Strategic Significance of America's Oil Shale Resource

Volume II
Oil Shale Resources
Technology and Economics

Office of Deputy Assistant Secretary
for Petroleum Reserves

Office of Naval Petroleum
and Oil Shale Reserves
U.S. Department of Energy
Washington, D.C.

March 2004

Strategic Significance of America's Oil Shale Resource

Volume II
Oil Shale Resources, Technology and Economics

March 2004
Final Report

Prepared for:

Office of Deputy Assistant Secretary
for Petroleum Reserves

The Office of Strategic Petroleum Reserves
U.S. Department of Energy

Work Performed Under:
Contract DE-AC01-03FE67758
Task Order 6

Prepared by:
AOC Petroleum Support Services, LLC
Washington, D.C.

Principal Authors:
Harry R. Johnson, INTEK, Inc.
Peter M. Crawford, INTEK, Inc.
James W. Bunger, JWBA, Inc.

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any or their employees or contractors, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process or service by trade name, trademark, manufacture, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Table of Contents

List of Figures

List of Tables

Foreword

It is generally agreed that worldwide petroleum supply will eventually reach its productive limit, peak, and begin a long-term decline. What should the United States do to prepare for this event? *An objective look at the alternatives points to the Nation's untapped oil shale as a strategically located, long-term source of reliable, affordable, and secure oil.*

The vast extent of U.S. oil shale resources, amounting to more than 2 trillion barrels, has been known for a century. In 1912, The President, by Executive Order, established the Naval Petroleum and Oil Shale Reserves (NPOSR). This office has overseen the U.S. strategic interests in oil shale since that time. The huge resource base has stimulated several prior commercial attempts to produce oil from oil shale, but these attempts have failed primarily because of the historically modest cost of petroleum with which it competed. With the expected future decline in petroleum production historic market forces are poised to change and this change will improve the economic viability of oil shale.

It has been nearly two decades since meaningful federal oil shale policy initiatives were taken. In that time technology has advanced, global economic, political, and market conditions have changed, and the regulatory landscape has matured. As America considers its homeland security posture, including its desired access to diverse, secure and abundant sources of liquid fuels, it is both necessary and prudent to reconsider the potential of oil shale in the nation's energy and natural resource portfolio.

Commercializing the vast oil shale resources would complement the mission of the Strategic Petroleum Reserve (SPR), by measurably adding to the country's energy resource base. Addition of shale oil to the country's proved oil reserves could occur in a manner similar to the addition of 175 billion barrels of oil from Alberta tar sand to Canada's proved oil reserves. With its commercial success, production of oil from tar sand now exceeds 1 million barrels/day. U.S. oil shale, which is as rich as tar sand, could similarly be developed and become a vital component in America's future energy security.

This report was chartered to review the potential of shale oil as a strategic liquid fuels resource. Volume I reviews the strategic value of oil shale development, public benefits from its development, possible ramifications of failure to develop these resources and related public policy issues and options. Volume II characterizes the oil shale resource, assesses oil shale technology, summarizes environmental and regulatory issues, and reviews tar sand commercialization in Canada as an analog for oil shale development in the United States.

A Peer Review meeting of selected experts from government, industry, business and academia was held February 19-20, 2004. Comments and suggestions were received and incorporated into the two volumes; comment excerpts are provided in Volume I, Appendix B. The reviewers agreed, based on the current and anticipated energy climate and the issues addressed in the report, that preparation of a Program Plan for oil shale is now warranted.

Anton Dammer, Director
Naval Petroleum and Oil Shale Reserves
U.S. Department of Energy
Washington, D.C.

Acknowledgements

"Strategic Significance of America's Oil Shale – Volume II," is a report sponsored by the U.S. Department of Energy, Office of the Naval Petroleum and Oil Shale Reserves (DOE/NPOSR), and prepared under Contract Number DE-AC01-03FE67758 (Task 6) by AOC Petroleum Support Services, LLC (AOC-PSS). Mr. Anton Dammer of DOE/NPOSR served as the Project Director and Mr. Frank Field of AOC served as the Program Manager for this task.

The DOE/NPOSR acknowledges the significant and invaluable contributions of the Steering Committee for providing overall guidance and direction for this report. The Committee members include: Mr. Anton Dammer (DOE/NPOSR), Mr. F.J. Gangle (DOE/NPOSR), Mr. Hugh Guthrie (DOE/NETL), Mr. Terry O'Connor (Shell Petroleum), Mr. Frank Field (AOC), Mr. Harry Johnson (INTEK), Mr. Peter M. Crawford (INTEK), Dr. James W. Bunger (JWBA), and Dr. Don Repici (Consultants).

Special recognition is due to those who directly performed the work on this project. The principal authors included, Mr. Harry Johnson (INTEK), Mr. Peter M. Crawford (INTEK), and Dr. James W. Bunger (JWBA). Mr. F.J. (Butch) Gangle of DOE/NPOSR is acknowledged for his immense effort in the review and critique of this report. Ms. Cortney Allen of INTEK served as the Administrator responsible for the day-to-day management of the project. Mr. Fred Hartsock of AOC is recognized for his effort in the production of the report.

The authors and sponsors also wish to recognize and thank the numerous experts from industry, government, and academia who reviewed the drafts of this document and who provided invaluable insights and comments in writing and through their participation in a peer review meeting.

While acknowledging the significant contributions of participating individuals and organizations, any error of facts, omission, or inconsistency remains the responsibility of the Project Director and Program Manager.

Oil Shale Resources, Technology and Economics

America's oil shale resources are extensive and concentrated. With long-term crude oil prices firming, oil shale appears to be nearing economic recoverability under a variety of resource-technology scenarios. While the Nation's resource base includes both eastern and western shales, the primary focus of this report is on the western oil shale resources of the Green River Formation. Western oil shale represents the greatest potential for near-term development to help meet the Nation's needs for liquid fuels. A broad range of technology exists to convert the kerogen in oil shale to fuels and high-value chemicals, while respecting and protecting the environment.

The purpose of this volume is to:

- present an updated overview of the known oil shale resource, on-going oil shale activities, and advances in oil shale technology and unconventional resource development, and to
- summarize environmental and regulatory issues that will influence public and private decisions when developing a domestic oil shale industry.

The information and conclusions presented in this volume are drawn from an extensive body of scientific and technical research and analysis conducted by industry, government, academia, policy analysts, and technical experts, as well as recent analyses conducted by the authors that compare the resource, technical, and economic characteristics of domestic oil shale with the analogous Athabasca tar sand, now being commercially produced in the Province of Alberta, Canada.

1.0 U.S. Western Oil Shale Resources and Infrastructure

The extent and characteristics of U.S. western oil shale resources, and particularly those in the Green River Formation, are well known and documented.

1.1 Characteristics of U.S. Western Oil Shale Resources

"Oil shale" is a hydrocarbon bearing rock that occurs in nearly 100 major deposits in 27 countries worldwide. It is generally shallower (<3000 feet) than the deeper and warmer geologic zones required to form oil. According to Dyni (Ref. 1), the origins of oil shale can be categorized into three basic groups; terrestrial (organic origins similar to coal-forming swamps), lacustrine (organic origins from fresh or brackish water algae), and marine (organic origins from salt water algae, acritarchs, and dinoflagellates).

Worldwide, the oil shale resource base is believed to contain about 2.6 trillion barrels, of which the vast majority, or about 2 trillion barrels, (including eastern and western shales), is located within the United States. (Dyni, ibid.) The most economically attractive deposits, containing an estimated 1.5 trillion barrels (richness of >10 gal/ton) are found in the Green River Formation of Colorado (Piceance Creek Basin), Utah (Uinta Basin) and Wyoming (Green River and Washakie Basins).

U.S. oil shale resources have been extensively characterized. Figures 1 and 2 show the areal extent of these resources.

Eastern oil shale underlies 850,000 acres of land in Kentucky, Ohio and Indiana. 16 billion barrels, at a minimum grade of 25 gal/ton, are located in the Kentucky Knobs region in the Sunbury shale and the New Albany/Ohio shale. Due to differences in kerogen type (compared to western shale) eastern oil shale requires different processing. Potential oil yields from eastern shales could someday approach yields from western shales, with processing technology advances.

Figure 1. Principal Reported Oil Shale Deposits of the United States (Ref. 2)

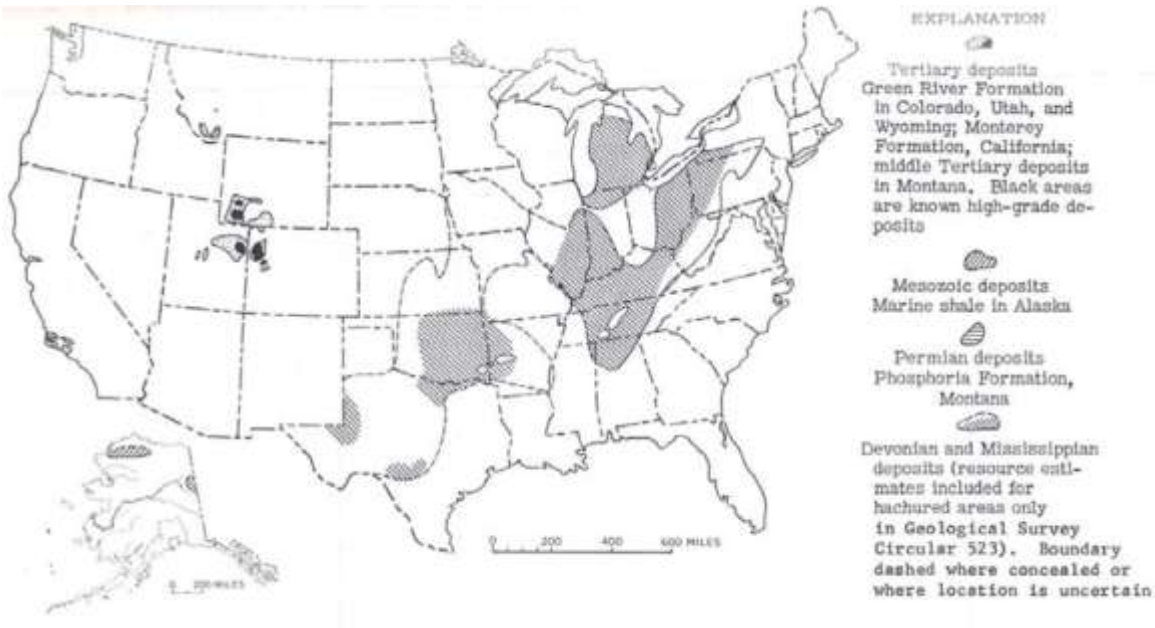
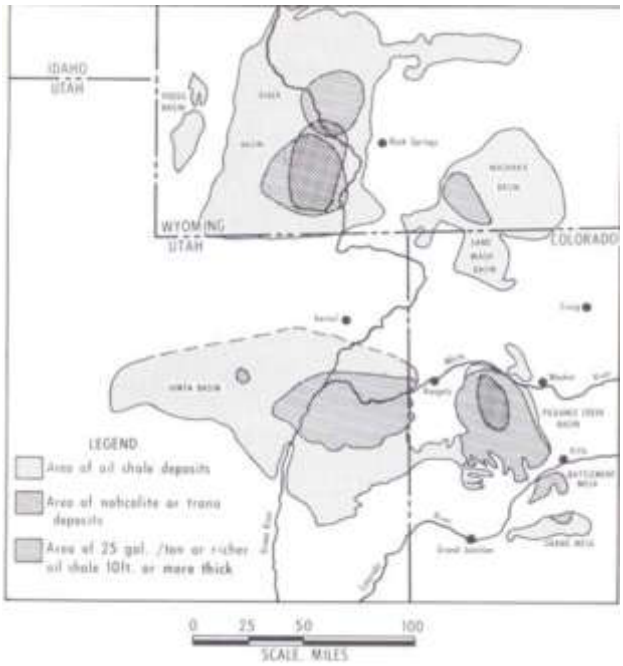


Figure 2 illustrates the most concentrated areas of western resources. More than a quarter million assays have been conducted on core and outcrop samples for the Green River oil shale. Results have shown that the richest zone, known as the Mahogany zone, is located in the Parachute Creek member of the Green River Formation. This zone can be found throughout the formation.

A layer of volcanic ash several inches thick, known as the Mahogany marker, lies on top of the Mahogany zone and serves as a convenient stratigraphic event that allows oil shale beds to be correlated over extensive areas. Because of it's relatively shallow nature and consistent bedding, the resource richness is well known, giving a high degree of certainty as to resource quality.

By assay techniques (Fischer assay being the commonly accepted method) oil yields vary from about 10 gal/ton to 50 gal/ton and, for a few feet in the Mahogany zone, up to about 65 gal/ton. Oil shale yields more than 25 U.S. gal/ton are generally viewed as the most economically attractive, and hence, the most favorable for initial development.

Figure 2. Oil Shale Areas in Colorado, Wyoming and Utah (Ref. 2)



When discussing oil shale resources, it is important to qualify the resource estimates by richness as well. According to Culbertson and Pittman (1973), of the 1.5 trillion barrels of western resource, an estimated 418 billion barrels are in deposits that will yield at least 30

gal/ton in zones at least 100 feet thick (Ref. 3). Donnell (Ref. 4) estimates resources of 750 billion at 25 gal/ton in zones at least 10 feet thick. These data correlate well with a logarithmic curve form illustrated in ***Figure 3***.

Oil shale resources lie within the basin with low dip in the general direction of prevailing regional drainages. Oil shale generally outcrops along the eroded margins of the basin, yielding multiple access points. The thickest, richest zones are found in the north-central portions of the Piceance Creek and northeastern Uinta Basins. Isopachous maps of the Piceance Creek and Uinta Basins are shown in ***Figures 4 and 5***.

Figure 3. Cumulative Resource Greater Than Indicated Richness

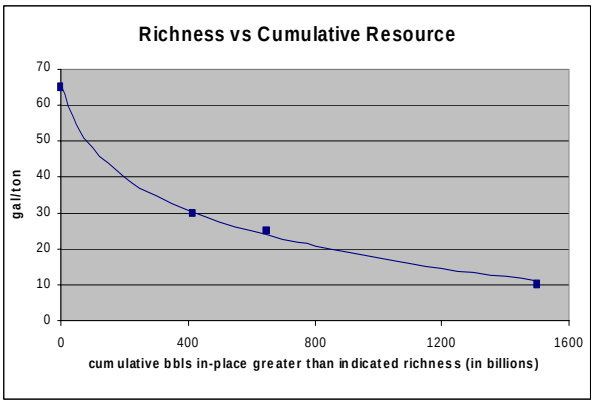


Figure 4. 25 Gallon/ton Isopach, Piceance Creek Basin (Ref. 5)

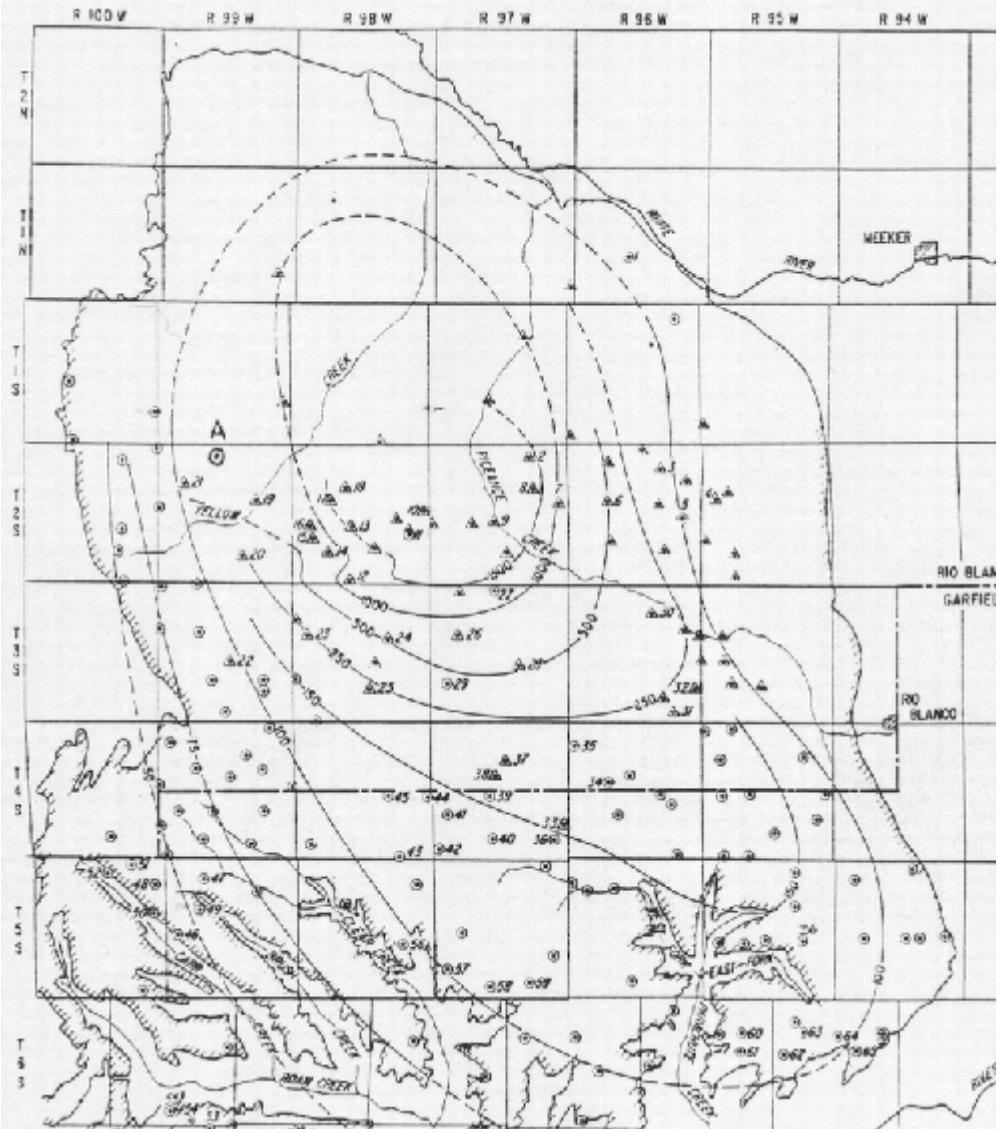


Figure 5. 25 Gallon/ton Isopach, Uinta Basin (Ref. 6)

