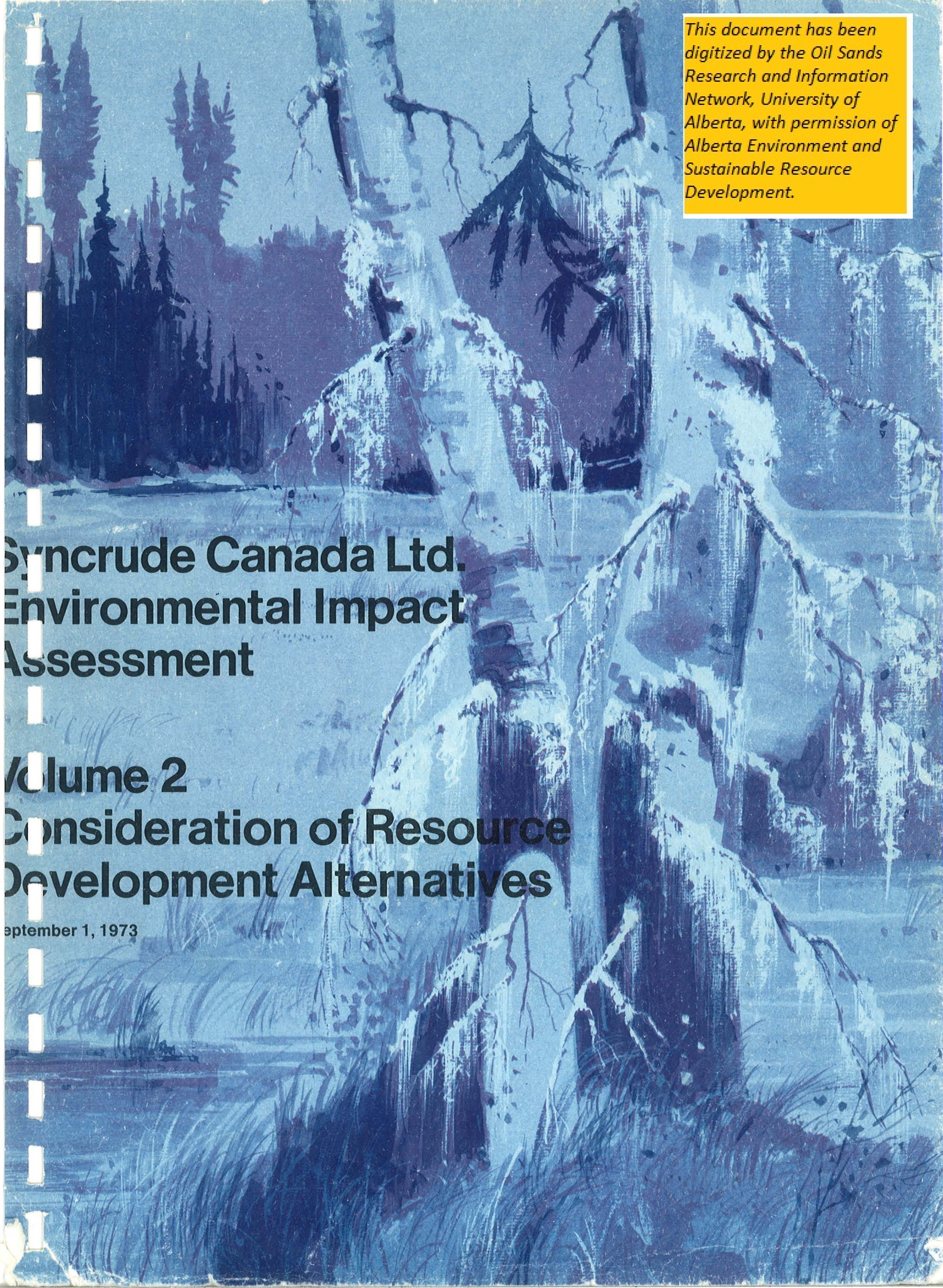

Syncrude Canada Ltd. Environmental Impact Assessment

Volume 2 Consideration of Resource Development Alternatives

September 1, 1973

ENVIRONMENTAL
IMPACT
ASSESSMENT

VOLUME II

CONSIDERATION OF RESOURCE
DEVELOPMENT ALTERNATIVES

SEPTEMBER 1, 1973

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PREFACE

This volume is a supplement to Section 3 of Volume I in which resource development is considered. In that section, the following specific information was provided:

A. The requirement for this Resource Development.

B. Alternate Sources of Liquid and Gaseous Hydrocarbons in North America.

C. Design Consideration in a Tar Sand Project.

D. Plant Design and Emission Information.

Introductory information provided in this volume is limited to that required to give some perspective to the sequence of events leading to the present design of the Syncrude project.

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SECTION I

INTRODUCTION

HISTORY OF THE SYNCRUDE CANADA LTD. ATHABASCA PROJECT

The tar sands of Athabasca have long been an enigma: their presence has been known for almost 200 years but until fairly recent years commercial extraction of that oil had been precluded by prohibitive separation costs. Gordon R. Coulson, a Calgary contractor, saw that the most difficult problem was somehow to remove the sand and clay from the oil, rather than the normal process of removing the oil from host material. He put some tar sand, water, and kerosene in his wife's washing machine, turned on the machine, and thus invented the centrifuge process he patented in 1953. The result was three separated levels, one each of oil, water, and sand. Coulson formed Can-Amera Oil Sands Development Company Ltd. to develop his patented process.

In 1949 the Alberta Government had constructed a five hundred ton per day oil sands separation plant at Bitumount to utilize the hot water separation process that had been developed by the Research Council of Alberta. Coulson's Can-Amera Company, now named Can-Amera Export Refining Company Ltd., purchased the plant in 1955 and used it for experiments utilizing and testing the Coulson centrifuge process, which involved the dilution of the tar sands with diesel oil to effect the separation, and then centrifuging to eliminate sand and fines from the bitumen.

In 1955, Can-Amera made an agreement with Royalite Oil Company, Limited calling for Royalite to carry on the research work and purchase the Bitumount plant for $180,000, which made available to Royalite the rights to utilize the Coulson centrifuging process with reimbursement to Can-Amera for its earlier work. In addition, Can-Amera obtained and still holds the right to acquire ten percent of whatever working interest Royalite might ultimately obtain in a commercial project. Royalite and Can-Amera acquired what is now Oil Sands Lease Number 17 in

December 1955 and continued the experimental program at Bitumount and on the area covered by that lease. Because of severe operating problems, the centrifuge process was abandoned in favor of more conventional separation techniques.

In June 1958 Royalite made an agreement with Cities Service Company, a major U.S. refiner, by which Cities Service acquired a 90% interest in the project in return for undertaking to make 100% of the future expenditures up to a cumulative total of $18,390,000 at which point Royalite's then existing expenditures of $1,839,000 would be equated on a 90%-10% basis. Cities Service had been conducting research on oil sand extraction processes at its Lake Charles, La., refinery in 1957 and was interested in the possibilities for extraction of oil from the sands using a warm water process as a result of its own laboratory and bench scale studies of various extraction methods.

With Cities Service as operator of the project, a thirty-five ton per hour pilot plant was installed in 1959 at Mildred Lake on Oil Sands Lease No. 17. By the end of that year, the project had cost $8,500,000. The pilot plant was designed as a research tool and it was operated to gather information on the mining and materials handling problems as well as on the performance of the extraction process.

About the middle of 1959 Richfield Oil Corporation acquired from Cities Service one-half of its working interest in the project. On October 1, 1959, Imperial Oil Limited joined the three-company group and the working interests in the project came to their present position of 30% each to Imperial, Cities Service, Atlantic Richfield Canada Ltd., and 10% to Gulf Oil Canada Limited. (Atlantic Richfield Canada Ltd. represents the continuity of Richfield Oil Corporation's interest through the merger with The Atlantic Refining Co. and subsequent change in Canada to Atlantic Richfield Canada Ltd., and Gulf Oil Canada Limited, formerly British American Oil Company Limited, acquired its interest when it amalgamated with Royalite in 1969).

A major research and testing program was conducted at the project site at Mildred Lake from mid-1959 until January 1964, with the facilities including a large tar sands extraction pilot plant, mining and materials handling equipment, a steam plant, power plant, shops, laboratory, waterhouses, air strip, and housing and commissary for an average crew of about 125 people. In addition, an engineering and office staff of about 50 people was located in Edmonton.

During the work on site at Mildred Lake, the warm water oil extraction process proved to be economically less attractive than a new extraction method, the modified dense phase process. Experimental testing for the new method took place on a 1000 pounds per hour bench unit which was constructed at Mildred Lake in addition to the main pilot plant. Although limited facilities had been installed at Mildred Lake to test the bitumen upgrading process, field work in this area was not necessary because normal refining techniques were considered applicable to this material. Mining and materials handling procedures were tested with bulldozers, a small mining wheel, blasting, and belt conveyors. It will be appreciated that the major problem in oil sands processing is that of handling vast quantities of sand, at a very low cost, and the operation is to a large degree related to mining rather than conventional oil production although the end product is oil.

On May 9th, 1962 Cities Service Athabasca, Inc. on behalf of the four-company group, made application for a license to produce 100,000 barrels per day of synthetic crude and 500 tons per day of sulphur. At this stage the project had cost over $15,000,000. The application was heard by the Alberta Oil and Gas Conservation Board in January 1963. Approval was sought for a $356 million project to produce 100,000 barrels per day of synthetic crude extending over a period in excess of 20 years with startup scheduled for 1969.

The project involved four phases:

(1) mining of sands,

(2) Separation of the sand and bitumen,
(3) upgrading the bitumen into a high quality synthetic crude, and
(4) moving the crude through a 295 mile pipeline from the plant site to Edmonton where the product could enter the Interprovincial or Trans Mountain pipline systems or both.

The manpower requirements were estimated to vary from one thousand to four thousand men for the project over the four year construction period. Manpower requirements for operating and maintaining the plant, power plant and pipeline would number in the neighbourhood of 1,700 with an annual payroll of about $14 million.

The Conservation Board announced deferment of the application in October 1963, but the applicants were invited to resubmit their application or amended application before the end of 1968. As a result the four-company group continued with its research and development activity at Mildred Lake until January 1964 and since that time at Edmonton, Alberta where a basic research and pilot operation was established in early 1964. (By the time the Mildred Lake facilities were shut down a total of over $22 million had been spent. Since moving the research and testing facilities to Edmonton, the group has spent an additional $7,512,000 bringing the overall total expenditures to $29,824,000).

The Alberta Oil and Gas Conservation Board cited the Alberta Government's Oil Sands Development Policy, as enunciated by Premier Manning in October 1962, as the reason for rejecting Syncrude's application. The policy was designed to ensure that the position of conventional oil in Alberta (at 47% of productive capacity in 1962) was not jeopardized by loss of limited markets to a new source of supply from the tar sands. The concern of the Alberta government was obvious, since the conventional oil industry generates over 40% of total provincial revenue in the form of Crown sale bonuses, rentals and royalties.

The policy placed no restriction on such production from the tar sands as might be able to enter markets clearly beyond present or foreseeable reach of Alberta's conventional industry. However, for such tar sands production as would be competitive in present or foreseeable markets for conventionally produced Alberta crude oil, the government decided that the best interest of the province would be served:

(a) in the initial stages of oil sand development by restricting production to about 5% of the total demand for Alberta oil, i.e. at a level of the order of that approved for Great Canadian Oil Sands;

(b) as market growth enables the conventional industry to produce at a greater proportion of its productive capacity by permitting increments in oil sands production as recommended by the Oil and Gas Conservation Board, on a scale, and so timed as to retain incentive for the continued growth of the conventional industry;

(c) by relating the scale and timing of oil sands production to the life index of provincial reserves of conventional oil, allowing the index to decline gradually from present levels (21 years in 1962) to ensure that it does not drop below 12 or 13 years.

The deferral of the application by the Conservation Board in October 1963 caused a change in the character of the project being operated by the four-company group. The ruling eliminated the possibility of starting commercial construction for some further years, and accordingly the Mildred Lake operations were shifted to Edmonton where a basic research laboratory as well as a pilot plant capable of processing tar sands at the rate of 1,500 pounds per hour were built and placed in operation.

Syncrude Canada Ltd. was incorporated on December 18, 1964 and as of January 1, 1965 took over control of the operation of the project for the four companies in the group. The company itself serves as an operator for its four shareholders on a no-profit, no loss basis, in controlling and managing the project.

In the period following 1963 there were several developments which have a significant bearing on the Syncrude project. First, further evaluation of reserves established a commercial mining area with a low overburden ration and more readily processable tar sands. Second, it was established by extensive field testing that tar sands can be mined with conventional scrapers, resulting in mining costs lower than earlier estimates. Third, a market study provided an insight into more realistic values for the synthetic crude plus a potential for the sale of certain specialty oils, particularly in the form of low sulphur - high quality fuel oils. Fourth, the scraper mining studies, test work carried out by Syncrude on extraction-froth treatment and improvements by industry in hydrotreating techniques increased confidence in the technical feasibility of the project. The Syncrude staff concluded that with these improvements a 34.0^{o} API synthetic crude could now be produced at costs (when considering the additional value of the synthetic crude) which would compare favourably with that of average conventional Canadian crude. The capital requirements were revised and re-estimated to be considerably less than those presented in the 1962 application. The conclusion was that these lower costs provided the flexibility to reduce throughput to something less than 100,000 barrels per day of synthetic crude and specialty oils.

At approximately the same time, other developments led to an overall reappraisal of the Syncrude project and made it essential that a determined effort be made to obtain a revision of the 1952 policy. These other developments included:

(1) A marked upturn in the discovery rate and probable reserves-life index for Alberta oil in 1964 and 1965 which at that time raised the possibility that the 1962 provincial policy would not allow any additional tar sands development for as long as another 15 to 20 years.

(2) The probability of a rapid increase in the gap between United States domestic supply and demand, particularly in Districts I and II.

From the standpoint of corporate planning, it became necessary for each of the four participants to determine whether or not they wished to continue indefinitely on a research and field testing program which had already resulted in an expenditure of approximately $24,000,000 by the end of 1964.

In September of 1965, after weighing these factors, the Syncrude management committee approved the initiation of discussions with the Provincial Government regarding Oil Sands Policy revision.

After a number of preliminary meetings with Government representatives, Syncrude submitted several briefs dealing with commercial development of the Athabasca tar sands to Premier Manning as did other companies and associations interested in this subject. These briefs, together with meetings called by Premier Manning on May 11, 1966 and on June 16, 1967, with representatives of the Alberta oil industry, led to reconsideration of the Government's oil sands development policy.

On February 20, 1968, Premier Manning tabled in the Legislative Assembly of the Province, a further statement of the Oil Sands Development Policy. The essential modifications are:

(1) The distinction between "within reach" and "beyond reach" markets is clarified. "Beyond reach" markets are stated to be any markets, including specialty markets, which Alberta's conventional industry is not now serving nor can reasonably be expected to serve in the foreseeable future because of price, quality specification or other reasons. Athabasca product can enter these markets without limitation.

(2) Where it can be demonstrated that the applicants' proposal would provide growth by the development of a "new" market within reach of conventional

industry, production from oil sands may be authorized in volume equal to 50 percent of the new market. However, the total volume of commercial oil sands production, including that already authorized, that will be permitted to enter new within reach markets, will be 150,000 barrels per day, which limit will remain in effect for 5 years.

(3) A scheme proposing marketing of oil sands production in a "within reach", but not "new" market, would be approved only when indicated by a trend in the life-index of the conventional industry. The percent utilization of productive capacity criterion is no longer useful and is being discontinued.

On May 3rd, 1968, Syncrude submitted an amended application requesting permission to build a plant of 80,000 BPD capacity by 1973, to cost, exclusive of townsite development, pipeline and power plant, approximately $200,000,000. Of the requested total output, 50,000 BPD would represent synthetic crude oil to be disposed of in "new within reach" markets. The Syncrude participants agreed to find new markets for a similar volume of conventional crude oil in accordance with the provision of the modified Oil Sands Policy. The remaining 30,000 BPD of plant output would be disposed of in "beyond reach" markets, 25,000 BPD as a premium industrial fuel oil, and 5,000 BPD as naphtha.

During the course of the hearing before the Alberta Oil and Gas Conservation Board, held in August, 1968, a somewhat rigid interpretation of the conditions necessary to satisfy a "new within reach" market evolved as a result of the very active intervention of a sizable segment of the conventional oil industry. Restrictions on all movements to the U.S. would have to be largely eliminated for a new within reach market to exist. The best available forecasts of the U.S. domestic supply/demand situation, prepared in early 1968, indicated that such condition would probably become a reality in 1974. However, during the summer of 1968, the announcement of a major oil discovery at Prudhoe Bay introduced a new element of uncertainty into the U.S. supply picture. The Conservation Board announced in December 1968 that they could not approve the application because of the unknown magnitude and rate of development of the Alaskan discoveries. In the belief that more information would be forthcoming shortly the Board said that they would be prepared to approve the application, following a further hearing to be held in November, 1969, if the applicants could satisfy the Board that the balance of probabilities, as they may then best be assessed, favoured the contention that the probable Alaskan developments would not significantly reduce the deficiencies originally anticipated in the United States indigenous supply of crude oil in the period 1973 to 1974.

The participants in the Syncrude project concluded that it was unlikely that sufficient additional information about the probable extent of the Alaska reserves would be available by November 1969 to satisfy the Board and, as a result they would be judged on the basis of the Board's assumed "high" Alaska case. The participants on February 19th, 1969 submitted a proposal to the Lieutenant-Governor-in-Council requesting that he consider seeking the advice of the Board to determine whether the Board would consent to modify the conditions under which they would be prepared to hear an amended application based on the following proposals:

(1) An amendment to the application to provide for an approximate three-year delay in start-up, and

(2) submission of new data indicating a higher future U.S. demand.

The Oil and Gas Conservation Board granted this request and on March 24th, 1969 Syncrude Canada Ltd. submitted an amended application proposing a three-year delay in startup supported by updated U.S. supply/demand figures. The hearing was held May 26th-27th, 1969.

On September 12th, 1969 the Alberta Oil and Gas Conservation Board issued Report 69-C authorizing Syncrude Canada Ltd. to build a plant with 80,000 BPD capacity to go onstream not before July 1st, 1976.

During the 1969 hearing before the Oil and Gas Conservation Board, and later in private discussions, Canadian Utilities Ltd. indicated its interest in building a major utilities plant in connection with the Syncrude oil project. This plant would utilize, as fuel, the residual material remaining after upgrading the tar sand oil in a thermo-electric plant to produce a base load of 100 megawatts of electricity for Syncrude plus a substantial block of power to be fed into the province-wide electric grid system.

In addition, this utilities plant would supply the Syncrude project with 17,000,000 pounds of steam and 2,000,000 gallons of treated water per day. In terms of size, the electrical capacity of the Canadian Utilities plant would be approximately equivalent to a plant supplying a city of over 200,000 population. Investment in the overall utilities complex would be in the range of 50 to 100 million dollars. This investment, when combined with the outlays required for the mining, extraction, and upgrading complex, and the pipeline facilities would bring the total capital expenditures to approximately $300,000,000.

Effective September 23, 1969, the assets in Canada of Atlantic Richfield Co. were transferred to its wholly owned subsidiary, Atlantic Richfield Canada Ltd. Effective December 31, 1970, Cities Service Athabasca Inc., a wholly owned subsidiary of Cities Service Co., transferred its assets to Canada-Cities Service Ltd., another wholly owned subsidiary of Cities Service Co. On April 18, 1969, Royalite Oil Co., Ltd. was amalgamated into Gulf Oil Canada Ltd.

Since the Syncrude Group appeared before the Oil and Gas Conservation Board in 1969, the necessity for several changes in the project became apparent. Consequently, on September 21 and 22, 1971 Syncrude submitted an application to the Energy

Resources Conservation Board (E.R.C.B.) proposing an amendment to their September 1969 approval to allow for an increase in the rate of production (of 45,625,000 BPY of synthetic crude oil and 2,000,000 net BPY of residual fuel) and to provide for the marketing of the synthetic crude oil under the life index criterion of the Oil and Sands Development Policy.

The application proposed changes in the area to be mined and the method of mining and transporting the oil sands material with the resultant consequences. Modest conservation and technical improvements were outlined including: expansion of the plant area coupled with a change in area; the change in the mining and materials handling conveyor scheme from a scraper, belt conveyor system to a dragline, rail haulage system; the consideration of mineable reserves under the tailing retention pond; off-site sale of power resulting from an overall energy imbalance in the plant. The status of certain environmental aspects were outlined in the areas of: (1) increased production of gaseous pollutants and particulate matter to be kept within the emission standards established for the province, (2) prevention of any movement of process water beyond the base boundary, and (3) reclamation of the mined out area.

The E.R.C.B. considered the conservation and technical revisions to be desirable and likely to result in improved conservation (an estimated one percent increase in recovery to sixty-two percent). Environmental protection revisions were satisfactory subject to the compliance of details with the appropriate departments and agencies of the Alberta Government in the areas of movement of process water and reclamation and pointed out the desirability that the condition of existing approval relating to environmental matters be made more specific and amended to incorporate reference to new Provincial standards.

In December 1971, the E.R.C.B. approved this application as superceding the March 1969 amendments and acknowledged Syncrude's prediction that U.S. deficiency of conventional crude oil from indigenous sources was to increase substantially in the decade between 1970 and 1980 and that the application qualified under the life index criterion of the Oil and Sands Development Policy.

By March 1973, an application outlining changes in the Mildred Lake plant design and an application for an order approving construction of a power plant to serve the Syncrude Mildred Lake tar sands Project were submitted to the E.R.C.B. Engineering evaluation of the processes included in a previous application had shown the need for technical changes in froth treatment, upgrading of the bitumen, and the utility plant with resultant improvement in conservation and environmental matters.

Contingent upon construction of the entire Syncrude Mildred Lake Project is the construction of a utility plant to serve the project. Technical particulars revealing location and description of the proposed plant with information on fuel efficiency, supply and source, and the relationship of the power plant to the provincial power grid, based on current estimates of power and heat requirements were outlined with consequent environmental features.

1. 1962 APPLICATION TO THE OIL AND GAS CONSERVATION BOARD CONCERNING OPERATIONS

THE OIL AND GAS CONSERVATION BOARD

APPLICATION under Part VI-A of
THE OIL AND GAS CONSERVATION ACT

by

CITIES SERVICE ATHABASCA, INC.
IMPERIAL OIL LIMITED
RICHFIELD OIL CORPORATION
ROYALITE OIL COMPANY, LIMITED

May 9, 1962
Amended to November 15, 1962

OPERATIONS

General Description of Operations

The overall design of the proposed facilities is predicated on the production of synthetic crude from the tar sands in the amount of 100,000 BPCD (36,500,000 barrels per year).

As later described in more detail, overburden is removed by dragline, slurried and pumped to disposal; tar sand is mined by bucket-wheel excavator and transported by belt conveyor to a reclaiming system which delivers an even flow to four parallel extraction units. Froth from extraction is treated for water and solids reduction, and then thermally dehydrated. Bitumen is coked by the fluid-coking process. The resulting liquid products are hydrotreated and netted out as a synthetic crude product.

The overall bitumen balance, including the overall plant fuel requirements, and a sulphur balance around the bitumen upgrading units, are shown on Tables C-1 and C-2 respectively. These balances are developed on the design basis.

Mining and Materials Handling

General Description

Mining and materials handling is based on a dry-mining scheme which operates continuously on a year-round basis. The overall scheme is shown on FIG. C-1, "Schematic Mining & Materials Handling Plan." The essential features are overburden stripping, tar sand feed to plant, and waste disposal systems. Although all three systems operate continuously, the overburden stripping system is independent of the other two.

The general plant layout and mining area are shown on FIG. A-2, "Plan of Lease Development." The mining area lies roughly to the south and west of Mildred Lake. The upgrading facilities and off-sites are located east of Mildred Lake, where foundation conditions are favourable. The extraction plant and dehydration plant are directly west of the southern end of Mildred Lake. This location was chosen for optimum use of conveying facilities.

Dams are to be constructed at the north end of Mildred Lake and across Beaver Creek. The upstream reach of Beaver Creek is used for plant water storage. This source is supplemented by water from the Athabasca River.

Waste solids (overburden, tailings and reject sands) are initially deposited in the area of Horseshoe Lake. The land north-east of Mildred Lake sloping down to the Athabasca River near the mouth of Beaver Creek can be used as a standby disposal area. The retention pond is located north of the dams at the north end of Mildred Lake.

Overburden Removal

The mining area is covered with a sparse timber stand and has many large, shallow muskegs. The water table is near the surface. The overburden materials are quite heterogeneous, with large pockets of clays, sands and rocks present. Some rocks are quite large and must be considered in design and selection of stripping and conveying equipment.

The average depth of the overburden is 65 ft. but the formation is highly variable, ranging in depth from 5 to 186 feet.

The extreme cold of the winter has to be considered in devising the stripping scheme. Wherever possible, work is scheduled for warm-weather operation, although the equipment described can operate during the winter and does to a limited degree.

Walking electric draglines of 45-cubic yard capacity are used to strip the overburden. The overburden is deposited in crawler-mounted hoppers where it is first screened to remove plus 18-inch material. The bulk of the material is slurried in water and pumped to disposal. The 9" to 18" material is crushed before this slurrying step. The plus 18" material is trucked to disposal.

The stripping facilities consist of two complete trains of dragline, slurry box, slurry pipeline and make-up water line. Each train operates 5,000 hours per year and is capable of handling 12,125,000 cubic yards during this 5,000-hour period.

Tar Sand Mining

The mining facilities are designed to give continuous high-capacity feed and to selectively reject gross areas of poor feed. Design capacity is 10,800 tons per stream-hour of feed and a service factor of 90% is to be maintained.

The feed and reject sections of the McMurray formation are defined by close drilling control ahead of the mining operation. Mining is scheduled so that reject material is handled by the machine not providing feed to the plant.

Two giant bucket-wheel excavators with a high wall reach of 200 feet are used to excavate the ore body. These machines operate from the limestone or base reject material, and can selectively dig lenses 10 feet in thickness. The design capacity of each machine is 10,800 tons per hour and each is expected to operate with a 75% service factor. There are periods when one wheel is digging tar sand while the other is digging reject material within the ore body. The duplicate wheel facilities allow for this condition since each wheel is capable of full plant feed.

A reclaiming ditch and wheel have been provided to even out the surges from the main excavators which, because of their cutting patterns and operational requirements, do not maintain a continuous, uniform feed. The 10-hour storage capacity in the reclaiming ditch will also permit emergency maintenance on the excavators or conveyors without affecting plant feed, thereby avoiding unscheduled shutdowns in the subsequent processing.

Ground water is controlled by ditch interception at the top of the ore body. When water does appear on the face, toe drains are provided to take the water back to the main pit sump.

Tar Sand Transportation

Except for the single face section serving the far mining wheel, the conveyor system is comprised of two conveyors in parallel through to the extraction plant. The parallel conveyors provide the necessary flexibility to convey feed and reject simultaneously or to convey feed to the reclaiming ditch and the extraction plant simultaneously. The face conveyors are sectionalized to permit successive movements forward without shutting down the mining operation.

The reclaiming ditch is located between the conveyors, adjacent to the extraction plant. From the reclaiming ditch, the two conveyors transfer the material to the feed-splitter on the extraction unit.

Each of these conveyors is designed for 13,000 tons per stream-hour. This makes allowance for surges from the 10,800 ton per hour mining wheels. Housing is provided for all belting.

When handling reject the conveyor system delivers such material to the sand tailings slurry box for disposal with the tailings.

Service factor of the conveying equipment is 90%.

Sand Tailings and Sludge Disposal

The sand tailings leave the extraction unit as a slurry containing

25% by weight water. Water is then added to form up to 50% by weight water-solids slurry. This slurry is pumped to an initial disposal area, shown on FIG. A-2, for the first 3 to 4 years, after which time it is returned to the mined-out area as shown in FIG. C-1.

The pumping system consists of one 32" sand pump discharging through 32" diameter thick-walled pipe. A 100% standby train is provided.

The design capacity is 36,600 GPM. Maximum particle size is 3/4 inch.

Sludges are defined as -325 mesh mineral matter in water with small amounts of bitumen.

The water and sludge which drain from the solids in the disposal areas are gathered and pumped as recycle slurrying water to the tailings disposal system, with the excess going to the retention ponds.

The retention ponds are intended to settle both bitumen and solids. Sufficient residence time is provided for settlement of all fine material, excepting a small fraction which will remain in suspension indefinitely, notwithstanding residence time.

Extraction-Dehydration System

Introduction

This system is designed to process 10,800 tons per stream-hour of tar sand containing 10.8% bitumen with a 0.90 service factor and 85% recovery of bitumen for upgrading to synthetic crude. The solids associated with tar sand feed contain an average of 18 weight per cent "fines" (-325 mesh solids). Extraction-Dehydration produces 134,400 barrels of bitumen per stream day. This is equal to 121,000 BPCD, of which 118,400 BPCD is further processed to synthetic crude in the bitumen upgrading section and 2,600 BPCD is used as liquid fuel. An average bitumen recovery in excess of the 85% design figure is expected to be achieved.

The size and cost of the major portion of the equipment in the extraction unit is determined by the rate of tar sand charge rather than by the bitumen content and, therefore, the unit has been sized for the fixed tar sand feed rate of 10,800 tons per hour. With tar sand of lower bitumen content than 10.8%, the bitumen production rate is below the 134,400 BPSD design level stated above. With tar sand of higher bitumen content than 10.8%, the bitumen production rate is above the 134,400 BPSD level. Tankage has been provided to handle the day by day variation in this bitumen production rate. The unit is designed for a feed bitumen content below the overall deposit average of 11.4% since there are extensive areas of the deposit averaging less than 11.4%. It would not be practical to handle this longer term variation by surge tankage.

The proposed commercial extraction unit is designed to process tar sand containing 6% or more bitumen and to charge lenses of tar sand lower than 6% in bitumen when these lenses are 10 feet or less in thickness. This results in rejecting only 14% of the total bitumen in the formation. The deposit does not contain much material in the 4 to 6% bitumen content range and therefore this cutoff point is not too critical from the standpoint of conservation. In practice it may be found feasible to charge part of this -6% material. However, it would not be economic to design facilities for leaner tar sand feedstock. The incremental bitumen recovery would be unattractive when consideration is given to the attendant increase in extraction facilities and tankage.

Extraction

Bitumen is extracted from the tar sand by the Dense Phase process which has been developed by the applicants. This is a two-stage aqueous process which the applicants have found to be superior to the hot water process in both operability and bitumen recovery.

The tar sand is delivered by belt conveyors to the Dense Phase extraction system, which consists of four parallel processing lines, each designed to handle 2,700 tons per stream-hour of tar sand. As shown in FIG. C-2, the tar sand is slurried by mixing at 180°F. with steam and fresh water in a tumbler. The tumbler is an 18-foot diameter by 46-foot long rotating scrubber, equipped with flights. The outlet portion of the tumbler is a rotating screen through which the bulk of the slurry passes. The coarser portion of the slurry (3/4" plus) is rejected from the end of the tumbler.

The slurry passes from the tumbler to the Primary Recovery Equipment. Here the slurry is contacted with hot water at 180°F. A 64' x 56' x 19' separation vessel is used to separate the bulk of the bitumen as a froth. Also, this separator effects the separation of the sand, which is diluted with recycle water (to approximately 45% solids content) and pumped to the sand disposal area.

The effluent water from the Primary Recovery Equipment is transferred at 180°F. to the Secondary Recovery Equipment where additional bitumen recovery, as a froth, is effected using a similar treatment to that of the Primary Recovery. A vessel 40' x 75' x 20' is used to separate the froth from the water. The effluent water, which contains the bulk of the fines, is transported to the settling pond.

The bitumen froth from Primary and Secondary Recovery, containing solids and water, is transferred to the froth treatment system, where a reduction of solids and water content is effected.

Froth Dehydration

The froth is then dehydrated thermally by heating in a furnace and flashing in the dehydration vessel at 235 psig and 450°F. The heat in the steam which passes overhead is utilized to generate low pressure process steam. Part of the lighter portion of the bitumen (gas oil) is carried overhead with the steam and separated from the overhead water. Bitumen is taken from the bottom of the dehydration vessel and flashed down to atmospheric pressure in the flash vessel. This completes the dehydration. The bitumen is then transferred to storage for subsequent upgrading to synthetic crude.

The furnaces for this thermal dehydration operation are of special design to provide for the solids in the feed and to handle the very high vapor to liquid ratio at the furnace outlet.

General

Froth de-ashing and dehydration has proven to be one of the most troublesome operations in tar sand processing. A froth treating method may work on froth from tar sand from part of the deposit and be unsuccessful on froth from another portion of the deposit regardless of bitumen content. The method presented herein has been demonstrated as a workable approach on all froths; however, the solids content of the bitumen product from dehydration is higher than desired in the feed to bitumen upgrading. Accordingly, work is continuing to develop a better and more efficient process. This work is encouraging and it is likely that an improved froth treatment system will be available before the construction of the commercial plant is started.

Table C-3, "Material Balances - Extraction, Froth Treatment and Dehydration", shows for each inlet and outlet stream the quantity and weight per cent of bitumen, water, solids, and fines (-325 mesh).

The design bitumen balance is summarized below:

	Bitumen Content		
	BPSD	%	
Tar Sand Feed	158,000		100.0
Products			
Gas Oil	8,650	5.5	
Dehydrated Bitumen	125,750	79.5	
Total Product	134,400		85.0
Loss			
Sand Tailings	7,000	4.5	
Effluent Water	15,200	9.5	
Vapor From Slurrying	700	0.5	
Reject From Slurrying	700	0.5	
Total Loss	23,600		15.0

The bitumen in the sand tailings and effluent water streams is intimately associated with the fine mineral matter which is dispersed in the continuous water phase of both these streams.

As this water in the sand tailings drains through the tailings pile, part of the fines and bitumen will be trapped in the sand voids. The net drainings from the sand tailings and the extraction effluent water will be transferred to the retention ponds. Any froth which results from this transfer will be skimmed from the surface of the retention ponds. The rest of the bitumen will settle with the fines in the retention ponds and result in final water disposed to the Athabasca River that is acceptable in both solids and bitumen content.

A discussion of the results of bench scale testing of the Extraction-Dehydration process is given in the Memorandum: "Extraction and Froth Treatment

Development", which appears at the end of this section, commencing on Page C-14.

Bitumen Upgrading

Bitumen upgrading is shown schematically on FIG. C-3.

The dehydrated bitumen is coked in two (2) fluid cokers. Each of the cokers is designed to coke fifty per cent (50%) of the net dehydrated bitumen to be upgraded. The dehydrator overhead gas-oil is charged to the fractionation section of the cokers.

The products from the cokers are fuel gas, naphtha, light gas-oil, heavy gas-oil and coke. The fuel gas is passed through a hydrogen sulphide removal unit and then goes to the hydrogen production plant and to the plant fuel system. The coke from the cokers is pneumatically conveyed to the power plant for fuel.

The principal products from the coking units, naphtha, light gas-oil and heavy gas-oil, must be treated further for the reduction of sulphur and nitrogen contents, before an acceptable synthetic crude can be produced. Hydrotreating facilities are designed to perform the necessary reduction of these components in the respective streams and also to saturate the more reactive unsaturated components of streams.

The hydrogen sulphide removal unit processes all the gaseous streams from the coking units and the de-sulphurizing units. It extracts the hydrogen sulphide and furnishes a concentrated H_2S stream to the sulphur plant for sulphur recovery to minimize atmospheric pollution and for the conservation of the sulphur.

The hydrogen plant produces the hydrogen required in the hydrotreating units. This unit produces the necessary hydrogen by the steam reforming process from coker gas and gas from the hydrogen de-sulphurizing units.

The sulphur plant serves the sole purpose of converting to elemental sulphur the H_2S removed from the gas streams in the hydrogen sulphide removal plant.

Waste Material Disposal System

Waste Water Disposal

All waters used in the overburden removal, sand slurrying and disposal, extraction and bitumen upgrading, will ultimately be collected and pumped to retention ponds. These ponds will hold all the waters for a period sufficient to ensure acceptable disposal to the Athabasca River. From the retention ponds the clean water is decanted to the Athabasca River.

Studies are currently underway to determine precisely the time required to make the effluent water of a sufficiently high quality so that it can be disposed to the river with no deleterious effect. The two prime considerations, as far as the effluent is concerned, are the bitumen or oil content and the level of solids.

The current studies have been discussed with the Sanitary Engineering Division of the Provincial Department of Health. The Division is in agreement with the program as it is currently being carried out and will be kept informed and will have an opportunity to appraise the results of the study. The final selection of effluent quality, and, therefore, the arrangement of and total retention time to be provided by the retention ponds, will be selected following joint meetings with the Public Health authorities.

In this proposal the quantity of the effluent water will be approximately 44,000 gallons per minute. It is currently planned that the retention ponds will be provided by either a single large dam or a multiplicity of smaller dams on the lower reaches of Beaver Creek. The final decision as to whether it will be a single pond or a multiplicity of smaller ponds in series will depend upon the studies currently being carried out. The proposed use of such ponds has been discussed with the Department of Health and, pending the final results of the study currently underway, the Sanitary Engineering Division of the Department has agreed to advise the Board by letter of its concurrence in the scheme.

Discussions with Government Departments

From inception of their project the applicants have endeavored to keep all interested departments of government, both Provincial and Federal, informed and up to date on the operation of their pilot plant, and on the general development of the project.

Specifically the officials of the Provincial Department of Public Health have visited the pilot plant, and have been consulted on all aspects of commercial operation thought to concern their department.

The applicants believe that all other departments of government concerned at this stage with commercial operation of Lease 17 are aware of the applicants' commercial intentions, and that the proposed operation will in due course receive the necessary approvals from such departments.

Auxiliary Facilities Development

Generating facilities will be constructed to furnish power and steam for the plant and the townsite. Fuel used for power and steam generation will be produced by the plant.

A products pipeline from the plant to an Edmonton pipeline terminal will be built with intermediate pumping stations. Details of the pipeline are contained in Section F.

Airport facilities will be constructed to meet requirements of the proposed operation.

An all-weather road with a bridge over the Athabasca River will be required between McMurray and the plant site. A study is currently being made to determine the economics of constructing a railway extension from Waterways to the plant site.

It is considered that a new townsite will be required in the near vicinity of Mildred Lake. The townsite development will be located, planned and administered by the appropriate provincial government agencies. The applicants will consult with and assist these agencies wherever possible. Financial aid in the early stages of townsite development will be available from the applicants if required.

Manpower Requirements

Over the four-year construction period, average annual manpower requirements for the plant, pipeline, power plant, and townsite will range from 1,000 to 4,000 men. Annual field payrolls will vary from $7 - 25 million, plus overhead and supervision.

Manpower requirements for operating and maintaining the main plant, power plant and pipeline will number 1,700. The annual payroll for these facilities will be about $14 million.

In addition to the payroll for those employed directly in the project operation, earnings of service personnel in the town are expected to exceed $3 million annually.

MEMORANDUM

EXTRACTION AND FROTH TREATMENT DEVELOPMENT

A discussion of the results of bench scale testing of the Extraction-Dehydration process

The applicants have carried out experimental work at several locations and for several years on development of a suitable process for recovering bitumen from Athabasca tar sand. During the last three and one-half years an intensive development program has been pursued at Mildred Lake, supplemented by continuing work in the applicants' laboratories.

Extraction

Both aqueous and anhydrous extraction processes have been developed and studied. The hot water process and variations thereof have been included in these studies.

From this work one extraction approach developed by the applicants, the "Dense Phase" process, was selected early in 1961 for commercial development. Since that time extensive work has been carried out on this process. Over 5,500 hours (230 days) of operation have been completed on the Dense Phase bench scale pilot unit at Mildred Lake with tar sand feed rates of 450 to 2000 pounds per hour and continuous runs of up to 17 days. Although the basic process has remained the same, very significant improvements have been made in the last one and one-half years.

Tar sand feed was secured from locations throughout the proposed mining area, from the top to the bottom of the deposit, in order properly to evaluate the process. Extensive study was carried out on the more troublesome areas in order to define conditions and equipment needed to handle the total deposit with acceptable results.

A most significant finding of this study is that the processability of tar sand in the commercial deposit varies greatly, and that processability of freshly mined tar sand is not solely a function of bitumen and fines content. The properties which define processability are not readily apparent, and the research laboratories of the applicants have given special attention to this problem.

The first stage of the Dense Phase process, by itself, provides improved bitumen recoveries with many tar sands that give poor recovery in the slurrying-flooding-separation operation of the hot water process.

This is illustrated by the results from laboratory batch treats of a tar sand containing 11.7% bitumen and 8.6% fines content. Bitumen recovery by the hot water technique was 71.0%, as compared to 93.8% bitumen recovery by the single stage Dense Phase technique. To study further the relative effectiveness of the Dense Phase technique, clay was added to this tar sand feed in three increments and the bitumen recoveries by the two processes determined as shown below:

% Clay added to Tar Sand	Bitumen Recovery %	
	Hot Water	Single-Stage Dense Phase
2	80.3	95.4
9	69.6	96.5
45	39.3	86.2

While the added clay was detrimental to hot water processing yields, it did not greatly reduce the recovery from the Dense Phase operation.

However, studies also show that much of the tar sand in the deposit requires more than the single stage Dense Phase operation to yield good recoveries, as illustrated in the following Table of bench unit recoveries.

Location	Tar Sand Feed % Bitumen	Tar Sand Feed % Fines	Dense Phase Extraction Bitumen Recovery % First Stage	Second Stage	Total
			Poor Processability		
9	12.7	5.7	68.5	10.5	79.0
4	12.9	4.4	71.2	15.3	86.5
9B	11.8	7.9	72.6	11.4	84.0
D1	8.5	8.3	59.6	28.7	88.3
11A	12.6	25.2	76.9	17.4	94.3
11A	10.0	12.0	69.9	12.0	91.9
46D	9.7	35.1	77.5	9.1	86.6
10D	8.3	27.8	77.7	13.0	90.7
130	6.7	47.0	75.6	14.7	90.3
			Intermediate Processability		
3	15.5	1.6	89.0	6.1	95.1
D1	13.6	5.4	88.5	7.8	96.3
110	16.3	1.9	82.6	8.1	90.7
130	10.8	16.0	89.1	6.0	95.1
103A	10.7	19.2	87.7	9.5	97.2
121	12.7	24.2	89.0	6.7	95.7
10D	14.4	44.1	87.8	8.4	96.2
121	11.6	26.8	89.5	6.4	95.9
			Good Processability		
193	6.2	40.5	92.0	0.5	92.5
221	9.2	26.3	96.5	O.S.*	--
1B	10.6	25.2	92.7	O.S.*	--
183	12.5	17.9	97.2	0.6	97.8
103A	12.5	34.2	95.0	1.3	96.3
183	15.4	21.3	98.2	O.S.*	--
B	13.6	5.2	96.3	0.5	96.8
1B	13.6	3.0	95.2	2.0	97.2
D1	10.4	4.9	96.8	1.7	98.5

* O.S. - Out of Service

Dense Phase recoveries shown in the above tabulated bench unit runs were obtained on tar sand from locations throughout the applicants' proposed mining area and from various depths down to the limestone base.

With tar sand exhibiting poor processability characteristics, the Dense Phase second stage increases the bitumen recovery by about 15 per cent. With tar sand classed as having intermediate processability this second stage increases the bitumen recovery by 8%. With tar sand of good processability the single-stage recovery is so high that little additional bitumen recovery can be effected by the second stage.

The tabulated data show that bitumen and fines content do not by themselves establish the processability characteristics of the tar sand. Tar sand of poor processability may be high in bitumen and low in fines content and, conversely, tar sand of good processability may be high in fines and low in bitumen.

Tar sands of poor and intermediate processability characteristics occur at one or more levels of the deposit in the majority of areas studied in the Mildred Lake bench unit program. The two-stage Dense Phase system is required to give improved recoveries from this substantial portion of the commercial deposit.

The applicants' present schedule contemplates a pilot plant operation (70,000 pounds/hour tar sand feed rate) on the Dense Phase process in 1963 to obtain the data needed for final commercial unit design

Froth De-Ashing and Dehydration:

Prior to 1962, several froth de-ashing and dehydration approaches were studied. These approaches would operate satisfactorily on the froths from some tar sand. However, further work on froth from other tar sands in the deposit showed that none of these approaches would handle all the froth expected to be produced commercially with a satisfactory recovery of bitumen for subsequent upgrading.

Late in 1961 a bench unit for thermal dehydration of froth was designed and during the spring and summer of 1962 the froth treatment and dehydration system proposed herein was developed at Mildred Lake.

The bench thermal dehydration unit functioned very well from initial start-up, and in 1,300 hours of operation has processed froth from ten different tar sand locations, including Primary plus Secondary Recovery froth from several of the most troublesome tar sand locations encountered in the deposit. Froth feed rate was 50 to 200 lbs/hr., and operating pressure was varied from 15 to 235 psig. The water content of the bitumen from the bottom of the dehydration vessel was dependent upon the temperature and pressure in the vessel and was readily reduced to 1% to 3% on the stream. (As shown in FIG. C-2, commercially this water is flashed from the bottoms before it goes to storage). The amount of gas-oil distilled overhead was in the range of 2% to 8% on the bitumen, being dependent on the operating temperature and pressure. In this bench operation the overhead gas-oil readily separated from the overhead steam condensate, giving a gas-oil product with about 0.5% water content and water having about 0.5% oil content. (Commercially, this water will pass to an API separator for further oil reduction.)

With the thermal dehydration of froth, all the solids in the feed froth are left in the dehydration bottoms stream. Accordingly, it is desirable to reduce the solids content of the Primary and Secondary Recovery froths before charging to dehydration. A system of froth treatment has been developed to reduce the solids.

Other processes for froth de-ashing and dehydration are also under investigation at Mildred Lake. They show promise of being able to yield a bitumen of lower solids content for the subsequent upgrading steps. It is quite possible that a froth treatment system that is better than the one proposed herein will be available before the construction of the commercial plant is started.

BITUMEN BALANCE

(Design Basis)

	Barrels per Calendar Day	1000 lbs. per Calendar Day
MINING		
Tar Sand Mined	-	466,600
Bitumen in Mined Charge	142,200	50,230
EXTRACTION		
Bitumen in Charge	142,200	50,230
Bitumen Out		
Bitumen to Upgrading	121,000	42,740
Bitumen to Sand Tailings	6,300	2,220
Bitumen to Effluent Water	14,900	5,270
	142,200	50,230
BITUMEN UPGRADING		
Bitumen In		
Bitumen and Gas-Oil from Extraction-Dehydration	121,000	42,740
Products Out		
Synthetic Crude	100,000	30,700
Fuel -		
Coke (Gross)	-	6,250
Liquid	2,600	920
Gases	-	3,360
Sulphur	-	1,010
Process Losses	-	500
		42,740

SULPHUR BALANCE AROUND BITUMEN UPGRADING UNITS

	Sulphur Content M.lbs./Year	Wt. % of Feed Sulphur
SULPHUR IN		
Bitumen Feed to Bitumen Upgrading Units	670,945	100.0
SULPHUR OUT		
Sulphur Product	368,941	55.0
Sulphur in Synthetic Crude	20,130	3.0
Sulphur Plant Stack Loss	32,280	4.8
Sulphur in Coke (Gross Coke Production)	215,177	32.1
Sulphur in Liquid Plant Fuel	14,417	2.1
Unaccounted-for Losses During Processing	20,000	3.0
	670,945	100.0

MATERIAL BALANCES - EXTRACTION AND FROTH DEHYDRATION

(DESIGN BASIS)

	Stream** Designation.	BITUMEN Tons Per Hr.	BITUMEN Wt.%	BITUMEN BPSD	WATER Tons Per Hr.	WATER Wt.%	SOLIDS Tons Per.Hr.	SOLIDS Wt.%	-325 MESH* Tons Per Hr.	-325 MESH* Wt.%	TOTAL Tons Per Hr.
EXTRACTION BALANCE											
STREAMS IN											
Tar Sand Feed	A	1,160	10.8	158,000	570	5.2	9,070	84.0	(1,630)	(15.1)	10,800
Steam to Slurrying	B				445	100.0					445
Fresh Water	C				9,670	100.0					9,670
Total In		1,160			10,685		9,070		(1,630)		20,915
STREAMS OUT											
Froth to Dehydration	D	990	68.8	134,400	410	28.4	40	2.8	(35)	(2.4)	1,440
Vapor from Slurrying	E	5	10.0	700	40	90.0					45
Reject from Slurrying	F	5	5.0	700	5	5.0	90	90.0			100
Sand Tailings	G	50	0.5	7,000	2,450	25.0	7,300	74.5	(500)	(5.1)	9,800
Effluent Water	H	110	1.2	15,200	7,780	81.6	1,640	17.2	(1,095)	(11.5)	9,530
Total Out		1,160		158,000	10,685		9,070		(1,630)		20,915
DEHYDRATION BALANCE											
STREAMS IN											
Froth to Dehydration	D	990	68.8	134,400	410	28.4	40	2.8	(35)	(2.4)	1,440
STREAMS OUT											
Dehydrated Bitumen	I	935	95.9	125,750			40	4.1	(35)	(3.6)	975
Gas Oil	J	55	99.0	8,650	0.5	1.0					55
Water to Retention Pond	K	Trace	(50 PPM)		410	100.0					410
Total Out		990		134,400	410		40		(35)		1,440

* Included in Solids
** Streams Designated by Letters on Extraction-Dehydration Schematic Flow Sheet

TABLE C - 3

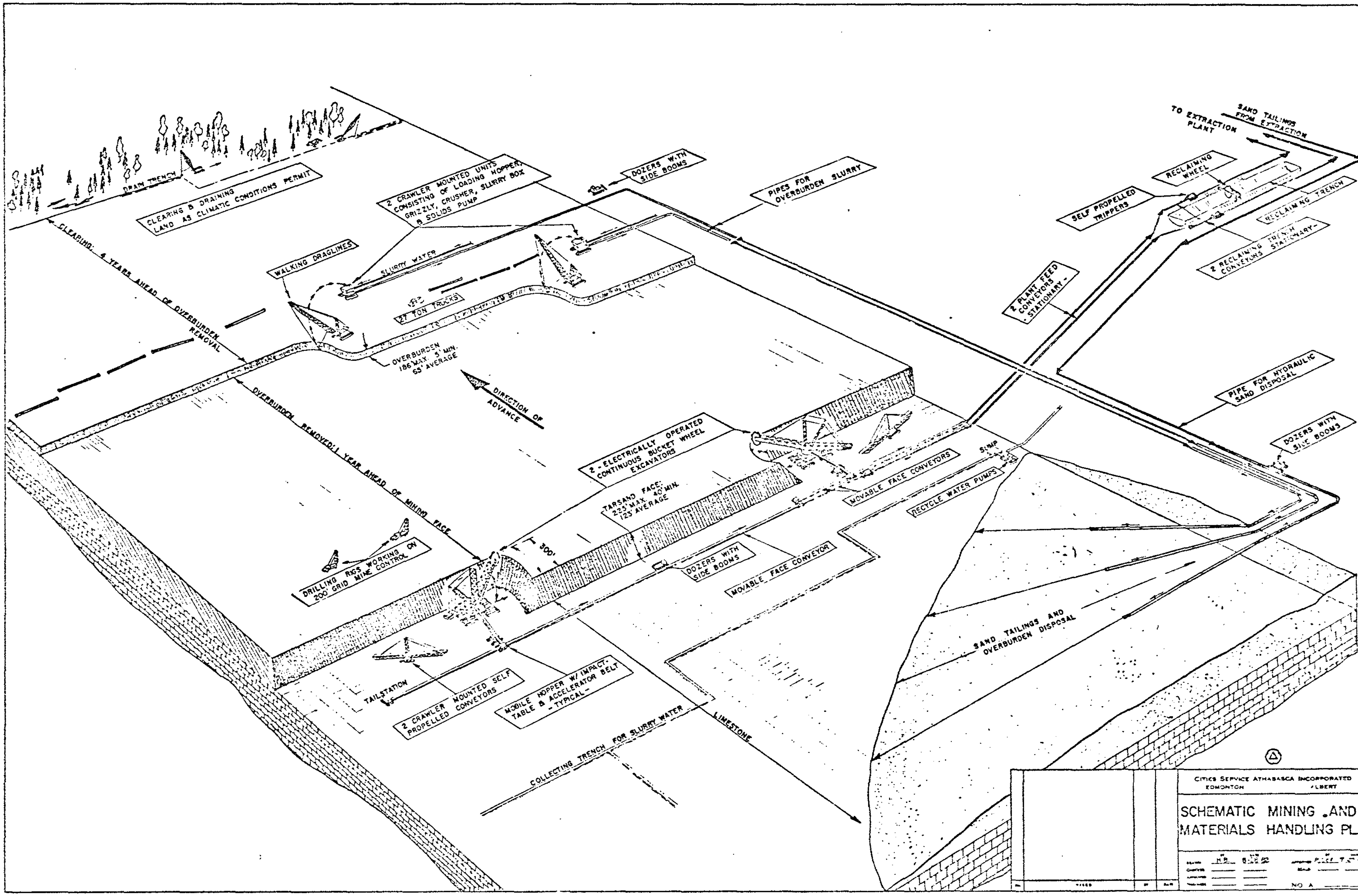
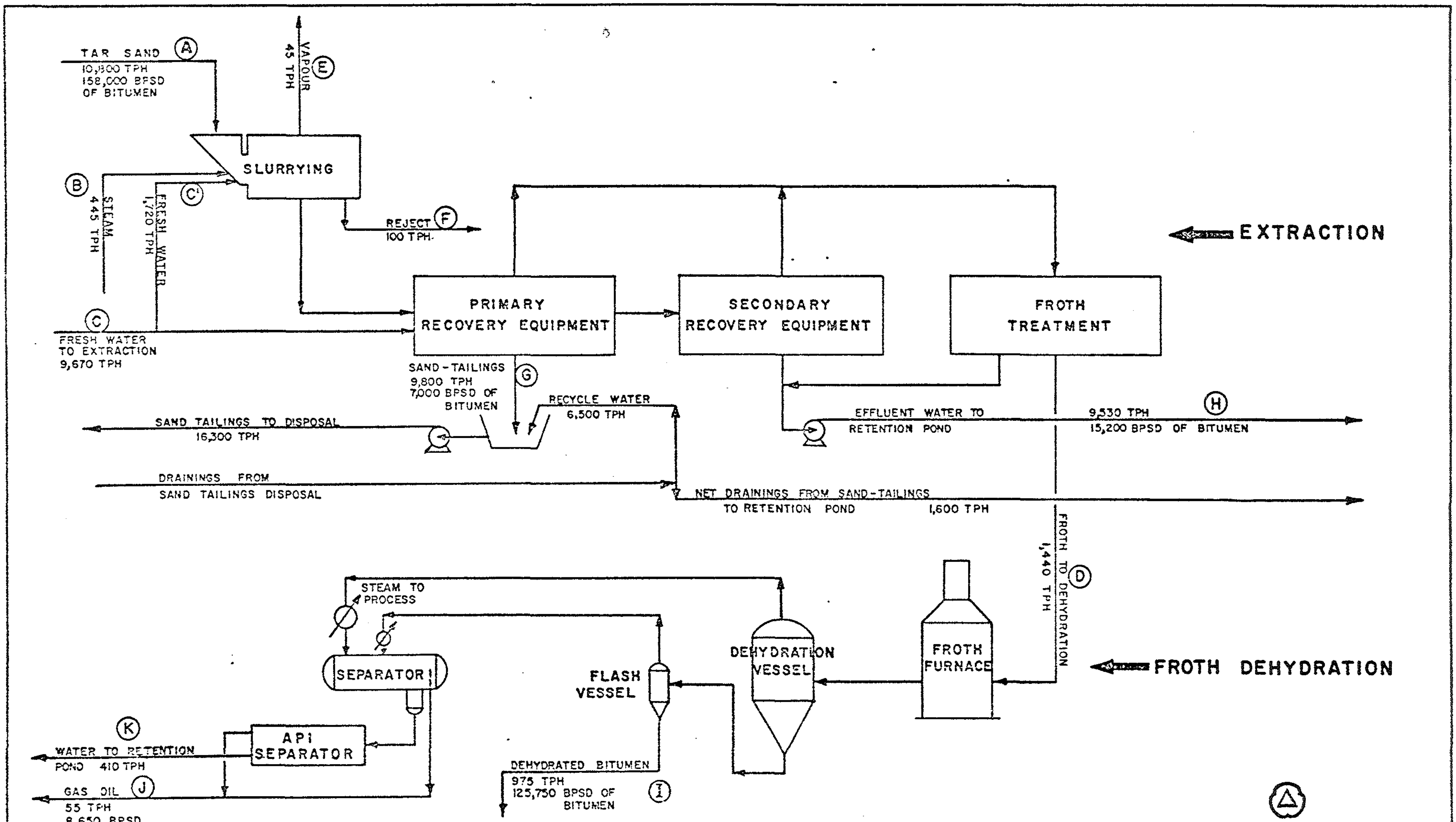

TO EXTRACTION PLANT
SAND TAILINGS FROM EXTRACTION
RECLAIMING WHEEL
RECLAIMING TRENCH
SELF PROPELLED TRIPPERS
2 RECLAIMING TRENCH CONVEYORS -STATIONARY-
DOZERS WITH SIDE BOOMS
PIPES FOR OVERBURDEN SLURRY
2 CRAWLER MOUNTED UNITS CONSISTING OF LOADING HOPPER, GRIZZLY, CRUSHER, SLURRY BOX & SOLIDS PUMP
DRAIN TRENCH
CLEARING & DRAINING LAND AS CLIMATIC CONDITIONS PERMIT
CLEARING: 4 YEARS AHEAD OF OVERBURDEN REMOVAL
WALKING DRAGLINES
SLURRY WATER
27 TON TRUCKS
OVERBURDEN 186' MAX. 5' MIN. 65' AVERAGE
DIRECTION OF ADVANCE
2 PLANT FEED CONVEYORS -STATIONARY-
PIPE FOR HYDRAULIC SAND DISPOSAL
DOZERS WITH SIDE BOOMS
OVERBURDEN REMOVED: 1 YEAR AHEAD OF MINING FACE
2 - ELECTRICALLY OPERATED CONTINUOUS BUCKET WHEEL EXCAVATORS
SUMP
MOVABLE FACE CONVEYORS
RECYCLE WATER PUMPS
TARSAND FACE: 225' MAX. 40' MIN. 125' AVERAGE
300'
DRILLING RIGS WORKING ON 200' GRID MINE CONTROL
DOZERS WITH SIDE BOOMS
MOVABLE FACE CONVEYOR
SAND TAILINGS AND OVERBURDEN DISPOSAL
TAILSTATION
2 CRAWLER MOUNTED SELF PROPELLED CONVEYORS
MOBILE HOPPER W/ IMPACT-TABLE & ACCELERATOR BELT -TYPICAL-
COLLECTING TRENCH FOR SLURRY WATER
LIMESTONE
CITIES SERVICE ATHABASCA INCORPORATED
EDMONTON ALBERT
SCHEMATIC MINING AND MATERIALS HANDLING PLAN

FIG. C-1



No.	REVISED	BY	DATE

TITLE

EXTRACTION — DEHYDRATION SYSTEM

SCHEMATIC FLOWSHEET

CITIES SERVICE ATHABASCA INCORPORATED
EDMONTON ALBERTA

	BY	DATE		BY	DATE
DRAWN	H. B.	11-6-62	APPROVED		
CHECKED			SCALE:	~	
APPROVED					
ENGINEER			NO. C		

FIG. C-2

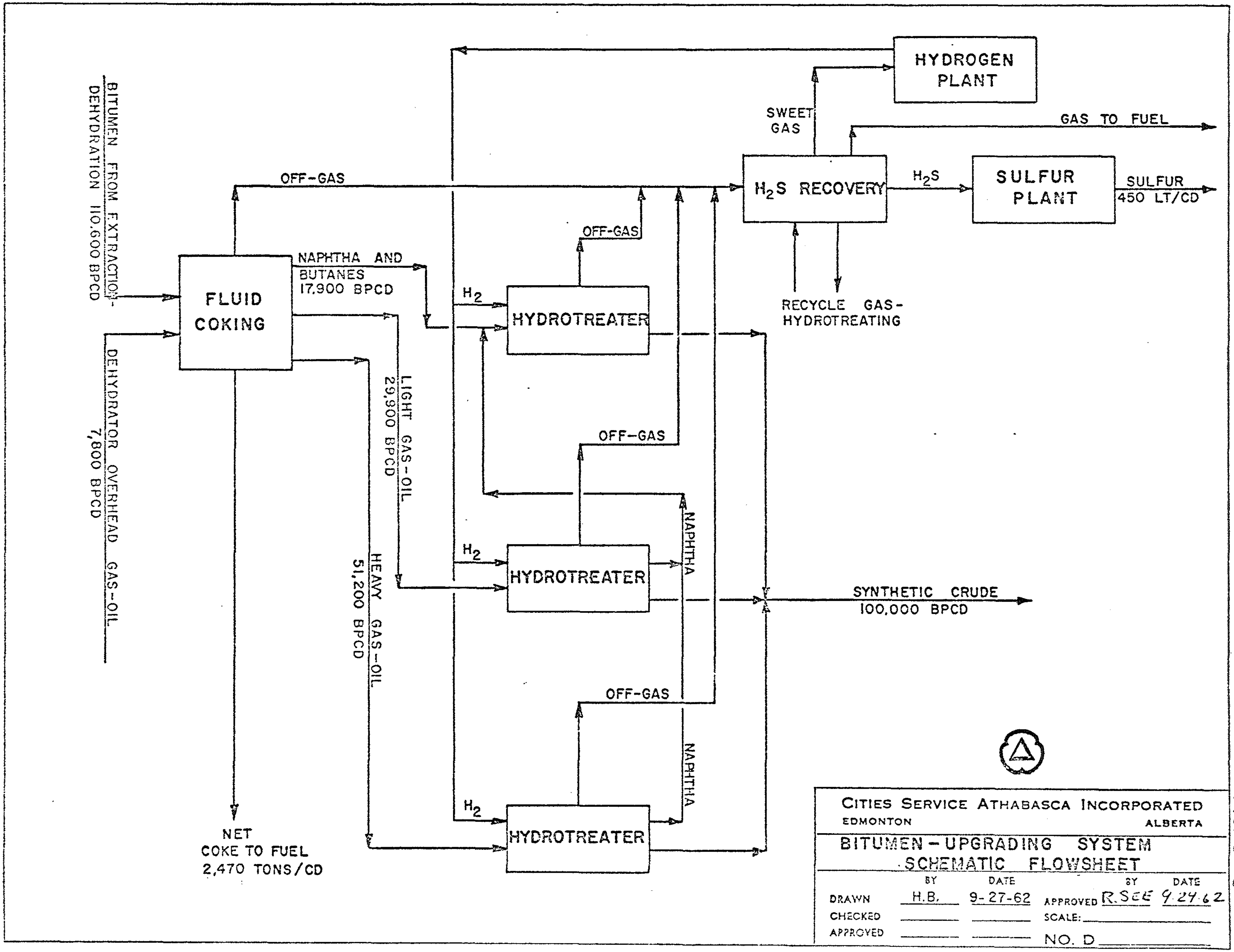

HYDROGEN PLANT
SWEET GAS
GAS TO FUEL
OFF-GAS
H_2S RECOVERY
H_2S
SULFUR PLANT
SULFUR 450 LT/CD
BITUMEN FROM EXTRACTION-DEHYDRATION 110,600 BPCD
FLUID COKING
NAPHTHA AND BUTANES 17,900 BPCD
OFF-GAS
H_2
HYDROTREATER
RECYCLE GAS-HYDROTREATING
DEHYDRATOR OVERHEAD GAS-OIL 7,800 BPCD
LIGHT GAS-OIL 29,900 BPCD
OFF-GAS
NAPHTHA
H_2
HYDROTREATER
SYNTHETIC CRUDE 100,000 BPCD
HEAVY GAS-OIL 51,200 BPCD
OFF-GAS
NAPHTHA
H_2
HYDROTREATER
NET COKE TO FUEL 2,470 TONS/CD
CITIES SERVICE ATHABASCA INCORPORATED
EDMONTON ALBERTA
BITUMEN-UPGRADING SYSTEM SCHEMATIC FLOWSHEET
BY DATE BY DATE
DRAWN H.B. 9-27-62 APPROVED R.SEE 9.24.62
CHECKED SCALE:
APPROVED NO. D

FIG. C-3

2. 1968 APPLICATION TO THE OIL AND GAS CONSERVATION BOARD CONCERNING RESERVES AND OVERBURDEN

APPLICATION

to the

ALBERTA OIL AND GAS CONSERVATION BOARD

Under Part VI-A of

THE OIL AND GAS CONSERVATION ACT

by

ATLANTIC RICHFIELD COMPANY

CITIES SERVICE ATHABASCA, INC.

