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

FOSSIL ENERGY RESEARCH WORKING GROUP - IIIA
(FERWG-IIIA)

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ABSTRACT

The Fossil Energy Research Working Group (FERWG), at the request of J. W. Mares (Assistant Secretary for Fossil Energy) and A. W. Trivelpiece (Director, Office of Energy Research), has 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 report summarizes the findings and research recommendations of FERWG.

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FOREWORD

During the terminal phase of operation, FERWG was asked by J. W. Mares(Assistant Secretary for Fossil Energy, DOE) and A. W. Trivelpiece (Director, Office of Energy Research, DOE) to conduct an "independent assessment providing for identification of research needs associated with oil recovery from heavy oil sources and tar sands." The DOE objectives for FERWG are defined in Appendix A. This assessment of oil-recovery technologies was administered through a DOE contract to the Energy Center at the University of California, San Diego, in La Jolla, California.

Members of FERWG performed an extensive schedule of site visits to process development units and facilities on tar sands and heavy oil sources, as well as to university and DOE laboratories, in order to familiarize themselves with current and planned research programs. Site-visit reports and evaluations, with emphasis on identified process and fundamental research needs, were prepared by participating FERWG members after each site visit. These site-visit reports are reproduced in Appendix B.

FERWG members held discussions with the Assistant Secretary for Fossil Energy, the Director of the Office of Energy Research, members of their staffs, DOE program managers, directors of laboratories and development engineers who are involved in oil recovery research and development (R&D) in both industrial and governmental organizations, and with university-based scientists and engineers who perform research related to oil recovery from heavy oil sources and tar sands. In addition, FERWG received written comments in response to the draft letter reproduced in Appendix A.

The Executive Summary is followed by an introductory discussion (Chapter 1) in which we present the FERWG study objectives, describe essential operating features of selected processes for oil recovery from heavy oil sources and tar sands, and summarize the research recommendations derived from our site-visit evaluations. More detailed research recommendations are discussed in Chapters 2-7.

The costing of oil recovery from heavy oil sources and tar sands formed the subject of a separate workshop. The results derived from these activities are summarized in Chapter 7.

Our research recommendations cover a wide spectrum of activities in recovery technologies for tar sands and heavy oils, ranging from fundamental science to process engineering. They have not been constructed to satisfy the desires of either the scientist or the development engineer. Adequate research support for programs relating to recovery technologies for tar sands and heavy oils may aid commercial implementation of the right technologies over the long term and may also be valuable in the definition and identification of new or different technologies that merit commercialization.

The members of FERWG acknowledge with thanks the advice and assistance given by many individuals in government, industry and the universities. The following people, among others, have contributed to our discussions, evaluations, and final recommendations: F. Allhoff (DOE); J. Allsup (DOE/BETC); C. W. Bowman (Alberta Oil Sands Technology and Research Authority [AOSTRA]); W. E. Brigham (Stanford University); J. W. Bunger (University of Utah); F. W. Burtch (DOE/BETC); M. A. Carrigy (AOSTRA); E. L. Cook (Mobil Research); A. Crawley (DOE/BETC); P. Dana (DOE/LETC); G. W. Dean (DOE/Oakland); A. Decora (DOE/LETC); J. Defir (Alberta Environment); J. Dooley (DOE/BETC); J. H. Duerksen (Chevron Research); R. Eson (Chemical Oil Recovery); R. G. Evans (Energy Resources Conservation Board, Alberta); J. Fitch (Chemical Oil Recovery); R. L. Folstein (DOE/BETC); F. Ghassemi (University of Southern California); W. Good (DOE/BETC); L. L. Handy (University of Southern California); F. V. Hanson (University of Utah); B. Harney (DOE); R. V. Henning (Alberta Municipal Affairs); L. G. Hepler (AOSTRA); B. G. Holmes (Mobil Production Research); F. Holzeiz (LLNL); A. Holzer (LLNL); J. Jennings (Gulf Research); H. R. Johnson (DOE/BETC); L. Johnson (DOE/LETC); R. Jones (American Petroleum Institute); G. Y. Jordy (DOE); N. Kilbourn (Sunoco Energy Development); C. A. Koch (Koch and Associates); L. Kronenberger (Exxon USA); Y. Ksander (The Engineering Societies,Commission on Energy); L. Lake (University of Texas); H. Lechtenberg (DOE/Oakland); A. Leighton (DOE/Oakland); E. J. Lievens (DOE); E. W. Malmberg (Sun Production Company); L. C. Marchant (DOE/LETC); C. Mathews (Shell Research); J. D. Miller (University of Utah); M. Misra (University of Utah); L. O'Brien (Union Oil); E. L. Oshlo (Conoco); T. Owen (DOE/LETC); H. W. Parker (The Engineering Societies,Commission on Energy); R. Y. Pei (Rand Corp.); G. Peterson (DOE/Oakland); K. E. Phillips (Rand Corp.); R. S. Phillips (AOSTRA); R. Porter (DOE/BETC); R. Poulson (DOE/LETC); M. Ray (DOE/BETC); R. E. Robertson, III (DOE); L. Romanowski (DOE/LETC); J. D. Seader (University of Utah); W. E. Showalter (Union Oil); W. H. Somerton (University of California, Berkeley); G. Standley (DOE/Oakland); B. Sudduth (DOE/LETC); D. Sutterfield (DOE/BETC); L. R. Turner (AOSTRA); V. N. Venkatesan (University of Utah); D. Ward (DOE/BETC); J. P. Watson (DOE); J. Weber (DOE/LETC); T. Wesson (DOE/BETC); J. F. Norton (Radian Corp.); W. Winsauer (Exxon); and T. F. Yen (University of Southern California).

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Oil recoveries from heavy-oil sources and Canadian tar sands represent currently commercial procedures, as is evident from the fact that about 300,000 BPD of heavy oils and 200,000 BPD of tar-sand 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. The particular role of federal funding therefore requires especially careful definition.

We have identified two very different primary areas of concern that should properly be addressed through federally funded R&D programs.

The first area of concern relates to implementation of effective but non-obstructive environmental controls at each of the many ($\sim$2500) sites where secondary and tertiary oil recovery is implemented, as well as at each of the many potential sites in the U.S. where oil recovery from tar sands may be practiced on a commercial scale. While we recognize important site-specific variations, the very large number of actual recovery areas implies that only a relatively small set of control measurements will be useful and that each of these will, in turn, be associated with a large number of potential field sites for application. The definition of measurement criteria and the identification of control parameters to assure resource recovery under acceptable, non-obstructive constraints will require careful monitoring at many sites, a substantial data base, and knowledgeable employees to assist policy makers in writing and enforcing appropriate environmental control legislation. Federal funding is needed to provide knowledge in this area and to establish wise environmental controls.

The second area of concern relates to the logical development of field-recovery technologies by industrial firms on their own lands or on leased lands. The judgement of when and how to proceed will necessarily and properly be made by an industrial firm on the basis of financial returns during the anticipated life of the operating 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.

Generally applicable areas of R&D problems appear to be suitable for federal support in order to define U.S. estimates of potentials for conversion of resources to reserves.

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 based on technologies advanced by fundamental research programs.

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

A. Resource Assessments (Chapter 2)

- The magnitudes of U.S. 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 (Chapter 3)

- Develop basic information 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.

- Develop improved procedures for injection of steam, additives, and combustion control.

- Implementation of thermal processing techniques will require improved methods for solids removal from liquids, gases, and combustion of coke on the pyrolyzed sand.

- 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.

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*Research recommendations represent a general concensus but each statement is not necessarily endorsed by all FERWG members.

- Such innovative studies as radiofrequency heating, mine-assisted steam injection, and CO_2 huff-and-puff merit support.

- 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.

Process research is properly the primary responsibility of industry. However, a federal role may be appropriate in joint efforts on high-risk studies with significant potential benefits to the entire industry.

C. Environmental Studies (Chapter 4)*

- 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.

- Improved understanding is needed of chemical processes involving organic sulfur and nitrogen compounds and of air dispersion in orographic regions.

- Hydrocarbons emitted to the atmosphere in appreciable concentrations require characterization and toxicological evaluation. We expect refined oils to be comparable to conventional petroleum products although newly formed crudes may represent toxicological hazards that require careful control.

- Long-term environmental constraints must be quantified before they limit commercial developments.

- 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.

*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.

- 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 (Chapter 5)

- A long range, federally sponsored basic research program in oil recovery is both appropriate and necessary.
- A level of effort in the range of 30 to 60 (1981) millions of dollars per year has been judged to be justifiable by some FERWG members, while others do not believe that a convincing case has been made for substantial governmental support.
- Important areas for these studies include:

  (a) resource and reservoir characterization;

  (b) fundamentals of flows in porous media;

  (c) studies in physical chemistry, including thermodynamics and the surface behavior of oil/water/steam/CO_2/sand systems;

  (d) problems of corrosion related to (c);

  (e) environmental problems encountered in recovery processes.

E. Upgrading and Refining (Chapter 6)

- 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

  (a) molecular structures and compositions of residua;

  (b) mechanisms of asphaltene conversions;

  (c) processes for the removal of sulfur and metals;

(d) kinetic studies on coke gasification;

(e) mechanisms involving gasification catalysts;

(f) methods of utilizing high-sulfur cokes and tars;

(g) coke desulfurization and utilization as synthetic feedstock.

F. Cost Estimations (Chapter 7)

Uncertainties in costing will be reduced by process R&D and, in the view of some but not all of the FERWG members, perhaps also by fundamental research.

G. Prioritization of Federal Research Expenditures

- Highest priority is assigned to the development of improved methods for resource characterization, process modeling, and the relation between resource characteristics and recovery costs. Basic studies leading to less costly control procedures for SO_x and NO_x and to improved fundamental understanding of flows in porous media also require urgent attention.

NOMENCLATURE

B = barrel (42 gallons)

BPD = barrels per day

cp = centipoise

cs = centistoke

MW_e = megawatts of electrical power

TPD = (short) tons per day

CHAPTER 1

OVERVIEW OF OIL RECOVERY FROM HEAVY OIL SOURCES AND TAR SANDS

Recovery of oils from heavy oil 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 by surface processing of tar sands in Alberta, Canada, currently amounts to about 2×10^5 BPD and is being expanded rapidly.

1.1 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.[1] 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. 1.1-1. 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

[1] T. M. Doscher, "Enhanced Recovery of Crude Oil," American Scientist 69, 193-199 (1981).

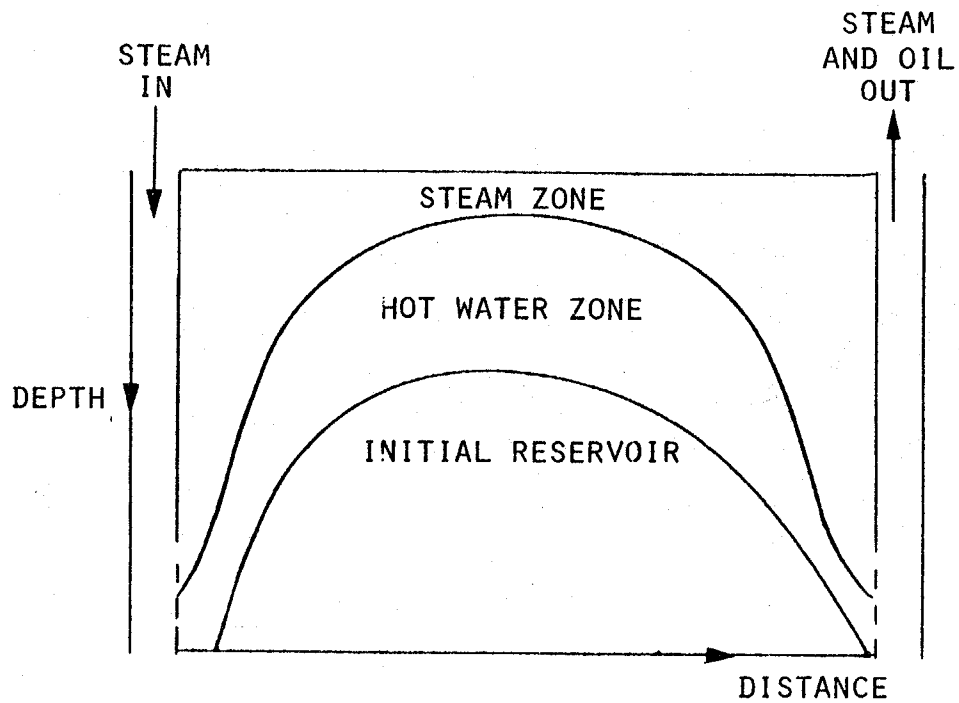

Fig. 1.1-1 Schematic diagram of a well-developed steamflood pattern.

in productivity (see Fig. 1.1-1), 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 enhanced 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 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 (compare p. AB-157) in Fig. 1.1-2.

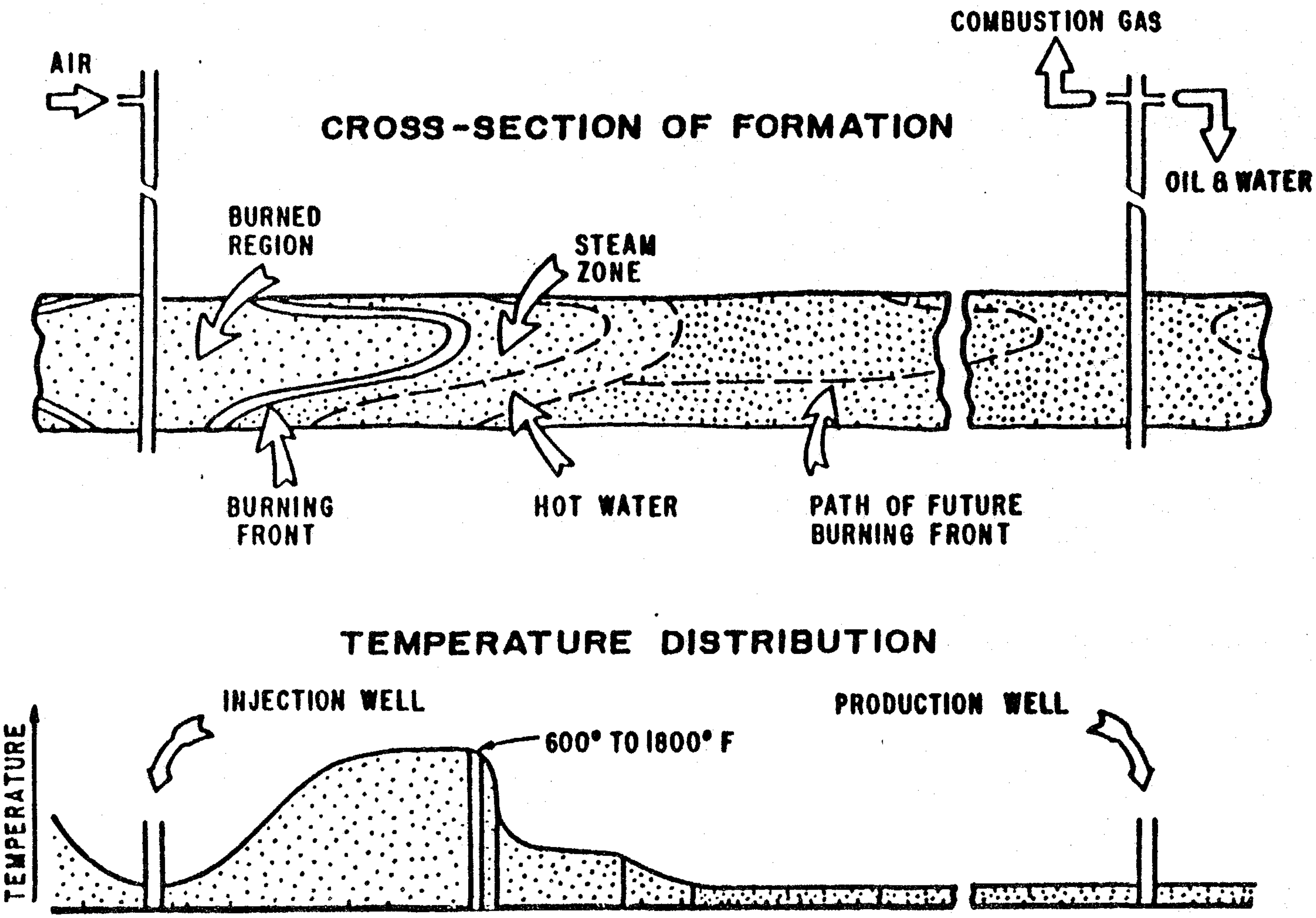

Fig. 1.1-2 The <u>in-situ</u> combustion process.

A good overview of the status of current technology of EOR is provided by the conference proceedings prepared by the DOE Fossil Energy Division, San Francisco Operations, for the "1981 Heavy Oil/EOR Contractor Reports," July 28-30, 1981, San Francisco, California.* We refer to this report and to our site visit summaries appearing in the Appendix (AB) for further information concerning the status of EOR.

The published studies 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.

1.1.1 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 and 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) and 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 con-

*Comments on this conference are contained in the Appendix, AB-6.

tain many heterocyclic aromatics, including 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 (cf. pp. AB 213-241) to the site-visit report in AB-5 contains a summary of heavy feed upgrading options and shows 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.

1.1.2 Some Previously Identified R&D Needs

Joint discussions (cf. Appendix AB-6) between FERWG members and representatives of the DOE Fossil Energy Division, San Francisco Operations, produced the listing of EOR R&D needs enumerated below:

A. Steam Additives

The purpose of steam additives is to improve recovery efficiency with steam injection. Recovery efficiency will be improved if (a) greater sweep efficiency is achieved and (b) more oil is recovered from the swept volume. While flow models are available that have been serving as a basis for achieving increased recovery efficiency, each of the following fundamental areas of study has been inadequately explored: (a) physicochemical studies (including thermochemical and rate measurements) referring to interactions between steam, steam additives, and oil-bearing sands; (b) physicochemical studies involved in surface adsorption, desorption, and substitution; (c) effects of physical and chemical properties of multiphase fluid mixtures on flows through porous media; (d) the interplay between fluid-dynamic phenomena and physicochemical properties (density, viscosity, surface properties) in producing channeling and instabilities during flows through porous media; (e) phase separations in steam-additive and oil-sand mixtures as functions of temperature and pressure; (f) studies of the mechanisms and rates of gel deposition on injection with steam and additives and of the subsequent degradation of encapsulated foams.

B. 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.

C. Alkaline Floods

The fundamental studies suggested by the use of alkaline floods for EOR are similar to those previously enumerated under additives. The key is mobility control of oil in an alkaline flood with appropriate use of surfactants to lead to oil-in-water or water-in-oil emulsions. Adequate control will minimize the consumption of caustic in the reservoir under conditions of extensive surfactant recovery. There is also an associated requirement for water treatment.

D. Mine-Assisted Steam Injection

These studies relate especially to improved steam-contacting with the reservoir bed. There are uncertainties in every aspect of the processes involved: (a) the reservoir is inadequately characterized and space-dependent estimates are not available for porosity, oil in place, permeability, surface properties; (b) if the reservoir bed were adequately characterized, the flow of the reacting fluids through the porous beds could be properly characterized only if constitutive equations were available under reservoir conditions ; (c) improved and remote diagnostic procedures are needed to follow the progress of steam floods with caustic and other additives through the reservoir.

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

E. Sand Control

In practice, the uncontrolled flow of (spent) sand from unconsolidated reservoirs may represent a serious impediment to achieving lasting output improvements. Fundamental problems relate to the flow of reacting fluids through porous media, constitutive equations for the original sand and for the spent sand, and the fluid dynamics of multiphase flows through porous media under defined pressure, temperature, and composition gradients. Problems of this type cannot now be modeled under controlled conditions and invite long-term investigations by competent scientists.

F. Thermal-Front Mapping

In each of our previous FERWG studies, we have emphasized the importance of developing well-calibrated instrumentation for needed <u>in situ</u> diagnostics to allow sequential comparisons between field measurements and computer models designed to describe the physical phenomena under study. EOR offers particular challenges in this respect because of the lack of homogeneity in relatively inaccessible reservoirs. The suggested uses of high frequency electromagnetic and controlled source audio magnetotelluric mapping, as well as applications of tracer techniques and other procedures, merit support. Priority should be given to measurements with good spacial resolution that have been carefully calibrated under well defined conditions and adequately tested in inhomogeneous media. A wide range of properties (including steam quality, temperature, pressure, porosity, flow speeds, etc.) is of interest.

G. High-Temperature Packers and Insulation Systems

Materials 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.

H. *In Situ* Combustion

Fireflooding involves combustion processes in porous, multi-phase media that have not been adequately studied and are accordingly poorly understood. The wide spectrum of fundamental phenomena involves exothermic oxidation reactions on porous beds, mass and heat transfer with mobilization of oil, and movement of the resulting multiphase mixtures through reservoirs. These represent a significant challenge to combustion scientists and reservoir modelers alike. A long-range, fundamental research effort in these fields merits support if fireflooding is to become more than an empirical field effort for enchanced oil recovery.

I. Reservoir Properties Research

This proposed program should emphasize the fluid-dynamic aspects of reservoir modeling, with particular attention to physical properties that determine absolute and relative permeabilities and fluid movements. Phase changes and supercritical phenomena may play a role in these processes.

J. Steam Quality Measurements

While it should be relatively easy to develop techniques for characterizing steam quality at injection (e.g., by the use of multicolor infrared absorption measurements), the design of systems of this type for down-hole monitoring (e.g., through the use of fiber-optical systems) represents an interesting challenge. In general, a separate allocation is appropriate for DOE research funds to assist in the development of needed instrumentation.

K. Oxygen-Enriched Thermal Recovery

Work with oxygen-enriched air represents an obvious and important special case of studies with additives to achieve enhanced oil recovery.

L. Advanced Concepts

In a field as poorly understood, as empirically based, and as practically important as EOR, there must be room for innovation. The remaining total resource is sufficiently large to justify long-term studies without specified constraints other than that competent people should concentrate their research efforts to achieve improved recovery under environmentally acceptable conditions.

1.2 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[2] gave the following estimates for the Athabasca deposits: 625×10^9 B with 285×10^9 B 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.[3] 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

[2] F. K. Spragins, "Mining at Athabasca - A New Approach to Oil Production," Journal of Petroleum Technology 19, 1337-1343 (1967).

[3] Various newspaper reports, December 1973.

[4] E. D. Innes and J. V. D. Fear, "Canada's First Commercial Tar Sand Development" in Proceedings of the Seventh World Petroleum Congress, Volume 3, pp. 633-650, Elsevier Publishing Co., New York, 1967.

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 $-50^{o}F$) 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 $-35^{o}F$. During the summers, temperatures may rise to $90^{o}F$ 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 to 8 weight percent) are rejected. The mean bitumen content of the tar sands (without overburden) for oil recovery in the GCOS operation[3] is 12.4 weight percent.

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

[5] W. A. Bachman and D. H. Stormont, "Plant Starts, Athabasca Now Yielding its Hydrocarbons," Oil and Gas Journal 65, 69-88, October 23, 1967.

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 x 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 3m, 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 upgrading facilities 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 x 10^6 kg/hr of steam are produced. The water-treatment plant has a maximum flow of 850 cm^3/sec.