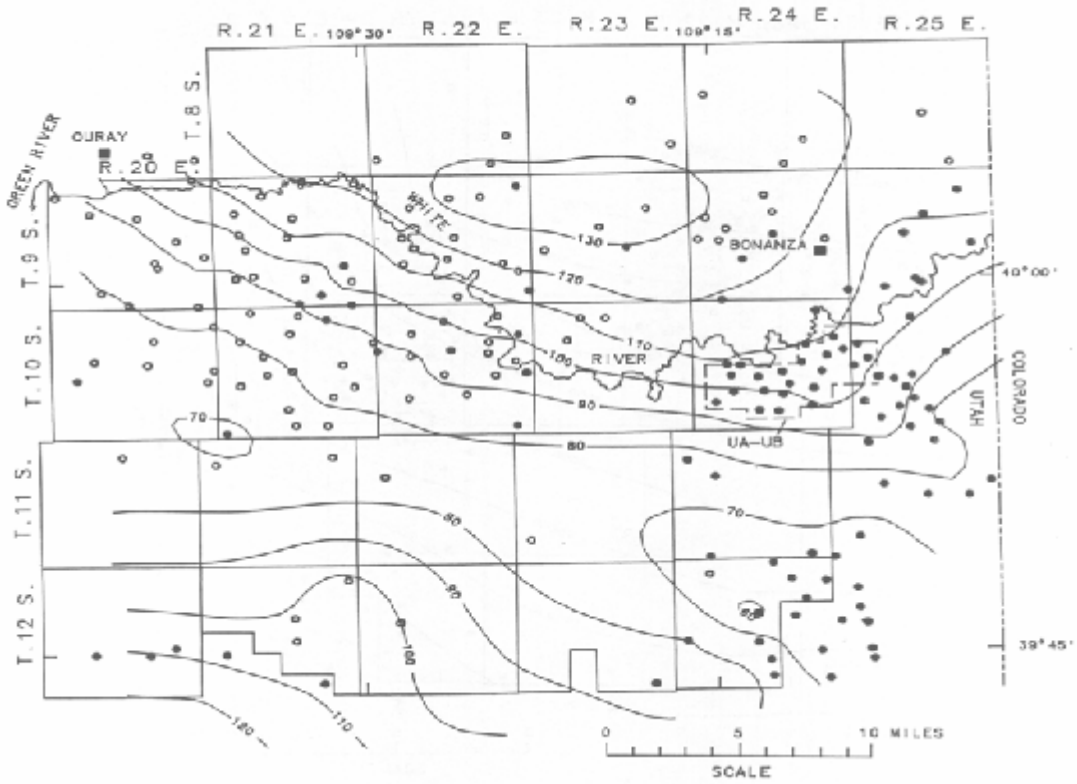
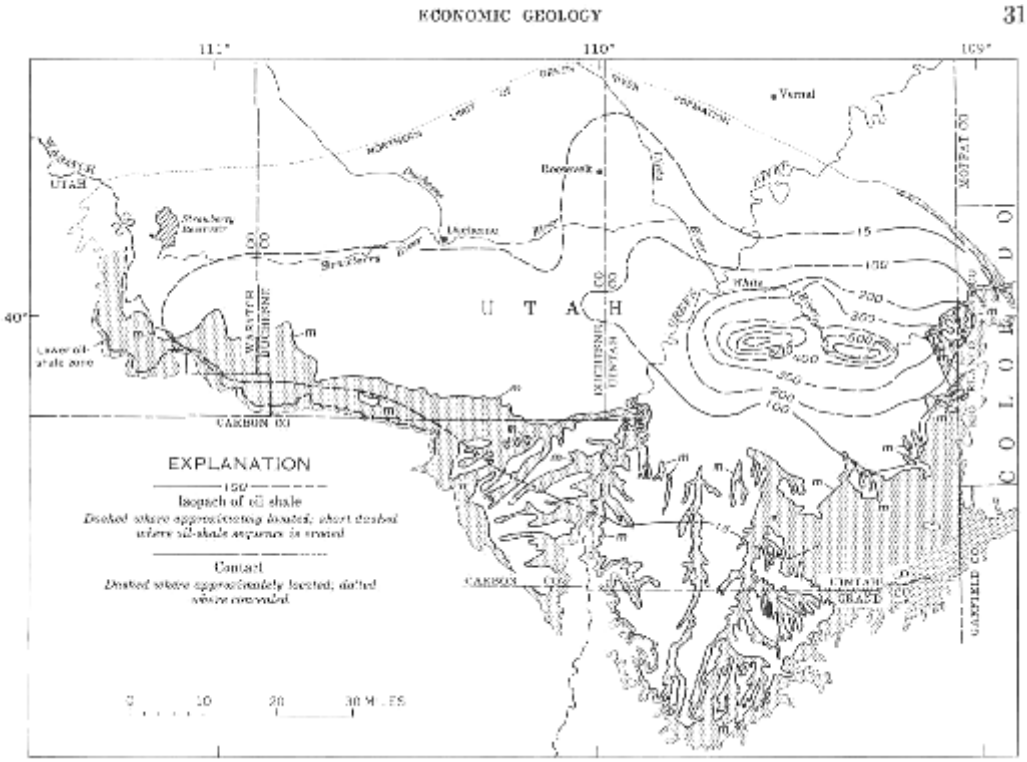


Figure 6. Areas Amenable to Surface Mining, Utah (Ref. 8)

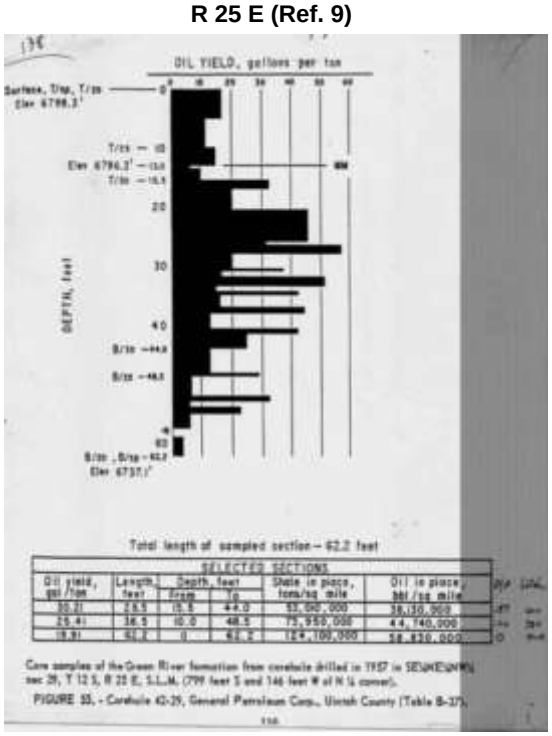


In general, surface mining is likely to be used for those zones that are near the surface or that are situated with an overburden-to-pay ratio of less than about 1:1. Economic optimization methods can be used to select stripping ratios, optimum intercept, and cutoff grades.

Oil shale exhibits distinct bedding planes. These bedding planes can be used to an advantage during mining and crushing operations. According to Cameron Engineers (1975), shear strengths along the bedding planes are considerably less than across the planes (Ref. 7), thereby, reducing operational demands.

Thin overburden, attractive for surface mining, tends to be found along part of the margins of the southern Uinta Basin and the northern Piceance Creek Basin. ***Figure 6*** depicts the locations accessible to surface mining in Utah, showing the surface outcrop along the southern margins of the formation (Ref. 8). ***Figure 7*** provides an example of a corehole histogram in which oil shale lies right on the surface (Ref 9).

Figure 7. Histogram from Utah Sec. 29, T 12 S, R 25 E (Ref. 9)



The choice of how deep or selective to mine is an economic optimization issue. Numerous opportunities exist for the surface mining of ore averaging better than 25 gallon/ton, with overburden-to-pay ratios of less than 1, especially in Utah.

In general, room and pillar mining is likely to be used for resources that outcrop along steep erosions. Horizontal adit, room and pillar mining was used successfully by Unocal. (Technology difficulties in the Unocal operation pertained primarily to the retort.)

Attractive locations in Colorado are found at the north end and along the southern flank of the Piceance Creek basin. Zones 25 feet thick or more, with yields of 35 gallon/ton can be found throughout this area. In Utah, opportunities for 35 gallon/ton ore exist along Hell's Hole canyon, the White River, and Evacuation Creek.

Deeper and thicker ores will require vertical shaft mining, modified in-situ, or true in-situ recovery approaches. Because the pay zone is more than 1,500 feet thick in some places, it is conceivable that open pit mining could be applied even with 1,000 feet of overburden.

In recent years, Shell has experimented with a novel in-situ process, (discussed below) that shows promise for recovering oil from rich, thick resources lying beneath several hundred to one-thousand feet of overburden.

There are locations that could yield in excess of 1 million barrels per acre and require, with minimum surface disturbance, fewer than 23 square miles to produce as much as 15 billion barrels of oil over a 40 year project lifetime.

It also deserves mention that in the northern Piceance Creek basin, zones of high grade oil shale also contain rich concentrations of nahcolite and dawsonite; high-value minerals that could be recovered through solution mining.

1.2 Infrastructure

1.2.1 Location and Community Infrastructure

The Green River Formation underlies parts of Colorado, Utah and Wyoming. This formation is located in the Upper Colorado River Basin. Its semi-arid climate is typical of the high plains region. The largest, closest towns to the oil shale deposits are Grand Junction, Meeker, Rangely, Rifle, Rock Springs and Vernal (see also Figure 2.).

1.2.2 Roads and Pipelines

Past and current oil and gas developments, as well as mining operations (trona, potash, etc.) have created a network of roads and pipelines that could be upgraded to serve oil shale developments. The southern Piceance Creek Basin is near Interstate 70 (I-70). A pipeline corridor runs from the Uinta Basin over Baxter Pass to the I-70 region in Colorado.

1.2.3 Natural Gas

Natural gas is indigenous to the area. There is currently major development of natural gas in the area. The ready availability of natural gas could help meet the requirements for hydrogen production needed to upgrade kerogen oil to refined products.

1.2.4 Petroleum

Oil production also occurs in and near this region. Oil is currently transported by either truck or pipeline. To the extent that regional petroleum reservoirs are candidates for improved recovery by carbon dioxide flooding, these resources may provide economic uses for carbon dioxide produced in the retorting processes. Similarly, previously depleted reservoirs (and coal seams) in the region may provide venues for carbon dioxide sequestration.

1.2.5 Electric Power

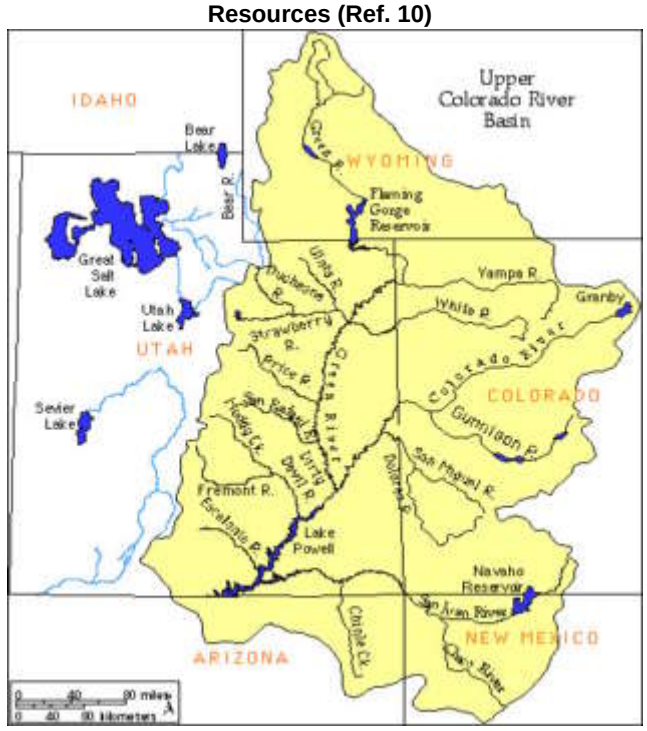
The region is a significant producer of electric power with the Bridger Power plant, (3000 MW); Moon Lake (Bonanza) Plant (420 MW), Hayden Power plant, Craig Station, Flaming Gorge, and several plants in the Four Corners area. These power generation facilities are adequate to meet process needs, at least in the early stages of development, that may not be supplied by co-generation facilities included in the shale project designs.

1.2.6 Water Availability

The development of western oil shale resources will require water for plant operations, supporting infrastructure, and the associated economic growth in the region. While some new oil shale technologies significantly reduce process water requirements, stable and secure sources of significant volumes of water may still be required for large-scale oil shale development. The largest demands for water are expected to be for land reclamation and to support the population and economic growth associated with oil shale activity.

Water in the oil shale regions derives from the Colorado River Basin System (***Figure 8***). This drainage system begins on the Pacific side of

Figure 8. Upper Colorado River Basin Water Resources (Ref. 10)



the Continental Divide in Wyoming and Colorado and extends through Utah, and along the borders of Arizona, Nevada and California.

Water availability is a growing concern in the western states as population shifts to the region have placed greater demands on the limited resources. The long-term trends are for transfer of agricultural water to urban and industrial use. The overall allocation of water today is governed by the Colorado River Compact, originally agreed to on November 24, 1922.

Currently there is a mix of both absolute and conditional water rights. Absolute rights are those that have been decreed by the state Water Court and are available for use. Conditional rights are rights that have not been through the Court process and therefore have not been decreed. Therefore, they cannot be used until a decree has been granted and the rights have been determined to be absolute. Conditional rights only preserve a holder's seniority in accordance with the doctrine of first in time, first in right. In addition conditional rights must undergo a diligence test every six years in order to preserve the conditional right.

An absolute right is still subject to being curtailed (a call) in the event the water balance is insufficient for all rights, and a senior right holder is being injured. To help assure supply it is customary to file an Augmentation Plan which may consist of a plan for reservoir storage and release or the purchase of senior rights that can be provided to a senior right holder.

A recent (October, 2003) agreement between the State of California and the Upper Basin States returns about 0.8 million-acre feet per year to the Upper Basin States that was being over-used by the State of California (Ref. 11). This 0.8 million acre-feet/year increment resolves some regional issues and is more than enough to support a 2 million barrel/day oil shale industry, should the water be allocated to this use. (See also section 3.2.5 Water Availability).

2.0 Oil Shale Technology Assessment

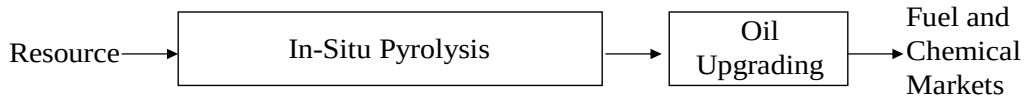
Energy companies and petroleum researchers have, over the past 60 years, developed, tested, enhanced, and in many cases, demonstrated a variety of technologies for recovering shale oil from oil shale and processing it to produce fuels and byproducts. Both surface processing and in-situ technologies have been examined. Generally, surface processing consists of three major steps: (1) oil shale mining and ore preparation (2) pyrolysis of oil shale to produce kerogen oil, and (3) processing kerogen oil to produce refinery feedstock and high-value chemicals. This sequence is illustrated in ***Figure 9***.

For deeper, thicker deposits, not as amenable to surface- or deep-mining methods, the kerogen oil can be produced by in-situ technology. In-situ processes minimize, or in the case of true in-situ, eliminate the need for mining and surface pyrolysis, by heating the resource in its natural depositional setting. This sequence is illustrated in ***Figure 10***. Both process sequences are described in greater detail below and in Appendix II – B. – Oil Shale Technologies.

By as early as 1978, the U.S. Department of Energy had concluded that the development of a domestic oil shale industry was technically

Figure 9. Conversion of Oil Shale to Products (Surface Process)

Figure 10. Conversion of Oil Shale to Products (True In-Situ Process)



feasible and was ready for the next steps toward aggressive commercialization (Ref. 12).

- Surface and sub-surface mining technologies were deemed commercially proven and economic.
- Numerous surface retorting technologies were largely demonstrated, although additional process design improvements were deemed desirable to improve reliability and to reduce costs.
- In-situ technologies, although less costly than surface retorts, had been demonstrated to a more limited degree, but warranted additional public and private R&D investment and testing.
- Environmental impacts, though significant at the time, appeared to be controllable to meet existing and anticipated regulatory standards with available technological controls in place.
- Upgrading and processing technologies to convert kerogen oil to quality fuels and chemical byproducts were considered proven, although on-site processing and new commercial refineries could be required to support a full-scale industry.
- The processes were expected to be economically competitive, based on oil price forecasts that followed the Arab Oil Embargo of 1973 and the supply disruptions and price shocks associated with the 1979 Iranian Revolution.

By 1984, reduced tensions in the Middle East and the availability of new petroleum supplies from non-OPEC sources, including production in the North Sea, coupled with decreases in world petroleum demand, caused prices to fall from $31/ Bbl to as low as $10 / Bbl. Numerous pilot- and demonstration-scale oil shale projects that were then under construction or in operation in the United States became uneconomic and were subsequently terminated.

Perceptions that projects in the 1980s and 1990s were terminated due to the quality of the resource are incorrect. In fact, it was the abundance, concentration, and high quality of the oil shale resources of the Green River Formation that attracted the billion+ dollars of investment in the first place.

Public and private sector decisions to terminate investments in R&D and large-scale demonstration projects were made largely based on evolving economic uncertainties associated with the supply and price of conventional petroleum, as well as oil shale plant design issues. For example, design issues in the UNOCAL retort created production bottlenecks that played a major role in Unocal's decision to shut down rather than retrofit its oil shale retort pilot plant.

Investment uncertainty was further compounded by regulatory and policy uncertainty. These uncertainties are now being resolved as petroleum prices firm, the regulatory environment matures, and the need for additional, diverse energy supplies brings renewed focus to government policy.

In many cases, the technologies developed to produce and process kerogen oil from shale have not been abandoned, but rather "mothballed" for adaptation and application at a future date when market demand for kerogen oil would increase, oil price risk would attenuate, and major capital investments for oil shale projects could be justified. Many of the companies involved in earlier oil shale projects still hold their oil shale technology and resource assets. The body of knowledge and

understanding established by these past efforts provides the foundation for ongoing advances in shale oil production, mining, retorting, and processing technology and supports the growing worldwide interest and activity in oil shale development.

2.1 Updating World Oil Shale Technology Activity

Although most U.S. oil shale efforts have been largely curtailed for more than a decade, public and private interest and activity in oil shale resources and technology continues, both in the United States and elsewhere in the world. This continuing interest and effort has enabled the art and science of oil shale mining and conversion, and shale oil processing to advance, albeit slowly.

Public and private entities in several nations are gaining insight from prior oil shale research, development and demonstration projects and applying this insight to improve technology efficiency and performance, produce better-quality fuels and byproducts, drive down technology capital and operating cost, increase product value, and to improve environmental controls and reduce environmental impacts.

At least five nations with significant oil shale resources currently have ongoing oil shale research, demonstration or commercial scale processing projects:

United States – In the United States, the repository of the world's largest and most concentrated known oil shale resources, efforts to commercialize oil shale, last attempted by Unocal, were terminated in 1991. Pockets of research and development interest and activity remain, however, and renewed commercial interest in oil shale is evident.

Among the most promising efforts is a new "true in-situ" approach being developed by Shell. Much of America's high-quality oil shale resource lies in thick deposits with significant vertical overburden. These deposits may be more technically amenable to efficient and less costly in-situ processing than mining and surface retorting. Shell has continued research in the Mahogany deposit in Colorado, which could demonstrate the economic and technical feasibility of in-situ development of oil shale and lead to commercial scale operations. Various technological challenges remain – including development of a more reliable heat delivery system.

