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PROCEEDINGS 1961 EASTERN OIL SHALE SYMPOSIUM

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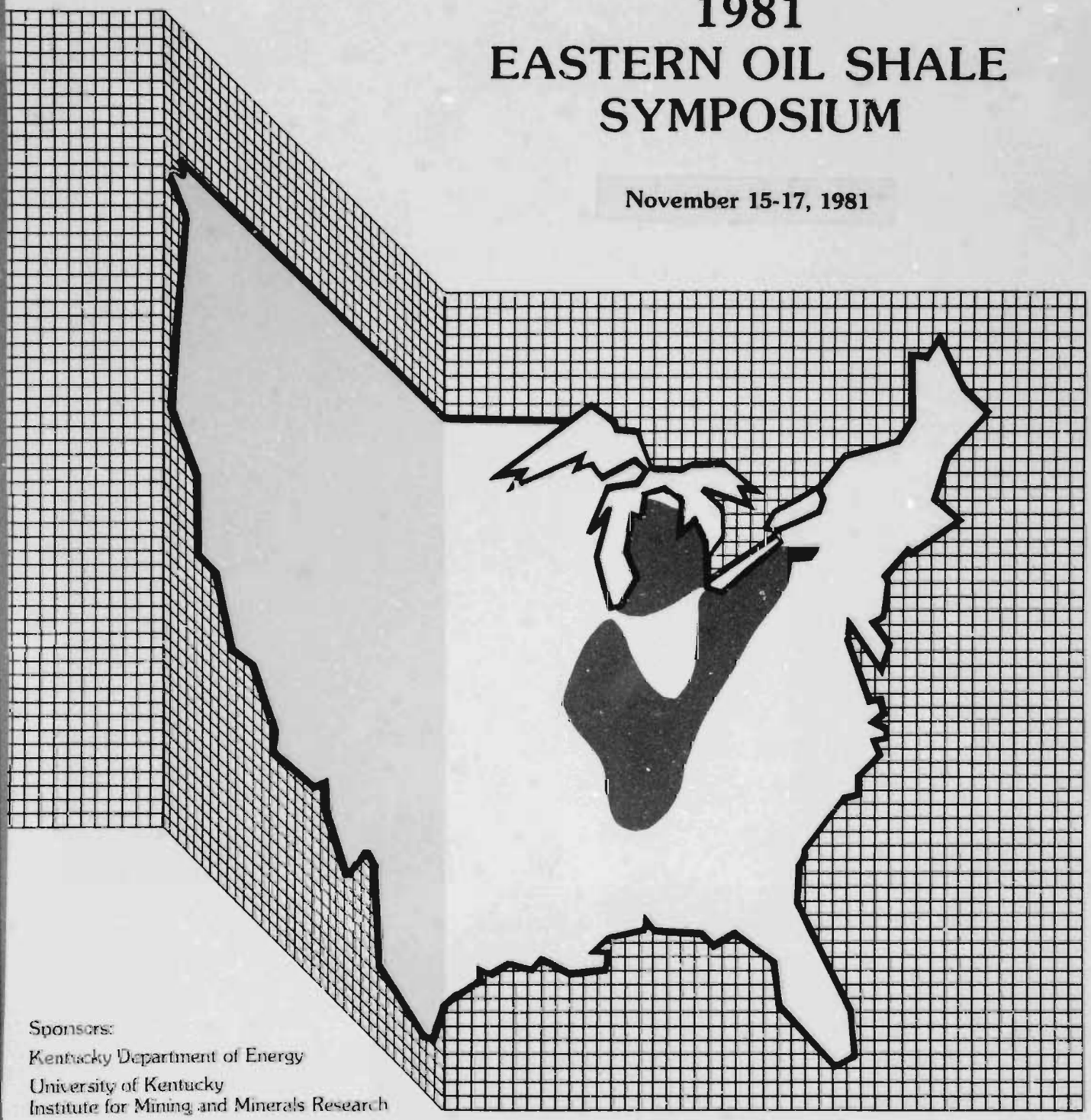
P R O C E E D I N G S

1981 EASTERN OIL SHALE SYMPOSIUM

November 15-17, 1981



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PROCEEDINGS

1981 EASTERN OIL SHALE SYMPOSIUM

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PROCEEDINGS

1981 EASTERN OIL SHALE SYMPOSIUM

November 15-17, 1981
Hyatt Regency
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PREFACE

Eastern oil shale has long been recognized as a large energy resource, but little has been done to develop a functioning industry. Recent research, coupled with steadily increasing oil prices, have increased the interest in eastern shale.

The Kentucky Department of Energy and the University of Kentucky recognized that the growing interest in eastern shale and the numerous research activities in this resource created a need for a technical symposium to disseminate information, create discussion, and generally advance the knowledge about eastern oil shale.

The University of Kentucky's Institute for Mining and Minerals Research (IMMR), which conducts much of the Commonwealth of Kentucky's energy research program for the Kentucky Department of Energy, was asked to take the lead in organizing the 1981 Eastern Oil Shale Symposium. The IMMR Office for Informational Services and Technical Liaison (OISTL) secured a volunteer Advisory Committee to oversee the planning of the symposium while OISTL made all of the procedural arrangements.

The 1981 Eastern Oil Shale Symposium attracted a large, diverse, and senior-level audience. This attendance, coupled with the favorable reaction of most attendees, confirms our judgment that the time was right for an eastern oil shale program.

I want to express my appreciation again to the Advisory Committee and the employees of OISTL who made the 1981 symposium possible. As with any venture of this type, the first year is the most difficult. I believe that future years will see the Eastern Oil Shale Symposium grow into one of the nation's finest and most popular energy symposia.

These proceedings provide a written record of the papers presented between November 15 and 17, 1981. I hope you find them beneficial.

Ronald L. Sanders
Engineering Resources, Inc.
Chairman, 1981 Eastern Oil Shale Symposium
Advisory Committee

AGENDA

1981 EASTERN OIL SHALE SYMPOSIUM

Sunday, November 15

1:00 - 6:00 p.m. Registration ..... Hyatt Lobby Booth

6:00 - 9:00 p.m. Reception ..... Regency Ballroom

Sponsored by: Phillips Petroleum Company
Pyramid Minerals
Cleveland Cliffs Iron Company
Davy McKee Corporation
Kentucky Department of Energy
University of Kentucky
Institute for Mining & Minerals Research

Monday, November 16

7:30 - 11:00 a.m. Registration (late) ..... Patterson Ballroom

8:00 a.m. General Session ..... Patterson Ballroom

Presiding: Ronald L. Sanders, Exec. Vice President
Engineering Resources, Inc.
Lexington, Kentucky

Welcome: William B. Sturgill, Secretary
Kentucky Department of Energy
Lexington, Kentucky

Keynote Address: James E. Funk, Director
Advanced Technology Center
Allis Chalmers, Inc.
Milwaukee, Wisconsin

9:00 a.m. Break

9:30 a.m. Morning Sessions (concurrent sessions in Process Technology and Mining & Reclamation Technology will be held in the Patterson Ballroom)

9:30 a.m. **Process Technology - Room A**
Kirit C. Vyas, Session Chairman
Davy McKee Corporation

9:40 a.m. ***The U.S. Department of Energy's Oil Shale Technology Base Program***
Douglas B. Uthus
U.S. DOE

10:10 a.m. ***Eastern Oil Shale Utilization***
Lewis A. St. Cyr, P.S. Sundar & O.A. Larson
Gulf Research & Development Company

10:40 a.m. ***Analytical Pyrolysis of Eastern Oil Shales***
John W. Reasoner
Western Kentucky University
Marshall Margolis
Institute for Mining & Minerals Research

11:10 a.m. ***Influence of Retorting Parameters on Oil Yield from Sunbury and Ohio Shales from Northeastern Kentucky***
A.M. Rubel, T.T. Coburn
Institute for Mining & Minerals Research

9:30 a.m. **Mining & Reclamation Technology - Room B**
Robert M. DeGabriele, Session Chairman
Cleveland Cliffs Iron Company

9:40 a.m. ***Oil Shale Hydrology - A Transfer of Knowledge from the Coal Regions***
Paul D. Nesbitt
Nesbitt Engineering, Inc.

10:00 a.m. ***A Comparison of Various Aspects of Mining Oil Shale in Western and Eastern United States***
E.D. Lindquist, G.D. Aho
Cleveland Cliffs Iron Company

10:20 a.m. ***Evaluation of a Potential Oil Shale Processing Operation in Alabama***
A.F. Hilleke, H.S. Hanna
University of Alabama

10:40 a.m. ***Preliminary Research on Potential Reclamation of Oil Shale Mined Lands in Kentucky***
W. Russell Hamon, Robert R. Kruspe
Institute for Mining and Minerals Research

Mining and Reclamation Technology - Room B (continued)

11:00 a.m. ***Comparison of Coal and Oil Shale Mining in Appalachia***
Tom Watkins, Jack Bender
Skelly & Loy

11:20 a.m. ***Disposal Concepts as Related to Retorted Shale Properties***
Phil Gerhart, Wes Holtz
Woodward Clyde

11:40 a.m. ***Engineering Properties of Kentucky Oil Shale***
Vincent P. Drnevich, Tommy C. Hopkins, Dave L. Allen & Sam Hale
University of Kentucky

12:00 noon Luncheon ..... Regency Ballroom

1:00 p.m. Afternoon Sessions (concurrent sessions in Process Technology and Resources Exploration & Geochemistry will be held in the Patterson Ballroom)

Process Technology - Room A (continued)
Kirit C. Vyas, Session Chairman
Davy McKee Corporation

1:00 p.m. ***TOSCO Technology Applied to Eastern U.S. Oil Shales***
L.R. Pease
TOSCO Corporation

1:30 p.m. ***Description of the T -Process and Its Applicability to Eastern Oil Shale***
Chang Yul Cha
Science Applications, Inc.

2:00 p.m. ***Paraho's Retort Technology for Eastern Oil Shale***
Adam A. Reeves, John B. Jones, Jr.
Paraho Development company

2:30 p.m. ***Superior Circular Grate Oil Shale Retorting Process***
John H. Knight, Loren H. Young
The Superior Oil Company

3:00 p.m. Break

3:15 p.m. ***Processing of Eastern Oil Shale for Liquid and Gaseous Fuels***
M.M. Ahmed, D.H. Archer
Westinghouse R&D Center

3:45 p.m. ***Fluidized Bed Oil Shale Retorting: A Bench Scale Evaluation for Eastern Oil Shale***
Marshall J. Margolis
Institute for Mining & Minerals Research

1:00 p.m. **Resources Exploration & Geochemistry - Room B**
Thomas Robl, Session Chairman
Institute for Mining & Minerals Research

1:10 p.m. ***Organic-Rich Shales (Mississippian & Devonian) in the Eastern Interior United States***
Roy C. Kepferle
United States Geological Survey

1:35 p.m. ***Hydrocarbon and Uranium Assessment of the Chattanooga (Devonian) Shale in North Alabama, Northwest Georgia and South Tennessee***
K.F. Rheams, L.J. Rheams, C.W. Copeland, T.L. Neathery
Geological Survey of Alabama

2:00 p.m. ***Chattanooga Oil Shale in Tennessee-Resource Assessment***
Wayne Leimer, Chris McGovern
Tennessee Technological University

2:25 p.m. ***An Overview of Oil Shale Development in Ohio***
Gene Johnson
Ohio Department of Energy

2:50 p.m. ***Resource Assessment of the New Albany Shale (Devonian & Mississippian) in Southeastern Indiana***
N.R. Hasenmueller
Indiana Geological Survey

3:15 p.m. Break

3:30 p.m. ***Chemical Composition of the New Albany Shale in Indiana***
R.K. Leininger
Indiana Geological Survey

3:55 p.m. ***Geochemistry of the New Albany, Ohio and Sunbury Shales in East Central Kentucky***
Alan E. Bland, Thomas L. Robl, D.W. Koppenaal
Institute for Mining and Minerals Research

4:20 p.m. ***Stratigraphy and Resource Assessment of the Oil Shales of East Central Kentucky***
Don Pollock, Lance Barron
Institute for Mining and Minerals Research
John Beard
Kentucky Geological Survey

6:00 p.m. Cash Bar ..... Regency Ballroom

7:00 p.m. Banquet ..... Regency Ballroom

Guest Speaker: Ken L. Smalley, Vice President
Phillips Petroleum
Bartlesville, Oklahoma

Tuesday, November 17

9:00 a.m. Morning Sessions (concurrent sessions in Process Technology and Socio-Economic & Environmental Studies will be held in the Patterson Ballroom)

9:00 a.m. **Process Technology - Room A**
Kirit C. Vyas, Session Chairman
Davy McKee Corporation

9:00 a.m. ***Eastern Oil Shale - Past, Present, and Future***
John Humphrey
Highland Energy Corporation
Robert Addington
Pyramid Minerals

9:30 a.m. ***Oil Shale Utilization at Morgantown***
A.A. Pitrolo, J.E. Notestein, J.Y. Shang, J.S. Mei, and L.W. Zeng
Morgantown Energy Technology Center

10:00 a.m. ***General Discussion of Various Other Eastern Oil Shale Processes***
Forrest Kinsey
Dravo Engineers and Constructors
Fred F. Storer
Phillips Petroleum Company
Byron G. Spars
Chevron Research Company

10:30 a.m. Break

10:45 a.m. ***Eastern Oil Shale Investigations at the University of Alabama***
H. Shafick Hanna, Carl Rampacek
University of Alabama

11:15 a.m. ***Corrosion Performance of Engineering Alloys in an Atmospheric Rotary Kiln Retort***
Diane Spencer, Alberto Sagues
Institute for Mining & Minerals Research

11:45 a.m. ***Summary***
Kirit C. Vyas
Davy McKee Corporation

12:00 noon: **Lunch (on your own)**

9:00 a.m. ***Socio-Economic & Environmental Studies - Room B***
Richard Shogren, Session Chairman
Kentucky Department for Natural Resources & Environmental Protection

9:10 a.m. ***The U.S. Department of Energy's Oil Shale Environmental Mitigation Program***
A.M. Hartstein, R. Franklin
U.S. DOE

9:40 a.m. ***Kentucky's Proposed Oil Shale Regulatory Program***
R.T. Shogren, E.T. Green
Kentucky Department for Natural Resources & Environmental Protection

10:10 a.m. Break

10:25 a.m. ***A Comparison of Proposed Oil Shale Regulations with Coal Mining Regulations***
S.G. Kinkel, J.J. Zaluski
Zaluski, Seay and Kirkland

10:55 a.m. ***Potential Economic Impact of Oil Shale Commercialization in Fleming County, Kentucky***
S.H. Miller
Buffalo Trace ADD, Inc.

11:25 a.m. ***Socio-Economic Impacts: Validity of Evidence from the Coal Mining Industry in Kentucky***
P.D. Nesbitt
Nesbitt Engineering, Inc.

1:00 p.m. Afternoon Sessions (concurrent sessions in Products, Upgrading Markets & Economics and Socio-Economics & Environmental Studies will be held in the Patterson Ballroom)

1:00 p.m. **Products, Upgrading Markets & Economics - Room A**
Mickey Jones, Session Chairman
Kentucky Department of Energy

1:00 p.m. **Socio-Economic & Environmental Studies - Room B**
Richard Shogren, Session Chairman
Kentucky Department for Natural Resources & Environmental Protection

1:10 p.m. ***Mineral Beneficiation of Oil Shale***
Terry A. Ring
Massachusetts Institute of Technology

Products, Upgrading Markets & Economics - Room A (continued)

1:40 p.m. ***Analysis of Oils Derived from Kentucky Oil Shale for Potential Refinery Feedstocks***
David A. Fabry
Ashland Petroleum Company

2:10 p.m. ***Shale Oil as a Source of Jet Fuel***
Herbert R. Lander
Wright Patterson Air Force Base

2:40 p.m. ***Break***

2:55 p.m. ***Processing Routes for Upgrading Eastern Shale Oil to Finished Petroleum Products***
Clayton P. Kerr
Tennessee Technological University

3:25 p.m. ***Metal Recovery From Eastern Oil Shale***
T.M. Gilliam, R.M. Canon, A.D. Ryon & J.S. Watson
Oak Ridge National Laboratory

3:55 p.m. ***Manufacture of Military Specification Jet Fuel From Oil Shale***
Mike Merdinger
Hydrocarbon Research, Inc
(A copy of this paper may be obtained from Hydrocarbon Research, Inc., Lawrenceville, New Jersey.)

1:00 p.m. ***Environmental Research for Eastern Oil Shale***
Jonathan G. Herrman
U.S. Environmental Protection Agency — IERL

Socio-Economic & Environmental Studies - Room B (continued)

1:30 p.m. ***A Preliminary Assessment of Environmental Impacts of Obtaining Oil from Chattanooga Shale***
J.F. McBrayer, Virginia R. Tolbert
Oak Ridge National Laboratory

2:00 p.m. ***Potential Impact of Oil Shale Development on Water Resources in Kentucky***
W.J. Mitsch, C.G. Lind
University of Louisville

2:30 p.m. ***Leaching Studies on Kentucky Oil Shale Products***
D.W. Koppenaal, K. Cisler & G. Thomas
Institute for Mining and Minerals Research

3.00 p.m. Break

3:15 p.m. ***Comparative Analysis of the Genetic Hazards of Eastern Oil Shale***
H.G. Enoch
Kentucky Department of Energy
J. Lochard, P.S. Sabharwal
University of Kentucky

3:45 p.m. ***Buffalo Trace Area Development District Study Synthetic Fuels from Eastern Oil Shale***
Steve Miller
Buffalo Trace ADD
Thomas Robl
Institute for Mining and Minerals Research
Gary Aho
Cleveland-Cliffs Iron Company
Kirit C. Vyas
Davy McKee Corporation

Adjourn

Keynote Address
Energy and Eastern U.S. Oil Shale

James E. Funk
Director
Advanced Technology Center
Allis-Chalmers, Inc.
Milwaukee, Wisconsin

Good Morning, Ladies and Gentlemen,

It is a great pleasure for me to be with you to begin this 1981 Eastern Oil Shale Symposium. You are dealing with a subject which has received relatively little attention in the past. The vast majority of interest and work on oil shale in the United States has been focused on western United States shales. Kentucky has taken an active interest in eastern U.S. oil shale development and is in a leadership position in the development of this important energy resource.

Any discussion of energy in the United States should begin with oil. Oil is the driving force in the very dynamic and changing energy picture in the United States, and it has been the driver since 1973. The predominant feature of the oil situation has to do with the great decrease in oil imports that we have seen in the past two years.

In 1980 crude oil and refined petroleum product imports were down 21 percent over 1979 and they are down another 20 percent so far in 1981. Our total energy consumption is also dropping. It was down 3.5 percent in 1980 over 1979 and was down about 4 percent during the first six months of 1981. Not only did domestic energy production decline during the first six months of 1981, but the portion of domestic energy consumption supplied by imports also decreased for the fourth year in a row. The level of U.S. net imports of energy also decreased for the fourth successive year. During the first half of 1981, petroleum consumption dropped by almost 7 percent and natural gas use decreased 3.6 percent.

The reasons for this turn of events are varied. Price-induced conservation is surely playing a major role. Prices are high, but have been holding steady during the past few months. Oil price stability, in my opinion, may be attributed to two major factors: the first is the depressed condition of the United States economy and the second is the strength of the United States dollar. We are both causing and paying for these conditions in the form of high interest rates. High interest rates depress the pace of economic activity and keep the United States dollar strong relative to other currencies. A strong dollar and weak demand have kept the price of oil from rising, but what is going to happen when, or perhaps I should say if, the economy of the United States and western Europe strengthens? We are having a temporary respite in our energy problems, but we have bought it dearly and the price is not yet fully paid.

Exploration for petroleum and natural gas increased to record levels during the first half of 1981. In June of 1981 almost 4,000 drilling rigs were in operation, the highest U.S. rig count to that date. This is a 38 percent increase over the June 1980 level. The total footage of wells completed was 158 million feet — 25 percent higher than the same period during 1980. Total domestic production of crude oil is holding constant at about 8.6 million barrels per day and, in fact, the average production during the first six months of 1981 was slightly lower than the average production figures for 1980. There is, as you all know, a great deal of talk about an oil glut and there has been some slight relief lately in the price of gasoline at the pump. The fact that the greatly increased exploration activity has not yet produced substantially increased petroleum reserves is ominous however. Recent actions by OPEC are also ominous. OPEC has agreed on a unified price of $34 a barrel, which caused some OPEC producers to drop their prices and caused Saudi Arabia to increase its price $2 per barrel. Saudi Arabia also cut her oil production by 500,000 barrels per day, and OPEC is now in a position to index the price of oil to the rate of inflation of the U.S. dollar. In addition to being vulnerable to price increases when the world oil glut is worked off, we are in a precarious position in the Middle East in general. Recent events in Iran and Egypt have not strengthened the U.S. position in that part of the world, and it is not difficult to believe that some unforeseen event might occur which would put in jeopardy the 3.4 million barrels per day of oil we import from OPEC. While our import figures are down substantially, we still bring into this country 3.8 million barrels per day of crude oil and 1.2 million barrels per day of refined petroleum products at a cost of at least $170 million per day or $62 billion per year. The point of all this is that while we are in a temporary hiatus, the situation is not a good one and is one in which we remain vulnerable. Both the United States and the balance of the western world are in a recession. If, and when, growth begins again, the demand for petroleum will increase dramatically. Oil fuels the economy of developed countries and provides the means by which less-developed countries can improve their economic position. We are not out of the woods with our energy problems; we have just found a small clearing in which to rest for a little while.

But this is not the time to rest. This is the time for us to concentrate on developing alternative sources of energy, and the development of eastern oil shale is certainly an important part of that effort.

But what about synfuels? Under the previous administration, and with congressional support, a crash synthetic fuels program to replace imported oil was started. This effort, along with conservation, was to augment our declining oil and gas production sufficiently to maintain present end-use patterns until renewable energy resources could fill the gap. The government was to play a major role in the development of a synfuels industry by attempting to take some of the financial risk early in the commercialization phase. It is now clear that the present administration does not envision such an aggressive role for government. Their view is outlined at the beginning of the national energy policy plan submitted by the U.S. Department of Energy to the Congress and dated July 1981. Quoting from this report: "The federal government has one overriding concern in energy during the years ahead. That is to establish sound, stable public policies that will encourage individuals and groups in the private sector to produce and use energy resources wisely and efficiently."

"Sound public policies must be based on recognition of the government's and the private sector's respective roles in energy production. The federal government's most direct impact on America's energy future arises from its position as the steward of the outer continental shelf and of 762 million acres of publicly controlled land, one-third of the land area of the United States. These lands contain an estimated 85 percent of the nation's oil, 40 percent of our natural gas, 40 percent of our uranium, 35 percent of our coal, 85 percent of our tar sands, 80 percent of our oil shale, and 50 percent of our geothermal resources. The federal role in national energy production is to bring these resources into the energy marketplace, while simultaneously protecting the environment."

"The President's action to end oil price controls and to dismantle the burdensome regulatory apparatus associated with those controls was a major step in implementing an energy policy focused on market realities. The challenge ahead is to provide a healthy economy and policy environment that enables citizens, businesses, and state and local governments to make rational energy production and consumption decisions — decisions that reflect the true value, in every sense, of all the nation's resources."

As far as synthetic fuels are concerned, the program has been restructured to rely more heavily on private investment initiatives and less on public funds. The task of commercializing synfuels technologies is being assigned to the private sector, with support possibly coming from the Synthetic Fuel Corporation. The private sector may have some problems financing synthetic fuel facilities due to high capital and production costs. Recent cost estimates (Balzhiser, "EPRI Journal," July/August 1981) are shown below for a plant producing 50,000 bbl/day fuel oil equivalent in 1980 dollars.

	Capital Cost billion $	**First Year Product Cost $/mm Btu**
Direct Liquefaction	1.6	5.5
Methanol	1.7	6.3
Medium Btu gas	1.1	3.8
High Btu gas	1.5	5.5
Shale Oil	**0.9**	**4.1**

Shale oil is an attractive alternative in this comparison.

The U.S. Geological Survey estimates that the total known resources of Devonian oil shale in the eastern United States are approximately 400 billion barrels and the probable extension of known resources at an additional 2600 billion barrels. These estimates are based on Fischer Assay results and may well be increased if retorting conditions can be found which will deliver yields greater than the Fischer Assay. Research and Development work aimed at finding such operating retort conditions is now ongoing in a number of organizations.

While the resource of eastern oil shale is not as extensive as that in the west, a number of factors tend to favor the development of eastern shale over western. These include such factors as

1. Water is much more plentiful.
2. Proximity to large markets and the ability to ship by barge.
3. A greater dispersal of facilities is possible, yielding environmental advantages. Smaller plants may be more easily justified in the east than in the west.
4. Mining costs may be lower.

There are other important differences between eastern and western oil shales. The hydrogen to carbon ratio is somewhat higher for western shales and the sulfur content is considerably higher in eastern shales. The amount of carbon dioxide produced when processing shale into oil followed by the burning of that oil is important and substantially lower for eastern than western oil shales. The carbon dioxide content of western oil shale is about 16 percent whereas for eastern oil shale it is about ½ percent. During retorting of western U.S. oil shales carbonate materials are calcined releasing significant amounts of carbon dioxide. Additional carbon dioxide is produced when residual carbon in the shale is burned in order to improve the process energy balance. Retorting of oil shales from the Green River formation and burning of the product oil could release 1.5 to 5 times

ERRATA PAGE

Figure Caption Corrections for the Bedford Shale and Sunbury Shale Isopach Maps

The isopach maps on pages 202 and 203 should be switched to correspond with their appropriate figure captions (see map legends).

more carbon dioxide than the burning of conventional oil to obtain the same amount of usable energy. On the basis of carbon dioxide production, therefore, eastern shales would be preferred over western.

There is generally more gas produced from eastern shales when they are retorted than from western shales, and there is a good deal more hydrogen sulfide in this gas. This means that additional gas-handling equipment will be required, but commercial technology is available to accomplish this task. In addition, spent eastern shale might be less leachable than western oil shales after all the combustible carbon is burned. There are less alkali carbonates in the eastern shales, and they may also tend to produce a glassy product upon combustion, depending on the process used. All in all, there are certain advantages associated with the development of eastern oil shales, not the least of which are the existence of an infrastructure, availability of water, and the potential ability to operate on a smaller scale.

Cost will be a very important factor in the development of oil shale. The Pioneer Colony Project, being done 60 percent by Exxon and 40 percent by Tosco, is designed for a sustained production of 43,500 barrels of shale oil per day. This shale oil will be partially refined at the plant site using coking and hydrotreating technologies. Upgrading will remove sulfur, nitrogen, and arsenic impurities, and otherwise improve the quality of the shale oil. The end product from the Colony Project will be a hydrotreated, partially refined liquid which could serve as high quality refined feedstock for processing directly into gasoline, jet fuel and diesel or be used directly, for example, as high quality turbine fuel for power generation. It will be readily compatible with the nation's existing network of refineries, distribution systems, and markets. The June 1980 estimated project cost including interest during construction, inflation at 16 percent annually, actual cost of mineral reserves, and a contingency allowance consistent with Pioneer Plant requirements, is $3.4 billion. Of that sum, Tosco's share would be $1.5 billion. Federally guaranteed loans cover 75 percent of Tosco's share, and Exxon is handling its investment directly. There has been a good deal of development of this process, including bench-scale work, a 25-ton-per-day pilot plant, and a 1,000-ton-per-day semi-works plant. I think it is fair to say that the cost estimates for the Colony Project are in substantially better shape than cost estimates for plants to produce oil from eastern U.S. shale. There remains a great deal of process development and engineering cost-estimating to be done before a comfortable estimate of total cost requirements is available. One of the few currently available cost estimates for oil from eastern shale was prepared under contract to the Kentucky Buffalo Trace Area Development District in which a number of processes were compared. Some questions have arisen, as would be expected, after the study was published and I am looking forward to hearing more about this during the symposium. A great deal of process development work remains to be done for eastern oil shale processes, and until that phase of the work is completed, there will always be questions concerning assumptions made for the design basis, yields, quality of oil, et cetera. It is of utmost importance that processing plants be developed which operate at maximum efficiency and minimum cost, and the substantial effort required to accomplish this for eastern oil shale has just started.

A recent report to the Congress dealing with cost effective R&D strategies has listed seven potential obstacles to the implementation of oil shale technology. Since the need for oil is clear, the obstacles to obtaining it must be considered carefully. These obstacles apply to both eastern and western oil shale and include:

1. **Technical Obstacles** — A major barrier to above-ground retorting is that the processes have not yet been scaled up to the commercial module level. A major problem with some in situ processes is that they do not yet consistently yield a high return of product.

2. **Economic Obstacles** — Major economic uncertainties facing an emerging oil shale industry include:

   a. Future production costs which may increase substantially.

   b. Future competitive price of oil in international markets.

   c. Huge capital requirements to construct commercial plants.

   d. Risk of major project delays which could also substantially increase product cost. Given the current economic conditions and federal policies affecting synfuels commercialization, many companies are continuing to be cautious toward investment in oil shale facilities.

3. **Environmental Obstacles** — High quality U.S. oil shales are often located in semi-arid, pristine regions of the country. There is concern that a large-scale industry might adversely affect human health and safety, fauna and flora, grazing and agricultural activities, and water and air quality. In addition, there exists a complex array of federal, state and local environmental laws and standards which must be met. In the press and before various governmental hearings, environmental groups, representatives of western states, and others have expressed concern over the potential environmental impacts of the large scale development of oil shale. Adverse public reaction to these impacts, whether justified or not, has served as a constraint to the development of oil shale.

4. **Social Obstacles** — A crash commercialization program could cause adverse social and economic problems for small towns that do not have the infrastructure to support a large influx of construction and operation workers and their families. The other side of that coin is that a shale industry would provide new job opportunities and increase the tax base of the community.

5. **Political Obstacles** — As we have seen recently, the political winds can blow hard and they can change directions quickly. The federal role in the commercialization of synfuels is still not clear. The potential exists through the Synthetic Fuel Corporation to clarify the role of the federal government in this area. The SFC has the potential to reduce many of the uncertainties associated with oil shale development. Whether this will in fact happen, however, remains to be seen.

6. **Legal Obstacles** — A number of legal problems have arisen including lawsuits in which states seek title to federally owned land and contested ownership of certain mining claims on oil shale properties. Furthermore, many, and sometimes unforeseen, ramifications of state regulations of the development of oil shale may also present serious barriers to the development of this industry.

7. **Water Supply Constraints Obstacles** — There is an ongoing controversy in the west concerning water requirements and water availability for oil shale development. This situation is not likely to ease in the future and is certainly one area in which the development of eastern oil shale would be favored over western shales.

This symposium addresses many of the problem areas just mentioned which must be dealt with before eastern oil shale can be developed into a contributor to the energy requirements of the United States.

The International Institute for Applied Systems Analysis in Vienna, Austria, recently completed a seven-year study which involved over 140 scientists from 20 countries. The objective of the study was to provide new and critical insights into the international long-term dimensions of the energy problem. An executive summary of this study, entitled "Energy in a Finite World," was published in May 1981 and contains the following conclusions:

1. The difficulties associated with supplying and using energy are not temporary; they will continue and we must learn to deal with them.

2. The energy problem is inherently global; no nation is untouched nor can any act in isolation.

3. Despite the strains on the world's physical resources, on its institutions, and on human ingenuity, the resources and potential exist for a world fifty years from now that is more prosperous than the world today while supporting a population double that of 1975.

4. If resources are developed judiciously and strategically, fifty years from now the world could be at the threshold of a critical and ultimately necessary transition from a global energy system based on depletable fossil fuels to one based on nondepletable, sustainable resources.

I would say that, on balance, those conclusions give us cause to be optimistic, and on that note I will close this address and let you get on with your work. Thank you very much.

Evening Address

Ken L. Smalley
Vice President
Minerals Group
Phillips Petroleum Company
Bartlesville, Oklahoma

It's a pleasure to be here this evening. I've always felt a special warmth and fondness for Kentucky. This is a state whose people emphasize the things dearest to my heart: agriculture, mining, petroleum, horses, tobacco, and bourbon.

There are few places I've seen as lovely as the Bluegrass area surrounding Lexington, home of some of the world's finest race horses. The people of Kentucky are proud of their Thoroughbreds, and well they should be. I didn't realize how proud they were until I tried to book a room here at the Hyatt.

I was startled to hear all the rooms were taken by buyers and sellers attending the Keeneland Fall Horse Sale. I was advised to try the plush new Marriott across town. And so I did, but upon calling the hotel I received a rude awakening. The receptionist said: "I'm terribly sorry, Mr. Smalley, but we just assigned our last room — to a three-year-old named Lucky Prancer.

Well, I did finally get to stay at the Marriott. I'm just not accustomed to paying my bill in hay and sugar cubes. But just the same, I'm excited to be here talking about a subject close to all of us — energy. There are three topics I'd like to discuss tonight. First, I'm going to present an overall view of the energy and pertroleum situation. Second, I'll address the role of alternate sources of energy in the present and future. And third, I'm going to talk about oil shale, specifically eastern oil shale.

Right now, the world market for oil is soft. Some prefer to use the term "glut" when describing the situation. World production has remained high while demand has eased. Fuel prices have stabilized and even declined in many areas.

But how long can we rely on conditions to remain as they are? I don't know. My colleagues in the oil industry don't know. Economists don't know. Bankers don't know. Politicians don't know. Even OPEC doesn't know. That, ladies and gentlemen, is a rare consensus of ignorance.

If any of you out there has the unique ability to foresee the future, to answer that baffling question of how long the status quo will continue, then you may have an illustrious career ahead in energy — or in picking the daily double at Keeneland Race Track.

I'm sorry to say I will not venture a guess as to how long we'll enjoy stable prices. I've never been very good at predictions, anyway. A year or so ago when everybody was asking, "Who shot J.R.?" I was dumbfounded. I didn't know anybody had anything against Jane Russell.

The truth is this: the world's energy situation teeters precariously between deficit and surplus. Right now, a number of inter-related factors are holding the line on demand and prices. I'm referring to conservation, sluggish economic activity and an ostensibly generous Saudi Arabian production schedule.

But the glut could literally vanish tomorrow. All of you are familiar with the events that have brought sudden change in the Middle East over the last decade — revolutions, assassinations, and anti-American sentiment. Add to those the Soviet ambitions in the Persian Gulf, and the oil glut could end with a single rifle shot or the twist of a valve.

Let's not kid ourselves. In the next twenty years, this balance is going to remain so delicate that a minor Mideast political uprising or a Western economic backlash — or the promise of newly developed energy sources — could tip the scales in either direction.

Total world demand for energy is projected to grow about 2½ percent each year until the turn of the century — less than half the 1965 to 1973 rate. In the United States, the growth rate will be the lowest, averaging less than 1 percent per year. Even at this low worldwide growth rate, energy demand is projected to increase from almost 140 million barrels of oil equivalent per day in 1979 to 225 million barrels equivalent per day by the year 2000.

Conventional oil supply is on the downswing. It is expected to grow less than 1 percent per year through 2000, resulting in a decline in oil's share of energy supply from one half in 1979 to one third by the year 2000.

OPEC's most recent action, on October 29, did not deal with this key issue of production, even though the Saudis announced they are going to cut back production by one million barrels a day. But, the OPEC meeting October 29 did bring on the first price cut in OPEC's 21-year history. Libya and Algeria dropped their prices from $40 to $38 a barrel. At the same time, Saudi Arabia increased its price from $32 to $34. This agreement may very well mean a two- to three-cent price increase in U.S. petroleum products. But if OPEC keeps its vow not to hike prices next year, the real, inflation-adjusted prices could actually decrease in 1982.

OPEC's price unification is aimed more at strengthening OPEC than at giving Western oil consumers a break — Sheik Yamani's comments notwithstanding. The Saudi Arabian Oil Minister has claimed responsibility for engineering the current glut, which is, to a large extent, true. He also claims to have engineered the OPEC price agreement last month because — and these are his words — "the Western economies need a rest." Well, yes and no. Yes, the Western economies do need a rest. But no, that's not why Yamani negotiated the OPEC price unification.

Yamani and other Saudi officials have admitted they are worried that the price of oil, which in the past decade has risen from $3 to $35 a barrel, is prompting major consuming nations to look for alternatives at a much faster pace than OPEC would like. In other words — Yamani is worried that traditional crude oil will be driven out of the market long before the Kingdom's reserves run out.

All of which leads me to point number two — the role of alternate sources of energy in the present and future. Though our dependence on imported oil has left the industrialized West vulnerable, the situation is far from hopeless.

The United States has tremendous energy potential. Proven and potential oil and natural gas reserves in this country could last 40 years at the current rates of production and consumption.

Coal reserves are vast, extensive enough to last for centuries. The United States is the OPEC of coal, with 28 percent of the world's recoverable reserves. Coal is projected to be a major source of energy supply growth. It is expected not only to meet a substantial share of new energy demand, but also to replace oil and gas in major industrial and electric utility markets. By the year 2000 coal will rival oil as the single largest source of energy.

In addition, the U.S. has huge quantities of other fuels — oil shale, tar sands and uranium — that could contribute to the energy mix. We also expect to receive a small but increasing amount of energy from renewable sources such as solar, geothermal and biomass.

We may not have to wait for OPEC prices to spiral farther upward before alternate energy sources become price competitive. Technological advances are joining hands with economic feasibility — and doing it now.

Do the American people favor development of alternate energy sources such as coal, nuclear, oil shale and tar sands? According to a recent Opinion Research Corporation study, the answer is a staunch yes. More than 80 percent of the American people polled said they would encourage major oil companies to speed up the development of alternate sources of energy.

In that same study, more than 80 percent claim to have heard or read at least a fair amount about synthetic fuels, such as oil from coal and shale rock. Of those people, 88 percent felt the production of synfuels is very important to the solution for our energy problems. Phillips and many other companies are working to develop these alternate fuels. Though the main thrust of our activities for the next few decades will be in oil and gas, we feel in the meantime it is crucial to explore fully the opportunities presented by alternate fuels.

Remember that shifts in the energy supply/demand scale may cause these projects to speed up or slow down, but be assured that our goals are based on the conviction that all fuel sources will be essential for the continued prosperity of our nation and its people. Oil shale, coal, geothermal, solar, nuclear power, and oil and gas are the collective skeletal energy structure for the years ahead. A fracture to any part will hamper growth and development. Our body of energy will be weak in a world that increasingly cries for strength.

The energy is here. But we cannot allow ourselves to scour the land and then leave it fallow. We cannot provide a comfortable living environment for ourselves while making the air we breathe unbreatheable and the water we drink undrinkable. We cannot relax the safety and reliability standards of our generating plants while professing to create a more stable world.

A blacker mark could not be stamped against us than to have it accurately said that OPEC set the cost while the American people paid the price.

Let me now focus my comments on oil shale. Oil shale development has been talked about, agonized over, studied, planned for, promised, abandoned and resurrected in a seemingly endless series since around the turn of the century.

There are, I am told, several thousand inventors' patents on the subject. But in the U.S. we have yet to produce our first barrel of shale oil on a commercial basis. It is ironic that while few American industries have been studied in such extraordinary detail before they were born, few suffer from such widespread misunderstandings as oil shale. And so it is that people can say almost anything at all about oil shale and never encounter doubt or disbelief.

I suppose a good place to begin in discussing oil shale is to try to clear up the misconceptions embodied in these three words: oil shale industry. Actually, today we are not really an industry, we are more of an idea, a group of companies working hard to become an industry.

The most obvious feature of this fledgling industry is the sheer magnitude of the resource. An estimated 600 billion barrels, of recoverable reserves are locked in western oil shale alone. That's more than the combined crude oil reserves of all the OPEC nations, and it approaches the amount of oil in the world's proven conventional reserves.

The U.S. Geological Survey has estimated the total "known reserves" of Devonian eastern oil shale at 400 billion barrels, and the "probable extension of known resources" at an additional 2,600 billion barrels, including both deep, and surface deposits.

A thriving oil shale industry has been predicted a number of times during this century. But each time, the optimism evaporated as the discovery of new sources of cheap and easily produced conventional oil and gas made production of oil from shale uneconomic.

Today, most experts believe the large, cheap and easy discoveries of conventional oil and gas have been made. That simple fact, combined with the events of the past decade makes development of a U.S. shale industry appear to be a realistic prospect.

The total of eastern and western oil shale energy potential is staggering. It's enough to fill and then overflow the banks of Lake Erie, enough to supply the world's energy needs for the next 70 years at current rate of consumption.

Companies involved in oil shale have begun development programs. And, while development is slow and methodical, make no mistake — development is under way and progressing.

Before we focus our attention specifically on eastern oil shale, I want to share with you the progress that is being made in making oil shale a commercial reality. Let's take a brief look at what's happening on Colorado's western slope and in eastern Utah.

An impressive who's-who of companies is involved in 14 planned oil shale development projects. Exxon, Tosco, Union Oil of California, Chevron, Conoco, Occidental, Phillips, and many others are working to supply a combined total of about half a million barrels of oil a day by the mid-1990s.

Let's now talk more specifically about eastern oil shale. As you know, eastern and western shales differ in their yields of oil. Eastern shales have a yield of about 10-20 gallons per ton and the western shales yield 20-30 gallons per ton. However, it is important to recognize that the overall energy content of both the shales is similar; therefore an opportunity exists to use the residual energy content of eastern shale to narrow the gap between eastern and western shales.

Though eastern shales will produce comparatively larger amounts of byproducts, that's not a deterrent to developing them. There are a number of overriding factors that make eastern oil shale attractive. Eastern oil shale deposits are much closer to the markets than western oil shale. The supply of eastern oil shale is vast. Mining, operating and construction labor is readily available. There are abundant water resources. The shale is located in an industrialized area.

The eastern shales which outcrop in Kentucky, Ohio, Indiana, and other states are located on privately held land and can be mined economically. All these add significantly to the commercial feasibility of developing this resource.

As I said earlier, the U.S. Geological Survey has estimated the total "known resources" of Devonian eastern oil shale at 400 billion barrels and the "probable extensions of known resources" at an additional 2,600 billion barrels, including both deep and surface deposits. These estimates are very encouraging. But, eastern oil shale development is still in its infancy.

My own company has done extensive studies and is now leasing land for possible development in Indiana, Ohio and Kentucky. We are anticipating the construction of a demonstration plant in four to five years and a commercial plant in about 10 years. This demonstration plant will be a scaled down version of a commercial plant, but we will be processing shale and researching the processing techniques, mining techniques, and environmental impact.

Although we are keeping an open mind about several types of processing techniques to be used on the eastern oil shale, we are doing some research jointly with the Institute of Gas Technology in Chicago on their process. The process is based on controlled heating of the oil shale in a hydrogen atmosphere at elevated pressure. Although the process can be applied to any oil shale, it seems to be uniquely suited to improving the yields of oil from eastern Devonian shales.

We will be conducting studies on several environmental matters. I want to state emphatically that we feel eastern oil shale must be developed in an environmentally acceptable manner. We realize that people are concerned about how oil shale development will affect the quality of the air, water and land. Each of these areas is being studied and examined by Phillips as well as other companies and institutions.

We are optimistic about environmental matters relating to oil shale. Let me tell you why. The commercial plant will comply with all pertinent state and federal air pollution controls. The sulfur content of the eastern shale — about six percent — will not pollute the air because we won't give the vast majority of it the chance to reach the air. The sulfur in the oil will be removed through a hydrotreating process. The sulfur in the gas will be scrubbed out so that less than one percent remains. The sulfur recovered will be sold to industrial users. Emissions of other air pollutants will meet the EPA standards.

At the same time that we're mining, using the moving pit method, we'll be reclaiming the land. In other words, we'll begin filling one hole the minute we start digging the next. And not just filling. First we'll return the spent shale to its original location. Next, we'll cover the shale with the various strata of rock and earth that were there from the beginning. Then — and this is very important — we'll restore the shapes and contours of the land, plant grass and trees and other vegetation, and leave the precious landscape of this area in as good as or better shape than we found it. This reclaimed land may be used for farming, recreational lakes, wildlife refuges, or forestry.

Well, I realize I'm sounding rather like a salesman today. But we in the energy business, in the political arena, and in the public's eye need to realize that the American people in general and the people living in oil shale-rich areas in particular are concerned about their land, their homes, their air and water, and their economic well-being.

These concerns are genuine and should not be taken lightly. They are not likely to vanish overnight. On the other hand, it is necessary for all of us to convince the public that oil shale can be a very important part of this nation's energy future, and that the industry will not be developed at their expense.

Oil shale is a long-term proposition. In the meantime, other steps are necessary to bolster the nation's energy situation now and over the next few years.

First, we must continue to conserve energy. The petroleum industry research foundation says the demand for petroleum in the non-communist world fell 5 percent in 1980, and it's projected to drop another 4½ percent this year. We need to maintain that pace.

Second, we must step up our search for domestic oil and gas reserves even though tremendous strides are already being made. It's estimated that the industry will drill 77 thousand wells this year. That's 23 percent more than last year. And it's 20 thousand more wells than in the last great oil boom in the 1950s.

Third, we've got to make better use of the alternate energy sources at hand and strive to develop new ones. We should double the use of our vast coal reserves. We should increase the use of nuclear power. By taking these steps, this nation will reduce its dependence on foreign oil. As long as we have that dependence, our energy future will be in doubt.

I'm very pleased to see that there are so many of you interested in our energy situation and specifically in eastern oil shale. Thank you again for the opportunity to visit with you.

Monday Morning Session

PROCESS TECHNOLOGY

Analytical Pyrolysis of Eastern Oil Shales

by

J.W. Reasoner, L. Sturgeon and K. Naples
Department of Chemistry
Western Kentucky University
Bowling Green, Kentucky 42101

Marshall Margolis
Institute for Mining and Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract. The effects of ceiling temperature, heating rate (ramp) and pyrolysis interval on both the pyrolysis yield and relative product distribution for two eastern oil shales (Sunbury and Cleveland member of the Ohio Shale) were studied. The technique of analytical pyrolysis (pyrolysis - gas chromatography) was employed. Carefully controlled pyrolysis of the shale by this technique allows separation into high and low volatile components and measurement of the relative peak areas in the pyrogram gives the yield of the high volatile and low volatile components. Linear temperature ramps of 500°, 200° and 100°C per second were employed. Ceiling temperatures of 450°C to 950°C and pyrolysis intervals of up to 20 seconds were investigated. Samples were also repeatedly pulsed to obtain intervals of up to 120 seconds. Carbon-hydrogen-nitrogen and thermal gravimetric analyses were also performed on the spent shale.

Our preliminary data suggest the following.

1. The total amount of pyrolysis product (organic liquids and gases) increases with increasing ceiling temperature.

2. The product molecular weight distribution decreases with increasing ceiling temperature and with increased rates of heating.

3. The effect of increased heat-up rates on yield enhancement seems to maximize in the 650° to 750°C region.

4. The lower ceiling temperatures require significantly longer pyrolysis intervals in order to obtain optimum yields.

Introduction

It is generally conceded that shale oil is one of our most promising and abundant alternative energy resources. It is, therefore, essential to investigate those parameters that will influence the overall yield of product derived from oil shale retorting and will affect the distribution of product between gases, light oils and heavy oils. The object of this study was to investigate the effects of ceiling temperature, heating rate and pyrolysis interval (total heating time) on the product distribution and overall yield from two eastern oil shales.

The oil yield from shale is presently measured by techniques similar to the U.S. Bureau of Mines modified Fischer Assay.[1] This technique specifies that the sample be heated under static conditions at a rate of 12°C per minute until a final temperature of 500°C is attained. This ceiling temperature is then maintained for 20 minutes and the yields of oil and water are measured. A Fischer Assay type retort does not readily lend itself to exploratory studies where very high heating rates are employed. The technique of analytical pyrolysis (pyrolysis - gas chromatography) seems ideally suited to applications of this type.

The technique of analytical pyrolysis has been applied to a number of interesting problems involving organic materials of high molecular weight. The analysis of lignites, the determination of tryptophan in protein, the analysis of carbon residues in spent catalysts and the analysis of

rubber and other high polymers are but a few examples.[2-5] It has also been applied to the analysis of organic material in sediments, petroleum source rocks and shales.[6-12]

Experimental

Oil Shales

Two eastern oil shales were employed in this study. Specimens of the Sunbury Shale (of the Mississippian Age) and Cleveland Member of the Ohio Shale (of the Devonian Age) from Lewis County in northeastern Kentucky were studied. Relevant analytical information on the raw shales is given in Table 1. The Sunbury and Cleveland Shales are reported to yield 16.4 and 14.0 gal/ton respectively on Fischer Assay.[13] Samples of both shales used in this study were in the 60/100 mesh size range and were prepared in the laboratories of the Kentucky Center for Energy Research Laboratory.

Instrumentation

A Chemical Data Systems model 100 Pyroprobe (coil probe) interfaced with a Varian model 3700 gas chromatograph (dual flame ionization detectors) and a Laboratory Data Control model 308 computing integrator were employed in these studies. A 50 cm. x 1/8 inch stainless steel 5% OV-101 column was used and a flow rate of nitrogen (carrier gas) of approximately 30 mL per minute was employed. The injector temperature was maintained at 270°C and the interface unit at 200°C. The Chemical Data Systems basic instrument allows linear temperature ramps of 100°C/second, 200°C/second and 500°C/second to be employed in the shale pyrolysis. In addition, the final pyrolysis temperature (ceiling temperature) is continuously adjustable up to 1000°C and can be maintained for intervals of up to 20 seconds. This technique easily allows one to employ very high temperature ramps and still restrict the final pyrolysis temperature in order to minimize the degree of carbonization of the shale oil product. This technique then permits a carefully controlled pyrolysis of the shale in an inert atmosphere, gas chromatographic separation of the product into "high volatile" (lower molecular weight) and "low volatile" (higher molecular weight) products and the measurement of the relative peak areas in the high and low volatile portions of the pyrogram. Non-hydrocarbon products (eg. H_2O, H_2, CO_2, H_2S, etc.) from the shale pyrolysis are not detected by the F.I.D. and are therefore not represented in the pyrogram.

Procedure

Quartz tubes 2.4 mm od x 2.5 cm long were fitted with quartz wool plugs and heated to 1000°C for 10 seconds in order to burn away any organic contaminates present. The tubes were then weighed on a Mettler model H-20T analytical balance, loaded with 4 to 5 milligrams of the 60/100 mesh shale and weighed again in order to obtain the actual weight of the shale being subjected to pyrolysis. The loaded and weighed tubes were then placed inside the coil of the CDS Pyroprobe heater unit and placed inside the interface unit attached to the injection port of the gas chromatograph. The samples were heated to 200°C (the equilibrium temperature of the CDS Pyroprobe - Varian gas chromatograph interface unit) and allowed to equilibrate for 20 minutes. The samples were then pyrolyzed at the specified temperature ramp, ceiling temperature and time interval. Pyrograms were obtained for each run and electronically integrated to determine the relative product ratios for the initial warm-up ("distillate") and for the high volatile and low volatile products from the actual pyrolysis. Analyses were carried out in replicate (4 to 10 runs) and average values and standard deviations calculated.

The pyrograms were divided into three regions for the purposes of this study as shown in Figure 1. The material that is evolved during the initial warm-up of the interface unit and that passes through the gas chromatography column (isothermal at 60°C) between 0 and 15 minutes during the equilibration is called the "distillate" fraction and is largely derived from the nonkerogen organic materials in the shale. This is essentially the same material that is extracted from the shale with organic solvents. Since each sample of a given shale is subjected to exactly the same equilibration conditions, the magnitude of the distillate fraction should be relatively constant and serve as a quasi-internal standard. Apparent changes in the distillate fraction should actually reflect changes in the amounts of material in the high and low volatile portions of the pyrogram. The material indicated on the pyrogram from 0 to 5 minutes after the probe is fired (20 to 25 minutes after turn-on) is called the "high volatile" fraction. This material passes through the column at 60°C (isothermal) and is made up of the organic gases and more volatile organic materials evolved during the oil shale pyrolysis. Finally, the material collected from 30 to 45 minutes after turn-on (10 to 25 minutes) after firing the probe is called the "low volatile" fraction. This material passes through the column with a program of 60°C to 250°C at a rate of 20°C per minute. This material is the less volatile higher molecular weight organic material derived from the oil shale. The temperature is held at 250°C for a total of 40 minutes to drive off as much of the organic material from the column as possible.

In addition to the ratio of material in the distillate, high and low volatile portions of the pyrogram, the overall product yield may be esti-

Table 1. Analysis of the Raw Shale

SHALE	% Carbon	% Hydrogen	% Nitrogen	% Moisture	% Volatile Matter	% Fixed Carbon	% Ash
Sunbury	15.98	1.84	0.59	0.90	15.6	7.10	76.4
Cleveland	12.4	2.03	0.56	2.3	15.1	6.6	76.0

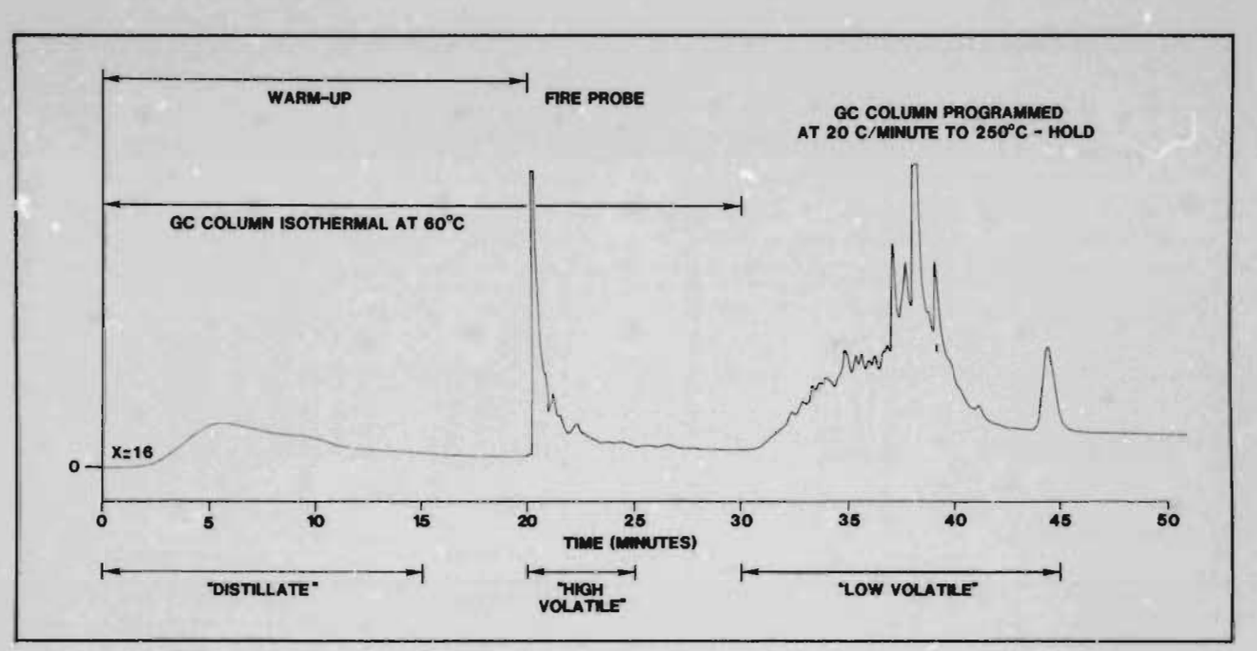

Figure 1. Pyrogram of Sunbury Shale (Typical)

mated in a number of different ways. The spent shale samples are weighed and the percent weight loss is determined. The weight loss for each sample is due, however, not only to the organic material being volatilized, but also due to loss of water, hydrogen, hydrogen sulfide, carbon dioxide and other materials which are not reflected in the pyrogram. The sum of the integrator counts obtained in the distillate, high and low volatile fractions can be divided by the sample weight to obtain a measure of the total product yield in terms of the number of product counts per milligram of oil shale pyrolyzed. Finally, the samples of spent shale are subjected to carbon-hydrogen-nitrogen and thermal gravimetric analyses. The difference in carbon content before and after pyrolysis as well as the difference between the volatile matter in the raw and spent shale can be used as estimates or measures of the total product yield.

The pyrolysis system, the control unit and the probe itself, have been calibrated to provide accurate heating rates and temperatures. There are, however, potential discrepancies between the temperature of the probe element itself and the instantaneous temperature experienced by the shale sample for the duration of the probe firing.

The data presented here have not been corrected for these differences. Therefore, these data may be approximately 100-150°C greater than those actually experienced by the sample. The reported trends, however, are independent of this phenomenon.

Work is presently underway to accurately determine the true temperature experienced by the probe's sample.

Results and Discussion

Ceiling Temperature

The results obtained for both Sunbury and Cleveland oil shales in terms of the effect of ceiling temperature are given in Tables 2 and 3. There are a number of observations that can be made with regard to ceiling temperature. At a heating rate of 500°C/second and a pyrolysis interval of 10 seconds, the overall yield of total pyrolysis product from Sunbury shale increases rather dramatically as the ceiling temperature increases from 650° to 750°C. A very similar effect is noted for the Cleveland shale as the temperature is increased from 550° to 650°C. In addition, both shales show a general increase in overall product yield with increasing ceiling temperature. This trend can be noted from the percent weight loss (Figure 2), from the number of integrator counts per milligram of shale pyrolyzed (Figure 3) and from the extent of the loss of volatile matter (as compared to Fischer Assay) in the spent shale as measured by thermal gravimetric analysis (Figure 4).

It should also be noted that both shales show a shift in the molecular weight distribution (degree of volatility) as a function of temperature. The quantity of gases and high volatile (lower molecular weight) material increases with increasing ceiling temperature (Figure 5). This strongly suggests that kerogen pyrolysis becomes extensive between 600° and 700°C under the conditions of this experiment. In addition to the increased rate of kerogen pyrolysis we are also apparently observing an increase in the extent of cracking of the higher molecular weight (low volatile) material at the higher ceiling temper-

Table 2. Product Yield and Distribution as a Function of Ceiling Temperature

Ceiling Temperature	% Distillate Fraction	% High Volatile Fraction	% Low Volatile Fraction	% Weight Loss	Integrator Counts per Milligram ($x10^3$)
Sunbury Shale					
450°C	36.1	1.1	62.9	5.9	23.1
550°C	33.0 (3.4)*	11.7 (2.2)	55.3 (5.2)	7.2 (3.8)	25.3 (3.9)
650°C	22.7 (5.4)	14.5 (2.2)	62.8 (6.3)	5.6 (3.1)	26.7 (8.7)
750°C	7.0 (4.3)	27.7 (3.5)	65.3 (5.0)	11.3 (5.7)	126.2 (49.9)
850°C	5.3 (2.3)	39.7 (4.6)	55.0 (4.3)	14.6 (2.5)	144.1 (51.5)
950°C	5.4 (2.2)	44.1 (10.1)	50.6 (7.9)	12.7 (2.2)	188.4 (91.1)
Cleveland Shale					
450°C	18.3 (1.0)	8.0 (0.1)	73.7 (1.0)	---	22.5 (4.0)
550°C	11.9 (2.3)	23.1 (2.8)	65.0 (3.0)	9.8 (5.7)	25.0 (7.0)
650°C	4.4 (3.5)	30.6 (3.0)	65.0 (2.3)	14.8 (1.5)	90.1 (27.3)
750°C	3.5 (2.0)	39.7 (2.9)	56.8 (1.9)	11.1 (2.3)	84.7 (50.4)
850°C	3.7 (3.2)	43.6 (3.8)	52.7 (3.6)	15.0 (6.0)	102.0 (47.6)
950°C	2.4 (0.4)	42.6 (4.7)	55.0 (4.3)	16.2 (0.0)	155.0 (27.3)

Temperature Ramp = 500°C/second Pyrolysis Interval = 10 seconds

*Based on the average of 4 to 10 runs. Standard deviation (1 sigma) is given in ( ) beside each value.

Table 3. Analysis of the Spent Shale as a Function of the Ceiling Temperature

Ceiling Temperature	% Carbon	% Hydrogen	% Nitrogen	% Moisture	% Volatile Matter	% Fixed Carbon	% Ash
Sunbury Shale							
Raw Shale	16.3	1.9	0.6	0.90	15.6	7.10	76.4
450°C	15.4	1.69	0.64	-	-	-	-
550°C	15.8	1.70	0.63	0.66	15.0	7.30	77.04
650°C	15.6	1.80	0.60	-	-	-	-
750°C	12.7	1.17	0.54	-	-	-	-
850°C	11.8	1.06	0.50	0.32	8.15	7.86	83.67
950°C	8.62	0.42	0.38	-	-	-	-
Fischer Assay	9	0.6	0.5	-	-	-	-
Cleveland Shale							
Raw Shale	14.7	1.9	0.55	2.3	15.1	6.6	76.0
450°C	-	-	-	2.02	14.67	6.08	78.34
550°C	-	-	-	0.72	14.10	5.74	79.44
650°C	-	-	-	0.79	9.24	7.10	81.32
750°C	-	-	-	0.60	11.35	6.59	81.56
850°C	-	-	-	0.54	8.86	6.92	84.00
950°C	8.39	0.42	0.35	0.46	5.85	6.85	86.84
Fischer Assay	9	0.6	0.5	0.36	4.9	9.1	85.6

Temperature Ramp = 500°C/Second Pyrolysis Interval = 10 seconds

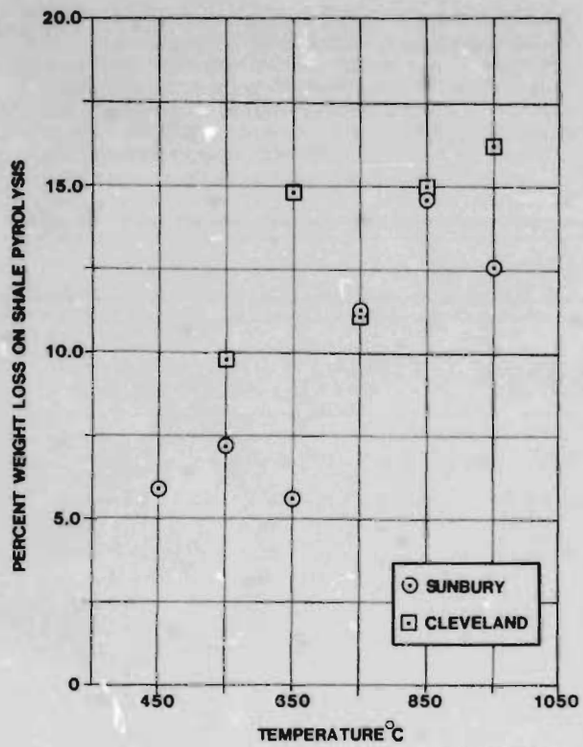

Figure 2. Weight Loss on Shale Pyrolysis as a Function of Ceiling Temperature

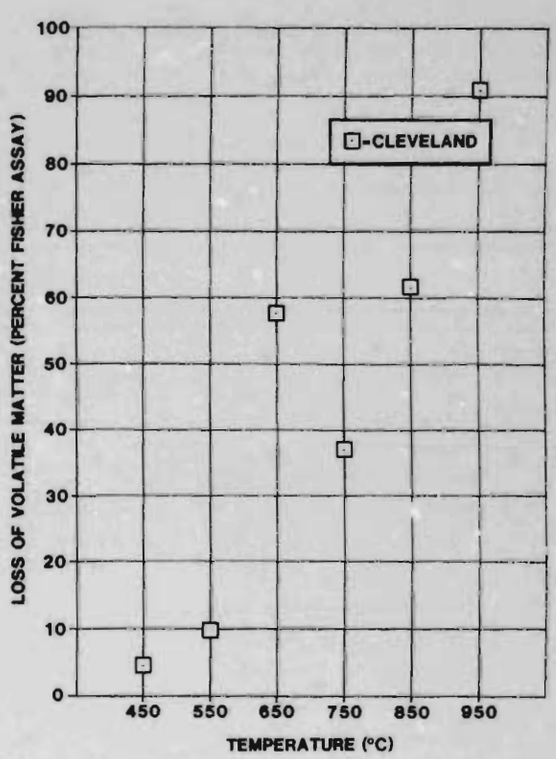

Figure 4. Yield Based pn the Loss of Volatile Matter on Pyrolysis

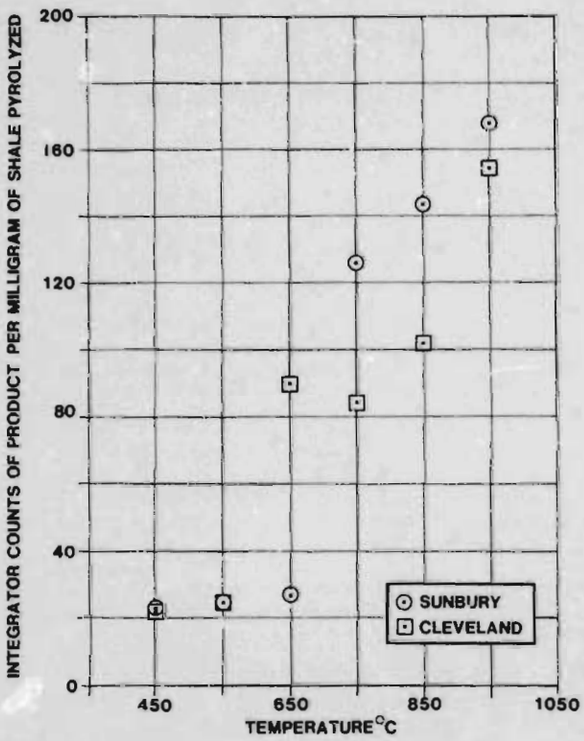

Figure 3. Yield Based on Integrator Counts Product per Milligram of Oil Shale Pyrolyzed as a Function of Ceiling Temperature

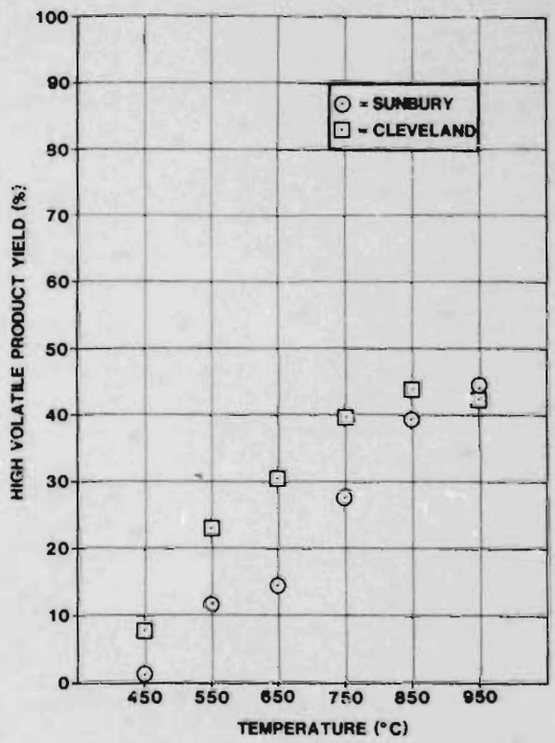

Figure 5. Yield of Material in the High Volatile Fraction as a Function of Ceiling Temperature

ature. This is in very good agreement with earlier observations by Leventhal on the stepwise pyrolysis of kerogen in sedimentary rocks.[14]

Heating Rate

The effect of heating rate (ramp) on overall yield and on product distribution is summarized in Tables 4 and 5. It appears that both the overall yield and product distribution are at least somewhat sensitive to the heating rate employed. The most notable difference occurs between 500°C and 100°C/second ramps. One must exercise caution however, as the differences are small in many cases. In addition, the effect observed may be at least in part due to differences in residence

Table 4. Product Yield and Distribution as a Function of Heating Rate

Heating Rate	% Distillate Fraction	% High Volatile Fraction	% Low Volatile Fraction	% Weight Loss	Integrator Counts per Milligram ($\times 10^3$)
Sunbury Shale					
Ceiling Temperature = 550°C					
500°C/sec.	33.0 (3.4)*	11.7 (2.2)	55.3 (5.2)	7.2 (3.8)	25.3 (3.9)
200°C/sec.	36.5 (3.4)	7.9 (1.9)	55.5 (2.3)	5.2 (2.3)	18.7 (4.1)
100°C/sec.	34.8 (6.4)	7.3 (1.4)	57.9 (5.6)	6.7 (2.2)	19.6 (4.4)
Average	34.8 (4.8)	8.9 (1.8)	56.4 (4.2)	6.5 (2.8)	21.1 (4.2)
Ceiling Temperature = 650°C					
500°C/sec.	22.7 (5.4)	14.5 (2.2)	62.8 (6.3)	5.6 (3.1)	26.7 (8.7)
200°C/sec.	23.8 (4.5)	13.5 (3.8)	62.8 (5.4)	7.0 (2.9)	26.1 (10.5)
100°C/sec.	25.4 (1.3)	13.1 (2.9)	60.6 (4.2)	7.1 (1.5)	23.6 (3.6)
Average	23.9 (4.3)	13.7 (3.0)	62.2 (5.5)	6.6 (2.7)	25.6 (8.4)
Ceiling Temperature = 750°C					
500°C/sec.	7.0 (4.3)	27.7 (3.5)	65.3 (5.0)	11.3 (5.7)	126.2 (49.9)
200°C/sec.	9.8 (3.1)	24.3 (1.6)	65.9 (2.0)	15.6 (2.1)	95.3 (49.8)
100°C/sec.	12.9 (2.5)	18.0 (4.7)	69.6 (5.8)	9.8 (4.8)	40.3 (27.4)
Average	9.4 (3.6)	24.3 (3.4)	66.5 (4.5)	12.2 (4.8)	92.0 (45.0)
Ceiling Temperature = 850°C					
500°C/sec.	5.3 (2.3)	39.7 (4.6)	55.0 (4.3)	14.6 (2.5)	144.1 (51.5)
200°C/sec.	5.5 (3.5)	37.9 (4.9)	56.5 (4.7)	13.5 (3.5)	142.8 (75.0)
100°C/sec.	6.1 (5.3)	35.6 (4.9)	58.3 (5.0)	12.1 (3.9)	113.3 (55.9)
Average	5.6 (3.7)	33.0 (4.8)	56.4 (4.6)	13.6 (3.2)	134.7 (60.3)
Cleveland Shale					
Ceiling Temperature = 550°C					
500°C/sec.	11.9 (2.3)	23.1 (2.0)	65.0 (3.0)	9.8 (5.7)	25.0 (7.0)
200°C/sec.	15.9 (3.4)	23.6 (2.2)	60.5 (1.9)	9.4 (3.8)	22.1 (4.9)
100°C/sec.	19.6 (5.0)	19.0 (3.3)	61.5 (2.8)	8.4 (2.6)	18.9 (5.0)
Average	15.8 (3.7)	21.9 (2.8)	62.3 (2.6)	9.2 (4.2)	22.0 (5.7)
Ceiling Temperature = 650°C					
500°C/sec.	4.4 (3.5)	30.6 (3.0)	65.0 (2.3)	14.8 (1.5)	90.1 (27.3)
200°C/sec.	3.8 (2.8)	27.9 (4.6)	68.3 (2.4)	9.6 (2.7)	79.2 (25.1)
100°C/sec.	4.8 (4.6)	27.6 (3.7)	67.7 (6.3)	9.9 (3.6)	55.0 (16.8)
Average	4.3 (3.7)	28.8 (3.8)	66.9 (4.0)	11.7 (2.7)	74.8 (23.5)
Ceiling Temperature = 750°C					
500°C/sec.	3.5 (2.0)	39.7 (2.9)	56.8 (1.9)	11.1 (2.3)	84.7 (50.4)
200°C/sec.	5.4 (1.9)	38.3 (3.1)	56.3 (1.7)	9.2 (2.1)	55.7 (29.4)
100°C/sec.	10.2 (5.8)	24.8 (8.7)	65.0 (3.0)	10.1 (4.7)	41.9 (32.3)
Average	6.1 (3.5)	34.9 (5.2)	59.0 (2.2)	10.3 (3.3)	62.1 (39.0)
Ceiling Temperature = 850°C					
500°C/sec.	3.7 (3.2)	43.6 (3.8)	52.7 (3.6)	15.0 (6.0)	102.2 (47.6)
200°C/sec.	2.8 (1.0)	44.8 (1.1)	52.4 (0.9)	12.2 (3.2)	108.6 (32.1)
100°C/sec.	6.1 (4.0)	37.6 (4.5)	56.3 (2.0)	11.7 (5.8)	88.7 (32.5)
Average	4.3 (3.1)	41.8 (3.6)	53.9 (2.5)	12.9 (5.2)	97.1 (37.6)

*Based on the average of 4 to 10 runs. Standard deviation (1 sigma) is given in ( ) beside each value.

Pyrolysis interval = 10 seconds

time at the ceiling temperature. The oil shale will spend more time at the ceiling temperature when a ramp of 500°C/second is employed than when a ramp of 100°C/second is employed. For a given ceiling temperature both Sunbury and Cleveland shales tend to give higher yields of product at the higher ramp. In addition, it appears that the higher ramps also favor the lighter (high volatile) materials. It should also be noted that the largest ramp effect observed for both Sunbury and Cleveland occurred at a temperature of 750°C for the 10 second pyrolysis interval.

It would be most interesting to compare results obtained at these extremely high ramps (30,000°C/minute) with those obtained under typical Fischer Assay conditions (12°C/minute). Our equipment is currently being modified to allow much lower ramps and longer pyrolysis intervals to be employed.

Table 5. Analysis of the Spent Shale as a Function of the Heating Rate.

Heating Rate	% Carbon	% Hydrogen	% Nitrogen	% Moisture	% Volatile Matter	% Fixed Carbon	% Ash
Sunbury Shale							
Ceiling Temperature = 550°C							
500°C/sec.	15.8	1.70	0.63	0.66	15.00	7.30	77.04
200°C/sec.	15.9	1.72	0.62	0.49	15.23	7.37	76.91
100°C/sec.	15.6	1.68	0.60	0.56	15.17	6.74	77.53
Ceiling Temperature = 650°C							
500°C/sec.	15.4	1.74	0.59	--	--	--	--
200°C/sec.	15.4	1.79	0.58	--	--	--	--
100°C/sec.	16.0	1.85	0.60	--	--	--	--
Ceiling Temperature = 750°C							
500°C/sec.	12.7	1.17	0.54	--	--	--	--
200°C/sec.	13.8	1.39	0.56	--	--	--	--
100°C/sec.	15.0	1.68	0.59	--	--	--	--
Ceiling Temperature = 850°C							
500°C/sec.	11.2	0.94	0.48	0.32	8.15	7.86	83.67
200°C/sec.	10.5	0.79	0.45	0.34	10.93	7.48	81.25
100°C/sec.	11.8	1.04	0.53	0.52	12.15	7.14	80.19
Cleveland Shale							
Ceiling Temperature = 550°C							
500°C/sec.	--	--	--	0.72	14.10	5.74	79.44
200°C/sec.	--	--	--	0.81	13.76	6.58	78.84
100°C/sec.	--	--	--	0.77	13.90	6.20	79.19
Ceiling Temperature = 650°C							
500°C/sec.	--	--	--	0.79	9.24	7.10	81.32
200°C/sec.	--	--	--	0.64	10.21	6.55	82.61
100°C/sec.	--	--	--	0.64	11.80	6.39	81.33
Ceiling Temperature = 750°C							
500°C/sec.	--	--	--	0.61	11.35	6.49	81.56
200°C/sec.	--	--	--	0.61	12.28	6.58	80.53
100°C/sec.	--	--	--	1.07	14.82	5.54	78.56
Ceiling Temperature = 850°C							
500°C/sec.	--	--	--	0.54	8.86	6.92	84.00
200°C/sec.	11.25	1.03	0.48	0.57	10.62	6.82	82.00
100°C/sec.	12.30	1.22	0.47	0.63	13.02	6.64	79.71

Pyrolysis Interval = 10 seconds.

Pyrolysis Interval

The effect of pyrolysis interval (total heating time during pyrolysis) is summarized in Tables 6 and 7. A ceiling temperature of 750°C and a ramp of 500°C per second was employed for these studies. Under these conditions the overall product yield tends to increase rapidly with increasing interval up to approximately 20 seconds. Carbon-hydrogen-nitrogen and thermal gravimetric analyses of both shales (Table 7) indicate that both generate product yields approximately equivalent to the Fischer Assay when a pyrolysis interval of 20 seconds or greater is employed at the 750°C temperature ceiling. Extension of the interval beyond 30 seconds (by the use of a number of 10 second or 20 second pulses) shows only a marginal increase in product yield at the 750°C ceiling.

The situation is quite different for the 550°C ceiling temperature. Samples of both Sunbury and Cleveland shale were repeatedly pulsed at ceiling temperatures of 750°C and 550°C and the integrator counts per milligram of shale pyrolyzed were measured (Table 8). This indicated that after 20 seconds at the 750°C ceiling both shales had evolved in excess of 90% of the total product measured. After 20 seconds at the 550°C ceiling the Cleveland shale had evolved less than 50% of the total product evolved. After 120 seconds (6 x 20 seconds) the total product yield as measured in terms of total number of integrator counts per milligram of shale pyrolyzed was still less than that obtained at the 750°C ceiling temperature (Figure 6).

This observation is consistent with the view that facile breakdown of the kerogen occurs above

Table 6. Product Yield and Distribution as a Function of Pyrolysis Interval.

Pyrolysis Interval	% Distillate Fraction	% High Volatile Fraction	% Low Volatile Fraction	% Weight Loss	Integrator Counts per Milligram ($x10^3$)
Sunbury Shale					
60 sec. (3x20)	2.0	36.5	61.5	18.6	206.7
20 sec.	2.9 (1.9)*	39.2 (3.4)	57.9 (2.6)	17.1 (1.9)	181.2 (27.6)
10 sec.	7.0 (4.3)	27.7 (3.5)	55.3 (5.2)	11.3 (5.7)	126.2 (49.9)
5 sec.	4.7 (2.0)	29.1 (2.7)	66.2 (3.3)	8.6 (1.9)	129.7 (13.6)
2 sec.	27.4 (1.5)	8.5 (1.3)	64.2 (1.6)	7.6 (3.7)	27.8 (5.4)
Cleveland Shale					
30 sec. (3x10)	1.3	39.3	59.4	14.8	162.0
20 sec.	1.8 (0.9)	43.6 (4.2)	54.6 (3.8)	20.2 (3.0)	173.3 (26.0)
10 sec.	3.5 (2.0)	39.7 (2.9)	56.8 (1.9)	11.1 (2.3)	84.7 (50.3)
5 sec.	6.2 (4.5)	26.9 (2.2)	66.9 (3.1)	7.8 (1.7)	103.2 (32.6)
2 sec.	24.2 (4.6)	7.2 (3.5)	68.5 (4.5)	4.9 (3.0)	18.1 (4.2)

Ceiling Temperature = 750°C Heating Rate = 500°C/second

*Based on the average of 4 to 10 runs. Standard deviation (1 sigma) is given in ( ) beside each value.

Table 7. Analysis of the Spent Shale as a Function of the Pyrolysis Interval.

Pyrolysis Interval	% Carbon	% Hydrogen	% Nitrogen	% Moisture	% Volatile Matter	% Fixed Carbon	% Ash
Sunbury Shale							
60 sec. (3x20)	8.8	0.49	0.42	--	--	--	--
30 sec. (3x10)	9.1	0.69	0.42	--	--	--	--
20 sec.	10.3	0.75	0.45	0.50	5.84	9.10	84.56
10 sec.	12.7	1.17	0.54	--	--	--	--
Cleveland Shale							
60 sec. (3x20)	8.7	0.49	0.40	--	--	--	--
30 sec. (3x10)	9.1	0.69	0.44	--	--	--	--
20 sec.	8.6	0.56	0.37	0.44	4.58	7.41	87.57
10 sec.	13.2	1.34	0.51	0.60	11.35	6.49	81.56

Ceiling Temperature = 750°C Heating Rate = 500°C/second

Table 8. Total Product Yield (Integrator Counts per Milligram of Shale) and Low Volatile Yield as a Function of Pyrolysis Interval (Pulse Experiment).

Pulse Number	Accumulated Time	% Low Volatile Fraction	Total Integrator Counts/milligram ($x10^3$)	Accumulated Counts/ milligram ($x10^3$)
Sunbury Shale Ceiling Temperature = 750°C Heating Rate = 500°C/second				
1	20 seconds	60.1	197.0	197.0
2	40 seconds	89.2	6.9	203.9
3	60 seconds	90.4	2.8	206.7
Cleveland Shale Ceiling Temperature = 750°C Heating Rate = 500°C/second				
1	10 seconds	57.4	140.7	140.7
2	20 seconds	71.9	14.2	154.9
3	30 seconds	74.3	7.1	162.0
Cleveland Shale Ceiling Temperature = 550°C Heating Rate = 500°C/second				
1	20 seconds	66.8	61.1	61.1
2	40 seconds	69.0	22.2	83.3
3	60 seconds	79.2	13.3	96.6
4	80 seconds	66.1	12.9	109.5
5	100 seconds	71.6	7.4	116.9
6	120 seconds	69.3	5.4	122.3

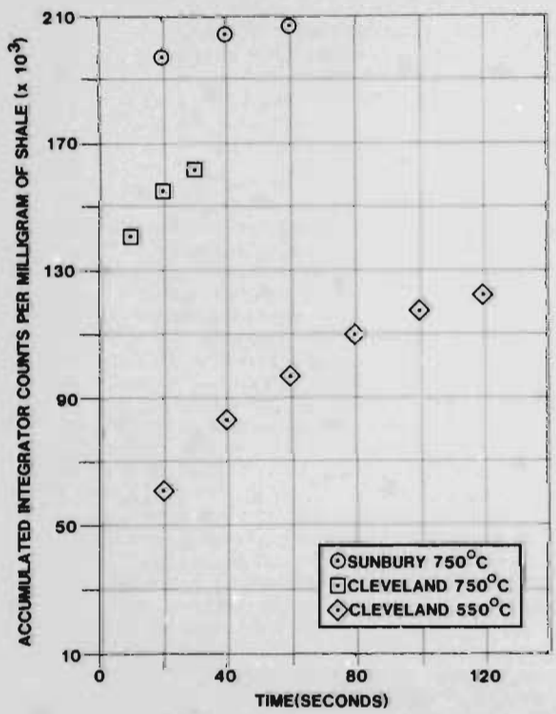

Figure 6. Total Product (Integrator Counts per Milligram of Shale) as a Function of Time

the 550°C temperature ceiling. Kerogen pyrolysis below 550°C appears to occur at a significantly slower rate. The pulse experiments have also shown that the major portion of the material evolved beyond the initial pulse at the 750°C ceiling temperature was in the higher molecular weight range (low volatile fraction). In the first 20 second pulse for the Sunbury shale the low volatile fraction accounted for approximately 60% of the total product. The second 20 second pulse gave much less material and approximately 89% of this was in the low volatile fraction. Cleveland gave similar results at the 750°C ceiling.

Summary

The purpose of this exploratory study was to attempt to utilize the technique of analytical pyrolysis to investigate the effect of ceiling temperature, heating rate and pyrolysis on the overall yield and product distribution for two eastern shales. Our results indicate that under the conditions employed the overall yield of pyrolysis product increases with ceiling temperature. In addition, the product molecular weight appears to decrease with increasing ceiling temperature and with increased heating rates. This effect seems to maximize for both shales in the 650 to 750°C region. The pyrolysis interval is also very important, especially at the lower ceiling temperatures. While only 20 to 30 seconds may be required to maximize the yield at 750°C and above (under the conditions of this experi-

ment), the interval may be several times as long to produce an equivalent yield at ceiling temperatures of 550°C and below. This suggests that both the ceiling temperature and residence time must be carefully considered in the design of shale pyrolysis experiments.

In this study the effect of each individual parameter was investigated holding the other two constant. It should be noted, however, that they are interdependent and all of these must be carefully considered in order to optimize the yield and/or product ratio in oil shale pyrolysis.

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Influence of Retorting Parameters on Oil Yield from Sunbury & Ohio Shales from Northeastern Kentucky

by

A.M. Rubel
T.T. Coburn
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract. A comprehensive survey of retorting conditions and their effects on oil yield from master batches of two eastern oil shales (Sunbury Shale and the Cleveland Member of the Ohio Shale) has been undertaken. A small bench scale retort was used to study the following retorting parameters: upper temperatures from 500 to 1000°C; heating rates from 0.1 to 55°C/min; preheated inert (N_2) gas sweeps; and vacuum and steam retorting.

Both Sunbury and Cleveland shales behave similarly when subjected to the variations in retorting parameters studied. Oil yields from both shales were not appreciably affected by changes in upper temperature limits between 500°C and 1000°C. Rapid removal of volatiles from the retort chamber during retorting with a preheated N_2 gas sweep, or by retorting under vacuum, enhances yield as does rapid heating. A heating rate of 55°C/min results in increased yields of 110-116% Fischer Assay. Retorting with steam also significantly increases oil yield. At a heating rate of 4°C/min with a 0.7 l/min steam flow, increases in oil yield were 125% Fischer Assay (Sunbury) and 123% Fischer Assay (Cleveland). Information gathered to date on Sunbury and Cleveland shales indicates that the optimum retorting technology will involve rapid heating coupled with rapid removal of volatiles from the retort chamber. For both shales the utilization of steam as a sweep gas should also be beneficial.

Introduction

The influence of different retorting conditions on oil yield has been thoroughly studied using western shales but little work has been performed on eastern shales. Several studies have addressed the basic differences between eastern and western shales and provide evidence that eastern shales will not pyrolyze in an identical manner to western shales. Kentucky shales have been shown to have a higher C:H ratio than western shales. The average C:H ratio for three composite New Albany Shale cores taken from either side of the Cincinnati Arch in south central Kentucky was 11.1 compared to 7.8 for the Green River Formation.[1] The Sunbury and Ohio (Cleveland) shales have an average C:H ratio of 9.6 and 9.1, respectively.[2] Thermal treatment of New Albany Shale yields only 1/3 conversion of organic matter to oil as compared to 2/3 for Colorado shales.[3] Other studies have confirmed lower than expected Fischer Assay oil yields for eastern shales based on organic C content.[4,5] Significant differences are also evident in the composition of kerogen from eastern Devonian and the Green River Formation. Several studies have indicated that the higher C:H ratio characteristic of Kentucky shales is caused by the increased aromaticity of eastern shales[1,6] in comparison to the aliphatic nature of kerogen from the Green River Formation.

These differences between eastern and western shales indicate that optimum retorting conditions for eastern shales will not be the same as for western shales. Comparison studies which have been conducted under conditions optimum for oil generation from western shale are far from ideal conditions for eastern shale retorting. This is particularly true of early work on the shales of Kentucky.[7] However, a number of recent reports allow interesting and useful direct comparisons.[8,9,10,11]

These direct comparisons often give little indication of how oil yield varies in response to changes in retorting conditions. The IGT work is a notable exception. A systematic evaluation of the effects of changes in retorting conditions on process oil yield from eastern shales under a hydrogen pressure has been reported.[10,12,13] We have recently reported our systematic laboratory study on how a number of retorting conditions affect

Sunbury Shale thermolysis.[14] Oil yield from Sunbury Shale was found to be particularly sensitive to heat-up rate. Poor results from previous retorting studies of eastern shales could be the effect of slow heating alone. For instance, retorting of Antrim Shale in a controlled state retort at 1°C/min resulted in an oil yield of 81% Fischer Assay as compared to 100% Fischer Assay for Colorado and Utah shales.[8] At a heating rate of 1°C/min for Sunbury Shale, our results would predict an 82% Fischer Assay yield.

For the purpose of this study, two Kentucky shales (Sunbury and the Cleveland Member of the Ohio) were chosen for evaluation of the effects of changes in retorting conditions on oil yields. They are from two different ages, Mississippian (Sunbury) and Devonian (Cleveland Member of the Ohio Shale). If differences in response to changes in retorting conditions exist between different eastern shales, they should be seen by studying these two shales. It is uncertain whether optimum retorting conditions for eastern shales will vary with lateral or vertical variations even though Cook[15] suggests that optimum retorting conditions for western shales are similar regardless of source rock depth. Additionally, there is some evidence to indicate that Sunbury Shale may respond differently from other Kentucky shales under Fischer Assay conditions. Sunbury Shale produces less oil per unit carbon than Cleveland Shale by approximately 10%.[2] The discrepancy between the response of Sunbury and New Albany Shale in the work by Miknis and Maciel[16] might, furthermore, reflect a difference between the Sunbury and Ohio shales.

It has been suggested that the processing of shale to synthetic crude products is far more sensitive to thermal efficiency than coal conversion processes. This is especially evident for lean shales. If the shale contains 17% organic material, Larson and Wen[17] have assessed that each 1% change in thermal efficiency results in a 4.78% change in product cost. This would imply that the need for an optimum technology is far more essential to the development of an oil shale industry for the East than for the West. Therefore, a thorough study of the effect of changes in retorting parameters on oil yield from the Kentucky shales was undertaken.

Experimental

Oil Shale. Three large master batches of shale, two from the Sunbury Shale and the other from the Cleveland Member of the Ohio Shale, were obtained by a bulldozer from subsurface outcrops in northeastern Kentucky (Lewis County). The Sunbury samples came from two locations. The collection and processing of the first Sunbury sample (Fischer Assay = 68.4 l/Mg; 16.4 gal/ton) has been previously described.[14] The second Sunbury sample (Fischer Assay = 59.2 l/Mg; 14.2 gal/ton) was dug from a location, latitude 38°-30'-40" north, longitude 83°-22'-00" west. The Cleveland sample (Fischer Assay = 58.4 l/Mg; 14.0 gal/ton) was collected from a site, latitude 38°-36'-25" north, longitude 83°-27'-30" west. The samples were crushed, blended, sieved, and riffled to produce uniform samples of approximately retort charge size (100-150 grams). Samples were -16 to +60 mesh.

The Retort. A bench scale batch retort based on the design of Stout, Koskinas, and Santor[18] with several modifications was used in this study. The design of the retort bomb was modified to allow for easy charging by welding half of a 1" stainless Steel Swagelok union to the top of the retort vessel which allowed use of a 1" Swagelok end cap for a complete leak proof closure of the bomb which was capable of withstanding pressures far in excess of 1000 psi. A porous stainless steel filter with an average pore diameter of 100 μm was positioned 2-4 mm from the bottom of the cans to allow use of the entire surface of the disc for escape of volatiles from the retort. These retort cans had an extended life since free volatile flow through the frit occurred without development of back pressure due to dust clogging the filter. Figure 1 illustrates the retort vessel with modification.

The retort assembly was also designed to accommodate several accessories. The end cap of the retort bomb could be replaced with a similar cap containing an additional port for the attachment of an inert gas preheater coil or a steam generator. The inert gas preheater has been previously described.[13] The steam generator consisted of a Laboratory Data Control slow speed minipump, 12 feet of coiled 1/8" stainless steel tubing, plus a 1/2" diameter by 6" heat exchanger filled with stainless steel shavings. This gave complete vaporization of the water entering the steam generator.

One or, when necessary, two stacked 2" x 12" Lindburg vertical split tube furnaces were used to heat the entire assembled retort. The upper furnace, used to heat preheater coils, was controlled by a Honeywell Digital Control Programmer, and the lower furnace where retorting was accomplished, was controlled by a Lindberg model 59344-El temperature programmer.

Procedures used for collection of oil and retort water and for oil yield determinations were as described previously.[14] Modifications to the product collection apparatus were required for two studies. For steam retorting 100 ml oil collection centrifuge tubes (ASTM D91) were routinely used to allow for the additional volume of condensates.

These tubes were also used for the inert gas flow experiments with Cleveland shales. In this case, the second tube of the collection system was completely filled with stainless steel balls for efficient heat transfer. For inert gas flow experiments, both collection traps were immersed in dry ice-isopropanol baths rather than one trap in an ice bath as in all other experiments.

Retorting Conditions. Retorting conditions were varied in a systematic way. At a heating rate of 13°C/min the following upper retorting temperatures were used: 500, 600, 700, 800, and 1000°C. Heating rates were then varied from 0.1 to 55°C/min with a 20 minute soak at 500°C. At a heating rate of 4°C/min, nitrogen, preheated to retort temperatures, was used as a sweep gas at the following flow rates: 5, 10, 15, 18, 25, 35, 50, 75, and 90 cc/min. Retorting under vacuum was accomplished with a Sargent Welsh Duo Seal high vacuum pump attached to the outlet tube of the collection apparatus and left running continously (pressure of < 0.1mm of Hg). Heating rates of 4°C/min and 22°C/min were used for vacuum retorting experiments. The heating rate for all steam experiments was 4°C/min and water flow rates from the micropump were 0.1, 0.2, and 0.3 cc/min.

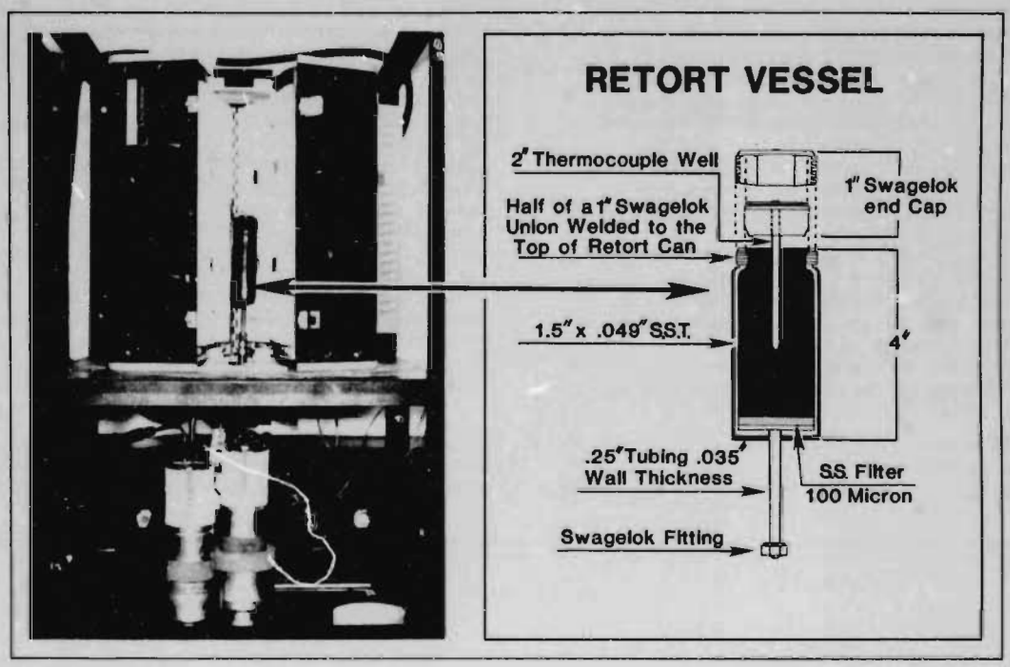


Figure 1. Retort Vessel and Assembled Bench Retort Apparatus

Additional Analyses. Densities of product oils were determined using a Mettler DMA40 density meter. CHN analysis of the spent shale was performed on a Carlo-Erba model 1106 elemental analyzer by standard procedures. Simulated distillation was performed on a Hewlett-Packard System 3351B by standard methods.[19] Thermogravimetric analysis was performed on a Perkin Elmer TGS2.

Results and Discussion

Liquid Product Collection. Efficient and reproducible trapping of oil vapors as a condensate was essential for this study. Simulated distillations performed at the IMMR shows that both Sunbury and Cleveland oils are higher in naphtha and light fuel oil fraction (by about 6%) than a typical western shale oil. Additionally, Cleveland oil is 8% higher in the naphtha fraction than Sunbury oil. Initial work demonstrated that complete oil collection from eastern shales required two condensation traps under Fischer Assay conditions and that the second trap required cooling with dry ice-isopropanol (-78°C). With a dry ice trap, approximately 6% more oil is trapped than with 0°C trapping (see Table 1). Western shale oils are trapped satisfactorily at ice bath temperatures.

Upper Retort Temperatures. The effect of upper retort temperatures on oil yield from Sunbury and Cleveland shales was studied at a constant heating rate of 13°+ 1°C. Oil yields from both shales were not significantly affected by increases in upper temperatures up to 1000°C (Table 2A). It is interesting to note that the reported deterimental effect of temperatures above 500°C on western shales[20] is not observed with the Kentucky shales studied. It should also be noted that retorting Sunbury and Cleveland shales to 1000°C produces a substantial increase in the amount of

Table 1

Liquid Product Collection Under Fischer Assay Conditions (13 ± 1°C/min; Sunbury shale)

Number of Experiments	Collection Method	% Oil	Oil Yield l/Mg (gal/ton)
3	two 0°C traps	6.3 ± 0.02%	65.5 ± 0.4 (15.7)
3	one 0°C trap & one -78°C trap	6.7 ± 0.06%	69.7 ± 0.4 (16.7)

non-condensable gas produced (although no significant additional oil formation is observed). Results from thermogravimetric analysis provide evidence in support of high temperature volatile matter release (Table 2B). Percent volatile matter remaining in spent Cleveland shale decreases from 5.09% for 500°C spent shale to 0.30% for 1000°C spent shale as a result of more complete conversion of residual organic matter to char as the upper retorting temperature is increased.

Heat-Up Rate. The effect of the heat-up rate on oil yield for Kentucky Sunbury Shale and Cleveland shale was studied using a 500°C, 20 min soak. Maximum temperature at the fastest heating rate approached 750°C. The large overshoot is due to thermal inertia of the furnace but the effect of upper temperatures has been previously shown to play a minor role (Figure 2)

Oil yield from Kentucky shales is significantly affected by the heat-up rate. Both shales responded similarly to changes in heating rate. Using a rate of 55°C/min, oil yield was enhanced an average of 12% over Fischer Assay. It is possible that even higher yields could have been realized at the fastest heating rate had more efficient trapping been possible. Oil vapors "explode" from the retort vessel during fast heating, limiting collection efficiency. As noted previously, slow heating has a detrimental effect on oil yields from Sunbury Shale.[14] At a heating rate of 2°C/min the oil yield from western shales is 96% Fischer Assay.[21] Whereas, at 2°C/min, Sunbury Shale yields only 85% Fischer Assay and 78% of the oil yield attainable at a 55°C/min heat-up rate; Cleveland shale at 2°C/min heat-up rate yields 84% Fischer Assay and 75% of the yield at 55°C/min. This suggests that an in situ process which may involve an even slower heating rate will not be a viable technology for retorting Kentucky shales.

Inert gas sweeps. At a heating rate of 4°C/min, preheated N_2 gas sweep was used to rapidly remove oil vapors from the retort chamber in order to

Table 2A

Effect of Upper Retort Temperature on Oil Yield (Sunbury and Cleveland Shale; heating rate = 13° ± 1°C/min)

	SUNBURY					OHIO (CLEVELAND)				
	Oil Yield					Oil Yield				
Soak Temperature °C	l/Mg	gal/ton	l/gm C	% Residual C	gms gas/gms C	l/Mg	gal/ton	l/gm C	% Residual C	gms gas/gms C
500	68.4 ± 0.8*	16.4	4.14×10^{-4}	10.2	0.17	58.4	14.0	4.01×10^{-4}	9.9	0.12
600	67.6	16.2	4.09×10^{-4}	10.3	0.16					
700	67.2	16.1	4.07×10^{-4}	10.1	0.18	59.1	14.2	4.06×10^{-4}	10.4	0.20
800	69.7	16.7	4.22×10^{-4}	10.4	0.23					
1000	70.9 ± 0.4†	17.0	4.29×10^{-4}	9.8 ± 0.1†	0.30	59.0	14.1	4.05×10^{-4}	8.6	0.29

* 4 replicate runs
† duplicate runs

Table 2B

Thermogravimetric Analysis of Spent Cleveland Shales From Upper Retort Temperature Study

Soak Temperature °C	% Moisture	% VM	% FC	% Ash
500	0.42 ± 0.08†	5.09 ± 0.24†	9.04 ± 0.06†	85.46 ± 0.26†
700	0.37	2.15	9.01	88.47
1000	0.10 ± 0.06†	0.30 ± 0.01†	8.49 ± 0.20†	91.10 ± 0.15†

† duplicate runs

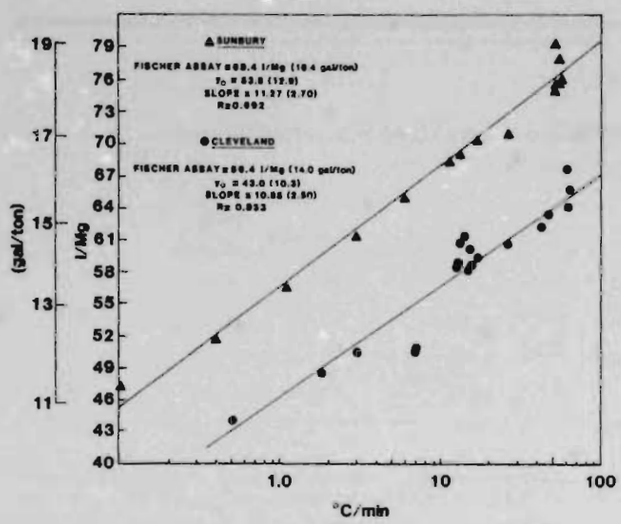
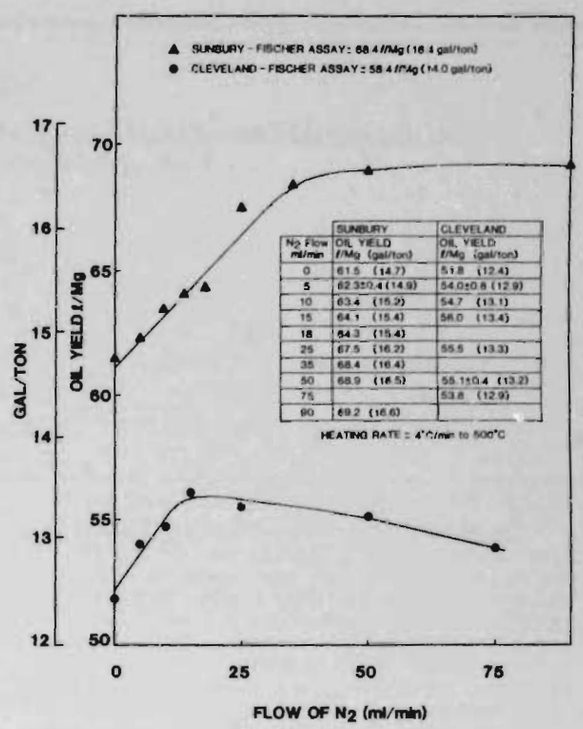


Figure 2. Semi-log Plot of Heat-up Rate vs. Oil Yield



N_2 Flow ml/min	SUNBURY OIL YIELD l/Mg (gal/ton)	CLEVELAND OIL YIELD l/Mg (gal/ton)
0	61.5 (14.7)	51.8 (12.4)
5	62.3±0.4 (14.9)	54.0±0.8 (12.9)
10	63.4 (15.2)	54.7 (13.1)
15	64.1 (15.4)	56.0 (13.4)
18	64.3 (15.4)	
25	67.5 (16.2)	55.5 (13.3)
35	68.4 (16.4)	
50	68.9 (16.5)	55.1±0.4 (13.2)
75		53.8 (12.9)
90	69.2 (16.6)	

Figure 3. Oil Yield vs. N_2 Gas Flow Rate

minimize oil losses due to coking and cracking. Figure 3 shows the effect of various flow rates of N_2 through the retort. For both shales rapid removal of volatiles resulted in an increased oil yield. The yield increased from 88-89% Fischer Assay with no sweep gas (heating rate of 4°C/min) to 101% Fischer Assay for Sunbury and 96% for Cleveland with a sweep gas. At high flow rates of N_2, again, the trapping of volatiles becomes more difficult, especially for the Cleveland oil which is higher in the naphtha fraction. Aerosols are particularly difficult to break under these experimental conditions. The observed decrease in oil yield with flow rates above 25 ml/min for Cleveland shale probably results from inefficient condensing of oil vapors and aerosols.

Vacuum Retorting. We have shown previously for Sunbury Shale retorting that variations in retort design which permit rapid removal of oil vapors from the retort chamber are beneficial.[14] Vacuum retorting is an alternative method for rapid product removal. Complete product isolation is more readily accomplished than under nitrogen flow conditions. Figure 4 presents the results of retorting Kentucky shales under vacuum. At 4°C/min retorting under vacuum resulted an increase of 26% and 14% over expected yields at that heating rate for Cleveland shale and Sunbury Shale, respectively. This represents an increase of 113% Fischer Assay for Cleveland and 105% Fischer Assay for Sunbury Shale. Increasing the heating rate from 4°C/min to 22°C/min did not significantly increase the oil yield from Cleveland shale retorted under vacuum. Elemental analysis and TGA of spend shale from the N_2 flow and from the vacuum retorting experiments support the suggestion that lower than expected yields obtained during the N_2 flow experiments on Cleveland shale may have been due mainly to poor trapping (Table 3). The spent shales have similar volatile matter, fixed carbon, and percent C analyses from N_2 flow retorting and from vacuum retorting. However, oil yield based on trapped condensables is higher, 66.0 ± 1.2 l/Mg (15.8 gal/ton), for vacuum retorting than for inert gas sweep experiments, 55.4 l/Mg (13.3 gal/ton). For comparison, data for Cleveland spent shale from Fischer Assay and a heating rate of 4° C/min are also presented in Table 3.

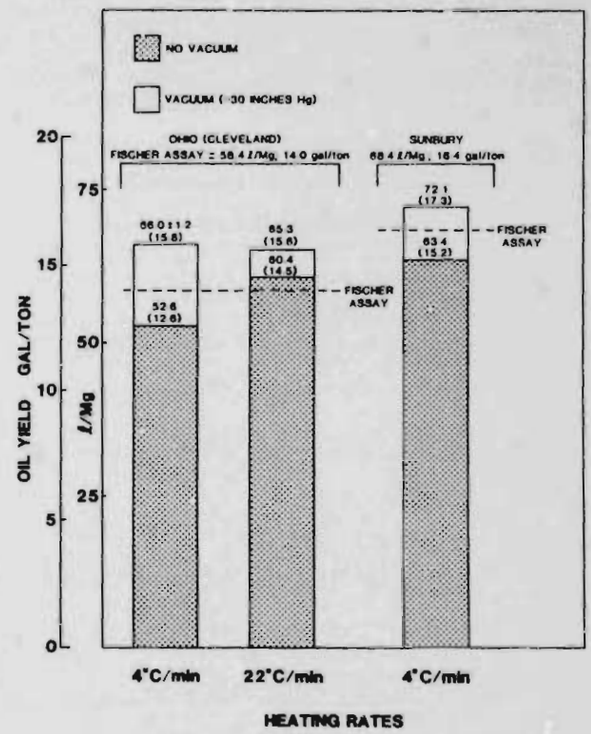


Figure 4. Oil Yield vs. Vacuum Retorting

Table 3

TGA and %C for Ohio (Cleveland) Spent Shale From Inert Gas Flow and Vacuum Retorting Experiments

Conditions	% VM	% FC	% C	l/Mg (gal/ton)
50 cc N_2/min; 4°C/min	3.76	9.25	9.75	55.4 (13.3)
Vacuum; 4°C/min	3.45 ± 0.48	8.36 ± 0.09	8.98 ± 0.10	66.0 ± 1.2 (15.8)
4°C/min	5.20	9.42	10.75	52.6 (12.6)
Fischer Assay	5.09 ± 0.24	9.04 ± 0.06	9.9	58.4 (14.0)

Steam Retorting. Stear flow experiments were also carried out at a heating rate of 4°C/min. Oil yields from both Sunbury and Cleveland shales were substantially improved over Fischer Assay oil yields, 23% for Cleveland and 25% for Sunbury (Figure 5). These yields represent a 36% and a 42% increase over oil yields expected at 4°C/min for Cleveland and Sunbury, respectively. Table 4 presents some representative elemental analysis and TGA of the spent shale from steam retorting experiments. Increasing steam throughput decreases the percent C and percent volatile matter remaining on the retorted shale. Coking also appears to be reduced by increasing the amount of steam used since fixed carbon is decreased from 9.42 without steam to 8.40 at 0.7 1/min steam flow. Another significant effect of steam appears to be a more efficient utilization of hydrogen. When using fast heating alone to increase oil yields all detectable hydrogen is removed from the shale. Therefore, increasing yields further by this method requires additional hydrogen. Whereas at the highest steam flow rate tested, 1/3 of the hydrogen initially available in raw Cleveland shale remained in the spent shale. This leaves the potential for realizing even better yields. Higher throughputs of steam will be tested in the future. The maximum steam flow rate possible in our system at present is 0.7 1/min and the data indicates that optimum steam flow has yet to be achieved.

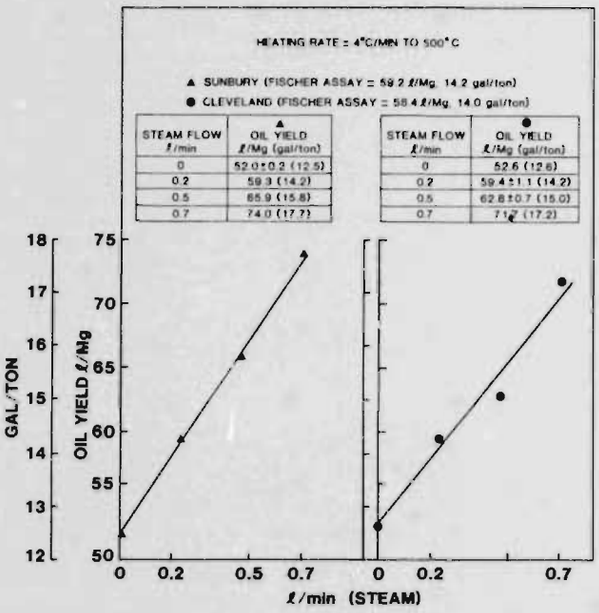


Figure 5. Oil Yield vs. Steam Flow

Summary

It is clear from the results of our bench scale retorting of Sunbury and Cleveland shales, that oil yields in excess of Fischer Assay are attainable by optimizing retorting conditions. Fast heating, rapid removal of oil vapors from the retort vessel, and the use of steam substantially increased oil yields for both shales. The experiments performed to date have been designed to single out and test individual retorting conditions. It remains to be ascertained if various combinations of beneficial conditions might produce even better oil yields. For instance, a fluidized-bed retort with steam used as some portion or all of the fluidizing gas would couple fast heating with the reduced coking and efficient hydrogen utilization provided by steam. The data suggest that while the limits of our currently available retorting apparatus have been reached, optimum heating and steam flow conditions remain to be realized. Since the Sunbury and Cleveland Shales are of commercial interest in northeastern Kentucky, and they respond similarily to variations in the retorting parameters studied, further optimization of retorting conditions rates a high priority. Since shale oil economics are more sensitive to yield factors than other synfuel technologies, our studies aimed at developing a retorting technology specifically adapted for eastern shales is continuing.

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Table 4

TGA Analysis and Residual CHNS for Spent Shale Steam Retorting Cleveland (FA = 58.4 l/Mg, 14.0 gal/ton)

Steam Flow l/min	Oil Yield l/Mg	(gal/ton)	% C	% H	% N	% S	% Moisture	% VM	% FC	% Ash
0	52.6	(12.6)	10.75	0.64	0.49	1.46	0.54	5.20	9.42	84.84
0.2	60.4	(14.5)	9.37	0.61	0.39	1.32	0.62	4.44	8.86	86.08
0.5	64.4	(15.4)	9.25	0.57	0.40	1.24	1.89	4.23	8.46	85.42
0.7	71.7	(17.2)	9.17	0.59	0.40	1.14	0.43	4.28	8.40	85.89

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Monday Morning Session

MINING AND RECLAMATION TECHNOLOGY

Oil Shale Hydrology — A Transfer of Knowledge from the Coal Regions

by

Paul D. Nesbitt, James P. Buschur
Nesbitt Engineering, Inc.
400 E. Vine St. Suite 310
Lexington, Kentucky 40507

Abstract. Many of the potential environmental problems faced by an emerging oil shale industry in eastern Kentucky are similar to those presently faced by the coal industry. One such problem is planning for water supplies for the associated mineral processing or preparation plants. Since shale oil retorts will require large volumes of water, the need for water supply evaluation is important when planning long term mining operations.

In order to evaluate streamflow potentials, flow duration curves were analyzed for streams in the Licking, Red, and Kentucky River basins.

Large rivers such as the Licking, Red, and the North Fork Kentucky have good low flow indeces which range from .038 cfs/mi^2 on the Red River at Clay City to .024 cfs/mi^2 on the Licking River at Farmers. Flow regulation on the Licking and Kentucky rivers have caused increases in the low flow indeces and have increased the amount of water available in the streams at all durations of time. Small tributaries and headwater streams have much lower low flow indeces. The lack of alluvium along these streams and their small drainage area reduces the amount of groundwater storage.

The Licking River and Kentucky River have sufficient flow to supply shale retorting water needs. However, as mining progresses away from these rivers and towards upland areas, water distribution systems will have to be constructed.

Introduction

The presence of large reserves of oil contained in the Upper Devonian and Lower Mississippian age shales of the eastern U.S. has been known for many decades. As the crude oil availability and cost intensifies, the economics of shale oil development will become more competitive with natural oil development. Major deposits of oil shale are located in the western and eastern United States. The two areas have different locational advantages which may influence the marketability of the resource. Although the western oil shales yield roughly twice the volumes of oil per ton (36 gal/t) than eastern shales, the eastern reserves might have an advantage by being situated closer to dense populations, industries, and more readily available water supplies.

Early shale oil analyses reported by McFarlan[1] of the Kentucky oil shales yielded 21 gallons of oil per ton and 3 to 4 thousand cubic feet of natural gas with a net heating value of 337 BTU's/ft^3. These early analyses compare favorably with results obtained by the Institute for Mining and Minerals Research (IMMR)[2] on shale samples from Lewis and Fleming Counties. The IMMR reported conservative values of 15 gallons per ton of shale. Some early studies reported that the byproducts of shale oil development could include raw materials for the brick or cement industry and ammonium sulfate (approximately 377 lbs/t) for fertilizer. Recent IMMR analysis indicate that other metals or minerals are obtainable from the resource such as Copper, Chromium, Molybdenum, Uranium, and Zinc but these substances do not seem to occur in economic amounts.

Many of the environmental problems or issues facing the new oil shale industry are similar to those experienced by the coal industry. Water supply and the allocation of this water for industrial, municipal and private use is one such

issue. For example, surface water is the primary source of process water for coal cleaning and preparation plants. Before a coal preparation plant site is selected streamflow studies should be completed to assess the capacity of the stream to provide a year round supply for the plant, as well as the problem of meeting stream standards with the discharge from the plant. The oil shale industry will need even larger volumes of water for the surface retorts in order to process the raw mined oil shale. Surface water systems will probably supply the majority of this water.

The ability of streams in the shale oil region to provide adequate water supplies to the industry as well as to provide for present consumptive uses deserves further study. This report is a preliminary discussion of the flow characteristics of gaged streams in three river basins, the Red, Licking, and Kentucky which contain portions of the oil shale region. Flow duration curves[3,4,5,6] are used to compare the frequency of flow of streams within each basin. Particular attention is directed towards identifying streams which have sufficient base flow to provide shale retorts with adequate amounts of water. The results of the study should be useful to those groups involved in planning for the eventual development of the oil shale resource in Kentucky.

Physical Environment

The rocks which make up the oil shale region have evolved into a characteristic topography known as the Knobs. The Knobs is a narrow belt of country which encircles the Outer Bluegrass region on the west, south, and east. Escarpments formed from more resistant limestones and sandstones form the outer limit of the Knobs region. These escarpments are known as the Mississippian age Muldraugh Hill in the west and south part and the Upper Mississippian/Lower Pennsylvanian age Pottsville escarpment on the east.

The Knobs are erosion remnants of the uplands located behind the escarpments. Conical forms are normal but where a cap rock remains they become flat-topped as the escarpments are approached. Near the larger drainage ways such as the Licking River and Red River, broad shale floored valleys are developed.

Rocks containing the oil shales were deposited in a marine environment as the Ohio or Chattanooga shale in Upper Devonian time. Deposition of shale and sandstone continued into lower Mississippian time with the accumulation of deposits now known as the Bedford shale, Berea sandstone, and Sunbury shale. Above these shales, predominantly calcareous Upper Mississippian sediments were deposited as alternating beds of limestone, mud, and silt. These alternating beds represent a transition from dominantly marine deposition to dominantly non-marine deposition which characterizes the rocks of the eastern coal fields.

Two high grade oil shale zones have been identified by the IMMR[2] in a study of Lewis and Fleming Counties. The two zones are the Upper Devonian Cleveland Member and the Lower Mississippian age Sunbury shale. These zones are separated by the Bedford shale and Berea sandstone. The areal extent of this high grade zone is undetermined. More core drilling will be needed to define it's limits. The high grade zones in Lewis and Fleming Counties outcrop on the upper slopes of the hills. The thickness of the intervening Bedford and Berea units ranges from 30 to 100 feet[2].

The boundary between the Knobs and the Eastern Kentucky Coal Fields as marked by the outcrop of Upper Mississippian and Lower Pennsylvanian limestones and sandstones. These rocks form the Pottsville escarpment. Further east the topography becomes more rugged as the upland area is attained. The headwaters of the major rivers traversing the Knobs, the Kentucky, Red and Licking, are located in the uplands represented by the coal fields. The river valleys have been the center of industry and commerce since the region was settled. Several municipalities and industries along the drainage ways use the water from these streams. If shale oil is to be processed in the Knobs region, careful attention will have to be paid to the ability of the area to provide the water that would be needed by the retorts.

Analysis of Low Flows in Three River Basins

In order to assess the overall availability of water in the shale region, flow duration curves were constructed for streams in the Licking River, Red River, and Kentucky River basins. Three gaged sites were selected in each river basin in order to determine the variability of flow in large and small catchment areas within the river basin. Comparisons were also made between catchments entirely within the coal fields with those entirely within the shale regions to assess the effects of geology on the low flow of streams.

Licking River Basin

The Licking River rises in Magoffin County and flows northwesterly across the coal bearing Breathitt Formation for approximately 49 miles. Below this point the river cuts into the Lower Pennslyvanian Lee sandstone formation near West Liberty. Mississippian rocks are exposed 16 miles below West Liberty and the Upper Devonian/Lower Mississippian oil shales are traversed within a few miles near Farmers. Alluvium filled valleys occur throughout the main valley except in the upper 12 miles. Discharge information was obtained for three continuous gaging stations located on Triplett Creek at Morehead, the Licking River near Saylorsville and the Licking River at Farmers. Data used to construct the curves was obtained from the U.S. Geological Survey, Open File Report series[7].

Figure 1 shows the flow duration curves of Triplett Creek at Morehead, the Licking River near Saylorsville in the headwaters, and at Farmers in the outcrop area of the oil shale deposits. Flow occurring at, or greater than, 90 percent of the time represents the dry weather or base flow of a stream. The shape of the lower end of the duration curve is indicative of average groundwater storage available to the stream to supply surface runoff. Differences in the lower ends of curves reflect the effects of geology of a basin on dry weather flow. The curves can be used to assess the reliability of a surface water supply.

The curves are similar in shape and magnitude at percentages of time less than 70 percent.

Greater differences occur however at percentages of time above 90 percent. At greater percentages of time the curves diverge. Triplett Creek at Morehead has the lowest discharge at all percentages of time. The steep slope indicates a highly variable stream whose flow is largely from direct runoff. Alluvium along a stream may store significant amounts of groundwater which is released and causes the duration curve to flatten. Although Triplett Creek has extensive alluvial deposits, their effect on the low flow of the creek is minimal. Since the alluvium is derived from fine grained sandstones and shales of Mississippian age the effective permeability of the alluvium may be reduced. The fine grained sandstones and shales are probably the reason for such low flow indexes for Triplett Creek. Triplett Creek has a flow of .0035 cfs per sq. mile at 95 percent duration. This is approximately .17 cubic feet per second.

The Licking River near Saylorsville shows slightly better low flow characteristics than Triplett Creek. The 95 percent duration flow is .011 cfs per sq. mile or 1.54 cfs, indicating considerably higher baseflow than that of Triplett Creek. The bedrock materials above the gaging station are in of the Breathitt Formation and are apparently more permeable than the bedrock in the Triplett Creek basin. The alluvium may also contribute greater quantities of groundwater to the stream.

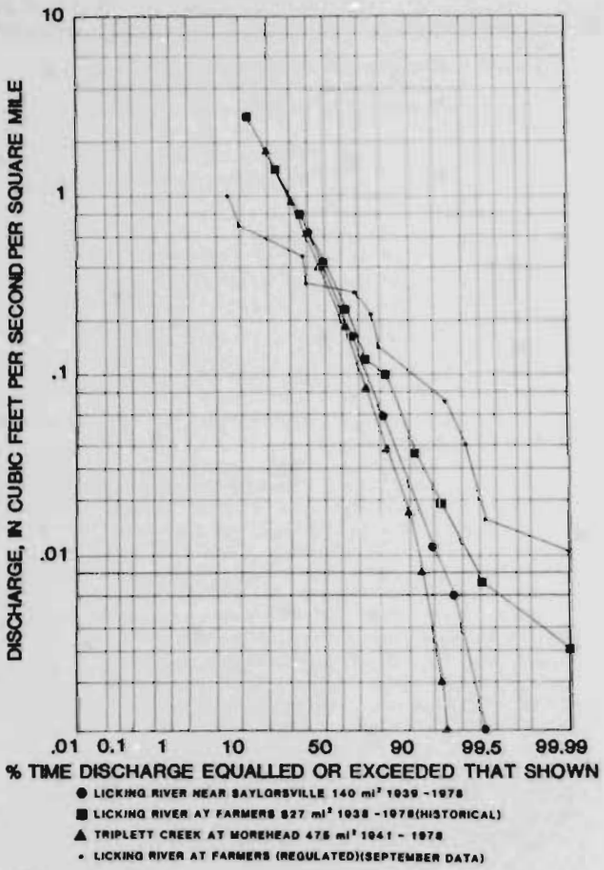

Figure 1. Flow Duration of Streams in the Licking River Basin.

Considerable changes in the flow indices of the Licking River occur between Saylorsville and Farmers as shown on Figure 1. The curve for the gaging station at Farmers is less steep than the previously mentioned curves, especially at duration greater than 95 percent. The reduced slope at the lower end of the curve indicates that a large amount of groundwater storage exists in this portion of the Licking River. The unit flow at 95 percent duration at Farmers is .024 cfs per sq. mi., which is approximately 19.8 cfs. or more than twice that at Saylorsville.

Most of the increased flow at Farmers comes from the wide alluvial valleys and the sandstones and limestones outcropping in the Pottsville escarpment. The Licking River largely drains the Breathitt Formation but in the northern part deep valleys are incised through the underlying Lee Formation and Mississippian rocks as the stream breaks through the escarpment. The oil shales are present in the low part of the valley for a short distance above and below Farmers.

Since the Licking River at Farmers has a large base flow at most durations of time and is close to the high grade zones identified in the IMMR resource study of Lewis and Fleming counties[2], the river should be considered as a source of water for shale processing facilities. Construction of Cave Run Reservoir has actually increased base flows over most durations of time. The reservoir has thus increased the available water over that which was historically available.

The effect of Cave Run Reservoir on the Licking River is also shown on Figure 1. When compared with the historical record of flow, the curve is flatter which indicates less variability in the flow regime. Discharges at the upper end are lower while low flows are considerably higher than those in the historical record. The 95 percent duration flow occurring in September is .076 cfs per sq. mi. or 62 cfs. This dry weather flow is more than adequate to supply a retort which may need between 11 cfs and 20 cfs.

It is also obvious that only large streams which cut through the shale regions will be able to supply the water needed for the retorts. The Red River and Kentucky River should also be considered as potential water sources for oil shale development. Although resource explorations have not been made into areas further south it is likely that similar high grade shale oil zones will be found.

Red River Basin

The Red River rises in eastern Wolfe County and flows in a westerly direction across the Breathitt formation for approximately 25 miles. The river cuts through Lower Pennsylvanian strata and Mississippian rocks for the next 23 miles of it's course. A few miles east of Stanton the valleys become wide as a result of the predominance of Mississippian shales. The oil shale zone begins at Stanton and remains with the river for the next 10 miles to it's confluence with the Kentucky River.

Figure 2 shows the flow duration curves for three streams in the Red River basin; Stillwater Creek at Stillwater, Red River at Hazel Green, and

the Red River at Clay City. The steep slopes for Stillwater Creek and the Red River at Hazel Green are similar to the curves for small streams in the Licking River basin. The small headwater areas lack significant groundwater storage capacity to contribute significantly to low flows. Unit base flows for these streams are similar to small streams in the Licking River basin, located adjacent to the Red River basin on the north.

The flow duration curve for the Red River at Clay City is much flatter than for headwater streams and indicates a significant amount of groundwater storage some of which is in the wide valleys above the gaging station. The flat curve can be attributed to the groundwater storage in extensive alluvial deposits and to groundwater discharge from the sandstones and limestones of the nearby Pottsville escarpment. The base flow characteristics of the Red River at Clay City are similar to those of the Licking River at Farmers. In fact, the 95 percent duration discharge of .038 cfs per mi^2 for the Red River is greater than that of the historical record for the Licking River at Farmers (.024). However, the absolute discharge corresponding to the 95 percent duration is smaller at Clay City by approximately 6 cfs. The lower discharge at Clay City is expected because the drainage area above Clay City is approximately half that of the Licking River above Farmers.

Dry weather discharge at Clay City is low, (5.4 cfs in October at 95% duration) which indicates potential water supply problems if the river is to be used as a source of process water for retorts. The shallow slope of the flow duration curve however reflects availability of groundwater in storage. Groundwater may therefore represent a supplementary source of process water. Actual potential well yields are not known but wells located near the Red River in alluvium may yield significant quantities of water. It is apparent however, that lack of sufficient dry weather streamflows in the Red River basin will slow the development of shale oil projects in the basin.

Kentucky River Basin

The upper Kentucky River basin covers over 2700 square miles in the west-central portion of the Eastern Coal Field. Three principal tributaries (the North, Middle, and South Forks) join within a few miles of each other near Beattyville in Lee County to form the Kentucky River. Above Beattyville, the drainage network is cut into the coal bearing Breathitt formation. Lower Pennsylvanian Lee sandstones occur in valley walls for eight miles between Beattyville and the town of Willow. Mississippian rocks occur in the area between Willow and Ravenna where the oil shale zone begins to crop out. This outcrop area is the most extensive of any of the shale oil zones discussed so far. The area also has the most readily available surface water supplies discussed up to this point.

Figure 3 shows the flow duration for three streams in the Kentucky River basin: Troublesome Creek at Noble, North Fork Kentucky River at Hazard, and the North Fork Kentucky River at Jackson. The lowest unit flows occur on Troublesome Creek. The steepness of the curve is similar to those for headwater streams in the

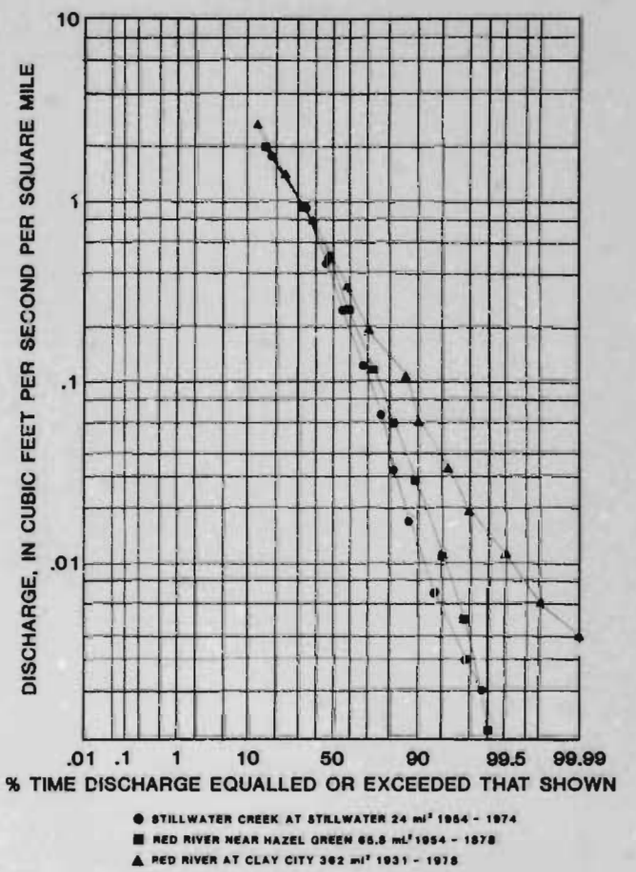

Figure 2. Flow Duration of Streams in the Red River Basin.

Licking and Red River basins, but the unit flow of .012 csm is the highest of all such streams. Troublesome Creek compares most closely with the Licking River above Saylorsville at 95 percent duration. The higher flows of Troublesome Creek may be caused by higher rainfall and more permeable strata occurring in the coal fields. The steepness of the slope shows that there is only a small amount of groundwater storage in the headwater streams.

Larger amounts of groundwater storage are indicated by the shallower slopes of the curves for the North Fork Kentucky River at Hazard and at Jackson. Alluvial deposits along the main stems of the larger streams store this groundwater causing increased sustained flows. It may be assumed that unit flows will increase with distance downstream. This is generally true over the entire stretch of a drainage network but local reversals can take place. This phenomena occurs on the North Fork between Hazard (drainage area 466 mi^2 and Jackson (drainage area 1101 mi^2). The 95 percent duration flows are very close for both streams. However, at greater durations, the unit flow at Hazard is larger than that at Jackson. Overall, the unit flows on the North Fork are comparable to the Red River at Clay City.

After the three forks meet at Beattyville the discharge of the Kentucky River is sufficient to

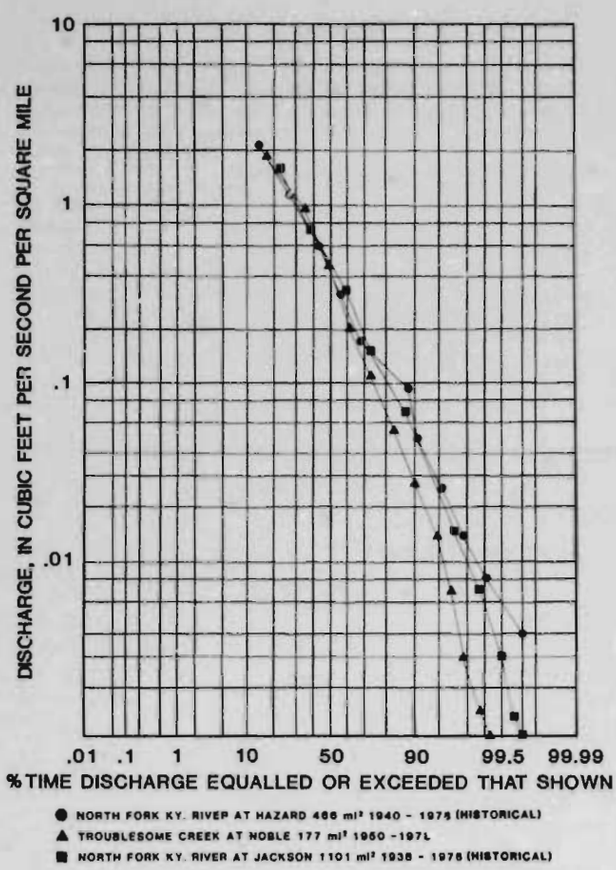

Figure 3. Flow Duration of Streams in the Kentucky River Basin.

supply the needs of the shale retorts. Flow regulation has effectively increased the discharge of the Kentucky River at Heidelberg upstream of the shale region to at least 70 cfs, 100 percent of the time. After flowing through the shale oil region the discharge at Lock 14 near Winchester is at least 127 cfs, 100 percent of the time.

Since potential retorting processes require water at a rate between 11 and 20 cfs, it can be seen that shale oil development along the Kentucky River in Madison and Estill Counties will not be restricted by a lack of water supply or mineable oil shale since the outcrop area is large.

Comparisons Between Coal and Oil Shale Hydrology

Many of the issues relating to hydrologic impacts from shale mining are presently being dealt with by the coal industry. Problems associated with runoff, sedimentation, water quality and recharge are under regulation. Some of the methods for dealing with coal mining impacts on the hydrologic regime could be applicable to shale mining. Although physical factors such as slopes, drainage area, land cover, and bedrock composition will vary between the two regions, it is likely that shale hydrologic control measures will vary in structural dimensions such as size or shape from those for coal operations but they will be similar in function.

Runoff from the mine site is dependent upon land features such as slope, acreage of disturbed area, mining method, and permeability of the mine spoils. Runoff is controlled by construction of dams designed to store the flow from a storm event of a particular duration and time. This method could be transferred to the shale oil region but the dams may have to be larger because shale mining will disturb much larger acreages of less permeable material.

Larger sediment ponds may also be necessary because of a greater erosion potential of shaley overburden. Although coal mining overburden contains appreciable amounts of fine grained material, shale oil overburden will overwhelmingly consist of fine grained shale and siltstone. Sediment dams may be prone towards filling if other control methods are not utilized to intercept sediment before reaching the dam. Vegetative filters may assume a large role in shale mining, a role that is not generally needed in coal mining operations.

Water quality of effluent from the storm detention dams is presently monitored under the NPDES guidelines. Coal miners must correct any violations of standards for parameters such as iron, manganese, sulfate, and pH. Control measures usually consist of neutralizing sediment pond water which causes some of these constituents to precipitate to the bottom of the pond.

Shale overburden has the potential to release large amounts of soluble minerals due to it's fine grained character and characteristically high mineral content. Effluent standards have not been established for mine sediment ponds, but the problems of maintaining the quality of the effluent from these ponds will probably be more difficult than presently encountered in the coal fields. Mining may have to be planned in order to limit the amount of exposed overburden present at any one time. This will reduce the potential for production of large amounts of mineralized water.

Mineral processing in the coal fields requires transporting the coal to a preparation plant where it is crushed and washed. A supply of approximately .2 cfs of water is needed for this activity and planning for plant locations must consider this factor. Most areas in the coal field can provide this amount of water and site location usually presents no major problem. Shale processing requires a supply between 11 to 20 cfs. This flow is not a common occurrence everywhere in the region and careful planning will be required in order to secure this water.

Conclusion

Table 1 summarizes the 95% duration flows for the streams discussed above. Large rivers such as the Licking, Red, and the North Fork Kentucky have good low flow indeces which range from .038 cfs/mi^2 on the Red River at Clay City to .024 cfs/mi^2 on the Licking River at Farmers. Groundwater storage in bedrock and in alluvium along the main stems of these rivers provides relatively large amounts of flow during dry weather. Flow regulation on the Kentucky and Licking Rivers has distorted the unit discharge

characteristics. The effect of these dams has been to increase the amount of discharge in the streams. The 95 percent duration flows for the Licking and Kentucky Rivers appear to be sufficient to supply shale oil retorts without greatly decreasing the overall flow of the streams.

Smaller tributaries and headwater streams in the Kentucky, Licking and Red River basins have much lower low flow indeces. Smaller drainage areas with corresponding smaller alluvial areas are unable to store significant quantities of groundwater to support high base flows. It is apparent that these streams would be unable to support shale retorting operations.

Two of three major streams (the Licking and Kentucky) which traverse the oil shale region have sufficient flow to provide a regular source of water to shale retorts. As mining progresses away from these rivers and towards upland areas, transportation costs may become prohibitive and mining will cease. Water pipelines may have to be constructed to on-site retorts in order to avoid the materials transport problem.

Eastern oil shales certainly are at an advantage over western shales as far as water supply is concerned. However, only large rivers can supply this water to the retorts and water pipelines will have to be considered when planning for the development of shale oil areas located in uplands away from major rivers. Although gross water supply is no problem in development plans for eastern oil shales, water distribution will have to be given serious planning attention.

TABLE 1:
SUMMARY OF STREAM FLOW DATA

MAJOR RIVERS

RIVER	95% MINIMUM FLOW cfs/mi.2	95% MINIMUM FLOW cfs	RECORD
RED RIVER AT CLAY CITY	≥ .038	≥ 13.7	1931-1978
NORTH FORK KY. RIVER AT HAZARD (HISTORICAL)	≥ .029	≥ 13.5	1940-1978
NORTH FORK KY. RIVER AT JACKSON (HISTORICAL)	≥ .025	≥ 27.5	1938-1978
LICKING RIVER AT FARMERS (HISTORICAL)	≥ .024	≥ 19.8	1938-1978

HEADWATER STREAMS

RIVER	95% MINIMUM FLOW cfs/mi.2	95% MINIMUM FLOW cfs	RECORD
TROUBLESOME CREEK AT NOBLE	≥.012	≥2.12	1950-1978
LICKING RIVER NEAR SAYLORSVILLE	≥.011	≥1.54	1939-1978
RED RIVER NEAR HAZEL GREEN	≥.008	≥.526	1954-1978
STILLWATER CREEK AT STILLWATER	≥.0045	≥.108	1954-1974
TRIPLETT CREEK AT MOREHEAD	≥.0035	≥.165	1941-1978

REGULATED STREAMS

RIVER	95% MINIMUM FLOW cfs/mi.2	95% MINIMUM FLOW cfs	RECORD
LICKING RIVER AT FARMERS	≥.076	≥ 62 (SEPTEMBER)	1975-1978
KENTUCKY RIVER AT HEIDELBERG	≥.026	≥ 70 (100% DURATION)	1962-1978
KENTUCKY RIVER NEAR WINCHESTER	≥.047	≥ 127 (100% DURATION)	1962-1978

RANGE OF DISCHARGE NEEDED FOR RETORT OPERATIONS (11 cfs to 20 cfs)

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A Comparison of Various Aspects of Mining Oil Shale in the Western and Eastern United States

by

Einer D. Lindquist
Gary D. Aho
Cliffs Engineering, Inc.
Rifle, Colorado 81650

Abstract. An overview is given of the available open pit and underground mining techniques which may be applicable to mining oil shale. Specific mining methods are discussed for first generation western and eastern underground and eastern open pit oil shale mining. Estimated capital and operating costs are depicted for the three examples of shale mining that are discussed.

Introduction

The purpose of this discussion is to compare conventional mining of western oil shale with how we envision the conventional mining of Kentucky shale for at least the first generation commercial operation. Order of magnitude estimates of capital and operating costs for mining, crushing and processed shale disposal are also presented for eastern surface mining and for western and eastern underground mining principally for ranking purposes.

The various retorting and upgrading schemes under consideration tend to overshadow the contribution of mining, crushing and processed shale disposal to the overall operating cost of an oil shale project, much less the magnitude and complexity of the associated materials handling systems. According to Robert B. Taylor in the September 7, 1981 issue of "Chemical Engineering", mining, crushing and spent shale disposal contribute more to the operating cost than either retorting or upgrading in western oil shale.

Open Pit Mining Discussion

Where overburden depths are favorable, open pit or surface mining is unquestionably the most cost effective mining method. However, in the United States the oil shale resources amenable to surface mining are limited. Although there have been studies undertaken to determine the feasibility of surface mining of western oil shale, to our knowledge there are no firm current plans to mine with this method in the West, although some companies are openly discussing the possibility. In the East however, the Buffalo Trace Study identified resources in northeastern Kentucky of sufficient quantity and shallow depth to support at least one and possibly two commercial open pit mining projects.

Surface mining technology is well established and has been developed to a high degree of proficiency in coal, copper, iron ore, etc. There is a broad range of proven drilling, loading and hauling equipment available to choose from. Depending upon economic, physical and other conditions the loading and hauling system can be a mix of wheeled loaders, conventional or hydraulic shovels, draglines, bucket-wheel excavators, and off-highway trucks and/or conveyors. Total resource recovery is generally higher for surface mining as compared to underground mining.

The thickness of overburden and interburden that can economically be removed to mine a deposit by open pit is extremely site specific. Major factors to be considered are the grade and thickness of the resource, the depth and dip of the deposit, and the costs to remove a yard of waste and mine a ton of ore. In western oil shale, because of the thickness and higher grade shales it may be economic to strip overburden and interburden to a depth of 300 feet to 400 feet. In the East however, approximately 100 feet would seem to be the cut-off thickness for stripping overburden and interburden, which relates to a maximum stripping ratio in the range of 2.5 to 1.

Because of the continuity of western shale deposits the configuration of a western open pit shale mine would resemble the vast, contiguous pits one sees in copper and iron ore operations. However, because of the dendritic pattern of the ridges containing oil shale in northeastern Kentucky the mining would resemble the ridge-top coal mining undertaken in the east.

Open pit mining has distinct environmental disadvantages in the areas of ground-water disturbance, waste disposal, and reclamation. There have been schemes proposed in the West where processed shale is placed back in the pit. The mining method described in the Buffalo Trace Study included reemplacing all the processed shale and 75 percent of the barren overburden on top of the mined-out ridge. This should be a viable method of disposal where all the resource has been recovered. However, when the mining depth is dictated by an assay cut-off, placing waste on top of lean ore may put the lower grade resource beyond the limits of ever being economically recoverable.

Underground Mining Discussion

The pilot underground mining of western shales has been underway for decades and has been covered extensively by numerous papers. In Cameron Engineer's extensive study for the U. S. Bureau of Mines in 1975, variations of sublevel stoping, room and pillar, block caving and longwall mining were evaluated as they would apply to western oil shale. The two variations on room and pillar, advance entry and chamber and pillar, required the lowest capital investment and were the most technically feasible. Block caving and sublevel stoping indicated lower mining costs and higher resource recovery than room and pillar mining. The lack of experience in applying the two latter methods in oil shale, the long preproduction development time and the higher capital investment tend to make them less attractive as first generation underground mining methods for western oil shale. The longwall mining method has potential but will require research and development on mining techniques and equipment; other systems offer better promise for the near future.

Comparison Of Specific Methods

The three mining systems we would like to compare for estimated operating and capital costs are typical western underground room and pillar, hypothetical ridge-top mining and underground room and pillar mining in northeastern Kentucky. All three mines are assumed to produce 60,000 tons per day, irrespective of grade or retort yield.

Western Underground

The western mine is conventional room and pillar with rooms 55 feet wide by 60 feet high and approximately 60 percent overall resource recovery, assumed to be gassy and with no anticipated surface subsidence. The mining is done in two lifts, the top cut is a 25-foot-high full face and the bottom half is taken as a 35-foot-high bench. The upper cut is drilled out by two-boom jumbos drilling horizontal holes. The lower bench is drilled vertically with electric-driven crawler drills. The broken ore is removed from the upper cut by permissible rubber-tired 6-1/2 cubic yard loaders and 35-ton trucks. The lower bench is loaded out with 15 cubic yard loaders and 75-ton trucks. The ore is trucked to a two-stage crusher and conveyed by inclined belt to the surface. Access for men and material into the mine is by vertical service shaft and additional bored shafts are used for ventilation and second outlets.

Eastern Open Pit (Ridge-Top)

The open pit mining portion of the Buffalo Trace Study was used as the model for developing the capital and operating costs for the surface mining method. The appropriate scale-up and escalation for a 60,000 tons-per-day operation in northeastern Kentucky is included here. The mining equipment fleet would be more or less conventional, consisting of crawler-mounted diesel-powered, 7-7/8-inch diameter rotary drill rigs, electric and diesel-hydraulic shovels, 12 and 11 cubic yard capacity respectively, and 85-ton end-dump trucks. Primary crushing would take place at the pit and crushed product would be conveyed to the plant. A return belt would convey the processed shale back to the mine for disposal in the pit bottom. The stripping ratio is estimated at 1.5 to 1.

Eastern Underground

The site selected for the eastern hypothetical underground mine is in northeastern Kentucky and is assumed to lend itself to access by horizontal adits into the mining zone. Shaft requirements would be limited to bored ventilation and secondary outlet shafts.

The eastern underground mining method is envisioned to be multiple seam room and pillar mining with a maximum 400 feet of cover. Although this is not a common mining technique, it has been successfully employed in coal mining both here and in Europe for many years. The rock strengths based on very preliminary rock mechanics tests indicate that safe roof spans will be considerably shorter than in western shale, but will allow respectable extraction ratios without subsidence. Room sizes in the 15-foot-thick Sunbury Shale would consist of a 28-foot roof span, 29-foot-square pillars with an approximate 65 percent overall extraction ratio. The site is assumed to have an intervening layer of siltstone and sandstone 50 to 60 feet thick (Berea/Bedford). The 30-foot-thick Cleveland high grade zone, occurring beneath the Berea/Bedford section would be mined with a 24-foot roof span and 29-foot-square pillars with an overall extraction ratio of approximately 61 percent.

The eastern underground mine is assumed to be classified as gassy for the purposes of equipment selection and mining method. Mining would be full face on both levels. The equipment fleet would consist of blasthole drill jumbos, charging machines, load-haul-dump vehicles, scaling machines, roof bolting jumbos, primary portable crushers and conveyors. Shale mined on the upper level would be dropped to the lower level by ore pass raises. Production from both levels would exit the mine on the lower level by conveyor belts. Processed shale disposal would be a separate operation with disposal on surface.

Operating Cost Comparison

An estimated cost comparison for western and eastern room and pillar mining and eastern ridge-top mining appears in Table 1. We estimate that these costs represent 25 to 30 percent of the total operating and maintenance costs of an oil shale operation. The costs in mid-1981 dollars include mining, primary and secondary crushing, and processed shale disposal, but do not include royalty, taxes, fee, insurance, final reclamation or amortization of capital. As one would suspect the open pit operation is by far the lowest cost operation per ton. The two underground operations are $0.36 per ton apart with eastern underground the highest cost. Some more obvious reasons for the high eastern underground mining costs are:

- Narrower and lower rooms necessitate smaller, less productive mining equipment;
- Full face mining requires a higher powder factor;
- Multiple seam mining requires twice the scaling and roof bolting effort.

Capital Cost Comparison

The estimated capital cost for the three

Table 1. Comparison of Operating and Maintenance Cost*/Ton Western Versus Eastern Shale - 60,000 Tons-Per-Day Plant Capacity (Preliminary Estimate)

	MID-1981 DOLLARS		
	WESTERN SHALE UNDERGROUND	EASTERN SHALE OPEN PIT	EASTERN SHALE UNDERGROUND
Cost Per Ton	$2.80	$2.08	$3.16

* Costs include mining, primary and secondary crushing and processed shale disposal, but exclude royalty, taxes, fee, insurance and final reclamation, and amortization of capital.

Table 2. Mining Capital Cost Comparison Western Versus Eastern Shale - 60,000 Tons-Per-Day Plant (Preliminary Estimate)

	MID-1981 DOLLARS ($000)		
	WESTERN SHALE UNDERGROUND	EASTERN SHALE OPEN PIT	EASTERN SHALE UNDERGROUND
Mine Development (1)	16,600	15,000	18,000
Mine Capital (2)	77,400	62,000	110,000
Mobile Equipment	54,000	76,000	38,000
TOTAL	148,000	154,000	166,000

(1) Where applicable includes shafts, adits, and preproduction stripping.

(2) Includes crushers, material handling, shops, employee facilities and other ancillaries.

operations in the comparison are depicted in Table 2. We estimate that the mining capital represents approximately 10 percent of the total capital required for an oil shale project. These costs include mine capital, development, and mobile equipment, but not contingency. Western underground requires the least capital and eastern underground the most. The total capital for eastern ridge-top mining is higher than western underground because of larger, more expensive mobile equipment required; the payback comes from the lower operating costs in the ridge-top mine.

Summary

When considering just the mining, crushing and processed shale disposal cost per ton, open pit mining of eastern shale is the least expensive of the operations in the comparison. However, in our opinion, the opportunities for surface mining, at least in Kentucky, are limited. If the oil shale resources in the East are to be exploited, low cost underground mining methods must be developed. Public information on the rock strengths and drilling, blasting, crushing and processed shale characteristics of eastern oil shale is practically nonexistent. On the other hand, western shale underground mining has been piloted to the extent that at least in the conventional room and pillar system there is a reasonable degree of confidence in the mining method and cost estimating. A pilot program in eastern oil shales, developed in an orderly manner, in which mining, retorting, processed shale disposal, reclamation and environmental aspects can be thoroughly investigated is a must before the full potential of eastern oil shales can be realized.

Evaluation of an Oil Shale Mining and Processing Operation in Alabama

by

A. Frank Hilleke Mining Engineer
H. Shafick Hanna Associate Professor
Mineral Resources Institute
The University of Alabama

Abstract. An engineering plan and economic evaluation is presented for mining and processing 33,000 tons per day of oil shale at a specific site in Madison County, Alabama. The proposed plant is designed to produce about 10,000 barrels per day of oil from shale containing 10 to 15 gallons of recoverable oil as determined by the Modified Fischer Assay method. A mining study including plans for disposal of overburden and spent shale is presented. The location and operation of a plant to retort the shale using the Paraho process are described. Processing plant economics assuming 13 gallons of oil per ton of shale are presented. The economic analysis indicated that a 13 percent return on equity is possible at an oil selling price of $40.00 per barrel.

Introduction

In August 1980, the School of Mines and Energy Development (SOMED) of The University of Alabama and the Geological Survey of Alabama (GSA) in cooperation with the Alabama Department of Energy, received funds from the U.S. Department of Energy to conduct a limited investigation entitled, "A Regional Resource Assessment and Feasibility Analysis of Fossil Energy Recovery from Chattanooga (Devonian) Oil Shale in Alabama and Adjacent States." The Survey was responsible for collecting and describing surface and core samples obtained from selected locations in Alabama and the adjacent parts of Georgia and Tennessee. The Mineral Resources Institute (MRI), a division of SOMED, was responsible for determining the economic and technical feasibility of mining and processing the shale at a specific site identified by the Survey's sampling program to be a potential resource of adequate size to support a commercial operation.

This is a preliminary paper which presents plans and an economic evaluation of a proposed oil shale mining and retorting operation in northeast Alabama. The assessment presented here is based on analyses of a limited number of outcrop samples obtained from an area in which a substantial resource of shale contains about 13 gallons of oil per ton. A paper detailing the results of the resources assessment investigation by K. F. Rheams and others of GSA is presented elsewhere in this volume. A more detailed report, based on subsurface core and surface samples, which delineated shale resources containing about 10 gallons of oil per ton, will be released at a later date.

The Survey has estimated that 300 exposed sections of Devonian shale exist in Alabama with the maximum thickness occurring in Madison County in northeast Alabama. The shale is well-exposed along the east and west banks of Hester Creek, northeast of Huntsville, Alabama with an average thickness of 15 feet. Based on the regional reconnaissance study, this area appears to have considerable promise in terms of reserves and oil yield.

Mining Study

Mine Site

The site selected for the operation is in Township 1 South, Ranges 1 and 2 East (Huntsville Meridian) and is located along Hester Creek about three miles northeast of New Market in Madison County, Alabama as shown in Figure 1. The relationship of the area to reported deposits of oil shale is illustrated by Figure 2. The principal criterion for selection of the site was a projection of extensive mineable reserves of shale oil (according to the modified Fischer Assays of samples from exposures in the vicinity). Additional consideration was given to the adequacy of plant site area, water resources, highway and railway service, utilities and other factors that effect an operation of this type. Property ownership was not considered as part of this study.

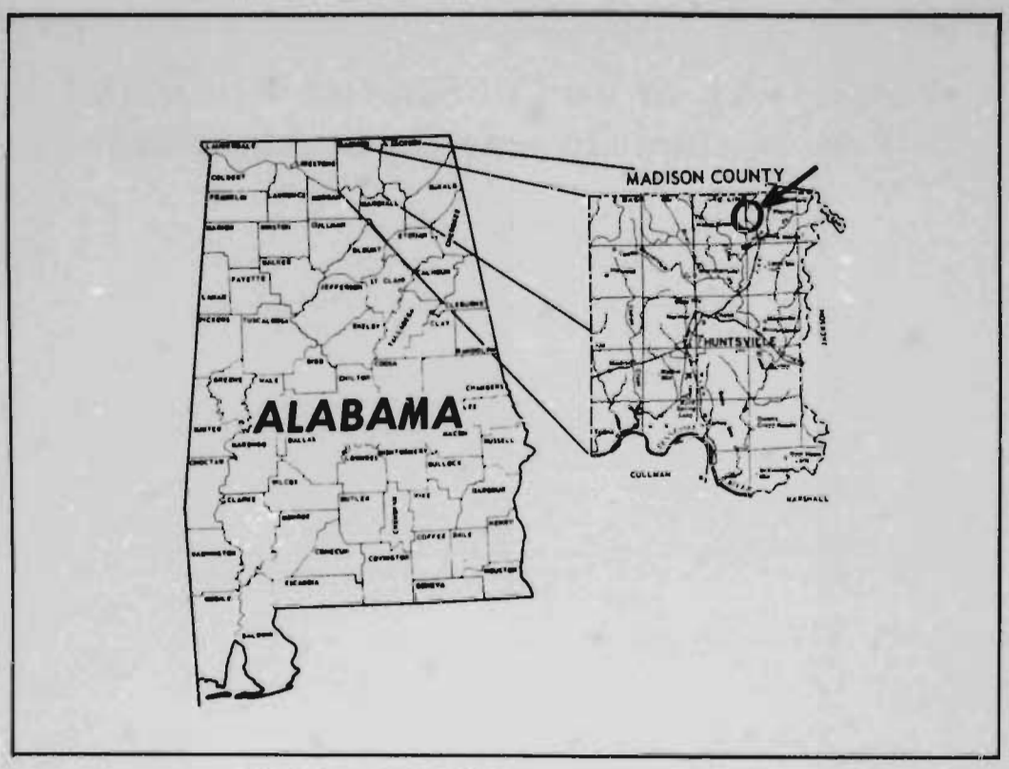

Figure 1. Location Map of Potential Oil-Shale Operation, Madison County, Alabama.

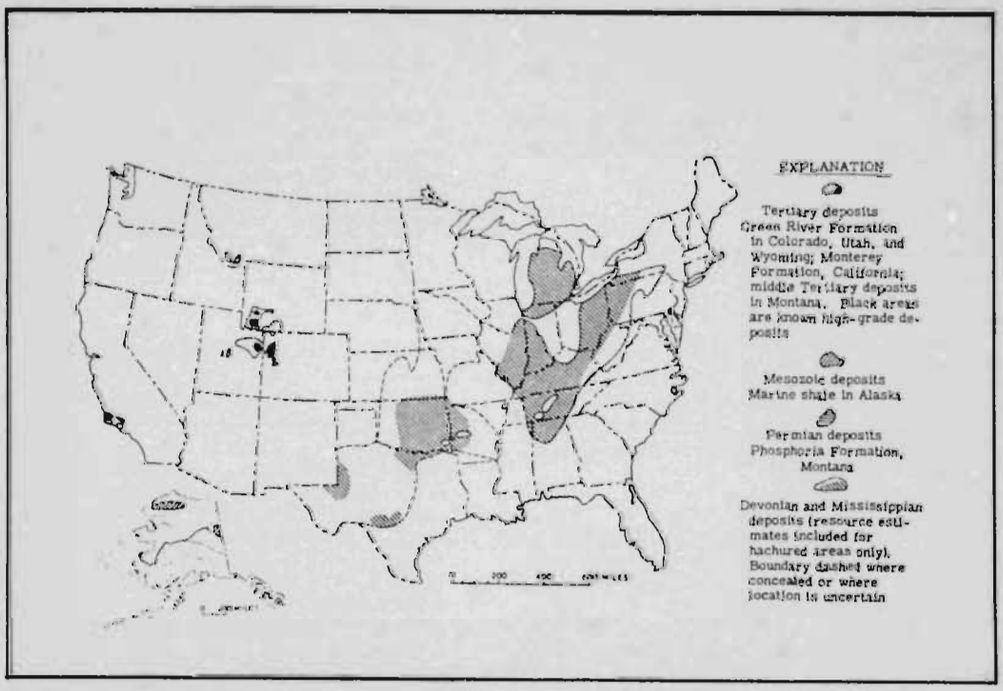

Figure 2. Principal Reported Oil-Shale Deposits of the United States.

Mine Site Geology

Geologic units present within the confines of the proposed mining area are, in descending order, the Fort Payne Chert, the Chattanooga Shale, and the Brassfield Limestone. General lithologic descriptions of these units, provided below, have been excerpted from the Geological Survey's published data.