The product bitumens are stored in a 477,000 m^3 tank, a 191,100 m^3 tank is used for gas oil and a tank with a capacity of 83,500 m^3 is used 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. 1.2-1), where 38 test wells to a depth of 1,800 feet 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 operations at Peace River are described in Appendix AB-7.

A number of other oil companies (Imperial, Amoco, a Japanese group, Mobil, Texaco, Chevron, Petro-Canada, Gulf, British Petroleum) are also experimenting with in situ recovery schemes. Many in situ projects are partly supported by the Alberta Oil Sands Technology and Reservoir Authority.

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[6] F. W. Camp, "The Tar Sands of Alberta, Canada," Cameron Engineers, Denver, Colorado, 1970.

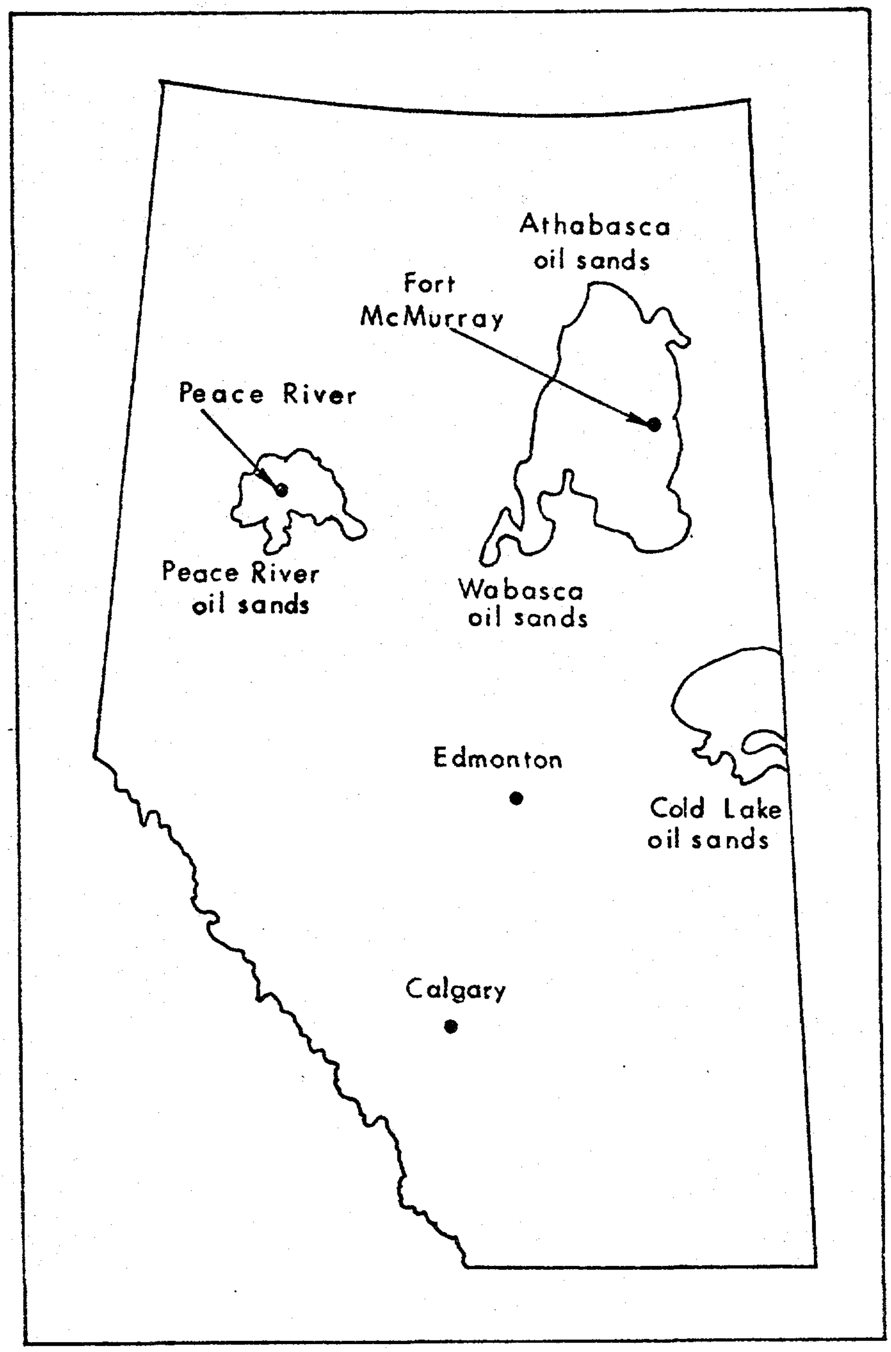

Fig. 1.2-1 Tar sand sites. The enclosed areas indicate the principal location of oil sands in the State of Alberta in Canada.

1.2.1 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. 1.2.1-1]. This mixture is introduced into a conditioning drum [② in Fig. 1.2.1-1], together with caustic soda, water, and steam for reduction of sand-lump size. The smaller particles pass a vibrating screen [③ in Fig. 1.2.1-1], 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.1.2.1-1]. The bitumen floats to the top of the separation cell and is largely recovered in this top-layer froth [④ in Fig.1.2.1-1], 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. 1.2.1-1] for separate treatment in a froth settler [⑥ in Fig. 1.2.1-1]. The top-froth layers from the separation cell [④ in Fig.1.2.1-1] and the froth settler [⑥ in Fig.1.2.1-1] are mixed with naphtha before introduction for upgrading in centrifuges [⑦ in Fig.1.2.1-1], from which tailings (bitumen-to-minerals weight ratio ≃ 0.21) and upgraded feed (bitumen-to-minerals weight ratio ≃ 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.1.2.1-2 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.1.2.1-2 is self-explanatory. The overall hydrogen consumption is about 1000 SCF per B of

[7] R. V. Roberts, "Comparative Economics of Tar Sands Conversion Processes," Stanford Research Institute, Menlo Park, California, 1970.

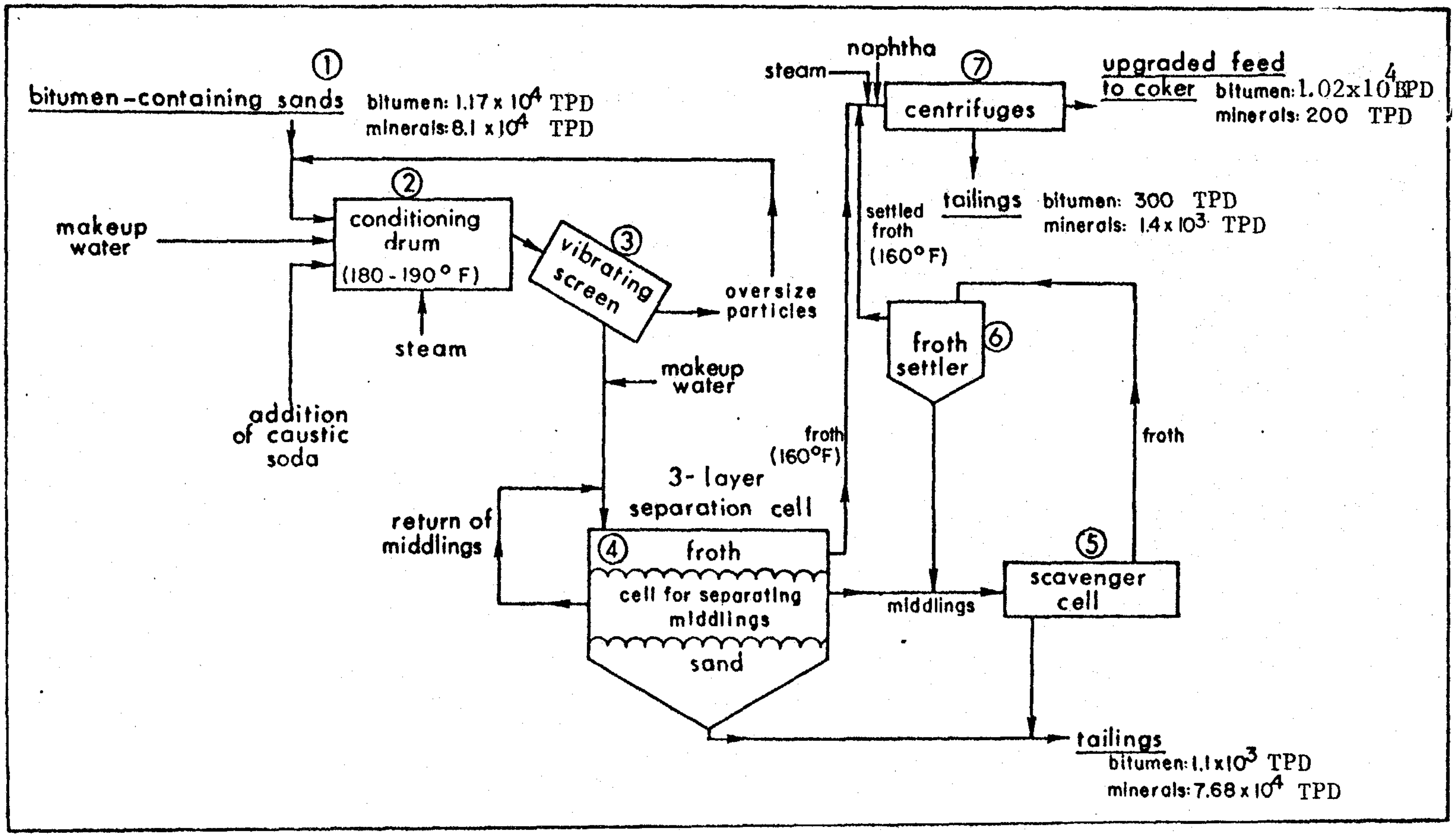

Fig. 1.2.1-1 The bitumen recovery scheme pioneered by GCOS and used by Suncor and Syncrude.[7]

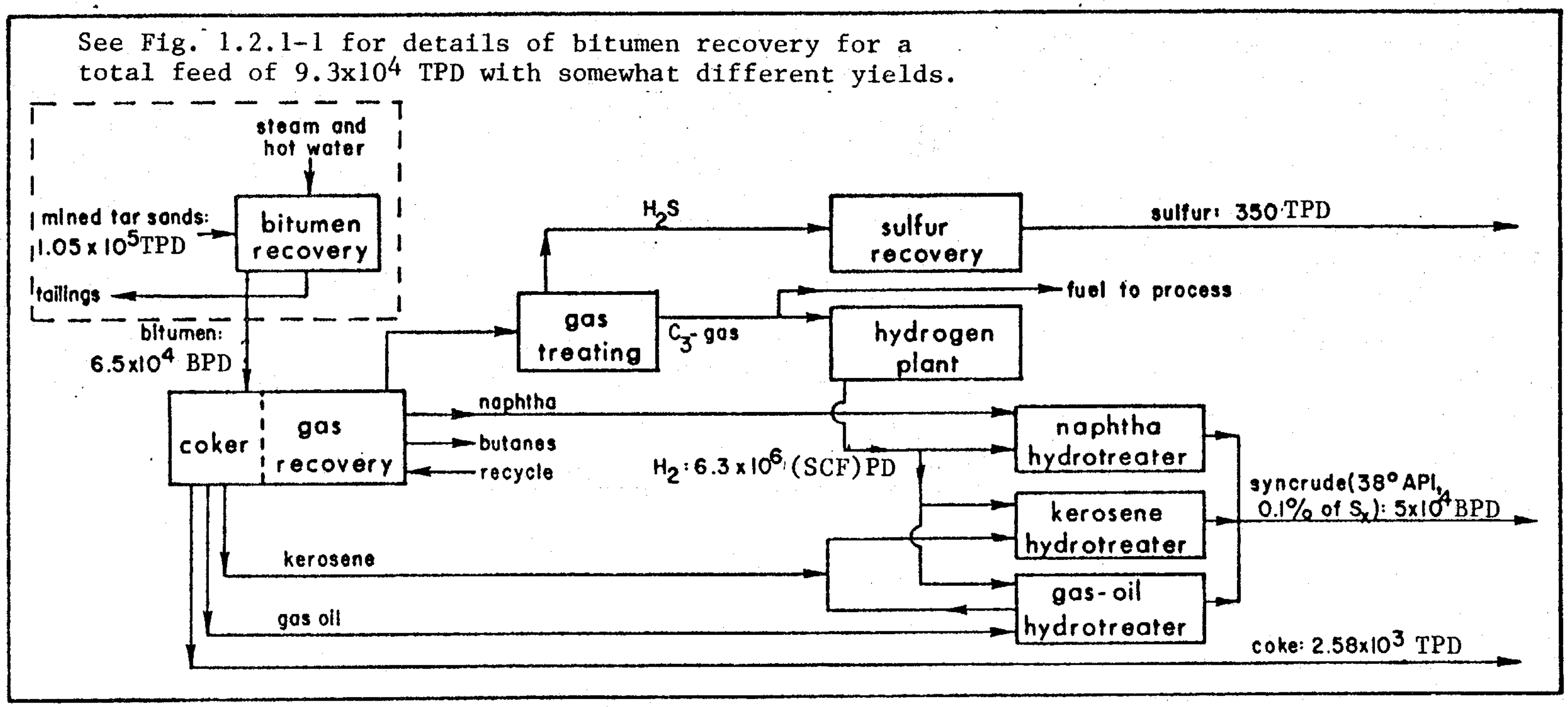

Fig. 1.2.1-2 The GCOS upgrading process for bitumen recovered from tar sands; reproduced with modifications from Ref. 7.

high-quality syncrude containing less than 0.1% of S_x.

1.2.2 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.

Details concerning current Syncrude operations are described in Appendix AB-7.

1.3 Oil Recovery from the Tar Sands of Utah*

1.3.1 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 resids 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.

The U.S. deposits of tar sands have been estimated to be about 36 x 10^9 B in place (Table 1.3.1-1). Examination of Table 1.3.1-1 shows that most of these tar sands are in Utah (Fig. 1.3.1-1).

*An overview of 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.

Table 1.3.1-1 Deposits of bitumen-bearing rocks in the United States with resources over 1 x 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

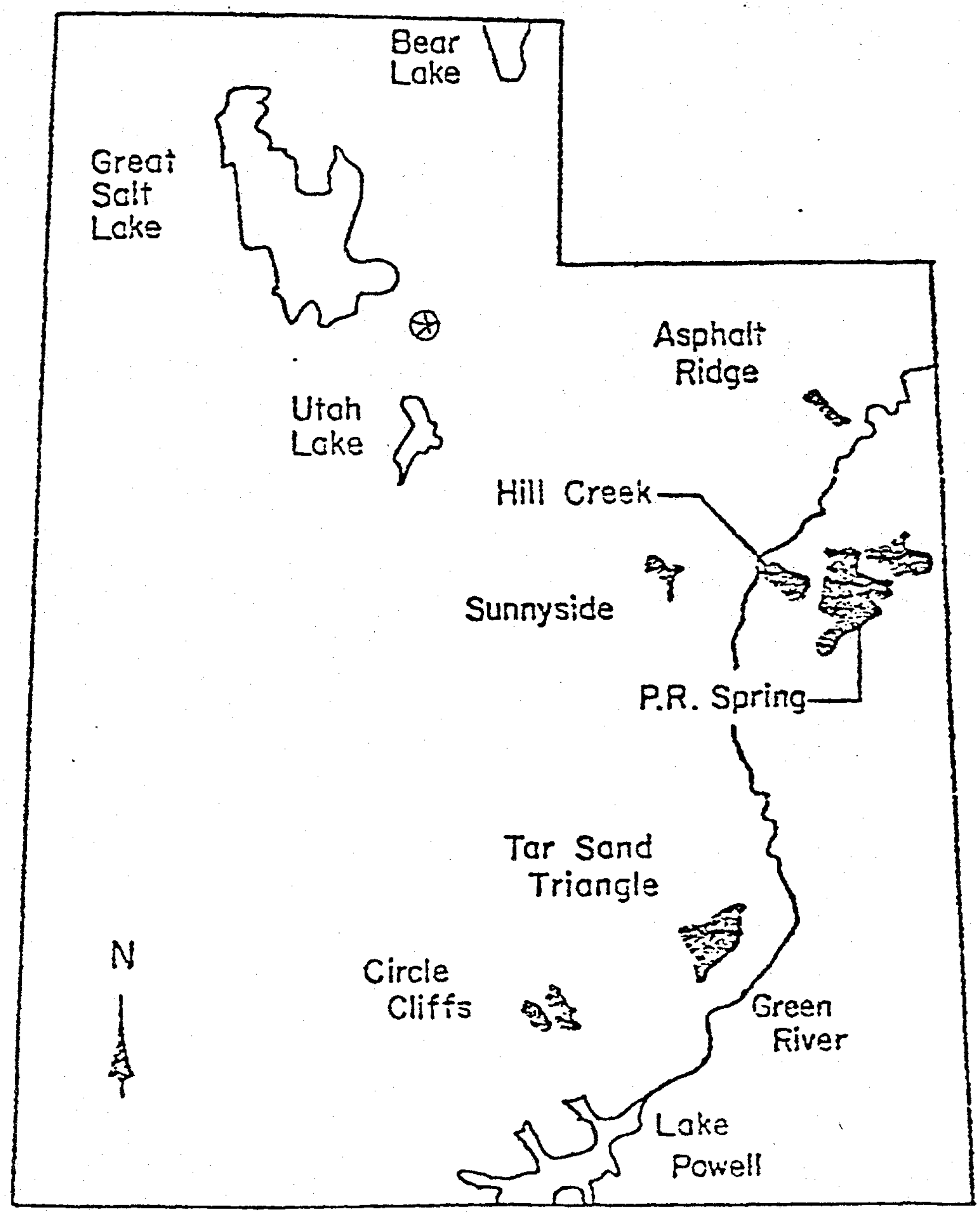

Fig. 1.3.1-1 Major tar sand deposits in the State of Utah.

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.

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[8] H. R. Ritzma, "Commercial Aspects of Utah's Oil-Impregnated Sandstone Deposits," paper presented to Interstate Oil Compact. Comm., New Orleans, December 3, 1973.

[9] V. A. Kuuskraa, S. Chalton, and T. M. Doscher, "The Economic Potential of Domestic Tar Sands," D.O.E. Report #HCP/T9014-01, U.S.C.-91, Los Angeles, California, January 1978.

[10] Private communication from Enercor, Inc., 57 W 2nd South, Salt Lake City, Utah, 1981.

1.3.2 The Utah Resource Base

Estimates of in place bitumens for Utah tar sands are given in Table 1.3.2-1. These estimates are based on Ritzma's data.[8] The bitumen contents shown are based on data of Wood and Ritzma.[11] 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[10] of material recoverable by mining and aboveground processing are shown in Table 1.3.2-2. Previous estimates in Ref. 9 were much lower than those shown in Table 1.3.2-2. The following criteria were used in Ref. 9 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 x 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 2.0 x 10^9 B are technically and economically feasible for recovery by using *in situ* techniques from the Tar Sand Triangle (1.5 x 10^9 B) and Sunnyside (0.5 x 10^9 B).

1.3.3 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

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[11] R. E. Wood and H. R. Ritzma, Special Study 39, Utah Geological and Mineralogical Survey and University of Utah, Salt Lake City, January 1972.

Table 1.3.2-1 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 1.3.2-2 Estimates of mineable tar sands assuming 3 cubic yards of overburden per B; 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

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 1.3.3-1). Generally, the Utah bitumens are one to four times more viscous than Athabasca bitumens (Fig. 1.3.3-1). Estimates of the bitumen content of the Utah tar sands vary from 4 to 14% (see Table 1.3.2-1). As with the Athabasca deposits, the grade varies within the deposits. More thorough definition is needed to firm up 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. Figure 1.3.3-2 shows particle size distributions 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 tailings. Large tailing ponds that are maintained for many years will probably not be needed in processing Utah tar sands.

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.

1.3.4 Recovery Technology

There are two basic technologies used for the recovery of oil from tar sands. These are: (i) mining and above-ground processing with (a) hot-water recovery, (b) solvent

Table 1.3.3-1 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 $77^{o}F$ ($0.05\ sec^{-1}$, poise)	$3\text{-}30\times10^{4}$	$0.4\text{-}1.5\times10^{4}$
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 $530^{o}C$ TBP	50	60

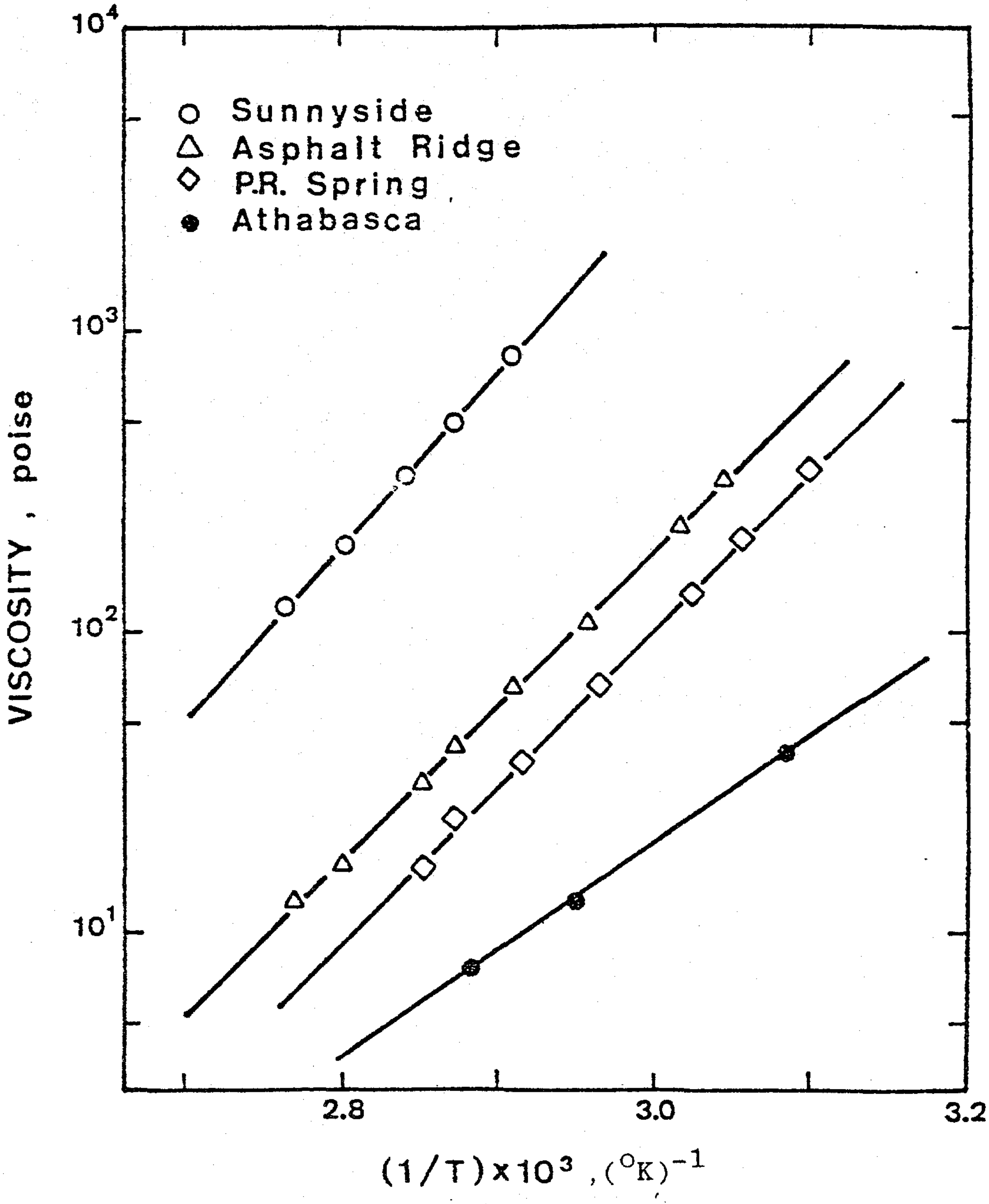

Fig. 1.3.3-1 Arrhenius-type plot illustrating the effect of temperature on viscosity for bitumens from various Utah and from Athabasca tar sand deposits.

