PROCEEDINGS
ATHABASCA OIL SANDS CONFERENCE

SEPTEMBER — 1951

BOARD OF TRUSTEES
OIL SANDS PROJECT
GOVERNMENT OF ALBERTA
EDMONTON, CANADA

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FOREWORD

The Oil Sands Conference was arranged by the Alberta Government for the purpose of studying the factors affecting the development of the Athabasca oil sands.

The conference was planned for this time in order to follow the publication by the Government earlier in the year of the Blair Report on this resource. That report suggested a sequence of possible processes that would be applicable for the development of the sands, and estimated the current costs. The general procedure used in the report was followed by the conference, in order to simplify reviewing the essential steps necessary for winning a commercial oil.

The meetings commenced on September 10th, 1951 and continued throughout the week. The first part of the conference, covering some three and one-half days, took place in Edmonton and was devoted to the technical and administrative aspects of the problem. The second part was directed to field examinations of the raw material and its possible separation, as seen at major outcrops near the town of McMurray and the quarry and pilot separation plant at Bitumount on the Athabasca River.

The technical studies included a review of the geology of the formation, possible mining methods, oil separation from the sand, refining of the oil and its transport. A series of papers were given on each section by parties with specialized knowledge gained through working with this actual material or, where some new phase of the development was under consideration, by parties who had experience with handling similar material on a major scale in industry.

The conference was thus fortunate and greatly appreciated the opportunity of both hearing from, and discussing each problem as it arose with recognized leaders in that type of development. Their papers are now being presented in the form of one volume to assist in the study of the subject as reviewed at the conference.

The delegates represented a wide cross-section of the industries that are likely to be associated with the development. About 50% were executives of oil companies throughout the continent and abroad, 30% represented major mining and engineering organizations, and 20% were delegates from governments, associated industries, financial groups and the press.

Through the courtesy of the University of Alberta, the delegates lived in the University buildings on the campus and the meetings were held in the University lecture rooms.

S. M. Blair,
Technical Director of Conference.

EDITORIAL NOTE

These Proceedings were compiled from submitted manuscripts and from tape recordings. In the few cases in which no manuscript was available, the tape recording was transcribed, edited and submitted to the speaker for revision. A similar procedure was followed for the discussions of the papers.

In editing the papers, the Canadian Government Editorial Style Manual, Ottawa, 1939, was followed with few exceptions.

Discussions of papers, where they occurred, are included. The names of delegates asking questions were not always obtained.

Reprinting of papers from these Proceedings is permissible provided that entire papers are reprinted and appropriate reference to these Proceedings is given.

K. A. Clark
D. S. Pasternack
G. W. Hodgson
M. R. Wardle

Research Council of Alberta
Edmonton
October, 1951

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Athabasca Hall. Courtesy of the Government of Alberta

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OFFICIAL OPENING

ATHABASCA OIL SANDS CONFERENCE

By Hon. Dr. J. L. Robinson
Minister of Industries and Labour, Government of Alberta

As Chairman of the Board of Trustees, Oil Sands Project, Government of Alberta, I bring greetings to this conference on Athabasca oil sands. I trust that the arrangements which have been made for you are to your liking, comfort and convenience. Another reason, I might say, for being here this morning is to give you a chance to take a look at the man who originated the invitation either to you or your company. In launching this program which follows immediately, I wish to thank all those who have contributed in any way to the organization and conduct of this conference up to the present time. I must pay tribute to the wonderful co-operation of the University of Alberta, the Research Council of Alberta, the Mines Branch at Ottawa, the National Research Council, and the research organizations of private companies and their staffs. I extend thanks to those of you who have devoted so much time and thought and effort in the preparation of material for presentation during the sessions. The co-operation of everyone has been most wonderful. The interest in the Athabasca oil sands shown by the many business organizations, educational institutions and research centres, that have sent representatives to this conference, is deeply appreciated. I trust that everyone attending will go away feeling that their time has been well spent, and that substantial progress has been made toward adding the Athabasca oil sands to the available sources of supply of oil in the North American Continent.

This conference is a follow-up of what is now known as the Blair Report on the development of the Alberta bituminous sands. This report indicates a certain sequence of known, proven operations. An evaluation of the processes involved in the sequence indicates that the time may have arrived when the bituminous sands can be successfully and profitably developed. The conclusions reached are most encouraging, to say the least. At last, in the report, an appraisal has been made of the oil-sand problem. However, in order that even more detailed appraisal can be made of the many vital questions still involved, many of which are still unanswered, this conference is to hear outstanding authorities on geology, mining, separation, desulphurization, refining, pipeline transportation, marketing and other subjects related to the problems involved. In launching this conference at this time, it is my privilege and pleasure to introduce to you the technical director of the conference and, at the same time, the author of the Blair Report, Mr. S. M. Blair, Consultant Petroleum Engineer, Toronto.

INTRODUCTION

By S. M. Blair

Technical Director of Conference

This Conference has been arranged for the presentation and consideration of information pertaining to the development of the Athabasca oil sands. Complete development of the sands is a subject which encompasses and co-ordinates several industries some of which are not usually closely associated with each other. This is because the physical nature of the oil sands necessitates different methods of oil recovery from those usually adopted. In this case, the oil will not drain from the sand nor can it be driven out by water or gas pressure under normal conditions. At the same time, the proximity of the sands to the surface allows consideration of other methods of oil removal which may permit more complete recovery of the total oil content than is usually possible. At the direction of the Government of Alberta, a survey has been made of the possibilities for commercial production of oils from this resource. The survey utilized the research findings and developments of Dominion and Provincial Government departments together with those of industries. In the survey a chain of operations was selected for securing marketable oils and they were evaluated. The operations chosen were ones that were capable of being co-ordinated into an effective sequence and also were ones which were adequately proven for evaluation and estimating purposes at that time. Factors were taken for general estimating purposes from the experience of the mining and oil-refining industry elsewhere. It was desired to keep such estimates reasonably conservative. In some cases further work may show that they were over-cautious. However, with the widening of interest by industries in this subject and with the steady development of new processes which can be applied, no analysis or evaluation of the oil-sand resource can be considered as final. The possibilities of development are continually growing.

We are very fortunate in this conference in having in one relatively small group the experienced authorities from organizations that are world leaders in each of the major steps necessary for oil-sand development. The work of the conference might be described as the application of free enterprise, reacting to the stimulus of encouragement, to the problems of developing a natural resource. The Government of Alberta, while drawing attention to the resource, is at the same time presenting all data available to it and, during the conference, will describe the future government policy under which it is proposed that the over-all development will proceed. The willingness of enterprise to co-operate is shown by the presence, here, of its representatives who have come from great distances to Alberta and who in many cases have brought with them the results of a great deal of work in the preparation of authoritative papers. The University has also contributed generously by making all their facilities available to this conference.

The companies here represented include both those who have been working continuously on oil-sand research projects and also groups with developed processes or established data that are pertinent to phases of the oil-sand development problem. To mention a few: in mining, the M. A. Hanna Company, well known everywhere for their vast mining undertakings and, in Canada, for their recent work on the Labrador iron ore range, have a representative here to discuss open-pit mining; the Climax Molybdenum Company, with world-wide reputation in the development of underground mining techniques, have sent representatives to consider the possible application of certain underground mining methods to oil-sand development; engineers from Mannix Ltd., an Alberta organization, have come to present data and speak both from their comprehensive mining work and their general field experience in this province; in oil refining, the Lummus Company engineers from New York have come to describe their new continuous coking process and to consider its possible application to oil-sand oil; representatives of Universal Oil Products Company of Chicago, which has contributed so much to research and engineering studies of the oil sands, have come to describe further the results of their recent work; the Union Oil Company of California scientists have come to describe their process for the removal of sulphur from oils by mild hydrogenation—a matter of very real interest in processing oil-sand oil. The Mines Branch at Ottawa, the National Research Council at Ottawa, the Research Council of Alberta, certain of the research institutes from the United States including Pennsylvania State College, are all contributing liberally with the results of their intensive research projects. It is the work of a number of these groups such as the Mines Branch, the National Research Council and the Research Council of Alberta that has provided the links which, when combined with processes from industry, make possible a sequence of practical operations for the handling of the oil sands. A comprehensive review of oil transportation in general, with particular reference to Alberta, is to be presented by the Bechtel Corporation.

The steps to be discussed in this conference fall into natural, general groups commencing with geology, followed by mining, oil recovery, oil refining and oil transportation. There will be a chairman for each of the groups. Taking the steps in their natural order, the first group is geology. The chairman is Dr. George Hume, Director-General of the Department of Mines and Technical Surveys of Canada. Dr. Hume is well known to most of you. He has an intimate personal knowledge and intense interest in the subject of the Athabasca oil sands and has contributed a vast amount to our knowledge of them. The conference is fortunate in having Dr. Hume personally present. I take pleasure in introducing Dr. Hume.

GEOLOGICAL SESSION

CHAIRMAN: G. S. HUME

Department of Mines and Technical Surveys, Ottawa

The geological program has been designed to give the setting for the economic considerations which will follow when the other phases of the program are considered. In devising this program, it seemed that the logical way would be to have two or three papers on the McMurray formation itself, then a couple of papers on the regional stratigraphy both of the Lower Cretaceous and Devonian, and finally a discussion of the possible origin of the bitumen in the bituminous sands. For the first phase of this program we have, therefore, three papers. The first is by Dr. Sproule who undertook a study of the McMurray formation as a thesis for his Ph.D. degree. At that time he was working for the Geological Survey. Since then he has been with the International Petroleum Company, and now is starting a consultant business of his own in Calgary. That will be followed by a paper by W. L. Falconer. Mr. Falconer worked at the Abasand plant when it was operated by Max Ball. He also had an opportunity to see the oil sands from the standpoint of drilling while with the Bear Oil Company. He was in charge of the operations when a number of wells were drilled for oil in that area. He now has an oil company of his own. The third paper on that phase will be given by F. A. Kidd of the Shell Oil Company. During World War II the Dominion Government carried out a considerable drilling program in the McMurray area. The cores were made available, and the Shell Oil Company sent some geologists to Ottawa to study them. Among those was Mr. H. D. Curry. Mr. Kidd's remarks will include some of the inferences drawn by Mr. Curry as a result of the study of the cores which were made available.

The second part of the program will deal with the regional stratigraphy. Dr. Wickenden of the Geological Survey staff, who has had a wide experience on the Lower Cretaceous stratigraphy, will give the regional picture. Dr. P. S. Warren, head of the Department of Geology at the University of Alberta, who has had a wide experience in stratigraphy and paleontology, will discuss some aspects of the Upper Devonian stratigraphy. Some of these early papers will not only deal with stratigraphy, but will also deal with stratigraphy in relation to the origin.

Dr. Link will give the possible Devonian origin of the bitumen. Then I am to present the paper on the possible Lower Cretaceous origin of the bitumen, and will be followed by a paper by Dr. Montgomery of our Mines Branch at Ottawa.

THE McMURRAY FORMATION IN ITS RELATION TO OIL OCCURRENCE

J. C. Sproule
Petroleum Exploration Consultant, Calgary

INTRODUCTION

This paper is a sequel to a paper entitled *Origin of the McMurray Oil Sands, Alberta* published in 1938 (17). It gives general coverage to those geological aspects of the McMurray formation that are closely related to the occurrence of oil. An attempt is made to avoid unnecessary repetition of details already given adequate coverage, although a certain amount of factual data must be duplicated here in order to build a background for discussion of the theoretical considerations presented.

The oil-soaked sands of the McMurray formation are known by reputation to practically everyone in the exploration and the development branches of the oil industry. Since it was recorded by Peter Pond in 1788 it has held a high place in the "oil occurrence wonders of the world" and still ranks as the largest reserve of oil known to man. Estimates of its areal extent range from 8,000 to 30,000 square miles and estimates of its reserves from 100 billion to 300 billion barrels. The question of origin of an occurrence of this magnitude is obviously worthy of a great deal of attention since, if the oil was formed in situ the entire reserve is probably still within the sand body, but if it came from outside the sand body, either from correlatives of the Cretaceous McMurray formation or from the underlying Paleozoic, the strata of indicated origin must immediately be placed in the category of a highly prospective exploration objective.

The McMurray oil sands are exposed on the banks of the Athabasca River for 65 miles below McMurray. For many miles beyond this, and on the Firebag River, there are bedded deposits of reworked oil sands of glacio-lacustrine origin, sometimes mistaken for McMurray sands. The most northerly outcrops recorded occur on Reid Creek, thirty miles east of the mouth of Firebag River. They extend for 30 miles east of McMurray up the Clearwater River to Cottonwood Creek. Southwest of McMurray up the Athabasca River they outcrop for a distance of less than 40 miles, where they plunge beneath the river valley on regional dip. South of McMurray a number of old drill holes penetrated Lower Cretaceous oil sands at Pelican Rapids and near Kinosis on the Northern Alberta Railway. More recently, Bear Oils and other companies have extended the occurrence farther south, not to mention the numerous occurrences of McMurray-equivalent Lower Cretaceous and Upper Cretaceous oil discovered elsewhere in Alberta during the present oil boom.

No mention of the historical background of exploration and exploitation of the McMurray oil sands is complete without reference to the work carried out by S. C. Ells between 1913 and 1931. K. A.

Clark (6) and S. M. Blair (4), and M. W. Ball (1, 2) also contributed materially to the problem of mining and extraction of the oil from the sands.

GENERAL GEOLOGY

To bring the oil sands problem into proper perspective we should like first to bring out a number of regional environmental considerations which could have as much bearing on the subject at hand as the stratigraphic, lithologic, mineralogic and other details of the occurrence itself. These features are illustrated on the Western Canada Basin map shown in Fig. 1. This Basin map is intended to represent the present surface of the Paleozoic, and Precambrian. The Paleozoic surface is roughly contoured in feet, the contours being referred to sea level. The features of particular interest on this map are:

Fig. 1. *Western Canada sedimentary basins showing (1) contours on the Paleozoic surface (datum—sea level), and (2) relationships of the McMurray formation.* (Published by permission of Imperial Oil Limited, Calgary.)

1. The Basin area under consideration is bounded on the west by the Canadian Rockies and the Franklin Mountains, and on the east

by the Precambrian Shield. It is divisible into three "sub-basins," the Moose Jaw (Williston) Basin, the Alberta Basin and the Mackenzie Basin.

2. The Lower Cretaceous McMurray formation occupies a position on the eastern slope of the broadly truncated Paleozoic surface. In Alberta the Paleozoic surface plunges westward to the axis of the Alberta Basin somewhere west of the edge of the foothills, whereas the bedding planes of the individual Paleozoic formations plunge westward at an even greater rate. The result is that the older Paleozoic formations are exposed at the surface on the western side of the Basin, with progressively younger rocks exposed at the surface toward the western margin of the Basin.

A suggestive feature of the restoration made is the present steep west slope of the Paleozoic compared to what it must have been prior to the Rocky Mountain uplift, with consequent foundering of the eastern and central Alberta region accompanied by marine invasions from both the north and the south. The potential significance of this paleogeographic relationship to the time of invasion of the oil into the McMurray formation is illustrated by Fig. 2 and is described below under the heading of "Summary of Significant Factors Relating to Oil Occurrence."

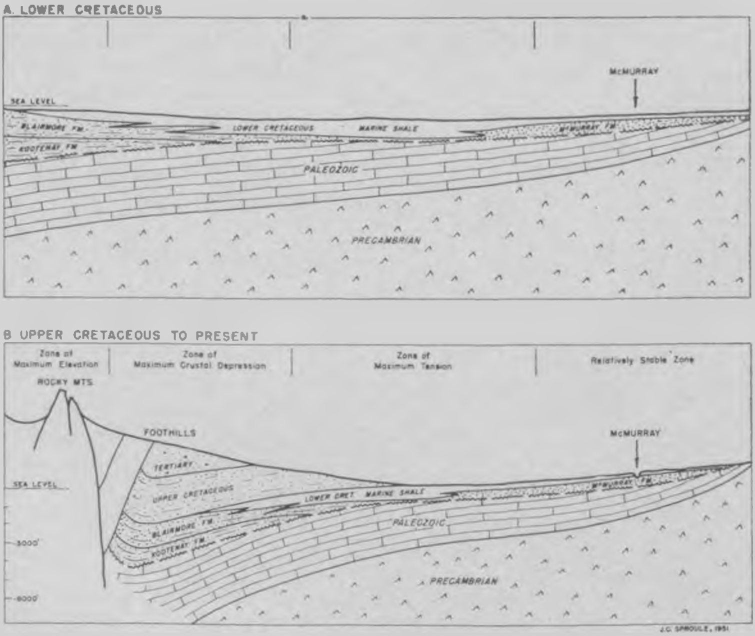

Fig. 2. *Paleogeographic relationships, McMurray formation, illustrating possible effect of crustal tilting in Late Cretaceous on migration of Paleozoic oil into McMurray formation.*

3. The Athabasca sandstones, of early Paleozoic age, cover a large area on the Shield immediately updip from the Lower Cretaceous McMurray sand formation. The intimate geographic relationship between the Paleozoic Athabasca sandstone and the paleogeo-

graphically downdip Cretaceous McMurray sand formation is regarded as suggesting strongly that the McMurray sand was derived from the Athabasca formation.

4. A wedge-shaped body of Jurassic strata occupies a position in the centre of the Williston Basin. Where the Jurassic occurs free oil has not been recorded from the overlying Cretaceous strata. Elsewhere, however, oil is common in the Lower Cretaceous. This is an important point that will be discussed below in connection with the possible origin of the McMurray oil.

STRATIGRAPHIC GEOLOGY

Detailed descriptions of the geological formations in association with the McMurray oil sands will be given here only insofar as they affect our understanding of the "Origin" problems at hand. For reference convenience the associated formations are presented in Table I*

TABLE I*

TABLE OF FORMATIONS

Period	Thickness in feet	Formation
Quaternary		Gravel, sand, and clay
Upper Cretaceous	1,100	La Biche formation
Lower Cretaceous	35	Pelican sandstone
	90	Pelican shale
	280	Grand Rapids formation
	275	Clearwater formation
	110 to 180+	McMurray formation
	Unconformity	
Devono-Silurian	850±	Dolomites, limestones, and shales Salt and gypsum
	Unconformity	
Lower Paleozoic	0 to 1,100	Athabasca sandstone
	Unconformity	
Precambrian		Quartzites, granites, and granite gneisses

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* Table I is adapted from one used in an earlier publication (17), with the Upper-Lower Cretaceous boundary corrected on the personal advice of Prof. Chas. Stelck of the University of Alberta and Dr. R. T. D. Wickenden, whose Lower Cretaceous top is a few feet above the bottom of the "La Biche" formation.

A brief summary of the formations most intimately concerned follows:

Precambrian

The Precambrian crystalline complex of granite gneisses, quartzites, etc. provides a deeply eroded and irregular basement surface, overlain by the limestones, shales, sandstones, and other sedimentary rocks of the Paleozoic. Knobs of the basement complex protruding as remnants through Paleozoic and Cretaceous strata testify to the irregular character of this surface. An excellent example of one of these basement knobs sticking up through the McMurray formation is to be observed at the intersection of the Muskeg and Athabasca Rivers, where quartzites of probably Huronian age (although they could be Paleozoic) are present as remnants overlapped by the McMurray formation.

Athabasca Formation (Early Paleozoic)

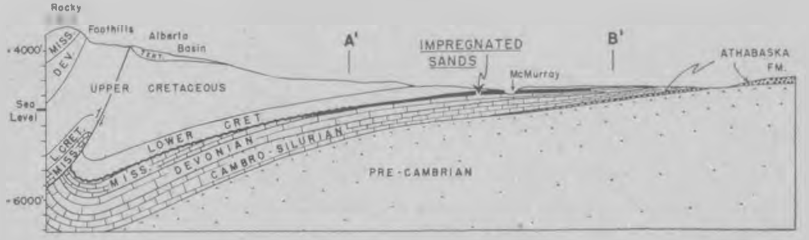
The Athabasca formation, unconformably overlying the Precambrian, is a large body of partly consolidated sandstones, arkoses, with some conglomerates, south and southeast of Lake Athabasca. The age of this predominantly sandstone body is mainly Paleozoic although the lower part of it could be late Precambrian, correlative of the Lake Superior sandstones, etc. The upper part of the Athabasca formation is apparently Devono-Silurian since it grades upward into rocks of that age on the Clearwater River in Saskatchewan. The question of the exact time interval over which this formation was deposited is not important to our present problem. What is more important is that it is older than the McMurray formation and was strategically situated to have provided much of the source material for the McMurray. It is of interest to note at this point that the lower part of the Devono-Silurian limestone group of the McMurray area contains a high percentage of sand grains similar to those that characterize the Athabasca and McMurray formations, thus indicating that the Athabasca has acted as a common source for much of the sand of the Paleozoic and early Mesozoic.

Paleozoic Limestone Formations

The areal extent of Paleozoic Systems of rocks within the western Canadian Basins is fairly well known, although much drilling must still be done before the distribution of individual geological formations is known. From wildcat wells drilled in Manitoba, Saskatchewan, Alberta and the Northwest Territories we now know that the greater part of the Paleozoic exposed below the Paleozoic-Mesozoic unconformity is Devonian in age although considerable areas in the central portion of the Alberta Basin, in Western Alberta and in the central part of the Williston Basin are Mississippian and some possibly Permo-Pennsylvanian in age. The relative positions of these Paleozoic rock groups, as well as of the overlying Mesozoic and Tertiary within the Alberta Basin are shown on the diagrammatic cross-section in Fig. 3.

The lower part of the Paleozoic sequence has not proven to be petroliferous in outcrops or in wildcat wells anywhere in the Western Canadian Basins area. Generally speaking, however, the upper part of the Devonian and the Carboniferous is highly petroliferous. Oil stains and residues have been observed in the Devonian limestones and shales of Northern Alberta and Northwest Territories almost wherever rocks of that age are known. More specifically, oil stains have been reported on Devonian outcrops throughout the McMurray district and oil has been observed in the Devonian at Vermilion chutes on the Peace River, at Windy Point and Sulphur Bay on Great Slave Lake, and in many other parts of the Mackenzie basin. In the Fort Norman area production is obtained from reefs of Upper Devonian age. The numerous discoveries of oil throughout Alberta are predominantly Devonian with those made in overlying rocks probably also of Devonian origin. Even such Upper Cretaceous fields as Joseph Lake are probably of Devonian origin. It may not be too long before the Devonian "mother" reef of the Joseph Lake field will be discovered. It is, under the circumstances, natural to suppose that any oil formed in the Upper Devonian and Carboniferous rocks should, under the proper conditions, have moved upward through tension rocks or eastward along permeable lines of least resistance into traps within the Paleozoic or into porous beds above the unconformity. This aspect of the problem has received such excellent coverage by T. A. Link (13) that it requires little further elaboration here. Link's conception of the mechanics of transfer into the Cretaceous, of oil from the underlying Devonian D-3 and other reefs might be added to, in that, in addition to tension fractures as avenues of escape, oil may also have escaped upward along permeable beds and bedding planes with in-

A LINE OF SECTION OF FIGURE 1. B



A' ENLARGEMENT OF A' – B' ABOVE B'

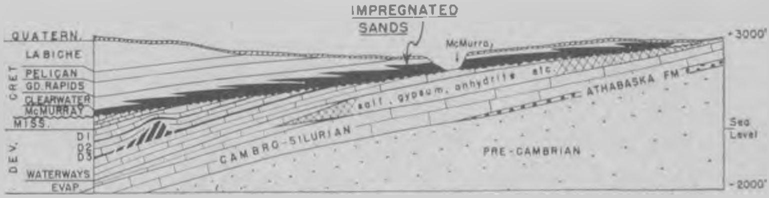


Fig. 3. *Diagrammatic cross-sections, Rocky Mountains to McMurray area.*

creasing Cretaceous tilting of the east flank of the Alberta Basin, as described below under "Regional Tectonics". Referring further to Fig. 5 of Link's "Tar Sands" report, in which are shown tension cracks as being scattered indiscriminately over the Upper Paleozoic surface below the unconformity, the suggestion is made that they be concentrated over the reef areas because of excessive compaction of the relatively thick sections of inter-reef shale, causing tension fractures on the flanks and crests of the reef areas. Regional crustal tilting would also cause the formation of tension fractures over reefs and other structurally high areas, both of them potential zones of crustal weakness.

The above conceptions of the means and timing of the formation of tension cracks and the change in structural attitude would answer one of Hume's objections (12) to the Paleozoic source theory. Hume does not believe oil could have remained in the reefs through the long period of the Paleozoic-Mesozoic unconformity, immediately prior to deposition of the McMurray sands.

McMurray Formation

The Lower Cretaceous McMurray formation overlies the eroded surface of the Paleozoic with an angular unconformity. Its upper contact with the marine Clearwater shales is transitional at the Saskatchewan border, to conformable farther west. As a unit, it appears to be a huge lenticular sand body composed of innumerable minor lenses, partings of clay, local carbonaceous and allochthonous lignite beds, etc. It is not known how far north the formation extended prior to the Pleistocene Age, but reworked glacio-lacustrine deposits indicate that it formerly extended some distance north of its present known limits, some sixty-five miles north of McMurray.

The unimpregnated sands and those from which the oil has been removed are predominantly light to pure white quartz sand. The grains are rounded, sub-angular and angular, and vary greatly in size. Many of the rounded particles are frosted and pitted. The commonest accessory minerals are feldspar, largely altered to kaolin, then garnets and kyanite. The presence of hornblende, apatite, staurolite and other readily destructible minerals testifies to a nearby source of supply. Pyrite and nodular marcasite are exceptionally common. Iron oxidation products stain and indurate thick beds in many localities. There is reason to believe that pyrite was originally much more common than it is now. It has been oxidized and in some cases recrystallized as marcasite. Much of the sulphur in the McMurray oil (averaging about 5%) should be credited to a pyrite source.

The degree of impregnation of the McMurray sands (0 to 25%) is as variable a feature as the character of the inorganic constituents. The more coarsely cross-bedded, and the medium-grained, massive strata (generally low in the formation) are more highly impregnated with oil, while the more impervious finely cross-bedded, and argillaceous lenticular beds may be low-grade or, like the fine silts and clays, entirely destitute of oil. "Tar springs," issuing from the strata overlying impervious clay or other partings, are a conspicuous feature of the richer beds. Fossil tree trunks are common, and may be associated with any type of lithology. In beds not soaked with oil (High Hills River), the wood is impregnated with iron salts and more or less decomposed, but in the oil impregnated strata it has been pickled so successfully that the most delicate cell structures are preserved. Freshly mined pieces are quite soft and cut like cheese.

Islands of entirely barren sands are not uncommon. In addition to the barren islands, the McMurray sands contain no visible oil in drill holes near Athabasca Landing and on exposures along the Clearwater River east of Cottonwood Creek. The unimpregnated sands in the latter area were carefully studied by the author and compared with the impregnated beds to the west, but so far as could be discovered, the complex set of conditions under which each was deposited was identical.

Post-McMurray Cretaceous

To the northwest, the McMurray formation merges laterally into the dark marine shales of the Loon River formation. Above the McMurray formation at McMurray are the marine Clearwater shales, which are transitional both vertically and laterally into the Upper McMurray, as illustrated in Fig. 2. The Clearwater shales are overlain in turn by the Grand Rapids formation and younger Cretaceous rocks.

Pleistocene and Recent

An irregular mantle of sandy boulder clay and glacio-lacustrine silts and sands covers the entire area. The principal significance to the present problem that we find in a study of the glacial features is that the excessively sandy character of the Paleozoic and Cretaceous formations in close proximity to the Athabasca formation is recapitulated in the Pleistocene of the same area. Fig. 4 taken from part of a glacial physiographic map (18) of a portion of the Athabasca sand area illustrates the excessive amount of loose sand that is available on the Athabasca sandstone outcrop for concentration by glacial action into drumlins (small rounded elongated areas up to 250 feet in height) and eskers (long narrow ridges up to 185 feet in height), both of them oriented in a northeast-southwest direction. By contrast to this impressive accumulation of sandy material, south of the boundary of the Athabasca formation, drumlin and esker material was carried for a short distance, beyond which there is only enough loose material to have formed scattered moraines.

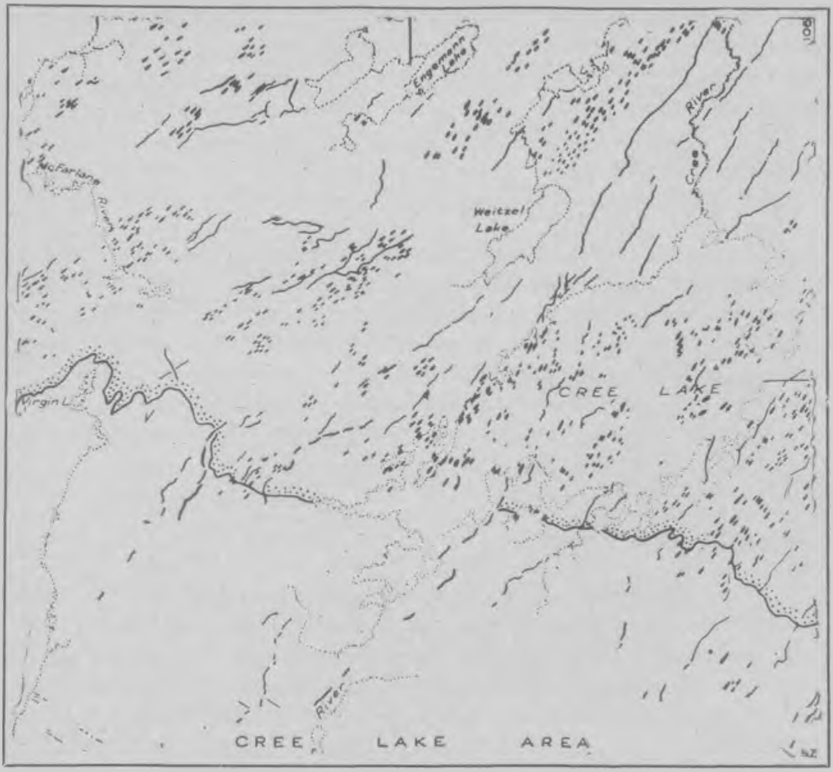


Fig. 4. *Glacial physiographic features of the Athabasca Formation area, Cree Lake area, Saskatchewan, illustrating abundance of loose sand derived from Athabasca formation.*

Fig. 5 is a photograph of a presently active sand dune in the Firebag Lake area, northeast of McMurray. Presently marching dunes

Fig. 5. *Part of a moving sand dune, Firebag area, illustrating abundance of loose sand derived from Athabasca formation.* (From S. C. Ells.)

in this area have made a desert waste of areas in excess of 25 miles wide. This photograph shows a dune overcoming a forested area. Dead stumps of the smothered trees are being left behind.

It is doubtful if as good an example as the above of the abundance of supply of loose sand from a single source can be found anywhere else in northern Canada.

THE ORIGIN OF THE OIL

When the huge size of this oil body and the possibility that it may be a type of oil seepage are considered, the question of its origin at once becomes of great importance. It is only natural, therefore, that numerous theories of origin should have been developed and a great deal written about them. The McMurray oil formation is undoubtedly one of the most fruitful fields for mental gymnastics known to geologists.

Some geologists have developed the idea that the oil was formed in situ, others that it seeped upward from the Paleozoic, others that it came from the Clearwater shale, others that it is the residue of bituminous Paleozoic strata, and still others that it originated in marine equivalents of the McMurray formation (other than the Clearwater). Although it is quite possible that the McMurray formation contains oil from all these sources, the number of actively sponsored theories of origin has been reduced to two, one of which is currently championed most vigorously by Hume (11), and the other by Link (13). In order to provide a better background for understanding of the theories under present consideration the highlights of the theories of origin thus far proposed might be briefly summarized:

In Situ Theory

The in situ theory was advanced by the late Arthur Beeby Thompson (19) of London, England, as a result of studies made in 1930. Thompson was of the belief that oil was formed from organic life in the sands during the time of the deposition of those sands. Further elucidation of Thompson's theory was later presented by Ball (1).

Clearwater Shale Theory

The theory that the Clearwater shales are parent rocks was proposed by F. H. McLaren in 1917 (14).

McMurray Equivalent Theory

The theory that has been sponsored for several years by G. S. Hume (11) is that the McMurray oil moved laterally, from marine equivalents, into the sands of the McMurray formation and the host rocks of the Lloydminster and Wainwright fields, etc. (Hume's latest dissertation in support of a Lower Cretaceous origin of the bitumen forms a part of these *Proceedings.)*

Residual Theory

The theory of a residual origin for the McMurray oil was suggested by S. E. Slipper (16). In the diagrammatic cross-section of the

Vermilion chutes on the Peace River, Northern Alberta, shown in Fig. 6, Slipper has illustrated what is taking place today where the Peace River flows over a resistant ledge of Upper Devonian bituminous dolomite underlain by less resistant limestone. The oil sands lying against the limestone beneath the chutes are assumed to be the weathered product of the bituminous dolomite. Slipper's views as to how this interpretation can be extended to explain the origin of the oil sands are presented in the following quotation:

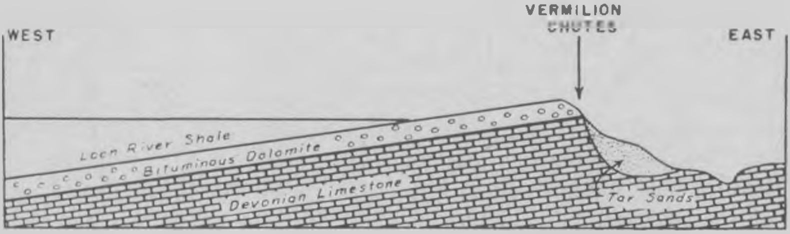


Fig. 6. *Diagrammatic cross-section of Vermilion chutes, Peace River, Alberta.* (From S. E. Slipper.)

> "First, the sands and clays of the McMurray formation are residual deposits, formed from the westward erosion of the Paleozoic limestone during the time interval between the emergence of the Paleozoic rocks and the Lower Cretaceous.
>
> "Second, this westward erosion of the Paleozoic took place as a wearing away of a series of receding escarpments.
>
> "Third, the Paleozoic limestones and dolomites contained horizons impregnated with bitumen and during the recession of the escarpment this bitumen was retained in the residual sands in the manner indicated on the accompanying diagram.
>
> "Fourth, subsequent submergence covered the McMurray sands with marine Clearwater shales and the overlying members of the Cretaceous groups."

Paleozoic Source Theory

The first to suggest Paleozoic formation as possible source rocks for the McMurray oil was Robert Bell of the Geological Survey of Canada (3). Bell considered that the oil seeped upward along cracks in the Paleozoic into the overlying porous McMurray sands. The present author is of the opinion that a modification of Bell's theory is the most acceptable explanation of the source of the bulk of the oil, although there is every reason to suppose that residual oil formed by the erosion of the petroliferous Upper Paleozoic is also involved. There is also no reason to suppose that oils from other available sources have not contributed, to a minor extent.

SUMMARY OF SIGNIFICANT FACTORS RELATING TO OIL OCCURRENCE

For further detailed accounts of the above theories reference is made to a paper by the present author written in 1938 (17). It is not practical to reproduce here full descriptions of the theories involved, and so the remarks will be confined to the salient features of each with special reference to significant facts having a bearing on the problem.

1. Relationship, Athabasca Sandstone to McMurray Formation

The Athabasca sandstone is a ready source of loose sand, and is regarded as having been a dominant factor in the formation of the McMurray formation. The McMurray formation is believed to owe its existence primarily to its paleogeographic position with respect to the nearby Precambrian highland, capped by a broad area of imperfectly consolidated Athabasca sandstone. The mere presence of this huge body of loosely consolidated early Paleozoic sandstone would seem to be sufficient circumstantial evidence in itself to explain the McMurray formation, without having to call on mechanically difficult theories such as the postulation of a possible origin in the Selkirk and Rocky Mountains. The Athabasca sandstone and Precambrian as a joint source, on the contrary, seems to provide a simple explanation for the facts at our disposal.

Aside from the close geographic relationship, it might also be pointed out that the Athabasca sandstone area was apparently in the shoreline zone of early Paleozoic seas, judging from the abundance of sand in the Devonian of the McMurray area. Later on, the Lower Cretaceous sea, of Clearwater - Loon River - McMurray age, entered from the Arctic into the interior of North America by way of the Mackenzie valley, and by the end of McMurray time had penetrated to somewherein central Alberta. The mere presence of this interior marine tongue lying between the McMurray area and the Rocky Mountains must have fairly well precluded the movement into the McMurray area of a supply of coarse clastics from the Selkirk and Rocky Mountain areas, sufficient to explain the McMurray formation, except by way of the southern shoreline in central Alberta.

2. The McMurray Formation Facies

The fact that the McMurray formation is a shoreline phase of a marine formation immediately suggests the possibility that the abundant life of the offshore area could have supplied oil that is found in the sands, and it is this physical relationship that apparently dominates the thinking of Hume and others who sponsor the idea of a Lower Cretaceous origin for the oil. It is, admittedly, a very strong argument.

3. Area of Impregnation

The area of impregnation of the McMurray formation is believed to have "Origin" significance. Although oil is found in the Lower Cretaceous equivalent of the McMurray formation over a considerable part of Western Canada, the greatest concentration occurs in the McMurray sand where the porosities and permeabilities are highest and where the sand is in close contact with the eroded and truncated reef producing part of the Devonian and potential oil source rocks of the Carboniferous group. In the McMurray area, the sands contain no visible oil east of Cottonwood Creek on the Clearwater River. Careful studies of the barren sands on the Clearwater River were made by the author in order to discover, if possible, the reason for the complete absence of oil in that locality, but after a thorough examination of these formations the conclusion was reached that the barren sands contain no significant features without counterparts among the impregnated beds farther west. The presence of these barren beds east of Clearwater River, in view of the impregnation of their lithologic counterparts farther west, makes it very difficult to believe in the possibility of an in situ source or in a source from the overlying and laterally equivalent Clearwater shales. The Clearwater shales overlying the McMurray sands east of Cottonwood Creek are the same soft grey and black shales and sandstones containing concretionary layers that are found farther west where the underlying McMurray sand is impregnated. The similar physical environments in the two areas should have fostered the propagation of similar organic life.

4. Scarcity of Oil in Formation Overlying the McMurray

There appears to be no sign of oil in the marine equivalents of the McMurray formation either at Vermilion chutes (where there is oil in the Devonian but none in the impervious Loon River shale), at Athabasca Landing, Lesser Slave Lake, or overlying it in the vicinity of McMurray. The presence of coarse sandy stringers and well-developed sandstone beds in the lower part of the Clearwater formation of the McMurray area, none of which have been observed to contain oil, makes it very difficult to understand how oil could have been formed in the Clearwater formation and flushed out into the McMurray sands without leaving some oil in the sandy stringers of the marginal zone.

5. Occurrences of Paleozoic Oil

Oil seepages and imbedded occurrences in Paleozoic limestone are very widespread through the Alberta and Mackenzie Basin, as well as elsewhere in central and northern North America where equivalents of these Paleozoic rocks are known, not to mention the more important of the several Devonian oil fields discovered in Alberta during the present oil boom. There can no longer be any question as to whether or not there is a satisfactory source for McMurray oil in the Paleozoic.

6. Islands of Unimpregnated Sands

Islands of unimpregnated sands occur in the oil-saturated area, apparently free of oil, either by virtue of the presence of impervious clay partings, or because of the fine nature of the sand which presumably contained water at the time of invasion by oil. Oil will invade sand and displace water most easily in a coarser sand, and to a lesser extent as the size of the pores diminishes, and there comes a "pore size" point, dependent upon the relative surface tensions of the liquids involved, when the oil will not replace water. This is another possible explanation of why the barren islands occur in those cases where impervious clay partings are not present.

The presence of barren islands makes it difficult for us to accept the in situ theory since, if the McMurray environment had sufficient life to form all that oil it should have left some of it in the barren lenses. The existence of these concretions are also hard on the residual theory.

7. Oil Springs

Oil springs issuing above impervious clay partings as well as in the oil-rich lower parts of the formation indicate that the oil probably entered and filled the formation previous to the later period of settling and re-adjusting, which is still taking place. This phenomenon is one that makes it difficult to accept the in situ theory.

8. Unimpregnated Sand Concretions

Unimpregnated sandy ironstone concretions are known at the mouth of the Christina River. The inference to be drawn here is that the concretions were formed by the crystallization growth of iron salts in permeable sandstone prior to the entry of the oil into the sand, thus preventing their impregnation when the oil entered the formation later on.

9. Impregnated Sand Concretions

By contrast with the above, a large fairly impregnated sandy concretionary body was observed by the present author on Reid Creek, a tributary of the Firebag River. On Reid Creek large concretionary bodies occur in a series of alternating beds of oil-impregnated and barren sands, the stratification of which may be traced into the interior of the concretions. A part of one of these structures is pictured on Plate XXXI of Canada Mines Branch Investigations for 1931 (9). The mineral responsible for the concretions has since been leached out and the pore spaces filled with oil, indicating not only that the oil entered the sands subsequent to the formation of the concretions but subsequent also to the removal from the concretions of original crystalline material by percolating ground waters. The evidence provided by these concretions is not in keeping with either the in situ theory or the residual theory.

10. Pyrite and Sulphur Content of McMurray Formation

The sulphur content of unimpregnated beds is, in some cases, equally as high as that of the impregnated beds, suggesting an originally high sulphur content for McMurray sediments, adding strength to our conclusion that sulphur, probably derived from pyrite, played a large part in the alteration of the oil after it came to rest in the McMurray formation.

11. Digestibility of the Crude

A feature that Max Ball has referred to as the "Digestibility of the Crude." is regarded as having considerable significance to theories of origin. The following is a quotation from Ball (2).

> "This sensitiveness of the crude oil to heat, which explains why such a complete line of products can be made from such a heavy, tarry material, is so striking as to require explanation. The crude in its natural state contains only a small percentage of low-boiling constituents and is itself heavier than many of the asphaltic products that have been described above as available from it. Nevertheless, all of the products referred to except the higher yields of high-octane gasoline can be made from it

> without cracking, and no pressure cracking is necessary to get gasoline yields of 25 to 30 per cent. The reason lies in a unique susceptibility of the crude to digestion at moderate temperatures for moderate periods of time.
>
> "As has been said, the crude has an A.P.I. gravity of from 4 to 10°, depending on the degree of its exposure to oxidation. Subjection for moderate periods to temperatures below the normal cracking range converts it to a much lighter, more fluid crude with A.P.I. gravities of 16 to 22°, without the formation of free carbon and without degrading the quality of the asphaltic fractions. Fresh 10° A.P.I. crude digests to 20 to 22° A.P.I.
>
> "This is not to be considered as cracking. No fixed carbon and virtually no free gases are formed, and, so far as analysis shows, no products are formed heavier than those originally in the oil. What appears to take place is a complete atomic and molecular rearrangement by which most if not all of the material is converted into lighter hydrocarbons without the formation of heavier ones."

This explanation of the apparent virginity of the oil is that it is probably very young and has, therefore, never been subjected to the "Pressure-Temperature-Time" treatment that characterizes the older oils. It would, however, seem that a more logical explanation is that the oil was pickled as a result of polymerization by sulpuhr, oxygen and other polymerizing agents. (See below under "Related Cretaceous Oils").

12. Oil-Soaked Tree Trunks

Fossil tree trunks pickled in oil are found in a number of places in the McMurray area, always in a horizontal position and somewhat flattened. They are fairly soft and cut like cheese, and their cell structure is still in almost perfect condition. Their prostrate state and position with respect to the bedding of sand and shale partings indicates that they floated to their present position. The organic matter comprising the occasional lignite seam that is found scattered throughout the area of the McMurray formation is also allochthonous.

The excellent state of preservation of these oil-soaked logs would indicate that they were impregnated by the oil not too long after burial. By contrast with the oil-soaked logs, flattened tree trunks on High Hills River in unimpregnated McMurray sands are rotted, rusty and almost unrecognizable as fossil wood.

If other types of floating organic matter, or in situ organic matter, had ever characterized the sand facies of this formation, they should have been preserved in similar fashion, but that is not the case. It is not easy to reconcile the state of preservation of these tree trunks, with no evidence of other life having been preserved, with the in situ theory which calls for the propagation of a fantastic amount of life. If the oil-forming life had been a primitive type, without resistant skeletal parts, they could not be expected to have been preserved, but where simple skeletonless forms exist in abundance many higher forms of life generally exist to prey on them. There seems little possibility of such a situation having existed here.

13. Related Cretaceous Oils

The presence of other Lower Cretaceous oils in strata equivalent to the McMurray formation, as at Lloydminster, Wainwright, Vermilion, Whitemud, Campbell, Gilbert, Acheson, Stony Plain and Stettler is sometimes given (12) as evidence in support of the idea that the Lower Cretaceous of the Western Canadian Plains is a common source of oil and, therefore, that the McMurray oil, being strategically situated with respect to a marine source, is almost sure to have been formed in that way. The error in that argument is believed to be the original assumption that the oil from the above fields is from the Lower Cretaceous. Most of the concrete evidence available supports the idea that these oils are seepages from the Devonian reef oil, as they are over the Woodbend, Acheson, and Stettler reefs, etc. The present author believes that it is only a matter of time until the Devonian source of the oil from such Lower Cretaceous fields as Joseph Lake, Lloydminster and Wainwright will be discovered.

The principal reason why adherents of the Lower Cretaceous theory do not like to see the heavy Lloydminster and Wainwright oils referred to a source common to that of the Gilbert and other light crude oils is that the present gravities and chemical compositions are so widely variable. That, however, need not be regarded as a serious obstacle. Oil is a liquid that is capable of dissolving an unknown number of minerals and elements. It is known that oil is polymerized by Fuller's earth, and there are undoubtedly numerous other catalysts in nature that can similarly affect it. Oil migrating through various permeable strata is subject to change by innumerable substances with which it comes in contact. The changes possible are infinite, depending upon the original oil, on the substances encountered, and on their chemical composition, etc. The influence of contact with later ground waters is another factor that is difficult to evaluate. It is a known fact, for example, that sulphate waters are never found in contact with the oil of a field, because of the action of the oil on the sulphate. With this thought in mind reference is made to the sulphur content of the McMurray, Wainwright and Lloydminster, etc., oils in which the gravity is directly related to the sulphur content. In the case of low gravity oils such as that of the McMurray formation, sulphur originating from pyrite derived from the Precambrian, one of the main accessory minerals, was already present in the McMurray sand before the invasion of the oil. It is reasonable to believe that the oil invaded the McMurray sand in the mobile state and became polymerized by contact with the sulphur in the sediments, or by later contact with sulphur and oxygen-rich waters. This explanation would acount for the high sulphur content of the oil, for its low gravity, for its apparent virginity, or as Max Ball has described it, its "digestibility," and for the fact that the pore spaces in the sand are only partly filled with oil, the volume of the oil having been reduced by polymerization.

Although figures are not at hand for the sulphur content of the Gilbert and other high gravity Cretaceous oils recently discovered, they are probably low in sulphur and the sediments in which they are found are probably also low in sulphur.

With further regard to the subject of the effect of environment on oil, reference is made to U.S.G.S. Professional Paper No. 117 by G. S. Rogers (15). After a study of the Sunset-Midway oil field in which the sands are interbedded with light oil sands, Rogers came to the conclusion that variation in gravity is more likely to be caused by chemical influences than by purely physical conditions. In his paper, Rogers describes the apparent effect of sulphur water and the oxygen-carrying water on the oil. He concludes that increase in gravity of the oil at certain horizons in that field was caused by contact with water containing both oxygen and sulphur. Polymerization is also mentioned as having had a powerful influence. According to Rogers, all that is necessary to explain the high gravity of the tar oils in the Sunset-Midway field is oxidation and polymerization, mainly through contact with percolating ground waters.

B. P. Brooks (5) made a study of the chemical effects of various sedimentary elements on oils and came to the conclusion that many different sedimentary rocks are capable of causing polymerization of unsaturated hydrocarbons, a property hitherto generally believed to be limited to Fuller's earth.

14. Williston Basin Evidence

The strongest evidence supporting the idea of a Paleozoic source for most of the Cretaceous oil of the Western Canadian Plains has been provided by the results of drilling in the Williston Basin. Numerous holes have been drilled in the Williston Basin of Saskatchewan and the Northern States, but so far as is known no free oil has ever been found in the Lower Cretaceous where it is underlain by the impervious wedge of Jurassic rocks that covers the central part of the Williston Basin. On the other hand, practically all holes drilled outside the margin of the Jurassic, where the truncated edges of the Paleozoic come into direct contact with the porous and permeable clastics of the Lower Cretaceous, have encountered free oil. Among the few exceptions are wells in eastern Saskatchewan, Manitoba, and eastern North Dakota where the Paleozoic rocks involved below the unconformity are older than the (reef-forming) Upper Devonian. If exceptions to this do not already exist they will probably be found, because it would be too much to expect that some Paleozoic oil would not find its way through the Jurassic cap rock. The principle, however, remains the same.

The inferences to be drawn from the above are,

1. That the Jurassic has acted as an impervious cap preventing upward migration of Paleozoic oil.

2. That the synclinal area occupied by the Jurassic is in general an area of compression rather than tension, thus discouraging oil migration.

15. Organic Matter in Marine Shale of Western Plains Mesozoic

Almost any of the Mesozoic marine shales of the Western Plains contain fair percentages of kerogen-like organic matter that can be "stewed" out by application of heat in an ordinary test tube. The richer of these organic shales are of Jurassic and Colorado age although the Upper Cretaceous Bearpaw shales also contain some. The Flavel oil shales of Manitoba (7) belong in the same category.

The inference drawn from the above is that these shales, although they are old geologically, are young in "experience" and that the organic matter contained therein has not been subjected to a sufficiently vigorous dynamic treatment to have formed oil. This is not in keeping with a widely accepted idea that oil is formed relatively soon after burial, but that idea as a blanket explanation for the formation of crude oils is not tenable.

16. Regional Tectonics

The so-called Laramide Revolution, of Cretaceous-Tertiary time, during which the Western Canadian basins were partly filled by Lower to Upper Cretaceous seas and later driven out by the closing phases of the activity culminating in the elevation of the Rocky Mountains, and concurrent foundering of the western portion of the Alberta Basin, can logically be expected to have developed tension zones between, and normal to, the Rocky Mountains and the Precambrian Shield. The resultant tension fractures will have formed most readily over such areas of weakness as reefs and other structurally high areas, and can be expected to have resulted in the release of gas, oil and water, upward along these lines of least resistance into the most convenient host rocks, which in the case under consideration is the McMurray formation.

The formation of tension fractures in beds overlying the reefs must also have been encouraged by excessive compression of the relatively thick compressible shales in the inter-reef areas.

The above explanation is given as an argument against the objections to the theory of a Paleozoic source for the oil on the grounds that it could not have stayed in the reefs during the long period of erosion represented by the pre-McMurray unconformity.

Another common objection to the upward migration theory is that faults are not sufficiently abundant in the Plains area to have been a factor. They are certainly not known to be abundant but they are present, as at the mouth of High Hills River on the Clearwater (17). Since the areal extent of bedrock outcrop is considerably less than 1% of the total area, it is not likely that the existence is known of any but an extremely small percentage of those that exist, especially since faults tend to erode most easily and therefore to become hidden in stream valleys and slump areas.

Small tension faults around local structural highs can not be expected to be known, which further invalidates the objection as to lack of knowledge of their existence.

CONCLUSIONS

The conclusions that would be drawn from the above described facts are:

1. The sediments comprising the McMurray formation have been derived mainly from the early Paleozoic Athabasca formation and adjoining portions of the Canadian Precambrian Shield. Additional supplies of materials from other sources are of minor importance.

2. There is little, if any, concrete evidence favoring the idea that the organic material contained in the Cretaceous of the Western Canadian Plains has been converted to free oil, at least in areas outside the Foothills of the Rockies. Dynamic and static metamorphism might, however, be expected to have effected the changes necessary in an area adjacent to the mountains.

3. The oil in the McMurray formation was derived mainly from the upper part of the Devonian and probably also from Mississippian rocks. Some of it was undoubtedly residual oil, left behind during erosion of the Paleozoic surface, but the bulk of it was probably due to oil seepages that have been active from Lower Cretaceous to the present, the principal migration having taken place during and immediately after the Laramide Revolution.

4. Other Cretaceous oils of the Western Canadian Plains probably have a somewhat similar historical background to that of the McMurray oil. The principal controlling influence effecting the principal changes in gravity and chemical variations in the various fields is believed to be inherent in the chemistry and petrology of the host sands themselves, plus the changes effected by the influence of media through which the oil passed during migration.

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STRATIGRAPHY OF McMURRAY FORMATION

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INTRODUCTION

For more than a century the bituminous sands of Alberta which form the banks of the Athabasca River and its tributaries in the vicinity of the town of Fort McMurray have attracted the attention of voyageurs, fur traders, prospectors, and pioneers of the land. All have been awed by its sights, and their imaginations have been fired by its potentialities.

Numerous geologists and engineers have studied these deposits, measured their extent and calculated their petroleum content. Among them the work of S. C. Ells carried out in the early 'twenties stands out as the most comprehensive survey. From 1942 to 1947 the Dominion Government explored four areas and outlined several rich oil-sand accumulations. Since the discovery of the Leduc and Redwater oil fields numerous wildcats have been drilled downdip from the oil-sand outcrops. These holes have greatly broadened the known extent of the sands.

THE McMURRAY FORMATION

Geology

The formation containing the Athabasca oil sands is known as the McMurray formation. It is the basal member of the Lower Cretaceous in northeast Alberta. It underlies the Grand Rapids sands and the Clearwater shales, and rests directly on Devonian strata truncated in post-Devonian times.

The main lithologic characteristics of the sandstone are its highly quartzose nature, massive oil impregnation and the ever-presence of a generally coarse cross-bedding. The lower contact is sharp, since it lies directly on Devonian strata, but there is no appreciable increase in the grain size towards its base. The upper contact with Clearwater shales is gradational.

Extent

This sandstone has a very broad distribution over northern Alberta. Its most northerly outcrop lies along the Athabasca River, some 75 miles north of Fort McMurray. Ells suggests this northern limit is due to an erosional unconformity. The eastern limit is not known to the writer, but it would appear to extend well into Saskatchewan.

The southern extent of the sand lies well south of Edmonton district, where it is known as the Basal Quartz Sand and has more recently been called the Ellerslie member of the Lower Cretaceous.

To the west, a sand in all respects similar to the McMurray was drilled in the Bear Villa well at the west end of Lesser Slave Lake. In addition, a basal Cretaceous sandstone is reported on the Mikkwa River, which empties into the Peace River at Red River below Vermilion chutes. Further west the Gething sandstone, the upper member of the Bullhead group, is correlated with the McMurray. The above limits are for the formation and do not indicate the area over which the formation is oil-saturated.

The formation is oil-saturated in the immediate area of the settlement of Fort McMurray, and can be observed in river cuts for a distance of 138 miles along the Athabasca and 40 miles along the Clearwater River. The formation first appears in river outcrops at Boiler Rapids on the Athabasca, 60 miles west of Fort McMurray. It is then in continuous outcrop along the Athabasca exhibiting a more or less complete saturation to Eymundsen Creek, 65 miles north of McMurray. For another ten miles further north, intermittent saturated outcrops occur to Lobstick Point and the Firebag River. Eastward from Fort McMurray the formation is generally covered by slump blocks and only a few outcrops are available for examination.

The most easterly outcrop containing bitumen is 40 miles east of Fort McMurray. In the northeastern part of the area, extremely rich sands are interlapping in the Firebag area, 20 miles east of the Athabasca River. From drilling to date, which has intersected the McMurray sands and gone on into the underlying Devonian, it is apparent that the heavy oil—oil-sand oil—only occurs to the northeast of where the green shale and D-3 occur at the Devonian-Cretaceous unconformity. Downdip from this point the Cretaceous oil is higher gravity and has been apparently derived from a different set of sources, although these need not necessarily have been of a different age.

Returning to the outcrops, in the over-all picture the outcrops show a remarkable similarity. In general, the richer beds appear at the base of the formation and comparatively barren beds in the upper portions. On a sunny day the outcrops appear leached and brown in color; however, following a rain they appear to be rich and black. Exceptions do exist and some of these warrant more than a passing interest:

(1) On the Hangingstone River near Waterways an outcrop occurs which includes a coquina bed from which practically all the fossils so far found have been obtained. The area represents a brackish water phase and is responsible for what age determinations have been made regarding the formations.

(2) Between the Steepbank River and the Athabasca many oil seepages occur, although no outcrops occur in the immediate area of the seepages. The typical outcrop pattern can be noted in the Steepbank River where the upper portions of the formation appear barren and oil is seeping slowly from the lower parts of the outcrops. The bedding in this area slopes westward—erosion has cut down the upper beds on the Athabasca side of the topographic nose allowing successively lower beds to come to the surface. Thus, the seepages are readily explained as a natural downdip migration.

(3) Opposite the old Hudson's Bay Company shipyard, a coarse conglomerate occurs within the McMurray formation. An oil film at one time covered the individual rock components; however, due to complete oxidation there is now only heavy bitumen and hard asphalt.

(4) At the mouth of the Firebag River occur a series of remarkable McMurray outcrops. They occur in an area of abundant sulphur water springs. The outcrops show an intercalation of barren white sand layers separated by beds of oil sand up to a thickness of 8 or 10 inches. Some of these thin oil-sand beds are quite rich, and some contain cores of lignite with grades both upward and downward away from the lignite oil sand, the bitumen content decreasing away from the lignite.

The minor shale partings between the sand beds have apparently been enough to contain the bitumen and retard vertical migration. Only 16 miles southeast, along the Firebag, these outcrops occur as thick rich massive beds. It is my belief that these outcrops at the mouth of the Firebag represent the most northeasterly limit of the bitumen accumulation.

Thickness

In the general vicinity of the type section the thickness of the formation is fairly uniform. In detail this thickness is quite variable because of the irregular topography of the underlying unconformity surface. In the vicinity of McMurray, sections 125 to 200 feet have been measured. At the west end of Great Slave Lake 115 feet of McMurray formation are reported. At Leduc the thickness may vary from 80 to 180 feet.

Lithology

Along the Clearwater River are several excellent exposures of McMurray sandstones which are not impregnated by oil and thus show up well the lithology of the formation. High steep cliffs expose a well cross-bedded sandstone of fairly good induration, made up of highly quartzose sands with prominent cross-bedding, generally westerly. The sand has fair to good sorting in which grain size varies from fine to pebblestone. Some beds are separated by thin, irregular brownish layers which are probably due to sideritic cement, and there are occasional discontinuous, irregular, carbonaceous layers. The beds contain good to excellent intergranular porosity.

Conditions of Deposition

The McMurray formation has variously been described as of fluviatile, deltaic, estuarine or near-marine origin. Various features suggest these multiple sources, and it is probable that when a complete section of McMurray is present its base represents fluvial deposition, its centre deltaic to estuarine, and its upper part grades into marine conditions.

It is generally agreed that most of the Cretaceous sediments came from the west, from the Cordilleran geanticline. There are several factors, however, that would suggest the McMurray sand, as seen on the Clearwater River, has had a source closer at hand and probably to the east. The general westerly dip of the cross-bedding certainly favors this view. The presence to the east of remnants of an older sand (early Paleozoic or Proterozoic) of very similar character certainly suggests this as a most plausible source for the McMurray sands.

Distribution of the Oil

Wherever cut by the Athabasca River, the McMurray sand shows some impregnation of oil or bitumen. However, this impregnation ceases some 30 miles east of the town of Fort McMurray. It has been found as far west as the west end of Lesser Slave Lake; however, the impregnation is not at all general nor is, in any given locality, the impregnation uniform in its vertical development. It is highly spotty and appears controlled by the grain size of the sand and its porosity, which in turn depends on its argillaceous content and the extent of cementation.

Normal upward and lateral migration of low grade residues from truncated pools of Devonian age are the most plausible methods of impregnation of the sands. Migration of oil within the beds exists even today. Numerous oil seeps are known to exist on the downdip slopes developed on the sides of highs on the unconformity. These seepages are necessarily slow, due to the oil's high viscosity. A recognition of the fact that migration is currently in progress within the beds, and that the oil is heavier than water, has resulted in the discovery of several of the better oil deposits since the richer deposits appear to accumulate in closed lows developed on the Devonian unconformity.

GEOLOGY OF THE BITUMINOUS SAND DEPOSITS OF THE McMURRAY AREA, ALBERTA

By F. A. Kidd
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The information here presented is based on the work performed by H. Donald Curry for Shell Oil Company during 1945. Curry spent a major part of the 1945 field season in the McMurray area making a study of the general geology of the district and particularly of the McMurray formation. During the winter of 1945-46 many of the core holes drilled by the Dominion Government were studied and the information obtained has been incorporated in the description of lithology.

While the Athabasca is much travelled, the side streams and the upper reaches of the Clearwater are seldom visited. Although the Clearwater River was once the famous travel route of the early fur traders, the rapids along the course as the Saskatchewan boundary is approached are effective barriers, and few people except local Indians travel beyond them. Much of the Clearwater channel is so shallow and so strewn with rocks and sand bars that only an experienced boatman familiar with the river can traverse it without an excessive amount of trouble and damage to his craft.

The outcrops along the Athabasca from Mountain Rapids to the mouth of the Firebag and those along the Clearwater from Granite Rapids to its mouth were studied during the course of the summer. In addition, the lower reaches of all the major tributaries were visited, with the exception of the Firebag River.

Detailed stratigraphic sections of both the McMurray formation and the underlying Paleozoic limestones were made at intervals along most of the streams, and fossils were collected where present.

STRATIGRAPHY

In the area investigated, the Cretaceous section above the lower part of the Clearwater formation has been removed by erosion. The main project was the study of the McMurray formation and its bitumen. Consequently, the rest of the stratigraphic section exposed in the region received attention in proportion to its presumed importance and bearing on the problems pertaining to the "tar sands." The higher Cretaceous formations which outcrop along the Athabasca River upstream from McMurray were not visited and Precambrian and Quaternary deposits were only superficially examined.

Precambrian

Gneiss and granitoids of Precambrian age underlie the Paleozoic section in the McMurray area and have been encountered in several wells in the district.

Cambro-Ordovician

In a large area south of Lake Athabasca the Precambrian metamorphics are overlain by a sandstone formation known as the Athabasca sandstone. This sandstone is thought by some workers to represent lower Paleozoic rocks, including parts of the Cambro-Ordovician, and to correlate possibly with the Winnipeg sandstone of Saskatchewan and Manitoba. It is not known to outcrop anywhere in the McMurray district or vicinity.

Middle Devonian or Silurian

In the immediate vicinity of the town of McMurray approximately 400 feet of sediments overlie Precambrian metamorphics and consist principally of anhydrite, gypsum, and pure rock salt, with only minor amounts of dolomite.

Upper Devonian (Waterways Formation)

By far the greater part of the Paleozoic rocks outcropping in the McMurray district is Upper Devonian in age.

A typical Devonian outcrop, particularly on the Athabasca River, consists of buff to cream weathering, light grey, massive to thin or irregularly bedded argillaceous limestone. Much of it is marly and rubbly weathering, but fine-grained dense layers are common, as is buff to greenish limey shale.

Many beds are highly fossiliferous and the majority of the specimens, particularly those from the softer limestones and shales, are almost perfectly preserved.

The Devonian age of these beds has been recognized by even the earliest workers and has been defined as the "Waterways formation" of Portage (lower Upper Devonian) age. A total thickness of approximately 450 feet of these beds is present in the McMurray area.

Cretaceous

McMurray Formation: As a relatively exhaustive study of this formation was the main object of the season's work it will be treated in detail later. These strata lie in unconformable contact with the Devonian limestone and in conformity with the overlying Clearwater shale where that formation is present. The age of the McMurray is Lower Cretaceous, equivalent to the lower part of the Blairmore formation of the foothills.

Clearwater Formation: This formation, which totals 275 feet in thickness is not fully exposed in the McMurray district except on the Athabasca River below Boiler Rapids, and on the upper reaches of Ells River. It consists of lead-grey to black marine shales, greyish sandstones, ironstone concretions and lenses, and glauconite and sandstone, the latter particularly toward the base.

Some horizons carry a prolific marine fauna of Lower Cretaceous age.

The basal beds of the formation carry glauconite, both in the shales and sandstones, and this mineral proves to be a reliable criterion distinguishing Clearwater sands and silts from those of the McMurray near their contact.

Grand Rapids Formation: No outcrops of this or overlying formations were visited.

The formation consists of sandstone with lesser amounts of shale and is about 280 feet thick.

Pelican Shale: This formation, about 90 feet thick, is a dark grey, fissile, marine shale of uniform composition, bearing a sparse *Inoceramus* fauna. It is named for its development just below the mouth of the Pelican River on the Athabasca.

Pelican Sandstone: At its type locality—the mouth of the Pelican River—this formation is described by McConnell as being a usually conspicuously white sandstone about 40 feet thick.

La Biche Shale: This formation outcrops along the Athabasca River between Athabasca Landing and Pelican River. It is a thick (about 1100 feet) dark marine shale comparable to the Alberta shales, and is of Colorado and Montana age.

Pleistocene and Recent

From the vicinity of the most northerly outcrops of the McMurray formation on the Athabasca northward toward the mouth of the river are increasingly thick deposits of loose, buff-colored, well-bedded to cross-bedded sands of Quaternary age. That they once covered a much greater area is indicated by the presence of 200 feet or more of such sands overlying the McMurray and Clearwater formations in the Fort Hills northeast of Bitumount. Along the river they occur unconformably above the truncated McMurray and where it is not present they overlie a thick section of bright pink and green sandy clay tills. The sands have lenses of bituminous sand conglomerate and layers of low-grade bituminous sand that are a result of secondary impregnation. In places these are rich enough to have confused some investigators.

These secondary deposits have no economic value but indicate what has happened to that part of the McMurray that has been eroded from the valleys and terraces.

These widespread unconsolidated Pleistocene sands presumably represent deltaic deposits of the Athabasca River in a late Pleistocene lake—probably the old Lake Athabasca.

The whole of the McMurray district is largely covered by a layer of till of varying thickness. In some places its constituents are largely sand and clay, while in others there are many boulders of gneiss and quartzites and other meta-sediments.

McMURRAY FORMATION

The Devonian-McMurray Contact

Throughout the McMurray district the McMurray formation unconformably overlies rocks of known Devonian age. The unique nature of this contact has occasioned comment by earlier workers.

The strata of the underlying Devonian limestones, marly limestones, and shales undulate markedly on a relatively small scale, but are not folded in the sense that the structures have any discernible and consistent strike. On the other hand the rocks are warped into small quaquaversal domes with flank dips ranging from 1° to a maximum of 20° or more in rare instances. On the Athabasca just below McMurray the beds are nearly horizontal for several miles.

The breadth of the domes vary from a few hundred feet to half a mile or more. The amplitudes of the domes or undulations also vary but they apparently range up to approximately 250 feet.

Superficial examination gives the impression that the McMurray-Devonian contact closely follows the warping of the Devonian strata, but this is not the case. On the contrary, erosional truncation of the undulating structure in the Devonian rocks took place in pre-McMurray time. One can visualize the pre-McMurray land surface as made up of low, rounded, dome-shaped hills, with irregular, sometimes interconnecting depressions between. The general surface would be a plain with the minor undulations undergoing erosion and their elevation being closely reduced. In places relict erosional remnants would stand above the general land surface as more prominent hills, and these would have only a coincidental relationship to the domed structure.

Detailed Description of McMurray Formation

The McMurray formation, as exposed along the Athabasca River and its tributaries, is a clearly defined stratigraphic unit, lithologically unlike the remainder of the section and sharply set off from the formations above and below. Throughout the major part of its outcrop area it is more or less highly impregnated with bitumen but is no less distinctive where no such impregnation occurs.

With the exception of bitumen content the formation is similar throughout the McMurray area, i.e., it exhibits the same or similar variations in lithology and, although no two exposures are the same, their variations are consistent in type. Consequently, generalized statements will apply in particular instances.

Environment of Deposition:

It has been generally accepted that the McMurray formation represents a deltaic deposit, the source of the sediments being from the Precambrian area to the north and east. Some modification of this concept will be made here, particularly in the emphasis of the continental nature of almost the entire formation. Unlike most deposits of wide extent that are regarded as deltaic, practically no recognizable marine intercalations are present. One exception to this rule consists of a relatively thin, lensing bed of black silty shale within a few feet of the top of the formation on the upper McKay River. On lithologic evidence alone this shale could possibly be of marine origin as it closely resembles elements of the Clearwater shale immediately above. However, no glauconite or marine fossils were found in it, and the probabilities are that it indicates a brackish water or lagoonal environment at best. Thus it is suggested that rather than being deltaic, most of the formation represents a broad flood plain or coastal lowland deposit and that a Lower Cretaceous sea lay some distance to the west.

McMurray Fauna:

The fauna of the McMurray formation throws some light on the problem of the environment of the deposition. Near the mouth of Hangingstone River is a lens of highly fossiliferous sandstone. The fauna consists of a number of small gastropods and pelecypods which have been studied by Russell (1932) and McLearn.

This McMurray fauna is thought by Russell to indicate a Lower Cretaceous age, contemporary with or slightly older than the Blairmore formation. The assemblage is "preponderantly of fresh water habitat, although the presence of some genera suggest proximity to the sea."

Lithologic Features:

As previously described, the McMurray-Devonian contact is not a plane but undulates markedly. In general, however, even the basal beds of the McMurray formation do not reflect these undulations, except in that they thicken and thin in conformation with lows and highs of the contact, so that their upper limits are essentially flat. Almost invariably there are several inches to several tens of feet of residual material resulting from the weathering of the Devonian limestone lying just above the contact, particularly on the flanks and in the troughs of the undulations.

As a general rule thick lenses of coarse sandstones, grits, pebbles, and conglomerate occur near the base of the formation rather than higher; and this criterion can be used with reservations as indicating the proximity of the basal contact where it is not actually exposed. As is the case with nearly every generality concerning this formation, there are notable exceptions.

Marcasite concretions ranging from one-half inch to several inches in diameter are a common feature of the McMurray formation, although they are by no means always present. Carbonized wood fragments and lignite seams, as well as relatively unaltered wood, are common throughout the formation, particularly in the lower part.

Sedimentary Structure:

The most accurate generalization that can be made concerning the McMurray formation is that it is exceedingly irregular, lensing, and inconsistent. The more massive beds tend to occur in the lower half of the formation, and thin, platy, even-bedded or laminated materials are more characteristic of the upper part. But all variations occur and no universal rule strictly applies, even in relatively restricted areas. Trustworthy marker beds are non-existent and often the units in two sections taken only a few hundred feet apart cannot be correlated. The whole formation is essentially made up of lenses of sand, silt, and clay, the lenses being of all dimensions, in some cases massive units within themselves and in others intimately divided by beds, cross beds, and laminations. Coarse sands grade laterally and vertically into fine; grits are replaced by siltstone; massive sands are truncated by laminated sandstones or silts. Cross-bedding is a common phenomenon, and the cross beds range in size from small structures within a lensing bed a few inches thick, up to huge sweeping foreset beds that cut diagonally from top to bottom of a large outcrop and are only discernible as such when the outcrop is viewed from a distance and as a whole.

There is a rough over-all sorting of the McMurray sands which may not be apparent in any one locality but can be said to apply to the whole formation in general. Coarse sands and grits and thick clay lenses occur toward the base of the section; massive medium- to fine-grained lenses are found most commonly in the lower one-third of the formation: relatively fine-grained sandstones alternating with siltstones are characteristic of the upper two-thirds; and thin-bedded to well laminated fine-grained sandstones and siltstones generally are found in the upper part of the section.

Thickness:

The thickness of the McMurray formation averages 180 feet in the vicinity of McMurray and varies from 150 to 200 feet down river. The thinnest full section of 135 feet occurs on the McKay River overlying a pre-McMurray high. The thickest section, that of 265 feet, is very questionable as it represents the interpretation of the log of an old well located southeast of Bitumount.

The abrupt variations in thickness are due largely to the undulations of the basal contact, or to old residual hills of Devonian limestone, and not to any marked increase in one direction. However, the formation apparently thins out to the southwest.

Mineral Constituents:

Characteristically the McMurray sands consist of angular to subround grains of translucent, slightly smoky quartz. In impregnated sands the oil film obscured the nature of the mineral grains and minor constituents are not discernible under the hand lens. It is Curry's opinion, however, that the McMurray sands in the vicinity of the Athabasca contain little feldspar, as only a very few grains were noted, even in coarse material. Analyses of sand from Abasand and Bitumount tailings show over 98% silica and less than 1% alumina, with minor amounts of iron and titanium oxides in both cases. These figures indicate only a very minor feldspar content.

To the east, in the unimpregnated area, there is a marked increase in feldspar, and presumably in heavy minerals, in the lower part of the McMurray sections. The sand is flecked with dull white feldspar grains. White mica, which is present in practically all the siltstones, becomes abundant in the sands as well.

Cementation.

If it were not for the binding and cementing effect of the heavy bitumen, the greater part of the McMurray formation would be practically non-indurated and unconsolidated. In almost all parts of the district, however, some lenses have been more or less tightly cemented by iron oxides and other minerals.

Known Extent of the Bituminous Sands:

Outcrops of the McMurray formation occur intermittently along the Athabasca River for a total distance of approximately 100 miles by river. Along the Clearwater River, main tributary to the Athabasca, the formation was found to extend well into Saskatchewan, although it is not impregnated with bitumen beyond tp. 89, rge. 5, W. 4th mer.

The lower portions of the major tributaries of the two main streams also cut into and expose part or all of the McMurray formation for varying distances, depending on their gradients and trends.

The smallest area encompassing all the known outcrops of the McMurray formation impregnated by bitumen approaches 3,000 square miles in extent; and the thinnest full section known within that area is more than 100 feet thick. These rough estimates only serve to indicate the immensity of the deposit.

Bitumen Content of the Sands and its Distribution:

Nearly all of the sands of the McMurray formation exposed in the district are impregnated with bitumen to some degree. In the majority of cases the amount present approximates the maximum that can be contained, considering the conditions under which the bitumen is held in the rock.

Unimpregnated Area:

It has been noted that a great area of the McMurray formation, that is exposed on the upper reaches of the Clearwater River and its tributaries, is outside the area of impregnation and absolutely barren of bitumen. At the Christina River are thick high-grade beds, and only at the top of the formation and then only in places is there any suggestion whatever of undersaturated beds. On Hollies Creek four miles to the east, however, only the very basal beds are saturated, and massive lenses that would normally be rich are brown and low-grade, while high strata are cream-colored and barren. Farther east, at Cottonwood Creek, the impregnating fluids are caught in the act, as it were. Massive, potentially rich beds are soft, white, and barren over a large part of the exposure but the same lens is much harder, light brown, and very low-grade (actually only oil-stained) at one end. The impregnated and non-impregnated sands grade laterally into each other through an irregular zone of mottled sand, consisting of small oval blebs of brown impregnated material which tend to have their long axes parallel to each other, set in a matrix of white sand. The McMurray formation in the unimpregnated region is lithologically exactly similar in every respect to that which carries the rich bitumen deposits, except for the fact that there is not, and never has been, any bitumen content.

Structure

Regional:

In a regional sense the geologic structure of the McMurray area is relatively simple. It consists of a broad westward dipping monocline, the strike of which trends a little west of north. This monocline is modified by some broad anticlines and terraces, several local synclines, and a major fault.

The local doming of the Devonian strata and the undulating nature of the McMurray-Devonian contact has been described. These irregularities, and the fact that they are not in general reflected in the structure of the overlying McMurray made this contact useless for structural study, except in a broad way.

A structure contour map drawn on the Clearwater-McMurray contact and based on meagre data brings out several interesting features:

1. There is a general but persistent northward trend in the strike, and a general westward dip in the eastern part of the area.
2. The Athabasca parallels a general synclinal depression for several miles north of McMurray.
3. Some of the underlying Devonian highs are reflected slightly in the Cretaceous structure.
4. Unlike conditions obtaining in the greater part of the region, the McMurray formation is sharply folded in the vicinity of Bitumount. There is a pronounced depression, the "Bitumount basin," modified by minor folds. The full extent and shape of this structure is conjectural, but the contours serve to indicate its presence and represent the best interpretation of the data at hand.

Fault:

The only fault of any consequence in the region was first noted by Sproule. The actual break is not exposed, but it apparently crosses the upper Clearwater River somewhere between Edwin Creek and High Hills River, presumably just below the Weymarn well. The McMurray-Devonian contact is over 300 feet higher on the east side, indicating that the fault has a displacement on that order of magnitude, with the downthrow to the west. The movement took place in post-Clearwater time. That formation is largely stripped away for some distance east of the supposed location of the fault, whereas on High Hills a few miles from its mouth a thick section of this formation is preserved. In consequence, slumping and huge landslides are a common feature of the landscape west of the fault.

Effect of Structure on Bitumen Content:

Since McLearn's early investigations in 1917 it has been repeatedly stated that there is an apparent structural control of the bitumen deposits, the richer material being found in the syncline where it has presumably been concentrated due to gravity.

Although McLearn was speaking of the depression called the "Bitumount basin" in his report, the theory has often been extended to apply to the minor synclines in the McMurray-Devonian contact This belief is presumably based on the tacit supposition that the doming and undulation has a reflection in the McMurray formation, which of course is not the case.

The depression in the McMurray-Devonian contact resulted in the deposition of a thicker McMurray section there than over the corresponding domes. Inasmuch as the lower units are those that are thickened, and as the lower lenses and beds tend to be more massive and uniform, it is true that rich deposits do occur at such points in many cases. On the other hand, where residual clays or massive siltstones occupy the lows in the undulating contact, the reverse is the case. As far as the minor lows are concerned it is apparent that the richness of the sand is almost entirely due to its ability to absorb oil, which is in turn a function of its porosity and size of grain; and that structure plays only an indirect part in such a deposit.

REGIONAL CORRELATIONS OF THE LOWER CRETACEOUS FORMATIONS OF THE McMURRAY OIL-SAND AREA

By R. T. D. Wickenden
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Since the time when R. G. McConnell and his contemporaries commenced a study of the stratigraphy of the Cretaceous formations of the Plains and Foothills of Western Canada, ideas on their sedimentation, stratigraphy, and correlation have undergone many changes. The concept of what constitutes a correlation has been complicated by considerations such as that of lithofacies, transgressing time zones, and by others resulting from further study of the environmental significance of sediments and fossils. Recognition of the transgression of time boundaries is especially difficult in the case of the Lower Cretaceous strata of the Plains of Canada, which were derived from various sources and deposited contemporaneously under varied marine and continental conditions. Under these circumstances, regional correlations are largely dependent on age determinations by fossils. It is admitted that the accuracy of this method may not be all that is desired, yet it yields results of practical value that no other methods approach. The broader correlations established by the writer are based on fossil studies by previous authors, such as Whiteaves, McLearn, and Warren, as well as on his own study of microfossils. In these correlations, the interpretation of the mode of origin or environment of deposition, the sources of the sediments, and recognition of paleogeographic features such as the locations of the basin of deposition and the adjacent land areas, have been given consideration.

According to McLearn (2), the general conditions in Lower Cretaceous times were those of a sea from the north invading a broad trough or basin. Although marine Lower Cretaceous formations are known in the southern part of the continent as well as in the north, apparently the seas of the north and south did not join until the close of Lower Cretaceous or early Upper Cretaceous time, but were probably separated by a low-lying land barrier. A lowland in the region of Saskatchewan and North Dakota may have existed during all of early Lower Cretaceous time, but the northern seas gradually occupied this area later in this epoch. Thus the basin was bounded on the east by the low-lying Precambrian and Paleozoic region, by a lowland of Jurassic and possibly Triassic sand and finer grained sediments in the south or southeast, and by a highland that furnished abundant sediments to the west and southwest.

In the writer's opinion, sands derived from the Precambrian terrain differ from those derived from the west in that they are composed of essentially pure quartz, whereas those derived from the west or southwest usually contain numerous grains and pebbles of chert and green and grey siliceous rocks, evidently detritus from very fine quartzites or similar metamorphosed rocks. It is admitted that the quartz sands are not necessarily all derived from the east, as some Cretaceous formations composed of nearly pure quartz sandstone do occur in the southern Foothills. On the other hand, the sands containing the grey and green siliceous grains are believed to have all originated from formations in the west and southwest. The fact that such sands do not occur in sediments older than the Riding Mountain formation of Montana age in Manitoba is evidence of the length of time required for detritus from the western sediments to be carried in some directions. In contrast, the Grand Rapids formation of the Athabasca River region contains pebbles and sand grains of the grey and green siliceous rocks that probably came from western sources, indicating a fairly rapid influx of this material. The sediments are thick on the western side of the basin and tend to thin to the east. Thus the deepest part of the basin lay in the present foothills and mountain areas, and the east side rested on the gently sloping Precambrian shelf of the Canadian Shield.

With this background of the conditions and environment of deposition during Lower Cretaceous time, correlation of formations in the vicinity of the oil-sand localities along Athabasca River with those of the rest of the region can be better understood. The general correlations with other regions considered by the writer are shown in Fig. 1. Some explanation of the reasons for these correlations are necessary, and in discussing them the sequence of formations at McMurray will serve as a convenient reference.

The Lower Cretaceous basin was first invaded by the sea in eastern British Columbia, where the lower Bullhead group contains beds of marine origin in the Monteith, Beattie Peaks, and Monach formations (1), but no evidence of formations of the same age occur in the McMurray area.

The basal beds of the Lower Cretaceous in the McMurray area comprise the McMurray formation. McLearn (2) has correlated these with the upper Bullhead group (Gething formation) and Lower Blairmore in the Foothills section. To the south, Nauss (3) suggested that the Dina member in the Vermilion area is the equivalent of the McMurray. The McMurray represents the transgression of Lower Cretaceous deposits over Paleozoic strata, and it is possible that the age may vary a little from place to place, though such a variation would be dificult to recognize, since the source and deposition of the sand were probably very similar, regardless of the time. For the same reasons, any intervals of non-deposition would be equally difficult to detect. In his description of the mollusca from the McMurray formation, Russell (5) noted the occurrence of a few brackish as well as fresh-water species. Examination of some of the thin interbedded shales near the upper part of the formation drilled in the Mildred-Ruth Lakes area revealed numerous arenaceous foraminifera which would indicate marine or brackish water conditions. It is probable that both continental and marine deposits are inter-tongued in the formation in parts of the area. The quartz sand that constitutes most

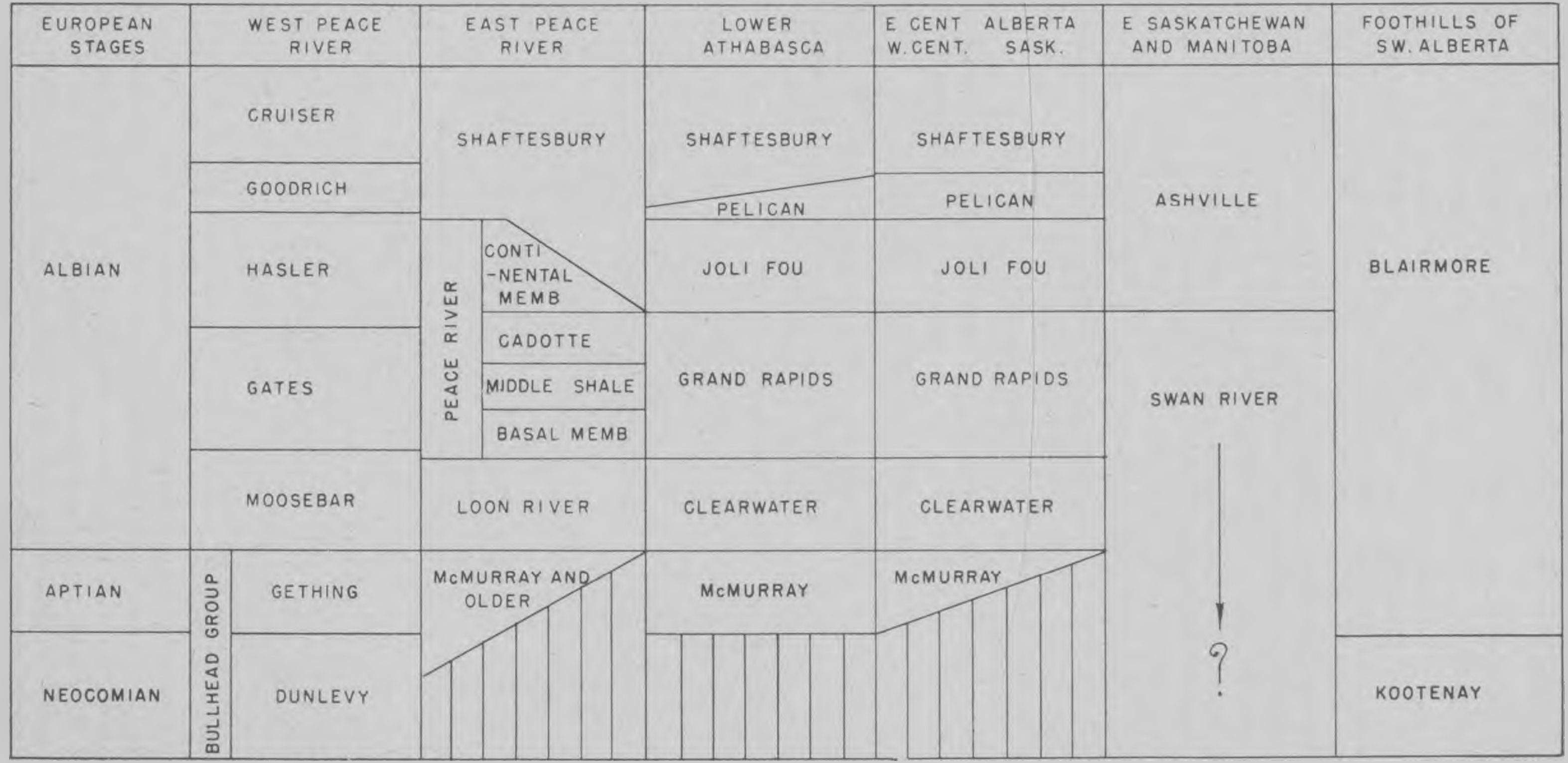

Fig. 1. *Correlation of Lower Cretaceous formations of the Athabasca River area with those of other areas in the Plains and Foothills.*

of the formation was probably derived from formations of Precambrian and Paleozoic ages on the east side of the basin.

In east-central Alberta, in the Wainwright area, the McMurray or equivalent beds did not completely cover the high hills on the Paleozoic surface. Still farther south, east at Unity, the McMurray equivalent is missing. It is probable that there is no direct connection between the McMurray and the oldest Cretaceous formation in Saskatchewan and Manitoba, although some parts may have beds of the same age. To the west, the McMurray probably merges into formations derived from western sources, and the equivalent beds are at least part of the sands and silts that underlie the Loon River or Moosebar formations.

Overlying the McMurray, the Clearwater formation represents a time in the Lower Cretaceous epoch when the sea extended over a considerable part of the Plains. McLearn has pointed out that the *Lemuroceras* or *Beudanticeres affine* fauna is common to the Clearwater, Loon River, and Moosebar formations. A dark shale occupies the same position as the Clearwater in the Vermilion and Lloydminster areas, and probably many occurrences of the 'ostracod zone' in the wells may represent the equivalent beds. The Cummings member and the associated glauconitic sandstones for the Vermilion and Lloydminster area are apparently the same formation, although the foraminifera fauna contains very few or no calcareous species at most southern localities. This may indicate that conditions were not so favorable for marine life in these districts.

At Unity, Saskatchewan, the equivalent of the Clearwater is composed of shale and silt in some localities and glauconitic sand in others, and is locally called the Unity gas sand. The marine deposits of this formation may not have extended much beyond Unity or Wilkie in Saskatchewan, and these beds are not recognizable at Saskatoon or Battleford. Wells drilled to the southwest, near Compeer, did not show the marine member, but elsewhere in Alberta an ostracod-bearing shale has been found in wells that may be the equivalent of the Clearwater, and it is probable that the southern and eastern borders of these beds formed an irregular pattern, and that farther south they may have extended far to the east. The Clearwater sea undoubtedly extended beyond the limits of the McMurray formation in the Athabasca area as well as in central Saskatchewan. As more details of the Clearwater are revealed, it will be found that there is much intercalation of marine and continental beds, but the equivent of the Clearwater as part of the continental beds of the Blairmore has not yet been recognized.

The Grand Rapids formation, which overlies the Clearwater in the Athabasca region, is composed of sands and silts of marine and non-marine origin, including shale and coal beds at some localities. The lower part of the formation is mostly marine, and the upper part is mostly brackish and continental in origin, in the writer's opinion. McLearn has correlated the Grand Rapids with the Peace River formation farther north and with the Gates formation and part of the

Hasler formation of the Foothills. It is admitted that most of the Peace River formation appears to be equivalent to the Grand Rapids, although the lower part of the Peace River, just above the Loon River shale, shows close faunal relationship to the latter in some localities, and possibly the exact horizon of the Grand Rapids-Clearwater contact is a little higher than that of the Loon River-Peace River contact. The beds in the two regions are not similar in all features, as they represent a different environment and facies of deposition. All the sands of the Grand Rapids formation in the Athabasca district show fragments of green and grey siliceous rock, and it is probable that most of the material originated in western areas, possibly west of the present Rocky Mountains. The upper part of the Grand Rapids contains fewer marine beds where it was observed on Athabasca River above Grand Rapids.

To the south, the Grand Rapids can be correlated with the upper part of the Mannville, as defined by Nauss, and the writer believes that it includes the Islay, Tovell, Borradaile, and O'Sullivan members. The lower two of these members are partly marine in origin, and they probably correspond with the more marine lower part of the Grand Rapids on Athabasca River. Farther south, McLearn has indicated that the Grand Rapids is equivalent to part of the Blairmore, the 'Varicoloured beds' of the Lower Cretaceous of the southern Plains, and the Swan River formation of eastern Saskatchewan and Manitoba. The succession of microfauna in the beds above the Swan River and the Grand Rapids indicates that the upper contact of these two formations is coeval. Whereas the top of the Blairmore of the southern Plains seems to occupy the same position and be the age equivalent of the top of the Grand Rapids, there is some doubt if this is true in the Foothills, and exact correlations have not yet been made.

The succeeding Joli Fou formation is a marine shale that appears to have been deposited during a time of very extensive advance of the sea over the area of the present Plains of Western Canada. A bed of coarse sand and grit a few inches thick commonly lies at or near the base of the formation. The contact with the sediments of the underlying Grand Rapids or equivalent formation is sharp, and there is probably a disconformity at this horizon over most of the Plains. The beds at the top of the Grand Rapids are non-marine sands and minor shales or silts, and the Joli Fou, in contrast, is a typical marine shale. The change is very abrupt, and must indicate a break in continuity of sedimentation. Along eastern Peace River valley, in the vicinity of the town of Peace River, all or nearly all of the formation is missing, as indicated in a more detailed discussion of the stratigraphy of that region in a recent report by the writer (7). Thus, although the break between the Grand Rapids and the Joli Fou seems to be at much the same horizon in the area between the Athabasca and much of southern Alberta, marked disconformities can occur in other regions.

The Shaftesbury formation, which overlies the Peace River formation in the eastern Peace River region, includes beds at the base that are the equivalent to all, or nearly all, of the Joli Fou formation at some localities, whereas at others most of this latter formation is missing.

To the east, beds equivalent to the Joli Fou are found in the lower part of the Ashville formation of Manitoba and eastern Saskatchewan. On the other hand, it is doubtful if there is any marine member equivalent to the Joli Fou in the southern Foothills, where this formation is probably represented by some of the upper beds of the Blairmore formation.

In the lower Athabasca region, the Pelican formation, which overlies the Joli Fou, is composed mostly of sand beds. A few dark shale beds occur among them at some localities, and evidence from wells shows that the formation as a whole becomes silty and sandy shale in places. Correlation by foraminifera indicates that the Viking sand and most, if not all, of the Bow Island sand occupies the same section in central and southern Alberta. In the eastern Peace River region, a few pebbles and thin sands at the base of the Shaftesbury, near the town of Peace River, are probably the equivalent of the Pelican; elsewhere the formations may be better developed, but exposures of this part of the Lower Cretaceous section were not observed by the writer when studying the formations along lower Peace River. Whether or not some of the sandstones in the Foothills along western Peace River represent the Pelican is not yet determined. Although beds of the same age exist in the Ashville in Manitoba, no sand member has been recognized as equivalent to the Pelican. Comparison of foraminiferal faunas from the Shaftesbury of the eastern Peace River region and those overlying the Pelican in the Athabasca River region indicate that these beds are correlative.

It is probable that some of the beds of the Shaftesbury formation north of the town of Peace River, where the Continental member at the top of the Peace River formation is missing, are in part equivalent to part or all of both the Joli Fou and Pelican formations. It is suggested, however, that, for the present, the name Shaftesbury be used only for the beds overlying the Pelican, as these beds are essentially the equivalent of the Shaftesbury in the vicinity of the town of Peace River. Eventually, this restriction to the definition of the Shaftesbury may be found to be applicable over a wide area. The top of the Shaftesbury, at the contact with the Dunvegan, has generally been taken as the top of the Lower Cretaceous Series. Just where this horizon lies in the lower Athabasca section is uncertain; it is undoubtedly at least 100 feet above the Pelican, and may be 200 feet or more above it. More detailed studies are needed to be certain of this. Farther west, the Shaftesbury contains the *Neogastroplites* fauna, according to McLearn (2), and probably some of the associated fossils can be expected to occur in the Shaftesbury shale above the Pelican. Recently, some of these ammonites have been reported by Reeside and Cobban (4) from the Mowry shale in Wyoming, indicating that the sea extended far south of the International Boundary.

There has been some doubt about the age significance of the *Neogastroplites* fauna. Reeside and Cobban mention the occurrence of both *Gastroplites* and *Neogastroplites* in the Mowry. This may indicate that the two fossils are in part contemporaneous to some extent, and remove some of the doubts about a Lower Cretaceous age of *Neogastroplites*.

The Shaftesbury and its correlative formation, the Ashville, are probably the youngest Lower Cretaceous formations in Western Canada, and may mark the time when the seas from the north and south united.

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SOME STRATIGRAPHIC FEATURES OF THE UPPER DEVONIAN SEQUENCE OF THE CANADIAN WESTERN PLAINS

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INTRODUCTION

The stratigraphic sequence of the Canadian Western Plains may be divided into three main groups, viz., (1) The Precambrian basement, (2) Paleozoic rocks which lie unconformably on the Precambrian, and (3) A thick section of Mesozoic strata disconformably overlying the Paleozoic rocks. Remnant areas of Tertiary strata are present in the south and west, and the whole region is covered by deposits from the Pleistocene glaciers.

The Paleozoic rocks are exposed along the eastern margin of the Great Plains area by the erosion of the overlying Mesozoic rocks. They are exposed, also, in the Rocky Mountains to the west of the plains area through orogenic uplift. Lower Paleozoic rocks appear to have a very sporadic distribution as judged by information accumulated from the drilling records. Upper Cambrian rocks are present under the southwestern part of the plains, but are not known to outcrop along the eastern margin. Upper Ordovician and Silurian rocks are exposed in the eastern and northern part of the area, but do not seem to have a wide distribution under the Western Plains area and rocks of this age do not appear in the front ranges of the Rockies. Devonian strata, however, have a wide distribution, appearing in outcrop on the eastern edge and in the front ranges of the Rockies, and have been encountered in all areas under the plains where drilling has been carried to sufficient depth. Carboniferous rocks were undoubtedly widespread over the plains, but pre-Cretaceous erosion reduced their areal extent to the western and southern flanks of the Canadian Western Plains. Rocks believed to be of Permian age have been encountered only in the Peace River basin. So far as areal extent is concerned, the Devonian strata outranks all other Paleozoic rocks in importance under the Western Plains. It is also proving the most important from an economic standpoint.

THE DEVONIAN SYSTEM UNDERLYING THE CANADIAN WESTERN PLAINS

The sea that deposited the Devonian rocks under the Canadian Western Plains transgressed the area from the north and covered an erosion surface on which rocks varying in age from Precambrian to Silurian were exposed. It was a typical epeiric sea, rather shallow and sufficiently warm to support the growth of corals in reefal facies, even in areas north of the Arctic circle. The fauna was of a cosmopolitan type with strong Asiatic and European affinities. The known extent of this sea was from the Arctic Ocean in the north to the southern United States, and from the Selkirk Mountains of British

Columbia east to the Canadian Shield in Manitoba. The sea transgressed the area about the beginning of the Middle Devonian and did not connect with the Devonian seas overlying eastern North America until Upper Devonian time.

In common with most epeiric seas there was a considerable amount of fluctuation in depth, producing a series of alternating limestones and shales. In Middle Devonian time, the sea did not appear to have such a wide areal extent as in the Upper Devonian, as indicated by well log data. Our information from drilling is still too scanty to make very definite statements about the distribution of Middle Devonian rocks. It is probable, however, that the land surface present at the advent of the Middle Devonian sea was a peneplain and many high areas stood out as monadnocks and were not covered by the sea till Upper Devonian time. We have evidence that this was actually the case in one or two localities and will probably prove to be the main reason for the erratic distribution of Middle Devonian rocks.

About the end of Middle Devonian time, the sea withdrew and erosion removed a portion of the Middle Devonian rocks, especially in the area of the lower Mackenzie valley and Anderson River. Through the area of central Alberta and Saskatchewan, salt, anhydrite and gypsum were deposited at about the time of this erosion interval (6). For the purpose of this paper, the unconformity will be considered as the division between Middle and Upper Devonian strata.