Fort Payne Chert. The Fort Payne generally consists of light-gray fossiliferous limestone, siliceous and dolomitic limestone and dolomite with thin beds of bluish-gray dense nodular chert. The thickness of the formation ranges from 155 to 185 feet. Residual soils derived from this unit consists of moderate-red to moderate reddish-orange clay with interbeds of dense chert or rectangular blocks of porous, fossiliferous chert. Underlying the Fort Payne is a very thin shale sequence known as the Maury Formation. The Maury is about 1 foot thick and consists of grayish-green fossiliferous shale and claystone commonly containing pyrite, glauconite, and small phosphate nodules.

Chattanooga Shale. This unit is a dark-gray to black fossiliferous, thinly bedded, partly fissile, partly pyritic shale with a discontinuous thin bed of medium-gray fine-grained sandstone at the base. The oil shale within the reserve area is relatively flat-lying with apparent dip being less than 10 feet per mile to the south. The thickness of the shale averages 15 feet but varies between 12 and 18 feet. The thickness of overburden ranges from 0 to 130 feet and consists of up to 40 feet of weathered rock and soil (regolith). On the higher slopes, the Fort Payne Chert overlies the oil shale. The area stratigraphy is shown schematically in Figure 3.

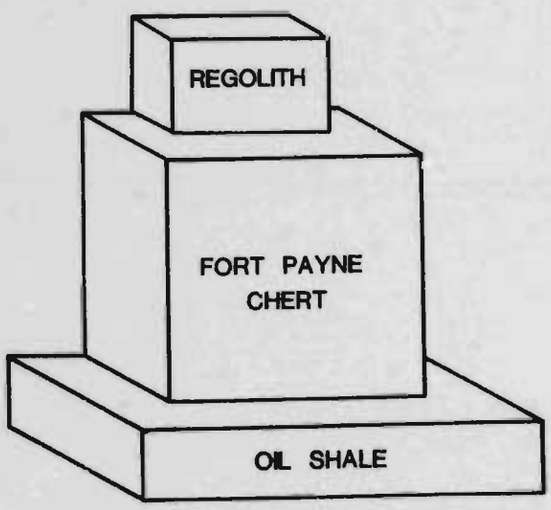

Figure 3. Schematic of Mine Site Stratigraphy

Brassfield Limestone (Silurian). Medium light-gray cherty fossiliferous, partly glauconitic limestone, dolomitic limestone, shale, and calcareous sandstone. The formation is laterally discontinuous and the thickness in stream valleys in the northern part of the county is about 10 feet. The maximum thickness of the formation is about 40 feet.

Regolith. Another lithologic unit which affects mining is the extensive unconsolidated residual soils (regolith) which may be up to 40 feet thick in the area. The regolith consists generally of clay with silt, sand, and scattered rock fragments of various sizes. Typically, the concentration of rock fragments increases with proximity to bedrock but rocky zones may occur well above the base of the regolith.

Mining

The Hester Creek area has sufficient reserves of Chattanooga Shale to supply 30,000 tons per day of ore to the processing facility for a minimum of twenty years which is the projected life of the operation.

The reserve is divided by Hester Creek into two nearly geometrically equal parts and for convenience the two reserve areas are referred to as Hester Creek east and west in this report.

Table 1 provides data relative to tonnages of overburden and shale and stripping ratios. Shale tonnages given were calculated based on an assumed mean shale thickness of 15 feet as indicated by exposures along Hester Creek.

Table 1. Overburden and Shale Tonnage Data

	East	West	Total
Acres	4,290	3,963	8,172
Waste Tonnage	911,220,000	694,830,000	1,606,050,000
Shale Tonnage	192,510,000	181,260,000	373,770,000
Stripping Ratio	4.73	3.83	4.30

Figure 4 shows the study area with surface contours on 25 foot intervals. The elevation of the top of the shale is approximately 780 feet above mean sea level.

The mine has been designed to produce 33,000 tons per day of run of mine ore which will furnish the Paraho retorting process plant with 30,000 tons per day of raw feed. Overburden removal will continue 24 hours-per-day, seven days-per-week; loading, hauling and crushing of ore will be on a two-shift basis seven days per week.

In order to provide the processing plant with 30,000 tons per day feed, about 3,449,000 cubic yards of overburden must be removed per month and 1,001,000 tons of shale must be mined while returning the spent shale to the pit. Materials handling data are shown in Table 2.

Mining Plan

Because the reserve is divided by Hester Creek, it is planned to initiate two box cuts approximately 120 feet wide along the south boundary of the reserve beginning at Hester Creek

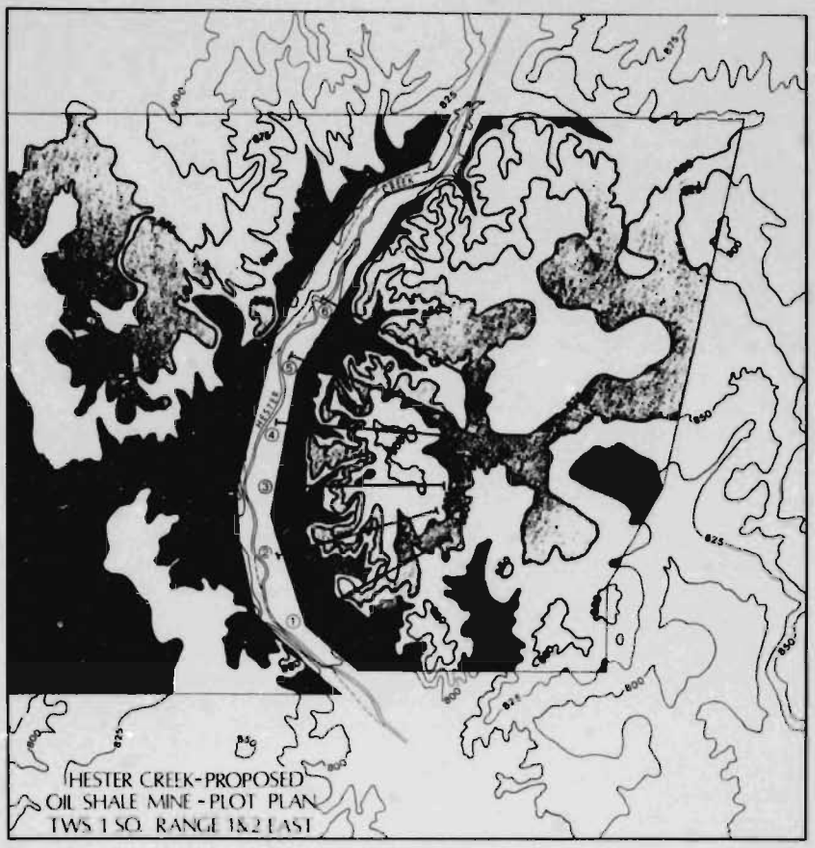

Figure 4. Proposed Mine Site (Shaded Area) Showing Topography and Drainage

Table 2. Materials Handling Data
Hester Creek Mine

	East				West				
Materials	Acres/mo.	Cast Yd^3/mo.	Drag Line Yd^3/mo.	Total Yd^3/mo.	Acres/mo.	Cast Yd^3/mo.	Drag Line Yd^3/mo.	Total Yd^3/mo.	Grand Total Yd^3/mo.
Overburden	10.9	658,226	1,222,271	1,880,537	10.9	548,993	1,019,557	1,568,550	3,449,087
	Tons/day	Tons/mo.			Shale Tons/day	Shale Tons/mo.	Total East & West Tons/mo.	—— Spent Yd^3/day	Shale —— Yd^3/mo.
Shale	16,446	500,551			16,446	500,551	1,001,102	25,265	768,050

Yd^3 shown based on 50% swell factor
Cast Factor: Material moved with explosives and bull dozers = 55%

Hollow and extending to the east and west boundaries as shown in Figure 5. Figure 6 shows typical cross sections of the east box cut with minimum and maximum overburden and Figure 7 shows typical cross sections of the east reserve with mean and maximum overburden. The mean and maximum overburden for the west reserve are 57 feet and 95 feet respectively.

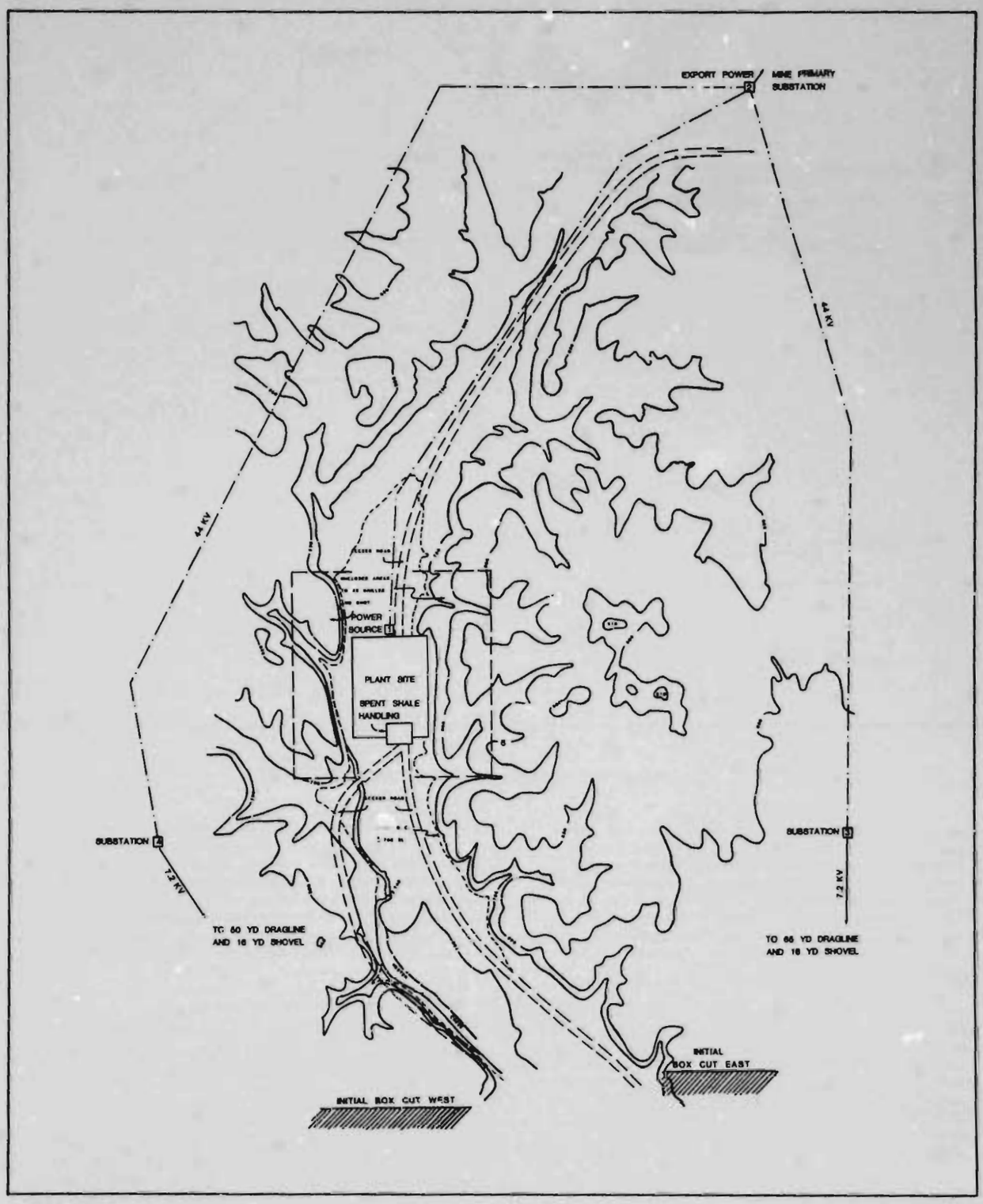

Figure 5. Schematic Surface Layout

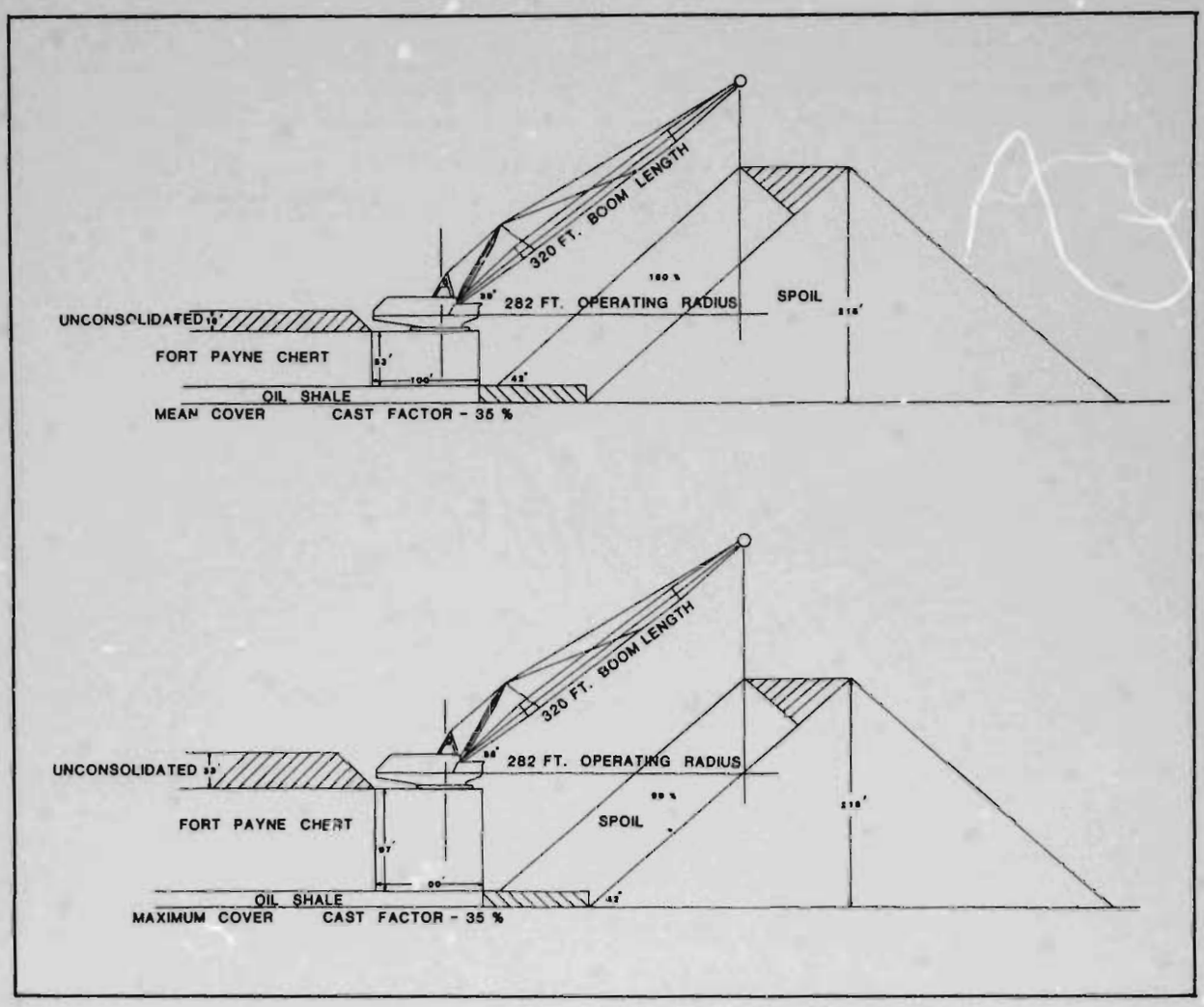

Figure 7. Typical Cross Sections East Reserve

assumed for this operation. Based on current practice in surface coal-mining operations in Alabama, it is anticipated that approximately one-third of the overburden will be moved with explosives and bulldozers grading for the draglines. One extra mobil drill unit has been included as a backup for drilling operations.

Drilling and Blasting Shale

Four drill units, 40,000 pounds each, capable of drilling holes 6 3/4 inches in diameter at a rate of 3095 feet per day on a 12 foot by 12 foot pattern have been selected for drilling blast holes in the shale. Two drills each in the east and west reserves will be required. Again, a combination of slurry Gel and AN/FO has been selected for blasting using 1.2 pounds of explosive per yard of shale (0.63 pounds per ton).

Removal of Overburden

Draglines were selected as the primary units to handle overburden. A 50-yard dragline was selected for the west reserve while a 65-yard dragline was selected for the east reserve because of the thicker overburden. After blasting and grading ahead of the draglines, the remainder of the overburden will be cast into the adjacent pit from which the shale has been removed (see Figure 7).

Loading and Hauling Shale

Two 16-yard electric shovels were selected for loading shale in both the east and west reserves. A rubber-tired dozer will be used as an auxilliary unit to work with each shovel. A fleet of twenty-five trucks (85-ton capacity) will haul the shale to the retort facility and return the spent shale to the pit. Two 6-yard loaders have been assigned to handle the spent shale and undersized (minus 3/8 inch) shale at the plant. The material handling procedures will be designed to feed the rejected material into a bin or direct it to an adjacent stock pile for surge control.

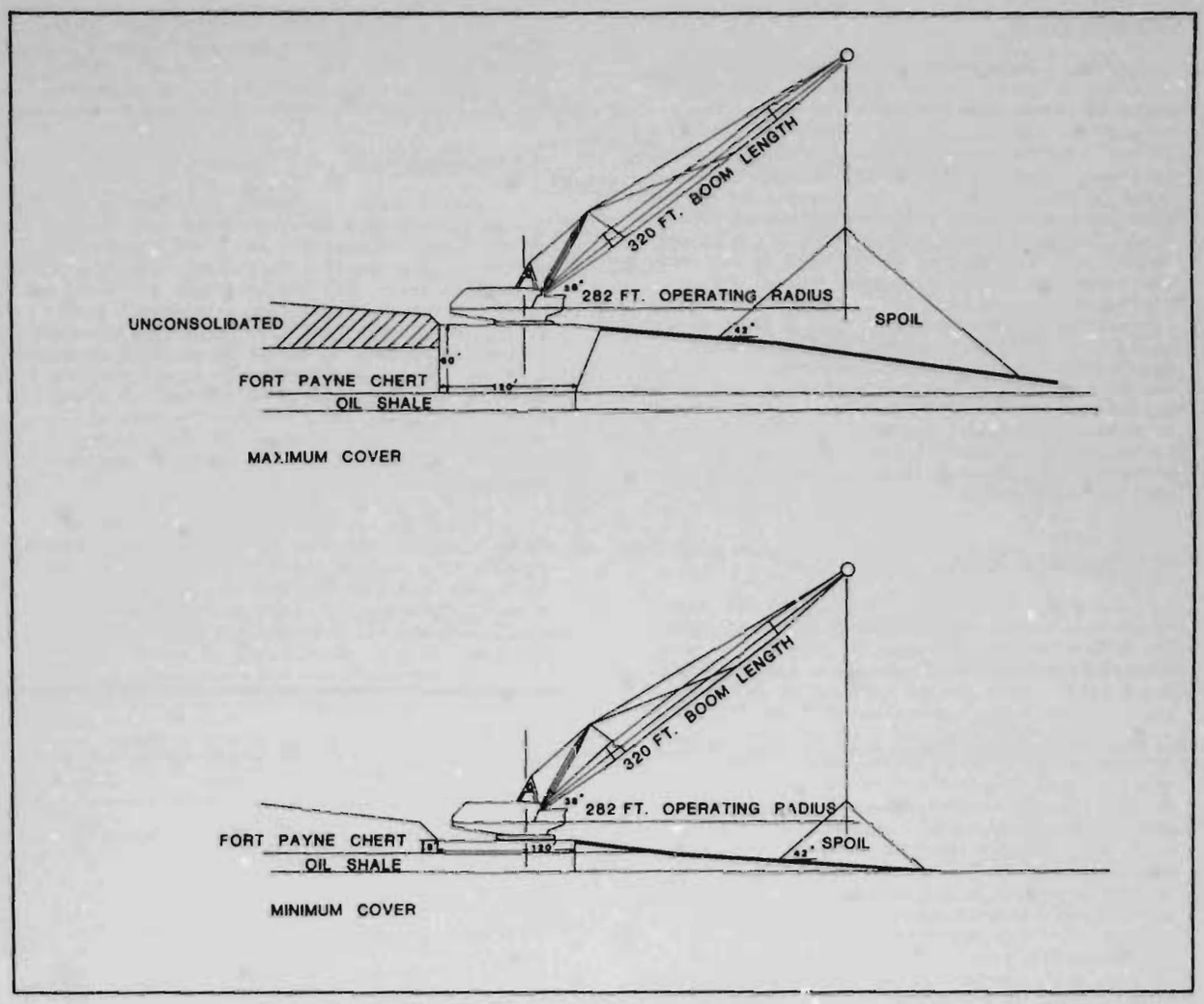

Figure 6. Box Cut Cross Sections East Reserve

The width of the initial cut was selected in order to allow subsequent cut widths of between 100 and 120 feet to take maximum advantage of the case factor (the amount of material moved with explosive). The overburden from successive parallel cuts will be cast with drag lines into the preceeding cut from which the shale has been removed. The shale will be loaded with electrically powered shovels and hauled by truck to the primary crushing station located at the retort facility. The trucks will back-haul the spent shale to the pit for disposal. Maximum haulage distance will be 2.5 miles during the mine life.

The power supply for the mining operation will be furnished from the retort facility via a 15,000 kva substation at 44 kv. The power will be distributed to two pit substations at 7500 kva each which will furnish 7200 volts for the draglines and shovels east and west (see Figure 5).

Clearing, Grubbing and Top Soil Removal

After the merchantable timber has been removed and the scrub growth cleared, approximately two feet of top soil will be stripped off by dozers and/or scraper pans and either stockpiled for future use or used concurrently in reclamation of disturbed land.

Drilling and Blasting Overburden

The overburden will be drilled with two 60,000-pound drill units capable of drilling holes 10 5/8-inches in diameter on a 24 foot by 32 foot spacing at a rate of 1840 feet per day (2 shifts). For blasting the overburden, it is proposed to use a combination of slurry gel and AN/FO explosive, depending on water conditions. About 1.5 pounds of explosive per yard of overburden will be used. Electric cap detonation has been

Land Reclamation

Land reclamation will continue concurrently with the stripping and shale removal. The spent shale and fines from the retort plant will be returned to the pit and, along with the cast overburden, will be graded to the approximate premining contours. At least two feet of topsoil will be added to the final grade. Two dozers, two 24-yard pans and a heavy duty grader have been assigned to grade the spoil banks, including spent shale and fines, to bring the area to the desired contours. This operation will include the removal and replacement of top soil and, from time to time, a 12-yard loader and two trucks will be used to accomodate the longer haulage distances which may be required. Following placement of top soil, the surface will be revegetated with a fast growing ground cover to minimize erosion. Experimentation to determine the best vegetation combination will be necessary but many of the same revegetation scenarios used in surface coal mine reclamation will probably suffice.

Surface Water Control

The removal of overburden and its replacement in the spoil banks has been designed to minimize the effect on the hydrologic balance of the area. Run-off from the spoil banks and other disturbed areas will be directed to sediment ponds strategically located for removal of silt and control of flow. Premining diversion drainage will be used to minimize flow in disturbed areas. Haulage roads will be properly graded and adequately drained through ditches directed to sediment ponds. Along the toe of the spoil banks adjacent to Hester Creek, a bench at least 20 feet wide will be graded to slope away from the creek. Run-off from this drainage will be directed to settling basins down stream from the mining operations. This drainage will be maintained a minimum of 300 feet from the creek. Detailed surface and groundwater hydrologic and hydraulic studies would be necessary prior to and during the project in order to provide design data for sediment retention structures and to comply with environmental quality and surface mining regulations.

Processing Study

Introduction

Of the several currently available oil shale retorting technologies, (Paraho, Union Oil, HYTORT, and TOSCO) only the Paraho and the HYTORT processes were studied as a preliminary phase of the site-specific evaluation. These processes were conceived, developed, and refined by the Paraho Development Corporation and the Institute of Gas Technology (IGT), respectively. The Paraho and HYTORT processes were chosen for study because of similarities between the Union Oil process and the Paraho process and because the TOSCO Corporation believes their process is not suited to the characteristics of eastern shales.

These processes are described in great detail in other studies and the interested reader is referred to the now voluminous technical literature on the subject.

The preliminary study revealed that, even though the HYTORT process gave significantly better oil yields, the overall economics favor the Paraho process. Thus, Paraho was selected for the site-specific study in Madison County.

Process Description

Table 3 shows the energy distribution for the system and Figure 8 is a schematic flow diagram of the Paraho process for oil shale. Oil shale is heated in a retort to yield an overhead product from which shale oil, sulfur, light oil (C_3H_6 to C_6H_{14}), and high Btu gas are recovered. Retorted shale, containing about 8 to 10 percent residual carbon, drops into a combustion and cooling section in which the residual carbon is burned with air. Incoming air is preheated by cooling the spent shale. Hot gases from the zone are used to produce steam, some of which is used in the combustion and the remainder used to generate electric power.

Because of the lower hydrogen content of Eastern shales, application of the Paraho process results in a smaller yield of shale oil, sulfur, light oil, and high Btu gas relative to Western shales. Consequently, more residual carbon remains in the retorted shale, which results in a higher yield of electricity.

Table 3. Overall Energy Balance

SOURCE	MM Btu/Day	Percent
Plant Input	160,500	100.0
Plant Output		
Shale Oil	58,904	36.7
Light Oil	12,038	7.5
High Btu Gas	23,754	14.8
Export Power	13,161	8.2
Sulfur	1,605	1.0
Spent Shale	12,037	7.5
Stack and Vent Gases Cooling Tower Losses, etc.	39,001	24.3
	160,500	100.0

Economic Evaluation

The site for this resource assessment and economic evaluation was selected on the basis of shale resources containing the most promising oil yields, according to the modified Fischer Assays, along with other related criteria previously described. Fischer Assays of surface samples taken from the reserve area varied between 10.3 to 15.0 gallons per ton of shale. Thus an average of 13 gallons per ton was assumed for the study area.

In order to make an economic evaluation of this site-specific oil shale processing operation, it was necessary to develop a mining system to determine the capital investment required and

the cost of mining within ± 25 percent accuracy. All costs are based on 30,000 tons per day output from the mine. All costs shown are in terms of fourth quarter 1981 dollars.

Mining Economic Analysis

The capital expenditure schedule for the mining equipment is shown in Table 4. The capital

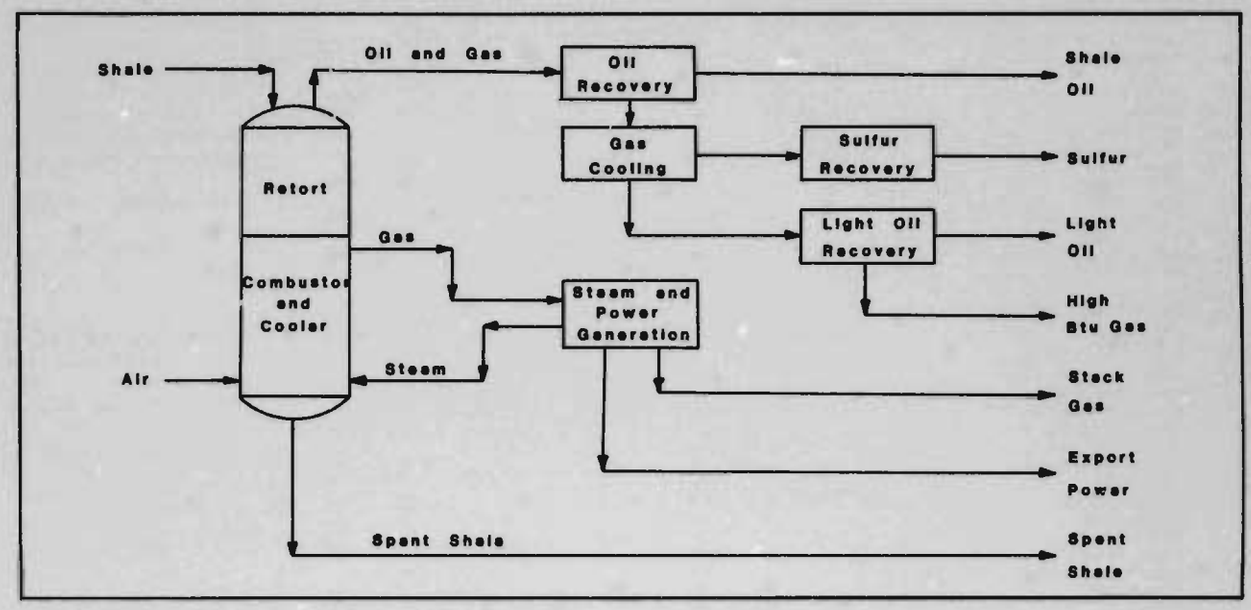

Figure 8. Schematic Flow Diagram Paraho Process

Table 4. Capital Expenditure Schedule for Mining Equipment
($ in 1000's)

Production Equipment	No. of Units	Avg. Life	Unit Cost	Years -2	-1	+1	2	3	4	5	6	7
Drill 10 5/8" Diesel	2	5	450	900					900			
Track Mounted Drill Rig	1	10	280			280						
Drill 6 3/4" Diesel	4	5	310		1,240					1,240		
D8 Dozers	6	5	260	520	520	520			520	520	520	
65 Yd Dragline	1	LOM	22,250	22,250								
50 Yd Dragline	1	LOM	20,000	20,000								
17 Yd Shovels	2	LOM	1,960	3,920								
85 Ton Trucks	25	7	530	1,072	8,576	3,752					1,072	8,576
H.D. Graders	3	6	253	506	253					506	253	
12 Yd Loaders	2	5	476		952					952		
6 Yd Loaders	2	6	327	327		327				327		327
Rubber Tire Dozers	2	5	249		498					498		
24 Yd Pans	2	6	485	970						970		
Service Equipment												
Water Truck	2	6	336		672						672	
Hydro. Crane 50 Ton	1	LOM	280	280								
Hydro Crane 25 Ton	1	10	157		157							
Hydro. Crane 8 Ton	1	5	67		67	67				67	67	
Fork Lifc 6,000 lb	1	5	28		28					28		
Fork Lift 12,000 lb	2	5	45		90					90		
Lowboy and Tractor	1	10	78		78							
Fuel Truck 2500 gal	2	5	36	36	36				36	36		
Lube Truck	1	5	78		78					78		
Mechanic Truck	5	5	51	51	102	102			51	102	102	
Welder Truck	2	5	38	38	38				38	38		
Flatbed Truck	2	5	16		16	16				16	16	
Powder Truck	4	5	40		200					200		
Elect Boom Truck	1	7	64		64							64
Pickup 4WD	8	3	9	18	27	27	18	27	27	18	27	27
Pickup 2WD	17	3	8	16	80	40	16	80	40	16	80	40
Pumps	4	7	18		36	36						36
Steam Jenny	2	5	4		4	4				4	4	
Radio (Set)	1	LOM	102		51	51						
GRAND TOTAL				50,904	13,863	5,222	34	107	1,612	5,706	2,813	9,070

Table 4--(Continued)

Production Equipment	8	9	10	11	12	13	14	15	16	17	18	19	20
Drill 10 5/8" Diesel		900					900						
Track Mounted Drill Rig				280									
Drill 6 3/4" Diesel			1,240					1,240					
D8 Dozers	520	1,520	520				520	520	520			520	
65 Yd Dragline													
50 Yd Dragline													
16 Yd Shovels													
85 Ton Trucks	3,752					1,072	8,576	3,752					
H.D. Graders				506	253					506	253		
12 Yd Loaders			952					952					
6 Yd Loaders				327		327				327		327	
Rubber Tire Dozers			498					498					
24 Yd Pans				970						970			
Service Equipment													
Water Truck					672						672		
Hydro. Crane 50 Ton													
Hydro. Crane 25 Ton			157										
Hydro. Crane 8 Ton			67	67				67	67				
Fork Lift 6,000 lb			28					28					
Fork Lift 12,000 lb			90					90					
Lowboy and Tractor			78										
Fuel Truck 2500 gal		36	36				36	36				36	
Lube Truck			78					78					
Mechanic Truck		51	102	102			51	102	102			51	
Welder Truck		38	38				38	38				38	
Flatbed Truck			16	16				16	16				
Powder Truck			200					200					
Elect Boom Truck							64						
Pickup 4WD	18	27	27	18	27	27	18	27	27	18	27	27	
Pickup 2WD	16	80	40	16	80	40	16	80	40	16	80	40	
Pumps	36						36	36					
Steam Jenny			4	4				4	4				
Radio (Set)													
GRAND TOTAL	3,822	1,652	4,171	2,826	1,032	1,466	10,255	7,764	776	1,837	1,032	1,039	

cost summary (Table 5) includes capital investment costs for the complete mine including the primary crushing facility. The initial capital investment is $102 million with an additional $57 million being required for equipment replacement over the life of the mine.

About 76 salaried employees and 368 hourly employees are required for the mining operation. Distribution of the work force and annual labor costs are shown in Table 6.

The estimated annual operating costs are shown in Table 7. Based on the computed labor costs, which represent 47 percent of the total operating costs, supplies and other costs represent 53 percent of the total.

Table 5. Initial Capital Cost Summary: Mining ($1000)

MOBILE EQUIPMENT	
Drills	2,420
Loading and Hauling	64,963
Service Equipment	2,606
SEDIMENT PONDS	656
SERVICE BUILDING	7,941
(Shop and Supply House)	
(Fuel and Lube Station)	
ELECTRICAL EQUIPMENT	1,578
POWDER MAGAZINES	56
ENGINEERING AND CONSTRUCTION MANAGEMENT	11,505
PRIMARY CRUSHER STATION	
Site Preparation	1,481
Drainage Structures	140
Crusher Erection	6,157
SUB TOTAL	156,517
MINE DEVELOPMENT	2,380
TOTAL	101,883

Processing Economic Analysis

As previously cited, an oil recovery of 13 gallons per ton of shale was assumed for the process economics calculations. The total and residual carbon in the raw and retorted shale were of the same order of magnitude as those of Kentucky samples referred to in "Synthetic Fuels From Eastern Oil Shale," prepared by Davy McKee for the Buffalo Trace Area Development District. Therefore, certain parameters, such as distribution of by-products from the Alabama shale, were extrapolated following the Davy McKee rationale.

Evaluation of the Alabama shale is based on treating 30,000 tons of shale per day yielding 13 gallons of oil per ton to recover 9285 barrels per

Table 6. Distribution of Work Force and Annual Labor Cost: Mining

Personnel Categories	Personnel Requirements	Avg. Salary Dollars/Year	Total Dollars/Year
Salaried Personnel			
Administrative-Accounting	12	23,921	287,052
Service Department	13	25,967	337,571
Production Supervision	26	29,147	757,822
Maintenance Supervision	25	31,488	787,200
Total Salaried	76		2,169,645
Plus 40% Fringes			867,858
			3,037,503
Hourly Employees			
Four Operating Crews	154	20,769	3,198,426
Dead Work Crew	44	20,769	913,836
Maintenance Employees	132	20,769	2,741,508
Hourly	330		6,853,770
Vacation, Absenteeism, and Training Allowance	38	20,769	789,222
Total Hourly	368		7,642,992
Plus 35% Fringes			2,675,047
			10,318,039
GRAND TOTAL	444		13,355,542

Note - (A) Overburden removal to be continuous three shifts per day, seven days per week.
(B) Drilling of overburden and shale, loading, hauling and crushing of shale will be on a two shift basis, seven days per week.
(C) Dead work crew scheduled Monday thru Friday on a two shift basis.

day on a 330 days per year operating schedule. The annual yield from this operation would be about 3,064,285 barrels.

The annual process by-products, the assumed unit prices and expected revenues are shown in Table 8. The capital cost and operating costs details of processing (including mining) are provided in Tables 9 and 10 respectively.

Economic Summary

Table 11 gives the total initial capital cost of $750.7 million including working capital and construction interest.

A summary of capital charges, operating costs and by-product credits expressed in dollars per barrel and in terms of a selling price for shale oil of $40.00 per barrel is provided in Table 12.

The capital charge includes $12.25 per barrel of oil to cover depreciation of the capital investment on a straight line over the 20-year life of the operation. The remaining $24.21 in the capital charge is principally profit before taxes. The $40.00 per barrel selling price would provide a 13 percent return on equity.

Table 7. Annual Operating Cost: Mining

Labor (47%)	$13,355,500
Supplied and Other (53%)	15,060,500
	$28,416,000

$$\text{Cost per ton of ore mined} = \frac{28,416,000}{10,950,000} = \$2.595$$

Conclusion

Within the context of the quantities of hydrocarbons found in this project and within the limitations of the accuracy of existing cost data for currently available retorting technology, it is apparent that commercialization of oil shale in the study area is not feasible at current world prices for conventional crude. The ultimate viability of an oil shale industry in Alabama and adjacent states may depend upon the combined results of oil price escalations, more exploration and testing to delineate the highest quality deposits, and continued research on improving hydrocarbon and by-product recoveries.

Table 8. Annual Process By-Product Revenues

By Product	Unit Price	Units/Day	Annual Revenue
High Btu Gas	$3.00/MM Btu	23,753 MM Btu	$23,516,000
Light Oil	$0.60/gal	109,520 gal	$21,685,000
Electrical Energy	$0.0275/kwh	54.8 mw	$11,944,000
Sulfur	$60/ton	151 ton	$ 2,988,000
TOTAL			$60,133,000

Table 9. Initial Investment Cost: 30,000 Tons/Day Oil Shale Mining and Processing Operation

Process Area	$ Million
Mining	102
Crushing, Screening and Storage	49
Retorting	128
Oil Recovery	14
Acid Gas and Ammonia	17
Light Oil Recovery	9
Sulfur Recovery and Tail Gas Cleanup	9
Steam and Power Generation	40
Waste Water Treatment	9
Shale Oil Storage	4
Spent Shale Disposal	7
Sulfur Dioxide Scrubber	15
Utilities and Offsites	25
Total Direct Cost	428
Professional Services	39
Field Indirect Costs	83
Insurance	7
Start Up Allowance	1
	$558
Contingency	27
Total Plant Investment	$585

All figures except mining are derived using a 12% escalation of those figures used by Davy McKee (4th quarter 1980) SYNTHETIC FUEL FROM EASTERN OIL SHALE, Vol. 1.

Table 10. Annual Operating Cost: Mining and Processing

	$(1000)
Consumables	
Catalysts and Chemicals (12% escalation)	1,095
Electricity 4.2¢/kwh	0
Untreated Water 50¢/1000 gal	483
Limestone $5/ton	1,759
Supplies - O&M (13% escalation)	23,394
SUB TOTAL	$26,731

Table 10 continued on next column.

Table 10 Continued...

Labor and Overhead	
Operating and Maintenance Labor	16,508
Payroll Burden, General Admin.	9,310
SUB TOTAL	$25,818
Taxes and Insurance	
Ad Valorem Taxes (1.65% Ip)	9,653
Insurance (1.5% Ip)	8,775
SUB TOTAL	$18,428
Gross Operating Cost	70,977
Total By-Product Credit	(60,133)
Net Operating Cost	$10,844

Table 11. Summary of Capital and Annual Operating Costs (millions of dollars)

	Capital	Operating
Mining	101.9	
Processing	483.0	10.8
Subtotal	584.9	
Working Capital*	19.9	
Construction Interest	145.9	
Total	750.7	10.8

*13% of annual shale oil revenue at $50.00 per barrel oil selling price

Table 12. Summary of Capital Charges, Operating Costs and By-Product Credits

	Dollars/bbl
Operating Cost	23.16
By-Products Credit	(19.62)
Capital Charge	36.46
Selling Price	$40.00

Preliminary Research on Potential Reclamation of Oil Shale Mined Lands in Kentucky*

by
W. Russell Hamon
Robert R. Kruspe
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract. The objective of this study was to conduct a preliminary investigation of the potential reclamation of oil shale mined land in Kentucky. Tests were made to assess the potential for establishing an adequate vegetative medium by use of the available soil and overburden materials, the potential for use of processed oil shales to improve the physical properties of high clay materials, and the potential treatments and vegetative species that would provide for the establishment of an adequate vegetative cover. These tests included the determination of physical and chemical properties of the field sampled and processed materials, including information on macronutrients, micronutrients, other pertinent elements and soluble salts, and growth chamber tests. Materials for the tests were obtained from five widely separated sites in the Knobs region and from one site in the Cumberland Saddle area.

Soils formed in residuum from oil shales and immediate overburden materials in the Knobs region have typical solums of 15 to 30 inches with topsoil depths of generally less than 6 inches, and are medium to extremely acid and of low fertility. Most of the materials have rather high erosion factors for the topsoils and moderate factors for the subsoils. The immediate overburdens were found to be extensive with similar characteristics, to have a high clay content, and to have an acid potential near neutral.

The elemental levels of macro- and micro-nutrients and other elements for the raw shales were generally within the limits usually found in soils. The processed oil shales, obtained from retorting and retorting-combusting and which were crushed, however, generally showed increases in exchangeable calcium, magnesium, and sodium, and marked increases in potassium. The HYTORT material was alkaline, but the other oil shale materials were found to be acidic.

Admixtures containing equal parts of soil or overburden materials and raw or processed oil shales, along with soil and overburden materials, were used to grow ryegrass in a growth chamber to test the assumption that a more desirable physical plant growth medium would result while retaining nutrient, pH, soluble salts, and other factors at desirable or tolerable levels. Yields from the admixtures were about 68 percent of the highest yielding soil material.

* This research was supported in part by the Kentucky Department for Natural Resources and Environmental Protection.

Introduction

Lands disturbed by mining of oil shale should be reclaimed as rapidly as possible with proper land forming and placement of surface materials, revegetated to minimize the environmental impacts, including erosion, sedimentation and water quality.

Obtaining the desired reclamation could be a problem with materials available. The soils in the vicinity of Devonian shale outcrops in Kentucky are, in general, medium to extremely acid, low in fertility, shallow to moderately deep and well drained.[1] This indicates the need to explore the possible utilization of overburdens and spent shale materials to augment the available soil materials.

Study Objectives

The objectives of this study, therefore, were threefold. The quality and quantity of the available soil and overburden materials, as well as their potential to support adequate vegetative cover, was determined. The use of oil shale or processed oil shale mixed with soil or overburden materials (admixtures) to enhance plant growth was also explored. In so doing, the effect of chemical constituents in the admixtures on plant production and water quality had to be addressed. Finally, a vegetative species and the appropriate treatments necessary to sustain an adequate cover had to be identified.

Study Materials

Residual soils occurring on the oil shales and on the overburden formations, in addition to the oil shales and overburdens, were sampled at five separate locations in the Knobs area with sites in Lewis, Powell, Lincoln, Nelson and Bullitt Counties. Also, samples from a residual soil on the immediate overburden was obtained, along with the oil shale and overburden samples, from the Cumberland Saddle area with the site located in Russell County. The general site locations are shown in Figure 1.

Field sampling of the overburden materials and of the oil shales was accomplished by use of a backhoe. Soil samples were obtained from pits with a channel sample taken from the entire solum.

Portions of the raw oil shale samples were retorted at 700 to 900°F and sub-samples combusted at 1200 - 1300°F temperature. In addition, the Institute of Gas Technology supplied New Albany oil shale material from the Bullitt County site that had been retorted by the HYTORT process. The oil shale sampling and processing were accomplished as part of a companion study and are discussed in a recent research report.[2]

Experimental Procedures

Detailed soil surveys are available for only about one-half of the counties where the oil shale outcrops in Kentucky.[1] A number of additional surveys have been completed and are pending publication. In addition, the (Kentucky) Division of Conservation is conducting a general soil survey of the remaining counties. The soil surveys contain, in addition to typical soil profile descriptions and soil maps, information on climate, land capability, crop yields, water management, soil engineering properties, and physical and chemical properties of the soils.

Soil surveys, where available, for the six selected, widely dispersed, sampling sites (Figure 1) were used, along with geologic quadrangle maps[3] to determine the soils and overburden materials that would be associated with oil shale mining operations at these sites. Selected residual soils associated with the oil shales and overburdens were described and classified by the soil Conservation Service and (Kentucky) Division of Conservation soil scientists. The soil descriptions, which also contain information on the exact location, position and vegetation, are presented in Appendix A.

Physical properties determined for the sample materials include particle density, bulk density,

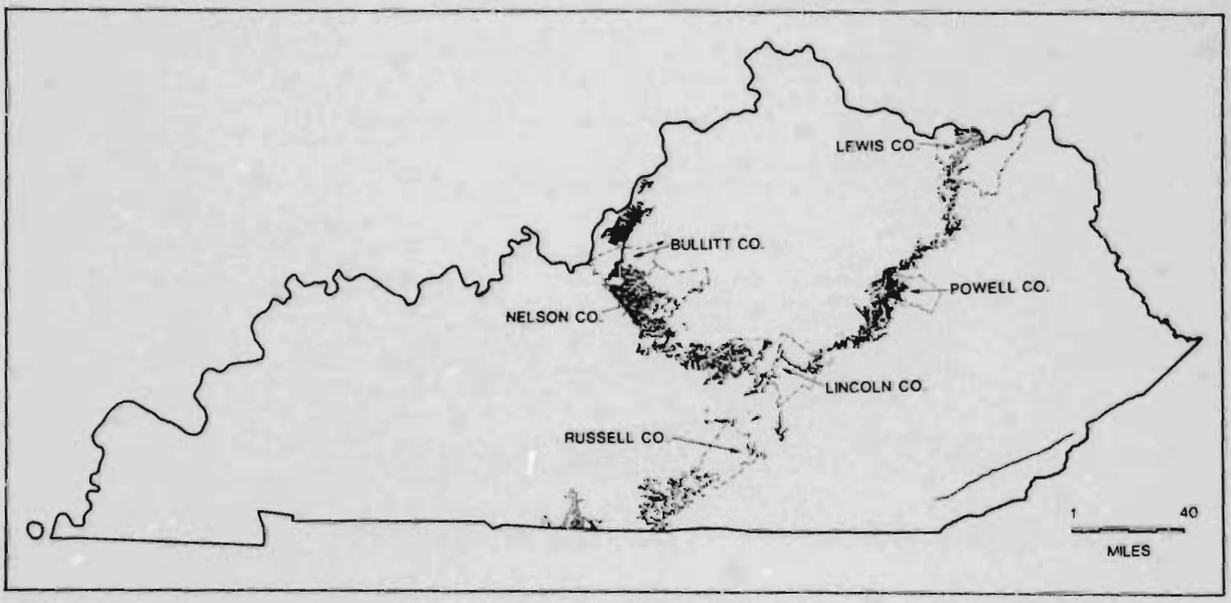

Figure 1. Location of Sampling Sites.

particle size analysis, water holding capacity, and permeability (saturated hydraulic conductivity). Other laboratory tests obtained information on pH, cation exchange capacity and carbon content. Information on the quantities of macronutrients (N, P, K, Ca, Mg and S), micronutrients (B, Cu, Mn, Mo, Zn and Fe), heavy metals (Cr, Ni and Pb), other elements (Na, Si, Co and Al) and soluble salts was obtained from the geochemistry of the samples[2] and from other appropriate laboratory tests.

Finally, to test vegetative response on these materials, a growth chamber study was conducted using the soils, overburdens, oil shales, processed oil shales, and admixtures containing equal parts of soils or overburdens in combination with oil shales or processed oil shales. The plant species used in this test was perennial ryegrass, which is commonly used in surface mine reclamation.

Quantities of Materials Available for Reclamation

As an example in assessing the availability of soils for reclamation use at a potential oil shale mining site, a soil map of the Bullitt County site is presented as Figure 2. The geologic cross-section for this site, indicated by A-A' (Figure 2) is found in Figure 3. For comparison, a cross-section of the Lewis County site is presented in Figure 4.

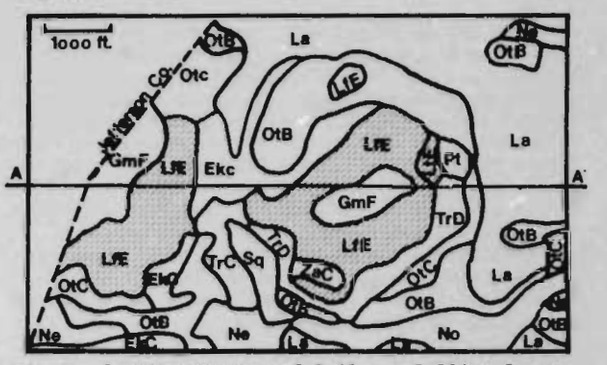

Figure 2. Distribution of Soils at Bullitt County Sampling Site, (Principal Soils Identified in Figure 5 and Section A-A' is Shown in Figure 3).

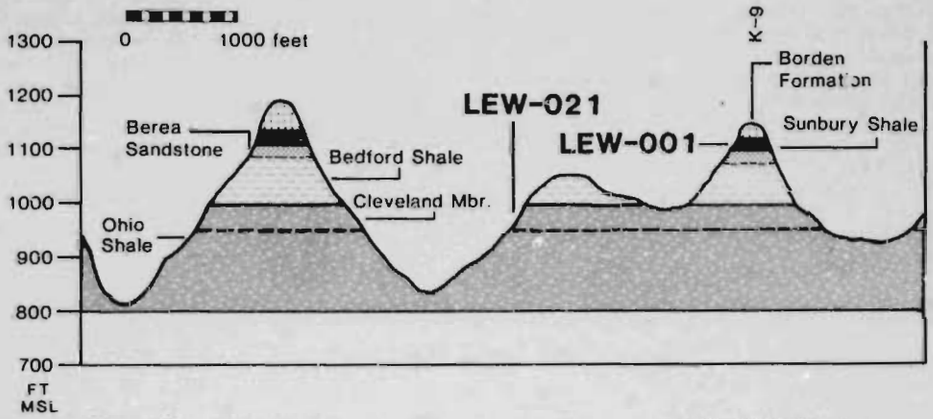

Figure 3. Geologic Cross-Section for Sampling Site in Bullitt County. (Vertical to Horizontal Scale 8:1).

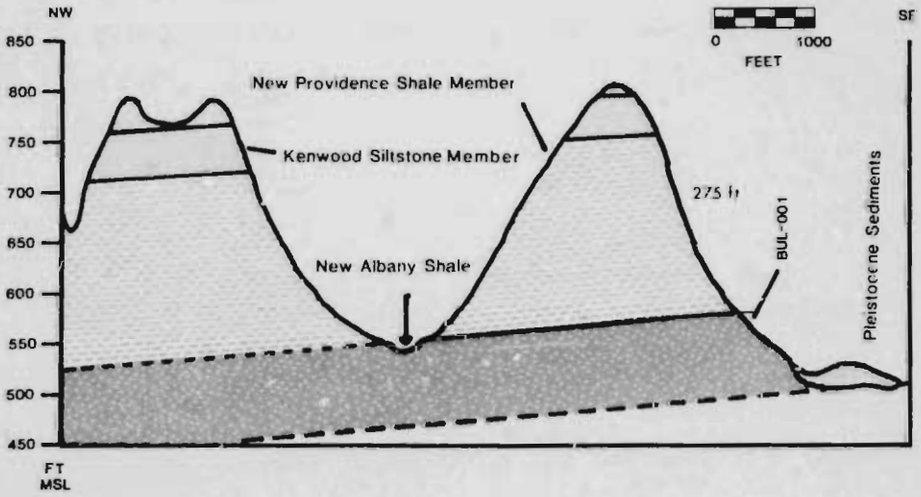

Figure 4. Geologic Cross-Section for Sampling Site in Lewis County. (Vertical to Horizontal Scale 8:1).

Soils

Soils sampled and analyzed were limited to the soils formed in residuums derived from oil shale and the overburdens.

The two principal soils formed in residuum derived from black (oil) shales are the Colyer and Trappist series. The Colyer soil is shallow with a typical solum thickness of about 14 inches with a topsoil (A-horizon) thickness of generally about 4 inches. This soil is located on slopes ranging from 6 to 60 percent.[4] The Trappist soil is moderately deep with typical solum and topsoil thicknesses of about 28 and 6 inches, respectively, and located on slopes ranging from 2 to 60 percent.[4] The Colyer soil was sampled at the Lewis County site and the Trappist soil at the Bullitt County site. Soil profile descriptions of these sampled soils are presented in Appendix A.

The principal residual soils on the immediate overburden materials in the Knobs outcrop area are the Lenberg and Rockcastle series. The overburden materials consist of the Borden Formation (Farmers-Henley Bed, Nancy, and New Providence members) and the Bedford Shale. The Lenberg is moderately deep with a typical solum thickness of 25 inches with a topsoil thickness of generally about 4 inches. This soil is situated on slopes ranging from 6 to 35 percent.[4] The similar Rockcastle soil has typical solum and topsoil thicknesses of 14 and 6 inches, respectively, and is located on slopes of 10 to 55 percent.[4] The Lenberg soil was sampled at the Bullitt, Lewis, Nelson and Powell County sites, and the Rockcastle soil at the Lincoln County site. Soil profile descriptions of these sampled soils are found in Appendix A.

In the Cumberland Saddle area, the Garmon soil was sampled at the Russell County site. This extensive soil in the area is formed from residuum of shaley limestones, calcareous shale, and siltstones of the Fort Payne formation. The Garmon soil is moderately deep with a typical solum thickness of 25 inches with a topsoil thickness of about 8 inches. This soil is located on slopes of 2 to 80 percent.[4] The sampled Garmon soil profile is described in Appendix A.

Two other less extensive soils were sampled and described at the Lewis County site. The Muse soil, formed in residuum or colluvium derived from shale and siltstone, has a typical solum thickness of 48 inches with a topsoil of 7 inches. It is located on slopes of 2 to 60 percent.[4] The Cranston soil, formed in a colluvial material has a typical solum thickness of 50 inches with a topsoil of 5 inches. It is located on slopes of 2 to 60 percent.[4] Soil profile descriptions of these sampled soils are presented in Appendix A.

Soil survey interpretation data for the sampled soils and associated soils for the six sample sites are listed in Table 1. In most cases, the soils formed on the more gentle slopes below the oil shale outcrop exhibit considerably deeper solums and topsoils. The sampled sites had topsoil depths less than typical (Table 1) because the sites were selected on slopes that could be theoretically affected by mining and erosion so that the soils would be truly "residual." Therefore, in the samples taken, the depth of the solum essentially represents the B-horizon.

The positioning of the soils at a typical "Knobs" location (Bullitt County site) is shown in

Table 1. Soil Survey Interpretations.[1]

Soils[2]	Horizon Thickness, (In)[3] (A)	(B)	(C)	Texture (Typ. Pedon)	Available Water (In/In)	Soil Reaction, pH	Permeability	Erosion Factors[4] (K)	(T)	Shrink-swell Potential
					--------- B-Horizon ----------					
-Bullitt Co. Site-										
(Surveyed Soils)										
Trappist	6 (1)	22 (26)	7 (0)	Silt loam	0.10-0.18	3.6-5.5	Slow	0.37-0.24	3-2	Low to moderate
Lenberg	4 (1)	32 (28)	12 (Cr027)	Silt loam	0.10-0.18	4.5-5.5	Moderately slow	0.43-0.28	3-2	Low to moderate
(Associated Soils)										
Garmon	5	24	0	Shaly silt loam	0.05-0.16	4.5-7.3	Moderately rapid	0.32-0.20	3	Low
Elk	10	42	18	Silty clay loam	0.18-0.23	4.5-6.5	Moderate	0.32-0.28	4	Low
Otwell	8	62	20	Silt loam	0.06-0.08	4.5-5.5	Slow	0.43	3	Low to moderate
Lawrence	8	46	18	Silt loam	0.18-0.22	4.5-5.5	Slow	0.43-0.37	3	Low
Nolin	9	43	6	Silt loam	0.18-0.23	5.6-8.4	Moderate	0.43	5	Low
Newark	9	25	26	Silt loam	0.18-0.23	5.6-7.8	Moderate	0.32	5	Low
Zanesville	6	47	10	Silt loam	0.08-0.22	4.5-5.5	Moderately slow	0.43-0.28	3	Low
Carpenter	6	45	3	Gravelly silty clay loam	0.10-0.20	4.5-6.5	Moderate	0.32-0.28	4	Low to moderate
Sensabaugh	8	26	20	Gravelly clay loam	0.10-0.16	5.6-7.8	Moderately rapid	0.20	5	Low

Table 1. (continued)[1]

Soils[2]	Horizon Thickness, (In)[3] (A)	(B)	(C)	Texture (Typ. Pedon)	Available Water (In/In)	Soil Reaction, pH	Permeability	Erosion Factors[4] (K)	(T)	Shrink-swell Potential
					--------- B-Horizon ---------					
-Lincoln Co. Site-										
(Surveyed Soil)										
Rockcastle	6 (2)	8 (27)	36 (Cr@29+)	Silty clay loam	0.10-0.17	4.0-5.5	Slow	0.43	2-1	Low to moderate
(Associated Soils)										
Colyer	4	5	5	Shaly silty clay loam	0.03-0.10	3.6-5.0	Slow	0.37-0.17	2	Low
Trappist	6	22	7	Silt loam	0.10-0.18	3.6-5.5	Slow	0.37-0.24	3-2	Low to moderate
-Lewis Co. Site-										
(Surveyed Soils)										
Colyer	4 (3)	5 (12)	5 (0)	Shaly silty clay loam	0.03-0.10	3.6-5.0	Slow	0.37-0.17	2	Low
Muse	7 (2)	41 (38)	12 (0)	Silt loam	0.10-0.16	4.5-5.5	Slow	0.37	3-2	Moderate
Lenberg	4 (1)	32 (11)	12 (25)	Silt loam	0.10-0.18	4.5-5.5	Moderately slow	0.43-0.28	3-2	Low to moderate
Cranston	5 (6)	45 (54)	26 (0)	Gravely silt loam	0.14-0.19	3.6-5.5	Moderately rapid	0.28	4	Low
(Associated Soils)										
Berks	10	16	7	Shaly loam	0.04-0.10	3.6-6.5	Moderate	0.28-0.17	3	Low
Trappist	6	22	7	Silt loam	0.10-0.18	3.6-5.5	Slow	0.37-0.24	3-2	Low to moderate
Bledsoe	5	47	18	Silt loam	0.12-0.19	5.6-7.8	Moderately slow	0.37-0.32	4	Low to moderate
Nolin	8	44	13	Silt loam	0.18-0.23	5.6-8.4	Moderate	0.43	5	Low
Newark	9	23	28	Silt loam	0.18-0.23	5.6-7.8	Moderate	0.43	5	Low
Melvin	7	13	40	Silt loam	0.18-0.23	6.1-7.8	Moderate	0.43	5	Low
Cotaco	10	31	25	Loam	0.07-0.15	3.6-5.5	Moderate	0.37-0.28	3	Low
-Nelson Co. Site-										
(Surveyed Soil)										
Lenberg	4 (1)	32 (26)	12 (1+)	Silt loam	0.10-0.18	4.5-5.5	Moderately slow	0.43-0.28	3-2	Low to moderate
(Associated Soils)										
Markland	7	21	12	Silty clay	0.09-0.13	5.1-8.4	Slow	0.49-0.32	3-2	Low up to high
Melvin	7	13	40	Silt loam	0.18-0.23	6.1-7.8	Moderate	0.43	5	Low
Newark	9	23	28	Silt loam	0.18-0.23	5.6-7.8	Moderate	0.43-0.37	5	Low
Rockcastle	6	8	36	Silty clay loam	0.10-0.17	4.0-5.5	Slow	0.43	2-1	Low to moderate
Whitley	9	41	12	Silty clay	0.10-0.22	4.5-5.5	Moderate	0.37-0.28	4	Low
Zanesville	7	32	21	Silt loam	0.08-0.22	4.5-5.5	Moderately slow	0.43-0.28	3	Low
Lawrence	8	46	18	Silt loam	0.18-0.22	4.5-5.5	Slow	0.43-0.37	3	Low
Huntington	11	53	10	Silt loam	--- ---	--- ---	Moderate	--- ---	-	------
Colyer	4	5	5	Silty clay loam	0.03-0.10	3.6-5.0	Slow	0.37-0.17	2	Low
Bedford	9	67	0	Silty clay loam	0.18-0.20	3.6-5.0	Moderate - very slow	0.43-0.32	3-2	Low to moderate
Trimble	7	61+	0	Cherty silty clay loam	0.14-0.19	3.6-5.5	Moderate	0.28-0.24	3	Low
-Powell Co. Site-										
(Surveyed Soil)										
Lenberg	4 (4)	32 (31)	12 (5+)	Silt loam	0.10-0.18	4.5-5.5	Moderately slow	0.43-0.28	3-2	Low to moderate

Table 1. (continued)[1]

Soils[2]	Horizon Thickness, (In)[3] (A)	(B)	(C)	Texture (Typ. Pedon)	Available Water (In/In)	Soil Reaction, pH	Permeability	Erosion Factors[4] (K)	(T)	Shrink-swell Potential
					--------- B-Horizon ---------					
(Associated Soils)										
Colyer	4 (3)	5 (12)	5 (0)	Shaly silty clay loam	0.03-0.10	3.6-5.0	Slow	0.37-0.17	2	Low
Trappist	6 (1)	22 (26)	7 (0)	Silt loam	0.10-0.18	3.6-5.5	Slow	0.37-0.24	3-2	Low to moderate
-Russell Co. Site-										
(Surveyed Soil)										
Garmon	5 (5)	24 (9)	0 (26+)	Shaly silty loam	0.05-0.16	4.5-7.3	Moderately rapid	0.32-0.20	3	Low
(Associated Soils)										
Frederick	7	63	25	Silty clay loam	0.12-0.18	4.5-6.5	Moderate	0.32-0.24	4	Low to moderate
Caneyville	5	29	0	Silt loam	0.20-0.60	4.5-7.3	Slow	0.43-0.28	3-2	Low to moderate

[1] United States Soil Conservation Service - Soil Survey Interpretations.

[2] Soils listed are those described at the sites (see Appendix A; and associated soils occurring generally within one-half mile of site.

[3] Horizon thickness for the typical soil series except values in parentheses represent the site values as described in Appendix A.

[4] Factor K is the soil-erodibility term in the USDA Universal Soil Loss Equation. Factor T is the soil loss tolerance in tons per year that will allow a sustained high level of crop production. Ranges are for A- and B- horizons.

Figure 2 and the soil profile depths are shown in Figure 5. Assuming an oil shale economic zone of 30 feet and an overburden to oil shale ratio of 2.5:1, the depth of available soil (solum) material would be in the order of 30 to 35 inches (see Figure 2 and 5). In comparison, the source of soil

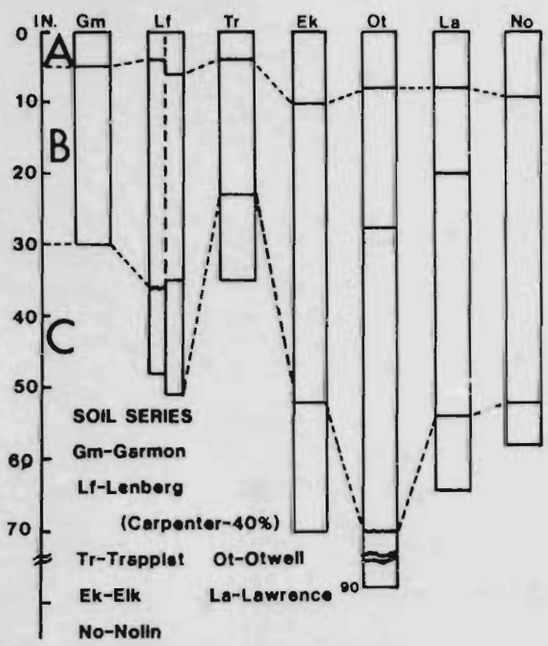

Figure 5. Depth Profiles for Soils in the Vicinity of Bullitt County Sampling Site (Figure 2). (Hatching Indicates Heavy Clay Materials).

materials below the outcrop elevation for an equally disturbed area would be 1.5 to 2.0 times greater. The availability of such materials, including both colluvial and alluvial materials, is highly site dependent and a mining/reclamation plan would be highly dependent on such availability.

Overburdens and Oil Shales

In the oil shale outcrop area of the Knobs region, the immediate overburden materials are extensive and of similar geochemical characteristics.[2] This accounts for the development of similar soils on these materials throughout the region. Again, considering the possible mining of 30 feet of the oil shale with overburdens of 2.5 times that thickness, the quantities of oil shale and overburden materials mined would be only about 5 percent different for slopes of 15 to 45 percent. For the Bullitt County site, Figure 3, excessive overburden exists while at the Lewis County site the existence of the Sunbury oil shale would probably allow for removal of the total overburden. Even for the Lewis County site, the quantity of Bedford shale is essentially equal to the mineable oil shale.

These overburden materials weather rapidly[5] and, if otherwise physically and chemically acceptable, they would offer a potential for utilization in reclamation. In the Cumberland Saddle region, the soils are of better quality and the immediate overburden materials of the Fort Payne Formation contain desirable limestone and calcareous shale components. The ranges in thickness of the immediate overburden materials for the geologic quadrangle maps[3] on which the 6 study sites are located, are presented in the prelude to the soils described in each county (Appendix A). The Bedford Shale for the Charters Geologic Quadrangle Map (Lewis County site) is the thinnest at 30-80 feet while

the Borden Formation (Nancy member) for the Clay City Geologic Quadrangle Map (Powell County site) is the thickest at 290 to 370 feet.

Characteristics of Materials in Relation to Reclamation

A number of geochemical determinations on the sampled materials, pertinent to reclamation, were obtained by x-ray fluoresence.[2] All samples to be used for further determination of physical and chemical properties were crushed by passing through a 3/8-inch jaw crusher. The particle size distributions resulting for the sample materials are presented in Figures 6, 7, 8, and 9. These particle sizes are smaller than would be produced in a commerical operation where they are more similar to gravels than to soils[5]. For special tests, as will be indicated, the materials were crushed to pass a 2 mm sieve. In addition, they appear to be much more durable than the overburden materials and probably would not weather rapidly.

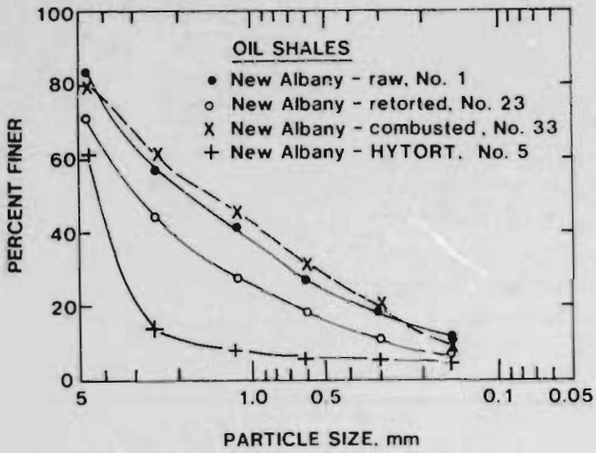

Figure 6. Particle Size Distributions for the Oil Shales After Crushing. (Sample Numbers Defined in Table 10).

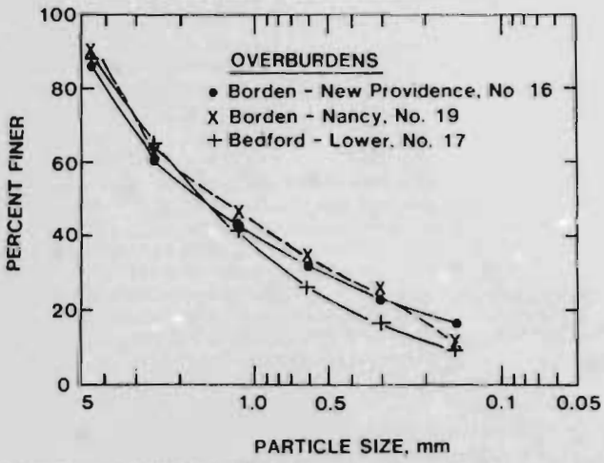

Figure 7. Particle Size Distributions for Overburdens After Crushing. (Sample Numbers Defined in Table 10).

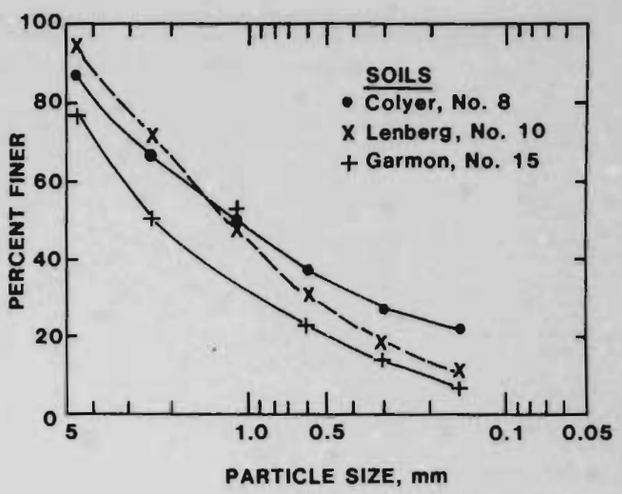

Figure 8. Particle Size Distributions for the Colyer, Lenberg, and Garmon Soils After Crushing. (Sample Numbers Defined in Table 10).

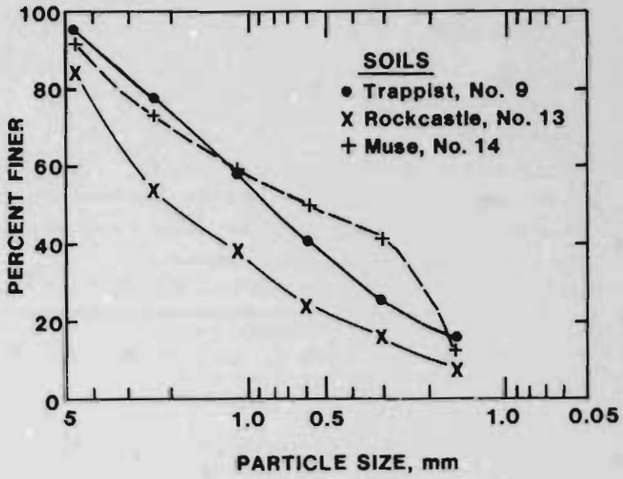

Figure 9. Particle Size Distributions for the Trappist, Rockcastle, and Muse Soils After Crushing. (Sample Numbers Defined in Table 10).

Physical Properties

The laboratory determined physical properties for the soils, overburdens and oil shales are tabulated in Tables 2 and 3. Ranges for typical soils of a number of physical properties are given in Table 1. The carbon content of materials is entered on Table 4.

Soils and Overburden Materials. The Colyer and Trappist soils, residual soils on the oil shale which occur throughout the outcrop belt, were significantly lower in clay content (40 to 45 percent) than the immediate overburdens and their residual soils in the Knobs region (55 to 67 percent). The clay content of the Cranston and Garmon soils were significantly lower in clay content at 38 and 31 percent, respectively (Table 2).

Table 2. Physical Properties of Soils, Overburdens and Oil Shales.

Materials	Sample No.	Growth Cham. No.	Particle Density[1]	Bulk Density	Particle size[2] Clay	Silt	Sand	Texture[3]	Water Holding Capacity[4] 1/3 Bar	15 Bars	Avail.	Permeability Unais.	Crushed[5]
			-- (g/cm^3) ------		----- % --------				---------- % ----------			---- cm/hr -----	
-Soils-[6]													
Colyer silt loam	LEW-203	8	2.64	1.47	39.3	51.0	9.7	SICL	(31.61)	(8.58)	(23.07)	-	-
Trappist silt loam	BUL-202	9	-	1.32	45.4	44.0	10.6	SIC	(33.71)	(11.20)	(22.51)	8.91	0.98
Lenberg silt loam(gray)	POW-201	10	2.81	1.44	56.4	43.0	0.6	SIC	(35.65)	(16.62)	(19.02)	3.38	0.13
Lenberg silt loam(red)	POW-202	11	-	1.44	59.4	40.0	0.6	SIC	-	-	-	6.18	-
Lenberg silt loam	BUL-201	12	-	1.40	55.4	42.0	2.6	SIC	-	-	-		
Lenberg silt loam	NEL-201	13	2.77	1.40	67.4	32.0	0.6	C	(24.51)	(9.99)	(14.53)	1.24	1.23
Lenberg silt loam	LEW-204	-	-	1.46	63.3	34.0	2.7	C	-	-	-	1.62	-
Muse silt loam	LEW-201	14	2.69	1.30	53.3	43.0	3.7	SIC	(34.18)	(11.39)	(22.79)	12.48	1.24
Cranston gr. silt loam	LEW-205	-	-	1.36	38.2	42.2	19.6	SICL	-	-	-	-	-
Rockcastle silt loam	NEL-201	-	-	1.61	54.6	42.8	2.6	SIC	-	-	-	-	-
Garmon silt loam	RUS-201	15	2.72	1.24	31.4	38.4	30.2	CL	22.85(28.01)	18.71(8.64)	4.14(19.37)	-	-
-Overburdens-													
Bedford shale (Lower)	LEW-105	17-18	2.73	-	50.8	34.2	15.0	C	(23.40)	(9.73)	(13.67)	-	2.65
Borden shale (Nancy)	POW-101	19-20	2.78	-	52.6	42.4	5.0	SIC	(24.24)	(9.33)	(14.91)	-	2.43
Borden shale (New Prov.)	BUL-101	4-16	-	-	-	-	-	-	-	-	-	-	7.25
Borden shale (Henley)	LEW-104	-	-	-	62.6	32.4	5.0	C	-	-	-	-	-
Borden shale (Henley-red)	LEW-102	-	-	-	58.6	38.8	2.6	C	-	-	-	-	-
-Oil Shales-													
New Albany - retorted	POW-004	23	2.63	-	-	-	-	-	19.48(27.00)	15.45(7.45)	4.03(19.55)	-	-
New Albany - combusted	POW-005	33	2.50	-	-	-	-	-	17.19(23.15)	11.63(7.00)	5.56(16.15)	-	-
New Albany - HYTORT	BUL-024	5	2.58	-	-	-	-	-	9.74(10.77)	6.57(3.34)	3.18 (7.43)	-	-

[1] Determinations on soil cores.

[2] Hydrometer method.

[3] Based on particle size analysis.

[4] Materials passed through 3/8-inch jaw crusher with values in parentheses for materials crushed to less than 2 mm.

[5] Materials passed through 3/8-inch jaw crusher and used as plant growth medium for two months.

[6] Field classification. Soil descriptions in Appendix A.

Table 3. Water Holding Capacities and Permeabilities for Admixtures.

Materials	Sample No.	Growth Cham. No.	Water Holding Capacity[1] 1/3 Bar	15 Bars	Avail.	Permeability[2]
			---------- % ----------			cm/hr.
-Admixtures-						
(1/2 Soil and 1/2 Oil Shale)						
Trappist soil + New Albany (oil) shale - retorted	(BUL-202 + POW-104)	34-35	26.51(33.19)	16.81(9.25)	9.70(23.94)	
Lenberg soil + New Albany (oil) shale - retorted	(POW-201 + POW-104)	26-27	32.58(34.56)	25.53(12.22)	7.06(22.34)	
Garmon soil + Chattanooga (oil) shale - retorted	(RUS-201 + RUS-004)	29-30	16.58(24.12)	10.23(6.58)	6.35(17.54)	
Rockcastle soil + New Albany (oil) shale - retorted	(NEL-201 + POW-004)	45	24.53(32.27)	13.22(7.59)	11.31(24.68)	
(1/2 Overburden and 1/2 Oil Shale)						
Bedford shale + Cleveland (oil) shale - retorted	(LEW-105 + LEW-024)	21	25.59(26.78)	19.93(8.87)	5.66(17.91)	
Borden shale + New Albany (oil) shale - retorted	(POW-101 + POW-004)	25	23.45(26.82)	19.36(8.21)	4.09(18.61)	2.10
Borden shale + New Albany (oil) shale - charred	(POW-101 + POW-005)	42	21.97(26.07)	12.60(12.06)	9.36(14.01)	0.26
Borden shale + New Albany (oil) shale - HYTORT	(BUL-101 + POW-005	6-7	18.32(26.34)	15.71(5.73)	2.62(20.61)	

[1] Materials passed through 3/8-inch jaw crusher with values in parentheses for material crushed to less than 2mm.

[2] Materials passed through 3/8-inch jaw crusher and used as plant growth medium for two months.

Table 4. Determined pH, Lime Requirement, Cation Exchange Capacity and Carbon Content for Sampled Materials.

Materials	Sample No.	Water pH	Buffer pH	Lime[1] (pH - 6.5)	C.E.C.[2]	Carbon (Total)
		(units)	(units)	(tons/ac)	(meg/100g)	(%)
-Soils-						
Colyer silt loam	LEW-203	4.4	5.3	11	7.7	1.45
Trappist silt loam	BUL-202	4.3	5.4	11	9.3	1.53
Lenberg silt loam (gray)	POW-201	4.9	5.7	9	11.2	0.72
Lenberg silt loam (red)	POW-202	4.7	5.1	13	13.3	--
Lenberg silt loam	BUL-201	4.5	4.9	15	13.5	1.49
Lenberg silt loam	NEL-201	4.6	5.8	8	11.5	0.85
Lenberg silt loam	LEW-204	4.6	5.3	11	11.7	--
Rockcastle silt loam	LIN-201	4.8	5.0	14	14.8	1.18
Muse silt loam	LEW-201	4.5	5.7	9	8.5	1.13
Cranston silt loam	LEW-205	4.9	5.8	8	8.7	--
Garmon silt loam	RUS-201	6.5	-	0	12.2	1.00
-Overburdens-						
Bedford shale	LEW-105	6.4	-	0	8.4	2.10
Borden shale (Nancy)	POW-101	5.8	7.0	0	9.2	0.68
Borden shale (New Prov.)	BUL-101	6.0	-	0	-	--
Borden shale (Henley)	LEW-104	6.0	-	0	10.4	--
Borden shale (Henley-red)	LEW-102	4.5	6.6	2	13.0	--
-Oil Shales-						
New Albany - raw	POW-002	3.7	6.0	6	7.3	12.5
New Albany - retorted	POW-004	3.0	4.8	15	10.0	4.0
New Albany - combusted	POW-005	3.7	5.8	8	5.7	2.8
New Albany - HYTORT	BUL-024	10.0	-	NA	6.8	--
Cleveland - raw	LEW-022	2.7	4.2	20	10.4	13.2
Cleveland - retorted	LEW-024	3.3	6.1	6	9.8	8.5
Cleveland - combusted	LEW-025	4.4	6.6	2	6.3	3.2
Sunbury - raw	LEW-002	2.5	3.7	50	12.0	9.7
Sunbury - retorted	LEW-004	3.2	5.1	13	11.2	6.5
Sunbury - combusted	LEW-005	3.5	5.2	12	8.4	3.6
Chattanooga - raw	RUS-002	3.9	6.4	4	5.7	12.2
Chattanooga - retorted	RUS-004	3.2	6.5	3	6.0	3.6
Chattanooga - combusted	RUS-005	3.9	6.4	4	4.6	3.5

[1] Lime requirements, based on buffer pH, to raise pH to 6.5.
[2] Cation exchange capacity

Available water capacities for the soils and overburden materials (Table 2), when crushed to pass a 2 mm sieve, were generally on the order of 15 to 20 percent with the Bedford and Borden shales lower in range (Figure 10). Published available water values for these soils range from 0.10 to 0.18 in/in, except for a lower value for the Colyer soil (0.03 to 0.10 in/in).

Permeabilities (saturated hydraulic conductivity), where obtained on the undisturbed soil cores, were not very consistent and ranged from moderately slow to moderately rapid (1.24 to 8.91 cm/hr) with the Muse soil rated as rapid (12.48 cm/hr)*.[6] Slow to moderately slow permeabilities are considered realistic (Table 1). Permeabilities for the crushed soil materials were slow to moderately slow (0.13 to 1.24 cm/hr) and for crushed overburden materials they were moderate to moderately rapid (2.43 to 7.25 cm/hr), (Table 2).

Soil erosion factors are given in Table 1 for use in the Universal Soil Loss Equation[7] and are high for the topsoil materials and medium for the subsoils. A typical value of the soil-erodibility term (K) for subsoil materials is 0.28 except for the Colyer soil which has a value of 0.17. When translated into yearly erosion rates for a bare soil situation (K = 0.28) under the rainfall energies for central Kentucky, the subsoil materials on a 200 foot slope length of 15 percent slope would erode at a rate of about 0.85 inches of soil per year. For the Colyer subsoil, because of the higher content of shale fragments, this value would be 0.52 inches per year. Again, for the topsoil materials a comparable rate would be about 1.21 inches per year. For all situations, the erosion losses would be reduced by about 90 percent when an 80 percent soil surface cover is supplied by either mulch or vegetation.[7]

Soils in the vicinity of those sampled generally exhibit higher available water capacities and permeabilities (Table 1).

Raw and Processed Oil Shales. Particle density of New Albany shale for both the retorted and HYTORT

* Data on particle densities, water holding capacities and hydraulic conductivity were obtained by the Agronomy Soils Laboratory, University of Kentucky.

samples was about 2.6, whereas the density of the combusted material was 2.5.

Water holding capacities for the New Albany shale (retorted and combusted), crushed by passing through a 3/8-inch jaw crusher, were only about five percent but when crushed such that the material passed a 2mm sieve the values increased three to five fold and were equivalent to that of soil materials similarly prepared. As for the HYTORT product, the values for both crushed samples were 40 to 60 percent less (Table 2 and Figure 10).

The carbon content of the oil shale, Table 4, was reduced from the 12-13 percent level to 3.6 to 6.5 upon retorting and upon combusting the carbon values ranged from 2.8 to 3.5 percent. Other physical properties of the oil shales are presented in an accompanying symposium paper.[5]

Admixtures. Admixtures, comprised of one-half soil material or overburden material and one-half raw shale or processed oil shale, were prepared as part of the growth chamber vegetative response tests.

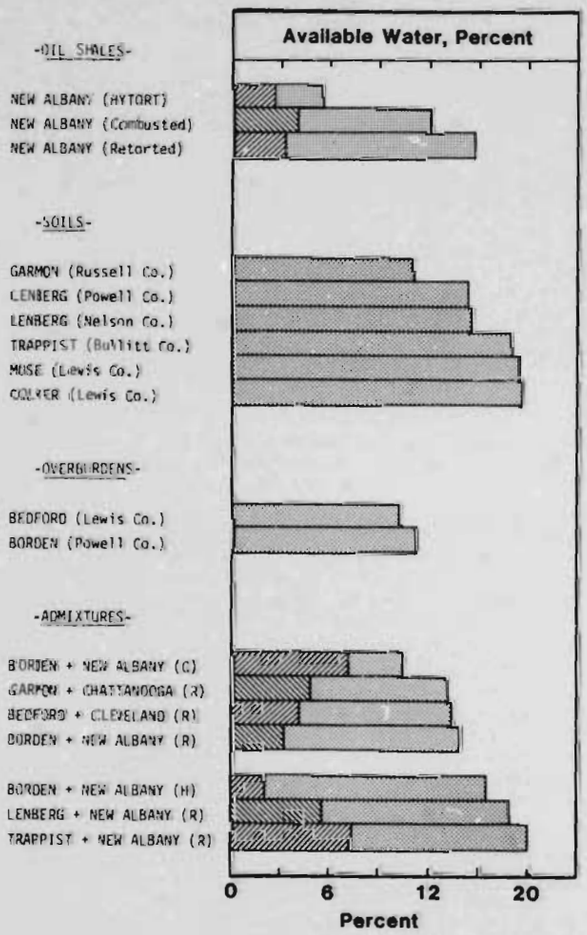

Figure 10. Bar Graph Representation of Available Water (percent) for Soils, Overburdens, Oil Shales and Admixtures. (Hatched Bars for Materials Passed Through a 3/8-inch Jaw Crusher. Combusted, C; Retorted, R; and HYTORT, H).

Water holding capacities of the soil/oil shale admixtures were essentially the same as for the soil materials for the same crushing. The two overburden/oil shale admixtures, however, showed a beneficial 28 percent increase for the finely crushed materials (Tables 2, 3 and Figure 10).

Chemical Properties

Soil analyses and extensive chemical and X-ray fluoresence analyses were made on the sampled materials at the Kentucky Center for Energy Research Laboratory to determine pH, cation exchange capacity, macronutrients, micronutrients, heavy metals and other constituents that could affect the establishment and maintenance of adequate vegetative cover. The obtained data are presented in Tables 4, 5, 6, and 7.

Soils and Overburden Materials. The soils sampled were very strongly to extremely acid with water pH's ranging from 4.3 to 4.9, except for the Garmon soil which had a pH of 6.5. From 8 to 15 tons of limestone per acre would be required to raise the pH to a value of 6.5 in the poorest materials. The sampled overburden materias, however, were essentially neutral except for a shallow (4 to 5 ft) zone of reddish Borden shale (located in the Henley member) at the Lewis County site. Cation exchange capacities for both the soil and overburden materials were low and generally ranged from 8-15 meg/100 g with values above 11 for the Lenberg and Rockcastle soils (formed from the immediate overburden materials) and the Garmon soil (Table 4).

As for macronutrients, Table 5, nitrogen and phosphorus levels were quite low in the soil and overburden samples.[9] Exchangeable potassium ranged from low to medium; calcium was low except for the Garmon soil and the principal overburden materials; and magnesium was at moderate levels for the Colyer and Trappist soils, but the other soil and overburden materials exhibited high levels.

The elemental content of the micronutrients (Cu, Mo, Zn, and Fe), Table 6, for the soils and overburdens occurred at levels usually found in soils (Table 7) except for molybdenum which was somewhat elevated for the Colyer, Trappist and Muse soils. Plants appear to tolerate relatively high concentration of this element and, unlike other micronutrients, the availability increases as the soil pH approaches neutrality or goes above pH 7.[10] A tentative determination of boron in a saturation extract (residence time of 2 hours), Table 6, was less than the 0.5 ppm which is considered satisfactory in irrigation water for all crops.[11] Tentative determinations of soluble manganese were also at acceptable levels for those soils tested.

For the heavy metals (Cr, Ni and Pb) the elemental contents were within the range usually found in soils (Tables 6 and 7). Other constituents (Na, Si, Co and Al) were at acceptable levels in the soil and overburden materials. Sodium and silicon play significant roles in plant production; cobalt is essential in animal nutrition; and soluble aluminum even in low concentrations, is possibly phytotoxic. An aluminum toxicity problem exists only at low pH values since the solubility decreases to almost zero when pH is increased to the pH 7 level.[12]

Soils associated with or in the vicinity of those sampled generally have higher pH's (Table 1)

Table 5. Determined Quantities of Macronutrients, Sodium, Silicon, and Cobalt in Sampled Materials.

Materials	Sample No.	N	P	K*	Ca*	Mg*	S	Na*	Si	Co
		Macronutrients								
		(%)	(lbs/ac)	ppm	ppm	ppm	(%)	(ppm)	(%)	(ppm)
-Soils-										
Colyer silt loam	LEW-203	0.08	13	98(2.0)	89(.10)	77(.29)	0.03	19(.16)	35.8	13
Trappist silt loam	BUL-202	0.06	18	119(2.5)	41(.10)	22(.38)	0.22	19(.21)	33.8	18
Lenberg silt loam (gray)	POW-201	0.05	7	142(3.6)	65(.09)	465(.88)	0.01	31(.27)	26.8	22
Lenberg silt loam (red)	POW-202	0.06	3	145(3.2)	57(.11)	445(.69)	0.02	28(.22)	31.0	18
Lenberg silt loam	BUL-201	0.04	12	145(3.5)	79(.10)	220(.77)	0.02	19(.54)	30.2	20
Lenberg silt loam	NFL-201	0.06	13	227(4.0)	288(.13)	565(1.01)	0.01	35(.41)	27.4	21
Lenberg silt loam	LEW-204	0.07	6	360(3.2)	836(.09)	200(.53)	0.02	26(.13)	29.8	20
Rockcastle silt loam	LIN-201	0.18	26	151(2.9)	143(.21)	380(.74)	0.01	25(.41)	29.4	18
Muse silt loam	LEW-201	0.06	6	161(2.4)	113(.10)	125(.36)	0.10	24(.13)	34.5	16
Cranston silt loam	LEW-205	0.06	4	103(.09)	48(.09)	245(-)	0.03	65(.04)	43.4	16
Garmon silt loam	RUS-201	0.16	20	117(1.9)	1815(.26)	257(.52)	0.01	31(.44)	35.9	13
-Overburdens-										
Bedford shale (Lower)	LEW-105	0.14	15	340(3.5)	113(.27)	665(.82)	0.39	35(.19)	29.3	22
Borden shale (Nancy)	POW-101	0.07	5	266(3.5)	1625(.21)	925(.90)	0.14	66(.33)	29.9	22
Borden shale (New Prov.)	BUL-101	-	-	- (3.9)	- (.28)	- (.98)	-	- (.50)	30.3	21
Borden shale (Henley)	LEW-104	0.07	7	213(3.7)	1140(.19)	610(.80)	0.06	67(.23)	28.4	20
Borden shale (Henley-red)	LEW-102	0.08	4	175(3.7)	485(.13)	990(.94)	0.02	99(.28)	27.5	29
-Oil Shales-										
New Albany - raw	POW-002	0.52	185	53(3.6)	1018(.37)	249(.83)	2.7	53(.34)	34.6	19
New Albany - retorted	POW-004	0.33	182	2320(3.[illegible])	1060(.41)	453(.84)	1.8	285(.36)	30.7	19
New Albany - combusted	POW-005	0.13	85	2400(3.9)	1155(.25)	631(.74)	1.1	345(.22)	30.5	27
New Albany - HYTORT	BUL-024	0.08	0.74	1345(3.7)	2675(.48)	461(.98)	-	225(.33)	29.2	14
Cleveland - raw	LEW-022	0.51	128	51(3.7)	150(.09)	124(.74)	1.9	39(.36)	30.3	18
Cleveland - retorted	LEW-024	0.43	102	1405(3.7)	115(.09)	33(.74)	1.4	174(.25)	30.9	18
Cleveland - combusted	LEW-025	0.15	64	1245(4.0)	449(.25)	312(.76)	1.3	230(.24	30.5	19
Sunbury - raw	LEW-002	0.37	72	14(3.5)	191(.09)	226(.80)	3.8	46(.24)	28.8	24
Sunbury - retorted	LEW-004	0.31	48	1600(3.6)	215(.13)	55(.81)	3.1	201(.20)	29.6	25
Sunbury - combusted	LEW-005	0.19	49	2050(3.7)	340(.17)	283(.76)	2.2	202(.20)	29.0	26
Chattanooga - raw	RUS-002	0.52	170	272(4.1)	395(.21)	157(.74)	3.5	53(.36)	30.2	27
Chattanooga - retorted	RUS-004	0.45	186	992(4.2)	333(.24)	114(.73)	3.2	139(.37)	30.2	26
Chattanooga - combusted	RUS-005	0.14	120	1975(4.1)	1105(.36)	814(.75)	1.6	337(.36)	30.3	27

* The quantities of K, Ca, Mg, and Na were determined as exchangeable bases while the elemental contents, as determined by X-ray fluoresence are noted in parentheses as percentages.

and more desirable chemical properties.[4]

Raw and Processed Oil Shales. Both the raw and processed oil shales were acid with pH values ranging from 2.5 to 4.4, except for the HYTORT material, but buffer pH values were medium to slightly acid (6.0 to 6.5) for the raw New Albany shale and the processed Cleveland and Chattanooga shales (Table 4). Lime requirements, on the basis of buffer pH, ranged from 2 to 50 tons per acre to obtain a pH of 6.5. The HYTORT material was alkaline with a pH of 10.

Cation exchange capacities for the raw and retorted shales were low but comparable to the Colyer and Trappist soils (formed on the oil shale) except for lower values for the Chattanooga oil shales. Combustion of the retorted shales resulted in significant lowering of the cation exchange capacity with similar values for the HYTORT material (Table 4).

As for the macronutrients (Table 5) the nitrogen levels were near 0.5 percent in the raw and retorted shales, but were reduced upon combusting to levels found in the soils and overburdens. Phosphorus levels were much higher than in the soils and overburdens, except for the HYTORT material, but were reduced by about one-half in the combusted samples. The Sunbury shale samples were intermediate in phosphorus content. Exchangeable potassium was low for the raw shales, except for the Chattanooga, but increased markedly with retorting for all samples and was further increased with combustion of the Sunbury and Chattanooga shales. The exchangeable calcium and magnesium were within the ranges common to agricultural soils but elemental sulfur contents were elevated.

Micronutrient levels (Table 6), except for iron, were generally higher in the oil shales than in the soil or overburden materials. Molybdenum was 3 to 14 times, zinc 2 to 10 times, and copper 2 to 4 times greater than the average values for the soils and overburden materials. (Other comparative values are found in Table 7.) Soluble manganese on several samples from preliminary determinations on saturation extracts was high and soluble boron, similarly determined, was generally in the 2 to 4 ppm range for the processed shales which is at the levels in irrigation water where tolerant crops produce satisfactory yields. The HYTORT material was the exception with apparent higher boron and lower manganese.

The levels of chromium, nickel, and lead were found to be within the limits of their usual occur-

Table 6. Determined Quantities of Micronutrients, Heavy Metals, and of Aluminum in Sampled Materials.

Materials	Sample No.	Micronutrients B*	Cu	Mn*	Mo	Zn	Fe	Heavy Metals Cr	Ni	Pb	Other Al
		ppm					(%)	ppm			(%)
-Soils-											
Colyer silt loam	LEW-203	---	40	---	74	113	3.1	77	21	83	5.4
Trappist loam	BUL-202	(0.08)	56	(1.55)	107	91	5.9	84	19	145	6.2
Lenberg silt loam (gray)	POW-101	(0.04)	30	(0.04)	0	103	6.2	105	57	0	10.4
Lenberg silt loam (red)	POW-202	---	29	---	5	84	4.4	86	40	16	9.7
Lenberg silt loam	BUL-201	---	36	---	14	123	4.8	86	47	36	9.6
Lenberg silt loam	NEW-201	---	32	---	10	76	4.7	87	65	17	9.6
Lenberg silt loam	LEW 204	---	47	---	15	188	4.8	110	39	38	10.2
Rockcastle silt loam	LIN-201	---	33	---	0	80	4.5	87	39	28	8.6
Muse silt loam	LEW-201	---	43	---	135	89	4.7	102	24	113	6.4
Cranston silt loam	LEW-205	---	6	---	3	56	0.3	85	13	47	1.0
Garmon silt loam	RUS-201	(0.02)	21	(0.04)	18	92	2.9	79	30	26	5.5
-Overburden-											
Bedford shale (Lower)	LEW-105	(0.49)	52	---	18	172	4.8	103	62	92	10.3
Borden shale (Nancy)	POW-101	(0.26)	36	---	2	156	3.8	93	65	48	10.0
Borden shale (New Prov.)	BUL-101	---	34	---	10	115	4.8	91	71	0	9.1
Borden shale (Henley)	LEW-104	---	56	---	2	75	3.8	99	56	22	9.9
Borden shale (Henley-red)	LEW-102	---	49	---	0	101	7.8	104	26	30	10.0
-Oil Shales-											
New Albany - raw	POW-002	(0.41)	126	(57.0)	95	491	4.6	202	162	92	8.3
New Albany - retorted	POW-004	(2.99)	130	(97.9)	87	502	4.8	203	166	90	8.4
New Albany - combusted	POW-005	(3.99)	91	(88.4)	123	320	5.1	125	199	124	8.9
New Albany - HYTORT	BUL-024	(3.07)	86	(0.4)	67	215	6.8	177	75	99	8.8
Cleveland - raw	LEW-022	(0.64)	137	(37.1)	189	641	4.2	237	155	98	8.9
Cleveland - retorted	LEW-024	(4.19)	127	(7.2)	184	647	4.1	236	151	93	8.9
Cleveland - combusted	LEW-025	(3.08)	150	(16.9)	152	669	5.1	233	162	107	9.1
Sunbury - raw	LEW-002	(0.55)	97	(54.5)	343	983	6.3	165	283	237	9.2
Sunbury - retorted	LEW-004	(0.75)	114	(79.8)	313	902	6.4	181	262	169	9.2
Sunbury - combusted	LEW-005	(2.11)	94	---	287	928	6.6	165	283	197	9.5
Chattanooga - raw	RUS-002	---	132	---	176	248	5.4	138	176	161	8.4
Chattanooga - retorted	RUS-004	---	134	---	165	335	5.7	144	161	163	8.5
Chattanooga - combusted	RUS-005	---	137	---	162	374	5.6	147	175	150	8.5

* Tentative quantities of water soluble boron and manganese were determined in saturation extracts by use of inductively-coupled plasma atomic emission spectrometry (ICP-AES).

Table 7. Variations in Constituents of Sampled Materials and Usual Ranges in Soils.

Constituent	Oil Shale[1] Raw	Oil Shale[1] Processed	Overburden	Soils[2]	Usual Range in Soils[3]
	ppm of Dry Material				
-Essential Plant Elements-					
Ca	900 - 3,700	900 - 3,600	1,300 - 2,800	900 - 2,600	
Mg	6,800 - 8,300	7,300 - 8,400	8,000 - 9,800	2,900 - 10,100	
K	36,000 - 41,000	36,000 - 42,000	35,000 - 39,000	1,900 - 42,000	
P	26 - 92	24 - 93	2 - 7	2 - 13	400 - 3,000
S	19,100 - 35,000	11,000 - 32,000	200 - 3,900	1,300 - 2,200	100 - 1,500
B*					2 - 100
Cu	97 - 132	91 - 150	34 - 56	21 - 56	2 - 100
Mo	95 - 343	87 - 313	0 - 18	9 - 135	0.2 - 5
Zn	248 - 983	320 - 928	75 - 172	76 - 188	10 - 300
Fe	42,000 - 63,000	41,000 - 66,000	38,000 - 78,000	29,000 - 62,000	14,000 - 40,000
Mn*					200 - 3,000
-Heavy Metals-					
Cd					0.01 - 0.7
Cr	138 - 237	125 - 236	91 - 104	77 - 110	1 - 1,000
Ni	155 - 283	151 - 283	26 - 71	19 - 65	5 - 500
Pb	92 - 237	90 - 197	0 - 92	0 - 145	2 - 200
-Possibly Phytotoxic-					
Al	83,000 - 92,000	84,000 - 95,000	51,000 -103,000	55,000 -104,000	14,000 - 40,000

[1] HYTORT material (Sample No. BUL-024) not included.

[2] Cranston soil (Sample No. LEW-205) not included.

[3] Source of data: Reference 8.

* Tentative quantities of water soluble boron and manganese determined in saturation extracts (Table 6).

rence in soils (Table 6 and 7), but somewhat greater than the levels in the overburdens. Tentative laboratory determinations indicated high soluble cadmium values in a few of the oil shales. Cadmium determinations and the leachate problem is discussed in another symposium paper.[13]

Other constituents (silicon, cobalt and aluminum) in the shale were essentially at the same levels as observed for the soil and overburden materials (Tables 5 and 6). Exchangeable sodium, while at the soil and overburden levels in the raw shales, was increased 4 to 7 times as a result of retorting.

Soluble Salts in Relation to Reclamation

The salt content of soils above which plant growth is affected depends upon several factors, including principally soil texture, composition of the salt, and the species of the plant. Soils have been considered to be saline if the solution extracted from a saturated paste (saturation extract) had an electrical conductivity value of 4 mmhos/cm or more.[14] The electrical conductivity (EC) of the saturation extract was adopted by the USDA Salinity Laboratory as the preferred scale for general use in estimating salinity.[15] Evidence has also been presented to show that the EC obtained on the saturation extract is a more reliable index to the EC of ground-water runoff than is the 1:1 extract.[16]

Saturation extracts, obtained after a 2-hour residence time, for the test materials and admixtures were used to obtain values of EC and total dissolved solids (TDS) with pH determined on the saturated paste (Table 8)*. A graphical relationship between TDS and EC is presented as Figure 11.

* Data obtained by the Soil Testing Laboratory (College of Agriculture), University of Kentucky.

Table 8. Electrical Conductivity, Total Dissolved Solids and pH of Saturation Extracts for Sampled Materials.

Materials[1]	Sample No.	Growth Cham. No.	pH	Total Dissolved Solids	Electrical Conductivity
			(Units)	(mg/l)	(mmhos/cm)
-Soils-					
Colyer silt loam	LEW-203	8	4.5	1,170	0.89
			(4.8)	(1,190)	(0.89)
Trappist silt loam	BUL-202	9	4.8	940	0.23
Lenberg silt loam	POW-201	10	4.6	190	0.11
Lenberg silt loam	NEL-201	13	4.9	120	0.34
Muse silt loam	LEW-201	14	4.6	140	0.16
Garmon silt loam	RUS-201	15	6.0	180	0.16
-Overburdens-					
Borden shale (New Providence)	BUL-101	16	6.0	2,680	2.39
Borden shale (Nancy)	POW-101	19	5.9	2,040	2.14
Bedford shale (Lower)	LEW-105	17	6.2	1,160	1.60
			(6.0)	(930)	(1.32)
-Oil Shales-					
New Albany shale - raw	POW-002	1	3.9	4,607	4.10
			(4.4)	(4,430)	(4.00)
New Albany shale - retorted	POW-004	23	3.4	24,536	15.00
New Albany shale - combusted	POW-005	33	3.7	29,092	16.65
New Albany shale - HYTORT	BUL-024	5	10.0	9,120	7.00
			(10.2)[2]		
Cleveland shale - raw	LEW-022	--	2.2	34,300	13.26
Cleveland Shale - retorted	LEW-024	22	3.1	6,840	7.5[illegible]
			(3.4)	(5,076)	(5.50)
Sunbury shale - raw	LEW-002	--	2.5	55,650	20.09
Sunbury shale - retorted	LEW-004	28	2.9	51,544	20.24
Sunbury shale - combusted	LEW-005	41	3.6	21,944	11.00
Chattanooga shale - retorted	RUS-004	24	3.3	16,992	10.78
Chattanooga shale - combusted	RUS-005	36	3.3	38,084	20.13
-Admixtures-					
(1/2 Soil + 1/2 Oil Shale)					
Lenberg soil + New Albany (oil) shale - retorted		26	3.8	1,960	2.63
Lenberg soil + New Albany (oil) shale - combusted		31	3.6	9,300	7.36
Trappist soil + New Albany (oil) shale - retorted		34	3.6	3,760	3.51
Trappist soil + New Albany (oil) shale - combusted		43	3.7	8,810	7.25
(1/2) overburden + 1/2 Oil Shale)					
Borden shale + New Albany (oil) shale - raw		2	4.1	5,200	4.78
Borden shale + New Albany (oil) shale - retorted		25	4.4	5,550	5.10
Borden shale + New Albany (oil) shale - combusted		42	4.3	8,900	7.54
Borden shale + New Albany (oil) shale - HYTORT		6	6.9	6,600	5.64
Bedford shale + Cleveland (oil) shale - retorted		21	4.7	3,660	3.35
Bedford shale + Cleveland (oil) shale - combusted		40	5.1	8,480	7.26

[1] Materials passed through 3/8 inch jaw crusher except for samples with values in parentheses which were ground to pass a 2mm sieve.

[2] Duplicate samples.

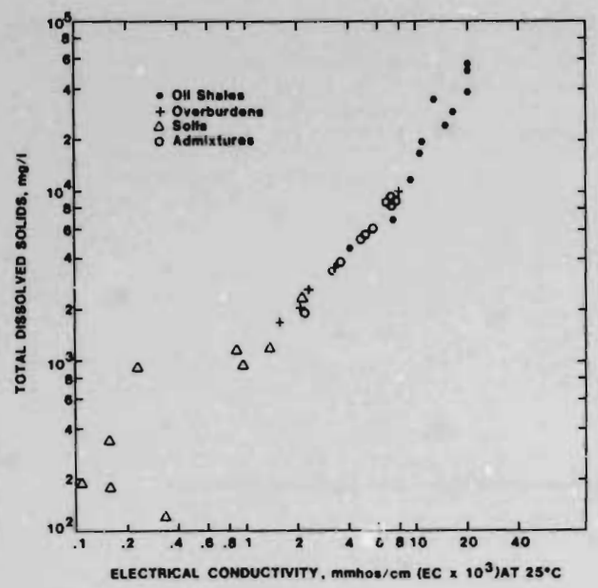

Figure 11. Total Dissolved Solids in Saturation Extract in Relation to Electrical Conductivity.

These values were determined on the dry, unleached materials that were used as a vegetative growth medium in the environmental growth chamber.

Values of EC for soils were less than 1.0 mmhos/cm and for the overburden materials the value was around 2.0. The EC values for the oil shales ranged from 4 to 20; the higher values being associated with the retorted or combusted materials except for the Cleveland shale (Table 8).

The level of potassium ions increased markedly as a result of processing. As seen in Table 5, the quantity of exchangeable potassium in processed shales was increased and exceeded that of sodium, calcium and magnesium. It has been observed that soils high in exchangeable potassium have better physical properties and are more readily reclaimable than soils containing similar amounts of exchangeable sodium but low amounts of exchangeable potassium.[15] The high EC values for the oil shales were significantly lowered when mixed proportionately with either the soil or overburden materials. The values obtained ranged from 3.2 to 7.5 mmhos/cm (Table 8).

The EC values obtained on the saturation extracts were probably near a maximum since no leaching had occurred. For an appreciable reduction in the dissolved solids concentration of the leachate, both laboratory and theoretical considerations indicate that a volume of water equal to about one pore volume must be passed through the material.[16] On this basis, a volume of water per unit area equal to about 0.2 - 0.5 times the total depth of the material would be required to obtain such results. The quantity of salts removed appears to decrease exponentially with the amount of water added, and leaching tests on mine spoils indicate that a volume of water equal to about 6.8 times the bulk volume of the sample was needed to reduce the EC of the leachate to 5 percent of the initial EC of the sample.[16]

The plant specie selected for the growth chamber tests was perennial ryegrass which is moderately tolerant to soluble salts (salinity) and its yield is considered to be unaffected at electrical conductivity values of less than 5.6 mmhos/cm and with only a 25 percent reduction in yield at a value of 8.9.[17] In comparison, yields are reduced for wheat at values above 7.0; for Bermuda grass above 6.9; for soybeans above 5.0; for tall fescues above 3.9; and for alfalfa above an electrical conductivity of 2.0.[17]

Native Vegetation and Crop Yields

Most of the sloping lands in the oil shale outcrop area are in forest or pasture. A forest cover occupies the steeper slopes because of the thin soil and erosion problem. Many cleared areas have become idle and are reverting to forests.[1] The native forests have oak, sugar maple, hickory, ash, gum, beech, eastern red cedar, and virginia and shortleaf pines as the dominant species. All sampled sites were forested.

The natural fertility of the soils formed on the oil shales (Colyer and Trappist series) and on the immediate overburdens in the oil shale outcrop areas of the "Knobs" region is generally rated as low[1] and for high levels of management, where not restricted by slopes and potential erosion, would require approximately 40-120 lbs/ac of phosphate and variable amount of potash, ranging from 0-180 lbs/ac for grass/legume production.[9] The pH of these sampled soils (mostly B-horizon) ranged from 4.3 to 4.9 and the lime requirements to raise the pH to 6.5, on the basis of buffer pH, ranges from 8 to 15 tons (Table 4). Soils formed from the limestones and calcareous shale overburdens of the Cumberland Saddle area are generally of moderate fertility and require less fertilizer and lime with pH's of 4.5 to 7.3 (Tables 1, 4, 5, 6, and 10) for high levels of crop and grass/legume management where not restricted by steep slopes and excessive erosion.

Colyer soils tend to be difficult to manage for pasture on steeper slopes and are more suited for timber production. Trappist soils respond well to lime and fertilizer and, where not too steep, are suited to most field crops and plants commonly grown in the area.[1] The principal soils on the immediate overburdens in the Knobs area (Lenberg and Rockcastle) have some slopes managed for pasture but are generally more suited for timber production.[1]

The sampled soils and associated soils at the sample sites are given in Table 1, and the potential production of grass/legume (under high levels of management) and of common trees for these soils is given in Table 9. Potential yields of grass/legume for soils formed on the soil shale and overburden materials are in the order of 2.0 to 2.8 tons/ac while the average of the listed, associated soils is 3.4. The site index for upland oak on the former soils is 80 and on the latter soils the index averages 76 (tree height in feet at 50 years).

Growth Chamber Vegetative Response Tests

An environmental growth chamber was used to

Table 9. Potential Production (for Unmined Conditions) of Grass/Legume and of Common Trees on the Sampled and Associated Soils.

Soil Series	Grass/ Legume[1]	Upland Oak	Yellow Poplar	Virginia Pine	Shortleaf Pine
	(tons/ac)	Site Index (ft)[2]			
Bedford	2.5	78	97	--	--
Berks	---	60	--	48	52
Caneyville	3.7	60	88	--	--
Carpenter	2.8	81	102	--	--
Colyer	3.5	60	--	53	--
Cotaco	3.0	83	99	75	--
Cranston	3.7	73	90	--	63
Huntington	---	85	95	--	--
Garmon	2.8	61	--	65	--
Elk	4.0	80	91	--	80
Lawrence	3.0	73	86	--	69
Lenberg	2.7	65	--	--	--
Markland	2.0	73	--	--	--
Melvin	3.5	--	--	--	--
Frederick	3.5	85	91	74	--
Muse	2.7	59	--	61	77
Newark	---	85	95	--	--
Nolin	3.5	--	--	--	--
Otwell	2.8	69	--	--	--
Rockcastle	---	59	--	59	55
Sensabaugh	2.7	80	100	75	80
Trappist	2.8	60	--	64	--
Trimble	2.6	80	90	75	75
Whitley	3.9	80	75	69	74
Zanesville	3.5	70	--	66	67

[1] Potential yields under high level of management.

[2] Site index is based on the tree's height, in feet, when 50 years old.

test the vegetative response on soils, overburdens, oil shales, and admixtures. The growth chamber was selected since the amount of materials and time would not permit field studies. The results of the tests in the growth chamber are not as good as field plots but useful since relative responses are obtained for the controlled conditions of the tests. The growth chamber was used as a screening tool to test the feasibility of using available materials as a soil substitute or blending stock in reclamation.

Procedures for Growth Chamber Tests

All materials for use in the tests were air-dried and passed through a 3/8-inch jaw crusher. (Particle size distributions are presented in Figures 6 to 9.) This was done to obtain uniformity and permit homogeneous blending of materials. Admixtures were comprised of equal parts, by weight, of the materials. Materials were placed in 10 inch diameter containers, with bottom openings for drainage, at densities slightly greater than the undisturbed materials in the field (Tables 2 and 10). Seeding of perennial ryegrass was at a rate of 30 lb/acre to achieve a pure live seed rate of 25 lb/acre. Chemical analysis of the soil materials indicated lime be applied at 4 tons/acre and fertilization (18-46-0) was at a rate of 120 lb/acre. After seed application, liming and fertilizing, the upper 1½ inch of soil was tilled to incorporate the materials.

The growth chamber was set to closely duplicate a natural day during the growing season. Temperature was set at 60°F for night and 80°F for day. The temperature started to increase from 60°F at 0700 and would not reach 80° until 1200 where it would stay until 1600 and then return in 5 hours (2100) to 60°F. Relative humidity was maintained at a constant 65 percent. Illumination was initiated at 0700, reached a peak of 7200 foot-candles/min for about 9 hours, then decreased and terminated at 2100.

Watering was at an average daily rate of about 80 percent of the free water evaporation, which was approximately equal to 220 ml/day. Water was applied daily by dosing from a sprinkler bottle for the first two weeks and then every other day for the following two weeks. Twice-a-week watering (pour on) was initiated 36 days after planting and at that time the vegetation containers were moved to a greenhouse following failure of the growth chamber's cooling system. Variable watering rates were practiced until the vegetation was harvested 33

days later after a 68 day growth period (planting to harvest).

About half of the vegetated containers were fitted with plastic bags to catch percolate which was recycled to simulate possible field conditions where rainfall did not exceed potential evapotranspiration, and to retain, at the end, water samples for analysis. The containers treated in this fashion are so indicated in Table 10.

Table 10. Vegetative Response on Soils, Overburden Materials, Oil shales and Admixtures.[1]

Materials[2]	Sample No.	Growth Cham. No.	Approx. Bulk Density	Number of Plants[3]	Height[4], (In) 7/31/81	8/14/81	9/8/81	Yield[5] (lbs/A)
-Soils-								
Colyer silt loam	LEW-203	8	1.37	42	2.5	5.5	10.5	1,047
Trappist silt loam	BUL-202	9	1.41	39	2.75	5.5	-	645
Lenberg silt loam (gray)	POW-201	10	1.37	3	.75	1.5	2.5	52
Lenberg silt loam (red)	POW-202	11	1.55	30	3	7	3.5	157
Lenberg silt loam	BUL-201	12*	1.49	59	2.5	6	6.5	611
Lenberg silt loam	NEL-201	13	1.50	27	1.75	5.25	7	314
Muse silt loam	LEW-201	14	1.44	15	1.75	2	2.5	52
Garmon silt loam	RUS-201	15	1.60	54	2.75	6	12	1,762
-Overburdens-								
Bedford Shale (lower)[6]	LEW-105	17-18*	1.60	62	2.75	5.75	8.75	576
Borden Shale (Nancy)[6]	POW-101	19*-20	1.60	42	2.75	6.12	9	707
Borden Shale (New Providence)[6]	BUL-101	4-16*	1.68	51	3.12	6.5	8.5	968
-Oil Shale-								
New Albany - raw	POW-202	1*	1.55	42	2	6.25	9	942
New Albany - retorted	POW-004	23*	1.44	44	2.25	5	8	576
New Albany - combusted	POW-005	33*	1.37	53	1.25	5	7.25	558
New Albany - HYTORT	IGT-024	5*	1.37	(4)	0	1.5	1	000
Cleveland - retorted	LEW-024	22	1.50	40	2	5.5	-	506
Cleveland - combusted	LEW-025	39*	1.44	29	2	4.5	8	349
Sunbury - retorted	LEW-004	28*	1.50	37	1.75	4	4	35
Sunbury - combusted	LEW-005	41	1.33	34	1.5	3.25	4.25	122
Chattanooga - retorted	RUS-004	24*	1.50	43	2	6.5	7	820
Chattanooga - combusted	RUS-005	36*	1.41	22	1.25	4	5	244
-Admixtures- (1/2 Soil + 1/2 Oil Shale)								
Trappist soil + New Albany (oil) shale[6]	POW-201 & POW-004	34-35	1.49	47	1	4.37	10	1,405
Trappist + New Albany (oil) shale[6]	POW-201 & POW-005	43-44	1.43	48	1.75	7.12	10	1,806
Lenberg soil + New Albany (oil) shale[6]	BUL-202 & POW-004	26-27	1.37	45	1.12	4.5	8.5	811
Lenberg soil + New Albany (oil) shale[6]	BUL-202 & POW-005	31*-32*	1.32	49	1.5	6	7.5	917
Gorman soil + Chattanooga (oil) shale[6]	RUS-201 & RUS-004	29-30	1.47	32	4.11	6.63	9.63	1,169
Gorman soil + Chattanooga (oil) shale[6]	RUS-201 & RUS-005	37-38	1.43	48	2.37	6.38	10.5	1,003
Rockcastle soil + New Albany (oil) shale	NEL-201 & POW-004	45	1.33	64[7]	2.25	7	9.5	1,230[7]
-Admixtures- (1/2 Overburden + 1/2 Oil Shale)								
Bedford shale + Cleveland (oil) shale	LEW-105 & LEW-024	21	1.44	50	2.75	6.5	11	1,657
Bedford shale + Cleveland (oil) shale	LEW-105 & LEW-025	40	1.44	49	2.75	6	8	1,204
Borden shale + New Albany (oil) shale	POW-102 & POW-004	23*	1.44	47	3	5.25	7.5	1,029
Borden shale + New Albany (oil) shale	POW-101 & POW-005	42	1.55	42	2	6	10	1,151
Borden shale + New Albany (oil) shale[6]	BUL-101 & IGT-024	6*-7*	1.32	33	1.38	6	5.5	166
Borden shale + New Albany (oil) shale[6]	POW-101 & POW-002	2*-3	1.69	62	2.89	7.12	8.87	1,003

1 Seeded in containers 10 inches in diameter and 9½ inches deep: Perennial ryegrass - 30 lbs/A; fertilizer (18-46-0) - 120 lbs/A; Agricultural limestone - 4 tons/ac.

2 Air dried and passed through 3/8 inch jaw crusher. Data on physical and chemical properties are listed in Tables 2 to 6 and Figures 6 to 10.

3 Average of three counts.

4 Leaf tips suffered some burning during overheating of growth chamber on weekend of August 05-06.

5 Vegetative growth harvested (dry weight) on September 23rd (Seeded July 17). Plants in growth chamber until August 21st; thereafter in unheated greenhouse.

6 Average of two replicates.

7 One-half of value to adjust for double seeding.

8 Indicates recycled percolate.

Measurements were made weekly of the number of plants and their height. At the end of the study, plants were harvested, dried and weighed for yield.

Results of Growth Chamber Tests

Plant growth varied from zero to twelve inches, depending upon materials used and the water deficits that developed. Number of plants, height and yield values are given in Table 10. Bar graphs of the individual container yields, including number of plants, are shown in Figures 12, 13, and 14. Pictures of a number of containers, just prior to harvesting, are shown in Figures 15 through 18.

No yield was obtained for the HYTORT material, probably because of alkalinity, low water holding

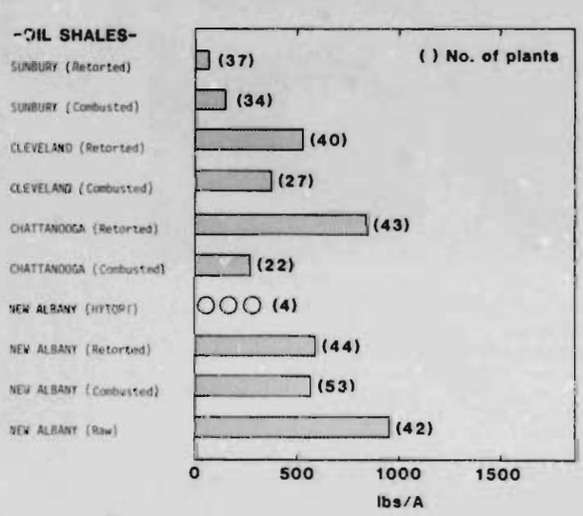

Figure 12. Bar Graph Representation of Ryegrass Yielded (68 day growth period) from Oil Shale Containers.

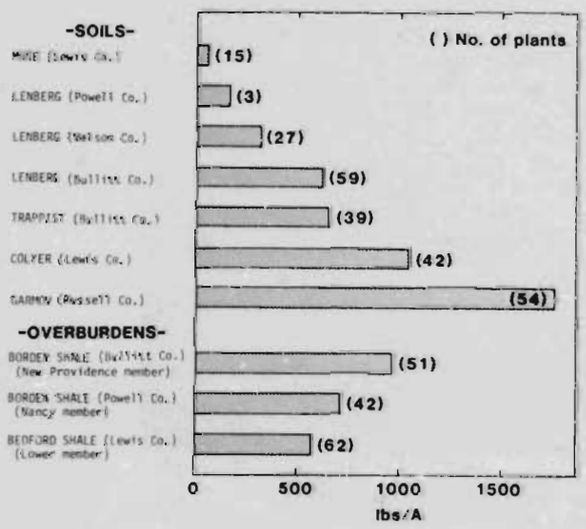

Figure 13. Bar Graph Representation of Ryegrass Yielded (68 day growth period) from Soil and Overburden Containers.

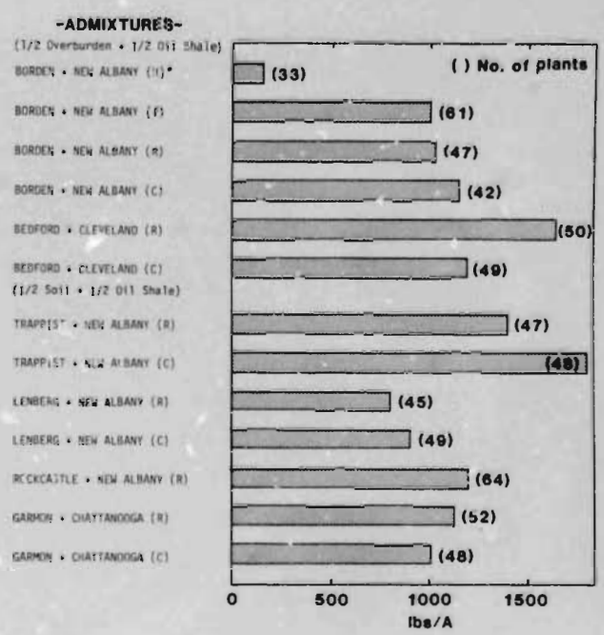

Figure 14. Bar Graph Representation of Ryegrass Yielded (68 day growth period) from Admixture Containers. (HYTORT, H; Raw, W; Retorted, R; and Combusted, C).

capacity, apparent high boron content and possibly other factors. The highest yield of 1,762 lbs/ac was obtained on the Garmon soil. The average yield from the soils on the oil shale and the immediate overburden materials was 471 lbs/ac; average yield from the immediate overburden materials was 750 lbs/ac; and the average yield from the oil shales, exempting the HYTORT material, was 461 lbs/ac.

Notable is the yield from the raw New Albany shale which is comarable to yields from Colyer and Trappist soils developed on the oil shale. The very low yields from some of the soil containers resulted from surface crusting along with moderate to severe cracking which resulted in water deficits that reduced yields. This was particularly true for the Muse soil (Lewis County) and the Lenberg soils in Powell County. Low water holding capacity, low pH values, low cation exchange capacities and high levels of soluble salts were apparently the major factors in the low yield response of the processed oil shale materials.

The admixtures were introduced into the tests to evaluate the assumptions that a more desirable physical plant growth medium would result while retaining nutrient, pH, soluble salts, and other factors at desirable or tolerable levels. For conditions of the limited tests, the vegetative response for the admixtures was rather respectable except for the containers with HYTORT material (Table 10 and Figure 18). The average yield for the soil-shale admixtures was 1192 lbs/ac and for the overburden-shale admixtures, eliminating containers 6 and 7 that contained HYTORT material, the yield averaged 1209 lbs/ac. These yields were about 68 percent of the highest yield observed from the Garmon soil container. Physical properties of the

Figure 15. Vegetative Response of Perennial Ryegrass for a 68-day Growth Period. (Table 10: Lenberg Soil, 13; Trappist Soil, 9; Colyer Soil, 8; and Garmon Soil, 15).

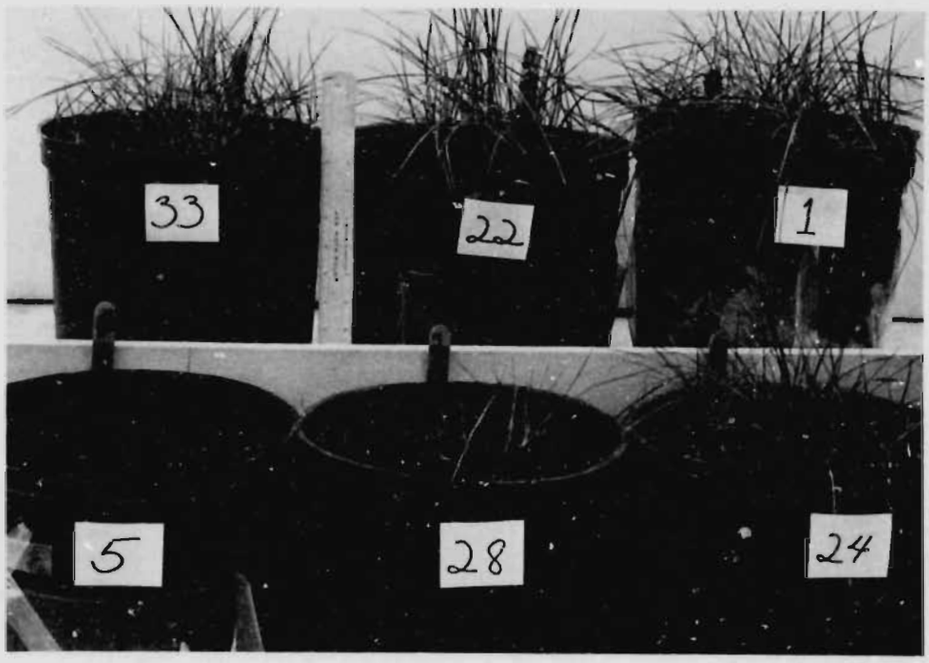

Figure 16. Vegetative Response of Perennial kyegrass for a 68-day Growth Period. (Table 10: New Albany Shale-Combusted, 33; Cleveland Shale-Retorted, 22; New Albany Shale-Raw, 1; New Albany Shale-HYTORT, 5; Sunbury Shale-Retorted, 28; and Chattanooga Shale-Retorted, 24).

Figure 17. Vegetative Response of Perennial Ryegrass for a 68-day Growth Period. (Table 10: Bordon Shale-New Providence, 4; Trappist Soil, 9; Bedford Shale-Lower, 17; and Borden Shale-Nancy, 20).

Figure 18. Vegetative Response of Perennial Ryegrass for a 68-day Growth Period. (Table 10: Borden Shale-Nancy and New Albany Shale-Raw, 3; Trappist Soil, 9; Garmon Soil, 15; Borden Shale-New Providence and New Albany Shale-HYTORT, 7; Borden Shale-Nancy and New Albany Shale-Retorted, 25; and Bedford Shale-Lower and Cleveland Shale-Retorted, 21).

admixtures, as demonstrated by observed water infiltration and water retention (availability), appeared to be desirable. The admixtures, whether containing the overburden materials or soils with the oil shale materials, gave similar vegetative responses as noted above.

Summary and Conclusions

Information available from soil surveys and geologic quadrangle maps for the oil shale outcrop area in Kentucky indicates that the quantities of materials available for reclamation, and their physical and chemical quantities, could present problems in establishing adequate vegetative cover to minimize environmental impacts of oil shale mining. To investigate this problem, materials from residual soils, overburdens, and oil shales were obtained from five widely separated sites in the Knobs region and from one site in the Cumberland Saddle area. Additional test samples were obtained from a portion of the oil shale samples that were subjected to steam retorting and to steam retorting and combustion. A sample from the HYTORT process was also made available.

Extensive physical and chemical analyses were performed on these materials and growth chamber tests conducted to determine the potential for extablishing an adequate vegetative cover on these materials or on admixtures of these materials.

Soils formed in residuums derived from oil shale and the immediate overburden materials have typical solums (A- and B- horizons) of 15-30 inches with topsoil (A-horizon) depths of generally less than 6 inches. The thinner soils are generally located on the steeper, wooded slopes such that physically separating the "topsoil" and "subsoil" could present a problem.

In the oil shale outcrop area of the Knobs, the immediate overburden materials are extensive, of similar characteristics, and weather quickly as verified by geochemical data, soil tests, and the highly similar soils mapped. These immediate overburdens, therefore, were investigated as to their suitability for use in reclamation, along with admixtures of soils and these overburden materials with raw and processed oil shales.

Soils formed on the oil shales are significantly lower in clay content (40 to 50 percent) than are the immediate overburdens and their residual soils in the Knobs region (55 to 67 percent). Most of the materials available for reclamation use have rather high erosion factors for the topsoils and moderate factors for subsoils. This indicates that mulching and the establishment of a rapid vegetative cover would be essential treatments to minimize the erosion and sedimentation impacts.

The soil materials in the oil shale outcrop region of the Knobs are very strongly to extremely acid and tests indicated lime requirements of 8 to 15 tons/ac. The soil tested in the Cumberland Saddle area and the immediate overburden materials were essentially neutral.

Macronutrient levels in the soil and overburden materials were very low for nitrogen and phosphorus; low to medium for potassium; low for calcium except for the overburden materials and the Cumberland Saddle area soil; and moderate levels for magnesium. The immediate overburden materials in the Knobs region, however, had levels of magnesium 2-3 times greater than did the soils there. Micronutrients were at levels which usually occur in soils except for Molybdenum which was somewhat elevated in a few samples.

The crushed oil shales and processed oil shales were found to be acidic, except for the HYTORT material which was alkaline. Cation exchange capacities were generally considerably lower than for the other materials.

The elemental levels of macro- and micronutrients and other elements for the raw shales were generally within the limits usually found in soils. The processed oil shales obtained from retorting-combusting, however, showed increases in exchangeable calcium, magnesium, and sodium, and marked increases in potassium. These increases in soluble salts in saturation extracts resulted in electrical conductivities that ranged from 11 to 20 mmhos/cm, except for the HYTORT material. Preliminary determinations of the water soluble levels of boron and manganese were significantly elevated. The saturated extract levels of boron and soluble salts were slightly higher than that tolerable to plants.

Soils, overburden materials and admixtures (half and half of the raw or processed oil shales and soil or overburden materials) were used as a plant growth medium in a growth chamber test. The electrical conductivity of the admixtures indicated somewhat saline conditions but below the determined threshold to be deleterious to a number of plant species, even before any leaching of salts. Primarily, the admixtures afforded a physical medium with desirable infiltration and water retention properties.

The vegetative response (perennial ryegrass) on the admixtures, whether containing soil or overburden material with the oil shales, was essentially the same but both were greater than that of either the overburden materials or soils, except for the best soil material that devloped on the calcareous shale material in the Cumberland Saddle area. The crushed overburden materials had yields greater than the soil materials which suffered from surface crusting, along with moderate to severe cracking that allowed for water loss and, in combination, these factors resulted in extreme water deficits.

The information acquired, along with other available data, indicates that the available soil resources in the oil shale outcrop area of the Knobs could be augmented by some use of the immediate overburdens. For both the subsoil and overburden materials, amendments (including topsoil) would be necessary to establish a medium with good infiltration and water movement properties. Also, adequate mulching and a rapid establishment of a vegetative cover would be essential for water conservation and for the prevention of harmful erosion and sedimentation. Such problems would probably be minor in the Cumberland Saddle area where the soils are of better quality and the overburden materials contain desirable limestone and calcareous shales.

The use of raw shale or processed oil shales as amendments to improve the physical properties of the high clay subsoils and immediate overburdens in the Knobs area appears as a possible alternative.

Selective use of these materials would require attention to the resulting levels of acidity, soluble salts, boron, and the heavy metals. Tests necessary to determine the practical use of these materials as soil amendments would require the use of particles as they would be produced and would require a long term study of the release of elements to soil waters.

An adequate vegetative cover could be established on the soils and overburden materials with amendments to create desirable infiltration conditions and with appropriate fertilization and correction of any acidity problem. Plant species selected would need to be relevant to the long term land use and adaptive to the available rooting zone and required erosion control, particularly for steeper slopes. If processed oil shales should be used in admixtures, plant selection would need to also consider salinity, possible problems related to trace elements, and the plant uptake potential for metals.

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APPENDIX A

At the six study locations, Figure 1 in report, samples of residual soils were obtained in cooperation with the United States Soil Comservation Service and the Kentucky Department for Natural Resources and Environmental Protection, Division of Conservation. These descriptions are included below:

Soil Descriptions

Bullitt County Location

Date of Survey: April 6, 1981

Brooks Quadrangle, Kentucky (Geologic Quadrangle Map)

Location: 1000 feet south of Jefferson and Bullitt county line on KY 1020 turn east on county road for one mile; then south for 3000 feet; Site #1 700 feet west of county road or 900' west of I-65.

Area: Black Shale - New Albany Shale, thickness 73-94 feet (approximately 525 feet elevation).
Borden formation - New Providence shale member, thickness 210-280 feet.
- Kenwood siltstone member, thickness 20-70± feet.
- Nancy member, thickness 53-130± feet.

SITE #1

Vegetation: virginia pine, scarlet oak, eastern red cedar, white oak, chestnut oak.

Slope: 15% Lower-sideslope (straight).
Aspect: 170° South-southeast.
Elevation: Approximately 580 feet.
Parent material: New Albany black shale.
Soil series: Trappist silt loam.
Classification: Clayey, mixed, mesic Typic Hapludult.

Profile Description

O1&O2 1-0"	loose, undecomposed and decomposed litter from mixed hardwood and pine forest.
A1 0-2"	dark grayish brown (10YR4/2) silt loam; weak fine granular structure; friable; common medium and fine roots; pH 4.5; gradual wavy boundary.
B1 2-6"	yellowish brown (10YR5/6) silt loam; weak medium subangular blocky structure parting to weak fine granular; friable; common medium and fine roots; pH 4.5; gradual wavy boundary.
B21t 6-9	yellowish brown (10YR5/6) silty clay loam (less than 35% clay); friable; moderate medium subangular blocky structure; few patchy clay films; 5% shale fragments up to 1 inch in size; common medium and fine roots; pH 4.5; gradual wavy boundary.
B22t 9-13"	strong brown (7.5YR5/6) silty clay loam (more than 35% clay); firm; moderate medium subangular blocky structure; few fine and medium roots; 15% shale and siltstone fragments up to 1 inch in size; continuous clay films; pH 4.5; gradual wavy boundary.
B23+ 13-17"	strong brown (7.5YR5/6) shaly silty clay; firm; few medium and fine roots; thick clay films on ped faces; 30% shale fragments up to 3 inches in size; pH 4.5; clear wavy boundary.
B3 17-30"	yellowish brown (10YR5/8) shaly silty clay; few fine distinct light yellowish brown (10YR6/4) and yellowish red (5YR4/6) mottles; moderate medium subangular blocky structure parting to relic shale structure; firm; patchy clay films; few fine roots; 35% dark grayish brown (10YR4/2) shale fragments up to 3 inches in size; pH 4.5.
R 30"	New Albany Black Shale.

Comments: None

Notes: Bulk density and growth chamber samples taken.

SITE #2

(About 200 feet up slope from Site #1).
Vegetation: virginia pine, scarlet oak, eastern red cedar, white oak, chestnut oak.
Slope: 18% Sideslope-convex.
Aspect: 170° South-southeast.
Elevation: Approximately 650 feet.
Parent material: New Providence member of Borden formation.
Soil series: Lenberg silt loam.
Classification: Fine, mixed mesic Ultic Hapludalfs.

Profile Description

O1&O2 1½-0"	loose, undecomposed and decomposed litter from mixed hardwood and pine forest.
A1 0-1"	grayish brown (2.5YR5/2) silt loam; friable; weak fine granular structure; many fine and medium roots; 3% siltstone fragments up to 1/4 inch in size; pH 4.5; clear smooth boundary.
B21t 1-11"	yellowish brown (10YR5/6) silty clay; firm; moderate medium subangular blocky structure; continuous yellowish brown (10YR5/4) clay films; 3% siltstone and shale fragments up to 1/4 inch in size; many fine and medium and few coarse roots; pH 4.5; clear wavy boundary.
B22t 11-21"	pale olive (5Y6/3) clay; few fine faint light olive gray (5Y6/2) and light olive brown (2.5Y5/6) mottles; firm moderate medium and coarse subangular block structure; common medium and fine roots; 2% siltstone and shale fragments up to 1/4 inch in size; thick continuous clay films; pH 5.5; gradual wavy boundary.
B3 21-27"	olive (5Y5/4) shaly clay; few fine distinct greenish gray (5GY6/1) and yellowish brown (10YR5/4) mottles; firm; weak coarse subangular block structure; few fine roots; 20% shale fragments up to 3 inches in size; pH 5.0.
Cr 27"+	olive gray (5Y5/2) relic shale platy structure.

Comments:
1. (2.5Y5/2) in A1 out of range for Lenberg.
2. (5Y6/3) in B22+ out of range for Lenberg.
3. (5Y5/4) in B3+ out of range for Lenberg.
4. 2.5Y and 5Y colors more typical of Rockcastle.

Notes: Bulk density and growth chamber samples taken.

Lewis County Location

Date of Survey: March 30, 1981.

Chapters Quadrangle, Kentucky-Lewis County (Geologic Quadrangle Map).

Location: 14,000 feet northeast of KY 10 on farm road; at the head of Ben Willen Branch.

Area: Black shale - Ohio Shale, thickness 220-250 feet (approximately 700 feet elevation); Cleveland member, thickness about 50 feet.
Bedford shale, thickness 30-80 feet.
Berea sandstone, thickness 1-40 feet.

Black Shale - Sunbury shale, thickness 15-20 feet.
Borden formation, thickness 380+.

SITE #1

Vegetation: sugar maple, red maple, white oak, sassafras.
Slope: 42% mid-sideslope (concave).
Aspect: 180° South.
Elevation: Approximately 960 feet.
Parent material: Black shale - Cleveland member of Ohio Shale.
Soil series: Colyer silt loam.
Classification: Clayey-skeletal, mixed, mesic Lithic Dystrochrepts.

Profile Description

10% shale and siltstone fragments up to 2" in size and 5% boulder size to siltstone up to 1' across on the surface.

01&02 1-0"	loose, undecomposed and decomposed litter from hardwood forest.
Ap 0-3"	yellowish brown (10YR5/4) silt loam; weak fine granular structure; friable; many fine and common roots; 5% siltstone and shale fragments up to 2"; pH 4.5; abrupt wavy boundary.
B21+ 3-8"	yellowish brown (10YR5/8) silt loam; weak medium subangular blocky structure; 10% shale fragments up to 2" in size; firm; few fine roots; few fine clay films; pH 4.5; abrupt wavy boundary.
B22+ 8-15"	strong brown (7.5Y5/6) and yellowish brown (10YR5/6) shaly silt clay loam; moderate medium subangular blocky structure; firm; few very fine roots; few fine clay films; 20% shale and siltstone fragments up to 4" in size; pH 4.5; abrupt wavy boundary.
Cr 15"+	Ohio black shale (Cleveland member); pH 4.0.

Comments: Outside of Colyer Series:
1. Argillic horizon described.
2. Coarse fragments less than 20%
3. Color in B21+ (10YR5/8) eight out of B horizon range.
4. Control section does not contain 35 percent or more fragments - not skeletal (inclusion).

Note: Bulk density samples taken at approximately 8 inches.

SITE #2

Vegetation: maple, oak, sassafras.
Slope: 22% sideslope.
Aspect: 170° south-southeast.
Elevation: 1000 feet.
Present material: Berea sandstone.
Soil series: Muse silt loam. (Note: to red in B horizon)
Classification: clayey, mixed, mesic Typic Hapludults.

Profile Description

10% siltstone fragments up to 6" in size on surface.

01&02 1-0"	loose, undecomposed and decomposed litter from hardwood forest.
Ap 0-2"	yellowish brown (10YR5/4) silt loam; weak fine granular structure; friable; common fine roots; pH 5.0; clear smooth boundary.
B1 2-6"	strong brown (7.5YR5/8) silt loam; moderate medium subangular blocky structure; friable; common fine roots 5% siltstone fragments up to 2" in size; pH 4.5; clear smooth boundary.
B21+ 6-11"	yellowish red (5YR5/8) silty clay, moderate medium subangular blocky structure; firm; few fine roots; common clay films; 10% siltstone fragments up to 5" in size; pH 4.5; clear smooth boundary.
B22+ 11-20"	red (2.5R4/6) gravelly clay; moderate medium and fine subangular blocky structure; firm; few fine prominent light brownish gray (2.5Y6/2) weathered shale material; common clay films; 20% siltstone fragments up to 6" in size; pH 4.5; clear smooth boundary.
B23+ 20-29"	red (2.5YR4/6) clay; strong medium subangular blocky structure; firm; common fine prominent light brownish gray (2.5 Y6/2) weathered shale material; few very fine roots; 10% shale fragments up to 2" in size; pH 4.5; gradual smooth boundary.
B3 29-40"+	red (2.5 YR4/6) shaly clay; weak fine subangular blocky strucrure; firm; common fine prominent light brownish gray (2.5Y6/2) weathered shale material; 25% shale fragments up to 2" in size; pH 4.5.

Comments: Outside of Muse Series:
1. 7.5YR5/8 out of range B1 horizon.
2. Silt loam texture out of range B1 horizon.
3. 2.5YR too red color in B22+ & B23+ horizons.
4. Chroma of 2 or less at 11" - due to weathered shale, not indication of poor drainage.

Note: Bulk density sample taken at approximately 11 inches.

SITE #3

Vegetation: chestnut oak, white oak, hickory.
Slope: 50% convex sideslope.
Aspect: 190° south-southwest.
Elevation: 980 feet.
Parent material: Bedford shale underlain by Cleveland member of Ohio Shale.
Soil series: Lenberg silt loam.
Classification: Fine, mixed, mesic Ultic Hapludalfs.

Profile Description

5% shale and siltstone fragments up to 4" in size and 2% large siltstone boulders up to 4 feet across on surface.

A 0-1" yellowish brown (10YR5/6) silt loam; weak fine granular structure; friable; many fine roots; 5% shale and siltstone fragments up to 2" in size; pH 4.0; abrupt smooth boundary.

B1 1-9" yellowish brown (10YR5/6) silty clay; moderate fine and medium subangular blocky structure; firm; many fine and medium roots; 5% shale and siltstone fragments up to 4" in size; pH 4.5; clear smooth boundary.

B2+ 9-12" yellowish brown (10YR5/6) silty clay; moderate medium subangular blocky structure; firm; few fine distinct light yellowish brown (10YR6/4) and light olive gray (5Y6/2) and common fine distinct red (2.5YR5/8) soft weathered shale fragments up to 4" in size; pH 4.5; abrupt wavy boundary.

C1 12-20" strong brown (7.5YR5/6) and light brownish gray (2.5Y6/2) clay; massive structure; firm; few medium and fine roots; 10% shale and siltstone fragments up to 4" in size; pH 4.5; gradual smooth boundary.

C2 20-36" pale olive (5Y6/4), light olive gray (5Y6/2) and olive yellow (2.5Y6/6) clay; massive structure; firm; few fine roots; 10% shale fragments up to 4" in size; pH 4.0.

Cr 36"+ Cleveland member of Ohio Black Shale (overlain by Bedford Shale).

Comments:
1. Black shale outcrop in areas below sample site makes up percentage of sideslope.
2. Solum only 12" thick needs to be 20-40".
3. 2 chroma mottles at 9" - due to weathered shale, not indication of poor drainage.

Notes: Bulk density samples at approximately 10 inches.

SITE #4

Vegetation: oak-maple.
Slope: 48% upper sideslope (convex).
Aspect: 270° west.
Elevation: 1040 feet.
Parent material: Farmers member of Borden Formation - siltstone, sandstone, and shale.
Soil series: Cranston gravelly silt loam.
Classification: coarse-loamy, mixed, mesic Ultic Hapludalfs.

Profile Description

25% siltstone fragments up to 6" in size on the surface.

01&02 1-0" loose, undecomposed and decomposed litter, very dark grayish brown (10YR3/2); many very fine and fine roots; 20% rounded siltstone fragments up to 4" in size; pH 4.5; abrupt smooth boundary.

A1 2-6" reddish brown (2.5YR5/4) gravelly silt loam; weak fine granular structure; friable; many fine and medium roots; 20% rounded siltstone fragments up to 2" in size; pH 5.0; clear smooth boundary.

B1 6-18" light yellowish brown (10YR6/4) gravelly silt loam; weak fine subangular blocky structure; friable; common fine and medium roots; 20% rounded siltstone fragments up to 4" in size; pH 4.5; clear wavy boundary.

B21+ 18-33" light yellowish brown (10YR6/4) very stony silty clay loam (less than 35% clay); weak fine subangular blocky structure; friable; few fine roots; 40% rounded siltstone fragments up to 12" in size; pH 4.5; clear smooth boundary.

B22+ 33-49" strong brown (7.5 YR5/6) silty clay loam (more than 35% clay); moderate fine subangular blocky structure; firm; few coarse distinct light brownish gray (2.5Y6/2) soft weathered shale; common fine and very fine roots; 10% siltstone and shale fragments up to 2" in size; pH 4.5; clear smooth boundary.

B23+ 49-56" yellowish brown (10YR5/6) silty clay; moderate medium subangular blocky structure; firm; few fine distinct light brownish gray (2.5Y6/2) mottles; few fine roots; 5% shale fragments up to 2" in size; pH 4.5; clear smooth boundary.

B3 56-60"+ yellowish brown (10YR5/6) and light olive gray (5Y6/2) silty clay; weak medium subangular blocky structure; firm; 10% shale fragments up to 3" in size; pH 4.0.

Comments: Classification - profile has more than 18% clay and by field description would not be classified as coarse-loamy.

Notes: Bulk density samples at approximately 36 inches.

Lincoln County Location

Date of Survey: April 21, 1981.

Halls Gap Quadrangle, Kentucky (Geologic Quadrangle Map).

Location: 1-3/4 miles north on U.S. 27 from Halls Gap; west on county road 1/4 of a mile; site 1 300 feet northeast off road.

Area: Black shale - New Albany shale, thickness 35-65 feet (approximate elevation 990 feet)
Borden formation - New Providence member, thickness 60-100 feet.

- Nancy member, thickness 40-100 feet.

SITE #1

Vegetation: virginia pine, white oak, shagbark hickory, red maple, sugar maple.
Slope: 6% convex finger ridge.
Aspect: 210° west-southwest.
Elevation: 1070 feet.
Parent material: New Providence member of Borden formation.
Soil series: Rockcastle silt loam.
Classification: fine, mixed, mesic Typic Dystrochrepts.

Profile Description

O1&O2 ½-0"	loose, undecomposed and decomposed litter from mixed hardwood and pine forest.
A1 0-2"	olive (5Y5/3) silt loam; friable; moderate fine granular structure; many fine and medium and few coarse roots; pH 4.5; abrupt wavy boundary.
B21+ 2-7"	light olive brown (2.5Y5/4) silty clay loam (less than 35% clay); friable; weak medium subangular blocky structure; many fine and medium and few coarse roots; pH 5.0; clear smooth boundary.
B22+ 7-20"	light olive gray (5Y6/2) silty clay; firm; moderate medium subangular blocky structure; common fine and medium roots; coarse medium prominent yellowish red (5YR5/6) and coarse medium faint light olive brown (2.5Y5/4) mottles; pH 4.5; clear smooth boundary.
B3 20-29"	olive gray (5Y5/2) clay; very firm; moderate medium subangular blocky structure; few fine roots; coarse medium prominent yellowish red (5YR5/6) and coarse medium faint light olive brown (2.5Y5/4) mottles; pH 4.5.
Cr 29"+	olive gray (5Y5/2) soft relic shale structure; very firm; pH 4.5.

Comments: None

Notes: Bulk density sample at approximately 7 inches. Base saturation 36%

Nelson County Location

Date of Survey: April 6, 1981.

Lebanon Junction Quadrangle (Geologic Quadrangle Map).

Location: 1 mile east of Boston Toll Booth on Bluegrass Parkway, 150 feet south of Bluegrass Parkway.

Area: Black shale - New Albany shale, thickness 65-70 feet (approximate elevation 455 feet).

Borden formation - Shale member 280-330 feet.
- Muldraugh member 70-110 feet.

SITE #1

Vegetation: eastern red cedar, virginia pine, shagbark hickory, white oak, scarlet oak, sugar maple, beech, mayapple.
Slope: 28% sideslope (convex).
Aspect: 230°.
Elevation: approximately 525 feet.
Parent material: Borden formation, lower part of shale member.
Soil series: Lenberg silt loam.
Classification: fine, mixed, mesic Ultic Hapludalfs.

Profile Description

2% siltstone on surface up to 1 foot in size.

O1&O2 1-0"	loose, undecomposed and decomposed litter from mixed hardwood pine forest.
A1 0-1"	dark grayish brown (10YR4/2) silt loam; friable; weak fine granular structure; many fine and medium roots; pH 5.0; clear wavy boundary.
B1 1-4"	brown (10YR5/3) silty clay loam (more than 35% clay); firm; moderate medium subangular block structure; common medium distinct strong brown (7.5YR5/6) mottles; common fine and medium roots; 3% siltstone fragments up to 1 inch in size; pH 5.0; gradual wavy boundary.
B21+ 4-12"	light olive gray (5Y6/2) silty clay; common medium distinct strong brown (7.5YR5/6) mottles; firm; strong medium subangular block structure; continuous clay films; common fine and few coarse roots; pH 5.0; abrupt smooth boundary.
B22+ 12-27"	Light brownish gray (2.5Y6/2) clay; firm; moderate medium subangular blocky structure; common fine and few coarse roots; continuous clay films; 5% shale fragments up to 1 inch in size; pH 7.0; abrupt smooth boundary.
Cr 27"+	olive (5Y5/3) relic shale platy structure; pH 8.0

Comments:
1. 5Y6/2 in B21+ out of range for Lenberg.
2. 2.5Y6/2 in B22+ out of range for Lenberg.
3. 75% base saturation indicates Typic Hapludalfs - this profile will be classified Ultic Hapludalfs with this footnote indicating it is a taxadjunct to the series because the base status exceeds 60% for this site.

Notes: Base Saturation 75%.
1 to 1 Water; pH 5.8.
1 + 1 KCl; pH 5.35.
Pedon in mapping unit Rockcastle.

Powell County Location

Date of Survey: April 1, 1981

Clay City Quadrangle (Geologic Quadrangle Map).

Location: 4,500 feet south on KY 1057 out of Clay City; just across Mountain Parkway turn on to gravel road to the left; site #1 1,000 feet on gravel road just south of road.

Area: Black shale - New Albany shale, thickness 130-150 feet (approximate elevation 620 feet).
Borden formation - Nancy member 290-370 feet.

SITE #1

Vegetation: white oak, northern red oak, virginia pine, beech, eastern red cedar.
Slope: 11% convex slope.
Aspect: 240°.
Elevation: 720 feet.
Parent material: Nancy member (gray) of Borden formation.
Soil series: Lenberg silt loam.
Classification: fine, mixed, mesic Ultic Hapludalfs.

Profile Description

O1&O2 1-0" loose, undecomposed and decomposed litter from mixed hardwood and pine forest.

A1 0-2" dark grayish brown (10YR4/2) silt loam; moderate fine granular structure; very friable; common fine roots; pH 5.0: abrupt smooth boundary.

A2 2-4" light yellowish brown (10YR6/4) silt loam; weak medium subangular blocky structure; friable; dark grayish brown (10YR4/2) coatings on ped faces; common fine roots; pH 5.0; clear smooth boundary.

B1 4-7" yellowish brown (10YR5/6) silt loam; moderate medium subangular blocky structure; friable, common fine roots; pH 5.5; clear smooth boundary.

B21+ 7-12" yellowish brown (10YR5/6) silty clay loam (less than 35% clay); yellowish brown (10YR5/4) common coatings on ped faces; few fine distinct strong brown (7.5YR5/6) mottles; common fine roots; firm; moderate medium structure; pH 5.5; clear smooth boundary.

B22+ 12-22" yellowish red (5YR5/6) and pale olive (5Y6/3) mixture; silty clay; few fine distinct light olive gray (5Y6/3) mottles; firm; moderate fine subangular blocky structure parting to weak fine subangular blocky structure; yellowish brown (10YR5/6) common coatings on ped faces; few fine roots; pH 6.0; clear smooth boundary.

B23+ 22-29" light yellowish brown (2.5Y6/4) silty clay; common fine distinct yellowish red (5YR5/6) and light olive gray (5Y6/2) mottles; firm; moderate medium subangular blocky structure parting to weak fine subangular blocky structure; 15% shale fragments up to 2" in size; few fine roots; pH 6.0; clear smooth boundary.
NOTE: 1/2" thick siltstone layer at 29".

B3+ 29-35" light olive gray (5Y6/2); shaly silty clay; few medium distinct yellowish red (5YR5/6) mottles; red (2.5YR4/6) coatings on ped faces; firm; few fine roots; 30% shale fragments up to 4" in size; weak medium subangular blocky structure; pH 6.0; clear smooth boundary.

Cr 35-40"+ brown to dark brown (7.5YR4/4) interior color of shale; relic platy structure; light gray to gray (5Y6/1) coatings on shale; common fine distinct yellowish red (5YR5/6) mottles; few very fine roots; pH 6.0.

Comments: 1. hue of 6 in A2 out of range.
2. 2.5Y6/4 colors in B23+ out of range.
3. 5Y6/2 colors in B3+ out of range.

Notes: Bulk density samples taken between 12-24". Base saturation at 35 inches.

SITE #2

30 feet up from pond.
Vegation: virginia pine, white oak, beech, northern red oak, ground cedar.
Slope: 28% sideslope (concave).
Aspect: 325°.
Elevation: 710 feet.
Parent material: Nancy member (red) of Borden formation.
Soil series; Lenberg silt loam.
Classification: fine, mixed, mesic Ultic Hapludalfs.

Profile Description

O1&O2 ½"-0 loose, undecomposed and decomposed litter from mixed hardwood and pine forest.

A1 0-2" grayish brown (10YR5/2) silt loam; weak fine granular structure; friable; many fine roots; pH 4.5; clear smooth boundary.

A2 2-6" brown (7.5YR5/4) silt loam; moderate medium subangular blocky structure; friable; common fine and medium roots; pH 4.5; clear smooth boundary.

B21+ 6-16" strong brown (7.5YR5/6) silty clay loam (more than 35% clay); moderate medium subangular blocky structure; firm; common fine and medium roots; light brown (7.5YR6/4) coatings on ped faces; pH 4.5; clear smooth boundary.

B22+ 16-24" reddish brown (5YR4/3) silty clay loam (more than 35% clay); weak medium subangular blocky structure; reddish brown (5YR5/3) coatings on ped faces; few fine roots; 12% shale

fragments up to 2" in size; pH 4.5; clear smooth boundary.

B3 24-36" reddish brown (5YR4/3) shaly silty clay loam (more than 35% clay); weak medium subangular blocky structure; firm; light brownish gray (10YR6/2) coatings on ped faces; few fine and very fine roots; 40% shale fragments up to 2" in size; pH 4.5; gradual smooth boundary.

Cr 36"+ Gray shale, underlying about 4 feet of red shale.

Comments: None

Notes: Control section - fine.
Growth study samples taken.
Bulk density samples taken at 8 inches.

Russell County Location

Creelsboro Quadrangle (Geologic Quadrangle Map)

Date of Survey: June 10, 1981

Location: Russell County, Kentucky - 900 Feet north of Highway 1730; 3.5 miles north of its junction with U.S. Highway 127.

Area: Black shale - Chattanooga shale, thickness 25-52 feet (approximate elevation 680 feet).
Fort Payne formation, thickness 200-325 feet.

SITE #1

Vegetation: mixed hardwoods.
Slope: 67% sideslope.
Aspect: 124°.
Elevation:
Parent material: Residuum from shaly limestone, calcareous shales and siltstones.
Soil series: Garmon silt loam.
Classification: Dystric Entochrepts, fine-loamy, mixed, mesic.

Profile Description

A1 0-5" dark grayish brown (10YR4/2) shaly silt loam; weak fine granular structure; friable; 3% small shale fragments; many fine roots; pH 5.5; gradual smooth boundary.

B21 5-14" dark yellowish brown (10YR4/4) shaly silty clay loam; weak fine subangular blocky structure; friable; 8% small shale fragments; common fine roots; pH 5.5; gradual smooth boundary.

C 14-40" dark brown (10YR4/3) very shaly silty clay loam; massive structure; firm; 50% small soft shale fragments; few fine roots; pH 7.0.

R 40"+ shaly limestone bedrock.

Comments: None.

Comparison of Coal and Oil Shale Mining in Appalachia

by

Jack Bender
Mining Engineer/Assistant Branch Office Manager
Skelly and Loy Engineers - Consultants
Lexington, Kentucky 40504

Abstract. The surface mining technique that is most applicable for extracting oil shale deposits is dictated by topography, geology, and extent of the reserves. A large percentage of the most promising oil shales lie under knobby terrain, isolated in ridgetops in deposits ranging in thickness from 15' to 50'. Since these topographical conditions are similar to those in the Appalachian coal field, several coal surface mining methodologies may be adaptable to efficiently extract oil shale.

Mountaintop removal methods, particularly the cross-ridge mining technique, utilizing mobile equipment fleets will enable reclamation to be performed concurrently with mine advance. This paper analyzes the various operations that must be performed for an oil shale mine of this type and delineates key economic factors affecting mine planning. In addition, alternative stripping techniques that may prove successful are also presented.

Introduction

A great quantity of the eastern oil shale reserve base may be economically feasible to mine by surface methods. The reserves considered surface mineable in this paper are those which have an in-place strip ratio less than 2.5 to 1.0 (tons waste rock to tons oil shale). These reserves exist under several types of mining conditions.