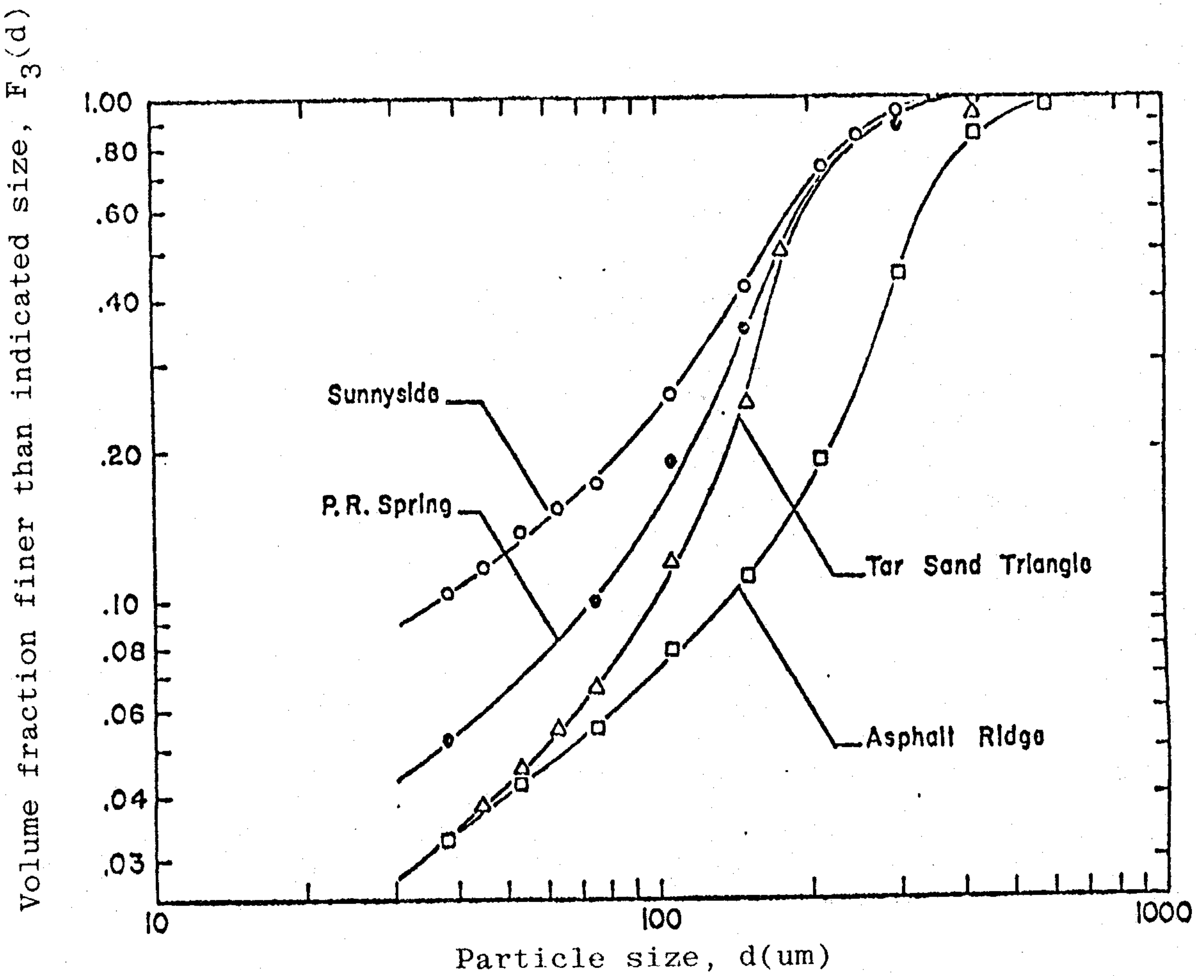

Fig. 1.3.3-2 Particle size distributions of sands from Tar Sand Triangle, P. R. Spring, Sunnyside, and Asphalt Ridge in Utah.

extraction, or (c) thermal recovery; (ii) in situ processing with (a) thermal methods with 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.

1.3.5 Hot-Water Recovery Process

The University of Utah process takes into account the differences between Athabasca and Utah tar sands, i.e., the much 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 to 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.

1.3.6 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. 1.3.6-1.

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.

1.3.7 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 1.3.7-1). 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.

1.3.8 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 has been constructed near the Chevron Refinery

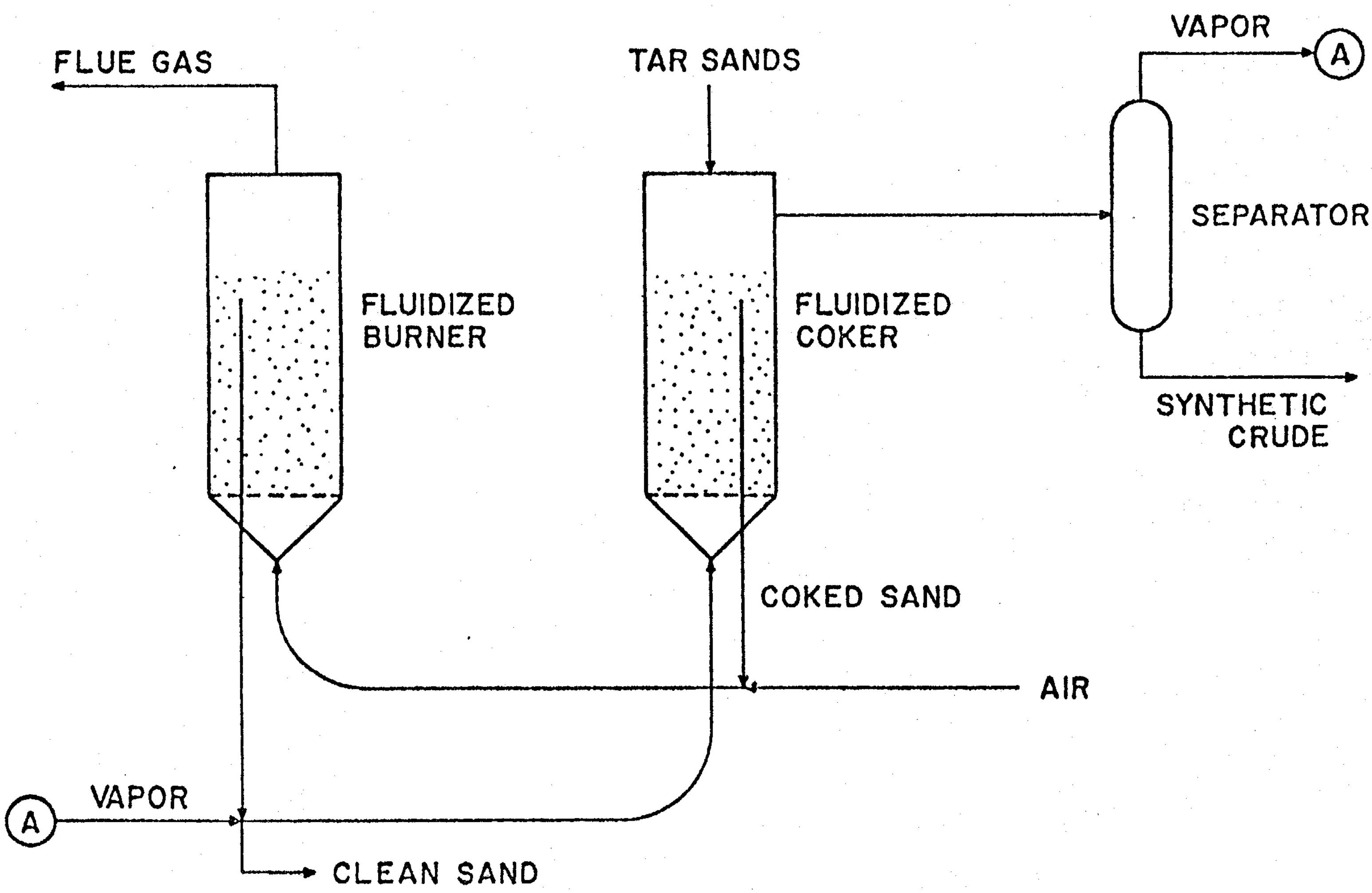

Fig. 1.3.6-1 Process scheme for thermal recovery.

Table 1.3.7-1 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

in North Salt Lake City. The plant is producing 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. A flow sheet for the pilot plant is shown in Fig. 1.3.8-1.

1.3.9 *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 1,150 B of oil and 6,250 B of water. The total steam injected was equivalent to 65,700 B of water.

1.3.10 Economics of Bitumen Recovery from Utah Tar Sands

A recent economic assessment (based on small-scale laboratory studies) of a 2000 BPD demonstration plant for producing synthetic crude oil from Utah tar sands was made available by Enercor (cf. Appendix AB-1) and involves mining, hot-water extraction and

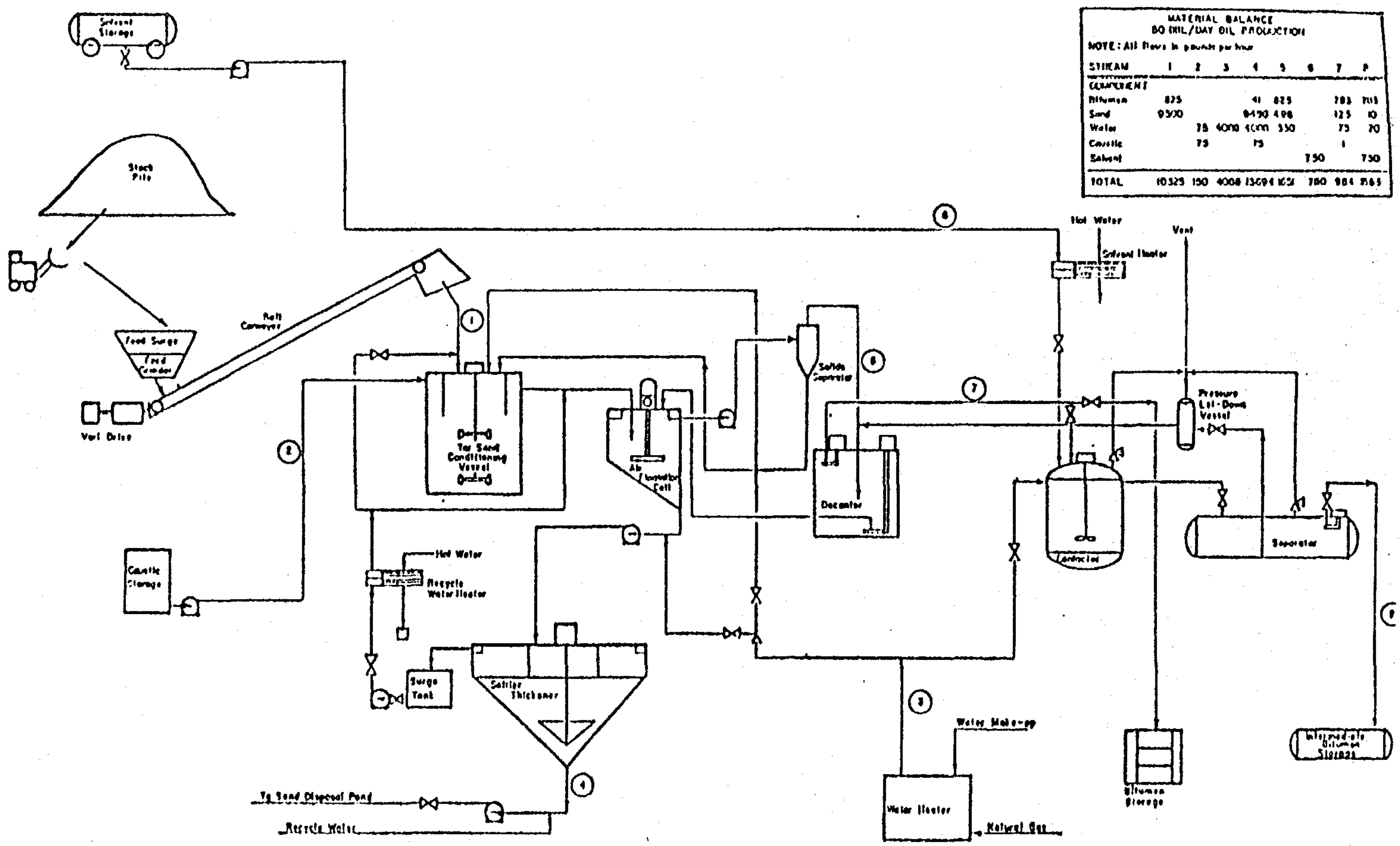

Fig. 1.3.8-1 Pilot plant for bitumen recovery by the University of Utah hot-water process.

Table 1.3.10-1 Summary of projected capital and operating costs (660,000 BPY).

Capital Costs in $\$10^3$	
Mine development	3,980
Permits and project direction	300
Engineering	1,500
Processing plant and materials handling	12,648
Offsites	1,638
Subtotal	20,066
Contingency of 20%	4,013
Total	24,079

Operating and Product Costs		
	Annual Operating Costs, $\$10^3$	Product Cost, \$/bbl
Plant labor	1,787	2.71
Labor, fringe benefits	518	0.78
Maintenance materials	565	0.85
Utilities	2,366	3.59
Chemicals	169	0.26
Taxes and insurance	339	0.51
Royalties	2,838	4.30
General administration	355	0.54
Mining costs (1,850,000 TPY) at \$3.64/ton	6,654	10.08
Contingency, 10% of non-mining costs	894	1.35
Total Cost	16,485	24.97

coking of the clean bitumen. The site for the operation is State Lands at a Northeast P. R. Spring site. The tar sand at that site is in a 24 foot thick seam with an average bitumen content of 8%. The average overburden is 0.92 ton per ton of tar sand and recovery was set at 75% liquid yield by volume. The data are presented in Table 1.3.10-1. No depreciation costs are shown nor are profitability estimates made. Depreciation will depend on what is done with the plant after the demonstration is completed. The sale price of the products, which will include coke and syncrude produced in the coker, has not yet been established on a firm basis.

1.3.11 Environmental Aspects of Tar Sand Development

The environmental issues that will have to be addressed in tar-sand development are as follows:

i. Requirements for auxiliary energy sources and for water and other renewable resources.

ii. Maintenance of local and regional air quality.

iii. Maintenance of local and regional water quality and supplies.

iv. Land disturbances and reclamation or reconstruction.

v. Preservation of archeological and historical sites.

vi. Survival and health of terrestrial and aquatic ecosystems.

vii. Population growth and socioeconomic impacts of a large developing industry.

[12] R. J. Barrett, "Projected Cost of the Combustion Process in Utah Tar Sand," Los Alamos Scientific Laboratory, Los Alamos, New Mexico, paper presented at a Meeting of the Interstate Oil Compact. Comm., Vail, Colorado, June 1980.

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 LETC and by the BLM and 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 are not expected to be required for Utah tar sands because of high bitumen recoveries and the 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.

1.4 Research Recommendations on Oil Recovery from Tar Sands Derived from Site Visits and Discussions

Site visits and dicussions involving FERWG members are summarized in Appendix B. In connection with these activities, R&D needs were repeatedly discussed. A compilation of research recommendations derived from these activities is given in Table 1.4-1. The topics identified in Table 1.4-1 are repeated elsewhere in this report in connection with discussions of R&D needs for specific purposes.

1.5 Selected Examples of 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] Topics include an overview of Alberta oil sands as a potential oil source and its geochemical history; included are the regional and cross-sectional maps reproduced in Figs. 1.5-1 and 1.5-2, respectively. K. N. Jha, D. S. Montgomery and O. P. Strausz (Ref. 13, pp. 33-54) discuss the composition of gases in Alberta bitumens and derived from low-temperature thermolysis of asphaltenes and maltenes; A. E. George, G. T. Smiley and H. Sawatzky (Ref.13, pp. 55-77) discuss changes in chemical composition during thermal hydrocracking of Athabasca bitumen; hydrocracking and separation are shown schmatically in Fig. 1.5-3. Laboratory studies

[13] Oil Sand & Oil Shale Chemistry, edited by O. P. Strausz and E. M. Lown, Verlag Chemie, New York and Weinheim 1978, Symposium on "Oil Sand and Oil Shale Chemistry, Montréal Québec, 1977.

Table 1.4-1 Summary of research recommendations derived from site visits and discussions (compiled from data in Appendix B).

Applications	R&D Requirements
Bitumen recovery from mined Utah tar sands.	Development of improved ambient and hot-water digestion-floatation techniques; improved thermal recovery techniques; shear stresses required to separate bitumens from sands; separation of bitumens by air floatation; solvent extraction of bitumens.
In situ recovery of bitumen from tar sands.	Evaluation of the relative merits of forward and of reverse combustion processes; comparisons of steam drive and combustion techniques; identification of factors determining recovery efficiencies; development of quantitative models to define recovery efficiencies for well characterized resources; recovery and cleaning of product waters; development of down-hole steam generators.
Generic problems common to many recovery processes of oil from tar sands.	Use of coal in fluidized-bed combustors as fuel for steam generation. Process-water purficiation; verification of recovery performance; scale-up to commerical sizes; upgrading and refining; minimization of steam-to-sand ratios and of associated energy costs; downhole steam generation; control of heterogeneity effects.
Long-term research and novel techniques relating to oil recovery from tar sands.	Resource assessments; use of RF heating; numerical modeling of resource beds during recovery; scale-up of operations; coke desulfurization and processing for feedstock; upgrading and refining.
Oil recovery from heavy-oil sources.	Assessments of long-term toxicity of chemical compounds used in heavy-oil recovery; production of stable foams (for use in permeability control) at elevated temperatures; upgrading and refining of recovered oils; mobility matching to improve reservoir performance; reservoir flooding with CO_2, surfactants, polymers, or caustic compounds; utilization of thermal recovery methods, fireflooding; analytical procedures and distillate characterization; down-hole steam generation; water availability and purity; migration of added chemicals through the oil reservoir; degradative pathways for chemicals introduced in EOR; adsorption and mobility of chemicals used in EOR.

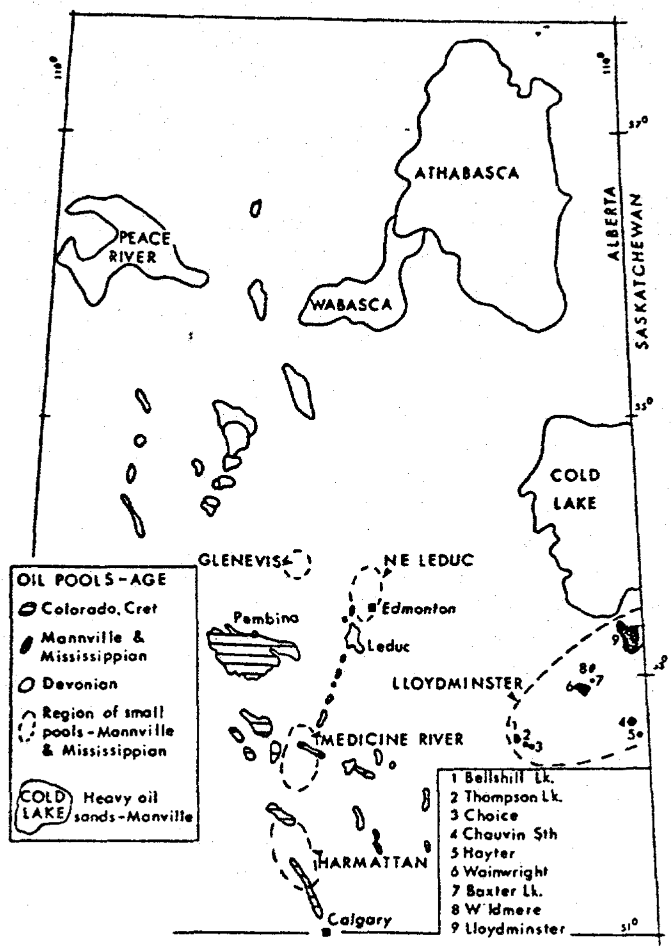

Fig. 1.5-1 Oil pools and oil sands deposits of Alberta; shown on page 12 of Ref. 13 in a paper by G. Deroo and T. G. Powell and reproduced from maps prepared by the Alberta Oil & Conservation Board, 1963.

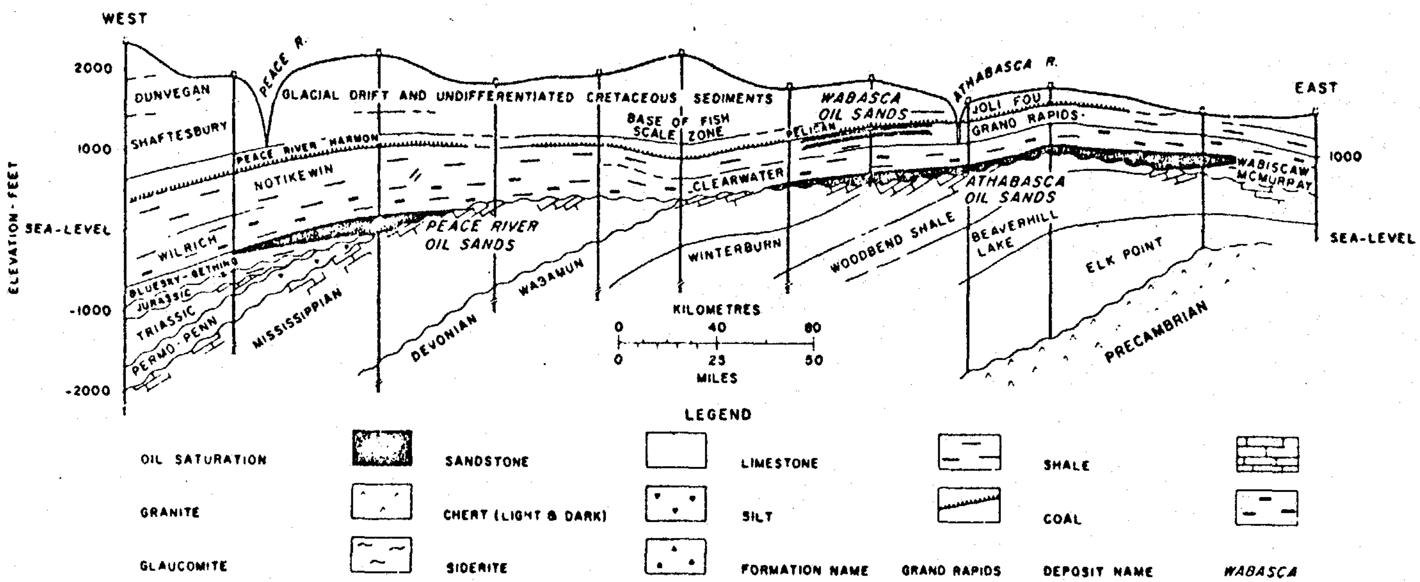

Fig. 1.5-2 Schematic cross-section (compare Fig. 1.5-1) between the western boundary of the Peace River deposit and the eastern boundary of the Athabasca deposit south of Fort McMurray (reproduced by R. D. Humphreys and R. Schutte on p. 3 of Ref. 13 and prepared by the Alberta Oil & Gas Conservation Board, 1963).