This in-situ process, referred to as the In-situ Conversion Process (ICP), described in more detail below, is quite novel and has the potential to make much deeper, thicker, and richer resources available for development, without the complications of surface or subsurface mining. The product quality of the produced shale oil could also be much better than shale oil produced from surface retorts. The next step, proposed for later in the decade, will be to integrate the various field trials into one, unified demonstration test. The results will influence a commercial project decision based on process technical performance, economic viability, oil-price risk, and permitting and regulatory issues (Ref. 12).

Other efforts also seek to advance oil shale technology. The New Paraho Corporation (now Synthetic Technology, Inc.) has developed a very successful and economic process for converting oil shale to a more durable, easier to use, and less costly road asphalt binder while simultaneously producing a by product that can be used as a naphtha feedstock. (Ref. 53).

Other organizations and individuals are exploring novel processes for extracting kerogen from oil shale and for converting the kerogen oil to fuels and chemicals. Interest is also growing in small-scale commercial "value enhancement" oil shale projects that could be made economic at a modest commercial-scale and at oil prices in the mid $20s. The value-enhancement process aims to produce heteroatom containing specialty high-value chemical

products, and premium asphalt additives, in addition to a slate of high-quality fuels.

Canada – Two major activities in Canada are directly relevant to U.S. oil shale industry development:

1. Canada's program for tar sand development and commercialization can serve as a model for effectively re-stimulating U.S. oil shale industry development.
2. A new surface retort technology, the Alberta Taciuk Process (ATP) technology, is being commercialized in Australia and is viewed by many as the current state-of-the-art for conventional surface oil shale retorting.

Continuing research, jointly funded by private industry and the Alberta Science and Research Authority) since 1970, has advanced ATP technology to the point of readiness for commercial scale demonstration and export.

Commercial-scale tar sand technology has steadily grown and is now producing oil at approximately 1 million barrels per day. A new "steam assisted gravity drainage" (SAG-D) in-situ technology, and incentives provided to stimulate commercialization efforts, has enabled Canada to build an industry that can technically recover as much as 174 billion barrels, about 10 percent, of its massive tar sand resource of 1.7 trillion barrels.

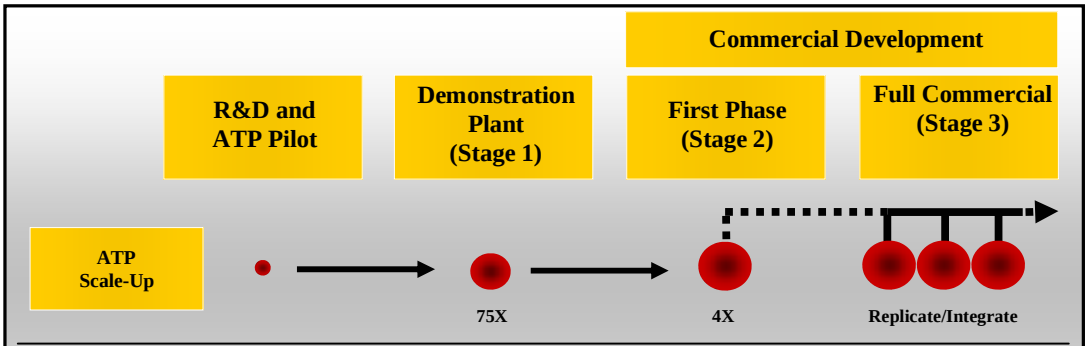
Recent revisions to proved reserves, based on proven tar sand technology, have caused Canada to be ranked second in the world (trailing only Saudi Arabia) in proved petroleum reserves by *Oil & Gas Journal* (Ref. 14).

Australia – Southern Pacific Petroleum NL (SPP) is developing Australia's largest known oil resource, some 17.3 billion barrels of oil held in ten oil shale deposits along the coast of Central Queensland.

Australia's oil shale resources are silica-based. They are less complex, have fewer impurities, and may be easier to process than carbonate-based U.S. western shales. These Queensland deposits could support production of more than one million barrels of oil per day.

SPP has adopted a multi-phased strategy ***(Figure 11)*** to develop the 2.6 billion barrel Stuart resource and is presently operating an industrial-scale pilot plant (Stage 1) near the industrial port city of Gladstone, Queensland to prove the commercial potential of the Alberta Taciuk Processor (ATP).

Figure 11 -- Stuart Shale Phased Development Strategy



Oil Shale (tpsd)	80	6,000	23,500	Up to 380,000
Oil Products (bpsd)[1]	80	4,500	15,500	Up to 200,000
Oil Products		ULSN, LFO	ULSN, LFO	Synthetic
Timing[2]	80	1999	2008	Staged 2012 - 2015

1. Reflects varying oil content in oil shale feed in various stages.
2. Timing of commercial development subject to regulatory approvals and financing.

SPP initially reviewed ten retorting technologies and six were further evaluated at pilot scale. The ATP technology was selected for its simple, robust design; energy self-sufficient process; minimal process water requirements; ability to handle fines; and its high kerogen oil yields. The process allows the mechanical transfer of solids through the machine with no moving parts and achieves improved process efficiencies through solid-to-solid heat transfer (Ref.15).

Stuart Stage 1 is a $260 million, 4,500 barrel per stream day (bpsd) demonstration plant that is a 75:1 scale-up of a small pilot plant in Canada that was originally developed to process oil sand. The Stage 1 plant has operated for more than 500 days and produced more than 1.3 million barrels of oil since 1999, including 629,000 barrels in 2003. The plant has run in excess of 96 days continuously at peak oil production rates up to 82 percent of nameplate capacity and has achieved sustained oil yield at up to 94 percent of design.

The Stage 1 plant produces a raw shale oil product that is fractionated into two streams of approximately equal proportions. The first stream, Light Fuel Oil (LFO) (24 API, 0.4% S) is sold as-is at a premium into the Singapore fuel market as a cutter stock. The second stream, raw naphtha, is hydrotreated to reduce nitrogen and sulphur levels to meet refinery specifications. This product, Ultra Low Sulphur Naphtha (ULSN) (57 API, S < 1 ppm, N < 1 ppm) is sold to Mobil Oil Australia under a long term contract for the production of gasoline, diesel, and jet fuel.

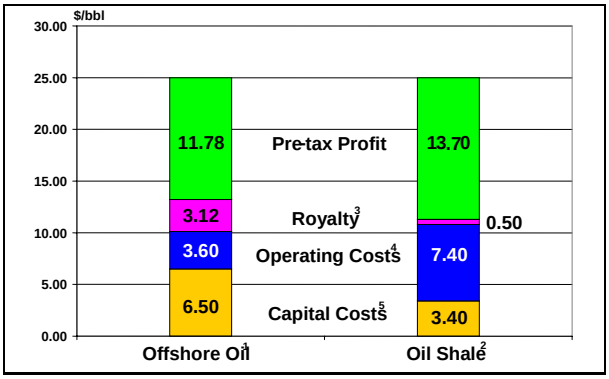
According to SPP, the successful performance of the ATP at the Stuart Stage 1 plant has demonstrated its technical viability, economic potential, and environmental sustainability.

The next phase of development is the $375 million (2002$) Stuart Stage 2 plant, a 4:1 commercial-sized scale up of Stage 1. It will process up to 23,500 t/d of shale to produce 15,500 bpsd of LFO and ULSN at operating costs of about $9 to $11 per bbl.

The full commercial plant, Stage 3, will utilize multiple Stage 2 ATP modules to achieve production of up to 200,000 bpd. This plant will produce a light, sweet, "bottomless" synthetic crude (48 API, 0.01% S). Several different plant sizes have been studied. However, a baseline design incorporating 13 ATP modules and producing 157,000 bpsd of synthetic crude is projected to cost $3.5 to $4.0 billion (2002$), and have operating costs of $7.50 to $8.50 per bbl, after full project implementation is complete.

At this scale, costs for producing oil from shale are very competitive, even when compared to comparable-sized conventional offshore projects in other parts of the world *(Figure 12)*. Although cash operating costs are somewhat higher for oil shale, capital costs (including initial capital amortized over the long project life) are much lower due to negligible exploration costs. Once established, a commercial plant at Stuart could produce 200,000 bpd for more than 30 years with no production decline.

Figure 12 – Stuart Shale Stage 3 ~ Projected Profitability at $25/bbl WTI



1. *Actual cost structure of GOM, West Africa, North Sea, Brazil. CERA Report July, 1999.*
2. *Projected oil shale costs for 157,000 bpsd commercial development (based on Stuart Stage 3 internal estimates January 2004), including in-plant greenhouse gas mitigation steps (energy efficiency; bio-ethanol co-production). Long term exchange rate A$/US$ = 0.65.*
3. *Oil shale 1.8% (Queensland State); Conventional 12.5% (assumed average).*
4. *Oil shale: average operating costs over 30 year projected life.*
5. *Oil shale: initial capital (amortised over 30 year projected life) and average annual sustaining capital. Offshore oil: finding and development costs.*

The Australian government has encouraged the Stuart Shale Project with incentives, primarily an excise tax rebate for naphtha that is used to make gasoline in refineries in Australia. This rebate applies only to naphtha from the Stage 1 plant until the end of 2005.

At the ultimate production level of 200,000 bpd, SPP estimates the Stuart Oil Shale Project will stimulate investment of $5 to $6 billion, improve Australia's balance of payments by $2 billion per year, and create 15,000 permanent jobs (Ref. 16).

Cost overruns in a capital improvement program in 2003 resulted in a greater than expected drawdown of corporate cash reserves. Due to the deterioration in the company's financial position, SPP's secured creditor placed the company into receivership. Subsequently, Sandefer Capital Partners contracted to acquire most of the assets of SPP through a new company, Queensland Energy Resources Limited (QERL). Following completion of the transaction, expected by mid-2004, QERL will conduct a careful evaluation of its resources and technology in the hopes of advancing a prudent and responsible plan to continue development of the Stuart resource.

The Stage 1 plant has continued to operate during this process to demonstrate the viability of the technology and plans are in place to further improve performance towards design yield and rates.

Estonia – Estonia has been processing oil shale since the 1920s. Estonian oil shale resources are currently put at 5.5 billion tons including 1.7 billion tons of active (mineable) reserves. At its peak in 1980, Estonia was producing and using some 31 million tons of oil shale per year. In 1999, 11 million tons of oil shale were produced.

Until recently, more than 80 percent of Estonian oil shale production was pulverized and used as boiler fuel for electric power generation, by Eesti Energia, the Estonian national electric power company. About 16 percent of the mined production was used in petroleum and chemical manufacturing, and the rest was used in cement production. In 1981, a new nuclear power station came on line in Leningrad, Russia and triggered a decline in Estonian oil shale production for power generation. The Estonian government has taken initial steps towards privatization of the oil-shale industry (Ref. 17).

Today, three (3) commercial retort operations produce about 8,000 bbl/day of shale oil. Two of these operations (VKG at Kohtle-Jarve and the former Ras Kivioli) use retorts known as the Kiviter retorts. Oil shale lumps (>25mm) are fed to the top of the retorts and retorted by a cross-flow of combusted retort gas recycled from production. These retorts operate relatively trouble-free and have been modified a number of times during their operations, starting in the 1960s.

The other type of retort is known as the Galoter retort, essentially a hot solids recycle, rotary kiln design. There are two such retorts operated by Eesti Energia. These are newer retorts, built in the early 1980s, and can handle oil shale fines. With the current elevated price of oil, all available retorts in Estonia are running at full capacity.

The Viru Keemia Grupp (VKG), a private Estonian chemical company, plans to construct a new $220 - $240 million oil shale processing project between 2005 and 2009 to take advantage of markets for shale oil and high-value by-chemical products. VKG has selected the ATP technology designed in Canada and proven in Australia for its project. VKG cites the environmental benefits of the ATP technology as a major driver for technology selection. These benefits include emissions controllable to achieve European Union limits; spent shale with total organic carbon less than 3 percent; and zero water emissions from the ATP process. VKG will license the ATP technology from the Alberta Research Council

with rights to sublicense the technology in Estonia and Russia.

The proposed plant will have annual production of 4 million barrels of liquid fuels (naphtha and distillate), 120 million cubic meters of fuel gas, and 12,000 tons of high value chemical compounds including phenols, cresols, and xylenols and alkylresorcinols. The value of these chemicals, estimated at $1,500 per ton, significantly improves the project's economics (Ref.18). The project is estimated to achieve break-even financial feasibility operating at as low as 30 percent of faceplate capacity, assuming a Brent crude oil price of $21/bbl or higher. At 50 percent utilization, the project is economic at a Brent crude price of $18/bbl. At full capacity, it could be economic at Brent crude prices as low as $13/Bbbl.

Although the cost of such inputs as mined shale and labor, are likely less in Estonia than they would be in U.S. western shales, VKG's estimates suggest that small scale commercial plants with a value-enhanced product slate can be economic at relatively low world oil prices using the ATP technology. (Ref. 18).

Brazil – The oil shale resource base in Brazil is ranked among the largest in the world. It was first exploited in the late Nineteenth century. The Ministry of Mines and Energy quotes end-1999 shale oil reserves as 445.1 million m3 oil (inventoried) and an additional 9,402 million m3 (estimated) with shale gas reserves as 111 billion m3 (inventoried) and an additional 2,353 billion m3 (estimated) (Ref. 19). (One (1) m3 oil is 6.29 barrels and approximately .92 metric tons. Gas reserves are assumed to be standard cubic meters.)

The world's largest surface oil shale pyrolysis reactor is the Petrosix 11-m vertical shaft Gas Combustion Retort (GCR) used in Brazil's oil shale development program. It was designed by Cameron Engineers, which also designed and built the U.S. Bureau of Mines GCR and, later, the Paraho GCR. Focusing on the oil shale deposits at São Mateus do Sul, the company brought a pilot plant (8 inch internal diameter retort) into operation in 1982 to use for oil shale characterization, retorting test, and evaluation of new commercial plants. A 6-foot (internal diameter) retort demonstration plant followed in 1984 and is used for the optimization of the Petrosix technology.

A 2,400 (nominal) tons per day, 18-foot (internal diameter) semi-works retort (the Irati Profile Plant), was originally brought on line in 1972, and began operating on a limited commercial scale in 1980. A larger commercial plant – the 36-foot (internal diameter) Industrial Module retort was brought into service in December 1991. Together the two commercial plants process some 8,500 tons of bituminous shale daily (Ref 19).

The 11-meter (36 foot) Petrosix retort yields a nominal daily output of 3,870 barrels of shale oil, 132 tons of fuel gas, 50 tons of liquefied shale gas and 82 tons of sulfur. Total output of shale oil in 1999 was 195.2 thousand tonnes. (Refs. 19 - 21) The Petrosix process, which is similar to the Paraho technology, is considered a highly reliable technology for use with U.S. oil shale.

China – The People's Republic of China is the fastest growing importer of crude oil and petroleum products in the world. China has produced oil from shale since the 1920s. Shale oil production decreased by more than 50 percent from its 1959 peak of 780,000 tons to about 300,000 tons by the 1980s, following discovery of significant conventional petroleum resources in the Daqing field in 1962. More than 200 old-style retorts were shut down in Fushun and Maoming. Sixty new retorts were put in place in the 1990's by the Fushun Bureau of Mines and 20 additional retorts were added in 1998, restoring about 90,000 tons of oil per year of shale oil production at Fushun by 2002.

Today, rapid increases in petroleum demand and increasing world oil prices are sparking additional interest in expanding China's oil

shale industry, including the addition of larger scale retorts and advanced retorting technologies to increase output and reduce environmental impacts. Additional projects in other regions plan to retort an additional 10,000 tons per day of oil shale to produce about 1000 tons per day of shale oil, quadrupling shale oil production. (Refs. 22 – 24).

2.2 Advances in Oil Shale Technology

The various processes for producing fuels and chemicals from oil shale are shown in ***Figure 13***. These include progressive improvements that have extended and advanced the state-of-the-art .

The processes involve heating (retorting) oil shale to convert the organic kerogen to a raw oil. There are two basic oil shale retorting approaches. Conventional surface retorts involve mining the oil shale by surface or underground mining, transporting the shale to the retort facility, retorting and recovering the raw kerogen oil, upgrading the raw oil to marketable products and disposing of the "spent" shale.

In-situ processes introduce heat to the kerogen while it is still embedded in its natural geological formation. There are two general in-situ approaches; true in-situ in which there is minimal or no disturbance of the ore bed, and modified in-situ, in which the bed is rubblized, either through direct blasting with surface uplift or after partial mining to create void space. Recent technology advances are expected to improve the viability of oil shale technology, leading to commercialization. These advances are summarized in ***Table 1***.

2.2.1 Oil Shale Mining

Advances in mining technology continue in other mineral exploitation industries, including the coal industry. Open-pit mining is a well-established technology in coal, tar sand and hard rock mining. At a large scale, direct mining costs are often less than $1/ton.

Room and pillar and underground mining have previously been proven at commercial scale for U.S. western oil shales. Costs for room and pillar mining will be higher than for surface mining, but these costs may be partially offset by having access to richer ore. Size reduction (crushing) costs may add as much as $1/bbl.

Figure 13. Generalized Processes for Conversion of Shale to Fuels and Byproducts

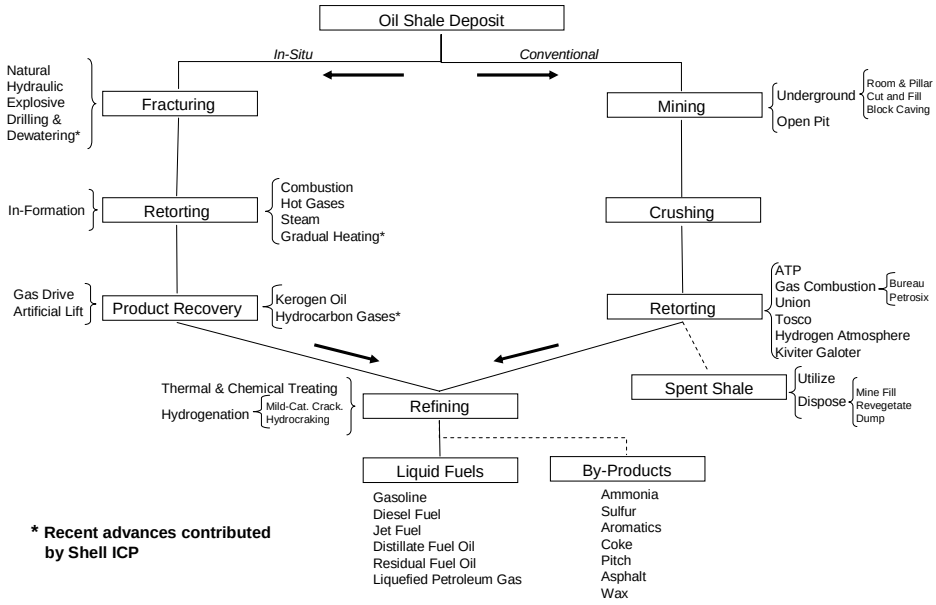


Table 1. Advances in Oil Shale Technology

Stage	Process Type	Advances	Status	Project
Mining	Open-Pit	Minor advances continue to reduce costs	Demonstrated at commercial scale	Stuart ; Alberta
	Underground	Room and pillar approaches	Demonstrated commercial scale	Unocal; Others
Retorting	Conventional	Shale pre-heating increases gas and oil yields; extracts intermediate products before high temperature pyrolysis Combusting carbon residue on pyrolized shale generates process heat; reduces emissions and spent shale carbon content Recirculation of gases and capture of connate water from shale minimizes process water requirements. Lower heat rates reduce plasticization of kerogen-rich shales	Demonstrated at pilot scale in ATP	Stuart Shale
	In-Situ	Slower heating increases oil and hydrocarbon gas yield and quality. Recovery of deeper resources enabled by heating technology Improved ability to control heat front by controlling heaters and back pressure	Proven at field scale Indicated Proven	Shell ICP Shell ICP Shell ICP
	Novel Processes	Supercritical extraction processes Higher heating rates Shorter "residence" durations "Scavengers" (hydrogen or hydrogen transfer/donor agents) Solvent extraction of kerogen from ore Thermal solution processes	Concept Research Proven Research Research Research	ATP
Processing	Value Enhancement	Separates nitrogen element for chemicals while generating fuels feedstocks	Proof of concept – 1 yr from demo	Bunger, et al.