IMPERIAL OIL LIMITED

ROYALITE OIL COMPANY, LIMITED

May 9, 1962
Amended to May 3, 1968

RESERVES AND OVERBURDEN

Continued reserves drilling programs since the 1963 application have outlined a large body of premium reserves in the area of Beaver Creek, on the west end of the originally proposed mining area. These reserves, which are shown as the initial mining area on the lease plan (Figure I-1), have a reasonably rich, uniform depth McMurray section with little reject material in the feed zone and favourable over-all stripping ratios.

Figure II-1 is an isopach of the total overburden plus the centre reject. Overburden is defined as all Pleistocene deposits, Clearwater shales, and any tar sand at the top of the McMurray formation containing less than 6% of bitumen by weight. Centre reject is defined as all material in the feed zone containing less than 6% bitumen and occurring in seams of five feet or more thickness.

Figure II-2 is an isopach of the tar sand feed section exclusive of any centre reject.

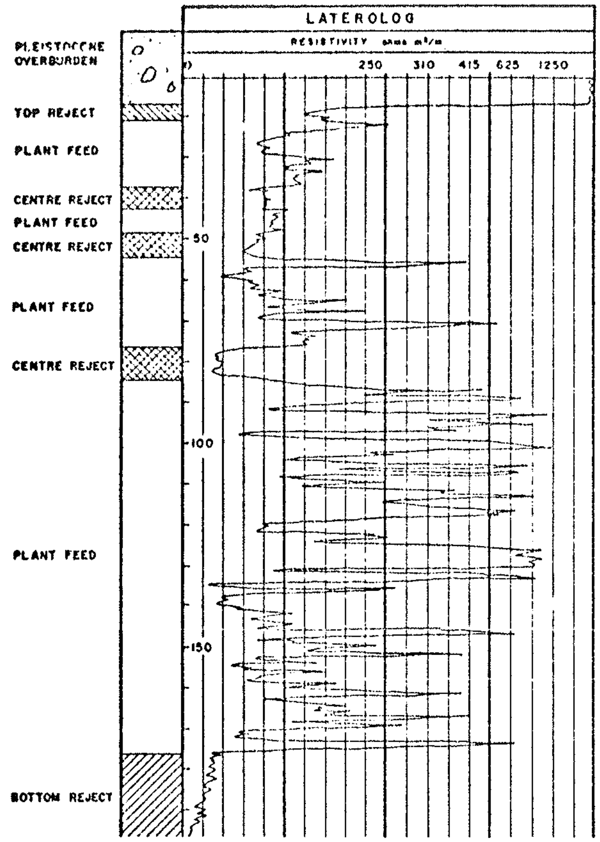
Method Used to Calculate Reserves

The calculation of reserves on Lease 17 incorporates drilling data from 408 holes drilled over an area of about 28 square miles. These holes were drilled over approximately a twenty-five year period by several different interests as follows:

	Syncrude	Royalite	Fed. Gov't.	Others	Total
Initial Mining Area	78	5	0	0	83
Balance Lease 17	139	149	15	22	325
Total Lease 17	217	154	15	22	408

Twenty-six of the Syncrude holes were drilled to coincide with Royalite hole locations so that a comparison would be provided between the two main sets of drilling data.

As noted in the tables of hole descriptions, some holes were cored and others were drilled and logged. Laterologs and Gamma Ray logs were used in obtaining the thicknesses of the tar sand sections in the logged holes. Correlations between core analyses and log readings from common holes indicated that a reading of approximately four divisions on the laterolog corresponded to a tar sand containing 6 percent bitumen by weight. The Gamma log was used to check the laterolog readings.



WELL LOG INTERPRETATION

The figure on the right shows a typical interpretation of feed and reject thicknesses from a laterolog reading. In all cases the overburden and top reject were established with the aid of samples collected at the time the hole was drilled.

Since the fluid content of the McMurray formation varies appreciably, the log-derived bitumen assay was considered inadequate for detailed reserves estimates. As a result, only the cored hole assays were used to estimate bitumen saturations.

The assays from the core hole data were prepared as a weighted average, in accordance with the following procedure:

1. Each sample interval in feet was multiplied by its corresponding bitumen content;

2. The values obtained under (1) were added and then divided by the total of the sample intervals;

3. The value obtained from (2) is then the weighted average bitumen content for that hole.

The hole locations were plotted on 1" = 200' maps.

The bitumen reserves and overburden volume of the mining area were calculated for 1000 ft. x 1000 ft. squares, using the Thiessen polygon method[(1)] to weight the influence of the holes.

Selective Mining

The reserves have been calculated on the basis of a selective mining scheme. The cut-off point is 6% bitumen content by weight; material greater than 6% bitumen will be fed to the plant, and material containing less than 6% (-6% material) will generally be rejected.

The -6% material above the feed section will be rejected with the overburden; the -6% material below the feed section will be left in place. Selective mining will reject -6% material contained within the feed section whenever this lean material occurs in seams of five feet or more in thickness. Seams of -6% material less than five feet in thickness occurring within the feed section have been included in the plant feed.

Mining Recovery

On the basis of selective mining, the extraction plant feedstock from the initial mining area contains an average of 11.8% bitumen by weight. The

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(1) Mining Engineers Handbook 3rd Edition Vol. 1, Section 10, Subject Heading #11, page 71.

average bitumen content of the reject material within the mining area is 2.1 wt.%. Reject represents 31.1% of the volume of the McMurray formation but only 7.3% of the bitumen in place.

The side slopes on the boundary walls and dykes of the mining pit contain a further 2% of the bitumen in place, a part of which may be recovered during expansion of the pit. The formation covered by the extreme surface outline of the initial mining area contains a total of 580,200,000 barrels of bitumen in place, of which 526,200,000 barrels will be mined and fed to the extraction plant - an overall mining recovery of 90.7%. These reserves would support the proposed operation for over 14 years.

The holes influencing the initial mining area are shown on Figure II-3 and listed in Table II-1. Footages and bitumen content are shown for all feed and reject material. The stripping ratio indicated for each hole includes top and centre reject material with the overburden to give a measure of the total waste material handled per yard of plant feed.

In arriving at an estimate of the reserves lost in the pit walls and dykes, a side slope of 60^{o} has been used. The perimeter of the pit is 40,000 feet and a 9000 foot partial dyke is required to split the pit. Figure II-4 is a schematic cross-section through the pit wall showing a typical slope and the average thickness of materials in the mining area. Average bitumen contents of feed and reject were applied to the shaded area of the pit wall, and to the cross-section of the partial dyke, to estimate the wall loss of 2%.

All quantities have been calculated on the basis of tar sand having an in-place unit weight of 125 lbs. per cu. ft. and bitumen weighing 353.3 lbs. per barrel. Percent bitumen in feed or reject is at all times expressed as a weight percent.

Expansion of Mining Area

Figure II-5 has been prepared to indicate the relative attractiveness of various reserves blocks from a mining standpoint. The shading legend has been built on an ascending scale of barrels of bitumen fed to the extraction plant per cubic yard of total material moved. The darker the square, the more attractive it is for mining. This figure is similar to a stripping ratio plot, but modified slightly by the varying bitumen contents in the feed zone. The potentially recoverable reserves in the area shown are approximately 3.1 billion barrels, sufficient to support the proposed operation for about 80 years.

The estimated overall stripping ratios are shown by block on Fig. II-6.

The distribution of reserves shown on Figure II-5 would suggest a probable expansion of the initial mining area in the order indicated by major blocks on the overlay. Initially, the pit would be extended to the southern boundary of Lease 17 (Area A) to allow for complete filling of the original mining area with tailings before Beaver Creek is rediverted. The operation would then move into Area B and out towards the escarpment. Area C would complete the mining to the east of Beaver Creek, after which there would be a major shift in operations to Area D in the west part of the Lease 17 reserves. Mining could then proceed north and west as determined by additional reserves development.

The preceding order of development must, of course, be considered as only a preliminary projection. The actual pattern might well be affected by operational requirements or additional reserves information.

The initial mining area plus expansion areas A and B contain reserves sufficient to support the proposed operation for well over the requested minimum term of the permit. The following table summarizes the expected recoveries and feed qualities from these areas:

	Initial Mining Area	Area A	Area B
Barrels of Bitumen in Place	580,200,000	241,700,000	866,600,000
Barrels of Bitumen Fed to Extraction	526,200,000	210,300,000	750,200,000
Mining Recovery	90.7%	87.0%	86.6%
Average Percent Bitumen in Plant Feed	11.8%	11.3%	11.8%
Average Percent Fines in Plant Feed	11.4%	14.5%	16.9%

Tables II-2 and II-3 list the holes influencing expansion areas A and B respectively.

Limiting Stripping Ratios

As with most of the large tar sands leases, the reserves on Lease 17 show a marked variation in quality over broad areas of the lease. Indications of much thinner tar sand and thicker overburden in the southwest corner of the lease suggest that these reserves might be beyond the economic limits of a mining operation. To aid in the evaluation of marginal reserves, Syncrude Canada Ltd. carried out a study on the likely limits of open pit tar sand mining.

The maximum allowable stripping ratio is determined by the limiting costs which can be incurred in mining within the economics acceptable to an operator. As such, it involves considerations confidential to any given operator and can only be illustrated in general terms.

The procedure followed by Syncrude was as follows:

1. Estimate the increased mining costs that would be associated with various stripping ratios. This is determined from pit geometry and quantities handled. In considering the limiting stripping ratio for a new operation in the tar sands, the pit opening costs become of considerable importance. For the limiting incremental production from an established pit, only the continuing operating costs are of major concern. As can be seen on Figure II-7, the cost variation with stripping ratio is also dependent to some degree on the thickness of the tar sand feed zone, resulting in a family of cost curves. The shape of the curves is similar for both of the above limiting conditions when the costs are expressed as a multiple of the base cost at 1:1 stripping ratio for each condition. As noted, the absolute costs at any given stripping ratio will be determined by whether total or only marginal costs are controlling for the condition under study.

2. Estimate the limiting feed costs that might be carried by the operation. As with the calculation of mining costs, the allowable feed cost would be different depending on whether one was considering the installation of a new operation or determining the shut-down of an existing pit.

3. The limiting stripping ratio, at a given tar sand thickness, can be estimated by picking off the appropriate allowable feed cost on the mining cost curves.

It can be appreciated that any forecast of limiting stripping ratio will be affected both by changes in unit mining costs and by what is considered economically sound by any given operator under the conditions existing at the time of decision. From the current study, Syncrude has estimated that the limiting stripping ratio will be in the order of 2.5:1 for new large-size operations when the tar sands mining industry has become well established, and that the limiting ratio for incremental operation of existing pits will approach 3.5:1.

Economically Unmineable Reserves

Reserves might be considered economically unmineable for either of two reasons: the material underlies permanent plant or disposal areas; or the stripping ratio is beyond allowable limits. The areas presently considered unmineable are also shown on the overlay on Figure II-5.

The permanent plant facilities and the initial tailings disposal have been located in areas reasonably poor in reserves. The plant facilities cover an area of 160 acres containing 28.6 MM barrels of bitumen in place. The initial tailings disposal area is 1680 acres and contains 249.7 MM barrels in place. The reserves under the sludge retention pond would not be permanently lost since sludges could eventually be settled on mined-out areas.

The section of Lease 17 to the southwest (Area U_1) and the two small blocks along the southern boundary (Areas U_2 and U_3) are presently considered unmineable because of excessive stripping ratios. The high stripping ratios to the southwest are indicated by only a few widely-spaced holes and may change markedly with additional exploratory drilling.

TABLE II-1

INITIAL MINING AREA

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	BASED ON 5' and 6% REJECT INTERVAL								Ratio Overburden + Top & Center Reject to Feed
	TOP REJECT		CENTER REJECT		BOTTOM REJECT		PLANT FEED		
	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	
CORE HOLES									
23-15-1	65	1.1	0	-	65	0.5	101	10.8	1.02
24-12-1	3	1.1	16	4.7	84	1.6	100	12.7	0.47
24-16-2	26	4.5	0	-	0	-	149	12.1	0.37
24-18-1	24	0.1	7	4.9	51	1.1	146	13.2	0.44
24-20-1	35	0.1	31	1.9	59	1.3	95	11.7	1.06
24-23-1	25	2.3	37	5.1	15	0.3	115	11.3	0.89
25-11-1	20	0.1	5	2.9	33	2.7	177	10.3	0.14
25-11-3	35	3.8	6	4.3	73	2.7	88	12.6	0.57
25-12-2	0	-	32	5.3	0	-	126	11.4	0.49
25-14-1	2	0.1	45	3.6	23	0.8	146	11.3	0.45
25-14-2	22	2.0	27	4.1	43	0.7	131	10.7	0.43
25-16-1	30	3.0	25	3.3	37	1.3	138	12.2	0.49
25-19-1	40	3.6	8	4.9	7	2.9	142	12.9	0.55
25-19-2	29	4.0	5	4.7	9	5.4	131	11.1	0.52
25-21-1	34	2.9	32	2.2	64	1.3	100	12.5	0.91
26-12-1	23	0.2	10	4.9	3	0.0	138	11.0	0.30
26-14-2	0	-	26	2.9	0	-	114	11.5	0.49
26-15-1	19	5.9	8	1.9	43	2.1	131	12.1	0.27
26-18-1	31	3.8	5	1.5	36	0.4	136	11.7	0.41
26-19-1	22	0.1	18	5.2	49	0.4	147	10.9	0.41
26-20-1	27	3.4	17	3.9	69	0.3	130	12.4	0.51
26-23-1	43	0.1	9	0.0	36	1.9	112	13.7	0.69
27-11-1	20	5.3	39	4.9	14	4.0	112	10.7	0.54
27-16-1	7	2.0	28	4.0	53	0.6	112	14.1	0.47
27-16-2	0	-	12	4.2	0	-	139	11.3	0.26
28-14-1	22	5.0	16	4.2	21	0.0	92	12.5	0.63
28-15-1	0	-	0	-	29	1.0	103	12.5	0.71
28-19-1	18	0.2	5	3.3	38	0.6	125	11.2	0.22
28-21-1	57	3.0	15	4.4	35	2.2	88	10.3	1.04
28-22-1	69	3.2	14	3.9	48	0.7	85	9.9	1.27
29-16-2	14	0.1	15	4.8	3	0.4	141	11.6	0.23
29-19-2	0	-	0	-	0	-	105	12.6	0.19
30-14-1	15	0.1	19	4.4	26	0.2	150	11.5	0.30
30-19-1	20	0.1	11	4.1	6	0.0	134	12.0	0.25
30-20-2	0	-	0	-	6	1.6	160	12.7	0.03
31-12-2	16	2.3	5	4.7	0	-	133	12.7	0.35
31-15-2	5	4.1	8	4.1	0	-	151	11.6	0.23
32-18-2	0	-	12	5.1	0	-	141	12.0	0.20
33-14-2	35	2.0	38	3.9	4	2.2	91	10.7	1.31
33-16-1	35	2.8	19	4.6	13	0.1	116	11.1	0.67
33-22-1	38	4.3	35	3.9	81	1.3	80	11.8	1.02

TABLE II-1 (continued)

INITIAL MINING AREA

HOLES INFLUENCING THE MINING AREA

Hole	BASED ON 5' and 6% REJECT INTERVAL				Ratio Overburden + Top & Center Reject to Feed
	TOP REJECT	CENTER REJECT	BOTTOM REJECT	PLANT FEED	
Number	Feet	Feet	Feet	Feet	
Drill Holes					
23-14-1	2	38	50	139	0.46
23-19-1	24	9	38	136	0.49
24-11-1	41	9	55	123	0.57
24-21-1	1	84	57	71	1.73
25-15-1	4	7	32	171	0.17
25-18-1	2	8	13	164	0.22
25-20-1	5	56	34	93	0.96
25-23-1	65	0	34	103	0.83
26-11-1	8	18	68	67	0.70
26-16-1	6	5	48	157	0.10
26-22-1	3	19	61	136	0.29
27-20-1	18	39	54	117	0.54
28-12-1	21	0	3	118	0.28
28-18-1	0	0	33	139	0.12
28-18-2	0	0	33	137	0.15
28-23-1	4	58	71	99	0.83
29-11-1	26	47	2	89	0.92
29-12-1	5	21	17	133	0.25
29-14-1	0	25	26	131	0.39
29-15-1	7	0	40	160	0.06
29-16-1	14	5	11	138	0.16
29-18-1	3	10	28	112	0.17
29-20-1	4	0	50	122	0.08
29-21-1	13	13	59	108	0.23
30-11-1	0	15	23	119	0.30
30-12-1	4	14	14	160	0.23
30-15-1	3	0	13	167	0.14
30-16-1	0	6	14	158	0.16
30-18-1	19	0	7	151	0.17
30-22-1	13	13	86	91	0.42
30-23-1	22	0	105	35	1.66
31-14-1	7	23	29	144	0.33
31-20-1	2	0	13	170	0.05
32-11-1	21	17	3	118	0.53
32-16-1	4	5	15	154	0.17
32-19-1	18	11	0	129	0.25
32-21-1	10	30	65	119	0.33
33-14-1	30	41	7	90	1.30
33-15-1	41	25	28	103	0.90
33-18-1	16	20	7	124	0.36
33-19-1	16	34	8	103	0.58
33-20-1	18	68	28	74	1.32

NOTE: Drill Holes evaluated by means of Electro-Mechanical Logs.

TABLE II-2

MINING AREA "A"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTER REJECT Feet	CENTER REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Pleistocene & Clearwater Overburden Feet
	BASED ON 5' AND 6% REJECT INTERVAL								
CORE HOLES									
22- 5-1	23	1.2	74	3.2	7	0.1	97	10.1	28
22- 8-1	18	2.4	0	-	197	4.0	5	6.0	13
22-11-1	4	5.7	0	-	207	3.0	7	6.5	33
24- 7-1	38	2.2	58	3.8	18	0.1	99	11.3	10
24-10-1	137	0.8	14	3.2	34	0.1	30	9.9	13
24-12-1	3	1.1	16	4.7	84	1.6	100	12.7	28
25- 6-1	0	-	44	4.1	7	0.8	112	10.4	31
25- 8-1	21	0.1	44	3.6	19	0.1	116	10.2	4
25-11-1	20	0.1	5	2.9	33	2.7	177	10.3	0
25-11-3	35	3.8	6	4.3	73	2.7	88	12.6	9
26- 7-1	16	0.1	52	3.2	6	1.2	103	10.1	5
26-10-1	34	0.1	9	1.7	2	0.9	128	13.5	5
27-11-1	20	5.3	39	4.9	14	4.0	112	10.7	2
28- 6-1	45	0.7	50	0.7	50	0.7	0	-	30
28- 8-1	23	3.9	10	2.8	52	0.9	78	11.4	10
29-11-2	0	-	35	3.6	0	-	103	11.4	36
31-12-2	16	2.3	5	4.7	0	-	133	12.7	25

HOLE NUMBER	TOP REJECT Feet	CENTER REJECT Feet	BOTTOM REJECT Feet	PLANT FEED Feet	Feet
DRILL HOLES					
24-11-1	41	9	55	114	20
25-10-1	52	21	40	76	17
26- 8-1	144	0	6	24	10
26-11-1	8	18	68	67	21
28-10-1	14	26	17	129	9
30- 8-1	0	36	0	108	27
30-11-1	0	15	23	119	21
32-11-1	21	17	3	118	25
35- 8-1	98	5	0	42	87

Note: Drill Holes evaluated by means of Electro-Mechanical Logs.

TABLE II-3

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTER REJECT Feet	CENTER REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Pleistocene & Clearwater Overburden Feet
	BASED ON 5' AND 6% REJECT INTERVAL								
CORE HOLES									
9-20-1	0	-	15	3.9	14	2.3	165	12.4	30
9-20-2	0	-	0	-	31	4.3	150	14.5	35
9-21-1	0	-	24	4.5	0	-	182	12.1	18
10-20-1	1	1.1	0	-	16	2.1	115	12.2	62
10-21-1	0	-	60	3.9	0	-	140	10.9	21
10-21-2	0	-	54	4.4	1	0.1	122	10.1	32
10-21-3	0	-	22	3.5	0	-	167	10.7	14
10-22-1	0	-	36	4.3	0	-	135	9.6	23
10-23-1	0	-	40	3.1	0	-	186	11.2	19
11-21-1	0	-	14	4.5	0	-	132	10.5	30
11-21-2	0	-	17	5.0	0	-	112	12.6	45
11-22-2	0	--	47	3.8	0	-	112	9.5	20
11-22-3	33	1.6	40	4.6	0	-	79	9.6	10
11-23-1	0	-	0	-	21	5.0	149	10.9	17
11-23-2	4	3.9	19	2.9	0	-	137	9.9	17
11-24-1	0	-	36	4.5	0	-	121	10.0	30
11-24-2	12	3.3	25	4.7	0	-	157	10.8	26
11-24-3	0	-	50	4.1	0	-	126	10.5	21
11-24-4	0	-	41	4.2	0	-	122	11.5	22
12-20-1	5	2.7	31	4.6	0	-	142	12.4	24
12-21-1	70	3.0	15	5.6	1	2.8	83	12.3	15
12-21-2	9	3.2	14	4.3	0	-	162	11.8	25
12-21-3	9	3.3	19	3.3	0	-	161	11.9	20
12-22-1	0	-	11	1.0	0	-	130	11.1	30
12-22-2	0	-	12	4.4	14	3.5	97	14.8	52
12-24-1	28	2.4	34	1.5	0	-	88	12.9	26
12-24-2	0	-	0	-	0	-	159	11.7	25
12-25-1	0	-	57	3.8	9	5.2	90	9.7	18
12-25-2	4	5.0	5	2.9	75	4.0	30	10.1	20
13-20-1	0	-	20	2.7	0	-	153	11.1	42
13-21-1	7	2.2	0	-	11	3.8	169	12.8	25
13-21-2	10	1.8	6	1.9	14	2.8	150	12.3	30
13-22-1	0	-	8	4.6	6	0.1	160	12.0	27
13-22-2	1	2.6	8	4.4	3	0.4	154	12.3	21
13-22-3	0	-	0	-	0	-	158	12.1	26
13-23-2	30	3.7	0	-	0	-	127	12.6	23
13-24-1	0	-	56	2.8	0	-	84	10.3	20
13-24-2	0	--	0	-	3	4.0	33	15.2	111
13-25-2	18	2.9	57	2.7	0	-	85	12.3	20
14-20-1	0	-	0	-	10	4.4	162	13.0	40
14-21-1	10	4.8	0	-	0	-	142	13.6	55
14-22-1	38	1.0	0	-	34	1.0	88	14.7	43
14-23-1	12	2.1	49	1.1	0	-	94	12.9	21
14-23-2	52	2.3	8	4.4	2	0.1	96	10.8	22
14-25-1	8	4.5	39	1.0	0	-	115	11.0	19
15-12-1	17	2.3	40	3.3	0	-	154	12.0	25

TABLE 11-3 - Continued

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTER REJECT Feet	CENTER REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Pleistocene & Clearwater Overburden Feet
	BASED ON 5' AND 6% REJECT INTERVAL								
CORE HOLES									
15-14-1	27	0.4	115	3.3	0	-	58	9.7	36
15-15-1	4	0.5	104	3.5	10	1.0	72	12.1	53
15-15-2	5	1.0	64	2.4	0	-	111	12.1	55
15-16-1	25	1.3	56	4.2	22	1.0	103	8.8	34
15-16-2	10	2.3	46	3.8	4	1.0	107	9.7	51
15-18-1	29	1.9	8	2.4	0	-	147	14.0	35
15-19-1	27	3.1	15	5.1	0	-	140	11.1	25
15-20-1	19	2.3	0	-	14	1.6	152	13.5	40
15-20-2	22	1.8	0	-	6	0.9	154	14.2	42
15-22-1	32	1.9	5	3.9	5	1.9	136	12.2	20
15-23-1	8	3.8	67	1.6	0	-	107	11.2	21
16-12-1	0	-	45	3.2	0	-	123	11.2	67
16-13-1	24	4.0	85	1.9	0	-	64	11.0	65
16-18-1	0	-	36	1.7	0	-	144	12.9	17
16-20-1	33	3.5	23	4.2	0	-	117	13.4	25
16-21-1	6	5.1	32	3.9	0	-	140	11.8	33
16-21-2	10	0.7	33	4.2	14	3.7	135	12.3	16
16-23-1	24	2.7	0	-	0	-	162	13.6	19
16-24-1	14	4.5	8	5.5	0	-	149	11.4	35
16-24-2	1	1.5	80	2.8	0	-	99	11.2	29
16-24-3	3	5.9	104	2.8	0	-	72	11.2	21
17-12-1	56	3.7	14	4.0	5	1.1	114	11.1	51
17-12-2	43	3.9	0	-	12	1.0	121	14.1	62
17-14-1	0	-	73	1.5	5	0.1	108	13.6	51
17-14-2	1	2.9	72	4.1	5	0.1	115	11.2	48
17-14-3	12	4.8	19	3.6	6	4.1	148	12.7	46
17-15-1	10	4.4	10	4.0	8	3.9	160	11.1	36
17-16-1	42	4.0	21	4.3	10	1.0	105	11.3	36
17-16-2	28	3.4	5	4.3	0	-	131	11.3	45
17-16-3	0	-	51	3.2	0	-	140	12.1	43
17-17-1	0	-	0	-	2	0.1	163	13.0	40
17-18-1	16	3.4	0	-	16	0.6	158	12.5	30
17-18-2	0	-	36	4.4	16	0.2	130	12.0	35
17-19-1	9	3.6	24	2.4	2	1.5	152	12.0	20
17-19-2	3	3.1	47	3.3	10	2.3	120	11.2	36
17-20-1	6	2.8	40	3.6	4	0.2	140	14.1	20
17-22-1	0	-	70	2.5	7	0.1	95	13.8	48
17-22-2	0	-	64	2.9	16	0.8	112	11.7	40
17-22-3	0	-	73	2.5	13	2.9	95	12.0	46
17-22-4	33	3.4	69	3.3	9	1.0	76	12.0	32
17-23-1	3	1.2	31	5.2	0	-	164	11.1	36
17-25-1	24	3.8	32	5.1	0	-	125	11.1	21
18-12-1	49	2.2	16	5.6	17	1.0	112	12.0	44
18-14-1	2	1.2	15	4.4	10	2.4	152	12.6	39
18-15-1	3	1.4	58	4.6	7	5.1	106	12.9	41
18-16-1	21	3.1	12	5.3	0	-	152	12.9	27
18-18-1	19	2.9	8	5.0	32	4.0	123	11.3	40

TABLE 11-3 - Continued

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	BASED ON 5' AND 6% REJECT INTERVAL: TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTER REJECT Feet	CENTER REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Pleistocene & Clearwater Overburden Feet
CORE HOLES									
18-18-2	0	-	27	3.9	9	4.0	130	13.2	45
18-19-1	9	0.8	65	3.5	0	-	100	10.0	36
18-20-1	78	1.7	13	4.6	4	0.8	88	12.2	35
18-21-1	1	0.1	19	2.8	3	0.6	164	13.0	26
18-23-1	24	3.6	53	4.0	0	-	121	9.7	28
18-23-2	16	5.2	47	4.3	0	-	100	11.8	60
18-24-1	35	4.1	36	4.2	5	0.6	115	10.9	30
18-26-1	18	1.7	31	4.2	7	2.9	112	10.7	27
19-12-1	5	0.6	37	3.5	51	2.3	135	13.4	37
19-12-2	27	3.3	0	-	32	0.1	137	14.7	61
19-13-1	17	2.0	0	-	34	1.3	148	11.8	40
19-14-1	10	2.2	18	4.0	49	3.4	153	12.4	41
19-14-2	0	-	36	3.5	57	2.4	126	13.0	50
19-15-1	41	4.0	26	2.9	19	1.0	118	11.3	41
19-15-2	44	2.8	13	4.5	43	2.9	104	13.3	41
19-16-1	30	3.8	0	-	28	1.0	112	11.0	50
19-18-1	0	-	52	4.0	3	0.4	121	12.9	40
19-19-1	0	-	32	4.2	14	0.7	144	9.5	41
19-19-2	0	-	38	2.8	12	0.1	137	10.2	43
19-20-1	10	3.0	87	2.5	0	-	71	10.0	40
19-20-2	1	0.5	69	2.0	12	3.4	85	12.1	44
19-21-1	30	3.0	14	3.0	21	0.8	132	12.7	39
19-22-1	0	-	81	1.5	9	1.0	94	10.9	55
19-22-2	50	2.6	16	5.2	17	0.1	116	10.6	50
19-24-1	5	0.5	61	4.3	8	0.1	113	10.0	46
19-26-1	22	3.3	17	3.3	7	5.6	112	10.5	30
20-14-1	0	-	44	4.3	40	0.4	131	13.3	61
20-16-1	0	-	31	4.7	8	0.2	160	12.1	24
20-17-1	12	4.2	46	2.6	2	0.2	103	12.7	54
20-18-1	12	2.4	59	4.1	28	0.7	110	12.2	40
20-22-1	0	-	54	3.5	30	1.2	112	10.0	49
20-23-1	4	1.4	49	3.4	4	1.0	122	10.8	40
20-27-1	32	3.6	16	2.0	0	-	122	10.8	24
21-12-1	8	1.4	42	4.7	42	2.2	112	11.3	33
21-14-1	7	1.1	89	3.6	26	0.9	84	10.4	47
21-15-1	4	0.6	31	3.8	39	1.6	157	12.1	36
21-16-1	30	3.1	30	3.4	28	0.8	114	13.0	48
21-18-1	7	1.4	83	2.7	16	2.7	75	12.2	44
21-19-1	45	2.5	5	1.0	19	0.7	124	12.6	50
21-20-1	6	3.0	85	1.7	10	0.7	94	9.9	42
21-22-1	1	1.3	31	3.8	35	2.3	143	12.8	36
21-23-1	6	1.5	46	3.8	6	0.4	127	11.1	39
21-24-1	2	0.3	54	4.6	0	-	118	10.1	43
21-26-1	0	-	72	4.4	0	-	102	10.7	39

TABLE 11-3 - Continued

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

HOLE	BASED ON 5' AND 6% REJECT INTERVAL								Pleostocene & Clearwater Overburden
	TOP REJECT		CENTER REJECT		BOTTOM REJECT		PLANT FEED		
NUMBER	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet
CORE HOLES									
21-27-1	2	1.0	50	3.1	26	4.2	90	10.8	23
22-12-1	23	4.4	14	2.7	61	2.1	124	10.2	40
22-12-2	15	1.7	22	3.4	71	2.0	113	9.9	45
22-14-1	7	1.6	44	2.5	74	0.8	116	14.4	47
22-15-1	6	2.0	29	4.4	56	0.6	146	11.8	45
22-16-1	4	0.7	55	1.2	36	1.1	111	12.0	50
22-18-1	13	1.2	24	3.9	18	0.6	131	10.9	44
22-18-2	26	0.1	32	4.7	18	0.5	95	11.2	51
22-19-1	74	3.1	7	5.9	7	1.5	91	10.4	35
22-20-1	3	0.8	88	2.9	43	0.8	72	13.1	48
22-20-2	32	2.5	49	1.5	8	3.9	89	11.0	45
22-22-1	0	-	69	1.6	0	-	93	12.5	50
22-23-1	5	5.3	13	3.7	27	3.5	145	10.2	36
22-24-1	0	-	46	2.8	12	1.0	113	12.2	41
22-26-1	7	1.0	92	3.6	25	0.7	83	11.0	55
22-27-1	0	-	88	3.8	3	1.0	78	11.6	25
22-28-1	17	1.6	113	2.7	0	-	40	11.3	22
22-28-2	14	2.9	89	2.3	0	-	62	10.8	23
23-15-1	65	1.1	0	-	65	0.5	101	10.8	38
24-12-1	3	1.1	16	4.7	84	1.6	100	12.7	28
24-16-2	26	4.5	0	-	0	-	149	12.1	29
24-18-1	24	0.1	7	4.9	51	1.1	146	13.2	33
24-20-1	35	0.1	31	1.9	59	1.3	95	11.7	35
24-23-1	25	2.3	37	5.1	15	0.3	115	11.3	40
24-26-1	0	-	35	4.1	29	0.2	140	11.7	35
25-24-1	2	2.0	15	5.1	46	1.8	120	11.2	42
25-24-2	7	3.5	10	3.4	39	0.9	130	11.0	40
25-27-1	18	2.9	29	4.3	5	0.9	107	9.1	28
26-23-1	43	0.1	9	0.0	36	1.9	112	13.7	25
26-26-1	19	3.2	26	4.6	5	0.9	110	11.5	40

TABLE 11-3 - Continued

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	BASED ON 5' AND 6% REJECT INTERVAL TOP REJECT Feet	CENTER REJECT Feet	BOTTOM REJECT Feet	PLANT FEED Feet	Pleistocene & Clearwater Overburden Feet
DRILL HOLES					
23-14-1	2	38	50	139	24
23-19-1	24	9	38	136	33
24-21-1	1	84	57	71	38
24-24-1	34	31	11	100	34
25-23-1	65	0	34	103	20

Note: Drill Holes evaluated by means of Electro-Mechanical Logs.

Fig. II - 1

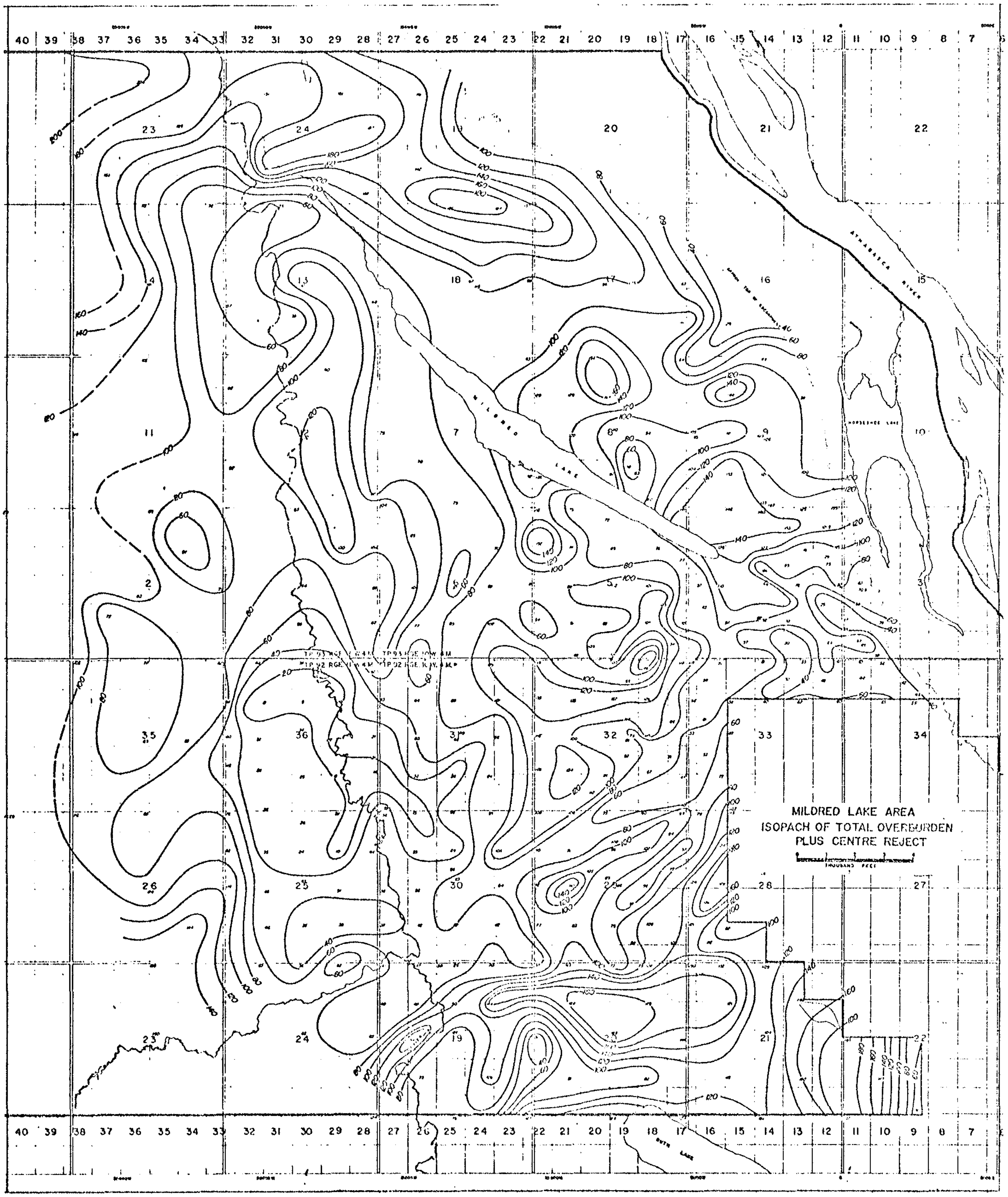
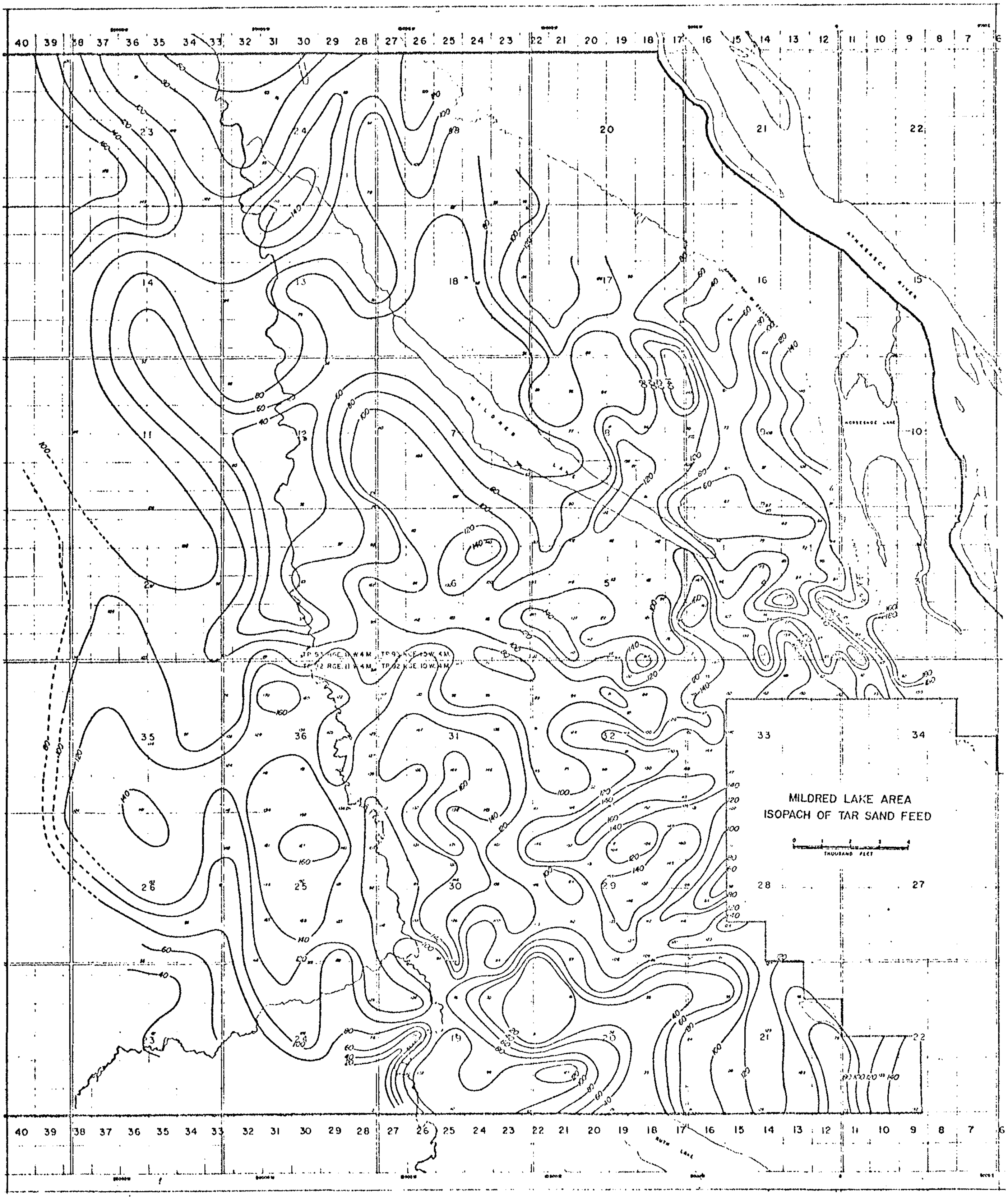
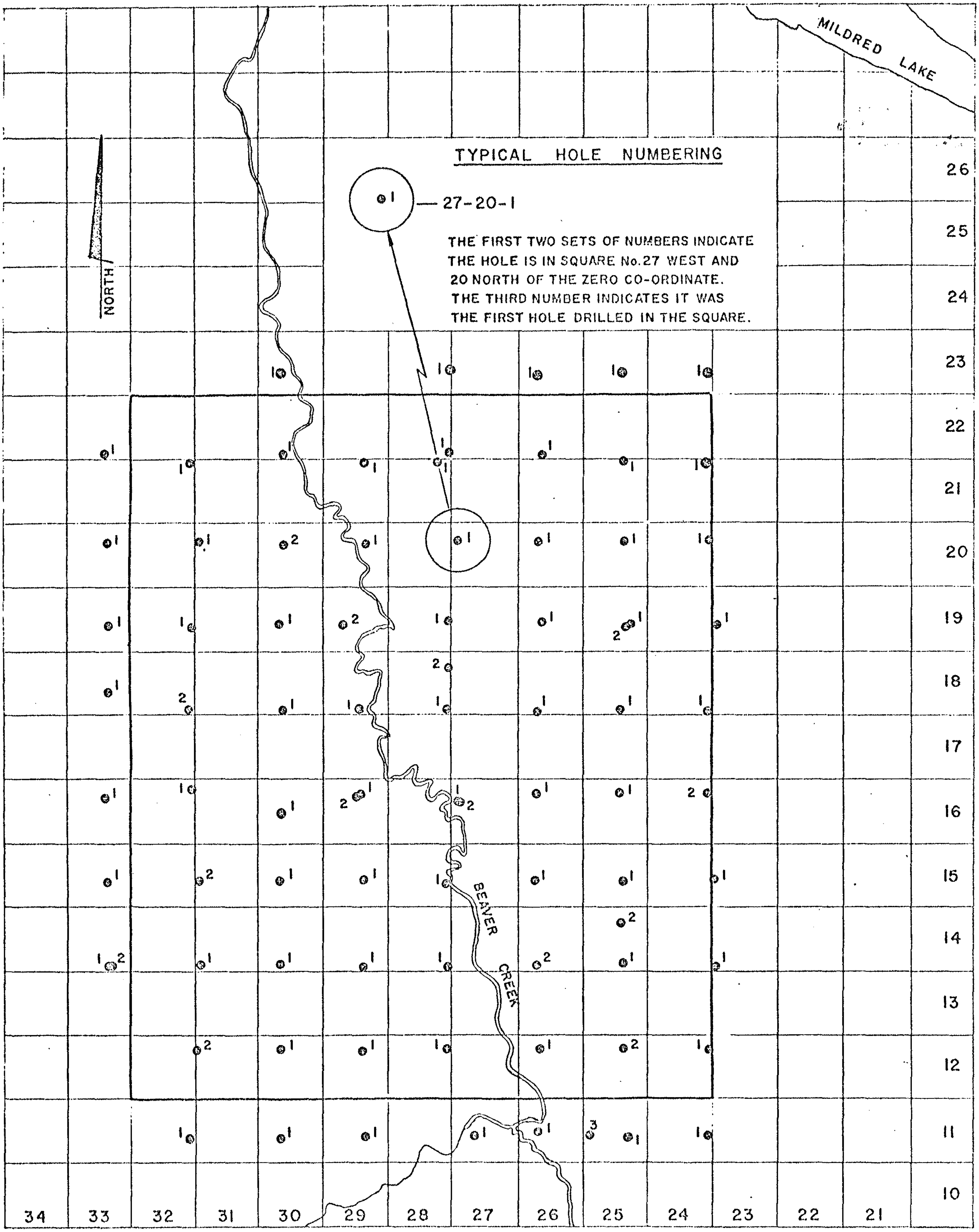
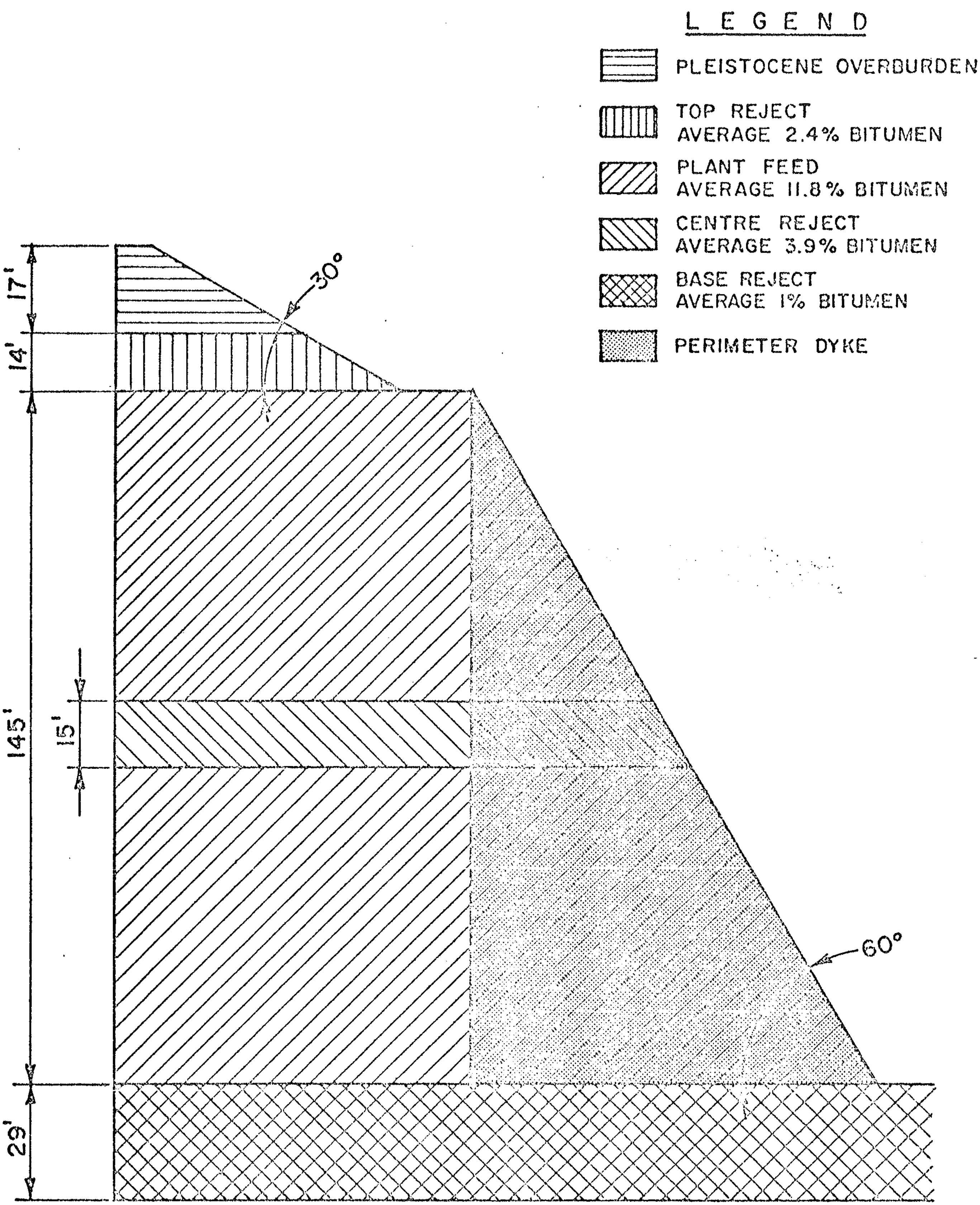

MILDRED LAKE AREA
ISOPACH OF TOTAL OVERBURDEN
PLUS CENTRE REJECT
MILDRED LAKE
ATHABASCA RIVER

Fig. II - 2

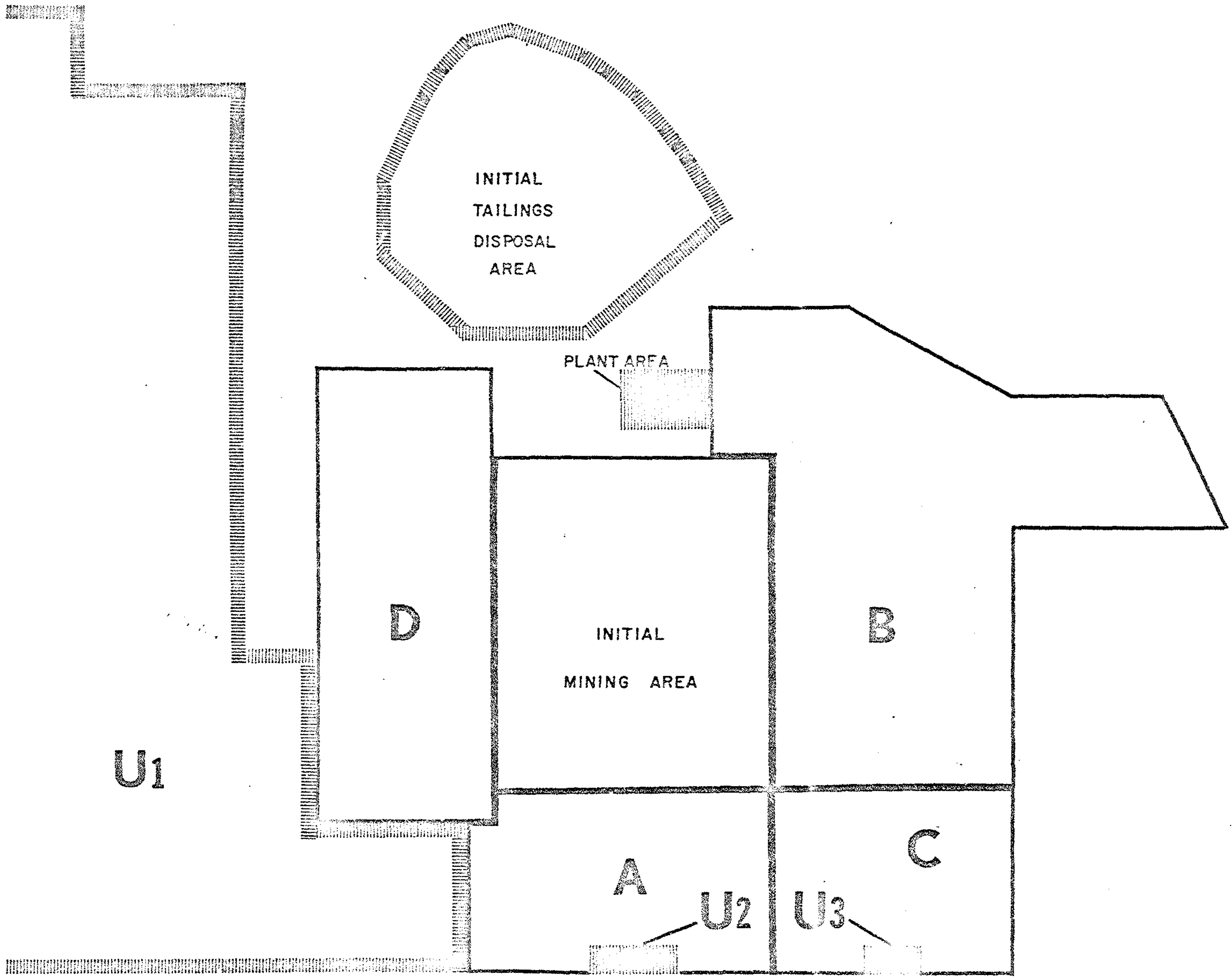

MILDRED LAKE AREA
ISOPACH OF TAR SAND FEED
THOUSAND FEET
ATHABASCA RIVER
MILDRED LAKE
HORSESHOE LAKE
RUTH LAKE

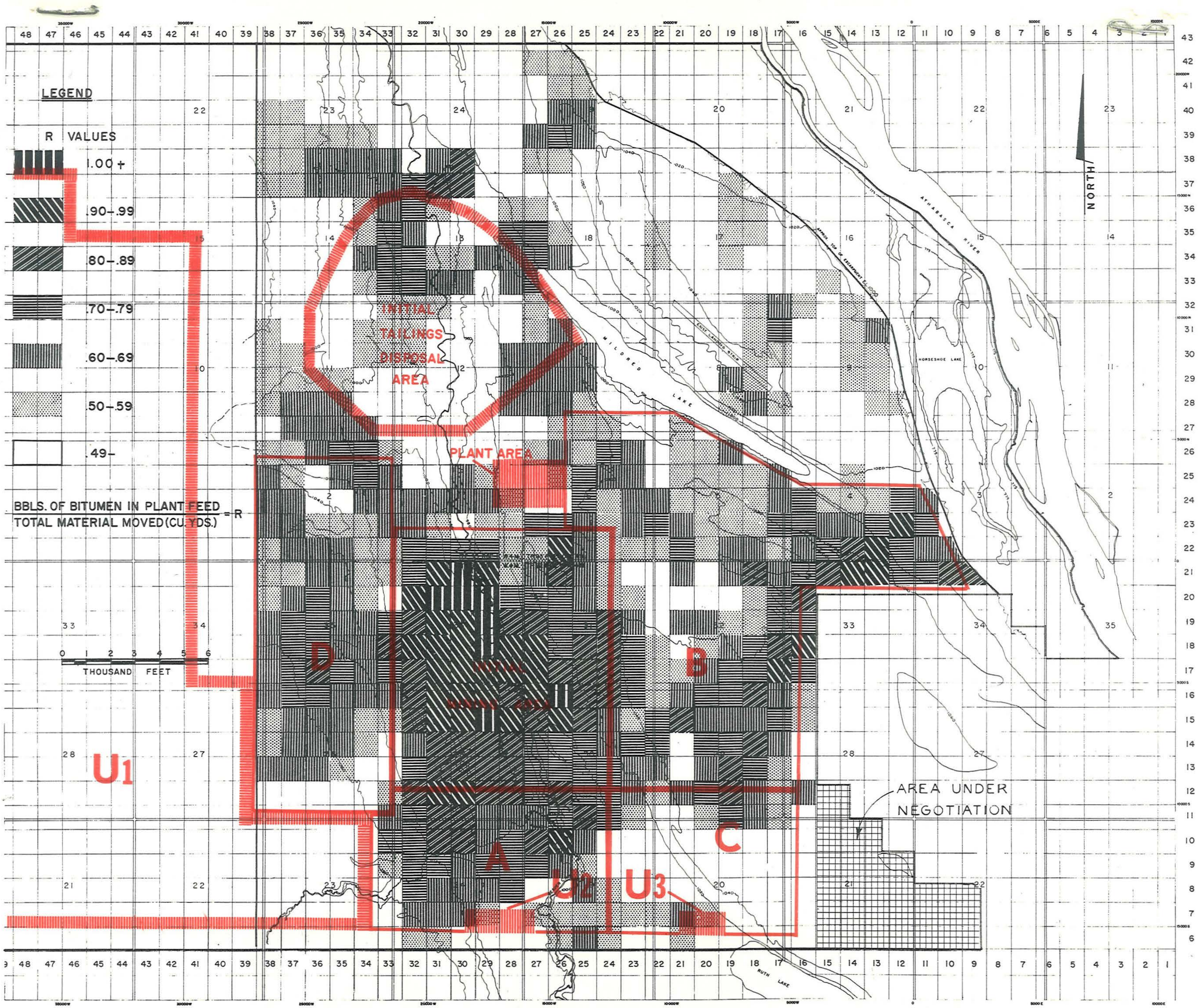


LOCATION OF HOLES INFLUENCING
INITIAL MINING AREA
(REFER TO TABLE No.II-1 FOR DESCRIPTIONS)