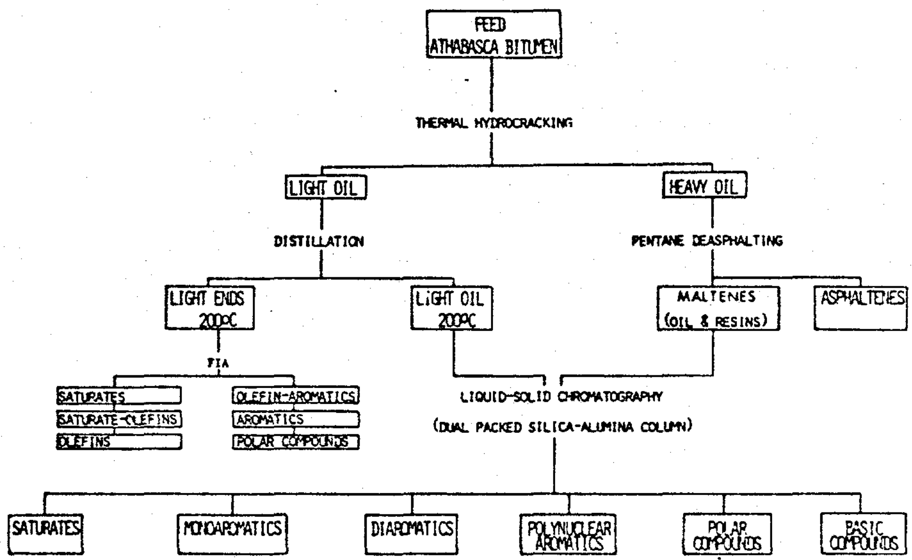

Fig. 1.5-3 Hydrocracking and separation scheme; reproduced from A. E. George, G. T. Smiley, and H. Sawatzky (p. 56 of Ref. 13).

of fireflooding are described by D. W. Bennion et al (Ref. 13, pp. 79-100); weight loss of heated oil sands was studied as a function of time by P. C. Stangeby and P. L. Sears (Ref. 13, pp. 101-118), while separation of oil sand bitumens into geochemical constituents forms the subject of a study by M. L. Selucky, T. C. S. Ruo, and O. P. Strausz (Ref. 13, pp. 119-144). Microbial extraction of bitumen from oil sands was examined by J. E. Zajic and D. F. Gerson (Ref. 13, pp. 145-161), whereas R. J. Crawford, C. Spyckerelle, and D. W. S. Westlake (Ref. 13, pp. 163-176) and I. Rubinstein and O. P. Strausz (Ref. 13, pp. 177-189) studied biodegradation of oil reservoirs and its relation to the origin of the Alberta oil sands; the degradation of aromatic hydrocarbons by bacteria and fungi is further discussed by C. E. Cerniglia and D. T. Gibson (Ref. 13, pp. 191-210). Other topics considered in Ref. 13 include comparisons between natural and synthetic asphaltenes (pp.211-222) and the nature of sulfur compounds found in heavy oils, oil sands, and oil shales (pp. 223-243).

A major additional publication dealing with oil recovery from heavy oils and tar sands has been published recently.[14] The following representative publications dealing with R&D are included: numerical simulation of a steam drive; identification of critical problem areas in oil recovery from Alberta tar sands, including cost reductions in overburden removal and handling, Clark-process modifications to allow shortened water-recycle times in tailing ponds, recovery from "oil-wet" sands, economical recovery from deeply buried sands and thin zones, bitumen recovery from carbonates, clean-up and reuse of product water (C. W. Bowman and M. A. Carrigy); innovative approaches for heavy (10-22°API) crude processing, including the use of solvents (e.g., pentanes-plus) to effect 35-55% recovery with low

[14]UNITAR, First International Conference on the Future of Heavy Crude and Tar Sands, Alberta, Canada, 1981.

solvent losses, use of agents to prevent viscosity increases in the well and production string, use of such compounds as poly-isobutylines to serve as "slickers" in pipelining, fireflooding with O_2 or oxygen-rich air to reduce air-compression costs, metabolic processes involving applications of bacteria or enzymes, generation of open-cycle steam in a wet combustion process to increase the ratio(product oil value/steam cost)(Z. G. Havlena); new ways for upgrading of tars and heavy crude (F. H. Adams et al); recovery of residual bitumen from aqueous tailings by sparging (E. S. Hall and E. L. Tollefson); role of asphaltenes in heavy crudes and tar sands (T. F. Yen); heavy crude oil and tar sand resources in the U.S. (R. L. Whiting); pipeline transportation of heavy oils (A. Sloan et al); fuels and chemicals from heavy crude and tar sands (J. W. Mohlman); experimental and mathematical modelling of *in situ* combustion in oil recovery (A. Satman et al); radiofrequency heating to recover oil from Utah tar sands (J. Bridges et al); water conservation in a steam stimulation project (M. J. Whalley and T. M. Wilson); stress and volume changes in gas-saturated, very dense sands (M. B. Dusseault); the chemistry of oil sand bitumen (D. P. Strausz); introduction to heavy oil upgrading (J. M. Wilkinson).

CHAPTER 2

RESOURCE ASSESSMENTS

2.1 Introduction and Definitions

2.1.1 Introduction

The definition of tar sand is presently being considered by DOE as a hydrocarbon resource having a viscosity at reservoir temperatures of >10,000 cp and the deposit must be produced through mining. Heavy oil, on the other hand, has no such clear definition. Many surveys do not include viscosity with resource descriptions. For the purpose of this chapter, we shall consider oils on a specific gravity basis rather than a viscosity basis as this property is more closely related to crude chemical properties and significance to upgrading. Viscosity relates crudely to specific gravity though correlations are highly scattered. Examples are provided in Table 2.1.1-1, where we show specific gravities and viscosities of various crudes.

The significance of these data to production can be realized by considering that at 60°F conventional crudes of 30-45°API have viscosities of only 3.5-48 centipoise and thus require several orders of magnitude less force to move through the ground than would be needed for heavy crudes.

The gravities of the heavy oil or bitumen deposits appear to 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 oil.

Table 2.1.1-1. Variations in viscosity with API[a] gravities (see Refs. 1 and 2). Modified from data in Leverson (1956),[1] Carrigy & Kramers (1973)[2] and selected journals.

Bitumen from	Specific gravity	°API (60°F)	Viscosity (centipoise)[b] (100°F)
Bradford, Pennsylvania	0.801	45.2	2.81
Rodessa, Texas	0.812	42.8	3.14
Abqaiq, Saudi Arabia	0.840	37.0	3.55
Rangely, Colorado	0.850	35.2	4.88
Walters, Kansas	0.879	29.3	17.47
Lagunillas, Venezuela	0.948	17.8	203.50
Spring Creek, Wyoming	0.980	12.6	1,276.20+
Cold Lake, Alberta	1.003	9.5	200,000[c]
Athabasca, Alberta	1.0-1.02	10.0-6.0	300,000 to 30,000,000[c]

a. In this chapter, API gravity is used as the measure of specific gravity. High API gravity is an indication of good quality to a refiner. Specific gravity and API gravity are related as follows:

$$°API = \frac{141.5}{\text{sp. gr. at } 60/60°F} - 131.5 \text{ .}$$

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.

b. One centipoise equals 1/100 of a poise. A fluid has a viscosity of 1 poise when a tangential force of 1 dyne causes a plane surface of 1 cm^2 area, spaced 1 cm from a stationary plane surface, to move with a constant velocity of 1 cm/sec, the space between the planes being filled with the viscous fluid (API Bul. 228, 1941).

c. Viscosities measured at 60^{o}F.

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[1]A. I. Leverson, The Geology of Petroleum, p. 703, W. H. Freeman and Company, San Francisco, California, 1956.

[2]M. A. Carrigy and J. W. Kramers, editors, "Guide to the Athabasca Oil Sands Area," p. 213. Contribution No. 628, Information Series 65, Alberta Research Council, Edmonton, Alberta, Canada, 1973.

Dietzman[3] defined 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 1,500 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 production of heavy oils in the United States also defined heavy oils as <25° API.[4]

Heavy oils as defined in this chapter include all 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, which are not discussed in this chapter, 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.

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[3] W.D. Dietzman, M. Carrales, Jr., and C.J. Jirik, "Heavy Crude Oil Reservoirs in the U.S., a Survey." U.S. Dept. Int., Bur. Mines, Inf. Circ. 8263, Washington, D.C., 1965.

[4] Bureau of Mines Circular 8352 "Heavy Crude Oil - Resource, Reserve and Potential Production in the U.S." U.S. Dept. of Interior, Washington, D.C., 1967.

The above definition for heavy oils encompasses a wide variety of petroleum resources, which have been referred to by a number of different subclassifications.

2.1.2 Definitions of Heavy Oil Classifications

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 2.1.2-1 and are defined below. They are listed in increasing order of desirability as feedstocks to present-day refineries.

Table 2.1.2-1 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 Carbonate-Oil Sand	6 to 12				
Heavy Crude Oil	10 to 16				

Asphaltites[5] These 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 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 minerals and have been so named. Representative 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[5] Bitumens of this type 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. Traditionally, 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).

Tar Sand, Oil Sand, Carbonate-Oil Sand The majority of the heavy oils fall within this category. 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 resouces are 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.

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[5] H. Abraham, Asphalts and Allied Substances, Vol. 2, D. Van Nostrand Company, Inc., Princeton, New Jersey, 1960.

Heavy Crude Oils These bitumens are all viscous liquids having API gravities in the range of 10 to 20 and generally contain >30% of distillable materials. They represent the only subclass of heavy oils which can be produced by primary methods (natural pressure or pumping). Generally, primary production yields <10% of the oil in place. Representative examples include the following oil fields: San Ardo (California), Lloydminster (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.[6] 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.[5] The reason for their early exploitation is the fact that heavy oils often occur as natural seepages or at shallow depths.

Generally, in a given location, heavy oils follow a rule-of-thumb that the API gravity increases with depth. Thus, the most accessible oils have the lowest value as sources of the petroleum hydrocarbons that are presently

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[6] G.J. Demaison, "Tar Sands and Super Giant Oil Fields," presented at the 157th Meeting of CIM, Canada-Venezuela Oil Sands Symposium, Edmonton, Alberta, May 1977.

needed. An unfortunate aspect of compositional difference with depth is that the credibility of reserve statistics also decreases with depth. Heavy crudes of low API gravity (10-20 °API) are often disregarded in present statistical surveys as they are often 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. The oil in these zones may be from the same or a different source and can therefore have different physical and chemical properties. Generally, lower zones have higher API gravities and lower viscosities and are therefore easier to produce.[7] 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.[8] API gravity is highest in lower levels, and commonly the paraffin content increases with depth. Examples of the various types of deposits and production zones in which heavy oils are found are illustrated in Figs. 2.1.2-1 through 2.1.2-4.

Because of the complexity of multiple seams and varying quality with depth, no distinction will be made as to the quantity of the individual subclasses or different quality crudes found within a given geographical location. Accordingly, the quantity of bitumen which is 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.

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[7]F.J. Gutierex, "The Orinoco Tar Belt of Venezuela," in Ref. 6.

[8]C.W.D. Milner, M.A. Rogers and C.R. Evans, J. Geochem. Expl. 7, 101 (1977).

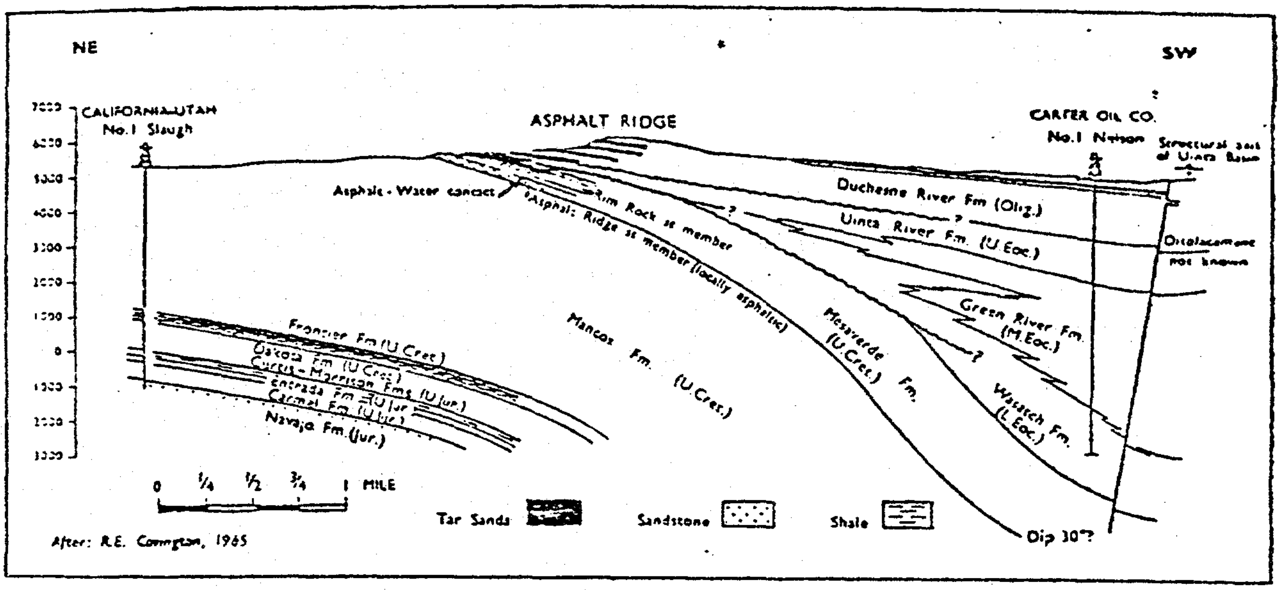

Fig. 2.1.2-1 Geologic cross profile, Asphalt Ridge Area, Utah.[9]

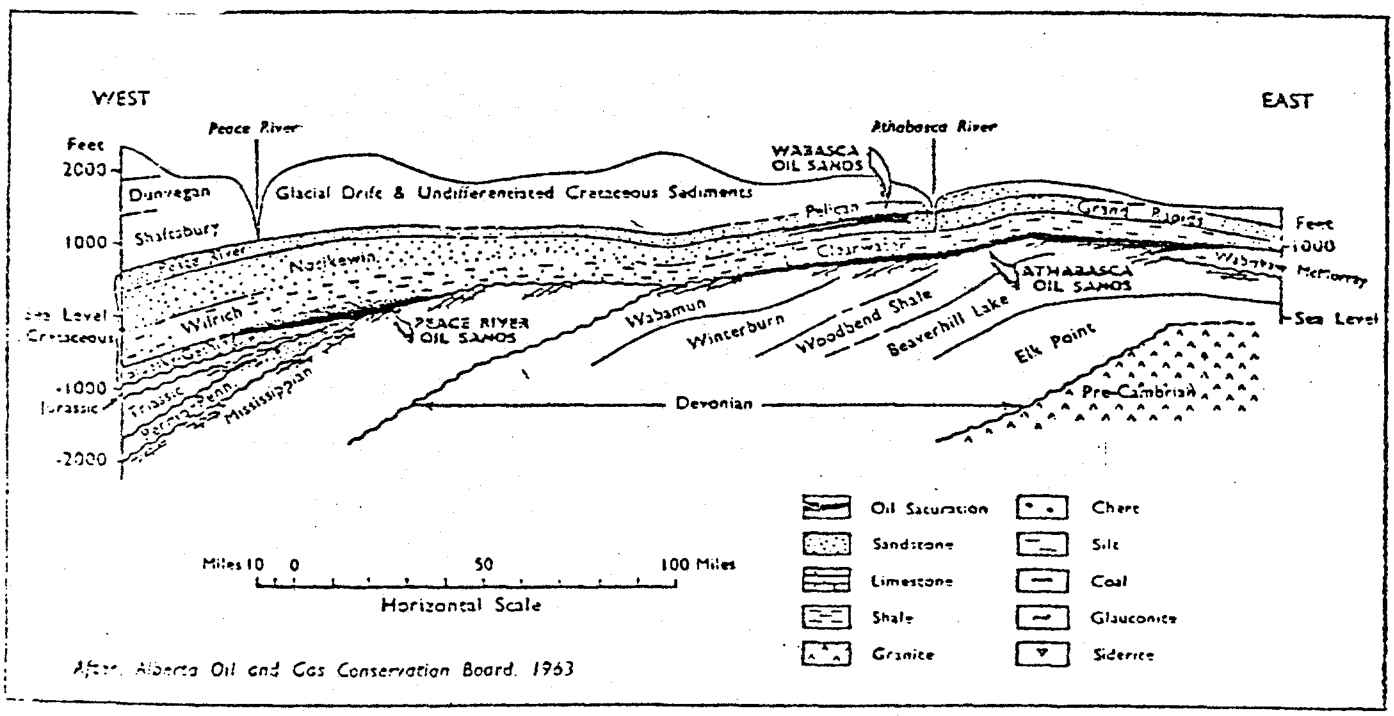

Fig. 2.1.2-2 Schematic geological E-W cross section showing the geological setting of the Athabasca Tar Sands.[9]

Many heavy oil deposits occur in multiple zones and often in different formations. As shown above, Wabasca consists of two formations. San Ardo, California (not shown in this figure) similarly has two production zones. Lower lying formations generally have higher API gravities.

[9] P.H. Phizackerley and L.O. Scott, "Major Tar Sand Deposits of the World," presented at the 7th World Petroleum Congress 3, 551 (1967).

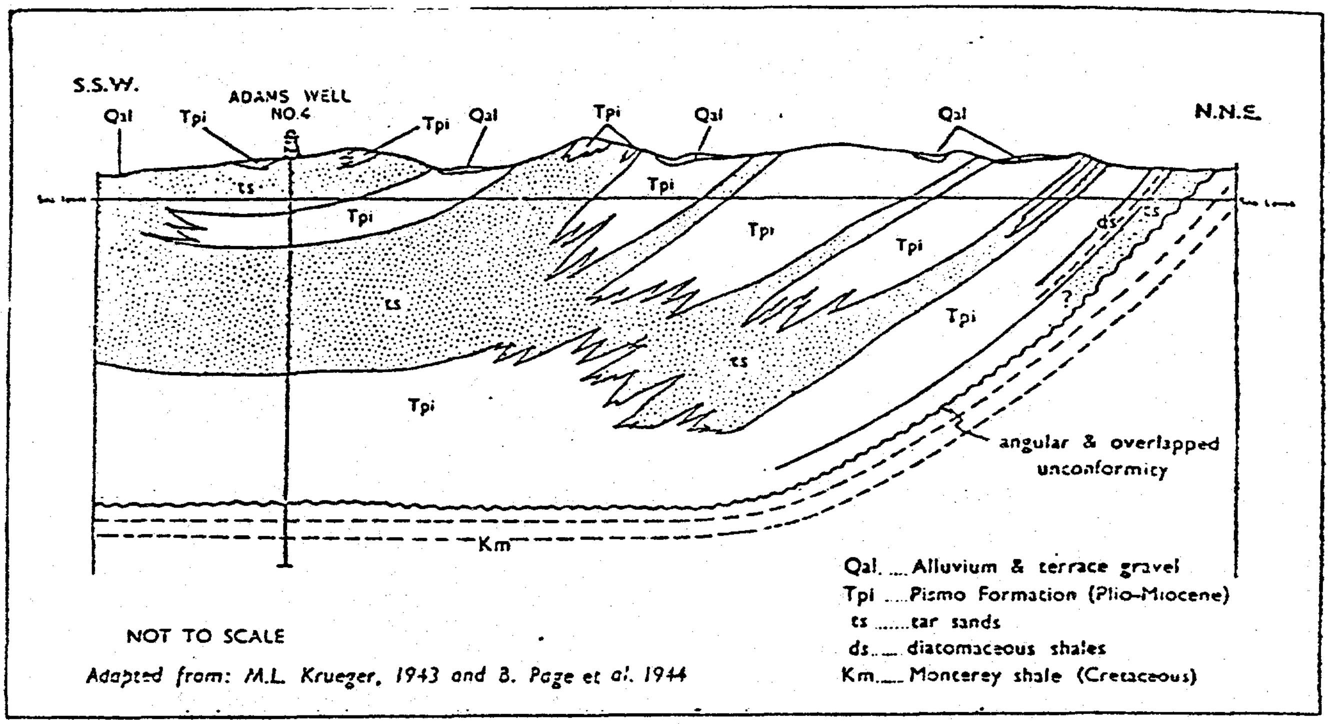

Fig. 2.1.2-3 Diagrammatic section through Edna Tar Sands, California.[9]

Some heavy oil deposits are composed of formations which extend from reasonable depths to the surface. In these instances, the quality of the crude can vary considerably with depth as biological degradation of the crude near the surface can cause major compositional changes.

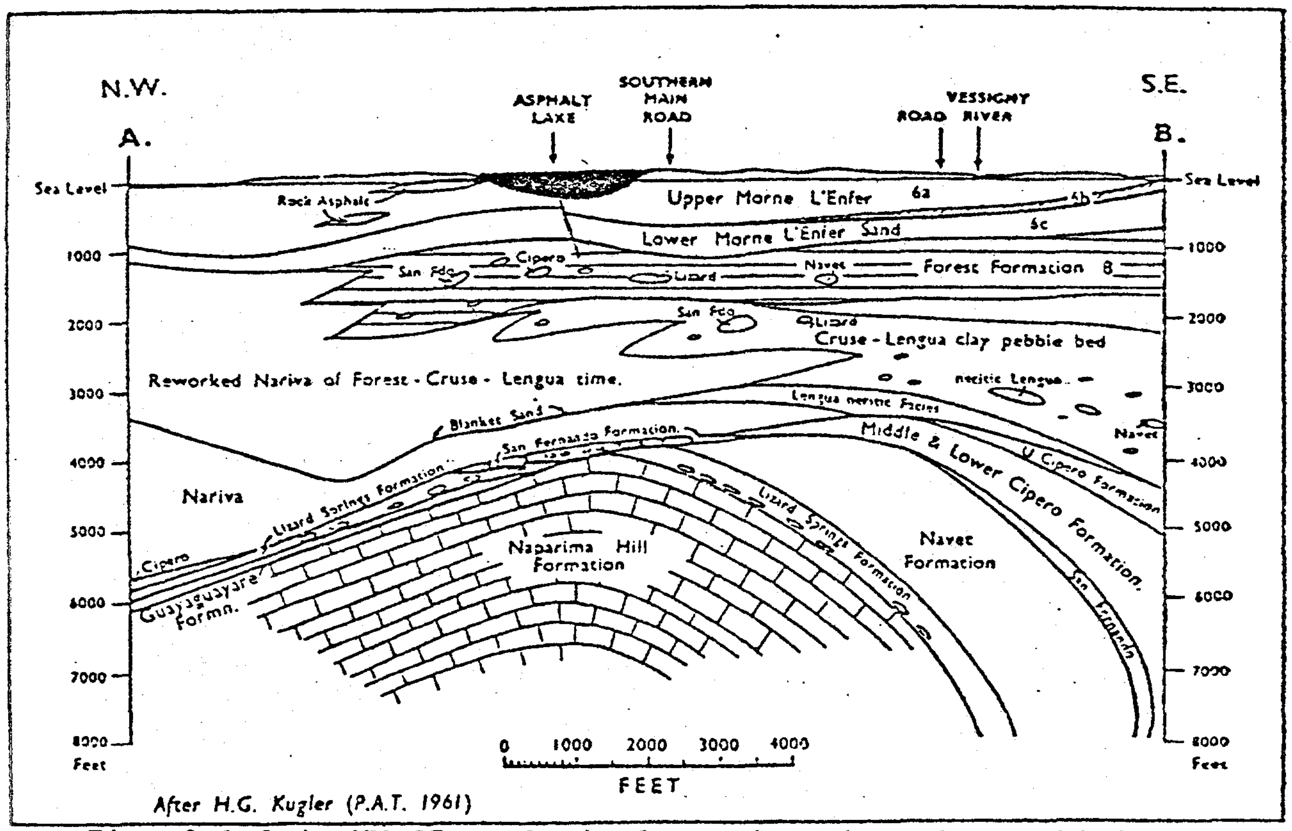

Fig. 2.1.2-4 NW-SE geological section through Trinidad Asphalt Lake Area.[9]

In a few instances, heavy oils occur in massive deposits of almost pure bitumen, as in the case of asphalt lakes.