The Upper Devonian sea was wider spread than that of Middle Devonian time in that it covered the area of the Canadian Rockies from Peace River south, an area in which Middle Devonian rocks appear to be entirely absent. The sea deposited a series of limestones and shales, somewhat similar to that of the Middle Devonian. A reefal facies is developed in some areas and, locally, the limestones have become changed to dolomites. It is the intention of this paper to elucidate some stratigraphic aspects of the Upper Devonian sequence, especially in its relationship to the accumulation of oil.

UPPER DEVONIAN STRATIGRAPHY AND ITS ECONOMIC ASPECTS

The Upper Devonian strata of the Western Plains and Mountains are capable of being divided into formations or groups of formations. This grouping will vary according to locality and many formational names have been introduced within the area under discussion. The correlation of the formations so named has been attempted by Warren and Stelck (7). Any such correlation has to take into account strong changes in sedimentary facies, some of which are very local. The change in sedimentary facies is often accompanied by an almost complete change in faunal facies which introduces grave difficulties in correlation over broad areas. Fig. 1 shows a correlation of some of the areas under discussion.

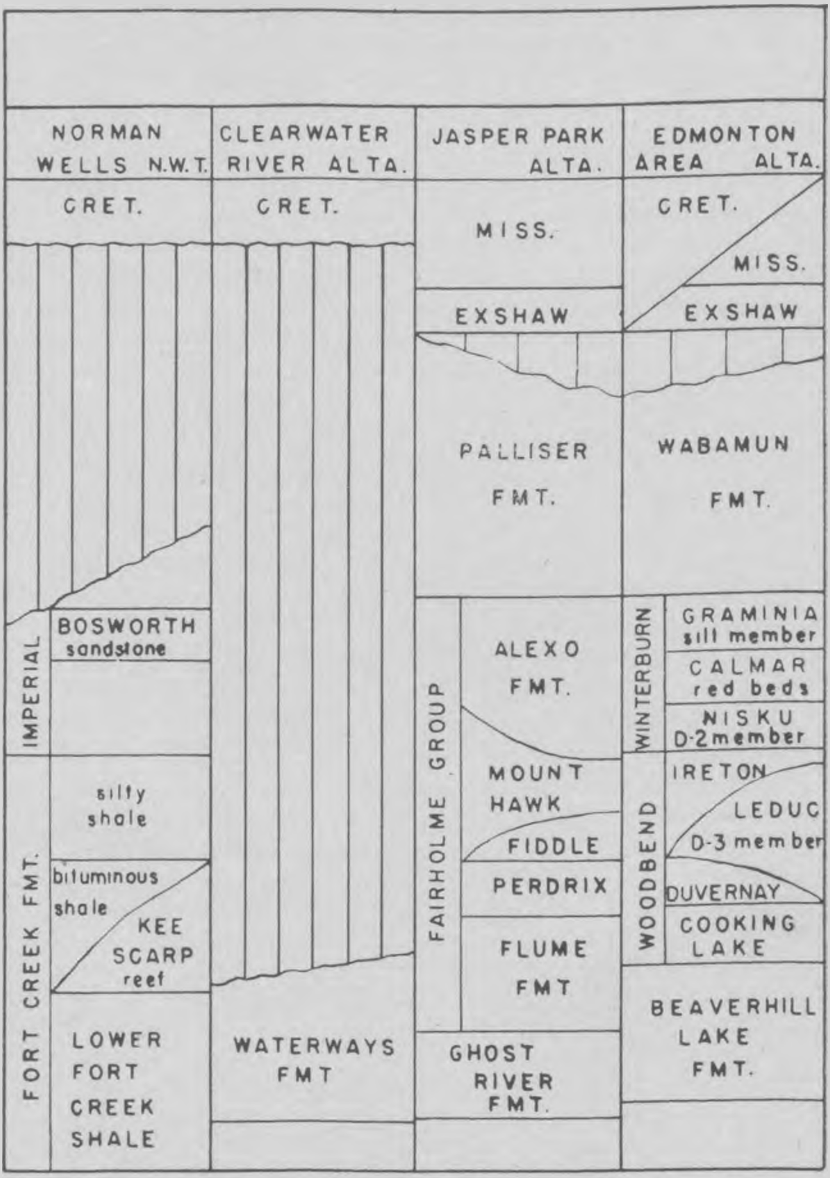

Fig. 1. *Four Upper Devonian sections of Western Canada.*

In Fig. 1 the nomenclature of formations and groups used is derived from publications of various geologists who have studied the different fields. The arrangement and correlation is that suggested by Warren and Stelck (7). In the Norman Wells area the nomenclature of formations is that used by Hume and Link (2). On Clearwater River the Waterways formation was named by Warren (4). At Jasper, the nomenclature followed is that used by deWit and McLaren of the Geological Survey of Canada with slight modifications (1). In the Edmonton area, the groups and formations (subsurface) are those suggested by the geological staff of Imperial Oil Ltd. (3). In the confines of this paper it is proposed to discuss the subsurface formations of the Edmonton area and to point out the stratigraphic significance of the various formations.

Beaverhill Lake Formation

The lowest formation which may be considered of Upper Devonian age is the Beaverhill Lake. In its type locality, it is over 700 feet thick and is composed of limestones and shales, the latter being of a greenish-grey color. Much of the formation is fossiliferous with brachiopods, algae and stromatoporoids the chief groups represented. The sediments appear to have been deposited in fairly deep water as there is no sign of wave action in any of the beds.

Beds of similar age are exposed on the Clearwater and Athabasca Rivers where they are known as the Waterways formation and where the faunas have been more extensively studied. Corals are almost entirely lacking in the formation and there is no development of reefs. The formation may be correlated with the base of the Fairholme group in the Rocky Mountains and with the lower part of the Fort Creek shale on the lower Mackenzie River.

Woodbend Formation

The Woodbend formation is best considered as a group of distinct lithologic units, each of which is sufficiently thick to be considered as of formational rank. The lowest member of the Woodbend is the Cooking Lake fragmental limestone with a thickness of 240 feet in the type section. It is composed of limestone with shale partings, many of the limestones being broken up through wave action. It is quite fossiliferous and biostromal zones are developed. In some areas reefs are developed in the upper part of the succession. The unit represents a definite shallowing of the Upper Devonian sea.

Beds of similar age are not exposed on Athabasca River, being removed by pre-Cretaceous erosion. In the lower Mackenzie, the basal part of the Kee Scarp reef may be correlated with this member. The upper part of the Flume formation at Jasper is undoubtedly equivalent to the Cooking Lake.

The fauna of the Cooking Lake is not well known to the writer. It appears to be quite similar to that of the underlying Beaverhill Lake formation. Brachiopods, algae, stromatoporoids and corals make up the major part of the fauna.

The Duvernay shale overlies the Cooking Lake limestone except in such places where strong reefs are present. The Duvernay is a black shale about 300 feet thick and has a very wide areal extent. It correlates with the black Perdrix shale of the Rocky Mountains and with black bituminous shales of the Fort Creek formation in the lower Mackenzie area. Planktonic types of fossils are abundant, but large fossils are rare.

The Duvernay shale presents a considerable stratigraphic problem, both as to its origin and its relationship to the reefs. A black shale of this type is usually considered to have been deposited in very deep water lacking circulation. This cannot be true of the Duvernay. Its widespread distribution in strata deposited by an epeiric sea would oppose very deep water deposition. The beds immediately underlying the Duvernay, the Cooking Lake limestone, represent very shallow water deposition and there is a gradational boundary between the two units. Also, reefs based on the upper beds of the Cooking Lake limestone continued to grow throughout Duvernay time, replacing the dark shale, and such reefs do not grow in very deep water. It is also evident that the water was not stagnant as reefs would grow only in well aerated water. It follows, therefore, that we must consider that the Duvernay shale had a shallow and not a deep water environment.

The environment of reefs growing in a sea depositing mud of a character to form the dark Duvernay shale appears to be rather unusual. The shale, in most places, is calcareous and of a dark grey color; some layers are bituminous and some argillaceous limestone bands are present. There was likely sufficient lime present in the water to supply the needs of the reef-building organisms. It is probable that the reef-building organisms were responsible for extracting a good deal of the lime at that time and thereby accentuating the black argillaceous character of the shale. It is also very probable that the oil in the reefs had its origin in the Duvernay, and the draining of the bituminous products from the shale was partly responsible for its present physical characteristics.

The Duvernay shale must represent the erosion of a fresh land surface brought up at the time of the shallowing of the sea as shown by the clastic deposits of Cooking Lake limestone. The absence of any coarse detritals in the Duvernay would indicate that the material of this unit was obtained through the erosion of an argillaceous limestone or calcareous shale—quite possibly such a formation as the Cooking Lake limestone which immediately underlies the shale. Differential uplift over the area covered by the Upper Devonian sea toward the end of Cooking Lake time would account for the fragmental limestones of the Cooking Lake and the mud that produced the Duvernay shale.

The Ireton member, which overlies the Duvernay shale, is, for the most part, a greenish, calcareous or dolomitic shale. In its full development it is over 700 feet thick. Where reefal conditions prevail, it becomes the off-reef facies and may be reduced to a thickness of a few feet of dolomitic shale capping the reef. The lower part of the unit is calcareous whereas the upper part is strongly dolomitic.

The name, Leduc member, has been given to the reefal facies of the Ireton. Reefs will replace the green Ireton shale partly or nearly completely. The reefs of Ireton age are usually based on reefs that had their origin in the Cooking Lake member and have grown upward through the Duvernay shale. Under these conditions it is impossible, in drilling through a reef, to distinguish the part of the reef equivalent in age to Ireton. It is customary to consider the Leduc member as extending down to the base of the reef, irrespective of horizon, and extending upward to the top of the reef in the Ireton, irrespective of the height of the reef. The term Leduc member, therefore, loses a good deal of its significance as a time unit. The Leduc member varies also in lithologic character, occurring as a limestone or dolomite.

Winterburn Formation

This formation overlies the Woodbend and is composed of a various assortment of beds with a thickness of 250 feet. It has been divided into three members, the Graminia, Calmar and Nisku. The upper member, the Graminia, is usually composed of silty dolomite, but anhydrite is usually present and sometimes makes up the larger part of the member. It overlies the Calmar member which contains a higher percentage of silt. It is usually grey in color, but is sometimes mottled red and green. The Graminia and Calmar members are probably correlative with the Alexo formation of the Fairholme group of the Jasper section.

The lowest member of the Winterburn formation is a more distinctive unit. The Nisku member is a dolomite which is often porous but does not appear to represent a true reef. Anhydrite and silt are present in the Nisku in some areas. The Nisku may be oil-bearing and is referred to as the D-2 oil horizon. When seen in outcrop in the mountains, the member seems to correlate with the upper part of the Mt. Hawk formation rather than with the Alexo.

The Winterburn formation represents a shallowing of the sea with the deposition of anhydrite. The silt beds appearing in this succession of strata also indicate uplift with fresh land surfaces. The silt grains are so uniform in size over the whole known area of distribution, and also in individual exposures, that we must accept the idea that the silt was transported into the area by the wind.

Wabamun Formation

The strata overlying the Winterburn silts and evaporites have been named the Wabamun formation. It is 572 feet thick in the type section and is composed of buff to green crystalline dolomites and limestone. Limestone is more characteristic of the upper part of the formation and dolomite is the preponderant rock throughout the remainder of the formation. Heavy oil occurs in the upper part of the formation, especially where directly overlain by the Lower Cretaceous shales and sandstones. This has been called the D-1 zone. The Wabamun is correlated with the Palliser formation of the Rocky Mountains which formation attains a thickness of about 1,000 feet. In the lower Mackenzie valley, strata of similar age have been eroded; the Bosworth sandstone, which is a correlative of the Winterburn formation, is the highest bed of the Devonian succession. The Wabamun represents a deepening of the sea after the uplift in Winterburn time with a final emergence and erosion near the end of Devonian time.

Exshaw Formation

The youngest Devonian formation found in the area is the Exshaw shale. It is a black shale, largely non-calcareous, and under the plains area is usually less than five feet thick. In the Rocky Mountains, where the formation was named, it is much thicker. In all areas where the base of the formation can be studied, it appears to lie disconformably on the underlying Palliser formation.

In some areas, both under the plains and in the mountains, there are two shales separated by limestone beds. In such cases confusion arises as to which to call the Exshaw. In the type area on Jura Creek near Exshaw, Alberta, the shale contains Devonian fossils, and for this reason the black shale lying above the Wabamun formation in the area west of the Leduc field will be considered Devonian in age.

The Exshaw shale appears to represent the black muds deposited by a transgressing sea. The formation is overlain conformably, and usually gradationally, by the Banff formation of Mississippian age. Stratigraphically, the Exshaw shale is more closely connected with the formations above it than with the underlying Devonian strata.

SIGNIFICANCE OF THE UPPER DEVONIAN STRATIGRAPHICALLY IN RELATION TO OIL

The Upper Devonian sequence of formations in northern Alberta represents three main cycles of transgression and regression of the sea. The earliest cycle commenced with the transgressing sea which deposited the Beaverhill Lake formation. It is best exemplified on Athabasca River in the Waterways formation which is a correlative formation of the Beaverhill Lake. The sea shallowed during the deposition of the Cooking Lake member of the Woodbend formation as shown by the fragmental limestones of this horizon.

The second cycle commenced with the Duvernay shale, which must represent erosion of a fresh land surface, and continued to the deposition of the Winterburn formation with its evaporites and silt beds. The third cycle is represented by the Wabamun formation under the plains and the Palliser in the mountains. This cycle ended with a complete withdrawal of the sea and an erosional interval before the next cycle commenced with the deposition of the black Exshaw shale.

It is interesting to note that in two cases the initial deposition of the transgressing sea is a black shale, and it is also true of the first transgression in Upper Devonian time in the lower Mackenzie valley where the dark Fort Creek shale forms the basal bed. The lowest beds of the last cycle, however, failed to produce black shale as the basal beds of the Wabamun and Palliser formations are limestone and dolomite.

The study of the development of the Upper Devonian reefs in relation to the shallowing and deepening of the sea is interesting and important. The first cycle represented by the Beaverhill Lake formation shows no development of reefs, and the formations correlative with the Beaverhill Lake—Flume, Waterways and the lower part of the Fort Creek shale—have no true reefs. The initial reefs occur in the Cooking Lake member of the Woodbend, and the Norman Wells reef started at the same time. Their origin was in the subordinate cycles of deepening and shallowing of the sea during Cooking Lake time. These Cooking Lake reefs seemed to form the base for the reefs which continued to grow through Duvernay and Ireton time. It is interesting that the muddy seas of Duvernay time did not interfere with the growth of the reefs. Some, undoubtedly started their growth as the seas cleared at the beginning of Ireton time. It is quite possible that all the D-3 reefs commenced growth at that time, and the largest sank under their own weight through the Duvernay muds and came to rest on the more substantial floor of the Cooking Lake member. There is a certain amount of evidence to substantiate such a theory. The reefs continued to grow upward through Ireton time, but most of them were drowned through overdeepening of the sea and were well capped by the green Ireton muds. At least one reef is known to have continued its growth to the horizon of the Nisku member of the Winterburn formation, and was probably stopped by the shallowing of the sea in Winterburn time or by the silts brought into the sea which smothered the corals or by the change in the constitution of the sea water which was depositing evaporites. No reefs are found in the Wabamun formation above the silts and anhydrites of the Winterburn formation.

The growth of the reefs in Woodbend time must be attributed to the presence of corals, especially of compound corals which are the true reef builders. The Beaverhill Lake formation, at the base of the Upper Devonian succession, is practically devoid of corals, as are the formations which are correlated with it. These formations are abundantly supplied with calcareous algae and stromatoporoids which play such a large part in the building of the reefs, but they do not appear to be able to build a good-sized reef by themselves. Corals of the compound type seem to be a necessary part of the organization that keeps the structure intact and promotes growth. They seem to act as a leaven to make the reef rise. Corals were never more plentiful in the Devonian than during the time of the deposition of the Ireton member of the Woodbend formation. It is this horizon that the writer, in an earlier paper (5), referred to as the coral zone. The disappearance of the corals during Winterburn time was a major calamity to the life of this epeiric sea. The genus *Atrypa* which vied with the corals for prominence in this sea, also disappeared in Winterburn time. The distinction between the life of the Woodbend and that of theWabamun formation is strongly marked. The diastrophic events of Winterburn time must have been more severe than at first supposed.

Of the formations which make up the Upper Devonian sequence, the Duvernay shale seems to be the most important member. The writer does not believe that the oil now present in the reefs is indigenous to them. There was undoubtedly sufficient life in the reefs to produce oil, but with the freely circulating water through the porous structure, such hydrocarbons that were developed through the disintegration of animal or plant matter would have escaped before the reef was capped. The porous reef would be a solid structure and lack the pressure deemed necessary for the formation of oil. Also, the circulation of water through the reef would tend to have an oxidizing effect on the hydrocarbons. It seems evident, therefore, that we must look for a source of oil outside of the reef structure. The Duvernay shale seems to be the only formation with the necessary qualifications. There was a plentiful life in the sea at Duvernay time as a source for the hydrocarbons. It would be free from oxidizing conditions after once covered; it would be subjected to the necessary pressure; and the oil could migrate **updip** to the reefs as the Duvernay shows a dip away from the reefs at the present time. Formation and transportation of the oil through the shale would be sufficiently slow to allow the reef to be capped before the oil occupied it. It might also be pointed out that some of the beds of the Duvernay are still bituminous.

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SOURCE OF OIL IN OIL SANDS OF ATHABASCA RIVER, ALBERTA, CANADA*

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ABSTRACT

The oil sands of the Athabasca or "McMurray bituminous sands" of Lower Cretaceous age in northeastern Alberta, Canada, are believed to have derived their bituminous content from the underlying coral-reef reservoirs of Upper Devonian age which come in contact and near-contact with the overlying sands at the unconformity between the Lower Cretaceous and the Devonian. The white quartz sands were supplied from the Precambrian "Athabasca sandstone" lying at the northeast on the Canadian Shield, and it is suggested that the escape of oil and gas through fissures and fractures from the Devonian reservoirs into the oil sands occurred primarily during, but also possibly subsequent to, the deposition of the Cretaceous oil sands. It is also believed that the Lower Cretaceous heavy oil of Lloydminster, Alberta, has had a similar history.

INTRODUCTION

The geologic cross-section or profile through central Alberta (Fig. 1 and 2) indicates an unconformity of considerable magnitude at the base of the Lower Cretaceous sediments, and it also depicts progressively deeper bevelling of Lower Mesozoic and Upper Paleozoic sediments from west to east, so that in the Alberta syncline, along the Foothills Front, the Lower Cretaceous beds rest on Jurassic rocks, thence eastward on Mississippian, Devonian, Silurian, and finally Precambrian (5).

In the Edmonton area, the Upper Devonian contains numerous bioherms or reefs, with and without gas and oil, and these lie at some depth below the unconformity in question. Eastward these reefs come nearer and nearer the unconformity previously mentioned until, in the Athabasca oil sands area, D-3 zone bioherms or equivalents, and also deeper ones, are in contact with the oil sands of Lower Cretaceous age (Fig. 2). The same applies to the D-2 zone biostrome which overlies the D-3 bioherm horizon. That Paleozoic sediments might have been the source of the bituminous sands oil was suspected by many geologists prior to the Leduc discovery in 1947 (7). Subsequently, this suspicion is regarded to be more reasonable than ever, and the natural corollary to that is the more specific theory that possibly the bitumen in the oil sands came from Upper and Middle Devonian reefs or bioherms. Prior to Leduc the main argument

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*Previously printed in the Bulletin of the American Association of Petroleum Geologists, 35, 854-864 (1951). Reprinted here with permission of the Association. It should be noted that in this reproduction the term "tar sands" has been replaced by either "oil sands" or "bituminous sands" and the term "tar" was generally replaced by either "oil" or "bitumen."

against such a theory was the apparent absence, or lack of recognition, of source and reservoir rock in the Paleozoic, and the proponents of the Lower Cretaceous shale source-bed theory rightfully awaited better and more evidence from the Paleozoic source-bed theorists. Furthermore, the manner and means of migration from the Paleozoic was only vaguely or inconclusively presented by its proponents. However, since the Leduc and Redwater discoveries, the Paleozoic-source theory has gained considerable momentum, and subsequent revelations that both the D-2 zone biostrome and great areas of D-3 bioherms are in actual contact with the oil sands at the unconformity have added tremendously to the possibilities of a Devonian source for the oil in the Lower Cretaceous. This contribution is merely a suggested theory for the mechanics of transfer of oil from the Devonian through the unconformity into the oil sands, which has previously been the weakest part of the postulated Paleozoic

Fig. 1. *Index map of Alberta and Saskatchewan showing areal relationship between oil sands of Lower Cretaceous age in sedimentary basin area and Precambrian "Athabasca sandstone" on Canadian shield. AB indicates position of cross-section* (Fig. 2) *which begins at B in Athabasca sandstone on the Shield, and passes through the oil sands, Redwater and Leduc coral-reef oil pools, near Edmonton, and thence through deeper part of Alberta syncline, Foothills Belt, and Rocky Mountains at A.*

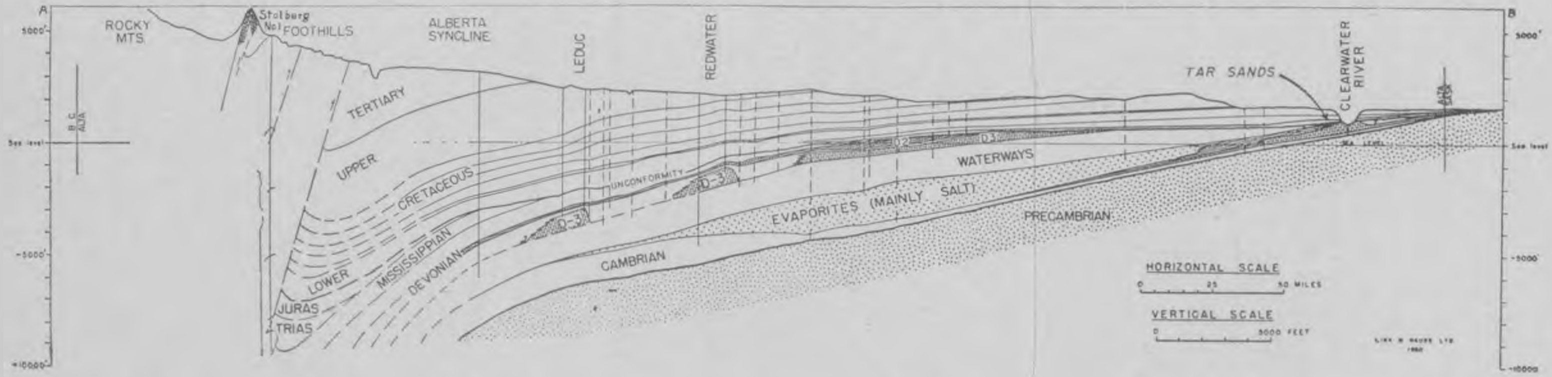


Fig. 2. *Generalized cross-section AB through central Alberta sedimentary basin area, as indicated on index map* (Fig. 1). Section *extends from Precambrian (Canadian) Shield through oil sands area; Redwater and Leduc oil fields; Alberta syncline; Foothills Belt; and to Rocky Mountains. Vertical scale is greatly exaggerated, but* Fig. 2a *shows Stolberg structure with vertical and horizontal scale the same.*

Section indicates: (a) D-2 and D-3 Upper Devonian reef and biostrome zones are in contact with oil sands of Lower Cretaceous age; (b) progressively deeper bevelling of Paleozoic rocks eastward; (c) widespread evaporite series below Waterways formation; (d) presence of bioherms or reefs and associated evaporites below Waterways formation in Clearwater River area which may also have been source of some oil for oil sands; (e) widespread extent of D-2 biostrome which could have acted as carrier bed for hydrocarbons, from deeper Devonian in Alberta syncline, to oil sands.

origin of the bitumen found in the oil sands which are also referred to as "bituminous McMurray sands."

Before presentation of this simple theory it may be in place to describe very briefly the geological setting of the oil sands of the Athabasca River. Along a considerable stretch of the Athabasca River, upstream and downstream from the confluence of the Clearwater (McMurray) River of northeastern Alberta, one may observe excellent outcrops of bitumen-impregnated sandstone which has an average thickness of 180 feet, and is composed primarily of a very fine-grained white quartz sand (after removal of the bitumen). For the most part, the bitumen is the cementing material of the sandstone, so that fresh samples are somewhat like damp brown sugar from which the bitumen can be squeezed. Locally the sandstone is cross-bedded and massive, and in such places the bitumen content is higher. In other places, and/or up and down the section, it is thinly bedded and leaner in bitumen content. There are some green shale breaks, but they are not common where the oil sands as such are best developed.

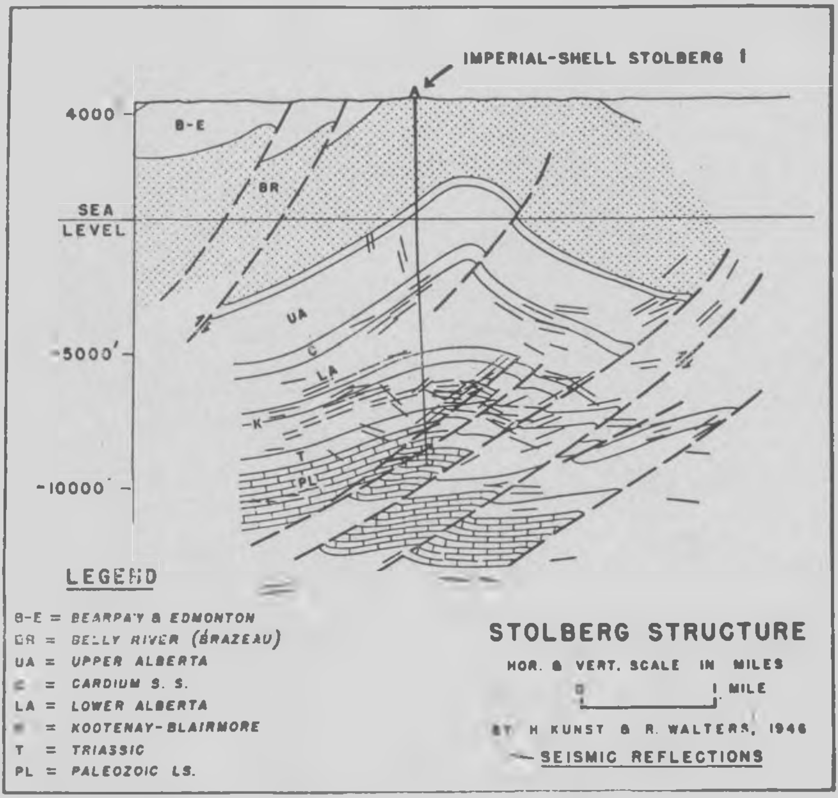


Fig. 2a. *Detail of Stolberg structure, with vertical and horizontal scale the same.*

The oil sands are listed in the geological column as the "McMurray bituminous sands" of Lower Cretaceous age and at the outcrops rest unconformably on Upper Devonian limestones, dolomites, or green shale termed the "Waterways formation," but southwestward, downdip into the Alberta syncline, the oil sands were found from recent drilling data to rest on the equivalents of the D-3 bioherm zone and the D-2 biostrome of Upper Devonian age which overlie the Waterways formation (Fig. 2). Still farther downdip the equivalents of the oil sands (sandstone and shales of Lower Cretaceous age) rest on Upper Devonian beds above the D-2 zone, and still farther downdip on beds of Mississippian age. At the outcrops the unconformity is more like a disconformity with very little noticeable angularity of dip and no basal conglomerate beds. Whereever the oil sands rest on the Devonian limestones in outcrop, the limestones are commonly white or cream-colored with no conspicuous evidence of bituminous content. However, at wells where the drill passed from the oil sands into equivalents of the D-2 or D-3 zones of the Devonian, the Devonian contained heavy or tarry oil with sulphur or salt water.

An excellent account of these oil sands and the various theories regarding the origins of the bituminous content was presented by Sproule (7) in 1938. Subsequently, Hume (4) has submitted much more detailed information derived from many core holes drilled through these sands. On the basis of these, he reiterated his belief that the bituminous content was derived from the interfingering and age-equivalent Lower Cretaceous shale and possibly the overlying Clearwater shale.

TENSION FISSURES

Tension fissures in bed-rock of practically any type are in evidence wherever outcrops are observed. Examination of outcrops and ability to see this phenomenon on a larger or grander scale from an aeroplane in areas of no overburden, as well as study of aerial photographs, substantiates this contention. The fissures are also referred to as joint planes, fractures, etc. They extend to varying depths, and as far as the problem under consideration is concerned their maximum downward extent as effective avenues for the escape of gaseous or liquid hydrocarbons from a porous reservoir has not been determined, although some geochemists seem to believe that there is no limit to the depth of minute fractures large enough to allow migration of hydrocarbons. It is more than likely that the depth should vary, dependent on the type of "cap rock" in question, structural conditions, and many other factors. However, only pertinent evidence along these lines is submitted herewith to serve the purpose of the theory with respect to the source of the bituminous sands oil.

The Norman Wells pool in northwest Canada is an excellent example of a coral-reef reservoir, overlain and surrounded by what is generally termed as effective cap rock, the dense Ft. Creek shale (Fig. 3). However, the gas and oil is today escaping from this reservoir through fractures, as indicated on the figure, giving rise to a series of active oil and gas seepages.

Since the shallowest depth to the top of the Norman Wells reef is approximately 1,000 feet it can be assumed that such surface fractures or fissures are effective as avenues for the escape of oil and gas from that depth or more, and given enough time, the Norman Wells pool will eventually loose its entire gas and oil content through these fractures unless again buried deep enough to close or seal the present-day surficial fractures. If the Norman Wells pool were in an area of subsidence, rather than erosion, and if sands were being deposited over the seepages, it is conceivable that such sands might become impregnated with a somewhat heavier oil than that escaping from the coral reef below. As a matter of fact, the gravels and sands of the delta of the creek which cover part of the seepage area are saturated with oil. This was demonstrated when digging the cellars for wells to be drilled on the delta of the creek. Furthermore, the first well drilled by means of cable tools back in 1919 and 1920 encountered oil from the "grass roots" downward, with corresponding increase in the grade and amount of oil as the well was carried deeper.

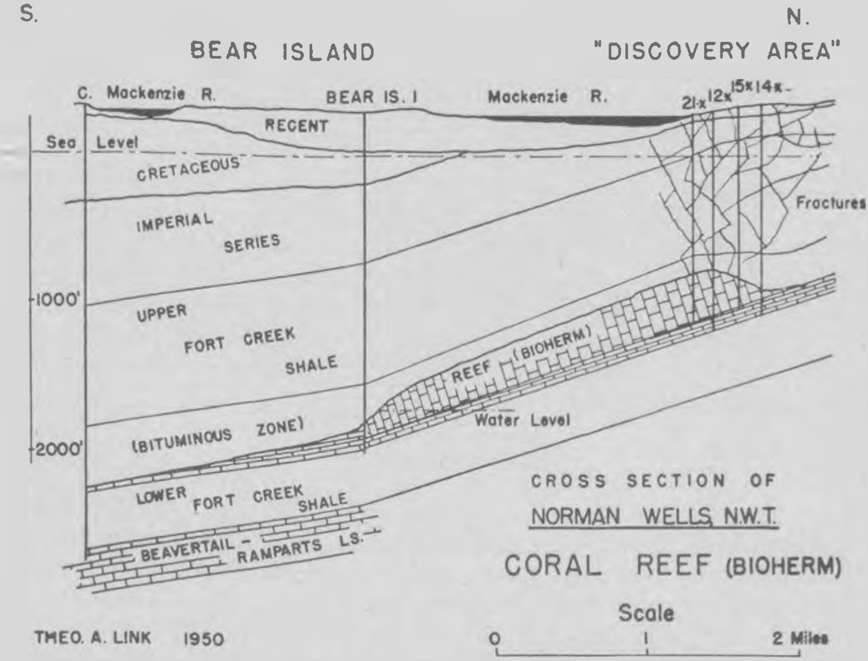


Fig. 3. *Cross-section, through Norman Wells pool, Northwest Territories, showing surface fractures through which oil and gas are escaping, giving rise to oil seepages and impregnation of recent delta gravels and sand deposits with oil. Depth from surface to top of reef is 1,000 feet.*

If a reef reservoir leaks oil and gas even though buried 1,000 feet, obviously a similar reef buried under a thinner cover would give rise to larger, more lively and effective seepages, so that the reef in question might loose practically all of its gas and liquid hydrocarbons in a shorter period of time, and obviously one which has had all its cover removed will lose all its liquids and retain only vestiges of oil in the form of bitumen, as illustrated in Fig. 4 which illustrates a reef involved in an anticlinal fold, exposed at the surface with no liquid oil content.

Practically all holes drilled through the oil sands and through the unconformity directly into D-3 zone bioherm equivalents revealed the presence of heavy, tarry oil in the D-3 limestones or dolomites. At Redwater (Fig. 2), where the D-3 zone bioherm lay at depths of 250 to 400 feet below the Cretaceous-Devonian unconformity, there is no gas cap and little gas in solution, thus suggesting that essentially all of the gas, and no doubt much of the oil, were lost at the time of the unconformity. In other words, during Lower Cretaceous time there were live seepages in the Redwater area. At Leduc, where the depth from the unconformity to the D-3 zone bioherm was about 1,000 feet, a gas cap still exists with an underlying oil column. This also suggests that at the time of the unconformity there may have been gas and oil seepages in that area similar to the present-day Norman Wells conditions. Furthermore, the oil in the Leduc pool is of lighter grade than that at Redwater, not so much because of present depth to the oil reservoirs, but because of the depth of these reservoirs at the time the Devonian beds were at the surface. As indicated on the general cross-section (Fig. 2) the D-2 zone biostrome which overlies the D-3 bioherms like a blanket porous zone might have played an important part in acting as a carrier bed from the deeper part of the basin updip into the oil sands. Fig. 5 is an ideal cross-section indicating how loss of oil and gas through surface fractures becomes less with greater depths to the oil and gas reservoir. At the extreme right A is reef limestone cropping out which shows only residual "tar," solid bitumen,

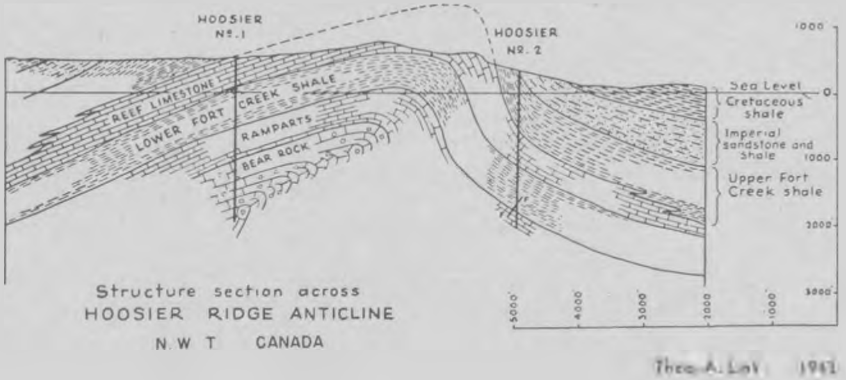


Fig. 4. *Cross-section through coral-reef anticline with reef exposed at surface crest where only "tar" and solid bitumen were encountered with sulphur water. Example of oil reservoir which has lost its oil content due to erosion of impervious cap rock.*

and sulphur water springs. At the left, downdip at **B**, is another reef which has lost essentially all its gas, but which still retains some of its original oil after considerable loss through fractures. It has no gas cap, and contains heavy oil. The third from the left at **C** is an example of a reef near enough to the surface to lose considerable gas and some oil, but it still has a small gas cap and lighter oil. The one at the extreme left at **D** is not near enough to the surface for the fissures and fractures to reach it; consequently, it contains the best grade of oil, a greater amount, and essentially its original gas cap.

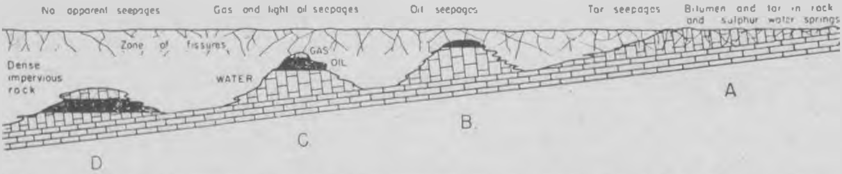
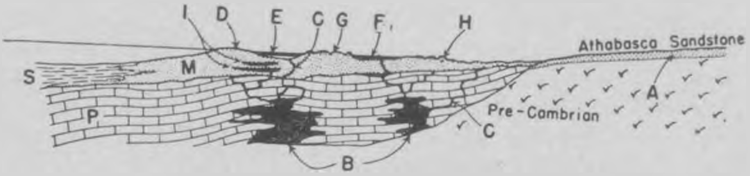


Fig. 5. *Ideal diagram illustrating escape of oil and gas through fractures from reef reservoirs at various depths. (A) Reef exposed at surface with only bitumen in rock and sulphur springs. (B) Reef near enough to surface to have lost all its gas and considerable oil. (C) Reef buried sufficiently to have retained some of its gas and most of its oil. (D) Reef buried at depth beyond reach of surface fractures so that it retained its original gas and oil content.*

SOURCE OF SANDS

Fig. 1 is a generalized map of Alberta and Saskatchewan showing the position of oil sands outcrops and their probable subsurface extent and their relationship to the Precambrian Shield, the recently discovered Devonian oil pools, and in particular the location of the "Athabasca sandstone" of either late Precambrian or early Paleozoic. That the quartz sands of the "McMurray bituminous sands" came from this ancient "Athabasca sandstone" body seems logical from this map, and many other reasons why such a conclusion seems to be correct were presented by J. C. Sproule (7). Since that time much core drilling has gone through the oil sands, and lately through the underlying Paleozoic. These additional data seem to confirm more fully the concept of Devonian origin of the bituminous content of the sands. For example, layers of what appeared from cores to be pure bitumen with little or no sand content were encountered in thicknesses of 20 feet or more, and likewise layers of sand barren of oil are also common. What is the mechanics of such phenomena other than bitumen lakes during deposition of the sands, or intrusion from the Paleozoic rocks below? Either of these suggestions seems to be better reconciled with a Devonian origin of the oil, rather than a local origin or downdip, and/or interfingering Cretaceous shale source rock, as propounded by Ball (1) and Hume (4).

Fig. 6 is a hypothetical section suggesting how the oil escaping from the Devonian might have impregnated "McMurray bituminous sands" which were being deposited contemporaneously with the escape of oil through fractures from the underlying Devonian reefs, bioherms, or biostromes. The layers of apparently pure bitumen might have had their origin as suggested on this diagram. There are alternating lean and rich layers of oil sands; the richer ones are usually more massive and not as thinly bedded, suggesting eolian deposition, and the sand grains are, according to Sproule (7), pitted or frosted. An oil lagoon filled by wind-blown sands from encroach-



M—McMurray sand
S —McMurray shale
P —Paleozoic

A—Source of sand for "McMurray sand"
B—Devonian reef reservoirs
C—Fractures through which light oil and gas are escaping upward into sands, either saturating them as deposited, or forming oil lakes in lagoons or embayments
D—Off-shore sand-bar or spit
E—Lagoon into which oil is seeping from Devonian source
F—Old lagoon, drained of its water, and now a bitumen lake (light ends lost to atmosphere)
G—Sand dunes
H—Old sand dunes which may shift again later on
I—Buried lagoon or bitumen lake deposit

Fig. 6. *Details of a phase of "McMurray sand" deposition and saturation with oil.*

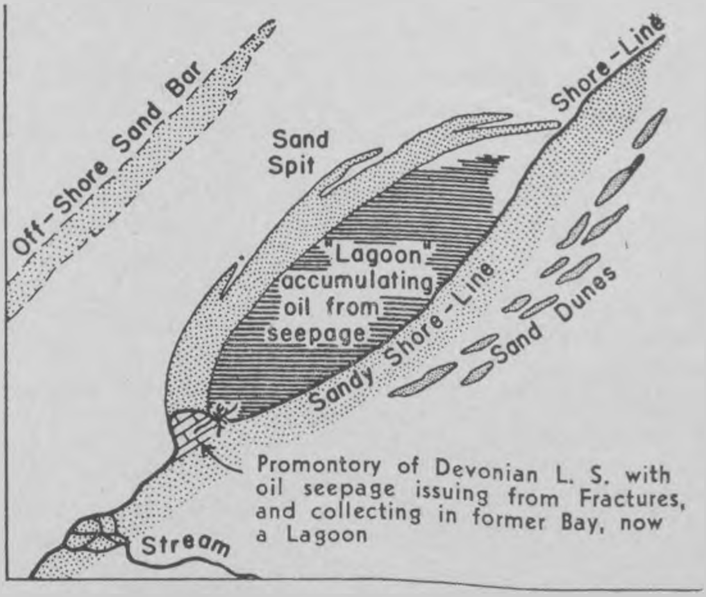


Fig. 7. *Sketch map illustrating how oil seepage from Devonian could cause accumulation of layers of "bitumen" interbedded in bituminous sands*

ing sand dunes could very well explain such massive richly-impregnated sands, while the well-bedded leaner material may have been water-laid, somewhat as suggested in Fig. 7. Pulsation of the oil seepages may also account for the alternating richer and leaner sands.

In Fig. 7 is depicted a lagoon caused by a "spit" which would eventually shut off circulation of water from the open sea and thus enable accumulation of oil and bitumen on the surface of the water. Wind-blown sands could fall into this oil lagoon, and thus give rise to some of the massive richer layers of oil sands. If no wind-blown sand were deposited in this oil lagoon for long periods of time, layers of solid, essentially sand-free bitumen would accumulate, and thus explain such layers encountered in the core holes as described by Hume (4). In the inland sand dunes brackish- and fresh-water lagoons, which are so characteristic of such near-shore sand-dunes area, could also accumulate oil from the seepages and be filled by the encroaching and ever shifting sand dunes. Thus the presence of marine, brackish- and fresh-water faunas, including tree trunks, in the oil sands would be expected. As already suggested, the thinly-bedded, leaner oil sands were probably water-laid with some current and sorting action.

Strangely enough such recent sand-dune areas of considerable areal extent may be observed along the south shores of Lake Athabasca, and the sand is apparently derived from the ancient Precambrian "Athabasca sandstone" which also appears to have been the sand source for the "bituminous McMurray sands" of Lower Cretaceous age. An aerial reconnaissance of this area revealed lakes and lagoons and stands of timber being encroached upon by the shifting sand dunes.

SUMMARY AND CONCLUSIONS

Until better evidence in favor of the Cretaceous origin of the bituminous content of the oil sands is forthcoming, the writer is inclined to favor the Devonian origin of the greater part of the oil. There is no doubt that Cretaceous "source beds" could have contributed some of the hydrocarbons, but it may not be coincidental that even the lighter oils in the Lower Cretaceous sands of the Edmonton area are almost identical with those of the underlying Devonian reefs (2, 3).

The heavy Lower Cretaceous oils in the Lloydminster and Vermilion areas of Alberta are also in sands which appear to be the stratigraphic equivalents of the oil sands, and this oil is also like that in the oil sands. This seems to suggest that conditions in the Lloydminster area were, during Lower Cretaceous time, very similar to the oil-sands area, and that nearby there may be discovered Devonian reefs with some of their original oil and gas content. Since the Lower Cretaceous rests on the Devonian Waterways formation in the Lloydminster area, as is the case in the oil-sands outcrop area, the Devonian reefs, if present, should be downdip from that area, and not directly beneath the Lloydminster oil sands.

If, as, and when the extraction of oil from the oil sands becomes commercial, there will be available 100 to 300 billion barrels of oil, and those who have risked their money in pipelines from Alberta to the larger markets need never worry about running out of oil to transport from Alberta. Also, if 100 to 300 billion barrels of oil have escaped from Devonian reservoirs into the oil sands, there ought to be at least 5 to 10 billion left in those Devonian reefs or bioherms which were not close enough to the unconformity to lose their original content through fractures.

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POSSIBLE LOWER CRETACEOUS ORIGIN OF BITUMEN IN BITUMINOUS SANDS OF ALBERTA

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THE PROBLEM OF ORIGIN

The processes by which oil is formed and accumulated are wholly inferred from the properties of oil itself and those of the strata in which it could have originated and in which it is found. In many cases the inferred source of origin is strongly supported by the evidence, but positive proof is rarely, if ever, present. In other cases, as with the bitumen in the bituminous sands of Northern Alberta, the geological conditions are such that no single possible origin suggested to date seems to meet all the requirements, and it appears that if proof of origin is found it will be discovered by tracing chemical changes in the bitumen back to the possible source or sources of origin. In the main, the problem in relation to the bitumen in the bituminous sands centres around one controversial issue, namely, whether the bitumen as it now occurs in the sands was "light" or "heavy" oil when formed and the transformations, if any, it has undergone since it originated.

CONDITIONS OF OCCURRENCE

The conditions of occurrence of the bitumen that must be considered in relation to the origin are briefly as follows:

1. The bitumen is a heavy asphaltic oil with a specific gravity greater than water.
2. The bitumen contains a high percentage of sulphur and some other minerals in small amounts.
3. The bitumen occurs as a coating around wet sand grains.
4. The sand of the bituminous sands is mostly extremely fine in comparison with producing sands in oil fields, and the bitumen separates the sand grains so that they are not always in contact with other sand grains. In other words, the intergranular space is in many places insufficient to account for the amount of bitumen present.
5. Drilling in the Mildred-Ruth Lakes area, 22 miles north of McMurray on the west side of the Athabasca River, has, in the writer's opinion, demonstrated the presence of beds of bitumen with only a slight sand content. It should be noted, however, that the presence of these bitumen beds has been questioned mainly on theoretical grounds.
6. The bituminous sands are lithologically quite variable both vertically and horizontally. The sands themselves are lenticular and are separated by clay bands of variable thickness up to many feet. In most places these clay beds are believed to

have been closely associated in origin with the sands themselves. In other cases, however, as shown in the Mildred-Ruth Lakes area, there are marine clay beds interbedded with the sands. The clay is extremely fine-grained and by ordinary standards would be considered impervious. As far as known it shows no oil staining.

7. The sands show a variable bitumen content not wholly related to their character.
8. The extracted sands after bitumen separation are white and mainly quartz grains. They contain relatively little carbonaceous materials but wood fragments and fossil shells occur associated with the deposit. In certain places also thin seams of lignite are present.
9. Sands not impregnated with bitumen are known on the eastern edge of the McMurray formation in which the bitumen occurs.
10. The lower part of the McMurray formation is wholly non-marine and is apparently a deltaic or alluvial fan deposit for which the sediments forming it were derived from the east by westerly flowing streams from the Precambrian Shield. The upper part of the formation contains partly marine beds (11).
11. From McMurray northward such evidence as is available suggests that the bitumen becomes progressively less viscous.
12. The bitumen in the bituminous sands is relatively easily "cracked" by moderate heat at low pressures. "Digestion" as described by Ball (3) was presumably a mild cracking.
13. Oil found at Lloydminster, Vermilion, and elsewhere in near-shore Lower Cretaceous strata has some of the characteristics of the bitumen of the bituminous sands.
14. The McMurray formation is conformably overlain by the marine Clearwater formation and the dividing line is placed at the base of a glauconitic sandstone considered to be in the Clearwater formation which contains a distinctive marine fauna.

POSSIBLE SOURCES OF THE BITUMEN

Possible Paleozoic Sources

The Devonian was suggested as a possible source of the bitumen by Bell (4) after an examination of the deposits on the Athabasca and Clearwater Rivers in 1882. In 1894 McConnell (9), influenced by his belief in the Devonian origin, suggested drilling down the dip in the hope that light oil might be found. Drilling was done, and when this failed to give the desired results McConnell expressed keen disappointment. The drilling did show, however, that the bituminous sands extended up the Athabasca River for a considerable distance beyond the outcrops.

Link (8) has recently presented the case for the Devonian origin of the bitumen. The Devonian contains large quantities of oil in Alberta, and the eroded edges of the porous beds underlie the bituminous sands in part. These facts lead to the assumption that the oil could have seeped upwards from the Devonian into the overlying Lower Cretaceous McMurray beds during their deposition. This possible origin for the bitumen would explain a few facts concerning the bituminous sands but there are other features largely unexplained. There is first the time difficulty. The origin of the oil in the Devonian reefs is not understood and it is open to question whether the oil originated in the reefs or migrated into the reefs after they were sealed off. The latter seems more likely for a variety of reasons that need not presently be discussed, but the time of origin of the Devonian oil formation becomes important in reference to the bitumen occurrence because of the hiatus in millions of years between the ages of the Devonian and Lower Cretaceous.

The bevelling of the Devonian which exposed the eroded edges of the porous beds must have provided a means of escape for any content of Devonian oil in the updip strata previous to any Lower Cretaceous deposition of sediments. This would leave for possible seepage to the Lower Cretaceous as it was being deposited only such oil as was contained in favorable structures that were sufficiently near the eroded Devonian surface to allow for fracturing and possible upward migration of any oil content. This at once greatly restricts the area from which Devonian oil could have been received directly by the Lower Cretaceous, and leaves us to imagine at least 150 fields the size of Redwater all fractured and seeping out oil into the McMurray sands during the comparatively short period of deposition to supply even the minimum 100 billion barrels the bituminous sands are said to contain. It would be difficult to imagine such a pouring out of a prodigious amount of oil without great wastage. Hence it is not only difficult to concede that such an operation could occur, but still more difficult to believe that the timing was so exact as to allow contemporaneous seepage from the Devonian with deposition of the Lower Cretaceous beds.

This hypothesis of Devonian origin and seepage into the McMurray beds, however, might appear to be much more probable if the oil in the Devonian were neither formed nor accumulated in the porous Devonian beds until a period in geological time later than the deposition of the Lower Cretaceous McMurray formation following the prolonged period of erosion which bevelled off the Devonian beds. Such a condition might allow migration updip into the truncated edges of the Devonian beds where these are in contact with the McMurray formation as well as into coral reef structures, and the area from which the Lower Cretaceous could receive oil would thus be increased immeasurably.

Thus, the timing of the origin of the Devonian oil itself becomes very important in relation to the possible Devonian origin of the bitumen, and although many geologists believe oil is formed in the source rocks comparatively soon after deposition and compaction, there is no actual proof that this need be so in all cases. The great advantage of the theory of the Devonian origin for the bitumen is that it offers an abundant source, a problem which any theory finds difficulty in meeting adequately.

There are other features of the bitumen not easily explained by a Devonian origin. It should always be remembered that the bitumen is heavier than water and the fact that heavy asphaltic material has been found in the Devonian in wells drilled through the bituminous sands is no proof of Devonian origin whatever. On the contrary, it may be cited as proof that the heavy oil has seeped downward into the Devonian as it would certainly do because of its specific gravity. The transformation of light to heavy oil needs explaining if the theory of Devonian origin of the bitumen is accepted. Would the oil in stagnant lagoons, as envisaged by Link, absorb sufficient sulphur not only to change the gravity radically, but to gain the sulphur content of about 5%?

The theory of Devonian origin as proposed by Link has one great advantage over any of the other migration theories of oil from the Devonian into the bituminous sands in that, by inference, the oil became weathered and changed to heavy oil while the McMurray formation was being deposited. Thus, no migration for distribution of the bitumen after deposition is necessary, a condition which it appears must be accepted because of the character of the bitumen itself and the lenticular nature of the sands with interbedded clays. On this basis the possibility that oil formed and accumulated in the Devonian migrating updip and coming into the McMurray sands after their deposition, loses much of its appeal. If it were possible for the oil to have migrated as light oil in the McMurray sands after these were deposited, and the writer does not think even this is admissable, it would still be difficult if not impossible to imagine relatively uniform change in all parts of the deposit to heavy asphaltic bitumen after distribution had ceased. Indeed, under such conditions of migration, McConnell's assumption that the place to look for lighter oil down the dip at the edge of the weathered seepage would have been quite correct in conformity with several such oil fields that have been discovered where the seal for the lighter oil was formed by weathered asphaltic material at the seepage.

In considering the Paleozoic origin for the bitumen the possibility of Mississippian or Permo-Carboniferous oil should not be overlooked. The Mississipian limestones, where exposed in the foothills and mountains, show evidences of oil, and many of these limestones, when struck with a hammer, emit a fetid odour. In fact, as far as the writer has observed, there is more field evidence for oil in outcrops of Mississippian limestones and dolomites than there is in Devonian beds. The Mississippian has also given proof of prolific oil and gas production in the foothills and oil is indicated at several places near the eroded edge of the formation, as at Oyen in southeastern Alberta and at Barrhead northwest of Edmonton on the Plains. This oil has the sulphur content which forms such a prominent part of the character of the bitumen in the McMurray sands.

In order to derive the oil in the bituminous sands from this source, however, it is necessary to postulate extensive migration along the erosional unconformity separating the Devonian and younger beds with all the attendant problems of distributing the bitumen in the McMurray sands in such great volume and yet leave no conspicuous traces along the unconformity such as would have been detected. However, if Devonian oil could have migrated into the bituminous sands, not as Link has postulated during their deposition, but afterwards as some geologists have assumed, there is no reason why the Mississippian or Permo-Carboniferous beds might not also have added their quota by updip migration toward the outcrop from the eroded porous edges.

Possible Lower Cretaceous Origin of the Bitumen

There are fundamental differences, beyond the question of age, between the possible origin of the bitumen from the Paleozoic (Devonian) and from the Lower Cretaceous. The theory of Devonian origin of the oil presupposes that the oil was light when it escaped from its Devonian environment into the Lower Cretaceous McMurray beds, and that either during deposition with the McMurray sediments as Link has postulated, or after its migration into these sediments as other geologists have supposed, it was changed to its heavy asphaltic character, presumably by oxidation, by the absorption of sulphur, or by other agencies such as contact with sulphate waters.

Thus the theory of Devonian origin is inseparable from original light oil changed to bitumen by assumed processes. On the other hand, the Lower Cretaceous origin for the bitumen assumes that the bitumen was heavy when formed and that up to the present it has undergone practically no significant change. The question, therefore, is whether the oil was originally light or whether it was heavy when formed. The evidence here seems to support strongly the theory of a heavy oil origin in that the bitumen cracks at abnormally low pressures and temperatures because it has never been subjected to the metamorphic changes inherent in severe compaction under heavy loads, perhaps augmented by strong pressures induced by tectonic movements. Ball (1) emphasized this character of the bitumen in a paper entitled *Athabaska Oil Sands: Apparent Example of Local Origin of Oil* and stated that in the particular characteristic referred to above the bitumen differs from residuums which it resembles "in appearance, viscosity, and specific gravity." McLearn (10) also emphasized the same feature in regard to oil found in sediments of a similar age at the base of the Lower Cretaceous in the Peace River area.

In a previous paper (5) the writer emphasized the probability that, if the bitumen originated in Lower Cretaceous time, its formation must have been contemporaneous with the deposition of the sediments with which it is interstratified. This seemed to be a necessity in the Mildred-Ruth Lakes area if the presence of the bitumen beds is conceded. The writer saw one of these bitumen beds cored and has no doubt about their occurrence in many wells, although it is realized that others have taken strong objections to such a conclusion. There seems no escape from contemporaneous deposition of the bitumen with the sediments if bitumen beds are present as revealed by drilling. Obviously Link has accepted these bitumen beds as a fact and it has greatly influenced him in setting forth his hypothesis of oil escape from the Devonian during deposition of the McMurray sediments, a feature which sharply distinguishes his theory of origin from those of some other geologists who have expressed strong preference for the Devonian theory of origin of the bitumen.

The theory that the bitumen was deposited contemporaneously with the McMurray sediments is in harmony with the fact, as pointed out by Ball (2) in 1935, that the oil or bitumen "is not a pore space filling but is present as a film around each grain of sand." Link at that time pointed out that each sand grain has a film of moisture around it inside the oil, or in other words, the sand was wet when the bitumen coated it. When Abasand Oils Limited was blasting the sands for excavation at its Horse River plant, the shock of the blast appeared to break the bitumen films. When, after a blast, a lump of black bituminous sand from the blasted area was picked up it would disintegrate in the hand, and as it did so the black color would change to grey. Thus it seemed that the grey sand grains were becoming exposed due to the breaking of the black oil film around them. Under certain conditions, therefore, it seems quite reasonable to expect there may have been some redistribution of the bitumen after deposition. However, migration of the bitumen into the McMurray sands after deposition seems to the writer to be wholly impossible on account of the lenticular character of individual sand beds and the clay bands separating the sands in various areas. It may not be quite so incredible to postulate that light oil could have penetrated the sands after deposition to give the present distribution and then be changed to bitumen in situ. However, migration of even light oil, in the writer's opinion, is difficult to reconcile with the facts of barriers created by innumerable clay beds. The facts support contemporaneous deposition of bitumen and sediments.

As already stated, the McMurray is an alluvial fan or deltaic formation with the sediments derived from the east from the Athabasca sandstone and other Precambrian rocks. The stream flow, therefore, was from an easterly to a westerly direction. This may be of importance in reference to some theories of migration which have suggested that the oil may have come from Paleozoic strata in the west or southwest and that it may have floated to contact the shore sediments.

This brings up the question as to whether marine sediments were being deposited west of the McMurray alluvial plain contemporaneous with it. The lower part of the McMurray formation is non-marine but fossils. *Astarte natosini* fauna, mainly pelecypods, are found in the upper part. These represent a depauperate fauna, not strictly marine, but with a brackish water environment tending towards marine conditions since normal species of these pelecypods would, it is understood, be considered marine. Similar fossils have been reported in the Luscar formation of the Blairmore group in the Mountain Park area so that the stratigraphic position is reasonably accurately known. The encroachment of the sea was obviously from the north and northwest, but it has not been ascertained whether Lower Cretaceous strictly marine sediments in this direction are the exact time equivalents of the McMurray formation. Proof that such marine sediments existed might lead to some speculation regarding the possibility of oil derived from older formations reaching the McMurray alluvial plain shoreline by floating on the water, but it would be quite different from the past suggestions that the oil originated to the south and west since indeed it would mean that the oil came more probably from the north and northwest areas, possibly from the great area south of the westerly end of Great Slave Lake.

In this connection McLearn's (12) paleogeographic maps published many years ago are worthy of serious study even though after the acquisition of much recent stratigraphic information the maps might be slightly modified from their original conception. The presence of a sea west of the McMurray alluvial fan during its deposition would fit either Link's postulated lagoonal collection of Devonian oil or the writer's theory of Lower Cretaceous origin. In fact, the presence of water on the edge of the alluvial fan or deltaic deposit seems to be essential to both theories of origin.

The conditions of sedimentation and environment as envisaged by the writer (6) for a Lower Cretaceous origin of the bitumen are identical with those postulated by Link for the accumulation of Devonian oil in lagoons contemporaneous with the deposition of the McMurray formation. The shoreline conditions were evident in some of the holes drilled in the Mildred-Ruth Lakes area where thin lignite seams and conglomeratic beds were present. In one hole, as previously reported, namely B22, coal occurred at a depth of 111 to 112 feet and was also present in other holes. In hole B19 gravel was reported at a depth of 152 feet, or 26 feet above the limestone contact, whereas in other places pebbles up to a half-inch in diameter occur in beds other than at the base. It was previously pointed out also that "these shoreline conditions might readily be regarded as favorable for the collection of source materials for oil although the difficulty seems to be the generation of such large volumes of oil as are necessary without any direct evidence or actual knowledge of source materials." Trask (13) has shown that there is more than sufficient organic material present in some sediments, both ancient and recent, to account for all the oil present in some rich oil fields. The conditions of sedimentation on the assumed shoreline of the McMurray alluvial plain are those generally conceded as being particularly favorable for oil formation.

In a previous paper (7) it was pointed out that, according to Sproule, the McMurray sands along the Clearwater River eastward from the mouth of Cottonwood Creek, 25 miles east of McMurray, to and beyond the Alberta-Saskatchewan boundary, are not impregnated with bitumen although there is no obvious difference in the character of the sediments in impregnated and unimpregnated sands. It was pointed out also that it may be quite significant that, at the eastern boundary of the bituminous sands on Cottonwood Creek, the upper only, and not the lower beds are impregnated with bitumen. Within the Mildred-Ruth Lakes area beds of marine shales carrying foraminifera have been found interstratified with the bituminous sands. Such a condition implies an oscillating strand line, and McLearn has shown that the upper part of the McMurray formation is more closely associated with marine conditions than the lower part.

Thus it appears logical, if bitumen as such was being generated within the Lower Cretaceous sediments contemporaneous with deposition, that the favorable localities of formation would be on, or close to, the shorelines. It may be, therefore, that in the eastern part of the McMurray deposit, that is, at the beginning of deposition, marine conditions were not yet sufficiently established to allow for the formation of the bitumen, and hence these sediments are unimpregnated. Later, as is known from the occurrence of marine clays with foraminifera, more normal marine conditions were established with a sea to the west for the upper part of the McMurray formation as indicated in McLearn's paleogeographic map, and it may be this fact, with its consequent more favorable conditions for bitumen generation, which accounts for the upper beds in Cottonwood Creek being impregnated by bitumen whereas the lower beds are not. This condition might also account for the richer bitumen beds being found in some areas, particularly in the westerly area of Mildred-Ruth Lakes, rather than in some other areas.

It is unfortunate that more is not known concerning the amount of interfingering of marine shales into the McMurray deposit. The knowledge of the extent of these marine beds would greatly aid in deciding the significance that should be placed on the relationship, if any, between rich bitumen beds and associated marine shales. It may be mere coincidence, of course, that rich bitumen beds occurred in an area where marine interfingering shales are known to be present, but the association is sufficiently important to attract immediate attention.

A further feature of distribution of heavy oil in Alberta should be considered in relation to the origin of the bitumen in the McMurray deposit. This is the heavy asphaltic character of the oil in the Lower Cretaceous of the Vermilion, Lloydminster, and Wainwright fields, and of some heavy oil occurrence in wells in the Smith area in slightly younger strata than the McMurray formation. It is known that, although a considerable part of the sediments of the Lower Cretaceous in east-central Alberta and west Saskatchewan are non-marine with thin coal seams, there are also interfingers of marine shales with foraminifera. The oil occurs at definite horizons in these fields and not in the basal sands, although gas is present in the basal sands of the Unity field in Saskatchewan. It is significant that this heavy oil is associated with near-shore conditions as is the bitumen in the McMurray formation, and any direct evidence of origin for either would be undoubtedly considered as strong indication of an origin under common conditions.

It is not reasonable to assume that the heavy oil in the east-central Alberta area is coming from the Devonian since some of the proponents of Devonian oil origin also are assuming that the light oil in the Lower Cretaceous of the Gilbert and other pools in the Edmonton area are also escaped oil from the Devonian. This seems like too much of a Devonian complex since the origin of the oil in the Devonian reefs themselves is not yet wholly satisfactorily explained. The similarity of the heavy oil in the fields of east-central Alberta and western Saskatchewan to the bitumen in the Athabasca bituminous sands is too striking to be ignored and it is logical to assume, since the sediments are, as far as known, of the same age, that the oil is also of similar origin and that this origin is probably Lower Cretaceous.

SUMMARY

Thus the conception of Lower Cretaceous origin for the bitumen in the McMurray formation may be summarized as follows:

1. The evidence appears to favor contemporaneous deposition of the bitumen with the McMurray formation of Lower Cretaceous age.
2. The McMurray formation is apparently a deltaic or alluvial plain or fan deposit, and as shown by fossils in its upper part, and interstratified marine clays containing foraminifera, at least the later stages of deposition were associated with the presence of a sea with a strand line along which it is conceived favorable conditions for oil formation could occur.
3. The distribution of the bitumen, not markedly different from place to place, calls for a local origin of the heavy asphaltic material. This does not rule out the possibility that oil of Devonian origin reached the deposit as light oil and was transformed to bitumen before deposition with the sediments. However, the difficulty of timing of the seepage of oil from the Devonian, its arrival at the place of deposition of the McMurray sands, and its weathering to bitumen before deposition, form a series of coincidental events that could, but are not likely to have taken place.
4. The character of the bitumen itself strongly supports the belief that it is new oil not greatly altered by even light metamorphism.
5. The presence of fields containing heavy oil in east-central Alberta, western Saskatchewan, and elsewhere in the Lower Cretaceous, suggests a common origin with the bitumen of

the bituminous sands, since all occurrences are known to be associated with near-shore conditions giving alternations of marine beds interstratified with non-marine sediments of Lower Cretaceous age.

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ON THE ORIGIN OF ATHABASCA OIL

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The present work is an outgrowth of the research conducted at the Mines Branch of the Department of Mines and Technical Surveys on the "Cold Water Separation Process", for removing the bitumen from the bituminous sands of Alberta. During this research it was evident that much time and effort was being spent by various government departments in devising separation schemes while comparatively little attention was being devoted to studying the chemical composition of the bitumen. On the other hand, it was felt that some knowledge of the chemical composition of bitumen might materially assist in the evaluation of the economic possibilities of this natural resource. During the course of this chemical study we were logically led to consider the influence of this information on the theories concerning the origin of the Alberta bitumen.

In the extensive and varied literature dealing with the origin of coal, bitumen and oil, there has been considerable controversy regarding the fundamental relationship between coal and oil. Are these substances in any way related? Have they been produced from analogous materials and are their differences due to variations in treatment of the original substances? Or, on the other hand, have they been produced from different materials but have undergone a parallel series of changes since entombment?

Interest in these questions was roused when a reference by G. S. Hume (10) was noticed to the effect that lignite seams were in some areas found to lie in strata above the bituminous sand. In considering the relationship between coal, bitumen and oil, it is interesting to compare the ultimate carbon and hydrogen analyses with the molecular weight of these substances following the scheme recently described by van Krevelen (11). In Fig. 1 the atomic hydrogen to carbon ratio is plotted against both the reciprocal of the carbon atoms per molecule and the oxygen to carbon ratio. The succession of points I, II, III . . . X represents the coalification sequence from wood cellulose and lignin to anthracite in the course of geological time. If we project the ordinate of each of these points on to the zero axis of the left hand graph in Fig. 1, we see at a glance that in the course of time oxygen has been eliminated from the cellulosic material and that the H/C ratio undergoes a continuous decrease. The only satisfactory way of accounting for the chemical stability of coal is that a large number of aromatic rings must be formed. It is also evident from the low solubility of coal in even the best solvents that there is also formed a considerable matrix of three dimensional gel structure (8).

The point XIV which represents the composition of Alberta bitumen clearly lies far outside the coalification route, which suggests that bitumen either is not of cellulose origin or a route of transformation has been followed which differs widely from that followed during the transformation of cellulose to coal.

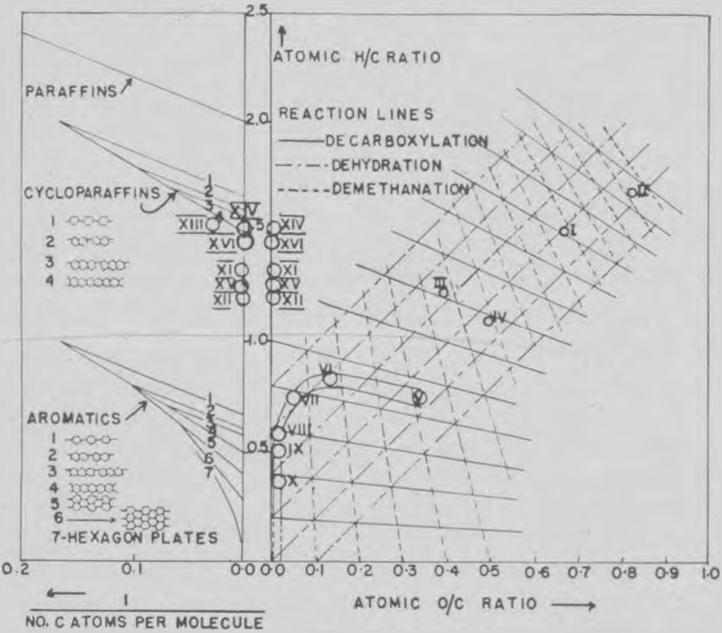

Fig. 1. *I Wood; II Cellulose; III Lignin; IV Peat; V Brown Coal; VI Low rank bituminous coal; VII Medium rank bituminous coal; VIII High rank bituminous coal; IX Semi-anthracite; X Anthracite (van Krevelen's Data); XI Bitumen and Resins (Katz); XII Asphaltenes (Katz); XIII Oil fraction (Katz); XIV Bitumen (Bowles & Booth; Pasternack & Clark); XV Asphaltenes (this research); XVI Bitumen (this research);—After van Krevelen.*

From a chemical point of view, the transformation of cellulose to bitumen involves many serious difficulties, which suggests that bitumen may not be of cellulose origin. If it is assumed that bitumen originated from cellulose, convincing explanations must be found for the following problems:

(1) The manner in which the oxygen has been eliminated from the cellulose without causing:
    (a) a drastic reduction in the molecular weight,
    (b) an extensive aromatization and gel formation as is observed on coal formation from cellulose under geological conditions (8).

(2) The cellulose origin alone does not account for the presence of 5.5% sulphur in the bitumen.

Any inorganic theory concerning the origin of bitumen hardly merits serious discussion. This also applies to the suggestion of Lind (13) that petroleum has been formed by the action of alpha radiation on methane. The optical activity of the oil fraction of Alberta bitumen is in itself sufficient to dismiss both these points of view.

With regard to the formation of oil and bitumen in general, two theories have been discussed in the literature. Seyer (15) regarded proto-petroleum as essentially paraffinic material which underwent a transformation with time to yield gases with a high H/C ratio and dense polycyclic naphthenes of lower H/C ratio. On the other hand, Hofer (9), Triebs (16), and Brooks (5) have taken the view that proto-petroleum was asphaltic and naphthenic. A third possibility has also been suggested with regard to the origin of Alberta bitumen. The view has been taken that this oil may have been formed by the migration and evaporation of oil which was formed during the Devonian period (14). As this hypothesis involves ideas which will be developed during the consideration of the first two general theories, the examination of this view will be deferred to the end of the discussion.

The thesis advocated by Seyer consisted of three postulates:

(A) Proto-petroleum is paraffinic.

(B) Under the effect of heat with the passage of time there is a tendency for an accumulation of light gaseous hydrocarbons with a high hydrogen to carbon ratio on the one hand and on the other hand, liquid and solid hydrocarbons becoming even poorer in hydrogen. Dense saturated molecules with low hydrogen to carbon ratios, such as polycyclic naphthenes, are produced to greater and greater extent.

(C) On account of the rate of decomposition, the mother substance of petroleum must have been exposed to temperatures of 200°C. for petroleum to have formed during the limits of geological time.

The study of the petroleums of the world has shown that Seyer's thesis and its logical extension lead to predictions which are in serious contradiction to the observed facts. Undue weight cannot, therefore, be given to this point of view. Suffice it to say as far as the Alberta bitumen is concerned, the optical activity (12) of the oil fraction is generally regarded as sufficient evidence that this bitumen has had a low temperature history. This suggests that the transition contemplated in postulate (B) would not have had time to occur.

The opposing theory that proto-petroleum was heavy, asphaltic and naphthenic was advanced by Hofer in 1922 (9) and was based on the belief that asphalts were original and not oxidation products. This view has been strongly supported by Triebs (16) and Brooks (4, 5), who cite the preservation of the porphyrins as evidence for the low temperature formation of oil, the original nature of the asphaltic material and the absence of extensive subsequent oxidation.

The assumption that proto-petroleum is naphthenic is also consistent with the findings of D. C. Barton (3). The character-age relation (naphthene base oils in formations of relatively young geological age; and of paraffin base oils in the old formations) was stated by Barton to hold throughout the world.

To support this contention Barton made a statistical study of the variation of the character of petroleum with age in the United States, as shown in Fig. 2. As a ready criterion for the character of the base of a crude, the United States Bureau of Mines uses the gravity of the 250 to 275°C. cut under atmospheric pressure and the cloud test of the 200 to 225°C. cut under 40 mm. The United States Bureau of Mines has established that, if the cloud test of the 275 to 300°C. cut is 5°F. or above, then the A.P.I. gravity of the 250 to 275° C. cut will be 40° or more if the base is paraffinic, 33.1 to 37.9° if the base if intermediate, and 30° or less if the base is hybrid.

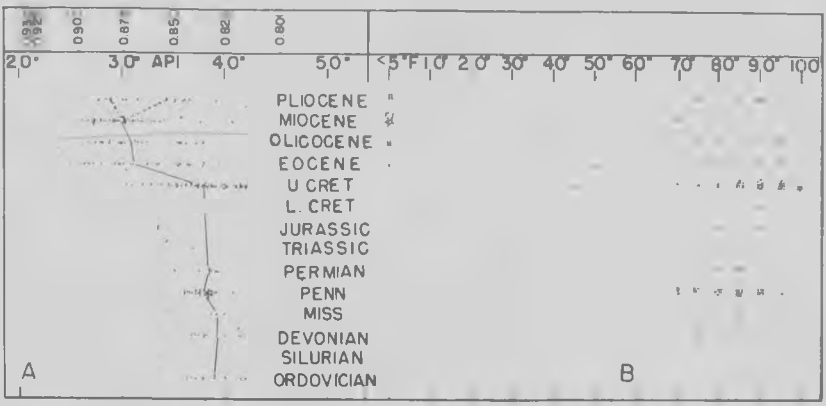

Fig. 2. *Variation of the base with age of all crudes for which D. C. Barton had both the stratigraphic age and the U. S. Bureau of Mines analysis. A. Variation of the A.P.I. gravity of the 250 - 275°C. cut under atmospheric pressure. B. Variation of the cloud test of the 200 - 225°C. cut under 40 mm. pressure in °F.*

Character of Base

1. *Paraffin, gravity 40° A.P.I. or above.*
2. *Intermediate, gravity 30° to 39.9° A.P.I.*
3. *Hybrid, gravity less than 30° A.P.I., cloud test 5°F. or greater.*
4. *Naphthene, gravity less than 30° A.P.I., cloud test less than 5°F.*

The specific gravity of the key cuts of the oils represented in Fig. 2 shows a marked decrease during the Tertiary period but no change, or only slight change, for oils of the Cretaceous to Ordovician age. The cloud test for the second key fraction correspondingly shows an increase through the Tertiary and Cretaceous, and only slight irregularities from the Cretaceous to Ordovician.

On plotting the A.P.I. gravity of the first key cut and the cloud point of the second key cut for Eocene crude oils of the Gulf Coast, Barton obtained a striking correlation between the present depth and the A.P.I. gravity of the first cut as shown in Fig. 3.

A study of the variation of the character of the crude oil of the Texas-Louisiana Gulf Coast also indicated a progressive increase

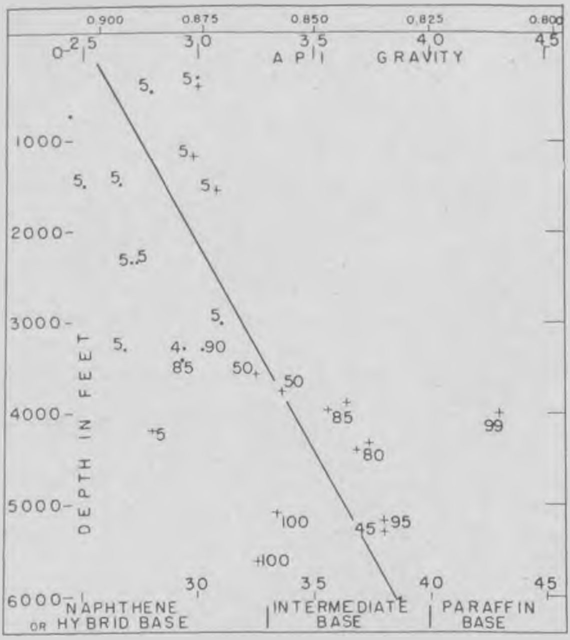

Fig. 3. *Depth-base variation of Gulf Coast Eocene crude oil. The graph gives the A.P.I. gravity of the 250-275°C. cut under atmospheric temperature, and the cloud test of the 200-225°C. cut under 40 mm. pressure in °F., according to D. C. Barton.*

● = *Upper Eocene (Jackson).*
+ = *Lower Eocene (Claiborne, Wilcox).*
5 = *Cloud test less than 5°F.*
20, etc. = *Cloud test in °F.*

in the light constituents and a progressive decrease in the heavy constituents with increasing depth and age, as shown in Fig. 4.

The success of the correlations found by Barton suggested that a similar study should be made of the oils of the Cretaceous period in Canada. If similar correlations were found to be valid, the Alberta bitumen which is considered by some to be a Cretaceous oil should conform with these correlations.

Following Barton's procedure, the specific gravity of the 250 to 275° C. cut and the cloud point of the second key cut of crude oils from various Canadian fields were plotted against the stratigraphic age in Fig. 5 (1, 2, 6, 7). While there are insufficient points to form a satisfactory statistical comparison with Barton's work, there does appear to be some measure of agreement.

The Canadian crude oils of the Upper and Lower Cretaceous period were then examined to determine whether there was any systematic variation in the density of the first key cut with the depth of the producing zone. As may be seen from Fig. 6, the slope of the straight line drawn through the points representing the Canadian Cretaceous oils is almost parallel to that found by Barton for Gulf

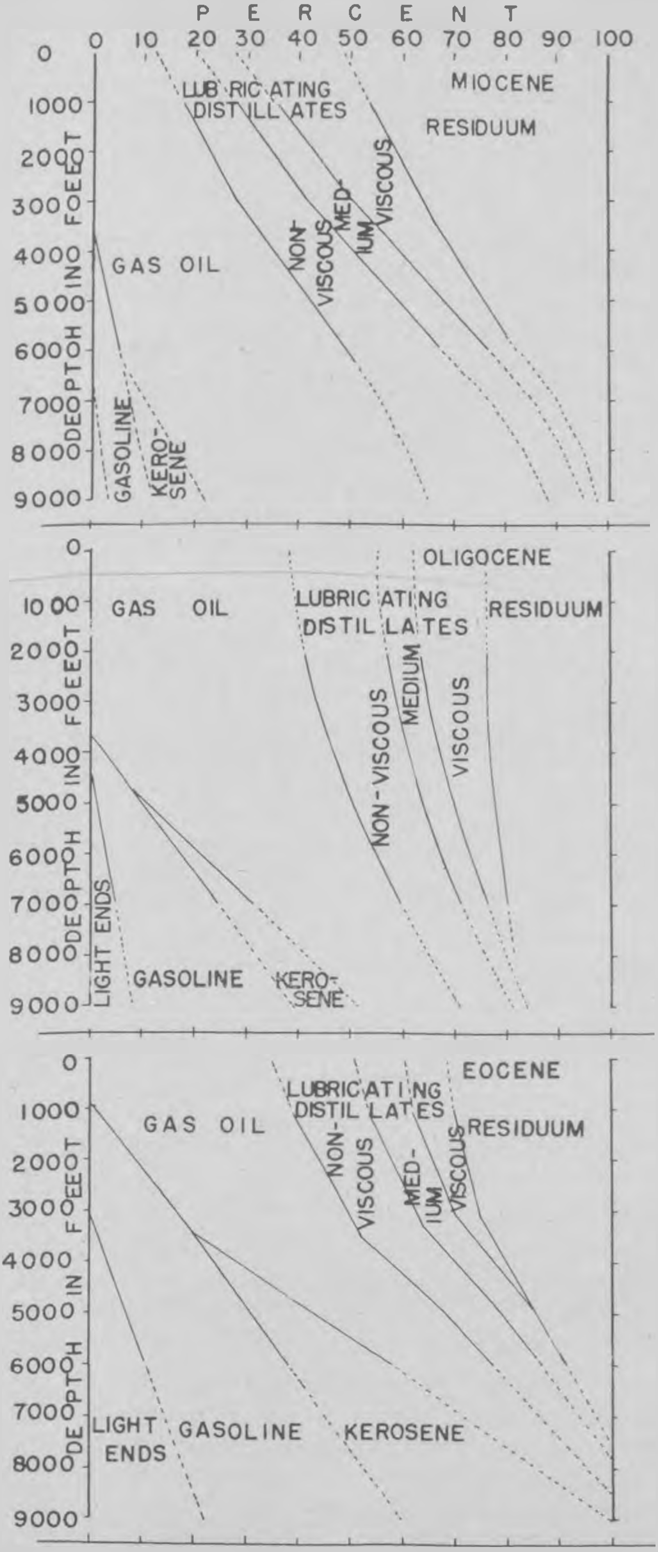

Fig. 4. *Variation of Gulf Coast crude oil with depth and age according to D. C. Barton.*

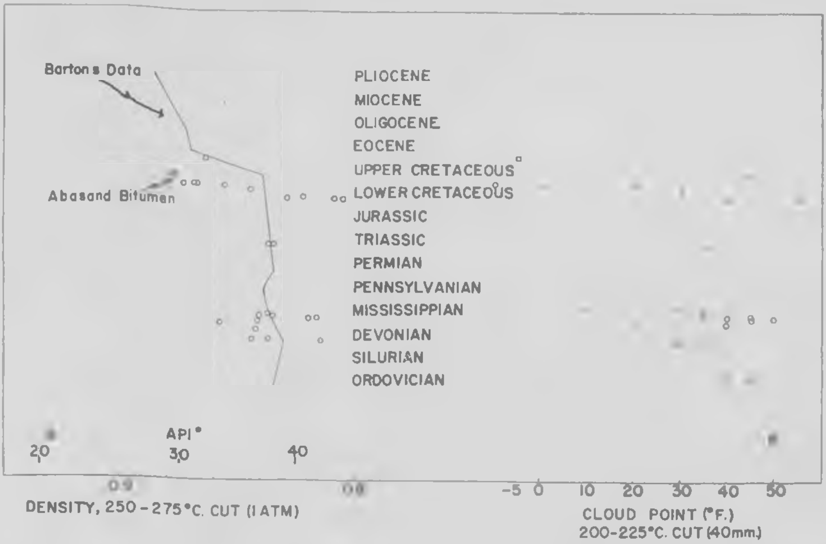

Fig. 5. *Variation of the base with age of Canadian crude oils for which the author had both the stratigraphic age and the distillation analysis.*

A. Variation of the A.P.I. gravity of the 250-275°C. cut under atmospheric pressure.

B. Variation of the cloud test of the 200-225° cut under 40 mm. pressure in °F.

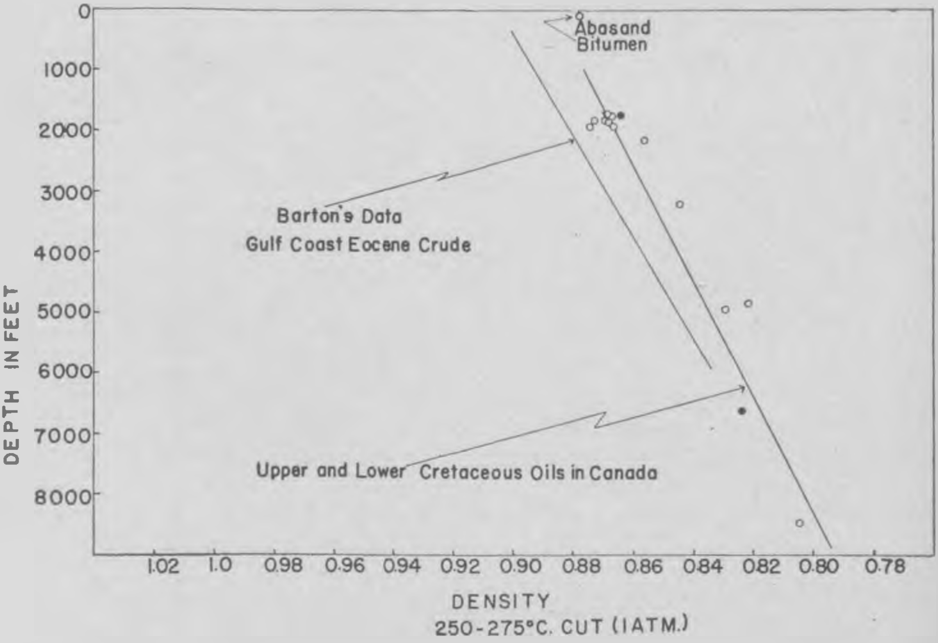

Fig. 6. *Depth-Base variation of Upper and Lower Cretaceous oils in Canada. The graph gives the variation of specific gravity of the 250-275°C. cut (at atmospheric pressure) with the depth of the horizon producing the oil.*

Coast crude oils of the Eocene period. If the straight line representing the change in density with depth of the first key cut of the Canadian Cretaceous oils is projected back to zero depth, the density so obtained is 0.885. This is in reasonable agreement with the density of 0.878 and 0.867 found for this key cut in Abasand bitumen. In the past, the decrease of the A.P.I. gravity of the entire crude has been explained rather commonly as the result of the greater evaporation of the lighter constituents from the shallower crudes. This explanation is not applicable to the variation of the key cuts from different crudes for these cuts are sufficiently narrow that they consist of molecules of essentially the same molecular weight. The observed variations in the physical properties of these cuts are, therefore, attributable to the different proportions present of the paraffins, cycloparaffins, aromatics and sulphur compounds.

It is considered to be very significant that the density of the first key cut for Abasand bitumen differs markedly from that of a typical Devonian crude such as Imperial Redwater No. 15 which has a value of 0.842.

A study of Canadian oils of the Cretaceous period by distillation analysis indicates that the present character of the crude is a function of the depth of the producing zone (see Fig. 7). This again is in agreement with Barton's study of the variation in character of the crude oil of the Texas-Louisiana Gulf Coast as revealed by the analyses of the United States Bureau of Mines. The extrapolation of the lines in Fig. 7 back to zero depth as done by Barton suggests that proto-petroleum contained large quantities of residuum. In Fig. 7, broken lines have been projected vertically upward from the distillation analyses of crude oils at the 1700 level. It will be observed that these projected lines cut the upper abscissa at points which agree well with the distillation analysis of bitumen. It is evident, therefore, that distillation analysis cannot distinguish between Abasand bitumen and Cretaceous oil located at a depth of 1700 ft. The obvious difference in the viscosity of the Abasand bitumen and these crude oils undoubtedly lies in the difference in the molecular weight of the residuum. The molecules in the residuum of the Abasand bitumen are probably sufficiently large that even if a large portion were degraded, they would still remain in the residuum and not modify the distillation analysis.

Briefly, distillation analysis shows the Abasand bitumen to be remarkably similar to the Cretaceous crude oils of Canada and that the specific gravity of the key cut (250 to 275°C.) follows the Depth-Base rule established for these oils.

As mentioned earlier, it has been suggested that Alberta bitumen may have been derived from Devonian oil. As we have previously shown, there is a marked difference in the specific gravity of the 250 to 275°C. cut of Abasand bitumen and of Redwater crude (Imperial No. 15) which is considered to be a typical Devonian crude oil. This cannot be explained by evaporation. It indicates that among the

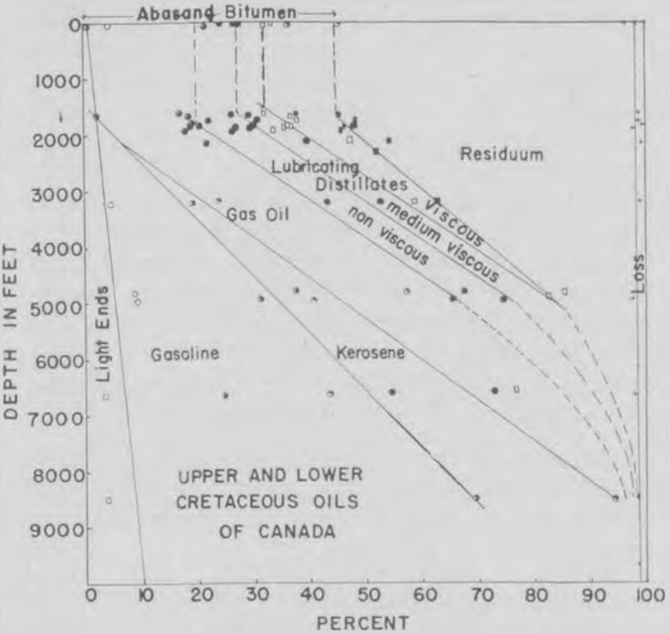

Fig. 7. *Variation of the distillation analysis of the Upper and Lower Cretaceous oils of Canada with depth.*

○ *Light ends*

◑ *Gasoline*

◔ *Gas oil*

◕ *Non-viscous lubricating oil*

□ *Viscous lubricating oil*

■ *Residuum*

● *Medium viscous lubricating oil*

molecules which are of the same size (boiling at the same temperature) in these two crude oils, there is a different proportion of paraffins, cycloparaffins, aromatics and sulphur-containing compounds.

If this distillation or evaporation hypothesis of the formation of Abasand bitumen is correct, it would seem reasonable to expect that a portion of the Devonian oil might be distilled off leaving a residue which bears some resemblance to bitumen. The question then arises as to how much should be distilled off. Since the asphaltene content of Redwater crude is 0.14% while that of Abasand bitumen is 22.5%, it is clear that 99.38% of the Redwater crude should be distilled over to make the asphaltene content of the residue agree with that of the bitumen.

On examining the distillation ranges of these two crude oils in Table I, it is evident that the molecular weight distribution is quite different and that they cannot be reconciled by distilling a fixed portion much less than 99.38%.

TABLE I

DISTILLATION RANGE

	McMurray International Bitumen Ltd. Experimental Plant		Imperial Redwater No. 15	
	Atmospheric pressure		Atmospheric pressure	
Temp., °F.	Sum, %	Specific gravity	Sum, %	Specific gravity
Up to 50			2.1	0.666
50 - 75			4.8	0.679
75 - 100			9.2	0.716
100 - 125			15.1	0.743
125 - 150			20.4	0.766
150 - 175			25.2	0.785
175 - 200	0.2	0.823	29.6	0.802
200 - 225	1.3	0.847	34.6	0.817
225 - 250	5.0	0.865	39.5	0.830
250 - 275	18.8	0.878	45.4	0.842
	Pressure 40 mm.		Pressure 40 mm.	
Up to 200	20.3	0.876	48.9	0.855
200 - 225	25.1	0.931	55.1	0.863
225 - 250	32.8	0.951	60.1	0.877
250 - 275	35.4	0.961	64.9	0.889
275 - 300	—	—	70.7	0.902
Residuum	63.1	—	26.9	0.967

If it is argued that the Devonian crude oil was partially evaporated and subsequently polymerized by the action of oxygen and sulphur compounds, it is remarkable that the bitumen is completely soluble in CS_2 and CCl_4. Other difficulties are also created. To illustrate this, Redwater crude was heated in an agitated vessel to a temperature of 220°C. to avoid thermal cracking. The vapor temperature reached 185°C. and 20.7% of the crude oil was distilled off. This made the bitumen and Redwater crude comparable in that they now both contained little material boiling under 185°C. The residual Redwater crude was now shown by analysis to contain 48.9% paraffins and cycloparaffins, 0.95% asphaltenes, 0.6% sulphur, and possessed a molecular weight of 312; whereas the bitumen contained 11.2% paraffins and cycloparaffins, 5.5% sulphur, 22.5% asphaltenes, and possessed a molecular weight of at least 800.

The first difficulty encountered is that a source of sulphur must be provided to increase the sulphur content of the residual Redwater crude from 0.6% to 5.5%. In addition, it might be expected that the reaction of sulphur compounds with an organic material as complex as crude oil would yield a wide variety of linkages. However, the examination of the bitumen has shown that the sulphur present is extremely unreactive and that almost no mercaptans are present. There is also no evidence that any elemental sulphur is present.

While it may be said that the aromatic portion of the residual Redwater crude underwent some polymerization or cross-linking with the aid of sulphur, it is not evident how the cycloparaffins could have been reduced from 48.9% to 11.2% to yield material of higher molecular weight.

Briefly, the numerous difficulties which arise when one assumes that Alberta bitumen was derived from a Devonian oil suggest very strongly that this was not the source. On the other hand, the molecular weight distribution as indicated by the distillation range and the specific gravity of the distilled 250 to 275°C. cut suggest very strongly that the Alberta bitumen belongs to the class of oils formed during the Cretaceous age. It should be realized, however, that the conclusions drawn in this work refer strictly to the bitumen of the Abasand quarry. Some caution should be exercised in extending these conclusions to the entire bituminous-sand area which is said to underlie 30,000 square miles.

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DISCUSSION OF GEOLOGY PAPERS

T. A. Link: In the paper presented by Dr. Hume, he lists fourteen conditions of occurrence which must be considered in relation to the origin or source of the bituminous content of the McMurray oil sands. There is no need to enumerate all these again since I regard some of them as relevant and others as irrelevant. Since most of the items throw no light in either direction on this controversy, I will not dwell upon them, but will confine my discussion to those points only which Dr. Hume regards as significant with respect to the Lower Cretaceous origin.

Item 1: That the bitumen is a heavy asphaltic oil with a specific gravity greater than water is, in my opinion, an observation which mitigates against Dr. Hume's theory, unless he can show by discussion or diagrams how a substance heavier than water will find its way into the McMurray sands at the time of formation of the bitumen and the deposition of the sand. In other words, if Dr. Hume will explain to us more specifically, or better still, by means of diagrams, how a bitumen which is heavier than water, which is being formed in the muds and oozes of the epicontinental sea, would migrate either through these muds or along the bottom of the sea into the contemporaneously deposited McMurray sands, it would be desirable.

Item 2: That the bitumen has a high percentage of sulphur and some other minerals in small amounts. This observation adds little either to the Cretaceous or the Devonian origin of the oil for the simple reason that in many oil fields the oil and the waters contain large amounts of sulphur and in many instances oil fields with several producing horizons indicate varying amounts of sulphur in the different horizons. If Dr. Hume is trying to demonstrate that the sulphur is indigenous in the oil, he may find considerable difficulties along chemical lines as well as on the basis of the geological data. There are pyrite and marcasite nodules in the McMurray formation. This has been revealed during the mining of these, and I see no particular difficulty in assuming that an oil which impregnated the McMurray sands could, or could not, become contaminated with sulphur. In this connection, I wish to state that, because of the fact that the McMurray bitumen has a different composition from the Devonian oil does not prove a thing one way or the other. After oil migrates through fractures along an unconformity and into a different host or reservoir rock it is bound to change its physical and chemical character discernable to the eye, under the microscope, or the spectrograph. Furthermore, the oil may lose some of its original mineral content and take up other substances encountered during migration into the new reservoir rock.

Items 3 and 4 are not of particular significance, save possibly the fact that Item 4 states that the bitumen itself is essentially the major part of the interstitial material of the McMurray sands. In my opinion this is a fact in favor of migration into the sands before consolidation has taken place. This fits either one of the theories.

Item 5 states that "in the Mildred Lake area, beds of bitumen with only slight sand content were bored." From personal communication with Dr. Hume, I am led to believe that he regards these layers as consisting of almost 100% bitumen. It is significant and most ironical to remark here that the presence of these layers of bitumen caused Dr. Hume to believe that they were the one big factor towards the argument in favor of Cretaceous origin. On the other hand, in my mind, they are exactly the opposite. Our interpretation of the processes of the past geological ages are based almost entirely upon today's geological processes as we observe them. Therefore, the most logical thing to do in this particular case is to scan the literature or look for conditions and processes taking place today which might simulate what took place in the McMurray area during Cretaceous time. The tar lake of Trinidad comes to mind. It is believed that this big tar lake is being fed from below. There is no reason why such a process could not have taken place in the McMurray area during Lower Cretaceous time. At Norman Wells, there is today a coral reef of Devonian age losing its oil content and saturating with oil the recent sands and gravel in the delta of Bosworth Creek.

With respect to Items 6 to 11 there are no comments. However, Item 12 seems to be the crux of the entire situation as far as the proponents of the Cretaceous origin are concerned. It reads as follows: "The bitumen in the bituminous sands is relatively easy to crack by moderate heat and low pressures. Digestion as described by Ball was presumably a mild cracking." Because of this, Max Ball asserts that the "Tar Sands" are a relatively young oil, or in his words, a "virgin oil." Neither Max Ball, nor any other geologist, is in a position to tell us today, on the basis of what we know, just exactly what a "virgin oil" is like. It could very easily be a very light substance. This point was thoroughly discussed in my paper on the origin of oil in reefs and I am still of an open mind with respect to the nature of so-called "virgin" oil. A quotation from this paper has some bearing. "Objections to foregoing reasoning are numerous, and the one favored is the suggestion that the oil migrated through what is now black shale at the time it was a mud, ooze, or silt. That leads to the all-important question: 'Just what is the nature of virgin oil?' Years ago we were taught that it was a heavy, tarry, or asphaltic substance, but this idea has lost favor, and many, including the writer, believe it may be a very light substance. If it is a heavy, tarry material, its migration through the muds is a serious physical problem from the outset. If it is a light substance and was generated before consolidation of the sediments it would have a tendency to move upward or vertically through the muds and oozes, and from these to the surface of the water and thus be dissipated. Gas is one of the first manifestations of hydrocarbons 'in the making' as attested by observations of swamps, sloughs, ponds, or marshy embayments of larger bodies of water. The writer believes that the presence of marsh gas may be the first step in the formation of hydrocarbons. Therefore, if a virgin oil is a light substance, its migration from muds or oozes would be primarily upward or vertically, and the wholesale or widespread migration of oil through carrier beds would require some lithification of the sediments before it could take place. However, if this rock is too fine-grained and dense, no appreciable movement of oil through it seems possible.