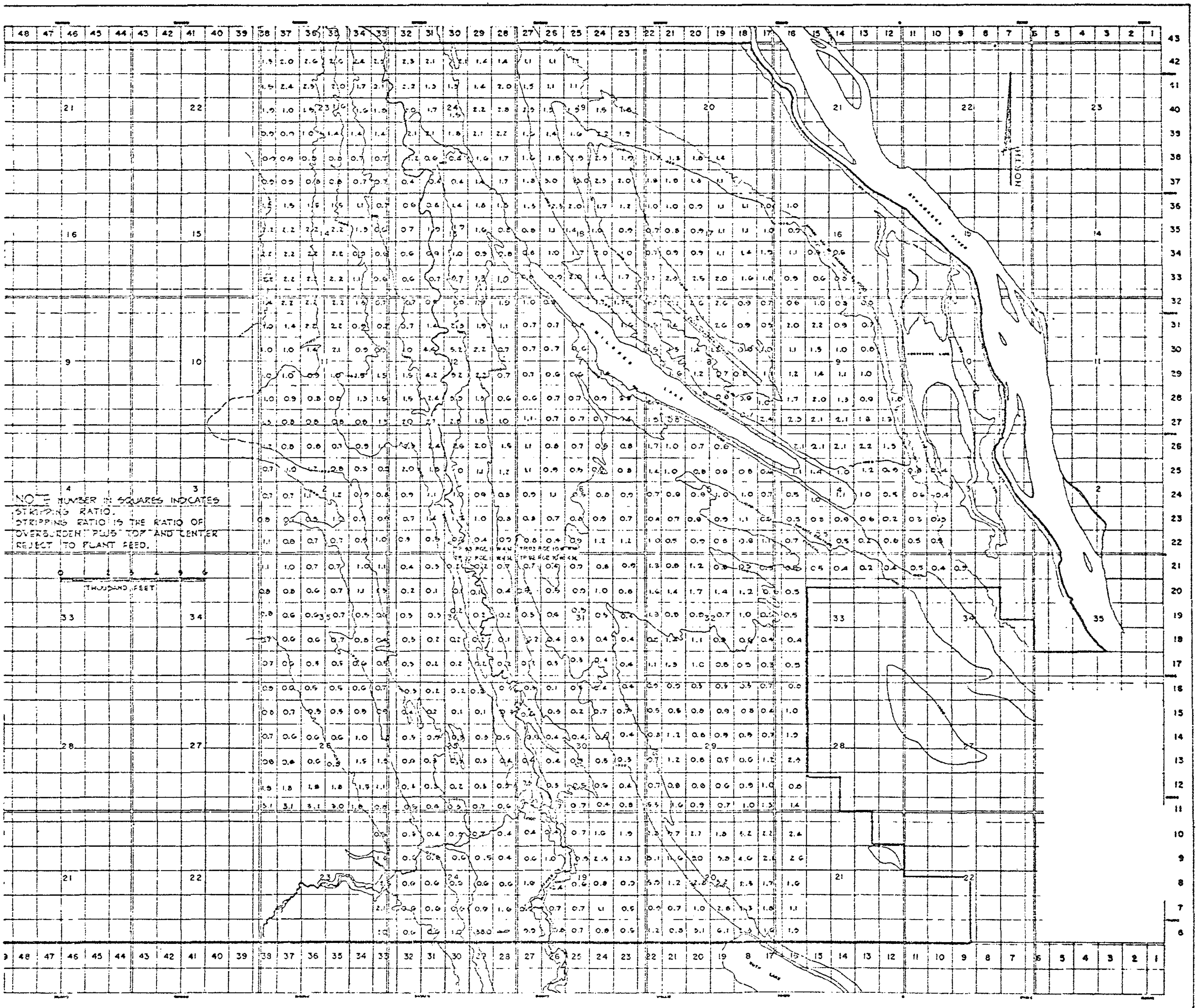
PIT WALL CROSS SECTION
AVERAGE THICKNESS OF MATERIAL


INITIAL
TAILINGS
DISPOSAL
AREA
PLANT AREA
D
INITIAL
MINING AREA
B
U1
A
U2
U3
C



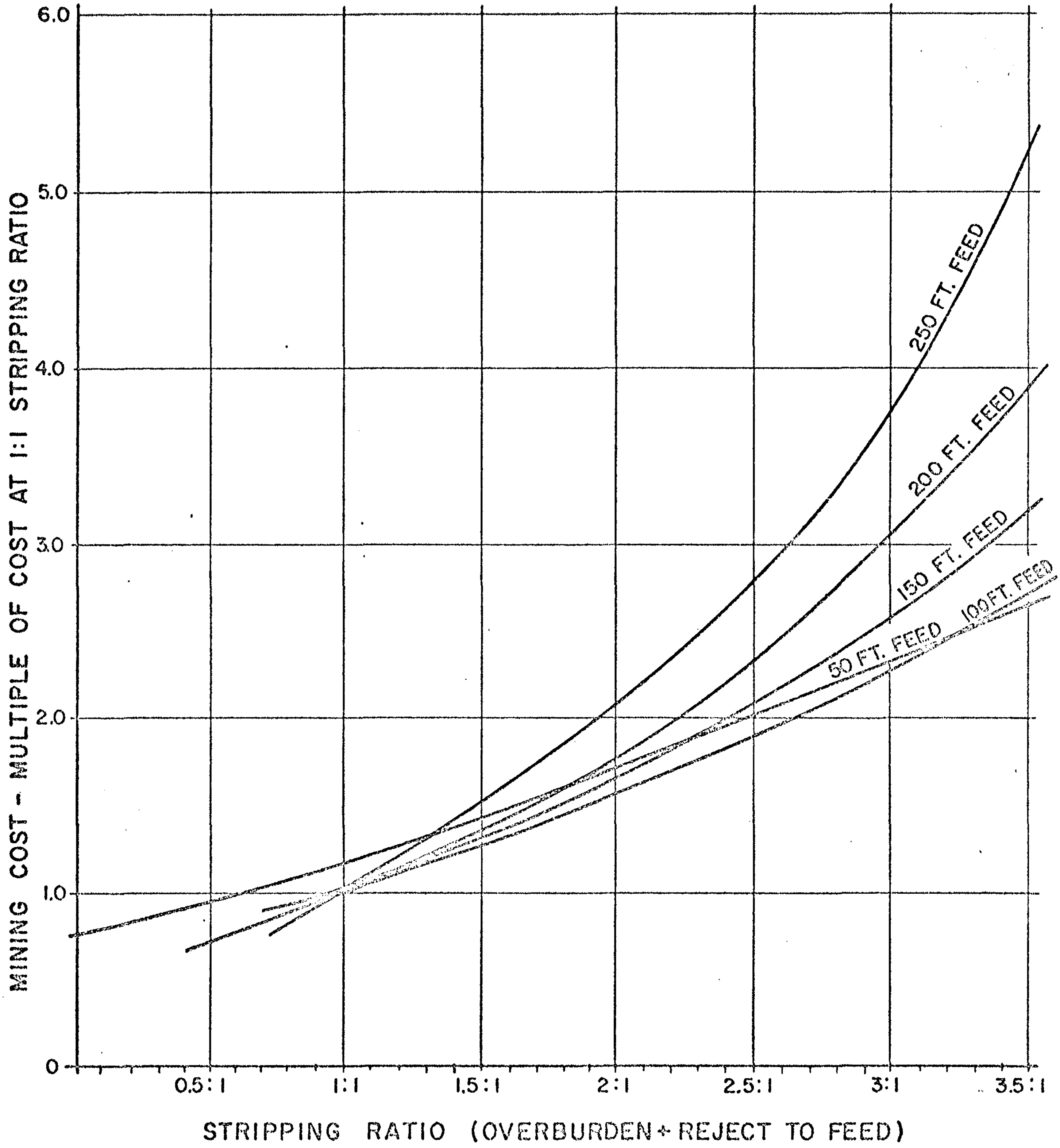
QUALITY OF RESERVES

Fig. II - 5



STRIPPING RATIO

Fig. II - 6



TOTAL MINING COSTS Vs. STRIPPING RATIO

3. 1971 APPLICATION TO THE OIL AND GAS CONSERVATION BOARD CONCERNING OPERATIONS

V CONSERVATION AND TECHNICAL MATTERS

(1) Views of the Applicants

The applicants calculated reserves of 2,440 million barrels of bitumen in the three mining areas, A, B and C, illustrated by Figure 1. Changes in the proposed mining areas from those proposed in the 1968 application resulted from additional mineable reserves being defined in Area B and a reduction in the size of Area C to allow for an increase in plant size and to provide for more regular pit geometry. The areas designated as U_1, U_2 and U_3 on Figure 1 were said by the applicants to be unmineable. There would be sufficient reserves in Areas A and B to supply the plant with feed for the 25-year life of Approval No. 1223.

Losses in mining recovery would be due primarily to bitumen included in the centre reject material and side slopes on the boundary walls. Side slope losses at the pit walls were estimated by the applicants to be 1.0 per cent of the bitumen in place compared to 2.0 per cent contemplated in the 1968 application. The distinction between mineable and reject material, would be made on a visual basis with confirmation by in-pit analyses.

The applicants stated that reject losses of 8.3 per cent of the bitumen in place are expected in the initial mining area. This loss is 1.0 per cent higher than that indicated for the initial mining area in the previous application and is due to the inclusion of lower grade material in the southern part of the area. Since the side slope losses of the boundary wall will be less as a result of the dragline method of mining, the net effect

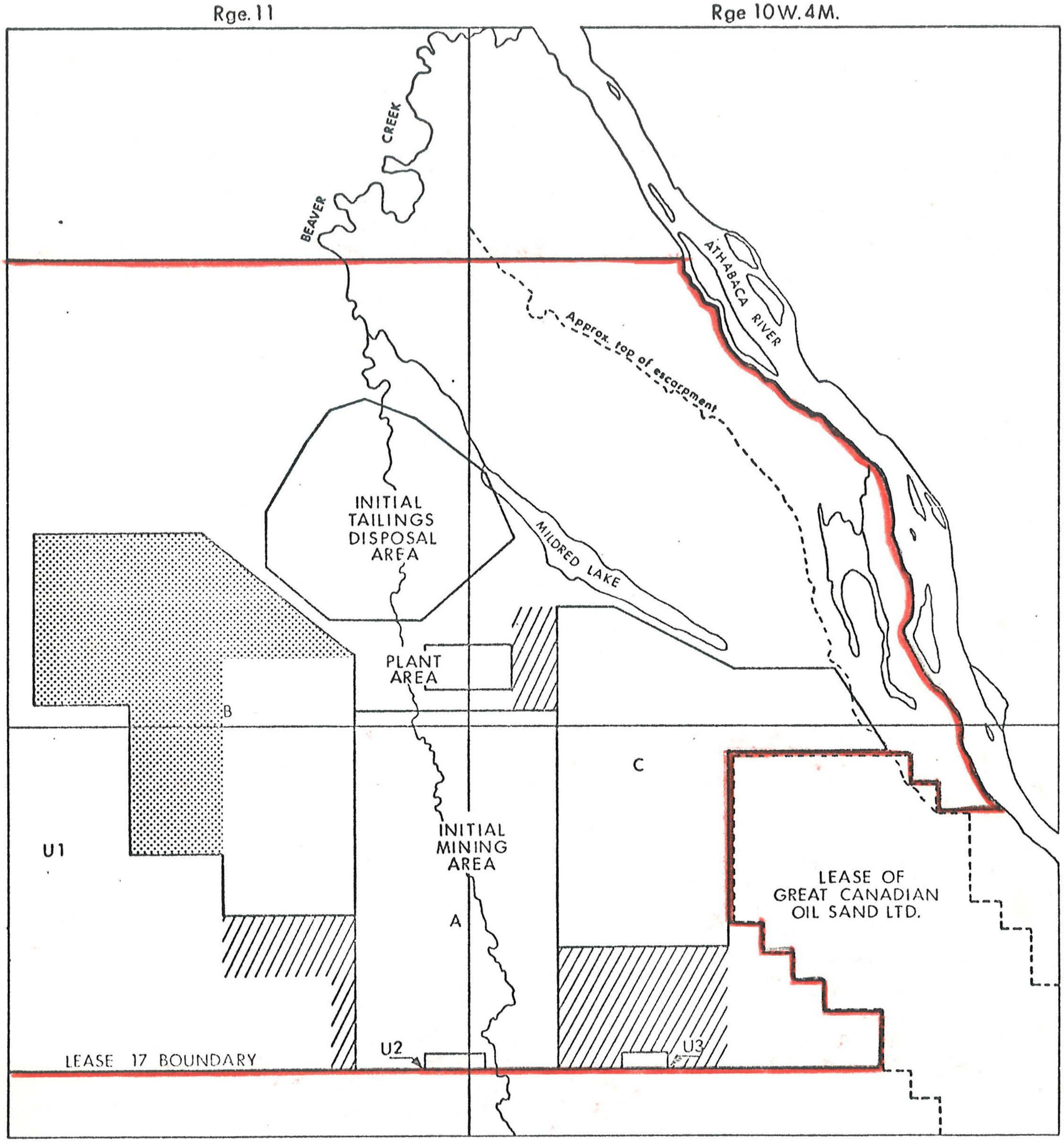


FIGURE 1 - PROPOSED MINING AREAS
(Most areas shown are approximate)

Scale: 0 1 2

- Deletion from 1968 propsal
- Addition to 1968 propsal

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA
DECEMBER, 1971

of these losses was a predicted mining efficiency in Area A about equal to that predicted for the initial mining area in the 1968 application. The reserves, feed gravity and mining recoveries estimated for Areas A, B and C are set out in Table V-1.

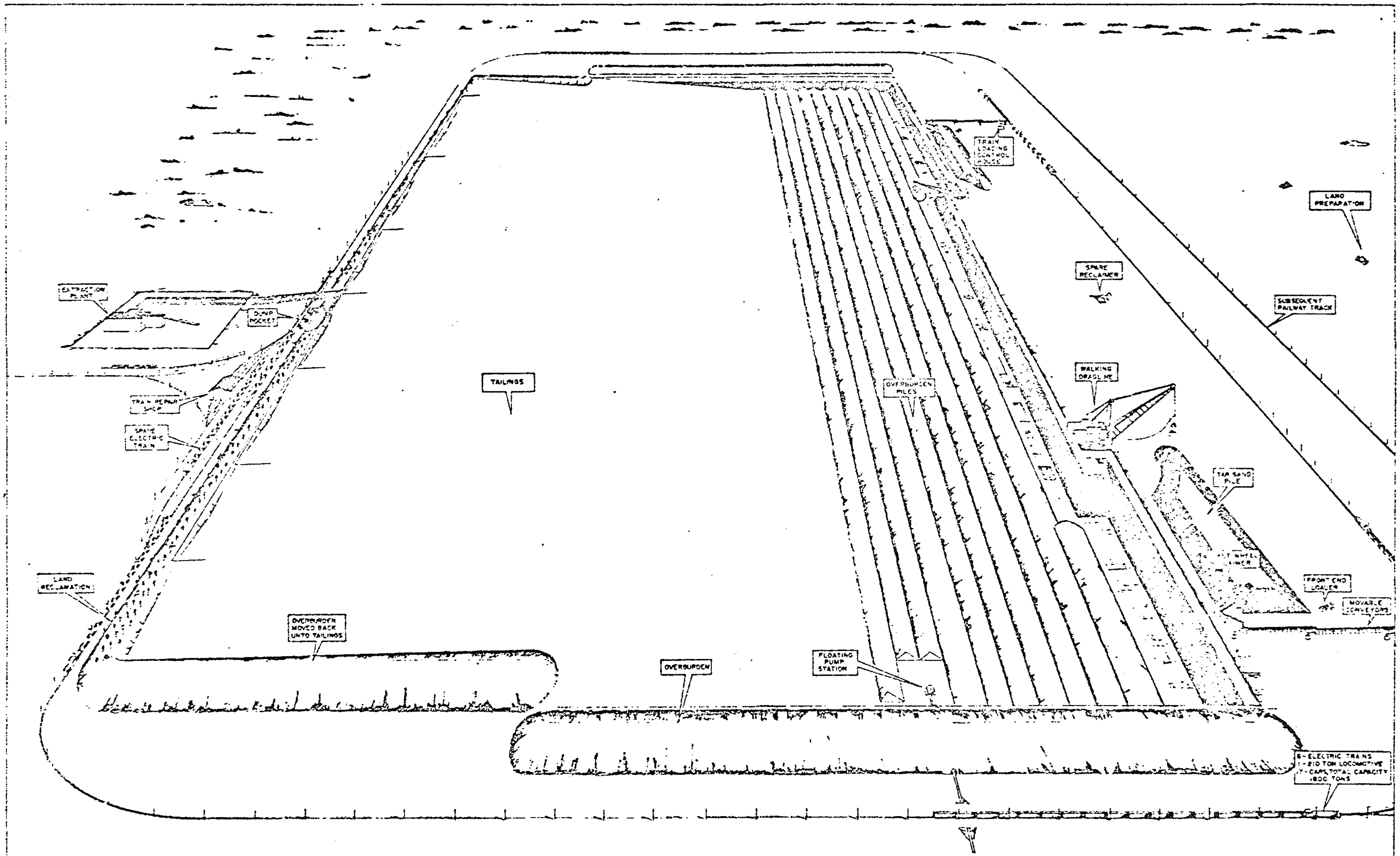
TABLE V-1

RESERVES AND MINING EFFICIENCIES

	Area A	Area B	Area C
Crude bitumen in place, bbl	807,000,000	821,000,000	816,000,000
Mining recovery, weight per cent	90.7	85.3	87.6
Crude bitumen in plant feed, bbl	732,000,000	700,000,000	714,000,000
Average crude bitumen saturation in plant feed, weight per cent	11.8	11.5	11.8
Average fines content in plant feed, weight per cent	11.4	12.4	11.9

In their submission the applicants stated that the reserves covered by the proposed tailings retention pond, estimated to be 990 million barrels of bitumen, would not be rendered unmineable since the waste material in this pond could be displaced to the mined out area. They did not expect this could be done until other mineable reserves had been utilized.

The dragline and rail haulage mining and transporting system proposed by the applicants is illustrated by Figure 2 taken from the submission of the applicants. The draglines to be used in



VIEW OF DRAGLINE MINING OPERATION AFTER YEAR 6

FIGURE 2 — MINING AND SOLIDS DISPOSAL

(REPRODUCED FROM APPLICANTS' SUBMISSION)

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CALGARY, ALBERTA
DECEMBER 1971

the mining operation would have bucket capacities of about 130 cubic yard capacity, near the upper size limit of such machines currently available for use. The applicants stated that the use of draglines for mining would provide for the recovery of the oil sand located in the irregularities of the Devonian surface underlying the deposit and would reduce side slope losses on the pit and lease boundary walls. They pointed out that the maximum digging depth of the machines, 210 feet, exceeded the maximum depth of oil sands of 190 feet encountered to date on this lease. Six trains would be utilized to haul the mined material to the plant, each being made up of seventeen 100-ton side dump cars.

The applicants stated that the bitumen extraction and froth treatment operations would be enlarged but essentially the same as those previously described. The predicted recovery efficiency of this process of the operation was estimated to decrease by 0.8 per cent to 92.9 per cent due to the increased rate of mining and the inclusion of feed of a higher fines content.

Research programs carried out by the applicants indicated that the settling rate of the fines from the water in the retention pond would be sufficient to provide a recycle of one-half the water required in the extraction process.

Upgrading of the bitumen would be accomplished through the use of the hydrovisbreaking and subsequent hydrotreating process described in the 1968 application. The applicants submitted that an increased conversion level in the upgrading process would result in an increase in efficiency from 87.2 volume per cent previously calculated to 89.4 volume per cent.

Table V-2 is a summary of the hydrocarbon recoveries for mining areas A, B and C on a weight per cent basis, as presented by the applicants:

TABLE V-2

LOSSES AND RECOVERY EFFICIENCIES
(Weight per cent based on total crude bitumen in place)

	Losses		Recovery		
Step	%	Descriptive	%	Descriptive	Cumulative Recovery,%
Mining	12	reject material and boundary walls	88	plant feed	88
Extraction & Froth Treatment	7.1	oversize reject and tailings	92.9	raw bitumen	82
Upgrading	24	fuel, sulphur and hydrogen plant feed	76	synthetic crude oil	62

the applicants expressed the intention of using off-site gas as fuel in the process heaters to that, at the level of bitumen upgrading, the plant would not realize an energy balance. Approximately 57 million cubic feet of natural gas per day would be required by the plant. Considering the fuel requirements needed to supply power to the plant, approximately 4900 barrels per calendar day of excess residual fuel would be produced. The level of bitumen conversion and consequently the amount of residuel fuel produced, was chosen having regard for the guarantees of the licenser and the fact that this is a new area of application of the hydrovisbreaking process. It is the applicants' expressed intention to evaluate higher stages of conversion as experience is obtained in this area.

The applicants proposed to use the excess residual fuel from the hydrovisbreaking process for the generation of approximately 150 megawatts of electric energy for off-site sale. They pointed out that construction of such a power plant would not likely be undertaken until it could be demonstrated that the required amount of residual fuel would be available.

(2) Views of the Board

An evaluation of the reserves in Areas A, B and C, by the Board staff indicated general agreement with the bitumen in place and recoverable bitumen estimates presented by the applicants.

The Board continues to consider the reserves under the tailings retention pond to be economically mineable under present overburden conditions and notes that the applicants intend to carry out further evaluation drilling programs in this area prior to the disposition of waste material. The Board believes that it is the applicants' responsibility to conduct their operation in a manner which will provide for the mining of the reserves in this area.

The Board accepts that the proposed mining system will result in improved recovery over the system previously proposed, by minimizing pit losses and facilitating the recovery of oil sands from the irregularities in the Devonian surface.

The Board is satisfied with the recovery efficiencies predicted for the extraction and upgrading phases of the operation and with the expected overall recovery by the scheme of 62 per cent, about one percent higher than previously expected by the applicants. The Board accepts that the planned modification by the applicants of the process previously approved could result in the production of an excess heavy residual fuel. Should the Board issue an approval as a result of this application a condition requiring that this by-product be stored or suitably marketed would be included.

The construction of a power plant for the generation of electric energy in excess of the requirements of the project and the facilities for off-site sales will be considered by the Board if and when suitable applications are made under The Hydro and Electric Energy Act.

VI ENVIRONMENT MATTERS

(1) Views of Applicants

The applicants stated that the overall sulphur recovery would be increased from that proposed in the 1968 application so that no increase in sulphur dioxide emissions would result from the increase in production rate from 80,000 barrels per day to 125,000 barrels per day. Unrecovered sulphur and sulphur compounds would be incinerated to sulphur dioxide and exhausted to the atmostpher through a 400-foot stack at a minimum gas exit temperature of 500 degrees Fahrenheit. The applicants said they chose the 400-foot stack because the maximum ground level concentration of sulphur dioxide calculated for a stack of this height was found to be 0.15 parts per million, one-half the provincial standard for this area. They stated that the calculated concentrations increased with wind speed but would not exceed 0.15 parts per million at wind speeds up to 30 miles per hour under neutral atmospheric conditions.

The applicants evaluated the combined effect on ground level sulphur dioxide concentrations of their proposed plant and the existing plant in the area. This evaluation indicated that under the critical condition of west-north-west winds (which would parallel the line joining the two plants) the ground level concentration of sulphur dioxide could exceed the provincial standard of 0.30 parts per million. Meterological data obtained for the area indicates that the critical west-north-west winds occur less than five per cent of the time. The applicatns indicated that if it became apparent, under actual operating conditions, that the overlapping of the plumes posed a problem, they could use sweet fuel to reduce sulphur dioxide emissions or raise the stack discharge temperature to increase the effective stack height. The applicants stated that this problem should be studied co-operatively by operators of all plants in the area and the appropriate regulatory agencies.

The reduction of sulphur dioxide emissions through further processing of the power plant fuel, to reduce the sulphur content, the removal of sulphur oxides from the flue gas, and the substitution of natural gas for the pitch have all been studied by the applicants. They expressed the opinion that none of these alternatives would be viable, having not been adequately demonstrated from a standpoint of technical or economic feasibility.

The applicants calculated ground level concentrations of nitrogen oxides, expressed as nitrogen dioxide, that would result from the plant operation and found it to be 0.015 parts per million, well below the provincial standard of 0.30 parts per million.

The applicants stated that the particulate emission rate would also be within the provincial allowable level of 0.85 pounds per 1000 pounds of flue gas, adjusted to 50 per cent excess air. The cyclone burners proposed would slag 70 to 80 per cent of the ash in the boiler fuel. Approximately 50 per cent of the unslagged portion would be removed by the dust collector, allowing

10 to 15 per cent of the ash to be discharged. The flue gas particulate concentration resulting would be 0.54 to 0.80 pounds per 1000 pounds of stack gas adjusted to 50 per cent excess air.

The applicants proposed to install three continuously operating air pollution monitoring stations and 20 to 25 cylinder-type exposure stations. Each continuous station would be equipped to determine at ground level the atmospheric sulphur dioxide, hydrogen sulphide and particulate concentrations. Particulate levels would probably be measured using a high volume air sampler. The exposure cylinder stations would determine monthly total sulphation, hydrogen sulphide and total dust fall levels. The stations would be located in critical areas determined in consultation with the Board.

The applicants gave an undertaking that no waste liquid would be allowed to enter any moving water system. The plant would be designed for maximum water recycle, and all process effluent streams would be contained in either the mined out areas or the retention pond. Approximately one-half the plant's water requirements would be obtained by clarifying and recycling water from the retention pond. The remainder would be made up from the Mildred Lake basin.

Recharge to the Mildred Lake basin would be obtained by diversion of Beaver Creek, or by pumping water from the Athabasca River during low flow periods in Beaver Creek. During high flow periods excess water in Beaver Creek would be diverted directly to the Athabasca River.

Mildred Lake would also be utilized as a cooling pond. The applicants did not provide estimates of the cooling load that would be placed on the lake or of the rise in temperature that the water in the lake would experience.

The applicants stated the revegetation of the mined area would follow development of the final upper surface of the tailings area, but the sand surface would not reach a final contour until after about 12 years of plant operation. The applicants stated they would conduct field tests during the interim period to establish the best plant types, level of fertilization and upper surface soil composition to be used.

(2) Views of the Board

The Board staff calculated ground level concentrations of sulphur dioxide that could occur due to the proposed sulphur dioxide emission from the 400-foot stack. These calculations indicate that concentrations would increase with wind speed and would be a maximum of 0.17 parts per million at a wind speed of 15 miles per hour and a maximum of 0.23 parts per million at a wind speed of 30 miles per hour. All calculations indicate the sulphur dioxide concentrations to be below the provincial standard of 0.30 parts per million.

The Board staff evaluated the combined effect of the plume from the proposed plant and the plume from the existing plant on ground level sulphur dioxide concentrations in the area. The calculations performed indicated that concentrations would exceed the provincial standard and that 0.30 parts per million at ground level would occur with a west-north-west wind. They also indicated that the contribution to the calculated excessive ground level concentrations by the proposed Syncrude plant would be less than the contribution by the existing plant. The Board is of the opinion that the Syncrude proposal is satisfactory since its contribution to calculated ground level concentrations in the overlap area is within one-half of the provincial standard but that the situation indicated by the calculations will have to be further appraised before the Syncrude plant commences operation.

The Board agrees with the applicants that installation of additional sulphur recovery equipment is not technically feasible at this time. If the Board should approve the present application it will review the situation in the future and may eventually require the installation of additional equipment to reduce sulphur dioxide emissions.

The Board staff calculated the nitrogen oxides concentrations that would result from the stack emissions. The maximum calculated concentration of nitrogen oxides, expressed as nitrogen dioxide, at ground level was 0.04 parts per million. This concentration is higher than that calculated by Syncrude but is well below the provincial standard of 0.3 parts per million and hence satisfactory to the Board.

The Board reviewed the particulate emission rates calculated by Syncrude and is satisfied, on the basis of the data presented, that the provincial standard would be met. The Board would, however, require a higher dust collector efficiency if the provincial standard should be modified to a more stringent level.

The Board is of the opinion that if this application is granted, the proposed air pollution monitoring network should contain a minimum of 25 exposure cylinders. The number and location of the cylinders would be determined in consultation with the Board and the Department of the Environment. The plan of the applicants to isolate from any flowing body of water their water storage, settling and handling facilities is satisfactory to the Board but would be subject to the requirements of the Board and of the Department of the Environment as to the details of the installation and operation of the system.

Although the Board is of the opinion that the surface restoration and revegetation plans of the applicants are adequate, any approval of the application would be subject to the condition that the applicants satisfy the Board and any other Department or Agencies of the Government having jurisdiction with respect to the details of these plans.

The Board believes that should the application be granted it would be appropriate to amend Approval No. 1223 to include the requirements regarding pollution control at the plant.

4. 1971 ENERGY RESOURCES CONSERVATION BOARD REPORT CONCERNING CONSERVATION AND TECHNICAL MATTERS AND ENVIRONMENT MATTERS REGARDING SYNCRUDE'S APPLICATION

AN APPLICATION

to the

ENERGY RESOURCES CONSERVATION BOARD

TO AMEND

APPROVAL NO. 1223

of the

OIL AND GAS CONSERVATION BOARD

Under Part 8 of

THE OIL AND GAS CONSERVATION ACT

by

ATLANTIC RICHFIELD CANADA LTD.

CANADA-CITIES SERVICE, LTD.

GULF OIL CANADA LIMITED

IMPERIAL OIL LIMITED

August 7, 1971

APPLICATION TO AMEND

APPROVAL NO. 1223

This is an application by Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited, and Imperial Oil Limited to amend the terms of Approval No. 1223 granted to them by O.C. 1735/69 dated September 22, 1969, by:

(a) amending clause 2 thereof whereby permission is now requested for the production of 45,625,000 barrels of synthetic crude oil and 2,000,000 net barrels of residual fuel per year.

(b) by deleting paragraphs 7, 10, and 14.

These amendments are designed to optimize the size of the plant components and to reflect the events that enable the applicants to meet the life index criterion of the Oil Sands Development Policy.

In its Report OGCB 69-C the Board stated its judgment on the evidence then available that these applicants would be able to satisfy the life index criterion of the policy about 1980. The applicants now submit that, on the basis of expected reserves additions and demand for Alberta crude, new tar sands production will be required much earlier than previously indicated in order to prevent the decline of the life index of Alberta proratable crude oil reserves below the critical level of 12 to 13 years.

Consequently, the applicants submit that their project can now qualify under the life index criterion of the Oil Sands Development Policy and request that their Approval No. 1223 be amended as herein proposed.

ATLANTIC RICHFIELD CANADA LTD.

By H E Bond

CANADA-CITIES SERVICE, LTD.

By H. S. Malakoff

GULF OIL CANADA LIMITED

By [illegible]

IMPERIAL OIL LIMITED

By J. A. Cogan

OPERATIONS

Overall operations involve a mining, extraction and upgrading scheme to produce hydrocarbon products from Crown Lease No. 17 in the Athabasca tar sands deposit. Environmental factors have been a major consideration in developing the overall operating scheme.

Tar sand will be mined and transported to an extraction plant where crude bitumen will be separated from mineral matter by a modified hot water process and upgraded to synthetic crude. Sand tailings and extraction water will be pumped to disposal and clarification facilities. The location of the initial mining area and other major facilities is shown in Figure II-1.

The following sections provide new information relative to operations and reflect the current state of engineering development.

RESERVES

A continued reserves drilling program has, since the 1968 application, outlined additional reserves in the area to the northwest of the proposed initial mining area "A". These reserves, which are shown as Area "B" on the lease plan (Figure II-2), have a reasonably rich, uniform depth McMurray section and favourable overall waste/tar sand ratios. The locations of the 59 holes drilled since 1968 are shown on Figure II-3. Total reserves in place for mining areas "A", "B", and "C" are now calculated at 2.44 billion barrels of bitumen.

Mining Recovery

On the approved basis of selective mining, the extraction plant feedstock from mining area "A" contains an average of 11.8 wt.% bitumen. The average bitumen content of the reject material within the mining area is 2.1 wt.%. Reject represents 33.7% of the volume of the McMurray formation but only 8.3 wt.% of the bitumen in place. The side slopes on the boundary walls of the mining pit contain a further 1.0% of the bitumen in place.

The formation included within the perimeter of mining area "A" contains a total of 807,000,000 barrels of bitumen in place, of which 732,000,000 barrels will be mined and fed to the extraction plant, resulting in an overall recovery of 90.7%. These reserves would support the proposed operation for approximately 13 years.

The holes influencing mining area "A" are shown in Figure II-4 and listed on Table II-1. Footages and bitumen content are shown for all feed and reject material. The waste/tar sand ratio indicated for each hole includes top and centre reject material with the overburden to give a measure of the total waste material handled per yard of plant feed.

In arriving at an estimate of the reserves remaining in the pit walls, a side slope of 60° has been used for the walls adjacent to future mining areas, whereas the wall at the lease boundary and along the unmineable area to the southwest will be essentially vertical. The perimeter of the pit is 52,000 feet of which 36,000 feet have a 60° pit wall. Figure II-5 is a schematic cross section through the pit wall showing a typical slope and the average thickness of materials in the mining area. Average contents of feed and reject were applied to the shaded area of the pit wall to estimate the pit wall loss of 1.0%.

Expansion of Mining Area

Figure II-6 has been prepared to indicate the relative attractiveness of various reserves blocks from a mining standpoint. The shading legend is based on an ascending scale of barrels of bitumen fed to the extraction plant per cubic yard of total material moved. The darker the square, the more attractive it is for mining. The potentially recoverable reserves in the total area outlined are sufficient to support the proposed operation for about 55 years.

The distribution of reserves shown on Figure II-6 suggests a sequence of development in the alphabetical order indicated by the major blocks on the overlay. This sequence of development is a preliminary projection. The actual pattern may be affected by operational requirements or additional reserves information.

The reserves remaining in the pit wall between areas "A" and "B" amount to 0.3% of the reserves in place in the two areas. The boundary of the unmineable areas would be precisely defined by information obtained from drilling in advance of the mining operation.

Combined mining area "A" and "B" contain reserves sufficient to support the proposed operation for the requested 25 years of the permit. The table below summarizes the expected recoveries and feed qualities from these areas.

	Area "A"	Area "B"	Area "C"
Barrels of Bitumen in place	807,000,000	821,000,000	816,000,000
Barrels of Bitumen fed to Extraction	732,000,000	700,000,000	714,000,000
Mining Recovery	90.7%	85.3%	87.6%
Average % Bitumen in Plant Feed	11.8%	11.5%	11.8%
Average % Fines in Plant Feed	11.4%	12.4%	16.9%

As shown in Figure II-6, the plant area covers eight 1000 foot square blocks. This is an increase of two blocks over the plant area indicated in the 1968 application and accommodates the increased plant size. A further change should be noted in the area designated "C". Ten blocks adjacent to the plant area on the east have been removed from the area. Tar sand transportation and access to the plant will be facilitated by the more regular geometry of area "C". Recovery of these reserves is still anticipated subsequent to depletion of areas "A", "B", and "C".

Unmineable Reserves

Reserves are considered unmineable for either of two reasons: the material underlies the permanent plant or the waste/tar sand ratio is beyond acceptable economic limits. The areas presently considered unmineable are designated "U" on the overlay on Figure II-6. The estimated overall waste/tar sand ratios are shown by block on Figure II-7.

The permanent plant facilities and the retention pond have been located in areas poor in reserves. The plant facilities cover an area of 200 acres containing 36.0 MM barrels of bitumen in place. A total of about 990 MM barrels of bitumen in place is covered by the total retention pond area. These reserves will be further delineated by a drilling program prior to the area being flooded.

MINING

As a result of continuing mining studies and recent developments in large scale mining equipment, the mining scheme has been revised from the scraper, belt conveyor system described in the 1968 application to a dragline, rail haulage system. Figure II-8 shows the overall dragline, rail haulage mining scheme.

Dragline Mining

Large walking draglines with bucket capacities of over 100 cubic yards are a recent development in the mining industry and appear to be ideally suited to the Syncrude mining area since the removal of overburden and mining of tar sand can be carried out in one continuous operation.

Two draglines operate along a mining face of approximately 9,000 feet. Overburden is removed and cast into the previously mined out area. Tar sand is then cast to the high wall side for subsequent transfer to the plant. Since the overburden is removed immediately ahead of the tar sand, vertical frost penetration of the tar sand is minimized.

The average depth the draglines will be required to excavate, over the working life time of the machines, is to 165 feet below the level on which they are operating. The maximum depth is 190 feet. The machines will be designed for a digging depth of 210 feet.

Modern draglines are designed for the specific digging conditions and can excavate with precise bucket control. An excellent example of this is an open pit coal mine near Hazleton, Pa., where a 200 ft. section of overburden is removed in one pass to uncover a high grade seam of anthracite coal. The dragline subsequently digs out the uncovered coal and casts it to the highwall side where it is loaded out by front-end loaders to large trucks. No other machine is used to clean off the coal in this operation.

The Devonian surface on which the tar sand lies is irregular. Since the draglines will not be positioned on that surface, tar sand in irregular pockets below the surface is recoverable. It should also be noted that, many draglines are operating successfully in recovering ores where the visual distinction between acceptable and unacceptable grades is less than that for the tar sands.

Syncrude has ordered a 17 cubic yard walking dragline, which will go into service in July, 1972, to establish optimum operating procedures for mining tar sands with large draglines. This dragline will also be used during construction of the proposed plant civil facilities.

Transportation of Tar Sand

Bucket wheel reclaimers will be used to reclaim the tar sand from the piles cast up by the draglines. A short moveable conveyor transfers the tar sand from bucket wheel reclaimer into the rail cars. Any large lumps of tar sand will be collected by a large front-end loader and transferred directly to the rail cars to prevent possible damage to the conveyors.

Each train will be made up of one 210 ton electric locomotive and seventeen 100 ton capacity side dump cars. There will be six trains in operation at all times with one complete spare train to replace the operating trains as they are removed for servicing.

The trains discharge their loads into a surge bin where the plus 12 inch material is separated from the minus 12 inch. The minus 12 inch goes directly to the extraction plant, the plus 12 inch lumps pass through a large impact type crusher where they are reduced in size before they are discharged onto the plant feed conveyor.

Tailing and Sludge Disposal

Tailings from the extraction plant are transported hydraulically. Initial disposal is to a spoil area where the tailings are deposted behind a retention dam. The downstream side of the tailings pile assumes the natural angle of repose. This procedure assures permanent stability of the tailings pile regardless of the percentage of fine material codeposited. The layout of the tailings pile and retention pond is shown on Figure II-9 along with a cross section through the dams, the retention pond, and the tailings pile.

The sand tailings will be disposed of in the retention pond for the first 3 to 4 years. After the mining has advanced sufficiently, the tailings will be deposited on top of the windrows of overburden. The water, containing fines, drained from the sand tailings deposited in the mined-out areas, is pumped to the retention pond for clarification and recycle to the plant. (See Figure II-10).

The plant has been designed for maximum water recycle and no effluent from the plant will be discharged and no overflow or outlet from the retention pond will be required other than the decant system to return water to the plant for reuse.

The final surface of the area where the waste sand is deposited will be approximately 100 feet higher than it was originally. Raising the surface of this mined-out area will provide room for tailings disposal from subsequent areas to be mined and establish a well defined drainage pattern.

Eventually the waste material deposited in the area occupied by the retention pond can be excavated. The sludge, the initial sand tailings, and the overburden covering the tar sand can be deposited in a mined-out area.

EXTRACTION-FROTH TREATMENT

The extraction - froth treatment process is the same as described in the 1968 application and is illustrated schematically in Figure II-11 to show the new flow rates. The material balance for extraction-froth treatment is shown in Table II-3. The overall recovery of bitumen is estimated 92.9%.

Extensive research has gone into developing the modified hot water process for separating bitumen from the coarse sand and fine mineral matter in the tar sand. Correlations have been developed to show the effect of the fine material variability in the deposit on the settling rate of the fines. As well, the influence of particle size and the effect of varying amounts of fine mineral matter in the reclaim water have been determined. This information has been used in calculating the size of retention pond required for recycle water clarification assuming that extraction plant tailings would be diverted to the mined out area at the end of year four. For a typical condition, the amount of water in the extraction plant tailings stream would be approximately 38,000 gpm. Typical distribution of this water would be as follows:

Evaporation and percolation losses	5,800 gpm
To voids in coarse sand tailings	9,600 gpm
To fine mineral sludge in retention pond	3,600 gpm
To extraction plant recycle	19,000 gpm

For the above condition the fresh water makeup would be 19,000 gpm that is, a 50-50 split of fresh and reclaim water would be fed to the extraction plant.

The net water input into the retention pond after year 4 would be the 3,600 gpm associated with the sludge. The total sludge volume would be approximately 230 MM ft^3/year as compared to a total retention pond volume of 12,200 MM ft^3. If necessary in the later years of the project, the sludge would be pumped to a mined out area where a greater degree of compaction would be achieved.

BITUMEN UPGRADING

The bitumen upgrading system is shown schematically on Figure II-12. The primary conversion unit is a hydrovisbreaker. This unit, which uses high pressure hydrogen, converts the major portion of the bitumen to lighter fractions. The resulting products are gas, naphtha, light gas oil, heavy gas oil and vacuum residue. The choice of hydrovisbreaking unit for the primary conversion step was influenced by the flexibility inherent in this process.

The 1968 application used a level of conversion which kept the plant in overall energy balance. Residue was to be burned in the process heaters. It is now proposed that process off-gas be supplemented by natural gas to enable process heaters to be gas fired to the extent economically justified.

The distillate streams from the hydrovisbreaker are treated for a further reduction in sulphur and nitrogen content. Hydrotreating facilities are designed to achieve the required reduction of these impurities in the respective distillate streams and to saturate any remaining unstable components. The treated streams are then recombined in the desired proportions. Different blends of the components may be made to provide several qualities of synthetic crude. The following inspection is typical of the type of synthetic crude which will be produced:

Gravity	33.1^{o}API
Sulphur	0.27 wt.%
Nitrogen	0.07 wt.%
C_5-380^{o}F	25.5 vol.%
380-650^{o}F	29.5 vol.%
650-975^{o}F	25.0 vol.%
975^{o}F+	0

The gaseous streams from the hydrovisbreaking unit and hydrotreating units are processed to remove hydrogen sulphide. The concentrated H_2S stream, along with gas from sour water stripper, is fed to a sulphur plant for sulphur recovery, thereby minimizing losses and conserving sulphur. The light hydrocarbon vapours leaving the acid gas removal unit are fed into the plant fuel gas system which is supplemented with natural gas. Natural gas also serves as feed to the hydrogen plant. The total natural gas requirement is estimated at 57 MMSCF per day. The participants have devoted considerable effort to determining gas reserves in adjacent leases. The quantity available is minimal. Negotiations are now underway to obtain the balance required for plant operation from other Alberta fields. Material and sulphur balances are shown on Table II-4 and II-5.

The increased conversion level in upgrading will result in an estimated 89.4 vol.% recovery of product from bitumen compared to 87.2 vol.% in the previous application. On a weight basis the recovery will be 76.0% compared to 73.5%.

An estimated 76.3% of the sulphur entering the upgrading process will be recovered as elemental sulphur, increased from 66.2% in the previous application. An increased sulphur recovery is due partly to the higher conversion, which results in less sulphur to the residual fuel, and partly to recovering sulphur from the sour water stripper in the sulphur plant. At the time of the previous application it was not definitely established that off-gas from the sour water stripper could be processed in the sulphur plant. It appears that a commercial process is now available. The sour water stripper off-gas will be processed along with the H_2S from the amine plant resulting in an overall sulphur recovery approaching 97% in the sulphur plant.

The above combination of process changes will allow production of 125,000 BPD with no increase in sulphur emissions over that in the previous application for 80,000 BPD.

UTILITIES

It is estimated that approximately 12,600 BPCD of residual fuel will be required to supply the Syncrude steam and power requirements. This would leave approximately 4,900 BPCD excess residual fuel which would be sufficient for an export power plant of approximately 150 MW operating at a load factor between 65 and 85%. If suitable contractual arrangements can be made, the total residual fuel will be burned in a central boiler plant to supply both Syncrude utilities and export power. Control of ground level SO_2 concentrations would be facilitated by utilizing a single stack. The tie-in with an export power facility should minimize the occurrence of electrical outage and any emergency flaring associated with such an outage.

The retention pond and the mined-out areas would contain all the process effluent streams and no outflow from this system will be permitted. A separate sewer system for oily water from the upgrading units will be provided with an API separator for recovering oil. Water from the API separator will be returned to the extraction section or pumped directly to the retention pond. The contours at the plant site are such that any runoff from this area will be to the west where it will collect behind the retention dam and be pumped into the retention pond.

TANKAGE AND DELIVERABILITY

The amended 1968 application proposed installation of approximately 4,000,000 barrels tankage which was designed to allow a variation in deliverability of approximately plus or minus 10%, an adequate range for the new markets the applicants were to provide. The improved market environment now expected requires no additional tankage.

ENVIRONMENTAL CONSIDERATIONS

Environmental considerations occupy an important position in the planning of the Syncrude operation and facilities. The following is a summary of programs and procedures designed to identify and minimize environmental impacts in the Lease 17 development. The approach to the inherent environmental problems has been:

a. to avoid damage by planning at the design stage,

b. to assess the implications of the development by research conducted by Alberta ecological consultants,

c. to continue research and monitoring to maintain, so far as feasible, the ecological integrity of the site and surrounding areas.

Implicit in the planning procedure is the recognition that localized disturbances are unavoidable if a plant is to be constructed and operated. Efforts are oriented towards containment of disturbances and potential disturbances. The following sections refer to major environmental considerations, as viewed at the present time. Additional details of procedures and measures to be implemented are discussed in related sections of this application.

Air

Emissions to the atmosphere, both gaseous and particulate material, will be within the limits prescribed by regulatory agencies.

The estimated maximum emission from the boiler plant and sulphur plant incinerator have been used for computer evaluation of the stack height. These calculations indicate that a plant stack height of 400 feet is more than adequate to hold this plant's contribution to the SO_2 ground level concentration below that permitted by government regulations for the area.

The sulphur plant will consist of dual trains and, with the sulphur content of the off-gases from the hydrovisbreaking and hydrotreating approximately equal, considerable flexibility will be provided in scheduling sulphur plant shutdowns for maintenance or catalyst regeneration.

A significant fraction of the mineral content of the utility plant fuel will be removed as a slag by using a cyclone burner. This will assist in controlling the particulate emission, and the slag will be investigated as a potential source of by-product minerals.

Details on stack design, including information on particulate emission rates, SO_2 ground level concentrations for maximum and minimum firing conditions and meteorological data are provided in Table II-6.

Water

Water utilization in the Syncrude operation will be such that no process water will move across lease boundaries or into any moving water system.

Water requirements and tailings disposal were noted in the sections on mining, extraction and upgrading. Figure II-1 shows the overall water and disposal system. Figure II-13 shows the fresh and reclaim water system for the processing areas. The Mildred Lake basin will be modified to function as a fresh water storage and cooling pond. Fresh water will be supplied to the Mildred Lake basin by diverting Beaver Creek or by pumping from the Athabasca River, depending on the flow rate in Beaver Creek.

Beaver Creek, during periods of high flow, is to be diverted directly into the Athabasca River. Two control weirs, one into Mildred Lake and one into the river, will avoid any accidental introduction of effluents from the Mildred Lake basin into the Athabasca system or thermal modification of Beaver Creek waters entering the Athabasca. At other times the flow from Beaver Creek is to be utilized as fresh makeup water. (See Figure II-1).

Advantage has been taken of the existing topography in the area to insure that drainage from the plant and storage areas will be contained on the lease. It should be noted that from the plant site which is at 1,000 feet, the surface elevation rises to the east to 1,030 feet and to the west to 1,050 feet. The containment area will be founded on the north by the low dam of the retention pond and on the south by the mining area dyke.

Sanitary sewage will be treated in accordance with good health engineering practice.

Land

The bitumen content in the proposed initial mine area "A" which will provide 13 years of production at 125,000 BPD from a total area of only 5.5 square miles, constitutes an unusually high concentration of available energy.

Dykes rising above the existing ground level will be continuously constructed from overburden, as mining proceeds. These dykes will be planted both for slope stabilization and to esthetically improve the dyke itself. Tailing sand will be hydraulically deposited behind the dykes for the life time of the mine. The area enclosed by the dykes may also receive tailing from a second mine during its initial period of operation.

Revegetation will follow development of the final upper surface of the tailing area. The sand, in this essentially level area, might be sealed with a layer of sludge clay to allow the covering growth supporting medium to retain moisture and fertilizers. The growth medium would be a mixture of overburden materials or sand and muskeg. Field tests and growth room studies, such as those recently completed by the Soils Branch of the Department of Agriculture on tar sand tailings, will be used to establish the best plant types, levels of fertilization, and soil composition to establish a self-maintaining and desirable land cover.

The retention pond covers an area of 9.32 square miles. It is anticipated that mining and subsequent reclamation of this area will not occur until other mineable reserves have been utilized. The final level in this area, after reclamation, would approximate that of the Athabasca River Valley (800 feet).

Wildlife and Fisheries

A reconnaissance wildlife habitat survey and background investigation of the area is presently being carried out. Preliminary indications are as follows:

1. nothing in the plant and mining area is unique or distinctive compared to the surrounding thousands of square miles,
2. present forest cover is of marginal commercial quality. The area is typical Boreal forest of northern Alberta,
3. land capability for agriculture of the plant and mining area is low or non-existent,
4. big game carrying capability of the area is average for the northern mixed wood forest. Deer population is sparse and scattered. Actual game population counts have not been completed.

Investigation is being continued to identify and evaluate the disturbances which will result from plant operation.

TABLE II-1

MINING AREA "A"

HOLES INFLUENCING THE MINING AREA

BASED ON 5' AND 6% REJECT INTERVAL

HOLE	TOP REJECT		CENTER REJECT		BOTTOM REJECT		PLANT FEED		Ratio Overburden + Top & Center Reject to Feed
NUMBER	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	Feet	Percent Bitumen	
CORE HOLES									
22- 5-1	23	1.2	74	3.2	7	0.1	97	10.1	1.29
22- 8-1	18	2.4	0	-	197	4.0	5	6.0	6.20
22-11-1	4	5.7	0	-	207	3.0	7	6.5	5.29
23-15-1	65	1.1	0	-	65	0.5	101	10.8	1.02
24- 7-1	38	2.2	58	3.8	18	0.1	99	11.3	1.07
24-10-1	137	0.8	14	3.2	34	0.1	30	9.9	5.47
24-12-1	3	1.1	16	4.7	84	1.6	100	12.7	0.47
24-16-2	26	4.5	0	-	0	-	149	12.1	0.37
24-18-1	24	0.1	7	4.9	51	1.1	146	13.2	0.44
24-20-1	35	0.1	31	1.9	59	1.3	95	11.7	1.06
*24-20-2	31	2.8	26	4.5	36	1.5	113	10.9	0.72
*24-21-2	18	1.0	33	2.1	58	4.0	108	12.0	0.81
*24-22-1	3	1.0	55	2.7	29	1.8	124	12.2	0.66
24-23-1	25	2.3	37	5.1	15	0.3	115	11.3	0.89
25- 6-1	0	-	44	4.1	7	0.8	112	10.4	0.67
25- 8-1	21	0.1	44	3.6	19	0.1	116	10.2	0.59
25-11-1	20	0.1	5	2.9	33	2.7	177	10.3	0.14
25-11-3	35	3.8	6	4.3	73	2.7	88	12.6	0.57
25-12-2	0	-	32	5.3	0	-	126	11.4	0.49
25-14-1	2	0.1	45	3.6	23	0.8	146	11.3	0.45
25-14-2	22	2.0	27	4.1	43	0.7	131	10.7	0.43
25-16-1	30	3.0	25	3.3	37	1.3	138	12.2	0.49
25-19-1	40	3.6	8	4.9	7	2.9	142	12.9	0.55
25-19-2	29	4.0	5	4.7	9	5.4	131	11.1	0.52
25-21-1	34	2.9	32	2.2	64	1.3	100	12.5	0.91
26- 7-1	16	0.1	52	3.2	6	1.2	103	10.1	0.71
26-10-1	34	0.1	9	1.7	2	0.9	128	13.5	0.38
26-12-1	23	0.2	10	4.9	3	0.0	138	11.0	0.30
26-14-2	0	-	26	2.9	0	-	114	11.5	0.49
26-15-1	19	5.9	8	1.9	43	2.1	131	12.1	0.27
26-18-1	31	3.8	5	1.5	36	0.4	136	11.7	0.41
26-19-1	22	0.1	18	5.2	49	0.4	147	10.9	0.41
*26-19-2	34	3.1	0	-	5	1.8	148	11.4	0.35
26-20-1	27	3.4	17	3.9	69	0.3	130	12.4	0.51
*26-21-1	11	2.5	8	2.2	16	0.9	138	11.8	0.40
*26-22-2	9	1.0	38	3.4	9	0.6	124	13.6	0.62
26-23-1	43	0.1	9	0.0	36	1.9	112	13.7	0.69
27-11-1	20	5.3	39	4.9	14	4.0	112	10.7	0.54
27-16-1	7	2.0	28	4.0	53	0.6	112	14.1	0.47
27-16-2	0	-	12	4.2	0	-	139	11.3	0.26
*27-19-1	27	4.2	0	-	10	0.7	131	12.1	0.46
*27-21-1	50	2.3	0	-	8	1.0	108	13.3	0.80
*27-22-1	80	3.7	0	-	27	1.4	101	12.5	0.94
28- 6-1	45	0.7	50	0.7	50	0.7	0	-	-
28- 8-1	23	3.9	10	2.8	52	0.9	78	11.4	0.55

TABLE II-1 - continued

MINING AREA "A"

HOLES INFLUENCING THE MINING AREA

HOLE NUMBER	TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTRE REJECT Feet	CENTRE REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Ratio Overburden + Top & Centre Reject to Feed
	BASED ON 5' and 6% REJECT INTERVAL								
CORE HOLES									
28-14-1	22	5.0	16	4.2	21	0.0	92	12.5	0.63
28-15-1	0	-	0	-	29	1.0	103	12.5	0.71
28-19-1	18	0.2	5	3.3	38	0.6	125	11.2	0.22
*28-19-2	0	-	0	-	12	1.0	164	11.1	0.04
*28-20-1	12	1.0	0	-	51	1.8	119	11.4	0.15
28-21-1	57	3.0	15	4.4	35	2.2	88	10.3	1.04
*28-21-2	29	2.9	0	-	48	1.0	124	12.5	0.28
*28-22-2	75	1.9	28	2.5	58	2.0	46	12.7	2.70
29-11-2	0	-	35	3.6	0	-	103	11.4	0.69
29-16-2	14	0.1	15	4.8	3	0.4	141	11.6	0.23
29-19-2	0	-	0	-	0	-	105	12.6	0.19
*29-19-6	0	-	5	0.8	12	1.7	112	12.9	0.18
*29-22-1	31	1.9	6	4.7	43	1.6	85	10.8	0.54
*29-22-2	13	3.0	0	-	75	1.7	75	10.3	0.57
30-14-1	15	0.1	19	4.4	26	0.2	150	11.5	0.30
30-19-1	20	0.1	11	4.1	6	0.0	134	12.0	0.25
30-20-2	0	-	0	-	6	1.6	160	12.7	0.03
*30-21-1	3	1.0	0	-	54	2.7	88	12.3	0.51
31-12-2	16	2.3	5	4.7	0	-	133	12.7	0.35
31-15-2	5	4.1	8	4.1	0	-	151	11.6	0.23
*31-20-2	0	-	13	2.6	6	0.3	161	11.3	0.10
*31-21-1	9	1.0	22	4.9	45	4.6	135	12.5	0.27
*31-21-2	25	0.8	0	-	44	3.7	133	13.3	0.23
*31-22-1	36	1.0	9	4.7	27	1.0	135	11.7	0.40
32-18-2	0	-	12	5.1	0	-	141	12.0	0.20
*32-20-1	9	2.2	5	5.5	7	0.8	148	10.3	0.16
*32-21-2	52	1.0	12	4.7	7	1.5	106	11.8	0.69
*32-22-1	12	1.0	43	3.8	48	1.6	113	11.6	0.62
33-14-2	35	2.0	38	3.9	4	2.2	91	10.7	1.31
33-16-1	35	2.8	19	4.6	13	0.1	116	11.1	0.67
*33-19-2	22	1.7	18	4.2	3	1.0	120	10.3	0.41
*33-20-2	7	1.0	59	3.4	9	1.8	96	9.4	0.84
33-22-1	38	4.3	35	3.9	81	1.3	80	11.8	1.02

* Asterisks denote new data added on the basis of holes drilled since 1968.

NOTE: Data from 15 additional holes, including 4 from outside areas "A", "B", and "C", is being prepared and will be available by the time of the public hearing on this application.

TABLE II-1 - continued

MINING AREA "A"

HOLES INFLUENCING THE MINING AREA

BASED ON 5' AND 6% REJECT INTERVAL

HOLE NUMBER	TOP REJECT Feet	CENTRE REJECT Feet	BOTTOM REJECT Feet	PLANT FEED Feet	Ratio Overburden + Top & Centre Reject to Feed
DRILL HOLES					
23-14-1	2	38	50	139	0.46
23-19-1	24	9	38	136	0.49
24-11-1	41	9	55	123	0.57
24-21-1	1	84	57	71	1.73
25-10-1	52	21	40	76	1.18
25-15-1	4	7	32	171	0.17
25-18-1	2	8	13	164	0.22
25-20-1	5	56	34	93	0.96
25-23-1	65	0	34	103	0.83
26- 8-1	144	0	6	24	6.42
26-11-1	8	18	68	67	0.70
26-16-1	6	5	48	157	0.10
26-22-1	3	19	61	136	0.29
27-20-1	18	39	54	117	0.54
28-10-1	14	26	17	129	0.38
28-12-1	21	0	3	118	0.28
28-18-1	0	0	33	139	0.12
28-18-2	0	0	33	137	0.15
28-23-1	4	58	71	99	0.83
29-11-1	26	47	2	89	0.92
29-12-1	5	21	17	133	0.25
29-14-1	0	25	26	131	0.39
29-15-1	7	0	40	160	0.06
29-16-1	14	5	11	138	0.16
29-18-1	3	10	28	112	0.17
29-20-1	4	0	50	122	0.08
29-21-1	13	13	59	108	0.23
30- 8-1	0	36	0	108	0.58
30-11-1	0	15	23	119	0.30
30-12-1	4	14	14	160	0.23
30-15-1	3	0	13	167	0.14
30-16-1	0	6	14	158	0.16
30-18-1	19	0	7	151	0.17
30-22-1	13	13	86	91	0.42
30-23-1	22	0	105	35	1.66
31-14-1	7	23	29	144	0.33
31-20.1	2	0	13	170	0.05
32-11-1	21	17	3	118	0.53
32-16-1	4	5	15	154	0.17
32-19-1	18	11	0	129	0.25
32-21-1	10	30	65	119	0.33
33-14-1	30	41	7	90	1.30
33-15-1	41	25	28	103	0.90
33-18-1	16	20	7	124	0.36
33-19-1	16	34	8	103	0.58
33-20-1	18	68	28	74	1.32

NOTE: Drill Holes evaluated by means of Electro-Mechanical Logs.