In the eastern Knobs physiographic region of Kentucky and in southcentral Ohio, the surface mineable reserves are often isolated in moderate to steep sloping ridges, outcropping around the hillside. Overburden composition in these hilly areas varies from predominantly shale to shale and sandstone. The thicknesses of the high yield oil shales varies from 15 to 50 feet, and many potential mine sites contain two surface mineable beds. The interburden between the two oil shale beds ranges from several inches to over 100 feet. As interburden thickness increases, it becomes more likely that the two beds cannot be completely recovered by one surface operation. However, in areas where the two beds are close together or form a single unit, the overall strip ratio can be as low as 1.0 to 1.0.

In other areas of the eastern oil shale region, surface mineable reserves lie under more gently rolling terrain and may only outcrop on one side of the deposit. Often the surface soils in these areas are considered prime farmland.

The surface mining technique that is most applicable for extracting oil shale is primarily dictated by topography, geology, and the extent of the reserves. The regulatory climate in each state will also have a great impact on mining methodologies. Even though the economic cut-off strip ratios are much lower for oil shale mining than for coal mining, modified area (gentle slope) and Appalachian (moderate to steep slope) surface coal mining techniques can be adapted to efficiently recover the eastern oil shales. Whereas, western United States oil shale surface mining will be primarily limited to open pit techniques and some large scale stripping due to greater overburden depths. This report will examine the applicability of the Appalachian surface coal mining methods for extracting eastern oil shale reserves that lie under knobby terrain. The operating and economic considerations for mine planning will also be presented.

Applicable Appalachian Surface Mining Techniques

Typically, Appalachian surface coal mining utilizes highly mobile equipment fleets to remove and dispose of overburden. Front-end loaders, dozers and trucks are often employed because they can easily be moved onto a site, can selectively handle various materials, and are adaptable to steep slope conditions. Selective handling and disposal of material will also be a primary component of oil shale mining. Finding sufficient and suitable spent shale disposal areas will also be imperative. The combined thicknesses of oil shale and waste rock beds will usually require several mining benches; and therefore, primary excavation equipment must be mobile.

Mountaintop removal methods have, in the past several years, become increasingly more prevalent for coal recovery in Appalachia. These methods are adaptable to oil shale deposits that are isolated in ridges. With this technique the entire ridge is stripped, resulting in complete resource utili-

zation. Mountaintop removal mining can be categorized into two basic types - conventional and cross-ridge. The characteristics of these two types of mountaintop removal must be examined to determine which is most suitable for oil shale mining.

Cross-ridge mining excavates material in parallel cuts perpendicular to the long axis of the ridge. Dependent on the number of oil shale beds and total material thicknesses, several benches may be advanced simultaneously. Because mining cuts consist of areas of high and low strip ratios, the average strip ratio encountered throughout the mine life is relatively consistent. As the mining faces advance, the entire bench width along the ridge behind the lowest active pit becomes available for overburden or spent shale storage. An advancing backstack of spent shale covered with waste rock can be constructed on this bench area to account for a large percentage of the storage requirements. Hollows adjacent to the site can be utilized for storage of any additional material. Cross-ridge mining allows the percentage of material going to either the backstack or hollow fills to be varied, depending on the economics of the haulage profiles at any point in time.

Conventional mountaintop mining also provides for complete resource recovery. However, this technique removes overburden in successive cuts along the contour of the ridge. This results in initial mining of low strip ratio areas with consequent high strip ratio areas encountered later in the mine life, thereby greatly increasing final reclamation costs. By operating in this manner, return on investment is maximized in early years, but equipment must be added at a faster rate in later years to meet required production levels for the retort. The primary drawback with this technique for oil shale mining is that bench areas cannot be effectively used for spent shale or overburden storage without sterilizing future reserves. Therefore, valley fills must store almost all spent shale and overburden until several cuts around the ridge have been taken and sufficient bench storage area is created. In many instances, ample hollow storage room may not be available to hold the large initial volume of materials, or state regulations may not allow disposal of spent shale in valley fills. Also, the average haul distance to each valley fill will be greater than is experienced in cross-ridge mining because the working face moves away from the fill at a faster rate.

Contour mining along the outcrop of an oil shale bed can be implemented to recover reserves that are covered by excessive volumes of overburden which prevent the economic use of mountaintop removal technologies. However, several characteristics of contour mining detract from its applicability as a viable oil shale mining technique. Bench disposal of spent shale or overburden will result in reserve sterilization; and complete backfilling of the highwall may be difficult. If a forty (40) foot bed is recovered to a cutoff strip ratio of 3.0 (1.5 average), the resulting highwall will be 160 feet high. Also, the haul distance to the retort will increase at a relatively fast pace for contour mining, and consequently, truck fleet requirements may be great.

Because of the drawbacks of contour and conventional mountaintop mining techniques, cross-ridge mining appears to be the most applicable surface technique for extracting oil shale reserves that are isolated in ridgetops. To fully illustrate the applicability of the cross-ridge methodology, the unit operations and key mining parameters affecting their implementation must be delineated.

Analysis of Cross-Ridge Unit Operations For Oil Shale Recovery

Overburden and Oil Shale Extraction

Regardless of the type of prime mover employed, common strip ratios indicate that as much as 200 feet of material must be excavated in many situations. The thickness to be moved along with the number of oil shale beds present determines the number of benches needed. At least three (3) benches will be needed for most ridge type sites. Because cross-ridge mining advances perpendicular to the axis of the ridge, consistent bench heights are maintained throughout most of the mine life.

The size of the prime mover production fleet depends on the daily feed requirements of the retort, the production capacity of the machines utilized, and the strip ratio. When multi-bed deposits exist or if several benches are needed, highly mobile front-end loaders may prove the most suitable for oil shale and waste rock excavation. These machines can easily be moved from bench to bench dependent on production needs. Because oil shale production requirements of a full-scale operation will probably range from 15,000 to 50,000+ tons per day, front-end loaders should have a capacity of at least 12 cubic yards to keep fleet requirements reasonable.

Electric shovels and crawler mounted hydraulic shovels can be successfully utilized on sites that do not require numerous working benches. Under these conditions, the prime mover will not have to be moved among benches often or at all, and thus, flexibility is not a major concern. As fuel costs increase, electric shovels will become even more attractive. The high break-out force of electric and hydraulic shovels may allow for lower powder factors resulting in lower blasting costs. The size of the shovels that can be used is restricted by the capacity of the trucks used for haulage.

Since the oil shale and overburden conditions at most sites mandate that several benches be utilized, large front-end loaders are probably best suited for excavation of material. Maintaining a steady flow of shale ore to the retort is imperative and the flexibility of front-end loaders allows this necessity to be easily met. Keeping all benches advancing at the same rate is more difficult with shovels due to poor tramming capabilities among benches. Utilization of both shovels and front-end loaders can provide for steady production but may complicate parts inventories and maintenance procedures.

Waste Rock and Spent Shale Disposal

As was previously mentioned, waste rock and spent shale must be disposed of in hollow fills or on the bench behind the working area. Primarily, the most economic disposal technique will utilize both storage areas. The backstack is usually closer to the excavation area; however, excessive backstack heights result in long uphill hauls by loaded trucks. Over-utilization of valley fills increases

the acreage disturbed and can also require long truck hauls. Therefore, the volumes of material to be stored must be carefully compared to the available storage locations and volumes to determine the best disposal scenario.

The area available for backstack construction is based on the bench acreage, the number of mine facilities on the bench, haul road needs, and the regulatory conditions. If material stored on the bench is toxic, either leachate ponds or a suitable spoil cover may be required by the regulatory authority to control toxic runoff and/or leachates. Other protective measures may also be specified. These regulations will affect backstack construction techniques and to an extent its storage volume.

The hollows around an oil shale property can be used for overburden disposal; however, some states may impose regulatory restrictions on spent shale disposal in hollow fills. Many of the valleys surrounding oil shale properties are long and shallow; thus, long hauls to the toe exist when large storage capacities are required. If sufficient durable rock exists, side dumping techniques for fill construction could greatly reduce haulage costs. Overall, the final status of each state's waste rock and spent shale disposal regulations will have a great impact on the economics of oil shale mining. Hopefully, the regulations in each state will be flexible enough to allow for many various disposal alternatives based on the site specific spent shale and waste rock characteristics.

Shale and Waste Rock Haulage

The haulage scenario at a mountaintop oil shale mine involves transport of shale ore to the retort and spent shale and waste rock to either valley fills or the backstack. Selection of the system or combination of systems to transport these materials depends on haul distance and relative location of the retort facility.

Off-highway rock trucks appear best suited for transport of material within the mining area. Trucks can selectively place overburden materials in either backstack or valley fill, and can easily alter their haulage destination to account for changes in production. Also, trucks transporting oil shale to the dumping area can return loaded with spent shale, thus efficiently utilizing all travel time.

If the average haul to the retort is relatively short over the mine life (approximately 7,000 feet or less), trucks alone are probably the most economic transport choice. However, as one-way haul distances approach two (2) miles, truck fleet requirements become excessive. This situation will commonly occur near the termination of mining (20-25 years) of a cross-ridge mine producing from 3,000 to 7,000 bbls. per day that has retort facilities adjacent to the mine site. Excessive hauls will be incurred much sooner for larger mines or if the retort is located several thousand feet from the ridge being mined (retort may be centrally located to several ridges). Under these conditions a combination of trucks and conveyors could potentially be more economic. Trucks would haul shale ore to a designated dump station from which conveyors would transport ore the remainder of the distance to the retort. Another conveyor would carry spent shale from the retort to the dump station. Periodically, additional conveyor sections must be added to keep truck hauls short. This system will eliminate the need for adding trucks as mining advances; however, the combination of equipment may result in an overall increase in downtime.

Because of haulage system considerations, retort facility location is a very important economic consideration in mine planning. Keeping the retort as close as possible to the mine always reduces mining costs for that particular property regardless of the haulage system. However, future utilization of the retort will be much more costly unless additional reserves are nearby. Locating a single large retort facility central to several ridges will allow relatively consistent mining costs to be incurred for each property, and retort construction will be a one time capital outlay. Haulage costs, and consequently mining costs, will be higher with this type of system.

Another possibility is to locate a single stage of the retort at each site and pump the crude shale oil to a central facility for further processing. This will reduce haulage costs, but the capital requirement associated with constructing a single stage of the retort will be incurred at each property. The trade-offs among mining costs, retort useful life, retort construction costs, and future market and inflationary conditions must all be analyzed in detail to determine which mining and retorting system may be the most profitable for each oil shale property or group of properties.

An Alternative Waste Rock Removal Technique

The flexibility of mobile equipment fleets makes them suitable for all ridgetop removal oil shale operations. However, as was mentioned, haulage costs for shale and waste materials can become excessive. Utilization of medium sized draglines for overburden or interburden removal can reduce haulage costs considerably.

A dragline would remove waste rock from above the lowest oil shale bed and spoil the material in the previous pit. A dragline with a sufficient reach should be used in order that spoil does not pile against the highwall reducing oil shale recovery. Benching ahead of the dragline could be accomplished with loaders and trucks, and the material hauled to valley fills.

Implementation of this type of system is contingent upon favorable regulatory conditions. Since the majority of the bench area storage is used for waste rock spoil, spent shale may have to be stored in valley fills. If disposal regulations do not allow spent shale to be placed in valley fills, it is doubtful that this type of system could be utilized efficiently.

On ridgetop sites where the interburden between two oil shale beds is too thick to allow complete mountaintop removal, a combination system can be used to recover most of the reserves. Contour mining of the lower bed to the cut-off strip ratio can be initiated to recover the surface mineable reserves. In conjunction with the contour operation, underground punch mining can recover as much as 50% of the remaining lower bed reserves. After the lower operations have proceeded some

distance, a cross-ridge operation can be used to recover all the upper bed reserves.

If the majority of the spent shale and overburden from the contour operation is stored in hollow fills, it may be possible to side dump waste from the upper operation onto the wide (up to 300 feet) contour bench. Once again, the regulatory climate will have a great impact on the use of this technique, especially concerning spent shale disposal from underground works.

Conclusion

Cross-ridge mining and other techniques hold promise for recovering oil shale from surface mineable deposits that lie under knobby terrain. Innovative methods may also be developed in the future to economically recover reserves. Oil shale is an important resource to this country and can be a great economic asset to the eastern states that have mineable reserves. Surface mining has a bad reputation with much of the public, largely because of past trends and unfamiliarity with the current state-of-the-art. In order to fully utilize this energy source in a timely manner, both industry and government must continue R & D programs as well as educate the general public that eastern oil shale mining can be performed without environmental degradation.

Disposal Concepts as Related to Retorted Shale Properties

by

Phil C. Gerhart
Vice President/Senior Associate

Wesley G. Holtz
Consultant

Woodward-Clyde Consultants
Denver, Colorado 80204

Abstract. Economical development of shale oil depends in a significant way upon the successful stabilization of its solid waste product--retorted shale. The physical and chemical properties of retorted shale depend largely on the retorting process. Retorting temperature, residence time, initial crushing, mechanical reworking within the retort vessel, and post-retort cooling are believed to cause the most effect. Utilizing retorted shale physical characteristics wrought by these processes, stable, environmentally acceptable embankments can be constructed.

Introduction

The combined eastern and western oil shale basins constitute the largest known oil reserve in the world. It has been estimated that, in the western basin alone, there are 600 to 800 billion barrels of oil in shale having a richness of 20 gallons per ton or greater, in the thicker deposits, that can be economically recovered. It has also been estimated that there are over 2 trillion barrels of oil in deposits having a richness of at least 10 gallons per ton, which might be recoverable later through advanced technological developments.

This paper treats a few of the concepts associated with unlocking this vast energy bank, while at the same time minimizing the impact of the solid waste products on society. To put the magnitude of retorted shale disposal in the proper perspective, a typically planned 10 module facility producing 100,000 barrels (16,000 m^3) of crude oil per day would generate about 150,000 tons (13.6×10^7 kg) of retorted shale per day which, when compacted, would be equivalent to about 125,000 cubic yards (95,600 m^3) per day. Assuming an on-stream factor of 90 percent, about 50 million tons (45×10^9 kg) would be produced each year, or 1 billion tons (91×10^{10} kg) over a 22-year period. This would cover one square mile (2.59 km^2) almost 1000 ft (305 m) deep.

Woodward-Clyde Consultants (WCC) has, over the past ten or more years, been involved in waste disposal and material characterization studies for all of the major above-ground processes. Some of that work[1] accomplished under partial federal funding has been published, however, much of the data is protected from disclosure by contractual agreements. Thus, the material presented in this paper will be general and largely unidentified.

Retorting Processes

Important to the characterization and disposal of retorted shales are the processes through which they have been caused to pass. The oil shale cycle begins with mining, crushing and transportation from underground mines or open pits to the plant, followed by additional crushing, screening, and introduction to the retort vessel where the raw material is treated and the oil vapors recovered. The final step involves cooling and transportation to the disposal area.

Several processes are in various stages of development and include the Paraho, TOSCO, Union, Chevron, Superior, Lurgi and others. Each process, with its patented components, affects the final physical and chemical properties of the retorted shale. Those process steps, thought to be the most critical include: (a) retorting temperature, (b) residence time, (c) initial crushing, mechanical reworking within the retort vessel, and (d) post-retort cooling processes.

High retorting temperatures and a mid-range of residence time produces a retorted shale with natural cementitious properties, whereas, free-carbon rich retorted shales produced by low temperature retorting processes demonstrate very little or no cementitious properties. Grain sizes and grain-size distributions are also important considerations in evaluating permeability, consolidation and strength characteristics. It is believed that the cementing mechanism and ultimately a major portion of the strength of moistened, compacted retorted shales may be the growth of acicular crystals of calcium aluminum sulfate between the contacts of retorted shale fragments[2]. Thus, it follows that fine grained, high temperature retorted shales would promote more crystal growth resulting in higher strengths and reduced permeabilities. Applying a basic understanding of soil mechanics also suggests the well graded and finer grained materials should also be less pervious than coarser grained, poorly graded materials for similar levels of compactable effort. Certain processes crush raw shale initially to finer sizes than do others and some processes mechanically work the raw and retorted materials with rock pumps, screw conveyors, turbulent beds, rotating grates and other such devices, resulting, ultimately, in a finer grained end product.

Cooling the hot retorted shale is at present conducted by quenching, spraying with water or just by air cooling during transportation to the disposal site. Final cooling at the disposal site is almost universally planned, and is an important factor in disposal design. In particular, one must be aware of the potential for spontaneous ignition and subsequent burning of the free-carbon component of the low temperature retorted shales.

Material Properties

Gradation

Retorted Piceance Basin shales classified in accordance with the Unified Soil Classification System (ASTM D 2487) range from sandy silts (ML) to silty gravels (GM). Typical gradation analyses of both coarse and fine grained specimens are presented on Figure 1 and represent five different processes. This data shows gravel-size particles represent from 0 to 75 percent, sand-size particles from 11 to 60.5 percent, and clay and silt-size particles from 9 to 64 percent of the total sample.

Results of laboratory compaction tests on retorted shale from the Paraho (direct heat) process shows considerable

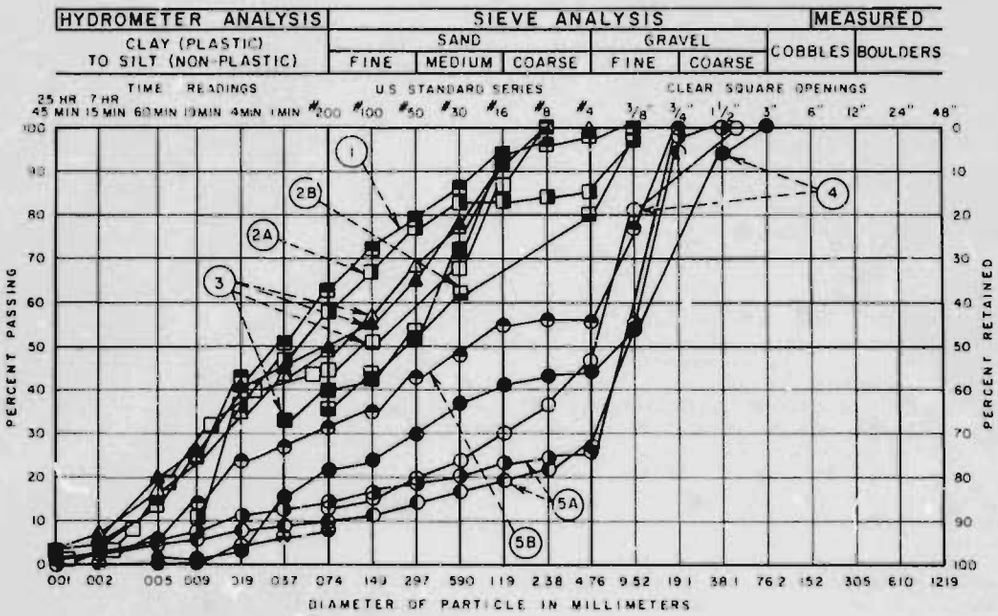

Figure 1. Gradation Analyses of Retorted Shale Samples (as-received).

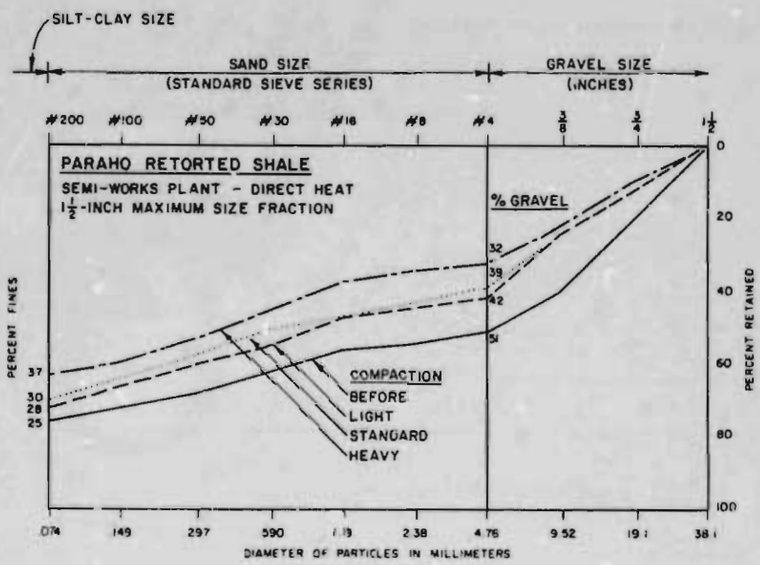

Figure 2. Effect of Particle Breakdown Under Compactive Effort.

particle breakdown in the gravel and sand sizes can occur. Figure 2 is a plot of the gradation, as-retorted, and the gradations after compaction showing the effects of particle breakdown under three different laboratory compactive efforts. The degree of particle breakdown under the different compactive efforts, of course, affects the other physical properties of the materials so produced. Other tests on fine, medium and coarse grained samples showed increases in silt- and clay-size fractions resulting from standard compaction (ASTM D 698) ranging between 0 and 25 percent.

The coefficient of uniformity, relating the D_{60}-size particle to the D_{10}-size particle ranges from 11.4 percent for those uniformly graded materials to 797.1 for those processes resulting in gap graded retorted shales.

Specific Gravity

Studies performed to date indicate the average apparent specific gravity (ASTM D 854) (permeable voids filled with water) ranges between 2.53 and 2.85.

Compaction

Compaction studies performed by WCC on fine and coarse grained retorted shales have employed three degrees of compaction. These were 6200-foot pounds per cubic foot (297 kJ/m^3) (1/2 of ASTM D 698) to represent the light compactive effort that might be associated with hauling and spreading equipment; 12,375-foot pounds per cubic foot (593 kJ/m^3) (ASTM D 698), which is standard compactive effort used for many types of earthwork construction; and 56,000-foot pounds per cubic foot, (2693 kJ/m^3) (ASTM D 1557), which represents the heavy compactive effort used for special earthwork situations where high densities are desired. The results of these tests on Paraho retorted shale (direct heat) are shown on Figure 3.

It should be noted that moistening dry retorted shale to an "optimum" moisture content produces only small increases in dry densities, being of the order of 2 to 3 pounds per cubic foot (0.032 to 0.048 g/cm^3). At some intermediate moistures, the dry densities were slightly less than that obtained at low moistures. A similar moisture density relationship was also obtained in the full-scale, field compaction experiments performed at Anvil Points, Colorado.[1]

Other results of laboratory compaction tests performed on both fine and coarse grained retorted shale samples compacted using "standard" effort (ASTM D 698) are presented in Figure 4. Characteristic flat curves and relatively high optimum moisture contents, as discussed above, are exhibited by both fine and coarse grained samples. Optimum moisture contents for the materials shown on Figure 4 range from 15.5 percent to

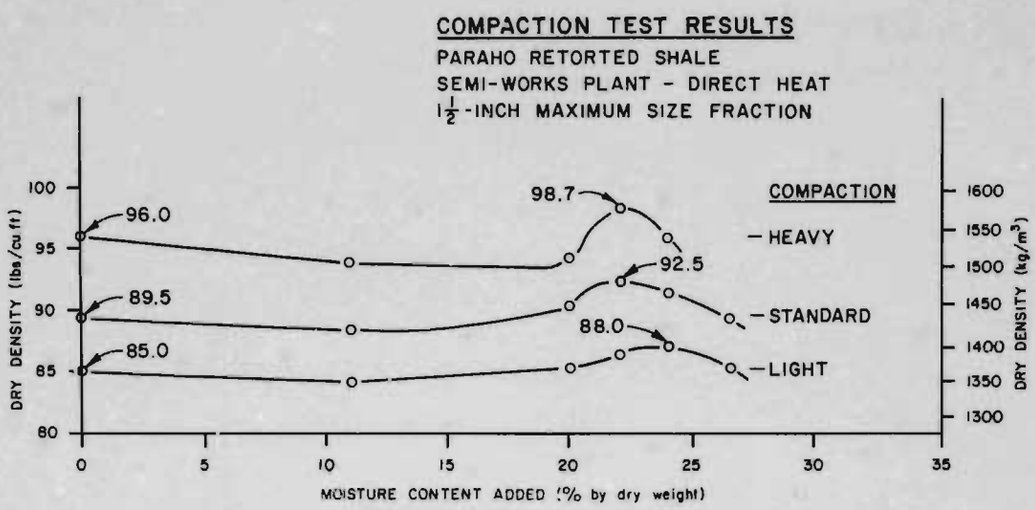

Figure 3. Compactive Test Results Using Different Levels of Compactive Effort.[3]

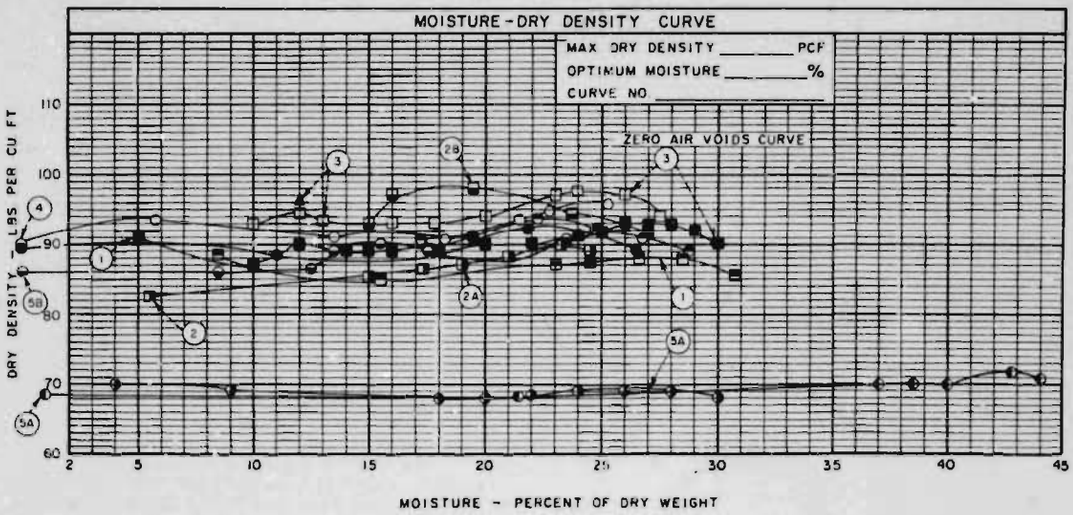

Figure 4. Compactive Test Results - Retorted Shale (ASTM D698).

42.8 percent and average 24.9 percent. Dry densities for these materials varied between 69.0 pounds per cubic foot (1.104 g/cm^3) and 97.5 pounds per cubic foot (1.56 g/cm^3) and averaged 89.2 pounds per cubic foot (1.427 g/cm^3). Obtaining near maximum densities without additional water during compaction is an important factor in western retorted shale disposal because of the scarcity of water in the arid or semi-arid areas where the oil shale is located.

Free-Fall Density

Studies performed at the United States Army Corps of Engineers Waterways Experiment Station (WES)[4] supplemented by WCC laboratory data relating the effects of drop height to density using dry retorted shale (WES & WCC) and moistened retorted shale (WCC) are presented on Figure 5. The results show dry densities become asymptotic to densities of between 80 and 85 pounds per cubic foot (1.28 g/cm^3 and 1.36 g/cm^3) at drop heights above about 4 feet (1.22 m). Maximum bulking of the relatively fine grained TOSCO retorted shale apparently occurs at a moisture content of about 8 percent or near the moisture content that might be developed during spray cooling and to minimize dusting. Such a decrease in density could mean increasing storage volumes for conveyor placed retorted shales by as much as 35 per-

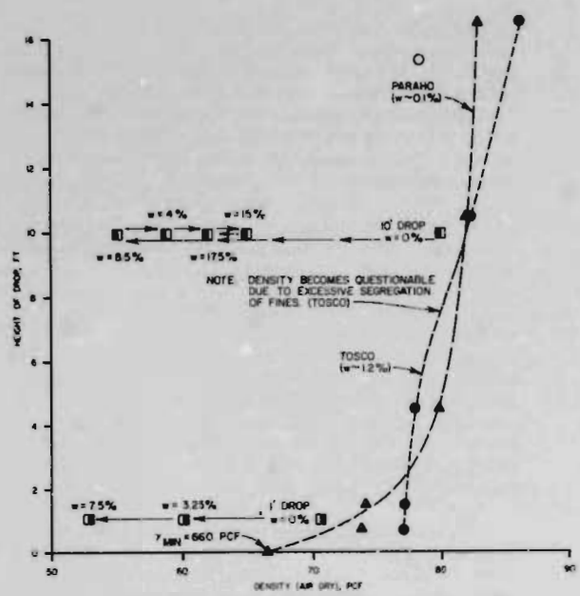

Figure 5. Effect of Drop Height on Density for Dry and Moist Retorted Shales.

cent. The tests were, however, conducted using relatively small amounts of retorted shales and do not account for further densification that could result from the effects of the weight of subsequently placed layers. It is felt that final, conveyor placed retorted shale densities should approach the 80 pound per cubic foot density line, although the time related effects of a reasonably stable microstructure due to cementing effects has not been thoroughly investigated.

Permeability

Current disposal schemes, in light of environmental safeguards related to leachate management are considering the use of "impermeable" linings. Sites would be covered with thick, highly compacted, impervious linings consisting of retorted shale materials or local clay deposits. Results of laboratory and field tests[1] show that retorted shale, highly compacted at a moisture content near that considered optimum for compaction, will provide the "impermeable" material for this type of construction.

The laboratory tests presented in Tables 1 and 2 were conducted in accordance with the United States Bureau of Reclamation (USBR) Designation E-13, except that each specimen was compacted in two equal layers and a thin ring of minus 1/4 inch (0.63 cm) material was placed adjacent to the cylinder wall, for coarse grained retorted shale samples, to prevent sidewall piping through the "gravelly" material. During the tests, loads were varied and settlement measurements taken.

Table 1. Permeability Test Results for Compacted Paraho Retorted Shale.[3]

PERMEABILITY TEST RESULTS

COMPACTIVE EFFORT	DRY DENSITY (PCF)	PLACEMENT MOISTURE (%)	PERMEABILITY (FT/YR) UNDER LOADINGS OF: 50 PSI	100 PSI	200 PSI
LIGHT	88.0	23.7	15.0	5.5	1.7
	88.0	0.0	42.0	---	---
STANDARD	92.5	22.0	7.0	1.4	0.8
	93.0	3.0	44.6	30.3	19.8
HEAVY	98.7	22.0	1.1	0.6	0.1
	98.0	3.0	39.5	33.6	26.0

NOTE: 1 FT/YR = 1 x 10^{-6} CM/SEC (APPROX.)

Table 2. Permeability Test Results for Various Compacted Retorted Shales.

PERMEABILITY TEST RESULTS

SHALE	COMPACTIVE EFFORT	PERMEABILITY (FT/YR) UNDER LOADINGS OF: 50 PSI	100 PSI	200 PSI
(1)	LIGHT	15.0	5.5	1.7
	STANDARD	7.0	1.4	0.8
	HEAVY	1.1	0.6	0.1
(2)*	LIGHT	---	0.4	0.3
	STANDARD	---	0.4	0.4
	HEAVY	---	0.4	0.2
(3)	LIGHT	0.003	0.003	0.002
	STANDARD	0.002	0.005	0.001
	HEAVY	0.001	0.001	0.001
(4)*	LIGHT	114.6	40.4	18.9
	STANDARD	54.0	44.5	26.4
	HEAVY	9.1	7.1	6.4

NOTES:

(1) COARSE SHALE, HIGH TEMPERATURE
(2) FINE SHALE, LOW TEMPERATURE
(3) FINE SHALE, V. HIGH TEMPERATURE
(4) COARSE SHALE, LOW TEMPERATURE
* APPROXIMATE LOADINGS
SAMPLES PLACED AT OPTIMUM OR OPTIMUM PLUS MOISTURES
1 FT/YR = 1 x 10^{-6} CM/SEC (APPROX.)

The tabulated data show "impermeable" material can be obtained, even under low loads, if the materials are highly compacted at optimum moisture conditions. It should be recognized that, in addition to obtaining higher densities with high compaction, the percent gravel-sized particles are reduced and the percent silt- and clay-sized particles increased (Figure 1). Table 1 emphasizes the importance of compacting retorted shales (in this case Paraho direct heat materials) at optimum moisture conditions as compared with low moisture conditions, when "impermeability" is important. Similar effects have been recognized in the soil mechanics field for many years.

Data presented in Table 2 also point out the expected influence of a large percentage of clay- and silt-size particles on compacted permeabilities. Although difficult, because of some differences in grain-size distribution, the effects of cementation can be inferred from the results of low temperature and very high temperature retorted shales.

One permeability test (Figure 6) on Paraho direct heat retorted shale, was performed on a sample compacted with light effort and zero moisture content to simulate the main body of a retorted shale disposal facility. The specimen was first permeated with distilled water for a period of 200 hours, after which the salty effluent liquor was recirculated through the system for about 900 additional hours. The permeability dropped from 42 feet per year (approximately 4.2×10^{-5} cm/sec) to 2.2 feet per year (approximately 2.2×10^{-6} cm/sec) as a result of salts concentrating within the void spaces. Such an event could occur in a disposal pile resulting ultimately in further attenuation of leachate movement.

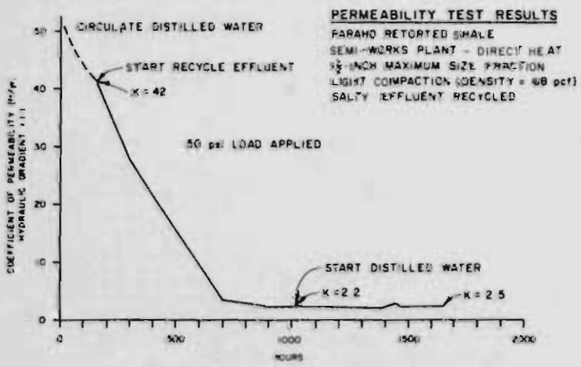

Figure 6. Permeability Test Results Using Distilled Water and Recycled Effluent.[3]

Strength

Early investigations by the Denver Research Institute (DRI)[5] suggested the possibility of increasing strength with time characteristics for retorted shales processed in high temperature environments. Test results to date have verified this relationship as well as others, including the link between strength and density, and strength and molding water content.

Figure 7 presents the results of unconfined compressive strength tests on fine and coarse grained retorted shales compacted at varying moisture contents and cured for periods ranging from 0 to 125 days. Similar strengths were obtained on cores drilled from field compacted materials placed in the Paraho test pond No. 1 lining.[1]

Several significant observations can be made from this data, including the following: (1) strengths will plateau shortly after placement; (2) increasing densities should result in an increase in strength; (3) high temperature processes produce higher strength materials than those involving low temperatures; and (4) strengths near those associated with weak concrete are possible.

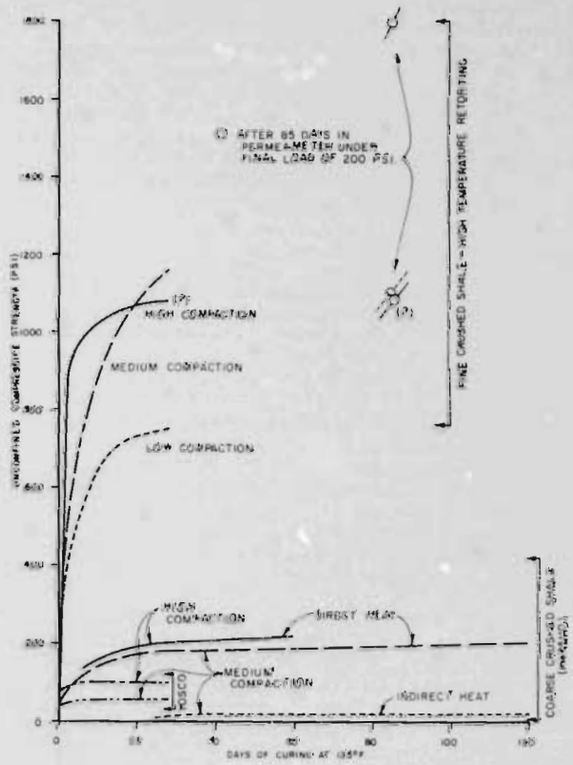

Figure 7. Results of Unconfined Compressive Strength Tests on Fine and Coarse Grained Retorted Shales.

The relationship between strength as measured in unconfined compression and molding water content are presented on Figure 8. This figure demonstrates both the coupled relationship between strength, curing time and moisture content, as well as a generally increasing strength with increasing moisture content to at least a point near the optimum moisture content. The process represented by the dark squares is typical of high carbon content, low temperature retorted shales.

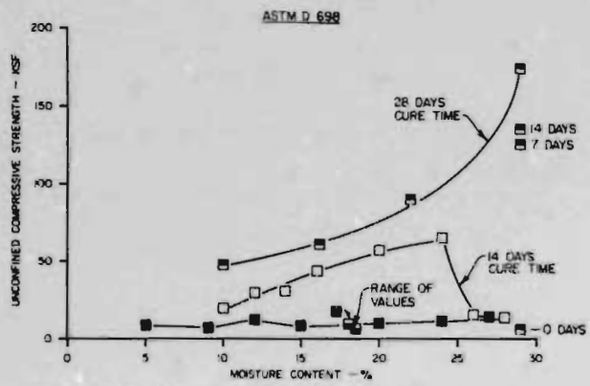

Figure 8. Results of Unconfined Compressive Strength Tests with Varying Molding Water Contents.

Table 3. Triaxial Shear Test Results on Shale Samples Retorted at Varying Temperatures and Compacted with Varying Efforts.

TRIAXIAL SHEAR TEST RESULTS

	COMPACTIVE EFFORT	DRY DENSITY (PCF)	FRICTION COEFFICIENT (TAN Ø)	COHESION (PSI) AT MOISTURE CONDITIONS INDICATED	
(1)	LIGHT	88.0	0.69	19.4 (DRY)	15.3 (SATURATED)
(1)	STANDARD	92.5	0.68	27.8 (OPTIMUM)	24.3 (SATURATED)
(1)	HEAVY	98.7	0.69	36.1 (OPTIMUM)	29.2 (SATURATED)
(1)	HEAVY	101.5	0.78	69.4 (OPTIMUM)	CURED 30-DAYS
(2)	LIGHT	95.8	0.75	1.4 (OPTIMUM)	
(2)	STANDARD	97.3	0.70	1.4 (OPTIMUM)	
(2)	HEAVY	103.9	0.93	0 (OPTIMUM)	
(3)	LIGHT	86.8	0.69	22.2 (OPTIMUM)	7.6 (SATURATED)
(3)	STANDARD	89.0	0.62	33.3 (OPTIMUM)	13.9 (SATURATED)
(3)	HEAVY	96.4	0.80	41.0 (OPTIMUM)	27.8 (SATURATED)

NOTES:
(1) COARSE SHALE, HIGH TEMPERATURE
(2) FINE SHALE, LOW TEMPERATURE
(3) FINE SHALE, V. HIGH TEMPERATURE

Triaxial shear test results for combinations of high and low temperature retored shales, light to heavy compactive efforts and fine to coarse grained materials are presented in Table 3 and on Figure 9. This data suggests the angle of internal friction is not a sensitive function of density (compactive effort), grain-size distribution or retorting temperature. This is significant from a disposal facility standpoint, since for deep seated slope failures, strength is directly related to the normal stress on the shearing plane and the angle of internal friction. Therefore, costly measures such as additional molding water content, increased compactive effort and higher retorting temperatures should not be influential from the standpoint of frictional resistence. Only the cohesion, as might be expected from the results of unconfined compressive strength tests appears to be materially affected by process and densification related activities.

Disposal Concepts

Current above-ground and mined-out area disposal schemes are regulated and closely monitored by state and federal agencies involved with environmental protection and mined land reclamation. The Colorado Mined Land Reclamation Act states:

> "It is the intent of the general assembly by the enactment of this article to allow for the continued development of the mining industry of this state, while requiring those persons involved in mining operations to reclaim land affected by such operations so that the affected land may be put to a use beneficial to the people of this state."

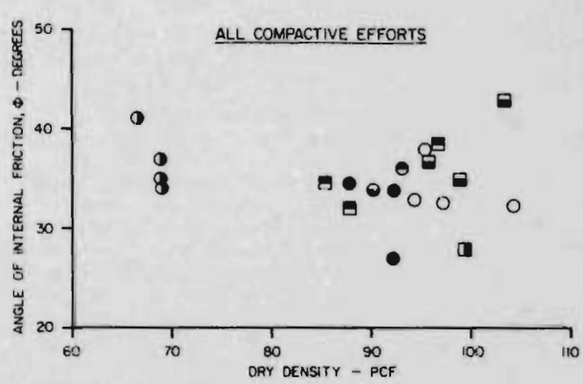

Figure 9. Triaxial Shear Test Results Related to Dry Density for Varying Compactive Efforts.

Energy companies are thus charged with constructing stable long-term facilities without driving the cost per barrel of oil, due to disposal operations, beyond that which the market is willing to bear. The engineering challenge is clear. Retorted shale properties that can economically enhance disposal pile stability must be incorporated into designs. Certain questions, it is believed, regarding retorted shale disposal have been answered during the course of laboratory and limited field tests. Verification and answers to questions that cannot be adequately modeled in the laboratory environment will, however, only be possible once prototype embankments are constructed, properly monitored, and the test data analyzed. Current disposal plans are then in that sense conceptual, and are a in very generic fashion presented in Figures 10 through 13. Many variations to the schemes presented are possible and in instances, necessary, depending on site conditions, retorted shale

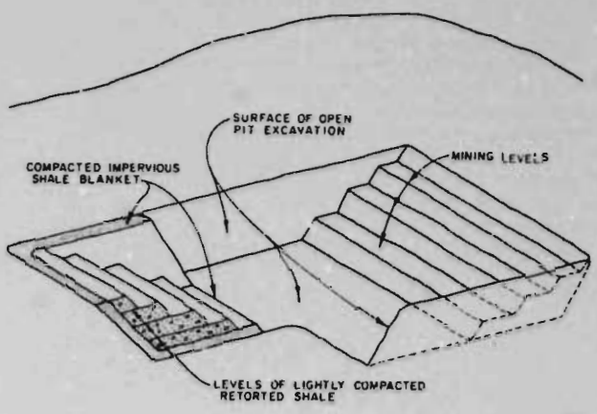

Figure 10. Schematic of Typical Open Pit Mine Backfill.

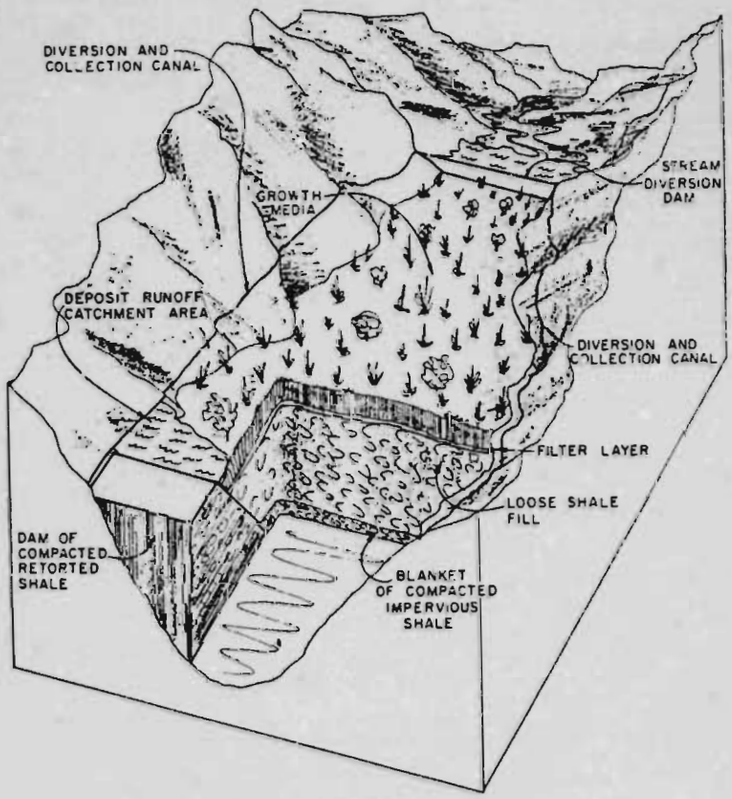

Figure 11. Schematic of Typical Cross-Valley Fill.

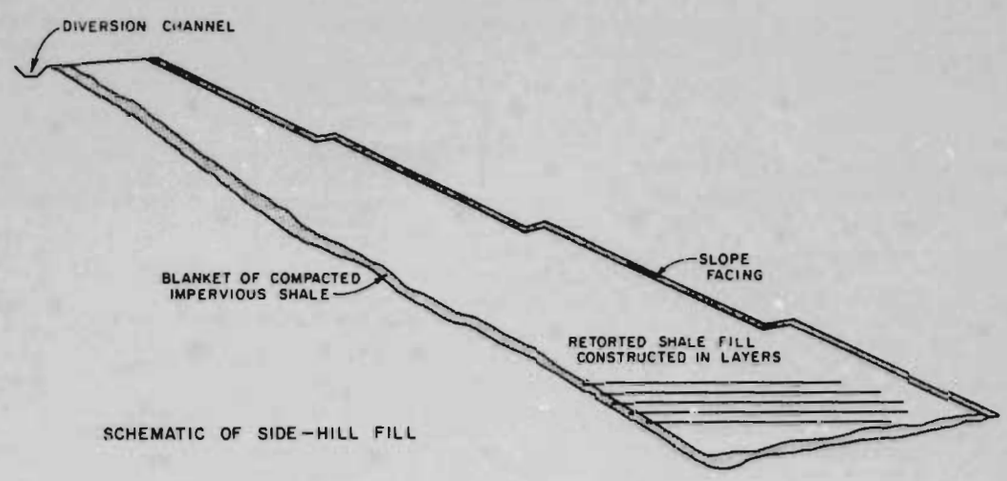

Figure 12. Schematic of Typical Side-Valley Fill.

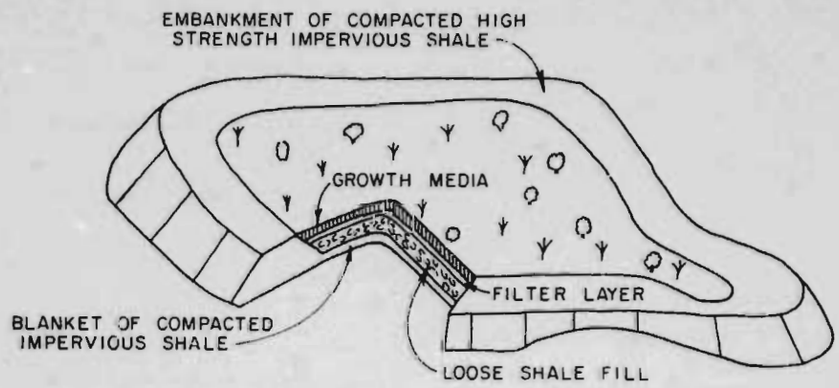

Figure 13. Schematic of Typical Surface Disposal Pile.

properties, local regulations, and construction material availability. The schemes also represent western oil shale lands and climate, the implications of which would have to be seriously considered in the eastern setting. Backfilling underground mine openings has also been studied but is not discussed herein.

Three common disposal concepts along with open-pit mine backfilling (Figure 10) are being considered and involve cross-valley fills (Figure 11), side-hill fills (Figure 12), and piles covering relatively level surface areas (Figure 13). Due to the large disposal volumes and rugged topography, concept combinations also coupled with open-pit mine backfilling are often used.

All four concepts employ the "belt and suspenders" approach, or multiple lines of defense, with regard to leachate and surface water management. This includes using the "impermeable" nature of adequately compacted retorted shales to provide a lower lining and an upper reclamation or slope facing zone, that could also consist of compacted retorted shale with or without possible additions of portland cement. Leachate attenuation is further strengthened by salt accumulations and associated reduced permeabilities. Mathematical seepage models are often employed to assist in dimensioning "impermeable" and

RETORTED SHALE STORAGE SCHEMES

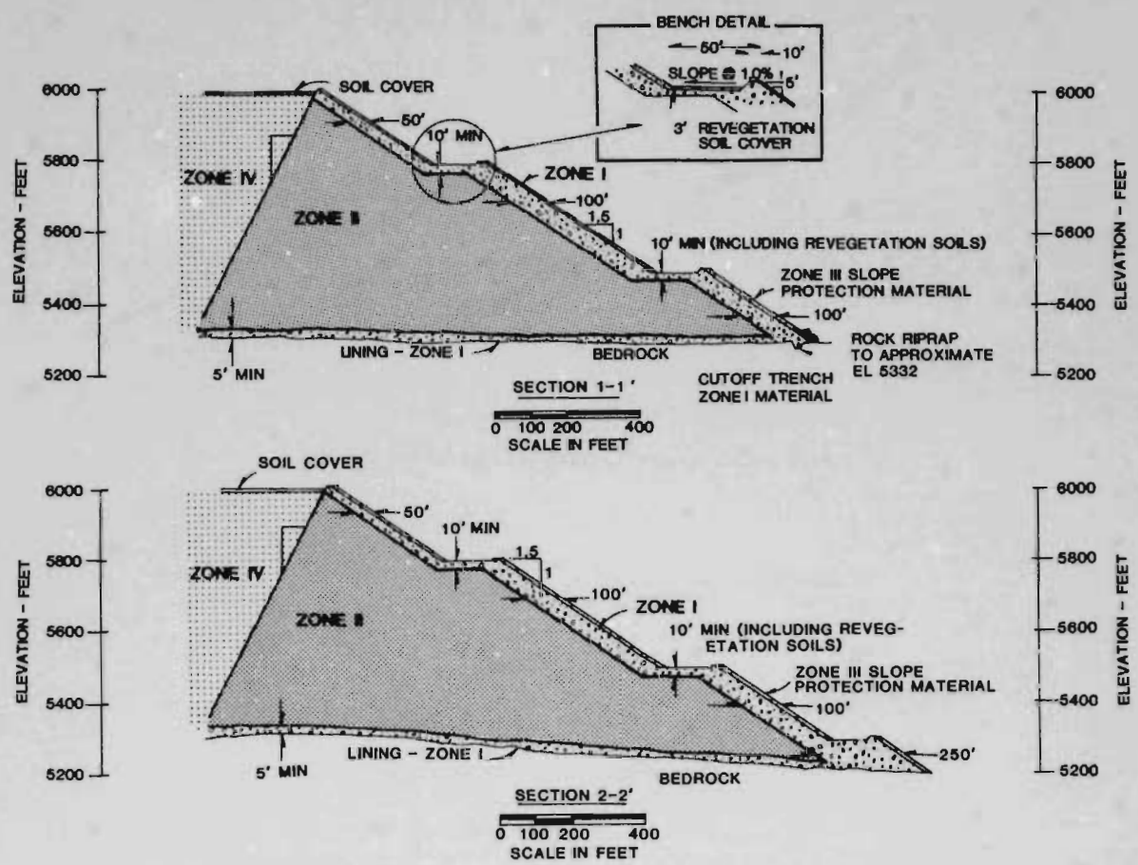

Figure 14. Typical Section of Retorted Shale Embankment.

reclamation zones and involve the application of non-saturated/two-phase flow theory. Such model studies must consider the high absorption characteristics of retorted shale, and the precipitation-evaporation characteristics of the disposal locations.

End and face slopes can be of the order of several hundred feet high and thus indicate, even to the casual observer, the need for strong durable materials. Since most natural slopes in the western oil shale region are relatively steep (2:1 and 1.5:1 horizontal to vertical) visual continuity suggests retorted shale disposal facilities should have similar steep slopes which also enhances the ratio between storage volume and disturbed land area.

Results of conventional stability analyses on embankment sections where the high strength potential of well compacted retorted shales, in some cases compacted at optimum moisture content, are utilized; show that relatively steep, high slopes can be constructed with low probability of failure. A typical section of one such embankment is presented on Figure 13.

Conclusions

1. Retorted Piceance Basin shales classified in accordance with ASTM D 2487 range from sandy silts (ML) to silty gravels (GM).

2. Dry density increases only slightly with additional moisture at similar compactive efforts. Particle breakdown during field and laboratory compaction could be significant.

3. Retorted shales tested to date can be compacted to densities sufficient to render them "impermeable."

4. Laboratory strength tests show strength varies with molding moisture content, curing time and density.

5. Natural cementation of hydrated retorted shale depends upon retorting temperature, grain size and the moisture available for hydration.

6. The disposal method will depend in large part on the physical properties described above.

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Engineering Properties of Kentucky Oil Shales

by

Vincent P. Drnevich,
Prof. and Chmn., Dept. of Civil Engineering
University of Kentucky

Tommy C. Hopkins, David L. Allen
Chief Research Engineers
Transportation Research Program
University of Kentucky

Samuel S. Hale
Graduate Assistant, Dept. of Civil Engineering
University of Kentucky

Abstract

Excavation, handling, and the environmentally safe disposal of spent oil shale and overburden materials require a knowledge of their geotechnical engineering properties. To determine these properties, a laboratory investigation of the physical and geotechnical engineering properties was made. The physical tests consisted of mechanical analyses, Atterberg Limits, and specific gravity determinations. Geotechnical properties were determined by moisture-density analyses, triaxial compression, permeability tests, slake-durability, one-dimensional compression tests, and Los Angeles abrasion. A one-dimensional compression test was devised to address the problem of placement, loading, and saturation of the spent shales and overburden materials. The compacted, unprocessed oil shales were more susceptible to inundation and compression than compacted specimens of retorted shales and chars. Comparisons of the geotechnical properties of the unprocessed oil shales and processed shales are made.

INTRODUCTION

The current energy shortage and a diminishing supply of petroleum have prompted efforts to search for alternate sources of energy. Serious attention has recently focused on the commercial development of oil shales because of a large abundance of these materials and their proximity to markets. Processsing of raw oil shale by heating to recover petroleum products involves the use of surface retorts and/or in situ retorting. Regardless of the technique used, sizeable volumes of retorted, or spent shales will be produced and require disposal. Generally, the oil shales are overlain by materials which do not contain oil and must be removed to recover the oil shales. The excavation, handling and environmentally and structurally safe disposal of the spent oil shales and overburden materials will require a knowledge of their geotechnical properties. This paper is a condensed version of a report (1) submitted in November 1981. For additional details, especially the application of these findings to slope design and settlement, the reader is referred to the report.

OBJECTIVES

The primary objective of this study was to characterize the various geotechnical properties of overburden materials, raw oil shales and processed, or spent shales. This information is needed in the commercial development of oil shale for developing environmental regulations, and providing for a means of safely disposing of the overburden and spent shales.

DESCRIPTION OF MATERIALS

Materials received for laboratory testing consisted of two basic categories: overburden materials and oil shales. The second category of materials consisted of the raw, or unprocessed oil shales, the retorted oil shales, the charred oil shales and the combusted oil shales. Brief descriptions of the materials submitted for testing are as follows:

OVERBURDEN MATERIALS

Overburden materials consisted of three shales and a siltstone. Two overburden shales were collected from the Borden and the Bedford formations of Lewis County, Kentucky. The siltstone sample was obtained from the Farmers Member of the Borden Formation in Lewis County, Kentucky. The third overburden shale was obtained from the New Providence Member in Bullitt County, Kentucky. The shale samples obtained from the Borden and Bedford formations consisted of flat light yellow, subangular particles. The siltstone was light olive gray in color, hard, and fine-grained. The New Providence Shale was gray to light yellow in color, very friable, platy and angular.

UNPROCESSED OIL SHALES

Seven oil shale samples submitted for testing were collected from the Sunbury, New Albany, Chattanooga, and the Ohio shale formations. The stratigraphy and composition of these shales are similar. In Ohio, and in Kentucky from Lewis County southwest to the vicinity of Irvine, a wedge of Bedford Shale and Berea Sandstone occurs between the underlying (Ohio) and overlying (Sunbury) black shales. The Ohio Shale has been subdivided into upper (Cleveland) and lower (Huron) members. Beyond the pinchout of the wedge of Bedford sediment the entire black shale interval (equivalent to the Ohio and Sunbury) is referred to as the New Albany Shale. This nomenclature is carried westward through Kentucky and into Indiana and Illinois. To the south, the black shale interval thins considerably and is referred to as the Chattanooga Shale. This nomenclature is used throughout southern Kentucky and Tennessee. Samples of the New Albany Shale were collected from Nelson, Powell, Lincoln, and Bullitt

counties, Kentucky. The Sunbury and Ohio samples were obtained from Lewis County, Kentucky. Samples of the Chattanooga Shale were obtained from Russell County, Kentucky. Particle-shapes of the raw oil shales and the overburden shales were similar. However, the raw oil shales were harder and contained less fines than the overburden shales. The raw oil shales ranged in color from dark yellow to gray and were darker than the overburden shales.

RETORTED SHALES

Six retorted samples were tested. Materials collected for the retorting process were obtained from the Sunbury, New Albany, Cleveland, and Chattanooga shale formations. The New Albany samples were collected from Nelson, Bullitt, and Powell counties, Kentucky. Samples of the Cleveland and Sunbury shales were obtained from Lewis County, Kentucky. The Chattanooga shale samples were obtained from Lincoln County, Kentucky. The double auger steam retorting process was used. Maximum particle-sizes of the retorted shales were smaller and individual particles were less angular than the raw oil shales or the overburden shales. The retorted shales contained little or no fines and were gray to black in color.

CHARRED SHALES

The next group of shales tested were the charred shales produced by the HYTORT process. Materials obtained for the charring process were obtained from the Sunbury, Cleveland, and New Albany Shale formations. Samples of the Sunbury and Cleveland shales were collected from Lewis County, Kentucky. The New Albany samples were obtained from Bullitt County, Kentucky. This group consisted of three shales which appeared to be identical. These materials were composed of much smaller particle sizes and contained fewer fines than the retorted shales. The charred shales were black in color and had an appearance similar to coal.

COMBUSTED SHALES

The last group of shales submitted for testing was the combusted shales and consisted of six materials. These materials were obtained from the Sunbury, Cleveland, New Albany, and Chattanooga shale formations, retorted, and then subsequently combusted. Samples of the Sunbury and Cleveland shales were obtained from Lewis County, Kentucky. Samples of the New Albany shale were obtained from Bullitt, Lincoln, and Powell counties, Kentucky while samples of the Chattanooga shale were collected from Russell County, Kentucky. These were processed in a gasifier with a 5% - 10% excess of oxygen. The combusted group of shales was hard and contained red, black and light gray, sub-angular particles.

TEST SPECIFICATIONS AND RESULTS

The testing program was divided into three categories: 1) material preparation, 2) classification, or physical property tests, and 3) engineering tests. Physical property tests consisted of particle size analyses, liquid and plastic limits, and specific gravity determinations. Engineering tests consisted of moisture content-density determinations, consolidation, permeability, triaxial compression, Los Angeles abrasion, a specially devised, one-dimensional compression test, and slake-durability. Test methods and results are described below.

MATERIAL PREPARATION

Particle sizes of the materials as received for laboratory testing ranged from cobbles, 3 inches in diameter, to fine-grained material passing the No. 200 sieve. The largest particle size that could be accommodated by the 4-inch diameter mold of the triaxial, permeability, and compaction tests was 3/4-inch. For this reason, after removing sufficient material for classification testing, the particle sizes of samples which had particles greater than 3/4-inch were reduced by the scheme outlined in Drnevich, et. al. (2). This procedure maintains the same percentages of gravel in the sample, as contained in the original sample and as received for testing.

PHYSICAL PROPERTY TESTS AND CLASSIFICATIONS

Liquid and plastic limit tests were performed on the shales and overburdens according to ASTM D 423-66 and ASTM D 424-59. The specific gravities of the soil solids were determined according to ASTM D 854-58. Particle-size analysis was determined according to ASTM D 422-63. Particle-size distribution curves for the overburden shales and the raw oil shales are given in Figure 1. The retorted shales and the charred shales are shown in Figure 2. The materials were classified according to both the AASHTO and Unified Soil Classification systems. Specific gravities, liquid limits, plasticity indices, and classifications are summarized in Table 1.

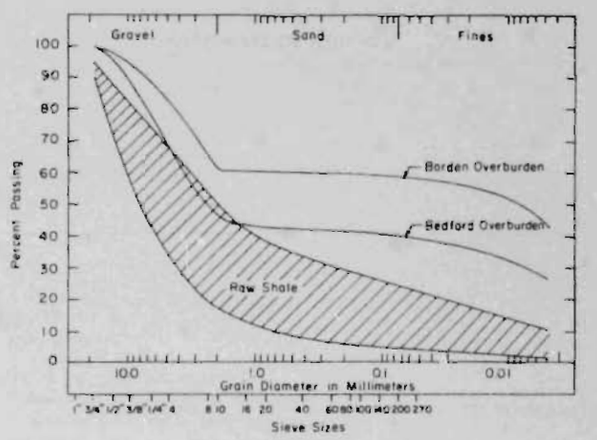

Figure 1. Particle Size Distribution Curves for Overburden Materials and Raw Shale.

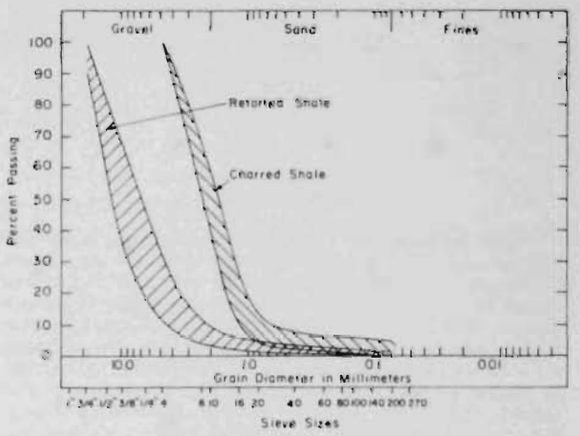

Figure 2. Particle Size Distribution Curves for Retorted Shales and Charred Shales.

ENGINEERING TESTS

Moisture - Density Relationships

Standard compaction tests were performed on the Borden and Bedford overburden shales using two different gradations. One moisture-density curve was developed for the portion of the overburden shales passing the No. 10 sieve. This compaction test was performed on this portion of the sample, instead of the portion passing the No. 4 sieve according to ASTM D 698-70 method A, because particle sizes of the materials as received for testing could not be accommodated in a 2.5-inch consolidometer ring and values of maximum dry density and optimum moisture content were needed for compacting the consolidation specimens. The second set of standard compaction tests were performed on the overburden shales to obtain values of maximum dry density and optimum moisture content which were needed for preparing triaxial specimens. These tests were performed using material that passed the No. 3/4-inch sieve. Because of the limited amount of material available, and because the overburden shales were so friable that each compaction sample could only be used once,

Table 1. Results of Physical Properties tests and Engineering Classifications.

MATERIAL	LIQUID LIMIT	PLASTICITY INDEX	SPECIFIC GRAVITY	CLASSIFICATION AASHTO	CLASSIFICATION UNIFIED	C_u*	C_c**
OVERBURDEN							
Borden (Lewis)	43	17	2.75	A-7-6(8)	CL	-	-
Bedford (Lewis)	37	16	2.68	A-4(6)	SC	-	-
RAW SHALES							
New Albany (Powell)		NP	2.39	A-1-b	GM	15	3.0
New Albany (Bullitt)		NP	2.41	A-1-b	GM	12	2.7
Sunbury (Lewis)	28	3	2.47	A-1-b	GM	680	3.7
Ohio (Lewis)	35	9	2.37	A-1-b	GM	50	2.3
Raw Blend			2.43				
RETORTED SHALES							
Cleveland (Lewis)		NP		A-1-a	GP	3.9	1.2
Chattanooga (Lincoln)		NP		A-1-a	GP	3.3	1.1
New Albany (Nelson)		NP		A-1-a	GP	3.1	1.5
New Albany (Bullitt)		NP		A-1-a	GW	4.0	1.4
New Albany (Powell)		NP		A-1-a	GP	3.2	1.3
Sunbury (Lewis)		NP		A-1-a	GW	4.3	1.2
Retorted Blend			2.54				
CHARRED SHALES							
New Albany (Bullitt)		NP		A-1-b	GP	3.3	1.2
Sunbury (Lewis)		NP		A-1-a	GP	3.0	0.9
Cleveland (Lewis)		NP		A-1-a	GP	2.8	0.6
Charred Blend			2.51				
COMBUSTED SHALES							
Sunbury (Lewis)		NP	2.36	A-1-a	SW	8.1	1.2
Cleveland (Lewis)							
New Albany (Bullitt)							
New Albany (Lincoln)							
New Albany (Powell)							
Chattanooga (Russell)							

*C_u is the coefficient of uniformity
**C_c is the coefficient of concavity

a 4-inch diameter mold was used.

Results of the compaction tests performed on the overburden shales are shown in Figures 3 and 4. Values of maximum dry densities of the overburden shales were less for specimens prepared with material passing the No. 10 sieve than values obtained for specimens prepared using material passing the 3/4-inch sieve. The Borden shale, the overburden which appeared to have the lowest shear strength at standard compaction, was selected for more extensive testing in the triaxial testing phase of the program.

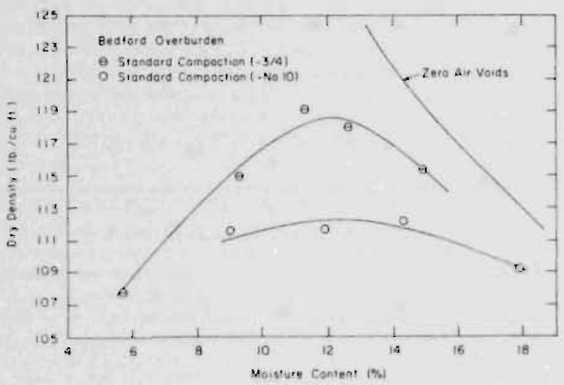

Figure 3. Moisture-Density Curves for Bedford Overburden Shale.

Two other compaction tests were performed on the Borden shale (Figure 4) using compactive energies which were lower and higher than the compactive energy of the standard compaction test. The high-energy compaction test was similar to ASTM 1557-78 method D (Modified Compaction) which uses a 10-pound hammer and an 18-inch drop, except a 4-inch mold was used instead of a 6-inch mold. The low-compactive energy was 20 percent of the compactive energy used in the standard method. This energy was obtained by using 1.84 pound aluminum hammer, 12 inch drop, and a reduced number of blows in a compaction procedure developed for use on mine spoils (2). Specifications of the different types of compaction tests are shown in Table 2.

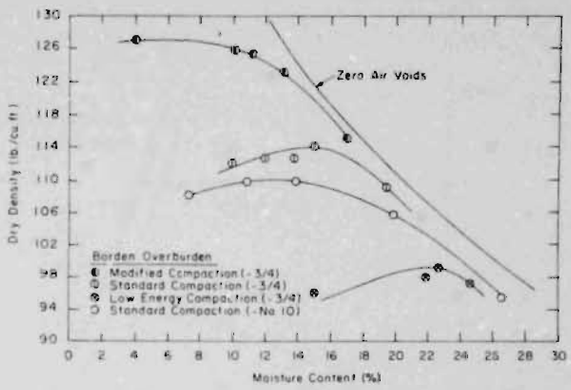

Figure 4. Moisture-Density Curves for Borden Overburden Shale.

Table 2. Compaction Specifications for Compaction and Triaxial Molds

Compaction Technique	Compactive Effort (ft. lb/ft^3)	AASHTO/ASTM Standard Mold (4.0" diameter x 4.584" high)	Triaxial Mold (4.0" diameter x 8.0" high)
Modified	56250		
10 lb hammer 1.5 ft drop		5 lifts 25 blows/lift	8 lifts 27 blows/lift
Standard	12730		
5.5 lb hammer 1.0 ft drop		3 lifts 25 blows/lift	5 lifts 25 blows/lift
Low Energy	2500		
1.84 lb hammer 1.0 ft drop		3 lifts 15 blows/lift	5 lifts 16 blows/lift

Since a limited amount of material from each location and geological formation was available for testing and since the oil shales within each major shale group had essentially the same classification, portions of the oil shales within each major shale group were combined to form a blended shale sample. With the exception of the overburden materials, all engineering tests were performed on a blended sample of each major shale group -- the raw oil shale group, retorted group of shales and the charred group of shales.

The results of the compaction tests on the raw, retorted, and charred oil shale blends are shown in Figure 5. As shown in this figure the retorting process greatly influences the maximum dry density of the samples when compared to the raw shales. The retorting process significantly decreases the maximum dry density of the oil shales while only slightly lowering the optimum moisture content. The process of charring the shales, on the other hand, causes the optimum moisture content to rise considerably while the maximum dry density is also greatly decreased. Maximum dry densities and optimum moisture contents obtained from the various compaction tests for the overburden materials, the raw oil shale blends, retorted blends and charred blended shales are compared in Table 3.

Consolidation Tests on the Two Overburden Shales

Consolidation tests were performed on the portion of the overburden shales -- Borden and Bedford -- passing the No. 10 sieve. This part of the overburden materials was used because any particles larger than the No. 10 could not be accommodated by the testing apparatus, and a specimen composed of only material passing a smaller sieve would not give an accurate representation of the behavior of the material as found in the field.

ASTM standard D 2435-70 was used as the test procedure. The specimens were 1 inch in height by 2 1/2 inches in diameter and were compacted at optimum moisture to the standard maximum compaction density.

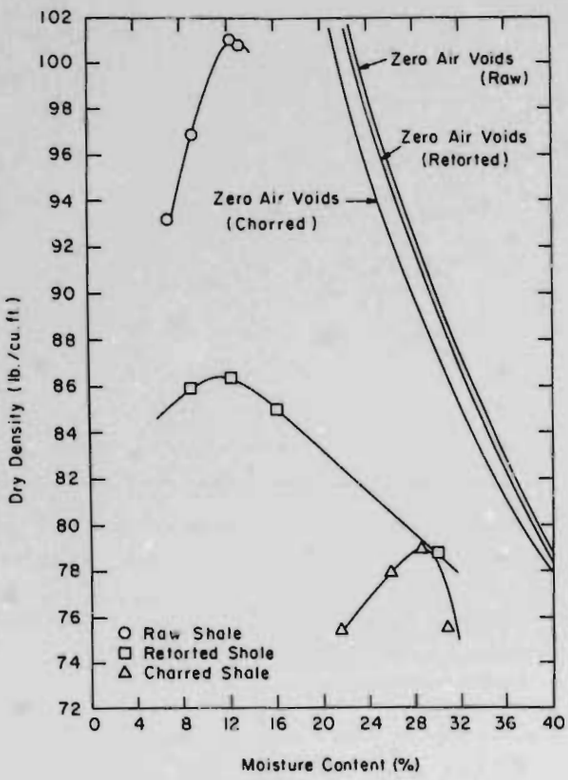

Figure 5. Moisture-Density Curves for the Raw Oil Shale Blended Samples, Retorted Blended Samples, and Charred Blended Samples.

Table 3. Comparison of Maximum Dry Densities and Optimum Moisture Contents Obtained from Compaction Tests Performed on Overburden Shales and Oil Shales.

Material	Size	Compactive Effort	Optimum Moisture Content (%)	Maximum Dry Density (lb/cu ft)
BORDEN				
	-10	standard	13.2	110.1
	-3/4	low	23.2	99.8
		standard	15.5	113.8
		modified	4.2	127.2
BEDFORD				
	-10	standard	12.1	112.2
	-3/4	standard	12.3	118.7
RAW BLEND				
	-3/4	standard	12.6	100.3
RETORTED BLEND				
	-3/4	standard	11.3	86.4
CHARRED BLEND				
	-3/4	standard	29.1	79.1

Void ratio-log of effective stress curves are shown in Figure 6 for the two overburden shales. The log-of-time and the square-root-of-time fitting methods were used to obtain the time corresponding to ninety per cent consolidation and to obtain the coefficient of consolidation, c_v. The average value of c_v obtained from the two fitting methods is also plotted as a function of the log of effective stress in Figure 6 for the two overburden shales.

Permeability

Permeability tests were performed on the overburden shales and on the oil shales, the raw oil shale blends, the retorted oil shale blends, and the

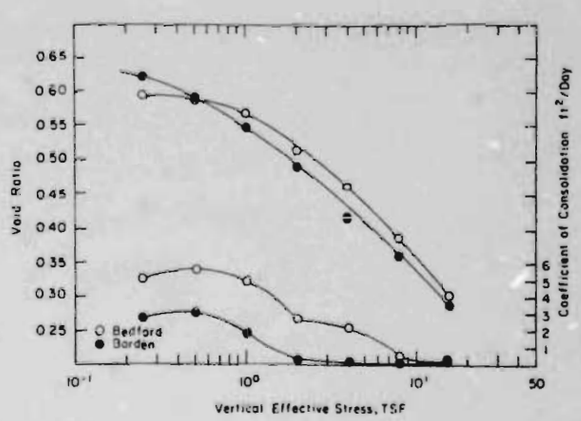

Figure 6. Void Ratio and Coefficient of Consolidation as a Function of Effective Log-of-Stress Obtained from The Consolidation Test on the Borden and Bedford Overburden Shales.

charred oil shale blends. A constant head test used by the Army Corp of Engineers and outlined in their laboratory soils testing manual (3) was used. The procedure utilized a cylindrical specimen confined in a rubber membrane and subjected to an external hydrostatic pressure during the test. This was accomplished by placing the specimen in a triaxial cell where confining and back pressures were applied.

This method of performing the permeability test was selected because of the following reasons: (1) The specimen can be easily formed in the same manner as the triaxial specimens, using the same molds and membranes; (2) the leakage along the sides, which occurs especially in permeameters, is prevented by the cell pressure acting against the wall of the membrane; (3) the specimen can be consolidated to a certain confining stress representing field conditions; (4) back pressure can be applied to the pore water to dissolve air entrapped in the compacted specimens; (5) and the saturation of the specimen can be checked in the same manner as in the triaxial tests.

Results of the permeability tests are given in Table 4. Low permeabilities obtained for the overburden materials were due to the presence of large percentages of fines, i.e. soil particles smaller than the No. 200 sieve. It has long been established that the percentages of fines of a soil have a large effect on its permeability. The results reported herein should be used with caution since these values are ones that represent the soil compacted at the standard compaction density and tested in a saturated condition. The materials also contained particle sizes smaller than 3/4 of an inch. The permeability of the material at any other particle size distribution may be different.

Table 4. Summary of Permeability Results.

Material	As Compacted		As Tested		Permeability
	Dry Density (lb/cu ft)	M.C. (%)	Dry Density (lb/cu ft)	M.C. (%)	k (cm/sec)
BORDEN	113.0	15.2	124.8	16.6	2.9×10^{-8}
BEDFORD	118.6	10.8	120.5	16.3	4.6×10^{-8}
RAW BLEND	-	-	-	-	1.5×10^{-5}
RETORTED BLEND	82.9	15.6	85.4	28.4	1.0×10^{-4}
CHARRED BLEND	77.9	25.9	76.5	39.9	2.3×10^{-3}

Field values of permeability may be different than values given in Table 4 because of the degree of compaction and the percent of saturation. It has been shown that the higher the density of a soil, the lower the permeability; also, the permeability of saturated soil is greater than non-saturated soil. In addition to density and saturation, the water content at which the soil is compacted can also influence the value of the permeability of a soil. The water content of the soil influences its microstructure when compacted

As the water content at the time of compaction increases, orientation of the particles become more parallel due to the compaction. This results in a reduced permeability for the soil.

Triaxial Compression Tests

Stability of a compacted shale embankment can be evaluated using either total stress parameters or effective stress parameters. Generally, effective stress parameters, ϕ', and c' – the effective internal angle of friction and effective cohesion – have more validity than total stress parameters, ϕ and c. Effective stress parameters can be obtained from drained triaxial tests or from undrained triaxial tests if pore pressure measurements are made. With the exception of two consolidated-drained triaxial tests, consolidated-undrained, triaxial compression tests with pore pressure measurements were used to obtain the effective stress parameters for the overhurden shales and the oil shale blends. These tests were performed at a constant rate of axial deformation which was sufficiently small so that pore pressure equalization criteria were satisfied (4). The specimens were compressed at a constant rate of axial deformation of 0.001 inch per minute. The two consolidated-drained triaxial compression tests were performed on the retorted and charred blended samples using the same axial rate of deformation as used in the consolidated-undrained triaxial tests.

The triaxial specimens were compacted to maximum dry density at optimum moisture content determined from the compaction phase of the testing program for the portion of the material passing the 3/4-inch sieve. The specimens measured 4 inches in diameter and 8 inches in height. These dimensions limited the largest particle size to 3/4-inch. Filter paper strips were mounted along the length of each specimen to permit faster equilization of pore water pressure. To prevent air from entering the specimen through the rubber memhrane when the cell pressure was applied, water was used in the chamber as the confining medium.

In performing consolidated-undrained triaxial tests with pore pressure measurements, it is essential that the specimens be saturated to avoid pore pressure lag during the shearing stage. To facilitate saturation and force air bubbles into solution, a back pressure technique similar to one described by Lowe and Johnson (5) was used. After saturation, the specimen was consolidated to the desired effective stress. For the overhurden shales (clayey shales), the time for ninety percent of consolidation to occur was determined from the square-root-of-time fitting method and used to determine when the axial loading of the test could he initiated. When the consolidation pressure was applied to the oil shale specimens, consolidation occurred so rapidly that the volume changes were difficult to obtain as a function of time. To have reasonable assurrances that the specimens were saturated, all were allowed to consolidate for a minimum of 24 hours under the desired back pressure and cell pressure.

Although several definitions of failure may be used to define the Mohr-Coulomb failure envelope, two criteria are commonly used in soils. These criteria are the maximum principal stress difference, or $(\sigma'_1 - \sigma'_3)$ max, and the maximum principal stress ratio, or (σ'_1/σ'_3) max. The latter definition is also known as maximum obliquity. In a drained triaxial test, the two criteria yield the same results, since the minor effective principal stress, σ'_3, is constant and the peak values of $(\sigma'_1 - \sigma'_3)$ and (σ'_1/σ'_3) occur simultaneously during the shearing stage of the test. However, σ'_3 cannot be held constant during the undrained shearing stage when the specimen is fully saturated. For saturated and highly overconsolidated materials, σ'_3 changes during undrained shearing and the peak value of (σ'_1/σ'_3) may occur before the peak value of $(\sigma'_1 - \sigma'_3)$ is obtained. The choice of which failure criterion to use for compacted materials has been discussed by Drnevich, et al (2).

For triaxial test results reported herein, the maximum obliquity failure criterion was used to develope failure envelopes and shear strength estimates of the overburden and oil shales. Triaxial test results are summarized in Table 5. Values of ϕ' obtained for the Borden overburden shale remolded to three different compactive efforts ranged from 26.6 degrees to 30.2 degrees. Essentially the same values of ϕ' --26.6 degrees -- were obtained for the Borden shale specimens compacted at standard and low compactive energies. No cohesion was obtained for the Borden shale at any of the compactive energies. Specimens compacted at a high compactive energy had a ϕ'-value that was 3.6 degrees higher than ϕ'-values of specimens compacted at standard and low compactive energies.

Values of ϕ' and c' obtained for the Bedford overburden shale compacted at standard compaction were 26.3 degrees and 216 pounds per square foot. These values were similar to values obtained for the Borden specimens compacted at low and standard compactive energies.

Table 5. Summary of Triaxial Test Data.

Test No.	Material	Compaction	Effective Confining Pressure (psi)	'B' Pore Pressure Coeff	ϕ' (Degree)	c' (psf)
51	Borden (Lewis)	standard	10	0.88		
52			30	0.88	26.7	0.0
511			45	0.90		
55	Borden (Lewis)	modified	70	0.90		
56			50	0.95	30.2	0.0
57			20	0.98		
58	Borden (Lewis)	low	70	0.97		
59			50	0.98	26.6	0.0
510			20	0.94		
51	Bedford (Lewis)	standard	60	1.00		
52			30	1.00	26.3	216
53			10	0.99		
51	Raw Blend	standard	20	1.00		
52			56	0.93	42.2	317
53			70	0.57		
51	Retorted Blend	standard	70	0.67		
52			50	0.65	*	*
53			20	0.83		
51	Charred Blend	standard	50	0.48		
52			20	0.86	*	*
55			30	1.05		

*A curved failure envelope was obtained for the retorted and charred shale blends. See Table 5.

Blended specimens of the raw oil shales remolded at standard compaction had a ϕ- value of 42.2 degrees and a c'- value 317 pounds per square foot.

Shear strengths of retorted and charred blended specimens remolded at standard compaction were very similar as illustrated in Figure 7. The two linear stress paths were obtained from the drained triaxial tests while the remaining stress paths were obtained from the undrained tests. A curved K_f-line was obtained for these series of tests and ϕ'- values ranged from 45 degrees to 22 degrees. (See next to last column in Table 6.)

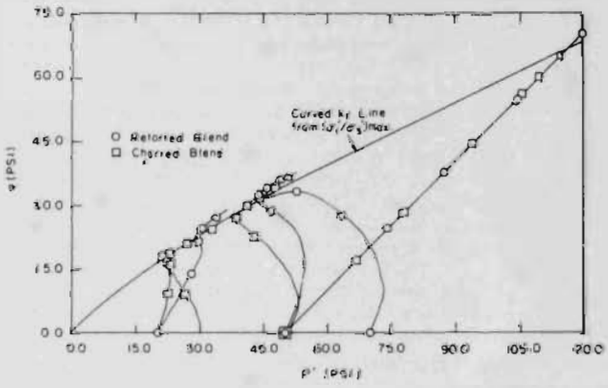

Figure 7. Triaxial p'-q Stress Paths Obtained from Retorted and Charred Blended Specimens Remolded at Standard Compaction.

Abrasion

The abrasion test on the Farmers Siltstone was performed in accordance with ASTM C 131-76, grading B. This test commonly called the Los Angeles Abrasion Test was only performed on the siltstone because the other shales appeared to he of much less hardness. Preparation of the material for testing consisted of breaking siltstone into roughly 3-inch pieces and then reducing it to particle sizes smaller than 3/4-inch using a mechanical crusher. The siltstone was then washed and dried to remove any dust adhering to the sides of the particles. The siltstone was sieved and combined to the required grading.

Table 6. Recommended Design Values of ϕ' for Various Pressures of Embankments Constructed of Charred and Retorted Materials.

p (psi)	q (psi)	$\sin\phi'$	σ_n (psi)	ϕ' curve (Degrees)	ϕ' recommended (Degrees)
10	9.2	0.71	3.5	45.2	36.0
20	16.2	0.68	9.0	42.8	36.0
30	22.8	0.65	15.2	40.5	35.0
40	29.2	0.62	21.9	38.3	34.0
50	35.2	0.59	29.2	36.2	33.0
60	41.0	0.56	37.1	34.0	32.0
70	46.4	0.53	45.4	32.0	31.0
80	51.6	0.50	54.2	30.0	30.0
90	56.4	0.47	63.5	28.0	29.0
100	61.0	0.44	73.2	26.1	28.0
110	65.2	0.41	83.3	24.2	27.0
120	69.2	0.38	93.7	22.3	26.0

The siltstone was then placed in the L. A. Abrasion machine with eleven steel balls. The number and weight of steel balls used depends on the gradiation of the material being tested. The machine was rotated at 33 revolutions per minute for 500 revolutions and then the material was removed. The siltstone was sieved again using the same sieve sizes as used before and subtracting the amount retained on each sieve from the original weight retained on each sieve to calculate the amount of wear. This amount divided by the original weight of the material gives the percentage of wear. The percentage of wear for the Farmers Siltstone was calculated to be 80.

One-Dimensional Compression Tests

One-dimensional compression tests were performed on blends of the unprocessed and processed oil shales. These tests were performed instead of consolidation tests because the oil shales had high permeabilities and excess pore water pressures would dissipate too quickly to give meaningful results. The test consisted of two different phases. The first phase of testing was designed to determine how the material in a dry state performed under one-dimensional loading. The purpose of the second phase was to evaluate creep characteristics of the oil shales when inundated with water.

The procedure for the first phase consisted of compacting the shales to ninety percent of maximum dry density in a 6-inch diameter mold to a height of 2.625 inches. These dimensions were used to minimize the effects of frictional forces acting on the sides of the mold during loading. To simulate field placement, the specimens were compacted in a dry state to ninety percent of maximum dry density. The specimens were loaded and deformations were recorded in a manner similar to the consolidation tests. Loads of 1, 2, 4, 8, and 16 tons per square foot were used. For each load, when the sample deformed less than .0025 inch in two minutes, the next load was applied. After loading to 16 tons per square foot, the samples were rebounded and the dial readings were recorded.

The strain for each load was calculated by dividing the deformation occurring under each load by the original height of the specimen. The stress-strain curves for the three oil shale blends and the Farmers Siltstone are given in Figure 8. A crushed limestone, considered a good construction material, was also tested for comparative purposes.

Creep characteristics of the oil shales were studied by reloading the previously loaded specimen to 4 tons per square foot. The specimen was allowed to compress for approximately fifteen minutes or until all deformation had stopped. The mold and specimen were inundated in water while the stress level remained constant at 4 tons per square foot. The time required to submerge the specimen was less than five seconds. Upon inundation, a timer was immediately started and deformations and elapsed times were recorded. Strains were calculated by dividing deformations associated with time after inundation by the original specimen height before loading. The strains after inundation were plotted as a function of time as shown in Figure 9. After sufficient time had elapsed to show the creep characteristics of the material, (approximately 1,000 minutes) the sample

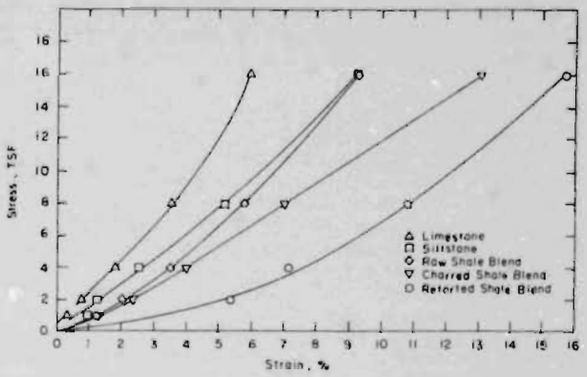

Figure 8. Stress-Strain Curves Obtained from One-Dimensional Compression Tests.

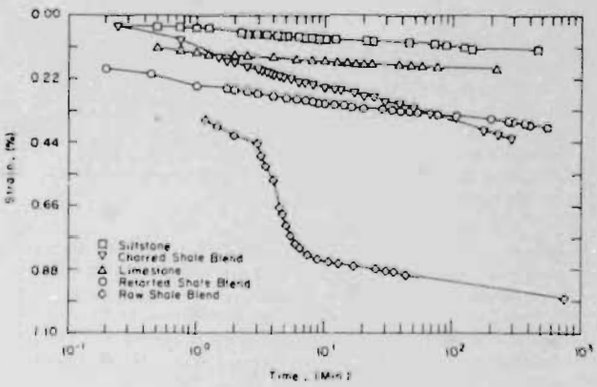

Figure 9. Strain-Time Curves for Inundated One-Dimensional Compression Specimens.

was removed and dried. The samples were observed to be wet throughout when removed. A sieve analysis was performed before and after the test on each material to determine if any appreciable amount of crushing had occurred. Based on particle size curves of the materials obtained before and after testing, no noticeable crushing of the particles was observed. Any slight differences that occurred was attributed to normal variances associated with sampling. Two of the materials tested, siltstone and retorted blend, had low creep on the same order as limestone. The charred blend exhibited slightly greater creep. The raw oil shales exhibited significant creep upon inundation.

Slake-Durability

To evaluate the weathering resistance of the shales, slake-durability tests were performed. The procedure used was a method originally proposed by Franklin and Chandra (6) and modified by Gamble (7). In this method, approximately ten representative pieces of oven-dried shale are selected to be as nearly equidimensional as practical. Each piece weighs approximately 40-60 grams. The material is placed in a rotating test drum which is partially submerged in water. The drum is rotated at 20 revolutions per minute for 10 minutes. The drum is comprised of a 2.00 millimeter standard wire mesh which allows abraded and slaked material to fall into a trough. After the first cycle has been completed, the material retained on the wire mesh of the drum is removed and oven-dried. A first-cycle slake-durability index is computed as the ratio of the oven-dried material remaining in the drum to the total oven-dried material originally placed in the drum. The remaining oven-dried material is placed in the drum and a second, 10 minute cycle is performed. Material retained in the drum is removed and oven-dried. A second and final slake-index is obtained as the ratio of the oven-dried wieght of material retained after the second cycle to the total oven-dried weight originally placed in the drum. Normally the slake-durability index (expressed as a percentage) is reported.

Slake-durability indices obtained from tests performed on the raw oil shales and retorted oil shales are summarized in Table 7. Results obtained for both cycles are shown. Slake-durability tests were not performed on the charred oil shales because the particle sizes of this material were too small. Slake-durability indices of the Borden and Bedford overburden shales were 43.2 and 42.5 percent, respectively. Those shales can be characterized as having very low slake-durability properties. The raw oil shales (New Albany, Ohio, and Sunbury) had slake-durability values in excess of 95 percent. Hence, these shales have very high slake-durability properties. Slake-durabilities of the retorted shales (New Albany, Sunbury, and Cleveland) were also very high, greater than 94 percent. Apparently, slake-durability of the oil shales is not lowered after processing or retorting.

Table 7. Values of Slake-Durability Obtained for the Overburden Shales, the raw Oil Shales, and Retorted Oil Shales.

MATERIAL	CYCLE 1 Initial dry wt (gms)	CYCLE 1 Final dry wt (gms)	CYCLE 1 SDI* (%)	CYCLE 2 Initial dry wt (gms)	CYCLE 2 Final dry wt (gms)	CYCLE 2 SDI* (%)
OVERBURDEN						
Borden (Lewis)	507.74	357.41	70.44	357.41	219.15	43.2
Bedford (Lewis)	508.00	372.11	73.25	372.11	215.97	42.5
RAW SHALES						
New Albany (Bullitt)	197.34	196.27	99.45	196.27	195.51	99.1
New Albany (Powell)	364.40	362.32	99.42	362.32	361.01	99.1
Ohio (Lewis)	172.18	169.47	98.43	169.47	168.82	99.4
Sunbury (Lewis)	197.90	193.69	97.87	193.69	189.81	95.9
RETORTED SHALES						
Sunbury (Lewis)	70.93	70.50	99.39	70.50	70.28	99.1
New Albany (Powell)	169.42	168.20	99.28	168.20	167.45	98.8
Cleveland (Lewis)	97.68	97.09	99.40	97.09	96.72	99.0
Chattanooga (Lincoln)	204.03)	202.91	99.45	202.91	202.11	99.1
New Albany (Nelson)	122.10	121.08	99.16	121.08	120.71	98.9
New Albany (Bullitt)	220.41	212.15	96.25	212.15	209.01	94.8

*Slake Durability Index

ANALYSIS AND DISCUSSION OF RESULTS

PHYSICAL PROPERTIES

Physical properties test data obtained for the oil shales and overburden materials can be used to give a general indication of their desirability for use as an engineering material. Properties such as compressibility, permeability, and shear strength are related to the physical characteristics of the material, such as its particle-size distribution. For this reason, classifications of the materials were made to place a material within a group of materials which have similar engineering properties. The classifications of the overburden materials and oil shales can be used with the engineering use chart devised by Wagner (cf8) to give general physical properties of the shales and their desirability for use as a homogeneous embankment material. This system of rating the desirability of a material for various purposes uses a scale ranging between 1 and 10, where 1 represents the best material and 10 the worst for engineering purposes. Using this system, the Bedford shale is rated as a 3 for use as a homogeneous embankment material, while the Borden shale is rated as a 5. The raw shales have negligible compressibility and a value of 2 as a rating for use as an embankment material. The retorted shale has a rating of 2. The charred and combusted shales has a rating of 3 as an embankment material.

Based on the engineering classifications and the ratings as an embankment construction material, it is obvious that a disposal embankment constructed of the retorted, charred, or combusted materials, should be strong but very pervious. If a disposal embankment is constructed of the overburden material, then it would be weaker, have a medium shear strength, and be impervious. This assumes that the actual materials are identical to the ones tested herein.

MOISTURE-DENSITY RELATIONSHIPS

The results of the compaction tests are shown in Figures 3 thru 5 and summarized in Table 3. If the specific gravities of several materials are the same, in general, the more granular a soil is the lower the optimum moisture content and the higher the maximum dry density. The Bedford shale which as classified as a sandy clay has a maximum dry density higher than, and an optimum moisture content lower than the Borden shale which was classified as a clay of low plasticity.

The standard optimum moisture content of the raw oil shale which was classified as a silty gravel was less than the standard optimum moisture contents obtained for the clay overburden shales. However, the standard maximum dry densities obtained for the overburden shales. Such a result is caused by such factors as different specific gravities, particle-size distributions, and particle shapes.

The retorted shales, which are either poorly- or well-graded gravels, also have a lower standard optimum moisture content and maximum dry density than values obtained for the overburden shales. The charred shales have a greater standard optimum moisture content than any of the materials tested while the maximum dry density was the lowest.

Compactive energy has a significant effect on the compaction results obtained for a given soil. Greater energy supplied in the compacting process causes the optimum moisture content to decrease while the maximum dry density increases. This can be seen in Figure 4 for compaction tests performed with three different levels of energy.

PERMEABILITY

Soils can be classified by their coefficients of permeability, k. One set of classifications have been recommended by Terzaghi and Peck (9). Using this method of classifying soils the overburden shales, which are clays, should have permeabilities less than 10^{-7} cm/sec. This is consistent with the values of permeabilities obtained and reported in Table 4. The overburden shales classify as practically impermeable. It is important to note that in performing the permeability tests on the overburden shales, a well graded shale with a large percentage of the sample passing the No. 200 sieve was used. This is representative of a shale which has been weathered or broken down by abrasive action. If the permeability tests were performed on the overburden shales at a different particle size distribution, then the results would not, necessarily, be the same.

The relative permeability classification for the raw oil shale blend is "low", and this corresponds to coefficients of permeabilities between 10^{-3} and 10^{-5} cm/sec. The classification for the retorted is also low. This classification is often used to describe sand or in this case silty gravels. The permeability of the charred shales is 2.3×10^{-3} cm/sec which would be classified as a "medium" relative permeability. Such a permeability is associated with a soil composed of sand and gravel.

TRIAXIAL TESTS

Overburden materials - The triaxial tests on both the Borden and the Bedford overburdens compacted to 100 percent of standard compaction, yielded similar shear strength parameters (ϕ' approximately 26.5 degrees and c' equal to zero). Two additional series of triaxial tests on the Borden overburden shales at high energy compaction and low energy compaction gave sufficient data to assess the effects of density, as well as confining stress, on shear strength. A normalizing parameter, C_R, was used for density. This parameter was used by Drnevich, et al (2) in a study of Eastern Kentucky mine spoil materials. It is the ratio of the dry density of the test specimen after compaction and consolidation to standard compaction dry densities. Therefore, C_R, or density ratio, includes the effects of volume change associated with the testing process.

The Borden and Bedford data were then combined and analyzed together. Multiple, linear regression analyses were used to establish equations for the abscissae and ordinates of the stress points corresponding to failure. The independent parameters were confining stress, σ'_3, and density ratio, C_R.

Using equations from the above analysis shear strength parameters were determined for standard compaction conditions. The angle of shearing resistance, ϕ', was 26.5 degrees and the cohesion was approximately 100 pounds per square foot. The angle of shearing resistance compares well with values for various mine spoils as shown by the data point labeled "overburdens" in Figure 10.

Values of ϕ' and c' were determined for density ratios, C_R, of 0.95 and 1.05 and were normalized by dividing by their respective values from tests at standard compaction. These compared well with curves from Drnevich, et al (2) on mine spoils. It is obvious that the cohesion is significantly affected by the density ratio whereas the angle of shearing resistance is not affected.

Based on this analysis, a ϕ'-value of 26.5 degrees is recommended for the overburden shales independent of the compaction density. The value of cohesion, on the otherhand, is quite dependent on the amount of compaction. A cohesion of 100 pounds per square foot is recommended for compaction dry densities equal to standard compaction dry densities and a cohesion of zero is recommended for compaction dry densities less than or equal to 90 percent of standard compaction dry densities. For dry densities between 90 percent and 100 percent, linear interpolation may be used to establish the cohesion.

Raw Oil Shales - These materials classified as coarse-grained materials and high shearing strength was to be expected. Results of the triaxial tests gave an angle of shearing resistance, ϕ', of 42.2 degrees and a cohesion of 316 pounds per square foot. These are similar to values reported by Allen (10) for dense graded aggregate. This angle of shearing resistance plots slightly higher than data from Drnevich, et al (2) as shown in Figure 10. For this reason, and because of weathering and variability of the material in the field, it is recommended that the angle of shearing resistance for design, ϕ'_{design}, be limited to 40 degrees.

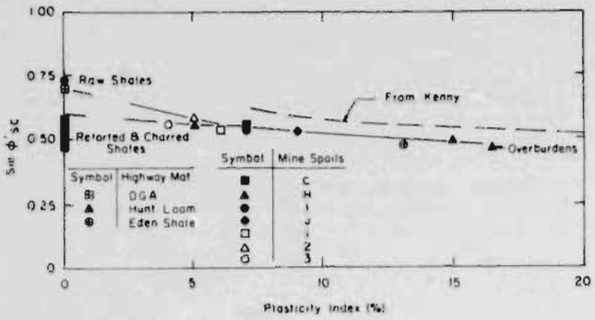

Figure 10. Variation of Angle of Shearing Resistance with Plasticity Index for Materials Compacted to Maximum Dry Density at Optimum Moisture Content by Standard Compaction (After Drnevich et al (1)).

Retorted and Charred Shales - These two materials are handled together because very little difference between the two was noted in the test results. Great difficulty was encountered in performing these tests. Multiple check tests had to be performed and an alternate type of triaxial test was performed. The problems stemmed from the nature of the material. First of all, there were little or no fines and the particles were relatively incompressible which gave a fairly stiff specimen even though the dry densities were quite low. Next, a chemical reaction was observed when water was added to the material. The reaction provided a gas (probably hydrogen sulfide) which also hampered the saturation process. The specimen was considered to be saturated when negligible additional water entered the pore space for an incremental increase in back pressure.

In order to circumvent the back pressuring and saturation problem, two additional triaxial tests were performed on specimens compacted at standard optimum moisture contents and maximum dry densities. These specimens were not saturated but simply tested in the drained condition. Since these materials are very free draining and because proposed regulations (11) require protection of these materials from ground water, it is recommended that drained triaxial tests be used in the future to establish shear strength parameters in terms of effective stress.

Effective stress paths for all triaxial test performed on the charred and retorted blends are shown in Figure 7. Rather than fit a straight line through the data (this would under estimate the shear strength for low fills), a second order least squares curve was fitted through the data. The curved K_f-line gave a cohesion of 280 pounds per square foot and an angle of shearing resistance which ranged from slightly over 45 degrees at low confining pressures to about 22 degrees at very large confining pressures.

For the design of embankments containing these materials, a cohesion of 200 pounds per square foot is recommended when the material is placed at dry densities equal to those of standard compaction. This value should be reduced to zero at dry densities corresponding to 90 percent of those for standard compaction. For intermediate values of dry density a linear interpolation may be used. It is also recommended that values of angles of shearing resistance be dependent on the confining stress within the embankment and that the values of ϕ' for design range from 36 degrees for low stresses to 26 degrees for very high stresses. Specific values of ϕ' design for various pressures are given in the last column of Table 6.

CONCLUSIONS AND RECOMMENDATIONS

The materials tested in this program represent overburdens from several formations, several types of raw oil shales, and spent shales with three different process histories which were termed retorted, charred, and combusted. Conventional index tests used in geotechnical engineering can be performed on all of these materials. The results can be used to classify these materials according to schemes used in soil mechanics. The measured engineering properties of these materials from physical (as opposed to index) tests are in good agreement with the expected properties based on the classifications and geotechnical engineering experience. Hence, the classification systems can be applied to these materials as an aid in determining their physical characteristics and approximate engineering behavior. It is recommended that index tests be used to classify materials from new sites or different processes as a means of establishing estimates of their engineering characteristics.

The overburden materials tested were shown to have low permeability and shear strength and to have medium compressibility. They also have low durability and as a result will break down with weathering from rock-like materials to soil-like materials. In actual mining operations, the overburdens may appear rock-like upon excavation. If placed in fills without processing, they will exhibit medium to high shear strength and high permeability for some time but will eventually breakdown into soil-like materials. Associated with this will be reduced shear strength and permeability, both of which can contribute to slope instability problems. It is recommended that overburden samples at each site be obtained during the actual mining process by use of the equipment actually doing the mass excavation. This material will most likely have a significantly different appearance from the material tested in this program because the means of obtaining the samples are different. The nature of the samples obtained will dictate what processing and what placement procedures will be needed in order that the constructed fills of this material be impermeable and stable over the long term. Most likely, different placement procedures will be needed for mountain top fills than for head-of-the-hollow fills.

The raw oil shales tested have significantly different engineering characteristics from the overburdens. These materials are more durable, less compressible, more permeable, and have much higher shear strengths. It is expected that they would be more difficult to mine but easier to handle. Stockpiles of these shales should not degrade appreciably. Fractions not used in processing could be deposed in fills that could be easily constructed by ordinary techniques. In the long-term, such fills, if properly designed and constructed, should not suffer from excessive settlement or slope failures. However, the geotechnical engineering properties of the materials actually obtained at a given site may vary from those reported herein due to local variations in the natural deposits, particle size distribution, and type of mining processing (transport, crushing, sieving, etc.). Consequently, it is recommended that geotechnical tests be performed on these materials at each site for a given process.

Three spent shales were studied and they were termed: retorted shale, charred shale, and combusted shale. Extensive tests were performed on the first two, but the combusted shale was received too late in the program for any testing but index testing. Visually, the three spent shales appeared significantly different. However, all were quite durable, and they had low compressibilities, high permeabilities, and substantially high shear strengths. The retorted and charred shales had significantly lower dry densities than the raw shales. The optimum moisture contents of these two materials differed significantly (factor of 2.5) which shows that the process used has a major influence on the resultant product. Both possessed an unpleasant odor and appeared to react with the water used in specimen preparation. The reaction produced a gas which hampered the saturation process that was needed for both the permeability tests and the triaxial tests. Nonetheless, good test data were obtained.

Both the retorted and the charred shales exhibited nearly the same shear strength characteristics when the two materials were compacted to

standard, maximum dry densities and optimum moisture contents. The failure envelope for these tests was curved downward, giving high angles of shearing resistance at low confinement and low angles at high confining stresses. Some small cohesion was obtained. Friction angles ranging from 36 degrees to 26 degrees, depending on confining stress, were recommended and a cohesion of 200 pounds per square foot was recommended. More shear strength testing is highly recommended on these materials. The tests should be of the drained type since excess pore pressures will rarely be generated in these materials after disposal in fills. The additional testing should include the effects of the degree of compaction since it is quite likely that densities in disposal fills could differ significantly from standard compaction values. Additional study is also needed on the effects of the chemical reaction on shear strength, compressibility, and permeability. Over the long-term, the physical behavior of the spent shale fill could be substantially altered by ongoing reactions.

ACKNOWLEDGMENTS

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Monday Afternoon Session

PROCESS TECHNOLOGY

Tosco Technology Applied to Eastern U.S. Oil Shales

by

L.R. Pease
Senior Sales Manager, Tosco Corporation
10100 Santa Monica Boulevard
Los Angeles, CA 90067

Abstract. The TOSCO II process was developed to process rich oil shales from the Western United States. Initial development started in 1955. During the period between 1964-72 the process was demonstrated at the 1000 tons/day scale on such shales. This period included a run of 30 consecutive days, a period considered to prove sustained operability. The process will be used to process 66,000 tons/day of shale at the Colony Shale Oil Project in northwestern Colorado. The Colony project is a commercial venture of Exxon and Tosco Corporation which is scheduled to be on stream by late 1985.

Eastern oil shales have several advantages over Western shales, including suitability for strip mining, private land ownership and local availability of refining capacity and infrastructure. To better utilize the Eastern shale and enjoy their advantages, Tosco has been developing spent shale combustion/gasification technology during the past several years. When integrated with the basic TOSCO II process, this technology is predicted to increase TOSCO II processing efficiency by 37% for Eastern shales.

Introduction

In the United States, oil shale occurs primarily in two locations, the Devonian and Mississippian deposits of the eastern U.S. and the Green River Formation located within the western states of Colorado, Utah and Wyoming (see Figure 1). It is believed the Green River Formation contains the largest concentration of potentially recoverable shale oil in the world. This formation is found in several distinct geologic basins, the Piceance, Uinta, Green River, and Washakie. The Piceance Basin, located in Western Colorado, is among the richest deposits (see Table 1) and is also one of the more intensely explored geologic regions in the United States.

Tosco Corporation was founded in 1955 for the purpose of developing a commercially applicable process for producing oil from western oil shale in the United States where large scale, continuous processing is required in order for a project to be economically viable. Since that time, the Company has become a major holder of shale lands in the western U.S., including major equity positions in two commercial shale oil projects in the U.S. -- the Colony Project in Colorado, a joint venture of Tosco and Exxon, and Tosco's own Sand Wash Project in Utah. Tosco also has completed the development and demonstration of its oil shale technology, and is participating with others in oil shale studies in several countries outside of the United States.

Table 1

	Area Overlain By Shale Thous. Acres	In-Place Oil Bil. Bbl.	In-Place Oil Thous. Bbls. Per Acre
Devonian & Miss. Shale	160,000	1,000	6
Green River Formation	10,000	1,800	175
Piceance Creek Basin	800	1.080	1,350

In addition, Tosco also operates four conventional oil refineries with an aggregate capacity of 260,000 barrels per day. Revenues of nearly $2.4 billion were booked in 1980.

The TOSCO II process was selected for development because of its potential for overcoming the disadvantages of gas combustion-type retorting processes for retorting the oil shales in Colorado and Utah. In 1957, after bench-scale studies of the TOSCO II process were completed, a 25-ton-per-day

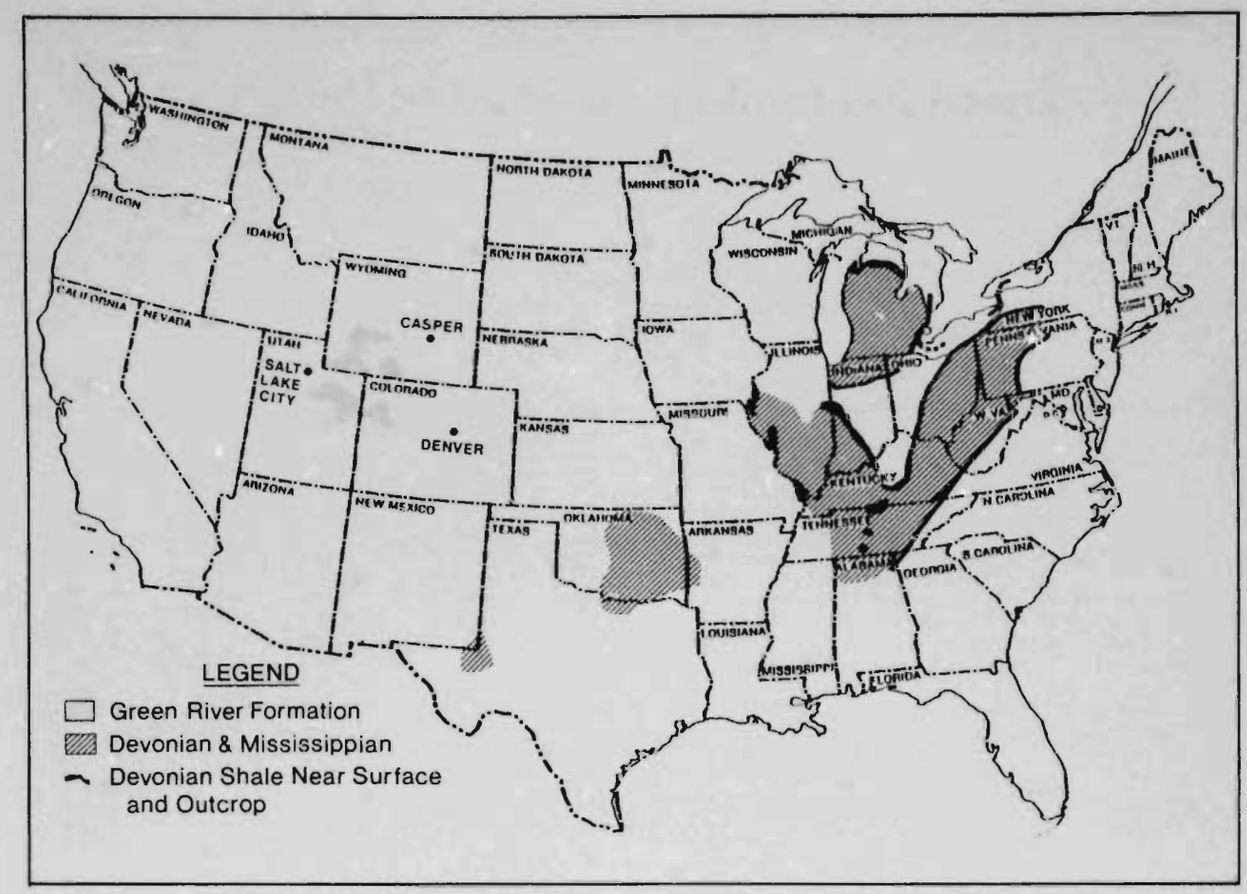

Figure 1. U.S. Oil Shale Deposits

pilot plant, featuring a rotary drum retort was constructed in Denver, Colorado. This plant now is located at Tosco's Research Center at Golden, Colorado.

Successful operation of the pilot plant and a favorable initial design and cost estimate for a commercial-scale facility led to construction of the 1,000 ton-per-day semi-works plant at the Colony project site. This semi-works plant (shown in Figure 2) is located on Parachute Creek, 15 miles north of the town of Parachute in northwestern Colorado. Construction was completed in 1965. Testing of the semi-works plant in 1965-67 confirmed operability of the process and showed that the process recovers 100 percent of the Fischer Assay hydrocarbons. At the conclusion of the initial operating period, Tosco retained an engineering contractor to review the results of operations and to prepare designs for the major equipment items to be included in a 66,000 ton-per-day commercial scale shale oil complex utilizing six parallel 11,000 ton-per-day TOSCO II retorts. This design study, completed in 1968, verified the viability of the process and resulted in recommendations for modifications of the detailed design of some of the equipment in the semi-works plant in order to reduce scale-up uncertainties and improve pollution control performance.

A second operating phase began in 1969 after plant modifications were made to implement these recommendations. The second operating period was successfully completed in April 1972, and included acquisition of further data for design of the commercial scale retorting units. During the two operating periods, the plant processed some 220,000 tons of shale and produced 180,000 barrels of crude shale oil. In addition, another one million tons of oil shale ore was extracted from the pilot mine at the Colony Project site during full-scale tests of mining equipment and techniques and mine design for the commercial project.

TOSCO II

The TOSCO II oil shale retorting process, which is based upon the principles of pyrolysis, uses an inert heat carrier mixed with crushed oil shale, 1/2" and smaller, in a rotary drum retort to pyrolyze, or liberate by heat, the kerogen in the shale matrix. The heat carrier is intimately mixed with the shale in the retort. Heat transfer is relatively rapid and complete pyrolysis of the shale takes place. The process recovers all of the hydrocarbon which can be volatilized from the shale through pyrolysis. In addition to the rotating drum retort, which is the heart of the TOSCO II process, the process also includes: 1) separation of the

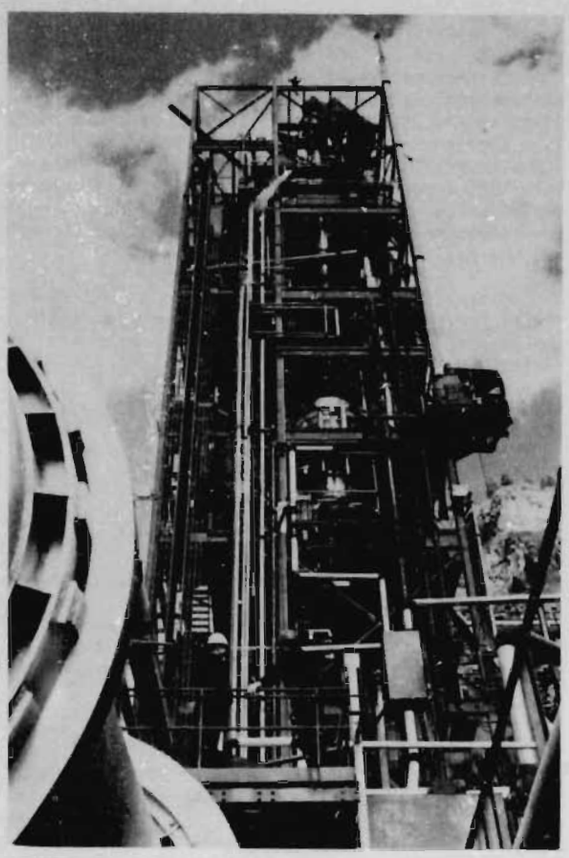

Figure 2. Semi-works Plants Located on Parachute Creek at the Colony Project Site.

spent shale from the heat carrier; 2) recirculation and heating of the heat carrier; 3) recovery and utilization of heat from volatile hydrocarbons, spent shale and flue gases; 4) condensation of the oil product; and 5) treatment of spent shale for disposal. The TOSCO II process is shown in Figure 3.

In the retorting section, oil shale which has been crushed to -1/2", dried and preheated is mixed with the inert heat carrier. The crushed shale and the heat carrier, ceramic balls, mix thoroughly as the retort rotates. Heat is transferred from the ceramic balls to the oil shale to heat it to approximately 900°F. The ceramic balls and shale reach thermal equilibrium in the retort. At this temperature, complete pyrolysis of the oil shale is rapid and assured, and the kerogen contained in the shale is vaporized. The ceramic balls are separated from spent shale by screening the balls and elutriating the spent shale. The balls are then lifted by a skip hoist and recycled to a heater. This ball heater is fueled with either oil or gas, and heating of the ceramic balls is accomplished by direct contact with hot combustion gases. After reaching a temperature above 1100°F, the balls are recirculated to the retort. The flue gases from the ball heater are then used to preheat the incoming raw shale in a series of lift pipes. Heat transfer between the flue gas and the shale is efficiently accomplished in the preheat section by direct contact of the shale feed with the flue gases. The gases are discharged from the preheat section at approximately 250°F and then scrubbed before going to the atmosphere. Spent shale, which leaves the retort at approximately 900°F, is cooled in a rotary tube steam generator and then moisturized for disposal. Waste waters and aqueous sludges are utilized to quench the spent shale and to moisturize it to ensure dust-free handling and to facilitate compaction.

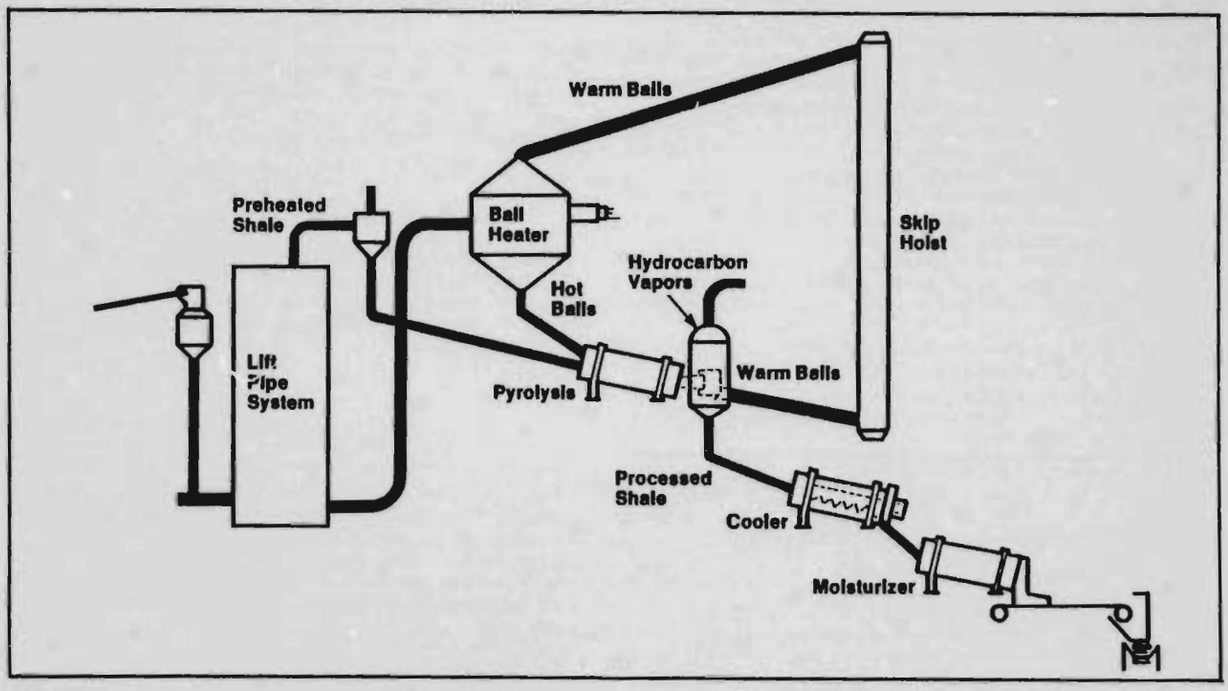

Figure 3. Pyrolysis Unit TOSCO II Process.

Hydrocarbon vapors, which also leave the retorting section at approximately 900°F, are condensed in an oil recovery section which for the Colony plant includes a conventional fractionator. In the oil recovery section, the oil vapor is cooled to separate the C5+ streams from the gases. The non-condensable gases from retorting have a high heating value, contain recoverable liquified petroleum gas (LPG) components, and are suitable for upgrading to hydrogen or synthetic natural gas or for use as plant fuel. Steam is generated from the sensible and latent heat of the hot oil vapors. The oil recovery unit can be designed to produce oil products of the optimum boiling ranges or a whole oil for upgrading.

Stringent emission and air quality regulations are met by conventional emission control processes. The low level of emissions from plant gas streams has been demonstrated at the semi-works plant. Emissions of sulfur and nitrogen oxides are controlled by selection of fuels used in the process and, in the case of nitrogen oxides, the configurations and firing temperatures of process heaters.

The Colony Shale Oil Project, a joint venture of Exxon Company USA, and Tosco, will use six parallel 11,000 ton/day TOSCO II retorts to process 66,000 tons/day of Colorado shale into 47,000 BPD of upgraded oil. Site work for the project and an associated community to house the workforce and others attracted to the region commenced in mid-1980. By the end of this year, a large percentage of the mechnical specifications for engineered equipment in the TOSCO II retorting unit will be completed. Additionally, procurement of key crushing and material handling equipment has commenced, and process design of all facilities within the complex is at an advanced stage. The facility is scheduled to start up in late 1985.

As stated above, the Colony project will produce 47,000 BPD of upgraded oil. However, this is based on the owners' selection of a particular upgrading scheme and does not really indicate the effectiveness of TOSCO II in liberating oil from shale. Looking at just the pyrolysis unit, the TOSCO II process produces 56,325 BPD from 66,000 TPD of 34.8 gpt Colorado shale. This is 103% of Fischer Assay yield. For a moist, foreign shale - 20 gpt and 8% moisture, the net liquid production from 66,000 TPD would be 28,540 BPD. The 28,540 BPD has already been debited for the energy used in drying the shale. For a 12.5 gpt Eastern shale, the net liquid production would be 28,164 BPD, which consists of 23,034 BPD of C5+ shale oil and 5,130 BPD of LPG liquids. Therefore, the TOSCO II process can recover 117% of Fischer Assay oil (C5+) and, in addition, the recovery of 5,130 BPD of LPG boosts total liquid production for Eastern shale to 143% of Fischer Assay. The information in this paragraph is summarized in Table 2.

Table 2

TOSCO II RETORT YIELDS FOR DIFFERENT SHALES

Source	Grade, GPT	% Moisture	Net Liquids, BPD
Kentucky	12.5	2.0	28,164
Morocco	20.0	8.0	28,540
Colorado	34.8	1.5	56,325

Basis: 66,000 TPD of raw shale

Eastern Oil Shales

Eastern oil shale occurs essentially in eleven eastern and southern states and encompases the Devonian and Mississippian deposits. Eastern shale is a true marine shale. The shale was formed 330-360 million years ago by rivers carrying organic materials into the Chattanooga Sea. The sea had no outlet which created a stagnant condition. This led to depositions of organic-rich black shales throughout the basin[1].

Mineral composition of the Devonian oil shales, the richer shale in the deposit, is predominantly quartz and illite, with substantial amounts of pyrite and marcasite.

Devonian oil shale differs from western U.S. shales in the following ways:

1. Devonian shales exhibit a greater degree of uniformity in the composition of the mineral matrix[2].
2. They contain 0.5% mineral carbonate versus 48% for western shales.
3. Retorting Devonian shales does not appreciably alter thermal conductivity[2] while for Green River shales it decreases 30 to 40%[3].
4. Thermal diffusivity of the Devonian shale is approximately half[2,3] that of Western shales.
5. For approximately the same organic carbon content, Devonian shales contain only 2/3 the hydrogen.
6. Devonian shale oil yields per ton are appreciably less.
7. Devonian shales yield more gas.

Given the tremendous land area encompassed by Eastern oil shale, some guidelines must be used to pinpoint areas where commercial development would be most likely to take place. The criteria used by IGT to identify these areas were:

- Organic carbon content in excess of 10 weight%;
- Overburden thickness of less than 200 feet;
- Stripping ratio of less than 2.5 to 1;
- Rock unit thickness of 10 feet or greater.[1]

IGT's resulting analysis located the best areas primarily along the Devonian outcrop and concentrated in Ohio, Kentucky, Tennessee, and Indiana. Table 3 shows a summary of these estimated resources of the four states. Note that as opposed to the average yield for the entire formation of 6,000 barrels per acre, these four states average 45,000 barrels per acre and Ohio, with 56 billion barrels of recoverable reserves, averages 89,000 barrels per acre.

Table 4 shows more detailed data about the deposits in each state. Comparing the Fischer Assay data with that of the Piceance Basin, it is clear

that development of this resource will require a significant increase in the price of oil. However, Eastern oil shale has several advantages over the Western U.S. shales that will push development. Among these are the facts that:

- The shale can be strip-mined;
- The land is mostly privately owned;
- More water is available for processing;
- More refining capacity is located nearby; and
- More infrastructure is available.

Table 3

ESTIMATED RESOURCES OF SHALE OIL IN OHIO, KENTUCKY, TENNESSEE AND INDIANA

State	Total Area Suitable for Surface Mining sq. mi.	Reserves Recoverable By Aboveground Retorting Billion Bbl	Bbl/Acre
Ohio	980	56	89,000
Kentucky	2650	76	45,000
Tennessee	1540	18	18,000
Indiana	600	16	42,000
TOTAL or Average	5770	166	45,000

Adapted from "Devonian Oil Shale" by Janka & Dennison; presented at the 1979 IGT Symposium

TOSCO II With Fluid Bed Boiler

Given the advantages for commercial development of Eastern oil shale, the existence of a significant commercial resource, and the high organic carbon content of Devonian spent shale, Tosco has made a modification to its basic TOSCO II process configuration shown in Figure 3. The modification (see Figure 4) incorporates a fluid bed boiler to recover the energy value of the residual organic carbon on the spent shale. The spent shale is routed from the accumulator through the fluid bed boiler. As Devonian shale is relatively dry, 2 wt% water, all of the energy on the spent shale can be converted to electricity by generating steam in a fluid bed boiler and using it to drive turbo generators. It is also possible to optimize the steam system and use extracted steam from the turbines elsewhere in the process. After passing through the fluid bed boiler, the spent shale (now an ash) passes through a cooler generating additional steam, and then to the moisturizer before going to disposal.

For a 12.5 gpt Eastern shale, the addition of the fluid bed boiler to the TOSCO II process enables export of 127 MW, net, and thus the overall efficiency of the process is increased by 37%. This modification to TOSCO II for combusting the high carbon spent shale results in a process which can produce total liquid products which are 143% of Fischer Assay and also generate a significant quantity of exportable electrical power.

Table 4

RESOURCE DATA

State	Rock Unit	Thickness - Feet	IGT Data Wt% Carbon Average	IGT Data Wt% Carbon Maximum	Published Data Fischer Assay gallons/ton Average	Published Data Fischer Assay gallons/ton Maximum	Estimated Recoverable Resources Billion Barrels
Ohio	Cleveland	60 to 100	10.6	12.6	10	15	56
	Huron	300	7.0	11.9	10	10	
	Lower Huron	100	10.0	11.9	10	10	
Kentucky	Ohio	40 to 100	10.6	17.9	10	23	76
	Sunbury	30	12.6	19.7	10	12	
	New Albany	70	12.5	15.8			
	Chattanooga	40 to 60	13.0	14.1	10	18	
Tennessee	Chattanooga	5 to 50	13.6	19.1	12	42	18
Indiana	New Albany	100 to 300	10.1	15.6	9	13	16
	Clegg Creek	40	14.4	15.6			

Adapted from "Devonian Oil Shale" by Janka & Dennison; presented at the 1979 IGT Symposium - "Synthetic Fuels From Oil Shale".

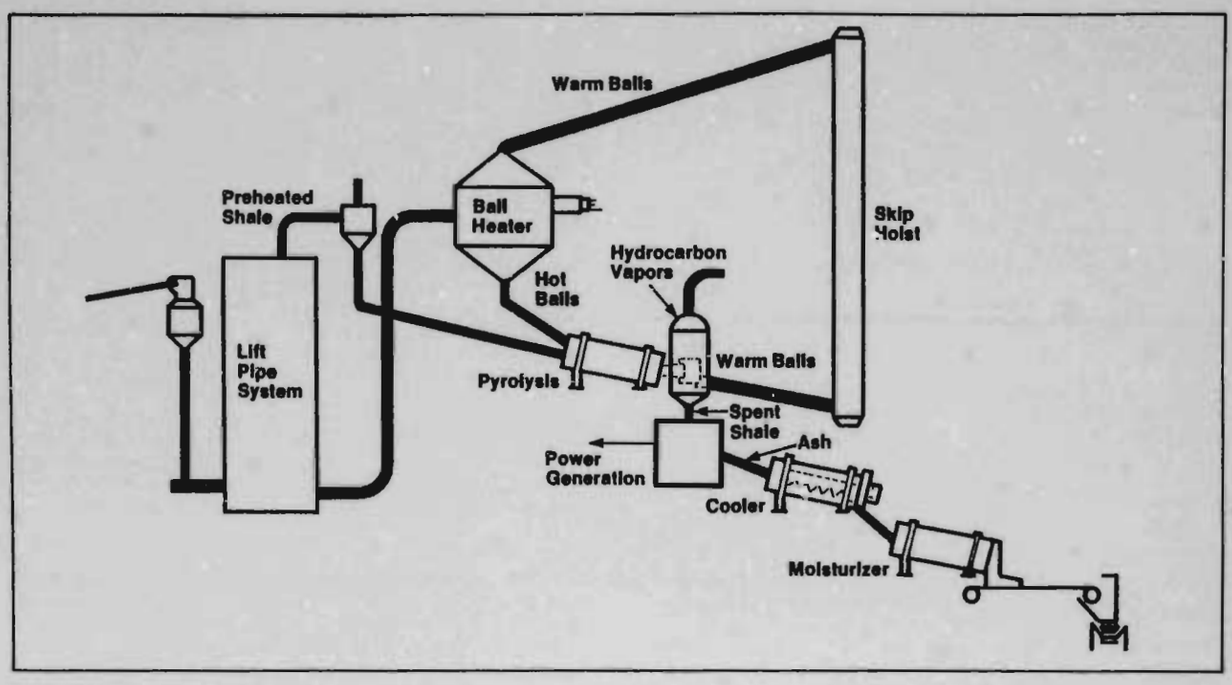

Figure 4. Pyrolysis Unit TOSCO II Process Modified to Produce Power.

Conclusion

Given the size of the Devonian oil shale resource, the inherent advantages of development in the region, and the estimated increasing shortfall of world crude production, Tosco believes that commercial development of the Devonian shales will occur. To this end, Tosco has been developing a modification to its basis TOSCO II process configuration which increases overall efficiency and produces significant amounts of power. The combination could lead to commercial development of Devonian shales via the TOSCO II technologies in the near future.

References

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Description of the T^3 Process and Its Applicability to Eastern Oil Shale

by

Dr. Chang Yul Cha
Science Applications, Inc.
Golden, Colorado 80401

Abstract. The Kingdom of Morocco has embarked on a development of their extensive oil shale resources to decrease future dependence on foreign petroleum imports and to support internal industrial growth. The Office National de Recherche of D'Exploitation des Petroleum has selected the T^3 semi-continuous surface retorting process, which has its roots in the extensive batch processing experience in the U.S.A. on the N-T-U process and the DOE 10-ton and 150-ton retorts. The T^3 process retains the salient features of the N-T-U batch retorting process while adding significant improvements based on recent technology development.

The presentation will give the detailed description of the T^3 process, the comparison of the T^3 process with other oil shale processes, and the applicability of such a process to the Eastern oil shale. The presentation will also review the retorting characteristics of Eastern oil shale and compare them to the characteristics of Moroccan shale.

General

The Kingdom of Morocco has embarked on development of their extensive oil shale resources to decrease future dependence on foreign petroleum imports and to support internal industrial growth. Morocco has substantial oil shale deposits, with the most significant being those of Timahdit, Tarfaya, and Tanger having estimated resources of 15 billion, 30 billion, and 3 billion barrels, respectively. From results of many years of study to choose the appropriate process to be used for the commercialization of Moroccan oil shale, the National Office of Petroleum Research and Development of Morocco has elected to develop the T^3 semi-continuous surface retorting process, which has its roots in the extensive batch processing experience in the U.S.A. on the N-T-U process and the DOE 10-ton and 150-ton retorts. The T^3 process retains the salient features of the N-T-U batch retorting process while adding significant improvements based on recent technological developments. The purpose of this paper is to describe the T^3 process in comparison to other oil shale processes in use or under development. Many distinct advantages of the T^3 process may make it possible to apply it to an Eastern oil shale deposit.

Oil shale is a nonporous, impermeable, inorganic component mixed with an organic polymer called kerogen. The oil shale at various locations has a different composition.

A typical inorganic mineral composition of Moroccan oil shale and of Colorado oil shale (Mahogany zone shale) is shown in Table 1. At present, an enormous amount of work has been done on Colorado oil shale; but a very limited amount of information is available on the Eastern oil shales.

Table 1. Inorganic Composition of Oil Shale

Mineral	Weight % Moroccan Shale	Weight % Colorado Shale
Dolomite ($CaMg(CO_3)_2$)	16.9	32
Calcite ($Ca\ CO_3$)	41.5	16
Quartz (SiO_2)	19.5	15
Illite ($(OH)_4K_2(S)_6Al_2)Al_4O_{20}$), Clay	---	19
Argiles (Illite-Kaolinite)	13.4	0
Albite ($NaAlSi_3O_8$)	---	10
Pyrite (FeS_2)	1.8	1
Analcite ($NaAlSi_2O_6 \cdot H_2O$)	---	1
$FeCO_3 + Fe_2O_3$	1.8	---
TiO_2 + phosphate	2.4	---
Microcline ($KAlSi_3O_8$)	---	6
Other Compounds	3.7	---
Total	100%	100%

Since the inorganic mineral composition of Eastern shale is not available, the composition of ash produced from combustion of oil shale will be used for comparison. Table 2 shows the compositions of ash produced from combustion of Eastern shales from three different locations (1). Compositions of Colorado and Moroccan shale ash are also shown in Table 2 for comparison.

It can be seen in Table 2 that the Eastern oil shale has a much lesser amount of inorganic carbonates (dolomite and calcite) and a much higher concentration of silicate than those in the Colorado and Moroccan shale. Since thermal decomposition of dolomite and calcite are highly endothermic reactions, the control of maximum retort temperature would be much more difficult for the Eastern oil shale than for the Colorado and Moroccan shale, when the combustion process is used for retorting.

The oil shale contains varying amounts of kerogen ranging from a trace in lean beds to about 46% by weight in shales from selected thin sections assaying 80 gallons of oil per ton. The elemental composition of the kerogen in the oil shale is remarkably uniform within the region. The structural distribution of the kerogen in the oil shale varies significantly from region to region. The thin section microphotos of Moroccan Timahdit oil shale show that the organic compound is not intermingled with inorganic mineral matrix, while the organic compound in the Colorado shale appears to be inside the inorganic carbonate matrix.

A typical composition of Eastern oil shale is not presently available but Fischer assay data published in Reference 1 was used to derive the kerogen composition of the Devonian oil shale. Table 3 shows the kerogen composition of the Devonian oil shale. Typical compositions of kerogen for Moroccan and Colorado shale is also presented in Table 3 for comparison. The concentrations of sulfur and oxygen in the Eastern shale are higher than those of Colorado shale, but lower than those of Moroccan shale. Table 3 also shows that the kerogen in Moroccan shale has a much higher sulfur and oxygen content and a lower hydrogen content.

When oil shale is heated to about 400-500°C, the kerogen decomposes to form the oil, gas, water, and carbonaceous residue left on the shale. The composition of products is dependent on the reaction temperature, residence time, and heating rate. The composition of products from thermal decomposition of kerogen obtained when the shale is heated with the heating rate specified in the Fischer assay analysis procedure is shown in Table 4. The products of Devonian shale shown in Table 4 were obtained from Fischer assay data given in Reference 1.

It can easily be seen in Table 4 that for the given amount of kerogen, the Eastern oil shale produces a much greater amount of residual carbon left on the spent shale and less oil than Colorado shale. The Eastern shale also produces more gas and water than Colorado shale. Moroccan oil shale also produces a much greater amount of water and residual carbon than Colorado shale.

The distribution of products from the retorting of Eastern shale is also dependent on the retorting gas. Table 5 shows the distribution of products produced from retorting of Devonian oil shale with hot nitrogen and with a mixture of 75% nitrogen and 25% steam using the controlled state retort at the Laramie Energy Technology Center (2). The temperature of inlet gas was maintained at 1000°F. As shown in Table 5, the steam increases the oil production, but decreases the gas production.

Table 2. Oil Shale Ash Composition (Wt %)

Component	Eastern Shale			Moroccan Shale	Colorado Shale
	Sunbury	Cleveland	Huron		
SiO_2	63.7	66.6	64.4	33.70	42.35
Al_2O_3	16.7	16.4	16.6	8.90	13.03
CaO	0.4	0.6	0.9	36.12	23.06
MgO	1.5	1.3	1.3	4.48	9.88
Fe_2O_3	8.7	6.8	7.9	3.58	4.52
K_2O	4.4	4.3	4.3	1.56	2.31
Na_2O	0.4	0.5	0.5	0.41	3.06
TiO_2	0.8	0.9	0.9	0.40	---
SO_3	3.4	2.6	3.2	6.17	1.79
P_2O_5	---	---	---	1.66	---
Other Compounds	---	---	---	3.02	---
Total	100.0	100.0	100.0	100.00	100.00

Table 3. Elemental Composition of Kerogen

Element	Weight % Devonian Shale	Moroccan Shale	Colorado Shale
Carbon	74.4	69.20	80.5
Hydrogen	9.6	6.56	10.3
Nitrogen	2.7	2.91	2.4
Sulfur	3.8	8.43	1.0
Oxygen	9.5	12.90	5.8
C/H	7.75	10.55	7.82

Table 4. Composition of Products From Kerogen Thermal Decomposition

Product	Weight % Devonian Shale	Moroccan Shale	Colorado Shale
Oil	33.1	43.01	65.63
Gas	18.7	15.75	16.15
Residual Carbon	42.8	30.80	18.22
Water	5.4	10.44	---

Table 5. Composition of Products from Retorting of Antrim Oil Shale (Wt%).

Product	Retorting With Hot N_2	Retorting with Mixture of 75% N_2 and 25% Steam
Oil	22.2	27.9
Gas	32.9	25.0
Residual Carb.	35.2	35.7
Water	9.7	11.4

Because of the higher concentration of residual carbon in the spent shale, it is expected that for the same grade of oil shale and operating conditions the maximum temperature for Eastern shales will be much greater than Colorado shale when the combustion process is utilized for retorting. It is also expected that the oil yield will be higher than Colorado shale for the same Fischer assay oil shale and operating condition due to a higher content of residual carbon in the spent shale.

From Table 4, it may be concluded that processes that are particularly attractive for use with Eastern and Moroccan shales are those capable of utilizing the residual carbon left in the retorted shale.

Development of T^3 Process

There are twenty or more identified oil shale processes in use or under development around the world (3), but at the present time, no single process has been universally accepted or demonstrated as an optimum solution to the shale oil production problems. Furthermore, none of the processes have been sufficiently developed to today's commercial scale. When scaling up a plant to commercial size, consideration must not only be given to the individual scale-up factor of the component equipment, but also to the overall capacity scale-up factor due to the synergistic effect of scaling up multiple components. Therefore, a simple capacity scale-up factor provides a good guideline for the anticipated difficulties associated with plant scale-up. Of course, even with the same capacity scale-up factor, it would be more difficult to scale-up more complex processes than to scale-up inherently less complex processes. A comparison of demonstrated sizes to the sizes required for commercial scale is presented in Table 6.

It can be seen in Table 6 that among the surface processes only the N-T-U type and Petrosix processes have been demonstrated at scales within an order of magnitude of commercial size. The development of the Union A process has been discontinued in favor of the development of Union B and Union SGR processes. The Petrosix is an energy inefficient process since it uses the gas and oil products for process heat and discarding the carbon on the spent shale. The amount of residual carbon remaining on the spent shale after retorting represents a significant energy value, especially for the Moroccan shale, as shown in Tables 7 and 8. The energy contained in one ton of 17 gallon per ton Moroccan shale is about 28% greater than Colorado shale. This additional energy is contained mainly in the residual carbon. The residual carbon produced from Moroccan shale contains over 33% of the total energy, which will be wasted unless utilized in the process, such as in direct heating processes.

Table 6. Commercial Vs. Demonstrated Scale

Oil Shale Process	Demonstrated Scale Tons/day	Commercial Scale Tons/day	Scale Factor
NTU Type (T^3 Process)	170	1,000	6
Paraho Direct	250	7,500	30
Union Oil A	1,200	10,000	8
Union Oil B	6	10,000	1,667
Union Oil SGR	3	10,000	3,333
Superior Oil	250	22,000	88
Petrosix	2,200	10,000	5
Tosco II	1,000	11,000	11
Lurgi-Ruhrgas	12	8,250	688
VMIS (Oxy Retort 3E)	60	2,100	35
VMIS (Oxy Retort 6)*	1,460	2,100	2

* Oil recovery was 63% of predicted oil yield which was based on Retort 3E data.

Table 7. Amounts of Oil, Gas, and Residual Carbon Produced From Retorting One Ton of 17 gpt Oil Shale.

Product	Weight (lbs/ton) Moroccan Shale	Colorado Shale
Oil	136.51	130.75
Gas	49.98	32.17
Residual Carbon	97.75	36.30
Total	284.24	199.22

Table 8. Energy Contained in Retorting Products From One Ton of 17 gpt Oil Shale.

	Moroccan Shale		Colorado Shale	
Product	Btu	Percent	Btu	Percent
Oil	2,263,609	54.3	2,323,166	71.4
Gas	523,291	12.6	419,947	12.9
Residual Carbon	1,379,037	33.1	512,113	15.7
Total	4,165,937	100.0	3,255,226	100.0

Another process which has been tested closest to the commercial scale is the vertical modified in-situ (VMIS) process. A retort having its dimensions of 36 feet in diameter and 113 feet in height, has been successfully built and operated by Occidental. The oil yield, however, was only 63% of the predicted amount. The major reason for this lower yield was attributed to the maldistribution of gas flow caused by uneven radial distribution of particles and void volume.

The retorting process of VMIS is almost identical to the N-T-U process. It may, therefore, be concluded that the largest size that has been built and operated successfully up to date without wasting the energy value in the residual carbon is the N-T-U type retort. In addition, the Laramie Energy Technology Center of DOE has been conducting retorting experiments for almost the last 20 years using 10-ton and 150-ton retorts which simulate the N-T-U and VMIS processes. The Lawrence Livermore Laboratory has also been conducting the similar retorting experiments using two pilot retorts (125 kg retort & 6000 kg retort) since 1974. The Occidental and Lawrence Livermore Laboratory have also developed the mathematical model for the N-T-U type retorting process and have successfully tested the model against the pilot plant data. Therefore, the N-T-U type oil shale process has been experimentally and theoretically tested or studied for the longest period of time on the largest scale among all oil shale processes which have been developed up to date.

One of the most significant drawbacks of the N-T-U process is that it is a true batch process. Several continuous processes have evolved from the basic configuration of the N-T-U type retort such as the Bureau of Mines gas combustion and the Paraho process. By making them continuous processes, however, they have increased the complexity in the retort as well as in the process control to the degree where the N-T-U experience no longer became applicable to those processes.

The continuous processes, which have evolved from the N-T-U process as well as from other non-N-T-U type processes, have significantly increased the throughput of the plant, but not without paying a price for it. The additional equipment consumes a significant amount of energy input which has to be supplied either internally using its own energy products or externally in the form of electricity. In addition, the complex plant design and construction increased the capital and the operating costs significantly, thus diluting the benefit of the increased throughput. As a result, the bottom line product cost per barrel of product oil has not improved much despite the evolution of more technically advanced processes.

More significantly, this trend of more sophisticated process plants pushed the size of an economically acceptable unit to a level where a very large capital investment is required before a single drop of the product oil is produced. Small investors without such a large sum of capital, holders of small oil shale tracts that can not support such a large production rate for a 30 year plant life, and the developing nations with a significant oil shale reserve but with no available capital, are all left out in the competition.

The development of the T^3 process is based on the fact that a process can be developed with a favorable overall economics by employing a relatively less sophisticated process scheme with a proven history, and thus minimizing the necessary process energy input, capital, and operating costs. The N-T-U process is one of these processes, except for its low batch throughput. Efforts were made to convert the process into a continuous one without necessarily complicating the process and without losing the benefit of applicable experience of the N-T-U process. This was achieved by utilizing a conjugated number of retorts operating in a semi-continuous mode. The process was named the T^3 process which is derived from the three major Moroccan oil shale deposits at Timahdit, Tarfaya, and Tangiers. The T^3 process, thus, has its roots in the extensive batch processing experience gained in the United States on the N-T-U process and the DOE 10-ton and 150-ton retorts. It incorporates the salient features of the N-T-U process developed in the U.S. in the 1920's and 1940's, and the extensive Bureau of Mines and DOE experiments with the 10-ton and 150-ton batch retorts along with significant improvements based on recent technology development including the VMIS oil shale process.

The process has been further improved using mathematical models developed for the T^3 process to incorporate the specific shale properties and characteristics of kerogen decomposition of the Moroccan and Utah shale. The detailed design of a pilot plant in Morocco with an 80 ton capacity has been completed and the equipment purchasing is pending upon loan approval from the World Bank in January, 1982. Operation of this pilot plant is expected early in 1983.

Description Of The T^3 Process

The T^3 process basically consists of two retorts; retorting and cooling sections as shown in Figure 1. The air enters into the bottom of the retort charged with hot spent shale. The water is injected into the air stream by fog nozzles or atomizers. The air mixed with water passes through holes in the retort bottom discharge cones. The water in the air is evaporated when it contacts the hot spent shale. The bottom layer of spent shale is cooled and most of the sensible heat contained in the spent shale is recovered in the form of steam. The mixture of air and steam flows through the hot spent shale bed. Since the residual carbon produced from kerogen thermal decomposition is not completely consumed during retorting, the additional heat energy will be recovered by burning the residual carbon in the spent shale.

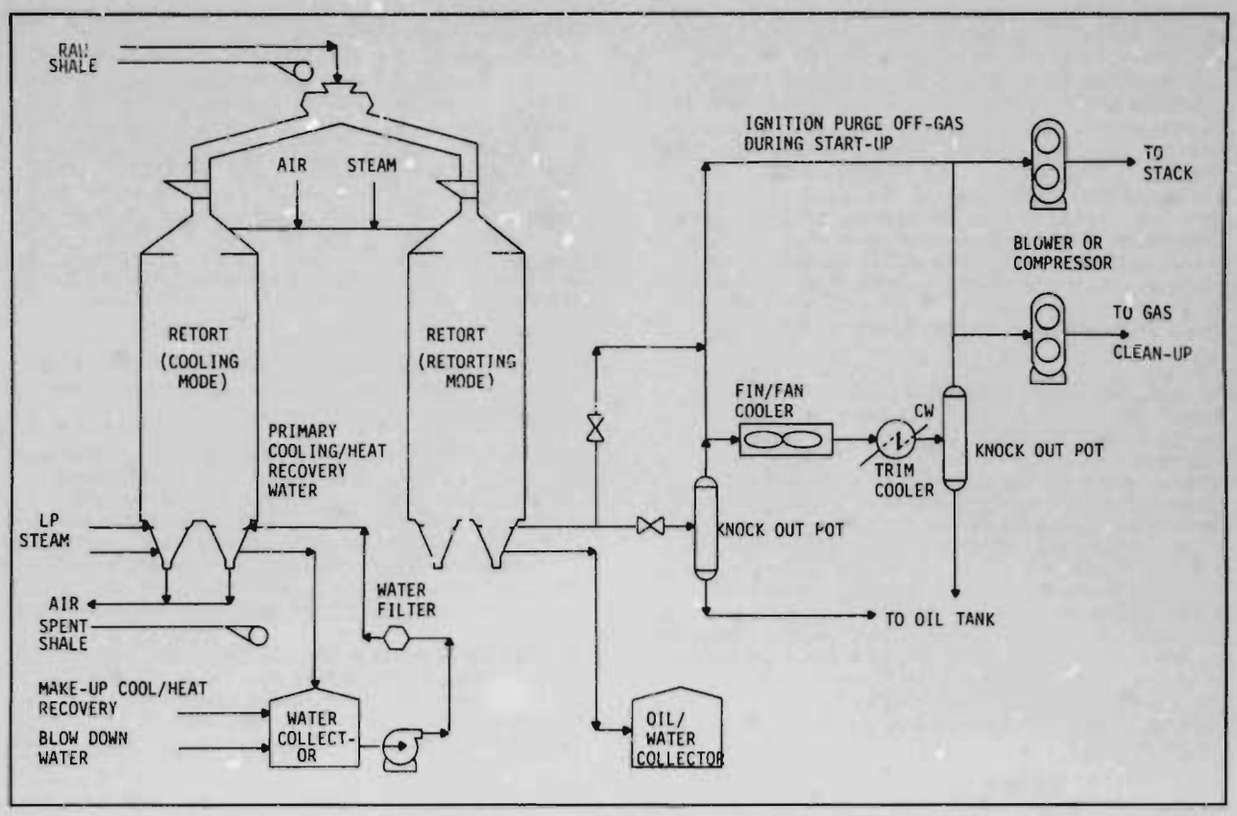

Figure 1. DIAGRAM OF T^3 PROCESS

The cooled spent shale near the retort bottom is discharged and an equal volume of raw shale is loaded at the top of the retort. The process is repeated until the retort is recharged with the raw shale. The mixture of air and steam will heat the raw shale entering into the retort from the top. The water in the raw shale is also evaporated to produce an additional amount of steam. The mixture of air and steam exiting the retort being operated in the cooling mode, is introduced into the retort being operated in the retorting mode. The supplemental steam from the topping turbine is mixed with the steam from the retort in the cooling mode, if necessary, to obtain the required steam concentration of the inlet gas in the retort while in the retorting mode. However, the supplemental steam is not expected to be required.

The product gas leaving the retort in the retorting mode passes through knock-out pots and gas cooler located before the blower. Because of high water concentration in the product gas, the blower is located after the gas cooler to reduce the actual volume of off-gas to be handled by the blower. The liquid and gas products are collected and separated in a space below the retort bottom. The liquid products flow into the oil and water separator during retorting which are used as the water storage during the cooling of spent shale. The liquid products are separated in the collector into the oil and water phases. The oil is pumped into the heater treater to remove the water. Purging lines are provided to remove combustible gases from the space below the retort bottom when the retorting is complete. The steam introduced into the retort bottom will also generate hydrogen and carbon monoxide by the reaction of steam with the residual carbon in the spent shale. This gas may be used as a start-up fuel.

Since the major mechanism for transferring the energy from hot spent shale to the gas stream is the evaporation of water droplets in the air, it is necessary to carry the water droplets through the spent shale bed. The spent shale absorbs the water, almost 30% of its weight, if the temperature is below 200°F. Therefore, it is necessary to discharge the spent shale incrementally from the retort bottom to avoid the water absorption by the spent shale. In addition, the incremental discharge of spent shale will also allow the incremental loading of raw shale into the retort. Because of a large retort height, the batch loading of raw shale may cause serious damage to the retort wall and may also cause degradation of shale particles. In order to obtain radially even movement of shale, it may be necessary to use multiple vibrating retort bottoms such as bin activators. The charging and discharging cycle is dependent mainly on the air velocity and water injection rate.

The semi-continuous operation of the T^3 process is achieved by alterating two retorts, one in the retorting mode and one in the cooling mode. Imagine that we placed the cooling retort upside down with hot spent shale on the top of the retorting retort filled with raw shale, then it will resemble

a single retort depicted in Figure 2 (Start). As the raw shale is ignited and the combustion, hence the retorting front moves downward, the incoming air and water from the top recovers heat from the spent shale and preheats the incoming raw shale before it enters the combustion zone as an air-steam mixture. The cooled spent shale is discharged from the top of the retort. The charging of the raw shale and the discharging of the spent shale are done incrementally. As the process proceeds, the combustion front moves further down the retort as shown in Figure 2 (Middle) until the entire raw shale at the bottom half has been retorted and the upper half is completely filled with raw shale already preheated as shown in Figure 2 (Final).

At the end of this cycle, again imagine that we cut the retort in half and put the bottom half on top of the top half, thus creating the same arrangement as in Figure 2 (Sart). This is done by simply switching the two retorts and by exchanging their roles as a cooling and as a retorting retort. By repeating this cycle, we have in effect created a semi-continuous retort with an oscillating combustion (hence retort) front at the bottom half of the retort compared to a fixed combustion front of a continuous process, as shown in Figure 3. Since the retorting retort operates exactly the same mode as the N-T-U process, all the relevant experience from the N-T-U process can be directly applied to the T^3 process. The inherent simplicity of this type of process also makes the scale-up a less formidable task.

In the N-T-U process, the spent shale is dumped to the ground without cooling or recovering sensible heat. The straight air or the mixture of air and recycle gas is used for retorting. Because of high temperature, the discharge of spent shale without cooling will result in serious environmental problems. In the T^3 process the spent shale is cooled before discharged and the significant amount of sensible heat contained in the spent shale is recovered in the form of steam. The mixture of air and steam instead of the air recycle mixture, is used for retorting oil shale in the T^3 process. In addition to controlling maximum retort temperature, the use of steam has the following advantages:

1. The steam increases the combustion rate of residual carbon in the spent shale through the water gas shift reactions.

2. The steam increases the hydrogen production per ton of oil shale by reacting with the carbon monoxide. The steam increases the reaction rate of residual carbon with carbon dioxide by increasing the porosity of spent shale. The residual carbon in the spent shale reacts with the carbon dioxide to produce carbon monoxide which reacts with the steam to produce hydrogen.

3. The steam reduces the oil loss due to thermal cracking in the retorting zone by increasing CO_2 production rate in the combustion zone. The steam minimizes the oil loss when it is released from the raw shale surface.

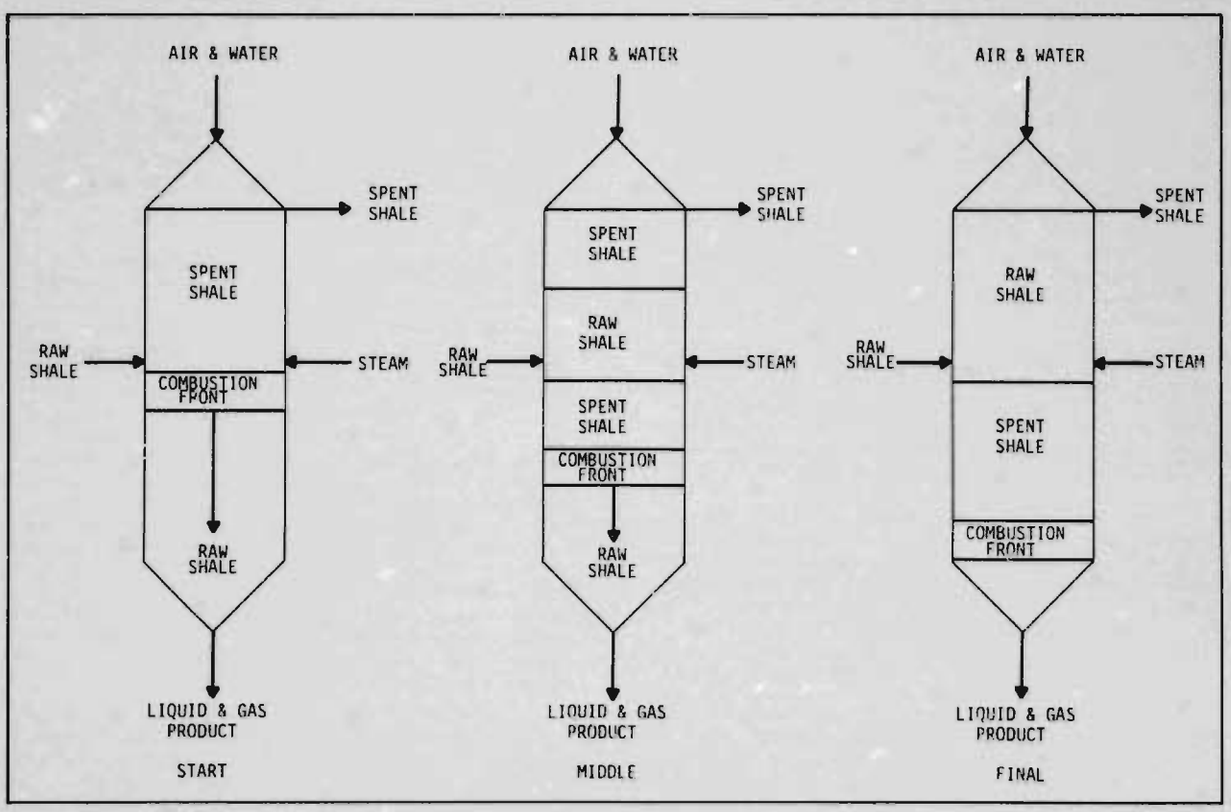

Figure 2. SCHEMATIC EQUIVALENCE OF T^3 PROCESS

4. The steam increases the retorting rate compared with the recycle gas.

The retorting of oil shale produces almost twice as much water as oil. This process water needs to be purified before being released into the environment or reused for other purposes. The treatment of this process water will be very expensive. In the T^3 process the process water is recycled to either the bottom or top of the retort. The organic pollutants in the process water will be burned and the inorganic pollutants will be removed by the hot spent shale in the retort.

In summary, the T^3 process has the following improvements over the N-T-U process:

1. Time-phase operation of two retorts in the module allows semi-continuous operation.

2. Hot spent shale is cooled before dumping from the retort thereby reducing the safety hazards.

3. Sensible heat and residual carbon contained in the spent shale are recovered in the form of steam which is used for retorting.

4. Use of steam instead of recycle gas allows the utilization of the desirable effects of steam on retorting processes.

5. Process water is treated in the retort so that the use of expensive conventional water treatment methods can be eliminated.

Comparison Of The T^3 Process With Other Processes

The economic analysis of return on investment and total capital cost usually provides the principal data for comparing various processes. However, the continuing energy crisis is leading to a new awareness of how much energy is used in producing useable energy from alternative solid fuel resources. An energy analysis can reveal the specific energy inputs at each step in the process.