"Expressed in another way, the writer regards the fine-grained black shales observed throughout the geologic column as source beds which retained their original oil because of its inability to migrate through such sediments after consolidation. It could be termed 'still-born oil', and its movement out of such impervious sediments could be effected only when subjected to intense deformation, high temperatures, and fracturing. A coarse-grained or porous rock above, below, or within such black shale could eventually accumulate some of the hydrocarbons from the shales, but the fact that the shales are black does not necessarily imply that at one time they contained much more oil. Such black shales are both the source and the reservoir rock which may never give up its hydrocarbons, excepting as here described."

Theory of transgressive and regressive reef (bioherm) development and origin of oil, Bull. Am. Assoc. Pet. Geol., **34**, (1950), by Theo. A. Link.

The youngest oils produced to date from the Tertiary vary from heavy to very light oils, depending on where the Tertiary is examined. Likewise, there are heavy and light oils in older formations such as the Devonian. The fact that the oil from the bituminous sands from the McMurray formation is easily cracked by moderate heat does not necessarily imply that this is a "virgin" oil. Therefore, until this is demonstrated to be the case, this supposedly significant point cannot be used by the proponents of the Lower Cretaceous origin.

Items 13 and 14 may be used by either proponent to advantage.

Let us now turn to the text of Dr. Hume's paper. The following is a quotation. "This would leave for possible seepage to the Lower Cretaceous as it was being deposited only such oil as was contained in favorable structures that were sufficiently near the eroded Devonian surface to allow for fracturing and possible upward migration of any oil content. This at once greatly restricts the area from which Devonian oil could have been received directly by the Lower Cretaceous, and leaves us to imagine at least 150 fields the size of Redwater, all fractured and seeping out into the McMurray sands during their comparatively short period of deposition, to supply even the minimum 100 billion barrels that the bituminous sands are said to contain. It would be difficult to imagine such a pouring out of prodigious amounts of oil without great wastage."

While it is difficult for Dr. Hume to imagine such a condition, it is also difficult for me to imagine other things. In other words, lack of imagination on my part, or on Dr. Hume's part, is no argument one way or the other. I, personally, see less difficulty in deriving the oil in the McMurray sands from 150 oil fields rather than imagine that the McMurray sands themselves are one large oil field. I do not wish to state that this is impossible, but would like to ask Dr. Hume if he believes, on the basis of the law of averages, that the possibility of deriving the oil from 150 other oil fields seems more reasonable than to postulate the formation of one tremendous oil field containing between 100 and 300 billion barrels of oil, with the formation and migration of the oil all done during the "comparatively short period of deposition."

So far as the time of formation of oil in the Devonian is concerned, it is obvious that those who believe that it migrated from the Devonian into the Cretaceous are assuming that the oil was formed and migrated into the Devonian reservoirs prior to the development of the unconformity between the Devonian and the Cretaceous.

Drilling since the Leduc discovery has revealed that the areal and volumetric proportions of the D-1, D-2 and D-3 reef limestones of Upper Devonian age is probably greater than that of the oil sands and one should attempt to visualize that by far the greatest percentage of these Devonian reefs drilled to date are water-bearing. Just how much of this reef material, before tilting, etc., was oil- and gas-bearing can only be surmised. Oil and gas is left only in the very tops of these large blanket sheets of reef. The remaining six or seven hundred feet of the D-3 reef thickness contains water, but it might have, at one time, contained a lot more oil and gas. To this may be added the established reef horizons below the Waterways formation of Middle Devonian age which, in all probability, have lost most of their gas and oil content to the overlying "Tar Sands."

The presence of interfingering marine shales and overlying marine shales seems to be of no particular significance, and adds essentially no argument in favor of the Cretaceous origin of the oil. It is possible for oil to originate in marine, non-marine, and continental deposits, and to migrate into them is also an accepted geological process. The presence of wood, logs, or leaves in the formation does not necessarily demonstrate that this formation was laid down as a terrestrial deposit.

Today, along the Arctic coast of the Northwest Territories, is found driftwood shifted many miles east of the Mackenzie River delta and this wood is from trees which grew in the headwaters of the Liard River hundreds of miles to the south. Nevertheless, the beach sands of the Arctic Ocean, where the wood is being deposited, are definitely a present-day marine deposition.

Further on in the text, Dr. Hume states, "The conditions of sedimentations and environment as visualized by Link for the Lower Cretaceous origin of the bitumen, are identical with those postulated by the writer, etc." As pointed out previously, this seems highly improbable in view of the fact that Dr. Hume states that the oil is heavier than water. That statement regarding the gravity of the McMurray oil should not be taken too seriously because I am not convinced that the oil is actually heavier than water, because during commercial extraction it may lose some of its lighter constituents.

In summary, I would say that in spite of the able presentation of his case, I am still not in agreement with Dr. Hume's theory that the McMurray sands derived all or the greater part of their bituminous content from the contemporaneously deposited Cretaceous sediments. More details and conclusive arguments with illustrations depicting the mechanics of such a process would be welcomed. As more data are gathered the correct answer may eventually come to light. However, there is one point I would like to emphasize and that is, that I am thoroughly convinced some oil was formed during Cretaceous time and some of this oil may be within the McMurray sands. However, it appears that the greater proportion of the oil was derived from a widespread and thick archipelago of Middle and Upper Devonian reefs lying underneath and downdip from the McMurray oil sands, and that these reservoirs did, at one time in the pre-Cretaceous periods, contain a great deal more oil and gas than they do now.

J. C. Sproule: Messrs. Falconer and Kidd both referred to the McMurray formation as being estuarine or deltaic in origin. I offered the same interpretation in my paper on the origin of the McMurray oil (1). Following a survey conducted for the Geological Survey of Canada in the Cree Lake-Athabasca area in 1937 (2), however, I was so impressed by the size, extent and character of the sands of the Athabasca formation as to realize that this tremendous body of early Paleozoic sand is all the explanation that is needed to account for the presence of the McMurray formation as a predominantly sand body. Rivers undoubtedly carried some of the sand from the Athabasca sandstone area to its present position in the McMurray formation but it is not necessary to postulate the presence of a single large river. The mere geographic proximity of these two sand bodies, one the Paleozoic updip source and the other the Mesozoic downdip redeposited body on the eastern margin of a Lower Cretaceous sea, provides very strong circumstantial evidence. South-moving currents down the eastern shore of this sea, swinging westward to join with the western shoreline of the Lower Cretaceous Arctic embayment somewhere south of Edmonton, have apparently carried much of the Athabasca sand to that general area where the equivalent of the McMurray formation is very well developed, as pointed out by Dr. E. W. Shaw.

Dr. Wickenden's paper has added important evidence supporting the idea of a Precambrian and Athabasca sandstone source for the McMurray formation, by reference to sedimentary elements derived

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(1) Sproule, J. C., Origin of McMurray oil sands, Alberta, Bull. Am. Assoc. Pet. Geol., 22, 1133-52 (1938).

(2) Ibid., Pleistocene geology of the Cree Lake region, Saskatchewan, Trans. Roy. Soc., Can., 33, sect. IV, 101-110 (1939).

from the Rocky Mountain area found in the Lower Cretaceous equivalent of the McMurray formation along the west flank of the Lower Cretaceous sea, but not in the McMurray formation on the east flank of the basin.

Mr. Falconer referred in his paper to the scarcity of feldspar in the McMurray formation. My A.A.P.G. paper by contrast referred to its abundance. Mr. Falconer is correct in that feldspar in its unaltered form is not abundant. There is in places, however, considerable kaolinized feldspar. There are, for example, massive beds of McMurray formation on the Clearwater River that are composed of a high percentage of rusted kaolinized feldspar.

Mr. Falconer and Dr. Hume have both described the oil sands near the mouth of the Firebag River as being of McMurray age. I have always regarded these sands, as well as others of the same character up the Firebag River and farther north, as being reworked sands of Pleistocene, glacio-lacustrine origin. This interpretation was based on the presence of boulder clay underlying the bedded oil sands and the mineralogic character of the sands themselves, composed of a high percentage of angular quartz grains. The true McMurray sands are composed mainly of subangular to rounded and wind-frosted grains. This discrepancy explains in part the varying estimates that have been made as to the extent of the sands and the size of the oil reserves contained therein.

Dr. Hume referred to my description (1) of the McMurray formation east of the mouth of Cottonwood Creek, where the upper but not the lower sands are impregnated with oil. He takes this as evidence to support the theory of a Clearwater shale origin, since the oil should, in keeping with that theory, tend to be closer to the upper marine phase and therefore in the top of the sand formation. If the oil did originate in the shoreline facies of the Clearwater sea there should be oil in the sand lenses of the Clearwater formation, but none have been recorded. My interpretation of the presence of this oil in the upper part of the formation is that the west-plunging shale partings between sand lenses tended to prevent free movement of the eastward migrating oil into the lower beds.

E. W. Shaw: There was a lot said today on the subject of the geology of the oil sands, but there was also a great deal of recent information not said. Concerning the distribution and occurrences of black and tarry oils, many people from out of the province may go away with the idea that all of these are confined to the oil-sand area. Actually this tarry black oil in the Lower Cretaceous has a very wide distribution in Western Canada. It is in various places in Saskatchewan, and all over Alberta—up in northern Alberta in the Peace River country. These occurrences, of course, do not all overlie the Devonian. They are in the Lower Cretaceous where the Lower Cretaceous overlies the Devonian; they overlie the Mississippian; they overlie the Permo-Pennsylvanian; they overlie the Jurassic; and they overlie the Triassic, and so let us not get the idea that they all come from the Devonian. The argument that they must come from the Devonian because they overlie the Devonian is certainly open to question.

Again, something that does not seem to have been very clearly stated is the very wide distribution of this McMurray sand—or as we more commonly call it—the basal Cretaceous sand. It has a very, very wide distribution in Western Canada—it doesn't just occur in a patch up around McMurray, as you may have been led to believe. It can be traced to the west as far as the mountains; it appears in the foothills and the mountains as a conglomerate. This tends to throw doubt on the statement which has been made time and time again about the McMurray sands having been derived from the Athabasca sandstone or from the Precambrian side. Since the formation goes all the way from the Precambrian to the mountains where it appears as a conglomerate, it is obvious that the bulk of this basal sand came from the mountains or, that is, from the west. Perhaps a small contribution did come from the east, but it must of necessity have been a small part, because the reconstructed topography of the Paleozoic surface shows that the drainage was toward the east and north. Therefore, if the great bulk of this Lower Cretaceous basal sand came from the east, it came uphill. It could be moved uphill by the action of wind, but certainly not by water.

As far as this controversy is concerned, at one time I believed in the Devonian origin and then changed to the Cretaceous origin, and now I am on the fence. One question about the Devonian theory, and this point was not brought out, is that there is tar oil in the Lower Cretaceous in the Leduc field. It is up in the midpart of the Lower Cretaceous, but cannot be produced from it. Below it, in the basal sand, there is a light oil that cannot be distinguished from the Devonian oil fields and it is generally agreed that it is a Devonian oil. It is a light oil, neither black nor heavy, and so it is a strong piece of evidence that the black tarry oil is from a different source.

With reference to the Cretaceous origin theory, it doesn't seem likely that the tar oil came from the Clearwater shales of the Cretaceous. There are very good sand reservoirs in the middle of thick marine shales of the Cretaceous all over northern Alberta, and yet there doesn't appear to be much black heavy oil in them. On the contrary, some light oil appears in them, as for instance in the Viking sand as at Joseph Lake.

L. M. Clark: If a hole is drilled into the Devonian downdip from the Athabasca oil-sand out-croppings, for instance in the vicinity of Wabiskaw or Lesser Slave Lake, in some places as much as four or five hundred feet of heavy oil will be found in the Devonian. It appears below the unconformity, in the top of the Devonian, and so it isn't restricted to the sands at all. That's true all over where the D-3 seems to be present.

J. C. Sproule: Dr. Shaw remarked that: "If the great bulk of this Lower Cretaceous basal sand came from the east, it came uphill."

I should like to ask Dr. Shaw how the Lower Cretaceous Clearwater sea managed to sit on that "side hill" leaving the shoreline sands of the McMurray formation downdip from it. The idea of a Lower Cretaceous sea lying in a basin to the west of McMurray has been supported by the paleontological and field work of Dr. McLearn, Dr. Wickenden and a number of other geologists. Their conclusion is that the upper part, at least, of the McMurray formation is the eastern shoreline equivalent of the Clearwater and other Lower Cretaceous marine bodies, and that the deeper-water shales are interfingered with the shoreline sands. As McLearn and others have represented the situation, the Lower Cretaceous sea came in from the Arctic as a narrow embayment which in Upper Cretaceous time joined with a marine embayment from the Gulf of Mexico.

E. W. Shaw: Although there are now a great number of wells west of McMurray, there is no evidence as yet to indicate that there was marine deposition contemporaneous with the deposition of the McMurray sand.

L. M. Clark: I think I am inclined to agree with Dr. Sproule. In the case of the Wabiskaw area, we cored about nine wells. This was downdip from the McMurray sand. We got the Ostracod zone, and as we went east the Ostracod zone approached to within a few feet of the surface of the Devonian. It was below it. Below it there was nothing but a little sandy clay. Above it was a glauconite sand which we call here the Wabiskaw sand. We had 250 feet of shale and some sand. It appeared that the glauconite sand and the Ostracod zone downdip had to be marine. There were non-marine beds below them. Apparently the Athabasca sands were either deposited above sea level at the same time that the glauconite sands were being deposited in the basin to the west, or very near that time, because the Ostracod zone there was very close to the Devonian.

G. W. Hodgson: Something might be added to what Dr. Montgomery said about porphyrin compounds in the oil. The chemical approach seems to afford a very direct means of correlating oils, and one might apply this method to the controversy regarding the Cretaceous versus Devonian origin. We examined the bitumen and found it to contain a porphyrin, or something that resembled a porphyrin, spectrophotometrically. Another black oil, a Cretaceous oil from Lloydminster, was found to contain the same porphyrin. This indicated a close correlation between these two oils. If the oil-sand oil were originally derived from a Devonian oil, it is reasonable to expect that a Devonian oil would show the presence of the same compound. However, a Devonian oil from the Bon Accord field was entirely devoid of porphyrins, and it may be tentatively concluded that the Link thesis is disproved.

MINING SESSION

CHAIRMAN: S. J. KIDDER

Mining Engineer, Toronto

When the mining fraternity is called upon to deliver a product to the refiner, the first thing that must be known is the nature of the product. There is no better picture than that obtained by drilling and sampling. Physical pieces of bituminous sand can be examined and analyzed, but drill cores must be the starting point. Dr. Hume, whose department headed up the exploratory drilling, will present us with a description of the results of the drilling and sampling that was done over a period of years in the oil-sand country of northern Alberta.

Dr. Hume's paper will be followed by one by Mr. P. B. Hall of Boyles Bros. Drilling Company which held the drilling contract for the work described in Dr. Hume's paper. Methods of drilling will be described, and this is important because the oil sands are quite different from the usual type of material encountered and special methods had to be developed.

After the description of the material to be mined, attention must be directed to methods of mining. Several different methods are known. It was reasonable to select a site near the river, where the ratio of overburden to oil sands was quite low, for the exploratory drilling. That particular area indicates that open-pit mining with the removal of overburden by large equipment followed by drilling and blasting the sands might be applicable. Mr. Bredvold of the M. A. Hanna Company, with experience in the large open-pit operations in the Mesabi iron range and the Labrador developments, will describe the mass movement of material in open-pit mining. This will be followed by one of the Mannix engineers, Mr. R. H. Latham, who will give a paper on the type of equipment with which they are completely familiar. He will be assisted by Mr. Evans of the Caterpillar Tractor Company. Following a discussion of the equipment and methods for open-pit development of an oil-sand mine, Mr. Latham will present a very brief description of a modified method of block caving as applied to underground mining of oil sands.

Open-pit development in the wintertime, and to a lesser extent in the summertime, may involve the use of explosives—drilling and blasting—to facilitate the operation of shovels and draglines. Mr. Logan of Canadian Industries Limited will present a short discussion on the methods that might be used.

Mr. Latham mentioned a method of block caving that might be applied to recovery of the sands. Another mining engineer has looked at the possibility of underground mining, and has arrived at an opinion of the feasibility. He is Mr. F. S. McNicholas of Climax Molybdenum of Colorado, who will describe block caving as it is applied to the mining of great ore bodies, and how this knowledge might be applied to the oil sands. Then Dr. K. A. Clark will describe some experiments done at the Research Council of Alberta which are related to the general problem of block caving and the movement of oil sands.

An entirely different method of recovering oil from the oil-bearing sands is to be described by Dr. C. M. Davis of Pennsylvania State College, who has been doing work on the secondary recovery in oil fields. The possibility of recovering oil in situ has great appeal and has attracted more than a little attention for many years. Consideration will be given to the applicability of the method to our material which is so near the surface and so amenable to experimentation. Since heating of the formation is an integral part of the above recovery method, it is fitting that he should be followed by Dr. Warren of the Mines Branch who will discuss the heat conductivity of the oil sands.

DRILLING AND SAMPLING BITUMINOUS SAND DEPOSITS

By G. S. Hume
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This paper is a short review of the results of drilling and sampling the bituminous sands of northern Alberta carried out by the Federal Department of Mines and Resources between 1942 and 1947 (1).

In 1942 a committee of the Department of Munitions and Supply of the Federal Government was appointed to study the bituminous sand situation in respect to planning a 10,000 bbl. per day plant. Although a number of attempts had been made to extract the bitumen at various localities no effort had been made to assess precisely the total content of any large areas by the necessary drilling and sampling. Field work starting in 1913 by the Mines Branch had been carried on by S. C. Ells until 1931 and the major outcrops had been mapped and assays taken. This sampling was done from shallow pits, trenches and shafts, but mostly by the hand turning of augers. Between 1925 and 1928, eight holes had been attempted; one had reached a depth of 237 feet and another 100 feet, but mostly the holes were relatively shallow. Sampling was done also by the Scientific and Industrial Research Council of Alberta and in 1924 some 250 samples were assayed from a shaft put down 45 feet near Fort McMurray and from 35 widely scattered outcrops. In 1941, by means of hand augers, Abasand Oils Limited under the direction of Max Ball had sampled deposits in eight localities from Steepbank River northward. At that time Consolidated Mining and Smelting Company were operating a gold mine on the north shore of Lake Athabasca. Fuel oil was needed, and some was supplied by International Bitumen Company from their plant at Bitumount. Both Consolidated Mining and Smelting Company and International Bitumen Company had been interested in and had done some exploratory work accompanied by sampling. All these efforts, including the work of Ells for the Federal Department of Mines and Clark for the Scientific and Industrial Research Council of Alberta, had shown the great variability of the sands both horizontally and vertically, and consequently the Committee of the Department of Munitions and Supply in 1942 recommended systematic drilling to test promising areas. This work was done under the auspices of the Mines, Forests and Scientific Services Branch, Department of Mines and Resources, Ottawa.

Drilling was commenced in 1942 by Consolidated Mining and Smelting Company in the Wheeler Island and Steepbank River areas, the former north of Bitumount and the latter about half-way between McMurray and Bitumount. Between July 1942 and January 1943, in addition to digging a number of pits, 21 holes averaging 144 feet were drilled by machine drilling methods but using a hand auger for sampling. The operation was slow, inefficient, and the sampling was unsatisfactory because of water flows into the holes. However, a promising area for further exploration was found in the Steepbank River area although the Wheeler Island area proved too erratic in bitumen content to justify further exploration at that time. An interesting feature of the Wheeler Island area is the occurrence over part of the area of 25 to 30 feet of dark carbonaceous shale above the limestone.

In the spring of 1943 Boyles Bros. of Vancouver undertook the drilling on contract. New methods of drilling using mud, as for drilling oil wells, were quickly developed and this not only greatly cut down the costs of operations but obtained much better core recovery. From 1943 to January 1947, 291 holes were put down representing 53,918 feet of drilling. A number of areas were tested including Steepbank and the Horse River reserve where the Abasand plant was located. The most favorable locality discovered was a new rich area in the vicinity of Mildred and Ruth Lakes opposite the mouth of Steepbank River.

The significance of the drilling in the Mildred-Ruth Lakes area has been noted (2). The deposit proved much richer than any other tested. In the northern part wells were spaced one-eighth mile apart, but in the southern part they were one-half mile distant from one another. In 33 holes, not only were rich bituminous sands found but there were beds containing 50 to more than 80% bitumen by weight. The thickness of the bitumen beds varied from a few inches to 21 feet. In making the calculations of bitumen content of the deposit, however, all assays were reduced to 18% by weight. The final engineering appraisal showed a "developed" reserve in the more closely spaced drilled area of 587,824,000 tons averaging 13.4% bitumen by weight, with a ratio of bituminous sands to overburden of 2.3 to 1. In the less closely spaced drilled area the "inferred" reserve is 574,841,000 tons of bituminous sands averaging 13.6% bitumen, with a ratio of bituminous sands to overburden of 2.6 to 1. These estimates indicate 900,000,000 barrels of bitumen in 4 to 4.5 square miles.

It should not be inferred from the above statements that rich, large, continuous areas are easy to locate within the bituminous sands. The drilling that has been done to date indicates the reverse is true. In the East Steepbank area, for example, two reserves of bituminous sands of more than 12% bitumen content by weight were located, separated by 2400 feet of lower grade sand. The two richer bodies of sand are 92 and 43 acres in extent respectively. The former contains 38,000,000 tons with a grade of 12.3%, and the latter contains an inferred amount of 58,000,000 tons with a grade of 12.7%. These are relatively small areas and hence their value for mining and extraction purposes for a plant that might have to be located at a larger, more favorably situated, deposit some distance away is rather questionable. On the other hand, these might be of value to a plant in the main Steepbank area where two deposits were located, the north body containing 69,817,000 tons of bituminous sand with a grade of 13.0% in 197 acres and the south body containing 97,863,000 tons with a grade of 12.9% in 323 acres. The total in the two areas is thus 167,680,000 tons. However, in this area, if 10% or better material is considered ore grade, there would be 297,779,000 tons with an average grade of 11.96% in 945 acres and with a ratio of bituminous sand to overburden of 2.5 to 1. Thus, although the Steepbank area was perhaps the most promising deposit drilled previous to the discovery of the Mildred-Ruth Lakes deposit, it is relatively small in comparison with the latter where there are 1,162,665,000 tons with a grade of 13.6%.

The results of the drilling, therefore, established one area considered to be both large and rich in bitumen and several smaller areas of lower grade, with moderate overburden.

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CORING OF THE BITUMINOUS SANDS IN THE FORT McMURRAY DISTRICT OF ALBERTA

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This paper deals with the methods employed in coring bituminous sands in the Steepbank, Mildred Lake and certain other areas adjacent to the Athabasca River, Fort McMurray district, Alberta. It must be understood the contractor concerned had no record of previous experience in successfully drilling and coring bituminous sands. Therefore, while the methods herein described may not necessarily be the best, they gave satisfactory results in this particular instance and were worked out entirely on the ground and during a period of very limited equipment supply because of war conditions.

In May, 1943, Boyles Bros. Drilling Company Ltd. was approached by W. Timm, then Director, Mines and Geology Branch, Ottawa, to undertake a program of 3,000 lineal feet of drilling in the Steepbank area, approximately 25 miles down the Athabasca River from Fort McMurray. Timm explained that an effort had been made the previous year to core the sands by conventional diamond drilling methods with very unsatisfactory results. Core recovery was either poor or nil, and it was found that the action of the water used as a circulating medium separated the bitumen from the sands thus giving an inaccurate sample. The conclusion had been reached that augering methods gave the most satisfactory samples; consequently it was requested that this method be employed. It was, however, agreed that if, in the course of the work, better methods were devised, consideration would be given to their use.

Work was accordingly started in June, 1943. A conventional diamond drill was used, although only the hoisting mechanism was employed in conjunction with the augering operations. The procedure was to rotate the drill rods by hand methods until the auger had penetrated eight inches to one foot; the rods and auger were then pulled, the sample, if any, being retained in the auger spiral.

It soon became evident that progress was going to be painfully slow, and sampling uncertain. Accurate sampling was complicated, and progress was retarded by seepage water at various horizons throughout the oil-sand beds. When these were encountered the sample was usually lost, the hole had to be cased and swabbed dry before drilling could be resumed, and it became more apparent daily that some other method must be found and used.

An examination of the outcrops and other exposures of the bituminous sands in places along the Athabasca River confirmed our belief that the sands could certainly be cored using a suitable type of core barrel and core size, slow rotation speed and rapid penetration feed. How to avoid leaching the bitumen from the sands was the remaining problem, and the decision was reached that collodial mud as used by the oil drilling industry might be the answer. It was believed that the collodial mud would serve two purposes: the first and most important would be to deposit a film over the core that would be impervious to water, and the second to deposit a protective film over the wall of the hole thus preventing it from caving and being seriously enlarged due to the wearing action of the drill rods while being rotated.

This method was discussed with S. C. Ells of the Department of Mines and Resources, who was in charge of operations at the site, and his permission was obtained to try it on one hole. It was agreed that if the method failed another hole would be drilled by augering methods at our own expense.

Due to the importance of this first experiment, we manufactured for the purpose a special core barrel with bits to fit at our Vancouver plant. The barrel was of the conventional pattern used for coal drilling, five feet long, with a ball-bearing mounted inner tube which is supposed to remain stationary while the outer barrel rotates. The bits were of the face ejection type, or in other words, the circulating fluid passed through holes in the bit face with as little contact with the core as possible. The whole assembly conformed to the standard diamond drill dimension commonly referred to as NX, the bit having an outside diameter of 2 15/16 in. and cutting a core 2⅛ in. in diameter. A friction feed head such as we then supplied to the Canadian Army overseas was mounted on the drill and the first effort to core the sands by this method was started. Everyone concerned was vitally interested in, and no one quite sure of, the results; and so when the first five feet were drilled by this method and the core barrel pulled, there was a great deal of relief to find a perfect core, five feet long, representing an accurate cross-section of the sands.

The drilling of this first experimental hole proved beyond a doubt that the use of mud fluids was definitely the answer to the problem, but many difficulties were experienced with the core barrel due to the very restricted clearances. To try to overcome this, the outside diameter of the bit was increased from 2 15/16 in. to 3 3/16 in. and water courses ¼ in. wide and ¼ in. deep were cut across the face of the bit directly over each of the eight water holes that conducted the mud through to the bit face. The increased outside clearance was a big improvement and core recoveries of over 90% were obtained. However, due to the restriction between the outer and inner tubes, only a very light mud fluid could be used without creating very high pump pressures. The maximum viscosity of the mud was determined by maximum working pressure of the pump, which was between 500 and 600 lb. per sq. in. when circulating approximately 15 gal. of fluid per minute. To overcome this difficulty, the outside diameter of the inner tube was reduced from 2 7/16 in. to 2 5/16 in. and the core size reduced likewise from 2⅛ in. to 2 in. This proved very satisfactory and, besides reducing the pump pressure to less than 150 lb. per sq. in., an average core recovery of 95% was obtained in the oil-bearing sands.

The only objection to this new core barrel, which was designated NF, was that it was too large to pass through NX casing consequently the NM size was designed. The NM bit cut a 2 31/32 in.

hole and produced a 1 27/32 in. core. The outside and inside diameters of the outer and inner tubes were as follows: 2⅞ in. and 2⅜ in., and 2⅛ in. and 2 in., respectively. This core barrel, besides being able to pass through NX casing, produced an average core recovery of 96%.

Drilling by this method soon became as routine as standard hard rock drilling. Standard procedure was to drive or rotate 3½-in. pipe through the overburden until thoroughly seated and a seal effected in the bituminous sands. Mud was then mixed in the mud pit, coring equipment put down the hole, circulation started and coring commenced. The rotation speed finally selected as giving best results was about 80 r.p.m. and a penetration feed of about 20 to 40 revolutions per inch. This was varied somewhat depending on whether the sand was low or high in bitumen content. Best core recovery continued to be obtained with the 5-ft. core barrel. Efforts to increase this to 10 ft. resulted in lower recovery as the core had a tendency to crush by the weight of its own mass. Holes in all cases were drilled down to the underlying limestone, and varied from 200 to 350 ft. in depth. Breaking down of the walls occurred in some of the deeper holes if exposed to rotary action too long, and in a very few instances holes were cased. This was the exception rather than the rule and could now be completely eliminated due to the better understanding of the use of mud fluids.

In the preliminary stages of the drilling program, large diamonds, varying in size from three-quarter to one per carat, were used as the cutting medium. This was later changed to tungsten carbide inserts. The cutting life of any bit was limited by the abrasive action of the sands wearing the metal away from the diamond or insert. A diamond bit would, therefore, last an average of 30 ft. before being reset, whereas carbide insert bits could be run 60 to 80 ft. due to the fact the inserts were long and deeply embedded in the metal. Inserts had to be resharpened at intervals of about 40 ft.

The following is a brief description of the equipment and methods used. The drill was a standard Boyles Bros. Model BBS-2 diamond drill fitted with a BUS-23HF swivelhead. This particular swivelhead was of the friction feed design and was sufficiently large to allow NX (3½-in. outside diameter) casing to pass through the feed screw. The drill pump was a standard Boyles Bros. Model BB5-12M, the maximum capacity and working pressure of the pump being 20 g.p.m. and 500 p.s.i. respectively. For handling the rods, casing, etc., the drill was fitted with a tubular steel derrick capable of handling 20-ft. sections. As mentioned earlier in this paper, the size and type of core barrel finally designed for the purpose was NM, which was used in conjunction with standard N size drill rods.

Due to the fineness and extremely abrasive nature of the sand, it was found more practical to use a small mud pit and change the mud frequently rather than try to separate the sand from the mud. Another reason for favoring the use of a small pit and changing fluid frequently was that, while drilling through the high-grade, the fluid would become contaminated with bitumen. If this was allowed to become excessive it caused considerable trouble due to its deposition in the pump, drill rods, core barrel, etc. The size of the pits varied but on the average were about 4 by 6 by 4 ft. When drilling in the low-grade sands the fluid in the pit was renewed after approximately every 100 ft. of hole, whereas in the high-grade it at times became necessary to change it as frequently as 25-ft. intervals.

For average coring conditions a mud having a viscosity of between 40 and 55 and a circulating volume of about 15 g.p.m. was found most satisfactory.

The actual drilling of the holes was the simplest part of the entire drilling program. The following are copies of the drill logs

Date		Progress feet					Formation and Remarks
		Drilled			Core	Cased	
		from	to	net			
Hole B10							
May 9/46	NS	0	5	5		5	Clay and boulders
10	DS	5	32	27		to 32	Clay and boulders
	ES	32	42	10		to 42	Clay and boulders
	NS	42	51	9		to 51	Clay and boulders
11	DS	51	72	21	15	to 57	Clay and boulders
	ES	72	105	33	30		Oil sand. **Mixed mud**
	NS	105	142	37	35		Bands of sand & clay
12	DS	142	188	46	45		Oil sand
	ES	188	230	42	42		Oil sand
	NS	230	246	16	12		Leached sand
13	DS	246	260	14	14		Clay. **End of hole**
Hole B25							
Aug. 10/46	DS	0	9	9		9	Boulders and gravel
	ES	9	16	7		to 16	Boulders and gravel
12	DS	16	30	14		to 30	Boulders and gravel
	ES	30	42	12		to 42	Same. **Casing broke**
13	DS	0	10	10		10	Salvaged 30 ft. Reset
	ES	10	17	7		to 17	Boulders and gravel
14	DS	17	22	5		to 22	Same
	ES	22	32	10		to 32	Same
15	DS	32	37	5		to 37	Blasting boulders
	ES	37	53	16	7	to 46	Clay. **Mixed mud**
16	DS	53	96	43	42		Clay. Oil sand
	ES	96	142	46	46		Oil sand
17	DS	142	188	46	46		Oil sand
	ES	188	230	42	38		High-grade
18	DS	230	253	23	23		High-grade. Repair hoist cable
	ES	253	283	30	28		High-grade
19	DS	283	300	17	17		Limestone. **End of hole**

from two average holes drilled in the Mildred Lake area and will help to give some idea of the actual progress made while drilling.

The drilling being of a reconnaisance nature, it involved long moves between drill sites. The areas being drilled were often cut up by deep ravines running at right angles to the Athabasca River. Often a move of 1,000 ft. between holes as shown on a map would involve a mile-long detour to cross a deep ravine. Miles of roads and trails were cut by hand methods as there was no bulldozer on the job, and while the drilling actually covered a period of 3½ years it was budgeted for in small amounts and there was never enough work in sight to warrant the capital investment in a large tractor and blade that would have greatly simplified road making and moving. Tent camps were used, which sometimes had to be re-established 10 to 20 miles away, moving over the ice in winter and by barge when available in summer. This made the job costly; out of proportion to the amount of drilling actually done. For example, the labor cost for the 51,568 ft. of drilling done during the period of 1944, 1945 and 1946 amounted to $2.95 per ft. which represented approximately one half the total drilling cost.

Should future drilling of the oil sands be considered, we believe that basically the coring methods we used would be found quite satisfactory. We understand the average core recovery was around 95%. However, it is felt that the methods used for penetrating the overburden could be improved upon by adopting standard rotary drilling procedure. A great deal could also be done to improve the mobility of the equipment if a large program were considered. Track-mounted equipment could be substituted for the skid mountings then used. Truck-mounted equipment is not recommended due to the rough topography adjacent to the river and the muskeg conditions that exist in areas on top of the escarpment. Portable camps, and of course a large tractor of the D7 or D8 class with blade, would also greatly speed up operations.

No serious problems were encountered with winter drilling. Water was hauled in 500-gal. tanks by tractor, and with the drill properly housed and heated there was no particular problem encountered that could not be overcome. In many cases moving was simpler due to snow and the muskegs being frozen.

DISCUSSION

S. J. Kidder: Would you tell about possible drilling conditions during the winter season when winter conditions really got rather snappy—how you had to modify your practice?

P. B. Hall: Winter drilling is always looked upon as being difficult, but in the north country it is possible on the average to make just as good progress when it is 30, 40 and 50° below as in summer. Moving becomes very much simpler, and the only drawback is heating. We had a stove in the drill shack, and although there was some danger of fire from escaping gas, it was not at all serious.

Only one fire was experienced in three and one-half years of drilling in the oil sands. Gas was struck in only six holes. It would appear to be more profitable to burn one, or even two or three, of these drill shacks than to undertake elaborate precautions to safeguard against fire.

Cold weather caused some trouble with respect to water used for drilling. Water was hauled in 500-gal. tanks. They were steel tanks on steel sleds, and all that was required was to build a small fire under them. Wood was plentiful. The mud pits were very small, and if the mud started to freeze it was a simple matter to add hot water to it.

Shelter for the crew consisted of a small shack, about 12 by 16 ft., built of corrugated or aluminum sheeting. It didn't weigh much over 1,000 or 1200 pounds. Once the crew got used to it, it proved quite satisfactory. It was not advisable to take crews from the city and put them out on these operations, however; they had to become adjusted to the rigors of the Canadian North.

In the wintertime, roads between Fort McMurray and the drilling site were maintained on the frozen Athabasca River. Although transportation did not present much of a problem, the Christmas break in operations aggravated the situation to some extent. It always took a long time to get going again after Christmas, but that had nothing to do with the actual drilling on the drill sites. The drilling itself went along very smoothly regardless of how cold it was. A lot of drilling is done right through the vicinity of Yellowknife to the Arctic Circle and it is found possible to maintain a fair pace of drilling down to 70° below zero, even while pumping water up to 1500 to 2,000 feet. On work with these small units, severe winter conditions do not cause any undue slowdown.

Question: Did you use a bentonitic mud?

P. B. Hall: Yes. We used "Aquagel" or "Altamud". In some cases we found one better than the other. The big trouble, as was mentioned, was in separating the very fine sand from the mud. In fact, it was so fine that we gave up trying to do that. Do not think in terms of big oil-well pumps; our pumps were only 2½-in. bore. When making the core, it was found desirable to keep the volume of fluid to a minimum. By turning slowly, pumping as little as possible, and feeding fast, very good core recoveries were attained.

D. S. Pasternack: It has been mentioned that during the drilling of the high-grade material, there was the question of whether the oil was draining into the hole. It was stated that on replacing the core barrel to the preceding depth and then removing it, no evidence was found that such drainage was taking place. Would the temperature of the material in situ be 36 to 40°F.? It would seem that if the core barrel was removed after drilling to, say, 150 feet and then reinserted within a period of a day or two, the high-grade material would not have flowed to any extent during that period because it would be too viscous at that temperature.

P. B. Hall: Yes, that is right. When the core barrel was withdrawn from the hole it was necessary to get the core out immediately and place it in bottles. As you point out, when it first came up its temperature was low and the core would remain as cored. It would flatten out slightly, but a lot of drilling was done in the Mildred Lake area in the summertime, and it was observed that in a matter of fifteen to twenty minutes the core would start to spread out. It was a rather novel experience to drillers to have to put the core in bottles to avoid having it spread throughout the core box.

Regarding the actual coring operation, perhaps too much credit is being given the mud for retaining the walls of the holes. It is quite likely that the material would not move at all, even if only water were used. However, it was found that water couldn't be used because the samples broke up. Furthermore, drilling with water would make withdrawal of the core from the barrel very difficult. Gasoline or kerosene would have to be used to swab the barrel to remove the core that would be stuck inside.

Question: Were the gas pockets in the overburden or in the oil sands themselves?

P. B. Hall: That point is not very clear, but it was believed that the gas was very close to the surface, actually in the oil sands or very close to the contact.

Question: What was the average cost per hole drilled?

P. B. Hall: Over the period, the prices changed slightly as we progressed. The average cost for the 51,568 feet done came to $6.49 per foot. That was the actual cost to the Government.

Mention might be made here that labor costs were very high, due to the moves being expensive. As a rule, the moves were about half a mile, and took place in country covered with windfalls often 8 to 10 feet deep. The cutting of the roads was a very major problem, and heavy mechanical equipment was not available for clearing the roads. Of the total time, very little was spent on drilling; and, of course, during the moves the operating costs continued to mount up. These included operating the camps and maintaining transportation to Fort McMurray.

Question: Would you give us some idea of the size of these boulders that were encountered?

P. B. Hall: All that can be said is that they were not excessive. There would be nothing more than two or three feet in diameter. Dr. Hume could probably give you a better picture of this. The majority would be much smaller than one or two feet, but when an attempt is being made to get pipe of that size down, a boulder of 18 to 24 inches might just as well be bedrock.

Question: Did the boulders need side tracking?

P. B. Hall: No, a rotary method wasn't used. Conventional diamond drill methods were used. When a boulder was encountered, it was shot.

MASS-MOVEMENT OF MATERIAL IN OPEN-PIT IRON ORE MINES

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It should be emphasized that this paper is not in the nature of a recommendation of methods to be used for bituminous sands removal, but rather, an opportunity to show the direction in which we are progressing in the mass-handling of material in open-pit iron-ore mines, with the hope that our experience will give a starting point for the consideration of this phase of the project.

The Mesabi Range of Minnesota has been the largest single source of iron ore since its development following discovery of the ore body about 1890. To date, over one and three-quarter billion long tons of ore have been mined and shipped from this Range, and to expose this ore in open pits the volume of surface overburden removed has run into the billions of cubic yards. From the pick-and-shovel methods of stripping and mining in the early days has developed a series of increasingly efficient systems progressing along with the best of practices in all fields of materials-handling.

Rail Haulage

Rail haulage was introduced early in open-pit operations, and became the accepted and proven method of moving overburden and ore in the pits having large surface area and a relatively small depth of overburden. Because railways have definite grade and curvature limitations, the smaller and deeper ore-bodies were left for future development as underground mines. The same limitations resulted in waste dumps and lean ore stockpiles fanning out over large areas surrounding the big pits. Larger locomotives and cars helped reduce hauling costs, and there was a definite advantage in being able to load the high-grade ore directly from the pit bank into the cars which carried it to the lakehead for transfer into the ore boats. Standard-gauge track and equipment has been the rule. But these easily accessible sources of ore became depleted until today there are only a few mines where the modern diesel locomotives go down to the big shovels in the pit bottoms.

Truck Haulage

Heavy-duty off-highway trucks were introduced for construction and quarry work in 1934 and soon gained wide acceptance by contractors and other users of earth-moving equipment. In 1937 these trucks were first brought to the Mesabi Range for application to open-pit mining. There were many problems in developing a truck that would stand up under constant mine usage, but rapid improvements were made by co-operation between users and manufacturers, and trucks have now become the most common transport medium in open-pit mining. The first units were 15 tons capacity, and perhaps may be called the counterpart of the Model T Ford in automobiles. Some 15-tonners are still used in many of the smaller operations, and are used for water tank trucks, etc., in the larger pits. They are powered by diesel engines of 150 to 200 h.p. In 1944-46, the 20- or 22-ton truck became the standard, using diesel engines of 250 to 300 h.p. Our fleet of 18 of these trucks at the South Agnew has given faithful service under difficult conditions, but the application of torque converters and improved transmissions to this model will add much to the efficiency and ease of operation. These improvements are now available, and this model still enjoys wide use and popularity.

Between 1948 and 1950 several of the manufacturers introduced tandem-axle trucks with rated payloads of 60,000 to 68,000 lb. During the past year or so most of the new operations have been set up for these trucks and they have gained wide acceptance. There is still some controversy regarding the motors for this size of truck. One manufacturer has developed a V-type 12-cylinder diesel engine of 400 h.p. for this application, but most of the trucks of this size have two engines of about 200 h.p. apiece, each driving one rear axle. Torque converters, semi-automatic transmissions, and power steering make these trucks easier to handle than the smaller units and tend to eliminate some of the human errors in gear shifting, etc. Ten of these trucks are used at our Morton Mine and have proved to be very efficient haulage units.

A 50-ton experimental model LLD Euclid truck having two 300-h.p. Cummins engines driving tandem rear axles. Note the thermostatically controlled shutter over the radiator core. The cooling fans are also controlled by the temperature of the engines. Capacity of the box is 32 cu. yd. water level.

In August, 1951, the Euclid Company placed at the South Agnew Mine an experimental unit of their new Model LLD rear-dump truck. Christened "Brutus" by our employees, it is powered by two 300 h.p. Cummins diesel engines, each driving one of the two tandem axles through an Allison torque converter and semi-automatic transmission. The tare weight of this truck is 104,000 lb., and the load capacity is 100,000 lb., using ten 33:00x18-32 ply tires. As usual with most experimental or pilot models, there have been some minor deficiencies, but as a whole its performance has been quite satisfactory. It has better bearing on soft roads and dumps than the smaller trucks; speed and maneuverability are about the same as the 30-ton units.

The application of trucks has made it possible to mine many of the smaller and deeper ore-bodies that were economically inaccessible for rail-haulage. Trucks working on steeper grades (the average is probably about 8%) have allowed waste dumps to be raised to greater heights. In many parts of the Range, dump space has become scarce and trucks permit smaller available areas to be filled. On most operations the trucks are used for haulage of ore during the shipping season and are transferred to stripping during the winter months, thereby providing year-round employment for the operating personnel.

Trucks admittedly are not as efficient for elevating material as they are for horizontal transportation due to the dead weight of the truck, approximately equal to the load it will carry. In order to make use of the flexibility of the truck, but to eliminate its inefficiency as an elevator from the deep pit, the use of conveyor belts to lift the ore from a central loading point in the pit has become widespread. These belts, usually 30 in. to 36 in. wide, take the ore to the surface from the screening plant in the pit where it is delivered by trucks from the shovels. On the surface, conveyor belts are used to transport the ore to the treating plant or the loading pocket for railway cars.

At our South Agnew Mine, which has an overburden depth averaging 160 ft. and a maximum depth of 550 ft. to bottom of ore, the quantity of overstripping or the amount of ore tied up in benches for conveyors appeared excessive. As an alternative, an inclined skipway was designed for installation on the natural pit slope. Two 25-ton capacity skips in balance are connected to a 1300 h.p. single-drum hoist, which is remote-controlled from the screening plant at the crest of the pit. Trucks dump directly into the skips in the pit, and the ore is hoisted at 1,000 f.p.m. to the surface where it is screened and transported by conveyor belt to the washing plant or loading pocket. As the pit is deepened the skipway tracks and the skip cables are lengthened, the loading point is lowered, and the trucks continue to haul the ore horizontally from the shovels. This equipment is used also for hoisting low-grade formation and rock when ore is not being produced.

It might be well to mention that the rear-dump truck is the predominant favorite for iron-ore mining and stripping. Both side-dump and bottom-dump trailer type haulage units have been used on the Range, but have not gained wide acceptance. The bottom-dump unit is more difficult to keep clean of frozen material in cold weather. Perhaps its greatest disadvantage is its inability to dump over the crest of a high embankment. Some difficulty is also caused by large boulders, chunks and slabs in the overburden and formation material. A trailer-type unit does not have the maneuverability of a rear-dump truck, and it requires a more complicated dumping layout when hauling ore. Steep grades cause a shifting of the centre of gravity away from the drive-wheels of the tractor, resulting in loss of traction, especially on slippery roads.

Distant view looking down into the South Agnew pit. On the opposite pit slope is visible the inclined skipway with the combination headframe and screening plant at the crest of the pit. A truck is backing into position to dump into the skip which is descending to be loaded; the other skip is ascending with its load to the screening plant. Three electric shovels are visible in the pit, two of them 6½-yard machines and one a 4½-yard machine. On the far bank are signs of the old underground workings. The upper sandy slope has been partially rip-rapped with coarse rock to prevent erosion. On the surface the crude ore conveyor runs to the left from the screening plant, past the mine buildings and the water tank to the washing plant and loading pocket.

For winter operation the engine exhausts are connected by ducts to the spaces between the box and the liner plates to prevent freezing of material to the truck box. Our South Agnew fleet was converted to exhaust heating four years ago, and the calcium chloride pumps and tanks, the scrapers, and all the other paraphernalia previously used were discarded. Since that time truck manufacturers have made arrangements to equip their trucks with exhaust heating connections at the factory, and it is now standard for all new trucks on the Mesabi Range.

Cold weather is not a complete disadvantage for our winter stripping operations, as it permits the haul-roads to freeze to rock-hardness and results in the equivalent of a paved highway for the heavy trucks. When working in soft and wet areas, a day or two of below-zero weather will provide a frost crust that will carry the trucks without difficulty.

An early snowfall before the advent of extreme cold weather will prevent the penetration of frost for a considerable time, and occasionally for the entire winter. With the larger shovels we usually operate without blasting until the surface frost becomes about 18 inches thick, after which the delay and the danger of shovel damage makes blasting advisable. Exposed areas, and any areas over which trucks and equipment operate, will require drilling and blasting. Frost will often penetrate six feet or more before the end of the winter season. For drilling of surface material we generally use a 6-in. bit on the same churn drills used in rock and ore with 9-in. bits. Spacing and loading of the holes are dependent upon the depth of frost and type of material. Rotary auger-type drills, both horizontal and vertical, in suitable material have also been used. Occasionally a steam jet may be found satisfactory for making blast holes in frozen surface

Tractor-Scrapers, Tournapulls, etc.

The use of self-loading haulage equipment such as tractor-drawn scrapers, Tournapulls, etc., has not become widespread on the Mesabi Range. There are several smaller pits which have been stripped with this equipment, and it is often used for specialized work, but for large-scale operations the haul distances are usually excessive. Boulders in the surface overburden cause difficulty, as does frozen ground in the winter, and the equipment is not suitable for ore production after completion of the stripping.

Hydraulic Methods

Hydraulic dredges have been and are at present in use for removal of surface overburden under suitable conditions. The Steep Rock Mine in Ontario is now stripping with a large dredge. An adequate supply of water is essential, the material to be moved must be suited to the method, and sufficient areas must be available for settlement of the pumpings. Iron ore itself is not generally suitable for transport through pipelines hydraulically, although at the present time our company is using this method for transporting reclaimed fine tailings to the treating plant.

Dragline-Conveyor Systems

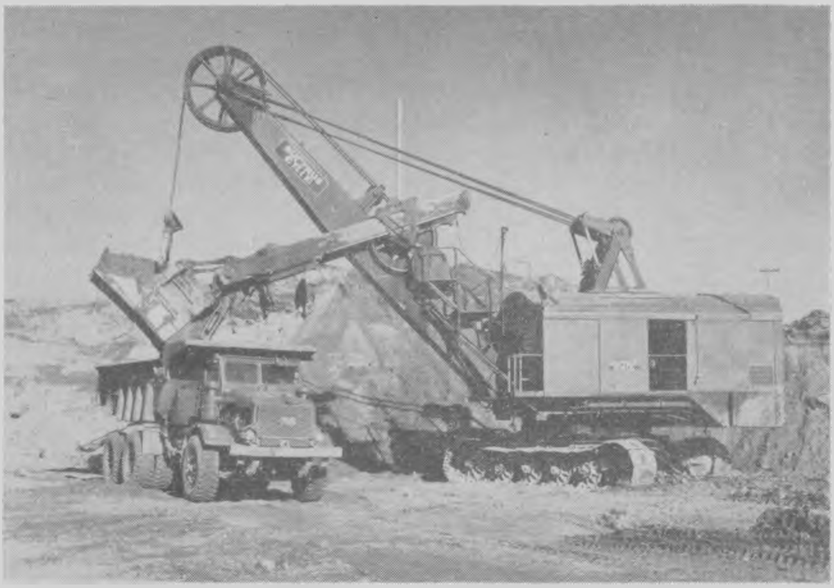
During the past several decades, and particularly during the war years, the demands for iron ore were so great that the easily-accessible ore was rapidly depleted and approaching exhaustion. Attention was then turned to the problem of developing the deep ore-bodies with high stripping ratios. Stripping ratio may be defined as the number of cubic yards of overburden to be removed to make available one ton of ore. The alternative was to remove the deeply-buried ore by underground methods. There is much to be said pro and con regarding underground versus high-stripping-ratio open-pit operations. One particular advantage of a developed open pit is its ability to respond to sudden increases in demand for production. Another is that the open pit exposes quantities of low-grade ore not presently marketable but becoming increasingly important as a future source of ore for specialized beneficiation. Extensive research and experimentation is in progress to develop methods of treating taconite, the low-grade iron-bearing material.

The greater cost of underground as compared with open-pit ore production resulted in limited activity in underground operations, particularly on the Mesabi Range, and many of the shafts sunk 25 to 40 years ago were abandoned as labor costs increased and economic conditions did not permit profitable operation. As a means of providing a cheaper method of removing overburden and thus permitting the mining by open-pit methods of a deposit heretofore classified as underground, dragline-conveyor stripping was introduced on the Mesabi Range in June, 1948, at the South Agnew Mine. Under the management of The M. A. Hanna Company, this project was completed in July, 1950. The equipment was then moved to the adjacent Morton Mine, likewise a Hanna property, where operations began the following month.

View of dragline and screening plant at the Morton mine. The model 1150-B dragline has a 180-ft. boom with a 30-cu. yd. bucket. The maximum digging depth is 110 ft. and the dumping height is 60 ft. Ground pressure of the base is 11 p.s.i. and of the walking shoes 21.9 p.s.i.

It may be of historical interest to note that the South Agnew was operated by another company as an underground mine from

1920 to 1931, during which period a total of 2,682,000 tons of ore were removed. In comparison, during the eight months of the present operating season, we will mine close to 2,000,000 tons of ore from the open pit, and, incidentally, beneficiate a substantial tonnage which had been abandoned in the underground operations as too low grade for removal. The Morton likewise was opened as an underground mine about 40 years ago, but extremely difficult operating conditions caused abandonment after removal of about 200,000 tons of ore.



Morton truck being loaded by a Bucyrus-Erie 170-B shovel with 7½-cu. yd. bucket. This is a Model 1FFD Euclid, 68,000 lb. capacity, having two 190-h.p. General Motors 2-cycle diesels for power. This equipment is operating in surface stripping.

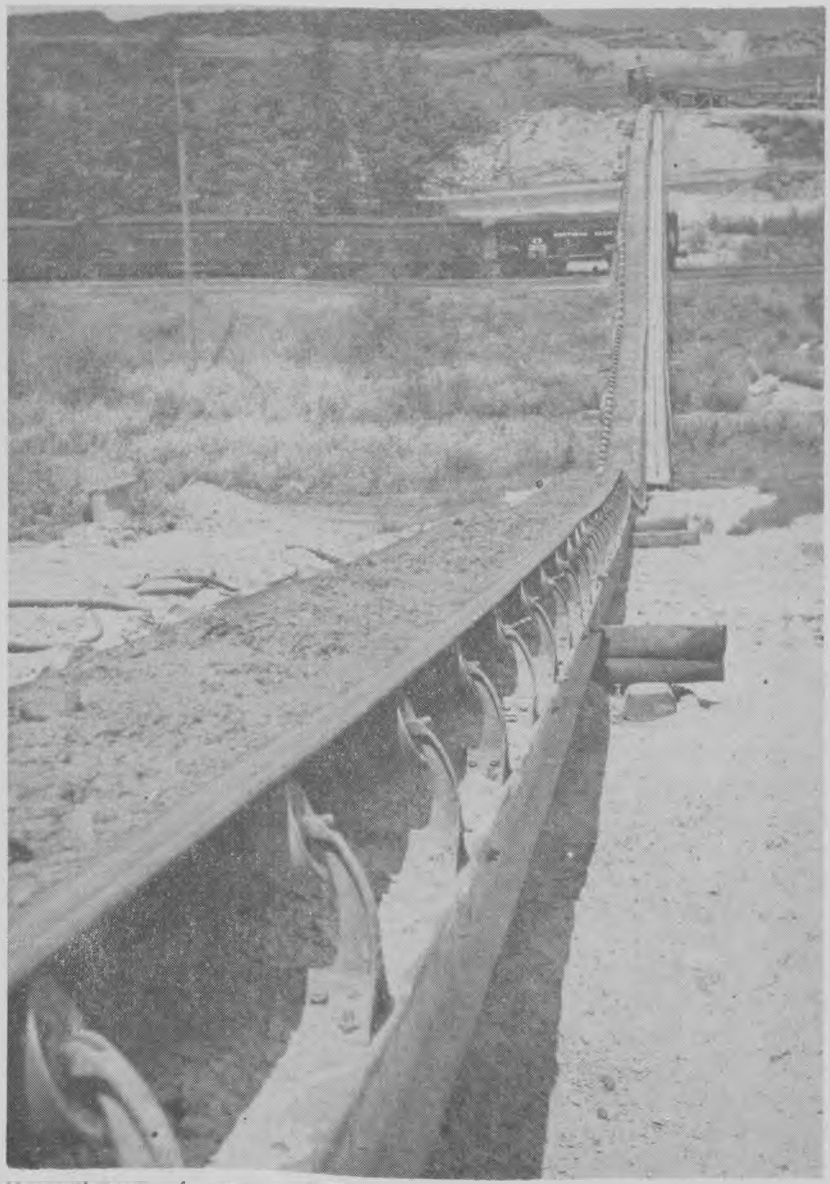
Briefly, our stripping installation comprises a Bucyrus-Erie 1150-B dragline which loads material through a travelling screening plant onto a 48-in. belt conveyor train. The conveyor transports the material to the disposal dump, where it is discharged over a travelling stacker to the face of an embankment 150 ft. high. The dragline swings a 30-cu. yd. bucket on a boom 180 ft. long, and at present is taking cuts 75 ft. deep and 215 ft. wide.

This paper will not give the detailed specifications of the various units, as considerable material has been published regarding this equipment while operating at the South Agnew Mine (1, 2).

This equipment was designed for use on stripping only, and, therefore, was planned to be simple to dismantle and to be adaptable to varying conditions at other properties. When moving from the South Agnew to the Morton, the conveyor sections were disconnected and moved in 20- and 40-ft. units. Transfer point structures were moved largely intact. The trailing conveyor truss and the stacker were disconnected and moved as two units, the first being 120 ft.

long and the latter 250 ft. long. The dragline and screening plant were moved under their own power over a specially constructed road. Six weeks after cessation of operations at the South Agnew, the equipment had been re-installed and was in operation at the Morton a mile away.

Total surface stripping at the Morton operation will be about 35,000,000 cu. yd. From an operating point of view, it would be



General view of conveyor belt showing the adaptability to the terrain. Conveyor is 1900 ft. from screening plant to stacker, with two transfer points, and is operated at 450 ft. per minute.

most satisfactory to remove the surface from the entire development before ore operations are commenced. On that basis, at the rate of 5,000,000 cu. yd. per year, seven years would elapse before the property would produce ore. However, in order to bring the property into production as soon as possible, stripping operations for the first three years will be concentrated in an area containing about 15,000,000 cu. yd. of surface. Ore will be produced from this portion of the property while stripping operations continue on the balance.

The overburden will average approximately 190 ft. in depth, with a maximum of 220 ft. A levelling cut of 20 to 40 feet was removed by shovel and trucks, thereby providing a solid level surface for the dragline-conveyor installation after disposal of the muskeg and swampy top soil. The 1150-B dragline is capable of excavating to a depth of 110 to 120 feet, but with the water conditions as they are, it has been found advisable to take cuts of about 75 ft. in depth in order to reach the material which "sluffs out" at the toe of the slope.

The surface formation in the South Agnew - Morton area is sand, clay and gravel. The impervious clay layers occur irregularly throughout the surface material, resulting in numerous perched water-pockets and ground-water flowage channels. Sumps will not appreciably draw down the water-table unless they are located at points which intersect the flow.

Direct operating labor requirements for the stripping system are low: an operator and an oiler on the dragline; an operator for each of the screening plant and the stacker; one attendant at each transfer point; a conveyor oiler; and a mechanic. A bulldozer is necessary for levelling in the pit and on the dump. The oversize from the screening plant has been very light at the Morton, and consequently a truck has been required only part-time. Additional labor is necessary from time to time to extend the trailing conveyor and to lay additional track as the stacker advances. Movement of the pit conveyor sections and belt into position for another cut is usually done by extra men while the screening plant continues to load through a temporary hopper onto the crossbelt at the end of the pit.

To date, approximately 11½ million cubic yards have been handled by this equipment. Peak month was about 800,000 cu. yd., with an average of 600,000 cu. yd. per month. During the best 24-hour period 38,000 cu. yd. were removed. Single eight-hour shifts have run as high as 14,500 cu. yd. The automatic swing recorder on the dragline shows delays, length of swing, etc., and permits an accurate count of buckets dumped. A pit location by the engineers determines the exact yardage removed each month.

Total bucket life is not yet known, as none have been used to destruction. One bucket has handled over 6,000,000 cu. yd. of abrasive material. It is worthy of mention that delays chargeable to the dragline have consisted mainly of changing ropes and buckets. To date, there have been no serious mechanical or structural failures. Wire rope life has averaged 800,000 cu. yd. per set of drag ropes and 1,100,000 cu. yd. per set of hoist ropes. Conveyor belt life has exceeded 11,000,000 cu. yd. on the main 48-in. belts except for short sections which usually have suffered mechanical damage. These belts are of 6-ply 48-oz. duck construction. The 60-in. belts on the screening plant are specially constructed with cushioned diagonal nylon cords and have averaged about a season of service, roughly 3½ to 4 million cubic yards.

Closeup of the screening plant. This plant was specially built on a 550-B shovel base equipped with hydraulic levelling mechanism. Over-all height is 48 ft., with hopper opening 28 by 30 ft. Material is taken from the hopper by a manganese pan feeder to a vibrating screen which removes the plus 9-inch material. Undersize falls on a 60-in. feed belt running under the screen and discharging onto the 60-in. boom belt. This boom belt adjusts vertically and horizontally and discharges the material to the main conveyor through a self-propelled rail-mounted hopper that straddles the conveyor belt.

Large draglines are used predominantly for casting in the coal fields, phosphate fields, etc. Naturally, casting is the cheapest method of removing overburden when such a procedure is possible, and greater yardages per month are possible than when loading into haulage equipment. In our operations the huge quantity of overburden must be removed from the mining area, eliminating the possibility of casting except for reloading and possibly at the margins of the pits.

Direct-loading of haulage equipment with a 30-yd. dragline has not proven practical as a regular procedure, although often a few trucks are loaded with gravel for roads, etc. The dragline has been used to load trucks through the screening plant for several months in the late fall, and the method proved to be fairly efficient.

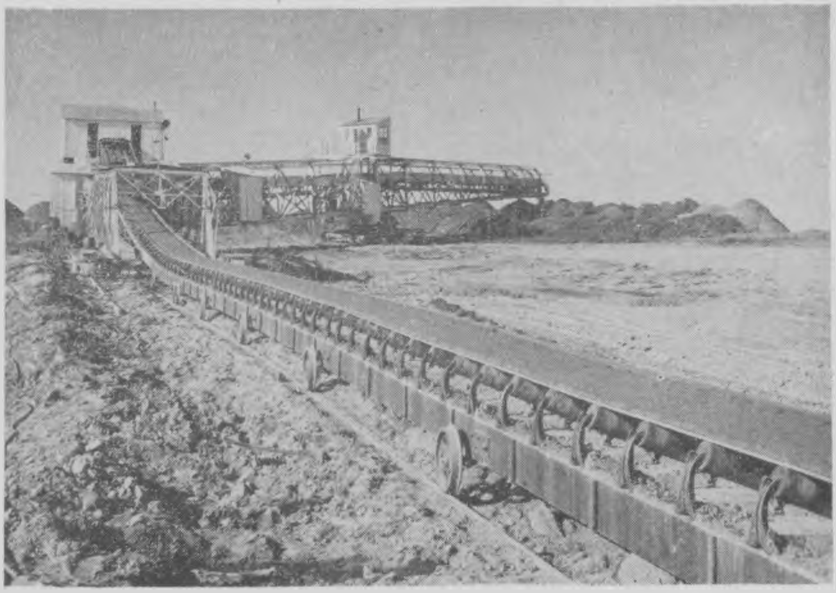
This would be practical through the winter if the material were fairly dry and the screening plant well heated.

Since one of our principal objectives in this paper is to appraise the applicability of dragline stripping methods, we may consider a few of the factors as follows:

(1) The nature of the material to be handled.
(2) Total quantity of material to be moved (area and depth).
(3) Distance to disposal point.
(4) Applicability of the same equipment for handling the ore.
(5) Weather and climatic conditions.
(6) Availability and cost of labor.

To comment briefly on these factors:

(1) Sand, gravel and clay can be handled efficiently by dragline and conveyor. Very wet material presents difficulties on the belt due to spillage and makes operation almost impossible at or below freezing temperature.



View of trailing truss and stacker. The stacker boom is 245 ft. long, with 75 ft. of cantilever beyond the support. Its centre of support is a ball and socket joint mounted on an electrically propelled 54-B shovel base. The stacker swings through an arc of 180°. Stacker equipment is controlled from the house directly above the support point. The trailing truss and conveyor are pulled forward by power units in the bolster at the pivot point as the dump advances. Stacker can advance on a grade of 10%, but length of trailing conveyor on 10% grade is limited to about 600 ft.

(2) Total quantity of material to be removed, as a function of the depth and area, will determine the feasibility of the required investment. Sufficient yardage must be handled to amortize the capital investment and the installation costs of the system. Depth of material should be sufficient to take advantage of the lifting ability

of the dragline and to reduce the frequency of moving the conveyor structure as much as possible.

(3) Distance to the disposal point is a major consideration. Casting and re-casting will often be cheaper than loading and transporting for a short distance. At the Morton and South Agnew Mines the distance to the disposal area has been one to two miles, and the conveyor system has proven very economical as a means of transportation.

(4) If the dragline can be used for removal of the ore after completion of the stripping, this extension of its use will permit its application at properties where the stripping alone would not justify the investment. In our mines the nature of the ore bodies requires sorting and classification during removal, and for that reason smaller equipment is necessary.

View of the overburden dump. Vertical height at this point is 150 ft. No difficulty has been experienced with slides except when depositing wet material on swampy ground covered with muskeg.

(5) No satisfactory method has been developed to date for the operation for a major conveyor belt installation in cold weather without totally enclosed and heated galleries. Such galleries are feasible for many belt installations. Sustained temperatures below freezing cause material to build up on the return idlers and pulleys. Operation under these conditions will quickly destroy a belt. Our system operates 6½ to 7 months out of the year, although the dragline is used intermittently during the winter months for casting and excavation of drainage sumps. The dragline is capable of working in cold weather. Rain and wet weather do not usually interfere with the operation of the dragline-conveyor system.

Heavy frost conditions are bothersome to a dragline operation. Because of the flat angle of approach of the bucket into surface frost, the force is exerted in compression rather than in shear, and buckets will not take the stress. In addition, it is very difficult to drill and blast frost ahead of the dragline. If the drilling equipment is to be in the clear of the swing, the drilling and blasting must be done so far in advance that frost will have re-formed before the area can be excavated.

In wet excavation, dragline loading has a great advantage in that loading and haulage equipment is located on top of the cut and out of the water.

(6) High labor rates induce investment in labor-saving machinery. The cubic yards per man-hour on our dragline-conveyor operation will average two to three times that of an efficient truck operation for the same lift and distance.

In general, it may be said that dragline-conveyor installations appear to be especially adapted to deposits of considerable depth, where access with conventional equipment causes problems in steep grades, over-stripping for approaches or benches, or the tie-up of ore in access benches. Draglines in themselves are efficient for use in wet or dry areas where the excavating, elevating and transporting ability of the machine is used to advantage.

Two other companies have now installed dragline-conveyor systems on the Mesabi Range, both using 10-cu. yd. machines and 36-in. belts. Another of our mines is using a 10-cu. yd. machine with 160-ft. boom for casting and direct-loading of trucks. The latter operation has been satisfactory, with production at about 6,000 cu. yd. per shift.

We believe that this type of equipment will continue to find application in the Minnesota ore district and in other places, and that the dragline-belt combination, within its limits, is probably the cheapest method of removing overburden yet devised.

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PROPOSED METHODS OF MINING ALBERTA OIL SANDS

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Mannix Ltd., Calgary

In view of its experience in coal stripping and loading and road building in wintertime, Mannix Ltd. was asked, in the fall of 1950, to inspect the oil sands and prepare several plans for handling the sands.

To be commercially competitive with crude oil, it is necessary to consider an average daily production of 15,000 to 20,000 barrels of oil, which involves handling a like number of cubic yards of oil-bearing sands, not once but twice, and disposal of such a quantity of sand soon becomes a problem of nightmare proportions unless a plan of disposal is adopted.

To eliminate sand storage problems, it is desirable that mining operations be carried on every day, which, of course, entails winter operation with all its attendant problems.

For open-pit operation, the frozen overburden and/or sand will have to be loosened by "shooting" or by "ripping". Experience has shown that as small a face as possible should be exposed to the elements and that the loading from this face should be continuous.

Special provisions must be made to heat the truck body or scraper; this can generally be done by using engine exhaust heat by means of tubing and suitable baffles so that the bed is kept warm. This will facilitate dumping and keep the amount of hauling equipment required to a minimum.

Care must be exercised in the use of equipment in loading and hauling in cold weather due to brittleness in steel caused by continued operation at low temperature.

Hydraulic controls tend to be sluggish, and air controls will freeze. Booster mechanisms will be required for steering gear on trucks.

Even fuel becomes a problem because the least amount of water will result in a frozen fuel line and a vehicle or tractor out of commission.

For the past several years we have operated throughout the winter stripping and loading coal. These operations have been carried out by the use of scraper, ripper and/or shovel to strip, depending on whether the overburden was earth or rock.

Road construction has been carried on in the Yukon the year round.

The new Labrador railroad project which was worked on all last winter is well known. The schedule for this job is so tight that all work will be carried on this winter. All types of equipment are being used here at temperatures as low as 70° below zero.

These jobs, plus many others, have provided a wealth of experience on winter construction problems and the solution to them.

With this experience as a guide, it is believed feasible to strip and load the oil sands throughout the entire year.

A study of several methods of handling the sands has been made. Basically, these methods may be divided into two general classifications:

(1) Open-pit mining,
(2) Block caving.

OPEN-PIT MINING

The following problems have been encountered during the course of our various developments. The experience gained thereby may be applied to the design of an open-pit method of mining oil sands. Each step in the process is described in detail in the subsequent sections:

1. Overburden removal—Haul and disposal of overburden,
   —Ratio of oil sands to overburden.
2. Methods of mining—Shortest haul distance of sands to plant.
3. Drilling and blasting.
4. Haul methods and roads.
5. Disposal of tailings.
6. Pumping.

1. Overburden Removal.

Overburden removal in previous operations at the oil sands has been by Sauerman slackline, bulldozers and/or scrapers. Areas stripped in the past have been small, and in all cases the overburden was light. In an operation to produce 15,000 cu. yd. daily, it becomes necessary to strip a large area, increasing the length of haul and forcing the overburden to be disposed of into large areas from which the sand has been previously mined. Estimating economical mineable sand for a four-year operation to be a depth of 150 ft., an are 1200 by 4200 ft. is required to be mined. Overburden material to be stripped is sand, gravel, clay, boulders and glacial drift. Deeper overburden has sandstone and shales. This overburden varies from a few feet to 1800 ft. in depth.

In this study and estimate, the overburden depth has been assumed to be on an average of 30 ft., the sands to be 150 ft. deep and excavation to be done in five lifts of 30 ft. each, in operation at the same time with natural slopes of 1.5:1.

The ideal form for an area to be mined to give the highest ratio of oil sands to overburden and shortest haul distance of sands to plant would be a square or a circle.

For mining 15,000 cu. yd. per day—365 days per year during four years—corresponding to an output of 18,000,000 cu. yd., an area of approximately 2200 by 2200 ft. would be necessary. In such a case the haul of overburden would be a minimum of 1200 ft., much too high to use scrapers economically. This would require the use of draglines or shovels, haul by trucks or tractor-drawn wagons, and result in a very high cost for the removal of such a great quantity of overburden.

If the maximum economical haul for scraper operation is considered to be 600 to 700 ft., the width of the mining area is limited to about 1200 ft. The use of this smaller width presents the disadvantage of a small mining area at the bottom of the pit 180 ft. deep with 1.5:1 slopes.

Overburden removed during the progress of the work (summer) would be hauled around the face and into the mined-out area. This could be done with Tournapull scrapers, cat.-loaded or boosted. Assuming an average depth of 30 ft. of overburden, this would amount to approximately 5,000,000 cu. yd. of excavation. With a haul of from 600 to 700 ft. and a period of 4½ months from June 1st to October 15th in which to remove the overburden from the necessary area to be mined, it is evident that a great number of scrapers would be required over and above the equipment required to haul sands. On the face of it, this does not appear to be a good or economical method. A shovel or dragline is, therefore, recommended to remove overburden. Hauling would be done by large trucks or tractor-drawn wagons.

Two months from the beginning of operations the overburden could be hauled to the mined-out area, as this would be the most economical way of handling it.

2. Methods of Open-Pit Mining.

As an open-pit operation, extreme snow conditions or heavy rains would cause considerable expense due to pumping. Shovels or excavators, drills, trucks, tractors, etc., would, of course, have to be operated continuously in all extremes of weather to maintain production.

In this particular case, the haul distance and the disposal of tailings are very important factors. Therefore, two methods of open-pit operation have been analyzed:

(a) Successive lifts of the entire area to be mined,
(b) Terrace methods over a minimum uncovered area.

In the first method, the shortest haul distance with a permanent haul road progressing with the excavations, and possible use of rail or lift methods of hauling, can be obtained. So far, this method presents two big disadvantages. Firstly, the whole area has to be uncovered in the first year, and secondly, the pit cannot be used for overburden and tailings disposals. These outweigh all advantages.

The second method adopted for cost analysis presents the advantage of the least area to be uncovered in order to start mining operations. This area is dictated by the length of the haul road, that is, the length required to keep grade to an operating minimum. At the same time, it solves the most important problem of the tailings and overburden disposals.

The principal disadvantage of this method is that the continuous displacement of the haul roads would require a permanent crew for grading and maintaining them. To date, it appears that the method of mining in terraces is the best method of open-pit operation. This is verified by the fact that large mines such as Mesabi and Utah Copper are terrace type.

This estimate is based on using three shovels of 5 to 6 yards dipper capacity which would excavate about 5,000 cu. yd. per 24 hours each, or 250 cu. yd. per hour each.

While 250 cu. yd. per hour may seem low for a 5-cu. yd. shovel, it must be remembered that one hour of each shift is used in lubrication and moving in the pit, and with the low temperature of the material (36°F.) the year round, more cannot be expected without some experimentation in operation.

It was found by those at Abasand who dug this material that the face, if left exposed for a long period of time, would soften for a foot or so in from the exposed surface in warm weather. However, this will be of no benefit to the planned operation as time of exposure of face is not sufficient to permit softening. Blasting should be light for shovels of this size.

3. Drilling and Blasting.

Known methods of drilling previously used here are expensive and inadequate for this material. Holes have been steam-jetted, drilled with churn and rotary drills, jack-hammered, and even augered. In each case, the abrasion by the silica sand caused rapid deterioration of the bits, and in the case of percussion drills, the sands plugged the blow holes and choked off the hole as the material was blown to the surface. Big holes that were steam-jetted showed a tendency to slough, as did rotary holes flushed with water. It would appear that horizontally drilled holes of large diameter (6 in.) made by using tungsten carbide bits would be the most practical method.

The sands being of a uniform temperature the year round, aside from freezing or thawing a few feet on the exposed face, the problems of excavation and drilling would be the same winter and summer. With continuous year-round operation, only two or three feet of face thickness would ever freeze. This, of course, would present no problem.

For blast holes, it is recommended that large diameter (6 in.) auger holes be made horizontally to depths of 50 ft. and loaded with explosives as soon as they are bored. Holes are calculated on 16-ft. centres for a 30-ft. bench or lift. To produce 15,000 cu. yd. of sand per day (3 shifts), it is necessary to take a cut or cuts aggregating 30-ft. depth by 50-ft. width. On 16-ft. centres this requires the drilling of thirty 50-ft. bore holes per day. This could be made with two Macarthy type horizontal augers drilling 6-in. holes and using tungsten carbide heads. Each drill would have self-propelled gasoline engine drive and be operated by a crew of two men.

Analysis shows that the cost of drilling and blasting amounts to 26.5% of the total cost, even though the powder required would be less than one pound per cubic yard. It indicates that by finding a more economical way of drilling, the cost of mining the oil sands would be nearly low enough to make this operation economically possible.

These estimates are somewhat uncertain because of the lack of experience in handling this unusual material.

4. Haul Methods.

The quantity of sands required per day is 15,000 cu. yd. Several methods would be available, namely, conveyor, truck, airline or cable. Conveyors, while the best from the standpoint of personnel required, uniformity of flow, and economy of power, could not be expected to handle the lumps encountered in winter blasting operations. Also, the hopper to load the conveyor would have to be propelled over the belt, and a minimum of three belts would be required for the three loading units contemplated. Heated coverings would also be required.

Trains could be used having bottom-dump wagons on standard 3-ft. gauge tracks. Track could be laid and moved sideways into the face easily enough and would provide a big loading target for the shovels, and by using diesel locomotives this method would give big production at low cost. Trains could maintain constant schedules between points and would be able to dump as fast as bottom-dump trucks. Four locomotives would easily maintain this haul and would be easier to house, repair, and maintain than the trucks necessary to haul this same quantity. However, in order to keep grade down, such long tracks would be necessary that this method must be eliminated. Also, a large crew would be required to keep moving track to keep it near the shovel.

Trucks to maintain this haul should be 20-ton, bottom-dump, air-controlled diesel of the Euclid type, or tractor-drawn wagons. With an average haul of 1.2 miles, the trucks could make a round trip in 36 minutes. With three minutes loading time, at 250 cu. yd. per hour, it would require 12 trucks to keep one shovel in continuous operation. For three shovels, 36 trucks would be required, plus four spares, a total of 40.

It is estimated that the cost of hauling represents 35% of the total cost.

In connection with the hauling, the haul roads must be considered. The type of roads for a pit of this size would always, of course, depend on the transportation methods used for the sand In the case of the oil sand, a usable surface road is made by merely blading the oil sand to a crown. Fifteen- to 25-ton trucks on grades of around 4% would not tear up the roads nor require constant patrol work. Roads prepared in the fall would be highway smooth all winter. Several types and sizes of trucks are available in heavy haul units. A truck of 50-ton capacity, diesel-powered, with air-controlled belly-dump trailer, would haul at the cheapest costs. A run-over dump, as is used for coal, could be located at the unloading point. In this case, the trucks dump "on the fly" and close the bottom doors on the return trip. Units of 50 tons would require flatter grades out of the pit, but would reduce the personnel and haul units required. Roads to support 50 tons probably would require a good rock sub-base. This is of questionable value as the haul road would have to be relocated several times as excavation of the face progressed.

A permanent motor patrol and crew would probably be sufficient for maintenance of the haul roads.

5. Tailings Disposal.

Previous operations were never bothered with an excessive amount of tailings because the operations involved only a small tonnage before they were abandoned or, at most, amounted to only 400 tons per day for a few days of operation. The present plan would involve 15,000 to 16,000 cu. yd. per day, and to mine an area without waste would necessitate dumping of the tailings in mined-out areas. In conventional mining operations, tailings normally are washed by gravity in wood pipes to a point below the plant or mill, but in this case would be disposed of above the plant levels. As the tailings are to be put back into a mined-out area, they would have to be dry or at least not be transported by water. A conveyor belt must be used to move a minimum of 650 cu. yd. per hour along the edge of the mined-out area, with a tripper to dump the belt at any desired spot.

A minimum of five million yards would be handled annually, and all conveying equipment would have to be housed. If the terrain afforded a good permanent dump ground close to the refinery, water pipes (wood) could be installed and the tailings dumped from trestles as in the manner of dredge fills. In such case, pumping of the tailings would be involved. This disposal system might suffice for one or two years' operations. However, it would soon dam the river and so it must be considered as an expedient only.

6. Pumping.

All previous operations have been excavated on a drainable pit bottom or, as in the case of Abasand, the pit was never large enough to involve pumping of any consequence.

In the case of a large pit, even though it was first opened with the floor or foot wall on a drain or open side, it would eventually be a box pit, that is, closed on all four sides. The depth would be 100 to 250 ft., and there would be a large quantity of surface water and rain water to contend with, as well as a large amount of melted snow. This means that a positive method of water disposal must be incorporated.

The floor being flat, it should be ditched in such a manner as to drain the water to a sump where an electric pump would lift the water to the surface or original ground. This would require two 4-in. electric pumps of 150-lb. pressure with a capacity of 50,000 gal. per hour each. They would be controlled by a float switch and would probably have to run an average of six months per year. Power would be supplied from the powerhouse at the refinery.

In addition, this method requires a large investment in equipment, shops, etc., as well as the building of a town for the many operators required.

To supply such an operation would require work on railroad, new road to plant, and other unforeseeable expenditures.

This operation is feasible, but in view of its attendant troubles, we believe there must be a better and cheaper method, namely block caving.

Summary of Open-Pit Mining:

1. The terrace type of pit is favored because it keeps the face exposure to a minimum. A disposal place is provided for plant tailings.
2. Drill holes should be of large diameter.
3. Electric shovels of five- or six-cubic yard capacity should be used to load sand, especially at first. While it is true that the larger walking-type shovel or dragline may move material cheaper, that type of equipment is usually tailored for a specific job, and delivery would be slow. Moving such a shovel to this site and erecting it would be a major operation. In order to get started this work would probably be contracted, and a large shovel is one piece of equipment no contractor owns or wants unless he is given a long-term contract involving the moving of several million yards at one place.
4. Hauling should be done by Euclid type trucks, probably of 20-cu. yd. capacity. However, it is possible that Caterpillar DW20 units may work here.

The estimated total cost of excavation is 55 cents per cu. yd. of oil-bearing sand.

In the opinion of the writer, the extremes of weather, abrasiveness of the sand, transportation of overburden from the oil sands, pumping and snow removal, and the many costs entailed by drilling and blasting, all these difficulties and problems of open-pit mining make underground mining the lesser evil.

UNDERGROUND MINING OR BLOCK CAVING

The alternate method proposed is as follows. A main tunnel, 1000 ft. long, would be driven into the limestone 10 ft. below the sands. The tunnel would be about 10 by 10 ft. From this tunnel, drifts or lateral tunnels would then be driven at right angles to it. These side tunnels would be spaced on 100-ft. intervals on each side of the main tunnel, and driven in a distance of 250 ft. In the roof of all tunnels on 100-ft. centres, there would be drilled a 36-in. hole up into the sands. A steam-jacketed liner would be installed in this hole extending down low enough to be close to a conveyor system in each tunnel and drift. The steam jacket would exhaust at its top. Steam would escape into the sands thereby causing spilling, and the sands would drop to the belt. As the void became large enough, the space between the voids would crush and bring the entire mass down gradually. This procedure would be worked over a large area at once, and would be carefully controlled. The overburden would not be moved, and the tailings would be piled on this area as the sands are removed. The operation would thus be free of drilling, blasting, excavation, roads, abrasive wear to excavators, and weather problems. Personnel problems and expenses would be considerably smaller. A disposal area for tailings would be provided. Areas with heavy overburden could be used as well as areas with light overburden.

The mass would come down onto a conveyor belt which would move it to the main conveyor belt located in the tunnel. From there it would move to the plant.

The heat loss in this system would be small as so-called waste heat would be utilized in subsequent removal of sands. The heated sand itself would be moved via conveyors to the main separation plant before all heat could be lost to outside air, thereby reducing the heat required at the plant.

This method would require about 55,000 B.t.u. per cu. yd. of sand to raise the temperature to 100°F. so that sand would flow onto the conveyor.

It is planned to use cycle timers and flow control valves to regulate automatically the flow of steam to each riser in such a manner that two or three risers would be working at all times. At the same time, steam would be started to a new face to raise its temperature so that it would start moving sand onto the conveyor belt at the instant one of the other faces was cut off when it was no longer economical to mine.

Tailings from the plant could be moved by conveyor to the surface above the worked-out area which would collapse and fill in the old area. Inasmuch as tailings disposal is a problem of major magnitude, this procedure would present a cheap and workable solution.

The estimated total cost per cubic yard by this block-caving method is 38.2 cents, or about two-thirds of the cost by the conventional open-pit method. Certainly this plan merits close study if the oil sands are to be used in the near future.

DISCUSSION

P. B. Hall: How is that volume of steam going to be disposed of? Do you expect full condensation?

R. H. Latham: Yes, sir.

Question: Were the core holes in the Mildred-Ruth area carefully evaluated before this scheme was arrived at? Were you not afraid of the effects of layers of clay, silt, and cemented layers?

R. H. Latham: There will be some. However, if the oil sand is withdrawn from underneath, the weight of the sand and overburden will break any thin layer of clay or conglomerate.

S. J. Kidder: In all block-caving operations with different types of material, there is a tendency for different draw points to cave together, and occasionally a chimney goes right through to the overburden. If there is a chimney effect in 135 feet of sands, isn't there going to be a great deal of material lost around there?

R. H. Latham: If that happens, some will be lost. It should be emphasized that this is strictly a theoretical solution. If it is considered practical, unquestionably there will have to be some experimentation done. Basically, the Mannix proposal would be to go in and do open-pit mining for a year, during which time experimentation with the modified block caving would be done. At the end of one year the modified block caving would probably have been shown to be workable and the open-pit work would be eliminated.

Question: Regarding the character of these cost figures that you mentioned, are there capital items, capital return items, or are they contract prices that you would contract on?

R. H. Latham: They are the prices on which we would have contracted at the time these estimates were worked out. The estimates included the conventional contractor's profit, his overhead, his move in and out, camp operation, and buying all the major items of equipment and writing them off at the A.G.C. rental rate, which is about 8% per month rental for 24-hour operation. We would probably lose our shirt in the wintertime if it turned cold, but probably it would be possible to make enough in the summertime to break even.

The prices of equipment were verified in the last two or three weeks, and they may sound high to people from the United States. A dragline of 12-yd. capacity priced at $520,000.00 in the States would cost $750,000.00 on the job in Canada. The difference represents duty, exchange, 10% sales tax, and additional freight, and amounts to about 50% extra on the price of the equipment.

Question: Concerning the position of the power plant; is the site to be far distant, and how is the steam to be carried to the quarry?

R. H. Latham: The steam contemplated for use will be low pressure or even waste steam from the refinery and separation plant. It will have to be run quite some distance, and the line will have to be well insulated. That is a common practice in oil refineries. High pressure steam is piped as much as two miles in oil refineries operating in temperatures of -20°F. day after day. There will have to be steam traps and probably extra heavy insulation.

Question: What happens to your scheme of mining where the overburden is much greater than 30 feet?

R. H. Latham: This method is believed to be the ideal solution for that 1800-foot overburden case. It is not important how thick the overburden is, because it doesn't have to be moved. It is believed that this method is more economical than open-pit mining, and certainly it can be used where the cost of moving the excess overburden would be prohibitive.

Question: How is it proposed to handle the boulders mentioned in the paper on drilling? Might not some of these boulders tumble down through the caving?

R. H. Latham: The boulders would be in the overburden, and no attempt would be made to recover even the leaner oil-sand beds underlying the overburden. When overburden started showing in the draw holes they would be plugged off and abandoned.

Question: How is it proposed to introduce this steam into the bituminous sand? Is it planned to have a vertical pipe?

R. H. Latham: A vertical pipe exhausting to the side would be used. It would be moved into the sands a little bit at a time. It would not go up to the very top of the cone.

Question: Has it been assumed that there would be electric power available at the site of these mining operations?

R. H. Latham: There would be electric power available at the plant site for use in the separation plant, hydrogenation plant, and the oil pipeline. The 5- or 6-cubic yard shovel was chosen because it can be self-contained with its own electric power plant. As such, it reduces the number of electric problems that will be encountered.

Question: When strip mining was being described, it was mentioned that the tailings would be disposed of as dry tailings. Would they be allowed to drain in a drain pile and then be picked up from that?

R. H. Latham: The tailings would be as dry as possible—about 70% solids content. They would be moved directly from the separation plant by conveyor belt to the disposal area.

S. J. Kidder: The point selected for initial mining is characterized by an area where the limestone is above the river level. After the overburden is removed, there is perfect drainage to the river.

R. H. Latham: During the first few months' or year's operation the sand would be dumped on the shelf between the escarpment and the river, below the plant. There is a disposal area there for several million yards without contaminating the stream.

DISCUSSION OF BLASTING

By H. A. Logan
Canadian Industries Limited, Edmonton

The purpose of this paper is to present a brief discussion of the methods and materials to be used for the blasting of the oil sands for the mining operations. The first operation in getting the oil sands from the quarry to the processing plant is the breaking up of the formation into a material which can be handled by conveying equipment. Although, at a later date, powerful equipment which has been used for ripping solid rock may be found applicable to the mining of oil sands, it is generally accepted at this time that drilling and blasting must be used.

The cost of drilling and blasting is directly related to the degree of fragmentation that is required. This, in turn, depends on the size of conveying equipment involved, which is, of course, dictated by the size of operations for the proposed oil-sand development. It has been suggested that a shovel as large as 36 or 40 cubic yards might be used for an operation with a throughput of say 50,000 cubic yards per day. Under those conditions the cost of drilling and the cost of powder would be quite low, as wide spacing of the holes and low powder factor would be quite satisfactory for breaking up the material into sizes that could be handled by shovels of that size. But if the loading equipment were smaller, the drilling factor and the powder factor per cubic yard would both have to be greater.

Past experience in drilling and blasting the oil sands is somewhat limited. However, a few years ago, Consolidated Mining and Smelting did some experimental blasting of these deposits. One of the greatest problems encountered was to get the holes into the oil sand. It appeared at that time that the use of a steam jet was the best method. However, R. H. Latham of Mannix Limited, has suggested that holes can be drilled in this material by using tungsten carbide bits. The Consolidated Mining and Smelting method, developed after about 13 test blasts, consisted of a pattern of vertical holes twenty feet deep on a 12 by 12 ft. square grid spacing. A powder factor of about half a pound per cubic yard of sand was used. The powder was a waterproof powder of the Forcite series. Latham planned to use horizontal holes on a thirty-foot face, probably with a fifty-foot spacing.

It is not desirable to employ the more expensive high velocity waterproof powders. The ideal powder for a weak material like the oil sands is an ammonia base powder, which is cheaper, lower in velocity, and of greater strength. Horizontal holes would be used, and would be drilled on a slight angle to permit water to drain out of them. This would be necessary so that the ammonia base powder, which must be kept dry, could be used. As noted above, the powder factor depends on the size of fragmentation required. If three- or four-cubic yard shovels are being used, and horizontal holes are being drilled along a thirty-foot face in a single row, the powder factor might have to be rather high. The 12 by 12 ft. spacing used by Consolidated Mining and Smelting required a factor of about half a pound per yard. Even with out cheapest powder, that would cost about 10 cents per cubic yard. With a single row of holes along a thirty-foot face the powder factor might have to approach a pound per cubic yard, which would increase the cost to 20 cents. A cost of 20 cents per cubic yard is rather expensive.

New developments in the field of blasting may be applicable to the oil-sands blasting. New slower and stronger powders have recently been developed, and the technique of split-second detonation has proved very valuable. With split-second blasting a far greater use of the energy in the explosives is obtained; the increase may be as much as 30% greater than was possible with instantaneous blasts, even on single row shooting. The split-second technique naturally works better in multiple rows, and even better in a box-cut type of shot. In the latter method the whole area is shot at once, with no free face, and with the delay periods in rows, ranging from zero to possibly eight and repeated as many times as necessary, according to the number of rows involved. Apparently, in this type of blasting there is a slight relief of burden towards the rows of zeros, but nevertheless the mass is held under tension by the previous shot when the next shot hits it. This appears to give a much higher efficiency for the use of the explosive.

The diameter and spacing of the holes for shooting must be given some consideration. With large diameter holes, charges would either have to be spaced or decked. The proper use of spacers between charges requires close supervision and trained operators, and also adds another accessory to the list of materials required for blasting. If charges are decked, two or three large charges are used and are separated by several feet of stemming. This calls for the use of "Primacord" . . . another expense.

DISCUSSION

Question: Do you consider the figure of 12 cents per yard for drilling and blasting as used in the Blair Report to be representative of that type of operation?

H. A. Logan: That depends on the size of equipment used. If we could get to a powder factor of one-quarter pound per yard, it is a very reasonable figure.

Question: Do your figures refer to the production of a mined material of a size suitable for direct processing in the separation plant?

H. A. Logan: No, it depends entirely upon what fragmentation is required for conveying. The Blair Report mentions shovels up to 35 or 40 yards. Under those conditions I think his figures are rather conservative. But there again, it would require secondary equipment, such as large crushers, to get the material down to smaller sizes at the plant.

Question: Should we interpret from your preliminary remarks that it has not yet been determined whether or not blasting is actually necessary?

H. A. Logan: I don't think anybody has tried to use a ripper on the oil sands yet. It is reported that if the temperature of the deposit is above 45°F., it can be dug by shovel. The temperature in situ is 36°F., so it seems reasonable to believe that it is not so much stronger that a very powerful ripper could not operate.

W. L. Falconer: Reference has been made by Mr. Logan to a report by Mr. Henry Giegrich of the Consolidated Mining and Smelting Company covering some fourteen shots detonated in the pit of Abasand Oils Limited during the spring of 1942. This report covers the blasting experience over a period of some eighteen months. Blasting in the oil sands was first used to provide material for an eagle shale planer, and during the final stages of this experiment to provide shovel material for a 1¼-cubic yard Lorrian power shovel.

Prior to the blasting experience, methods other than open-pit mining were attempted. These included the use of an eagle shale planer, rippers, scrapers, dragline and hydraulic methods. Early in 1942, out of desperation, a power shovel was moved into the pit to provide separation plant feed when all other mining methods had apparently failed due to high costs and discontinuous performance. The power shovel indicated that, within limits, it could maintain continuous feed to the separation plant. The limits were the strength of the shovel as compared to the strength of the material. Blasting was resorted to in order to cut down line breakage and to provide material of such small dimensions as could be easily fed to the plant.

In the deposit of the Abasand plant at Horse Creek, once the sand had been shaken by blasting the shovel was able to dig it very readily. It was, therefore, apparent that it was necessary only to shake the sand in order to provide a good plant feed, and that a complete disintegration of the material in place was not necessary. From this observation it may be concluded that in the richer parts of the deposit it may not be necessary to blast all the quarry material. It must be remembered that the only binder in the sand is the oil itself. There is no other cementing material, and once the oil film surrounding the individual sand grains has been ruptured the resulting production is an incompetent mass. In those areas where the oil content is only 10 or 12% or less, the material would have to be blasted. It is questionable whether it would be necessary on materials richer than this.

The experiments were very limited in that we were faced with the problem of making muck for small units such as a 1¼-cubic yard shovel. The shots were placed very close to the plant and, since it was resting on a cut bank of oil sands about 15 to 18 feet above the pit floor, care had to be exercised so that the plant would not start moving down into the pit. Consequently, the blasting experiments were not conclusive regarding fragmentation.

Observation can be made regarding the time intervals between shooting the sand and digging it. Early in 1941, a surplus lot of powder had to be destroyed. About 700 pounds were placed in a deep hole in the Abasand quarry and detonated. In the normal course of subsequent shovel operations, this point was reached about 18 months later. The material disturbed by this explosion was found to be perfect shovel material. The sands had not reconsolidated as has so often been suggested in the literature.

We found what we considered to be a fundamental in handling the sands up until the oil had been separated and was ready for the refinery; that one had to handle it slowly and without violence. Therefore, the slower burning powders should make the best plant feed. This was found to be the case, and is reflected in the Giegrich report.

H. A. Logan: On borderline cases, wouldn't it be possible to use a ripper for the oil sand—a method of mining that would be safer than blasting and drilling?

W. L. Falconer: Yes, except for one thing. A ripper has the same integral parts as a shale planer. At Abasand, the shale planer was used against the face before and after blasting. The blasting sometimes helped the shale planer considerably but the limiting factor was tooth wear. The shale planer carried 140 teeth, and the life of a tooth against the face was about twenty minutes. You can imagine the number of welders required to rebuild the teeth under those conditions. In view of this, it is probable that tooth wear and abrasion on a ripper would be excessive.

INTRODUCTION OF MR. S. C. ELLS TO THE CONFERENCE DELEGATES

S. M. Blair: Allow me to interrupt the program in order to insert an unplanned item. I am happy to tell you that we have with us this afternoon one of the outstanding, colorful figures in the oil-sand story to date. Mr. S. C. Ells began his work on the oil sands for the Mines Branch, Department of Mines and Resources, Ottawa, in 1913. At that time, and on until about 1920, the only way to get into and out of the Athabasca country was to traverse the Athabasca River by canoe between Athabasca Landing and McMurray. Eighty-five miles of this stretch of river are interspersed with rapids. From 1913 until his retirement, except for the war years when he was overseas, Mr. Ells was in the North each year. He mapped the whole oil-sand area, demonstrated the usefulness of the oil sands as a paving material, pioneered the exploration and sampling of the deposit by drilling, and pushed the study of the oil sands along other lines. It was Mr. Ells' faith in the oil sands and his indefatigable efforts over a lifetime that laid much of the foundation on which the present consciousness of the significance of the Athabasca oil sands has it base. We are happy that Mr. Ells has been able to come to Edmonton to look in on our conference. Now that he is in our midst, I am sure you will want to hear a few words from him.

S. C. Ells: Thank you, Mr. Blair and gentlemen, for your kind reception. It is much appreciated. I only wish that the many men who have worked with me so loyally and, indeed, fanatically, throughout the years on many undertakings in the north country, often under very trying conditions, were here with me to share in the reception.

I have no intention of using up time that is needed for your full program. But I would like to repeat something that I heard at a convention of the Canadian Institute of Mining and Metallurgy which I attended in uniform during the First World War. The principal speaker, an outstanding mining engineer, took as his text the Irish proverb, "Come back to me says a half-done job." He then went on to say that whether one is a lawyer or a doctor or a mining engineer or anything else, if one leaves a job undone to come back to it in a month, a year or five years, one finds that it then takes a great deal of time and expense to pick up the loose ends again and that it is very hard to get the job finished satisfactorily. So my thought now is that with such capable men as have assembled here at this convention having put their hands and minds to the problem of oil-sand development, the job should not be left until all the processes involved are worked out in detail so that when the time for development comes, whether in an emergency or otherwise, there will be no years of delay in picking up loose ends and in getting things rolling again.

Thank you, Mr. Chairman.

BLOCK CAVING

By F. S. McNicholas
Climax Molybdenum Company, Denver

BLOCK-CAVING METHODS

A description of all the variations of block-caving methods will not be attempted. Only the two principal ones will be discussed. The first is the block method which is common in the Southwest; and the other is the panel method used in N. Changa, Northern Rhodesia and by Climax. Fully protected block caving consists of developing, undercutting and drawing to exhaustion a block of ore of predetermined size, without co-ordination of the mining or withdrawal with adjoining areas. The block is mined and drawn as an independent unit. In fully protected block caving, two sides of the block are against solid. On the other two sides there is caved cap material that has been allowed to consolidate for a considerable period of time—at least a year. Mining of the block begins essentially from this broken cap material, and proceeds into the solid area. Boundary weakening is driven along the block boundary to allow the block to cave and to define the extent of the caving area, which is usually about 200 feet square. This weakening is not an entire cut-off. It is only enough to furnish a line of weakness that will allow the block to cave at the appropriate time. Premature caving would prevent completion of the undercut. The draw in this method proceeds from the solid to the loose material allowing fingers next the loose to lag in order to get uniform withdrawal, and proceeds until 25 to 30% of the block is drawn, at which time the whole block has caved and draw may then proceed in equal amounts from all fingers.

