	99	169	95	162
Load factor LF_g		0.69	0.68	0.66	0.64
Annual utilization (T_{si}= 0°C)		0.69	0.77	0.66	0.75
Heating System (Mine Air Only)*					
Supply load q_g	(GJ/h)	15	22.6	15	22.6
Annual energy Q_g	(TJ)	86.9	102.5	75.2	76
Load factor LF_g		0.66	0.52	0.57	0.38
Annual utilization (T_{si} = 0°C)		0.58	0.46	0.5	0.33

* T_2 = 5°C

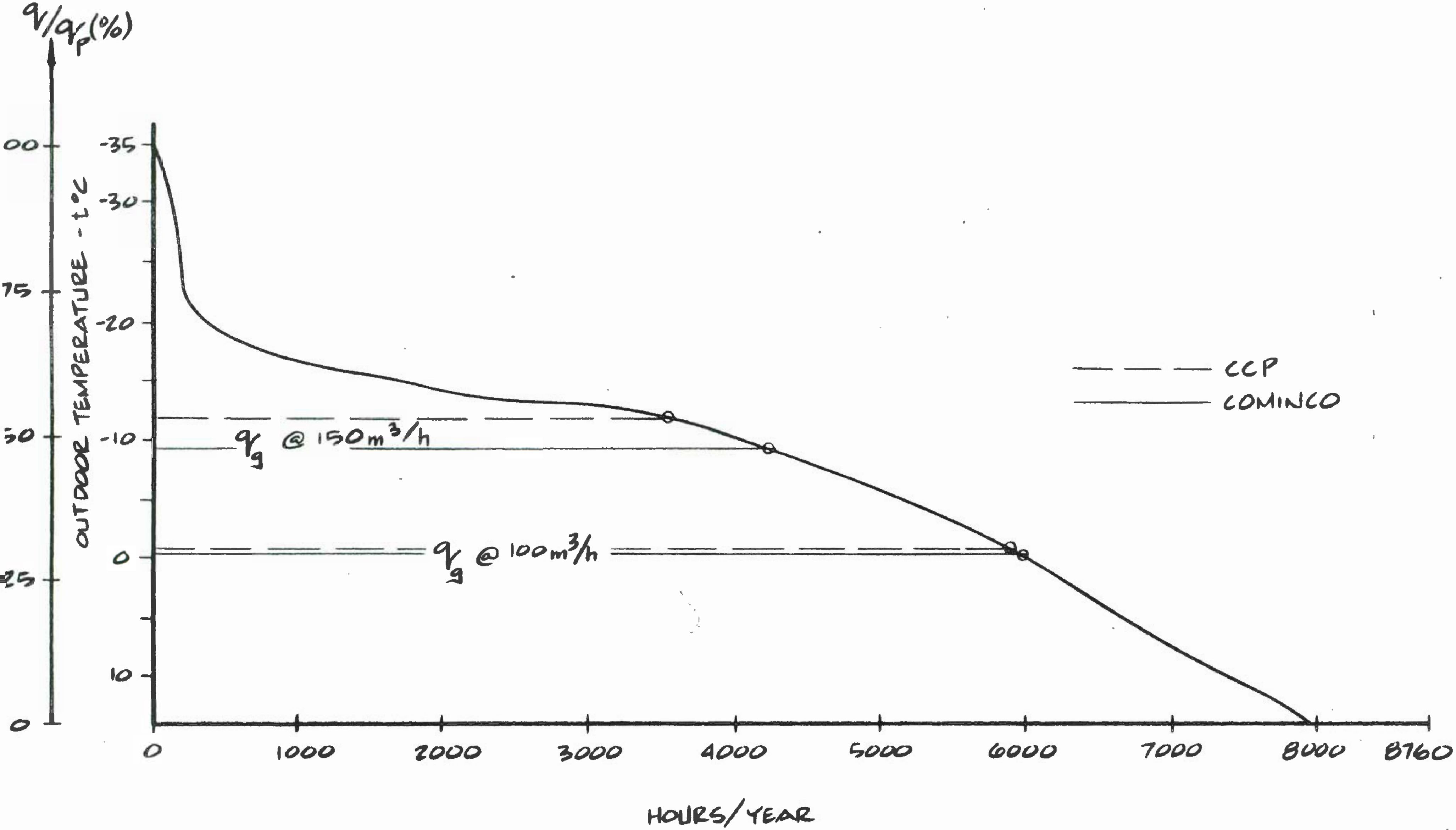

FIG. 5-2

GEOTHERMAL MINE AIR HEATING
HISTOGRAM - PROCESS BLDG. / MINE AIR DEMAND

ACRES

5.4 Site Arrangement and Heating System Details

Figures 5-3 and 5-4 show the site arrangements for CCP and Cominco respectively with the piping for the heat distribution system superimposed: also shown are tentative locations for geothermal supply and disposal wells. The supply well requires locating as remote from the process brine and geo-fluid disposal wells as possible. A distance between wells of 1 km is expected to provide sufficient separation to prevent premature temperature deterioration of the geo-supply.

The glycol heat distribution piping would be laid in existing trenches where available. Within the process building it would be suspended from the building structural steel and routed in existing pipe chases.

The central heat plant comprising the primary heat exchanger glycol tanks and recirculation pumps are located in existing mine air intake structures.

5.5 Corrosion and Materials Section

Appendix B contains details of typical geofluid chemistry for various geothermal aquifers encountered beneath Saskatchewan. The Winnipeg/Deadwood formations, situated directly above the precambrian basement, are the candidate geothermal heating sources appropriate to this study.

Appendix B includes an analysis of the corrosion potential and a provisional guide to the selection of materials for components of the primary geothermal circuit including well casings.