TABLE 11-2

MINING AREA "B"

HOLES INFLUENCING THE MINING AREA

BASED ON 5' and 6% REJECT INTERVAL

HOLE NUMBER	TOP REJECT Feet	TOP REJECT Percent Bitumen	CENTRE REJECT Feet	CENTRE REJECT Percent Bitumen	BOTTOM REJECT Feet	BOTTOM REJECT Percent Bitumen	PLANT FEED Feet	PLANT FEED Percent Bitumen	Ratio Overburden + Top & Centre Reject to Feed
CORE HOLES									
33-14-2	35	2.0	38	3.9	4	2.2	91	10.7	1.31
33-16-1	35	2.8	19	4.6	13	0.1	116	11.1	0.67
*33-19-2	22	1.7	18	4.2	3	1.0	120	10.3	0.41
*33-20-2	7	1.0	59	3.4	9	1.8	96	9.4	0.84
33-22-1	38	4.3	35	3.9	81	1.3	80	11.8	1.02
33-24-1	27	3.0	32	2.5	28	0.1	98	12.0	0.81
34-12-1	40	1.0	44	2.4	0	-	93	11.5	1.55
*34-15-1	22	1.7	19	3.8	7	1.9	107	10.9	0.89
*34-18-1	26	2.1	26	3.9	6	0.6	103	11.3	0.91
*34-20-1	28	1.7	0	-	8	5.2	133	11.3	0.41
*34-23-1	9	1.0	9	4.4	15	1.0	154	12.8	0.27
34-25-1	39	1.0	12	3.9	24	1.5	108	12.5	0.53
35-14-1	22	4.7	14	2.6	10	1.1	133	10.6	0.63
36-19-1	37	2.2	0	-	21	4.3	114	12.3	0.59
36-24-1	0	-	66	3.0	21	3.7	97	10.7	1.16
*37-15-1	8	2.6	13	2.3	32	1.0	121	11.5	0.67
*37-17-1	21	1.0	0	-	1	0.4	144	11.4	0.48
*37-20-1	31	2.1	6	4.9	33	1.0	106	11.7	0.75
37-23-1	33	1.0	21	3.1	49	0.1	109	11.8	0.66
*38-19-1	13	2.2	21	3.0	4	0.3	132	9.0	0.67
*38-27-1	34	1.7	32	4.1	16	0.4	89	10.6	1.28
*40-17-1	11	0.2	54	3.3	0	-	98	10.4	1.27
40-20-1	7	1.7	63	2.7	2	0.2	84	8.9	1.62
40-22-1	4	1.0	0	-	5	0.1	173	10.0	0.27
*41-24-1	5	1.9	-	-	83	1.0	117	11.1	0.45
*41-29-1	3	1.0	38	3.9	12	0.8	123	11.5	1.31
*42-23-1	7	0.1	5	4.2	6	0.9	171	12.6	0.39
*43-27-1	13	0.7	54	3.0	19	2.7	109	10.7	1.26
*44-29-1	16	3.4	0	-	20	0.7	166	12.5	0.57
*46-24-1	4	1.0	20	4.0	6	0.6	114	11.5	1.05

HOLE NUMBER	TOP REJECT Feet	CENTRE REJECT Feet	BOTTOM REJECT Feet	PLANT FEED Feet	
DRILL HOLES					
33-14-1	30	41	7	90	1.30
33-15-1	41	25	28	103	0.90
33-18-1	16	20	7	124	0.36
34-19-1	44	34	0	97	0.96
35-27-1	28	39	15	106	0.80
36-16-1	25	5	7	141	0.47
36-22-1	44	0	56	105	0.73
38-16-1	38	7	9	124	0.77
38-22-1	38	31	24	98	1.10
38-30-1	36	16	2	114	1.00
41-16-1	43	0	107	0	-
41-27-1	159	0	34	5	-
44-22-1	90	0	36	16	11.00

* Asterisks denote new data added on the basis of holes drilled since 1968.

TABLE II-3

MATERIAL BALANCE - EXTRACTION-FROTH TREATMENT

(Average Basis)

		Bitumen		Water	Solids	Total
Streams In	Stream	Tons/CD	BPCD	Tons/CD	Tons/CD	Tons/CD
Tar Sand Feed	A	26,600	150,250	9,470	189,360	225,430
Steam	B	-	-	9,470	-	9,470
Hot Water	C_1	-	-	75,000	-	75,000
Condensing Water	C_2	-	-	100,230	-	100,230
Total		26,600	150,250	194,170	189,360	410,130
Streams Out						
Dehydrated Bitumen	D	24,720	139,640	-	770	25,490
Reject	E	30	180	330	2,930	3,290
Tailings	F	1,850	10,430	193,840	185,660	381,350
Total		26,600	150,250	194,170	189,360	410,130

TABLE II-4

MATERIAL BALANCE

on

BITUMEN UPGRADING UNITS

	BPCD	M lbs./CD
Materials In		
Bitumen Feed	139,640	49,440
Natural Gas to H_2 Plant		2,990
Steam to H_2 Plant		2,680
		55,110
Materials Out		
Synthetic Crude	125,000	37,580
Fuel Gas		3,740
Residue	17,460	7,100
Sulphur		1,850
Diesel Fuel	70	20
Process Losses		
Sulphur Stack Loss		56
Other Losses*		4,764
		55,110

* Includes CO_2 rejected from Hydrogen Plant and H_2 and NH_3 burned in Sulphur Plant

TABLE II-5

SULPHUR BALANCE

on

BITUMEN UPGRADING UNITS

Sulphur In	LT/CD	M lb/CD	Wt.%
Bitumen Feed to Upgrading	1,081	2,421	100.0
Sulphur Out			
Sulphur Product	826	1,850	76.5
Incinerator Stack Loss	25	56	2.3
Sulphur in Synthetic Crude	46	103	4.2
Sulphur in Pitch	184	412	17.0
	1,081	2,421	100.0

TABLE II-6

STACK DESIGN

BASIS Common stack, (400 ft. high, 25'8" I.D., Exit. Temp.500°F min.) for all boilers and sulphur plant incinerator. Location is Twp.93, R.10, W4, Section 31. Elevation at stack base is 1030 ft.

The 350 ft. G.C.O.S. stack is located ca. 33,000 ft. ESE at an elevation of 850 ft.

PARTICULATE EMISSION

The cyclone burner will slag 70-80% of the ash in the boiler fuel.

Pitch fired (excl. solids)	8236 M lbs/SD
Ash	915 M lbs/SD
Non-slagged portion 20%-30%	183-275 M lbs/SD
Stack gas (adjusted to 50% excess air boiler portion only)	171 MM lbs/SD
Allowable solids discharge (0.85 lbs/M lb stack gas adj. to 50% excess air)	145 M lbs/SD
Min. required removal in dust collector 80%-70% slagged	21%-47%
Planned dust collector efficiency	>50%

METEOROLOGICAL DATA

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sept.	Oct.	Nov.	Dec.	Year
Percentage frequency wind from WNW	5	5	5	3	4	4	4	4	5	5	6	6	4.7
Average velocity from WNW (mph)	5.5	5.8	7.0	7.7	8.5	6.0	6.1	6.5	6.1	6.5	7.1	5.8	6.5

(Fort McMurray Airport 1967-1970)

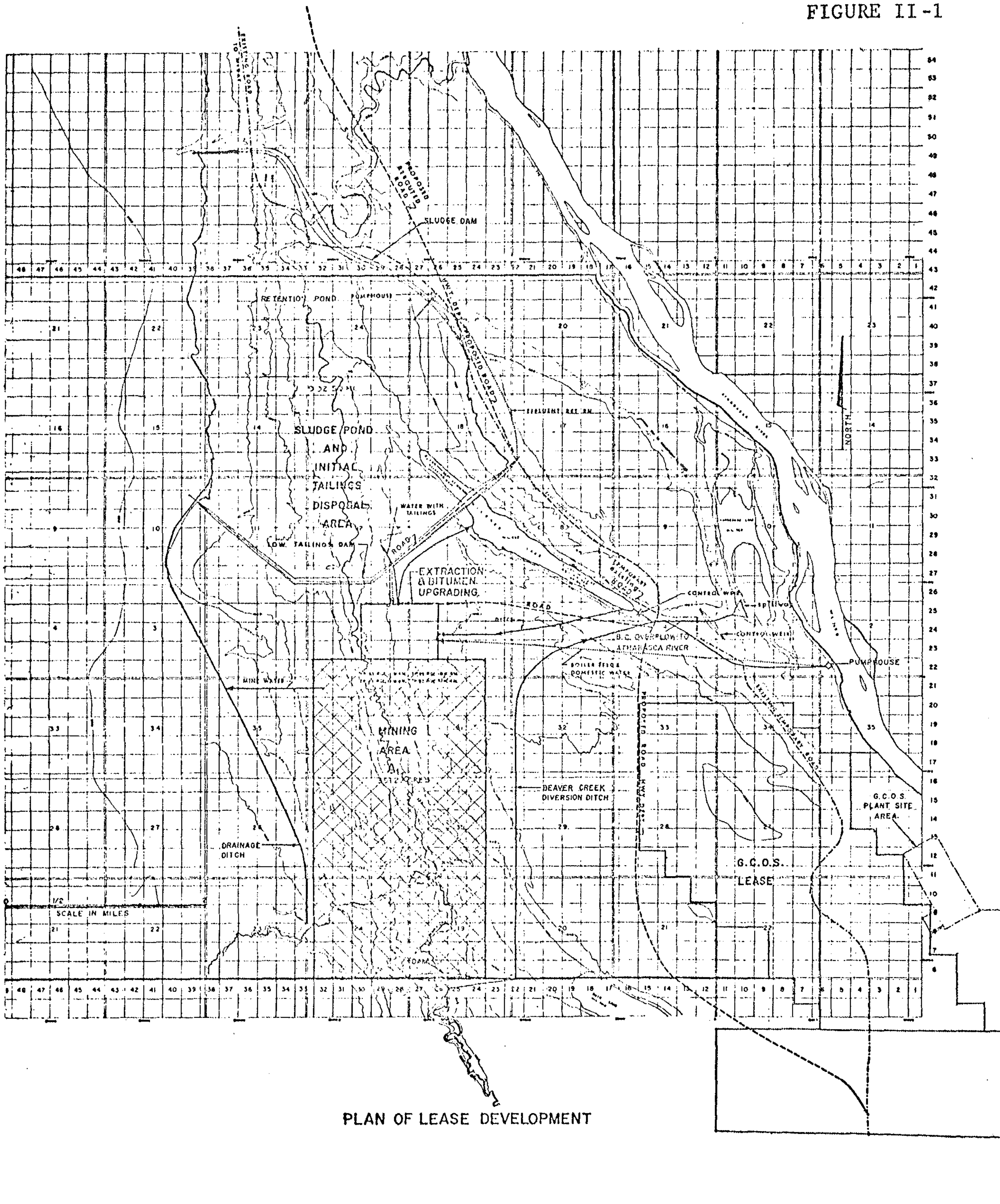
CALCULATION OF GROUND LEVEL CONCENTRATIONS OF SO_2

Pasquill Method - Wind Direction on Syncrude-GCOS axis from WNW. Elevations are the highest in a 45° segment centered on this axis. Atmospheric conditions: heavy overcast day or night.

	Maximum Boiler Firing	Minimum Boiler Firing
Total Volume Stack Gas (14.7 psi, 70°F)	20951 CFS	14266 CFS
Volume SO_2	76 CFS	53 CFS
Exit Velocity	73.4 FPS	50 FPS

Source Distance (Thous.Ft.)	Elevation Differences	Eff. Stack Height (ft.)	Concentration (ppm)	Eff. Stack Height (ft.)	Concentration (ppm)
Wind Velocity		10 MPH			
20	30	1831	.0000	1649	.0001
30	20	1841	.0005	1659	.0016
40	45	1816	.0029	1634	.0062
50	120	1741	.0117	1559	.0184
60	220	1641	.0280	1459	.0365
70	300	1561	.0428	1379	.0501
80	420	1441	.0642	1259	.0681
90	500	1361	.0789	1179	.0781
100	570	1291	.0896	1109	.0841
130	670	1191	.0949	1009	.0814
Wind Velocity		15 MPH			
20	30	1234	.0068	1063	.0204
30	20	1244	.0261	1073	.0466
40	45	1219	.0486	1048	.0674
50	120	1144	.0811	973	.0927
60	220	1044	.1101	873	.1105
70	300	964	.1223	793	.1140
80	420	844	.1367	673	.1190
90	500	764	.1375	593	.1144
100	570	694	.1339	523	.1076
130	670	594	.1097	423	.0837
Wind Velocity		20 MPH			
20	30	996	.0365	842	.0722
30	20	1006	.0698	852	.0958
40	45	981	.0923	827	.1052
50	120	906	.1183	752	.1167
60	220	806	.1347	652	.1204
70	300	726	.1353	572	.1144
80	420	606	.1376	452	.1102
90	500	526	.1302	372	.1008
100	570	456	.1210	302	.0914
130	670	356	.0925	202	.0674

FIGURE II-1



PLAN OF LEASE DEVELOPMENT

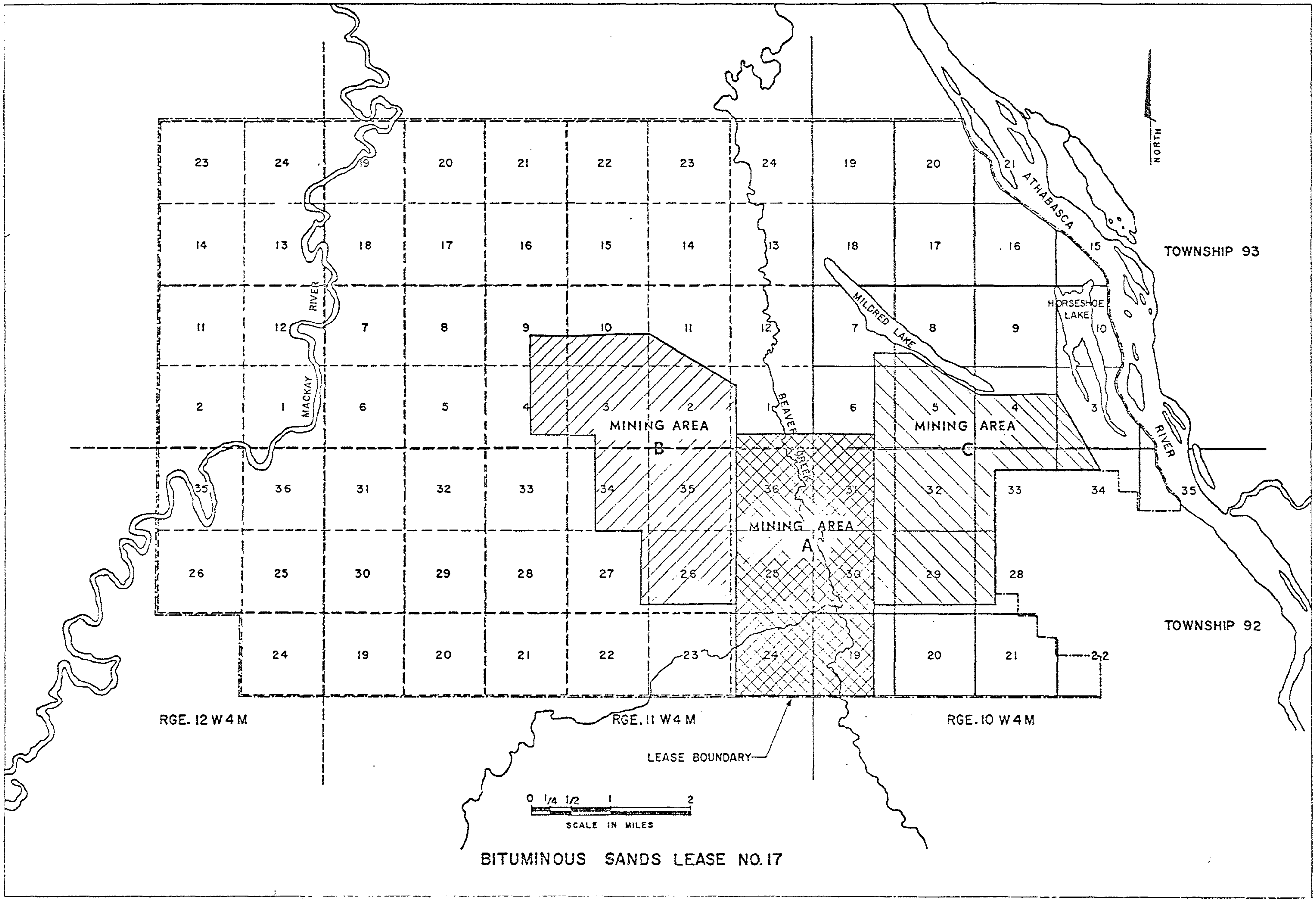
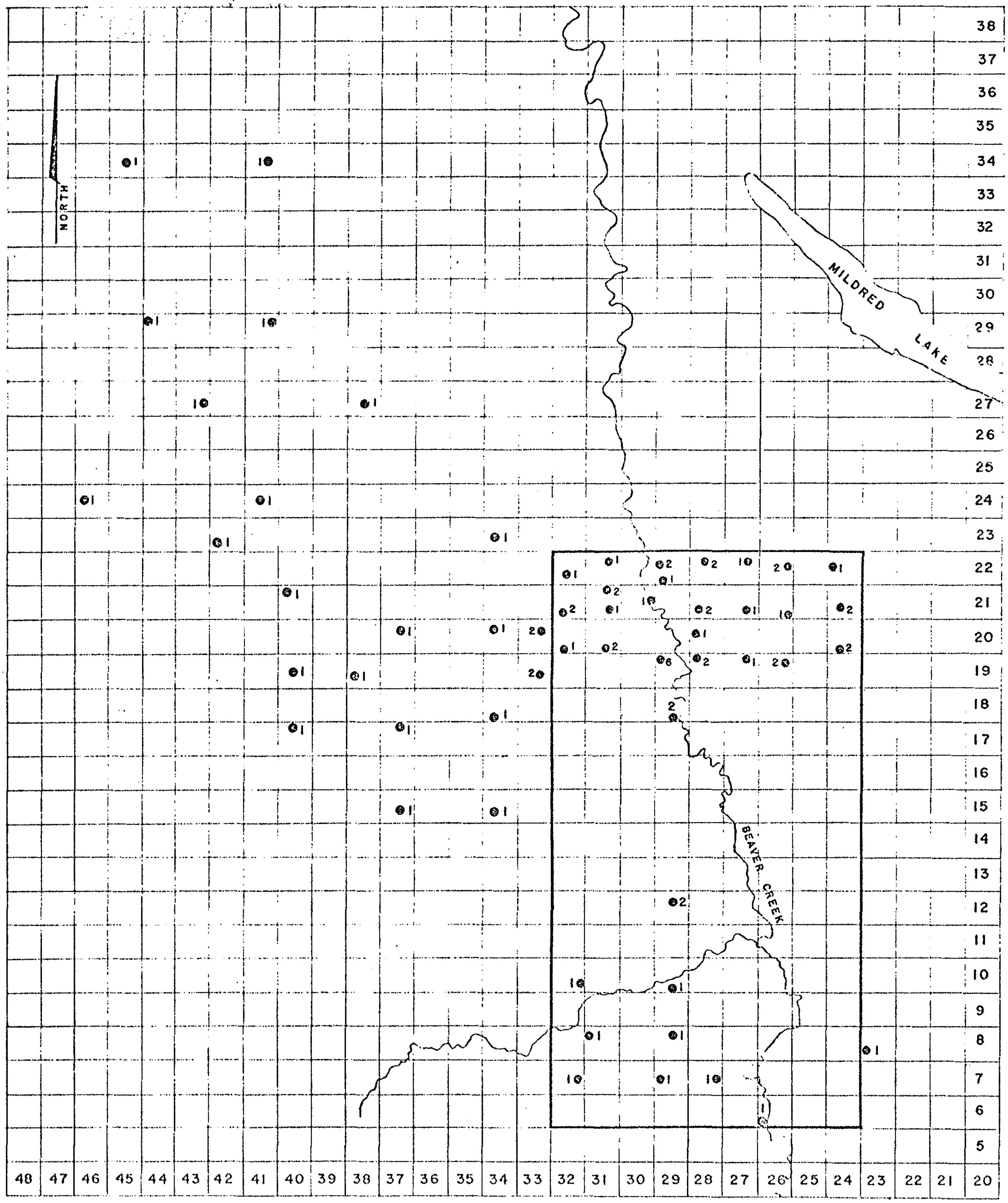

NORTH
TOWNSHIP 93
TOWNSHIP 92
RGE. 12 W 4 M
RGE. 11 W 4 M
RGE. 10 W 4 M
MACKAY RIVER
BEAVER CREEK
MILDRED LAKE
HORSESHOE LAKE
ATHABASCA RIVER
MINING AREA B
MINING AREA C
MINING AREA A
LEASE BOUNDARY
0 1/4 1/2 1 2
SCALE IN MILES
BITUMINOUS SANDS LEASE NO. 17

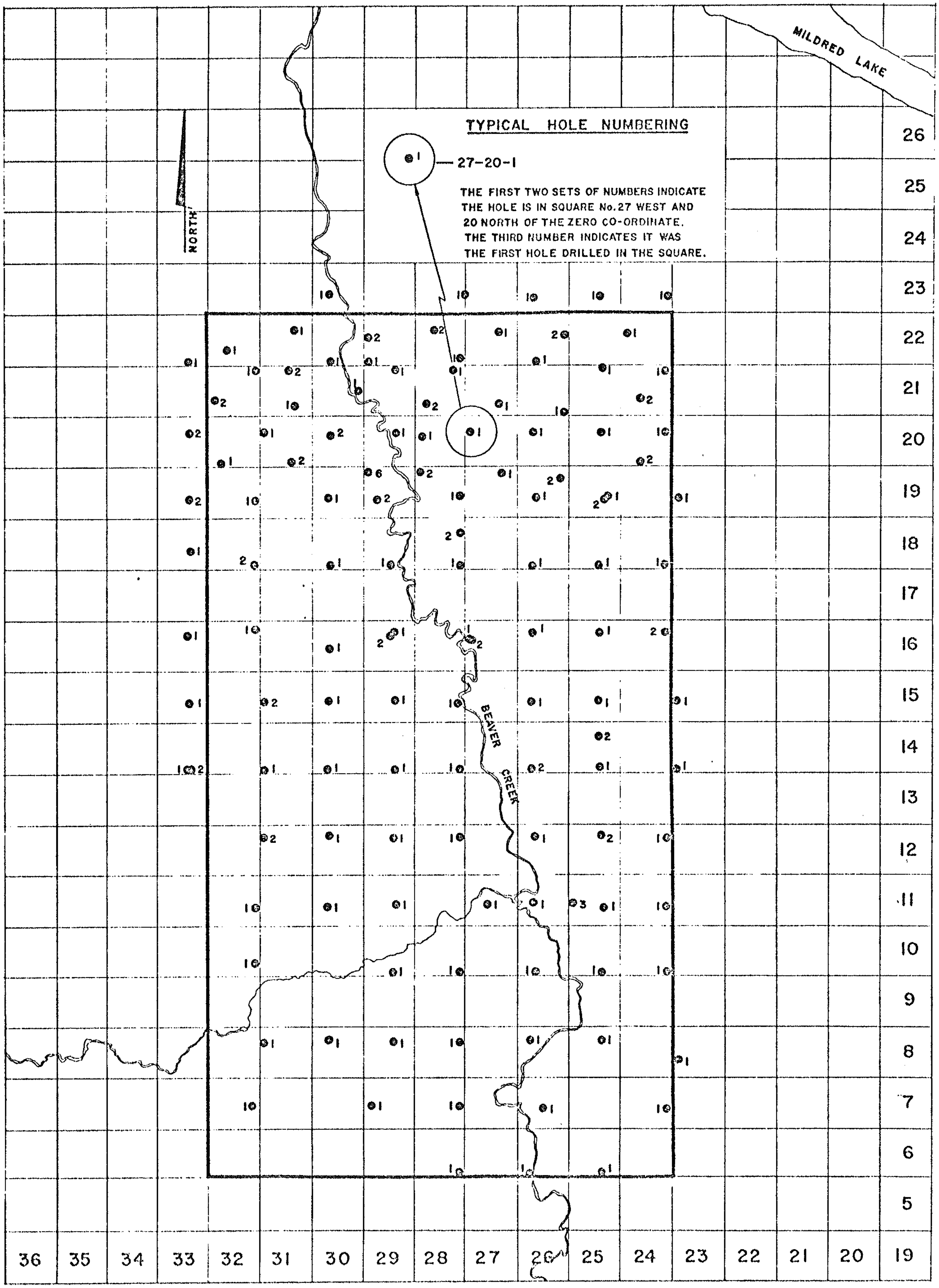
FIGURE II-2

FIGURE II-3

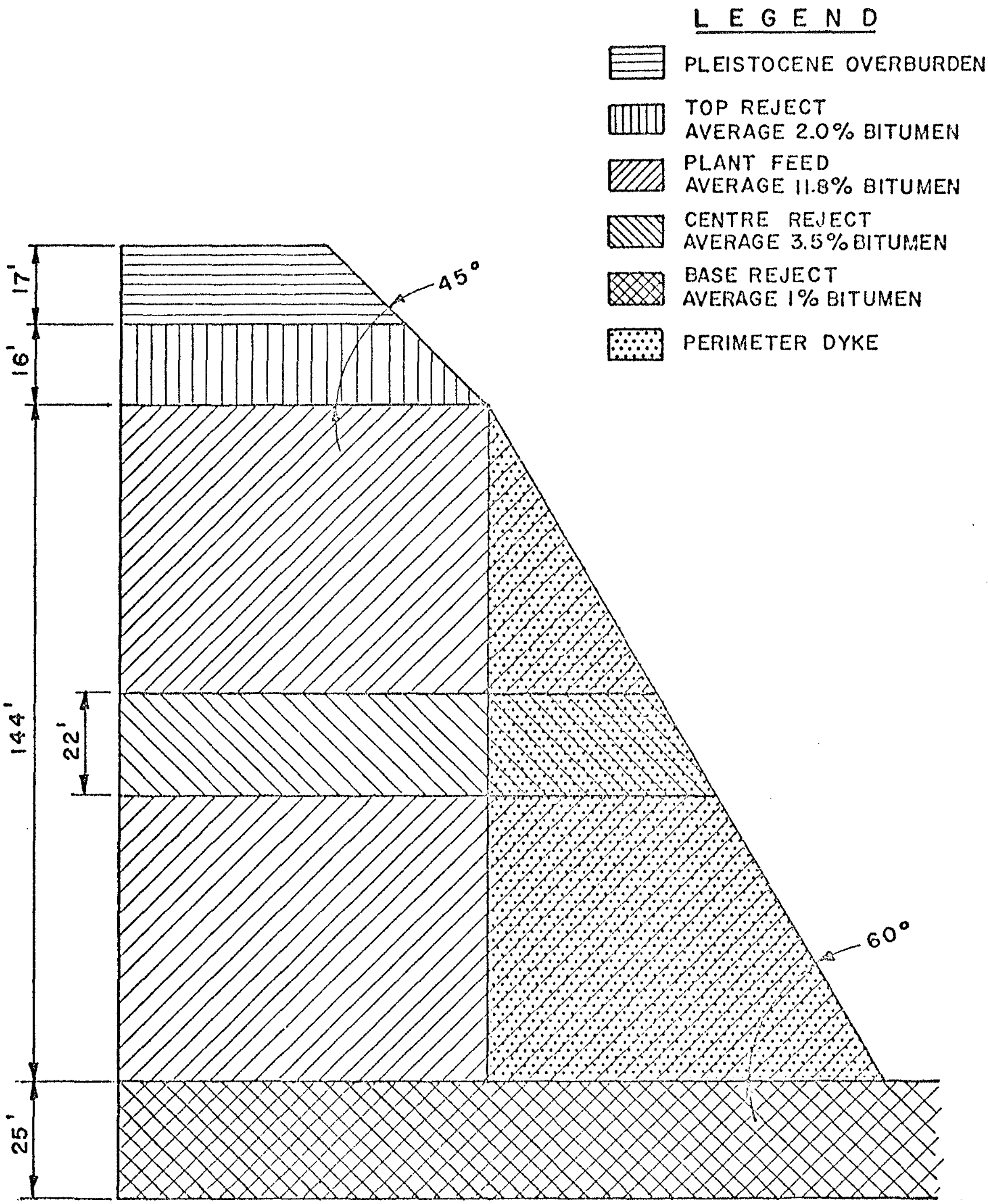


LOCATION OF HOLES DRILLED IN 1970 & 1971

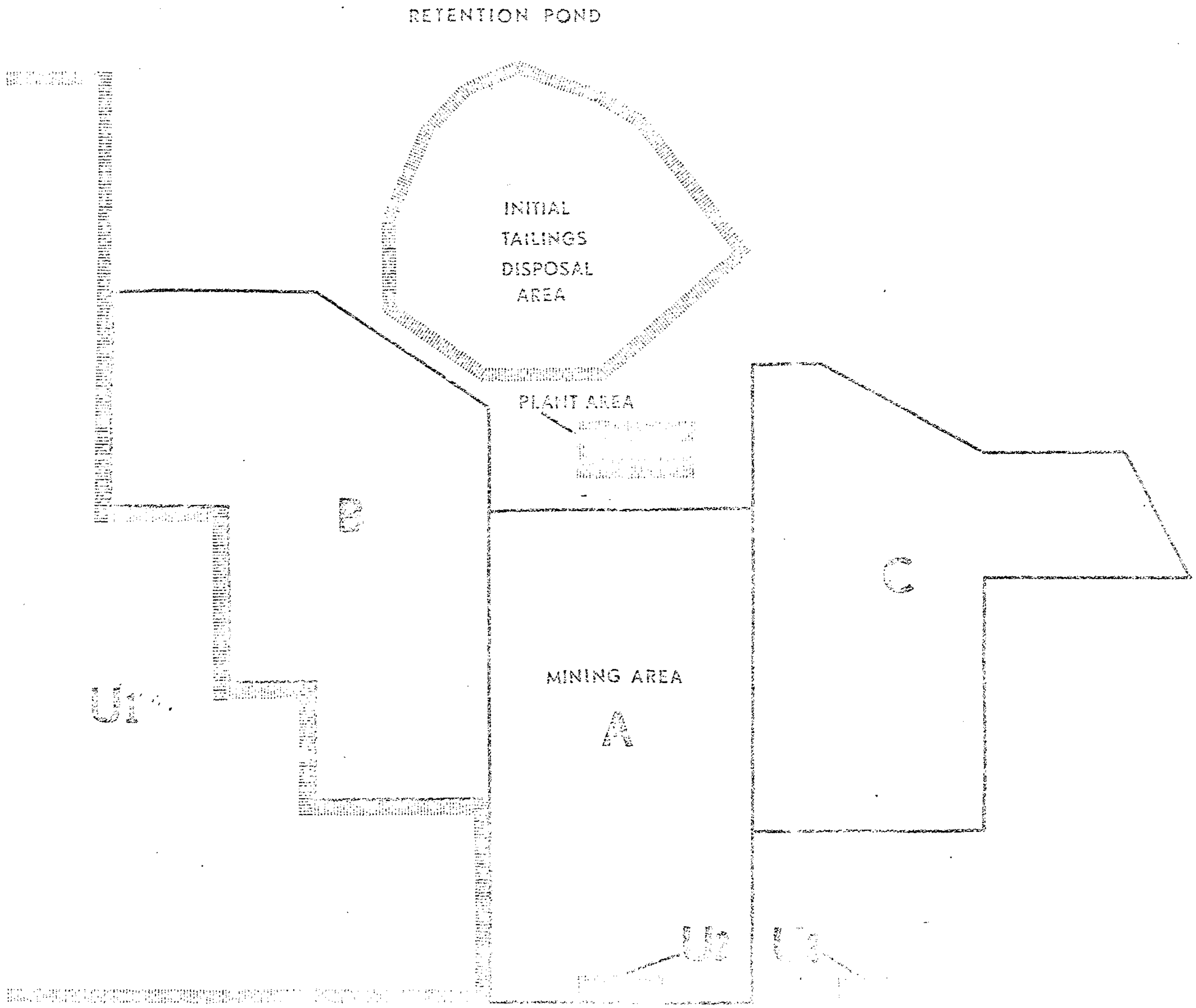
FIGURE II-4

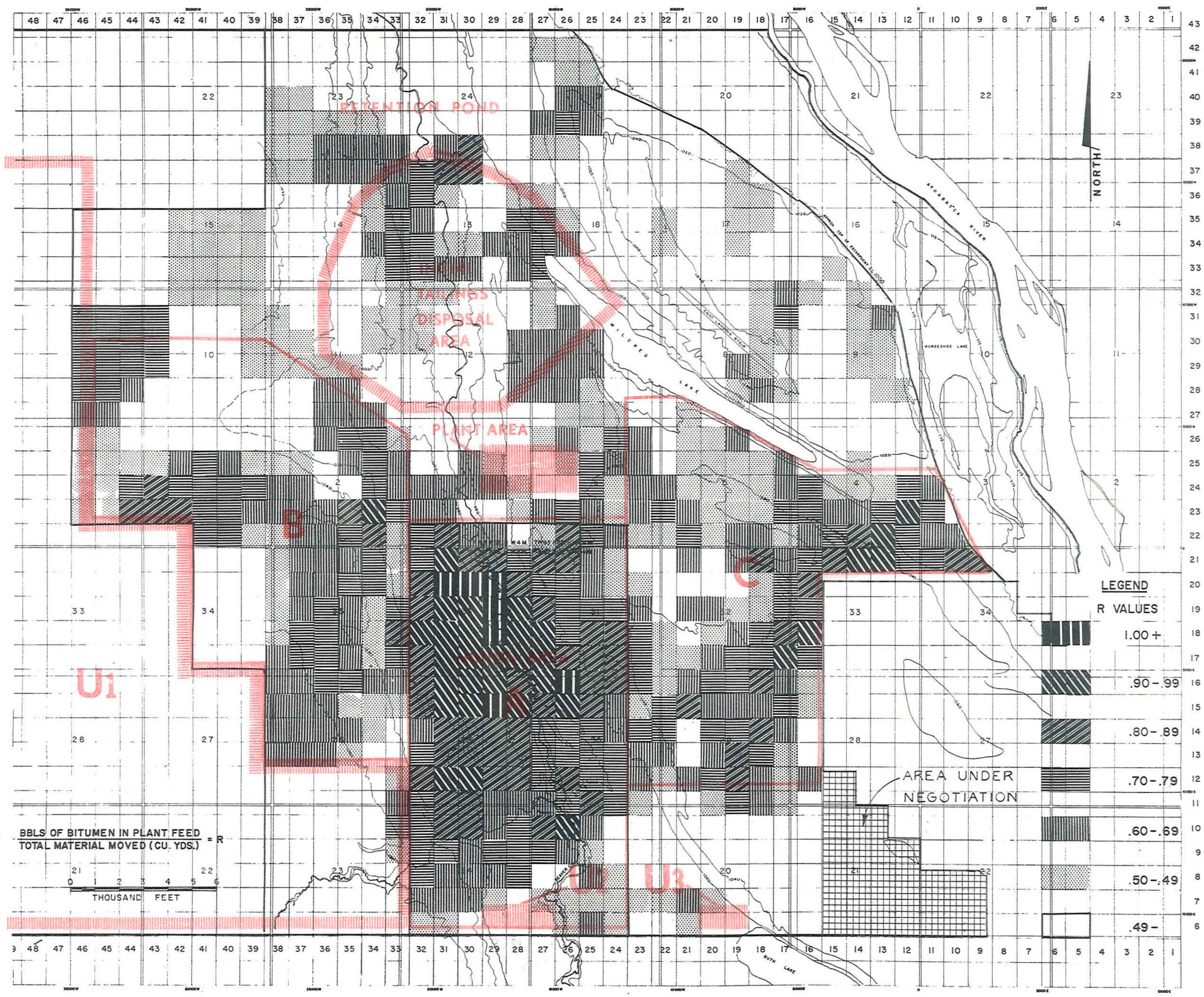


LOCATION OF HOLES INFLUENCING
MINING AREA "A"
(REFER TO TABLE No. II-1 FOR DESCRIPTIONS)

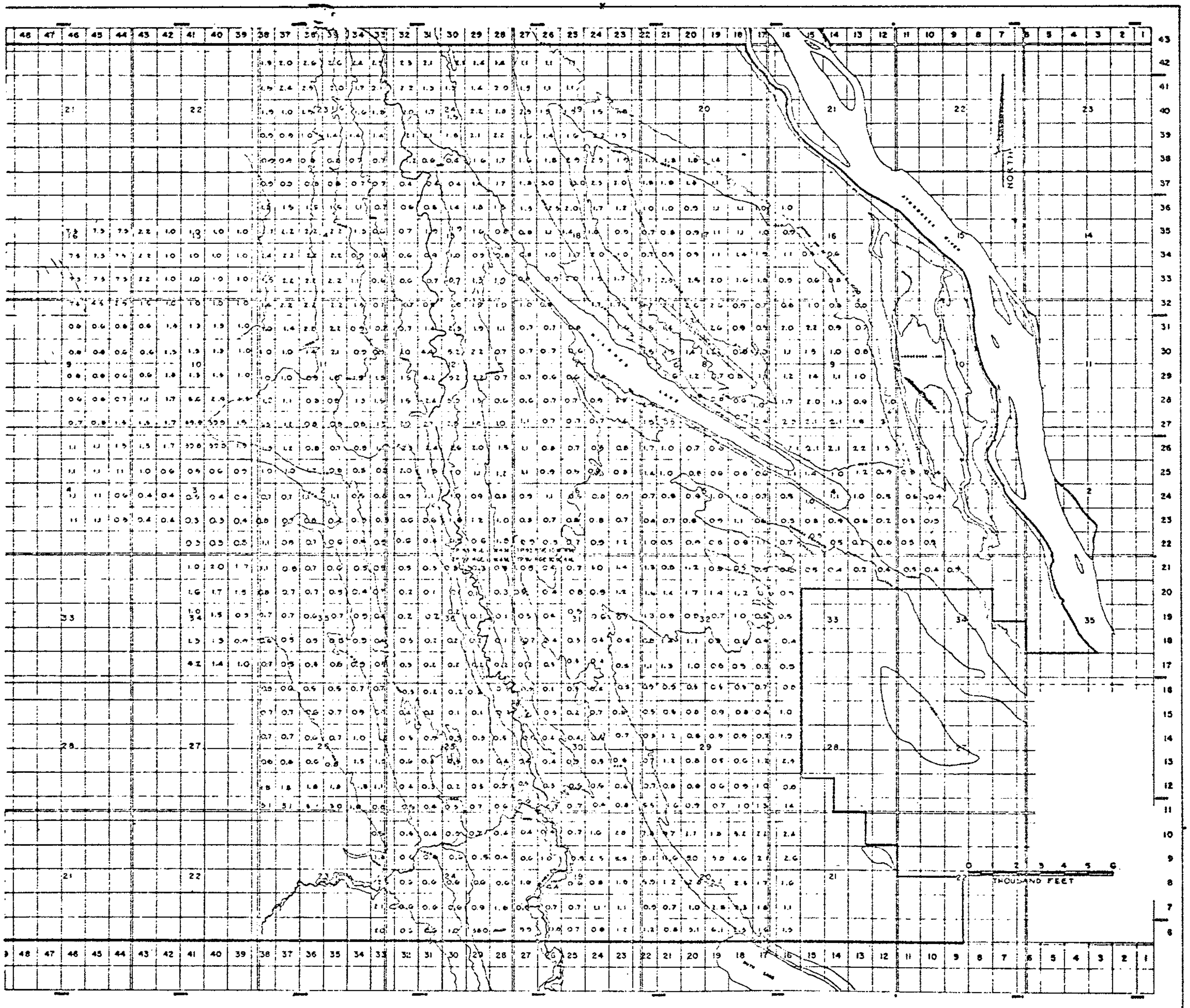


PIT WALL CROSS SECTION
AVERAGE THICKNESS OF MATERIAL


RETENTION POND
INITIAL
TAILINGS
DISPOSAL
AREA
PLANT AREA
B
C
MINING AREA
A

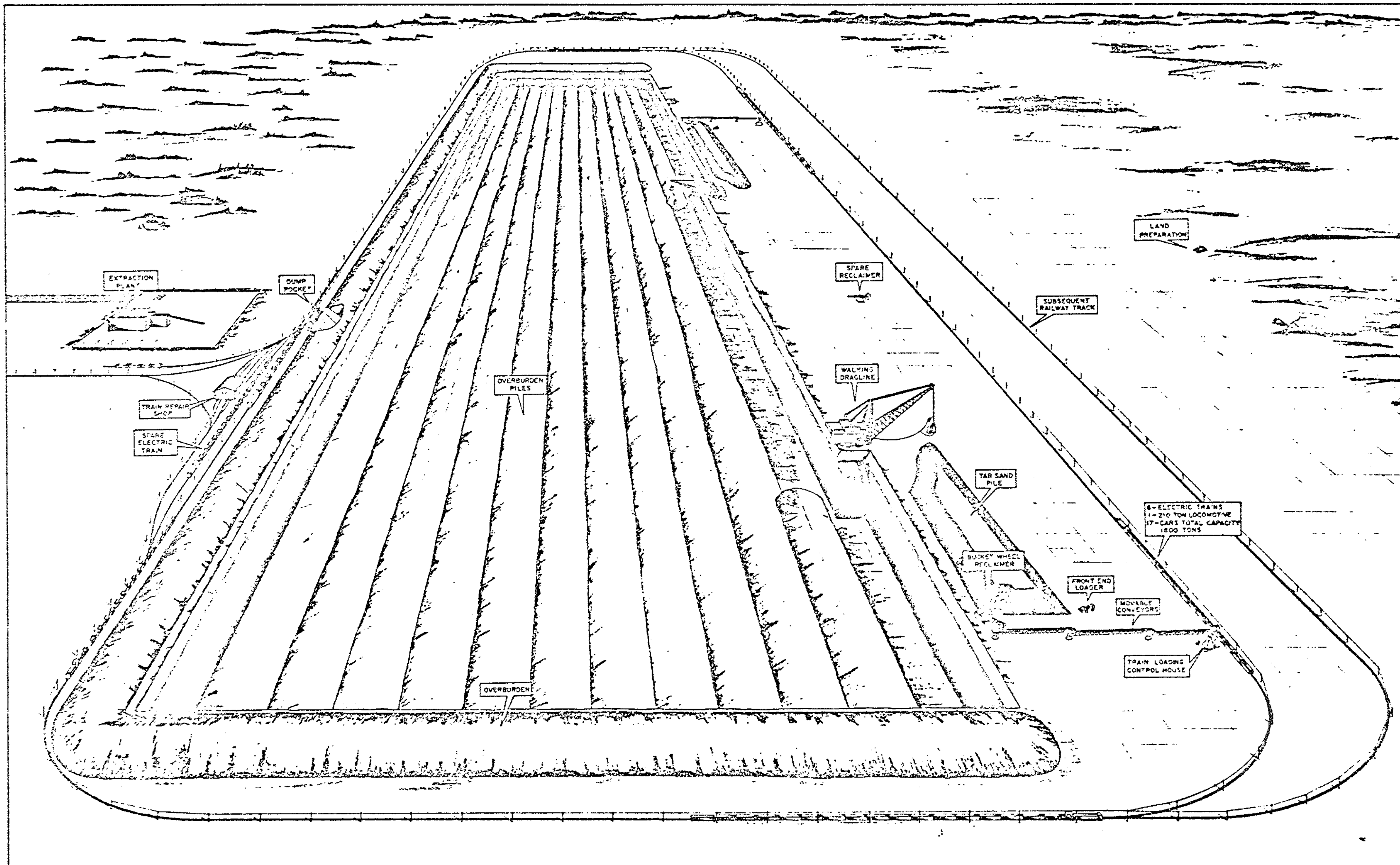


QUALITY OF RESERVES



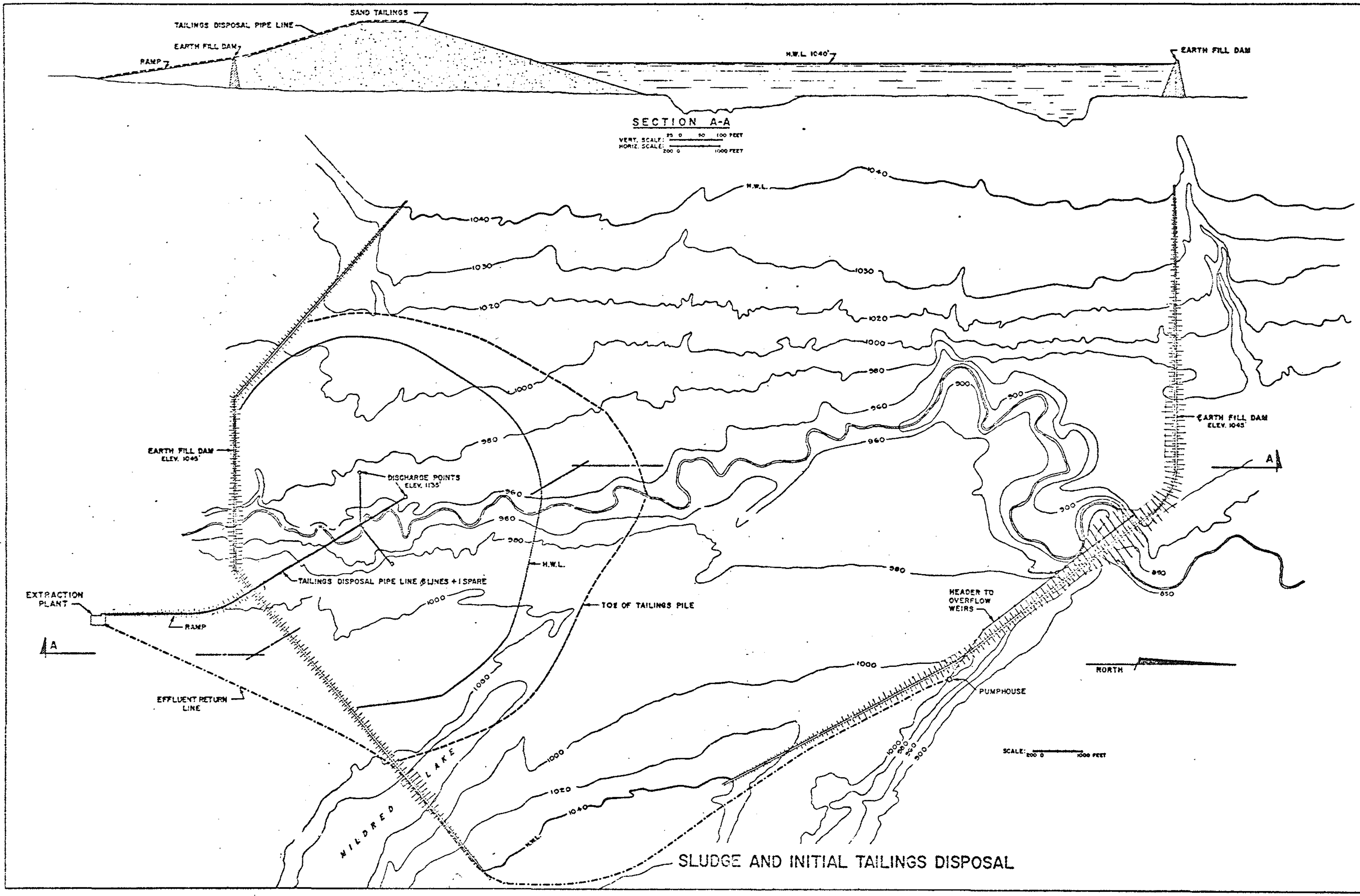
WASTE/TAR SAND RATIOS

FIGURE II-7



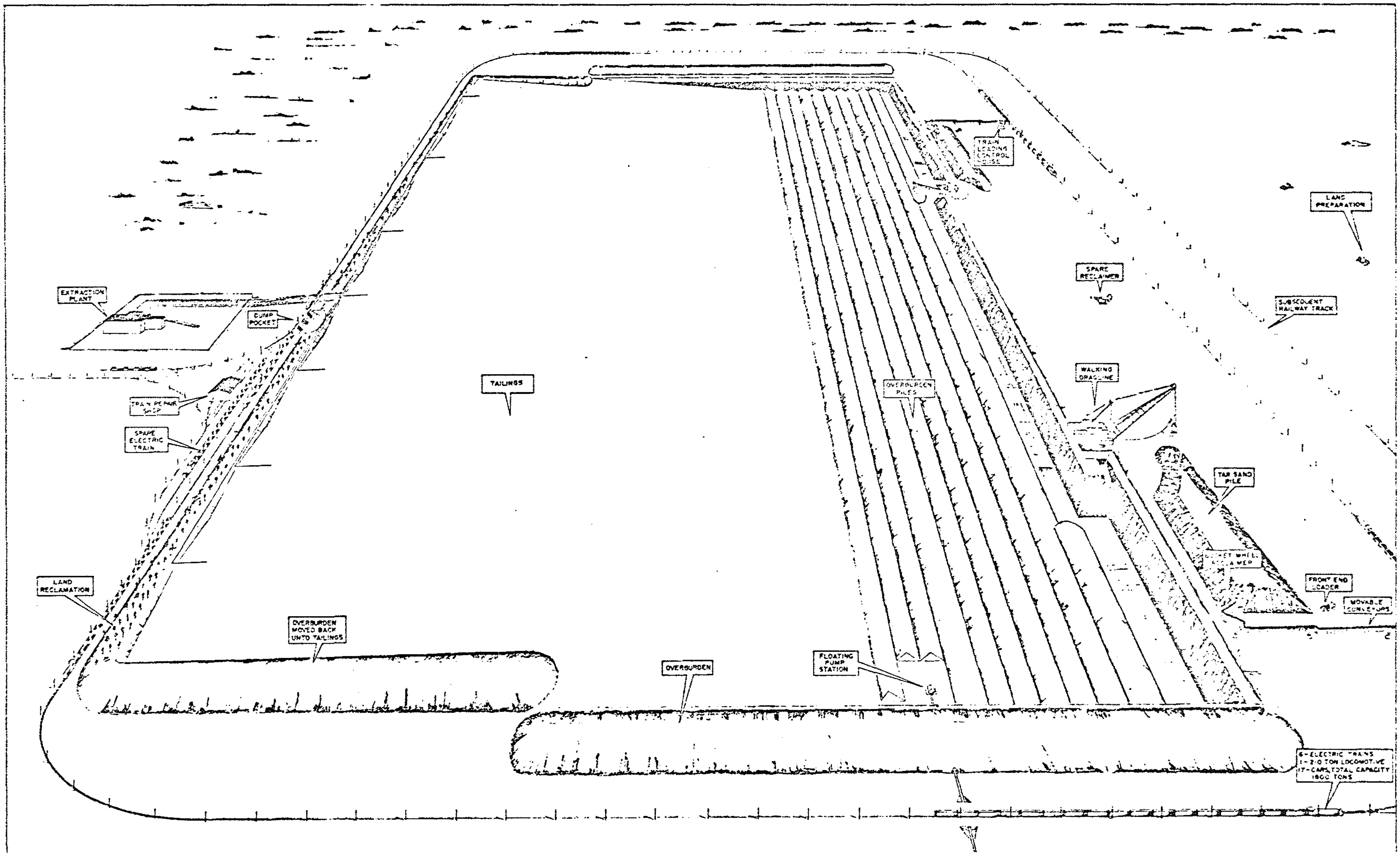
VIEW OF DRAGLINE MINING OPERATION AFTER YEAR 2

FIGURE II-8



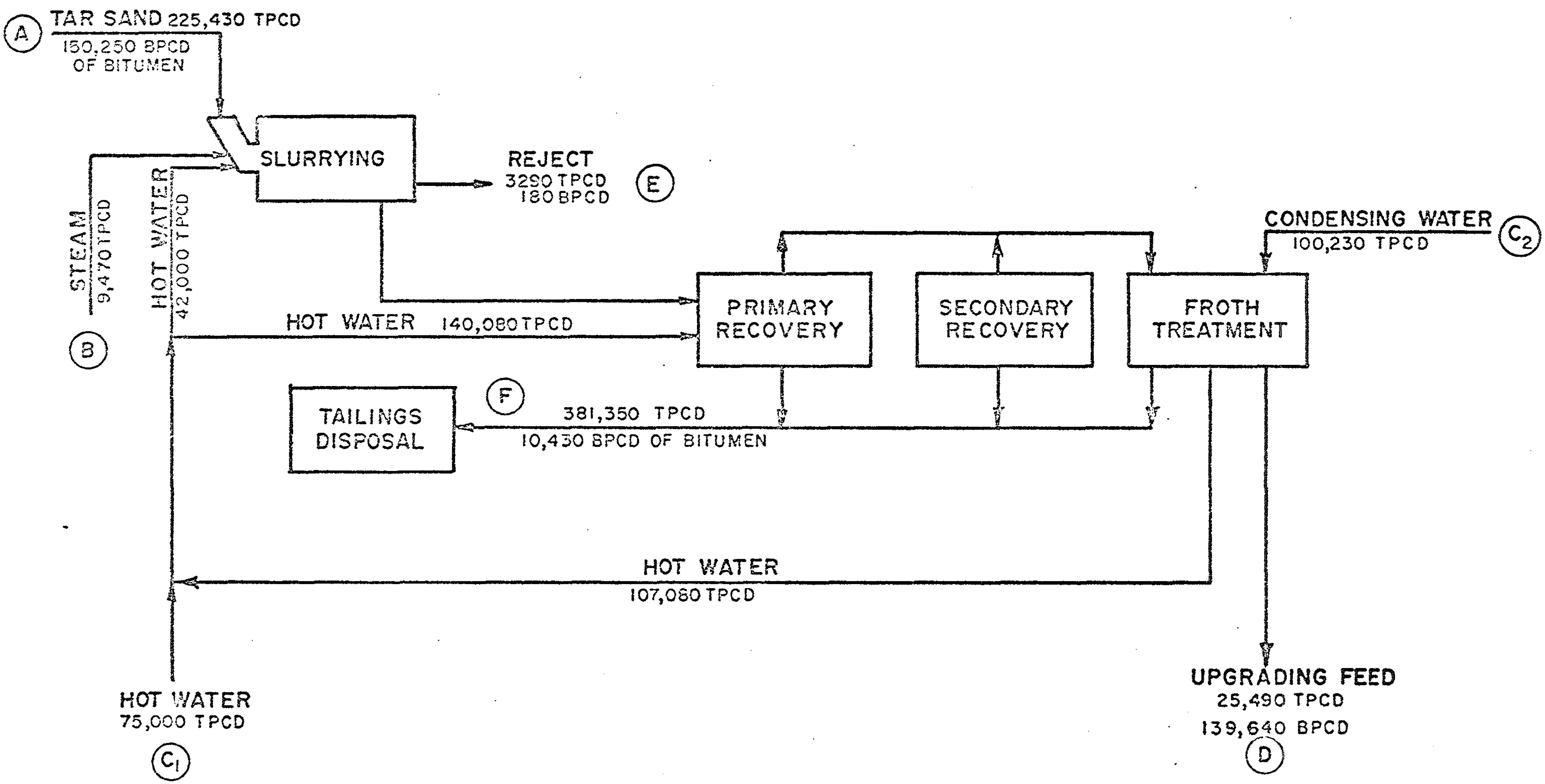
SLUDGE AND INITIAL TAILINGS DISPOSAL

FIGURE II-9



VIEW OF DRAGLINE MINING OPERATION AFTER YEAR 6

FIGURE II-10

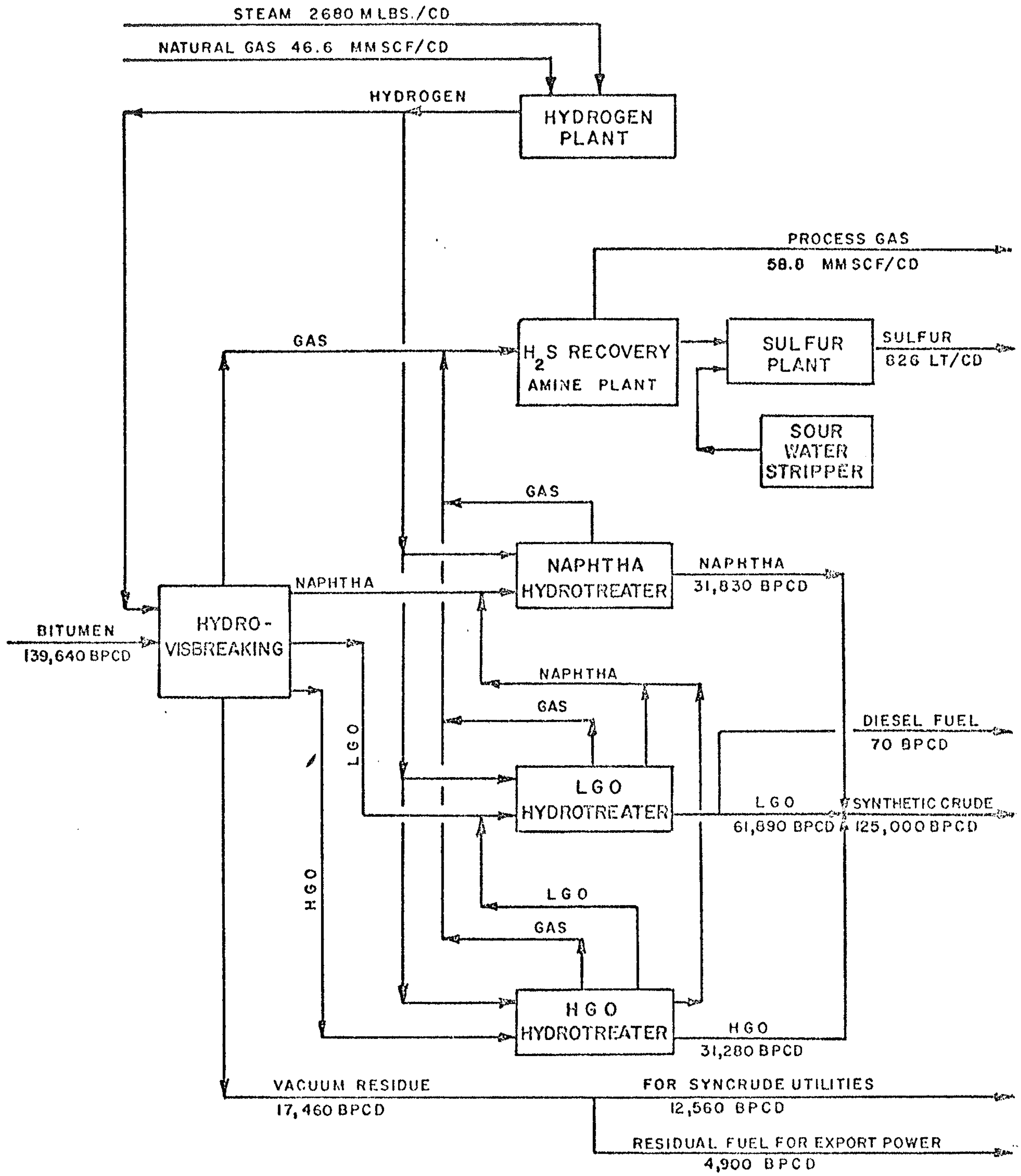


EXTRACTION - FROTH TREATMENT

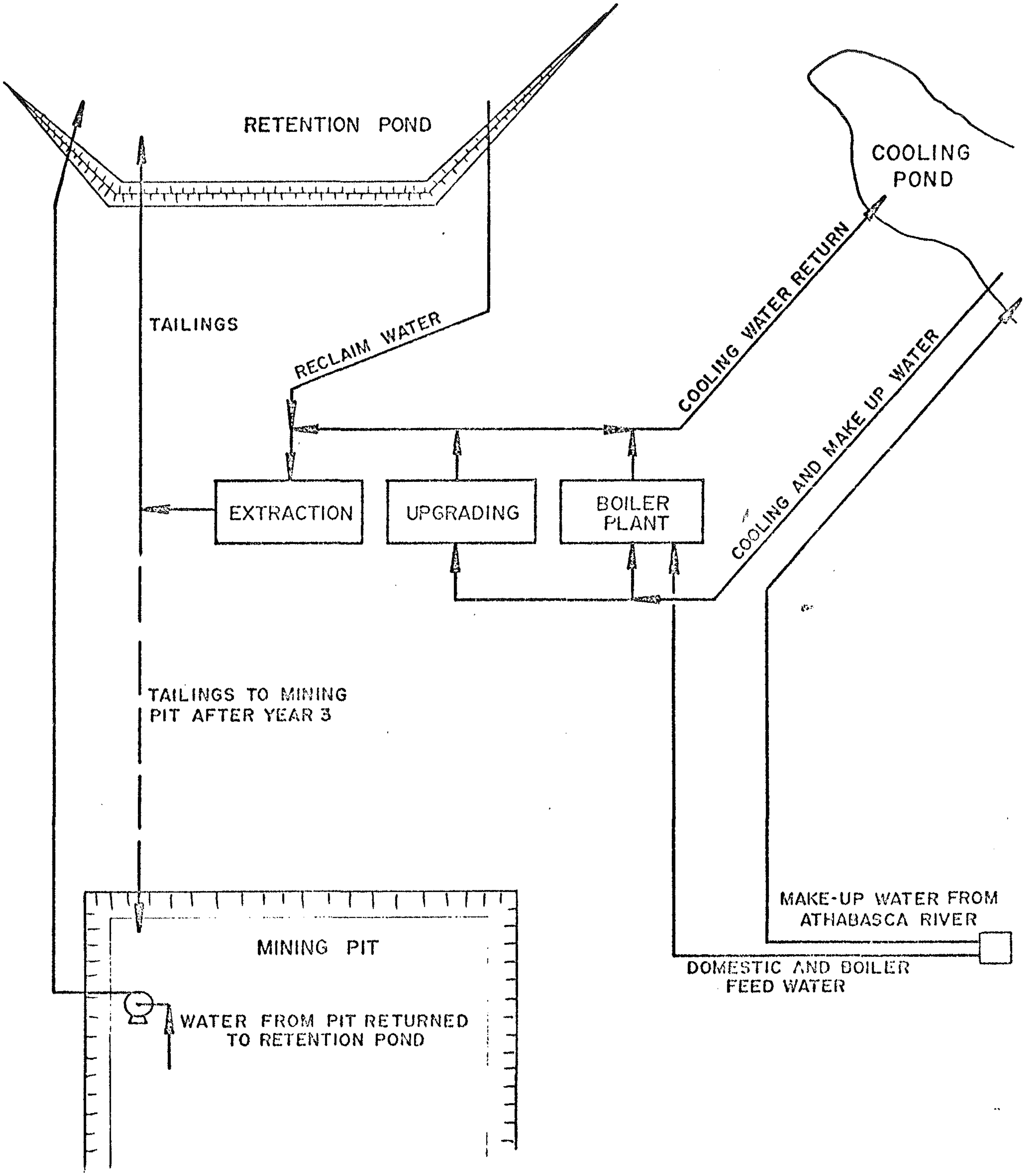
SCHEMATIC FLOW SHEET

TPCD - TONS PER CALENDAR DAY (TOTAL MATERIAL)
BPCD - BARRELS PER CALENDAR DAY (100% BITUMEN)

FIGURE II-11



BITUMEN UPGRADING
SCHEMATIC FLOW SHEET



FRESH AND RECLAIM WATER SYSTEM

5. MARCH 5, 1973 APPLICATION TO THE ENERGY RESOURCES CONSERVATION BOARD CONCERNING AMENDMENT OF APPROVAL NO. 1725

INTRODUCTION

GENERAL

The proposed Mildred Lake Project is a high risk venture and demands that the various processing operations be chosen carefully to assure a reliable operation.