One ton of mined oil shale is chosen as a basis for energy efficiency calculations. The energy content of the oil shale is calculated from the products obtained from the kerogen thermal decomposition at Fischer assay analysis conditions. The electric energy required for gas compression, pumping, mining operation, and crushing was multiplied by 2.89 in order to convert to the equivalent Btu for their primary fuel sources. The shale oil and combustible gases are major energy outputs from the retorting process. For processes not using small sizes of oil shale, it was assumed that 87% of the thermal energy contained in shale fines is recovered to produce electricity using the fluidized bed combustor. Since the energy output in the form of gas and oil shale fines is useful only when it is converted into electricity, the energy recovered from the gas and shale fines will be converted into electricity, the energy recovered from the gas and shale fines will be converted into electricity by

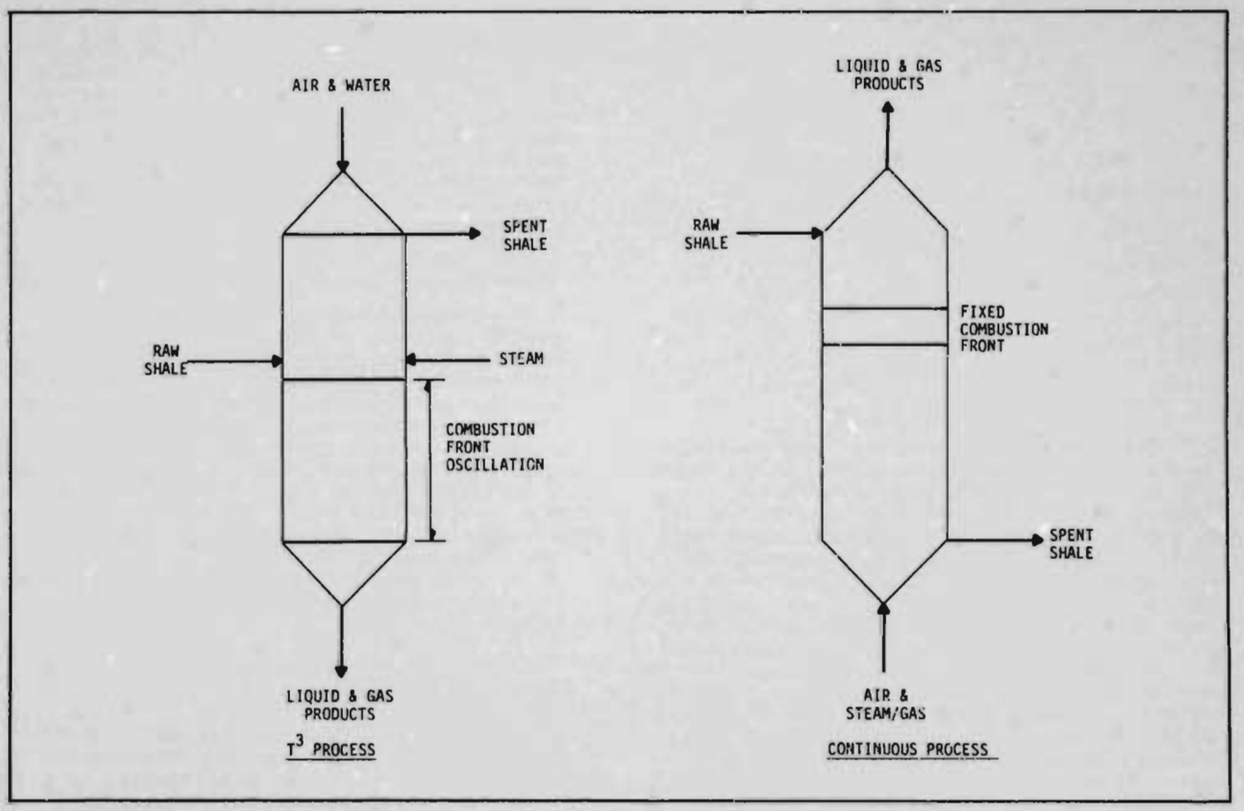

Figure 3. COMPARISON BETWEEN T^3 AND CONTINUOUS PROCESS

dividing it by 2.89. Therefore, net energy output is found by:

Net Energy = Shale Oil Btu - Diesel Fuel Btu + (Fines Btu + Gas Btu)/ 2.89 - (Mining Electricity + Crushing Electricity + Retort Electricity) x 2.89 - Heating Fuel Btu

The net energy efficiency (η) may be defined by:

$$\eta = \frac{\text{Net Energy Output From Process}}{\text{Energy of Raw Shale}} \times 100$$

The net energy efficiency has been calculated for various oil shale processes using 17 gpt Moroccan shale and 25.6 gpt Utah shale. The results are shown in Table 9. It can be seen in this table that the T^3 process has the second and third highest net energy efficiency for Utah and Moroccan oil shale, respectively. The Moroccan oil shale gives lower energy efficiency mainly due to the fact that 33.1% of the total energy in the raw shale is produced in terms of residual carbon. Although the Lurgi-Ruhrgas process has the highest net energy efficiency, about 20% of the oil produced from this process has a significant amount of spent shale dust (about 50% by weight).

Table 9. Net Energy Efficiency

Process	17 gpt Moroccan Shale	25.6 gpt Utah Shale
Paraho, Direct	46.4%	63.0%
Paraho, Indirect	43.9	60.6
Superior, Direct	45.9	61.1
Tosco II	40.8	62.3
Union B	41.5	61.4
Union SGR-3	48.0	62.7
Lurgi-Ruhrgas	50.7	66.5
Petrosix	41.9	60.2
Galoter	47.6	60.7
Kiwiter	41.0	52.7
T^3	47.7	63.7
VMIS	47.6	61.9

The water supply will be a serious limitation to the oil shale industry, especially at the Timahdit site and the Western slope of the U.S.A. The majority of the water used in a retorting facility is used for dust control and revegetation of spent shale. This amount is strongly dependent on the shale particle size retorted and the method of retorting. The water consumption for each process has been estimated mainly from published data. The results are given in Table 10. It should be pointed out that the water required for H_2S removal from the product gas is not included in the water consumption estimates in order to compare the various processes on the same basis. The H_2S removal methods proposed by the various oil shale processes were not the same. It can easily be seen in Table 10 that the T^3 process requires the least amount of water.

Table 10. Net Water Consumption

Process	Barrels of Water Consumed Per Barrel of Oil Produced
Paraho, Direct	1.54
Paraho, Indirect	1.77
Superior, Direct	1.59
Tosco II	4.53
Union B	2.52
Union SGR-3	2.68
Lurgi-Ruhrgas	4.31
Petrosix	2.37
T^3	0.56

A more recent and rigorous in-house study showed that most of the surface processes we studied have very comparable economic prospects. In fact, the differences in the economic measures of the processes were too small to have much statistical significance in comparison to the uncertainties in the cost estimates, especially when no commercial scale unit for the processes has been built and operated. This indicates that at the present time, the process considerations such as energy efficiency, water consumption, technological risks associated with scale-up, net power consumption, and byproduct usage play a more important role in the selection of an optimum process. The T^3 process ranks high in many of the areas previously mentioned as well as in the overall economics. Experiments have been successfully conducted utilizing the low Btu gas and undersized raw shale fines expected from the T^3 process. This was accomplished by burning these in a fluidized bed combustor (4). The heat generated can be used to generate enough on site steam and electricity required for the process and the excess electricity can be exported. The process can also convert the sulfur into a stable sulfate for disposal or, if needed, an elemental sulfur can be produced as a sellable byproduct.

Applicability Of T^3 Process To Eastern Oil Shales

The large amount of residual carbon in the spent shale can be recovered by the T^3 process in the form of product gas and steam. By controlling the concentration of steam in the inlet gas, the large portion of residual carbon can be recovered through the reaction of residual carbon with the steam. The residual carbon part remaining in the spent shale at the end of the retorting can be burned during the cooling operation to produce the steam from the water contained in the incoming shale. Since the maximum temperature of the retort can be controlled by controlling the oxygen concentration of the inlet gas, no technical difficulties are anticipated in using the T^3 process for retorting Eastern oil shales.

The T^3 process can be built in modules and, therefore, high initial capital investment, high technological risks due to process complexity, and high scale-up factors could be avoided. In addition, the technical and operating data from the T^3 process can be used to design or develop a more efficient process for Eastern oil shales. The T^3

process will be especially suitable for the areas where the oil shale reserves are relatively small.

Conclusion

The T^3 process was developed as an alternative to processes that require a high initial capital investment with a high technological risk due to the process complexity and high scale-up factor. The process can be built in modules. Although the process was originally developed for the Moroccan Timahdit shale, it can also be applied to the Eastern oil shales. As it was mentioned earlier, there is no single process that has been accepted or demonstrated as a universal solution to all the problems in the shale oil production. Despite many technical and economic advantages over other processes, the T^3 process is no exception. Each project must be treated separately and an optimum process has to be found that will best satisfy the specific requirements for the given resource. The T^3 process is only one of the many candidates to be considered with many distinct merits.

In summary:

1. Scale-up of the T^3 process represents little or no risk so that the economic and technological risk will be minimized.

2. Net energy efficiency is higher than other processes except for the Lurgi-Ruhrgas process.

3. Requires the least amount of water.

4. Capital and operating costs are not significantly different from the continuous processes.

5. Development of a series of plant modules allows for utilization of the mined shale during the mine development so that the cash flow can be generated earlier than any other process at the same capital cost.

6. Expensive process water treatment facilities can be eliminated.

7. Full utilization of byproducts and on site power generation is possible.

8. Energy recovery from Eastern oil shale could be maximized by the T^3 process.

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Paraho's Retort Technology for Eastern Oil Shale

by

Adam A. Reeves
John B. Jones, Jr.
Paraho Development Corporation
Grand Junction, Colorado 81501

Background

The U.S. Bureau of Mines (USBM) Anvil Points engineering staff in 1946 surveyed the then available retorting processes. Their analysis was that the vertical shaft kiln had the greatest potential if it could be made to operate continuously and efficiently. The NTU batch retort was the first process tested, but it produced shale oil in only moderate yield due to the inefficiency of batch operations. It was a direct heated process with downward flow of an air and recycle gas mixture. Table 1, Oil Shale Retorting Methods, shows a list of retorting processes which is the basis of oil shale retorting experience of key Paraho personnel.

Although NTU operations were continued to produce oil for refining tests, the USBM also conducted pilot plant experiments in the indirect heated mode (externally heated recycle gas) using the batch Royster process and the continuous Gas Flow retort. The latter was heated by a cross-flow of hot gas. Although oil yield was good, overall efficiency was low, owing in part to the energy needed to heat the recycle gas.

From an analysis of the above retorting experience, it was believed that a countercurrent direct heated mode of retorting would have the greatest promise. A series of retorting experiments progressed from the Dual Flow through the Countercurrent pilot plant experiments to the successful USBM Gas Combustion retort. An important breakthrough was the identification of retorting parameters which could be controlled so that external condensation of oil vapors was not required.

TABLE 1

OIL SHALE
RETORTING METHODS
EXPERIENCE OF PARAHO PERSONNEL

INDIRECT HEATED	COMBINATION HEATED	DIRECT HEATED
ROYSTER (BATCH)	PARAHO - CH	NTU (BATCH)
GAS FLOW		ROYSTER (BATCH)
STEAM RETORTING (BRAZIL)		DUAL FLOW
PETROSIX (BRAZIL)		COUNTER CURRENT
PARAHO - IH		SHALE COMBUSTOR
		GAS COMBUSTION
		PARAHO - DH

When the Anvil Points facility was shut down in 1955, Russell Cameron and John B. Jones, Jr. formed the firm of Cameron and Jones, Inc. and the firm obtained a contract with Petrobras of Brazil to develop oil shale retorting technology for Brazilian shales. A vertical shaft kiln pilot retort was built and operated in Brazil using superheated steam or externally heated recycle gas (Petrosix process). Cameron and Jones, Inc. designed the 2,000 ton per day Petrosix retort now processing Irati shale in Brazil.

In 1966, Mr. Jones left the firm and was the principal in the formation of two new companies for the purpose of developing and licensing new vertical kiln concepts based on his new inventions.

Development Engineering, Inc. (DEI) and Paraho Corporation were formed and they searched for an industry which could utilize the process and hardware concepts developed since 1946. The hardware techniques were believed to be very important for the reason that experience showed that most innovative vertical kiln techniques which looked good in principle could not be demonstrated successfully owing to limits in operating equipment. Although there were successful vertical limestone calcination kilns in commercial operation the new concepts were expected to provide improvement in fuel efficiency and quality of lime products.

The Paraho lime kiln is shown in Figure 1. The innovative hardware concepts included distribution of the screened limestone uniformly over the cross-section of the kiln and withdrawing the calcined limestone (quicklime) continuously at the bottom of the kiln in a manner to insure the uniform descent of solids throughout the kiln. Other hardware concepts involved the distribution of air and gas mixtures within the descending bed of solids so that controlled combustion of gas in the void space of the bed would result in the decomposition of the limestone to carbon dioxide and calcium oxide. Hardware inventions also included a bottom distributor for air to cool the hot quicklime.

Process development included the selection of air and gas mixtures and quantities to be injected into the kiln using the distributors and the amount of cooling air distributed at the bottom of the bed of lime.

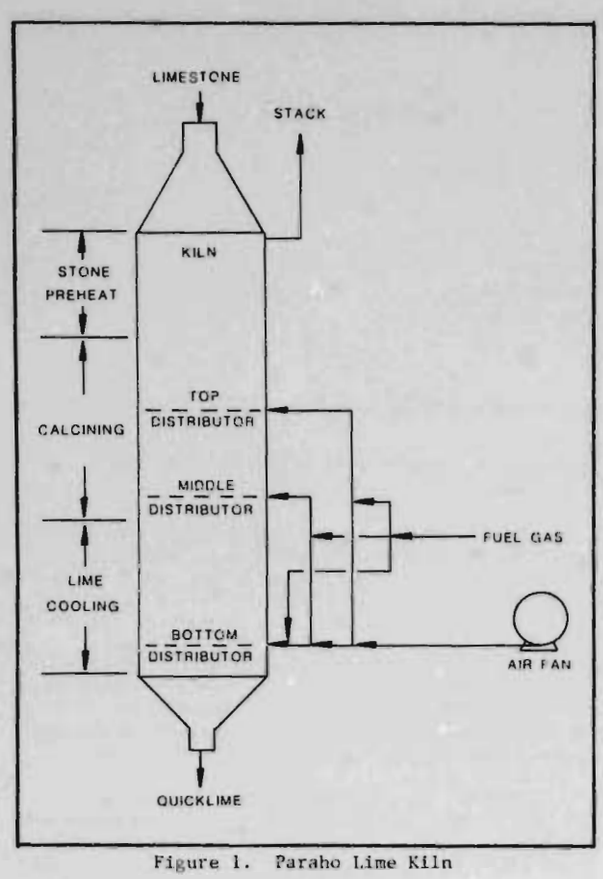

Figure 1. Paraho Lime Kiln

The first application of the Paraho lime kiln technology was a 300 ton per day unit (based on limestone feed rate) constructed in 1966. This was soon increased to 400 tons per day at a small increment of investment cost.

Two improved lime kilns were designed and built in 1969, each operating at 600 tons of limestone per day feed rate. Improvements were incorporated to produce a high quality product. Later, the first kiln's capacity was increased to 700 tons per day by eliminating bottlenecks in the auxilliary equipment, principally air blower capacity and pipe sizes.

Paraho Oil Shale Retort - Process Description

As with the calcination of limestone, the Paraho process depends on the uniform countercurrent contact of shale and gas. Figure 2 shows the principal items of processing equipment and an isometric sketch of the retort vessel. The crushed and screened oil shale is charged to the retort through a hopper (which is kept full) and descends through a rotating spreader which assures even distribution of the granular solids with minimum particle size segregation.

The shale descends slowly past the gas collectors and becomes preheated before entering the retorting zone. The shale becomes heated to about 900°F and the organic matter, kerogen, decomposes to form oil vapor, gas and a carbon residue.

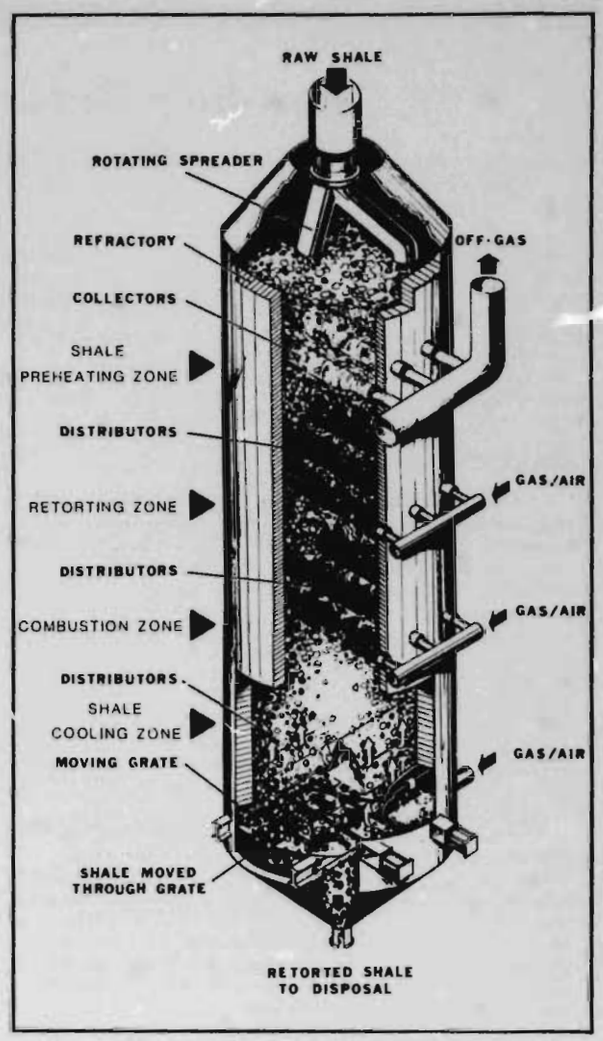

Figure 2. Paraho Retort, Direct Heating Mode

The shale descends through the combustion zone where a portion of the carbon residue burns to supply a significant part of the process heat requirements. The shale is cooled in the bottom of the retort and is removed by the grate mechanism shown in Figure 2. Cool recycle gas enters the shale bed near the grate and moves upward and becomes heated by removing heat from the descending hot shale. The distributors at two levels near the center of the retort inject air diluted with recycle gas. Combustion tskes place within the shale bed void space, and the products of combustion mix with the preheated recycle gas ascending through the shale bed. The hot gas mixture passes through the retorting zone and is mixed with the evolved shale gas and oil vapors. The gas becomes cooled by the descending shale and a stable mist of oil droplets is formed by condensation in a manner similar to the formation of clouds when an air mass becomes cooled. The cooled gas, now laden with the oil mist, disengages from the shale bed in the gas collector channels and is drawn by the gas blower through the oil/gas separating equipment. See Figure 3, Paraho DH

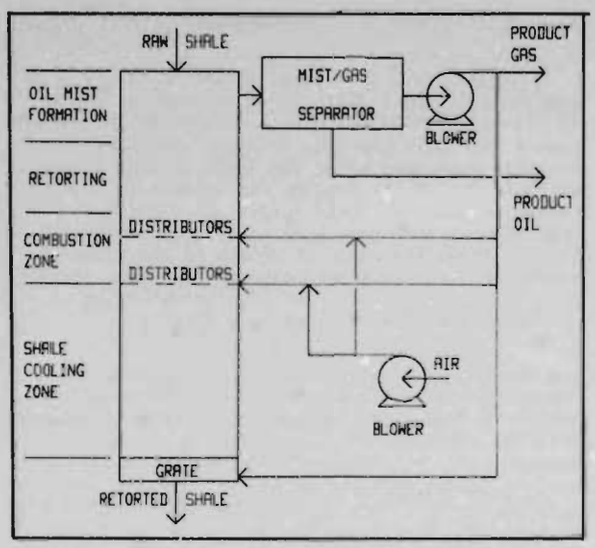

Figure 3. Paraho DH Retort

(Direct Heated) Retort. A large volume of the gas is recycled to the retort and the net make gas (product gas) is treated before being utilized in a combined cycle of gas turbines and waste heat boiler steam turbines to generate shaft power.

Steady-state temperature profiles in the retort are shown in Figure 4. One of the options of direct heated retorting is the addition of air to the cooling gas entering the bot om of the retort. Thus, in these profiles, the gas temperature crosses over the rock temperature after combustion initiates in the top of the shale cooling zone. Notice that both gas and rock temperatures increase above each distributor. The shape of the profile is confirmed by temperature probes in the Paraho retorts, and these probes indicate a value between the rock and gas temperatures. Therefore, the temperature differentials shown in the profiles is only a representation. Note the low temperature levels of the shale and gas leaving the retort.

In a distillation column, liquid is recirculated as reflux whereas in vertical kiln technology heat is recirculated internally in the retort. For example, the sensible heat flow diagram for the Parsho oil shale retort is shown in Figure 5. The shale enters the retort at 60°F in the upper left-hand corner of the diagram and retorted shale leaves at 300°F in the lower left-hand corner. Recycle gas enters the retort at 180°F (lower right-hand corner) and the retort off-gas leaves at 140°F (upper right-hand corner). Arrows pointing left indicate the flow of sensible heat to the shale and arrows pointing to the right show the flow of heat to the gas medium. The width of the heat flow streams is proportional to the quantity of heat. Note that heat of combustion transfers to both the solids and the gas streams. The temperatures of gas and shale shown are consistent with the temperature profiles shown in Figure 4. As will be shown later, the heat input could be by an externally fueled furnace (Indirect Heated Mode - also called IH Mode) or an external heat exchanger (Combination Heated Mode - also called CH Mode).

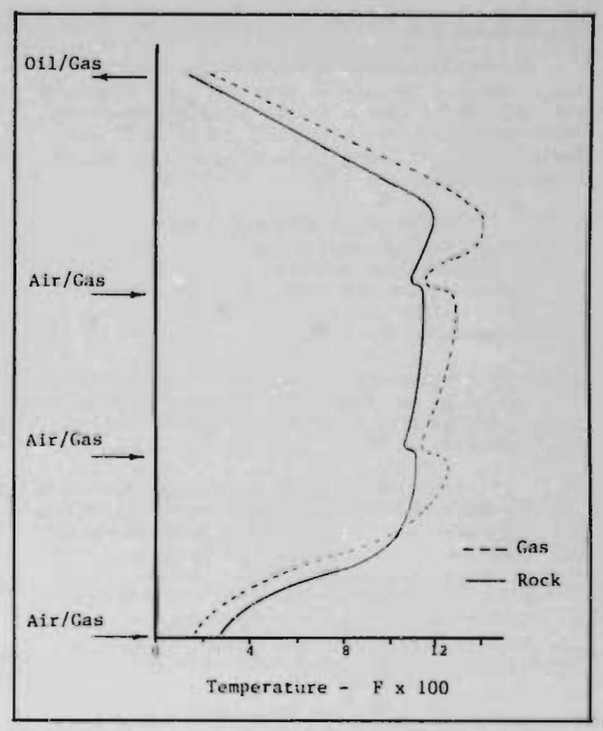

Figure 4. Paraho DH Retort, Temperature Profiles

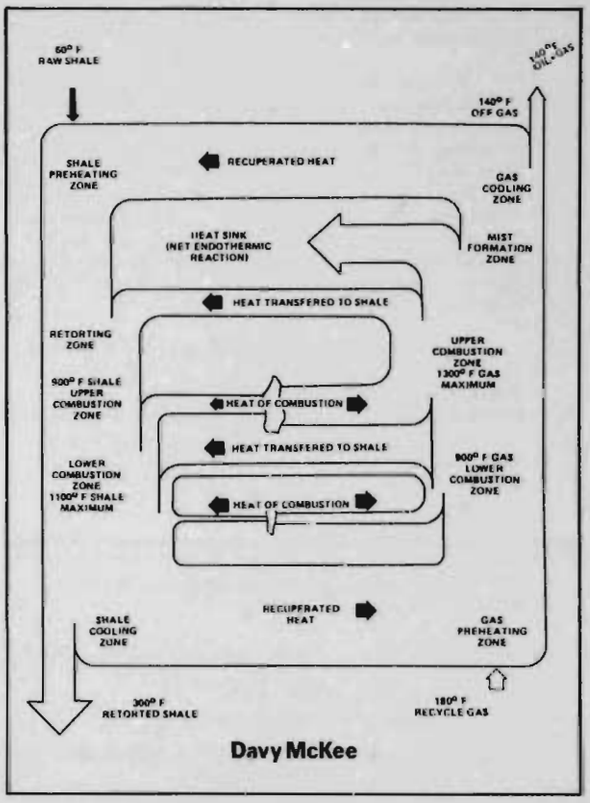

Figure 5. Paraho Oil Shale Retort Sensible Heat Flow Diagram

Paraho Oil Shale Process Development

Paraho leased the Anvil Points, Colorado oil shale research facilities from the U.S. government and performed a series of oil shale process development programs using retorts of their own design. Table 2 lists these programs and others conducted by Paraho.

Program No. 1 - This $10,000,000 demonstration program was funded privately by 17 sponsors who purchased rights to use the Paraho technology which would be developed. A pilot retort and semi-works retort were constructed and operated.

Program No. 2 - Was a production-type run funded by the Department of the Navy, and about 70,000 barrels of crude shale oil were produced.

Program No. 3 - Paraho was contracted by the Navy to manage a refinery run to produce military-type fuels from the crude shale oil produced in the two previous programs. The Standard Oil Company (Ohio) conducted pilot plant refining tests and then refined about 90,000 barrels in a hydrocracking unit at their Toledo, Ohio refinery. All of the products have been used in tests by designated agencies.

Program No. 4 - This program of pilot plant retort operations has continued since 1979. These tests have confirmed Paraho's ability to conduct examinations and amenability tests, to select operating conditions, and to plan and execute pilot plant operations with oil shales having different properties.

Program No. 5 - Paraho and the Department of Energy have jointly funded a $9 million mine and retort module design program. Paraho received their funds from 14 sponsors which made prepayments of future process royalties. The detailed design and cost estimate have been completed and the final report was presented in December. Most of the features of the retort design have been demonstrated by Paraho oil shale operations and all of the components are conventional items of equipment.

Program No. 6 - The DOE awarded Paraho a $3.1 million grant to conduct a commercial feasibility study based on 3 Paraho retort modules, a suitable mining plan and design, and the necessary support facilities to produce over 42,000 barrels per day of hydro-treated shale oil.

TABLE 2. PARAHO PROGRAMS 1973-1981

NO.1	1973-1976	DEMONSTRATION (17 SPONSORS)
NO.2	1976-1978	NAVY PRODUCTION
NO.3	1978-1979	REFINE 90,000 BBLS.
NO.4	1979-	PILOT PLANT - NON-GREEN RIVER SHALES
NO.5	1980-1982	MODULE DESIGN (14 SPONSORS)
NO.6	1981-1982	FEASIBILITY STUDY

Summary of Paraho Oil Shale Operations

The majority of runs in the pilot retort (4.9 sq. ft. cross section) and the semi-works retort (49 sq. ft. cross-section) were performed in the direct heated mode of operation, although important work was also performed using the indirect heated mode of operation. One outstanding characteristic of the Paraho retorts was their ability to operate continuously through a wide range of conditions. Table 3 shows the range of values of the principal operating parameters for Colorado and other western oil shales. The table confirms the important criteria of adaptability and operability.

In the next table, Table 4, the Paraho demonstration runs are summarized. The first semi-works demonstration run was started in January 1975 for the purpose of establishing equipment operability. In addition to a long 56 day run period, Paraho obtained important operating data and process analysis data. Another demonstration run of 26 days was conducted with the semi-works retort in November 1975. The purpose was to confirm the design basis for a commercial evaluation case study.

Program No. 2 of Table 2 required a preliminary production program for demonstration of equipment capability. This resulted in a continuous 105-day run in the semi-works retort, shown in the third column of Table 4. Subsequently in 1977 and 1978, 90% on-stream operation produced about 60,000 barrels of oil.

The demonstration runs in the pilot retort show the versatility of the Paraho direct heated process. The 77 day run had the specific purpose of providing standby purge gas for the indirect heated mode development runs conducted in the semi-works retort. A secondary purpose was to correlate pilot plant results with the semi-works demonstration run (Column 2). Analysis of data from the data periods in the pilot retort confirmed that operations were equivalent over cross-sectional areas in a ratio of 10 to 1. Thus, a basis was established for the design of commercial retorts using the demonstrated functional elements of the Paraho Direct Heated Mode.

The other three pilot retort demonstration runs were made using shales with higher moisture and carbon contents than western shale. In each run, tests with western shales established a comparison base and other tests simulated the planned operating conditions for the foreign shale tests. Transition from one type shale to the other was smooth, and the foreign shale test results were used to perform feasibility studies for potential commercialization.

Paraho Indirect Heated Retort

The Paraho indirect heated mode is shown in Figure 6, Paraho IH Mode. The oil mist formation, retorting and shale cooling gases are equivalent to those zones for the direct heated mode shown in Figure 3 earlier. The difference is the method of supplying process heat. The external heater shown in Figure 6 is a two-coil furnace for heating recycled retort gas. Individual furnaces may also be used.

TABLE 3 PARAHO DH RETORT
RANGE OF OPERATIONS FOR COLORADO OIL SHALE

	RETORT	
	PILOT	SEMI-WORKS
VARIABLES		
SHALE GRADE - GAL/TON	18.6 - 36.4	24.5 - 36.6
AIR - SCF/T	4,250 - 7,600	4,080 - 5,830
RECYCLE GAS - SCF/T	12,000 - 18,600	12,860 - 18,400
SHALE RATE - LBS/HR/FT^2	173 - 640	343 - 549
PRODUCT GAS		
NET PRODUCTION - SCF/T (WET)	4,680 - 10,300	4,700 - 9,640
HEATING VALUE (HHV - BTU/SCF (DRY))	62 - 153	100 - 173

TABLE 4 SUMMARY
DEMONSTRATION RUNS

PARAHO DIRECT HEATED RETORTS

	Semi-Works				Pilot		
RUN:							
OBJECTIVE	1/	2/	3/	4/	Israeli-1	Israeli-2	Morocco
STARTED (Month/year)	1/75	11/75	1/78	12/75	9/79	9/80	1/81
LENGTH -- Days	56	26	105	77	17	20	13
COMMERCIAL DESIGN DATA							
PERIODS -- No.	--	13	--	--	--	2	2
RUN VOLUNTARILY TERMINATED	Yes	Yes	Yes	Yes	Yes	Yes	Yes

1/ Equipment Operability.
2/ Develop Design Basis for Commercial Evaluation.
3/ Develop Oil Production Costs for the Navy.
4/ Produce Purge Gas for Semi-Works Retort Indirect Hold Operation.

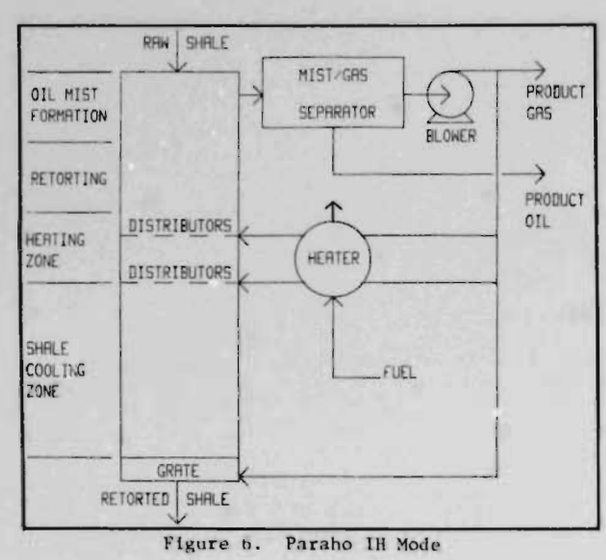

Figure 6. Paraho IH Mode

The process differences become evident in examination of Table 5, Typical Yields, Colorado Oil Shale. The oil and gas produced from the Fischer assay is shown in gallons per ton, with the equivalent oil yield of the gas calculated from its composition.

In the direct heated mode, the Paraho retort produces more gas on an equivalent oil basis than the assay because part of the shale carbon residue is gasified by partial combustion to carbon monoxide. Although the product gas is a low BTU gas (about 140 BTU/CF), it can be burned to produce electricity in a direct combustion gas turbine and a waste heat boiler and steam turbine in a combined cycle arrangement. The liquid oil yield is 89% of the assay oil yield, but the combined oil plus gas yield is 103% of the assay yield. Furthermore, the direct heated mode uses a part of the carbon residue of the retorted shale and a portion of the shale gas to fuel the process, and the equivalent oil value is an increment of yield, so that the total retort yield is 114% of the shale assay.

Returning now to the discussion of the indirect heated mode, the product gas is a high BTU gas (about 950 BTU/CF) like the assay gas, and the gas yield is somewhat higher on an equivalent oil basis. However, the net oil plus gas yield is only 82% compared with 103% for direct heated mode retorting. That is, when the heater fuel requirement is met (by burning oil, for example), the overall net retort yield is only 82% vs. 114%. This is a significant yield penalty for the production of a high BTU gas.

Paraho Combination Heated Retort

With an objective of combining the energy efficiency of the direct heated mode with the production of undiluted high BTU product gas, Paraho has invented a second generation oil shale retort. Basically, the retort has two independent zones (a retorting zone and a combustion zone) separated by a dynamic seal which allows retorted shale to pass while preventing the mixing of gases between the zones. Figure 7, Paraho CH Retort, is a block flow diagram of the second generation retort. Parts of the process have been simulated using Colorado and Israeli shale, but the hardware has not been

TABLE 5. Paraho Retort Typical Yields
Colorado Oil Shale

	RETORT DIRECT	RETORT INDIRECT
SHALE ASSAY - GPT		
OIL	27.4	27.4
GAS - (EO)*	2.1	2.1
TOTAL	29.5	29.5
RETORT OUTPUT - GPT		
OIL	24.4	24.9
GAS - (EO)*	6.0	3.1
THERMAL ENERGY USAGE (EO)*		
INTERNAL COMBUSTION	3.2	0.0
HEATER FUEL	0.0	-3.8
TOTAL	33.6	24.2
YIELD - % OF ASSAY		
OIL	89	91
PRODUCT**	103	82
RETORT ***	114	82

* EO = EQUIVALENT OIL
** PRODUCT = OIL PLUS GAS (EO)
*** RETORT = PRODUCT PLUS ADJUSTMENT FOR THERMAL ENERGY USAGE (EO)

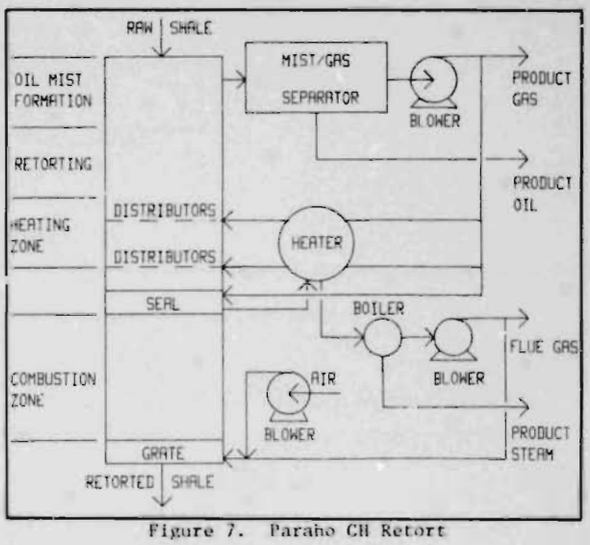

Figure 7. Paraho CH Retort

incorporated in the pilot retort. Paraho has designed the dynamic seal mechanism and has developed operating programs to demonstrate the new technology.

Paraho has utilized a stepwise procedure for evaluating oil shales to determine the suitability of the Paraho technology. This consists of amenability tests and detailed laboratory examinations, followed by simulation of heat and material balances and planning for pilot plant development programs. Using these techniques, we were able to plan and execute the Israeli and Moroccan shale pilot plant programs. We underestimated the liquid oil yields somewhat, but the predicted operating conditions were very satisfactory.

From the experience with direct heated and indirect heated mode operations with the pilot and

semi-works retorts and the retort simulation procedures described in the previous paragraph, Paraho has projected yields from Colorado shale using the second generation combination heated (CH) mode retort. The assay yields will be 90% liquid oil yield and 95% product yield (oil plus gas). Furthermore, the total energy yield will be 106% after the addition of the energy with steam generated in the waste heat boiler. This exceeds the 103% energy yield from the direct heated mode retort, and a further advantage is the production of a high BTU gas which is amenable to lower cost sulfur removal and has a potential as feedstock for the facility which would manufacture hydrogen for hydrotreating the crude shale oil. These advantages must be examined carefully in the light of the incremental capital requirement for the heat exchanger.

High Carbon Shale Processing

The combination heated mode of retorting has special advantages for high residual carbon shales such as the eastern U.S. shales. A detailed laboratory examination and retort balance calculations were made for a sample of Sunbury shale assaying 12.5 gallons of liquid oil per ton. The equivalent oil content of the gas yield was 9.3 gallons per ton. In summary, the projected energy recovery as a percent of Fischer assay was:

Liquid oil yield	95%
Oil plus gas (EO) yield	100%
Net Retort yield - includes combustion energy from carbon	141%

Commercial Oil Shale Retort Design

To achieve larger cross-sections than the lime kilns (78 square feet) and semi-works retort (50 square feet), a choice had to be made between an approximately cylindrical structure or a rectangular structure. Referring to Figure 2 earlier, the principal design parameters are the length of the distributors and the dimensions of the grate mechanism. All functions within the retort vessel were prescribed to be equivalent, such as the bed area supplied by a shale feed tube, the distance between air/gas distributors, and length of reciprocating grate parts.

A basic design was achieved which used distributors longer than used before, but well within structural design criteria. The reciprocating grate parts were designed slightly shorter, and fixed shale feed tubes, each of the same diameter as in the rotating spreader (actually 4 tubes), used in the semi-works retort. Figure 8, 400 SF Sub-Module, shows the retort design for a 400 square foot cross section with a 2,500 ton per day processing rate. It can be seen from this cutaway isometric drawing, that submodules can be joined to form larger capacity retorts.

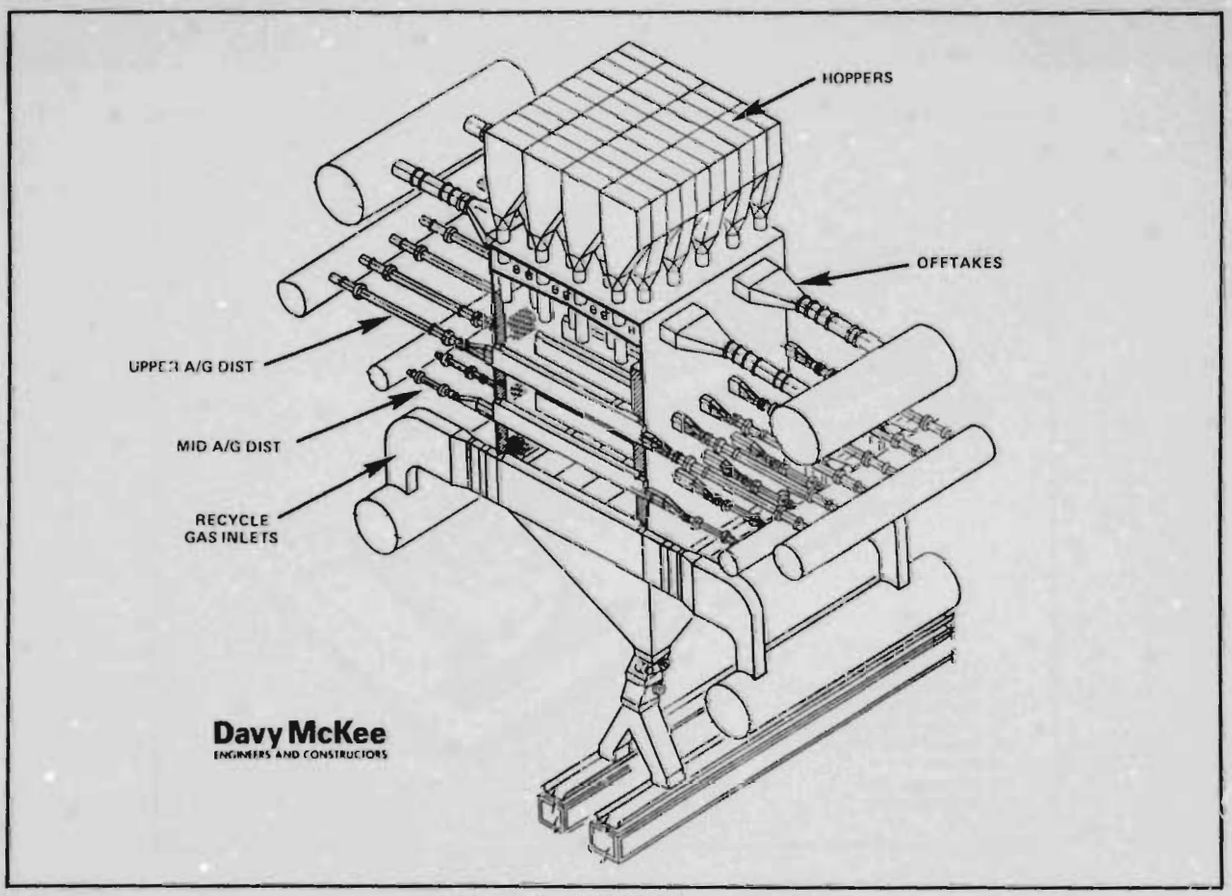

Figure 8. 400 SF Sub-module

Figure 9, Paraho Commercial Module Retort, shows at least 4 submodules of the Paraho direct heated retort and, in fact, Paraho has developed a definitive design and cost estimate for an aggregate of 8 submodules with a total capacity of 20,000 tons per day. This figure shows a portion of the feed system which consists of a combination of tripper conveyor and shuttle conveyor already in use in the steel industry. There are no internal walls between sub-modules so there is a wide range of cross-sectional area retorts available, perhaps up to 30,000 tons per day.

In Figure 9, item 1, the shale feed system fills all of the hoppers in a programmed sequence. The shale level in the hoppers is maintained to assure a full column of shale in the feed tubes at all times. The shale descends and spreads slowly from the tubes to fill the entire retort cross-section, and then descends vertically at a uniform rate past the top and middle distributors. The processed shale then flows between the inverted vees to be removed continuously by the grate mechanism, number 6, passing through rotary gas seals at number 7.

Bottom recycle gas, number 5, enters the inverted vees and contacts the processed shale, cooling the shale by countercurrent heat exchange. Air/gas mixtures from ducts number 4 and 3 enter the distributors and combustion of carbon takes place within the shale bed. The gas in the air/gas mixture is used as a diluent to control combustion. Hot products of combustion mingle with the preheated bottom recycle gas and the mixture ascends to the retorting zone. The retorting and mist formation zones have been described previously in this paper. The cool gas with the entrained oil mist is disengaged from the shale bed and is withdrawn through a duct, number 2, to the oil recovery and gas handling system.

A conceptual and preliminary design has been made to modify the module retort to the combination heated mode. However, a definitive design will only be justified by successful pilot retort operations and a suitable feasibility study.

Paraho-Ute Commercial Shale Oil Facility

A feasibility study (see Table 2, item no. 6) has been completed which combines all of the operations required to produce a premium distillate from hydrotreating of crude shale oil. A by-product of the commercial 42,000 BPD facility would be excess electrical energy (about 50MW) above the power requirements for the mine, a battery of 3 Paraho direct heated retorts, shale crushing, gas treatment, hydrotreating, and all of the support facilities. The electric energy is produced by combustion of cleaned product gas. For eastern shale operations, the product gas would be a co-product of the oil and electricity would be generated from steam produced in the waste heat boiler of the combination mode retort.

Figure 10 is an artist's concept of the complete plant at a proposed location on land leased by Paraho in eastern Utah on the White River near the Colorado border.

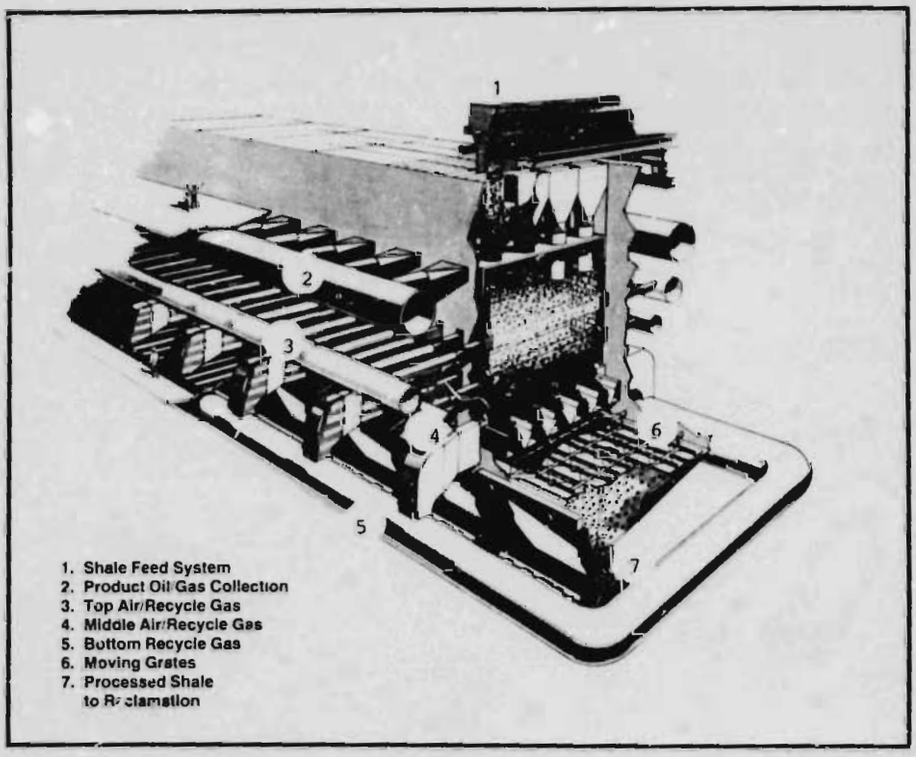

Figure 9. Paraho Commercial Module Retort

Figure 10. Artist's Conception of Proposed Plant

Superior's Circular Grate Oil Shale Retorting Process

by

John H. Knight
Division Manager

Loren H. Young
Manager Technical Services

Oil Shale Division
Superior Oil Company
Englewood, Colorado 80110

Abstract. Superior's retorting process development effort focused on adaptation of the circular grate hardware for oil shale retorting. Both circular and straight grates have long been in commercial use for iron ore pellet sintering, cooling, and other kiln applications. This effort included construction and operation of an adiabatic fixed-bed retort designed to duplicate the conditions encountered by a section of solids as it travels through the separate processing zones in the circular grate. The adiabatic retort tests identified the significant process variables and their analyses established optimum ranges in which to design and operate the semi-works retort.

The semi-works retort operations defined design and scale-up information for the oil removal system and control conditions. These operations also confirmed the mechanical reliability of solids flow on a variety of oil shales. The major results of this process development effort have been:

- Attainment of thermal efficiency for the cross-flow circular grate which approaches that achieved in counter-current flow devices.
- Product oil yields of over 98 percent of Fischer Assay.
- Development and demonstration of a proven oil recovery system.
- Optimized operation and process control conditions.

Superior is currently completing the basic engineering design of a nominal 25,000 ton per day (15,000 barrel per day) demonstration plant. This program includes detailed engineering of a 60 meter diameter circular grate retort.

Limited laboratory testing of Eastern United States oil shales by Superior has indicated that a high potential exists for these shales to be economically processed in a Superior circular grate retort. Methods based on Superior's circular grate process patents are presented and discussed in this paper.

Introduction

In the early 1970's Superior recognized that additional mineral resources and synthetic fuels production would be required in future years and initiated a multi-mineral shale development effort. One significant result of this effort was the development of Superior's circular grate oil shale retorting process. Figure 1 is a conceptual view of the circular grate retort. Oil shale is fed via three feed chutes onto a traveling grate which carries the resulting shale bed through various processing zones. Once the shale particles are placed on the grate, they are fixed in position and there is no movement in relation to each other, nor to the walls and grate. The shale and grate containment components move only in relation to the earth. In the first zone heated recycle gas is passed through the shale bed where the heat is transferred to the shale and the gas is cooled. Heating of the shale causes the organic kerogen

to decompose. The resulting liquid and gas products termed "shale oil" and "retort gas" are carried out the bed with the exiting recycle gas. Once the kerogen in the shale on the top portion of the bed has been evolved, oxygen (air) can be injected into the entering recycle gas stream. The oxygen preferentially reacts with the third product from kerogen decomposition, "residual carbon" which is left on the shale particles as residue. The heat resulting from the residual carbon/oxygen reaction is carried further down into the bed to complete the retorting (oil evolution) of the shale located in that portion of the bed. The shale oil bearing exit gases are passed through a water-flash cooler/scrubber to cool the gas stream and an electrostatic precipitator to recover the shale oil. The recycle gas exiting the precipitator is then passed through the retorted shale to remove the sensible heat from the shale and preheat the recycle gas.

Gas flow in the Superior circular grate retorting process is unidirectional, usually all downflow, with the pressure drop across the bed being held constant. This feature, defined in U.S. Patent Number 4058905, allows for overlapping of processing zones and enhances throughput through the machine and thermal efficiency. Unidirectional flow also significantly reduces interzone gas leakage and enhances residual carbon recovery as graphically shown in Figure 2.

For most shales, Superior has found that throughput and thermal efficiency are also enhanced by layering the bed. The larger particles are placed on the top portion of the bed where they are exposed to the higher thermal driving force. The smaller particles are placed on the lower portion of the bed.

Superior's Development Program

Superior's program for the selection and development of a retorting process was divided into the following steps:

1) Evaluation of equipment and processes to determine inherent advantages and disadvantages.

2) Implementation of laboratory and adiabatic fixed-bed pilot retort test programs.

3) Testing of a circular grate pilot plant retort.

4) Engineering, design, and cost estimation for a commercial size circular grate retort.

STEP 1: Evaluation of Existing Processes

During the evaluation of various heating and cooling processes, Superior placed strong emphasis on methods which had a long history of development and commercial application. Both the circular grate and straight grate have long, successful operational histories at large throughput rates. Other advantages of the grate systems are that temperature and gas flow rates can be controlled independently, thus allowing

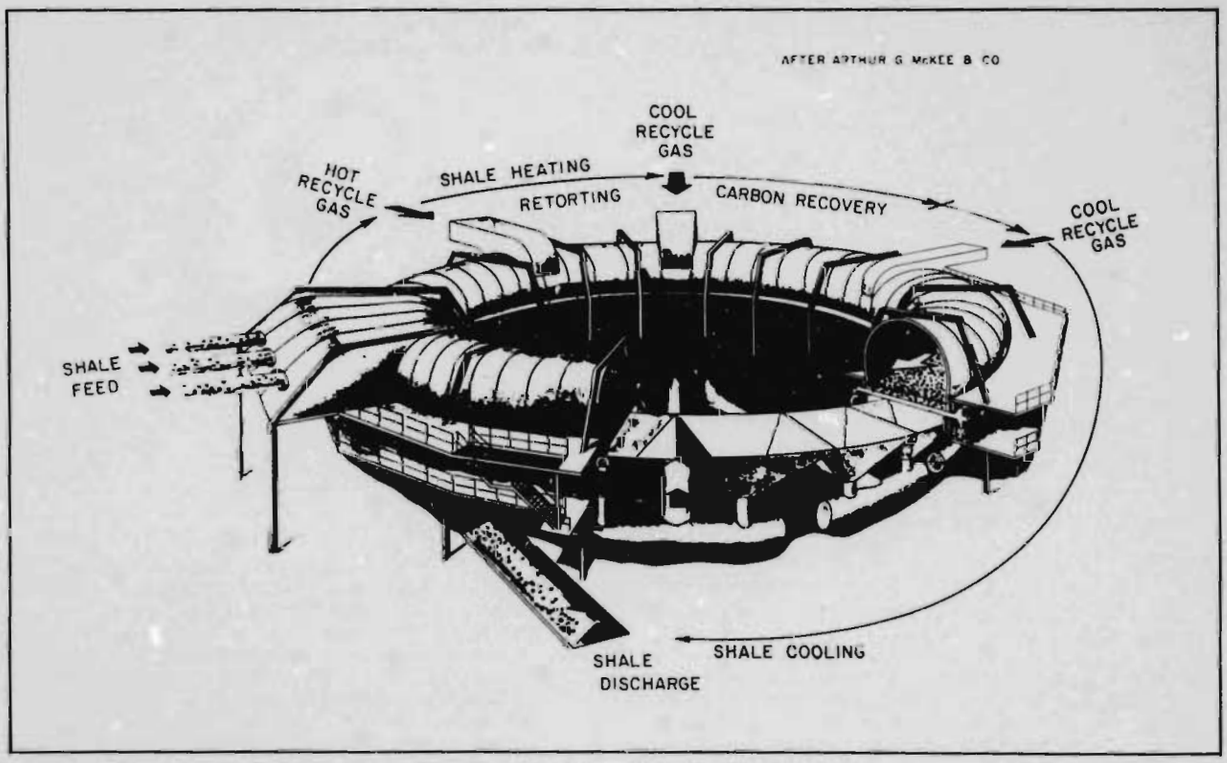

Figure 1. Superior Retorting Process

for control of energy delivery in each processing zone. Therefore, the close control of temperature and residence time can be achieved. Existing installations have been designed to handle pellets with low green strength with little or no attrition to the solids. This equipment allows for the introduction of solids and layering of the bed with different rock size fractions. In these processes, the solids do not move relative to each other, the grate or the grate walls, as the solids move in a horizontal plane through each of the processing zones. Because the particles do not move relative to each other, they do not abrade or degrade; thus, the amount of dust carryover with the oil mist in oil shale retorting is minimal. Additionally, the particles need not have the high mechanical strengths required in heating (retorting) devices where the particles are continually rubbing against each other.

The circular grate equipment is designed with water seals between the top stationary hoods and bottom stationary windboxes at the inner and outer walls to seal in hydrocarbon process gas and seal out air. These water seals also allow for unrestrained thermal expansion of structural members. Thus, leaks from cracks caused by thermal expansion stress can be avoided. The materials of construction for refractories and the grate itself have been operated at 2400°F, which is a considerably more severe operating condition than the 900°F to 1000°F required for shale retorting. An example of a commercial water-sealed circular grate constructed by Davy McKee Corporation is in La Perla, Mexico. This unit is used to sinter iron ore pellets at grate temperatures in the 2400°F range. This circular grate, water trough-sealed system is the most advanced state of the art in equipment development. For the above reasons, the water-sealed circular grate system was selected by Superior for further development and testing of oil shale.

Prior to development by Superior, the circular grate process had a number of shortcomings which required improvement and testing to make the process applicable for oil shale retorting. Thermal efficiency, throughput rate per square foot of active grate area, and circulation of heating media required improvement. An oil removal system was also required in the circulating gas stream and this system required optimization for retorting oil shale.

STEP 2: Adiabatic Fixed Bed Retort Testing and Laboratory Testing

The adiabatic fixed-bed retort simulates a section of the solids on the moving grate as it travels through the various processing zones in the circular grate retort. This is shown in Figure 3. Figure 4 is a simplified flow diagram of the adiabatic fixed-bed retort facilities. Time in the fixed-bed retort is equivalent to a length of travel of the solids section in the circular grate retort. The adiabatic fixed-bed retort was used to establish significant process variables and their effects on retorting cost responses in the same manner that smaller

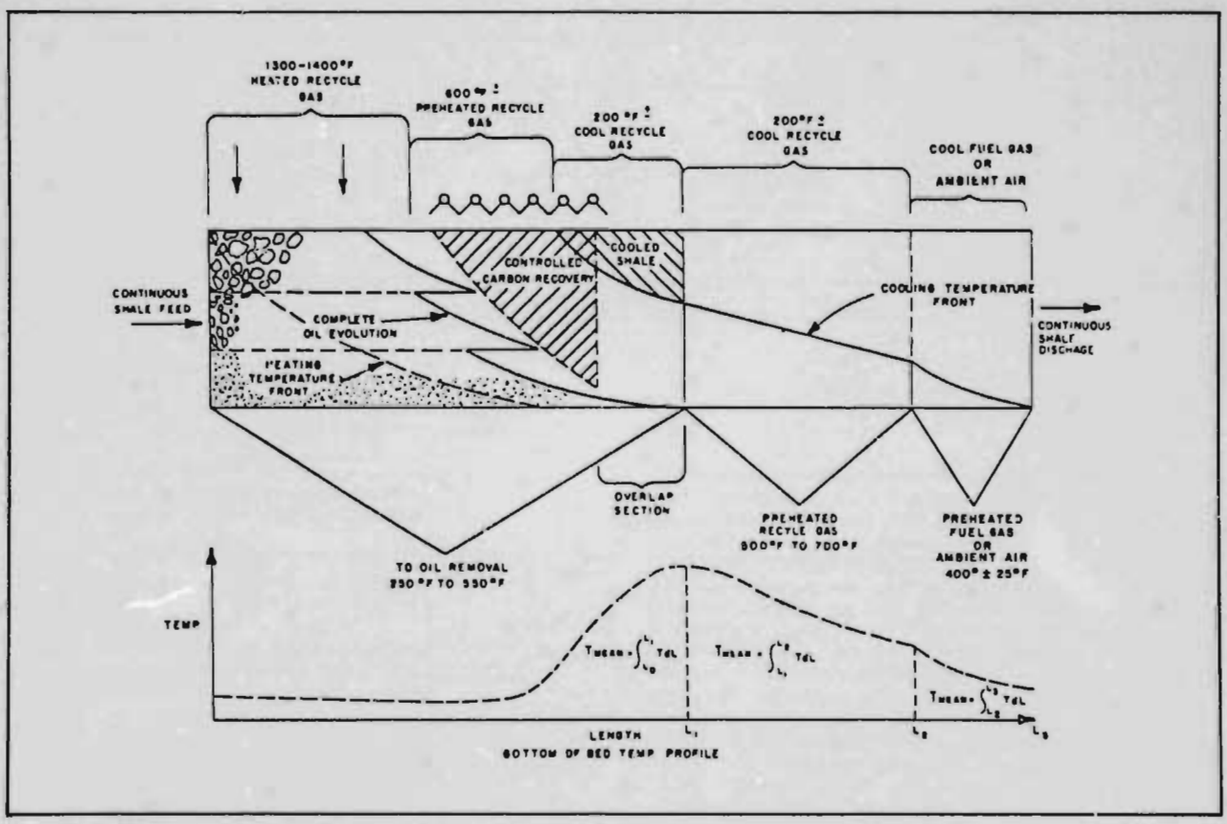

Figure 2. Circular Grate Bed Profiles the Superior Oil Co.

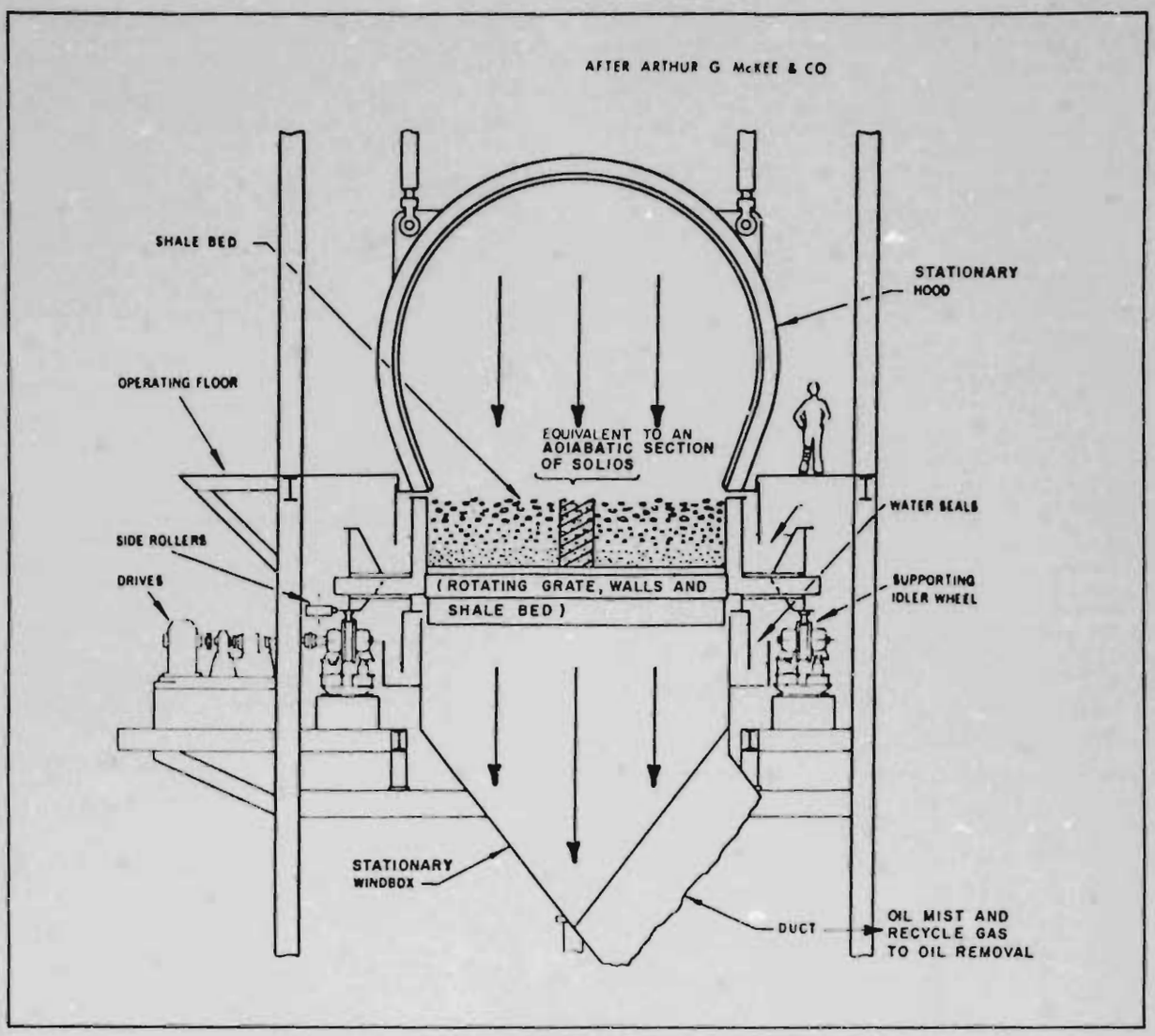

Figure 3. Cross Sectional View - Circular Grate Retort

fixed-bed devices are used to obtain sizing data for straight and circular grates in other kiln applications.

Preliminary variable and cost sensitivity analyses were conducted prior to conducting the adiabatic retort tests. This was a comprehensive study of the effect of energy transfer variables on process economics. This included determining the cost sensitivity effect which changes in process variables have on cost responses such as throughput rate, thermal efficiency, product quality, product yield, etc. Insignificant variables and cost responses were eliminated. A test program was developed and hundreds of tests based on a statistical experimental design were conducted using the adiabatic retort to determine optimum ranges of variables (Ref. 1). The primary cost responses in a cross-flow, gas-to-solid heating device were determined to be:

1) Throughput which is increased by reduction of heating and cooling residence time.

2) Feed preparation cost which is reduced by retorting larger sized rock which reduces crushing costs.

3) Utilities cost which is a function of gas pressure drop as it passes through the bed.

4) Thermal efficiency which was increased by optimizing bed height and utilizing unidirectional flow.

5) Oil Yield. High yields are obtained because no internal recycle of oil takes place, thus essentially no thermal cracking or coking is experienced which would result in a yield loss.

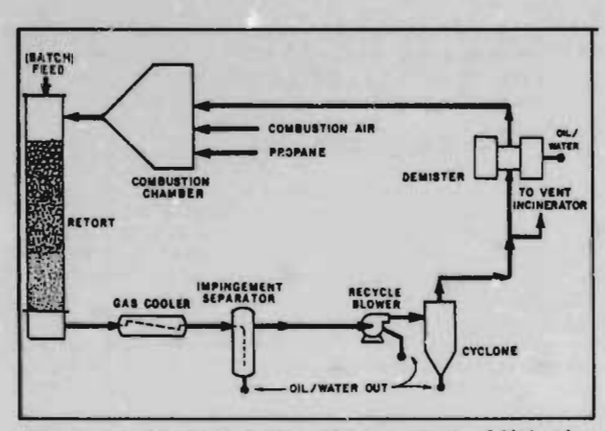

Figure 4. Simplified Flow Diagram of the Adiabatic Retort

STEP 3: Pilot Plant Circular Grate Testing

In addition to determining the optimum ranges for variables, process improvements were also tested utilizing the adiabatic retort and were included in modifications to the pilot circular grate retort. Proper oil removal operation and equipment scale-up data were determined from continuous steady state operation of the pilot circular grate retort. A simplified flow sheet of the pilot circular grate retort is shown in Figure 5. The 240-ton-per-day pilot plant defined scale-up information for the oil removal system which had not been tested on prior circular grate applications. This system is a combination of a direct contact spray scrubber and an electrostatic precipitator.

As a result of the data generated from the statistical adiabatic test program investigating significant cost responses and variables, optimum process design criteria for commercial-size retorts were generated. These optimum design criteria were verified in subsequent pilot retort testing.

One key process improvement tested in the adiabatic retort and confirmed by the pilot circular grate retort tests was the enhancement of throughput by overlapping zones, thus increasing thermal efficiency by eliminating interzone leakage, and optimizing residual carbon recovery (Ref. 2). This effect is graphically shown in Figure 2. When oil evolution from the large rock at the very top of the bed is complete, (this rock is exposed to the hottest gases at the very beginning) controlled oxidation (Ref. 3) of the residual carbon is initiated and the energy from the carbon-oxygen reaction replaces external energy requirements. The retorting temperature front then continues down through the bed. Recycle gas temperature and oxygen concentration is progressively changed to control bed temperature

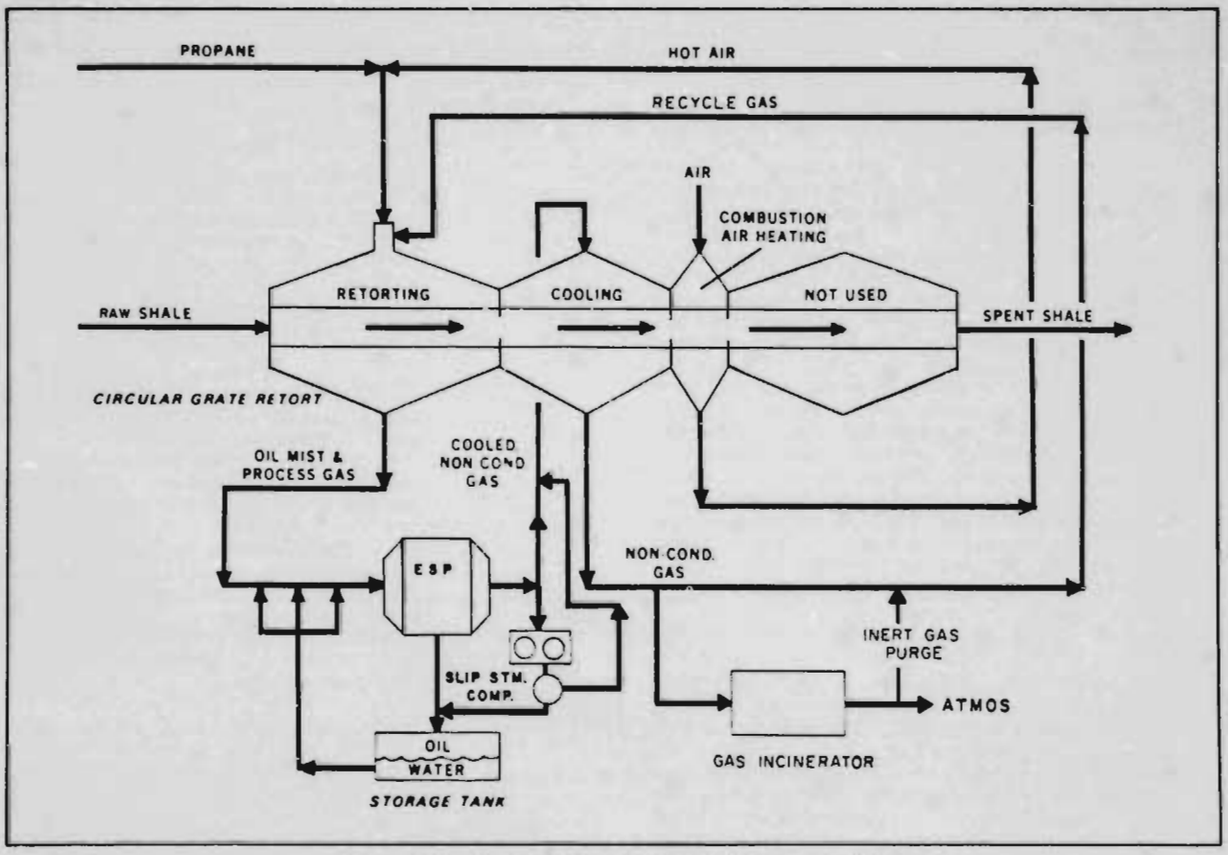

Figure 5. Pilot Circular Grate Oil Recovery Unit

during carbon oxidation. The cool gas also begins to cool the solids in the upper portion of the bed. Sensible heat from the top of the bed and the carbon-oxygen reaction furnish the energy necessary to complete the retorting of the bottom of the bed. Thus, cooling and retorting operations are overlapped, using the same grate area. By this method, significantly increased shale tonnage rates for a specific residence time and equipment size are achieved.

Depending on the type of shale used and several other variables, the gas temperature at the bottom of the retort in the oil evolution zone ranges between 230°F and 340°F with approximately 60 percent of the oil in liquid mist form. Upon leaving the retort, the stream of oil mist and process gas is contacted with water sprays. The functions of these direct contact sprays are:

- To cool the gas and water vapor mixture to the steady-state saturation temperature (180°F ± 20°F).
- To condition the oil mist for subsequent recovery in the electrostatic precipitator.
- To scrub sulfur compounds from the gas phase.
- To stabilize the electrostatic precipitator ionizing electrodes and grounding plates.

Both wet and dry pilot electrostatic precipitators were tested. The two precipitators used were both flat plate units which previously had been used to scale equipment for other commercial oil mist electrostatic precipitation applications.

In addition to defining oil removal scale-up information, the solids handling characteristics of shale from four different sources were tested in the pilot unit. Oil shale grade varied between 19 gallons and 40 gallons per ton and sodium content varied between .5 and 9 weight percent sodium carbonate equivalent. The original process configuration of the pilot plant was acquired with the contract for the equipment construction. This configuration had a maximum throughput rate of 60 tons per calendar day with 39 percent of Fischer Assay oil recovery obtained in January 1976. Superior Oil then implemented process improvements defined predominately by U.S. Patent No. 4,058,905 and hundreds of adiabatic retort tests. With heating and cooling gas ducts connected to two thirds of the active grate area, these improvements resulted in a throughput rate of 250 tons per calendar day and 98+ percent of Fischer Assay oil recovery.

STEP 4: Commercial Designs

Commercial design configurations have been completed for both direct-heated and indirect heated modes of operation. In the direct-heated mode part of the retort gas phase is burned and the flue gas produced is mixed with preheated recycle gas from the shale cooling zone. The resulting combination of gases produces retort zone hood inlet temperatures as desired normally (between 1100°F and 1800°F). This heating mode produces surplus retort gas with a heating value of from about 60 to 150 BTU per standard cubic foot, depending on shale type and grade. Figure 6 shows the direct heated mode.

Another mode of operation is indirect heating, as shown in Figure 7. In this mode, part of the retort gas phase is burned with preheated air in a tubular furnace to heat recycle gas to the desired temperature for introduction to the retort zone hoods. Carbon recovery is achieved by controlled oxidation with either preheated air or oxygen. Oxygen is used when higher heating value product gas is desired since dilution by nitrogen is avoided. The gas produced by an indirect-heated retort has a higher heating value but a lower total energy content than that produced by a direct-heated retort. This is the result of the stack losses in the indirect heater and the dilution effect of the flue gas on the gas evolved from the shale in the direct-heated mode.

Process designs have also been completed using O_2 plants and combinations of direct-indirect firing to produce product gas heating values as desired or required in the approximate range of 60 to 700 BTU/ft^3.

Superior has completed process designs and corresponding capital and operating costs for nominal 10,000 and 25,000 tons-per-calendar-day units. The optimized process, demonstrated process improvements, and successful pilot plant operation, combined with an existing history of commercial operations for the circular grate equipment, make Superior's circular grate process a viable surface retorting system.
The current state of Superior's circular grate development program is as follows:

- Commercial designs from adiabatic fixed-bed retort tests have been confirmed on a 240 TPD pilot circular grate retort including optimum determination of throughput, residence time, pressure drop, rock size, bed height and others. Continuous operation proved the integration of all system components.
- The mechanical shale handling capability of the circular grate retort has been proven in water sealed configuration equivalent to 6000 to 7000 tons-per-day and in mechanical seal configuration equivalent in diameter and bed height to 20,000 tons-per-day.
- The oil mist removal efficiency of the direct-contact water spray electrostatic precipitator combination has been demonstrated in the 240 ton-per-day pilot unit at the ±99% level with scalable manufacturer's flat plate design.
- The mechanical oil-handling reliability and scale-up criteria for the electrostatic precipitator has been proven.
- Oil evolution (retorting) efficiencies have been demonstrated at the ±99%

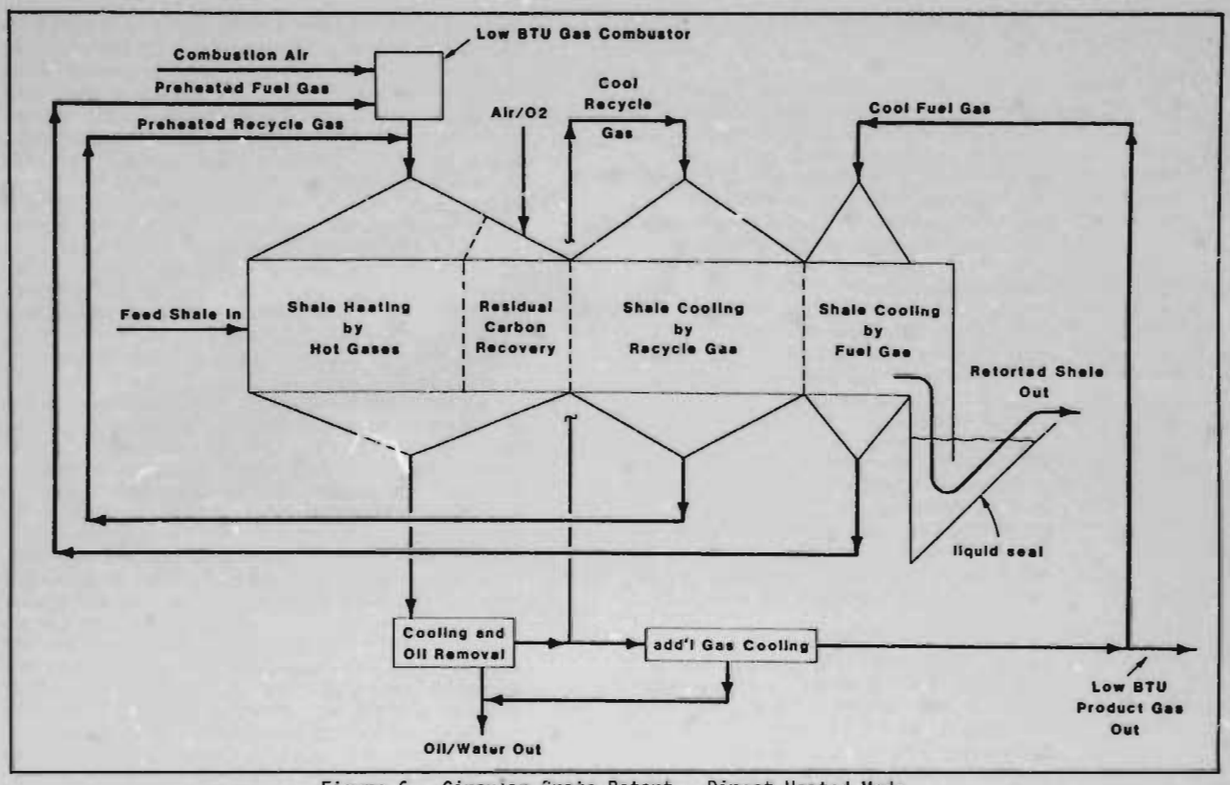

Figure 6. Circular Grate Retort - Direct Heated Mode

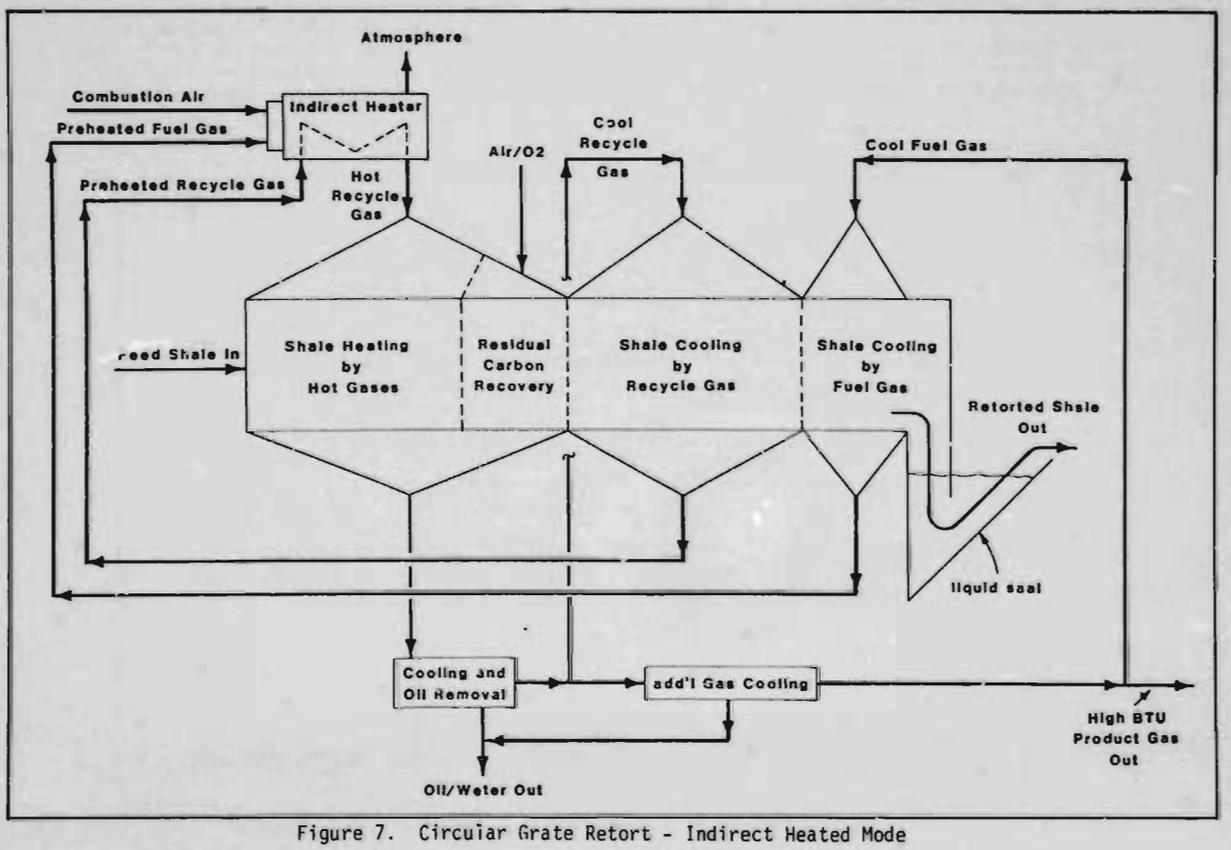

Figure 7. Circular Grate Retort - Indirect Heated Mode

level at throughput rates of 240 TPD (Ref. 4).

- The reliability and high service factor (95+%) of commercial scale mechanical equipment of identical design and similar capacity (6000-7000 TPD) to that proposed for the full scale oil shale retort has been proven for five years in commercial operation. Mechanical seal configurations with over 20 years of commercial applications have been demonstrated.

- Preliminary engineering and capital and operating cost estimates (±20%) have been completed for nominal 10,000 and 25,000 TPCD modules (Ref. 5).

- Basic design engineering for a nominal 25,000 TPCD demonstration plant to be situated on the Pacific Property of which Superior is a co-owner is currently underway. This program includes detailed engineering of a 60 meter mean diameter circular grate retort and is targeted for completion in mid-1982.

- Testing and retorting process designs have been completed for various other domestic and foreign oil shale deposits in support of Superior's retorting technology licensing program.

Circular Grate Retort For Processing Eastern U.S. Oil Shales

Limited testing by Superior on oil shales from the Eastern U.S. has led to the preliminary conclusion that this type of shale has a high potential for being economically processed in the Superior circular grate retort. Eastern U.S. oil shale, after retorting, generally exhibits a slightly higher residual carbon than the Colorado/Utah (i.e., Green River) oil shales. Superior's circular grate process accommodates recovery of residual carbon as well as the recovery of shale oil via controlled oxidation (see Superior's U.S. Patent Number 4,083,645). It is anticipated that a large portion of the residual carbon from Eastern U.S. oil shale can be utilized to supply a significant part of the heat necessary for the retorting process. Because the circular grate allows both the separation and/or the overlapping of process zones, several options are available to optimize the residual carbon recovery. The first option is to initiate oxidation of the residual carbon as soon as possible after the top portion of the shale bed is completely retorted (i.e., all oil and gas have evolved). This concept, an example of zone overlapping, can be seen from Figure 2. The heat generated from carbon oxidation is transferred downward through the bed to retort the shale in the lower portion of the bed. Figure 2 depicts residual carbon recovery terminating before O_2 breakthrough at the grate. Additional recovery of residual carbon can be accomplished, if desired, by extending the carbon recovery zone and inserting separate windboxes so that the O_2 bearing gas after breakthrough is not mixed with the hydrocarbon gas from the retort zone. This process method, shown in Figure 8, would provide high temperature gas for uses such as predrying and/or additional energy production, etc. It should be pointed out that residual carbon recovery has been tested and modeled on Western U.S. and Australian oil shales (which, like Eastern U.S. oil shales also exhibits slightly higher residual carbon contents). Furthermore, the residual carbon

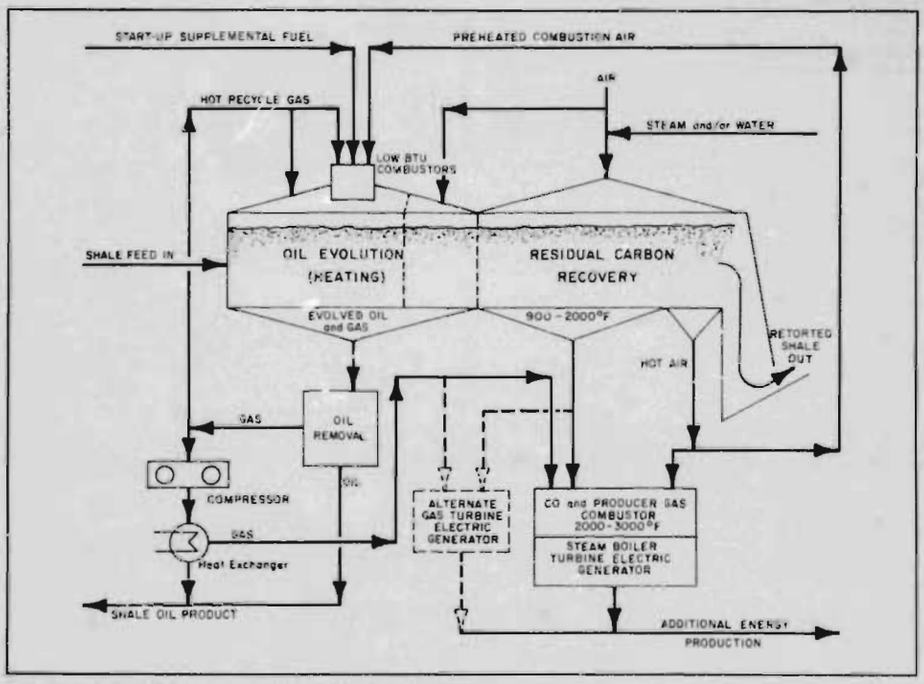

Figure 8. Superior's Retort for High Residual Carbon Shales

recovery was also demonstrated on the Superior pilot circular grate. Another method which has been tested on Superior's mineral bearing oil shale is to inject water (steam) along with the oxygen in the extended carbon recovery zone to generate a low BTU gas via the water-gas-shift reaction ($C+O_2$ + steam = $CO_2+H_2+CO_2$). This is also shown in Figure 8. Air or oxygen mixed with steam and/or water is passed through the hot shale bed after all the oil has been evolved. The gas exiting this residual carbon recovery zone would contain both H_2 and CO. While the gas would have a relatively low heating value (25 to 50 BTU/SCF range), because it is hot (900° to 2000°F range) it could be combusted utilizing the preheated combustion air in standard low BTU gas combustors. The resulting thermal energy could then be utilized such as for the production of electrical power as depicted in Figure 8. Recovery of the energy from the residual carbon increased the viability of processing this type of ore, and because the circular grate has a proven history of reliable operation in high temperature (2000° to 2400°F range) applications, its utilization enhances the potential for economically processing Eastern U.S. oil shales.

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Processing of Eastern Oil Shale for Liquid and Gaseous Fuels

by

M.M. Ahmed and D.H. Archer
Westinghouse R&D Center
Pittsburgh, PA 15235

Abstract. Experiments have been carried out to investigate how Eastern Devonian oil shales might be processed most effectively to obtain liquid fuels. The key processing step, shale pyrolysis has been studied using samples of Kentucky's Sunbury shale. The effects of shale heating rate, of vapor and solid residence times, and of gas composition on devolatilization products have been explored in laboratory scale fixed and fluidized bed reactors. Experiments have been conducted in nitrogen or hydrogen gas flows at atmospheric pressure and peak operating temperatures of 500-520°C. The products (liquid, gas and solid) collected have been analyzed and the information used to perform overall material and elemental balances.

The experimental results have revealed that the primary process variables affecting liquid yield are peak temperature and vapor products residence time; and that only a certain fraction of Sunbury shale carbon can be recovered as liquid fuel independent of the heating rate and the reacting gas nature (N_2 or H_2). Comparison of the data obtained with those from IGT bench-scale and PDU tests using Sunbury shale reveal similar liquid yield and quality.

Introduction

The energy potential of eastern oil shales located primarily in Kentucky, Ohio, Tennessee, and Indiana has been estimated to be around three trillion barrels.[1] Recent estimates indicate that at least 400 billion barrels could be recovered with existing technology.[2-5] Although some sampling and shale characterization efforts have been carried out,[2-7] a comprehensive effort to assess the full potential of eastern shales as a resource for utility fuel has yet to be made.

Two processes have been proposed for eastern oil shales. The HYTORT process, developed by IGT, is based on direct non-catalytic hydrogenation of oil shale kerogen at high pressures (up to 500 psi H_2 partial pressures). Originally proposed to produce substitute natural gas, the HYTORT retort design has been tested at bench scale and PDU scale (1000 lb/hr shale feed rate) to produce shale oil from several eastern and western shales, including Sunbury shale found in Kentucky.

The Paraho process, developed by the Paraho Development Corporation, is based on pyrolysis of oil shale at low pressure (~ 16 psia) and combustion of residual carbon in pyrolyzed shale. The Paraho Corporation believes that their retort designs, developed and tested at pilot scale using western oil shales cannot be used as such to efficiently process eastern oil shales.[6]

Both Paraho and HYTORT processing schemes have been evaluated by the Davy McKee Corporation (DOE sponsored study),[6] and the Hycrude Corporation.[8] Examining these studies indicate that additional process data would have been helpful in evaluating the two processes.

Study Scope

The primary objective of the experimental work presented in this paper has been to generate process data for assessing the potential of eastern oil shale as a utility fuel resource.

The eastern oil shale sample used in the experimental work is from the Kentucky area (Sunbury shale). The composition of the Sunbury shale sample determined by an independent laboratory (Galbraith Laboratory, Inc.) for the Westinghouse R&D Center is summarized in Table 1.

Results of analyses performed by IGT[9] and IMMR[10] for Sunbury shale samples used in some of their studies are also given in Table 1. These results indicate that the Sunbury shale samples studied by Westinghouse, IGT, and IMMR could be from different locations. The shale sample studied at the Westinghouse R&D Center is richer in carbon and hydrogen and contains less sulfur than the samples tested by IGT and IMMR. In the following sections, some experimental results are presented and briefly discussed.

Table 1. Sunbury Shale Analysis

	Westinghouse*	IGT[9]	IMMR[10]
Carbon, wt%	17.37 ± 0.84	14.71	13.63
Hydrogen	2.08 ± 0.05	1.74	1.83
Nitrogen	0.63 ± 0.01	0.56	0.61
Sulfur	2.48 ± 0.19	3.25	3.16
Oxygen (by difference)	2.07 ± 1.12	2.66	
Ash	75.37 ± 0.29	77.05	
	100.00	100.00	
H/C Atomic Ratio	1.40 ± 0.06	1.41	1.61

* Average of six analyses

Results and Discussion

A series of shale pyrolysis experiments have been conducted using fixed-bed or fluidized-bed reactor. The flow schematic for the test unit is shown in Figure 1. The objectives of these experiments have been to verify and evaluate the effects of critical process variables identified in earlier Westinghouse studies, as well as by other investigators, such as IGT, and IMMR on the products yield. These process variables are: (1) heating rate, (2) reactant gas composition/flow rate, (3) product (vapor/liquid) residence time in hot zone/quench rate, (4) reaction temperature, (5) pressure, and (6) shale particle size.

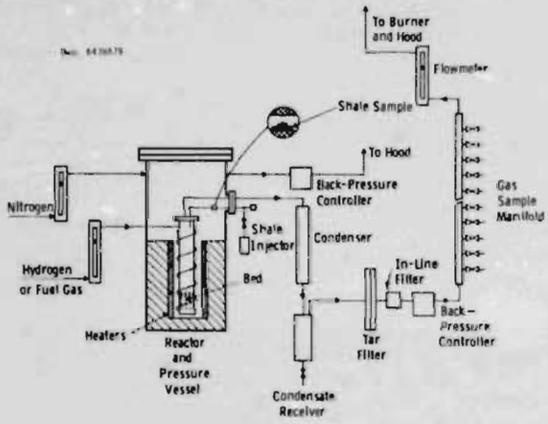

Figure 1. Flow diagram of laboratory fluidized-bed test unit.

The operating conditions and results of the current set of laboratory experiments to investigate shale oil yields and quality are summarized in Table 2. Two typical commercial scale reactor operations have been simulated with respect to heating rate: moving bed (∿ 10°C/min) and fluidized bed (> 1000°C/min). Experiments were conducted using either pure nitrogen or pure hydrogen as feed gas at atmospheric pressure and a maximum temperature of 500 to 520°C. The gas velocities and gas residence time studied were in the range of 2 to 15 cm/sec and 1 to 5 seconds, respectively. The shale was heated to 500°C and then held at that temperature for 30 minutes. The raw shale particle sizes studied were in the range of 0.16 to 0.8 mm. The devolatilized (spent) shale and the product oil (shale oil) have been analyzed, and the elemental compositions are summarized in Table 3. The product gas samples were analyzed for CO, CO_2, CH_4, C_2H_4, C_2H_6, H_2, and N_2 contents. The gas samples may also contain C_3, and C_{3+} compounds, but were not accounted in the results presented in this paper.

Shale Oil Yield. The results of experiments 1 through 4 (summarized in Table 2) indicate that heating the Sunbury shale at 10°C/min to 500-520°C in nitrogen results in 15.4 to 17.2 gallons of shale oil yield per 1000-kg of raw shale. The process parameters having different magnitudes in these experiments were: 1) gas flow rate (0.6-2.7 liters/min), which influences the dilution of products generated; 2) gas residence time (1.2 to 4.4 sec), which affects the extent of polymerization, condensation, and coking reactions; and 3) the shale particle size (0.5-0.8 mm), which influences the pore diffusional resistance. Studies have indicated that shale particle size in the range studied has a negligible effect on shale oil yields. The different shale oil yields observed in these experiments, therefore, could be due to products dilution and residence time effects, and also due to experimental

Table 2. Sunbury Oil Shale Processing Results -- Products Yield

	Westinghouse Studies - Laboratory Scale							IGT Studies[9]	
	1	2	3	4	5	6	7	Bench-Scale	PDU-Scale
Reactor Tube Material	Quartz	Quartz	Quartz	SS 304	SS 304	Inconel	Inconel	Inconel	SS
Reactor Diameter, cm	2.54	2.54	2.54	1.93	1.93	3.49	3.49	10.16	30.48
Operating Mode	Fixed-Bed	Fixed-Bed	Fixed-Bed	Fixed-Bed	Fixed-Bed	Fluid-Bed	Fluid-Bed	Moving Bed	Moving Bed
Critical Process Variables									
Oil Shale Charge, g	58.4	60.0	60.0	52.22	52.41	51.56	49.19	13.6 lb/hr	985 lb/hr
Heating Rate (Approx.), °C/Min	10	10	10	10	10	> 1000	> 1000		
Reactant Gas	N_2	N_2	N_2	N_2	H_2	N_2	H_2	H_2	90-95% H_2
Bed Temperature, Avg./Max., °C	500/520	500/520	500/520	500/520	500/520	500/520	500/520	638/677	694/749
Pressure, atm	1	1	1	1	1	1	1	35.6	28.4
Gas Flow Rate @ Avg. T & P, l/Min.	0.66	0.88 -	1.14	2.66	2.66	3.19	3.19	39.4	776.3
Static Bed Height, cm	9.5	10.2	10.8	17.8	17.8	18.4	18.4	274	305
Gas Velocity @ Avg. T & P, cm/sec	2.18	2.52	3.75	15.1	15.1	5.55	5.55	8.1	17.7
Gas Residence Time, sec	4.4	4.0	2.9	1.2	1.2	3.3	3.3	33.9	17.2
Shale Particle Size, mm	0.5	0.537	0.537	0.798	0.798	0.163	0.163	0.718	8.03
Reactant Gas/Shale Feed Ratio, Scf/lb	–	–	–	–	–	–	–	11.3	12.5
Shale Oil Collected, ml	3.5	3.5	3.9	3.4	3.0	3.3	3.3		
Shale Oil Yield, gal/1000 kg-Oil Shale	15.8	15.4	17.2	17.2	15.1	16.9	17.7		16.1
Shale Oil Yield, kg/kg - Oil Shale	0.0486	0.0501	0.0638	0.0643	0.0547	0.0619	0.072	NA	0.051
Spent Shale Yield, kg/kg-Oil Shale	0.865	0.887	NA	0.878	0.874	0.861	0.849		0.827
Product Gas + Unaccounted, kg/kg-Oil Shale	0.0864	0.0629	–	0.0577	0.0713	0.0771	0.079		0.122

Table 3. Sunbury Oil Shale Processing Results - Products Analysis

	Westinghouse Studies - Laboratory Scale							IGT Studies[9]	
	1	2	3	4	5	6	7	Bench-Scale	PDU-Scale
Shale Oil Analysis									
C, Wt. %	NA	NA	84.31	82.64	84.76	83.27	81.04	NA	8[illegible]
H			9.28	9.01	9.01	8.96	9.18	NA	9.70
N			1.82	1.92	1.98	2.03	2.22	1.8	2.07
S			1.81	2.16	2.04	2.20	1.77	1.6	1.37
O (by Difference)			2.78	3.92	2.00	3.44	5.79	NA	1.17
Ash			0.0	0.35	0.21	0.10	0.00	NA	0.10
H/C Atomic Ratio			1.32	1.31	1.28	1.29	1.36	1.45	1.36
Gravity, °API			12.9	11.4	16.1	14.4	10.0	NA	13.4
Spent Shale Analysis									
C, Wt. %	NA	NA	9.97	12.05	11.69	11.17	8.22	NA	6.17
H			0.44	0.76	0.95	0.56	0.50		0.36
N			0.49	0.50	0.50	0.47	0.35		0.25
S			1.97	2.09	1.55	1.76	1.58		1.52
O (by Difference)			0.54	1.60	0.69	0.53	2.30		0.56
Ash			86.59	83.00	84.62	85.51	87.05		92.26
H/C Atomic Ratio			0.53	0.76	0.98	0.60	0.73		0.70

scatter in shale oil collection. As indicated in Table 2, 50 to 60 g of raw shale was processed to yield 3 to 3.9 ml shale oil -- which is relatively small compared to the volume of gas flowing through the system. The shale oil was collected by washing the condenser and connecting lines downstream of the reactor with acetone, and then allowing the acetone to evaporate at ambient conditions.

The results of Experiment 5 indicate that heating Sunbury shale at 10°C/min to 500-520°C in hydrogen gives 15.1 gallons of shale oil per 1000-kg of raw shale. The relatively lower shale oil yield can be due to hydrogenation of some of the oil into lighter fractions, which escaped the shale oil collection system with the gas, and/or formation of gaseous hydrocarbons. Analysis of the shale oil collected indicates a composition similar to that of oils collected from nitrogen runs (Table 3).

Experiments 6 and 7 were conducted in the fluid-bed operating mode typical of fast heating (> 1000°C/min). The shale oil yields in nitrogen and hydrogen environments were 16.9 and 17.7 gallons per 1000-kg raw shale, respectively. The shale oil yield using nitrogen as feed gas is within the same range as that observed at a slower heating rate in Experiments 1 through 4. The relatively higher shale oil yield using hydrogen in a fluidized bed may be due to the differences in product release pattern at slow and at fast heating rates.

Comparison with IGT Data. As shown in Table 2, the shale oil yields (15.1 to 17.7 gal/1000-kg raw shale) obtained in this study are similar in magnitude (16.1 gal/1000-kg raw shale) to those obtained in IGT studies at high pressures using 90 to 95% H_2 in feed gas. In the following material, a brief summary of the elemental distribution data are presented to gain an insight into the products yield and quality as functions of operating conditions severity.

Organic Carbon Distribution. The results summarized in Table 4 indicate that approximately 30 wt% of the carbon in raw shale is accounted for by the carbon in shale oils produced and collected in the Westinghouse laboratory scale experiments and in the larger-scale experiments conducted by IGT. In the IGT studies, the shale was heated to a relatively higher temperaure (∿ 750°C); this resulted in significantly less carbon in the spent shale, and relatively more in the form of gaseous hydrocarbons, such as methane. IGT assumes that the unaccounted carbon is in the shale oil not collected. If this is true then the shale oil yields will be higher than those shown in Table 2. As far as the liquid yield is concerned, the operating conditions of temperature, pressure, gas composition, and residence time seem to have little effect.

Organic Hydrogen Distribution. The hydrogen to carbon atomic ratio in raw shale is about 1.40 (Table 1), whereas in shale oils it is between 1.28 to 1.45. The shale oils produced in the Westinghouse and IGT studies account for 24-28 wt% of hydrogen in raw shale, suggesting that a significant portion of hydrogen remains in the spent shale and/or emerges in the form of gaseous compounds.

Organic Nitrogen and Sulfur Distributions. The shale oils produced in Westinghouse laboratory-scale and IGT larger-scale studies contain 1.8 to 2 wt% nitrogen, and 1.37 to 2.2 wt% sulfur (Table 4).

The higher pressures (28-35 atm) in the IGT runs seem to have provided little or no advantage in producing a low nitrogen and a low sulfur content liquid fuel. Results of the elemental balances summarized in Table 4 indicate that 17 to 20 wt% of nitrogen and 2 to 6 wt% sulfur in raw shale are accounted for by nitrogen and sulfur contents in shale oils. The IGT data indicate that when the shale is heated to a high temperature, the sulfur and nitrogen in the devolatilized shale will be released in the form of gaseous compounds. This information suggests that the shale oil yield and quality observed under less severe operating conditions in Westinghouse laboratory studies are comparable to those observed in IGT studies under relatively more severe operating conditions of temperature and pressure.

Comparison with Davy McKee and Hycrude Process Evaluation Bases. The Davy McKee study[6] assumed that the Paraho and the HYTORT processes recover 33.7 wt% and 43.0 wt%, respectively of the raw shale carbon. The Hycrude study[8] assumed that the Paraho and the HYTORT processes recover 24.2 wt% and 54.2 wt%, respectively of the raw shale carbon. Of course, the compositions of raw shales assumed as feedstock in these two studies are quite different. The results obtained at Westinghouse and shown in Table 4 indicate that the shale oil collected accounts for up to 33 wt% of Sunbury shale carbon.

Table 4. Sunbury Oil Shale Processing Results -- Elemental Balances

		Westinghouse Studies - Laboratory Scale							IGT Studies[9]	
		1	2	3	4	5	6	7	Bench-Scale	ODU-Scale
Material Balance (Wt. % Distribution)*										
Carbon:	Shale Oil	NA	NA	31.0	30.6	26.7	29.7	33.6	NA	29.9
	Spent Shale			NA	60.9	58.8	55.4	40.2	27.0	35.0
	Product Gas**			NA	1.1	2.7	3.3	NA	16.0	24.4
	Unaccounted			69.0	7.4	11.8	11.6	26.2	57.0	10.7
Hydrogen:	Shale Oil			28.6	28.0	23.8	26.8	31.9	NA	28.4
	Spent Shale			NA	32.3	40.2	23.3	20.5		17.1
	Product Gas**			NA	4.5	4.4	8.4	NA		58.4
	Unaccounted			61.4	35.2	31.6	41.5	47.6		3.9
Nitrogen:	Shale Oil			18.4	19.7	17.3	20.1	25.4		18.9
	Spent Shale			NA	70.1	69.7	64.6	47.2		36.9
	Product Gas**			NA	NA	NA	NA	NA		NA
	Unaccounted			81.6	10.1	13.0	15.3	27.4		44.2
Sulfur:	Shale Oil			4.8	5.7	4.6	5.6	5.2		2.2
	Spent Shale			NA	75.4	55.7	62.3	55.2		38.7
	Product Gas**			NA	NA	NA	NA	NA		NA
	Unaccounted			95.2	18.9	39.7	32.1	39.6		59.1
Ash:	Spent Shale			NA	99.2	100.7	100.3	99.0		99.0
	Unaccounted			–	0.8	–0.7	–0.3	1.0		1.0

* Unaccounted Depends on Products Collection and Analytical Precisions

** In Westinghouse Studies the Gas Released is not Analyzed for C_2 + Compounds, H_2O, H_2S, and NH_3 Which can be Present in the Gas

Conclusions

The following conclusions can be drawn based on the results presented in this paper:

(a) Devolatilization rate independent of reacting gas nature (N_2 or H_2) at atmospheric pressure.

(b) Up to 33 wt% of raw shale carbon seems to be recovered as liquid fuel (shale oil).

(c) The primary process variables affecting liquid yield are reactor operating temperature and vapor products time-temperature history.

(d) The pyrolyzed shale contains significant percentage of raw shale carbon, hydrogen, nitrogen, and sulfur.

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Fluidized Bed Oil Shale Retorting: A Bench Scale Evaluation for Eastern Oil Shale

by

Marshall J. Margolis
Institute for Mining and Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract

The effects of retorting eastern oil shale under extremely rapid heat-up rate conditions were investigated. Heat-up rates of approximately 33,000°C/min were investigated in both a simple quartz tube reactor and a fluidized bed system.

The results from these studies indicate an improvement over the 30-35% carbon removal achieved under classical Fischer Assay conditions. Under rapid heat-up conditions 50-60% of the raw shale's carbon is easily removed.

Evaluation of spent shale carbon analyses and product collection data suggest that 120-140% of Fischer Assay yield may be achieved.

The data presented suggest that a retort system incorporating the features of a fluidized bed reactor can provide the conditions necessary to effect this yield enhancement.

Introduction

There has been considerable commercial interest in shale oil production in the United States during recent years. However, almost without exception, these interests have focused on western oil shale. Comparatively little attention has been given to deposits in the eastern United States.

The identification of a substantial oil shale resource in Kentucky and the evaluation of its oil generating potential suggests that its commercial development is viable.[1] The translation of this potential into a reality is contingent, however, on the identification and development of appropriate technologies.

Oil shales are found world wide and present a variety of characteristics. Technologies must be developed which accommodate their individual oil generating potentials, retorting characteristics, and total energy content.

Western oil shales differ significantly from those found in the eastern United States in a number of ways. Most notable are the lower oil yields associated with eastern shales when compared by standard Fischer Assay techniques.[2] These differences are not limited to their oil generating potential, however, but include fundamental differences in their mineral and chemical composition and retorting characteristics.

By comparison to western shales, Kentucky shales contain less retortable carbon (on a classical Fischer Assay basis), are depleted in hydrogen, contain little carbonate, and under Fischer Assay conditions produce less liquid oil.

Recent investigations at the Institute for Mining and Minerals Research have demonstrated that the oil yields from eastern shales are considerably more dependent on retort conditions than those of western origin. In particular, liquid and gaseous hydrocarbon products increase beyond Fischer Assay yields with increasingly rapid heating rates.[3,4]

Eastern shales tend to produce a comparatively lighter oil (approximately 50% boiling below 650°F by simulated distillation) and more high Btu gas.[5]

A wide variety of approaches have been promoted for producing shale oil. All of these are fundamentally pyrolysis schemes and only differ in the method of heating, material handling, and energy dynamics. Again, with little exception these processes have been developed to accommodate the physical, chemical, and retorting characteristics of western oil shale.

The observation that oil yields from eastern shales may be enhanced by rapid heating suggests that a retort incorporating this characteristic may be advantageous. For this reason fluid bed technology has been suggested as a basis for an

oil shale retort. A fluid bed reactor would particularly accommodate the rapid heat-up requirement because of its excellent heat transfer characteristics. Furthermore, this type of retort would provide short product residence times and presumably would help minimize coking and oil decomposition. The reactor itself would be mechanically simple and provide rapid oil shale throughput.

This investigation has, therefore, been principally concerned with the evaluation of very rapid heat-up rate retorting achieved through the use of fluidized bed systems. The two major components of this project investigated to date have included:

(1) the evaluation of the effects, on yield, of heating rates far greater than those obtainable in Fischer Assay type equipment; and

(2) the construction of a bench scale retort incorporating a fluid bed reactor and the examination of the oil generating potential under these conditions.

Experimental

Oil Shale Samples

Oil shale samples were obtained from the Sunbury Shale (of Mississippian age) in the Lewis and Fleming Counties (Kentucky) region. Detailed information on the chemical and geological aspects of these shale deposits has already been reported.[1] Samples were ground and prepared to yield representative splits of sieved portions of shale.

Tube Reactor

Evaluation of the response of these shales to extremely rapid heat-up conditions was conducted in a vertically mounted, electrically heated, 1/2" quartz tube reactor. Approximately 1.0 g samples of prepared shale were rapidly introduced, without pre-heating, into the heated zone of the reactor. The reaction system was continuously purged by and the particles fluidized with a stream of preheated high purity nitrogen. After five minutes the quartz tube reactor was removed from the furnace, cooled to room temperature, and the spent shale removed under nitrogen for analysis.

Under these conditions the extent of oil production was gauged by a comparative carbon-hydrogen-nitrogen analysis of the shale before (raw) and after (spent) retorting. Decreased amounts of carbon in the spent shale correspond to greater amounts of retorted product.

Several mesh sizes and temperature ranges have been examined in this manner.

Fluidized Bed Reactor

Fluid bed oil shale retorting was examined through the use of the system illustrated in Figures 1 and 2. The basic unit consists of a quartz reactor with a fixed fluid bed capacity of approximately 15 grams of shale. The reactor was vertically mounted within an electrically heated tube furnace and was capable of operating at temperatures up to 1200°C. Raw shale was continuously fed into the fluidized bed with a variable speed screw feeder (60-300g/hr) mounted at the top of the reactor.

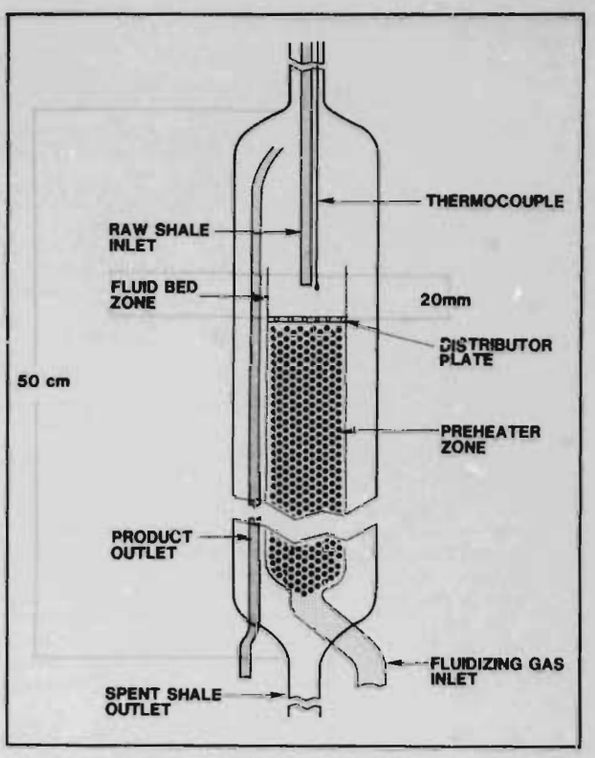

Figure 1. Quartz Reactor Section of the Bench Scale Fluidized Bed Oil Shale Retort

When operating with 20x30 mesh shale the system required approximately 5L/min of nitrogen gas to maintain fluidization. Under fluidized conditions spent shale was continuously displaced as raw shale was added to the reactor bed.

Products from the retorting shale were continuously swept from the reactor into a series of two cooled traps. Each trap was packed with 5-6 mm glass raschig rings and immersed in dry ice/acetone at approximately -70°C. Noncondensables and permanent gases were vented directly into a fume hood. Spent shale discharged from the reactor was collected in a chilled receiver under an inert atmosphere.

The amount of oil produced was determined by weighing the amount of material collected in the traps and correcting for water and particulate matter content. Water content was measured by Karl Fischer titration and particulates were determined from their retention on Whatman no. 40 filter paper.

Results and Discussion

Rapid Heat-up Retorting

The examination of rapid heat-up retorting under simple tube reactor conditions has been summarized in Table 1. The data presented here come from the evaluation of a Sunbury Shale with

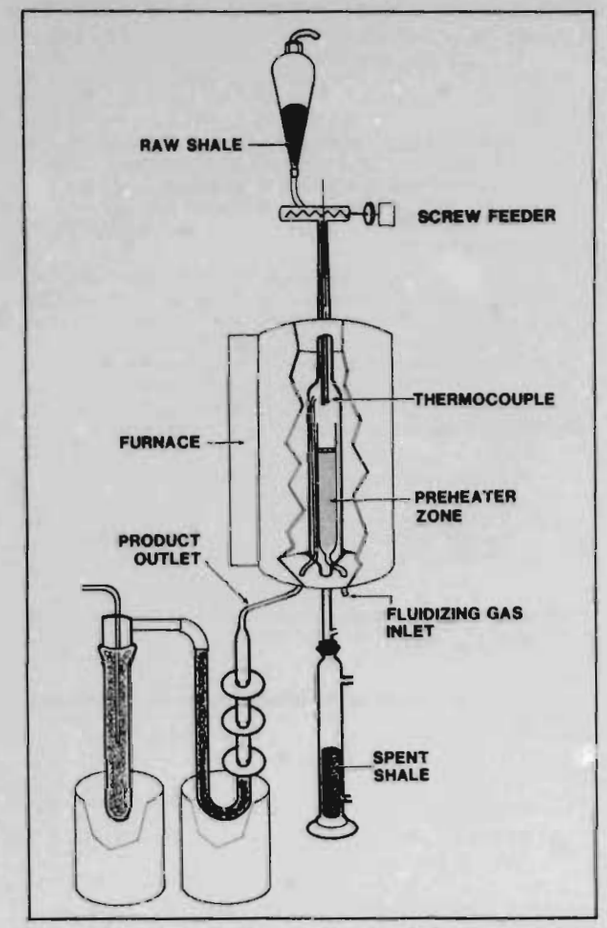

Figure 2. General View of the Bench Scale Fluidized Bed Oil Shale Retort System

a classical Fischer Assay of approximately 18 gal/ton.

Although residence times in the reactor were approximately 5 minutes, visual observations indicate that the major evolution of oil ceased within 10-15 seconds of sample introduction. Calculations based on the thermal properties and physical characteristics of this shale suggest that this range of particle size would have experienced heat-up rates approaching at least 33,000°C/min.

Based on the elemental composition of the raw and spent shale several conclusions can be drawn from this data. At the higher temperature, 538°C, approximately 54-57% of the carbon, virtually all of the detectable hydrogen, and only 40% of the nitrogen was removed from the shale on an as-received basis. These data also show an invariance with particle size for either retort temperature. This would suggest that the fastest heating rate (experienced by the smallest material, 30/40 mesh) is no more effective than the slowest heating rate (experienced by the largest material, 10/20 mesh) in these experiments. This suggests that the heating rate effect plateaus at a rate intermediate to that experienced by a 10 mesh particle (approx. 33,000°C/min) and the maximum rate obtained in fixed bed batch retorting experiments (approx. 60°C/min).

Similar results have been obtained from the fluid bed reactor system. These results have been summarized in Table 2 and similarly show that 50-60% of the carbon and 90-100% of the hydrogen can be retorted under rapid heat-up conditions.

These data also illustrate the requirement of retort temperatures high enough for kerogen pyrolysis. Although at approximately 400°C heating rates are extremely high, carbon removal is still only comparable to those of classical Fischer Assays.

Table 1. Effect of Rapid Heating on Oil Shale Composition in a Tube Reactor System.

FLUIDIZED ZONE QUARTZ TUBE REACTOR

Sunbury Shale (Lewis County, Kentucky)

	RAW SHALE			SPENT SHALE					
				412°C			538°C		
MESH	C	H	N	C	H	N	C	H	N
10/20	17.5	3.0	0.7	12.3	1.1	0.5	8.5	0.2	0.4
				(38)	(68)	(37)	(57)	(94)	(50)
20/30	17.4	2.6	0.6	13.9	1.2	0.6	8.6	ND	0.4
				(30)	(59)	(12)	(57)	(100)	(41)
30/40	17.7	2.7	0.6	13.4	1.1	0.6	9.2	0.2	0.4
				(33)	(64)	(12)	(54)	(94)	(41)

( ) = % of original oil shale carbon removed.

ND = Not detected.

Table 2. Summary of Effects from Rapid Heat Retorting of Oil Shale in Tube and Fluid Bed Reactors.

SUNBURY OIL SHALE -- LEWIS COUNTY, KENTUCKY

°C	SYSTEM	% C RAW	/	% C SPENT	% REMOVED C	% REMOVED H
412	Tube	17.4	/	13.9	30	59
538	Tube	17.4	/	8.6	57	100
600	Tube	17.3	/	7.5	62	--
600	Tube	16.7	/	8.4	56	--
488	Retort	15.5	/	6.1	65	88
510	Retort	16.5	/	9.5	50	89
593	Retort	17.4	/	8.5	57	100
704	Retort	15.8	/	7.7	57	100
704	Retort	17.5	/	8.1	59	100

The extent of carbon removal achieved in all of these experiments is significantly greater than the 30-35% carbon removal under Fischer Assay conditions. Extrapolation of Fischer Assay data (gal/ton vs. residual carbon), as illustrated in Figure 3, to the carbon levels generally obtained here suggests oil yields in the 20-25 gal/ton range.

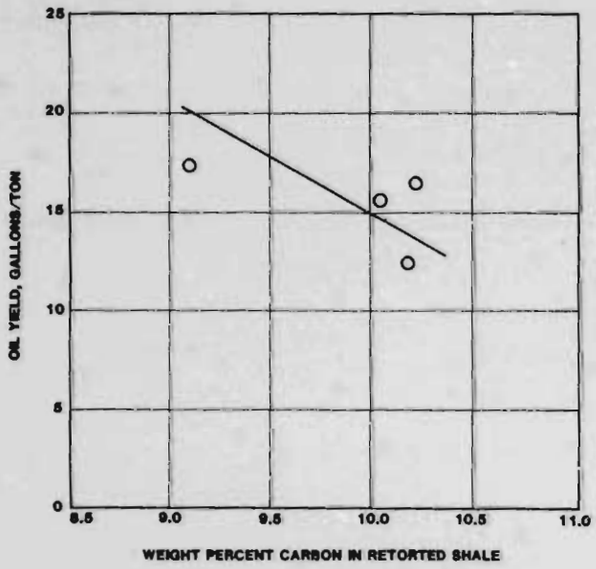

Figure 3. Correlation Between Residual Carbon Analyses of Spent Shale and Fischer Assay Yields

Fluid Bed Retorting

The bench scale reactor system permitted the collection and quantitation of liquid products in addition to spent shale analysis. The reaction conditions and results from two runs appear in Tables 3 and 4.

Table 3. Summary of Sunbury Shale Fluid Bed Retort Run Conditions

Feedstock

Sunbury Shale, from Lewis County, Kentucky
Composition = 17.4% Carbon, 2.6% Hydrogen
Fischer Assay = 18.0 ± 0.2 gal/ton
Size = -20 +30 mesh

High Temperature Run

Temp = 725 ± 8°C (1337°F)
Total Shale Processed = 59.64 g
Run Duration = 75 Minutes
Total Product Recovered = 7.08 g
Product Composition = 1.00 g ash*, 0.25 g H_2O,** 5.83 g oil

Low Temperature Run

Temp = 580 ± 15°C (1076°F)
Total Shale Processed = 44.39 g
Run Duration = 45 minutes
Total Product Recovered = 6.19 g
Product Composition = 0.29 g ash, 0.44 g H_2O, 5.46 g oil

* Ash = particulate trapped by Whatman no. 40 filter paper
** Determined by Karl Fischer titration

Table 4. Summary of Fluid Bed Retorting of Sunbury Shale

SUNBURY SHALE 20/30 MESH (LEWIS COUNTY, KENTUCKY)
17.4% Carbon 2.6% Hydrogen 18 Gal/Ton Fischer Assay

	725°C	580°C
TOTAL SHALE PROCESSED	59.6 g	44.4 g
Oil Produced:		
Weight*	5.8 g	5.5
% of Feed	9.8	12.3
Gal/Ton**	25	31
Spent Shale:		
% Carbon	8.1	8.5
% Hydrogen	N.D.	N.D.
% Carbon Retorted	59	57

* Determined after correction for water and particulates.
** Assuming a product density of 0.95 g/cm^3
N.D. = None Detected

In terms of experimental variables between these runs all parameters were essentially the same with the exception of the retort temperatures.

Both runs do, however, continue to support the trends of high carbon and hydrogen removal observed earlier. Based on the residual carbon and hydrogen in both runs it seems that the amounts of product (per gram of shale) should have been quite similar. The data, however, show a significant difference in the amount of liquid product collected.

The apparent explanation of this observation lies in the operating temperature of the reactor. Visual inspection of both reactors showed that significantly more coking had taken place on the walls of the hotter reactor. It seems fair to assume that at temperatures far in excess of those required for kerogen pyrolysis, major liquid product losses occur as a result of degradation and coking. The oil yields here (approximately 25-30 gal/ton), however, continue to support the yield enhancement trend observed earlier.

Extrapolation of data generated by rapid heating in Fischer Assay systems on the same shale have been made. The residual carbon and measured oil yield from these fluid bed runs have been compared to this yield enhancement trend in Figure 4. These data are not inconsistant with similar trends established earlier and continue to suggest yield enhancements of 120-140% beyond classical Fischer Assay at minimum.

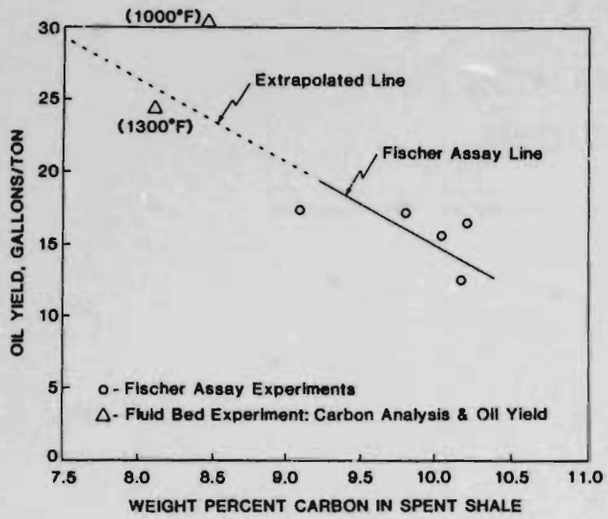

Figure 4. Relationship of Fluid Bed Retorting Results to Extrapolation of Fischer Assay Data

Summary

The data presented here further support the observation that oil yields from eastern shales can be enhanced by rapid heating retorting. Relative to the classical Fishcer Assay, this work demonstrates the extent of carbon removal improvement that can be achieved at extremely rapid heating rates.

Preliminary application of this approach in a model fluid bed retort system suggests that this improved carbon removal can be translated into liquid products. An apparent increase in liquid oil of at least 120-140% beyond classical Fischer Assay seems possible.

A fluidized bed based retort seems capable of effecting this yield enchancement for two reasons. It can provide the very rapid heat-up environment necessary to generate greater quantities of oil. In addition, the very short product residence times in the reactor certainly help to minimize post generation oil losses through degradation and coking.

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Acknowledgement

I would like to thank various members of the staff at the Institute for Mining and Minerals Research for their support during this project: Aurora Rubel for sharing her retorting experience, Jim Hasler for help in designing the fluid bed retort, and Gerald Thomas and Lucille Canter for providing analytical support.

Monday Afternoon Session

RESOURCES EXPLORATION AND GEOCHEMISTRY

Organic-Rich Shale (Devonian and Mississippian) in the Eastern Interior United States

by

Roy C. Kepferle
Department of Geology
Eastern Kentucky University
Richmond, Kentucky 40475

Abstract.

Organic-rich shale of Devonian and Mississippian age has been the object of characterization studies by private industry, universities, and state and federal organizations. These studies (since 1976) concentrate on the shale in the Michigan, Illinois, and Appalachian basins. In the Michigan basin, the Antrim Shale lies at depths of less than 3,200 feet and consists of more than 700 feet of sediments, of which the organic-rich part is less than 140 feet thick. In the Illinois basin, drilling depth to the base of the New Albany Shale is generally less than 5,500 feet. The total thickness of the New Albany Shale in the Illinois basin is less than 470 feet. In the Appalachian basin, the organic-rich part of the Devonian and Mississippian clastic sequence is generally less than 500 feet aggregate thickness of an eastward-thickening inorganic wedge that reaches nearly 9,000 feet where the depth to the base is more than 11,000 feet. The dark shale thins westward from a maximum in central Ohio, and where preserved on the Cincinnati arch in south-central Kentucky are less than 40 feet thick.

Correlation of the organic-rich tongues of the dark shales within the basins is facilitated by wire-line logs and physical stratigraphy. Correlation within the Appalachian basin, in addition, has used biostratigraphic zonation and beds of volcanic ash, so that units named from outcrops in New York State have been traced and identified in the subsurface through eastern Ohio and Kentucky, western Pennsylvania, West Virginia, and Virginia, as far south as eastern Tennessee. The discovery of one of the biostratigraphic zones (characterized by the alga? *Foerstia=Protosalvinia*) in cores and outcrops on the eastern margin of the Illinois basin provides further basis for correlating the organic-rich layers associated with the *Foerstia* zone in the Huron Member of the Ohio Shale in the Appalachian basin with similar *Foerstia*-bearing shale in the Clegg Creek Member of the New Albany Shale in the vicinity of Louisville, Kentucky. The significance of such detailed correlation is increased with the recognition of depositional control over the organic and trace-metal content of the individual beds within this deceptively homogeneous-appearing sequence.

Hydrocarbon and Uranium Assessment of the Chattanooga (Devonian) Shale in North Alabama, Northwest Georgia and South Tennessee: A Summary Report

by

Karen F. Rheams, Lawrence J. Rheams, Charles W. Copeland and Thornton L. Neathery
Geological Survey of Alabama
P.O. Drawer O
University of Alabama

Abstract. Devonian Chattanooga Shale occurs over almost all of north Alabama and south-central Tennessee. It ranges in thickness from 0 to 90 feet and is typically a dark gray to black shale with pyrite laminae and nodules. Very small lenses and interbeds of sandstone and siltstone, calcite streaks, phosphate nodules and cherty layers occur locally. The unit is correlative with the Gassaway Member as recognized in Tennessee.

More than 120 outcrop sections have been measured and sampled within the study area. Approximately 500 shale samples have been collected from exposures and core holes and analyzed for oil content by Fischer Assay, and for uranium content. One hundred thirteen (113) samples from extreme north Alabama and south-central Tennessee have yielded greater than 7 g/t oil; the average value of these is 13 g/t, with a maximum of 23.9 g/t. Uranium values ranged from 0 to 88 ppm. Analyses of selected Chattanooga Shale cores indicate good correlation between outcrop and subsurface material.

Shale samples of high oil content are typically very dark gray to black, slightly pyritic and some have a petroliferous odor. The shale ranges in thickness from 0-25 feet in the outcrop in the Highland Rim section in north Alabama and south-central Tennessee. Sandy and silty shale samples show a sharp decrease in oil yield values. Overburden in the Highland Rim section ranges from 0 to 140 feet.

The Chattanooga Shale in this region appears to have accumulated in a shallow (less than 100 feet) marine reducing environment with a highly irregular shoreline and some scattered islands. If this depositional hypothesis is correct, it may account for the sporadic occurrence and variable thicknesses of the shale unit.

Introduction

A regional resource assessment of the Chattanooga (Devonian) Shale in Alabama and adjacent states supported by the United States Department of Energy was begun in October 1980 by the Geological Survey of Alabama and the Mineral Resources Institute at the University of Alabama.* The objectives of the Geological Survey of Alabama's program were to complete a reconnaissance sampling of the Chattanooga Shale in northern Alabama, northwest Georgia and south-central Tennessee and to analyze the collected shale for oil yield and uranium content. Analyses for trace metal content are also being conducted on shale samples showing 7 g/t or greater oil yield. This reconnaissance sampling provided 507 bulk Chattanooga Shale samples for analysis. During this investigation, 9 core holes were drilled and the recovered shale cores were also analyzed for oil and uranium. Maps of the study area have been compiled which show the location and thickness of individual outcrops, subsurface thickness penetrated in drill holes, the structural configuration of the top of the Chattanooga Shale, and the thickness of the overburden above the Chattanooga Shale.

*Department of Energy Grant No. DE-FG44-80R410200 to the Alabama Department of Energy, University of Alabama and the Geological Survey of Alabama.

Geology of the Area

The Chattanooga Shale of Late Devonian age occurs over almost all of north Alabama, northwest Georgia and south-central Tennessee (figure 1). The shale is commonly a dark gray to black,

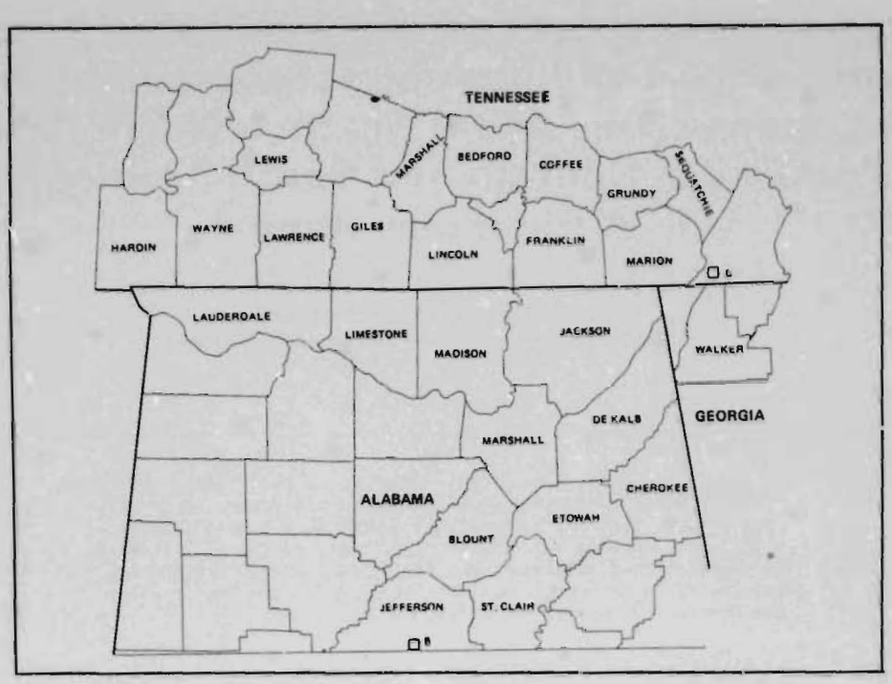

Figure 1. Study area.

thinly laminated, organic, pyritiferous marine shale with small lenses and interbeds of sandy or silty shale. Calcareous or cherty zones and phosphate nodules occur locally. In most outcrops, the Chattanooga is finely fissile when weathered. Two almost perpendicular joint set patterns are visible in the studied outcrop area: one trending towards the northeast and one towards the northwest. In the Highland Rim outcrops, the Chattanooga breaks into large blocks defined by these joint sets. These blocks of shale also become fissile with weathering. This joint pattern is evident in the fold belts of the Appalachian Plateaus and the Valley and Ridge but is spaced much closer together than in the Highland Rim section. The highly fractured nature and well developed fissility of the shale in this region makes it difficult to determine how important the joint sets may have been in the fracturing in these folded areas. Stratigraphically, the Chattanooga Shale unconformably overlies Ordovician or Silurian age formations (limestone or shale), and is overlain by the Mississippian Maury Formation or the Mississippian Fort Payne Chert.

The Chattanooga Shale section in northern Tennessee includes a lower Dowelltown Member and an upper Gassaway Member. In Alabama, Georgia and south-central Tennessee only the Gassaway Member is present. It is this upper Gassaway Member that shows the greatest oil shale potential.[1]

Exposures of the Chattanooga Shale within the study area are located along stream valleys in the Highland Rim section of Alabama and Tennessee; on the flanks of the major folds (Sequatchie Anticline, Wills Valley anticline and Murphrees Valley anticline) in the Appalachian Plateaus Province; and in the Valley and Ridge Province of Alabama, Georgia, and southeast Tennessee (figure 2). Shale thicknesses range from 0 to 40 feet in these exposures, with thickness exaggerations of up to 80 feet or more along the flanks of the major folds. In north Alabama and south-central Tennessee the Chattanooga Shale crops out along the southern margin of the Nashville Dome, and is generally less than 20 feet thick. The shale thickens away from the margin of the dome towards the folded provinces to the south and east.

Deposition of the Chattanooga Shale within the study area (particularly in northern Alabama and south-central Tennessee) was apparently sporadic since the presence and thickness of the shale can vary significantly within a short distance. Areas where the Chattanooga is very thin or absent may have been topographic highs during the Devonian (scattered islands) or beyond the bounds of the Chattanooga Sea during deposition (ex. west Alabama--Mississippi area). Absence of the shale indicates that either the shale was not deposited or was eroded before deposition of the overlying Maury Formation.[2]

Reconnaissance Sampling of the Chattanooga Shale

A reconnaissance sampling of the Chattanooga Shale was conducted in north Alabama, northwest Georgia and south-central Tennessee. Approximately 127 surface exposures were measured and described, and 409 bulk shale samples were collected. Sections more than 2-feet thick were sampled. Additional data accumulated at each site included a measured section of the Chattanooga Shale, stratigraphic description of the exposure, structural attitude of the formation, and overburden thickness.

Nine (9) exploratory core holes were drilled in the study area. Four core holes were drilled

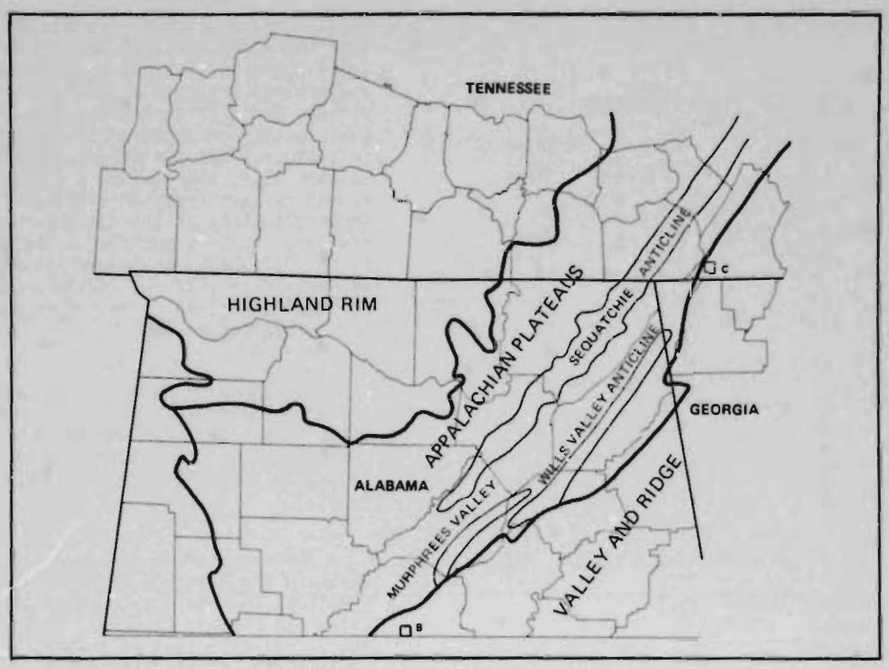

Figure 2. Physiographic provinces within the study area.

on the flanks of the Wills Valley anticline near Sulphur Springs, Alabama, and 5 core holes were drilled in northern Limestone and Madison Counties in the Highland Rim section of Alabama.

Analyses

Shale samples collected from surface exposures and the core samples from the drilling program were crushed and submitted for analysis of shale oil content by modified Fischer Assay methods and were also analyzed for total uranium (table 1) content by the U.S.G.S. Fluorometric method.[3] Sample yielding greater than 7 g/t oil content were analyzed for major and trace element content using standard atomic absorption techniques.

Table 1. Sample Location, Thickness, Oil Content and Uranium Analyses for Chattanooga Shale Samples in Limestone and Madison Counties, Alabama, and Giles and Lincoln Counties, Tennessee.

Limestone County, Alabama

Sample number	Thickness (ft)	Oil (gal/ton)	Uranium (ppm)
1	2+	11.1	21
2	2+	9.84	22
3	3.5+	15.5	19
4	5+	13.2	12
5	2+	11.5	19
	Average	12.2	

Madison County, Alabama

Sample number	Thickness (ft)	Oil (gal/ton)	Uranium (ppm)
1	4+	10.4	24
2	7+	11.7	17
8*	10	10.9	-
3	10+	8.7	19
9*	14.3	9.2	-
4	2+**	3.21	3.7
5	5+	14.3	22
6	5+	11.6	18
6*	4.4+	13.2	-
7	5+	12.1	19
8	4+	11.9	18
	Average	10.6	

Giles County, Tennessee

Sample number	Thickness (ft)	Oil (gal/ton)	Uranium (ppm)
1	5+	15.5	23
2	1.5+	18.2	16
3	4+	19.2	15
4	3+	14.3	30
5	6+	15.7	14
6	4.5+	15.2	21
7	3.5+	16.6	21
8	4.5+	14.9	17
9	1+	11.5	11
10	10+	19.9	20
11	4+	15.5	25
12	7+	15.7	13
13	5+	14.8	11.5
14	2+	14.8	12
15	4+	15.5	20
	Average	15.82	

Table 1 Continued.

Lincoln County, Tennessee

Sample number	Thickness (ft)	Oil (gal/ton)	Uranium (ppm)
1	5.6+	19.0	18
2	5+	14.3	20
3	4.8+	12.0	14.5
4	3.7+	9.8	13
5	7+	6.9	21
6	2.5+	16.5	21
7	2+	16.7	19
8	2+	16.9	7.6
9	2+	11.3	28
10	2+	11.5	21
11	4+	14.7	10.5
12	4+	11.0	15
13	6+	14.5	15
14	6+	13.6	23
15	2+	12.1	18
		Average 13.4	
Average for 4-county area		13.2	

*Drill site number
**Weathered

Analytical results indicate that the oil yields for the outcrop samples correlate very well with values obtained from the core samples within the same area. This correlation indicates that surface sampling can be an effective method for regional shale evaluation. For example, surface sample MAD-2 has an average oil content of 11.8 g/t, while nearby core hole number 8 has an average oil yield of 12.1 g/t.

Discussion

Based on this reconnaissance study, the area underlain by Chattanooga Shale in northern Alabama, south-central Tennessee and northwest Georgia can be divided into two parts: areas of greater than 7 g/t and areas of less than 7 g/t. In general, the results of the Fischer Assays of samples from the folded Appalachian Valley and Ridge and the Appalachian Plateaus Province are poor, where as those from the Highland Rim section indicate some potential for development.

Fischer Assays of samples from the folded Appalachian Valley and Ridge Province and the Appalachian Plateaus Province indicate less than 5 g/t, with most samples closer to 0 g/t. There are several possible explanations for the low oil contents in this area. The low oil content may be related to the type of plant material preserved in the shale, or the loss of volatile constituents caused by the pressures and elevated temperatures of folding. The types of plant material preserved in the shale and possible differences in the total organic carbon content of the shale in the three major geologic provinces involved have not been determined as a part of this investigation. According to Swanson (1960), shales with larger amounts of humic organic matter (organic matter derived primarily from the woody parts of plants) are confined to areas close to shore at the time of deposition and exhibit relatively low Fischer Assay oil yields. Abundant sapropelic organic matter (organic matter composed of algae, spores and pollen) in shales is associated with relatively high Fischer Assay oil yields. Shales of this type are formed farther from shore and oil yields increase proportionately as the distance from shore increases.[4] Shale deposited in the area underlain by the Valley and Ridge and the Plateaus Province may have been adjacent to the ancient shoreline and thus contained a greater amount of humic organic matter.

Work done by Anita Harris and others in 1978 relating conodont color alteration to thermal maturity of sediments and hydrocarbon potential indicates that the Chattanooga Shale in these folded belts has been heated to between 50°C to 170°C.[5]

The highest oil yield values are in the Highland Rim Province of Alabama and Tennessee in Limestone and Madison Counties, Alabama, and Giles and Lincoln Counties, Tennessee (figure 3). All oil yield values in this 4-county region are greater than 7 g/t, the highest value of 23.9 g/t is located in Lincoln County, Tennessee. The Chattanooga Shale in most of this area is either exposed, or occurs within 100 feet of the surface. The average oil yield from the collected samples and core samples in this 4 county area is 13.2 g/t. The thickness of the shale ranges from 1 to 15 feet (figure 4). In most cases, the highest oil yields have come from the upper sections of the sampled intervals, or the upper part of the Gassaway Member.

Analyses indicate that uranium values are higher in the Valley and Ridge Province and in the Appalachian Plateaus Province than in the Highland Rim. A maximum value of 88 ppm uranium was indicated from sample CHE-2A from Cherokee County, Alabama. These higher values may be the result of close proximity to the source area for the uranium. Uranium source material was probably derived from the ancestral Appalachians to the east and accumulated in greater quantities near the ancient shoreline.

The richer oil shale areas of the Highland Rim Province has lower uranium values than the fold belts. Previous workers suggest that the higher the oil content, the higher the uranium content.[6] This conclusion does not appear to hold true for all areas within the Highland Rim Province. Our preliminary uranium results indicate uranium values ranging from 0 to 45 ppm, which are not nearly as high as values from the oil depleted shale sampled in the fold belts to the east.

Summary

The shale oil content of the Chattanooga Shale in the Highland Rim Province of northern Alabama and south-central Tennessee is equal to that reported in northern Tennessee and Kentucky. The results of this investigation indicate that

Figure 3. Sample locations and Fischer Assay results in Giles and Lincoln Counties, Tennessee, and Limestone and Madison Counties, Alabama.

the Highland Rim area contains more oil and less uranium than the folded Valley and Ridge Province and Appalachian Plateaus Province. Although the thicknesses are not great in the Highland Rim Province, the higher oil yield, numerous exposures and thin overburden make this area promising for future oil shale development.

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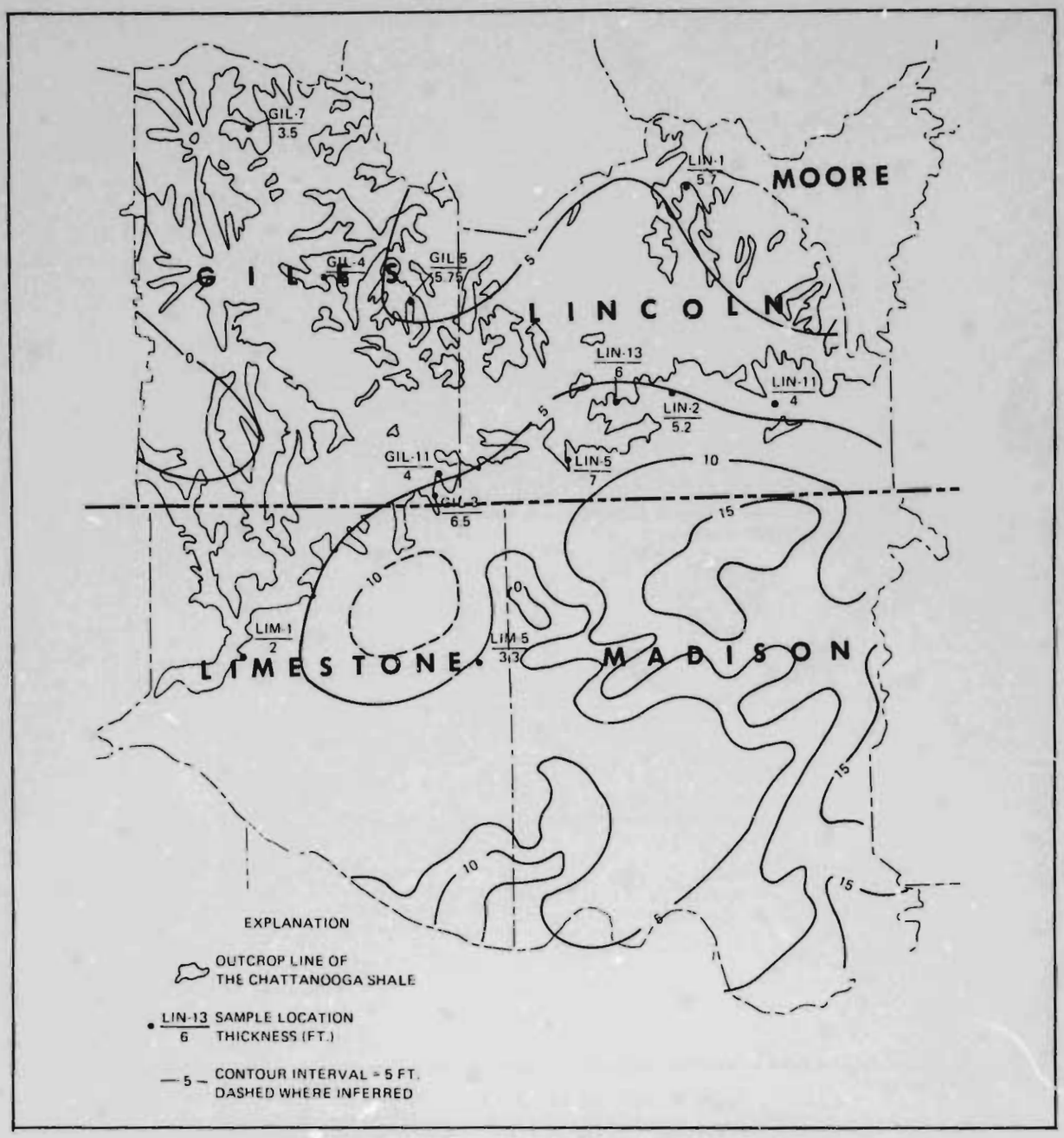

Figure 4. Thickness map of the Chattanooga Shale in Giles and Lincoln Counties, Tennessee, and Limestone and Madison Counties, Alabama.

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Chattanooga Oil Shale in Tennessee — Resource Assessment and Characterization

by

H. Wayne Leimer
Department of Earth Sciences

Chris McGowan
Department of Chemistry

Tennessee Technological University
Cookeville, Tennessee

ABSTRACT

At the time of its deposition during the Devonian Period, the Chattanooga Shale apparently covered all of Tennessee west of the Unaka Mountains except for two small areas. Erosion has removed the shale from west Tennessee, most of the Central Basin, and most of the valley and ridge. Folding and faulting further obscures its distribution in the valley and ridge. Five cores from a seven county Eastern Highland Rim area were analyzed for shale thickness, organic elements, mineralogy, major inorganic elements, trace elements, and Modified Fischer Assay. Analyses indicate that in the initial study area, the SW Putnam - NW White County area is the best potential mine-plant site. Six additional cores were taken in this restricted area and analyzed as before. This data was also compared with similar data from an east Tennessee Chattanooga Shale core. One square mile of Chattanooga Shale in the restructed study area contains 14.4 X 10^6 barrels of oil -- 11.5 X 10^6 barrels from the Gassaway member and 2.9 X 10^6 barrels from the Dowelltown member using normal retorting methods. Topography, nature and depth of overburden, other geologic conditions, and environmental considerations almost dictate underground mining. Underground methods give approximately 50% resource recovery. Hydrogen retorting should increase the oil yield by a factor of two. Although the east Tennessee section is 21 times thicker (720 feet compared to 35 feet) than the Eastern Highland River section, it is much leaner as far as extractable materials and is thus eliminated as an oil source. Organic analyses indicate potential carcinogenic materials present.

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H. Wayne Leimer
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Overview of Oil Shale Development in Ohio

by

Gene O. Johnson
Research Administrator
Ohio Department of Energy
Columbus, Ohio 43215

Abstract. The energy resource contained in the oil shale of Ohio represents a significant reserve for future development. These black shales were deposited during the Devonian and Mississippian Periods beneath a deep equatorial inland Kaskaskia sea that accumulated detrital organic sediments at the bottom. The oil rich shales of Ohio are the lower and upper Huron Members, the Cleveland Member of the Ohio Shale, and the Sunbury Shale. Thermal maturation of the vitrinite in the Ohio shale averages 0.54 Ro in Ohio. The present distribution of the oil shale in Ohio is in both glaciated and unglaciated areas in the north/south central and northeastern part of the state. The shale oil industry to develop these energy resources began with the pioneers and in 1866 with the St. Louis Shale Oil Company. Financial and technological interest continues today.

OVERVIEW OF OIL SHALE DEVELOPMENT IN OHIO

INTRODUCTION

The energy potential of oil shales in Ohio have long fascinated the citizens of the state. These shales continue to represent a significant energy resource for potential development. As much as 8.56×10^{20} Joules (8.12 Quadrillion Btu's) may be contained in these deposits of Ohio.

These oil shales are Devonian and Mississippian in age and crop out along the central North-South portion of the state. These shales extend into the Appalachian Basin at an easterly dip of approximately 6 to 7 meters per kilometer (30-35ft/mi). The Devonian oil rich formation is the Ohio Shale composed of the Huron, Chagrin, and Cleveland Members in ascending order. The Mississippian formations include the Bedford/Berea Shale and Sandstone overlain by the thin but oil rich Sunbury Shale. Overburden above the Sunbury Shale includes the lean Cuyahoga and Logan Formations.

The overall thickness of the Ohio Shale on the average ranges from 64 meters in the south central portion of the state to 150 meters in central Ohio and 1200 meters in the eastern subsurface. The oil shale lithology is generally represented by dark, organic rich, beds in the Huron and Cleveland Members. The middle member or Chagrin is generally represented by blue-gray clay shale with low organic content. The Sunbury shale is stratigraphically consistent and three to six meters thick.

Interest in the energy resources of these organic shales and their mineral constituents has a long history for the Ohioans. The indians used the shale and its components for rituals and facepaint, hence, the name "Paint Creek" of the major Ross County stream and the Olentangy River and type locality of the Olentangy blue clay shale. References to pioneer mining of natural copperas (Melanterite), alum, pyrite, and "coal" within these units as well as tar and oil springs are found in the early histories and geologic surveys of the shale area. Attempts to enhance these natural phenomena were tried during the industrial revolution and ranged from simple kettle stills to combustors and massive retorts - most proved uneconomical.

The present economic setting and need for pumpable hydrocarbons has renewed the technological and financial interest in the eastern oil shales. These interests include increasing technological efficiencies in extracting the hydrocarbons from the shale matrix as well as tax and loan advantages for financing the oil shale's industrial development. Given the premise that man is a problem solver rather than a trend follower, the energy resources of these oil shales will become a physical reality in the future.

DEPOSITIONAL ENVIRONMENT OF THE OIL SHALE IN OHIO

Sometime between 400 and 350 million years ago a unique depositional environment developed throughout the east and central portion of North America.[1] At that time the combined continent of Pangaea had drifted across the equator. Along the contact of the Eurasian and the American components of Pangaea, the Arcadian orogeny had produced the ancestral Appalachian Mountains with a strike running across the equator. These mountains straddled the equatorial low pressure

area and shielded the northeast and southeast trade winds from the central portion of the North American craton. This orographic barrier produced a relative rain-shadow desert on the leeward or western side of the Appalachians.

The relative ocean level had steadily retreated from the craton during the end of the Tippecanoe Sequence[2] (late Silurian and early Devonian Periods). The onlap of Kaskaskia Sequence (from early Devonian through Mississippian) eventually inundated the craton ranging from Northern Georgia to Manitoba and from Texas to Ontario.[2] the sea level may have been as deep as 900 meters in the developing Appalachian basin of Ohio.[1] Waters as deep as these develop a pycnocline that insulates the benthic environment from the aerobic environment of the oxygenated surface waters. This restricted circulation by the pycnocline produced an anaerobic environment in the reducing waters of the bottom.

Life in and around this sea include some of the early land plants and varieties of pelagic vegetation, as well as invertebrates and vertebrates. The early land plants include the scouring rush type represented by Callixylon and clubroot tree ferns Aneurophyton or the Gilboa Tree.[3] The pelagic vegatation included planktonic algae (seaweed) varieties represented by the spores Tasmanites (sp.) of Pachysphaera and Foerstia (sp.).[4] The invertebrates are represented by conodonts, linguloid brachiopods, and a near biologic spectrum of other phyla. The vertebrates are represented by rare pisces (fish) fossils. The anaerobic bottom was probably dominated by bacterial forms similar to Desulfotomaculum nigrificans (sp.).

The dominant organic source in this equatorial inland sea probably was a sargassum at or near the surface. This vegetative mass could have thrived on upwellings of nutrient rich waters from the depths of the inland sea. The natural attrition of these individual algae as well as waterlogged flotsam from the land plants created a detrital source of organic fragments that rained through the pycnocline to the bottom. It has been estimated that less than 1 percent of the organic material ever reached the bottom of the inland sea to form the hemipelagic deposits of the oil shale.

LITHOLOGIES

The exposed shale sequence containing the oil rich members rests on an unconformity throughout Ohio.[3] The underlying members range from the Niagaran Series - Lockport Group in the south to the Erian Series-Delaware Limestone in the north. The relief on this unconformable surface has been found to be more than 18 meters and may extend up to 55 meters. The dominant lithology of these underlying members and formations are dolomites in the south and limestone in the north. The relief on these underlying carbonates played a significant role in the lower facies of the oil shale sequence.

The Olentangy Shale is the basal member of the oil bearing shale sequence. The Olentangy is a bluish-gray to greenish-gray clay shale with black fissile shale beds in the upper portion. It contains flat concretionary masses of blue limestone in central Ohio that gain continuity in northern Ohio to become the Prout Limestone. In southern Ohio the basal shale is composed of interbedded blue clay shale and black or blue black fissile shale. In the south this basal member is usually bioturbated and displays well preserved Callixylon fossils. The thickness of the Olentangy averages 8.5 meters throughout much of the central outcrop. To the north and northwest it thickens to 11 meters and 28 meters respectively. To the south the interbedded facies representing this unit ranges from a few millimeters on the highs to 18 meters and more in the pre-Kaskaskia valleys.

The Huron Shale Member of the Ohio Shale rests conformably on the underlying Olentangy Shale.[3] The Huron Member is organically rich and represents the basal member of oil producing shale. The Huron is a black fissile shale ranging in color on the fresh surface from bluish black and grayish black to brownish black. The Lower huron is characterized by an assortment of concretions ranging in size from a few millimeters to 5 meters and more. The mineral composition of these masses is usually iron-disulfide components from the smaller individuals to various carbonates for the larger ones. The shale is typically a quartz-illite-chlorite rock even in the clay fraction.[8] Kaolinite is normally absent. Pyrites and carbonates comprise the remaining mineral components. The organic matter in the Huron ranges from abundant fossil and plant fragments and spores to thin films of coal. These organic remnants have a thermal maturity in the Ohio Shale as indicated from vitrinite reflectance ranging from 0.37 at the outcrop to 0.71 in the subsurface with an average of 0.54.[5] The thickness of the Huron ranges from an average 125 meters[3], along the outcrop to 39 meters over the Silurian highs in southern Ohio and to 106 meters in the subsurface. The Huron has been divided into three submembers based on the relative natural radioactivity.[6] The lower and upper Huron submembers are higher in active isotopes than the middle.[6] The middle member is a dark greenish gray shale, nonradioactive and is characterized by the time stratiographics zone of the fossil algae Foerstia.[4] The upper submember is a black shale facies and is radioactive.[6]

The Chagrin Shale Member of the Ohio Shale is characterized by light bluish gray clay shale with thin sandstone and siltstone lenses in the north and thin-interbedded blue gray and black shale in the south. The upper part of the Chagrin has been termed the "Three Lick Bed" and is the lithology recognized in the southern part of the state.[7] The Chagrin in the northeastern part of the state reaches a maximum thickness of about 366 meters and may facies into the black shales of the Huron to the south and west.[3] In the north central portion of the state the Chagrin thins to 34 meters. The equivalent "Three Lick Bed", in the south is 8 meters thick. The "Three Lick Bed" and Chagrin Member have low or nonexistent carbon content and usually represent non productive shale oil potential. The major mineral components of the Chagrin are quartz-illite-chlorite-kaolinite.

The Cleveland Shale is a black bituminous shale characterized by its lack of concretions and its stratigraphic overburden of the Bedford and Berea Formation. The fresh shale is bluish black to brownish black and turns to a medium brown upon weathering. Further weathering develops dark gray, platy to flaky pieces that remain non plastic. Fractured fresh samples give off a petroliferous odor from the high kerogen content.[3] The Cleveland Shale is composed of quartz-pyrite-illite-chlorite mineralogy.[8] The quartz particles range down to the 2 to 7 micron range.[3] The thickness ranges from 6 to 16 meters on the outcrop and thickens to 30 meters in the subsurface.[9]

The Cleveland shale has been reported to contain plant fragments of sufficient quantity to produce cannel coal as well as fragments of true coal.[3] The Cleveland Member pinches out to the east in the subsurface and thickens in lows along the outcrop. The outcrop expressions of the Cleveland is usually concealed by the colluvium from the weathered Bedford Shale further up slope.

The Bedford Shale is the lower formation of a delta wedge that filled the Kaskaskia Sea over Ohio. The Bedford is a medium gray to dusky red clay shale with increasing clastic size from bottom to the basal contact of the Berea Sandstone. The low organic content and obvious bioturbation of the sediments display the final emergence of the bottom sediments through the pycnocline and the oxygenation of the waters. The Bedford Formation is approximately 18 meters thick on an average and is the prodelta deposit of the prograding Berea delta of the early Mississippian Period. The Bedford Shales are composed of quartz-illite-chlorite-kaolinite mineralogy.[8] The kaolinite has a major effect on the clay fraction and contributes to its plastic and elastic qualities. The siltstone and sandstone beds in the Bedford are occasionally ripplemarked with the crests oriented N 60° W indicating wind direction of N 30° E or S 30° W.[3]

The Berea Sandstone is represented along the outcrop as a distributary channel sand and a series of subaqueous splay and bar sands. The combined Berea/Bedford sequence establishes a cessation of the long lived equatorial oil shale environment in Ohio. This combination of formations ranges in thickness from more than 80 meters in the north to 14 meters in the south. The Berea Sandstone has sufficient porosity along the outcrop to produce springs and seeps of both water and oil. The Berea Sandstone in the eastern subsurface of Ohio is a significant energy resource reservoir for both oil and gas. A characteristic of the Berea is the basal flow rolls produced by load casting of the underlying soft sediments.