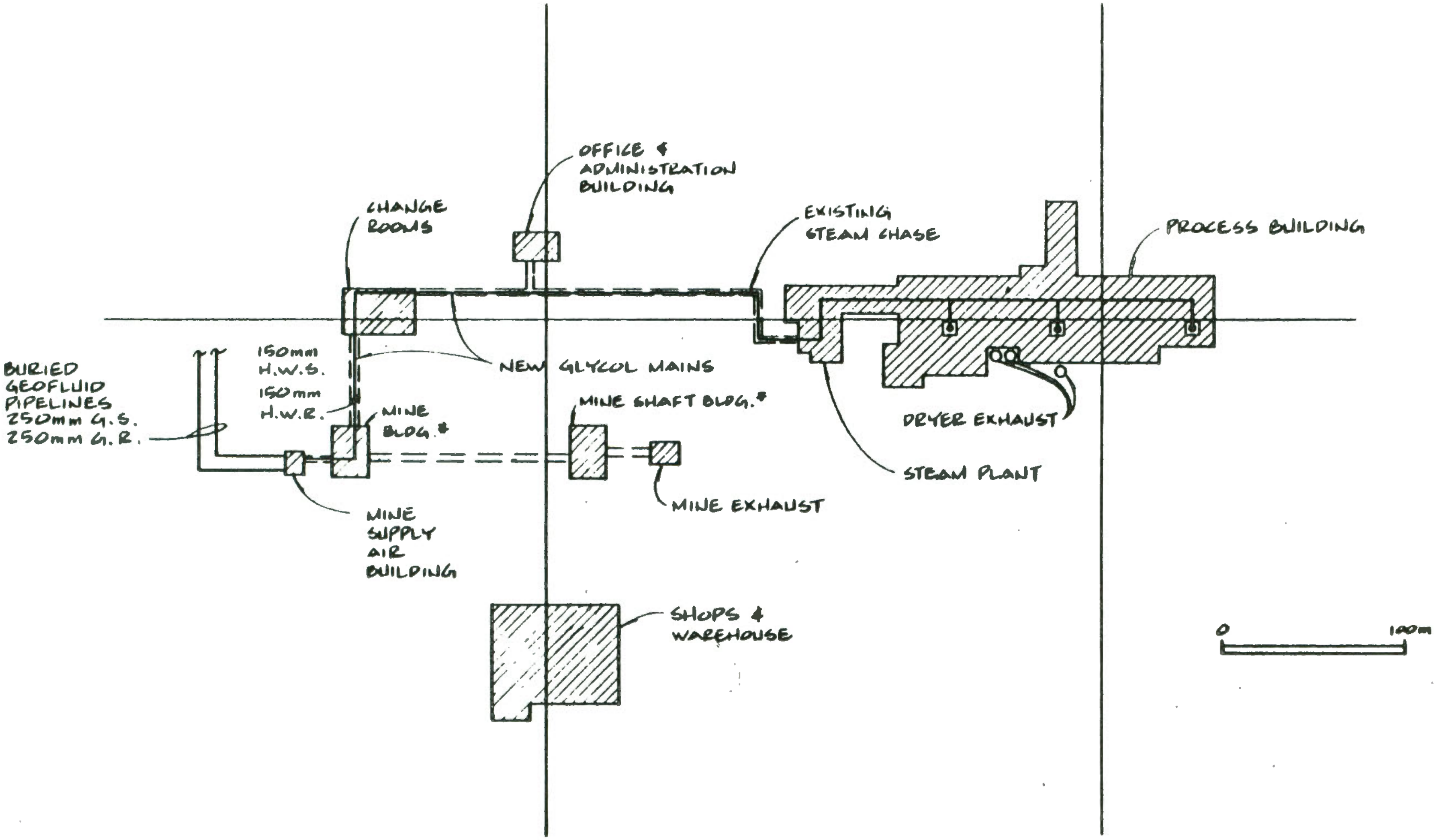

FIG. 5-8

GEOTHERMAL MINE AIR HEATING
HEAT DISTRIBUTION SCHEME-CCP

ACRES

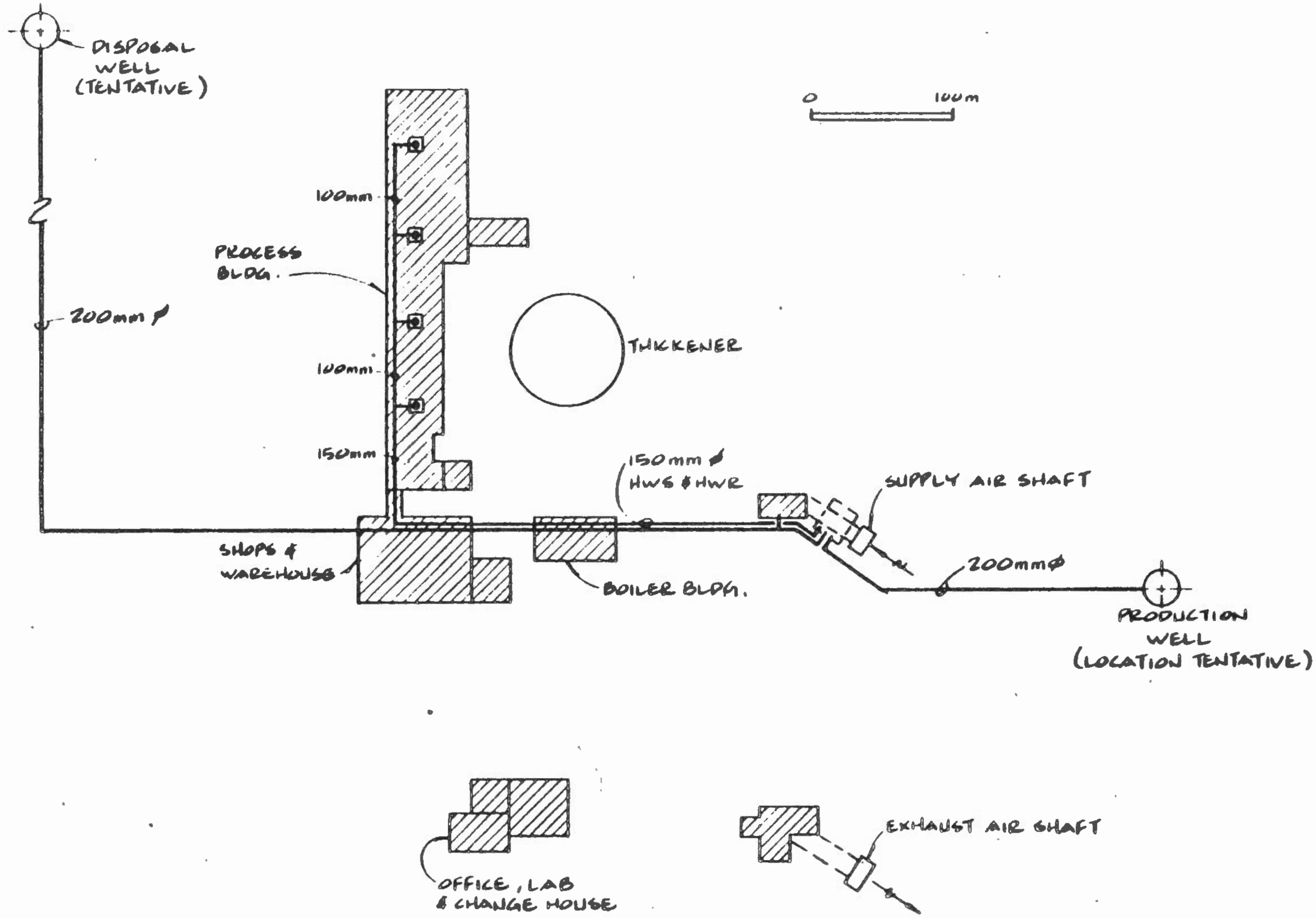

FIG. 8-4

GEOTHERMAL MINE AIR HEATING
HEAT DISTRIBUTION SCHEME-COMINCO

5.6 System Costs

Conceptual level capital cost estimates prepared for these arrangements are presented in Table 5-2.

Piping costs are based on jacketed, insulated pipe. Typical unit prices, installed, are as follows.

	$/m
Geofluid (Buried Service, Single Pipe)	
- 200 mm supply incl. excavation	300
Glycol Heat System (Trenches, Buildings)	
- 150 mm supply and return (2-pipe)	400
- 75 mm supply and return (2-pipe)	200

Make-up air units, each 120,000 m3/h capacity, are estimated to cost, installed, $36,000.

Prices for the plate type, primary heat exchanger were obtained from Alpha Laval. Byron Jackson provided prices for multi-stage vertical turbine pumps of the totally immersed, downhole type complete with integral motor.

Well costs are based on U.S. historical costs for the industry, corrected for exchange, and expressed in current dollars. The basis for these costs can be found in the previous study. For 1.5 km deep wells the total installed cost for supply and disposal including completion and testing, is estimated at $1,100,000.

Annualized costs shown in Table 5-2 are based on:

- real cost of capital at 10 percent, and 30 year project life;

TABLE 5-2

INDICATIVE CAPITAL & ANNUALIZED COSTS

CAPITAL COST ESTIMATE

		$
GEO-SYSTEM SUPPLY & DISPOSAL		
Well costs		1,100,000
Supply and disposal pumps		120,000
Supply and disposal pipelines		350,000
Primary heat exchanger		100,000
Electrical and miscellaneous		25,000
CENTRAL MINE AIR PLANT		
Pumps, piping and tankage		75,000
Air/glycol heat exchanger		50,000
Fan modifications, ducting, dampers		25,000
Electrical, instrumentation and controls		35,000
Building modifications		25,000
HEAT DISTRIBUTION SYSTEM - SITE & PROCESS BLDG.		
Piping		130,000
Make-up air units		200,000
Electrical power supplies		20,000
Building structural modifications		50,000
	Sub-total	2,305,000
Engineering @ 10%		230,000
Contingency allowance @ 15%		380,000
	TOTAL CAPITAL	$2,915,000

ANNUALIZED OWNING & OPERATING COSTS

		$/yr
Fixed	- Annualized capital cost	320,000
	- Operation and maintenance labour	55,000
	- Overheads, taxes, insurance	40,000
Variable	- Pumping costs	60,000
	- Interim replacement	20,000
	- Supplies and miscellaneous	10,000
	TOTAL ANNUALIZED O&O	$505,000
	ANNUALIZED LEVELIZED O&O	$515,000

- pumping power costs at the incremental industrial rate of 4¢/kWh, subject to 2 percent annual real increase, and variable speed pump control; and,

- labour, maintenance and material prices remaining static at zero percent real (i.e. keeping pace with the general inflation rate).

Capital and annualized costs are indicative; they provide an order of cost considered to be suitable for both the Cominco and CCP operations.

5.7 Unit Energy Costs

From the levelized, annualized (i.e. lifetime annual average) costs of Table 5-2 and annual energy delivery of approximately 160,000 GJ/yr (F_g equal to 150 m^3/h), the levelized unit cost of geothermal energy is approximately $3.25/GJ.

Analysis of gas prices, Section 6.0, indicates a 1988 price of $3.90/GJ. With a 2 percent real increase, the levelized unit cost of direct fired gas heating is approximately $5/GJ, or $6.50 to $7/GJ for the indirect case.

Comparing the above lifetime average unit costs of the two energy forms shows the potential for considerable savings, before tax, in favour of geothermal energy. Under the present tax regime the retained savings, after tax, is very much less.

6.0 ECONOMIC ANALYSIS

Preliminary assessments of mine air heating indicated that investment in such projects would yield very favourable financial results, (Acres, 1984). Three potential projects were examined and found to provide internal rates of return on a discounted cash flow basis of between 18 percent and 24 percent in "real" terms.

Since the completion of the preliminary study, further technical feasibility investigations have been conducted and are documented in this report. In addition, various other factors which would influence the financal assessments have been identified. Specifically, two key financial variables requiring further analysis, projected natural gas prices and taxes are addressed in more detail.

6.1 Natural Gas Price Review

Reliable long-term forecasts of energy prices are unfortunately no more available today than they were one year ago. As a result, planning for capital intensive, long-life energy projects remains a risky endeavour. At the present time, negotiations are continuing between the federal and Alberta governments on pricing and revenue sharing agreements. These negotiations are taking place in an environment that is by no means in equilibrium. Partial deregulation of gas prices in the U.S., slack demand in the U.S. and Canada, price distortions caused by transmission arrangements and uncertainties for future oil price trends all contribute to the dilemma.

In the Acres 1984 study, it was assumed that project start-up would be in 1990. Following discussions with Energy, Mines and Resources Canada, a price for natural gas of $6/GJ was used for that year in 1984 dollars. In the past year, natural gas markets have remained weak and as a result, prices have increased less than anticipated in last year's study.

In general, the consensus persists that energy prices in general and natural gas prices specifically will increase. In discussions with personnel at Saskatchewan Energy and Mines, and EMR Canada as well as a review of various energy forecasts by independent experts, there is a belief that the current situation is temporary. Factors and assumptions contributing to this reasoning include:

- the surplus in the U.S. will be absorbed in one or two years;
- world oil prices will firm up as OPEC will not disintegrate and demand will increase;
- the Alberta and federal governments have promoted the objective of increasing the return to producers which means raising wellhead prices;
- the provincial and federal governments are not in a financial position to reduce their revenues from gas and in fact are seeking more revenue;
- producing provinces and the federal government have targetted gas prices for 65 percent of oil prices on an energy equivalent basis;

- over time, the least cost sources of "old" gas will be replaced by more expensive "new" sources; and finally,

- gas is a non-renewable commodity and the forces of scarcity alone will put upward pressure on prices.

Thus, while there are substantial reasons to conclude that gas prices will go up, it remains quite difficult to project the timing of such increases. To add to the uncertainty, there is some sentiment in the country to deregulate gas prices which in the short run, would be expected to reduce gas prices until markets adjust.

For this study, a more conservative approach than that used in the 1984 report is employed. It is assumed that by 1988, gas prices will approach the "65 percent of equivalent oil" prices level. Crude oil currently cost about $40 (Canadian) per barrel which equates to an energy price of about $6/GJ. At 65 percent, gas would then cost $3.90/GJ at the wholesale level. This is the value used in the financial assessments presented here for the project start-up date of 1988. Since the value used in the 1984 report was $6/GJ by 1990, the fuel cost savings assumed in this study are about 33 percent lower, which is obviously a significant reduction in the projected benefits of a mine air heating system.

6.2 Corporate Taxes and PRPA Assessments

The Acres 1984 report assumed an income tax rate of 40 percent for private corporations as this rate represents an average for resource-based industries. However, there is a unique tax regime in place for the potash industry in Saskatchewan. Before any other adjustments, potash producers in Saskatchewan face the same levels of corporate income tax as any other corporation (i.e., 34 percent percent federal, and 16 percent provincial). A variety of resource depletion allowances, tax credits and other allowances tend to reduce these levels in most circumstances. However, for marginal income where such allowances have already been used up, these rates would apply. Royalties or other severance taxes tend to increase the effective tax rate on these companies. In the interest of erring on the side of conservatism, the corporate income tax rate has been increased to 50 percent in this analysis from the 40 percent used in the previous study.

For potash producers in Saskatchewan, however, there is an additional tax assessment imposed under the Potash Resource Payment Agreement (PRPA). PRPA payments are comprised of two components. The first is a base payment assessed on a per ton of potash produced basis. Since this study addresses only the conversion of mine air heating systems, it can be assumed that there will be no change in the rate of production attributable to the geothermal project. Therefore the base portion of the PRPA payment is not relevant to the analysis.

The second portion of the PRPA assessment is based on the level of gross profit earned by the corporation. The rate of this payment is graduated between 0 percent and 50 percent in 10 percent steps. In other words, if gross profit is less than about $6 million, the graduated portion of the PRPA is 0 percent. Gross profits in excess of about $50 million will attract a PRPA graduated payment of 50 percent.

For the base case assessment conducted here, a PRPA level of 20 percent was assumed. According to personnel contacted at some of the potash mines, the 20 percent rate is frequently used for their own internal planning purposes. The actual rate is determined by the overall operations of the mine and is therefore an extraneous variable to the suitability or non-suitability of a mine air heating project. However, since any cost savings resulting from geothermal heating would be incremental net operating income, such savings would be subject to the prevailing level of graduated PRPA payment; it is also possible that some portion of the savings could attract payment at the next higher level of assessment i.e. a level 10 percent greater that that obtaining without the project.

It should be noted that the PRPA is roughly based on net operating income, rather than net taxable income. Therefore, a 20 percent PRPA rate is 20 percent of revenues less operating costs. As a result, the overall tax rate is not simply a matter of 50 percent plus 20 percent but can be up to about 85 percent depending upon the amount of cca's and other allowances used in the calculation of taxable income.

The impact of the PRPA payments is to substantially increase total corporate tax rates. They also introduce an element of uncertainty in projected cash flows associated with particular investment projects, because it is necessary to know what the overall level of profit will be in order to determine the rate of PRPA graduated payments. On average, in profitable years the potash mining companies pay anywhere between 60 percent and 85 percent of their taxable income in taxes. Under these circumstances, it becomes very difficult to justify investment projects from the company's stand point, since the project must generate between \$2.50 and \$4.00 of savings to yield \$1 of after-tax cash benefit to the corporation. There are not many investments which can be expected to produce those kinds of returns.

Twenty percent has been used as the base level of PRPA payment in the financial analysis. The effect of a 50 percent rate, which would be the maximum, and 0 percent, which is the minimum PRPA situation, are also examined.

The present PRPA agreement expires at the end of 1986. Negotiations are underway between the potash mines and the provincial government and while it is assumed that some form of equivalent revenue will be required by the government, the basis for its calculation may be some factor other than gross revenue, which tends to penalize incremental cost saving investment projects.

There is also a possiblity that energy conservation projects, research and development projects and applications of new technology may be exempted from the PRPA plan. Under these conditions, application of geothermal mine air heating would be far more attractive to the corporation since it would be able to retain more of the benefits flowing from the project.

