ATHABASCA TAR SANDS STUDY
THE ENVIRONMENTAL IMPACT OF
IN SITU TECHNOLOGY

A report prepared for
Intercontinental Engineering of Alberta Ltd.

by
M. A. Carrigy, P. Geol.
and
I. J. McLaws, P. Geol.

Research Council of Alberta
January, 1973

FOREWORD

The Athabasca Oil Sands have been estimated to contain more than 600 billion barrels of heavy oil, and are generally considered to be the largest known reservoir of oil. They outcrop along the Athabasca River valley and its tributaries in northeastern Alberta between latitudes 56°30' and 58° north, and between the Saskatchewan-Alberta boundary and 112° west longitude. The extent of the oil-impregnated sand in the subsurface is incompletely delimited, but it appears to extend over an area of 20,700 square miles bounded by latitudes 55° and 58° north between the Fourth and Fifth Meridians (Fig. 1). It is thus 204 miles long and 120 miles wide.

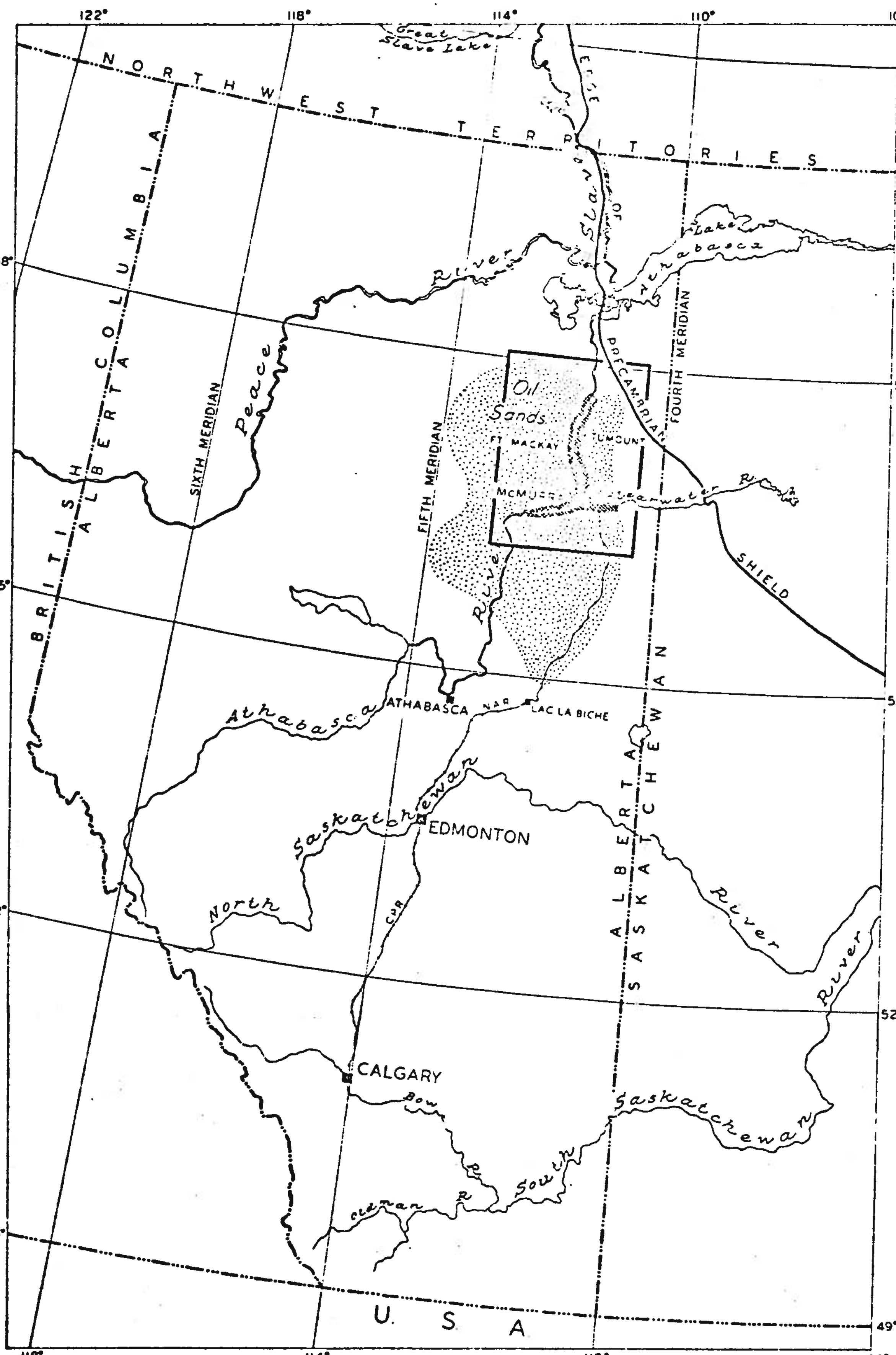

FIGURE 1

SUBSURFACE EXTENT-ATHABASCA OIL SANDS

OUTCROP

BITUMINOUS SANDS AREA (After Carrigy & Zamora)

25 0 25 50 75 100 125 150

SCALE IN MILES

RESEARCH COUNCIL OF ALBERTA

87TH AVENUE AND 114TH STREET
EDMONTON, ALBERTA, CANADA

EARTH SCIENCES BRANCH T6G 2C2 OUR REF: MAC/IJM/bb

January 15, 1973

Mr. Harold V. Page
Project Director
Athabasca Tar Sands Study
Intercontinental Engineering of Alberta Ltd.
11055 - 107 Street
EDMONTON, Alberta

Dear Mr. Page:

We have the pleasure to transmit herewith our report, "The Environmental Impact of *In situ* Technology," for the Athabasca Tar Sands Study as requested in your letter of August 15, 1972.

Yours sincerely,

M. A. Carrigy

M. A. Carrigy, P. Geol.

Jean McLaws

I. J. McLaws, P. Geol.
Geology Division
Research Council of Alberta

Telephone: (403) 424-0311 Telex: 037-2060 TWX: 610-831-2470 Cable: Abell Edmonton

Intercontinental Engineering of Alberta Ltd.

11055-107 Street Edmonton, Alberta, Canada

August 15, 1972.

Dr. M.A. Carrigy,
Research Council of Alberta,
11315 - 87 Avenue,
Edmonton, Alberta.

Dear Maurice:

Re; Athabasca Tar Sands Study
In-situ Technology

This will confirm our recent discussions in which we indicated a desire to have you provide consulting services on the environmental impacts of the in-situ recovery technology.

This will comprise part of Phase III of our Study and we have allocated $5,000. of our Study budget to the specific investigation of the in-situ method.

I believe you are already familiar with the terms of reference for our Study as a result of your participation to date. We sincerely appreciate the support and advice which you have provided throughout Phase II of our Study. Your technical contributions were incorporated into our progress report to the Client, a copy of which is being mailed with this letter.

We can discuss this subject in further detail at our meeting scheduled for Tuesday, August 29th.

Yours truly,

Harold

Harold V. Page, P.Eng.,
Project Director.

ATHABASCA TAR SANDS STUDY

HVP:ejb

P.S. Please note that the Client has designated our progress report as strictly confidential and therefore the information provided therein should be used only for the requirements of our Study.

ACKNOWLEDGMENTS

The writers are indebted to a number of colleagues for assistance in the preparation of this report. J. D. Lindsay, Head of the Soils Division, supplied maps and photographs and offered advice on the terrain, organic soils, and sand dune distribution in the Bituminous Sands Area. C. R. Neill, P. Eng. of the Highways and River Engineering Division, gave us advice with regard to estimations of runoff and supplied aerial photographs of streams in the area. We are also grateful to officers of the Department of Lands and Forests and the Energy Resources Conservation Board who supplied data on request.

We are grateful to all of these people for assistance, but the writers accept full responsibility for the accuracy and manner in which the data is presented in this report.

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INTRODUCTION

For the purposes of this study, we have examined the demands that will be made on the environment of the Bituminous Sands Area by the production of 1.3 million barrels per day* of bitumen by *in situ* methods of extraction, *in situ* extraction implying the recovery of bitumen from the pores without disturbing the reservoir rock. This process usually involves the drilling of many injection and production wells into the reservoir in a closely spaced pattern, and the collection and delivery of the bitumen to a field plant for upgrading to a synthetic oil.

Most of the *in situ* methods require the application of differential pressure to the reservoir, and for this reason it is generally conceded that for safe and effective operations with today's technology, the overburden should not be less than 500 feet. The study area is therefore confined to that portion of the Athabasca deposit buried to depths of more than 500 feet in the Bituminous Sands Area. This *in situ* area comprises about 3,700 square miles and is about 64 per cent of the Athabasca deposit within the Bituminous Sands Area. Some 2,000 square miles of the Athabasca deposit, all of it buried deeper than 500 feet, lies outside the Bituminous Sands Area and is not considered in this report. In addition, that portion of the Athabasca deposit covered by 200 to 500 feet of overburden has not been included, although it may conceivably be developed by *in situ* methods at some future time.

Existing patents on *in situ* technology and extensive literature on secondary recovery of petroleum have been reviewed. It is clear that much of this technology cannot be transferred to the Athabasca deposit without considerable modification.

Our predictions, at this time, of the environmental effects of large scale *in situ* production are subject to some significant limitations. Firstly, there is no commercial production from *in situ* operations in the Bituminous Sands Area, and although some experimental work has been carried out by two oil companies with two of the most promising methods, factual data is scarce.

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* It is assumed that 1.3 million barrels of bitumen will yield 1.0 million barrels of 'synthetic' oil.

Secondly, the area has until very recently been largely inaccessible and little factual data exist on the meteorology, hydrology, soils, vegetation, and wildlife of the area. Current evaluations of the economic values of the renewable resources of the area were not available during the preparation of this report.

Within this context, we have proceeded to examine in a theoretical way those actions which we believe will have a significant effect on the environment in the Bituminous Sands Area should commercial *in situ* production begin.

Shell Canada Limited and Muskeg Oil Company applied to the Energy Resources Conservation Board for permission to go into commerial or semi-commercial production, but both applications were subsequently withdrawn. The Shell Canada Limited submission was based on a steam-injection system for extraction and included data on upgrading the bitumen to a synthetic oil in two stages. The first stage processing was to take place at the production site and the final upgrading in Edmonton. The Muskeg Oil Company submission was concerned only with the production of the raw bitumen by a modified underground combustion method and did not include details of the bitumen upgrading phase; thus, it is considered to be a semicommercial venture. Because of these differences, it is difficult to make meaningful comparisons between the two systems. For example, in the Muskeg Oil Company application, details of the field gases are given because, in the absence of a processiong plant, they will have to be flared or vented. In the Shell application, no field gas analyses are given because they enter the primary processing plant along with the steam and bitumen emulsion. Similarly, saline water produced along with the bitumen emulsion in the Muskeg Oil Company method has to be concentrated and disposed of before the bitumen is delivered to a distant processing plant, whereas in the Shell Canada Limited system, the saline water in the emulsion is diluted by process waters and ultimately discharged into the surface drainage system.

From our examination of these two applications for commercial and semi-commercial production by *in situ* methods, we believe the following major environmental impacts can be anticipated.

1. Air quality

a) Steam injection (field and primary upgrading facility)

In the Shell Canada Limited application, 460,000 long tons a year of sulphur dioxide was to be emitted to the atmosphere from a plant producing 100,000 barrels of synthetic oil a day. These emissions will come from the burning of the high sulphur residual fuel (pitch) in the power plant used to generate the steam for injection and the electricity for primary processing.

If this process were to be used for the production of 1 million barrels of synthetic oil, without SO_2 abatement, 4.6 million long tons of sulphur dioxide would be emitted annually from fewer than 10 plants. This amount of sulphur dioxide would be equivalent to 20 per cent of the estimated annual emission of sulphur dioxide from the untreated stack gases of all stationary power plants in the United States in 1970.* About 80 per cent of the SO_2 emission would be produced by burning fuel to produce steam for injection into wells.

b) COFCAW (field facilities only)

Extrapolation of experimental data provided by Muskeg Oil Company suggests that 0.5 million tons of SO_2 a year would be produced by flaring the gases collected with the bituminous emulsion for each 1.3 million barrels of raw bitumen produced.

2. Land clearing (field facilities only)

To accommodate drilling sites, roads, pipelines, etc., required by *in situ* extraction, large tracts of land have to be occupied for periods of up to 7 years. For example, a well field producing 130,000 barrels of bitumen a day would have about 1,600 operational wells spaced less than 300 feet apart over an area of 5.0 to 6.0 square miles at all times. If the clearing is confined to pipeline rights of way, servicing roads, and well sites, 50 per cent of the vegetation would have to be cleared. Thus, to produce 1.3 million barrels of bitumen, the total area cleared of vegetation at any one time would be between 25 and 30 square miles in fewer than 10 well fields.

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* *Ad hoc* panel on Control of sulfur oxide from Stationary Combustion Sources: National Academy of Engineering, Washington, D.c. 1970.

3. Water consumption

a) Steam injection (field and primary and secondary upgrading facilities)

A fully integrated steam-injection system capable of producing 100,000 barrels of synthetic oil would require 25,200 gallons of water a minute, which is equivalent to a stream flow of 55.5 cubic feet per second. Thus, 10 plants producing a total of 1.0 million barrels of synthetic oil would require an amount of water equivalent to a flow of 555 cubic feet per second.

b) Steam injection (field facilities only)

The water requirement for production of 1.3 million barrels a day of raw bitumen by steam injection is estimated to be about 260 cubic feet per second.

c) COFCAW (field facilities only)

Early experimental data indicate that less water is required for bitumen production by underground burning than for steam injection, as most of the formation water produced along with bitumen can be recycled without treatment.

4. Groundwater contamination

Although no estimate of the magnitude of the groundwater contamination problem can be given at this time, we can anticipate that, during *in situ* extraction, chemicals will be injected into the reservoir for a variety of reasons, for example, to initiate combustion, stimulate production, seal off permeable layers, and to heat the formation. Normally the concentrations of these chemicals will be low, and most of them will be recovered during production. However, it must be emphasized that *in situ* operations conducted in the Bituminous Sands Area are in the zone of moving groundwater which ultimately discharges into the surface drainage system, and constant monitoring will be needed to prevent contamination of the groundwater supplies which may be needed for domestic or industrial purposes.

5. Liquid efflents

a) Steam injection (upgrading facilities only)

Little data are available on the temperature or composition of the effluents to be discharged from a steam injection processing plant. Shell

Canada Limited, in their submission, estimated that 10 barrels of oil dispersed in 396,000 barrels of water would be discharged into the Ells River for each 100,000 barrels of synthetic oil produced.

b) <u>COFCAW</u> (field facilities only)

A large volume of saline water will be produced along with the bitumen. The salts in this water will be concentrated during field processing. Experimental data supplied by Muskeg Oil Company suggest that up to 600,000 barrels a day of salt water will be collected during the production of 1.3 million barrels of raw bitumen.

CONCLUSIONS AND RECOMMENDATIONS

With regard to Environmental Protection

If the full oil-producing potential of the Athabasca Oil Sands is to be realized, a viable method or methods of *in situ* extraction must be available. At the present time, no applications are pending to produce commercial quantities of bitumen by *in situ* methods, and we estimate that it will require 8 to 10 years of intensive research and development to evolve a suitable method and to do the field testing necessary to ensure that it will meet acceptable conservation and environmental criteria. Environmental problems associated with the two most advanced *in situ* methods developed to date are discussed in this report in some detail.

Because of the lead time available before commercial *in situ* development begins in the Bituminous Sands Area, there is time, if work is begun immediately, to establish the basic environmental criteria by which to ensure that when commercial development is approved it can proceed with the minimum of disturbance to the environment.

To collect the data necessary to establish these environmental criteria the following actions and time table for their initiation or completion are recommended:

1) Effective immediately, require that all holders of leases in the *in situ* area begin collecting ecological baseline data, so that adequate environmental impact statements can be provided to the Department of the Environment when applications for commercial development are made.

2) Effective immediately, prohibit withdrawal of water from all lakes and streams in the *in situ* area until a survey has been made of all possible sources and the volumes available. Priorities of water use can then be established.

3) Effective immediately, begin drafting regulations requiring the minimum of land clearing around wells, pipelines and other temporary field facilities.

4) As soon as possible, establish a network of recording stations in the *in situ* area to measure the following parameters at appropriate intervals for a period of at least 10 years:
a) precipitation, b) evaporation, c) air temperature, d) stream flows, e) lake levels, f) water tables, g) water temperatures, h) water quality, i) pressures at several depths in deep observation wells drilled from ground surface to base of the bituminous sands.

5) As soon as possible, draft regulations requiring monitoring of all experimental *in situ* test sites for groundwater contamination.

6) As soon as possible, draft regulations to ensure that no toxic concentrations chemicals or radioactive materials are injected into the bituminous sands reservoir.

7) Before commerical *in situ* development permits are issued, draft regulations to ensure the production zone is flushed and refilled with compatible formation water after production has ceased.

8) Before 1975, determine the location of all suitable dam sites on streams crossing the *in situ* area so that water storage sites and catchment areas may be protected.

9) Before 1978, make an inventory of all renewable resources such as lumber, fish, wildfowl, fur-bearing animals and big game in the *in situ* area.

10) Before 1978, make a survey of the *in situ* area to establish the presence of any unique animals, plants, nesting sites, spawning grounds, ecosystems, etc., with a view to making satisfactory arrangements for their protection.

11) Consider early assessment of impact of commercial development on native people and establish lines of communication.

12) Before commercial *in situ* development permits are issued, draft regulations to ensure land reclamation objectives will be achieved after production has ceased.

With regard to Government Policy

Because of the early stage of development of *in situ* extraction processes in the Athabasca Bituminous Sands, there is an opportunity for the Alberta Government to maintain control of, and exercise leadership in, the development of the major portion of the Athabasca reserves.* The first requirement is a new leasing policy for the whole deposit, one feature of which should be that no more than 50 per cent of the deposit** shall be leased at any one time, and that these leases shall be distributed throughout the area in some sort of checkerboard pattern.***

In addition to the 50 per cent restriction on leased acreage within the *in situ* area, it is recommended that no more permits or leases be issued in the Bituminous Sands Area where depths of overburden are greater than 200 feet but less than 500 feet. This area or zone, which comprises 838,000 acres, completely surrounds the mining area, and the bituminous sands beneath this area are too deeply buried for open-pit mining and too shallow for *in situ* methods. Keeping this strip clear of leases will prevent jurisdictional disputes that will undoubtedly arise if these two methods of extraction are allowed to share common lease boundaries. It will also simplify administrative procedures if, in the future, different regulations are to apply to the mining and *in situ* leases.

With regard to Research Policy

We believe the problems of *in situ* technology in the Athabasca deposit to be sufficiently different from conventional "secondary recovery" methods used in the petroleum industry to require unique solutions which can only be tested and evaluated in the area of development. Therefore, the Alberta Government should encourage cooperation among lease holders for the testing of new and novel methods of *in situ* extraction by initiating and supervising research and development programs.