Engineering evaluation of the processes included in the previous application has shown the need for technical changes in the Syncrude Mildred Lake Project. The applicants request amendments to Approval No. 1725 to incorporate the necessary changes.

No change is sought in the amount of synthetic crude oil to be produced, although for design, the initial output will be approximately 104,500 BPD with the final output to be reached as plant bottlenecks are removed. Material balances contained herein show both 125,000 BPD and 104,500 BPD synthetic crude output. No change in the anticipated 25-year project life is expected.

Review of the construction schedule as related to critical equipment delivery and the availability of construction labour indicates a possible delay in recovery of saleable hydrocarbon products beyond the specified January 1, 1977 date in Clause 8 of Approval No. 1725. The applicants request that the specified January 1, 1977 date be revised to January 1, 1978.

The applicants plan no alteration to the decision date of August 31, 1973 as specified in O.C. 244/72. If the decision on this application is favourable, the applicants plan to proceed on September 1, 1973 with detailed engineering and construction subject only to evaluation as required of regulatory, fiscal and economic factors which could seriously jeopardize the success of the project.

FROTH TREATMENT

In prior applications, the applicants indicated that thermal dehydration would be used to remove water from the bitumen froth recovered in the primary extraction process. The applicants have concluded that further development work is necessary to assure the ability of thermal dehydration to cope with rapid changes in froth water or solids content, and to solve problems of scale-up.

Dilution centrifuging for the removal of water and solids from tar sands bitumen froth is a proven commercial process and has been chosen for the initial Syncrude plant.

UPGRADING OF BITUMEN TO SYNTHETIC CRUDE OIL

Hydrovisbreaking has previously been proposed as the primary upgrading step. Continued pilot work on hydrovisbreaking of bitumen indicated potential operation problems, at high conversion rates, which require resolution to scale-up this potentially attractive process to a commercial design. As alternates, both fluid coking and delayed coking were considered. Fluid coking has been chosen as the primary upgrading process because of its more favourable yield structure compared to delayed coking.

UTILITY PLANT

The 1971 application was based on using most of the hydrovisbreaker pitch for utility plant fuel and proposed the sale of the excess pitch for export power generation. Natural gas usage was estimated at 57 MM SCFD for supplying hydrogen plant feed and supplementing the plant fuel to process heaters.

Fluid coking, by comparison, produces substantially more fuel gas than hydrovisbreaking, as well as producing part of the total plant steam requirement from the associated CO boilers. This makes it feasible to incorporate a gas-fired utility plant and still keep the purchased natural gas quantity at or below the quantity estimated in the 1971 application. The gas-fired utility plant will also result in lower total sulphur emission and is an integral part of the overall change in using fluid coking as the primary upgrading process.

Attachment 1 shows an energy balance for the initial plant throughput.

SULPHUR EMISSION

With hydrovisbreaking, the main source of sulphur emission was the pitch-fired utility plant with sulphur plant losses contributing a relatively minor quantity. With fluid coking there will be essentially no sulphur emission from the gas-fired utility plant. The main sources will be the CO boilers plus the sulphur plants.

No changes have been made in the sulphur plant design from previous applications. A recovery efficiency of 95% has been used in calculating total emission. Study of sulphur plants processing acid gas containing ammonia shows 95% recovery to be realistic. This is developed in Appendix I attached. The total emission at 143 long tons per day is a significant reduction from the 243 long tons per day specified in Approval No. 1725.

TAR SAND GRADE

Evaluation of the selectivity of mining has led to a reduction in the average grade of plant feed from the 11.8% in the previous application to 11.59%. This reduction is due only to dilution of the richer ore with more lower grade material than originally estimated. The material balances included with this application are based on the lower figure.

PROCESS COOLING

Previous applications considered the use of Mildred Lake as a cooling pond for the plant. A closed circuit cooling water system with a cooling tower has been chosen instead because of the excessive organic material in Mildred Lake.

APPLICATION

The applicants understand that they are applying only to advise the Energy Resources Conservation Board of major technical changes as outlined in Paragraph 6 of Approval No. 1725 and that they and all other parties to the hearing, are bound by the Board's findings in Reports OGCB 68-C, OGCB 69-C, and ERCB 71F-OG, except insofar as new and significant events or data affect these findings.

TECHNICAL CHANGES

FROTH TREATMENT

Syncrude has conducted extensive pilot plant work on thermal dehydration of bitumen froth.

The direct scale-up of the pilot plant unit to the commercial size unit would have involved a scale-up on the order of 1500 to 1. This large scale-up factor led to uncertainty in the behavior of water vapour and solids in the commercial units, particularly in view of uncertainty in the water and solids content of the primary froth. Resolution of this uncertainty would have required further development on a larger scale, with a substantial time penalty and no guarantee that a commercially viable process would result.

Dilution centrifuging was chosen over thermal dehydration for the initial Syncrude plant since it is a commercially practiced scheme and is demonstrably reliable. Dilution centrifuging does, however, indicate higher losses of hydrocarbon than thermal dehydration.

Syncrude, in order to improve the performance of dilution centrifuging, is nearing the completion of a substantial pilot unit. It is expected that this dilution centrifuging pilot unit will be in operation in mid-March 1973. The prime objectives of this pilot unit will be to:

1. Evaluate sources and amounts of hydrocarbon losses during operation.
2. Initiate studies into hydrocarbon loss reduction.

In the meantime, pending the completion of the pilot work, the applicants are basing the design on proven commercial performance. Block flow diagrams of the design showing initial and ultimate throughput are shown on Attachments 2 and 3.

The drawings show that the recovery of bitumen and naphtha fed to the froth treatment plant is expected to be 98%. This, combined with the extraction recovery of 93% gives an overall hydrocarbon recovery through the froth treating step of 90.1%. It is expected that this recovery will be enhanced by the results of our pilot plant work and by continued development work following plant start-up.

BITUMEN UPGRADING

Primary Upgrading

In previous applications, the applicants had considered hydrovisbreaking as the primary upgrading step. For hydrovisbreaking to be significantly more attractive than other processes, the conversion level must be high. Operating difficulties were indicated by extensive piloting at certain desirable process conditions. Agreements with licensors relating to this proprietary process preclude disclosure of these conditions. The development time to resolve these difficulties would be of uncertain duration. These considerations also apply to combinations of primary upgrading processes in which hydrovisbreaking would be used as well as to the case described in our previous application.

In order to proceed on the project it was decided to explore various alternatives to hydrovisbreaking, among them fluid coking and delayed coking. Fluid coking results in a more favourable yield pattern than delayed coking and was therefore adopted.

Interest is being maintained in hydrovisbreaking. As its development proceeds it may be useful in any future plant expansion used in combination with the planned fluid coking.

Attachment 4, Bitumen Balance, shows the yield pattern employing fluid coking in upgrading. Values are expressed for the initial output contemplated and for the anticipated ultimate throughput.

The values shown are based upon maximum yield of synthetic crude oil, and minimum coke yield. The process is quite flexible with respect to increase in gas yield but this would entail sacrifices in overall yield of saleable liquids and higher coke production.

Attachment 5 is a typical flow diagram for one of the two fluid cokers. Bitumen feed from the diluent recovery plant is heated and atomized through a large number of nozzles into a fluidized bed of coke particles (generally less than 200 micron size) at 900-1000^{o}F. When the feed bitumen comes in contact with the hot coke particles, the lighter oil constituents are vapourized, and the heavier constituents cracked to form gas, distillate or coke. High pressure attrition steam is injected below the feed zone to control coke particle size. Stripping steam is used in the bottom of the reactor to displace hydrocarbon vapour and prevent loss of liquid and gas product to the burner. The steam and hydrocarbon vapours keep the reactor coke bed fluidized. When the vapours reach the less dense zone near the top of the bed, they are heated further by the hot coke return, and pass into the scrubber through cyclones (to remove most of the coke fines). The remaining coke fines are washed from the vapour as it passes up through the scrubber. Heat is removed from the scrubber pump-around by steam generation. Scrubber bottoms are returned to reactor feed.

Coke inventory in the reactor is maintained by transferring coke from reactor to burner. Reactor temperature is maintained by transferring hot coke from burner to reactor. The system is pressure balanced at 10-30 psig. Coke is transferred with steam injection at the bends. Burner air is supplied from a blower. Coke inventory is maintained in the burner by coke removal through an elutriator which maintains product coke size by returning smaller coke particles to the burner.

The vapour product is sent to a fractionation system where the distillates are separated for hydrotreating. The gas is amine treated to remove hydrogen sulphide and used for plant fuel.

The burner off-gas is burned in a CO boiler with supplemental fuel gas. The CO boilers produce a large part of the steam necessary for extraction of bitumen from tar sand. The effluent from the sulphur recovery plants will also be burned in the CO boilers to effect incineration of the sulphur compounds. The flue gas from the CO boilers will pass through appropriate dust removal devices to ensure particulate removal consistent with environmental protection standards. The flue gas will be exhausted to the atmosphere combined with the flue gas from the utility boilers at 450-500°F through a 600 foot concrete stack with an independent steel liner.

The reactions in the coker burner tend to reduce the amount of sulphur in the coke burned, and concentrate the sulphur in the net product coke. The net coke will contain about 9% sulphur and approximately 6% solids.

Attachment 6 shows the sulphur balance around the upgrading units. All values are shown on a calendar day basis except for the sulphur equivalent of the sulphur dioxide emitted to the atmosphere shown at the bottom of the page which is shown on a stream day basis.

The bases chosen for Attachment 6 are for the worst sulphur emission case during normal operation, with the ultimate emission of 143 long tons of sulphur emitted as sulphur dioxide chosen for the design of emission control equipment. The anticipated maximum sulphur dioxide emission is approximately 200 long tons per day less than that permitted under Approval No. 1725.

Potential for CO Boiler Flue Gas Scrubbing

Syncrude has considered possible processes for removal of sulphur dioxide from flue gases from the CO boilers but has been concluded that stack gas cleanup is not feasible at this time.

The most promising of these processes at this time is lime or limestone slurry scrubbing of the stack gases. The technical status of this process has been the subject of many studies. Results of one of the most recent studies was presented by Dr. Ivor E. Campbell and John D. Ireland and published on Page 78 of the December, 1972 issue of the Engineering and Mining Journal. It is also reviewed in API Publication No. 4153 of January 1973. The latter publication lists sixteen power stations which have installed or are going to install this process. Of these, the following have started operations with results noted:

- Kansas Power & Light; Lawrence, Kansas
  Started Fall 1971 but experienced plugging problems which has limited operations.
- Union Electric Company, St. Louis.
  The process has been abandoned.
- Commonwealth Edison; Will County, Illinois.
  Intermittent operation due to several equipment failures and plugging problems.

Particulates in CO Boiler Stack Gas Effluent

The effluent from the CO boiler will be combined with the utility plant effluent gases into a single stack. Electrostatic precipitators will be used on the effluent gas from the CO boilers prior to entering the single main stack. An efficiency of 75% particulate removal will keep the concentration in the main stack gas below the 0.2 lbs. per 1000 lbs. of flue gas (adjusted to 50% excess air) required by Provincial standards.

Fluid Coke Product

The net product coke will be slurried with water and transported to an initial storage area at the site of gravel pit no. 1 as indicated on Attachment 10. A small inventory will be kept in silos as operating coke inventory and surge.

A section of the mined-out area will be diked off and used for long term coke storage. This area will be such that the coke can be readily reclaimed when its use becomes practicable.

Slurried coke, if undisturbed, forms a surface crust which prevents dusting loss.

Secondary Upgrading

The coker products must be hydrotreated to remove sulphur and nitrogen. An overall block flow diagram for bitumen upgrading is shown in Attachment 7.

The sulphur is removed as hydrogen sulphide and processed into elemental sulphur in parallel sulphur recovery plants.

The quality of the synthetic crude oil is essentially unchanged from that in previous applications. The following are gross properties:

Gravity	30° API
Sulphur	0.1 wt% max.
Nitrogen	0.1 wt% max.
Vol. @ 430°F.	26%
1000°F.	95%

The applicants have studied the possibility of extending the upgrading process to produce a higher gravity synthetic crude oil. This is not desirable under present conditions. It would be imprudent to unnecessarily increase the capital costs of this high risk project by a substantial increase in plant complexity at this time in the face of rapidly changing product requirements.

Steam and Power Generation

In addition to the steam produced by the CO boilers and process heat exchangers in the upgrading facilities, additional steam will be required from the utility plant. The CO boilers are sized by the amount of CO containing gas produced from the coker burners which is in turn dictated by the fluid coking unit process heat requirements. The CO boilers will be among the largest ever built. Producing more steam in the CO boilers by additional supplemental fuel gas-firing is uneconomic due to the high unit cost of this type of boiler.

The utility plant is the subject of a separate application to the Energy Resources Conservation Board under Section 7.2 of the Hydro and Electric Energy Act. The utility plant will be gas-fired and will employ a combined gas turbine-steam cycle to maximize fuel efficiency. Gas turbine generators will supply hit combustion air to the boilers. High pressure steam from the boilers will be used to drive back-pressure turbo-generators and the low pressure exhaust steam will go to the processing units.

The applicants have studied the firing of fluid coke in the power boilers. The high sulphur content of the fluid coke would result in additional sulphur emission to the atmosphere on the order of 200 long tons per day. Thus a significant factor in the rejection of the use of fluid coke in the utility plant was the avoidance of the release of this much additional SO_2 to the atmosphere.

Air Quality

Discussions with the Department of Environment have resulted in selection of a design in which flue gas from the CO boilers is combined with flue gas from the gas-fired utility boilers. The principal air contaminants from the stack will be sulphur dioxide and particulates.

The concentration of SO_2 in the main stack gases is estimated to be less than 0.2 mol %. The volume of stack gas, including the sulphur plant tail gas, for normal operation and calculated ground level concentrations under various conditionas are tabulated in Attachment 8. These calculations are based on the Bosanquet-Carey-Halton formula for plume rise and Pasquill-Gifford formula for dispersion. The calculated maximum SO_2 concentration is less than 0.04 ppm at ground level for a 600 foot stack.

The stack height and its resulting calculated ground level concentration are based on the following factors:

1. Consideration of future tar sands development in the area.
2. Ability to avoid excessive ground level concentrations of sulphur dioxide in the event of a sulphur plant upset by diverting a substantial quantity of sulphur plant feed gas to the CO boilers and thence to the main stack.

The ground level concentration of nitrogen oxides will not be a problem. The concentration in the flue gas from the main stack will be less than one-fourth that of sulphur dioxide.

Appendix II outlines stack monitoring instrumentation.

Plant Energy Balance

Attachment 1 shows a plant energy balance, based on the initial design output of 104,550 BPCD of synthetic crude oil.

A substantial portion of the natural gas requirement is for the generation of hydrogen for hydrotreating. This is reflected in the energy available in the synthetic crude oil. It will be noted that 67% of the energy input in the form of bitumen, natural gas, and electric power is recovered in the synthetic crude oil.

Water Balance

Attachment 9 shows the projected water balance for the project. The balance is based on:

1. Average weather conditions as compiled by the Department of Transport.
2. The initial design synthetic crude oil output of 104,550 BPCD.
3. Conservative predictions of water evaporation due to weather and thermal evaporation from hot reject streams.

4. A percolation rate from impoundments of twelve inches per year per square foot of impoundment area.
5. Including the average annual run-off water from 15 square miles.
6. Decantation of the reclaimed water at 3% solids and compaction of the remaining sludge to 30% solids.

Surface run-off water external to the plant and mine area will be diverted to existing watersheds. No process water, mine water, or plant drainage water will be discharged to present watersheds under the existing plan. While no change is contemplated, should the discharge of any water become necessary, it would be treated to meet all environmental standards and monitored in accordance with the standards of the Clean Water Act.

Plot Plant of Facilities

Attachment 11 shows a plot plan of the facilities incorporating the features in this application. This plot plan will be subject to minor adjustments as necessary to optimize the layout.

No sulphur storage area is shown on the plot plan pending further soil investigation.

APPENDIX I

Sulphur Recovery

No changes have been made in the sulphur plant design from previous applications. A recovery efficiency of 95% has been used in calculating total emission. Study of sulphur plants processing acid gas containing ammonia shows 95% recovery to be realistic. This is based on the following factors:

1. Refinery acid gases contain varying amounts of ammonia, which generally ultimately go to the sour water treating plant and thence to the sulphur recovery plant.

2. The ammonia entering the sulphur plant must be preferentially oxidized to nitrogen and water vapour, or it rapidly de-activates the sulphur plant catalyst as ammonium sulphate (completely non-regenerable).

3. The conditions under which the ammonia must be destroyed are such as to reduce the reaction furnace yield, as explained below.

4. The extra nitrogen and water vapour in the plant stream downstream of the reaction furnace depress yield.

5. Refinery gases contain considerable aromatic and cyclic gases, traces of which contaminate the acid gas.

While sulphur recovery at refineries is quite an old process, the on-stream time, catalyst life, and efficiency have been quite low--particularly where hydrotreating of high nitrogen streams has been involved. Syncrude intends to approach this problem as follows:

The acid gas from the DEA regenerator reflux drum will be piped to an acid gas knockout drum for delivery to the sulphur recovery plant. Liquid from the knockout drum will be drained under level control to the sour water treating system.

A second knockout drum will be provided for the ammonia-contaminated acid gas stream from the sour water stripping facilities.

The ammonia acid gas will be introduced into the sulphur plant reaction furnaces through a special burner where it will be burned with all the air required for the normal sulphur reaction with the hydrogen sulphide content of both the ammonia and DEA acid gas. The following reactions will take place in this combustion zone:

1. $2NH_3 + 1\frac{1}{2}\ O_2 \longrightarrow N_2 + 3H_2O$
2. $H_2S + 1\frac{1}{2}\ O_2 \longrightarrow SO_2 + H_2O$

The conditions will be maintained in this combustion zone such that all ammonia will be decomposed, but that excess nitrogen oxides are suppressed and the minimum amount of SO_3 is formed. These conditions will be maintained by adding a controlled amount of DEA acid gas to the special burner along with the ammonia gas.

The balance of the DEA acid gas will be introduced into the furnace through secondary burners downstream of the special burner where it will react with the excess air remaining from the special burner, in approximate accordance with reaction (2) above and the following reaction:

$$H_2S + \tfrac{1}{2}O_2 \longrightarrow S + H_2O$$

The balance of the plant will be a conventional three-converter sulphur plant. Indirect re-heat will be used on the gases to the last catalytic stage to maximize yield.

Following is the proposed form of instrumentation.

The sulphur recovery plants will be controlled from the central control house, but will be started up manually from local control panels before transferrring control to the central system.

Basic control will be by controlling the ratio of air entering the plants to the amounts of gas entering the plants from two sources: DEA regenerator gas, and sour water system ammonia acid gas.

The flow of each sour gas stream is measured by orifice plates with flow transmitters. The flow transmitters transmit signals to square root extractors which transform the square root signals to linear signals.

The linear flow signals are fed to an adding relay. The output of the adding relay goes to an air-gas ratio controller which sets the main process air flow control by also receiving an air flow signal from an orifice transmitter via a square root extracting relay.

The total amount of ammonia acid gas and DEA acid gas going to the special burner is measured by an orifice plate. The output from the orifice plate transmitter will be fed to a square root extractor, and then to a ratio controller which will control the total flow of gas to the special burner in accordance with the total air flow to the plant.

The signals from the adding relays in the ammonia acid gas circuits will go to their respective ratio controllers via bias relays so that adjustments can be made in accordance with changes in temperature, pressure, and composition. It is contemplated that these bias adjustments be made through a computerized feed-forward control system taking the following items into account:

1. Analysis of the ammonia acid gas stream for H_2S, NH_3 and hydrocarbon.

2. Analysis of the DEA acid gas stream for H_2S and hydrocarbon.

3. Temperature, pressure, and moisture content of acid gas and air streams.

A tail gas analyzer will be provided for each sulphur plant to analyze the tail gas stream for H_2S and SO_2. A computer control will be installed that will tend to return the total sulfur in the tail gas stream to a minimum, by adjustment of a trim air valve that by-passes process air around the main process air control valve.

An orifice- or pitot tube-type velocity meter will be installed in the tail gas line from each sulphur plant. This meter will provide for future integration with the tail gas chromatograph, for automatic computation of losses.

A number of ammonia-burning sulphur plants have been built by one major contractor, and one licensed by a major licensor. Success has been varied. Problems have been:

1. Catalyst fouling from ammonium sulphate;

2. Refractory damage caused by insufficient excess air in the ammonia oxidation zone;

3. Poor yield, due to poor thermal yield conditions.

The main innovation in design will be in the instrumentation proposed for control of the ammonia oxidation. This is considered to be experimental. If successful, the sulphur recovery plants will exceed 95% conversion efficiency. The plants will meet 95% efficiency with good manual operation of the ammonia oxidation.

APPENDIX II

Stack Monitoring Instrumentation:

1. Four 12" x 12" ports at the midpoint for the admission of the pitot tube meters of the Department of Health or other government regulatory body;

2. Temperature-recording thermocouples at bottom, midpoint and exit of stack;

3. Annubar or pitot-flow velocity measuring device;

4. Heated sample line from the platform at midpoint;

5. Platform at midpoint and below the tip;

6. Stack gas analyzer (chromatograph);

7. Instrumentation for future installation of an integrator for calculation of total sulphur emission.

In order to balance stack gas emission, the duct work from each sulphur plant to its respective CO boiler will be equipped with:

1. Gas chromatograph for H_2S, SO_2 and N_2 or, alternately, a Dupont ultra-violet analyzer;

2. Annubar, or other flow measurement device;

3. Temperature recorder;

4. Provision for integrator, as above.

ATTACHMENT 1

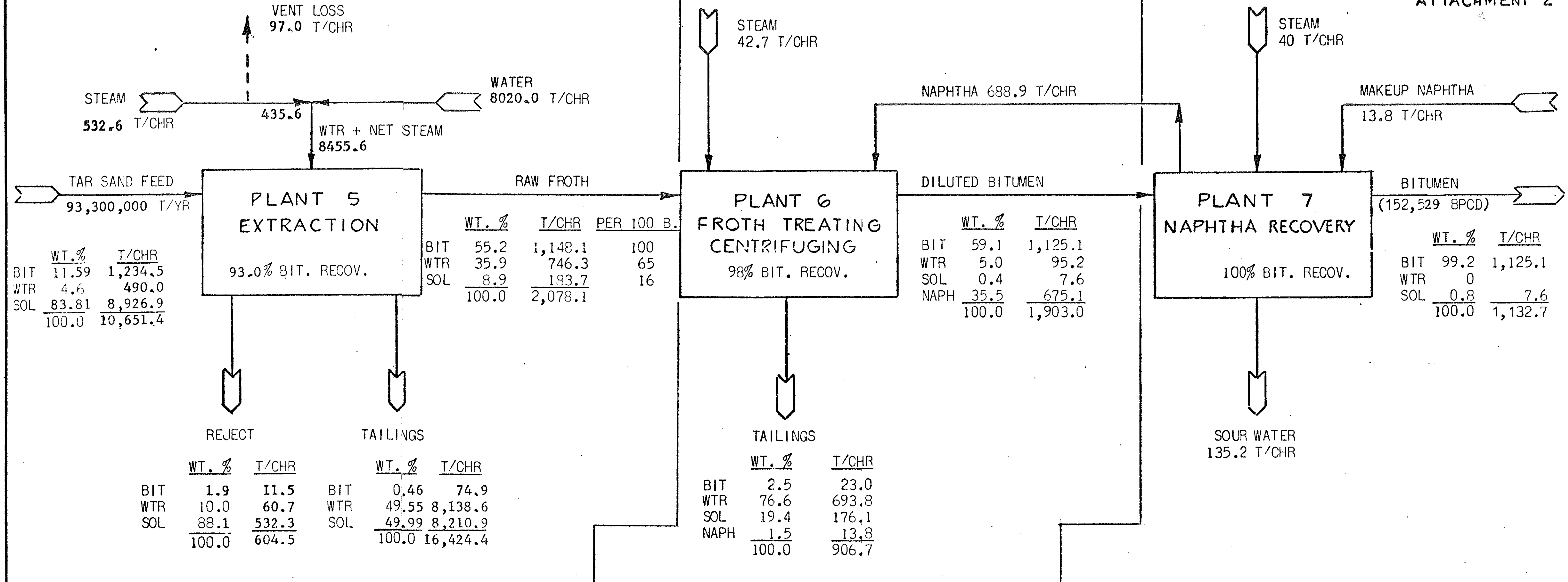
PLANT ENERGY BALANCE

INITIAL DESIGN CASE

	Mlbs/CD	BTU/lb LHV	BTU x 10^9/CD LHV
IN			
Bitumen Mined	49,560	16,750	830.1
Natural Gas			41.0*
Electric Power			1.2
			872.3
OUT			
Bitumen in Extraction Tailings	3,469	16,750	58.1
Bitumen in Centrifuging Loss	922	16,750	15.4
Naphtha in Centrifuging Loss	553	18,850	10.4
Heat Rejected			139.1
Net Coke (Solids Free Basis)	4,242	13,600	57.7
Product Sulphur	1,546	3,991	6.2
Synthetic Crude	32,044	18,270	585.4
			872.3

*Plant energy requirements are under review. Up to a total of 52 x 10^9 BTU/CD may be required from natural gas depending upon the final fuel balance.

ATTACHMENT 2



MATERIAL BALANCE **EXTRACTION**

	TAR SAND	STM/WTR	TOTAL IN	FROTH	TAILINGS	REJ	TOTAL OUT
BIT	1,234.5		1,234.5	1,148.1	74.9	11.5	1,234.5
WTR	490.0	8,455.6	8,445.6	746.3	8,138.6	60.7	8,995.6
SOL	8,926.9		8,926.9	183.7	8,210.9	532.3	9,144.9
NAPH							
TOT	10,651.4	8,455.6	19,107.0	2,078.1	16,424.4	604.5	19,375.0

MATERIAL BALANCE **FROTH TREATING**

	FROTH	NAPH	STM	TOTAL IN	DIL BIT	TAILINGS	TOTAL OUT
BIT	1,148.1			1,148.1	1,125.1	23.0	1,148.1
WTR	746.3		42.7	789.0	95.2	693.8	789.0
SOL	183.7			183.7	7.6	176.1	183.7
NAPH		688.9		688.9	675.1	13.8	688.9
TOT	2,078.7	688.9	42.7	2,809.7	1,903.0	906.7	2,809.7

MATERIAL BALANCE **NAPHTHA RECOVERY**

	DIL BIT	STM	MAKE UP NAPH	TOTAL IN	BIT	NAPH	SOUR WTR	TOTAL OUT
BIT	1,125.1			1,125.1	1,125.1			1,125.1
WTR	95.2	40		135.2			135.2	135.2
SOL	7.6			7.6	7.6			7.6
NAPH	675.1		13.8	688.9		688.9		688.9
TOT	1,903.0	40	13.8	1,956.8	1,132.7	688.9	135.2	1,956.8

NOTE: ALL UNITS - SHORT TONS/ CALENDAR HOUR

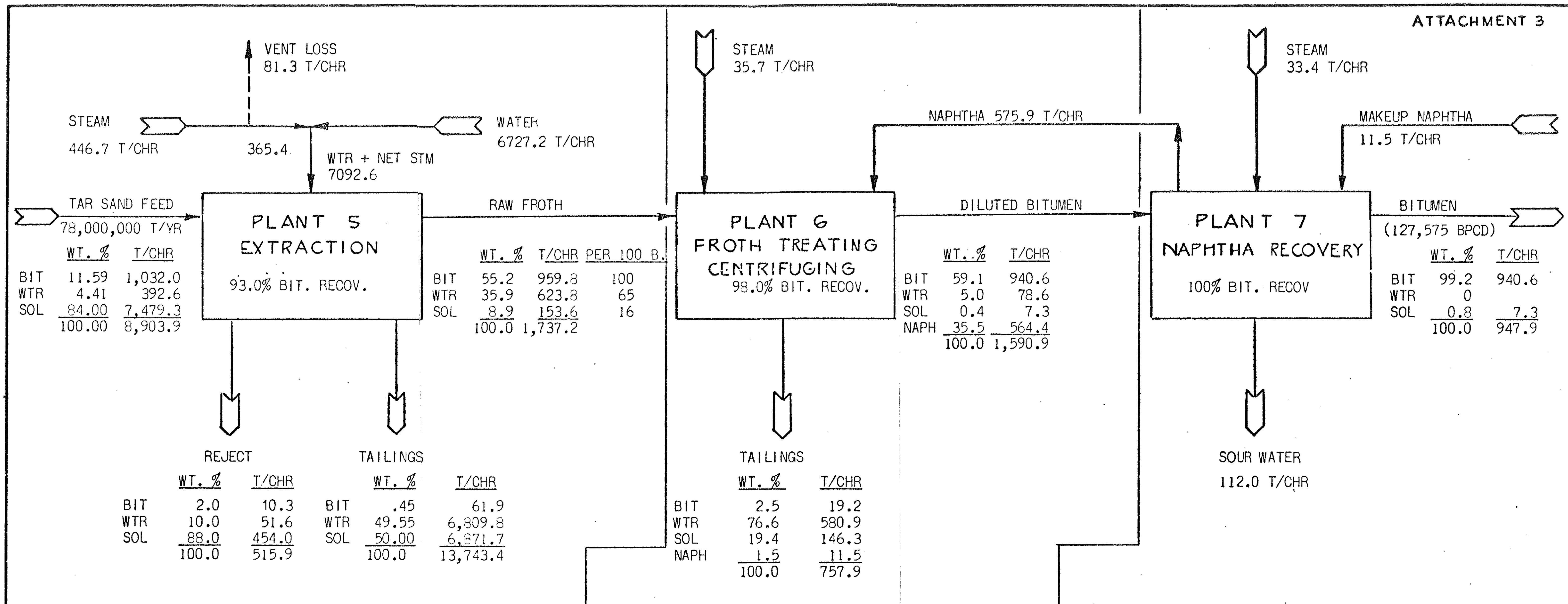
REFERENCE	No.	DATE	REVISED	BY	APP.
	1	JAN 16 '73	REVISED REDRAWN	WR	

SYNCRUDE CANADA LTD.

EXTRACTION, FROTH TREATING AND NAPHTHA RECOVERY BLOCK FLOW DIAGRAM 125,000 BPCD SYNCRUDE

DRAWN W.R.	DATE JAN 16/73
CHECKED	DATE
DESIGNED	DATE
APPROVED	DATE
SCALE NIL	
DRAWING No. B-8-100-79-1	REV. 1

ATTACHMENT 3



Tar sand feed:

	WT. %	T/CHR
BIT	11.59	1,032.0
WTR	4.41	392.6
SOL	84.00	7,479.3
	100.00	8,903.9

Raw froth:

	WT. %	T/CHR	PER 100 B.
BIT	55.2	959.8	100
WTR	35.9	623.8	65
SOL	8.9	153.6	16
	100.0	1,737.2	

Diluted bitumen:

	WT. %	T/CHR
BIT	59.1	940.6
WTR	5.0	78.6
SOL	0.4	7.3
NAPH	35.5	564.4
	100.0	1,590.9

Bitumen:

	WT. %	T/CHR
BIT	99.2	940.6
WTR	0	
SOL	0.8	7.3
	100.0	947.9

Reject:

	WT. %	T/CHR
BIT	2.0	10.3
WTR	10.0	51.6
SOL	88.0	454.0
	100.0	515.9

Tailings (Plant 5):

	WT. %	T/CHR
BIT	.45	61.9
WTR	49.55	6,809.8
SOL	50.00	6,871.7
	100.0	13,743.4

Tailings (Plant 6):

	WT. %	T/CHR
BIT	2.5	19.2
WTR	76.6	580.9
SOL	19.4	146.3
NAPH	1.5	11.5
	100.0	757.9

MATERIAL BALANCE EXTRACTION

	TAR SAND	STM/WTR	TOTAL IN	FROTH	TAILINGS	REJ	TOTAL OUT
BIT	1,032.0		1,032.0	959.8	61.9	10.3	1,032.0
WTR	392.6	7,092.6	7,485.2	623.8	6,809.8	51.6	7,485.2
SOL	7,479.3		7,479.3	153.6	6,871.7	454.0	7,479.3
NAPH							
TOT	8,903.9	7,092.6	15,996.5	1,737.2	13,743.4	515.9	15,996.5

MATERIAL BALANCE FROTH TREATING

	FROTH	NAPH	STM	TOTAL IN	DIL BIT	TAILINGS	TOTAL OUT
BIT	959.8			959.8	940.6	19.2	959.8
WTR	623.8		35.7	659.5	78.6	580.9	659.5
SOL	153.6			153.6	7.3	146.3	153.6
NAPH		575.9		575.9	564.4	11.5	575.9
TOT	1,737.2	575.9	35.7	2,348.8	1,590.9	757.9	2,348.8

MATERIAL BALANCE NAPHTHA RECOVERY

	DIL BIT	STM	MAKE UP NAPH	TOTAL IN	BIT	NAPH	SOUR WTR	TOTAL OUT
BIT	940.6			940.6	940.6			940.6
WTR	78.6	33.4		112.0			112.0	112.0
SOL	7.3			7.3	7.3			7.3
NAPH	564.4		11.5	575.9		575.9		575.9
TOT	1,590.9	33.4	11.5	1,635.8	947.9	575.9	112.0	1,635.8

NOTE: ALL UNITS - SHORT TONS/ CALENDAR HOUR

REFERENCE	No.	DATE	REVISED	BY	APP.

SYNCRUDE CANADA LTD.

EXTRACTION, FROTH TREATING AND NAPHTHA RECOVERY

BLOCK FLOW DIAGRAM
104,550 BPCD SYNCRUDE

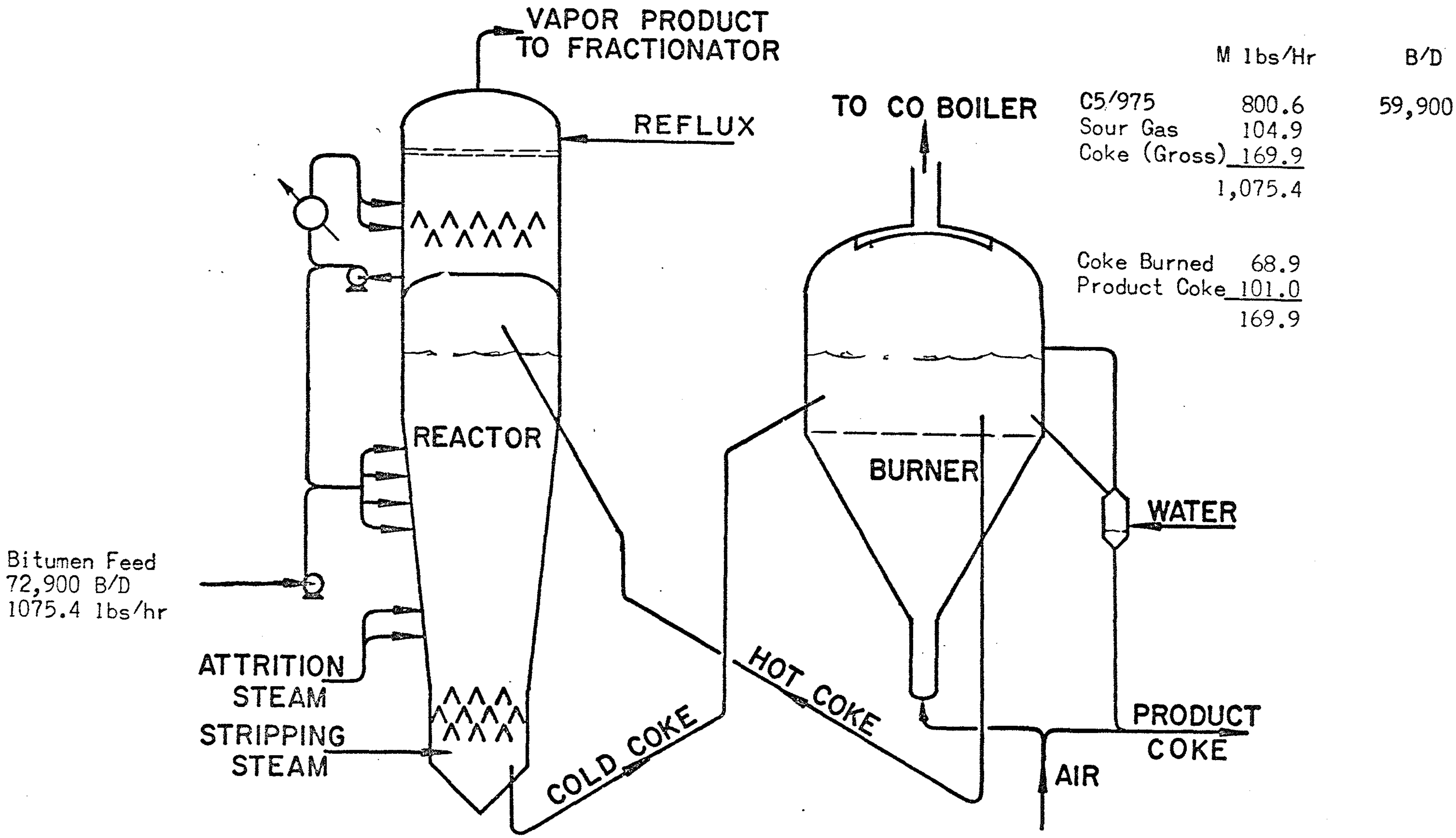
DRAWN W.R.	DATE JAN 17/73
CHECKED	DATE
DESIGNED	DATE
APPROVED	DATE
SCALE NIL	
DRAWING No. B-8-100-79-2	REV.

ATTACHMENT 4

BITUMEN BALANCE

	INITIAL OUTPUT		ULTIMATE OUTPUT 125M BPCD Output Expected Within Ten Years from Start-up	
	BPCD	Mlbs/CD	BPCD	Mlbs/CD
Mining				
Tar Sand Mined	(78.04 MMTPY)	427,612	(93.30 MMTPY)	511,251
Bitumen in Tar Sand	139,976	49,560	167,347	59,254
Extraction (% Recovery)	93		93	
Bitumen in Froth	130,179	46,091	155,633	55,106
Bitumen in Tailings	9,797	3,469	11,714	4,148
Froth Treatment (% Recovery)	98		98	
Bitumen Feed	130,179	46,091	155,642	55,106
Naphtha Feed (261.1 #/B)	105,917	27,655	126,600	33,064
Bitumen Loss	2,604	922	3,112	1,102
Naphtha Loss	2,118	553	2,532	661
Bitumen Upgrading				
Bitumen Feed	127,575	45,169	152,529	54,004
H_2 Chem. Cons.		480		574
		45,649		54,578
Synthetic Crude	104,550	32,044	125,000	38,312
C_4 & Lighter Fuel		3,925		4,693
Coke		4,242		5,072
Sulphur		1,546		1,848
Release in Burner & CO Boiler		3,339		3,992
Makeup Naphtha	2,118	553	2,532	661
		45,649		54,578

FLUID COKER


VAPOR PRODUCT
TO FRACTIONATOR
REFLUX
TO CO BOILER
M lbs/Hr B/D
C5/975 800.6 59,900
Sour Gas 104.9
Coke (Gross) 169.9
1,075.4
Coke Burned 68.9
Product Coke 101.0
169.9
REACTOR
BURNER
WATER
Bitumen Feed
72,900 B/D
1075.4 lbs/hr
ATTRITION
STEAM
STRIPPING
STEAM
COLD COKE
HOT COKE
PRODUCT
COKE
AIR

ATTACHMENT 6

SULPHUR BALANCE

	DESIGN		ULTIMATE	
	M#/CD	LT/CD	M#/CD	LT/CD
Sulphur in Feed	2213	988	2646	1181
Sulphur in Syncrude	50	22	60	27
Sulphur in Coke	382	171	457	204
Released from Stack				
- from Coker Burner	154	69	184	82
- from Sulphur Plant Tail Gas	81	36	97	43
Product Sulphur	1546	690	1848	825
Total Sulphur Output	2213	988	2646	1181

SULPHUR TO ATMOSPHERE

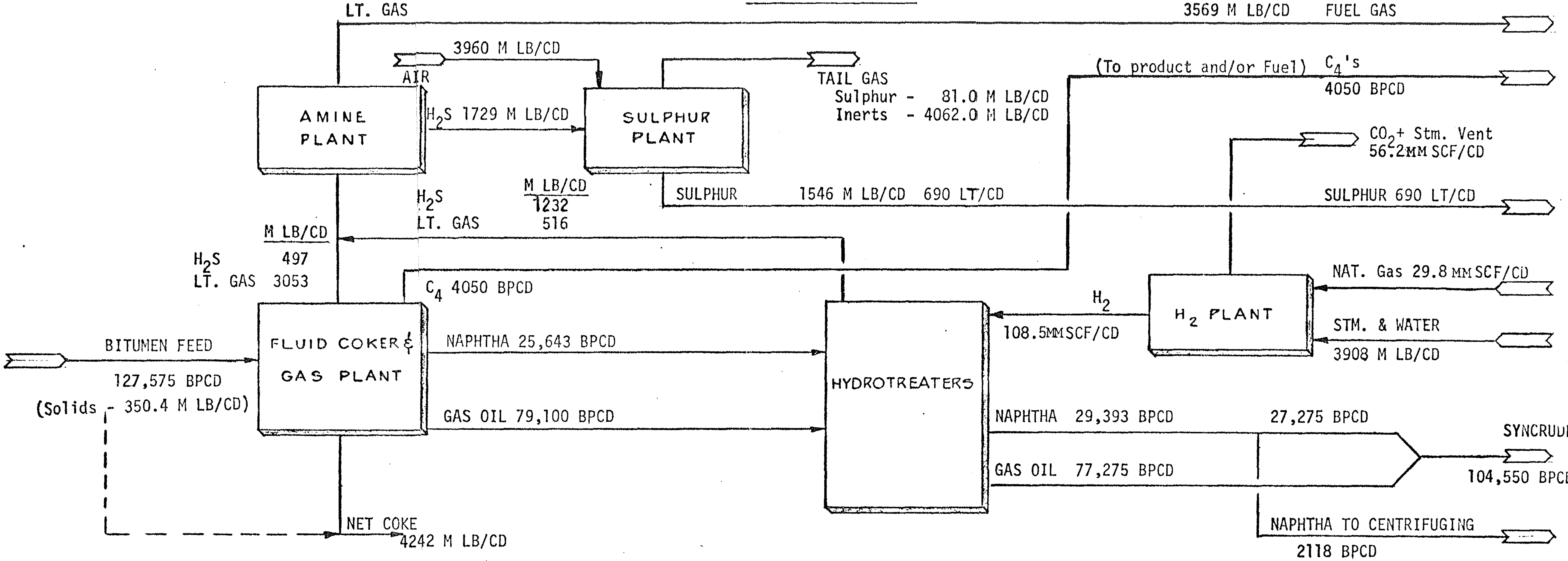
	LT/SD*	LT/SD
Coker Burner	79.0	94.0
Sulphur Plant Tail Gas	41.0	49.0
Utility Plant Process Heaters	0.3	0.3
	120.3	143.3

* (LT/SD)(0.875)=(LT/CD)

ATTACHMENT 7

OVERALL BLOCK FLOW & MATERIAL BALANCE
UPGRADING UNITS

INITIAL DESIGN CASE



FLUID COKER

		M LB/CD	BPCD
FEED		45,169	127,575
(Ex. solids)			
Total		45,169	127,575
PRODUCTS			
H_2S		497	
To Fuel	(Inerts	234)	
	(H_2, C_1/C_3	2819)	
C_4's		831	4,050
Naphtha		6821	25,643
Gas Oil		26803	79,100
Gross Coke		7164	
Total		45,169	108,793

HYDROTREATERS

		M LB/CD	BPCD (MM SCF/CD)
FEED			
Naphtha		6,821	25,643
Gas Oil		26,803	79,100
H_2		721	(108.5)
Total		34,345	104,743
PRODUCTS			
H_2S		1,232	
To Fuel	(Net C_1/C_3	275)	
	(Vent H_2/C_1	241)	
Naphtha		7,727	29,393
Gas Oil		24,870	77,275
Total		34,345	106,668

H_2 PLT

	M LB/CD	MMSCF/CD
FEED		
Natural Gas	1,306	29.8
Stm & Wtr	3,908	
Total	5,214	
PRODUCTS		
H_2	721	108.5
Wet CO_2	4,493	56.2
Total	5,214	

AMINE PLT

	M LB/CD	MM SCF/CD
FEED		
H_2S	1,729	19.27
Lt. Gas	3,569	
Total	5,298	
PRODUCTS		
H_2S	1,729	19.27
Lt. Gas	3,569	
Total	5,298	

SULPHUR PLT

	M LB/CD	MM SCF/CD
FEED		
H_2S	1,729	19.27
Air	3,960	
Total	5,689	
PRODUCTS		
Sulphur	1,546.0	
Tail Gas		
Sulphur	81.0	
Inerts	4,062.0	
Total	5,689.0	

CENTRAL STACK-NORMAL-

ATMOSPHERIC CONDITION, HEAVY OVERCAST DAY OR NIGHT

STACK HEIGHT = 600.0 FT

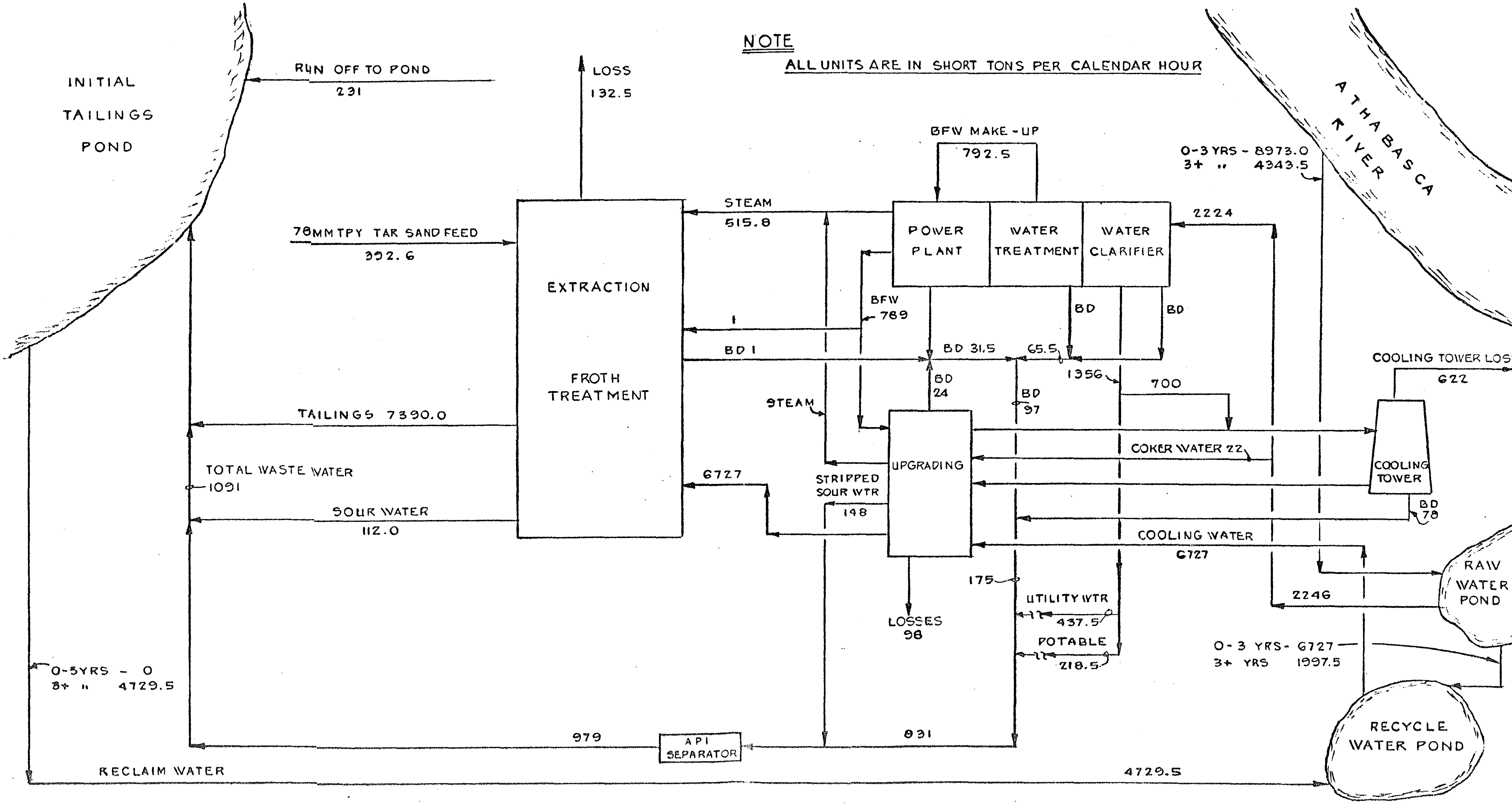
SOURCE DIST.(FT)	DIFF.IN ELEV.(FT) (SURFACE)	EFF.STACK HEIGHT	CONCENTRATION (PPM) AT GROUND LEVEL
WIND VELOCITY = 36.67 FPS NEUTRAL STABILITY			
1000.0	.0	1043.0	.0000
5000.0	.0	1043.0	.0000
10000.0	.0	1043.0	.0002
25000.0	.0	1043.0	.0199
45000.0	.0	1043.0	.0373
70000.0	.0	1043.0	.0365
100000.0	.0	1043.0	.0308
125000.0	.0	1043.0	.0268
200000.0	.0	1043.0	.0191
WIND VELOCITY = 29.33 FPS NEUTRAL STABILITY			
1000.0	.0	1251.7	.0000
5000.0	.0	1251.7	.0000
10000.0	.0	1251.7	.0000
25000.0	.0	1251.7	.0062
45000.0	.0	1251.7	.0225
70000.0	.0	1251.7	.0287
100000.0	.0	1251.7	.0278
125000.0	.0	1251.7	.0258
200000.0	.0	1251.7	.0204
WIND VELOCITY = 22.00 FPS NEUTRAL STABILITY			
1000.0	.0	1508.2	.0000
5000.0	.0	1508.2	.0000
10000.0	.0	1508.2	.0000
25000.0	.0	1508.2	.0011
45000.0	.0	1508.2	.0102
70000.0	.0	1508.2	.0193
100000.0	.0	1508.2	.0228
125000.0	.0	1508.2	.0235
200000.0	.0	1508.2	.0216
WIND VELOCITY = 14.67 FPS NEUTRAL STABILITY			
1000.0	.0	2157.8	.0000
5000.0	.0	2157.8	.0000
10000.0	.0	2157.8	.0000
25000.0	.0	2157.8	.0000
45000.0	.0	2157.8	.0004
70000.0	.0	2157.8	.0029
100000.0	.0	2157.8	.0068
125000.0	.0	2157.8	.0098
200000.0	.0	2157.8	.0150
WIND VELOCITY = 7.33 FPS NEUTRAL STABILITY			
1000.0	.0	2910.1	.0000
5000.0	.0	2910.1	.0000
10000.0	.0	2910.1	.0000
25000.0	.0	2910.1	.0000
45000.0	.0	2910.1	.0000
70000.0	.0	2910.1	.0001
100000.0	.0	2910.1	.0010
125000.0	.0	2910.1	.0025
200000.0	.0	2910.1	.0087

TOTAL GAS FLOW RATE =23377.0 CFS EXIT GAS VEL. = 60.0 FPS
T2 = 475.0 DEG F. T1 = 70.0 DEG F. Q = 44.00 CFS

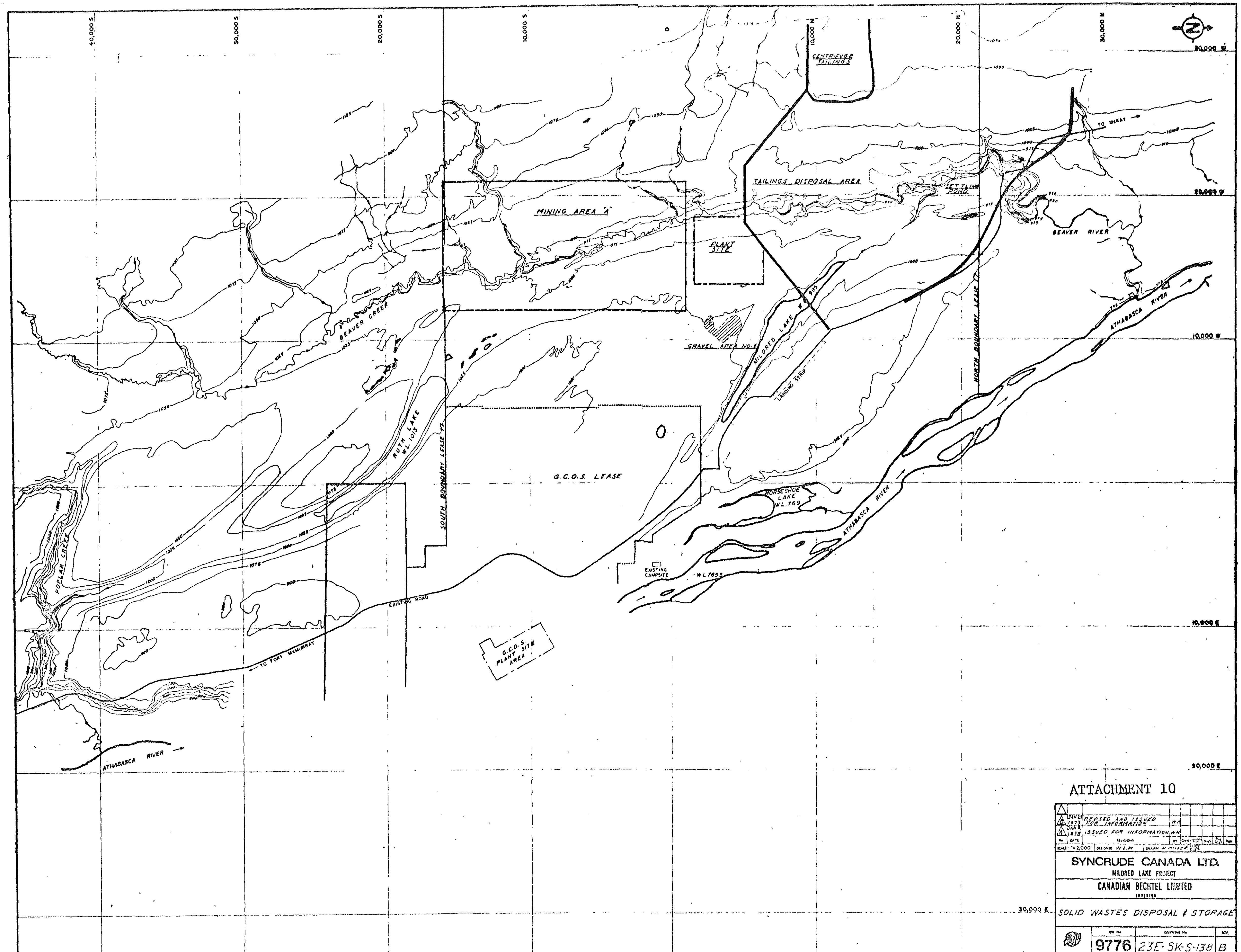
OVERALL WATER BALANCE

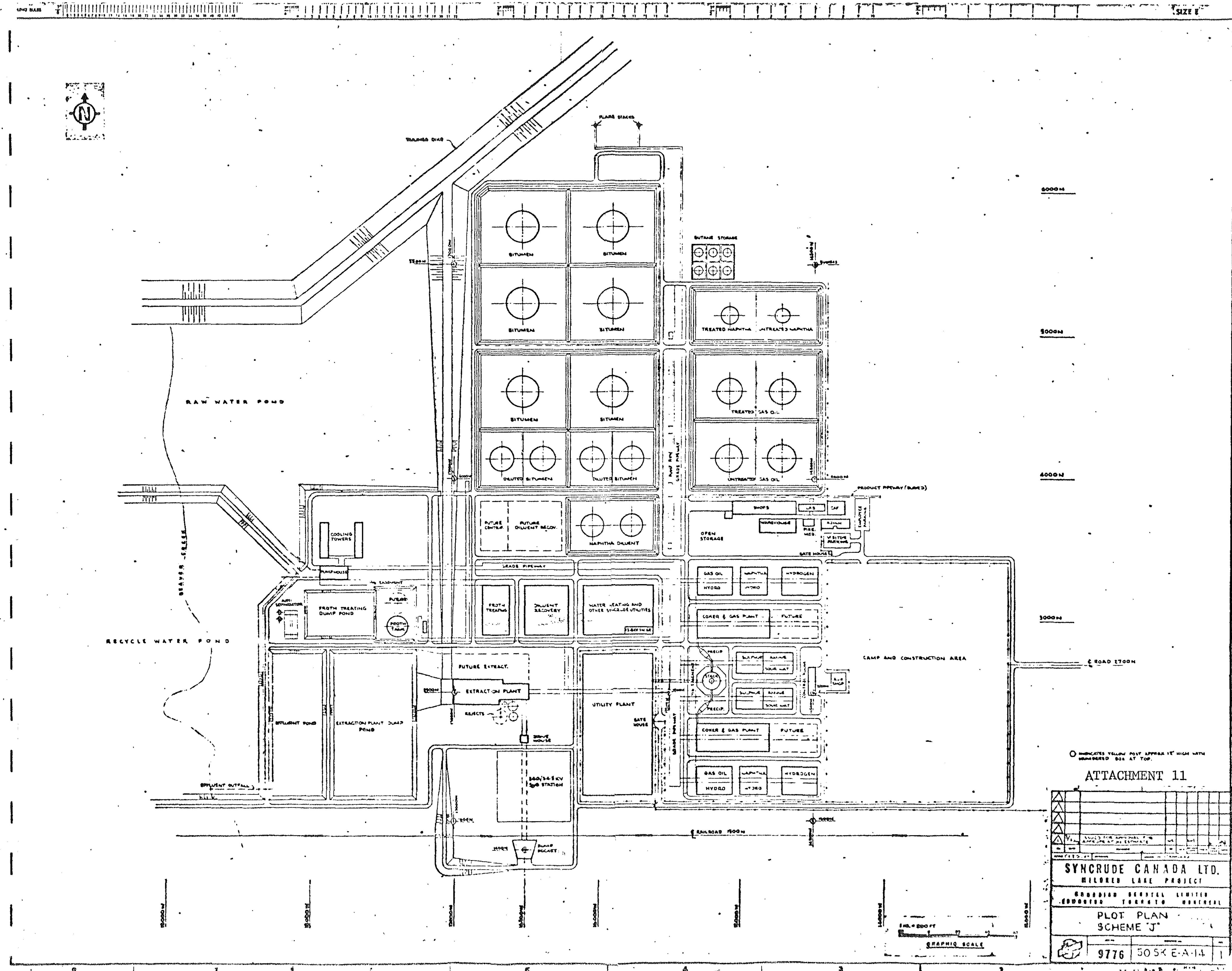
104,550 BPCD SYNCRUDE CASE

ATTACHMENT 9



ATTACHMENT 10





ATTACHMENT 11

6. MARCH 5, 1973 APPLICATION TO THE ENERGY RESOURCES CONSERVATION BOARD CONCERNING APPROVAL TO CONSTRUCT AND OPERATE A POWER PLANT FOR SYNCRUDE MILDRED LAKE PROJECT

GENERAL

Syncrude Canada Ltd. requires the following utilities in the operation of its proposed Mildred Lake Tar Sands Project:

1. Electrical power for the operation of mining machinery, tar sand extraction and bitumen upgrading facilities.
2. Steam and hot water for extraction of bitumen from the tar sands.
3. Boiler feed water for process steam generators.