6.3 Financial Model

To indicate the financial viability of geothermal systems for mine air heating, discounted cash flow analysis methods were used to examine two of the potential projects discussed in this study: Cominco, Vanscoy-Delisle and CCP-Colonsay. These were selected since they were also analyzed in the Acres 1984 study and are considered representative of other operations in the Saskatchewan potash potash mining industry. Also, these two examples provide a comparison of a direct fired gas heating system vs. an indirect fired system. The latter is in use at CCP-Colonsay.

In addition to the altered assumptions discussed above with respect to gas prices and taxes, other minor changes have been incorporated in this financial assessment that differ from the previous work. The principal revisions are as follows:

Land Costs - these have been reduced from \$100,000 to \$20,000 on the assumption that the property is already owned by the mine, or all that is required is an easement across other property.

Fuel Cost Savings - as noted above, a value of \$3.90/GJ is used in the direct fired case. For the indirect fired case, a combustion efficiency of 65 percent is assumed, yielding a net gas cost of \$6/GJ (\$3.90/0.65).

Operating and Overhead Costs - based on subsequent analysis, the annual cost of geofluid pumping has been reduced to \$45,000 and an allowance for overhead is now considered unnecessary.

Capital Cost Allowances (cca's) - Class 34 accelerated depreciation provisions for energy conservation equipment expire in 1985. Therefore, conventional cca's at 20 percent per annum are included in this analysis.

Taxes - in accordance with the discussion above, an income tax rate of 50 percent of taxable income is provided and in the base case, a PRPA rate of 20 percent of operating income is included.

Project Start-up - timing for these projects has been brought forward such that construction and development occurs in 1987 and operation commences in 1988.

Other assumptions embodied in the financial model are identical to those utilized in the Acres 1984 study.

6.4 Financial Analysis - Mine Air Heating Only

PRPA of 20 Percent

As would be expected, the combined influence of lower gas prices and sharply higher taxation introduced by the PRPA results in after-tax returns to the mining companies which are much more modest than those found previously. This is reflected in the revised base cash flow analyses for CCP and Cominco, presented in Tables 6-1 and 6-2. Key features of the financial analysis are tabulated overleaf.

As noted, the real returns are 8 and 12 percent respectively as compared to the initial study results that showed returns of 18 percent (Cominco) and 24 percent (CCP).

With the much reduced rates of return it is considered unlikely that the mines would find them sufficient to stimulate implementation of geothermal heating. Though given in real terms (that is, excluding inflation), these rates would probably not be able to meet minimum financial investment hurdle rate criteria. With current corporate

CASH FLOW ANALYSIS - CCP MAH BASE CASE

TABLE 6-1

GEOTHERMAL ENERGY SYSTEM MINE AIR HEATING

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40	
GRADIENT: (DEG. C./KM)	23.5	
SURFACE TEMP.: (DEG. C.)	5	
HOLE DEPTH: (KM)	1.4894	CCP COLONSAY
SYSTEM SUPPLY (TJ/YR):	75.2	INDIRECT FIRED GAS

CASH FLOWS	YEAR 1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
CAPITAL COSTS									(000's 1985 $)										
Land	20																		
Exploration and Drilling	430																		
Above-Ground Equipment	575						50					90					50		
TOTAL CAPITAL COSTS	1025	0	0	0	0	0	50	0	0	0	0	90	0	0	0	0	50	0	0
ANNUAL FUEL COST SAVINGS	0	451.2	460.2	469.4	478.8	488.4	498.2	508.1	518.3	528.7	539.2	550.0	561.0	572.2	583.7	595.3	607.3	619.4	631.8
OPERATING COSTS																			
Exploration Drilling Costs	645																		
Geofluid Pumping		45.0	45.5	45.9	46.4	46.8	47.3	47.8	48.2	48.7	49.2	49.7	50.7	51.7	52.8	53.8	54.9	56.0	57.1
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	44.6	44.9	45.1	45.3	45.5	45.8
TOTAL OPERATING COSTS	645.0	85.0	85.9	86.7	87.6	88.5	89.3	90.2	91.1	92.0	93.0	93.9	95.1	96.3	97.6	98.9	100.2	101.5	102.9
NET OPERATING INCOME	-645.0	366.2	374.4	382.7	391.2	399.9	408.8	417.9	427.2	436.6	446.3	456.1	465.9	475.9	486.1	496.5	507.1	517.9	528.9
CAPITAL COST ALLOWANCES																			
UCC	1025.0	820.0	656.0	524.8	419.8	335.9	318.7	255.0	204.0	163.2	130.5	194.4	155.5	124.4	99.5	79.6	113.7	91.0	72.8
CCA @20%	0	205.0	164.0	131.2	105.0	84.0	67.2	63.7	51.0	40.8	32.6	26.1	38.9	31.1	24.9	19.9	15.9	22.7	18.2
TAXABLE INCOME	-645.0	161.2	210.4	251.5	286.3	316.0	341.7	354.2	376.2	395.8	413.6	430.0	427.0	444.8	461.2	476.6	491.1	495.2	510.7
INCOME TAXES @ 50%	-322.5	80.6	105.2	125.8	143.1	158.0	170.8	177.1	188.1	197.9	206.8	215.0	213.5	222.4	230.6	238.3	245.6	247.6	255.4
PRPA PAYMENT @20%	0.0	73.2	74.9	76.5	78.2	80.0	81.8	83.6	85.4	87.3	89.3	91.2	93.2	95.2	97.2	99.3	101.4	103.6	105.8
NET INCOME	-322.5	7.4	30.3	49.2	64.9	78.0	89.1	93.5	102.7	110.6	117.6	123.8	120.3	127.2	133.4	139.0	144.2	144.0	149.6
NET CASH FLOW (NI+CCA-CC)	-1348	212	194	180	170	162	106	157	154	151	150	60	159	158	158	159	110	167	168

NET PRESENT VALUE	@6%	@9%	@12%	@15%	@18%	@21%
	830	295	-24	-225	-357	-447

CASH FLOW ANALYSIS - COMINCO MAH BASE CASE

TABLE 6-2

GEOTHERMAL ENERGY SYSTEM   MINE AIR HEATING

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40	
GRADIENT: (DEG. C./KM)	23.5	
SURFACE TEMP.: (DEG. C.)	5	
HOLE DEPTH: (KM)	1.4894	VANSCOY DELISLE
SYSTEM SUPPLY (TJ/YR):	86.9	DIRECT FIRED GAS

(000's 1985 $)

CASH FLOWS	YEAR 1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
CAPITAL COSTS																			
Land Easement	20																		
Exploration and Drilling	430																		
Above-Ground Equipment	575						50					90					50		
TOTAL CAPITAL COSTS	1025	0	0	0	0	0	50	0	0	0	0	90	0	0	0	0	50	0	0
ANNUAL FUEL COST SAVINGS	0	338.9	345.7	352.6	359.7	366.8	374.2	381.7	389.3	397.1	405.0	413.1	421.4	429.8	438.4	447.2	456.1	465.3	474.6
OPERATING COSTS																			
Exploration Drilling Costs	645																		
Geofluid Pumping		45.0	45.5	45.9	46.4	46.8	47.3	47.8	48.2	48.7	49.2	49.7	50.7	51.7	52.8	53.8	54.9	56.0	57.1
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	44.6	44.9	45.1	45.3	45.5	45.8
TOTAL OPERATING COSTS	645.0	85.0	85.9	86.7	87.6	88.5	89.3	90.2	91.1	92.0	93.0	93.9	95.1	96.3	97.6	98.9	100.2	101.5	102.9
NET OPERATING INCOME	-645.0	253.9	259.8	265.9	272.1	278.4	284.8	291.4	298.2	305.0	312.1	319.2	326.3	333.5	340.8	348.3	355.9	363.7	371.7
CAPITAL COST ALLOWANCES																			
UCC	1025.0	820.0	656.0	524.8	419.8	335.9	318.7	255.0	204.0	163.2	130.5	194.4	155.5	124.4	99.5	79.6	113.7	91.0	72.8
CCA @20%	0	205.0	164.0	131.2	105.0	84.0	67.2	63.7	51.0	40.8	32.6	26.1	38.9	31.1	24.9	19.9	15.9	22.7	18.2
TAXABLE INCOME	-645.0	48.9	95.8	134.7	167.1	194.4	217.7	227.7	247.2	264.3	279.4	293.1	287.4	302.4	315.9	328.4	340.0	341.0	353.5
INCOME TAXES @ 50%	-322.5	24.5	47.9	67.3	83.6	97.2	108.8	113.8	123.6	132.1	139.7	146.6	143.7	151.2	158.0	164.2	170.0	170.5	176.8
PRPA PAYMENT @20%	0.0	50.8	52.0	53.2	54.4	55.7	57.0	58.3	59.6	61.0	62.4	63.8	65.3	66.7	68.2	69.7	71.2	72.7	74.3
NET INCOME	-322.5	-26.3	-4.0	14.2	29.1	41.5	51.9	55.6	64.0	71.1	77.3	82.7	78.4	84.5	89.8	94.5	98.8	97.8	102.4
NET CASH FLOW (NI+CCA-CC)	-1348	179	160	145	134	126	69	119	115	112	110	19	117	116	115	114	65	120	12[illegible]

NET PRESENT VALUE	@6%	@9%	@12%	@15%	@18%	@21%
	29		-30		[redacted] -53	

	CPP	Cominco
Flow Rate, F_g (m^3/h)	100	100
Annual Energy Supply, Q_g (GJ/yr.)	75,200	86,900
Initial Cost (capital and exploration drilling expenses	1,670,000	1,670,000
Year 1 fuel cost savings	451,000	339,000
Year 1 operating costs	85,000	85,000
10-year average pretax cash flow	410,000	285,000
10-year average after tax cash flow	154,000	117,000
10-year average tax rate	62%	59%
Internal rate of return (real) on after tax cash flow	12%	8%

borrowing rates of about 12 to 14 percent, and inflation running close to 5 percent, a real return of 8 percent after tax is considered the minimum risk-free return necessary to recover invested capital and cover interest charges.

The two projects (mine air heating only) analyzed here just barely meet or exceed the minimum criteria. To be considered viable there would have to be no other better investment opportunities for the mining companies, anywhere. Discussions with financial accounting personnel at the mines indicate this is not the case. Tight money and low after tax margins have forced the companies to postpone a number of attractive capital projects. Only those considered essential to continuing operation, or which provide very short paybacks (measured in months) and exceedingly high rates of return, are currently being approved. Under the assumptions used in the base case analyses, neither of the projects can be viewed in this light.

More than half of the benefits flow to the federal and provincial governments in the form of taxes. This is one of the principle factors limiting viability. Over the first 10 years of project operation, the average tax rate on net operating income (before cca's) is 62 percent for CCP and 59 percent for Cominco. In subsequent years, the effective rates are even greater because the tax shielding effect of cca's is reduced. For example, in Year 15, the taxes are over 80 percent. These tax rates occur with the PRPA graduated payment set at a 20 percent level. Depending on the company's overall level of operating profit, the PRPA assessment could be as high as 50 percent on incremental cost savings. At this PRPA bracket, geothermal projects could never achieve payback on an after-tax basis.

PRPA of 0 Percent

The other extreme for the PRPA is the 0 percent bracket. If this rate applied, the internal return to CCP increases to 19 percent and to 14 percent for Cominco. At these levels, the projects can be considered much more viable.

In general, the PRPA imposes a large degree of uncertainty to the planning of any project investments relating to efficiency improvements or cost savings. To the extent that the PRPA discourages efforts to develop alternative energy sources, another government objective, it conflicts with these public policy objectives.

Summary

As initially indicated by the earlier study results, geothermal mine air heating continues to offer substantial economic benefits, even with lower gas prices. If the future price trend turns out to be greater, the economic returns would also improve in proportion.