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* It is estimated that 3.7 million acres or 73 per cent of the Athabasca deposit is overlain by more than 500 feet of overburden.

** In the Bituminous Sands Area 39 leases comprising a total of 1.7 million acres are located in the *in situ* area. This represents 53 per cent of the land in the Bituminous Sands Area with more than 500 feet of overburden.

*** This will allow lease boundaries to be adjusted to ore body dimensions without disturbing neighbouring lease holders and prevent the establishment of monopolies.

PART I BITUMINOUS SANDS AREA

1.1. Topography and drainage
1.2. Climate
1.3. Surficial deposits
1.4. Soils
1.5. Vegetation
1.6. Fauna
1.7. Bedrock geology
1.8. Groundwater

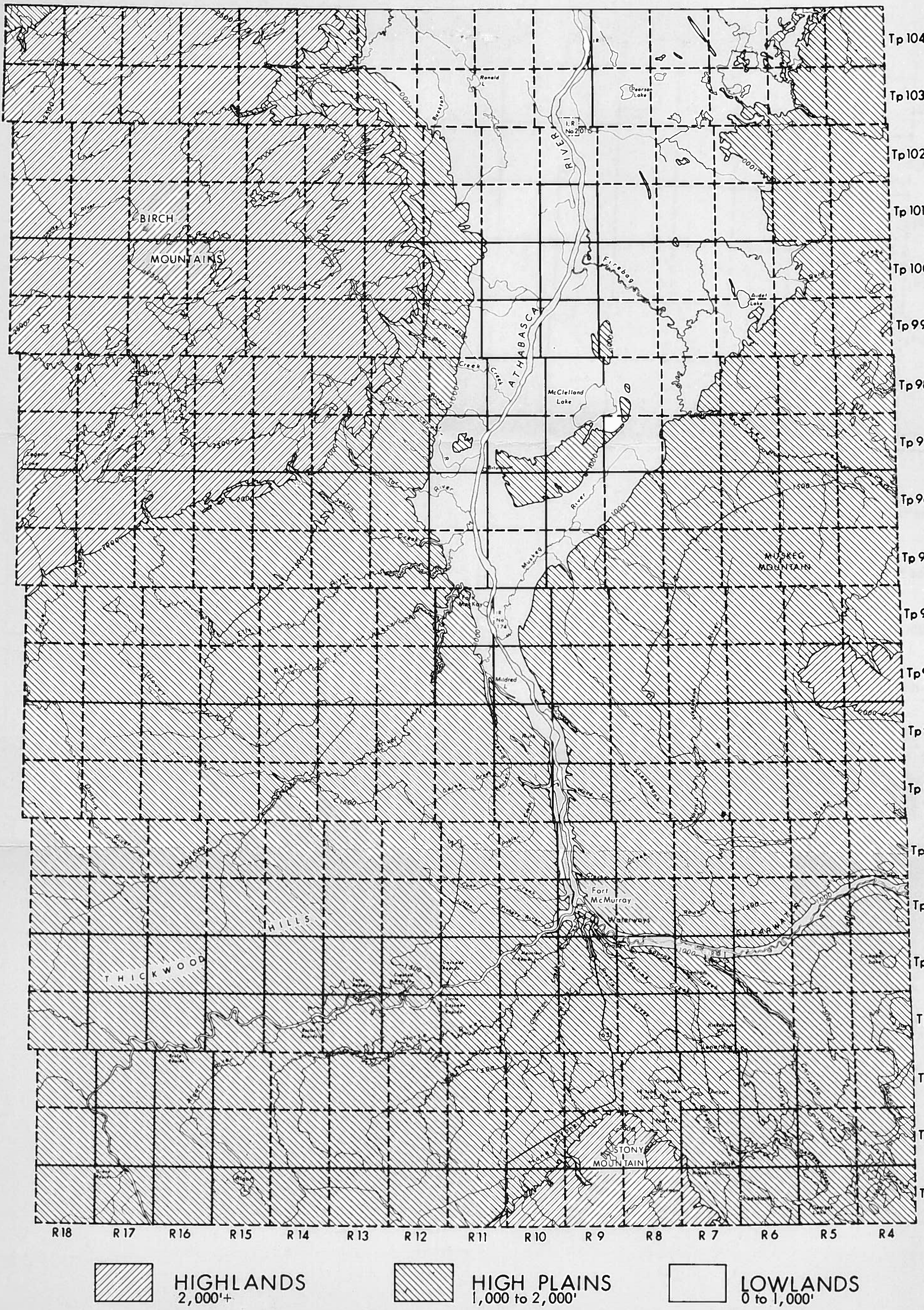
1.1. Topography and drainage

The Bituminous Sands Area is located in northeastern Alberta on the Interior Plain, adjacent to the Canadian Shield. The main drainage of the area is provided by the Athabasca-Clearwater system, the valleys of which are incised into a broad, gentle, muskeg-covered high plain to depths of 200 to 300 feet (Map 1). The tributary streams originate in three highland areas: the Birch Mountains to the northwest, which rise to about 2700 feet; Stony Mountain to the south, reaching an elevation of 2500 feet; and Muskeg Mountain to the east, with a gradual rise to 1900 feet. To the southwest of the area, between Birch Mountains and Stony Mountain and north of the eastward flowing Athabasca River, is a subdued highland with gentle slopes called the Thickwood Hills. These hills give rise to northward flowing tributaries of the MacKay River, with only a few short streams flowing southward to the Athabasca.

A few shallow lakes are located in the area, the largest and most numerous of which are located on the top of Birch Mountains and form an interconnected chain of lakes which flow into the Ells River. These are called Eaglenest, Gardiner, and Namur Lakes. The only other lakes of any size, Algar and Gregoire Lakes, are located on the high plain to the south, with streams flowing in and out of them. McClelland Lake is located in the lowlands northeast of Bitumount in an area of internal drainage.

1.2. Climate

The climate of the Bituminous Sands Area is subarctic and is similar in many respects to that experienced in Edmonton. Fort McMurray, at an elevation of 800 feet, has a mean annual temperature of 29.8 degrees Fahrenheit and on an average remains frost free for approximately 67 days each year. Mean annual precipitation is approximately 18 inches over the region, although there is good reason to believe that there is an orographic effect on precipitation distribution.



MAP 1. TOPOGRAPHY AND DRAINAGE OF THE BITUMINOUS SANDS AREA

1.3. Surficial Deposits

Most of the Bituminous Sands Area is covered by unconsolidated glacial, fluvial, and lacustrine deposits ranging in thickness from a few to several hundred feet. Glacial drift up to 600 feet thick covers the north flank of Muskeg Mountains and much of the Stony Mountain area. Many of the minor landforms and the uppermost mantle of sediment over the whole area are the result of the retreat of the continental glacier which covered the area until 10,000 years ago.

Aeolian deposits found as sheet deposits and dunes derived from outwash sands and gravels are widespread adjacent to the Athabasca River valley in the northeast of the Bituminous Sands Area.

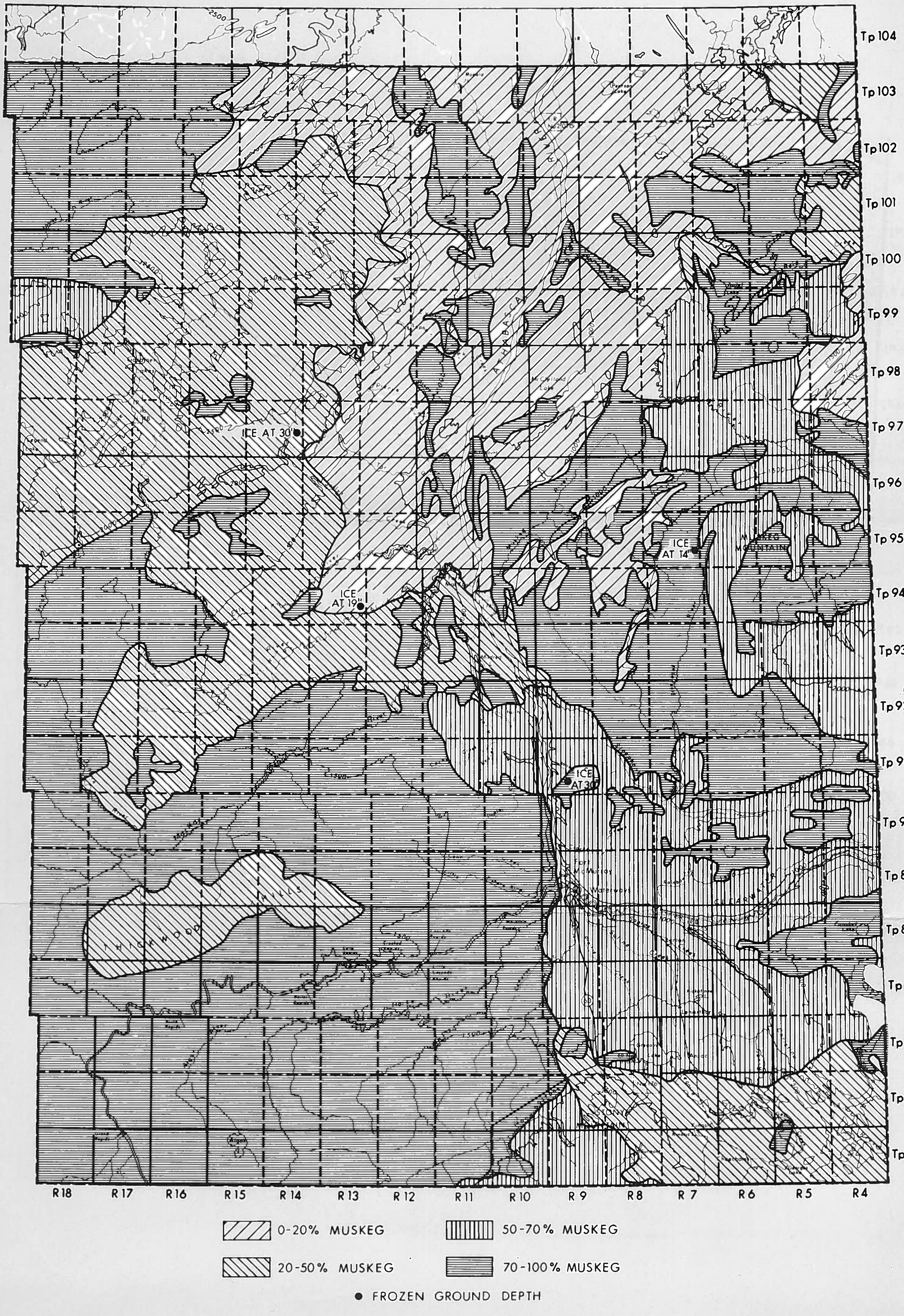
Recent alluvial deposits composed mainly of sand are found along the valley of the Athabasca River and silt and clay along some smaller streams. Slumping of soft Cretaceous bedrock occurs on the steep slopes in many parts of the area.

1.4. Soils

All mineral soils developed in the Bituminous Sands Area fall in the Grey Wooded soil group; however, at least 60 per cent of the area is covered by organic soil, often referred to as muskeg or sphagnum moss bog (Map 2). Organic soils are defined as those which have over 12 inches of peat at the surface. These soils are acid to moderately acid in reaction and have a high water-holding capacity, and ice is commonly encountered at depths of 16 to 30 inches.

Grey Wooded-Podzol soils develop where there is better drainage and a continuous tree cover. The soil profile typically has a few inches of leaf litter beneath which there is a grey zone where the soil is leached of any plant nutrients (Photo 1). These soils have a low natural fertility and at the surface have an acid reaction which ranges between 4.8 and 7 pH units.

Most of the Bituminous Sands Area has been classed as pasture and woodland. A combination of poor soil and lack of drainage makes this area of little value for agricultural development (Lindsay *et al.* 1957, 1961, 1962).



MAP 2. ORGANIC SOILS OF THE BITUMINOUS SANDS AREA

Photograph available

Photo I. Typical grey-wooded soil profile of northeastern Alberta. Note the thin layer of pine needles and grey leached layer.

Photo courtesy, J. D. Lindsay
Soils Division

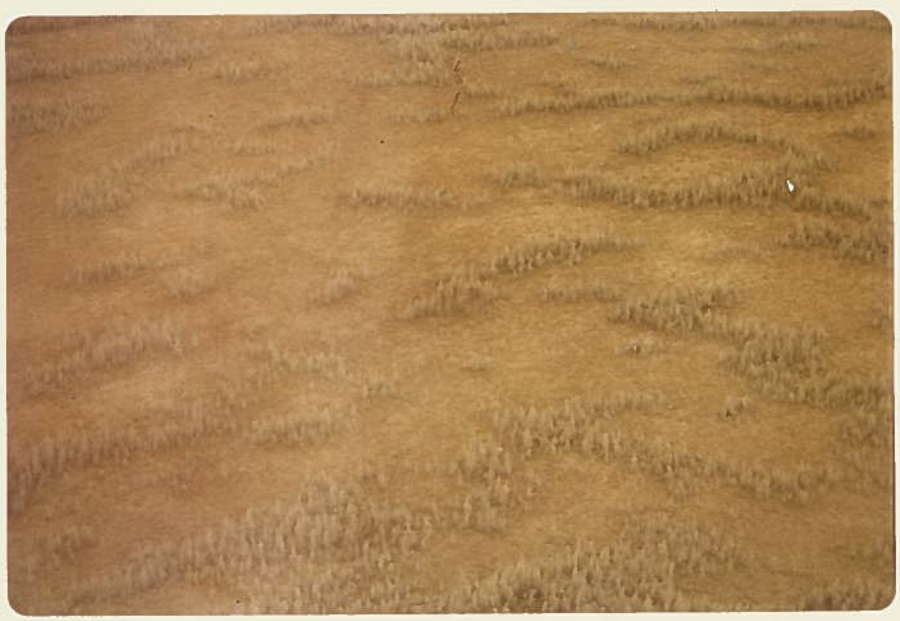


Photo 2. Typical bog (muskeg) vegetation of in situ area.

Photo courtesy, J. D. Lindsay
Soils Division

Photo 3. Mixed wood forest on top of Birch Mountains.

Photo courtesy, J. D. Lindsay
Soils Division

1.5. Vegetation

The Bituminous Sands Area lies entirely within the boreal forest region. The vegetation is a mixture of deciduous and evergreen trees. The greater part of the area is treed by aspen poplar but large areas are open sphagnum moss bogs with clumps of stunted black spruce (Photo 2). Small islands of jack pine and white spruce are scattered throughout the area.

There is a very close relationship between topography, soils, and vegetation in the area. The inorganic grey wooded soils have a mixed cover of trembling aspen, white spruce, and jack pine where the drainage is moderately good (Photo 3). The poorly drained areas have white spruce as the major cover with occasional aspen. Improvement in drainage and irregular topography give rise to relatively pure aspen stands on hill crests.

The organic soils are generally treeless but where the layer of organic matter is thin and drainage improves, black spruce and labrador tea appears. Tamarack is also present but is not common.

1.6. Fauna

Among the most characteristic large mammals of this area are the black bear, wolf, Canada lynx, white-tailed deer, mule deer, moose, and caribou.

The Bituminous Sands Area is located on the Mississippi and Central flyway of waterfowl but it is not believed to be an important resting or nesting ground. The area includes the breeding range of the blue jay and boreal chickadee and the summer grounds of the white pelican. Among the many birds found in the area are the lesser yellowlegs and solitary sandpiper, the myrtle warbler, the yellow warbler, spruce grouse, ptarmigan, and ruffed grouse.

Common fish found in lakes and rivers of the Bituminous Sands Area are the walleye, northern pike, goldeye, lake trout, and Arctic grayling.

1.7. Bedrock Geology

The sedimentary succession overlying the Precambrian basement reaches its maximum thickness of about 3,000 feet at the southwestern corner of the area and thins fairly uniformly to zero at the edge of the Precambrian Shield in the northeast (Fig. 2).

The Precambrian granites and gneisses are overlain disconformably by carbonate and evaporite strata of Middle to Late Devonian ages, which are inferred to underlie glacial deposits in the lowlands adjacent to the Athabasca River in the northeastern part of the map area (Map 3). The Middle Devonian succession is composed of dolomite, minor dolomitic limestone, salt, shale interbedded with gypsum, and possibly anhydrite units of unknown thicknesses. The Upper Devonian Waterways Formation comprises a succession of interbedded limestone and argillaceous limestone, exposed mainly along the Athabasca, Muskeg, and MacKay River valleys in the central part of the map area.

Strata of Early Cretaceous age underlie much of the high plain adjacent to the Athabasca River in the southwest part of the map area, extending under the highlands to the northwest (Birch Mountains) and to the east (Muskeg Mountain). The Cretaceous succession consists of oil-impregnated quartzose sands and silty shale of the McMurray Formation.* The bituminous sands are overlain by bentonitic marine shales and feldspathic sandstones of the Clearwater and Grande Rapids Formation. The youngest bedrock strata are the dark marine shales of the Shaftesbury and Labiche Formations, which cap the upper slopes of the Birch Mountains. None of the Cretaceous units are well exposed outside of the Athabasca River valley and the lower reaches of its tributary streams.

