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ASSESSMENT OF RESEARCH NEEDS FOR OIL RECOVERY FROM HEAVY-OIL SOURCES AND TAR SANDS†

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Abstract—We have reviewed and evaluated the U.S. programs on oil recovery from heavy oil sources and tar sands. These studies were performed in order to provide an independent assessment of research areas that affect the prospects for oil recovery from these sources. This paper summarizes our findings and research recommendations.

NOTATION

B	barrel (42 gallons)
BPD	barrels per day
MW_e	megawatts of electrical power
TPD	(short) tons per day
cp	centipoise
cs	centistokes

1. INTRODUCTION

The DOE Fossil Energy Research Working Group (FERWG) has prepared an extensive evaluation of EOR‡ and oil recovery from tar sands. The results of these studies are presented in Ref. 1, which contains extensive discussion of on-site observations. Here, we present a shorter version of this study.

Oil recoveries from heavy-oil sources and Canadian tar sands represent commercial procedures, as is evident from the fact that about 300,000 BPD of heavy oils and 200,000 BPD of tar sands oils are currently being produced. While only relatively small pilot plants are in operation or planned for oil recovery from Utah and other U.S. tar sands, several different recovery procedures are generally viewed to be suitable for near-term commercialization.

†This paper is based on studies[1] performed by the Fossil Energy Research Working Group (FERWG-IIIA) of the Department of Energy dealing with Oil Recovery from Heavy-Oil Sources and Tar Sands under DOE Contract No. DE-AC01-79ER10007. The participants in these studies were: S. W. Benson (Co-Director, Hydrocarbon Research Institute, University of Southern California, Los Angeles, CA 90007), F. W. Camp (Manager of Technology, Synthetic Fuels Division, Sunoco Energy Development Company, 12700 Park Central Place, Suite 1500, Dallas, TX 75251), J. Clardy (Department of Chemistry, Baker Laboratories, Cornell University, Ithaca, NY 14853), J. Deutch (Department of Chemistry, Room 6-123, Massachusetts Institute of Technology, Cambridge, MA 02139), A. E. Kelley (Vice President, Engineering and Development, Union Science and Technology Division, Union Oil Company of California, P.O. Box 76, Brea, CA 92621), A. E. Lewis (Oil Shale Project Manager, Lawrence Livermore National Laboratory, University of California, L-207, P.O. Box 808, Livermore, CA 94550), F. X. Mayer (Engineering Advisor, Exxon Research and Development Laboratory, P.O. Box 2226, Baton Rouge, LA 70821), A. G. Oblad (Department of Mining and Engineering, University of Utah, Salt Lake City, UT 84112), S. S. Penner (FERWG Chairman, Director, Energy Center, B-010, University of California, San Diego, La Jolla, CA 92093), R. P. Sieg (Manager, Synthetic Fuel Division, Chevron Research Company, P.O. Box 1627, Richmond, CA 94802), W. C. Skinner (Manager, Reservoir Exploitation Research and Technical Service, Field Research Laboratory, Mobil Research and Development Corp., P.O. Box 900, Dallas, TX 75221), and D. D. Whitehurst (Manager, Coal and Heavy Liquids, Central Research Division, Mobil Research and Development Corp., P.O. Box 1025, Princeton, NJ 08540).

FERWG, at the request of J. W. Mares (Assistant Secretary for Fossil Energy, DOE) and A. W. Trivelpiece (Director, Office of Energy Research, DOE), has reviewed and evaluated the U.S. programs on tar sands and heavy oils. These studies were performed in order to provide an independent assessment of critical research areas that affect the long-term prospects for tar sands and heavy oils availability. This paper summarizes the findings and research recommendations of FERWG. These studies were monitored by H. R. Anderson (Office of Oil, Gas and Shale, DOE), J. F. Kaufmann (Deputy Associate Director for Program Analysis, DOE), R. Roberts (Acting Director for Advanced Research and Technology, DOE), and J. J. G. Stosur (Director, Office of Oil, DOE).

The authors are indebted to very many people for advice and information. These people are identified in the preface to Ref. 1.

‡EOR = enhanced oil recovery.

A primary problem relates to implementation of effective but non-obstructive environmental controls at each of the many (~2500) sites where secondary and tertiary oil recovery is implemented, as well as at each of the many potential sites where oil recovery from tar sands may be practiced on a commercial scale. Because of the very large number of actual recovery areas, only a relatively small set of control measurements will be useful and each of these should be associated with a large number of fields for application. The definition of measurement criteria and the identification of control parameters to assure resource recovery under acceptable, nonobstructive constraints will require careful monitoring at many sites and a substantial data base.

Industrial development will proceed on the basis of anticipated financial returns during the life of the facility. The efficiency of resource recovery enters parametrically because it is needed to make estimates of return on investment. Economically viable enterprises will generally be defined in terms of partial resource recovery. Termination of commercial operations will accompany failure to obtain adequate returns on investment. Implementation of new and more costly recovery processes can only be expected to occur if these are judged to be competitive with alternative investments.

Significant progress on environmental impact assessments and control, as well as improved resource recovery, will be achieved over the long term as a result of fundamental research programs dealing with all aspects of these technologies. Commercial implementation of entirely new recovery procedures may be hoped for and will be aided by technologies advanced by fundamental research programs.

We summarize below important research areas for which more detailed justification is presented in the following sections.†

(a) *Resource Assessments* (*Section* 3)

The magnitudes of tar-sand and heavy oil resources and reserves should be assessed on a systematic basis, both in terms of quantity and the physical and chemical properties of the oil in place.

(b) *Process research relating to oil recovery from tar sands and heavy-oil sources* (*Section* 4)

(a) Basic information is required for modeling *in situ* and aboveground recovery procedures and involving the use of CO_2, steam, surfactants, caustic flooding, or combustion. These models should describe sweep and conversion efficiencies. (b) Improved procedures are needed for injection of steam, additives, and combustion control. (c) Implementation of thermal processing techniques will require improved methods for solids removal from liquids, gases, and combustion of coke on the pyrolyzed sand. (d) For improved *in situ* combustion recovery, the following studies are needed: better designs for high-temperature packers and insulation systems, steam generation in the oil formations, cleanup and disposition of low-Btu gas, and cost-benefit studies on the use of oxygen-enriched air. (e) Such innovative studies as radiofrequency heating, mine-assisted steam injection, and CO_2 huff-and-puff merit support. (g) Other important studies include sand control to achieve lasting oil-production improvements, transportation of bitumen–water–sand slurries, and the augmented use of down-hole steam generators. The presumed advantages of sulfur removal and enhanced oil yield with downhole steam generation should be verified.

(c) *Environmental studies* (*Section* 5)‡

(a) Because environmental studies are strongly site-specific and total production may ultimately be limited by emissions regulations for SO_x and NO_x, research to improve scrubber technologies should be supported. (b) Improved understanding is needed of chemical processes involving organic sulfur and nitrogen compounds and of air dispersion in orographic regions. (c) Hydrocarbons emitted to the atmosphere in appreciable concentrations require characterization and toxicological evaluation. We expect refined oils to be comparable to conventional

†Research recommendations represent a concensus but are not necessarily endorsed by all FERWG members.

‡For further discussions, especially considerations of safety, health, biological, and toxicological issues, we refer to the following recently completed study: "Synfuels Facilities Safety", National Research Council, Assembly of Engineering, Committee on Synfuels Facilities Safety, Washington, D.C., April 1982.

petroleum products, although newly formed crudes may represent hazards that require careful control. (d) Long-term environmental constraints must be quantified before they limit commercial developments. (e) Fundamental studies are needed on water treatment under conditions encountered in regions where oil is recovered from tar sands or heavy oil sources on commercial scales. Less expensive procedures than are now available should be sought. Methods are needed for the characterization and removal of dissolved organic compounds. (f) The use of alkyl sulfonates in EOR may lead to special control requirements in order to alleviate environmental problems. Chemical studies should be performed to define mechanisms and rates in the mobilization of oils by micellar additives and heating with combustion products. Studies should be supported on the migration and fate of combustion products formed from bitumens.

(d) *Fundamental research* (*Section* 6)

A long-range, basic research program in oil recovery should be pursued. Important areas for these studies include the following: (i) resource and reservoir characterization; (ii) fundamentals of flows in porous media; (iii) studies in physical chemistry, including thermodynamics and the surface behavior of oil/water/steam/CO_2/sand systems; (iv) problems of corrosion related to (iii); environmental problems encountered in recovery processes.

(e) *Upgrading and refining* (*Section* 7)

Refining technologies currently used on heavy petroleum crudes can be employed with confidence on heavy oils and bitumens. The development of improved processes may profit from better understanding of the following physicochemical phenomena: (i) molecular structures and compositions of residua; (ii) mechanisms of asphaltene conversions; (iii) processes for the removal of sulfur and metals; (iv) kinetic studies on coke gasification; (v) mechanisms involving gasification catalysts; (vi) utilization procedures for high-sulfur cokes and tars; (vii) coke desulfurization and utilization as synthetic feedstock.

2. OVERVIEW OF OIL RECOVERY FROM HEAVY OIL SOURCES AND TAR SANDS

Recovery of oils from heavy oils sources and tar sands is needed in order to satisfy near-term and intermediate term goals for the U.S. to augment domestic fuel supplies for the transportation sector. Heavy oils currently contribute about 3×10^5 BPD to U.S. supplies, of which about 90% is recovered by steam flooding and 10% by underground combustion. While oil recovery from tar sands in the U.S. has not been implemented on commercial scales, oil recovery from tar sands in Alberta, Canada, currently amounts to about 2×10^5 BPD and is being expanded rapidly.

2.1 *Oil recovery from heavy oil sources*

A readable tutorial on enhanced oil recovery has been published recently and we refer to this paper for background information concerning goals, methods and achievements.[2] Here, we content ourselves with a brief summary of essential features of these processes.

A highly simplified schematic diagram of a well developed steam-flood pattern is shown in Fig. 1. The initial reservoir temperature is raised by contacting with the steam flood (generally, the steam has a quality well above zero), which is preferably injected near the base of the reservoir. While the contacted oil is heated, the steam is cooled and condensed, depending on reservoir conditions. After some time, the bed permeability is effectively reduced and the steam will then tend to override the productive oil layer with a concomitant decrease in productivity (see Fig. 1), depending on the paths taken by the steam between the injection and production wells. Also, when the steam loses less heat, it tends to be buoyed upward more by gravitational forces.

It is apparent that the physicochemical processes actually occurring during enhancement of oil recovery (EOR) by steam injection are very complex and depend on many features and properties that are only poorly understood. A quantitative model of the efficacy of enhanced oil recovery would require the following types of information: physical properties of the oil-bearing sands, including local values of permeability and porosity and proper constitutive equations as functions of temperature and pressure for these porous beds; quantitative

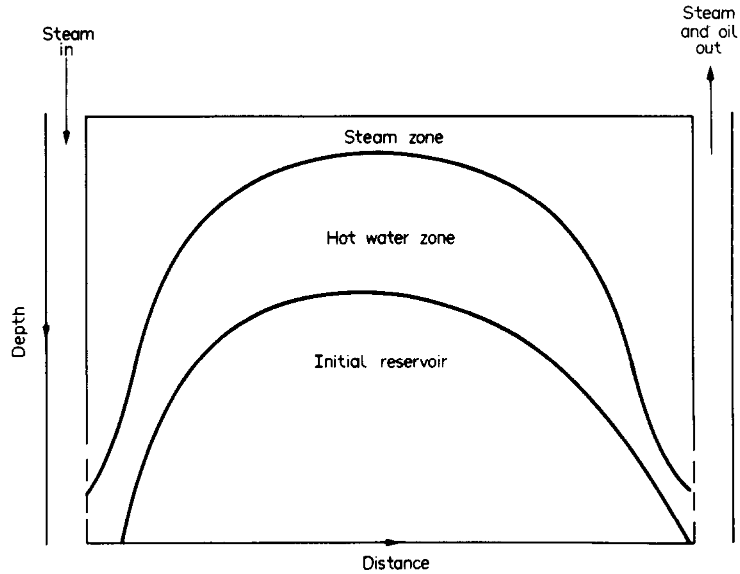

Fig. 1. Schematic diagram of a well-developed steamflood pattern.

descriptions of the geochemistry of oil-bearing sands and all other strata that are located between the injection and production wells; physicochemical data relating to mechanisms and rates of the surface processes that are involved in the movements of heavy oils through the formations as heat transfer from the steam is effected; thermophysical data allowing quantitative evaluations of rates of heat transfer from the steam (including thermal diffusivities, heat capacities, heats of adsorption and desorption, etc.); adequate understanding of the fluid dynamics in the flows of multiphase mixtures through non-uniform, porous media.

In practical applications, the problems are further complicated when additives are introduced with the steam in varying proportions (without or with underground combustion) to enhance the mobility of the oils that are to be recovered. Additives may be CO_2, air with or without oxygen enrichment to facilitate combustion, surfactants to enhance removal of the heavy oils from the oil-bearing sands, etc. Additives have also been injected for the purpose of producing partial blockages of passageways in the steam override region in order to augment penetration of the productive beds by the injected steam or other material.

A schematic diagram showing the use of fireflooding in EOR is reproduced in Fig. 2 (compare p. AB-157 in Ref. 1).

Published studies on EOR (compare Appendix AB-6 in Ref. 1) indicate each of the following: numerous examples of successfully achieved heavy oil recoveries by industrial firms, which justify the view that we are dealing with commercially developed technologies; the use of simplified models and their partial verification in bench-scale and pilot-size tests; ingenious approaches by scientists and engineers in efforts to obtain quantitative models and understanding of the processes involved; incomplete understanding in commercial recovery schemes.

2.1.1 *Some properties of heavy oils.* The following definitions are currently in use: (a) Heavy crude oil has a gas-free viscosity of 100 to 10,000 mPa-s (centipoise) inclusive at original reservoir temperature or a density of 943 kg/m^3 (20°API gravity) to 1,000 kg/m^3 (10°API gravity) inclusive at 15.6°C at atmospheric pressure. (b) Tar sand oil has a gas-free viscosity greater than 10,000 mPa-s at original reservoir temperature or a density greater than 1,000 kg/m^3 (less than 10°API gravity) at 15.6°C (60°F) at atmospheric pressure.