In an economic analysis of project viability, one that ignores the distribution of benefits (i.e., transfer payments in the form of taxes), the economic returns provided by these projects are 18 and 22 percent in real terms. Notwithstanding, the tax effects are such that, in order for the companies to launch these projects, they would probably require some form of assistance with capital costs or some reduction in the tax burden that these cost-saving projects would generate.

6.5 Financial Analysis - Process Bldg/Mine Air Heating Schemes

The following addresses the financial analysis of the combined heating system serving the process building and mine ventilation air supplies. The analysis covers only the Cominco case. The CCP results from displacing the indirect gas fired heating MAH system would be even more favourable.

For the increased geothermal flow, incremental increases in both capital and operating costs are incurred. They include:

- $545,000 additional capital cost in the "Above-Ground Equipment" account for larger pumps, extensive heat distribution piping and glycol/air heat exchangers;

- $75,000 additional operating cost for geofluid pumping power and O & M Labour.

In return for these increased costs, the annual energy supplied by geothermal is seen (reference Table 5-1) to increase dramatically from 86.9 TJ/yr (base case, 100 m^3/h) to 169 TJ/yr for the combined heating case (150 m^3/h).

PRPA of 20 Percent

Table 6-3 presents the cash flow print-out for the financial (after-tax) analysis of the combined heating case. Comparing Table 6-3 against 6-2 shows an improvement in first-year annual fuel cost savings of $320,000 resulting from the incremental investment of $545,000. After deducting the somewhat larger O&M expenses, a substantial increase of $245,000 in annual net operating cash flow (before-tax) still remains.

The larger energy cost savings obtained with the combined heating demand presents an attractive economic opportunity with a before-tax return to Cominco above 25 percent. However, on an after-tax basis the internal return is between 11 and 12 percent real.

PRPA of 0 Percent

Table 6-4 illustrates returns of over 18 percent attained with 0 percent PRPA, a situation made possible by either

GEOTHERMAL ENERGY SYSTEM

CASH FLOW ANALYSIS - COMINCO
PROCESS BLDG/MAH CASE (20% PRPA)

TABLE 6-3

COMINCO (VANSCOY DELISLE)

PROCESS BLDG/MINE AIR HEATING

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40.0
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5.0
HOLE DEPTH: (KM)	1.5
FLOW RATE: (CU. M/HR)	150.0
SYSTEM SUPPLY: (TJ/YR)	169.0

CASH FLOWS	YEAR 1987.0	1988.0	1989.0	1990.0	1991.0	1992.0	1993.0	1994.0	1995.0	1996.0	1997.0	1998.0	1999.0	2000.0	2001.0	2002.0	2003.0	2004.0	2005.0	2006.0
CAPITAL COSTS (000's 1985 $)																				
Land Easement	20.0																			
Exploration and Drilling	430.0																			
Above-Ground Equipment	1120.0						100.0					100.0					100.0			
TOTAL CAPITAL COSTS	1570.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0
ANNUAL FUEL COST SAVINGS	0.0	659.1	672.3	685.7	699.4	713.4	727.7	742.3	757.1	772.2	787.7	803.4	819.5	835.9	852.6	869.7	887.1	904.8	922.9	922.9
OPERATING COSTS																				
Exploration Drilling Costs	645.0																			
Geofluid Pumping		100.0	101.0	102.0	103.0	104.0	105.1	106.1	107.1	108.1	109.1	110.1	111.1	112.1	113.1	114.1	115.2	116.2	117.2	118.2
O & M Labour		60.0	60.6	61.2	61.8	62.4	63.1	63.7	64.3	65.0	65.6	66.3	66.9	67.6	68.3	69.0	69.7	70.4	71.1	71.8
TOTAL OPERATING COSTS	645.0	160.0	161.6	163.2	164.8	166.5	168.1	169.8	171.4	173.1	174.7	176.4	178.1	179.7	181.4	183.1	184.8	186.5	188.2	189.9
NET OPERATING INCOME	-645.0	499.1	510.7	522.5	534.6	546.9	559.6	572.5	585.7	599.1	613.0	627.0	641.4	656.2	671.2	686.6	702.3	718.3	734.7	733.0
CAPITAL COST ALLOWANCES																				
UCC	1570.0	1256.0	1004.8	803.8	643.1	514.5	511.6	409.3	327.4	261.9	209.5	267.6	214.1	171.3	137.0	109.6	187.7	150.2	120.1	96.1
CCA @20%	0.0	314.0	251.2	201.0	160.8	128.6	102.9	102.3	81.9	65.5	52.4	41.9	53.5	42.8	34.3	27.4	21.9	37.5	30.0	24.0
TAXABLE INCOME	-645.0	185.1	259.5	321.5	373.8	418.3	456.7	470.2	503.9	533.7	560.6	585.1	587.9	613.3	636.9	659.2	680.4	680.7	704.6	708.9
INCOME TAXES @50%	-322.5	92.6	129.7	160.8	186.9	209.2	228.3	235.1	251.9	266.8	280.3	292.6	294.0	306.7	318.5	329.6	340.2	340.4	352.3	354.5
PRPA PAYMENT @20%	0.0	99.8	102.1	104.5	106.9	109.4	111.9	114.5	117.1	119.8	122.6	125.4	128.3	131.2	134.2	137.3	140.5	143.7	146.9	146.6
NET INCOME	-322.5	-7.3	27.6	56.3	80.0	99.8	116.4	120.6	134.8	147.0	157.7	167.2	165.7	175.4	184.2	192.3	199.7	196.7	205.4	207.9
NET CASH FLOW (NI + CCA - CC)	-1892.5	306.7	278.8	257.2	240.7	228.4	119.3	222.9	216.6	212.5	210.1	109.1	219.2	218.3	218.5	219.7	121.6	234.3	235.4	231.9
NET PRESENT VALUE	at 3 %		at 6%		at 9%	at 11%	at 12%		at 15%		at 18%		at 21%							
	2249.5		1088.2		384.3	62.5	-68.4		-375.7		-594.5		-757.0							

CASH FLOW ANALYSIS - COMINCO
PROCESS BLDG/MAH CASE (0% PRPA)

TABLE 6-4

GEOTHERMAL ENERGY SYSTEM

COMINCO (VANSCOY BELISLE)

PROCESS BLDG/MINE AIR HEATING

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40.0
GRADIENT: (DEG. C./KM)	23.5
SURFACE TEMP.: (DEG. C.)	5.0
HOLE DEPTH: (KM)	1.5
FLOW RATE: (CU. M/HR)	150.0
SYSTEM SUPPLY: (TJ/YR)	169.0

CASH FLOWS	YEAR 1987.0	1988.0	1989.0	1990.0	1991.0	1992.0	1993.0	1994.0	1995.0	1996.0
CAPITAL COSTS (000's 1985 $)										
Land Easement	20.0									
Exploration and Drilling	430.0									
Above-Ground Equipment	1120.0						100.0			
TOTAL CAPITAL COSTS	1570.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0
ANNUAL FUEL COST SAVINGS	0.0	659.1	672.3	685.7	699.4	713.4	727.7	742.3	757.1	772.2
OPERATING COSTS										
Exploration Drilling Costs	645.0									
Geofluid Pumping		100.0	101.0	102.0	103.0	104.0	105.1	106.1	107.1	108.1
O & M Labour		60.0	60.6	61.2	61.8	62.4	63.1	63.7	64.3	65.0
TOTAL OPERATING COSTS	645.0	160.0	161.6	163.2	164.8	166.5	168.1	169.8	171.4	173.1
NET OPERATING INCOME	-645.0	499.1	510.7	522.5	534.6	546.9	559.6	572.5	585.7	599.1
CAPITAL COST ALLOWANCES										
UCC	1570.0	1256.0	1004.8	803.8	643.1	514.5	511.6	409.3	327.4	261.9
CCA @20%	0.0	314.0	251.2	201.0	160.8	128.6	102.9	102.3	81.9	65.5
TAXABLE INCOME	-645.0	185.1	259.5	321.5	373.8	418.3	456.7	470.2	503.9	533.7
INCOME TAXES @50%	-322.5	92.6	129.7	160.8	186.9	209.2	228.3	235.1	251.9	266.8
PRPA PAYMENT @20%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET INCOME	-322.5	92.6	129.7	160.8	186.9	209.2	228.3	235.1	251.9	266.8
NET CASH FLOW (NI + CCA - CC)	-1892.5	406.6	380.9	361.7	347.7	337.8	231.2	337.4	333.8	332.3

CASH FLOWS	1997.0	1998.0	1999.0	2000.0	2001.0	2002.0	2003.0	2004.0	2005.0	2006.0
CAPITAL COSTS (000's 1985 $)										
Land Easement										
Exploration and Drilling										
Above-Ground Equipment		100.0					100.0			
TOTAL CAPITAL COSTS	0.0	100.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0
ANNUAL FUEL COST SAVINGS	787.7	803.4	819.5	835.9	852.6	869.7	887.1	904.8	922.9	922.9
OPERATING COSTS										
Exploration Drilling Costs										
Geofluid Pumping	109.1	110.1	111.1	112.1	113.1	114.1	115.2	116.2	117.2	118.2
O & M Labour	65.6	66.3	66.9	67.6	68.3	69.0	69.7	70.4	71.1	71.8
TOTAL OPERATING COSTS	174.7	176.4	178.1	179.7	181.4	183.1	184.8	186.5	188.2	189.9
NET OPERATING INCOME	613.0	627.0	641.4	656.2	671.2	686.6	702.3	718.3	734.7	733.0
CAPITAL COST ALLOWANCES										
UCC	209.5	267.6	214.1	171.3	137.0	109.6	187.7	150.2	120.1	96.1
CCA @20%	52.4	41.9	53.5	42.8	34.3	27.4	21.9	37.5	30.0	24.0
TAXABLE INCOME	560.6	585.1	587.9	613.3	636.9	659.2	680.4	680.7	704.6	708.9
INCOME TAXES @50%	280.3	292.6	294.0	306.7	318.5	329.6	340.2	340.4	352.3	354.5
PRPA PAYMENT @20%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET INCOME	280.3	292.6	294.0	306.7	318.5	329.6	340.2	340.4	352.3	354.5
NET CASH FLOW (NI + CCA - CC)	332.7	234.5	347.5	349.5	352.7	357.0	262.1	377.9	382.4	378.5

NET PRESENT VALUE

at 3 %	at 6%	at 9%	at 12%	at 15%	at 18%	at 19%	at 21%
4685.4	2764.3	1688.5	871.7	376.5	27.3	-66.6	-229.3

the expiry of, or exemption from, the PRPA (reference, Section 6.2).

In summary, the gain in real returns is sufficient to justify incorporation of processing building air heating with geothermal mine air heating. Based on this analysis the combined heating approach should be pursued.

6.6 Improvements from Co-use of Brine Disposal Well

There appears to be a practical possibility to co-utilize existing process brine disposal wells for geo-fluid disposal. It could involve increasing the present pumping capacity and/or adjusting existing process brine disposal operations to even out short duration surges in disposal demand.

Avoiding the need for a geo-fluid brine disposal well potentially reduces capital costs by some $400,000. For the base cases (MAH only) analysed herein, CCP internal after-tax returns increase from the 12 percent (Table 6-1) to 15 percent.

For Cominco the real return increases to 11 percent, up from 8. This three percentage point improvement would be somewhat less in the combined heating case. It is nevertheless a possibility to be considered during future analysis.

7.0 CONCLUSIONS & RECOMMENDATIONS

7.1 Conclusions

Geothermal energy thrives in situations demanding large and steady loads. In general, the more energy that is used the lower the cost. Heat recovery tends to diminish the opportunity to fully exploit the output of a geothermal supply. In the process, this can result in the loss of substantially greater cost savings overall and the less productive use of the investment dollar.