2.2 Available Physical Property Data on Tar Sands and Heavy Oils

To assess the value of a given crude, physical property data are very important. Crude oil physical property data are scattered in a multitude of reports that vary from detailed analytical and processing studies[10] to a mere listing of API gravity and sulfur. Viscosity data are very often omitted in present surveys.

(1) A systematic accumulation of data is, however, furnished by the Bureau of Mines as assays in the form of a multitude of Research Investigations (RI) of various crudes. Data reported by the Bureau of Mines are exemplified by Table 2.2-1 for 11.1 °API San Ardo, California, crude. In addition to these printed RI, data for 9,000 Bureau of Mines assays are available in the form of punched cards in Fortran language for computer-manipulated searches.

(2) 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. Typical printouts are shown in Table 2.2-2.

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

[10] "Gulf Kuwait Crude Oil Handbook," Gulf Oil Corporation Report No. 753RA006, Pittsburgh, Pennsylvania, 1970.

Table 2.2-1 A representative Bureau of Mines data report.

Item 69
Bureau of Mines Bartlesville Laboratory
Sample [illegible]

IDENTIFICATION

San Ardo field
Lombardi, Miocene
2,100-2,250 feet

California
Monterey County

GENERAL CHARACTERISTICS

Gravity, specific, 0.992 Gravity, °API, 11.1 Pour point, °F., 80
Sulfur, percent, 2.25 Color, brownish black
Viscosity, Saybolt Universal at 100°F., over 6,000 sec.; at 130°F., over 5,000 sec. Nitrogen, percent, 0.813

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

Stage 1—Distillation at atmospheric pressure, 749 mm. Hg
First drop, 352 °F.

Fraction No.	Cut temp. °F	Percent	Sum. percent	Sp. gr. 60/60° F.	°API, 60° F	C. I.	Refractive index, n_D at 20° C	Specific dispersion	S. U. visc., 100° F.	Cloud test, °F.
1	122									
2	167									
3	212									
4	257									
5	302									
6	347									
7	392	1.0	1.0	0.832	38.6	-				
8	437	1.4	2.4	.861	32.8	53				
1/ 9	482	4.1	6.5	.867	31.7	-	1.45473	125.6		
10	527									
Stage 2—Distillation continued at 40 mm. Hg										
11	392	4.9	11.4	0.892	27.1	-	1.48846	141.1	43	Below 5
12	437	5.5	16.9	.909	24.2	58	1.49896	155.4	57	do
13	482	6.3	23.2	.930	20.7	64	1.51260	161.6	93	do
2/ 14	527	3.2	26.4	.946	18.1	-	1.51365	-	200	do
15	572									
Residuum		72.0	98.4	1.025	6.6					

Carbon residue, Conradson: Residuum, 6.6 percent; crude, 3.6 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	°API	Viscosity
Light gasoline				
Total gasoline and naphtha				
Kerosine distillate				
Gas oil	11.2	0.825	30.2	
Nonviscous lubricating distillate	8.5	.901-.931	25.6-20.5	50-100
Medium lubricating distillate	4.6	.931-.946	20.5-18.1	100-200
Viscous lubricating distillate	1.6	.946-.951	18.1-17.3	Above 200
Residuum	72.0	1.025	6.6	
Distillation loss	1.6			

1/ Distillation discontinued at 482° F.
2/ Distillation discontinued at 509° F.

Table 2.2-2 Example of data retrievable from API tapes.

```
                                                                    PAGE    1
       PHYSICAL PROPS OF HEAVY OILS & BITUMENS - 76-218 (ENGLISH)
-----------------------------------------------------------------------------


AN  - 225184
TI  - AVERAGE TEMPERATURE MEASUREMENT IN STORAGE TANKS
AU  - LEAVER R H
SO  - PETROL TIMES V 80. NO 2031. PP 38. 41. 7/9/76
DE  - *ABOVEGROUND STOR FACILITY: AVERAGING: CALCULATING: CHANGE:
      CONVECTION: CONVERSION: CRUDE OIL. DENSITY: DETECTOR: *ELECTRICAL
      PROPERTY: EMPIRICAL ANALYSIS: ENGLISH: FLOW MEASURING: FLOWMETER:
      FLUID FLOW: GRADIENT: HEATING. HEATING EQUIPMENT: *INSTRUMENT:
      MATHEMATICAL ANALYSIS: MATHEMATICS: *MEASURING: OIL DENSITY:
      PETROLEUM: *PHYSICAL PROPERTY. POWER: PRODUCT: *RESISTIVITY:
      SOLAR ENERGY: *STORAGE FACILITY: TANK: *TEMPERATURE MEASURING:
      TEST PROBE: *TESTING: THERMAL GRADIENT: THERMAL PROPERTY:
      *THERMOMETER: VISCOUS CRUDE OIL: VOLUME


AN  - 224565
TI  - THERMAL CHARACTERISTICS OF ANALCIME AND ITS EFFECT ON HEAT
      REQUIREMENTS FOR OIL-SHALE RETORTING
AU  - JOHNSON D R: ROBB W A: YOUNG N B
SO  - FUEL V 54. NO 4. PP 249-252. OCT 1975 (AO)
DE  - *ANALCIME: CENOZOIC: CHANGE: *CONVERSION PROCESS: CRUDE OIL:
      CRYSTALLIZATION. DECOMPOSITION: DEVELOPMENT: DISTRIBUTION: EARTH
      AGE: ENERGY SOURCE: ENGLISH. EOCENE: GEOLOGIC STRUCTURE: *GREEN
      RIVER FM: MANUFACTURED CRUDE OIL: *MINERAL: NORTH AMERICA: *OIL
      AND GAS RECOVERY: *OIL RECOVERY: OIL SHALE: PETROLEUM: PHASE
      BEHAVIOR: PHASE CHANGE: *PHYSICAL PROPERTY: *PYROLYSIS:
      RESERVOIR: *RETORTING: ROCK: SEDIMENTARY ROCK: SHALE: SHALE OIL:
      *SHALE OIL RECOVERY: SHALE RESERVOIR: *SILICATE MINERAL:
      SOLIDIFICATION: TEMPERATURE: TERTIARY PERIOD: THERMAL
      DECOMPOSITION: *THERMAL PROPERTY: UNITED STATES


AN  - 224265
TI  - PROPERTIES OF UTAH TAR SANDS:  NORTH SEEP RIDGE AREA. P.R. SPRING
      DEPOSIT
AU  - CUPPS C Q: JOHNSON L A: MARCHANT L C
SO  - LARAMIE ENERGY RES CENTER REP NO LERC/RI--75/6. 19 PP. NOV 1975
      (AO)
DE  - ALT FUELS + ENERGY SOURCES: ANALYTICAL METHOD: *BITUMINOUS
      SANDSTONE: *CHARACTERISTIC: COMPOSITION: *CRUDE OIL: DENSITY:
      *ENERGY SOURCE: ENGLISH: FLUID PROPERTY: FORMATION THICKNESS:
      MANUFACTURED CRUDE OIL: NITROGEN CONTENT: NORTH AMERICA: *OIL AND
      GAS RECOVERY: *OIL RECOVERY: OIL SATURATION: P R SPRING AREA:
      PERMEABILITY: PERMEABILITY (ROCK): *PETROLEUM: *PHYSICAL
      PROPERTY: PORE VOLUME: POROSITY: POROSITY (ROCK): *RESERVOIR
      CHARACTERISTIC: RESULT: *ROCK. *SANDSTONE: SATURATION:
      *SEDIMENTARY ROCK: SULFUR CONTENT: *TAR SAND: *TAR SAND OIL: *TAR
      SAND OIL RECOVERY: TESTING: THICKNESS: UNITED STATES: UTAH:
      VISCOUS CRUDE OIL: VOLUME
```

changes in temperature in a common manner. It is unlikely to cause unusual changes in viscosity by a simple change in the temperature of a heavy crude. 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 has been found to be very important in pipelining Venezuelan heavy oils.[11] 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.[11] 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 lbs/100 ft^2; beyond that point, little effect is noted.[11] 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.

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 2.2-3.

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[11] R.G. Gunzalo, "Rheological Behavior of Extra Heavy Crudes from the Orinoco Petroleum Belt," presented at Canadian-Venezuela Oil Sands Symposium 77; Edmonton, Alberta, May 31, 1977.

Table 2.2-3 Desirable compositonal 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
  - State Name
  - County Name
- Geological Source
  - Name of Formation
  - Age of Formation
  - Depth of Formation from Surface
  - Thickness of Pay Zone
  - Type of Pay Zone
- PVT Properties
  - °API Gravity
    - Separator
    - Reservoir
  - Viscosity at Reservoir Conditions
- Bubble Point Pressure
- Viscosity at Formation Conditions
- Oil Formation Volume Factor
- Gas Formation Volume Factor

Crude Oil Summary - Bureau of Mines Classification

- Gravity, API
- Specific Gravity, 60/60F
- Distillation
- IBP
  - 5 PCT Vol Recovered
  - 10
  - 20
  - 30
  - 40
  - 50
  - 60
  - 70
- Fraction 400-500F, PCT Vol
  - Gravity, API
  - Mercaptan Sulfur, PPM
- Flash Point, F, (TAG)
- Pour Point, F, (upper)
- Viscosity
  - Kinematic, 60F (15.6C), CS
    - 100F (37.8C), CS
    - 130F (54.4C), CS
- Carbon Residue, PCT WT (CCR)
- Aniline Point, °F
- Sulfur, PCT WT
- Hydrogen Sulfide, PPM
- Neutralization No., Total Acid
- Water and Sediment, PCT Vol
- Salt Content, pounds/1000B
- Reid Vapor Pressure, pounds
- Nitrogen, Total, PPM
- Nickel, PPM
- Vanadium, PPM
- Ash, PPM
- Carbon, Pct Wt
- Hydrogen, Pct Wt
- Carbon/Hydrogen Ratio

Distillation Summary

- Gasoline-Naphtha, IBP-392°F, % Vol
- Kerosine, 392-527°F
- Light Gas Oil, 527-690°F
- Heavy Gas Oil, 690-790°F
- Residuum, 790°F+

2.3 Resources and Reserves of Heavy Oils

2.3.1 Definitions

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, at least two numbers need to be considered:

- Resource Quantity - The total stock-tank volume of heavy oil and tar sand remaining in a reservoir, without regard to technologic or economic feasibility of recovery.
- Proved Reserve Quantity - 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.[12] The in-place resources of Alberta are presently estimated as 2601×10^9 barrels* of heavy oil and tar sand. By contrast, the proved recoverable reserves are estimated to be between 157 and 472×10^9 barrels.

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[12] C.D. Outtrim and R.G. Evans, "Alberta's Oil Sand Reserves and Their Evaluation," presented at the 157th Meeting of CIM, Canada-Venezuela Oil Sands Symposium, Edmonton, Alberta, May 1977.

* In this chapter, all resources are reported in units of billions of barrels. To put this in perspective, 1×10^9 barrels represents a volume the size of a football field 22 mi. high. The United States presently consumes over 5 billion barrels of oil each year.

2.3.2 Resources of Heavy Oils and Tar Sands

The occurrences, quantity of resources, and historical uses of asphaltites and asphalts have been described in detail.[5] Tar sands etc. and extractable bitumens (<12 API) of the world have been extensively surveyed[3,4,6,9,12-18] and the reader is referred to these papers for detailed information. More recently, workers at the Laramie Energy Technology Center have surveyed the tar sands resources of the United States. Figure 2.3.2-1 indicates the location of U.S. tar sands and Table 2.3.2-1 provides the latest estimates of the in-place resources of tar sands in the U.S. Figure 2.3.2-1 should be compared with earlier surveys. which included all accumulations of oil in shallow deposits. Figure 2.3.2-2 represents a superimposition of two such earlier surveys conducted by the U.S. Department of Interior.[3,15] These earlier reports showed more extensive deposits, although some of these resources were undoubtedly heavy oils rather than tar sands as now defined.

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[13] V.A. Kuuskraa, S. Chalton and T.M. Doscher, "The Economic Potential of Domestic Tar Sands," DOE Contract Number 9014-018-021-22004, Washington, D.C., 1978.

[14] C.A. Koch, "Oil Resources in Tar Sand Deposits in the United States," DOE Order Number DE-AP-20-80LC01022, Washington, D.C.

[15] Ball Associates, Ltd., "Surface and Shallow Oil-Impregnated Rocks and Shallow Oil Fields in the United States," U.S. Dept. of Interior, Bureau of Mines, Monograph 12, Washington, D.C., 1965.

[16] D. Ball, "United States Tar Sands as a Petroleum Source", Paper presented at the symposium "An Assessment of Some Factors Affecting the Availability of Oil and Gas in the United States through 1980," U.S. Dept. of Interior, Washington, D.C., March 1967.

[17] H. R. Ritzma , "Oil Impregnated Sandstone Deposits of Utah - A Progress Report," Interstate Oil Compact Comm. Bull. 11, No. 2, 24-34 (December 1969).

[18] H. R. Ritzma , "Location Map and Oil Impregnated Rock Deposits of Utah," Utah Geological and Mineralogical Survey, Map No. 33, Salt Lake City, Utah, April 1973.

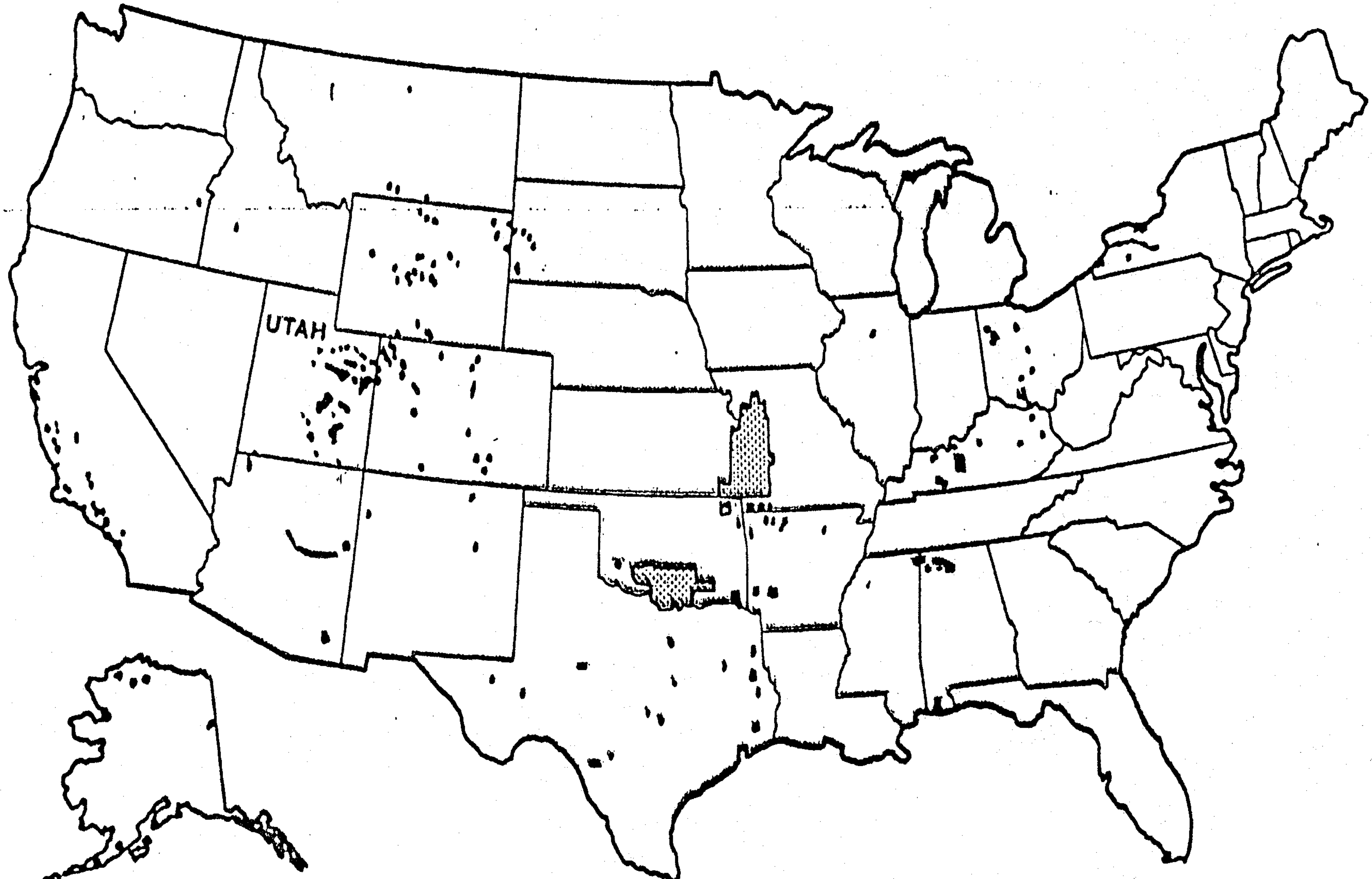

Fig. 2.3.2-1 Tar sand occurrences in the U.S.

Table 2.3.2-1 Deposits of bitumen-bearing rocks in the U.S. with resources over 1,000,000 barrels; prepared by workers at LETC, Laramie, Wyoming.

State and Name of Deposit	Estimated Resources (Billions of Barrels) Low	High
CALIFORNIA:		
Oxnard	.565	
Santa Maria	.500	2.000
Edna	.141	.175
South Casmalia	.046	
North Casmalia	.040	
Richfield	.040	
Paris Valley	.030	.100
Sisquoc	.029	.106
Santa Cruz	.010	
McKittrick	.005	.009
Point Arena	.001	
California Total	1.407	3.093
KENTUCKY:		
Kyrock Area	.018	
Davis-Dismal Area	.007	.011
Bee Spring Area	.008	
Kentucky Total	.003	.037
NEW MEXICO:		
Santa Rosa	.057	.600
TEXAS:		
Uvalde	.124	3.000
UTAH:		
Tar Sand Triangle	12.504	16.004
P.R. Spring	4.000	4.500
Sunnyside	3.500	4.000
Circle Cliffs	1.000	1.507
Asphalt Ridge	1.000	1.200
Hill Creek	.300	1.160
San Rafael Swell Area	.385	.470
Asphalt Ridge, Northwest	.100	.125
Raven Ridge	.075	.100
Whiterocks	.065	.125
Wickiup	.060	.075
Argyle Canyon	.050	.075
Rim Rock	.025	.030
Cottonwood-Jacks Canyon	.020	.025
Pariette	.012	.015
White Canyon	.012	.015
Minnie Maud Creek	.010	.015
Willow Creek	.010	.015
Littlewater Hills	.010	.012
Lake Fork	.007	.010
Nine Mile Canyon	.005	.010
Chapita Wells	.008	.008
Ten Mile Wash	.002	.006
Tabiona	.001	.005
Thistle	.002	.003
Slpring Branch	.002	.002
Cow Wash	.001	.001
Utah Total	23.166	29.513
UNITED STATES TOTAL	24.787	36.243

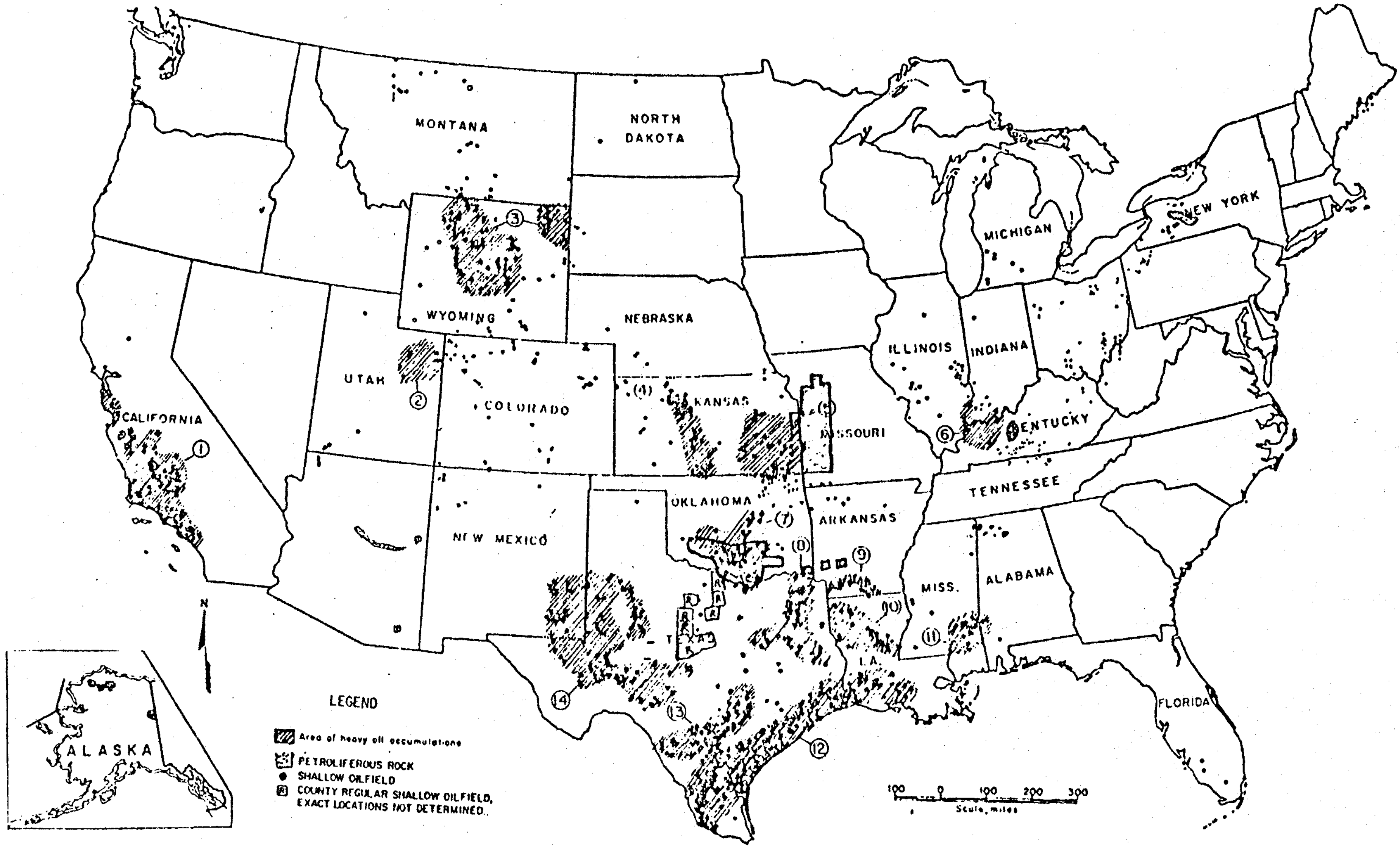

Fig. 2.3.2-2 Geographical location of heavy oil fields in the United States. *This map illustrates the superposition of data from two reports (Refs. 3 & 15), which included information on heavy crude fields, heavy oil accumulations, and petroliferous rocks. Deposits in Wyoming, Oklahoma, and Kansas, although large in areal extent, are disperse. Major deposits having high local concentrations of heavy oils occur in Utah and California.*

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.[4] This survey further classified the resources with respect to ease of recovery as follows:

> Class 1 - Desirable characteristics for thermal recovery operations -- sandstone reservoirs at depths of less than 3,000 feet, greater than 10 feet thickness, stock tank oil saturations of 750 bbl/acre-ft or greater, viscosity of oil sufficient for mobility at existing conditions.
>
> Class 2 - Some of the above desirable characteristics, but not all.
>
> Class 3 - Only a few of the above desirable characteristics.