Current mining advances continue to reduce mining costs, lowering the cost of shale delivered to conventional retort facilities. Restoration approaches for depleted open-pit mines are demonstrated, both in oil shale operations and other mining industries.

2.2.2 Surface Retorts

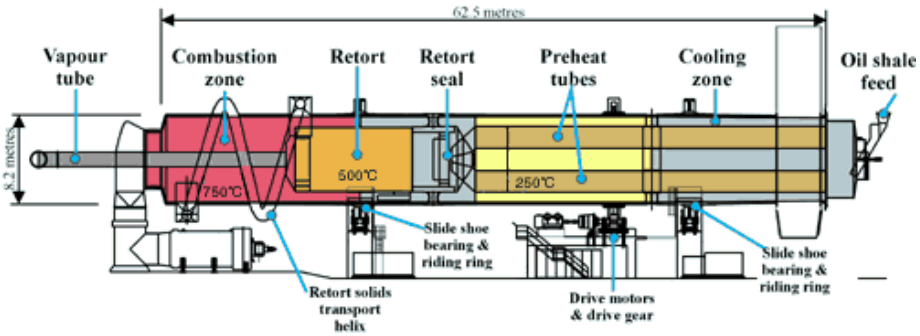
Numerous approaches to oil shale pyrolysis were tested at pilot and semi-commercial scales during the 1980s (Ref 55). The principal objectives of any retorting process are high yields, high energy efficiency, low residence time and reliability.

Larger-than-pilot-scale tests were made by TOSCO, Paraho, and Exxon. UNOCAL operated a full-scale commercial module. Occidental ran a large-scale modified in-situ (MIS) project. These are discussed in greater detail in the appendices.

The surface retorting technology that is garnering the most attention today is the Alberta Taciuk Processor (ATP). The ATP process, initially designed for extracting bitumen from tar sand, combines use of gas recirculation and direct and indirect heat transfer from circulated hot solids in a rotating kiln environment (***Figure 14***). The process allows the energy self-sufficient transfer, retorting and combusting of shale ore. Some of the hot processed shale that is recirculated into the retort section, mixing with the fresh feed, and providing the heat for pyrolysis by direct, solid-to-solid heat transfer.

ATP promises to improve on previous surface retort technologies, including the TOSCO II gas combustion retort, in a variety of ways.

Figure 14. ATP Schematic (Ref. 25)



ATP increases kerogen oil and combustible gas yields, improves thermal efficiency, reduce process water requirements, and minimizes residual coke remaining on spent shale, thus improving its qualities for environmentally-safe disposal.

Environmental controls minimize SO_2, NO_x, CO_2 and particulate emissions. Importantly, the ATP process has been identified by private interests in both Australia and Estonia as the leading technology for continuing development of their respective oil shale resources, as described below. In Australia, the ATP technology was selected by Southern Pacific Petroleum for its simple, robust design; energy self-sufficient process; minimal process water requirements, ability to handle fines, and for its kerogen oil yields. A similar rationale was cited by VKG in Estonia for making its technology selection (Ref. 25).

The ability to handle fines is important for U.S. shales, which are high in friable carbonate minerals and tend to disintegrate into small particles when agitated. These particles can find their way into the pyrolized shale oil and be very difficult and costly to remove. However, ATP has not yet been tested and demonstrated for U.S. western oil shales.

2.2.3 IN-SITU PROCESSES – The major advances in in-situ processing are found in a new true in-situ process. Shell has developed and patented a new technology, known as the in-situ conversion process (ICP) (***Figures 15 and 16***). ICP could potentially produce high quality transportation fuels from oil shale, oil

Figure 15. Overview of In-Situ Conversion Process

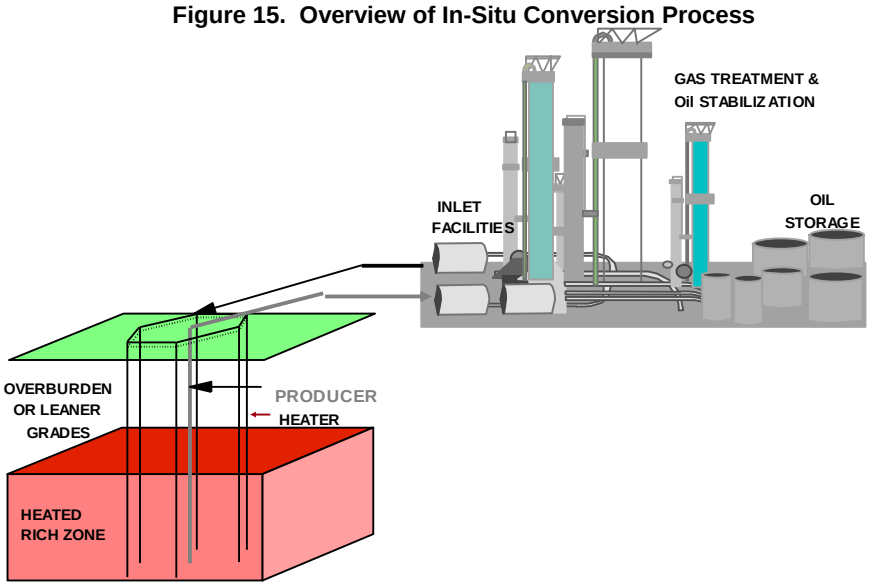
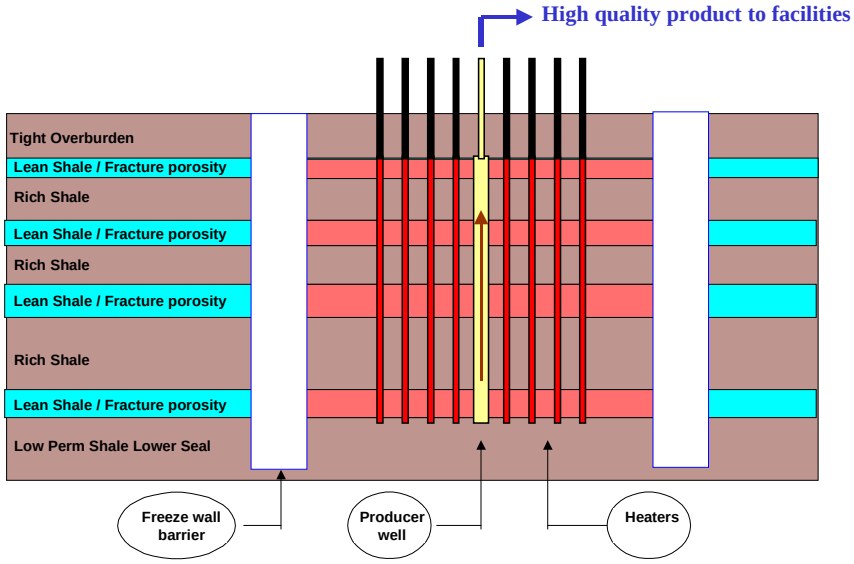


Figure 16. In-Situ Process Detail



sand, and coal in a technically, economically and environmentally sound manner.

The ICP process, when applied to oil shale, produces a range of gases including propane, hydrogen, methane, and ethane, as well as high quality liquid products – jet fuel, kerosene, and naphtha – after the initial liquid product is hydro-treated. The ICP process involves placing either electric or gas heaters in vertically drilled wells and gradually heating the oil shale interval over a period of several years until kerogen is converted to hydrocarbon gases and kerogen oil which is then produced through conventional recovery means.

The ICP process appears to improve heat distribution in the target deposit, overcoming heat-front control problems traditionally associated with other in-situ combustion processes. Due to the slow heating and pyrolysis process, the product quality is improved and subsequent product treating is less complex, as compared to oil produced by surface retorting or conventional in-situ approaches.

In the ICP process, traditional mining operations are replaced with well drilling, heat delivery systems, containment/freeze wall chillers, and product gathering piping. Economies of scale are important, and are driven by the need for energy efficiency, cost effective upgrading, and reasonable logistics / infrastructure costs. It is important to maximize the volume of the heated oil shale compared with the surface area of the overburden so that heat loss is minimized. This helps minimize production costs.

Capital and operating costs for product upgrading and pipeline shipments also fall, on a $/bbl basis, as the total throughput increases. When targeting transportation fuel production, economies of scale favor shale oil projects larger than100,000 bbl/day. The company believes that the technology should be profitable at or about $25/bbl. However, as it will take many years before the product stream (and therefore revenue) reaches steady state production (well after hoped-for first generation commercial start up early in the next decade) and because the process is so capital intensive, the economic risk is very high, even if the technology start up flawlessly.

According to Shell, the ICP process significantly reduces (and in some cases eliminates) the environmental impacts resulting from previous shale oil recovery techniques. The ICP method involves no open-pit or sub-surface mining, creates no leftover piles of surface

tailings, and minimizes unwanted byproducts and water use. Much more oil and gas may be recovered from a given area utilizing the ICP process, since the early indications show that hydrocarbon products can be produced at greater depths than would be accessible by other technologies.

Shell is currently operating a modest field research effort in northwestern Colorado's Piceance Basin to test ICP's viability on the basin's world-class oil shale reserves. Although initial results are very promising, decisions to expand and advance the research effort, leading to a decision to proceed with investment in commercial–scale operations, will depend on overcoming certain technical hurdles and perceptions of future market conditions and investment risks. (Ref 26.)

2.2.4 Novel and Advanced Conversion Process Concept

Both conventional and in-situ retorting processes result in inefficiencies that reduce the volume and quality of the produced shale oil. Depending on the efficiency of the process, a portion of the kerogen that does not yield liquid is either deposited as "coke" on the host mineral matter, or is converted to hydrocarbon gases. For the purpose of producing shale oil, the optimal process is one that minimizes the regressive thermal and chemical reactions that form coke and hydrocarbon gases and maximizes the production of shale oil.

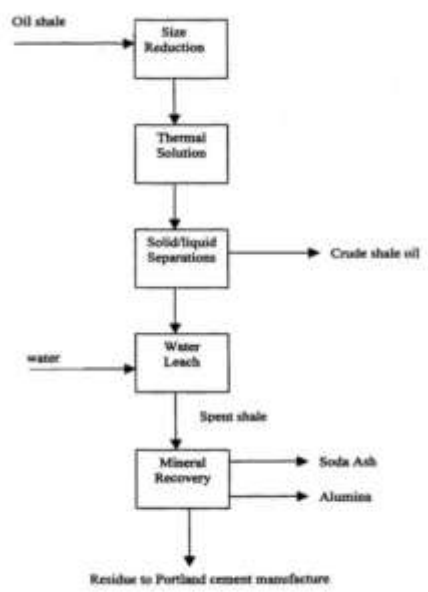
Novel and advanced retorting and upgrading processes seek to modify the processing chemistry to improve recovery and/or create high-value by-products. Novel processes are being researched and tested in lab-scale environments. Some of these approaches include: Lower heating temperatures; higher heating rates; shorter residence time durations; introducing "scavengers" such as hydrogen (or hydrogen transfer/donor agents); and introducing solvents (Ref. 27).

A thermal solution process, still in lab-scale development, represents a radical departure from conventional oil shale retorts and in-situ retorts (***Figure 17***). The process incorporates thermal solution in a recycle solvent for recovery of shale oil, followed by leaching of the spent shale with hot water to recover valuable mineral by-products, including soda ash, alumina, and a stream suitable for processing to Portland cement.

According to the researcher, the process achieves enhanced oil yields (up to 150 percent of the Fischer Assay versus about 90 percent for conventional retorts); low olefin oil that is more stable for storage or shipping than conventional kerogen oil which must be hydroprocessed immediately; improved recovery of by-products (40 pounds of alumina, 160 pounds of soda ash, and 800 pounds of Portland cement base per ton of oil shale); and reduced environmental impacts due to lower volumes of spent shale for disposal (Ref. 27).

Many elements of this process still need to be proven at demonstration-scale outside of the lab, before feasibility at commercial-scale can be determined.

Figure 17. Thermal Solution Process



2.2.5 Shale (Kerogen) Oil Upgrading and Processing

Kerogen oil is the pyrolysis product of the organic matter (kerogen) contained in oil shale rock. The raw kerogen oil produced from retorting oil shale can vary in properties and composition. ***Table 2*** illustrates some of these variations. The two most significant characteristics of U.S. western oil shales are the high hydrogen content, derived primarily from high concentrations of paraffins (waxes), and the high concentration of nitrogen, derived from high concentrations of pyridines and pyrroles.

The waxes give value to the fuel products for use as diesel and jet fuels, but can require special processing to improve the freeze point properties. The nitrogen compounds give the kerogen oil value for manufacturing specialty chemicals.

2.2.6 Value Enhancement Processes

Research sponsored by the U.S. Department of Energy and the Republic of Estonia, shows attractive potential for profitable, near-term development of value enhancement processes at a small scale (e.g. 10,000 to 20,000 bbl/day).

In prior attempts to substitute shale oil for petroleum as a source for fuels, a costly catalytic hydro-processing step has been used to remove the heteroatoms. In such cases, the value of the final product, governed by the price of crude oil, has been insufficient to offset the costs of production and upgrading.

If, instead of removing heteroatoms by catalytic hydroprocessing, the heteroatom-containing compounds are extracted for their chemical values, the economics are dramatically improved. Not only do the chemicals improve the revenue stream but the remaining oil, representing the majority of the barrel, is now readily upgraded to a premium petroleum substitute. (Ref. 28).

In the value-enhancement approach, heteroatom-containing compounds are extracted and refined to marketable chemicals. A schematic of the approach is shown in ***Figure 18.***

Figure 18. Value Enhancement

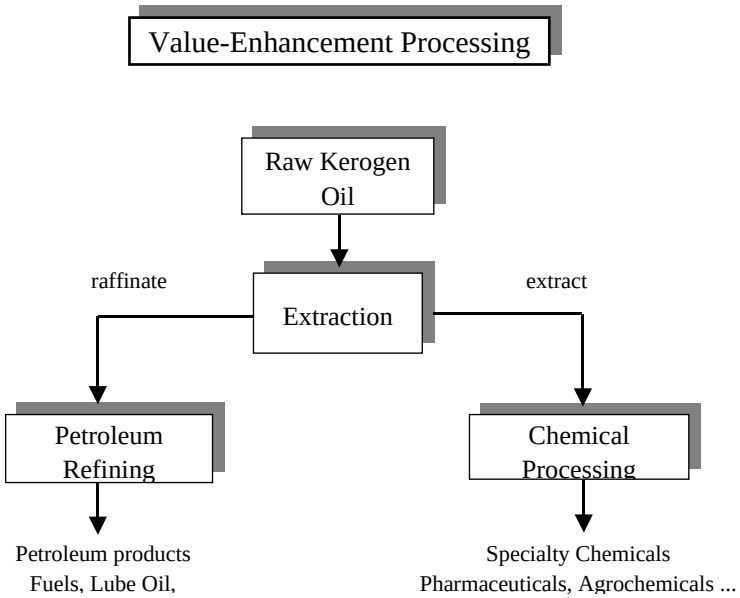


Table 2. Composition and Properties of Selected U.S. Shale Oils (Cameron Engineers, 1975, Shell 2003)

	Gas Combustion Retorting Process	Tosco Retorting Process	Union Oil Retorting Process	Shell ICP Process
Gravity, API	19.8	21.2	18.6	38
Pour Point, °F	83.5	80	80	
Nitrogen (Dohrmann), wt. %	2.14 ±0.15	1.9	2(KJELDAHL)	1
Sulfur (X-ray F), wt. %	0.6999 ±0.025	0.9	0.9 (P BOMB)	0.5
Oxygen (neutron act.), wt. %	1.6	0.8	0.9	0.5
Carbon, wt. %	83.92	85.1	84.	85
Hydrogen, wt. %	11.36	11.6	12.0	13
Conradson carbon, wt.%	4.71	4.6	4.6	0.2
Bromine No.	33.2	49.5	Not available	
SBA wax, wt. %	8.1	Not available	6.9 (MEK)	
Viscosity, SSU.:				
100° F	270	106	210	
212° F	476	39	47	
Sediment, wt. %	0.042	Not available	0.043	
Ni, p.p.m	6.4	6	4	1
V,p.p.m.	6.0	3	1.5	1
Fe, p.p.m.	108.0	100	55	9
Flash (O.C.)°F	240		192 (COC)	
Molecular weight	328		306 (Calculated)	
Distillation				TBP/GC
450° at Vol. %	11.1	23	5	45
650° at Vol. %	36.1	44	30	84
5 Vol% at °F	378	200	390	226
10	438	275	465	271
20	529	410	565	329
30	607	500	640	385
40	678	620	710	428
50	743	700	775	471
60	805	775	830	516
70	865	850	980	570
80	935	920		624
90	1030			696
95	1099			756

Kerogen oil may be high in nitrogen, as from Green River Formation oil shale (U.S.A.), or high in oxygen, as from the Kukersite oil shale (Estonia). The mole-percent of heteroatom-containing compounds in these liquids is usually higher than 30 percent and may exceed 50 percent. Nitrogen compounds (primarily pyridines) that are valuable for manufacturing chemicals are selectively extracted from the kerogen oil. The extract would be refined to produce pure compounds and concentrates with special properties. These chemicals and concentrates may be used to manufacture agrochemicals, detergents/ surfactants, anti-bacterials, polymers for tire cords, photovoltaic receptors for solar panels, anti-strip asphalt additives, solvents, and other industrial and consumer products. These products, with values ranging from $60 to $600/Bbl, could serve domestic and export markets (Ref. 28.)