Concerning waste heat recovery opportunities, the main options include recapture from mine exhaust air and recapture from the process dryer exhaust. Both are considered to be difficult to implement due to the cost and complexity of the retrofit operations and suspected fouling problems that could cause operating difficulties and disruption of the process. For these reasons it is concluded that implementation of heat recovery is unlikely.

Pursuing this theme, the combining of process building and mine air heating usefully improves the base load of the geothermal system and the annual energy delivered with advantages that include reduced unit energy costs and enhanced returns. The following tabulation, summarizing the results of the financial analyses, shows the 3 to 4 percentage point improvement obtained from incorporating process building heating with the mine air duty.

Real Rate of Return (%)

Geothermal Heating System

	Cominco	CPP
Mine Air Heating (100 m^3/h) - 20% PRPA	8	12
Mine Air Heating (100 m^3/h) - 0% PRPA	14	19
Process Bldg/Mine Air Heating (150 m^3/h) - 20% PRPA	11.5	15
Process Bldg/Mine Air Heating (150 m^3/h) - 0% PRPA	18	22

The Cominco case is representative of mines which directly fire natural gas for mine air heating. The improved returns for CCP (indirect gas fired MAH), from inclusion of process building heating, are estimated.

The adverse impact of the PRPA tax is evident, reducing returns by 5 to 6 percentage points. The possibility that the PRPA will be replaced in 1986 with a substitute form, more conducive to incremental investments in cost saving measures, clearly is beneficial to geothermal prospects at the mines. Certainly, real returns of 14 to 18 percent, in the region of 20 percent actual, should be sufficient to stimulate some interest in further exploration of the potential, either for mine air heating alone or combined with process building heating.

Capital assistance through the ENERDEMO program of EMR, Canada, is also a possiblity. From recent work(2) and from discussions with the Saskatchewan branch of EMR (L. Epp, personal communications) there is a possibility of eligibility for ENERDEMO funding assistance: an amount of

$250,000 might be a reasonable estimate of the order of assistance available. Nevertheless, at the present time, there is evidence of some shifting in government priorities and programs, indicating a more selective encouragement of specific alternative energy and energy conservation applications. The situation needs to settle before attempts are made to identify the level of government assistance for mine heating and other geothermal applications.

Concluding, this study shows that geothermal heating continues to offer a practical, technically straightforward, and financially favourable means for reducing energy costs at the potash mines. Including the preheating of process dryer air, through the heating of process building ventilation air, is an economically useful and attractive addition to the mine air heating duty.

7.2 Recommendations

The PRPA has contributed substantially to creating a very pessimistic investment climate in the Saskatchewan Potash industry. Until such time as the PRPA is removed and replaced with a less regressive form of tax, the industry's interest in pursuing geothermal (or any other "non-mandatory" investment for that matter) appears to be slight.

It is recommended that:

- the industry be appraised of the further practical and economic potential for geothermal heating at the mines through distribution of the study report;

- the proposed retirement of the PRPA in 1986 be monitored and the alternative resource tax legislation examined when such becomes available;

- at that time, the economic/financial aspects of this study should be re-worked to identify the impact of any new resource tax legislation, the analysis to also address federal funding assistance benefits available and the possible co-useage of brine disposal wells.

Without the benefit of the companion study into the below-ground aspects of the geothermal resource, knowledge of resource conditions rests on broad, regionally-based, interpretation of data(1) . Pump power requirements are dependent on a number of resource-related factors including the hydrostatic level of the Winnipeg/Deadwood formation. Information enabling power requirements to be clarified would be most helpful. It is suggested that the postponed resource study be commissioned for this purpose.

REFERENCES

REFERENCES

1. Study of Mine Air Heating with Geothermal Energy, Acres, 1984. National Research Council, Ottawa.

2. Moose Jaw Geothermal Study, Acres, 1985. Energy Mines and Resources, Ottawa.

APPENDIX A

MARITIME POTASH MINE SURVEY, RESOURCE APPRAISAL AND GEOTHERMAL MINE AIR HEATING POTENTIAL

1.0 INTRODUCTION

There are presently three potash developments within the structural feature known as the Moncton Sub-basin (Figure 1). The Potash Corporation of America at Sussex is the only current producer. Denison-Potacan Potash Company at Salt Springs plan production for mid-1985, and BP Resources Canada Limited are undertaking feasibility studies at Millstream.

A brief survey of mine air heating factors at the three mines was undertaken. The results of the survey are included at the end of this appendix.

2.0 GEOTHERMAL RESOURCE OVERVIEW

Potential Source Rocks

The potential source rocks are Lower Carboniferous clastic sedimentary sequences underlying the Carboniferous Windsor Group evaporites which host the potash deposits. As the potash exploration and development drilling was essentially limited to the evaporite sequence, little is known of the local character of these rocks. The operators' only substantial interest in the underlying rocks were troublesome aquifers should these rocks be penetrated. Local interpretations must be derived by extrapolation of regional descriptions. Consequently, discussion is limited to groups of rocks rather than individual favorable stratum.

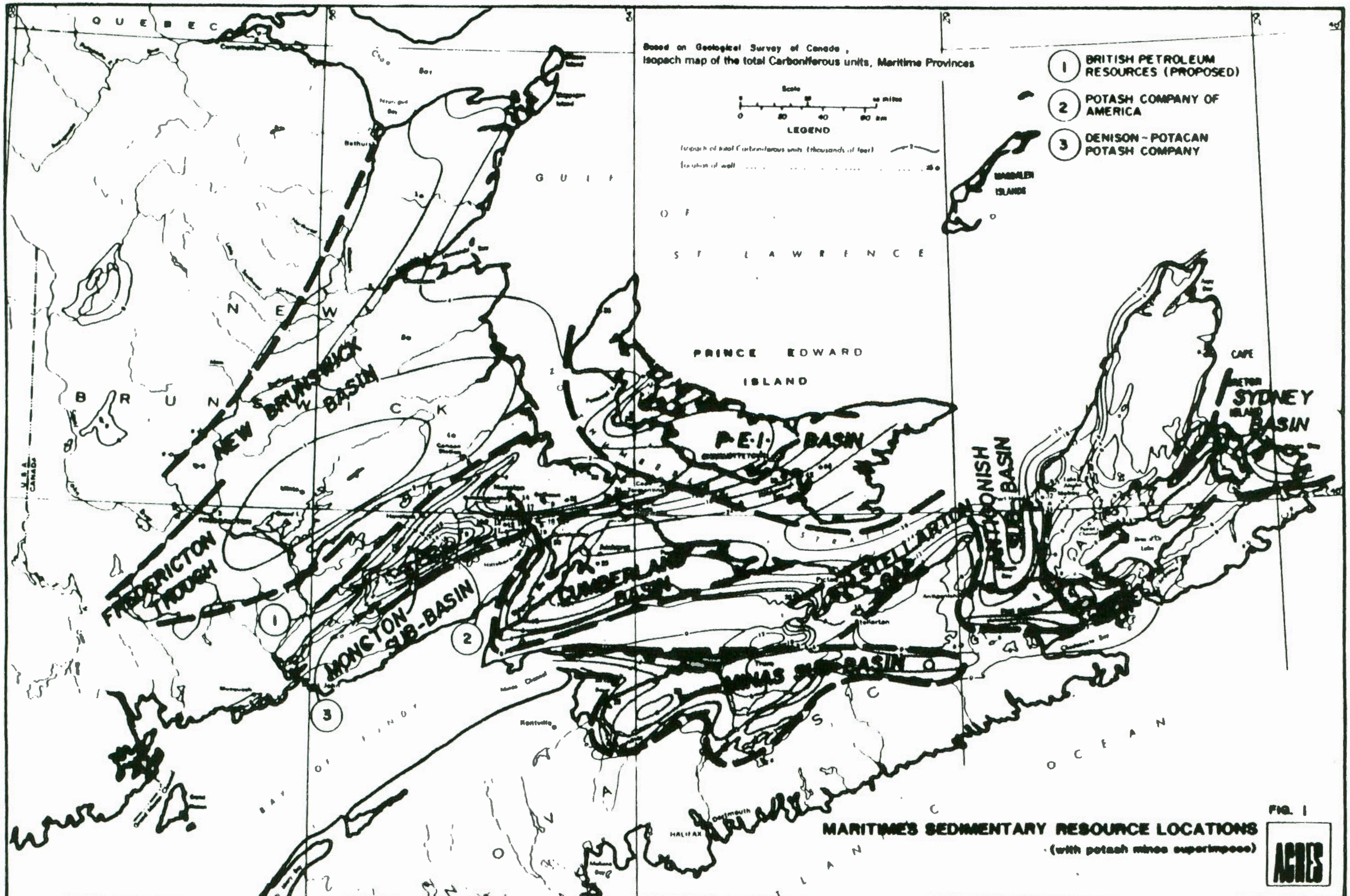

FIG. 1

MARITIMES SEDIMENTARY RESOURCE LOCATIONS

(with potash mines superimposed)

ACRES

The Moncton and Horton groups of rocks of Carboniferous age are considered potential source rocks. The following descriptions are summarized from Gussow (1953).

The Moncton Group is comprised of a sequence of red mud-stone, shale and siltstone with local basal conglomerate which is overlain by a sequence of coarse red sandstone, grit and conglomerate and minor shale. The thickness of this group increase northward across the Moncton Sub-basin. At Upham, two kilometres south of the Denison-Potacan deposit, it is only about 100 metres thick. A thickness of about 460 metres has been estimated in an area a few kilometres to the northeast. Elsewhere within the sub-basin, 1,800 to 2,100 metres is indicated as a maximum thickness.

The basal Horton Group consists of a sequence of sandstone and conglomerate overlain by shale. The sandstone and shale sequence ranges from 120 metres in the southwest part of the sub-basin to more than 2,100 metres in the northeast part. The shale unit has a thickness of 150 metres in an area about four kilometres south of the Potash Coporation of America deposit at Sussex. It is more than 760 metres thick at a distance of 25 kilometres to the northeast.

There are no available data on the porosity and permeability of the potential source rocks in the areas of interest. Data concerning potential aquifers, extraction flow rate potential, water chemistry, natural piezometric levels, and so on, are also not available.

Basin Features

The potash deposits are confined to broadly folded basin-like features within the larger, fault-bounded Moncton Sub-basin. The accompanying regional isopach map (Figure 1) and geophysical and drilling data sited by Andele et al (1978) suggests depths in excess of 1,800 metres for these features.

Thermal Data

Although all the potash interests have apparently collected thermal data, none are publicly available. A published temperature log from a classified location within the area indicates a thermal gradient of eight degrees centigrade per kilometre.

Temperature data cited in the accompanying questionnaires and obtained from discussion with company personnel indicate thermal gradients ranging from 10 to 22 degrees centigrade per kilometre. There are indications that the thermal gradient may differ within each potash area as well as from area to area. This variance may, in part, be attributed to a "chimney effect". Salt-bearing structures often have abnormally high thermal gradients within and above the salt with abnormally lower thermal gradients in adjacent areas.

Assessment

Lack of pertinent thermal and rock property data precludes a detailed evaluation of this resource. Consequently, such data would have to be collected particularly should financial and engineering considerations indicate practicability. Access to existing data compiled by the potash companies may help to meet this requirements and would reduce the cost of a full and complete assessment.

3.0 ASSESSMENT OF GEOTHERMAL MINE AIR HEATING POTENTIAL

There are a number of factors which indicate geothermal heating at the New Brunswick mines to have a very much reduced potential, in both practical and economic terms, compared to those in Saskatchewan.

Firstly, the geothermal gradient in the Moncton Basin is lower, with a previous study[a] indicating a range of 11 to 18°C/km. The depth to the expected sedimentary resource level is greater, possibly exceeding 2000 m. Accordingly, with development costs for wells increasing exponentially with depth, the costs to exploit such a resource will be considerably greater.