The second main method is the Climax method—full panel caving. Full panel caving consists of developing and undercutting adjacent blocks of ore in a regular retreating manner. The draw follows the mining sequence and is regulated to give a retreating draw plane which maintains a toe of broken ore against the block being mined. No block boundary cut-off or weakening is used. Cut-offs are needed only on the periphery of the ore body and to initiate caving. Almost any sequence of mining the adjoining blocks may be followed provided that a plan of retreat is used that will avoid having a block with more than two sides against caved material. This method of mining is applicable to strong ores in which cantilever action is used to fragment and cave the ore. The ore is weakest in tension, and by undercutting in the proper manner cantilever action is produced to sheer, crush and fragment the ore to a suitable size.

There are two variations of each of these methods. The variation is in the main haulage. The first is the slusher, conveyor or shaker method in which the ore is scraped, conveyed or shaken along a drift into cars. In the second, the chute and grizzly method, the ore is delivered by sets of finger raises to grizzlies through which it goes to loading chutes and thence to cars.

The Climax caving and drawing practice is as follows. It is the full panel method. Loading drifts on the level are driven on 200-foot centres. Slusher drifts are driven at the elevation of the cap of the haulage drift sets. These are driven on 68-foot centres and have double fingers on 33⅓-foot centres, which gives a draw-point spacing of 33⅓ to 34 feet. Since 68 feet is a multiple of car length, a train of cars can be loaded from one, two or perhaps three slusher drifts simultaneously.

OIL-SAND BLOCK CAVING

An attempt will now be made to apply block-caving knowledge to determine the applicability of this method to the bituminous sand deposit. It is not possible to make categorical statements regarding bituminous sand with the limited study given the problem. However, certain similarities to conditions known in detail may exist. Caving methods have been successfully applied to a wide variety of strengths of rock. Climax, at one extreme, is an example of where the rock caves large, while at the other extreme are Consolidated Copper Co., Inspiration, and Sunrise, where the rock caves small with the production of considerable fines. Bituminous sand falls tentatively into the latter class. However, there is a marked difference. The sands in place seem to be rather strong, but on moving them with a bulldozer it is evident that there is little strength to the material. There is a bedding pattern related to the clay seams, and the fracture pattern indicates that the material caves easily. But successful caving depends also on the capping characteristics. It is important to note that the sand developes a flow pattern, the characteristics of which are related to temperature.

Another consideration is the method and manner of draw. This depends upon draw-point spacing and regulation of the draw. In general, for dry material with some chunks in it, draw-point spacing depends on the size to which the material breaks. For large chunks, large spacing; for small chunks, small spacing. The spacing depends upon the arching effect of the rock and, to keep an area active, the arch must be destroyed as is done at Climax by the use of high pressure water and by bombing. With finer material, the arching effect is less pronounced and, as a result, the maximum possible spacing is reduced. The draw occurs first by the development of a flat angle in the finger. The angle expands to a certain limit, and then the material caves in a vertical direction and draws in a vertical direction. The broken material falls in two manners. It dribbles and it slumps. The method of draw is such that while it is dribbling, the draw hole is open. After dribbling for a while, the material slumps and fills up the hole until the draw controls cut off the flow, at which time the cycle renews. The maximum spacing of the draw points is that which will just permit the vertical slumping actions to merge with one another. Otherwise, the draws will pull through to the overburden at the surface independently of each other and leave a great bulk of the block untouched.

While the action of the material being mined determines the maximum draw-point spacing, the economics of the situation determine the final spacing to be practiced. Recovery considerations may indicate that a closer spacing is desirable. It is customary to run tests on scale models to duplicate mining conditions, and they show quite well what is to be expected from any particular block-caving practice. In particular, they show how low recoveries and dilution with capping are encouraged, and what can be done about them. The amount of dilution depends to a great degree upon the height of the back of the ore body. When the capping material is thin, it is often advisable to strip it off because dilution of the ore with the overburden is unavoidable to some extent.

The use of steam for breaking the arch of the oil-sand material would not change the draw conditions appreciably from those of conventional methods of moving the caved material. It is very likely that a steam blow-pipe would disturb the oil-sand arch and allow the draw to proceed. However, it would be necessary to provide room for a man to work to clear the draw holes. So the result of the use of steam is, as yet, unpredictable.

The only possible advantage of caving oil sands under low capping, in our opinion, is to avoid winter working conditions. But these conditions are avoided only to a partial extent. Part of the mine would be drawn to exhaustion and abandoned and open to the air. This condition has been encountered in the Climax operations, and it has been necessary to close down portions of the mine in the winter because of the extreme cold. Consequently, underground mining may not solve the winter conditions completely.

Costs

The cost of mining the oil sands may be inferred from the costs of other underground operations. Most other block-caving workings have backs of 200 to 400 ft. compared with 100 to 200 ft. for oil sands, so that it is reasonable to believe that the oil sand costs would be higher. Costs are given as slightly under $1.00 per ton for the Western United States. It is my belief that such costs probably exceed $1.00 per ton. It is important to notice that this cost does not include a good deal of preliminary development such as ventilation. The relative costs of underground and open-pit mining dictate which method should be used for a given property. A major cost in open-pit mining is the item for the removal of overburden or capping. In the open-pit operations at Consolidated Copper, Ruth, Utah and Inspiration, the ratios of stripping to ore are 3.3:1, 4:1, 1.5:1 and 3:1 respectively. In general, the operators of these mines believe that a ratio of even 5:1 would indicate the use of open-pit methods in preference to underground practices. It might be noted that open-pit coal mining is sometimes done with a ratio as high as 10:1. In view of these operations, the 0.25:1 ratio for the oil sands would seem to indicate open-pit mining.

Hazards of Underground Mining of Oil Sands

Underground mining of oil sands presents hazards not present in most metal mines. Some bombing of draw-points would probably be required. Such bombing might produce startling results under certain gas conditions. Alternately, steam jets or high pressure water could be used, but the use of water on the oil sands which are already saturated would produce slimy material that would be difficult to handle. The gas and oil present in the deposits indicate poor working conditions. Somewhat similar conditions are encountered at the gilsonite property at Barber, Utah, and many explosions and mine fires are experienced. Although explosive companies are trying to develop suitable explosives for these conditions, they have not been successful as yet. The oil shale mine at Rifle, Colorado, has had no explosion and fire difficulties but the shale does not contain free oil. It is released only by heat treatment. However, some coal and metal mines present explosive hazards due to coal dust, gas and fine sulphide dust, yet continue to operate.

If steam is used, flooding of the shaker tunnels, conveyor tunnels and drifts can be expected. It could convert the oil sands into a liquid material, and the method of controlling the draw of such material is not clear at this time. It seems certain that the oil sands mine would be very dirty and, as a result, working conditions would be undesirable.

It is generally agreed that underground work requires more manpower per unit of production than does open-pit work. Technological progress in underground mining has lagged far behind increases in wages and supplies during the last ten years. The opposite is true for open-pit work. Underground caving mines are using every effort to convert to open-pit. Typical of these are Inspiration, Ray, Bagdad, Consolidated Copper. Climax would convert if it were able to do so. Underground mining does not permit the expansion and development of the size of equipment as does open-pit work. The operator is tied to the original scheme of development. He is tied to rock strengths, to maximum openings that can be used, and to the manpower that does not like to work underground any more.

Conclusions

The flat-lying beds of oil sand 100 to 200 feet in thickness with 0 to 70 feet of overburden, say 0.5:1 ratio of sand, gravel, clay and soil, are ideal for open-pit operations.

The cost of the open-pit operations, assuming that the oil-sand operations would approximate those of the Western States, would be as follows. The average cost of open-pit operations in the Western United States, using medium-sized trucks of 15 to 20 cubic yards and medium-sized shovels of 3 to 6 yards capacity, is approximately 20 cents per ton. This includes haulage averaging ½ to ⅝ mile. For sands weighing about 3300 pounds to the cubic yard, this would approximate 33 cents per cubic yard. It is my opinion that the oil sands could be mined for this price or perhaps for slightly less. Therefore, with a stripping ratio of 0.5:1 in the oil sands, the mining costs would be around 49.5 to 50 cents per yard. It is possible that the cost would be reduced by the use of scrapers, though opinion is divided on their applicability. It is largely a question of the material to be handled and the haul involved. On a property where the material can be rooted and loaded with a Turnadozer and the haul kept below a quarter of a mile the above costs can be reduced by 40 to 50%, or to about 20 cents per yard. With the oil sands it is probable that the overburden could be handled in this manner. However, the oil sands themselves probably could not be rooted in the winter.

My conclusion is as follows. The comparative costs of open-pit mining versus caving, together with complete recovery without dilution by open-pit work, together with the underground hazards and unknowns inherent in the caving method, make open-pit mining the choice at this time. The only practical application of caving would seem to be to make a partial recovery of caved sands to the point where the entire mass has caved to an extent to allow leaching or washing action for recovery of oil without transporting all of the material. Caving may become applicable when the cost of removal of overburden becomes excessive and the selling price of the oil is high enough to compensate for the inevitable dilution and low recovery. Experimental work in scale model should be conducted, after which, at the appropriate time, an experimental block should be opened to apply the results of such experimentation.

DISCUSSION

S. M. Blair: Mr. McNicholas has been so generous in giving cost figures; would he give us a figure for the removal of tailings from the plant?

F. S. McNicholas: Tailings are being moved at Climax a distance of about two miles by gravity pipeline at a cost of about 2½ to 3 cents per ton.

ELECTROVOLATILIZATION OF OIL IN SITU

By C. M. Davis
Pennsylvania State College, State College

Electrovolatilization may be defined as the vaporization of a material by the application of heat by electrical means. The material is forced to become an electrical conductor and the passage of current through it raises its temperature. Usually organic substances offer high resistance to the passage of electrical current, but as the impressed voltage is increased, a point is reached at which the resistance is broken down and the organic material becomes a good conductor. It is customary to heat the material electrically at first and to complete the heating by a more economical means. For example, a partial combustion of the material using compressed air may be used.

The recovery of petroleum by primary methods of field exploitation is estimated at about 30 to 40% of the initial amount of the oil in the reservoir. There are many examples of primary recovery where advantage has not been taken of the expansive energy of any dissolved gas and energy from edge water and other forces to augment production. As a result, even after secondary recovery mechanisms such as flooding water have been employed, as much as 30% of the original oil is still unrecovered.

In addition to the oil remaining in exhausted reservoirs, there are vast amounts of viscous asphaltic oils that cannot be produced in the normal way. Millions of barrels of potential motor fuels and furnace oils are represented by these known reserves, and attention should be directed toward developing processes that will make them available. The asphaltic oils and pyrobitumens (8) are not amenable to recovery by water flooding or by extraction methods. A process in which heat is applied in some manner to the reservoir would appear to offer a means of recovering the heavy oils. The action of the heat would be to lower the viscosity to permit ordinary reservoir production, but in the extreme, it could be used to crack the asphaltic oil in situ to produce a light cracked distillate which could then be produced in the normal manner. It is logical to assume that the addition of heat in situ to a reservoir of this type would also result in an increase of the vapor pressure of the connate water and of any low boiling hydrocarbons which had been formed as a result of cracking. The increase in reservoir pressure would thus facilitate the movement of oil in the reservoir.

The purpose of this paper is to relate the laboratory results which have been obtained, and to present certain theoretical calculations which have been made as a prelude to any field tests that may be undertaken. Application of electrovolatilization to a few specific cases has been made.

Historical Sketch

The process of electrovolatilization of carbonaceous materials was introduced to the North American Continent by E. Sarapou (6), following work done by him at the Mining Academy of Freiberg, Germany. He developed the technique of passing high-voltage electricity through coal seams and thereby completely removing the volatile materials along with the fixed carbon.

Electrical carbonization and gasification of coal in situ were demonstrated on the property of the Sinclair Coal Company, November 13, 1950, at Hume, Missouri. The following is a brief description of the field work (7). The coal seam used for the test is classed as Bevier by the United States Bureau of Mines. It was two feet thick and lay under 23 feet of overburden consisting of gray shale and clay. It is a high-volatile coal with a bed moisture of 7.5% and a sulphur content of 3 to 4.5%. Preparations for the test included the auger drilling of four holes into the coal seam in a straight line, on 30-foot centres. A steel pipe electrode was placed in each of the bore holes with sufficient clearance between the pipe and bore hole surface to eliminate any chance for arcing or grounding. Each electrode contained several drilled holes in the part fitting snugly in the coal seam to allow passage of vapors and liquids during the test. An excavation about three feet in diameter was made to a depth of a few feet around each electrode used in the test. Cement was poured into these two excavations. The purpose of this cement cap was to overcome shrinkage of the ground around the electrodes which had caused leakage in previous tests. A 500-kva. single phase converter was employed.

Breakthrough is defined as a breakdown of the resistance of any material so that it becomes an electrical conductor. In the field tests, breakthrough had been effected prior to November 13, 1950. The breakthrough voltage required was 2300 volts for the 30-foot electrode spacing. At the time of actual carbonization, a voltage of 1200 volts was used with a gradual decrease to 300 volts. Brownish vapors emanated from the bore holes. It must be realized that the power requirement varies with the distance between electrodes. High voltage initiates breakthrough and as a result, resistivity drops off rather rapidly. The impressed voltage was, therefore, lowered correspondingly in an attempt to keep the power as constant as possible. After the resistance leveled off, the gasification step was started. Gasification consisted of forcing compressed air through the fissures created by the breakthrough as well as through the porous coke which had been formed during the carbonization step.

Typical data were as follows. A current density of 7.6 to 10.2 amp. per sq. in. and a carbonization voltage of 300 volts were used. During carbonization, a gas of 500 to 600 B.t.u. per s.c.f. was evolved. Its composition was 15% methane, 50% hydrogen, 15 to 18% carbon monoxide, 6 to 8% carbon dioxide, and 4% hydrogen sulphide. Other hydrocarbon gases made up the remainder. During the gasification step, a gas of 90 B.t.u. per s.c.f. was produced.

It was believed that at least 2,000 tons of coal could be gasified at 90-foot electrode spacing. Each ton of coal would supply 4,000 s.c.f. of carbonization gas at 600 B.t.u. per s.c.f., and each pound of coal would evolve 65 s.c.f. of 120 B.t.u. gas during the gasification step.

The Ljungstrom process, which was developed in Sweden, makes application of in situ recovery by cracking the kerogen in oil shale (5).

Laboratory Results

Laboratory studies concerned with the application of the electrovolatilization technique to the recovery of oil from reservoir rocks have been undertaken, and the results may be summarized as follows:

1. Breakthrough is possible with consolidated asphaltic sands, Venango sands, Bradford sands and Colorado oil shale.
2. Breakthrough voltage is a function of time, water saturation, electrode spacing, and naturally occurring organic matter other than oil.
3. Oil and water may be vaporized with electrical energy to the extent that only 8 to 9 % of the oil remains in place as a carbon deposit.
4. High brine saturation makes the core act as a dead short in the electrical circuit, with the result that breakthrough is not possible until the water saturation has been decreased sufficiently.
5. Oil and water will move by a vaporization process using electrical energy.

Work was initiated (3) with core materials available from an asphaltic sand obtained from the United States Bureau of Mines, Bartlesville district. Other samples were obtained from a defunct oil field near Richards, Missouri. The oil content of the sands was determined either by extraction or retorting; whichever type of analysis was applicable. It was found that retorting was necessary to determine the oil content of the Bureau of Mines samples, and either extracting or retorting could be used for the Missouri samples. Table I shows the reservoir data for the Missouri sample.

TABLE I

RESERVOIR DATA FOR MISSOURI SAMPLE

Porosity, % of total volume	21.90
Oil saturation, % of pore space	67.40
Water saturation, % of pore space	2.00
Air or gas, % of pore space	30.60
Oil density, gm. per cc.	0.855
Oil gravity, °A.P.I.	29

To determine the optimum recovery by thermal means, various heating rates were used. Oil from the pyrobitumen cores of the Bureau of Mines samples was recovered only very slowly at low temperatures of the order of 200 to 300°C., but a rather rapid increase in the rate of recovery was noted for a temperature of 300 to 450°C.

It leveled off in the range of 450 to 500°C. The same trends were found for the Missouri samples. The rate of oil recovery at 350°C. showed its greatest value during the first hour, and then it leveled off to a rather constant value.

Although the resistivity of the Bureau of Mines asphaltic sand was very high, it was believed that a sufficiently high voltage could be impressed to cause carbonization resulting in breakthrough. To determine breakdown voltage, the sample was placed across the secondary side of a 230/6900-volt distribution transformer. The circuit on the primary side consisted of an ammeter, voltmeter, and a circuit breaker which limited the current flow to 25 amperes. The impressed voltage was controlled by means of a Variac—a continuously variable auto-transformer. The electrodes were steel discs placed firmly against the ends of the cylindrical core. The application of a high voltage across the core caused the resistance to break down rather quickly with a resultant increase in current. The breakthrough made the core split along the bedding planes. Examination showed the presence of a carbon path.

Breakthrough values for the Bureau of Mines cores were very erratic. Some of the variations of 1,000 to 6,000 volts may have been caused by difference in spacing of the electrodes ranging from 1⅛ to 1 5/32 inches, but this was not sufficient to account for all the variation. No ready explanation is available.

Because the conductivity of the core changed rapidly after breakthrough it was thought that a constant-current transformer might be suitable for controlling the input current to the core during the heating period for the recovery of the oil. Thus, the samples, after breakthrough had been established, were placed between electrodes on the secondary side of the constant-current transformer. The current was maintained at 6.6 amperes, but this was found to be too great. Temperatures were reached at which the core fused and melted the electrode discs. It was found that the conductivity increased rapidly as heating progressed. The development of the technique of obtaining breakthrough without too much fissuring proved rather costly. Only two of the Bureau of Mines samples were available after the breakthrough step for heating to recover the oil.

Breakthrough potentials for the Missouri cores were almost as erratic as those for the foregoing samples. It was learned that breakthrough in the natural state was not possible with any of these samples because the core material had been left exposed for many months. When artificial saturation was used to reconstitute the cores, the breakthrough potentials were erratic, varying from 2700 to 6,000 volts for practically the same electrode spacing.*

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* During the breakthrough step it was found that the current increased as the impressed voltage was increased for a short time, and then the current dropped to no readable value with the ammeter available. As the voltage was increased further, a point was reached at which the current increased almost instantaneously. This point was the breakthrough being sought. From there on, the resistance decreased rapidly.

After breakthrough of the Missouri cores, electrical heating tests were carried out on a 230-volt line using an induction regulator to maintain reasonably constant power. The cores were held in a quartz reaction tube 1¼ inches in diameter and six inches long. The reaction tube was connected by means of glass to a gas collecting flask. A cooling coil was placed in the line to condense any oil vapors that might come from the reaction tube. The electrodes were one-quarter inch diameter steel rods. They made contact with the core in the following manner. A quarter-inch hole was drilled to a depth of a quarter inch in each end of the core samples. When the electrodes were carefully inserted into the holes they made close contact with the core material.

The electrical circuit for the breakthrough operation was essentially the same as that for the Bureau of Mines samples. For the heating step, the circuit consisted of an induction regulator, ammeter, voltmeter, wattmeter, and the sample. Source of power was a 230-volt line. Heating was conducted at several power ratings, namely, 40, 60, 80, 100, 120 watts for a total of five experiments, each at a constant power rating.

A typical experiment, the constant 40-watt experiment, showed an oil recovery of 89.3% by weight of the oil in place. Gas obtained consisted of methane, illuminants, hydrogen, carbon dioxide in small amounts, some carbon monoxide, oxygen, and nitrogen.

An energy balance for the same experiment follows. In determining the amount of energy required to obtain from the core the hydrocarbons, water, and gases formed by cracking, consideration must be given to sensible and latent heats of the oil and water, the sensible heat of the rock, and the heat of reaction of the gases formed. The energy balance is based on a temperature of 280°C. because this was the maximum temperature reached during the experiment. The heat of reaction for dehydrogenation is based on only one chemical reaction: ethane to ethylene. Both the reference temperature and the dehydrogenation reaction were chosen on an arbitrary basis. In the following tabulation the figures are based on a particular sample of reservoir rock weighing 48.315 grams.

Heat Balance

Input		Output
Sensible heat—oil	373 cal.	Oil—27,200 cal.
Latent heat—oil	103	
Sensible heat—water	66	
Latent heat—water	487	
Sensible heat—water vapor	80	
Heat of reaction	106	
Sensible heat—rock	3,110	
Heat losses	2,070	
Total	6,395 cal.	27,200 cal.

Thus, the ratio of the energy that must be put into the system to the energy in the oil produced is:

$$\frac{\text{output}}{\text{input}} = \frac{27{,}200}{6{,}395} = 4.26$$

Attention is drawn to the fact that the actual input of energy in the experiment was not 6,395 calories but was 10,350 calories. In other words, the energy required to denude the core was considerably less than that consumed in the experiment. The item for the heat losses represents 20% of the electrical energy input, and is believed to be reasonably sound (1).

In the 60-watt experiment the oil recovery was 90.6% by weight of the oil in place. The gas had more illuminants and a greater amount of hydrogen than had that for the 40-watt run. The energy balance indicated the following ratio:

$$\frac{\text{output}}{\text{input}} = \frac{27{,}700}{14{,}830} = 1.86$$

The data presented for the 40- and 60-watt experiments suggested that there may be an optimum power rate to use, at least in laboratory investigations. The data for the 80-, 100-, and 120-watt experiments support this belief.

Data from recent studies on Pennsylvania cores, the quartzitic second Venango sand, indicate that there is a definite relation between the electrode spacing and the salt water saturation of the core. For a given electrode spacing, the breakthrough voltage decreases as the saturation of the core with brine increases, until the core ultimately acts as a short circuit. There appears to be a critical saturation of brine which brings about breakthrough for a given electrode spacing. It has been possible to obtain excellent heating with an optimum brine saturation without resorting to breakthrough up to a 13-inch spacing. Breakthrough at 13-inch spacing had not been attainable because of insufficient transformer capacity.

The following is an attempt to apply the laboratory results in a calculation of three hypothetical field tests. In each case, a real example of a field reservoir is taken and a method of application of the electrovolatilization technique is suggested. As in the foregoing heat balances for the laboratory cores, the heat and power requirements are calculated for the production of oil from the reservoir rock under consideration. Assuming a yield comparable to that obtained in the laboratory core experiments, and a cost of electricity applicable to the location under consideration, it is possible to estimate the cost of production of oil by these means. Detail of the calculation is shown for Case 3.

Case 1—Asphaltic Type Consolidated Reservoir

Let the basic reservoir data be as follows:

Thickness of formation, feet	30
Porosity, % of total volume	21.9
Oil saturation, % of pore volume	67.40
Water saturation, % of pore volume	37.60
Specific gravity of the oil	0.855

The well system to be used will be the modified five-spot system shown in Fig. 1. The oil content of the block of reservoir under consideration may be calculated from the above data to be 15,670 bbl. Following the method used above for the calculation of the heat required to denude the reservoir rock of oil, the heat required for vaporizing the oil and water in the block under consideration is 10.189×10^9 B.t.u.

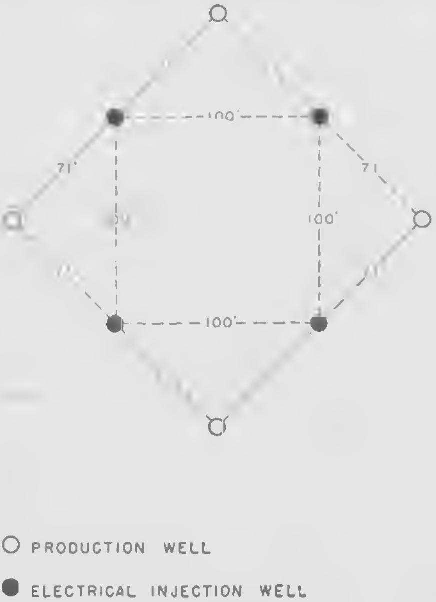

Fig. 1. *Modified five-spot well system for recovery of oil by electrovolatilization.*

The mechanism of heat transfer by conduction may be considered to take place from a point source or a line source. Since breakthrough occurs along a line between the electrodes, it seems logical to postulate that the heat transfer mechanism will be according to a line source. Application of the Ingersoll and Zobel equation (4) to the problem indicates that a heat input of 1.36×10^4 B.t.u./(hr.)(ft.) for a total 400-foot electrode spacing in four units of 100 feet each, will cause an isothermal concentric cylindrical plane at 380°F. to move a radial distance of 22 feet in 3,720 hours. The heat required for this is 20.2×10^9 B.t.u. Of this, 20% is lost, amounting to 4.05×10^9 B.t.u.

Thus, the sum of the heat to vaporize the oil and water plus the heat lost is 14.24×10^9 B.t.u. The heat value of the oil product is 80.2×10^9 B.t.u. based on 19,000 B.t.u. per lb. Therefore, the output to input ratio of the heat terms is 5.63, which compares very favorably with the experimental value.

The total electrical energy expressed as B.t.u. required for the production of 14,100 bbl. of oil, which amounts to about 90% of the reservoir oil, was 20.2×10^9. At a cost of 0.8 cents per kwh., typical in the Pennsylvania area, the direct cost of electricity for producing a barrel of oil from the reservoir described would be $3.46. No consideration to recovery of heat is given in this paper. However, it is a matter which bears examination.

Case 2—Premium Crude Oil Reservoir

Let the basic reservoir information be as follows:

Thickness of formation, feet	50
Porosity, % of total volume	15
Oil saturation, % of pore volume	40
Water saturation, % of pore volume	40
Gas saturation, % of pore volume	20
Specific gravity of the oil	0.8

The well system is the same as for Case 1.

This example differs from Case 1 in that the oil is recovered by means of a steam distillation process. The presence of two liquid phases and a vapor phase will mean that there is one degree of freedom. That is, if the temperature of the reservoir is fixed arbitrarily, the pressure in the reservoir will be automatically fixed. The total pressure will be fixed by the vapor pressure of the water and the vapor pressure of the oil at any specified temperature.

It is further assumed that vaporization of oil and water will be controlled by the back pressure at the producing wells. Increasing the temperature of the formation will increase the mobility of the oil, but will tend to decrease the effective permeability of the oil. This statement is based upon some laboratory investigations. Because the mobility effect is the predominating factor, increasing the temperature of the formation results in higher oil recoveries since recoveries are improved by decreasing the mobility factor. The temperature of the reservoir is to be raised to an average value of about 400°F. At this temperature the vapor pressures of the oil and water are about 100 p.s.i.a. and 250 p.s.i. respectively.

In the portion of the reservoir under consideration, a block 142 feet square as shown in Fig. 1 and 50 feet deep, the recoverable oil is determined by the vapor pressure relation between water and oil. Assuming a molecular weight of 200 for the oil, the recoverable oil amounts to 11,170 pound-moles. To distil this quantity of oil requires about 27,900 pound-moles of steam. The reservoir actually contains 206,000 pound-moles of water, and so it is concluded that there is more than enough water present to steam distil the oil.

The heat required to recover the oil is taken as the sensible and latent heat of the oil, sensible heat of all the water, the latent heat of the water used to steam distil the produced oil, and the sensible heat for the rock. For the system selected, this amounts to 14.217×10^9 B.t.u.

As before, the application of 1.36×10^4 B.t.u./(hr.) (ft.) will cause a 400°F. isothermal cylindrical plane to reach a radius of 26 feet in a finite time. In this case, the time required is about 5,445 hours, and the heat from the permanent source along the line of breakthrough is 29.6 x 10^9 B.t.u. It is necessary to add 20% of this figure to the 14.217 x 10^9 B.t.u. value, giving 20.127 x 10^9 B.t.u. for the total heat input. The heat value of the oil produced is 43.5 x 10^9 B.t.u. Hence, the ratio of heat value obtained to the heat value added is 2.27.

Assuming a cost of electricity of 0.8 cents per kwh., the direct cost of obtaining oil from this reservoir by electrovolatilization is $9.70 per bbl.

Case 3*—Athabasca Oil Sands

Data selected for calculations follow:

Reservoir data:	
Quartz sand, wt. %	83.3
Oil, wt. %	15.8
Water, wt. %	0.9
Inspection of the oil:	
Characterization factor	11.05
Average boiling point, °F.	950
Molecular weight	1000
Heat of reaction to form a cracked oil, B.t.u./lb.	130
Inspection of the oil product:	
Characterization factor	10.5
Average boiling point, °F.	655
Specific gravity	0.959
Viscosity, cp. at 100°F.	21
Viscosity, cp. at 210°F.	3.5
Molecular weight	240

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* Line source of heat may be taken as a continuous series of point sources along an infinite straight line. According to Ingersoll and Zobel (4) if a line source of permanent type is started at zero time and the sand mass is initially at 36°F., the temperature at any later time becomes:

$$\text{Excess T} = \frac{S'}{2\pi\alpha}\int_{r\eta}^{\infty}\frac{\epsilon^{-B^2}}{B}\,dB =$$

$$\frac{S'}{2\pi\alpha}\text{(Value of Integral)} = \frac{Q'}{2\pi K}\text{(Value of Integral)} \quad \ldots\ldots\text{(I)}$$

$$\text{where } \eta = \frac{1}{2\sqrt{\alpha t}},$$

t = time in hours,

α = thermal diffusivity in (ft.)²/(hr.)

K = heat conductivity in B.t.u./(hr.) (ft.) (°F.)

Q′ = heat added in B.t.u./ (hr.) (ft.)

The expression may be generalized for a permanent source, and it becomes:

$$\text{Excess T} = \frac{S' r^{(2-n)}}{2\pi^{n/2}\alpha}\int_{r\eta}^{\infty} B^{(n-3)}\epsilon^{-B^2}\,dB$$

$$= \frac{Q' r^{(2-n)}}{n\pi^{n/2}K}\text{(Value of the Integral)} \quad \ldots\ldots\text{(II)}$$

Q′ represents B.t.u./(hr.) for the three dimensional case, and for the line source (n = 2) it is expressed in units of B.t.u./(hr.)(ft.)

The oil present in the Athabasca oil sands has a much lower characterization factor than the oil in the other two reservoirs described in Case 1 and Case 2. The average molecular weight of the Athabasca oil is about 1,000, whereas the other oils were characterized by a molecular weight of about 200. For this reason, a simple heating of the oil-sand reservoir will not be adequate. It is proposed instead to heat the deposit to about 1,000°F. to bring about extensive cracking of the oil in situ. It is believed that this treatment will produce an oil with the properties listed above. While the use of the high temperature will tend to result in higher heat losses, this tendency will be offset by the fact that the oil-sand beds are sufficiently thick with respect to the electrode spacing that very little heat will be lost to the overburden and to the underlying limestone, and by the fact that the heat conductivity of the material is very low.

The oil sand for treatment lies, as before, in an area 142 feet square with the location of the production and injection wells unchanged. The thickness of formation to be processed is 50 feet. The

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Material balance is as follows:

$(7758)\ (50)\ (0.456)\ (350)\ (2.06) = 128 \times 10^6$ lb. total

$(128 \times 10^6)\ (0.833) = 106.7 \times 10^6$ lb. quartz sand

$(128 \times 10^6)\ (0.158) = 20.2 \times 10^6$ lb. oil

$(128 \times 10^6)\ (0.009) = 1.1 \times 10^6$ lb. water

Heat balance is as follows:

Sensible heat of sand: $(106.7 \times 10^6)\ (1000 - 36)\ (0.24) = 2.46 \times 10^{10}$ B.t.u.

Sensible heat of oil: (based on enthalpies) $(20.2 \times 10^6)\ (650 - 20) = 12.73 \times 10^9$ B.t.u.

Latent heat of oil: $(20.2 \times 10^6)\ (710 - 650) = 12.13 \times 10^8$ B.t.u.

Sensible and latent heat of water (water in critical range):

$(1.1 \times 10^6).(970) + (1.1 \times 10^6)\ (1000 - 212)\ (0.5) + (1.1 \times 10^6)\ (212 - 36) = 15.46 \times 10^8$B.t.u.

Heat of reaction for cracking: $(20.2 \times 10^6)\ (130) = 2.63 \times 10^9$B.t.u.

Total 42.72×10^9B.t.u.

Employing equation (I) to get the calculated required electrical energy input, we have:

$$964 = \frac{1.36 \times 10^4}{6.28 \times 0.34} \text{(Value of Integral)}$$

$$\text{Value of Integral} = \frac{964 \times 6.28 \times 0\ 34}{1.36 \times 10^4} = 0.1513.$$

If 0.91 is used as the value for $r\eta$ which corresponds essentially to the integral value, 0.1513, according to Table F1 of Ingersoll and Zobel (4)

$$\eta = \frac{0.91 \times 28}{2\sqrt{0.013t}}$$

$$t = \frac{237 \times 10^3}{13} = 18{,}200 \text{ hours.}$$

Therefore, the heat required is:

$$(1.36 \times 10^4)\ (400)\ (18{,}200) = 9.9 \times 10^{10} \text{ B.t.u.}$$

$$9.9 \times 10^{10} \times \frac{1}{3413} = 2.9 \times 10^7 \text{ kwh.}$$

At 1.7¢/kwh. the cost of the heat is:

$$(2.9 \times 10^7)\ (\$0.017) = \$494{,}000.00$$

Assuming a 90% volume yield, the cost of cracked oil is:

$$\$494{,}000 \times \frac{350 \times 0.95\text{[illegible]}}{20.2 \times 10^6 \times 0.9} = \$9.08/\text{bbl}$$

sensible and latent heats of the water and oil components, the sensible heat of the sand, and the heat of reaction for cracking, require the addition of 42.72 x 10^9 B.t.u. As in the previous cases, a heat source of 1.36 x 10^4 B.t.u./(hr.) (ft.) is used to move an isothermal concentric cylindrical plane of 1,000°F. outward through the oil-sand formation. To do this requires about 18,200 hours and the injection of 2.9 x 10^7 kwh. Assuming a volume yield of 90% and a cost of electricity of 1.7 cents per kwh. (2), the cost of producing the cracked oil from the oil sand in situ is $9.08 per bbl.

It is obvious that electricity at 1.7 cents per kwh. cannot be used for complete volatilization and recovery of oil from the Athabasca oil sands. Two alternatives exist. An attempt might be made to produce electricity at a much lower price. On the other hand, the volatilization process need only be started with electricity. The fissure pattern so produced would then provide passages for the injection of compressed air to support combustion. In this manner, a partial combustion of the oil in situ would provide a heat source for the volatilization of the oil. A thorough treatment of this method is beyond the scope of this paper.

CONCLUSIONS

1. Each possible application of electrovolatilization requires a complete new set of conditions which must be evaluated.

2. From this analysis it does not appear economically attractive to rely on electrical energy as the source of heat but only for the purpose of creating a fissure system for the passage of air to support combustion. Electrical energy is the best means of raising the temperature to the kindling point before the introduction of air for combustion. In areas where electricity costs as much as 1.7 cents per kwh., it is evident that electricity can be used only as the initial source of heat.

3. Electrode spacing is a function of the power available, time, brine saturation (either naturally occurring or artificially supplied). For a given electrode spacing, a rough measure of the voltage to be used is approximately one per cent of the voltage required to break down an air gap of equal distance.

4. In the final analysis, a field test is the only manner in which a process such as electrovolatilization can be evaluated.

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DISCUSSION

L. Nelson: Has Dr. Davis any actual experimental data where compressed air was used after preliminary heating with electricity had been done?

C. M. Davis: Not on oil, but on coal.

S. J. Kidder: Has Dr. Davis seen the fine sands? Does he think air would go through them?

C. M. Davis: That would have to be tried. Is the porosity of these sands known?

K. A. Clark: The mineral aggregate of good grade oil sand has a permeability that would have to be expressed in darcys rather than in millidarcys. The impregnated oil sand, that is, the mineral aggregate along with its oil content, especially at the formation temperature of 36°F., is very impermeable. It is probable that little success would be had in attempting to cause hot oil vapors under pressure to penetrate the cold oil-sand formation. They would back up instead of going forward.

C. M. Davis: After breakthrough and heating a fracture system would have developed and, due to coking, a permeable path would have been established; thus air could pass through to support combustion.

DISTRIBUTION OF HEAT LIBERATED FROM A WELL IN BITUMINOUS SAND

By T. E. Warren

Mines Branch, Department of Mines and Technical Surveys, Ottawa

The fact that the viscosity of bitumen is higher than that of flowing petroleum suggests that, if its viscosity could be reduced, bitumen might flow through the sand and be recovered at a well. One conceivable method of reducing the viscosity is to raise the temperature of the bituminous-sand structure. At moderate temperatures bitumen has a viscosity corresponding to that of petroleums that are produced from wells. There has been speculation, therefore, concerning the possibility of heating a bed of bituminous sand from a centrally located heat source. The purpose of this paper is to present quantitative data that can be used in assessing the feasibility of such a method of heating.

There are upper and lower limits to the temperature range that would be effective. The lower limit is set by the temperature at which the bitumen would be fluid enough to flow through the sand. This temperature is, very approximately, 200°F. The upper limit is set by the temperature above which cracking and coke formation occur. Coking of the bitumen would result in formation of an impermeable solid between the sand grains. Bitumen cracks to form coke at temperatures above 700°F. The technical problem is, therefore, to bring as large a proportion of the sand bed as possible to temperatures between these limits.

As an example of the way in which the heating might be accomplished, let us assume that heat is supplied at a constant rate from a pipe set vertically in the sand structure. The temperature will be highest at the pipe and will decrease with increasing distance from it. If the heating is continued, the temperature at the pipe will rise until it reaches the upper allowable limit. When this condition has been reached the amount of sand that has been brought between the temperature limits is a function of the rate at which heat has been supplied, the thermal conductivity of the sand bed, its specific gravity and specific heat.

If all of these factors are known it is possible to calculate the amount of sand that will be raised to temperatures between the limits. The heat transfer problem involved is, however, an unusual one that is not treated in the ordinary textbooks. Fortunately, a procedure for solving this type of problem has been published (3). The procedure involves graphical integration of the fundamental equations, and charts are given for solution of numerical problems. Algebraic development of the present calculations cannot, therefore, be presented and, for verification or extension, reference should be made to Newman's original paper.

Before applying Newman's method to the problem at hand, it was considered advisable to verify it by comparison with experimental data obtained under conditions that could be produced in the laboratory. A six-inch pipe was placed in a cylindrical container and the annular space filled with bituminous sand. Heat was supplied within the pipe at a rate of 3700 B.t.u. per hour per foot of length. Under these conditions the temperature at the wall of the pipe rose 685°F. in 2.8 hours. Increase in temperature at two other locations within the bituminous sand bed at the same time is indicated by the points shown in Fig. 1.

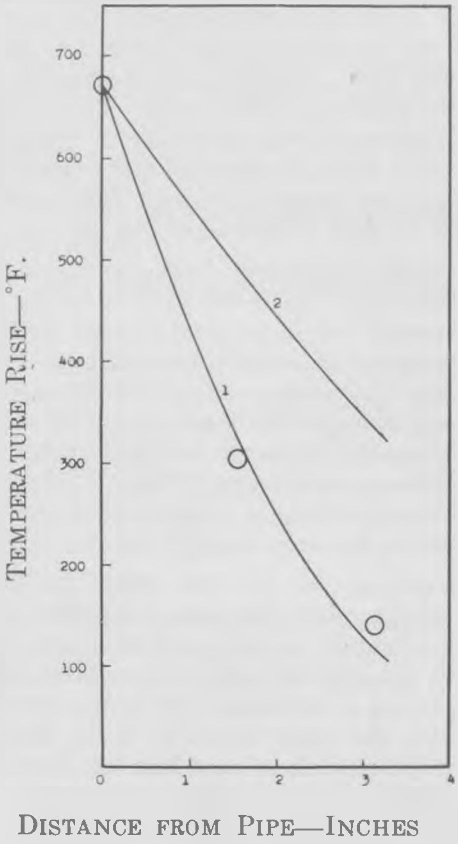

Fig. 1.

At the time when the experiment was made, no data were available on the thermal conductivity of bituminous sand. It was assumed, therefore, to be the same as sand—0.0009 calories per square centimetre per centimetre per second per degree Centigrade (2). Using this value, a specific heat of 0.22 calories per degree Centigrade per gram, a specific gravity of 2.0, and the same rate of heating as in the experiment, the temperature at the wall of the pipe was calculated to rise 685°F. in 3.5 hours. The calculated temperature gradient at this time is shown by Curve 1, Fig. 1.

At a later time, K. A. Clark reported measurements of the thermal conductivity of bituminous sand (1). These showed that a sample of rich sand in its natural state had a thermal conductivity of 0.0035 in c.g.s. units, or nearly four times that which had been assumed for the calculation of Curve 1. Using this value and the same rate of heating as in the previous calculation and the experiment, the temperature at the wall of the pipe was calculated to rise 685°F. in eight hours. The temperature gradient at this time is shown in Curve 2.

A possible explanation of the fact that the experimental points are closer to the curve corresponding to the lower conductivity is that the sample used for the experiment had a low bitumen content. It was also dried to some extent and was probably not packed firmly enough to simulate the natural state. Clark's investigation has shown that bituminous sand after being broken and remoulded has a lower conductivity than in its natural state and that conductivity decreases with decreasing oil content.

The two curves can be considered as based on extremes of conductivity, and it is expected that experimental data with most natural sands would lie between them.

Having compared the temperature gradients calculated according to Newman's method with experimental data, the next step was to calculate the gradients corresponding to elapsed times and distances of much greater magnitude. For these calculations the value of 0.0035 for conductivity was used. It is also assumed that the initial temperature of the bituminous-sand bed is 35°F. Using these values and supplying heat at the rate of 850 B.t.u. per linear foot of pipe per hour, the temperature at the pipe is calculated to rise to 720°F. in one year. The temperature gradient is shown in Curve 1 of Fig. 2.

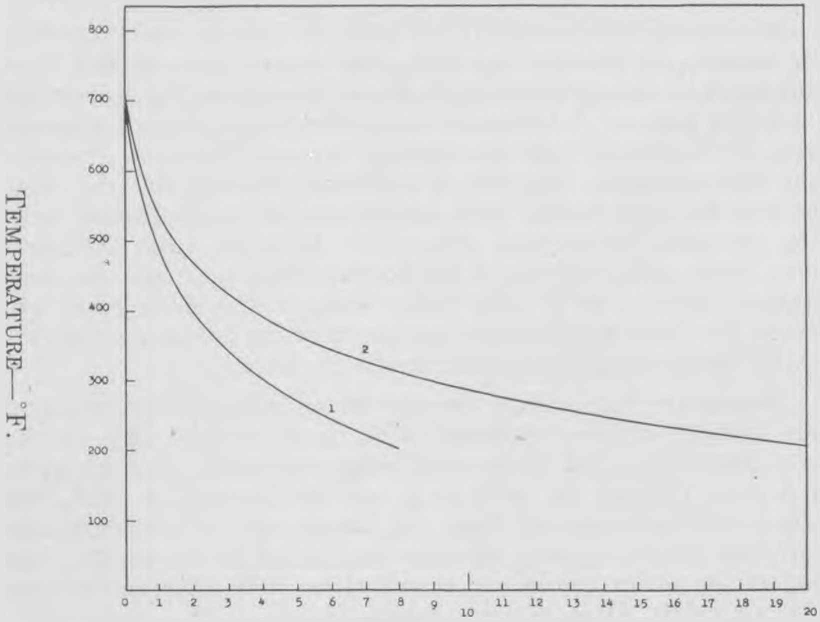

Fig. 2.

The distance from the pipe has been extended beyond the range of Newman's charts by the assumption that conditions after one year at locations near the pipe approximate those of steady state heat flow. In this case the temperature is inversely proportional to the logarithm of the distance from the centre of the pipe.

Reducing the rate of heating to 670 B.t.u. per foot of pipe per hour the temperature at the pipe reaches 720°F. in ten years and the temperature gradient is as shown in Curve 2.

From these curves it is seen that even if heating were continued for ten years, only the zone extending 20 feet from the pipe would lie between the effective limits of temperature. It should also be recalled that the most favorable conditions of high conducticity and high permissible final temperature have been employed.

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DISCUSSION

G. B. Shea: In connection with Dr. Warren's experiments I might mention some tests conducted in the San Francisco laboratory of the Bureau of Mines to find out if the application of heat in drifts or tunnels in partly depleted oil sands would result in the recovery of additional oil. A laboratory oil field was constructed consisting of a liquid-tight wooden box three feet square and one foot high equipped with five drainage wells (¼-in. perforated pipe) arranged in a 5-spot pattern. A U-shaped heavy wire screen formed a tunnel across the bottom of the box midway between the sides. Twenty-eight thermocouples were placed uniformly throughout the box. The box was then packed with unconsolidated sand saturated with 25% interstitial water and 75% 13.1° A.P.I. oil from the Kern River, Calif., field. Packing of the box was done in a constant temperature room at 84°F.—the temperature of the Kern River reservoir. The cover fitted snugly into the top of the box and was drawn tightly, compressing the sand as much as possible.

During the first part of the test the oil drained from the sand body through the five wells and 57% of the oil and 28% of the water originally added to the sand were recovered. After no more oil drained through the wells at a sand temperature of 84°F., the packed sand was removed from the tunnel and a thermostatically controlled electric heating element was placed in the tunnel. The temperature in the tunnel was increased by 50°F. increments from 84°F. to 235°F. After applying heat in the tunnel for 75 days the temperature at the farthest corner of the box—about 18 inches from the tunnel—had increased only to 97°F. and less than one per cent of the oil remaining in the sand was recovered. The experiment verified computations that radial flow of heat from a tunnel results in only a small rise in temperature in the surrounding sand body. These tests are reported in detail in the U.S. Bureau of Mines Report of Investigations 4391, "Laboratory Studies of Gravitational Drainage of Oil from Unconsolidated Sands", by R. V. Higgins and G. B. Shea.

D. S. Pasternack: In 1929 Mr. Absher tried to distil oil out of the oil sands in situ at a location near McMurray. His procedure was to drill a vertical hole into the oil sand, then ignite some kerosene at the bottom of the hole and pass in air. It was expected that once cracking of the oil was started it would continue as a self-sustaining process, and that an oily product could be condensed from the vapors issuing from the hole. It was found that the fire in the hole would go out quickly unless kerosene was continuously passed in, and that at the end of any period the amount of oily product recovered was considerably less than the amount of kerosene used up. In 1930, while observing one of those experiments, Dr. K. A. Clark suggested to Mr. Absher that he drill one of his holes near the edge of a hill so that after the burning period was over, the hole could be immediately exposed and examined. This suggestion was acted upon, and a fire was kept burning in such a hole for two or three days. On exposing the hole it was found that the oil had become carbonized around the immediate bottom of the hole, but that one foot away from the carbonized material the temperature was only about 212°F. This illustrates the poor heat conductivity of the oil sands, and points out Mr. Absher's failure when trying to get the oil sand to sustain combustion.

C. M. Davis: It might be well to say that the temperature obtainable along the line of breakthrough runs between 2,000 and 2500°F.

SOME LABORATORY RESULTS RELATED TO MINING OIL SAND BY BLOCK CAVING*

By K. A. Clark and E. L. Alexander
Research Council of Alberta, Edmonton

The mining of oil sand from underground workings holds promise of three important advantages over open-pit mining provided that the economics of the method are favorable. These are: the escape from the necessity of operating excavating equipment under the quite long and severe winter conditions; the avoidance of the problem of crushing lumpy oil sand from large-scale open-pit work; and independence from the factor of overburden which bears directly on the cost of open-pit mining. The oil-sand formation lies on a floor of limestone. The top of this limestone lies, generally, somewhat higher than the level of the Athabasca River and can be entered, readily, from the valley. It should be a favorable medium in which to drive and maintain tunnels. The general idea would be to get below the oil sand and to induce it to fall down onto an underground conveyor system. Underground mining of oil sand is worthy of consideration.

Not much can be done in a laboratory to test a mining method. Trials under actual mining conditions are required to get convincing answers. However, in the case of the oil sands there are some factors involved that can be examined in a small way. The progress that has been made in laboratory work is reported in what follows.

Block Caving of Oil Sand

Mining ore by the block method involves undercutting the ore over a sufficient area to cause the unsupported column to fragment and fall away. Oil sand should be amenable to block caving. The material is unconsolidated sand held together by a liquid. In its natural state of packing and with the oil at the formation temperature of 36°F., the oil sand is more stable than one is liable to credit it with being. However, it has no inherent strength and, if support is removed from below, it should spall and fall away.

A field test would be necessary to ascertain the behavior of oil sand under block conditions. However, a laboratory experiment that was made has some significance. A box 16 in. square inside and five feet high was tamped full with oil sand from the Bitumount quarry. The density of packing was 109 lb. per cu. ft. as compared with about 120 lb. for undisturbed oil sand. The temperature was about 70°F. The bottom of the box had a central section 12 in. square that was removed when packing was complete. Oil sand fell out of this opening until an arch formed. Then nothing more fell away. When the oil-sand column was undercut to the sides of the box, caving took place and the box gradually emptied itself. There was no slipping of the oil-sand column along the sides of the box.

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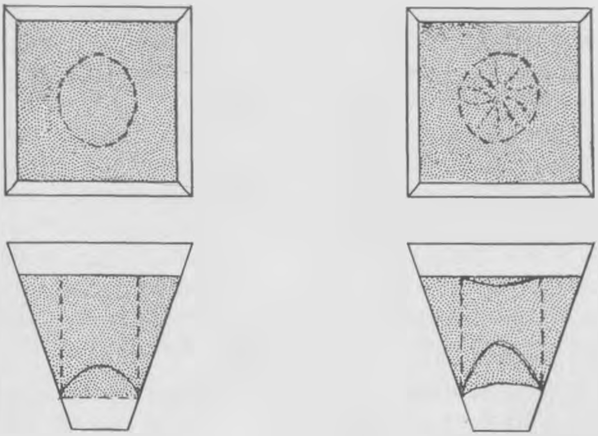
*This paper was not read at the Conference.

Withdrawal of Caved Sand through a Raise

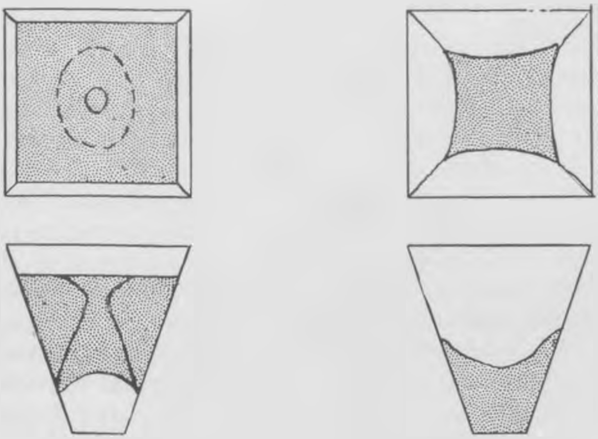
Granted that oil sand would cave under practical conditions, the withdrawal of the caved material through a raise may appear to present difficulties. However, this operation should be the same as feeding oil sand from a storage hopper. This was done without difficulty at Bitumount.

The movement of oil sand through a hopper is not entirely clear, and some experiments were performed to gain information. A small hopper in the form of an inverted pyramid with sides 20° from the



(A) CRITICAL DIAMETER OF THE ARCH RESULTING IN SHEAR FAILURE THROUGH THE OIL SAND MASS.

(B) SLUMP OF TOP SURFACE INSIDE THE SHEAR FAILURE.



(C) BREAK—THROUGH.

(D) CLOSING OF THE HOLE AND ESTABLISHMENT OF STEADY FLOW.

Fig. 1. *Diagram indicating the stages of movement of oil sand through a hopper.*

vertical was made. The top of the hopper was 30 in. square. The bottom was so constructed that openings 4 in., 6 in. and 8 in. square could be used. The 700 lb. of oil sand on hand did not completely fill the hopper. Oil sand was shovelled into the hopper without packing by tamping.

When the 4 in. square opening for the hopper was opened, oil sand fell out until an arch over the opening was formed. Then no more oil sand dropped away. The same action took place with the 6 in. square opening. But with the 8 in. opening, the arch that formed was not stable. Oil sand continued to fall but in a slow, unpredictable way. This action continued until the arch had a diameter of about 12 in. Then an elliptical crack appeared on the top surface of the oil sand in the hopper. Oil sand now commenced to fall from the hopper opening continuously. The stages of the movement are indicated in Fig. 1. The top surface of the oil sand slumped inside the elliptical crack. The column of oil sand below the crack flowed out of the bottom opening at an accelerating rate. A hole formed, and the rest of the oil sand in the hopper fell into this hole and on out through the bottom. If the hopper was well filled with oil sand to start with, the material fell into the hole faster than it could get away through the bottom. An equilibrium state of flow then became established and the hopper emptied itself at a fairly constant rate.

Work had to be discontinued at this point in the investigation. Movement in a hopper terminating in a vertical passage corresponding to a raise should be examined. Also there is the action of steam pressure from perforated pipes running through the basal part of the hopper to be studied. The investigation will be continued at the first opportunity.

Development of Stopes by Steaming

A method for underground mining of oil sand is discussed in the Blair report. Outside of the usual procedure of driving tunnels and raises, the main feature of the method is to develop stopes above the raises by the use of steam. The idea behind this scheme was that the surface layer of the oil-sand wall of the stope would soften, in contact with a steam atmosphere, and slump down. The softened material combined with condensed steam was expected to accumulate in the bottom of the stope over the raise in the form of an oil-sand pulp that could be drawn off, as required, through the raise. The writer discussed this idea with the engineers of Mannix Limited who proposed it, and gave them encouragement to continue thinking along this line. He was aware that the assumption that the surface layer of the oil sand on a stope wall would soften and slump when in contact with a steam atmosphere needed to be checked.

A simple laboratory experiment was set up for testing the behavior of the face of a mass of oil sand when in contact with a steam atmosphere. The arrangement is indicated in Fig. 2. A steam atmosphere was maintained inside the steam jacket for four hours.

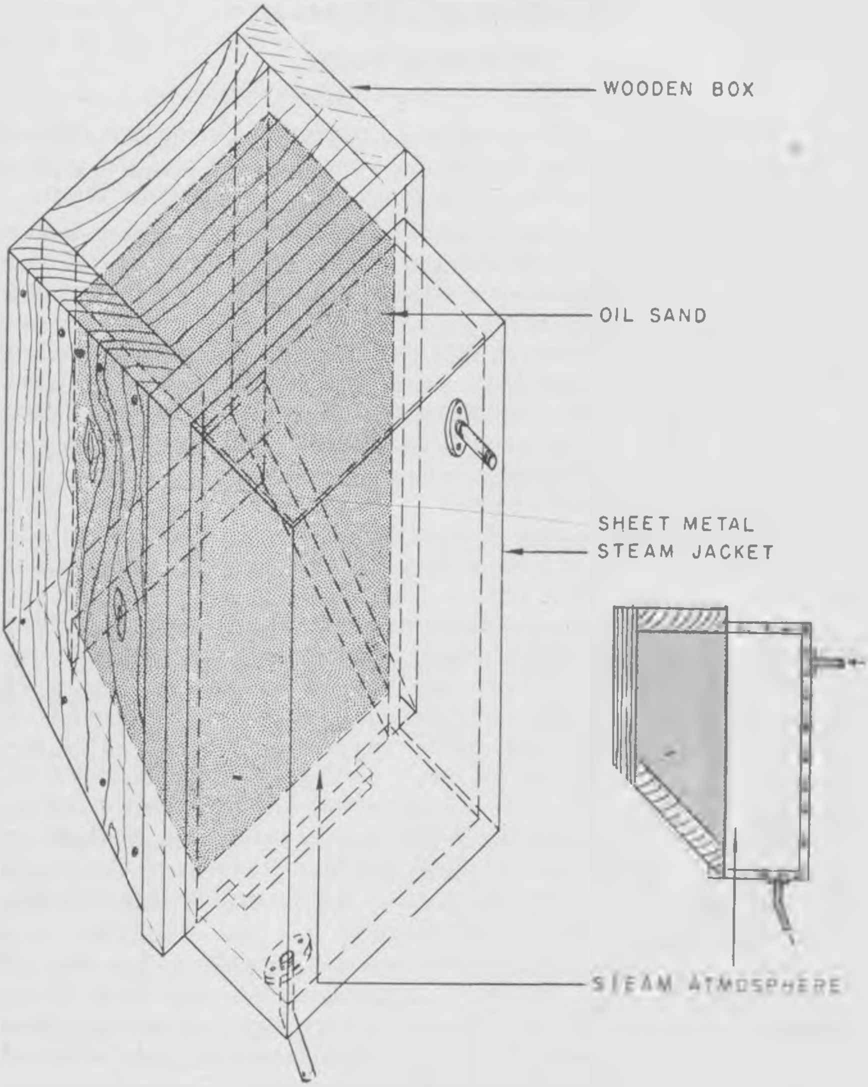


Fig. 2. *Experimental set-up for testing the effect of a steam atmosphere against the surface of a mass of oil sand.*

A thermocouple buried in the oil sand ½ in. back from the face registered 200°F. for two of the four hours. No slumping of the material on the oil-sand face took place. After prolonged steaming, the lower part of the oil-sand mass broke away by caving.

The conclusion to be drawn from the experiment is that the surface layer of an oil-sand mass will not slump off as it is heated by contact with a steam atmosphere.

OIL MINING IN GERMANY*

By Walter Ruehl
Deutsche Erdol-Aktiengesellschaft, Wietze

The following short survey of oil mining in Germany is offered as a contribution to the discussion of the open-pit and the underground block-caving methods for mining the Athabasca oil sands.

Three underground oil mines were developed in Germany during the years of the first world war and were in operation in 1919. The first one was at Pechelbronn in Alsace. This mine now has over 200 miles of tunnels driven through the overburden immediately above the oil sands and from which short, vertical shafts extend downward into the oil sands. These shafts serve as drainage pits into which oil seeps and collects. While the Pechelbronn mine was being developed, an 860-ft. shaft was started at Wietze near Celle in the Province of Hanover for an underground system of workings for draining the oil sands of the Wealden reservoir at the base of the Cretaceous. This field had been exploited for 50 years in the orthodox fashion and 1600 oil wells had been drilled. Since the sinking of the shaft, a network of tunnels totalling about 40 miles in length has been driven through the oil sands. This mine has produced over 700,000 tons of oil. A third mine was started in 1919 at Heide in Holstein north of Hamburg. It was operated for several years but was abandoned because of economic and engineering difficulties. In contrast to the oil sands of Wietze and of Pechelbronn, the oil reservoir at Heide is an oil-impregnated white chalk, 200 feet thick, of Upper Senonian age. Several years ago investigations were started to find new methods for coping with the difficulties of mining in this plastic, gas-bearing oil-chalk. It is hoped that the laboratory studies will point the way to the means for commercial recovery of the 10 to 15 million tons of high-viscosity oil still contained in the Heide reservoir.

The Wietze oil sands drain by gravity to a small extent. The oil has a specific gravity of 0.960 to 0.970 and a viscosity at 20°C. of 4,000 to 5,000 centipoises. Important factors regarding the operation of the Wietze mine are that there is no hydrostatic pressure in the oil sands and the edgewater level remains constant.

Geology of Wietze

Wietze is located on the northern end of one of the 200 salt domes that occur in Germany. The first well into the reservoir was drilled in 1858, but systematic drilling did not start until 1874. Drilling continued until about 1935. In all, 2100 wells have been drilled of which 1600 were producers and 300 are still yielding oil. About 2½ million tons of oil have been taken from the reservoir to date. The chief reservoir rocks are sands and sandstones of Rhaetic, Upper Liassic, Upper Dogger (Cornbrash), Wealden at the base of the Lower Cretaceous and, lastly, of transgressing Senonian age. The tectonics are complicated and will not be discussed. Many faults

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* This paper was read at the Conference on the evening of September 12.

occur. Mining is carried on only in the Wealden beds. These are at a depth of 730 to 1,000 feet.

The Wietze Oil-Sand Deposit

The Wealden deposit consists of a sequence of clays, loose oil sands, and consolidated sandstones totalling 200 feet in thickness. It may be divided into four oil-sand reservoirs of 100 feet combined thickness. Owing to changes of facies, the petrographic rock characteristics are variable, i.e., there are irregular shale intercalations in all the reservoirs causing sections in them to be dry. The third uppermost reservoir is the thickest and best, while the fourth uppermost does not yield any oil. The sands are fine to medium grained, and are seldom pure. There are generally thin shale intercalations. The shale sections are usually interbedded with layers of oil sand.

Sixty to seventy percent of the sand grains are below 0.2 mm. in size. The porosity varies between 15 to 42%. The average porosity of the third and most important oil-sand reservoir is 36%. The permeability is 1,000 to 15,000 millidarcys. The connate water content shown by the analyses of 600 samples is 9 to 14%.

Pore Space Content and Recovery Factor

Each individual deposit may be divided into the following sections:

(a) a dry oil-sand zone at the top,
(b) an oil-wet or liquid zone,
(c) a water zone below.

The dry oil-sand zone at the top is probably the result of the primary drainage of the reservoir by wells drilled since 1874. It is no longer saturated with oil and cannot be worked by the seepage method to be described. The only way to get further oil out of it is to excavate the sand and to wash it with water. Oil can be recovered from the oil-wet zone by gravity drainage. This fact is the basis for the mining method consisting of sinking a shaft into the oil-wet zone and in driving tunnels from this shaft through the oil sand. The extensive drainage surface developed by this system results in the recovery of a large amount of oil. Oil is collected in gutters in the bottom of the tunnels and is pumped out of the mine. Sixty-five percent of the oil production of the Wietze mine is obtained in this way. After the oil sand ceases to yield oil by drainage it is excavated, hoisted to the surface, and then put through a washing process. Thus, the production of oil at Wietze progresses through three stages:

1. Gravity drainage by means of oil wells. Oil amounting to 11 to 14% of the pore space of the oil sand is recovered in this stage.

2. Recovery of oil by seepage into tunnels driven through the oil sand. The oil obtained in this way amounts to 18 to 25% of the pore space.

3. The oil still remaining in the oil sand after gravity drainage by wells and by seepage into tunnels is recovered by excavating the oil sand and washing it in a surface plant.

The oil sand, after drainage into wells has ceased, contains about 15.7 lb. oil per cubic foot. About 11.8 lb. oil per cubic foot still remains in the sand after seepage into underground tunnels has ceased. This is the amount available for recovery by washing.

Mining Engineering

During the first years of operation at the Wietze mine it was found that, in spite of the advanced stage of depletion of the reservoir by oil wells, the rock pressure was still high enough to cause difficulties. In some places neither wooden tunnel frames, brick walling, nor even supports made of basalt columns arranged in close arches would withstand the pressure. It was necessary to resort to the use of supports made of old rails arranged in a trapezoidal or polygonal pattern. This type of support is used in the seepage tunnels without major difficulty. The oil-sand deposits are intersected by tunnels and cross-cuts in several storeys running with the rise or dip in the direction of the strike. Wherever possible, the oil-sand deposits are approached from the underlying beds. The cross-section of a tunnel is 38 square feet. Iron supports are set at intervals of 20 to 25 feet. The roof and sides must be lagged with piling to prevent the exposed oil sand, which soon commences to seep oil, from mudding off the tunnels. Wooden boxes or large-sized perforated pipes are set at definite intervals along both faces of the tunnels, or little shafts are sunk, to catch the oil that seeps out of the sand. All oil entering the tunnels is led to these gathering points from where it is automatically transferred by air pressure to a gathering pit. Oil sand excavated incidental to driving tunnels is hoisted to the surface where it is processed along with oil sand produced from underground oil-sand mining operations. In hard sandstones of the Rhaetic, this method is replaced by another one consisting of drilling sloping or horizontal wells by a specific system into sandstones impregnated with light oil. These wells have lengths up to 500 feet. They will not be discussed further.

The actual mining of oil sands by excavation is carried out by advancing in the direction of the strike. Solid back-fill is used. From an overhand haulage-way that is driven into the centre of the mining area, faces 8.3 feet high and 230 to 330 feet long head out into the field in the direction of both wings. The workings are first secured by a safety pillar. Headways for haulage or ventilation are advanced at the lower and upper ends of the faces. The support consists of the spiling commonly used in Germany along with 6½- to 8-in. props and bars. The roof is wainscotted with 2-in. piling. In order to secure the breast of the face, a so-called "mountain-leg" is left standing in each working area of 10-foot length. This leg is excavated only after the support has been fixed in place. In rather loose sands the face is secured by wainscotting. The oil sand is broken loose by means of pneumatic picks. Stone intercalations are removed by shooting, with observance of all precautions even though there is no gas. Transportation of the oil sand is accomplished by conveyor belts and haulage mine cars. The back-fill, which consists of washed oil sand mixed with sawdust, is dumped down from the surface through a borehole especially drilled for this purpose or through an abandoned well. It is then picked up by conveyor belts and brought to the face. Here it is transferred to shaker conveyors hanging on chains and provided with electric drives. These pile the back-fill into place.

Treatment

The oil sand, after being mined and brought to the surface, is dumped into a rotary tipper and is conveyed to a rotating screen. Material smaller than a walnut passes through the screen and goes into three washing boilers. Over-size material is crushed and then put into the boilers. Each boiler has a capacity of 700 cubic feet. Live steam and compressed air are introduced constantly into the boiler through a number of choked inlets in such a way as to agitate the contents by setting up a whirling motion. Chemicals such as alkalis, etc., are not used. After 1½ hours of treatment, 95% of the oil has been displaced from the sand. The separated oil is drained off, heated with steam to 165°F., and then dehydrated to a water content of 1% by the Cottrell method. Settling in a series of tanks reduces the water content to 0.5%. Oil is recovered from wash water in large settling basins. The recovered oil is processed in a topping plant. The washed sand is returned to the mine for back-fill, or is wasted on a dump.

The current monthly rate of production of oil at Wietze is: 300 tons from oil wells, 1500 tons from seepage oil mining, 500 tons from oil sand that is excavated and washed.

ADDRESS OF WELCOME

By Hon. Gordon E. Taylor

Minister of Highways, Government of Alberta

Mr. Chairman, Hon. Premier, and Gentlemen: I am very happy indeed, tonight, to extend a sincere welcome to all delegates attending this Oil Sands Conference.

Through the years, the words "welcome" and "Athabasca oil sands" have become very closely associated. Three occasions stand out conspicuously in this regard.

The welcome given to Peter Pond at the present site of the pilot plant away back in 1788 was indeed a delight to this first white man to ever travel in that part of the country. He saw the "tar" oozing from the banks and he saw the Indians using the "tar" to gum their canoes. The hearty welcome given to him by the Indians in that day meant a great deal; so much so, that he spent many years in that part of the country and indeed developed what is now known as the Peter Pond river boat, one of which you will observe later this week on your visit to our pilot plant at Bitumount.

Again, these words were closely associated in 1793 when Sir Alexander Mackenzie travelled in that part of the country. In his memoirs he tells about arriving at what is now the site of McMurray. One of his canoes was badly damaged. The Indians, who by this time had learned the ways of the white man, refused to give Mackenzie any of their gum mixture to repair his broken canoe until a bottle of whiskey was delivered to the Chief. Mackenzie reluctantly exchanged the bottle of Scotch for the gum mixture. He was then royally welcomed into the camp and given food and shelter. Imagine the "pang of conscience" suffered by this mighty Scot when, a few days later, travelling downstream, he saw the "tar" oozing out of the banks—gallons of which he could have had free. Truly, however, he was fascinated and termed this sight "fountains of bitumen" in his later memoirs.

And now, again, in 1951 the words "welcome" and "oil sands" are closely associated.

The world's demand for more and more petroleum products increases every day. Railways, industrial consumption, household requirements, automobiles, trucks and tractors accelerate this peacetime demand. The present international unrest aggravates anxiety occasioned through the expanding requirements for a war economy. Our dependence in Canada on surplus supplies of other nations causes us grave concern. Truly, in the face of all this, the development of the great Athabasca oil sands could be a tremendous stabilizing influence.

It is indeed a far cry from Peter Pond and the oozing "tar" made to run by a powerful sun, to the modern pilot plant that you will see at Bitumount; a century separates the primitive gumming of canoes by Sir Alexander Mackenzie and the modern uses made of petroleum; but the warmth of the welcome accorded you by the people of Alberta tonight is just as radiant, just as sincere, just as captivating as that accorded the early explorers by the primitive red men.

Yes, on behalf of the Government and the people of Alberta, I say "a hearty welcome to each and every one to this oil symposium!" From other parts of Canada you come, from the United States, and from countries beyond the seas, and we welcome you. God has endowed us with this great natural resource and it is our hope and wish and prayer that it be developed in the interests of mankind, to attain a world of freedom for all men, to build a greater Province, a greater Canada, indeed a better world.

May the words "welcome" and "oil sands" ever be closely associated!

INTRODUCTION OF THE SPEAKER

By Hon. Dr. J. L. Robinson

It is my privilege to introduce to you the Hon. Mr. Tanner. You have heard from me yesterday morning when your conference began and you heard earlier this evening from the Hon. Mr. Taylor, the two of us being on the Board of Trustees of the Oil Sands Project. The other member is the Hon. Mr. Tanner. He has been a member of that Board of Trustees for a long time. Mr. Tanner has been a member of the Legislative Assembly in this province for over 16 years continuously. He was Speaker of the House the first year that he was a member. He was taken into the Provincial Cabinet in the early part of 1937 and has been Minister of Mines in this province since that time. He has done an outstanding job, in my opinion, in the administration of the natural resources of this province. And that isn't my opinion alone. I think that outside of this province his reputation is very high. As an example, I might let you know that the Governor of the Barbados invited Mr. Tanner a little over a year ago to go to the Barbados and help the government down there draw up regulations in respect to their oil development. I think that was a great tribute to the job that he has been doing in Alberta. When it comes to leasing and royalties, Mr. Tanner knows pretty well where he is going; which way he is headed. He is not like the story I heard the other day about the dude rancher at the Calgary Exhibition and Stampede. He was putting the saddle on his horse and a cowboy standing by says, "Say, Mister, you are putting on that saddle wrong side forward." "Ha, ha," says the dude rancher, "why, you don't even know which way I am going." Well, we can't say that about Mr. Tanner in the leasing and rental policies of the Government in respect to our natural resources. He does know where he is going; he knows where he is headed. I have great pleasure in calling at this time upon the Hon. N. E. Tanner, Minister of Mines and Minerals in the Province.

GOVERNMENT POLICY REGARDING OIL-SAND LEASES AND ROYALTIES

By Hon. N. E. Tanner
Minister of Mines and Minerals, Government of Alberta

Mr. Chairman, Mr. Premier, and Gentlemen: I am very happy this evening to have this opportunity of addressing you and to welcome you to Alberta to this symposium. I hope that your stay here has been enjoyable up to the present time and that it will continue to be enjoyable, that your experience here will be such that you will want to hurry back.

I at this time wish to congratulate those who have arranged the symposium, the committee that has worked so faithfully and has so successfully worked out your program while here. I hope that your discussions will be profitable as well as interesting, and, as a result of your study and your stay in Alberta, that more of you will be interested in the development and be able to participate in it here in our great province. It is encouraging to see so many people here tonight and to see them attending the meetings as regularly as they have been for the last two days. I am very happy to bring you the greetings of the Government, as Mr. Taylor has done already.

The Province of Alberta is a very young province. The province was formed in 1905—it's less than a half century old—but until just about 1935 very little was known of this great province until that crazy Social Credit Government was elected with its funny money ideas, and people then began to talk about and know that the Province of Alberta was here and a part of Canada and an entity in itself. At that time, the common talk was that that same Social Credit Government would be the ruination of this province, in spite of the fact that conditions at that time were not the very best. In fact, the province at that time was in debt about 167 million dollars and the credit of the province was nil. The province had had a pretty rough ride. From 1905 to 1921, a period of about 16 years, they had a Liberal Government; from 1921 to 1935, a U.F.A. Government; and in 1935, conditions were such that everyone was sure that the Social Credit Government would just ruin the province. But, in spite of that same Social Credit Government, with the faith that the citizens in the province had in Alberta and its future and the interest that others have taken in the development of the province, Alberta has gone ahead.

The provincial debt, as I said, was 167 million dollars. That was the debt of the province in 1935-36. The debt on a per capita basis was $216.00. Today, the debt in the Province of Alberta is just under 100 million dollars, or an average per capita debt of $120.00. The debt program is such that if continued at its present rate, our debt will be paid off in less than 23 years and the province will be entirely out of debt. The thing I should like to emphasize in this particular part of the program is that this program was under way before the oil strike in 1947. The debt had been reduced annually before that time. The program had been worked out before that time. It is true that the strike at Leduc and the oil development since have accelerated the rate at which the debt is being paid off.

We, in Alberta, are glad and proud to be Albertans. I have been asked on several occasions if I were a native of Alberta. Well, I couldn't be a native of Alberta because I am older than the province itself. One of the school teachers asked my daughter if I were a native of Canada. She said, "No, he was born in the United States by mistake." I don't know whether she was trying to be so true to Canada or whether she was just trying to state in a very brief sentence how that thing worked out. My mother who had moved to Canada prior to my birth, said that she wanted to go back to the United States so that she could be present at the time of my birth and she brought me here when I was six weeks old.

This province of ours is a large province. We can compare it with States or we can compare it with countries in Europe, and we could place several of them in the Province of Alberta and still have room to spare. But, it is a young province. Our future lies before us; our history, we might say, lies before us, and though we have not done much to talk about we are determined to try to grow up as a province should grow up to take its part among the other provinces and states in this great continent. That is our determination. The province has an area of 255,000 square miles, a width of over 300 miles, a length of over 800 miles, and a population of less than a million—about four people to the square mile, which I am sure shows you that there is great room for growth and expansion here in Alberta.

We have gone in stages of development through the stages when the fur traders were here, the ranchers, the farmers, into the mining and now into the industrial development part of our program. And that industrial development is going ahead at a very satisfactory rate. During the two years of 1949 and 1950, 75 million dollars were spent in industrial development in this province, while at the present time the announced development for this year alone is over 60 million dollars.

Although the mineral development has seemed to be holding the limelight for the past few years, agriculture is still the basic industry of the province. Here we have about 90,000 farmers—farm families—in the province. During the year of 1950, those same 90,000 farmers produced and sold cash crops amounting to 500 million dollars, or over $5,000 per farm family. The average production in this province during the past 10 years has been over $2,800 per farmer. We have here over 60 million acres of land that are suitable for agricultural purposes, so you can see that our province offers room for development in that field. I could take time to tell about our homesteading program and tell you how easy it is for a man to establish himself on the land, and I shall just briefly state that 320 acres—a half-section of land—is made available to a man. He can go in there with no cost to himself, no cost as far as taxes or rental are concerned, for the first three years. After that time, he pays an eighth of the crop each year until the end of ten years, at which time the land becomes his free of any payment of cash whatever.

Though this province is referred to as a Prairie province, 40% of it is covered with timber, and we are carrying out the best conservation program that is possible for us to do with our present information, forest engineers, and so on.

As I stated before, it was in 1905 that Alberta was made a province. Prior to that time we were part of the Northwest Territories, and even until 1930 all of the natural resources were held by the Dominion Government and administered by them, and the conditions at the time of the transfer of the natural resources to the province were as follows. Up until 1887, when the Dominion Government gave title to any of its crown lands to an individual, the mineral rights went with the surface rights. In 1887, an Order in Council was passed by the Dominion Government retaining the minerals in the right of the Crown when the surface was sold or disposed of. When the natural resources were transferred in 1930, 10% of the mineral rights had been disposed of with the title to the surface. The Hudson's Bay Company had received or retained large blocks of land when they made the settlement with the Dominion Government; the C.P.R. was granted large tracts of land when they built the transcontinental railway; the C. & E. (Calgary and Edmonton) and the homesteaders who had their homesteads prior to 1887 all were given the mineral rights with the title to the surface.

I will now give you the development of the oil, which I think is the thing you are particularly interested in tonight. In February 1947, when the Leduc strike was made, Alberta was producing barely enough oil to satisfy her own requirements. Conditions were such that the companies here were considering seriously the possibility of making synthetic gasoline from natural gas, and some had started to search for natural gas in order to establish a field for that purpose. Since that time there have been 17 new oil fields discovered. Besides the 17 new oil fields, there have been strikes in 13 other areas where one or more wells have produced or are able to produce oil.

I should like to give you just a little picture of the development that has taken place and the rate at which it is taking place at the present time. The wells drilled up to December 31st of 1950, that's all of the wells that had been drilled up to that time, were 3,926—just under 4,000 wells; while during the year 1950 alone we had a thousand wells drilled. Up until December 31st, 1950, there were 2200 producing oil wells or wells capable of producing oil, and during the year 1950, 753 wells were brought into production or an average of better than two wells per day, every day of the year. At the present time we have over 150 geophysical crews at work in the province, 140 drilling rigs at work—that has been increased since these figures, and 50 drilling companies are registered as drilling companies in the Province of Alberta. The production for the year, last year—1950, was 27.5 million barrels, as compared with 6.8 million in 1947 when the Leduc strike was made. To give you an idea of the rate at which development is going forward, you might be interested in knowing that 10,624 leases are at the present held covering 5¾ million acres of land, and besides that there are over 360 reservations covering 40 million acres of land—that is, the land that is held by the companies either under reservation for prospecting purposes or leasing for development and production purposes. The highest daily average production for any week during 1950 was 101,000 barrels and the daily average production for the highest week during this present year up to date is 180,000 barrels, and so you see the rate of production has increased from 100,000 to 180,000.

It might be of interest to you to know at what rate money is being spent here in the province in the search for and the production of oil. During the year 1947, 36 million dollars were spent—that's for the search for and production; 1948, 50 million; 1949, 100 million; 1950, 150 million; and 1951, at the rate money has been spent and is being spent at the present time, it will reach the 200 million mark. This does not include the money being spent for refineries, transportation, and so on. The development has gone forward and the production has increased to the point where we are now able to serve 40% approximately—well over a third—of the requirements of the Dominion of Canada. The interprovincial pipeline running from Edmonton to the head of the Great Lakes, a distance of about 1150 miles, is capable of carrying between 75,000 and 90,000 barrels of oil a day. That oil is being stored at the head of the Lakes and also storage is available at Sarnia, and refineries are being built at Superior which will take some of that oil.

Now that we have undertaken to make available Canadian oil to the United States for use in their refineries there, we have taken the stand that oil going into the United States should go in duty free, at least as long as oil is being imported from the United States in quantities equal to or greater than the amount of oil that will go into the United States. We feel that that is fair; we feel that it is reasonable; and we feel that it is something that should be given serious consideration and worked out between the two federal governments. At the rate development is going forward today, it will be only a very short time until a pipeline will have to be built to the West Coast and probably the interprovincial pipeline looped in order to handle larger quantities of oil.

The question has been raised by some of the members here today as to what our attitude is toward the question of gas export because the hearing is on again at Calgary at the present time. I should just like to give you briefly the progress that has been made and the attitude of the Provincial Government on the export of natural gas. We have taken the stand that our first responsibility is to protect the interests of the people here in Alberta, but if, as, and when sufficient gas reserves are established and proven to meet our projected domestic and industrial requirements and there is a surplus sufficient to justify the export of natural gas, it will be in the best interest of Alberta and of Canada to have that gas sold outside of Alberta. The Provincial Government cannot say whether gas should go outside of Canada or not. That's a question for the Dominion Government to decide. But we feel that the sale of natural gas outside of the province would encourage further development; we feel that our sister provinces and those adjoining us are entitled to the gas if we have a surplus. We have changed our natural gas regulations so as to encourage further development, and I am very happy to say that the search for gas and the development of gas reserves is going on at a greatly accelerated rate over what it was at the time we changed our gas regulations. In fact, since January of this year, there have been 27 new strikes of gas in the province—that is, in areas where gas had not been found at any previous time. Besides that, of course, several of the other fields have been extended. The hearing is proceeding today.

I have tried to give you gentlemen a quick resume of conditions as they are. I should like to explain to you briefly what our policy has been and why. The Government has a definite policy as to the development of our natural resources. We feel that it is our responsibility as the oil-producing province in Canada to do what we can to encourage the development of that most valuable resource, and we have our legislation and our regulations to encourage that development, and from the figures that I have given you and the activity that is at present taking place here in the province I am sure it shows that development is going ahead at a very satisfactory rate. We are endeavoring to see that it is done in the best interests of the people of the Province of Alberta, and of Canada as a whole. Our conservation program, which we think is most important, is one to which we have given considerable attention and we have today a conservation program, which I say without any fear of contradiction, is second to none any place on this, the American continent. We feel that this resource is one that should not and must not be wasted, that development should be carried on according to the best engineering practice available to us. We have done all possible to prevent monopoly. We are opposed to monopoly of any kind, whether it be the government, a company or a group of companies. We feel that only through individual enterprise where we have good wholesome competition can development go forward as it should go forward, and we are determined to see that that same competition, individual free enterprise as you refer to it, is carried on and our natural resources developed under that program. At the same time, we are determined to do what we can to see that the people of the Province of Alberta get a fair share of the returns resulting from that development. As I said to a group of oil men the other night, "We are quite prepared and anxious to have you come in and spend your risk capital in the development of our natural resources. We want to give you a good run for your money. We want you to know that if you are successful in the search, that you will get a profit out of the development and the production. At the same time, we would like you to know that we are going to try to be at the end of the rainbow to get our share at the same time." That seemed to be accepted by the oil men as a fair deal and I would like to emphasize this: We, as a government, feel that the only way our natural resources can be developed fairly and development continued is for both parties to be fairly dealt with, and we are prepared to try to see that those who are prepared to spend their money in the search for and development of our oil resources will get a fair break.

We have been asked, and this is one point in our policy, "What do you do with the oil dollar?" We realize that as the oil is being taken out of the ground one of our capital assets is being depleted, and that it cannot be replaced, and the oil dollar should be used for capital expenditures in the building of permanent buildings, roads, and for other things such as paying off the debt which could be termed as capital expenditures. We feel that a country should be prepared to pay its current expenditures out of current revenue, and that the capital should be used for capital expenditures. So that is the reason why we are carrying on that program.

Tonight I am sure you are particularly interested to hear the policy of the Government as pertaining to the oil sands. You know that the Government established a pilot plant up at Bitumount some years ago. That plant has been operated successfully; we have proven as a result of that plant that the oil can be separated from the sand. We proceeded and progressed to the point where we felt that this information should be correlated, that it should be used in connection with other information available to an engineer, and we arranged, as you know, with Mr. Sid. Blair to head up this study and to bring in his report. I am sure you have all had copies of that report, and as a result of that report and our desire to see this natural resource developed we have called this symposium in which you have taken part and will continue to take part during the remainder of the week.

I have a written statement as to our policy because this is being recorded tonight and we would like to have a statement that we can hand to you so that there can be no misunderstanding as to what the policy is.

POLICY REGARDING OIL SANDS' DEVELOPMENT — ALBERTA

The Alberta Government is desirous of doing all that is reasonably possible to encourage the orderly development of the enormous oil sands' deposits in the interest of the people of the Province and of Canada as a whole, and, further, to the security of this continent.

At this early stage in the development it is important that the Government policy be set out as clearly as possible so that those interested in the development may know the terms and conditions under which they might obtain prospecting reservations and leases; at the same time it is essential that the policy be kept flexible in application in order to meet the variety of programs which may be pro-

posed by those interested in the development and also changing conditions and circumstances.

The following policy has been adopted to encourage immediate development to meet the ever-increasing demand for petroleum products and to offset the effect of the uncertainty of supply elsewhere in the world:

Any person desiring to undertake geophysical or subsurface geological exploration must first obtain a license to do so from the Department of Mines and Minerals at Edmonton. The license is issued for a fee of $25.00 and a cash deposit of $1,000.00 as security that all operations shall be conducted in accordance with The Mines and Minerals Act and the regulations established thereunder.

When a licensee, operating only under a license, locates an area of encouragement, any application that he would make for a bituminous sands' prospecting permit would be subject to the rights of others that might have already been established by previous disposals by the Province.

No doubt it would be logical for anyone wishing to explore the subsurface to first obtain an exclusive right to a defined area under prospecting permit by application to the Department.

Prospecting Permits

The maximum area to be included in a prospecting permit may not exceed 50,000 acres, and each applicant will be permitted to apply for only one permit. The fee for a permit will be $250.00, the rental payable for the first year will be five cents an acre and a deposit of $50,000.00 will be required from the applicant to guarantee that a satisfactory exploration program will be diligently conducted.

The term of the permit will be for one year and providing exploration is progressing with reasonable diligence, the permit may be renewed for one year at ten cents per acre and for a further period of one year at twenty-five cents per acre, provided that the renewals do not extend the period of the permit beyond three years from the date of granting the permit.

The applicant must present a plan detailing the nature of the proposed examination and the date when it is expected that the examination will commence. If the plan and date of commencement of operations are satisfactory to the Department then the permit will be granted.

If during the period of the permit or any renewal, the holder finds that a type of investigation not included in his plan would be beneficial in exploring the area, the plan may be varied with the consent of the Department.

Before the termination of the permit the holder must furnish to the Department a report including a map or maps showing the factual data obtained in the geological and geophysical examination together with the logs of any test holes drilled and such further information and data as the Department may require pertaining to the investigation. Evidence of expenditures incurred in the examination will be required from time to time and at the expiry of the permit.

The permit may be terminated at any time at the option of the holder and provided he has complied with the requirements of the Department he shall have the exclusive right to acquire by application a lease of bituminous sand rights within the area covered by the permit.

Where application is made for a lease, the deposit accompanying the application for the permit will be retained until the establishment of the plant to the satisfaction of the Department; providing a lease is not required and the permittee has complied with the conditions of the permit the deposit will be refunded.

Leases

The nature of the deposit determined by the investigation and the proposed capacity of the plant to be erected will be the main factors in determining the acreage that may be applied for under lease, as it is intended that each lessee would be entitled to a lease that would satisfy the requirements of a plant of the capacity proposed for a period of at least thirty years.

The lease will grant the right and privilege to mine, quarry, work, remove, treat and dispose of the bituminous sands and products thereof in and under the lands described in the lease but will not convey the right to drill for petroleum or natural gas.

The term of the lease will be twenty-one years, renewable for further terms each of twenty-one years so long as the plant is in operation.

The annual rental for a lease will be $1.00 an acre payable yearly in advance and the royalty to be collected during the first term will not exceed 10% of the products extracted from the sands and in the event that the sands are to be subjected to some other commercial use, a royalty will be payable on such sands.

The royalty payable during any renewal will be at such rate as may be prescribed from time to time by the Lieutenant Governor in Council.

The lease will require that construction of a plant of the agreed capacity must be commenced within two years of the granting of the lease and be completed and in operation within five years of the granting of the lease and thereafter processing of the sands must be diligently carried on.

That states as clearly as I can what our policy is, leaving it as flexible in administration as we can leave it so as to meet the varying conditions.

In the administration of this Department and in my talk tonight I have dealt with material things and in reading this statement to you, you will notice this particular sentence: "The following policy has been adopted to encourage immediate development to meet the ever-increasing demand for petroleum products and to offset the effect of the uncertainty of supply elsewhere in the world . . . **and to further the security of this continent."** It is important that we carry out a good program of development of our natural resources in the interest of security.

It is as important in our minds, gentlemen, that we carry out other programs, that we realize that the development of our natural resources and forests will not guarantee us any security, as world conditions are today. There are other things that count. It is important if we continue to enjoy the freedom that we do enjoy in this great country of ours, that we take time out to realize just what the problems are, that we take time out to let our youth know what those problems are. We get all tied up in these material things in the development of our natural resources, in our racehorses, in our dogs, etc., and some do it to the extent that they forget that they have children and youth growing up around them with ideals probably contrary to their own ideals and which are not in the best interests of that youth or of our country. Too often we fail to teach our children to appreciate their heritage, the opportunities that are theirs, the freedom and liberty which they enjoy and the great advantages of our Christian way of life, where men are free to choose their lives and what they'll be, and to help them realize that in return they have a great responsibility to help maintain their liberty and freedom. We forget that the future of this great country depends on the ideals and attitude of the children in our care. A little boy woke up in the morning and said to his mother, "Mother, how is it that last night when that pup was sick, Dad got up and he worried about it and he tended it and he called the vet so that the vet could take care of it, and when I am sick at night, all he does is turn over and groan?" The mother, after thinking for a little while and finding herself really on the spot, said: "Well, son, that pup's father is a thoroughbred and we must take care of it." I needn't say any more.

If we will realize that that child might be a thoroughbred, if we will appreciate the things we have, if we will recognize a Higher Power and help our youth to do the same, then we will be contributing more to the welfare and the security and the peace and happiness of this world than anything else we can do. May we acknowledge God as our Maker and be prepared to put into practice His teachings; may we do that in connection with the development of our resources and live to enjoy peace and happiness in this old world of ours. Communism and dictatorship have been able to take over in countries only to the extent that the people refused to accept and apply the teachings of God in their lives, and where they failed to take an active interest in public welfare. We must realize that the service we give is the rent we pay for the privilege of living in this old world, and the higher rent we pay, the better place we shall have to live in. Thank you.

DISCUSSION*

S. M. Blair: Mr. Tanner has come to amplify or explain further the policy outlined in his address on Tuesday evening. Mr. Tanner has a very packed program this morning which he has come away from to meet with us. We will, therefore, just interrupt our discussions now to hear from Mr. Tanner.

N. E. Tanner: I hadn't anything in particular that I wanted to say but I gathered from some of the discussions that there should be more clarification on points that were raised at the banquet the other night. So, at Mr. Blair's suggestion, I said that I would be quite happy to come here and answer questions and try to make clear any of the points that were not clear with regard to policy. There was one thing that I wanted to make abundantly clear in my talk the other night, and that was this: We are very desirous of having development here in the province of all our natural resources, and we feel that whatever company or companies are prepared to put their risk capital into this development are actually partners with the Government and the Government with them in that undertaking. We are very much against the promoter who is in there just for promotion's sake. If he is there for development and he thinks that the money is in the oil and not in the people; fine. But if he is there thinking that the money is in the people, we don't want any part of it. On the other hand, if we have bona fide operators who are interested in the development, we are quite prepared to "string along with them" as long as they are endeavoring to do the job. Now, that is one point that I wanted to make abundantly clear.

The other point was, and it was raised yesterday: "Just how flexible is your program? From the way you said that, it seemed to be pretty rigid." Well, I set that out as clearly and definitely as I could, and as near to what you might call regulation form as I could, so that there would be no misunderstanding as to just what was meant, but I fail to see any rigidity there. As far as being flexible is concerned, you will notice that the area can be up to 50,000 acres; you will notice the royalty is not to exceed 8% for the first term—21 years. And, further, our position is this: If you hold a reservation in that area, you hold it on the understanding that you have taken it to carry on exploration work, and if the exploration work is being carried on there will be no problem.

I think, Mr. Chairman, that that is all I should like to say, but I shall be quite happy to answer any questions if there is anything that anyone would like to raise.

Question: Is the royalty 8% or 10%?

N. E. Tanner. The royalty will not exceed 10%.

Question: To what extent does the province intend to provide roads, schools and other such facilities for families that might be involved in operations?

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* This discussion took place on Thursday, September 13th, during the final technical session.

N. E. Tanner: I would refer you to our program in the past—that is, what we have done in the past. When development goes forward, we deal with any area the same as any present-day established area. We would not build the schools; we would assist in building and pay the grants the same as we would in any other area. As far as roads are concerned, we have a policy. For example, getting into the area for exploration work and so on is the responsibility of the company. If development takes place and communities are developed, then we accept the responsibility in connecting them with the rest of the province.

Question: I have two questions that I would like to ask. The first is this: Does your figure of 10% represent 10% of the "in place" oil, or 10% of the ultimate product because of the fact that there are losses due to processing?

N. E. Tanner: Our royalty is placed on the raw product in all of our calculations. There may be one exception to that. In a condensate field where the gas goes through a separation plant we take our royalty on the amount that the producer receives or his share, but in this case it would be on the raw product.

Question: My second question: What incentives are being offered for a company which would like to set up a pilot plant first before they make a final decision about going in?

N. E. Tanner: Well, that could be done in his first three years. He could certainly, if he wanted to, undertake that right from the start—that is part of his exploration as far as we are concerned. That is the reason that I make the statement that you should have your program in mind so that you can outline it to the Department. If this man wants to undertake one kind of exploration—research work—that's satisfactory; we will work it out on that basis. If another chooses a different kind of program, we will work it out on that basis. Furthermore, the Government is prepared to consider giving some special concession to the person or company establishing the first commercial plant in the area.

Question: In other words, Mr. Tanner, you are quite prepared for the fact that this process is still far from being perfected technically and that there may be a good deal of development still to do.

N. E. Tanner: Yes, and the type of work that one operator wishes to undertake may be quite different from the type of work that another operator would wish to undertake, but it is all going forward to the final development and production of oil in that area.

Question: How do you evaluate that raw material in order to apply your 10% royalty factor?

N. E. Tanner: That could be done in one of two or three ways. We would try to get what we would call a fair value. I don't think that the Government should take an arbitrary stand on this and say that the value is a dollar or that the value is sixty cents. Coming back to that word "partner"; I am sincere when I say that

I think any government has to act that way if they are going to carry on with a long-range policy. The company must make money. It must have a profit if it is going to continue in operation; and only to the extent that the company continues in operation is it beneficial to the province. Well, I think people who know will tell you that that is the attitude of the Government and I fail to see why any other government should take a different attitude. If they do, I can't help that, but I wouldn't expect them to. I am not answering your question directly, but I think it is impossible to answer it. You could say, "Here is the value of the product and here is the cost of getting it to that point and here is the profit on it and so just deduct that from what you sell it for." There are ways that it can be arrived at; that is what I am trying to say.

Question: When you say the first three years for pilot-plant work, are you referring to the permit period in which 5, 10 and 25 cents per acre is being charged?

N. E. Tanner: I understood this gentleman to mean that he was going into the pilot-plant operation now. If that is what he meant, then my answer was right. If he meant later, that after three years' exploration he wanted to put up a pilot plant, then that would have to be decided at that time by the two parties concerned because, otherwise, construction of the plant must be commenced within two years of the granting of the lease and be completed and in operation within five years of the granting of the lease. So all in all, if the man took a reservation today and he continued diligently to carry out the undertaking he has made with the Department, he has eight years to get into production.

Question: It has been made abundantly clear to the delegates here that certain of the deposits in the Blair report, particularly those lying along the Athabasca River, are more advantageous than other parts of the deposit. I think that it is only common sense that those deposits with less overburden are, of course, more attractive ones than the alternate deposits. In your policy, regarding the 50,000-acre block, has a policy been written regarding shape or configuration or location of that block relative to these thin overburden deposits and the river access properties?

N. E. Tanner: No, it hasn't been written into the regulations but much thought has been given to it. Due to the complexity of the thing it was decided definitely not to state what it would be. Conditions vary in that area. We do feel that no company should be permitted to take their lease right along the river bank and make it narrow and take full control of the river bank. They may want to get back away from the river. They may want it running east and west; they may want it running north and south; and it will depend on the location as to just what they can expect. Whatever lease or whatever reservation they take will be granted on the survey line. I don't mean that it would be a perfect rectangle but it would be on the survey lines. We think that no company should be permitted to take all the river front, and I think everybody would agree with that. We feel that probably a four-, five-, or six-mile river front should be the maximum, and then they can go back a distance of eight or ten miles in order to get the amount of land that they require. On the other hand, they may want river front only for access, for drainage, or for water supply. We wouldn't require them to take the river front. So we would try to see that the area they wanted was granted to them providing that it was a reasonable request. And I think it's much better to be in that position than it is to say, "You can only have a six-mile river front." Well, they might not want a river front.

Question: If two companies were to go in with entirely different processes to develop this oil sand with different operating costs, would the Government set the same dollar royalty on both plants or would it take into account the difference of operating costs?

N. E. Tanner: We would not be in a position to take into consideration the operating cost. We never work on a net royalty, but if we take it on the raw material, then the better operator has the advantage. We never admit that the poorer operator has the disadvantage.

Question: Is there any provision for setting aside a Crown reserve?

N. E. Tanner: No, not in this area.

Question: Can the original block be controlled by the company and developed?

N. E. Tanner: No, not exactly. They may require the whole 50,000 acres. They take the reservation of 50,000 acres and if, when they have completed their work, they wish to lease the 50,000 acres, and the Department and the company agree that that amount is required to operate their proposed plant for a period of at least 30 years, then they would be permitted to lease all or any part of that area if it were required. You remember the statement that the kind of operation, the amount of land, and the findings as a result of the exploration, would determine the acreage required to supply the plant for a minimum of 30 years.

Question: Must the tract under consideration be continuous?

N. E. Tanner: The lease? Not necessarily. Not if it's within that area.

Now, there is one other point that just comes to mind. As I read that statement of policy again yesterday, I saw two or three places that might not be exactly clear unless you could see what was in our minds or what had caused us to write it that way. There is a difference between a prospecting license and a prospecting permit. For $25.00 and a deposit of $1,000.00, you can get a prospecting **license** which permits the carrying on of exploratory work, but it does not guarantee that you can lease any particular area after you have completed your work. If you want to do that, you can carry on under a prospecting license for any number of years but you have no assurance that any particular parcel of land will be available to you when the prospecting has been completed. However, if you have a prospecting permit then you take it on a specified area and have the assurance that you can lease any part of it which is necessary for your operation.

Question: First come, first served?

N. E. Tanner: Yes.

Question: In the maps we were given, is there any indication of various areas along the river which are reserved?