A variety of procedures is available for heavy oil processing, all of which involve desulfurization and nitrogen and metals removal steps, as well as hydrotreating. Carbon-to-hydrogen weight ratios are typically around 8. Transportation and application requirements determine the needed severity of refining. Sediments from oil production or upgrading typically contain many heterocyclic aromatics and other organic nitrogen compounds, with environmental and health effects varying from strongly deleterious to harmless. Additional new facilities may have to be built to upgrade heavy ends. The Appendix (see Ref. 1, pp. AB213-241) to the site-visit report in AB-5 contains a summary of heavy feed upgrading options and shows

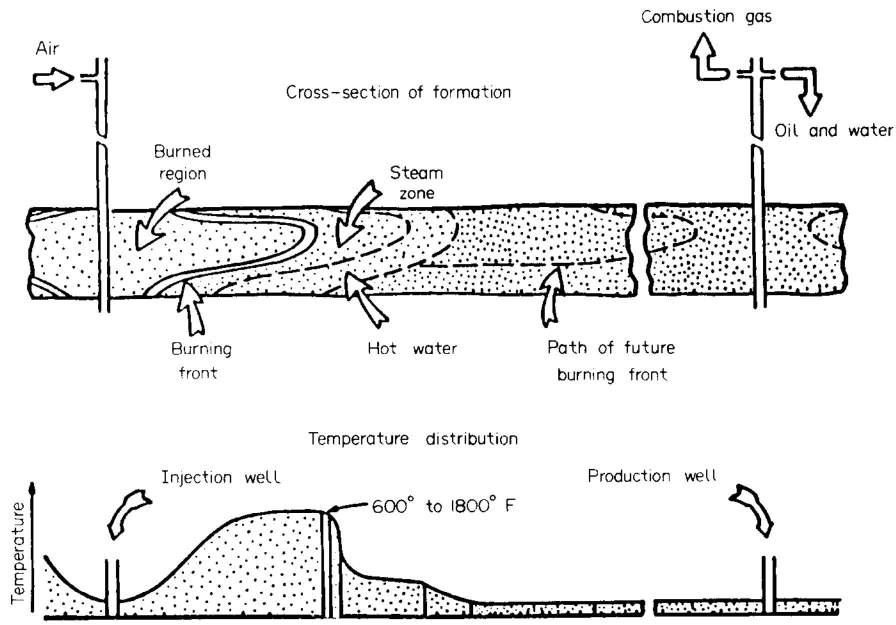

Fig. 2. The *in situ* combustion process.

the following important processing steps: for carbon rejection, fluid coking or flexicoking, delayed coking, deasphalting; with hydrogen addition, hydrodesulfurization and hydroconversion; process-combination options are hydrotreating and coking, hydrotreating with catalytic cracking, deasphalting with hydrodesulfurization, and pretreatment such as demetallization.

2.1.2 *Some previously identified R & D needs relating to enhanced oil recovery.* Joint discussions (see Appendix AB-6 of Ref. 1) between FERWG members and representatives of the DOE Fossil Energy Division, San Francisco Operations, produced an extensive listing of EOR R&D needs enumerated in Ref. 1 and consistent with our statements given in Section 1.

2.2 *Oil recovery from the tar sands of Alberta*

Oil recovery from the tar sands of Alberta has been practiced for some years on commercial scales. A review of activities on oil recovery from this enormously rich resource is therefore appropriate.

In 1967, Spragins[3] gave the following estimates for the Athabasca deposits: 625×10^9B with 285×10^9B recoverable with "current" (1967) technology. The total Alberta deposits are now generally classified as containing about 1.4×10^{12}B of which 25–30% is considered to be recoverable with 1980 technology.

A Sun Company subsidiary, formerly called the Great Canadian Oil Sands, Ltd. (GCOS) and now a division of Suncor, Inc., has been developing this area for some years. Investments amounted to $\$300 \times 10^6$ by 1973, at which time a cumulative deficit of $\$90 \times 10^6$ had been incurred. The 1973 GCOS (now Suncor) production in an open pit mine amounted to 0.055×10^6 BPD and involved the use of 140,000 T of tar sands and removal of 130,000 T of overburden per day; at 100% recovery (actual recoveries are 60–75%), these estimates correspond to an oil-to-sand weight ratio of about 7×10^{-2}. Production has been accomplished in a region where the ratio of overburden-to-tar-sands thickness is less than unity. The oil recovered contains bitumens, which are naturally occurring hydrocarbons. The overburden is scraped away to allow exposure of the bitumen-rich sands, which are then dug out with giant bucket-wheel excavators before removal on conveyor belts[4] to the bitumen recovery and upgrading plant.[4,5] While initial production favored regions of low overburden, about 5.0 T of Canadian tar sands and overburden must be handled on the average for each B of oil produced. The producing area is covered by muskeg swamp (thick deposits of partially decayed vegetable matter of wet boreal regions), which is a semi-floating mass of decaying vegetation with sparse growth of tamarack or larch (a pine family with short fascicled deciduous leaves) and black spruce.

Drainage networks are required for water removal and should ideally be installed two years before excavation begins. The low temperatures (to −50°F) encountered in the region produce extremely cohesive quartz-bitumen matrices, which are very difficult to penetrate and cause rapid deterioration of the excavator alloy cutting teeth. Even with the new and improved equipment that is now available, mining operations are curtailed at temperatures below about −35°F. During the summers, temperatures may rise to 90°F and the tar sands now become sticky with higher vapor pressures, but these features do not interfere significantly with current mining operations. Tar sands containing less than a critical amount of bitumen (6–8 wt%) are rejected. The mean bitumen content of the tar sands (without overburden) for oil recovery in the GCOS operation[3] is 12.4 wt%.

The largest commercial tar sand project in Alberta is currently the Syncrude plant at Ft. McMurray. Site clearance began in December 1973 and the project went on stream in July 1978. Annual production reached around 125,000 BPD during 1980 and is projected to increase up to 160,000 BPD in 1982. The total project cost was about $\$3.25 \times 10^9$ in 1977 dollars and the current owners are Imperial Oil (30%), Cities Service (30%) the Canadian federal government (15%), Alberta (10%), Gulf Canada (10%), and Ontario (5%). The Syncrude mine is one of the largest open-pit mines in the world. The oil-bearing silica sands are surrounded by films of water which, in turn, are surrounded by bitumen. The estimated life of the mine is 25 years (to 2003) and a total of about 1×10^9 B of oil is expected to be produced during this period. The Syncrude plant area covers 5 km^2, the open pit mine 25 km^2, the tailing pond area 30 km^2; the average muskeg depth is 3 m, the overburden is 15 m thick, and the oil-sand depth is 42 m. The peak-construction work force was 7500, while the current work force on site is 3100. One m^3 of oil sand yields 1.4 m^3 of sand and 0.22 m^3 of bitumen from which 0.18 m^3 of synthetic crude and 15 m^3 of gas are recovered.

The mine is 4.2 km long, 7.5 km wide and 60 m deep. There are 4 draglines, the buckets hold 60 m^3, the booms are 110 m long, and the draglines have a working radius of 104 m. The overall weight of a dragline is 6100 mt and the electric power use is 10 MW$_e$. There are 4 bucket wheels in operation, each carrying 14 buckets with a capacity of 6400 mt/hr; individual buckets carry 2 m^3. Each bucket wheel uses 3.7 MW$_e$, weighs 2250 mt, and is 140 m long. Conveyor belts cover 17.7 km in the mine, 1.6 km in the plant, and they are 2.1 m wide and 3 cm thick.

The extraction plant processes 11,800 mt/hr of oil sand and produces 2050 mt/hr of bitumen-bearing froth. The froth-treatment plant produces 676 dm^3/sec of diluted bitumen.

The stack for the upgrading facility is 180 m high with a 20 m diameter at the base and an 8 m diameter at the top. There are 2 fluidcokers in use which are 63 m high.

The utility plant has an installed capacity of 260 MW$_e$ of which 185 MW$_e$ represent the normal operating load; 1×10^6 kg/hr of steam are produced. The water-treatment plant has a maximum flow of 850 cm^3/sec.

The bitumens are stored in a 477,000 m^3 tank; a 191,100 m^3 tank is used for gas oil while a tank with a capacity of 83,500 m^3 is employed for naphtha.

Shell Canada Ltd. filed an application in 1973 with the Alberta Energy Resources Conservation Board for bitumen recovery with the objective of 0.10×10^6 BPD recovery by 1980. *In situ* recovery operations for deeper-lying bitumen were tested by the Shell Oil Co. on 160,000 acres of leased land at Peace River (see Fig. 3), where 38 test wells to a depth of 1,800 ft had been drilled by the end of 1973. A prototype development plan called for a $\$30 \times 10^6$ program on 50 closely-spaced injection and production wells in 1974, with injection involving either steam, hot water, or light petroleum. This type of injection-recovery scheme should be contrasted with partial-burning procedures.[6] It was anticipated that the porosity of the tar sands was sufficient to allow successful development of *in situ* recovery procedures. Current (1981) operations at Peace River are described in Appendix AB-7 of Ref. 1.

Other oil companies (Imperial, Amoco, a Japanese group, Mobil, and Texaco) are also experimenting with *in situ* recovery schemes.

2.2.1 *The GCOS (Suncor) recovery and upgrading procedure of oil from tar sands (Clark Process).* The GCOS recovery process begins with excavation of bitumen-containing sands consisting, for example, of a mixture of 11,700 TPD of bitumens and 81,000 TPD of minerals [① in Fig. 4]. This mixture is introduced into a conditioning drum [② in Fig. 4], together with

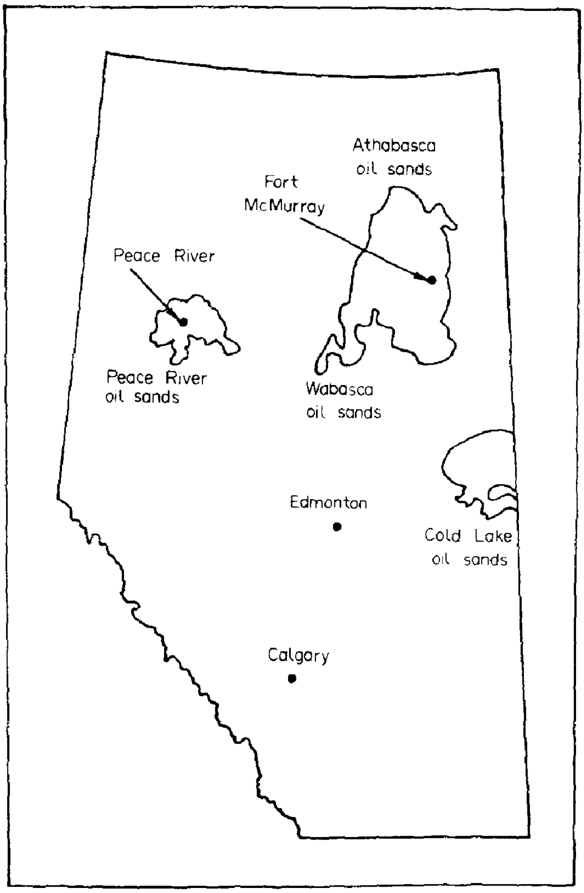

Fig. 3. Tar sand sites. The enclosed areas indicate the principal location of oil sands in the State of Alberta in Canada.

caustic soda, water, and steam for reduction of sand-lump size. The smaller particles pass a vibrating screen [③ in Fig. 4], while oversize particles are discarded. More water is added to the particles passing the screen prior to introduction into a three-layer separation cell [④ in Fig. 4]. The bitumen floats to the top of the separation cell and is largely recovered in this top-layer froth [④ in Fig. 4], while sand is discarded at the bottom and the middlings of intermediate density are partly returned to the separator for recycling and partly forwarded to a scavenger separation cell [⑤ in Fig. 4] for separate treatment in a froth settler [⑥ in Fig. 4]. The top-froth layers from the separation cell [④ in Fig. 4] and the froth settler [⑥ in Fig. 4] are mixed with naphtha before introduction for upgrading in centrifuges [⑦ in Fig. 4], from which tailings (bitumen-to-minerals weight ratio $\simeq 0.21$) and upgraded feed (bitumen-to-minerals weight ratio $\simeq 51$) for the coker are supplied; about 87% of the feed bitumen enters the coker. This feed bitumen is an 8° API oil containing 4% of sulfur.

The GCOS upgrading process for the tar-sand bitumens is shown schematically in Fig. 5 and is reproduced from Roberts.[7] The total mined tar sand input is 0.105×10^6 TPD, corresponds to 0.065×10^6 BPD and produces 0.050×10^6 BPD of syncrude (77% conversion), as well as 2.58×10^3 TPD of coke and 350 TPD of sulfur. The flow diagram shown in Fig. 5 is self-explanatory. The overall hydrogen consumption is about 1000 SCF per B of high-quality syncrude containing less than 0.1% of S_x.

2.2.2 *The Syncrude recovery and upgrading procedure of oil from tar sands.* The Syncrude recovery process is also a version of the Clark process; the upgrading procedure involves fluid coking of bitumen in such a manner that the released gases contain appreciable amounts of H_2S. The resulting liquid product is a mixture of butanes, oil residue, and intermediate fractions containing naphtha and light and heavy gases, which are further hydrotreated catalytically. The syncrude-to-bitumen recovery ratio is raised to 87% but with somewhat higher sulfur content than the GCOS syncrude.

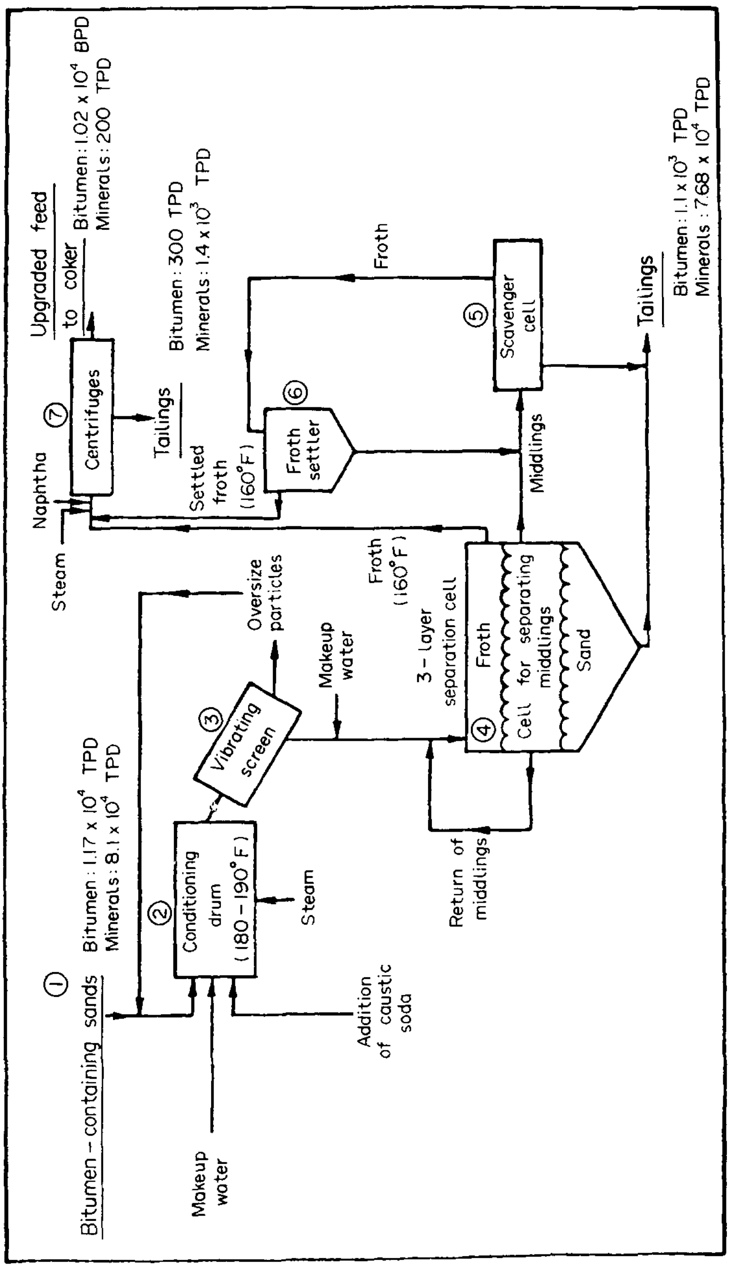

Fig. 4. The bitumen recovery scheme pioneered by GCOS and used by Suncor and Syncrude.[7]