Secondly, winter outdoor air temperatures are less extreme in New Brunswick and, also, the temperature of ventilation air delivered to the mining areas is lower (i.e. 0 to 2°C as compared to 10 to 24°C). Both these combine to significantly lower the peak heating load demand, the duration of the heating season, and the annual energy consumption.

(a) Survey of Geothermal Energy in the Maritime Provinces, Acres 1984; National Research Council

Thirdly, resulting from the first two, the more expensive geothermal heating source would be under-utilized, resulting in higher unit energy costs.

Compensating for the above adverse factors to some degree is the higher cost of conventional energy (propane vs. natural gas) and the absence of a PRPA type tax.

It is provisionally concluded that the potential for economic exploitation of geothermal resources for mine air heating is poor at this time. In addition to the factors mentioned above, the limited knowledge regarding the existence, boundaries and properties of the New Brunswick geothermal resources must be regarded as a considerable constraint, affecting the promotion and encouragement of geothermal energy use in the area.

The potash mine operations may be almost the only ones to have penetrated to the present evaporite depths in the Moncton Basin. There may be some merit in establishing a liaison with the companies to obtain data of interest to the geothermal resource identification program. BP Resources is currently at the investigation and exploration stage which suggests the opportunity for a useful co-operative venture.

BP Resources Canada Limited , via telephone from Keith Crosby, geologist

MINE VENTILATION QUESTIONNAIRE

Mine Production Rate (KCL)

- Present (tonnes/yr) Feasibility stage
- Projected (tonnes/yr) 1,200,000 in 1993

Design Ventilation Rate

- Present (cfm)
- Projected (cfm) 500,000

Ventilation Air Temp

- supply air (in) °C 0 to 27°C
- discharge air (out) °C 18 to 24°C

Ventilation Air Heating

- fuel (propane/oil/other)
- current fuel cost ($/unit)
- heating method (steam/hot water/direct combustion)

Depth to Mining Level (m)

840 to 1,050 m

Temperature at Mining Level (°C)

21 to 25°C

Process Brine Disposal

- injection rate (Igpm)
- injection temperature (°C)

Brine pipeline to the Bay of Fundy

Energy Conservation/Recovery Devices at Mine

(Please tick as applicable)

None considered to date

__ ~~ventilation air~~ heat recovery from discharge

__ product dryer exhaust heat recovery by dryer intake air

__ brine waste stream recovery to process make-up water

__ other (please specify e.g., recovery by product cooling, recrystalizer stream, etc.)

DENISON – POTACAN

MINE VENTILATION
QUESTIONNAIRE

Mine Production Rate (KCL)

- Present (tonnes/yr) NIL
- Projected (tonnes/yr) 3,492,000

Design Ventilation Rate

- Present (cfm) 50,000
- Projected (cfm) 250,000 to 500,000

Ventilation Air Temp

- supply air (in) °C +2°C Winter to +29°C Summer
- discharge air (out) °C +22°C Winter to +26° C Summer

Ventilation Air Heating

- fuel (propane/oil/other) Propane
- current fuel cost ($/unit) $20,000/month (Winter)
- heating method (steam/hot water/direct combustion)

Depth to Mining Level (m)

800 m

Temperature at Mining Level (°C)

22°C

Process Brine Disposal

- injection rate (Igpm) Pipeline to Bay of Fundy
- injection temperature (°C) +2°C (Winter) to + 18°C (Summer)

Energy Conservation/Recovery Devices at Mine

(Please tick as applicable)

__ ventilation air heat recovery from discharge

X product dryer exhaust heat recovery by dryer intake air

__ brine waste stream recovery to process make-up water

__ other (please specify e.g., recovery by product cooling, recrystalizer stream, etc.)

Response By: A.G. Speed
Date: Feb. 24, 1985

Potash Corp. of America, via telephone from Mr. N. Brown, Mine Superintendent

MINE VENTILATION QUESTIONNAIRE

Mine Production Rate (KCL)

- Present (tonnes/yr) Fluctuating at present
- Projected (tonnes/yr) 700,000

Design Ventilation Rate

- Present (cfm) 200,000
- Projected (cfm) 250,000

Ventilation Air Temp (Winter heating)

- supply air (in) °C Winter air, temperature not available
- discharge air (out) °C 60°F (15.5°C)

Ventilation Air Heating

- fuel (propane/oil/other)
- current fuel cost ($/unit) Not available
- heating method (steam/hot water/direct combustion)

Depth to Mining Level (m) 1,900 ft. (580 m)

Temperature at Mining Level (°C) 65°F (18.3°C)

Process Brine Disposal

- injection rate (Igpm) No disposal system
- injection temperature (°C) Evaporation used

Energy Conservation/Recovery Devices at Mine

(Please tick as applicable)

__ ventilation air heat recovery from discharge

X product dryer exhaust heat recovery by dryer intake air (in mill)

X brine waste stream recovery to process make-up water (from evaporation system)

__ other (please specify e.g., recovery by product cooling, recrystalizer stream, etc.)

APPENDIX B

SOUTH SASKATCHEWAN GEOTHERMAL SYSTEMS:
WATER CHEMISTRY, CORROSION AND MATERIALS SELECTION

J. Postlethwaite,
Interprovincial Corrosion Consultants Ltd.

CONTENTS

March 1985

1. INTRODUCTION

Corrosion in the form of pitting, stress corrosion cracking, and hydrogen blistering is a major problem in the geothermal industry [Ref 1]. In liquid dominated systems such as the ones under discussion here, the hot water is often a brine with high chloride concentrations. Such brines can be very corrosive especially if they contain small amounts of dissolved hydrogen sulphide or oxygen. Hydrogen sulphide causes pitting [Ref 2] sulphide stress cracking (SSC) and hydrogen blistering [Ref 3]. Contamination of the brine with oxygen above ground by leakage through valve stems and at pumps during operation [Ref 1] and during shut down periods can lead to severe pitting corrosion [Ref 4]. Oxygen contamination in brines containing H_2S can result in drastic increases in corrosion rates by as much as two orders of magnitude [Ref 16]. The pH of these brines is usually on the acid side of neutrality.

The acidic pH relates to the partial pressure of dissolved carbon dioxide. A release of the pressure on the liquid at the wellhead can cause a rise in pH by as much as two units to less corrosive values. Unfortunately this rise in pH can cause the deposition of calcium carbonate scale on the walls of the pipes and heat exchangers and a liquid dominated system used for heating should be maintained under pressure and not flashed [Ref 1].

This corrosion engineering evaluation deals with the water chemistry; the impact of this chemistry on the corrosion of candidate construction materials; and the provisional selection of suitable materials of construction. Consideration is given to water taken from various formations within the three gross lithological divisions [Ref 5]: an Upper Clastic Unit (1000m) of shale and sandstone with minor limestone and anhydrite in the lower part; a Carbonate Evaporite Unit (1000m) of dolomite, limestone, salt (halite and potassium salts) and anhydride; and a Basal Clastic Unit (200m) of sandstone and shale.

2. WATER CHEMISTRY

The specific formations involved are listed below; along with the projected temperature and total dissolved solids for the Moose Jaw area which is one potential site for a future geothermal project.

Table 1. Water Sources

	Formation	Depth/m	Temp/°C	TDS/ppm
Upper Clastic	Mannville	855	35	10,000
	Gravelbourg-Sandstone	1,009	38	15,000
Carbonate Evaporite	Souris Valley	1,115	42	20,000
	Birdbear	1,320	45	35,000
Lower Clastic	Winnipeg/Deadwood	2,100	65	180,000

The projected analyses of these waters, Table 2, were prepared using the analyses assembled by Vigrass [Ref 6] taking into account the fact that,

> 'the waters from below the 650 m depth are sodium chloride waters of the Williston Basin type. Total dissolved solids are said to be determined largely by the sodium and chloride content, and the remaining ionic composition (calcium, magnesium, bicarbonate, sulphate) is remarkably constant.' [Ref 5].

The latter statement is supported by the accompanying Stiff diagrams [Fig 1] of subsurface water in the Regina-Moose Jaw area [Ref 5]. It should be emphasised that the analyses are for use only as a guideline for identifying potential corrosion problems and for preliminary materials selection purposes.

The major uncertainties in the projected water compositions are:

i) the dissolved H_2S content of the brines from the formations above the Winnipeg/Deadwood

ii) the dissolved oxygen content

iii) the pH

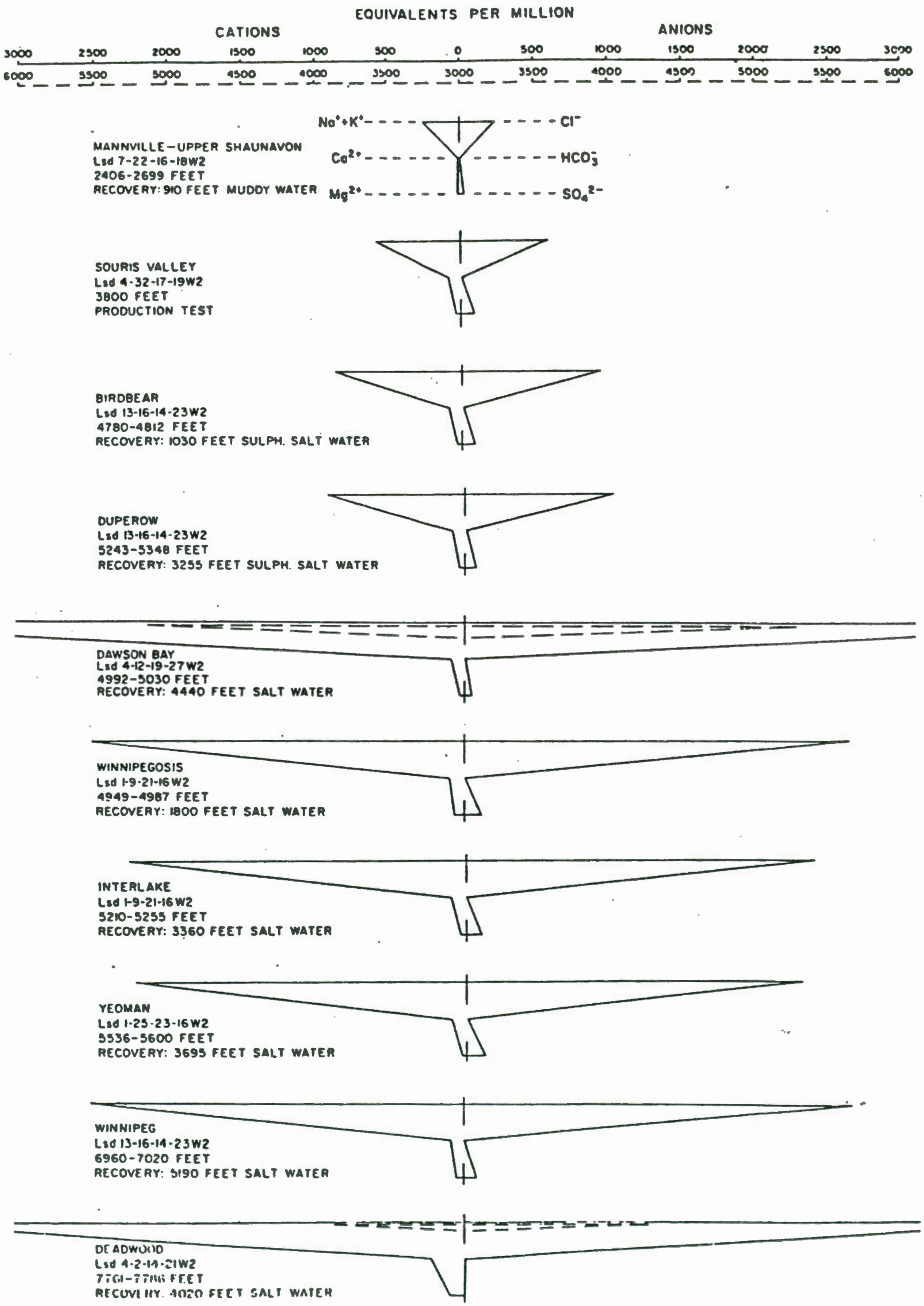

Fig 1. **Representative Stiff diagrams of subsurface waters in the Regina - Moose Jaw area.** [Ref 5]

Table 2. Projected Water Analyses - Moose Jaw.