N. E. Tanner: No, they are patented.

Question: Patented or leased?

N. E. Tanner: Just a word of explanation on those maps. The red areas are patented. In every case, either the Dominion Government or some company has the patent for those areas. Then, there is an area that is leased to Abasand Oils Ltd. There is an area, I think marked in yellow, that is held in reservation by Champion out of which he can lease 3,840 acres. The reservation held by Champion allows him to lease 3,840 acres providing he does the work that he has undertaken to do. That is all I can think of at the moment.

Question: As far as you know, does either the Provincial or the Dominion Government have any plans for further drilling in this area regardless of what companies do?

N. E. Tanner: The Province hasn't. Dr. Hume could tell you whether or not the Dominion has any further drilling program, or any testing program, in that area. I say, as far as the Province is concerned, we haven't any program.

G. S. Hume: We have no program at present.

N. E. Tanner: Mr. Chairman, I wish to thank you for this opportunity because I did want to leave a clear-cut understanding of just what our attitude and policy is. Thank you.

OIL-RECOVERY SESSION

CHAIRMAN: K. A. CLARK
Research Council of Alberta, Edmonton

Attention is being turned, in this session, to the recovery of oil from the oil sands. A brief history of the main events in the study of the application of methods of recovery of oil from the Athabasca oil sands will serve as a background for the four papers to be presented.

The Research Council of Alberta, when it commenced its oil-sand investigations in 1920, judged that the hot water washing method offered the best promise for successful recovery of oil from the sands. Consequently, it applied itself to the study of the applicability of this method to the Athabasca oil sands and has continued with this work up to the present time. Much of the work has been done in the laboratory but use has been made of small pilot plants. Two of these were built and operated in Edmonton during the 'twenties and a third one was located on the Clearwater River near Waterways in 1929-30. This latter small plant was used in a co-operative project of the Research Council of Alberta and the Dominion Mines Branch, the former organization concerning itself with the separation of oil while the latter did the mining and utilized the oil that was separated for experimental paving work at Edmonton. Coming to more recent years, the Research Council of Alberta had a part in the planning and operation of the Government of Alberta plant at Bitumount. The flow-sheet of this separation plant was the up-to-date expression of the results of Research Council of Alberta studies.

Two private companies installed hot water separation plants in the North soon after the demonstration of the method by the Research Council of Alberta on the Clearwater River. The first was the International Bitumen Company, which erected its plant at Bitumount. The place name was that given to the post office established at the plant. The hot water method used deviated considerably from the procedure of the Research Council of Alberta.

The second company to build a plant was Abasand Oils Ltd. The site of its activities was in the valley of Horse River a few miles by road from McMurray. Mr. Max W. Ball was the president of the company. The design of the separation plant was that of Mr. J. M. McClave. His hot water separation procedure also differed from that of the Research Council of Alberta. He formed and heated his oil-sand pulp by adding enough hot water to the oil sand to obtain a resultant temperature of around 150°F. A very watery pulp was obtained and heat requirements were high since there was no re-use of hot water.

The Abasand Oils plant was taken over by the Dominion Government during the war for experimental purposes. The high heat consumption of the plant led the federal workers to the view that the hot water washing method was uneconomical. A procedure for accomplishing oil recovery using cold, or at least cool water was sought. Progress was made and the plant was redesigned to operate on cold water. A fire destroyed the plant before it got into full operation on this system. Further study of the cold water procedure was undertaken by the Mines Branch at Ottawa. A laboratory pilot plant was built and operated, and the work was carried forward to an advanced stage.

Fairly recently a different approach to recovery of oil from the oil sands has been presented by the National Research Council at Ottawa. Retorting of the oil sand is an obvious way of dealing with the recovery problem but this method has, in the past, had the disadvantage of being a batch operation. Dr. P. E. Gishler saw that the operation could be made continuous by using the fluidized solids technique. His first paper on the results of the application of this technique to the Athabasca oil sands appeared in 1949. Oil sand was used as the feed material in the first work on the method. The study of oil sands development as a whole that preceded the Blair report indicated that it would be advantageous to use the wet crude oil product of the hot water separation process as the feed to the fluidized solids continuous retort. Consequently, Dr. Gishler and his associates ran tests on this feed to find out what operational problems were involved and whether the coker distillate was different from that obtained from an oil-sand feed.

The Research Council of Alberta has continued with its oil-sand work since the operation of the Provincial Government plant at Bitumount in 1949. Because it considers that the hot water process has been sufficiently investigated for the time being, at least, attention has been turned to the simplification of the separation plant.

The papers to be presented at this session deal with the cold water, the hot water and the fluidized solids methods of recovering oil from the oil sands, and with hot water separation plant simplification. The first one gives an account of the work of the Mines Branch, Department of Mines and Technical Surveys, Ottawa, on the development of the cold water process.

COLD-WATER METHOD OF SEPARATION OF BITUMEN FROM ALBERTA BITUMINOUS SAND

By L. E. Djingheuzian
Mines Branch, Department of Mines and Technical Surveys, Ottawa

One of the processes which S. M. Blair described in his report is the cold-water process of separation of bitumen from Alberta bituminous sand as worked out at the Mines Branch in Ottawa on a small pilot-plant scale. The idea of using cold water, in contrast to the use of hot water, is probably inherent in the hot-water method and this, the writer believes, is what caused initiation of the experimental work on cold-water separation of bitumen in the laboratories of Abasand Oils Limited.

The laboratory work having indicated the feasibility of cold-water separation, a cold-water separation pilot unit was installed by the General Engineering Company of Toronto, who were managers of the plant of Abasand Oils Limited. This pilot unit consisted of a mixer to which the bituminous sand together with water and light oil, the latter having properties of kerosene, was fed at around 70 to 80°F. The mixer was followed by a Geco flotation cell, the floated diluted bitumen from the cell going to settling chambers. The results obtained with this pilot unit were stated to be so good that the whole hot-water plant of Abasand was converted to the cold-water process. Unfortunately, before this cold-water plant, expected to handle upwards of 500 tons of bituminous sand in 24 hours, was started, it was destroyed by fire in 1945. In this fire practically all the records of the preliminary investigations were lost.

When, after the fire, Abasand Oils Limited was unable to continue the experimental work, laboratory research was started at the Mines Branch in Ottawa. This laboratory work was carried out by H. L. Beer and subsequently by P. V. Rosewarne and A. A. Swinnerton under general supervision of T. E. Warren. A trial semi-pilot run was made by H. L. Beer and a 200 lb. per hour pilot plant was designed and erected.

Investigations and Results

Pilot-plant investigations using the cold-water method of separation of bitumen, for which 150 tons of bituminous sand were obtained from the Horse River property of Abasand Oils Limited, near McMurray, were started on April 19, 1949, and completed on May 19, 1950.

The purpose of these pilot-plant investigations was to establish cold-water separation of bitumen from Alberta bituminous sand as an ore-dressing process, to work out the operational technique, and to establish the most economical flow-sheet possible.

To do this it was necessary to proceed in a systematic way, each week's run being made under constant conditions so as to obtain more reliable data. The performance of each machine had to be evaluated, basing these evaluations on the results of weekly runs. The characteristics of each procedure tried had to be determined with a view to deciding on a machine or a re-arrangement of the flow-sheet which might be an improvement on the previous one. Sampling procedure had to be standardized most carefully. In addition, the samples had to be assayed within 24 hours, for which purpose a special section was set up at the Division of Fuels for rapid analysis of the samples. A close check was kept on the controlled additions of the alkaline reagents and wetting agents, and effects of those additions studied.

The terms used in discussion of the experimental data are defined as follows:

Diluent—a petroleum distillate, which added to the feed, would combine with liberated bitumen;

Oil—combined bitumen and diluent;

Crude oil or finished product—No. 1 thickener overflow;

Classifier sands—mineral matter eliminated by the classifier from the feed;

Tails—No. 2 thickener underflow;

Classifier extraction—oil overflow from the classifier and pumped into No. 1 thickener;

Recovery—oil overflow from No. 1 thickener and delivered to the refinery;

Net recovery—bitumen input minus total oil loss in terms of bitumen.

Hence:

$$\%\ \text{sands eliminated by classifier} = \frac{\text{dry classifier sands}}{\text{mineral matter in feed}} \times 100$$

$$\%\ \text{classifier extraction} = \frac{\text{oil input—oil in classifier sands}}{\text{oil input}} \times 100$$

$$\%\ \text{indicated recovery} = \frac{\text{oil input—oil in total tails}}{\text{oil input}} \times 100$$

$$\%\ \text{net recovery} = \frac{\begin{array}{c}\text{bitumen input—oil (in bitumen terms)}\\ \text{in total tails}\end{array}}{\text{bitumen input}} \times 100$$

The bituminous sands can be regarded as, essentially, a compacted mass of sand particles held together by bitumen which forms a film around each particle. When a light oil having the properties of kerosene is added to the bituminous sand at the same time as the bitumen films around the sand particles are ruptured or scoured off by some rubbing action, bitumen dissolves in the light oil, forming a compound oil with a specific gravity of less than one. When this process takes place in water, the heavier-than-water sand particles, liberated from oil, fall to the bottom of the vessel and the lighter oil rises to the surface. Thus, fundamentally, the cold-water process is a gravity concentration process in which the valuable constituent of the ore rises to the surface and the gangue sinks to the bottom.

In the preliminary stages of pilot-plant investigations the process consisted of the four following steps:

(1) Disintegration of bituminous sand by means of a low-discharge pebble mill; kerosene in amounts approximately equal to the bitumen content of the sand was fed into the pebble mill together with the sand. Soda ash was also added to the feed.

(2) Separation of combined bitumen-kerosene, designated as oil, from the sand in an agitator.

(3) Classification of agitator discharge, by means of a rotary classifier, into sand and oil slurry fractions.

(4) Settling the oil slurry with cone classifiers and in tanks.

A product suitable for the heat-treatment plant (refinery), as designed by the Division of Fuels, was obtained.

The optimum temperature range was determined as 73 to 81° F. Below 73°F. the separation became less efficient and incomplete. When the temperature approached 83°F. the sand discharged from the rotary classifier started becoming dirty and more free oil ran over with it, while higher temperatures resulted in still dirtier sand discharge. Thus the temperature control of the classifier overflow was the key to the efficient operation of the plant with high bitumen recoveries.

In these preliminary runs the indicated recoveries of oil were over 97%, and samples of crude oil, taken with a dipper from a tank after overnight settling, averaged 76.4% oil, 1.9% mineral matter, and 21.7% water. The requirements of the refinery for the crude oil, as specified by the Division of Fuels, were "not less than 65% oil and not more than 5% mineral matter and 30% water," and a crude oil suitable for treatment in the refinery was always obtained when settling was allowed. However, in a big plant settling meant a very large tankage capacity, which from the ore-dressing point of view did not appear to be attractive. Hence, it was decided that, while keeping the recoveries as high as possible, all the efforts should be directed towards obtaining a crude oil of sufficiently high grade without the necessity of prolonged settling.

It turned out that this was a wise decision. As the investigations progressed, it was found that settling caused an excessive oil loss through the formation of an oil emulsion termed sludge which settled at the bottom of the tanks. When attempts were made to adapt the ore-dressing techniques, already worked out, to the recovery of oil from the sludge they proved to be failures.

Djingheuzian and Warren say (3): "The magnitude of this loss was not known at first and it was not taken into consideration in calculating the recovery of oil. In the final arrangement of apparatus, a different settling procedure eliminated sludge formation.

"During the preliminary runs, the equipment was progressively altered and the final apparatus and operating scheme were as follows. The low-discharge pebble mill was satisfactory, as initially used for the mixing and disintegration step. With a charge of 0.5 lb. of pebbles per lb. of bituminous sand per hr., the oil was separated with very little size reduction of the sand. The agitator was also satisfactory. The vertical centrifugal pumps were found to cause froth formation and were replaced by suction pumps with a positive action. The rotary classifier was replaced by a 14 in. by 8 ft. duplex rake classifier. The settling operation was carried out in two thickeners. The classifier overflow was pumped into the first of these, which was 4 ft. in diameter and 4 ft. deep. The overflow from the first thickener was the finished product of the hydrometallurgical section of the plant (cold-water separation plant). The underflow from the first thickener, which still carried appreciable amounts of oil, was pumped to a second thickener 4 ft. in diameter and 3 ft. deep. The underflow from the second thickener was sent to waste and the overflow returned to the first thickener. The settling tanks were removed in

TABLE I

Oil sand treated, lb.	Feed rate, lb./hr.	Soda ash, lb./ton	Wetting agent, lb./ton	Av. temp., °F.	pH of class. o'flow	Bit. in feed, %	Visc. comb. oil, cp.	Class. sand, %	Oil in class. sand, %
Series of Weekly									
6550	238.1	1.46	Span 80, 0.041	77.4	9.5	15.8	103.7	92.8	0.41
4050	238.1	1.45	Rosin Amine, 0.041	77.2	9.2	16.2	103.7	89.6	0.47
6600	300.0	1.56	Span 80, 0.031	78.3	9.3	14.9	103.7	88.3	0.38
3100	215.0	1.51	Span 40, 0.041	77.0	9.1	15.9	103.7	82.0	0.26
Series of Weekly Runs									
4450	170.0	0.68	Span 80, 0.062	79.0	8.6	15.4	336	87.7	0.26
5700	215.8	0.89	Span 80, 0.045	81.5	9.0	16.5	336	92.3	0.35

order to avoid prolonged settling which was always attended by sludge formation. The revised flow-sheet is shown in Fig. 1."

The combination of apparatus shown in Fig. 1, with the use of soda ash and suitable wetting agents, eliminated the necessity of settling the thickener overflow and a crude oil of a grade sufficiently high to be suitable as a direct feed to refinery was produced in a continuous process.

Table I gives the results obtained with the last six weekly series of runs the first four being made to test the effectiveness of different wetting agents using kerosene as a diluent, and the last two using as a diluent, a heavier-than-kerosene petroleum distillate obtained from the experimental plant operated by the Alberta Government at Bitumount, Alberta.

Several observations, which also sum up the results obtained from numerous daily runs, can be made from a study of the above table:

(1) In every series of runs, with high over-all recoveries maintained,

TABLE I

Class. oil yield, %	Tails oil loss, %	Tails to waste, lb.	Indic. recov., %	Net recov., %	Bit. loss, lb./ton	Dil. loss, lb./ton	No. 1 thickener overflow		
							Oil, %	M.M., %	Water, %
Runs with Kerosene									
98.6	0.12	14,960	97.8	95.6	7.2	6.8	71.3	2.1	26.6
98.6	0.17	11,000	97.1	94.2	9.4	8.9	71.5	1.3	27.2
98.8	0.12	18,040	97.7	95.4	6.9	7.4	75.6	2.2	22.2
99.3	0.10	10,120	98.2	96.4	5.7	5.6	75.6	1.7	22.7
with Bitumount Diluent									
99.2	0.18	20,240	96.5	93.0	10.6	10.5	67.5	3.0	29.5
99.0	0.12	22,880	97.5	95.0	8.1	8.5	70.9	2.7	26.4

a thickener overflow was obtained which could be fed directly into the refinery.

(2) The optimum amounts of soda ash required per ton of oil sand are governed by pH of the classifier overflow. Whenever this pH dropped below 9.0, the recoveries started to fall off.

(3) The beneficial effects of all three wetting agents on the treatment of oil sand were firmly established. Indications were that Span 40 gave the best results, followed by Span 80 and Rosin Amine D Acetate.

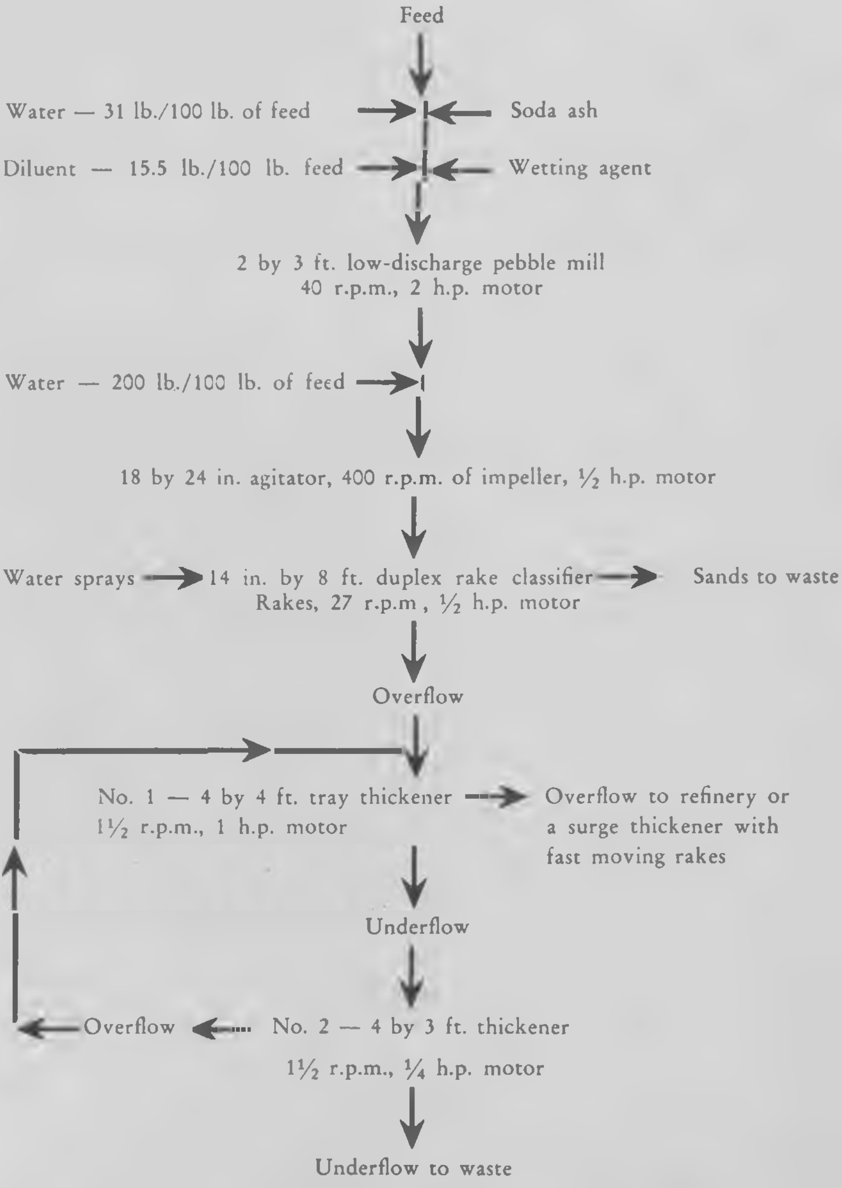

Fig. 1. *Flow-sheet.*

(4) The indicated recoveries of oil by the use of the Bitumount diluent were practically the same as with kerosene, and, more important, the grade of the thickener overflow was suitable as a refinery feed so that settling was unnecessary. Since the diluent to be used in a large commercial operation must be a derivative from the bitumen itself, it was essential to ascertain whether the ore-dressing technique, already worked out with kerosene as a diluent, would apply also when using heavier oils directly derived from bitumen. For this purpose, six barrels of an oil derivative from Alberta bituminous sand were obtained from the Bitumount plant in Alberta.

Effect of Clay in Bituminous Sand and the Effect of Reduced Water Additions to the Mill Circuit on Oil Recoveries

As it is well known, the Alberta bituminous sands carry varying amounts of clay.

The observations made at the Mines Branch on the effect of clay on oil separation and recoveries in the cold-water process (2, 3) were similar to those made already by Clark and Pasternack in the hot-water separation process (1).

Investigations were also carried out on the effect of reduced water additions on oil recoveries. Though it was found that for the highest recovery of oil a total water to feed ratio of 3:1 by weight was the optimum ratio, there was sufficient evidence to show that the best economical balance would be obtained with water to feed ratio of somewhere between 2.5:1 and 2:1.

SUMMARY AND CONCLUSION

(1) A flow-sheet with standard ore-dressing equipment was developed which, using Bitumount diluent and small amounts of soda ash and wetting agent, obtained a net recovery of 95% of bitumen from Horse River sand.

(2) The use of soda ash is imperative. When its use was discontinued the result was always a low recovery of oil, even if the pH was over 9.

(3) The optimum range of temperature was found to be 73 to 81°F., though good recoveries were also obtained at as low a temperature as 70°F. and as high as 83°F.

(4) The optimum pH required appeared to be just over 9.

(5) To obtain the best recoveries the mineral matter in the bituminous sand had to be reduced in the pebble mill from 5 to 7% minus 200 mesh to 11 to 15% minus 200 mesh. This grind was the measure of efficient loosening and scouring of the bitumen off the sand.

(6) Increases in clay content affected thickener recoveries adversely. However, since the best separation of oil in the classifier took place with a certain content of clay in the mill feed, there appears to be an optimum content which will assist in effecting the highest over-all recoveries.

(7) Crude oil of a grade suitable for refinery treatment was produced consistently in a continuous process.

COMMERCIAL APPLICATION OF THE COLD-WATER METHOD TO PROCESSING OF ALBERTA BITUMINOUS SAND

It is evident that commercial exploitation of bituminous sand is possible only on a large scale. However, the operation of the Mines Branch pilot plant cannot be used as a basis for the design of a mill for treating 20,000 cu. yd. (33,700 tons) per day because the operation of the pilot plant does not give sufficiently conclusive data on mill capacities for large-scale calculations. It is suggested that the operation of a 500 ton per day pilot mill would furnish the necessary data for the design of a 20,000 cu. yd. mill. Accordingly, a flow-sheet for a 500 ton mill was designed.

The cost of the equipment for this 500 ton mill together with motors f.o.b. Waterways, Alberta, will come to around $140,000 (1950 prices) or, it might be said that the cost of the 500 ton mill erected on site will be roughly $300,000. This will also include the cost of the mill laboratory.

Fig. 2 shows this flow-sheet for the 500 ton mill.

While conducting his survey, Blair asked the writer whether he could prepare an estimate for a 20,000 cu. yd. per day cold-water separation plant, together with an estimate of personnel required to operate the plant. The writer stated that with the present data on hand such an estimate could, at the best, be only a very rough approximation. However, on the assurance that the estimate would be treated as such, a rough estimate was prepared, and it is shown below in a slightly revised form. The slight revisions were necessary when more information became available with the issuance of the Blair report.

Estimated Capital Cost of the Plant

1. Machinery, complete with electrical equipment, f.o.b. Waterways, Alberta	$ 6,000,000
2. Add 100% for costs for the erection of buildings and installation of machinery, and also costs for transportation of machinery and materials from Waterways to the site of the construction	$ 6,000,000
Total estimated capital cost	$12,000,000

In the above estimate of the cost of machinery, since there was no time to obtain proper specifications and quotations for some of the equipment from the manufacturers, the writer had to base prices of this equipment on his past experience and to bring them to 1950 levels.

The cost of erection of buildings, installation of machinery, etc., was estimated at 100% of the machinery cost. This was based on the cost of the erection of buildings, installation of machinery, etc., for

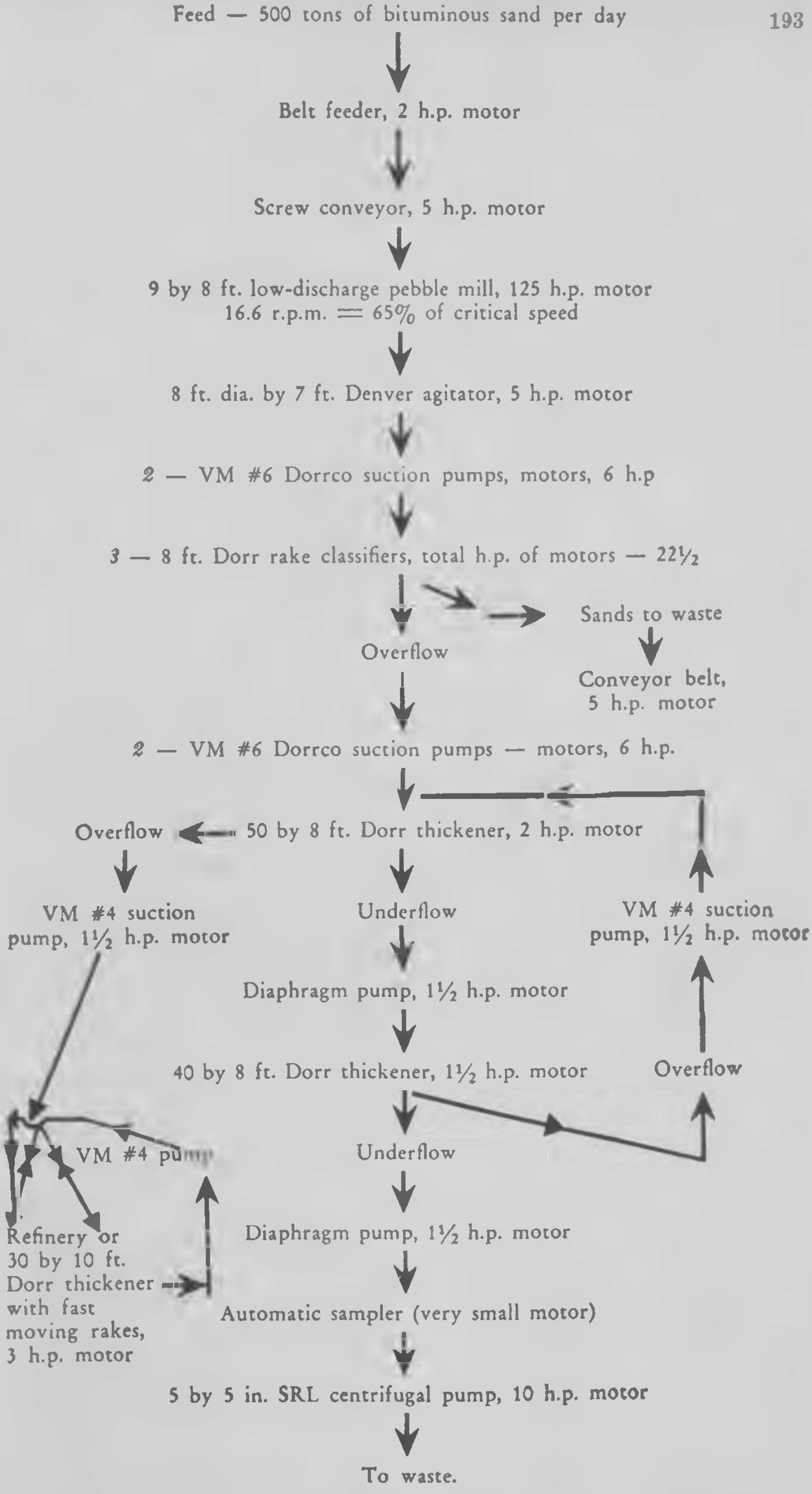

Fig. 2. *Flow-sheet*

the Bitumount plant which amounted to 98% of the total cost of machinery f.o.b. Waterways. However, it must be added that within the writer's experience, the costs of building, etc., at the mining

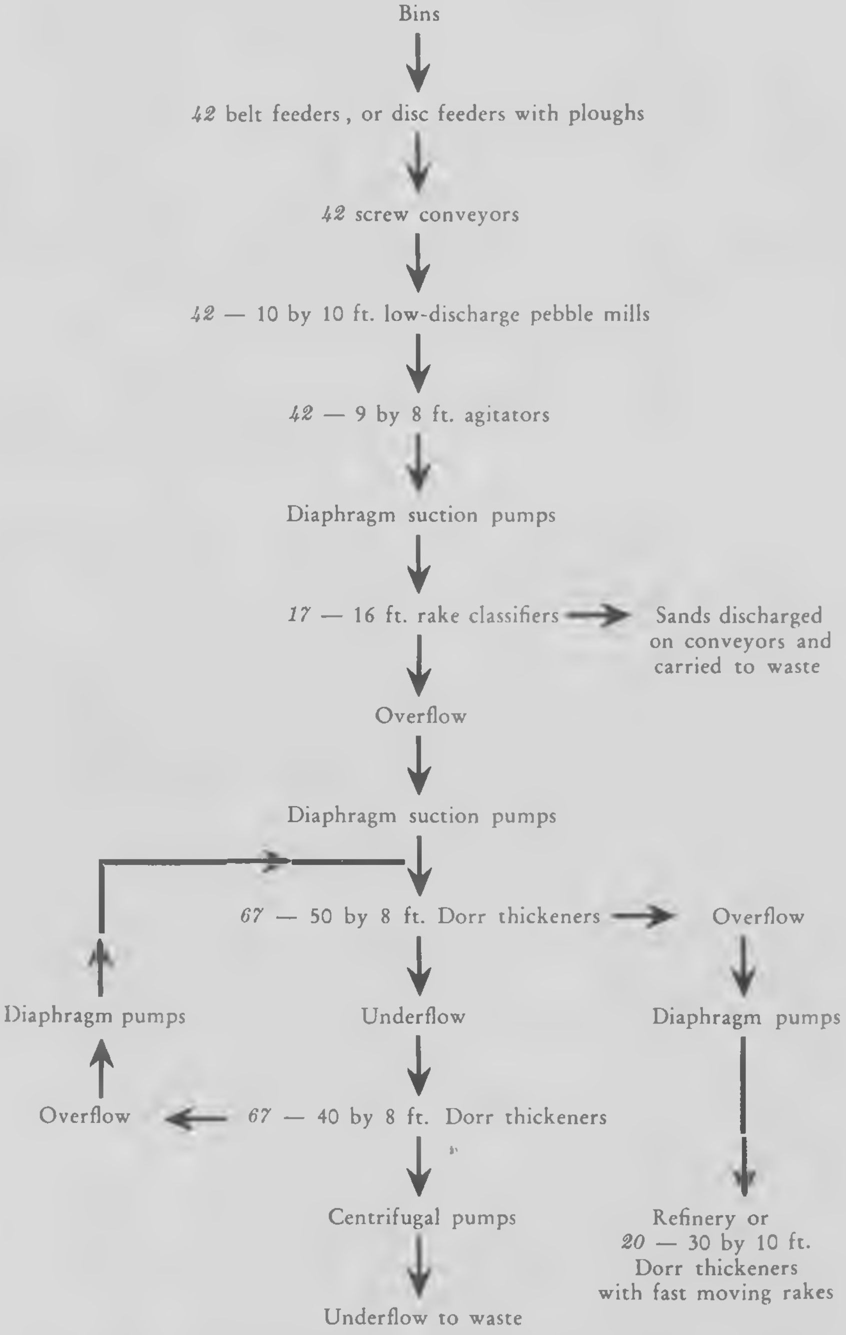

Fig. 3. *A preliminary rough estimate of a cold-water separation plant treating 20,000 cu. yd. of Alberta bituminous sand per day.*

camps of Northern Ontario and Quebec have been around 125% of the cost of machinery f.o.b. manufacturing points.

The flow-sheet in Fig. 3 is based on the following assumptions:

(1) Tonnages handled by pebble mills are directly proportional to the pebble charge. In other words, at 0.6 lb. of pebbles per lb. of feed per hour, a 10 by 10 ft. mill will handle 471 cu. yd. or 785 tons of bituminous sand per day.

If, on the other hand, the capacity of the mill varies as the diameter to 2.4 power, which is the capacity of cylindrical mills when grinding paints, then the capacity of a 10 by 10 ft. mill will be 1,471 tons, or around 872 cu. yd. of bituminous sand per day. This, by cutting down the required number of 10 by 10 ft. mills to 23, will cut down the capital cost and, by cutting down labor, power, etc., will cut down operating costs also.

(2) Rough calculations indicate that a 16-ft. Dorr rake classifier will handle 2,000 tons or around 1,185 cu. yd. of bituminous sand per day. It is, of course, expected that classifier capacities must be first determined by the operation of a 500 ton pilot mill.

In actual practice it would be better to use a smaller classifier for each individual pebble mill. The advantages of this method are obvious, since this would eliminate the necessity of controlling the amount of feed to each classifier.

(3) A 50 by 8 ft. Dorr thickener will handle a minimum feed equivalent to the original 500 tons or 300 cu. yd. of bituminous sand per day. Thickening would thus require 67 50-ft. thickeners. However, it is expected that a 50-ft. thickener would handle more feed and, if this be so, then less than 67 thickeners would be required to handle a feed equivalent to 20,000 cu. yd. per day. This will also cut down the number of secondary thickeners required, thus affecting more reduction in capital and operating costs.

It might be asked here why thickeners of larger diameter are not used. A 100-ft. thickener, for instance, has four times the capacity of a 50-ft. thickener but, by using a 100-ft. thickener, the time of contact is correspondingly increased and this might contribute towards sludge formation.

From the foregoing estimate and discussion it can be seen that the preceding flow-sheet (Fig. 3) gives the picture of the cold-water separation plant in its most expensive form. However, it must be emphasized that no design of a 20,000 cu. yd. plant can be contemplated before the capacities of the various plant units are established by the operation of a 500 ton or 300 cu. yd. per day pilot unit. There is little doubt in the writer's mind that with the data obtained from the operation of this pilot unit, the flow-sheet given in this report can be vastly improved and costs reduced.

Basing the estimate of personnel on the flow-sheet given in this report, the following is the proposed list of superintending staff and operating labor for a 20,000 cu. yd. per day plant for cold-water separation of bitumen.

Personnel

1—Mill superintendent
1—Assistant mill superintendent
1—Research engineer
4—Laboratory assistants
3—Mill shift bosses
1—Grinding engineer
3—Thickener shift bosses
18—Pebble mill operators
18—Pebble mill helpers to look after agitators, feeding of pebbles, etc.
6—Classifier operators
21—Primary thickener operators
15—Secondary thickener operators
3—30-ft. thickener operators
1—Mill statistician
1—Draftsman
1—Stenographer
2—Clerks

Maintenance labor is not included in the above estimate of the personnel. However, for the purposes of estimating costs, the maintenance charge per year may be assumed to be 5% of the capital cost. Actually, this is a very high figure, since in ore-dressing installations, because of the robustness of ore-dressing machinery, the maintenance cost is much lower.

The personnel estimate also does not include labor, in case it is required, for feeding bituminous sand from the bins onto belt feeders. The feeding of sand was a problem that the writer had neither opportunity nor means to study at the Mines Branch.

Since feeding arangements appear to be a definite problem, it must be listed as a separate step in the process and given a thorough study at the 500 ton pilot plant. However, for the purposes of this preliminary estimate it is suggested that, provisionally, feeding methods used at Bitumount should be considered in order to arrive at some idea as to the extent that the feeding process is going to influence the costs.

Commenting further on the above estimate of the personnel, it must be said here that it is fully expected that this estimate will be checked. At the same time, no estimate can be considered correct until studies are made when operating a 500 ton pilot mill.

To illustrate the point an example will suffice: At Chino Mill, Nevada Consolidated Copper Co., one man per shift takes care of 21 thickeners ranging from 20 to 75 ft. in diameter, whereas in this estimate the writer assigned 10 thickeners to a man per shift, his chief reason being that the overflow of the thickeners in the cold-water separation of bitumen must be controlled very closely. In addition, to make this control as foolproof as possible, three additional jobs had to be created, namely, those of thickener shift bosses. It is possible that the operation of a pilot plant might show that a man can take care of more than 10 thickeners and, at the same time, keep the overflows under close control. However, till complete data are obtained from the pilot-plant operations, care should be taken that, for the purposes of this estimate, every possible factor which might influence the costs is taken into consideration.

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DISCUSSION

Question: Concerning this film of bitumen that surrounds the sand grains as you put it, are the sand grains coated by water or by bitumen?

L. E. Djingheuzian: In bituminous sands, Dr. Clark's investigations disclosed that a very thin layer of water surrounds each sand particle and this in turn is surrounded by a bitumen film. As regards classifier sands in the cold-water process, the sand itself appeared to be very clean and coated with water. It is only clay particles which adsorb bitumen, so that the final loss of oil depends on the amount of clay present.

Question: How much diluent is used, and what is the loss of diluent in the tailings?

L. E. Djingheuzian: The amount of diluent used is equal to the oil content of the sands. That is, if the oil sand contains 15% oil, or 300 pounds per ton, 300 pounds of diluent are used. The diluent loss in the tails is the same as the bitumen loss. Consequently, when the direct oil recovery is about 97.5%, the actual bitumen recovery is 95% assuming that the diluent lost is equivalent to the same amount by weight of bitumen.

Question: What is the water content of the oil going to the dehydration process?

L. E. Djingheuzian: It is about 25 or 26%. Corresponding to this is a mineral matter content of about 2.7%.

Question: What is the quantity of soda ash and water added?

L. E. Djingheuzian: About a pound and a half of soda ash was used to keep the pH of the classifier overflow at 9+. For highest recoveries, the best amount of water to add was in a ratio of 3 to 1. That is, for every ton of bituminous sand, the total water added was 3 tons. About 10% of this was added in the pebble mill, and the remainder in the agitator and in the classifier wash sprays.

Question: Is there any change in the sulphur content?

L. E. Djingheuzian: There is no reason to expect any change in the sulphur content of the bitumen itself, beyond the change brought about by the dilution of the bitumen with the diluent. Hence, the sulphur content of the combined oil was half that of the bitumen.

Question: What through-put does the 1.5 pounds of soda ash treat?

L. E. Djingheuzian: That was 1.5 pounds per ton of bituminous sand. However, the quantity required depends entirely upon the pH of the classifier overflow. For instance, less soda ash was required when Bitumount diluent, which was more alkaline than kerosene, was used—about 0.9 pound per ton. It is quite possible that since the diluent is recovered and recirculated, less soda ash would be required.

Question: What was the quantity of wetting agents used?

L. E. Djingheuzian: The amount used was 0.04 pound per ton of bituminous sand.

Question: Since the sand was already wet with water, why was the wetting agent required?

L. E. Djingheuzian: Wetting agents were added directly to the bituminous sands before they entered the pebble mill. The use of wetting agents made it possible to obtain sands properly wetted with water. The addition of wetting agents undoubtedly contributed to producing practically pure water-wetted classifier sands. Secondly, without wetting agents, it was not possible to get a sufficiently high-grade oil in the thickener overflow. It was running about 65%, and even less, until the wetting agents were used. How the wetting agents affected the oil adsorption by clay we do not know at this stage.

Question: Have any estimates been made of the cost of this process?

L. E. Djingheuzian: Yes, but some of the estimates of the cost and power requirements were conservative. For example, a pebble mill was used. In ore dressing, Coghill's formula (U.S. Bur. Mines) is used to calculate the capacities of cylindrical mills. It is an exponential formula where the capacity of the mill varies as the diameter to the 2.6 power. This formula was proven by Lake Shore Mines for commercial mills, but whether it applies to mills disintegrating bituminous sands it is not possible to say without further experimenting. Consequently, our estimates show the capacity of the pebble mill varying as the square of the diameter, and this indicates a rather high power requirement for the mills. For a mill handling

500 tons per day, 100 horsepower is required. On the other hand, paint manufacturers appear to use an exponent of 2.4 (calculated from catalogues) for grinding paints. Using this value for the 500 tons per day, the power requirement is reduced to 68 horsepower.

S. M. Blair: It might also be mentioned that the Mines Branch have prepared a very careful weight balance and heat balance for this whole process, and it is available for distribution.

OIL RECOVERY FROM THE ALBERTA OIL SANDS BY THE HOT WATER WASHING METHOD*

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The purpose of the present paper is to point up the simplicity of the hot water washing method of recovering oil from the Alberta oil sands, and to indicate the leeway that is possible in carrying out the operation. The details of the process have been amply described in the literature (1, 2, 3, 4).

General Features of the Process

Freshly mined Alberta oil sand contains about 2 to 5% water and 10 to 17% oil, the balance being mineral matter. The hot water separation process as practiced by the Research Council of Alberta involves increasing the water content to about 12% by means of hot water and/or steam while the oil sand is being heated to a temperature of about 176°F. (80°C.), during which time a certain amount of mixing or kneading of the oil sand takes place. A residence time of 15 minutes in the conveyor and mixer is sufficient. When the pulp reaches a temperature of about 176°F. it is dropped into a turbulent stream of circulating plant water. In the case of the separation plant at Bitumount, it is dropped into what has been termed the sand distributor. The circulating plant water passing through the sand distributor washes the pulp into a comparatively large body of hot water, in what is called the separation cell, the temperature of which is about 185°F. (85°C.). In the separation cell the oil floats as a froth on the surface of the water and is skimmed off, while the bulk of the mineral matter sinks to the bottom and is removed and discarded. The plant water containing finely divided material in suspension is continuously withdrawn from the separation cell to a water settler. The overflow from the water settler is passed through a heater to bring it back to a temperature of about 185°F. and it then goes on its way through the sand distributor, thus completing the circuit.

The hot water separation process as practiced by the Research Council of Alberta features three points:

(a) the presence of the proper amount of water in the oil-sand pulp—about 12%,

(b) a turbulent flow of plant water through the sand distributor with a minimum amount of aeration,

(c) a circulating stream of plant water.

Tolerances

A water content in the pulp of about 12% is aimed at, but there is considerable elasticity for this value and water contents of about 10 to 15% produce equally good separations. The purpose of the pulping operation is to rupture the oil film surrounding each sand

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This paper was read by D. S. Pasternack.

grain, and in properly pulped oil sand just before it drops into the sand distributor one may notice the flecks of oil lying among clean grains of sand. The washing operation from the sand distributor to the separation cell simply disperses the pulp so that the oil flecks and the sand grains may go their respective ways, the oil flecks floating in the form of froth and the sand grains sinking. If too little water is present during the pulping operation the rupturing of the oil films will not be complete, resulting in a decreased yield and a higher mineral content in the oil froth. If too much water is present during the pulping operation the flecks tend to collect together into oil clots in the pulp. Sand grains are enmeshed during the formation of these clots. On flooding the pulp, these clots enter the froth bringing their high mineral content with them. Oil clots that are too heavily laden with mineral matter tend to sink, thus reducing the yield.

A turbulent flow of water in the sand distributor assists in the dispersion of the pulp. However, aeration should be kept to a minimum, because with strong uncontrolled aeration the mineral content of the froth will mount to 25% or more instead of, say, 5% with a minimum of aeration.

The use of a circulating stream of plant water conserves heat. The only make-up water required is that for replacing water removed with the tailings. Low pressure exhaust steam from the generation of necessary electric power suffices to keep the plant water hot and to heat make-up water.

The following experiment* illustrates the simplicity of the process. The materials required are oil-sand pulp in a beaker immersed in a hot water bath to maintain the pulp at about 175°F., and a beaker of water at about 185°F. A large spoonful of pulp taken from the pulp supply is introduced into the beaker of hot water and is dispersed by gentle stirring. On allowing the contents of the beaker to come to rest, it is seen that a black layer of oil froth has collected on the surface of the water, that clean sand has sunk to the bottom, and that the hot water has become murky with suspended silt and clay.

The pulping and washing operation demonstrated by the experiment was carried on at the Government of Alberta pilot plant at Bitumount during the season of 1949 on a scale of 500 tons per day. The mineral content of the oil froth varied between 4 and 8%. There was one period of 3½ days when the mineral content stayed within the range of 4.4 to 5.3%.

The hot water washing process is very elastic in many respects. It has already been mentioned that the water content of the pulp

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*The experiment was performed on the lecture table. The oil-sand pulp was prepared beforehand by mixing and heating oil sand with enough water to give the resulting pulp a water content of 12%. The mixing and heating was continued for 15 minutes. During this pulping operation, the oil films around the sand grains of the oil sand were ruptured and the oil became dispersed as oil flecks lying detached among clean, water-wet sand grains.

may vary between about 10 to 15% and still produce equally good separations. The temperature of the oil-sand pulp before flooding with hot water may be also varied considerably. One usually mentions that the temperature should be about 176°F. The range might be, say, about 150° to 195°F. The lower limit would be affected by the viscosity of the oil present in the oil sand. For example, a higher temperature would be required for the Abasand oil-sand pulp than would be required for the Bitumount pulp because of the great difference in viscosity of the two oils.*

The duration of the pulping operation (the heating and kneading) has considerable leeway. For freshly mined oil sand, 15 minutes should be ample. At the pilot plant at Bitumount, 15 minutes represented approximately the time it took for the oil sand to travel through the conveyor system from the storage hopper to the separation cell. Excellent separation has been obtained in the laboratory at Edmonton with some oil sands when the pulping operation was as short as 3 minutes, the temperature of the pulp reaching 176°F. during that period. Exceptionally long periods of pulping—say of several hours duration—does not reduce the yield or increase the mineral content of the wet oil froth. In other words, the duration of the pulping operation need only be long enough to produce the results desired and no harm results from lengthening it.

One usually mentions that the temperature of the plant water should be about 185°F. Actually, the temperature of the plant water could have a range of, say, about 150° to 195°F. It also does not matter much whether the separation plant water is acid or alkaline or whether it is clean or loaded with suspended silt and clay (2).

Although the pH of the plant water is of minor significance in the hot water washing process, the pH of the oil-sand pulp should be around 7 for the best separation results. A pulp that is neutral or slightly alkaline is preferred. An acid condition in the oil sand tends to retard considerably the rate of rupturing the oil film which surrounds the individual sand grains, whereas an alkaline condition hastens it.

Freshly mined Alberta oil sand has a pH of about 7. This is a fortunate fact. At the pilot plant at Bitumount about 15,000 tons of oil sand were made into pulp and the oil separated by means of the hot water process. No reagent of any kind was added to the oil sand during the pulping operation. It was not needed. In fact, the pilot plant at Bitumount contained no provision for the addition of any reagent. The oil separated readily as shown in the preceding experiment.

In other parts of the world—France, Germany, Russia, Madagascar, the United States—where oil sands also occur, it is necessary to add a monovalent alkali such as sodium carbonate, sodium silicate

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*Samples of Bitumount and Abasand oils were on display. The difference in viscosity of the two oils, representing extremes in the Athabasca oil-sand deposits, was very apparent.

or sodium hydroxide to neutralize the acidity present and facilitate separation by hot water.

The oil in Bitumount oil sand is about 15 to 20% asphaltenes; that from the Abasand quarry 50 miles south of Bitumount, 23% asphaltenes. Yet oil sand from Abasand with 23% asphaltenes separates just as effectively in hot water as that from Bitumount with 16% asphaltenes (5). The viscosity of the oil is of negligible importance since oil from Abasand is considerably more viscous than that from Bitumount due primarily to the higher asphaltene content.

The sizing of the mineral aggregate is of negligible importance if one does not take the silt and clay portions into consideration. About 75% of the mineral matter in Abasand oil sand passes the 100-mesh sieve whereas only about 25% of the mineral matter in Bitumount oil sand passes 100-mesh. Nevertheless, they are both separated equally well by the hot water washing process.

Secondary Recovery of Oil

The mineral aggregate of the oil sand contains silt and clay and the amount may vary up to about 15%. A certain amount of silt and clay, say 3 to 5%, is necessary for satisfactory separation to take place in a reasonable time. The presence of too little silt and clay, less than about 0.5%, considerably increases the time required for the water to rupture the oil coating of the sand grains and to enable flecks to be formed in the pulp. The presence of too much silt and clay reduces the primary yield by increasing the proportion of fine flecks that are formed. The coarser flecks (and those flecks that have the least mineral matter associated with them) tend to form oil froth, but the finer flecks (and those flecks that are more heavily laden with mineral matter) stay suspended in the water of the separation cell and settle out in the water settler when the circulating plant water passes through it for clarification.

The underflow from the water settler contains fine sand as well as silt and clay and fine oil flecks. Passing this underflow through another settler in which the residence time is short, say about 1 to 2 minutes, would serve to remove the fine sand. The overflow from this second settler can then be passed through a conventional flotation cell for recovery of the fine oil flecks as a secondary oil froth which is similar to, and can be combined with, the primary oil froth skimmed from the separation cell. By the use of controlled aeration in the flotation cell and/or by the use of wetting agents or monovalent alkalis, the mineral content of the secondary oil froth can be held to whatever limit desired.

Attempting to recover the secondary oil froth at the same time as the primary oil froth by using increased aeration when the pulp is washed into the separation cell would result in the oil froth containing much more mineral matter, say a content of about 25%, while the yield of primary oil froth would increase only slightly.

Secondary recovery from the underflow of the water settler is a simple operation. With oil sands containing normal amounts of silt and clay, secondary recovery would augment the yield by only a few percent. With oil sands containing comparatively large amounts of silt and clay, however, secondary recovery would probably be essential for maintaining a satisfactory over-all oil recovery. The temperature of the material passing through the flotation cell should be over 150°F., and it would be preferable to have it about 170°F. Here, again, there is considerable leeway.

Aging of Oil Sand

Some comments in connection with the aging of oil sand after being mined should be of interest. Oil sand sent to Edmonton for study was shipped in closed containers in which the oil sand was packed as tightly as possible. However, at least four or five weeks would elapse from the time of packing until any of the material was separated at Edmonton, and for portions of the material a much longer time would elapse before their use. Whereas a yield of about 83% was the best that could be obtained in the laboratory at Edmonton, yields of 90 to 95% were the rule at the pilot plant at Bitumount where freshly mined oil sand was separated. However, storage for the four or five weeks at Edmonton did not affect the mineral content of the separated oil froth. For a normal separation this mineral content ran about 5% dry basis.

It was the custom at Edmonton to store the closed containers of oil sand outdoors in the shade, and usually the material was collected in the North in August or September. So storage at Edmonton began when the outdoor temperature had become cooler. When separation of the oil sand was carried out after some months of outdoor storage, the mineral content of the separated wet crude oil would show a slight increase to 6.5% or 7% and some months later to, say, 8%. But the yield of oil was not affected.

Storage of the carbide cans containing the oil sand outdoors in the shade of the laboratory building at Edmonton was unsightly and orders were received to store them indoors. At that time "material balance" experiments were under way in order to account for all the oil in laboratory separation runs. Experiments in other connections had indicated that the oil flecks which were formed during the pulping operation contained varying amounts of silt and clay, that only the flecks which had a mineral content lower than a critical amount floated during the washing of the oil-sand pulp into the separation cell, and that this critical content of mineral matter depended on the degree of aeration during the washing procedure. If that were the case, it seemed logical that the increased mineral content of the separated oil after continued storage of the oil sand might be due to an increased association taking place between the oil and the silt and clay during the additional storage period, and further that storage indoors at room temperature would accelerate the rate at which association took place. Material balance experiments carried out seven months after the initial material balance experiments on two lots of oil sand verified this deduction (3). In one case the yield was unaffected while the mineral content of the separated oil increased from 5% to 21%, and practically the entire increase was in silt and clay. In the second case the yield of oil decreased about 40% while the mineral content of the separated oil increased from 6% to 11%. Again, most of the increase consisted of silt and clay. The two results are compatible. In the first instance the ratio of silt and clay to oil in the oil sand was 48:100, whereas in the second case it was 190:100. Hence in the second case, due to the high silt and clay content, a portion of the oil which later formed flecks had become associated with sufficient silt and clay to be unable to float under the aeration conditions existing in the pulp-flooding operation of the experiment.

If association of the oil with the silt and clay took place during storage, then it seems reasonable to assume that similar association took place, also, during the four or five weeks between the time the oil sand was placed in carbide cans in the North until it reached Edmonton for experimental use. The fact that the primary yield of separated oil at the pilot plant at Bitumount was 90 to 95% as compared to a maximum yield of 83% when oil sand from Bitumount was separated in the laboratory at Edmonton, would indicate this happened.

One may wonder why the association of the oil with the silt and clay did not take place during the many thousands of years that the oil sands have been lying in the deposit. One must remember that the temperature of the oil-sand formation is about 36°F. (3), a temperature at which the oil is extremely viscous. Since the oil sand is a poor conductor of heat and the temperature of the oil sand in situ is very uniform, the amount of water vapor present in the oil sand would not only be slight, but would not vary from point to point.

On the other hand, when oil sand is placed in a closed container and stored at room temperature, a number of points must be taken into consideration. The oil sand is not packed as tightly as it was in situ; the temperature is considerably higher and may vary from day to day and/or during each day. At room temperature the oil is capable of flowing slowly. Also, at room temperature the water vapor pressure is greater, and it would seem that the movement of the water vapor from one point to another while the temperature varies in the closed container enables the association of the oil with the silt and clay to take place. Silt and clay are preferentially wet by oil rather than by water*, but if the silt and clay are already wet by water, then the water has to leave (in this case in the form of water vapor) before the association between the oil and the silt and clay can take place. A partially filled carbide can of freshly mined oil sand will show water droplets on the underside of the cover after being stored at room temperature for some weeks.

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*Based on numerous observations and analyses during the experimental work on the hot water washing method of separating oil sand.

In conclusion, one might add that during the many years that work on the hot water washing method of recovering oil from Alberta oil sands has been carried on by the Research Council of Alberta, much information about it has been accumulated. We feel that sufficient is now known about the process for dealing with its practical application.

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THE FLUIDIZED SOLIDS TECHNIQUE APPLIED TO ALBERTA OIL SANDS PROBLEM*

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PART I—PILOT PLANT DESCRIPTION AND OPERATION

Introduction

A fluidized solids pilot plant has been used to study the various phases of oil recovery from Alberta bituminous sand. The pilot plant was built following bench-scale experiments (1), to produce oil by direct distillation from the bituminous sand. The plant had to be somewhat modified, to study other phases of the problem.

Description of Pilot Plant

The pilot unit is suspended through an open well 2 by 8 feet and has an overall height of 16 feet including the bituminous sand feeder. The collection system is in the immediate vicinity of this well so that floor space occupied in the upper level is about 12 by 4 feet. The gas meters, instrument panel and process gas recycle compressor are somewhat separated from this main group.

Fig. 1 is a flow-sheet of the pilot plant as set up for bituminous sand feed. Bituminous sand is forced through a perforated plate by a screw conveyor. An effective gas seal is formed at the perforated plate. The bituminous sand extrusions drop to the fluidized sand bed maintained in the still; the oil flashes and is carried to the collection system. The distillation is acompanied by cracking of the oil and this causes coke to be deposited on the sand grains. This coked sand is withdrawn through a screen, down the standpipe and through a slide valve. The slide valve acts to keep a constant bed level in the still. The coked sand is then carried, by preheated air, up the riser into the burner where the coke is burned. Temperature of the sand is thereby increased. Sufficient of this hot sand is recycled to the still, through a slide valve, to maintain the still bed at operating temperature. A constant inventory of sand is maintained in the system and the excess, equal to the quantity in the feed, spills over a constant level pipe in the burner into a closed vessel.

The oil distilled from the sand in the still passes to a cyclone separator maintained at or above still temperature. Here most of the entrained solids are collected. The gas stream is cooled and fine oil droplets (fog) form. They remain suspended, for the most part, in the carrier gas (process gas and nitrogen). A steam-jacketed electrical precipitator removes the fog and remaining dust but passes the light ends and any water in the feed. Further cooling removes water and

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* Part I was read at the Conference by W. S. Peterson and Part II by P. E. Gishler.

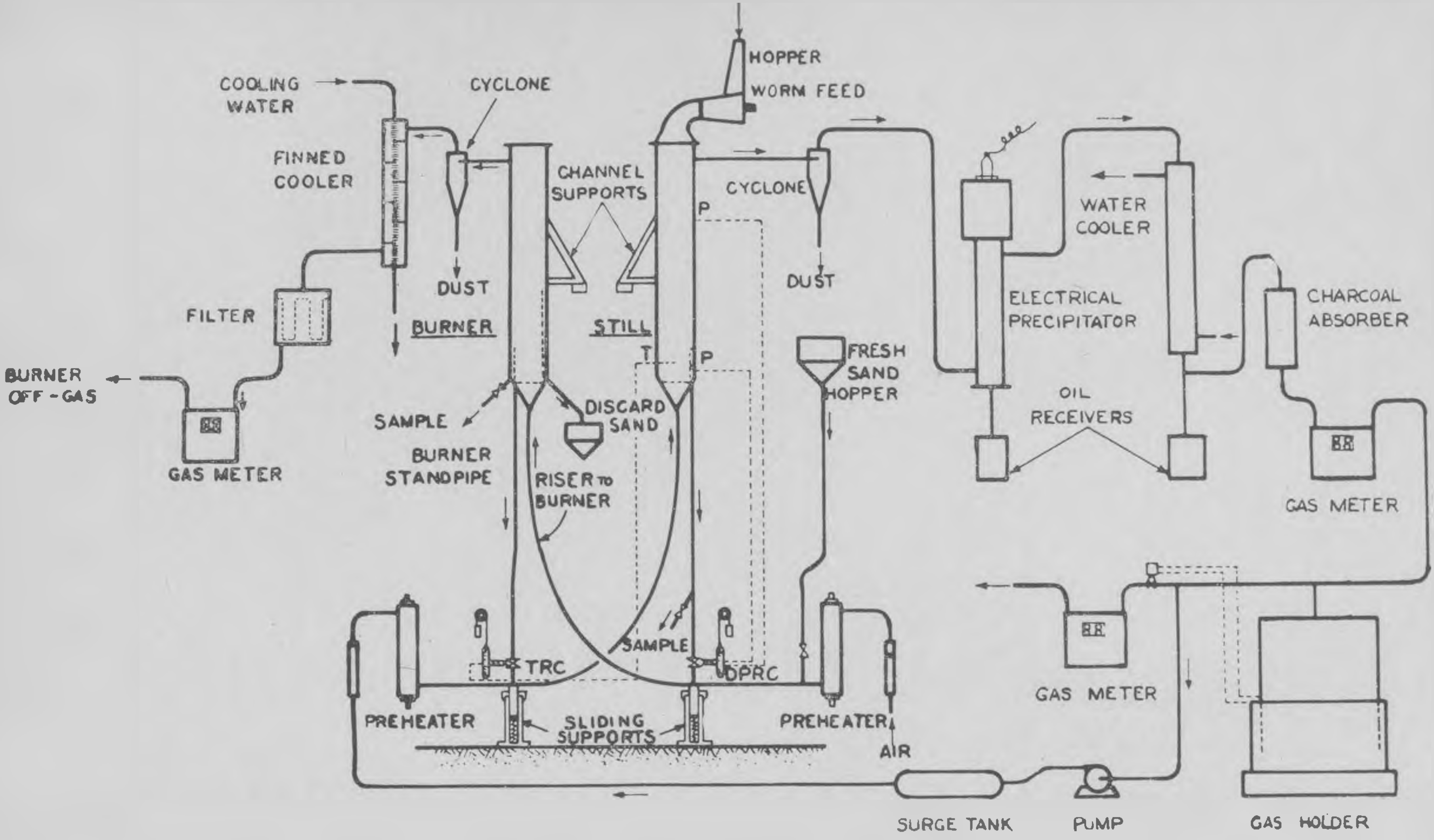

Fig. 1. *Pilot plant layout showing recycle system.*

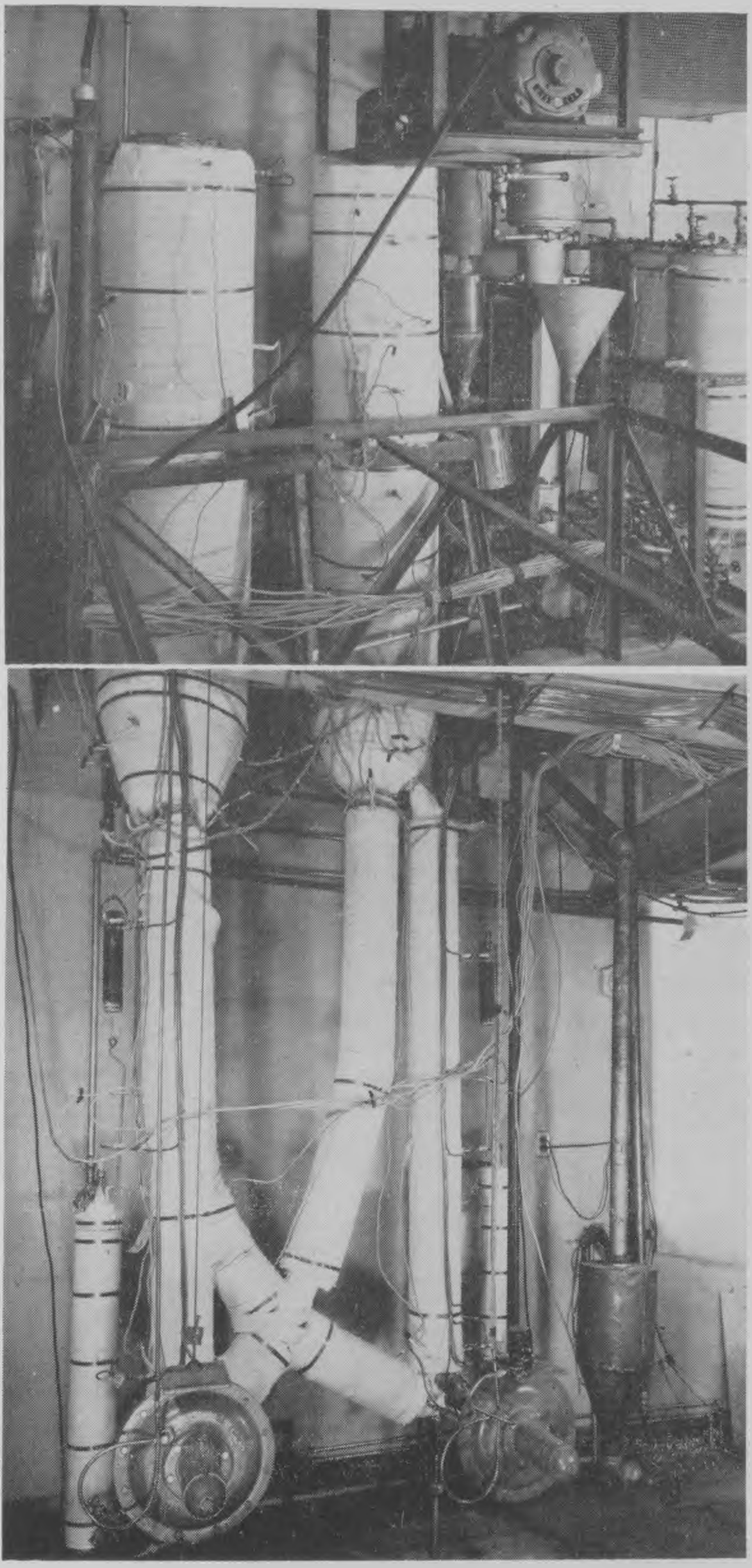

Fig. 2. *Pilot plant.*

some of the lighter oil. Charcoal adsorbers strip the gas stream further. The stripped process gas is metered, compressed and then recycled to the still as fluidizing gas.

Fig. 2 is a photograph of some of the plant.

The still design is shown in Fig. 3. It is six inches in diameter by six feet high and made of stainless steel. Maximum bed depth is about three feet without excessive entrainment of solids. There is no enlarged section at the top due mainly to lack of headroom, but also because bituminous sand may have collected on the sloping side after dropping from the feeder.

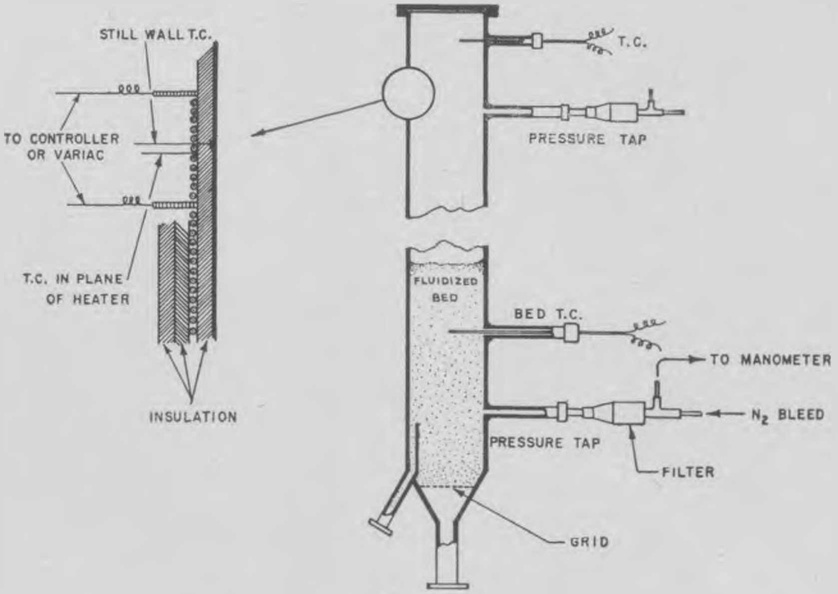

Fig. 3.

The still was designed to operate under approximately adiabatic conditions as follows:

The metal wall is covered by a layer of 1½ inch diatomite type of insulation and then wound with five resistance heaters. A metal can outside this provides a 4-inch annulus which is filled with vermiculite. At the midsection of each heater one thermocouple registers wall temperature and a second one registers the temperature of the winding. The input to the heaters is adjusted to keep these temperatures about equal.

The burner is similar in design to the still except that it is nine inches diameter by six feet high. Beaded resistance wire is wound directly on the wall to bring the solids to operating temperature prior to an experiment. The windings are also used as auxiliary heat supply when needed during a run. Further auxiliary heat can be supplied by burning propane in the burner. This is more convenient than using process gas.

Fluidizing gases to the still and burner can be preheated when necessary.

Product Removal

On the still side, dust was collected from the cyclone. Oil was collected from the Cottrell precipitator, cooler and charcoal adsorbers.

On the burner side, dust was collected from the cyclone and filter bag. Water, from combustion, was collected in a trap.

Sampling System

The feed was sampled at the appropriate place. Coked sand sample was withdrawn continuously during a run from the standpipe just above the slide valve. Burned sand sample was withdrawn intermittently from the standpipe. Cumulative gas samples were collected from both gas streams. The process gas left in the gasholder at the end of a run was compressed and a Podbelniak low-temperature distillation was carried out to determine the hydrocarbons present.

Instrumentation

The two main controls were those for still bed temperature control and still bed level control. A temperature recorder-controller, actuated by a thermocouple in the still bed, controlled the flow of hot burned sand to the still by adjusting the position of the slide valve. The still bed depth was controlled by a bellows type differential pressure recorder-controller which operated the slide valve at the base of the still standpipe.

Pressure taps gave considerable trouble with partial or complete blocking. This, of course, made it difficult to control the still bed level. This difficulty occurs when a high boiling oil, i.e., bituminous sand or wet crude, is fed to a sand bed. The heavy ends tend to condense in the lines and collect solids forced into them by the pulsing of the beds. Shale, stones and clay occur in the bituminous sand and will block the pressure taps when the particle diameter is about the same as the pressure tap diameter. Blockage from this source occurs suddenly, but can usually be remedied by momentarily increasing the gas purge.

Mechanical

A nearly constant inventory of process gas is maintained in the still system by allowing the gas holder to operate between narrow limits. When the gas holder goes to the upper limit switch, a solenoid valve is opened and process gas is purged through a wet test meter and discarded. This volume of gas is equal to the amount of the nitrogen bleeds plus gas formed during cracking.

Pressures were measured at many points in the system, and manometers were the main indicators used. Pressure tap holes were purged with nitrogen bleeds, and filters used were similar to those described in the literature (2). The slide valve design was also similar to valves described in the same article.

Temperatures were recorded manually and automatically for many points in the plant.

Most electrical windings were controlled by Variacs.

Operation

Bituminous sand was run through the feeder before an experiment to eliminate large rocks and hard material which could not be extruded by the feeder. The holes used to extrude the bituminous sand were 3/8 inch diameter for Bitumount and 1/2 inch diameter for Abasand. Samples of the feed were taken during this treatment.

After the feed had been treated as above, the electrical heaters were turned on and left at half power for the night preceding the run. The next morning the nitrogen bleeds were turned on, sand was added to the burner and full power turned on. When this sand had reached the operating temperature of the still, it was transferred to the still until the proper bed depth had been established. Nitrogen was then recirculated by compressor. The bed depth in the burner was adjusted by addition of more cold burned sand. The temperature of the burner was allowed to rise to the operating temperature. Bituminous sand feed was commenced and brought up to the operating rate.

Oil was collected and measured hourly from the Cottrell and the cooler. The following were taken half hourly: still cyclone dust, burner cyclone dust, sand discard, burned and coked sand samples. burner and still off-gas samples, dry and wet gas meter readings, manometer readings, temperature readings and nitrogen bleed rotameter readings. The water trap on the flue gas line was emptied hourly and measured. Light oil was recovered from the charcoal adsorbers at the end of each run by steam stripping.

The preceding description has been concerned with the pilot plant operating with bituminous sand feed. Other types of feed have been used:

(a) Hot-water separated bitumen ,(wet crude), and cold-water separated bitumen (diluted crude).

(b) Bitumen concentration core samples.

(c). N.R.C. coker distillate produced by flash distillation in the fluidized bed.

Catalyst beds, as well as sand, have also been used.

Wet Crude

This material was the primary separation product from the hot water separation process. Initial tests to separate the water and solids from the bitumen were carried out by feeding wet crude to a fluidized sand bed. Flashing of the liquids occurred and the solids and water were easily separated from the oil product. The bitumen was cracked and coke was deposited on the sand as in the bituminous sand tests.

In a few experiments the wet crude was pumped to the still riser where the oil and water vapors would carry the solids into the still. However, coking of the riser (and still grid when used) took place, even when the water in the wet crude was partially vaporized before pumping it into the riser. This feed point was abandoned and the wet crude was fed into the conical section at the bottom of the fluidized still bed. Even at this point severe coking was observed in some experiments, leaving masses of coke in the cone. The different positions seemed to have no effect on the oil yield.

The wet crude (and mud) contained fine solids which were blown out of the fluidized beds. These solids caused considerable trouble in the still cyclone, evidently by impinging on the wall at the inlet throat and sticking there despite high gas velocities in this section. It is believed that the dust carried some "heavy ends," and when the hot wall of the cyclone was contacted further cracking took place and a hard deposit of coke was found plugging the cyclone completely in some cases. There is a possibility that there were cold spots in the piping that contributed to this effect. It is noteworthy that none of these troubles occurred when a catalyst bed was used, even when the cyclone wall temperature dropped considerably below the still bed temperature.

The bitumen capacity of the pilot plant was low when working with wet crude. The flashed water supplied the main volume of fluidizing gas and so the feed rate was low to give a reasonable superficial gas velocity. Another limitation on the feed rate was due to the inability of the burner to supply sufficient heat to evaporate the water contained in the feed.

To keep dusting to a minimum with catalyst bed and wet crude feed, the weight hourly space velocity was about 0.3 (cf. 0.6 with topped coker distillate, and 1 to 5 normal practice).

Catalyst Bed

The pilot plant was altered slightly when handling catalyst. The burner (regenerator) bed was cooled with a hairpin cooler dipping into the bed and generating steam. This was used to control the burner bed temperature and to increase the coke burning capacity of the burner. Most heater windings were turned off when operating. An internal cyclone was added to the burner to keep the solids in the system. On the still side, however, the external cyclone remained, due mainly to the complicated heater-wound piping involved in a small space. No grid was used in the still when oil was charged. A stripper was not used. Some stripping of the spent catalyst, however, took place in the standpipe due to aeration gas. At the feed rates used, the stripping was adequate if the rate was steady. However, with the pumping equipment used on the liquid feeds, the feed rate was not normally steady and this caused rapid fluctuations in the catalyst recycle rate. Under these conditions the catalyst was not properly stripped.

The weight hourly space velocity when feeding reduced coker distillate was about 0.6 and so cracking was more severe than would be encountered in practice. The reasons for low weight hourly space velocity were:

(1) The burner could not handle the carbon load at higher feed rates without a stripper.

(2) The amount of oil available in many cases was not sufficient for a six- or ten-hour run at high feed rates.

(3) A deep bed (30-inch) was used so that with the rapid fluctuations of recycle catalyst rate encountered, an adequate bed level would be maintained. It should be pointed out that even at the low feed rates used the carbon level on the regenerated catalyst rose steadily during the course of all tests.

No plugging of pressure taps or still cyclone was noted with a catalyst bed and liquid oil feed.

Core Samples of Bitumen Concentration

This material was fed with the bituminous sand feeder onto the top of a fluidized bed of catalyst (Davison C_1 and C_2 silica-alumina). Only one experiment was possible because of the small amount of feed available, and the feed arrangement was not altogether satisfactory due to the very unsteady feed rate. During the run the catalyst was diluted with the solids from the feed. The silica pebbles in the feed were of the correct size to cause some trouble with pressure taps.

N.R.C. Coker Distillate

This feed material was distillate obtained from previous tests with bituminous sand. The material boiling below 200°C. was removed before feeding to the catalyst bed. It should be pointed out that "regenerated" catalyst was carried to the still by process gas (not vaporized oil), and the liquid reduced coker distillate was pumped directly into the fluidized bed in the conical part at the bottom of the still.

TABLE I

FLUIDIZED SOLIDS PLANT OPERATING CONDITIONS

Bed material	Bed level, in.	Superficial gas velocity, f.p.s.	Temperature, °C.	Feed rate, lb. per hr.		
				Oil sand	Wet crude	Reduced crude
Sand						
Still	30	0.6*	475 to 560	100	10 to 15	—
Burner	36	0.6 to 1	625 to 800			
Catalyst						
Still	30	0.3	475 to 525	—	5	10
Burner	36	0.3 to 0.4	525 to 590			

* 0.6 normal; on occasion up to 1.5

Operating Conditions

A general summary of operating conditions is given in Table I.

REFERENCES

1. Gishler, P. E., Can. J. Res., 27, sect. F, 104-111 (1949).
2. Trainer, R. P., Alexander, N. W., and Kunreuther, F., Ind. Eng. Chem., 10, 175-182 (1948).

PART II—PILOT PLANT RESULTS

The work reported below was carried out at the National Research Council laboratories using the small fluidized solids pilot plant described in Part I. This plant was completed about two years ago, and the initial work was on the direct distillation of oil from bituminous sand. Blair's survey of the bituminous sands problem indicated a high capital cost for the direct distillation process. It was suggested that a more attractive approach would be an initial hot water washing step, followed by dehydration and coking in a fluidized solids bed. The hot water separation had been worked out by K. A. Clark. The National Research Council undertook to study the dehydration-coking operation. The results indicated that this was a satisfactory method for handling the wet crude.

A tempting but rather unorthodox modification of the above step became apparent, that is, the use of a catalyst bed. The "cat" cracking of a viscous oil containing over 30% water and 5% solids may appear as unusual. A few initial runs have been made and they will be described. One other possible application of the fluidized solids technique is concerned with the bitumen that is believed to occur as irregular pools in the Mildred-Ruth Lakes area. This, too, will be discussed briefly.

This paper will describe briefly the work on: (1) direct distillation, (2) dehydration-coking, and (3) dehydration-catalytic cracking.

Direct Distillation of Oil from Bituminous Sand

Bench-scale tests demonstrated that when lumps of bituminous sand were dropped into a hot fluidized sand bed, the oil flashed off and the lumps broke down to individual grains of free-flowing sand each coated with a thin closely-adhering film of coke. The purpose of the pilot plant was to establish yields, capacities and materials, and heat balances. It was also meant to study the influence of temperature and other variables on the quality of the oil produced.

Samples from three sources—Bitumount, Waterways (Abasand), and Mildred-Ruth Lakes—were available. The Mildred-Ruth Lakes area is of chief immediate interest because of the large reserves of sand established there by drilling. Only about 50 pounds of this material were available. They were the core samples and were sufficient to produce a sample of oil for analysis but not enough to establish yields. The Mines Branch, Ottawa, donated this material, and also supplied about 10 tons from the Abasand (Waterways) deposit. The Alberta Government supplied sand from the Bitumount area.

The properties of the Abasand and Bitumount material differed markedly. The Abasand material consisted of fine-grained sand impregnated by extremely viscous oil. The Bitumount material consisted of coarse-grained sand impregnated by a less viscous oil. Table I shows the screen analysis of the mineral aggregates.

TABLE I

SCREEN ANALYSIS OF EXTRACTED SAND

Mesh	Abasand	Bitumount
on 35	0.1	10.6
35 - 60	0.7	34.4
60 - 80	4.0	36.0
80 - 100	27.3	9.9
100 - 150	43.0	5.0
150 - 200	15.7	1.6
Through 200	8.2	1.6

It was found that still capacities were high. Feed rates of at least five tons per day per cu. ft. of still bed volume should be attainable. However, the heat requirements were high because of the high ratio of sand to oil. A net recovery of 80% was indicated. Temperature was found to be the only variable to have a significant effect on the yield or on the properties of the oil. Discussion here will be limited to a study of a temperature series of Abasand and Bitumount feed.

Table II gives the operating data. The duration of each run varied from 6 to 10 hours. The Abasand feed was somewhat richer in oil. It was also more sensitive to higher cracking temperatures, giving higher yields of gasoline than did the Bitumount feed. Total oil yields from Bitumount feed were somewhat higher. Suspended solids and water content were low.

Oil inspections are shown in Table III. The density of the oil produced remained constant over a wide range of reaction temperatures. Viscosity decreased with increase in reaction temperature. Sulphur content was reduced to 4%.

Composition of Coker Distillate

Analysis of the bituminous sand coker distillate was carried out by Matchen of the National Research Council (4). A similar analysis of the coker distillate from wet crude feed has not been completed. However, it has been found that the coker distillate from the two sources is very similar and hence the following discussion applies to either product.

TABLE II

PILOT PLANT OPERATING DATA

Source	Abasand				Bitumount			
Run No	12	11	16	17	13	9	10	18
Feed								
Duration, hr.	10	10	6	6	6.6	10	10	5.5
Weight, lb.	830	864	453	500	704	886	854	435
Bitumen, %	17.0	16.4	16.4	16.4	13.5	13.5	14.5	15.8
Water, %	0.3	0.3	0.5	0.3	0.35	0.5	nil	0.9
Rate, lb./hr.	83	86.4	75.5	83	107	88.6	85.4	79
Oil product								
Vol., U.S. gal.	14.3	14.2	6.7	7.2	9.9	12.4	12.8	6.4
Yield, vol. %	84.0	83.5	75.0	73.5	85.7	86.5	86.0	82.5
Solids (settled oil), %	0.1	0.25	trace	trace	trace	nil	trace	trace
Water, %	trace	trace	trace	trace	nil	trace	nil	0.1
Operation								
Still temp., °F	925	977	1022	1067	932	950	977	1022
Still dust, lb	9.5	15.3	7.3	6.4	7.0	5.1	2.1	2.6
Burner temp., °F	1303	1286	1373	1436	1220	1320	1265	1400
Burner dust, lb.	19.3	21.1	18.0	22.0	7.2	13.0	10.3	7.0
Recycle ratio	2.9	4.4	3.8	5.0	4.4	4.7	—	3.9

TABLE III

OIL INSPECTION

Feed	Abasand				Bitumount			
Run No.	12	11	16	17	13	9	10	18
Reaction temp., °F.	925	977	1022	1067	932	950	977	1022
Sp. gr. at 60°F.	0.954	0.962	0.959	0.950	0.961	0.954	0.961	0.961
Viscosity, kin. cstks. at 100°F.	68.0	52.0	21.9	11.5	62.0	52.0	—	41.6
kin. cstks. at 210°F.	5.6	6.2	3.7	2.7	7.4	5.2	—	5.5
Distillation								
I.B.P., °F.	160	176	156	125	180	178	182	182
5%	280	338	245	215	308	426	412	412
10	—	460	325	284	435	500	482	472
20	585	575	487	417	540	580	558	448
30	615	630	569	525	609	—	600	600
40	638	660	614	596	645	662	630	637
50	650	682	646	638	670	682	650	655
60	662	700	660	668	692	710	662	680
70	672	715	670	686	708	720	672	701
80	670	730	682	707	714	728	670	720
Sulphur, wt. %	4.0	—	—	—	—	—	3.9	4.0

The following analyses were made:

(1) Asphaltenes, resins and oily material were determined on composite samples from each run.

(2) Aromatics, olefins, and paraffins plus naphthenes were determined on the oily material fraction of the above samples.

Pilot-plant results had indicated that the highest yields and best operating conditions were in the temperature range 500 to 525°C. A temperature of 515°C. was arbitrarily taken as standard.

A sample of Bitumount and Abasand coker distillate produced under these conditions was therefore studied more intensively. Each sample was distilled into seven cuts and each cut studied separately.

1. Asphaltenes, resins and oily material

A five-gram sample was dissolved in benzene and poured into n-pentane. The asphaltenes precipitated as a flocculent powder. This was filtered, dried and weighed. The filtrate was poured onto Fuller's earth contained in a glass column. The oily material was first desorbed by n-pentane. The resins were desorbed by a 9:1 solution of benzene and methanol. The results are shown in Table IV. Asphaltenes were reduced to 1% or less. Resins were reduced substantially, with a corresponding increase in oily material.

TABLE IV

ASPHALTENE, RESIN AND OILY MATERIAL CONTENT OF FLUIDIZED SOLIDS STILL FEED AND PRODUCTS

Bitumount series					
Sample	Raw feed	B-6	B-9	B-10	B-18
Reaction temp., °C.	Untreated	480	510	525	550
Oily material, %	45.0	67.3	72.5	76.0	79.0
Resins, %	34.7	28.4	22.6	20.7	19.0
Asphaltenes, %	17.9	0.15	0.5	0.7	1.0
Abasand series					
Sample	Raw feed	B-7	B-11	B-16	B-17
Reaction temp., °C.	Untreated	505	525	550	575
Oily material, %	47.7	72.8	78.0	81.6	81.1
Resins, %	32.1	26.6	20.4	16.8	14.2
Asphaltenes, %	19.5	0.4	1.2	1.6	3.5

2. Aromatics, olefins, and paraffins plus naphthenes

A 50-ml. sample of oily material was pipetted onto the top of an activated silica gel column. The paraffins, naphthenes and olefins were swept through with n-pentane. The aromatics were then desorbed by methanol. They were viscous liquids, brownish-red by transmitted light. The so-called olefins were separated from the paraffins-plus-naphthenes fraction at 0°C. by shaking in a solution of P_2O_5 in concentrated H_2SO_4 and then separated by centrifuging.

Caution must be exercised in the interpretation of the results. A technique very similar to that developed by Mair (5) was used. Mair's method is known to apply to light sweet distillate. Here it was applied to a heavy distillate high in sulphur. The average molecular weight of this material was high. An extremely wide variety of molecules would be present including both aromatic and naphthene rings with all kinds of side chains both saturated and unsaturated. The separation as made, therefore, gives only a very rough indication of what was present. At this stage of the work it was considered advisable to refrain from using the terms olefin, paraffin and naphthene and instead classify the non-aromatic material as acid-soluble and acid-insoluble. The results are shown in Table V. The material appears to be highly unsaturated.

TABLE V

INFLUENCE OF REACTION TEMPERATURE ON COMPOSITION OF OILY MATERIAL (ABASAND)

Run No.	Raw	7	16	17
Reaction temp., °C.	Untreated	505	550	575
Refractive index	—	1.5163	1.5351	1.5413
Acid insoluble, vol. %	57.4	12.1	9.1	9.2
Acid soluble, vol. %	5.4	54.9	60.0	56.8
Aromatics, vol. %	37.2	32.9	30.7	33.7

3. Analysis of seven cuts of standard samples

The following samples were vacuum distilled and divided into seven cuts:

(1) Pilot-plant oil produced at 520°C. from Abasand bituminous sand feed.

(2) Pilot-plant oil produced at 510°C. from Bitumount bituminous sand feed.

(3) Raw bitumen from the Abasand deposit. A few litres of this were obtained by extractions in a jumbo-size Soxhlet extractor.

Determinations on each of the seven cuts included specific gravity, refractive index, molecular weight, sulphur content, viscosity, oily material, resins, asphaltenes, aromatics, acid-soluble and acid-insoluble. The results are shown in Tables VI, VII and VIII.

The high acid-soluble content of the various cuts of the raw Abasand bitumen sample is difficult to explain. Space does not permit a detailed discussion of the results. They are described in more detail in a report by Matchen and Gishler (4).

Dehydration-Coking of Wet Crude Bitumen

The hot water washing of bituminous sand yields a product that normally contains somewhat over 30% water, 2 to 5% solids in an

TABLE VI

INSPECTION OF OIL FRACTIONS FROM RAW ABASAND BITUMEN

Distillation range, °F.	I.B.P. to 464	464 to 536	536 to 608	608 to 644	644 to 750	750 to 825	Residu
Sp. gr. at 60°F.	0.8932	0.8920	0.9101	0.9228	0.9489	—	1.0349
Refractive index at 68°F.	—	1.4838	1.4953	1.5064	1.5227	1.5402	—
Sulphur, wt. %	2.10	1.37	1.84	2.20	2.95	—	5.65
Viscosity, kin. cstks. at 0°F.	—	35.6	128.0	518.0	6290.0	—	solid
kin. cstks. at 68°F.	—	4.0	6.8	12.1	36.8	—	—
Distillate, vol. %	5.5*	1.3	3.2	3.6	11.0	—	75.3
wt. %	4.9	1.2	2.9	3.3	10.4	—	77.8
Asphaltenes, %	nil	nil	nil	nil	nil	trace	32.2
Resins, %	1.05	0.6	1.8	2.3	6.4	6.2	36.0
Oily material, %	99	99	93	98	93	93	33.3
Aromatics, %	18.3	16.5	19.1	22.8	29.2	41.8	—
Acid soluble, %	27.1	26.2	24.3	25.7	27.8	—	—
Acid insoluble, %	54.6	57.3	56.6	51.5	43.0	—	—

* Includes H_2O and CCl_4.

TABLE VII

INSPECTION OF OIL FRACTIONS FROM PILOT PLANT PRODUCT PRODUCED AT 520 DEGREES C. FROM ABASAND FEED

Distillation range, °F.	Composite	I.B.P. to 356	356 to 464	464 to 536	536 to 608	608 to 644	644 to 750	Residue
Sp. gr. at 60°F.	0.960	0.7720	0.8497	0.8801	0.9009	0.9165	0.9439	1.019
Refractive index	—	1.4348	1.4719	1.4860	1.4980	1.5061	1.5234	—
Sulphur, %	4.01*	1.70	2.59	2.69	3.21	2.76	3.51	4.92
Viscosity, kin. cstks. at 100°F.	43.2	1.24	1.65	2.73	3.98	8.51	27.7	10721.0
kin. cstks at 210°F	5.7	0.77	0.8	1.12	1.58	2.12	3.9	77.8
Distillate, vol. %	—	6.6	5.9	3.6	5.8	3.4	17.8	54.7
wt. %	—	5.1	5.0	3.2	5.7	3.1	16.8	55.7
Asphaltenes, %	1.2	nil	nil	nil	nil	trace	trace	3.75
Resins, %	18.7	0.94	1.8	2.4	3.0	4.1	4.4	39.4
Oily material, %	77.8	99	98.2	97.6	97.0	95.2	93.9	57.9
Aromatics, %	—	7.4	16.1	17.3	12.8	19.7	17.4	—
Acid soluble, %	—	63.3	51.2	45.5	48.8	45.7	54.6	—
Acid insoluble, %	—	29.3	32.7	37.2	38.4	34.6	27.8	—

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*Excludes gasoline cut.

TABLE VIII

INSPECTION OF OIL FRACTIONS FROM PILOT PLANT PRODUCT PRODUCED AT 510 DEGREES C. FROM BITUMOUNT FEED

Distillation range, °F	Composite	I.B.P. to 356	356 to 464	464 to 536	536 to 608	608 to 644	644 to 750	Residue
Sp. gr. at 60°F.	0.954	0.7875	0.8477	0.8747	0.9000	0.9218	0.9465	1.003
Refractive index	—	1.4384	1.4680	1.4815	1.4952	1.5098	1.5252	—
Sulphur, %	4.0*	1.71	1.87	2.12	2.70	3.03	3.61	4.73
Viscosity, kin. cstks. at 100°F.	52.0	2.1	1.88	2.91	5.14	9.81	28.7	4550
kin. cstks. at 210°F	5.2	1.06	0.87	1.15	1.59	2.27	4.0	54
Distillate, vol. %	—	3.5	6.1	5.7	7.7	4.0	17.2	50.0
wt. %	—	2.8	5.2	5.0	6.9	3.7	16.2	50.2
Asphaltenes, %	0.5	nil	nil	nil	nil	trace	trace	1.03
Resins, %	22.6	1.40	1.66	1.74	2.2	3.9	6.7	26.6
Oily material, %	72.5	98	98	97.6	97.0	94.5	92.7	71.7
Aromatics, %	—	4.9	11.4	12.4	18.4	33.3	38.4	—
Acid soluble, %	—	44.8	41.3	39.0	39.6	29.5	38.6	—
Acid insoluble, %	—	50.3	47.3	48.6	42.1	37.1	25.0	—

*Excludes gasoline cut.

extremely finely-divided state, and about 65% bitumen. The bitumen is in an unaltered condition and therefore extremely viscous. The product of the hot water process will be referred to as wet crude in this paper. The purpose of the work was to separate the water and solids from the bitumen and to reduce the viscosity of the bitumen substantially by thermal cracking. The method adopted was to pump the wet crude directly into the still bed which consisted of silica sand. The sand used was that produced in a previous flash distillation run. Peterson has provided the operating data for this work in Part I, and since the oil product is the same as that described in the above section, the results of the dehydration-coking work will be described very briefly. This is described in detail in a report by Hodgson*, Peterson and Gishler (2).

Three types of feed were used in the dehydration work. At the Bitumount demonstration plant the bulk of the wet crude had been processed in a flash dehydrator, and only a few hundred pounds were available for our work. This supply was augmented by several drums of material produced in about 1942 by the International Bitumen Company at Bitumount. After eight years of settling the water content had been reduced to about 20%. This was brought up to 30% or more by the addition of water. The third sample was a mud containing about 25% solids and 20% water. It was studied for the following reason.

It had been anticipated that a part of the solids contained in the charge stock would be retained by the fluidized bed. The mud was used to try to build up a final bed within a reasonable length of time. It happened that the solids in the feed were sufficiently fine so that all either blew out of the still bed, or were carried to the burner bed cemented to sand particles by the coke. Once the coke was burned off, the dust escaped from the bed. The use of internal cyclones may have permitted some buildup of the fines introduced by the feed.

TABLE IX

DEHYDRATION-COKING OPERATING CONDITIONS

Experiment No.	35	37	39	40	45
Still temp., °C.	502	517	536	562	515
Burner temp., C.	710	755	762	810	713
Charge temp., °C.	60	69	72	69	70
Charge rate, lb./hr.	7.17	12.7	14.3	16.9	15.9
Burner bed depth, in.	30	30	30	30	30
Still bed depth, in.	31.2	29.6	30.4	31.3	30
Still gas vel., ft./sec.	0.66	0.86	1.00	1.17	1.07
Burner gas vel., ft./sec.	—	0.99	0.99	1.00	0.90

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* We are deeply indebted to the Research Council of Alberta for loaning us Dr. Hodgson for a period of three months, and we are deeply indebted to Dr. Hodgson for his assistance during that period.

Table IX gives the operating conditions for a temperature series on wet crude. The temperature range was from 500 to 560°C. Charge rates as high as 17 lb. per hr. were used. Linear gas velocities in both the still and burner were approximately 1 ft. per sec.

TABLE X

DEHYDRATION-COKING CHARGING STOCK

Experiment No.	35	37	39	40	45
Solids, %	22.4	3.5	3.1	2.9	3.5
Water, %	28.9	30.2	30.8	33.0	38.1
Oil by diff., %	48.7	66.3	66.1	64.1	58.4

Table X shows the analysis of the feed. Sample 35 was the mud to which reference has been made. Samples 37, 39 and 40 were the International Bitumen Company wet crude to which water had been added to bring it to 30% which is considered by K. A. Clark (1) to be normal for the hot water process.

TABLE XI

DEHYDRATION-COKING SOLIDS RECOVERY

Experiment No.	35	37	39	40	45
Feed solids, lb.	9.52	1.69	2.66	3.00	3.30
Recovered solids, lb.					
Still cyclone	4.69	0.51	1.34	1.59	2.07
Oil	0.41	0.12	0.31	0.81	0.29
Burner cyclone	1.61	1.07	1.27	1.28	1.31
Burner filter	0.38	0.19	0.31	0.12	0.06
Total, lb.	7.09	1.89	3.23	3.80	3.73
Still gas rate, ft./sec.	0.66	0.86	1.00	1.17	1.07

Table XI indicates where the solids in the feed go. The amount that showed up in the oil product varied. This could, in all probability, be reduced by recycling of the heavy ends. Recycling to extinction of the heavy ends would also result in a considerable reduction in viscosity.

Table XII gives an analysis of the process gas*. The two dominant gases are methane and hydrogen.

Table XIII gives the data for the oil. Run 35 was for mud. Yields were somewhat lower. It would appear that the high concentration of extreme fines had caused more severe cracking. The

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* We are greatly indebted to the Mines Branch, Ottawa, for these analyses, and for a great many viscosity and sulphur analyses.

TABLE XII

DEHYDRATION-COKING — PROCESS GAS ANALYSIS

	Vol., %	Vol., %*
Methane	8.31	55.7
Ethylene	0.23	1.5
Ethane	nil	nil
Propylene	0.35	2.4
Propane	nil	nil
Iso-butane	0.29	1.9
n-butane	0.24	1.6
Iso-pentane	0.12	0.8
n-pentane	0.53	3.5
S-compounds	0.50	3.4
Carbon monoxide	0.50	3.4
Hydrogen	3.83	25.8
Nitrogen by diff.	85.1	—

*Corrected to zero nitrogen.

TABLE XIII

DEHYDRATION-COKING TEMPERATURE EFFECTS

Experiment No.	35	37	45	39	40
Still temp., °C.	502	517	515	536	562
Liquid yield, vol. %	80.0	88.2	83.5	84.3	83.4
Coke yield, wt. %	11.4	8.1	—	8.2	8.2
Gas yield, wt. %	4.1	4.9	—	—	6.2
Oil inspection,					
Water, %	0.2	0.2	0.2	0.1	0.3
Suspended solids*, %	2.61	0.49	0.84	0.85	1.76
Viscosity, kin. cstks., at 100°F.	—	55.0	—	53.4	25.4
Gravity, ° A.P.I.	17.6	16.7	14.7	15.9	15.6
Sulphur, %	4.1	4.1	—	4.1	4.1
Distillation					
I.B.P., °F.	143	146	150	159	150
5%	374	352	378	358	276
10	458	458	464	448	361
20	534	557	550	536	498
30	577	600	600	595	566
40	618	630	630	625	609
50	635	646	649	641	635
60	653	662	668	656	652
70	664	677	682	666	661
80	670	686	695	674	662

*Determined in Cottrell oil.

distillation data however do not bear this out. The solids in the oil are excessive. This was an unusual feed. The yields of runs 37, 39 and 40 are somewhat higher than those from bituminous sand. Run 45 was meant to be a check on 37 except that the former was a relatively new crude (1 year old), and therefore more closely represented a feed that would be available on a commercial scale. The value of 83.5% is believed to be more realistic. Viscosities, densities, sulphurs and distillation curves are very similar to those for oil from bituminous sand. This is to be expected.

Bitumen Beds in the Mildred-Ruth Lakes Area

The presence of bitumen in concentrations greater than those required to saturate the sand has been reported by Hume (3). It is not the purpose of this paper to discuss the possibility or impossibility of these occurrences. Core assays have indicated bitumen concentrations ranging from below 20% to as high as 80%. Some holes showed substantial amounts of this material. For example, hole B-17 indicated 92 feet at 42.7% bitumen and the still richer hole B-15 indicated 74 feet at 60% bitumen by weight. On the other hand, holes only a quarter of a mile away showed only the regular bituminous sand. It was found impossible to correlate the results of the holes and, therefore, impossible to arrive at an estimate of the implied amount of bitumen present. If the results were spurious and the cores did not represent the formation, no further consideration need be given to them. On the other hand if the apparent occurrences do exist, then some day they will have to be "mined" and processed.

These bitumen cores resembled wet crude bitumen except that the water content was lower and in most cases the solids were higher. It was believed that this material could be fed directly to a fluidized solids bed. Sufficient material was made available by the Mines Branch for one run. A catalyst bed was used. The run will be described later.

Heat Requirements

In the coking either of wet crude or bituminous sand or possibly pool bitumen, the techniques are similar. The products and yields are very similar. There is, however, a considerable difference in the heat required to carry out the coking operation, and this will be reflected in the size of burner required.

Table XIV shows the heat necessary to heat one pound of bitumen plus the contained solids and water, for a variety of materials which could possibly be handled in a fluidized bed. The bed temperature assumed was 932°F. and the base temperature was 32°F. No heat credits are given. For a complete picture, applicable heat credits would have to be assigned to individual cases. The thermal demand for wet crude depends on the water content. It is believed that up to the present the emphasis in the hot water work has been on low solids because of possible trouble in handling solids in tubular equipment. In a fluidized bed it is advantageous, both thermally and from the point of still capacity, to hold the water in wet crude to a minimum even if it results in a substantial increase in the solids content of the feed. Some pool bitumen samples are included for comparison. The highest heat demand values are for raw bituminous sand.

TABLE XIV

HEAT REQUIRED TO DISTIL ONE POUND OF CONTAINED BITUMEN AT 932°F. (500°C.) BASE TEMP. = 32°F. (0°C.)