The Sunbury Shale is a black to blue black fissile shale with pyritic nodules and grains. The Sunbury is the basal member of the Waverly Group. The lithology of this group is dominated by marine clastics of both deep water and near shore depositional environments. The Sunbury lithology represents a reoccurrance of the Cleveland Shale environment over the Berea/Bedford Delta wedge[10] In eastern Ohio the Sunbury is anomalously thick where the Berea/Bedford are missing. Here the two black shales of the Sunbury and the Cleveland join to form a single lithologic unit.[10] This lithologic setting expanded geographically during the height of the Kaskaskia onlap and veneered the central craton with 5 to 9 meters of highly organic black shale of very similar composition to the Cleveland Shale. It has been estimated that the Sunbury was deposited in a water depth of 230 meters in the Kaskaskia Sea.[1] This subsequent loading of the underlying delta clastics may account for the flow rolls at the base of the Berea.

The Cuyahoga Formation is represented by a series of marine clastic sediments ranging from the redeposited red clay of the Henley and Rarden Members to the massive conglomeratic sandstone of the Black Hand Member.[11] The Cuyahoga Formation represents the major overburden ontop of the oil shale. The lithologies and members of the Cuyahoga Formation change with geography. These range from coarse to fine clastic ratios of sandstone to shale. The formation to the south central portion of the state is dominantly clay shales with splays of both trubidite and barrier bar sandstones or siltstones (Buena Vista Sandtone and McDermott stone). Marine bay muds developed into the medium blue gray shales of the Portsmouth Shale Member. The upper portion of the Portsmouth Shale has a graditional facies into the overlying Logan Formation. The Cuyahoga Formation ranges in thickness from 25 to 60 meters.

The Logan Formation caps the hilltops and forms plateaus along the outcrop area of the oil shale. It is typically represented by interbedded sandstone, siltstone, and shale of light to medium gray color. The Logan Formation is void of significant economic value over the majority of its exposure.[11]

PRESENT DISTRIBUTION OF ENVIRONMENTAL FACTORS

The minable oil shales of Ohio are distributed along an outcrop through the central and northeastern part of the state in a band 5 to 50 kilometers wide. An outlier of approximately 5 x 10 kilometers is in the northwest central portion of the state. The northwest corner of Ohio also is underlain by oil shale. Within the outcrop area of Ohio, most of the oil shale is buried under Pleistocene and Holocene deposits ranging in thickness from a few meters to nearly 200 meters. The Pleistocene glacial drift includes both carbonate rich and lean tills as well as outwash. The soils developed on these glacial deposits include numerous series classed as prime farmland with high agricultural productivity.[13]

The surface and ground waters within these areas are supported by the 1.11 meters of annual precipitation within the area. The surface water runoff from this precipitation ranges from 0.25 to 0.38 meters. The ground water infiltration and recharge from this precipitation is dependent on the local and regional permeability of the outcrop area. The ground water potential for well production ranges from more than 38 cubic meters per minute in the glacial river valleys to dry holes in the oil shales.

SHALE OIL INDUSTRY IN OHIO HISTORY

> "Messrs Wells A. Hutchins, Larun N. Robinson, and Alexander C. Anderson have as sociated themselves for the purpose of engaging in the business of mining shale and manufacturing oil out of same in Green Township, Adams County, Ohio."

Thus the St. Louis Shale Oil Manufacturing Company came into existiance with incorporation papers at the Office of the Secretary of State in Ohio allocating 100 shares of stock. Shale oil production is on its way as of the 2nd of April, 1866.

Other shale oil ventures in Ohio have included the Devon Shale Oil Company of 1921 at Clay City near Chillicothe, Ohio. The Red River Shale Oil Company of the same area leased a tract of land at the same time.

Plans were drawn up and initial construction of the retort was begun at approximately the same time at the town of Omaga north of Waverly, Ohio.

Attempts were made in the 1930's to burn the shale and create sinter for use in concrete. The process was directed toward self sustained combustion to make it economic. However, the energy balance was negative and the process was given up as uneconomic.

Recent developments in the oil shale of Ohio have included several areas of leasing with continued experimentation and testing being performed on the major oil shale deposits.

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Resource Assessment of the New Albany Shale (Devonian and Mississippian) in Southeastern Indiana — Preliminary Report

by

N.R. Hasenmueller
Indiana Geological Survey
Bloomington, Indiana 47405

Abstract. The New Albany Shale (Devonian and Mississippian), which consists essentially of brownish-black organic-rich shale and greenish-gray shale, is present throughout the Illinois Basin and is considered a potential source of hydrocarbons. In southeastern Indiana, where the shale crops out at the surface or underlies thin deposits of glacial drift, it is 100 to 130 feet thick. On the basis of lithology five members are recognized in the outcrop area; in ascending order these are the Blocher, Selmier, Morgan Trail, Camp Run, and Clegg Creek Members.

An area including parts of Clark, Scott, and Jackson Counties has been identified as having the most potential for the initial development of the shale as a source of synthetic oil. This area was selected for study because (1) the percentage of organic carbon by weight in the shale is high, (2) the organic-rich shale facies is thick, (3) the shale is at or near the surface and could be removed by surface mining, and (4) the population is relatively sparse.

In the study area the Blocher Member, the upper part of the Camp Run Member, and the Clegg Creek Member contain the highest percentage of organic carbon by weight. Because the Blocher is relatively thin, is underlain by carbonate rocks and is overlain by thicker shales with lower organic material, and contains an average of only 8.5 percent organic carbon, it is not considered a promising resource now. The combined thickness of the upper part of the Camp Run Member and the Clegg Creek Member ranges from 51 to 58 feet in the study area. This interval contains an average of more than 10 percent organic carbon by weight and has the greatest potential as a source of synthetic oil.

Introduction

The New Albany Shale in the Indiana part of the Illinois Basin (fig. 1)[1] consists of brownish-black organic-rich shale and, to a lesser extent, greenish-gray shale. It also contains minor carbonate, siliceous, and phosphatic beds. The New Albany Shale is late Middle Devonian to Early Mississippian in age, but most of the formation is Late Devonian.

The name New Albany Black Slate was first used by Borden in 1874 for brownish-black shale exposed at New Albany in Floyd County, Ind.[2] Later Blatchley and Ashley introduced the name New Albany Shale.[3] Lineback subdivided the New Albany Shale into five members in southeastern Indiana (fig. 2).[4]

The shale is 100 to 130 feet thick along the outcrop in southeastern Indiana and thickens in a southwesterly direction. In southwestern Indiana the shale attains its maximum known thickness of 337 feet. In Indiana the shale has a gentle southwesterly dip. Within 20 miles of the outcrop belt the rocks dip 20 to 30 feet per mile to the southwest; basinward the dip increases to about 50 to 60 feet per mile.[5]

The New Albany Shale overlies Middle Devonian limestones of the Muscatatuck Group except in a small area in White County in northern Indiana where the New Albany rests on Silurian rocks.[6] The shale is overlain by the Rockford Limestone (Mississippian) throughout much of the Illinois Basin. In the areas where the Rockford is absent the shale is overlain by the New Providence Shale of the Borden Group (Mississippian).

In southeastern Indiana the shale crops out at the surface or beneath deposits of Illinoian and older drift that thickens northward from the Ohio River to Bartholomew County. North of this area the bedrock is covered by still thicker de-

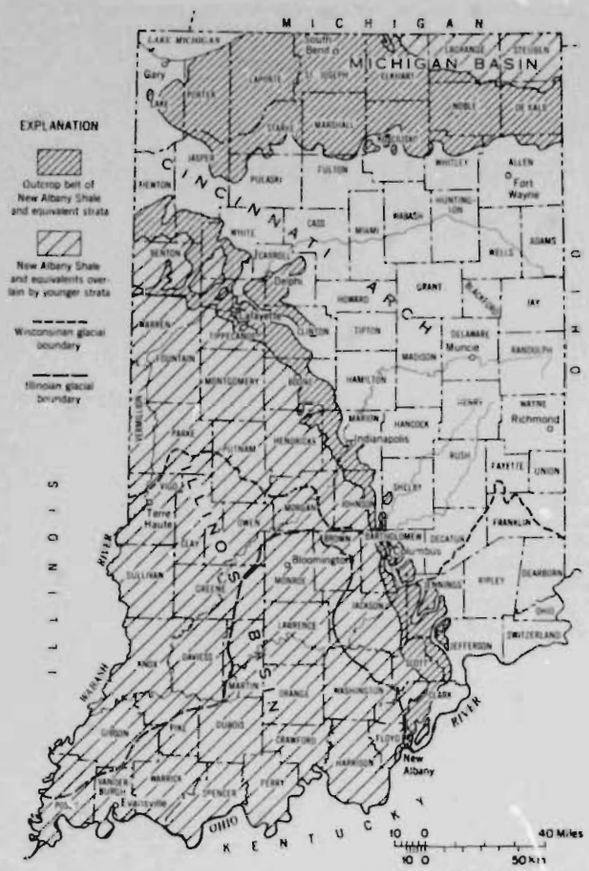


Fig. 1 Map of Indiana showing distribution of the New Albany Shale and equivalent strata. Geology modified from Indiana Geological Survey 1° x 2° Regional Geologic Map Series.[1]

posits of glacial material, most of which are Wisconsinan in age, and exposures are few.

Following the completion of a 3-year intensive study of the gas potential of the New Albany Shale, supported in part by the U.S. Department of Energy, in 1980 the Indiana Geological Survey began an assessment of the synthetic-oil potential of the New Albany in southeastern Indiana. A three-county area, hereafter called the study area, that includes Clark, Scott, and Jackson Counties was selected as the area with the most potential for the initial development of the shale. This area was selected for study because (1) the percentage of organic carbon by weight in the shale is high, (2) the organic-rich shale facies is thick, (3) the shale is at or near the surface and could be removed by surface mining, and (4) the area has a relatively sparse population.

Work has centered around core drilling, sampling and describing cores, analyzing core samples chemically, and mapping the shale resource. Future work will include taking and analyzing additional cores of the shale, determining overburden thickness, and estimating reserves.

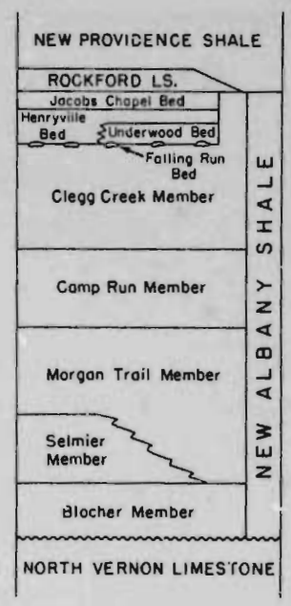


Fig. 2. Chart showing stratigraphic terminology of the New Albany Shale in southeastern Indiana.

Physiographic Province

Most of the outcrop belt of the New Albany Shale lies within the physiographic unit designated as the Scottsburg Lowland. This lowland is a linear north-south belt of low relief that follows the outcrop belt of the relatively nonresistant New Albany and New Providence Shales. The western edge of the Scottsburg Lowland is at the base of an eastward-facing cuesta scarp, called the Knobstone Escarpment, that throughout much of its extent rises 300 feet above the Scottsburg Lowland.[7] The Knobstone Escarpment is the eastern part of the Norman Upland, a dissected plateau underlain by the relatively resistant siltstones of the Borden Group (Mississippian).[7]

Cores

Seven cores were examined to evaluate the potential of the New Albany as a source of synthetic oil (fig. 3; table 1). Four cores were taken recently by the Indiana Geological Survey in southeastern Indiana, just west of the outcrop area, specifically to aid in the resource assessment. Cores were taken just west of the outcrop belt to obtain complete vertical sections of the shale, to obtain fresh unweathered material for chemical analysis, to obtain information on overlying as well as underlying rock units, and to gain information near areas where the shale could be removed by surface mining. Two of the cores were taken in Harrison and Floyd Counties, but because of thick overburden in Harrison County and the relatively dense population around New Albany in Floyd County, these two counties are not now included in the preliminary resource assessment. Geophysical logs and lithologic columns from the two core sites are included, however, on the stratigraphic cross section (fig. 4). The three other cores were already

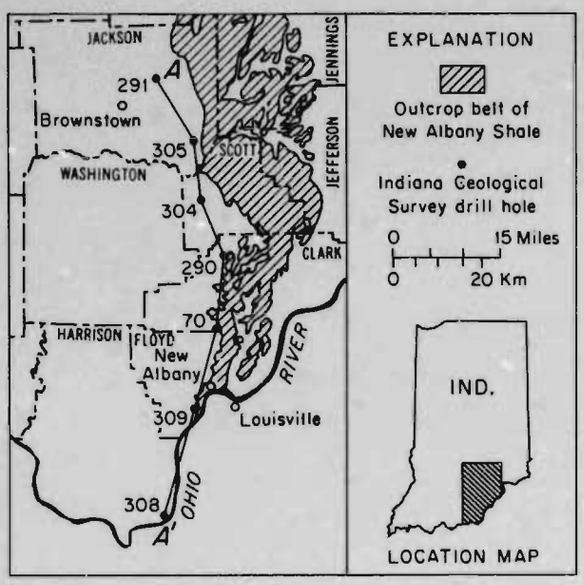


Fig. 3. Map of part of southeastern Indiana showing locations of Indiana Geological Survey drill-holes used in this study.

on file in the Indiana Geological Survey core library. The spacing between the seven cores ranged from 9 to 16 miles.

Geophysical logs are available for six of the seven core holes. On five holes both electric (self-potential and resistance) and natural gamma-ray logs were run, and on one hole only a gamma-ray log was run. The five members of the New Albany are most easily recognized on the natural gamma-ray logs. For the most part contacts between members of the New Albany are distinctive on the gamma-ray logs. The only contact that is difficult to determine on some of these logs is the contact between the Morgan Trail Member and the overlying Camp Run Member.

Lithology and Stratigraphy

Introduction

In the three-county study area the New Albany Shale ranges in thickness from 109 feet in southern Clark County to 130 feet in Jackson County. The shale paraconformably overlies the North Vernon Limestone (Middle Devonian) of the Muscatatuck Group and is conformably overlain by the Rockford Limestone (Mississippian). The Rockford is predominantly a greenish-gray fine-grained argillaceous limestone or dolomite and is 3 to 6 feet thick. In Indiana Geological Survey drill hole (SDH) 305 in Jackson County and in SDH 304 in Scott County the upper foot of the Rockford is calcareous shale. In some areas of Clark County the Rockford Limestone is absent, and the New Albany is directly overlain by the New Providence Shale of the Borden Group (Mississippian). The New Providence is a soft greenish-gray to medium-gray shale or claystone.

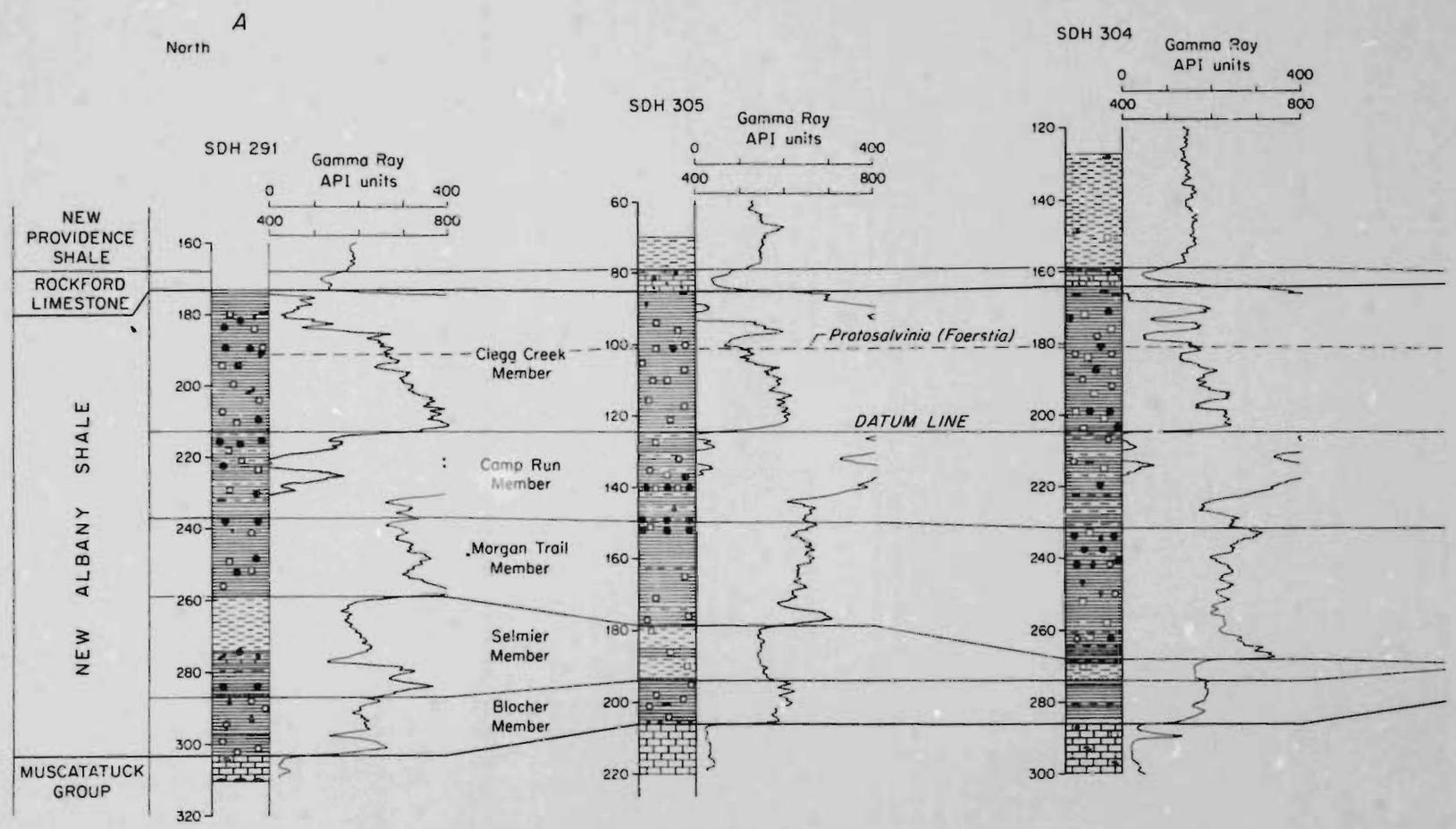
The New Albany Shale can be subdivided into five lithologically distinct members in the outcrop area. In ascending order these are the Blocher, Selmier, Morgan Trail, Camp Run, and Clegg Creek Members (fig. 2).[4] The Blocher Member, the upper part of the Camp Run Member, and the Clegg Creek Member have the highest concentrations of organic material (figs. 5 and 6).[8]

Blocher Member

The Blocher Member of the New Albany Shale consists of slightly calcareous brownish-black (5YR 2/1) to grayish-black (N2) finely-laminated organic-rich shale and noncalcareous brownish-black to grayish-black finely laminated organic-rich shale with numerous carbonate laminae and beds. The slightly calcareous shale is in the lower part of the member. The member in SDH 291 and SDH 290 contains an overall average of 8.5 percent organic

Table 1. Cores of the New Albany Shale examined in this study

Core designation	County	Location	Operator and well name
SDH 70	Clark	3400' NEL, 100' NWL Gr. 146-1S-6E	Indiana Geological Survey No. 70 Louisville Cement Co.
SDH 290	Clark	2210' NWL, 1330' SWL Gr. 283-2N-7E	Indiana Geological Survey No. 290 (EGSP IN-2) Clark State Forest
SDH 291	Jackson	SENWSE 27-6N-5E	Indiana Geological Survey No. 291 Schepman
SDH 304	Scott	NESESW 22-3N-6E	Indiana Geological Survey No. 304 Woodruff
SDH 305	Jackson	NESESW 9-4N-6E	Indiana Geological Survey No. 305 Nehrt
SDH 308	Harrison	SWNENW 3-6S-5E	Indiana Geological Survey No. 308 Knear
SDH 309	Floyd	NESWSW 16-3S-6E	Indiana Geological Survey No. 309 Eve


A
North
SDH 291
Gamma Ray
API units
0
400
400
800
SDH 305
Gamma Ray
API units
0
400
400
800
SDH 304
Gamma Ray
API units
0
400
400
800
NEW PROVIDENCE SHALE
ROCKFORD LIMESTONE
NEW ALBANY SHALE
MUSCATATUCK GROUP
Clegg Creek Member
Camp Run Member
Morgan Trail Member
Selmier Member
Blocher Member
Protosalvinia (Foerstia)
DATUM LINE
160
180
200
220
240
260
280
300
320
60
80
100
120
140
160
180
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220
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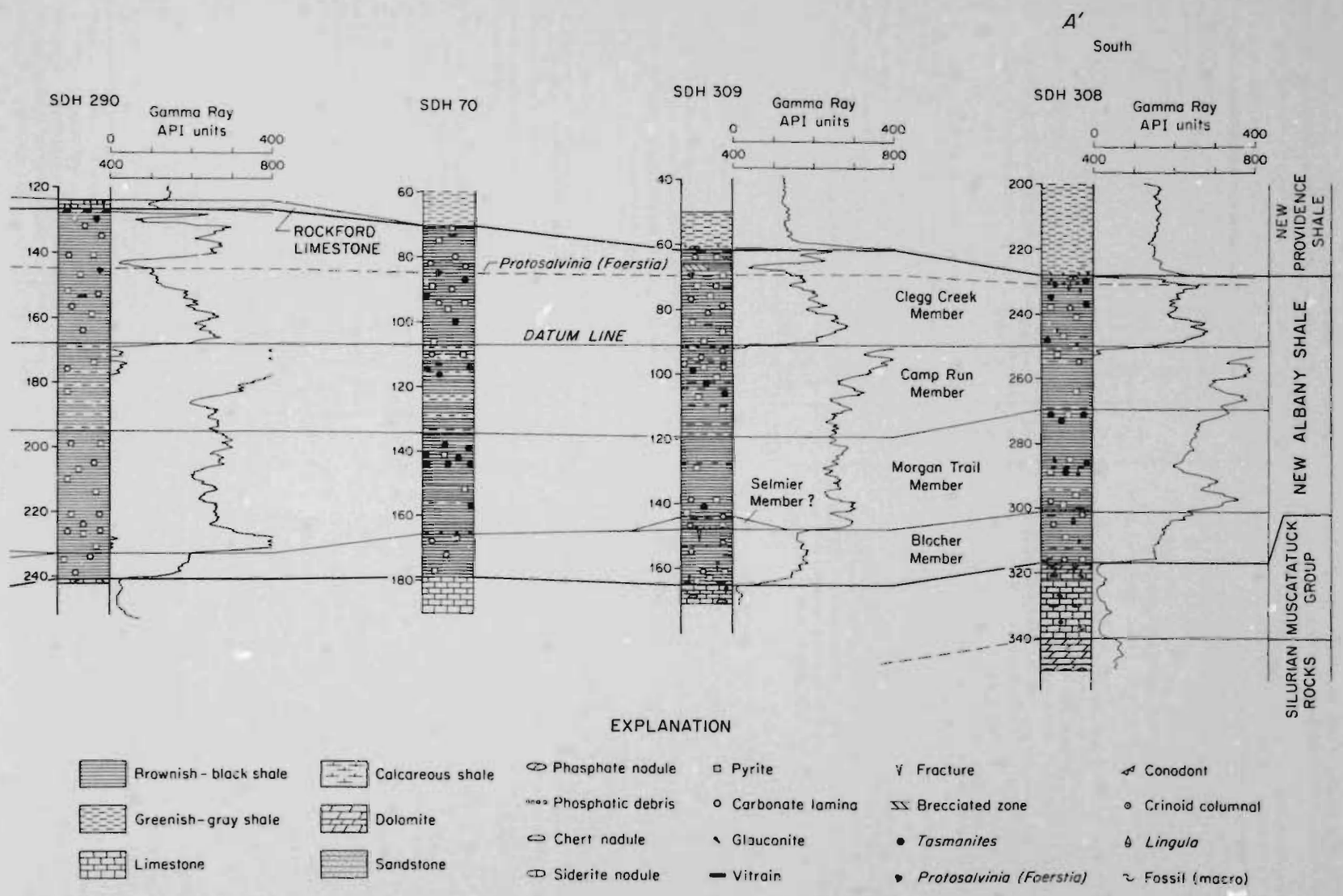

Fig. 4. Stratigraphic cross section showing subsurface correlation of the New Albany Shale in southeastern Indiana. Datum is the base of the Clegg Creek Member. No horizontal scale. Locations shown in figure 3.

carbon by weight (figs. 5 and 6). This unit is 5 to 15 feet thick in southeastern Indiana.[9]

In several cores vertical fractures are present, and in outcrop exposures the shale is jointed. The Blocher contains some fossils, including Tasmanites, conodonts, Styliolina, Tentaculites, linguloid brachiopods, and some small calcareous brachiopods. Although the Blocher contains an average of 8.5 percent organic carbon, it is characterized by a low to moderate intensity on gamma-ray logs (fig. 4).

Selmier Member

In southeastern Indiana the Selmier Member consists predominantly of greenish-gray (5GY 6/1) to olive-gray (5Y 4/1) shale, but it also contains small amounts of brownish-black shale, dolomite, limestone, and thin beds of quartzose sandstone. Besides laminae and thin beds of carbonate rock, the Selmier in some areas contains dolomitic septarian concretions as much as 2 feet thick and 5 feet in diameter. At the base of the Selmier are thin fine- to medium-grained light-gray calcareous pyritic quartzose sandstone beds. In many places these beds contain abundant phosphatic debris and carbonized plant remains. The organic-carbon content of the Selmier is low, commonly less than 1 percent by weight, although some beds in the lower part of the member contain as much as 7 percent (fig. 5).

The Selmier is absent from most of Clark County. The member is 6 feet thick in the Scott County core and thickens northward to 28 feet in the core taken in northern Jackson County (fig. 4). The northward thickening of the Selmier appears in part to be the result of a facies relationship with the overlying Morgan Trail Member.

The Selmier contains conodonts, a few pelecypods and gastropods, and Spathiocaris and other crustaceans.[10,11] Burrows and trace fossils are also present. The Selmier is characterized by low to moderate intensity on gamma-ray logs (fig. 4).

Morgan Trail Member

The Morgan Trail Member consists mainly of brownish-black (5YR 2/1) to olive-black (5Y 2/1) finely laminated siliceous shale with numerous pyritic and carbonate laminae and beds, but it also contains a few thin beds of olive-gray (5Y 4/1) shale. The organic content is about 5 to 6 percent by weight (figs. 5 and 6). The unit ranges from 22 to 38 feet in thickness (fig. 4). From Clark County northward the Morgan Trail thins as the Selmier increases in thickness. Spores (Tasmanites) are fairly common, particularly in the upper part of the unit. In outcrop exposures the shale is jointed; a few small fractures were noted in two of the cores. This member is characterized by moderate to high gamma-ray intensity (fig. 4).

Camp Run Member

The Camp Run Member consists of greenish-gray (5GY 4/1) to olive-gray (5Y 4/1) shale interbedded with brownish-black (5YR 2/1) finely laminated organic-rich shale. The amount of organic carbon in the Camp Run Member ranges from less than 1 percent in the greenish-gray shale to slightly more than 11 percent in the brownish-black shale. In general the upper one-half to two-thirds of the

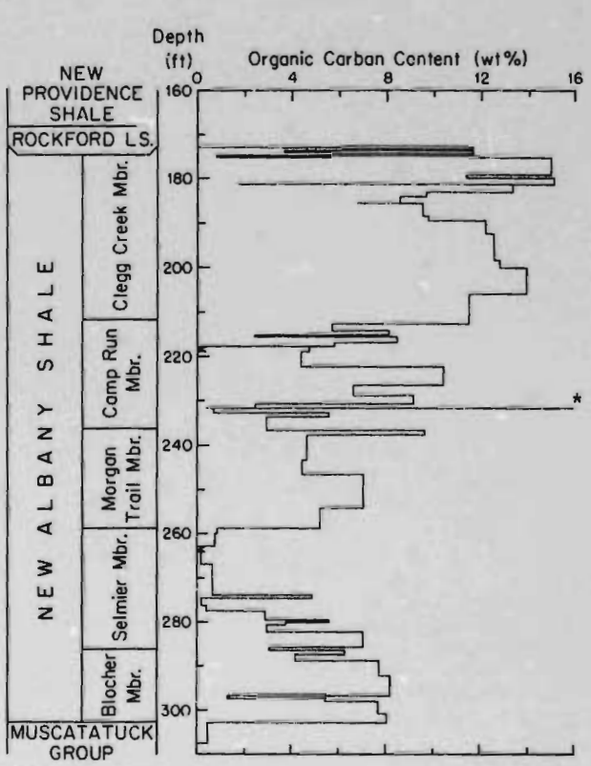

Fig. 5. Graph showing the percentage of organic carbon by weight in core of the New Albany Shale from Indiana Geological Survey drill hole 291, Jackson County. M indicates that core sample was not analyzed by the Survey. (*Vitrain sample.)

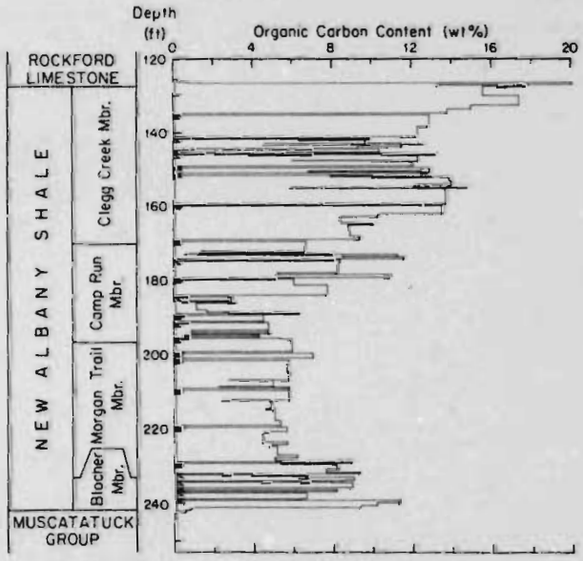

Fig. 6. Graph showing the percentage of organic carbon by weight in core of the New Albany Shale from the Indiana Geological Survey drill hole No. 290, Clark County. M indicates that core sample was not analyzed by the Survey.[8]

Camp Run contains a higher concentration of organic material than the lower part of the unit (figs. 5 and 6).

The unit is fairly uniform in thickness throughout the study area and ranges from 24 to 28 feet in thickness. The Camp Run Member is characterized by moderate to high gamma-ray intensity; the upper part of the member generally has higher intensity (fig. 4). While the contact between the Camp Run Member and the underlying Morgan Trail Member is easily recognized in cores, this contact is difficult to distinguish on some gamma-ray logs.

Clegg Creek Member

The Clegg Creek Member is the uppermost member of the New Albany Shale in southeastern Indiana. The unit is characterized by brownish-black (5YR 2/1) to black (N1) finely laminated pyritic organic-rich shale. The Clegg Creek contains the highest concentrations of organic material in the New Albany (figs. 5 and 6). Organic carbon generally averages more than 12 percent by weight. The Clegg Creek Member is about 40 feet thick in Jackson, Scott, and Clark Counties, but it thins southward to 22 feet in the Harrison County core. This thinning is in the upper part of the member (fig. 4).

Protosalvinia (Foerstia) was recognized in the upper part of the Clegg Creek Member (fig. 4). Conodonts, linguloid brachiopods, and Tasmanites are also present in the brownish-black shale of the Clegg Creek. In outcrop exposures the Clegg Creek is jointed; small fractures were noted in several cores. The member is characterized by very high intensity on gamma-ray logs (fig. 4).

In the study area several thin beds have been formally recognized in the upper part of the Clegg Creek. In ascending order these are the Falling Run Bed, the Underwood Bed, the Henryville Bed, and the Jacobs Chapel Bed (fig. 2). Each of these beds is characterized by distinctive lithology and composition. The Falling Run Bed is an interval of phosphate nodules 0.2 foot thick that have high concentrations of P_2O_5 and yttrium.[12] Some nodules from the Falling Run Bed contain articulate and inarticulate brachiopods, arthropods, fish remains, and plant fossils.[10] The Underwood Bed consists of thin (0.4 foot) greenish-gray shale. This bed is known from only a single locality in Clark County and contains a prolific fauna of conodonts and scolecodonts. The conodonts indicate that the Underwood is Kinderhookian in age.[10] Sparse phosphatic nodules within the shale of the Underwood Bed also contain pelecypods, gastropods, and articulate and inarticulate brachiopods.[10] The Henryville Bed consists of a thin (0.5 to 1.7 feet) brownish-black (5YR 2/1) to black (N1) shale with high concentrations of trace elements and organic carbon.[12] In several cores the organic carbon in the Henryville is greater than 20 percent by weight (fig. 6). The Jacobs Chapel Bed is the uppermost bed of the Clegg Creek Member and is a thin (0.2 to 0.6 foot) greenish-gray glauconitic shale. The Jacobs Chapel is recognizable wherever the Rockford Limestone is present in southeastern Indiana.

The Devonian-Mississippian boundary is near the top of the Clegg Creek Member in the outcrop area in southeastern Indiana. The Underwood Bed contains a conodont fauna which is Early Mississippian in age. The Devonian-Mississippian boundary is at or just below this bed.[13]

Overburden

In southeastern Indiana south of the Wisconsinan glacial boundary the New Albany Shale crops out at the surface or beneath thin glacial deposits. The unconsolidated material overlying the shale is less than 50 feet thick except along the Ohio River, in eastern Jackson County, and in northwestern Scott County.[14]

Immediately west of the outcrop belt the shale is overlain by the Rockford Limestone, which is 3 to 6 feet thick, and the New Providence Shale, which is 125 to 150 feet thick. The Rockford Limestone is thin and would probably not present any problems in surface mining. The New Providence Shale, however, is a fairly soft incompetent unit that might restrict the movement of heavy equipment in a surface mine.

Oil Yields

Data on oil yields from the New Albany Shale in Indiana are limited. In 1922 John Reeves[15] reported yields from 6 to 14 gallons of oil per ton of shale by standard retorting methods. This involved simply heating the shale in a closed retort, similar to the standard Fischer Assay.

Meinschein determined the oil, water, and gas yields and organic-carbon content of selected samples from a core of the New Albany Shale from Sullivan County in southwestern Indiana.[16] He reported that a linear relationship exists between oil yield and organic-carbon content of the shale. The slope of the oil-yield plot corresponds to an oil yield of about 1 gallon of oil per ton of shale per 1 percent organic carbon (fig. 7). A similar relationship between the oil yield and organic-carbon content appears to exist in the Sunbury Shale and the Cleveland Member (Ohio Shale) high-grade zone in Lewis and Fleming Counties, Ky.[17]

The percentage of organic carbon by weight has been determined for the seven cores of the New Albany Shale from southeastern Indiana. In our quantitative estimates of reserves we plan to assume that the oil yield will be 1 gallon of oil per ton of shale per 1 percent organic carbon.

Oil Shale Intervals with Major Potential

The stratigraphic intervals with the highest concentrations of organic carbon in the study area are the Blocher, the upper part of the Camp Run, and the Clegg Creek. Because the Blocher is generally less than 15 feet thick and contains an average of less than 10 percent organic carbon, it is considered only a marginal resource now. The upper part of the Camp Run Member contains an average of 7 to 8 percent organic carbon by weight, and the Clegg Creek Member contains an average of more than 12 percent. The combined thickness of the upper part of the Camp Run Member and the Clegg Creek ranges from 51 to 58 feet, and the interval contains an average of more than 10 percent organic carbon by weight.

Future Work

The Indiana Geological Survey will be preparing reserve estimates of recoverable oil in the

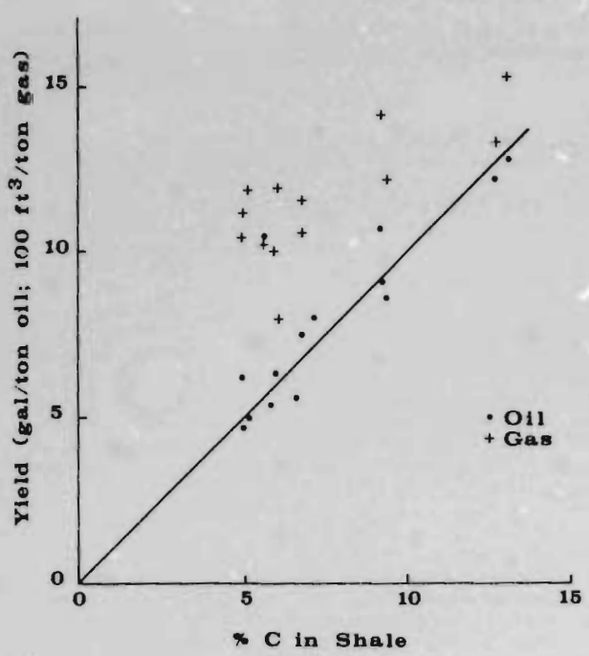

Fig. 7. Plot of oil and gas yields versus organic-carbon content (percentage of C) for samples of the New Albany Shale from the Phegley core, Sullivan County.[16]

New Albany Shale. Additional cores will be obtained and analyzed. The thickness and extent of the upper Camp Run-Clegg Creek interval will be determined, and the thickness and extent of overburden will be mapped. Reserves will be calculated for areas where the reserve interval is thick enough and overburden thin enough to permit shale recovery by surface mining.

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Chemical Composition of the New Albany Shale in Indiana

by

R.K. Leininger
Indiana Geological Survey
Bloomington, Indiana

Abstract.

The New Albany Shale (Devonian and Mississippian) in Indiana consists of several lithologies of which the two most prevalent are silty shale with significant organic matter and the same matrix without organic matter. Carbonate minerals, mostly dolomite, may be present and even form beds of impure carbonate rock as much as about 2 feet thick. Quartz, dolomite, calcite, pyrite, or rarely fluorite or barite may be present as paper-thin laminae that show on cores as white streaks parallel to bedding. Pyrite and (or) marcasite, siderite, dolomite, and apatite form nodules or concretions; some carbonate concretions are more than a foot in diameter.

The composition of the black shale of the Antrim Shale reported by Ruotsala, Sandell, and Leddy at the 1981 annual meeting of the AAPG included (in weight percent) 30 Si, 8 Al, 4 Fe, 2 Mg, 3 Ca, 2 S, and 5 C. Converted to oxides, except S and C, these add to 99 percent and are similar to our figures, although they are somewhat high for Mg and Ca and do not allow for the normal 2 to 5 percent potassium, sodium, and titanium oxides.

At many locations in Indiana the topmost 1- to 3-foot interval, usually underlain by a phosphatic bed, is highest in organic carbon and certain trace elements, including Mo, Ni, V, and Zn. Sphalerite and chalcopyrite have been observed by reflected light microscopy and energy dispersive X-ray spectrometry.

For development of the New Albany Shale as an oil shale, the most important constituents are organic carbon and hydrogen. In Indiana the southeastern area underlain by the full section of the New Albany Shale is the most promising. Five cores from Scott, Jackson, and Clark Counties were found to contain between 50 and 60 feet of shale with an average of 10 to 11 percent organic carbon.

Geochemistry of the New Albany, Ohio and Sunbury Shales in East Central Kentucky

by
Alan E. Bland
Thomas L. Robl
D.W. Koppenaal
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Introduction

Resource assessment work in Lewis and Fleming Counties, Kentucky has indicated that Kentucky oil shales are potential synthetic fuel feedstocks. A summary of this previous work is presented in another paper at this symposium (1). The Institute for Mining and Minerals Research (IMMR) of the University of Kentucky is continuing this work throughout the oil shale outcrop with support from the U. S. Department of Energy and the Kentucky Department of Energy. This paper presents our evaluation to date of the oil shales in the east-central portion of the central Kentucky outcrop belt. It includes the analysis of shales from Rowan, Bath, Montgomery, Powell, and Estill Counties, Kentucky, and a comparison with data obtained earlier on the Lewis-Fleming County shales. Stratigraphic and geochemical data were obtained to provide: 1) basic information to assess the nature of the oil shale as a synthetic fuel feedstock; 2) preliminary information on the potential for by-product recovery; and 3) preliminary information on the reclamation and environmental characteristics of the resource.

Project Sampling and Analysis

Eleven NX cores were drilled near the outcrop in a northeast-southwest trending line in Rowan, Bath, Montgomery, Powell, and Estill Counties (D-series of Figure 1). The coring was continuous with the Lewis-Fleming County work to the north (2), and was concentrated in regions which have potential for surface mining. Sample analysis was comparable to that used in the Lewis-Fleming County work.

The cores were described and measured in the field and returned to the Kentucky Center for Energy Research Laboratory. Each core was sawed in half and samples collected on a 2- to 6-foot interval basis. A total of 692 samples were generated. Each sample was jaw crushed to approximately -1/4 inch and roller-milled to approximately -10 mesh. Two 250-gram fractions were riffled out of each sample. One fraction was retained for Fischer Assay, and the second was reduced by ring and puck grinder to -360 mesh. Moisture, ash, carbon, hydrogen, nitrogen, and sulfur analyses were performed on the finely ground fraction. Ash determinations were performed at 500°C to prevent the volatilization of trace elements. Major element oxide and trace element determinations were performed on the 500°C ash fraction by X-ray fluorescence using international rock and mineral standards for calibration.

Oil Shale Stratigraphy

The stratigraphy and lithologies of the oil shale units and associated strata are discussed in detail in a previous paper at this symposium (1) and only a summary is presented here. The principal units of interest include (top to bottom) the Sunbury Shale (an oil shale), the Bedford Shale (a gray clay shale), and the Ohio Shale. The Ohio is divided into the Cleveland Member, the Three Lick Bed, and the Huron Member. These units are primarily oil shales; however, the Three Lick Bed and the lower Huron are significantly thick with barren, bioturbated, green-gray shales.

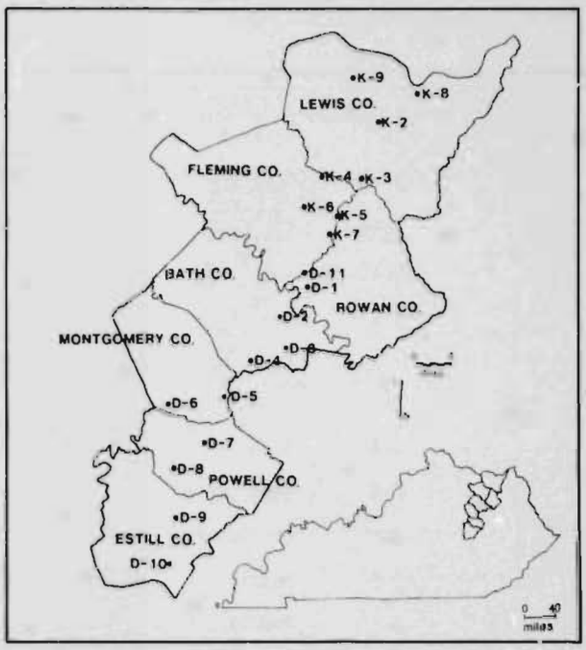

Figure 1. Distribution of Cores in the Study Area (D Series of Rowan, Bath, Montgomery, Powell, and Estill Counties) With Distribution of Cores From Previous Work (K Series of Lewis and Fleming Counties).

Thicknesses of the principal oil shale stratigraphic units are presented in Table 1. All of the units thin significantly toward the south in the study area (Rowan, Bath, Montgomery, Powell, and Estill Counties). The largest relative change is in the Sunbury Shale, which decreases from 16.7 feet in Rowan County to 4.0 feet in Estill. The total thickness of the Ohio changes from 215.9 to 133.8 feet over this same region.

Organic Geochemistry

Carbon is presented and discussed in this paper as total carbon. Mineral-bound carbon (from dolomite, $CaMg(CO_3)_2$ and calcite, $CaCO_3$) is also present. Mineral carbon determinations were performed on the K-5 core from Fleming County to the north of the study area (2, 3). The average values found for the Sunbury, Cleveland, and Huron intervals were 0.01, 0.06, and 0.13% as C. Although this determination has not been completed for all the samples of this study, the Sunbury and Cleveland intervals of the D-6 core had mean values of 0.02 and 0.04% as C. Thus, mineral carbon is an insignificant fraction of total carbon in these samples, and the carbon data is indicative of organic content. There is one small exception to this observation. In cores D-5, D-6, D-7, and D-8 the basal 2-12 feet of the Huron contains a dolomitic lithology referred to as the Duffin (4) where mineral carbon is expected to be a significant component.

Hydrogen has been corrected for surface-bound water, but not mineral-bound water, as this is a difficult determination for materials of this type. The consistent nature of the inorganic chemistry of the cores indicates that stratigraphic and geographic variations in hydrogen are probably related to changes in the chemistry of the organic matter.

A bar graph of carbon distribution in three of the study cores (one each from the northern, central, and southern portions of the study area) is presented in Figure 2. The carbon decreases in concentration from values in the 10-15% range in the Sunbury and upper portion of the Cleveland to 4-6% in the Three Lick Bed and upper Huron, and increases to 8-12% in the basal portion of the Huron. The changes in thickness in the stratigraphic units in the study area do not affect the carbon distribution pattern beyond compressing it to some degree. The stratigraphic distribution of hydrogen (Figure 3) and nitrogen follow that of carbon closely with the highest concentration found in the upper and lower portions of the cores.

Mean values of C, H, and N are presented in Table 2 for each of the cores. The values have been weighted for individual sample interval thicknesses. The grand average among all the cores' means is presented in Table 3 along with coefficients of variation (standard deviation/mean X 100) for the core data. The variability of shale chemistry for the defined stratigraphic units is not large, with coefficients of variation of approximately 10% calculated for the Sunbury and Cleveland. The Huron is somewhat less uniform, with coefficients of variation of 16, 14, and 21% calculated for C, H, and N, respectively.

The variability of the organic chemistry of these cores is significantly greater than what was found for those drilled in Lewis and Fleming Counties (2). Those coefficients of variation were less than 3% for carbon and less than 7% for hydrogen and nitrogen for these same stratigraphic units. This increased variability in chemistry is a reflection of geographic trends, discussed later in this paper.

Table 1. Thicknesses (in feet) Of Oil Shale Stratigraphic Units As Determined From Study Cores.

			Ohio Shale		
Core	County	Sunbury Shale	Cleveland Member	Three Lick Bed	Huron Member
D-11	Rowan	16.4	49.6	10.7	125.4
D-1	Rowan	16.7	49.4	10.9	124.4
D-2	Bath	14.7	46.7	10.2	112.8
D-3	Bath	12.4	41.4	9.5	116.2
D-4	Bath	12.6	44.0	8.3	106.6
D-5	Montgomery	9.1	42.6	7.2	104.6
D-6	Montgomery	6.1	38.3	5.4	96.0
D-7	Powell	6.8	41.3	6.2	98.7
D-8	Powell	5.1	41.4	5.9	97.0
D-9	Estill	5.3	34.9	5.3	75.6
D-10	Estill	4.0	33.4	4.5	72.7

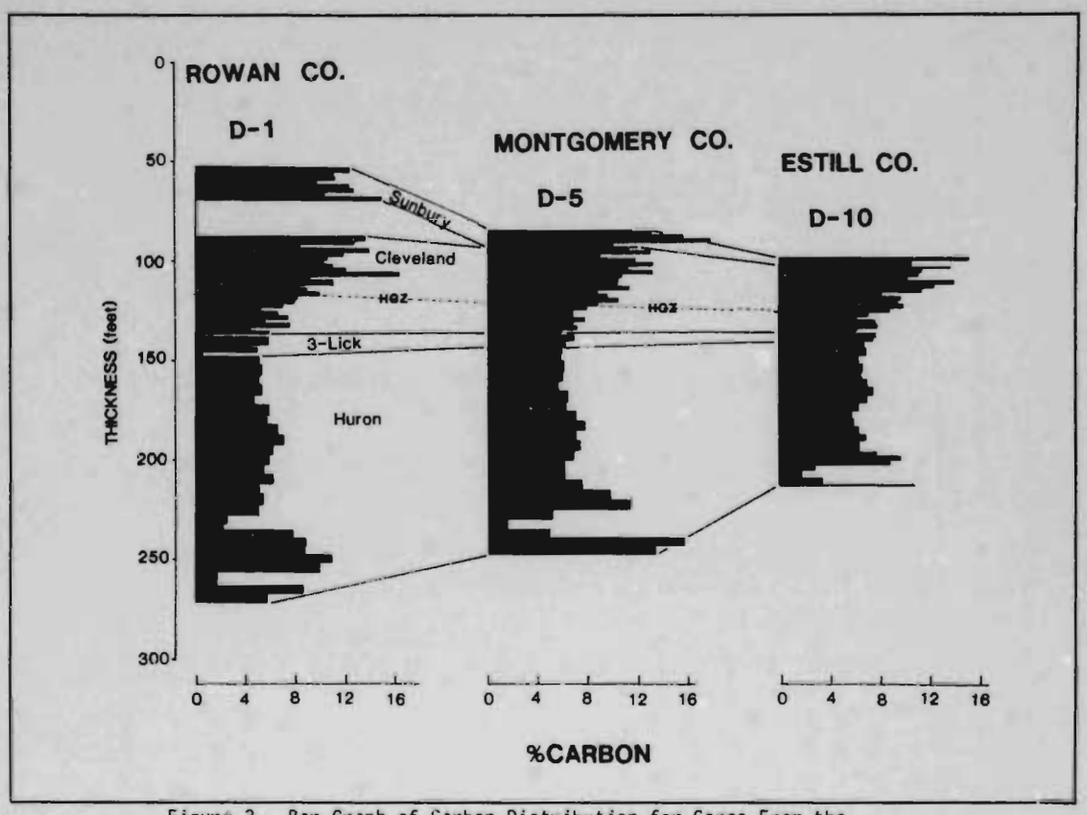

Figure 2. Bar Graph of Carbon Distribution for Cores From the Northern, Central, and Southern Portions of the Study Area.

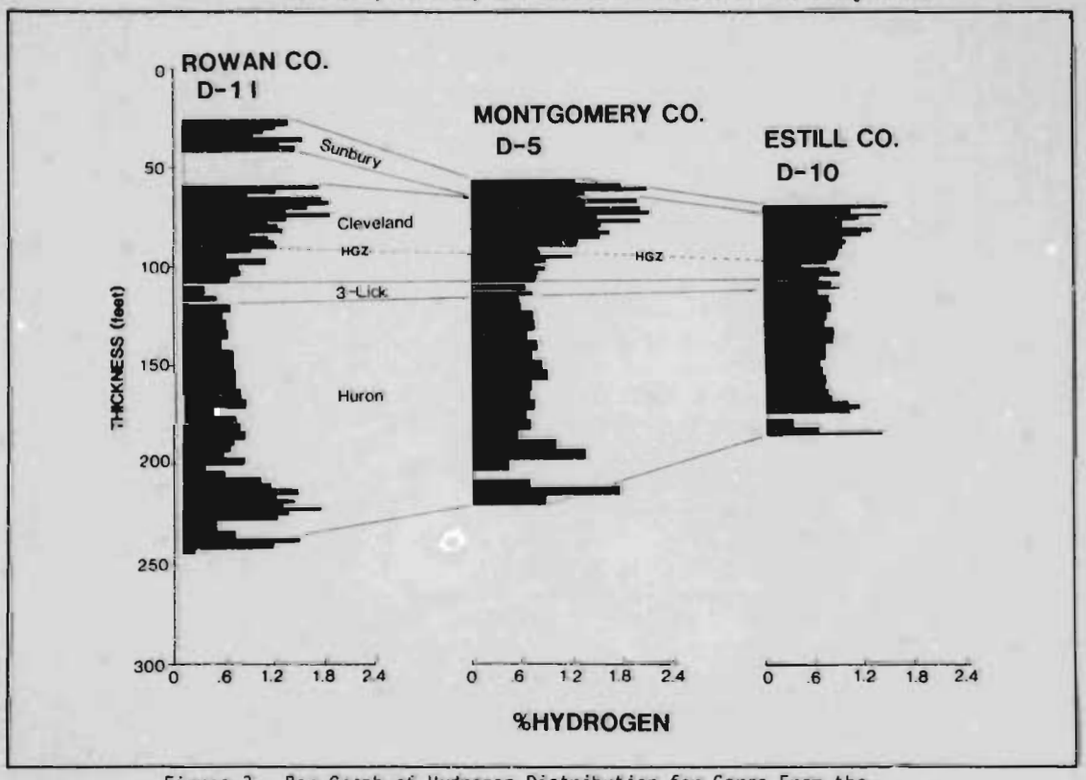

Figure 3. Bar Graph of Hydrogen Distribution for Cores From the Northern, Central, and Southern Portions of the Study Area.

Table 2. Average Chemical Composition for Major Oil Shale Stratigraphic Units of D-series Cores.

	DN 11			DN 1			DN 2			DN 3			DN 4		
	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur
C[1]	11.95	9.45	5.87	11.67	9.31	5.86	12.21	9.38	5.98	12.66	9.11	5.80	12.78	10.08	6.30
H	1.19	1.06	0.69	1.36	1.01	.77	1.35	0.99	0.69	1.59	1.06	.66	1.31	1.09	.72
N	0.41	0.33	0.22	0.40	0.31	0.21	0.39	0.38	0.22	.39	0.29	0.21	.45	0.35	.17
S	3.64	2.48	3.27	3.60	2.37	3.38	3.96	2.69	3.52	3.39	2.66	3.49	3.34	2.52	3.73
SiO_2[2]	64.31	64.92	63.05	65.49	66.37	63.34	66.26	65.73	63.76	65.59	66.86	62.28	66.27	66.29	63.26
TiO_2	0.72	0.88	0.88	0.71	0.87	.86	0.71	0.86	0.87	.73	0.87	.87	.81	0.87	.86
Al_2O_3	15.55	16.06	16.75	15.76	16.10	16.87	15.46	15.92	16.84	15.75	15.79	17.00	16.02	15.84	16.43
Fe_2O_3T[3]	8.34	6.67	8.17	8.24	6.53	8.11	8.49	6.49	8.37	7.82	6.66	8.50	7.13	6.33	8.35
CaO	0.32	0.62	0.61	0.17	0.80	.65	0.24	0.73	0.61	.34	.65	.63	0.47	0.49	.84
MgO	1.50	1.47	1.56	1.39	1.37	1.46	1.47	1.43	1.55	1.53	1.44	1.62	1.45	1.40	1.55
K_2O	4.00	4.19	4.36	4.06	4.18	4.38	4.03	4.28	4.42	4.09	4.20	4.46	4.09	4.21	4.26
Na_2O	.40	.57	.60	.29	.48	.53	.29	0.38	0.49	0.30	0.46	.49	0.34	0.49	0.50
P_2O_5	.12	.16	.10	.12	.16	.10	0.13	0.20	0.10	0.14	0.14	0.10	0.25	0.14	0.12
Ba[4]	638	559	595	614	589	586	624	587	606	613	585	592	621	604	589
Co	23	19	26	23	20	27	24	20	27	23	20	27	24	19	27
Cr	192	154	88	198	164	94	188	162	93	194	156	94	181	164	91
Cu	121	91	61	121	93	64	126	92	64	123	88	64	121	95	65
Mo	306	107	87	345	98	81	316	101	85	310	101	79	288	105	88
Ni	273	124	84	287	125	85	297	133	88	283	123	84	246	131	91
V	1485	676	202	1528	659	208	1383	660	214	1389	658	204	1101	693	216
Zn	1183	382	160	1116	404	172	1183	443	171	1108	390	159	1003	421	158

1. C, H, N, and S as weight percent raw sample H corrected for surface moisture
2. Major element oxide as weight percent 500°C Ash
3. Total iron reported as Fe_2O_3
4. Trace elements as ppm 500°C Ash

Table 2 Continued

	DN 5			DN 6			DN 7			DN 8			DN 9			DN 10		
	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur	Sun	Cleve	Hur
C[1]	13.82	9.50	7.16	15.23	10.35	9.05	14.84	10.17	7.20	15.11	9.87	6.75	14.00	9.95	6.38	12.51	9.65	6.30
H	1.58	1.31	.78	1.70	1.13	0.93	2.05	1.25	.71	1.91	1.10	.78	1 58	1.13	.71	1.22	.92	.75
N	0.48	0.33	.25	0.51	0.36	0.32	0.45	0.30	0.23	0.49	0.28	.22	0.47	0.30	.22	.42	.31	.21
S	3.56	2.93	3.58	4.11	2.91	3.70	4.16	2.89	3.60	4.52	3.19	3.46	3.39	2.85	4.21	3.04	3.22	3.86
SiO_2[2]	64.78	66.78	62.29	61.79	66.41	60.07	64.65	66.50	61.13	62.82	65.93	59.93	62.41	63.94	60.90	61.21	64.62	62.58
TiO_2	0.74	0.85	0.84	0.77	0.84	0.80	0.77	.84	0.81	0.76	.83	0.81	0.84	0.84	0.86	0.82	0.86	0.90
Al_2O_3	15.40	15.42	15.80	15.53	15.36	15.11	15.77	15.31	15.40	15.41	15.19	15.13	15.92	14.96	15.87	14.83	15.24	16.68
Fe_2O_3T[3]	7.90	6.55	8.11	9.00	6.53	7.94	8.59	6.63	7.88	9.71	6.99	7.93	7.68	6.92	8.97	6.64	7.12	8.23
CaO	0.82	0.76	1.68	0.77	0.77	2.61	0.53	.81	2.17	1.11	.88	2.88	1.16	1.52	1.43	3.71	1.13	0.88
MgO	1.43	1.33	1.96	1.42	1.32	2.41	1.44	1.32	2.11	1.40	1.31	2.51	1.41	1.33	1.59	1.31	1.33	1.38
K_2O	4.02	4.17	4.20	4.26	4.24	4.19	4.11	4.13	4.08	4.10	4.10	4.05	4.31	3.95	4.08	4.23	4.08	4.33
Na_2O	0.33	0.46	0.50	0.43	0.60	0.63	0.46	.55	0.56	0.38	0.38	0.47	0.44	0.59	.56	0.50	0.53	.53
P_2O_5	0.40	0.23	0.12	0.32	0.26	0.12	0.19	0.21	0.18	0.27	0.19	0.11	0.33	0.48	0.15	0.89	0.27	0.10
Ba[4]	583	577	523	666	578	528	610	569	560	722	567	549	587	527	521	562	551	538
Co	23	19	26	26	19	27	26	19	25	26	20	26	24	19	27	22	20	27
Cr	160	160	98	175	166	98	154	162	89	158	161	93	172	154	94	153	159	92
Cu	134	96	86	160	102	107	147	101	82	160	104	85	149	100	71	117	103	69
Mo	269	104	84	339	115	97	311	104	84	318	103	82	275	105	88	90	101	89
Ni	254	128	104	371	137	124	279	131	104	344	133	103	292	129	95	239	131	96
V	917	664	216	1091	739	236	794	670	216	899	660	214	934	654	230	713	652	226
Zn	905	414	180	1355	477	209	1328	448	185	1406	412	189	1455	390	168	1132	370	331

A comparison of particular stratigraphic intervals throughout the study area shows less variation than a comparison of stratigraphic intervals within a single core. For example, the coefficients of variation were computed for the individual samples of the Sunbury, Cleveland, and Huron intervals for the D-5 core. In this core the sample intervals were relatively uniform and consisted of 5 2-foot samples in the Sunbury, 22 2-foot samples in the Cleveland, and 22 4-foot samples in the Huron. Although not exactly comparable, this information does provide a general indication of relative variability. The stratigraphic coefficients of variation for C, H, and N were 2-4 times greater than the variation among the cores.

Sulfur followed a grossly similar trend to carbon, with highest values in the upper and lower sections of the cores. The Huron averaged 3.58% compared to 3.70% for the Sunbury. Much of this sulfur, however, is present in the high carbon interval at the base of the unit, where values of 5-7% were found. Previous determinations (2) indicated the principal form of sulfur to be pyritic.

Inorganic Geochemistry

Major and trace element determinations were performed and are presented as percent or ppm of the 500°C ash fraction of the samples. This was done to eliminate the effect of variation in organic content and to facilitate comparisons.

When the major element chemistry for the various stratigraphic units are compared, no large differences are found (Tables 2 and 3). The concentration of Al_2O_3 in the shales is less than what would be expected from a clay shale, which together with the SiO_2 content, indicates a significant quartz content. The level of K_2O present (about 4%) indicates that the clays are primarily illitic, which agrees with mineralogic determinations made on the shales (5). The CaO concentration in all of the stratigraphic units is low (generally less than 1.0% (Table 2)), which is in agreement with the previous observations made for mineral carbon. Calcium content is generally higher in the Huron, particularly in the D-5 through D-8 cores where the Duffin lithology is present. There is also a small geographic trend of increasing CaO concentrations from north to south in the study area.

The coefficients of variation determined among the cores for the major element oxides are generally very low (Table 3) and in many cases almost at the level of analytic uncertainty. Two exceptions to this are CaO and P_2O_5 which are associated with carbonate minerals and phosphate nodules. These are not part of the primary lithologies of the shale and are subject to being either locally abundant or absent.

Unlike the organic elements, the major element chemistry does not show large stratigraphic zonation compared to its lateral continuity. Coefficients of variation for the stratigraphic intervals for the D-5 core are only slightly greater than those calculated for the average core data (Table 3).

The concentration and distribution of the determined trace elements are stratigraphically controlled. Highest concentrations are found in the Sunbury, followed by the Cleveland and the Huron. The elements which show the greatest zonation based on stratigraphic unit include Mo, Ni, V, and Zn. Each of these elements is found to have concentrations in the Sunbury at levels of 2-3 times those of the other units (Table 2).

As in the case of the major elements, the coefficients of variation calculated for the trace elements among the cores for the stratigraphic intervals are very low in most cases (Table 3). Unlike the majors, however, the stratigraphic variations calculated for the D-5 core are high. This is reflective of zonation within the individual stratigraphic units.

Trace-element major-element associations in the oil shales have been a subject of several studies (6, 7). In general, the trace elements can be divided into three groups: those which have an affinity for carbon (Cu, Cr, Ni, V), those which have an affinity for sulfur (Co, Zn), and those which have an affinity for the silicates (Ba, Sr, Rb). The associations are also, to some degree, stratigraphically dependent. For example, in the shales from Lewis and Fleming Counties, Cr, Ni, and V concentrations were found to be strongly correlated with carbon concentration (correlation coefficients = .95, .91, and .82, respectively) in the shales of the Cleveland Member, but not strongly correlated in the Huron and Sunbury (7). Zn is listed as having an affinity for sulfur, even though it did not have a significant correlation. It is often associated with its own mineral phase (sphalerite, ZnS) and the lack of correlations with total sulfur is not surprising. The trace element affinities discussed are similar to the observations of Keogh (8) who studied the trace element chemistry of the organic matter separated from the shale.

Geochemistry of Defined Economic Zones of the Study Area

Economic zones were defined, based on carbon concentration, for resource assessment purposes and are discussed in a previous paper at this symposium (1). Two intervals were defined and include the entire Sunbury Shale, and the upper portion or high grade zone (HGZ) of the Cleveland Member of the Ohio Shale. The Cleveland HGZ extends from the top of the Cleveland Member to the point where carbon concentration drops below 8%. The Sunbury averaged 13.28% carbon and 1.55% hydrogen. The Cleveland HGZ averaged 11.09% carbon and 1.30% hydrogen. The average chemical compositions for these intervals are presented in Table 4, along with the composition of the total Cleveland for comparison.

A third zone containing carbon in excess of 8% was identified in the lower Huron. However, because of the thick sequence of lean (less than 8% carbon) shales between the Cleveland HGZ and the Huron high carbon zone, it was not included in the resource assessment. It may be of local significance or of value for underground mining.

The Sunbury Shale thins to the south in the

study area from a high of 16.7 feet in D-1 in Rowan County to a low of 4.0 feet in D-10 in Estill County (Table 1). This regional thinning of the Sunbury does not appear to be gradual, but instead appears to occur in steps. The most obvious step occurs between D-4 and D-5 with a 3.5 foot decrease in thickness (Table 1).

The Cleveland HGZ shows a general thinning to the south from a high of 32 feet in D-1 in Rowan County to a low of 23.2 feet in D-10 of Estill County. The most rapid change in thickness occurs between D-8 and D-9 (Powell and Estill Counties) where the unit decreases by approximately 5 feet (Table 5).

Physical and Chemical Trends in the Defined Economic Zones

The analysis of the D-series cores, in conjunction with the previous resource assessment work in Lewis and Fleming Counties, defined some of the chemical and physical trends in the economic zones throughout the eastern portion of the

Table 3. Mean Values And Coefficients of Variation of the Oil Shale Units of D-Series Cores.

	Sunbury			Cleveland Member			Huron Member		
	$\bar{X}$[5]	V_c[6]	V_s[7]	$\bar{X}$	V_c	V_s	$\bar{X}$	V_c	V_s
n[8]		(11)	(5)		(11)	(22)		(11)	(22)
C[1]	13.34	10	22	9.71	4	23	6.60	14	42
H	1.53	18	24	1.10	10	36	.74	10	44
N	0.44	10	20	0.31	8	32	.23	16	54
S	3.70	12	27	2.79	10	15	3.61	7	39
SiO_2[2]	64.14	3	4	68.85	1	2	62.05	2	10
TiO_2	0.76	6	5	0.86	2	8	0.85	4	11
Al_2O_3[3]	15.58	2	13	15.56	3	6	16.17	5	13
Fe_2O_3	8.14	11	21	6.67	4	10	8.23	4	27
CaO	0.89	111	97	0.83	34	57	1.36	63	76
MgO	1.43	4	15	1.37	4	7	1.79	22	81
K_2O	4.12	3	8	4.16	2	5	4.26	3	10
Na_2O	0.37	19	19	0.50	16	18	0.53	9	17
P_2O_5	0.29	77	102	0.22	44	107	0.12	22	48
Ba[4]	622	7	4	572	4	4	564	5	18
Co	24	6	15	19	3	6	27	3	19
Cr	175	10	25	160	3	29	93	3	23
Cu	134	12	22	97	6	33	74	19	79
Mo	297	14	59	104	4	37	86	6	39
Ni	288	14	41	139	3	18	96	13	42
V	1112	26	52	671	4	49	217	5	20
Zn	1198	14	94	414	8	61	189	26	71

1. C, H, N, and S as weight percent raw sample, hydrogen corrected for surface moisture
2. Major elements as weight percent 500° ash
3. Total iron reported as Fe_2O_3
4. Trace elements as ppm 500°C ash
5. Grand average for mean values of stratigraphic intervals for the 11 D-series cores
6. Coefficient of variation among core values in percent (standard deviation/mean x100)
7. Coefficient of variation for samples within a stratigraphic interval, data for D-5 core (see text)
8. Number of values for V_c and V_s

Table 4. Geochemistry of the Defined Economic Zones of the Study Cores

	Sunbury Shale[3]	Cleveland HGZ[4]	Cleveland Member[5]
C[1]	13.28	11.09	9.64
H	1.55	1.30	1.12
N	0.44	0.36	0.32
S	3.70	2.93	2.77
SiO_2	64.18	66.16	65.78
TiO_2	0.76	0.82	0.85
Al_2O_3	15.58	15.15	15.57
Fe_2O_{3T}	8.12	6.83	6.67
CaO	0.88	0.84	0.90
MgO	1.43	1.36	1.37
K_2O	4.11	4.08	4.13
Na_2O	0.38	0.47	0.50
P_2O_5	0.29	0.28	0.22
Ba	622	568	570
Co	24	19	19
Cr	174	185	151
Cu	134	114	97
Mo	298	92	104
Ni	288	139	129
V	1155	796	677
Zn	1202	510	412
Fischer Assay[2]	11.4	11.4	

1. See footnotes in Tables 2 and 3.
2. Fischer Assay in gallons/ton.
3. Grand average for mean values of defined stratigraphic intervals for 11 D-Series cores.
4. Cleveland High Grade Zone.
5. Total Cleveland.

central Kentucky oil shale outcrop belt. Table 5 presents a summary of carbon, hydrogen, and selected trace element data, along with measured thicknesses of the economic zones for the D and K series cores. The core data are listed approximately from north to south along the strike of the Ohio Shale. Seven cores, one from each of the counties investigated, are illustrated in Figures 4 and 5 (see also Figure 1).

The Cleveland HGZ is very consistent in thickness through most of the eastern Kentucky outcrop belt, but shows significant thinning south of the D-8 core (Powell County). One apparent exception to this is the D-3 core. Examination of this core indicated that the top of the Cleveland at this site may be scoured out by local channeling in the Bedford Shale and thus is not representative of regional trends. Throughout the Lewis to Powell County region (cores K-8 through D-8) the total Cleveland decreases in thickness by about 10 feet, indicating that the thinning of this unit is taking place in the leaner shales below the high grade zone cutoff.

The Sunbury Shale is found to be relatively consistent in thickness in the northern portion of the eastern oil shale outcrop belt and shows a trend of thinning from Bath County southward.

In addition to the thinning of the economic zones to the south, there is a marked decrease in interburden thickness (Figure 4, Table 5). This thinning includes the disappearance of the Berea Sandstone at about the Lewis-Fleming County line (2), as well as a decrease in thickness of the Bedford Shale from a high of 67.8 feet in Lewis County to a low of less than 1 foot in the southern part of the study area. An obvious stepping decrease in thickness also occurs with the Bedford. This break in thickness occurs between D-4 and D-5 where the Bedford decreases from 14 feet in D-4 to less than 1 foot in D-5. This break in thickness coincides with a break in thickness of the Sunbury. The causes of these abrupt thickness changes are beyond the scope of this paper. However, preliminary evaluations indicate that they are probably tectono-depositional in character. The details of this tectono-depositional relationship are presently the subject of further study by IMMR personnel.

Several notable trends are present in the chemistry of the defined economic oil shale units. The hydrogen and carbon contents of the Sunbury Shale increase from approximately 11% C and 1.1% H in Lewis County to 15% C and 2% H in Powell County (Table 5), decreasing again south of Powell County. The most rapid increase in carbon and hydrogen occurs where this unit thins, and may be reflective of slower depositional rates.

Regional trends in the Cleveland HGZ were not as strong as those in the Sunbury. The average carbon and hydrogen contents for the K-series cores (Lewis and Fleming Counties) were 11.11% C and 1.21% H, while the D-series averaged 11.09% C and 1.30% H.

The concentrations of certain trace elements also appear to show regional trends. As an example of these trends, Figure 5 presents the regional distribution of Mo, Ni, V, and Zn. Each of these elements shows a slight overall decrease in concentration between Lewis County (K-9 or 8) in the north and Estill County (D-10) in the south for both the Sunbury and the Cleveland HGZ. However, the regional trends for the Sunbury are somewhat obscured by an increase in concentration for Mo, Ni, and Zn, and a decrease in concentration for V in the region between Montgomery and Powell Counties. The cause for these regional anomalies is presently unclear.

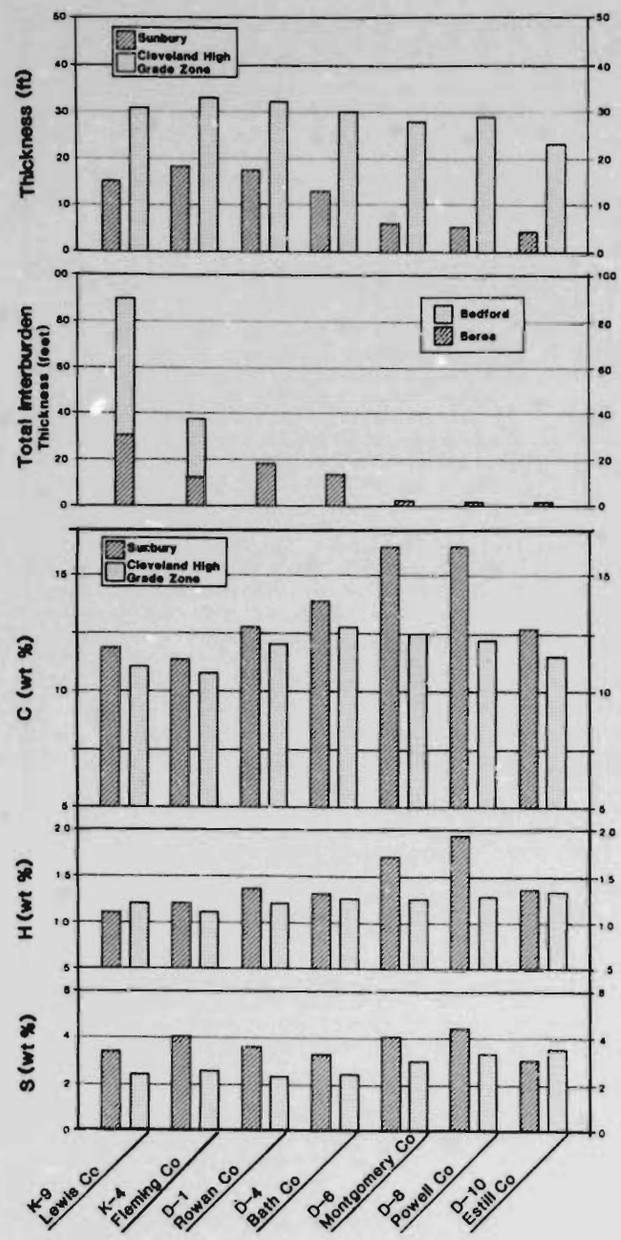

Figure 4. Mean Carbon, Hydrogen, Sulfur, and Thickness Data for Defined Economic Units of Study for Selected Cores From Each of the Counties Investigated to Date. Also Presented is the Thickness of the Units (Interburden) Separating the Defined Economic Units.

Economic Implications of Regional Trends

The regional trends in the stratigraphy and geochemistry of the defined economic units are relevant to mining, processing, and by-product recovery potential. Data relevant to these

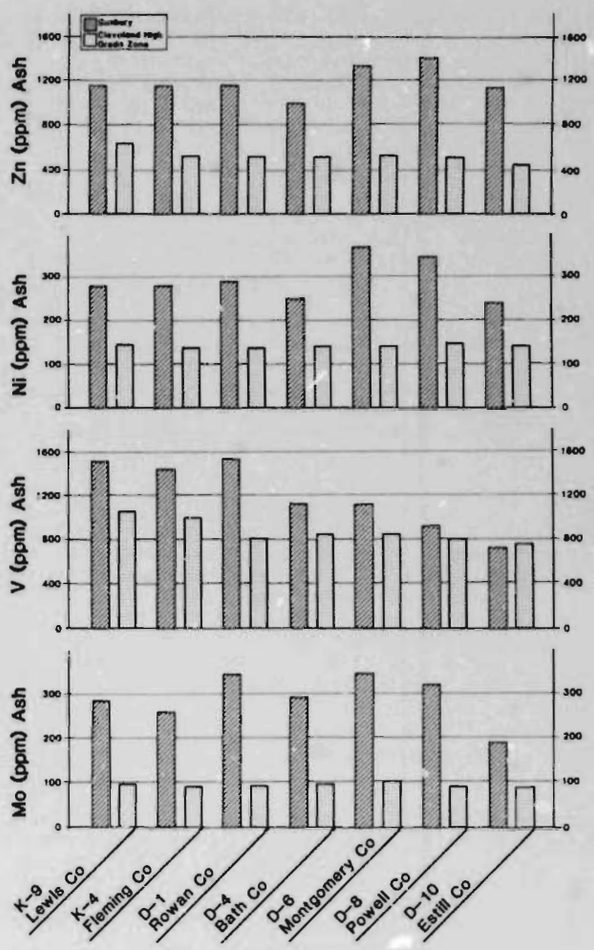

Figure 5. Mean Trace Element Concentrations for Defined Economic Units for the Cores of Figure 5. Data Presented as ppm 500°C Ash.

economic considerations are presented in Table 5. The data for the total economic zone are weighted for the thickness of the Cleveland HGZ and Sunbury Shale and therefore are representative, at least to some degree, of potential feedstocks for a retorting system.

The decrease in thickness, from north to south, of the stratigraphic units which separate the Sunbury Shale from the Cleveland HGZ is an important mining factor. The amount of material handled per ton of feedstock delivered would be much less in the southern counties (Bath, Montgomery, Powell, Estill) than in the northern counties for equivalent mining conditions. However, there is also a decrease in economic zone thickness from 51 feet in Fleming County (K-4) to approximately 27 feet in Estill County (D-10). Balancing these two offsetting regional trends, the southern resources still contain significant thicknesses of oil shales in a more favorable mining configuration.

Regional trends also impact process feedstock quality with respect to retorting. Table 5 pre-

Table 5. Thickness and Chemistry of the Defined Economic Zones for K and D Series Cores

		Sunbury			Interburden[3]	Cleveland HGZ			Total Resource						
Core	County	Thickness[1]	C[2]	H	Thickness	Thickness	C	H	Thickness	C	H	Mo[3]	Ni	V	Zn
K-8	Lewis	13.3	10.90	1.12	116.2	31.5	11.42	1.26	44.8	11.27	1.22	140	182	1166	775
K-9	Lewis	15.3	11.81	1.10	89.1	30.5	10.47	1.18	45.9	11.25	1.15	158	191	1226	819
K-2	Lewis	14.3	11.42	1.17	94.9	27.9	11.55	1.23	42.2	11.52	1.21	151	186	1248	778
K-3	Lewis	16.7	11.10	1.20	55.3	32.3	10.87	1.23	49.0	10.95	1.22	155	183	1201	763
K-4	Fleming	18.4	11.33	1.21	37.4	32.8	10.77	1.11	51.2	10.97	1.15	151	187	1164	749
K-5	Fleming	17.3	11.48	1.28	35.2	30.0	11.26	1.22	47.3	11.34	1.24	156	188	1244	827
K-6	Fleming	17.6	11.88	1.25	26.7	30.0	11.60	1.23	47.6	11.70	1.24	160	189	1196	790
K-7	Fleming	17.9	11.43	1.23	28.7	31.8	10.93	1.21	49.7	11.13	1.22	152	184	1139	842
D-11	Rowan	16.4	11.95	1.19	16.8	30.2	11.40	1.27	46.6	11.59	1.24	171	186	1086	751
D-1	Rowan	16.7	11.67	1.36	18.2	32.0	10.49	1.20	48.7	11.19	1.26	175	187	1054	724
D-2	Bath	14.7	12.21	1.35	8.8	32.0	10.93	1.17	46.7	11.33	1.23	161	193	974	750
D-3	Bath	12.4	12.66	1.59	19.1	25.1	10.83	1.53	37.5	11.44	1.42	161	184	1015	708
D-4	Bath	12.6	12.78	1.31	13.7	29.7	11.72	1.26	42.3	12.04	1.27	152	172	911	663
D-5	Montgomery	9.1	13.82	1.58	0.3	28.8	10.73	1.52	37.9	11.47	1.53	134	164	820	614
D-6	Montgomery	6.1	15.23	1.70	1.5	27.7	11.49	1.25	33.8	12.16	1.33	144	184	831	698
D-7	Powell	6.8	14.84	2.05	0.6	30.4	11.38	1.47	37.2	12.01	1.58	132	163	757	669
D-8	Powell	5.1	15.11	1.91	0.3	29.4	11.05	1.27	34.5	11.65	1.36	123	169	766	614
D-9	Estill	5.3	14.00	1.58	0.4	25.0	11.16	1.30	30.3	11.66	1.35	123	162	768	626
D-10	Estill	4.0	12.51	1.22	0.4	23.2	10.83	1.02	27.2	11.08	1.05	99	153	738	545

1. Thickness in feet.
2. C and H as weight percent raw sample.
3. Mo, Ni, V, Zn as ppm 500°C Ash.

sents the weighted carbon and hydrogen values for each of the core sites. Carbon and hydrogen values for the Sunbury economic zone vary regionally, but become much more subtle when the entire economic zone is considered. However, there is a slight increase of up to approximately .6% in carbon and up to approximately 0.3-0.4% hydrogen in Bath, Montgomery, and Powell Counties (D-4 through D-7).

The trace metal concentration in eastern oil shales have led to considerable speculation concerning the potential for by-product metals recovery (9, 10, 11, 12, 13). Much of this interest has centered on the recovery of such metals as Mo, V, Ni, Co, U, Th, and Al_2O_3. Table 5 presents the weighted means for four metals potentially recoverable from the oil shale including Mo, Ni, V, and Zn. Regionally there is a decrease in trace metals content, in the total defined economic zone, south of the D-3 core (Bath County). This is primarily due to the thinning of the Sunbury Shale.

In summary, regional trends indicate that the oil shale resources of Bath, Montgomery, and Powell Counties are most favorable of those investigated to date from mining and hydrocarbon content considerations. There is, however, some reduced potential for metals recovery from those resources.

Conclusions

- The principal form of carbon present in the oil shale is as organic matter. Mineral-bound carbon was found to be insignificant, with the exception of the Duffin zone, a localized dolomitic lithology present near the base of the Huron.

- Carbon and hydrogen are strongly zoned stratigraphically, with highest levels present in the upper and lower portions of the oil shale section. The variability of the organic chemistry among the study cores is low in comparison.

- The major element chemistry is found to be both stratigraphically and laterally consistent for the oil shales.

- Trace element concentrations are found to be highest in the Sunbury Shale, followed by the Cleveland and Huron members of the Ohio Shale. Trace element concentrations were found to be strongly stratigraphically zoned, but relatively consistent, among the cores.

- The major stratigraphic intervals of economic interest from a surface mining standpoint include the Sunbury Shale and the upper portion, or high grade zone (HGZ), in the Cleveland Member of the Ohio Shale.

- The major regional trends affecting mining, processing, and by-product recovery (north to south and including Lewis and Fleming Counties) include:

  1) the thinning and virtual disappearance of the stratigraphic intervals separating the Sunbury Shale and Cleveland HGZ;

  2) the thinning of the Sunbury Shale;

  3) an increase in carbon and hydrogen in the Sunbury Shale (concommitant with thinning); and

  4) a decrease in trace element content for the total defined economic zone.

- The Cleveland HGZ is consistent in thickness and geochemistry throughout most of the eastern portion (Lewis to Powell County) of the central Kentucky outcrop belt.

- Regional trends indicate that the oil shale resources of Bath, Montgomery, and Powell Counties are most favorable of those investigated to date from mining and hydrocarbon content considerations. There is, however, some reduced potential for metals recovery from those resources.

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Stratigraphy and Resource Assessment of the Oil Shales of East Central Kentucky

by

Don Pollock
Lance Barron
Institute for Mining & Minerals Research
University of Kentucky
John Beard
Kentucky Geological Survey

Abstract.

Heightened interest in the organic rich shales of Mississippian and Devonian age as a source of oil has resulted in intensive leasing along the shale outcrop belt in Kentucky. Eleven cores of the black shales from the counties of Rowan, Bath, Montgomery, Powell, and Estill were examined and analyzed in an effort to relate details of stratigraphy to the oil rich horizons and to indicate areas of potential resources. This report will not treat Estill County regarding the resource assessment.

Formations of interest are the Sunbury Shale (Early Mississippian Age) and the Ohio Shale (Late Devonian age). The name, Ohio Shale, is used throughout this report, but it was mapped as the New Albany Shale in the southern part of the study area by the U. S. G. S. The generalized stratigraphy (Early Mississippian through Middle Devonian age) is, in descending order: Borden Formation, Sunbury Shale, Bedford Shale, and Ohio Shale. Useful key markers in the sequence are the Three Lick Bed and Foerstia zone; which are both in the Ohio Shale. The Three Lick Bed divides the Ohio Shale into the Cleveland Member, above, and the Huron Member, below. The Ohio Shale is underlain by the Middle Devonian Boyle Dolomite or the Silurian Bisher Dolomite, or the Crab Orchard Formation, also Silurian in age.

The organic content is highest in the Sunbury Shale and in the Cleveland Member of the Ohio Shale. In the cores, the total thickness of the Sunbury Shale range from 17 to 4 feet (5.2 to 1.2 m). The thickness of the Bedford Shale, ranges from 18.0 to .2 feet (5.5 to .1 m). The Cleveland Member of the Ohio Shale ranges from 49.0 to 33.0 feet (14.9 to 10.1 m.).

Assuming a stripping ratio of 2.5:1, more than 4.5×10^6 acre-ft of shale having a carbon value of greater than 8% is minable by means of existing methods. A conservative estimate of the amount of the potential strippable shale-oil resources in the four county area is 3.88×10^9 bbls.

Introduction

Scientists have been studying the Devonian-Mississippian black shales of Kentucky from the time of the first Geological Survey in the Middle of the 19th Century (1). Since then they have been predicting that oil from this oil shale would become a source of illuminating oil (2), lubricant (3), natural gas (4), and refinery feedstocks (5, 6, 7, 8) in the near future. In the past, the principal focus of interest, has been on the western shales of Utah, Wyoming and Colorado. Within the last few years significant interest has developed in the Devonian-Mississippian oil shales of Kentucky and neighboring states. Social, geographical, and institutional barriers to development in the West have, in part, helped to create this interest.

Some of these barriers to development in the West include the semi-arid climate, remoteness from markets, lack of social and technological infrastructure, and institutional problems related to government ownership of oil shale property (9). These problems are substantially less in areas where eastern oil shale is found.

Research by the Institute of Gas Technology (IGT) in the development of retorts which employ hydrogen have demonstrated that it is possible to derive oil yields well in excess of Fischer Assay (5, 6) on eastern shale. This work plus symposia (10, 11) and resource studies (12) by IGT have helped to highlight the potential of eastern oil shale.

Since the late 1970's, oil and mineral companies have been leasing rights to oil shale in Kentucky and neighboring states. The General Assembly of the Commonwealth of Kentucky has required the Kentucky Department of Natural Resources and Environmental Protection promulgate regulations controlling the mining of oil shale in Kentucky.

The Institute for Mining and Minerals Research (IMMR) began working in oil shale in late 1979 with its involvement in the study of eastern oil shale funded by the U. S. Department of Energy through the Buffalo Trace Area Development District. The Davy McKee Corporation managed the project and evaluated processes and economics; Cleveland-Cliffs Iron Company developed a site-specific mine plan; and IMMR assessed and characterized the oil shale resource in the near-outcrop areas of Lewis and Fleming counties, located in northeastern Kentucky.

The resource assessment and characterization work was based on 10 NX wireline cores (two of which were donated by Pyramid Minerals, Inc.). Chemical analyses included C, H, N, S, moisture, and ash, major element and trace elements. Lithologic, geophysical, and stratigraphic logs were also produced. Carbon was the basis for resource assessment. Within a stripping ratio of 2.5:1, 1.3 billion barrels of oil, in place, based on Fischer Assay were estimated to be located in Fleming County and southwestern Lewis County.

Following the Buffalo Trace study, the U. S. Department of Energy funded a continuation of the resource work. The resource assessment part of this paper will be concerned with Rowan, Bath, Montgomery, and Powell counties.

General Geology

In Kentucky, the dark organic rich shales of Late and Middle Devonian and Early Mississippian (Kinderhookian) age outcrop in a belt which surrounds the Cincinnati Arch from Lewis County on the east to Jefferson County on the west, an approximate distance of 200 miles (Figure 1); south of this outcrop area, in the Cumberland Saddle these shales are relatively shallow or they outcrop. (Same Figure).

Various names have been applied to these shales and Kentucky shares three different names. David Dale Owens described the shales as the "Black Lingula Shale" in 1856 (13); he accurately described the geographic position of this horseshoe shaped outcrop and studied it in some detail for associated coal deposits, concluding there were none.

East of the Cincinnati Arch, the Ohio Shale of Devonian age (14) is recognized and was subdivided by Pepper, de Witt, and Demarest (15) and Provo, Kepferle and Potter (16). The Sunbury of Mississippian age (17) is separated from the Ohio by the Bedford-Berea but this unit thins southward along the outcrop belt.

West of the Cincinnati Arch this section is the New Albany Shale (18) and was subdivided by Lineback, (19). The Chattanooga Shale (20) was examined in Tennessee by Hass (21), Conant and Swanson (22); and their sections extended into south-central Kentucky, so Chattanooga was used in the mapping of the strata in south central Kentucky. The various names used are indicated in Figure 1.

The Ohio-Chattanooga-New Albany sequence is generally 20' to 40' thick along the crest of the Cincinnati Arch - Cumberland Saddle and consists of dark shales varying in color from black to dark gray with minor amounts of gray to greenish-gray clay shale produced by bioturbation; minor constituents are pyrite, siltstone, sandstone, limestone, and dolomite. Fossil material is present but not abundant consisting primarily of inarticulate brachiopods, Lingula and Orbiculoidea, and the sporomorph Tasmanites.

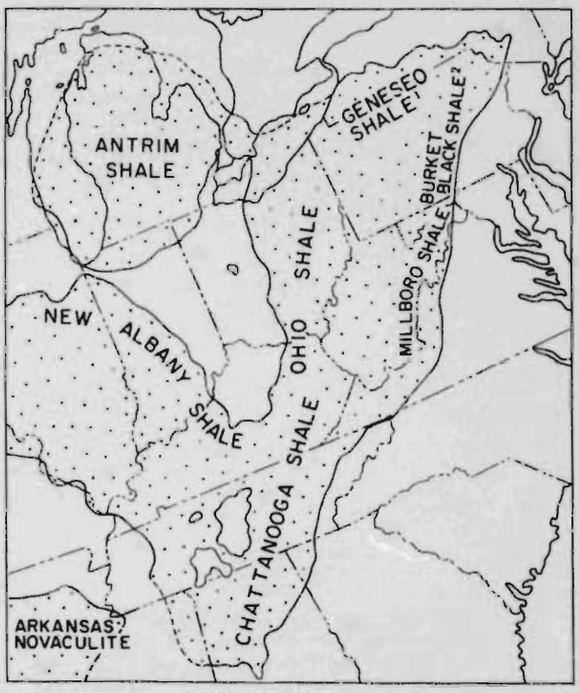


Figure 1. Geographic Distribution of Devonian-Mississippian Oil Shale in the Eastern United States.[22]

West of the Cumberland Saddle these rock dip westward and thicken into the Eastern Interior Basin where it attains a thickness of 460' in Hardin County, Illinois and Union County, Kentucky. It has been subdivided and isopached in the subsurface using wireline logs by Schwalb & Norris (23).

East and northeast of the Cumberland Saddle this shale sequence thickens into the Appalachian Basin and attain a thickness in excess of 1700' in extreme eastern Kentucky; it is recognized as the Sunbury Shale of Mississippian age and the Ohio Shale of Devonian age.

The outcrop and shallow-subsurface deposits of Devonian-Mississippian black shales in Kentucky represent some of the most extensive and accessible deposits of oil shale in the eastern United States. Principal among the three areas where the black shale outcrops, the Knobs region forms a roughly semi-circular pattern around the Bluegrass (see Figure 2). The Knobs are capped by more erosion-resistant rocks that overlie the black shale. The Bluegrass is a peneplained topographic basin which resulted from erosion of the Lexington Dome, that is a structural prominence on the Cincinnati Arch (see figure 3). The oldest rocks are more easily weathered

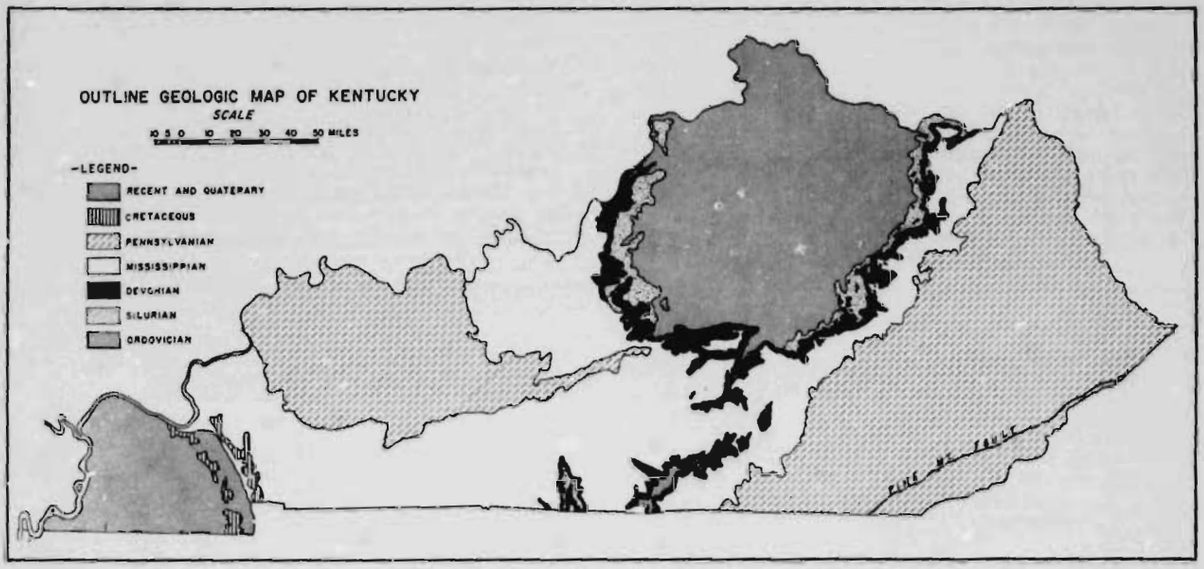


Figure 2. Geologic Map of Kentucky.

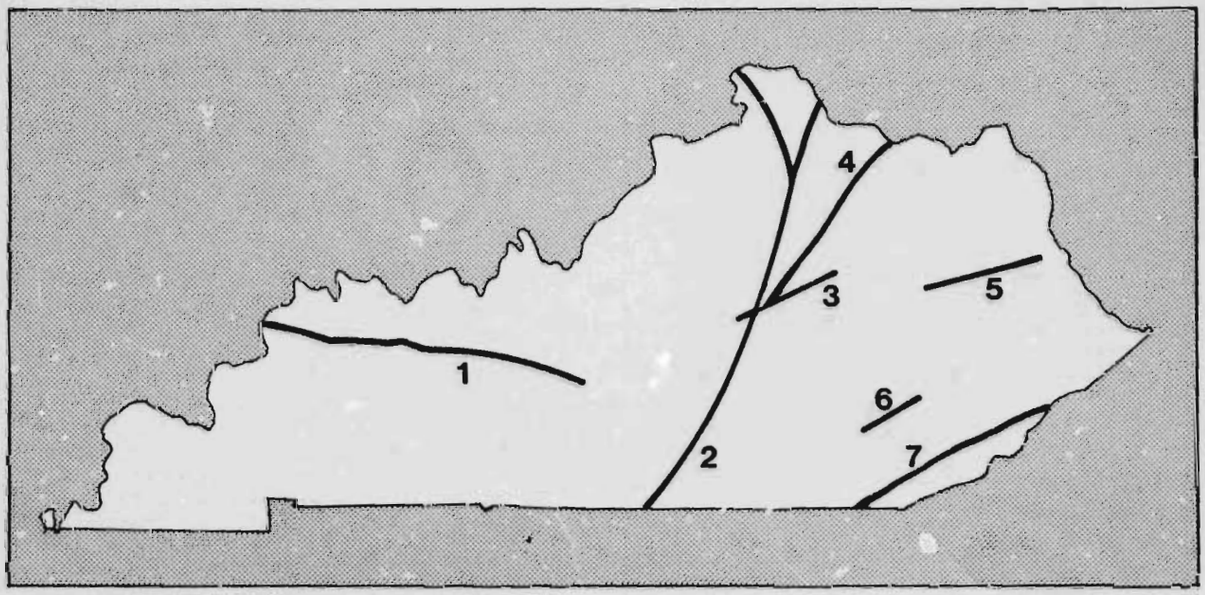


Figure 3. Map of Kentucky With Major Structural Features: 1) Shawneetown-Rough Creek Fault; 2) Cincinnati Arch; 3) Kentucky River Fault; 4) West Hickman Fault; 5) Irvine-Paint Creek Uplift; 6) Rockcastle Uplift; 7) Pine Mountain Fault.

Ordovician carbonates and shales exposed at the center of the dome; progressively younger, and at the same time, more erosion-resistant, rocks are exposed on the flanks of the arch (see Figure 4). The black shale outcrops in the Knobs and dips into the subsurface away from the arch.

In the structural saddle between the Lexington Dome and the Nashville Dome on the Cincinnati Arch, the black shale is exposed by entrenchment of rivers into the relatively shallow overburden (see Figure 2). The third area of black shale exposed at the surface is along the Pine Mountain Thrust Fault in southeastern Kentucky (see Figure 2). The fault block moved on the black shale; therefore, the shale is of little interest as an oil shale because of its thermal history during the faulting.

Figure 5 shows the disposition of the core holes completed for this study (D-series). This pattern is an extension of the near-outcrop cores drilled for the Buffalo Trace study (K-series). The average spacing between cores was 6.5 miles except between D-1 and D-11. An entire section of the black shale sequence plus overlying and underlying rocks was recovered in each core. In addition to the data available from the cores, the resource assessment work was greatly facilitated by the availability of geologic quadrangle maps for the entire area, and by the notes of the mappers (26-53) (see Figure 6). Each core was described and logged at the drill site, and detailed lithologic descriptions were completed at the laboratory.

Sample preparation is described in the paper by Bland et al. in this volume.

Stratigraphy and Lithology

The Devonian-Mississippian oil shale in this study area is known by two sets of stratigraphic names. In the northern part of the study area, the oil shales were mapped as the Lower Mississippian Sunbury separated from the underlying Devonian Ohio Shale by the Bedford Shale. South of and west of the Olympia Quadrangle, the sequence is mapped as the New Albany Shale on the U. S. Geological Survey geologic quadrangle maps at a scale of 1:24,000; the Sunbury Shale and the Bedford Shale could not be shown. However, in cores drilled in this project, the Sunbury and Bedford were still

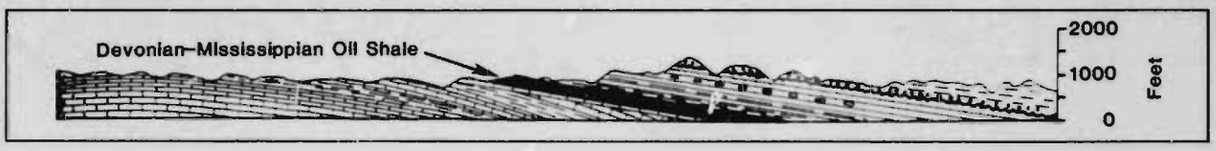


Figure 4. Geologic Cross-Section in Eastern Kentucky Through Fayette, Clark, Montgomery, Bath, Rowan, Carter, and Boyd Counties. (From Geologic Map of Kentucky, W. R. Jillson, Kentucky Geological Survey, Ser. 6, 1929).

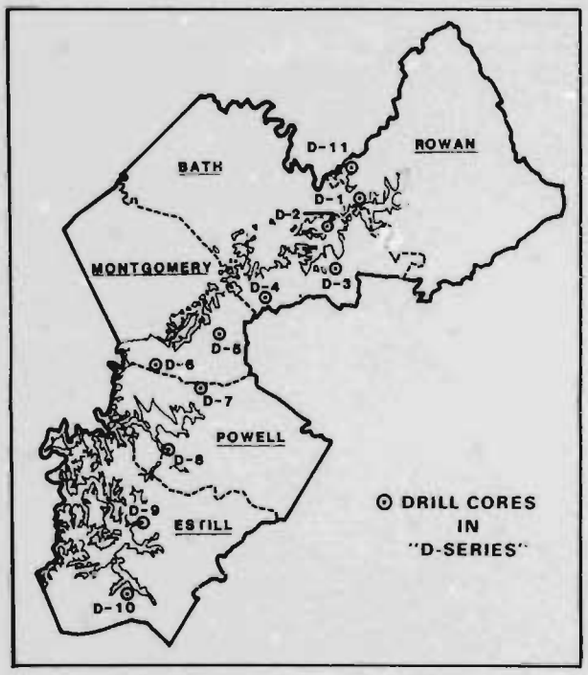


Figure 5. Geographic Distribution of the D series cores.

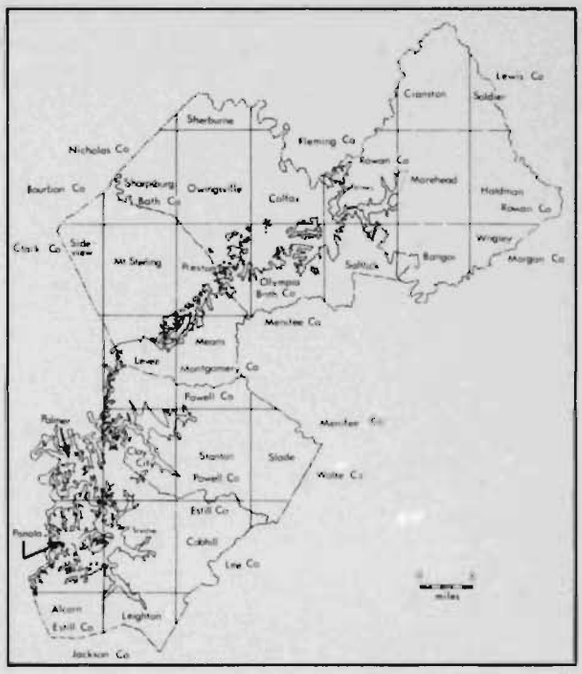


Figure 6. Locations of the Quadrangles used in the D series Cores.

present even in Powell County, although the Bedford Shale is only a few inches thick. Even though the oil shale was mapped as New Albany Shale, we will use Ohio Shale terminology while it is recognizable, as suggested by de Witt.(54)

The principal black shales of interest are the Devonian Ohio Shale and the overlying Mississippian Sunbury Shale. These are the black shales within the study area. The Sunbury Shale is overlain by the Borden Formation. Below the Sunbury and overlying the Ohio Shale is the Bedford Shale. The Ohio Shale is underlain by the Boyle Dolomite, the Bisher Dolomite, or the Crab Orchard Shale. The following descriptions of these units are in the order of youngest to oldest and are summarized in Figure 7.

Borden Formaton. The Mississippian Borden Formation is chiefly comprised of shales, siltstones, and some sandstone. The members that comprise most of the Borden in the study area are the Cowbell Member (predominantly siltstones and shale); and the Nancy Member, (predominantly shale and siltstone in the upper part to a silty shale in the lower part). Below the Nancy Member is the Farmers Member consisting of interbedded siltstones and shale. Underlying the Farmers Siltstone Member and forming the base of the Borden Formation is the Henley Bed, a shale. The Nancy Member, Farmers Member, and the Henley Bed are the most important for this discussion.

Farmers Member of the Borden Formation

The Farmers Member was found in five cores. It is light-gray (N-7) to light-olive-gray (5Y6/1) siltstone interbedded with silty shale, light gray

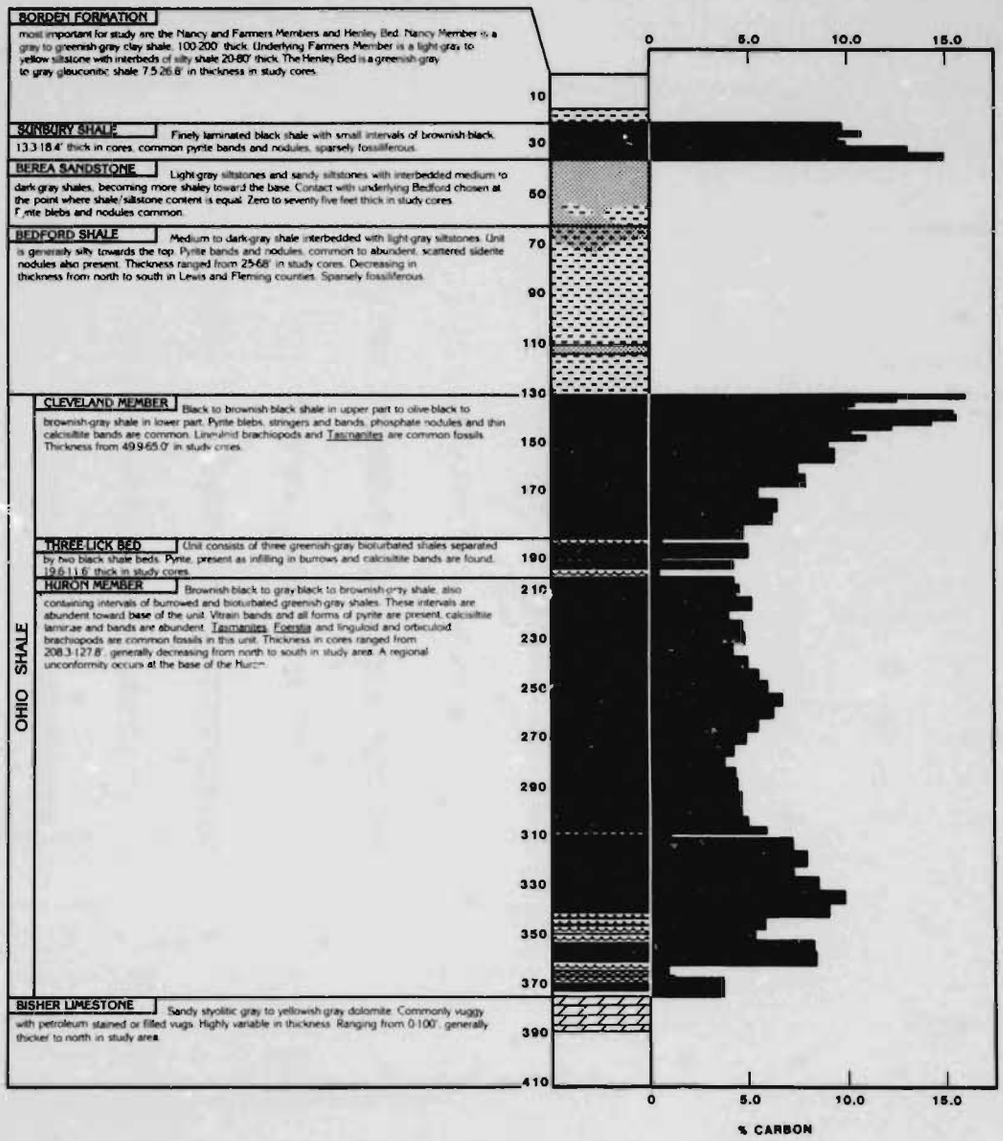


Figure 7. General Stratigraphic column for the Devonian-Mississippian Black Shales in Eastern Kentucky.

(N-6) to greenish gray (5G6/1). The bedding characteristics of the Farmers indicates that it is a series of turbidite flows. The top of the Farmers was identifiable in the cores D-11 south through D-4. This unit ranged in thickness from 30.0 feet in the north to 2.0 feet in southern Bath County. South of Bath County, into southern Powell County, the Farmers is represented by the Clay City Bed. A persistent bed of siltstone, light bluish gray (5B6/1) to medium bluish gray (5B5/1) and is equivalent to the uppermost bed of the Farmers siltstone (36).

The Clay City Bed varies from 1.5 feet in thickness in southern Montgomery County in core D-5 to 1.0 foot thick in southern Powell County in core D-8, where it wedges out.

The Henley Bed of the Borden Formation

The Henley Bed, a shale, is medium dark gray (N-4) to dark greenish gray (5GY4/1) and is occasionally glauconitic. It was present in all cores where the Farmers Member and the Clay City Bed were identifiable. The thickness of the Henley Bed ranged from 6.0 feet in the northernmost core (D-11) to 1.5 feet in the southernmost core where the Clay City Bed was present (D-8).

Sunbury Shale. The Mississippian Sunbury Shale constitutes one of the economic intervals in the study. The Sunbury is principally black (N-1), and it quite often contains bands of brownish black (5YR2/1) shale. Large pyrite nodules and thin pyrite bands as well as an occasional calcareous lamina occur in the unit. Fossils are rare in the Sunbury and are mostly limited to lingulid and orbiculoid brachiopod fragments and conodonts[9]. A bone bed was found at the base of the Sunbury in cores D-11 and D-1, but not in any others farther south. The Sunbury ranged in thickness from 17.0 feet in the northernmost core D-11, to 4.0 feet in the southernmost core in the study area, D-8 (see Figures 8 and 9).

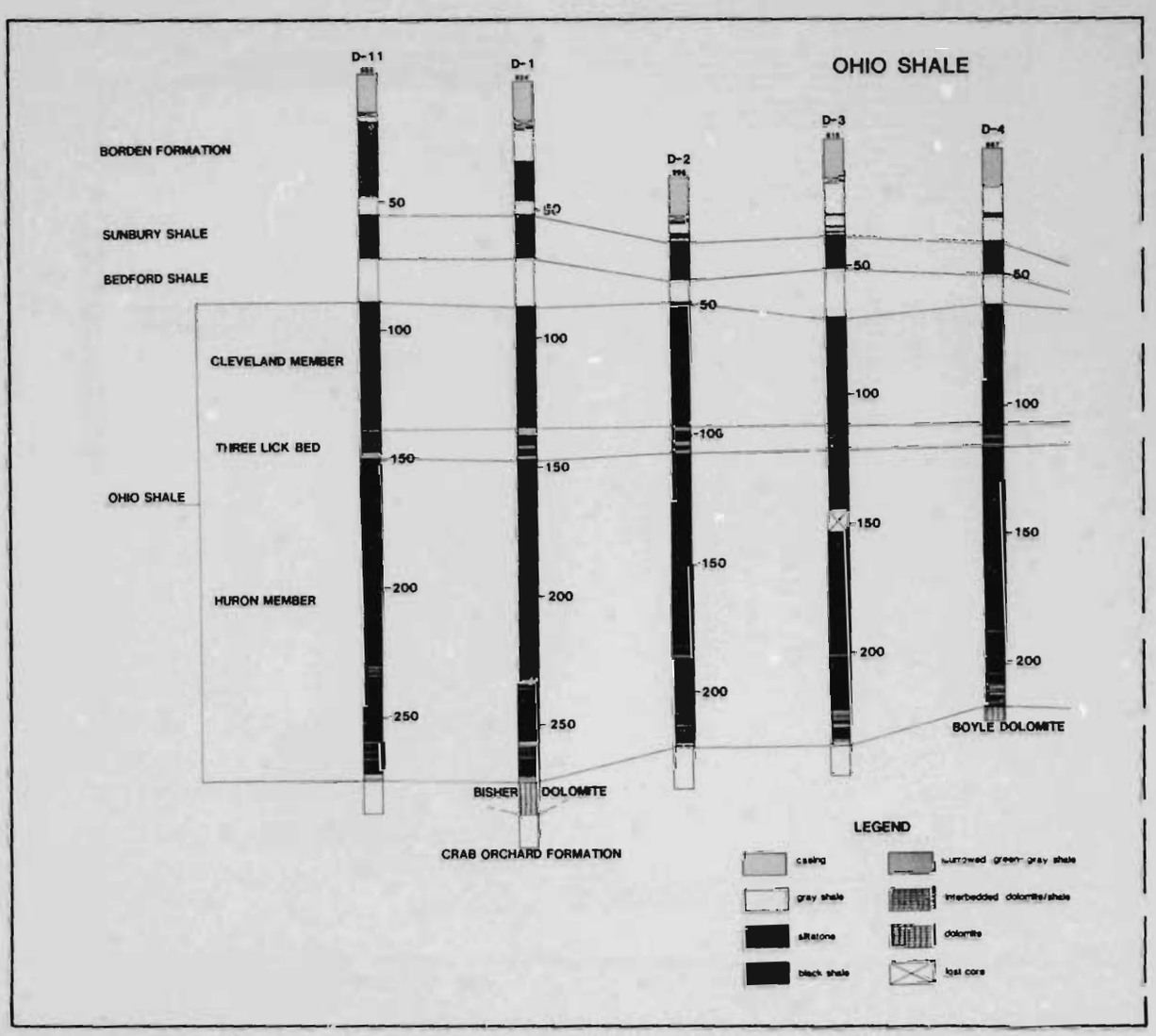


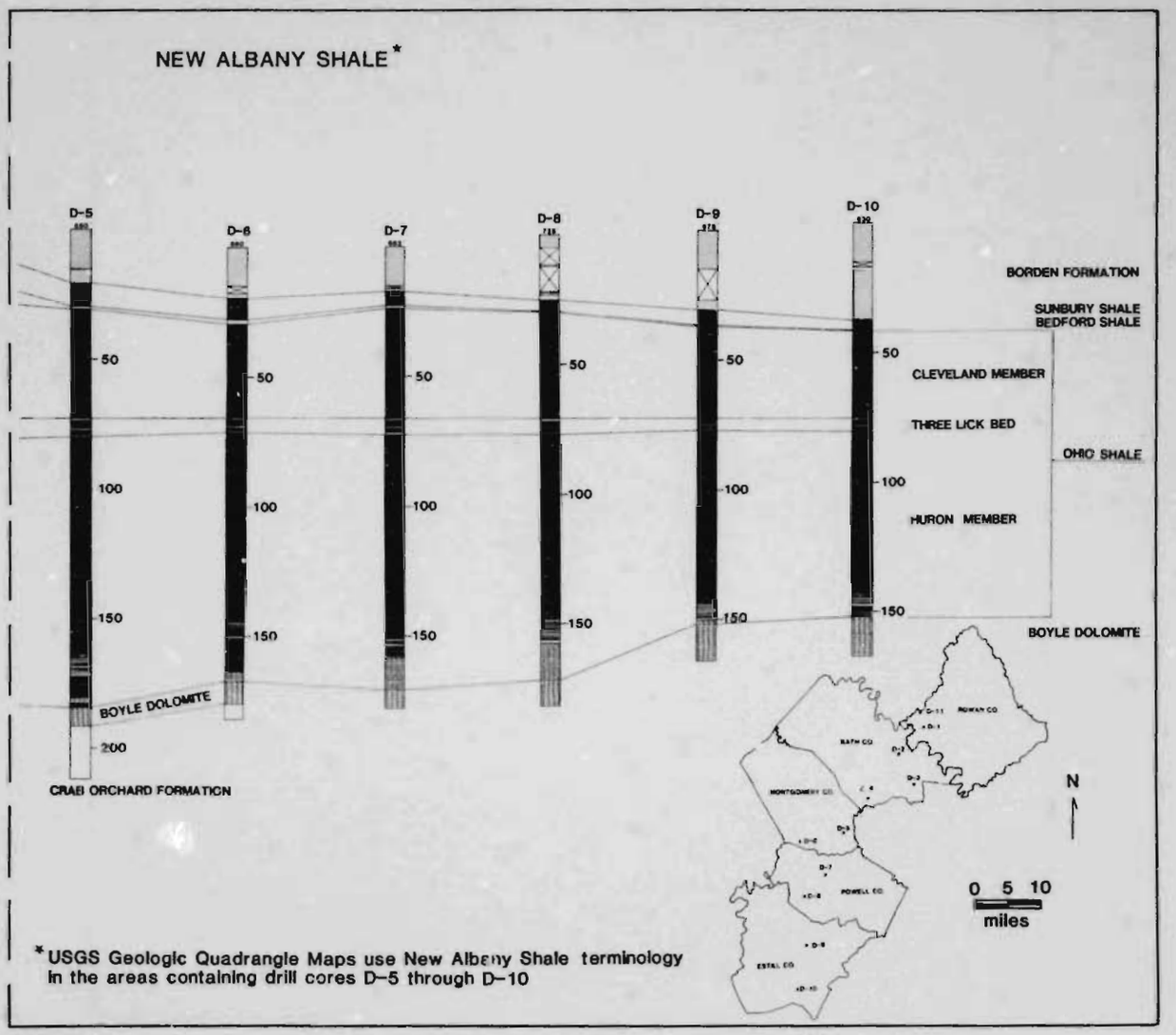
Figure 8. Stratigraphic Cross Section Through the D series cores.

Bedford Shale. The Mississippian-Devonian Bedford Shale, a medium-gray (N-5) to medium-dark-gray (N-4) shale, interlaminated with silty medium-light-gray (N-6) shale, is continuous in the subsurface throughout the entire study area. The relative percentage of silty laminae decreases towards the base of the unit and geographically towards the south in the study area. Pyrite blebs and nodules are abundant in the northern portion of the study area but decrease toward the south.

The thickness of the Bedford Shale gradually decreases in a southerly direction, ranging from 18.0 feet in core D-11 in northern Rowan County to 11.0 feet in core D-4 in southern Bath County. Between cores D-4 and D-5, in northern Montgomery County, the Bedford Shale thins dramatically to .43 feet. From core D-5 south throughout the remainder of the study area, the Bedford Shale is continuous as a thin bed ranging from 3.0 feet to .20 feet thick (see Figures 8 and 10). This unit readily weathers and is easily covered by slumping of the overlying Sunbury Shale where it is thin. This makes field identification of the Bedford very difficult. This factor is duly responsible for the Sunbury being undifferentiated from the Ohio Shale, resulting in the name New Albany Shale being applied to the black shales south from southern Bath County, on the Olympia Quadrangle, throughout the remainder of the study area. For a clearer understanding of these lateral relationships please see Figure 8.

Ohio Shale. The Ohio Shale is of Late Devonian age and is divided into two members and one formally defined bed. These are (from top to bottom) the Cleveland Member, the Three Lick Bed, and the Huron Member. This unit thins to the south (see Figure 8).

The Cleveland Member of the Ohio Shale. The Cleveland Member contains the second of the



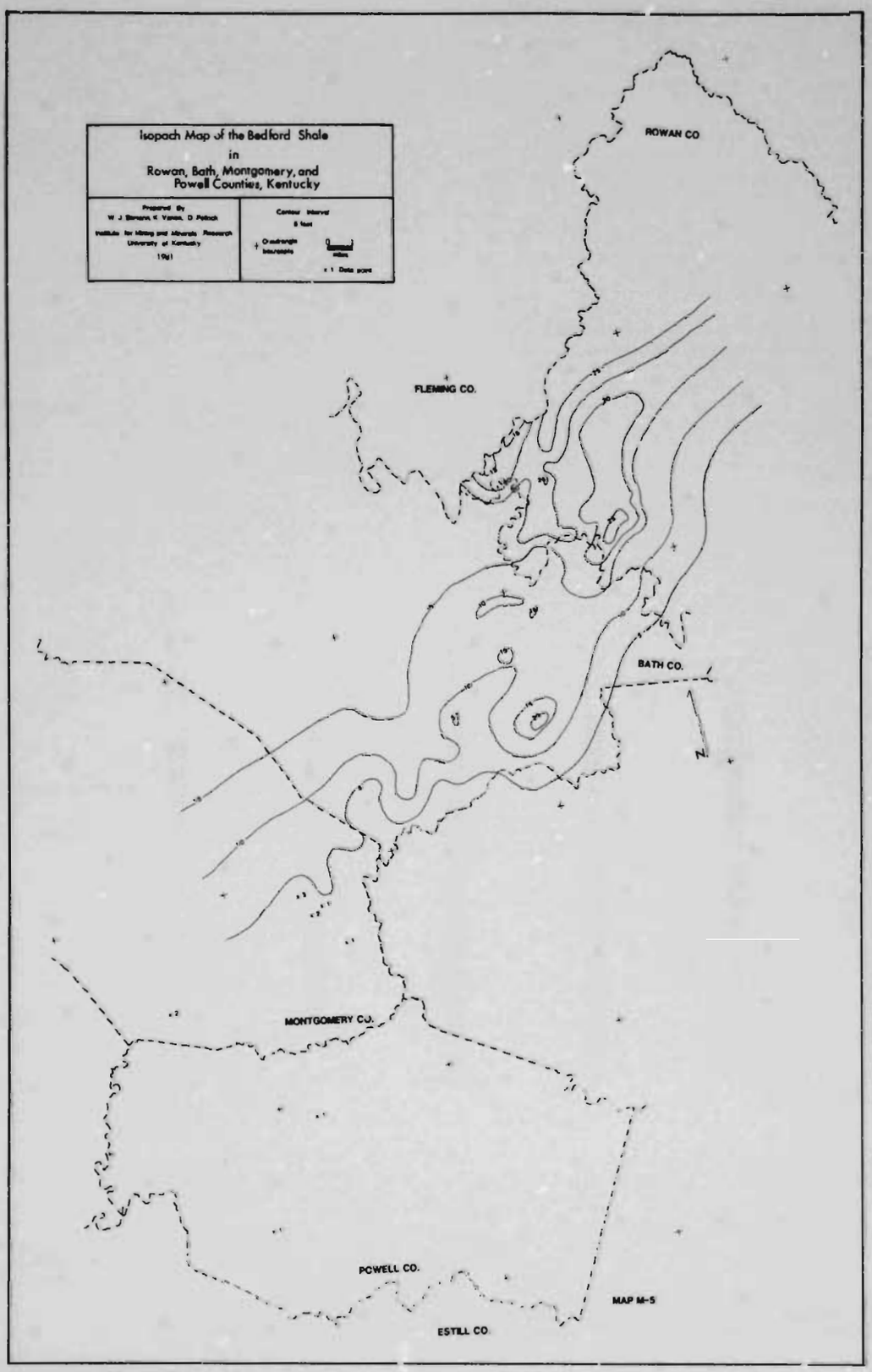


Figure 9. Isopachous Map of the Sunbury Shale in the D series Study Area.

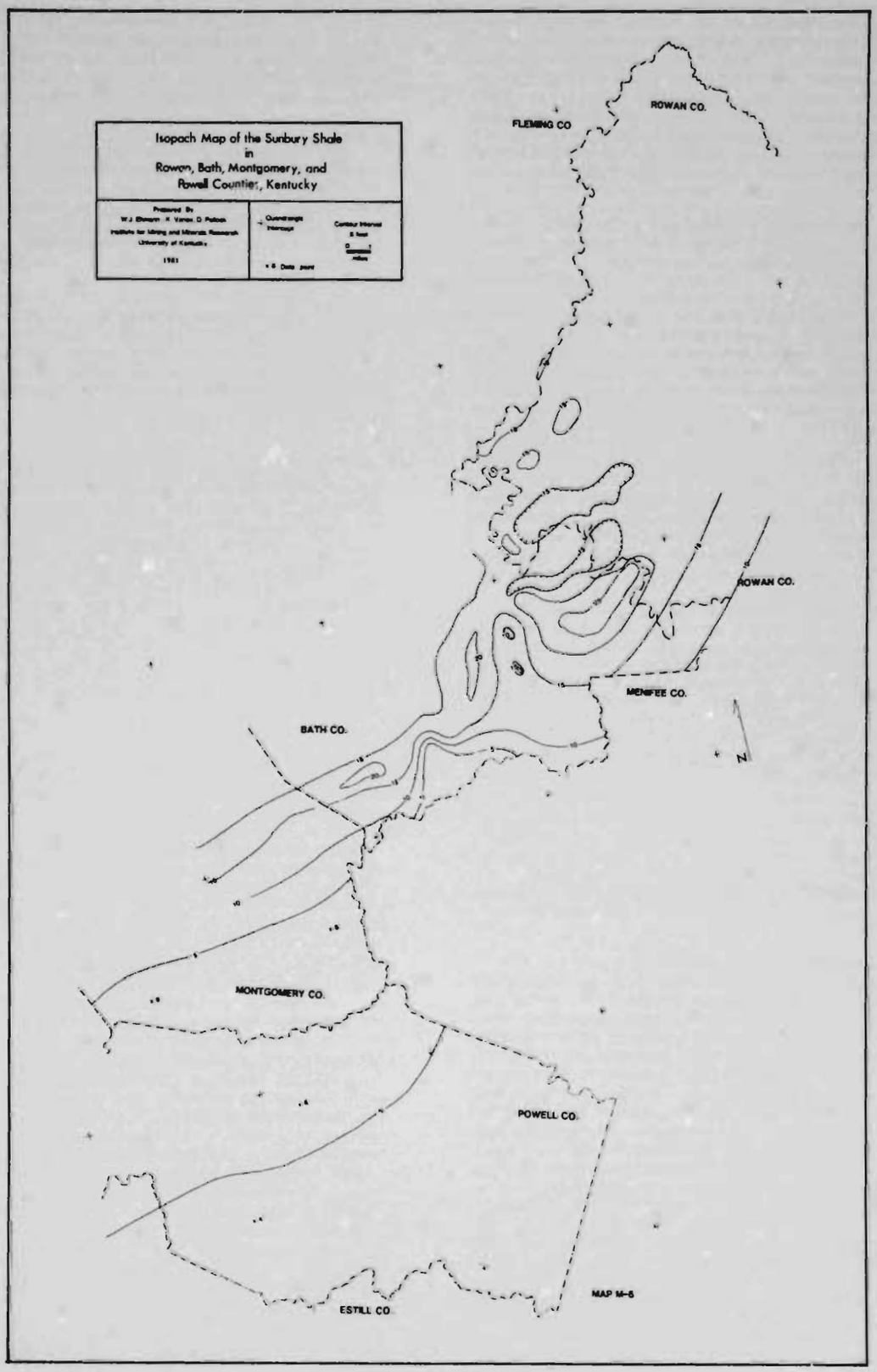


Figure 10. Isopachous Map of the Bedford Shale in the D series Study Area.

economic intervals of the study, the other being the Sunbury Shale. The Cleveland Member varies in color from black (N-1) to brownish black (5YR2/1) in its upper part, to olive black (5Y2/1) to brownish black (5YR2/1) in the lower part. The upper 10 feet of the Cleveland Member commonly contains abundant phosphate nodules. Pyrite, in the form of nodules and bands, and calcisiltite bands and laminae are scattered throughout.

The Cleveland Member shows the most consistency in thickness (see Figure 8). From D-11 southward to D-4, the average thickness of the Cleveland was 48.5 feet. It ranged from 50.1 feet in core D-11 to 46.6 feet in core D-4. The thickness of the Cleveland in core D-3 was reduced (possibly) by scouring at the top of the member. This results in a thickness in this locality of 41.5 feet, but surrounding data suggests that the normal thickness, if no scouring occurred, would be around 46.6 feet.

Southward from core D-4 the Cleveland Member thins to 42.5 feet in core D-5 in northern Montgomery County. From D-5 south to core D-8 in Powell County, the Cleveland again is consistent in thickness ranging from 42.5 feet in core D-5 to 41.4 feet in core D-8, with an average thickness of 40.7 feet. Regionally this unit thickens toward the east.

Three Lick Bed of the Ohio Shale. The Three Lick Bed is a regional stratigraphic marker. It consists of three greenish-gray (5G6/1) to dark greenish-gray (5GY4/1) burrowed shales separated by two brownish-black shale intervals. The unit contains pyrite, often occurring as infilling in the burrows, and calcisiltite laminae.

The Three Lick Bed is observed to thin gradually to the south. It attains a maximum thickness in core D-1 of 11.0 feet and thins to 8.4 feet in core D-4 and again thins to a thickness of 5.7 feet in core D-8, the southern most core in the study area (see Figure 8).

The Huron Member of the Ohio Shale. The Huron Member varies in color from brownish black (5YR2/1) to olive black (5Y2/1) to brownish gray (5Y3/1). The lower part of the Huron contains significant intervals of burrowed greenish-gray shale with dolomite bands and beds occurring at the base of the unit in the southern part of the study area. This zone of interbedded brownish-black shale and dolomite is called the "Ravenna" in Powell and Estill counties. Tasmanites, and Foerstia (Protosalvinia) plant fossils; as well lingulid and orbiculoid brachiopods are fossils that occur in the Huron. The Foerstia (Protosalvinia) is a biostratigraphic marker fossil. The variations in the thickness of the Foerstia zone may be related to the associated variations in the lithology of the zone in which it is found, as conveyed by Kepferle.[55] Vitrain bands and lenses are common in this unit. All forms of pyrite are common to abundant, with pyrite often occurring as burrow fillings. Calcisiltite laminae and bands are relatively abundant in the Huron, in contrast to the Sunbury Shale and the Cleveland Member of the Ohio Shale. Limestone bands are common throughout the study area. These limestones are cone-in-cone, medium gray (N-6) and were not found to be correllative although some zones of limestone occurence did seem to carry between selected cores.

In the study area the Huron Member shows an overall thinning trend to the south. The thickness of the Huron ranged from 125.1 feet in core D-11, the most northern core in the study area, to 97.1 feet in core D-8, the southernmost core in the study area. Regionally the unit thickens to the east into the Appalachian Basin.

A regional unconformity occurs at the base of the Ohio Shale (see Figure 8). The Late Devonian age Ohio Shale is underlain by the Middle Devonian Boyle Dolomite or the Middle Silurian age Bisher Dolomite or the Middle and Early Silurian age Crab Orchard Formation.

Boyle Dolomite. This dolomite of Middle Devonian age is olive gray (5Y4/1) to medium gray (N-5) to light brownish gray (5YR6/1). The unit is vuggy and commonly contains bluish-white (5B9/1) to medium-blue-gray (5B5/1) chert bands and nodules. The Boyle was found in all study cores except cores D-11 through D-3 in the northern part of the study area. The base of the Boyle was penetrated only in cores D-5 and D-6. Due to pre-and post-Boyle erosion the thickness of the Boyle ranged from 7.0 feet to 22.0 feet where it was present in the study area (see Figure 8). Many of the cores from this unit were petroleum stained.

Bisher Dolomite. The Bisher was present underlying the Ohio Shale only in core D-1 in Rowan County (see Figure 8). The Bisher, a dolomite of Middle Silurian age, is very light gray (N-8) to medium light gray (N-6) to light bluish gray (5B7/1). It is fine to medium grained and vuggy throughout. The recovered core also showed petroleum staining. The thickness of the Bisher ranged up to 12 feet in Rowan County and is present as remanents on topographic highs on the pre-Boyle erosional surface in the vicinity of Clay City in Powell County (43).

Crab Orchard Formation. The Crab Orchard Formation (upper part) is characterized by interbedded greenish-gray (5G6/1) to medium-bluish-gray (5B5/1) clay shale and thin light-gray (N-7) to light-brownish-gray (5YR4/1) dolomite and dolosiltite bands. The entire thickness of the Crab Orchard was not penetrated in any of the cores. The unit was found to underlie the Ohio Shale in cores D-11, D-2, and D-3 (see Figure 7). The Crab Orchard Formation was present throughout the entire study area. Geologic maps indicate an average thickness of 140 feet in the study area and they also indicate a thinning trend toward the southern end of the study area.

Stratigraphic Correlations

The major units of the black shales were

easily correlated, both lithologically and geophysically. The lithology of the black shale stands out in strong contrast with overlying and underlying rocks. The Three Lick Bed served as an excellent, easily discernible marker for the subdivision of the Ohio Shale. The Sunbury Shale was found to be discernible throughout the study area from subsurface lithology and geophysical logs. In addition to lithologic and geophysical correlations, a biostratigraphic zone that was previously defined based on the fossil Foerstia (Protosalvinia), was also found to be traceable throughout the area.

The changes in thickness in the black shale units from the cores were found to be gradual and systematic. This, along with the highly correlateable nature of the shale, strongly supports the validity of extrapolations made from the cores in the resource assessment (9).

Stratigraphic and Geographic Distribution of Carbon, Hydrogen, and Nitrogen

Carbon occurs in the oil shale either in organic matter (kerogen, bitumen) or in carbon-bearing minerals principally calcite ($CaCO_3$) and dolomite ($CaMg(CO_3)_2$). Mineral carbon determinations were performed on core K-5 of the Buffalo Trace study (56). The average mineral-carbon content of the Sunbury, the Cleveland, and the Huron intervals are 0.01, 0.06, and 0.13 wt.% as carbon with ranges of <0.01-0.03, <0.01-0.16, and 0.05-0.30 wt.%, respectively. Therefore for all practical purposes, reported values of total carbon can be considered as indications of concentrations of organic carbon. As shown in the values above, the concentrations of mineral carbon are somewhat higher in the Huron. The occurrence of discrete bands and laminae of calcite and the dolomite facies called the Ravenna (57) causes the values of mineral-carbon in the Huron to be higher in this study than in the K-series. This increase was not observed in the Sunbury and Cleveland units.

Hydrogen may be present in either surface moisture, in mineral-bound moisture, or in organic matter (kerogen, bitumen). Total hydrogen was measured as was surface moisture. The reported hydrogen value was corrected for the surface moisture, but a simple and accurate technique for measuring mineral-bound moisture was not available for rocks rich in organic matter. It is therefore assumed that a small fraction of the reported hydrogen is in the form of mineral-bound moisture. The uniformity of the major-element chemistry found in the oil-shale sequence suggests that the stratigraphic variations observed in the hydrogen concentrations probably reflect changes in the organic content rather than variations in the major-element chemistry.

The carbon distribution shows very consistent stratigraphic variations in the study cores (see Figure 11). The upper section and the lower section show comparatively high carbon values compared to the leaner middle section. The Sunbury and Cleveland form the upper section of high carbon. The lower section of high carbon is a comparatively thin zone in the Huron Member. The Sunbury and the Bedford (interburden) thin to the south and therefore the carbon distribution patterns within the Sunbury and Cleveland, respectively, are not as evident as in the previous study to the north. The carbon values generally decrease down the core within the Cleveland. The three greenish-gray shales of the Three Lick Bed show up as large decreases in carbon content. Additionally, the Three Lick Bed thins to the south, and the zones of low carbon values are less conspicuous, but still present. Carbon distribution in the Huron is erratic and inconsistent due to increased interbedded greenish gray shale, calcareous beds and laminae, and the dolomitic facies.

The mean carbon concentrations for the stratigraphic intervals of the Sunbury, Cleveland, and Huron from all the cores are 13.28, 9.64, and 6.37 wt.% C, respectively. The coefficients of variation among the cores (standard deviation/mean X 100) for the units are 10.4, 4.6, and 15.9, respectively.

The mean hydrogen concentrations for the Sunbury, Cleveland, and Huron are 1.55, 1.12, and 0.73 wt.% H, respectively. The coefficients of variation are 17.3, 9.4, and 15.9, respectively.

The mean values for nitrogen in the Sunbury, the Cleveland, and the Huron stratigraphic intervals were .44, .32, and .21 wt.%, respectively, with coefficients of variation of 10.2, 9.6, and 20.7, respectively. The range of mean nitrogen values for individual cores were .38 to .51% wt.% for the Sunbury; .28 to .38 wt.% for the Cleveland; and .13 to .32 wt.% for the Huron. As with carbon and hydrogen, the higher values for nitrogen are in the Sunbury and Cleveland. The greatest variation is in the Huron.

Economic Zones and the Relationship of Fischer Assay to Carbon

As was noted in the resource assessment in Lewis and Fleming counties (55), only certain stratigraphic intervals could be reasonably considered as feedstocks to a conventional retort, because of the distribution of carbon. The two economic zones defined were the entire Sunbury Shale and a high grade zone in the upper part of the Cleveland Member. These economic zones were identified based on carbon concentrations greater than 8%. In this study, both of these economic zones have been recognized. The Sunbury Shale, as mentioned before, thins to the south. In D-11, it is 16.4 feet thick on the northern end of the study area, and it thins to 4.0 feet in D-10 on the southern end. The mean carbon concentration averages 13.28 wt.%, ranging from 11.58 wt.% to 15.23 wt.%. Within the Sunbury interval in D-11, using two-foot sample intervals, the carbon concentration varies from 9.31 to 13.4 wt.%. Within the four foot interval in D-10, there were two samples with 14.25 and 9.80 wt.% C, respectively. There were no Sunbury samples with a carbon concentration less than 8%, and most were over 10%.

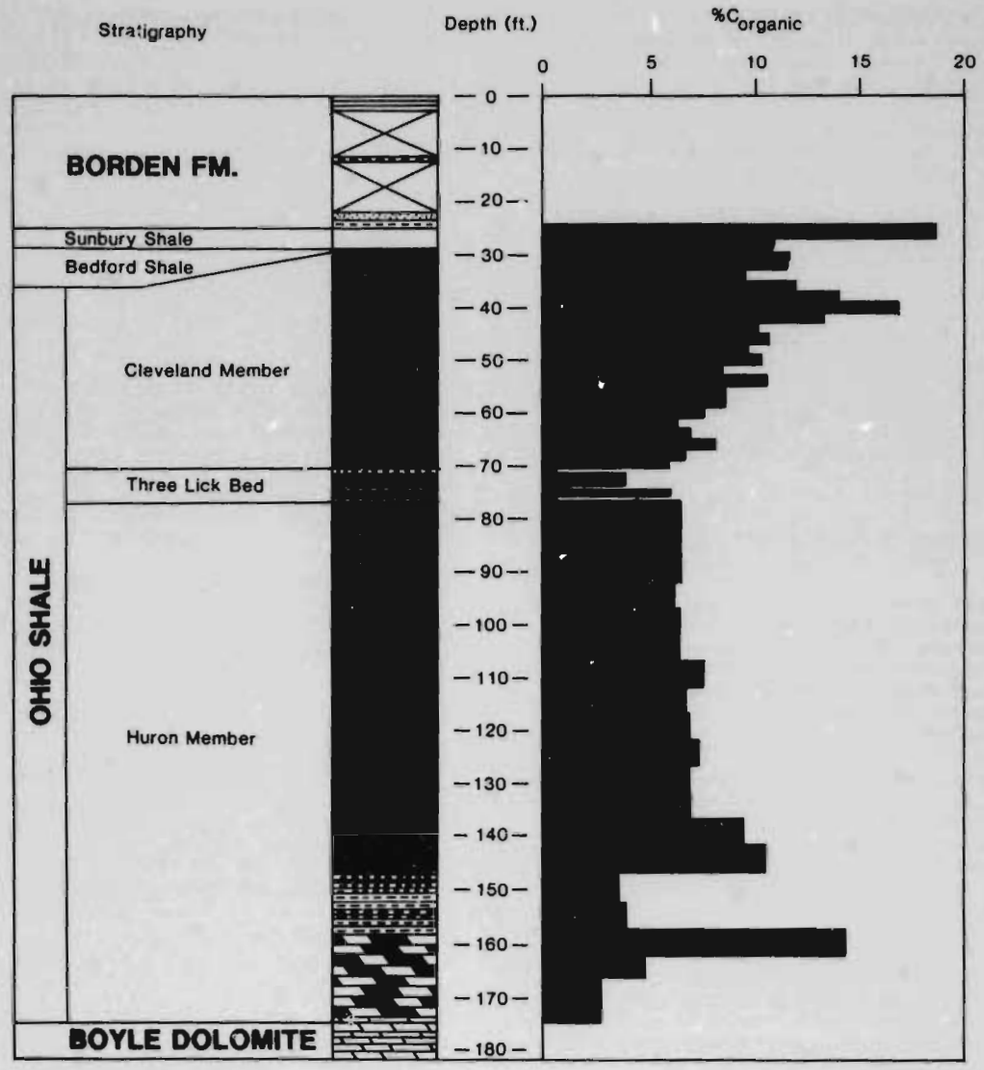


Figure 11. Down-core Distribution of Carbon for Core D-8 With a Stratigraphic Column.

The Cleveland High Grade Zone (HGZ) was defined as the upper contiguous part of the member with carbon concentrations greater than 8%. In the Buffalo Trace study (56), the 8% cut-off point was in an interval where the carbon content was decreasing quite rapidly, as shown in Figure 8. The zone was consistently 30 feet thick in the Buffalo Trace study (56). That consistency continued in this study. Considering all of the D-series cores, the Cleveland HGZ averaged 28.9 feet thick with a standard deviation of 2.7, and coefficient of variation of 9.4. However, when considering the cores from only Rowan, Bath, Montgomery, and Powell counties (D-11 through D-8), the mean thickness is 30.0 feet, with a standard deviation of 1.3, and coefficient of variation of 4.5. Within the Cleveland High Grade Zone, the mean carbon concentration is 11.09 wt.%, considering all of the D-series cores, compared to 9.64 for the entire Cleveland Member.

The Huron Member contains an interval of black shale with more than 8% carbon. For a number of factors, this interval was not considered to be an economic zone. It is quite variable in thickness, with a mean of 12.5 feet, standard deviation of 4.2, and coefficient of variation of 33.9%. Additionally, this interval lies beneath a section of leaner black shale (<8% C) that separates it from the Cleveland HGZ. The overlying lean shales average 8.2 times the thickness of the interval with high carbon. Within the high-carbon zone, the sulfur values are always greater than 5 % and most often greater than 6 %. Compare this to mean sulfur

concentrations from the Sunbury and the Cleveland HGZ of 3.7 and 2.43%, respectively. Thus, from both environmental and economic points of view, this section of the Huron is less adequate than the Sunbury or the Cleveland HGZ.

Modified Fischer Assays were conducted on samples from the Sunbury, the Cleveland HGZ, and the high carbon section of the Huron. There is an attendant controversy when Fischer Assay is applied to the eastern Devonian-Mississippian oil shales. When conducted in a standardized and reproducible manner, it does provide some basis for internal comparison of the samples of the study. Additionally, the results provide a conservative estimate of the amount of oil which conceivably could be extracted from the oil shale. It is important to remember, though, that it does not measure the total recoverable energy in the shale because it does not account for the significant quantities of lighter oils, noncondensible high-Btu gas, and steam that can be produced in retorting eastern oil shales (Refer to the paper by Rubel in the volume).

The mean Fischer Assay values of the weighted averages for the cores (D-11 through D-7) are 11.38 gpt for the Sunbury Shale, 11.44 gpt for the Cleveland HGZ, and 7.89 gpt for the high carbon section of the Huron. The coefficients of variation calculated were 12.9, 3.37, and 24.49%, respectively. For the Sunbury the range was from 9.69 to 14.25 gpt, weighted average for the interval. The range for the Cleveland HGZ was 11.03 to 11.59 gpt, and for the high carbon section of the Huron it was 5.43 to 11.35 gpt. As with other analyses mentioned before, the higher values are in the Sunbury and Cleveland HGZ, and the highest variation is in the Huron.

Although the mean carbon values for the Sunbury are higher than those for the Cleveland HGZ, the mean Fischer Assays for the two units are almost equal. This implies a higher yield of oil per unit of carbon in the Cleveland HGZ than in the Sunbury. The exact relationship of carbon to Fischer Assay is not clear and, of course, depends on the form of organic carbon.

The mean sulfur concentrations for the Sunbury, the Cleveland HGZ, and the Huron are 3.70, 2.93, and 3.58 wt.%, respectively, with coefficients of variation of 11.9, 12.0, and 7.2%, respectively. In a gross sense, the pattern of the stratigraphic distribution of sulfur follows that of carbon. The higher levels are in the Sunbury and the Huron. As previously mentioned, the high carbon section of the Huron has unusually high sulfur values. The mean of weighted averages for the high carbon section of the Huron is 6.22 wt.% sulfur. The bulk of the sulfur is present as iron sulfide (probably pyrite)(56).

Resource Assessment

Resource assessment of the oil shales was limited to that oil shale which would be accessible with currently available mining technology. Since there is essentially nothing known about underground mining of the Devonian-Mississippian oil shale, this limits resource assessment to that oil shale which can be recovered by surface mining. The overburden/interburden to economic oil shale ratio used was 2.5:1. This ratio is roughly analogous to that used in surface mining of coal, with the oil shale having much lower energy value per ton and higher ash content.

The shale resources were estimated according to overburden/interburden ratio for Rowan, Bath, Montgomery, and Powell counties (see Figure 6). The estimate was based on two economic zones as previously discussed: the Sunbury Shale and the Cleveland HGZ. These units were defined with a lower cutoff of 8% carbon, and they are separated by an interburden unit, the Bedford Shale. This interburden thins southward from 16.8 feet in core D-11 to 0.3 feet in core D-8. The variation of this interburden unit complicated the resource estimation. Additionally, the Sunbury Shale thins from 15.4 feet in core D-11 to 5.1 feet in core D-8. The mean thickness of the Cleveland HGZ for cores D-11 through D-8 was 30.0 feet with a standard deviation of 1.3 and a coefficient of variation of 4.5%.

The resources were divided into three categories by two calculated lines: 1) the Vertical Stripping Index (VSI) line and 2) the Overall Ratio Estimator (ORE) line. The VSI line was derived as follows. The Sunbury Shale and Cleveland HGZ thicknesses were added together and multiplied by 2.5, and the thickness of the Bedford interval was subtracted from this value. This figure was added to the elevation of the upper contact of the Sunbury Shale, and these values were contoured. The intersection of this artificial surface with the topographic surface defined the VSI line. The VSI line connects the points along slope where the overburden-interburden to oil shale ratio reaches 2.5:1. The overall ratio (from outcrop edge to this point) at this point is less than 2.5:1 and is a function of the thickness of the economic shale intervals and the thickness of the interburden. Since the variation in the thicknesses of the oil shales are small, it is primarily a function of the thickness of the Bedford. The overall ratio (OR) of the overburden is defined as follows:

$$OR = 1.25 + 1/2(TB/TO)$$

where TO is the combined thickness of the Sunbury Shale and Cleveland HGZ, and TB is the Bedford thickness. The overall ratio at the VSI line for any region in the study area may be estimated from the thickness of the Sunbury Shale and the Bedford interval using the above formula.

The ORE line is derived similarly to the VSI line. The ore zones were added, multiplied by 2.5, and the thickness of the interburden subtracted. This value was then multiplied by two and added to the elevation of the top of the Sunbury. Then these points were contoured and intersected with the topography. The ORE line connects the points along the slope where the overall overburden-interburden to oil shale ratio (from outcrop edge to this point) reaches 2.5:1, assuming a constant slope between the top of the Sunbury Shale and the ORE line. This is a reasonable assumption for the study area.

The 7 1/2-minute quadrangle maps (scale 1:24,000) were used as a base for the resource calculations (Figure 6). The map areas were measured with a computerized planimeter. The individual 7 1/2-minute maps were reduced to a scale of 1:48,000 for compilation purposes and further reduced in Figure 12. The stippled areas on the map (O-VSI and VSI-ORE) represent ridges and knobs where oil shale is covered/separated by overburden/interburden that is less than 2.5 times

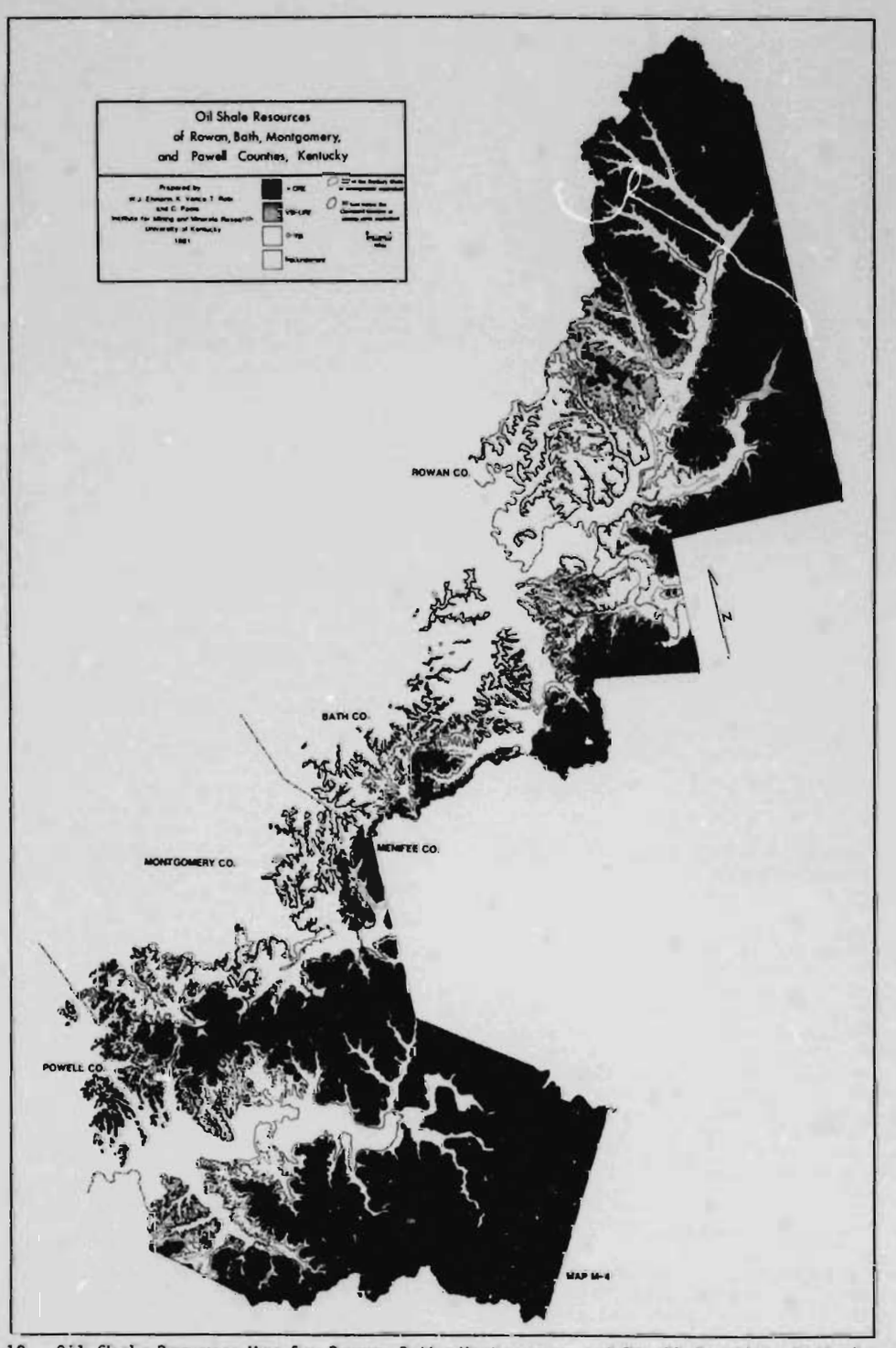


Figure 12. Oil Shale Resource Map for Rowan, Bath, Montgomery, and Powell Counties, Kentucky, with Distribution of the Oil Shale According to Stripping Ratios.

as thick as the economic oil shale. The black areas represent areas where the overall stripping ratio is greater than 2.5:1.

Oil Shale Resources

A summary of the oil shale resources is presented by quadrangle in Table 1. The breakdown includes the following categories: volume in acre-feet, weight in tons, and oil yield in place by Fischer Assay in barrels, according to stripping ratio (0-ORE and greater than ORE).

These stripping ratio categories roughly represent strippable and nonstrippable resources, as previously discussed. A similar breakdown of oil shale resources by county is presented in Table 2.

Of the three estimates presented (volume, weight, oil yield), the volumetric is the most accurate. The tonnages were calculated using a density of 142 pounds per cubic foot, which was derived from bulk density-carbon regression analysis (9, 56). The oil yields were derived from weighted Fischer Assay data for the economic oil shale intervals from the three cores in or nearest a given quadrangle. The data are presented as the combined resource of the Sunbury and Cleveland HGZ.

Within the four counties of the study area,

Table 1. Resource[1] Summary for the Oil Shales of Rowan, Bath, Montgomery, and Powell Counties, Kentucky, By Quadrangle.

	Volume[2] (acre-feet)		Weight[3] (10^6 tons)		Oil Yield[4] (10^6 barrels)	
Quadrangle	0-ORE	> ORE	0-ORE	> ORE	0-ORE	> ORE
Cranston	363,239	1,303,003	1,123	4,030	297	1,070
Plummers Landing	57,885	25,687	179	79	49	22
Farmers	751,173	54,976	2,326	170	621	45
Morehead	657,558	1,130,416	2,033	3,500	562	967
Preston	110,384	589	341	2	94	1
Colfax	7,670	-	113	-	31	-
Olympia	495,511	75,241	1,537	233	428	65
Salt Lick	405,689	388,992	1,255	1,200	345	331
Means	560,780	434,014	1,733	1,340	479	370
Levee	401,944	140,256	1,243	434	337	118
Clay City	218,850	118,815	676	367	187	102
Stanton	455,998	857,923	1,410	2,650	393	738
Slade	67,941	800,706	210	2,480	56	561
Stricklett	-	89,820	-	278	-	74
Cob Hill	-	20,881	-	65	-	18
Zachariah	-	101,640	-	314	-	88
	4,554,622	5,542,959	14,179	17,142	3,879	4,570

1 Combined resource of the Sunbury and the Cleveland HGZ.
2 This includes a .25 slope adjustment factor for that part of the Cleveland HGZ not capped by overburden.
3 Assumed density of 142 lbs./ft.^{3}
4 Based on Fischer Assay values.

Table 2. Resource[1] Summary for the Oil Shales of Rowan, Bath, Montgomery, and Powell Counties, Kentucky, by County.

	Volume[2] (acre-feet)		Weight[3] (10^6 tons)		Oil Yield[4] (10^6 barrels)	
	0-ORE	> ORE	0-ORE	> ORE	0-ORE	> ORE
Rowan	1,829,853	2,603,903	5,661	8,057	1,529	2,178
Bath	1,006,737	466,343	3,212	1,440	887	398
Montgomery	659,097	237,693	2,032	733	558	192
Powell	1,058,933	2,235,021	3,274	6,912	903	1,801
	4,554,620	5,542,960	14,179	17,142	3,877	4,569

1 Combined resource of the Sunbury and the Cleveland HGZ.
2 This includes a .25 slope adjustment factor for that part of the Cleveland HGZ not capped by overburden.
3 Assumed density of 142 lbs./ft.^{3}.
4 Based on Fischer Assay values.

we estimate a resource of 4.55 million acre-feet or 14.2 billion tons of oil shale within an overall stripping ratio of 2.5:1. This is conservatively estimated to represent 3.88 billion barrels of oil in place, based on Fischer Assay. We also estimate that the four counties contain an additional 5.5 million acre-feet or 17.1 billion tons of oil shale with a stripping ratio of greater than 2.5:1; and this represents an estimated 4.6 billion barrels of oil in place.

Conclusions

1. The organic matter (kerogen) in the Devonian-Mississippian oil shale in the study area is concentrated in three stratigraphic zones: the Sunbury Shale, the Cleveland high-grade zone, and the high-carbon section of the Huron.

2. Of the economic zones identified, the Cleveland HGZ demonstrates the greatest uniformity. It averaged 30.0 feet thick for the interval covered form core D-11 to core D-8.

3. Hydrogen concentrations in the Sunbury Shale and in the Cleveland HGZ increase to the south in the study area.

4. Oil yields also increase to the south in the Sunbury Shale and the Cleveland HGZ.

5. Significant resources of oil shale were found with in a configuration which is probably accessible by surface mining. An estimated 14.2 billion tons conservatively represent 3.88 billion barrels of oil in place, based on Fischer Assay.

6. The greater amount of oil shale in the four-county study area is probably accessible only by underground mining, which requires much additional research before it is known whether or not it is feasible.

Acknowledgements

This work is part of a continuing effort to assess and characterize the resource of the Devonian-Mississippian oil shale in Kentucky. This study was funded by the U. S. Department of Energy through its Atlanta office in cooperation with the Kentucky Department of Energy. This was a follow-on to IMMR's resource assessment and characterization work in the Buffalo Trace study.

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Last, but far from least, we acknowledge the staff of IMMR at the Kentucky Center for Energy Research Laboratory for invaluable and timely contributions to this study.

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Tuesday Morning Session

PROCESS TECHNOLOGY

Eastern Oil Shale — Past, Present, and Future

by

John Humphrey
Highland Energy Corporation
Olive Hill, Kentucky

Robert Addington
Pyramid Minerals
Olive Hill, Kentucky

Abstract. From its founding the United States has played a dominant role in the development and production of the oil resources of the World. From 1776 on into the mid-eighteen hundreds the U.S. was the leader in sperm and whale oil production - the leading oils for lighting and lubrication. Increased demand, declining supplies and price escalation resulted in the development of a coal and shale oil industry along the Ohio River Valley sometime around 1850.

In 1859 petroleum was discovered at Titusville, Pennsylvania, and the modern oil industry was born. The price of natural petroleum rapidly fell from twenty dollars per barrel to ten cents. As a result the coal and shale oil industry could not compete. The end of each World War saw a renewed interest in oil shale, but commercial production was never realized. Today we are prepared to move forward in shale oil production from the same shales that produced oil in the eighteen hundreds.

"In each period in our history, the nation has responded to challenges which have demanded the best in all of us.

This is one of those times.

Our energy crisis is an invisible crisis, which grows steadily worse - even when it is not in the news. It has taken decades to develop, as our demand for energy has grown much faster than our supply. It will take decades to solve. But we still have time to find answers in a planned orderly way - if we define the changes we must make and if we begin now.

We can rediscover the ingenuity and the efficiency which have made our nation prosper, rather than deepening our dependence on insecure imports and increasingly expensive conventional supplies. We can rediscover small-scale, more creative ways of satisfying our needs. If we are successful, we can protect jobs, the environment, and the basic American standard of living, not only for ourselves but also for our children and grandchildren.

I know that, if we work together as a united people, we will succeed."