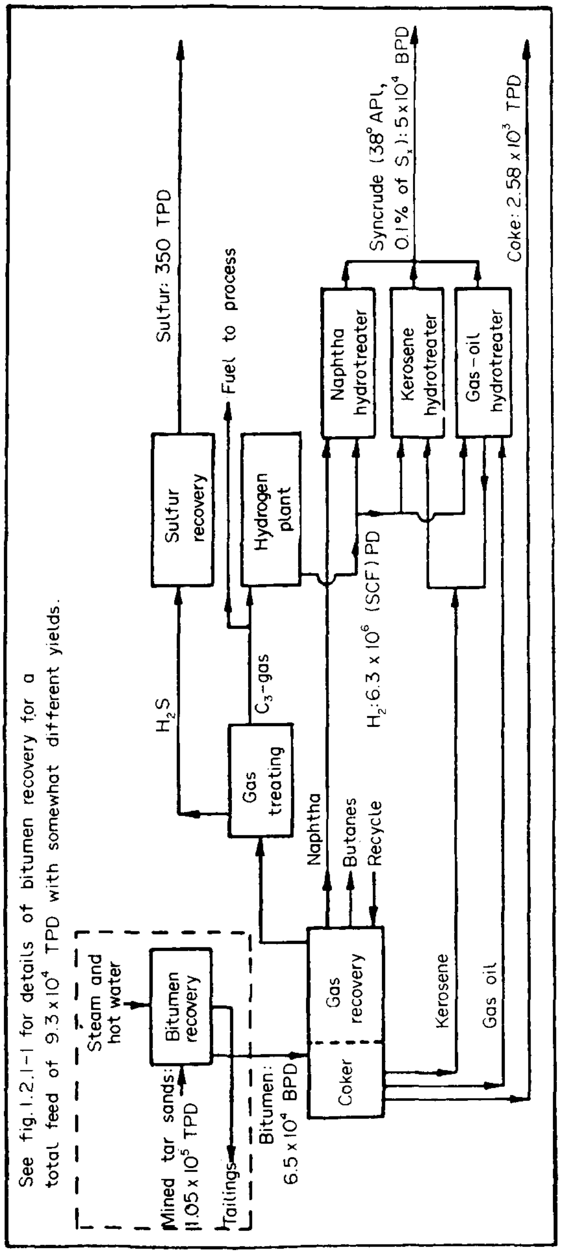

Fig. 5. The GCOS upgrading process for bitumen recovered from tar sands; reproduced with modifications from Ref. 7.

Details concerning current (1981) Syncrude operations are described in Appendix AB-7 of Ref. 1.

2.3 *Oil recovery from the tar sands of Utah*†

2.3.1 *Introduction.* The United States has large deposits of heavy oils which resemble heavy petroleum residues, as well as tar sands with hydrocarbons known as bitumens that are generally more viscous than petroleum residues and black oils. The resource base of black oil and tar sands in the U.S.A. may be as high as 10^{11} B in place. A definition regarding what a tar sand is has not yet been acceptably established by the scientific and engineering communities, but the D.O.E. has recently proposed that a tar sand deposit is a deposit containing bitumen with a viscosity in excess of 10,000 cp at reservoir temperature (compare Sec. 2.1.1).

The U.S. deposits of tar sands have been estimated to be about 36×10^9 B in place (Table 1). Examination of Table 1 shows that most of these tar sands are in Utah (Fig. 6). The work of Ritzma and his associates at the Utah Geological and Mineral Survey in defining these deposits has been responsible for generating much of the present interest in Utah tar sands.[8] More recent studies on Utah tar sands have been performed by Kuuskraa *et al.*[9] and by workers at Enercor.[10] Definitions and characterizations of U.S. tar sands as a resource are still incomplete and much more must be done before commercialization can begin. Reliable estimates of resources suitable for commercial exploitation, either by *in situ* recovery procedures or by mining and bitumen recovery involving processes similar to those used in Canada or other technologies are not generally available.

A survey of the literature on technology relating to bitumen recovery from U.S. tar sands in the early 1970s, using *in situ* methods or mining and aboveground processing, showed that little information was available. The literature on Canadian tar sands is, however, extensive. Workers at the U.S. Bureau of Mines had performed bench scale work on water extraction in 1948. There have been several attempts at pilot operations in the field for both *in situ* and aboveground processing. Backyard inventors have been active in extracting oil from Utah tar sands for many years, mainly by solvent extraction, but none of these processes has led to significant commercial activity. This situation began to change during the middle 1970s when larger scale work began at LETC on *in situ* recovery and at the University of Utah on aboveground processing of tar sands. Recently, groups in private industry have become active in developing technology for processing Utah tar sands.

2.3.2 *The Utah resource base.* Estimates of in place bitumens for Utah tar sands are given in Table 2. These estimates are based on Ritzma's data. The bitumen contents shown are based on data of Wood and Ritzma[11] and are used in recent studies at Enercor.[10] The bitumen contents in any deposit vary widely from point to point within the deposit and much more work is required to substantiate these estimates.

Recent estimates at Enercor of material recoverable by mining and aboveground processing are shown in Table 3. Previous estimates in Ref. 11 were much lower than those shown in Table 3. The following criteria were used by Enercor to define tar-sand deposits suitable for mining and aboveground processing: 8% or higher bitumen content (grade); overburden-to-ore ratio = 0.4 for the Tar Sand Triangle, P. R. Spring, Sunnyside, and Hill Creek deposits and 1.0 for Asphalt Ridge. When these requirements were combined with a minimum overburden of 350 ft for *in situ* recovery, the following estimates were obtained: $100–200 \times 10^6$ B are suitable for mining at Asphalt Ridge (no suitable deposits were found elsewhere on the basis of available core data) and possibly as much as 2.4×10^9 B are technically and economically feasible for recovery by using *in situ* techniques from the Tar Sand Triangle (1.5×10^9 B), Sunnyside (0.5×10^9 B), and Asphalt Ridge (0.4×10^9 B) deposits.

2.3.3 *Chemical analyses of Utah tar sands.* Utah tar sand bitumens may be classified into two general groups. Those in the Uinta Basin are believed to be of lacustrine origin and those of south central Utah are thought to be of marine origin. Uinta Basin bitumens are low in sulfur and aromatic content while those in the Tar Sand Triangle area have similar properties to Athabasca bitumens and also have similar sulfur and aromatic contents (Table 4). Generally, the Utah bitumens are one to four times more viscous than Athabasca bitumens. Estimates of the

†An overview of current U.S. tar sands resources and recovery projects has been prepared by L. C. Marchant and C. A. Koch and is reproduced in Appendix AB-8 of Ref. 1.

Table 1. Deposits of bitumen-bearing rocks in the United States with resources over 1×10^6 B; prepared by workers at the Laramie Energy Technology Center of the Department of Energy.

State and Name of Deposit	Estimated Resources (Millions of Barrels) Low	High
CALIFORNIA:		
Oxnard	565.0	
Santa Maria	500.0	2,000.0
Edna	141.4	175.0
South Casmalia	46.4	
North Casmalia	40.0	
Richfield	40.0	
Paris Valley	30.0	100.0
Sisquoc	29.0	106.0
Santa Cruz	10.0	
McKittrick	4.8	9.0
Point Arena	1.2	
CALIFORNIA TOTAL	1,407.8	3,092.6
KENTUCKY:		
Kyrock Area	18.4	
Davis-Dismal Area	7.5	11.3
Bee Spring Area	7.6	
KENTUCKY TOTAL	33.5	37.3
NEW MEXICO: Santa Rosa	57.2	600.0
TEXAS: Uvalde	124.1	3,000.0
UTAH:		
Tar Sand Triangle	12,504.0	16,004.0
P. R. Spring	4,000.0	4,500.0
Sunnyside	3,500.0	4,000.0
Circle Cliffs	1,000.0	1,507.0
Asphalt Ridge	1,000.0	1,200.0
Hill Creek	300.0	1,160.0
San Rafael Swell Area	385.0	470.0
Asphalt Ridge, Northwest	100.0	125.0
Raven Ridge	75.0	100.0
Whiterocks	65.0	125.0
Wickiup	60.0	75.0
Argyle Canyon	50.0	75.0
Rim Rock	25.0	30.0
Cottonwood-Jacks Canyon	20.0	25.0
Pariette	12.0	15.0
White Canyon	12.0	15.0
Minnie Maud Creek	10.0	15.0
Willow Creek	10.0	15.0
Littlewater Hills	10.0	12.0
Lake Fork	6.5	10.0
Nine Mile Canyon	5.0	10.0
Chapita Wells	7.5	8.0
Ten Mile Wash	1.5	6.0
Tabiona	1.3	4.6
Thistle	2.2	2.5
Spring Branch	1.5	2.0
Cow Wash	1.0	1.2
UTAH TOTAL	23,164.5	29,512.3
UNITED STATES TOTAL	24.787.1	36,242.2

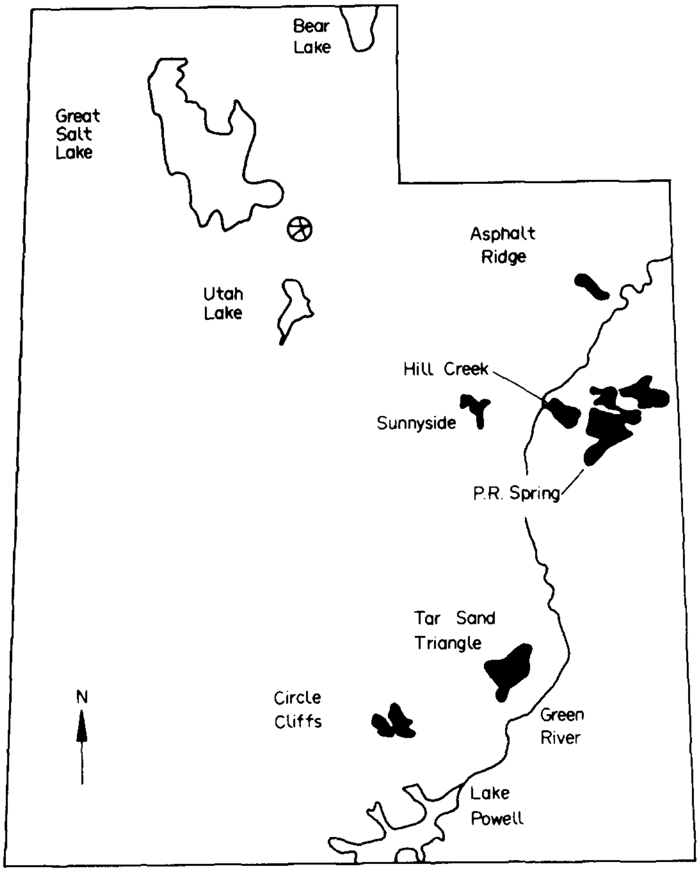

Fig. 6. Major tar sand deposits in the State of Utah.

Table 2. Tar-sand deposits in Utah; from Ref. 11.

Deposit	Bitumen in Place (10^9 B)	Bitumen Content (wt. %)
Tar Sand Triangle	12.4 - 16.0	5 - 8
P. R. Spring	4.0 - 4.5	6.5 - 14
Sunnyside	3.5 - 4.0	8 - 9
Hill Creek	1.2	6 - 7
Circle Cliff	1.3	5 - 7
Asphalt Ridge	1.15	8 - 14
White Rocks	0.6 - 1.25	4 - 7

Table 3. Estimates of mineable tar sands assuming 3 cubic yards per B overburden; reproduced from Ref. 11.

Deposit	B Recoverable
Asphalt Ridge	150×10^6
White Rocks	100×10^6
P. R. Spring	1.5×10^9
Sunnyside	2.0×10^9

Table 4. Typical bitumen properties for general groups of tar-sands deposits.

Properties	Group 1: Asphalt Ridge, Sunnyside and P. R. Spring, Utah	Group 2: Tar Sand Triangle, Utah, and Athabasca, Canada
Carbon weight %	85	83
Hydrogen	11.4	10.3
Nitrogen	1.0	0.5
Sulfur	0.5	4.7
Oxygen	Variable	Variable
C/H atomic ratio	0.60-0.65	0.65-0.70
Vanadium (ppm)	25	100-300
Nickel (ppm)	120	50-100
Viscosity at 77°F (0.05 sec^{-1}, poise)	$3\text{-}30 \times 10^4$	$0.4\text{-}1.5 \times 10^4$
Penetration 1/10 mm, 50 g, 5 sec	<300	<300
Specific gravity	0.985	1.00
API gravity, degrees	12.0	10
Carbon residue (Rammsbottom)	3-12	10-22
Asphaltenes (pentane)	4-16	16-26
Avg. M.W. (VPO-benzene)	660-800	540-600
Heating value (Btu/lb)	18,500	17,800
% Volatiles at 530°C TBP	50	60

bitumen content of the Utah tar sands vary from 5 to 14% (see Table 4). As with the Athabasca deposits, the grade varies within the deposits. More thorough definition is needed to confirm these rough estimates of grade, which are derived from outcrops and analyses of available core samples.

The mineral part of the Utah tar sands is largely quartz (beach sand) with some small amounts of other minerals. Particle-size distributions have been measured for various sands in Utah. The mineral matter in Utah sands contains very little, if any, clay material, as opposed to the Athabasca sands which contain as much as 8% finely divided clay minerals, some of which exhibit swelling in water. The clay minerals contribute to the formation of sludge in the Clark hot water process employed in Alberta and make the large settling ponds necessary for disposal of the tailings. Large tailing ponds that must be maintained for many years will probably not be needed in processing some of the deposits.

Another occasional difference between Utah tar sands and those at Athabasca is the water content of the freshly mined sand. Some of the Utah tar sands are dry and contain less than 0.5 wt.% of connate water while others are similar to Athabasca tar sands and contain 3–5 wt.% or more. This difference makes for important processing differences, as will be discussed in the following sections.

2.3.4 *Recovery technology.* There are two basic technologies used for the recovery of oil from tar sands. These are: (i) mining and aboveground processing with (a) hot-water recovery, (b) solvent extraction, or (c) thermal recovery; (ii) *in situ* processing with (a) thermal methods and partial combustion or (b) steam injection.

Since 1973–74, A. G. Oblad *et al.* (with federal funding) at the University of Utah have studied most of these alternatives and selected to concentrate on mining and aboveground processing. Study of the three recovery alternatives for aboveground processing indicated that the best prospects were hot water processing and thermal recovery. In the latter, a promising alternative appeared to be the use of fluid-bed technologies similar to the procedures applied in the petroleum industry for catalytic cracking. The *in situ* work has been continued at the Laramie Energy Technology Center.

2.3.5 *Hot-Water recovery process.* The University of Utah process takes into account the differences between Athabasca and some Utah tar sands, i.e., the higher viscosity of the Utah bitumens and the absence of a water film coating the sand between the oil and the sand surface. The process involves a digestion of the sand in hot water under high shear conditions, adjustment of the reaction pH with alkali, and final separation by a modified flotation technique. The main variables in the digestion step are temperature, H_2O/sand weight ratio, pH, degree of agitation, time, viscosity of the bitumen, and grade of the tar sand. The main variables in the floatation step are temperature, time and rate of air injection.