Type of bitumen material	Analysis, %			Weight, lb.			Heat*, B.t.u.			
	Bit.	Sol.	Water	Bitumen	Solids	Water	Bitumen	Solids	Water	Total
Pure	100	—	—	1	—	—	717	—	—	717
Wet	71	4	25	1	0.056	0.35	717	12	542	1271
Wet	63	4	33	1	0.063	0.52	717	13	806	1536
Wet	56	4	40	1	0.071	0.71	717	15	1100	1832
Pool	75	10	15	1	0.13	0.20	717	28	310	1055
Pool	50	40	10	1	0.80	0.20	717	170	310	1197
Pool	50	35	15	1	0.70	0.30	717	149	465	1331
Pool	50	30	20	1	0.60	0.40	717	128	620	1465
Pool	25	60	15	1	2.4	0.60	717	511	930	2158
Sand	12	87.5	0.5	1	7.29	0.042	717	1551	65	2333
Sand	14	85.5	0.5	1	6.10	0.036	717	1300	56	2073
Sand	16	83.5	0.5	1	5.22	0.031	717	1111	48	1876

* 1 lb. bitumen $\Delta H = 717$ B.t.u.
1 lb. sand $\Delta H = 213$ B.t.u.
1 lb. water $\Delta H = 1550$ B.t.u.

Coking Operation—Summary

It has been shown that it is possible to start either with bituminous sand as mined, or with wet crude as produced by the hot water separation process, and in a single operation obtain good yields of a fairly clean dry oil. In this operation, the bitumen contained in the feed has been considerably altered. The viscosity has been greatly reduced. The asphaltene content has been reduced to a fraction of one per cent. A small amount of gasoline has been produced.

The oil, however, was still far from a marketable product. Viscosity was 250 to 300 Saybolt seconds at 100°F. This could be reduced by recycling heavy ends. The sulphur at 4% was still high, and analysis showed the oil to be very highly unsaturated. Warren has one per cent. A small amount of gasoline has been produced.

Dehydration-Catalytic Cracking

In the dehydration-coking of wet crude it was found that the bed remained unaltered. This suggested the possible use of a more active bed material such as a catalyst. Two silica-alumina catalysts were used, one from Davison Chemical Co., and the other donated by Universal Oil Products Co. Runs have been made on the following materials:

(1) Coker distillate from bituminous sand.
(2) Wet crude produced by the hot water process.
(3) Diluted wet crude produced by the cold water process.
(4) Pool bitumen recovered as cores from the Mildred-Ruth Lakes area.

Their properties are shown in Table XV.

TABLE XV

PROPERTIES OF CATALYST CHARGING STOCK

Material	Topped coker distillate	Hot-water wet crude	Cold-water wet crude	Pool bitumen
Water, wt. %	Trace	26.6	7.9	15.4
Solids, wt. %	Trace	2.9	0.6	44.8
Oil, wt. %	100	70.5	91.5	39.8
Analysis of oil				
Sp. gr. at 60°F.	0.983	1.02	0.913	1.02
Sulphur, wt. %	4.1	5	2.53	5
Viscosity				
kin. cstks. at 100°F.	115+	600,000+	37.8	600,000+
Distillation				
I.B.P., °F.	460	—	—	—
5%	530	605	340	—
10	562	652	395	—
20	600	750	418	—
30	626	—	445	—
40	642	—	475	—
50	654	—	500	—
60	666	—	522	—
70	674	—	730	—

Before describing the results, it is necessary to define the status of the work. The catalysts have not been run for a sufficient length of time for evaluation. Operating staff for long term tests was not available. The pilot plant was not designed for catalytic work and hence, as Peterson has pointed out, it was impossible to prevent coke buildup on the catalyst without going to entirely ridiculous catalyst-to-oil ratios. The catalyst work has only just begun. The results, therefore, should be considered as indicative, and not as a means of arriving at fixed conclusions.

During a run the coke content of the catalyst continued to increase. The collection system, however, made it possible to remove the oil when and as formed. The oil samples collected were, therefore, representative. Fig. 4 illustrates conditions for one run.

(1) Topped Coker Distillate

This material was used for the initial runs in order to reduce difficulties to a minimum until a lead was obtained. There was one other reason. In some earlier work, topped coker distillate had been recycled to a sand bed and no substantial amount of cracking had taken place. There was a natural curiosity to learn what a catalyst would do to this material.

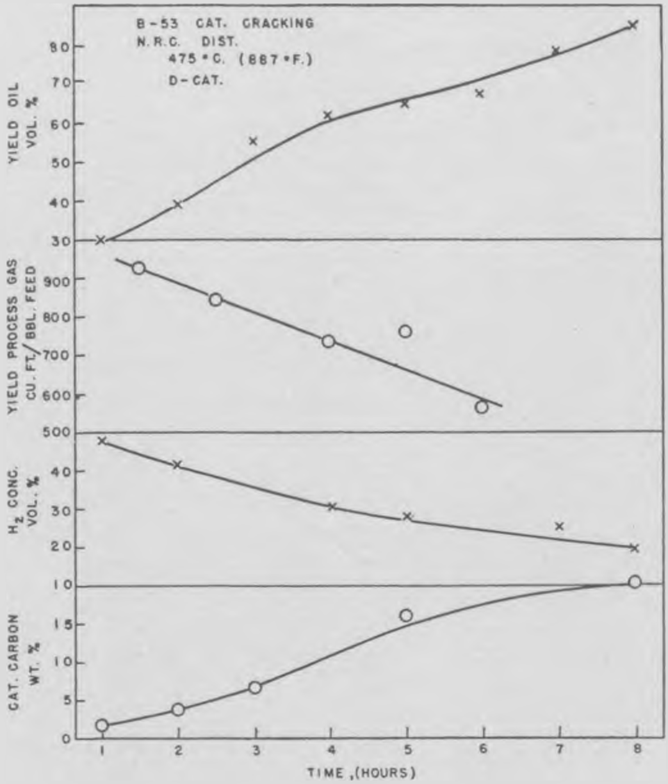

Fig. 4.

The first run was made at 515°C. (960°F.). The yields were low, process gas formation was very high and the product was light, over 40% gasoline. Sulphur on the composite product was down somewhat, i.e., from 4.1% in the feed to 3.3% in the product. Sulphur in the gasoline fraction was 1.65%. In later runs lower temperatures were used. Two runs, one with each of the catalysts at 475°C. (887°F.) are illustrated in Table XVI.

(2) Hot-Water Wet Crude

Three runs were made, none of them under steady state or what may be called practical operating conditions. The reasons for this have already been given. A temperature of 500°C. was chosen. This was high, but it was a safe temperature for the initial runs; difficulty might have been encountered at 475°C. Table XVII gives the operating conditions, the yields of oil and gas and their analyses.

In all of these, catalytic coke values were too high; weight hourly space velocities were much too low. However, a few interesting points

TABLE XVI

CATALYTIC CRACKING OF N.R.C. COKER DISTILLATE AT 475°C. (887°F.)

Run No.	53		56		
Catalyst (SiO_2-Al_2O_3)	Davison		U. O. P.		
Period, hr.	1-6	7-8	1-4	5-7	8-10
Feed rate, lb./hr.	8.44	9.38	8.87	8.94	9.00
Wt. hr. space velocity	0.56	0.62	0.59	0.596	0.60
Catalyst coke range, wt.%	1-16	16-20	3-13	13-20	20-28
Oil yield, vol. %	52	82	46	58	63
Process gas (corr. to zero N_2)					
Reject, cu. ft./bbl.	760	—	470	520	450
Charcoal, cu. ft./bbl.	30	30	110	110	110
Analysis reject gas					
NaOH soluble, vol.%	8.1	12.1	—	10.1	10.5
Illuminants, vol. %	10.7	10.4	—	13.4	11.5
Hydrogen, vol. %	33.5	25.2	—	10.2	13.0
Carbon monoxide, vol. %	3.0	4.7	—	5.8	7.4
Paraffin hydrocarbons, vol. %	44.0	46.1	—	58.2	57.3
Oil inspection					
Sp. gr. at 60°F.	0.947	0.942	0.924	0.922	0.923
Viscosity, kin. cstks. at 100°F.	2.66	7.08	1.45	1.70	2.09
Sulphur, %	3.6	3.4	3.26	3.14	3.07
Distillation					
I.B.P., °F.	142	130	136	132	124
5%	245	215	175	169	170
10	289	295	210	208	212
30	412	532	322	342	382
50	522	612	438	468	506
70	608	669	526	556	590
90	717	688	683	695	698
Gasoline cut					
Vol., %	28	16	43	41	32
Mixed aniline point, °F.	—	—	—	86.9	—
Sulphur, %	—	—	—	1.78	—
Bromine No.	—	—	—	54.7	—

should be mentioned. In run No. 54, for example, an oil yield of 55% was obtained directly from wet crude. This oil had an extremely low viscosity. Forty-one per cent boiled in the gasoline range. About 70% boiled in the gasoline plus kerosene range, and a large amount of process gas high in hydrogen was formed. The sulphur content was

TABLE XVII

CATALYTIC CRACKING OF HOT-WATER WET CRUDE* AT 500°C. (932°F.)

Run No.	54		57			58		
Catalyst (SiO_2-Al_2O_3)	Davison		U.O.P.			U. O. P.		
Period, hr.	1-4	5-6	1-4	5-7	8-10	1-4	5-7	8-10
Feed rate, lb./hr.	9.28	9.94	6.88	8.23	7.89	4.83	5.03	4.90
Bitumen, wt. %	72.9	76.3	73.5	73.1	72.9	70.0	70.7	71.7
Wt. hr. space velocity	0.45	0.50	0.34	0.40	0.38	0.23	0.24	0.23
Catalyst coke range, wt. %	1-9	9-12	23-28	28-29	29-30	7-11	11-13	13-15
Oil yield, vol. %	39	55	41	70	75	22	32	35
Process gas								
Reject, cu. ft./bbl.	1160	860	405	400	400	1210	1080	1050
Charcoal, cu. ft./bbl.	75	75	140	140	140	250	250	250
Analysis reject gas								
NaOH soluble, vol. %	6.6	7.3	16.7	17.9	19.4	15.5	11.0	11.2
Illuminants, vol. %	12.7	10.0	3.5	3.5	4.9	3.0	3.8	4.9
Hydrogen, vol. %	38.2	37.5	22.6	17.1	17.6	42.3	42.7	38.4
Carbon monoxide, vol. %	2.1	2.5	17.2	18.9	21.7	14.1	12.7	13.6
Paraffin hydrocarbons, vol. %	37.6	42.0	39.2	38.8	36.2	24.5	29.6	31.7
Oil inspection								
Sp. gr. at 60°F.	0.909	0.907	0.927	0.952	0.951	0.860	0.910	0.916
Viscosity, kin. cstks. at 100°F.	1.39	1.48	—	—	—	—	—	—
Sulphur, %	2.97	3.03	—	—	—	—	—	—

Distillation								
I.B.P., °F	110	94	122	144	146	99	78	102
5%	160	142	190	282	284	120	120	125
10	192	182	244	360	388	132	160	168
30	318	327	388	542	566	230	288	308
50	418	451	510	626	634	304	366	422
70	538	554	618	660	662	408	478	554
90	690	704	—	—	--	550	650	—
Gasoline cut								
Vol. %	46	41	32	13	11	69	55	47
Mixed aniline point, °F	—	84.6	—	100.6	—	—	72.1	—
Sulphur, %	—	1.75	—	2.13	—	—	1.85	—
Bromine No.	—	62.7	—	87.4	—	—	48.3	—

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* International Bitumen Company

somewhat improved. The feed contained about 5% sulphur, the product contained about 3% sulphur, the gasoline cut being 1.75%.

(3) Diluted Wet Crude

This material was supplied by the Mines Branch, Ottawa. It was produced in their cold water pilot plant. The diluent used was kerosene and not a recycle product of the process. Distillation indicated it to be a light cut 400 to 525°F., amounting to slightly over 50% of the product.

TABLE XVIII

CATALYTIC CRACKING OF COLD-WATER DILUTED WET CRUDE AT 500°C. (932°F.)

Run No.	55	
Catalyst (SiO_2-Al_2O_3)	Davison	
Period, hr.	1-4	5-6
Feed rate, lb. hr.	12.86	14.4
Bitumen, wt. %	90.6	93.3
Wt. hr. space velocity	0.78	0.9
Catalytic coke range, wt. %	7-10	10-13
Oil yield, vol. %	60	70
Process Gas		
Reject, cu. ft./bbl.	860	—
Analysis reject gas		
NaOH soluble, vol. %	3.8	4.6
Illuminants, vol. %	15.9	18.4
Hydrogen, vol. %	43.6	35.7
Carbon monoxide, vol. %	1.8	2.8
Paraffin, vol. %	34.0	38.4
Oil Inspection		
Sp. gr. at 60°F.	0.854	0.844
Viscosity, kin. cstks. at 100°F.	1.40	1.46
Sulphur, wt. %	1.26	1.06
Distillation		
I.B.P., °F.	135	128
5%	226	221
10	274	285
30	367	392
50	414	441
70	463	478
90	532	565

One dehydration-catalytic cracking run was made. The results are shown in Table XVIII. The diluent was not as sensitive to cracking conditions as the bitumen. Yields, therefore, were somewhat higher. At this stage in the work it would be impossible to sort out the relative effect on the diluent and the bitumen. Decrease in sulphur, from 2.53% to 1.06%, was more marked than for undiluted crude. The product was very light.

(4) Direct Cracking of Pool Bitumen

This feed was obtained by combining core samples from a number of holes in the Mildred-Ruth Lakes area. It was therefore representative. However, because of the high solids content of the feed, the catalyst rapidly became contaminated. In this run the reaction temperature was reduced to 490°C. This temperature, combined with the high catalyst-to-bitumen ratio, still resulted in extremely severe cracking conditions. The yields were low and the product was high in gasoline. The results are shown in Table XIX.

TABLE XIX

CATALYCTIC CRACKING OF MILDRED-RUTH LAKE POOL BITUMEN AT 490°C. (914°F.)

Run No.	61
Catalyst	Davison
Period, hr.	3-6
Feed rate, lb./hr.	12
Bitumen, wt. %	36.3
Wt. hr. space velocity	0.3
Catalytic coke range, wt. %	3-4
Oil yield, vol. %	40-50
Process gas	
Reject, cu. ft./bbl.	800
Charcoal, cu. ft./bbl.	250
Analysis reject gas	
NaOH soluble, vol. %	5.8
Illuminants, vol. %	5.8
Hydrogen, vol. %	63.0
Carbon monoxide, vol. %	3.7
Paraffin hydrocarbons, vol. %	21.4
Distillation	
I.B.P., °F.	92
5%	102
10	132
30	242
50	351
70	512
90	661

The unusual feature about these results is the extremely high hydrogen content of the process gas. It differed from the other tests in two ways: (1) the feed was high in solids, (2) it was from the Mildred-Ruth Lakes area. The contaminated catalyst is being retained for further work. No firm conclusions are possible until the results have been confirmed. They do point, however, to the desirability of learning more about the material from the Mildred-Ruth Lakes area.

SUMMARY

1. The direct distillation of oil from bituminous sand on a small pilot-plant scale has been described. Yields of about 85% are obtained. At the temperatures used, considerable cracking takes place resulting in a product with properties that differ markedly from those of the bitumen in the feed.

2. It has been found possible to produce simultaneously and continuously, a dry, fairly clean, coker distillate from the wet crude oil produced in the water separation processes.

3. Some initial work has been done on catalytic cracking of wet crude. The pilot plant was not designed for this work. It is planned to make the necessary modifications. The results are encouraging and show in what direction future work should be carried out.

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FLOW CHARACTERISTICS OF SAND SUSPENSIONS*

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The usual methods of recovering oil from the Alberta oil sands require that the sands be mined and transported to a processing plant in which the oil-bearing material is treated in one of three well known methods (2, 3, 6). Regardless of the method of processing, the sand once devoid of its oil content must be moved away to a disposal area. For every barrel of oil recovered there is more than a ton of sand to be wasted.

Two general methods of transportation of waste sand and like materials are available. One is a haulage method employing cars, trucks, or conveyor belts. The other method makes use of a pipeline in which the waste solids are carried along suspended in water. In general, the pipeline is preferred for moving large quantities of uniform particles of size small enough that suspensions of them are relatively stable. The mining industry encounters similar disposal problems in milling operations. A typical example is the tailing disposal at the Hollinger Consolidated Gold Mines Ltd. (1) where about 5,500 tons of solids per day are conveyed to disposal areas by pipelines 12 inches in diameter. The solids involved are only slightly smaller than the mineral aggregate of the Alberta oil sands. Pipeline transport appears to be used in most cases for moving tailings from mine mill operations treating gold ores and other metallic ores (4, 5). In the pipelines the suspensions move either by gravity flow or by pumping.

A disposal system for tailings from an oil-sand development consists of three parts: the production of a suitable suspension of the solids, the transferring of this suspension from the plant site to waste area, and the production of a suitable deposition of the sand in the tailings area. The purpose of this paper is to report laboratory studies concerned with the first two operations. Part I deals with an assembly of equipment for removing sand at a controlled rate from a separation plant vessel by suspending the sand in a stream of water. Part II is a study of the flow characteristics of the suspension in a pipeline.

PART I—PRODUCTION OF A SAND SUSPENSION

Figure 1 is a diagram of a circular separation cell as might be operative in a separation plant using the hot-water separation process for the production of a crude oil from the oil sands. The oil-sand pulp is introduced into the central region of the cell and the oil rises to the surface, while the clean sand sinks to the bottom and accumulates there. A mechanical rake rotates very slowly in the lower part of the cell and tends to move the sand to the centre. Operating conditions

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*This paper was not read at the Conference.

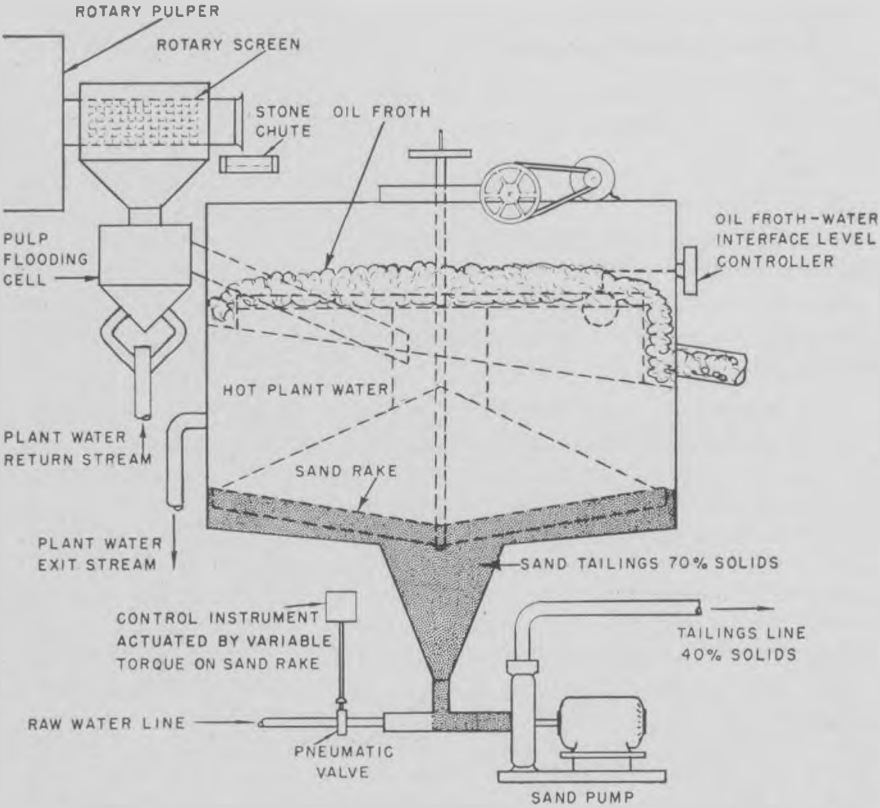

Fig. 1. *Diagrammatic drawing of simplified separation cell.*

are such that a bed of sand is maintained in the cell, and removal of the sand takes place at a controlled rate through an opening at the apex of the conical bottom. It is at this point that the sand meets a stream of water and is carried along to the pump. The need for a method of controlling the egress of sand from the cell and the need for a knowledge of the nature of the suspending process led to a laboratory study of this part of the separation cell.

Small-scale equipment was assembled to simulate the lower section of the separation cell. A bed of sand was maintained in a cone 24-inches deep equipped with a 1½-inch pipe nipple exit. An inverted tee of the same size fitted to the nipple served as the mixing chamber for the stream of sand coming down from above and the stream of raw water entering from one side. The mixture left through the other arm to the suction of the sand pump, and was ultimately returned to the cone by means of a suitable launder. In the cone, the sand settled out and the excess water overflowed to waste. As in the cell outlined above, a mechanical rake was mounted in the cone about 12 inches above the cone outlet. It had a two-fold purpose. It moved the sand toward the centre, and it formed the detector for a sand-level controller. The latter purpose was achieved by measuring the current drain of a small electric motor driving the rake at 2 r.p.m.

through an 800/1 speed reducer. As the sand level in the cone rose and fell the current rose and fell correspondingly and was recorded by a converted temperature recorder-controller.

Figure 2 shows that for a given sand pump through-put, the solids concentration in the suspension was inversely proportional to the flow of raw water entering the tee. Several arrangements of mixing zones were investigated. In one case, a gate valve was included in the line just above the tee. While it had been observed in earlier work that gate valves are quite unsatisfactory for controlling the flows of sand and sand suspensions, it was interesting to note that the presence of a gate valve did not interfere appreciably with the egress of sand from the cone. The results with the gate valve are presented in Fig. 2 as "a restricted flow". It will be noted that these results do not differ appreciably from the results with the cast iron tee, or with the glass tee. It has been shown, therefore, that the rate of flow of sand from the cone may be controlled by varying the flow of raw water to the mixing zone.

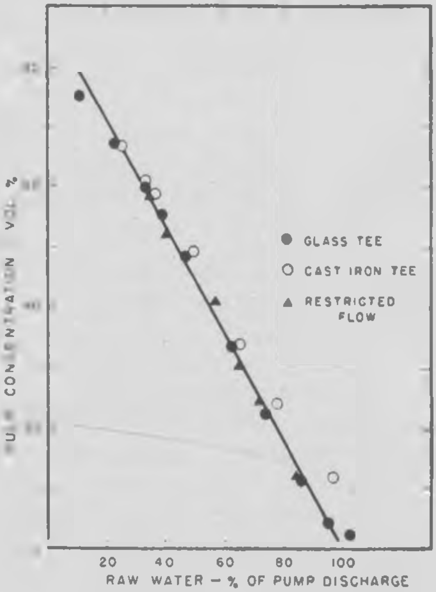

Fig. 2. *Effect of raw water flow on pulp concentration.*

A tee fabricated from glass was used to permit observation of the mixing action. It was observed that the sand did not leave the cone as a slug or plastic flow, but rather as a flow of fluidized sand. Examination of the sand bed lying in the cone revealed that the central part of the bed was in a fluidized state, while further out from the axis the sand bed was quiescent. Sand entered the fluidized section either by direct settling of fresh sand in that area or by slumping of the quiescent bed adjacent to the central part. This was favored by the action of the rake. Although there was no net upward flow until the raw water flow exceeded the pump capacity, the agitation within the cone appeared to be directly proportional to the flow of raw water.

In conclusion, it was shown that the level of sand in the cone could be detected and controlled by a simple automatic control instrument regulating the addition of raw water to the sand leaving the system, and that the mixing of the sand with water took place in a fluidized zone of sand in water extending from the tee upward into and through the sand bed.

PART II—PUMPING THE SAND SUSPENSION: FRICTION FACTOR MEASUREMENTS

To design a pumping system for handling sand suspensions, information must be available regarding the friction factor and the stability of the suspension passing through a pipe. To obtain information of this nature for sand tailings from oil-sand workings, a laboratory pumping system was assembled for measuring friction factor of suspensions of sand, and the influence on it of such variables as temperature, particle size, and nature of the pipe material. Some indication of the stability of the suspensions under various flow conditions was also sought.

The magnitude of the friction factor was measured in the usual way by determining the pressure drop along a measured length of horizontal pipe conducting the flow of material under study. The sand was held in suspension in water in the reservoir of the pumping system and was pumped from there to the measuring pipes by a centrifugal water pump. The scale of operations selected for study was as large as could be managed satisfactorily in the laboratory and involved the use of pipe of two-inch diameter with flows of 30 to 110 Imperial gallons per minute. The pump discharge entered twenty feet of brass pipe connected by a return bend to twenty feet of steel pipe lying parallel to it. Measurement of the pressure drop along the brass pipe was made possible by establishing pressure stations ten feet apart in the downstream part of the twenty-foot length. The downstream location was selected so that there would be a long calming section ahead of the first pressure station. For the steel pipe the pressure stations were fourteen feet apart. Each station consisted of a brass block machined to fit the contour of the pipe, and was drilled to take an ordinary ¼-in. fitting. The block was welded to the pipe and communication between the pressure station well and the inside of the pipe was accomplished by an ⅛-in. hole through the wall of the pipe. Care was taken that the drilling of the hole did not leave an obstruction in the inside of the pipe. Each pressure station led to an air trap connected in turn to an inverted, air-over-water differential manometer.

Flow rates of the desired magnitude were established by adjusting a by-pass on the pump discharge and by constricting the discharge opening from the pumping system. Flow rates were measured by timing the accumulation of a measured volume in a secondary receiver. Specific gravity of the suspension was obtained from the weight of a known volume of discharge. From the specific gravity was calculated the concentration of sand in the suspension. The precision of the measurement of flow rates and specific gravity was ±1% and ±0.3% respectively. The precision for pressure drop was about ±5%.

Temperatures above room temperature were attained by the injection of low-pressure steam into the pump reservoir. Temperature of the flow-line discharge was taken as the operating temperature.

RESULTS

Suspensions of Bitumount sand were studied under the following conditions:

Sand concentration:	24 - 53% by wt.
Temperature:	100 - 140°F.
Linear flow velocities:	4 - 12 ft./sec.
Reynolds' numbers:	1.5×10^5 - 4×10^5

Suspensions of Abasand sand were studied less extensively. Measurements were made at about 100°F. for flows of 9 to 12 ft./sec. for sand concentrations of 18 to 39%, and for low flows at 38% at 120°F.

Table I shows the mechanical analysis of the two sands. The Bitumount sand is somewhat coarser than the Abasand with a mean particle diameter of 0.24 mm. compared with 0.14 mm. for the Abasand sand.

TABLE I

MECHANICAL ANALYSIS OF IGNITED SANDS

Mesh size	Bitumount	Abasand
30	0.0%	0.0%
—30+50	25.0	0.4
—50+80	60.0	9.7
—80+100	9.7	28.8
—100+200	5.2	59.0
—200	0.6	2.3
	100.5%	100.2%

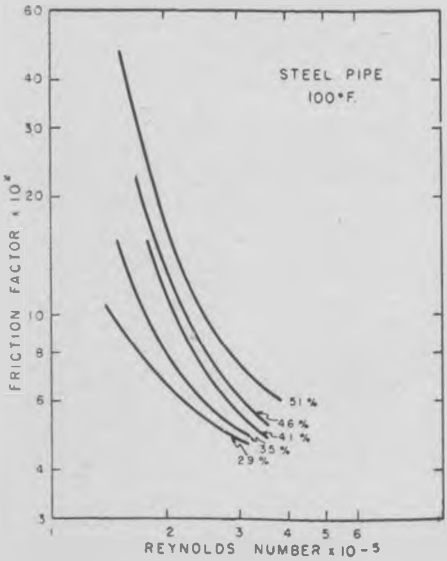

Fig. 3.

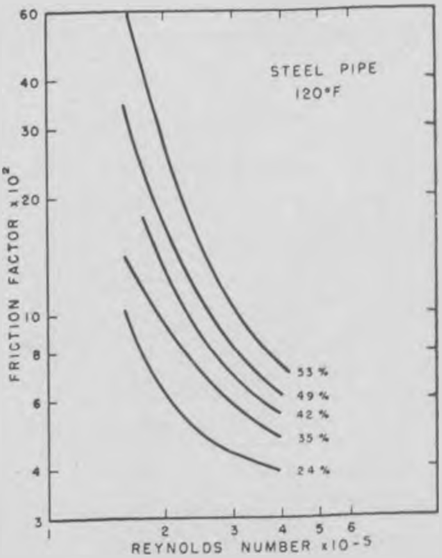

Fig. 4.

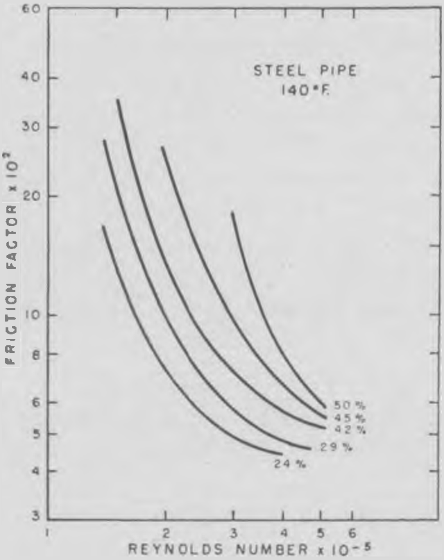

Fig. 5.

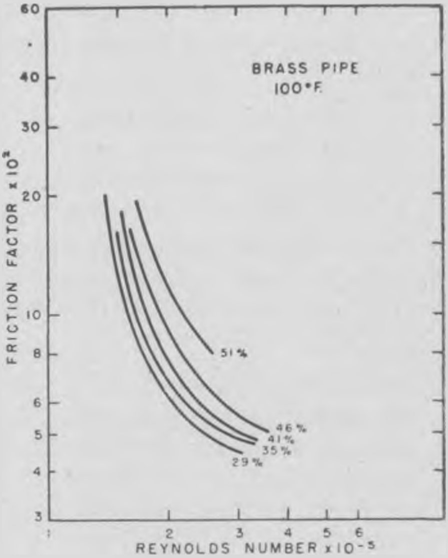

Fig. 6.

The results of the flow experiments are plotted in Fig. 3 to 8 as logarithm of the friction factor against logarithm of the Reynolds' number. It will be noted that the shape of the curves obtained was not the customary straight line that is characteristic of turbulent flows of Newtonian liquids, but deviated from it considerably at lower Reynold's numbers. This point will be discussed at length in a later section.

Temperature Effect

It was observed that with rising temperatures the friction factor for a given suspension increased. Table II shows typical data interpolated from the appropriate log. f vs. log. Re curves.

TABLE II

EFFECT OF TEMPERATURE ON FRICTION FACTOR

Conditions: 42% solids, Bitumount sand, steel pipe

Reynolds' number	Friction Factor x 10^3		
	100°F.	120°F.	140°F.
3.5×10^5	5.0	6.1	6.2
3.0×10^5	5.6	6.9	7.1
2.5×10^5	7.1	8.7	9.0
2.0×10^5	10.8	13.3	13.7
1.5×10^5	——	——	34.0

Particle Size

Table III shows that for a given solids concentration at a fixed temperature, the friction factor of the coarser Bitumount sand is greater than that of the Abasand sand.

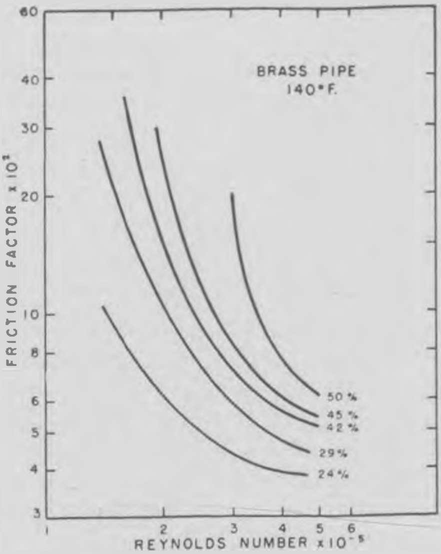

Fig. 7.

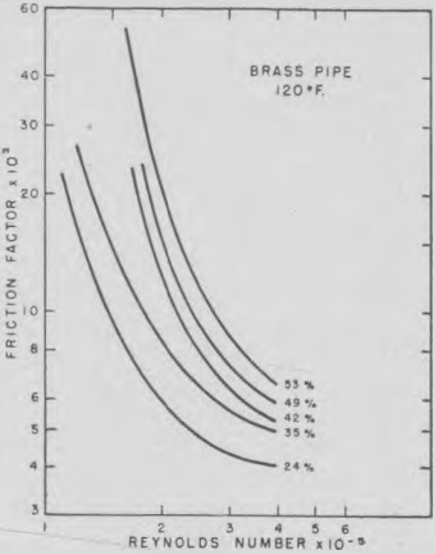

Fig. 8.

TABLE III

EFFECT OF PARTICLE SIZE ON FRICTION FACTOR

Conditions: 36% solids; 120°F., steel pipe

Reynolds' number	Friction factor x 10^3	
	Bitumount	Abasand
3.5×10^5	5.2	4.5
3.0×10^5	5.8	5.1
2.5×10^5	7.0	6.1
2.0×10^5	9.5	8.0
1.5×10^5	15.5	12.0

Nature of the Pipe Material—Steel vs. Brass

It is generally recognized that piping can be divided into two classes on the basis of observed friction factors. The class comprising commercial pipes of steel, iron, etc., shows a higher friction factor than does the class of smooth tubes made up of glass, copper, brass, etc. The data in Table IV indicate that this generalization may be extended to pipes conducting sand suspensions.

TABLE IV

FRICTION FACTOR

Conditions: 35% solids; 120°F., Bitumount sand

Re	Steel pipe	Brass pipe
3.9×10^5	0.0054	0.0046
3.0×10^5	0.0062	0.0053
2.5×10^5	0.0081	0.0060
1.25×10^5	0.033	0.026

DISCUSSION

The fact that the friction factor observed for the sand suspensions deviates from the value found for water and other Newtonian fluids is of considerable interest. Undoubtedly, the deviation is related in some manner to the fact that the former fluid is a suspension, and like all suspensions it is not stable under all conditions. It is reasonable to believe that in the case under study the stability of the suspension is maintained by the turbulence of the flows involved, and if the turbulence were reduced in some manner, the stability of the suspensions would be reduced to such a point that the sand would settle.

At the conclusion of the experiments described above, a length of glass pipe of two-inch diameter was incorporated into the flow system to permit observations of the conditions within the pipe at representative flows. At low Reynolds' numbers sand was observed to settle out and accumulate on the bottom of the pipe. The lower the Reynolds' number, the more settling that occurred. It was not possible to make precise measurements of the extent of settling, but no detectable settling appeared to take place until the flow rate was reduced to a Reynolds' number of 2.5×10^5. At 1.8×10^5 sand had settled out to the extent that the cross-sectional area of the pipe was reduced by about one-third. Under these conditions, it is clear that the Reynolds' number calculated from the volume of suspension entering the pipe and the inside diameter of the pipe did not properly describe the system. For the same reason, the friction factor observed for the system did not describe the interaction between the flowing fluid and the walls of the pipe in the usual manner.

It has been shown that at high flow rates the apparent friction factors for the suspensions are nearly the same as for water. It has also been shown that at the point where the suspension curve begins to deviate appreciably from the curve for water, the sand suspension has become unstable and sand has settled out and accumulated on the bottom of the pipe. An examination of the stability of the sand in suspension may be made with the following basic assumptions:

1. A sand suspension behaves as a Newtonian fluid, with a viscosity equal to that of the suspending medium and a density of the suspension (or pulp) at Reynolds' numbers in which the sand is uniformly distributed throughout the suspending fluid.
2. The tendency for a sand particle to remain suspended in a horizontal pipe varies directly with the Reynolds' number of the fluid passing in that pipe.
3. The tendency for a solid particle to remain suspended varies inversely with the velocity of settling of those particles.
4. The tendency for the solid particle to remain suspended varies inversely with the concentration of the solids. Thus, the tendency for the sand particle to remain suspended is given by a hold-up term, $H = \mathrm{Re} \times \frac{1}{v} \times \frac{1}{c}$ where v is the settling velocity of the particle according to Stokes' Law, c is the concentration of sand in the pulp.

If the hold-up expression is applicable to the system under consideration, the data presented in Fig. 3 to 8 should fall on a single curve when hold-up is substituted for Reynolds' number. Fig. 9 is a plot of the logarithm of the observed friction factor against the logarithm of the hold-up. The fact that the experimental points fall very close to a single line indicates that the hold-up expression is valid.

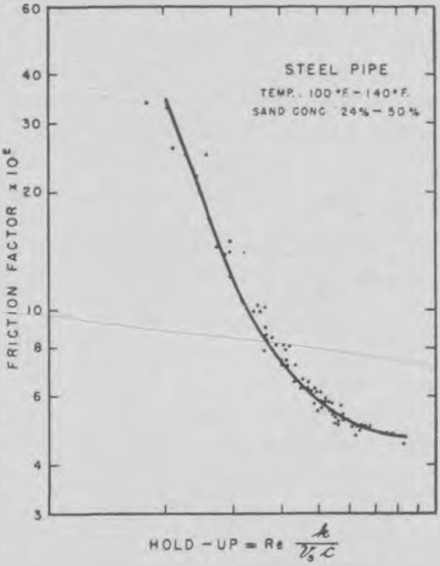

Fig. 9. *Relation between friction factor and hold-up. Note that the slope of the curve approaches —5 as the flows are reduced.*

It seems reasonable to use the hold-up number as the basis of an examination into the behavior of the suspension at low Reynolds' numbers. When the flow conditions are such that the sand is held uniformly in suspension, the relation between friction factor and Reynolds' number shows a close parallel to that of other fluids. But when conditions are changed so that sand tends to settle, the observed friction factor tends to change markedly. The most obvious thing that happens when sand settles out is that the dimensions of the inside of the conducting pipe are changed by the accumulation of sand therein. Consider a situation where the flow of a suspension is changed to a state where the suspension is unstable. Sand settles out until conditions within the pipe become sufficiently turbulent to prevent further settling. This increased turbulence results, of course, from an increased linear velocity due to the reduced cross-section for a given throughput. As a first approximation, it may be postulated that the hold-up term for the flow remains constant under settling conditions at a minimum figure.

Since it has been shown that the expression for hold-up holds for all practical temperatures and concentrations, it may be concluded that under settling conditions the hold-up has a constant value and, therefore, the product of DV in the expression for H must also be constant.

$$H = \frac{DV\rho}{\eta} \times \frac{1}{\psi} \times \frac{1}{c} \quad \text{(1)}$$

That is:

$$DV = k \quad \text{(2)}$$

The friction factor is given by

$$f_t = g\frac{D\Delta P}{2LV^2} \quad \text{(3)}$$

where it is understood that this is the true friction factor.

From the flow through the pipe,

$$\frac{\pi}{4}D^2V = Q \quad \text{(4)}$$

where D and V are variables depending on the extent to which sand has accumulated in the pipe.

From (1), (2), and (3) the true friction factor is:

$$f_t = \frac{32g}{\pi^3}\frac{Q^3\Delta P}{k^6 L} \quad \text{(5)}$$

If, as a first approximation, the friction factor is taken as a constant, then

$$\Delta P\, Q^3 = K \quad \text{(6)}$$

Since the observed friction factor was proportional to $\Delta P/Q^2$, (6) may be re-written as

$$\Delta P/Q^2 = K/Q^5 \quad \text{(7)}$$

Since the observed Reynolds' number, and the hold-up term were directly proportional to the flow, Q, then

$$\Delta P/Q^2 = K'/H^5 \quad \text{(8)}$$

If the assumptions made in the development of the relation between observed friction factor and hold-up term were sound, the relation in equation (8) should agree with the experimental data. A check with experimental data is afforded by measuring the slope of the curve of the logarithm of the observed friction factor plotted against logarithm of the hold-up. From equation (8) a slope of —5 would be predicted. An examination of the curve shown in Fig. 9 shows that the slope of the curve approaches —5 at the lowest flows studied.

It would appear that the assumptions made for the settling conditions have been substantiated. It may be concluded, on the basis of this agreement, that the flow of a suspension under settling conditions involves a stabilization of the sand suspension entering the flow system. The stabilization results from an accumulation of sand in the pipe to the extent that the turbulence of the stream is sufficient to hold the sand in suspension.

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OIL-REFINING SESSION

CHAIRMAN: S. M. BLAIR

It was planned to have Mr. E. F. Nelson, Vice-President, Universal Oil Products Company, act as chairman for the oil-refining session. Mr. Nelson fully intended to be here. He is very much interested in the oil-sands development problem. It was a great disappointment to him that business pressures developed that made it impossible for him to come to the conference. With your permission I shall undertake to be the substitute for Mr. Nelson and to fulfil the duties of chairman.

A review of ground covered so far in the conference and a forward look to what is still ahead may be helpful. The oil-sand deposit which is the source of raw material, the mining of the oil sand, the recovery of oil from the sand and the coking of the crude recovered oil to yield a coker distillate have been discussed. Still to be considered are an alternative method for making coker distillate, the treatment of the coker distillate, and the transportation of the treated oil.

The extent of the oil-sand formation, its stratigraphic relationships and the possible origin of the oil were discussed during the session on geology. From the standpoint of development, the extensiveness of the deposit and its mode of occurrence have been described. This information has been followed by the statement of government policy by the Hon. N. E. Tanner regarding the leasing of oil-sand properties. Thus, the cost of the undeveloped raw material can be estimated.

The problem of mining oil sand has been considered. Three approaches have been presented, namely, open-pit mining, underground mining by the block-caving method, and the obtaining of oil from the oil sand in situ. Prior to this conference during the preparation of the Blair report a cost of 55 cents per cubic yard for mining oil sand by the open-pit method and for delivering it in suitable form to a separation plant was estimated. Discussions here at the conference indicate that, for open-pit mining on a sufficiently large scale, this estimate is conservative. It is recognized, of course, that the inflationary tendencies of the times could significantly alter the basis for calculations.

Three methods for recovering oil from the mined oil sand have been described. These are the hot water and the cold water washing methods and the retorting of the oil sand by the fluidized solids technique. It will be noticed that no mention of the solvent recovery method has been made. This does not mean that this method has been ruled out of consideration. Propane extraction of oil sand has been examined as a matter of fact, and there seems to be no great technical difficulty involved. The yield of recovered oil is about 55% as compared to a yield of 80 to 85% of coker distillate when crude separated oil is coked by the fluidized solids technique of the National Research Council. Because of this unfavorable comparison, propane extraction was dropped from consideration. It is quite possible that a solvent extraction method that is advantageous will appear as time goes on.

Hot water washing is the oil-recovery method that appears in the sequence of operations proposed in the Blair report. That does not mean that it was judged that the method was the final answer to oil recovery. It appeared to be a good one, however, and enough study had been given to it to provide a sound basis for proceeding to an estimate of costs. Using the construction costs and engineering data obtained from the 500 ton per day Bitumount plant it was a fairly simple matter to estimate the costs for a 35,000 ton per day plant. This was done by increasing the Bitumount plant to a 2,000 ton per day size and then visualizing a battery of 17 such units. The resulting cost figures are probably high. If commercial work were undertaken, ways for increasing the capacity of units and for reducing their number would be found. Doing this should reduce both capital and operating costs.

The National Research Council has shown that coker distillate can be recovered directly from oil sand by the continuous fluidized solids retorting method. However, when the estimating of costs for this operation is undertaken serious difficulties arise. One of these is the handling and disposal of great quantities of very hot sand. Another is that the use of the method on the scale that is necessary for economic oil-sand development calls for consideration of units that are far larger than the largest catalytic cracking plants so far built. Thus, engineering studies of a major sort appear necessary before sound estimating of costs can be done.

The crude oil that is recovered from the oil sands by hot water washing contains about 30% water and 4 to 5% mineral matter and the oil itself is a very heavy one. This crude product must be coked to yield a coker distillate. There are a number of ways in which the coking can be done. These include the old shell still method and the conventional delayed coking method. Both of these methods would necessitate the dehydration of the wet crude oil prior to coking. This necessity, as well as the coking operation itself in the case of the conventional method, involve pumping the crude with its high mineral content through tube stills. Such a procedure spells trouble to any oil refiner. Coking by use of the fluidized solids technique offers a means of avoiding the troubles of preliminary dehydration and of handling mineral matter through a tube still. The National Research Council has shown that the wet crude oil with its mineral content can be fed directly to its continuous fluidized solids retort. Another possibility that is to be presented during this session is the continuous coking method developed by the Lummus Company.

Coking of the crude oil-sand oil yields a coker distillate. This is a product that is approaching something of commercial value. But it has a content of about 4% sulphur. It appears obvious that this high sulphur content must be reduced drastically before the coker distillate can be offered as a commercial product and before an evaluation can be put on it. Mild hydrogenation is the means that is emerging in refinery practice for such sulphur removal. The hydrogenation process of the Union Oil Company of California is to be described to the conference during this session. Further data on sulphur removal by hydrogenation from work in progress at the Mines Branch, Ottawa, will be given.

After covering the steps required for producing a sulphur-free coker distillate, there remains the problem of transporting this product to the marketing area. Pipeline transportation costs are to be discussed during the continuation of this session tomorrow morning.

With this brief summary of the ground covered and still to be covered we will proceed with the session on oil refining.

CONTINUOUS CONTACT COKING

By E. R. Smoley and A. H. Schutte
The Lummus Company, New York

The foregoing papers have been very broadening and describe what has happened from the prehistoric days in the sands, through the mining and the oil-sands separation steps, to the gummy bitumen, which contains about 30% water and 4% sulphur and some 2 to 3% minerals. The processing of this bitumen for recovery of distillate fuels bears great resemblance to the problems of handling shale oil, and heavy petroleum pitches and asphalts. Coking has been used for converting such heavy materials to lighter distillates and coke. Along with the removal of the carbon are also removed heavy minerals or metallic compounds which would cause serious troubles in further process steps. To illustrate, coking of heavy petroleum residues removes coke and metals like vanadium, which increases catalyst life in catalytic cracking or other process operations charging this coker distillate.

Coking of bitumen would yield a synthetic crude oil of low carbon and mineral content which would be ready to be refined by conventional methods and further upgraded by such a process as hydrogenation to produce premium distillate fuels.

The discussion here will be limited to the primary coking step. Time did not permit a thorough study of the application of this new coking process (continuous contact coking) to the Alberta Oil Sands Project. This paper is limited, therefore, to a general description of the process and the presentation of some typical data from semi-commercial plant operations. This new process lends itself to operation on extremely heavy materials from a wide range of origins including petroleum pitches, asphalts, naturally occurring bitumens and shale oil. This process has been developed by extensive work through the semi-commercial stage, and the next step is large-scale operation.

Continuous contact coking has been described in two publications (1, 2). Fig. 1 shows a simplified process flow diagram. A continuous stream of coke particles circulates through the reactor vessel and the reheater. This circulation is obtained by means of mass flow lift which elevates the material as a dense phase unagitated column. The power for the lifting is provided by high pressure steam. The charge material is contacted with the reheated circulating coke at its entrance to the reactor in such a way that uniform distribution of the oil on the coke particles is obtained.

At the oil-coke contacting zone, the lighter portions of the feed are vaporized and the heavier unvaporized material is taken up as a liquid film on the coke particles. The wetted coke particles travel down slowly through the coking reactor as a compact bed and are allowed a residence time of approximately 30 minutes to complete the coking and drying reaction. At an intermediate point in the reactor, the product vapors are removed through an internal draw-off device and the coke descends below this vapor disengaging zone into a stripping zone, where the final drying out is obtained in an atmosphere of steam. The dried coke particles are then elevated to the spent coke lift disengager from which they flow by gravity into the coke reheater under control of a remote operated valve which determines the coke circulating rate in the entire system. In the reheater, the coke drops on to a free pile subjected to radiation from internal gas burners. Part of the heating is done by this direct radiation and part is done by contact with the flue gases which pass concurrently with the coke through the reheater. From the bottom of the reheater the coke discharges by gravity into the lock tank which forwards it into the high pressure lift tank for recirculation back to the oil contacting zone above the reactor.

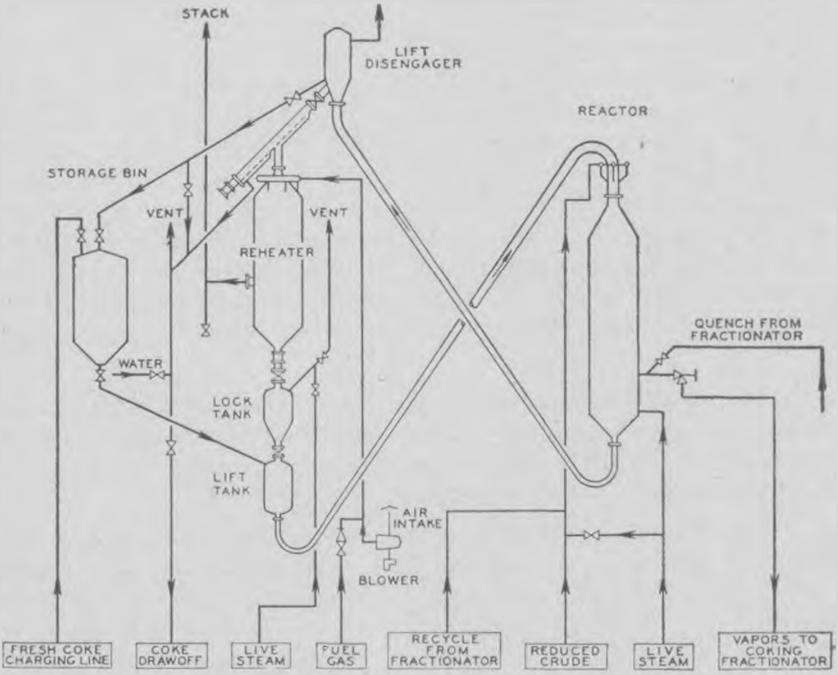

Fig. 1.

As oil is charged to the unit, the successive layers of coke deposited on the circulating material result in a gradual increase in particle size and an increase in the inventory of coke in the system. The larger particles are drawn off through a classifier as a product coke stream to maintain essentially constant inventory in the system. The coke product is in the form of very hard dense pellets of rounded form and low volatile content. The major dimensions of these pellets may range from one-half to one inch.

This process eliminates the semi-continuous operation of coking chambers required in conventional methods. It eliminates the labor, operating supervision and utilities involved in removing the coke from the coking chambers. The yields of hydrocarbon products are superior to those obtained by previous processes, and the coke product is obtained as a stream of dry, high strength pellets, free of fines. This eliminates handling losses and fines production in the transportation and subsequent processing of the product coke.

Since the heat requirements of the process are obtained from the circulating coke stream, it is unnecessary to heat the bitumen charge above the temperature required for pumpability and convenient handling. Former processes required all the heat to be put into the oil charge stream in a fired heater at temperature levels in excess of 900°F. For this reason the continuous contact process is applicable to charge materials of higher carbon residue and solids content than in the case of the delayed coker. It was also necessary in the conventional drum type coking operations to maintain the volatile content of the product coke within rather narrow limits in order to permit its easy removal from the drum at the end of the coking cycle. This, in turn, fixed the temperature level of the operation and the degree of conversion obtainable within relatively narrow limits. Since no similar limitation exists in this continuous contact process, a very wide range of operating conditions and degrees of conversion is obtainable.

The applicability of contact coking to very heavy materials may be shown by referring to the semi-commercial plant data obtained on a 4-gravity Wilmington asphalt of 14 penetration and 150°F. ring and ball melting point. Typical yields and product distribution in contact coking of this stock are shown in Fig. 2 for once-through and recycling conditions. It should be noted that once-through yields of about 25% C_4 to 400°F. were obtained from this material. The research octane number of the debutanized gasoline was 78 to 83 clear and 88 to 92 with 3 cc. of TEL.

On comparing contact coking results with delayed coking of lighter stocks where both methods are applicable, we find that contact coking produces more gas, more gasoline of a higher octane number, more gas oil and less coke than delayed coking.

The data presented graphically in Fig. 2 show the decrease in end point and increase in light product yield obtainable by recycling heavy material, and indicate a high degree of conversion of the recycle component.

The 30% water-bitumen would be preheated by exchange and preflashed as integral part of unit to remove most of the water.

In addition to the applications in petroleum refining, the contact coking process is being considered for handling a wide variety of materials obtained by recovery from natural deposits or as processed residues. Each project requires special study to determine the utility of the new tool and its best place in the over-all scheme of operations.

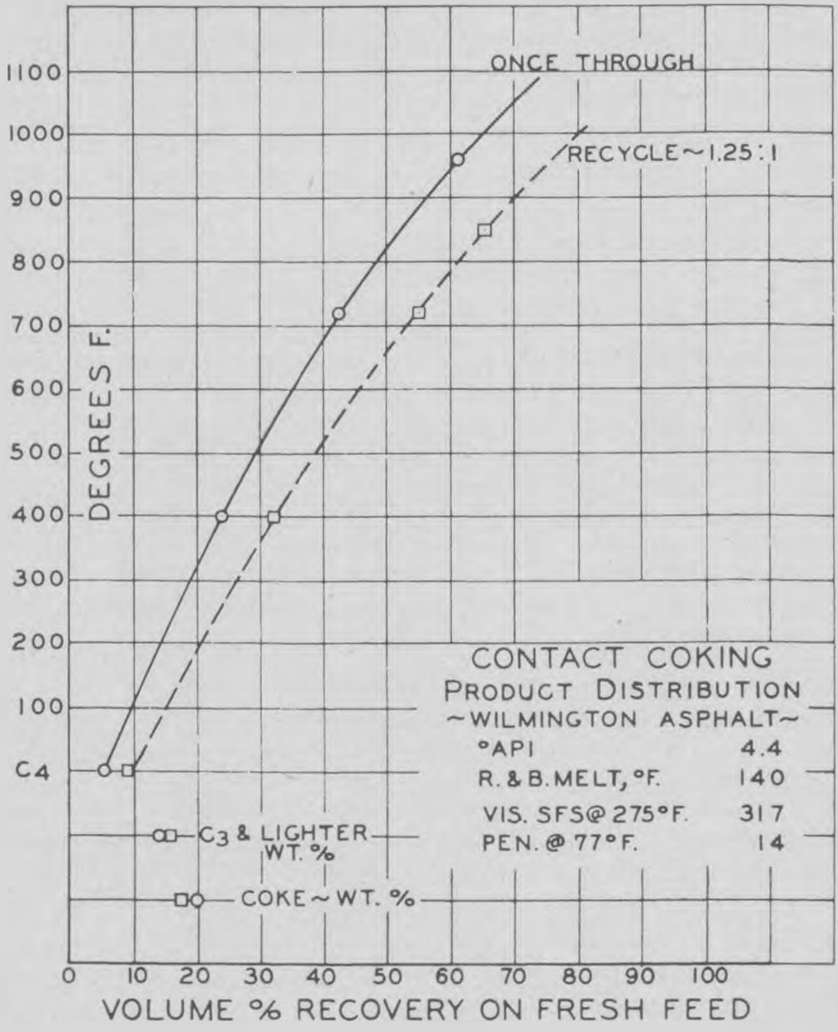

Fig. 2.

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DISCUSSION

S. M. Blair: Could you give some indication of the capital cost and operating costs?

E. R. Smoley: The cost of a large unit handling, say, 10,000 bbl. of heavy charge per day should be one and a half to two million dollars. A rough estimate of the operating costs of similar units of that size would be as follows. For topping units, 10 to 15 cents per barrel; for thermal cracking units, 25 to 30 cents; for catalytic cracking, 30 to 35 cents; and for coking 35 to 50 cents. That is the general order of figure; a more exact figure could be worked out from the utilities for established units.

S. M. Blair: That capital cost figure is for a plant within battery limits, that is, it assumes that all refinery services are provided separately?

E. R. Smoley: That was within battery limits. We have designed a unit of about that size which would fit into this sort of scheme, and it fits the order of figures given.

D. S. Pasternack: What would be the effect of an increase in the mineral content of the wet oil?

E. R. Smoley: We would expect it to be included in the progressive layers laid down on the coke particles and thus to appear as ash in the coke product. A coke having an ash content of, say, 10% may be an advantage when it is used for domestic or industrial fuel.

D. S. Pasternack: Will the increase in size of the balls be important?

E. R. Smoley: Gradual increase in the size of the circulating coke is normal, and classification equipment is included in the installation.

Question: Does the 35- to 50-cent estimate for coking represent the direct operating cost only, or does it also include amortization?

E. R. Smoley: It was given as a direct operating cost.

Question: In a unit like this, how does the sulphur distribute itself? Does it concentrate in the coke?

E. R. Smoley: The coke sulphur distribution was quite similar to conventional coking. In processing this type of material the sulphur usually goes to the heavy ends. Dr. Gishler's figures showed the same result—that the sulphur tends to concentrate in the heavy reduced crude portion which ultimately goes to coke. This process is very similar to delayed coking and the coke contains considerable sulphur.

Question: Could you estimate the sulphur in, say, the gas oil from a 5% sulphur stock?

E. R. Smoley: Dr. Gishler's figures were about 3%.

P. E. Gishler: Our coker distillate started out at 1½% in the light ends and increased to well over 4% in the heavy ends. The average was 4%. The gas oil averaged 3%.

S. M. Blair: What is the fuel consumption?

E. R. Smoley: A very approximate estimate would be in the range 4 to 5% on charge. It runs that in most cracking operations. There is a slight amount of heat of cracking, and some recovery from the products going out. In this type of process, the coke could probably be used as such on power generation schemes.

S. M. Blair: What is the volatile content of the coke?

E. R. Smoley: It is about 3%.

Question: In the application of this coking process to the wet oil, is it planned to remove the water first?

E. R. Smoley: The conjecture is that this 30%-water stock would first be heated up and the majority of the water would be flashed off. A second flashing would remove the lighter gas oils before the oil was charged to the coke reactor.

S. M. Blair: One point of concern because of the high mineral content in the charge, is the type of equipment required for the flashing taking place in front of the coker. It seems desirable to do it, if possible, directly in the coker and avoid the use of a tube still or heat exchanger.

E. R. Smoley: The 4% sulphur and 2% minerals do bother a bit on pumping through a tubular heater, but it can be worked out satisfactorily at the low preheat temperatures required.

Question: What size pilot plant is being considered?

E. R. Smoley: It is a 100 bbl./day unit.

Question: You have operated a smaller one, have you not?

E. R. Smoley: Yes. The history of the development of this process started with a small one in the laboratory. It is described in the first reference. From there it went to a 50 bbl./day unit—an improvised unit—in Ohio. From it was built the unit from which these last data have been quoted. It is in the Richfield refinery at Wilmington, California. In that operation, the practicability of running was well established.

THERMAL COKING OF OIL FROM ALBERTA BITUMINOUS SAND

By M. J. Sterba
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Extensive measurements have been made of the physical properties of the hydrocarbon material associated with Alberta bituminous sands. Although the properties of this material, which can be called a bitumen, vary somewhat with its source, it has an average specific gravity of about 1.02, a sulfur content of about 5% and is quite viscous when compared with crude petroleum. Very little information has appeared in the literature on the chemical properties of the bitumen.

Another method of characterizing raw materials of this kind is that of noting their behavior when processed in conventional thermal cracking operations. It is the subject of this discussion to consider the experimental thermal coking of the bitumen, and to compare the results with the thermal coking of other hydrocarbon materials.

A comprehensive report was prepared recently by Blair (2) who outlined the technical and economic aspects of processing commercial quantities of bituminous sands to produce a marketable distillate oil. In this report Blair suggests the following sequence of processing steps:

1. Mining the sand to be delivered to a processing site.
2. Separation of the bitumen from the sand using water as the partition agent.
3. Thermal coking of the separated bitumen to produce a distillate oil.
4. Mild hydrogenation of the coke distillate to remove sulfur as hydrogen sulfide.

Crude bitumen produced by water separation from oil sands is never entirely free either from solids as mineral matter or from water. It is the intent of the thermal coking step to produce a low-viscosity distillate oil which is relatively free of solids and carbon residue.

Gishler (4), and Peterson and Gishler (7, 8) have proposed and demonstrated the use of a fluidized solids technique to accomplish the separation of bitumen from sand and the coking of the bitumen simultaneously in one processing step. These investigators have also used the fluidized solids technique to coke crude bitumen separated from sand by the hot water method. In this operation the crude bitumen is dehydrated, freed of solids and coked simultaneously. This type of processing of the separated crude bitumen was proposed by Blair for the third step in his sequence of operations.

Conventional thermal coking methods developed and used by the petroleum industry for many years may be applied to relatively dry crude bitumen which has been separated from sand. Several types of thermal coking processes and equipment have been described by Watson (9). One extreme of product distribution obtainable by thermal coking is referred to as ultimate coking in which only coke, gasoline and gas are produced by the recycling of distillate heavier than gasoline to extinction. The other extreme of product distribution is represented by the production of minimum yields of coke, gasoline and gas with maximum yields of intermediate distillates, using what is variously named once-through, delayed, or partial coking. The latter procedure is used rather frequently by the petroleum industry for the production of gas oil catalytic cracking feed stocks from reduced crudes (3, 6). Because it is the objective of the coking operation to produce maximum yields of distillate oil from the bitumen, the once-through type of process was selected for this experimental study.

Raw Bitumen Feed Stock

The particular bitumen used in this coking study was received some time ago as a dry 20.1° A.P.I. gravity blend with a diluent which was removed by vacuum distillation to produce the 7.3° A.P.I. gravity bitumen described in Table I. This sample was separated by the hot water method as it was applied at that time, from oil sand whose exact geographical source is unknown.

Physical inspections of this bitumen are presented in Table I, and are typical of those reported in the literature for materials originating from Athabasca sands. The U.O.P. characterization factor of 11.18, derived from the gravity and viscosity of the bitumen, is distinctly lower than that of commonly occurring virgin petroleum fractions. The usual values of characterization factors normally encountered among unaltered petroleum range from about 11.3 for the most naphthenic Gulf Coast fractions to about 12.3 for the very paraffinic Pennsylvania crude cuts. The low value of 11.18 for the bitumen suggests either high contents of naphthenes and aromatics, or anomalous viscosity effects of very high boiling asphaltenes or sulfur compounds.

Although not determined for this specific sample, a Conradson carbon value of 17.9% and a nitrogen content of 0.43% have been reported (2) for a similar bitumen.

TABLE I

LABORATORY INSPECTIONS OF BITUMEN

Gravity, °A.P.I. at 60°F.	7.3	
Specific gravity at 60°F.	1.0194	
Total sulfur, wt. %	5.32	
Cold test, °F.	75	
Viscosities:		
Kin. cstks. at 210°F.	233	
S. S. F. at 210°F.	110	
U.O.P. Characterization factor	11.18	
100 ml. distillation:	Atmos.	Vac.
I.B.P., °F.	456	453
5%	543	570
10%	590	627
30%	670	803
50%	703	——
70%	709	——
Recovery, %	83.0	32.0
Bottoms, %	——	68.0
Coke, wt. %	16.6	——

Batch Still Coking of Bitumen

An exploratory coking run was made on the bitumen in a 15-gallon gas-fired batch still equipped with a 3-inch diameter packed fractionator. During the run a coke distillate and gas were separated in a fractionator overhead receiver at atmospheric pressure. At the end of the run only coke remained in the still. Subsequently, the coke distillate was resolved into gasoline and gas oil cuts.

Product yields and inspections are presented in Table II, and will be discussed later. This batch coking run was made in order to orient processing conditions for the continuous once-through coking tests, and because the batch still technique is no longer in commercial use no practical significance is to be given to the results.

TABLE II

BATCH STILL COKING OF BITUMEN

Yields:		Wt. %	Vol. %
Gas (molecular weight = 31.7)		13.1	——
Gasoline		12.9	17.1
Gas oil		44.9	50.3
Coke		29.6	——
Product recovery		100.5	67.4
Product Properties:	Coke distillate	Gasoline	Gas oil
Gravity, °A.P.I. at 60°F.	30.9	52.5	24.1
Specific gravity at 60°F.	0.8713	0.7690	0.9094
Total sulfur, wt. %	——	1.84	3.04
Mercaptan sulfur, wt. %	——	0.043	——
Bromine number	——	69	28
Reid vapor pressure, lb.	——	3.5	——
Octane No., motor method:			
Clear	——	64.6	——
+ 3 ml. TEL/U.S. gal.	——	69.1	——
Conradson carbon, wt. %	——	——	0.026
Cetane number	——	——	33
Viscosity:			
S.S.U. at 100°F.	33 9	——	42.4
Kin. cstks. at 100°F.	2.35	——	5.03
U.O.P. Characterization factor	11.22	11.79	11.09
100 ml. distillation:			
I.B.P., °F.	158	117	444
10%	294	194	485
30%	449	256	527
50%	528	297	563
70%	583	330	601
90%	647	369	650
E.P.	700	399	704
Inspection of Coke:			
Moisture, wt. %		0.0	
Ash, wt. %		2.8	
Volatile matter, wt. %		10.9	
Sulfur, wt. %		5.65	

Pilot-Plant Once-Through Coking of Bitumen

In its simplest form a partial coking unit would consist of a heater, coke chambers, and fractionation equipment to resolve the coke distillate and light hydrocarbons. Two or more coke chambers are employed so that while one is being filled with coke another can be emptied by appropriate coke removal equipment.

The pilot-plant equipment consisted of a tubular heater, a coke chamber, a condenser, and a receiver in which gas and total coke distillate were separated. In this experimental work the coke distillate was resolved into gasoline and gas oil by batch fractionation, although the pilot plant is equipped to perform this resolution continuously. Actually, the plant uses two coke chambers; one is used while operating conditions are being brought to equilibrium at which time a test period is begun by switching the heater effluent into the other chamber. When the test chamber is considered to be filled with coke the run is terminated. These provisions allow rather accurate measurements of product yields at constant operating conditions which prevail during a test period.

Although several coking tests were made in order to prepare sufficient quantities of coke distillate for further processing, the detailed results of only one test period will be considered in this discussion. Operating conditions and product yields are shown in Table III, and inspections of the products are outlined in Table IV for this test period.

TABLE III

ONCE-THROUGH PILOT-PLANT COKING OF BITUMEN

Operating Conditions and Product Yields

Operating Conditions:		
Coke chamber pressure, p.s.i.g.	51	
Product Yields:	Wt. %	Vol. %
H_2S	1.2	——
C_4 & lighter hydrocarbons	7.0	——
Debutanized gasoline	15.4	20.3
Gas oil distillate	55.0	58.8
Coke	21.0	——
Total	99.6	79.1
C_4 & lighter hydrocarbons:	Cu. ft./bbl. of bitumen	Mol. %
H_2	46.6	11.0
CH_4	199.4	47.1
C_2H_4	7.7	1.8
C_2H_6	60.0	14.2
C_3H_6	25.9	6.1
C_3H_8	49.2	11.7
i-C_4H_8	5.2	1.2
n-C_4H_8-1	5.5	1.3
n-C_4H_8-2	4.8	1.1
i-C_4H_{10}	5.7	1.4
n-C_4H_{10}	12.9	3.1
Total	422.9	100.0
Mol. % olefin in C_2 fraction		11.4
Mol. % olefin in C_3 fraction		34.4
Mol. % olefin in C_4 fraction		45.5

In order to make a comparison with the once-through coking of heavy petroleum fractions, the results of processing a cracked residuum and two virgin oils are presented in Table V.

TABLE IV
ONCE-THROUGH PILOT-PLANT COKING OF BITUMEN
Laboratory Inspections of Products

	Total coke distillate	Debutanized gasoline	Gas oil bottoms
Gravity, °A.P.I. at 60°F.	25.5	51.9	16.6
Specific gravity at 60°F.	——	0.7715	0.9554
Total sulfur, wt. %	3.60	1.86	4.04
Mercaptan sulfur, wt. %	——	0.226	——
Hydrogen sulfide, wt. %	——	0.014	——
Bromine number	——	80	47
Octane No., motor method:			
Clear		69.1	
+ 3 ml. TEL/U.S. gal.		74.0*	
Reid vapor pressure, lb.		3.0	
Viscosity:			
Kin. cstks. at 100°F.	3.15	——	13.32
S.S.U. at 100°F.	36.6	——	70.8
U.O.P. Characterization factor	11.0	11.65	10.85
100 ml. distillation:			
I.B.P., °F.	118	126	443
5%	182	165	466
10%	245	186	486
30%	438	232	550
50%	550	275	621
70%	657	315	690
90%	750	358	715
E.P.	760+	400	760+
Recovery, %	97.0	98.5	97.5
Bottoms, %	—	1.0	—
Loss, %	0.9	0.5	—
Coke, wt. %	2.1	—	2.5
Vol. % C_3 hydrocarbons	0.33	0	0
Vol. % C_4 hydrocarbons	1.12	0	0
Inspection of Coke:			
Proximate Analysis:			
Moisture, wt. %		0.30	
Ash, wt. %		2.95	
Volatile matter, wt. %		10.85	
Sulfur, wt. %		6.42	
Apparent density		0.98	
True density		1.38	
Cell space, %		29.3	

* On Unisol sweetened sample.

DISCUSSION OF RESULTS

It is noted that there is considerable variation in the yield and gravity of the total coke distillate when comparing batch, once-through and fluidized solids coking. The extent of the thermal decomposition of the bitumen in these operations is roughly indicated by the amount of coke produced from the bitumen. By plotting the gravity and yield of coke distillate against the coke yield for the three types of coking operations as shown in Fig. 1, a continuous trend is indicated. Although no ultimate coking data are available

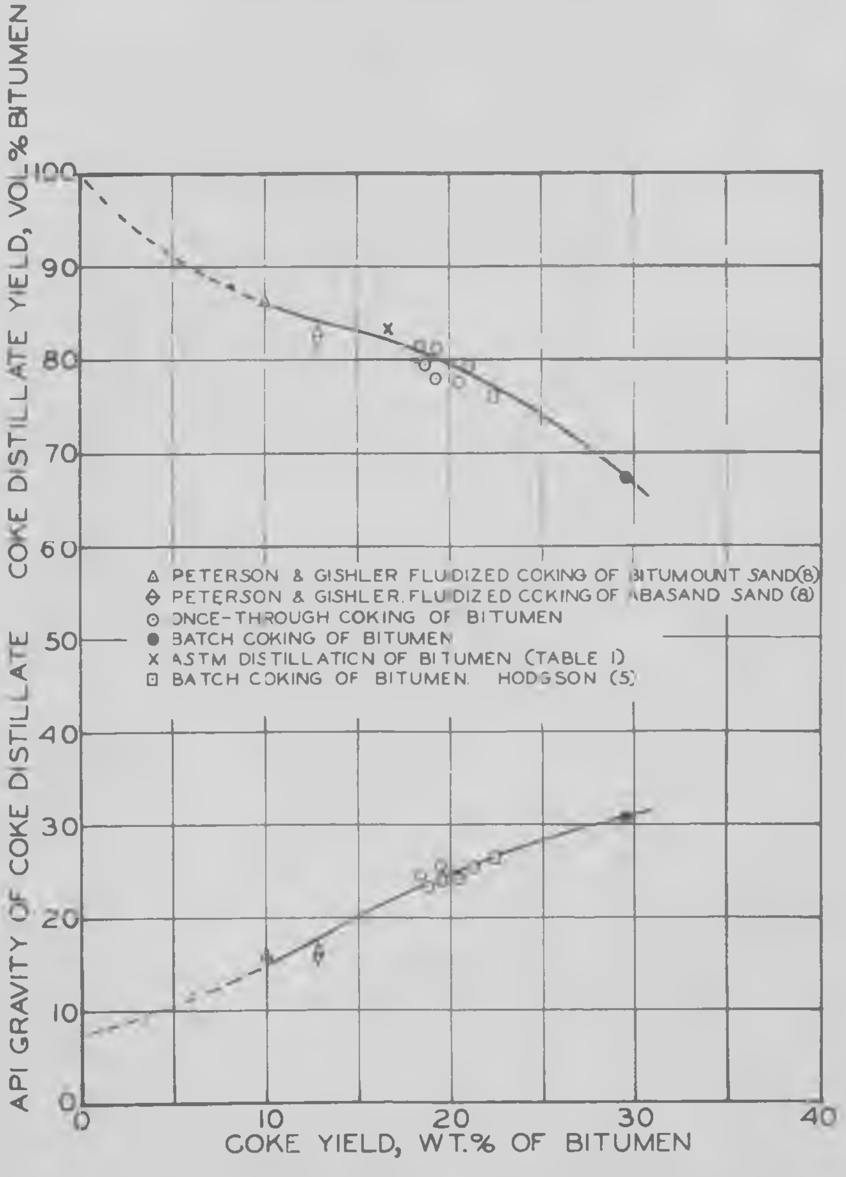

Fig. 1. *Yields and gravities of various coke distillates produced from bitumen.*

for the bitumen it is estimated that if it were to be cracked to only gas, gasoline and coke, about 41 vol. % of 51° A.P.I. gasoline would be produced along with a coke yield of 49 wt. %. The lines on Fig. 1 extrapolate reasonably well to these estimated ultimate coking yields. In Table I, the A.S.T.M. 100 ml. atmospheric distillation of the bitumen was continued until only coke remained in the distillation flask. This inspection test corresponds to a miniature batch-coking operation with very little liquid reflux, and the 83% liquid recovered at a 16.6% coke residue represented as a point on Fig. 1 is in good agreement with the trend indicated.

Another point on Fig. 1 represents a similar, but larger scale, laboratory batch-coking test performed by Hodgson (5).

While the method of application differs among the various coking methods represented on Fig. 1, the pattern of points suggests that the thermal decomposition is similar in character although its extent varies considerably.

Viscosities of coke distillates produced by various methods are plotted on Fig. 2 against the yield of coke. The point shown for the viscosity at 100°F. of the unaltered bitumen was estimated from its

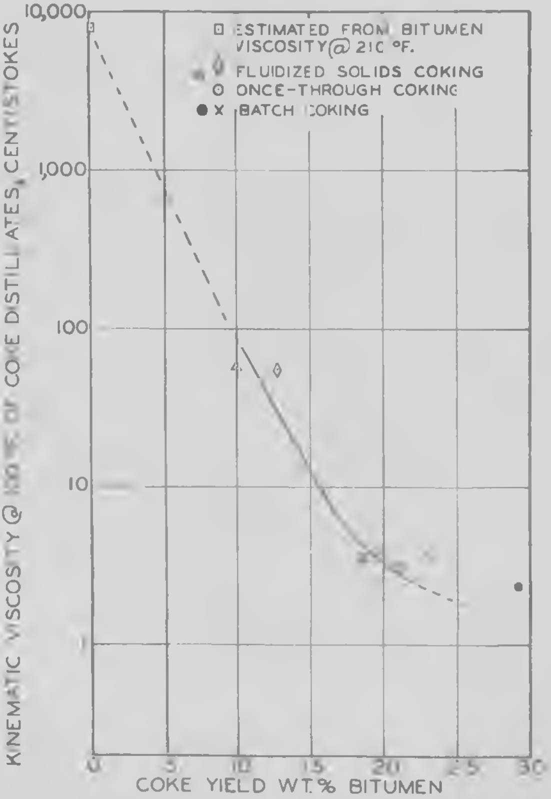

Fig. 2. *Viscosities of coke distillates produced from bitumen.*

measured viscosity at 210°F. Two points shown for batch coking indicate that the distillate from this process is slightly more viscous than from once-through coking at the same coke yield. This might be due to light fractions leaving the batch-coking still during the early stages of distillation when the temperature is low and thermal decomposition is therefore minimized. On the other hand, in once-through coking all fractions of the bitumen spend more nearly the same time in the high temperature reaction zone where the light fractions would be subjected to thermal decomposition and viscosity reduction. Further indications of this difference are reflected by lower octane numbers, a lower olefin content and a higher characterization factor for the batch gasoline relative to the once-through gasoline. These differences suggest milder over-all cracking severity in the case of batch coking.

The relative amounts of light hydrocarbons in the C_4 and lighter gas produced in once-through coking are shown in Table III. Increasing olefin contents of C_2, C_3 and C_4 fractions in the order named is typical of the thermal cracking of petroleum hydrocarbons. Furthermore, the gas composition predicted from generalized correlations for the thermal coking of a hypothetical petroleum fraction having the nominal physical properties of bitumen, is in good agreement with that observed in the bitumen coking test as shown below:

	Predicted for petroleum coking	Observed for bitumen coking
H_2	11.0 Mol. %	11.0 Mol. %
CH_4	50.5	47.1
C_2	17.0	16.0
C_3	12.0	17.8
C_4	9.5	8.1
Total	100.0	100.0

Outlined in Table V are the results of once-through coking of three heavy petroleum fractions; a cracked residuum and two virgin pitches. Although none of these materials has the same gravity and characterization factor as the bitumen, the distillate-coke yield relationship for these petroleum stocks is not too different from that represented on Fig. 1 for bitumen coking. The 9°A.P.I. cracked residuum, which was coked at the same processing conditions as the bitumen, produced more coke and gas than the bitumen even though its specific gravity was lower.

TABLE V

PILOT-PLANT ONCE-THROUGH COKING OF VARIOUS HEAVY PETROLEUM OILS

	Cracked residuum		Virgin pitch		Virgin pitch	
Feed Stock Inspections:						
Gravity, °A.P.I. at 60°F.	9.0		10.5		11.8	
Specific gravity at 60°F.	1.0071		0.9965		0.9874	
Total sulfur, wt. %	—		2.34		4.38	
Cold test, °F.	55		95		40	
Viscosity:						
S.S.F. at 210°F.	327*		175		40.8	
U.O.P. Characterization factor	11.0		11.53		11.4	
Operating Conditions:						
Coke chamber pressure, p.s.i.g.	50		0		25	
Yields:	Wt. %	Vol. %	Wt. %	Vol. %	Wt. %	Vol. %
Gas	9.6		7.9		6.0	
Coke distillate	64.7	73.5	70.6	79.0	74.8	83.8
Coke	26.5		21.0		19.2	
Prod. recovery	100.8		99.5		100.0	
Coke Distillate Properties:						
Gravity, °A.P.I. at 60°F.	28.3		27.4		27.6	
Total sulfur, wt. %	1.67		—		2.95	
Viscosity: S.S.U. at 100°F.	37.7		—		43.5	
U.O.P. Characterization factor	11.28		—		11.4	
100 ml. distillation:						
I.B.P., °F.	138		187		118	
10%	282		363		298	
50%	600		671		620	
90%	754		741		760+	
E.P.	760+		745		—	
Vol. % at 400°F.	20.5		12.0		18.5	

* at 122°F.

It might be concluded, then, that less coke would be obtained in the once-through processing of bitumen than would be produced from cracked residue having the same gravity. Because the virgin stocks were coked at processing conditions somewhat different from those used for the bitumen, and because their specific gravities are lower, direct product distribution comparisons cannot be made. However, generalized once-through coking correlations would predict that for equivalent feed gravities and at the same operating conditions the bitumen would yield about the same or slightly less coke than would be obtained from a corresponding petroleum stock.

The 69.1 clear motor method octane number shown in Table IV for the gasoline obtained from bitumen coking is higher than values of from 60 to 65 observed for debutanized gasolines produced by once-through coking of petroleum stocks. Because of its high sulfur content of nearly 2% the lead response of this gasoline is very poor.

Inspections of the coke, listed in Table IV, indicate an ash content of nearly 3%, due to the suspended solids invariably carried by the bitumen. Petroleum coke usually always shows an ash content of less than 1%. However, the true density, apparent density and cell space of the bitumen coke are typical of those observed for petroleum coke.

SULFUR DISTRIBUTION

Because of the high sulfur content of the bitumen it is of interest to study the appearance of sulfur in the various reaction products,

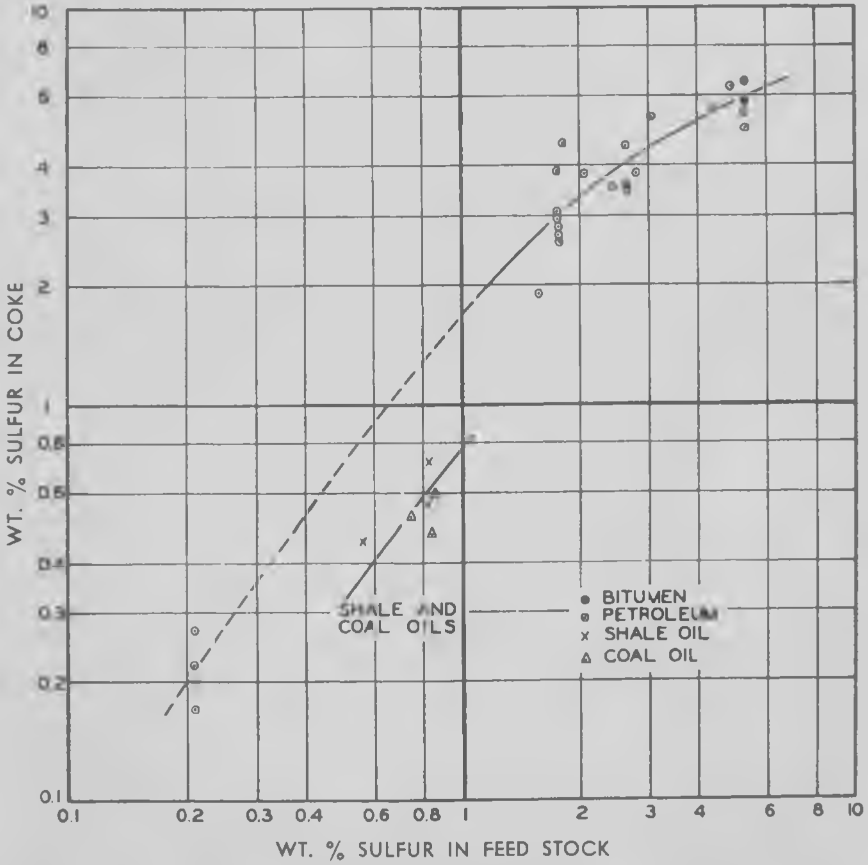

Fig. 3. *Sulfur contents of coke produced by thermal cracking.*

TABLE VI

SULFUR BALANCES FOR THERMAL COKING OF BITUMEN AND PETROLEUM PITCH

	Product yield wt. %	Wt. % S in product	Wt. % S, based on bitumen	Sulfur, as % of S in bitumen
Once-through Coking of Bitumen				
Bitumen charge	100.0	5.32	5.32	100.0
Products:				
C_4 & lighter gas	8.2	13.8	1.13	21.2
Debutanized gasoline	15.4	1.86	0.29	5.5
Gas oil distillate	55.0	4.04	2.22	41.7
Coke	21.0	6.42	1.35	25.4
Unaccounted for	0.4	—	0.33	6.2
Total	100.0		5.32	100.0
Batch Coking of Bitumen				
Bitumen charge	100.0	5.20	5.20	100.0
Products:				
Gas	13.1	11.8	1.54	29.6
Gasoline	12.9	1.84	0.24	4.6
Gas oil distillate	44.9	3.04	1.36	26.2
Coke	29.6	5.65	1.67	32.1
Unaccounted for	-0.5	—	0.39	7.5
Total	100.0		5.20	100.0
Once-Through Coking of 11.8°A.P.I. Petroleum Pitch				
Pitch charge	100.0	4.89	4.89	100.0
Products:				
Gas	6.0	16.9	1.02	20.9
Total coke distillate	74.8	2.95	2.21	45.2
Coke	19.2	5.47	1.05	21.5
Unaccounted for	0.0	—	0.61	12.4
Total	100.0		4.89	100.0

and to make comparisons with sulfur distribution in once-through coking of petroleum stocks.

Fig. 3 is a plot of the sulfur contents of coke obtained by the processing of petroleum, bitumen, shale oil, and coal oil feeds containing widely varying amounts of sulfur. Both ultimate and once-through types of coking are represented on this plot which shows the expected general trend that the higher the sulfur content of the feed the higher will be the sulfur content of the coke. The points for bitumen coking are in good agreement with the points shown for petroleum stocks.

Barron, Vanderploeg, and McReynolds (1) have shown that for a given geographical region the sulfur content of thermal cracked gasoline is proportioned to the sulfur content of the feed stock from which it was derived, but that the proportionality constant varies from a value of 0.06 for Arabian stocks to 0.34 for California stocks. This constant, which is the ratio of sulfur concentration in the product to that in the feed, is 0.35 for the gasoline produced from bitumen. It is, therefore, similar to California stocks with respect to the appearance of sulfur in the gasoline.

Sulfur balances are shown in Table VI for the coking of bitumen and a petroleum pitch having nearly the same sulfur content as the bitumen. In the gas streams the sulfur appeared as H_2S, and its concentration was about the same for both types of bitumen coking. However, for the petroleum pitch the sulfur factor of 3.5 in the gas stream is somewhat higher than the factors of 2.3 to 2.6 for bitumen coking. This would indicate that the sulfur compounds in this particular petroleum fraction decompose into H_2S slightly more easily than those found in bitumen.

Sulfur factors of the total distillates from once-through coking of the bitumen and the high sulfur virgin pitch are 0.68 and 0.67 respectively. These nearly equal residual sulfur contents of the total liquid products relative to the sulfur in the feed stocks suggest that there are no basic differences in the thermal decomposition of sulfur compounds found in bitumen and petroleum.

SUMMARY

1. The general character of thermal decomposition is similar when coking bitumen in batch, fluidized solids or once-through types of operation, even though the extent of the decomposition varies from one process to another.

2. When compared with the once-through coking of heavy virgin petroleum fractions, the product distributions obtained from bitumen or the petroleum materials are similar.

3. Excepting for a higher ash content, the coke obtained from bitumen is not different from petroleum coke produced from high sulfur feed stocks.

4. The clear octane number of gasoline made by the coking of bitumen is slightly higher than of gasolines produced by petroleum coking. Sulfur contents of bitumen gasoline are as high as would be found in gasolines made by coking California petroleum fractions of the same sulfur content.

Based on the appearance of H_2S in the process gas it would appear that the sulfur compounds in bitumen are only slightly more refractory than those occurring in petroleum fractions. However, the relative sulfur concentrations in the total distillates obtained from bitumen and a high sulfur petroleum pitch are nearly equal, and points to no basic differences in thermal decomposition of sulfur compounds found in these two types of raw materials.

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DISCUSSION

Question: Would Dr. Sterba have any idea as to what extent the catalytic cracking and thermal processes would show comparison of these crudes?

M. J. Sterba: The gas oil made from a series of these once-through coking tests that were described has been catalytically cracked, but the data are not at hand. However, it seems that the catalytic cracking of this 16° A.P.I. gravity gas oil was appreciably different from the catalytic cracking of the usual saturated virgin petroleum gas oil. This was to be expected because it may, first of all, form more coke and more gas than is experienced by the catalytic cracking of a saturated gas oil having the same boiling range as this.

Question: Does the catalytic cracking of gas oil and coker gas oils from the thermal coking of California residual oils give an equal or poorer gas oil for feed to catalytic cracking?

M. J. Sterba: More can be said on that topic. There isn't complete agreement that thermally-coked gas oils are much different from virgin gas oils. On the other hand, it has been our experience that thermally-coked gas oils are inclined to show higher coke formation in catalytic cracking than is obtained from a virgin gas oil having the same boiling range, so that it is somewhat unfair to speak about the catalytic cracking of a coked gas oil from bitumen, rather than to speak about the catalytic cracking of a virgin fraction from bitumen.

Question: Has the Universal Oil Products Co. done any work on the solvent extraction of some of these materials? It seems that concentration of the sulfur in the extracts may be possible.

M. J. Sterba: We have done no work specifically directed toward the solvent extraction of sulfur from bitumen components.

REFINING OF HIGH SULFUR STOCKS BY THE COBALT MOLYBDATE PROCESS

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INTRODUCTION

Refining techniques for the handling of low quality high sulfur stocks have received an important advance in the development of the cobalt molybdate process. This process facilitates the production of premium fuels from high sulfur crudes as well as stocks derived from shale and oil sand.

This refining operation employs catalytic treatment in the presence of a recycle hydrogen stream. The high activity of the catalyst effects virtually complete elimination of sulfur, nitrogen, and oxygen from the charge stock. It is generally preferable to prepare the charge stock to this refining step by coking to adjust the boiling range.

The cobalt molybdate process is adaptable to treatment of stocks under conditions varying from mild hydrogenation to reforming. Under said hydrogenation conditions full range coker distillate is converted into high grade diesel fuel and jet fuel. Where motor fuel is desired as a product, treatment of the light coker distillate fraction under reforming conditions is employed to yield high octane gasoline of premium quality.

FUNDAMENTAL REACTIONS

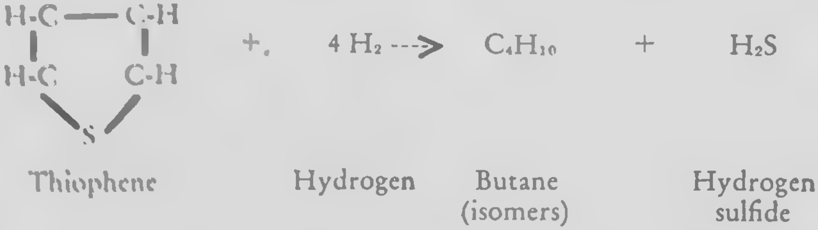
The cobalt molybdate process employs as its fundamental reactions the conversion of organically combined sulfur, nitrogen, and oxygen to hydrogen sulfide, ammonia, and water by contact of the feed stock with the catalyst in the presence of hydrogen. The catalyst has been developed over a number of years by the Union Oil Company, and exhibits excellent activity as well as heat stability and abrasion resistance (1, 2, 3).

The desulfurization of low grade stocks in this process is associated with the consumption of hydrogen and an appreciable exothermic heat of reaction. Hydrogenation of the olefins in the stock occurs, but under the conditions normally used essentially none of the aromatics present are hydrogenated. When reforming conditions are utilized, substantial dehydrogenation of naphthenes occurs, but under mild hydrogenation conditions this occurs only to a minor degree. Conversion of the sulphur, nitrogen, and oxygen compounds to saturated hydrocarbons and inorganic by-products occurs by cleavage of the carbon-sulfur, carbon-nitrogen, and carbon-oxygen bonds. Essentially no carbon-to-carbon bonds are broken. As an illustration of the nature of the reactions occurring during cobalt molybdate refining, the following reactions are presented, illustrative of the various classes of compounds undergoing conversion.

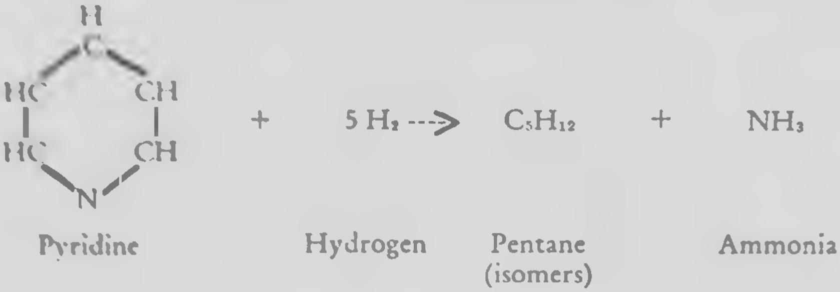
TABLE I

REACTIONS OF VARIOUS CLASSES OF COMPOUNDS IN COBALT MOLYBDATE REFINING

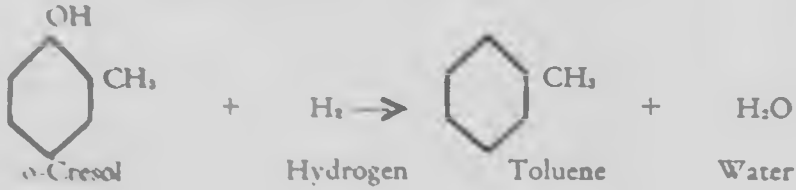
Hydrogenation of Sulfur Compounds



Hydrogenation of Nitrogen Compounds



Hydrogenation of Oxygen Compounds



Hydrogenation of Olefins

C_5H_{10}	+	H_2	$\rightarrow$	C_5H_{12}
Amylene		Hydrogen		Pentane (isomers)

PROCESSING CONDITIONS FOR TYPICAL HIGH SULFUR STOCKS

Processing conditions for the cobalt molybdate refining of low grade stocks have been worked out in extended pilot-plant investigations (1).

A summary of processing conditions and product characteristics for the treatment of coker distillate from Santa Maria Valley crude is presented in Table II.

TABLE II

PILOT-PLANT PROCESSING CONDITIONS AND PRODUCT INSPECTIONS IN COBALT MOLYBDATE REFINING OF FULL RANGE SANTA MARIA COKER DISTILLATE

Operating conditions—	
Average bed temperature, °F.	[illegible]
Reactor pressure, p.s.i.g.	1600
Feed rate, gal./hr.	3.01
Space velocity, V/V/hr.	3.19
H_2 content recycle gas, vol. %	89.0
Run length, hr.	126
Calculated results—	
Liquid product yield, C -free, vol. % feed	102.7
Pentanes, vol. % feed	2.16
Butanes, vol. % feed	1.79
Dry gas, C_1-C_3, s.c.f./bbl. feed	196.7
Net H_2 consumption, s.c.f./bbl.	907
Material balance, %	99.2
Product analysis—	
Gravity, °A.P.I.	39.0
Sulfur, wt. %	0.04
Nitrogen, wt. %	0.075
Distillation yield, vol. %	
Jet fuel	[illegible]
Diesel[a]	67.9
Residuum	3.9
Gasoline analysis:	
Gravity, °A.P.I.	57.1
Sulfur, wt. %	0.03
Nitrogen, wt. %	0.011
Knock rating, motor method	54.0
Diesel analysis:	
Gravity, °A.P.I.	38.1
Sulfur, wt. %	0.04
Nitrogen, wt. %	0.10
Cetane number	41
Pour point, °F.	[illegible]
Residuum analysis:	
Gravity, °A.P.I.	25.1
Sulfur, wt. %	0.12
Nitrogen, wt. %	0.18

[a] This material represents maximum diesel within specification boiling range.

These studies were carried out in the pilot plant illustrated in Fig. 1. The pilot plant was designed to develop as nearly as possible the process conditions and expected cycle to be used in commercial operations. The unit is equipped with an adiabatic reactor and accessory equipment so that the recycle hydrogen and scrubbing of

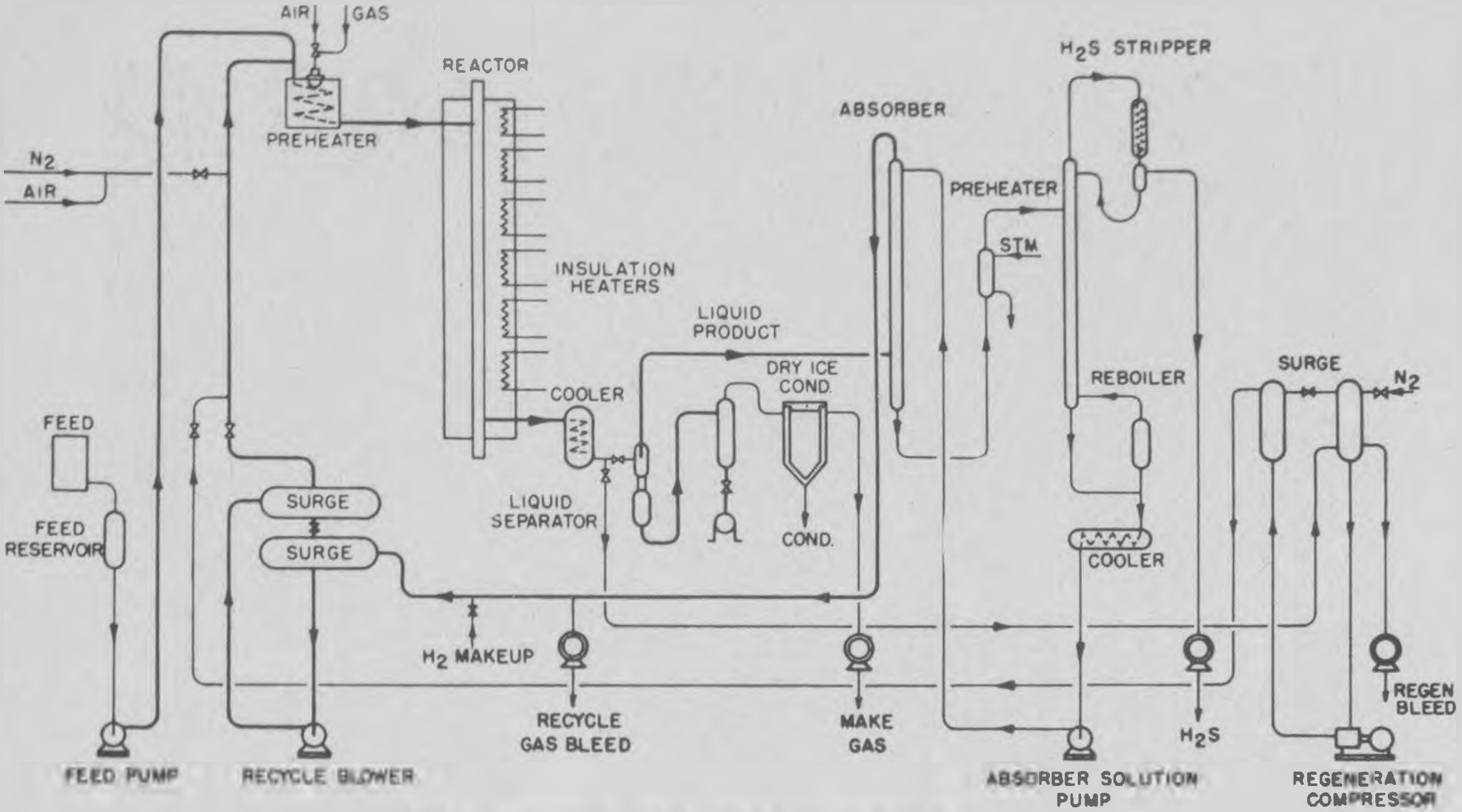


Fig. 1. Diagram of cobalt molybdate catalyst pilot plant.