For the purpose of this chapter, we have considered only those crudes with API gravities <20. Accordingly, the locations of known resources of heavy crudes of the U.S. are shown in Fig. 2.3.2-3, and their ease of production is indicated in Table 2.3.2-2. As can be seen from the table, about 55.5 billion barrels of heavy crude (<20 API) were in place in 1966. Had we chosen crudes <25 API, the estimate would have been much larger (106.8 billion barrels).

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 billion bbl

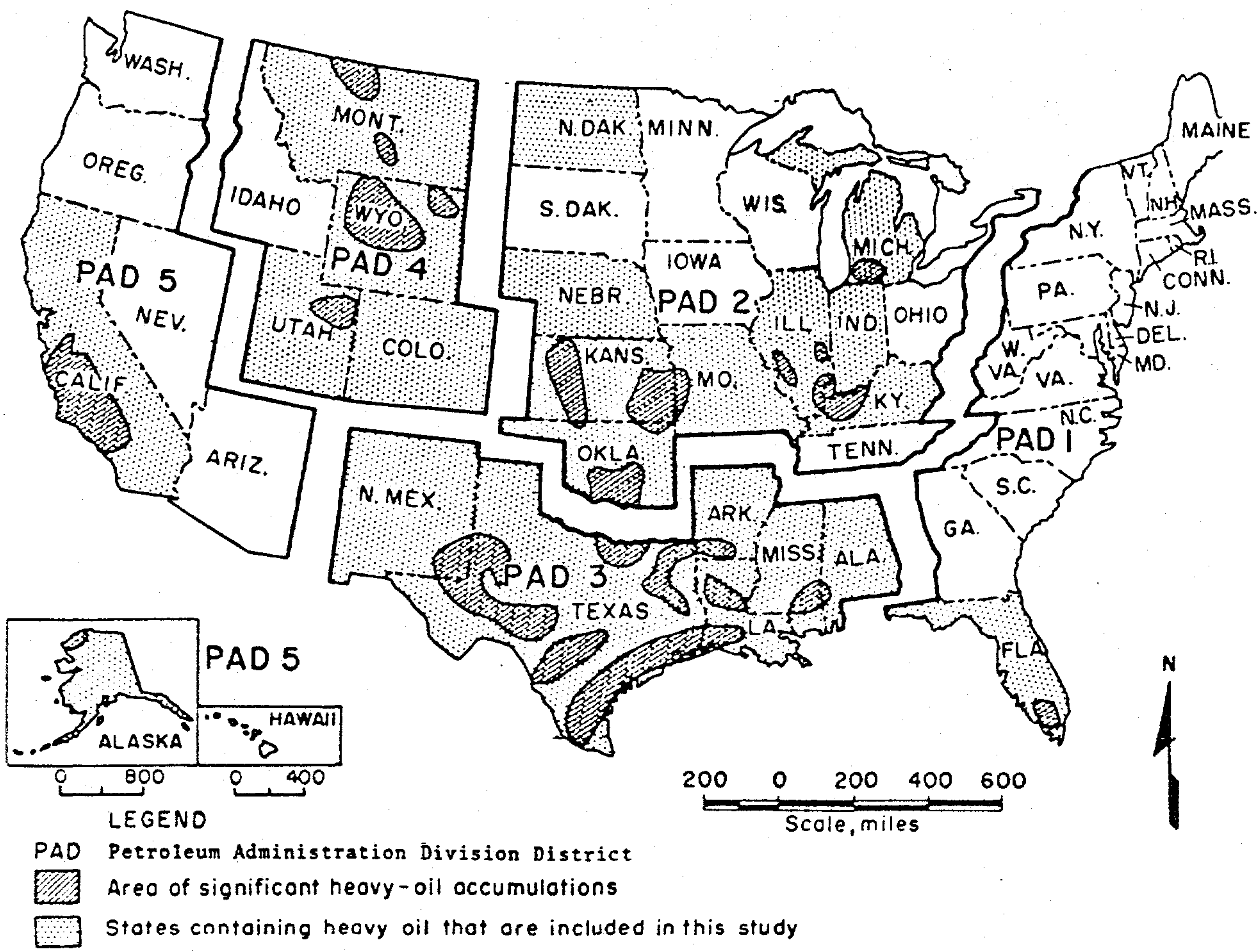

Fig. 2.3.2-3 States containing heavy crude oil included in this study.

Table 2.3.2-2 United States heavy crude oil resources (less than 20°API with some mobility[4]).

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

of oil have been made.[19] However, recent estimates by each state's geological survey office 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, December 1977, has indicated a resource base of 0.200-0.225 billion barrels of oil-in-place, none of which is recoverable under 1977 existing technology and economics. The estimates of resource size are severely downgraded from earlier estimates due to discontinuous nature, thinness and shaliness of the reservoir sandstone bodies.[20]

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.[21]

An inventory of heavy oil in western Missouri, by the Missouri Department of Natural Resources, Division of Geology and Survey, September 1979, estimates that a resource of 1.4 to 1.9 billion barrels of oil-in-place is present, none of which is considered in a reserve category under present economics and technological parameters.[22]

Many heavy oil reservoirs are presently being produced using thermal techniques. A recent summary of U.S. thermal projects is provided in Table 2.3.2-3.[23] A similar list can be found in Ref. 4. Table 2.3.2-4 provides some additional data on the production of heavy crudes. The total U.S. reserves estimated in 1975 were 2.6 billion barrels.[24]

[19] R.T. Johansen, "Chemical and Physical Principles of Enhanced Recovery Processes," presented at the Fossil Fuel and Energy Conf. (CONFAB), Saratoga, Wyoming, July 1977.

[20] BETC Publication #RI-77/20, Bartlesville, Oklahoma, December 1977.

[21] BETC Publication #1812-1, DOE #ET-76-S-031812, Bartlesville, Oklahoma, June, 1979.

[22] BETC Publication #1808-1, DOE #ET-76-S-03-1808, Bartlesville, Oklahoma, September 1979.

[23] Oil and Gas J. 74, 107 (April 5, 1976).

[24] International Petroleum Encyclopedia 1975, Petroleum Publishing Company, Tulsa, Oklahoma, 1975.

Table 2.3.2-3 Thermal recovery projects in the United States (Ref. 23).

Field	State	County	Operator	Start date	Area, acres	Number wells Prod.	Number wells Inj.	Pay zone	Porosity, %	Permeability, md	Depth, ft	Reservoir oil °API	Reservoir oil cp	Reservoir oil @ °F.	Previous production	Residual oil saturation, % Start	Residual oil saturation, % End	Project maturity	Enhanced prod., bo/d	Project eval.	Profitable
Steam soak																					
Coalingua	Cal.	Fresno	Shell	2/67	2,520	385		Temblor	28	1,000	900-2,800	16-18	200 5.5M	@ 90-160	Prim.	89	69	HF	3,900	Succ.	Yes
W. Coalingua	Cal.	Fresno	Socal	66	1,280			Temblor	35	400	1,200	14	1.2M	@ 90	Prim.	85	75	90% compl.		Succ.	Yes
Asphalto	Cal.	Kern	Getty	3/75	120	4		Tulare	31	450	1,400	12	780	@ 140	Prim.	100	85	HF	100	TETT	
S. Belridge	Cal.	Kern	McCulloch	70	100			Tulare	25	1,000	800	12	...		Prim.	60	40	HF		Prom.	No
Cymric	Cal.	Kern	Getty	1/68	70	22		Tulare	32	4,000	1,000	12	2.7M	@ 100	Prim.	95	85	NC	500	Succ.	Yes
Cymric	Cal.	Kern	Gulf	6/66		8		Tar			1,000	10			...			...		Succ.	Yes
Cymric	Cal.	Kern	Mobil	7/65	170	46		Welport, Amnicola	38	3,000	400-900	12-13	1.5M	@ 95	Undev.	99	75	32% compl.	400		
Cymric	Cal.	Kern	Socal	66	700		...	Tulare	35	4,000	1,000	13	2.4M	@ 85	Prim.	90	75	60% compl.		Succ.	Yes
Edison	Cal.	Kern	Exxon	65	1,100	75		Kern River	30	2,000	1,100	16	310	@ 95	Prim.			HF	600	Succ.	Yes
Kern Front	Cal.	Kern	ARCO	11/64	160	56	..	Chanac	32	1,600	1,600	13.7	400	@ 120	Prim.					Succ.	Yes
Kern Front	Cal.	Kern	Getty	5/66	1,080	132		Chanac-Etch.	30.4	1,500	2,300	13.5	406	@ 90	Prim.	82	77	HF	1,676	Succ.	Yes
Kern Front	Cal.	Kern	Mobil	5/74	600	100	..	Chanac-Etch.	37	1,000	1,800	14.4	800	@ 100	Prim.	84	73	JS	450		
Kern Front	Cal.	Kern	Socal	70	640			Chanac	27	700	2,400	12	3M	@ 110	Prim.	80	75	75% compl.		Succ.	Yes
Kern River	Cal.	Kern	Chans.-West.	5/64	240	172		300 ft	33	4,000	100-800	13	4M	@ 90	Prim.	80	40		900	Succ.	Yes
Kern River	Cal.	Kern	Getty	60	3,000	1,271		Kern River	39	3,000	900	13.5	4.1M	@ 90	Prim.	90	86	NC	14,588	Succ.	Yes
Kern River	Cal.	Kern	Getty	74	9	3	.	Kern River	39	3,000	900	13.5	4.1M	@ 90	Prim.	86	76	HF	10	Prom.	Yes
Kern River	Cal.	Kern	Shell	4/63	1,300	443		Kern River	31	2,000	300-1,300	11-13	3M	@ 85	Prim.	90	73	HF	9,000	Succ.	Yes
Kern River	Cal.	Kern	Socal	66	1,400		....	Kern River	31	2,000	1,000	14	4M	@ 85	Prim.	85	78	85% compl.		Succ.	Yes
Lost Hills	Cal.	Kern	ARCO	6/67	15	7		Etchegoin	32	2M	500	12.5	1M	@ 100	Prim.			NC		Succ.	Yes
Lost Hills	Cal.	Kern	Getty	1/68	150	61	..	Etchegoin	38	1,000	500	13	1M	@ 100	Prim.	90	80	HF	500	Succ.	Yes
Lost Hills	Cal.	Kern	Gulf	8/64		43	...	Tar		.	200-400	16			...		..	..		Succ.	Yes
Lost Hills	Cal.	Kern	Gulf	2/75	1	3	..	Zone "A"			700	15			Prim.			JS		TETT	No
McKittrick	Cal.	Kern	Getty	64	500			Potter	30	3,000	1,200	15	600	@ 100	Prim.	75	52	HF	7,600	Succ.	Yes
McKittrick	Cal.	Kern	Getty	6/74	3		....	Potter	30	3,000	1,200	15	600	@ 100	SS	68	65	NC		Disc.	No
McKittrick	Cal.	Kern	Occidental	4/65	46	.	.	Olig. sand	37		900	14			Prim.			HF		Succ.	Yes
McKittrick	Cal.	Kern	Socal	71	120		..	Tulare	35	2,000	820	15	4M	@ 100	Prim.	98	75	80% compl.		Succ.	Yes
Midway-Sunset	Cal.	Kern	ARCO	9/63	1,000	216	..	Etch. & Potter	30	1-3,000	1,000-2,500	12-17	200-200M	@ 100	Prim.	..	..	...	...	Succ.	Yes
Midway-Sunset	Cal.	Kern	Chans.-West.	3/64	1,970	821		200 ft	30	1,500	400-1,800	12	4M	@ 100	Prim.	85	40	...	20,000	Succ.	Yes
Midway	Cal.	Kern	Getty	6/64	215	21	....	Etch. Spellacy	37	2,000	850+ 1,150	13.5	775	@ 100	Prim.	94	91	HF	390	Succ.	Yes
Midway	Cal.	Kern	Getty	9/64	125	71	..	Potter	35	2,000	1,200	14	405	@ 100	Prim.	69	51	HF	2,100	Succ.	Yes
N. Midway	Cal.	Kern	Getty	11/64	155	70		Potter	33	2,500	1,400	13.4	1-4M	@ 100	Prim.	91	81	HF	1,800	Succ.	Yes
Midway	Cal.	Kern	Getty	11/67	86	16		Potter A-B-C-	37	2,000	1,800	11	1M	@ 150	Prim.	99	91	HF	60	Succ.	Yes
Midway-Sunset	Cal.	Kern	Getty	1/71	35	44		Potter	32	2,000	1,700	12	4.8M	@ 100	Prim.	82	53	JS	2,150	Succ.	Yes
Midway-Sunset	Cal.	Kern	Mobil	11/67	350	200	0	Potter	35	1,000	1,000	13	1M	@ 100	Prim.	85	70	HF	3,500	..	..
Midway-Sunset	Cal.	Kern	Mobil	10/70	950	50	0	Monarch	34	4,000	950	13.5	800	@ 85	Prim.	95	81	40% compl.	504		.
Midway-Sunset	Cal.	Kern	McCulloch	65	60	117	. .	Potter	25	2,000	1,100	12	5M	@ 80	Prim.	75	40	60% compl.	3,000	Succ.	Yes
Midway-Sunset	Cal.	Kern	Occidental	9/64	23		...	Monarch	33	2,400	1,000	12.6			Prim.			HF		Succ.	Yes
Midway-Sunset	Cal.	Kern	Shell	1/64	565	530		Potter	30	2,000	600-1,900	10-14	2.4-5M	@ 80-100	Prim.	95	70	HF	9,000	Succ.	Yes
Midway-Sunset	Cal.	Kern	Socal	66	160			Potter	36	1,300	1,200	14	1.1M	@ 100	Prim.	80	70	HF		Succ.	Yes
Midway-Sunset	Cal.	Kern	Sun	64	226	198	cylic	Potter	35	1,000+	1,000-1,500	12	3M	@ 60	Prim.	90	50	HF	4,300	Succ.	Yes
Poso Creek	Cal.	Kern	Getty	9/74	84	14		Chanac-Etch.	39.8	1,500	2,000	13.1	4.1M	@ 90	Prim.	82	76	JS	128	TETT	
Poso Creek	Cal.	Kern	Socal	70	240			Chanac	28	1,500	2,500	14	1M	@ 120	Prim.	90	80	80% compl.	.	Succ.	Yes
Santiago	Cal.	Kern	Gulf	4/66		18		Tar			550-1,250	14	...		Prim.					Succ.	Yes
S. Belridge	Cal.	Kern	Socal	66	150			Tulare	37	2,000	550-1,250	14	4.8M	@ 92	Prim.	85	50	HF		Succ.	Yes
S. Belridge	Cal.	Kern	McCulloch	70	100	40	...	Tulare	25	1,000	800	12	...	...	Prim.	60	40	HF	150	Prom.	Yes
Huntington Beach	Cal.	Orange	Burmah	64	50	9	0	Tar			2,800	14	25	@ 130	Prim.	95	70	HF	200	Succ.	Yes
Huntington Beach	Cal.	Orange	Burmah	64	710	48	0	TM	35	1,000	2,000	13	80	@ 125	Primary	98	60	HF	1,500	Succ.	Yes
Huntington Beach	Cal.	Orange	Socal	4/65	300		..	Tar Zone	34	2,000	2,000	12.7	2M	@ 140		88	50	60% compl.		Succ.	Yes
Yorba Linda	Cal.	Orange	Gulf	10/62		86		Tar & Repetto			200-2,000	12	...		Primary					Succ.	Yes
Yorba Linda	Cal.	Orange	Shell	3/61	180	202	23	Up. congl.	30	600	400-830	12	6.4M	@ 85	Primary	96	50	HF	8,500	Succ.	Yes
Cat Canyon	Cal.	Santa Barbara	Conoco	63	650	130	..	Sisquoc	30	1,200	3,000	10	1.3M	@ 130	Primary	95-100	80	HF	4,000	Succ.	Yes
Cat Canyon	Cal.	Santa Barbara	Getty	64	1,700	100	0	S1-8	31	5,000	2,300	9	25M	@ 100	None	99	85	HF	2,000	Succ.	Yes
Cat Canyon	Cal.	Santa Barbara	Getty	65	300	13	0	S8-16	30	3,000	3,000	12	2M	@ 130	Primary	99	85	HF	163	Succ.	Yes
White Castle	La	Iberville	Shell	11/74	57	2		V	40	5,000	1,350	16	500	@ 80	Primary	99	50	JS	200	Prom.	
White Castle	La	Iberville	Shell	3/75	37	2	..	U	40	5,000	1,000	15	1.1M	@ 80	Primary	99	50	JS	200	Prom.	
Anderson Ranch	Tex.	Zavala	Exxon	7/74	2	1	1	San Miguel	30	100	525	9	10M	@ 80	None			Term. 5-75	2-100	Disc.	No
Uvalde	Tex.	Zavala	Gulf	2/75	3	.	..	San Miguel	...	..	300	10	...	..	None	.	.	Term. 8-75		Disc.	No
Steam drive																					
Smackover	Ark.	Ouachita	Phillips	71	985	120	9	20 ft	35	2,000	1,920	20	75	@ 110	Prim.	71	50	HF	1,300	Succ.	
Belridge	Cal.	Kern	Mobil	6/64	2,381	250	38	Tulare	35	3,000	1,000	14	1.3M	@ 90	Prim	94	56	14% compl.	5,400		

Table 2.3.2-3 (Continued)