A process has been developed in which the variables have been optimized. Laboratory recoveries in the 95% range have been achieved consistently with both high and low grade materials, including the P.R. Spring, Asphalt Ridge, Sunnyside, and White Rocks deposits in Utah. Good results have also been obtained with low grade tar sands of Kentucky. The oil contents of the concentrate vary from 30–75%, depending on tar sand grade, viscosity of the bitumen and sand particle-size distribution. Methods have been developed for upgrading the concentrate to 98 wt.% bitumen or better.

2.3.6 *Fluid bed thermal recovery.* Heating of tar sands to temperatures as high as 500°C leads to vaporization and cracking of the bitumen content. Gaseous and vaporized yields of liquids are typical of those achieved in coking a heavy petroleum residuum. Coke produced remains with the sand. The coked sand can be burned cleanly by using air at 500°C and higher. A substantial effort has been made by various workers at Utah to translate these findings into successful processes. No commercial operations are as yet in existence.

After considering a range of possibilities for thermal recovery (including the use of Lurgi reactors, rotary kilns and fluid beds), fluid bed reactors were chosen. It was observed early in the program that cleanly burning tar sands can be readily fluidized. Hence, a study of this system was carried out. The effects of temperature, retention time and sand particle-size distribution on the recovery of syncrude were studied. The results showed that recoveries of liquid products in excess of 70 wt.% and perhaps as high as 80 wt.% are possible, with coke and gas makes of 15–20 wt.% and 10–20 wt.%, respectively. Properties of the synthetic crudes vary widely, depending on the properties of the bitumen contained in the sand, temperature of reaction and retention time. The crudes are similar to heavy crude oils and are in the 15–25°API range.

All thermal routes for oil recovery require much energy, which may be obtained by burning the coke from the sand. Theoretically, there is more than enough energy released in this step to provide the heat needed for the coking step. With this in mind, an integrated process scheme has been designed, which involves coking and burning of the sand in separate steps and transfer of heat from burning to coking by recycle of burned sand. This sequence is similar to catalytic cracking and is shown schematically in Fig. 7.

Analysis of such a scheme by computer modeling shows that the most promising version is one of upgrading the bitumen grade to 25–40% and using this concentrate as feed to the thermal system. This step, which can be carried out readily with hot water recovery or by ambient temperature techniques now under development at the University of Utah, removes as much as 75% of the sand, which then does not need to be handled further. Thus, the thermal equipment can be greatly reduced in size, the recycle ratio (hot sand/feed) can be brought to a reasonable level, and the sand burning temperature can be limited.

2.3.7 *Upgrading of the recovered bitumens.* The bitumens from Utah tar sands have been characterized and subjected to the techniques used in the U.S. petroleum industry for upgrading heavy petroleum fractions. Visbreaking, thermal cracking, coking, catalytic cracking, hydrotreating, and hydropyrolysis (a new technique) have been employed. Coking, catalytic cracking and hydropyrolysis appear to be promising routes for upgrading (see Table 5). The important conclusion derived from these investigations is that high grade, synthetic crudes similar to those made commercially in Canada can be obtained from Utah tar sands. The design of the optimal processing scheme will require thorough economic analysis for elucidation.

2.3.8 *Pilot plant studies.* Many important pilot plants are currently being tested, including a pilot plant to test the University of Utah hot water recovery process, which is currently being

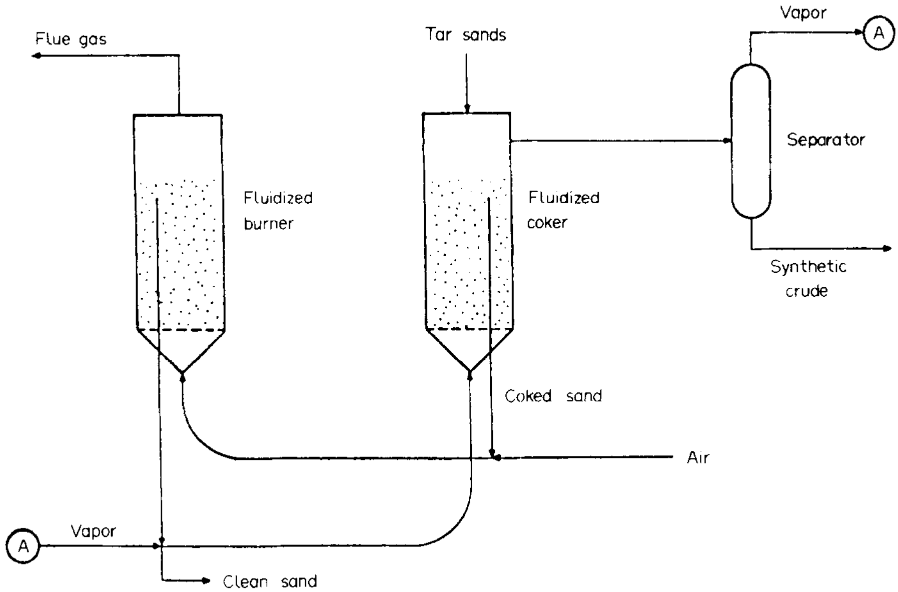

Fig. 7. Process scheme for thermal recovery.

Table 5. Comparison of yield and conversion results for the primary processing of Asphalt Ridge bitumen; conversion is defined as the percentage of material boiling above 538°C that is converted to material boiling below 538°C.

Process	Yield of			% Liquids distillable	Conversion
	Gases	Liquids	Total gases and liquids in wt.%		
Visbreaking (VB)	1	99	100	67	46
Coking TC(80)	7	70	77	100	62
Catalytic cracking (CC)	10	74	84	99	72
Coking TC(0)	4	83	87	97	74
Hydropyrolysis (HP)	27	73	100	85	82

built near the Chevron Refinery in North Salt Lake City. The plant will produce a concentrate which can be upgraded. The upgrading will not be done at the pilot plant, but the product bitumen will be tested elsewhere. Technology for upgrading by coking is already available. Upgrading by catalytic cracking or by hydropyrolysis will have to be tested at a pilot plant scale before these technologies can be commercialized.

2.3.9 In situ *recovery.* Workers at the Laramie Energy Technology Center have carried out three *in situ* tests at Asphalt Ridge since 1975. The site selected for these tests is located at the north end of the deposits. Two of these tests involved reverse combustion and a more recent third test was carried out using steam injection. The combustion tests were done on a 12-ft seam of sand, which is 350–450 ft below the surface; the steam flood tests were done on a 45–50 ft seam at a depth of 550 ft. In the second test employing reverse combustion, up to 25% of the bitumen values were recovered as upgraded oil. About 50% of the air injected was accounted for in the recovered gases. The steam flood was similar in concept to those being used in Alberta at Peace River and Cold Lake. Steam was injected at 360–530 psig. Total production during 160 days of operation was 1150 B of oil and 6250 B of water. The total steam injected was equivalent to 65,700 B of water.

2.3.10 *Economics of bitumen recovery from Utah tar sands.* A recent economic assessment (based on small-scale laboratory studies) for producing synthetic crude oil from Utah tar sands in a 2000 BPD plant was made available by Enercor and is reproduced in Ref. 1. This study shows a product cost of about $25/B corresponding to a selling price of about $39/B.

A preliminary cost estimate has been prepared also by Barrett for an *in situ* recovery process.[12]

2.3.11 *Environmental aspects of tar sand development.* The following issues will have to be addressed in tar sand development: (a) Requirements for auxiliary energy sources and for water and other renewable resources. (b) Maintenance of local and regional air quality. (c) Maintenance of local and regional water quality and supplies. (d) Land disturbances and reclamation or reconstruction. (e) Preservation of archeological and historical sites. (f) Survival and health of terrestrial and aquatic ecosystems. (g) Population growth and socioeconomic impacts of a large developing industry.

It is expected that the development of Utah tar sands will have modest environmental effects. Studies are currently being carried out to assess these effects at government laboratories and in private industry. Water use is expected to be in the range of 2–4 B/B of bitumen produced.

The main environmental impacts will involve land disturbances and air pollution in the case of mining and aboveground processing. As we have already noted, the large tailing ponds required in Canada will not be needed for some of the Utah tar sands because of the high bitumen recoveries and very low clay contents of the sands. These two factors are the principal causes of the sludge produced in Athabasca tar sand processing and make the very large tailings ponds necessary. For *in situ* recovery, the main impacts will involve air pollution and, possibly, long-range modifications of regional hydrology.

2.4 *Research recommendations on oil recovery from tar sands derived from site visits and discussions*

Site visits and discussions involving FERWG members are summarized in the appendix of Ref. 1. In connection with these activities, R&D needs were repeatedly discussed. A compilation of research recommendations derived from these activities may be found in Ref. 1.

2.5 *Current studies relating to oil recovery from heavy-oil sources and tar sands*

There is an extensive literature on many aspects of oil recovery from tar sands and heavy-oil sources. A useful sample of current research may be found in a monograph published in 1977.[13] Some features[13] of the Athabasca oil pools are reproduced in Figs. 8 and 9.

A major additional publication dealing with oil recovery from heavy oils and tar sands has been published recently.[14]

3. RESOURCE ASSESSMENTS

3.1 *Introduction and definitions*

A tar sand is a hydrocarbon with a viscosity at reservoir temperatures >10,000 cp and the deposit is produced through mining. Specific gravities and viscosities of various crudes fall in the range 0.8–1.02 g/cm^3 (6–45.2°API) and 2.8 to 3×10^7 cp, respectively, while conventional crudes at 60°F have densities† of 30–45°API and viscosities of only 3.5–48 cp, respectively; as the result, they require several orders of magnitude less force to move through the ground than is needed for heavy crudes.[15,16] The gravities of heavy oil or bitumen deposits center around 8–12°API, but the observed range in some reservoirs is greater or may be shifted by several degrees toward lower or higher gravities. There is no generally accepted gravity definition for heavy oils.

Dietzman *et al.*[17] defined a heavy oil as having a gravity of 25°API or less. However, much oil in the range 12–25°API is producible "in its natural state through a well by ordinary production methods." In fact, still flowing giant fields have oil with gravities of 12–20°API (e.g., in Mexico: Ebano-Panuco, 12.5°API and exceptionally high viscosity of about 1500 centipoise at 122°F; Golden Lane, average 20°API; in Venezuela: Tia Juana/Maracaibo average 18.8°API). In eastern Venezuela, the giant Quiriquire field, with 16.3°API oil, was initially flowing. An earlier survey by the Bureau of Mines assessing the resource, reserve and potential for the production of heavy oils in the United States also defines heavy oils as <25°API.[18] We shall

†The specific and API gravities are related by $°API = (141.5/\text{specific gravity at } 60°F) - 131.5$. Thus, a crude with API = 10° has the specific gravity of water and crude with API gravity higher than 10° will float while that with less than 10° will sink in water.

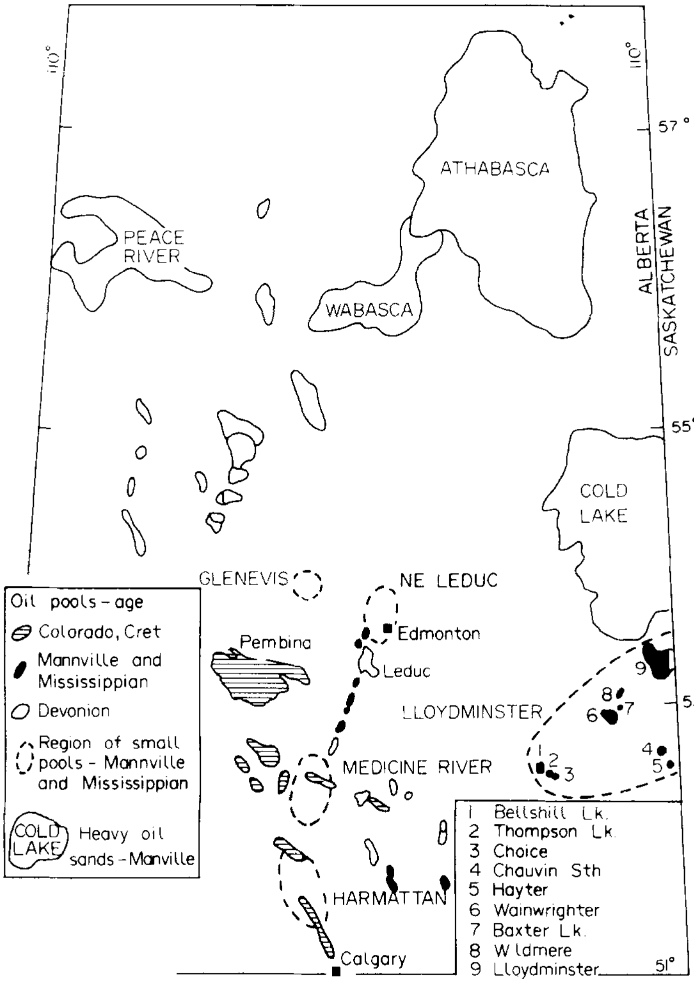

Fig. 8. Oil pools and oil sands deposits of Alberta; shown on page 12 of Ref. 13 in a paper by G. Deroo and T. G. Powell and reproduced from maps prepared by the Alberta Oil & Conservation Board, 1963.

refer to heavy oils as naturally-occurring petroleum resources having API gravities of less than 20°. Crudes of this nature generally are highly viscous and flow only slowly unless heated. This makes them difficult to produce and transport. Even with the least viscous heavy oils, less than 10% of the oil in place can be produced by primary means (natural pressure or pumping). Heavy oils contain high concentrations of asphaltic components and normally less than 50% can be distilled. These features make them unacceptable as major feedstocks to present-day refineries.

Waxy crudes have higher API gravities (generally <20°). Although they are also difficult to produce and transport, they may be upgraded with existing technology and are acceptable major feedstocks to present-day refineries.

All heavy oils fall within the broad classification of bitumen. A bitumen is defined as any petroliferous, naturally-occurring material which is extractable by common organic solvents (usually CS_2) from the rock in which it is found or, when not associated with rock, it can be dissolved. These bitumens are all dark in color (black or deep brown) and exist as solids or highly viscous liquids at room temperature. Within the classification of bitumen, there are a number of subclassifications which overlap; distinctions between these have often been arbitrary. These subclassifications are summarized in Table 6, where they are listed in increasing order of desirability as feedstocks to refineries. The bitumens listed in Table 6 will now be defined.