2.2.7 Upgrading of Oil for Refinery Feedstock

One of the most significant characteristics of Green River kerogen oil is its high hydrogen content, which is due to the high concentrations of paraffins (waxes). Waxes give value

Table 3. Properties and Composition of Hydrotreated Refinery Feedstock (Ref. 7, 26, 28)

Properties	Unocal hydrocracked	JWBA raffinate	Hydrotreated ICP Oil
Gravity, degrees API	40	36.8	49
Specific gravity 15/15	.825	0.841	0.784
Sulfur, ppm	5	200	50
Nitrogen, ppm	20	1200	<1
UOP K Factor		12.0	
Pour Point °C	< -4	4	NA
Viscosity at 37 °C cSt		3.3	
Distillation yields, weight percent	Estimated from Reeg (33)		
<200 °C	24	29.8	32
200-275 °C	23	16.2	38
275-325 °C	17	12.3	20
325-400 °C	22	23.2	9
400-538 °C	14	18.5	1
Composition, weight percent	NA-Not available		
n-paraffins		34.8	41
i-paraffins		35.7	19
naphthenes		14.7	29
aromatics		12.1	11
olefins		2.7	

to the oil for use as diesel and jet fuels and result in high yields of valuable products in fluid catalytic cracking units when manufacturing gasoline.

Specifications for various refinery feedstocks are given in ***Table 3***. In conventional processing, Unocal catalytically hydrocracked raw kerogen oil. The process was both severe and costly, but resulted in a premium refinery feedstock. In the value-enhancement process, the raffinate, which has had its most problematic nitrogen removed, is hydrotreated under mild (~300°C), and low-cost conditions. This yields a refinery feedstock nearly as good as the Unocal feedstock. A comparison with the ICP oil shows the premium quality of this in-situ oil, which is almost entirely atmospheric distillate. Each of these oils would have a higher value than the market price of crude (NYMEX-West Texas intermediate). In general, oil from Green River oil shale is high in hydrogen and exhibits excellent properties for manufacturing aviation turbine fuel and diesel fuel. These products also produce less carbon dioxide per unit of energy.

2.3 Conclusions about Oil Shale Technology, Potential, and Timing

The current state of shale oil production, mining, retorting, and upgrading technologies are sufficiently advanced to support the implementation of a new generation of oil shale projects by 2011 along with the development and commercialization of a domestic oil shale industry of 2 MM Bbl/day by 2020.

- Existing open-pit, and room and pillar mining techniques have been commercially proven in the mineral process industries and are adaptable to mining oil shale. Additional techniques will likely be required for deeper resources.

- At least five alternative conventional surface retorting processes and approaches are also available, and have been tested in the United States using U.S. western oil shales, but not at commercial scale.
- Although no commercial-scale retort has been demonstrated in the United States, worldwide experience with commercial-scale technologies has been met with success in Estonia, Brazil and China using modified versions of 1970s-era retort technology.
- The Alberta Taciuk Process may represent the current state-of-the-art for surface retorting operations. The design benefits of the ATP process are its one-step, thermodynamically efficient, direct-heating features. The success of ATP in Australia, suggests that it may be successful in the United States with significant reductions in cost over earlier technologies. However, ATP has not yet been demonstrated in the United States, or using U.S. western shales.
- In-situ processes requiring minimal mining and restoration can be significantly less costly than conventional oil shale processes in several known deposits where it is applicable. A variation of the "pure in-situ" approach, embodied in Shell's In-Situ Conversion Process, may represent the most effective in-situ process to date. This process has the potential to access much deeper oil shales, opening resources that were previously deemed inaccessible.
- Chemical processes have high potential for extracting high-value by-products that improve the economics of the overall process. Small-scale value enhancement projects may be initiated more quickly than larger scale conventional or in-situ projects, due to improved economics, once the technology is proven. The potential of this approach is limited, however, by the size of the market for nitrogen-based chemicals.
- Determining the best technology application for any oil shale project depends on the location, the setting, and the composition of the target oil shale deposit(s) and requires individual design considerations to maximize its economics.
- Other novel processes for chemical and/or thermal extraction of kerogen from shale may yet be proved, but are open to additional industry research opportunity.
- Environmental control technologies developed for other mining, petrochemical industries, and electric power generation appear to be applicable for controlling impacts of scaled up oil shale development.

As discussed later in this volume, the experience of the tar sand development in Alberta, Canada may prove to be a direct analog by which the U.S. government can assess the potential, pace of development, and issues associated with commercialization of the U.S. oil shale resource.

The scope and immediacy of potential public actions to remove development constraints and to encourage private investment will likely be a greater determinant of the pace and timing of oil shale industry development than will be the readiness of the technology.

3.0 Environmental and Regulatory Issues

Production of U.S. western oil shales will be focused in a relatively concentrated land area in parts of the states of Colorado, Utah, and Wyoming. As described in the Resource Characterization section of this report, the nation's richest oil shale deposits are located in the Uinta Basin and Piceance Creek Basin. Developing and operating industry-scale oil shale mining, production, and processing facilities could unfavorably impact the environment and some current uses.

This region is largely rural and semi-arid. These areas are remote from major population centers, but do contain small towns and cities that make their livelihoods primarily from economic activity focused on oil and gas production, mineral processing and agriculture. Other current uses include ranching, outdoor recreation, and vacation and retirement homes. With the possible exception of natural gas and nahcolite leases discussed elsewhere, no major conflicts with other developments are expected. Oil shale development, therefore, could be viewed as consistent with historic economies and as a technological extension of current activities.

The identified resource sites are proximate to current oil and gas production where roads and utilities are partially developed. Products could be pipelined through current installations where declining petroleum production is providing spare capacity, or through new pipelines that could parallel established pipeline corridors if new lines are required.

The potential environmental impacts of oil shale development pertain to air and water quality, land use and reclamation, socioeconomic, resource allocation and other considerations. Stringent discharge standards will mandate maximum recycle of process water, providing the added benefit of low water consumption.

Standards are now established in State and Federal laws and regulations, unlike 25 years ago, when regulations and permitting processes protecting the environment and controlling development were in their infancy. It should be noted, however, that the Department of the Interior conducted a comprehensive Programmatic Environmental Impact Statement for the Prototype Oil Shale Leasing Program that was determined to be exhaustive and objective by virtually all of the hundreds of State, Local, and Federal government entities, NGOs, and other stakeholder organizations that participated in the planning and permitting process. This body of technical, environmental, and socio-economic data provides a valuable baseline resource that can be updated for future decision-and should be used whenever possible.

Technology advances now enable industrial projects to control and limit emissions and discharges and other impacts to predetermined levels that would be established in the permitting process. The integration of advanced technologies could be used to control and mitigate environmental impacts and if analogous natural resource developments are a guide, could achieve these objectives at reasonable costs.

3.1 Oil Shale Processes that Impact the Environment

There are two basic retorting approaches. Conventional surface retorts involve mining the oil shale by surface or underground mining methods described above, moving the mined shale ore to a retort facility, retorting and recovering shale oil and other gases, and cooling and disposing of the “spent” shale material.

In-situ retorts involve introducing heat to the kerogen while it is still embedded in its natural geological setting beneath the earth’s surface. Pure in-situ processes drill access shafts to reach the shale layer(s), apply process heat to the shale by heaters or direct combustion, and move the resulting shale oil and gases to the surface through conventional oil and gas wells. Modified in-situ processes create a much larger shaft to transport personnel and equipment to the shale formation, fracture and rubblize a portion of the shale resource, and ignite the rubblized shale to generate heat for pyrolysis.

Under most conventional and in-situ processes, the kerogen oil produced must be refined or upgraded to stabilize it and render it suitable for transportation and use as feedstock in conventional petroleum refineries or chemical plants. These processes are de-

scribed in greater detail in the technology assessment sections of this report and the oil shale technology appendix.

The broad range of potential environmental impacts and the issues they raise relative to the feasibility of commercializing specific processes and a domestic oil shale industry are discussed below.

3.2 Impacts and Issues

3.2.1 Oil Shale Mining Impacts

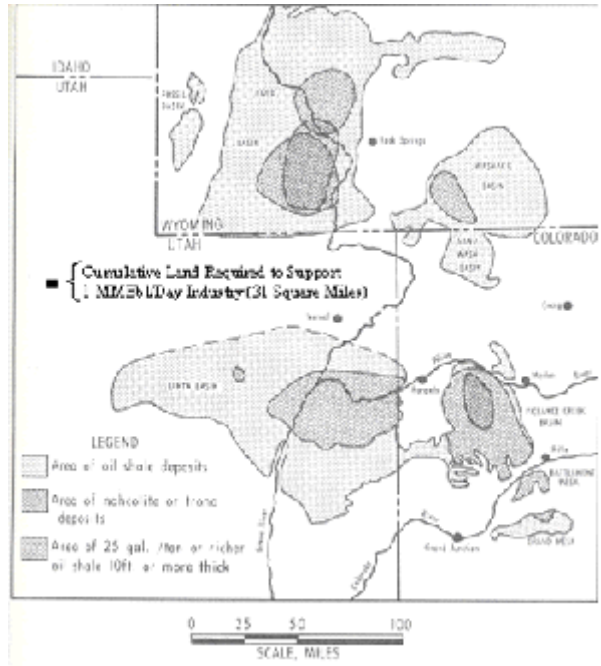
Because oil shale deposits may be near-surface or deeper, and in thin or thick beds, a matrix of recovery techniques will be required to access the resource base. The deeper and thicker beds may be more accessible through in-situ recovery (see below), whereas the near-surface and outcropping beds are more amenable to mining and surface processing.

A 2 million bbl/day surface retorting oil shale industry would require 1 billion tons of raw shale ore material per year. Based on U.S. Department of Interior estimates, the cumulative surface area impacted by a domestic oil shale industry implemented in the most optimal settings, over its lifetime of 40 years, would be about 31 square miles per million barrels of daily shale oil production capacity. By this unit of measure, a 2 million Bbl/D oil shale industry would impact 62 square miles over its lifetime. As shown in ***Figure 19***, this represents only a fraction of one percent of the total land area of the oil shale region.

Typical production from near-surface deposits could conservatively yield about 100,000 bbls/acre, a very large production for a relatively small area of disturbance. Under some scenarios, the yield could be as high as 300,000 bbls/acre. This also means that the cost of reclamation will be small in relationship to the extracted value of oil.

Open-pit mining involves significant surface disturbance and can impact surface water run-off patterns, subsurface water quality, fugitive

Figure 19. Surface Area Impact of 1 MMBbl/D Industry



dust controls, and flora and fauna. Extensive past experience with open pit mining of coal and oil shale in this region has demonstrated that the impacts can be minimized and that the land can be beneficially restored following mineral extraction. Among the various recovery approaches, open pit mining is likely to result in the highest recovery of resource.

Underground mining involves much less surface disturbance, but does entail subsurface activity and involves tailings disposal. While various underground mining processes may be used, depending on subsurface geologic and mineral conditions, room and pillar mining will likely prevail.

Environmental issues will include protection of aquifers, and the controlling and disposing of mine water. Surface impacts can be limited, but will include run-off and fugitive dust emissions from surface-level shale storage. The use of heavy equipment for open-pit or underground mining potentially could degrade local ambient air quality.

3.2.2 Retorting and Processing Impacts

Air Quality: Most U.S. western oil shale source rock is a carbonate-based kerogen-bearing marlstone. Retorting involves heating the source rock, embedded with kerogen, to temperatures between 450 and 550 degrees centigrade. Heating carbonate rock to these temperatures generates not only kerogen oil, but also a slate of gases, some of which can be beneficially captured and re-used in plant operations or sold for conventional energy use.

The off-gases and stack gases of oil shale processes contain principally: oxides of sulfur and nitrogen, carbon dioxide, particulate matter, water vapor and hydrocarbons. Also a potential exists for the release of other hazardous trace materials to the atmosphere, such as polynuclear aromatic organic matter – a complex array of condensed, aromatic organic compounds, and trace metals. (Ref. 29) Commercially available stack gas cleanup technology could be used to limit emissions to within permitted quantities.

Gases such as CO_2, are generated in large quantities and may need to be captured and processed, or sequestered. The design requirements will need to be responsive to the prevailing regulatory environment. With significant oil production in close proximity to the oil shale regions of Utah, Colorado, and Wyoming, potential beneficial use for significant quantities of CO_2 for improved oil recovery may exist. Opportunities may also exist to sequester CO_2 from oil shale operations in depleted oil and gas reservoirs. NOx and SO_2 can most likely be controlled using commercially proven technologies developed for petroleum refining and coal-fired power generation.

Prospective oil shale developers will need to deploy best available control technologies to reduce potential air emissions which otherwise could result from construction and operation of surface facilities. Furthermore, because of the existence of federally-designated sensitive lands – such as wilderness areas, national parks, national monuments and national forests that are located throughout the Rocky Mountain West, oil shale development may be more stringently regulated, depending on the site-specific locations and technologies proposed. These constraints could tend to limit the size of the industry in any one area and will affect the industry's rate of development.

Water Quality: Controls are required to protect surface and ground waters from contamination by runoff from mining and retorting operations, from treatment facilities for products, other waste waters, and, particularly from retorted shale waste piles with respect to heavy metals in the leachate (Ref. 29). The controls that could be used and the costs of those controls need to be assessed.

Safe drinking water regulations could impact oil shale *in-situ* processes if it is found that reinjected water or contaminants from underground burning enters an aquifer, resulting in downstream contamination. New technologies being developed in association with the new In-Situ Conversion Process would avoid issues of runoff and show promise to protect underground aquifers (See 3.2.4 below).

3.2.3 Spent Shale Disposal

Surface retorts generate significant quantities of spent shale. Many major retort processes of the 1980s era were constrained by inefficiencies that restricted the ability to convert all of the kerogen to oil and gases. As a result, significant coke was deposited on the spent shale, making solid waste from these earlier designs unsuitable for direct landfilling. Numerous technology advances have improved the efficiency, reducing residual carbon content. Satisfactory disposal and reclamation has been achieved with the later generation technologies.

Use of spent shale in cement manufacture has been practiced in Estonia and Germany and

demonstrated in the U.S. Other uses in road beds or construction materials also offer potential for reducing or eliminating costs for disposal.

Processing shales in surface facilities causes spent shale to increase in volume by as much as thirty percent, primarily because of the void space created by crushing and size reduction. As such, the disposal area needed for the spent shale exceeds the original capacity of the geological formations from which it is extracted, whether from deep underground mines or open pit surface mines. The U.S. Department of the Interior conducted extensive analysis of this phenomenon and the options for disposing of the increased volumes of shale in its 1973 *Final Environmental Statement for the Prototype Oil Shale Leasing Program (Ref. 2).*

3.2.4 In-Situ Recovery Impacts

In-situ recovery technologies are one of two approaches, modified or true in-situ. Modified in-situ first creates a void space, either through mining and blasting, or direct blasting, as in the Geokinetics approach, followed by ignition of a direct combustion retort in the rubblized shale. True in-situ recovers oil *without* first disturbing the beds to create void spaces. As such, the issues associated with surface mining, deep mining, and spent shale disposal discussed above relative to surface retorts do not apply to true in-situ processes. However, other subsurface impacts, including ground water contamination, are possible and must be controlled.

A true in-situ process, such as Shell's current research, has the potential to dramatically reduce the surface footprint, waste disposal problems, runoff and other problems associated with mining, spent shale disposal and surface reclamation. Since the vertical wells of a true in-situ process are able to access very thick sections of oil shale, the surface disturbance for a given production rate may be smaller by a factor of as much as 10. There are locations of thick resources that could yield in excess of 1 million barrels per acre and require, with minimal surface disturbance, fewer than 23 square miles to produce 15 billion barrels of oil over a 40 year project lifetime.

In addition, since the hydrocarbon products are expected to be much higher API gravity than those produced by surface retorting technologies, further upgrading will be less costly. Upgrading could be done on-site, at local area refineries, or more distant refineries accessible by pipeline.

In conjunction with its development of ICP, Shell has developed an environmental barrier system called a freeze wall to isolate the in-situ process from local groundwater. The freeze wall is created by freezing ground water occurring in natural fractures in the rock into a ring wall surrounding the area to be pyrolyzed. This barrier protects the groundwater from contamination with products liberated from the kerogen while at the same time keeping water out of the area being heated.

Once pyrolysis is completed, the remaining rock within the freeze wall is flushed with water and steam to remove any remaining hydrocarbons and to recover heat from the spent reservoir. Heat from the steam can be used to generate additional electric power. Once the area has been sufficiently cleaned, the freeze wall can be allowed to melt and groundwater can flow through this area once more.

3.2.5 Water Availability Issues

Fundamentally, water rights are real property that can be bought and sold. The older or more senior rights generally have greater value. Most of the early water rights were filed for agricultural irrigation or domestic use. Understanding western water law is complex and difficult for those unfamiliar with each State's system and the historical interstate compacts that now dictate how the States cooperate.

As private individuals and corporations recognized the value of oil shale in the western

states and began staking mining claims in the early 1900s, water was not perceived to be much of an issue. However, during the 1950s and 1960s, as interest in oil shale increased and larger plants were being planned, the companies and government agencies recognized the need for secure water supplies for the plants and associated communities.

Participating companies aggressively filed for water rights on the major streams and began planning water storage reservoirs to hold water. Some companies also began purchasing senior water rights from ranchers. Interest in groundwater increased, and some water wells were drilled to secure subsurface water rights. Most companies with private oil shale holdings have, at a minimum, now secured conditional water rights and have plans in place to develop and store sufficient water for their future operations. Nearby communities, in most cases, have water supplies to support some growth but will likely look to the companies to augment those supplies as part of the project approval process to minimize socioeconomic impact.

The real issue then becomes whether adequate water is available if the federal government, which controls over 80 percent of the western oil shale lands, begins to lease large blocks for additional shale oil plants. It is unlikely the government can provide any water rights with an oil shale lease. The lessee will need to file for new junior water rights or purchase or lease existing water rights from others. This can be done, and in some cases there are water storage projects that still have excess water for sale.

During the 1970s and 1980s, the heightened interest in western oil shale drew much attention to this water issue. There were numerous studies completed and the federal government took a hard look at water supplies to support the leases offered under the prototype oil shale leasing program and those that might follow. At the time it was determined that water was available to support a sizeable industry in the region. However, water may still be a constraining factor. Water requirements for the infrastructure and socioeconomic demands, could place a burden on the neighboring communities, which would see tremendous growth as a result of a new oil shale industry in the region.

Many of the historical planning documents and previous studies are still valid and should be reviewed in any new oil shale development scenario. Part of that review will need to reexamine the entire water needs and availability issue.

3.3 Human Health and Safety Impacts and Issues

The hazards and risks to human health and worker safety associated with oil shale production are similar to those that exist and are controlled in other mining, oil production, chemical processing, and refining industries.

Since oil shale was first seriously considered in the United States in the 1970s, most of these environments have been characterized in terms of required industrial hygiene and safety analyses. Still, it is possible that workers may be subjected to exposure to toxic materials for which proven health protective measures do not yet exist. Modern industrial hygiene practices will need to be employed to prevent workers from direct exposure to oils and vapors.