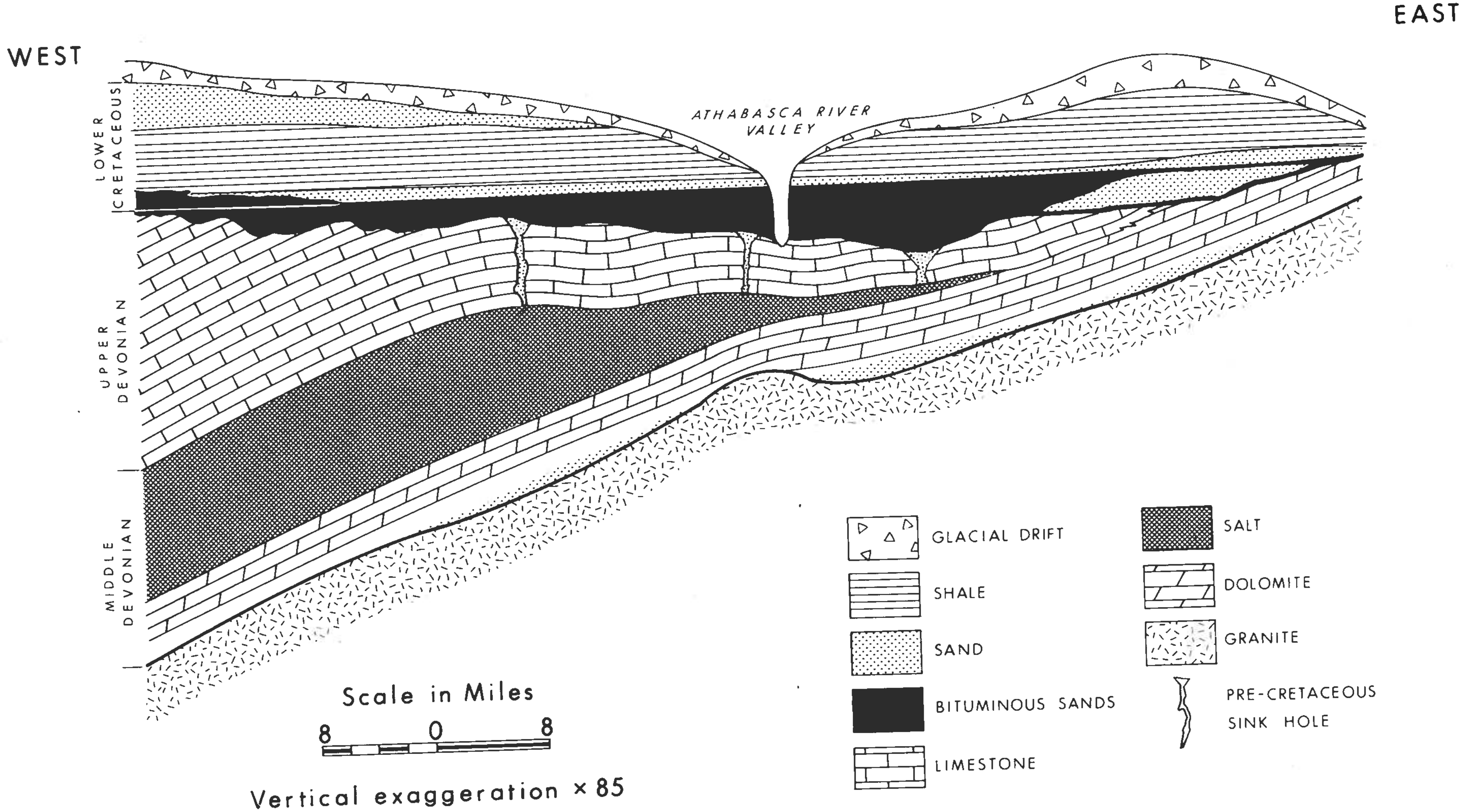
The Athabasca Bituminous Sands refers to the oil-impregnated part of the McMurray Formation.

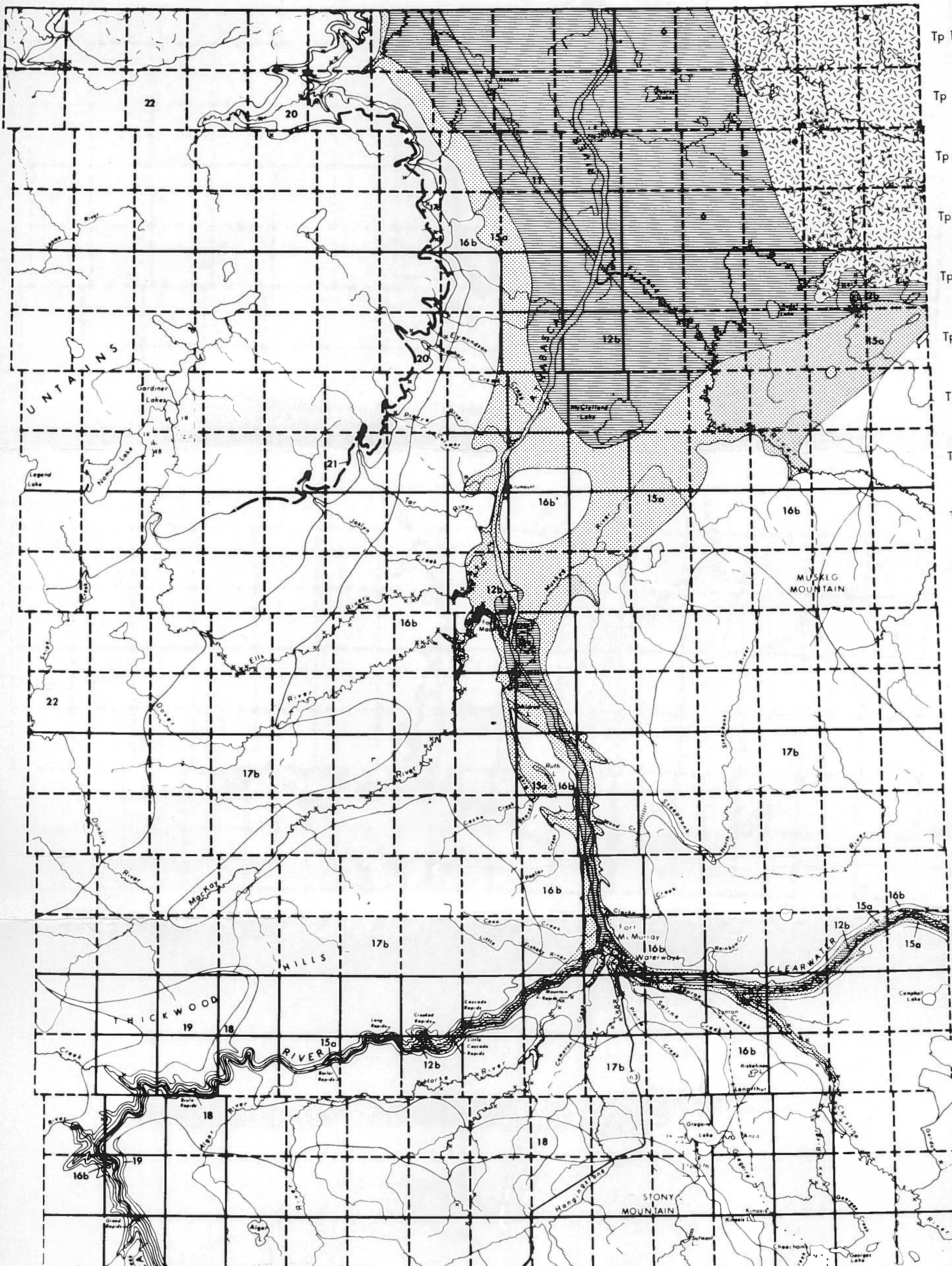
The McMurray Formation consists of sediments of continental origin deposited in fluviatile, deltaic, lacustrine, and lagoonal environments and it rarely exceeds 200 feet in thickness. No fossils permitting precise

* These oil-impregnated beds are variously known as the Athabasca Tar Sands, Athabasca Bituminous Sands, or Athabasca Oil Sands. The Mines and Minerals Act refers to the oil sands within the designated study area as Bituminous Sands and this terminology is used throughout this report.

FIGURE 2

SIMPLIFIED GEOLOGICAL CROSS SECTION SHOWING ATHABASCA BITUMINOUS SANDS





UNDIVIDED CRETACEOUS STRATA

MCMURRAY FM

DEVONIAN

PRECAMBRIAN

MAP 3. BEDROCK GEOLOGY OF THE BITUMINOUS SANDS AREA

(After Carrigy and Green, 1970)

age determination have been obtained from the McMurray Formation, but the current opinion is that it is of early Cretaceous age. The overlying Clearwater Formation carries a well developed marine macro- and microfauna of Cretaceous Middle Albian age (Mellon and Wall, 1956).

Although the beds of the McMurray Formation have a heterogeneous appearance due to the variation of grain size and bitumen content of the sediments, the petrographic characteristics of the formation are remarkably uniform. The major constituent of all grain sizes is quartz, with minor amounts of feldspar and mica. In the nonopaque heavy mineral fraction the most abundant minerals are tourmaline, chloritoid, zircon, and staurolite (Mellon, 1956). The clay-size material is composed of illite, kaolinite, chlorite, and quartz.

The bulk properties of the bituminous sands vary with the percentage of bitumen. The range of values is shown in table 1.

The variations in thickness shown in figure 3 of the bituminous sands are mainly due to topography on the limestone surface.

TABLE I

BULK PROPERTIES OF THE ATHABASCA TAR SANDS†

Property	*Bitumen Content (per cent of dry weight)*	*Range of values*	*Average*
Bulk Density	>10	1.75–2.09	1.90
	unknown	1.86–2.36	1.972
	unknown	1.98–2.08*	
	unknown	2.10–2.19**	
Porosity (per cent)	>10	34–46	40.7
	unknown	17.6–43.3	31.4
	unknown		40*
	unknown		34**
Saturation (per cent)	>10	Oil 44–98	
		Water 1–39	
		Total 61–97	
Air Permeability (millidarcys)	>10	0–215	50
	4–10	0–600	100
	<4	0–35	10

* 200 feet below surface.
** 1000 feet below surface.

† After Carrigy, 1967

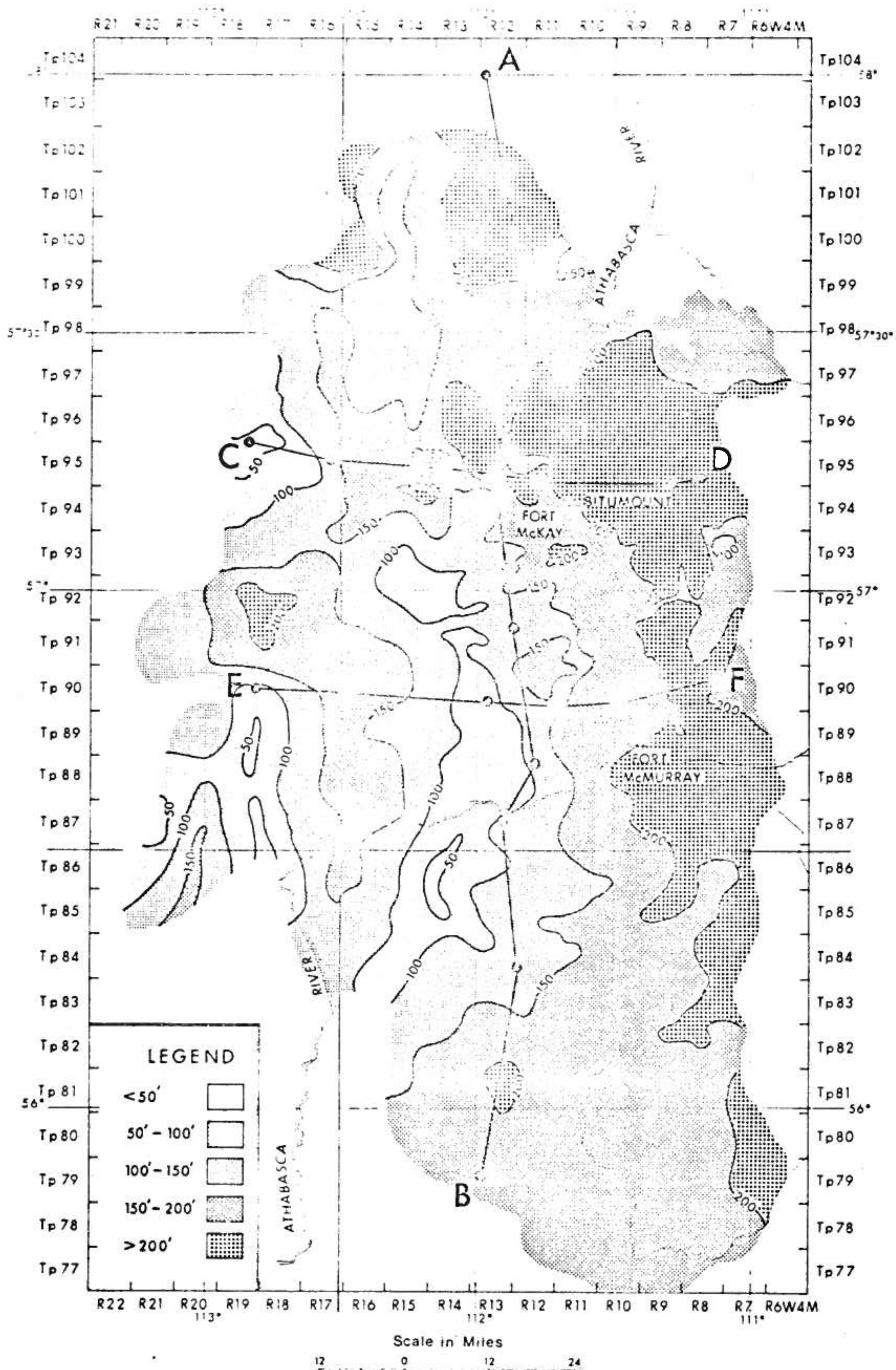


Figure 3. Variations in the thickness of bituminous sands within the evaluated area of the Athabasca deposit (After Carrigy, 1971).

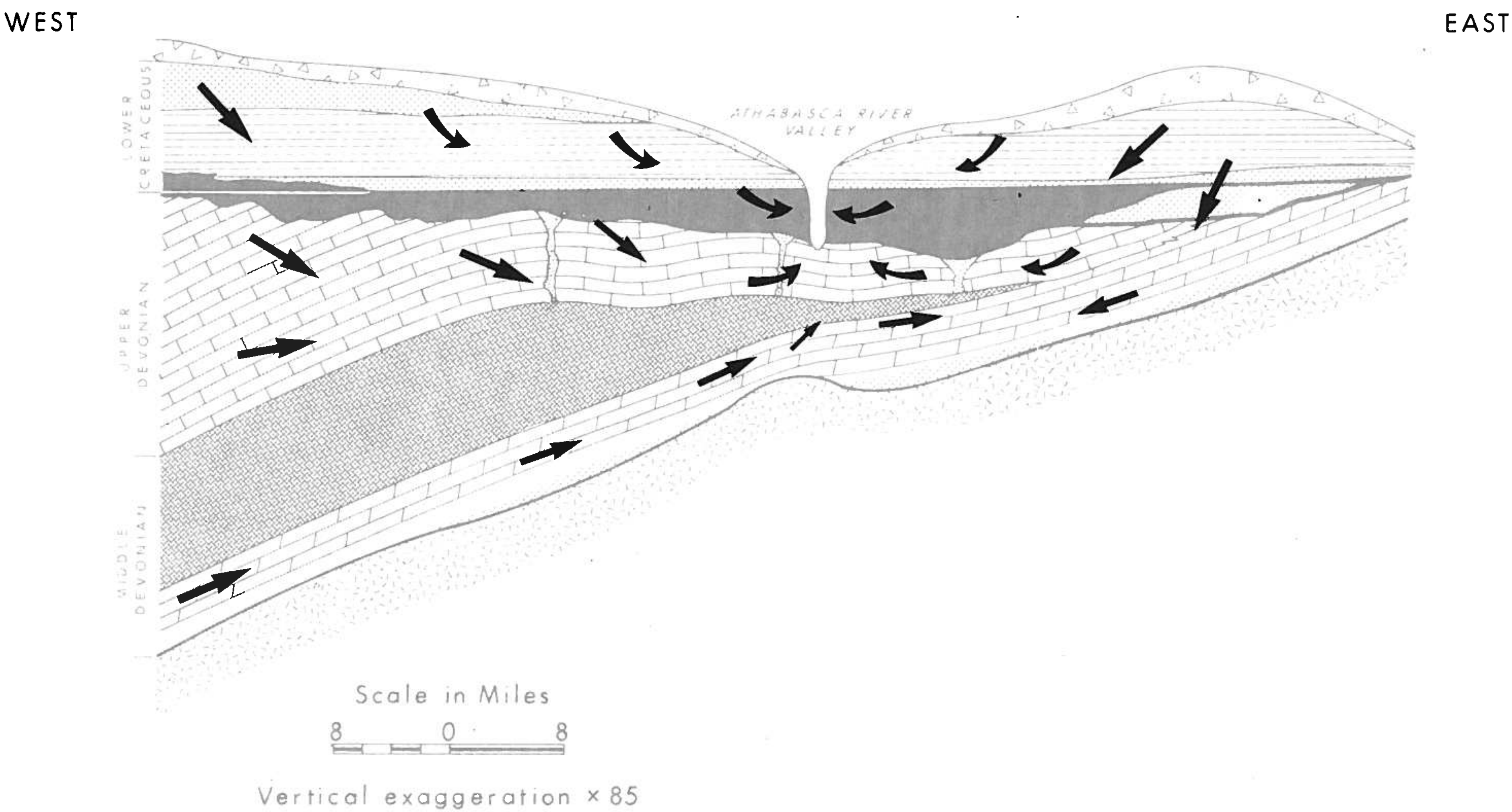
1.8. Groundwater

Few data exist on the hydrogeology of the Bituminous Sands Area. A theoretical pattern of the probable flow of fresh water and saline formation water is shown on figure 4. Knowledge of the regional hydrogeology is important for predicting the safe ultimate disposition of pollutants generated during *in situ* operations. It is also important in locating supplies of potable water for urban development and satellite industry.

One geological feature dominates the groundwater flow pattern in the Bituminous Sands Area. This is the thick bed of Elk Point salt which underlies the Waterways limestone. This salt bed is being dissolved by the fresh-water flow and discharged into the Athabasca River at saline springs. This process, which has been in operation for possibly 100 million years or more, has resulted in an abundance of collapse structures and undulations in the overlying limestones. In one of the larger structures, near Bitumount, the overlying beds have dropped several hundred feet over an area of 50 square miles (Map 3). In addition to this large feature there are many hundreds of small (less than 100-foot diameter) circular holes in the limestone filled with rubble known as "sinkholes." Most of these sinkholes were formed and filled before the bituminous sands were deposited, but there is evidence that some sinkholes are still active. The role of sinkholes in the regional groundwater flow system is as yet unknown and needs to be investigated.