Asphaltites[19] are natural solid bitumens which generally are not associated with rock. They have API gravities in the range of −15° to 5°, exhibit high fusing points (>230°F), and contain

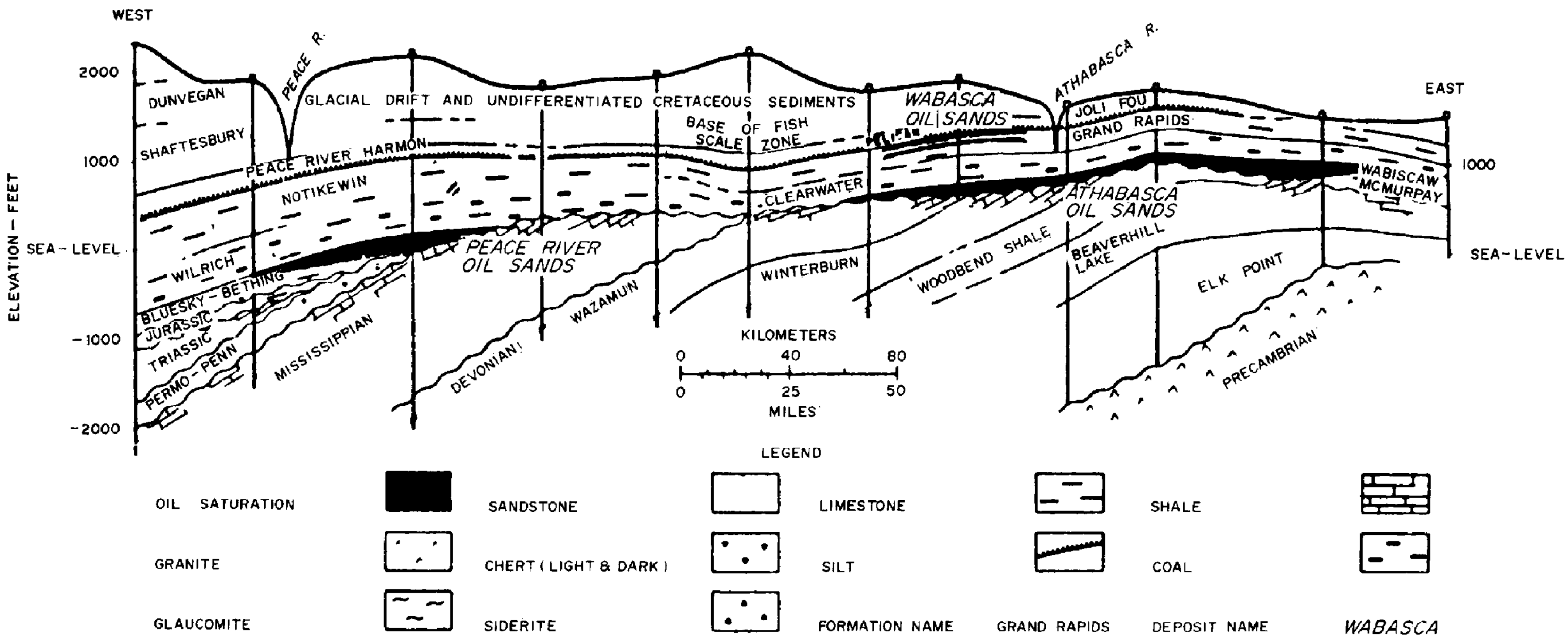

Fig. 9. Schematic cross-section (compare Fig. 3) between the western boundary of the Peace River deposit and the eastern boundary of the Athabasca deposit south of Fort McMurray (reproduced by R. D. Humphreys and R. Schutte on p. 3 of Ref. 13 and prepared by the Alberta Oil & Gas Conservation Board, 1963).

Table 6. Classification of heavy oils.

Bitumens	Range of API Gravity	4	3	2	1
Asphaltites	-15 to 5	Increasing Asphalt	Increasing Fusing Point	Increasing Distillate	Desirability as Petroleum Sources
Native Asphalt	-5 to 12				
Tar Sand					
Oil Sand	6 to 12				
Carbonate-Oil Sand					
Heavy Crude Oil	10 to 16				

little or no distillable components. On pyrolysis (800°C), they leave >20% carbonaceous residue (fixed carbon). Most materials of this type are considered to be organic materials. Examples are gilsonite and uintaite which are prevalent in Utah, glance pitch (or Manjak) found in Mexico, South America and the Mid West, and grahamite which is found in North and South America.

Native asphalt[19] bitumens have API gravities in the range of −5° to 12°, are generally fusible at <200°F, and contain small amounts of distillate. They may or may not be found in association with porous rock. These materials have been used as caulking materials for boats or for road paving. Representative examples are found in Asphalt Ridge (Utah), Santa Cruz (California), Asphalt Lake (Trinidad), and Guanoco Asphalt Lake (Venezuela).

The majority of the heavy oils fall within the category of tar sand, oil sand, or carbonate-oil sand. API gravities range from 6° to 12°, bitumens are semi-solids or viscous liquids at room temperature, and they contain significant amounts of distillates. The majority of these resources is found in single, massive deposits. Representative examples are the Athabasca Oil Sands of Alberta, the Orinoco Tar Belt of Venezuela, the Melekess Oil Sands of Russia.

Heavy crude oils are viscous liquid bitumens having API gravities in the range of 10° to 20° and generally contain >30% of distillable materials. They represent the only sub-class of heavy oils which can be produced by primary methods. Primary production yields <10% of the oil in place. Representative examples include the oil fields at San Ardo (California), Lloydminister (Alberta), Gela (Italy), Ebano Pancuo (Mexico), and Boscan (Venezuela).

The significance of tar sands and heavy oils is that they are potentially the third most abundant energy source in the world and the largest source of naturally-occurring petroleum. Several single deposits of heavy oils individually contain more petroleum than the total known world reserves of conventional light oil.[20] However, they have not been exploited.

Heavy oils were historically the first petroleum resources to be utilized by man. Several references to the use of heavy oil for caulking boats occur in the Book of Genesis, and the first directly recorded uses were in 3800–2500 B.C. by the Sumerians.[19] The reason for their early utilization is the fact that heavy oils often occur as natural seepages or at shallow depths. Generally, the API gravity increases with depth. Thus, the most accessible oils have the lowest value as sources of the petroleum hydrocarbons that are presently needed. Unfortunately, the credibility of reserve statistics also decreases with depth. Heavy crudes of low API gravity (10–20°) are often disregarded in statistical surveys and are classified as unproducible by conventional techniques. Although many heavy oils occur as massive single deposits, within most deposits there are multiple seams or producible zones.[21] The oil in these zones may be from the same or a different source and can therefore have different physical and chemical properties. Within a single deposit, if one portion of the field is near the surface and another portion is deep, the quality of the crude may vary with increasing depth.[22] API gravity is highest in lower levels, and commonly the paraffin content increases with depth. The quantity of bitumen found in different locations will be referred to as the amount of oil in place and will be defined as the resource for that location.

3.2 *Available physical property data on tar sands and heavy oils*

Crude oil physical property data are scattered in a multitude of reports that vary from detailed analytical and processing studies[23] to a mere listing of API gravity and sulfur contents. Viscosity data are very often omitted.

A systematic accumulation of data is furnished by the U.S. Bureau of Mines as assays in the form of a multitude of Research Investigations (RI) of various crudes. In addition to these printed RI, data for 9000 Bureau of Mines assays are available in the form of punched cards in Fortran language for computer-manipulated searches.

Another source of information is API search tapes, including Petroleum Abstracts. References retrieved by these searches refer only to information published in the standard literature and do not include proprietary assay data published by oil companies or the Bureau of Mines.

Viscosity data, which are critical to production assessment for heavy crudes at different temperatures, are poorly documented. However, from available data it may be concluded that the viscosity change with temperature is fairly uniform for crudes with the same viscosity. Furthermore, the viscosities of the majority of heavy crudes appear to respond to changes in temperature in a common manner. Unusual changes in viscosity are not usually produced by a change in temperature. However, it has been reported that some heavy crudes are non-Newtonian fluids and some shear stress has to be applied before movement begins. This phenomenon has been found to be important in pipelining Venezuelan heavy oils.[24] The yield point as a function of temperature for a variety of heavy crudes gave a fairly linear response for most crudes. However, in one case (PAO-IX, a Venezuelan crude), a very sharp change in yield point with a small change in temperature was observed.[24] This fact indicates the importance of considering other approaches to traditional observations (e.g., ASTM viscosity) obtained for normal crudes. It has been recommended[11] that all viscosity measurements for heavy oils should be made under at least one standard shear rate. The viscosity is dramatically reduced with an increase of shear rate up to 40 lb/100 ft^2; beyond that point, little effect is noted.[24] Reduction of viscosity by blending with cutter stocks is an extensively used and well-defined procedure in the manufacture of heavy fuel oils from residues. However, the use of such a procedure for viscosity reduction of heavy crudes is not well defined or documented. Information of this nature should be obtained and included in reports of crude oil physical properties to aid in assessment potential.

The lack of critical physical data often limits the credibility of resource assessment. A recommended list of physical properties to be determined on U.S. heavy crudes is provided in Table 7.

3.3 *Resources and reserves of heavy oils*

Estimating the amount of oil contained in the United States is a difficult task because not all of the oil present in the ground can be economically produced. Accordingly, the following two numbers need to be considered: (a) Resource quantity, i.e., the total stock-tank volume of heavy oil and tar sand remaining in a reservoir, without regard to technologic or economic feasibility of recovery. (b) Proved reserve quantity, i.e., that part of the heavy oil or tar sand that can be recovered under existing economic and operating conditions in a given year. Another term often used is potential reserve, which represents that part of a resource that could become proved reserve using enhanced recovery operations (e.g., steam stimulation). The significance of the distinctions between the various definitions becomes clear when one considers some recent, well-documented studies of the oil found in Canada.[25] The in-place resources of Alberta are presently estimated as 2601×10^9 B of heavy oil and tar sand.† By contrast, the proved recoverable reserves are estimated to be between 157 and 472×10^9 B.

The occurrences, quantity of resources, and historical uses of asphaltites and asphalts have been described in detail.[19] Tar sands etc. and extractable bitumens (<12°API) of the world have been extensively surveyed.[17,18,20,25–31] Figure 10 indicates the location of U.S. tar sands and Table 1 provides recent estimates of the in-place resources of tar sands in the U.S.

Resource estimates of heavy crudes are much less definitive. Heavy crudes are of particular interest, however, in that some primary production (10%) is possible with these materials and large amounts are presently being produced by thermal stimulation techniques. Such crudes represent a larger fraction of the U.S. oil resource than tar sands. A survey of crudes of <25°API with some mobility in place was conducted in 1966 by the U.S. Bureau of Mines.[18] In

†1×10^9 B represent a volume the size of a football field and 22 miles high. The U.S. presently consumes over 5×10^9 B of oil each year.

Table 7. Desirable compositional and production data for heavy oils for inclusion in heavy crude assay databanks.

Geographical, Geological and Production Summary	
Crude name, sample identification, name of field, field location (with state and county names), geological source (with name, age, and depth of formation below the surface, thickness and type of pay zone), PVT properties (including $^{\circ}$API gravity for the separator and reservoir), viscosity at reservoir conditions, bubble-point pressure, viscosity at formation conditions, oil-and gas-formation volume factors.	
Crude Oil Summary - Bureau of Mines Classification	
Gravity, $^{\circ}$API	Carbon residue, wt.% (CCR)
Specific gravity, $60^{\circ}/60^{\circ}$F	Aniline point, $^{\circ}$F
Distillation	Sulfur, wt.%
IBP (5,10,20,30,40,50,60,	Hydrogen sulfide, PPM
and 70% volume recovered)	Neutralization No., total acid
	Water and sediment, vol.%
	Salt contents, lb/1000B
	Reid vapor pressure, lbs
	Nitrogen, total in PPM
	Nickel, PPM
	Vanadium, PPM
	Ash, PPM
Fraction 400-500F, % volume	Carbon, wt.%
gravity, $^{\circ}$API	Hydrogen, wt.%
mercaptan sulfur, PPM	C/H ratio
Flash point, $^{\circ}$F (TAG)	Distillation summary
Pour point, $^{\circ}$F (upper)	
Viscosity	Gasoline-naphtha, IBP-392°F,
kinematic, 60°F (15.6°C), cs	vol.%
100°F (37.8°C), cs	Kerosine, 392-527°F
130°F (54.4°C), cs	Light gas oil, 527-690°F
	Heavy gas oil, 690-790°F
	Residuum, 790°F^{+}

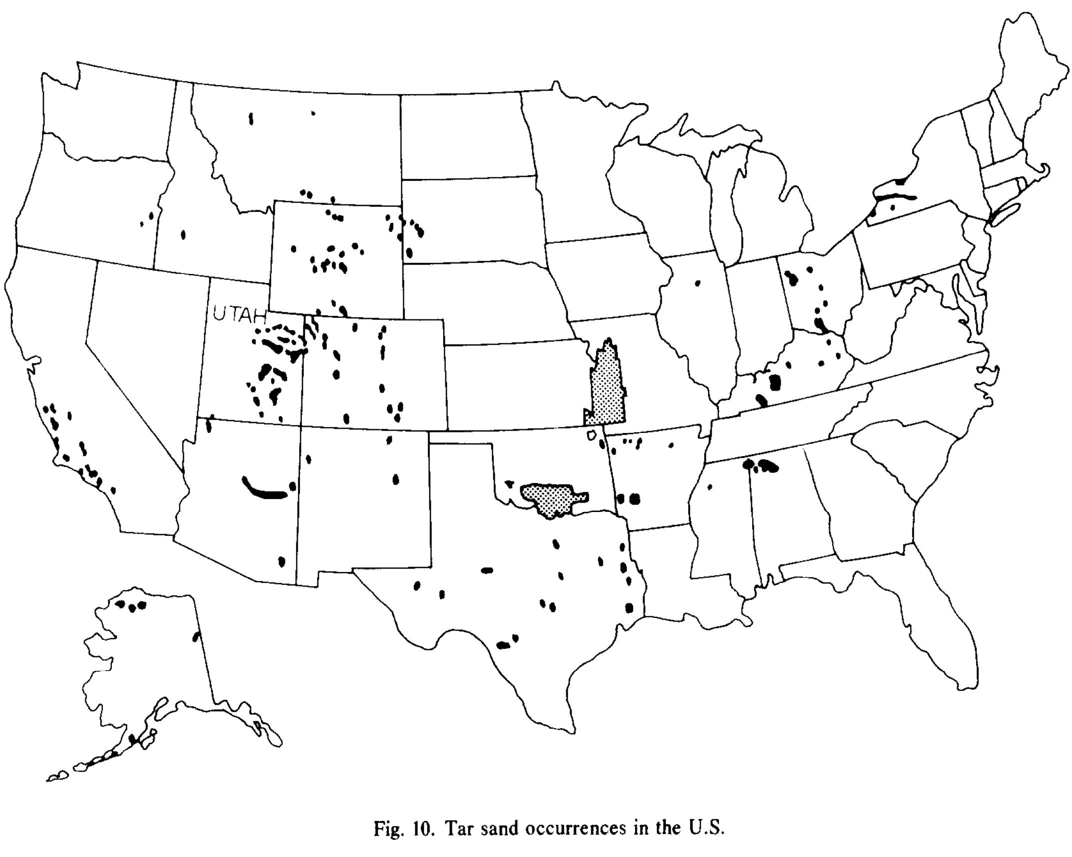

Fig. 10. Tar sand occurrences in the U.S.

this survey, resources were further classified with respect to ease of recovery as follows: (a) Class 1—Desirable characteristics for thermal recovery operations, such as sandstone reservoirs at depths of less than 3000 ft, greater than 10 ft thickness, stock tank oil saturations of 750 B/acre-ft or greater, viscosity of oil sufficient for mobility at existing conditions. (b) Class 2—Some but not all of the specified desirable characteristics. (c) Class 3—Only a few of the listed desirable characteristics.

We consider only crudes with API gravities <20°. The locations of known resources of heavy crudes of the U.S. are shown in Fig. 11 and their ease of production is indicated in Table 8. Reference to Table 8 shows that about 55.5×10^9 B of heavy crude (<20°API) were in place in 1966. Had we chosen crudes with <25°API, the estimate would have been larger (106.8×10^9B).

Magnitudes for the resources of heavy oils and tar sands of Kansas-Missouri-Oklahoma have fluctuated dramatically in the past few years. Estimates as high as 100×10^9B of oil have been made.[32] However, recent estimates made by state geological survey offices have tended to be much less optimistic.