President Jimmie Carter
The National Energy Plan
April 29, 1977

Shale Oil - Prior to 1900

From its very beginning the United States has played a dominant role in the development and production of the oil resources of the world. Just prior to the Revolutionary War the American Colonies had one hundred eighty-three ships in the North Atlantic and one hundred twenty-five others cruising from Newfoundland to Brazil, all in search of the premium oils of the day - sperm and whale oil. These two oils were in great demand for they were essential for lubrication and lighting. The streets of our major cities were lighted by whale oil as were most homes. It was used as cutting oil, in the manufacture of cord and rope, and was in great demand for tempering steel. Even the settlings from whale oil was used extensively to produce synthetic gas to light theaters and public buildings.

So important was whale oil that even as early as 1670 an American shore-boat fishery was established to hunt the abundant Atlantic right whales off the coast of Long Island and in Delaware Bay. Sometime later the Colonists pursued whales in sailing ships and in 1712 a Nantucket whaler was

first to take a sperm whale in open water. From here on the American whale oil industry was to boom. The sperm whale was to rapidly grow in importance and was to be hunted by every major power and in every ocean of the globe. But none were to pursue the whaling industry as feverishly as the Americans. In 1790 a British vessel was the first to round the Cape Horn and open the Pacific to sperm whales. The British may have been first, but the Americans were soon to follow and push whaling to enormous proportions.

Except for a period during the Revolutionary War and the War of 1812 - even then our oil supplies were threatened by foreign intervention - the American oil industry thrived and grew prosperous. By 1839 we had 555 vessels involved in whaling, mostly in the Pacific. By 1847 the U.S. fleet had grown to 594, all other foreign vessels numbered only 230. In 1864 the U.S. whaling fleet reached its maximum of 736 ships sailing from such world famous ports as New Bedford, Nantucket, and Salem, and a host of lesser known New England towns and villages. In that year capital invested, exclusive of outfits and supplies, had reached over twenty-one million dollars. The entire fishery and its associated industries is estimated to have had a capital worth of around forty million dollars and to have employed nearly forty thousand people. An impressive early oil industry.

From 1840 to 1860 the value of the U.S. whale catch averaged about eight million dollars annually. The maximum value reached in 1854 was nearly eleven million. In that year sperm oil was selling for $1.48 3/4 per gallon ($62.48/bbl) and whale-oil for 59 5/8 cents per gallon ($25.04/bbl). Whale bone, also a valuable product, was worth 39 1/5 cents per pound. The total catch netted 2,315,924 gallons (55,141 bbls) of sperm oil, plus 10,074,866 gallons (239,878 bbls) of whale oil and 5,652,300 pounds of bone.

By the mid-eighteen hundreds the major whale herds of the world had been fairly well exhausted, especially the larger high oil yielding species. Small varieties were being taken in large numbers, but oil production would never again reach the level of 1854. As supplies diminished price began to increase, but the U.S. and the rest of the world was in the beginning of the industrial revolution. Therefore there was a strong demand for oil. This could be called the first U.S. oil crisis.

This first oil crisis was not unique to the U.S. The rest of the world was feeling the pinch of diminishing whale oil and economic difficulties brought on by high world oil prices. The major world powers were involved in heavy industrialization and future economic growth required additional supplies of lubricating and machine oils. While there had always been some oil (petroleum) derived from naturally occurring seeps, it was far from being adequate for the new growing oil demand. Man had yet to discover how to influence these oil flows, but the time was to come. Other sources had to be found and synthetic oil was a natural outcome.

One particular natural oil seep played a very important role in synthetic oil production. In December of 1847 Lyon Playfair was to draw the attention of a chemist, James Young of Glasgow, Scotland, to a natural oil seep at Alfreton in Derbyshire. To quote the 1891 Encyclopedia Britannica, Vol. 18: "...with the view of turning the material to commercial advantage." Young began production in 1848, but within three years the seep was nearly exhausted. Young being a true scientist theorized that this natural oil may have been produced by the action of heat on the underlying coal beds and had begun earlier a series of experiments on the pyrolysis of coal. In October, 1850, he was to secure a patent for the manufacture of paraffin and paraffin oil from bituminous coal. Young's efforts didn't stop with coal, it didn't take him long to realize that the Boghead coal of Scotland also could yield paraffin oils and in 1851 he established an industry based upon that mineral. Young soon became involved in a lawsuit over his right to mine and process Boghead. His leases claimed to work only coal (as did his patent). The courts finally ruled that the mineral was close enough to coal to allow him to proceed. Without this decision Young's patents and coal leases would have been practically worthless, and his future developments could not have proceeded.

The material retorted by Young in the early years would yield 120 to 130 gallons of oil per ton and produced large quantities of gas. This mineral was limited and emphasis was soon shifted to the bituminous Scottish shales, which produced around thirty-five gallons per ton. The Scottish shale industry was to continue production for the next hundred years and is one of the most sited successful oil shale operations of the free world.

Whether the Scottish developments influenced events in the U.S. may be questioned. However, the period from 1840 to 1860 saw a large number of immigrants to the U.S. from the British Isles. Undoubtedly the success of James Young and the Scottish shale industry came with them. Prior even to Young (1838) the French had had a shale oil industry. It is even possible that knowledge of oil shale came to us in a 1694 English patent, which reads in part "...after much paines and expenses, I hath certainly found out a way to extract and make great quantities of pitch, tarr, and oyle out of a kind of stone of which there is sufficient plenty within our Dominious of England and Wales."

In any case the U.S. did develop a thriving coal oil and shale oil industry in the U.S. along the Ohio River Valley sometime prior to 1860. This is an area of the country which has readily accessible oil shales and coals, and was a logical area for oil development to begin. There are no written details concerning the oil shale industry in this part of the country, but is estimated that probably one-hundred retorts were in operation making both coal oil and shale oil. One can only speculate as to the design and capacity of these units, but it is doubtful that each produced but a few barrels of oil per day. They were most likely batch type indirect heated retorts of stone construction. Probably similar to the iron blast furnaces of the period, constructed and still standing as historical monuments in Kentucky. The source of fuel for heat could have been either wood or coal, as both are prevalent in the area. The early Scottish retorts were batch indirect coal heated vessels, so one could speculate these were similar. However, they did exist and were

successful in producing shale oil from the same black Devonian/Mississippian oil shales in which we are again interested.

As most everyone is aware it was in 1859 that Colonel Edwin Laurentine Drake brought in the world's first artesian oil well near Titusville, Pennsylvania, and caused the birth of the modern petroleum industry. It was in the late 1850's that a group of Connecticut investors hired the 40 year old retired railroad conductor Drake to investigate properties leased by the Pennsylvania Rock Oil Company. Drake had literally no qualifications for the job other than he possessed a pass which allowed him to ride free on eastern railroads. In the winter of 1857 Drake journeyed to Titusville, Pennsylvania, and returned to his benefactors with such a glowing report of the oil prospects of the property he surveyed that he was immediately made general agent and chairman of the newly formed Seneca Oil Company (successor to the Pennsylvania Rock Oil Company). His salary was set at $1,000 per year with an expense account to match. Even then oil men knew how to live.

Drake returned to Titusville in the spring of 1858 and immediately began to have trouble, as he couldn't find labor to dig for oil. When he did find them he nearly drowned the crew because of an underground spring encountered in the pit they were digging. In desperation he finally decided to bore a hole similar to what was being done by salt well drillers in Pennsylvania, West Virginia, Kentucky and Tennessee. After obtaining the services of a skilled driller, "Uncle Billie" Smith, drilling began in June of 1859. But progress was slow and plagued with problems. On August 27, the drill slipped into a crevice and stuck at 69½ ft. The tools were finally withdrawn and left idle for Sunday. That afternoon Smith peered into the well to see a dark green liquid frothing and bubbling near the top. He recognized this as petroleum as it had been a nuisance in previous brine wells he had drilled. Smith bailed a few gallons and mounted his mule and rode off to Titusville to show all that Drake's folly was a dream come true. Drake had brought in a new era by combining the ancient art of brine drilling with the critical demand for oil at just the right time in our history.

It is interesting to speculate how Drake's venture would have succeeded in today's climate. First of all OSHA wouldn't have allowed him to even start; secondly the EPA would have stopped him because of potential hydrocarbon emissions, and third he probably would have spent the next 120 years just filling a multitude of permit applications. But Drake did succeed. In 1859 only 2,000 barrels of oil were produced, by 1860 it was 500,000 as others entered into this new industry. Just ten years from Drake's discovery the U.S. was producing nearly four million barrels of oil per year.

The exploration and production of crude wasn't the only industry to prosper. 1860 saw John Rockerfeller enter the oil refining business. By 1863 the first oil tanker (Ramsey) was moving crude oil. 1865 saw the first rail tank car and pipeline for oil. In 1869, only ten years after the first drilled well, the U.S. was shipping oil to the rest of the world on the Belgian tanker, Charles. To say the oil industry boomed is to put it mildly. In 1859 oil was selling for about $20 per barrel, by 1862, its price had fallen to 10 cents as oil wells sprang-up everywhere and supply far exceeded demand.

It's not surprising that our fledgling shale oil industry did not survive the onslaught of competition. It is far simpler to poke a hole in the ground and watch petroleum pour forth than to mine hard rock, transport it, retort it, collect the product, and dispose of spent material. With the over-supply of petroleum and the drastic drop in oil price there was just no feasible way to compete. The U.S. had again approached oil production in the same manner it did in sperm and whale oil gathering. The pressure created by this new industry was felt world wide. Even the prosperous Scottish shale oil industry started to flounder, because of U.S. oil imports. However, through some very innovative process changes, like burning spent shale for process heat, and through substantial government support, it was able to survive until discovery of oil in the North Sea put it, too, to rest in 1964.

Shale Oil - 1920 to 1940

The coal oil and shale oil industry in the United States was to lay dead and buried for more than fifty years. At the end of World War I there was a revival, though by this time the West had been settled and the vast Eocene age deposits of Green River oil shale in Colorado, Utah and Wyoming had been discovered. The U.S. Government recognized our vulnerability in time of war and how important oil was to our national defense, so they became heavily involved in energy planning. A federal program was implemented to develop other domestic oil resources under the direction of the Department of the Interior. The responsibility for carrying out this program was given to the U.S. Geological Survey and the U.S. Bureau of Mines. The prime directive of these agencies was to develop mineral resources on Federal Lands and the Western shales fit well within this charter.

This was also a time in our history when, if a gas well was discovered, it was considered a dry hole unless a market was very close by. The U.S. was in need of easily transported liquid oil, not natural gas which had no distribution system. The Eastern oil shales were not Federally held and were known to give low oil and high gas yields on retorting, so they were not considered in our national energy plan of the time.

Then as now, Government interest produces private interest, and developments were carried on privately in both the East and the West. Of note were those eastern efforts by the Devon Oil Company in Kentucky and on the Humphrey farm in Ohio to set up commercial oil shale processes. The research community also perks up to national programs, even though grant monies weren't available then. The Kentucky Geologic Survey became deeply involved in research and promotion of their shale resources. C.S. Crouse of the survey wrote extensively of the black shales of Kentucky and of their valuable products and by-products. However, these efforts were really minimal in comparison to the promotion given Western oil shale.

What effort that was expended on oil shale made little difference East or West because it was in the 1920's that the vast crude fields of Texas and Oklahoma were discovered and the U.S. proceeded on a new and even more feverish industrial expansion based upon petroleum. Domestic markets grew with the expansion of the automobile industry and petroleum export markets grew right with it. The U.S. was again the dominant world oil user and supplier. Oil shale lost out again to cheap abundant petroleum.

Shale Oil - 1940 to Date

During World War II the U.S. Government again realized how essential petroleum was to our national defense. The large Texas and Oklahoma fields were nearly twenty years old and were being rapidly depleted. In 1944 the Congress passed Public Law 290 known as the Synthetic Liquid Fuels Act. The Act and extensions authorized the construction and operation of demonstration plants to produce liquid fuels from coal, oil shale and other materials and a total of $87 million was appropriated. As before the prime responsibility was given to the U.S. Bureau of Mines.

Since the directive was for the production of liquid fuel and was to be carried out by a government agency dedicated to the development of minerals on public lands, all indicators pointed toward Western shale. As already stated Eastern shale gives relatively low oil and high gas yields. The Act specifically required production of liquid fuel. The nation still did not have an adequate gas distribution system, and would not have until the late fifties and early sixties. There just was no market for gas. Again Eastern oil shale lost out in national energy planning and little if any research was carried out on it. However, a tremendous amount of work was carried out on Western shales. Programs were established to develop both mining and retorting techniques on a fairly significant scale. Over-all about $18 million dollars was spent on the Anvil Points shale project near Rifle, Colorado, where most of the oil shale activity was centered.

As with earlier programs, government interest generates private interest and several companies carried on programs on their own. Some of these were carried out at a fairly significant scale. Union Oil in one demonstration run operated their unique retort-A at 1200 tons per day on Western shale. There were no significant development efforts carried out on Eastern oil shale. The only shale to have supported commercial production in the mid-1800's was forgotten.

Funding for the Synthetic Fuel Act was finally halted by Congress in about 1956 and interest in all shale oil gradually dwindled. The mammoth oil fields in the Middle East were discovered and the world was faced again with a glut of oil. Much of the oil was under U.S. control, as it was U.S. capital that paid for exploration and production development. We were again safe and secure.

From the late fifties through the sixties there were no massive shale programs. Government retrenched into Laramie, Wyoming, to carry-on small scale laboratory, pilot plant and field projects on Western shale. Several firms worked on proprietary efforts and continued process development and engineering evaluations. In the fifties Eastern shale did get a brief look. The Atomic Energy Commission, through the U.S.G.S., started a sampling program because of Uranium content. The Devonian shales though are, for the present, too poor to be considered as Uranium resources. The U.S.G.S. continued evaluating shale reserves around the world and in 1966 published one of the most over quoted papers in shale history, i.e., "Organic-Rich Shale of the United States and the World Land Areas", Geological Survey Circular 523. In this document they pointed out that shales of less than twenty-five gallons per ton were not economic. This was done without regard to geographic location, mining conditions, political climate, or recovery of by-products. This has been a most difficult stigma for Eastern shale to overcome. Few of these shales in commercial quantities will assay more than fifteen gallons of liquid, but if gases are included, on an oil equivalent basis, will frequently exceed twenty gallons per ton. Eastern shale again was excluded from national energy resources.

The early seventies saw the formation of the Energy Research and Development Administration formed to foster novel energy technologies and solve our new national energy dilemma. The U.S. was now faced with declining petroleum reserves and increasing oil imports. Natural gas supplies were falling also with increasing demand. Most Middle-East oil had been nationalized and the Organization of Petroleum Exporting Countries (OPEC) had been formed to control major world supplies and prices. OPEC was rapidly taking over the role in world oil markets, that the U.S. had played since 1776. ERDA was the Government's super agency formed from parts of Government agencies still involved in energy research (USBM, EPA, AEC, OCR, etc.). ERDA was to solve all problems. Oil shale activities again picked-up tempo. But according to ERDA (USBM-Oil Shale) everything that needed doing in above ground shale retorting had been done. Only in-situ work needed funding under their programs. The only Eastern shale work funded by ERDA was that proposed by Dow Chemical Company in 1973 for testing in-situ techniques in the Antrim shale of Michigan. Dow had had an extensive research program in the mid-fifties and late sixties and had re-opened research efforts in 1970 after realizing the nation was in for hard times, because of energy and hydrocarbon supplies.

Also under ERDA the Devonian shales gas program was initiated. The black shales of the East are known to contain naturally occurring gas. Several fields were in operation and this was a means to expand efforts in Devonian shale for gas production. This program also encompassed an extensive Devonian shale resource evaluation program (as did Dow's project for Michigan). This program is still going on and is generating a wealth of basic information.

The late seventies saw government expand on energy issues. Several regulatory bodies were combined with ERDA to form DOE. A truly super agency. Oil shale efforts moved forward, but as

always with Government very slowly. In 1979 we finally got a national energy plan from Congress. Funding for energy development was greatly expanded. Funds were provided for feasibility studies and for beginning full scale development directed toward real production. Oil shale was to share in these funds.

The Institute of Gas Technology was funded to carry on their basic research work and resource evaluation; efforts that they had themselves funded since early sixties. Several grants were made for shale feasibility studies. One small one was made to the Buffalo Trace Area Development District (BTADD) to access the possibility of shale-oil production in their area of Kentucky. A second round of grand awards was started in mid-1980 and many were announced.

In November, 1980, the Nation elected to change administrations. With the new President's desire to reduce spending, many of the synfuel projects just being started were cut. This is a short-sighted Government policy. It is not understandable how we can talk of national security without a strong energy policy which includes synfuel development. Just one more example of confused Government thinking.

Shale Oil - 1980 to ??????

There is no question that the Federal Government's spending of enormous amounts of money on shale development would probably have had an accelerating effect. Loss of Federal monies only means it will take private industry a little longer to raise the necessary capital through other sources, and the move to commercialization will be stretched out, both in the East and West. Almost all the experts in synfuel development are in full agreement that oil shale is our only reasonable near term option which can make any significant impact on future oil imports.

The process to extract oil from shale is very simple (mine it, crush it, retort it, dispose of the residue, and market the products). No complex machinery is required and we technically understand all the steps. The only trick is to do it in a thermally and economically efficient manner, competitive with imported petroleum. This will require some ingenuity, but it can and will be done. It may be a problem to convince investors that it is accomplishable and profitable. This may be the most difficult task of all because of miserable past oil shale history, and there is presently no commercial operations upon which investors can judge the probability for success or profitability. But like Drake's oil well, when the first oil shale plant comes in, someone will grab a bucket full of oil, mount their mule and ride off to tell everyone the shale folly is a dream come true. First though we have to have an "Uncle Billie" Smith to see the first oil in the pipe, in-other-words we need commercial production.

Over the past sixty years the U.S. and other countries of the world have expended considerable effort developing shale retorting technology. Energy Development Consultants, Inc., (EDC) of Golden, Colorado, estimate there are at least ten processes ready for immediate commercialization. Because of the emphasis on Western shale in the U.S., one might assume that these processes are not ready for Eastern shale. The two shales are vastly different in their oil yields and in their mineral make-up but this should not prevent application of current shale technology in the East.

In fact just the opposite is true. In most cases retorting is far more difficult to carry-out on Eocene shale.

Higher oil yields make tar fogs more difficult to collect, and the spent shale less strong and more unstable. Retorting of Western shale, which is really a marlstone, not a true clay shale as is Devonian, requires very close temperature control otherwise energy wasting decarboxylation reactions occur and result in thermally inefficient operation. Oils from Green River shales are very viscous with pour points above 60°F, while Devonian shale oil will usually have a pour point below zero. This makes Eastern shale oil much easier to handle in collection equipment and downstream processes. Generally speaking Devonian shale oil is lower in nitrogen, which is a problem for later refining. While it will still have to be reduced, it should be somewhat easier, because of lower concentrations.

If one looks rationally at processing Devonian shale, you will find that it really is very simple. This shale is very similar to most of the oil shales commercially processed in other parts of the world. For example, it is very difficult to tell the difference on visual inspection between Brazilian Irati shale and Kentucky Ohio shale. Even chemical analysis shows very close similarity. The shales of Colorado, Wyoming and Utah are probably the strangest in the world, and as a result have required careful process testing to assure retorting can be carried-out.

Still one can argue that the West is far ahead of the East in the scale that processes have been tested. The East however is far ahead of the West in both market development, manufacturing capability, and supporting labor force and infrastructure. BLM has estimated that a 50,000 bbl per day oil shale development will require about 2,000 people, both during construction and operation. If one assumes that each one of these new jobs creates four others in support, this means a work force of about 10,000 people. If each worker represents a family of four this could mean 40,000 people in support of such a facility.

Because of the remoteness of the western operations entire cities must be built to accommodate this influx. Totally Wyoming, Colorado and Utah have less than four million people. Kentucky, Ohio and Indiana, the most likely areas of Eastern development, contain about twenty million people. Therefore it is easier for these Eastern states to find the direct and supporting labor force in the area, and adjust to minor population shifts. If one assumes that $100,000 (probably conservative) must be invested per family for housing and community functions, this would mean a billion dollar national expenditure beyond the cost of the processing plant. A factor that is rarely considered in development of Western shale.

This should be much less in the populated East.

Product markets are also more developed in the East. Kentucky, Ohio and Indiana have a present oil refining capacity of about 1.5 million barrels of oil per day. Colorado, Wyoming and Utah less than one-half a million. The only really conceivable markets for Western shale oil are on the West Coast, which means moving products over the Rocky Mountains, a distance of about 800 miles. Nearly the same distance as the Alaskan pipeline which cost about seven billion dollars. Another factor not accounted for in shale oil development. In the East markets exist rather locally and distribution systems are well developed throughout the Ohio River Valley, in the form of highways, pipelines, railroads and very economical river traffic. All of which will need building in the West.

One of the major issues surrounding shale oil development has been water. Estimates of process water requirements vary widely from about 2,000 to 10,000 acre feet per year for a 50,000 BPCD plant. This does not include demands made outside the system. Water needs for one person in a city may be as high as 250 gallons per day. For a population of 10,000 this may be as high as 10 to 11 thousand acre feet per year in addition to process plant needs. In the arid West this could certainly tax the available water resources. Along the Ohio River Valley, where precipitation can exceed forty inches per year, this presents no problem. People's water needs are rarely factored into oil shale development, but may be the true limiting factor in the West.

Environmental issues are of concern both East and West. There is no question that shale development will have a regional impact wherever it occurs. Anything that man does has some (all the way from cutting firewood to building massive highways across the land). If one approaches the issues rationally with sound judgement, it is evident that all of the operations involved in oil shale processing are manageable and can be carried-on meeting reasonable environmental constraints.

Oil shale mining and spent shale disposal seem to be the issues of greatest concern. It should be remembered that an oil shale operation is more like a rock quarry than a coal strip-mine. Because of the tonnages of rock to be moved, processed and disposed of, the operation must be very localized. Being in a reasonably confined area makes monitoring and control of the mining/disposal site quite simple. Engineering practice is more than adequate to control dust emissions, surface run-off and spent shale dumps. Over-all if surface restoration is properly done the land left after shale processing should be far more valuable than it is today. One of the difficulties presently in the Eastern shale belt is that the steep cliffs and sharp ridges are very unstable. A situation which is very common in shale outcrop areas. One accomplishment of mining would be to stabilize the hazardous situation nature has created. The instability of this area is certainly one reason it has been so sparsely populated and the land not used for industrial, agricultural or residential purposes.

Recent studies have shown that spent shale will support corn and that leaching from the shale should not be a problem. This data is quite preliminary and additional data by both private industry and Government, is being gathered. In the next year sufficient information should be available to make it possible to engineer very adequate mining and disposal sites for Eastern shale. The Irati shales of Brazil are very similar chemically to Devonian. The Brazilians have found that just covering the spent shale with two or three feet of top soil is sufficient to grow trees. They have been testing land restoration and leaching for the last ten years and have found no insurmountable problems. A similar finding will occur in the areas having Devonian shale.

The benefits that shale development would have in the Eastern shale belt are substantial. Already mentioned are the 10,000 new jobs that one 50,000 bbl/day commercial plant would generate. The income base this would create in an area is tremendous. Assuming a family generates about $15,000 annually this would mean $150 million dollar payroll. The land owners will receive probably twenty-cents per ton of shale mined which could generate nearly ten million additional per year in revenues. Plant profits could be as high as $66 million ($40/bbl oil, 10% return on sales). This could mean over two hundred million dollars annually generated, much of which would be spent in the immediate area. The cost estimates for such a large plant are at this time quite variable. However, it is felt it would be in the range of $2 to $2.5 billion. The amount this would create in property taxes is staggering and probably far exceeds any that one industry now generates for State government.

While one 50,000 barrel per day plant represents something less than one percent of our current national oil imports, it is still very significant. For one thing it would begin a development that could again make the U.S. a leader in oil production, a position we held from 1776 to about 1970. For another just one plant would improve our balance of payments by nearly three quarters of a billion dollars. Oil imports are wrecking our trade balance and shale oil would start to stabilize it.

Shale oil development in the East would regionally have the most beneficial effect. This is our industrial heartland. The short fall of natural gas in this area in the winter of 1978 saw over two million people out of work, and eight states apply for disaster relief, showing how sensitive this area is to fuel supplies. The Arab oil embargo of 1973 and oil crisis of 1979 saw long gasoline lines almost disabling our transportation network. There are currently several major companies now showing an interest in Eastern shale development. They are finally recognizing there are factors other than oil yield to shale oil production. Over-all the future looks bright. The one item missing so far is a commercial operation. The technology is in place, only innovative financing is now needed.

Oil Shale Utilization at Morgantown

by

A.A. Pitrolo **J.E. Notestein**
J.S. Mei **J.Y. Shang**
L.W. Zeng
Morgantown Energy Technology Center
United States Department of Energy
Morgantown, West Virginia 26505

Introduction

The Morgantown Energy Technology Center (METC), United States Department of Energy (U.S. DOE), is the designated lead technology center for the areas of fluidized-bed combustion, coal gasification, gas cleanup, solids handling, and computer modeling. In pursuing the designated responsibility in fluidized-bed combustion, METC embarked on a comprehensive program of widening the fuel-supply base. Feasibility studies were conducted for various low-grade fuels and oil shales were among the fuels of interest to METC.

As the world energy supply initiated an economic strain in the petroleum-importing countries, means of recovering hydrocarbon fuels from oil shales gained increasing attention from the oil-shale-producing states. In response to requests from DOE Headquarters, METC has also conducted numerous feasibility studies in oil-shale utilization, combustion, and retorting for foreign countries. Oil shales from Israel and Morocco were test burned and retorted. As a result of METC's efforts, innovative designs for oil-shale combustion and retorting were developed. Some oil shales have a high limestone (calcium-carbonate) content and indiscriminate application of heat will result in calcining the limestone and consumption of a considerable amount of heat within the process without the benefit of high heat recovery. A pseudo two-staged fluidized-bed combustion design was proposed as an approach to mitigate this effect. The feasibility of burning the oil-shale volatiles without producing excessive calcination of the limestone was demonstrated in METC's FBC units.

One of the major criteria for achieving high-energy conversion efficiency in coal gasification as well as oil-shale retorting is the proximity of the heat-generating reaction, combustion, and heat-consuming reaction—gasification or retorting. In fact, this is why the moving-bed, counter-current gasifier or oil-shale retort has a slightly higher conversion efficiency than that of the conventional fluidized-bed reactors. However, owing to the vigorous inter-particle motion inside a fluidized bed, a high heat-transfer rate can be used to achieve good heat recovery between the hot spent shale and the cold fresh shale. A twin-bed fluidized-bed oil-shale retort/combustor was conceived and developed at METC, with a special feature of separating the products of retorting and/or gasification from the products of combustion.

Fully aware of the nation's need to develop high-risk and long-term research in eastern oil-shale and low-grade oil-shale utilization in general, the U.S. DOE/METC

[1]Deputy Division Director, Technology Development and Engineering Division (TDE), Morgantown Energy Technology Center (METC).

[2]Division Director, Technology Development and Engineering Division (TDE), Morgantown Energy Technology Center (METC).

[3]Mechanical Engineer.

[4]Research Chemist

[5]Research Chemist.

[6]Visiting Scholar, West Virginia University.

initiated an eastern oil-shale characterization program. In less than 3 months, METC produced shale oil from a selected eastern-U.S. oil shale with a Fischer assay of 8.0 gallons/ton. In view of the relatively low oil yield from this particular oil shale, efforts were directed to determine the process conditions which give the highest oil yield. A 2-inch-diameter electrically heated fluidized-bed retort was constructed, and "Celina" oil shale from Tennessee was selected to be used as a representative eastern oil shale. After more than 50 runs, the retorting data were analyzed and reviewed and the best oil-yield operating condition was determined. In addition, while conducting the oil-shale retorting experiments, a number of technical problems were identified, addressed, and overcome.

The oil-shale retorting study was supported by a competent and well-equipped technical staff that is capable of conducting conventional solid-fuel analyses, size distribution, surface-area measurement, electron microscopic analysis, low- and high-temperature ash analyses, differential thermal and thermogravimetrical analyses, etc.

The retorting process conditions, temperature, residence time, and rate of heating (size distribution) do affect the yield and composition of the shale oil retorted. Shale oil is produced from the thermal decomposition of oil-shale organics. Under the thermal-decomposition conditions, the organics in the oil-shale matrix are converted into char, gases, and liquid hydrocarbons. The manner under which the oil shale was retorted contributes to both the amount and composition of the shale oil produced.

Two-Inch-Diameter, Electrically Heated, Fluidized-Bed, Oil-Shale Retort

METC has designed and constructed a 2-inch-diameter electrically heated fluidized-bed retort (EHFBR) for use in this retorting study. This reactor allows accurate study of the effects of various precisely controlled, process/thermal conditions on shale oil yield and characteristics, recognizing that combustion effects will be evaluated later. The EHFBR is made of a 2-inch-diameter, 21-inch-long schule 160, 316 stainless-steel tube. The exterior of the EHFBR is wrapped with an electrical heating element which is capable of heating the EHFBR to 1200°F. Hot nitrogen, with a controlled temperature in the range of 700 to 1000°F, is fed into the bottom of the EHFBR below the distributor. The distributor is made of a perforated plate with an open area of 1.8 percent. The 37 .03-inch-diameter perforations are arranged in a triangular pitch of .26 inch and counter-sunk to control the plugging and weeping. The distributor pressure drop is maintained at 4 to 5 inches of water to assure flow stability and to prevent maldistribution. The expanded bed height is controlled to be 5 inches by the provision of an over-flow drain of 3/4-inch-diameter tube. This drain tube is branched downward to form an angle of 26 degrees with the major vertical axis of the EHFBR. The in-bed residence time is controlled by internal baffles which form a triangular truss with a main function of controlling bubble growth. Solids are delivered to the retort by a 1/4-inch-diameter screw feeder which receives crushed oil shale from a hopper and enters the EHFBR bed region at a pressure balance point (the pressure balance point is the point where the local pressure is equal to atmospheric pressure). The screw solid feeder has a feeding capacity of up to 250 gm/hour and the rate of feed is controlled by a variable-speed motor. The size of crushed oil shale utilized in the tests was 30 x 45 mesh. The cold minimum fluidization velocity was determined to be 0.3 ft/sec at room temperature. The operating fluidization velocity was in the range of 0.9 to 1.0 ft/sec.

The experimental configuration using this retort is shown in Figure 1. The gaseous products of retorting were passed through a glass-wool filter (GWF) which removed accompanying dust particles. An air-cooled condenser was used which collected about 20 percent of the heavy oil, and a subsequent water-cooled condenser collected about 30 percent of the light oil. A membrane "filtration" technique was then utilized to collect the remaining 50 percent of oil which was in the form of an oil "fog." The fog, or aerosol, was passed through a membrane filter with a pore size of 5 microns. The small pores force the aerosol droplets to coalesce into larger liquid drops which are then trapped and recovered after the membrane. The uncondensable gases are then passed through an activated carbon-packed bed, a glass-wool filter, and a vacuum-pump gas meter before being vented into an exhaust hood. The oils collected were weighed and an overall material balance was computed. Most of the material balances were accurate to within 95

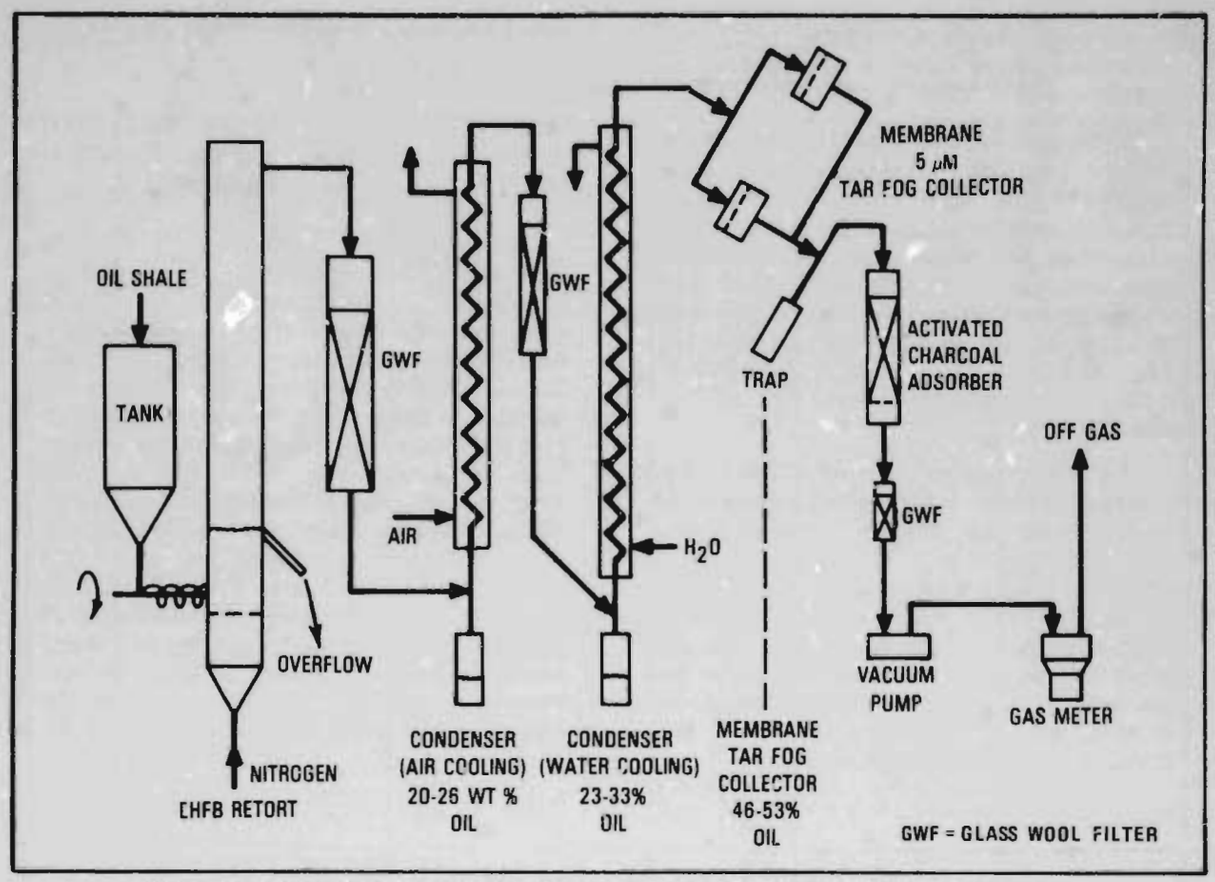

Figure 1. Two-Inch-Diameter, Electrically Heated, Fluidized-Bed Retorting System, Experimental Configuration

percent, which is quite good for a lab-scale unit.

Retorting Test Activities

METC designed a series of experiments with the intention of determining controllable process variables which yield more oil and one with characteristics more compatible with conventional refineries. At present, the controllable process variables are the oil-shale feeding rate, the retorting temperature, and the oil-shale particle-size distribution. Determination of the product oil's compositions in terms of the fractions represented by saturated (paraffinics and naphthenic), unsaturated (olefinic), and aromatic hydrocarbons as well as a host of other pertinent oil feedstock properties is currently in progress. Reportedly, low retorting temperature favors the formation of paraffinic hydrocarbons, intermediate temperature favors olefinics, and high temperature favors aromatics. The rate of heating also affects the hydrocarbon composition. At a heating rate below 1°C/min, the retorting product is mostly paraffinic; at a rate between 1 and 100°C/min, the retorting products are mostly olefinic; if the heating rate is faster than 100°C/min, the retorting products are mostly aromatic. Of the three types of candidate oil-shale retorting processes (packed-bed, fluidized-bed, and entrained-bed), the fluidized-bed retorting process can easily achieve the heating rate of 100°C/min with a wide feedstock size distribution to achieve a desirably high aromatic hydrocarbon yield.

In view of the low hydrogen content of the eastern oil shale and the low hydrogen-to-carbon ratio in the aromatic hydrocarbons, fluidized-bed retorting appears to be the logical means of eastern oil-shale retorting. To date, METC has conducted 60 retorting runs using the electrically heated fluidized-bed retort for a wide variety of oil shales. The ultimate and elemental analyses of these oil shales (Celina, Tennessee; Sunbury, Kentucky; Colorado; Morocco; and Israel) and

Fischer assays are shown in Table 1 and their respective material balances for the retorting tests are shown in Table 2.

As mentioned above, METC selected the oil shale from Celina, Tennessee, as the basis for this study. Two controlling variables (retorting temperature and oil-shale feeding rate) were also adopted as the two main controlling, or independent, variables. The results of the variable study are summarized in Table 2. The temperature of retorting was varied from 700 to 1000°F; the oil-shale feeding rate was varied from 115 to 206 grams/hour.

The retorted-shale oil yield was plotted as a function of the retorting temperature and oil-shale feed rate. This is shown in Figure 2. In the contour plot, the data are divided into three groups with oil-yield ranges of 0.96 to 1.21, 1.73 to 2.00, and 2.51 to 2.77 weight-percent. A regression analysis was applied to correlate the shale oil yield as the function of retorting temperature and oil-shale feed rate. The regression analysis produced the following relationship:

$$Y = -24.813 + 0.0536T - 2.703 \times 10^{-5}\,T^2 + 0.0381\,F - 8.96 \times 10^{-5}\,F^2 - 1.799 \times 10^{-5}\,T \cdot F$$

where: Y is the shale yield in weight-percent; T is the retorting temperature in °F; and F is the oil-shale feed rate in grams/hour.

Based on the consideration of high throughput and maximum oil yield for reduced retort investment requirements, a retorting temperature of 950°F and a feeding rate of 180 grams/hour appear to be the logical retorting condition. Current efforts are directed at determining the effect of oil-shale size distribution on the oil yield and composition. We expected to receive the shale oil analyses including API gravity, ASTM distillation, paraffinic, olefinic, naphthenic, aromatic-hydrocarbon contents, and sulfur and nitrogen contents in time for this printing; however, they are not yet complete. A process parameter study will be conducted using the analytical results to determine the controlling variables and magnitude of the effect on the yield and composition of the shale oil.

Table 1. Properties of the Oil Shales

Type of Oil Shale/ Analysis Items	U.S. Oil Shale						Moroccan Oil Shale		Israeli Oil Shale	
	U.S. Oil Shale Celina, TN		Sunbury Oil Shale, KY		Colorado Oil Shale					
	Fresh	Spent	Fresh	Spent	Fresh	Spent	Fresh	Spent	Fresh	Spent
Gallon/Ton Oil	8.0		16.4		23.0		17.7		13.6	
Gallon/Ton Water	2.4		6.5		3.4		10.2		10.1	
Wt % Oil	3.1		6.5		8.7		7.1		5.4	
Wt % Water	1.0		2.7		1.4		4.2		4.2	
Wt % Spent Shale	93.1		88.1		87.5		85.0		86.8	
Wt % Gas + Loss	2.8		2.8		2.3		3.6		3.5	
Specific Gravity 60°/60°F	0.925		0.945		0.911		0.970		0.963	
Tend to Coke	None		None		Slight		None		None	
Moisture	0.45	0.25	0.93	0.48	0.21	0.14	4.34	0.32	4.14	0.56
Ash	79.37	85.68	75.45	86.79	67.77	79.04	62.77	75.56	64.24	70.92
Sulfur	6.98	6.38	1.98	1.81	0.45	0.53	1.83	1.18	3.07	1.97
Hydrogen	1.31	0.49	1.73	0.68	1.74	0.36	1.76	1.27	1.53	0.68
Total Carbon	11.49	7.73	15.86	8.39	16.53	7.82	18.34	7.52	15.22	6.71
Nitrogen	0.36	0.29	0.53		0.36	0.15	0.51	0.35	0.35	0.23
Oxygen	0.04		3.52	1.85	12.94	11.96	10.45	13.8	11.45	18.93
Silicon, SiO_2	60.74	61.04	67.34	66.29	47.58	47.02	40.62	40.64	23.49	24.33
Aluminum, Al_2O_3	13.76	13.76	15.99	15.59	10.07	9.83	11.28	11.29	9.67	9.69
Iron, Fe_2O_3	15.30	15.29	7.22	7.20	4.79	4.56	5.76	5.61	4.24	4.16
Calcium, CaO	0.83	0.89	0.57	0.55	20.87	19.70	27.08	27.04	51.92	51.55
Magnesium, MgO	1.52	1.55	1.68	1.36	8.39	7.99	6.43	6.07	0.75	1.31
Sodium, Na_2O	0.67	1.09	1.14	1.53	1.18	3.07	0.50	1.01	0.66	1.08
Potassium, K_2O	4.91	4.88	4.60	4.65	3.05	2.93	1.61	1.62	0.75	0.76
Phosphorus, P_2S_5	0.17	0.18	0.28	0.24	0.36	0.38	1.84	1.81	2.31	2.29
Titanium, TiO_2	0.88	0.86	0.92	0.91	0.44	0.45	0.68	0.69	0.42	0.46
Sulfur, SO_3	1.01	0.76	0.52	0.43	2.89	2.36	4.88	4.10	6.92	4.46
Heating Value, Btu/lb	2,617	1,699	3,120	1,558	2,296	310	2,543	1,010	1,669	486
Ash Fusion, °F	2,133 2,205 2,245						2,135 2,160 2,200		2,665 2,680 2,695	

Table 2. Oil-Yield Data Obtained in the 2-Inch-Diameter Fluidized-Bed Retort

Run No.	Type of Tested Oil Shale	Retorting Temperature °F	Feed Rate g/hr	Oil Yield From Tests		Fischer Assay Oil Yield		Water + Gas + Loss	Mass Balance out/in %	Oil Yield of Fischer Assay wt %	Experimental Errors %
				wt %	gal/ton	wt %	gal/ton				
032	U.S. Oil Shale Celina, TN	700	115.7	1.16	3.02	3.1	8.0	3.8	93.4	37.4	- 2.8
025	U.S. Oil Shale Celina, TN	800	131.8	2.45	6.38	3.1	8.0	3.8	94.3	79.0	- 1.9
045	U.S. Oil Shale Celina, TN	900	130.6	2.77	7.22	3.1	8.0	3.8	99.3	89.4	+ 3.1
046	U.S. Oil Shale Celina, TN	1000	132.6	2.74	7.14	3.1	8.0	3.8	95.9	88.4	- 0.3
041	U.S. Oil Shale Celina, TN	700	167.2	1.07	2.79	3.1	8.0	3.8	94.0	34.5	- 2.2
033	U.S. Oil Shale Celina, TN	800	153.2	2.29	5.97	3.1	8.0	3.8	99.3	73.9	+ 3.1
039	U.S. Oil Shale Celina, TN	900	165.8	2.61	6.80	3.1	8.0	3.8	96.5	84.2	+ 0.3
040	U.S. Oil Shale Celina, TN	1000	162.5	2.71	7.06	3.1	8.0	3.8	97.3	87.2	+ 1.1
044	U.S. Oil Shale Celina, TN	700	199.0	1.05	2.74	3.1	8.0	3.8	94.8	33.9	- 1.4
043	U.S. Oil Shale Celina, TN	800	179.0	2.09	5.45	3.1	8.0	3.8	97.7	67.4	+ 1.5
042	U.S. Oil Shale Celina, TN	900	206.4	2.14	5.58	3.1	8.0	3.8	94.7	69.0	- 1.5
036	U.S. Oil Shale Celina, TN	1000	190.5	2.31	6.02	3.1	8.0	3.8	93.0	74.5	- 3.2
053	Sunbury Oil Shale, KY	900	182.6	6.14	16.00	6.5	16.4	5.5	93.5	94.5	- 1.0
052	Colorado Oil Shale	900	120.6	7.34	19.12	8.7	23.0	3.7	96.5	84.4	+ 0.2
057	Moroccan Oil Shale	900	153.2	6.63	17.27	7.1	17.7	7.8	86.9	93.4	- 5.3
058	Israeli Oil Shale	900	162.7	4.15	10.81	5.4	13.6	7.7	87.7	76.9	- 4.6

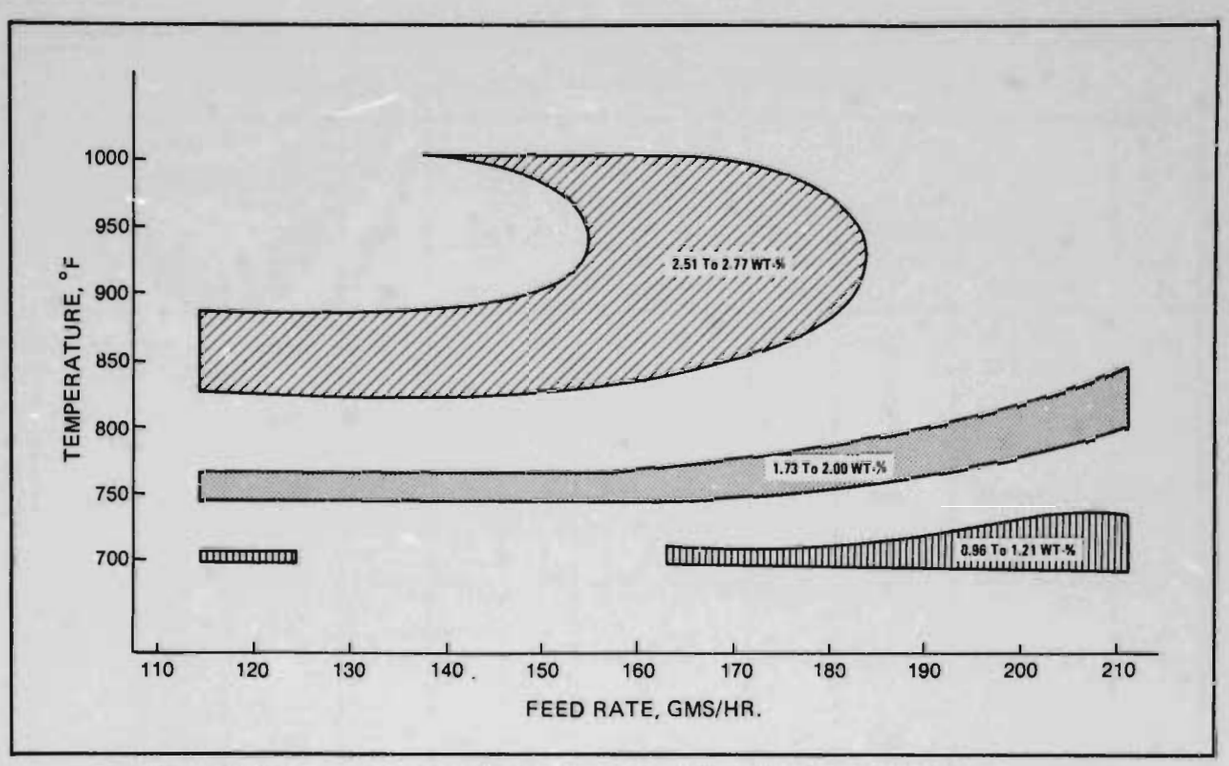

Figure 2. Contour Plot of Oil Yield as a Function of Feed Rate and Retorting Temperature

Israeli oil shale was available and selected to study the effect of oil-shale size distribution on retorted-shale oil yield. In addition, Israeli oil shale has a very small average pore size with an approximate pore population of 10^8 pores per square centimeter, which is about one order of magnitude less than that of the Colorado oil shale. Four batches of the Israeli oil shales of size distribution 60 x 80, 30 x 45, 20 x 30, and 14 x 20 mesh with a respective average size of 0.21, 0.50, 0.72, and 1.13 millimeters were subjected to the retorting study in the 2-inch-diameter electrically heated fluidized-bed retort. The bed temperatures were 900°F. The fluidization velocity utilized was three times minimum fluidization velocity for each size, and the resulting average residence times were in the range of 42-47 minutes. It was found that oil yields were virtually all identical with a value of 75 percent of the Fischer assay. We therefore concluded that the shale oil yield is not a function of oil-shale particle distribution within the 0.21- to 1.13-mm range. Other oil shales from Sunbury, Kentucky; Piceance, Colorado; Morocco; and Israel were also test retorted at 900°F using varied feeding rates. Respective oil yields of 94.5 percent, 84.4 percent, 93.4 percent, and 76.9 percent of Fischer assay were obtained. No effort was made to recover the uncondensables and the accompanying water vapors. The representative oil-yield data are shown in Table 2.

The Fischer assay of fresh shales in terms of gallons per ton, ultimate analysis and heating values of the fresh and spent shales, and elementary analysis of the fresh shales are shown in Table 1. It is interesting to note that about half of the carbon is retained in the spent shale for Celina and Sunbury oil shales which have low calcium-carbonate contents and is reflected in the heating values of the spent shales.

The 6-Inch-Diameter Fluidized-Bed Combustor

The experimental facility and major dimensions of the 6-inch-diameter laboratory-scale fluidized-bed combustor (FBC) are shown schematically in Figure 3. This 6-inch-diameter FBC unit is a refractory-lined cylindrical vessel. The bed region is 16 inches tall. The expanded freeboard section, 8 inches in diameter, is 100 inches in height. The 6-inch FBC unit has a conical air-distributor

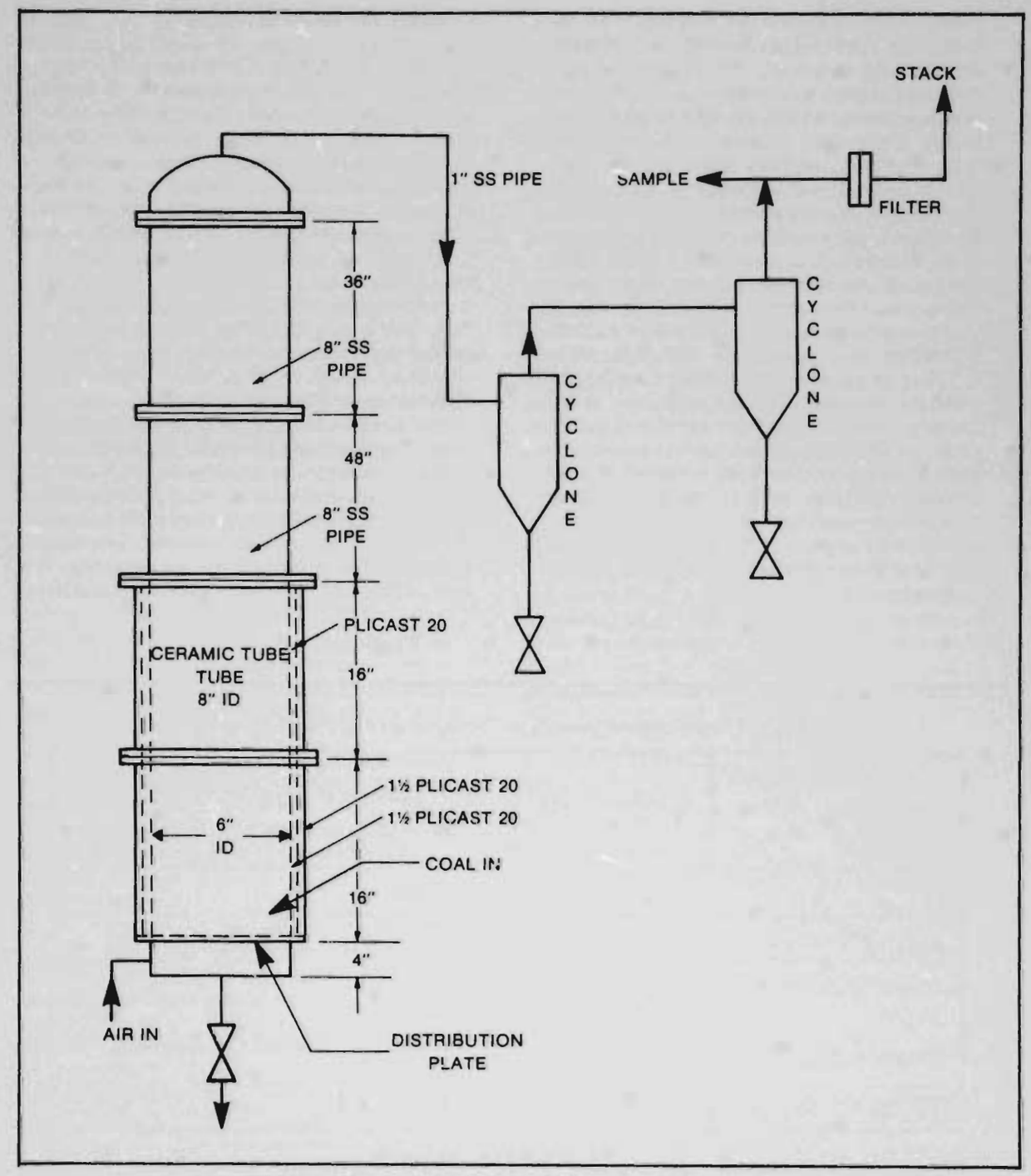

Figure 3. Six-Inch-Diameter Fluidized-Bed Combustor, Schematic Diagram

plate which has an open area of 2.77 percent of the total distributor area. Fluidizing air from the plenum passes through sixty-four 1/8-inch-diameter nozzles arranged in three concentric circles. Solid fuel from the hopper is fed directly into the bed by a 1-inch-diameter, variable-speed metering screw with a water-cooled jacket. Limestone, when needed, is fed directly into the top of the expanded bed through a 3/4-inch screw

feeder. Spent-bed material can be extracted from the combustor through a 3/4-inch-diameter drainpipe at the bottom of the conical distributor or removed through an overflow tube which penetrates the combustor side wall at an angle of 30° with the vertical axis of the combustor. The overflow pipe is typically set such that a bed level of 4-1/2 inches is maintained. The bed solids are discharged into a lockhopper which is periodically emptied. The products of combustion are passed through two cyclones connected in series. The flue gas is filtered through a porous metal filter for ultimate dust removal before its final release to the atmosphere.

Flue gases are continuously sampled for carbon monoxide, carbon dioxide, sulfur dioxide, nitrogen oxides, oxygen, and hydrocarbons. The carbon-monoxide and carbon-dioxide levels are measured by non-dispersed infrared analyzers, sulfur dioxide by flame photometric analyzers, oxides of nitrogen by chemiluminescence analyzers, oxygen by thermomagnetic analyzers, and total hydrocarbon by flame ionization.

Combustion Test Activities

Colorado, Celina (Tennessee), Sunbury (Kentucky), Israeli, and Moroccan oil shales were selected for combustion in the 6-inch-diameter FBC unit. One may notice from Table 3 that oil shales from Colorado, Morocco, and Israel contain sufficient limestone to, at least theoretically, absorb the sulfur dioxide generated from the combustion of their inherent sulfur. METC's experience in the fluidized-bed combustion of these limestone-containing oil shales indicated that, in fact, they can be burned without the addition of limestone or other modifications and meet the existing U.S. environmental regulations. These data are presented in Table 3.

In view of the high limestone content in the oil shales from Colorado, Morocco, and Israel, a concept was developed to isolate the devolatilization of oil shale and the combustion of volatiles by effecting a pseudo two-staged fluidized-bed combustion process. The main theme of this design was to take advantage of the difference between the temperatures

Table 3. Typical Experimental Results of Fluidized-Bed Combustion of Oil Shales

TYPE OF OIL SHALE / PROCESS VARIABLES	COLORADO OIL SHALE	TENNESSEE OIL SHALE	KENTUCKY OIL SHALE	ISRAELI OIL SHALE	MOROCCAN OIL SHALE
OPERATING CONDITIONS					
BED TEMPERATURE (°F)	1550	1530	1600	1300	1450
SUPERFICIAL VELOCITY (ft/sec)	3.68	2.10	2.18	2.68	3.96
STATIC BED DEPTHS (in)	6	6	6	6	4
EXCESS AIR (%)	33.50	53.39	58.76	44.20	40.0
EXPERIMENTAL RESULTS					
COMBUSTION EFFICIENCY (%)	99.54	98.37	99.39	99.86	97.91
SO_2 EMISSION (lb/10^6 Btu)	0.37	24.32	8.80	0.26	0.29
NO_x EMISSION (lb/10^6 Btu)	0.53	1.67	1.20	1.00	1.00

required for devolatilization and calcination in these oil shales to preclude unnecessary energy consumption by the calcination reaction. The fluidized bed at the lower part of the oil-shale burning boiler will have devolatilization as its main function. It is known that the fluidized bed is an excellent solid burner, primarily because the fluidized bed offers vigorous mixing between particles. However, the fluidized bed is a poor gas burner, primarily because of poor mass and heat transfer between the solid and gas phases for any bubbles rising through the bed. As a consequence, a gas bubble may pass through the fluidized bed without completing combustion. It is thus highly desirable to take advantage of the fluidized bed as a devolatilizer or retort and burn the volatiles (gas phase) in the freeboard region. Secondary air will be introduced over bed to burn the volatiles to achieve high combustion efficiency and yet maintain the freeboard temperation within the temperature "window" for pollutant-emission control. For sulfur retention under atmospheric pressure, the optimum temperature is 1550°F. The relaxation and reduction of nitrogen oxides to nitrogen and oxygen occur best in a temperature "window" of 1450 to 1550°F. The burnout of carbon monoxide occurs at a temperature above 1300°F. The key to pollutant-emission control is the maintenance of an adequate freeboard temperature high enough for the completion of sulfur retention, nitrogen-oxide relaxation and reduction, and burnup of combustibles (carbon monoxide and hydrocarbons) but low enough to preclude thermal NO_x formation.

A pseudo two-staged, combustion-concept, feasibility-verification test was conducted at METC to demonstrate the viability of achieving staged combustion in a fluidized-bed combustion unit without incurring excessive calcination However, due to the poor insulation of the freeboard, a stable high freeboard temperature was difficult to maintain. Therefore, relatively high nitrogen-oxide emission levels were observed for high excess air in the fluidized-bed combustion of oil shales. However, this is felt to be an artifact of the test combustion design. Otherwise, the process did function and the concept is felt to be viable.

It is of great interest to point out that for the limestone-containing oil shales (Colorado, Israeli, and Moroccan), the sulfur-dioxide emissions were considerably below the EPA's sulfur-dioxide emission limit of 1.2 lb/million Btu. The inability to maintain favorable conditions for nitrogen-oxide reduction and relaxation, such as the maintenance of freeboard temperature, providing of reductants, etc., resulted in nitrogen-oxide emission levels on the order of 1.0 to 1.2 lb/million Btu. Current efforts at METC are addressing the nitrogen-oxide emissions from fluidized-bed combustion of oil shale. We believe that we have obtained some very encouraging results.

For eastern oil shales with high-sulfur content and low-limestone content, the addition of limestone to insure compliance with EPA's sulfur-dioxide emission standard may be required. Current research at METC is also addressing the sulfur-dioxide emission issue. It is expected that the sulfur-retention mechanics will be no different from the combustion of the high-sulfur bituminous coal. A calcium-to-sulfur molar ratio, Ca/S, of 3 to 4 may be required to lower the sulfur-dioxide emission so as to meet the EPA standard.

However, it should be pointed out that the high Ca/S ratio requirement could be attributed to the short sorbent residence time in the 6-inch-diameter bed. The small bed size requires constant withdrawal of spent-bed material. The high ash content of the eastern oil shale may also accelerate the process of spent-bed material withdrawal. Therefore, it is contemplated that a two-staged FBC may also be desirable as a means to insure complete combustion in the first stage and satisfactory sulfur retention in the second stage.

The combustion efficiencies for all the oil shales were on the order of 98 percent or higher. Only in two cases was the combustion of oil shales below 98 percent. Therefore, it is concluded that fluidized-bed combustion of oil shale is a viable energy-conversion process for oil shale.

Innovative Concepts of Oil-Shale Utilization

The cost of energy calls for efficient utilization of energy. METC has conceived and reduced to practice a number of innovative concepts for the efficient utilization of oil shales. It is indeed our pleasure to share this with the user public.

• ***Pseudo Two-Staged Combustion:*** As mentioned before, the fluidized bed, due to its inability to implement good mass transfer between the gas bubble phase and the surrounding emulsion phase, is a poor gas burner. However, because of the vigorous solid-solid

mixing inside the bed, the fluidized bed is an excellent solid heater and combustor. Therefore, it is proposed that the combustion of oil shale take place in two stages, functionally separating devolatilization and combustion. This pseudo two-staged combustion calls for a fluidized-bed combustor with a high or a diverted freeboard such that the devolatilization in the fluidized bed and combustion in the freeboard can be isolated to avoid the excessive heat-consuming limestone-calcination reaction. A conceptual design of an FBC system for high-calcium carbonate-bearing oil shale is shown in Figure 4. The retorting process is consummated in the fluidized bed at the left. The retorting temperature is maintained by the heat released in the freeboard from the combustion of volatiles. Generally, the retorting process should be maintained sufficiently below the limestone calcination temperature. METC's in-house study has found that less than 50 percent calcination of Israeli oil-shale limestone could be maintained when the fluidized-bed temperature was maintained below 1300°F. This is depicted in Figure 5 which provides test data on carbonate decomposition as a function of bed temperature. A differential

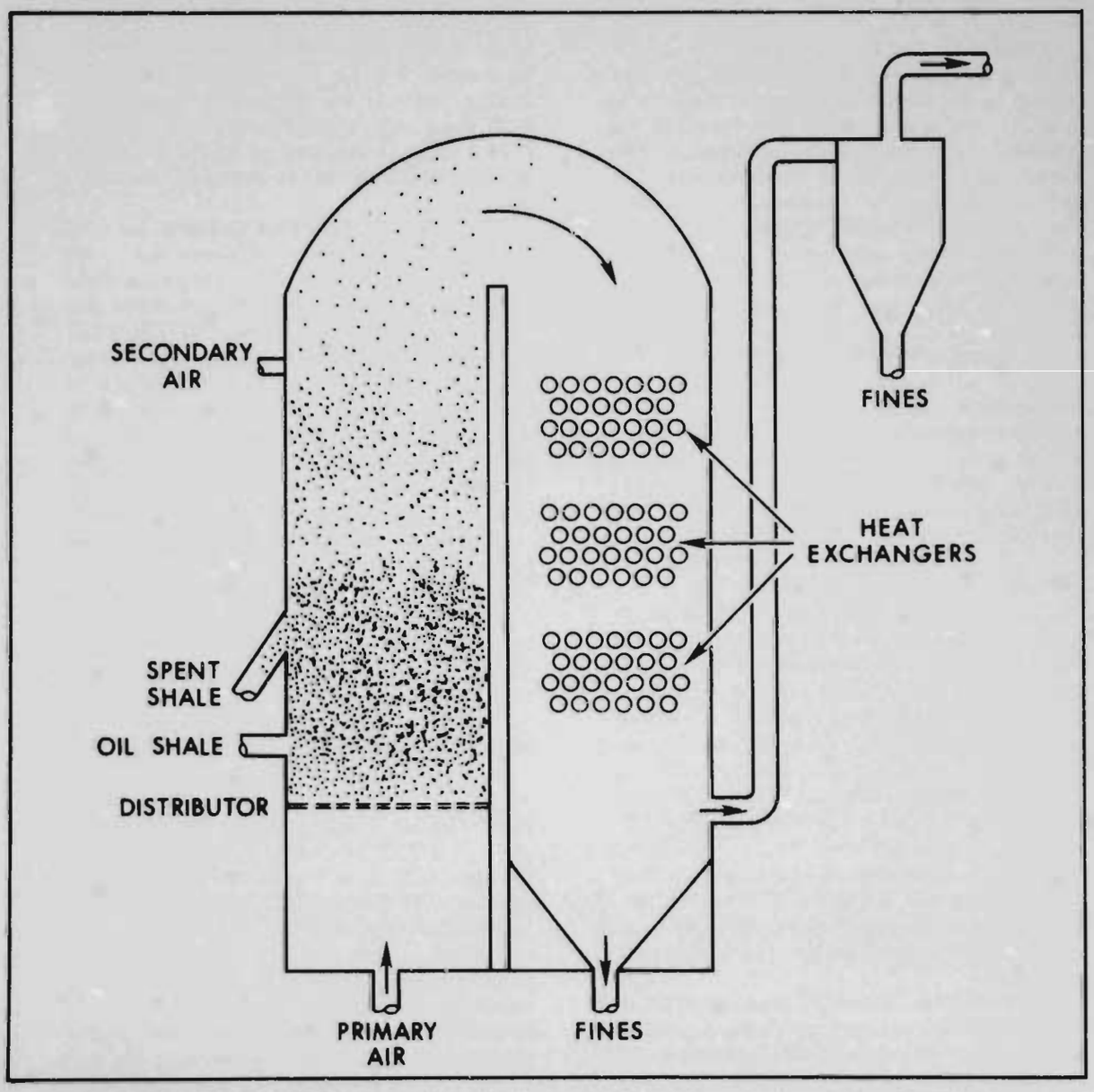

Figure 4. Conceptual Design of an FBC System for High-Calcium Carbonate-Bearing Oil Shale

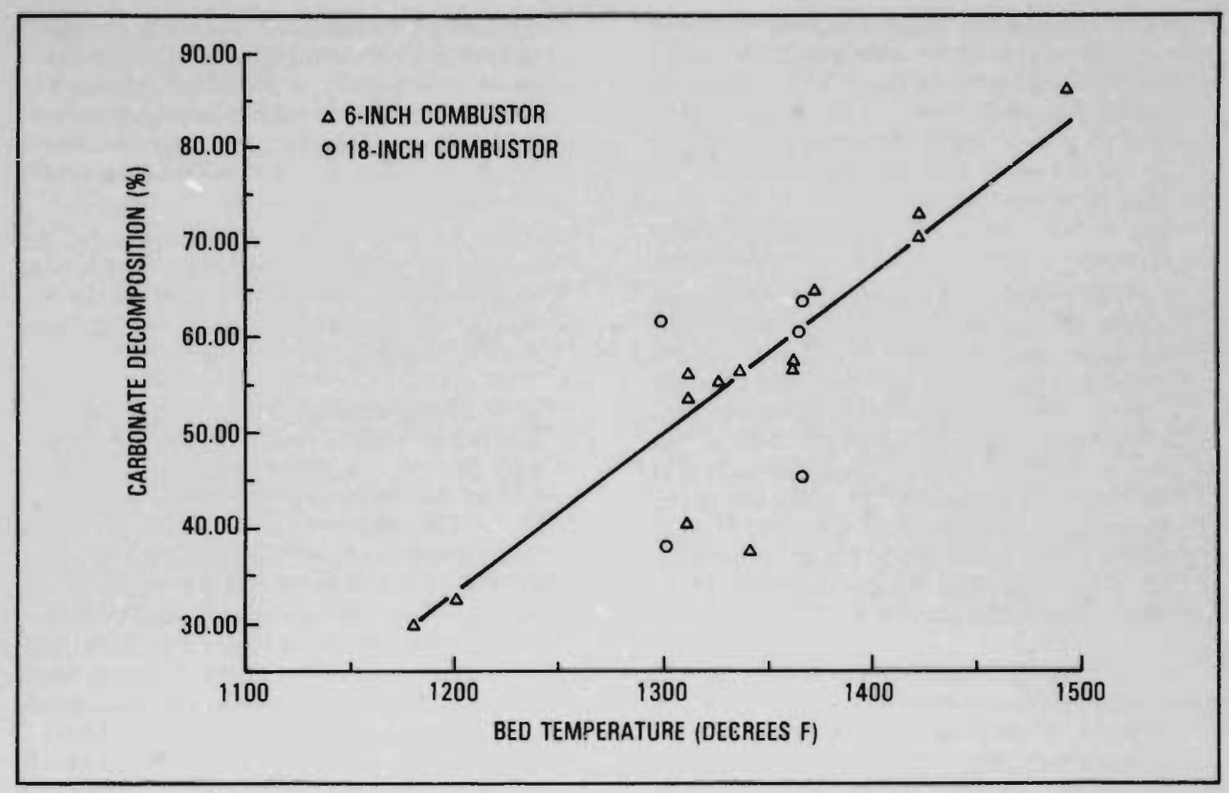

Figure 5. Carbonate Decomposition as a Function of Bed Temperature

temperature analysis for an oil shale can also assist in pinpointing the most favored retorting temperatures.

The secondary air injected in the freeboard region would burn the combustibles from retorting to a satisfactory extent. The heat of combustion would be extracted from the flue gas by a waste-heat boiler which is located at the right side of the fluidized bed. Some of the heat of combustion in the freeboard would radiate down at the fluidized bed to keep the fluidized bed at a favorable retorting temperature. The waste-heat boiler volume also serves as a settling chamber where the fines are collected for disposal or as a heat source to assist at keeping the retorting fluidized-bed temperature at the most favored retorting conditions.

• ***Two-Staged Fluidized-Bed Combustion:*** This design physically separates the devolatilization combustion and sulfur retention. A conceptual design of this type FBC system for eastern oil shale is shown in Figure 6. In this approach, the retorting is conducted in a fluidized-bed retort with a slanted distributor to facilitate bed-material (spent-shale) movement. The heat of retort-

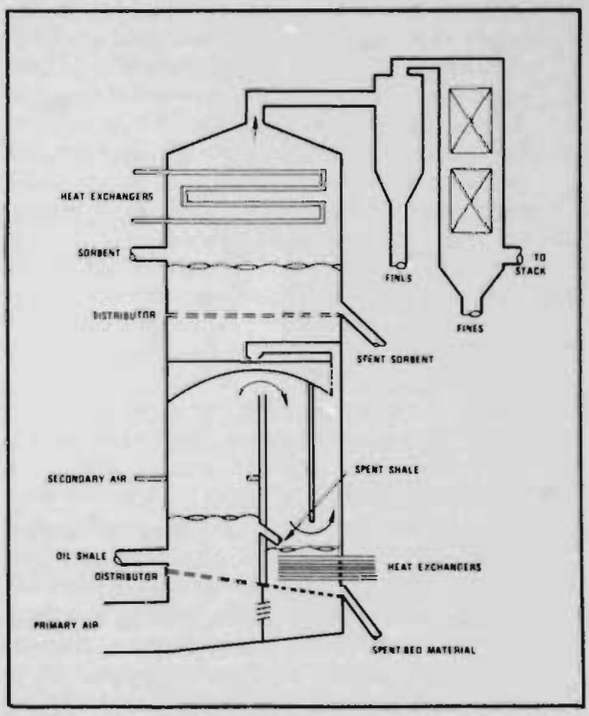

Figure 6. Conceptional Design of a Two-Staged FBC System for Eastern Oil Shale

ing is supplied by the partial combustion of oil shales. The spent shale passes through a waste-heat recovery fluidized bed, on the right, where the sensible heat of the spent shale is used to preheat the fluidizing and combustion air for the upper fluidized bed. Owing to the high inert content of the eastern oil shales, the sensible heat recovery from the large quantity of spent shale is an economical must.

The products of retorting and preheated air from the lower fluidized beds enter the upper fluidized bed, or the second stage, to complete combustion and pollutant-emission control. The gaseous retorting products, high in carbon-dioxide content, can enlarge the pore size of the calcium limestone such that the threefold increase of the molar volume of the sulfated limestone does not result in plugging the pore openings and reduction of calcium utilization. This design may be high in pressure drop, and shallow beds are preferred.

• ***Twin-Bed Retort/Combustor:*** In this approach, the sensible heat of the spent-bed material is utilized to supply the heat of oil-shale retorting. Figure 7 shows a conceptual design, and the principal feature of the twin-bed retort/combustor fluidized bed is a partition wall which separates the combustion and retorting compartments. Two in-bed passages and the design of the distributor plates keep the bed materials in the twin beds circulating properly. The circulation of bed materials is accomplished by use of a slanted distributor and/or slanted distributor nozzles. The freeboard regions of the combustion and retorting beds are separated so as to avoid contaminating the product gases from retorting with the products of combustion.

Raw oil shale is fed into the retort bed at a point where it is mixed with the hot spent-bed material from the combustion bed. The sensible heat of the spent-bed material heats the fresh oil shale to a temperature for oil-shale retorting. The gaseous retorting products pass through the freeboard region, leave the unit, and are transported to a hydrocarbon-recovery system for eventual hydrocarbon recovery. After the completion of retorting, the retorted oil shale flows into the combustion compartment for the burn off of the residual carbon. The gaseous products of combustion are directed to a flue-gas waste-heat recovery system for the generation of process steam. The hot-bed material, after some bleed off to control the total solid materials inventory in the bed, is recycled into the retort bed as a heat source.

The fluidizing gases in the combustion and retort beds can be different. For example, steam and/or easily recoverable inert gas (i.e., flue gas or carbon dioxide) can be used as fluidizing gas for the retorting bed. Air or oxygen can be used as the fluidizing gas for the combustion bed.

The key to desirable performance is the keeping of a pressure equilibrium between these two separated beds to avoid contamination of the retorting products by the combustion products.

• ***Devolatilization Bed:*** The oil-shale devolation process takes place in a few seconds. The rate of devolatilization may subject the region near the feeder to a reducing environment. The presence of sulfur compounds can cause the formation of metal sulfides on the metal surfaces exposed to the reducing and corrosive environment. Subsequent instability in the location of the barrier of the reducing and corrosive environment may expose the metal surface to an alternating reducing and oxidation zone (AROZ). Owing to the very nature of the metal oxides and sulfides, catastrophic metal failures can occur under this condition. This conceptual design, depicted in Figure 8, utilizes a devolatilization sub-cell to allow substantial completion of the devolatilization process in a fluidized-bed sub-cell with virtually a constant reducing environment and few to no metal

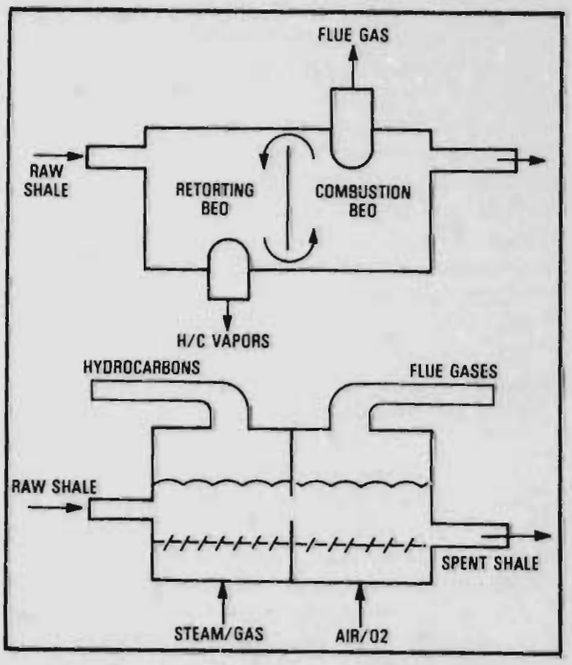

Figure 7. Twin-Bed Retort/Combustor

surfaces present. In addition to its designed function of devolatilization, the devolatilization sub-cell can also serve as a header for feeding devolatized oil shale into a number of fluidized-bed combustion cells. The devolatilization sub-cell is an integral part of the fluidized-bed combustor and receives heat from the adjacent combustion cell via conduction through the refractory partition and heat transfer from the overbed gases and reradiating ceiling. The devolatilization cell, as depicted in Figure 8, will have a low adiabatic refractory ceiling, which will also insure a freeboard temperature high enough to produce nitrogen-oxide reduction and relaxation. The volatiles generated are burned in the freeboard region and the devolatized oil shale, with considerable carbon content, is burned in the primary fluidized-bed combustion cell. Hot bed material overflows into a secondary combustion cell which achieves the final stage of combustion and recovers sensible heat from the hot spent-bed material to increase the overall efficiency of combustors. Immersed in-bed heat-transfer surfaces will cool the spent-bed material and preheat the fluidizing air for combustion.

Conclusion

Oil shale constitutes a major source of future fossil-energy supply in the form of direct combustion as well as retorting. Owing to the inherent high rates of heat and mass transfers inside the fluidized bed, the fluidized-bed combustor and retorting appear to be a desirable process technology for an effective and efficient means for oil-shale utilization. The fluidized-bed operation is a time-tested, process-proven, high-throughput, solid-processing operation which may contribute to the efficient utilization of oil-shale energy.

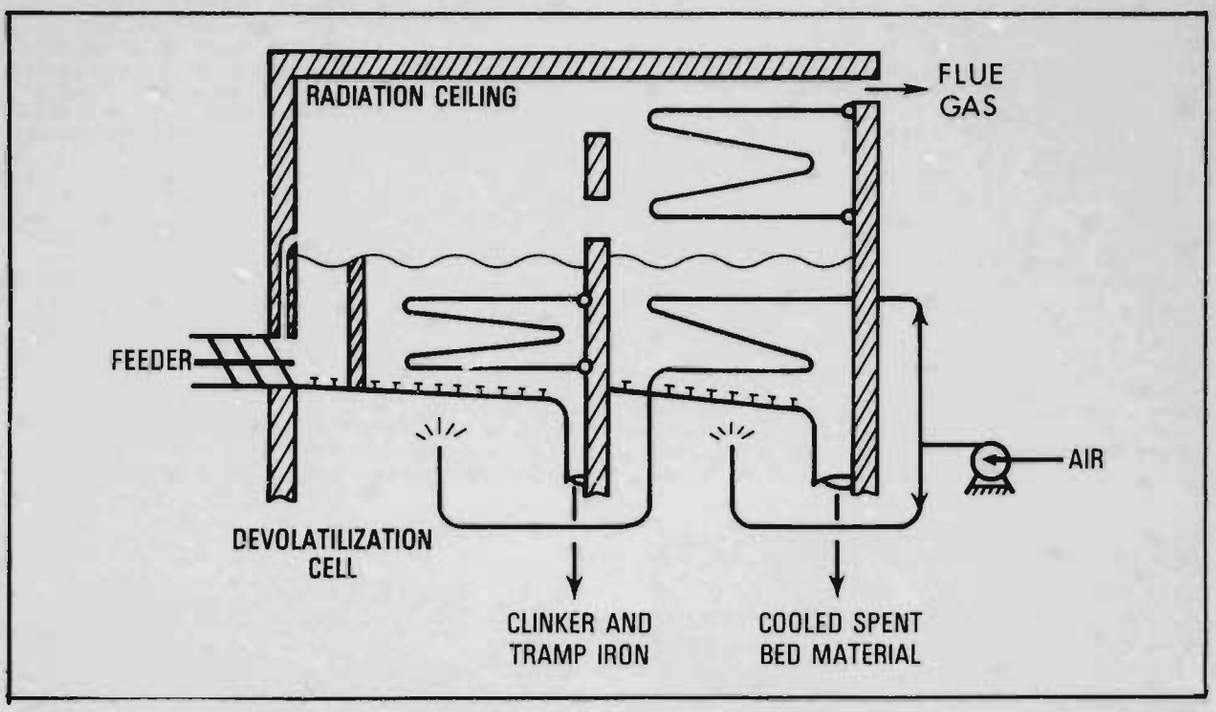

Figure 8. Use of a Devolatilization Cell

The Dravo Traveling Grate Process for Oil Shale Retorting

by

Frank Forbes
Vice President, Oil Shale

Forrest W. Kinsey
Technical Manager, Oil Shale

Dravo Engineers and Constructors
Pittsburgh, Pennsylvania 15222

Abstract. Dravo began investigating the use of the traveling grate for retorting oil shale in late 1979. The program for the development of the Dravo traveling grate process from the laboratory through the pilot plant will be reviewed.

We at Dravo have been involved in a variety of mining and minerals processing projects for many decades and have become a world leader in the pyro-processing of iron ores through sintering and pelletizing. In this effort, we have developed rather intimate familiarity with the handling of bulk minerals and process gases for the treatment of minerals.

As we become involved with oil shale, we gained an appreciation for the complexities associated with retorting. We were witness to the evolution of modern retort technology, from the first vertical kiln design (figure 1), which we engineered and constructed for the U.S. Bureau of mines, through present concepts.

In 1979, it became apparent to us that a key element in the successful retorting of oil shale was adequate materials handling and felt that the traveling grate would be an ideal means of retorting oil shale.

We built a test retort (figure 2) at our Research Laboratory and began testing the parameters for oil shale retorting in early 1980. We also came to appreciate the advantage of having a traveling grate pilot plant on which we could complete our testing and demonstrate our process as soon as possible. This required a retort in place which could be modified to suit our purposes (figure 3). We initiated discussions and ultimately acquired McDowell-Wellman in May of 1980.

The pilot plant has been modified for the Dravo Traveling Grate Retort Process (figure 4). Ten test runs have been made to check out equipment and to verify process details. We are now ready for pilot plant testing for clients.

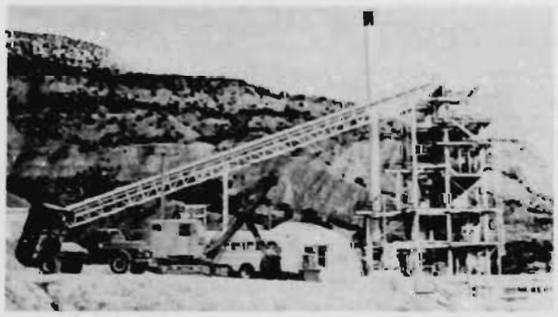

Figure 1 Bureau of Mines Vertical Shaft Kiln

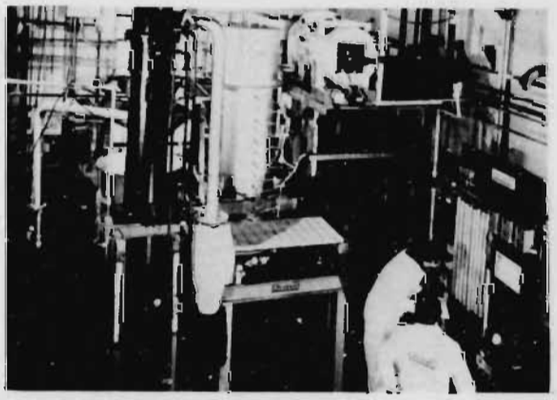

Figure 2 Laboratory Batch Retort

Figure 3 Oil Shale Pilot Plant

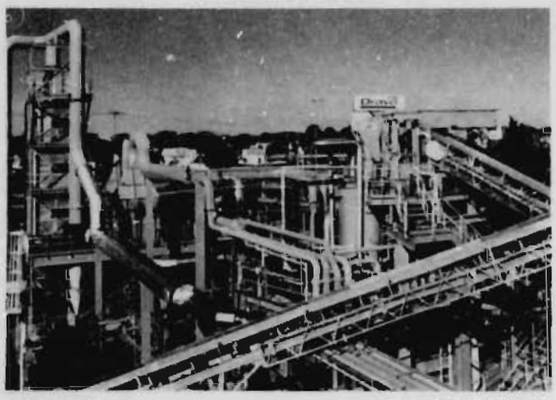

Figure 4 Modified Oil Shale Pilot Plant

Parallel to the laboratory process development and the modification of the pilot plant, we began engineering the Dravo surface retort in order to define the details of a commercial sized facility and derive capital and operating cost estimates (figure 5). Our work has confirmed that the process is indeed viable and, we believe, quite competitive.

Figure 5 Proposed 50,000 TPD Oil Shale Pilot Plant

Process Development

As we surveyed oil shale developers, we found a common set of interests which we adopted as our Process Objectives, including:

- o Recovery of all the oil in the shale;
- o Development of an autogenous (self-fueled) process;
- o Use of all the shale mined;
- o Attainment of a high production rate; and
- o Installation of the facility at a competitive cost

In order to achieve these objectives, we realized that we should try to meet certain additional requirements which any surface retorting operation would include:

- o Efficient handling of massive tonnages of shale;
- o Employment of proven equipment;
- o Controlled heating of the shale;
- o Adequate cooling of spent shale;
- o Thorough removal of dust and oil from the gas stream; and
- o Production of a usable off-gas

Our plan was to develop a shale oil process which would meet the objectives while satisfying all requirements in an economically viable manner.

In the Dravo Retorting Process the raw shale will be retorted on a traveling grate (figure 6). The retorting section will be divided into three parts: Zone 1, an intial heat-up zone; Zone 2, the burning of carbon and gas in the bed; and Zone 3, completion of shale retorting. The shale will then be cooled for disposal. Off-gases from the retorting and cooling sections, after cooling and oil recovery are reused in the process as heat carriers. Excess, or by-product gas, is bled from the system as necessary.

Dravo Traveling Grate Oil Shale Retorting Process

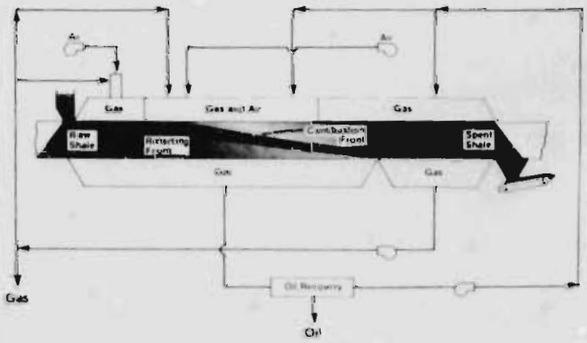

Figure 6 Dravo Retorting Process

During retorting there is no relative movement between particles where abrasion could degrade the particles and disrupt the process. We can remove water from the shale concurrently with retorting or in a separate zone ahead of the retorting zone, if necessary.

In developing our process, we recognized that the traveling grate machines we had designed for iron ore sintering and pellitizing were durable, efficient, yet capable of processing large tonnages of raw material. Likewise, Dravo's experience in handling fines could be applied to the preparation of shale fines for retorting. Furthermore, we had broad experience separating dusts, hydrocarbons and aerosols from large volumes of gases for processing plants we built.

It was also clear that Dravo had the know-how to develop a process and then scale-up the technology for commercial size. Additionally, we had already built systems of proven dependability in the sizes envisioned for oil shale retorting.

A traveling grate is a continuous chain of moving pallets for pyro-processing a wide variety of bulk materials (figure 7). For a proven process, such as the pelletizing or sintering of iron ores, the process can be simulated and scaled up from a small pot grate (or batch retort), (figure 8) to a full size, continuous production unit. Dravo has built 68 traveling grate machines to date. All have been designed from and have met process guarantees developed from our batch laboratory equipment.

Laboratory Investigation

The principal processing variables studied during the initial investigation phase included;

- o Retorting methods
- o Particle size
- o Bed depth
- o Bed segregation
- o Agglomeration of fines; pelletizing, sintering, cold bonding, pressure forming
- o Pressure drop
- o Gas flows
- o Initial heating:
  - ^{o}Time
  - ^{o}Temperature
- o Air (or oxygen) addition to the retorting zone

Retorting tests were evaluated with respect to:

- o Oil removal, recovery, and properties;
- o Process rate;
- o Gas properties; and
- o Spent shale properties

All the oil was removed from the shale and a high rate of recovery from the gas stream was indicated.

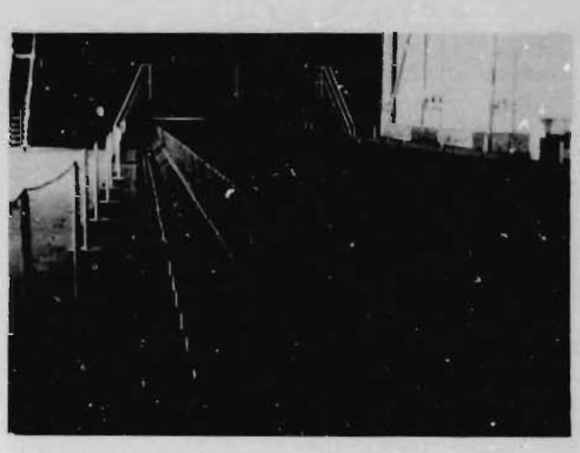

Figure 7 Straight-Line Traveling Grate

Figure 8 Laboratory Sinter Pot

During our test, we also monitored the rate at which raw shale could be retorted. This was measured in tons of raw shale processed per square foot of processing area per 24 operating hours. The time of processing for this calculation was from the start of retorting until the average temperature of the spent shale was low enough to permit handling on conveyor belts. A high raw grate factor is indicated from the test results. Processing 25,000 to 30,000 tons of shale per day on a single machine is within existing technology based on Dravo's pyro-processing experience. Figure 9 shows the increase in size of grate machines over the years. The largest traveling grate on the world today is a Dravo machine built for a Brazilian client.

The heating value and quantity of by-product gas are principally determined by the amount and purity of oxygen added, the efficiency of processing, and the amount of kerogen in the shale. A heat-

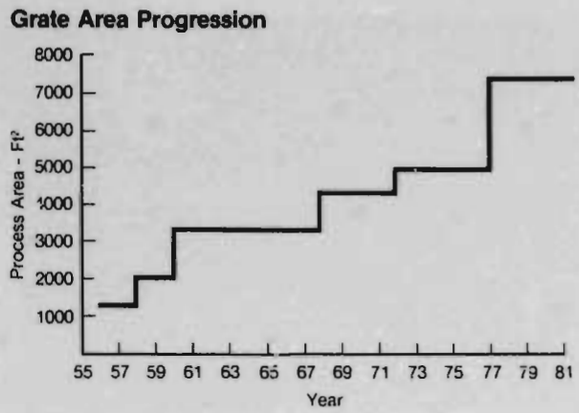

Figure 9 Great Areas Built by Dravo

ing value of 100-110 BTU/SCF is indicated in our process for 28 GPT North American oil shale. The ultimate use of air or oxygen would depend on an economic evaluation.

The weight of spent shale for a 28 GPT Colorado shale would be 83% of the shale charged to the grate. Less than 10% of the carbonate is calcined and about half the carbon is burned out. Disposal problems are not unique from our analysis.

Fines were successfully retorted in the batch retort. This portion of the test program was run using mainly pellets and briquettes.

We verified the technical feasibility of agglomerating oil shale fines and recycling solids separated from the oil. The latter processing would eliminate a difficult disposal problem. We would expect agglomeration to be used, however, only if economically viable for a given property.

A water balance has been made for the Dravo process. Only a nominal amount of water is required to make up losses from the water sealing system. For such losses inside the hood, it is possible to recover the water. Approximately 5 gallons of water per ton of raw shale retorted is recovered from a 28 GPT Colorado oil shale and is available for plant use.

The by-product gas can be burned to produce steam and electricity. Our analysis shows that after all traveling retorting process energy requirements are satisfied, approximately 12.5 KWH per ton of shale retorted is available for other uses in the plant.

Oil Properties

Quality inspections of raw shale oil are an indicator of further upgrading requirements. Typically, raw shale oils have high pour points, contain appreciable nitrogen, and are relatively lean in 1050+ residue and naphtha content. The carbon/hydrogen ratio of most oil shales is slightly higher than that of petroleum crudes ranging from 7.2 to 7.4. In addition, the composition and characteristics of shale oil are dependent on the composition of the kerogen from which it is derived. To demonstrate this point, table 1 shows the properties of the oil recovered from laboratory retort tests on two totally different oil shales.

TABLE 1
Shale Oil Quality from Different Shales

Gravity		
°API	19.60	22.90
Specific	0.936	0.916
Composition, Wt. %		
Carbon	84.50	82.49
Hydrogen	11.36	11.89
Nitrogen	1.91	1.07
Sulphur	0.62	0.62
C/H Ratio	7.44	6.94
Pour Point, °F	85	90

From the refiner's point of view, shale oil B would be the most desirable because of its higher hydrogen content and lower percentage of nitrogen resulting in less upgrading requirements.

In table 2, inspections of a raw shale oil product from the Dravo retorting process are compared with those from other oil shale retorting processes and with Arabian Light crude.

The quality of the oil produced from the Dravo Travelling Grate Process is comparable to the oil produced from the other processes and is most similar to that produced from the Paraho process. The data also suggest that most of the material boils in the kerosene and gas oil range.

Table 2
Oil Shale Retorting Process Comparisons Raw Oil Quality

	Dravo	Paraho	Tosco II	Union B	Oxy-MIS	Arabian Light Crude
Retort Method	Direct	Direct	Indirect	Indirect	Direct	-
API Gravity	20.8	19.3	21.2	22.7	24-25	34.7
Pour Point, °F	85	85	80	60	50-65	-15
Sulfur, Wt. %	0.98	0.71	0.67	0.9	0.64	1.71
Nitrogen, Wt. %	1.82	2.00	1.85	2.00	1.50	0.08
Viscosity @ 100°F, CP	75.0	78.5	27.1	98.0	15.8	5.5
C/H Ratio	7.41	7.4	7.3	7.3	7.2	6.2
Naphtha (-310°F), LV%	0	0	7.1	6.0	1.3	23
Kerosene (310/500°F)	9.0	6.8	14.0	12.8	14.0	21
Gas Oil (500/1050°F)	83.0	84.2	80.2	67.6	80.2	42
Residue (1050+°F)	8.0	9.0	4.5	13.6	4.5	14

Source: Shale Oil, Occidental Petroleum Corporation and Dravo Corporation

Pilot Plant

Dravo's Shale Oil Pilot Plant is located in Cleveland, Ohio, at our Research Center on South Waterloo Road. It was originally constructed in 1974, and operated for several runs. It has been revamped to conform with the latest Dravo technology and shale oil recovery methods. It is a circular grate having 88 square feet of active grate area. It can process 300 tons-per-day of oil shale.

The pilot plant flowsheet (figure 10) illustrates the basic flow scheme of this facility. We duplicate the process completely but the pilot plant does have some equipment differences from what we process in a commercial plant. Raw shale will be crushed and screened. Belt conveyors will move the crushed shale to the traveling grate machine over a weigh belt scale for material weight recording.

The shale bed travels under the first retorting zone hood, which contains hot, oxygen-free, process gas. The first retorting zone covers several of the machine's 12 windboxes.

The second and third retorting zones cover additional windboxes. The second retorting zone is fed by oxygen-enriched, recycled process gas. The third retorting zone is fed with oxygen-free process gas.

The air that is injected into the second retorting zone hoods causes combustion of shale carbon to provide the heat for further retorting. At the discharge end of the retort zone, 100% of the oil has been extracted from the shale, approximately 50% of its carbon has been burned, and a significant percentage of the shale has been cooled.

The cooling zone consists of the last several windboxes which has been fed with cool, oxygen-free process gas.

The shale is then conveyed to the discharge area where the pallets are tipped and the shale falls into a water-sealed discharge hopper. A belt conveys the shale to a refuse pile for ultimate disposal.

The retort gases are collected in windboxes and ducted to an oil recovery system.

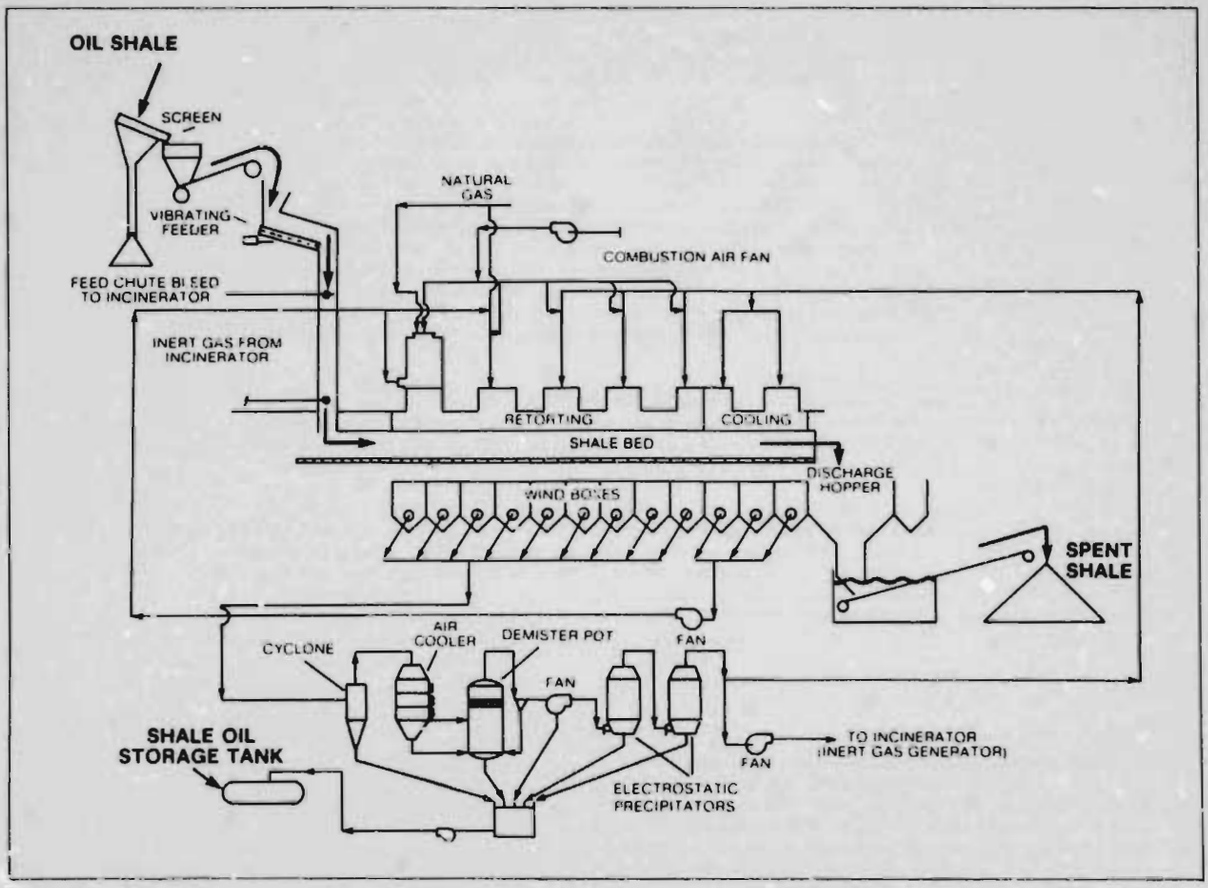

Figure 10 Pilot Plant Flowsheet Schematic

Our laboratory testing demonstrated that the 1000 tons of shale we retorted in the pilot plant is different from the shale tested previously, even though both were from Colorado. We ran over a dozen tests to determine the optimum processing parameters.

We have run 10 pilot plant tests to date. The first six were of 8-12 hours duration to test systems such as the heat distribution under the burner, oil collection systems, gas and air flow distributions, etc. The last four were sustained runs.

Pot and pilot plant tests indicated a 98-100% oil removal and collection efficiencies up to 100% of Fischer Assay oil under optimum conditions. This was under varying conditions in the retort and in the collection system.

The objective of the preliminary tests in the pilot plant was to (1) prove the process and (2) obtain a reliable operating plant.

Before, during and subsequent to those tests, we have evaluated means of improving the retort and have installed and tested equipment to accomplish this.

From the results to date, we are satisfied we have taken our retorting system from the batch-laboratory step to a continuous pilot plant operation.

The Dravo traveling grate retorting process is simple and efficient yet distinct from other processes proposed for shale oil recovery.

Eastern Oil Shale Investigations at the University of Alabama

by

H. Shafick Hanna
Associate Professor

Carl Rampacek
Director

Minerals Resources Institute
The University of Alabama

Abstract. The School of Mines and Energy Development of University of Alabama is engaged in a research program incorporating basic and applied studies, on a laboratory and small continuous scale, to develop and evaluate innovative and advanced process technology for recovering oil from Eastern Devonian shale.

Three major areas are under investigation: concentration of the fossil energy values into enriched products using standard beneficiation techniques accompanied by recovery of the oil from the upgraded products using conventional extraction techniques; development and evaluation of fluid-bed retorting of raw and beneficiated shale to recover liquid hydrocarbons followed by gasification of the char; and low to moderate temperature and pressure extraction of oil from raw and beneficiated shale.

A novel feature of the program is the application of standard flotation techniques to recover concentrates containing about twice the Fischer Assay values found in the raw shale. The beneficiation step offers the potential benefits of reduced capital costs of plant equipment, lower processing costs, lower energy requirements and decreased environmental impact. Further, because of the finely-divided state of the beneficiated products, they should have superior heat transfer properties and greater chemical activity during retorting while permitting a broader choice of equipment with which to treat the shale.

The second area of study, the fluidized-bed retorting of raw and beneficiated oil shale, has the objective of identifying various parameters favoring maximum oil and gas recovery from the finely-ground shale and determining the merits of fluid-bed processing as an alternative to conventional retorting.

The third area of research involves low to moderate temperature and pressure extraction of liquid hydrocarbons from Eastern shale. Preliminary studies have indicated that, under certain moderate conditions of temperature and pressure, a substantial portion of the kerogen-based oil can be extracted by the use of organic solvents. The objective of the proposed studies therefore will be to further develop these novel processing approaches.

Introduction

The importance of defining additional domestic reserves of conventional and unconventional hydrocarbon fuels is now well established. A potential and, yet unexploited, source of unconventional crude oil, gas and uranium may be the huge black shale deposits of Late Devonian-Early Mississippian age underlying more than 250,000 square miles in the Eastern and Central United States. The deposits extend from Alabama through Michigan, and from Texas to New York.[1] Large resources of Devonian shale, known as Chattanooga shale, have been reported for Alabama and the adjacent states of Tennessee and Georgia. Initial estimates of the Eastern oil shale resource are that over 2,000

square miles of land area containing perhaps 2600 billion barrels of oil would be suitable for surface mining.[2]

Despite their wide occurrence, the Devonian black shales have been of secondary interest to the Western shales because of their low oil yield when subjected to the conventional retorting processes originally designed for the hydrogen-rich Western shales. Therefore, new, more efficient approaches are needed for extracting the liquid and/or gaseous hydrocarbons from Eastern shales. Toward this end, a program, administered by the School of Mines and Energy Development (SOMED) of The University of Alabama, is underway to evaluate methods and processes for recovering the energy and non-energy mineral values from oil shale. Elements of the program encompass characterization and evaluation of oil shale samples from Alabama and adjacent shales, evaluation of certain advanced and/or near commercial retorting techniques as applied to Eastern oil shales, and investigations of new processing approaches to obtain maximum recovery of the energy values. Among the new approaches under investigation are the use of physical beneficiation techniques as an important first step in processing the Eastern shales; fluidized bed retorting and/or gasification; and the use of moderate temperature and presssure solvent extraction techniques for extracting the kerogen from the shale. The program also includes fundamental studies of the kinetics of pyrolysis and retorting characteristics of the shale.

Chattanooga Shale Characterization

The purpose of the shale characterization work at The University of Alabama is to develop more thorough physical, geochemical, lithological and resource inventory data on the Chattanooga Shale deposits in Alabama and adjacent states. These data will support and complement other phases of the program concerned with sample evaluation, beneficiation, retorting and extraction, process evaluation and environmental studies. Part of the characterization study is directed toward comparing the characteristics of the Chattanooga and Western shales.

Unlike the wealth of information relating to characterization of Western oil shale, the Eastern shales have received minimal attention. Except for recent studies most of the efforts have been focused on determining the inorganic constituents of Eastern shales, particularly for the purpose of extracting uranium and such trace elements as vanadium, cobalt, nickel, and molybdenum.[3,4,5,6] In a report on studies of the Antrim shale of Michigan, Lund has discussed the effects of the shale's mineralogical composition on its retorting properties.[7]

The Chattanooga shale is a fine-grained laminated shale. Mineralogically it is composed of 16 to 22 percent of organic matter (kerogen), about 31 percent of the clay minerals illite and kaolinite, 22 percent quartz, 9 percent feldspars, 11 percent pyrite and marcasite, and other minerals such as calcite, apatite, tourmaline and zircon.[8] Petrographic examination of thin sections indicates that the kerogen occurs as coatings on larger mineral grains as well as stringlike concentrations and patches along laminae or bedding planes in the schist.[9]

According to Swanson the kerogen which gives the marine black shales their characteristic color, consists predominantly of hydrogen-deficient "humic" substances derived primarily from cellulose and lignin, and smaller amounts of the hydrogen rich "sapropelic" matter derived from algae, spores and pollen.[5] Chattanooga shale, therefore, has a low hydrogen to carbon ratio and upon retorting gives low oil yields by the Fischer Assay method. The characteristics of Eastern and Western oil shales are compared in Table 1, which shows much lower Fischer Assay oil yields from Eastern shale than from Western shale even though their organic carbon contents are somewhat comparable. The data suggest that the standard modified Fischer Assay method does not indicate the full potential energy value of Eastern shales because it does not take into account a significant quantity of gas that can be recovered from the char and residual carbon produced during pyrolysis.[7]

Table 1. Comparison of Analyses of Eastern and Western Oil Shales

	Alabama[10]	Tennessee[11]	Kentucky[12]	Colorado[12]
Ultimate Composition (Dry Basis) wt. pct.				
Organic Carbon	17.3	14.1	13.4	13.6
Hydrogen	2.0	1.55	1.65	2.1
Sulfur	4.3	5.2	5.66	0.5
Carbon Dioxide	0.5		0.5	15.9
Nitrogen	0.4	0.4	0.5	0.5
Ash	73.4	78.3	75.8	66.8
Fischer Assay				
Oil Yield, wt. pct.	4.9	4.5	4.0	11.4
Assay, gal/ton	13.6	11.4	10.1	29.8
Conversion to Oil, pct.	35.3	30.0	30.0	84.0

Sample Evaluation and Oil Yields

Fischer Assay and sample evaluation studies of over 400 samples, collected by Geological Survey of Alabama (GSA) in a reconnaissance sampling program covering the area shown in Figure 1, have indicated the existence of two major types of Chattanooga shale: undeformed and deformed.

Deformed shales are represented by surface and core samples collected from the flanks of the Wills Valley anticline in Jackson (JAC), Dekalb (DEK), Blount (BLO), Etowah (ETO), Walker (WAL) and other counties in Alabama, and in Chattanooga (CHT) County in Georgia. These samples are characterized by low Fischer Assay oil yields (ranging from 0 to 5.2 gallons per ton), high water yields and high residual carbon in the spent shale as shown in Table 2.

Undeformed shales are represented by surface and core samples collected from Madison (MAD), Limestone (LS), and Lauderdale (LAU) counties in Alabama, and Franklin (FRA), Coffee (COF), Marshall (MAR), Moore (MOO) and Lincolin (LIN) counties in Tennessee. This material is similar to that previously reported for samples from Tennessee and Kentucky. Oil yields from samples of this type are shown in Table 3. The shales yield as much as 16 gallons of oil per ton with a probable

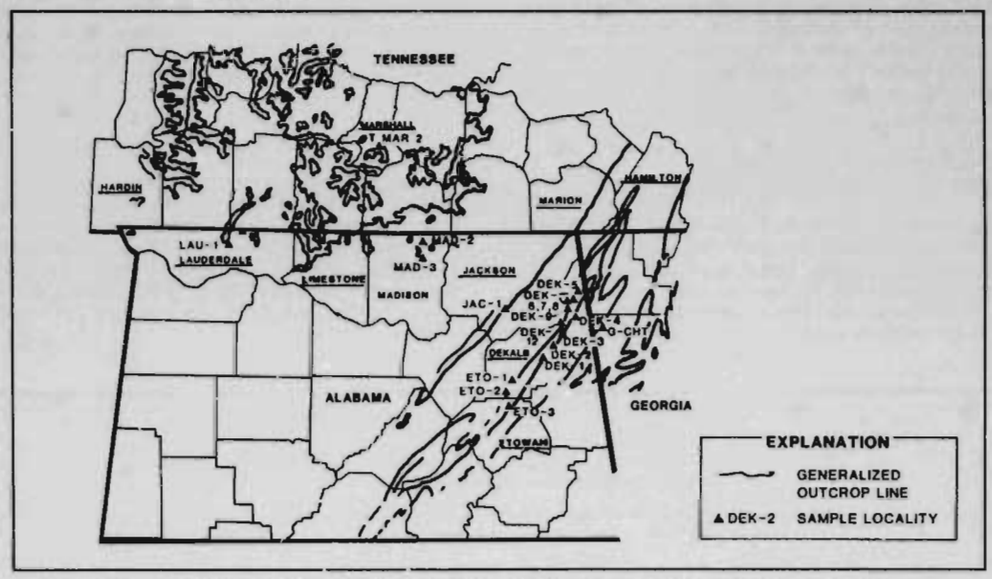

Figure 1. Diagram Showing the Generalized Outcrop Pattern of the Chattanooga Shale in the Study Area and the Location of Selected Samples Collected for the Fischer Assay Analyses.[13]

Table 2. Fischer Assay Yields of Deformed Chattanooga Shale From Alabama and Adjacent States

Sample ID#	State	Oil Gal/Ton	Water Gal/Ton	Spent Shale Wt.%	Gas and Loss Wt.%
BLO-3	Alabama	0	11.6	93.1	2.4
BLO-4AC	Alabama	3.8	3.6	94.8	1.2
**DEK-C1	Alabama	0.3	3.4	98.2	0.4
**DEK-C2	Alabama	0.9	2.7	97.4	1.3
DEK-9A	Alabama	0	12.7	92.4	1.9
DEK-10B	Alabama	0	8.6	94.8	1.6
ETO-5	Alabama	0	16.4	90.6	2.8
ETO-6AS	Alabama	2.4	8.4	94.7	.9
ETO-6T2	Alabama	0	10.7	93.2	2.3
JAC-7	Alabama	0	8.0	95.2	1.4
JEF-1	Alabama	0	9.1	94.6	1.6
STC-1	Alabama	0.5	9.8	93.5	2.2
STC-2	Alabama	5.2	5.5	92.7	3.0
WAL-2	Alabama	0	6.5	96.4	1.6
CHE-1	Georgia	0	9.5	94.6	1.5
*CHE-8	Georgia	0	4.7	98.0	0.4
COF-3H	Tennessee	4.0	3.6	95.2	1.8
SEQ-1	Tennessee	1.0	8.5	95.0	1.0

*Bulk sample average 4 determinations
**Core hole average

average yield of 10 to 13 gallons per ton. In light of their similarity to Kentucky and Tennessee shale oil yields, the research efforts at the University of Alabama have been focused on the undeformed shales.

Wide variations in the Fischer Assay yields for the deformed and undeformed shales confirm the conclusions of other investigations that there is little correlation between the oil yields and the carbon content as shown in Figure 2. For this reason, efforts have been made to use a more precise method than the standard Fischer Assay for evaluating the hydrocarbon potential of Chattanooga shale. Thus, the "TOSCO material balance assay" method which more accurately determines the yields of oil, water, and product gas has been adopted to assist in the characterization studies.[13] A gas-tight thermogravimetric unit (Figure 3) designed to handle 10 to 30-gram samples has been constructed in our laboratory.

Fundamental Studies of the Pyrolysis Characteristics of Chattanooga Shales

Our current research is designed to determine the critical operational factors that may increase the oil recovery from Eastern shales. Emphasis is being placed on such factors as the rate of heating and soaking, pyrolysis temperature, and the effect of various additives during pyrolysis.

Thermovolumetric analyses of CH_4, C_2H_4, C_3H_8, H_2CO and CO_2 produced during the pyrolysis of Chattanooga shale were conducted and typical data are shown in Figures 4, 5 and 6 for a composite sample of Chattanooga shale from north Alabama and south Tennessee. The pyrolysis was conducted on a minus 2 plus 4 mesh size fraction of the shale at a heating rate of 2°C/min. with no preheating (soaking). Initial analyses of the above results indicate that most of the evolution curves obtained can be fitted with a first order kinetic mechanism. However, the appearance of a secondary peak in the case of CO_2 may suggest a more complicated evolution mechanism. A complete evaluation of these results, and others, concerned with the effect on the oil and gas yields of such factors as particle size, temperature of soaking and its duration, the rate of heating and type of sweeping gas, will be published at a later date.

Characterization of Kerogen by Instrumental Methods

A study underway by the Department of Physics is concerned with developing and demonstrating the practical feasibility of using nuclear magnetic resonance (NMR) and electron spin resonance (ESR) techniques to make rapid, nondestructive determinations of the quantity and quality of kerogen in Eastern shales.[16]

Table 3. Fischer Assay Yields of Undeformed Chattanooga Shale From Alabama and Adjacent States

Sample ID#	State	Oil Gal/Ton	Water Gal/Ton	Spent Shale Wt.%	Gas and Loss Wt.%
MAD-1	Alabama	10.3	7.9	90.3	2.3
*MAD-0	Alabama	13.6	4.5	89.6	1.5
**MAD-C2	Alabama	12.9	3.7	89.8	3.7
MAD-2A	Alabama	13.1	6.0	90.9	1.4
MAD-2B	Alabama	15.0	6.3	88.9	1.2
MAD-3	Alabama	8.1	7.6	91.9	1.3
**MAD-C4	Alabama	12.3	3.1	90.5	3.5
**MAD-C5	Alabama	10.0	2.7	92.0	3.3
MAD-6A	Alabama	13.7	6.5	88.7	3.2
MAD-7A	Alabama	13.4	4.9	90.0	2.7
MAD-7B	Alabama	11.2	5.5	89.4	3.9
MAD-8A	Alabama	13.1	4.8	89.0	3.8
MAD-8B	Alabama	11.3	5.8	89.7	3.4
LS-1A	Alabama	9.9	8.9	88.7	3.7
LS-2B	Alabama	12.5	6.8	88.9	3.2
LS-3A	Alabama	16.0	12.0	86.0	2.7
LS-3B	Alabama	12.1	10.5	86.8	4.0
FRA-3A	Tennessee	9.5	4.9	91.6	2.6
FRA-3B	Tennessee	12.3	5.6	90.1	2.7
FRA-4	Tennessee	9.5	9.0	88.8	3.8
FRA-5	Tennessee	12.0	3.2	90.7	3.3
GIL-14	Tennessee	14.8	8.3	85.1	4.9
MAR-2D	Tennessee	16.4	9.6	85.8	2.8
MAR-3	Tennessee	15.8	6.1	87.7	3.5
MAR-4	Tennessee	15.6	7.9	86.0	4.5
MAR-5A	Tennessee	10.7	11.2	88.0	3.0
MAR-5B	Tennessee	16.3	8.2	86.4	3.9
MOO-2A	Tennessee	11.9	4.9	89.3	3.9
MOO-2B	Tennessee	11.8	5.4	89.6	3.7

*Bulk sample average of 9 determinations
**Core hole average

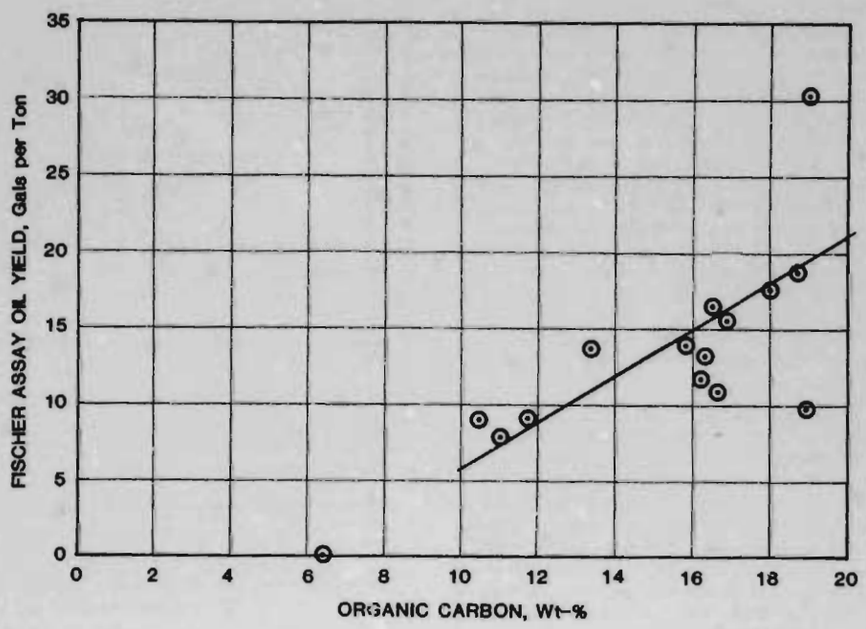

Figure 2. Relationship Between Fischer Assay Oil Yield and Organic Carbon Content[12]

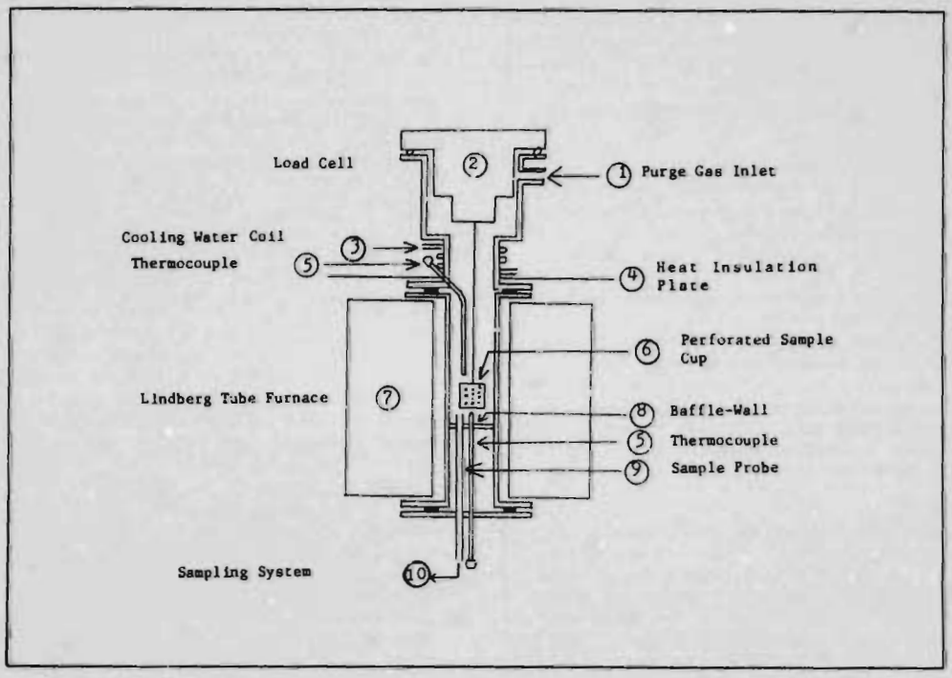

Figure 3. Experimental Setup for Thermogravimetric Analysis[15]

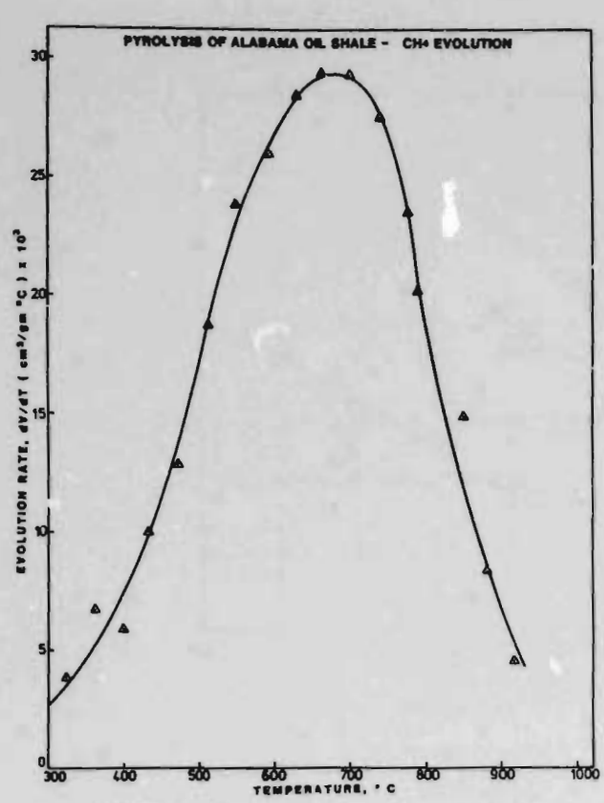

Figure 4. Evolution Rate of Methane From Pyrolysis of Chattanooga Shale

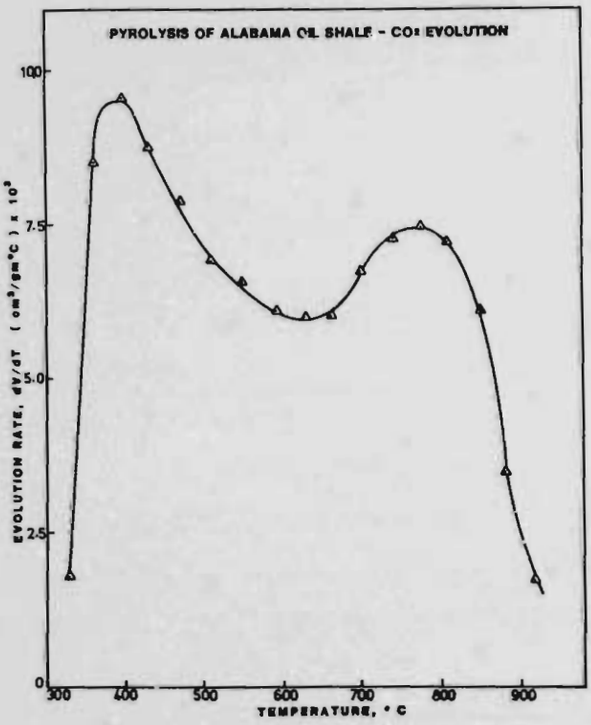

Figure 5. Evolution Rate of Carbon Dioxide From Pyrolysis of Chattanooga Shale

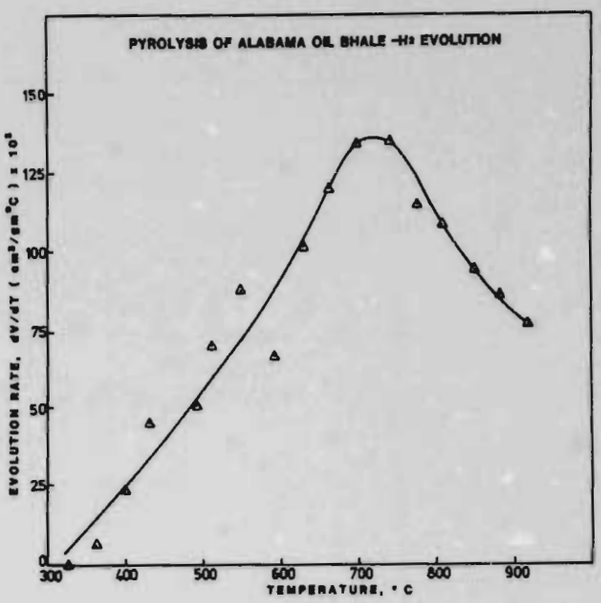

Figure 6. Evolution Rate of Hydrogen From Pyrolysis of Chattanooga Shale

It has been shown by other investigators that the total amount of hydrogen in a sample can be accurately measured by NMR and it has been recognized that, while most of the hydrogen in oil shale is associated with the kerogen, some hydrogen may be present in other forms, such as water.[17] Preliminary NMR measurements of Alabama shale have shown that the NMR signal is directly correlated with the amount of extractable oil as determined by the modified Fischer Assay method. In addition, the kerogen and non-kerogen constituents of the shale have been distinguished on the basis of hydrogen relaxation times. Some of the results are shown in Figure 7. Figure 7 shows the results of the resolved NMR signals, $M_o - M_{100msec.}$ and $M_o - M_{150msec.}$, as a function of the Fischer Assay of synthetic mixtures of kaolinite and high grade oil shale assaying 27 gallon/ton. In both cases a straight line relationship exists and both curves predict correctly the Fischer Assay of the tested sample to be 18 ± 0.2 gallon/ton.

The use of ESR as a tool to assist in better characterizing the Eastern oil shales also will be investigated. Electron spin resonance signals can be obtained from samples containing free radicals or paramagnetic ions. Preliminary ESR measurements at the University of Alabama have detected and measured signals from free radicals and manganese in Western shales, and from free radicals and vanadium in Alabama shale. It is thought that free radical determinations will assist in the identification of organic groups in the Eastern shales that are related to the conversion of kerogen to oil. In addition, the studies may demonstrate a relationship between the paramagnetic metals, free radicals and kerogen content of the shale.

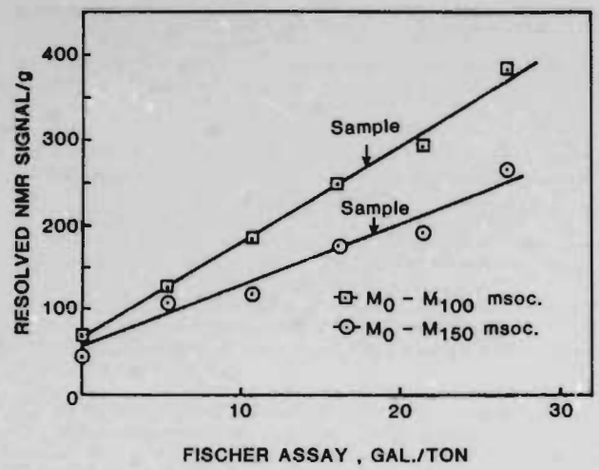

Figure 7. Correlation of Fischer Assay Oil Yield with NMR Response for Chattanooga Shale Sample

In support of the NMR and ESR research, X-ray diffraction and scanning electron microscopic (SEM) examinations will be made of samples of raw shale, beneficiated shale and spent shale to determine the mineralogical constituents present and to relate them to the behavior of the kerogen during retorting. Such studies may reveal details of the structural characteristics of the kerogen during thermal decomposition. The effect of preheating kerogen-bearing samples in the temperature range of 150 to 400°C also will be examined by NMR and ESR techniques to determine the hydrogen and free radical distribution resulting from the low temperature treatment.

Beneficiation and Retorting Research

The beneficiation and retorting research focuses on three major areas: (a) concentration of the oil and uranium into enriched products using standard beneficiation techniques followed by recovery of the oil from the upgraded products using conventional and/or developing extraction techniques, (b) development and evaluation of fluid-bed retorting of raw and beneficiated shale to recover liquid hydrocarbons followed by gasification of the char; and (c) low to moderate temperature and pressure extraction of oil from raw and beneficiated shale.

Physical Beneficiation

Physical beneficiation techniques have long been used on a large scale in the mineral and coal industry for obtaining enriched products from run-of-mine ore. These techniques normally involve crushing and grinding to liberate the ore for subsequent physical separation or concentration steps which rely on the differences in the physical and physico-chemical properties of the ore constituents.

Beneficiation of oil shale to recover kerogen-enriched products was proposed as early as 1920 by Dolbear who used flotation to recover up-graded products for characterization studies.[18] Later, the Bureau of Mines and others reported work on beneficiation of Western oil shales by flotation.[19] The primary purpose of the Bureau's concentration schemes also was to obtain materials for characterization studies. Subsequently, the potential benefits of up-grading Western oil shales was discussed and flotation was mentioned as part of a potential beneficiation scheme but details of the work were not presented.[20] In the above cited cases, the grade of products that might be obtained or the benefits that might be derived from beneficiating low grade oil shale such as the Eastern shales were not considered. From the information available, it can only be concluded that the beneficiation approaches used to treat the Western shales were not successful in producing substantially upgraded concentrates.

Tests by the Mineral Resources Institute have shown that enriched oil shale products can be recovered from Eastern oil shale by fine grinding and flotation. The tests are part of a broader study to determine the technical feasibility of concentrating oil shale and other carbonaceous and bituminous raw materials by physical methods. Results of preliminary tests on a Western shale, Eastern shale, and an Alabama tar sand are given in Table 4. The tests demonstrate that Alabama raw shale containing about 10 gallons per ton of oil, can be upgraded to a product containing about 18 gallons per ton by the flotation procedure. Recovery of the oil-bearing "kerogen" constituents in the upgraded product was over 95 percent. Almost one-half of the weight of the raw shale was rejected as essentially barren waste. As shown in the table, similar results were achieved with Western oil shale and Alabama tar sand samples. The process is described in a report (in preparation) which also presents an economic evaluation of a combined beneficiation/retorting process. In general, the process involves fine grinding followed by several flotation steps to recover the enriched concentrates. These tests are continuing.

The concentration of the fossil energy values by flotation prior to retorting and/or other innovative oil extraction processes and approaches has significant potential benefits. Rejecting almost 50 percent of the raw shale while recovering an enriched concentrate for further retorting treatment will eliminate a bulk quantity of barren mineral matter that otherwise would be retorted. This would serve to reduce the size of processing facilities required to recover a given quantity of oil and thus lower the energy requirements. Additionally, by employing flotation, the need to selectively mine certain oil-enriched shale seams separated by partings of barren rock would be minimized.

A comparison of the cost of retorting beneficiated and raw shale is shown in Table 5. The data on raw shale retorting is for a Kentucky shale using the Paraho-process as evaluated by Davy McKee.[22] As determined by Davy McKee, the return on equity for retorting raw shale yielding 12.5 gallons of oil per ton is about 12 percent for a stand alone venture at a selling price of $40.00 per barrel. By comparison, the return

Table 4. Flotation Concentration of Bituminous Materials

Alabama Oil Shale

Product	Weight Percent	Oil, gallons/ton Analysis*	Distribution
Concentrate	55.3	18.0	96.6
Waste	44.7	0.8	3.4
Total	100.0	10.3	100.0

*Method of Analysis: Modified Fischer Assay

Wyoming Oil Shale

Product	Weight Percent	Oil, gallons/ton Analysis*	Distribution
Concentrate	69.0	80.5	93.1
Waste	31.0	13.3	6.9
Total	100.0	59.7	100.0

*Method of Analysis: Modified Fischer Assay

Alabama Asphaltic Sandstone

Product	Weight Percent	Asphalt, gallons/ton Analysis*	Distribution
Concentrate	25.6	10.0	92.8
Waste	74.4	0.3	7.2
Total	100.0	2.8	100.0

*Method of Analysis: Solvation of Asphalt with Benzene

Table 5. Comparison of Costs of Retorting Raw and Beneficiated Shale (Dollars per Barrel)

	Direct Retorting of Raw Shale[21]	Beneficiation Followed by Retorting of Upgraded Products
Operating Cost Mining and Retorting	$23.51	14.37
Operating Cost - Beneficiation	-0-	12.14
By Product Credit	$(19.56)	(26.12)
Capital Cost	$12.07	9.16
	$16.02	9.55
Other Debt Service, Equipment Replacement, IRR**	$23.98	23.98
	$40.00	33.53

*Straight line depreciation of total initial capital required over 20 years.
**IRR (internal rate of return = 12% for Davy McKee's Process but higher IRR is expected for the MRI process.

These figures are subject to further adjustment.

on equity for beneficiating the raw shale followed by retorting of the upgraded product (18 to 20 gallons of oil per ton) appears to favor beneficiation followed by retorting of the upgraded product.

From an environmental point of view, beneficiation should markedly alleviate the shale waste disposal problem. Mineral wastes generating during physical beneficiation are no different in chemical composition than the mined material. Inasmuch as safe and environmentally acceptable systems have been developed for disposing of finely ground beneficiation plant wastes in impoundments, the adverse impact of disposing of about one-half of the oil shale mined should be decreased.

The beneficiation test results reported above are only indicative of what can be expected by flotation. Systematic studies on the flotation characteristics of several samples of Eastern and Western oil shale are now underway to determine the mesh of grind, reagent combinations, and general flotation conditions favoring maximum recovery of enriched oil shale concentrates having a higher oil content than shown in Table 5. Although the present investigations emphasize concentration of the oil shale by flotation, the application of other mineral processing techniques such as selective flocculation and oil agglomeration also are being investigated. Several of these, in combination with flotation, offer the means for recovering the kerogen in the shale in even higher-grade products than are obtained by simple flotation. The various products obtained are being evaluated to determine their oil yield as well as to ascertain other beneficial returns that might be expected by combining beneficiation with conventional retorting. Adequate quantities of beneficiated products also will be generated during this phase of the study for use in oil extraction tests discussed in the sections which follow.

The Fluidized-Bed Retorting

The objective of these studies is to determine various parameters favoring maximum oil and gas recovery from finely-ground raw and beneficiated shale and to determine the merits of fluid-bed processing as an alternative to conventional retorting approaches.

As already discussed, finely ground, kerogen-enriched concentrates can be produced from Eastern shale by beneficiation. Because of the finely divided state of the beneficiated products, they should have superior heat transfer properties and greater chemical activity during fluidized-bed retorting. The reactor provides ease of temperature control, good gas-solid contacting, high heat transfer and a high throughput capacity.

Fluidized-bed processing of oil shale is not new. In recent years a number of patents have been issued covering the use of the fluidized-bed reactor for processing oil shale by a combination of retorting and cracking to recover as much as 90 percent of the oil.[22-25] Most of these studies, however, have been focused on raw Western shales ranging from one-half inch to five inches in size. On the other hand, information on retorting of material as fine as the products obtained by beneficiating Eastern shale is lacking. The present research, therefore, is oriented towards ascertaining the fluid-bed retorting characteristics of the finely ground feeds produced from Alabama, Tennessee and Kentucky oil shales. For this purpose an externally heated batch-type reactor has been assembled and another semi-continuous laboratory unit is under construction. These units will be used for single retorting, and/or gasification, at different temperatures using preheated neutral or reducing gases such as methane, hydrogen, carbon dioxide, carbon monoxide and others as the fluidizing medium. This will be followed by two-stage retorting (under optimum conditions defined in the single-stage tests) to recover the readily available hydrocarbons and gases. Also, the residual carbon in the spent shale will be gasified to produce a low or medium Btu gas and additional liquid hydrocarbons. The composition and yield of the liquid and gaseous products obtained under the different retorting conditions will be determined and evaluated.

Extraction of Oil From Shale at Low to Moderate Temperatures and Pressures

Investigations in our laboratory on a potential process for extracting oil from Eastern oil shale at low to moderate temperatures and pressures have shown some promise. Numerous investigations have been made in the past to characterize oil shale and explain the kinetics and chemistry of pyrolysis.[26-28] Among the studies are those of Hill and Dougan who observed the behavior of oil shales at different temperatures and hypothisized the reactions taking place.[26] Their investigations suggested that at temperatures of 450°C to 620°C the kerogen in the shale is converted to bitumen and oil more rapidly than those products can escape from the oil shale particle pores in which they are formed. Consequently, these products are confined in the pores, where they are polymerized, only to be decomposed and later released as high molecular-weight hydrocarbons together with other gaseous products and chars. They theorized that the sequence of events was conversion of kerogen to bitumen, to polymers, to oil, to gas and char.

The reactions proposed by Hill and Dougan have suggested that, if the bitumen formation step can be controlled, the unpolymerized kerogen constituents in oil shale might be recovered by a simple dissolution step using organic solvents.[29,30] To demonstrate this, tests have been conducted using low temperature preheating of an Alabama shale with the objective of converting kerogen to bitumen. This step was followed by extracting the bitumen with benzene at a relatively low temperature under autoclave conditions. The results of preliminary tests using this approach are given in Table 6 which

Table 6. Solvent Extraction of Oil From Eastern Oil Shale

Preheat Step		Extraction Step				Oil Recovery
Temp. C°	Time Hr.	Solvent	Temp. C°	Pressure psi	Time Hr.	Gal/Ton
---	---	Benzene	250	360	1	4.4
300	0.5	Benzene	200	160	1	5.9
Fischer Assay						11.2

also shows the oil yield by the conventional Fischer Assay method. Although the oil recovery obtained by solvent extraction was only about 50 percent of that obtained by conventional retorting, the results appear promising enough to warrant a more detailed study of this novel approach to processing the Eastern shales.

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Corrosion Performance of Engineering Alloys in an Atmospheric Rotary Kiln Retort

by

Diane Spencer
Alberto Sagüés
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract. Corrosion test coupons of carbon steel, 410 stainless steel, and 304 stainless steel were exposed at two process points in an indirect heating, rotary auger retort which was processing eastern oil shale. The materials response was characterized by weight change determination, metallographic examination and elemental analysis of corrosion scales. Alloy performance improved with increasing alloy content. The highest corrosion rate observed was 84 mils per year for a carbon steel coupon exposed at a location with a temperature of 455°C. Examination of the corrosion scales revealed sulfidation and oxidation as the main deterioration mechanisms. The results are interpreted in terms of the environment surrounding the coupons and experiences in other retorting operations.

Introduction

Oil shale technology, though not a totally new concept, is emerging as a potentially viable source of energy. As in any new field, information on related materials problems is limited and, in the case of Kentucky shales, is practically nonexistent. Because of the corrosive nature of oil shales under process conditions, materials problems are certain to arise.

The development of oil shale technology has been concentrated in the areas of processing and resource characterization. As adequate processing options emerge from the research effort, technological feasibility becomes increasingly dependent on the availability of economically suitable materials for construction. Materials problems are recognized factors in the development of new fossil fuel technologies (1). The majority of these problems can be addressed successfully using the solutions developed in related, well established industries. However, materials problems unique to the new technology may appear for which no solutions are developed.

An example of that situation happened in direct coal liquefaction plants where severe corrosion incidents were encountered in the distillation area of those processes. It was determined that the corrosion was the result of synergistic effects between chloride, phenolic, and basic nitrogen compounds present in the coal liquids (2, 3). This is a problem with no direct parallel in the petrochemical field.

A second example is the solid particle erosion problems which occur while conveying slurries in coal liquefaction plants or while operating fluidized bed coal combustors (4). This has created the need for developing new materials to withstand these conditions since components currently available had short lifetimes (1).

Oil shale retorting poses different materials questions depending on whether direct heating (as in in-situ underground retorts) or indirect heating operations are considered. A number of underground materials performance experiences have been recorded (5, 6, 7) mostly in the form of control equipment (thermocouple) failures. The combustion area creates high temperatures and phenomena not unlike those encountered in coal gasification environments, including the formation of metal oxides and complex sulfides at the alloy-gas interface. Some data obtained by exposing corrosion coupons in a simulated in-situ retort have been reported (7). The total amount of information available to date in this area is still small. Data on materials performance in indirect heating retort operations are even more scarce. The maximum process temperatures in the indirect heating case are usually lower than those used in direct heating retorts. However, this by itself does not ensure fewer problems. For example, in the fluidized bed combustion of coal the temperatures encountered are lower than in traditional utility boilers, but because of thermodynamic and transport effects, corrosion mechanisms are active that were not in the high temperature case. Preliminary experiments in laboratory environments approaching those of indirect heating retorting conditions showed that sulfidation is an active mode of corrosion (8).

In addition to the retort itself, materials problems have been observed in the support operations downstream of the retort. An example of this is the waste water by-product from the above ground oil shale retort operated in Estonia by the

U.S.S.R. The corrosive action of the waste water was traced to the presence of carboxylic acids (9).

Because phenols, chlorides, and amines are generated during the retorting process, their combination downstream of the retort (for example, during distillation of the shale oil) may result in corrosion problems similar to those encountered in the coal liquefaction plants.

The Kentucky Center for Energy Research Laboratory (KCERL), operated by the Institute for Mining and Minerals Research (IMMR), is engaged in an extensive program to develop Kentucky oil shales as a significant factor in the energy picture. This involves a number of above-ground retorting processes. In light of the potential materials problems in oil shale processing, the IMMR has set up several materials research projects to identify problem areas early on and to develop feasible solutions. Long range goals involve understanding the mechanisms of material loss and the effect of process variables such as temperature and chemical composition. Short range projects have been established in order to address immediate problems in materials selection. Two bench scale retorts are being operated at the Institute: one a fixed bed retort, and the second a fluidized bed retort. Coupons are being exposed to these environments and examined afterward to identify specific forms of corrosion that may occur. In addition, the Institute has made several runs on a larger, indirectly heated rotary kiln retort approaching industrial conditions. Coupons were exposed during these runs, and the results are documented in this report.

Process Description

The metallurgical specimens were exposed in an indirectly heated two-stage rotary auger kiln retort. It consists of two inclining screw conveyors connected in series and two product condensers (Figure 1). A vapor draw off line connects each conveyor with a condenser. Burner heaters positioned along the lengths of the conveyors raise the temperature of the shale and drive off the shale oil vapors. Saturated steam is injected at the entrance of each conveyor cocurrent to the process flow in order to displace oxygen from the system.

For the sake of brevity, the equipment associated with the first stage of the process (coldside) will be denoted with the postscript A, and for the second stage (hotside) postscript B will be used.

The shale feed hopper is located at the lower end of conveyor A. Conveyors A and B are roughly 3.5 meters long each, and 0.3 meters in diameter. The shale is heated to retort temperatures as it is slowly transported up the conveyor at approximately 4 mm per second. The vapor is condensed in a 0.15 m double-pipe condenser The shale is pushed to the apex of conveyor A and drops into conveyor B by gravity. The second vapor draw point is located at the apex of conveyor B. The second condenser is a 0.2 m double-pipe heat exchanger. The spent shale is discharged through a lock hopper into a receptacle for storage or disposal. The condensed vapors from each exchanger are combined and the water separated out, yielding the end product, shale oil. The noncondensables are emitted out the stack. During the period when the corrosion monitoring coupons were in place, the retort was run for several tests, processing a total of 5070 kilograms of shale. Sources of the feed shale and amounts used in these tests are given in Table 1. The retort was on stream for a total of 46 hours for conveyor A and 42 hours for conveyor B. The average processing rate was approximately 110 kg of shale per hour.

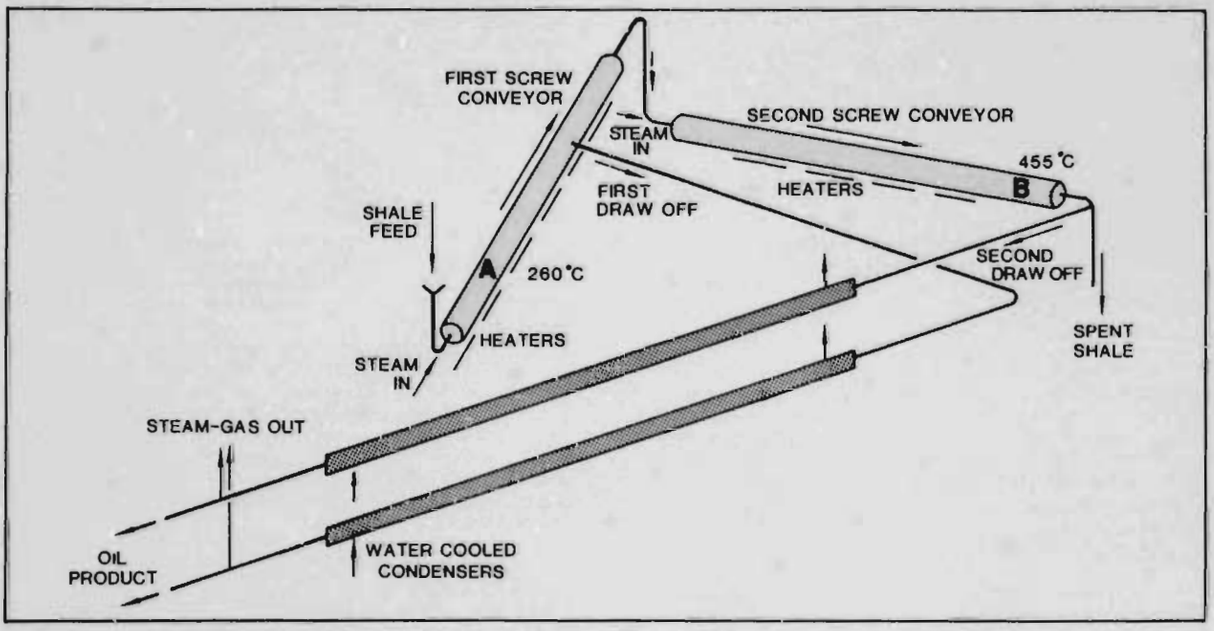


Figure 1. Schematic of the two stage rotary auger kiln retort. A, B approximate the locations of each coupon rack.

Table 1. Shales Used in the Retort Experimental Runs With Corrosion Test Coupons in Place

Shale	kg. Shale
Sunbury Shale Lewis Co., KY	670
New Albany Shale Powell Co., KY	560
Cleveland Shale Lewis Co., KY	590
New Albany Shale Bullitt Co., KY	620
New Albany Shale Lincoln Co., KY	890
New Albany Shale Nelson Co., KY	690
Chattanooga Shale Russell Co., KY	1050
Total	5070 kg.

Other aspects of this process are described elsewhere in this conference proceedings (11).

Experimental

Two racks containing three coupons each, 304 stainless steel (SS), 410 SS, and 1050 carbon steel (CS) were built and mounted in the retort. Rack A was positioned 1.1 meter from the shale feed hopper, rack B was located directly in front of the vapor draw off point at the end of the second conveyor (Figure 1). The nominal temperature at rack A was 260°C and was 455°C (close to the highest process temperature) at rack B.

Since a plugged coupling was available at both locations, plugs were used as a convenient support for the racks. The lengths of the stems holding the racks were adjusted to avoid interference with the screw feeder operation and yet adequately expose the coupons to the process environment. The coupon racks were simple structures consisting of a short length of 308 SS welding rod for support with a bend at the tip to retain the coupons. Coupons were oriented parallel to each other and parallel to the process fluid flow. The coupons were squares, 12 mm on the side, with holes drilled through the center of the flat face to string them on the support. The squares were cut out of 3.2 mm sheet stock of each alloy; surface preparation consisted of light glass bead blasting. The alloy compositions were within the limits of their respective AISI designations.

Ceramic inserts, 5 mm OD, 3 mm long served as spacers between the coupons. The function of the spacers is to separate the coupons and allow for exposure to the process stream on both faces. No electrical insulation was provided between the support rod and the coupons since galvanic corrosion was not expected to play an important role in the vapor spaces sampled. The base of the support rod was welded to the plug, allowing for easy insertion and extraction of the assembly.

Materials were positioned with the 304 SS coupon closest to the screw, 410 SS in the middle, and the 1050 CS closest to the plug.

Results

The coupon racks were extracted shortly after the end of exposure to the process conditions described earlier. At the time of retrieval, the coupons on rack A (260°C) were no longer suspended near the tip of the support rod, but were instead pushed closer to the plug end. The tip of that support rod was covered by fouling deposits. In addition, both ceramic spacers on rack A broke during exposure, allowing the coupons to be closer together. Rack B (455°C) did not experience any significant mechanical damage, and its coupons were thus exposed more evenly to the process stream. The as-retrieved appearance of both racks is shown in Figure 2.

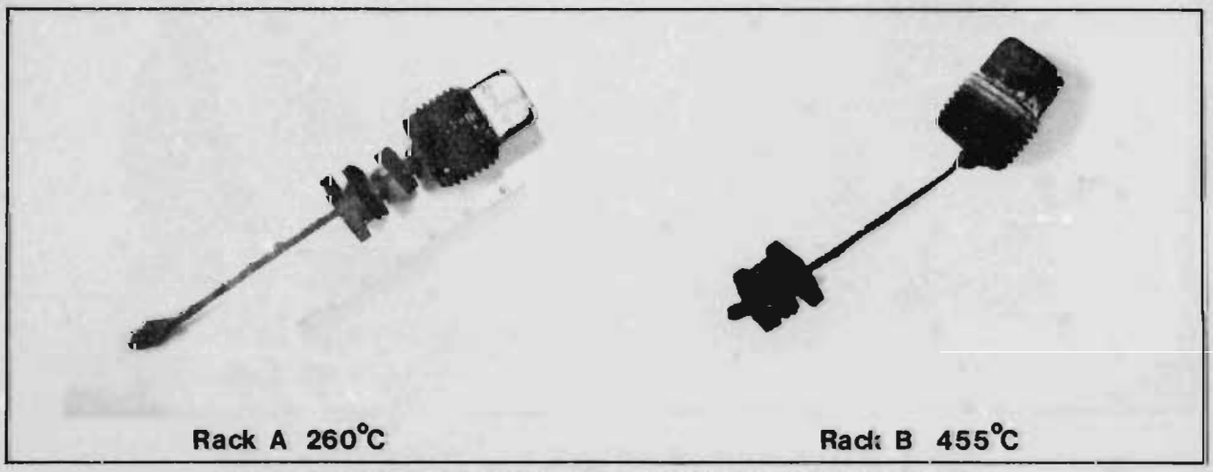


Figure 2. Exposed coupon racks after retrieval from the shale retort.

The racks were disassembled and the soot deposits removed from the coupons by lightly brushing and cleaning in methanol. Figures 3 and 4 show the appearance of the individual coupons after exposure. The coupons removed from rack B (455°C) were darker than those from rack A (260°C). Also, for all coupons, the front face (closest to the process stream) was smoother and had thinner adherent deposits than the back face (closer to the plug support). The carbon steel coupon from rack B (CSB) showed blisters on the scale on both surfaces, whereas the carbon steel coupon from rack A (CSA) showed no blisters and much less surface effects. The surface of the 410

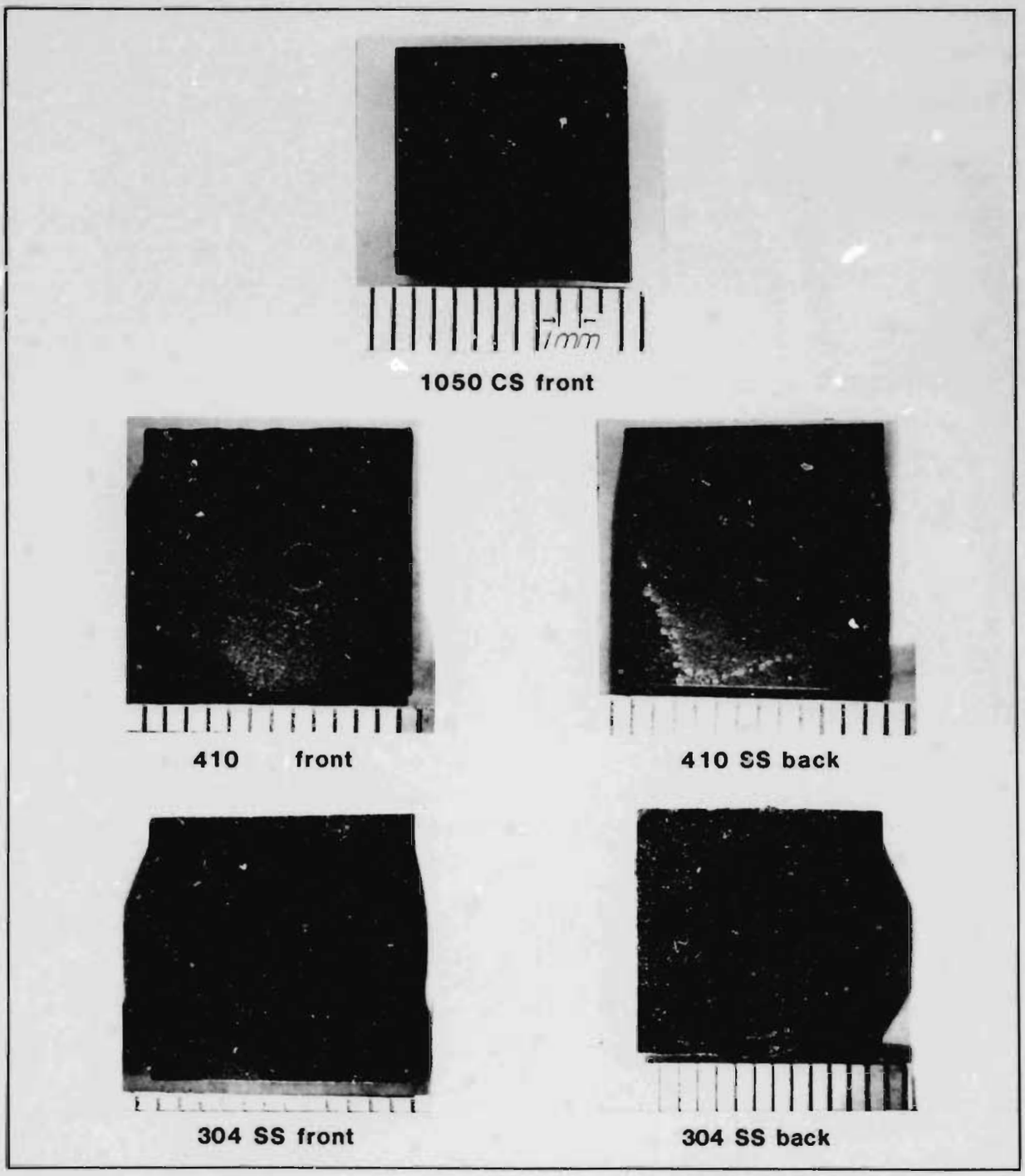


Figure 3. Appearance of coupons after their exposure at location A for a period of 46 hours at approximately 260°C. Both sides of the 1050 CS coupon presented similar appearance.

coupon from rack B (410B) was rougher than that of its counterpart from rack A (410A). Intermittent small patches of deposit remained adhered to the surface of 410A.

Features of the faces of the 304 coupons were unique when compared to those of the other coupons. The front of the 304 coupons from rack B (304B) has patches of deposits adhered to its surface. The back face had rough, thick deposits on most of its surface. In the case of the 304 coupon for rack A (304A), the back surface was covered by a tar-like, dark, and very shiny deposit. The front of 304A was considerably more smooth.

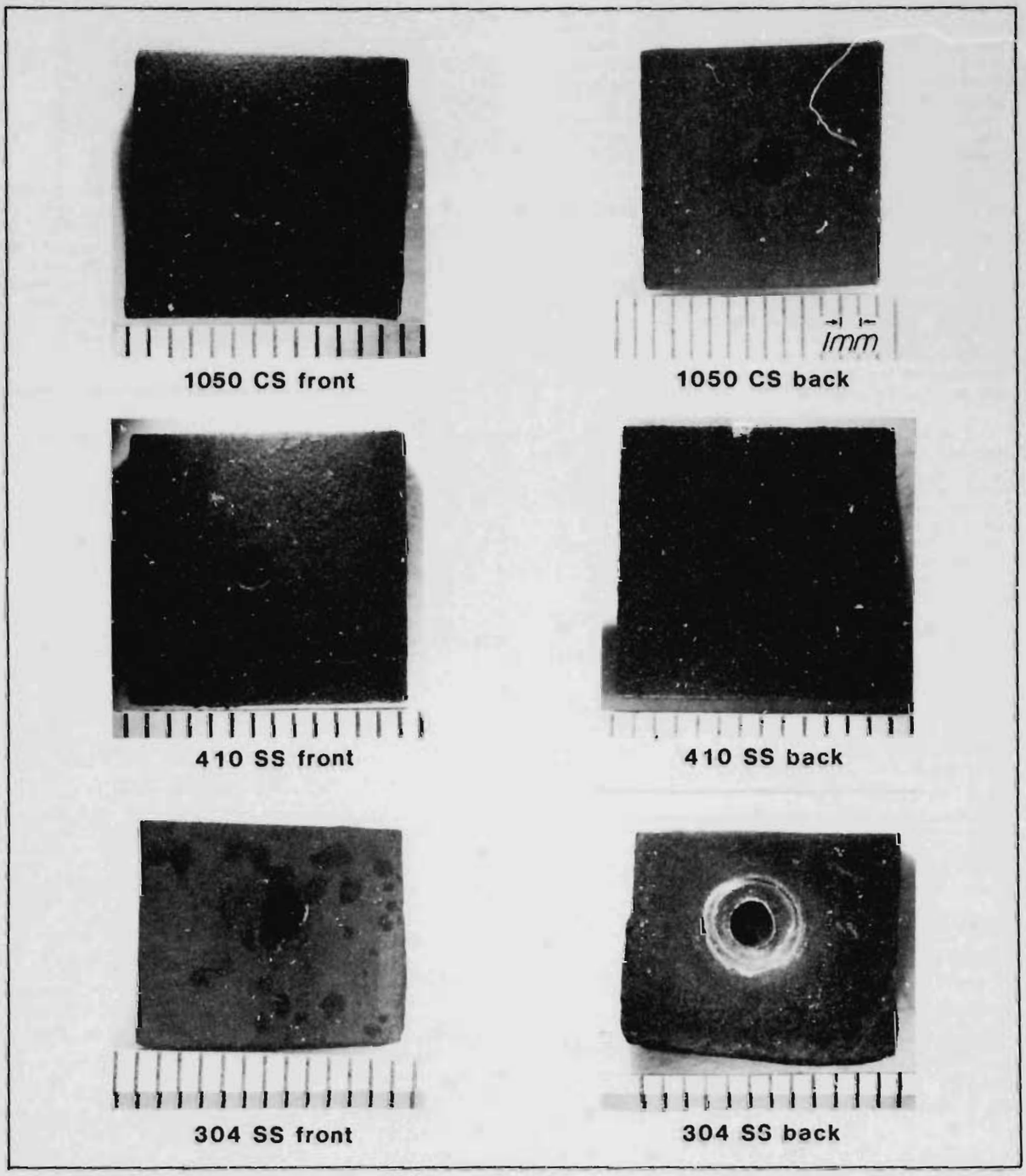


Figure 4. Appearance of coupons after their exposure at location B for a period of 42 hours at approximately 455°C.

The coupons were then evaluated for weight loss of base metal in order to establish average corrosion rates for the exposure period. This was done by cleaning the coupon of deposits and corrosion scale and comparing the weight of the cleaned coupon with its weight before exposure to the retorting environment. The cleaning was by means of light glass bead blasting, which removes brittle deposits and scales while leaving the sound base metal virtually unaffected. Part of the coupon surface was masked during blasting in order to preserve a portion of the scale and deposits for microscopic examination. The weight of scale or deposits unremoved because of masking was estimated by careful weighing before and after blasting, and prorating on the basis of the extent of masked areas. An equivalent cleaned weight of the coupon was then obtained for the corrosion rate calculations. This method has been used successfully in other corrosion monitoring investigations (10).