FORMATION	TDS/ppm	CATIONS/ppm			ANIONS/ppm			H_2S ppm	O_2 ppm	pH
		$Na^+ + K^+$	Ca^{++}	Mg^{++}	Cl^-	HCO_3^-	$SO_4^=$			
MANNVILLE	10,000	2,927	401	255	4,806	122	1,488	NR*	NR	5.5-6.5
GRAVELBOURG	15,000	2,933	1,684	610	6,792	244	2,785	NR	NR	5.5-6.5
SOURIS VALLEY	20,000	4,600	1,805	547	8,722	244	4,083	NR	NR	5.5-6.5
BIRDBEAR	35,000	10,189	2,005	608	17,872	244	4,083	many reported sulphurous		5.5-6.5
WINNIPEG/ DEADWOOD	180,000	66,800	1,940	360	105,509	400	4,100	24	1.0	5.3**

* None reported
** This is an accurate well head value of the unflashed fluid. The fluid produced ca 2% gas when flashed [Ref 7]. Other values are corrected laboratory values for flashed fluid.

The dissolved H_2S content in the Winnipeg/Deadwood water was determined on-site at the Regina well [Ref 7] and the value is considered reliable.

The waters from the Carbonate-Evaporite Unit may all contain some H_2S since this Unit contains little iron which converts H_2S to pyrites, as is the case in the Upper-Clastic Unit. Many of the waters from the Birdbear formation have been reported [Ref 6] to be sulphurous indicating the presence of H_2S. The Souris Valley, which is at the top of the carbonate-evaporite zone, is the least likely of the formations in this zone to contain H_2S and indeed there are no reports [Ref 6] of waters from this formation containing H_2S. However the presence of traces of H_2S in these waters must be regarded as a possibility. The Gravelbourg and Mannville waters are unlikely to contain H_2S since these formations are in the Upper-Clastic unit which contains iron.

The reported presence of 0.9 - 1.2 ppm of dissolved oxygen [Ref 7] in the water from the Winnipeg/Deadwood formation is a contentious issue. Given sufficient time to react oxygen and hydrogen sulphide cannot co-exist in a brine and it is commonly assumed that freshly produced brines containing H_2S are free of O_2 [Ref 1,3,8]. They may of course be contaminated above ground by inleakage at valve stems and pumps. The reaction between dissolved O_2 and H_2S is slow [Ref 8] and it is conceivable that the co-existence could be attributed to waters being produced from different formations which were vertically separated by permeable or semi-permeable barriers [Ref 7]. The presence of oxygen at upper levels is more likely where there is little chance of H_2S as for example in the Mannville and Gravelbourg formations. Measurements of dissolved oxygen in these waters have not been reported. Syrett et al did consider that the Nowlin No 1 Heber, California [Ref 9] wellhead brine may naturally contain some oxygen as well as H_2S on the basis of the non-condensable gas composition, but did go on to suggest contamination as a source of this gas. Other geothermal waters contain dissolved oxygen [Ref 1] but this either occurs in the absence of H_2S or there are uncertainties about whether the oxygen relates to contamination at the well head.

The pH of the Regina water [Ref 7] from the Winnipeg/Deadwood formation was 5.3 prior to flashing after which it rose to 6.6. Such a rise is expected when brines containing carbon dioxide species are flashed. The projected values in Table 2 are the laboratory values with an approximate correction to allow for this change.

3. POTENTIAL CORROSION AND SCALING BEHAVIOUR

3.1 Corrosion

Hot brines are corrosive. The corrosion rate of carbon steel increases with a rise in the chloride concentration and temperature [Ref 1]. Such laboratory data should be treated with caution as it often does not permit sufficient time for protective scales to develop which eventually slow down the early rapid corrosion rate. And much of the data used to discuss brine corrosion is laboratory data. The present brines increase in chlorinity and temperature with increasing well depth and it can be assumed that higher uniform corrosion rates of carbon steel would obtain the deeper the well.

There is a rapid rise in the corrosion rate as the pH is reduced below 5 in solutions containing CO_2 [Ref 10]. The present brines are at the worst just above this value at 5.3. The presence of the CO_2 will undoubtably increase the uniform corrosion rate, but not to an unacceptable value at the temperatures involved in the present study.

The presence of H_2S will increase the uniform corrosion rate but more importantly may give rise to severe pitting, [Ref 1,2,3], sulphide-stress corrosion cracking (SSC) [Ref 1,3] and hydrogen blistering [Ref 1,3]. The concentration of H_2S required to crack high strength carbon steels is as low as 0.1 ppm, with a less chance of attack at temperatures above 66°C [Ref 3] which is coincidently the high temperature expected in the present waters. Fortunately sulphide stress cracking and hydrogen blistering can be controlled by the use of low strength metallurgically clean and void free steel [Ref 1].

The combination of hydrogen sulphide and carbon dioxide is more aggressive than hydrogen sulphide alone in terms of pitting corrosion and the presence of even minute quantities of oxygen have been stated to be disastrous [Ref 3].

The presence of oxygen would lead to severe pitting of carbon steel, stainless steels and other alloys by the produced brine [Ref 1]. Conventional wisdom in the oil industry is that 'water produced with oil, even when fresh, seldom contains dissolved oxygen' and 'that oxygen corrosion found in downhole equipment is usually caused by careless operating techniques or faulty equipment' [Ref 3]. Similarly in the geothermal industry, oxygen contamination by inleakage is considered to be the source of the severe oxygen corrosion that sometimes occurs [Ref 1,4]. Oxygen corrosion occurs in secondary oil recovery and cannot normally economically controlled by the inhibitors usually applied in primary oil production [Ref 11]. Inorganic inhibitors used in aerated water are too expensive and the concentrations of filming amine are similarly uneconomic and internally coated steel pipe is usually required to handle these brines. Oil of course is a high value product and as discussed later any inhibition with geothermal brines is much more relatively expensive.

The other constituent of the brine which may cause a corrosion problem is sulphate. Sulphate ions are less aggressive than chloride ions and by themselves do not constitute a problem. However in anaerobic conditions they can be reduced to H_2S by sulphate reducing bacteria which process leads to rapid pitting corrosion of steel. This for example is a common form of corrosion of buried water mains in heavy clay soil containing gypsum, and is also a problem in oil wells [Ref 12].

The waters from the Mannville and Gravelbourg formations, which are in the Upper Clastic Unit, would be the least corrosive. They have the lowest temperatures and salinities and are unlikely to contain any H_2S.

The water from the Souris Valley formation is predicted to be the next least corrosive with a somewhat higher temperature and salinity and no reported H_2S. As mentioned above however the presence of H_2S cannot be entirely discounted in water from this formation.

The water from the Birdbear formation is likely to contain H_2S and will be more corrosive. The most corrosive water will be that from the Winnipeg/ Deadwood formation, which contains H_2S as well as having the highest temperature and salinity.

3.2 Scaling

Scaling could interfere with the flow of the fluid and the heat transfer in the plate heat exchanger. The scales that could form on the pipe and other equipment are;

calcium carbonate,
calcium sulphate or
silica.

The solubility of calcium carbonate decreases with a rise in pH and decreases with a rise in temperature. Thus providing that the geothermal fluid is maintained under pressure and the pH not allowed to rise calcium carbonate scaling is unlikely. Calcium carbonate scaling is a problem in heat exchangers where the water is a coolant and undergoes a rise in temperature and not a drop as in this case.

Calcium sulphate has a higher solubility than calcium carbonate and similarly the solubility increases as the temperature decreases and calcium sulphate scaling is unlikely with the present brines. The solubility of calcium sulphate is not sensitive to pH changes in the pH range of geothermal fluids [Ref 1].

The solubility of silica increases with temperature, however it is considered that silica scaling should not be a major problem for resources with reservoir temperatures less than approximately 150°C provided no flashing occurs [Ref 1].

4. MATERIALS SELECTION

This provisional materials selection takes into account; the previous operating experience of geothermal systems [Ref 1]; the experience of the oil industry in handling brines during primary and secondary production [Ref 3,11,12] and brine disposal by reinjection [Ref 8].

Mechanical and thermal properties and the cost of corrosion resistant materials have been considered along with the projected costs of corrosion protection by inhibition and cathodic protection.

The geothermal system components considered are:-

- production well
- production pump
- piping, pre and post injection pump
- heat exchanger
- reinjection pump
- injection well

4.1 Production Well

Sour service API - J55 or similar low strength casing which is resistant to SSC is the recommended metallic material of construction for the production well casing. This mild steel has performed satisfactorily in sour brine geothermal service and is included in the NACE Standard for SSC resistant metallic material for oil field equipment [Ref 13] for tubing and casing for all temperatures. API J55 178 mm 8 mm thick casing would cost approximately $36.37/m FOB Moose Jaw.

Protection of the outside of the casing would require the application of an impressed cathodic protection system similar to that used for many oil well casings [Ref 3]. The ground around a well is sometimes saturated with brine left over from the initial drilling operations and the resulting soil may be very corrosive. Such a system has been installed at the U. of R. well [Ref 14]. Geothermal well casings at Wairakei have suffered severe external corrosion near the surface where they have been in contact with aerated ground water [Ref 1]. Multiple casings with careful cementing were used to solve this problem. Such multiple casings would not be required if an external cathodic protection system were in place. The cost of the cathodic protection system would be \$15 - 25,000. This system could protect both wells.

The inside of the casing could be inhibited with weighted filming amine inhibitors [Ref 12]. The chemicals for an intermittent treatment on a monthly basis would cost \$50 - 100/month depending on the well depth and casing size.

An alternative to using a metallic well casing would be to use fibre-glass-reinforced plastic (FRP) casing. One geothermal well in France with water temperatures of 60°C is a known to have such casing [Ref 15]. One problem with FRP casing is making sufficiently strong joints to join the sections together when casing deep wells. One standard FRP pipe system is said to be good for 1,000 m. Casing 203 mm OD, 11 mm thick sufficient to withstand the external collapse pressure during cementing would cost \$150/m for the material. The cementing would have to be done in 300 m stages to avoid collapse. At the present time there does not seem to be a wealth of knowledge regarding the use of FRP well casing in the oil-industry and the recent materials selection guidelines for geothermal systems [Ref 1] does not include a single case of its use for casing. Extra casing with steel near the surface would protect the FRP from mechanical abuse. FRP is a brittle material. FRP with a vinyl ester resin would probably have the best combination of corrosion resistance and mechanical properties.

The FRP would be the most suitable from the corrosion standpoint for the deepest well where the most H_2S will be found. However the technology for wells deeper than 1,000 m is not well developed and FRP casing is not recommended for this project.

Epoxy coatings could be applied to the inside of the steel casing. However the life of these brittle coatings is doubtful. They could be damaged by rough handling of the casings during installation. The cost of such coated steel would be approximately 1.3 the cost of plain steel tube. These coatings are liable to failure by blistering and peeling [Ref 1].

4.2 Production Pump

This is a key component of the system and should be constructed from alloys likely to give good performance at a reasonable cost. Titanium and high nickel alloys (such as Hastelloy C 276 and Inconel 625) would perform very well but could triple the cost of a pump using more conventional materials. The cost of one particular pump which would handle 150 m^3/h, with a total dynamic head of 150 m would be in the $60 - 70,000 price range. This pump is used extensively in the oil industry and has a carbon steel housing, with external Monel flame spray; Ni Resist impellers and diffusers and a Monel shaft. Such a pump has been used to handle oil containing brine, SG = 1.07, with a high H_2S and CO_2 gas content, at 82°C.