FIGURE 4

SCHEMATIC DIAGRAM OF REGIONAL GROUNDWATER FLOW



PART II IN SITU AREA

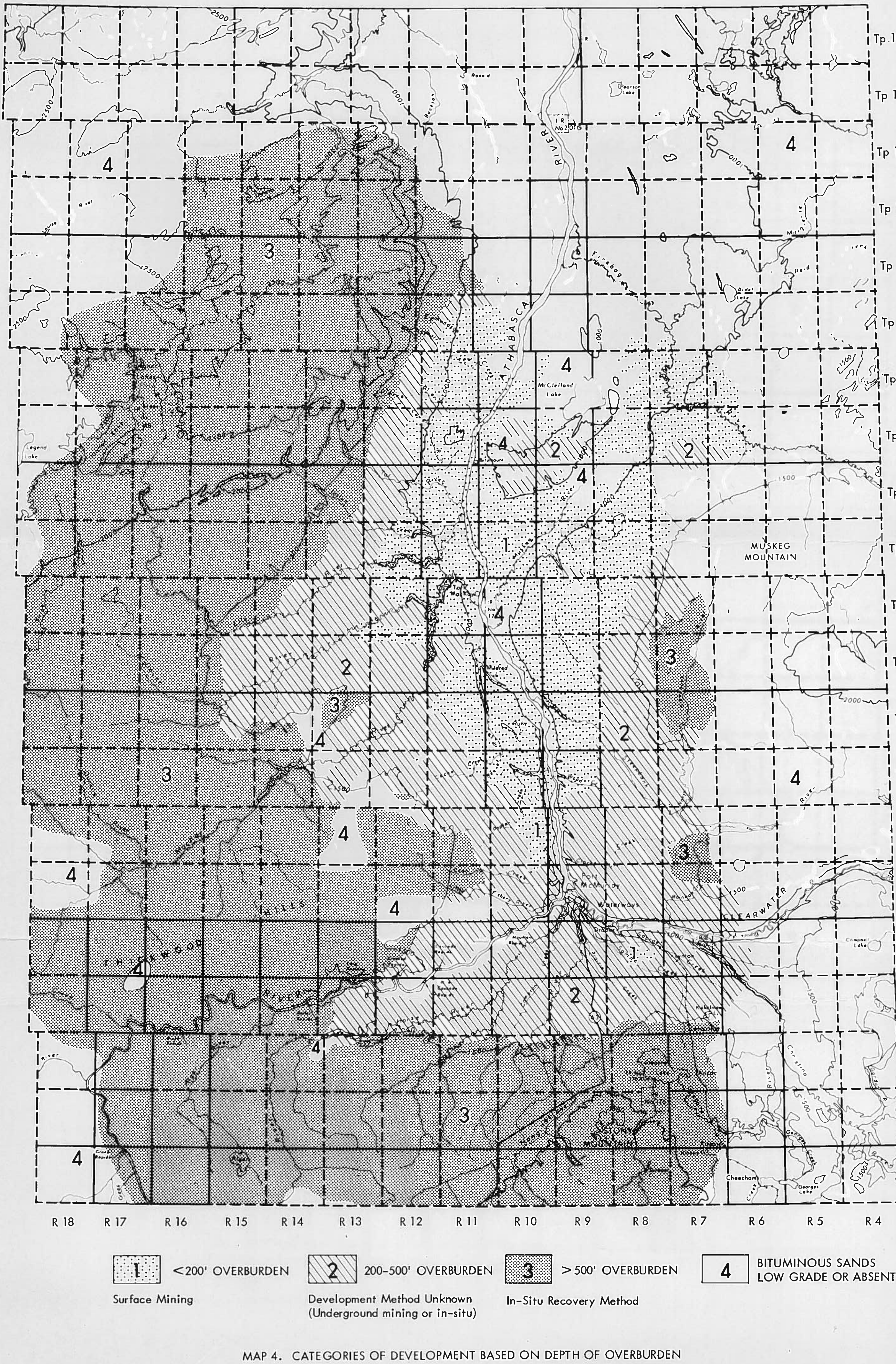
II.1. Introductory Statement

The method of extracting the bitumen depends on the depth of burial which in the Athabasca deposit is largely a function of topography. It is possible to outline four categories of development within the Bituminous Sands Area (Map 4) and to assign to each a most likely method of extraction as follows:

	1 Surface Mining	2 Unassigned*	3 In situ	4 None**
Depth of overburden (feet)	0 to 200	200 to 500	greater than 500	not applicable
Per cent of Bituminous Sands Area	7.3	11.4	33.3	48
Per cent of oil-saturated portion of the Athabasca deposit within the Bituminous Sands Area	14	22	64	0
Location	Lowlands adjacent to Athabasca River north of township 89	Zone between surface mining and *in situ* area	Highland and high plains in the west and southwest part of the Bituminous Sands Area	Mainly in the northeast and eastern portion of the Bituminous Sands Area

* Currently too deep for surface mining, and too shallow for *in situ* methods.

** Land under which there is little or no oil saturation or the formation has been removed by erosion.



MAP 4. CATEGORIES OF DEVELOPMENT BASED ON DEPTH OF OVERBURDEN

It should be noted that only 52 per cent of the Bituminous Sands Area is underlain by oil-saturated sands of the Athabasca deposit, and 64 per cent of this is categorized as suitable for *in situ* development.

11.2. Bitumen Reserves

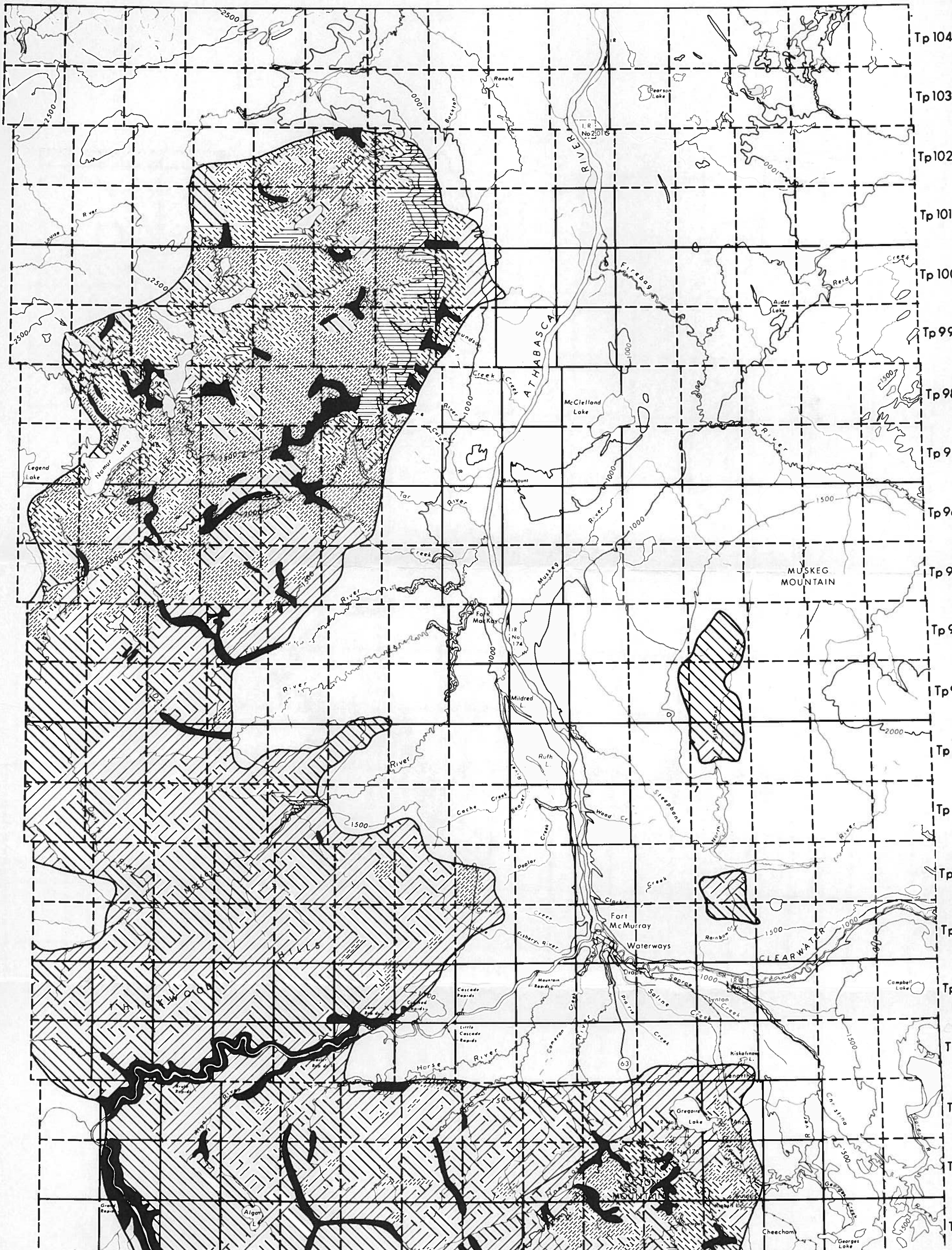
Because the *in situ* portion of the Athabasca deposit is very large and the overall density of drilling is low, the bitumen reserves of this area are only imperfectly known. In 1963 the Energy Resources Conservation Board estimated that there were 416.5 billion barrels of bitumen, in place, in that portion of the Athabasca deposit with more than 500 feet of overburden. This amounts to 66 per cent of the total in-place reserves of the Athabasca deposit. These reserves were classified as drilled, 45.3 billion barrels, and undrilled, 371.2 billion barrels. The drilled reserves are based on wells less than 1 mile apart and, by analogy with classification of coal reserves, can be described as "indicated." The undrilled estimate of reserves is based on wells more than 1 mile apart and can be described as "inferred." No estimate of the in-place reserves of the *in situ* portion of the Bituminous Sands Area was available to us for this report.

11.3. Terrain

Preliminary terrain analysis of the *in situ* area (Map 5) clearly shows a difference between the highland areas and the high plain. In the Birch and Stony Mountain areas rolling and gently rolling terrain (Photo 4) predominates and streams have eroded well-defined narrow valleys. On the intervening high plains flat to undulating land and bog (muskeg) (Photo 5) predominates and most streams meander across the surface in extremely shallow depressions, with the exception of the Athabasca River which has cut a deep narrow gorge 300 feet deep through the high plain in the southwestern part of the area.

11.4. Frozen Ground

Studies of frozen ground conditions in northern Alberta are reported by Lindsay and Odynsky (1965). Their results show that ice is only



ROLLING COUNTRY

GENTLY ROLLING COUNTRY

BOGGY LAND

HILLY LAND

ROUGH AND BROKEN

FLAT UNDULATING LAND

BOUNDARY OF DEPOSIT AREA OVERLAIN BY MORE THAN 500' OVERBURDEN

Compiled from data supplied by Soils Division, Research Council of Alberta

MAP 5. TERRAIN ANALYSIS OF THE IN SITU AREA

Photo 4. Gently rolling terrain on top of Birch Mountains.

Photo courtesy, J. D. Lindsay
Soils Division

Photo 5. Flat terrain (muskeg) of the high-plains.

Photo courtesy, J. D. Lindsay
Soils Division

encountered in organic soils which are thicker than 24 inches. In the *in situ* area frozen ground is found on the top of the Birch Mountains, and this area is considered by Lindsay and Odynsky to be a permafrost area for organic soils. In the remainder of the area the frozen condition in organic soils is temporary but may last more than one year.

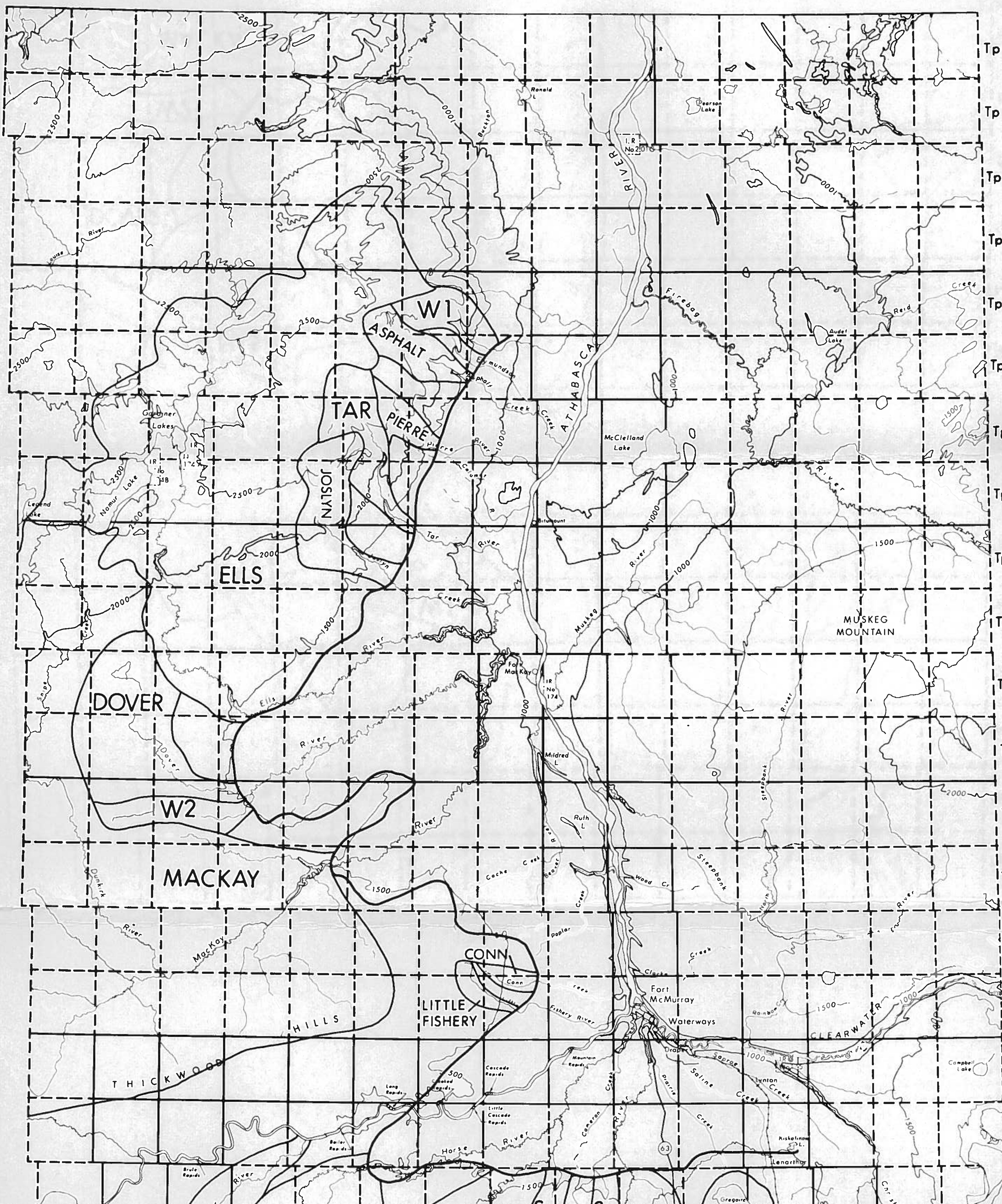
II.5. Surface Water Supply

Estimates of the amount of water available within the confines of the *in situ* portion of the Bituminous Sands Area must of necessity be very tentative. The catchment areas are all located in the upper reaches of tributaries (Map 6) where most streams meander across vast areas of partially frozen muskeg (Photo 6), and watershed boundaries are difficult to define. So far as we are able to determine, no reliable rainfall, evapotransiration, or stream flow measurements exist for this area; however, it has been estimated (C.R. Neill, personal communication) that the average runoff will probably be between 0.37 and 0.50 cubic feet/sec./square mile. The estimated average discharge of the streams crossing the *in situ* area based on the lower figure is given in table 2.

Water storage will be required to even out annual and seasonal variations in precipitation. One feature of the terrain of the *in situ* area, which will have a limiting effect on the availability of the local surface water in some catchments, is the lack of erosional valleys and hence dam sites.

II.6. Inhabitants

The principal residents of the *in situ* area are two bands of native people who depend on the lakes and rivers within the area for fishing, hunting, and trapping. The Fort McMurray Band, which numbers 101 people, is settled on three reserves located on the shores of Gregoire Lake. The Fort Mackay Band uses the two reserves located on the shores of Namur and Gardiner Lakes on the top of the Birch Mountains.



MAP 6. DRAINAGE BASINS OF THE IN SITU AREA

Photo 6. Tributary stream meandering across flat terrain of the in situ area. Note the absence of an erosional valley and hence the lack of a damsite.

Photo courtesy, C. R. Neill
Highways and River Engineering Division

Table 2. Estimated average discharges from *in situ* catchment areas

Drainage basin	Catchment area (sq mi)	Minimum average discharge (cu ft/sec) (area x 0.37)
W1 (unnamed stream)	28.80	10.65
Eymundson	8.16	3.02
Asphalt	38.40	14.21
Pierre	24.80	9.18
Tar	63.36	23.44
Joslyn	69.12	25.57
Ells	882.60	326.56
Dover	147.20	54.46
Dover, W2	37.44	13.85
MacKay	1,502.72	556.00
Algar	127.00	46.99
Horse	382.88	141.66
Horse, S1	268.48	99.34
Horse, S2	24.80	9.17
Hangingstone	171.52	63.46
Hangingstone, S3	45.12	16.69
Hangingstone, S4	27.68	10.24
Conn	11.68	4.32
Little Fishery	10.72	3.97
Surmount Ck.-Gregoire Lake	92.48	34.21

II.7. Renewable Resources

II.7.(i) Lumbering

Within the *in situ* area about 60,000 acres of land has been leased for lumbering. There is an estimated 117,272,000 board feet of timber available in these leases, worth about $11.7 million at an estimated average price of $100 per thousand board feet.

The *in situ* area is included in forestry management units A-3, A-4, A-8 and the west half of A-5. The total value of marketable timber available in these management areas should be evaluated before development begins.

II.7.(ii) Fishing

There is no commercial fishing in the lakes and streams of the *in situ* area. However, Namur and Gardiner Lakes are designated as trophy lakes and a tourist fishing lodge is located on the shores of Namur Lake.

Fishing is also an important cultural activity and source of food for the native people of the area.

II.7.(iii) Trapping

Fur-bearing animals are abundant in the Bituminous Sands Area and many traplines cross the *in situ* part. Trapping is a very important part of the native economy, and many of the indigenous people supplement their income from this source. It has been estimated that 70 persons are employed in this activity in the *in situ* area.

PART III *IN SITU* EXTRACTION METHODS

III.1. General Statement

In situ processes proposed for the recovery of the heavy viscous crude hydrocarbon (bitumen, tar, etc.) of the Athabasca deposit involve some method of increasing the mobility of the bitumen so that it will flow through the pores of the reservoir sand and be produced from a well. All of the schemes devised for reducing the viscosity of the bitumen involve the injection of liquid or gaseous solvents, heat, and/or emulsifying chemicals into the reservoir, and the production of the mobile hydrocarbon solutions or mixtures through another well or wells.

Secondary recovery methods widely used in the petroleum industry to stimulate additional production from partially depleted reservoirs containing high gravity oils are fundamentally different from the *in situ* techniques required to produce bitumen from the Athabasca deposit. To be successful, secondary recovery techniques require that the reservoir have good permeability and be filled with oil mobile enough to move through the pores to the production well. This is in direct contrast to the situation in the Athabasca deposit, where a heavy oil or bitumen occupies up to 90 per cent of the pore space and the permeability to introduced fluids is close to zero. Also, the viscosity of the bitumen, at the low formation temperatures (32-60°F) prevailing in this near-surface deposit, is so great that it has to be considered immobile even if considerable external pressure is applied to the formation. Therefore, in order to produce this bitumen it must be dissolved, emulsified, or heated. To do any of these things in a reasonable time, the area of contact between the viscosity reducing medium and the bitumen must be made as large as possible, i.e., the reservoir must be fractured. The most desirable fractures are basal horizontal planes which, while increasing the injected fluid to bitumen contact area, provide the shortest pathway from the injection well to the producing wells for the cycling of the solvents, gases, heat, and chemicals. Once such a permeable pathway has been established, the circulating fluids, gases, etc. will gradually eat away the bitumen and transport it to the production well until 50 to 70 per cent of the bitumen in the reservoir has been recovered. Production is stopped when the ratio of circulating fluid to bitumen becomes excessive.