Field	State	County	Operator	Start date	Area, acres	Number wells Prod.	Number wells Inj.	Pay* zone	Porosity, %	Permeability, md	Depth, ft	Reservoir oil °API	Reservoir oil cp	Reservoir oil @ °F.	Previous production†	Residual oil saturation, % Start	Residual oil saturation, % End	Project‡ maturity	Enhanced prod., bo/d	Project§ eval.	Profitable
Coalingua	Cal.	Fresno	Shell	1/63	700	104	73	Temblor	31	1,000	1,500	22	160	@ 100	SD	51	38	NC	1,300	Succ.	Yes
W. Coalingua	Cal.	Fresno	Socal	73	30			Temblor	35	400	1,200	14	1.2M	@ 90	SS	80	50	40 % compl.		Succ.	Yes
Cymric	Cal.	Kern	Socal	5/75	18	21	9	Tulare	25-40	1,000	900	13	4M	@ 90	Prim.	50	15	JS	400	Prom.	No
Kern River	Cal.	Kern	Chans.-West.	76	15	13	11	60 ft	30	5,000 1,752	660	13	4M	@ 90	None	95	40	JS		TETT	
Kern River	Cal.	Kern	Getty	8/62	2,000	1,373	781	Kern River	39	3,000	900	14	4M	@ 90	Prim.	89	52		39,200	Succ.	Yes
Kern River	Cal.	Kern	Getty	5/73	22.5	16	9	Kern River	39	3,000	900	14	4M	@ 90	Prim.	89	47	HF	. . .	TETT	
Lost Hills	Cal.	Kern	Getty	11/75	11	9	4	Tulare	38	800	200	14	577	@ 100	Prim.	99	45	JS	. . . .	TETT	
Kern River	Cal.	Kern	Chans.-West.	3/72	1¼	4	10	120 ft	34	2,400	700	13	4M	@ 90	Prim.	78	40	JS	270	Succ.	Yes
Kern River	Cal.	Kern	Socal	66	1,400			Kern River	34	4,000	1,000	14	4M	@ 85	Prim.	85	78	85% compl.		Succ.	Yes
N. E. McKittrick	Cal.	Kern	Socal	9/75	90	29	16	Amnicola	35	2,500	1,200	11	5M	@ 110	Prim.	57	15	JS	900	Prom.	No
Midway-Sunset	Cal.	Kern	ARCO	6/69	6	12	2	Potter	30	1-3M	1,000-2,500	12-17	200-200M	@ 100	Prim.			HF	. .	Prom.	Yes
Midway-Sunset	Cal.	Kern	ARCO	1/72	3.7	7	1	Etchegoin	30	1-3M	2,000	12	1M	@ 100	Prim.			HF	. .	Prom.	Yes
Midway-Sunset	Cal.	Kern	ARCO	3/72	12.2	10	3	Potter	30	1-3M	2,500	13	1M	@ 100	Prim.			HF		Prom.	Yes
Midway-Sunset	Cal.	Kern	Chans.-West.	1/67	20	16	4	110 ft	35	3,500	1,500	11	4M	@ 100	Prim.	95	20	HF	980	Succ.	Yes
Midway-Sunset	Cal.	Kern	Chans.-West.	1/68	1¼	4	1	200 ft	33	3,500	1,200	11	4M	@ 100	Prim.	90	40	Term. 2-74		Succ.	Yes
Midway Sunset	Cal.	Kern	Chans.-West.	10/72	5	4	1	130 ft	30	1,100	1,000	11	4M	@ 100	Prim.	90	50	JS	95	Prom.	Yes
Midway-Sunset	Cal.	Kern	Chans.-West.	10/75	6.5	8	4	50 ft	30	1,800	600	11	4M	@ 100	None	100	20	JS	80	TETT	
Midway-Sunset	Cal.	Kern	Shell	8/71	120	51	17	Potter	32	2,000	1,200	11	5M	@ 90	SS	91	45		3,000	Succ.	Yes
Midway-Sunset	Cal.	Kern	Socal	11/75	21	15	6	Monarch	25-35	1,000-3,000	1,200	13	1.2M	@ 90	SS	50	15	JS	0	TETT	No
Midway Sunset	Cal.	Kern	Texaco	72	10	8	1	Tulare	39	1,500	1,200	12	4M	@ 100	Prim.			HF	103	Prom.	Yes
Mount Poso	Cal.	Kern	Shell	10/71	500	60	11	Upper Vedder	33	20,000	1,800	16	280	@ 110	Prim.	60	30		8,000	Succ.	Yes
San Ardo	Cal.	Monterey	Mobil	6/63	3,041	450	40	Lombardi & Aurignac	34	6,000	2,100 & 2,300	11	3.1M	@ 125	Prim.	92	64	23% compl.	8,000		
San Ardo	Cal.	Monterey	Texaco	65	1,725	192	39	Aurignac	39	2,200	2,200	13	4.5M	@ 100	SS			HF	22,900	Succ.	Yes
San Ardo	Cal.	Monterey	Texaco	69	80	29	2	Lombardi	39	8,000	1,900	11	11M	@ 100	SS			HF	100	Prom.	Yes
Brea-Olinda	Cal.	Orange	Chans.-West.	3/74	15	10	1	144 ft	31	1,086	800	12	3.1M	@ 100	Prim.	97	77	JS	127	Prom.	Yes
Caddo Pine Isl.	La.	Caddo	Texaco	7/75	36	4	1	Nacatoch	37	500	800	21	160	@ 100	None	100	71	JS	9	TETT	No
Port Barre	La.	St. Landry	Texaco	8/74	6.4	4	1	1,500-ft sand	34	1,570	1,450	19	60	@ 95	Prim	72	57	JS	9	Prom.	No
Slocum	Tex.	Anderson	Shell	3/67	258	259	49	Carrizo	34	500-3,000	520	19	2M	@ 75	Prim.	97	50	NC	1,900	Succ.	Yes
Slocum	Tex.	Anderson	Texaco	8/70	18	15	3	Carrizo	32	1,250	580	19	1.8M	@ 82	NP			Term. '74	29	Disc.	No
Toborg	Tex.	Pecos	Gulf	6/75	20	9	4	Toborg				22			Prim.			JS	30	TETT	No
Winkleman Dome	Wyo.	Fremont	Amoco	3/64	100	21	13	Nugget	24	481	1,225	14	900	@ 81	Prim.		50	HF	720	Succ	Yes
Combustion projects																					
Kern River	Cal.	Kern	Chans.-West.	6/75	5	4	1	60 ft	31	2,200	400	13	4M	@ 90	SS	55	15	JS	20	TETT	
Lost Hills	Cal.	Kern	Mobil	4/61	140	50	6	300 ft	37	8,900	300	16	410	@ 95	Prim.	99	66	HF	500		
Midway Sunset	Cal.	Kern	Chans.-West.	1/72	157	12	3	182 ft	32	3,500	1,550	12	5M	@ 95	SS	90	35	JS	300	Succ.	Yes
Midway Sunset	Cal.	Kern	Mobil	1/60	150	31	5	Moco	36	1,500	2,700	15	110	@ 125	NR	99	52	75% comp.	507	. . .	. . .
Midway-Sunset	Cal.	Kern	Mobil	1/67	390	40	5	Int. Webster	33	2,000	1,600	14	600	@ 113	Prim.	89	69	30% comp.	293	. . .	
Paris Valley	Cal.	Monterey	Husky-ERDA	1/75		18	5	Ansberry			800	11	188M	@ 75		99		JS	. . . .	. . .	
Brea-Olinda	Cal.	Orange	Union	3/72	44	20	2	Miocene	29	300	3,500	22	20	@ 135	Prim.	72	50	HF	3,500	Succ.	Yes
Cat Canyon	Cal.	Santa Barbara	Conoco	2/74	3	4	1	Sisquoc	31	1,500	3,900	9	1.7M	@ 70	Prim.	97	70	JS		TETT	No
Russel Ranch	Cal.	Santa Barbara	ARCO	4/71	20	6	1	Dibblee	24	102	3,500	32	0.99	@ 140	WF	.		NC	0	Disc.	No
Robinson	Ill.	Crawford	Marathon	8/61	130	41	3	Robinson	20	350	1,000	23	18-80	@ 60	WF	40		NC		Disc.	
Bellevue	La.	Bossier	Cities	3/71	10	21	4	Nacatoch	31	1,000	400	19	226	@ 60	Prim.	95	68	NC	300	Succ.	
Bellevue	La.	Bossier	Cities	6/74	10	21	4	Nacatoch				19	226	@ 60	Prim.	95		JS		TETT	
Bellevue	La.	Bossier	Getty	63	513	194	55	Nacatoch	35	1,000	330	19	500	@ 80	Prim.	92	40	HF	2,000	Succ.	Yes
Pine Island	La.	Caddo	Conoco	4/73	60	17	6	Nacatoch	35	494	1,023	21	320	@ 102	Prim.	95	50	HF	50	TETT	No
W. Heidelberg	Miss.	Jasper	Gulf	12/71	300	6	1	Cotton Valley			11,750	24			Prim.			HF	430	Prom.	Yes
W. Heidelberg	Miss.	Jasper	Gulf	7/75	5	3	1	Christmas 10			5,000	21			Prim.			JS	100	TETT	No
Red Bank	Ok.	Creek	Sun	6/66	200	6	2	Dutcher	20	1,850	3,300	20	60	@ 120	Prim.			NC	100	Prom.	Yes
Loco	Ok.	Stephens	Conoco	5/75	24	25	5	J-Shallow	30	1,000	220	19	2	@ 70	Prim.	100	50	JS	30	TETT	No
West 76	Tex.	Duval	Mobil	10/68	546	8	1	Cole	31	1,087	1,350	20	25	@ 96	Prim.	90	83	NC	90	Succ.	Yes
Talco	Tex.	Franklin & Titus	Exxon	7/72	20	7	1	Paluxy	26	1,000	4,200	22	26	@ 147	WF			Term. 10-75	30-40	Disc.	No
Gloriana	Tex.	Wilson	Sun	5/69	513	9	2	Poth "A"	35	1,000	1,600	21	174	@ 112	Prim.	92	81	Term. 1-74		Prom.	Yes
Glen Hummel	Tex.	Wilson	Sun	1/68	600	18	4	Poth "A"	36	1,200	2,300	21	45	@ 114	Prim.	85	70	NC		Succ.	Yes
Little Tom	Tex.	Zavala	Hanover-ERDA	1/75	14	3	1	San Miguel	22	64	2,700	17	90	@ 125		57		JS	0	TETT	No

*All reservoirs are sandstones. †Prim = primary, Undev = underdeveloped, SS = steam soak; SD = steam drive; NP = non-productive, NR = new reservoir; WF = waterflood; ‡HF = half finished; NC = nearing completion, JS = just started, Term. = terminated. §Succ = successful, TETT = too early to tell; Prom. = promising; Disc. = discouraging

Table 2.3.2-4 Major heavy oil fields around the world[24]

(all crudes <20 API° are included).

AREA, FIELD, DISC.	NO. WELLS	1974 PROD.	MILLIONS OF BBL		PAY, FEET	API GRAVITY°	SULFUR WT %
			CUMULATIVE PRODUCTION 1/1/75	ESTIMATED RESERVES 1/1/75			
INDONESIA, Kitty	6	1	3	147	4,000	17.3-22.8	....
ITALY, Ragusa	30	2	106	98	12,460	19.7	....
MEXICO, Ebano-Panuco	467	3	931	373	1,450	12.0	5.38
NEUTRAL ZONE							
WAFRA: Eocene	220	7	357	3,604	2,200	18.5	....
UNITED STATES							
ARKANSAS: Smackover	2,611	3	508	21	2,000	19.0	2.1
CALIFORNIA							
San Joaquin Valley:							
Belridge South	2,667	8	195	78	1,042	17	0.23
Buena Vista	1,137	4	617	32	1,800	17-32	0.59
Coalinga	2,219	6	633	66	1,899	15-37	0.75
Cymric	746	3	131	24	3,825	13-42	....
Edison	537	1	113	13	5,825	13-42	....
Fruitvale	349	1	102	11	4,690	18-20	....
Kern Front	952	3	135	30	2,350	14-21	....
Kern River	4,531	27	636	850	913	13	1.10
Lost Hills	1,149	2	119	22	6,048	13-32	....
McKittrick	952	7	206	43	9,144	14-34	....
Midway Sunset	6,027	5	1,197	420	1,740+	15-25	....
Mount Poso	498	3	168	21	2,616	14-17	....
Rio Bravo	48	.2	113	2	11,611	12-40	....
Coastal Area:							
Cat Canyon	590	6	174	48	6,000	12-23	....
Orcutt	176	2	149	13	2,700	14-31	....
San Ardo	913	13	274	104	2,150	11	....
Santa Maria Valley	214	4	159	27	5,738	12-17	....
Los Angeles Basin:							
Brea Olinda	721	3	344	24	2,698	18-31	0.75
Huntington Beach	1,118	19	924	119	2,100	12-28	1.57
Inglewood	432	4	297	25	2,200	19-30	2.50
Montebello	178	.6	185	5	7,650	19-44	....
Richfield	304	1	165	16	3,800	16-25	....
Santa Fe Springs	242	.8	601	11	2,117	11	2.25
Torrance	364	3	182	18	4,400	14-30	....

continued...

Table 2.3.2-4 (Continued)

AREA, FIELD, DISC.	NO. WELLS	1974 PROD.	MILLIONS OF BBL CUMULATIVE PRODUCTION 1/1/75	MILLIONS OF BBL ESTIMATED RESERVES 1/1/75	PAY, FEET	API GRAVITY°	SULFUR WT %
UNITED STATES (con't)							
LOUISIANA ONSHORE:							
Lake Barre	119	5	171	49	3,400+	18-45	0.49
LOUISIANA OFFSHORE:							
West Delta Blk. 30	216	22	312	137	2,152+	18-34	0.33
MISSISSIPPI, Baxterville	198	7	167	68	3,158+	12-19	2.71
TEXAS							
District 3:							
Hull-Merchant	385	2	194	11	400	18-50	0.35
Humble All	413	1	162	28	700+	18-44	....
Magnet Withers All	286	3	81	44	838+	15-59	....
Raccoon Bend	135	2	92	33	900+	19-39	....
West Columbia	193	1	158	12	600+	18-60	....
District 4:							
Quitman All	246	3	80	29	3,980+	16-67	....
District 8:							
Dollarhide	147	6	150	60	6,500+	18-45	....
WYOMING							
Hamilton Dome	246	4	218	36	2,000	15-25	3.07
VENEZUELA							
Anzoategui: Merey	252	9	178	73	5,700	11.4	....
Monagas:							
Morichol	106	10	115	90	3,312	10.7	....
Quiriquire	372		722	768	7,200	16.4	....
Zulia:							
Boscan	279	26	494	542	7,500	10.3	5.53
Mene Grande	310	4	580	588	4,132	18.8	2.65
Tia Juana	1,827	116	2,909	1,586	3,000	18.8	1.49
			T O T A L (non-U.S.)	3,800			

2.3.3 Ultimate Recovery of Heavy Oils (Proved Reserves)

In the above discussion, the term resource has been used to designate the amount of oil-in-place. Typically, only about on-third of this oil is recoverable by conventional technology. This means that one-third of the oil in the ground can be brought to the surface. However, 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 case of recovery of heavy oils by above-ground mining of tar sands, much energy is consumed in the removal of overburden, mining of the tar sands, and land reclamation. This energy may have to be supplied by the crude which is produced. Thus, only about 50% of the original heavy oil would be recovered for sale or upgrading.

Accordingly, the province of Alberta has recently initiated economic studies to assess the ultimate recoverable resources and the ultimate yield of upgraded crude for each of the major tar-sand deposits in Alberta.[12] Similar studies were recently conducted for United States tar sands using somewhat different criteria for reserve estimation.[13]

In the Alberta study, individual zones of Cold Lake and Wabasca were treated separately. The reader is referred to the above-cited work for specific details. A summary of the reported conclusions is presented in Table 2.3.3-1. A summary of the areas of economic recoverability of Alberta deposits is provided in Fig. 2.3.3-1. As can be seen from the table, only a small fraction of the original oil in place is estimated to be actually recoverable as upgraded crude oil.

It is significant to note that 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, certain criteria must be met. The authors of the cited paper[12] have made assumptions for mineability based on the weight percent of raw bitumen present, the overburden thickness and the energy required for mining the bitumen. Accordingly, they obtain a "mineability factor" which they assume must be >5 to have an economically viable recovery. Figure 2.3.3-1 shows the zones which meet this criterion in Athabasca.

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 criterion of "thermal ratio" (crude produced vs. crude burned) was developed.[12] A value of four was believed to be required for economic production. In Fig. 2.3.3-1, the zones of economic producibility by steam for Alberta's tar sands are presented.

One basic flaw in these calculations is the assumption that all forms of energy are equivalent.

Table 2.3.3-1 Ultimate recoverability of tar-sand bitumen in Alberta;* from Ref. 12.

RESOURCE	PRODUCTION METHOD	TOTAL RESOURCE IN PLACE bbl x10^9	FRACTION OF OIL IN PLACE ECONOMICALLY RECOVERABLE BY METHOD** (total area)	FRACTION OF OIL IN PLACE ACTUALLY RECOVERED BY PRODUCTION METHOD	ULTIMATE RECOVERABLE RESOURCE bbl x 10^9	ULTIMATE RECOVERABLE SYNTHETIC CRUDE OIL bbl x 10^9	FRACTION OF ORIGINAL OIL IN PLACE CONVERTED TO SYNTHETIC CRUDE
Athabasca (<50 feet overburden)	Strip Mining	74.2	0.54	0.90	40.9	27.1	0.37
Athabasca (>75 feet overburden)	In Situ Steam	747.9	0.205	0.431	143.8	110.1	0.15
Peace River	"	91.8	0.088	0.410	2.6	2.0	0.02
Cold Lake A_1	"	75.5	0.065	0.418	1.6	1.2	0.02
Cold Lake A_2	"	120.8	0.171	0.426	8.8	6.6	0.05
Cold Lake B	"	40.3	0.100	0.412	1.9	1.4	0.03
Cold Lake C	"	34.0	-	0.395	-	-	-
Wabasca A	"	66.1	0.236	0.397	4.8	3.7	0.06
Wabasca B	"	52.8	-	0.370	-	-	-

*Not all data have been entered. These figures represent the most reasonable estimates for favorable economic recovery of the resources. For all data and bases the reader is referred to the original paper.

**This figure represents that fraction of the deposit which lends itself to production by the method being considered. Economic criteria are defined in Ref.12.

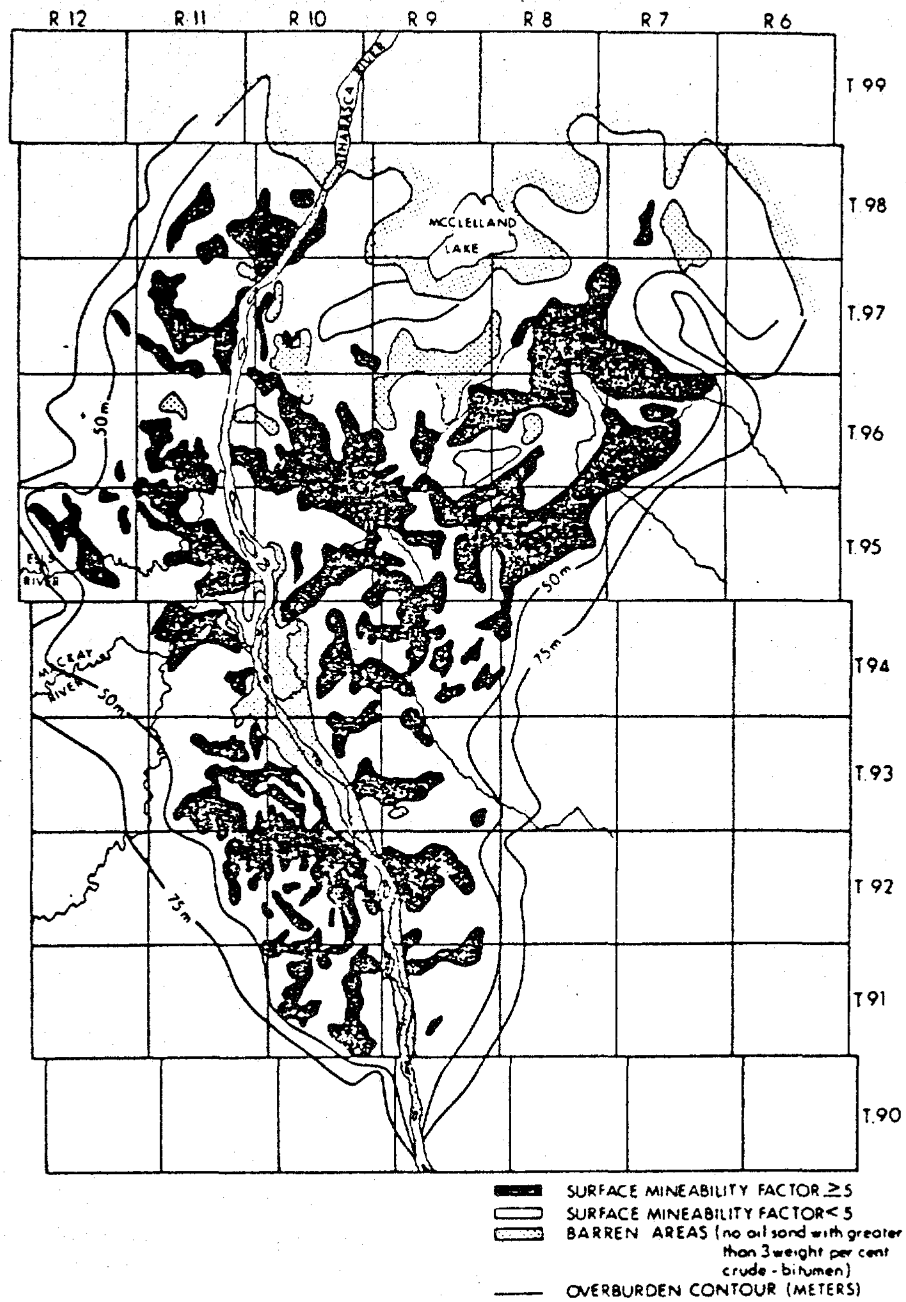

Fig. 2.3.3-1 Surface-mineable oil sand deposits in the Athabasca area.

Replacement of the energy source for the production by a less valuable fuel (e.g., coal) could provide the same BTUs at lower cost. This, in turn, would allow higher ultimate yields of upgraded crude. Imperial Oil has considered coal as a heat source in Alberta.

Similar studies in the United States, conducted under Contract 9014-018-021-22004 for DOE in 1978, provided a detailed analysis of the ultimate producibility of U.S. tar sands. The authors of this report concluded that only ~0.1-0.2 billion barrels of U.S. tar sands could be recovered by mining and ~2 billion barrels of oil 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 billion barrels 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 figures.

2.4 Recommendations

This brief review of the resources and reserves of the United States clearly shows that much valuable information is lacking on potential contributions of heavy oils and tar sands to the future energy needs of the United States.

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. We recommend that a systematic assessment of the U.S. tar sands and heavy oil resources be undertaken. This assessment should include enough detailed information about the criticalities in either mining or *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[12] and in past surveys in the U.S.[13] is strongly recommended. This information should be made available in a manner similar to the Bureau of Mines crude assay data bank (either in the form of computer cards or tapes) so that commercial ventures can be encouraged.

CHAPTER 3

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 (cf. Sec. 1.2). 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,[1] incorporation of a high shear mixing step in the hot water process,[2] and pyrolysis.[3]

Laboratory testing of advanced concepts using fluid-bed pyrolysis[4] are under way.

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[1] "In California Diatomite May Yield Petroleum," Geotimes, March 1981; G. Karnofsky, "Solvent Extraction of Bitumen from Tar Sands and Diatomaceous Earth," Dravo Engineers & Constructors

[2] J. E. Sepulveda and J. D. Miller, "Separation of Bitumen from Utah Tar Sands by a Hot Water Digestion-Flotation Technique," Technical Papers; J. R. Smith and J. D. Miller, Society of Mining Engineers of AIME, Preprint No. 80-100, AIME Annual Meeting, Las Vegas, Nevada, February 24-28, 1980; M. Misra and J. D. Miller, "The Effect of Feed Source in the Hot Water Processing of Utah Tar Sand," Mining Engineering, March 1980; J. D. Miller and M. Misra, "Concentration of Utah Tar Sands by an Ambient Temperature Flotation Process," University of Utah, Salt Lake City, Utah, 1981.

[3] R. W. Rammler, Canadian Journal of Chemical Engineering 48, 552 (1970).

[4] V. N. Venkatesam, F. V. Hanson, and A. G. Oblad, "The Thermal Recovery of a Synthetic Crude from the Bituminous Sands of the Sunnyside (Utah) Deposit," First International Conference on the Future of Heavy Crude and Tar Sands, Edmonton, Alberta, Canada, June 4-12, 1979.

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 (AB-7) and the Saner Ranch work of Mobil and Continental Oil (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.

3.1 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 by Lurgi and Taciuk,[5] 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.

3.2 *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 wellbore 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.

[5] Taciuk Oil Sands Processor, Nonconfidential Disclosure and Consultive Participation Information Brochure, Alberta Oil Sands Technology and Research Authority and UMATAC Industrial Processes, Ltd., April 1981.

3.2.1 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 intensive 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.[6] 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 particular resource.

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[6] C. W. Bowman, "Molecular and Interfacial Properties of Athabasca Tar Sands," <u>7th World Petroleum Congress</u>, Vol. 3, pp. 583-640, Elsevier, 1967.

3.2.2 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 modeling seems in order.

3.2.3 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 favorable. Two methods for heating the reservoir are steam injection and *in situ* combustion of hydrocarbons (coke).

3.2.4 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.

3.2.5 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.

3.2.6 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. Radio-Frequency 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.

These 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 the 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.

3.2.7 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.

3.2.8 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 analytical 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.

3.2.9 Transportation of Bitumen-Water-Sand Slurries

Bitumen-water-sand slurries[7] 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.

3.2.10 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.

[7] R. Simon and W. G. Poynter, Patent No. 3,519,006 on "Pipelining Oil/Water Mixtures"; Patent No. 3,425,429 to Chevron, "Method of Moving Viscous Crude Oil through Pipeline"; R. Simon and W. G. Poynter, "Downhole Emulsification for Improving Viscous Crude Production," Journal of Petroleum Technology 20, 1349 (1968).

3.2.11 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 and insulations systems 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.

3.2.12 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.

3.2.13 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.

CHAPTER 4

ENVIRONMENTAL ASPECTS*

Oil from tar sands and heavy oil crudes cannot readily be 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 to 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.

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*This chapter should be read in conjunction with a recently completed NRC study entitled "Synfuels Facilities Safety," National Research Council, Assembly of Engineering, Committee on Synfuels Facilities Safety, Washington, D.C., April 1982.

4.1 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 to three 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 pounds 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 through 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 technique has been developed in which ammonia is added to reduce NO_x in the gas stream at 1750^{o}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 quantitative measurements of organic effluents and their toxicological characterization.

4.2 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 LETC* 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 may be absent in the processing of Utah tar sands

*LETC = Laramie Energy Technology Center.