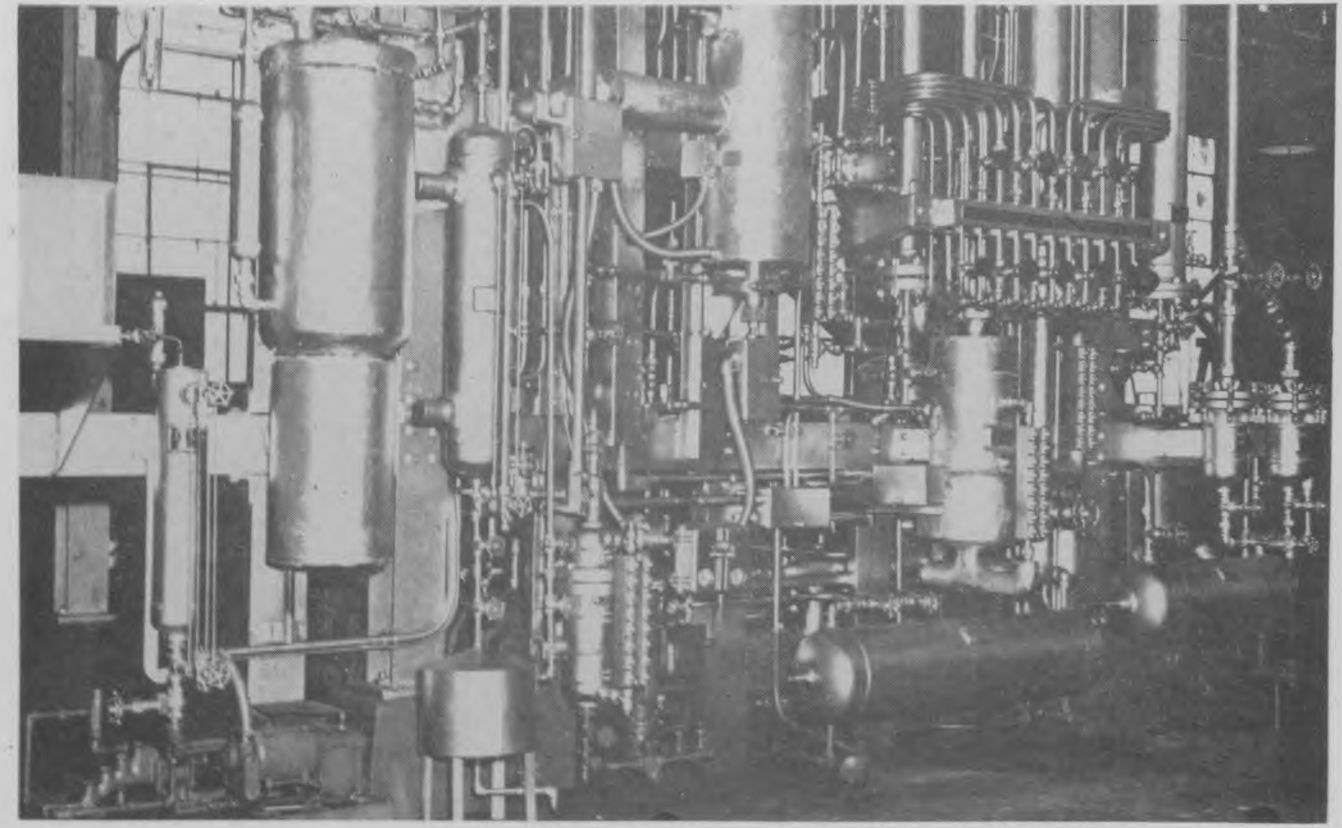


Fig. 2. *Photograph of cobalt molybdate refining pilot plant.*

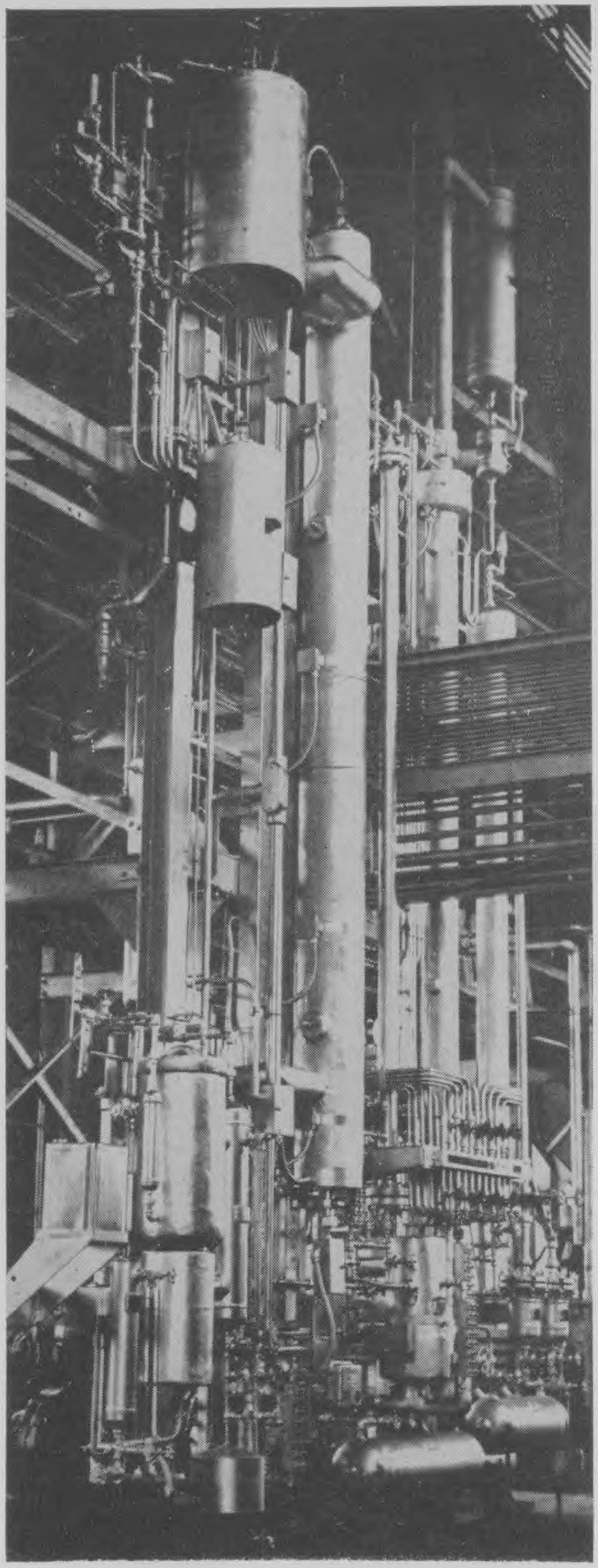


Fig. 3. *Photograph of cobalt molybdate refining pilot plant.*

this stream for removal of hydrogen sulfide and ammonia can be carried out. The reactor corresponds with expected commercial design with respect to catalyst and lineal velocity of recycle hydrogen and naphtha vapors through the bed. Operation of reaction, regeneration, re-heat and purge were carried out to correspond as nearly as possible to the expected commercial cycle in regard to rate, direction of flow, temperature, and duration. Photographs of this pilot plant are given in Fig. 2 and 3.

Where motor fuel is desired as an end-product from the light distillates of coking, reforming conditions are employed. By the utilization of higher temperatures and lower pressures in the refining step, dehydrogenation of the naphthenes occurs simultaneously with the various other upgrading reactions outlined in the previously described plant. A substantial amount of isomerization and hydrocracking also occurs, which appreciably contributes to the premium quality of the motor gasoline produced. Table III presents the inspections of motor gasoline produced from Santa Maria Valley light coker distillate by reforming.

TABLE III

INSPECTION OF FEED AND PRODUCT IN PILOT-PLANT REFORMING OF SANTA MARIA LIGHT COKER DISTILLATE BY COBALT MOLYBDATE PROCESS

	Feed	Product
Gravity, °A.P.I.	52.7	60.0
Engler distillation, °F.		
I.B.P.	147	87
10%	192	131
50%	267	205
90%	342	328
95%	364	415
E.P.	390	429
Sulfur, wt. %	3.47	0.035
Nitrogen, wt. %	0.020	0.002
Octane rating:		
F-1, + 3 cc. TEL	80.0	94.5
F-2, + 3 cc. TEL	69.5	87.0

Hydrogen consumption in the mild hydrogenation plants treating full range coker distillate is on the order of 750 to 1,000 cubic feet per barrel, whereas hydrogen consumption in Hyperforming plants reforming light coker distillate is on the order of 300 to 600 cubic feet per barrel.

COMMERCIAL APPLICATIONS

The cobalt molybdate desulfurization process is adaptable to a number of different programs for the utilization of low grade stocks containing sulfur, nitrogen, and oxygen. Typical stocks which require the highly effective refining of the cobalt molybdate process are Santa Maria Valley crude oil, shale oil, and oil from the Athabasca oil sands. Table IV gives typical inspections of these crude oils. It will be noted that high sulfur and nitrogen compounds are typical of all these stocks.

TABLE IV

LOW GRADE STOCKS SUITABLE FOR REFINING BY THE COBALT MOLYBDATE PROCESS.

Crude Oils

	Santa Maria Valley crude	Shale oil	Athabasca oil-sand oil
Gravity, °A.P.I.	15.2	20.7	5.6
Sp. gr. at 60°F.	0.965	0.930	1.032
Ash, wt. %	—	0.03	0.894
Sulfur, wt. %	4.90	0.77	5.12
Nitrogen, wt. %	0.64	2.01	—
Carbon residue, wt. %	10.14	—	—
Visc., S.S.F. at 210°F.	—	—	373
Visc., S.S.U. at 100°F.	—	223	—
Visc., S.S.U. at 210°F.	—	46	—
Softening point, °F.	—	—	83

As the first step in refining, it is generally desirable to carry out thermal coking to adjust the boiling range of these stocks to that of commercially marketable premium fuel. The products of coking then actually become the charge stocks to the cobalt molybdate refining process. In Table V are given the inspections of coker distillates derived from the respective crudes listed above.

It will be noted that only minor reductions of sulfur, nitrogen, and oxygen occur in coking, although an appreciable change in boiling range is effected. In the course of coking a substantial amount of gas is generated, and this gas stream is utilized for the production of hydrogen by steam-methane reforming. A flow-sheet detailing the continuous contact coking operation with subsequent steam-methane reforming is given in Fig. 4. Before entering the catalyst-containing reactor of the cobalt molybdate reforming plant, the coker distillate and recycle hydrogen are preheated by heat exchange in separate exchangers against the hot reaction products. Fig. 5 outlines the details of this mild hydrogenation plant. The exothermic heat of reaction obtained by the coker distillates is of

TABLE V

LOW GRADE STOCKS SUITABLE FOR REFINING BY THE COBALT MOLYBDATE PROCESS

Coker Distillates

	Santa Maria Valley crude	Shale oil	Athabasca oil-sand oil
Gravity, °A.P.I.	27.6	32.6	16.6
Nitrogen, wt. %	0.27	1.47	—
Sulfur, wt. %	3.77	0.74	4.04
Engler distillation, °F.:			
I.B.P.	160	172	443
10%	340	337	486
30%	438	440	550
50%	560	524	621
70%	690	582	690
90%	816	654	715
E.P.	957	713	—
Rec., %	99.0	98.0	97.5

sufficient magnitude to make the process independent of appreciable preheat requirements except during start-up periods. The recycle gas is purified of hydrogen sulfide and ammonia by absorption at reaction pressure. Regeneration is accomplished by adding air to a stream of inert combustion gas which is circulated over the catalyst by means of a blower. Inert gas for this purpose is generated by burning fuel gas in a special furnace.

Where motor fuel is desired as an end-product from the light distillates of coking, an additional modified cobalt molybdate reforming plant is employed. A diagram of this plant is presented in Fig. 6. The principal difference in operating characteristics of the reforming plant is utilization of higher temperatures and a lower pressure in the refining step.

Products from Cobalt Molybdate Refining

The combination of coking and cobalt molybdate refining leads to very high yields of directly commercially marketable products. The refined products derived from Santa Maria Valley crude and crude oil from Athabasca oil sands would be rather similar, and it will be noted that both the crude and the coker distillates have comparable inspections as to sulfur contents. Table VI presents the yield and quality of products derived from refinery operations on 100,000 barrels of Santa Maria Valley crude oil.

It will be noted that a yield of approximately 82% of high grade fuels is obtained and that the nitrogen and sulfur are almost completely eliminated from the refined products.

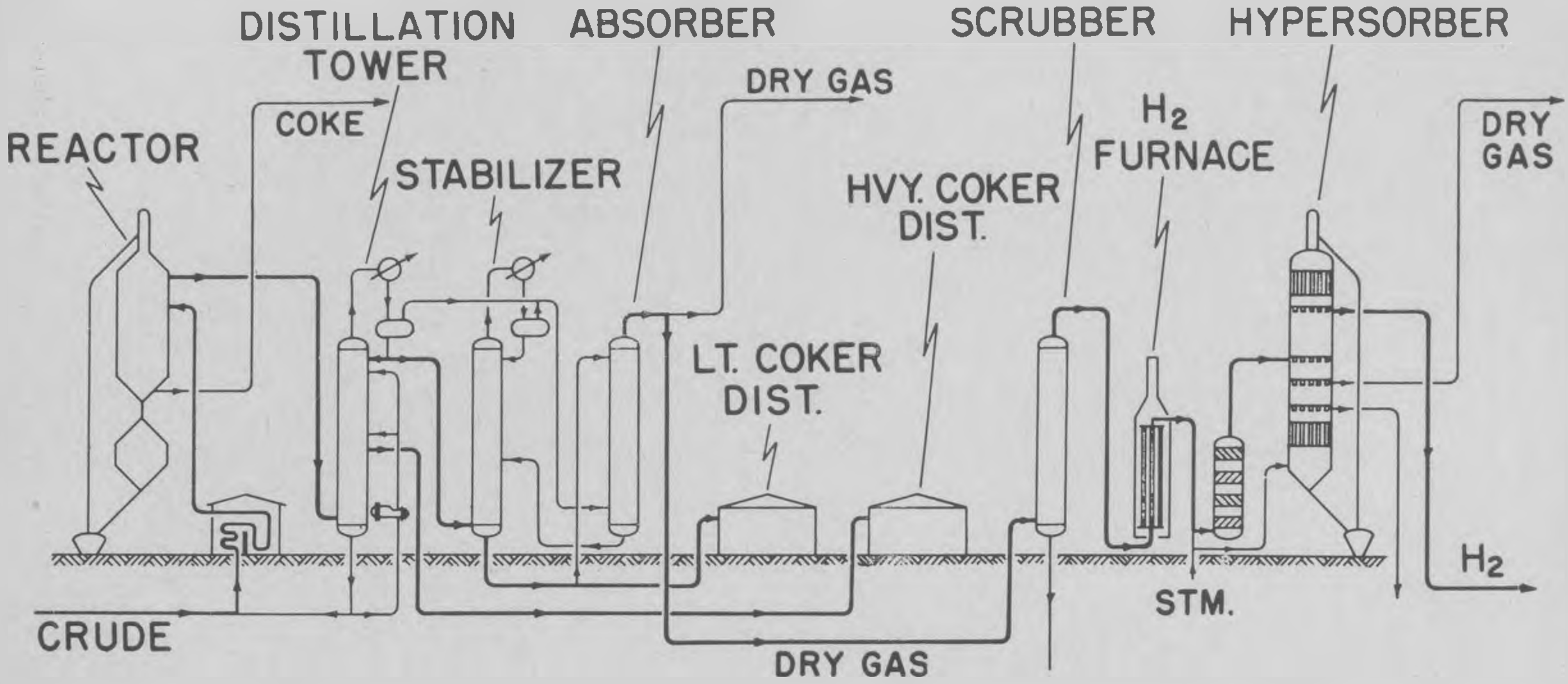


Fig. 4. *Flow-sheet of coking operation and hydrogen production.*

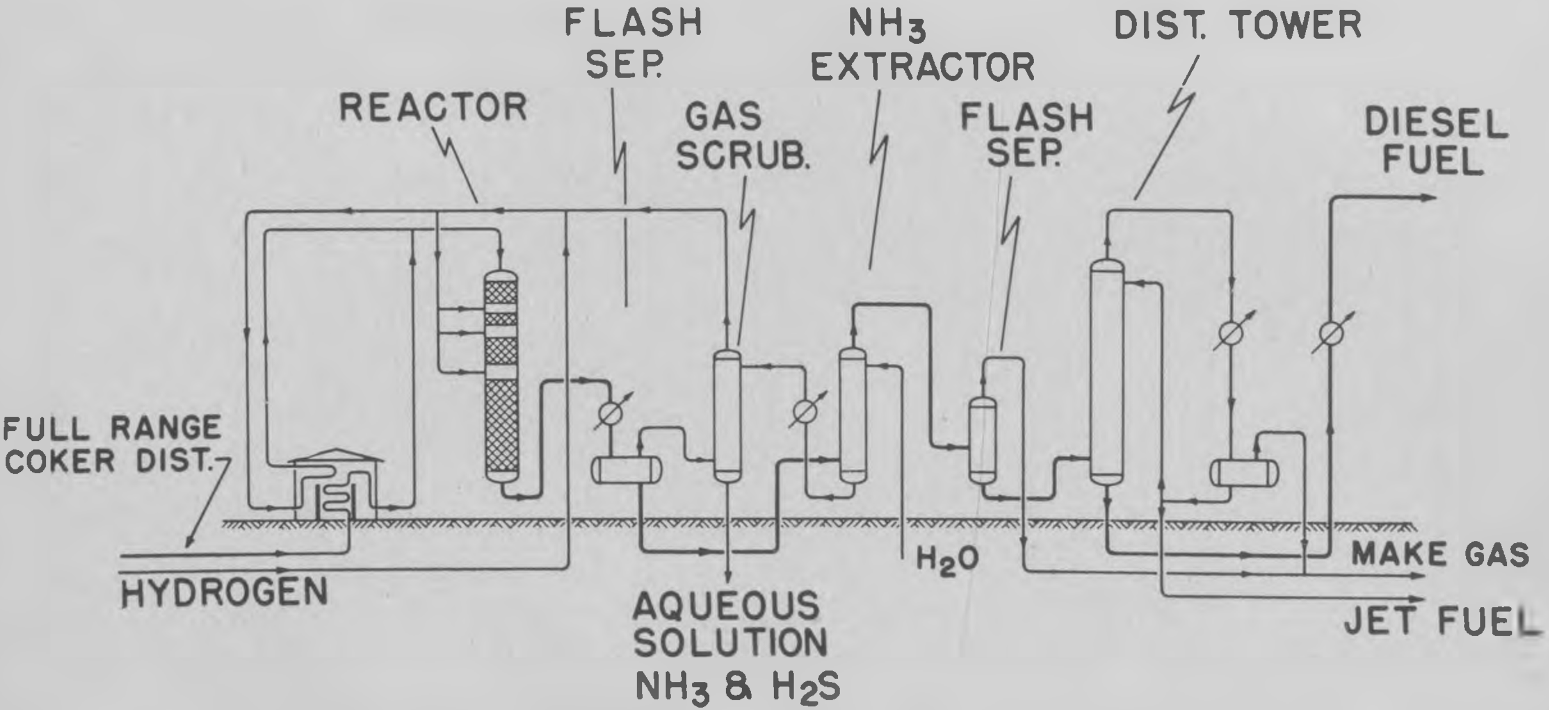


Fig. 5. *Flow-sheet of cobalt molybdate refining plant (mild hydrogenation).*

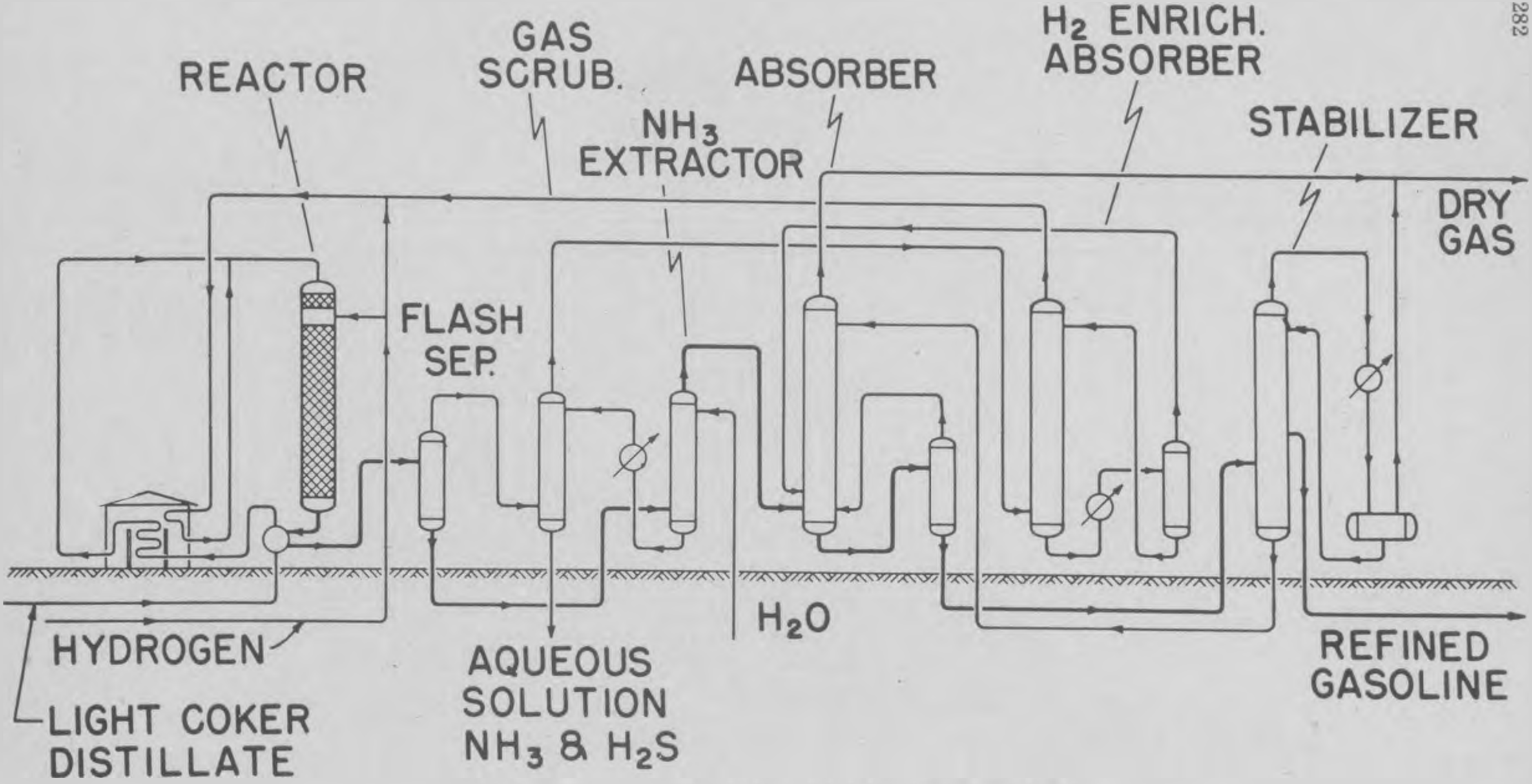


Fig. 6. Flow-sheet of cobalt molybdate reforming plant.

TABLE VI

PRODUCTS FROM THERMAL COKING AND COBALT MOLYBDATE HYDROGENATION OF 100,000 BARRELS OF SANTA MARIA CRUDE OIL

Gas, M s.c.f.	22,710
Jet fuel	23,300
Diesel fuel, bbl.	56,300
Residuum, bbl.	3,230
Coke, tons	2,570
Ammonia, tons	37

Product data	Jet fuel	Diesel fuel
Gravity, °A.P.I.	57.1	33.1
Freezing point, °F.	-75	—
Bromine number	0.4	—
Sulfur, wt. %	0.03	0.04
Nitrogen, wt. %	0.011	0.10
Cetane number	—	41
Pour point, °F.	—	-5

A very similar sequence of refining steps is carried out on shale oil, and a table of yield and quality products derived from these operations on 100,000 barrels of shale oil is presented in Table VII.

The high yield and quality of products obtained from the refining operation establishes the cobalt molybdate refining process as one of major importance in the upgrading of these low grade stocks.

TABLE VII

PRODUCTS FROM THERMAL COKING AND CATALYTIC HYDROGENATION OF 100,000 BARRELS OF CRUDE SHALE OIL

Gas, M s.c.f.	51,000
Jet fuel, bbl.	51,500
Diesel fuel, bbl.	33,500
Coke, tons	2,380
Ammonia, tons	260

Product data	Jet fuel	Diesel fuel
Gravity, °A.P.I.	51	37
Freezing point, °F.	-70	—
Bromine number	0.5	—
Sulfur, wt. %	0.05	0.02
Nitrogen, wt. %	0.01	—
Cetane number	—	59
Pour point, °F.	—	25
Visc., S.S.U. at 100°F.	—	39

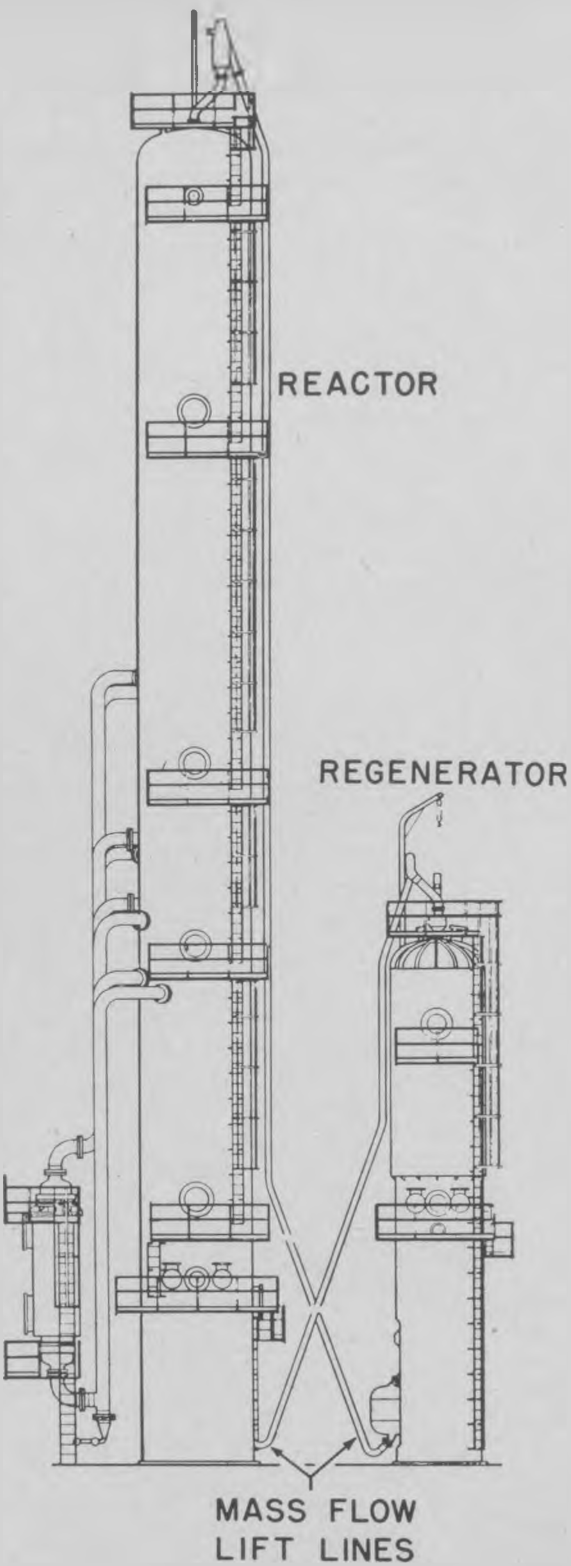


Fig. 7. *Hyperforming unit.*

HYPERFORMING

An important advance in the facilities available for catalytic upgrading and reforming has recently been achieved by the development of the Hyperforming process. This process eliminates the use of fixed bed reactors and permits continuous reaction and regeneration of the catalyst. An assembly diagram of a Hyperforming plant is given in Fig. 7. Circulation of the catalyst is effected by means of the mass-flow solids moving principle recently developed by the Union Oil Company, which moves catalyst at very low velocities and at a minimum attrition loss. By the use of continuous reaction and regeneration in the catalyst cycle, a substantial economy in plant construction is effected and plant maintenance is substantially reduced.

The reductions in over-all plant investment and utility requirements effected by this most recent advancement in refining technique, the Hyperforming process, are a distinct contribution to the technology of the upgrading of low grade stocks and a variety of refinery products.

ACKNOWLEDGMENT

The author wishes to express his appreciation to the Union Oil Company of California for permission to publish this review of the refining of high sulfur stocks by the cobalt molybdate process.

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2. Byrns, A. C., Bradley, W. E., and Lee, M. W., Ind. Eng. Chem., **35**, 1160-1167 (1943).
3. Hendricks, G. W., Huffman, H. C., Parker, R. L., and Stirton, R. I., Paper read at the 109th Meeting of the American Chemical Society, Atlantic City, N.J., April 8-12, 1946.

DISCUSSION

Question: Are there any estimates of capital costs or operating costs on a 10,000 barrel per day basis for any of the tabulations shown?

C. Berg: No capital or operating costs are available for those particular tabulations. They are primarily material balance tabulations. However, the mild hydrogenation operation, which is the most expensive, would probably cost about 50% more than catalytic cracking or approximately 80 cents per barrel for a 10,000 barrel per day plant. That is within boundary limits. The capital cost of facilities outside the boundary limits may run as high as the cost of the plant within. The capital investments for this process are approximately 50% higher than for catalytic cracking. Incidentlly, the older form of coking is apparently slightly more expensive than catalytic cracking. The new form of contact coking may show economies.

This process can be set up in many different ways and, depending upon the sequence of operations preceding or paralleling it, the relative costs will vary appreciably, but this operation will effectively refine a very inferior stock and make products equal or superior to that which can be made from ordinary petroleum stock of low sulphur content.

Question: How will the catalyst behave in the presence of water vapor and hydrocarbon vapor? Or must the hydrogenation be done entirely in the liquid state?

C. Berg: The conditions in the reactor range between mixed phase and pure vapor phase contacting the catalyst. The catalyst is stable to steam.

H. A. Logan: In view of the shortage of sulphur, has any work been done on the recovery of sulphur from oils with a high sulphur content?

C. Berg: There has been a considerable amount of engineering study. Any plant that refines large quantities of high sulphur stock such as the Athabasca oil sands, or this California crude, can produce large quantities of sulphur as a by-product.

Question: This process appears to produce two main products: diesel oil and jet fuel. Would you make some observations regarding the gasoline potentialities?

C. Berg: The alternative flow-sheet described a reforming type operation which operates at a higher temperature and makes a premium gasoline. The inspection was 94.5 octane (research), and the nitrogen and sulphur were very low.

S. M. Blair: In mild hydrogenation, approximately what hydrogen consumption is expected?

C. Berg: In mild hydrogenation, the hydrogen consumption is about 950 cubic feet per barrel. In the following reforming type operation the hydrogen consumption will drop to the order of 400 to 450 cubic feet per barrel.

S. M. Blair: Is the figure 950 to 1,000 cubic feet per barrel an adequate figure to take for hydrogen consumption for cost analysis?

C. Berg: Yes.

Question: In operating the hydrogenation plants, the CO_2 is removed in aniline plants, is it not?

C. Berg: There is no aniline plant shown in the flow-sheet. The CO_2 is removed by a Hypersorption unit.

Question: If the aniline process were needed, it would also be available for absorbing hydrogen sulphide, would it not?

C. Berg: No, it would not be utilized because we have separate facilities on the plant itself.

Question: Does the value of 950 cubic feet per barrel apply to a coker distillate high in unsaturates?

C. Berg: The refinery coker distillate has 100% acid solubility. It is essentially all unsaturates or aromatics, and this stock would probably be similar.

Question: Can you give any estimate on the ultimate catalyst life which might be expected on the mild hydrogenation of coker distillates?

C. Berg: The catalyst has been given an effective two years' operating treatment in pilot-plant equipment and found to be slightly more active than when it was started. The catalyst life is not known.

Question: Were there periodic regenerations during that time?

C. Berg: Yes, on mild hydrogenation, we had a run of 124 hours. It is important to notice that this process could be run at any pressure. We have extensive data on the same operation at 100, 300, 1100, 1600 and 5,000 pounds per square inch. The 1600 pounds pressure just happened to be the optimum for handling coker distillates of high sulphur content.

S. M. Blair: Is it your thought that the approach in handling the coker distillate would be to desulphurize to extinction? Apparently the diesel in your report is being taken down to a much lower figure than is normally found for diesel.

C. Berg: In the diesel an attempt was being made to get well below the nitrogen content of commercial products, and the sulphur went a little further than necessary.

Question: As the pressure of hydrogenation was lowered, did the hydrogen consumption change appreciably?

C. Berg: Yes, hydrogen consumption varies with pressure. Actually, the optimum pressure is very nearly the same point as that at which optimum hydrogen consumption occurs. When the pressure is dropped, the temperature must be increased to effect the same removal. A little more hydrogen is lost in the formation of methane.

Question: What order of magnitude of C_4's and lighter fractions are there likely to be in the 1600-pound, 850° hydrogenation coker distillate?

C. Berg: About 100 or 150 cubic feet per barrel.

T. E. Warren: What was the size of the catalyst pellets used? This, along with other information given in your paper, will permit us to correlate our results with yours.

C. Berg: The pilot-plant work was done with full commercial-sized pellets—$^3/_8$ inch.

Question: Has this hydrogenation process been incorporated into a commercial installation?

C. Berg: There is no commercial installation of this particular operation at the present. However, within the next year there probably will be one.

HYDRODESULPHURIZATION OF COKER DISTILLATE FROM ATHABASCA BITUMEN

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INTRODUCTION

In his report on the Alberta bituminous sands, Blair (2) has indicated that it will be necessary to remove the sulphur from the coker distillate produced from bitumen in order to obtain a charging stock that is suitable for subsequent refining. He stated that the coker distillate could be refined to a gas oil suitable as feed stock for catalytic cracking by means of mild hydrogenation. This step is, however, the most expensive single operation in the processing sequence and it was considered advisable, therefore, to study the reaction in order to determine the most suitable operating conditions. The present report gives the results of experimental work on the operating variables, temperature, pressure, liquid feed rate, hydrogen feed rate, and catalyst activity using a laboratory scale apparatus.

From information available in the technical literature it was known that the sulphur content of heavy gas oil can be effectively reduced by catalytic hydrodesulphurization. This procedure decomposes organic sulphur compounds and converts them to hydrogen sulphide. In addition to reduction in sulphur content the oil is beneficiated by increase in volume and volatility, reduction of viscosity, carbon residue, and olefin content, and the elimination of nitrogen and oxygen. On the other hand, the pour point is increased and there is a small loss in weight.

Most of the previous work on catalytic hydrodesulphurization has been done on high-sulphur distillates boiling in the gasoline range. The catalysts employed have been mainly cobalt, molybdenum, tungsten, and nickel as molybdates, tungstates, chromates, or sulphides. Of special note is the cobalt-molybdate desulphurization process of the Union Oil Company of California, which is capable of handling a wide range of petroleum stocks.

In developing this process Byrns, Bradley and Lee (3) catalytically desulphurized gasoline with and without hydrogen and found that the presence of hydrogen had a marked effect upon the reduction of the sulphur. Of the various catalysts investigated, cobalt molybdate, resulting from the chemical union of cobalt oxide and molybdenum oxide, was found to be the most active. The cobalt molybdate is used alone or supported on a carrier such as alumina. It was also found that elevated hydrogen pressures gave better results than atmospheric pressure. By means of this process the sulphur content of gasolines containing 3 to 4% sulphur could be reduced to less than 0.01%. In further laboratory work, Hendrics et al. (5) successfully extended this process to the treatment of petroleum stocks in the

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* This paper was read at the Conference by T. E. Warren.

heavy gas oil range. Additional development of the process is reported by Berg et al. (1) who conducted pilot-plant studies on a heavy coker gas oil and other refinery stocks. Treatment of the coker gas oil containing approximately 4% sulphur resulted in a product having a sulphur content of 0.4%. They found the following operating conditions to be the most suitable for this heavy oil: inlet reaction chamber temperature, 700-750°F.; pressure, 450 lb. per sq. in. gauge; liquid space velocity, one volume of feed per hour per volume of catalyst; recycle gas rate, approximately 4,000 standard cu. ft. per bbl. of feed.

Hughes, Stine and Faris (6) of the Standard Oil Company of Ohio also desulphurized heavy petroleum oils using the cobalt-molybdate-on-alumina catalyst of the Union Oil Company. They desulphurized several high boiling overhead stocks, reducing the sulphur from the range of 0.5 to 2% in the feed to the range of 0.1 to 0.5% in the product. Their optimum operating conditions were: 750°F., 300 lb. per sq. in. pressure, liquid space velocity of 1.0 volume of feed per hour per volume of catalyst, and hydrogen circulation rate of 1,000 cu. ft. per bbl. of feed.

Hale, Simmons and Whisenhunt (4) of the United States Bureau of Mines desulphurized a crude oil containing 2% sulphur, reducing the sulphur to 0.17%. Cobalt molybdate deposited on bauxite was the catalyst used and the conditions were: 750°F., 225 lb. per sq. in. pressure, space velocity of 0.33 volume of feed per hour per volume of catalyst, and a hydrogen circulation rate of 1,600 cu. ft. per bbl. of feed.

The foregoing references to previous experimental work on the hydrodesulphurization of heavy oil show some variation in the selection of operating conditions. This is probably due, in part, to the difference in the characteristics of the oils fed, each one requiring, within limits, a specific set of operating conditions which is best suited to that particular oil. It will be noted, however, that the investigators all selected a temperature of approximately 750°F. This was probably chosen to avoid excessive cracking and at the same time accomplish sufficient desulphurization.

EXPERIMENTAL

Feed and Catalyst

The coker distillate used for the present experimental work was separated by the cold-water method from bituminous sand obtained from the Horse River area. Water and diluent were removed from the separated bitumen by the quench distillation method* and the bitumen was distilled to coke in a quench heated* still. In order to remove a small amount of fine solid material, the oil was filtered through a bed of glass wool supported on a 100-mesh screen. The coker distillate as charged was a heavy, black oil having a sulphur content of 3.5% and a specific gravity of 0.936 (19.7° A.P.I.).

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* Heat supplied by superheated vapor or gas.

The catalyst used in this work was cobalt molybdate supported on an alumina base which was supplied through the courtesy of the Union Oil Company of California, and consisted of 1/8 by 1/8 in. pellets designated as Type N.

Description of Apparatus

The apparatus used for the desulphurization experiments is arranged as shown in Fig. 1. Its function is to pass hydrogen and a liquid oil through a vertical bed of catalyst at controlled temperature, pressure, and feed rates. The main pieces of high-pressure equipment used are a feed vessel, a vertical cylindrical reaction chamber with heater, a water-cooled condenser, and a liquid product receiver. These are arranged in vertical sequence to permit gravity flow of liquid.

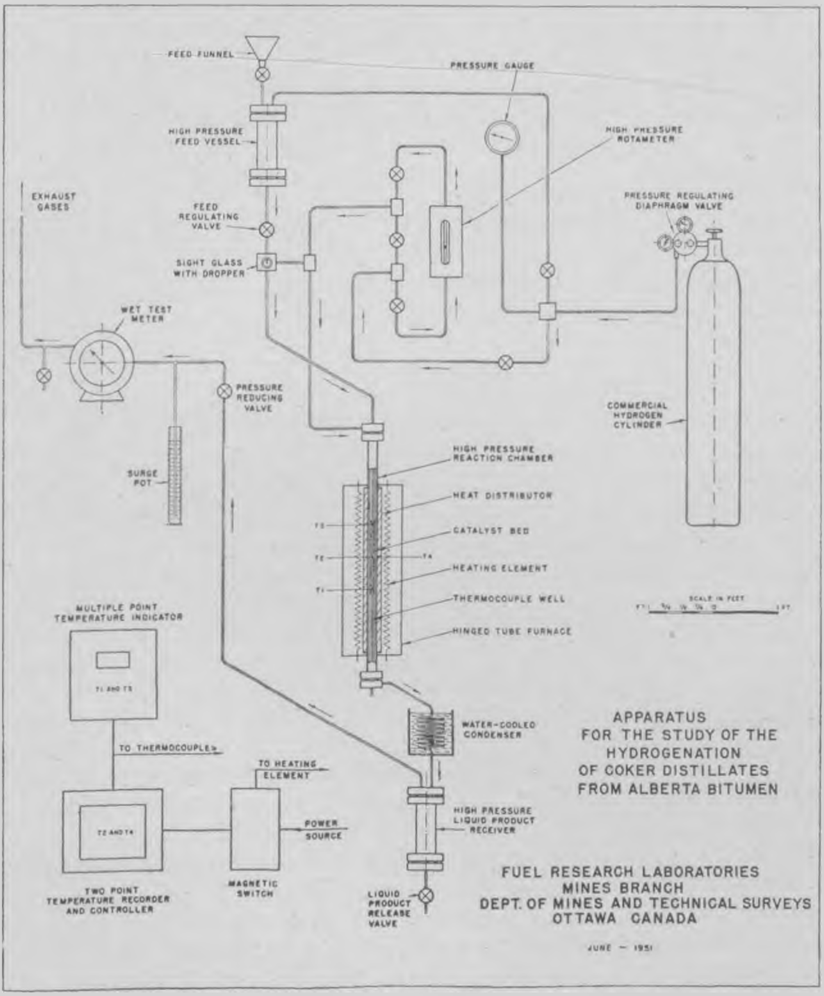

Fig. 1

The measured liquid oil feed is first charged to the 18-8 type stainless steel feed vessel, made of 3-in. extra-strong pipe. This is approximately $2\frac{7}{8}$ in. inside diameter and $12\frac{1}{2}$ in. inside length, utilizing stainless steel lens ring closures at both flanged ends. With the hydrogen pressure balance above and below the liquid in the feed vessel, the liquid flows down by gravity. The liquid feed rate is controlled by regulating its passage through a needle valve, and is estimated during operation by counting drops passing through a sight glass from a shaped dropper.

The hydrogen feed is obtained in standard commercial cylinders containing the equivalent of 180 cu. ft. of gas at atmospheric pressure and room temperature. When full, the cylinder pressure is approximately 2,000 lb. per sq. in. The desired operating pressure is obtained by setting a pressure regulating diaphragm valve at the cylinder, which maintains the pressure constant at a reduced value. The pressure is measured with a Bourdon-type gauge with a range from zero to 8,000 lb. per sq. in. The hydrogen feed rate is controlled by the rate of release at the outlet end of the system. An instantaneous indication of the hydrogen feed rate is obtained from a high-pressure flowmeter of the rotameter type which has been calibrated for various pressures.

The hydrogen feed and the liquid feed pass down through vertical tubing and meet at the top of the reaction chamber. This pressure tubing is 18-8 chromium nickel stainless steel, $\frac{1}{4}$-in. outside diameter and 1/16-in. inside diameter, and it is used throughout the apparatus. All connections are made with union type superpressure fittings with conical seating surfaces.

The reaction chamber is made of 1-in. double extra-strong steel pipe, 18-8 chromium nickel steel, approximately 19/32-in. inside diameter, standing vertically, and with a reaction space length of $46\frac{1}{2}$ in. Both flanged ends are sealed with steel lens rings. For a length of 30 in., the chamber is enclosed by a split heat distributor of cast iron $\frac{3}{4}$ in. thick, which is further enclosed by a hinged tube furnace rated at 3,675 watts. The chamber contains a stainless steel thermocouple well of $\frac{1}{4}$-in. outside diameter tubing with 20-gauge wall thickness, inserted in the bottom or outlet end and extending centrally throughout the length to the inlet end. The catalyst pellets are contained in the annular space between the thermocouple well and the inside wall of the chamber. They are supported by a retainer ring with drilled passages which fits over the thermocouple well tube and is in turn supported by a formed piece of 1/16-in. diameter stainless steel rod extending to the bottom of the reaction space. Fifty milliliters of the pelleted catalyst occupy a length of approximately $13\frac{1}{4}$ in.

The desired temperature is obtained from the previously mentioned electric tube furnace, and is maintained by a recorder-controller of the potentiometer type operating a magnetic switch in series with the furnace heating element. The controlling ironconstantan thermocouple is inserted between the outer surface of the reaction chamber and the heat distributor, at the mid-point of the depth of the catalyst bed. The corresponding temperature at the mid-point but within the bed is recorded from a thermocouple in the well. Temperatures just within the bed at the top and bottom are indicated by two additional thermocouples in the well.

The hydrogenated products flow downward from the reaction chamber through a condenser coil immersed in a cold water bath. The coil consists of about six turns, 6 in. in diameter, of 1/16-in. inside diameter 18-8 tubing with an equivalent length of 10 ft. From the condenser, the products enter a receiver which is the same as the feed vessel previously described. The liquid product accumulates here and may be drained off through a needle valve.

The excess hydrogen and uncondensed gases pass off from the top of the product receiver continuously through another needle valve, the rate of release being used to control the hydrogen feed rate as previously mentioned. The rate of flow of these exit gases is constantly checked as they pass through a wet test meter, measuring 1/10 cu. ft. per revolution at atmospheric pressure. The meter is protected from accidental over-pressure by a water-filled surge pot. With this arrangement of apparatus the exit gases are exhausted to the atmosphere and consequently wasted, but in actual larger-scale practice they would be recirculated.

General Procedure of Experiments

In a typical operation, the measured liquid feed is added to the feed vessel at atmospheric pressure. By introducing hydrogen the pressure in the vessel is then increased to the operating pressure. It is desirable to allow the feed to stand overnight under full anticipated operating hydrogen pressure. This promotes steadier operation of the sight glass dropper, probably by saturation of the feed with dissolved hydrogen.

To commence a run, the electric furnace is switched on. When the desired operating temperature has been reached and stabilized, the hydrogen gas flow rate is adjusted, and then the liquid feed flow is started and set at the desired rate.

Although the rotameter gives an indication of the hydrogen flow rate, the final figures recorded are for the exit gas rate as obtained from the wet test meter at atmospheric pressure. In determining the hydrogen feed as cubic feet per hour and cubic feet per barrel of liquid feed, it has been assumed that the volume of the uncondensed gases is the same as the volume of the inlet hydrogen. Although these conditions probably do not exactly prevail, the approximation is considered sufficiently accurate, since the hydrogen consumed is only about 15% of the hydrogen fed, and since the exit gases contain the hydrogen sulphide and uncondensed hydrocarbon gases formed. In the calculations, the average exit gas rate is obtained from the recorded total and the elapsed feeding time, and this offers a good check against the averaged indicated rates.

The liquid feed rate is indicated by the number of drops passing through the sight glass. To facilitate obtaining the desired number of milliliters per hour, a relationship between these quantities has been established, with correction factors for the pressure and the rate. With feeds of varying viscosity, it is necessary to determine an additional correction factor. In the calculations, the average liquid feed rate is obtained from the total volume of feed and the elapsed time.

The hydrogen cylinder pressure is recorded, as well as the operating pressure. The former is used in the calculations of hydrogen consumption to determine the actual amount of hydrogen fed without introducing the approximation already mentioned in connection with the exit gas rate.

The temperature of the controlling thermocouple and the temperatures at the top, bottom and centre of the catalyst bed have been recorded. For the data included with the present report, the temperature at the centre of the catalyst bed has been used, although the average catalyst bed temperature has been calculated as well.

To prevent residue from a previous run from contaminating samples, the preliminary liquid product is withdrawn after the first half hour of feeding. It is then measured and discarded. Following completion of the liquid feed, the operating conditions are continued for one-half hour to allow the apparatus to drain before completion of withdrawal of the liquid product.

This latter sample is used to obtain the specific gravity, which is determined by means of a Westphal chainomatic specific gravity balance, and to obtain the sulphur content, which is determined by the A.S.T.M. bomb method. In addition, the weight of this sample is combined with that of the preliminary product to obtain the weight yield. The volume yield used is based on the weight yield and the specific gravity.

In calculating the hydrogen consumption, the volume of hydrogen input is calculated from the hydrogen cylinder pressures at the start and finish of the liquid feeding period, and is based on a cylinder volume of 1.58 cu. ft. The exit gases as measured at the wet test meter are assumed to consist of hydrogen sulphide (H_2S), methane (CH_4) and hydrogen (H_2). The hydrogen sulphide is assumed to contain the difference between the weight of sulphur in the feed and the weight of sulphur in the product, and thus the volume of hydrogen sulphide can be determined. The weight of methane is assumed to be the difference between the total weight loss of the product and the weight of sulphur in the hydrogen sulphide, from which the volume of methane can be determined. By subtracting the volumes of hydrogen sulphide and methane from the volume of the exit gases, the amount of unused hydrogen is determined. Subtracting this from the amount of input hydrogen gives the hydrogen consumption. It should be noted that some error is introduced by the difficulty of reading the gauge for hydrogen cylinder pressure with sufficient accuracy.

In the experiments conducted for the purpose of studying the regeneration of the catalyst without removing it from the reaction chamber, the accumulated coke is removed by heating it in a controlled atmosphere of oxygen diluted with nitrogen. The catalyst may be contaminated either by a series of regular desulphurizing runs, or by deliberate fouling runs at a low operating pressure of less than 100 lb. per sq. in. It is necessary to make a desulphurizing run under standard conditions both before and after the actual regenerating run, and the analytical results from these runs provide an indication of the effect on the activity of the catalyst.

For a regeneration run, nitrogen from a standard commercial cylinder, reduced through a needle valve to a pressure of a few inches of water, flows to the top of the reaction chamber through a dry test meter protected by a water-filled surge pot. Oxygen is supplied by compressed air at 90 lb. per sq. in. reduced through a needle valve to a pressure of a few inches of water, and flowing through another test meter to the top of the chamber. Since this operation is at low pressure, rubber tubing is used for all connections. The exhaust gases from the bottom of the reaction chamber are discharged to the external atmosphere.

The reaction chamber is flushed with nitrogen to remove any hydrogen, and brought up to heat with the nitrogen flowing. When the desired temperature has been reached and stabilized, the flow of air is started and increased, while the flow of nitrogen is simultaneously decreased until the desired oxygen percentage is reached with the desired total flow rate maintained. If the temperature within the catalyst bed appears to be reaching a peak so high that the catalyst might be damaged, the oxygen content can be reduced. The air and nitrogen flow rates are recorded, as well as the temperatures at the same points as in the desulphurizing runs. The operation is allowed to proceed until no products of combustion are evident at the exhaust point, and until the temperature difference between the external heater control point and the centre of the catalyst bed is negligible.

Experimental Results

The temperature variable, which was expected to be the most influential, was the first investigated. Experimental runs were made at ten different temperatures through the range 324 to 477°C. (615 to 891°F.). All operating conditions, with the exception of temperature, were identical in each of these runs and were as follows:

Pressure	1000 p.s.i.g.
Liquid feed rate	90 - 92 ml./hr.
Exit gas rate	3.0 - 3.3 cu. ft./hr.
H_2 feed rate	4370 - 4800 cu. ft./bbl. liq. feed
Total vol. of feed	359 - 364 ml.
Catalyst volume	50 ml.
Liq. hr. space vel.	1.80 - 1.84 vol. feed /hr./vol. cat.

Table I and Fig. 2 show the results obtained.

TABLE I

Temp.		Sulphur in prod., % by wt.	Sp. gr. of prod.	Yield - % of feed		Hydrogen consumed cu. ft./bbl. liq. feed
°C.	°F.			By wt.	By vol.	
324	615	2.42	0.920	97.0	98.7	183
343	649	1.79	0.912	95.6	98.3	—
367	693	1.19	0.905	97.8	101.3	257
392	738	0.70	0.895	97.4	101.7	333
410	770	0.35	0.886	99.1	104.6	553
421	790	0.19	0.876	94.7	101.2	624
438	820	0.11	0.865	93.7	101.6	926
448	838	0.05	0.861	93.3	101.2	781
463	865	0.05	0.849	90.5	99.9	888
477	891	0.04	0.840	86.2	96.0	1510

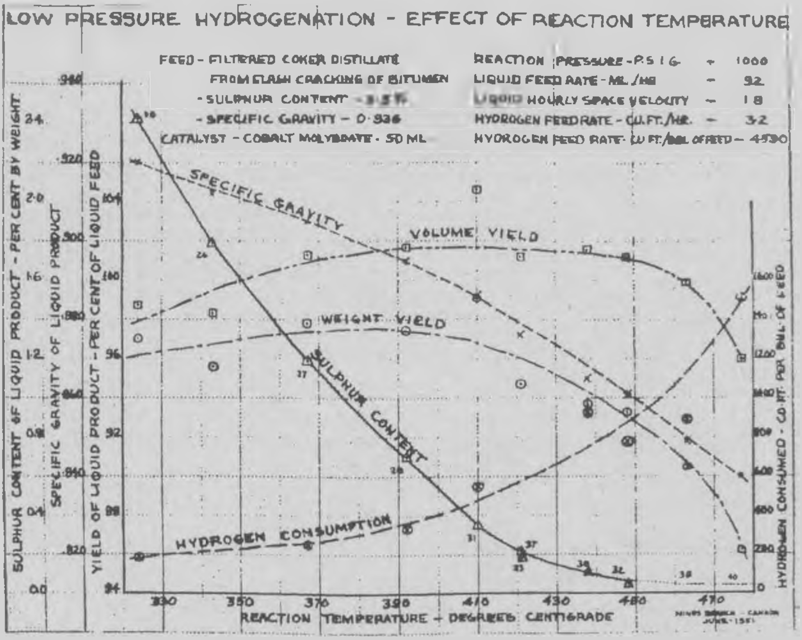

Fig. 2

From the data obtained from these runs a temperature of approximately 423°C. (794°F.) gave the most satisfactory results, and this temperature was used in the investigation of the other variables.

The pressure variable was the next investigated. Test runs were made employing varying pressures with the following operating conditions maintained.

Temperature	420 - 423°C. (788 - 793°F.)
Liquid feed rate	90 - 95 ml./hr.
Exit gas rate	3.0 - 3.4 cu. ft./hr.
H_2 feed rate	4370 - 5010 cu. ft./bbl. liq. feed
Total vol. of feed	359 - 365 ml.
Catalyst volume	50 ml.
Liq. hr. space vel.	1.80 - 1.90 vol. feed/hr./vol. cat.

Table II and Fig. 3 summarize the results obtained.

TABLE II

Pressure, p.s.i.g.	Sulphur in prod., % by wt.	Sp. gr. of prod.	Yield — % of feed	
			By wt.	By vol.
100	2.01	0.915	95.7	98.0
250	1.28	0.902	94.2	97.9
500	0.43	0.889	93.4	98.4
750	0.24	0.882	94.6	100.5
1000	0.19	0.876	94.7	101.2
1250	0.18	0.874	95.8	102.8
1500	0.19	0.874	95.7	102.7
1750	0.13	0.872	96.0	103.0

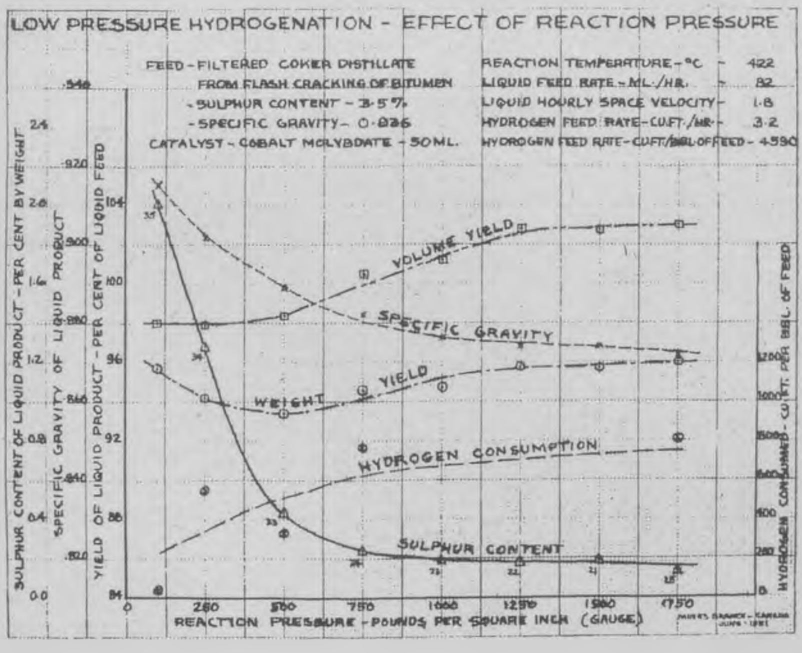

Fig. 3

Pressure was found to have an important influence in the range below 1,000 p.s.i.g. as shown by Fig. 3, but at higher pressures had only a small effect on the properties of the product. Thus, the choice of an operating pressure of 1,000 p.s.i.g. for the temperature tests was a fortunate one, and this pressure was used when testing the effect of the other variables.

The liquid feed rate variable was examined next, maintaining the other operating conditions as follows:

Temperature	423 - 425°C. (793 - 797°F.)
Pressure	1000 p.s.i.g.
Exit gas rate	2.8 - 3.3 cu. ft./hr.
Total volume of feed	250 - 596 ml.
Catalyst volume	50 ml.

It will be noted that the exit gas rate was maintained and the volume of hydrogen feed per volume of liquid feed allowed to vary. The reverse probably would have been preferable except that difficulty was experienced in maintaining any exit gas rate below 3.0 cu. ft. per hr. and, at a low liquid feed rate, control of the exit gas rate would have been impossible.

As the liquid feed rate was varied, so both the hydrogen feed rate per unit volume of liquid feed and the liquid hourly spare velocity varied. This variation and the results obtained by varying the liquid feed rates are shown in Table III and Fig. 4.

TABLE III

Liq. feed rate, ml./hr.	H_2 feed rate, cu. ft./bbl. liq. feed	Liq. hr. space vel.	Sulphur in prod., % by wt.	Sp. gr. of prod.	Yield — % of feed	
					By wt.	By vol.
48	9110	0.96	0.09	0.860	92.9	101.1
92	4470	1.84	0.19	0.876	94.7	101.2
121	3510	2.42	0.37	0.883	95.5	101.2
167	2600	3.34	0.49	0.888	96.3	101.7
209	1960	4.18	0.92	0.895	96.6	101.1

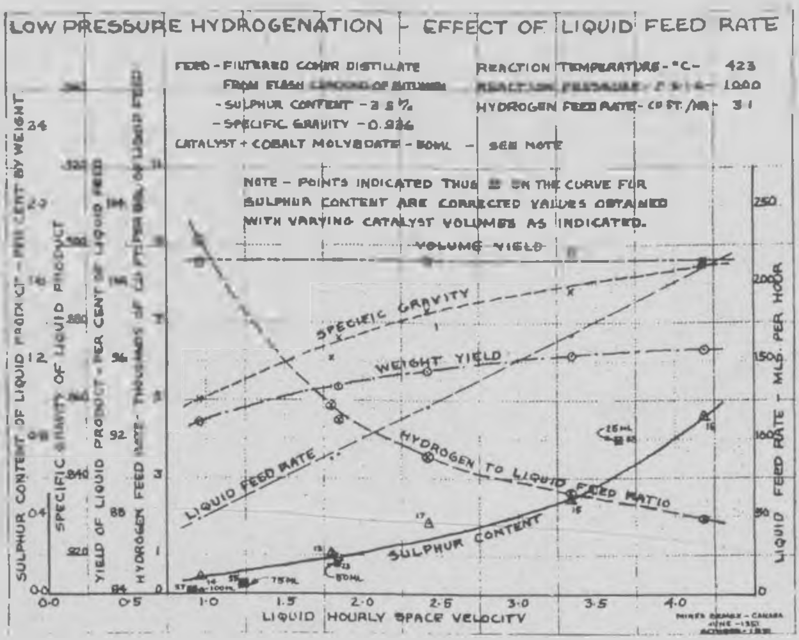

Fig. 4

The hydrogen feed rate variable was investigated maintaining the following conditions:

Temperature	421 - 423°C. (790 - 793°F.)
Pressure	1000 p.s.i.g.
Liquid feed rate	92 - 93 ml./hr.
Total vol. of feed	361 - 364 ml.
Catalyst volume	50 ml.
Liq. hr. space vel.	1.84 - 1.86 vol. feed/hr./vol. cat.

The exit gas rate varied with the hydrogen feed rate and both are shown with the results of hydrogen feed variation in Table IV and Fig. 5.

TABLE IV

H_2 feed rate, cu. ft./bbl. liq. feed	Exit gas rate, cu. ft. per hr.	Sulphur in prod., % by wt.	Sp. gr. of prod.	Yield — % of feed	
				By wt.	By vol.
2710	1.9	0.23	0.878	95.7	102.1
4470	3.1	0.19	0.876	94.7	101.2
5760	4.0	0.21	0.879	94.6	100.9
7060	4.9	0.13	0.877	95.6	102.1

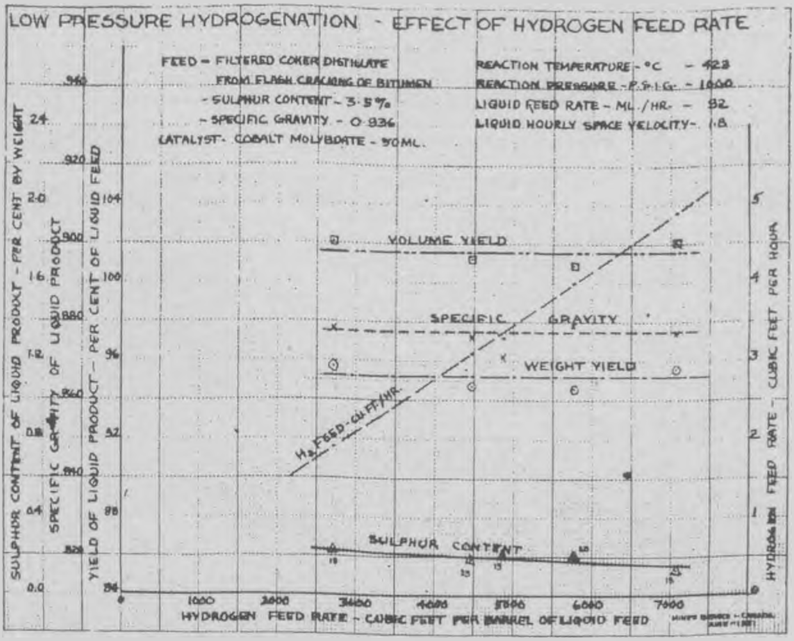

Fig. 5

In all runs to this point, the catalyst volume has been 50 ml. The liquid hourly space velocity has been varied by varying the liquid feed rate. However, the effect of varying the liquid hourly space velocity by varying the catalyst volume and maintaining a constant feed rate was investigated. Theoretically, the effects should be similar. The following conditions were maintained for these runs:

Temperature	418 - 427°C. (784 - 810°F.)
Pressure	1000 p.s.i.g.
Liquid feed rate	91 - 92 ml./hr.
Exit gas rate	2.9 - 3.3 cu. ft./hr.
H_2 feed rate	4220 - 4800 cu. ft./bbl. liq. feed
Total vol. of feed	361 - 363 ml.

As the length of the catalyst bed was increased, the top and bottom temperatures of the catalyst bed fell further below the control point. In all previous runs made, the average temperature of the catalyst bed ran a maximum of 4°C. (7°F.) below the control point temperature which was in the centre of the catalyst bed. However, when the volume of the catalyst bed was increased to 75 ml. its average temperature dropped 16°C. (29°F.) below the control point temperature, and when the bed was increased to 100 ml. the discrepancy was 37°C. (67°F.).

Thus, the results as they stood could not be compared with those from the liquid feed rate experiments. However, the hydrodesulphurization reaction obeys the Arrhenius equation, and the sulphur content values of the products formed have been corrected by means of this relation. The results of these runs and the corrected sulphur values are shown in Table V. The corrected sulphur values are also shown on Fig. 4.

TABLE V

Cat. vol., ml.	Liq. hr. space vel.	Average temp. of cat. bed.		Actual sulphur in prod., % by wt.	Sulphur in prod. corrected to 423°C., % by wt.	Sp. gr. of prod.
		°C.	°F.			
25	3.64	426	799	0.75	0.80	0.891
50	1.84	419	786	0.19	0.16	0.876
75	1.23	409	768	0.11	0.06	0.874
100	0.91	381	718	0.11	0.01	0.871

The foregoing runs were all conducted using the coker distillate feed described earlier. The following series of runs employed a different feed, namely, the products of previous runs containing various percentages of sulphur.

The purpose of these latter runs was to determine whether the percent sulphur in the product was directly proportional to the percent sulphur in the feed. If this were so, then it might be possible to use this relationship and the data obtained by varying the operating conditions, to set up a theoretical equation embracing all the operating variables and the initial and final sulphur contents.

Accordingly, runs were made using feeds of nine different sulphur contents. The temperature employed was chosen low enough so that the final sulphur contents would differ to an extent sufficient to provide a relationship. This temperature was chosen from the liquid product sulphur content curve in Fig. 2, and is listed below along with the other operating data.

Temperature	388 - 391°C. (730 - 736°F.)
Pressure	1000 p.s.i.g.
Liquid feed rate	87 - 94 ml./hr.
Exit gas rate	2.8 - 3.3 cu. ft./hr.
H_2 feed rate	3920 - 4860 cu. ft./bbl. liq. feed
Total vol. of feed	199 - 214 ml.
Catalyst volume	50 ml.
Liq. hr. space vel.	1.74 - 1.88 vol. feed/hr./vol. cat.

Table VI and Fig. 6 show the results of these runs.

TABLE VI

Sulphur in feed, % by wt.	Sulphur in prod., % by wt.	Sp. gr. of feed	Sp. gr. of prod.	Yield — % of feed	
				By wt.	By vol.
3.5	0.78	0.936	0.893	95.0	99.5
2.42	0.53	0.920	0.892	97.8	102.7
1.79	0.42	0.912	0.890	98.0	103.1
1.19	0.28	0.905	0.888	98.1	100.0
0.70	0.19	0.895	0.885	98.2	99.4
0.43	0.19	0.889	0.880	99.9	100.9
0.35	0.13	0.886	0.880	98.5	99.2
0.05	0.00	0.861	0.862	100.3	100.3
0.04	0.02	0.842	0.848	96.9	96.0

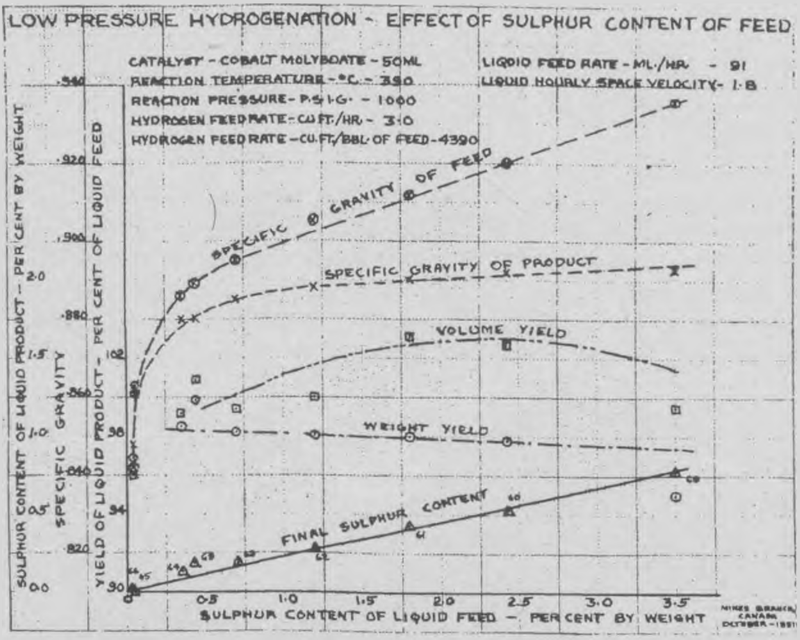

Fig. 6

A minimum of work has been done to date on the investigation of catalyst life and regeneration. No actual catalyst life tests as such have been run. However, one batch of catalyst was used with no noticeable decline of activity for approximately 90 operational hours in discontinuous service.

Only two regenerating tests were run. In the first test the temperature at the centre of the catalyst bed was brought up to 550°C. (1022°F.) in an atmosphere of nitrogen. Oxygen (using air) was then introduced until, after fifteen minutes, the proportion of oxygen to nitrogen was 1 to 5 by volume. This proportion was maintained for an additional hour and 45 minutes. During this period, a peak temperature of 649°C. (1200°F.) was reached at the top of the catalyst bed. After cooling, the catalyst was examined and appeared to have suffered no damage. Subsequent check runs showed that the original activity had been restored.

In the second test, the centre of the catalyst bed was brought to a lower temperature of 480°C. (896°F.), again in a nitrogen atmosphere. Oxygen was then introduced, and the proportion this time brought to 1 part of oxygen to 13 parts of nitrogen by volume. This proportion was maintained for 3 hours and 45 minutes. The peak temperature this time was 532°C. (990°F.), again at the top of the catalyst bed. The catalyst once more suffered no ill effects and recovered its activity.

CONCLUSIONS

Five operating variables, temperature, pressure, liquid hourly space velocity, hydrogen feed rate, and sulphur content of feed have been investigated. No extensive studies of the properties of the products have been made to the present. The data collected have been confined to sulphur content, specific gravity, yields, and hydrogen consumption.

It appears that a temperature of 420°C. (788°F.), a pressure of 1,000 lb. per sq. in. gauge, a liquid hourly space velocity of 2, and a hydrogen feed rate of 4,000 cu. ft. per bbl. of liquid feed will be satisfactory for impending tests on the rate of catalyst degeneration.

Under these conditions, the product contained approximately 0.2% sulphur, the hydrogen consumption was in the neighborhood of 600 cu. ft. per bbl. of liquid feed, and the volume yield was about 101 to 102% of the liquid feed.

The temperature variable was found, as expected, to exercise the greatest influence on the properties of the product. A small decrease in temperature below 420°C. (788°F.), while the other operating conditions were maintained as stated above, caused a large increase in the sulphur content of the product. However, above 425°C. (797°F.) a corresponding increase in temperature caused only a slight decrease in the sulphur content of the product.

There was a steady decrease in the specific gravity of the product throughout the range of temperatures investigated. The volume yield increased with the temperature to a maximum of close to 102% near 400°C. (752°F.), holding constant to about 440°C. (824°F.), and then falling off rapidly above this temperature.

Pressure was found to have an important influence in the range below 1,000 lb. per sq. in. gauge, but at higher pressures it had only a small effect on the properties of the product. It is expected, however, that pressure will have an important influence on the rate of coke formation on the catalyst and thus on the catalyst life. In the relatively short runs of the present series of tests, coke formation was appreciable only at the lower pressures. As the reaction pressure was decreased below 1,000 lb. per sq. in. gauge the corresponding sulphur content of the product increased rapidly, accompanied by a rapid increase in specific gravity.

The liquid hourly space velocity had a consistent influence on the product. As the liquid hourly space velocity increased there was a steady rise in both the sulphur content and the specific gravity of the product.

The hydrogen feed rate in the range tested had little influence on the properties of the product. Hydrogen feed rate is not to be confused with hydrogen consumption.

Varying the sulphur content of the feed showed that the ratio of sulphur in product to sulphur in feed remains constant throughout the range investigated. Up to a sulphur content in the feed of 0.5%, the specific gravity of the product increases proportionately to the specific gravity of the feed. Above this point the specific gravity of the product increases only slightly with a correspondingly large increase in the specific gravity of the feed.

In general, it can be said that the results obtained to date are encouraging. A single set of easily attainable conditions can be selected that gives more favorable results than those assumed by Blair for his cost estimate. Selecting, for instance, a temperature of 423°C. (794°F.), a pressure of 1,000 lb. per sq. in. gauge, a liquid hourly space velocity of 1.8, and a hydrogen recycle rate of 4,590 cu. ft. per bbl. of liquid feed, the following table compares the experimental results with those given in the Blair report.

	Blair report	Mines Branch observations
Sulphur in product, % by wt.	0.26	0.20
Specific gravity of product	0.897	0.878
A.P.I. gravity of product	26.2	29.7
Volume yield, % of feed	101.6	101.6
Hydrogen consumption, cu. ft. per bbl. of feed	1000	600

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DISCUSSION

M. A. Elliott: We can add very little to what Dr. Berg and Dr. Warren have reported. In our work, a Union Oil Co. catalyst was used for the hydrogenation of coker distillate prepared at the Bureau of Mines Oil Shale Demonstration Plant at Rifle, Colo. The reaction was carried out in a pilot plant having a capaciiy of two barrels per day at a pressure of 1500 p.s.i.g. Sulphur concentration of the feed was about 0.9%. Application of the Warren equation, developed from results obtained in a smaller scale operation, predicted that there would be a negligible sulphur content in the product. Our results showed only 0.01% sulphur in the product, so that the equation appears to be fairly general and applicable to this type of catalyst.

There is one more point that should be mentioned. It may not be of great significance here, but it is very important when handling high nitrogen feed stocks. Under these conditions, as Dr. Berg pointed out yesterday, nitrogen may become the controlling factor. It is frequently necessary, for example, in treating shale oil where the feed contains about 3% nitrogen, to operate at very low space velocity; that is, at low time of contact. For example, a space velocity of 1 instead of 3 is required for high nitrogen feed stocks. Under these conditions at a temperature of about 835°F., the hydrogen consumption is somewhat greater than the 750 cubic feet per barrel that is given for desulphurization. In the hydrogenation of coker distillate, the hydrogen consumption was about 1200 cubic feet per barrel to reduce the nitrogen from about 2.2 to 0.05%.

REMOVAL OF SULPHUR FROM ALBERTA BITUMEN*

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INTRODUCTION

In 1950 S. M. Blair prepared a report (6) summarizing much data concerning the practical development of Alberta bituminous sands. Untold quantities of potential hydrocarbon distillates are located along the Athabasca River in Northern Alberta, and await exploitation by individuals with the necessary capital and technical ability. Blair showed that a complete sequence of operations for the bitumen processing plant was possible, and that the cost of product ($3.10 per barrel for a distillate) at a Great Lakes terminal port was low enough in cost and high enough in quality to warrant consideration by industry and government.

Recent current events have stimulated considerable interest in these data, and many oil companies are examining the facts.

An interesting technical editorial comment (3) has just been made about the Blair report:

> "Petroleum from shale, petroleum from coal, the continuing discovery of new natural oil fields, and now petroleum from bituminous sands must be disconcerting to those gloomy prognosticators of impending depletion of our oil reserves . . . If the cost of $2.90 a barrel delivered to the Great Lakes region can be realized, oil from these sands is in a competitive position today."

The problem of the reduction of bitumen processing costs is apparent in peacetime, and its solution is urgent. Many things contribute to the over-all figure of $3.10 per barrel, and one important item involves the sulphur removal from the bitumen or its distillates. Blair's data indicate that the materials contain 4 to 5% sulphur by weight, and that this quantity of sulphur makes its removal mandatory.

The use of the bitumen (Athabasca crude oil) in its unaltered state is believed impractical for industrial fuels. Liquid fuels must pass definite specifications concerning fluidity, viscosity index, suspended matter, water, and sulphur content, etc. Table I shows that the various crudes have high viscosity, much sulphur, and low volatility; in addition, the fluidity of the material at room temperature is that of a semi-solid, and its mineral content is very high.

It might be argued that the Athabasca crude oil in its unaltered form could be treated by hydrogenation to remove the sulphur. The temperatures involved, and the presence of the solid materials associated with the crude, make a continuous process impractical because of short catalyst life (7). A batch process might be possible, but the cost of equipment and operating cost including the catalyst make it unattractive commercially.

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* This paper was not read at the Conference.

At the present time the treatment of a distillate prepared from the crude is the only practical solution. It will be recalled that hydrocarbon recovery was carried out by propane extraction (6) and that a yield of 56% of a gas oil was obtained. In contrast, bitumen distillation by the National Research Council (6) fluidized technique gave oil yields of 80 to 85%. Propane extraction was abandoned, therefore, in favor of the distillation procedure.

Examination of Table I shows that the distillate produced from the crude still contains undesirable amounts of sulphur (4% by weight). For use in internal combustion units the sulphur must be removed since it causes corrosion and suppresses the action of tetraethyl lead in gasoline engines. The presence of sulphur in domestic fuel oil burners might be tolerated in uncongested regions, but it could not be used in densely populated areas.

It might be thought that the coker distillate could be refined by further simple distillation. Unfortunately, the sulphur present is associated with all fractions distilled. This distillate is high in aromatic content, and it appears that most of the sulphur present is associated with an aromatic nucleus. Recent work by Gishler (14) of the National Research Council and Montgomery (26) of the Bureau of Mines has demonstrated the fact that coker distillate distilled fractions contain much aromatic material, and that the aromatics are always associated with high sulphur content. In addition, Tables II and III show that no cut contains less than 1.5% sulphur. Its removal, therefore, must be accomplished by procedures more rigorous than simple distillation.

Two possibilities exist for treatment. Either the coker distillate may be sweetened, or it may be catalytically cracked to prepare gasoline and fuel oils of lower sulphur content. Recent literature (34) indicates that low-boiling distillates may be desulphurized by processing the feed over silica-alumina cracking catalysts. Best results, however, were obtained with hydrocarbons containing aliphatic sulphur compounds. Since the Athabasca coker distillate contained considerable aromatic sulphur it was decided to restrict this study to other sulphur removal methods.

SULPHUR REMOVAL FROM ALBERTA BITUMEN DISTILLATE

Hydrogenation

Preliminary studies made by the Universal Oil Products Company for the Blair report showed that mild hydrogenation of the coker distillate removed the sulphur as hydrogen sulphide, but the operation was costly. The Union Oil Company of California have reported a process involving catalytic hydrodesulphurization to treat coker distillate from Santa Maria Valley crude. This material contains 4.5% sulphur and has been successfully processed to produce a low-sulphur hydrocarbon product. A full-scale commercial installation (35) is now under construction, and cost data may be available in the near future.

TABLE I

LABORATORY INSPECTIONS OF DISTILLATES PRODUCED BY COKING BITUMINOUS SAND BITUMEN

Properties	Conventional Coking		Fluidized Solids Coking (total distillate)			Desulphurized blend of Abasand and Bitumount distillates
	Debut. gasoline	Coker distillate	Abasand	Bitumount	Mildred-Ruth	
Gr., °A.P.I. at 60°F.	51.9	16.0	15.5	16.6	14.1	26.2
Sp. gr. at 60°F.	0.7715	0.9554	0.9626	0.9554	0.9718	0.8973
Total sulphur, wt. %	1.86	4.04	4.12	4.01	3.83	0.26
Mercaptan sulphur, wt. %	0.226					
Nitrogen, wt. %			0.27	0.22	0.27	
Conradson carbon, wt. %			7.9	5.7	7.85	1.22
B.S. & W., vol. %		0.1	0.05	0.15	1.5	
Tar acids, vol. %		0.2	0.8	2.1		
Tar bases, vol. %		0.1	0.36	0.6		
Bromine No.	80	47	54	45	49	10
Olefin content, wt. %	55				89	
Aromatic content, wt. %	12					
Pour point, °F.		20	30	30	25	35
Viscosities,						
S.S.U. at 210°F.						34.2
S.S.U. at 100°F.		70.8	200	173	321	55.3

Kin. cstks. at 100°F.		13.32	49.17		37.15		69.37		2.377	
Kin. cstks. at 32°F. (est.)		90	540		430				8 984	
Octane No.										
F-2, clear (Unisol sweet)	69.1									
F-2, 2.5 c.c. TEL/gal.	74.0									
Ash content, p.p.m.			176		315		660		58	
Distillation	Atmos.	Atmos	Atmos	Vac	Atmos.	Vac	Atmos.	Vac.	Atmos.	Vac.
I.B.P.°F.	126	443	185	122(a)	224	100(a)	181	98(a)	200	108(a)
5%	165	466	285	246(a)	365	321(a)	362	312(a)	294	250
10%	186	486	400	375(a)	450	421(a)	500	462(a)	364	330(a)
30%	232	550	617	662	610	651	633	702	537	580
50%	275	621	658	776	668	776	679	806	634	681
70%	315	690	694	886	703	877	705	909	720	751
90%	358	715	720	960(b)		956(b)	726	972(b)	760	857
E.P., °F	400	760								
Recovered, %	98.5	97.5	90.5	82.0	92.5	83.0	91.0	86.5	98.5	97.5
Bottoms, %	1.0			18.0		17.0		13.5		2.5
Coke, wt. %		2.5	9.3		7.5		9.0		1.3	
% at 400°F.				11.3		8.6		7.0		15.3

(a) Atmospheric Hempel (b) 80% point

TABLE II

INSPECTION OF OIL FRACTIONS

Pilot-Plant Product (510°C.) from Bitumount Oil Sand

Distillation range °F.	Composite	I.B.P. to 356	356 to 464	464 to 536	536 to 608	608 to 644	644 to 750	Residue
Sp. gr. at 60°F.	0.954	0.7875	0.8477	0.8747	0.9000	0.9218	0.9465	1.003
Refractive index	—	1.4384	1.4680	1.4815	1.4952	1.5098	1.5252	—
Sulphur, %	4.0*	1.71	1.87	2.12	2.70	3.03	3.61	4.74
Viscosity,								
Kin. cstks. at 100°F.	52.0	2.1	1.88	2.91	5.14	9.81	28.7	4500
Kin. cstks. at 210°F.	5.2	1.06	0.87	1.15	1.59	2.27	4.0	54
Distillate,								
vol. %	—	3.5	6.1	5.7	7.7	4.0	17.2	50.0
wt. %	—	2.8	5.2	5.0	6.9	3.7	16.2	50.2
Asphaltenes, %	0.5	nil	nil	nil	nil	trace	trace	1.03
Resins, %	22.6	1.40	1.66	1.74	2.2	3.9	6.7	26.6
Oily material, %	72.5	100	100	97.6	97	94.5	92.7	71.7
Aromatics, %	—	4.9	11.4	12.4	18.4	33.3	38.4	—
Acid soluble, %	—	44.8	41.3	39.0	39.6	29.5	38.6	—
Acid insoluble, %	—	50.3	47.3	48.6	42.1	37.1	25.0	—

* Excludes gasoline cut

TABLE III

INSPECTION OF OIL FRACTIONS

Raw Abasand Bitumen

Distillation range, °F.	I.B.P. to 464	464 to 536	536 to 608	608 to 644	644 to 750	750 to 825	Residue
Sp. gr. at 60°F.	0.8932	0.8920	0.9101	0.9228	0.9489	—	1.0349
Refractive index at 68° F.	—	1.4838	1.4953	1.5064	1.5227	1.5402	—
Sulphur, wt. %	2.10	1.37	1.84	2.20	2.95	—	5.65
Viscosity,							
Kin. cstks. at 100°F.	—	35.6	128.0	518.0	6290	—	solid
Kin. cstks. at 210°F.	—	4.0	6.8	12.1	36.8	—	—
Distillate,							
vol. %	5.5*	1.3	3.2	3.6	11.0	—	75.3
wt. %	4.9	1.2	2.9	3.3	10.4	—	77.8
Asphaltenes, %	nil	nil	nil	nil	nil	trace	32.2
Resins, %	1.5	0.6	1.8	2.3	6.4	6.2	36.0
Oily material, %	99	99	98	98	93	93	33.3
Aromatics, %	18.3	16.5	19.1	22.8	29.2	41.8	—
Acid soluble, %	27.1	26.2	24.3	25.7	27.8	—	—
Acid insoluble, %	54.6	57.3	56.6	51.5	43.0	—	—

* Includes H_2O and CCl_4

Processes involving hydrogen, however, are costly in comparison with simple physical procedures that might be used for sulphur removal from the coker distillate. This is true because of the cost of hydrogen, the compression cost for the use of hydrogen at elevated pressures, and because of the capital cost of the hydrogenation plant. It was believed, therefore, that a study of other physical methods would be worthwhile. It might be found that a simple preliminary treatment would remove part or all of the sulphur compounds, and that hydrogenation of the treated material could be simplified. If a preliminary sulphur removal could be effected at a low cost (less than 20 cents per barrel), the final desulphurization by hydrogenation could also be reduced because of decrease in hydrogen consumption, compression costs, and decrease in capital cost of the plant.

Bauxite Treatment

A study of the current literature (9) indicated that many petroleum fractions had been processed over bauxite to remove sulphur-containing compounds. It was believed that the Athabasca coker distillate might be similar to gas oil already treated by industry, and it was decided to solicit the advice of several petroleum manufacturing groups.

Answers from various concerns were consistent in their estimate of the use of bauxite for the desulphurization of Athabasca coker distillate. The replies indicated that the distillate prepared from Alberta bitumen would not be suitable for bauxite treatment if it contained considerable aromatic compounds. In addition, it was reasoned that a large proportion of the sulphur in the product might be thiophenic, thiophanic or more complicated aromatic sulphur structures. If this were true, the bauxite process would be ineffective in this type of sulphur removal and less than 25% of the original sulphur would be withdrawn. Additional literature studied (9) pointed out that the life of the bauxite would be short if the olefinic content of the distillate were great.

Recent unpublished data (26) supplied from Ottawa have supported the aforementioned theories. Hydrocarbon cuts were separated from a distillate prepared from various bituminous sands, and were analysed for aromatic, olefinic, paraffinic and sulphur content.

The results are shown in Tables II and III, and it is clearly indicated that the cuts contain considerable olefins and aromatics, and that an increase in aromatic content shows a corresponding increase in sulphur content. These facts discouraged further study of the bauxite process.

Solvent Extraction for Sulphur Removal

Solvent extraction has been used by gasoline manufacturers for many years (12), but the problem of sulphur removal by liquid-liquid contact is less well understood. Edenlau's (11) treatment of kerosene fractions with liquid sulphur dioxide is well known. The success of this treatment involves the selective solvent action of the sulphur dioxide for aromatics contained in the kerosene. Edenlau's paper also indicates that considerable sulphur was withdrawn with the aromatics into the solvent. This action can be understood if the sulphur compounds are of aromatic structure.

It would be reasoned that sulphur dioxide should be a logical solvent for the sulphur removal from coker distillate. This is a possibility, but it is believed that the presence of much olefinic material in the hydrocarbon would make its choice undesirable because of the tendency of olefines and sulphur dioxide to react and form resinous materials. Inhibitors might be used to prevent this reaction but their cost would certainly increase the over-all processing figure.

Aluminum halides and the halide acids have also been used commercially to separate aromatics from lubricating oils (18, 27) by solvent extraction. The solvent was expensive, however, and polymerized olefinic fractions with great ease.

Recently, liquid hydrogen fluoride has been described as a reagent for the removal of sulphur compounds from hydrocarbons (13, 21, 28). The selectivity of the hydrogen fluoride could be increased markedly by the addition of small amounts of boron trifluoride (17). In this latter case most of the aromatics and sulphur impurities were withdrawn into the solvent and were easily recoverable. Enquiry has been made to the Standard Oil Company of Ohio about the practicability of the HF-BF_3 system for a coker distillate. It is believed that the presence of the olefines complicates the issue since they polymerize in the presence of hydrogen fluoride except at low temperatures.

Two possibilities exist that should be investigated carefully. One involves the use of furfural which has been used for the removal of aromatics from lubricating oil in large-scale practice (20). Lately the Calco Chemical Research Division has discovered that nitriles are quite selective in the solution of aromatics in contrast to paraffins, and that some of their specially prepared compounds have a more selective action than furfural (25). Data are needed concerning the stability of the nitriles, the reaction with the olefins, the effect of olefins on the aromatic separation, and the cost of the process for a 20,000 barrel per day plant. Rough estimates indicate that the cost of an extraction column coupled with a distillation unit would range from 20 to 30 cents a barrel. The aromatic and sulphur fraction separated from the solvent could be hydrogenated in a much smaller plant than the one originally contemplated for the coker distillate. This should also lower the overall cost of processing because of the small quantities of hydrogen used and the smaller capital cost.

Extractive Distillation for Sulphur Removal

Ordinary distillation methods are of little use in the separation of sulphur compounds from coker distillate. This fact can be explained by the fact that the sulphur compounds boil at approximately the same temperature as the many hydrocarbons, and that their volatility is much the same as the hydrocarbons. However, the addition of another component or mixture of inert components may effect the relative volatility of aromatics, sulphur molecules or both relative to the paraffins, olefins, and napthenes. This is certainly possible since the structure of all of these substances is quite different; and the addition of a foreign substance properly chosen may create a condition so that the paraffins, olefins and napthenes have an increased fugacity and are in much better condition for enhanced separation.

The industrialist terms this physical behavior "Extractive Distillation" and has made much use of it (5).

Thus considerable quantities of toluene were produced in World War II by the use of phenol for the separation of aromatics from hydrocarbon distillates. It seems reasonable that the coker distillate could be treated with a solvent to separate the major portion of the sulphur impurities or aromatics, or that both could be withdrawn with the selective agent for further treatment. An exact cost for this process is not known but it is believed that this distillation procedure might be carried out at an overall cost of 20 to 30 cents per barrel. It is suggested that a series of tests be tried at once to learn if this physical method has practical possibilities.

Sulphur Separation by the Arosorb Process

The Arosorb process has been developed by the Sun Oil Company in the past few years (39) for the separation of aromatics from the reformate produced in the Houdriforming process. Basically it is accomplished by the selective adsorption of aromatics on a silica gel, with the subsequent desorption from the saturated solid by specially selected solvents. It is supposed that sulphur compounds may be adsorbed with the aromatics and released by the special desorbents. It is not impossible to conceive that the use of several desorbing solvents might selectively release aromatics and sulphur impurities in a relatively pure state.

Cost figures for a 2,000 barrel per day plant are quoted as follows:

Plant investment $1,900,000,

Total operating costs $1.20 per barrel feed.

This is high but the literature indicates that the basic cost is much reduced for larger installations. Such a physical separation is economically applicable at present to the production of high-value aromatics, but the principle warrants further study.

TABLE IV

SUMMARY OF SULPHUR REMOVAL PROCESSES

Process	Existing size	Probable cost, dollars per bbl.	Remarks
Hydrogenation	Laboratory	0.80	Only known process for aromatic sulphur compounds. Union Oil Co. now building large unit.
Bauxite treatment*	Large-scale		Unable to handle organic sulphur compounds.
Extraction	Large-scale	0.20 to 0.30	Furfural and organic nitriles offer possibility.
Extractive distillation	Large-scale	0.20 to 0.30	Has been used to separate aromatics from hydrocarbons.
Adsorption	Laboratory	1.20	Large plant just constructed by Sun Oil Co. Cost will likely be reduced with large-scale production.

* Not applicable to oil-sand distillates.

A summary of the possible alternative processes is given in Table IV with approximate costs. It is believed that extraction, extractive distillation, adsorption and hydrogenation merit a continued study of the economics of these procedures.

SUPPLY AND DEMAND OF SULPHUR

Attention, up to this point, has been directed to the production of a saleable hydrocarbon product at a minimum price. The presence of sulphur in the bitumen, however, is challenging, and if recoverable as elemental material is extremely important.

Study of a 20,000 barrel per day processing unit indicated that approximately 50,000 tons of sulphur could be recovered each year if the coker distillate were hydrogenated (6). This quantity of valuable raw material represents about 15% of the sulphur imported to Canada during the year 1950 (10).

This fact may seem unimportant until it is realized that sulphur has become one of the most critically needed natural materials today.

Without doubt, sulphur is the chemical industry's principal supply problem (31). World industry, which for years has been using sulphur at a tremendous rate, has taken for granted that the supply was inexhaustible. Predictions, however, indicate that the United States native deposits will be depleted within 25 years if used at the current rate of 5,000,000 long tons per year (31).

It must be realized that the production of sulphur by the Frasch process revolutionized that phase of world industry (16). This unique and economical procedure gave a product which was so cheap and pure that all other sources of sulphur disappeared from the industrial market until, by 1947, 94% of the world's supply was produced in the United States (23).

Fig. I shows that the shortage began to be felt acutely in the latter half of 1950. For 1950 as a whole, United States brimstone production was 5,300,000 long tons compared to total sales of 5,700,000 (4,259,000 tons domestic, and 1,441,000 tons foreign, including Canada). The difference of 400,000 tons was made up by withdrawal from stocks of sulphur previously mined.

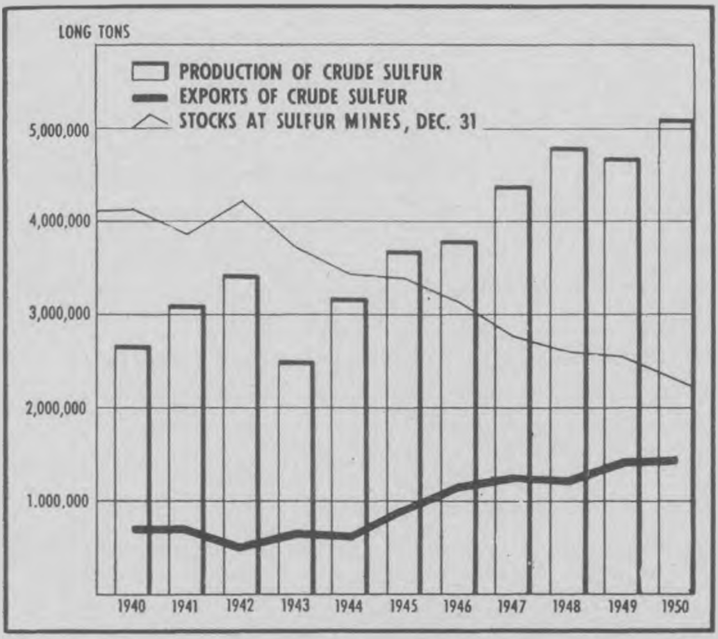

Fig. 1. *Study of sulphur supply in the United States (31).*

The picture in 1951 is not expected to change although relief is expected in 1953. It has just been announced (2) that a large elemental sulphur deposit has been found in the Gulf of Mexico near New Orleans, La. Approximately 500,000 tons will be recovered per year by 1953 by the Frasch process. In 1951, however, it is expected that the demand will be greater, but the supply will be less because further withdrawals from stocks should not be made. The stockpiles have fallen from a two-year reserve before World War II to a six months' supply in January, 1951. This is a minimum decided upon by the United States; hence current needs must be met by current production (33).

Additional evidence of the gravity of the situation is given by the statement, "Sulphur has become the third item to be placed under international control since World War II" (32). It is believed that Canadian consumers will receive 85% of the sulphur purchased in the base period of October 1, 1949 to September 30, 1950.

The principal reasons for the shortage are as follows:

(a) Great demand from abroad,
(b) Sudden expansion of the military preparedness program,
(c) A disproportionate increase in domestic requirements,
(d) The low price of brimstone, which has tended to discourage development of higher cost sources,
(e) The difficulty of finding new brimstone deposits.

The greater demand from abroad is due to the failure of foreign sources to recover from the disruption of war, and to the fact that United States sulphur is cheaper and purer than foreign sulphur. These factors have influenced European sulphuric acid makers to choose brimstone instead of pyrites as their source of sulphur when rebuilding war-damaged acid plants or constructing new ones. As a result, exports of United States sulphur to all countries, including Canada, were 155% higher in 1950 than they were in 1935 to 1939 (33). This is represented in another way in Table V. Here it will be observed that the United States accounted for 46% of the world's sulphur supply in 1950 as compared to 26 to 28% before World War II.

TABLE V[1]

ESTIMATED WORLD SUPPLY OF SULPHUR FROM ALL SOURCES BY COUNTRIES

Country	1935 - 1939 Average		1950	
	Long tons	%	Long tons	%
United States	2,569,000[2]	31	5,966,000[2]	51
Japan	1,093,000	13	859,000	7
Italy	738,000	9	628,000	5
Spain	1,116,000	14	558,000	5
Norway	418,000	5	311,000	3
Portugal	195,000	2	295,000	3
Cyprus	173,000	2	289,000	3
Sub-Total	6,302,000	76	8,906,000	77
Other 26 countries	1,898,000	24	2,794,000	23
Total	8,200,000	100	11,700,000	100

Between the 1935-1939 period and 1950:

U.S. sulphur production (all sources) increased	134%
U.S. brimstone production increased	146%
Foreign sulphur production (all sources) increased	2%

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[1] See (33).

[2] In 1935 to 1939, 85% represented brimstone, In 1950, 90% represented brimstone.

The increase in the demand for sulphur by United States industry and agriculture has been of a much greater proportion than the increase in general industrial activity. Shipments of brimstone to United States consumers in 1950 were 180% above the average shipments in 1935 to 1939, while general industrial production was up 100% (31). These increased domestic shipments of sulphur were caused by the expanding requirements of large consuming industries. For example, the per capita consumption of fertilizer, chemicals, rayon and cellulose film was about three times the average for 1935 to 1939. The average per capita consumption of sulphur for 1935 to 1939 was 35 pounds; in 1950 it was 75 pounds. These data are graphically depicted in Fig. 2.