The most promising *in situ* methods tried to date in the Bituminous Sands Area are the steam-injection process pioneered by Shell Canada Limited (Fig. 5), and a modified *in situ* combustion process called the combined forward combustion and waterflood (COFCAW) process developed by Amoco Canada Petroleum Company Limited (Muskeg Oil Company). Both of these companies have submitted applications to the Energy Resources Conservation Board for permission to produce oil commercially from the Bituminous Sands Area. Another *in situ* method using nuclear detonations as a source of heat has been proposed by Richfield Oil Corporation of California. A method of heating bituminous sands by injection of radioactive salts such as the waste from atomic power plants has also been patented (U.S. Pat. 3,233,669).

III.2. Steam Injection

III.2.(i) Definition

In the steam-injection process for the recovery of crude bitumen, the steam is used to heat the bitumen and to form an emulsion of bitumen and hot water, which is then pumped from the production well.

III.2.(ii) Description

Before production can begin a series of injection and production wells are drilled on a closely spaced five-spot or nine-spot pattern (Fig. 6). A permeable path is established between the injection and production wells by hydraulic fracturing. This permeable layer is enlarged as the steam is circulated and bitumen emulsion production begins. Production within a single pattern usually begins after 100 days, rises to a maximum after about 1 year, and declines quickly after 3 years (Fig. 7). Production ceases when the ratio of water to oil in the emulsion becomes excessive. This usually occurs when 50 to 70 per cent of the bitumen in place has been extracted.

In 1962, Shell Canada Limited applied to the Energy Resources Conservation Board for permission to produce 47,450,000 barrels per year (130,000 B/D) of crude hydrocarbon product (bitumen) from leases 26, 42,

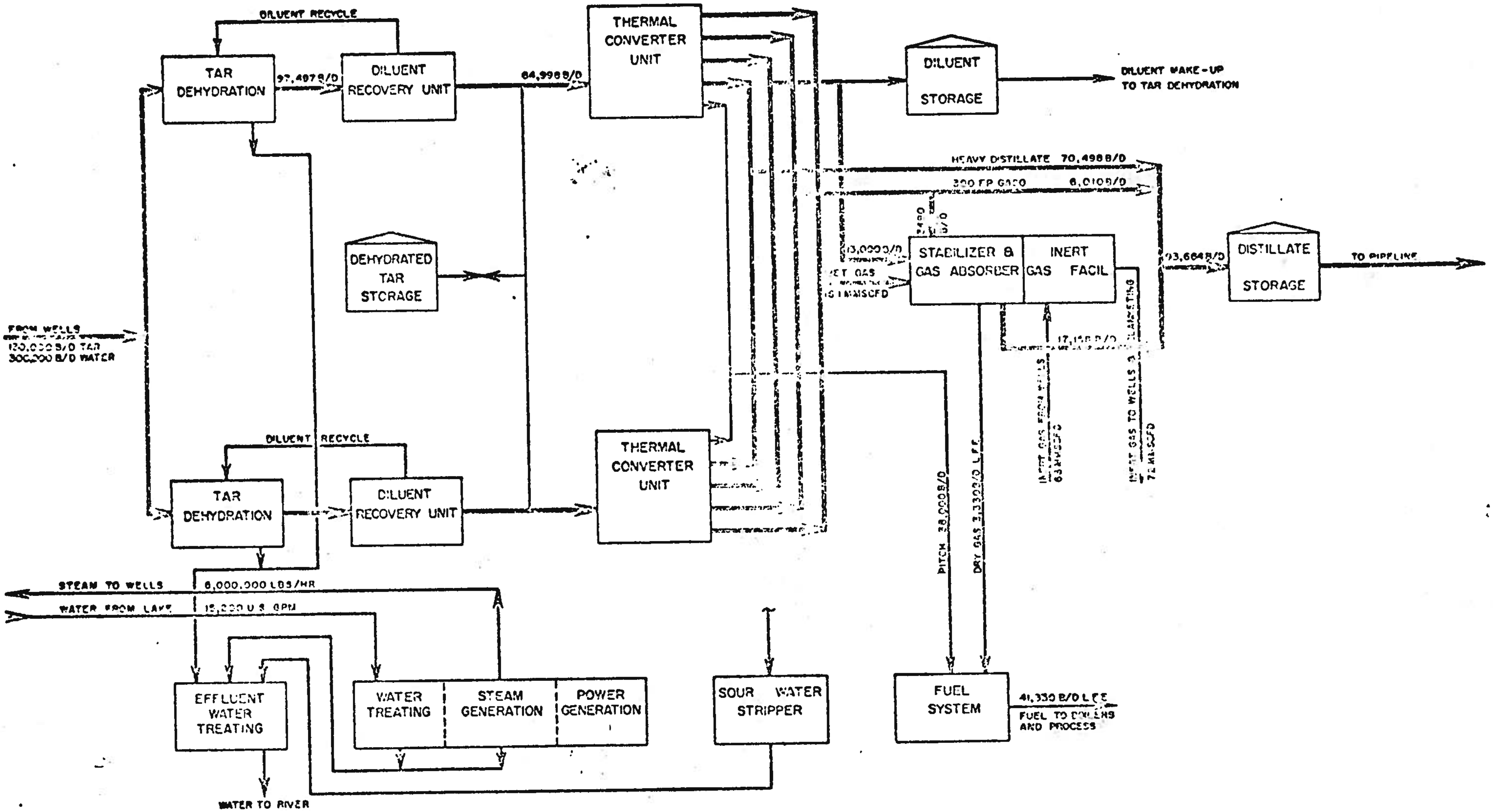
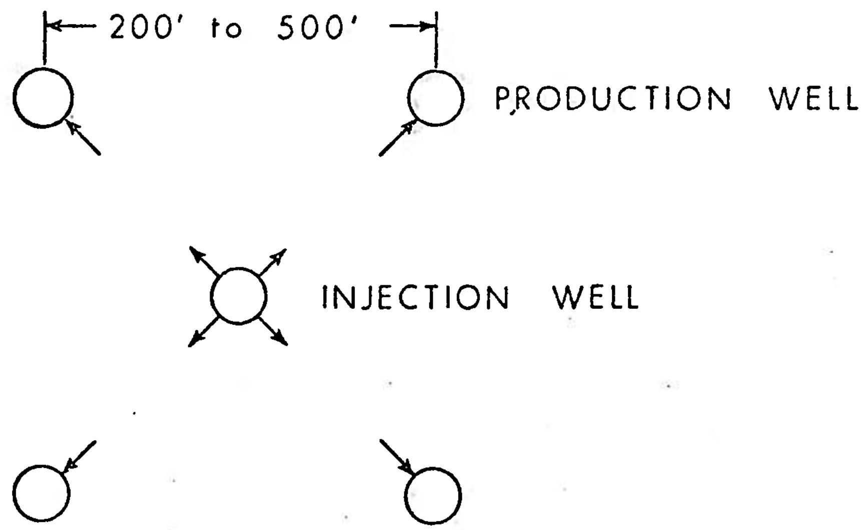


Figure 5. A process flow diagram for on site upgrading of bitumen produced by steam-injection.

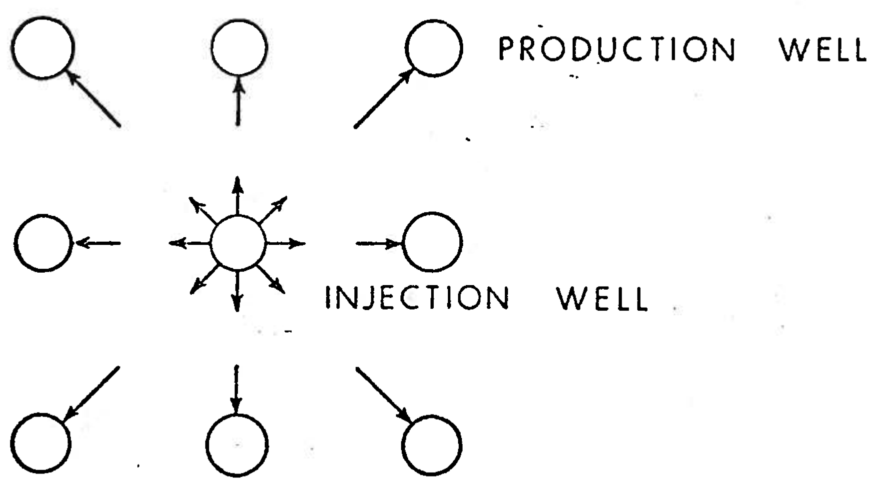
Reproduced from submission of Shell Canada Ltd. to the Energy Resources Conservation Board, 1963

FIGURE 6

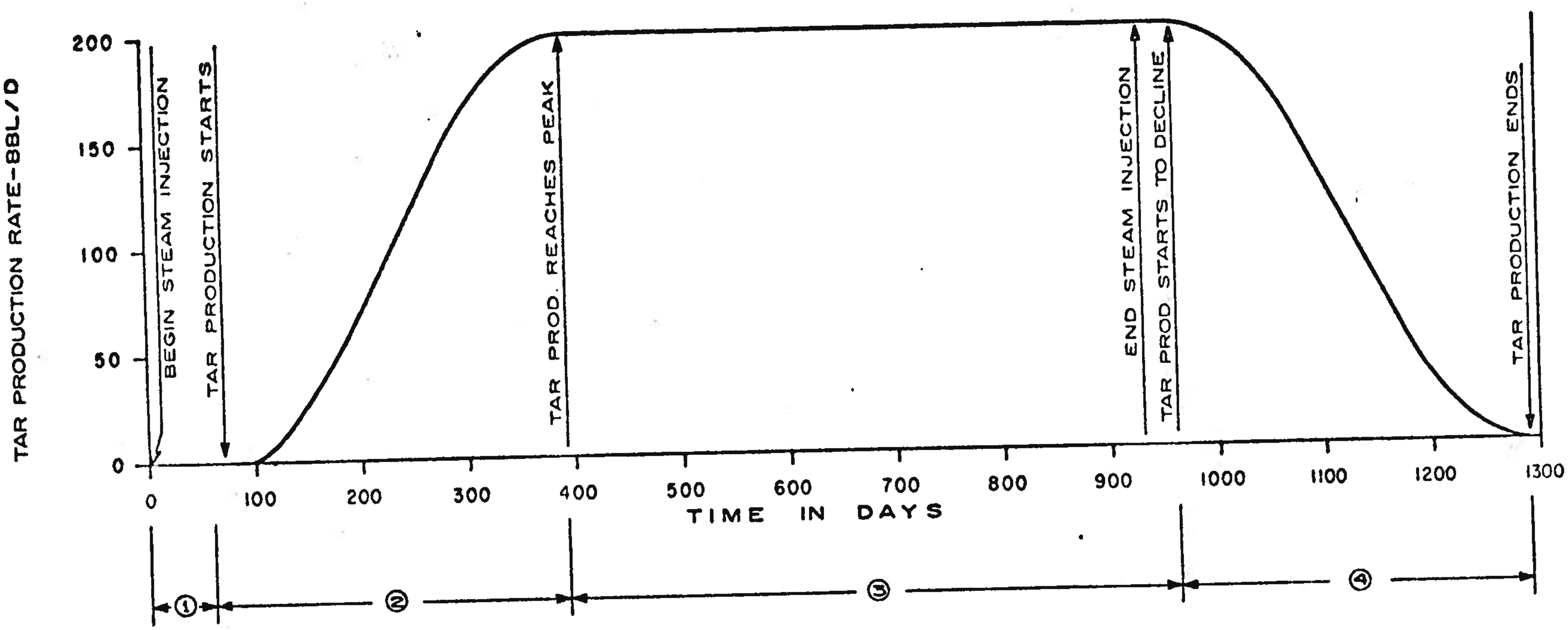
PRODUCTION UNIT WELL PATTERNS FOR IN-SITU METHODS



FIVE SPOT



NINE SPOT



① - STEAM INJECTION INTO PRODUCTION WELL

② - STEAM INJECTION INTO INJECTION WELL

③ - TAR PRODUCTION CONSTANT AT PEAK 200 BBLS / DAY

④ - TAR PRODUCTION DECLINES

Figure 7. Predicted injection and production performance of a single well in a five-spot pattern in a steam-injection project.

Reproduced from submission of Shell Canada Limited to the Energy Resources Conservation Board, 1963

45 and 53 (Fig. 8). The method of recovery was described as a thermal technique which involves the injection of steam and/or hot alkaline solutions into the bituminous sands, the emulsification of the bitumen in place by these solutions, and the production of the emulsion at production wells. Shell stated their belief that the method could be used to develop all of the bituminous sands except for a region close to the outcrop. The application was heard by the Energy Resources Conservation Board in 1962 and a decision on the approval was deferred until 1968 if the company reapplied. Shell did not reapply and the proposal was dropped. The idealized behavior of a single production unit in the Shell process is illustrated in figure 9.

III.3. Underground Combustion

III.3.(i) Definition

In situ combustion is a process for the recovery of a partially upgraded bitumen in which part of the crude bitumen is burned underground to provide heat so that the viscosity can be reduced sufficiently for displacement to producing wells. Other names for this process are fire-flood, underground combustion, subsurface combustion, underground burning, and underground retorting.

In the forward combustion process the production zone is in front of the burning zone, and in the reverse combustion technique the heated liquids pass through the burning zone and are produced from the burned-out part of the formation.

III.3.(ii) Description

To initiate production from a reservoir by the *in situ* combustion process, a series of injection and production wells are drilled in a predefined pattern. The usual pattern consists of a central injection well surrounded by four producing wells (five spot) or eight producing wells (nine spot) (Fig. 6). The distance between the injection and production wells is commonly less than 300 feet. Communication between wells in an impermeable reservoir, such as the Athabasca deposit, is established by lifting the strata (by applying hydraulic pressure) and injecting sand into

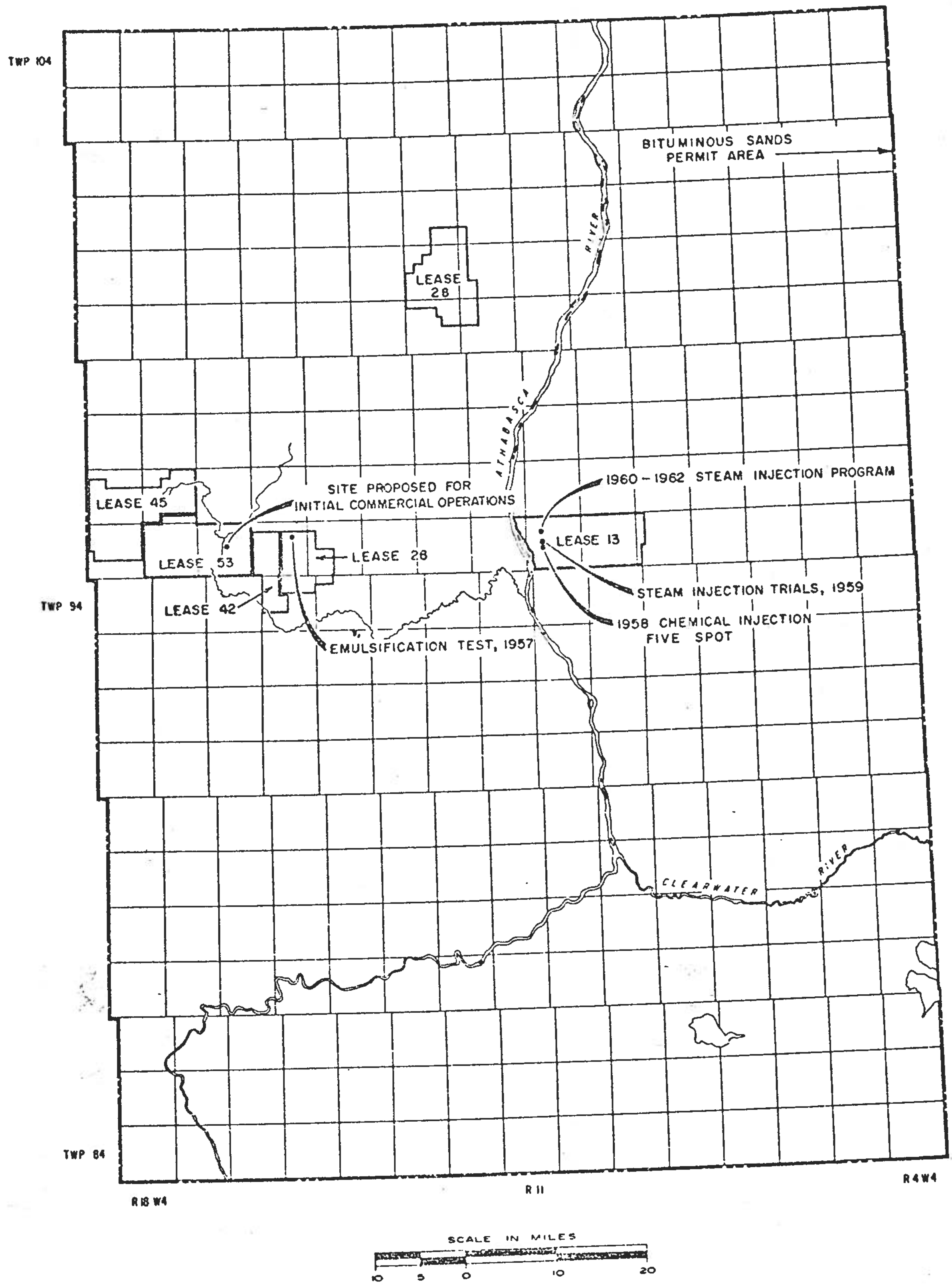


Figure 8. Location of steam-injection experiments and site of proposed commercial operations of Shell Canada Limited.

Reproduced from submission of Shell C~nada Ltd. to the Energy Resources Conservation Board, 1963

STEAM-INJECTION

ILLUSTRATION OF IDEALIZED BEHAVIOUR OF A SINGLE PRODUCTION UNIT
(After Doscher 1967)

EXPLANATION OF DIAGRAM

1. Initiation of basal fracture by hydraulic pressure.
2. Widening of fracture with chemical emulsifier.
3. Initial effect of steam heating in early production stage.
4. Possible "tonguing" of steam during production.
5. Spread of heat during production.
6. Final depletion.