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.

4.3 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.

CHAPTER 5

FUNDAMENTAL RESEARCH ON OIL RECOVERY FROM HEAVY OIL SOURCES AND TAR SANDS

5.1 Basic Research Policy

A growing domestic population and continued political and economic uncertainty associated with imported oil have placed an increasing premium on the utilization of oil from tar sands and heavy oil sources, as well as on all other domestic energy supplies. The nature of the supply problems has moved the government to intervene in the energy scene. This intervention, despite current signs of a movement towards detachment, is probably permanent. Against this background, the evolution of long range, joint government-industry policy and action in relation to energy resources are both necessary and appropriate. It is particularly important that these joint endeavors focus on the level and content of the basic research program associated with the development of EOR, heavy oil and bitumen production, and use in the U.S.A.

Basic research requires stable funding, is long range, and is not usually addressed to the solution of near-term problems, although it may be motivated by and relate to these. The impact of basic research often becomes evident in social and technological applications 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 for potential payout is not an attractive use of available funds, particularly when many short-term opportunities for more rapid payout are generally available. 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 in the energy area in research and development have been relatively smaller, with correspondingly very modest investments in basic research. This policy is puzzling in view of the fact that many recent advances in this industry have arisen from basic research. An example of the resources allocated to basic research 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.

To enhance the level of basic research, the government can stimulate private industry, either through incentives or by providing funds for this purpose. Without these, the level of funding for basic research on energy is not likely to be commensurate with apparent needs and potential. It has long been known that heavy oils and bitumens exist in quantity in the U.S.A., but it is only in recent times that serious development efforts have been implemented to recover these fuels. While the performance of basic research does not guarantee technological development, our past experience with basic research is that it is the most cost-effective way of making significant new technological discoveries.

A critical question is the level of government effort that is reasonable. 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. Persuasive arguments can be 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.

5.2 Examples of Basic Research Relating to Oil Recovery from Heavy Oil Sources and Tar Sands

In this section,we list key areas of basic research. In the following sections, we discuss some of these areas in detail.

A. Resource Characterizations:

1. properties of heavy oils and tar sands;
2. methods for resource characterizations;
3. geochemistry of oil-bearing rocks, including the structures of clays, sands, sandstones, etc.

B. Reservoir Characterizations:

1. electromagnetic methods;
2. diagnostics using sound-propagation;
3. studies of elastic waves in reservoirs;
4. nuclear signatures;
5. seismic data;
6. 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:

1. the theory of one-component flows in non-isothermal porous media (for various gas-surface interaction models), as verified by laboratory experiments;
2. flows of mixtures with two and more components through porous media;
3. 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:

1. thermodynamic equilibrium data for appropriate multicomponent systems;
2. thermochemical and transport coefficients;
3. interfacial phenomena;
4. wetting of porous media;
5. surfactant designs and mechanisms by which they act, including studies of emulsification;
6. behavior of polymers that have been added to effect drag reductions, oil/water compatibility, modifications of surface forces, etc.;
7. interactions of chemical additives with oil-bearing sands and rock surfaces, including especially studies of the influence of pH.

E. Reservoir Engineering:

1. simulation of forced flow patterns in rock matrices;
2. improvements in modeling multiphase flows in porous media during resource recovery.

F. Thermal Recovery:

1. *in situ* combustion phenomenology, with emphasis on flame-front propagation, wave stability, reproducibility of measurements, and model validation;
2. steam flow patterns and steam recovery;
3. reservoir integrity during resource recovery, thermal front mapping, and comparisons with model predictions.

G. Materials Problems:

1. down-hole erosion and corrosion assessments;
2. pumps and valves for operation in high-temperature, high-salinity environments.

5.3 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.

5.4 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 obviating the necessity 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. A program of study of the effects of combustion on the physical (flow) and chemical properties of oil-sand formations should 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.

Theoretical 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 are not generally 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^{o}C and 225 psia at 200^{o}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 steam-drive techniques. A part of the problem with hot water drive is that the water, being much less viscous than the oil, will move more rapidly through sandstone pores which are not wetted by oil. While this is desirable for heating, it introduces the heat in the wrong part of the formation. This area 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 may have advantages over water-steam mixtures because it is a gas 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 its use. Although some information of this type may already exist in unpublished industry reports, it is not generally available.

5.5 Chemical Additives

Chemical additives have been used to improve the efficiency of the steam/water drive. In principle, the mechanism of oil release by hot water is to heat the oil first 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. This type of research could provide important guidelines on the potential uses of additives.

Important in all of these considerations is the realization that many oil fields contain large amounts of brine and other salt deposits, which may significantly 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 clays and 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.

5.6 Environmental Problems

Basic and applied research on environmental problems are discussed in Chapter 4. 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.

CHAPTER 6

UPGRADING AND REFINING

6.1 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 hetero-atom 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 chapter 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.

6.2 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 6.2-1.

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

Table 6.2-1 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.

f. Resid catalytic cracking alone or combined with residuum hydrotreating are 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 6.2-2, we list by-products associated with the specified residuum-conversion alternatives.

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.

Table 6.2-2 Residuum conversion of by-products.

Conversion to special fuels:

a. high viscosity, high sulfur tar or pitch from residuum hydrocracking, solvent de-asphalting;

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.

6.3 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 disproportination. 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.

CHAPTER 7

COSTING OF OILS FROM EOR AND UTAH TAR SANDS

Some cost information and data will be found in most of the site-visit reports.

While we have not arrived at generally useful cost estimations for oils from EOR and Utah tar sands, the attached Appendix 7-I by K. E. Phillips 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 centrifuging 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.

Appendix 7-I

COSTING OF OIL FROM HEAVY OIL SOURCES AND TAR SANDS[†]

A7-I.1 Application of Statistical Cost and Performance Methodology to Enhanced Oil Recovery Technologies

We first comment briefly on a previous Rand study.[1] This pioneer plants study was an attempt to design statistical methods for (a) applying proper contingencies to conventionally derived engineering estimates and (b) for predicting overall levels of plant performance during the first year after startup. The statistical equations that were developed applied to projects that were clearly capital intensive and that contained any number of continuously linked process units, i.e., the models were calibrated toward process plants.

In current form, neither the mathematical structure of our models nor their parameter estimates are suitable for direct application to EOR technologies. However, the logic and some of the technical issues captured in the equations appear relevant and suggest some reasonable directions for future EOR research.

A common structure underlying both the cost and performance equations derives from a recognition that uncertainties can be quantified if they can be approximated by measures of how much is known (i.e., what has actually been accomplished) concerning the stage of process development. A second and separate area, relevant mainly for understanding project costs, concerns the state of information about the physical project itself, i.e.,

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[†]Prepared by K. E. Phillips, the Rand Corporation, 1700 Main Street, Santa Monica, California 90406.

[1]E. Merrow, K. E. Phillips, and C. Myers, "Understanding Cost Growth and Performance Shortfall in Pioneer Process Plants," The Rand Corporation, Santa Monica, California 90406, Report No. R-2569, September, 1981.

locational specifics and site requirements that must (at least for process plants) affect the civil and structural engineering designs and, consequently, overall project costs. The first area can probably be addressed via statistical predictive models for EOR technologies using information that now exists in the literature. The second area appears to have no direct analogy at the present time.

For our research on first-of-a-kind plants, we focused on the level of process development to help determine the state of knowledge about the basic conversions and unit operations going on within the plant itself. We developed several measures to approximate the level of process understanding including: (a) difficulties encountered in specifying the balance equations for the plant; (b) problems with impurity buildups and recycle streams; (c) problems with waste handling; (d) assessments of the general stage of process R&D. These measures were incorporated into statistical models to isolate the cost and performance difficulties associated specifically with unknowns about the major conversions and unit operations within the system.

In parallel fashion, a potentially useful area of research involving EOR technologies would first identify parameters that are consistent and replicable from one technology to the next and then to develop variables to approximate the stage of uncertainty that remains about each relevant parameter. The latter task presents the greatest challenge for it requires not only isolating the critical issues governing project costs and performance but, more importantly, it requires the development of appropriate measurement scales for these variables. During our research on first-of-a-kind plants, the first 18 months were required for accomplishing these general tasks.

The second area of interest, the measurement of project definition, was found to be critical for the analysis of project costs but not for understanding plant performance. It is in this area that the analogy between our research and application to EOR technologies is weakest. Our key findings showed that the ability to estimate project costs accurately depended upon the complete specification of the project site, along with measures of the level of engineering definition associated with each critical site characteristic. Based on discussions with FERWG members, the arguments presented in the literature, findings presented at the DOE Contractor Conference, and preliminary indications given at the AOSTRA meetings, it appears that, given the current state of technology, developing an accurate horizontal profile of any reservoir that is a candidate for some EOR method is both costly and subject to considerable errors. This fact suggests that the portion of total cost that is related to information about the project site will be difficult to obtain. Further complicating the problem is the general relationship that exists between thorough site characterization and the recovery of original oil in place. In other words, contrary to our findings for new process plants, system performance in EOR technologies is dependent on thorough site characterization.

In those areas where current information can contribute to greater understanding through statistical models, such work is worth pursuing. The primary difficulty is that process aspects represent only a portion of the total information requirements for accurate prediction of costs and ultimate recovery. We conclude that, when thinking about the applicability of a statistical methodology for EOR technologies, the limitations posed by reservoir characterization constitute a binding constraint. This statement is consistent with arguments offered in the past.

A7-I.2 The Costs and Performance for Recovering and Processing Utah Tar Sands and the Relevance of the Suncor and Syncrude Experience

We have no detailed data on project-specific cost estimates for a substantial extraction and upgrading plant designed to process Utah tar sands. Consequently, we are unable to suggest what level of cost contingency or first year performance would be appropriate for a given level of engineering and process development required to generate a real cost estimate. It is possible, however, to make some observations concerning the following points: (a) the manner in which handling and processing requirements for Utah tar sands might differ from those of Canada; (b) the general direction in which these differences might influence costs.

Regarding concern about lessons from the Canadian experience, some general observations on the design differences between the Suncor and Syncrude plants might prove helpful for isolating performance problems that derive not from feedstock differences (since both plants process the same Athabasca sands) but from design differences between the two units.

Cost estimates for the Suncor plant were close approximations to actual project costs. Problems were confined primarily to performance difficulties that plagued the project during its early years of operation. The most severe difficulties pertained to materials handling and not to the process portions of the plant. A notable exception involved failures in the bitumen-coke-fired power boilers. More specifically, the large wheel and bucket excavators suffered severe damage (i.e., millions of dollars in costs) when encountering the frozen and abrasive tar sands. Solutions to this problem involved explosive rubblization of the seam face in winter and designs for stronger teeth on the excavators. Furthermore, belts used to convey the excavated tar sands suffered severe clogging and efforts to unclog them using conventional kerosene solvent resulted in belt destruction. Solutions here involved the development of new rubber compounds for belt fabrication. All of these technical difficulties were eventually resolved and the plant reached steady state performance at design capacity approximately 24 months after the July 1967 start-up date.

Available information on the Syncrude unit is sketchy. However, the known problem areas occurred at precisely those points where Syncrude chose to deviate from the Suncor experience. Specifically, the use of fluid coking, as opposed to delayed coking, and the use of drag-line in place of wheel-and-bucket excavation, both resulted in performance problems and necessary correction costs. The Syncrude plant, therefore, experienced problems both in materials handling and in a major portion of the process.

These brief comparisons lead one to expect that the mining and materials handling operations in a Utah tar sands plant will pose some challenges, especially if the chosen techniques deviate from those with which there is available commercial experience. Since these problems emerge after construction, during the first year of startup, product costs may suffer considerably. Replacement of equipment and hardware will affect the capital cost portion of the product costs, while the loss in plant performance will drive product costs even higher.

We now address what may prove to be significant design differences between the process portions of the Canadian plants and those that would be built to handle Utah tar sands. The feedstock differences between the Canadian and Utah sands might affect the plant design in three specific areas, including (a) environmental and waste handling difficulties, (b) dilution or visbreaking requirements for the extracted bitumen, and (c) sulfur-removal requirements. The environmental issues related to tailing-pond effluents and the danger of perpetual emulsions, that cannot be safely disposed of, may be a lesser problem in Utah. We expect these differences to follow from the oil-wet character of the Utah tar sands in contrast to the water-wet sands in the Athabasca deposit. This important difference between the two feedstocks may contribute significantly toward obtaining the political and environmental clearances to move ahead with this particular alternative energy source in the United States. Furthermore, one can reasonably conclude that a plant processing Utah sands would enjoy considerable cost savings if the earth moving and expensive equipment for tailings pond construction can be dispensed with.

The second issue of concern, dilution of the extracted bitumen for viscosity reduction, may affect costs for the Utah plant in a negative manner. The Utah sands are between 2 and 5 orders of magnitude more viscous than those in the Athabasca deposit. Where the Suncor and Syncrude plants achieve post-extraction viscosity reduction with simple naptha dilution, more severe treatment might be required for handling the Utah feedstocks. An extra process step, possibly a mild thermal cracking or visbreaking, may be required to achieve the required viscosity characteristics for further processing.

A third area of interest might involve the extent to which a plant in Utah could reduce the costs required for the initial cleanup of the extracted and viscosity-treated bitumen. The Suncor plant, for example, utilizes centrifuging to remove water and grit from the partially processed feedstock. Since Utah contains oil-wet tar sands and because clays are confined to easily detectible lenses, a processing facility located in Utah may achieve some cost reduction by eliminating the centrifuge step. Since the literature on process-equipment failures indicates abnormally high failure rates on rotating machinery, the elimination of this step could also improve long-run plant performance, as well as reduce the costs of plant maintenance.

A final point of interest involves sulfur-removal requirements. The Utah tar sands contain only 10-13% of the average sulfur level in the Athabasca deposits. The Canadian plants each require two separate sulfur removal operations. The first is accomplished when the bitumen is coked (delayed coking at Suncor and fluid coking at Syncrude) to remove bottoms and heavy trace metals. The second is accomplished (at Suncor) after the coked bitumen is sent to distillation towers for fractionation into napthas, middle distillates and fuel oils. In separate unifiers, each stream is hydrogenated under pressure to remove more sulfur and also nitrogen and oxygen. At Syncrude, the coke bitumen is not fractioned with separate stream treatment but there is a sulfur-removal plant that treats the sour fuel gas. The synthetic crude and the coke retain the rest of the sulfur.

If a plant located in Utah were designed only for the production of synthetic crude, the much lower sulfur levels might justify eliminating much of the post-coking sulfur removal. Perhaps a lower sulfur crude would yield lower sulfur coke, while cleaner off gases could still be obtained. One could, therefore, expect significant cost savings in sulfur removal. On the other hand, if the Utah plant were designed to process the crude on site, as is done by Suncor, and produce final products, additional sulfur removal might be required. However, some cost savings should still be realized because of the lower severity of sulfur treatment.

EXTENSION

of Studies by the Fossil Energy Research Working Group-III

March 1, 1981 -- December 31, 1981:

OIL RECOVERY FROM TAR SANDS AND HEAVY OILS

STATEMENT OF WORK

The objective of this addition to the current program is to conduct an independent assessment providing for identification of research needs associated with oil recovery from tar sands and heavy oils, using all available means for effective processing of these resources. This work is expected to include recommendations to DOE for research programs that can best contribute to the successful long-term development of new oil recovery technologies from tar sands and heavy oils.

In fulfillment of the project objectives, the contractor will be expected to work with both the academic community and industry. The assessment will consider all of the basic disciplines involved in the development of techniques for oil recovery from tar sands and heavy oil sources. Members of FERWG will be expected to gain first-hand familiarity with operational aspects of usable technologies through site visits, interviews, examination of development studies and reports, and other means.

Typical of the kinds of long-range issues that will be addressed are the following:

1. How much cheaper or more efficient may we expect oil recovery from tar sands and heavy oils to be in the future, compared with those that are now in use or under development?

2. Can we identify the scientific and engineering directions that will be useful in making these technological improvements?
3. What are likely near-term and long-term environmental impact assessments for large-scale commercialization of these technologies?
4. What scientific and technical areas that are key to the success of ongoing oil recovery R&D from tar sands and heavy oils are still "open" areas for research and are likely to profit from a broader or deeper look?
5. What disciplinary or interdisciplinary fields or research ideas should be supported because they hold long-range potential for generating innovative and useful technologies in these fields?

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January 5, 1981

DRAFT LETTER TO REVIEWERS

Enclosed you will find a preliminary version of a report dealing with oil recovery from tar sands and heavy oils, which has been prepared by the DOE Fossil Energy Research Working Group. A very long Appendix contains site-visit reports and is not included.

In view of your acknowledged expertise in these programs, I would greatly appreciate your reviewing the enclosed document and commenting in writing as appropriate. We prefer responses that we may bind and include in our final report, which will be widely distributed. Any errors to which you call our attention will, of course, be corrected in the final text. However, important omissions and differences in points of view are best handled by including your response over your signature.

Please accept my sincere expression of appreciation for your time and advice in preparing a document that may be of greater utility to policy planners.

Sincerely yours,

S. S. Penner
Professor of Engineering Physics and
Director, Energy Center
Chairman, DOE Fossil Energy Research
Working Group

SSP/ln
encl.

Shell Oil Company

One Shell Plaza
P.O. Box 2463
Houston, Texas 77001

January 19, 1982

Dr. S. S. Penner
Chairman, DOE Fossil Energy Research
Working Group
Mail Code B-010
La Jolla, California 92093

Dear Dr. Penner:

I have read "Assessment of Research Needs for Oil Recovery from Heavy Oil Sources and Tar Sands", as requested in your letter of January 5, 1982. In summary, my opinion is that the report contains a good description of the state-of-the-art of tar sands recovery methods. It also clearly points out the necessity to develop site-specific recovery techniques for each field case. It does not, in my opinion, make a clear case for additional basic research.

Production from U. S. tar sands is almost non-existent. To make a case for tar sands basic research the report would need to discuss: (1) What are the factors that inhibit production of U. S. Tar Sands? (2) On which of these factors could research make a difference? (for example research could not change a lean tar sand into a richer one).

Additional analysis, such as used in section 3.2,2 would be helpful in qualifying the need for research.

Much is already known about multi-phase fluid flow, heat transfer, combustion, kinetics, interfacial forces, wetting, capillarity, sandstone and carbonate deposition, fracturing, etc. This knowledge is being used currently in exploitation of heavy oils. You need to show how additional knowledge in one or more of these areas would be beneficial to tar sands.

You are to be commended for attacking a difficult problem. Tar sands have been known in the U. S. for many years. Many have tried to exploit them, yet few have succeeded. Current higher energy prices should help. But the technical problems remain formidable. Perhaps the work of your committee will help to stimulate some answers.

Yours truly,

CSMatthews

C. S. Matthews
Sr. Consulting Petroleum Engineer
Head Office

CSM:rgb

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Bartlesville Energy Technology Center
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January 25, 1982

Dr. S. S. Penner
Professor of Engineering Physics and
Director, Energy Center
Chairman, DOE Fossil Energy Research
Working Group
University of California, San Diego
Mail Code B-010
La Jolla, CA 92093

Dear Dr. Penner:

Thank you very much for providing us with the opportunity to review the third revised draft of a report dealing with oil recovery from tar sands and heavy oils prepared by Fossil Energy Research Working Group- IIIA (FERWG-IIIA). The attached copy has been marked up for your use. In addition, we would like to make some comments about the report.

In general, the report is well written. The one aspect of the report that was noted and commented on by all BETC reviewers was that of prioritization. One reviewer's remarks that reflect those of the others is as follows: "Important research areas are provided [by] a general 'shopping list' approach in the report, but are only given brief prioritization in Section G of the Executive Summary. It seems that some systematic development of the research need priorities should be provided."

When budgets are limited, setting priorities serves a useful purpose in establishing a research program. BETC would like to be involved in any discussion of priorities for tar sands and heavy oil research that the FERWG-IIIA may have in the future.

The members of the Fossil Energy Research Working Group have made a real contribution in terms of time and thought to the preparation of this document. We would like to express the appreciation of the Bartlesville Energy Technology Center for this effort.

Sincerely,

Harry R. Johnson
Director

Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

February 3, 1982

Professor S. S. Penner
Director, Energy Center
University of California
Mail Code B-010
La Jolla, CA 92093

Dear Dr. Penner:

Our Fossil Energy Division at Oakland has reviewed the FERWG draft report on Heavy Oil and Tar Sands research. We believe that FERWG has done a good job in pointing out research needs and we have no further comments to make on the draft. Our previous comments made on two previous reviews of report drafts are adequately covered in the current report. Thank you for the opportunity to provide input to your group on this very important and timely exercise.

Sincerely,

Gordon W. Dean, Director
Fossil Energy Division

American Petroleum Institute
2101 L Street, Northwest
Washington, D.C. 20037
202-457-7170

Ronald L. Jones
Refining Director

February 8, 1982
Ref: M-15

Mr. S. S. Penner
University of California, San Diego
Mail Code B 010
La Jolla, CA 92093

Dear Professor Penner:

We have reviewed the documents attached to your letter of January 5, 1982, and find that technical review by the Institute is not needed. Several members of Fossil Energy Working Group IIIA lead technical activities covering tar sands and heavy oil subjects within the Institute. Thus the use of our review mechanism would be redundant in this case, particularly in view of the advanced stage of development of this report.

Please do not interpret this to reflect any unwillingness by the Institute to participate in future work by your group. We would like to participate when we can be helpful to the Department.

Very truly yours,

Ronald L. Jones

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SCHOOL OF ENGINEERING
DEPARTMENT OF CIVIL ENGINEERING

March 15, 1982

Dr. S. S. Penner
University of California, San Diego
Energy Center
Mail Code B-010
La Jolla, CA 92093

Dear Dr. Penner:

I and my associates have thoroughly read your report dealing with oil recovery from tar sands and heavy oil, which you have prepared for the DOE Fossil Research Energy Group. Let me say that the document is well prepared. However, I personally feel that the following aspects need to be stressed further.

One very important aspect is the need to characterize for heavy oil as well as the bitumens of tar sand. In my definition, both materials are a mixture of bitumen and oil (see my enclosed statement for the First International Conference on Heavy Oil and Tar Sands). I feel that classification of heavy oil and tar sands, as well as their chemical constitution is very important for recovery. Please also refer to my suggestion at the New York UNITAR Origanizing Committee Meeting, as well as the paper presented at the Second International Conference on Heavy Oil and Tar Sands, which are also enclosed. The fact is if we understand the chemical nature of the oil, then the recovery method can be developed according to the difference in the composition of heavy oil. For example, an asphaltene-rich oil will precipitate out and plug the pores during recovery if CO_2 is used.

Another point is, in some selected reservoirs, microbes may enhance heavy oil recovery. DOE sponsors several projects related to microbial enhancement of oil recovery. Some bacterial species are able to utilize heavy ends. The reduction in oil viscosity supposedly leads to enhanced recovery. Microbial enhanced oil recovery has also been known to occur by other mechanisms like biosurfactant and biogas production, etc. More detailed work on characterization of heavy components needs to be done. In some information on component properties is necessary:

1) the composition of heavy oil, and
2) the possible utilization of the heavy components by microbes.

I hope the above will be helpful in your decision making process. I apologize for the delay in answering your letter.

Sincerely,

T. F. Yen

Enclosures: as stated