Table 2 shows the average corrosion rates, expressed in thousandths of an inch per year (mpy) (one thousandth of an inch = 25.4 μm), evaluated from the weight loss measurements. Since the actual total exposure time was less than 50 hours, these corrosion rates should be interpreted only as representing relative trends of material behavior in lieu of long-time exposure data.

In both rack locations, the order of alloy ranking from best to worst was 304 SS, 410 SS, and 1050 CS. These results correlate well with the total alloying content. At location A the average corrosion rate for carbon steel was 36 mpy, and both 410 SS and 304 SS corroded at less than 1 mpy each. The carbon steel exposed at location B degraded at a rate of 84 mpy, which was the highest corrosion rate amongst the six coupons tested. The 410 SS at location B corroded at a rate of 38 mpy, which was less than half that of carbon steel. As in the case of location A, the 304 stainless at B corroded at a rate less than 1 mpy.

Metallographic sections of the unblasted portion of the coupons were prepared. All coupons presented surface deposits in the form of adhered solidified organics and ash, but only three, CSA, CSB, and 410 B, developed a corrosion scale on the metal thick enough to be examined metallographically. Those three coupons had also shown a measurable weight loss as a result of their exposure in the shale retort. The metallographic sections were further examined with a scanning electron microscope (SEM), provided with X-ray energy dispersive and wavelength elemental analyzers. This allowed for the identification of the constituents in the layers of scale.

Figures 5 to 7 show unetched metallographic cross sections of the deposits and scales and the energy dispersive X-ray spectra for coupons CSA, CSB, and 410 B. A schematic has also been included in order to identify the specific scale locations referenced in the energy dispersive spectra.

Four layered zones appear to be present in the scale on CSA. These are labeled A, B, C, and D, where A is closest to the base metal. All four zones were rich in iron and sulfur with only minor peaks for other elements. The ratio of the X-ray spectrum peak heights for sulfur and iron was used in qualitively comparing the compositions of the various zones. The results are summarized in Table 3 together with the typical thickness of each zone.

Table 2. Average Corrosion Rates of Coupons

Location A 260°C		Location B 455°C	
Coupon	mpy*	Coupon	mpy*
1050 CS	36	1050 CS	84
410 SS	<1	410 SS	38
304 SS	<1	304 SS	<1

* 1 mpy equals 25.4 μm per year.

Table 3. Composition of Scale - CSA Coupon

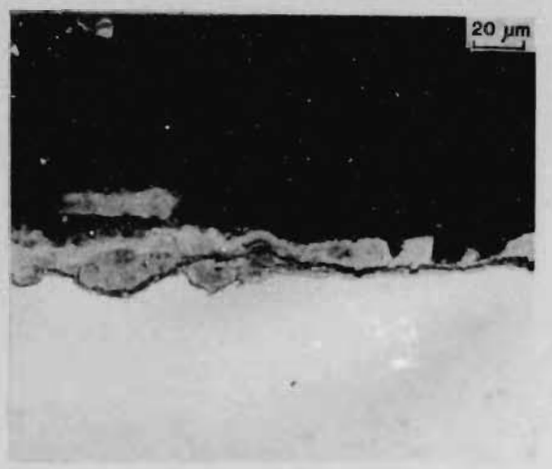
Zone	S/Fe Peak Ratio	Typical Thickness μm
A	0.55	14
B	1.83	8
C	2.06	6
D	1.96	10

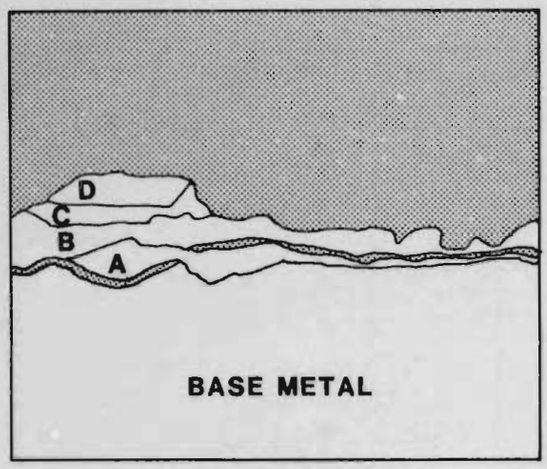
Similarly, four zones were also identified on the surface of CSB. The S/Fe peak ratio and thickness of zones are listed in Table 4.

In both carbon steel coupons, the inner scale had the lowest sulfur/iron peak ratios relative to the other three scales present. The peak ratios

Table 4. Composition of Scale - CSB Coupon

Zone	S/Fe Peak Ratio	Typical Thickness μm
A	0.94	20
B	1.64	30
C	1.64	40
D	1.54	46





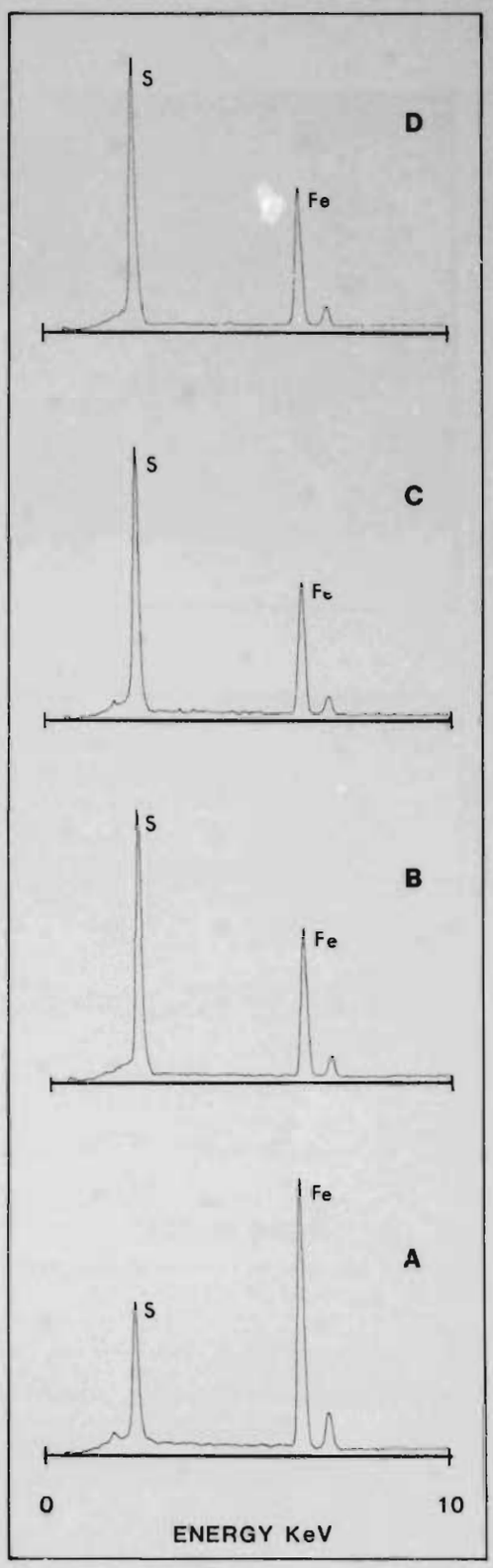
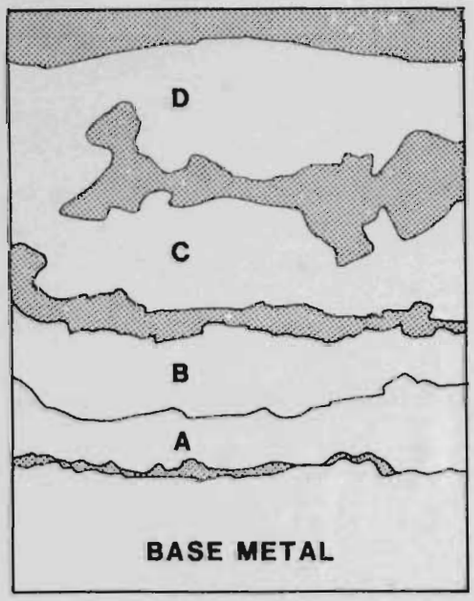


Figure 5. Micrograph (top left), schematic of scale zones (lower left), and X-ray energy dispersive spectra (right) of a cross section near the surface of the 1050 CS A specimen, which was exposed at 260°C for approximately 46 hours. The height of the peaks represents a relative estimate of the concentration of specific elements at the point being analyzed.



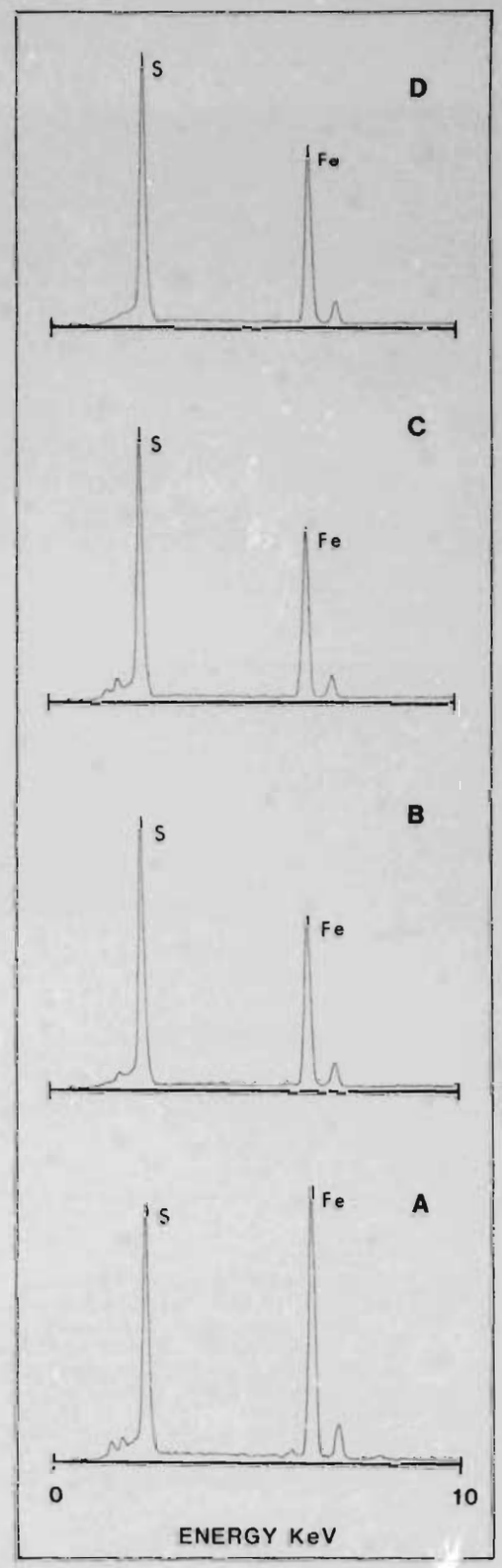
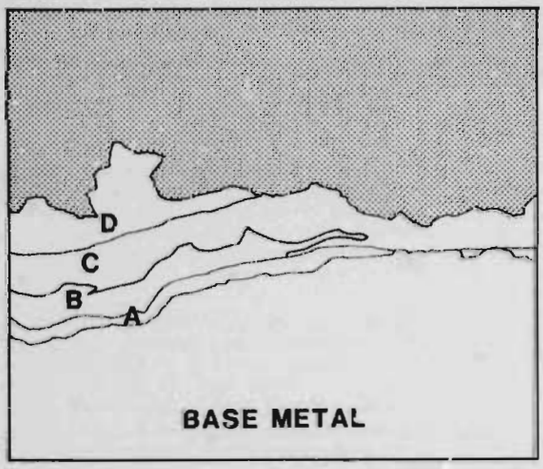


Figure 6. Micrograph (top left), schematic of scale zones (lower left), and X-ray spectra (right) of the 1050 CS B specimen, which was exposed at 455°C for approximately 42 hours.



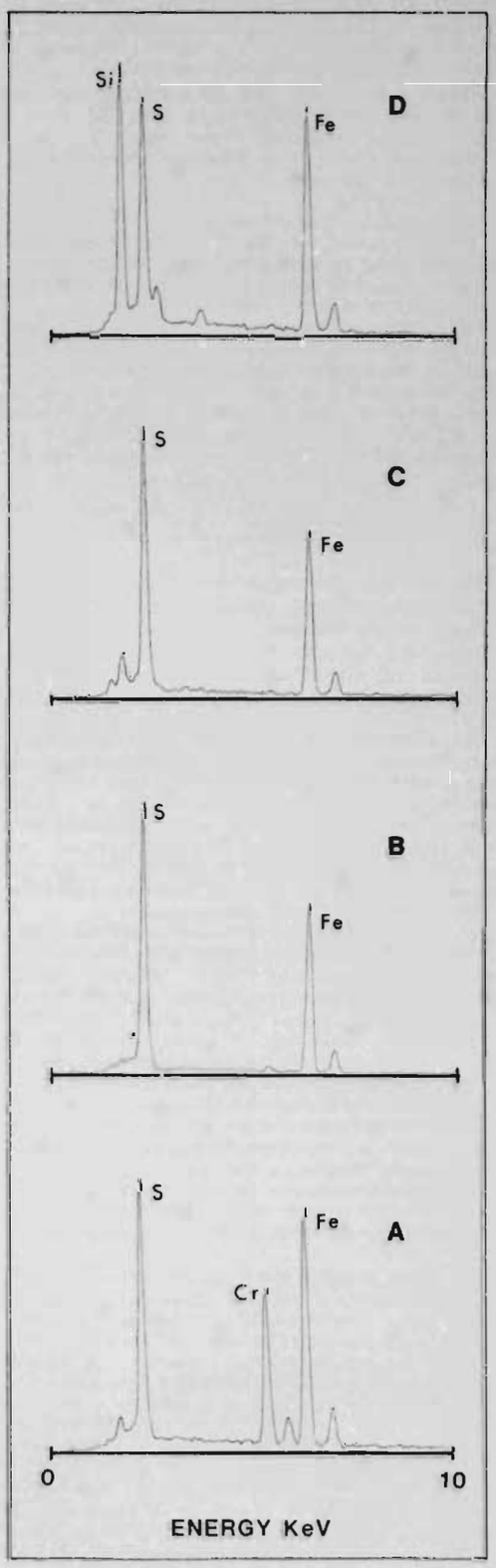


Figure 7. Micrograph (top left), schematic of scale zones (lower left), and X-ray spectra (right) of the 410 stainless steel B specimen, which was exposed at 455°C for approximately 42 hours.

for these remaining layers of scale were not significantly different from each other. It seems likely that in the carbon steel coupons, layers B, C, and D are actually a single layer with minor compositional or morphological variations. Upon qualitatively analyzing both carbon steel specimen scales for the presence of oxygen with the wavelength elemental analyzer, it was found that in each case zone A was clearly oxygen rich relative to the rest of the scale.

Four zones were apparent on the 410 B scale. These zones, unlike the carbon steel specimens, contained chromium, silicon, and smaller amounts of chlorine and calcium. The chromium is a constituent of 410 SS, and its presence was observed in the innermost zone only. Silicon was present in all four zones and is especially pronounced in the outermost zone, which also contained the chlorine and calcium. The presence of silicon, chlorine, and calcium is probably related to the mineral content of the shale. The S/Fe peak ratios and depth of scales for sample 410 B are given in Table 5.

Discussion

The surface appearance of the exposed coupons is typical of components immersed in high temperature hydrocarbon streams. Most of the macroscopic surface features are solidified organic and ash and are not directly related to corrosion products.

The corrosion rates measured show commonly observed trends: the severity of the corrosion increases with temperature and decreases with increasing alloy content. As indicated earlier in the paper, the corrosion rate values reported here are the result of a relatively short exposure, and the values in mpy represent an extrapolation. Moreover, the small coupon size and rack positioning limitations introduce uncertainties typical of coupon exposures in the field. Nonetheless, the reported rates can be contrasted with the 20 mpy acceptable limit commonly used in industry. That comparison would suggest the future use of 304 SS at the 455°C point and of 304 SS or 410 SS at the 260°C location. Some form of protection (such as refractory lining) would be recommended if the other material(s) were chosen for each location and long-term operations were intended. The metallographic cross-sections of the exposed coupons did not reveal internal deterioration or other microstructural damage of the alloys studied. These observations should be supplemented with future investigations of the effect of exposure on the mechanical properties of the alloys tested.

The environment present at the material test points consists mostly of the gases emitted by the retorted shale combined with the sparging steam. An analysis of the gases present in this particular retort is not available. However, an idea of the gas composition can be obtained from the results of laboratory retorting experiments by Coburn (12) using a Sunbury Shale representative of the feedstock of the rotary kiln in this test. The analysis of constituents of the shale used in those experiments is given in Table 6. The shale was indirectly heated at a rate of 4°C per minute and the gases evolved were examined with an on-line mass spectrometer. At those heating rates gas evolution reaches a peak at approximately 430°C. Near that peak the molar ratio of evolved H_2S to H_2 was within an order of magnitude of unity. Water was also evolved but its relative amount was not measured in those experiments. However, the amount of water vapor evolved was estimated as being comparable to that of H_2. In the rotary kiln retort, the presence of steam is likely to have brought the water partial pressure to a much higher value, for example an order of magnitude higher than that of H_2.

Based on the above estimates and assuming simple H_2S-H_2-S_2 and H_2O-H_2-O_2 equilibria, a region of likely environmental conditions can be shaded in the phase stability diagram for the system Fe-S-O. This has been done in Figure 8 for a simplified diagram calculated for 455°C(13). The shaded region falls mostly within the iron sulfide fields and matches the experimental observation of an iron-sulfur-rich corrosion scale on the carbon steel coupons. The position of the shaded region is not incompatible with a corrosion path resulting also in the formation of an oxide layer nearer to the metal. The inner scales on the carbon steel coupon are oxygen-rich relative to the rest and may represent an approach to conditions created by such a corrosion path.

At 455°C (and more so at 260°C) both corrosion and gas reactions may be sluggish and the application of the phase stability diagram can be limited. In addition, many of the features in the corrosion scales could be the result of on-stream changes of the process parameters instead of steady-state thermodynamic effects. Because of these limitations, the makeup

Table 5. Composition of Scale - 410 B Coupon

Zone	Peak Ratio S/Fe	Typical Thickness μm
A	1.11	6
B	1.57	11
C	1.57	20
D	1.02	20

Table 6. Analysis of Sunbury Shale Used in Gas Evolution Experiments (Reference 11)

Constituent	Weight Percent
Total N	0.27
Total C	13.60
Total H	1.64
Total S	3.24
Total Ash	77.14
Acid CO_2	0.06

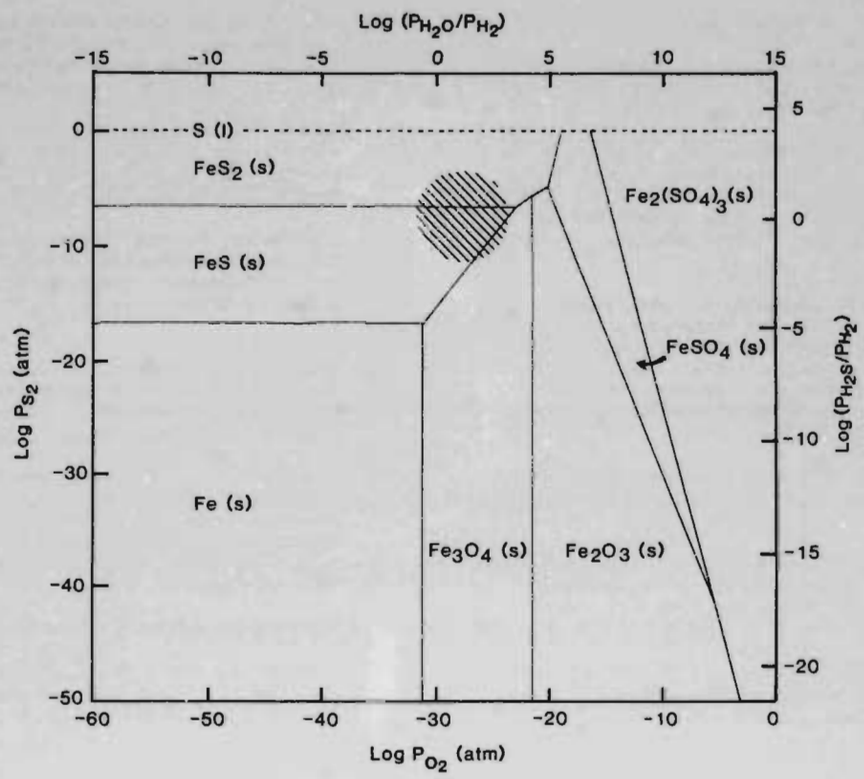


Figure 8. Simplified Fe-S-O phase stability diagram, calculated for 455°C. The shaded region represents an estimate of the environment present at the test point B. (s): solid phase (l): liquid phase.

of scales that are more complex (as in 410 B) or formed at the lower temperature cannot be adequately interpreted at this time. Laboratory experiments under controlled conditions are presently being conducted to answer some of these questions.

The materials deterioration observed in this study appears to be much less severe than that observed in in-situ or modified in-situ retorting environments (5, 6, 7). Estimates of a simulated in-situ retorting environment composition place it also in the metal sulfidation region (5). The much higher peak temperatures reached there (typically 1000°C) would account for faster reactions and transport, hence resulting in greater corrosion rates. In view of the present results, there is no evidence of a corrosion trend reversal with increasing temperature.

The results reported here represent an attempt to begin building a data base for materials selection in the construction of indirectly heated retorts processing eastern shales. It is hoped that other investigators will be encouraged to conduct additional studies in this area.

Conclusions

1. Alloy performance improved with increasing alloy content. At both the 260°C and the 455°C locations, the 304 SS coupons showed no measurable weight loss during the testing period.

2. Both CS and 410 SS showed measurable corrosion rates that were greater at the higher temperature location. The highest corrosion rate measured was 84 mpy for carbon steel at the 455°C location.

3. Most deposits on the coupon surfaces were solidified process substances. Corrosion scales on the CS and 410 SS coupons point to sulfidation as the main mode of material loss, with some indication of oxidation predominating near the metal surface. The sulfidation of iron is also predicted by estimates of the coupon environment at 455°C and thermodynamic data.

4. The severity of corrosion appears to be much less than observed in similar studies in direct heating retorting environments.

Acknowledgments

We wish to thank Pyramid Minerals Corporation for this opportunity to expose coupon racks in an operating shale retort. We also thank T. Coburn and B. Davis for helpful discussions on environments in shale retorts. R. J. DeAngelis computed the Fe-S-O phase stability diagram. R. Furman prepared the racks and metallographic samples and G. Estes performed SEM examinations.

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Tuesday Morning Session

SOCIO-ECONOMIC AND ENVIRONMENTAL STUDIES

The U.S. Department of Energy's Oil Shale Environmental Mitigation Program

by

Arthur M. Hartstein
Office of Oil, Gas, and Shale
Office of Fossil Energy
U.S. Department of Energy

Ralph E. Franklin
Office of Health and Environmental Research
Office of Energy Research
U.S. Department of Energy

Abstract. The largest untapped fossil fuel resource in the United States is the oil bearing shales in the western part of the country and the black shales in the east. The oil shale resource concentrated in three western states is estimated to be equivalent to more than two trillion barrels of crude oil and a comparable amount in the lean deposits of the Eastern U.S.

The Department of Energy (DOE) has established a research and development (R&D) program for encouraging the development of the country's oil shale resource at a commercial scale to help in the mitigation of the present and future energy demands. The aim of the R&D Program is to stimulate the commercial production of oil shale by eliminating technical and environmental barriers. This paper provides an overview of the DOE R&D Program, addressing its essential environmental elements. Particular emphasis is given to the Department's internal planning process.

Introduction

The Department of Energy completed an Oil Shale Management Plan for its research and development program about two years ago. The Plan has undergone several revisions, and although it is still in the draft stage, it provides a basis for program development and has served to establish research priorities. This Plan is unique in that it integrates research activities that are conducted by two program offices supporting research dealing with oil shale.

Organization

Research in the Department has been supported by two principal components; the Office of Health and Environmental Research which resides in the Office of Energy Research, and the Oil Shale Division which resides in the Office of Fossil Energy.

Prior to development of the program plan and the implementation of a unified approach, oil shale research in the Department followed a more or less traditional pattern. That is, the environmental scientists determined potential problems associated with oil shale development, but stopped short of dealing with ways to eliminate these hazards. On the other hand, process development researchers, investigated the retorting process, studied the physics and chemistry of shale and its rock fragmentation properties. However, research on environmental control development or testing of conventional controls was not within the scope of governmental sponsored research, nor to our knowledge was it part of the emerging oil shale industry's approach. In fact, to some extent, there were rewards for each side for either showing how bad the problems were or for being able to prove that the problems did not exist. Surprisingly, in spite of all the process development research carried out to date, there is no actual performance data available for any emission control devices with any pilot or larger size oil shale retort.

A major contribution of the joint Program Plan was the unification of the research of the environmental scientists and the process development engineers with the establishment of a common set of objectives. In the Plan, they were referred to as "deliverables" and included:

- an environmentally acceptable emission control strategy
- development of systems for treatment and disposal of contaminated process waters
- sound spent shale management systems
- guidelines to ensure the health and

safety of workers and the general public

- o documentation of regional ecological impacts
- o method for control of subsidence and socioeconomic impacts.

The overall environmental goal is to focus the research on finding solutions to the various problems and to document the real consequences of oil shale operations.

The specific objectives of the oil shale R&D program are:

1. Develop a sound technology base to assist in second generation activities of industry
2. Develop new unique technologies characterized by reduced environmental impact and increased thermal efficiency
3. Develop improved environmental data; demonstrate and/or develop environmental control technology

Every innovative process that is developed must satisfy four basic requirements. First, it must protect the health and safety of the worker and the general public. Second, it must be environmentally acceptable in terms of protection of air, water, land, and environmental systems. Third, it must be economic. Fourth, it must conserve the resource.

What is the Environmental Research Strategy?

The strategy followed by the oil shale program is given in Figure 1. The research process starts with a problem definition. This can take place in a variety of ways. In the most simple sense, from interviews with knowledgeable people. In the case of oil shale, the basic problems are reasonably well-defined and have been the subject of considerable public debate for some time. They are the familiar issues associated with air pollution, water contamination, solid waste disposal, etc. The information assembled by the data base comes from experimental studies conducted both in the field and in the laboratory and from monitoring data from field operations. This information is organized and assembled via a risk analysis step. The purpose of this analysis is to bring to bear appropriate environmental models of transport and pollutants in the environment, models for damage functions to both people and other organisms, and to ask questions as to the significance of the release of various residuals (what are the significant consequences, what will be the real cost in terms of human health and environmental damages). The primary function of this step is to organize the data and the facts so that those who need to make judgements about the environmental acceptability of oil shale processes have the benefit of a set of well-organized facts and figures. Based on these judgements, guidance can then be provided for the third principal step of control development or the development of procedures for mitigating and minimizing the environmental impacts. In simple terms, this process leads from problem definition to analysis to problem solution or to documentation that a problem is not of sufficient significance to warrant concern.

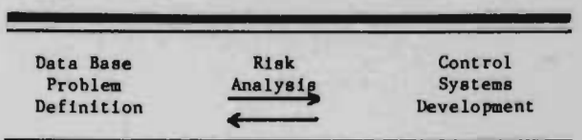

Figure 1. What is the Environmental Strategy?

How is the Work Done?

The research activities include both generic as well as research that is specific to a series or a subclass of processes. Work that is generic is generally applicable to any or all processes as a result of commonalities such as in mining and the treatment of various residuals in waste water. Other activities are specific to a class of processes because of unique characteristics of one class compared to another, such as indirect versus direct heating modes of operation or the fact that some processes produce spent shale of certain physical and chemical characteristics. The initial research is based on general concepts and models of how processes work and how that relates to particular characteristics of the waste products or the way in which the technology interfaces with the environment. For example, in the case of spent shale we know that its characteristics when placed within a large, compact pile will vary somewhat depending upon maximum temperature that was achieved within the retort, generally whether the retort environment tended to be oxidative or reducing in its character, the particle size distribution of the retorted shale, the amount of residual carbon, the water holding capacity, the compaction density of the material, and so forth. Research is then conducted that relates to specific studies in order to confirm various models that relate environmental behavior to characteristics of the process. Such validation is essential in order to confirm and gain confidence in the solutions to the various environmental problems. Some of the research is carried out in the laboratory, while other activities are implemented in the field at operational sites or study sites. Both are important towards development of the data base and evaluating the performance of controlled systems. The laboratory work is essential in order to achieve appropriate control over many of the experimental variables that are known to be important. It is also important to isolate the effect of one variable on another, which is usually impossible to do at operational sites. The field research also plays important roles in allowing confirmation of laboratory findings under real world conditions and permits the evaluation of the interaction of a number of variables which cannot be simulated in the laboratory. Figure 2 shows how various operational sites have been utilized to carry out research in specific areas. For example, the Paraho operation at Anvil Points has been used to conduct research activities related to water management and solid waste disposal.

	Paraho	Oxy (Logan Wash)	Rio Blanco (CA)	Geokinetics
Water	X	X		
Solid Waste	X			
Air		X	X	
Health & Safety		X		X

Figure 2. Examples of Process Specific Studies

Discussion of the Research Issues

Solid Waste

What are the Major Problems with Solid Waste Management? The most obvious problem in waste management is the tremendous amount of spent shale to be disposed of. At an average yield of 30 gallons/ton, a 50,000 barrel per day oil shale facility will generate about 65,000 tons/day of spent shale. The question is how is this material to be isolated and stabilized so that (1) the surface of the pile is resistant to wind and water erosion and, therefore, is not a chronic source of pollution to surface waters or the landscape, and (2) no leaching of soluble salts into groundwater systems occurs. Numerous studies have been conducted with small quantities of spent shale in plots ranging from a foot to several feet in thickness. However, no experiments or demonstrations have been conducted on a pile which would be comparable to that developed for a commercial scale facility. Here we are talking about piles that cover many acres and may be as thick as a thousand feet. The principal problem arises as a result of soluble salts which are contained in the spent shale. There is potential for these soluble salts to migrate to the surface and, as a result of this salinization, prevent vegetation from becoming established. In the absence of a stable plant community, the surface remains vulnerable to wind and water erosion. Another problem is that the soluble salts may in fact leach to the bottom of the pile and contaminate groundwater. There are many factors which affect the hydrological and salt flux within a shale pile. Some of these are particle size density, compaction density, the amount of water used in cooling and compacting the pile, the depth of plant root penetration, evapotranspiration rates, the amount of infiltration of precipitation into the pile, and mineralization reactions which alter the solubility of the salts initially present in the spent shale. Thus, it is uncertain as to which direction water and salts will migrate in a commercial scale solid waste pile and how stable will the ecological communities be which are established on the landscape. These then remain the significant factors and the subject of experimental studies currently being conducted.

What is the Solid Waste Strategy? For surface disposal of wastes, the strategy is to stabilize the surface using some form of plant ecological community to reduce leaching as a result of precipitation, to reduce erosion as a result of wind, and to provide for physical stability of the pile. With regard to underground disposal, such as would be applicable to in situ retorting and underground mining with surface retorting, the strategy is to isolate the waste from groundwater intrusion and to minimize subsidence.

Water

What are the Major Problems with Water? The problems associated with water may be categorized into availability and contamination. Water availability is the key factor in the western U.S. On the other hand water for operations can be supplied in a variety of ways. For example, water can be obtained through (1) development of impoundments to increase utilization and effectiveness of precipitation which falls on the area; (2) modifying the process, i.e., the development of improved technological processes which are more water conservative or more water efficient; (3) increasing the utilization of groundwater (it is known that considerable amounts of groundwater exist but there is much uncertainty in terms of its distribution and local availability), and (4) import water from other river basins. However, there are legal and technical uncertainties with each of these with the exception of the process variability, and there are technical uncertainties so that it remains to be seen how viable these options are in fact.

The size of an industry that can be supported with regard to various assumptions made on water availability is shown in Table 1. An eight million barrel/day production would require importation of water from other river basins. The other estimates are based on utilization of water from within the region but vary according to assumptions that are made with regard to current water use, projected use, and maintenance of stream flow requirements. The Colorado estimate is the most conservative and expresses the concerns within the state for competitive uses (e.g., agriculture) in a water scarce region.

Table 1. Water Availability

Assumptions

- o Import water
- o Building impoundments
- o Process variability
- o Uncertainty of region hydrology
- o Legal uncertainties

There are three principle concerns with respect to contaminated water. They include groundwater contamination from abandoned in situ retorting operations, the clean-up process water, and the disposal of mine water. The Department's research and development program focuses on this aspect of the water question.

What is the Water Clean-up Strategy? There are two general uses for contaminated water. It may be reused in the process or it may be used for environmental controls. Water used in the process, such as to generate steam for retorting, must be cleaned to meet specifications of the equipment, e.g., boilers. We do not think that this use has environmental implications. Water used in environmental controls or where dispersal in the environment is likely, such as

for irrigation, must be cleaned to meet environmental specifications or agricultural criteria. When contaminated process water is used to moisturize spent shale or irrigate waste piles, the principal concern is with runoff from the waste pile, contamination of surface streams, and the biological accumulation of residuals by plants growing in it.

Air

What are the Major Problems with Air? We assume that any development which takes place will comply with the ambient air quality standards. Problems arise, however, because of the uncertainty in predicting characteristics of the meteorology of the region. Principally, the uncertainty exists with regard to the transport and dispersion of pollutants emitted at a given point within the region. Current models for predicting transport and dispersion within complex terrain are acknowledged to be grossly in error and, therefore, uncertainty remains as to the effect of locating an industrial activity within the region on adjacent sensitive areas such as national parks and forests. Another major uncertainty exists with regard to the performance of even conventional emission control equipment. Since no demonstrations have been conducted to date of any of the emission control devices on a demonstration or commercial size unit, uncertainty remains as to the effectiveness of these systems and whether or not they will perform as well with oil shale systems as they do in other industrial applications. Problems could arise as a result of the interference of chemical substances in emission streams with the performance of various cleanup devices. Other weaknesses in our knowledge of the air quality problem stem from insufficient knowledge of the chemical speciation of sulphur compounds in fuel gas and the presence of toxic components in gaseous emissions. The overall emission control strategy is shown in Figure 3.

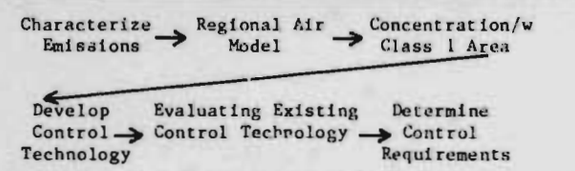

Figure 3. Air Strategy

Health and Safety

What are the Major Problems with Health and Safety? First, let us consider the case of underground mining with aboveground retorting. The principal problems here appear to us to be the ventilation of large gassy rooms, possible roof falls, and industrial hygiene requirements (i.e., what special precautions will be required in order to protect workers from fugitive emissions and exposure to potentially toxic or hazardous materials as a result of inhalation or skin contact).

In the case of underground retorting or in situ processing, the principal problems we see are the maintenance of a fire underground while workers are located below ground and similar industrial hygiene requirements to those indicated above, but with the potential for more extensive exposure to volatile substances.

What is the Health Research Strategy? With regard to the two principal exposure pathways, inhalation and skin contact, we see a rather practical and common sense approach being used as a first approximation to reduce exposures to acceptable levels. This would include ventilation and fugitive emission control. Ventilation is probably the simplest way to reduce exposures and would be the preferred method for control. Once the maximum level of ventilation is reached, the next attempt to reduce exposure would be made through improved controls for fugitive emissions within the working area. If further controls would be required to reduce exposures due to inhalation, various forms of breathing apparatus would be looked to. In the case of skin contact, two further steps would involve relying on personal hygiene procedures and protective clothing in order to reduce exposure to skin.

What is the Safety Strategy? Research on occupational safety often receives secondary or tertiary importance in research programs. Yet, with regard to workers risk, safety is apt to be equally important to occupational health in oil shale operations. Our strategy will be to rely on the following approaches:

- maximum credible accident scenarios
- building on coal, metal and nonmetal experience
- determining the need for permissible equipment and the ramifications of such a need

How Does the DOE Program Interact With Regulations and With Other Agencies

The oil shale program works closely with other groups and agencies to accomplish the research objectives. For example, the program has been highly interactive with industry and the American Petroleum Institute on research relating to occupational health and with the Mine Health and Safety Administration on safety research; many of the studies relating to groundwater contamination and emissions control have been closely coordinated with the offices of the Department of the Interior, particularly the U.S. Geological Survey. In other cases, we have supported cooperative studies and have collaborated with the Environmental Protection Agency and the Department of Health and Human Services. In addition, close ties have been maintained with the various state offices in Colorado with regard to both regulatory requirements and issues as well as research topics. Most recently, the program has worked closely with the Environmental Protection Agency on environmental control technology. Our goal is to see that oil shale as an emerging technology is capable of meeting and even exceeding present day rules and regulations but also that oil shale processes will be able to meet the standards of tomorrow.

Eastern Oil Shale Program

To date, much of the activity associated with oil shale has been conducted in a small area of Colorado, Utah, and Wyoming. Exploiting the extensive eastern oil shale deposits would appear to have the advantage of reducing the environmental and socioeconomic pressures on the western resource by providing an alternative resource for development. However, there are several more environmental concerns that must be addressed. The Department's strategy in implementing research in this area will parallel our efforts in the western shales. There are of course differences between the two resources that must be considered, such as, the acidic eastern soil versus the basic western soil. Therefore, the production of oil from eastern shales could generate a problem of mine acid drainage comparable to that now caused by the mining of coal. It is imperative that methods be developed for the prevention of acid drainage leaving the mine property before there is extensive eastern shale development. This will be a very high priority research area for the program. Other high priority areas are in the development of novel concepts that have low environmental impact and acquiring a data base to determine potential environmental hazards.

Industry and Environmental Comments on Kentucky's Proposed Oil Shale Regulatory Program

by

Richard Shogren
Administrator, Office of Special Projects
Department for Natural Resources and Environmental Protection*
Frankfort, Kentucky 40601

Abstract. Due to an increased interest in mining Kentucky's oil shale resources, the 1980 Session of the General Assembly passed legislation (KRS 350.600) mandating the Department for Natural Resources and Environmental Protection (DNREP) to "develop regulations for oil shale operations to minimize and prevent their adverse effects on the citizens and the environment of the Commonwealth." The Department designed the proposed regulations with an emphasis similar to existing coal mining regulations. The Department filed the proposed oil shale regulations with the Regulations Compiler on June 30, 1981, as mandated by the legislation.

Public comment on the proposed regulations has been extensive. Industry representatives have criticized the regulations as placing severe constraints on the development of a major new industry and recommended withdrawal of the proposed regulations until technical studies are completed which better define environmenal impacts. Environmental representatives fear that the oil shale industry will create severe environmental impacts and support stringent regulations. The Kentucky DNREP will submit a formal response to the comments in December, 1981, with recommended changes in the proposed regulations.

Introduction

Due to an increased interest in mining Kentucky's oil shale resources, the 1980 Session of the General Assembly passed Kentucky Revised Statute (KRS) 350.600 mandating the Department for Natural Resources and Environmental Protection (DNREP) to "develop regulations for oil shale operations to minimize and prevent their adverse effects on the citizens and the environment of the Commonwealth."[1] The legislation provided that the regulations be based on the best available sound, scientific and engineering data and be consistent with existing standards for land, water and air protection.

Commercial oil shale mining is currently prohibited by KRS 350.600 until adoption of the proposed regulations. The existing legislation does provide that persons may conduct core drilling, experimentation, removal of samples, or a pilot and demonstration plant which involves the mining of not more than five acres for production of oil shale in any one county. Written notification of the intent to perform such operations must be filed at least fifteen days prior to commencement of operations with the Secretary of DNREP. The Department has the authority to monitor such operations and to collect sound and reasonable scientific and engineering data upon which regulations pertaining to the oil shale mining operations can be based.

The Department utilized the format of the state's coal regulatory program extensively in developing the oil shale regulations because of similarities between shale mining and coal mining. Chapter 30 of Title 405 of the Kentucky Administrative Regulations (KAR) was reserved for the proposed oil shale regulations which were filed by the Department with the Commonwealth's Regulations Compiler on June 30, 1981. Table 1 shows the organization and descriptive titles for the proposed regulations.

Following publication in the August 1 issue of the Administrative Register of Kentucky,[2] four public hearings to review the regulations were held

* The conclusions and interpretation made in this paper are those of the author. The Kentucky Department for Natural Resources and Environmental Protection has not yet determined the form or emphasis of its final oil shale regulations.

in September, 1981. Approximately 200 interested citizens attended the hearings which were held in Morehead, Richmond, Bardstown and Lexington, Kentucky. A total of 38 separate comments were submitted at the four public hearings. Due to major interest indicated by both potential operators and environmentalists, the initial September 15 deadline for public comments was extended to October 15. As of October 20, the Department had received 20 additional written comments in addition to those submitted during the public hearings.[3]

This paper briefly summarizes the contents of the regulations, major concerns indicated by the public comments and observations resulting from the public comment process.

Table 1.
Descriptive Titles of Proposed Regulations Applicable to Oil Shale Mining

Title/Chapt./Reg.	Descriptive Title
405 KAR 30:010	Definitions.
405 KAR 30:020	General Provisions.
405 KAR 30:030	General requirements for performance and liability insurance.
405 KAR 30:040	Amount and duration of performance bonds.
405 KAR 30:060	Form, terms and conditions of performance bonds and liability insurance.
405 KAR 30:070	Procedures, criteria and schedule for release of performance bond.
405 KAR 30:080	Bond forfeiture.
405 KAR 30:090	General provisions for inspection and enforcement.
405 KAR 30:100	Enforcement.
405 KAR 30:110	Public participation in inspection and enforcement.
405 KAR 30:120	Oil shale exploration permits.
405 KAR 30:130	Oil shale operation permits.
405 KAR 30:140	Written approval required for transfer of permit; successor in interest.
405 KAR 30:150	Oil shale records open to public inspection; confidential nature of certain data.
405 KAR 30:160	Date requirements.
405 KAR 30:170	Citizen demands for enforcement.
405 KAR 30:180	Petitions for rulemaking.
405 KAR 30:190	Process and criteria for designating lands unsuitable for oil shale operations.
405 KAR 30:200	Petition requirements to designate lands unsuitable.
405 KAR 30:210	Signs and markers.
405 KAR 30:220	Postmining land use.
405 KAR 30:230	Air resources protection.
405 KAR 30:240	Protection of fish, wildlife and related environmental values.
405 KAR 30:250	Use of explosives.
405 KAR 30:260	Access roads, haul roads, overland conveyor systems, pipelines and other transport facilities.
405 KAR 30:270	Casing and sealing of drilled holes.
405 KAR 30:280	Prime farmland.
405 KAR 30:290	Topsoil.
405 KAR 30:300	Protection of the hydrologic system.
405 KAR 30:310	Diversion of flows and water withdrawal.
405 KAR 30:320	Water quality standards, effluent limitations and monitoring.
405 KAR 30:330	Sediment control measures.
405 KAR 30:340	Leachate control.
405 KAR 30:350	Permanent impoundments.
405 KAR 30:360	Disposal of wastes other than excess spoil.
405 KAR 30:370	Disposal of excess spoil materials.
405 KAR 30:380	Spent shale disposal.
405 KAR 30:390	Backfilling and grading.
405 KAR 30:400	Revegetation.
405 KAR 30:410	In situ operations.

Source: Kentucky Department for Natural Resources and Environmental Protection, Bureau of Surface Mining Reclamation and Enforcement, Regulations for Oil Shale Operations - Informational Copy, August, 1981.

Summary of Proposed Oil Shale Regulations

General Provisions

The proposed regulations require any person, partnership or corporation desiring to initiate oil shale exploration or operations to file with the DNREP, Bureau of Surface Mining Reclamation and Enforcement, for a permit to conduct the operations. A valid permit must be issued before operations may commence (KAR 30:020). For a large operation, each permit applicant must demonstrate, utilizing necessary technical, scientific and engineering data, the impacts their operation will have on the environment. Data used in this justification must be derived from studies on eastern shales having comparable characteristics to shales in the proposed project area. If the applicant cannot demonstrate the extent and magnitude of possible adverse environmental impacts of the facility, its size shall be limited to a pilot project.

Pilot Projects. A pilot project is defined as an operation which disturbs less than 25 acres annually or produces 1,000 barrels or less of shale oil per day, whichever is smaller. This section was included in the regulations to encourage industrial development of pilot projects. Data from studies on pilot projects would provide information on environmental impacts, which could be incorporated into the regulations, before a commercial facility is started.

Permit Classes. Two types of permits are defined in the proposed regulations: exploration and operation permits. Exploration permits are valid for two years and provide for gathering of surface or subsurface geologic, physical or chemical data at proposed mining sites. Exploration operations must be conducted in accordance with the environmental protection standards in the proposed regulations.

Operation permits are valid for a term of five years except for pilot project permits which are valid for two years. An operation permit allows oil shale extraction, experimentation, exploration, processing, waste disposal and reclamation activities, or removal of overburden for the purpose of determining the location, quality or quantity of a natural oil shale deposit, or activity to facilitate or accomplish the extraction or removal of oil shale. All of the premises, facilities, roads and equipment used in the mining and processing of oil shale from a designated area are defined as part of the disturbed area.

Exploration Permit Requirements. KAR 30:120 outlines the contents of an exploration permit application. Basic requirements for this type permit are: (1) a description of the proposed exploration area, (2) a description of the methods to be used to conduct oil shale exploration and reclamation, (3) an estimated timetable for conducting each phase of the exploration and reclamation, (4) estimated amounts of oil shale to be removed and a description of methods to be used to determine these amounts, and (5) a description of the methods to be used to comply with the applicable performance standards of these proposed regulations. The Department will have 21 days in which to notify the applicant of the completeness of the application. After filing of a complete exploration permit application, the Department will have 60 days in which to act on the application.

Operation Permit Requirements. KAR 30:130 outlines the contents of an operation permit application, requirements similar to the coal mining permit application process. Some of the requirements for this type permit are: (1) maps showing location of operation and surrounding landowners, (2) a transportation plan, (3) a plan for restoration of prime farmland (if applicable), (4) a postmining land use plan, (5) a blasting plan, (6) a topsoil handling and restoration plan, (7) a backfilling and grading plan, (8) a revegetation plan, (9) a spoil disposal plan, (10) a plan for handling of waste materials and acid-forming and toxic-forming materials, (11) a surface water control and monitoring plan, (12) a groundwater control and monitoring plan, (13) an air resources protection plan, and (14) a fish and wildlife plan. The Department will have 21 days in which to notify the applicant of the completeness of the application. Because of the complex nature of the operations permit application, the Department will have 120 days after filing in which to act upon the complete application.

Permit Approval Terms. All permits will be reviewed at the midlife of the permit to ensure that the operation is being conducted in compliance with KRS 350.600 and applicable regulations. Fees for all permits will be $500 per application and $50 per acre. No permit may be transferred and no operation can be succeeded to by another without the prior written approval of the Department (KAR 30:140).

Prior to issuance of a permit, an applicant must make certain demonstrations showing that the operation is consistent with all applicable environmental laws of the Commonwealth. The proposed operation must be designed to reduce adverse effects to the hydrologic balance, must not be within an area where oil shale operations are prohibited and must not adversely affect fragile lands (such as a wild river and lands with uncommon geologic features), or constitute a hazard to life or to physical damage to specified facilities. An applicant's past compliance history is considered in the Department's review of an application. Anyone injured by an order or determination of the Department has the right to an administrative hearing to contest the order or determination.

Baseline Data. Extensive baseline data (KAR 30:160) to describe the environment of the proposed site is required before any mining operations begin. As determined by the DNREP, baseline (existing condition) data shall be required in the following areas: air quality and meteorology, water quality and quantity, aquatic and terrestrial flora and fauna, and historic, geologic, pedologic and archaeological features. This data provides a reference point for evaluating ongoing studies, and will prove beneficial in identifying existing problems which might be attributed to oil shale operations. The minimum period of data collection shall be one year. Sampling and monitoring locations used in the baseline data collection may be used to collect data during the active life of the operation and thereafter to assess the environmental impacts of the operation. The Department has the authority to require applicants to collect technical or engineering data for an oil shale operation to assess the impacts of such activities on the environment and natural resources.

Regulation Amendment. An important provision of the proposed regulations provides for adaptability as new data and technology becomes available. The provision allows petitions to be filed by any person in order to initiate a proceeding for the issuance, amendment or repeal of any regulations (KAR 30:180).

Site Inspections. Regular inspections shall be made of all oil shale operations (KAR 30:090). If an inspector observes a violation of the regulations, a Notice of Non-compliance and Order for Remedial Measures will be issued (KAR 30:100). An inspector, upon issuance of a Notice of Non-compliance and Order for Remedial Measures, shall reinspect the permit area on or soon after the date given in the Notice or Order for completion of remedial measures. The correction of a violation does not affect the right of the Department to assess civil penalties for that violation pursuant to these regulations or to impose any other applicable sanctions as authorized by law. After an adminstrative hearing, violators may be penalized under KRS 350.990(6) which imposes civil penalties of not more than $25,000 with each day of continuing violation deemed to be a separate violation.

Any person having an interest which is, or may be adversely affected by an oil shale operation, may request that the Department inspect the operation (KAR 30:110). Within ten days of the inspection, or if there is not inspection, within 15 days of receipt of the person's written statement, the Department shall send the person an explanation of the reasons why no inspection was conducted, or, if an inspection was made, a description of the enforcement action taken.

Any person having knowledge that any of the statutes and regulations pertaining to oil shale operations are not being enforced may bring such failure to enforce to the attention of the Department (KAR 30:170). After a demand for enforcement is received, the Department must respond in writing to the person making the demand and explain the result of an investigation and the action, if any, the Department has taken or intends to take. If the Department refuses after an unreasonable time to enforce the law, then the citizen has the right to initiate an action to compel enforcement in the circuit court of the county in which the operation is located.

All oil shale records of the Department will be open to public inspection except any record or information which constitutes a trade secret or confidential business information and is designated as such by the Department upon the satisfactory showing by the owner of such record (KAR 30:150).

Bond Procedures

Bond procedures and requirements are similar to those for coal mining. All permittees must provide the Department with performance bond coverage and public liability insurance to provide for personal injury and property damage protection (KAR 30:030). Operation permits will have a minimum amount of $5,000 per acre, but in no event shall an oil shale operation permit be for an amount of less than $20,000. The amount of bond shall be reviewed and may be adjusted at any time during the life of the permit. Bonds may be surety, cash, certificates of deposit, letters of credit or acceptable escrow accounts (KAR 30:060).

The regulations (KAR 30:070) provide for three phases of bond release which are tied to progress on land reclamation. Partial release of bonds occurs on a schedule of 60% for Phase 1, 25% for Phase 2 and 15% for Phase 3. Phase 1 is considered ended when the permittee completes backfilling, regrading, topsoil replacement and drainage control, and a planting report for the area has been submitted to the Department. Phase 2 is considered complete when: (1) revegetation standards have been successfully met, (2) water quality and drainage control standards are satisfied, (3) soil productivity has been restored if prime farmland is involved, and (4) provisions for future management of any permanent impoundment have been implemented. Phase 3 is considered complete when the permittee has successfully completed all oil shale operations in accordance with the approved reclamation plan and has achieved compliance with requirements of the proposed regulations and the applicable liability period. Bonds may be forfeited for failure to reclaim, revocation of permits, or for such other good cause as the Department determines (KAR 30:080).

Lands Unsuitable for Mining

The regulations establish a petition procedure for the designation of certain lands as unsuitable for all or certain types of oil shale operations. Petitioners must have an interest in certain important values of the land which is or may be adversely affected by oil shale operations (KAR 30:200). Examples of such values are: damage to important historic, cultural, scientific or aesthetic values or natural systems; reduction of long range agricultural and silvicultural lands and production; reductions in availability of water supplies; and endangerment of life and property by affecting natural-hazard lands. The petition procedure for designating lands unsuitable provides a mechanism to identify for industry areas which are unsuitable for oil shale operations prior to applying for a permit.

The regulations define procedural requirements (KAR 30:190) for all petitions including processing procedures, public notices and public hearing procedures. The Department shall designate an area as unsuitable for all or certain types of oil shale operations only after evaluating the validity of petitioners' request and results of the public hearing.

A designation of unsuitability may be rescinded if it can be demonstrated by new evidence, technology or a specific method of operation that all or certain types of oil shale operations can be conducted on the land without adversely affecting the conditions which led to the designation.

General Environmental Controls During Mining Operations

Fugitive dust control measures are to be employed during shale mining operations (KAR 30:340). These measures shall include watering, chemical stabilization and paving of roads, stabilizing areas adjacent to roads, restricting travel to established roads, minimizing area of disturbed land, revegetation of disturbed lands and planting of special windbreak vegetation at critical points.

Oil shale permits shall comply with specific requirements and measures for the protection of fish, wildlife and related environmental values and enhance such resources where practical (KAR 30:240).

The permittee must comply with all applicable local, state and federal laws and regulations and KAR 30:250 in the storage, handling, preparation and use of explosives. A blasting plan and schedule must be submitted to the Department and meet established standards in KAR 30:250.

Transportation facilities shall be designed, constructed and maintained according to specific grade and drainage provisions to reduce sediment and other impacts on the hydrologic balance (KAR 30:260).

Exploration holes, core holes, boreholes or other exposed underground openings must be appropriately cased, sealed or managed to prevent acid or toxic drainage from entering ground or surface waters (KAR 30:270).

Disturbances to the hydrologic balance shall be minimized through practices which prevent or limit water pollution or changes in flows (KAR 30:300). Water diversions shall be designated to be adequate to pass safety the peak runoff of a 10 year, 24 hour precipitation event for temporary diversions, or a 100 year, 24 hour precipitation event for permanent diversions with drainage areas less than 200 acres, or larger events specified by the Department for drainage areas greater than 200 acres.

Surface drainage from disturbed areas shall be passed through sedimentation ponds (KAR 30:300). Discharge from these ponds shall meet effluent limitations if the discharge results from a storm event less than a 10 year, 24 hour storm. When deemed necessary by the Department, leachate containment structures shall be constructed below sources of leachate not meeting water quality standards (KAR 30:340). Such structures shall be maintained until leachate meets applicable water quality standards (KAR 30:350).

Waste Management Procedures

Classes of Waste. Wastes associated with an oil shale operation are defined in three categories: mining wastes and processing wastes (KAR 30:360), excess spoil materials (KAR 30:370) and spent shale (KAR 30:370). DNREP may require necessary tests and data to determine whether mining and/or processing waste materials are classified as hazardous. Drainage from acid-forming and toxic-forming materials shall be prevented from entering ground water and surface water. Methods to be used may include burying and treating the material or preventing water contact with the material. All acid-forming and toxic-forming materials shall be covered with a minimum of four feet of non-toxic and non-combustible material and impermeable liners as required by the Department.

Excess Spoil Disposal. Spent shale has a volume as much as 20% greater than raw shale. This characteristic may result in excess spoil material (KAR 30:370) being disposed of in mine working , and also in areas approved for disposal of this excess material. The major requirements for the design of a fill for excess spoil material are as follows: (1) spoil shall be placed to ensure that leachate and surface runoff will not exceed effluent standards of KAR 30:320, fill will be stable, and disposal areas will

be suitable for reclamation compatible with the natural surroundings; (2) fill shall be designed using recognized professional standards and certified by a registered professional engineer; (3) slope protection shall be provided to minimize erosion; (4) disposal areas shall be located on the most stable area available; (5) spoil shall be placed and compacted to ensure a long-term static safety factor of 1.5; (6) final configuration must be suitable for postmining land use plan; and (7) an underdrain system shall be required when applicable. Prior approval of DNREP shall be necessary before disposal of excess spoil in head-of-hollow or valley fills.

Spent Shale Disposal. Locations for burying spent shale areas (KAR 30:380) shall meet the following criteria: (1) spent shale fill areas be designed using recognized professional standards and certified by a registered professional engineer, (2) the bottom and sides of the disposal areas shall be lined with an impermeable material to prevent leachate from entering ground or surface waters, (3) spent shale shall be placed in layers and compacted to obtain optimum density, (4) spent shale shall be cooled to a temperature approved by the Department before covering, (5) disposal areas shall be covered with an impermeable material of sufficient depth to prevent surface water from entering spent shale, (6) a minimum of four feet of non-toxic forming and non-acid forming material shall be placed on the impermeable cover, (7) minimum static safety factor of 1.5 for the fill, (8) fills shall not be constructed in the 100 year floodplain of any perennial stream and a stream channel may not be changed to meet this requirement, (9) all surface drainage from undisturbed areas above the fill shall be diverted away from the fill, (10) leachate ponds shall be constructed below all spent shale disposal areas and (11) spent shale disposal areas shall meet the requirements for topsoil and revegetation.

Reclamation of Mined Areas

Lands affected by oil shale operations shall be restored in a timely manner to conditions capable of supporting uses equal to or higher than predisturbance conditions (KAR 30:220). Separate regulations exist for prime farmland and non-prime farmlands. The proposed oil shale mining areas are located in an area of Kentucky containing more prime farmlands than the coal fields of Kentucky. The regulations were written to ensure that the productivity of this valuable resource is restored if mining occurs on prime farmlands.

Prime Farmland. The regulations define prime farmland according to specific soil characteristics and require that these soils be identified by a soil survey conducted by a soil scientist, who has experience and knowledge in conducting soil surveys in accordance with the standards and procedures of the National Cooperative Soil Survey Program (KAR 30:280). The minimum depth of soil to be restored is 48 inches. The permittee may demonstrate the reconstructed soil productivity by either growing crops to comparable predetermined target yields, to be established by the Department, or by a comparison of soil survey information and data before and after mining to meet various soil parameters, which are to be developed by the Department. The permit liability period is for a minimum of seven years and the first two or three years may be used to grow grasses and legumes to protect the reconstructed soil from erosion.

Non-prime Farmland. For oil shale operations occurring on non-prime farmlands (KAR 30:290), the regulations require that a minimum depth of 24 inches of soil, subsoil or soil substitute material be restored on the disturbed area. The regulation sets standards for the removal, storage and redistribution of topsoil, and requirements for determining topsoil substitution material.

Backfilling. Mined areas do not have to be backfilled to achieve approximate original contour configurations (KAR 30:390). Backfilling materials shall be selectively placed and compacted, and topsoil replaced and seeded in accordance with vegetation requirements. A minimum static safety factor of 1.5 shall be achieved for all backfilled areas.

Revegetation. A revegetation regulation (KAR 30:400) establishes the standards for disturbed areas, and also that the temporary or permanent vegetation be effective in stabilizing the redistributed soil against erosion. The success of the vegetation may be demonstrated by the comparison of ground cover and productivity must equal the approved standards for the last three years of the seven year liability period.

Summary of Public Hearing Comments

Extensive comments were made at four oil shale public hearings or submitted in writing to the official record for the public hearings. Generally, most comments can be categorized as coming from industry sources or from environmental interest groups. The comments by persons representing potential developers were more extensive than comments from environmental interests. Comments submitted by individual citizens were directed toward environmental concerns. Major comments supporting industry interests were received from Pyramid Minerals, Mobil Oil, Phillips Petroleum, and the Kentucky Department of Energy. Major environmental comments were received from Appalachia-Science in the Public Interest and the Kentucky Rivers Coalition.

The summary of comments presented below has been organized into five general categories. Wherever possible, the summary reflects the emphasis that was placed on the comments by the individuals or organizations which made the submission. Each of the summary sections highlights those remarks considered to be industry recommendations and those made by environmental interests. The five categories for summarization are as follows:

1. General remarks;
2. Baseline data requirements and characteristics of permits;
3. Disposal requirements for solid and liquid wastes;
4. Differences from existing coal mining regulations;
5. Other comments.

In some cases, certain comments in a section may appear contradictory. The sequencing of the comments is the author's interpretation of the relative prioritization.

General Remarks

Withdraw Regulations. A number of the commenters representing industry groups believe that the entire set of regulations are premature and should be withdrawn. Many of these comments were based on the premise that insufficient scientific and technical study

results exist to be able to define regulations for oil shale mining. The economics and mining and processing technologies of the oil shale industry are still not fully understood or defined. To establish regulations at this stage of the industry's development is not reasonable. Rather, extensive research and testing of techniques is needed to justify the definition of reasonable standards for development of the industry. To allow this research to occur, a relatively brief set of regulations is needed which provides flexibility for evaluation of alternate techniques for oil shale mining and processing. Industry supporters expressed the view that there should be provision for experimental practices for pilot plants, an appropriate step for an industry that is just beginning to come of age. This general position was advocated by Mobil Oil, Phillips Petroleum and the Kentucky Department of Energy, and, to some extent, by Pyramid Minerals.

Excess Departmental Discretion. A second major concern which was expressed by most of the respondents who favor less stringent regulations is that an excessive amount of departmental discretion exists in the regulations. Clear standards and responsibilities for a permit holder should be identified through further research and specifically stated in the regulations. A reduction of discretionary interpretation by the DNREP will allow the requirements of the regulations to be clearly understood by industry, the Department, and the general public. Industry comments strongly opposed the lands unsuitable regulation (30:200) which provides too great a discretionary responsibility to the Department in defining lands where oil shale mining would be prohibited.

Additional Regulations. A third general criticism by industry representatives was the lack of several procedural regulations that commonly exist to provide flexibility in the permit review process. Proponents of industry would like to see variance procedures defined in the regulations to provide options for minor deviations from the regulations where this is appropriate. Additionally, a clear statement is needed of the appeals process that is available to permit applicants in the event they disagree with departmental interpretation of the regulations.

Responses from environmental groups also requested a significant change in regulatory authority. DNREP should have specific authority in the regulations to issue summary cessation orders when a significant danger to human health exists.

Potential Environmental Problems. Environmental groups expressed the view that the Department should not have the discretion to approve operations larger than the size limits identified in the proposed regulations (25 acres or 1,000 barrel per day capacity). No large development should be allowed until clear proof exists that the proposed reclamation procedures work, that underground systems will not be affected by pollution and that surface water systems will not be destroyed by acid drainage from the oil shale operation.

The potential environmental harm by a poorly regulated oil shale industry is immense. Commercial oil shale operations have been described as being as large as 50,000 barrels of oil per day which would require the mining of at least 100,000 tons of shale per day and probably in excess of 100,000 tons of overburden per day. These operations are proposed to be long-term investments which would exist for twenty to thirty years. A single operation over this span of time will consume hundreds of acres of land and have major potential impacts on water quality, groundwater elevation, existing terrain, and existing structures, roads and crop areas within a mining area. The oil shale belt passes through the richest agricultural land in the state and the impacts on agricultural production could be severe. The effectiveness of the reclamation techniques that are proposed in the regulations is not known because of the questions that remain concerning the entire mining/retorting procedure and the characteristics of spent shale.

Baseline Data Requirements and Characteristics of Permits

The major problems which industry has are the size restrictions and time limits defined for an operations permit (30:020; 30:130). The size restriction of 25 acres of annual disturbed area is too severe for a pilot project. The proposed time limit for a pilot permit of two years is probably an insufficient time for a retorting facility to be built. An operations permit time limit of five years for a commercial oil shale operation is completely insufficient for a major site investment which will last a total of twenty years or longer. These types of restrictions will prevent the industry from ever acquiring the financing to begin site operations.

Environmental groups support the concept of a size restriction on initial operations and indicated that an appropriate acreage ceiling should be determined by the Department. There was no strong support from the environmental groups for the 25 acre size limit as opposed to a higher acreage limitation.

A second major criticism by industry supporters was directed to the exploration permit requirements (30:120) which are excessive since minimum environmental impacts are expected. The bulk of exploration activity will consist of the extraction of core samples which do not involve any on-site oil extraction process for the shale or create any type of environmental pollution. A number of comments recommended that the exploration permit regulation be withdrawn. One suggestion was that a general exploration permit regulation for all types of mining was needed.

A third recommendation by one industry representative was that pilot plant operations should be allowed under a separate regulation which would provide for more flexibility and experimentation than operations permits for large commercial plants. A suggested time period for a pilot project was five years with an area limitation of 250 acres. As stated above, environmental interests strongly supported a pilot project as a preferred initial mining operation.

A fourth major comment made by industry representatives was that baseline data requirements are excessive for oil shale mining. Several commenters indicated that the baseline data requirements regulation (30:160) should be entirely withdrawn and reworked. There is not presently any justification for more stringent regulations for oil shale operations as opposed to other mining operations. Environmental comments supported a number of the baseline data requirements as being necessary to determine impacts of any mining and processing operation.

Disposal Requirements for Solid & Liquid Wastes

Comments regarding the proposed disposal requirements for solid wastes from the mining and processing of oil shale (30:300 to 30:400) are the most controversial sections within the proposed oil shale regulations. Industrial interests believe that the proposed disposal standards are far too stringent and completely unjustified. However, environmental interests believe that the standards might not be stringent enough and were certainly not too stringent in terms of the potential for major environmental problems. On this particular issue, both industrial and environmental interests expressed the view that there was insufficient technical information from which to make a final determination. The DNREP has attempted over the past nine months to undertake or sponsor studies that wll increase the amount of information available on eastern shales or to research existing data which would more clearly support a disposal technique. Preliminary results of several technical studies sponsored by DNREP are being presented at the 1981 Eastern Oil Shale Symposium.

Industry Position. Comments strongly oppose the use of impermeable liners around spent shale disposal areas. Spent shale is not a hazardous waste. Industry laboratory tests on retorted and combusted shales prove that EPA concentrations for toxic minerals are not exceeded. The proposed provisions for disposing of spent shale are completely unreasonable and treat spent shale as if it was a hazardous waste. Existing and past oil shale operations in other countries have demonstrated that spent shale does not create environmental problems. In fact, spent shale has many characteristics which can make it feasible to use as a construction material. Further, leaching tests performed on Kentucky shale indicate that there is not a problem with metals leaching out in concentrations sufficient to create environmental problems. Carbon and natural sulfur will be combusted and their quantities greatly reduced during the processing of spent shale. The major reduction in proportions of sulfur and carbon should eliminate any significant problems that might be related to them. The two major regulations pertaining to disposal of excess spoil materials and spent shale (30:370 and 30:380) should be withdrawn until current scientific and technical studies are completed.

Environmental Position. Commenters stated that spent shale will almost certainly create major sulfuric acid problems which will encourage the release of soluble heavy metals. Studies of weathering of western shale with relatively low sulfur contents (less than one percent) have shown a major change in pH toward a more acid condition. High sulfur eastern shale (two to five percent) would have more serious oxidation problems than western shale which will create major acid releases. While leachability characteristics of spent shale depend on the retorting process, it is likely that leaching of small quantities of metals for most processing techniques will be significant enough to create a toxic concentration. As a result, an impermeable liner around the spent shale is essential.

Other comments were directed to the effects of acidic conditions on reclamation. A current study underway at the University of Kentucky is designed to test the importance of depth of topsoil in improving productivity. Preliminary results of that test indicate little improvement in soil productivity is gained below two feet of topsoil if the spoil material below the topsoil has been limed so that potential acid problems are eliminated. The addition of lime is recommended as the major solution for solving acid waste problems. Generally, substitution of deeper soil horizons for topsoil is not advisable since high acidity, high clay and low nutrient conditions exist below existing topsoil. The importance of carefully separating and marking the different layers of soils which are stripped off to get to the spent shale is emphasized in order to achieve a high productivity on reclaimed land.

Differences From Existing Coal Mining Regulations

A common criticism by potential developers was that many of the proposed oil shale regulations were more stringent than coal mining regulations. Specific comments were directed to the following:

1. The seven year period for operator reclamation responsibility and full bond release is greater than the five year period for coal.
2. Bond requirements for reclamation of mined land are much higher than bond requirements for coal mining.
3. General bonding and insurance procedures are more stringent in the proposed regulations than for coal mining.
4. Topsoil requirements are greater for oil shale mining than for coal mining.
5. The requirements for buffering an oil shale operation from stream and other critical land uses near the permitted site are more stringent than for coal mining.
6. Blasting requirements are more stringent for oil shale operations.
7. The prime farmland requirements are more stringent for oil shale operations.

In each of these cases, it was recommended that the proposed oil shale regulations be amended so that the regulations are not more stringent than those currently provided for coal mining.

Comments from environmental groups disagreed in some of these cases. Generally, the bonding limits proposed in the regulations were felt to be reasonable or low considering the potential investment in oil shale operations and the cost of reclaiming land if the Department had to assume responsibility. A number of respondents indicated that an inflation scale should be provided for the bonding requirements within the regulations. Another comment was that because of the amount of shale that will have to be moved per day to meet the requirements of a commercial processing plant, more strict blasting notification procedures within the regulations were quite appropriate. Finally, given the questions that remain relative to success of any reclamation plan, the seven year period proposed in the oil shale regulations was felt to be justified.

Other Comments

A comment by industry representatives questioned the appropriateness of the postmining land use regulations (30:220) which monitor land use during reclamation. Since approximate original contours are not required in the proposed oil shale regulations, this monitoring is unnecessary. The

issue of returning land to equivalent premining productivity should be determined by soil testing, not land use monitoring.

Another comment indicated that certain statutory exemptions which are similar to those for coal should be included in the regulations for oil shale. Thus, mining operations which have less than two acres of mining area should have a special permit which has less stringent regulations than a large mining operation. Similarly, coal regulations exempt operators producing less than 250 annual tons from requiring a permit; a similar exemption should be applicable to oil shale.

Although it does not directly relate to the regulations, a concern expressed by environmental interests was the perception that oil shale would lead to a boom-bust economic condition for local communities. During construction of a processing plant, there would be a great demand on local services to satisfy the requirements of construction workers who would temporarily reside in an area. After operations begin, the demand for these services would decrease substantially. The net result would be a negative impact on an area's economy since many of the rural counties which exist in the oil shale mining area lack the community services to absorb the short-term needs of transient construction workers.

A related general comment was that there is no reason to rush into development of this resource. The value of oil shale is going to increase in time as other petroleum resources that are easier to obtain are exhausted. There is no expectation that the need for petroleum products will ever be completely eliminated; petroleum products are going to be a major requirement for the U.S. economy for the foreseeable future. As a consequence, a wise course of action to take is one of more thorough research to identify the best techniques to efficiently mine and process oil shale.

Observations from the Public Hearing Process

The Kentucky Department for Natural Resources and Environmental Protection is currently in the process of preparing an Affirmative Consideration, a response to the comments that were raised during the oil shale public hearings. This response will address all of the issues and questions raised by those comments. No final decisions have been reached as of this conference concerning changes in the regulations or the response to any of the comments that have been raised at the public hearing. The discussion below represents the views of the author only.

The Oil Shale Industry Will Develop Slowly in Kentucky

Unless a major reduction in foreign oil sources occurs, Kentucky's oil shale industry cannot be expected to develop very rapidly despite the vast underground resources which appear to be economically accessible. The reasons for expected slow development go well beyond the current lack of technical data on mining and processing of eastern oil shale. First, the recovery rate for shale oil is relatively low for eastern shales; yields have been estimated as ranging from 10-15 gallons per ton of shale to as high as 25 gallons of shale, the variation depending upon the process technology which is used.[4] In contrast, the yields of western shales in the Green River formation located in western Colorado and eastern Utah have been estimated at 25-30 gallons per ton of shale, rates that are independent of the process technology which is used. Accessible reserves in the western shale belt area have been estimated to exceed reserves in the eastern shale area.

A second factor which will contribute to the slow development of the industry is that costs for a large retorting facility to extract oil from the shale are very high. The October 5, 1981, issue of Synfuels Week[5] estimated the cost of a 50,000 barrel per day processing plant as being about $2.8 billion. Since western oil shale has higher yields than eastern shales, it has attracted more interest by developers. The funds to finance even a medium size plant in Kentucky are likely to be limited unless the cost of oil rises substantially or the supply of oil available outside this country is sharply reduced.

The above factors would seem to indicate that the short-term impact of oil shale mining and processing within Kentucky's 2,600 square mile Devonian oil shale belt is very small. A single commercial site may have an impact area of several square miles due to extensive mining and processing, but the proportional impact in the oil shale belt would be very small.

Oil Shale Mining is Not Like Coal Mining

There are several major differences from oil shale mining as compared to coal mining. First, it is unlikely that there will be extensive impacts over a large area of the state as have been the case with coal mining because of the opportunity that small developers have to extract and mine coal. Whereas hundreds of mines are in operation in eastern and western Kentucky, the number of shale mining and processing operations is anticipated to be small.

A second factor which differentiates coal from oil shale mining and operations is that the raw shale must be processed at a high cost in order to produce oil. The oil shale mining is not going to lead to extensive transportation of the raw shale product to a multitude of locations where the product can be used directly to produce energy. The effectiveness of any oil shale operation will depend on mining as much raw shale as possible adjacent to the processing plant. This is important because the shale has to not only be transported to the processing retort, but also returned to the open mine for burial after extraction of oil has occurred. For most retorting processes, the volume of spent shale will be greater than the raw shale due to the difficulty of compacting spent shale into the volume originally occupied by the raw shale. As a consequence, the ground elevation of the mined area will increase, or nearby low areas will be filled with some composite of spent shale and overburden.

Even for a small processing plant, the volume of spent shale produced will be substantial. A 10,000 barrel per day processing plant with a yield of 16 gallons of oil per ton of oil shale would require the processing of 26,600 tons of shale per day. This is equivalent to about 440,000 cubic feet of shale per day, which is 10.1 acre feet of shale per day or 3,000 acre feet of shale per year. Three thousand acre feet of shale is equivalent to covering

100 acres of land to a depth of 30 feet. While preliminary indications indicate that spent shale will not be hazardous nor will it be toxic, the possible impacts of burying 3,000 acre feet of shale per year in a mined area that has had groundwater and surface flow characteristics disrupted is relatively unknown. These concerns account for the Department's view expressed in the proposed regulations that spent shale should be handled with great caution.

Conclusion

Kentucky's proposed oil shale regulations are based on existing coal mining regulations. Due to lack of data concerning the mining of eastern oil shales, the regulations were prepared assuming worst case impacts. Studies prepared on western oil shales by the Environmental Protection Agency[4] indicate that many unanswered questions remain concerning the environmental impacts of oil shale mining and processing. The Department filed the proposed regulations on June 30, 1981, as mandated by Kentucky statutes.

Representatives of the oil shale industry have indicated that current form of the proposed regulations will greatly restrict development opportunities, and that the regulations are not based on scientific, technical and engineering data. Environmentalists are concerned that less stringent regulations will lead to abuses by applicants for oil shale permits. The limited knowledge of spent shale characteristics means that abuses could cause major negative environmental impacts.

Western oil shale resources favor development of the industry in that area rather than within the eastern oil shale belt. Further, the character of the industry is such that mining operations are certain to be limited to a small area around a retorting facility.

Both environmental and industry groups agree that a pilot retorting plant of limited size is the most appropriate first step to take in the development of the industry. Since the opportunity for development of a pilot plant is limited to a small number of potential developers, it would appear best to make major modifications in the regulations to allow more flexibility for development to occur. Since various environmental groups have major concerns about the industry, close monitoring of the effects of a pilot plant on the local environment is desirable. Given the size of the oil shale resource, a multitude of potential sites exist for locating a pilot plant. The Department should work with prospective developers to identify a site where the potential for negative environmental impacts is minimized.

REFERENCES

1. Commonwealth of Kentucky, Kentucky Revised Statutes 1980 Cumulative Supplement, Vol. 12, "KRS 350.600 - Oil Shale Mining," 327 and 328, August, 1980.

2. Commonwealth of Kentucky, Administrative Register of Kentucky, Vol. 8, Number 2, "Regulations for Oil Shale Operations," 87-137, August, 1981.

3. Department for Natural Resources and Environmental Protection, "Public Comments on Oil Shale Regulations," comments submitted September - October, 1981.

4. United States Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, EPA-600/2-80-205a, February, 1980.

5. _____, "Shale Finance Timing May be Off," Synfuel Week, October 5, 1981.

A Comparison of Proposed Oil Shale Regulations with Coal Mining Regulations

by

Joseph J. Zaluski and Steven G. Kinkel
Zaluski, Seay & Kirkland
213 St. Clair Street
Suite 200, P.O. Box 495
Frankfort, Kentucky 40602

The Kentucky General Assembly through the adoption of KRS 350.600 mandated the Kentucky Department for Natural Resources and Environmental Protection to promulgate reasonable regulations for the mining of oil shale in the Commonwealth. Although the statute itself consists of some six short paragraphs, the Department for Natural Resources and Environmental Protection has proposed some 137 pages of regulations. An attempt will be made in this paper to comment on several portions of the proposed regulations and to compare those to the proposed coal mining regulations of the Commonwealth.

The Department's overall approach to oil shale regulation is one of the extreme conservatism. In its preparation of the oil shale regulations the Department for Natural Resources and Environmental Protection chose to apply nearly every proposed coal regulation to the infant oil shale industry. One should keep in mind that the Department's proposed coal regulations were written in response to, and as a mirror image of, the United States Department of the Interior's permanent coal mining regulations. In essence then, the Department has stated that Washington's regulations concerning the coal industry are also proper for Kentucky's infant oil shale industry. Kentucky's approach therefore creates an oil shale regulatory scheme at least as stringent, and more stringent in some areas, as its coal mining regulatory scheme. The Department's approach seems rather odd when very little is known about the mining and processing of eastern oil shale.

The General Assembly stated, through its adoption of KRS 350.600, that the Department for Natural Resources was best suited to develop oil shale regulations because of its expertise (experience) in the regulation of coal mining. The Department may have misunderstood its mandate and thought it was to simply apply all of its coal regulations to the oil shale industry; and to further use its "expertise" and its crystal ball (however cloudy) to promulgate elaborate regulations for an industry, the environmental effects of which are completely unknown to itself, to industry and to the so called environmentalists.

Although our presentation is entitled A Comparison of Proposed Oil Shale Regulations with Coal Mining Regulations, it is difficult to make such a comparison without critizing many of the regulations proposed by the Department for Natural Resources and Environmental Protection. However, in an attempt to relay necessary information to the reader, we have divided our presentation into four areas: Permitting Regulations, Performance Bond Regulations, Performance Standard Regulations and Enforcement Procedure Regulations.

The brief time period of this presentation prohibits the discussion of much detail. Rather, and attempt will be made to compare the proposed Kentucky Oil Shale Regulations to the proposed Permanent Coal Mining Regulations of Kentucky and to draw the reader's attention to several key distinctions. The reader must decide the effect the regulations will have upon the oil shale industry if they go into effect substantially as proposed.

Permitting

The proposed oil shale regulations addressing permitting are 405 KAR 30:020, 405 KAR 30:120, 405 KAR 30:130, 405 KAR 30:140 and 405 KAR 30:160. Of these regulations, the following deserve comment as they compare to the proposed permanent coal mining regulations of the Commonwealth.

Oil Shale Regulation 405 KAR 30:020 §1

> Section 1. Applicability. The regulations in Chapter 30 of Title 405 shall apply to any oil shale operation conducted on or after the effective date of these regulations on lands containing oil shale deposits and any other lands used, disturbed, or redisturbed in connection with or to facilitate such operations or any other activity related to oil shale development. The extraction of oil shale by a landowner for his own agricultural related use from land owned or leased by him is exempt from the requirements of this chapter. [emphasis added].

Comment

This section is intended to describe those operations that are subject to the oil shale regulations. The regulation exempts extraction of oil shale by a landowner for his own agricultural related use.

Comparable Coal Regulation (In-Part) 405 KAR 7:020 E §1 (115)

(115) "Surface coal mining operations" means activities conducted on the surface of lands in connection with a surface coal mine and surface operations and surface impacts incident to an underground coal mine. Such activities include excavation for the purpose of obtaining coal, including such common methods as contour, strip, auger, mountaintop removal, box cut, open pit, and area mining, the use of explosives and blasting, and in situ distillation or retorting, leaching or other chemical or physical processing, and cleaning, concentrating, or other processing or preparation, and the loading of coal at or near the mine-site. Such activities shall not include the extraction of coal by a landowner for his own noncommercial use from land owned or leased by him....

Comment

This provision also contains a similar exemption as that created by the oil shale regulations. However, there is no requirement that the individual use the coal for agricultural purposes.

* *

Oil Shale Regulation 405 KAR 30:020 §6 (1) and (2)

Section 6. Extraction and Processing Operations. (1) Any person engaged in an oil shale operation shall demonstrate to the department utilizing necessary technical, scientific, and engineering data the impacts their operation will have on the environment. Such data used in the justification shall have been generated on eastern shales having comparable characteristics to the shales in the location of the proposed project area.

(2) In the event the applicant cannot demonstrate to the department's satisfaction the extent and magnitude of possible adverse environmental impacts of the facility, its size shall be limited to a total annual surface disturbance of twenty-five (25) acres or a production capacity of 1000 barrels per day whichever is smaller. Total surface disturbance shall include, but not be limited to, areas upon which mining activities occur or where such activities disturb the natural land surface, lands affected by the construction of new roads or the improvement or use of existing roads to gain access to the site and for haulage, lands accommodating conveyor systems, and excavations, workings, impoundments, dams, ventilation shafts, entry ways, spent shale banks, spent shale disposal sites, dumps, stockpiles, overburden piles, spoil piles, tailings, holes or depressions, repair areas, storage areas, processing areas, shipping areas and other areas upon which are sited structures, facilities, or other property or materials on the surface, resulting from or incident to such activities. (emphasis added).

Comment

This regulation simply establishes an impossibility. An operator will not be able to obtain an oil shale permit unless he can demonstrate to the Department (utilizing existing technical, scientific and engineering data) the impact that the operation will have on the environment. The data used in the justification must have been generated on eastern shales having comparable characteristics to the shale in the location of the proposed project area. The Department does not acknowledge the reality that the data does not exist. However, the regulation does provide that if the applicant cannot so demonstrate, the size of the entire operation shall be limited to a total annual surface disturbance of twenty-five (25) acres or a production capacity of 1,000 barrels per day whichever is smaller.

Comparable Coal Regulation None

Comment

The Department has never related the size of a mining operation to the applicant's ability to demonstrate its technical, scientific and engineering expertise in the mining sciences.

* *

Oil Shale Regulation 405 KAR 30:130 §3 (1) and (2)

Section 3. Term of Permits. (1) Except for pilot projects, an oil shale mining permit shall be valid for five (5) years from the date of issuance. A permit shall terminate, if the permittee has not substantially commenced the oil shale operation covered by the permit within three (3) years of the issuance of the permit.

(2) Pilot Projects. A permit for a pilot project shall be valid for a term of two (2) years from the date of issuance.

Comment

This section sets forth a five year term for all oil shale permits except for pilot projects which will have a two (2) year term. Although no definition of "pilot project" appears in the regulations, it is the general understanding that

a pilot project is an operation consisting of less than 25 acres or 1,000 barrels per day.

Comparable Coal Regulation None

Comment

There is no "pilot project" provision in the coal regulations. Coal exploration is provided for, but is not analogous to what is believed to be intended by the Department's term of "pilot project".

* *

Oil Shale Regulation 405 KAR 30:130 §10 (1) and (2)

> Section 10. Department Review of Outstanding Permits. (1) The department shall review each permit issued and outstanding under this chapter during the term of the permit. This review shall occur not later than the middle of the permit term.
>
> (2) After this review, the department may, by order, require revision or modification of the permit provisions or may increase the amount of the bond to ensure compliance with all applicable statutes and regulations.

Comment

This provision empowers the Department to increase bond amount during the life of the permit in order to "insure compliance with all applicable statutes and regulations." This authority to increase bond amounts is much broader than the Department's authority to increase bonds posted pursuant to coal mining permits.

Comparable Coal Regulation 405 KAR 10:020 E §4(1)

> Section 4. Adjustment of amount. (1) The amount of the performance bond liability applicable to a permit shall be adjusted by the department as the acreage in the permit area is increased or decreased, or when the department determines that the cost of future reclamation, restoration or abatement work has changed substantially. Increase in performance bond liability shall not affect existing obligations of sureties without their consent.

Comment

Although the Department has the authority to increase bonds posted pursuant to coal mining permits, the criteria for increase is much clearer and the authority therefore much more limited.

* *

Oil Shale Regulation 405 KAR 30:130 §13 (9) (g)

> Section 13. Criteria for Permit Approval and Denial. No application for a permit and no oil shale operation shall be approved or allowed, unless the application affirmatively demonstrates and the department determines on the basis of information set forth in the application, and other available information as necessary, that:
>
> (9) The proposed permit area is:
>
> (g) Not within 300 feet, measured horizontally, of an occupied dwelling unless the applicant submits with the permit application a written waiver from the owner of the dwelling consenting to such an operation within a closer distance of the dwelling specified in the waiver. The waiver must be knowingly and intelligently given and be separate from a lease or deed unless the lease or deed contains an explicit waiver. [emphasis added].

Comment

The phrase "knowingly and intelligently given" is new language. How the Department will determine if these two requirements will be met should prove to be interesting.

Comparable Coal Regulations 405 KAR 24:040 E §2 (5) (a)

> Section 2. Permit application review. Unless the required approvals or waivers are obtained, upon receipt of a complete application for a surface coal mining and reclamation operation permit, and subject to valid existing rights, the department shall review the application and deny the permit if it determines that the lands which would be disturbed by the proposed operation include:
>
> (5) Lands within 300 feet, measured horizontally, from any occupied dwelling, unless the owner of the dwelling has provided a written waiver consenting to surface coal mining operations closer than 300 feet.
>
> (a) The applicant shall submit with the permit application a written waiver from the owner of the dwelling, consenting to such an operation within a closer distance of the dwelling specified in the waiver. Valid waivers obtained prior to August 3, 1977 are valid for the purposes of this paragraph. Waivers obtained from previous owners shall remain effective for subsequent owners who had knowledge of the existing waiver at the time of purchase. [emphasis added].

Comment

This regulation provides for a similar waiver, but there is no requirement that it be "knowingly and intelligently" given.

* *

Performance Bonding

The proposed oil shale regulations addressing performance bonding are 405 KAR 30:030, 405 KAR 30:040, 405 KAR 30:060, 405 KAR 30:070, and 405 KAR 30:080. Of these regulations, the following deserve comment as they compare to the proposed permanent coal mining regulations of the Commonwealth.

Oil Shale Regulation 405 KAR 30:040 §2

> Section 2. Minimum Amount. The minimum amount of bond for exploration permits involving drilling and coring shall be $2,000 For all other oil shale operation permits the minimum amount of bond per acre shall be $5,000, but in no event shall such a bond be less than $20,000.

Comment

This regulation establishes minimum per acre bond amounts for oil shale operations; and also provides for bonding for exploration operations. The coal regulations are quite different.

Comparable Coal Regulation 405 KAR 10:020 E §2

> Section 2. Minimum amount. The minimum amount of the bond for surface coal mining and reclamation operations at the time the permit is issued shall be $10,000 for the entire area under one permit.

Comment

No bond is required for coal exploration operations and there is no minimum per acre established by this regulation. The minimum total bond per permit is half the amount set for oil shale.

* *

Oil Shale Regulation (In-Part) 405 KAR 30:040 §3 (2)

> Section 3 (2) In addition to the period necessary to achieve compliance with the requirements of all applicable statutes and regulations and the conditions of the permit, the period of liability under performance bonds shall continue for a period of seven years beginning with the last year of substantially augmented seeding, fertilizing, irrigation or other work ....[emphasis added].

Comment

This regulation sets forth a period of liability substantially longer than that set forth for coal mining.

Comparable Coal Regulation (In-Part) 405 KAR 10:020 §3 (2)

> Section 3 (2) In addition to the period necessary to achieve compliance with all requirements of KRS Chapter 350, Title 405, Chapters 7 through 24 and the permit including the standards for the success of revegetation as required by 405 KAR 16:200E and 405 KAR 18:200E, the period of liability under performance bond shall continue for a period of five (5) years beginning with the last year of substantially augmented seeding, fertilizing, irrigation or other work.... [emphasis added].

Comment

This regulation sets forth a liability period of five (5) years for coal mining operations. There appears to be no reason for the longer term set forth in the oil shale regulations.

* *

Oil Shale Regulation 405 KAR 30:060 §1 (1) and (2) (a), (b) and (c)

> Section 1. Types of Performance Bond. (1) The form for the performance bond shall be prescribed by the department.
>
> (2) The performance bond shall be either:
>
> (a) A surety bond, or
>
> (b) A cash bond, which may include certificates of deposit, letters of credit, and acceptable escrow accounts, or
>
> (c) A combination of these bonding methods as approved by the department.

Comment

This regulation sets forth the general requirements for performance bond liability insurance. There is no provision for incremental bonding.

Comparable Coal Regulation 405 KAR 10:010 E §2 (2) (a)(2)

> Section 2 (2) (a) Liability on the performance bond shall cover all surface coal mining and reclamation operations to be conducted within the permit area until all reclamation requirements of Title 405, Chapter 7 through 24 have been met. After the amount of the bond has been determined for the permit area in accordance with 405 KAR 10:020E, the permittee or applicant may either file:
>
> 2. An incremental bond

schedule and the new performance bond required for the first increment in the schedule.

Comment

The proposed coal regulations provide the flexibility for incremental bond.

* *

Oil Shale Regulation 405 KAR 30:080 §3 (1) (d)

Section 3. Criteria for Forfeiture. (1) The department shall have the authority to forfeit a bond if:

(d) For such other good cause as the department determines is sufficient.

Comment

This regulation grants the Department extremely broad authority to forfeit bonds. Absolutely no criteria are set forth in this paragraph, although the entire section is entitled: Criteria for Forfeiture. Neither the Department nor the operator, has any idea as to what is meant by this regulation.

Comparable Coal Regulation None

Comment

Bond forfeiture criteria are set forth at 405 KAR 10:050 E. Language similar to that of the oil shale regulation does not appear in the coal regulations.

* *

Performance Standard

The proposed oil shale regulations addressing performance standards are 405 KAR 30:020, 405 KAR 30:210, 405 KAR 30:220, 405 KAR 30:230, 405 KAR 30:240, 405 KAR 30:250, 405 KAR 30:260, 405 KAR 30:270, 405 KAR 30:280, 405 KAR 30:290, 405 KAR 30:300, 405 KAR 30:310, 405 KAR 30:320, 405 KAR 30:330, 405 KAR 30:340, 405 KAR 30:350, 405 KAR 30:360, 405 KAR 30:370, 405 KAR 30:380, 405 KAR 30:390, 405 KAR 30:400 and 405 KAR 30:410. Of these regulations, the following deserve comment as they compare to the proposed permanent coal mining regulations of the Commonwealth.

Oil Shale Regulation (In-Part) 405 KAR 30:350 §4

Section 4. Public Notice of Blasting Schedule. At least ten (10) days, but not more than twenty (20) days before beginning a blasting program in which explosives that use more than the equivalent of five (5) pounds of TNT are detonated, the permittee shall publish a blasting schedule in a newspaper of general circulation in the locality of the proposed site. Copies of the schedule shall be distributed by mail to local governments and public utilities and to each residence within one-half (1/2) mile of the blasting sites described in the schedule. The permittee shall republish and redistribute the schedule by mail at least every three (3) months....

Comment

The redistribution schedule set forth in this regulation is more stringent than that set forth in the coal regulations.

Comparable Coal Regulations 405 KAR 16:120 §3 (1) (c)

Section 3 (1)(c) The permittee shall republish and redistribute the schedule by mail at least every twelve (12) months.

Comment

This regulation provides for the redistribution of blasting schedules annually.

* *

Oil Shale Regulation 405 KAR 30:290 §2 (1)

Section 2. Removal. (1) Topsoil shall be removed from areas to be disturbed, after vegetative cover that would interfere with the use of the topsoil is cleared from those areas, but before any drilling, blasting, mining, or other surface disturbance of those areas. The minimum depth of topsoil and subsoil material or topsoil substitute material to be restored on non-prime farmland areas shall be twenty-four (24) inches, in accordance with Section 4. [emphasis added].

Comment

This regulation presents a most significant departure from the coal regulations. The requirement to segregate 24 inches of material apparently has no scientific basis and would prove to be an extremely expensive requirement for oil shale operators

Comparable Coal Regulation 405 KAR 16:050 §2 (2) and (3)

Section 2(2) All topsoil shall be removed in a separate layer from the areas to be disturbed, unless use of substitute or supplemental materials is approved by the department in accordance with subsection (5) of this section. If use of substitute or supplemental materials is approved, all materials to be redistributed shall be removed.

(3) If the topsoil is less than six (6) inches in depth, a six (6) inch layer that includes the A horizon and

the unconsolidated materials immediately below the A horizon or the A horizon and all unconsolidated material if the total available is less than six (6) inches, shall be removed and the mixture segregated and redistributed as the surface soil layer, unless topsoil substitutes are approved by the department pursuant to subsection (5) of this section. [emphasis added]

Comment

The coal regulation is a much more unreasonable approach. The Department is keenly aware of the extensive debate over this provision and is also aware of the scientific research concerning root zones. There appears to be no justification for 405 KAR 30:290 §2 (1).

* *

Oil Shale Regulation (In-Part) 405 KAR 30:310 §1 (2)

Section 1. Diversions and Conveyance of Overland Flow and Shallow Ground Water Flow, and Ephemeral Streams... The following requirements shall be met for all diversions and for all collection drains that are used to transport water into watertreatment facilities and for all diversions of overland and shallow ground water flow and ephemeral streams:

(2) To protect fills and property and to avoid danger to public health and safety, permanent diversions shall be constructed to pass safely the peak runoff from a precipitation event with a 100-year recurrence interval, or a larger event as specified by the department.... [emphasis added].

Comment

The Department has, without any apparent scientific basis, substantially changed the performance criteria for diversion facilities.

Comparable Coal Regulation (In-Part) 405 KAR 16:080 §1 (2)

(2) To protect fills and property and to avoid danger to public health and safety, permanent diversions shall be constructed to pass safely the peak runoff from a precipitation event with a ten (10) year recurrence interval, or a larger event as specified by the department.... [emphasis added].

Comment

The Department's adoption of a 100 year standard for oil shale and 10 year standard for coal cannot be reconciled. If the Department believes the 10 year standard is adequate the oil shale standard should be changed.

* *

Oil Shale Regulation 405 KAR 30:340

Leachate Control

Comment

There is no counterpart to this regulation present in the coal regulations.

Comparable Coal Regulation None

Comment

None

* *

Oil Shale Regulation 405 KAR 30:360 §2 (2)

Section 2 (2) Final disposal of such wastes shall be in a designated disposal site in the permit area or other appropriate disposal areas approved by the department. Disposal sites shall be designed and constructed with appropriate water barriers on the bottom and sides of the designated site. Wastes shall be routinely compacted and covered to prevent combustion and from becoming windborne. When the disposal is completed a minimum of four (4) feet of nontoxic and noncombustible cover shall be placed over the site soil material.... [emphasis added].

Comment

The depth of cover requirements of this regulation is double that of the coal regulations.

Comparable Coal Regulation 405 KAR 16:150 §1 (2)

(2) Disposal. Final disposal of such wastes shall be in a designated disposal site in the permit area or other appropriate disposal areas approved by the department. Disposal sites shall be designed and constructed with appropriate water barriers on the bottom and sides of the designated site. Wastes shall be routinely compacted and covered to prevent combustion and windborne waste. When the disposal is completed a minimum of two (2) feet of soil cover shall be placed over the site.... [emphasis added].

Comment

This regulation requires only 2 feet of cover for coal waste disposal. There appears to be no rational basis for the Department's departure in their proposed oil shale regulations.

* *

Oil Shale Regulation 405 KAR 30:380

Spent Shale Disposal

Comment

There is no counterpart to this regulation present in the coal regulations. This section is probably unnecessary inasmuch as the disposal of waste is handled by Chapter 405 KAR 30:360. By establishing this separate section, the Department is obviously intending to apply different criteria to the disposal of spent shales verses other wastes.

* *

Enforcement Procedures

The proposed shale regulations addressing enforcement procedures are 405 KAR 30:020, 405 KAR 30:090, 405 KAR 30:100, 405 KAR 30:110 and 405 KAR 30:170.

Comment

The enforcement regulation set forth in the proposed oil shale package are virtually identical to those contained in the Department's coal mining regulations. Any potential operator should be aware of the Department's approach and of their decision to include the same "citizens rights" regulations in their present regulatory scheme. Finally, the oil shale industry should be aware that the enforcement provisions would not only apply to a typical operation, but also to pilot projects and oil shale exploration.

Conclusion

Although the Department has intended to extensively and conservatively regulate the oil shale industry, there is some expectation that the Kentucky General Assembly, during its 1982 session, will take a very close look at the proposed regulations. The General Assembly may choose to re-write, amend or delete from the present oil shale package; or it may choose to statutorily direct the Department to engage in such regulation reworking. It is our opinion that the final version of the oil shale regulations has not yet been written.

Potential Economic Impact of Oil Shale Commercialization in Fleming County, Kentucky

by

Stephen H. Miller
Associate Director
Buffalo Trace Area Development District
Maysville, Kentucky 41056

Abstract. The purpose of this paper is to research and evaluate the potential economic impact that may result from synthetic fuels development in Fleming County, Kentucky. The goal of this paper is to objectively present the anticipated economic benefits and costs that can result from the commercialization of extracting kerogen from oil shale in rural southeastern Fleming County, Kentucky.

Introduction

In 1980, the Buffalo Trace Area Development District contracted for the preparation of an oil shale feasibility study for Fleming and Lewis Counties. The Study within its scope, determined that the resource is present and commercialization appears feasible. This study is the basis of synthetic fuel plant assumptions in this paper. This paper assumes commercial feasibility and evaluates the economic impact on Fleming County, based on a 10,000 barrel per day processing plant on a 2,000 acre site in southeastern Fleming County. Other assumptions include that the processing technology is the type developed by the Paraho Corporation and the resources are obtained by surface mining.

The paper emphasizes the local economic impact based on: (1) population, (2) labor force/employment, (3) personal income, (4) housing, (5) retail sales, (6) education, (7) transportation, (8) health care, (9) government, (10) law enforcement/fire protection, and (11) utility services.

The method of research relies on personal interviews, publications and study reviews. The basic methodology is to assess current economic conditions and determine how the synthetic fuel development will change the economic environment of Fleming County, Kentucky.

Fleming County Profile

Fleming County is the selected area for analysis for this paper. Fleming County is chosen to be the subject area as a result of the study completed for the Buffalo Trace Area Development District by the Davy McKee Corporation. Fleming County is a rural county with a population of 12,332 persons, which has historically relied on agriculture for economic stability.[1] In 1980, one out of every four persons depended on agriculture for a livelihood.[2] Major nonagricultural employers in Fleming County are the Randall Corporation, U.S. Shoe Corporation, Kentucky Department of Transportation District Nine Office, and the Fleming County Hospital.

The largest single source of personal income in Fleming County is agriculture. Over twenty-six percent of the county personal income is attributable to agriculture. Following are manufacturing and trade which account for nineteen and thirteen percent respectfully. The average weekly wage in Fleming County for nonagriculture employment is $170.75. This represents only seventy-three percent of the statewide average.[3]

In 1970, Fleming County had 4,055 year-round occupied housing units. Only 2,119 of all housing units in Fleming County have all plumbing facilities and forty-two percent or 1,719 of the total number of units were identified as being substandard. The substandard percentage is over double the statewide percentage. The county housing stock is represented by sixty-three percent being built before 1940 with only ten percent built after 1965.[4] Between 1970 and 1978, the average annual number of housing sales in the county was only forty-nine with the 1978 average sales price being $27,600 for a previously occupied home.[5]

Fleming County contains one public school system with five elementary schools, one middle school and one high school. The county also has recently opened a vocational wing at the high school in Flemingsburg. The fall 1980 enrollment of the Fleming County school system was 2,387 students. Student/teacher ratios for each level are as follows: elementary - 16:1; middle school - 16:1; and high school - 19:1.[6]

Flemingsburg, the hub of economic activity in Fleming County, is served by Kentucky Highways 11, 32 and 57, all AAA-Rated trucking highways. U.S. 68 is approximately fifteen miles from the Flemingsburg via Kentucky Highways 32 and 165. The nearest interestate facility is at Morehead via Kentucky 32, approximately twenty-five miles distance. Interstate 75 in Lexington is approximately fifty-seven miles distance.

There is no rail service directly serving Flemingsburg. However, rail service is available at Flemingsburg Junction, three miles west of Flemingsburg in Fleming County. Air services are

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There is no rail service directly serving Flemingsburg. However, rail service is available at Flemingsburg Junction, three miles west of Flemingsburg in Fleming County. Air services are

available from the Fleming-Mason Airport located seven miles north of Flemingsburg in Mason County, Kentucky. The nearest scheduled airline service is Bluegrass Field in Lexington, Kentucky, approximately fifty-seven miles distance. The nearest navigable waterway to Flemingsburg is the Ohio River at Maysville, Kentucky seventeen miles north.

Retail sales in Fleming County totaled $36,550,000 in 1979. The largest groups of retail sales in Fleming County were auto dealers, thirty-seven percent, and food stores, twenty-eight percent.[7]

Fleming County in Fiscal Year 1981 had an assessed evaluation for real estate of $148,263,150 and $29,831,020 for tangible property. The City of Flemingsburg had an assessed property value for real estate of $1,217,900 and $267,234 for tangible property. In the same year, Fleming County Fiscal Court had a general fund budget of $419,460 and a road fund budget of $418,245. The City of Flemingsburg had a Fiscal Year 1981 general fund of $382,000.[8]

Fleming County and the City of Flemingsburg are served by a total of twelve full-time police staff. Fire protection is provided on a volunteer basis with a total of forty-six volunteer firemen throughout the County.[9]

Electrical utility services are provided by the Kentucky Utilities Company in Flemingsburg and its immediate adjacent areas. The remainder of the county is served by the Fleming-Mason Rural Electric Cooperative Corporation. Natural gas is available in Flemingsburg and a limited adjacent area by Columbia Gas of Kentucky, Inc. Water service in the county is provided by the City of Flemingsburg, Fleming County Water Association, and the Western Fleming Water District. Sewer service is only available in the Flemingsburg area.

Proposed Oil Shale Development

This paper determining the potential impact of oil shale commercialization in Fleming County bases its findings on the location of a oil shale plant as described in the recently completed report by the Davy McKee Corporation entitled "Synthetic Fuels from Eastern Oil Shale." The study directed its scope of research to the geographic area of Fleming and Lewis Counties. (See Figure 1) The following briefly describes the proposed oil shale development as proposed in the study.

The Buffalo Trace Study proposed ridge-top mining to supply 30,000 tons per day of oil shale to a surface retorting facility. Mining locations were proposed in two locations. These are: Pea Ridge and North Ridge in southeastern Fleming County. (See Figure 2) The Study examined two processing technologies, the Paraho and Hytort. This paper assumes the Paraho Retort based upon the recommended processing technology of the Study. The plant is designed for a 30,000 ton per day retorting capacity. The plant, requiring approximatly 65 acres, would employ 900 persons.[10]

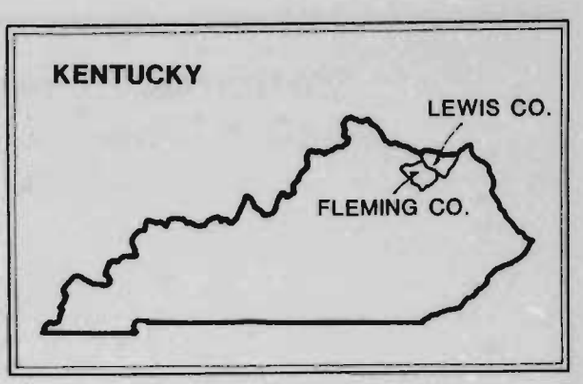

Figure 1: Location of Fleming and Lewis Counties, Kentucky.

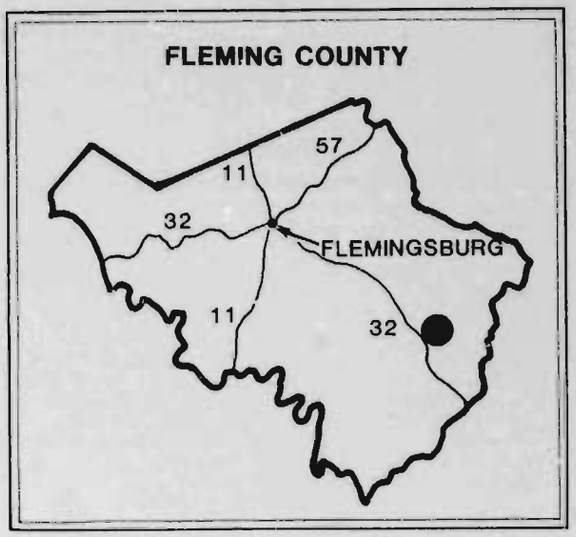

Figure 2: Proposed Fleming County Plant Site with Major Highways Shown.

Based on plus or minus twenty-five percent capital cost estimates, the initial plant investment cost for the Paraho Retort is $504 million. This cost is for a "grass-roots" plant, which includes mining, mineral handling, retorting, oil recovery facilities to meet environmental standards and all necessary off-sites. Total initial capital required for the Paraho Oil Shale Plant is $647.2 million. Gross annual operating cost for the Paraho Plant is $63.1 million. The net operating cost was determined at $10.6 million.[11]

Impact Assessment

Methodology

The methodology used to examine the economic impact of the commercialization of synthetic fuels from oil shale in Fleming County was prepared by Murphy/Williams Urban Planning & Housing Consultants. The report entitled "Socio-Economic Impact Assessment: A Methodology Applied to Synthetic Fuels," was prepared in April, 1978 for the U.S. Department of Energy.

The impact methodology utilizes a community development model based on socio-economic profiles of eleven mining dominant counties in the United States. The county profiles are intended as a working tool and point of reference for socio-economic issues. The methodology is not a substitute for judgment, nor can it produce precise accuracy. However, as an analytical tool, the the methodology can prove helpful to decision-makers.[12]

There are two factors which should be pointed out as significant in the use of this model. First, the profile based on eleven mining dominant communities has more relevance to the operation phase than construction phase. The methodology provides limited resources for the characterization of transit construction work force. Second, the occupational mix of synthetic fuels differs from that in the profile counties or traditional mining industry in general. This results from the fact that synthetic fuels require resource conversion rather than simple extraction.[13]

The impact assessment from the community development model provides gross estimates based on the location of an oil shale synthetic fuels plant in Fleming County, Kentucky. The model is used to determine impact at the county level. To interpret how the impact will effect Fleming County requires two additional steps.

First, the assumed plant location is in rural southeastern portion of Fleming County with the closest community of significant size being Morehead, KY, located in Rowan County. The purpose of this paper being to determine the impact on Fleming County, requires identifying the impact applicable to Fleming County.

The second requirement to determine the impact on Fleming County is to examine the end results of the model which is based on a "typical community" and characterize the impact on Fleming County based on examination of the existing economic factors. The economic effects are estimated based on the determined gross impacts of oil shale development and the unique characteristics of Fleming County.

Identification of the Impact Area

The definition of the impact area is important as the magnitude and geographic instances of impact are a function of the geographic size of the area. For this study, two areas of impact are defined. First, is the primary effected area, which includes the geographic area which is anticipated to be the recipient of the greatest demographic, land use, economic and social effects resulting from the construction and operation of the oil shale plant. The second area of impact will receive a lesser effect as a result of the distance from the proposed project. The second area of impact constitutes the commuting region from which construction workers are expected to commute either on a daily or weekly basis.

Operational Phase

The primary impact area is of greatest interest for this study in determining impact to Fleming County. The political subdivisions, public facilities, businesses and citizens in the primary effected area are more significantly effected by the construction and operation of the proposed synthetic fuels plant, than the secondary or commuting region.

Figure 3 identifies the geographic definition of the two impact zones suggested. The boundaries as defined were determined by a judgment evaluation of: (1) geographic distance; (2) time travel; (3) existing commuting patterns; (4) identified labor market area; and (5) identification of cities as providers of markets (i.e. retail trade, services, community facilities, etc.).

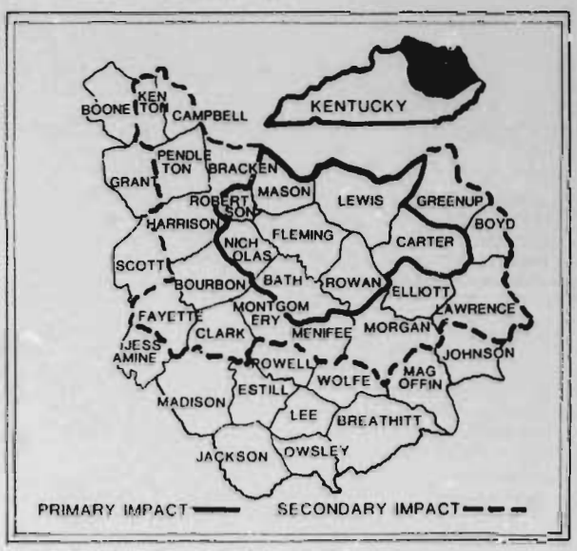

Figure 3: Primary and Secondary Impact Areas as Identified

The primary effect area as identified is composed of eight counties. The eight counties are; Bath, Carter, Fleming, Lewis, Mason, Nicholas, Robertson, and Rowan. Each of these counties are located within twenty miles of the assumed oil shale plant site in Fleming County.

After identifying the primary impact counties, significance of the impact by county was determined. The significance of impact is identified by the percent of gross impact applicable to each county identified in the primary effected area. The percent of gross impact applicable to each county was calculated as a function of existing population, factored by distance to the assumed oil shale plant site.

Population was selected in comparison to distance by assuming that county population equates with labor supply, public facilities and services, retail markets, housing markets and cultural opportunities. The distance factor was determined by the distance from the proposed plant site to the community of most significant population in the county. However, in the instance of Carter County, two communities were identified as having significant population concentrations. In this situation the center point between these two communities was located and used for determining distance.

The entire operation phase impact is assumed to be limited to the primary impact area. Based on a described method of calculating percent of the impact by the county, the results are shown in Table 1.

Table 1. Percent of County Impact in the Primary Effected Area.

County Name	Percent
Bath County	10%
Carter County	14%
Fleming County	19%
Lewis County	10%
Mason County	11%
Nicholas County	5%
Robertson County	1%
Rowan County	30%

As shown, the significance of gross impacts determined for the oil shale plant is nineteen percent for Fleming County in the operation phase. Rowan County is identified as the county of most significant impact with thirty percent.

Construction Phase

The community development model provided gross impact results for demographic and social factors during the construction phase. In this paper the only analysis of these results is an identification of the secondary impact area. The secondary impact area is defined as an area expected to provide workers commuting on a daily or weekly basis during the construction phase.

Fleming County Impact Assessment

Introduction

The applicability of the gross impact of the proposed oil shale plant is determined as nineteen percent for Fleming County. Based on the methodology applied, nineteen percent ranks Fleming County second in significance of impact during the operation phase. This fact may appear surprising. However, the oil shale plant site proposed is in a sparsely populated portion of southeastern Fleming County. The area economy is characterized by agriculture and timber production. The nearest communities of significant size are Morehead in Rowan County with a population of 7,773 and Flemingsburg in Fleming County with a population of 2,826.[14] Each community is twelve miles from the proposed plant site.

Residents in the proposed synfuel plant site area depend on Flemingsburg and Morehead as the major market and service areas. Due to the fact that Morehead contains a population of over twice that of Flemingsburg, more market and service opportunities exist. Thus, the determined greater impact associated to Rowan County rather than Fleming County appears realistic.

Impact Analysis

Synthetic fuels development can significantly impact economic, demographic and social land use and physical environment of a community or communities. Given this information, the following model estimates; (1) economic impacts, (2) demographic and social impacts, (3) land use impacts, and (4) local government impacts. Tables 2 through 6 detail the estimated impact of oil shale commercialization. The impact analysis is not limited to the political subdivisions of Fleming County, Kentucky. The analysis as shown estimates the total impact of the synthetic fuels plant. Association of the magnitude of impact of Fleming County is made following the determination of total impact.

Table 2. Economic Impact of Oil Shale Commercialization in Fleming County.

Economic Impacts	Total Impact	Fleming County Impact
Permanent Employment		
Peak Construction	2,627	499
Operating Phase	900	171
Local Secondary Employment		
Peak Construction	1,655	314
Operating Phase	1,278	243
Local Secondary Employment - By Industrial Category (70% Capture Rate)		
Operating Phase		
Construction	146	28
Transportation	207	39
Commercial & Public Utilities	75	14
Wholesale Trade	56	11
F.I.R.E.	74	14
Personal Business	49	9
Professional Services	174	33
Government	142	27
Total Annual Employment Earnings		
Primary Employment Peak Construction	$55,734,432	$10,589,542
Primary Employment Operating Phase	18,830,700	3,577,833
Secondary Employment Peak Construction	21,986,675	4,177,468
Secondary Employment Operating Phase	16,978,230	3,225,864
Total Local Income		
Peak Construction	85,493,217	16,243,711
Operating Phase	42,970,716	8,164,436
Per Capita Income		
Peak Construction	14,282	14,282
Operating Phase	13,222	13,222
Local Retail Sales		
Operating Phase	17,188,286	3,265,774
Local Services		
Operating Phase	3,580,893	680,370

Table 3. Demographic and Social Impact of Oil Shale Commercialization in Fleming County

Demographic & Social Impacts	Total Impact	Fleming County Impact
Female Employment		
Primary		
Peak Construction	53	10
Operating Phase	36	7
Secondary		
Peak Construction	828	157
Operating Phase	636	121
Total Population		
Peak Construction		
Working Age Males	2,627	499
Working Age Females	1,287	254
Other Population	2,072	394
Operating Phase		
Working Age Males	990	188
Working Age Females	881	167
Other Population	1,379	262
Population/Age Distribution		
0-5 Years of Age		
Peak Construction	862	164
Operating Phase	335	64
5-17 Years of Age		
Peak Construction	1,431	272
Operating Phase	933	177
18-29 Years of Age		
Peak Construction	1,898	360
Operating Phase	910	173
30-44 Years of Age		
Peak Construction	1,138	216
Operating Phase	634	120
45-64 Years of Age		
Peak Construction	623	118
Operating Phase	328	62
65 + Years of Age		
Peak Construction	36	7
Operating Phase	111	21
Social Services Personnel		
Peak Construction		
Physicians	6	1
Registered Nurses	36	7
Health Support Personnel	12	3
Police & Firemen	18	3
Operating Phase		
Physicians	5	1
Registered Nurses	26	5
Health Support Personnel	8	2
Police & Firemen	11	2
School Enrollment		
Peak Construction	1,288	245
Operating Phase	840	160
School Teachers		
Peak Construction	58	11
Operating Phase	38	7
Total Households		
Peak Construction	1,294	246
Operating Phase	787	150

Table 3. (Cont'd) Demographic and Social Impact of Oil Shale Commercialization in Fleming County.

Demographic & Social Impacts	Total Impact	Fleming County Impact
Total Housing Needs		
Peak Construction	1,423	270
Operating Phase	826	157
Housing Needs by Types		
Single Family		
Peak Construction	640	122
Operating Phase	496	94
Mobile Home		
Peak Construction	498	95
Operating Phase	207	39
Multi-Family		
Peak Construction	285	54
Operating Phase	124	24

Table 4. Land Use Impact of Oil Shale Commercialization in Fleming County

Land Use Impact	Total Impact	Fleming County Impact
Land Requirement Synfuel Plant Operating Phase	2,000	
Retail Sales by Type		
Operating Phase		
Hardware	$ 1,409,439	$ 267,793
General Mechandise	1,323,498	251,465
Food Stores	4,761,155	904,619
Auto Dealers	3,351,716	636,826
Gas Stations	1,650,075	313,514
Appliances	996,921	189,415
Furniture	378,142	71,847
Eating & Drinking	1,031,297	195,946
Drug Stores	618,778	117,568
Miscellaneous Retail	1,667,264	316,780
Retail Building Space		
Operating Phase		
Hardware	28,189	5,356
General Mechanics	26,470	5,029
Food Stores	39,676	7,538
Auto Dealers	83,793	15,920
Gas Stations	41,252	7,838
Appliances	19,938	3,788
Furniture	12,605	2,395
Eating & Drinking	17,188	3,266
Drug Stores	8,840	1,679
Miscellaneous Retail	55,575	10,559
Service Receipts by Type		
Operating Phase		
Hotels & Motels	$ 886,576	$ 164,649
Auto Repair	329,442	62,594
Miscellaneous Repair	687,531	130,631
Amusement & Recreation	433,288	82,325
Legal Services	243,501	46,265
Miscellaneous	1,020,554	193,905

Table 4. (Cont'd) Land Use Impact of Oil Shale Commercialization in Fleming County

Land Use Impact	Total Impact	Fleming County Impact
Commercial Services/ Building Space Operating Phase		
Hotels & Motels	19,257	3,659
Auto Repair	8,236	1,565
Miscellaneous Repair	22,918	4,354
Amusement & Rec.	28,886	5,488
Legal Services	8,117	1,542
Miscellaneous Services	51,028	9,695
Office Employment Operating Phase		
Construction	15	3
Transportation	21	4
Comm. & PU	8	2
Wholesale Trade	6	1
F.I.R.E.	37	7
Personal Business	25	5
Professional Services	174	33
Government	43	8
Office Building Space Operating Phase		
Construction	2,250	427
Transportation	3,150	598
Comm. & PU	1,200	228
Wholesale Trade	900	171
F.I.R.E.	5,550	1,054
Personal Business	3,750	712
Professional Services	30,450	5,785
Government	7,525	1,430
Land Requirements Building Space		
Retail Service Office	526,742	100,081
Parking Space	987,643	187,652
Other Land Required	378,596	71,933
Manufacturing Employment Operating Phase	99	19
Industrial Building Space Operating Phase	54,450	10,345
Land Required - Industry Operating Phase		
Parking Space	25,740	4,891
Other Land Required	16,038	3,047
Land Requirements - Residential Operating Phase		
Single Family	165	31
Mobile Home	41	8
Multi-Family	12	2
Land Requirements - Schools	11	2
Land Requirements Operating Phase		
Playgrounds	6	1
Neighborhood Parks	10	2
Community Open Space	12	2
Estimated Land Cost		
Police	$ 10,400	$ 1,976
Fire	8,320	1,581
Government Adminin.	3,900	741
Health	46,020	8,744
Library	7,995	1,519

Table 4. (Cont'd) Land Use Impact of Oil Shale Commercialization in Fleming County

Land Use Impact	Total Impact	Fleming County Impact
Land Requirements - Other Public Facilities	9	2
Residential Roads		
Arterials	4,734	900
Collectors	8,717	1,656
Minor Streets	29,106	5,550
Community Street System		
Arterials	8,333	1,583
Collectors	7,588	1,442
Minor Streets	32,016	6,083
Land Requirements - Minor Roads Operating Phase	1,792,115	340,502

Table 5. Local Government Cost Impact of Oil Shale Commercialization in Fleming County

Local Government Costs	Total Impact	Fleming County Impact
Facility Development Costs Operating Phase		
Playgrounds	$ 56,745	$ 10,782
Neighborhood Parks	129,675	24,638
Commercial Open Space	18,037	3,427
Total Capital Costs (Including Land Costs) Operating Phase	439,270	83,461
School Enrollment		
Elementary School	605	115
High School	235	45
Building Space Operating Phase		
Elementary Schools	72,600	13,794
High Schools	35,250	6,127
Facility Development Costs		
Elementary Schools	$ 2,468,400	$ 468,996
High Schools	1,198,500	277,715
Other Costs		
Furnishings		
Parking		
Paving		
Landscaping - Total	440,028	83,605
Total Capital Costs with Land Operating Phase	4,271,205	811,529
Facility Development Costs		
Arterials	974,928	185,236
Collectors	556,129	105,664
Minor Streets	1,184,614	225,077
Total Capital Costs	2,905,768	552,096

Table 5. (Cont'd) Local Government Cost Impact of Oil Shale Commercialization in Fleming County.

Local Government Costs	Total Impact	Fleming County Impact
Facility Development Costs		
Police	30,000	5,700
Fire	104,000	19,760
Government Admini.	65,000	12,350
Health	767,000	145,730
Libraries	133,250	25,317
Total Capital Costs - Community Facilities with Land		
Operating Phase	1,275,885	242,418
Non-residential Facility Development Costs		
Operating Phase		
Sanitary Sewers	325,766	61,896
Storm Drainage	306,632	58,260
Water Supply	466,994	88,729
Gas & Electric Util.	101,878	19,357
Utilities Total Capital Costs		
Operating Phase		
Facility Development Costs	5,765,406	1,095,427
System-Wide Develop. Costs		
Sanitary Sewers	476,649	90,563
Water Supply	224,766	42,706
Gas & Electricity Utilities	179,793	34,161
Solid Waste Collection - Total		
Capital Costs		
Operating Phase		
Development Costs	24,845	5,101
Landfill Costs	2,148	408
Annual Capital Costs - Debt Service		
Total	1,335,714	253,786
Adjusted Total	1,211,533	230,191
General Operation & Maintenance Costs		
Elementary	659,450	125,296
High Schools	256,150	48,669
Bussing Costs		
Elementary Schools	5,899	1,121
High Schools	3,024	575
Operating & Maintenance Costs - Schools		
Operating Phase		
Elementary Schools	665,349	126,416
High Schools	259,174	49,243
Operating & Maintenance Costs		
Arterials	10,416	1,979
Collectors	7,191	1,366
Minor Street	20,170	3,832
Operating & Maintenance Costs		
Police	84,500	16,055
Fire	84,500	16,055
Government Admini.	39,000	7,410

Table 5. (Cont'd) Local Government Cost Impact of Oil Shale Commercialization in Fleming County.

Local Government Costs	Total Impact	Fleming County Impact
Health	393,250	74,717
Libraries	13,000	2,470
Recreation	32,500	6,175
Operating & Maintenance Costs		
Sanitary Sewers	32,500	6,175
Storm Drainage		
Water Supply	35,750	6,793
Gas & Electric Util.	406,250	77,187
Solid Waste Collection	30,875	5,866
Operating & Maintenance Costs - Other Government Services	274,000	46,930
Total Operating & Maintenance Costs	2,361,426	448,671
Adjusted	1,679,901	319,181

Table 6. Local Government Revenues Impact of Oil Shale Commercialization in Fleming County.

Local Govern't Revenues	Total Impact	Fleming County Impact
Residential Building Values		
Operating Phase		
Single Family	$ 17,856,000	$ 3,392,640
Mobile Home	3,312,000	692,280
Multi-Family	2,790,000	530,100
Residential Property Value		
Operating Phase	25,395,480	4,825,141
Non-Residential Property Value		
Operating Phase		
Retail	6,670,528	1,267,400
Services	3,461,033	657,596
Office	1,917,125	364,254
Industry	1,089,000	206,910
Non-Residential Property Value - Total		
Operating Phase	13,925,946	2,645,930
Total Value Taxable Property	39,321,426	7,471,071
Local Property Tax Revenues		
Operating Phase	865,071	164,364
Other Locally Raised Revenues		
Operating Phase	493,091	93,687
Intergovernment Local Revenues	950,713	180,636

Table 6. (Cont'd) Local Government Revenues Impact of Oil Shale Commercialization in Fleming County.

Local Govern't Revenues	Total Impact	Fleming County Impact
Total Local Revenues	2,308,875	438,687

Population

The impact analysis determined an additional population of 617 will locate in Fleming County as a result of the oil shale plant location. This represents a 5% growth when compared to the 1980 population of 12,332.[15]

The community development model reveals that the population increase will be composed of 188 working age males, 167 working age females, 241 persons in preworking age categories, and 21 persons retirement age. Table 7 provides details of population by age distribution and also examines the percentages by age category compared to 1970 Fleming County age distribution characteristics.

Table 7. Population Impact Growth by Age Group in Fleming County.

Group	Number	Percent Of Total	1970 Fleming County Percent of Total
0- 5	64	10%	8%
5-17	177	29%	25%
18-29	173	28%	15%
30-44	120	19%	16%
45-64	62	10%	22%
65+	21	4%	14%

Source: Buffalo Trace Area Development District, Integrated Program Design, 1977, p. II-14.

Labor Force/Employment

The impact of the proposed oil shale plant is calculated to create 171 new jobs for plant employment and 243 new secondary jobs for Fleming County, representing a nine percent increase in employment compared to the 1980 total employment statistics of 4,744. This figure compared to 3,644 persons in non-agricultural employment in 1980 represents an eleven percent employment increase.[16]

As noted, 171 of the 414 new jobs are directly attributed to the oil shale plant. However, the remaining 243 jobs are created by secondary employment and result in various industrial categories. Table 8 shows the resulting secondary employment by category and compares the distribution to existing characteristics of the county. The capture rate for secondary employment is assumed to be seventy-two percent.

Table 8. Secondary Employment Impact by Industrial Category in Fleming County.

Industry	Employment	Percent Of Total	1979 Percent Of Total
Mining & Quarrying	0	0%	0%
Construction	28	10%	5%
Trans., Comm. & Utilities	54	31%	6%
Wholesale & Retail Trade	20	11%	34%
Fire	14	8%	5%
Services	60	34%	50%

Source: Kentucky Department for Human Resources, Bureau for Manpower Services, Research and Statistics Branch, Kentucky Labor Force Estimates, Annual Averages, 1979, pp. 30-31.

Personal Income

The calculations from the community development model present a most dramatic change in personal income as a result of the location of the oil shale plant. It was determined that the total local income resulting to Fleming County from the plant location will total $8,164,436. This represents an amount equal to thirty-four percent of the 1980 wages in Fleming County. The additional annual income of $8,164,436 almost equals the income derived from farm activities in Fleming County which is $8,835,000.[17]

The 1980 average weekly wages by industrial category in Fleming County ranged from approximately $95.00 to $270.00 a week. As a result of primary employment from the oil shale plant the predicted weekly wage for the 171 persons employed by the plant would be $492.37. The average weekly wage calculated for secondary employees resulting from the plant location is $255.48. These weekly wages point to an average per capita income of $13,222.00 for the new population. This compares to an existing per capita income in Fleming County of $4,680.[18]

Housing

Determination of impact upon housing shows during the operational phase of the oil shale plant 150 new households will occur in Fleming County. Projected total housing needs from these new households total 157 units. A break-down of the housing needs by type is: single family - ninety-four; mobile home - thirty-nine; and multi family - twenty-four.

As can be seen the housing demands will be substantial over a short period of time. The housing needs in Fleming County are approximately 112 to 178 per five year period through the year 2000. The location of the impact of the oil shale plant in Fleming County will require the doubling of new housing units over a five year term.

Education

The community development impact model determined the plant location impact upon the Fleming County School System would consist of 160 new students requiring seven additional teachers. This compares to a 1980 Fleming County School enrollment of 2387 students.[19]

As determined from the model the school system would require an additional two acres for serving the additional pupil needs with development costs estimated at $468,996 for elementary schools and $227,715 for the high school. The additional costs attributable to general operations and maintenance are $125,296 for the elementary schools and $48,669 for the high school. Annual busing costs are estimated to increase $1,696.

Transportation

Transportation impact as defined by the impact analysis consists of three areas: land requirements, capital cost, operation and maintenance costs. The scope of the analysis was limited to the streets and highways.

Land requirements were first identified in three categories for improvement needs. These three groups and subdivisions are as follows:

1. Residential Roads
   a. Artierials 900 feet
   b. Collectors 1656 feet
   c. Minor Streets 5550 feet
2. Community Street Systems
   a. Arterials 1583 feet
   b. Collectors 1442 feet
   c. Minor Streets 6083 feet
3. Minor Roads - 340,592 feet

The development cost for the three systems identified are arterials - $185,236, collectors- $10,664, and minor streets - $225,077. Operation and maintenance costs for the three same systems are as follows: arterials - $1,979, collectors - $1,366, and minor streets - $3,832.

Retail Sales

The total increases in retail sales calculated for Fleming County as a result of the oil shale plant location is $3,265,733. This figure represents nine percent of the 1979 retail sales total for Fleming County.[20] Table 9 illustrates the retail sales impact by major groups.

Health Care

The impact analysis indicates the need for eight additional health service personnel. A breakdown of the eight personnel is: one physician, five registered nurses, and two health support personnel.

Health facility improvement costs (excluding land costs) are estimated to be $143,730. Operation and maintenance costs are expected to increase $74,717 annually.

Table 9. Increased Retail Shale in Fleming County Attributable to the Impact of the Oil Shale Plant.

Major Group	Retail Sales	Percent o. Total Sales
Food	$ 904,619	28%
Eating & Drinking	195,946	6%
General Merchandise	241,465	8%
Home Furnishings	261,262	8%
Auto Dealers	636,826	20%
Drug Stores	117,568	3%
Other Stores	898,033	27%
TOTALS	$ 3,265,773	100%

Government Cost and Revenues

The community development model provides estimates of the costs and revenues during the operation phase of the oil shale plant. Additional government costs resulting from the synthetic fuel plant location are associated with the following areas: recreation, schools, roads and streets, public services (police, fire, libraries, etc.), public utilities, and solid waste. Each of these impact areas are examined by estimated capital costs and operation and maintenance costs. Table 10 provides a breakdown of estimated costs by category.

Table 10. Estimated Local Government Costs For Fleming County by Category.

Area	Capital Costs	Operation & Maintenance Costs
Recreation	$ 83,462	$ 175,659
Schools	811,539	7,178
Roads & Streets	552,696	122,882
Public Services	243,417	96,021
Public Utilities	1,262,862	96,021
Solid Waste	5,509	46,930
TOTAL	$ 2,957,875	$ 448,671
Adjusted Total	$ 2,642,883	$ 319,181

The community development model assumes annual capital costs as the partial payment on a twenty-five year loan at seven percent interest. Also assumed is the loan results from single bond issue. By making this assumption, total annual debt service will be $253,786. By excluding minor streets, gas and electric, the adjusted annual debt service total is $230,191.

Local government revenues are based on receipts from residential and nonresidential property taxes, locally raised revenues and intergovernment revenue transfers. Table 11 shows the amount of revenues associated to each service.

Table 11. Estimated Local Government Revenues for Fleming County by Category

Source	Revenues
Property Taxes	$ 164,364
Other Locally Raised Revenues	93,687
Intergovernment Revenue Transfers	180,636
TOTALS	$4,381,687

In evaluating costs versus revenues, it was first calculated that additional annual costs of Fleming County local government is $549,372. In comparison to projected annual revenue of $438,686, a short fall of $110,686 is evidenced.

The determination of a $110,686 short fall, is based upon the methodology of Murphy/Williams. However, the model does not adequately provide for minerals severence tax revenues that would be applicable to the proposed project.

Current Kentucky tax laws provide for a minerals severence tax. The tax applicable to oil shale is levied at 4.5 percent of the gross value of minerals severed or processed in Kentucky.[21] As currently interpreted for oil shale, the tax would be levied as 4.5 percent of the value of crude oil. Approximately fifty percent of the tax levied by the state is returned to the county government where the extraction occurs.[22]

Assuming the value of crude oil at $40 a barrel, with production of 10,000 barrels a day, 365 days per year, local government annual revenues from the minerals severence tax would be $3,285,000. It is easily evidenced that the model developed by Murphy/Williams did not provide for the existence of 4.5 percent minerals severence tax.

By including the receipts of mineral severence tax revenues in addition to revenues determined from the impact model, no local government deficit can be expected for Fleming County. An annual surplus of $3,174,314 is indicated.

Although Fleming County is the focal point of this paper, it is important to note that the benefit from the minerals severence tax is applicable only to the county of mineral extraction. By excluding Fleming County from this analysis, the model indicated that the remaining seven counties of primary impact will receive annual revenues of $1,870,189 while annual costs total $2,342,061. This is a shortfall of $471,872 or twenty percent annually.

Law Enforcement/Fire Protection

The impact analysis indicates the need for three additional police and firemen in Fleming County as a result of the oil shale plant location. Additional facility development costs are estimated at $7,676 for law enforcement and $21,340 for fire protection. Annual operation costs will increase $16,055 for each.

Utilities

The impact of the oil shale plant location will necessitate $84,160.12 in nonresidential natural gas and electric improvements. To make these service improvements $34,161 in the system-wide improvements will be required. Total improvement costs will require $137,677.

Water

Water improvement costs associated to the oil shale plant impact will be incurred as a result of residential development, non-residential developments, system-wide improvement costs and increased operation and maintenance costs. Residential and non-residential costs are $385,777 and $88,729. The total of $474,507 would most likely equate as 11.9 miles of water line extensions. This is assuming $40,000 per mile of extensions.

System-wide improvements necessary as a result of extensions of water service are calculated at $42,706. Increased operation and maintenance costs are estimated at $6,793.

Sewerage

Increased sewage costs are also associated to residential developments, non-residential developments, system-wide improvement costs and increased operation and maintenance costs. Residential and non-residential costs are $143,943 and $61,896 respectfully. The equivalent of the total cost of $205,838 number of extension miles is 5.1. This is also assuming $40,000 per mile.

System-wide improvement costs required to serve the improvements are expected to cost $90,563. Increased operation and maintenance costs are estimated at $6,175.

Conclusions

Several conclusions can be made based on the impact assessment of the oil shale plant location, in comparison with the socio-economic profile of Fleming County. The impact conclusions and recommendations are oriented to the operation phase.

In formulating the following conclusions, each area of impact was examined as to the significance of impact in view of the current county profile. The analysis is made acknowledging the limitations and assumptions of the methodology techniques used. This paper attempts not to provide an exact determination of impact for preparation of conculsions and recommendations, but rather to generally define the impact as a decision-making tool to be complimented with good judgment.

1. New Fleming County jobs created directly by the oil shale plant total 171. Secondary employment provides an additional 243 new jobs.

2. The resulting population growth of 617 in Fleming County will be much younger, characterized by sixty-seven percent being age twenty-nine or younger.

3. The additional jobs created in the secondary employment market will be characterized by greater demand in the area of transportation, communication and utilities.

4. Personal income will dramatically increase from existing levels because of the new jobs created by the oil shale plant. Per capita income projected by those persons employed as a result of the oil shale plant will be $13,222. A negative impact that can result by the higher income will be existing employers being required to compete with the same labor force with a much lower pay scale, which will most likely force existing employers to compete by offering higher salaries.

5. New housing units required will total 157 as a result of the increase in population of 617. This impact parallels what is currently projected as the five-year requirement of additional housing needs in Fleming County.

6. A new student enrollment of 160 requires seven additional teachers, as a result of the oil shale plant location.

7. Street and road improvements will require an investment of $515,977. Operation and maintenance costs for these new roads and streets will require an additional $7,177.

8. Retail sales are expected to increase $3,265,773. This represents a nine percent increase over 1979 Fleming County retail sales.

9. Health care professionals will require an additional eight personnel which will include one physician, five registered nurses, and two health support personnel. Health facility improvement costs are estimated at $145,730 with operation and maintenance costs increasing by $74,717.

10. Fleming County as a result of receipts from the Kentucky Mineral Severence Tax from the oil shale plant operation, can expect a $3,174,314 local government surplus. If not for mineral severence tax receipts, a short fall of $110,686 would be evidenced.

11. The remaining seven counties of primary impact will receive revenues of $1,870,189, with annual costs totaling $2,342,061. This represents a short fall of $471,872 or twenty percent annually. As a result of this shortfall, alternatives available to the seven counties of primary impact (not including Fleming County) would be deferred capital outlays which would result in inadquate services, deferred maintenance costs leading to deteriorating facilities and inadequate operating capital reducing public services (police, fire, etc.), and/or higher taxes

12. The impact will create the need for three additional police and three additional firemen in Fleming County. Additional development costs would require investment of $7,676 for law enforcement and $21,340 for fire protection. Annual operating cost would increase $16,055 for each.

13. Total electric and natural gas improvements will cost $137,677 to serve the new population.

14. Water service improvements required will total $517,212.

15. Sewage system improvements will total $296,402. There will be an increase of $6,175 in annual operation maintenance cost.

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Tuesday Afternoon Session

PRODUCTS, UPGRADING MARKETS AND ECONOMICS

Mineral Beneficiation of Oil Shale

by

Terry A. Ring
Department of Materials Science and Engineering
Massachusetts Institute of Technology
Cambridge, MA 02139

Abstract. The potential mineral beneficiation routes for oil shale are compared using separation efficiency as a consistent measure of separation. Two general types of oil shale separations are compared. One type is based on a density difference between the kerogen and the minerals and the other type of separation is based on the wettability difference. Wettability separations are twice as efficient as the density separations, but even the wettability separations are a long way from being 100% efficient.

All of these separations are performed in water and as a result require the concentrate to be dried before being retorted. For this reason, a dry separation method would be desirable. Such a method is electrostatic separation. Experiments are described which use this separation method. The results of these experiments show very low separation efficiencies for all size ranges investigated.

Introduction

Oil Shale is a composite material consisting of kerogen and minerals. Depending on its grade, oil shale may contain between 5 and 35% kerogen, which decomposes upon heating at 500-600°C into crude oil. Conventional processing of oil shale is a three-step process which includes mining, crushing and retorting. Such processing means that a large portion of the retort feed consists of relatively inert minerals. This dilute feed makes the retort larger and more expensive to operate. Processing, which includes mineral beneficiation, attempts to reject much of the minerals before the retort step. A simplified flow sheet for the mineral beneficiation of oil shale is shown in Figure 1.

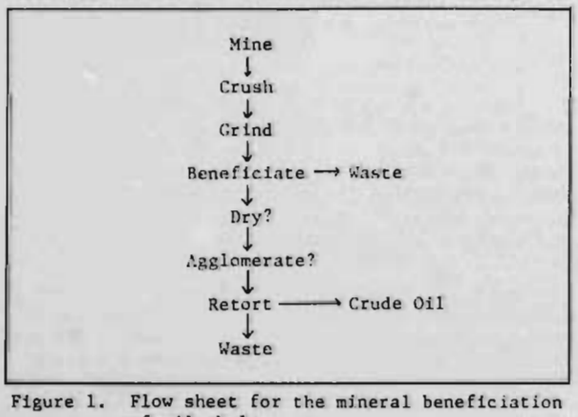


Figure 1. Flow sheet for the mineral beneficiation of oil shale.

This process includes the extra steps of:

1) Grinding the oil shale to its "liberation size."
2) Performing a physical separation of the oil shale.
3) Drying the kerogen concentrate if the separation was performed in water.
4) Agglomeration of the kerogen concentrate if its particle size distribution is too small to be retorted efficiently.
5) Disposal of mineral gangue which may be wet.

Each of these extra steps incurs a cost. To be feasible, the sum of these extra costs must be less than the savings produced by a smaller retort. Both the costs of beneficiation and the savings of a smaller retort are highly dependent upon the oil shale grade. For a very high grade oil shale, the cost of a beneficiation process would be more than that of a simple retort process, while, for a very low grade oil shale, the cost of a simple retort process would be more than that of a beneficiation process. The grade at which the crossover occurs is dependent upon the methods used for grinding, separation, and retorting.

To determine the feasibility of mineral beneficiation of oil shale, several questions must be answered. These questions are in the areas of grinding, separation and retorting.

Grinding

1) What is the effective "liberation size."
2) Where is the kerogen in this "liberated" material.
   a) as discrete particles?
   b) attached to mineral particles?
   c) smeared on the mineral surfaces?

3) Is this "liberation" dependent on the type of grinding?

Separation

1) What physical property should be used for separation?
2) Does the efficiency of the separation depend on what size the particles are or how they were ground?
3) What is the rate of disengagement?

Retorting

1) What type of retort should be used?
2) What is the retort rate of different size particles?

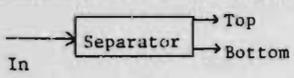
Once these technical questions are answered, we can evaluate which route (i.e., grind, separate, retort) will lead to an overall process which is most economical for a given grade of shale.

This work is confined to the technical questions associated with the separation step. Several physical properties have been used to obtain a physical separation of the kerogen from the minerals. The most popular physical property used was the density difference between kerogen ($\rho \sim 1.07 gm/cm^3$) and the minerals ($\rho \sim 2.7 gm/cm^3$). The other most popular physical property used was the wettability difference - kerogen is oil wetting and the minerals are water wetting.

Literature Review

Due to the different types of separation and the different grades of oil shale used in experiments, it is very difficult to compare the separations based on kerogen recovery or enrichment ratio. These separations need to be compared on a consistent basis. Such a comparison can be made with either the separation factor or the separation efficiency.

Consider the generalized separation drawn below.



The separation factor, α, is given by[2]

$$\alpha_1 = \frac{X_T^1(1-X_B^1)}{X_B^1(1-X_T^1)} \qquad (1)$$

where

X_T^1 = % wgt of component 1 in Top Stream

X_B^1 = % wgt of component 1 in Bottom Stream

The separation factor has a range of values from one to infinity corresponding to no separation and complete separation, respectively. The separation efficiency, η, is given by[1]

$$\eta = R_1 - R_2 \qquad (2)$$

where R_i corresponds to the recovery of component i in the top stream. The recoveries are given by

$$R_1 = \frac{X_T^1 Q_T}{X_I^1 Q_I} \qquad (3)$$

$$R_2 = \frac{X_T^2 Q_T}{X_I^2 Q_I} \qquad (4)$$

where

Q_T = flow rate of the Top Stream,

Q_I = flow rate of the Input Stream,

X_I^i = %wgt of component i in the Input Stream.

The separation efficiency has a range of values from zero to one corresponding to no separation and complete separation, respectively.

For each separation method, it is necessary to consider what particle size was used. Oil shales are composed of mineral particles which are on the order of 10μm in diameter.[10] True liberation, if it exists at all, does not occur at sizes larger than ~10μm. For separations which utilize particle sizes larger than ~10μm, the separation is made between kerogen rich particles and kerogen lean particles. Such separations are highly dependent on the type of stratification in the oil shale and the methods used to crush and grind the oil shale.

Density Separation

Density separations use a liquid which has a specific gravity between 1.07 and 2.7. In this liquid kerogen, rich particles float and mineral rich particles sink. Since settling rate is proportional to the square of the particle diameter, small particles settle at a slower rate than large particles. Therefore, density separations which operate on small particles will have slow disengagement rates unless the gravity force is increased. The gravity force may be increased by using a centrifuge or a cyclone. Results obtained from the literature on various density separations are summarized in Table 1.

Settling experiments by Knowles[3] on -37μm oil shale particles were performed with various density liquids over a three-day period. The best separation (η=27.9%) for these experiments was obtained with a liquid with a density of 2.15gm/cc. Centrifugation experiments with a +180-250μm sample gave a lower separation efficiency (η=10%).

A settling cascade was used by Larson, et al.[4] on large +6,000-19,000μm particles of oil shale. The maximum separation efficiency of 14% was obtained at the second stage where the liquid density was 1.95gm/cc.

Roberts and Schaefer Resource Services[5] has evaluated a heavy media cyclone. Their results show a separation efficiency of 36%. No information was given concerning either the particle size used or the liquid density used for the 20 ton test.

Wettability Separations

Two types of wettability separations have been investigated. The results of these separations are also summarized in Table 1. One method involved mixing a water slurry of oil shale with a solvent for kerogen. The results of this separation were kerogen containing organic phase pellets and a water slurry of minerals. Pelletization experiments

Table 1. Separation Method Comparison

	Input Grade (gpt)	Particle Size (μm)	Liquid Density (gm/cc)	Separation Factor α	Separation Efficiency η(%)	Ref
Density Separations						
Settling	30.7	-37	2.15	3.9	27.9	3
Centrifuge	12.5	+180 -250	2.35	2.9	10.0	3
Settling	25.8	+6,000 -19,000	1.95	3.2	14.5	4
Cyclone	~30	-	Heavy Media	4.5	36.0	5
Wettability Separations						
Pelletization	44.3	-150	H_2O + heptane	42.7	69.2	6
Flotation	28.4	80%<15μm	1.0	71.0	75.0	7

were performed by Reisberg[6] on -150μm oil shale particles. A separation efficiency of 69.2% was obtained using heptane as the solvent. The other separation method based on wettability was froth flotation. This method used air bubbles to collect kerogen particles from a water slurry of the oil shale. Froth flotation experiments were performed by Fahlstrom[7] on ground oil shale with 80% <15μm. A separation efficiency of 75% was obtained using an oil as a collector.

In conclusion, density separations give moderate separation efficiencies. Density separations appear to be limited by the degree of liberation that can be obtained for particle sizes which will settle at reasonable rates. Wettability separations give higher separation efficiencies. Based on the relative separation efficiencies of these two separation methods, it is expected that complete liberation does not occur with conventional grinding to -37μm and that at this size kerogen will be smeared on mineral surfaces.

All of these separations are wet separations and would require an expensive drying step before the concentrate was retorted. Could the process economics be improved by using a dry separation? What types of dry separations are feasible for oil shale? The balance of this work is an evaluation of the electrostatic separation of oil shale - one of the potential dry separation methods.

Electrostatic Separation

As shown in Figure 2, electrostatic separations are performed by subjecting the particles to a corona discharge which charges the particles. As the charged particles leave the corona area they are discharged. Conducting particles discharge quickly while non-conducting particles discharge slowly. The slowly discharged particles stick to the rotor and the quickly discharged particles are free to follow a normal trajectory. The particles which stick to the rotor are removed by either the A.C.corona or the brush scraper. The technique has proved successful for non-dusty powder mixtures like Fe_2O_3 and SiO_2 or SiO_2 and TiO_2.[8]

Experimental

A 50 kg sample of Western oil shale was obtained from Occidental Research of Irvine, California. The sample had a specific gravity of 2.20gm/cc which corresponds to a grade of ~25gal/ton. Half of the sample was crushed and screened to give several size ranges. Each of these size ranges was separated with a Carpco electrostatic separator.

Crushing

A 4 inch jaw crusher was used to reduce the partical size of the oil shale from 3-7cm to -1mm.

Screening

Using 8 inch U.S. Standard sieves and a Rotup shaker, a 1/2 hour screen analysis was performed on a representative sample of the crushed oil shale. The results of this analysis are shown in Figure 3.

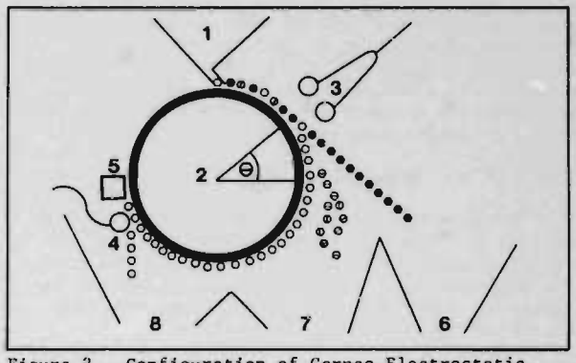


Figure 2. Configuration of Carpco Electrostatic Separator. 1-feed bin, 2-rotor, 3-D.C. corona discharge electrodes, 4-A.C.corona electrode, 5-brush, 6-Conductors hopper, 7-middings hopper, 8-insulators hopper.

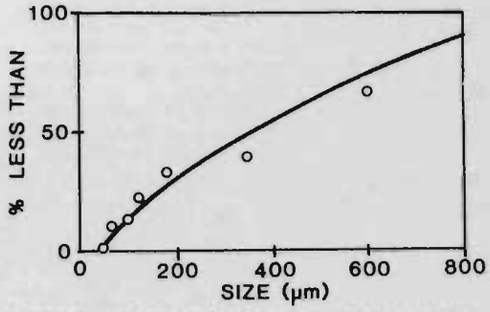


Figure 3. Size Analysis of Crushed Material.

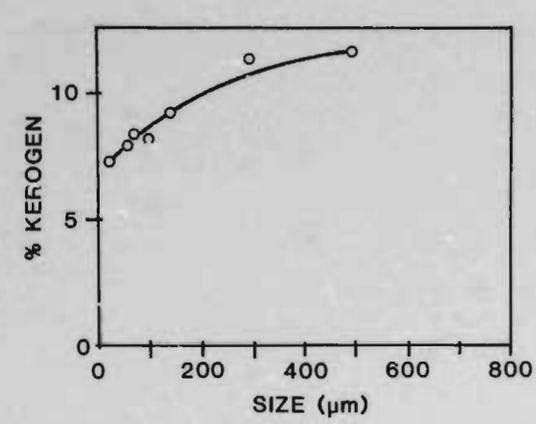


Figure 4. Kerogen Analysis of Each Size Fraction.

The mean size of the crushed material was approximately 500 μm. Screen analyses performed for 1 hour and 1½ hours were essentially the same as that for ½ hour.

500 gm samples in various size ranges were obtained by screening 25 kg of the crushed shale. These samples were used for electrostatic separations.

Analysis

The amount of kerogen in any oil shale sample was determined by the weight loss between 110° C and 560° C. The method used for this analysis was to dry the sample at 110° C overnight. Then a 1 gm sample was placed in a furnace at 560° C for 1 hour. When the sample was removed from the oven, it was placed in a desiccator to cool before it was reweighed. The results of this analysis for the screened oil shale fractions are shown in Figure 4. The larger size fractions have more kerogen in them than the smaller size fractions.

Separation Results

A Carpco High Tension Research Separator Model HT (36) 111-15 with a vibratory feed bin was used for all separations. The operating parameters of the separator are given in Table 2. A 500 gm sample was removed from a 110°C drying oven and placed in the feed bin.

Table 2. Operating Conditions for Carpco Electrostatic Separator.

Rotor Diameter	36 cm
Rotor Speed	80 rpm
Feed Position	90°
Splitter Position	
1	340° - 1 cm from Rotor
2	280° - 4.5 cm from Rotor
Electrode Position	
1	60° - 3 cm from Rotor
2	35° - 3 cm from Rotor
3	240° - 1 cm from Rotor
Brush Position	220°
Electrode Potential	
1	+ 25 ± 1 kv DC
2	+ 25 ± 1 kv DC
3	7 ± 1 kv AC
DC Current	10 - 20 μ amps
Feed Rate	1 - 4.5 kg/hr

The rotor was started and an infrared lamp which heats the rotor turned on. The vibrator feed rate was adjusted so that a uniform layer of particles was fed to the rotor. The feed was turned off and the sample which had been deposited in the right hopper returned to the feed bin. The electrode potentials were then set and the feed started again at the same rate as before. The time required for the bin to empty was recorded, which allowed for calculation of the feed rate. The weight and % kerogen of the material collected in the three hoppers was determined. From these measurements the separation factor was determined using the % kerogen for the material in the conductor hopper as X_T and the % kerogen of the material in the non-conductor hopper at $95X_B$ (see Equation 1). The separation factors for each size range are given in Figure 5. Very low separation factors were observed for all size ranges; however, as the particle size decreased, the separation factor increased. Different feed rates, rotor speeds, splitter positions and D.C. currents were tried to improve the separation; however, these variables did not significantly change the separation factor that was obtained for a given size range.

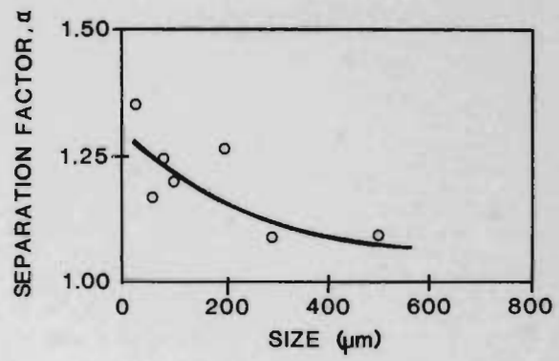


Figure 5. Electrostatic Separation Factor, α, for Each Size Fraction.

Discussion

By lumping the hopper where the insulators were collected with the hopper where the middlings were collected, we have a two stream separation which may be analyzed by the separation efficiency. For the +0 - 45 μm size range, the highest separation factor was observed at $\alpha = 1.35$. The separation efficiency for this size range was calculated to be a mere 2.5%. For all other size ranges the separation efficiency was smaller.

For these separation experiments, the kerogen was concentrated ever so slightly in the hopper which contained the conducting particles. This observation is contrary to the findings of Mukai, et al.[8] for coal. In those experiments the ash minerals were concentrated in the hoppers which contained the conducting particles. At this juncture we asked two questions: 1) why is the electrostatic separation of oil shale so poor? and 2) how are oil shale and coal different?

Microscope investigations of the crushed and screened oil shale particles showed that the individual particles were covered with a layer of much

smaller particles. These much smaller particles were primarily mineral particles in the - 44 μm size range. This particle coating made the particles behave in the electrostatic separator like mineral particles because the surface charge of the particles determined whether or not they would stick to the rotor. Washing the oil shale with water removed this particle coat. These washed oil shale particles were dried and used for an electrostatic separation. For the + 250 - 355 μm size range, a separation factor of 2.64 and a separation efficiency of 29.3% was obtained. For this separation, the kerogen was concentrated in the insulator and middling hoppers, and the minerals were concentrated in the conductor hopper -- a behavior similar to that observed with the electrostatic separation of coal.[8]

Conclusions

As a completely dry separation method for oil shale, the corona discharge is not sufficiently efficient to be commercially practical. A much more efficient separation was obtained when the oil shale particles were washed with water before separation; however, this defeats the purpose of a completely dry separation. The separation efficiency of the electrostatic separation of the washed material is similar to that obtained with density separations. Density separations give only moderate separation efficiencies which depend on the particle size of the oil shale and the liquid density. By far the most efficient oil shale separation is based on the wettability difference between kerogen and the minerals. This type of separation is performed wet and may require both drying and agglomeration steps before the concentrate can be retorted. For these reasons, the search for a dry separation method for oil shale should continue.

Acknowledgement

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Analysis of Oils Derived from Kentucky Oil Shales for Potential Refinery Feedstocks

by

D.A. Fabry
H.F. Moore
Ashland Petroleum Company
Research & Development Department
Ashland, Kentucky 41101

Abstract. Oil shales from the eastern United States are receiving increasing attention as potential sources of refinery feedstocks. In order to define potential refining factors for these materials, shale oils produced from Kentucky oil shale deposits have been evaluated. Results are presented for the whole crude oil and representative refining fractions derived therefrom. These properties are contrasted with similar data from western U. S. shale oils, graphically demonstrating the differing character of these materials.

INTRODUCTION

Deposits of materials known as oil shale are found worldwide. These materials, which are of varying geological origin, present the common factor of releasing hydrocarbon-like compounds upon thermal treatment. These deposits have repeatedly gained attention as potential energy sources, but never quite attained full commercial status in this country. Commercial retorting was practiced, however, in Scotland during the late 1800's.[1]

Major oil shale deposits in the United States are generally broken into western and eastern categories. The western shales generally are found in very thick seams with relatively high oil yields of 15-30 gallons per ton or more. These factors have led to a focus of major attention on the western shales. As a result, these materials, and particularly the oils derived therefrom, are well characterized including previous work by these researchers.[2,3,4,5,6]

Eastern oil shales are found in major deposits extensively through Ohio, Kentucky, Tennessee, Indiana, and Michigan in particular. These deposits in general show thinner seams and lower assay (generally less than 15 gallons per ton) than the western shale, and have received proportionately less attention. Major proponents of these resources in past years were Jillson[7] and Crouse,[1,8,9] with Crouse in particular performing detailed retorting studies of these materials. Later, researchers from the Laramie Energy Technology Center[10,11] also performed evaluations of these deposits, primarily by studies of core samples.

Major focus on these resources, however, did not occur until the 1970's, and in particular the late 1970's. The major effort on eastern shales during the early portion of this period was performed by Dow[12] for gas production and IGT[13] for hydrocarbon liquids. Other studies were also performed by Wen, et al.[14] Major efforts began during the latter part of this period, particularly by the state of Kentucky,[15-17], Monsanto,[18] and Davy McKee and Cleveland Cliffs.[19] These efforts, and the necessity for evaluation of all potential energy sources available to the United States, have led to a veritable hotbed of present activities in this area. Emphasis on eastern shale research by DOE[20] and extensive leasing efforts by some refiners and private investors underscore this activity.

The Ashland Petroleum Company Research and Development Department maintains review of the majority of these efforts. As a major refiner in this region, our interest must lie in the potential of these materials to serve as refinery feedstocks. As noted previously, studies on western shale oils provide the basis for much of our present efforts on eastern shale oil.