LEGEND

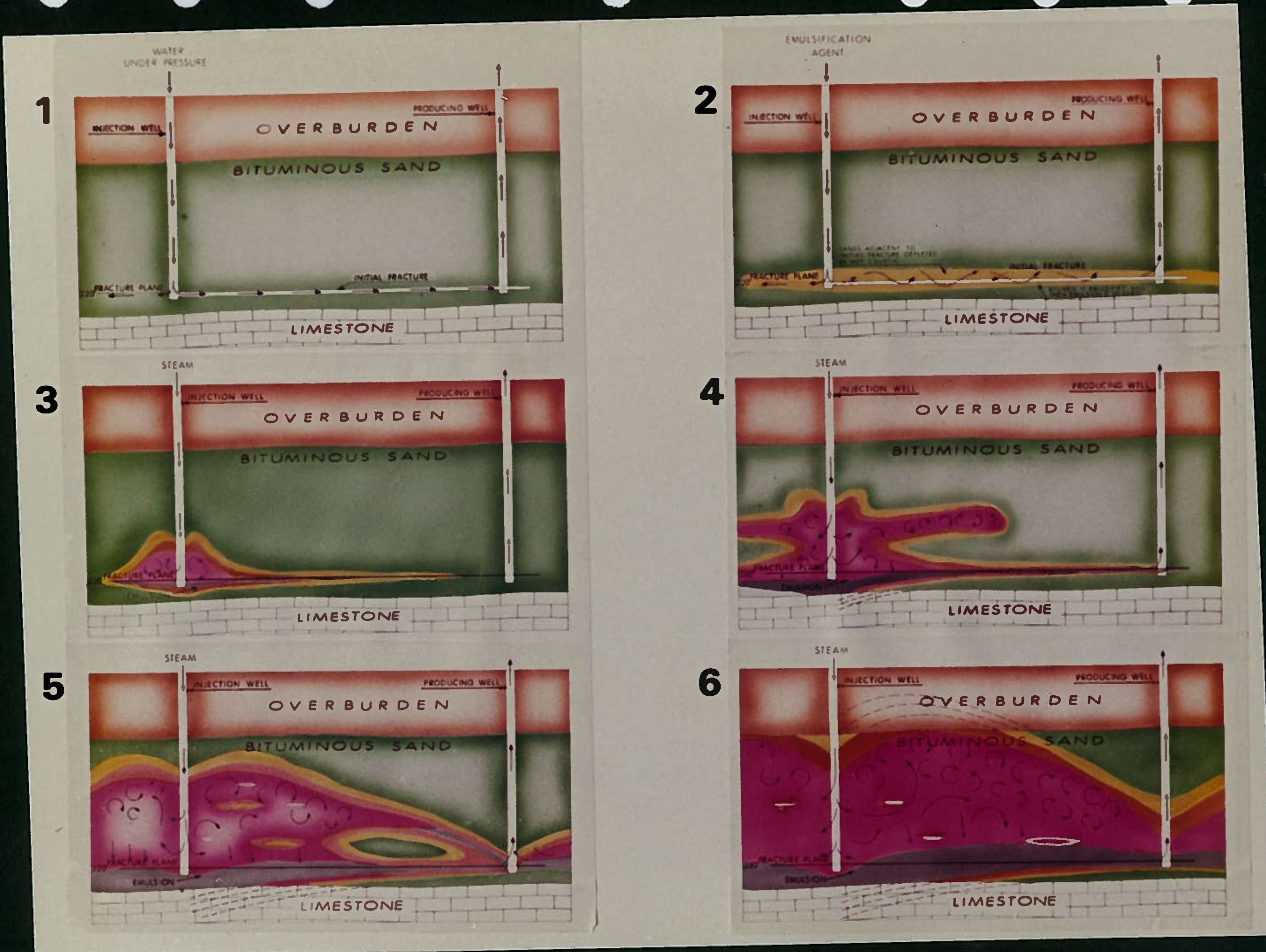
emulsion

300° F+ emulsion

200° - 300° F

100° - 200° F

50° - 100° F


1
WATER
UNDER PRESSURE
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
INITIAL FRACTURE
FRACTURE PLANE
LIMESTONE
2
EMULSIFICATION
AGENT
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
INITIAL FRACTURE
FRACTURE PLANE
LIMESTONE
3
STEAM
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
FRACTURE PLANE
LIMESTONE
4
STEAM
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
FRACTURE PLANE
EMULSION
LIMESTONE
5
STEAM
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
FRACTURE PLANE
EMULSION
LIMESTONE
6
STEAM
INJECTION WELL
PRODUCING WELL
OVERBURDEN
BITUMINOUS SAND
FRACTURE PLANE
EMULSION
LIMESTONE

the fractures until a permanent permeable path between the injection and production wells is confirmed by continuous circulation of water or gas. The bitumen in the vicinity of the injection well is then ignited, and a gas containing oxygen is circulated to keep the bitumen burning and advancing toward the production wells in a controlled manner. After a prolonged period of burning (up to six months) the injection of oxygen ceases and an inert gas is used to carry the heat into the formation in order to raise the temperature of the whole formation to about 200°F. At this temperature the bitumen is fluid enough to move under pressure (Fig. 10) and be produced from a well along with the gaseous combustion products and formation water. Production of oil is continued for a period of about 5 1/2 years or until the burning front reaches the production wells. If reservoir conditions are favorable, it is reported that 40 to 70 per cent of the bitumen in place will have been produced at the end of this period.

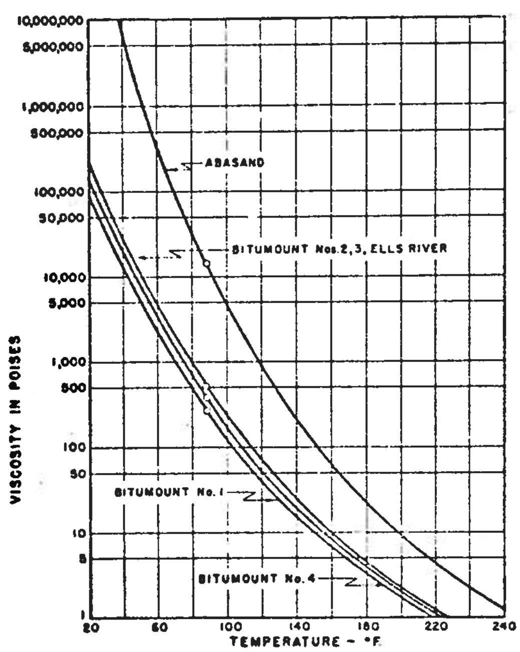


Figure 10. Plots of viscosity versus temperature for Athabasca bitumen from various localities (After Carrigy, 1971)

The amount of oil produced will depend on the thickness of the reservoir, the bitumen saturation, and the porosity and permeability of the sand. The presence of a gas cap or a basal water layer could cause by-passing of the burning zone and have a detrimental effect on the production. Extensive shale layers within the reservoir will also have an adverse effect on this process.

III.3.(iii) General Application

Over the past 20 years *in situ* combustion has been tested in at least 77 projects in the U.S.A., but only three of these have been commercial successes (Simms, 1972). Most of this experience has been from stimulation of depleted reservoirs and is probably not too relevant to the Bituminous Sands Area.

It seems unlikely that a pure *in situ* combustion process will be suitable for the Athabasca deposit because the low permeability of the thickly saturated sand layers prevents the efficient distribution of heat throughout the formation (Table 3).

TABLE 3

PHYSICAL CONSTANTS

1. *Athabasca Tar Sand*

Specific heat of formation[1] (1000 feet below surface) 0.298 cal/gm/°C

Specific heat of tar sand[2] (17.1% Bitumen, 0.9% water) 0.218 cal/gm/°C

Thermal conductivity of tar sand[2] cal/(sec)(cm²)(cm/°C) at 45°C

Undisturbed sample, 17.1% bitumen, 0.9% water 0.0035

Remoulded samples	(17.1% bitumen)	0.0027–0.0032
	(11.7% ,,)	0.0021
	(8.6% ,,)	0.0024
	(3.0% ,,)	0.0017

2. *Athabasca Bitumen*

Specific heat[2] 0.35 cal/gm/°C

Specific gravity[3] 1.002–1.027

Viscosity[3] Abasand location 600,000 poise at 59°F

Bitumount location 6–9,000 poise at 50°F

Calorific value[2] 17,900 BTU/lb.

Sources of Information

1. Shell Canada Limited
2. Clark[7]
3. Ward and Clark[12]

(After Carrigy, 1971)

III.4. COFCAW Process

In October 1968, Muskeg Oil Company, a wholly owned subsidiary of Amoco Canada Petroleum Company Limited, applied to the Energy Resources Conservation Board to produce 15 million barrels of crude bitumen a year at the rate of 8,000 barrels a day. The method of production proposed is a patented process designed to incorporate the best features of forward combustion and steam flood and is called a combination forward combustion and water flood (COFCAW). The concept is illustrated diagramatically in figure 11. The site of this semicommercial operation was to be the Gregoire Lake Indian Reserve No. 176. This company also holds two other leases in the area surrounding Gregoire Lake (Fig. 12).

Muskeg Oil Company withdrew its application before a decision was reached by the Energy Resources Conservation Board; however, experimental work has continued at the site.

III.5. Thermal Heat From Nuclear Detonations

In 1959 the Richfield Oil Corporation of California proposed an experiment designed to test the feasibility of economic extraction of deeply buried bituminous sands by the explosion of small nuclear devices beneath the Athabasca deposit. The Richfield proposal was to detonate a 9 kiloton bomb in the limestone beneath the bituminous sands at a depth of 1,250 feet. The explosion would create a cavity into which the bituminous sand would fall and be heated to temperatures at which the oil could be recovered by conventional drilling and production.

This proposal was considered by the Alberta Government and the Government of Canada in 1959. A technical committee appointed by the Government of Alberta, after extensive study of the possible contamination by radioactive products, recommended that the experiment proceed.* However, Federal Government approval to conduct the experiment was never obtained.

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* Alberta Technical Committee report to the Minister of Mines and Minerals and the Oil and Gas Conservation Board, August 1959.


UNDERGROUND COMBUSTION
C.O.F.C.A.W. CONCEPT
BITUMEN
GAS
WATER
PRODUCING WELL
COMPRESSED AIR
WATER
INJECTION WELL
BITUMEN
GAS
WATER
PRODUCING WELL
OVER BURDEN
500'+
500'+
COLD BITUMEN 60°F
HOT BITUMEN 300°F
800°F
FLAME FRONT 1500°F+
BURNED OUT ZONE
GAS & STEAM
CONDENSATION
FRACTURE
LIMESTONE

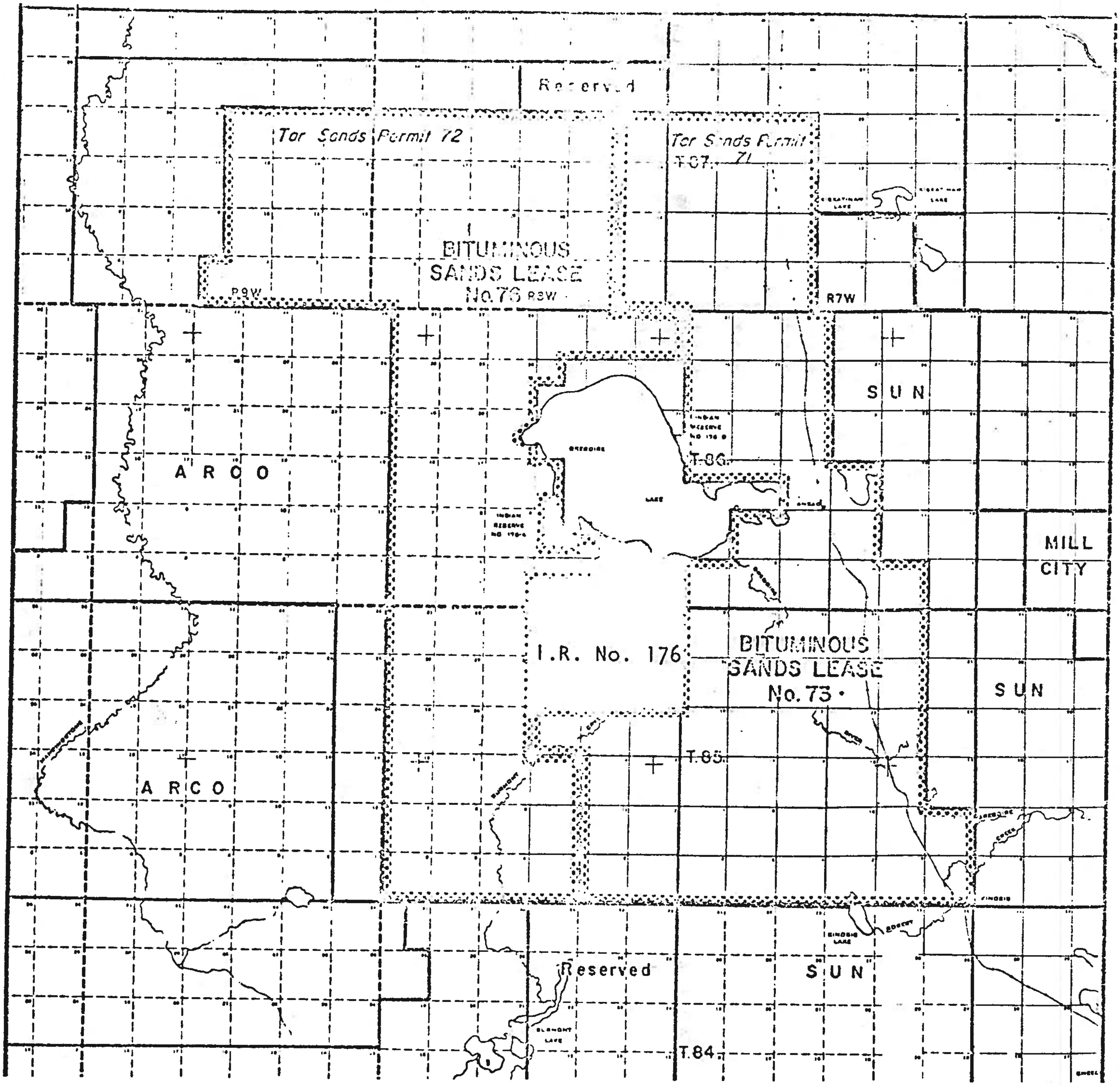


Figure 12. Bituminous sands leases held by Amoco Canada Petroleum Company Ltd. in the Gregoire Lake area. Indian Reserve 176 is the proposed site of the semi-commercial operation proposed by Muskeg Oil Company in 1968.

Recently (Paz-Castillo and Kruger, 1971), the feasibility of using a nuclear explosion at a depth of about 15,000 feet, to fracture sufficient rock to produce steam from geothermal heat for *in situ* recovery by steam-injection, was examined. It was estimated that steam for injection could be produced by this method for about the same cost as steam generation from fossil fuel.

A schematic diagram showing these nuclear detonations in relationship to the geological situation in the Bituminous Sands Area is shown in figure 13.

III.6. Heat From Decay of Radioactive Isotopes

A process to heat underground reservoirs, such as the Athabasca bituminous sands, has been patented in the United States (U.S. Pat. 3,233,669). In this method an insoluble radioactive material is introduced into the formation by injecting a clear solution of the radioactive element and reacting the solution *in situ* to form a radioactive insolute. One way to achieve this is to inject an aqueous solution of an alkali hexametaphosphate ($Na_6P_6O_{18}$) into which is dissolved a salt, hydroxide, or oxide of a radioactive element, such as strontium 85, 89 or 90, barium 140, calcium 41 or 45, cerium 141 or 144 and mixtures thereof. The polyphosphate complexes formed, slowly decompose to insoluble orthophosphates which remain in the reservoir. A quantity of 40 milligrams of strontium 90 per gallon of strontium 90 polyphosphate solution with a concentration of 5 grams of sodium hexa-metaphosphate per gallon has an activity of 6 curies per gallon. It is estimated that injecting 25 million barrels of solution per square kilometer would heat the formation sufficiently to begin production of oil at the end of a ten year period.

The inventor believes that the sand grains will hold the radioactive material so that the petroleum produced will remain uncontaminated. He also believes that this method would be a way of economically disposing of undesirable fissionable elements produced during nuclear power generation.

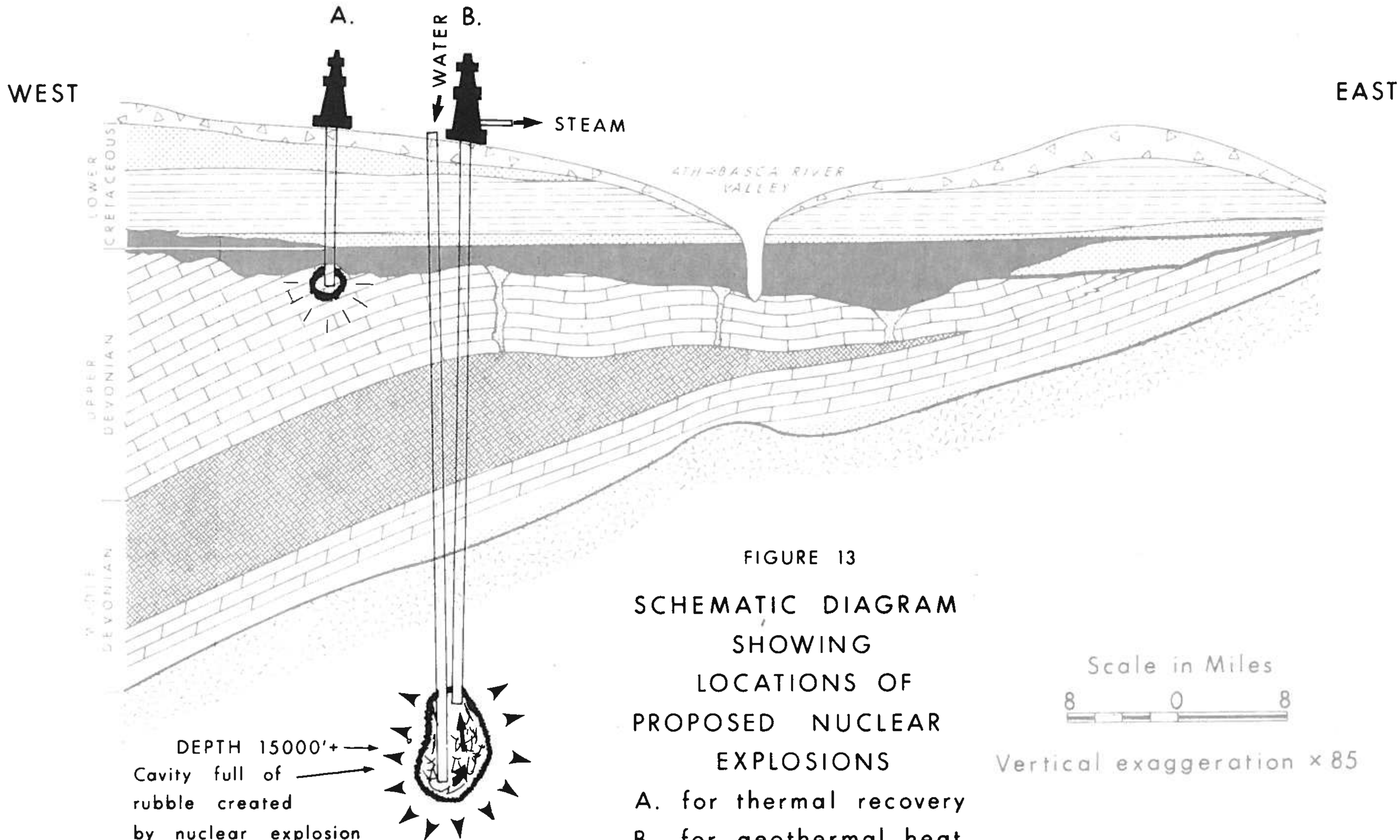


FIGURE 13

SCHEMATIC DIAGRAM SHOWING LOCATIONS OF PROPOSED NUCLEAR EXPLOSIONS

A. for thermal recovery

B. for geothermal heat

PART IV ENVIRONMENTAL IMPACTS

IV.1. Land transformation

IV.2. Water requirements

IV.3. Groundwater contamination

IV.4. Possible modification of groundwater flow pattern

IV.5. Liquid effluent disposal

IV.6. Air pollution

IV.6.(i) Field gases

IV.6.(ii) Sulphur emission from recovery and production

IV.6.(iv) Dust

IV.1. Land Transformation

All of the *in situ* methods for extracting oil from the Bituminous Sands Area involve the drilling of many rows of wells 200 to 300 feet apart to depths of 500 to 1,800 feet. For example, as many as 1,600 production and injection wells will be required to produce 100 thousand barrels a day of synthetic oil, and each well will be connected to the processing plant by one or more pipes carrying either injection or production fluids (Fig. 14). Because of the temporary nature of most of these facilities, it is presumed that they will be installed above ground and salvaged for re-use. To facilitate access and servicing of this network of wells and piping, the companies may feel that it is economically desirable to remove all of the ground cover above the producing reservoir (Photos 7 and 8). If this is done then an area of 54 to 60 square miles would need to be cleared for the production of 1 million barrels of product oil a day. As the economic productive life of a well varies from 3 to 7 years, from 8 to 20 square miles will have to be cleared of vegetation each year until the reservoir is depleted (Table 4). An equal amount of land will be abandoned each year and be available for reclamation.