3.4 Permitting Issues

Oil shale plants will be required to obtain dozens of permits and approvals, involving all levels of government. The number of permits required for oil shale development can range upward of 75. In 1977, an oil shale developer reported that it took two and a half years just to identify all of the requirements and that others may yet surface. Today, however, environmental laws have matured and may permitting processes have been streamlined.

The regulatory environment is now capable of addressing all of the significant issues, including, but not limited to endangered species, air emissions, water discharges, fugitive dust, noise, odor, occupational health and safety, hazard communications, land reclamation, scenic vistas, water use, socioeconomic and others.

Without attempting to describe the procedures or substance, the following laws and regulations and permitting requirements will likely apply to oil shale projects:

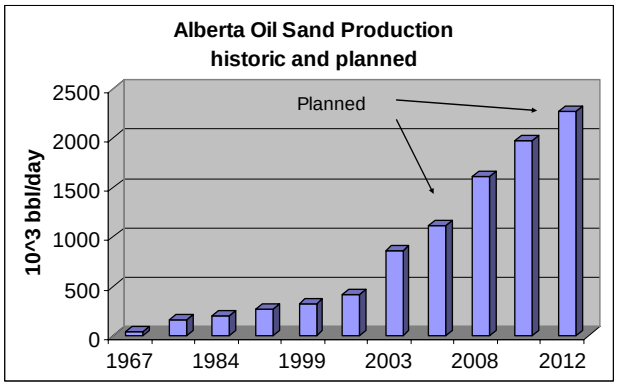
- Mineral Leasing Act of 1920
- National Environmental Policy Act
- Clean Air Act and Amendments (including: Prevention of Significant Degradation of Air Quality Permit.; Non-Attainment Permit; New Source Performance Standards (requires best available technology); and Visibility Impairment limits.
- Clean Water Act
- Safe Drinking Water Act
- Toxic Substances Control Act
- Resource Conservation and Recovery Act & Amendments
- Occupational Safety and Health Act (OSHA) if mining process; MSHA may supercede.
- Endangered Species Act of 1973
- Antiquities Act of 1906
- Federal Mine Safety and Health Act (if resource to be mined MSHA)
- National Historic Preservation Act of 1966
- Forest Rangeland Renewable Resources Act
- Federal Land Policy and Management Act of 1976
- National Pipeline Safety Act
- Emergency Planning and Community Right to Know Act
- The Pollution Prevention Act
- State and Local Permits

Permitting delays can delay entire projects, and programs, impacting achievement of public policy goals and targeted production levels. Through a cooperative effort, the concerned federal and state agencies can greatly reduce the number and complexity of the required applications. This can then significantly reduce the permitting barrier.

4.0 Analogy to Alberta's Tar Sand Commercialization

The commercially successful production of oil from Alberta tar sand serves as a model for the potential development of US oil shale. Many parallels exist between the respective resources, technology, markets and economics.

Figure 20 - Alberta Oil Sand Production



Oil was first produced at a commercial scale from Alberta tar sand more than 35 years ago. Today, tar sand production is nearly 1 million bbls/day, including both mining-based and thermal production. With planned and approved expansions output is expected to exceed 2 million bbls/day within the next 8 years (***Figure 20***).

Recent incentives, including forgiveness of tar sand royalties until project payback is

achieved, have stimulated more than $65 billion in private investments to accelerate development and achieve industry-scale operations during this decade (Ref. 30). Ultimate production may reach 10 million bbls/day. Operating costs are reported to have been brought down to $8.50/bbl (Ref. 31). As such, these operations may now be as profitable and as investment-worthy as conventional petroleum production.

According to Suncor's Rick George, "A large part of the rest of this industry is chasing the world for reserves…We have reserves…We have no exploration risk and also have no decline curve, so we have a completely different business model from the conventional crude oil producer" (Ref 56).

As the Alberta tar sand industry has matured, technology performance and product quality have improved, higher efficiencies have been achieved, and the per-barrel energy and operating costs have steadily declined. First Law Efficiency has improved from an initial 70 percent to its present day value of about 82 percent. While this is lower than the efficiency for conventional petroleum, at about 93 percent, the lower efficiency is offset by assured production (no production decline) and uniform, high quality product. As discussed below, efficiencies similar to tar sand can be expected for oil shale.

The advances resulting from phased-commercialization of tar sand technology in Canada provide a defensible analog for effective and economic oil shale development in the United States. An assessment of major economic and technical criteria shows that U.S. oil shale compares quite favorably in most evaluation criteria. These are summarized in ***Table 4*** and discussed below.

Like Canada's tar sand, America's oil shale is rich, accessible, geographically concentrated, and well-defined. The magnitude of both resources warrant long-term development initiatives. This preliminary comparison suggests that U.S. oil shale could generate productivity and profitability similar to Alberta tar sand. This analog includes five major areas of direct comparability:

- Resource characteristics
- Technology performance and product quality
- Environmental impact and controls
- Mass balances and energy requirements
- Production economics

A 100,000 Bbl/D sweet refinery feedstock facility is taken as the base case. Round numbers are used, as the precision of the data does not warrant a higher number of significant figures. All units are expressed as U.S. gallons, barrels and short tons (2,000 lbs.) unless specified. All energy calculations are expressed in Btu/bbl and are based on the final product yield. All economics are presented in U.S. dollars. One U.S. dollar equals CAN 1.43 dollars.

Table 4. Comparison of Principal Factors Influencing the Economics of Unconventional Crude Oil Production

Characteristic	Athabasca Tar Sand	Green River Oil Shale
Resources	More than 1 trillion bbl	More than 1 trillion bbl
Grade (Richness)	25 gallon bitumen/ton	25 gallon kerogen oil/ton
Hydrogen Content (bitumen | raw oil)	10.5 Wt%	11.8 Wt%
N and S requiring removal	6.2 Wt% (mostly S)	4.0 Wt% (mostly N)
Loss of liquids to Coke and Gas	40 lb/ton-ore	11.6 lb/ton-ore
Net yield of oil	0.53 bbl/ton processed	0.60 bbl/ton processed
Quality of oil	34°API	38°API

4.1 Resource Characteristics

Alberta - The average bitumen content of Athabasca tar sand is about 10 weight percent. For a bitumen specific gravity of 1.0, this equates to about 25 gallons/ton. For purposes of this analogy 100 percent recovery of bitumen is assumed. (The Alberta Energy and Utilities Board (EUB) has set a target of 95 percent recovery). (Ref. 32).

United States - For a first-generation oil shale facility an average retort yield of 30 gallons/ton can be achieved. This assumption is supported by the previous discussion on resource characterization (section 1). In fact, Unocal reported averaging 38 gallon/ton, at least in the early stages (Ref. 33), and are believed to have averaged about 34 gallon/ton over the life of the project.

4.2 Technology Performance

A comparison between the established technology used for the Alberta tar sand project and an analogous mining, surface retort and upgrading operation for oil shale show that oil shale retorting serves the same purpose as extraction and coking of tar sand bitumen (***Figure 21***.)

4.2.1 Mining and Ore Preparation

Alberta – The ratio of overburden to pay is estimated to be about 1:1. Cost of overburden removal is $1.00/bbl and for ore mining, $1.25/bbl. (Ref. 34). Shovels and trucks are used as the main equipment. The energy cost of mining (overburden and pay) is estimated to be about 550,000 BTU/bbl (Ref. 35). By using reported costs for recent expansions as a guide, an estimate of $7,210/ daily barrel of-syncrude capacity can be made. This translates to $1,725/daily-tonne-capacity when 1:1 overburden and overall yields are taken into account.

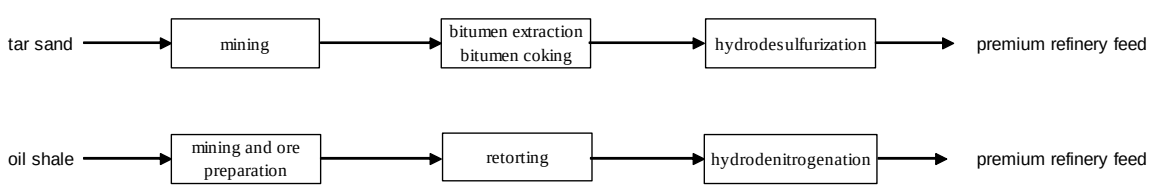
United States – Surface mining will be conducted by shovel and truck operation as in Canada. Surface mines would use equipment about the same size as used in Alberta and per ton costs are expected to be similar, or $1,600/daily-ton-capacity (note different weight units from above). A more benevolent climate in the United States should result in some advantages to mining costs. Ore preparation capital costs will add an estimated $275/ daily-ton-capacity.

Underground room and pillar mining, with horizontal access, will utilize mechanical miners and trucks. With any mining technology maximum economy of scale is approached at the point of one full-sized set of equipment. A minimum headspace of about 25 feet is required for maximum efficiency. For room and pillar mining we assume miners and trucks are 0.5 the size of the Alberta case. A scaling factor of 0.8, typical of mining and materials handling equipment, suggests equipment costs of $1,850/daily-ton capacity. Add to this $275/daily-ton-oreprep equipment.

4.2.2 Extraction, Coking and Retorting Technology

Alberta – The Alberta technology involves removing oversized material, and contacting the ore with warm water with caustic added. The bitumen is disengaged from the minerals, and the mixture is sent to a series of settlers and froth flotation devices that recover the bitumen overhead and the minerals as under-

Figure 21- Analogous steps in production for tar sand and oil shale



flow. The bitumen is dried and cleaned of remaining solids by first diluting with naphtha and passing the lower viscosity solution through fines and water removal units; inclined plate settlers, cyclones, centrifuges, etc. There is effectively no loss of bitumen in this stage.

The energy costs are estimated to be about 140,000 BTU/Bbl (12 percent of 1.2 MM BTU for the entire process (Ref. 36). The original capital costs were 15 percent of the total plant costs, implying $3,500/daily-barrel-bitumen capacity for bitumen extraction, froth treatment and diluent recovery.

The clean bitumen is either coked directly, sent to hydrocrackers or first distilled by vacuum distillation. If the latter process is used, the overhead is sent directly to the hydrodesulfurization units and the bottoms are sent to coking or hydrocracking. If the bitumen is coked directly the mass yield distribution is approximately 5 percent gas, 79 percent liquids (29 API) and 16 percent coke. Energy costs for the coker are estimated at 210,000 BTU/Bbl (estimated from Ref. 40). Capital costs are estimated at $5000/daily-bbl-capacity.

United States – For surface retorting, ore is sized and fed to a retort where kerogen is converted to raw kerogen oil in yields of 30 gallon/ton (the base case).

If the Alberta Taciuk Processor (ATP) technology is used, all of the retort energy used is generated in the combustor by burning the coked ore. Dryer heat requirements are fully satisfied by the fuel obtained from the retort gases (Ref. 52).

Electrical requirements to drive the rotating kiln (Stage 2 scale) are estimated at 12 -15 kW-hr/tonne. Capital costs for the ATP, exclusive of ore preparation and product upgrading, are about $7,500 to 10,000/daily-barrel-capacity for 30 gal/ton ore (Refs. 37, 52).

4.2.3 UPGRADING TECHNOLOGY

Alberta –All coker or distillate product is ultimately hydrotreated to remove sulfur and to partially hydrogenate aromatics. The end result is an 80 percent volumetric yield of sweet synthetic blend, based on bitumen feed (Ref. 38). Energy costs for coker distillate upgrading are estimated at 100,000 BTU/bbl (HDS only). (Ref. 39). Additional energy costs for distillation and sulfur processing are estimated at about 100,000 BTU/bbl. Capital costs for the hydrotreater, hydrogen plant, distillation units and sulfur plant are estimated at $7780/daily-bbl-capacity (Ref. 40).

United States – For oil shale, the analogous step to coking is completed in the retort and so the upgrading of raw kerogen oil is comparable to upgrading of coker distillate. There are two potential approaches to upgrading raw kerogen oil. In the first upgrading approach, applicable at a small scale, kerogen oil is extracted and separated into a polar concentrate and a non-polar raffinate. The polar concentrate is converted and refined into chemicals, while the raffinate is hydrotreated directly to a 38° API sweet refinery feed. Total product yield on a feed barrel, by weight, is 84 percent sweet refinery feed, 10.5 percent specialty and commodity chemicals and 14 percent chemical grade CO_2. (Totals exceed 100 percent because of water input in steam reforming).

In the second upgrading approach, raw kerogen oil is hydrocracked to remove nitrogen heteroatoms in a process similar to Unocal's upgrader. Unlike coking of Athabasca bitumen, there is effectively no loss to coke with kerogen oil processing. The volumetric yield loss is negligible because hydrogen addition reduces the density, offsetting the loss to heteroatom removal. Upgrading of raw kerogen oil yields 30.6 bbls/ton of ore retorted based on a 93 percent weight recovery and a gravity improvement from 21° API to 38° API. Energy costs for hydrocracking are estimated at

120,000 Btu/bbl. Capital costs are estimated at $3000/daily-bbl-capacity (Ref. 40).

4.2.4 Product Quality

Athabasca Tar Sand – Synthetic crude oil from tar sand exhibits an API gravity of 34°. The syncrude has no bottoms, but like any pyrolysis product, it has high proportions of vacuum gas oil. This difference in yield profile and certain quality issues place limits on how much synthetic crude oil can be blended with petroleum in a typical refinery (ref 51). Because of transportation costs and quality differentials, Suncor values its product at West Texas Intermediate (WTI) – $2.75 (Ref. 41).

United States Green River Shale – For comparison, U.S. syncrude will be 38° API or higher (see also Table 3 in Section 2). Between the higher hydrogen content of the product and closer proximity to markets, a market value at a premium to West Texas Intermediate (WTI) grade conventional crude oil can be justified. Anecdotal evidence indicates that Unocal product was valued at a premium to WTI.

Military JP-4 jet fuel derived from the Unocal refinery feedstock exhibits a freeze point of -76° F compared to -72° F, normally a tough standard to meet with conventional crude oil (Ref. 42). As with Athabasca synthetic crude oil, both products convert in high yields to liquid transportation fuels.

4.2.5 Technology Summary

In summary, all of the processes used in Alberta today are proven at a large, commercial scale. Total energy costs are approximately 1.1 million Btu/bbl-syncrude for an overall thermal efficiency of about 82%. Every effort should be made to achieve this efficiency level, or higher, with U.S. oil shale.

In the United States, mining technology will be adapted from other rock mining experience. The Unocal mine showed that room and pillar mining could be conducted efficiently. Upgrading of raw oil products to premium refinery feedstocks will utilize conventional technology. The Unocal experience proved this technology could produce a highly marketable product. Thus, there is low technical risk in the mining and oil upgrading portions. The immature technology for the U.S. case is the retort. The experiences around the world should be closely analyzed to determine which is the most efficient and operable. High operability, i.e., a high on-stream factor, is critically important to meeting production targets.

4.3 Environmental Impacts and Controls

The primary environmental issue with Athabasca tar sand processing is the tailings ponds. Other issues relate to mine reclamation and sulfur generation. The emissions and discharges are being controlled to regulatory standards with proven technologies.

By comparison, U.S. oil shale is dry and may not require tailings ponds. Reclamation costs for oil shale will be about the same whether for open pit mining or underground mining. The Unocal operation proved this can be managed to environmental standards. For in-situ recovery, neither tailings nor reclamation issues are significant.

The U.S. shale oil contains about 0.5-0.75 percent sulfur, compared to more than 5 percent for Athabasca bitumen. Sulfur disposal or sale will be a much smaller problem in the United States than in Canada.

The shale oil contains higher amounts of nitrogen, which if not extracted for its chemical value is converted to ammonia and can be recovered and sold as a byproduct. (Ammonia is worth about $0.30-0.40/lb). Hydrotreating produces about 6 lb of ammonia per barrel of oil.)

Production of CO_2 will be higher for oil shale than for conventional petroleum and must be addressed in the design and permitting phases.

Table 5. Mass Balance Comparison (Daily Metrics)

	Over-bur-den/barren Tons	Ore Tons	Extraction Input Tons	Extraction Output Bbl-Bitumen	Retorting Input Tons	Retorting Output Bbl-Raw Crude	Up-grading	*Loss-Swell	Sweet Re-finery Feed
Athabasca Oil Sand	210,000	210,000	210,000	125,000			125,000	25,000	100,000
U.S. Oil Shale	24,173	136,978			136,978	97,841		(2,159)	100,000

*Loss is to coke, gas and N, S, removal; Swell is due to cracking and hydrogenation effects.

4.4 Mass Balances for Oil Shale and Tar Sand Production by Mining and Surface Processing

Initial analysis by Bunger and Associates, Inc. (Ref. 43) shows a dramatic difference between mass balances of the oil shale process in comparison to tar sand (***Table 5***).

For an equivalent output of sweet refinery feedstock, U.S. oil shale could require less than 50 percent of the mine capacity required for tar sand. The retort is more than 30 percent smaller than the bitumen extraction unit (although the retort is also more expensive).

These differences result from two key characteristics:

- The Green River kerogen ore is inherently richer and the mine approach (room and pillar) recovers this rich ore with little need to mine barren or low grade material.
- With oil shale, the yield of oil is measured after the retort, after primary coke and gas losses have already been deducted. In the Alberta case, loss of liquid yield to coke and gas in the coker are significant. This is shown in the column -'loss' minus 'swell'. There is a net volumetric gain for shale oil during upgrading, not unlike what transpires in a conventional petroleum refinery.

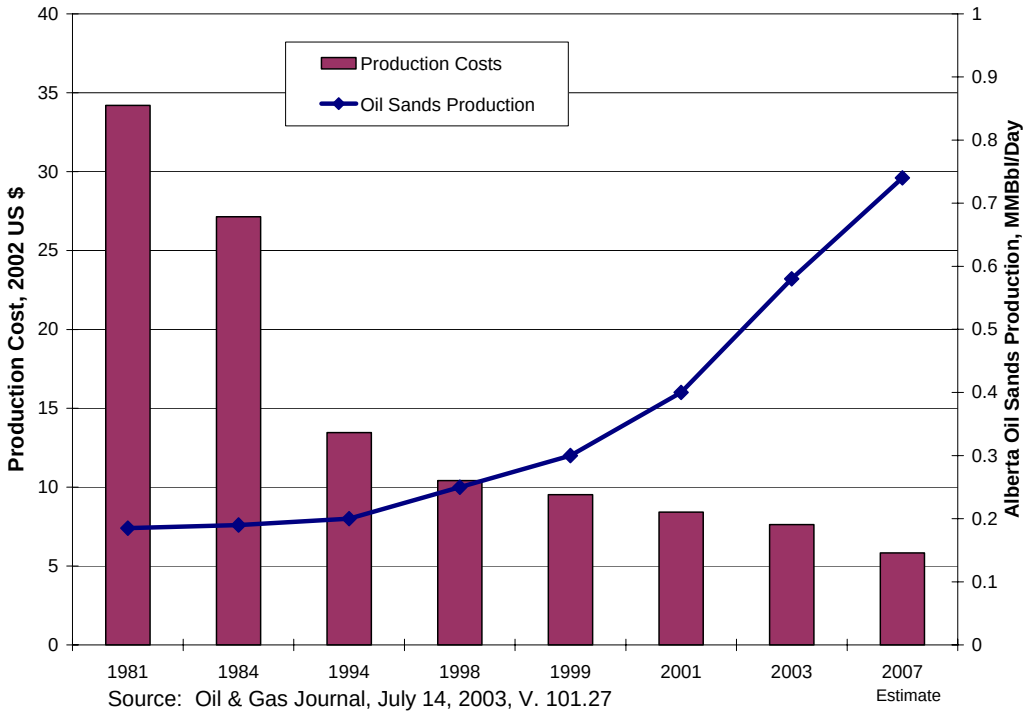
4.5 Production Goals and Economics

Production output of Alberta's tar sand deposits have been increasing and the costs of production have been decreasing over the past two decades (***Figure 22***). The trend toward increasing profitability is the characteristic of any new industry as lessons learned are applied to future generations of the technology.