Evaluation of heavy oil and tar sands in Bourbon, Crawford and Cherokee Counties, Kansas, by the Kansas Geological Survey in December 1977 indicated a resource base of $0.200–0.225 \times 10^9$ B of oil-in-place, none of which was recoverable for 1977 technology and economics. The estimates of resource size are severely downgraded from earlier estimates because of the discontinuous nature, thinness and shaliness of the reservoir sandstone bodies.[33]

An evaluation of the heavy oil potential of northeastern Craig and northwestern Ottawa Counties, Oklahoma, by the Oklahoma Geological Survey (June 1979) concludes that insignificant quantities of heavy oil are present.[34]

An inventory of heavy oil in western Missouri, by the Missouri Department of Natural Resources, Division of Geology and Survey (September 1979), showed a resource of 1.4 to 1.9×10^9 B of oil-in-place, none of which was considered in a reserve category for 1979.[35]

Many heavy oil reservoirs are presently being exploited using thermal techniques.[18,36] The total U.S. reserves estimated in 1975 were 2.6×10^9 B.[37]

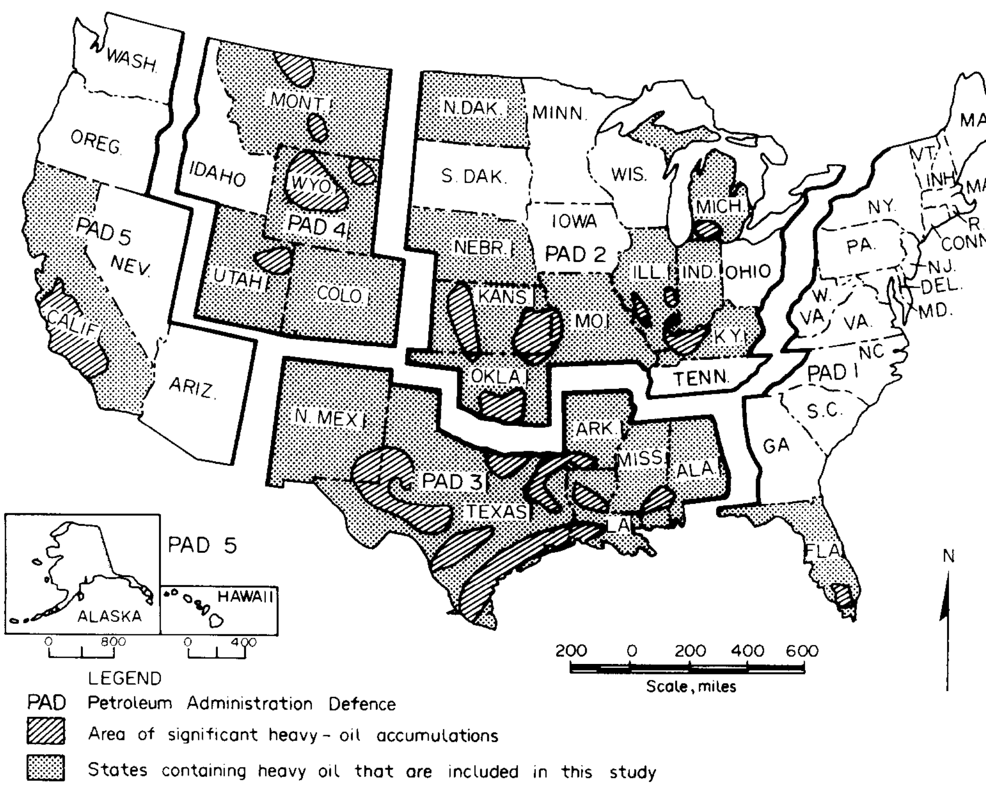

Fig. 11. States containing heavy crude oil included in this study.

3.4 *Ultimate recovery of heavy oils (proved reserves)*

The term resource has been used to designate the amount of oil-in-place. Typically, only about one-third of this oil is recoverable by conventional technology. In the production of heavy oils, heat must be applied to the reservoir to render the oil fluid. This is generally done by the injection of steam, which also aids in pushing the oil to the production well. This steam, in turn, is commonly generated by burning a portion of the crude that has already been produced. As much as 40% of the produced crude oil may be consumed to generate the required steam. Thus, only 20% of the original oil-in-place would be available for sale. This saleable heavy crude oil will require upgrading to conventional crude quality, which results in additional losses of resource.

In the recovery of heavy oils by aboveground mining of tar sands, much energy is consumed in the removal of overburden, mining of the tar sands, and land reclamation. This energy is supplied by the crude which is produced. As the result, only about 50% of the original heavy oil is recovered for sale or upgrading.

In Alberta, economic studies have been initiated to assess the ultimate recoverable resources and the ultimate yield of upgraded crude for each of the major tar sand deposits;[25] individual zones of Cold Lake and Wabasca were treated separately. Similar studies were recently conducted also for U.S. tar sands using somewhat different criteria for reserve estimation.[26]

The fractional recovery from mined sands is about twice that for *in situ* production of Athabasca sands. Thus, mining is the preferred route where possible. *In situ* production from other reservoirs in Athabasca provides very low yields of recoverable oils (2–6%).

For economical recovery of the bitumen from a given deposit, well defined criteria must be met. The authors of Ref. 25 have made assumptions concerning mineability based on the weight percent of raw bitumen present, the overburden thickness and the energy required for mining the bitumen. They define a "mineability factor," which must be >5 to have an economically viable recovery. Similarly, when the bitumen is produced via steam injection, a certain fraction of the crude must be burned to generate steam. For such steaming to be economical, a "thermal

Table 8. United States heavy crude oil resources (less than 20°API with some mobility[18]).

PAD district	Location	1965 estimate of oil-in-place, billions of bbl	Resources by class		
			Class 1	Class 2	Class 3
1	East Coast (mostly Florida)	0	0	0	0
2	Illinois	0.0003	0.0003	0	0
2	Indiana	0.0102	0	0	0.0102
2	Kansas	0.0002	0	0	0.0002
2	Michigan	0.0010			
2	Oklahoma	0.472	0.039	0.035	0.398
3	Alabama-Mississippi	4.548	3.919	0.612	0.017
3	Louisiana	0.486	0.384	0.032	0.070
3	New Mexico	0.051	0	0	0.041
3	Texas	10.310	0.670	2.730	6.910
4	Colorado	0.010	0	0	0.010
4	Montana	0.010	0.005	0.001	0.003
4	Utah	0.633	0.616	0	0.017
4	Wyoming	1.032	0.752	0.270	0.010
5	California	36.339	29.010	3.656	3.673
5	Alaska	0.013			
	TOTAL:	55.546	35.396	8.734	11.416

ratio" (crude produced vs crude burned) was developed.[25] A value of 4 was believed to be required for economical production.

Different forms of energy are not equivalent. Replacement of the energy source used in production by a less valuable fuel (e.g., coal) will provide the same energy at lower cost. This, in turn, will allow higher ultimate yields of upgraded crude. Workers at the Imperial Oil Co. have considered coal as a heat source in Alberta.

Similar resource assessments in the U.S. have provided a detailed analysis of the ultimate producibility of U.S. tar sands; only $\sim 0.1\text{–}0.2 \times 10^9$ B of U.S. tar sands could be recovered by mining and $\sim 2 \times 10^9$ B could be recovered by *in situ* techniques.

An assessment of the potential recoverable reserves of heavy oils (<20°API with some mobility in place) was conducted in 1966; at that time, estimates of 2.5 to 5.5×10^9 B of recoverable reserves were made. However, these data did not include information on Alaskan oil. Many new heavy oil reservoirs have been identified since that time and it would be advisable to update these earlier estimates.

3.5 *Conclusions*

Resources and reserves need to be much more clearly defined, both in terms of resource quantity and the physical and chemical properties of the oil-in-place. A systematic assessment of the U.S. tar sands and heavy oil resources should be undertaken. This assessment should include enough detailed information about mining and *in situ* stimulation to allow reasonable estimates of the proved and potential reserves from all major U.S. reservoirs. An approach similar to that taken in Alberta[25] and in past surveys in the U.S.[26] is recommended. This information should be made available in a manner similar to that used in the Bureau of Mines crude assay data bank (either in the form of computer cards or tapes) so that commercial ventures may be encouraged.

4. PROCESS RESEARCH RELATING TO OIL RECOVERY FROM TAR SANDS AND HEAVY OIL SOURCES

The following discussion deals with oil recovery from tar sands and heavy oil sources.

First-generation technology for oil recovery from tar sands through surface mining and aboveground processing is being practiced commercially in Canada (see. Section 2.2). Considerable work is in progress to demonstrate modified and alternative extraction concepts in place of the hot water process practiced in Canada. These operations are being conducted in large-scale demonstration plants located in the field. The concepts involve solvent extraction,[38] incorporation of a high shear mixing step in the hot water process,[39] and pyrolysis.[40]

Laboratory testing of advanced concepts using fluid-bed pyrolysis[41] are under way.

The major portion of the tar sands resource will have to be processed by applying *in situ* techniques. *In situ* processing has not been commercialized on tar sands and is currently limited to field tests. Two of the ongoing projects are described in the site visit reports on the Shell Canada test site at Peace River (Ref. 1, AB-7) and the Saner Ranch work of Mobil and Continental Oil (Ref. 1, AB-5). Combustion and steam drives are being investigated. Novel ideas dealing with radio frequency heating and combinations of mining and *in situ* methods have also been proposed but have not been tested on substantial scales.

4.1 *Surface mining and aboveground processing of tar sands*

The large and long-duration settling ponds associated with the water extraction process present a challenging and serious problem and may be needed for some U.S. tar sands. Development work on ways to reduce the oil content of the aqueous residues from the process should be supported at both the laboratory and demonstration scales. It is also desirable to develop economical methods for diminishing the settled volumes of inorganic fines in the ponds, thereby reducing the ultimate sizes needed for the ponds. Purification of large volumes of clarified water will generally be a site-specific investigation. Successful fundamental studies should provide leads relating to the effectiveness of the use of resins, microbial action, floatation, oxidation, colloidal techniques, flocculation, etc.

Solvent extraction of tar sands eliminates serious problems encountered in connection with use of the settling ponds that are needed in the hot-water Clark process. On the other hand, the use of solvents entails the disadvantages associated with handling large amounts of expensive, flammable solvents and the associated augmented capital and operating costs. An item requiring special attention is the reduction of hydrocarbons in the discharge sand streams to acceptable levels in view of existing air standards. A number of industry-sponsored projects is currently underway utilizing solvent extractions. Because of these proprietary investigations, only fundamental research is recommended in this area. However, the support of field projects may be appropriate when the federal government is involved as a partner.

Thermal processing techniques, such as those proposed at Lurgi and Taciuk,[42] as well as the use of fluid-bed technologies, will involve the common problems of solids removal from liquids and gases and combustion of coke on the pyrolyzed sand. Improved methods and apparatus for implementing these processes should be supported at both the laboratory and demonstration scales.

4.2 In situ *processing of tar sands and heavy oil sources*

In situ processing has two characteristics which are fundamentally different from mining followed by aboveground processing. These bear importantly on the choice of appropriate research topics and on prospects for success. *In situ* recovery involves well-bore technology. This statement implies that only very limited control can be exercised over flow processes in the reservoir. Furthermore, it is not possible to obtain exact information on reservoir properties and flow conditions. Secondly, it is practiced in hundreds of reservoirs. There are, perhaps, thousands of candidate reservoirs. Each site or potential site represents a unique situation characterized by oil properties, host-rock, reservoir fluid, geology, resource size, etc. This diversity means that each site or potential site has many characteristics that require site-specific approaches. The search for a general solution to improved *in situ* recovery may not be fruitful.

4.2.1 *Intensive oil and rock properties.* Those oil and rock properties which depend on the composition but not the spatial arrangement of oil and host rock are most susceptible to fruitful laboratory studies. Generally, this means defining the chemistry of the reservoir of interest. Topics for study in this category include, for instance, (a) rock mineralogy, (b) chemical compositions of oils, (c) interactions of clay with caustic, (d) absorption and adsorption data on surfactants, (e) reservoir brine compositions, (f) interfacial tension modification by surfactants, (g) sacrificial surfactants, (h) oxidation processes occurring underground, (i) reservoir pressures as functions of variables, (j) reservoir temperatures as functions of other parameters.

In many cases, examination of intense oil, rock, and reservoir properties will narrow the range of possible EOR techniques and suggest likely candidates. The thermodynamics of oil-rock interactions has been formulated with elegance and generality.[43] Unfortunately, the data tend to be highly specific to the intensive properties of the candidate reservoir under study. Possibly, if the required data were available in many cases, they could be used to estimate upper limits on recovery possibilities. At present, such estimates can probably be produced to useful accuracy by rules-of-thumb or by assumption.

It has been suggested that amassing data banks covering many reservoirs will be useful. This hypothesis seems questionable because, since reservoir data are extremely site-specific, the data bank may have limited general utility. At the present time, it is still necessary that holders of individual candidate reservoirs develop the specific data needed for their own reservoirs.

4.2.2 *Reservoir descriptions and modeling.* Real reservoirs regularly contain faults, inhomogeneities, and other such unpredictable structures that it is not to be expected that laboratory results will be matched in the field. Mathematical reservoir modeling has proved to be useful in relating physical descriptions of a reservoir with data on oil, rock, and other intensive properties to suggest *in situ* process control strategies and to predict performance results for given control strategies.

As the computational art has advanced, models have become larger and more sophisticated. Not surprisingly, there is a continuing demand for larger and more exact models (which, of course, require better input data) and for more exact resource characterization (which requires better models to utilize the data). There is no limit, in a practical sense, to the size and sophistication of models nor to the detail with which data may be developed. It is, however, axiomatic that perfect reservoir descriptions can never be had.

Each specific proposal must necessarily be judged on its merits. Criteria such as the following may be useful:

(a) Will more data (improved resource characterization, indirectly measured *in situ* diagnostics) cause a given model to produce different results? (b) Will an improved model formulation (e.g., more exact flow equations) utilize data which can be obtained at reasonable cost? (c) Given new information (model predictions) from (a) and (b), can this information be implemented in new and practical field operating procedures? (d) Will the new procedures improve project economics?

If affirmative answers are not expected at the outset, healthy skepticism about the proposed new data and/or modelling seems in order.

4.2.3 *Tar Sands processing.* Because the viscosity of oil decreases exponentially as the temperature is raised, heat injection or *in situ* heat generation in a reservoir may be desirable procedures if the reservoir conditions are favourable. Two methods for heating the reservoir are steam injection and *in situ* combustion of hydrocarbons (coke).

4.2.4 *Thermal recovery with steam.* A useful steam soaking technique is huff-and-puff steaming. In this procedure, steam is injected for a period of time into the well and the flow of steam is then terminated after soaking. The well is subsequently put on production. For suitable formations, augmented production will result for an acceptably long period of time.

An alternative idea involves steam drive. In this process, the steam flows into the oil reservoir through injection wells and the reservoir oil is produced through adjacent production wells. Formation permeability and oil saturation must be adequate for implementation of this procedure.