The organic soils of the *in situ* area are composed of extremely compressible material, usually a living layer of mosses and sedge underlain by partially decomposed organic material with a very high water content. Such soils do not provide a good subgrade for road construction. In areas of discontinuous permafrost, such as the top of Birch Mountains, it will be necessary to remove all the frozen material and replace it with well drained material. The depth of the freeze and thaw zones in these areas are not known. Frost penetration into tar sands at lease 17 was 7 feet (Carrigy, 1967).

If all-terrain vehicles are not used, service roads will need to be constructed to a fairly high standard to carry the high axle loadings associated with normal drilling and servicing equipment, especially during the spring thaw. This will require the removal of the organic soil layer and the emplacement of an embankment to a level about 12 inches above the surrounding ground plus 6 to 12 inches of gravel. If this type of construction is necessary, substantial quantities of fill and gravel will be

FIGURE 14

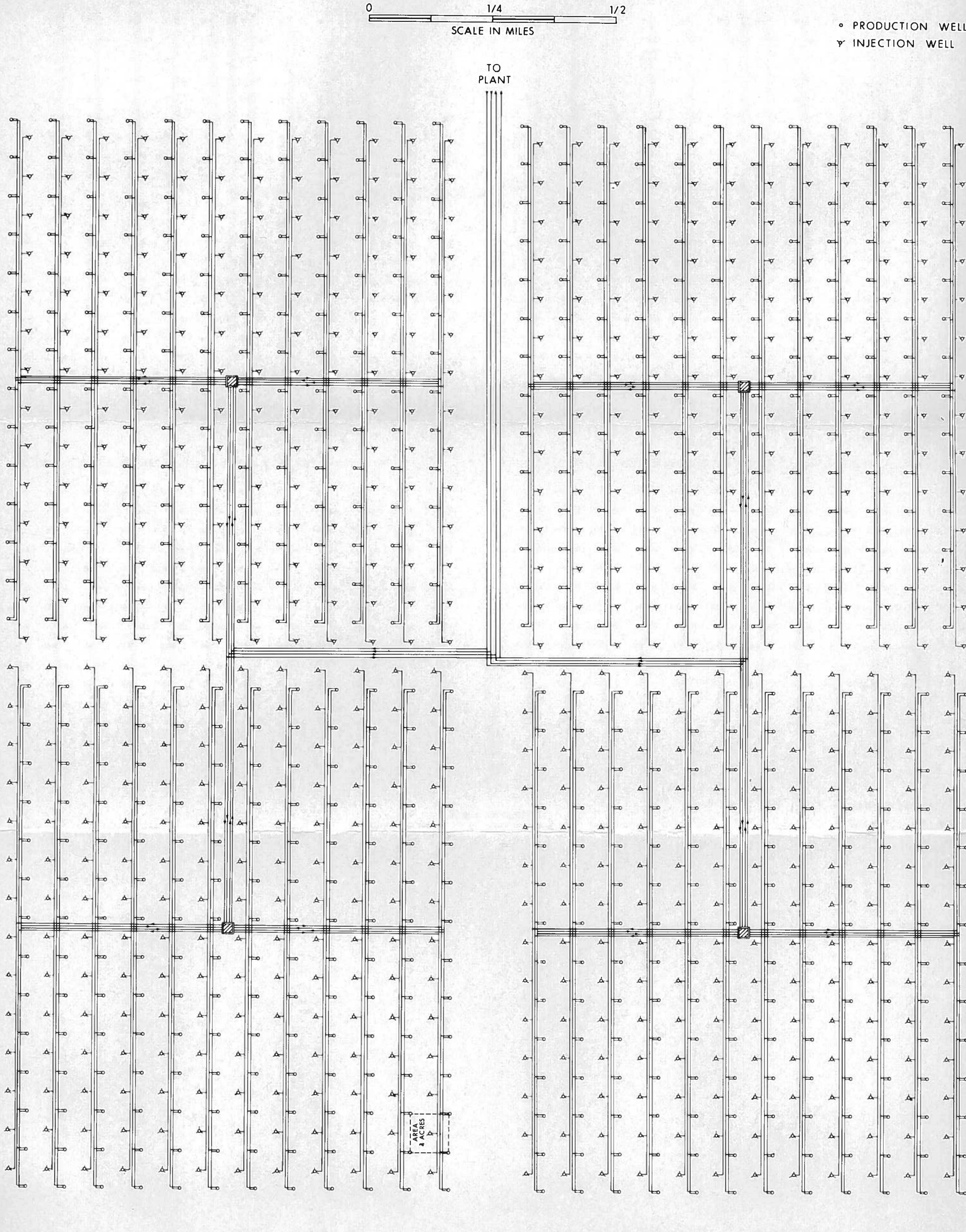
THEORETICAL WELL PATTERN AND PIPING LAYOUT FOR A COMMERCIAL IN-SITU DEVELOPMENT

(producing 80-100,000 barrels of bitumen per day)

(5 spot, 4 acre spacing)

0 800 1600 2400
SCALE IN FEET

0 1/4 1/2
SCALE IN MILES



Photograph Available

Photo 7. Field test site for steam-injection experiments located in mixed-wood forest on the eastern slopes of the Birch Mountains.

Photo courtesy, Edmonton Journal

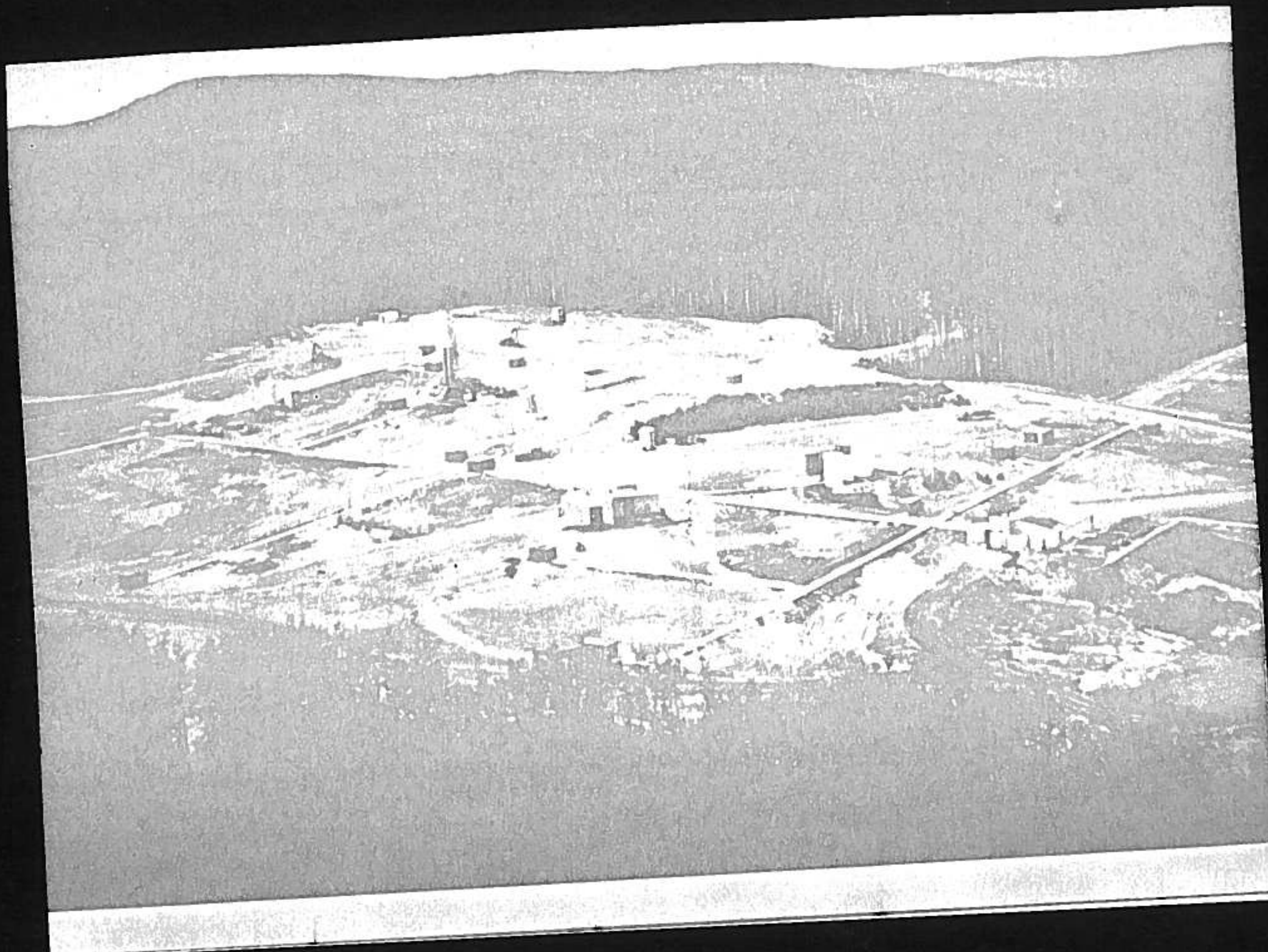


Photo 8. Field test site for COFCAW experiments located in aspen forest on northeastern slope of Stony Mountain.

Photo courtesy, D. Harrington
Department of the Environment

Table 4. Comparison of areas of land clearing associated with *in situ* and mining methods for the production of 1.3 million barrels/day of bitumen from the Bituminous Sands Area.

		IN SITU				MINING*	
		COFCAW		STEAM		HOT WATER	
		Square miles	Acres	Square miles	Acres	Square miles	Acres
Area cleared of all vegetation	Max.	53.7	34,368	60.0	38,400	31.0	19,840
	Min.	25.0	16,000	25.0	16,000	-	-
Amount of land to be reclaimed each year	Max.	7.67	4,908	20.0	12,800	3.4	2,176
	Min.	3.57	2,284	8.3	5,331		
Interval before reclamation		7 years		3 years		6 years	

* Note that land to be reclaimed in the mining development is underlain by sterile sand and will require a great deal of preparation before it will support a permanent growth of vegetation.

needed, and many pits and quarries will have to be opened. To facilitate regrowth it may be necessary to remove these road construction materials after production has ceased.

As most *in situ* operations will be located in the upper reaches of the drainage basins of tributary streams (Map 6) removal of the ground cover, especially of muskeg, could result in increased runoff and cause severe erosion in the immediate area. The resulting increased sediment loads could have adverse effects on downstream processing plants and the aquatic life in these streams.

The removal of trees and shrubs from large areas of land will mean reduced food and cover for large and small land animals. However, it is anticipated that all land under development will have to be fenced, because of the danger of rupture of the high pressure steam lines, and therefore this land may not be accessible to large mammals.

It is not known at this time how much merchantable timber is located in the *in situ* part of the Bituminous Sands Area. Some thought will have to be given to harvesting this valuable resource prior to exploitation.

In view of the large tracts of land which need to be cleared of vegetation for the *in situ* field operations, it would be desirable for the government to initiate a policy requiring the minimum removal of ground cover. For example, if the trees in forested areas are 50 feet high, a corridor 100 feet wide cleared along the pipeline right-of-way and around wells may be sufficient to prevent windfall damage. If clearing were restricted in this manner, more than 50 per cent of the natural vegetation cover could be left undisturbed, and the total amount of clearing required for the production of 1 million barrels of oil would probably not exceed 25 square miles. It is assumed that these untouched strips of natural vegetation would facilitate the regrowth of the natural vegetation into the cleared areas as soon as the field production facilities are removed (Photo 9).

If the gathering and injection pipelines are buried, narrower corridors and hence lesser amounts of clearing might be possible.*

It should be noted here that the permanent clearing of land for processing plants, product pipelines, highways, railways, and power transmission are not included in the above estimates.

To maintain the natural vegetation growth in these wet and boggy areas, drainage should be kept to a minimum. In the absence of a clear objective for improving the area for agricultural or recreational use, it is recommended that the land be returned to its natural state. To facilitate the regrowth of the natural vegetation the policy should be to:

1) remove as little vegetation as possible

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* Burial of pipelines will disturb the soil profile and this may offset the advantage of lesser area of clearing.

Photo 9. Regrowth of vegetation on pipeline, right-of-way crossing the high plains.

Photo courtesy, C. R. Neill
Highways and River Engineering Division

2) disturb the soil and muskeg as little as possible
3) remove the imported gravel from all areas of construction and add organic matter so that these areas will revegetate naturally.

IV.2. Water Requirements

Commercial *in situ* systems proposed for extracting and processing bitumen from the Athabasca deposit will require large quantities of good quality water. With the Shell steam-injection method, we have estimated that some 5.2 million barrels of water a day (333 cu ft/sec), is required for partial upgrading of 1.3 million barrels of crude bitumen. Complete upgrading to produce 1 million barrels of synthetic oil would, we estimate, require 555 cubic feet per second. The COFCAW method proposed by Muskeg Oil Company requires large quantities of make-up water only in its early stages. However, the writers estimate that for production of 1.3 million barrels of crude bitumen a day up to 1.7 million barrels of water a day (110 cu ft/sec) will be required for field operations. The additional water required to upgrade this bitumen will have to be added to this figure to get comparable water requirement figures for comparison with the steam-injection method.

It might be useful to examine the water requirements of the single plant as proposed by Shell Canada Limited in its application to the Energy Resources Conservation Board in 1962 to produce 130,000 barrels a day of bitumen from leases 26, 42, 45 and 53 in the upper Ells River drainage basin. In their application Shell sought permission to take water from Namur and Gardiner Lakes located on the top of Birch Mountains. The long term average in-flow from the catchment areas of both these lakes was estimated by Shell (Table 5) to be 200 cubic feet per second, and the water requirements for field and processing operations at the site were 33 cubic feet per second, or about 17 per cent of the average in-flow and possibly 50 per cent or more of the minimum in-flow. One plant, therefore, would use a significant proportion of the surface water stored in these lakes. In view of the possible desirability of reserving the water in these lakes for

Table 5. Estimated yearly average flow

	Namur Lake Outlet (cu ft/sec)*	Gardiner Lakes Outlet (cu ft/sec)*	Total (cu ft/sec)
Long term average	56	144	200
Mild drought occurring about once in 10 years	28	66	94
Moderate drought occurring about once in 50 years	17.5	45	62.5
Severe drought occurring about once in 100 years	15.5	39	54

* After Shell Canada Limited (1962)

future domestic use (INTEG Progress Rept. Phase II) and the necessity to guarantee a base-flow to maintain the integrity of the downstream aquatic life, a careful study of alternative sources of water will need to be made before any water from these lakes is diverted to industrial use.

A similar situation arises with respect to the water requirements of Muskeg Oil Company. In their application to the Energy Resources Conservation Board, Muskeg Oil Company proposed that sufficient water for their field operations could initially be drawn from shallow wells, but that Gregoire Lake would ultimately be needed as a reliable source of fresh water.

From the analysis of the water requirements presented above, it is evident that most of the surface water available in lakes and tributary streams will be required for large scale *in situ* development (Table 2). In view of the competing demands of industry, the people, and the environment, it will be necessary to undertake an extensive and lengthy survey of the water resources available, and to evaluate the consequences of water withdrawal, and storage. Before permission is granted to withdraw water from any natural storage area, it must be established that any change in the natural seasonal fluctuations in water levels will not adversely effect the habitats of wildlife or potential recreational use, and that the aesthetic qualities of the area will not be reduced. The effect of change on the cultural and economic livelihood (hunting, fishing, trapping) of the native people also will have to be assessed.