It must be recognized that the power and heat requirements for the Mildred Lake complex are not firmly fixed at this time. The information contained herein is based on current estimates of the quantities required.

The proposed utility plant will be gas fired, and the fuel supply will be integrated with the total plant fuel gas system. Sweetened fuel gas generated in the various bitumen upgrading facilities, supplemented as required with natural gas, will be used to supply fuel for process heaters and the utility plant. An exact balance for this total system has not yet been determined, but the natural gas requirement should not exceed 20MM SCFD. This gas, together with that required for hydrogen plant fuel, will be supplied by pipeline.

LOCATION OF THE PROPOSED UTILITY PLANT

The proposed utility plant will be located on the Syncrude Mildred Lake Plant Site approximately twenty-five miles north of Fort McMurray, Alberta, in Sec. 6 Twp. 93 Rg. 11 W4M. The tentative location of the facility in the plant area is shown in Attachments 10 and 11.

DESCRIPTION OF PROPOSED PLANT

A flow diagram of the proposed utility plant is shown in Figure 1. In order to maximize fuel efficiency, the utility plant will employ a combined gas turbine - steam cycle. The exhaust from gas turbine generators will supply hot combustion air to the boilers. High-pressure steam from the boilers will be used to drive back pressure turbo-generators, and the low-pressure exhaust steam will be used for process heat requirements. Figure 1 shows the anticipated steam, electric and boiler feed water requirements. Two cases representing summer and winter operation are indicated along with the corresponding fuel consumption.

The basis for the design shown is as follows:

- Steam generation pressure (650 psig) matches the pressure of steam generated in the upgrading area (CO Boilers, coker and hydrogen plant). Steam generated in the upgrading areas in excess of process requirements is mostly used in back pressure turbines (50 psig) driving centrifugal compressors. Some 650 psig steam is normally returned to the utility plant, but the flow could be reversed during certain shut down conditions. (Note: Although it may be desirable, it is not necessary to match the utility plant steam generation pressure and the upgrading steam generation pressure. Actual design pressure will depend on final optimization studies.)

- The winter load condition (stream no. 7--1387M LB/HR) with an unscheduled outage of one boiler determined the number of boilers (3) and the steam generating capacity of each (750M LB/HR). The third boiler is also required during certain turnaround conditions in the main Syncrude complex.

- The number (3) and sizing (40 M.W.) of the back pressure turbo generators are such that one turbo generator is normally a spare. The spare would be used in the event of an unscheduled outage in one of the other two back pressure turbo generators or in the event of an unscheduled outage in one of the gas turbine driven generators. In the latter case, the extra low pressure steam produced from the spare back pressure turbo generator would be used to heat the extraction plant water to a higher temperature.

- The gas turbine generating capacity shown in Figure 1 is based on supplying the power difference between the total demand (146 M.W.) and that generated by the back pressure turbo generators in the winter (68.5 M.W.). The difference (77.5 M.W.) can be supplied with three commercially available gas turbines of 25 M.W. iso rating. During the hotter periods of the summer (80^{o}F), the gas turbines can only generate 62 M.W. when fully fired. During this period the low pressure (50 psig) steam demand is also at a minimum and the back pressure turbo generators will only generate 51 M.W. to meet this steam demand. The total power generated would be 113 M.W. against a total requirement of 146 M.W. The difference (33 M.W.) could be generated by increasing the steam to the back pressure turbo generators and venting the increased 50# steam production or using it to heat extraction water to a higher temperature. This would not be thermally efficient and the alternates are to install additional gas turbine or condensing turbine generating capacity or bring in 33 M.W. via the proposed Alberta Power transmission line. This 33 M.W. would be classified as interruptible power and would be the most efficient way of meeting the summer power requirement.

- As previously noted, the power and heat requirements for the Mildred Lake complex are not firmly fixed at this time and final optimization studies may change such things as steam generation pressure and number and sizing of the various turbo generators.

FUEL EFFICIENCY

An energy balance for the utility plant design shown in Figure 1 is given in Table 1. It will be noted that approximately 78% of heat input to the utility plant is recovered in the form of (a) steam and boiler feed water supplied to the processing areas, and (b) electric power generated. If all heat losses are charged to power generation, power is produced for approximately 7600 BTU/KWH.

FUEL SUPPLY

Fuel supply for the utility plant and process heaters in the upgrading area will come mainly from the butanes and lighter gases produced in the upgrading units. The combined fraction of butanes and lighter gases is commonly referred to as C_4 minus in refinery operations. The expected analysis of the butanes and the expected analysis of the lighter gases is shown in Table 4. The C_4 minus fraction may have to be supplemented with natural gas in order to supply the process heater and utility plant requirements. The amount of natural gas required will depend on the final fuel balance and the C_4 minus yield from the fluid coker. Natural gas will also be required for the hydrogen plant feed. The total natural gas requirement will be supplied by pipeline. The exact source of natural gas has not been contracted for at this time but the analyses will probably be typical of gas produced in the Martin Hills area.

USE OF FLUID COKE AS FUEL

Syncrude Application No. 6889 to the Energy Resources Conservation Board is based on Fluid Coking as the primary bitumen upgrading process. It is proposed that the net coke produced in this process be stockpiled rather than used as a fuel source at this time. The reason for this is the high sulphur content (9%) and the lack of any proven commercial process which would reduce the sulphur emission to atmosphere. Surveys have been made of the more promising stack gas scrubbing processes. Limestone scrubbing appears to be the closest to commercial development. The technical status of this process has been the subject of many studies. Results of one of the most recent studies was presented by Dr. Ivor E. Campbell and John R. Ireland and published on page 78 of the December 1972 issue of The Engineering and Mining Journal. It is also reviewed in API Publication No. 4153 of January 1973. The latter publication lists sixteen power stations that have installed or are going to install this process. Of these, the following have started operations with results noted:

Kansas Power & Light; Lawrence, Kansas:

Started Fall 1971 but experienced plugging problems which has limited operations.

Union Electric Company; St. Louis:

Has abandoned process.

Commonwealth Edison; Will County, Illinois:

Intermittent operation due to several equipment failures and plugging problems.

It has therefore been concluded that limestone scrubbing is not feasible at this time. An evaluation has, however, been made for a coke fired utility plant with limestone scrubbing of stack gas in order to explore its potential in relation to the proposed combined cycle gas fired utility plant.

A flow diagram for the coke fired utility plant is shown in Figure 2. The philosophy in design regarding equipment sizing and sparing, etc., is similar to that described earlier for the gas fired utility plant but the gas turbine generators are replaced with condensing turbine generators. Extra power would be required for coke pulverizing, limestone crushing and pumping of limestone slurry. All the fluid coke produced would be burned plus some C_4 minus gas from the upgrading area. The amount of C_4 minus gas required for this case happens to be approximately equal to the amount of supplemental fuel that would be required in any event when burning low volatile fluid coke. The energy comparison for coke firing versus gas firing is shown in Table 2. It will be noted that burning 21,600 MMM BTU of coke per year results only in a net credit of 14,100 MMM BTU of C_4 minus gas to the coke fired case. The 14,100 MMM BTU credit would be realized through increased butane sales and lower natural gas purchases for the coke fired case.

An economic comparison of coke firing versus gas firing is given in Table 3. This comparison shows that the 14,100 MMM BTU/year credit to the coke fired case would have to be worth 41.5¢/MM BTU in order to pay for the extra operating cost of the coke fired case with no return on the extra capital invested.

In summary, it can be said that coke burning with flue gas scrubbing has not been demonstrated commercially and is not economically attractive at this time. A further point is that sulphur removal efficiency would be 80% or less and, for the case evaluated above, would result in an additional 40 tons/day of sulphur release to the atmosphere. Also, the sulphur is removed as a waste product in the spent limestone slurry.

Some of the newer gasification processes would appear to hold more potential than stack gas scrubbing for future use of fluid coke. High pressure gasification under reducing conditions permits the removal of sulphur as H_2S and holds the promise for high efficiency to electric power when the cleaned gas is used in a combined gas turbine - steam cycle.

The applicants do not plan to make any provision for burning coke in the proposed gas fired utility plant, but plot space will be provided for possible future gasification facilities. No deterioration in heating value will occur as a result of stockpiling coke.

RELATIONSHIP OF POWER PLANT TO PROVINCIAL POWER GRID

It is proposed that the Syncrude power and utility plant be connected to the Alberta Power System and thereby to the provincial power grid by a 240 KV transmission line, as outlined in the Alberta Power Limited Application No. 6880. An electrical single line diagram is attached showing the interface between the Syncrude power plant and the transmission line.

The reasons for this connection are as follows:

1. The transmission line connection will assist the Syncrude power plant in absorbing the power swings created by large electrically-powered draglines. Further details regarding voltage swings, etc. are given in Attachment 7.
2. The connection will enable Syncrude to check out all

mining equipment well in advance of completion of the power plant itself.

3. As previously noted under "Description of Proposed Plant," the preferred alternate for balancing the power supply-demand situation in the summer months will be to bring in approximately 33 M.W. via the transmission line. The Syncrude power plant will, however, have the capability of generating this power on a stand alone basis if necessary, and any power brought in via the transmission line will therefore be classified as "interruptible".

As indicated in the electric power balance in Figure 1, the proposed utility plant will not have the capability of supplying any power to the provincial system on a thermally efficient basis. Emergency power up to the capability of the spare back pressure turbo generator (40 M.W.) could be supplied for short periods but at low thermal efficiency (26,000 BTU/KWH). It should be noted that Syncrude can make no guarantee to supply emergency power since the spare generating capacity may not be available at the time of the emergency requirement.

With the proposed gas fired utility plant it would not be economic to install extra generating capacity for the sole purpose of supplying power to the provincial system since the energy source would have to be natural gas imported via the pipeline.

Stockpiled fluid coke represents a future energy source, but its use depends on further development of sulphur removal processes as noted previously under "Use of Fluid Coke as Fuel."

ENVIRONMENTAL FEATURES

GENERAL

In view of the integration with the Syncrude processing facility, common waste disposal systems will be used.

AIR QUALITY

Discussions with the Department of Environment have resulted in selection of a design in which flue gas from the CO boilers is combined with flue gas from the gas fired utility boilers. The principle air contaminants from the stack will be sulphur dioxide and particulates from the CO boilers.

The concentration of SO_2 in the total stack gases from the boilers is estimated to be less than 0.2 mol %. The concentration of SO_2 in the utility plant stack gas before it enters the main stack is estimated to be .001 mol %. The total volume of stack gas, including the sulphur plant tail gas for normal operation, and the calculated ground level concentrations under various conditions are tabulated in Attachment 8. These calculations are based on the Bosanquet-Carey-Halton formula for plume rise and Pasquill-Gifford formula for dispersion. The calculated maximum SO_2 concentration is less than 0.04 ppm at ground level for a 600-foot stack. In arriving at the stack design, consideration was given to future development in the area.

Nitrogen oxide ground level concentration will not be a problem as the concentration in the flue gas will be less than one-fourth that of SO_2.

COOLING WATER SYSTEM

The primary cooling duty will be bearing cooling water, which will be supplied by the Syncrude plant cooling water system. A closed circuit with a cooling tower has been chosen for that system.

WATER TREATMENT

Athabasca River water will be settled, clarified, softened and demineralized for boiler feed water make up.

CHEMICAL AND DOMESTIC WASTES

Chemical and domestic wastes will be disposed of in the main Syncrude facilities.

LIST OF ATTACHMENTS

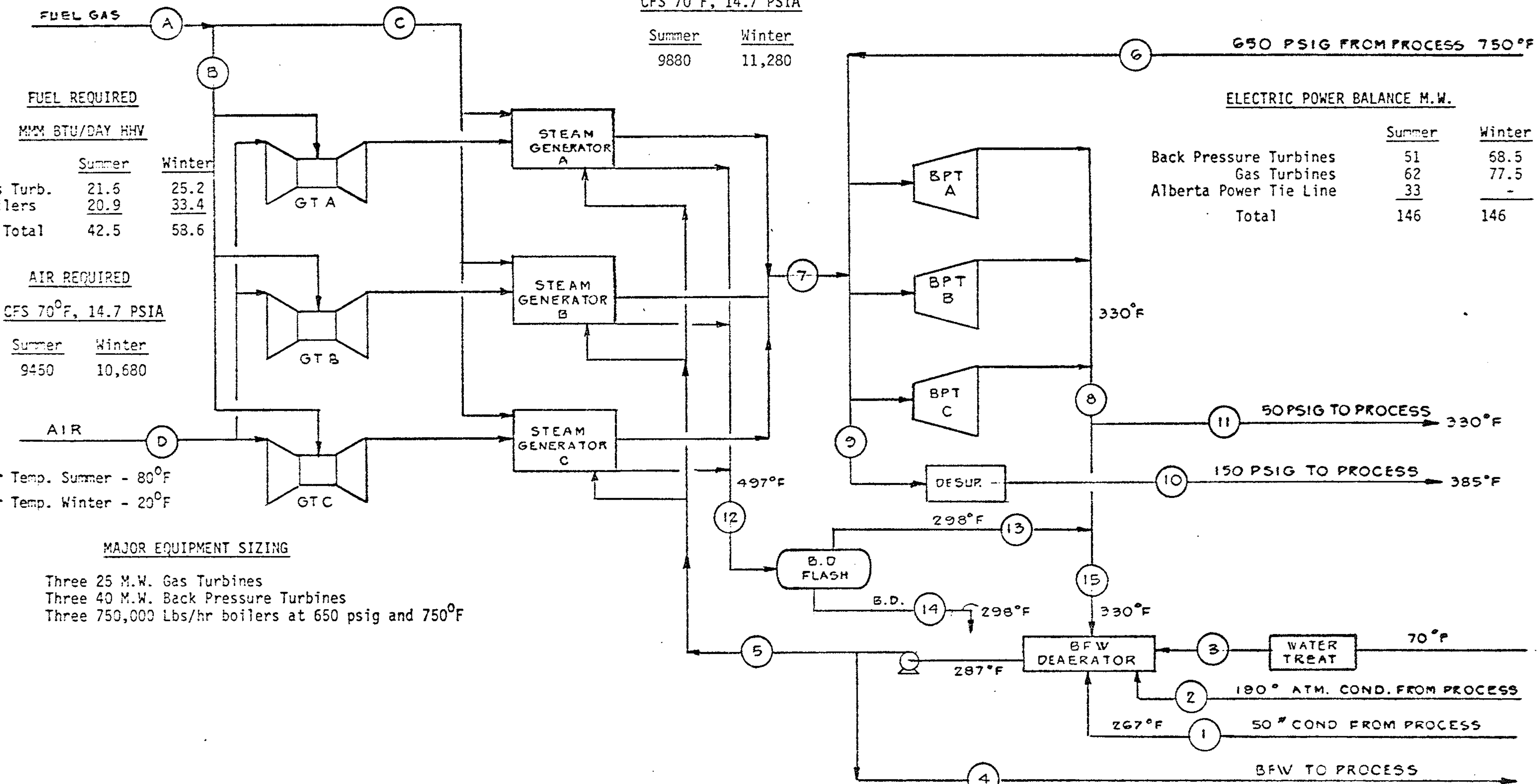
1. Figure 1 - Flow Diagram, Utility Plant
2. Table 1 - Energy Balance, Utility Plant
3. Figure 2 - Flow Diagram, Coke Fired Utility Plant
4. Table 2 - Energy Comparison, Coke Fired Utility Plant versus Gas Fired
5. Table 3 - Economics of Coke Firing versus Gas Firing
6. Table 4 - Fuel Compositions
7. Effect of Mining Load Changes on Interconnected System
8. Stack Gas Calculations
9. Single Line Diagram Showing Connection to Transmission Line
10. Solid Wastes Disposal
11. Plot Plan
12. Copy of Application to Improvement District No. 17
13. Area Contour Map

FIGURE 1 - FLOW DIAGRAM UTILITY PLANT

TOTAL FLUE GAS

CFS 70°F, 14.7 PSIA

Summer	Winter
9880	11,280



FUEL REQUIRED

MMM BTU/DAY HHV

	Summer	Winter
Gas Turb.	21.6	25.2
Boilers	20.9	33.4
Total	42.5	58.6

AIR REQUIRED

CFS 70°F, 14.7 PSIA

Summer	Winter
9450	10,680

Air Temp. Summer - 80°F

Air Temp. Winter - 20°F

ELECTRIC POWER BALANCE M.W.

	Summer	Winter
Back Pressure Turbines	51	68.5
Gas Turbines	62	77.5
Alberta Power Tie Line	33	-
Total	146	146

MAJOR EQUIPMENT SIZING

Three 25 M.W. Gas Turbines
Three 40 M.W. Back Pressure Turbines
Three 750,000 Lbs/hr boilers at 650 psig and 750°F

MATERIAL BALANCE M LBS/HR

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Summer	799	95	1941	2311	994	124	972	1023	73	83	550	22	7	15	480
Winter	899	389	1943	2311	1412	124	1387	1372	139	158	869	25	8	17	511

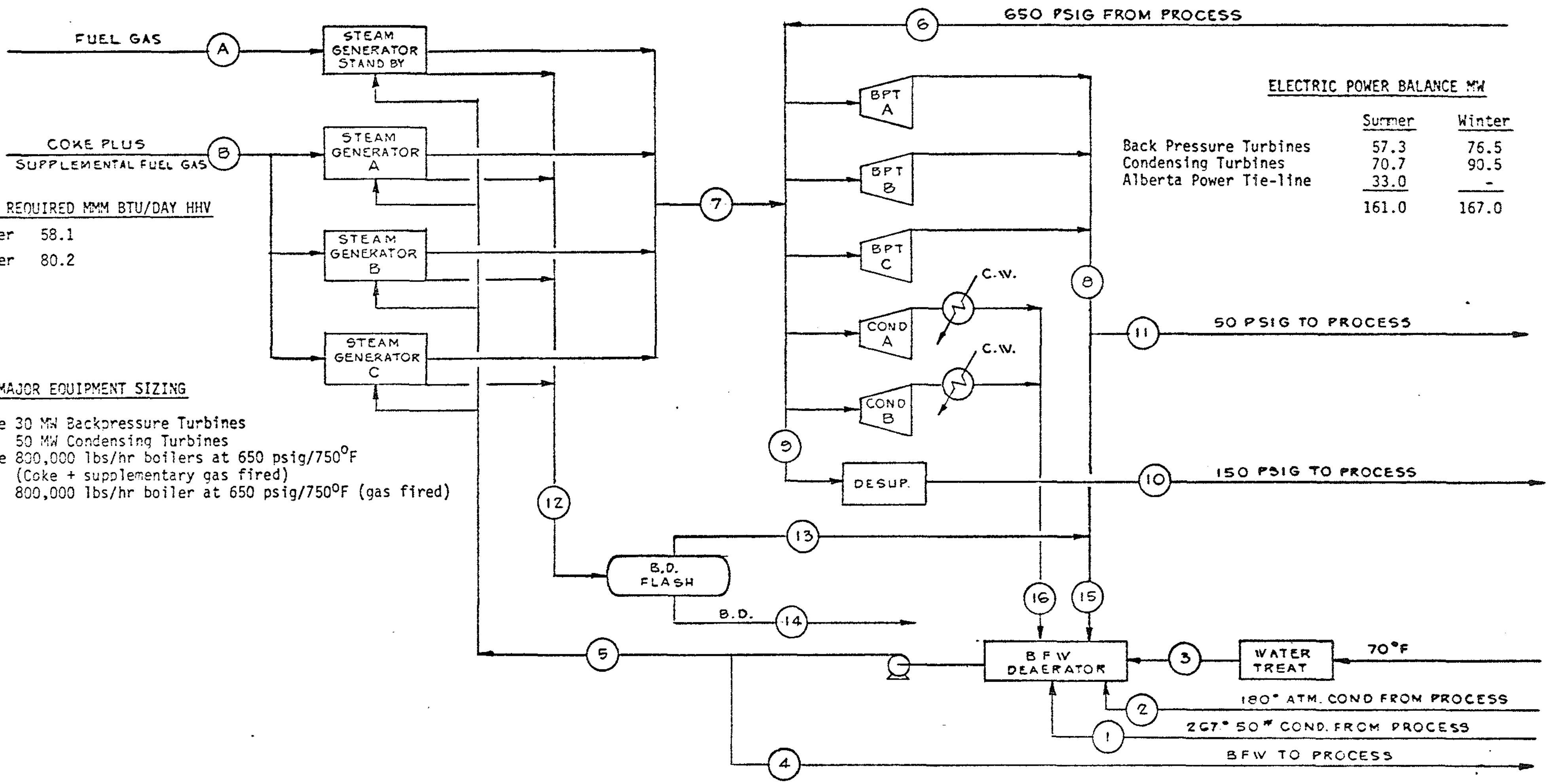
TABLE 1

ENERGY BALANCE - UTILITY PLANT

STREAM	SUMMER IN MM BTU/HR.	SUMMER IN %	SUMMER OUT MM BTU/HR.	SUMMER OUT %	WINTER IN MM BTU/HR.	WINTER IN %	WINTER OUT MM BTU/HR.	WINTER OUT %
A Fuel (HHV)	1,770	83.0	-	-	2,441	85.3	-	-
6 650# Stm.	169	7.9	-	-	169	5.9	-	-
1 50# Condensate	165	7.7	-	-	186	6.5	-	-
2 ATM Condensate	11	0.5	-	-	47	1.6	-	-
3 Make-up Water	19	0.9	-	-	19	0.7	-	-
11 50# Stm. to Process	-	-	650	30.5	-	-	1,027	35.9
10 150# Stm. to Process	-	-	99	4.6	-	-	189	6.6
4 BFW to Process	-	-	524	24.6	-	-	524	18.3
Power Generation (Theoretical)	-	-	386	18.1	-	-	498	17.4
Loss	-	-	475	22.2	-	-	624	21.8
TOTAL	2,134	100.0	2,134	100.0	2,862	100.0	2,862	100.0

	Summer	Winter
Power Generated	113 M K.W.	146 M K.W.
BTU to Power if All Loss Charged to Power Generated	386 + 475 = 861 MM BTU/HR.	498 + 624 = 1,122 MM BTU/HR.
BTU/KWH	$\frac{861\ MM}{113\ M} = 7,620$	$\frac{1,122\ MM}{146\ M} = 7,680$

FIGURE 2 - FLOW DIAGRAM COKE FIRED UTILITY PLANT



FUEL REQUIRED MMM BTU/DAY HHV

Summer	58.1
Winter	80.2

ELECTRIC POWER BALANCE MW

	Summer	Winter
Back Pressure Turbines	57.3	76.5
Condensing Turbines	70.7	90.5
Alberta Power Tie-line	33.0	-
	161.0	167.0

MAJOR EQUIPMENT SIZING

Three 30 MW Backpressure Turbines
Two 50 MW Condensing Turbines
Three 800,000 lbs/hr boilers at 650 psig/750°F (Coke + supplementary gas fired)
One 800,000 lbs/hr boiler at 650 psig/750°F (gas fired)

MATERIAL BALANCE M LBS/HR

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Summer	799	95	1949	2311	1796	124	1761	1150	73	83	550	35	12	23	611	662
Winter	899	389	1958	2311	2443	124	2395	1532	139	158	869	48	6	32	679	848

TABLE 2

ENERGY COMPARISON - COKE FIRED UTILITY PLANT VERSUS GAS FIRED

Utility Plant Fuel HHV (See Fig.1 and Fig.2)

	Summer (150 Days)	Winter (200 Days)	Total (350 Days)
	MMM BTU/Day	MMM BTU/Day	MMM BTU
Coke Fired Case	58.1	80.2	24,800
Gas Fired Case	42.5	58.6	18,100

Coke available per cal. day - 4,240 M lb., HHV 14,000 BTU/lb.
Total coke available - 4,240 M x 14,000 x 365 = 21,600 MMM BTU/yr.

Supplimental gas required for coke fired case = 24,800 - 21,600 = 3,200 MMM BTU/yr.

Gas saving in utility plant for coke firing versus gas firing = 18,100 - 3,200 = 14,900 MMM BTU/yr. less 800 MMM for hydrotreating gas saved (see below) = 14,100 MMM BTU/yr

With a gas fired utility plant, the C_4 minus gas produced in upgrading will be in close balance with the total project fuel requirement and purchased natural gas will be mainly for the hydrogen plant feed. For the coke fired case, the gas saving indicated above would result in excess C_4 minus gas from upgrading. This excess C_4 minus gas would require hydrotreating (see Table 4) to produce suitable fuel for the hydrogen plant and butanes which would be blended into the synthetic crude. The hydrotreating (and the increased hydrogen production for hydrotreating) would consume approximately 800 MMM BTU of the 14,900 MMM BTU shown above leaving a net saving of 14,100 MMM BTU/yr. for the coke fired case.

TABLE 3

ECONOMICS OF COKE FIRING VERSUS GAS FIRING

Extra capital for coke firing -

Utility Plant	\$ 16.5 MM
Cooling Water for Cond. Turbines	3.1 MM
Limestone Scrubbing and Stack	28.4 MM
Sub-Total	\$ 48.0 MM

Plus increased cost in upgrading for treating excess C_4 minus gas (\$3.4 MM, see Table 2).

Total increased capital for coke firing \$51.4 MM.

Increased annual operating costs -

Depreciation at 5% =	\$ 2.57 MM
Maintenance at 3.5% =	1.8 MM
Insurance and Taxes at 1.5% =	0.77 MM
Operating Labor and Overhead =	.25 MM
Limestone - 900 Tons/Day at \$1.50/Ton =	.47 MM
Total	\$ 5.86 MM

If the net gas saving of 14,100 MMM BTU/YR (Table 2) for coke firing is credited against decreased natural gas purchase and increased butane production at 41.5¢/MM BTU, the saving would just equal the annual operating cost with no return on extra capital invested.

TABLE 4

FUEL COMPOSITIONS

A. Butane Composition

	Mol.%
C_3H_6	3.9
C_3H_8	6.7
i C_4H_{10}	7.1
C_4H_8	49.5
C_4H_6	3.3
n C_4H_{10}	27.4
C_5H_{12}	2.1
	100.0%

HHV--4.5MM BTU/BBL

B. Fuel Gas Composition

	Mol.%
NH_3	0.1
H_2	31.4
CH_4	33.8
C_2H_4	8.8
C_2H_6	12.6
C_3H_6	6.7
C_3H_8	5.1
iC_4H_{10}	0.2
C_4H_8	0.6
C_4H_6	0.5
nC_4H_{10}	0.2
	100.0%

HHV--1142 BTU/SCF

Sulfur content - less than 10 grains per 100 SCF.

ATTACHMENT 7

EFFECT OF MINING LOAD CHANGES ON INTERCONNECTED SYSTEM

The question of voltage swings and flicker has been dealt with by Alberta Power Limited in Application No. 6880 and is stated as follows:

> *"The Syncrude Canada Ltd., load will include two 120 yard electrically operated draglines. Each dragline has an operating cycle of about one minute during which the load will vary from about +23.5MW to -14MW. Periodically, the cycles of the two draglines will coincide giving loads from +47MW to -28MW with an average load for the two machines of about 20MW. During these load swings, the voltage will be maintained within acceptable limits by the excitation systems of the Syncrude plant machines. There will be a periodic change in phase angle between the voltage at the Syncrude utility bus and the voltage at the Mitsue bus as well as other buses on the interconnected system. Additional transient condition studies will be carried out to determine more precisely the magnitude of this phase angle change and the resulting frequency change, however, preliminary load flow studies indicate a maximum phase angle change of about 12 degrees in 16 seconds or a frequency change of ±.002 cycles per second.*

The harmonic interference with communication systems will be minimized by specifying limiting Telephone Influence Factors within the equipment purchase specifications. In the mining area, the railway system, as well as the draglines, will be isolated by transformers from the main electrical distribution system.

Furthermore, Alberta Power is proposing the use of transformer delta-connected secondaries, between the 240KV transmission line and the Syncrude utility bus, to reduce residual third harmonic currents and voltages. It is recognized that even though the harmonic content in the area will be minimized, it still would be possible to have some of these harmonics amplified and cause difficulties in other parts of the system. As it is virtually impossible to predict where such effects may occur, Syncrude will cooperate with Alberta Power and will work with Alberta Government Telephones to find the most economical means of eliminating such harmful effects.

CENTRAL STACK-NORMAL-

ATMOSPHERIC CONDITION, HEAVY OVERCAST DAY OR NIGHT

STACK HEIGHT = 600.0 FT

SOURCE DIST.(FT)	DIFF.IN ELEV.(FT) (SURFACE)	EFF.STACK HEIGHT	CONCENTRATION (PPM) AT GROUND LEVEL
--------	--------	---------	******

WIND VELOCITY = 36.67 FPS
NEUTRAL STABILITY

1000.0	.0	1043.0	.0000
5000.0	.0	1043.0	.0000
10000.0	.0	1043.0	.0002
25000.0	.0	1043.0	.0199
45000.0	.0	1043.0	.0373
70000.0	.0	1043.0	.0365
100000.0	.0	1043.0	.0308
125000.0	.0	1043.0	.0268
200000.0	.0	1043.0	.0191

WIND VELOCITY = 29.33 FPS
NEUTRAL STABILITY

1000.0	.0	1251.7	.0000
5000.0	.0	1251.7	.0000
10000.0	.0	1251.7	.0000
25000.0	.0	1251.7	.0062
45000.0	.0	1251.7	.0225
70000.0	.0	1251.7	.0287
100000.0	.0	1251.7	.0278
125000.0	.0	1251.7	.0258
200000.0	.0	1251.7	.0204

WIND VELOCITY = 22.00 FPS
NEUTRAL STABILITY

1000.0	.0	1508.2	.0000
5000.0	.0	1508.2	.0000
10000.0	.0	1508.2	.0000
25000.0	.0	1508.2	.0011
45000.0	.0	1508.2	.0102
70000.0	.0	1508.2	.0193
100000.0	.0	1508.2	.0228
125000.0	.0	1508.2	.0235
200000.0	.0	1508.2	.0216

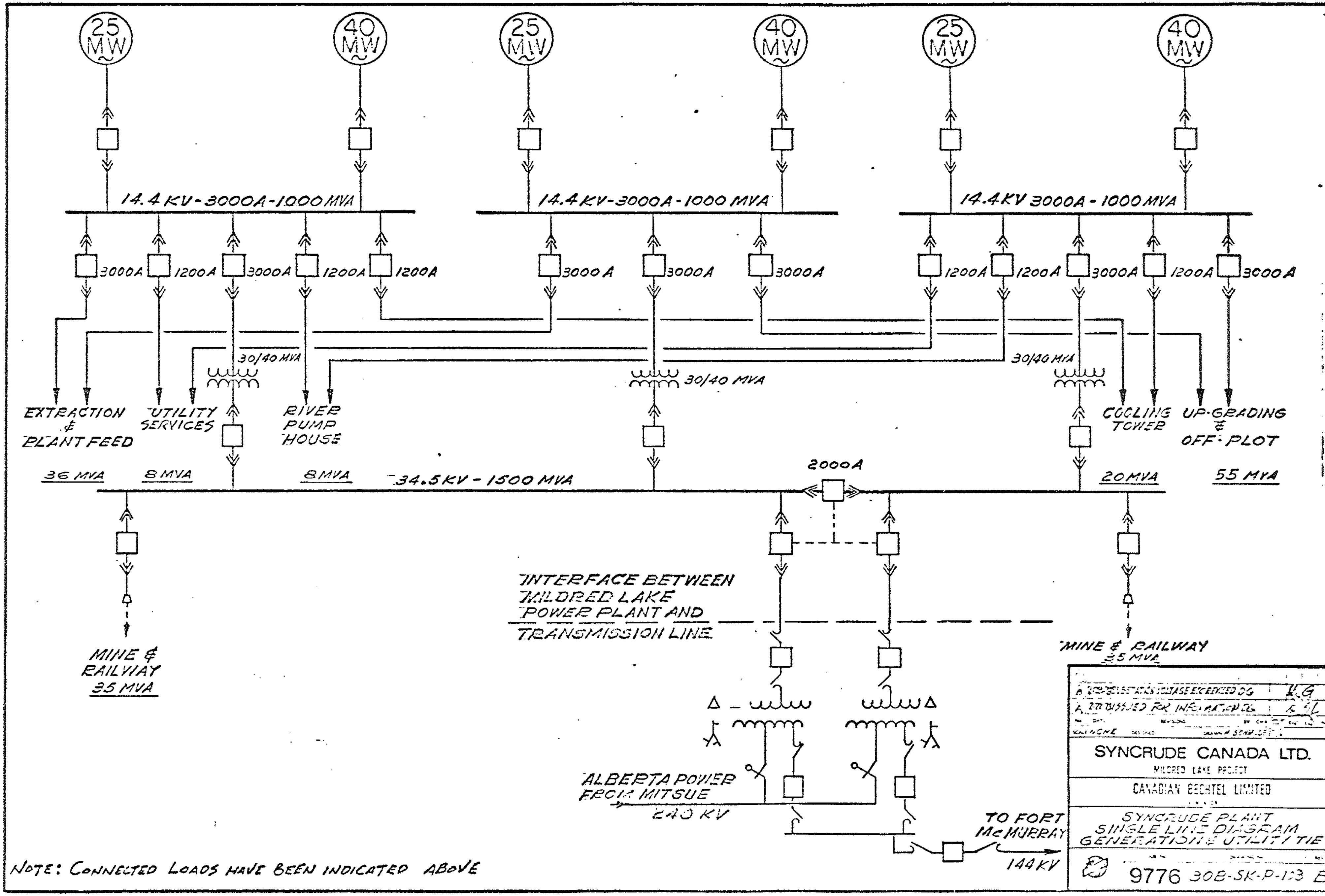
WIND VELOCITY = 14.67 FPS
NEUTRAL STABILITY

1000.0	.0	2157.8	.0000
5000.0	.0	2157.8	.0000
10000.0	.0	2157.8	.0000
25000.0	.0	2157.8	.0000
45000.0	.0	2157.8	.0004
70000.0	.0	2157.8	.0029
100000.0	.0	2157.8	.0068
125000.0	.0	2157.8	.0098
200000.0	.0	2157.8	.0150

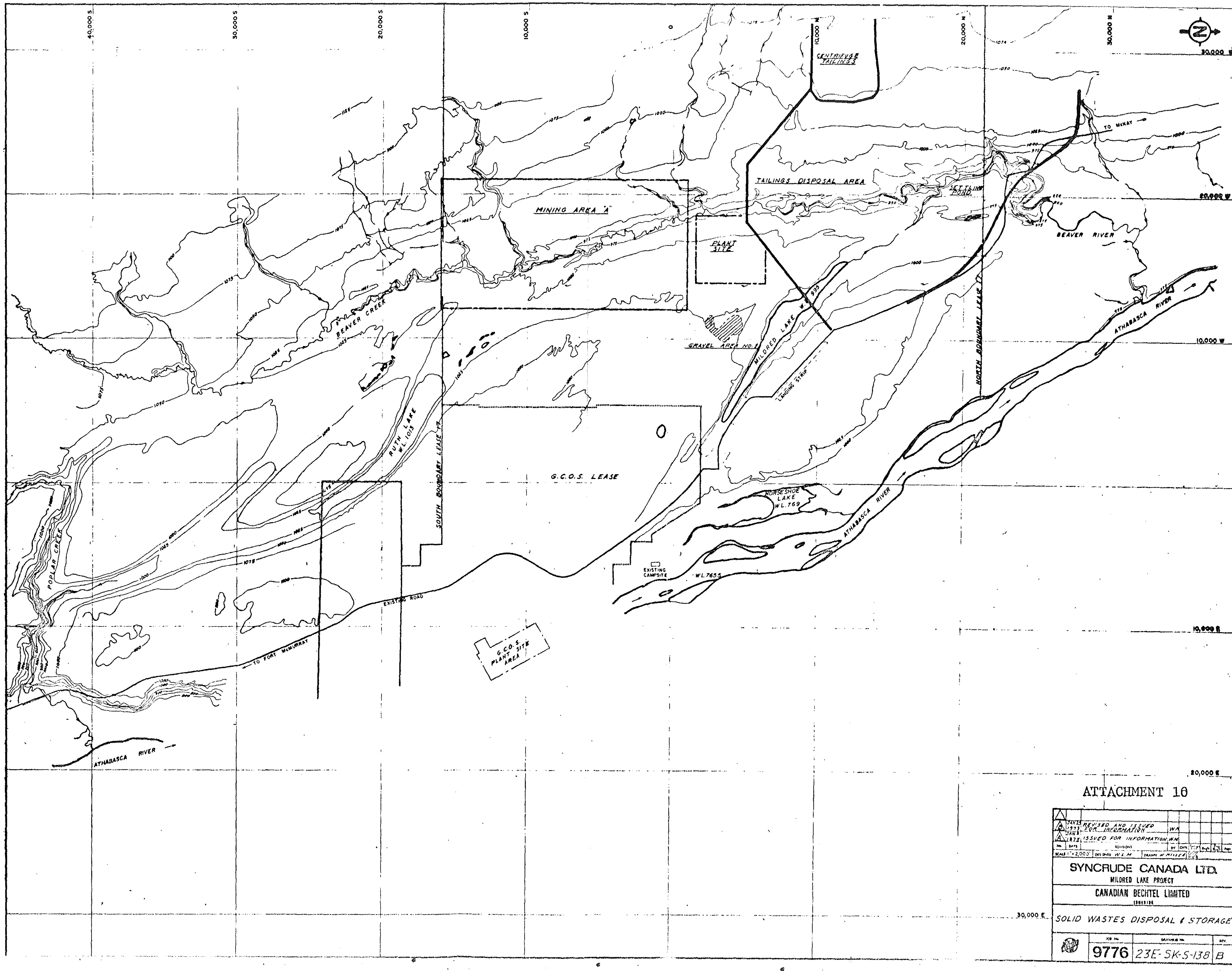
WIND VELOCITY = 7.33 FPS
NEUTRAL STABILITY

1000.0	.0	2910.1	.0000
5000.0	.0	2910.1	.0000
10000.0	.0	2910.1	.0000
25000.0	.0	2910.1	.0000
45000.0	.0	2910.1	.0000
70000.0	.0	2910.1	.0001
100000.0	.0	2910.1	.0010
125000.0	.0	2910.1	.0025
200000.0	.0	2910.1	.0087

TOTAL GAS FLOW RATE =23377.0 CFS EXIT GAS VEL. = 60.0 FPS
T2 = 475.0 DEG F. T1 = 70.0 DEG F. Q = 44.00 CFS



25 MW
40 MW
25 MW
40 MW
25 MW
40 MW
14.4 KV-3000A-1000 MVA
14.4 KV-3000A-1000 MVA
14.4 KV 3000A-1000 MVA
3000A
1200A
3000A
1200A
1200A
3000A
3000A
3000A
1200A
1200A
3000A
1200A
3000A
30/40 MVA
30/40 MVA
30/40 MVA
EXTRACTION & PLANT FEED
UTILITY SERVICES
RIVER PUMP HOUSE
COOLING TOWER
UP-GRADING & OFF-PLOT
36 MVA
8 MVA
8 MVA
34.5 KV - 1500 MVA
2000A
20 MVA
55 MVA
INTERFACE BETWEEN MILDRED LAKE POWER PLANT AND TRANSMISSION LINE
MINE & RAILWAY 35 MVA
MINE & RAILWAY 35 MVA
ALBERTA POWER FROM MITSUE
240 KV
TO FORT McMURRAY
144 KV
NOTE: CONNECTED LOADS HAVE BEEN INDICATED ABOVE
SYNCRUDE CANADA LTD.
MILDRED LAKE PROJECT
CANADIAN BECHTEL LIMITED
SYNCRUDE PLANT SINGLE LINE DIAGRAM GENERATION & UTILITY TIE
9776 30B-SK-P-103



ATTACHMENT 10

No.	DATE	REVISIONS	BY
B	JAN 23 1973	REVISED AND ISSUED FOR INFORMATION	WM
A	JAN 3 1973	ISSUED FOR INFORMATION	WM

SCALE 1" = 2,000' DESIGNED W.L.M. DRAWN W. MILLER

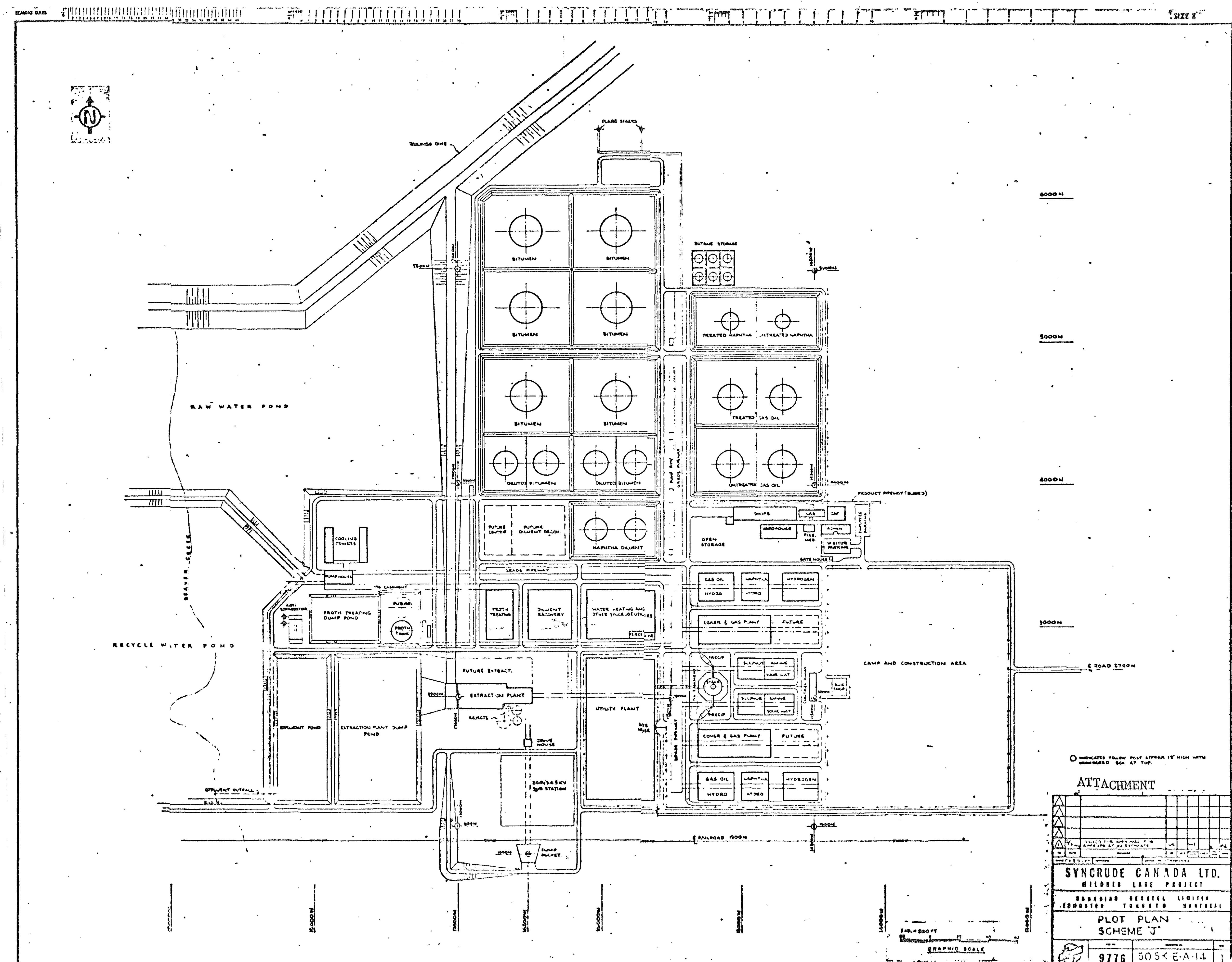
SYNCRUDE CANADA LTD.

MILDRED LAKE PROJECT

CANADIAN BECHTEL LIMITED

SOLID WASTES DISPOSAL & STORAGE

JOB No. 9776 DRAWING No. 23E-SK-S-138 REV. B



TAILINGS DIKE
FLARE STACKS
BUTANE STORAGE
BITUMEN
TREATED NAPHTHA
UNTREATED NAPHTHA
TREATED GAS OIL
UNTREATED GAS OIL
DILUTED BITUMEN
FUTURE CENTRIF.
FUTURE DILUENT RECOV.
NAPHTHA DILUENT
PRODUCT PIPEWAY (BURIED)
SHOPS
LAB
CAF
WAREHOUSE
OPEN STORAGE
VISITOR PARKING
GATE HOUSE
RAW WATER POND
BEAVER CREEK
COOLING TOWERS
PUMPHOUSE
GRADE PIPEWAY
FROTH TREATING DUMP POND
FROTH TANK
FROTH TREATING
DILUENT RECOVERY
WATER HEATING AND OTHER SYNCRUDE UTILITIES
GAS OIL
HYDRO
NAPHTHA
HYDROGEN
COKER & GAS PLANT
FUTURE
CAMP AND CONSTRUCTION AREA
RECYCLE WATER POND
FUTURE EXTRACT.
EXTRACTION PLANT
REJECTS
UTILITY PLANT
PRECIP
STACK
SULPHUR
AMINE
SOUR WAT
EFFLUENT POND
EXTRACTION PLANT DUMP POND
DRIVE HOUSE
240/34.5 KV SUB STATION
EFFLUENT OUTFALL
RAILROAD 1500N
PUMP POCKET
ROAD 2700N
6000N
5000N
4000N
3000N
GRAPHIC SCALE
ATTACHMENT
SYNCRUDE CANADA LTD.
MILDRED LAKE PROJECT
CANADIAN BECHTEL LIMITED
EDMONTON TORONTO MONTREAL
PLOT PLAN
SCHEME "J"
9776
50SK-E-A-14
SIZE E

SYNCRUDE CANADA LTD.
807 BAKER CENTRE • 10025 - 106 STREET • EDMONTON, ALBERTA
T5J 1G4
RESEARCH AND DEVELOPMENT OF THE ATHABASCA TAR SANDS

Reference No. 288
January 26th, 1973

Mr. N. W. Hanevich
Improvement District Administrator
Department of Municipal Affairs
Lac La Biche, Alberta

Dear Sir:

Re: Application For Development Permit

We herewith submit, on behalf of Syncrude Canada Ltd., Application For A Development Permit (and accompanying sketch) in triplicate. Further details will be supplied at a later date.

Yours truly,

J. E. Leeper

J. E. Leeper

JEL:LS
Enclosures: Application For A Development Permit (3)
Mildred Lake Project Preliminary Sketch (3)

2116-41

SCHEDULE A

Application No. ______

THE IMPROVEMENT DISTRICT NO. 18

DEVELOPMENT CONTROL REGULATION

APPLICATION FOR A DEVELOPMENT PERMIT

I/WE hereby make application for a development permit under the provisions of the Development Control Regulation in accordance with the plans and supporting information submitted herewith and which form part of this application.

Applicant: SYNCRUDE CANADA LTD.

Address: 807 Baker Centre, 10025 - 106 Street
Edmonton, Alberta, Canada T5J 1G4 Tel. No. 424 - 0651

Registered owner of land: PROVINCE OF ALBERTA

Address: ______ Tel. No. ______

Address of property on which the development is to be effected: Sec 31 Twp 93 Rg 11 W4M

Lot (parcel) ______ ; Block ______ ; Registered Plan No. ______

Existing use of land or building on the property: None

Proposed use of land or building on the property: Power Plant

Proposed yards, Front: ______ ; Rear: ______ ; Side: ______

Estimated Commencement Date: 1973 ; Estimated Completion Date: 1977

Estimated Cost of Development: About Sixty-Five Million Dollars ($65,000,000)

Interest of Applicant if not owner of property: Mineral leaseholder

Other supporting material attached: Sketch

Signature of Applicant: James E. Leeps Date: January 13, 1973

FOR OFFICIAL USE ONLY

NOTICE OF DECISION

The above application has been

APPROVED SUBJECT TO THE FOLLOWING CONDITIONS

REFUSED FOR THE FOLLOWING REASONS

Date of Decision: ______ Date of Issue of this Notice and Permit: ______

______
Development Officer

(Important - See Notes Over)

7. FEBRUARY 20-23, 1972 PAPER NO. 540 ON CONVERSION OF ATHABASCA BITUMEN (PRESENTED TO 71ST NATIONAL MEETING OF THE AMERICAN INSTITUTE OF CHEMICAL ENGINEERS)

CONVERSION OF ATHABASCA BITUMEN

INTRODUCTION

The Athabasca tar sands of Northern Alberta appear on the threshold of major development. Over the past decade, the Alberta Energy Resources Conservation Board and its predecessor, the Alberta Oil and Gas Conservation Board, have held eight hearings to consider applications for commercial tar sands projects. These are summarized in Table 1.

Production from the tar sands is currently limited to 45,000 barrels of synthetic crude per day - the authorized output of the Great Canadian Oil Sands project - but Syncrude Canada Ltd. recently has been granted permission to construct a project with a capacity of 125,000 BPD. The Board, in its decisions, has been guided by the policy of the Alberta government which has been to restrict tar sand production until the markets for crude oil have increased to the point of being able to absorb the province's conventional production. At the projected rate of growth, the surplus of conventional capacity is expected to disappear by 1974[(1)]. With the conventional industry facing higher exploration and production costs as it moves offshore and into remote northern areas, the incentive for tar sand development is expected to increase. Syncrude, in its recent commercial application [(1)] estimated that Alberta synthetic crude production could amount to 300,000 barrels per day by 1980. Conceivably, the rate of addition of increments of productive capacity beyond 1980 could be limited only by the availability of capital and skilled construction manpower.

Since Athabasca bitumen is a viscous material with a high content of impurities, upgrading is necessary in order to produce a synthetic crude which can be pipelined to markets. The upgrading schemes which have received the most serious consideration to date are based on converting the heavy residual fraction of the bitumen to lower-boiling hydrocarbons.

The resulting distillate fractions are then selectively hydrotreated to saturate unstable hydrocarbons and remove undesirable constituents such as sulfur and nitrogen. This general upgrading approach is illustrated schematically in Figure 1.

As shown in the list of tar sand hearings (Table 1), four different primary conversion processes have been proposed by the various applicants: thermal visbreaking; delayed coking; fluid coking; and H-Oil hydrovisbreaking.

While many factors must be taken into consideration prior to selecting a processing sequence, central to any evaluation are good yield and product quality information. This paper examines each of the four primary conversion processes proposed in the applications for commercial tar sands projects. Data presented are based on pilot plant studies conducted for Syncrude Canada Ltd. by various licensors and engineering firms.

CHARACTERISTICS OF ATHABASCA BITUMEN

Before considering the conversion processes, it is desirable to examine the properties of the feedstock. Bitumen has a characterization factor of 11.18 which compares with 11.3 for the most naphthenic Gulf Coast fractions and 12.3 for the paraffinic Pennsylvania crude cuts[2]. Its API gravity of about 8^{o}, and sulfur content approaching 5.wt.% also set it apart from other crude oils. An excellent description of bitumen and the inorganic compounds associated with it has been presented by Bowman[3].

Many inspections have been reported in the literature, a number of which have been compiled by Camp[4]. Table 2 lists the ranges of values reported and gives an inspection typical of bitumen from Lease 17, the site of the proposed Syncrude project.

Before accepting any analysis at face value, a knowledge of the history of the sample is desirable. Several points should be considered:

(a) Bitumen obtained under ideal conditions, - i.e. from carefully recovered blocks of in situ tar sand which were maintained in a frozen state until laboratory extraction - will generally exhibit a higher API gravity, a lower initial boiling point, and a lower viscosity than tar sand samples handled without these precautions. However, such a sample may not necessarily be representative of a commercial feedstock to upgrading. The mining, conveying and extraction operations, during which the tar sand is worked, exposed, aerated and slurried with hot water and steam, will result in a material which is more deficient in light ends than a carefully prepared sample. A commercial bitumen feedstock can be as much as one degree lower in API gravity than the in situ bitumen - i.e. 7.4^{o} versus 8.4^{o}.

(b) Samples of bitumen invariably contain between 0.5 and 3.0 wt.% of fine solids. If not properly accounted for, the apparent properties of the bitumen and the residual fraction will be distorted.

(c) The solids content is comprised mainly of Kaolinite, Illite, fine silica and hard organic material. During normal ashing procedures, organic material and water of hydration are cost, making the determined ash value lower than the actual solids content by 10 to 30%.

(d) Reported oxygen values have been obtained by difference in many cases, containing thereby, accumulated errors in analysis and any elements that were omitted from the analysis. Where an oxygen analysis has been carried out, oxygen in the solids may have been measured as part of the oxygen content of the bitumen if activation analysis was employed. Reported values of oxygen generally are in excess of 1 wt.%, however, it would appear that values in the range of .60 to .75 wt.% are more correct.

Bearing the above points in mind, the real differences in physical and chemical characteristics undoubtedly are less than the extremes reported in the literature.

As shown in Table 2, approximately half of the bitumen boils below 1000°F and there is little naphtha present. In Table 3, inspections of the virgin distillates are provided. Figure 2 presents a typical distillation curve and a plot of API gravity vs mid liquid volume yield. In Figure 3, the sulfur and nitrogen contents and the Conradson carbon residue (CCR) of the distillate fractions have been plotted against the mid liquid volume percent. Comparison of the latter two figures will enable estimation of the properties of any virgin distillate fraction. It will be noted, for instance, that as the end point approaches 1000°F, the incremental heavy gas oil is very high in Conradson carbon - about 3.0%. While the bitumen contains approximately 400 parts per million of metallic elements, well-fractioned virgin gas oil of 650° - 1050°F TBP boiling range will contain less than 0.5 ppm of each of nickel, vanadium, and iron.

The properties of the virgin residua or pitch are given in Table 4. Solvent separation of plus 1000°F residuum indicates the following approximate composition:

	Wt.%
Dark Oils (saturates and aromatics)	22
Resinous Material	44
Asphaltenes	34

The Conradson carbon of whole bitumen is approximately 14 wt.%, and of the plus 1000°F residuum about 25 wt.%. It is mainly this virgin pitch fraction that is converted to lighter hydrocarbons in the production of synthetic crude.

THERMAL VISBREAKING

The term thermal visbreaking is used here to describe once-through thermal cracking of the whole bitumen or virgin pitch even though the cracking severity employed may be greater than normally implied by the use of the term. Bitumen cracks so readily upon the application of heat that Ball[5] considered it unique in this respect. Subsequent work by other researchers [6] [7], confirmed the ease with which the material can be converted but revealed, however, that several other heavy crudes exhibit an equal or even greater susceptibility to thermal cracking. Henderson and Weber [7] found that mild cracking of the bitumen can be described by first order kinetics. They measured an activation energy of 49.0 kcal per mole. Experiments conducted by Syncrude support this general value but indicate that at the onset of cracking, where decarboxylation and rupture of sulfur bonds predominate, the activation energy may be as low as 30 kcal per mole.

Batch experiments by Syncrude illustrate the cracking susceptibility of the bitumen at moderate temperatures. In these tests, the bitumen was held at a given temperature for a period of 100 minutes under a pressure of 75 psig. The results are plotted in Figures 4a, b and c. Incipient alteration of the gravity and viscosity begins at about 400°F. Gradual changes are being experienced up to about 600°F; above 600°F conversion increases markedly.

No appreciable increase was noted in the benzene insolubles (coke) up to a temperature of 735°F. At higher temperatures, coke formation became significant; for example, a test at 765°F produced 6.5% coke. This indicated degree of stability appears to be at variance with the observation of Henderson and Weber that for a one-hour residence time above 700°F, between 15 and 30 wt.% of heavy oils (including Athabasca) are commonly converted to a coke-like material. The transition of asphaltenes to coke and the simultaneous formation of "new" asphaltenes as the severity of cracking is increased, have been investigated by Pasternak[8]. His results showed the same magnitude of coke formation as that obtained by Syncrude.