The following application areas should benefit from a field-test support program: (a) establishment and maintenance of flows; (b) generation of lower cost steam, e.g., by fluid-bed combustion using lower cost fuels than are produced; (c) improvement of down-hole steam generation; (d) measurements of down-hole steam quality; (e) determinations of benefits derived from the use of clay stabilizers by multiple-well testing in a sensitive fresh-water formation; (f) improved processes for recycling water to the steam-generation plant or preparing the water for disposal; (g) steam distributions to produce reductions of channeling and of steam override; (h) the use of reduced well spacing; (i) use of drainholes; (j) high-pressure injection of steam into low permeability formations.

4.2.5 *Thermal recovery with combustion. In situ* combustion methods are used in a number of variations. These encompass dry combustion using only air injection and quenched *in situ* combustion which utilizes simultaneous or alternate injection of air and water into a reservoir that supports burning. Quenched combustion produces flows of flue gases through the formations. High-pressure, down-hole steam generation also induces flows of the flue gases through the formations.

The sequential use of reverse combustion during a preparatory stage, followed by a forward combustion drive, has been reported.

Support of field projects is desirable in each of the following areas. (a) The development of high-temperature packers and insulation systems merits support. (b) Steam generation in the oil formations by means of *in situ* combustion and water injection, with supplementary injection of fuel for *in situ* combustion, is an untested technique that may improve the *in situ* generation of steam. (c) Cleanup and disposition of low Btu gases and their use for cogeneration of air compression are possibilities. (d) The determination of benefits derived from injection of oxygen-enriched air or pure oxygen should be studied.

4.2.6 *Novel techniques.* The following discussion covers some novel ideas which may be applicable to *in situ* processing. Support for these concepts at the pilot plant and field stages is worthy of consideration.

(a) *Radiofrequency heating.* As proposed by workers at the Illinois Institute of Technology, a pattern of bore holes is drilled at a suitable site. This pattern of conductors is designed in such a manner that radiofrequency energy may be applied. The formation is first heated to 100°C and, subsequently, the bore holes are converted into injection and production wells. A hot caustic flood has been proposed for later injection.

(b) *Mine-assisted steam injection.* Several concepts have been proposed for mine-assisted steam injection. A modified *in situ* process involves rubblizing the formation so that *in situ* techniques can be used in highly permeable sections. Another idea requires drilling of tunnels upward. Heat is injected to cause the oil to drain into the tunnels. Alternatively, caverns could be mined and horizontal radial wells drilled into the formations.

The concepts relate especially to improved steam-contacting within the reservoir bed. There are uncertainties in every aspect of the processes involved: (i) the reservoir may be inadequately characterized and space-dependent estimates will not be available for porosity, oil in place, permeability, surface properties; (ii) if the reservoir bed were adequately characterized, the flow of the reacting fluids through the porous beds could be described quantitatively only if constitutive equations were available under reservoir conditions; (iii) improved *in situ* diagnostic procedures are needed to follow the progress of steam floods through the reservoir beds.

The idea that directional drilling and horizontal injection at selected reservoir depths will improve oil recovery has practical appeal and resulting measurements may be expected to lead to improved reservoir-performance models.

(c) CO_2 *huff and puff.* Alternate injection and release of CO_2 in a formation with suitable integrity, both with and without steam preheating, offers possible advantages that are worth pursuing.

4.2.7 *Process research relating to heavy oil sources.* As with mining and aboveground processing of tar sands, EOR for heavy oil sources is commercial technology. In fact, U.S. oil production from these sources is about twice the rate of Canadian syncrude production.

The *in situ* techniques used with the tar sands are applicable to heavy oil sources. These include thermal processes using steam, combustion, a combination of steam and combustion, CO_2 injection, etc. In addition, surfactant chemicals are sometimes employed.

4.2.8 *Fundamental supporting research.* The following research items cover both laboratory and field tests and apply to either or both surface or *in situ* processes.

(a) *Basic clay research.* An area of research applicable to both surface and *in situ* tar sands processing is related to the effects of fresh water solutions on some clays. Basic research on the properties of clays, using the best available techniques and tools, will be useful for two reasons: (a) better understanding of clay properties should lead to reductions of oil loss in silts and clays and consequent reductions of the sizes needed for the holding ponds encountered in practice when the hot-water bitumen-recovery process is employed; (b) new approaches may lead to the stabilization of fresh-water-sensitive formations containing swelling clays.

Fundamental work should be pursued on purifying the clarified process waters to make them environmentally acceptable.

(b) *Sand control.* In practice, the present need to control the flow of sand may represent a serious impediment to achieving lasting oil-production improvements. Alternatives to sand control in unconsolidated formations should be investigated. The sand-bitumen mixture could be produced and separated at the surface. The method of lifting could involve a pump capable of handling a slurry. Development work on such a pump would be appropriate.

4.2.9 *Transportation of bitumen-water-sand slurries.* Bitumen-water-sand slurries[44] have been shown to have greatly reduced viscosities at moderate temperatures. A large scale field test to determine the feasibility of using slurries rather than diluents would be of interest.

4.2.10 *Down-hole steam generation.* Each of the following R&D programs may contribute to better understanding and improved oil recovery in the long-term utilization of down-hole steam generators: (a) combustion research (including equipment changes, use of preheaters, recirculation, etc.) to allow direct utilization of oil-field crude in down-hole steam generation; (b) long-term environmental impact assessments (involving both gaseous effluents and residue stability) with down-hole steam generation; (c) quantitative studies on the efficacy of mixtures of steam and combustion products in enhancing oil recovery.

4.2.11 *High-temperature packers and insulation systems.* Material problems and studies bear on the design of packers to confine fluids in the well annulus. The high-temperature environments under which the packers must function for prolonged periods of time pose special problems. Of particular importance is maintenance of bottom-hole integrity with quantitative characterization of heat and other losses.

4.2.12 *Reservoir properties research.* This program will presumably emphasize the fluid-dynamic aspects of reservoir modeling, with particular attention to physical properties that determine absolute and relative permeabilities and fluid movements.

4.2.13 *Compatibility studies.* Transportation of the bitumen produced from *in situ* processing usually requires addition of a diluent. Compatibility studies for projected mixtures would be useful.

5. ENVIRONMENTAL ASPECTS†

Oils from tar sands and heavy oil crudes cannot be readily extracted because of their high viscosities at reservoir temperatures. They are found in a variety of deposits and display a wide spectrum of site-specific properties. The mobilities of these oils are increased by using a variety of heating techniques or by extraction with chemical additives. Both *in situ* and aboveground treatments are used. Domestic reserves of heavy oil sources need to be better characterized and are currently estimated at 110–125 billion barrels of which 7.5–20.5 billion barrels appear to be recoverable at competitive costs. Current domestic production from EOR is about 300,000 barrels per day. Expanded production has been restricted by economic and environmental constraints. Current domestic production is accomplished by using *in situ* EOR. Domestic aboveground processes are still at the model study stage.

Most of the environmental problems can be solved through application of existing control technologies. However, currently available control technologies may be costly. There are areas where research would be expected not only to lessen environmental impacts but also to improve process economics. We focus here on key environmental issues for which further research may be expected to have a significant impact on production. Our discussion is not meant to represent a review of all of the many environmental problems which could be addressed. Important issues relate to air, water and land disturbances.

5.1 *Air quality*

Air-quality constraints are potentially limiting in the use of thermal methods for enhanced oil recovery when the combustion phase takes place above ground. Steam-injection technology is widely used in Kern County and air-quality considerations in this area illustrate the serious nature of the problem. If crude oil is burned as a heat source, problems may arise from the production of SO_x, NO_x, particulate matter, and hydrocarbons. Roughly one barrel of oil is burned for every two net barrels of oil produced.

The sulfur contents are typically 1–1.5%. During combustion, 99% of this sulfur is converted to SO_2 along with 1% of SO_3, Thus, 7.5 pounds of SO_2 are produced for every barrel of oil burned. The current Kern County emissions limits are 250 tons of SO_2, daily.

The NO_x emissions are produced, in part, by combustion using air (thermal NO_x) and, in part, from nitrogen in the fuel. The steam generators used in Kern County have typical NO_x emissions of 3.5 pounds per barrel of crude burned. The total NO_x emissions from thermally enhanced crude oil production in Kern County are about 120 tons per day. Uncontrolled emissions of particulate matter are 0.66 pound per barrel burned, with current daily emissions estimated to be 23 tons per day. During steam drive, hydrocarbons are emitted along with excess steam from the well casing. These emissions are estimated to be 337 tons per day for all of the wells in Kern County.

There currently exist partial technical solutions to these emission problems. The SO_x emissions are most commonly controlled by flue-gas desulfurization using exposure to a single pass of sodium hydroxide, lime or limestone slurry, or double alkali solutions. With all three of these methods, 95% reductions in SO_x are achieved. Sodium hydroxide and lime are currently in service on oil-field steam generators. These methods produce additional environmental problems in the disposal of the scrubber waste stream, either through reinjection into the well, in a holding pond, or another storage area. The wastes are classified under current regulations of the Resource Conservation and Reclamation Act. Disposal sites in Kern County are rapidly running out of capacity. The scrubbers are not cheap and they have been estimated to contribute as much as \$6–9 per barrel of oil produced to the final product cost.

The NO_x emissions are partially controlled through combustion modification techniques. With some commercially available burners, NO_x emissions are lowered by 50%. These are the most cost effective available procedures for reducing NO_x emissions. A flue gas clean-up

†Important issues dealing with facilities safety, worker health and a health registry, biological and toxicological problems, and other environmental aspects are reviewed in an NRC study on "Synfuels Facilities Safety", Washington, D.C., April 1982.

technique has been developed in which ammonia is added to reduce NO_x in the gas stream at 1750°F. A patented, commercially available system is Thermal DeNO_x, which is licensed by Exxon. This NO_x removal system has a very narrow temperature window for effective operation, as well as other critical process variables.

Particulate emissions are currently partially controlled by the SO_x clean-up procedures. Conventional SO_x scrubbers remove roughly 50% of particulate matter. Other scrubbers have been designed to reduce particulate emissions by up to 90%. Electrostatic precipitators and baghouses may also be used. Hydrocarbon emissions can be controlled by trapping the emitted steam at the wellhead and passing it through separators and condensers. The Getty Oil Company has used these systems in Kern County with excellent results.

Since SO_x emissions are currently believed to be potentially limiting, they should receive priority attention. There is a need for improved scrubber technology and this improved technology should also be of potential benefit in other synfuels processes such as direct coal utilization. Current work on down-hole steam generators should be vigorously pursued since recent Sandia studies have shown that most of the emissions will be trapped by the deposits underground. Down-hole steam generation is a more efficient thermal technique than above-ground steam generation and is applicable for deep deposits.

Another useful research area involves approaches for lowering the sulfur contents of fuels before they are burned. This reduction may be accomplished by using available refining technologies but the economics for this approach are unattractive. Research on inexpensive methods for sulfur removal is a high priority recommendation.

A 1979 study by A. Goodley of the California Air Resources Board suggested that NO_x emissions could be the constraining element for enhanced oil recovery in Kern County. Hence, improved methods should be developed for scrubbing NO_x from flue gases, including procedures for trapping the nitrogen in usable form for applications in fertilizers and other commercial products.

Among priority research items, we note the need for air-dispersion models over mountainous regions, as well as quantitative measurements of organic effluents and their toxicological characterization.

5.2 *Water quality*

Potential problems in enhanced oil recovery or tar sands development are water availability and maintenance of water quality. These are not near or even medium term problems. At steady-state production, it is estimated that 2 to 4 barrels of water will be used for each barrel of oil produced; for comparison, we note that enhanced oil recovery by steam stimulation in the Cold Lake region of Alberta involves the use of 2.5 barrels/barrel. Because in current processes little use is made of process waters, there are several waste streams to be disposed of. The largest of these (~1.5 barrels/barrel) and the most difficult to treat is the produced water, which is a mixture of condensed steam and the usually saline waters within the reservoirs that are contaminated by an array of not well characterized, dissolved organic materials.

As for air emissions, it appears that water cleanup should be achievable by using currently available technologies. Two potential problems should be emphasized. A probable disposal route could be reinjection into the formation through a deep well. The hydrology of each deposit would have to be well known in order to avoid contamination of high-quality aquifers. However, such aquifers appear to be uncommon at most recovery sites. Standards are now being set, on a state by state basis, for underground injection codes. The proposed Utah code would exempt some aquifers from regulation but would otherwise require modeling and monitoring. The theoretical basis for this type of modeling is not well understood and there have been difficulties in monitoring highly complex hydrological systems. Further studies in these areas, as well as research on improving the quality of recycle waters, are recommended.

Special problems arise with the use of alkyl sulfonates as micellar additives. Studies coordinated at the Laramie Energy Technology Center have shown adverse biological effects for these materials. Investigations are needed to define the migration and ultimate fates of these materials. Similar studies should be performed on the combustion products from bitumens that will be left after applying *in situ* combustion technologies.

A major problem encountered in the Canadian tar sands industry involves large, highly alkaline tailings ponds. This problem will be absent in the processing of Utah tar sands according to studies performed at the University of Utah. On the other hand, for other resources, aboveground treatments may be used on oils bound to deposits with high clay contents. For these, research on clay chemistry could serve to ameliorate the settling pond problem when it arises. These investigations should include fundamental studies of the effects of surfactants of all types, including microbial surfactants, in enhancing settling rates in tailings ponds.

A long range, fundamental program on water recycling and cleanup, under the special conditions arising in oil recovery from tar sands, should be started. The problem of removing dissolved organics is a priority concern.

5.3 *Land*

We have not noted land-use problems produced by underground enhanced oil recovery. Since the proposed development of the Utah tar sands will utilize surface mining, there is an issue of land reclamation. This problem can, however, be readily solved with good mining practices. The sand returned to the mine will be cleaner than the material that is originally removed. We have not identified research needs relating to land reclamation.

6. FUNDAMENTAL RESEARCH ON OIL RECOVERY FROM HEAVY OIL SOURCES AND TAR SAND TECHNOLOGY

6.1 *Basic research policy*

Basic research requires stable funding and is not usually addressed to the solution of near-term problems, although it may be motivated by and relate to these. The impact often becomes evident some 20 to 35 years after a discovery is made. This lead time is reduced to 10 to 15 years in rare instances. Such a long time span is not attractive for capital investments. For this reason, even the most technologically advanced and research oriented industries have generally chosen to put only a small fraction (0–8%) of their R&D efforts into basic research. Traditionally, the investments of private industry have been relatively smaller in energy research. An example is provided by the Gas Research Institute, which is a cooperative venture sponsored by the public utilities providing natural gas in the U.S. About 8% of the R&D effort has been earmarked for basic research (in 1982, about $4 million). This amount should be contrasted with about $25 billion in sales generated annually by the U.S. gas utilities.

Without government funding, it is unlikely that adequate basic research will be done. Without basic research, it is less likely than it might otherwise be that the technologies employed in future energy industries will be either substantially different or far more efficient than currently known technologies. While the performance of basic research does not guarantee technological development, it has been shown to be the most cost-effective method for making significantly new technological discoveries.

Using estimates that have prevailed historically in the petroleum industry with respect to R&D expenditures relative to sales, we estimate that the oil industry will spend $30 to $60 million per year on basic research in the EOR and tar oil industries as these resources are phased into production. Arguments have been made that a comparable sum should be spent in a government program. Historically, private sector and government expenditures in R&D have been about equal.

6.2 *Examples of basic research*

We list key areas of basic research.

(a) Resource characterizations: (i) properties of heavy oils and tar sands; (ii) methods for resource characterizations; (iii) geochemistry of oil-bearing rocks, including the structures of clays, sands, sandstones, etc.