IV.3. Groundwater Contamination

In the petroleum industry all production, including secondary recovery, is from reservoirs that have an efficient fluid trapping mechanism, usually well below the zone of potable groundwater, and extreme care is taken during drilling and production to protect these supplies of fresh water. However, in the McMurray region the *in situ* operations will be conducted at shallow depths where injected fluids could contaminate potential domestic and industrial supplies of groundwater (Fig. 15). It is therefore important to know the nature of all fluids injected into the reservoir and the possible reaction and degradation products which might remain in the formation after *in situ* operations have ceased. For example, one patented method of igniting the hydrocarbons in an oil reservoir for recovery by *in situ* combustion (U.S. Pat. 2,747,642) uses 1 pound of phosphorous in 200 cubic centimeters of carbon disulphide. Another method (Oil and Gas Journ., 1960, p. 113) uses pellets of calcium phosphide which, when, contacted with water, produces phosgene gas which ignites spontaneously in the presence of oxygen. The possible use of such chemical ignition procedures in the Athabasca deposit in thousands of wells would pose the risk of serious

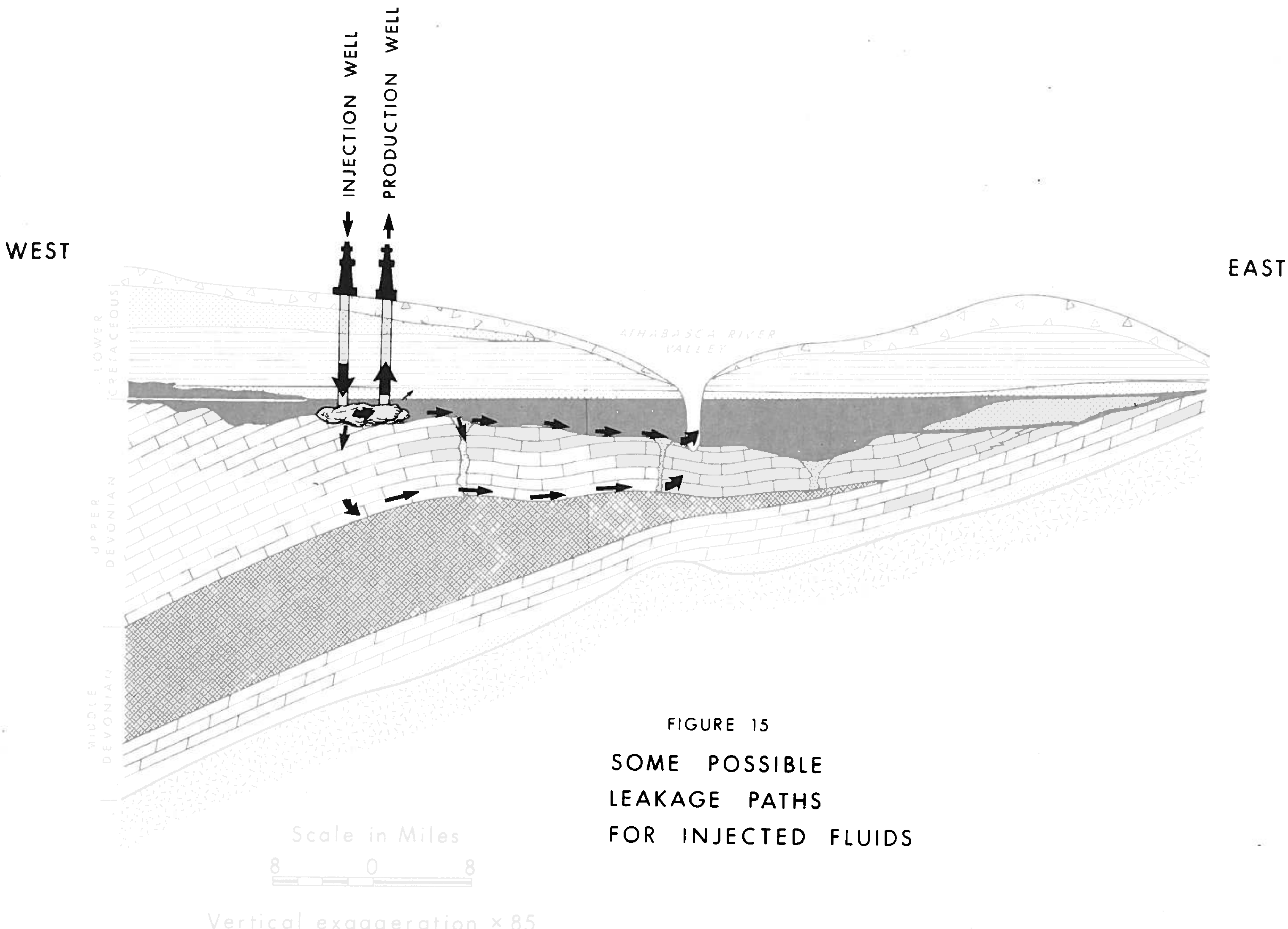

FIGURE 15
SOME POSSIBLE LEAKAGE PATHS FOR INJECTED FLUIDS

groundwater contamination in the area. Other chemicals may be introduced in gaseous form as catalysts to maintain combustion. Mentioned in U.S. Pat. 2,804,146 are phosphorous trichloride, phosphorous oxychloride, chloride, chlorine, hydrogen chloride, or chlorine derivatives of methane such as tetrachloromethane, trichloromethane, and dichloromethane.

In all *in situ* processes liquids may be injected to seal off permeable layers. Some of the liquids which might be used for this purpose mentioned in Can. Pat. 746,724 are carboxymethyl cellulose and calcium silicate.

In addition to the chemicals used for ignition and maintenance of combustion, the steam-injection process calls for the addition of surfactants and emulsifying agents, such as sodium hydroxide, potassium hydroxide and/or lithium hydroxide (Can. Pat. 711,556) in concentrations varying between 0.0025 and 1.0 weight per cent. It is surmised that these hot alkaline solutions will dissolve some of the silicate minerals present in the reservoir and could result in increased concentrations of silica and metallic ions in the effluent discharged into the surface waters. Also, after production has ceased, unless a flushing period with steam or fresh water is undertaken, these alkaline solutions will remain in the formation. The eventual discharge of these chemicals into the surface drainage system is a long term possibility that needs to be examined carefully.

It has been suggested (U.S. Pat. 3,233,669) that radioactive waste from nuclear powerplants could be injected into the reservoir in sufficient amounts to heat the bitumen hot enough for normal production.

In our opinion, no toxic chemicals, fluids, or gases should be injected into the reservoir without proper government approval and supervision.

IV.4. Possible Modification of Groundwater Flow Pattern

Two other effects of the *in situ* operations which need to be examined are the possibility that the high injection pressures and the increased porosity and permeability of the reservoir after the removal of the bitumen will affect the groundwater flow rates and pattern well beyond the production area. There is also the possibility of establishing connection with deeper flow systems *via* sinkholes in the underlying limestone, causing increased flow rates from saline springs present in the area. With our present limited knowledge of the regional groundwater flow-pattern there is no way of predicting the location or the magnitude of these effects.

IV.5. Liquid Effluent Disposal

Little data are available on the nature of the effluents that are likely to be generated during *in situ* extraction and upgrading operations in the Bituminous Sands Area. In the Shell Canada Limited application to produce 130,000 barrels of bitumen a day it is noted that 10 barrels a day of oil was to be discharged into the Ells River along with 397,890 barrels a day of treated process water of unknown composition and temperature. Simple extrapolation gives a figure of at least 100 barrels a day for oil discharged into the Athabasca drainage system from the production of 1 million barrels of synthetic oil a day.

In the Muskeg Oil Company COFCAW process a quantity of saline formation water is produced along with the bitumen. The salts in this water are concentrated during primary field processing, and will need to be disposed of in a satisfactory manner. A chemical analysis of the saline water produced by the COFCAW experiments is shown in table 6. From extrapolation of the volumes of salt water produced during these experiments, it can be assumed that up to 600,000 barrels a day of salt water would require disposal during the production of 1.3 million barrels of bitumen. The most environmentally desirable method of disposing of this waste would be to drill a well and inject it into the strata below the salt beds of the Middle Devonian Elk Point Group which underlies the Bituminous Sands Area at depth (Fig. 16). On the one hand, this would eliminate the risk, apart from accidents, of salinization of the surface waters. But on the other hand, the extra pressure exerted on the system by the injection procedure may increase the flow rate at existing saline springs which emerge in the Athabasca River valley. The applications by both Muskeg Oil Company and Shell Canada Limited state that the waste water will be disposed of in a manner approved by the Department of Health.

Table 6. Produced water analysis*
(From Muskeg Oil Company application)

Major Ion Analysis	mg/l
Sodium	2,884
Calcium	68
Magnesium	63
Potassium	0
Chloride	4,220
Bicarbonate	561
Sulphate	280
Carbonate	0
Total	8,076

Total solids, mg/l	8,110
NaCl resistivity, mg/l	7,586
Specific gravity at 72°F	1.006
pH	7.4

* Produced during COFCAW experiments

The question of the location of processing plants for upgrading the bitumen produced by *in situ* and mining operations needs careful examination particularly with regard to the possible discharge of large volumes of liquid effluents into small tributary streams. At the present time no recommendations can be made because no reliable data exists on the flow characteristics of most of these streams. Nevertheless, the empirical data on runoff and drainage areas (Table 2) would suggest that the number of upgrading facilities be kept to a minimum, and that they be located on streams with flow rates sufficient for adequate dilution of the wastes.

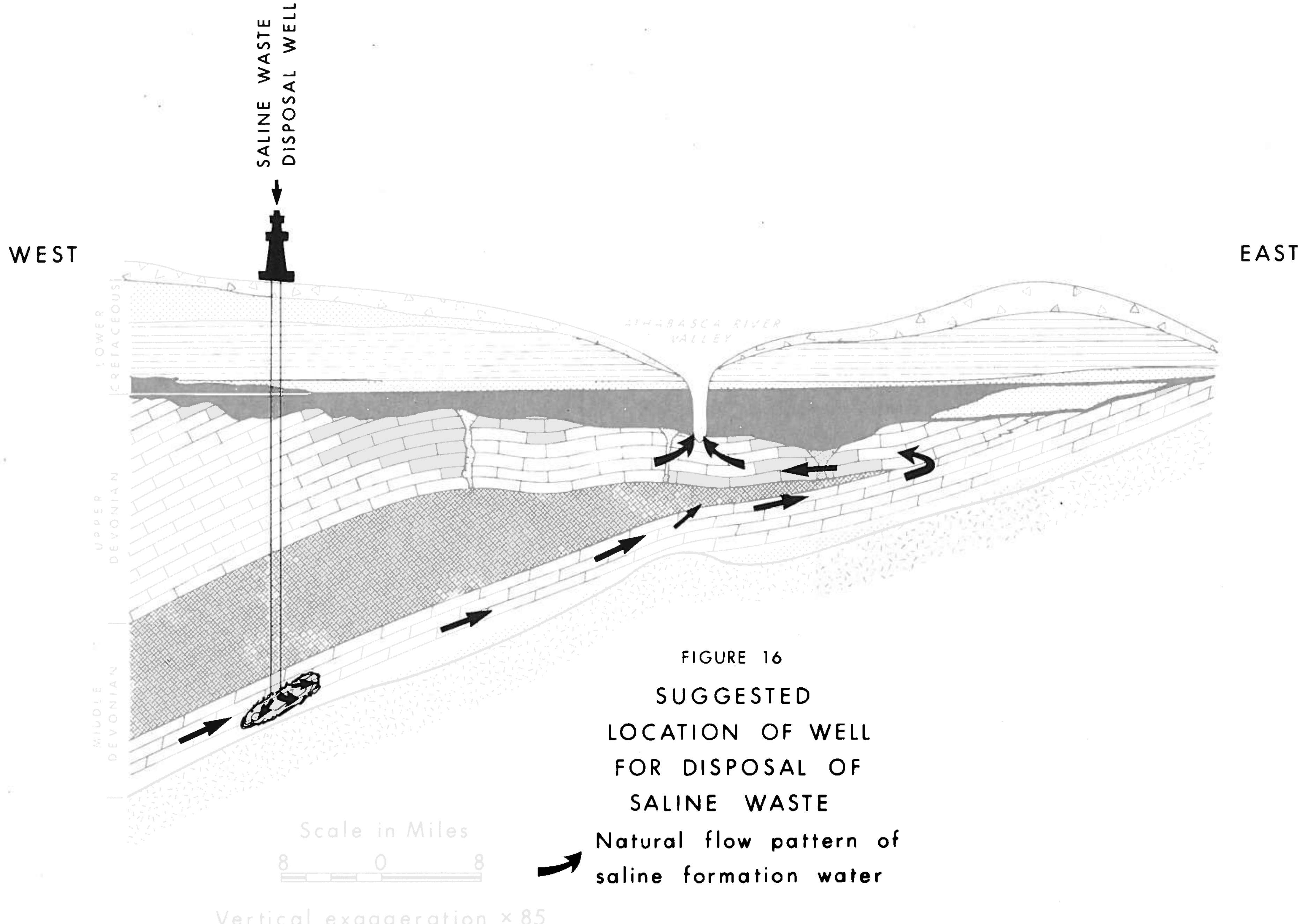

FIGURE 16

SUGGESTED
LOCATION OF WELL
FOR DISPOSAL OF
SALINE WASTE

IV.6. Air Pollution

IV.6.(i) Field Gases

In the COFCAW process, gases containing a mixture of oxygen and inert gases will be injected into the formation to maintain and control the combustion of the hydrocarbon in the subsurface. Most of the oxygen injected will be consumed in the burning process, and the gaseous combustion products will be withdrawn from the formation along with the bituminous emulsion at the production wells. The field gases so produced will then be separated and vented to the atmosphere or flared. An estimate of the maximum volumes of field gas that might be vented or flared from an operation producing 1 million barrels of synthetic oil by the COFCAW method are shown in table 7.

Table 7. Probable amount of field gas produced during the production of 1.3 million barrels of bitumen/day by the COFCAW Process*

	From Early Production Phase Wells	From Late Production Phase Wells	From All Wells
H_2	8.33**	3.33	11.66
CO_2	20.52	33.55	54.07
CO	0.64	0.95	1.59
N_2	32.25	115.89	191.14
O_2	0.00	0.04	0.04
H_2S	3.26	0.25	3.51
COS	0.00	0.02	0.02
Hydrocarbon	54.19	13.54	67.73
Toluene	0.18	0.02	0.20
TOTAL	119.37	210.59	329.96

* Extrapolated from Table F1 Muskeg Oils Ltd.

** Millions of cubic feet

If flared the combusted gases will consist of H_2O, CO_2, NO_x and SO_2. The environmentally significant pollutants in this list are SO_2 and NO_x. For 1.3 million barrels a day production of bitumen we have estimated that 1,260 long tons a day of SO_2 would be released into the atmosphere in the field. If vented the most toxic components will be hydrogen sulphide and carbon monoxide. Venting of this quantity of gas will undoubtedly result in odor problems, and flaring from a high stack is the preferable treatment. Sublethal concentrations of hydrogen sulphide and carbon monoxide during venting must be avoided. A discussion of the limits of concentrations of various gaseous pollutants is discussed in the Phase II INTEG report and need not be considered further here.

The gaseous emissions from the upgrading and utility plants will be the same as those discussed previously,* and whether these can be safely dispersed cannot be known until the location of the plant has been decided upon. The meteorological study report in Phase II suggests location of upgrading plants at higher elevations could be an advantage in dispersal of gaseous pollutants, especially if they are above the level of the thermal inversions.

Studies elsewhere of gases produced from underground combustion projects (U.S. Pat. 2,914,309) have detected, in addition to those gases mentioned by Muskeg Oil Company, phenols, and ammonia, and Howard (1965, p. 102) reports that "even when hydrogen sulphide is not present the combustion gases have a distinctive odor that is objectionable to most people. If combustion operations are undertaken near populated areas disposal of these gases will be a problem."

No analyses of produced gas were included in the application for commercial development of the steam-injection process by Shell Canada Limited in 1962. However, one of the limitations of steam injection listed by Simm (1972) is the release of frequently hazardous H_2S with produced oil and steam.

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* Integ report on mining hot-water extraction

IV.6.(ii) Sulphur Emission From Recovery and Production

Large quantities of sulphur-bearing gases will be vented to the atmosphere, if abatement measures are not taken, during the production of bitumen by COFCAW or other combustion methods of *in situ* recovery. In these underground burning methods the sulphur comes primarily from two sources, the bitumen and the sulphide minerals such as pyrite (FeS_2) in the reservoir.

Because the Muskeg Oil Company's proposal is not an integrated process and most of the sulphur will be released and recovered at a processing plant, no analyses showing the sulphur content of the partially distilled product expected to be recovered are available to make estimates.* Therefore, a sulphur balance for this process cannot be drawn up at the present time.

The amount of sulphur that would be recovered in the elemental form in the steam-injection process outlined by Shell Canada Limited in 1962 is 39.38 per cent of the total sulphur in the bitumen. This would amount to 4,086 long tons a day if a million barrels of synthetic oil were to be produced (Table 8). The remaining 60.62 per cent, or 6,290 long tons a day, would be released to the atmosphere when the bitumen and its by-products are burned. As near as we can estimate, the quantities of sulphur that would be emitted to the atmosphere at various locations are given in table 9.

Table 9. Sulphur emitted to atmosphere daily from preparation of bitumen recovered by the steam-injection process *

In the Bituminous Sands Area	5,703.0 long tons
In Edmonton	200.8 long tons
From burning or refining of synthetic oil	386.2 long tons
Total	6,290.0 long tons

* From production and consumption of 1 million barrels of synthetic oil. Extrapolated from data supplied by Shell Canada Limited to Energy Resources Conservation Board, 1962

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* In the transcript of the proceedings of the hearing of Muskeg Oil Company application by the Energy Resources Conservation Board (1969), the sulphur content of the bitumen produced during experiments was said to be 3.5 weight per cent.

Table 8. Sulphur balance for steam-injection process* (for production of 1 million barrels of synthetic oil)

	Sulphur (Long tons/day)
Bituminous Sands Area	
Input:	
Bitumen	10,376
Output:	
Distillate to Edmonton	4,673
Fuel (pitch)	4,372
H_2S in fuel gas	1,331
Edmonton	
Input:	
Distillate from Bituminous Sands Area	4,673.0
Output:	
Gasoline	11.6
Hydrotreated Naphtha/LGO	28.0
Hydrotreated HGO	346.0
Incomplete conversion in sulphur plant	200.8
Elemental sulphur	4,086.0

* Extrapolated from data supplied by Shell Canada Limited to Energy Resources Conservation Board, 1962.

The total emissions of sulphur per year for the production of 1 million barrels a day of synthetic oil by the steam-injection system, without abatement, would be equivalent to 4.6 million tons of SO_2.* This amount of SO_2 is about one-fifth of the estimated annual emission of sulphur dioxide to the atmosphere from all stationary power plants in the United States in 1970. As most of this sulphur dioxide is produced during the burning of the "pitch" residue as fuel on the extraction site, it will probably be released simultaneously at a number of plant sites. The spacing and pollution limitations on these plants will have to be regulated carefully and will require extensive knowledge of air movements in the whole Bituminous Sands Area if major pollution of the atmosphere, soils, and water is to be avoided. The only presently available method for reducing SO_2 emissions is the substitution of low-sulphur fuels.*

IV.6.(iv) Dust

Little data are available on which to base an estimate of the solid waste disposal problems for *in situ* operations in the Bituminous Sands Area. The only reference to solid waste is contained in the Oil and Gas Conservation Board Report on the Shell Canada Limited application, wherein it is stated that about 180 tons a day of mineral matter produced along with the bitumen emulsion would remain in the "pitch." Presumably this mineral matter will be emitted as dust into the atmosphere with the flue gases when the fuel is burned. Extrapolating these data to the production of 1 million barrels a day of synthetic crude oil gives a figure of 1,800 tons a day of solids emitted into the atmosphere from the upgrading plant associated with the steam-injection process.

As no analyses of the mineral content of the bitumen produced by the COFCAW process are available, no estimate of the quantities of dust to be emitted to the atmosphere from the burning of "pitch" or coke made from bitumen recovered by this process can be made. However, it is assumed that

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* Ad Hoc Panel on Control of Sulfur Oxide from Stationary Combustion Sources; National Academy of Engineering, Washington, D.C., 1970.

it will be equal to or greater than that produced by the steam-injection method.

It is recommended that attempts should be made to get samples of the bitumen produced by the steam injection and COFCAW experiments* in the Athabasca deposit for analysis, so that some meaningful projections of environmental effects of dust emission can be made.

* In the transcript of the proceedings of the hearing by the Energy Resources Conservation Board of the Muskeg Oil Company (1969) application, the solids content of the bitumen was said to be less than 1 per cent.

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