Improving profitability has helped to create the economic climate needed to encourage industry to commit massive capital investments for oil sand development. The Alberta Energy and Utilities Board (EUB) "estimates that $23 billion (Canadian) has been invested in oil sand expansion since 1996, $7 billion for new projects under construction, and a further $30 billion in planned projects has been announced for the next 10 years" (Ref. 44).

These expansions incorporate advances in mining and materials handling. For example, materials are now moved by slurry instead of conveyor. Processing is now employing low-energy extraction methods that cuts by 40 percent the energy required to produce a barrel of bitumen (Ref. 45). Other significant technical advances include: steam-assisted gravity drainage, vapor extraction of bitumen, and a new cyclic steaming technique. These improvements have resulted in the high energy efficiency (82 percent) and low operating costs ($8.50/bbl) cited earlier.

Figure 22. Tar Sand Economics and Production Continue to Improve



Source: Oil & Gas Journal, July 14, 2003, V. 101.27

Through the early 1990's, the petroleum industry invested in the preliminary steps needed for oil shale development in the United States. The industry can build on that existing technology base by adopting new tar sand and oil shale technology developed during the past ten years.

Development of the U.S. oil shale resources will start high on the learning curve. While production costs are likely to be higher in the first-generation plants, costs are expected to fall as industry matures. Comparison of the capital costs for the main units suggests an improvement in the investment economics of oil shale similar to that the improvements experienced in Canada with tar sand. Higher capital costs for the retort (compared to extraction and coking of tar sand bitumen) may be offset by the substantially lower mining costs for oil shale. Upgrading costs are comparable.

At present it is not possible to tell if oil shale economics will parallel Alberta tar sand, but comparisons of richness, resource magnitude, production assurance, process steps and product quality strongly suggest that, at maturity, oil shale will afford a profitable opportunity. The resource is large enough to support a goal of 2 million bbl/day, achievable in a time frame that will be driven by a consensus of need. It is likely that production at this level will require several technology approaches.

Getting started, however, is the key. The initial investment thresholds and project risks are huge. The importance of getting over the first hurdle can be understood by realizing that investment decisions are typically made with 10-year internal rate-of-return calculations, while the resource base supports a physical life of 40 years or more.

After the initial depreciation and amortization period has been completed, second and future generation investment can be made by amortizing the capital over a larger production base. This is what is transpiring in Alberta today and is one reason why government incentives are not likely to be needed after a

first-generation facility (for each technology/resource type) is in production.

Government can, and should, play a role by serving as the catalyst for jump-starting the domestic oil shale industry.

Once started, industry will optimize the processes as required to make the oil shale industry both profitable and self-sustaining, with governmental assistance declining to the point of ultimate elimination -- just as the Alberta tar sand industry did.

Conclusions

The oil shale resources of Colorado, Utah and Wyoming exceed 1 trillion barrels, in-place. Rich, high quality zones yielding greater than 30 gallon per ton are found throughout the region. Past failures to commercialize this vast resource can be attributed to price uncertainty and immature technology, not an inherent deficiency in the resource.

Worldwide, there have been significant advances in technology in the past two decades. Mining and retorting technologies are being practiced in Estonia, Brazil, China and Australia. In the past several years a new, more environmentally sensitive, in-situ technology has been studied that promises production of high quality oil and gas from thick, deep beds where the majority of the resource lies.

Environmental technologies and regulations have matured to a point where regulatory uncertainty is diminished. Oil shale is highly concentrated, and contrary to popular perception provides the greatest yields of oil per acre disturbed of any of the Nation's energy resources.

The rapidly expanding and highly profitable development of Athabasca tar sand resources of Alberta, Canada serves as a model for the initiation and growth of an oil shale industry in the United States. As the tar sand industry has matured production efficiency has improved to over 80 percent and costs have declined, reflecting the learning process.

There are direct parallels between tar sand and oil shale with respect to resource size, resource quality, mining, recovery and upgrading technologies, and production certainty. In nearly all respects oil shale compares favorably to tar sand.

Getting the industry started is the hardest step. This is because of the high capital costs, investment risk, and customary uncertainties surrounding a first-generation facility. Once started, a maturing of an oil shale industry, similar to the tar sand industry, can be expected.

If the United States is to supply more of its own energy needs and reduce its dependence on foreign sources of oil, it has little choice other than to develop its oil shale resources. The current economic climate and evidence for the emerging viability of oil shale warrant development of a Program Plan to advance this objective.

References

1. Dyni, John R., "Oil Shale", U.S. Geological Survey, Rev 02/27/03, (cf www.emdaapg.org/oilshale.htm, September 12, 2003.) p. 1-9
2. Final Environmental Statement for the Prototype Oil Shale Leasing Program, U.S. Department of the Interior, Bureau of Land Management, Volume I, 1973.
3. Culbertson, W. J. and Pitman, J. K. "Oil Shale" in United States Mineral Resources, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.
4. Donnell, J. R. Geology and Oil-Shale Resources of the Green River Formation, Proceedings, First Symposium on Oil Shale, Colorado School of Mines, pp. 153-163, 1964
5. Stanfield et al, Department of the Interior, U.S. Bureau of Mines RI 7051, 1967.
6. Stanfield et al, Department of the Interior, U.S. Bureau of Mines RI 6420, 1964.
7. Cameron Engineers, Synthetic Fuels Data Handbook, 1975
8. Cashion, W. B. Geology and Fuel Resources of the Green River Formation, USGS Profesional Paper 548, 1967
9. Stanfield, et. al., Department of Interior, U. S. Bureau of Mines RI 5081, 1954. Core Hole Histogram
10. www.engineering.usu.edu /uwrl/atlas/ch7/ch7upcolcom.html
11. cf Salt Lake Tribune, October 17, 2003, Page A-1
12. Draft Commercialization Strategy Report for Oil Shale: Parts I, II, & III; U.S. Department of Energy, Washington, DC., 1978.
13. "Shell's In-Situ Conversion Process", a Briefing by Mr. Terry O'Connor to Oil Shale Report Steering Committee. Washington, D.C., October 2003, and related materials.
14. Oil and Gas Journal, Dec 23, 2002.
15. "SPP Information Pack for Estonia Symposium, 18 –1 22 November 2002". Southern Pacific Petroleum, Inc.
16. Anderson, Campbell: "Greenpeace vs. The Future of Australian Oil Shale" Presentation to the 53rd Sydney Mining Club. Southern Pacific Petroleum, May 2, 2002.
17. World Energy Council, Estonia Oil Shale Extract from the Survey of Energy Resources 2001, www.worldenergy.org/wec-geis/publications/reports/ser/shale/shale.asp , October 24, 2003.
18. "Shale Oil Production – ATP Plant" Presentation. Viru Keemia Grupp, July 2003.
19. World Energy Council, Brazil Oil Shale Extract from the Survey of Energy Resources 2001, www.worldenergy.org/wec-geis/publications/reports/ser/shale/shale.asp , October 24, 2003.
20. Petzrick, Paul A., 1995, Oil Shale and Tar Sand: Encyclopedia of Applied Physics, v.12, p.77-99: VCH Publishers, Inc.

21. An Assessment of Oil Shale Technology, Congress of the United States, Office of Technology Assessment, Washington, D.C., 1980. p.

22. World Energy Congress, China Oil Shale Extract from the Survey of Energy Resources 2001, www.worldenergy.org/wec-geis/publications/reports/ser/shale/shale.asp , October 24, 2003.

23. Qian, Jialin. and Janqui Wang, and S. Li,, "Oil Shale Development in China": Oil Shale, v. 20, no.3, p. 356-359: Estonian Academy Publishers, 2003. p. 356-359.

24. Qian, Jialin , Jianqui Wang, and S. Lian, "World Oil Shale 2002", Petroleum University, Beijing, China, February, 2003.

25. SPP Ibid

26. "Shell's In-Situ Conversion Process" brief description provided by Mr. Terry O'Connor, Shell Oil Company, October 2003.

27. Baldwin Robert M., "Oil Shale: A Brief Technical Overview": Colorado School of Mines, July, 2002.

28. Bunger, J. W., Cogswell, D. E., and Russell, C. P., "Value Enhancement Extraction of Heteroatom Containing Compounds from Kerogen Oil" PREPRINTS, Div. of Fuel Chem. ACS 2001, 46 (2) p 573.

29. Draft Commercialization Strategy Report for Oil Shale: Parts I, U.S. Department of Energy, Washington, DC., 1978, p. 7-8.

30. Haines, Leslie, "Alberta's Heavy Oils": www.oilandgasinvestigator.com, October 2001. p. 32-40.

31. Suncor, CAPP Oil and Gas Investment Symposium, Calgary, June 2003.

32. Province of Alberta, Energy Resource Conservation Board, Informational Letter, I1, pg. 84-6.

33. Reeg, et al. Proceedings, 23rd Oil Shale Symposium, Colorado School of Mines, 1990.

34. Suncor 2003 http://www.suncor.com/SiteAdmin/data/1/rec_docs/533_Booklet.pdf)., slide 20.

35. Derived from chart named Suncor Cost Distribution and related data, ref. 31, ibid.

36. http://www.syncrude.com/syn_library/action_plan00/summary.html

37. Odut, S. personal communication, UMATAC Industrial Processes, Calgary Nov, 2003.

38. Suncor, CAPP Presentation, Ibid.

39. Data from www.suncor.com/SiteAdmin/data/1/rec_docs/533_Booklet.pdf

40. Hydrocarbon Processing Refining Processes Handbook, 1998.

41. SUNCOR, CAPP Presentation, Ibid.

43. Bunger, J. W., Estimates made for report "Strategic Significance of America's Oil Shale Resources", US DOE, Dec. 2003

42. Reeg, Ibid.

44. Alberta Energy and Utilities Board (EUB) estimates as reported in Williams, Bob, OGJ V101.29, July 28, 2003 p 24.

45. Oil and Gas Journal, Williams, July 28, 2003.

46. Petzrick, Ibid.

47. An Assessment of Oil Shale Technologies, Congress of the United States, Office of Technology Assessment, Washington, D.C. 1980.

48. Commercialization Strategy Report for Oil Shale, Parts I – III, U.S. Department of Energy, Oil Shale Task Force, 1978.

49. Shell Mahogany Research Project, Briefing Document, Shell Oil Company, 2003.

50. Fuels to Drive Our Future, National Academy of Sciences, National Research Council, Washington, D.C., 1990.

51. Oil Sands Technology Roadmap, Alberta Chamber of Resources, January 30, 2004.

52. Corbet, Bruce, The Stuart Oil Shale Project, Southern Pacific Petroleum, Proceedings-Oil Shale Peer Review meeting, February, 2004.

53. Lukens, L. Personal communication, Feb 18, 2004.

54. Projections estimated from Utley, J., Flying J. Refinery, Salt Lake City, Feb 24, 2004, and data contained in ref 51. Historic data obtained from open literature sources.

55. National Research Council "Fuels to Drive our Future", pp 76-88, 1990.

56. Moritis, Guntis, Suncor's George: "Oil Sands a long-life, low-risk resource", OGJ 102.11, March 15, 2004, pp. 37-38.

Appendix A

A Brief History of Oil Shale

Oil shale is sedimentary marlstone rock that is embedded with rich concentrations of organic material known as kerogen. U.S. western oil shales contain approximately 15 percent organic material, by weight. By heating oil shale to high temperatures, kerogen can be released and converted to a liquid that, once upgraded, can be refined into a variety of liquid fuels, gases, and high value chemical and mineral byproducts. The United States has vast known oil shale resources that could translate into as much as 2.2 trillion barrels of known kerogen "oil-in-place." Oil shale deposits concentrated in the Green River Formation in the states of Colorado, Wyoming and Utah, account for nearly three-quarters of this potential.

Because of the abundance and geographic concentration of the known resource, oil shale has been recognized as a potentially valuable U.S. energy resource since as early as 1859, the same year Colonel Drake completed his first oil well in Titusville, Pennsylvania. Early products derived from shale oil included kerosene and lamp oil, paraffin, fuel oil, lubricating oil and grease, naphtha, illuminating gas, and ammonium sulfate fertilizer.

Since the beginning of the 20th century, when the U.S. Navy converted its ships from coal to fuel oil, and the nation's economy was transformed by gasoline-fueled automobiles and diesel fueled trucks and trains, concerns have been raised about assuring adequate supplies of liquid fuels at affordable prices to meet the growing needs of the nation and its consumers.

America's abundant resources of oil shale were initially eyed as a major source for these fuels. Numerous commercial entities sought to develop oil shale resources. The Mineral Leasing Act of 1920 made petroleum and oil shale resources on Federal lands available for development under the terms of federal mineral leases. Soon, however, discoveries of more economically producible and refinable liquid crude oil in commercial quantities caused interest in oil shales to decline.

Interest resumed after World War II, when military fuel demand and domestic fuel rationing and rising fuel prices made the economic and strategic importance of the oil shale resource more apparent. After the war, the booming post-war economy drove demand for fuels ever higher. Public and private research and development efforts were commenced, including the 1946 U.S. Bureau of Mines Anvil Point, Colorado oil shale demonstration project. Significant investments were made to define and develop the resource and to develop commercially viable technologies and processes to mine, produce, retort, and upgrade oil shale into viable refinery feedstocks and byproducts. Once again, however, major crude oil discoveries in the lower-48 United States, offshore, and in Alaska, as well as other parts of the world reduced the foreseeable need for shale oil and interest and associated activities again diminished. Lower-48 U.S. crude oil reserves peaked in 1959 and lower-48 production peaked in 1970.

By 1970, oil discoveries were slowing, demand was rising, and crude oil imports, largely from Middle Eastern states, were rising to meet demand. Global oil prices, while still relatively low, were also rising reflecting the changing market conditions. On-going oil shale research and testing projects were re-energized and new projects were envisioned by numerous energy companies seeking alternative fuel feedstocks (***Table A-1***). These efforts were significantly amplified by the impacts of the 1973 Arab Oil Embargo which demonstrated the nation's vulnerability to oil import supply disruptions, and were underscored by a new supply disruption associated with the 1979 Iranian Revolution.

By 1982, however, technology advances and new discoveries of offshore oil resources in the North Sea and elsewhere provided new and diverse sources for U.S. oil imports, and dampened global energy prices. Global political shifts promised to open previously restricted provinces to oil and gas exploration, and led economists and other experts to predict a long future of relatively low and stable oil prices. Despite significant investments by U.S. energy companies, numerous variations and advances in mining, restoration, retorting, and in-situ processes, the costs of oil shale production relative to foreseeable oil prices, made continuation of most commercial efforts impractical.

Table A-I shows a summary timeline of the major events associated with oil shale development in Western Colorado. ***Table A-II*** shows the status of numerous projects that were initiated and then terminated, primarily due to economic infeasibility relative to expected world oil prices or project design issues.

Several projects failed for technical and design reasons. Federal research and development, leasing, and other activities were significantly curtailed, and most commercial projects were abandoned. The collapse of world oil prices in 1984 seemed to seal the fate of oil shale as a serious player in the nation's energy strategy.

Table A-1. Oil Shale Timeline (Source: Shell Mahogany Research Project, 2004)

1909	U.S. Government creates U.S. Naval Oil Shale Reserve
1910	Oil shale lands "claim-staked"
1916	USGS estimates 40 B Bbls of shale oil in Green River formation in CO, WY, and UT
1917	First oil shale retort kiln in DeBeque, Co.
1918	First oil shale boom begins with over 30,000 mining clams; lasts until 1925
1920	Mineral Leasing Act requires shale lands be leased through the Secretary of Interior
1929	Test retort at Rulison stops at 3,600 bbls after oil discoveries in CA, TX, and OK
1944	U.S. Synthetic Liquid Fuels Act provides $18 million for experiments at Anvil Points
1950s	Gulf Oil and Shell Oil both purchase oil shale lands in Green River formation
1956	Anvil Points operations cease after testing three experimental retort processes
1961	Unocal shuts down Parachute Creek "Union A" retort after 18 months and 800b/d due to cost
1964	Colorado School of Mines leases Anvil Points facility to conduct research on US Bureau of Mines Gas Combustion Retorts
1967	CER and U.S. AEC abandon plans for "Project Bronco" atomic subsurface retort
1972	Tosco, Sohio and Cleveland Cliffs halt Colony oil shale project begun in 1964 after 270,000 bbls of production
1972	Occidental Petroleum conducts first of six in-situ oil shale experiments at Logan Wash
1972	Paraho is formed as a consortium of 17 companies, obtains a lease of Anvil Points facility and builds and operates 24 ton/day pilot plant and 240 ton/day semi-works plant.
1970s	Shell researches Piceance Creek in-situ steam injection process for oil shale and nahcolite
1974	Four oil shale leases issued by BLM under Interior's Prototype Leasing Program.
1974	Unocal develops new "Union B" retort process; Shell and Ashland join Colony Project
1976	Navy contracts with Paraho to produce 100,000 barrels of shale oil for testing as a military fuel

Table A-1. Oil Shale Timeline (Source: Shell Mahogany Research Project, 2004)	
1977	Superior Oil abandons plan for Meeker oil shale plant planned since 1972
1976	Unocal begins planning commercial scale plant at Parachute Creek to be built when investment is economic; imported oil prices reach $41/bbl
1979	Shell, Ashland, Cleveland Cliffs and Sohio sell interests in Colony to ARCO and Tosco; Shell sells leases to Occidental and Tenneco
1979	Congress passes Energy Security Act, establishing U.S. Synthetic Fuels Corporation; authorizes up to $88 Billion for synthetic fuels projects, including oil shale.
1980	Exxon buys Arco's Colony interest and in 1981 begins Colony II construction, designed for 47,000 b/d using Tosco II retort process
1980	Congress approves $14 billion for synthetic fuels development
1980	Unocal plans Long Ridge 50,000 b/d plant applying "Union B" retort; begins construction in 1981
1980	Amoco Rio Blanco produces 1,900 bbls of in-situ oil at C-a tract
1981	Exxon begins to build Battlement Mesa company town for oil shale workers
1981	Second Rio Blanco in-situ retort demonstration produces 24,400 bbls of shale oil
1982	Oil demand falls and crude oil prices collapse
1982	Exxon Black Sunday: announces closure of Colony II due to cost and lower demand
1982	Shell continues in-situ experiments at Red Pinnacle and labs through 1983
1985	Congress abolishes Synthetic Liquid Fuels Program after 40 years and $8 billion
1987	Shell purchases Ertl-Mahogany and Pacific tracts in Colorado
1987	Paraho reorganizes as New Paraho and begins production of SOMAT asphalt additive used in test strips in 5 States.
1990	Exxon sells Battlement Mesa for retirement community
1991	Occidental closes C-b tract project before first retort begins operation
1991	Unocal closes Long Ridge after 5 MM bbls and 10 years for operational issues and losses
1991	LLNL plans $20 million experiment plant at Parachute; Congress halts test funds in 1993
1991	New PARAHO reports successful tests of SOMAT shale oil asphalt additive
1997	DOE cedes oil shale lands to DOI/BLM
1997	Shell tests in-situ heating on Mahogany property; defers further work on economic basis
2000	BLM seeks public comment on management of oil shale lands
2000	Shell returns to Mahogany with expanded in-situ heating technology research plan (on-going)
2004	DOE Office of Naval Petroleum and Oil Shale Reserves initiates study of the strategic significance of America's oil shale resources.