(b) Reservoir characterizations: (i) electromagnetic methods; (ii) diagnostics using sound propagation; (iii) studies of elastic waves in reservoirs; (iv) nuclear signatures; (v) seismic data; (vi) characterizations using a multiplicity of techniques.

In all cases, the emphasis should be on understanding how the measurements yield information on the structure of the porous media and containment of fluids. An instructive example is provided by dielectric constant measurements, for which combinations of theory, laboratory experiments on simulated porous media, experiments on rocks and sands, and finally field tests are required to establish assessments for the utility of these data as a function of frequency.

(c) Flows in porous media: (i) the theory of one-component flows in non-isothermal porous media (for various gas-surface interaction models), as verified by laboratory experiments; (ii) flows of mixtures with two or more components through porous media; (iii) multiphase, multicomponent flows. For these important studies, applicable constitutive equations are required, which must be solved with proper allowance for thermal, diffusive and reactive processes, subject to well defined initial and boundary conditions.

(d) Physico-chemical phenomena: (i) thermodynamic equilibrium data for appropriate multicomponent systems; (ii) thermochemical and transport coefficients; (iii) interfacial phenomena; (iv) wetting of porous media; (v) surfactant designs and mechanisms by which they act, including studies of emulsification; (vi) behavior of polymers that have been added to effect drag reductions, oil/water compatibility, modifications of surface forces, etc.; (vii) interactions of chemical additives with oil-bearing sands and rock surfaces, including especially studies of the influence of pH.

(e) Reservoir engineering: (i) simulation of forced flow patterns in rock matrices; (ii) improvements in modeling multiphase flows in porous media during resource recovery.

(f) Thermal recovery: (i) *in situ* combustion phenomenology, with emphasis on flame-front propagation, wave stability, reproducibility of measurements, and model validation; (ii) steam-flow patterns and steam recovery; (iii) reservoir integrity during resource recovery, thermal front mapping, and comparisons with model predictions.

(g) Materials problems: (i) down-hole corrosion assessments; (ii) pumps and valves for operation in high-temperature, high-salinity environments.

6.3 *Resource characterization*

Unusual problems result from resource inhomogeneities. There is no one characteristic or canonical heavy oil or tar sand. There are many sources and products, varying broadly in chemical composition and physical properties and occurring under an extraordinary diversity of conditions and terrains. This variability has profound effects on the technologies that may be used in the recovery of heavy oils from a given location. A successful approach in one deposit does not guarantee similar success in another, even in a nearby field.

The diversity of oil-sand materials suggests that a prime task is establishment of major categories of heavy oils and of sand formations. If this program succeeds, then a central sample bank could be used to make comparisons of results obtained at different locations. Resource classification programs of this type exist for coal and shale. Even the conclusion that a characterization program cannot be developed is useful because this fact will profoundly influence the types of work that can be done and the kinds of results that can be expected. Of equal importance is the need to define recovery costs in terms of resource-characterization parameters.

Work on flow properties in heavy-oil deposits depends on the physical structures of the formations, as well as on their depths, porosities, and dimensions. It is of interest to attempt classification according to these properties. The owner of an oil field will be interested, almost exclusively, in his own field. If every field is substantially different from every other field, a basic research program may not be fruitful.

6.4 *Thermal recovery methods*

To extract heavy oils, they must be mobilized, which is currently done by heating or by dissolution. The temperatures needed are 100 to 200°C and higher. A variety of methods has been used to heat oil fields. These include steam injection, hot fluid injection, hot CO_2 injection, and *in situ* combustion. These techniques are currently applied empirically. Several operators have developed programs to model oil-field response to steam/water treatments. At temperatures above about 350°C, heavy oils begin to pyrolyse and release lower molecular weight gas and fluids, as well as non-volatile chars. Pyrolysis has profound and irreversible effects on flow properties through the deposits.

In situ combustion produces heat directly in the deposit, thereby removing the need to transport thermal energy down a long pipe. It also appears to reduce environmental problems associated with power generation, since some of the exhaust gases from the burners are absorbed in the oil formations. However, the effects of the higher temperatures on the oil and sand, as well as the influence of hot exhaust gases from the combustion zone on oil-sand properties, are not well understood. Study of the effects of combustion on the physical (flow) and chemical properties of oil-sand formations may prove to be fruitful. Common to all of these thermal methods is the transport of heat by gases (steam, CO_2, etc.), fluids such as hot water, or alkaline solutions. Thermal energy transports should be modeled quantitatively for various types of oil-sand formations and a theoretical effort aimed at improved understanding of thermal transports in low-porosity media might yield substantial rewards.

Modeling should be done of flow properties in oil-sand media under treatments such as steam drive, alkaline flooding, steam or CO_2 drive, etc. Theoretical efforts should be closely coupled to tests. The empirical approaches actually used are often employed in the absence of detailed characterization of the field. Thus, when they are totally or partially unsuccessful, reasons for the failures may not be apparent.

Heating of a heavy oil deposit involves heat transport and fluid flows under conditions of high pressure and partial or total immiscibility. Transport of heat by conduction is so slow that we must rely on convective heat transfer in the field. Convection involves motion of gases, liquids or both through the field. Steam has a vapor pressure of 69 psia at 150°C and 225 psia at 200°C. If the field pressure exceeds these values at the specified temperatures, the steam will change to liquid water, which is much denser, has a much greater viscosity, and flows extremely slowly in capillaries wetted by oil.

The steam quality is an important parameter in steamdrive techniques. A part of the problem with hot water drive is that the water, which is much less viscous than the oil, will move more rapidly through sandstone pores that are not wetted by oil. While this is desirable for heating, it introduces heat into the wrong parts of the formation. This problem is susceptible to theoretical analysis and detailed modeling. The steam-water composition changes quickly and depends on field pressures and temperatures, as well as on source temperature.

Hot CO_2 is preferred over water-steam mixtures because it is soluble in oil and, furthermore, oil/CO_2 solutions have lower viscosities than pure oil. However, CO_2 is more expensive to use than water. In addition, CO_2 also moves rapidly through the more porous parts of the field so that its use occurs effectively in a huff-and-puff mode. It is pumped into a closed field without open channels. A study of the transport properties and phase behavior of CO_2 in heavy oils is essential for understanding the use of CO_2.

6.5 *Chemical additives*

Chemical additives have been used to improve the efficiency of the steam/water drive. Oil release by hot water involves heating of oil in the sandstone capillaries to the point where it expands and then flows. In contact with hot water, the oil will tend to form droplets and emulsions. The use of alkaline water enhances oil flows and emulsion formation, presumably by lowering the water-oil interfacial tension.

Water-soluble polymers have been used to increase the viscosity of the water and make its flow match the oil flow. Surfactants have also been used to enhance emulsion formation by lowering the surface tension of water and thus improve water-sand-oil wettability. A major problem with additives, including inexpensive alkali solutions, is the high loss rate of the chemicals to the sandstone formation. A study of the mechanism of this uptake is important in understanding whether the losses can be diminished. Many oil fields contain large amounts of brine and other salt deposits, which may influence the phase behavior, flow and surface tensions of the oil-water-additive systems. Studies designed to explore the interactions and mechanisms of additive behavior should be extended to include the effects of locally occurring salt deposits.

One of the potentially interesting uses of additives relates to the movement of fine sand particles in heavy oil deposits. The various fluid treatments used to recover the oil can initiate the movement of fine sand particles in the deposit. In general, this motion has a degrading influence on the permeability of the deposit. It is important to investigate the conditions under which these phenomena are produced and to explore the use of chemical additives which may retard the movement of fines. Thixotropic additives are used in drilling oil wells to prevent similar fine sand deposition, which would tend to impede or even freeze the drilling motion. Perhaps similar additives will be effective in heavy oil treatments.

6.6 *Environmental problems*

Basic and applied research on environmental problems have been discussed in Section 5. Here, we note only that an opportunity may arise in connection with the upgrading of heavy oils and tar sand oils in relation to heavy metal contents. Vanadium and nickel can occur in these oils in amounts up to 300 ppm. Methods for their removal and, possibly, recovery should be explored. At 100 ppm each, there are about 0.4 oz. of nickel and 0.4 oz. of vanadium in every barrel of crude. Nickel and vanadium are both valuable metals. Sulfur is one of the most important industrial chemicals. Nitrogen may lead to fertilizers. A program to recover and use trace metals, as well as sulfur and nitrogen compounds, could pay dividends to the fossil fuel industry and might be worth some federally sponsored effort.

7. UPGRADING AND REFINING

7.1 *Introduction*

Potential problems associated with upgrading and refining of heavy oils and bitumens produced in various enhanced oil-recovery and tar-sand extraction processes are very different from those associated with synthetic crudes produced from oil shale and coal. Colorado shale oils produced by state-of-the-art retorting technologies are mainly distillates and are chemically and structurally different from petroleum crudes in heteroatom contents, particularly nitrogen, oxygen, arsenic, and iron. Synthetic crude fractions for down-stream refining from direct coal-liquefaction processes such as EDS, SCR-II and H Coal are also mainly distillates and are again chemically and structurally different from petroleum crudes, being very high in ring structure and aromatic content and correspondingly different in hydrogen concentration. The heavy oils and bitumens (hereafter collectively referred to as residua) discussed in this paper are chemically and structurally similar to many petroleum crudes, particularly asphaltinic crudes, but may be very much higher in resid content. For this reason, modern refining technologies being practiced on heavy petroleum crudes can be employed with confidence on these materials.

The major problem envisioned for a refiner facing a substantial shift in crude input to these higher resid content oils is bottom of the barrel conversion capacity. Further discussion in this chapter will be limited to the residuum conversion and upgrading to produce specification transportation fuels. Upgrading for use as power plant fuels will not be discussed.

7.2 *Residuum conversion alternatives*

More than a dozen residuum conversion processes and combinations are commercially practical process alternatives and may be used for converting the bottom of the barrel (residuum) into light products. These processes are summarized in Table 9.

Each of these listed processes has attributes and disadvantages, depending on the specific

Table 9. Residuum conversion alternatives.

Thermal processing: delayed coking, fluid coking, visbreaking; the Japanese Kureha process which involves high temperature thermal cracking.
Fischer-Tropsch synthesis including methanol production.
Solvent deasphalting.
Residuum catalytic cracking.
Hydroprocessing, including desulfurization, hydrocracking, asphaltene hydrocracking.
Combined processing using combinations of the preceding alternatives.

refinery application, viz.:

(a) Visbreaking is usually the least expensive process but provides only a modest degree of residuum conversion. Its applicability is further constrained by oil-quality considerations involving stability and compatibility.

(b) Delayed coking is relatively easy to implement, requires moderate investments, provides a high degree of conversion, but may produce a large volume of low value coke. Residuum desulfurization, coupled with coking, reduces the volume of low valued by-product coke and produces mid-distillates, but it is relatively expensive.

(c) Fluid coking is similar to delayed coking in many respects but produces higher yields. However, the coke produced usually has a lower value and the gas oils are somewhat more difficult to refine.

(d) Gasification, followed by Fischer-Tropsch synthesis and including methanol production, is commercially feasible but expensive.

(e) Solvent deasphalting is an especially attractive option for converting residua that contain very high levels (>300 ppm) of metals. Since deasphalting is accomplished in a separation process, the deasphalted oil must usually undergo extensive hydrotreating and cracking before conversion to light products. In addition, a low quality pitch is formed which may be difficult to dispose of.

(f) Resid catalytic cracking alone or combined with residuum hydrotreating is characterized by conversion capabilities similar to coking, but the processes are expensive, produce large quantities of high-pressure steam, and the product is primarily gasoline.

(g) Catalytic residuum hydrotreating (H-Oil or L-C fining) is relatively expensive, produces relatively low quality distillate products and residual tar, and some plants may have relatively low operating factors.

In evaluating residuum processing alternatives, economics play an important role. Each of the following factors affects the economic outcome significantly: (i) product yields and qualities; (ii) by-products; (iii) investments; (iv) operating costs, particularly fuel requirements; (v) the extent of process commercialization, i.e., the proven record of operating success; (vi) environmental controls. The volume of light products produced is particularly important in view of the differentials that have existed in the marketplace between light and heavy products.

Another important consideration is that of by-product disposal, which is common to all residuum conversion processes. In fact, the final process selection may depend upon whether or not there is an economic outlet for the by-product. In Table 10, we list by-products associated with the specified residuum-conversion alternatives.

Table 10. Residuum conversion of by-products.

Conversion to special fuels:

a. high viscosity, high sulfur tar or pitch from residuum hydrocracking, solvent deasphalting;

b. high sulfur delayed coke;

c. low to medium sulfur delayed coke;

d. fluid coke;

e. low-btu fuel gas from flexicoking.

Use of non-liquefiable by-products for energy production:

a. steam or electric power from residuum fluid catalytic cracking or partial oxidation.

Use for by-product upgrading:

a. low-sulfur coke from coke calcination;

b. hydrogen by gasification of tar or coke.

In summary, there is a variety of residuum conversion alternatives available for the design of new refineries or for modification of existing refineries. These will accommodate substantial increases in the conversion of heavy oils and bitumens to transportation fuels. All procedures have costs and problems. The optimal cost-effective process selection will be highly site- and project-specific.

7.3 *Research needs*

Many of the residuum-conversion alternatives, particularly the less expensive ones not employing high-cost, manufactured hydrogen and extensive hydrocracking conversion, involve some form of hydrogen disproportionation. Thus, parts of the resid are converted to a liquid with higher hydrogen to carbon ratio and the concurrent production of solids with lower hydrogen to carbon ratio or of liquid by-products of marginal market value. Research programs should include both primary conversion technologies and cost-effective recovery of energy values from by-products.

The following suggested studies could lead to the development of more cost-effective processes: (a) More comprehensive knowledge is needed of the molecular compositions and structures of residua, including bitumens. Particularly important are identifications of asphaltenes and metals contents. (b) The mechanisms and selectivity of asphaltene conversion reactions require study. (c) New reactions should be sought for the removal of sulfur and metals from residuum and by-products of residuum conversion. (d) The kinetics of petroleum coke gasification processes, including the use of catalysts, should be investigated. (e) Improved catalysts are needed for residuum hydrocracking and should be sought through basic research. (f) Novel and efficient processes are needed for recovering energy values from high-sulfur cokes and tars.

8. COSTING OF OILS FROM EOR AND UTAH TAR SANDS

Some cost information and data will be found in most of the site-visit reports (see Ref. 1).

While we have not arrived at generally useful cost estimations for oils from EOR and Utah tar sands, a study by K. E. Phillips (see Ref. 1 for details) highlights the technical areas in which studies must be performed in order to refine cost estimations prior to commercialization.

For EOR, the principal uncertainties deal with reservoir characterization and with achievable resource recovery using diverse technologies.

For oil recovery from some of the Utah tar sands, primary uncertainties deal with a possible cost advantage derived from the use of oil-wet sands without intermediate water layers, bitumen production with lower sulfur contents, and the possibility of eliminating an intermediate contrifuging step in the primary clean-up of bitumens; a disadvantage is associated with the initial production of Utah bitumens with greatly increased viscosity compared to the bitumens obtained from the Athabasca tar sands.

Since EOR and bitumen recovery from Canadian tar sands are currently commercial processes, we are not concerned with establishing commercially competitive industries but rather with cost reductions for processes which are known to be economically viable.

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