It is of interest to examine the degree of viscosity reduction attainable by once-through cracking of the bitumen. Tests were carried out in a continuous pilot plant operation during which the feed was pumped through a 200 ft. long electrically heated coil. The space velocity was held at 9.3 volumes of oil per hour per volume of coil and the outlet temperature was varied between 850°F and 950°F. A back pressure of 300 psig was maintained. Feed material used for the bulk of these runs was obtained from the Bitumount area and contained about 4% of light gas oil solvent. A second set of runs was conducted on Mildred Lake bitumen which, in these tests, should be considered as a more representative material. The viscosity of the total liquid streams from the cracking of the two samples of bitumen has been plotted against the gasoline make in Figure 5a. The viscosity of the Bitumount product reached an apparent minimum between 12 and 14 vol.% gasoline yield. Presumably heavy polymers formed through secondary reactions tended to offset the effect of higher yields of light fractions beyond this region. The lowest viscosity (sus @130°F) obtained for the Bitumount visbroken products represented a 20-fold reduction from that of the original sample of diluted bitumen, whereas Mildred Lake product containing 10% gasoline has a viscosity that was approximately one-seventieth of the original bitumen. Substantial coking was experienced in the cracking coil in the more severe Bitumount runs; these were, of necessity, only a few hours in duration.

As shown in Figure 5b, the benzene insoluble content started to increase at about 10 vol.% gasoline yield. Also, as indicated in the same figure, the total products from the more severe runs exhibited a basic incompatibility and upon standing, or centrifuging, would settle into two distinct layers. Though not shown, the breakpoint in compatibility for the Mildred Lake material, as with the Bitumount material, was fairly well defined and occurred at about 10 vol.% gasoline make. It should be explained that in all of these tests a simple ASTM distillation procedure was used for quick results. If a Hemple distillation had been used throughout to provide more precise fractionation, and the yields corrected for the C_4-C_6 content in the wet gas, the amount of total C_4-400°F gasoline would have been about 30% higher than the yields plotted here.

Buether et al[9] have presented a comprehensive paper on the subject of instability in visbroken products. They described the mechanisms as follows: as cracking severity is increased, the heavy oils and resins, which act to peptize and maintain the asphaltic constituents dispersed in the oil, are more completely cracked to lighter oils; thus, the asphaltic constituents tend to separate from the bulk oil and form deposits during the Navy Boiler and Turbine Laboratory (NBTL) heater test, and, for that matter, in the cracking coil. Concurrently, as the extent of thermal cracking increases, the concentration of reactive constituents in the furnace increases. The higher concentration of reactive radicals promotes condensation to tars and coke - molecules which are larger and more difficult to keep dispersed than the original asphaltic material.

Their test results indicated that the maximum severity of visbreaking which could be tolerated without producing a plus 400°F product that would fail the stability test for Navy Special fuel oil, correlated well with the asphaltene content of the residuum feedstocks used in their studies. Their data embraced ten samples with pentane insoluble (asphaltene) contents ranging from 2.5 to 25.4%. Athabasca residuum, as previously mentioned, contains about 34% asphaltenes, which is outside the range of their data. Stability tests on plus 400°F visbroken bitumen from Syncrude's once-through cracking experiments showed all samples from runs with gasoline yields above 3.5 vol.% failed; when the light gas oil fraction was removed, a marked improvement in stability was noted.

In a typical refinery application, visbreaking is used to crack virgin vacuum tower pitch to reduce the amount of cutter stock required to meet fuel oil viscosity specifications. In a tar sands project, it would be unlikely that the pitch would be cut back prior to burning it; the object would be to produce that amount of pitch dictated by project fuel requirements. Pilot plant visbreaking experiments have been carried out for Syncrude on both full range bitumen and plus 1000°F residual to provide yield and product quality data, and operating guidelines. In Figure 6, the product distribution from visbreaking of the total bitumen can be seen and compared with the combined product distribution from vacuum reduction of the total bitumen followed by visbreaking of the 51.9 vol.% (55.5 wt.) residual fraction. As shown, the yields from the runs on both stocks investigated formed smooth curves. For the same yield of total product lighter than 1000°F, more gas and gasoline and less gas oil are produced when visbreaking total bitumen than by vacuum reduction and visbreaking of the reduced bitumen.

The translation of laboratory operating history to anticipated commercial performance is a controversial subject. Syncrude, in discussions with various experts, find some engineering companies tending to regard pilot plant data as useful in predicting yield distribution and product quality but not operating conditions. They prefer to build commercial cracking coils based on their own well-established design criteria; in other words, they are guided only in a very general way by the pilot plant space velocities, pressures and temperature profiles. At the other end of the spectrum, Gulf Oil[9] apparently have been able to obtain fairly good agreement between their pilot plant and commercial visbreaking unit operating conditions. It is in the determination of maximum obtainable conversion consistent with reasonable commercial run lengths that translation is most difficult.

A rule-of-thumb guide would equate a 1/4 inch diameter laboratory coil operated for 3 days without coking to the point of non-operability, with 90 days of commercial operation. In neither of the pilot plant operations used to generate the data in Figure 6, were cracking severities at the point where complete coking of the coil occurred; however, they were sufficiently high to indicate that the severities required commercially probably could not be obtained without some operating difficulties. Thus, one would tend to regard the yields shown for the most severe runs for the two operations as the maximum that could reasonably be expected in a commercial operation. While the gasoline make shown for the once-through cracking runs in Figure 5a was not corrected to the same basis as that for the pilot plant visbreaking runs shown in Figure 6, the production of measurable quantities of benzene insolubles occurred in the former runs at about the same level of conversion where coil coking appeared significant in the latter runs. The pilot plant operating conditions for the most severe run in the pilot plant tests for each of the total bitumen and vacuum reduced bitumen feedstocks are listed in Table 5.

If these tests have properly defined the limiting severities for the two operations, then a deeper conversion of the residuum can be achieved by cracking the total bitumen than by cracking the plus 1000°F fraction. The yields of C_5 to 1000°F distillate were 73.5 vol.% for the whole bitumen and 70.3 vol.% for the combined operation; residuum yields were 23.9 and 20.6 vol.%, respectively. Volumetric yields of liquid products from visbreaking of the total bitumen are shown in Figure 7. Qualities of the products from the most severe run on total bitumen are shown in Table 6.

Visbreaking is a relatively inexpensive primary conversion process. However, it will produce more pitch than can be utilized as plant fuel in a mining type tar sands project. It may, though, very well fit the in situ type of project which has a large requirement for steam. Shell Oil, in their 1963 application to the Alberta Oil and Gas Conservation Board, based their upgrading scheme on the use of thermal visbreaking; their estimated fuel needs corresponded to about 35 wt.% of the bitumen produced.

DELAYED COKING

Delayed coking is the residual conversion process in widest use today. There are approximately 45 delayed coking units in operation or under construction in the United States alone. Rose [10] in a recent article listed the capacity of these units as exceeding 850,000 BPD, with coke production in excess of 35,000 tons per day. Delayed coking is also the primary upgrading process adopted by Great Canadian Oil Sands, the first commercial tar sands project. The GCOS delayed coking unit is the world's largest, with a design feed rate of approximately 60,000 barrels of bitumen per calendar day and a coke make of 2,600 tons per day.

Delayed coking has been used by refiners since the mid 30's. The equipment has undergone constant evolution, which has helped to offset rising construction costs. A study in 1960 by Cities Service Athabasca, Inc., the original operator of the Syncrude project, indicated that a plant processing 100,000 BPD of synthetic crude using the largest equipment built to that time, would have required 24 coke drums of 21 ft. in diameter by 56 ft. tangent to tangent. By 1965, 26 ft. diameter by 75 ft. high drums were being designed and the number required for a 100,000 barrel project would have been reduced to 12. In his article, Rose predicted that at some time in the future, drums of 30 ft. in diameter will be built, and this would reduce the number required to eight.

In the delayed coking process (see Figure 8), the feedstock is heated to 900 to 950^{o}F - typically 920^{o}F - and fed to large drums operating at a pressure of 20-50 psig. The drums are installed in multiples of two so that one can be charging while the other is being decoked; they usually are sized to permit filling over a 24-hour period. In the coke drums, the feed material is thermally cracked. The gases and distillates so formed pass overhead to a fractionator while the asphaltic constituents and heavy polymers remain to form coke. Since the vapors generally entrain some residual material and volatile organo - metallic compounds, it is common practice to recycle the high boiling fractions from the bottom of the fractionator back to the coke drums. A recycle ratio of 0.25 based on fresh feed would be considered average. The end point of the coker distillate is normally maintained under 950^{o}F when it is to be subsequently fed to a catalytic cracking unit.

The coke yield is related to the Conradson carbon residue (CCR) of the feedstock. According to Rose, for paraffinic stocks in the range of 10% CCR, the coke yield when producing 950^{o}F end point gas oil is approximately 1.75 times the carbon residue; at 20% CCR the ratio is closer to 1.70. The coke and gas yields for the same gas oil end point are slightly higher when processing naphthenic stocks; gasoline and gas oil yields are correspondingly lower. These relationships are quite consistent. Mekler and Brooks [11] stated that if the reported yield of coke is much lower than 1.75 times the CCR of the feedstock, look for an explanation in the CCR content and the end point of the gas oil produced; invariably, they claimed, the CCR in the total gas oil will be much higher than the 0.3% by weight which is normal for 950^{o}F end point paraffinic coker gas oil. They went on to indicate that irrespective of the coking process, the ultimate gross yields of coke would be approximately the same for a given end point and CCR of the gas oil produced.

Delayed coking does not offer much flexibility in terms of control of yield patterns. However, some variation can be achieved. The yield of heavy gas oil (and total distillate) will be greatest when the unit is operated under conditions of low pressure and low recycle ratio. The coke and gas yields, conversely, will be at a minimum under these conditions. If it is desired to increase the yield of light gas oil, (which will increase the ratio of cracked to virgin in the product) higher pressures, temperatures and recycle ratios are required. Rose cautioned that too high a temperature - e.g. 950^{o}F will lay down coke in the heater tubes and produce a hard coke that cannot be cut from the drums in the allotted time.

Three sets of yield data from the coking of total Athabasca bitumen have been noted in the literature [2, 12, 13]. They are summarized in the first three columns of Table 7. The corresponding product quality data for references (2) and (12) are given in Table 8. Insufficient information has been provided to know whether the total gas oils contained less than 0.3% CCR. However, since the end point of the UOP coker gas oil [2] was listed as 760°F, it is likely it met the CCR criterion. In the cases of the Sun Oil pilot data [12] and the GCOS commercial data [13], 850°F end point heavy gas oil was produced along with a small yield of higher boiling "fuel oil". These products are mixtures of virgin and coker gas oils and, if the inspection of the heavy gas oil from the visbreaking operation, presented in Table 6, is any guide, they also would meet the criterion of Mekler and Brooks. As noted, the coke yields reported were 21.0, 22.7 and 22.2 wt.%, respectively. None of the three sets of data listed the corresponding CCR of the bitumen feedstock used. The literature contains a number of values, of which 13.6 and 17.9 wt.% represent the extremes. Tests performed by Syncrude tend to be in the range of 13.6 to 14.0 wt.% CCR, but samples of bitumen that have been analyzed for Syncrude by others have included values up to 15.6 wt.%. Using the highest coke yield of 22.7 wt.% and the lowest CCR value of 13.6 wt.% a ratio of 1.67 is obtained. Other combinations are more favorable. Thus, notwithstanding the naphthenic nature of the bitumen, coke yields equal to or lower than those normally expected from paraffinic stocks can be achieved.

The volumetric yields of C_5 to end point distillate from delayed coking of the total bitumen in the three cases shown in Table 7 were 79.1, 76.7 and 78.5 vol.%. (The latter two cases were estimated by Suncrude from the somewhat incomplete literature data.) To determine the maximum recovery attainable, a pilot plant run was made for Syncrude under conditions of low pressure and no recycle. Vacuum reduced bitumen representing 53.7 vol.% (56.5 wt.%) of the total bitumen was charged in a single-pass operation at a coil outlet temperature of 920°F into coke drums operating at 5 psig.

A diluent was used to maintain coil velocity. The yield data are given in Column 4 of Table 7 and the product inspections in Table 8. The C_5 to end point distillate amounted to 60.0 vol.% of the reduced bitumen feed but when combined with the IBP - 1000°F virgin distillate, the overall recovery became 83.9 vol.% on total bitumen. The yields of gas and coke, correspondingly, were lower than the values for these products reported in the literature for the coking of total bitumen. The gas oil produced in the low pressure, once-through operation had an end point of approximately 1100°F and as shown in Table 8, a CCR of 2.64 wt.%. If the fraction boiling above 1000°F were recycled to extinction, it is estimated that the coke yield would increase from 18.2 wt.% on bitumen to 19.7 wt.%. The product distributions from coking of the reduced bitumen in the one-pass and minus 1000°F ultimate operations are given in Figure 9. Here they are compared with the yield patterns achieved in the visbreaking work and, as shown, fall on straight line extensions of the visbreaking yields. It should be mentioned that it would prove difficult to achieve a coke drum pressure of 5 psig in a commercial unit since the pressure drop through a normal transfer line, fractionator, overhead line and condenser system ranges between 15 and 20 psi. However, through the application of stripping steam in the commercial coke drums and vacuum flashing of the fractionator bottoms, it should be possible to approach the yield structure obtained in the low pressure pilot plant run.

A prospective tar sands operator considering the delayed coking process has several options. He can charge hot total bitumen to the coke drums (Option A), he can charge a vacuum reduced pitch (Option B), or he can introduce the bitumen into a combination tower which serves as the fractionator for the virgin as well as the coker distillates (Option C); these three options are indicated on Figure 8. Also, as mentioned in the previous paragraph, he can increase liquid recovery through the addition of a vacuum tower on the fractionator bottoms. Equipment requirements are minimized by the combination tower approach since it does not require the installation of a vacuum unit as for option B, and utilizes smaller furnaces and heat exchangers than would be the case where total bitumen is charged. Since the virgin gas oils do not pass through the coking equipment, they will undergo no alteration. Combination case yields and product qualities have been estimated based on the results from the low pressure, once through pilot plant coking of the pitch and adjusted to the bitumen assay given in Table 1. The yields and inspections shown for a combination tower in Tables 7 and 8 were calculated, assuming a 30 psig operating pressure and recycle of gas oil above a 925^{o}F cut point. A coke yield of 23.2 wt.%, which is 1.70 times the Conradson carbon in the feedstock, was developed by a process engineer experienced in the interpretation of the pilot plant results. However, if the data reported in the literature by GCOS are representative of their average operation, the coke yield shown for the combination case may be slightly high.

The translation of pilot plant results to commercial performance can be made with more assurance for delayed coking than for thermal visbreaking. Because of the batch-like nature of the process, multiple trains of equipment would be required for a tar sands project, which could tend to reduce start-up risks through a safety-in-numbers approach. The primary conversion products are of relatively good quality and can be hydrotreated to produce jet fuels and premium cat cracker feedstocks. These factors, among others, probably influenced Great Canadian Oil Sands in their selection of delayed coking for the first commercial tar sands venture.

FLUID COKING

Fluid coking is a proprietary process licensed by Esso Research and Engineering Company. There are now 10 commercial units in operation with a total design throughput of 118,000 barrels per stream day.

Figure 10 is a simplified flow diagram illustrating the major components of the process. In concept, it is similar to a fluid catalytic cracking unit, the main difference being that fluidized beds of coke granules are employed instead of catalyst.

Bitumen feed can be introduced into the scrubber section (Option A) or it can be sprayed directly through multiple nozzles into the reactor (Option B). In the former case, virgin distillate fractions are stripped by hot rising vapors and carried into the fractionator; the reduced bitumen is commingled with the heavier cracked fractions for recycle to the reactor. Feed entering the reactor, either whole bitumen or reduced bitumen, is converted at a temperature in the range of 900 - 1000^{o}F. and a pressure of approximately 10 psig. The light products formed pass, as vapors, through cyclone separators which remove most of the entrained coke, and into the scrubber section. Heavier fractions and fine coke are returned as a slurry from the bottom of the scrubber, or, as in the case of a one-through operation (Option C), withdrawn for separate processing. The coke-forming asphaltic fractions are deposited on the hot coke particles comprising the fluid bed. Steam is added to the bottom of the reactor to assist the cracked product vapors in fluidizing the coke. There is a stripping section below the reactor where additional steam is added to strip adsorbed hydrocarbons from the circulating coke.

Coke is continuously withdrawn from the stripper through a standpipe and transferred to the burner vessel. Air is blown into the bottom of the burner to consume enough of the coke to meet the process heat requirements.

Hot coke is circulated back to the reactor. The net coke produced is withdrawn from the burner to maintain the system inventory.

A number of articles (e.g. 14, 15) have appeared in the literature describing the process and presenting yield and product quality data for a variety of feedstocks. However, none of the papers published contain information specific to the fluid coking of Athabasca bitumen.

A somewhat analagous system, using tar sand as feedstock, was investigated by the Canadian Department of Energy, Mines and Resources in Ottawa. In the initial experiments (16) a fluidized solid technique was used to accomplish the separation of the bitumen from the tar sand and the coking of the bitumen simultaneously in one processing step. The work was later extended to coking, over fluidized sand and catalyst, of bitumen containing water and solids, as recovered from the hot water separation process (17).

Sterba [2] in 1951 correlated the experimental results obtained by various researchers, including Peterson and Gishler [16] (in Ottawa), who were investigating different bitumen coking techniques; he plotted the coker distillate yield and the gravity of the coker distillate versus the coke yield. These curves have been updated to include some of the more recent delayed coking data and some fluid coking data which are based on pilot plant tests carried out by Esso Research and Engineering. The added points, as can be seen in Figure 11, are in good agreement with the previous data. The ability of the fluid coking process to achieve lower coke yields, and correspondingly higher yield of light products, is one of its advantages relative to delayed coking.

Several fluid coking cases, relating to Options A, B and C, have been assembled. The yield data derived are shown in Table 9 and the matching product inspections are contained in Table 10.

In Option A, the "combo" coker case, bitumen enters the top of the scrubbing tower. Depending on the amount of reflux added, the recycle cut point (RCP) can be varied up to a maximum of about 925°F. Columns 1 and 2 of Table 9 give the anticipated product yields for RCP's of 850°F and 925°F. Raising the end point from 850°F to 925°F increases the overall C_5 to end point yield from 76.0 to 79.0 vol.%. The yield of heavy gas oil is increased significantly at the expense of gas, gasoline and coke.

In Option B, the bitumen, instead of being charged to the top of the scrubber, is fed into the reactor system; the normal point of introduction for the refinery pitch feedstocks typically handled by fluid cokers. The higher temperatures to which the vapors are heated result in a greater lifting action, making it possible to increase the RCP to 975°F or higher. This option is referred to here as "whole bitumen coker feed - 975°F RCP". The additional heavy gas oil produced raises the liquid yield to 81.3 vol.% and lowers the gross coke yield to 16.0 wt.%. Even higher liquid yields could be obtained at higher cut points.

Another possible alternative is presented as Option C. In this case, the material that is normally recycled to extinction is withdrawn as a separate stream. Operating in this "once through" manner increases the overall yield to 84.7 vol.%, though the fraction boiling below 975°F would decrease to 75.4 vol.%. The production of gross coke is further reduced to 12.3 wt.% and the net coke to a low of 7.3 wt.%.

A material balance around the coking operation shows that if less carbon is removed as coke, more carbon must be contained in the other products. This is evident in Table 10 where the heavy gas oils and fuel oils from the cases producing the least coke have the lowest API gravities and the highest CCR.

Normally one tends to equate high CCR with a high metals content which will result in rapid catalyst deactivation in the subsequent hydrotreating operations. However, fluid coking is quite effective in destroying volatile nickel and vanadium containing porphorins. Heavy gas oils from fluid coking operations are being successfully hydrotreated in a number of locations to lower their sulfur contents or to enhance their characteristics as catalytic cracking unit feedstocks.

The plus 975^{o}F fuel oil fraction from the "once-through" case is high in CCR - about 25 wt.%. In spite of this it is a potential feedstock for a residual fuel desulphuriza-process - perhaps in combination with the 650 - 875^{o}F heavy gas oil stream - because much of the metal content has been deactivated; at present, though, this scheme should be considered speculative pending pilot plant substantiation.

The coke from the fluid coking process is an interesting material. Because of its small particle size it can be withdrawn continuously in a hot, dry state and transported pneumatically to silos or storage piles. This is in marked contrast to the hydraulic removal of coke from delayed coking drums, which can be a very troublesome operation, particularly during the long, cold Alberta winters; the delayed coke must also undergo extra crushing and drying operations before it can be utilized as fuel. The properties of delayed and fluid coke derived from bitumen are compared in Table 11. Significant differences exist in the volatile matter, sulfur content and grindability. The sulfur content of the net fluid coke, as shown, is 10.2 wt.%, whereas the gross coke contains 7.5 wt.% or about 75% of that of the net coke level. Thus in the burner of the fluid coking unit, the portion of the coke that is preferentially burned contains a lower-than-average sulfur content.

Another feature of the fluid coker products that warrants comment is the highly olefinic nature of the gaseous streams. The C_3 fraction contains 55 wt.% propylene and the C_4 fraction contains 72 wt.% butylenes. Since alkylation processes will probably play a major role in the forthcoming production of low-lead gasoline, olefinic feedstocks could be in great demand.

The largest fluid coker now operating has a capacity of 42,000 barrels per stream day; however, there is no reason why units with a capacity of, say, 75,000 BPSD cannot be built to take advantage of the economies of scale. This factor, combined with the ease which the coke can be handled, the olefinic nature of the gaseous streams, the low yield of residual product and the correspondingly high yields of lighter hydrocarbons, makes fluid coking a process that should receive careful consideration by a prospective tar sands operator.

H-OIL HYDROVISBREAKING

H-Oil hydrovisbreaking is a process, licensed through Cities Service Research and Development Company, that was developed to produce high yields of distillate products. It operates under very moderate conditions compared to most hydrocracking processes and appears to be uniquely suited for handling Athabasca bitumen. The process flow plan has been described briefly by Rapp and Van Driesen[18]. It is basically simple and involves introducing heated bitumen and hydrogen into a reactor system under the proper conditions of temperature and pressure. The application of this process to the upgrading of Athabasca bitumen has been discussed in a paper by Gray and Haston[19].

The response of Athabasca bitumen to thermal hydrocracking techniques has also been investigated by the Canadian Government Department of Energy, Mines and Resources[20,21]. Operating pressures as high as 10,000 psi have been studied. The scientists carrying out the program concluded that high pressures, while increasing catalyst life, retard the cracking necessary for the conversion of the bitumen. The effects observed at pressures of 3000 psi and lower are largely the result of the hydrogenation of the products of the primary cracking reaction. Deep hydrogenation of high molecular weight hydrocarbons occurs only at pressures above 5000 psi. In addition to the catalytic work, Parsons, of the above department, has studied thermal hydrogenation of the bitumen at pressures ranging from 500 to 3500 psi[21].

H-Oil hydrovisbreaking would be utilized in a tar sands project in much the same manner as the other three primary conversion processes discussed in this paper. The main object would be to achieve maximum conversion of the bitumen consistent with moderate hydrogen consumption; final product quality would be obtained through subsequent hydrotreating of the distillate streams.

Figure 12 presents yield data obtained from hydrovisbreaking of the bitumen at three conversion levels - 68%, 77.5% and 85%. Conversion is defined here as disappearance of the plus 975^{o}F residuum; a conversion level of 85% represents, therefore, a volumetric yield of residue of approximately 7.5%, based on total bitumen. This compares to 23.9 vol.% of residue or approximately 52% conversion, obtained by severe thermal visbreaking (refer to Figure 7). The yields of total C_5 - 975^{o}F distillate for the three conversion levels noted are 85.4, 89.9 and 93.6 vol.%, respectively. The hydrovisbreaker yield data presented here are representative of bitumen containing 49,7 vol.% distillate boiling below 975^{o}F, whereas the assay recorded in Table 1, which was used as the basis for adjusting the coking yields, contained only 45 vol.% below 975^{o}F. Adjustment to a higher residuum content bitumen would mean that for a given conversion level, slightly more hydrovisbreaker residue and less distillate would be produced; additional hydrogen would also be required. Comparison of the overall synthetic products from the various upgrading processes indicates that hydrovisbreaking produces a higher percentage of middle distillates than the other primary conversion processes studied, mainly at the expense of heavy gas oil production.

The amount of hydrogen required to achieve a given conversion level is shown in Figure 13. Similar hydrogen rates were presented by Gray and Haston[19] as a function of wt.% of the unconverted residual fraction.

Brief inspection data of the products from hydrovisbreaking of the bitumen are listed in Table 12. Properties of the vacuum reduced pitch from both thermal visbreaking and H-Oil hydrovisbreaking operations are given in Table 13. Both pitches have high softening points which may provide the option of handling them either as a liquid or as a solid fuel.

H-Oil hydrovisbreaking of Athabasca bitumen has been extensively investigated in pilot plant operations ranging over a 13-year time period. Because of the high yields of distillate obtainable with this process it should be considered as a strong contender for the primary conversion role in a tar sands upgrading complex.

SUMMARY

Product yields and inspections have been presented in this paper for the four primary upgrading process which have been proposed in the various applications for commercial tar sands projects. The data have shown that Athabasca bitumen can be thermally visbroken more readily than most feedstocks, that the yields of coke are as low as, or even lower than those normally obtained from high quality paraffinic stocks, and that high conversion and high distillate yields can be obtained by hydrovisbreaking. The information presented illustrates the degree of flexibility inherent in each of the four processes and, it is hoped, should prove of interest to those contemplating the development of this resource.

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TABLE 1

TAR SAND HEARINGS

DATE	COMPANY	SIZE OF PROJECT BPD	UPGRADING APPROACH	STATUS
1960	GCOS	31,500	Delayed Coking	Deferred
1962	GCOS	31,500	Delayed Coking	Approved
1963	GCOS	increase to 45,000	Delayed Coking	Approved
1963	CSAI	100,000	Fluid Coking	Deferred
1963	Shell	100,000	Thermal Visbreaking	Deferred
1968	Syncrude	80,000	H-Oil Hydrovisbreaking (68% conversion)	Deferred
1969	Syncrude	80,000	H-Oil Hydrovisbreaking (68% conversion)	Approved
1971	Syncrude	increase to 125,000	H-Oil Hydrovisbreaking (75% conversion)	Approved

TABLE 2

PROPERTIES OF ATHABASCA BITUMEN

	Range of Literature Values	Syncrude Bitumen Lease 17
Gravity, API°	5.7 - 8.6	8.3
Distillation Temp. °F		
IBP	- 505	300
10%	560 - 610	610
30%	795 - 840	835
50%	965 - 1,010	1,025
Viscosity		
CS @ 100°F	4,993 - 500,000	4,993
CS @ 210°F	513 -	348
Molecular Weight	539 - 800	539
Elemental Analysis, Wt.%		
Carbon	81.9 - 83.6	83.1
Hydrogen	9.5 - 10.6	10.6
Oxygen	0.2 - 2.9	0.7
Nitrogen	0.3 - 0.6	0.4
Sulfur	3.8 - 5.5	4.9
Metals, ppm		
Vanadium	210 - 290	290
Nickel	82 - 100	82
Iron	- 75	75
Hydrocarbon Type, Wt.%		
Asphaltenes	16.0 - 23.4	17
Resins	22.0 - 34.7	22
Oils	45.0 - 61.0	61
Conradson Carbon, Wt.%	13.6 - 17.9	13.6

TABLE 3

PROPERTIES OF VIRGIN DISTILLATES

Boiling Range, °F	430-650	650-850	850-1050
Gravity, API°	25.9	17.3	10.7
Sulfur, Wt.%	1.55	2.95	4.10
Diesel Index	34	21	14
Pour Point	-55	0	70
Con. Carbon %	0.01	0.08	1.65
Nitrogen	0.01	0.16	0.27
Visc. S.U. @ 130°F	40	205	4700
@ 210°F	32.5	57	235

TABLE 4

PROPERTIES OF THE VIRGIN RESIDUUM

Boiling Range, °F	650+	850+	1050+
Gravity, API°	5.3	2.8	0.0
Sulfur, Wt. %	5.2	5.6	6.7
Visc. S.F. @ 210°F	530		
@ 275°F	94	382	4750
Con. Carbon, %	15.2	19.0	28.0
Nitrogen, Wt. %	0.56	0.64	0.72
Soft. Point, °F	-	137	186
Pen. @ 77°F, MM	-	39	3

TABLE 5

VISBREAKER PILOT PLANT OPERATING CONDITIONS

(FOR HIGHEST CONVERSION RUNS PLOTTED IN FIGURE 6)

	Total Bitumen Feed	Vacuum Reduced Bitumen Feed
Outlet Temperature, °F	950	920
Outlet Pressure, psig	101	75
Space Velocity, vol/hr. oil/vol. coil	30.9	32.9

TABLE 6

PROPERTIES OF DISTILLATES FROM VISBREAKING OF TOTAL BITUMEN

	Naphtha	Light Gas Oil	Heavy Gas Oil
Nominal Boiling Range, °F	C_5/380	380/650	650/1000
Gravity, API°	54.0	25.8	13.2
Sulfur, Wt. %	2.02	2.11	3.91
Nitrogen, Wt. %	0.011	0.045	0.28
Bromine Number	115	38	20
Conradson Carbon, %			0.23

TABLE 7

DELAYED COKING YIELDS (a)

WT. % ON FEED

FEED	Bitumen	Bitumen	Bitumen	Vacuum Reduced Bit. (b)	Bitumen; Combo Toner
Source of Data (Ref.)	2	12	13	Syncrude	Syncrude
Gases, C_4 & ltr.	8.2	8.3	7.9	8.6 (4.8)	6.7
Naphtha	15.4	12.1	12.7	10.6 (6.0)	10.9
Light Gas Oil		10.0	15.0		22.6
Heavy Gas Oil	55.0	41.4	36.2		36.5
Fuel Oil		4.2	6.0	48.1 (27.2)	
Coke	21.0	22.7	22.2	32.7 (18.5)	23.2

(a) Boiling Ranges of fractions are not identical; refer to inspections in Table 8.

(b) Wt.% on vacuum bottoms feed to coker; numbers in parentheses include recombined virgin fractions and are expressed as wt. % on total bitumen.

TABLE 8

PROPERTIES OF DISTILLATES FROM DELAYED COKING

FEED	Bitumen	Bitumen	Combined Virgin & Coker Distillates Vac. Reduced Bit.	Bitumen Combo Tower
Source (Reference)	2	12	Syncrude	Syncrude
Naphtha				
Nom. Boiling Range, °F	126/400	180/400	C_5/330	C_5/380
Gravity, API°	51.9	46.8	42	55.8
Sulfur, Wt.%	1.86	2.2	0.6	1.85
Nitrogen, Wt.%		0.015		0.012
Bromine Number	80	61		70
Light Gas Oil				
Nom. Boiling Range, °F		400/525		380/650
Gravity, API°		32.9		27.3
Sulfur, Wt.%		2.7		2.7
Nitrogen, Wt.%		0.040		0.051
Bromine, No.		36		14
Heavy Gas Oil				
Nom. Boiling Range, °F	400/760+	525/850	330/1100	650/925
Gravity, API°	16.6	18.3	16.5	15.7
Sulfur, Wt.%	4.04	3.8	3.7	3.7
Nitrogen, Wt.%		0.200		0.298
Bromine No.	47	20		12
Conradson Carbon, %			1.5	
Fuel Oil				
Nom. Boiling Range, °F		850+		
Gravity, etc.		N/A		

TABLE 9

YIELDS FROM FLUID COKING OF TOTAL BITUMEN

	Combo Coker (Option A)				Whole Bitumen Feed		Whole Bitumen Feed	
	850°F RCP		925°F RCP		975°F RCP (Option B)		Once-Thru (Option C)	
	Wt. %	Vol. %	Wt. %	Vol. %	Wt. %	Vol. %	Wt. %	Vol. %
Gas	9.8		8.0		9.1		7.9	
Butanes		4.5		3.3		3.6		1.5
Naphtha C_5/380°F		19.7		15.8		19.1		11.5
Lt. Gas Oil 380/650°F		25.3		24.5		26.6		21.2
Heavy Gas Oil 650/EP		31.0		38.7		35.4		42.7
Fuel Oil, 975°F+		-		-		-		9.3
Gross Coke	19.8		17.7		16.0		12.3	
Net Coke	15.3		13.7		10.0		7.3	

TABLE 10

PROPERTIES OF FLUID COKER DISTILLATES

	Combo Coker (Option A) 925°F RCP	Whole Bitumen Feed (Option B) 975°F RCP	Whole Bitumen Feed Once-Thru (Option C)
Naphtha, C_5/380°F			
Gravity, API°	51.1	52.1	56.0
Sulfur, Wt.%	1.3	1.4	1.0
Nitrogen, Wt.%	0.014	0.016	0.01
Bromine Number	133	130	130
Aniline Pt., °F		50	50
Light Gas Oil, 380/650°F			
Gravity, API°	24.5	25.8	26.1
Sulfur, Wt. %	2.8	4.1	3.3
Nitrogen, Wt. %	0.07	0.08	0.06
Bromine Number	53	90	90
Aniline Pt., °F		65	65
Heavy Gas Oil, 650/925/975°F			
Gravity, API°	13.0	10.7	11.0
Sulfur, Wt. %	4.1	5.4	4.8
Nitrogen, Wt.%	0.33	0.41	0.3
Bromine Number	18	30	30
Aniline Pt., °F		85	85
Conradson Carbon, %		3.2	2.2
Fuel Oil, 975°F+			
Gravity, API°			2.7
Sulfur, Wt. %			5.4
Nitrogen, Wt. %			0.43
Conradson Carbon, %			25.0

TABLE 11

PROPERTIES OF COKE

	Delayed	Fluid
Ultimate (Ash Free)		
Carbon	88.5	85.6
Hydrogen	3.6	2.0
Sulfur	6.0	10.2
Nitrogen	1.4	1.7
Oxygen (By Diff.)	0.5	0.5
Volatile Matter, %	11.6	6.0
Hargrove Grindability	55	18
Gross Heating Value, BTU/Lb.	14,500	14,000

TABLE 12

PROPERTIES OF DISTILLATES FROM H-OIL HYDROVISBREAKING

(75% Conversion)

	Naphtha	Light Gas Oil	Heavy Gas Oil
Nom. Boiling Range, °F	C_5/380	380/650	650/975
Gravity, API°	51	28.6	10.5
Sulfur, Wt. %	1.0	1.9	3.47
Nitrogen, Wt. %	0.027	0.08	0.32
Bromine Number	48	25	12

TABLE 13

PROPERTIES OF VACUUM REDUCED PITCH

	Thermal Visbreaker	H-Oil Hydro-visbreaker
Specific Gravity @ 60/60°F	1.22	1.25
Ultimate Analysis, Wt. %		
Carbon		83.2
Hydrogen		7.2
Sulfur	7.0	5.5
Nitrogen	1.3	1.2
Oxygen (By Diff.)		2.9
Conradson Carbon, %	57	60
Softening Point, °F		250
Viscosity, SFS @ 450°F		77.4

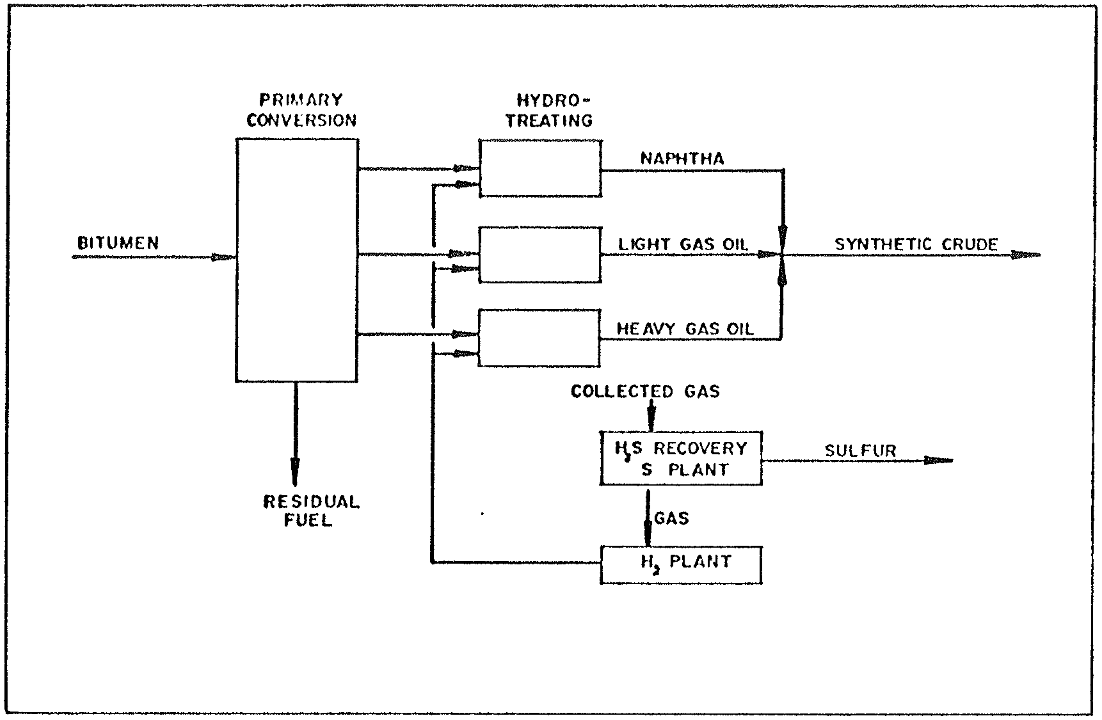

FIGURE 1

BITUMEN UPGRADING – SCHEMATIC DIAGRAM

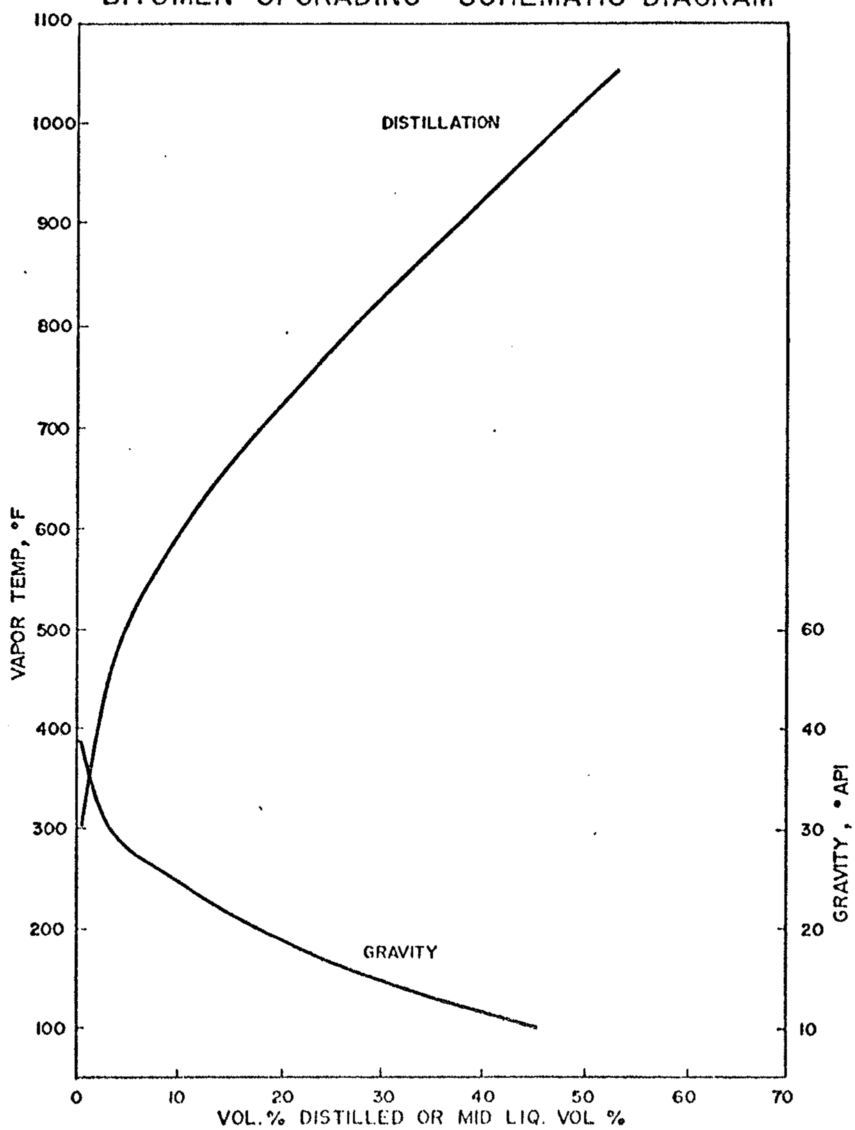

FIGURE 2

DISTILLATION CURVE and GRAVITY of DISTILLATE CUTS
ATHABASCA BITUMEN

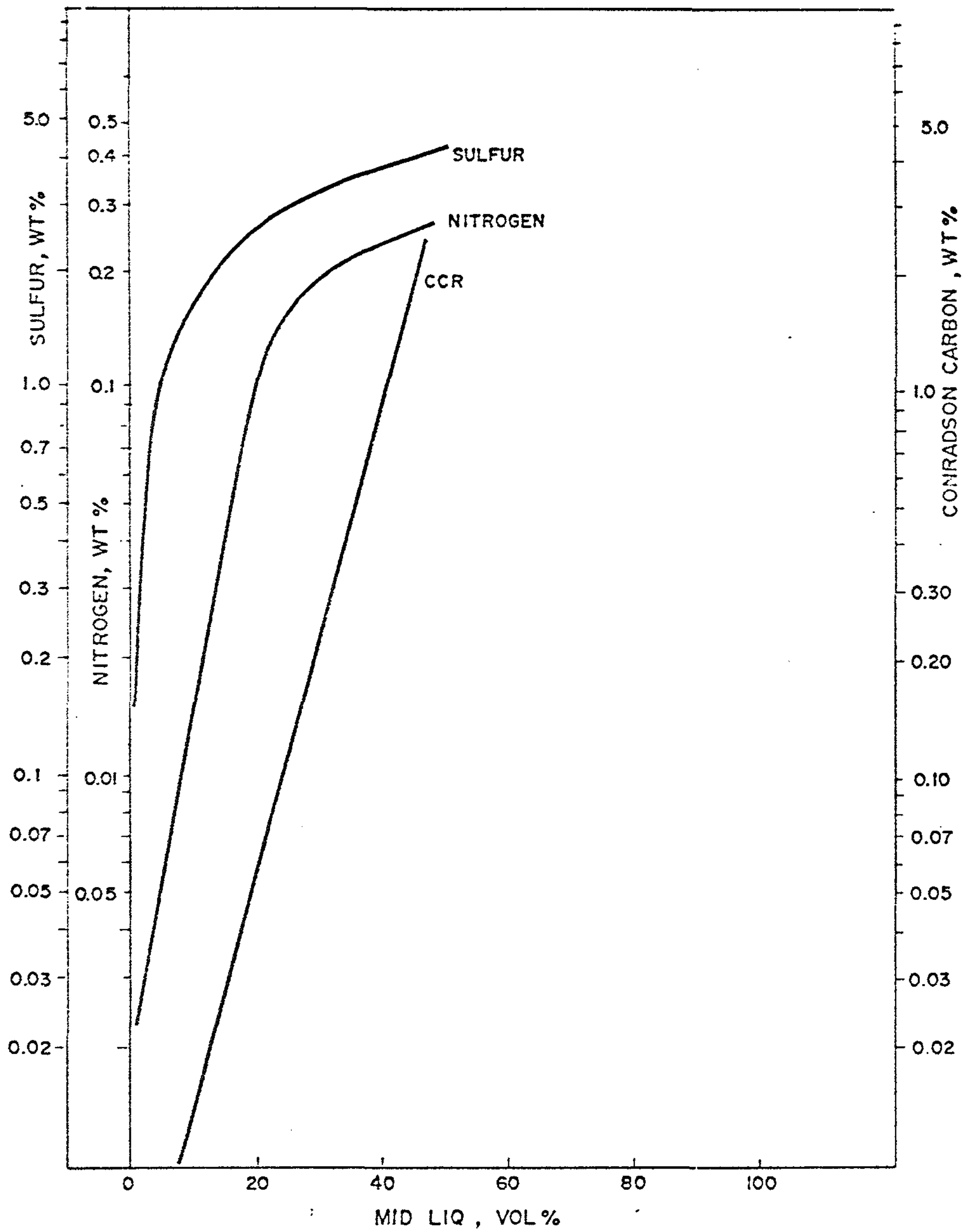

FIGURE 3

SULFUR, NITROGEN and CONRADSON CARBON CONTENTS
ATHABASCA VIRGIN DISTILLATES

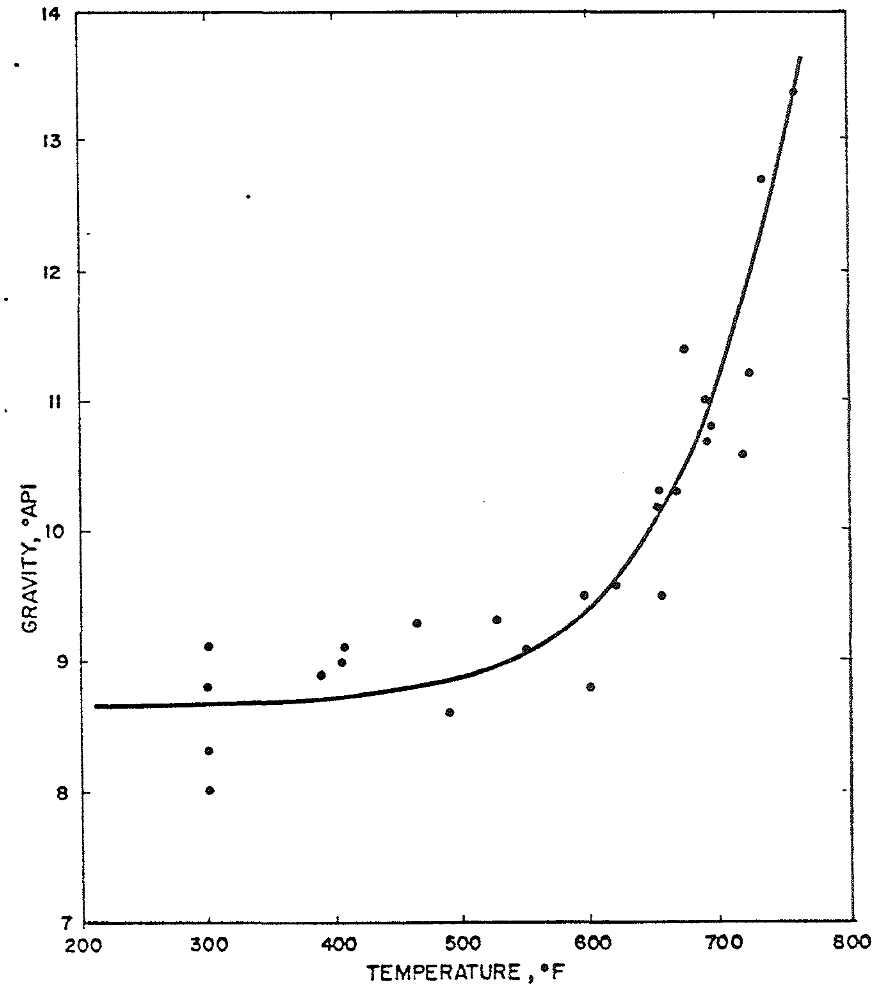

FIGURE 4 a

BATCH THERMAL SOAKING
(100 min @ 75 PSIG)

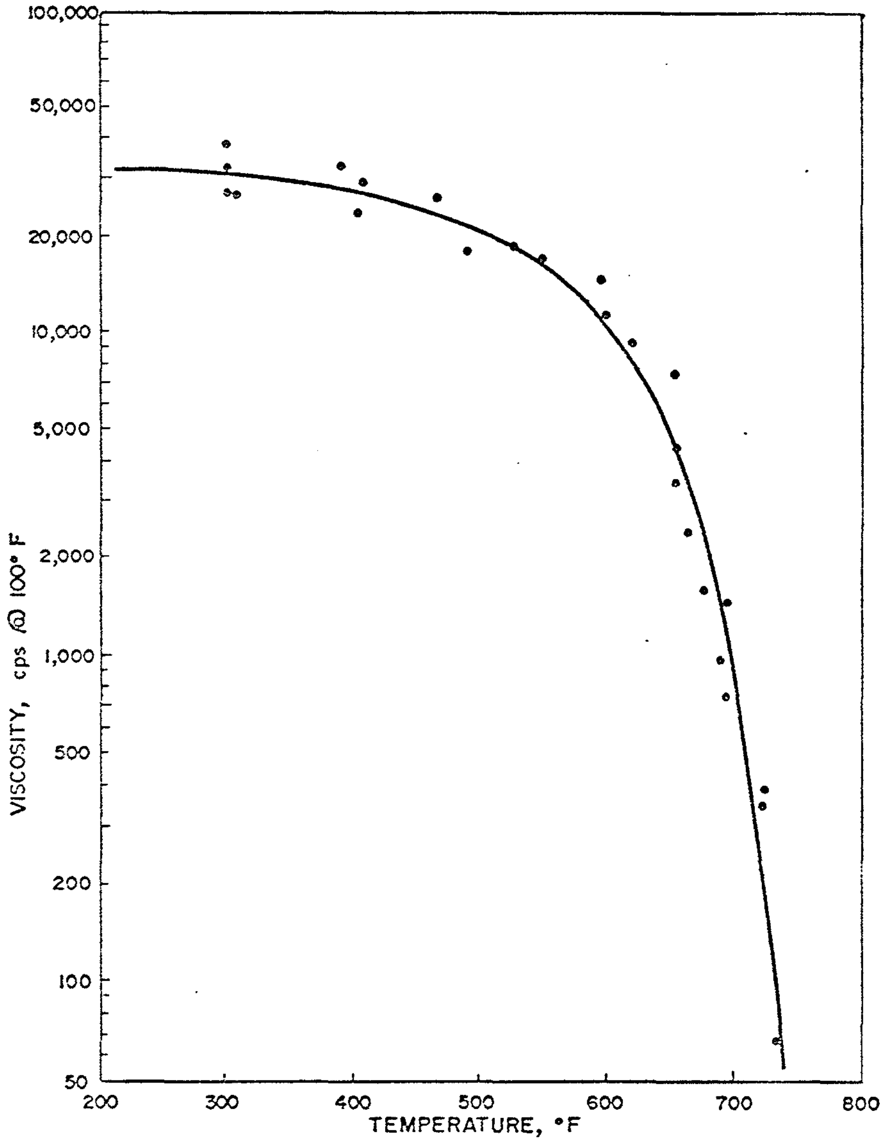

FIGURE 4b

BATCH THERMAL SOAKING
(100 min @ 75 PSIG)

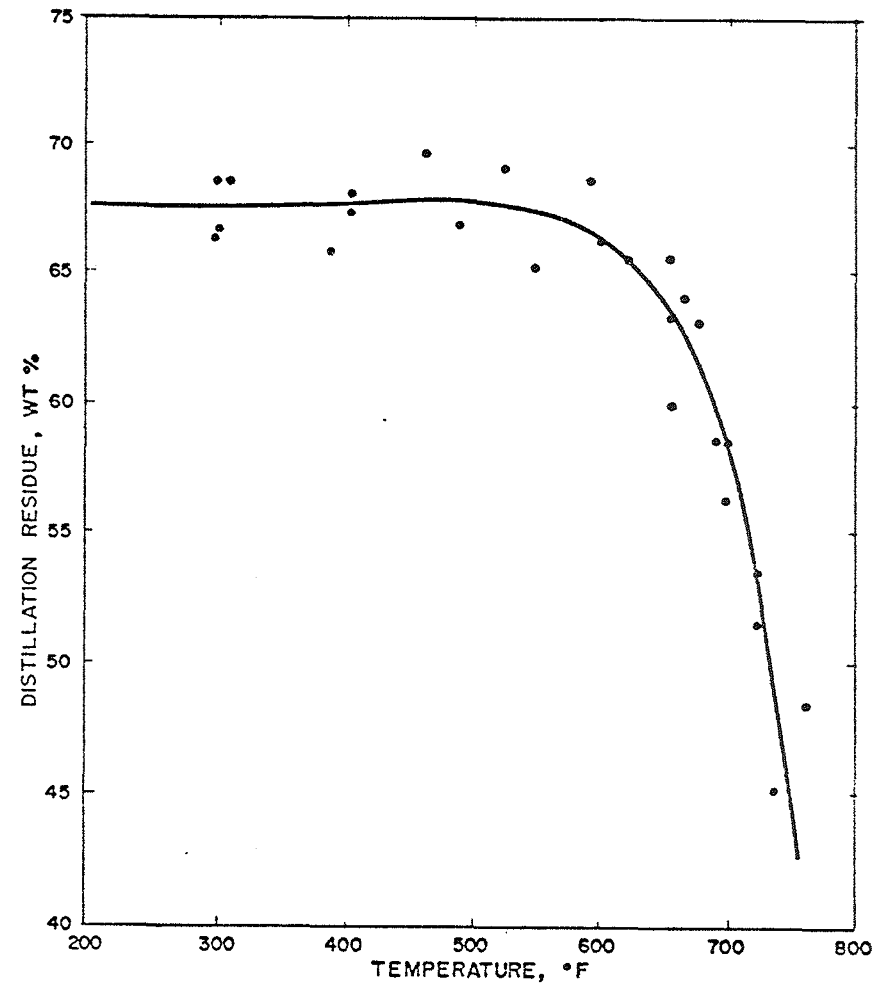

FIGURE 4c

BATCH THERMAL SOAKING
(100 min @ 75 PSIG)