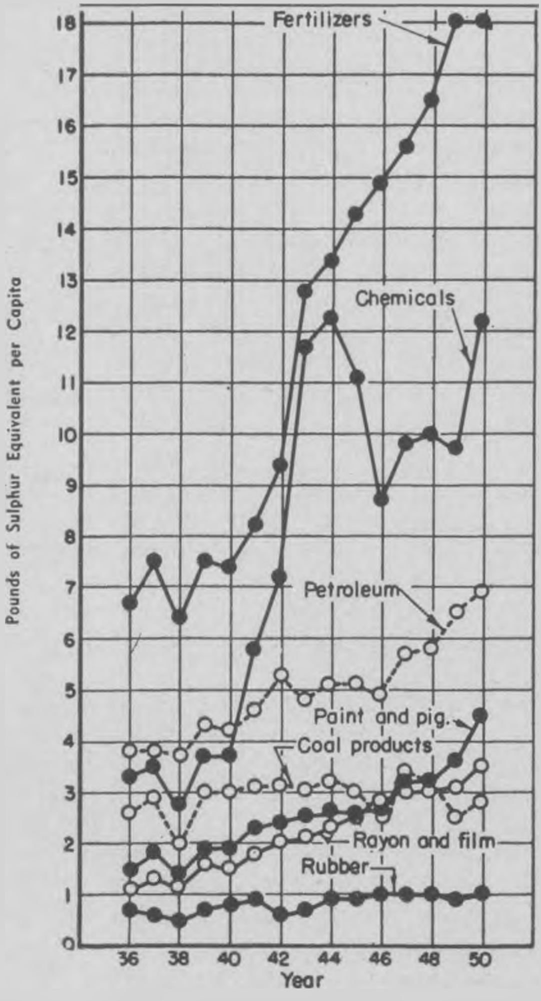

Fig. 2. *Per capita consumption in the United States, 1936 to 1950, of sulphur used in major industrial applications. The sharp (300 to 400%) increase in sulphur consumption in fertilizer and chemical production is clearly portrayed here (37).*

Chemical Engineering has made an extrapolation in the future for several of the chemical process industries (29). It indicates that the fertilizer industry may rise from an index level of 260 in 1950 to an index of 380 by 1960. This does not take into consideration the demands fostered by the present world situation. If these are considered, an index level of 480 is indicated. If such an increase becomes a reality, it means that the use of sulphuric acid in fertilizers may nearly double.

It is difficult to attribute to specific products all the increased demand for sulphuric acid in industry. There has been a rapid increase in the production of detergents, many of which are sulphonated products. Many organic syntheses require sulphuric acid as a dehydrating agent. The sharp rise in the production of organic chemicals has accounted for much of the acid required by chemical industry. *Chemical Engineering* indicates that if recent trends are maintained, the chemical industry index will rise to 900 in 1960 from the current level of 420. It is reasoned that the sulphuric acid index will parallel industry, so that twice as much acid will be needed in 1960 as in 1950.

The postwar demand for petroleum surprised everyone. *Chemical Engineering* estimates that the petroleum industry will rise to a production level indicated by an index number of 330, from its present level of 215. Increases in refinery throughput and increased use of alkylate will force the use of sulphur to follow the petroleum trend just mentioned. A number of plots and extrapolations for various chemicals using sulphur are given in Fig. 3 (37). The unprecedented demand for sulphur, plus the recent increase in the price of sulphur at the mine is likely to cause two things: first, previously submarginal sources of supply will be examined critically, and some will be used; and second, consumers of sulphur will study carefully processes for conservation or re-use of previously wasted material. This undoubtedly suggests that price increases and further restrictions in elemental sulphur may be expected in the near future.

The chemical industry in Canada will certainly be adversely affected unless sulphur restrictions are lifted or new sources of the element are developed. Canadian pulp and paper manufacturers are claiming that they will be forced to curtail newsprint production unless more sulphur is available (31). The fact that pulp and paper manufacture represented Canada's leading industry in 1948 on the basis of gross value of products indicates the importance of maintaining a steady supply of sulphur to the manufacturing plants.

Table VI indicates the amount of elemental sulphur imported into Canada from the United States (24). It will be observed that the quantity has risen from 216,000 tons in 1940 to 385,000 tons in 1950 with U.S. dollar values of $3,600,000 and $7,500,000 respectively. Note in Table VII that 80% of the imported product is used

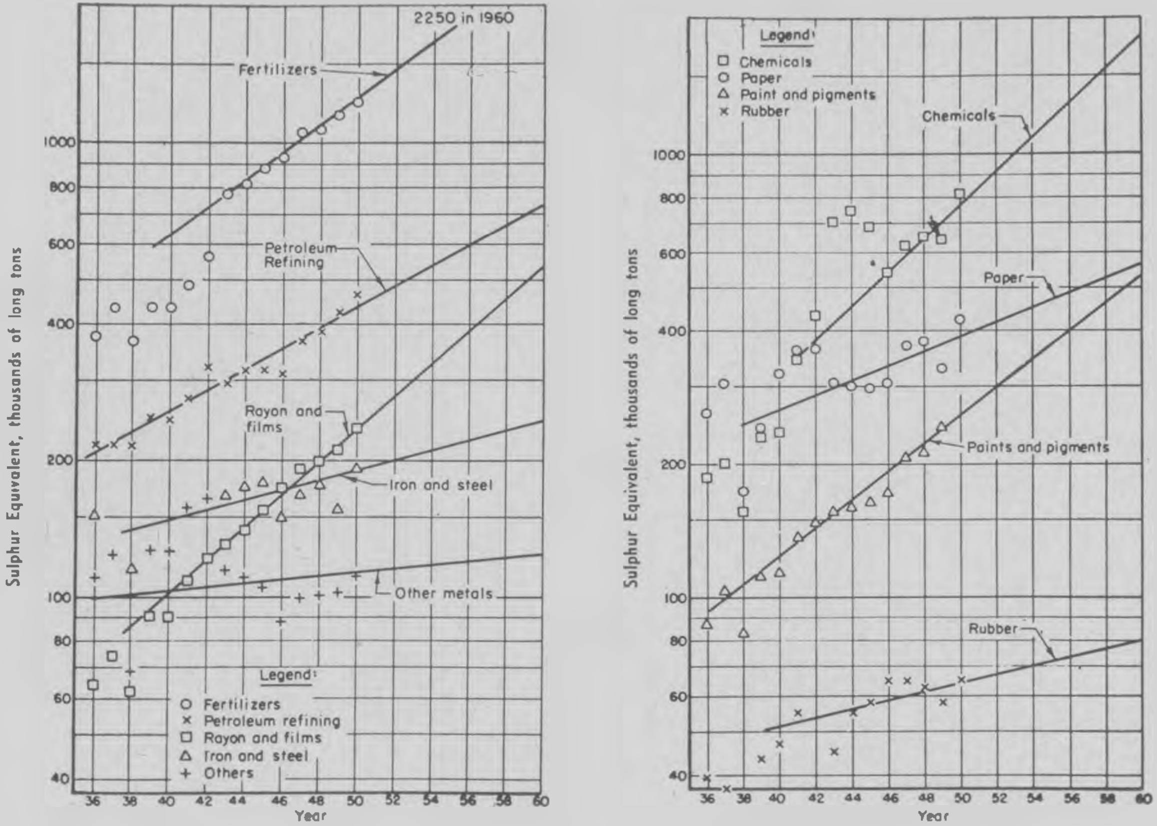

Fig. 3. *Plot of sulphur consumed by major industries in the United States (37).*

TABLE VI

SULPHUR IN CANADA FROM 1940 TO 1950

Year	Production of sulphur in pyrites and smelter gases		Imports of sulphur		Exports of sulphur in pyrites	
	Tons	Dollars	Tons	Dollars	Tons	Dollars
1940	170,630	1,298,018	215,597	3,628,348	40,380	230,981
1941	260,023	1,702,786	235,271	3,920,184	129,629	585,258
1942	303,714	1,994,891	290,121	4,680,672	166,451	700,918
1943	257,515	1,753,425	218,527	3,524,006	104,509	409,597
1944	248,088	1,755,739	235,955	3,875,649	90,836	353,441
1945	250,114	1,881,321	248,846	4,063,324	75,479	315,232
1946	234,771	1,784,666	273,502	4,271,081	68,045	286,254
1947	221,781	1,822,867	361,424	5,466,201	56,336	281,880
1948	229,463	1,836,358	354,622	5,528,740	50,243	195,710
1949	249,205	1,939,200	266,461	4,899,651	84,597	357,214
1950			385,000	7,500,000		

Note: 1949 imports and exports are for 11 months only.

in pulp and paper manufacture although it may be expected that a greater percentage will be used in chemical manufacture in the future. If Canadian industry maintains its steady increase in production, it might be expected that sulphur consumption would reach 700,000 tons in 1960 with a probable U.S. value of $20,000,000.

TABLE VII*

AVAILABLE DATA ON THE CONSUMPTION OF SULPHUR IN CANADA FOR 1947 AND 1948

	1947	1948
By Industries:	tons	tons
Pulp and paper	253,423	260,912
Heavy chemicals	63,265	60,882
Rubber goods	2,165	2,154
Explosives	1,496	1,759
Insecticides	1,545	1,293
Adhesives	93	61
Starch	267	227
Fruit and vegetable preparations	38	26
Sugar refining	127	107
Petroleum refining	127	168
Matches	92	74
Miscellaneous	180	480
Total	**322,818**	**328,143**
By Provinces:		
Nova Scotia	5,312	4,455
New Brunswick	34,512	37,542
Quebec	120,192 (38%)	124,074
Ontario	130,740 (42%)	128,605
Manitoba	1,659	1,867
Alberta	109	92
British Columbia	30,294 (10%)	31,508
Total	**322,818**	**328,143**

* Ref. (24).

It is interesting to observe in part (b) of Table VII that 38, 42, and 10% of the sulphur consumed in Canada in 1948 was used in Quebec, Ontario, and British Columbia respectively. These data are important in the determination of alternative sources of material since availability, processing, and transportation play a very important role in the economic choice of a raw material.

It is also important to note the breakdown given in Table VIII for the use of sulphur by various industries in the United States and Canada. No similarity exists in the uses. The bulk of the sulphur in the United States is changed into fertilizer whereas most of the Canadian import is used for pulp and paper manufacture. There is no doubt that the Canadian chemical industry will grow in the future, and will need more brimstone for the production of new industrial chemicals. If the pulp and paper industry maintains its steady growth it may be expected that considerably more than 700,000 tons of sulphur will be used in Canada by 1960.

TABLE VIII

COMPARISON OF SULPHUR USES IN UNITED STATES AND CANADA

Industry	United States (1949)[1] % of total	Canada (1948)[2] % of total
Fertilizer	28.0	—
Pulp and paper	7.7	80.0
Heavy chemicals	15.0	19.0
Explosives	2.4	negligible
Petroleum refining	9.9	"
Rayon and films	4.8	"
Rubber	1.3	"
Chemical and misc.	12.4	"
All other uses	19.5	"

[1] See ref. (37).

[2] See ref. (24).

POSSIBLE SOURCES OF SULPHUR IN CANADA

The fact that a sulphur shortage exists now, and that it will affect Canadian chemical production unless new sources of supply are found, prompted the author to study the possibilities of recovering sulphur from various known Canadian natural resources. These are listed as follows and are discussed in some detail:

(1) Alberta oil sands,
(2) Alberta natural gas,
(3) Pyrites,
(4) Smelter gases,
(5) Anydhrite.

Sulphur from Alberta Oil Sands

The recovery of sulphur from Alberta oil sands is largely dependent on the cost of freight transportation from a processing unit at Edmonton. It also presupposes that the sulphur would be changed to hydrogen sulphide during hydrogenation of the coker distillate. The hydrogen sulphide is then transformed to sulphur by a modification of the Claus process (15).

Data obtained from the Girdler Corporation, Louisville, Kentucky, indicated that approximately 80% of the sulphur could be recovered from the effluent gas stream. Blair (6) estimated that the over-all cost of the product would be $8.10 per ton. This figure is based on the sulphur released from bitumen when processing 20,000 barrels of crude per day, and it includes no interest on the investment.

Correspondence with one of the Canadian railroads indicated that freight rates, in minimum carload lots of 30 tons, would approximate $14.00 per short ton to Vancouver, and $20.00 per short ton to Sault Ste. Marie and Kapuskasing, Ontario. It has been mentioned (6) that the paper industry west of Sault Ste. Marie would use about 50,000 tons of sulphur annually. With sulphur now selling at $22.00 per short ton f.o.b. Texas mines (31) it is believed that a market for this product could be established, especially under present-day conditions.

It will be recalled that about 400,000 tons of sulphur were imported into Canada in 1950. The shortage in the United States will cut the quantity shipped to Canada by at least 15% for the year 1951 (31). This means that 60,000 tons will have to be supplied by other sources of raw material, or by improvement of existing processes so that less primary product is used. Some Canadian manufacturers have been aware of this condition for some time and have developed new sources of sulphur that may aid during the critical shortage.

Sulphur from Alberta Natural Gas

The recovery of sulphur from sour natural gas can be justified for several reasons: additional income is realized from a known resource; sulphuric acid produced from this impurity stimulates growth of other industries in the area; and the civilian population is assured that the effluent gases will not pollute the atmosphere.

The most common method of recovery involves the use of ethanolamine-water mixtures for scrubbing the hydrogen sulphide from the natural gas. The solute is released by heating, and is transformed to elemental sulphur by the modified Claus process.

This type of recovery has its limitations unless the natural gas contains sufficient quantities of hydrogen sulphide. In the American West about 150,000 tons of elemental sulphur are produced per year from natural gas containing 28% hydrogen sulphide (19, 31). It has just been announced that the Shell Oil Company of Canada will erect a 10,000 ton per year plant near Calgary to produce sulphur from Alberta natural gas (4).

It is estimated that Alberta has a natural gas reserve of seven trillion cubic feet (38). This offers interesting possibilities for sulphur recovery. If it be assumed that the Alberta potential supply contains 160 grains of impurity per 100 cubic feet, then approximately 800,000 tons of sulphur could be recovered. The economic processing of natural gas, however, is largely dependent on the content of hydrogen sulphide. This fact is illustrated in Table IX showing the cost of arbitrarily processing 14,000,000 cubic feet per hour of sour natural gas to remove varying hydrogen sulphide impurities. It will be observed that the overall cost of sulphur per ton, without interest on investment, ranged from $7.70 to $3.70 per ton for gases containing 160 and 830 grains of hydrogen sulphide per 100 cubic feet respectively. It is evident, therefore, that the use of sour gas must be studied carefully for quantity of supply, impurities, future supply, and neighboring markets before any decision can be made about the economics of the process.

TABLE IX

COST OF SULPHUR FROM SOUR NATURAL GAS BY THE GIRBITOL PROCESS

Basis: 14,000,000 cu. ft. per hr. sour gas treated

H_2S content, grains per 100 cu. ft.	167	500	830
Sulphur recovered per day, tons	36	118	206
*Cost of sulphur per ton, dollars	7.70	4.50	3.70

* These costs are not absolute, and are used for comparative purposes only.

Sulphur from Pyrites

Pyrites is a general name for all iron sulphide minerals containing 25 to 50% sulphur. Tremendous reserves offer industry the most compelling alternative to Frasch sulphur if enough economic stress and resulting increased price occur. It is estimated that 76,000,000 tons of this mineral exist in the United States (22). The largest known world reserves exist in Spain and Portugal where over 200,000,000 tons of recoverable sulphur are available (22). At least 100,000,000 tons of the material are known to exist in Ontario (23) and await use when the market price becomes attractive. However, at the present price of $22.00 per ton for elemental sulphur the use of pyrites is a costly proposition.

It has been found by industry that the capital cost of a plant using pyrites is twice as much as one using brimstone for the manufacture of sulphuric acid. In addition, operating costs are approximately twice as great for the pyrites unit as for the brimstone plant (37). If the iron oxide produced in the pyrites burning process is to be sintered for blast furnace use, the difference in cost favors the brimstone plant even more.

It is believed that the use of sulphur from pyrites will compete with Frasch sulphur when the price of brimstone at the mine rises to $30.00 per ton (31).

Mention should be made of a new development recently announced by Noranda Mines (1). After ten years of study they have evolved a process for obtaining sulphur and iron ore from pyrites, and will build a $4,000,000 plant along the St. Lawrence River near Montreal. This plant will treat 300 tons of pyrites per day, and produce 50 tons of sulphur, 100 tons of sulphuric acid, and approximately

100 tons of sintered iron ore. The exact choice of plant location has been delayed since the economics of this process require very careful consideration of the cost of raw materials, transportation charges, and markets for the products. Noranda Mines are favorably situated, however, in Eastern Canada where the bulk of the sulphur and iron ore are utilized by industry.

Sulphur from Smelter Gases

Each year tremendous quantities of sulphur dioxide are evolved in the smelting of non-ferrous sulphide ores. Annually in Canada and the United States, approximately one million long tons of sulphur are potentially recoverable from the smelting of zinc, nickel, lead and copper ores (31). In 1949, however, the equivalent of only 300,000 tons of sulphur was obtained from smelters in Canada and the United States.

International Nickel Company and Canadian Industries Limited have been investigating the recovery of liquid sulphur dioxide from waste gases. This problem has been solved, and Canadian Industries Limited have recently announced that they will erect a new plant at Copper Cliff, Ontario, to produce 90,000 tons of high-grade liquid sulphur dioxide annually (10). The product will be recovered from smelter gases evolved by the operating of an enriched air smelting process developed by the International Nickel Company. The use of enriched air gives an effluent gas with a sulphur dioxide concentration that is high enough to permit recovery of sulphur dioxide as a liquid product in an economical manner.

This new development will place liquid sulphur dioxide on the market in large quantities for the first time. Discussions with pulp and paper technical personnel indicate that the chemical can be used for the manufacture of sulphite pulp with no difficulty; in fact, it eliminates the need for sulphur burning equipment. The original price of four cents a pound in carload lots discouraged its use. Canadian Industries Limited now claim that this new development will place the chemical on the market at a fraction of its present price.

Sulphur from Anhydrite

The scarcity of brimstone, and the lack of effective control over the price of pyrites, forced British scientists to study the use of anhydrite for the manufacture of sulphuric acid (36). This material is a pure form of calcium sulphate with no water of crystallization, and occurs in many parts of England.

Basically, the process consists of heating together crushed anhydrite, sand, coke, and ash containing alumina. The reaction at high temperature evolves sulphur dioxide and a clinker suitable for the manufacture of cement. The sulphur dioxide is then converted to sulphuric acid by the well known contact process. Imperial Chemical Industries have just allocated $10,000,000 for the construction of a plant to produce 150,000 tons of sulphuric acid per year and a similar quantity of cement clinker (30).

This process provides a logical choice for British industry where cheap raw material, low transportation costs, and ready markets exist.

In Canada large deposits of anhydrite are found in Nova Scotia, New Brunswick, Manitoba, Alberta and British Columbia (8). Unfortunately, the mineral is usually associated with gypsum which is separated before it is used for sulphuric acid manufacture (8). The presence of water in gypsum reduces the quantity of acid produced per ton of raw material and makes it necessary to dry the sulphur dioxide evolved before its transformation to sulphur trioxide in the contact process.

Basically, however, the choice of anhydrite or gypsum is dependent on the economics of both processes. The use of either mineral requires a ready market for sulphuric acid and cement in Canada. These materials are used in different sections of the country, and so must be transported at low cost because of their relatively low value. The large-scale manufacture of cement by these processes would surfeit the Canadian market with sulphuric acid and the surplus would have to be disposed of in foreign markets. Further chemical and economic study is needed to evaluate this potential source of sulphur.

Conclusion

It is apparent, therefore, that there is no lack of potential sulphur supply in Canada. However, the need today is urgent since industry requires sulphur and is faced with a 15 to 25% reduction in supply. It is also indicated that the use of sulphur will increase in this country in the future.

It has been shown by Blair that large amounts of hydrocarbon distillates may be produced from Athabasca crude oil at a competitive price. The demand for oil is great, both here and abroad, and may exceed the readily available supply in the future. It is indicated, therefore, that the development program for the Alberta oil sands should be intensified for the recovery of industrial fuels and sulphur.

SUMMARY

1. The recovery of hydrocarbon distillates from Athabasca crude oil has been discussed, and it has been shown that the distillation of the crude in its unaltered state offers the only practical means of recovery.

2. The presence of sulphur in the distillates makes the products less desirable, and several methods of purification have been studied and evaluated.

3. It has been found that the only known practical sulphur-removal procedure involves the hydrogenation of the coker distillate at low pressures. The cost of this operation is high, but new cost data should soon be available when the Union Oil Company of California completes the construction of its oil hydrodesulphurization unit.

4. It has been found that the treatment of coker distillate with bauxite offers no solution at present to the sulphur-removal problem since the bauxite is incapable of removing the sulphur-containing

compounds in this boiling range from the distillate. The life of the bauxite catalyst is also reduced by the coke formation from olefinic compounds in the distillate.

5. The use of furfural and some organic nitriles has been suggested for liquid-liquid extraction procedures. It has been shown in industrial practice that these materials may extract aromatic compounds from other hydrocarbons. It is believed that extraction of the sulphur and aromatic compounds may be accomplished at low cost.

6. Distillation procedures involving the use of special solvents may be capable of withdrawing aromatic sulphur-containing compounds. This phase of the work should be tried in small-scale equipment to determine the possibilities for large-scale practice.

7. The sulphur shortage in the United States and Canada has been discussed and various remedies for it have been outlined.

8. The effect of this sulphur condition on Canadian industry has been shown and a forecast given.

9. There is no lack of potential economic sulphur supply in Canada provided the price of brimstone does not fall in the United States. Sulphur may be obtained in Canada from Athabasca crude oil, smelter gases, natural gas, pyrites, and the mineral anhydrite. It is believed that recovery from the pyrites, smelter gases, and Athabasca crude oil has the greatest potential value.

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PIPELINES FROM THE BITUMINOUS SANDS OF ALBERTA

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The Athabasca sands contain a lot of oil. Max Ball, formerly Director, Oil and Gas Division, U.S. Department of the Interior, stated in 1940 that the sands contained more oil than the combined reserves of all the oil fields of the world discovered up to that time. Furthermore, the immense deposit is located in an area remote from major markets, and is in a form which requires the most economical engineering design and operation to put its development on a paying basis.

All these conditions attract the pipeliner. He has a business peculiarly susceptible to wholesale operations. Every time the diameter of a pipeline is doubled, the steel required is substantially doubled, but about four times the flow at half the initial pressure is obtained and the product is delivered at about half the former over-all cost.

Transportation is an important part of the bituminous sand development—Blair (1) stated that it would amount to a third of the total cost of the product—and of the total cost, nine per cent would be required to transport even as far as Edmonton. As his estimates show only a possible five or six per cent for interest and profit, it can be seen how important a transportation study is to the project's success. Transportation beyond Edmonton is already established and available to the East by the Interprovincial Pipe Line, and a line from Edmonton west was the subject of intensive study this past summer by Canadian Bechtel Limited for the Trans Mountain Oil Pipe Line Company.

Therefore, curves and cost figures have been prepared to cover the movement from the McMurray area to Edmonton only. Map scaling shows this line to be 255 miles long, and a flowing viscosity of 400 seconds Saybolt Universal, or 86.6 Kinematic centistokes, has been assumed. This assumes some form of viscosity breaking to make the product sufficiently fluid for reasonable pipeline transportation.

Fig. 1 shows a general comparison between the optimum pipeline for any chosen production and normal railroad and truck rates. It can be seen that for any production above about 2,000 barrels per day, a pipeline can be built which will make a substantial saving over any other means of transportation. In fact, with production as high as 20,000 barrels per day, the best pipeline cost is only about one-fifth as great as its nearest competitor. Having determined that a pipeline is the most economical means of transport, the line size best adapted to our general plans must be chosen.

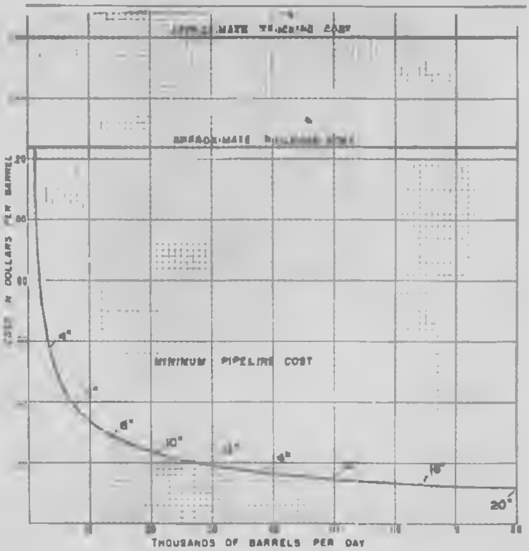

Fig. 1. *Transportation cost, Bitumount to Edmonton, September, 1951.*

For this purpose, Fig. 2 has been prepared showing the relative cost of different sized lines at different capacities. This chart shows the potentialities of the larger sizes, both in lower cost and in provision for expansion. It should be noted that while the minimum cost drops rapidly with the larger sizes, the curve also broadens and flattens out indicating a reasonable cost over a much wider range. Of course, these tendencies continue beyond the maximum size shown on this chart. The Trans Arabian line is already operating with 31-in. pipe, and Bechtel interests are now building a 32-in. line for Iraq Petroleum Company.

There is a unique opportunity and a special urge in the project under consideration to choose the very optimum in transport facilities. The raw material is unlimited, and so the decision as to size of project is subject to rigorous economic study. Note for example that 34 cents per barrel is the lowest possible transportation cost for a production of 10,000 barrels per day, but that if production were on a 25,000-barrel basis, the transport could be reduced to 20 cents. Fourteen cents per barrel could easily make the difference between a highly successful undertaking and a sadly losing one. Relatively, these costs can be depended upon for reasonable accuracy. Individually, they should be carefully checked before being incorporated in any final estimate. Prices on material, equipment, and wages are changing constantly. McMurray and Waterways have been visited and the intervening terrain flown over a number of times, but the on-the-ground survey which would be necessary for an accurate estimate has not been made by the writer. However, experience on the Canol Project which built and operated a line from the Mackenzie to the Yukon gives ample proof of the entire feasibility of such a line and is particularly reassuring regarding minimum pumping temperatures.

That line, which was small and all above ground, was operated throughout a northern winter with a flowing temperature which seldom went below zero, and averaged about 20°F. above, even in the cold winter months when air temperatures went as low as -49°F. The daily cycle was only a few degrees on this line, in spite of the fact that its only protection was the natural snow blanket.

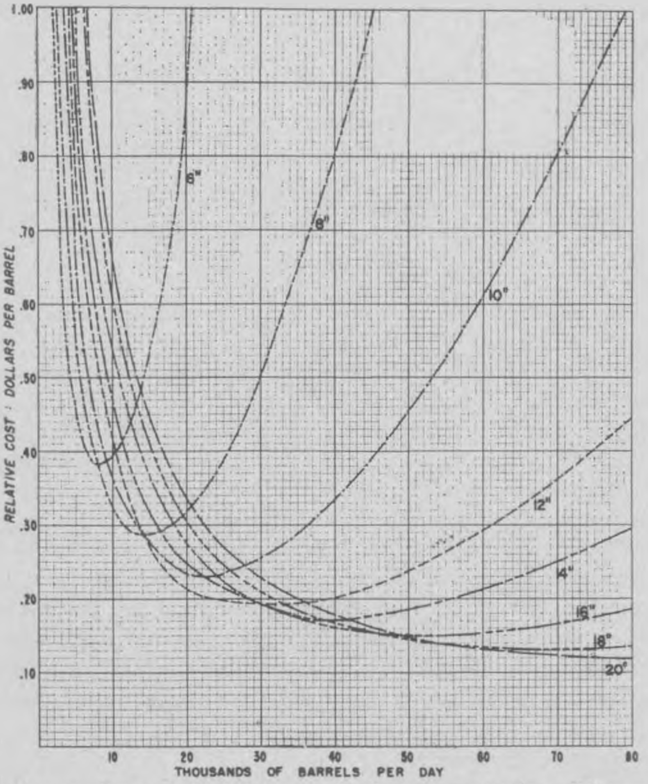

Fig. 2. *Approximate relative cost of oil transportation, Bitumount to Edmonton, by pipelines, September, 1951.*

If a line to Bitumount is buried, as most of it probably could be, the flowing conditions should be much better than those experienced on Canol, and successful year-round operation should be even more certain.

The object of presenting these curves and comments is to indicate the economic importance of careful pipeline selection and the very tangible savings which can be made by a large-scale operation. Similar savings will accrue in other parts of the work as the scale of the undertaking is increased. It is a project which, if it is to pay at all, requires "big thinking," and the bigger the thinking, the surer it is to pay and pay well. It is the kind of undertaking to challenge the ability and imagination of every engineer, constructor, and backer connected with it, but, if successfully accomplished, it should afford a corresponding measure of pride and satisfaction.

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DISCUSSION

Question: Was there an item included in these equations for the retirement of capital cost?

H. H. Hall: Yes. Fixed charges of 15% were used. However, a number of things were adjusted so no one equation can be given to show how the curves were obtained. There was a combination of equations and assumptions.

Question: Was the figure 400 seconds Saybolt used, in general, for the viscosity of the material?

H. H. Hall: Yes. Of course, it's perfectly obvious that the crude oil-sand oil would not be suitable for pipeline transportation. It was assumed that the processing would be of such a nature that the viscosity would be broken, or the oil would be diluted down to a transportable condition represented by a flowing viscosity of 400 seconds Saybolt. That is, the processing must produce an oil with a viscosity of 400 seconds at the temperature at which it must be transported.

Question: What consideration was given to the high sulfur content of the oil in the pipeline transportation?

H. H. Hall: Some very sour crudes are moved in pipelines. It is dangerous to some extent, and the tanks involved undergo some corrosion. However, Arabian crudes are fairly high in sulfur and no special provision so far as the pipeline is concerned has been made.

Question: Is the line insulated or buried?

H. H. Hall: From a practical standpoint, the reasonableness of a pipeline through this territory is assured. In the Canol Project, about 1700 miles of pipeline were laid all above ground, and crude was pumped throughout a winter through one of those pipelines quite successfully and with very little trouble. That line is a great deal farther north than this one would be, yet in spite of that the lowest temperature ever experienced at any one of the ten stations was -19°F. That was the lowest temperature recorded, and many of the stations did not get below zero even in a winter that involved temperatures of -50°F. Of course, the explanation is that the lines were covered with snow and never did get to air temperatures. This "oil sand" pipeline then appears to be thoroughly practical. There will be no physical obstacles that cannot be overcome. As to whether it should be buried or not, it should probably be put underground although the use of above-ground lines has proved practical for the Canol lines and for parts of the Trans Arabian line. Considering the construction and the high viscosity, an underground line would be preferred. Outside corrosion can be overcome by treating the line and putting on a cathodic protection. The combination of the two will take care of external corrosion.

CANADIAN TAXATION IN RELATION TO THE OIL AND GAS INDUSTRY *

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The following remarks are made in the light of the income tax acts which were in effect as of September 30, 1951, and it must be realized that such acts are subject to change from time to time by the responsible legislative bodies. It is not possible to give a complete resume of all pertinent tax acts here and still keep the remarks to a reasonable size. It must be stressed that any given set of circumstances may require special consideration between taxpayer and income tax officials in regard to incidence of tax, and this applies particularly to taxation relating to oil companies.

While there has been oil production in Canada for many years, it is only since 1947 that oil in Canada has become a major factor, and consequently it is only since that time that both tax officials and oil operators and their advisors have given really serious consideration to the incidence of taxation relating to oil operations. This has resulted in a number of tax changes since that time, and in the future there will no doubt be many more tax changes.

Income taxes are levied by the Canadian Government and the ten Provincial Governments, but not by cities, towns or municipalities. All Canadian provinces except Ontario and Quebec have a reciprocal agreement with the Canadian Government whereby provincial taxes are calculated on the taxable income computed for purposes of Canadian income tax, and the exigible taxes are paid to the Canadian Government. The present tax rate in these eight provinces is 5%; in Ontario and Quebec the rate is 7%. Provisions are made in all provincial income tax acts to avoid double taxation between provinces. The Canadian tax rate at present is 15% on the first $10,000 of taxable income and 38%, plus 20% defence surtax on the 38%, on taxable income in excess of $10,000. The 20% surtax on the 38% makes an effective rate of 45.6%.

If two or more corporations are related to each other in a taxation year, only one of them may take advantage of the 15% tax on the first $10,000 of taxable income; the related corporations may, each year, agree between them as to which one may claim the lower rate, but if they cannot agree the Minister may designate the corporation which shall benefit from the lower rate. One corporation shall be deemed to be related to another corporation in a taxation year if, at any time in the year (a) one of them owned 70% or more of all issued common shares of the capital stock of the other or (b) 70% or more of all the issued common shares of the capital stock of each of them is owned by one person, by two or more persons jointly or by persons not dealing with each other at arm's length, provid-

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* This paper was not read at the Conference.

ing such persons not dealing with each other at arm's length own shares in the capital stock of both corporations.

Consideration will now be given to expenses which are deductible or non-deductible for tax purposes, which relate particularly to the oil industry.

The cost of acquisition of oil or gas leases can not be charged as an expense for tax purposes nor can it be amortized in any way. There is no depletion allowance based on cost such as in the United States of America and if a lease is abandoned, any resulting loss is capital in nature.

Section 53 appended to the Income Tax Act permits drilling and exploration costs to be charged as expenses for tax purposes but only if the taxpayer's principal business is the production, refining or marketing of petroleum or petroleum products or the drilling for oil or natural gas. In the winter of 1950 the Western Canada Petroleum Association requested in a brief to the Canadian Government that this allowance be extended to all businesses to act as an incentive to release more capital for the development of oil, but the request was not granted and to date there is no indication that such a request will be granted. This section also refers to syndicates, associations and partnerships but does not refer to individuals. Consequently, as the act now stands an individual has no right to claim these expenses so in order to qualify for such expenses he should sell a small percentage of his interest and thus carry on as a partnership.

Exploration expenses include all general geological and geophysical expenses incurred directly or indirectly. Lease rentals up to one dollar per acre per annum are chargeable as expense. The tax department has taken the stand that any greater annual payments represent part of the cost of acquisition of a lease and that as such they represent capital expenditures. If it is necessary to pay, say, ten dollars per acre for a ten-year lease, care should be exercised to see that the agreement is properly worded to insure that, on interpretation, such payment may come within the wording of the Act in order to claim the payments as an expense for tax purposes. Surface rights, which are usually considerably more expensive than one dollar per acre per annum, are allowed as an expense.

These drilling and exploration expenses may be handled any way desired on the firm's own accounting records but for tax purposes they may only be claimed to the extent of the income in any year. This means that if such expenses have been incurred in excess of the income a taxable loss may not be filed. The Income Tax Act allows a business to claim a loss against the previous year's income, if any, and any such loss or part thereof not so absorbed may then be carried successively against future years' profits not exceeding five years. Hence, those in the oil business are really not permitted to take advantage of this provision in the Act unless a loss is incurred before charging off any drilling or exploration expenses. Since our depletion allowance is based on net profit after charging off drilling and exploration expenses this regulation acts to reduce the depletion which could otherwise be claimed. Depletion will be discussed hereunder.

The Act also states that drilling and exploration expenses which were not deductible in prior years may be taken in a future year. The word used in the Act is **deductible** not **deducted**, and consequently it is interpreted to mean that if any drilling or exploration expenses have not been used against available taxable income, they must be so absorbed or the right to claim them is lost. As pointed out earlier there is a relatively low rate of tax on the first $10,000 of taxable income. Most companies would probably be pleased to pay this tax and carry the drilling and exploration expenses forward, but that is now prohibited.

The next major point is that of depletion allowances. As stated above there is no such thing as cost depletion. Up to the end of 1948 depletion was based on net income, and net income was obtained only after deducting all exploration and drilling costs regardless of whether or not they were expended on wells, leases or reservations.

In 1949 the new Income Tax Act merely stated that expenditures reasonably attributable to the well were chargeable. In September 1951, however, the depletion regulations were amended by Order in Council and it is now specified that, effective for 1951, all exploration and development costs must be charged against income before any depletion is permitted. As a result, a company who ploughs its earnings back into exploring for new fields will receive little or no benefit from the depletion regulations as they now stand, whereas a company who finds one field and merely produces from that field or a company who buys proven oil properties only will be able to claim the depletion allowances.

The regulations set forth the rates of depletion as follows:

(1) Where the taxpayer operates an oil or gas well the deduction allowed for a taxation year is 33⅓% of the income for the year reasonably attributable to the production of oil or gas from the well and,

(2) Where a person other than the operator has an interest in the proceeds from the sale of the products of an oil or gas well or an interest in income from the operation of the well, the deduction allowed for a taxation year is 25% of the amount in respect of such interest included in computing his income for the year.

Special attention should be paid to the word "operates" in (1) above and to words "other than the operator" in (2). Where a property is owned jointly by more than one taxpayer an agreement is often drawn up purporting to have one taxpayer as the operator and any other interested party as non-operator. The choice of words in such an agreement could mean the difference in claiming depletion on a 33⅓% basis or on a 25% basis.

Depletion is allowed on dividends in varying percentages. If the company distributing dividends receives less than 25% of its income from oil or gas production, the shareholder is allowed no depletion; if 25% to 50% of such income is received by the company, 10% depletion is allowed the shareholder; if 50% to 75% of such income is received by the company, 15% depletion is allowed the shareholder; if over 75% of such income is received by the company, 20% depletion is allowed the shareholder.

Depletion of 25% is allowed on royalty income.

It should be noted here that some problems may arise in regard to depletion allowances for oil production in the oil sands. At the moment there do not appear to be any depletion regulations in the Income Tax Act covering such operations, since the Act refers to depletion based on "production of oil or gas from the well". There are also depletion regulations covering base and precious metal mines, industrial mineral mines and coal mines. If production from the oil sands is obtained from mining operations rather than from wells, the taxation department would have to change the wording in the regulations governing oil depletion or would have to classify such production as being from an industrial mineral mine, if the taxpayer is to receive any depletion allowance. Regulation 700 issued by the Income Tax Department under Order in Council contains a definition of "minerals" which states specifically that petroleum or natural gas are not minerals.

Depreciation is allowed to the extent of "such part of the capital cost to the taxpayer of property, or such amount in respect of the capital cost to the taxpayer of property, if any, as is allowed by regulation". All depreciation rates are applied on the net book value of any class of assets, i.e., the original cost less depreciation accumulated to date. Fifteen classes of assets have been defined and are synopsized as follows:

Class 1—4% on bridges, canals, culverts, dams, jettys, moles, roadways, railway track and grading that is not the property of a railroad system.

Class 2—4% on most electrical generating equipment; pipelines for oil, gas or water; generating and distributing equipment and plant of a producer or distributor of electrical energy; manufacturing and distributing equipment and plant of a producer or distributor of gas; distributing equipment and general plant of a distributor of water.

Class 3—5% on buildings or other structures, including component parts such as electric wiring, plumbing, sprinkler systems, air-conditioning and heating equipment, lighting fixtures, elevators and escalators; non-wooden breakwaters; docks; trestles; windmills and wharves (see Class 6 for higher rates on certain types of buildings).

Class 4—6% on telephone and telegraph systems; railway and tramway systems.

Class 5—10% on pulp and paper buildings and equipment.

Class 6—10% on frame, log, stucco on frame, galvanized or corrugated iron buildings including component parts listed in Class

3; wooden breakwaters; fences; greenhouses; oil or water storage tanks and railway tank cars.

Class 7—15% on boats, ships and related equipment.

Class 8—20% on all depreciable assets not enumerated elsewhere but specifically excepting animals, gas or oil wells, mines, radium, railway tracks, grading or crossing and timber limits.

Class 9—25% on some electrical generating equipment; radar equipment; radio transmission and receiving equipment.

Class 10—30% on automobiles; aeroplanes; tractors; trailers; trucks; wagons; buildings acquired for the purpose of gaining or producing income from a mine (except an office building not situated on the mine property and a refinery); contractors' moveable equipment (including portable camp buildings); gas or oil well equipment that is normally used above ground and mining machinery and equipment.

Class 11—The items originally under this Class have been transferred to Class 12, and for the time being this Class is inoperative.

Class 12—100% on chinaware, cutlery, glassware, linen, uniforms, tools costing less than $50, and jigs, dies, patterns, molds and lasts; a mine shaft sunk after the mine came into production.

Class 13—On property that is a leasehold interest, except an interest in a mine, oil or gas well or timber limit, an amount may be claimed not exceeding the least of:

(a) 20% of the capital cost,

(b) the capital cost apportioned equally over the unexpired term of the lease, or

(c) the balance of the undepreciated capital cost.

Class 14—On patents, franchises, concessions, licenses in respect of property but not in respect of mines, oil or gas wells (except a franchise for distributing gas to consumers) or timber limits or leasehold interest, an amount may be claimed not exceeding the lesser of:

(a) the capital cost apportioned equally over the unexpired life of the property, or

(b) the balance of the undepreciated capital cost.

Class 15—Applying to timber operations only.

There are three items of major importance to the oil industry which are not mentioned specifically in any of the above Classes. Casing may be written off to expense as used, but if any casing is salvaged such salvage must be included in income. Drill pipe may be handled in one of two ways. A basic amount of drill pipe may be included in the cost of the drilling rig and depreciated as part of that rig, in which case additional purchases of drill pipe will be charged off to expense; the other method is to inventory the drill pipe at the end of each fiscal period so that all pipe is charged to expense when consumed and by this method no depreciation rate is involved. Tubing is a depreciable item and is subject to a rate of 30%.

The above rates are maximum and a taxpayer may claim a lesser amount should he so desire. A corporation, however, may not claim for tax purposes an amount of depreciation greater than the amount charged off in the current and previous taxation years either through income or surplus account. If a taxation year is less than twelve months only a proportion based on a per diem basis on 365 days to a year will be allowed.

If a lease contains a renewal privilege, the period of the lease unexpired at the time costs were incurred shall include the next succeeding term for which it may be renewed. Land is not a depreciable item.

When depreciable property is disposed of the proceeds of disposition are credited to the undepreciated capital cost on the books for that class except for the excess of the sale price over the original capital cost, if any, which excess would be a capital profit and not subject to tax. If such application of the proceeds of disposition creates a credit balance in any class, such amount shall then be included in taxable income. If an entire class of assets is disposed of but an undepreciated balance still remains after applying the proceeds of disposition, such balance may be written off to expense in that year. Proceeds of disposition include sale price, compensation received for damage, etc., and amounts received from insurance.

In his budget resolutions of 10th April, 1951, the Minister stated that the right to claim depreciation on assets purchased after 10th April, 1951, and covered by Classes 3, 5, 6, 7, 8, 13 and 15 will be deferred to the fourth subsequent taxation year, such deferment not to cover residential property, property used in the business of farming, fishing or professional service, property acquired to replace a property that was destroyed by fire, flood, wind, lightning or other act of God, or property in respect of which the Minister of Trade and Commerce has issued a certificate of eligibility. The Minister of Trade and Commerce may issue a certificate of eligibility in respect of property acquired for the fulfilment of a defence contract or subcontract, for a purpose which contributes to the defence of Canada or for business in the primary industries (e.g., mining, oil, logging, etc.), in transportation and transmission business, in shipbuilding, etc., but not covering hotel property or a property primarily for the purpose of office use, commercial or financial services, wholesale or retail trade or renting for other than residential habitation. Note that no depreciation is actually lost to the taxpayer; it is merely deferred.

There are a few types of expenses which are not deductible from taxable income in Canada. All expenses of incorporation, reorganization or changes in capital structure are treated as capital expense; similarly all expenses relating to bond issues or premiums paid on retirement of funded debt are capital expenses; if a bond issue is sold in excess of par, that excess represents a non-taxable profit. Entertainment expenses as such are disallowed but bona fide sales promotion expenses are allowed. Life insurance premiums on the lives of officials of a company are a non-taxable expense and any proceeds received from the insurance company are also non-taxable. Donations are allowed up to 5% of taxable income in the case of corporations and up to 10% for individuals; if a taxable loss is sustained in any year, all donations are disallowed as expense. Legal fees covering the establishment or protection of franchises are not allowed nor are legal fees incurred covering the acquisition of any capital asset. Income tax paid to a province is not allowed for Dominion tax purposes and vice versa. There is a protective section in the Act to the effect that any outlay or expense must be reasonable; this is directed at excessive salaries, bonuses, travelling expenses, etc.

The last matter to be touched on is that of non-resident taxation. Canada has conventions with the United Kingdom and the United States of America for the avoidance of double taxation. The provisions of these treaties are both lengthy and complex so that mention will merely be made of the fact of their existence and no details will be discussed here.

If a foreign company commences business operations in Canada it may do so in one of three ways. First, it may incorporate a Canadian subsidiary company in which case the subsidiary's income is subject to the regular corporation tax rates and dividends paid to the parent company must have a 5% tax deducted at source. If the subsidiary is not wholly owned the tax is 15%. Second, a foreign subsidiary could be formed whose entire operations are carried on in Canada. Here again the taxable income is subject to regular corporation tax rates but there is no withholding tax on dividends. Third, a branch of the foreign company could be opened in Canada. In this case separate records must be maintained covering the Canadian branch operations and taxable income is subject to regular corporation tax rates. Canadian tax authorities watch closely to see that merchandise and other expenses are not charged at inflated prices and if any evidence of this is found they will apply certain Articles of the above-mentioned Conventions.

Any payments made by a resident in Canada to a non-resident which are in the nature of rents, dividends, interest, royalties, etc., are subjected to a 15% withholding tax. Directors' fees and management fees are not subjected to this tax, but they must be reasonable in size considering the benefits received by the Canadian operation.

A person becomes a resident for Canadian tax purposes if he resides in Canada more than 183 days in a calendar year. A resident must declare all his income from whatever source he receives it, and after computing such tax he may claim a reduction based on the length of time spent outside Canada during said year and on the amount of tax paid to the foreign government. If a person is resident less than 183 days he pays tax only on the income received while in Canada. However, if he has earned a salary of less than $5,000.00 and has resided in Canada less than 183 days he need pay no tax.

CLOSING REMARKS

By S. M. Blair

By way of a conclusion for the technical sessions, a backward look over the ground that has been covered will be taken. The Hon. N. E. Tanner, in his dinner address and in his further remarks here this morning, has given a clear presentation of government policy about leasing regulations, royalties and general control. The discussions about mining have clarified thinking about that problem and a basic figure for mining costs has been arrived at. Suggestions for ways of reducing this figure have been made. The costing of the intermediate step of separation has been done by using cost data obtained from the Bitumount plant and expanding it to the required scale. The resulting figure is a reasonable one for present purposes but is probably high because of the assumption that the large-scale plant would consist of a battery of 17 units. An actual plant would hardly be designed that way. The cost of producing coker distillate by the fluidized solids technique has been arrived at through analogy with catalytic cracking plants and the known cost data for them. The cost for sulphur removal by mild hydrogenation that is given in the Blair report has been checked at this conference by the figures given by Dr. Berg of the Union Oil Company of California. The two costs from independent sources are in close agreement. It may be noted that both cost figures are for fairly small plants. It is probable that costs for really large plants would be considerably less. The final cost item for transportation of oil from the Athabasca River area to Edmonton is the one, as given in the Blair report, that is misleading. It was calculated for an eight-inch pipeline. The general trend of discussion at the conference has been toward favoring oil-sand development on a much larger scale than the 20,000 barrel per day scale used as the basis for estimates in the Blair report. If the scale of development is increased, a larger diameter pipeline would be required. Mr. Hall showed in his discussion of pipeline transportation costs that doubling the pipe diameter cuts the transportation cost in half. Thus the cost for an eight-inch line that would handle a production of 20,000 barrels per day would come down by a third or a half depending on the increase in the scale of development.

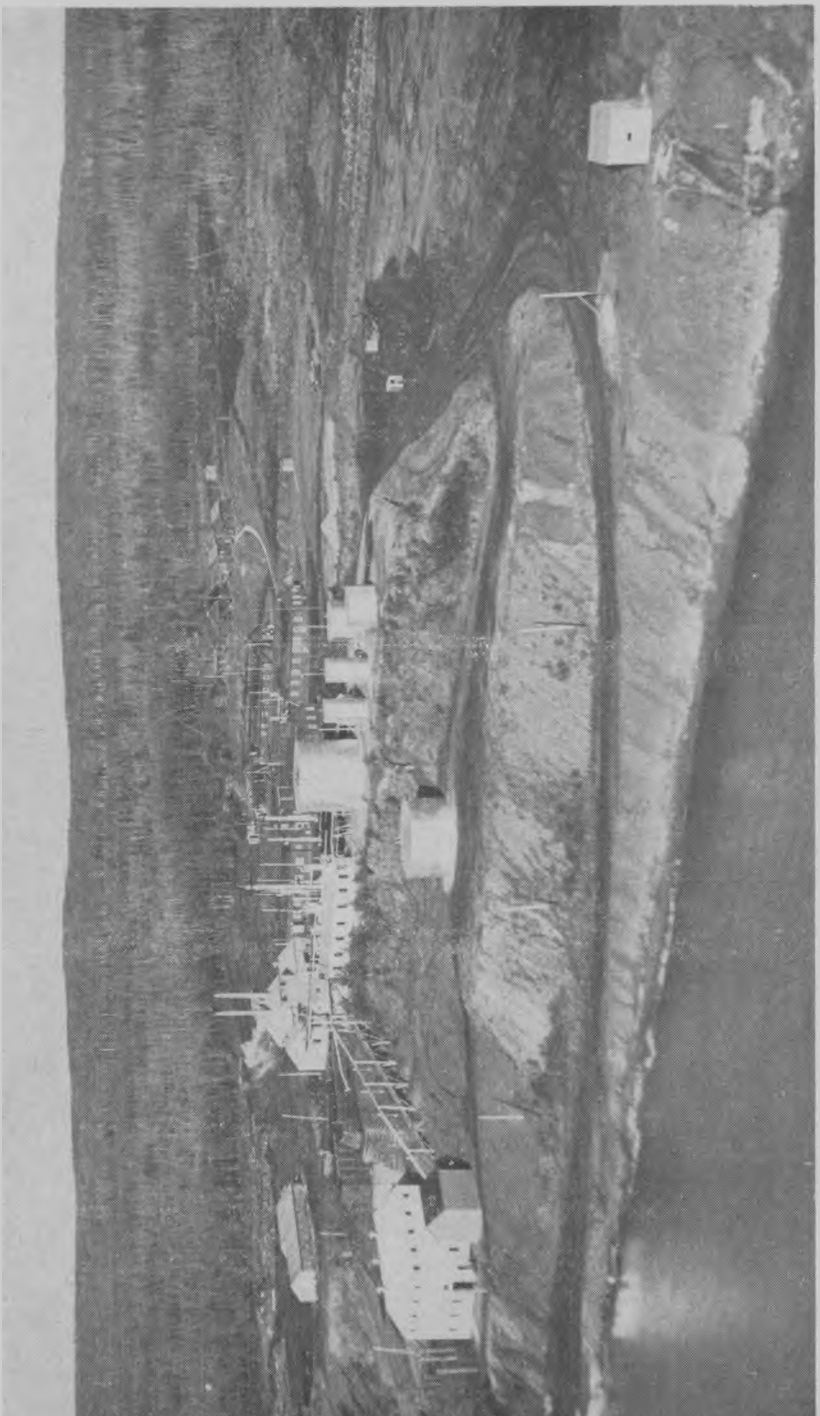
Some comments on the evaluation of the desulphurized coker distillate that is given in the Blair report should be made. The value of an oil is not the same to everyone. It depends on how the oil fits into one's particular scheme of things, what one's marketing conditions are and on other factors. Two oil companies, each making a thoroughly sound evaluation of an oil, will arrive at somewhat different answers because of the difference in their viewpoints. Thus, the delegates to this conference will make different evaluations for the oil-sand desulphurized coker distillate. It can be suggested, however, that a surprising number of oil evaluators seem not to appreciate the fact that gas oils during the past 15 to 20 years have sold at a higher price than the crude oils from which they were obtained. This relationship was confirmed by statistical study of price figures extending over 17 years by one of the major oil companies and was expressed in striking graphical form in the Blair report. The desulphurized coker distillate is a gas oil carrying an appreciable percentage of fractions of premium value such as jet fuel as indicated by Dr. Berg. The value of jet fuel as a refinery product probably depends on the location of the refinery. In any case the coker distillate contains gasoline, and the remainder can be evaluated on the basis of No. 2 furnace oil, diesel oil or catalytic cracking stock. The opinion has been expressed in various quarters that the evaluation that has been made for the desulphurized coker distillate is too low. However, it is considered to be somewhere near the mark on the conservative side.

The sulphur that must be removed from the coker distillate is worth something but it is hard to say just how much. The difficulty is in determining just how much of a sulphur market would be available. There might be a large enough market for development on the 20,000 barrel per day scale but not enough if the scale was stepped up to 50,000 barrels per day. Consequently no credit for sulphur has been included in the evaluations so far made.

The technical sessions of the conference have reached their end. The program has been tightly packed but it has proceeded well thanks to the courtesy and co-operation of everyone. It is trusted that the remaining conference activities, in particular the flights into the North to visit the oil-sand area at McMurray and Bitumount, will be as successful.

GUIDE TO THE ALBERTA OIL-SAND AREA ALONG THE ATHABASCA RIVER BETWEEN McMURRAY AND BITUMOUNT AND TO THE OIL-SAND SEPARATION PLANT OF THE GOVERNMENT OF ALBERTA AT BITUMOUNT.

BY K. A. CLARK

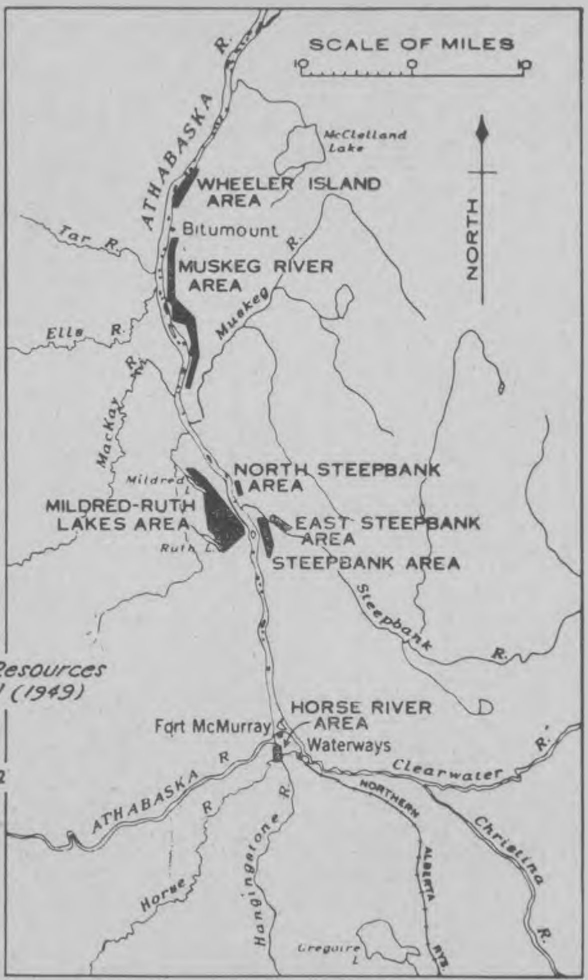


The Government of Alberta Pilot Plant at Bitumount

FIGURE I - 2

Dept. of Mines & Resources
Pub. No 825 Vol I (1949)

Key Map Showing Relation of Fort McMurray to Edmonton, Alberta



Key Map Showing Areas Explored by Drilling since 1943

VISIT TO McMURRAY AND BITUMOUNT*

The purpose of this booklet is to assist visitors in acquainting themselves with the country in which the Alberta oil sands occur, with the oil-sand formation and with the development work that has been done at the plant of the Province of Alberta at Bitumount. The journey north is best made by plane. During the flight to McMurray airport, the gradual change in the nature of the country from farmland around Edmonton to muskeg and sand ridges north of Lac la Biche can be noted. The town of McMurray is 12 miles by road from the airport. It is at the junction of the Clearwater River with the Athabasca River. There is a high cutbank of oil sand lying on Devonian limestone along the Athabasca River at McMurray. Other exposures can be seen in the valley of Horse River nearby. The site of the Abasand Oils Ltd. plant is in Horse River valley a mile by trail or several miles by road from McMurray. Oil-sand exposures occur all along the Athabasca River. These can be seen on the flight between McMurray and Bitumount. The limestone close to the water level of the river is a noticeable feature of the Athabasca valley. At Bitumount good grade oil sand is exposed to view in the quarry. The separation plant can be examined in detail. The dehydration and distillation equipment, although not conforming to the sequence of operations proposed in the Blair report, is of interest.

EDMONTON TO McMURRAY AIRPORT

The country lying between Edmonton and McMurray is of interest in its own right and also because the pipeline for a bituminous sand development would pass through it. In the vicinity of Edmonton the scene is one of well developed farmland. The Redwater oil field lies about 30 miles to the northeast. Proceeding northward, the farms thin out. The reason, it will be seen, is that muskeg is occupying more and more of the surface. Farmers set fire to the muskeg and when all that will burn is consumed, they plow the remainder into the underlying clay. They extend their fields in this way. However, muskeg becomes more and more prevalent northward and farming ceases in the neighborhood of Lac la Biche. Further north the country is a wilderness of muskegs and sand ridges. It is much more interesting to fly over than to walk through.

The oil-sand formation extends southward from McMurray but how far is not yet known. The Geological Survey well (1898) at Pelican Rapids and a recent exploratory well about 75 miles south of McMurray encountered the formation at about 900 feet depth. Wells 75 miles west of Pelican Rapids also passed through oil sand at about 2,000 feet depth. Oil-sand exposures appear east of McMurray on the Clearwater River. But at Cottonwood Creek, 25 miles upstream, the sand is found to be devoid of oil. Apparently oil impregnation of the formation does not extend far east of the Athabasca River. It is interesting to ponder, as one flies toward McMurray,

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*This formed a portion of a guide booklet which all delegates received on arrival.

that the country as far as the eye can reach is underlain by the extensive oil-sand deposit.

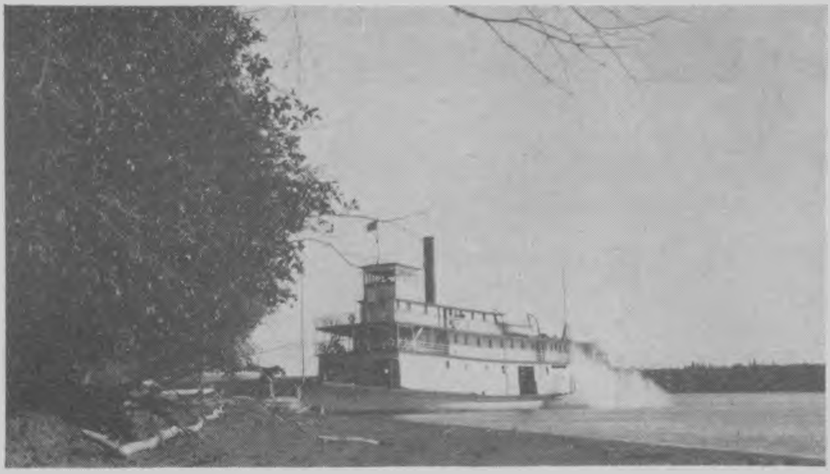
McMURRAY

The town of McMurray grew around the trading post of the Hudson's Bay Company—Fort McMurray. The post was on the river bank at the foot of the main street of the town. The buildings have disappeared. The post was established in 1870 in anticipation of the use of steamboats by the company for river transportation. There are rapids on the Athabasca River above McMurray, but navigation is uninterrupted downstream to the boundary of the province. The first of the steamboats, shallow draft stern wheelers, was built in 1882 at Athabasca Landing on the Athabasca River about 100 miles north of Edmonton, and was brought through the rapids for service on the river north of McMurray. The original canoe route of the fur trade into the Athabasca and Mackenzie region was across Methy Portage from the headwaters of the Churchill River to the Clearwater River. Fort McMurray was an important point on this route during the latter years of its use. The oxen for hauling carts across the 12-mile portage were wintered on the "prairie" — a natural meadow area between McMurray and Waterways. The building of the Canadian Pacific Railway, which reached Edmonton in 1891, made the Methy Portage route and method of transportation obsolete. The trade route then was from Edmonton to Athabasca Landing by road, down the Athabasca River by steamer to the head of the rapids, and through the rapids by barges to McMurray. The town of McMurray had its beginnings at about this time. Pilots for taking the small barges through the rapids landed at McMurray and walked back by trail for another trip. This activity ceased with the completion of the railway to Waterways in about 1922. The steamboats were a picturesque feature of the river up to the outbreak of the last war. They burned cordwood, cut and piled at convenient

Water Front at Waterways

intervals on the river bank by trappers. Diesel-powered boats displaced the steamers. The last of them, the S.S. Athabasca, was kept in service during World War II and then dismantled.

McMurray was an important base for pontoon planes around 1930 when prospecting of the north country by means of them was in its beginnings. Planes are still in evidence on the "sny." However, during the war, airports for wheel planes were established throughout the north. The McMurray airport was built at this time.



S.S. Athabasca

McMurray had a place in the war effort. Great quantities of materials and equipment for the Canol pipeline were shipped to Waterways. The "prairie" was filled with barracks for American work troops and with supplies of all kinds. A tent for military police stood at the corner near the hotel in McMurray. White and black soldiers alternated in spending off-duty time in town.

The old fur trade of the Hudson's Bay Company still goes on throughout the North. Wartime projects belong to the past. The main activity now is mining—uranium on Great Bear Lake, gold at Yellowknife on Great Slave Lake, and more uranium at the east end of Lake Athabasca. The time is approaching when an oil-sand industry along the Athabasca River will become a major item in the development of the north country.

OIL SANDS AT McMURRAY

The oil-sand area of immediate significance from the standpoint of development lies along the Athabasca River for about 70 miles north of McMurray. The formation here outcrops in the banks of the main and tributary rivers and lies under a mantle of sand and clay varying from a few feet to 150 in thickness. It is of Lower Cretaceous age and lies unconformably on a floor of Upper Devonian limestone. The oil sands are 150 to 175 feet thick.

An imposing cutbank of oil sand and of the underlying limestone occurs along the Athabasca River starting just upstream from the site of the old fort at McMurray and continuing for a quarter of a mile to the mouth of Horse River. The exposure shows off well the thickness of the formation. Much of the section consists of beds of poor grade material.

Oil-Sand and Cutbanks on Athabasca River with Limestone Showing Just Above Water Level

There are other cutbanks along Horse River. There was once a large lens of high-grade oil sand here. It was about 75 feet thick lying on the limestone. Most of this lens was eroded away during the formation of Horse River valley. The remnant underlies the valley flats. The Abasand Oils Ltd. quarry and plant was in Horse River valley about a mile from the mouth. The plant has been dismantled.

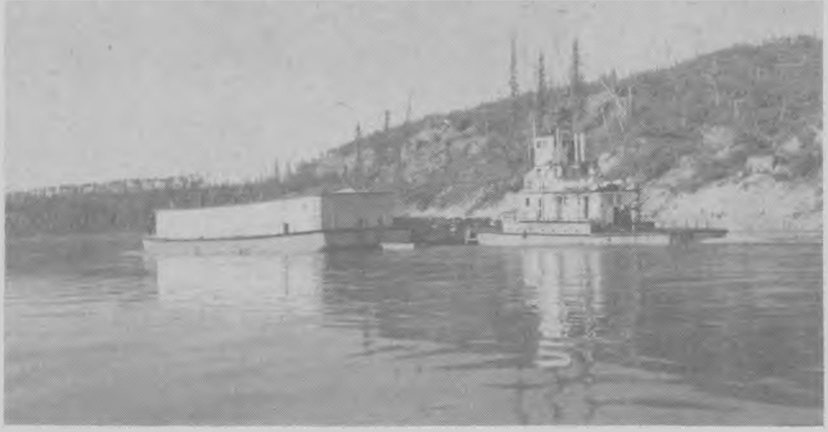
THE ATHABASCA RIVER

Rapids can be seen on the Athabasca River at the bend upstream from McMurray. This is the last of a series of rapids extending for about 85 miles. Below McMurray the river has a current of about three miles per hour. Conditions are favorable for sandbar formation and the river is full of them. The deep channel follows a tortuous course that makes changes along its way from time to time. There is navigation by power boat and barges from McMurray northward to Lake Athabasca and beyond to the boundary of the province near Fort Fitzgerald. Navigation is interrupted at Fort Fitzgerald by rapids. A sixteen-mile road must be used to reach navigable river again at Fort Smith. There are no further interruptions to navigation right through to the Arctic Ocean.

The top of the Devonian limestone is well above river level at McMurray. It continues in view for more than 40 miles beyond Fort MacKay. It is higher above river level at some places than at others.

Close-Up of an Oil-Sand Cutbank

The oil sand with the limestone below can be seen frequently. Low limestone cliffs along river flats contribute a picturesque touch to the scenery along the river. Below MacKay the limestone disappears from view. At Bitumount it is 100 feet or more below river level. It reappears on the west shore about five miles below Bitumount.



Diesel-Powered Boat and Freight Barges

At McMurray the banks of the river valley rise quite abruptly. High oil-sand cutbanks occur. Going downstream, the valley broadens and the rise to the general country level becomes more gradual.

The first sizable tributary entering the Athabasca from the east is Steepbank River. Its mouth is about 20 miles below McMurray. Core drilling has revealed several bodies of high-grade oil sand near

Limestone Exposures Along the Athabasca River

Steepbank River that occur in a way that is favorable for mining. The Mildred-Ruth Lakes area lies on the west side of the river. This is the most favorable area for development so far found by coring. However, only a good start has been made on exploratory drilling.

Devonian Limestone

BITUMOUNT

The Quarry

The river bank at Bitumount rises about 65 feet above water level. This bank is oil sand of good grade. There is evidence that the top of the bank is at the top of the oil-sand formation and that the formation goes below river level for over a hundred feet to the limestone floor. No core drilling has been done in the vicinity of Bitumount. At the top of the bank the overburden of sandy soil, shell rock and weathered oil-sand beds is only about 8 feet deep. This condition extends back for several hundred feet. The ground level then rises due to thickening overburden. The quarry was opened in the easy overburden conditions along the top of the bank. The top beds mined contained about 11% oil by weight. The oil content increased to 15% at lower levels.

The showing of oil on the stripped surface of the quarry area is interesting. It is due to ground water working through the top beds displacing oil. Seepage oil is found at many points throughout the oil-sand area. It is always associated with water emerging from oil-sand beds.

The oil sand was dug directly from the face of the quarry by a ¾-yard power shovel. This was done during the spring and summer months, and digging was confined to the zone of material affected by the warm weather. The shovelman developed a face about 10 feet high. When asked why he did not go deeper, he said that the oil-sand was frozen further down. Actually, the temperature obtained by lowering a thermometer into a three-foot auger hole bored from

Oil-Sand Quarry at Bitumount

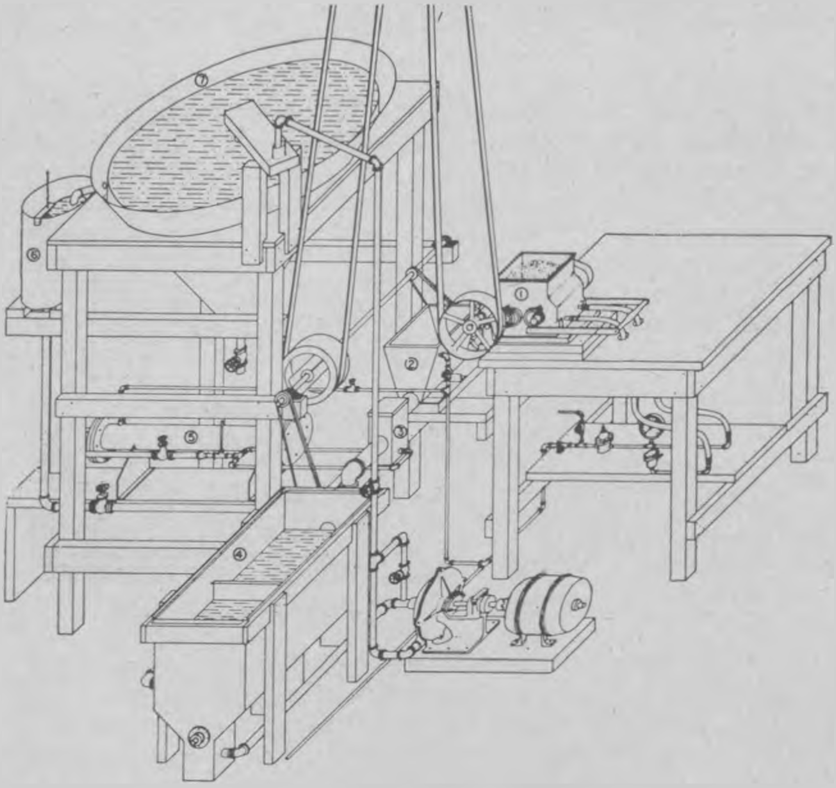
the shovelman's "frozen" floor was 42°F. A temperature measurement in a diamond drill hole in the Mildred-Ruth Lakes area at 200 feet depth was 36°F. The oil sand is an unconsolidated sand aggregate cemented with a viscous oil. The viscosity of the oil increases rapidly with decreasing temperature and, conversely, becomes much more fluid and a weaker cementing agent as the temperature rises. Consequently, a small power shovel is able to dig the oil sand at Bitumount directly from the beds quite readily when the temperature of the sand is above, say 45°F. At the Abasand plant near McMurray, even

Excavating Oil Sand

in summertime, a shovel would not dig effectively without first shattering the oil-sand beds by light blasting. This is because the oil sand becomes progressively more viscous going southward from Bitumount along the Athabasca River. In large-scale mining at any location the surface layer of material affected by either warm summer or cold winter weather would have little significance. Mining in all seasons would be concerned with oil-sand beds at about 40°F. This thought should be kept in mind when examining the Bitumount quarry. Impressions gained from the appearance and feel of warmed surface material can be misleading.

Separation Plant

The Alberta oil sands are very amenable to washing with hot water for recovery of their oil content. The operation is a simple one. The oil sand is mixed and heated with water to a pulp containing 12 to 15% water. This pulp is then flooded in excess hot water. The oil separates from the sand and floats to the surface as a buoyant froth. The sand sinks. Fine mineral matter and some oil in fine fleck form become suspended in the plant water. The oil froth is skimmed from the surface of the plant water; sand tailings are removed by suitable mechanical means; and the load of sediment



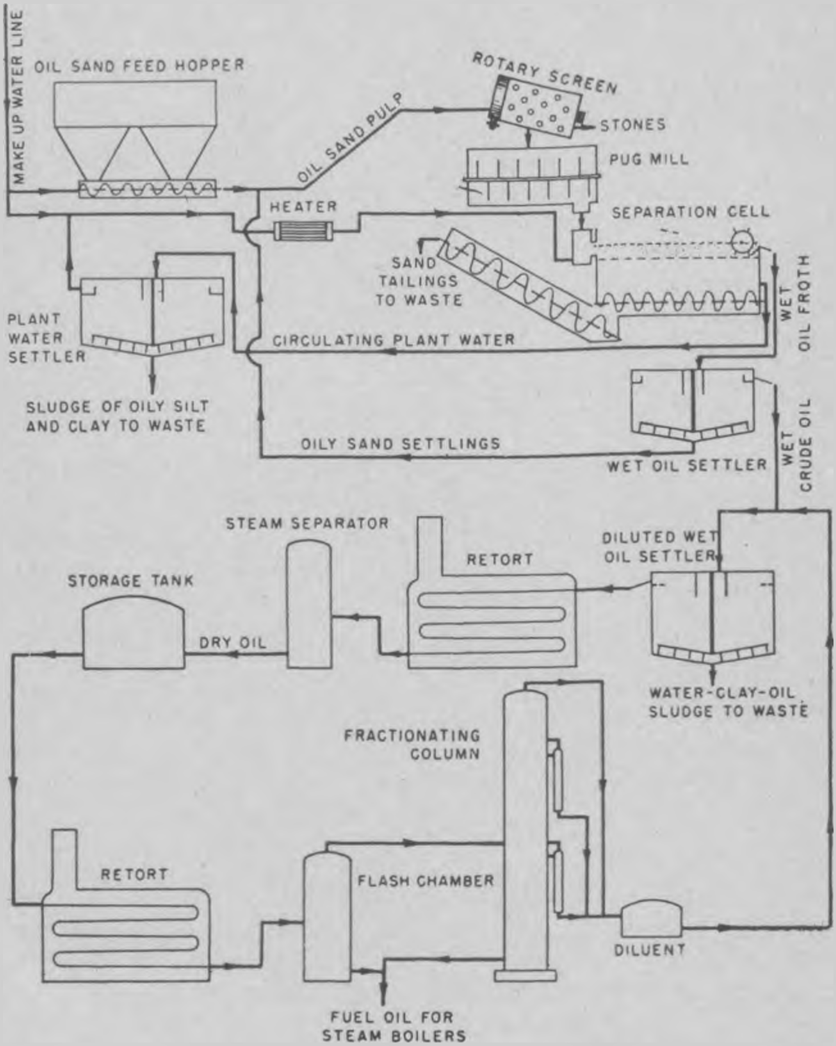
Isometric Drawing of Laboratory Hot Water Separation Plant at Edmonton in the plant water is kept within bounds by some form of settling. The hot plant water is circulated with addition of make-up to replace water going out with the tailings.

Oil sand was brought from the quarry in trucks that dumped their loads onto a grating with six-inch openings covering the top of the storage hopper. The material as excavated contained lumps of oil sand. The lumps lay on the grating until they collapsed of their own weight, sometimes with a little help. As the weather became cooler in the autumn, lumps became more prominent in the oil sand coming to the storage hopper and they did not disintegrate and fall through the grating without a great deal of help. It seemed obvious that for winter operation a suitable crushing plant would be required. Very little stony material occurred in the Bitumount quarry.

The storage hopper at the head of the plant is interesting. The feeding of a material like oil sand from a hopper looks like a difficult problem but the hopper works well. Its action centres on the perforated steam pipes just above the discharge openings of the hopper into the screw conveyors below. When steam is shut off, the oil sand bridges and the downward movement of sand ceases. On application of steam pressure, the bridging is kept broken and oil sand moves downward steadily as the conveyor carries it away. The steam also heats the oil sand. In fact, this is the way to get the pulp up to the desired temperature of about 175 to 185°F. The steam-jacketed conveyors and pug mill do little more than maintain the temperature. The storage hopper works. But further study of the factors at work is needed for intelligent design of hoppers of large throughput.

Storage Hopper at Head of Separation Plant

The various parts of the separation plant are of simple design. The flow-sheet should make them easily understood. Attention may be drawn to what is termed the "sand distributor." It is here that the effective separation of oil from sand takes place. The circulating plant water enters the distributor in a manner that causes turbulence but only slight entrainment of air. The oil-sand pulp drops from the pug mill into the turbulent water stream and is completely disintegrated. The oil forms a froth with water vapor supplemented by enough air to raise the pressure to that of the atmosphere. Sand and froth are swept into the large body of water in the separation cell where they sink and float, respectively.



Flow-Sheet of Oil-Sand Pilot Plant at Bitumount

The continuous settling tank into which the oil froth flowed from the separation cell was provided to settle sand from the oil in case it proved to be sandy. If the plant followed laboratory performance there would not be much sand. On the other hand, all former separation plants in the North had produced very sandy oil froths. Actually the mineral content of the oil froth ranged between 4 and 8% and most of this was silt and clay. Hence the settling tank was functionless. It would not have functioned in any case since there was not a sufficient drop in temperature to cause the froth to collapse. Sand does not settle out of an oil froth readily.

The separation plant gave better results than were obtained in laboratory work. The sand content of the froth was low as has been mentioned. The recovery of oil was 90%. In laboratory work recoveries were around 80%. The reason for the better recovery in the plant was that freshly mined oil sand was being worked with. Oil sand deteriorates, from the standpoint of separation, when kept in storage.

The 10% of oil that was not recovered became dispersed as very small flecks in the plant water. It settled together with fine mineral matter in the plant-water settler. Half of it could be recovered by passing the underflow from this settler through a conventional mineral flotation cell.

An interesting and practical point is that the fine mineral matter carried by the plant water coagulates. Consequently, it settles readily.

The separation plant at Bitumount is of simple design. But it could be simplified still further. The inclined screw conveyor for removing sand tailings from the separation cell was a cumbersome arrangement. It was used because all former plants had inclined screws and the designers were reluctant to depart from precedent. Work at the Research Council of Alberta indicates that the separation cell could be of circular construction with oil froth overflowing a lip as in a Dorr thickener and with sand tailings flowing from a bottom cone discharge at 70% solids by weight into the suction pipe of a sand pump. This pipe would also conduct a raw water flow that would be controlled by variations in the sand level in the separation cell. Sand tailings would be discharged to waste at about 40% solids by weight. A rake in the separation cell would bring the sand over the central discharge and would provide means for an automatic sand-level control. A control for the water - oil froth interface would be needed also. The load of sediment in the plant water could probably be kept sufficiently low by use of a hydrocyclone. Within wide limits, dirty plant water has little effect on the performance of the process.

Dehydration of Wet Separated Oil

The dehydration and refinery units at Bitumount have little significance. The operations they performed are not included in the sequence of operations proposed in the Blair report. However, they are of some interest.

The Bitumount plant was built to demonstrate the practicability of the hot water separation process for recovering oil from the oil sand. The processing of the oil was not under study. However, the elimination of water and coarse mineral matter from the wet oil product of the separation process had to be accomplished for two reasons. In the first place, the hot water process was of no use if its oil product could not be got into usable form for refining. In the second place, fuel oil for the power plant had to be obtained to keep the separation plant running.

At the time the Bitumount plant was designed, the only sure method available for eliminating the high content of water from the wet separated oil was the one that had been used at the Abasand plant. This consisted of mixing the wet oil with a distillate to reduce both the gravity and the viscosity and then to settle the diluted crude. Water and mineral matter settled out to a degree that was dependent on the extent of the dilution and the length of the settling period. At the Bitumount plant the wet oil was pumped from the separation plant, up the hill to the refinery area. Here it was mixed with hot distillate amounting to about 50% by volume of the actual oil in the wet crude. The diluted crude was passed through a continuous settler. Considerable mineral matter and water settled out but the overflow from the settler still contained about 15% water. The overflow was pumped through a heater in which the water present was converted to steam. The resulting oil-steam foam was passed into a steam separator. The oil which was obtained in this way contained about 0.2% water.

This method of eliminating water was not regarded as a good one but it was, as has been said, the only method known at the time. The addition of distillate, that had to be recovered by distillation, to the crude oil was not desirable. Also, stubborn emulsions formed in the continuous settler and went out with the underflow. A serious loss of oil resulted. However, the method served its purpose of cleaning up the wet separated oil so that fuel oil could be prepared from it.

The pressure settling vessel shown in the flow-sheet was an idea of the designers. Such vessels are used in certain refineries to eliminate water from crude and it was thought that it might work at Bitumount. Laboratory work at the Research Council of Alberta indicated that the scheme was not applicable to wet oil-sand oil. It worked no better at the plant than in the laboratory.

Refinery

The refinery was of the simplest sort. The dry diluted crude oil was heated to 825°F. and passed into a flash chamber. The vapors from this chamber passed into a fractionating column. All distillates collected from the column were combined and used for diluting the wet crude oil. The combined bottoms from the flash chamber and column were used as fuel. There was some difficulty in establishing conditions in the refinery that would result in recovery of all the distillate added to the crude along with enough new distillate to cause the supply to build up and yet have a bottoms product that was not too heavy to handle in the piping and pumping system provided. The difficulty was met, at least for summer operation conditions. Only a small part of the bottoms were needed for fuel. The balance went to storage. There is plenty of it on hand to start up the plant again.

In the Blair report it is proposed to feed the wet crude oil from the separation plant directly to a fluidized solids continuous retort. The products would be a fluid coker distillate, gas and coke. The coke would be consumed in the burner of the retort. The gas would be utilized as fuel. The coker distillate, after desulphurization by mild hydrogenation, would be the final product for marketing.

Discharging Sand Tailings to Waste

DATA

TRANSPORTATION

The Northern Alberta Railway connects Edmonton with Waterways on the Clearwater River. Waterways is 305 miles by rail from Edmonton and about three miles by road from McMurray. The railway service to Waterways is one passenger and freight train per week with two extra freight trains during the summer months.

The Northern Transportation Company takes freight from Waterways down the Athabasca River by diesel boats and barges during the season of navigation. Navigation starts about the first of May and ends during October.

The Canadian Pacific Airlines operates a daily (except Sundays) plane service from Edmonton to McMurray and on to Yellowknife and return. It also operates a weekly pontoon plane service from McMurray to points on the Athabasca River and Lake Athabasca.

SUMMARY OF TEMPERATURES, PRECIPITATION AND SNOWFALL

Month	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Year
McMurray — 30-year Averages													
Avg. daily max., °F.	1	15	28	49	64	71	76	72	61	46	24	6	43
Avg. daily min., °F.	—20	—13	— 2	21	34	42	47	44	35	25	6	—13	17
Avg. daily mean, °F.	— 9	1	13	35	49	56	61	58	48	36	15	— 4	30
Avg. precipitation, in.	1.1	0.6	1.0	0.8	1.5	2.1	3.3	2.2	2.0	1.1	1.0	1.0	17.7
Avg. snow-fall, in.	10.6	6.0	9.6	3.4	1.1	—	—	—	0.3	3.7	9.2	9.8	53.7
Embarass* — 7-year Averages													
Avg. daily max., °F.	2	6	14	42	59	71	76	71	59	47	20	7	39
Avg. daily min., °F.	—17	—17	— 4	17	36	46	51	47	40	30	6	—11	19
Avg. daily mean, °F.	— 9	— 2	12	31	47	56	62	59	49	38	15	2	30
Avg. precipitation, in.	0.9	0.7	0.8	1.2	1.4	1.3	1.9	2.7	2.4	1.2	1.1	0.9	16.5
Avg. snow-fall, in.	9.4	7.0	9.5	5.5	1.3	—	—	—	1.1	5.2	10.0	9.4	58.4

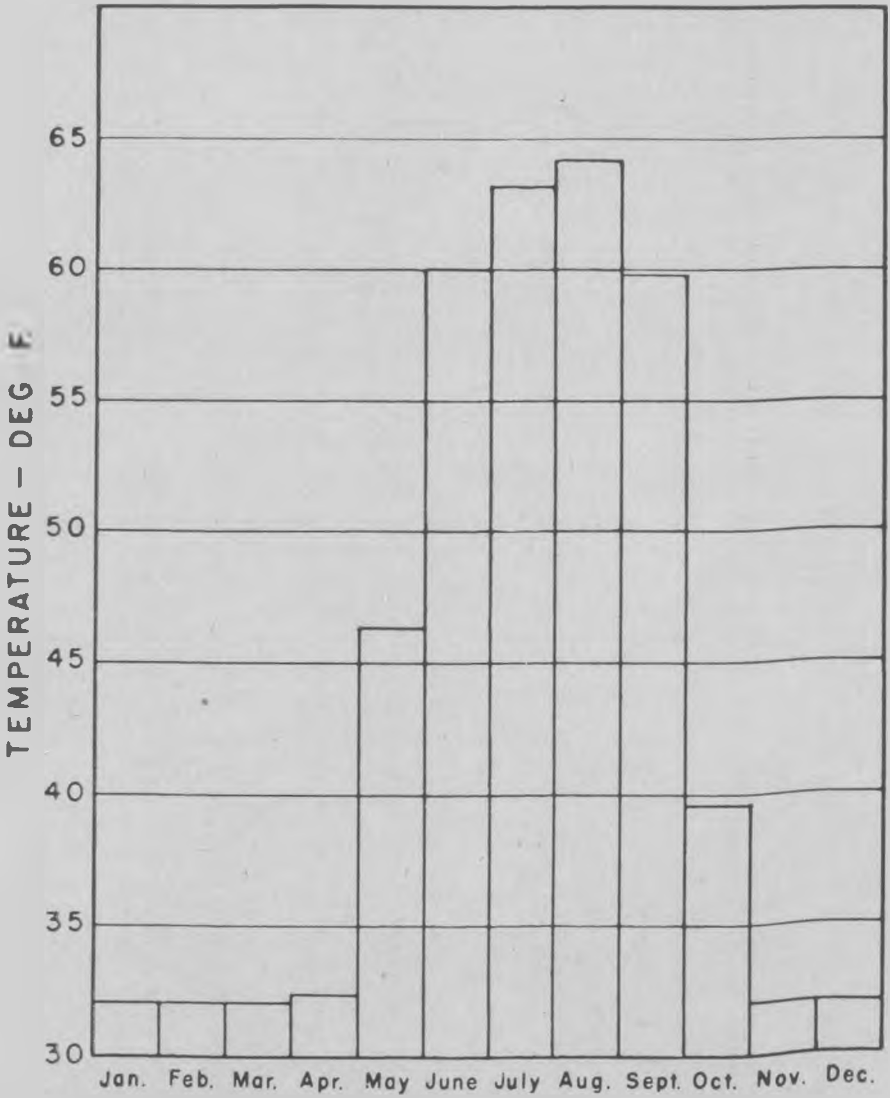
*Embarass is in the delta of the Athabasca River about 120 miles north of McMurray.

The temperature drops to —50°F. for short periods during December to February. It reaches 90°F. during the months of May to August.

The plane leaves on Friday and returns Saturday. Planes can be chartered for special flights at McMurray.

McMURRAY

The elevation of McMurray is about 830 feet. Its population is roughly 700. The Franklin Hotel—Mr. J. L. O'Coffey, Manager—offers comfortable room accommodation. Several restaurants provide meals. General stores and a pharmacy cater to the local needs. Direct telegraph communication is given by the Alberta Telegraph Service. The Canadian Army Signals operates by wireless to points throughout the north country. Bitumount, for instance, communicates through this station. Canadian Pacific Airlines has an office in Mc-



Athabasca River Temperatures at Bitumount, 1950

Murray. Its pontoon plane as well as other planes harbor at the mouth of the Clearwater River in the "sny."

Waterways has a population of about 400. It is the terminal of the railway and the head of navigation for freighting down the Athabasca River. The freight shed and office of the Hudson's Bay Company are at Waterways; those of the Northern Transportation Company are nearby at the "prairie." A hotel and general stores take care of the needs of the town.

ANALYSIS OF ATHABASCA RIVER WATER[1] AND BITUMINOUS SEPARATION PLANT WATER[2]

	River	Plant
Total soluble matter, p.p.m.	194	845
Calcium carbonate	95	70
Calcium sulphate	......	183
Magnesium carbonate	16	
Magnesium sulphate	15	29
Sodium sulphate	15	170
Sodium chloride	9	10
Silica	6	30
Organic matter	34	350
Total hardness, p.p.m.	127	228
Carbonate hardness	114	70
Non-carb. hardness	13	158
pH	8.0	8.2

1. The river water carries a variable amount of sediment depending on the volume of flow. It should be filtered for power plant and other uses. The sample was collected at medium flow.
2. The analysis of the separation plant water indicates the soluble salts contained in the oil sand at Bitumount. The sample was filtered prior to analysis.

STRATIGRAPHY

The stratigraphic succession in the Athabasca area is as follows:

Lower Cretaceous:

Clearwater formation: Grey and dark marine shales.

McMurray formation: Bituminous and fine-grained sands, in part cross-bedded and lenticular interstratified with clay and shales. Thin lignite seams and plant material.

Erosional disconformity.

Upper Devonian:

Waterways formation: Shaly and massive fossiliferous limestone, in places overlain by residual limy clay of variable thickness.

NATURE OF BITUMINOUS SAND DEPOSIT

The bituminous sand deposit, in the area of outcrops along the Athabasca River, has a thickness of about 200 feet. It is composed of beds of unconsolidated sand, silt and clay more or less impregnated with a very viscous, asphaltic oil. The sand beds are apparently the result of sedimentation under deltaic conditions, for they show much cross-bedding and lensing. Generally, the mechanical grading of the sand can be adequately expressed in terms of the 50-mesh sieve size and smaller. The percentage of material finer than 200 mesh varies from a few per cent to high percentages. Silt and clay occur as sand constituents, also as thin partings and as prominent beds. Close interbedding of sand, silt and clay is common. The oil content of the bituminous sand varies, mainly, with variations of silt and clay content. As a general rule, the sand becomes silty or clayey in nature as the content of material passing the 200 mesh sieve exceeds 20%. As the sand becomes clayey the oil content decreases and the water content increases. Bituminous sand, as mined with less than 20% fine material, generally contains from 10 to 17% oil by weight and from 2 to 8% water.

The sand particles of the mineral aggregate of bituminous sand consist mainly of quartz. But as much as 5% of these particles may be mica, rutile, ilmenite, tourmaline, zircon, spinel, garnet and pyrite. Lignite material is of common occurrence in parting planes. Large carbonized tree trunks have been found embedded in the bituminous sand beds.

Clay and sand cemented by pyrite into very hard, heavy, flattish or rounded stones or nodules occur in some localities. Partings of a thin, friable sandstone with a carbonate cementing occur in others. There is a quite persistent layer of hard sandstone with a siliceous cementing agent near the top of the formation. It varies from a few inches to a few feet in thickness.

The bitumen of the bituminous sand is a viscous asphaltic oil displaying considerable variation in properties. Its specific gravity at 25°/25°C. ranges from 1.002 to 1.027. At ordinary temperature the lighter oils pour somewhat readily while the heavier ones can barely be said to pour. The content of 100 penetration asphalt ranges roughly from 65 to 80%. The lighter hydrocarbons present correspond, in volatility, to the heavy end of gasoline. The lighter crude oils probably never contain more than 1 or 2% of such hydrocarbons and the heavier ones practically none at all. The sulphur content of the crude oils is 4 to 5%. The crude oil is very susceptible to thermal decomposition, cracking being appreciable at 650°F. The products of simple refining of the crude are a few per cent of a high-sulphur gasoline together with diesel oil, fuel oil and asphalt residuum.

Bituminous sand in its natural state of packing weighs about 125 lb./cu. ft. Its coefficient of thermal conductivity is of the order of 0.0035 in c.g.s. units* The specific heat of the mineral aggregate is 0.18 cal./gm. while that of the oil is 0.35. The calorific value of the oil is 17,900 B.t.u./lb.

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* 0.0035 gm. cal./sec./cm.^{2}/cm./°C=10.2 B.t.u./hr./ft.^{2}/in./°F.

ANALYSES OF BITUMINOUS SAND OILS FROM VARIOUS LOCATIONS

Location of oil sample	Clearwater River quarry	Abasand Oils Ltd. quarry		Eils River	Bitumount	Mildred-Ruth Lakes	Exploratory drill holes	
							77-9-W.4	95-5-W.5
Ultimate Analysis:								
Carbon, %	83.6	83.3	83.0	83.3	83.3	83.4	83.4	82.9
Hydrogen, %	10.3	10.4	10.2	10.4	10.4	10.4	10.4	10.3
Sulphur, %	5.5	5.1	3.8	4.6	4.7	4.5	4.7	5.4
Nitrogen, %	0.4	0.4	0.5	0.4	0.4	0.5	0.6	0.5
Oxygen (diff.), %	0.2	0.8	2.5	1.3	1.2	1.2	0.9	0.9
C/H ratio	8.1	8.0	8.1	8.0	8.0	8.0	8.0	8.1
Cal. val., B.t.u./lb.	—	—	17,860	17,690	17,910	17,810	17,870	17,700
Sp. gr., 77°/77°F.	—	—	1.022	1.007	1.007	1.010	1.006	1.022

Twp. 77, R. 9, W. 4 is about 75 miles south of McMurray.

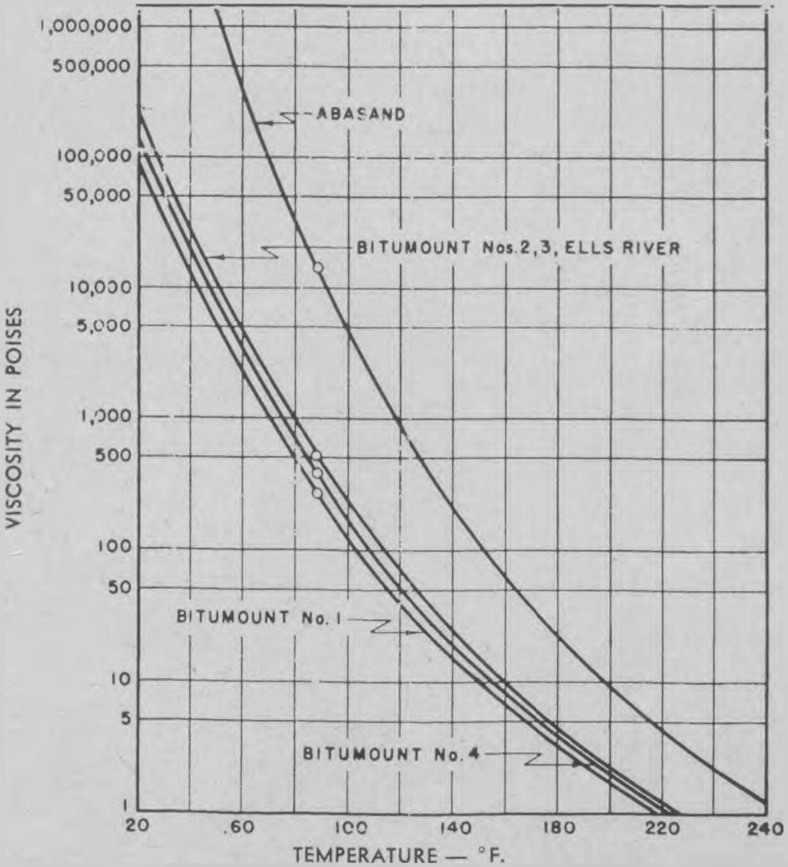
Twp. 95, R. 5, W. 5 is about 120 miles west of McMurray.

COMPARISON OF VARIOUS ATHABASCA BITUMINOUS SANDS AS REGARDS THE COMPONENTS OF THEIR BITUMEN

Bituminous sand*	Components			Asphaltenes as % of asphaltenes plus resins
	Asphaltenes, %	Resins, %	Oily constituents, %	
Bitumount 1A	20.1	25.0	54.9	44.6
" 1B	16.0	25.6	58.4	38.5
" 3	20.4	25.1	54.5	44.8
" 4	16.9	26.0	57.1	39.4
" 5	19.3	25.9	54.8	42.7
" 6A	19.4	24.8	55.8	43.9
" 6B	20.3	26.2	53.5	43.7
" 6C	22.8	29.0	48.2	44.0
Abasand	23.4	29.0	47.6	44.6

* The numbers Bitumount 1 to 6 inclusive represent different depths in the deposit at Bitumount; the larger the number the greater the depth.

Solvents used—n-pentane, ethyl ether, benzene.



Viscosity-Temperature Relationship for the Oils Occurring in Bituminous Sand Beds at Various Locations and in Beds at Different Elevations of the Same Location

COMPOSITIONS AND SIEVE ANALYSES OF BITUMINOUS SANDS USED IN SEPARATION RUNS FOR ACCOUNTING FOR ALL OIL

Bituminous Sand	Bitumount No. 2	Bitumount No. 4	Abasand	Bitumount No. 3	Bitumount No. 1	Ells River	Bitumount No. 3 + Clay *
Composition:							
Water .... %	1.0	4.5	3.1	3.1	2.1	4.5	
Mineral matter .... %	84.7	84.8	81.7	81.4	82.8	84.1	
Oil (by difference) .... %	14.3	10.7	15.2	15.5	15.1	11.4	
Sieve analysis of mineral matter after ignition:							
Retained							
on 50 mesh .... %	11.0	41.2	0.3	13.0	18.3	0.2	
on 80 mesh .... %	46.8	34.3	3.3	41.0	49.9	3.5	
on 100 mesh .... %	20.8	10.2	17.9	20.0	13.3	14.5	
on 200 mesh .... %	16.4	9.0	69.9	18.5	11.0	61.0	
Passing 200 mesh .... %	5.0	5.3	8.6	7.5	7.5	20.8	
Mineral matter still suspended in water after 1 minute settling .... %	3.5	4.0	4.0	5.7	5.7	7.4	16.8 (calc.)

* The clay added was from a clay parting occurring in the bituminous sand formation.

DISTRIBUTION OF OIL BETWEEN OIL FROTH, SAND IN TAILINGS, CLAY IN TAILINGS AND PLANT WATER IN SEPARATION RUNS TO ACCOUNT FOR ALL OIL

Bituminous Sand	Bitumount No. 2	Bitumount No. 4	Abasand	Bitumount No. 3	Bitumount No. 1	Ells River	Bitumount No. 3 + Clay
Composition of oil froth:							
Water .... %	35.4	37.8	27.7	35.7	36.4	36.5	35.4
Mineral matter .... %	4.5	2.8	4.7	3.9	5.8	3.9	3.8
Oil (by difference) .... %	60.1	59.4	67.6	60.4	57.8	59.6	60.8
Oil content of sand tailings (dry basis) .... %	0.50	0.41	0.44	0.27	0.56	0.25	0.41
Oil content of clay in tailings and in plant water (dry basis) .... %	52.8	43.5	47.4	44.8	41.8	42.2	35.0
Per cent of total oil found in:							
Oil froth	78.6	76.1	77.1	80.3	79.4	63.4	44.2
Sand tailings	2.7	3.0	2.1	1.3	2.9	1.6	1.2
Clay in tailings and plant water	13.3	17.1	15.4	14.9	12.1	31.4	52.4
Miscellaneous	2.7	1.6	4.1	1.6	2.2	2.1	1.6
Total oil accounted for .. %	97.3	97.8	98.7	98.1	96.6	98.5	99.4

CONFERENCE DELEGATES

DELEGATES ATTENDING CONFERENCE

Adams, G. W.	Canadian Industries Limited
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