Table A-2. Status of Major U.S. Oil Shale Projects

Project	Location	Proposed Technology	Production Target (barrels per day)	Status Summary
Rio Blanco Oil Shale Co: Gulf, Standard of Indiana	Federal lease tract C-a, Colorado	MIS and Lurgi-Ruhrgas aboveground retorts	76,000 (1987)	Shaft sinking for MIS module development. Designing Lurgi-Ruhrgas module, PSD permit obtained for 1,000 Bbl/day.
Cathedral Bluffs oil Shale project: Occidental Oil Shale: Tenneco	Federal lease tract C-b; Colorado	Occidental MIS	57,000 (1986)	Shaft sinking for MIS module development. Process development work being done at Logan Wash, PSD permit obtained for 5,000 Bbl/Day.
White River Shale project: Sundeco; Phillips; SOHIO	Federal lease tracts U-a and U-b; Utah	Paraho aboveground retorts	100,000	Inactive because of litigation between Utah, the Federal Government, and private claimants over land ownership.
Colony Development Operation: ARCO; Tosco	Colony Dow West property; Colorado	TOSCO II aboveground retorts	46,000	Inactive pending improved economic conditions. PSD permit obtained for 46,000 Bbl/Day.
Long Ridge project: Union 011 of California	Union property; Colorado	Union "b" aboveground retort	9,000	Inactive pending improved economic conditions. PSD permit obtained for 9,000 Bbl/Day.
Superior Oil Co.	Superior property: Colorado	Superior aboveground retort	11,500 Plus nahcolite, soda ash, and alumina	Inactive pending BLM approval land exchange proposal. PSD permit obtained for 11,500 Bbl/day.
Sand Wash project: Tosco	State-leased land; Utah	TOSCO II aboveground retorts	50,000	Site evaluation and feasibility studies underway. Lease terms require $8 million investment by 1985.
Paraho Development Corp.	Anvil Points: Colorado	Paraho aboveground retorts	7,000	Inactive following completion of pilot plant and semiworks testing. Seeking Federal and private funding for modular demonstration program.
Logan Wash project. Occidental Oil Shale: DOE	D.A. Shale property; Colorado	Occidental MIS	500	Two commercial-size MIS retorts planned for 1980 in support of the tract C-b project. PSD permit obtained for 1,000 Bbl/Day.
Geokinetics, Inc., DOE	State-leased land; Utah	Horizontal-burn true in-situ	2,000 (1982)	Continuation of field experiments, About 5,000 bbl have been produced to date.
BX Oil Shale project Equity Oil Co.; DOE	Equity property; Colorado	True in-situ retorting with superheated steam (Equity process)	Unknown	Steam injection begun and will continue for about 2 years. Oil production expected in 1980. Production rate has not been predicted.
Shell In-Situ Conversion Research Project	Shell Property. Colorado	In-Situ Conversion using underground heaters	Unknown	Research initiated in 1993 has continued leading to technology advancement and proof of concept. Additional R&D could lead to pilot demonstration by 2006

Source: OTA 1990, An Assessment of 0il Shale Technologies p.114; Shell Oil 2003

Appendix B

Oil Shale Technologies (to 1991)

This appendix reviews the major technologies that were developed for oil shale mining, retorting, and upgrading between 1960 and 1991. Much of the information in this appendix is excerpted from external sources (Refs. 46 – 50.) More recent technology advances that can contribute to improved performance and cost-efficiencies and yield value-enhancing byproducts are discussed in Volume II, Section II of this report)

There are two basic retorting approaches. With conventional surface processes, the shale is brought to the heat source, namely the retort. With in-situ processes, the heat source is placed within the oil shale itself. Conventional surface retorts require the mining of the oil shale by surface or deep mining methods: the transporting of the shale to the retort facility, the retorting and recovering of the shale oil, and finally the disposing of the "spent" shale. In-situ retorting involves the application of heat to the kerogen while it is still embedded in its natural geological formation, and then the recovery of the fluid kerogen by conventional means. Examples of in-situ approaches include modified and true in-situ processes, as described below.

I. Mining

With the exception of the "true in-situ" process to be described below, oil shale must be mined before it can be converted to shale oil. Depending on the depth and other characteristics of the target oil shale deposits, either surface mining or underground mining methods may be used.

Surface Mining – Due to less complexity, fewer safety issues, and lower costs, open-pit surface mining is the preferred method whenever the depth of the target resource is favorable to access through overburden removal. In general, open-pit mining is viable for resources where the over burden is less than 150 feet in thickness and where the ratio of overburden thickness to deposit thickness is less than one – to- one. Removing the ore may require blasting if the resource rock is consolidated. In other cases, exposed shale seams can be bulldozed. The physical properties of the ore, the volume of operations, and project economics determine the choice of method and operation.

Underground Mining – When overburden is too great, underground mining processes are required. Underground mining necessitates a vertical, horizontal or directional access to the kerogen-bearing formation. Consequently, a strong "roof" formation must exist to prevent collapse or cave-ins, ventilation must be provided, and emergency egress must also be planned.

Room and pillar mining has been the preferred underground mining option in the Green River formations. Advanced technologies have already been developed, tested, and demonstrated, safely and successfully, by Cleveland-Cliffs, Mobil, Exxon, Chevron, Phillips and Unocal. Technology currently allows for cuts up to 27 meters in height to be made in the Green River formation, where ore-bearing zones can be hundreds of meters thick. Mechanical "continuous miners" have been selectively tested in this environment, as well.

Depending on the ore size limitations of various retorting processes, mined oil shale may need to be crushed using gyratory, jaw, cone or roller crushers, all of which have been successfully used in oil shale mining operations.

For limited uses, including electric power generation, oil shale can be burned directly, without further processing to liquid form. This has been the norm in Estonia where raw oil shale is burned as power plant boiler fuel. The high calcium carbonate content of some oil shale ores provides an effective matrix for oil shale use in fluidized bed combustion technologies. Atmospheric- and pressurized-fluidized bed technologies have been developed and used in the United States since the 1970s to burn medium and high-sulfur coals in power plant applications and minimize sulfur dioxide and other atmospheric emissions. Another direct use of oil shale is for road paving. Road paving applications range from simple compaction on the roadbed to mixtures with water or hydrocarbon solvents and asphalt pitch.

II. Converting Ore to Shale Oil

Unlike the bitumen derived from tar sand, the kerogen in oil shale is a solid that does not melt and is insoluble. (Ref. 22) To create other fuels, the kerogen must be converted from a solid to a liquid state. In general, releasing organic material from oil shale and converting it into a liquid form requires heating the shale to some 500 degrees C – in the absence of oxygen - to achieve a pyrolysis which converts the kerogen to a condensable vapor which, when cooled, becomes liquid shale oil. This process is called "retorting." (Ref. 29)

Depending on the efficiency of the process, a portion of the kerogen may not be vaporized but deposited as "coke" on the remaining shale, or converted to other hydrocarbon gases. In some processes, residual carbon and hydrocarbon gases may be captured and combusted to provide process heat. For the purposes of producing shale oil, the optimal process is one that minimizes the thermodynamic reactions that form coke and hydrocarbon gases and maximizes the production of shale oil. (Ref. 29)

Maximum oil production requires pyrolysis at the lowest possible temperature (about 480 degrees centigrade) to avoid unnecessary cracking of hydrocarbon molecules, which reduces oil yields. (Ref. 22)

Conventional Oil Shale Retorts

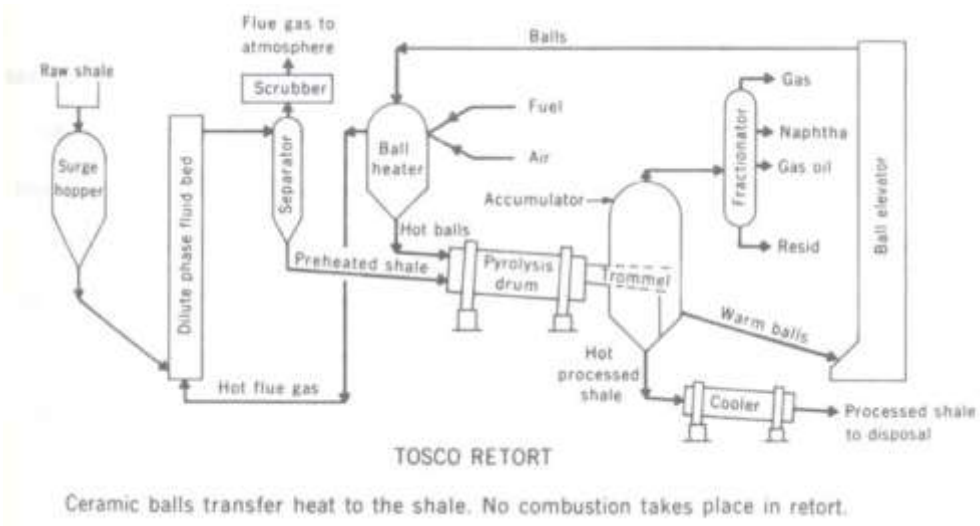
Examples of conventional retorts include "TOSCO II" and "Union B", Petrosix gas combustion, Paraho, Lurgi-Ruhrgas and Kiviter, as well as the new Alberta Taciuk Process ("ATP") now being demonstrated in Australia.

Of the projects and processes used in the U.S., Union B was the longest lived, produced the most shale oil (4.5 million barrels between 1980 and 1991), and received the most significant technological evaluation. Worldwide, the Petrosix retorts in Brazil and Kiviter Retorts in Estonia have produced tens of millions of barrels over their lifetimes.

Union B – "The retort developed by Union Oil Company of California (Unocal) was tested at a demonstration scale between 1956 and 1958. This retort consists of a vertical refractory-lined vessel. It operates on a downward gas flow principle, and the shale is moved upward by a unique charging mechanism usually referred to as a "rock pump." Heat is supplied by combustion of the organic matter remaining on the retorted oil shale and is transferred to the [raw] oil shale by direct gas-to-solids exchange. The oil is condensed on the cool incoming shale and flows over it to an outlet at the bottom of the retort. The process does not require cooling water. The company announced that its operation of the plant had yielded enough information to justify the design of a larger scale operation and to satisfy whatever energy demand that economic conditions warranted. (Ref. 21)

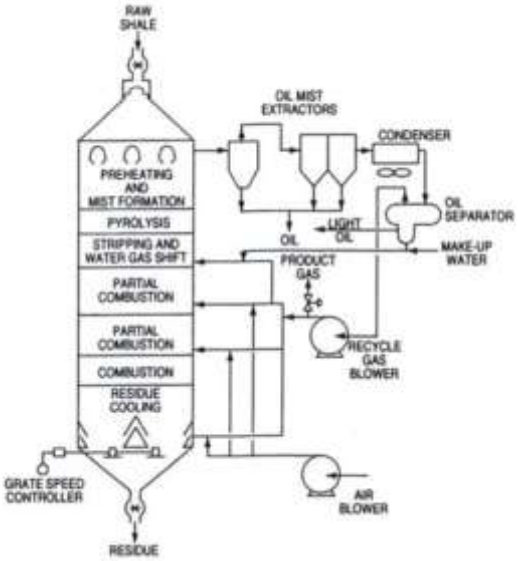
TOSCO II – Colony Development Operation, comprised of Arco, Sohio, the Oil Shale Company (TOSCO), and the Cleveland Cliffs Iron Company operated projects from the mid 1960s to 1972 using the TOSCO II retort (Figure B-1). This process employed a rotary type kiln utilizing ceramic balls heated in external equipment to accomplish retorting. Shale reduced to one-half inch size or smaller is preheated and pneumatically conveyed through a vertical pipe by flue gases from the ball-heating furnace. The preheated shale then enters the rotary retorting kiln with the heated pellets where it is brought to retorting temperature of 900 degrees F (500 degrees C) by conductive and radiant heat exchange with the balls. Passage of the kiln discharge over a trommel screen permits recovery of the balls from the spent shale for reheating and recycling. The spent materials are then routed to disposal. Excellent oil recoveries and shale volumes were

Figure B-1. TOSCO Retort (Fig. I-4 from EIS pg. I-13)



Gas Combustion Retort – Vertical-shaft retorts can be traced back to Scottish oil shale retorts that evolved from coal gasification technologies. "When U.S. Bureau of Mines engineers set out to develop a high-efficiency, high throughput oil shale retort specifically for the Green River Formation shale, they elected to develop a vertical shaft Gas Combustion Retort (GCR) that would burn the incondensable gases of the retorting process as fuel." (Ref. 20) Of the numerous technologies studied in the Bureau of Mines program, the gas combustion retort [then] gave the most promising results (***Figure B-2***). This retort is a vertical, refractory-lined vessel through which crushed shale moves downward by gravity. Recycled gases enter the bottom of the retort and are heated by the hot retorted shale as they pass upward through the vessel. Air is injected into the retort at a point approximately one-third of the way up from the bottom and is mixed with the rising hot recycle gases. Combustion of the gases and some resid-

Figure B-2. Gas Combustion Retort

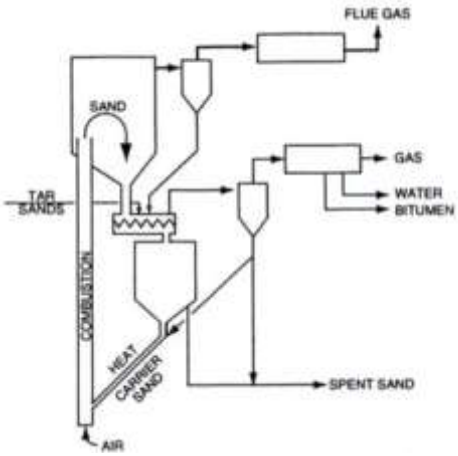


ual carbon from the spent shale heats the raw shale immediately above the combustion zone to retorting temperature. Oil vapors and gases are cooled by the incoming shale and leave the top of the retort as a mist. The novel manner in which retorting, combustion, heat exchange and product recovery are carried out gives high retorting and thermal efficiencies. The process does not require cooling water, an important feature because of the semi-arid regions in which the oil shale targets occur. This project was terminated before operability of the largest of the three pilot plants had been demonstrated. (Ref. 20 and 21).

Paraho – The Paraho retorting process is typical of vertical-shaft retorts in which crushed shale with the fines removed descends through the retort under the influence of gravity. Zones for each step in processing the shale are maintained by managing gas flow in the retort. The retort can be operated in a direct or indirect combustion mode. The indirect combustion mode burns process gas in a separate furnace and hot gases carry heat to the retort. (Ref. 20).

Lurgi-Ruhrgas – The Lurgi-Ruhrgas technology developed in Germany (***Figure B-3***), features a lift pipe in which residual carbon is burned off spent hot solid feedstock to provide process heat. Burned feedstock is carried to the retort for solid-to-solid heat transfer to the raw feedstock. It has been successfully tested for processing Green River Oil Shale. (Ref. 20)

Figure B-3. Lurgi-Ruhrgas Retort

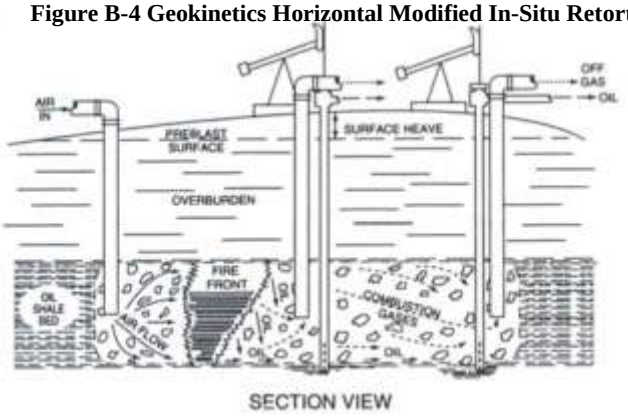


Petrosix Vertical-Shaft Retort – The largest surface oil shale pyrolysis reactor currently operating is the Petrosix 11-m vertical shaft Gas Combustion Retort (GCR) used in Brazil's Oil shale development program. It was designed by the engineers who designed and built the Bureau of Mines GCR and the Paraho GCR. The Petrosix technology is discussed in Section 2. (Ref. 20)

In-Situ Retorting Processes – In-situ processes can be technically feasible where permeability of the rock exists or can be created through fracturing. "True in-situ" processes do not involve mining the shale. The target deposit is fractured, air is injected, the deposit is ignited to heat the formation, and resulting shale oil is moved through the natural or man-made fractures to production wells that transport it to the surface.

In true in-situ processes, difficulties in controlling the flame front and the flow of pyrolized oil can limit the ultimate oil recovery, leaving portions of the deposit unheated and portions of the pyrolized oil unrecovered. An example is shown in ***Figure B-4***. (Ref. 20).

Figure B-4 Geokinetics Horizontal Modified In-Situ Retort



Modified in-situ processes attempt to improve performance by exposing more of the target deposit to the heat source and by improving the flow of gases and liquid fluids through the rock formation, and increasing the volumes and quality of the oil produced. Modified in-situ involves mining beneath the target oil shale deposit prior to heating. It also requires drilling and fracturing the target deposit above the mined area to create void space of 20 to 25 percent. This void space is needed to allow heated air, produced gases, and pyrolized shale oil to flow toward production wells. The shale is heated by igniting the top of the target deposit. Condensed shale oil that is pyrolized ahead of the flame is recovered from beneath the heated zone and pumped to the surface.

The Occidental vertical modified in-situ process was developed specifically for the deep, thick shale beds of the Green River Formation. About 20 percent of the shale in the retort area is mined; the balance is then carefully blasted using the mined out volume to permit expansion and uniform distribution of void space throughout the retort. A combustion zone is started at the top of the retort and moved down through the shale rubble by management of combustion air and recycled gases. Full-scale retorts would contain 350,000 cubic meters of shale rubble. (Ref. 20)

Note: Discussions of the features of many of the major technology advances achieved since 1991 are provided in the prior sections of this volume.