The NACE Standard RP-04-75 [Ref 19] which deals with the selection of metallic materials to be used in all phases of water handling for injection into oil bearing formations is relevant. This standard includes lists of materials for both vertical submersible pumps (downhole motor driven) and vertical turbine pumps (shaft driven). Materials are listed for four environments aerated and non-aerated with and without H_2S. The selections are very similar for all environments. The original standard should be consulted for complete details, including alloy compositions.

The materials listed for all four environments for the vertical submersible pumps and for non-aerated environments with and without H_2S for the vertical turbine pumps are shown in Table 3.

Table 3. Production Pump Materials.

	Vertical Submersible All environments	Vertical Turbine (Shaft driven) non-aerated without H_2S	non-aerated with H_2S
Bowl, impeller stationary and rotating rings	316 stainless, Ni $Al_{w\ \&\ ca}$ $AlBr_{ca}$ $NiRe^{ca}$ Hard Co, Hard Ni/316	316,316L AlBr $63Br^{ca}$ NiRe	316,316L $AlBr_{ca}$
Shaft	316,K500	400M,K500,316	400M,K500,316
Bearings	C BrgBr, NiVBr	C NiVBr	C NiVBr
Cable Sheathing	NM		
Motor; case and protector	Fe_c		
Line Shaft Bushing	-	NM	NM
Head	-	Cl_cFe_c	Cl_cFe_c
Column	-	Fe_{2c}, Fe_c	Fe_{2c}, Fe_c

The materials having the greatest expected life are placed on the first line, the next longest life expectancy on the second line etc.

Potential corrosion problems with the alloys in Table 3 are that: 316 is subject to pitting and SCC cracking in chloride solution in the presence of small amounts of oxygen which would contaminate the brine during operation or shutdown; copper alloys are susceptible to severe corrosion when traces of sulphide are present [Ref 1] and should be avoided. $NiAl_{ca}$ and $NiAl_w$ are 80-81% copper alloys. $AlBr_{ca}$ is a 85% copper alloy, Ni Resist does not contain sufficient Cr to prevent pitting if oxygen enters the system. However as mentioned above these materials are used extensively in the oil industry where corrosive brines containing H_2S and CO_2 are handled and the use of a pump with standard materials is recommended for the present project. Materials recommended by the NACE Standard these should be chosen in consultation with the pump manufacturer when the pump has been designed.

Bimetallic corrosion effects should be carefully studied. Sometimes however a base metal such as iron can cathodically protect stainless steel for example and permit its use as pump and valve trim with a steel body [Ref 17].

The recommendation at this stage of the project is to use 316 stainless steel for the bowl and impellers and Monel or 316 for the shaft; and C for the bearings, with the objective of avoiding copper alloys which can cause problems when the H_2S concentration in geothermal fluids is as low as 7 ppb [Ref 1]. It has been suggested that virtually all geothermal fluids contain sufficient H_2S to damage copper alloys [Ref 1].

Stainless steel components should be drained and rinsed during shut down periods to avoid the initiation of localized corrosion. Stagnant conditions are to be avoided [Ref 1].

4.3 Pre-Injection Pump Line

FRP pipe is recommended for this line which is expected to have a pressure of 0.7 M Pa.

Many geothermal lines have suffered severe corrosion, especially when oxygen has infiltrated into the system [Ref 1]. The cost of inhibiting carbon steel lines on a continuous basis is expensive. One m^3 of brine cooled from 65 to 33°C liberates heat equivalent to 47¢ worth of natural gas. The cost of inhibiting this water to the level normally used in the oil-industry (ca. 20 - 30 ppm) would be 8 - 12 ¢ or for a $100m^3/h$ system, 70,080 to $105,129/annum, which would be approximately equal to the initial capital cost of the line for this project. Additional costs would be associated with the external coating and cathodic protection of a steel line.

The NACE Standard which applies to the selection of metallic materials to be used in water handling for injection into oil bearing formations is relevant. Gathering and injection lines for water which is non-aerated and aerated with and without H_2S are all recommended to be either internally coated steel or non-metallic. Mild steel line internally coated with epoxy and externally coated for protection against soil corrosion by yellow jacket or tape insulation costs approximately 1.5 - 1.8 plain mild steel when laid. There are problems with epoxy lined pipe if it is roughly handled during installation and it is doubtful whether a 20 - 30 year life could be assumed. Pitting corrosion at breaks in the coating could be a problem.

FRP pipe is being used in one geothermal project [Ref 1] where a line failed due to oxygen corrosion. Otherwise little data is available from geothermal experience. However FRP pipe was being successfully used for concentrated brines at 80°C in 1965 [Ref 18] in a caustic-chlorine plant and is presently being used in the oil fields to handle corrosive brines and FRP vinyl ester pipe is recommemded for this line. The cost would be approximately 1.2 the cost of mild steel pipe laid. Such pipe is very light and can be laid by a two man crew. The pipe can be glued or ball and spiggot joints can be used. The pipe could be insulated with styrofoam pipe insulation. One problem that has been encountered with buried FRP pipe in the oil inustry is stone breaks due to ground movement in the spring. The pipe should be laid on a 6" sand bed and covered by sand. ASTM A53 steel pipe could be used to join the buried pipe to the well head. The steel pipe would be much more robust and less liable to accidental damage. This short section of steel pipe could be internally coated with epoxy.

4.4 Plate Heat Exchanger

Plate heat exchangers have several advantages over the more standard shell and tube exchangers for use in geothermal applications. They are readily cleaned; the stamped plates are thin and can be made of expensive materials which may be required for corrosion resistance; and approach temperatures are smaller. The latter factor is important in low temperature geothermal applications.

Titanium preferably ASTM Grade 12 is preferred for this equipment. It has very good resistance to corrosion in hot brines aerated to deaerated as evidenced by the fact that it is one of the major contenders for the disposal of nuclear waste by deep burial, where ground water containing NaCl might occur. The ASTM Grade 12 has a better resistance to pitting and crevice corrosion in brine than commercially pure titanium [Ref 1]. In various field tests at geothermal sites and laboratory tests titanium has proven to have outstanding corrosion resistance. It is a strong, ductile metal and highly suitable for plate heat exchanger manufacture.

It is important not to have pitting or other localized corrosion in the heat exchanger. In-leakage of cooling water could cause severe oxygen corrosion of the injection well. Out-leakage of the brine containing the H_2S from the Winnipeg/Deadwood formation would pose an immediate health hazard [Ref 7].

4.5 Injection-Pump

The NACE Standard RP-04-75 [Ref 19] lists suitable materials for the construction of injection-pumps for aerated and non-aerated waters, with and without H_2S.

A multistage centrifugal pump, similar to that used by the potash industry in Saskatchewan for brine disposal, would be used. Positive displacement pumps have insufficient capacity for the flowrates under consideration.

It is recommended that materials for the present project be chosen from: casing, 316, 316L stainless steel; impellers, 316, 316L stainless steel; stationary rings, 316, 316L stainless steel; rotating rings, tungsten carbide, Hard Co, Hard Ni; shaft sleeves, tungsten carbide, Hard Co, Hard Ni; shaft, Monel K500, 17-4 PH stainless steel (wrought) or ACI Grade CB - 7 Cu (cast), 316 stainless steel; mechanical seal (316 + NonZnBr + C + WC - complete unit). The materials for the shaft are in order of ranking. These materials are recommended by the NACE standard for all the above mentioned environments. The NACE Standard should be consulted for full details.

The precautions relating to the use of stainless steel components mentioned earlier would also apply to this pump.

4.6 Post Injection-Pump Piping

The pressure on the line after the injection pump may be 2.4-4.0 M Pa. FRP pipe can be made to withstand this pressure, however it is considered that lined steel pipe would be preferable for this service. This line should be kept as short as possible. Some of the alternatives are: epoxy lined steel pipe - which is used widely in the oil industry for handling brines; FRP lined steel pipe; polyethylene lined steel pipe; PVC lined steel pipe.

The recommendation is to use mild steel pipe with a FRP lining. The couplings would contain corrosion barrier rings. The cost of the lining is approximately $24.75/m for a 152 mm pipe and $15.68/m for a 102 mm pipe.

4.7 Injection Well

It is assumed that the injection well will consist of a tube run into a casing and the tubing casing annulus closed off with a packer. The annulus can be filled with inhibited water to prevent internal casing corrosion.

API J55 or similar [Ref 1,13] would be suitable for the casing.

The tubing could be internally protected by: an epoxy coating; a cemented FRP lining; a cemented PVC lining. One such system for example at Midale, Saskatchewan is using PVC lined tube to a depth of 1,500 m. An FRP lined tube is recommended.

As discussed earlier the continuous addition of inhibitors to the produced water of a geothermal system would not be economical. This has also been pointed out elsewhere [Ref 1]. Oxygen scavengers, in particular sodium sulphite have been used in Iceland, but again continuous treatment may be uneconomic, and geothermal fluid pretreatment and post treatment if required are presently undefined [Ref 1].

4.8 Effect of Water Source on Materials Selection

The selection of API J55 or similar low strength mild steel well casing is recommended for all the well casings.

The water from some of the upper formations may not contain H_2S however because of the high chloride content and seemingly inevitable oxygen contamination, during operation or especially shut down, then the FRP pipe is considered the best selection for the pre-injection-pump piping and FRP lined mild steel pipe for the post-injection-pump piping. Similarly the water entering the reinjection well should be considered corrosive and the use of FRP lined steel tubing inside an unlined mild steel casing is recommended for all the fluids.

The plate heat exchanger with titanium plates is recommended for all fluids.

It is considered that standard pumps similar to those in use in the oil and potash industries could be used for the production and injection pumps for the waters from all the formations. The waters from the Mannville, Gravelbourg and Souris Valley formations would likely cause the least corrosion problems to the pump materials listed above.

5. SUMMARY OF MATERIALS SELECTION FOR CORROSION CONTROL

The materials selected for the various pieces of equipment are shown in Table 4 along with any necessary corrosion control measures.

Table 4. SUMMARY OF MATERIALS SELECTION FOR CORROSION CONTROL

EQUIPMENT	MATERIAL	COST	CORROSION CONTROL SYSTEM	CORROSION CONTROL COST
Production Well Casing	API J55 or similar	$36.37/m FOB Moose Jaw 178 mm diameter 8 mm thick	External - Cathodic Protection Internal - weighted filming amines	Capital Cost $15-25,000 $50-100/month
Pumps Production and Injection	316 stainless Monel		Stainless steel components should be drained and rinsed during plant shutdown Avoid stagnant conditions	
Pre Injection-Pump Piping	FRP vinyl ester pipe with styrofoam pipe insulation, buried	Approx. 1.20 x mild steel laid.	none required	
Post Injection-Pump Piping	(ASTM A53, API 5L) with FRP vinyl ester lining	152 mm pipe - liner cost $24.75/m 102 mm pipe, liner cost $15.68/m. pipe - see below*	Corrosion barrier rings in coupling. External - cathodic protection - linked to casing cathodic protection	
Plate Heat Exchanger	plates and parts in contact with brine - titanium or or Ti - Code 12	2.5 cost of an equivalent stainless steel unit ?		
Injection Well Casing	API J55 or similar	see above	External - cathodic protection - linked with other system.	
Tubing	API J55 lined with FRP vinyl ester liner		Annulus inhibited water.	Inhibited water $50-100/treatment.

For comparison purposes mild steel pipe:

ASTM A53	102 mm (4" SCH 40)	$13.74/m;		ASTM A53	102 mm (4" SCH 80)	$23.58/m;
ASTM A53	203 mm (8" SCH 40)	$35.03/m;		ASTM A53	203 mm (8" SCH 80)	$70.78/m.

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