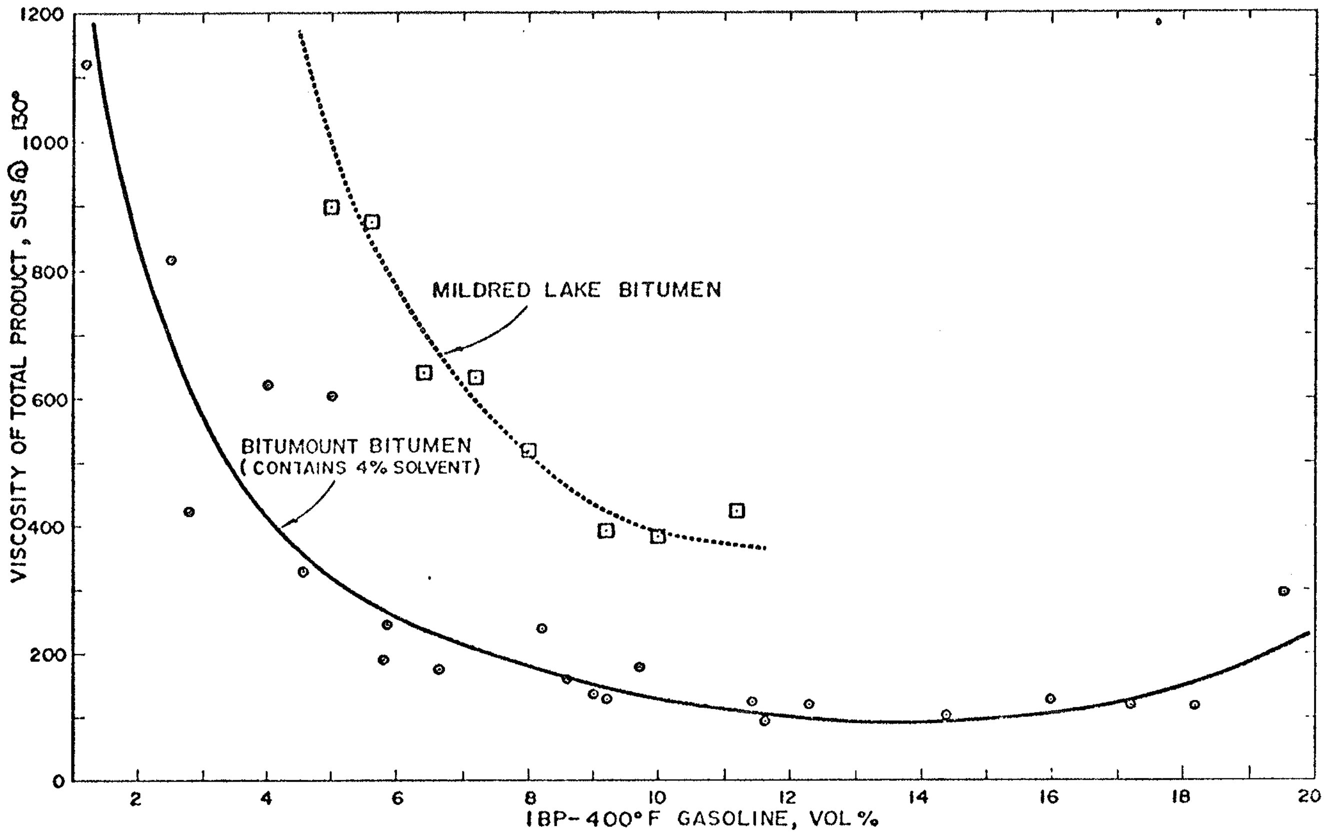

FIGURE 5a

VISCOSITY OF VISBROKEN PRODUCT VERSUS GASOLINE PRODUCTION

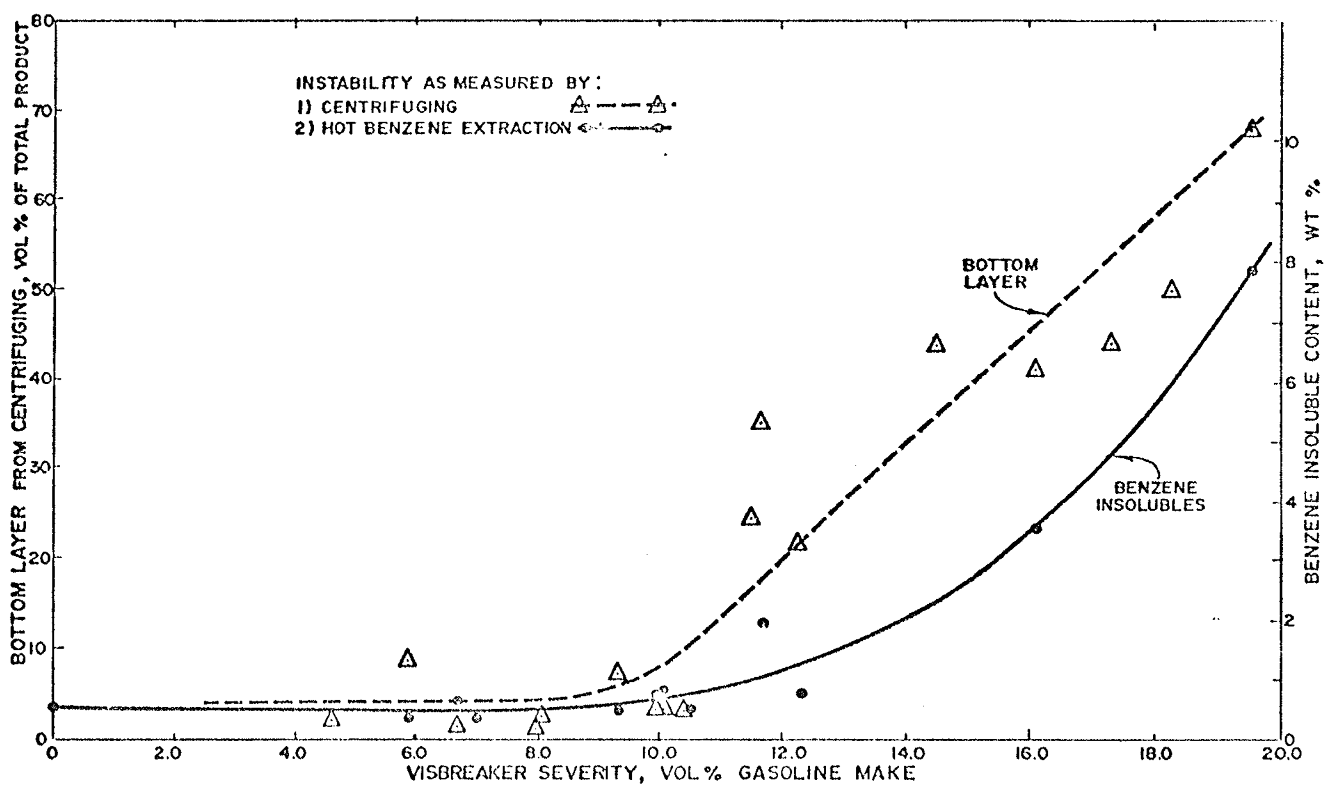

FIGURE 5b

INCOMPATIBILITY of VISBROKEN BITUMOUNT BITUMEN VERSUS VISBREAKER SEVERITY

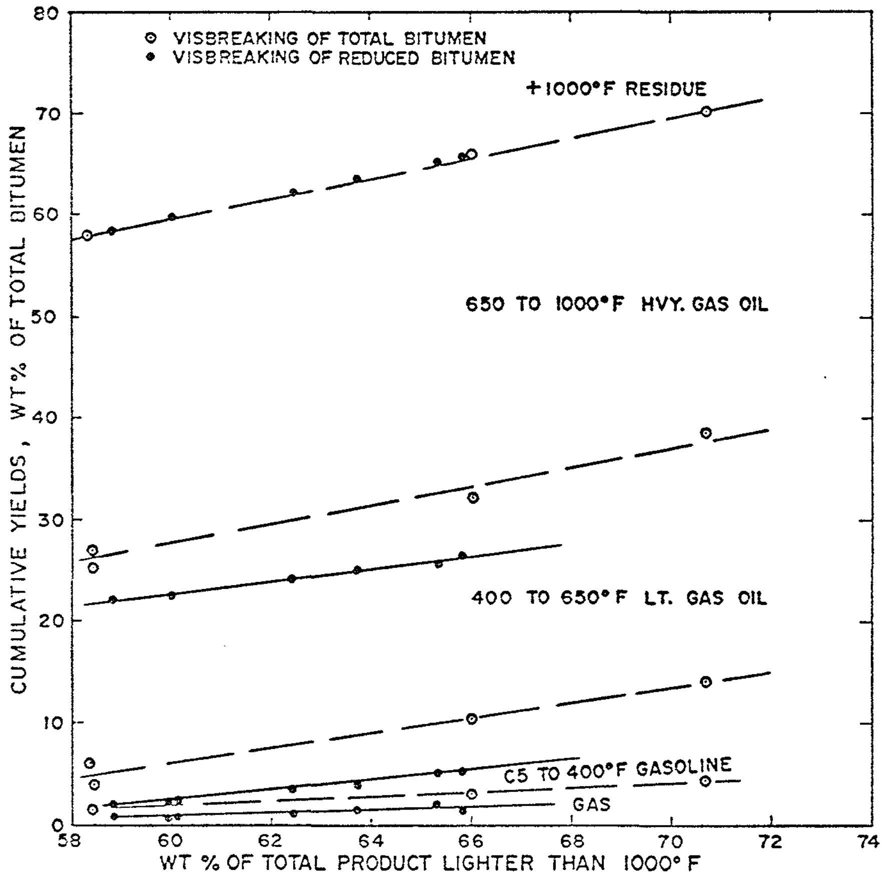

FIGURE 6

YIELDS FROM VISBREAKING TOTAL BITUMEN AND COMBINED YIELDS AFTER VISBREAKING VACUUM REDUCED BITUMEN

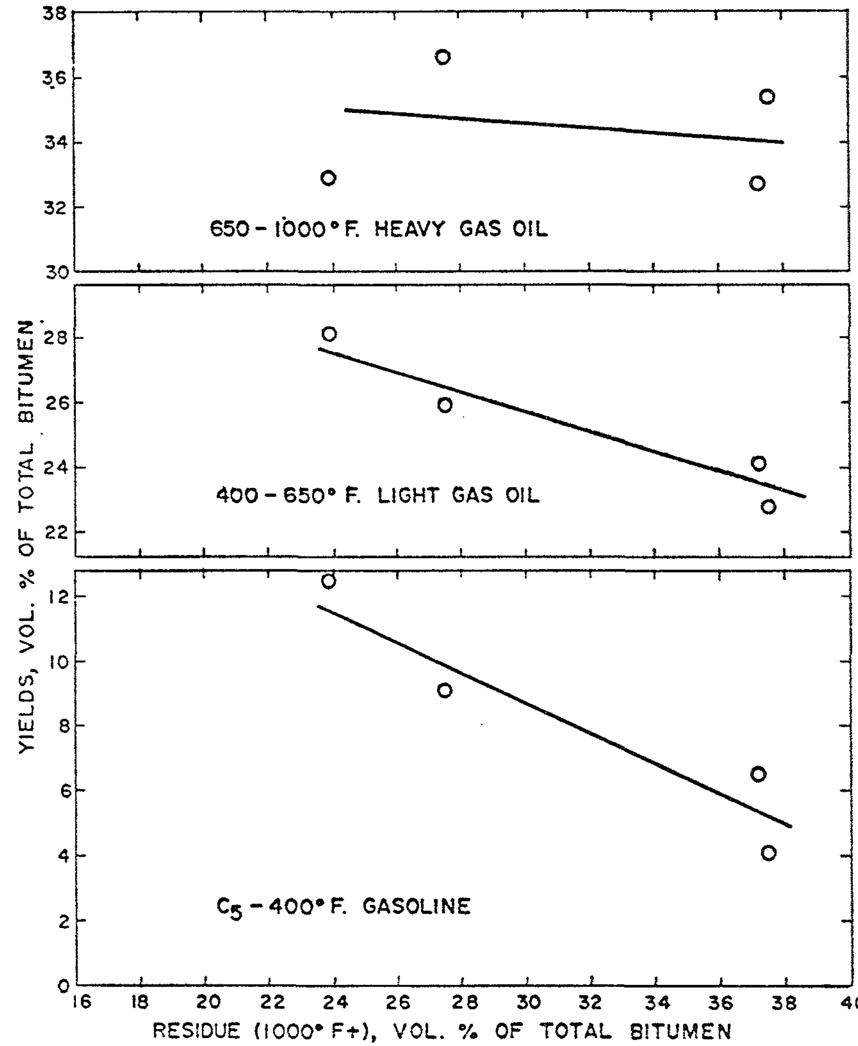

FIGURE 7

VOLUMETRIC YIELDS OF LIQUID PRODUCTS FROM VISBREAKING OF TOTAL BITUMEN

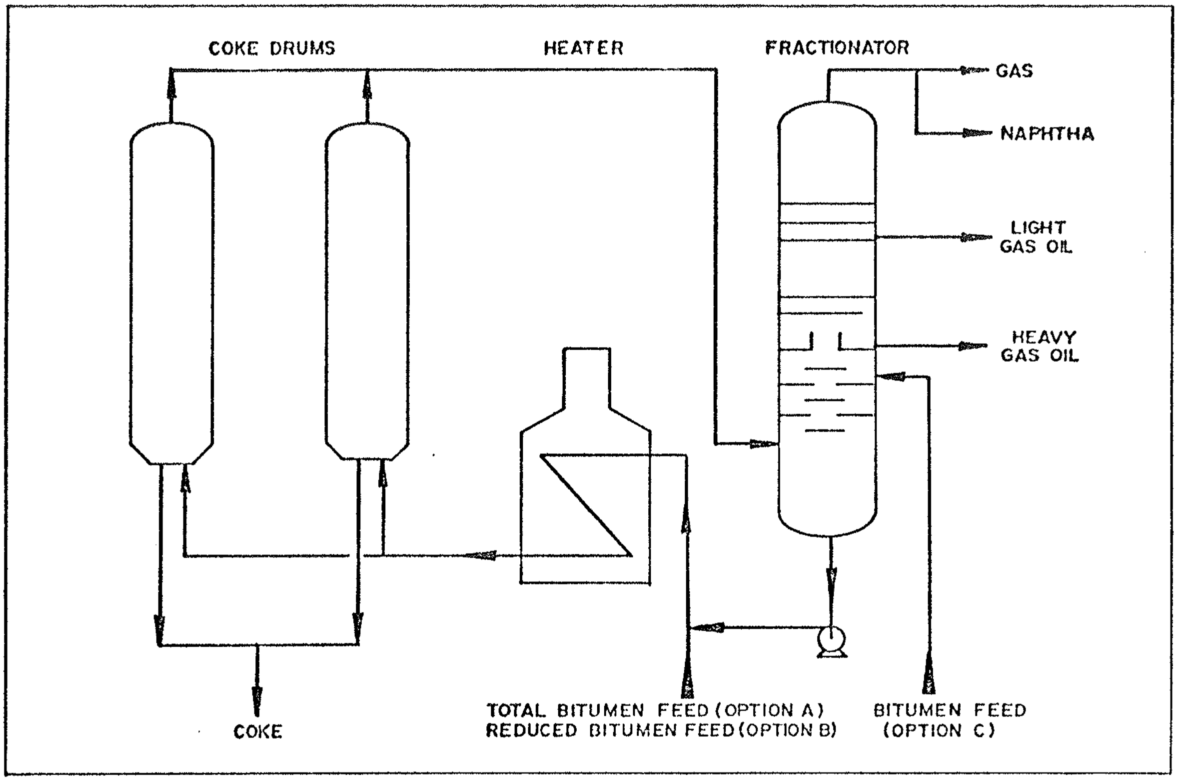

FIGURE 8
BASIC DELAYED COKING PROCESS

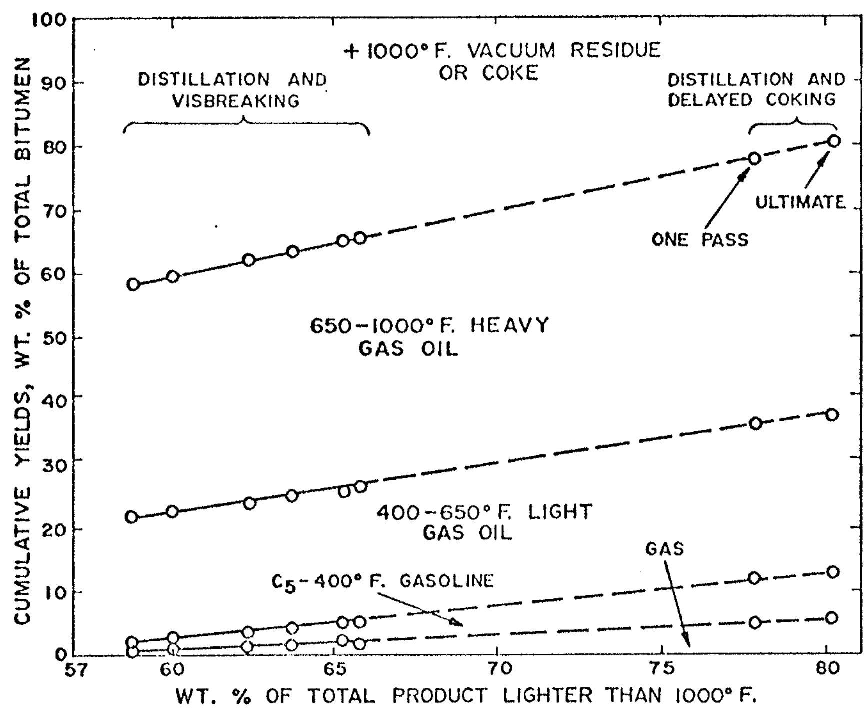

FIGURE 9

COMPARISON of DELAYED COKING
AND THERMAL VISBREAKING YIELDS:
COMBINED PRODUCT DISTRIBUTION FROM VACUUM
REDUCTION OF TOTAL BITUMEN FOLLOWED BY
CONVERSION OF REDUCED BITUMEN

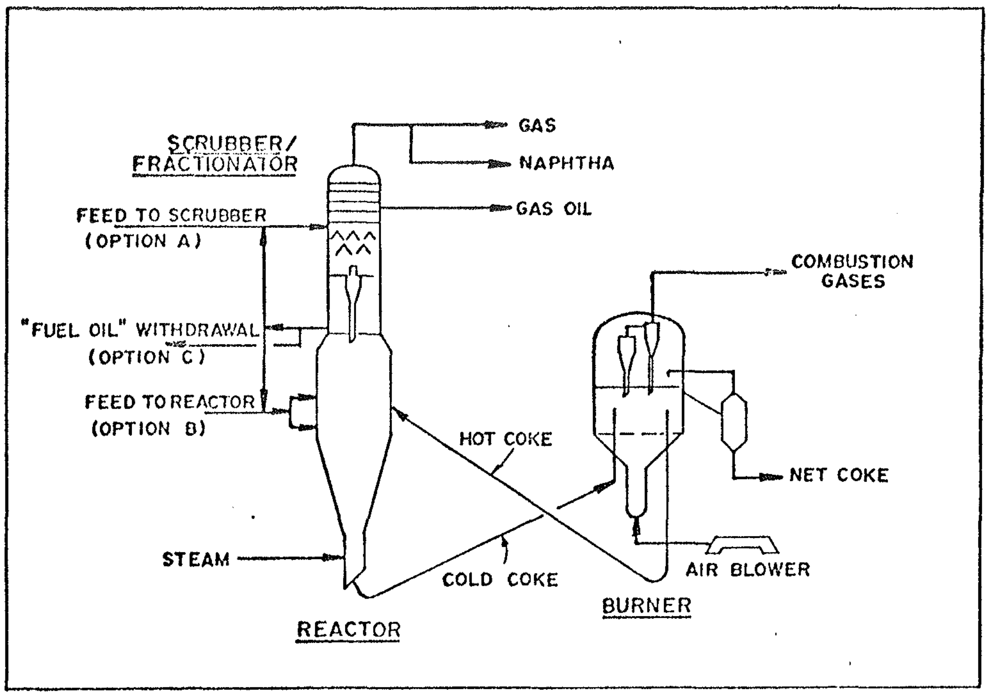

FIGURE 10

BASIC FLUID COKING PROCESS

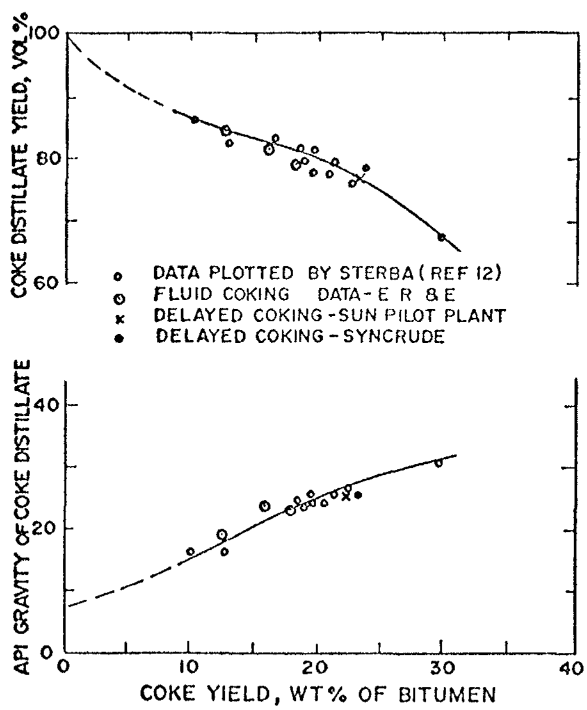

FIGURE 11

YIELDS AND GRAVITIES OF VARIOUS
COKER DISTILLATES PRODUCED FROM BITUMEN

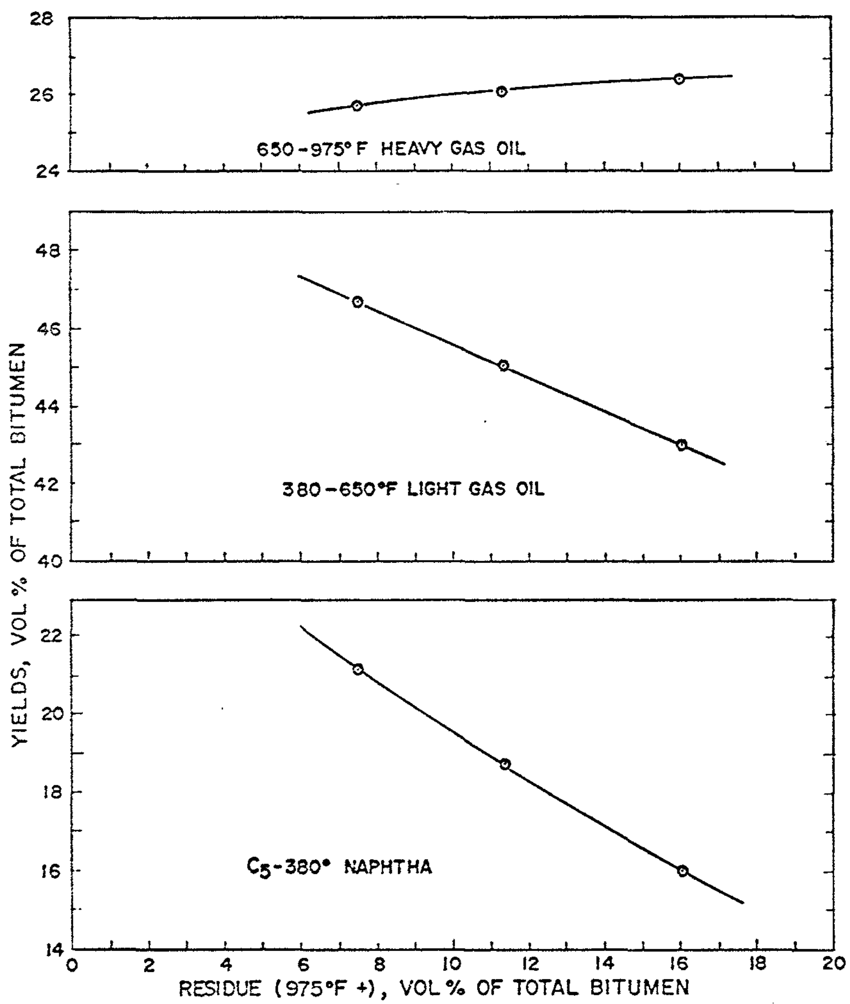

FIGURE 12

VOLUMETRIC YIELDS OF LIQUID PRODUCTS FROM H-OIL HYDROVISBREAKING OF BITUMEN

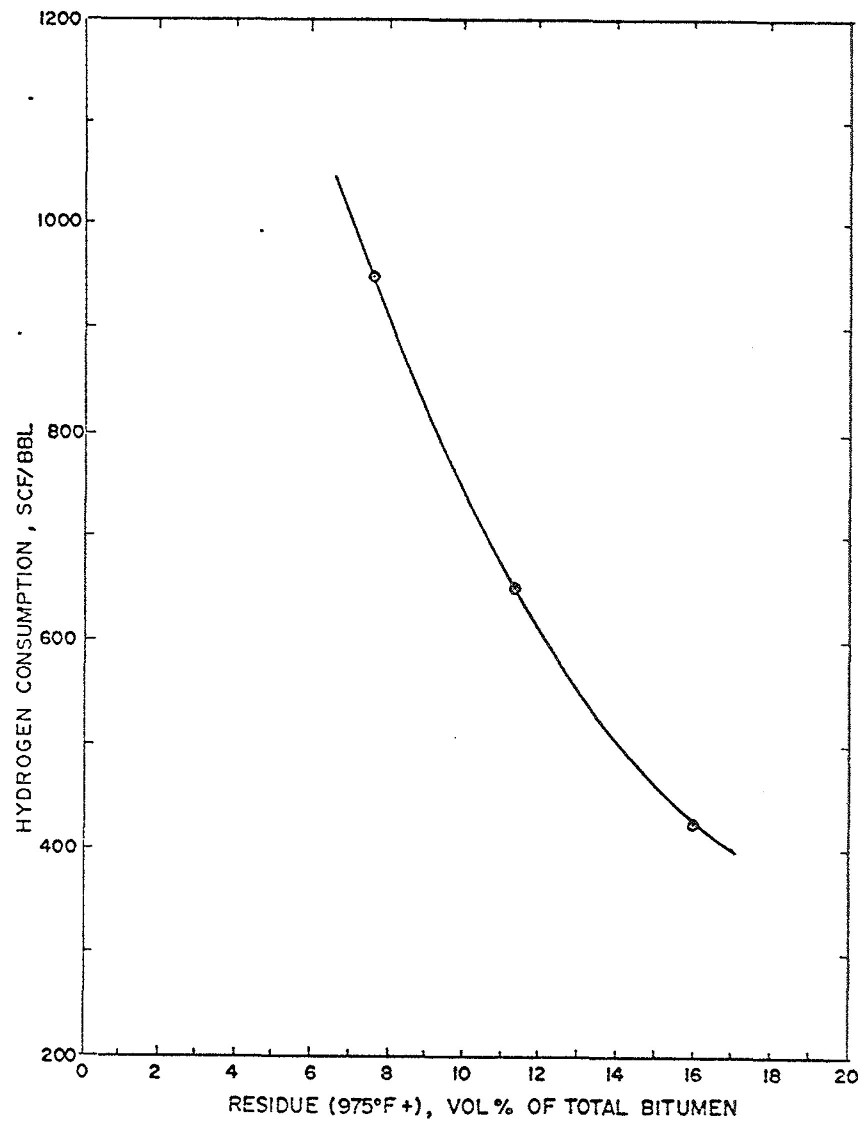

FIGURE 13

HYDROGEN CONSUMPTION Vs. CONVERSION H-OIL HYDROVISBREAKING OF BITUMEN

8. SEPTEMBER 19, 1972 PAPER ON ATHABASCA BITUMEN - HIGH CONVERSION TO SYNTHETIC CRUDE (PRESENTED TO 22ND CANADIAN CHEMICAL ENGINEERING CONFERENCE)

With the decline in reserves of conventional crude oil and the search for new large reserves being limited to more remote high cost areas, interest in producing synthetic crudes from coal, oil shale and tar sands is increasing. Syncrude Canada Ltd. has been granted a permit to construct a tar sands plant near Fort McMurray, Alberta, with a capacity of 125,000 BPCD of synthetic crude. The planned complex includes an open pit mine, a hot water oil extraction plant, dehydration-demineralization, and bitumen upgrading facilities. (Slide 1). Other plants are sure to follow.

Athabasca bitumen is a heavy, viscous, high sulphur oil containing approximately 50% of material boiling above 1000°F. Depending on the method of recovery it can contain up to 3½% of mineral fines. Slide 2 shows a typical bitumen assay.

In order to make the bitumen into a product which is transportable by pipeline and marketable it must be upgraded to a lighter mineral-free synthetic crude with reduced sulphur and nitrogen content. Proposed methods for accomplishing this have generally consisted of a primary conversion (cracking) step, followed by hydrotreating (olefin saturation and sulphur, nitrogen reduction) of the distillates produced (Slide 3). One of the main objectives in bitumen upgrading is to obtain high yields of high quality synthetic crude from the recovered bitumen.

Over the years four primary upgrading processes have been proposed. These are thermal visbreaking, delayed coking, fluid coking and H-Oil hydro-visbreaking A comparison of these four processes was well documented by Gray[1] in a paper presented to the A.I.Ch.E. earlier this year.

Thermal visbreaking produces a large quantity (approximately 30 wt.%) of pitch with high sulphur, ash and pour point and having some stability problems. Assuming the pitch were to be used as fuel for the complex it would be in excess of requirements. The process is therefore of little interest to a mining type operation. In a steam stimulated in-situ operation where the fuel demand could consume all of the pitch sulphur emission problems would undoubtedly be encountered.

Delayed coking is the only process presently used commercially on Athabasca bitumen. It produces 21-23 wt.% coke on feed and 6-8 wt.% C_4 and lighter. Distillate end point is low which reduces potential problems in downstream hydrotreating. The coke produced is more than can be used in providing steam and electrical energy for a surface mining operation. Batch operation of the drums and hydraulic coke cutting are less than ideal for severe climate operation. However, due to the commercial lead it is doubtful if other processes would get much consideration if it were not for the fact that considerable excess coke is produced with delayed coking and that yield patterns can be substantially improved with other processes. This paper will attempt to take a closer look at fluid coking and H-Oil hydrovisbreaking. Fluid coking like delayed coking is a carbon removal process, hydrovisbreaking is a hydrogen addition process.

FLUID COKING

Fluid coking, a proprietary process of Esso Research and Engineering Company, uses the techniques of fluid cat-cracking in a non-catalytic system on residual oil. The process has been well described by Busch[2] .

Slide 4 shows a schematic flow for a fluid coker. Feed is atomized through a multiplicity of nozzles into a fluidized bed of coke particles (generally less than 200 microns) at 900-1000°F. When laid down on the coke particle the lighter oil constituents are vaporized and the heavier constituents cracked to form gas, distillate or coke. High pressure attrition steam is injected below the feed zone to control coke particle size. Stripping steam is used in the bottom of the reactor to displace hydrocarbon vapor and insure that the coke flowing to the burner is low in volatiles. The steam and hydrocarbon vapors keep the reactor bed fluidized. When the vapor reaches the dilute phase it is further heated (by the hot coke return) and passes into the scrubber through a cyclone(s) which removes most of the coke fines. The remainder of the coke fines are washed from the vapor as it passes up through the scrubber. Heat is removed from the scrubber pump-around by some form of heat exchange (feed preheat or steam generation). Vapor boiling above the desired cut point is condensed. Scrubber bottoms are normally returned to the reactor feed with the contained coke fines. A fuel oil stream consisting of some or all of the recycle material can be drawn from the scrubber pump-around.

In some cases a reduced crude rather than vacuum pitch is fed to the coker reactor after first being topped in the scrubber. This is known as a "combo" coker. These alternatives are shown in Slide 5.

Coke inventory in the reactor is maintained by transferring coke from the reactor into the burner. Reactor temperature is maintained by transferring coke (at 1100 - 1200°F) from the burner back into the reactor. The system is pressure balanced at 10-30 psig. Coke is transferred with steam injection at the bends. Burner air is supplied from a blower. Coke inventory is maintained in the burner by coke removal through an elutriator which maintains product (net) coke particle size by returning fines to the burner.

A tar sands operator has a number of options with fluid coking. He can inject the whole bitumen into the reactor or he can top the bitumen before coking, either in the scrubber in a combo operation or in a vacuum tower. Comparative yields for coking of whole bitumen and coking of vacuum reduced 975^{o}F+ bitumen are shown in Slide 6. It should be noted that yields could be further improved by going to a higher vacuum cut point on the reactor feed. The coke make is determined by the Conradson Carbon Residue (CCR) in the feed and the severity (temperature, time) of the operation. If a fixed operating temperature is chosen, gross coke make can be reduced by by-passing high CCR distillate around the coker by high end point prefractionation and/or by decreasing the vapor residence time by extra steam (or possible water) injection. A third case with prefractionation and steam injection is shown in Slide 7. This case has the highest liquid volume yields. Note that the fluid coker also produces a great deal of gas. The process consumes approximately 6 wt.% of the feed (as coke) in the burner. However, a substantial portion of this heat is recovered in the form of steam surplus to coker requirements even when blower horsepower requirements are taken into account. Steam is generated in scrubber pump-around cooling, fractionator pump-around and in the CO boiler.

H-OIL HYDROVISBREAKING

H-Oil hydrovisbreaking is a process licensed by Cities Service Research and Development and by Hydrocarbon Research Inc. and has been described by Rapp and Van Driesen[(3)]. Because of the easy cracking characteristics of Athabasca bitumen (1) the H-Oil hydrovisbreaker can operate under milder conditions than required for normal resids. Its potential for high liquid yields makes it of great interest to any tar sands operator. A simplified flow plan is shown on Slide 8. Oil is contacted in a reactor with hydrogen under proper conditions of temperature and pressure, the reactor effluent is taken to a separator where reactor liquid and vapor are disengaged. The remainder of the flow plan consists in flashing down of the reactor liquid and purification of the recycle hydrogen. A typical yield pattern for hydrovisbreaking at 75% conversion* is shown in Slide 9. Yields and qualities are somewhat better than for fluid coking. Since the economics of a synthetic crude plant using only hydrovisbreaking are dependent on very high conversion of the 975°F+ material and high cut points in the vacuum tower, there may be some incentive in combining hydrovisbreaking with other processes to further treat the residual material for the first commercial application.

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* Conversion = vol.% disappearance of 975°F+ material

HYDROVISBREAKING - COKING

These considerations, as well as the gas long position of fluid coking, make a combination of hydrovisbreaking and fluid coking worth considering. In such a case bitumen is first hydrovisbroken and the residual then fluid coked perhaps after blending with some virgin bitumen (Slide 10). The hydrovisbreaker is now used more for CCR reduction than for disappearance of high boiling liquid and the optimum choice of operating conditions may be different. Hydrogen in the residual is no longer "wasted" if it results in greater liquid yields from the coker. Slide 11 shows yields where the bitumen is first hydrovisbroken at 60% conversion and the pitch is then fluid coked. Note that the C_5 - 975°F liquid yield is higher than for straight hydrovisbreaking at 75% conversion. Because of the high CCR of the feed, severity for this case is high. It is in this situation that additional steam injection is of greatest benefit. A yield pattern for this case with additional steam is shown in Slide 12.

HIGHER YIELDS

This is the highest liquid yield of any case yet examined, but it is by no means the ultimate. Increasing the hydrovisbreaker conversion above 60% in the system could reduce overall coke make substantially. It might even be desirable to recycle the scrubber bottoms from the coker to the hydrovisbreaker to get some coke precursor saturation again reducing coke make. These ideas are of course speculative and any yield benefits would require pilot demonstration. Integration of fractionation would have some thermal advantages - the coker product is in vapor form, the hydrovisbreaker product in liquid form.

Conceivably economics might favor production of alkylate from the olefin gases and isobutane produced in the primary processes and hydrotreating, resulting in even greater liquid production.

The optimum combination of these elements - vacuum unit, H-Oil hydrovisbreaker and fluid coker for primary conversion depends on natural gas costs, syncrude value and the desired syncrude quality from hydrotreating as well as the capital cost of the elements themselves. There is freedom of choice in the design stage in how the three elements should be combined and there would be considerable operating flexibility in any such system after installation.

As mentioned previously, the distillates produced from these primary processes must be hydrotreated to produce a good quality synthetic crude. This is generally conventional hydrotreating except that sulphur and nitrogen levels are high and the required units would probably be fairly large. Hydrogen requirements could run from 500 - 2000 SCF/Bbl. on the various streams depending on the quality desired.

Any system which produces high yields of good quality liquid products from such low grade material as Athabasca bitumen will have high hydrogen requirements and consequently the overall tar sands plants could require substantial quantities of natural gas. This should not be of too great concern since tar sands plants are large net producers of clean energy.

In the long term the use of FLEXICOKING (see Matula, Weinberg and Weissman[4] to convert the coke to a gaseous fuel would substantially reduce natural gas requirements for a tar sands plant (Slide 13). With FLEXICOKING a third vessel, the gasifier is added to the fluid coker. Low BTU gas is produced in the gasifier from steam - air (or oxygen) addition to the coke at approximately 1800^{o}F. Heat is transferred through the heater into the reactor.

The goal of greater utilization of the recovered bitumen consistent with ecological considerations will push technological development into higher liquid yields and perhaps generation of fuel gas or hydrogen from the residual material.

The processes discussed here involve hydrogen addition and carbon removal. There may be other combinations of other processes to achieve similar objectives. The demands on processing will become more severe as recoveries approach 100%. Substantial development effort will be required to reduce the technical risks and/or economic barriers inherent in high yield operations. The system discussed here is only a first step in that direction using current technology.

REFERENCES

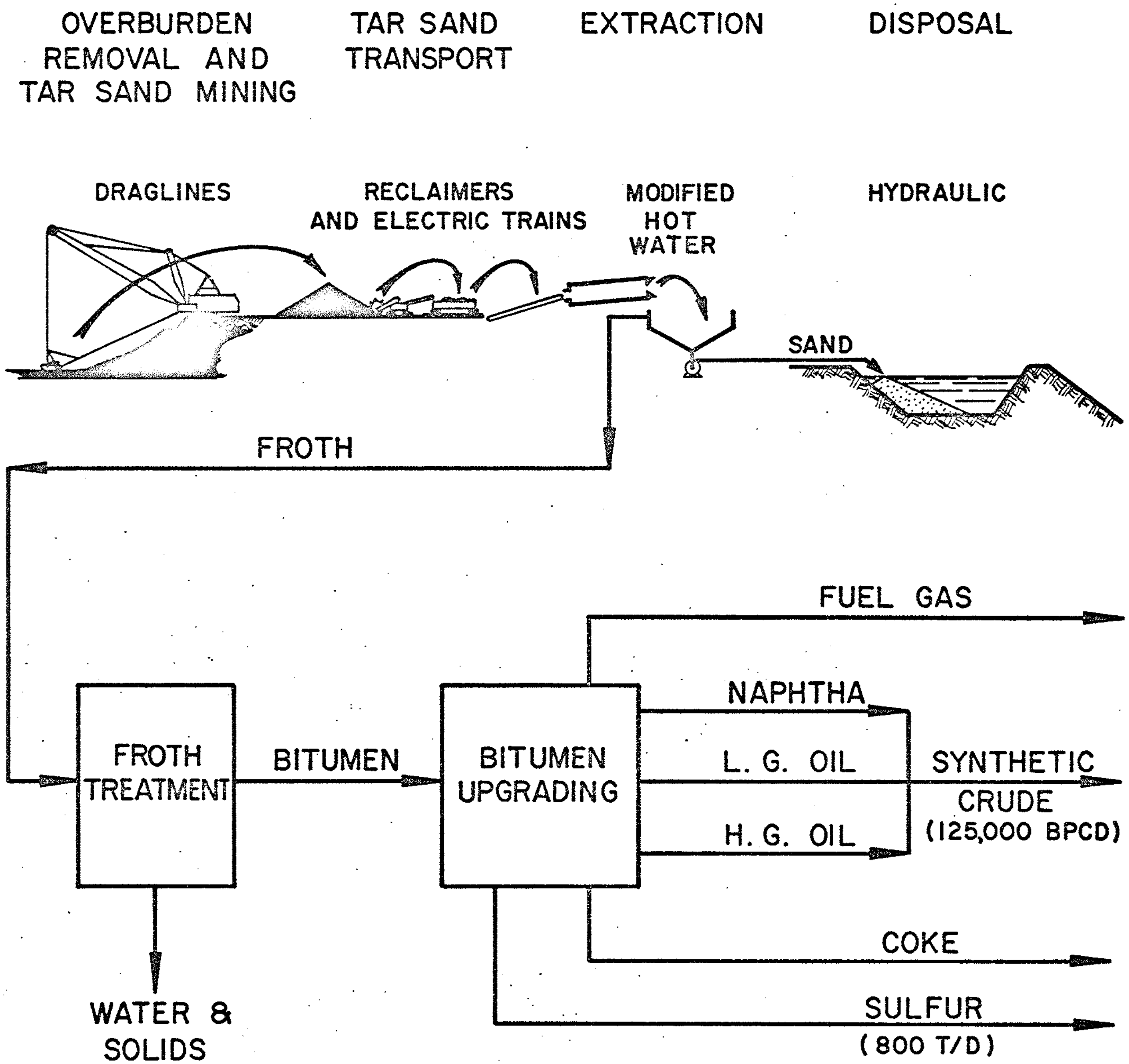
1. Gray, G.R., "Conversion of Athabasca Bitumen", 71st National Meeting of the American Institute of Chemical Engineers, February 20-23, 1972.

2. Busch, Robert G., "Fluid Coking: Seasoned Process Takes On New Jobs". The Oil and Gas Journal, pp. 102-111, April 6, 1970.

3. Rapp and Van Driesen, "H-Oil Process Gives Product Flexibility". Hydrocarbon Processing, pp. 103-108, December 1965, Vol. 44, No. 12.

4. Matula, Weinberg and Weissman, "Flexicoking - An Advanced Fluid Coking Process", 37th Midyear Meeting of the American Petroleum Institute's Division of Refining, May 11, 1972.

TAR SANDS EXTRACTION PLANT



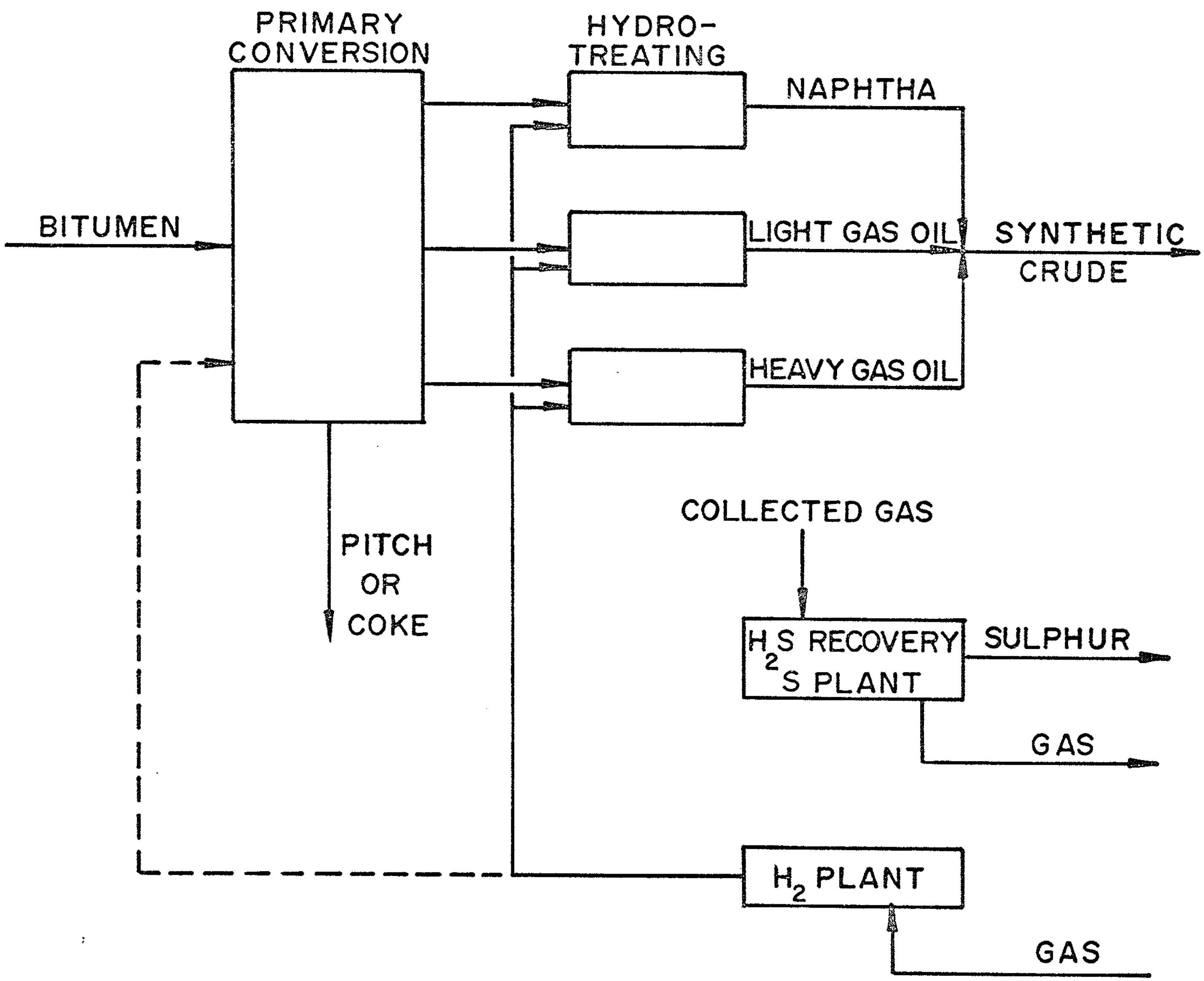
SLIDE 2

BITUMEN ASSAY - SOLIDS FREE

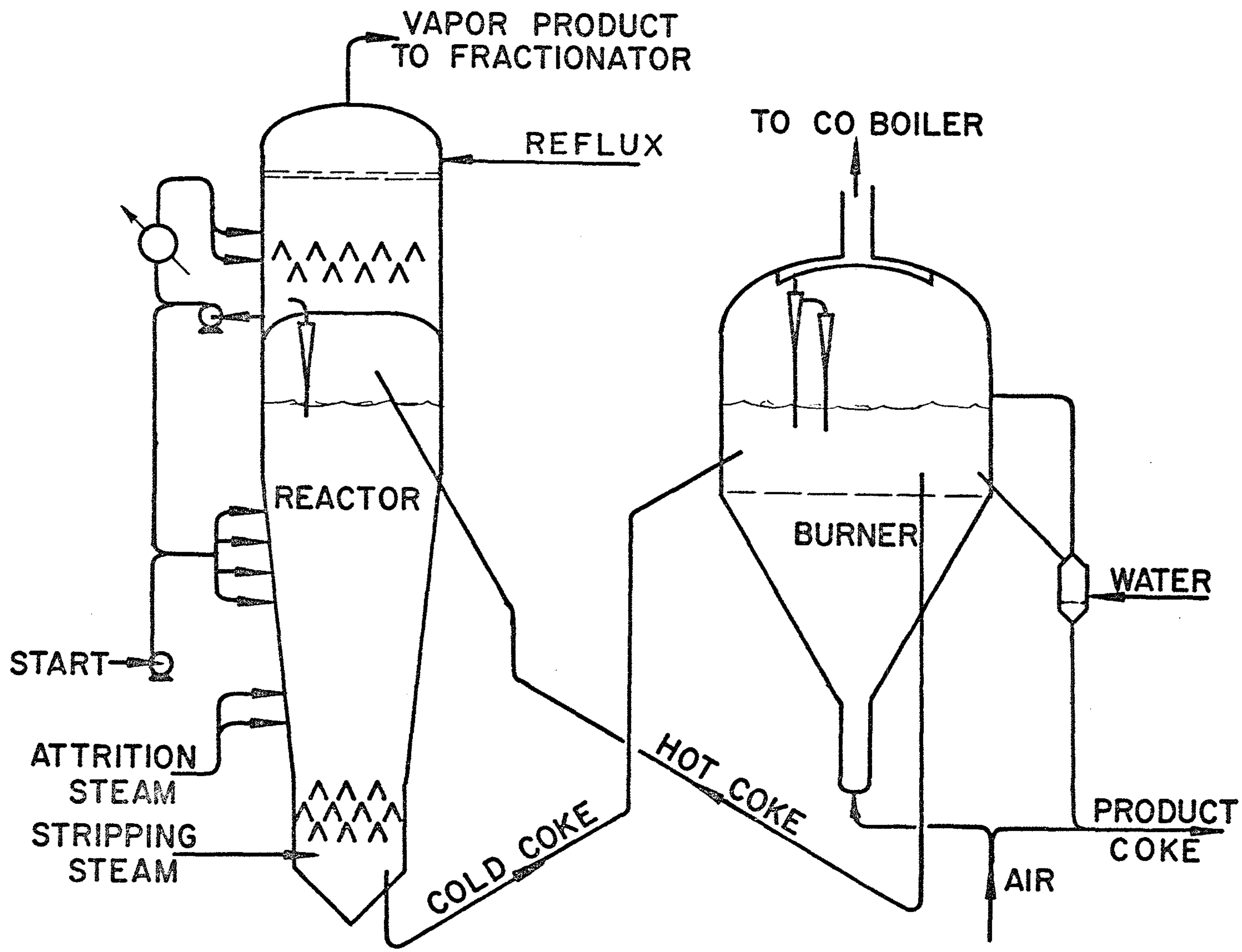
	Crude	i/380°F	380/650°F	650/975°F	975°F+
°API	8.3	36.2	24.6	14.1	0.8
LV%	100	0.2	14.5	33.9	51.4
%S	4.9	0.70	1.90	3.65	6.4
%N	0.45	0.01	0.012	0.16	0.73
CCR	13.6				

SLIDE 3

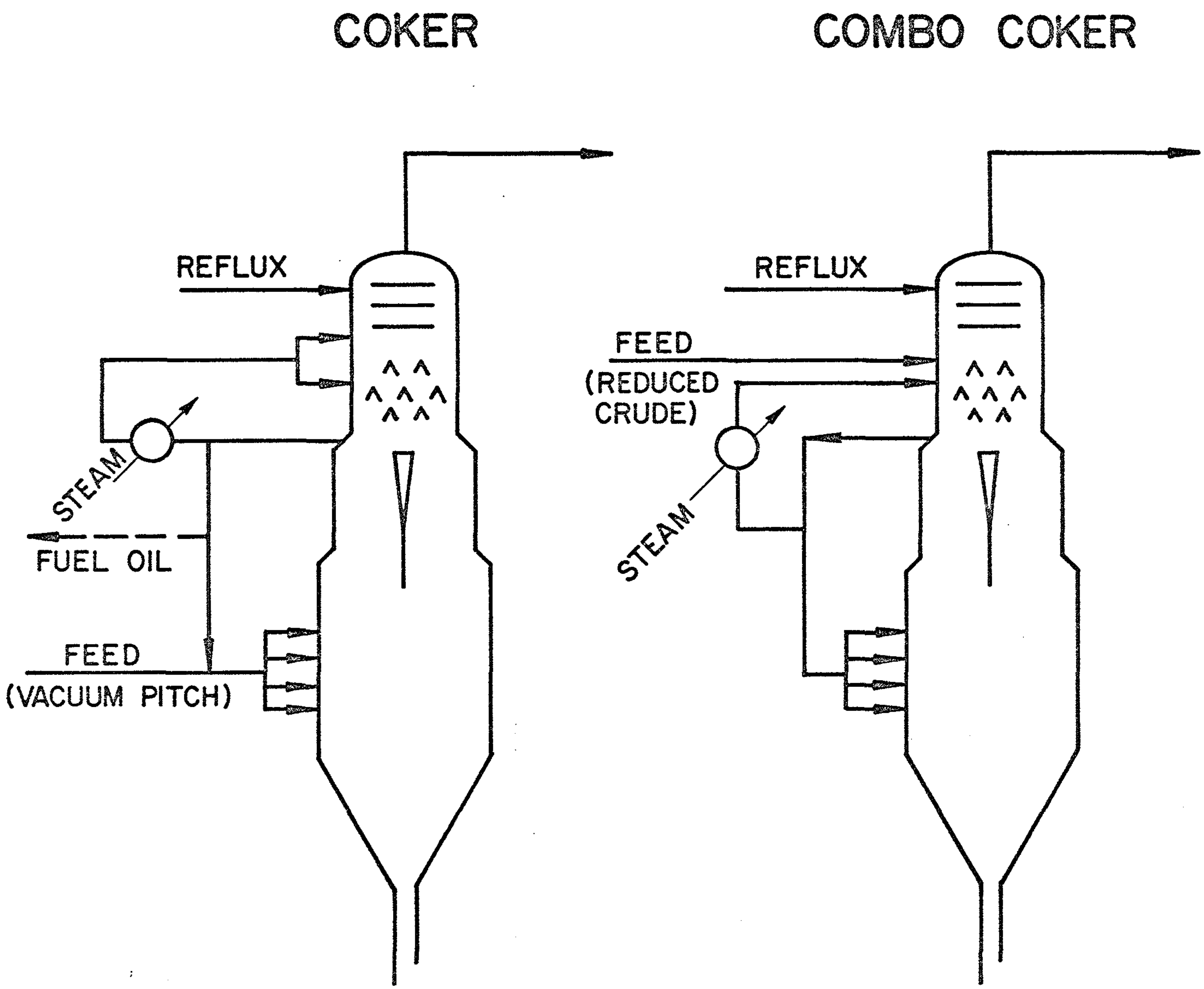
BITUMEN UPGRADING



FLUID COKER



VAPOR PRODUCT
TO FRACTIONATOR
REFLUX
TO CO BOILER
REACTOR
BURNER
WATER
START
ATTRITION
STEAM
STRIPPING
STEAM
HOT COKE
COLD COKE
PRODUCT
COKE
AIR


COKER
REFLUX
STEAM
FUEL OIL
FEED
(VACUUM PITCH)
COMBO COKER
REFLUX
FEED
(REDUCED
CRUDE)
STEAM

SLIDE 6

FLUID COKING YIELDS ON BITUMEN

Whole Bitumen to Reactor vs. 975°F+ to Reactor*

	Wt.%	Vol. %		% S	N ppm	Br. No.	°API
Whole Bitumen to Reactor							
H_2S	1.3						
C_3 Minus	6.8						
C_4	1.9						
C_5/380	11.8	16.0		2.0	80	115	58.0
380/650	24.2	26.9	82.1	3.2	500	45	24.2
650/975	38.2	39.2		4.4	2500	22	12.1
Gross Coke	15.8						
Net Coke	9.8						
975°F+ to Reactor*							
H_2S	1.0						
C_3 Minus	5.3						
C_4	1.1						
C_5/380	7.1	9.6		2.8	130	107	57.5
380/650	20.0	22.4	82.7	2.9	390	22	25.0
650/975	49.2	50.7		4.5	2580	19	12.6
Gross Coke	16.3						
Net Coke**	13.0						

* i/975°F virgin material included in yields.

** Net coke assumes 6% wt. on feed burned. This can vary somewhat depending upon feed temperature.

SLIDE 7

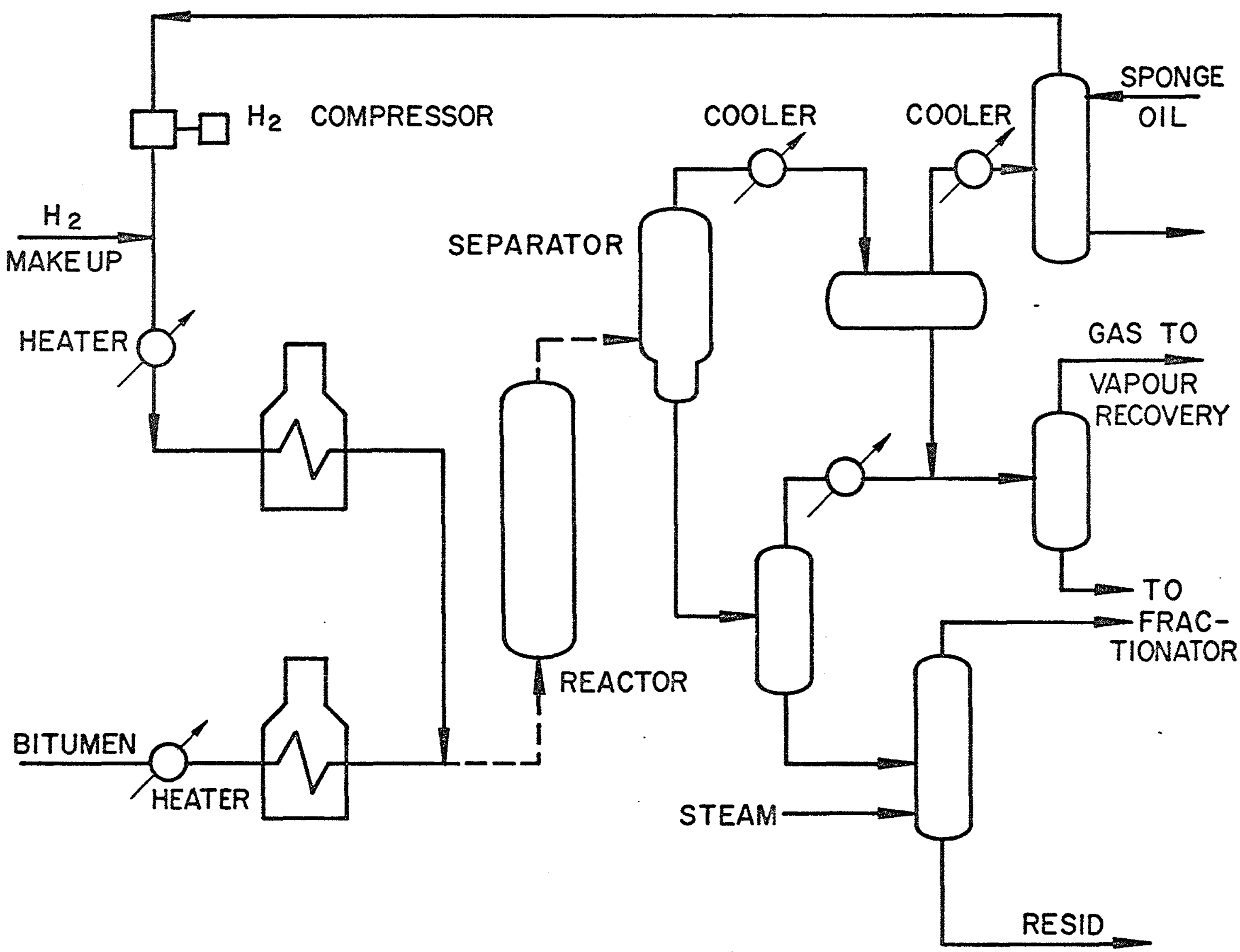
FLUID COKING YIELDS ON BITUMEN

WITH STEAM ADDITION

975°F+ to Reactor* (Severity reduced to that with whole bitumen to Reactor)	Wt. %	Vol.%		% S	N ppm	Br. No.	°API
H_2S	1.0						
C_3 Minus	5.0						
C_4's	1.0						
C_5/380	7.4	10.0	84.1	2.7	130	107	57.4
380/650	20.2	22.7		2.9	400	22	25.0
650/975	49.9	51.4		4.5	2600	19	12.6
Gross Coke	15.5						

* i/975°F virgin material included in yields.

H-OIL HYDROVISBREAKER



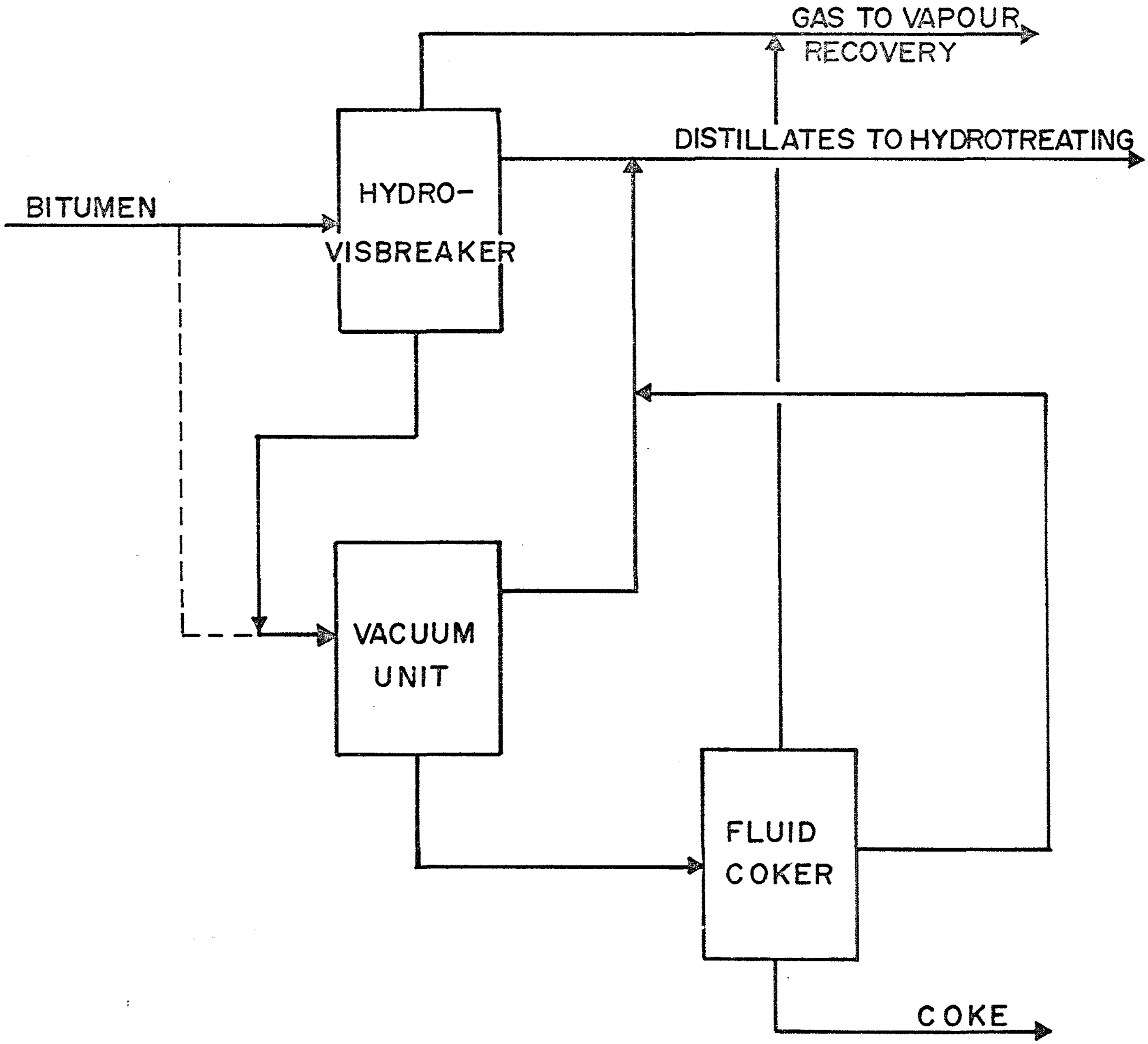
TYPICAL HYDROVISBREAKER YIELDS - 75% CONVERSION*

	Wt. %	Vol.%		% S	N ppm	Br. No.	^{o}API
H_2S	2.4						
NH_3	0.1						
C_3 Minus	3.5						
C_4	1.6						
C_5/380	13.7	17.9		1.0	274	65	51.0
380/650	38.8	44.3	88.3	2.0	800	25	27.9
650/975	25.6	26.1		3.5	3200	12	11.0
975^{o}F+	15.1	12.9		5.5			-12.4
	100.8	101.2					

H_2 Chem. Cons. 600 SCF/B

* Vol.% disappearance of 975^{o}F+

H-OIL - HYDROVISBREAKING - FLUID COKING



SLIDE 11

H-OIL HYDROVISBREAKING - FLUID COKING

	Wt. %	Vol.%		% S	N ppm	Br. No.	^{o}API
Hydrovisbreaking (60% Conversion)							
H_2S	1.63						
NH_3	.10						
C_3 Minus	2.12						
C_4's	.57						
C_5/380	8.40	11.2		1.4	300	70	55
380/650	28.14	31.8	81.0	2.4	700	33	26.5
650/975	36.64	38.0		3.4	3000	20	13.5
975^{o}F+	23.04	20.6		5.8			-6.5
	100.64						
Coking 975^{o}F+ H-Vis. Resid							
H_2S	1.8						
C_3-	7.9						
C_4's	1.4						
C_5/380	9.0	13.6		1.2	190	110	58.0
380/650	9.0	11.7	49.1	2.9	1600	58	28.0
650/975	21.5	23.8		4.3	7000	32	7.0
Gross Coke	49.4						
Combined Yields on Bitumen							
H_2S	2.0						
NH_3	0.1						
C_3-	3.9						
C_4's	0.9						
C_5/380	10.5	14.0		1.4	280	78	55.4
380/650	30.2	34.2	91.1	2.4	760	35	26.7
650/975	41.6	42.9		3.5	3480	21	12.7
Gross Coke	11.4						
	100.6						

SLIDE 12

H-OIL HYDROVISBREAKING - FLUID COKING

	Wt. %	Vol. %		% S	N ppm	Br. No.	^{o}API
Hydrovisbreaking (60% Conversion)							
H_2S	1.63						
NH_3	.10						
C_3 Minus	2.12						
C_4's	.57						
C_5/380	8.40	11.2	81.0	1.4	300	70	55
380/650	28.14	31.8		2.4	700	33	26.5
650/975	36.64	38.0		3.4	3000	20	13.5
975^{o}F+	23.04	20.6		5.8			-6.5
	100.64						
Coking 975^{o}F+ H-Vis. Resid (At reduced severity)							
H_2S	1.6						
C_3-	7.1						
C_4's	1.3						
C_5/380	10.3	15.6	56.2	1.2	190	110	58.0
380/650	10.3	13.4		2.9	1600	58	28.0
650/975	24.6	27.2		4.3	7000	32	7.0
Gross Coke	44.7						
Combined Yields on Bitumen							
H_2S	2.0						
NH_3	0.1						
C_3-	3.8						
C_4's	0.8						
C_5/380	10.8	14.4	92.6	1.4	280	79	55.6
380/650	30.5	34.6		2.4	770	35	26.7
650/975	42.3	43.6		3.5	3540	22	12.6
Gross Coke	10.3						
	100.6						

FLEXICOKING