More specifically, data reported herein for western shale oils were derived for oil samples from both Occidental's in situ retort #6 as well as the Paraho above-ground retort at the Anvil Points, Colo., facility. These samples were provided under contractual agreement with the United States Air Force, contract number F33615-78-C-2080.

In order to maintain an up-to-date data base on these materials, several eastern shale oil samples have been obtained

from various Kentucky shale sources. Of interest to this report, two samples were obtained in five-gallon quantity and evaluated for potential refining properties. Sample 53-SH was obtained through the efforts of Major Don Potter, USAF, and was retorted by private means from an undisclosed Kentucky shale source. Processability of sample 53-SH has previously been reported.[21] Sample 08-SH was obtained from John Kuhn of the Kentucky Center for Energy Research Laboratories. This sample was produced in April, 1981, on a Crouse-type retort owned by Pyramid Minerals and operated at Olive Hill, Kentucky.

These samples were then utilized with the objective of determining pertinent refining properties of each shale oil, plus the properties of relevant fractions derived therefrom. Future work will determine actual refining response of these oils and oil fractions.

EXPERIMENTAL

Each sample was purged of excess water and sediment by simple filtration and distillation techniques as necessary prior to analysis of the oils. The dewatered, sediment-free oils were then sampled and subjected to complete chemical and physical evaluation.

Subsequent treatment of the two shale oil samples is exhibited in Figure 1. Each sample was distilled on a one inch diameter externally heated distilling column having a three foot length of random-packed 1/16 inch glass helices. The oil samples were fractionated sequentially to atmospheric equivalent temperatures of 400°F and 600°F. The 600°F+ bottoms material was transferred to a second apparatus, consisting of a flask with no packing, and distilled to an atmospheric equivalent 1000°F temperature. Pressure measurement was accomplished by use of a tilting McLeod manometer. Very low pressure and minimal residence time were maintained in order to retard thermal decomposition of the sample.

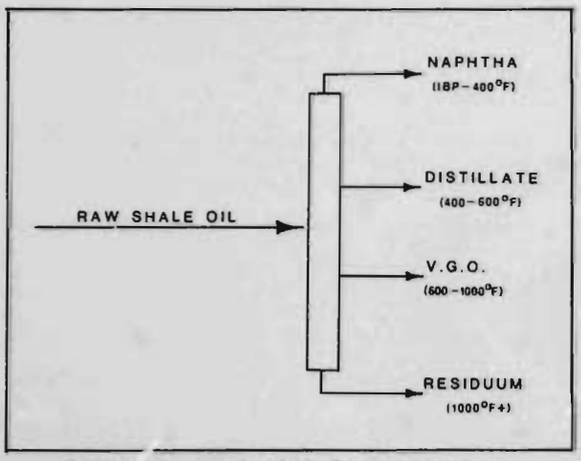

Figure 1. Shale Oil Fractionation

Samples of the naphtha (IBP-400°F), distillate (400-600°F), vacuum gas oil (600-1000°F), and residuum (1000°F+) fractions were subjected to analytical evaluation in a manner similar to the analysis of the crude shale oils. Results and implications of the data derived for each crude shale oil and its fractional components will be presented in the sections that follow.

To supplement the evaluation, a sample of Arabian Light (ABL) crude petroleum was fractionated in an identical manner and subjected to the same evaluation procedure. Data shown herein are derived from that specific crude oil sample.

OIL EVALUATION

Raw Shale Oil

Properties of the two raw oil samples are shown in Table 1. Interestingly, properties of the oils appear very similar; so much so that the assumption that the two samples were produced from similar shale sources appears valid. While sample 53-SH exhibits higher nitrogen content as well as slightly lower gravity and sulfur content, virtually no major differences are apparent.

Yields of the various boiling fractions from distillation of each of the Kentucky shale oils were nearly identical, as shown in Figure 2. Gravity of the 53-SH sample is somewhat lower than the 08-SH sample. Characterization factor (K) for the two oils is identical. Hydrogen contents of the full range oils are similar with 53-SH slightly lower in hydrogen than 08-SH.

Heteroatom contents are characteristically high for the two eastern oils,

TABLE 1. PROPERTIES OF EASTERN SHALE OILS

	53-SH	08-SH
GRAVITY, °API	10.4	11.5
K FACTOR	10.6	10.6
ELEMENTAL:		
HYDROGEN, WT%	9.19	9.63
NITROGEN, WT%	1.86	1.17
SULFUR, WT%	1.57	2.16
OXYGEN, WT%	1.26	1.60
POUR POINT, °F	-5	-20
TOTAL METALS, PPM	52	25

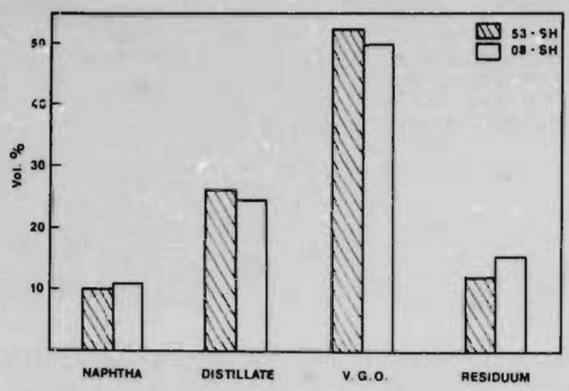

Figure 2. Eastern Shale Oil Distillation Yields

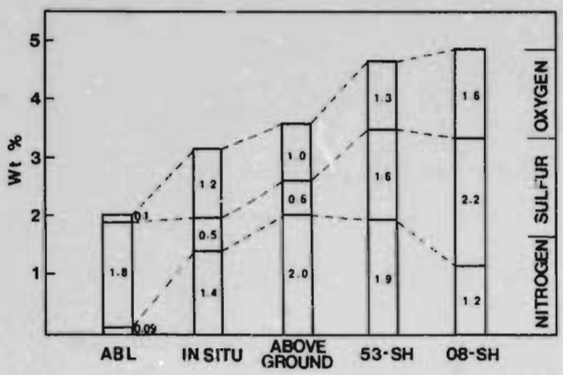

Figure 3. Heteroatom Contents

as seen in Figure 3. Nitrogen content of the 53-SH sample is considerably higher while sulfur content is somewhat lower than the 08-SH sample. Oxygen content, as determined by fast neutron activation analysis, is slightly lower for 53-SH.

Both eastern shale oil samples exhibit low pour points and relatively low levels of metals contamination. Iron and nickel constitute the major contaminants in sample 53-SH, while iron and arsenic serve that role in 08-SH. High levels of other contaminants are to be found in the eastern shale oils as well. Organic chlorides were detected at 278 ppm in 53-SH, while 08-SH showed only 15 ppm chloride. Salt (NaCl) content was high for both samples: 8.9 and 6.9 pounds per thousand barrels for 53-SH and 08-SH, respectively. Bottoms, sediment and water (ASTM D-96) was higher at 1.1 vol% for 53-SH compared to 0.15 vol% in 08-SH. Phenol and the isomers of cresol and xylenol were detected at 1.4 wt% in sample 53-SH and at 0.4 wt% in 08-SH. Maleic anhydride value is high for both 53-SH and 08-SH (38.5 and 50.0, respectively) indicating a potential for unstable handling and storage properties. This analysis, however, is complicated by the high level of heteroatoms present. Ramsbottom carbon residue for the two samples was determined to be 3.2 wt% in the case of 53-SH and 5.2 wt% for 08-SH.

Comparison between shale oils from the East and those of the Green River formation in the West is shown in Table 2. The most striking contrast between these oils are the type of hydrocarbons which are derived. Western shale oils have typically

TABLE 2. PROPERTIES OF EASTERN OILS VS. WESTERN OILS AND PETROLEUM

	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT	MEXICAN MAYA
GRAVITY, °API	10.4	11.5	23.6	20.9	33.3	22.2
K FACTOR	10.6	10.6	11.6	11.4	11.9	11.7
ELEMENTAL:						
HYDROGEN, WT%	9.19	9.63	11.0	11.43	12.8	----
NITROGEN, WT%	1.86	1.17	1.42	1.97	0.09	(>0.3)
SULFUR, WT%	1.57	2.16	0.53	0.62	1.80	3.40
OXYGEN, WT%	1.26	1.60	1.21	1.04	0.13	----
POUR POINT, °F	-5	<-20	+65	+70	<-20	<-20
TOTAL METALS, PPM	52	55	67	106	27	340+

been characterized as being highly paraffinic. This is apparent after considering the relatively high hydrogen content, higher characterization factor, and higher pour points as compared to eastern oil. The two subject oils, on the other hand, appear to be highly aromatic in character. This is suggested in part by their lower hydrogen contents, lower characterization factor and much lower pour points. This trait has been recognized by other investigators.[14] This information carries strong implications for the refiner since highly aromatic naphthas serve as ideal high octane gasoline precursors. Conversely, high severity treatment of higher boiling materials is indicated in order to reduce heteroatom contents, increase hydrogen content and meet transportation fuel specifications. This high aromatic content would in fact be detrimental to the production of high quality diesel and turbine fuels.

Figure 4 shows boiling range distribution for the eastern shale oil as opposed to those of the West and a petroleum crude. Slightly more naphtha and residuum are derived from these eastern oils compared to the western oils. The bulk of the eastern oil lies in the vacuum gas oil (600-1000°F) boiling range. This is true of the western oils as well.

In Figure 3, heteroatom contents are shown for the subject oils as well as for two different western shale oils. Nitrogen content shows considerable variability and is high (1-2 wt%) in both eastern and western shale oils. Oxygen content is slightly, but consistently, higher for the subject oils than for oils from western shale. Sulfur content of the eastern shale oils is much higher than that of the western oils, nearly 350% higher in some cases. Removal of this high sulfur constituent should still occur readily at the severities required for nitrogen removal.

The much lower pour points of the eastern oils indicate the absence of many of the transportation problems anticipated for oils from the western shales. Total metals content, also, is lower in the eastern oils. The arsenic content in particular is much lower in the eastern oils indicating fewer hazards to catalytic processes, not to mention health and environmental considerations. Higher quantities of organic chloride, salt and BS&W are found in the eastern shale oils. Phenolic content varies for both eastern and western oils, but is of the same order of magnitude in each. Maleic anhydride value is comparably high for eastern and western oils, given the analytical limitations mentioned earlier. Carbon residue is consistently lower in oils from western shales.

In Table 2 some properties were given for eastern and western shale oils, as well as for two petroleum crudes. Significant differences are noted immediately in gravity, hydrogen and heteroatom contents. The highly aromatic character of the eastern shale oils is again evident when contrasted with the higher gravity, characterization factor, and higher hydrogen content of the petroleum crudes.

As seen in Figure 4, the fractional yield distribution is quite different for the Kentucky shale oils versus a typical Arabian Light crude oil. The petroleum crude shows a much more even boiling range distribution with significantly more naphtha (IBP-400°F) and distillate (400-600°F).

Compared to the petroleum crudes, the subject shale oils contain much higher levels of nitrogen and oxygen, as seen in Figure 3. In spite of the high sulfur content of the eastern shale oils, this is not outside the realm of the petroleum crudes processed in many refineries today. The Mexican Maya crude, for example, contains more sulfur than either 53-SH or 08-SH.

There is some variability in metals content between oils from eastern shale and petroleum crude oil. Higher levels of arsenic were detected in the eastern shale oils, while the reverse was true in the case of vanadium content.

In general, higher levels of contaminants were found to exist in the Kentucky shale oil versus petroleum crudes. More phenolic compounds, organic chloride, salt, BS&W, and higher maleic anhydride value were attributed to the eastern oils.

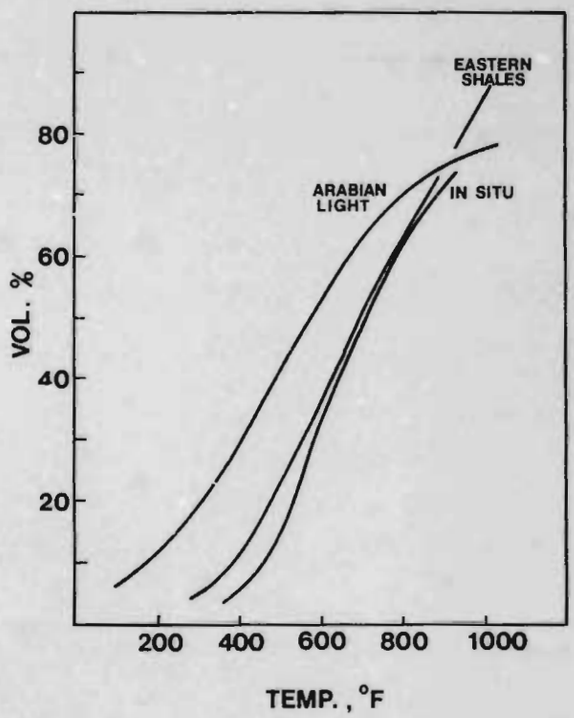

Figure 4. Boiling Range Distribution

Naphtha (IBP-400°F)

Properties of the IBP-400°F portions of the two subject oils are shown in Table 3. Yields of this fraction after distillation were nearly identical for 53-SH and 08-SH as were gravity, K factor and hydrogen content.

Nitrogen content remains higher for 53-SH compared to 08-SH naphtha. Sulfur remains lower in this fraction of 53-SH compared to 08-SH, and oxygen content likewise is slightly lower for 53-SH.

Except for the higher heteroatom content, few contaminants are found in this fraction of the subject oils. No metals were detected for naphthas from either sample. Phenolic compounds were found in 53-SH, but due to sample limitations the analysis was not performed on the 08-SH naphtha. Due to the gum forming tendencies induced by this level of phenolics, storage stability of motor fuels derived from these naphthas would be adversely affected.

Figure 5 reveals the levels of saturate, olefin and aromatic hydrocarbon types in naphthas from the two subject oils. A fairly even distribution is seen, though the aromatics content reported may be biased by the high heteroatom contents. The analysis was performed using the fluorescent indicator adsorption method.

In Table 3 are given the properties of naphthas from the two subject oils and two western shale oils for comparison. As can readily be seen, gravity, characterization factor and hydrogen content are slightly lower for the eastern oil naphthas than for their western counterparts.

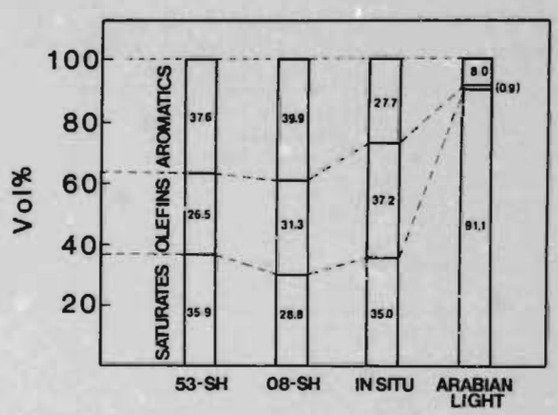

Figure 5. Naphtha Hydrocarbon Types: Shale Oils Vs. Petroleum

Naphtha yield from the eastern oils is about twice that reported for the two western shale oils. Both subject oils contained approximately 10 vol% naphtha compared to 3.5 vol% naphtha for the in situ oil and 4.8 vol% naphtha for the above-ground oil.

High levels of heteroatoms are found in the oils derived from both eastern and western shales. The data indicate that the eastern shale oil naphthas are slightly lower in nitrogen content and consistently higher in the amount of sulfur present. No values were available for oxygen content in the western shale oil naphthas.

Phenolic components are found in larger proportions in the western shale oil naphthas as compared to naphthas from the eastern oils.

TABLE 3. EASTERN SHALE OIL NAPHTHA VS. WESTERN AND PETROLEUM

	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT
GRAVITY, °API	38.8	39.3	40.7	43.3	63.4
K FACTOR	11.2	11.2	11.6	11.2	12.3
ELEMENTAL:					
HYDROGEN, WT%	11.99	12.05	----	12.38	15.07
NITROGEN, WT%	1.16	0.36	1.02	1.40	0.0001
SULFUR, WT%	1.50	1.73	0.80	1.06	0.05
OXYGEN, WT%	0.61	0.75	----	----	0.04
PHENOLS, WT%	1.77	----	2.[illegible]4	3.98	0

A great deal of similarity exists between the eastern and western shale oil naphthas regarding hydrocarbon types. This can be seen in Figure 5. The eastern oils still aprear to demonstrate a higher level of aromatics in this fraction although, as mentioned previously, some analytical interferences are introduced by the high level of heteroatoms.

Table 3 also provides a comparison between properties of naphthas derived from Arabian Light crude oil and those of the subject eastern shale oils. Although not shown in the cited table, naphtha yield is much higher from Arabian Light crude oil than that derived from the eastern oils studied. Nearly a 30 vol% yield of naphtha was distilled from the crude oil while the eastern shale oils produced only about 10 vol% of IBP-400°F material.

The Arabian Light naphtha again exhibits a higher characterization factor and much higher gravity and hydrogen content than naphtha from 53-SH and 08-SH. These traits combine to suggest a high paraffin and naphthene content as opposed to the even distribution of hydrocarbon types seen in the eastern shale naphthas. The comparison shown in Figure 5 substantiates this conclusion.

As expected, heteroatom levels in the eastern shale oil naphthas are extremely high as compared to the petroleum naphtha. The Arabian Light naphtha contains hardly any nitrogen, and less than 0.1 wt% of sulfur and oxygen combined. These data imply that relatively higher processing severities and hydrogen supply will be required for production of high quality motor fuels from the eastern shale oil naphthas.

Phenolic components represent yet another contaminant absent from the petroleum based naphtha. Although the eastern shale oil naphthas contain lower levels of phenolic species than their western shale oil analogues, they still exhibit a much higher phenolic content than petroleum naphtha.

Distillate (400-600°F)

Properties of distillate material from 53-SH and 08-SH are shown in Table 4 along with properties of western shale oil and Arabian Light distillates for comparison.

The two subject oils show similar yields, gravity, characterization factor, and hydrogen contents as well as nearly identical viscosities. The same trend is observed for heteroatom contents as seen in the naphtha fraction, i. e., nitrogen appears higher while sulfur and oxygen contents are lower for 53-SH compared to 08-SH. No metals were detected in either of the Kentucky shale oil distillates. Some phenolic components have been found in the 400-600°F fractions of the subject oils, but the available analytical methods have precluded detection of phenolic types with molecular weights greater than xylenol.

On comparison with distillate material from the western shale oils, it can be seen that both eastern shale oil distillates exhibit lower gravity, K factor and hydrogen contents. This trend follows the same pattern observed in the lower boiling

TABLE 4. EASTERN SHALE OIL DISTILLATE VS. WESTERN AND PETROLEUM

	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT
GRAVITY, °API	22.7	23.0	31.6	30.7	39.6
K FACTOR	10.7	10.7	11.6	11.2	11.9
ELEMENTAL:					
HYDROGEN, WT%	10.68	10.81	11.5	12.0	13.83
NITROGEN, WT%	1.42	0.78	1.17	2.23	0.0015
SULFUR, WT%	1.36	1.74	0.59	0.85	0.69
OXYGEN, WT%	1.29	1.66	----	----	0.04
VISCOSITY, SUS @ 100°F	35.2	34.5	4.9	39.9	34.2

fraction. Nitrogen content of the eastern oil distillates is marginally lower while sulfur content is substantially higher than that found in the western shale oil distillates. No oxygen data were available for the in situ and above-ground distillates.

Viscosities of the eastern shale oil distillates are of the same order of magnitude as distillate from the above-ground retorted western shale oil. A considerably lower viscosity is observed in the case of the in situ distillate.

Arabian Light crude oil distillate shows higher gravity and characterization factor as well as much higher hydrogen content compared to the 53-SH and 08-SH distillates. Heteroatom content of the crude oil based distillate is generally much lower than the eastern shale oil distillates. Sulfur represents the most abundant heteroatom in the petroleum distillate and is still less than half that seen in the Kentucky shale oil distillates.

Interestingly, viscosities are almost identical between the eastern shale oil and petroleum distillates, indicating that the same handling and pumping characteristics might be expected to apply to both.

Vacuum Gas Oil (600-1000°F)

The VGO fraction represents the most abundant liquid portion, about 50 vol%, of each of the eastern shale oil samples. Properties of the VGO from 53-SH and 08-SH are shown in Table 5, along with properties of analogous fractions from the Green River shale oils and Arabian Light crude oil.

At first glance the 08-SH sample appears to have slightly higher gravity and K factor and to contain more hydrogen. However, after subjecting the appropriate fraction to simulated distillation analysis it is evident that a slightly higher concentration of lower boiling components existed in the 08-SH sample. Apparently, less efficient operation of the distillation unit was maintained during fractionation of the 08-SH oil.

Higher heteroatom contents are, as expected, found in the higher boiling fractions. The pattern continues between fractions of the two subject oils; that is, higher nitrogen content and lower sulfur and oxygen levels were detected in 53-SH VGO compared to 08-SH VGO.

The eastern oil VGO samples show very similar pour points, as well as low metals content. The 08-SH VGO is slightly higher in metals, owing to a 13 ppm contribution from arsenic.

Table 5 also shows properties of VGO from Green River shale oils. These materials show much higher gravities than their eastern counterparts, higher K factors and nearly 2 wt% more hydrogen. The high paraffin content of the western shale oil VGO is obvious in view of the very high pour points compared to the VGO derived from eastern shale oil.

Nitrogen content is highly variable in this fraction, with the eastern oil

TABLE 5. EASTERN SHALE OIL VGO VS. WESTERN AND PETROLEUM

	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT
GRAVITY, °API	6.5	8.2	23.2	21.7	26.0
K FACTOR	10.4	10.6	11.6	11.4	11.8
ELEMENTAL:					
HYDROGEN, WT%	9.04	9.19	11.8	11.4	12.62
NITROGEN, WT%	2.14	1.59	1.62	1.81	0.05
SULFUR, WT%	1.65	2.04	0.51	0.65	2.18
OXYGEN, WT%	1.53	1.90	----	----	0.08
TOTAL METALS, PPM	1	16	22	19	1
POUR POINT, °F	+30	+25	+75	+65	+60

fraction. Nitrogen content of the eastern oil distillates is marginally lower while sulfur content is substantially higher than that found in the western shale oil distillates. No oxygen data were available for the in situ and above-ground distillates.

Viscosities of the eastern shale oil distillates are of the same order of magnitude as distillate from the above-ground retorted western shale oil. A considerably lower viscosity is observed in the case of the in situ distillate.

Arabian Light crude oil distillate shows higher gravity and characterization factor as well as much higher hydrogen content compared to the 53-SH and 08-SH distillates. Heteroatom content of the crude oil based distillate is generally much lower than the eastern shale oil distillates. Sulfur represents the most abundant heteroatom in the petroleum distillate and is still less than half that seen in the Kentucky shale oil distillates.

Interestingly, viscosities are almost identical between the eastern shale oil and petroleum distillates, indicating that the same handling and pumping characteristics might be expected to apply to both.

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The VGO fraction represents the most abundant liquid portion, about 50 vol%, of each of the eastern shale oil samples. Properties of the VGO from 53-SH and 08-SH are shown in Table 5, along with properties of analogous fractions from the Green River shale oils and Arabian Light crude oil.

At first glance the 08-SH sample appears to have slightly higher gravity and K factor and to contain more hydrogen. However, after subjecting the appropriate fraction to simulated distillation analysis it is evident that a slightly higher concentration of lower boiling components existed in the 08-SH sample. Apparently, less efficient operation of the distillation unit was maintained during fractionation of the 08-SH oil.

Higher heteroatom contents are, as expected, found in the higher boiling fractions. The pattern continues between fractions of the two subject oils; that is, higher nitrogen content and lower sulfur and oxygen levels were detected in 53-SH VGO compared to 08-SH VGO.

The eastern oil VGO samples show very similar pour points, as well as low metals content. The 08-SH VGO is slightly higher in metals, owing to a 13 ppm contribution from arsenic.

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	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT
GRAVITY, °API	6.5	8.2	23.2	21.7	26.0
K FACTOR	10.4	10.6	11.6	11.4	11.8
ELEMENTAL:					
HYDROGEN, WT%	9.04	9.19	11.8	11.4	12.62
NITROGEN, WT%	2.14	1.59	1.62	1.81	0.05
SULFUR, WT%	1.65	2.04	0.51	0.65	2.18
OXYGEN, WT%	1.53	1.90	----	----	0.08
TOTAL METALS, PPM	1	16	22	19	1
POUR POINT, °F	+30	+25	+75	+65	+60

showing slightly more nitrogen on the average. Sulfur, however, is much more abundant in the eastern oils' 600-1000°F fraction. No oxygen data is available for VGO from the Green River shale oils.

Metals contamination is slightly higher in the western shale oil VGO. Arsenic is the major contaminant in this fraction of the western oils.

Properties of VGO from Arabian Light petroleum, shown in Table 5, reveal much higher gravity, K factor and hydrogen content than their comparable fractions from the eastern shale oils, and the yield of 600-1000°F material from Arabian Light petroleum is about half that from the eastern shale oils.

Heteroatom contents are, naturally, much higher for the eastern shale material with one exception: sulfur is more abundant in VGO from Arabian Light petroleum than in the Kentucky shale oil VGO. Metals content is extremely low for the petroleum based VGO and its pour point is about twice that of the VGO from 53-SH and 08-SH.

Residuum (1000°F+)

Properties of the residuum from the fractionation of 53-SH and 08-SH are given in Table 6. The materials are quite similar and are characterized by high densities and low hydrogen contents.

Analysis of heteroatom contamination again reveals a higher nitrogen content in the 53-SH residuum and lower sulfur and oxygen contents than in 08-SH. Metals contamination is highest in this fraction of both subject oils with iron being the major contributor. Arsenic concentration is much higher in the 08-SH residuum.

Residua from the western shale oils exhibit a lower density, higher K factor and higher hydrogen content. Heteroatom contents of the eastern shale oil residua are consistently higher; and sulfur, in particular, is significantly higher for the eastern shale material. Total metals content of the western shale oil residua is somewhat lower than that found in the eastern materials. Arsenic content is intermediate between the 53-SH and 08-SH samples.

Arabian Light residuum, shown also in Table 6, exhibits a density intermediate between the eastern and western shale oil residua. Once again, higher K factor and hydrogen content are characteristic of the petroleum based residuum. Higher yields of residuum are derived from the crude oil, about 23 vol%, as compared to about 12 vol% and 15 vol% for 53-SH and 08-SH, respectively.

TABLE 6. EASTERN SHALE OIL RESIDUUM VS. WESTERN AND PETROLEUM

	53-SH	08-SH	IN SITU	ABOVE GROUND	ARABIAN LIGHT
SPECIFIC GRAVITY	1.161	1.167	0.9522	0.9665	1.0029
K FACTOR	10.5	10.3	11.8	11.7	11.9
ELEMENTAL:					
HYDROGEN, WT%	7.1	7.2	11.09	10.60	10.12
NITROGEN, WT%	2.71	2.18	1.54	2.45	0.28
SULFUR, WT%	1.38	1.96	0.49	0.58	3.32
OXYGEN, WT%	1.80	2.34	----	----	0.25
IRON, PPM	174	171	111	138	14
NICKEL, PPM	132	36	23	10	18
VANADIUM, PPM	7	12	2	2	68
ARSENIC, PPM	1	66	40	32	<1

Sulfur is concentrated more heavily in the petroleum bottoms, while nitrogen and oxygen are more abundant in residua from the Kentucky shale oil samples. Total metals content in the petroleum residuum is about one-third that of the eastern shale oil bottoms. No arsenic was detected and greater levels of vanadium exist in the Arabian Light residuum as compared to the 53-SH and 08-SH residua.

CONCLUSION

The two sample oils derived from Kentucky shale studied herein exhibit very similar physical and chemical properties, both in the full range oils and in the fractions distilled therefrom.

The eastern shale oils examined can be characterized as highly aromatic oils with lower API gravity, lower hydrogen contents and lower pour points than their western shale oil relatives. Comparably high heteroatom contents are observed in oils derived from eastern and western shales, but sulfur content of the eastern oils studied is substantially higher than that found in oils retorted from the Green River shales.

Fractionation of the subject samples yielded an abundance of material boiling in the 600-1000°F range, with slightly more naphtha and residuum produced than that found in the western shale oils.

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Processing Routes for Upgrading Eastern Shale Oil to Finished Petroleum Products

by

Clayton P. Kerr
Professor of Chemical Engineering
Tennessee Technological University
Cookeville, Tennessee 38501

Abstract. The key to upgrading Eastern shale oil to finished petroleum products is primary and secondary hydrotreating. The primary hydrotreating of the crude shale oil would require new capital investment at an Eastern refinery. Existing refinery hydrotreating facilities would serve as secondary hydrotreating. Tennessee shale oil has a low pour-point and is transportable to refineries without upgrading facilities at the retort.

Introduction

The first step in the definition of a route for upgrading shale oil to salable products is to conduct a marketing study to determine the desired products. One need only to read the recent literature to realize the markets for refined petroleum products are changing and demand for leaded gasoline, fuel oil, residual fuel oil, and coke is shrinking. A refiner of Eastern shale oil can expect competition from Eastern and Western coal, the natural gas industry, coal liquefaction, coal gasification, Western oil shale, and nuclear power. The most prudent shale oil refining route is probably one that maximizes yields of components that are suitable for blending fuels that are used in the transportation sector-motor gasoline, diesel fuel, and jet fuel. These fuels have been traditionally obtained from petroleum.

Crude Shale Oil Pour-Point

If the crude shale oil produced by retorting is not transportable because of high pour-point or because of degradation in storage, it will be necessary to partially upgrade the crude shale oil at the retort site. Several routes are available:

Coking
Addition of pour-point depressants
Hydrogenation

Coking cracks the oil into lighter oils that have lower pour-points. Coking is probably not an acceptable method because the coke has a low selling price, and the yields of oil are greatly reduced. Since Eastern shales have low oil yields, this route is clearly not acceptable.

Pour-point depressants can be used. However, not all types of depressants are suitable for many oils. Also, pour-point depressants do not improve the yields of the most desirable products from the shale oil refining.

Pour-Point can be improved by hydrogenating the crude shale oil. Pour-Point is improved by converting sulfur in the oil to hydrogen sulfide; the nitrogen in the oil is removed as ammonia. Oxygen in the oil is converted to water. This route has the advantage that it also improves the quality of the oil shipped to the refinery. The principal disadvantage is that hydrotreating is expensive. This is a significant disadvantage because most Eastern oil shale ventures (mine and retort) are being sized for 10,000 B/D versus 50,000 B/D for a typical synfuel venture. Thus, hydrotreating at the retort site would lose considerable advantages of scale.

The oil that we have produced from Tennessee shales in our laboratory studies appears to have a low enough pour-point (about 5°F) such that the oil is transportable as produced from the retort without additional treatment. However, this conclusion should not be extrapolated to all Eastern shale applications.

Siting Factors

To keep environmental impacts within acceptable limits, most Eastern oil shale mines and retorts will probably be sized for 10,000 B/D of crude shale oil. This will require the oil from several of these ventures be shipped to a central refinery for upgrading to salable products. U. S. refineries are presently operating at only 65% of capacity. Hence it appears that existing refineries should be utilized rather than building new ones specifically designed for Eastern shale oil.

For a refiner to make a committment to the refining of Eastern shale oil, it will clearly be necessary that several retorts be scheduled to come on stream at roughly the same time.

The transportation of the crude shale oil from retort to refinery by river barge would probably be the most desirable method. The oil would probably be moved by pipeline from the retort site to barge facilities. Thus, mine sites located

near navigable rivers appear to be desirable.

Hydrotreating

Our studies with Tennessee shale oils have identified the presence of nitrogen, sulfur, and oxygen in the bitumen. We believe the first step in the refining process would be the removal of nitrogen, sulfur, oxygen, and heavy metals, particularly heavy metals and nitrogen which are catalyst poisons. A hydrotreater with some kind of guard bed for removal of heavy metals would probably be used. Hydrotreating would also have the advantage that the hydrogenation would increase the yields of lighter components which are suitable for transportation blending stocks and hence more valuable. We believe that hydrotreating is the key upgrading process for refining Eastern shale oils.

The hydrotreating would be done in two basic parts. The first would be a hydrotreatment of all the shale oil for gross removal of nitrogen, other impurities, and catalyst poisons. After crude fractionation, some additional downstream hydrotreating would be required to protect more sensitive catalysts.

After the primary hydrotreater, the upgraded oil would be fractionated. One fraction would go directly to gasoline blending. Another somewhat higher boiling fraction would go to a reformer with the reformate going to gasoline blending. Other higher boiling fractions would be hydrotreated and these products would go to jet fuel and diesel fuel. The fraction with boiling range of 650°F plus would probably go to a hydrocracker to increase gasoline yields even more. A fluid catalytic cracker could probably be substituted for the hydrocracker although the gasoline yields would be less. We believe Tennessee shale oil is aromatic and hydrocracking may be more desirable than fluid catalytic cracking.

We believe that considerable secondary hydrotreating will be required after the shale oil has gone through crude fractionation. Naphtha hydrotreating will be required to remove gum forming materials in order to improve storability. If octane ratings are to be improved, some of the naphtha may be processed in catalytic reformers. Since reformer catalyst is quite sensitive to nitrogen, the reformer feed should be hydrotreated.

Distillates that are to be used for diesel and jet fuel blending should probably also be hydrotreated to improve storability. Jet fuel would probably require a more severe secondary hydrotreat than diesel.

Atmospheric and vacuum gas oils produced from shale oil could be used as feed to hydrocrackers or fluid catalytic crackers to improve the yields of blending stocks for transportation products. Because catalysts for catalytic cracking are nitrogen sensitive, a secondary hydrotreat to get the nitrogen content down to several thousand ppm will be required. The same is true if gas oils are used as feed for hydrocrackers.

The important point to realize about secondary hydrotreating is that there are many large refineries operating in the U. S. with imported sour crude, and the secondary hydrotreaters are already in place operating on fractionator cuts. Thus we believe that existing secondary hydrotreaters could be utilized if sour foreign crude is replaced with Eastern shale oil. Thus, the principal new refinery investment would be for primary hydrotreating.

We also believe there is an important transportation advantage for Eastern shale oil. Eastern shale oil would probably move to refineries on barges utilizing the inland waterway system and would replace a 9,000 mile tanker lifting from the Middle East.

Conclusions

Crude Tennessee shale oil will probably not require treating at the retort site to be transportable to refineries. Hydrotreating is the key upgrading process. The primary hydrotreater would require new capital investment. The secondary hydrotreating would be done in existing facilities.

Metal Recovery from Eastern Oil Shale

by

T.M. Gilliam, R.M. Canon, A.D. Ryon, and J.S. Watson
Chemical Technology Division
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

Abstract. Results are shown for the acid extractability of several minerals from: (1) raw shale, (2) shale that has been retorted with hydrogen under pressure, and (3) retort residue that has been subjected to an oxidative roast. Six elements (Al, Co, Fe, Mo, U, and V) have been identified as having the greatest potential for economical recovery. Conceptual process flowsheets for their recovery are presented.

Introduction

The United States depends on foreign sources for supplies of many metals including aluminum, cobalt, and nickel. Eastern shale contains these elements as well as iron, molybdenum, uranium, and zinc. Recovery of minerals as a by-product of oil recovery could have economic as well as strategic benefits. Additionally, mineral recovery could have environmental advantages since the leached shale residues would be more inert than the retort residues.

Metal recovery from Chattanooga shale is not a new concept, and several researchers have explored uranium recovery by a sulfuric acid leach.[1,2] Work at Ranstad, Sweden,[3] has also been underway for several years on recovery of uranium from shale via sulfuric acid leach. Previous work has emphasized sulfuric acid leach because (1) the technology for uranium recovery is well known and (2) the sulfur contained in the shale is a source of sulfuric acid.

Although previous studies on metal recovery from shales have focused on uranium, substantial research which has been done on metal (primarily aluminum) recovery from clays and coal combustion ash may be applicable to shale. Early studies with these materials also used sulfuric acid as a dissolution agent.[4,5] Difficulties in obtaining a sufficiently pure alumina product and in acid recycling led to interest in other systems, such as that using hydrochloric acid.[6,7] Recent studies at Oak Ridge National Laboratory (ORNL) have concentrated on metal recovery from fly ash via a hydrochloric acid leach.[8-10]

Metal Leachability

The Chloride System

The reference shale [provided by Institute of Gas Technology (IGT)] used in this study was obtained from Clay County, Tennessee. The metal content of the reference material is shown in Table 1. Uranium analyses were performed by the optical fluorescence method, while analysis for all other metals was by Inductively Coupled Plasma Spectrometry.

Table 1. Metal Content of the Reference Chattanooga Shale Used in Leaching Studies.

Element	Concentration (ppm)
Al	64500
B	78
Ba	640
Be	3
Ca	3000
Co	69
Cr	214
Cu	106
Fe	70600
K	23100
Li	33
Mg	6825
Mn	126
Mo	205
Na	3126
Nb	11
Ni	338
P	699
Pb	14
Sc	11
Sr	57
Th	6
Ti	3508
U	64
V	360
Y	13
Zn	124
Zr	105

A product value analysis of the reference shale (Table 2) clearly indicates that aluminum (as alumina) should be a major product of interest.[11] Our studies with fly ash have shown that when alumina is a major product, the chloride system has important advantages over the sulfate and nitrate systems.[8,9] Thus our recent studies on Chattanooga shale concentrated on treatment via hydrochloric acid leach.

Table 2. Chattanooga Shale Product Value Analysis.

Possible products	Value ($ per short ton of shale)
Alumina (Al_2O_3)	24.51
Cobalt (Co_2O_3)	3.20
Iron (Fe_2O_3)	10.49
Molybdenum (MoO_3)	4.90
Uranium (U_3O_8)	3.75
Vanadium (V_2O_5)	3.68

Effect of Hydrocarbon Liberation on Metal Recovery

This study concentrated on metal recovery from the residue of the IGT HYTORT process, which is representative of the state-of-the-art in Chattanooga or Eastern shale development. However, other hydrocarbon liberation processes may prove as effective and possibly more economical. The retort residue, presently envisioned as a waste, also contains significant residual carbon and sulfur and thus may be gasified for heat recovery and sulfur removal.[12] Consequently, 3-h reflux-temperature leaches using excess 6 N hydrochloric acid were performed on (1) raw shale, (2) retort residue (i.e. shale subjected to a reducing atmosphere), and (3) retort residue processed for heat recovery and sulfur removal in an oxidizing atmosphere at 650°C for 4 h. The resulting metal removal values are shown in Table 3.

The data indicate that significant quantities of the metals of interest (Al, Co, Fe, Mo, U, and V) are extracted by the direct hydrochloric acid leach. Treatment of the raw shale appears more suitable for uranium recovery than for recovery of other metals. As expected, prior treatment of shale for carbon removal generally increases the metal removal values. The lower values for recovery of molybdenum and uranium from the retort residue may result from the exposure to the retort reducing atmosphere since both elements are known to exhibit lower acid solubilities in the reduced state. Subjecting the retort residue to an oxidative roast increases the leachability of both metals. The roast also appears to increase the leachability of aluminum, although the reason for this is unclear. The overall data confirm that metal recovery depends on retorting conditions.

Process Development

As indicated by the reflux-temperature leach data (Table 3), metal removal from the three materials used appears to be feasible. However, the leachates of each material will require different (although not unique) processing schemes for the recovery of the six elements of interest. Three possible approaches are presented in this study.

Table 3. Metal Extraction Values from 3-h Reflux-Temperature Leaches with 6 N Hydrochloric Acid.*

Element	Extraction (%) Shale	IGT retort residue**	Roasted retort residue***
Al	31	63	79
B	53	59	86
Be	72	96	98
Ca	95	95	97
Co	30	97	100
Cr	82	60	80
Cu	17	34	84
Fe	15	97	99
K	29	62	71
Li	55	23	22
Mg	62	88	97
Mn	71	93	96
Mo	22	11	99
Na	8	24	27
Ni	45	95	98
P	99	93	95
Sc	43	77	86
Sr	49	70	72
Ti	4	5	8
U	75	56	67
V	26	74	96
Y	84	63	67
Zn	93	97	93

*It should be noted that all feed materials were ground to -35-mesh size prior to leaching.
**Shale subjected to retort under hydrogen pressure at high temperatures.
***Oxidized in air for 4 h at 650°C.

IGT Retort Residue

Since the IGT HYTORT process is representative of the state-of-the-art in Eastern shale development, considerable effort was expended on metal recovery from IGT retort residue. X-ray diffraction analysis indicates that the sulfur in this residue is primarily associated with the iron as FeS, and literature data indicate that sulfides containing a single sulfur atom (e.g., FeS) are relatively easy to leach.[13] Therefore, an ambient-temperature, excess-acid leach of the residue was performed with the results shown in Table 4. As indicated, the 24-h leach removes significant quantities of Co, Fe, Ni, U, and Zn. This ambient-temperature leach not only isolates three products of interest (see Table 2) but also provides a significant purification of aluminum by removing significant quantities of the Ca and P. Aluminum purification normally is difficult in the presence of high concentrations of iron and the IA and IIA elements.

The sulfur in the leach solution will be present as H_2S, suggesting the possibility of isolating Co, Ni, and Zn as sulfide precipitates.

Table 4. Extractions Resulting from a 6 N HCl Ambient-Temperature Leach of Retort Residue.

Element	Extraction (%) Leach time (h) 1	3	6	24	72
Al	2	2	3	5	6
B	5	0	9	6	15
Be	0	0	12	26	26
Ca	84	86	87	86	88
Co	95	95	96	96	97
Cr	41	42	42	50	52
Cu	0	0	3	0	0
Fe	89	90	91	90	92
K	4	5	6	9	6
Li	0	0	5	0	2
Mg	5	8	10	17	23
Mn	44	51	54	57	64
Mo	0	0	6	0	0
Na	4	5	6	7	8
Ni	77	82	85	91	87
P	82	82	85	82	84
Sc	0	0	5	0	8
Sr	47	49	50	49	50
Ti	0	0	1	0	1
U			30	66	65
V	9	10	12	13	18
Y	54	51	52	54	56
Zn	67	72	78	69	80

Results shown in Table 5 were obtained for an ambient-temperature leach using an acid-deficient system (0.6 N acid at 20% solids is the stoichiometric amount required) at leach times of 1 h and 24 h. The decreasing extraction of Co and Ni with longer leach time strongly suggests that precipitation has occurred. A mixture of Co-Ni-Zn sulfides could be sold as an ore concentrate.[2]

Sulfur removal may be accomplished via aeration in a manner similar to that used for wastewater cleanup. Determining the quantity and concentration of acid contained in the off-gas will be of paramount importance in deciding whether the H_2S can be routed to the disposal system used in the hydrocarbon liberation step or whether a separate H_2S disposal scheme must be used. Need for a separate system would have a significant impact on the economics of metal recovery.

Several approaches to removal of uranium from a chloride system are available in the literature. Uranium removal by solvent extraction with di-2-ethylhexyl phosphoric acid in combination with trioctylphosphine oxide has been reported by Blake et al.,[14] with the uranium recovered as uranyl tricarbonate by stripping the organic phase with carbonated ammonia solution. The precipitated uranyl tricarbonate is calcined to U_3O_8 at 600°C. Seeley[15] has reported uranium extraction coefficients on the order of 10^4 from a chloride system using a quaternary amine solvent. Kraus[16] reported uranium distribution coefficients on the order of 10^3 with quaternary amine polystyrene divinyl benzene ion exchange resin in the chloride system.

The aqueous stream remaining after uranium removal contains primarily ferrous chloride, which

Table 5. Extractions Resulting from an Acid-Deficient Ambient-Temperature HCl Leach of Retort Residue.

Element	Extraction (%) Run 2*	Run 3**
Al	1	1
B	2	6
Be	0	0
Ca	81	82
Co	68	1
Cr	28	33
Cu	0	0
Fe	83	82
K	3	3
Li	1	3
Mg	3	5
Mn	37	43
Mo	0	0
Na	4	5
Ni	29	1
P	68	56
Sc	0	0
Sr	25	31
Ti	0	0
V	7	6
Y	44	45
Zn	1	0

*Leach conditions: 1 h at 20% pulp density with 0.5 N HCl (slightly acid-deficient).
**Leach conditions: 24 h at 20% pulp density with 0.5 N HCl (slightly acid-deficient).

can be converted to Fe_2O_3 (with hydrochloric acid recovered for recycle) using technology available from treatment of spent steel-pickling liquor.[17-19] The process involves the pressure oxidation of the ferrous chloride to ferric chloride in oxygen atmosphere at ∿150°C and 145 psia. The ferric chloride is then hydrolyzed to Fe_2O_3 at ∿160°C with volatilized acid recovered for recycle.

The solid discharge from the ambient-temperature leach (i.e. leached retort residue) can then be processed for aluminum recovery. Table 6 summarizes results from a 6 N HCl, reflux-temperature leach (2nd stage) of retort residue that had been previously subjected to a 24-h ambient-temperature leach in excess 6 N HCl (1st stage). The data indicate that maximum aluminum and vanadium removals can be achieved with a 3-h leach. The leach also extracts significant quantities of other elements, primarily the alkali metals, which must be removed from the final products. [Sato et al.[20] have presented data on the extraction of vanadium from hydrochloric acid solutions using tri-n-octylphosphine oxide (TOPO) or tri-n-butylphosphate (TBP)].

The aqueous solution remaining after vanadium removal, containing primarily aluminum chloride, may then be processed for recovery of alumina (Al_2O_3) by fractional crystallization via HCl sparging[21] in which aluminum (as $AlCl_3 \cdot 6H_2O$) is preferentially precipitated at high hydrochloric acid concentrations. Our scouting studies indicate that $AlCl_3 \cdot 6H_2O$ crystals of sufficient purity can be obtained from the 2nd-stage leach liquor in two

Table 6. Extractions Resulting from Second-Stage Reflux-Temperature Leach.*

Element	Extraction (%) Leach time (h) 0.25	1	3	8
Al	15	36	77	78
B	27	43	73	74
Be	35	69	98	94
Ca	49	62	66	71
Co	92	98	99	97
Cr	20	89	75	79
Cu	60	52	55	38
Fe	38	56	84	83
K	24	43	72	70
Li	8	13	25	20
Mg	34	62	94	95
Mn	46	39	91	89
Mo	21	22	17	21
Na	10	19	20	19
Ni	74	73	77	73
P	56	64	87	85
Sc	25	53	87	86
Sr	24	31	53	49
Ti	1	2	8	8
V	32	53	83	84
Y	17	23	41	35
Zn	74	79	90	88

*Leach conditions: 3-h, 6 N HCl, reflux-temperature leach of the residue from a 24-h, 6 N HCl, ambient-temperature leach of retort residue.

Table 7. Extractions Resulting from a 6-h Hydrochloric Acid, Reflux-Temperature Leach of Roasted Retort Residue.

Element	Extraction (%) Roast temperature* 550°C	650°C	750°C	850°C	950°C
Al	78	79	77	61	9
B	83	86	82	43	15
Be	94	98	85	39	13
Ca	96	97	96	83	68
Co	100	100	96	69	40
Cr	92	80	79	57	43
Cu	89	84	78	46	15
Fe	99	99	99	95	88
K	72	71	71	63	7
Li	39	22	26	26	8
Mg	97	97	93	50	17
Mn	96	96	94	66	38
Mo	99	99	97	78	70
Na	27	27	39	40	16
Ni	99	98	95	83	45
P	96	95	92	84	71
Sc	86	86	87	64	23
Sr	71	72	75	60	24
Ti	8	8	10	10	14
U	66	67	63	41	18
V	96	96	92	68	24
Y	67	67	63	72	56
Zn	99	93	84	65	20

*Air roast for 4 h.

crystallization stages.[22] Calcination of $AlCl_3 \cdot 6H_2O$ to saleable alumina at ~500°C is well documented.[23]

The acid liquor remaining after the crystallization of $AlCl_3 \cdot 6H_2O$ will contain primarily the alkali metals and other elements of little or no commercial value. These can be isolated for disposal by one of two methods: (1) sparge crystallization to precipitate the metals as chlorides (by raising the HCl content to >35 wt %) or (2) treatment of a bleed stream with H_2SO_4 (to precipitate the alkali earth metals as sulfates). The method of choice will depend primarily on environmental considerations in the disposal of the waste salts (chlorides vs sulfates). Therefore, identification of the waste components is essential. With either method, the remaining liquor (laden with HCl) will be recycled to the leach step.

IGT Retort Residue Subjected to Oxidation (Roasting)

As indicated by Table 3, oxidation of the retort residue causes a substantial increase in extraction values for several elements in an excess hydrochloric acid leach at reflux temperature. The increased extraction value for molybdenum may make it a viable product from this material. An ambient-temperature leach of the oxidized retort residue gives no clear-cut metal separations, so the two-stage leach process described previously is not applicable to this material. However, since a reflux leach removes substantial quantities of the six metals of interest, several components of the two-stage leach process may be used for product isolation.

Table 7 presents the effects of roasting temperature on extraction values. The data show that phase changes or sintering occurring between 750 and 850°C result in reduced extraction. Thus, the roast must be performed at lower temperatures for effective metal recovery. Data obtained by Spiewak[24] with a sulfuric acid system suggest that the reduced extractions begin at roasting temperatures between 750 and 800°C.

The leachate resulting from a reflux-temperature leach of oxidized residue contains a number of metals, including the six of most interest (Al, Co, Fe, Mo, U, and V). The iron, present primarily as ferric chloride, may be isolated by anion exchange using Dowex 2-X8 resin.[9,25] The anion exchange strip liquor laden with ferric chloride can be processed to recover Fe_2O_3 and hydrochloric acid for recycle as described previously (note that the pressure oxidation step is not needed).

The effluent from the anion exchange may be processed for uranium and vanadium recovery in a manner similar to that described in the two-stage leach process. Vieux et al.[26] have presented results on the extraction of molybdenum from chloride solutions using a quaternary amine. Seeley[15] reported that tertiary or quaternary amines

can be used for the extraction of both cobalt and molybdenum from chloride solutions. Kraus[16] reported that anion exchange may also be used for cobalt removal.

The remaining solution can be processed for the recovery of alumina as described previously. The isolation of contaminants and recovery of acid for recycle could also be performed as in the two-stage process.

Shale

Data shown in Table 3 indicate that a direct acid leach of raw shale is suitable only for uranium recovery. Since the presence of chloride in the hydrocarbon liberation step is known to cause corrosion problems, a sulfuric acid leach of the raw shale was performed (Table 8). These results show that an ambient-temperature sulfuric acid leach removes significant quantities of uranium and only minor amounts of the other elements of interest (with the possible exception of molybdenum and cobalt). Uranium could then be recovered from the aqueous sulfate stream using commercially available technology.[27] Items of concern here are: (1) the effect of the leach on any subsequent hydrocarbon liberation step, and (2) the degree of dryness required for the hydrocarbon liberation step (which could have a significant impact on the economics of uranium recovery).

Table 8. Extractions Resulting from an Ambient-Temperature Leach of Shale with 6 N Sulfuric Acid.

Element	Extraction (%) Leach time (h) 0.25	1	24	72
Al	<1		2	1
B	10	15	28	13
Ba	0	0	0	<1
Be	0	0	0	0
Ca	74	91	95	92
Co	18	21	32	24
Cr	10	7	13	6
Cu	11	19	35	22
Fe	1	2	8	5
Mg	2	3	9	6
Mn	15	19	31	21
Mo	7	12	20	13
Na	5	3	12	52
Ni	23	23	34	24
Sr	13		14	8
Ti	<1	<1	<1	<1
U	22	39	54	59
V	<1	25	2	<1
Zn	26	12	62	59

The sulfur contained in the retort residue (i.e., the sulfur removed as SO_2 by the oxidative roast) could be recovered as H_2SO_4 and used in the shale leach step. The other metals of interest could be recovered as described previously from the roasted residue.

Summary

Results are shown for metal leaching values in an acid system for three types of feed material: (1) shale, (2) IGT retort residue, and (3) retort residue subjected to an oxidative roast. Although leach data are shown for 28 elements, only six have been identified as having potential commercial interest (Al, Co, Fe, Mo, U, and V). Of the six, aluminum and iron have the greatest potential commercial value. Preliminary data have permitted the formulation of three possible metal recovery schemes, which are summarized in Figures 1 and 2. Although each process step appears to be technically feasible, the role of contaminants has not been demonstrated experimentally. In addition, the processes make substantial use of recycle streams, and potential problems associated with contaminant buildup have not been assessed. Development of suitable techniques for waste disposal would require the careful characterization of waste streams.

Although three approaches to metal recovery have been presented, the optimum approach will depend on the hydrocarbon liberation step used. Uranium recovery from raw shale may require that the shale be ground prior to the leach step, and the presence of fines is incompatible with some retort

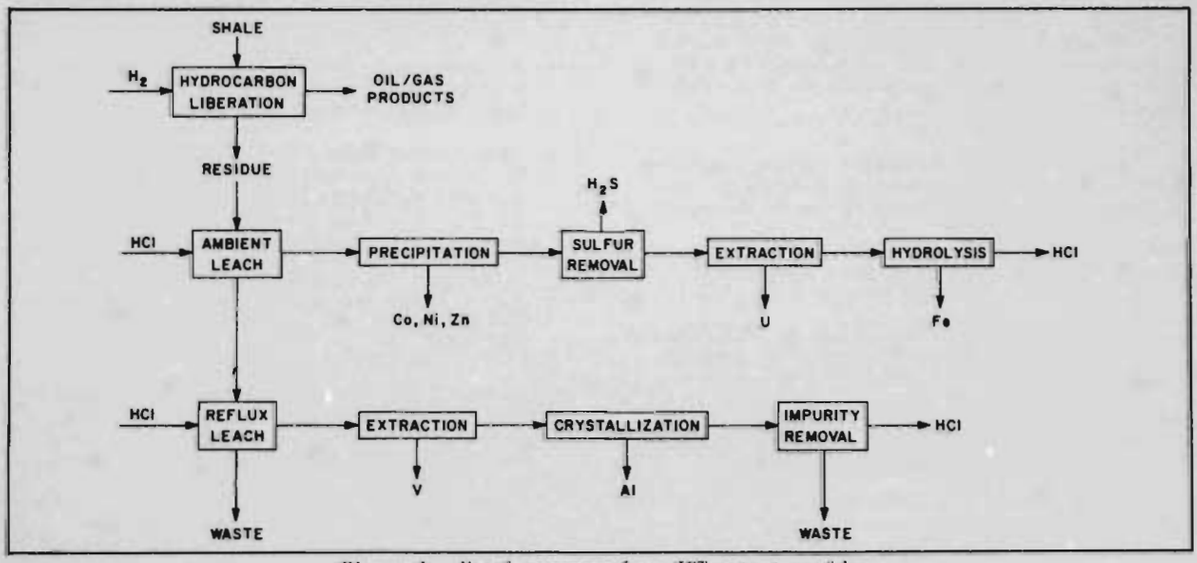

Figure 1. Metal recovery from IGT retort residue.

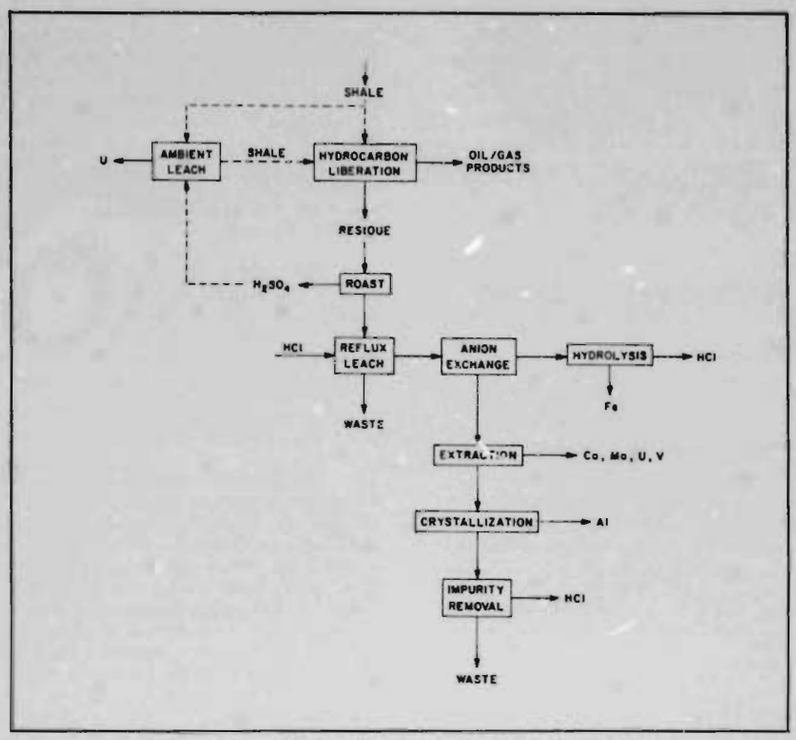

Figure 2. Metal recovery from roasted residue.

schemes. Also, the effect of residual water in the retort is unclear. The use of the two-stage or single-stage treatment of retort residue for metal recovery depends on the retort atmosphere (i.e., reducing or oxidizing). However, it is clear that no matter which approach proves to be optimum, economic metal recovery would have a favorable effect on the development of an Eastern shale industry.

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Tuesday Afternoon Session

SOCIO-ECONOMIC AND ENVIRONMENTAL STUDIES

Socio-Economic Impacts: Validity of Evidence from the Coal Mining Industry in Kentucky

by

Paul D. Nesbitt, Barbara Lovan, John Mays
Nesbitt Engineering, Inc.
400 E. Vine St. Suite 310
Lexington, Kentucky

Introduction

A number of activities currently being undertaken suggest that Eastern Oil Shale Resources will be extensively developed in the near future. In Kentucky, it has been estimated that more than 200,000 acres of land has been leased for oil shale purposes. Options for leases have been obtained on hundreds of thousands of additional acres in several of our neighboring states, including Indiana, Ohio, Tennessee and Alabama. Several feasibility studies for different methodologies of mining have been conducted, with more being initiated or monies being sought for their initiation. The federal government, through the Environmental Protection Agency and the Department of Energy, is monitoring and assisting in research projects on the development of the eastern oil shale industry, and some believe that the eastern industry may very soon surpass the more advanced western shale developments in the race for commercial production.

As far as Kentucky is concerned, our oil shale resource is one of the nation's most extensive and most accessible, and on a Btu basis, there is more potential energy contained within Kentucky's oil shale than within it's coal resources.

It has been contended that, environmentally, the mining of oil shale will not be extremely different from the mining of coal and other various minerals in Kentucky. Environmental controls established by the regulators are being modeled from the coal mining regulations, with concerns for variances between the two mining types only arising in a few key sections[1]. Precise environmental impacts, however, are admittedly difficult to predict, especially in light of the sparse knowledge which currently exists on specific mining and processing methodologies to be used.

An even more difficult concept to prognosticate for the oil shale industry in Kentucky, however, is the socio-economic impact of the geographic area of the Knobs Region. The main focus of this paper will be to lay some groundwork for such impact, using an introduction and summary description of socioeconomic factors, followed by an analysis of selected factors.

This study was based on the observation that the issue of oil shale development in Kentucky was being connected very closely or even tied directly to the impacts of the coal mining industry, more specifically that of eastern Kentucky. It was apparent that the agenda for discussion of oil shale was derived too often from a list of well known coal mining impacts, including environmental, legal, and financial, as well as socio-economic categories.

This formulation of the oil shale issue on the basis of coal mining impacts is not wrong, but actual evaluation of the issue in the same manner is. Conditions in the coalfields cannot be applied automatically to the Knobs region and its oil shale deposits. The latter area and the impacts of an emerging or fully developed oil shale industry must be assessed on their own merits or deficiencies.

Therefore, the purpose of this study is, not only to introduce impact factors applicable to the oil shale region, but also to explore whether these impacts differ between the coalfields and the oil shale region. An associated purpose is to identify contrasts within the oil shale region, since distance variations will not justify the application of broad generalities borrowed from <u>any</u> other region, not just the eastern Kentucky coalfields.

This study did not undertake a comprehensive treatment of all socio-economic factors. Some cannot be quantified, while others belong to the domain of public policy analysis and decision-making. This necessarily excludes some very visible public issues such as desirability of growth, land use, cultural values, and aesthetics. The intent was to examine a sufficient number of factors in order to establish the existence of differences on a inter-region and intra-region basis. Such evidence will support the independent evaluation of the oil shale region, not pre-judgement decided on the testimony of some other region.

Description of Study Area

Physiography

The Knobs Region's physiography is an extension of the Bluegrass region, with the Knobs themselves being erosion remnants of the uplands located behind the escarpments (i.e. the Appalachian mountains to the southeast wherein the Eastern Coal Fields lie). The western half of the

Knobs are gently rolling and more or less continuous with the Outer Bluegrass Region. The eastern half of the Knobs Region contains long wide valleys extending into a rough and hilly belt of the Knobs proper. The Kentucky River and some of it's major tributaries are entrenched into the region's gently rolling uplands.

The Eastern Coal Field's physiography is much less subdued, and presents a sharp contrast to that of the Knobs Region. For the most part, it is characterized by broad uplands of moderate relief combined with narrow ridges bordered on each side by deep valleys with precipitous walls. The Kanawha section, which forms the largest part is a much dissected plateau characterized by narrow, crooked valleys and narrow, irregular, steep-sided ridges. The local relief of the Kanawha section increases from 300 or 400 ft. in the north to about 2,500 ft. in the south part of the region. Some major streams are entrenched in flood plains of moderate width, but most of the smaller creeks have no valley floors[2].

Study Area Delineation

This study will compare data between a group of counties in which oil shale deposits may be easily extracted and a group of counties that are current coal producers. Because the focus on the impacts of coal production tends to be directed at the eastern Kentucky coalfields, only coal counties from that region will be studied.

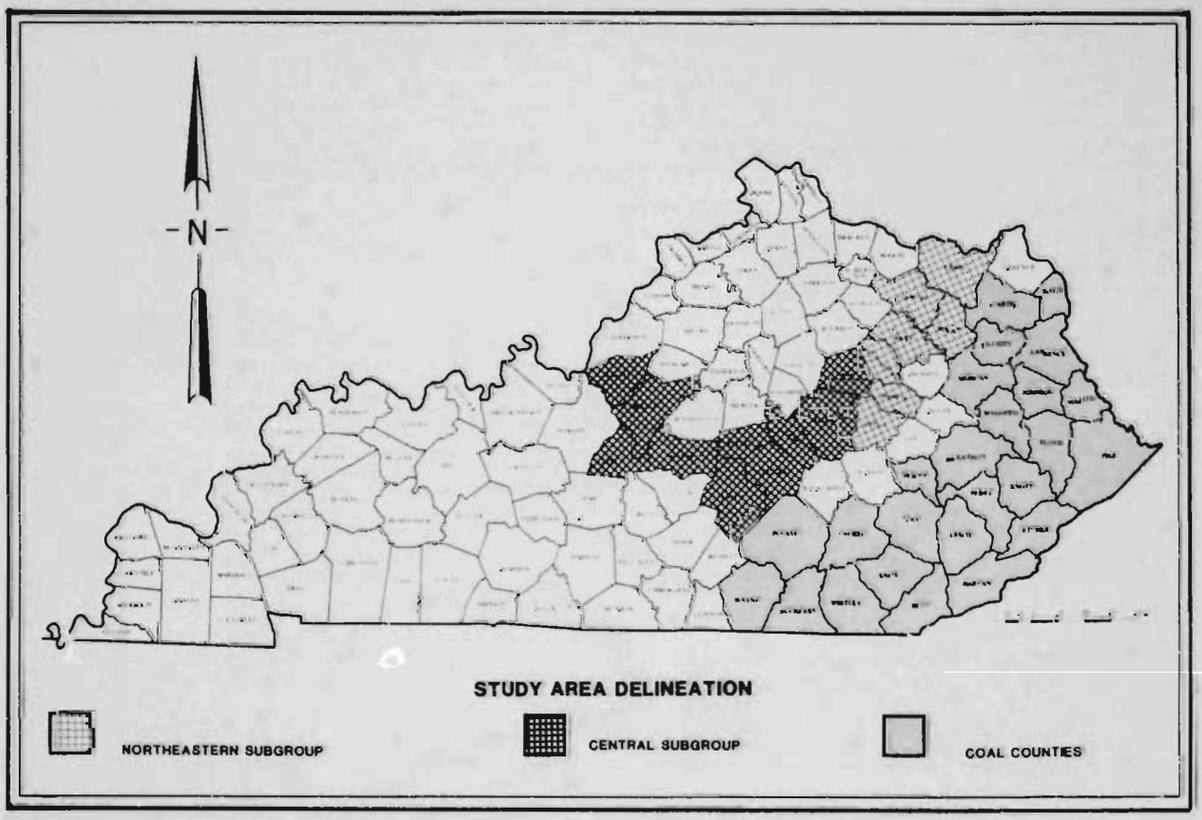
Oil shale counties were selected from a general geologic map of Kentucky[3] (Figure 1). The intent was to choose the principal, contiguous deposit counties. Some counties were omitted, although deposits are indicated.

Coal counties selected from eastern Kentucky were those with a production of approximately 250,000 tons or more in 1979[4].

The resulting counties chosen for study are shown in Figure 1. The peripheral counties of both groups lie adjacent to each other, but the middle areas are separated by a four county band. These four separation counties are characterized more by small coal production than by the presence of any small oil shale deposit outcrop.

In the representative analysis section, contrasts will be made between counties within the oil shale group (also referred to as Knobs Region). Two subgroups were established, the "northeastern" and the "central". Member counties were as follows:

Northeastern Subgroup		Central Subgroup	
Bath	Montgomery	Boyle	Larue
Estill	Powell	Bullitt	Lincoln
Fleming	Rowan	Casey	Madison
Lewis		Clark	Marion
		Garrard	Nelson



(Figure 1).

A total of 17 counties were selected in the oil shale group.

The coal group (Eastern Coal Fields) included 25 counties as follows:

Coal Counties

Bell	Leslie
Boyd	Letcher
Breathitt	Magoffin
Carter	Martin
Clay	McCreary
Elliott	Morgan
Floyd	Owsley
Harlan	Perry
Johnson	Pike
Knott	Pulaski
Knox	Wayne
Laurel	Whitley
Lawrence	

Existing Socio-Economics of The Oil Shale vs. The Coal Region

Because of the overt distinctions between the physiographic characteristics of the Knobs Region and the Eastern Kentucky Appalachian Region, the resulting socio-economic development of both areas are also quite distinguishable. In reviewing the statistics for each economic development factor it can be seen that the Knobs Region's development has been, overall, more homogeneous, more sophisticated, more predictable and has occurred at a significantly greater rate than the development which has occurred in the coal fields. Below is a general comparison of each of the most important of these development factors.

Labor Force Characteristics of Residents

The total combined Labor force characteristics for the seventeen counties comprising the Oil Shale Region, as listed on Insert A[3], indicate a strong diversity between the agricultural and non-agricultural labor. As might well be expected, the region's labor force is extended over several types, including agriculture, industry, mining and business. The Knobs Region includes large areas of prime farmland soil resources, both on slopes and ridgetops as well as in the bottomlands, and this tends to be the major reason for predominance in grazing and cropland development.

The labor force for the Eastern Coal Fields, on the other hand, is predictably coal-mining oriented. An indication of this is displayed on Insert B[6], which depicts characteristics for the 25 counties comprising the Eastern Coal region. Nonagricultural employment figures for both the coal region and the oil shale region are included as inserts C & D. Labor force and employment characteristics will be analyzed in detail in a later section.

Median Family Income

Insert E[8] depicts the median family incomes for the oil shale region and the coal region. These figures do not reflect counties within the Standard Metropolitan Statistical Areas, (SMSA) which include Bullitt and Clark Counties of the oil shale region. These statistics will be analysed in detail in the Representative Analysis.

(INSERT A)

LABOR FORCE CHARACTERISTICS OF RESIDENTS: 1979

OIL SHALE REGION

COUNTY	CIVILIAN LABOR FORCE	EMPLOYMENT	AGRICULTURAL	NON-AGRICULTURAL
KENTUCKY	1,563,000	1,476,000	73,049	1,402,951
BATH	3,568	3,218	696	2,522
BOYLE	12,608	11,918	696	11,222
BULLITT	16,189	15,452	226	15,226
CASEY	6,301	5,744	921	4,823
CLARK	15,133	14,412	971	13,441
ESTILL	5,558	5,112	78	5,034
FLEMING	4,865	4,559	1,125	3,434
GARRARD	4,083	3,838	689	3,149
LARUE	5,142	4,834	694	4,140
LEWIS	4,837	4,430	594	3,836
LINCOLN	6,428	5,824	1,220	4,604
MADISON	27,761	26,624	1,383	25,241
MARION	6,884	6,383	982	5,401
MONTGOMERY	7,861	7,316	630	6,686
NELSON	11,091	10,218	959	9,259
POWELL	3,510	3,216	103	3,113
ROWAN	8,154	7,685	229	7,456
TOTAL FOR REGION	149,771	140,783	12,196	128,587
AVERAGE PER COUNTY	8,810	8,281	717	7,563

(INSERT B)

LABOR FORCE CHARACTERISTICS OF RESIDENTS: 1979

COAL REGION

COUNTY	CIVILIAN LABOR FORCE	EMPLOYMENT	AGRICULTURAL	NON-AGRICULTURAL
KENTUCKY	1,563,000	1,476,000	73,049	1,402,951
BELL	12,639	11,656	63	11,593
BOYD	22,267	21,090	232	20,858
BREATHITT	5,718	5,204	164	5,040
CARTER	7,686	6,858	407	6,451
CLAY	7,306	6,621	272	6,349
ELLIOTT	3,522	3,246	145	3,101
FLOYD	14,511	13,382	46	13,336
HARLAN	12,012	10,978	43	10,935
JOHNSON	7,242	7,693	63	7,630
KNOTT	4,534	4,081	45	4,036
KNOX	12,096	11,214	339	10,875
LAUREL	18,242	17,189	669	16,520
LAWRENCE	3,759	3,325	226	3,099
LESLIE	4,555	4,137	23	4,114
LETCHER	7,416	6,349	15	6,334
McCREARY	4,076	3,634	56	3,578
MAGOFFIN	4,476	3,913	63	3,850
MARTIN	7,777	7,471	38	7,433
MORGAN	5,010	4,574	385	4,189
OWSLEY	1,703	1,508	244	1,264
PERRY	12,609	11,599	144	11,455
PIKE	29,194	27,289	37	27,252
PULASKI	20,370	19,035	1,254	17,781
WAYNE	7,558	7,004	981	6,023
WHITLEY	9,991	9,148	108	9,040
TOTAL FOR REGION	247,219	228,198	6,062	222,136
AVERAGE PER COUNTY	9,889	9,128	243	8,885

(INSERT C)

NONAGRICULTURAL EMPLOYMENT BY INDUSTRY, BY PLACE OF WORK: 1979

OIL SHALE REGION

COUNTY	ALL INDUSTRIES	MINING & QUARRYING	CONTRACT CONSTRUCTION	MANUFACTURING	TRANSPORTATION, COMMUNICATIONS, & PUBLIC UTILITIES	WHOLESALE & RETAIL TRADE	FINANCE, INSURANCE, & REAL ESTATE	SERVICES	OTHER
KENTUCKY	1,145,564	54,257	69,074	296,898	58,772	268,707	50,980	339,863	7,013
BATH	905	0	120	19	49	205	47	462	*
BOYLE	10,442	*	411	3,699	537	2,743	316	2,648	57
BULLITT	4,501	*	263	1,205	141	1,053	160	1,627	21
CASEY	2,424	*	136	1,268	67	383	45	508	*
CLARK	10,648	*	375	4,397	1,231	2,353	326	1,899	68
ESTILL	2,046	*	99	499	73	478	67	592	0
FLEMING	2,417	*	83	593	100	608	98	898	8
GARRARD	1,855	*	102	644	24	400	76	593	*
LARUE	1,683	0	90	496	67	432	95	494	10
LEWIS	1,831	*	28	951	64	229	85	472	0
LINCOLN	1,965	*	100	412	47	428	111	768	9
MADISON	16,380	56	426	4,571	275	4,488	402	6,111	50
MARION	3,157	*	94	804	80	735	127	1,278	23
MONTGOMERY	6,378	*	295	2,741	139	1,646	227	1,309	16
NELSON	5,919	91	549	1,763	280	1,417	181	1,628	10
POWELL	1,454	31	180	332	104	258	49	499	0
ROWAN	5,472	*	257	713	242	1,489	157	2,590	*
TOTAL FOR REGION	79,477	**	3,608	25,107	3,502	19,345	2,569	24,379	**
AVERAGE PER COUNTY	4,675	**	212	1,477	207	1,138	151	1,434	**

* NOT DISCLOSED ** INCOMPLETE DATA

(INSERT D)

NONAGRICULTURAL EMPLOYMENT BY INDUSTRY, BY PLACE OF WORK: 1979

COAL REGION

COUNTY	ALL INDUSTRIES	MINING & QUARRYING	CONTRACT CONSTRUCTION	MANUFACTURING	TRANSPORTATION, COMMUNICATIONS, & PUBLIC UTILITIES	WHOLESALE & RETAIL TRADE	FINANCE, INSURANCE, & REAL ESTATE	SERVICES	OTHER
KENTUCKY	1,145,564	54,257	69,074	296,898	58,772	268,707	50,980	339,863	7,013
BELL	8,973	1,952	352	849	607	2,169	397	2,634	12
BOYD	25,111	196	3,340	7,492	1,680	5,336	923	5,876	333
BREATHITT	2,657	444	37	265	216	551	96	1,048	*
CARTER	3,868	202	193	1,000	87	932	160	1,248	47
CLAY	4,462	1,435	61	189	169	872	87	1,647	*
ELLIOTT	636	172	5	53	28	57	*	306	*
FLOYD	9,854	3,314	439	533	456	2,084	338	2,685	6
HARLAN	10,354	4,043	330	468	354	2,049	250	2,860	*
JOHNSON	5,477	849	221	561	447	1,577	216	1,596	10
KNOTT	2,751	1,086	194	29	124	371	36	911	*
KNOX	5,089	610	223	1,314	163	1,164	138	1,475	*
LAUREL	10,851	478	959	3,851	428	2,386	278	2,424	47
LAWRENCE	1,988	116	107	89	236	539	59	843	0
LESLIE	1,778	498	46	44	127	239	*	802	0
LETCHER	5,661	2,589	115	99	201	934	148	1,571	*
McCREARY	1,836	269	85	357	65	368	57	618	*

Continued, next page.

Insert D, continued .

NONAGRICULTURAL EMPLOYMENT BY INDUSTRY, BY PLACE OF WORK: 1979

COAL REGION

COUNTY	ALL INDUSTRIES	MINING & QUARRYING	CONTRACT CONSTRUCTION	MANUFACTURING	TRANSPORTATION, COMMUNICATIONS, & PUBLIC UTILITIES	WHOLESALE & RETAIL TRADE	FINANCE, INSURANCE, & REAL ESTATE	SERVICES	OTHER
KENTUCKY	1,145,554	54,257	69,074	296,898	58,772	268,707	50,980	339,853	7,013
MAGOFFIN	1,635	543	13	215	89	215	48	513	0
MARTIN	4,131	3,014	43	27	95	359	75	518	0
MORGAN	2,286	346	84	461	209	465	5	647	18
OWSLEY	452	100	15	0	4	95	15	223	0
PERRY	9,620	3,624	493	179	583	1,918	237	2,582	*
PIKE	20,477	9,153	895	298	936	3,708	578	4,891	18
PULASKI	13,932	221	589	4,337	780	3,138	570	4,253	44
WAYNE	3,303	104	179	1,447	88	582	93	805	*
WHITLEY	9,252	1,125	574	1,294	387	2,542	330	2,921	78
TOTAL FOR REGION	166,434	36,483	9,592	25,451	8,559	34,650	**	45,897	**
AVERAGE PER COUNTY	6,657	1,459	384	1,018	342	1,386	**	1,836	**

* NOT DISCLOSED ** INCOMPETE DATA

(INSERT E)

MEDIAN FAMILY INCOME FOR NON-METROPOLITAN COUNTIES: 1980

OIL SHALE REGION	
COUNTY	AMOUNT
KENTUCKY	$15,615
BATH	10,000
BOYLE	17,200
CASEY	10,700
ESTILL	10,800
FLEMING	10,700
GARRARD	14,100
LARUE	12,000
LEWIS	11,500
LINCOLN	11,700
MADISON	14,200
MARION	12,700
MONTGOMERY	14,100
NELSON	13,900
POWELL	11,600
ROWAN	12,400

COAL REGION	
COUNTY	AMOUNT
KENTUCKY	$15,615
BELL	9,400
BREATHITT	7,000
CARTER	12,000
CLAY	6,800
ELLIOTT	8,300
FLOYD	10,700
HARLAN	9,900
JOHNSON	9,400
KNOTT	7,200
KNOX	7,400
LAUREL	10,100
LAWRENCE	9,200
LESLIE	7,700
LETCHER	9,700
MAGOFFIN	8,000
MARTIN	7,500
McCREARY	6,800
MORGAN	8,000
OWSLEY	5,300
PERRY	10,100
PIKE	11,900
PULASKI	11,400
WAYNE	6,900
WHITLEY	9,100

Transportation Resources

In observing the three major modes of transportation in the oil shale and coal regions - highways, rail and waterways - it can be seen that the oil shale region has a more advanced, more accessible and more flexible overall transportation network. This is an obvious consequence of the region's topography and industry development. There are, within the oil shale region, at least nine major rail lines, three of which facilitate traffic density of 30 million annual gross tons. All of these major lines are "through lines", connecting with all major areas of the country. The oil shale region also contains an advanced highway system of three interstates and several dozen "AAA" (80,000 LB Gross Load Limit) and "AA" (62,000 LB Gross Load Limit) highways, forming a complex and integrated road network. In water transportation, the Kentucky River transects the region, but the river's commerce transport is very limited and not considered as economically feasible as other available methods. On the other hand, the Ohio River, which adjoins several of the oil shale region's counties, is a notable asset to the area's industrial development; and continues to play a major role in the movement of agricultural, industrial, and mining products.

In the Coal Fields, freight service is the most predominant industrial transportation mode. In this region, like the oil shale region, there also exists three major freight lines that move over 30 million annual gross tons each. The remainder of the network, however is comprised mostly of smaller lines with traffic densities of less than 5 million annual gross tons each. None of these smaller lines are "through" lines, but carry "single destination" traffic, and connect to larger lines for system integration. The highway system in the region is also somewhat more antiquated than that which was described for the oil shale fields. Two interstates, both on the periphery of the coal region, are the most advanced portion of the region's total road system. Less than twenty-five "AAA" and "AA" roads pass through the region's 25 counties, some of which are not considered connector roads. No commercially navigable waterways pass through the coal region.

Both the highway and the rail system of the region are direct consequences of the coal mining industry, designed for the specific purpose of transporting coal, and reflective of that purpose[5].

Immediate Impacts of Industry

As a basis for discussing the impacts of the oil shale industry on its long-term economic development, it is important to briefly describe the industry's more immediate and obvious impacts.

First, necessities of the industry's growth will include significant increases in employment, income and population, as well as secondary growth impacts on support and community services.

The mining of the shale will require allocation of large sections of land and, combined with the construction of oil shale processing facilities, will mandate the development of new roads and rail systems, diverting some prioritizations in overall land-use planning schemes.

Environmental resources of the Knobs Region will also be significantly effected by the development of oil shale, and depending on the mitigation factors required, may have a small or large effect on the region's economic development. Specifically, mining and processing of oil shale will affect:

1. Surface water quality, through direct discharge to streams, surface runoff, and groundwater contaminated leachates. These changes could have direct effects on drinking water sources and survival of natural ecosystems and croplands.

2. Groundwater quality, through the disruption of subsurface flow, and contamination by leachates. These results could also have direct effects on some communities where groundwater is depended on for drinking and products development.

3. Vegetation and soils, through the removal of the vegetation and topsoil itself for mining purposes and the stockpiling and long-term storage of spent shale on the surface as well as adjacent to vegetated areas. Because of the hilly terrain of the oil shale region, stabilization of the cleared slopes and reestablishment of vegetative cover may prevent the mined areas from other uses for an extended period of time. Soils and vegetation currently play an important role in the economics of the Knobs Region, so the amounts of vegetation and topsoil to be disturbed in the development of the industry will be a large factor in the resulting economic picture.

4. Fauna, through the disruption of the animal communities themselves, and, even more so, as a secondary effect of the disruption of the surface water, ground water, and vegetation. Like soils and vegetation, the effects on the fauna will tend to negate the use of the land in it's original use for an extended period of time.

Representative Analysis

Purpose

The primary purpose of this paper is to address in a more detailed manner selected factors that are representative of those introduced above. Various terms of analysis will be employed.

Reasons for representative, and not complete, analysis are several. First, some factors do not lend themselves to quantitative measure. Second, data for some factors is extremely limited. Lastly, the subsequent analysis is intended to raise the issue of careful background investigation before hasty comparisons are made between the coal industry of Kentucky and its potential oil shale development, or before the entire oil shale or the Knobs region is assumed to be perfectly homogeneous. If representative evidence is introduced to give the study of these questions some credence, then a preliminary effort has been made to describe more thoroughly the actual impact of oil shale development in Kentucky.

Influencing the choice of factors to be studied in more detail was a goal of incorporating some of the visible issues that have been raised about the coal industry in eastern Kentucky. Not all of them will be treated, but the analysis has been built around aspects that were convenient for a rudimentary study. Included in the following sections will be an introduction to issues such as land use, income differentials, and employment concentration, location, and diversification.

Data is presented and summarized on twenty-five coal producting counties of eastern Kentucky and seventeen counties of known oil shale deposits in northeastern and central Kentucky. Subgroups of the counties are considered in order to emphasize differences between and within the two principal groups. The county is the basic unit of analysis due to the availability of data. Specific counties for analysis have been identified above.

Land Use

Although coal mining has focused considerable attention on the use of land, almost no large scale activities compete with mining in eastern Kentucky. Areas of substantial size have been reserved for parks and forests, but this use will not become widespread.

One type of land use that does occupy large areas is agriculture. A comparison was made of the average percentage of land in farm use in 1978. The results are shown in the following table:

Average Percent of Farmland[10]	
17 oil shale counties	71
25 coal counties	21
7 "northeastern" oil shale counties	59
10 "central" oil shale counties	79

The difference between the oil shale and coal counties is dramatic. Eight of the coal counties had percentages of two or less. Within the oil shale group, the northeastern counties that are nearer the coal counties had less area in farmland than did the ten central counties farther removed from any coal production where the average was 79%.

This data demonstrates that, not only is farming a predominant land use in the oil shale area, but also that a significant change in farmland usage occurs within the shale bearing region. The impact of development on the Knobs could vary to some extent, depending on the competition for farmland.

Income

Median Family. Wage differentials between the higher paying mining industry and other employers have been wide enough to cause some disruption in worker attraction and retention. Median family incomes from the two oil shale and coal county groups were averaged. The following table indicates the resulting calculations:

Average Median Family Income, 1980[11]	
15 oil shale counties*	$12,500
24 coal counties*	$ 8,700
7 "northeastern" oil shale counties	$11,600
10 "central" oil shale counties	$13,200

*SMSA counties unavailable

Median family income differs to a great degree between the two major groups. Considerably less difference is evident within the oil shale counties, but the lower "northeastern" subgroup resembles more closely the coal counties than the "central" subgroup.

Since the coal industry has high wages for the most part, the low median incomes may illustrate the gap between mining and other coalfield wages. The higher incomes in the oil shale areas may indicate that high wage mining and processing jobs will not create a gap that will be as disruptive to other employment areas as has occurred in the eastern Kentucky coalfields.

Weekly Wage

Another approach to income was to investigate weekly wages in all industries. The results are shown in the next table:

Average Weekly Wage, All Industry 1979[12]	
17 oil shale counties	$177
25 coal counties	$236

The higher rate in the coal counties is due primarily to the mining industry which paid an average weekly salary of $355 during the same period. It is evident that the weekly non-coal wage is substantially lower than even the average oil shale figure of $236. This indicates the gap in wages between industries in the eastern coalfields.

There was no meaningful difference between the counties of the oil shale group. Considering the effect of coal mining jobs, the weekly wage of the oil shale areas is higher than the non-coal wage in the coal counties. Less differential in wages resulting from the development of oil shale mining and processing should occur in these counties.

Employment

In the following sections, a projection of potential oil shale industry employment has been made in order to create a comparison model for use with employment data of the coal industry which already exists. A feasibility study for Fleming County, Kentucky, established an employment level of 900-1100 for a mining and processing plant with a capacity of 10,000 barrels of shale oil per day[13].

It was assumed that potential oil shale development would equal two similar plants, or a total of 2,000 workers, per county. This employment was considered primary and able to produce secondary service jobs that would require addition to the new employment total for each county. Statewide and regional employment data for Kentucky were reviewed[14] and primary to secondary employment ratios were calculated at an average of three to one. Primary employment included mining, manufacturing, and farming. Since oil shale industrialization will build to some extent on existing services that will not expand proportionally, the ratio for oil shale was assumed to be two to one. Therefore, 2,000 oil shale and 4,000 service workers were added to each county's existing employment data.

Principal Industry Ratio. The first employment factor assessed was the simple ratio of oil shale/coal industry workers to total working force. As assumed in this paper, 2,000 persons were counted as the oil shale employment in each county. The resulting ratios are as follows:

Employment Ratio, 1979[15]	
17 oil shale counties	16
25 coal counties	15
7 "northeastern" oil shale counties	20
10 "central" oil shale counties	14
15 high production coal counties*	21

*Bell, Breathitt, Clay, Floyd, Harlan, Johnson, Knott, Knox, Lawrence, Leslie, Letcher, Martin, Morgan, Perry, Pike.

From this very general index, the effects of employment ratio on both groups is very similar. The oil shale ratio would be lower if it were not assumed that two mining and processing plants were

developed in each county. On the other hand, the coal industry figure reflects the actual state of affairs.

More useful comparisons can be made within the oil shale region and between the oil shale region and between the oil shale and high coal production counties. The "northeastern" oil shale counties have a higher ratio of employment than do the "central" counties. Fifteen high production coal counties have an industry ratio similar to the "northeastern" oil shale group, but 50% higher than the "central" oil shale group.

Based on this factor, the oil shale region has a distinctive variation within its reaches. In addition, the "northeastern" oil shale group is very similar to the large production coal counties. It is this latter group that receives the most attention about the effects of a large scale industry.

Location Quotient. A measure utilized in regional and national economic analyses is the location quotient[16]. This is an indication of how representative a specific industry is with respect to a larger area. If a region was characterized by representative industries, then it will be classified as diversified and less subject to the dominance or fluctuations within one or a few industries.

One persistent condition in the eastern Kentucky coalfields has been the dominance of the coal industry and the resulting lack of diversification and susceptibility to economic fluctuations. Calculation of a location quotient may indicate whether a similar condition might result from the development of oil shale mining and processing.

Location quotients for manufacturing and farming were adopted as two indicators for comparison. Employment in these two sectors were divided by total employment (including the assumed oil shale primary and secondary additions). The same ratio was calculated for the larger area, which in this case was Kentucky. The formula for the location quotient was:

$$\frac{\text{Industry A in coal (oil shale)}}{\text{Total employment in coalfields (oil shale region)}} \qquad \frac{\text{Industry A in KY}}{\text{Total employment in Kentucky}}$$

A quotient of or near one indicates a representative and diversified industry. Higher or lower quotients are characteristic of industries that are not representative of larger areas and that are not located in diversified areas.

The next table summarizes the findings for manufacturing and farming location quotients:

Location Quotients[17,18]

	Manufacturing	Farming
17 oil shale counties	0.52	1.03
25 coal counties	0.64	0.57
7 "northeastern" oil shale counties	0.40	0.95
23 coal counties less Boyd and Pulaski	0.42	0.52

These calculations show that the impact of either the oil shale or coal industry leaves a less diversified manufacturing sector than a farming sector.

With respect to farming, the coal counties are less diversified than the oil shale counties, and no clear distinctions within each group are apparent. The "northeastern" oil shale subgroup and a modified subgroup of coal counties without two highly industrialized counties differed very little from the parent groups.

A more significant contrast can be drawn from the manufacturing quotients. The coal counties remain more diversified than the oil shale group. However, in combination with the farming quotients, the oil shale region is still more diversified.

As found in other factors, the "northeastern" oil shale counties show a difference from the remainder of the group. Additionally, they compare very favorably to a 23 coal county subgroup that is derived by omitting Boyd and Pulaski counties, which are marginal coal producers, but highly represented by manufacturing employment. This comparison supports evidence that the "northeastern" subgroup is more closely contrasted with the coal producing counties than the remainder of the oil shale region. A further conclusion is that the "northeastern" subgroup and the coal counties are less diversified from the remainder, or "central" subgroup, of oil shale counties.

Diversification. A more general type of measure for diversification is the coefficient of specialization[19]. The more specialized a region is, the less diversification would be found in it's industry or employment mix. A coefficient is determined by first calculating the ratio of available employment sectors to total employment in a region. A similar ratio is calculated for a larger area. Then, each percentage in the study region is compared with the larger area percentage, and the differences for all sectors are added. A higher number is indicative of a specialized, or less diversified, economy.

In this study, seven sectors were utilized - manufacturing, farming, contract construction, transportation/communications, wholesale and retail trade, finance/insurance, and services. The larger area used was Kentucky.

Coefficients were determined for the oil and coal groups, as well as the two oil shale subgroups. The results are shown in the next two tables:

Coefficients of Specialization[20, 21]
Oil Shale and Coal Counties

Sector	% KY	% Oil	% Coal	Difference Oil	Difference Coal
Manufacturing	24.6	18.5	18.6	6.1	6.0
Farming	6.1	9.0	4.4	2.9	1.7
Construction	6.0	5.4	7.1	0.6	1.1
Trans/Comm.	5.2	5.3	6.3	0.1	1.1
Trade	23.7	25.2	25.7	1.5	2.0
Finance	4.4	3.5	3.8	0.9	0.6
Services	30.0	33.1	34.1	3.1	4.1
Total	100.0	100.0	100.0	-	-
Coefficient	-	-	-	15.2	16.6

Coefficients of Specialization[22,23]
Northeastern (NE) and (Central Cc) Subgroups

Sector	% KY	% NE	% C	Difference NE	Difference C
Manufacturing	24.6	15.2	19.8	9.4	4.8
Farming	6.1	9.0	9.0	2.9	2.9
Construction	6.0	5.6	5.3	0.4	0.7
Trans/Comm	5.2	4.1	5.8	1.1	0.6
Trade	23.7	26.0	24.9	2.3	1.2
Finance	4.4	3.9	3.3	0.5	1.1
Services	30.0	36.2	31.9	6.2	1.9
Total	100.0	100.0	100.0	-	-
Coefficient	-	-	-	22.8	13.2

The coefficients for the two principal groups do not differ substantially. Since this indicator is a general one the results demonstrate that the impacts of the oil shale and coal industries are similar over their respective areas.

A significant contrast was found within the oil shale region. The "northeastern" subgroup was more specialized than the "central" subgroup. This leads to the potential conclusion that the oil shale industry will be more dominant in the northeastern area than the remainder of the region. In this respect, and in combination with the preceding derivation of location quotient the northeastern subgroup more closely resembles the coal counties than the other oil shale counties.

Conclusion

This study has analyzed a set of development factors and impacts on the oil shale and eastern coal producing regions of Kentucky. Both general and detailed analyses were performed. For purposes of comparison with existing coal county data, potential oil shale county development data was established by assuming a level of direct and indirect employment in each of the oil shale counties. Additionally, the oil shale region was divided into northeastern and central subgroups in order to investigate the existence of contrasts within the area.

The analysis results indicate that definite contrasts exist between the oil shale and coal regions and within the oil shale region itself. Inter-region differences were evident in labor force, income, transportation and land use. Intra-region contrasts for oil shale were apparent for the factors of land use, income, principal industry ratio, and the two diversification indexes of location quotient and coefficient of specialization.

In some respects, the northeastern oil shale counties resemble more closely the coal producing counties of eastern Kentucky from the other oil shale counties.

These contrasting factors are related to many of the issues raised about the existing coal industry and the potential development of an oil shale industry. It is such differences that suggest any broad generalizations transferred from the coal region to the oil shale region are inappropriate.

The oil shale region should be analyzed on its own basis during future efforts to evaluate development impacts. Independent decisions are justified solely on the evidence of distinct contrasts between regions, regardless of the tendency to equate coal mining and oil shale development. Even more reason for this kind of decision-making rests on the differences that exist within the oil shale region. In either case, this study argues for the arrival at impact evaluations of potential Kentucky oil shale industry that are not preconceived conclusions about the coal mining industry of the same state.

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Environmental Research for Eastern Oil Shale

by

E.R. Bates, J.G. Herrmann, J.F. Martin, R.C. Thurnau
Oil Shale and Energy Mining Branch
Energy Pollution Control Division
Industrial Environmental Research Laboratory
Cincinnati, Ohio 45268

Abstract. The U.S. Environmental Protection Agency's Industrial Environmental Research Laboratory in Cincinnati, Ohio (IERL-Ci) has performed research related to oil shale processing and disposal since '973. More recently, the Laboratory has become involved in research related to oil shale mining. The major thrust of this research work has been directed toward the large oil shale deposits located in Colorado and Utah where much of the pilot scale development of the oil shale industry has been concentrated. Increased emphasis in developing Eastern oil shales has heightened interest in defining and resolving environmental concerns related to these extensive resources.

IERL-Ci is interested in defining environmental problems related to Eastern oil shale development, evaluating the transferability of environmental control technology from related areas, such as Western oil shale development and Eastern coal mining, to Eastern oil shale development, and in developing new control technology as necessary. Initially, samples of Eastern retorted oil shale, such as HYTORT, are being evaluated to assist in the development of technology applicable to spent shale disposal in the East. Research sponsored by IERL-Ci is being closely coordinated with other Federal and state agencies.

INTRODUCTION

Primary emphasis in the production of shale oil has focused on the marlstone deposits of the Green River Formation located in Colorado, Wyoming, and Utah. Historically, extensive mining and retorting research has been conducted in this area or on its shale in anticipation of a commercial oil shale industry. Recently, private sector interest has been exhibited in the production of oil from the development of Devonian shale outcrops located in Kentucky, Ohio and Indiana.

The Environmental Protection Agency's (EPA's) Industrial Environmental Research Laboratory located in Cincinnati, Ohio (IERL-Ci) has performed a substantial amount of environmental research work related to oil shale development. This research has emphasized the evaluation and development of methods to control pollutants of various oil shale mining and retorting processes, including the problems associated with the ultimate disposal of the spent shale. This research is in support of the Clean Air Act, the Federal Water Pollution Control Act, and the Resource Conservation and Recovery Act.

Research emphasis has been directed at western oil shale resources. Recently, a small environmental research program for eastern shale development was initiated emphasizing identification of environmental problems and the evaluation and transferability of control technologies from related fields. Three key categories of potential pollution problems from eastern oil shale development are to be addressed: (1) Mining (including mine drainage, dust, and mine area reclamation); (2) Shale Processing (air and water pollution); and (3) Solid Waste (management and disposal).

MINING

The mining category is basically a multimedia investigation of the extraction activities leading up to shale processing and conversion to a fuel product. The mining phase of the shale oil production process can impact air and water quality, water supply, land uses, noise levels, aquatic and terrestrial biota and worker health and safety.[1] Mining of eastern shale appears to exhibit the classical problems that mine operators have wrestled with when extracting other minerals in the East. These potential problems include mine drainage, sediment control, trace metals, and control of organics and acids. Many eastern soils and rocks have significant potential for producing sulfuric acid presenting mine operators

in certain locations with mine drainage treatment problems. Research to characterize this drainage should yield information on specific constituents which may be prevalent and require special treatment and handling.

Although particulates should be less troublesome in the humid East than from mines in the semi-arid to arid West, research should characterize and quantify fugitive dust from large-scale earth-moving operations and blasting, loading, transporting and crushing unit operations.

Since many of the proposed mining methods for shale are identical to those in coal mining (mountaintop removal, area mining, room-and-pillar) the same reclamation problems will face the oil shale operators. Depending on specifics of State and Federal regulations, they will be concerned with slope stability, revegetation, hydrologic balance, and return to approximate original contour. Disposal of massive amounts of spent shales in mine workings and pits may, however, complicate the reclamation picture beyond that encountered in coal mining. Information is necessary to define any special problems associated with handling and placement of spent shales which have not been evident in placement and disposal of coal mine wastes.

Since many of the expected environmental impacts from eastern oil shale mining are similar to those impacts found in coal mining, it is logical to expect much of the coal mining environmental control technology to be applicable. For example, the character of sediment from oil shale mines should differ little from coal mine sediment. Although sediment control remains a primary concern of coal surface mining operations, the techniques used at coal mines such as sediment ponds and debris basins, silt fences, straw bale dikes and gulley plugs, and rapid cover by vegetation could be applicable. Treatment systems for acid or alkaline drainage, trace metals, etc., may also be directly transferrable from coal mining. Some tailoring of treatment systems may be necessary for removal of specific parameters or organic compounds found in association with oil shale deposits.

Although emission factors may differ because of varying overburden and mineral characteristics of shale deposits in the East, control of fugitive dust may be similar to that applied at coal mines or other earth-moving activities developed for eastern mines.

Reclamation and revegetation work for surface oil shale mines in the eastern U. S. should be similar to that for coal mines, with consideration given to differences in regulations and standards. The major exception is disposal of spent shale. This by-product is expected to differ significantly from coal mine and preparation plant waste in leaching potential, physical size and shape, and compaction and stability characteristics. If the oil shale industry develops in the East, information will be needed to both characterize pollutants from spent shales and develop environmentally sound disposal configurations.

SHALE PROCESSING

Atmospheric emissions of sizeable concentrations could occur as a result of processing eastern oil shale. Estimating environmental impacts from an emerging industry, such as oil shale, is difficult because there are no operating units to supply information.

The magnitude of potential air pollution emissions, discussed below, from eastern oil shale processing is based on several assumptions:

1. Using retorting technologies being developed for western shale,
2. An oil yield of 42 l/tonne (10 gallons/ton), and
3. A retorting operation of 8,000 m^3/day (50,000 bbls/day) with an on stream efficiency of 90%.

Estimates for some of the Criteria Pollutants are summarized in Table 1. These are compared with IGT's estimate of pollutants from the HYTORT process[2], which is expected to be one of the processes used in retorting eastern shales.

Table 1. Estimated Emissions of Air Pollutants (Tonnes/day)

	EPA	HYTORT
Particulates	2-4	12
Sulfur Oxides	1-8	5
Nitrogen Oxides	12-20	16
Hydrocarbons	0.5-3	1

Particulates

Opinions on the severity of the particulate emission problems from oil shale retorting operations range from no expected problem to a severe problem. To support an 8,000 m^3/day oil shale industry, about 182,000 tonnes/day would have to go through the system, potentially emitting pollutants at every step.

A wide range of particulate emissions have been reported for western oil shale retorts. The latest permit estimates indicate a range of 1-2 tonnes/day[3]. Using those estimates and the fact that eastern shale has nearly 15% more ash content and that twice as much raw shale is projected to be processed each day, the particulate emissions from eastern oil shale could be as high as 4.3 tonnes/day. This estimate does not correspond well with the estimate for HYTORT. However, when factors for fugitive emissions generated in other parts of the oil shale operation are added, the particulate emissions estimate would agree more closely with the HYTORT estimate.

Sulfur Oxides

The estimation of sulfur emissions from eastern oil shale retorting is more uncertain than the particulate estimate. Elemental analysis of eastern oil shale shows that the sulfur concentration (approximately 2.0%)[4] is about a factor of 2 higher than western shale. If this fact is coupled with the other assumptions made for particulates, one would expect the sulfur problem for

eastern shale to be about four times greater than for western shale. A range of 1-2 tonnes/day is projected for western shale[3] and extrapolating to eastern shale, up to eight tonnes/day could be expected.

However, there was a considerable difference in the geological history of the two shales. The sulfur in the eastern shale is almost exclusively in pyritic form and under reducing conditions does not react. If this is the case, the sulfur emissions would be lower than the western shales and near 1 tonne/day or less.

In many of the oil shale retorting technologies air is used to burn a portion of the shale. The heat generated by combustion is drawn into the shale and retorting occurs. This is not a reducing condition and the pyrite would be turned into sulfur oxides. The emission rate under these conditions could be greater than 8 tonnes/day because of the additional pyrite in eastern shale. In reality, the answer probably lies between the two extremes of 1-8 tonnes/day.

Nitrogen Oxides

Oxides of Nitrogen are usually not derived from the retorting operation itself, but from the combustion products associated with retorting. Recent estimates of oxides of nitrogen from western shales were in the area of 6-10 tonnes/day. Using the same rationale expressed above, they might expect to double to about 12-20 tonnes/day for eastern shale. Modeling efforts by oil shale developers and EPA indicate that 6-10 tonnes/day of NO_x would not violate the ambient air standard of 100 ug/m^3 (0.05 ppm). The effect of doubling the emission rate would have to be modeled before the impact could be estimated.

IGT[4] indicates a sizable concentration of nitrogen in the oil (1.5%). If the oil was burned on site without clean up an additional burden of NO_x would be placed on the environment.

Hydrocarbons

Hydrocarbons present in the offgas means that a portion of the product is lost, and the overall efficiency of the process decreases. Consequently, such emissions are important from both the process and environmental standpoint. Using the same assumptions developed for the earlier discussions, it is estimated that the hydrocarbon emissions for eastern shale will be in the range of 0.5-3 tonnes/day.

Perhaps the most striking difference in the development of eastern oil shale versus oil shale in the West is the availability of large volumes of relatively clean water. In western oil shale operations, water is looked on as a resource and recycled several times through the plant. Most western oil shale plants plan to clean up their wastewater for its next best use and plan for a zero discharge.

In areas like Kentucky, Ohio, and Indiana, the availability of water lowers its relative value to the process, and less care may be taken to maximize its use. It has been suggested that eastern oil shale operations may have water for discharge, implying a need for waste water treatment. The extent of water recycle versus discharge for eastern oil shale facilities will be determined by the costs of treatment for reuse versus treatment required for discharge rather than the scarcity of water which applies in the West.

The concept of transferring control technology or methods to the oil shale industry from parallel or related industries is the basis of our research efforts. For those parameters in oil shale effluents that are unique, further definition of applicable control methods will be needed.

Any new pollution control systems developed for oil shale effluents will concentrate on making present control methods more effective or in reducing the overall cost of pollutant control.

SOLID WASTE

The principal solid wastes from an Eastern Oil Shale operation include: overburden, interburden and wasted lean oil shales, retorted (spent) oil shale, raw oil shale fines from particulate control devices, and hazardous wastes (including those listed as hazardous wastes and those determined to be hazardous by testing). Overburden, interburden and wasted lean oil shales would be produced in significant quantity by most types of surface mining operations. Disposal of these materials by return to the mine pit appears most likely though valley fills and head-of-hollow fills may also be considered. Major environmental concerns from mining have already been discussed.

Retorted (spent) oil shale will probably be returned to the mine pit or disposed of in surface landfills. Major environmental concerns include impacts upon air quality from dusts or gaseous emissions, upon surface and groundwater quality from runoff and leachates, upon aesthetic values due to changes in landscape or vegetation types and upon mass stability of disposal sites and embankments.

Raw oil shale fines such as those from baghouses or other particulate control devices may have a possible (but as yet undefined) potential for auto oxidation or auto ignition which would impact air quality. They will also have a significant potential for producing fugitive dust if disposal is not properly handled. These properties should be carefully evaluated prior to proposing co-disposal with other oil shale solid wastes.

Hazardous wastes from oil shale operations pose a significant risk of impact upon the environment and should be handled in conformance with regulations for hazardous wastes in a manner similar to hazardous waste from other industries. Spent catalysts will likely be hazardous, but may have potential for recycle/reuse if the volume produced is large enough. Sludges will be produced from oil-water separators, as well as air and water treatment systems. Though some sludges may be listed hazardous wastes, many will have to be tested to determine their classification. Co-disposal of hazardous and non-hazardous wastes may be possible. However, this practice may result in the mixture being classified as hazardous. Unless the volume of hazardous wastes from oil shale facilities proves to be quite large, it may be more cost effective to dispose of these wastes at established hazardous waste disposal

sites rather than to operate hazardous waste sites at oil shale facilities.

A substantial amount of research has been sponsored by EPA, The Department of Energy (DOE), the Department of the Interior (DOI), and the oil shale industry to develop control technology for the disposal of retorted oil shale in Colorado and Utah. Although many important questions remain regarding disposal of retorted shale in the West, it would be beneficial if the body of information already obtained could be applied to disposal of eastern retorted shale. The extent to which this western technology can be transferred to the East is unknown but several serious differences exist which may preclude the direct transfer of western retorted shale disposal technology to the East. These differences include:

1. Western oil shale is actually a kerogenaceous marlstone, not a true shale as exists on the East.

2. Western oil shale contains a substantial amount of carbonate material, while eastern shales generally will have far less carbonate material and are likely to have more pyrite.

3. Western retorted shales generally produce an alkaline (pH 8-12) leachate. Eastern retorted shale leachates will likely be much more acidic.

4. Breakdown of the carbonates in western shales induces a cementateous property in the spent shale. The extent to which this property is developed depends upon the carbonate content, retorting temperature, residence time in retort and particle size. Since eastern shales generally lack the high carbonate content, it is not likely that this cementateous property will be as evident in eastern retorted shale.

5. The climate of western disposal sites differs greatly from the East. The western disposal sites are arid to semi-arid having low precipitation and high evaporation rates. This substantially impacts considerations for control of runoff and leachates.

6. The vegetation species and revegetation techniques used in the arid and semi-arid West have little utility for the East.

Control technology for hazardous wastes is expected to be applicable to both western and eastern sites and will be generally similar to other industries. The principles of control technology for retorted shale disposal in the West such as use of liners, drains, covers, and selected placement should apply in the East. However, the specifics of land fill design could be substantially different.

RESEARCH ACTIVITIES

Through the cooperation of Phillips Petroleum, The Institute of Gas Technology, and the Commonwealth of Kentucky, a sample of eastern oil shale retorted by the HYTORT technology has been obtained for laboratory testing. The HYTORT spent shale will be tested at Colorado State University as part of an EPA program for determining hydraulic properties of spent shales from leading retorting processes. This program which is the only specific research effort we have initiated related to eastern shales has the following objectives:

1. Determine the chemical composition of leachates as a function of pore volumes of the effluent from several different spent oil shales under conditions that will permit direct comparison between the spent shales.

2. Compare the chemical composition of leachates from identical materials (both spent and raw shales) extracted by different laboratory methods. Possible methods include (a) column leaching with de-ionized water, (b) shake tests proposed by ASTM, and (c) the RCRA Test.

3. Conduct a comprehensive study of permeability and water holding capacity of spent shales as a function of compaction and loading. The permeability and water holding capacity will be determined for nine different combinations of compactive effort and loading conditions simulating different points in a spent shale disposal site.

The above testing program will provide valuable information on the potential for water movement through HYTORT spent shale disposal sites and the resulting leachate quality. This research may also provide a general indication of anticipated hydraulic properties for eastern oil shale retorted by other technologies.

COORDINATION OF RESEARCH EFFORTS

The Oil Shale Research Program of the IERL-Ci is coordinated with the industry itself and with efforts by other Federal and State agencies including the Department of Energy (especially the Office of Fossil Energy and the Office of Health and Environmental Research), the Department of Interior (Bureau of Mines and U.S. Geological Survey), and the Commonwealth of Kentucky (Department of Natural Resources and Environmental Protection and Kentucky Department of Energy). The EPA welcomes the opportunity to meet and discuss oil shale research efforts with all interested parties--Federal, State, academic, and private--in the hope of furthering coordination of efforts and increasing our understanding of the environmental problems and their solutions.

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A Preliminary Assessment of Environmental Impacts of Obtaining Oil from Chattanooga Shale

by

V.R. Tolbert, G.K. Eddlemon, R.H. Ketelle, J.F. McBrayer, R.R. McKeown, E.D. Waits, and J.W. Webb
Oak Ridge National Laboratory
Oak Ridge, TN 37830

Abstract. The environmental impacts of producing 8000 m^3/d of oil from the Chattanooga Formation by means of underground mining and surface retorting have been assessed. The major impacts were determined to be those associated with surface disposal of spent shale. Disposal of spent shale can have a significant impact on surface and groundwater quality as the result of trace elements and toxic substances leached from the shale. Changes in water quality from these releases and those associated with land disturbance can have significant long-term effects on aquatic biota. Significant changes in land use and effects on terrestrial ecosystems can occur if large areas are covered with spent shale and cannot be revegetated. From this assessment, it was determined that additional information must be obtained about the resource and extraction processes before impacts associated with development of the Chattanooga Formation can be more precisely quantified.

Introduction

Interest in Chattanooga shale dates back approximately 25 years when Oak Ridge National Laboratory (ORNL) and others first began evaluation of the Chattanooga shale formation as a possible source of uranium.[1] Recently, interest in obtaining oil from shale was renewed, in part by escalating petroleum prices and the stated objective of energy independence. This report assesses the environmental consequences of developing an oil shale industry utilizing the Chattanooga Formation. It is part of a larger "in house" ORNL study that explored the technical and economic feasibility as well as the environmental implications of developing the Chattanooga shale resource.[2]

The Chattanooga oil-shale region consists of 21 counties in south-central Kentucky, 57 counties in central Tennessee, 16 counties in northeastern Alabama, and 3 counties in northwestern Georgia (Fig. 1). The most probable area for initial development is along the Highland Rim, where the shale lies at or near the surface. This assessment is restricted to the prime resource area, consisting of 19 counties along the southern, eastern, and northern margins of the Highland Rim where the outcrop occurs (Fig. 1).

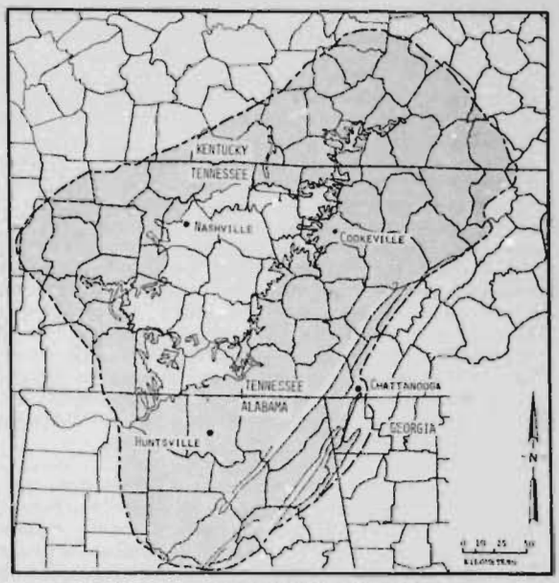

Figure 1. The Chattanooga Shale study area (shaded). The prime resource area is considered to be the outcrop along the Northern, Eastern, and Southern margins of the Nashville Basin (central, unshaded area).

This initial assessment is necessarily limited because the technology for producing oil from Devonian shales is not well advanced. There has been no demonstration-scale mine, and retort in the Chattanooga shale region and extrapolations from laboratory-scale units are only of limited

[1]Research sponsored by the U. S. Department of Energy under contract W-7405-eng-26 with Union Carbide Corporation as part of Oak Ridge National Laboratory's Exploratory Studies Program. Publication No. 1618, Environmental Sciences Division, Oak Ridge National Laboratory.

value. Additionally, extrapolations from the more advanced development and processing of western shales are limited by the differences in origin and characteristics of the two shale resources. The marine origins, high pyrite, and trace metal content of the eastern shales may contribute to previously unforeseen impacts associated with development of the Chattanooga shale.

Resource Description

The Chattanooga Formation underlies approximately 70,000 km^2 surrounding the Central Basin in Kentucky, Tennessee, and Alabama (Fig. 1). It outcrops at the boundary between the Central Basin and the Highland Rim and dips gently eastward away from the basin to lie at depths of 580 m beneath the Cumberland Mountains.[2] The Chattanooga Formation overlies Ordovician rocks and is overlain in most areas by the Fort Payne formation, an extremely hard, cherty, dolomitic limestone. The Fort Payne is not uniform throughout the shale region and ranges from a hard, water-bearing stratum in some portions of the area to highly weathered, fracturable areas near the outcrops.[3]

The Chattanooga shale formation is divided into the Gassaway and Dowelltown members. Concentrations of both oil and uranium are greater in the Gassaway member than in the Dowelltown; consequently, the Gassaway member is more likely to be developed first. The thicker areas of the Gassaway member occur along the northern and eastern portions of the Highland Rim and in the Black Warrior Basin of Alabama.[2]

Anticipated Extraction Technology

Because uncertainties about recovery technologies exist, we made the following assumptions about the processes to be used. Along the Highland Rim, shale may be extracted by surface mining of the shale outcrop. In most portions of the shale region, however, underground mining was assumed to be the primary method of shale extraction because the hardness of the overlying Fort Payne Formation and an unfavorable stripping ratio (greater than 2.5) would preclude surface mining. The areas along the Highland Rim where the Gassaway member occurs in thicknesses greater than 3 m (Fig. 2) will be developed first by surface mining then by underground mines which can be accessed from outcrop areas. Development of the resource in the Black Warrior Basin and other deep-lying seams would require construction of vertical shafts.[4]

In-situ processing of the Chattanooga shale was not considered economically feasible because of its low recovery efficiency[5,6] and the low volume of oil present in the shales (average Fischer Assay 42 L/Mg). We assumed that 6000 to 8000 m^3/d of oil would be produced from aboveground retorts by any of three approaches: (1) single mine and retort, (2) single retort with multiple mines, and (3) multiple mines and retorts. Production of this volume of oil would require, on a daily basis, about 190,000 Mg of raw shale with a Fischer Assay of 42 L/Mg.

The shale will be retorted using a conventional process such as Paraho, Petrosix, or possibly Union "B".[7,8] These methods are expected to produce an average of 48 L of oil/Mg of shale from the Chattanooga Formation. The Institute of Gas Technology (IGT) HYTORT process has been demonstrated to produce more than twice the Fischer assay yields from eastern shales.[9] However, this process has not yet been demonstrated at a commercial or pilot scale and was not considered a proven process in this assessment.

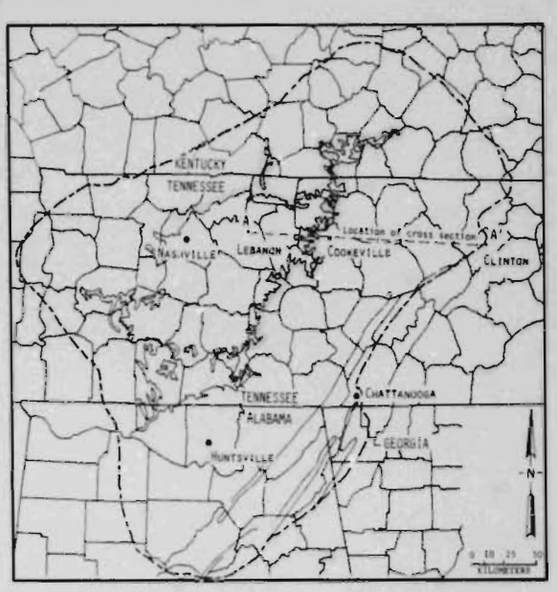

Figure 2. Areas within 8 Km of outcrop having Gassaway member thickness of 3m or more.

Several valuable by-products, including uranium, aluminum, iron, sulfur, ammonia, and the trace elements cobalt, copper, chromium, manganese, molybdenum, nickel, vanadium, and zinc, may be recovered from the retorted shale.[2,4,10] Ammonia will be recovered from the retort off-gases and the shale roasted after retorting to recover the remaining sulfur. Following roasting, uranium and iron can be leached from the roasted shale. The elements remaining after the initial acid leaching will be bulk leached using either sulfuric[10] or hydrochloric[11] acid.

The ORNL team estimated that retorting of and subsequent metals recovery from 190,000 Mg/d of raw shale would produce from 80,000 to 110,000 Mg/d of spent shale.[2] The volume of this waste would be approximately 5.8 x 10^8 m^3/20 years because the shale would expand by 80 to 100% of its original volume during processing. At most, only 50 to 55% of the spent shale was assumed to be returned to the mine site for disposal.[2] The remainder (2.9 x 10^8 m^3) must be disposed of above ground.

Impacts

Solid Waste Disposal

Because large volumes of spent shale will be produced, its disposal may be the most serious environmental problem associated with development of the Chattanooga shale resource. The volume of solid waste produced by a 8000 m^3 of oil/d facility would be approximately 9.7 x 10^4 m^3/d

for a total production over an operational period of 20 years of 5.8×10^8 m^3. Approximately 2.88×10^8 m^3 of the spent shale generated over 20 years of plant operation would require surface disposal. Because there are currently no regulations that require backfilling of spent shale, it is possible that disposal of the entire quantity would be on the surface.

If extensive mining of the resource occurs, thousands of hectares of land surface could be required for disposal of spent shale. The exact area necessary for shale disposal will depend upon the depth and capacity of suitable disposal sites. In areas where the shale is removed by contour mining or mountain-top removal, most of the shale would most likely be disposed of in unmined valleys. Such valley fill operations involve lining the area with rock drains, impounding runoff and seepage below the filled area, and in some cases rerouting runoff past the disposal area. Impoundments are built across the lower end of the valley and are filled with solid wastes. Valley fill of spent shale may resemble that used by the coal mining industry; however, spent shale will be more finely crushed and will have a different chemistry than coal mine spoil. Disposal of spent shale is not currently regulated so practices involved in disposal cannot be described with certainty; however, it is apparent that a minimum of several hundred hectares, probably considerably more, would be required for disposal of shale from an 8000 m^3/d facility.

Revegetation. Preliminary characterization of Chattanooga shale combined with studies on revegetation of western shale residues suggest that spent shale alone will not support plant growth. If the retorted shale is not roasted and leached for metals recovery, the sulfur remaining in the shale can react in the presence of water to leach trace elements from the shale. To minimize impacts associated with trace elements either remaining in or leached from the shale, a reclamation plan will have to be divised that will stabilize and revegetate the spent shale for long-term stability.

Revegetation of spent shale will aid surface stability, reduce erosion potential, help maintain surface and groundwater quality, preserve aesethetic values, and represent a first step in restoring a balanced, functional ecosystem. Experience with revegetating strip mines in the east suggests that liming to raise soil pH will frequently be needed but that irrigation usually will not be necessary.[12] It is important to recognize, however, that successful reclamation of Chattanooga shale wastes may be much more difficult than planting on mine overburden. Water-holding capacity, pH, and levels and mobility of nutrients and toxic materials in the spent shale itself may be important in determining successful revegetation if plant roots penetrate the soil cap covering the spent shale. Much research will be required to achieve successful, long-term revegetation using a diverse assemblage of native species.

The primary effects of surface disposal include disruption of current land uses, loss of natural communities and habitats, loss of ecological and agricultural productivity, and potential alteration of air and water quality. The latter may also affect land use and cause extensive alteration of the landscape. In addition to occurring over large areas, impacts from spent shale disposal can be long term and cumulative if the disposal site cannot be successfully reclaimed and revegetated. Research will be needed to determine the composition of spent shale, the stabilization and reclamation potential, and the revegetation requirements before specific impacts and mitigation measures can be identified.

Water

Both surface and groundwater resources could be affected by Chattanooga shale development. These impacts can occur in association with mining, retorting, metals recovery, and/or solid waste disposal.

Impacts to groundwater will be highly site-specific and will depend upon the geology of the area and the location of aquifers associated with the overlying strata. On the Highland Rim, the predominant bedrock aquifers occur in the Fort Payne and the overlying Warsaw and St. Louis formations.[13] The Fort Payne formation forms an outcrop band as much as 25 km wide along the Highland Rim Escarpment. The bedrock and overlying residuum within this outcrop band locally contain an aquifer which supplies most water used by humans and wildlife either through wells and springs, or by supplying the base flow to streams.

There is a considerable potential for local dewatering of the aquifer overlying the shale during mining. The effects of undermining portions of an aquifer are expected to range from little or no decline in groundwater levels to almost total dewatering of the aquifer within 1 km of the mine perimeter. If the base of the aquifer rests on the Maury and Chattanooga shales, undermining would result in dewatering of portions of the aquifer. In areas where the basal portion of the Fort Payne is unweathered or unfractured, undermining would not be expected to damage the aquifer unless subsidence caused failure of the basal aquiclude. Areas in which porous zones penetrate to the base of the Fort Payne currently cannot be identified. Quantification of groundwater impacts can only be discussed on a site-specific basis following field testing of the aquifer.

Impacts on groundwater quality may result from leaching of raw shale in storage piles and abandoned mines and from leaching of solid wastes remaining after shale processing. Preliminary tests of raw shale leachates indicate that leachate from exposed shale will be acidic and may not meet drinking water criteria for concentrations of arsenic, copper, iron, manganese, zinc, and sulfate.[2] The sulfur remaining in the retorted shale that has not been processed for metals recovery, may produce sulfides and sulfuric acid and leach undesirable metallic elements which could enter the groundwater system by infiltration, surface water inflow, or direct leaching of spent shale disposed of underground. The leaching characteristics of the spent shale residue remaining after retorting, roasting, and metal recovery are unknown. Metals remaining in the shale following roasting may become acid soluble.

Impacts on surface water from development of

eastern oil shale could occur during mining, stockpiling, retorting, metals recovery, and spent shale disposal. Impacts to protected wild and scenic rivers may occur in association with any of these processes. Specific impacts on surface water hydrology will result from increased runoff, erosion, and sedimentation resulting from vegetation removal during mining and construction.[14] The magnitude of these impacts will depend on the location of mine and disposal sites in relation to potentially affected surface waters, the slope and topography of the affected watershed(s), and the regulations promulgated to govern the mining, processing, and disposal of spent shale.

Water quality of receiving streams can be affected by suspended material, toxic and carcinogenic aromatic hydrocarbons, salts, and inorganic trace constituents that occur as the result of runoff from, erosion of, and percolation through raw and retorted shale or from wastewater produced during retorting.[7,15,16] Leachates can emanate from the mine sites, the raw shale storage area at the retort site, the spent shale stockpiled for roasting and metal recovery, spent shale following the above processes, and process waters from retorting, roasting, and metal leaching. In addition, water withdrawn for shale processing, potential accidental spills, and overflow from waste water containment areas may affect water quality.

Water Use. Water use for a mining-retorting facility is based on the U.S. Office of Technology Assessment[17] calculation of 6 x 10^6 to 15 x 10^6 m^3/year. To supply this volume of water would require a continuous flow of between 0.2 and 0.5 m^3/s. Water resources of the Tennessee and Cumberland river basins of the Chattanooga shale region have adequate flow to supply 0.5 m^3 on a continuous basis. Smaller rivers and streams which cannot support a large operation (190,000 Mg/d) may provide a more-than-adequate year-round supply for a smaller facility. Siting a shale processing facility along a small river, however, may preclude further development along that river because a large percentage of the 7-day, 10-year low flow may be consumed by the shale processing facility.

The present water use for the region consumes only a small percentage of the critical low flow. Water consumption during the critical-low-flow month could increase approximately 10 times before exceeding the 7-day-10-year low-flow withdrawal limits.

Air

A commercial Chattanooga shale operation will emit general atmospheric pollutants capable of degrading air quality. Because eastern shales are high in sulfur, emissions of SO_2 and other sulfur species are of primary concern. Total suspended particulates (TSP), nitrogen oxides (NO_x), carbon monoxide (CO), non-methane hydrocarbons (HC), and oxidants can also occur as emissions from oil shale processing facilities. Several substances that are currently unregulated may also be emitted in significant quantities; these include ammonia (NH_3), hydrogen sulfide (H_2S), trace metals, and trace organics.

Large releases of atmospheric pollutants are of concern in the Chattanooga shale region, in part because of its generally poor conditions for atmospheric dispersion. These conditions occur more frequently in the region than in most of the eastern United States. Low-level (below 150 m) temperature inversions exist about 45 % of the time with little major seasonal variation.[4] Eighteen counties in the region have recorded violations of national primary or secondary standards for SO_2, TSP, or photochemical oxidants. Of these counties, Davidson and Sumner are in the prime resource area (Fig. 1).[18]

If we assume only retorting and no roasting and no control measures or stack recovery, emissions from a 190,000 Mg/d oil shale facility (producing 8000 m^3 of oil/d) that uses shale of average (4.9%) sulfur content[19] would total 2250 Mg/d of H_2S and ultimately 4500 Mg/d of SO_2. With environmental control technology capable of removing 99% of the sulfur, emissions from oil shale processing may be less than 90 Mg/d or about one-half that expected from a 1000-MWe coal-fired power plant.[2]

The impact of particulates will depend partly on the degree to which trace metals in raw shale are entrained and emitted in retort gases or in water droplets from cooling towers. Trace metals may accumulate in soils and vegetation, building to damaging levels for plants, animals, and man.[20] Particulates are generated in association with both mining and retorting and are usually produced from areal sources rather than from specific points, which make them difficult to estimate and control.

Chattanooga shale contains about 0.5% nitrogen,[21] most of which can be recovered as ammonia from the retort off-gases. Combustion of the retort gases for process heat would produce NO_x. The potential ammonia and NO_x emissions from a commercial shale facility are not known. Mountain States Research and Development[4] estimated that about 4.5 Mg/day of NO_x might result from combustion of retort off-gases from an 8000 m^3/d eastern oil shale plant. At present there are no environmental control technologies for NO_x.

Geology

The major geologic impact associated with development of the shale resource is that of subsidence. Areas closest to the shale outcrop areas would have the greatest potential for subsidence because the overlying strata are thinnest in these areas. Mines will have to be designed with suitable support mechanisms to minimize these impacts and to avoid mining under towns, highways, reservoirs, and other sensitive areas. For the most part, however, the Fort Payne formation is expected to provide a competent roof and provide little potential for subsidence.

Land Use

The direct impacts of shale development on land use, both along the outcrop area and on a regional scale, should be limited. The most intensive land-use change will occur at shale disposal sites (Solid Waste Disposal section), at the mine mouth, and at the processing plant. A surface mine that would supply 190,000 Mg/d of raw shale for a retorting facility would disturb

approximately 300 to 600 ha of land each year. Over a 20-year operating life of a plant, between 60 and 120 km^2 of land could be disturbed by mining. This figure does not include the areas for storage of overburden, stockpiling of soils, and disposal of spent shale.[4] The area disturbed by mining and the processing facility will cover an area of approximately 60 ha. Because most mining will occur underground, surface effects are expected to be limited to mine-mouth disturbance, subsidence, and isolation of ventilation exhaust systems. Land-use can also change as mining progresses and additional ventilation exhaust shafts become necessary. These shafts must be isolated because they emit dust and toxic gases such as methane and radon which may have a high potential for adverse impacts on wildlife, agriculture, and human health. If most of the spent shale from underground mining is disposed of on the surface, the amount of land disturbed will be comparable to that of a surface-mining operation.

The surface effects of subsidence on land use should be minimal with initial mining, but they will increase as the mining progresses and interior supporting structures deform and fail. Areas closest to the shale outcrop areas have the greatest potential for subsidence because the overlying strata are thinnest in these areas. Although underground mines should be designed to minimize subsidence, some local subsidence will almost certainly occur. The subsidence can result in local accumulations of runoff either as ponds or marshy areas, in structural damage to buildings, and in local, probably minor, changes in forests.

If reclamation of the spent shale disposal sites is successful, the sites could be suitable for grazing or recreation, but the low nutrient content of the shale and potential difficulty of stabilization and revegetation will limit return of these areas to their original patterns of cropland and forest. Removal of farm and forested land from private ownership and use for other purposes, such as mining or spent shale disposal, is not unprecedented in the Chattanooga shale region.

Disposal of spent shale will have a significant impact on soils because large volumes of waste material are generated. Soil may be adversely affected either by burial beneath the shale (presumably in a valley fill) or by being dug, transported, stored, and spread over the shale. Covering the spent shale with soil may be necessary to enhance revegetation. The large volume of solid waste produced over the 30-year life of the facility (5.8×10^8 m^3) could require up to a 10-to 15-cm surface covering (good nutrient status and moisture holding ability) and a 35-to 45-cm moisture-holding subsoil to augment revegetation. Until the revegetation potential for spent shales and the design for disposal sites are known, the impacts to regional soils either through burial or use in revegetation cannot be determined precisely. However, disposal of all spent shale from a site would cover an area of 34 km^2 to a depth of 30 m. This is comparable to covering Manhattan Island to a depth of 30 m or five stories.

Ecosystems

Effects of oil shale development on both terrestrial and aquatic ecosystems will depend on the (1) mining method, (2) retort process used, (3) source terms for the waste process stream, (4) chemical and physical characteristics of both raw and spent shale, (5) stabilization of spent shale disposal sites, (6) suitability of spent shale as a plant growth medium, and (7) reclamation and long-term revegetation of spent shale with diverse plant communities.

Terrestrial. Development of a Chattanooga oil shale industry will primarily impact forests and cultivated fields and pasture (Land section). Forest types of the region include oak-hickory, cedar, pine, maple-beech, and elm-ash-cottonwood forests. Virtually all phases of development, including mining, construction of the retort plant and support systems, and disposal of spent shale will produce impacts to terrestrial ecosystems.

Available evidence indicates that the problems of spent shale disposal will be serious in terms of the volume requiring surface disposal, the terrestrial ecosystems impacted by disposal, and the problems associated with revegetating the shale and establishing productive ecosystems.

A substantial amount of relatively natural forests and significant agricultural areas occur in the prime resource area. These areas constitute an important part of the habitat requirements for many wildlife species, including game.

Construction of processing facilities or disposal of spent shale (Solid Waste Disposal and Land sections) in forests and riparian habitats, rather than in agricultural areas, would be of greatest ecological concern because these areas support a greater diversity of plant and animal life. In addition these areas provide multiple uses (e.g., logging, recreation) as compared to agroecosystems.

Apart from the direct destruction or disturbance of terrestrial habitat, oil shale operations may have other impacts on terrestrial ecosystems. Releases of significant quantities of SO_2, NO_x, and oxidants from processing of eastern shale could stress local forests. Trace metals released as particulates from the mine and shale-handling areas, and in the gaseous releases from the retorting and metal extraction processes could be taken up by vegetation and passed on to consumers.[22] Based on studies of western shale, eastern shales may also have the potential for a higher fraction of aromatic hydrocarbons than conventional crude oil.[16] Spills of product oil and process wastes from shale processing could contaminate soil with these and other organic pollutants, a number of which have been shown to have toxic, teratogenic, and carcinogenic properties. Other impacts include noise effects on wildlife and effects on terrestrial biota resulting from degradation of water resources. Only broad qualitative designations of impacts to terrestrial ecosystems are possible at this point. Additional local and regional-level data will be needed before the severity of the impacts can be adequately assessed.

Aquatic. Aquatic biota may be affected during any or all stages of shale mining, retorting, metal extraction, and disposal. The extent and duration

of the impacts to aquatic biota will depend upon measures that are taken to minimize impacts to water quality and hydrology and upon the successful reclamation of shale disposal areas. Direct impacts can result from sediment addition and increased runoff,[23] or from input of acid or other toxic drainage.[24] These factors can collectively result in decreased light penetration and subsequent inhibition of photosynthesis and primary production,[14] interference with reproduction and habitat selection, and abrasion of aquatic biota.[25-28]

Impacts from shale extraction along the outcrop areas of the Cumberland Plateau will be qualitatively comparable to those resulting from coal mining in the region, except that an order of magnitude greater volume of raw shale is required for processing.

Impacts to aquatic ecosystems can also result from mobilization of sulfur from the raw or retorted shale and ultimately the production of sulfuric acid. Acid drainage associated with sulfur compounds can significantly reduce the diversity of species present downstream of the acid source.[24] Acid leaching of raw and retorted shale will probably mobilize metals and other potentially toxic substances from the shale that conceivably could leach into area streams in quantities sufficient to harm aquatic life. These substances include Co, Cu, Fe, Al, Ni, Zn, and other trace elements and hydrocarbons mobilized from the raw or retorted shale.[2] Because of the larger-scale mining operations, storage of raw and retorted shale, and the large volume of shale to be disposed of above ground, impacts to aquatic ecosystems can be significant and long term unless measures are taken to control effluents from the mining, processing, and disposal sites. Without successful stabilization and revegetation of mined and disposal sites, recovery of aquatic ecosystems from damages sustained during mining and shale disposal will be a long, slow process.

Sensitive species. The impacts to endangered, threatened, or sensitive species of plants and animals are of particular concern in oil shale development. Because many sensitive plant species are found in only one or a few specific locations, the effects of site location as well as the more gradual effects of habitat degradation through effects on air and water may contribute significantly to species extinction. The greatest number of sensitive plant species found in the 19-county prime resource area is found in Coffee, Franklin, and Davidson counties.

Impacts to sensitive animal species are typically a result of destruction or disturbance of suitable habitat. Direct long-term effects, exemplified by the effects of pesticides on raptor eggs, could occur from as yet unknown pollutants that might be generated by an oil shale industry. The U.S. Fish and Wildlife Service has listed four bird, three mammal, and one plant species that may occur in the Chattanooga oil shale area as threatened or endangered (Table 1).

There are currently 19 federally listed and about 80 state-listed threatened or endangered aquatic species (Table 1) believed to reside in the Chattanooga shale resource region. Within the 19-county prime resource area, the seven southernmost counties and DeKalb County, Tennessee, have one or more federally listed species. Bedford, Coffee, and Franklin counties in Tennessee each have at least five endangered species. Many of these species live in the Duck and Paint Rock river systems.

Table 1. Federally listed endangered and threatened terrestrial and aquatic species.

Common name	Scientific name	Status
Vertebrates		
Gray bat	Myotis grisescens	E
Indiana bat	Myotis sodalis	E
Eastern cougar	Felis concolor	E
Bald eagle	Haliaeetus leucocephalus	E
Peregrin falcon	Falco peregrinus	E
Red-cockaded woodpecker	Picoides borealis	E
Kirtland's warbler	Dendrocia kirtlandii	E
Plants		
Green pitcher plant	Sarracenia oreophila	E
Mussels (pearly)		
Alabama lamp	Lampsilis virescens	E
Birdwing	Conradilla caelata	E
Cumberland bean	Villosa trabalis	E
Cumberland monkeyface	Quadrula intermedia	E
Orange-footed pimpleback	Plethobasus cooperianus	E
Pale lilliput	Toxolasma cylindrella	E
Pink mucket	Lampsilis orbiculata	E
Turgid-blossom	Epioblasma turgidula	E
Turbercled-blossom	Epioblasma torulosa torulosa	E
Yellow-blossom	Epioblasma florentina florentina	E
White wartyback	Plethobasus circatrieosus	E
Tan riffle shell clam	Epioblasma walkeri	E
Fine-rayed pigtoe	Fuscanaia cuneolus	E
Rough pigtoe	Pleurobema plenum	E
Dromedary	Dromus dromas	E
Fish		
Alabama cavefish	Speoplatyrhinus poulsoni	T
Spotfin chub	Hybopis monacha	T
Slackwater darter	Etheostoma boschungi	T

Protection of all federally listed species is required by law for projects involving federal agencies. State-listed threatened or endangered species, although not having legal status, should be considered in the siting of processing facilities, and mining and shale-disposal locations since these species may be afforded legal protection in the future.

Socioeconomics

The development of a shale industry in the prime resource area will have locally significant "boomtown" effects. Development of the mine and retort facilities will cause a large population influx into nearby communities. This influx will diminish rapidly with distance from the facilities. Because the operations work force will be greater than that required during construction, there should be no "bust" cycle and impacts should be minimal. The skilled construction force will come from outside the area, while the operation personnel will most likely come from the local area. Population growth, service facility, education and health care services, and transportation impacts will be borne by local residents. These impacts will be offset, in part, by the benefits of an expanded local economy and the opportunities for growth in the service sector. The tax base from the mine/retort complex as well as expanded retail and service trades and housing will be greatly increased. Housing will be heavily impacted with initial development of the industry, but it should improve in quality and quantity with time. There will be short-term trade-offs; however, over the

long-term, the quality of life should remain high. Although development of an eastern shale industry will create localized "boomtown" effects, the prevailing attitude in the area is likely to be that development is an economic boost to a currently depressed area. Impacts to historical and archaeological resources will be minimal due to the low frequency of occurrence in the area.

Conclusions

Initial development of the Chattanooga shale will be along the outcrop; however, most of the resource will be extracted by underground mining. The major impacts as the result of shale development will be those associated with surface disposal of spent shale. Disposal of the spent shale can have significant impacts on surface and groundwater quality as the result of trace elements and toxic substances leached from the shale. Changes in water quality from these releases as well as from sedimentation and erosion can have significant long-term effects on aquatic biota. If large areas are covered with spent shale and cannot be successfully reclaimed, then there will be significant changes in land use and effects on terrestrial ecosystems. In addition, if large volumes of topsoil are needed for reclamation of spent shale and most shale is disposed of above ground, significant impacts can occur on land use. The terrestrial ecosystem can also be impacted by runoff and leachates and by air quality changes possible from emissions of processing facilities. The impacts associated with development of Chattanooga shale cannot be more precisely quantified until more is known about (1) the resource; (2) the processes to be used for oil and metals extraction; (3) the waste products that either will be leached from the raw, roasted, or spent shale or will remain in the spent shale; and (4) the methods of spent shale disposal and reclamation.

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Potential Impact of Oil Shale Development on Water Resources in Kentucky

by

William J. Mitsch and Christopher G. Lind
Systems Science Institute and Environmental Engineering Program
University of Louisville
Louisville, Kentucky 40292

Abstract. Major water resource issues that may emerge in Kentucky should oil shale development occur are discussed. Water quality and streamflow from three major watersheds that contain oil shale reserves as described. Potential water quality problems from shale mining, shale processing and spent shale disposal are presented.

Introduction

The development of Devonian oil shale as an energy resource in Kentucky will require some regional commitment of water resources for that development to occur. The degree of the commitment of water resources, both in terms of water use and water degradation, is uncertain for several reasons. There have been no pilot or commercial oil shale retort facilities built in the Eastern oil shale region, as are being built in Western shale regions. Furthermore, it is still not known which retort processes would be used on Eastern shale and what their water requirements and effluents will be. Mining of shale has not been attempted in the region on a large scale although seams have been excavated in certain locations for highway construction. Likewise, little is known about the physical and chemical characteristics of spent shale and what effects it may have on water quality. In addition to these uncertainties, specific locations of mining, retort facilities, and spent shale disposal cannot be determined with any certainty; this requires any analysis of environmental impact to be generic or, at best, regional in approach[1].

The Knobs area of Kentucky (Figure 1) is the most likely region of oil shale development in Kentucky. The water resources and aquatic ecosystems of that region must be well understood to predict conclusively the water resource impact of oil shale development. While reasonable data are available for streamflow and water quality of the larger streams that pass through the Knobs, few comprehensive "ecosystem-level" or "watershed-level" studies for these streams exist. These omissions, in addition to the paucity of data on smaller and intermittent streams that originate in the Knobs, may further contribute to the uncertainty about the water resource impact of oil shale development in Kentucky.

Our paper will first present a review of the pertinent literature on water resources and oil shale. This will be followed by a description of the existing water resources in the Knobs region of Kentucky and a description of the water problems that are likely to be encountered if Devonian oil shale is developed in Kentucky. Professional judgment will replace the existence of hard data in many instances so our results must be viewed as preliminary. Much research is still needed on the many issues involving water and oil shale in the East. Companion papers on oil shale in Kentucky include an environmental impact model[1] and a regional net energy analysis[2].

Figure 1. Eastern Devonian oil shale resources showing semi-circular Knobs region in Kentucky.

Previous Studies - Oil Shale and Water Quality

Several studies have documented the potential water use and water pollution problems that may be associated with the development of oil shale in Western United States, particularly in the Green River Formation of Colorado. There have been far fewer assessments of the impact of Eastern oil shale development on water resources. It is misleading to rely too extensively on Western oil shale studies

for Eastern Devonian shale for several reasons. The Eastern shale (a true shale) is different in physical and chemical properties from the Western shale (a marlstone). Differences in the geochemical properties of the rocks and soils may lead to vastly different water quality problems. The climatic and hydrologic conditions are different in the two regions. Kentucky, for example, averages 109 to 119 cm of precipitation, compared with the precipitation of 25 to 50 cm in the Piceance Creek Basin of Colorado.[3] This difference in climate leads to dramatically different terrestrial and aquatic ecosystems. Nevertheless, a review of general water resource impacts in the Western region can provide some data applicable to Kentucky and the East.

West Shale

General environmental impacts, including water impacts, of oil shale development in Western states have been summarized by Kilburn[3], Crawford et al.[4], Brown[5], and Bates and Thoem[6]. Studies dealing with water quality in particular have been done by Kinney et al.[7] and Skogerboe et al.[8] Most authors state that oil shale developers envision zero discharge of wastewater from commercial facilities. Wastewaters from one unit operation will be used as a water source for another operation, such as using retort wastewater to wet down spent shale.

Total water consumption by oil shale operations varies according to processes used. McKee et al.[9] estimated a water requirement of 0.4 m^3/sec (13.8 cfs) for a 100,000 barrel per day Paraho oil shale operation. Kilburn[3] suggested that "water use could become limiting" for oil shale development in the West and found an approximate water use for a TOSCO II system of 0.3 m^3/sec (11 cfs) for a 50,000 barrel per day facility. A range of 0.24-0.38 m^3/sec (8.5-13.4 cfs) for a 50,000 barrel per day plant can be calculated from data given by Crawford et al.[4]

Major wastewater types, regardless of whether they are recycled, include 1) retort wastewater, 2) shale oil upgrading wastewater, 3) mine drainage, 4) sanitary effluents, and 5) leachate from spent shale disposal.[6] Many pollutants are found in these wastewater flows, including soluble salts, complex trace organics, and trace inorganic elements. Parameters of primary interest for regulation include total suspended solids, phenols, pH, lead, arsenic, cadmium, copper, chromium, mercury, selenium and silver.[6] Harbert et al.[10] and Kilkelly et al.[11,12] presented results from several years of lysimeter and runoff studies of spent shale piles. They concluded that salinity from spent shale deposits could have a high potential for pollution of adjacent waterways. Laboratory tests of spent shale by Stollenwerk and Runnells[13] and McWhorter[14] suggested that fluoride, boron, molybdenum, aluminum, zinc, and lead may have potentially high levels in leachate. Fransway and Wagenet[15] found that processed Paraho shale "would be capable of contributing massive quantities of salt to surface and groundwaters if enough water was present to leach the shale."

Eastern Shale

Little has been documented on water quantity or quality problems with Eastern oil shale development. IGT and Dames and Moore[16,17] discussed environmental issues with Devonian shale development, including impacts on water resources. Those impacts are summarized in Table 1 for mining, processing, and spent shale disposal. Major water problems include supplying adequate water and pollution control that would minimize or eliminate erosion, sedimentation, and discharge of process pollutants. One study[16] estimated a water requirement of 0.57 m^3/sec (20 cfs) for a 50,000 barrel per day HYTORT operation. A range of 0.20 to 0.55 m^3/sec (6.9 to 19.3 cfs) is estimated for the same process in a companion report.[17] Cooling tower loss was expected to be about 91% of the total water requirement.

Table 1. Water Resource Impacts for Eastern Devonian Oil Shale Development as Summarized by IGT and Dames & Moore[16].

Mining

*interruption of small streams and drainage patterns
*increased erosion and sedimentation
*possible interference with shallow aquifers
*effects of toxic elements on aquatic ecosystems

Processing

*high water use from available sources
*potential contamination of surface water from solid wastes
*stream interruption and sedimentation during construction

Spent Shale Disposal

*potential source of toxic pollution to ground and surface water
*possible water quality problems from major cations (calcium, magnesium, sodium, and potassium), chlorides, iron, and polyaromatic hydrocarbons
*potential acid drainage

It was assumed in both of these reports that water use could be much greater for oil shale development in the Eastern shale region than in the West because of greater water availability. Vyas et al.[18] suggest that the water supply for a proposed oil shale plant in Fleming County could obtain its water supply from the Ohio River although "pipeline easement problems could be severe." That study also presented extensive chemical analyses of Kentucky oil shale although interpretation of the data from a water pollution perspective was brief.

Water Resources in the Kentucky Knobs

Climate and Precipitation

Most elements of Kentucky's climate vary appreciably across the state. The state's geographical location is within the belt of westerly winds which continuously bring a succession of low pressure storm systems. The storms are periodically displaced by high pressure, fair weather systems. The continual passage of these two types of weather systems through Kentucky causes changeable weather patterns during each season.

Annual precipitation averages 114 cm (45 inches) in Kentucky. In the oil shale region, precipitation varies from 112 cm in Maysville to 124 cm in Richmond (Figures 2-4). The months of September and October average 20 to 30 percent less rainfall than the heavy precipitation months of January and February. There are 110 to 130 days of measurable

precipitation in the oil shale region. Annual patterns of adjusted pan evaporation (PE) are also shown in Figures 2-4.

All climate diagrams suggest excess water from October through May with general water deficits from June through September. Spring flooding of streams is frequent, due to excess water and thaw, although this phenomenon is not as pronounced as in northern states. An overall precipitation/PE ratio for the oil shale region is 1.58 which indicates that there is a 58% excess of water for streamflow and groundwater recharge.

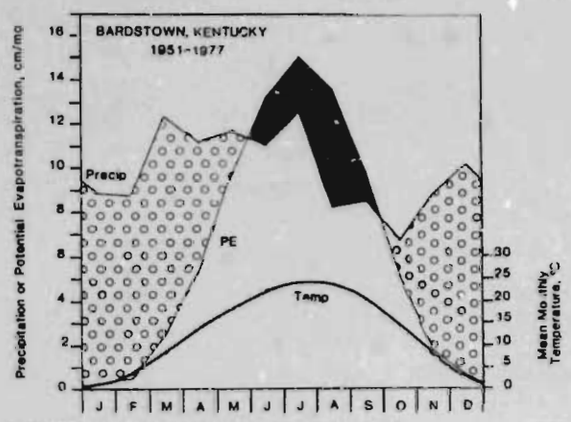

Figure 2. Precipitation and evaportranspiration patterns for Bardstown, Kentucky, in western part of Knobs.

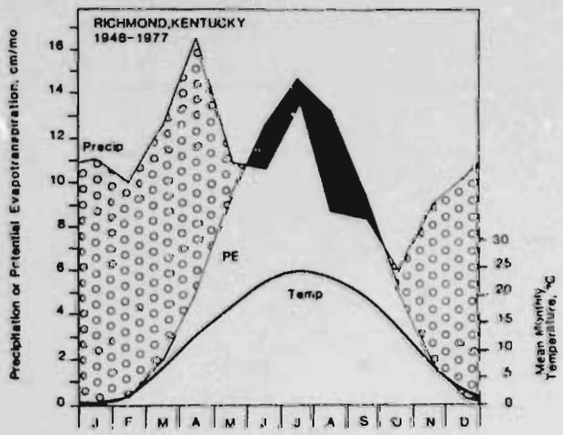

Figure 3. Precipitation and evapotranspiration patterns for Richmond, Kentucky, in southeastern part of Knobs.

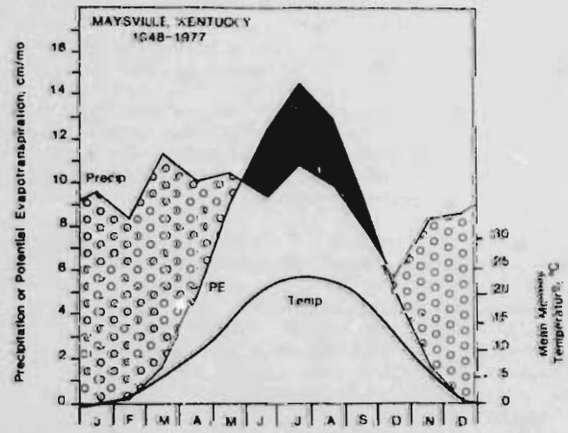

Figure 4. Precipitation and evapotranspiration patterns for Maysville, Kentucky, in eastern part of Knobs.

Surface Water Resources

Several major watersheds, namely the Salt River, the Kentucky River, and the Licking River Basins traverse the oil shale region of Kentucky (Figure 5). All of these watersheds drain towards the Ohio River. The Ohio River itself is adjacent to shale deposits in Lewis County in the east and Jefferson County in the west. However, it is not anticipated that oil shale development will utilize that river.

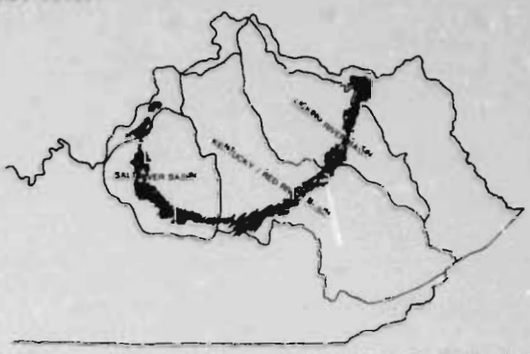

Figure 5. Major drainage basins in Knobs oil shale region in Kentucky.

Figures 6 through 8 are drainage maps for three major watershed areas investigated in detail here. Table 2 gives flow data for selected streams in those regions. The Rolling Fork River watershed (Figure 6) is 3400 km^2 with an average flow of 51.5 m^3/sec (1,819 cfs) near Boston in Nelson County. This average discharge is equivalent to 48 cm/year or 40 percent of the total precipitation of the area. The Kentucky and Red Rivers (Figure 7) are the major streams that intersect the central portion of the oil shale region. The Kentucky River, with an average flow of 150 m^3/sec (5,307 cfs) is the largest stream to pass through the oil shale region. The Red River, a tributary of the Kentucky River, averages 13.8 m^3/sec (487 cfs). Each of these two rivers drains approximately 40 cm/yr from their watersheds and has its headwaters in the Appalachian Mountains and Eastern Coal Field of Kentucky. The Licking River (Figure 8) drains through the eastern part of the oil shale region of Kentucky.

Low flow conditions for some streams in or near the oil shale region of Kentucky are also shown in Table 2. The Kentucky River is the only stream with substantial flow during 10-year low flow conditions and is 12 times that of the next highest low flow discharge, the Red River. The Rolling Fork River, in the western part of the oil shale region, has a low flow of only 0.06 m^3/sec (2.0 cfs) and the Salt River has zero discharge during low flow conditions. Little flow could likewise be expected in the Licking River during 10-year low flow conditions.

The Knobs region, where many oil shale deposits are near the surface is a hilly terrain with many miles of small low order streams. Most of these streams are seasonally intermittent. Should oil

Table 2. Average Discharge and Low Flow For Selected Streams Near Oil Shale Regions Of Kentucky.

River/Stream	Location (County)	Drainage Area, km2	Average Discharge, m3/sec	7 day-10 yr low flow, m3/sec
Rolling Fork Watershed				
Rolling Fork	Boston (Nelson)	3,364	51.5	0.06
Rolling Fork	Lebanon Junction (Hardin)	3,561	----	0.06
Rolling Fork	Lebanon (Marion)	619	9.7	0.0
Kentucky-Red Watershed				
Kentucky (North Fork)	Jackson (Breathitt)	2,852	36.9	0.09
Kentucky (Middle Fork)	Tallega (Lee)	1,391	20.9	---
Kentucky (South Fork)	Booneville (Owsley)	1,870	30.3	0.0
Kentucky	Heidelberg (Lee)	6,882	104.0	---
Kentucky	Winchester (Madison)	10,243	150.3	1.2
Red River	Hazel Green (Wolfe)	170	2.6	0.0
Red River	Clay City (Powell)	938	13.8	0.1
Licking River Watershed				
Licking	Farmers (Bath)	2,139	30.3	---
Triplett Creek (North Fork)	Morehead (Rowan)	219	3.9	0.0
Rock Lick Creek	Sharkey (Fleming)	10	0.2	---
Licking (North Fork)	Lewisburg (Mason)	308	4.3	---

shale resources be developed, these ephemeral streams may become important conduits. No data were found, however, on the quantity or quality of these streams.

Stream Water Quality

Water quality data available for our study watersheds in the oil shale region are summarized in Appendix A. A general discussion of the major characteristics of these streams follows.

pH and Buffering Capacity. All major streams in the region are circumneutral and range from an average pH of 7.3 in the Red River to a pH of 7.8 in the Salt and Licking River. The Kentucky River and to a greater extent the Red River have relatively low alkalinities, suggesting that these streams are less buffered against pH changes than are the streams in the eastern or western parts of the oil shale region.

Dissolved Oxygen. None of the streams showed any low dissolved oxygen measurements. Values for BOD and Chemical Oxygen Demand (COD) are very low at the sampling stations selected, indicating that the large streams of the region have few problems of low oxygen even in the summer months.

Major Ions (Salinity). Total salinity (dissolved materials) is reflected in the conductivity and dissolved residue measurements. The Red River is the lowest in dissolved materials (ave. = 73 mg/l) and the Salt River is the highest (ave. = 272 mg/l). This range reflects the differences in surface and subsurface geology, the relative importance of groundwater inflows, and the possible presence of cultural sources. Calcium dominates the dissolved cations in all streams, although it is much lower in the Red and Kentucky Rivers. Anions are generally dominated by the bicarbonate ion (as reflected in the alkalinity measurement), although the Kentucky River has relatively high levels of sulfates, possibly due to upstream coal mining.

Nutrients. Nutrients, particularly nitrogen and phosphorus, can cause eutrophication of waterways with proliferation of algae and aquatic plants. Nitrogen and phosphorus levels are generally very low in the Red and Kentucky Rivers and at moderate levels in the Licking, Salt, and Rolling Fork Rivers. The higher levels in these last rivers may be indicative of runoff from adjacent farmland. If these streams were impounded for oil shale development, eutrophication problems could result in the reservoir.

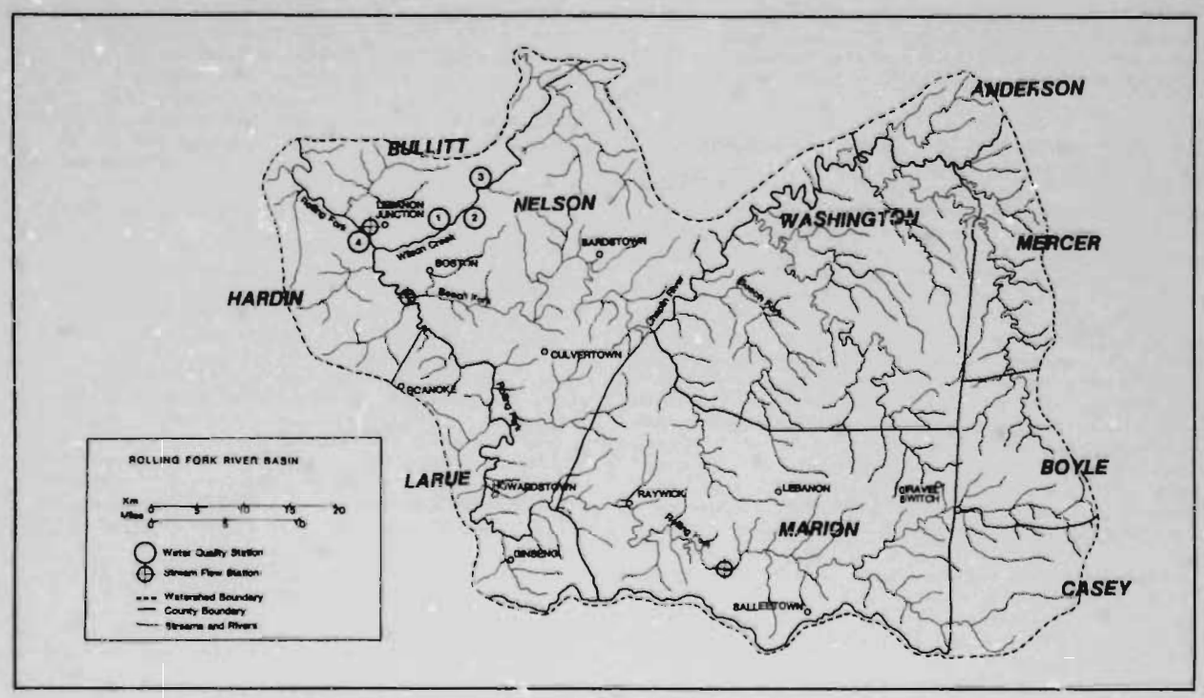

Figure 6. Rolling Fork Watershed in central Kentucky.

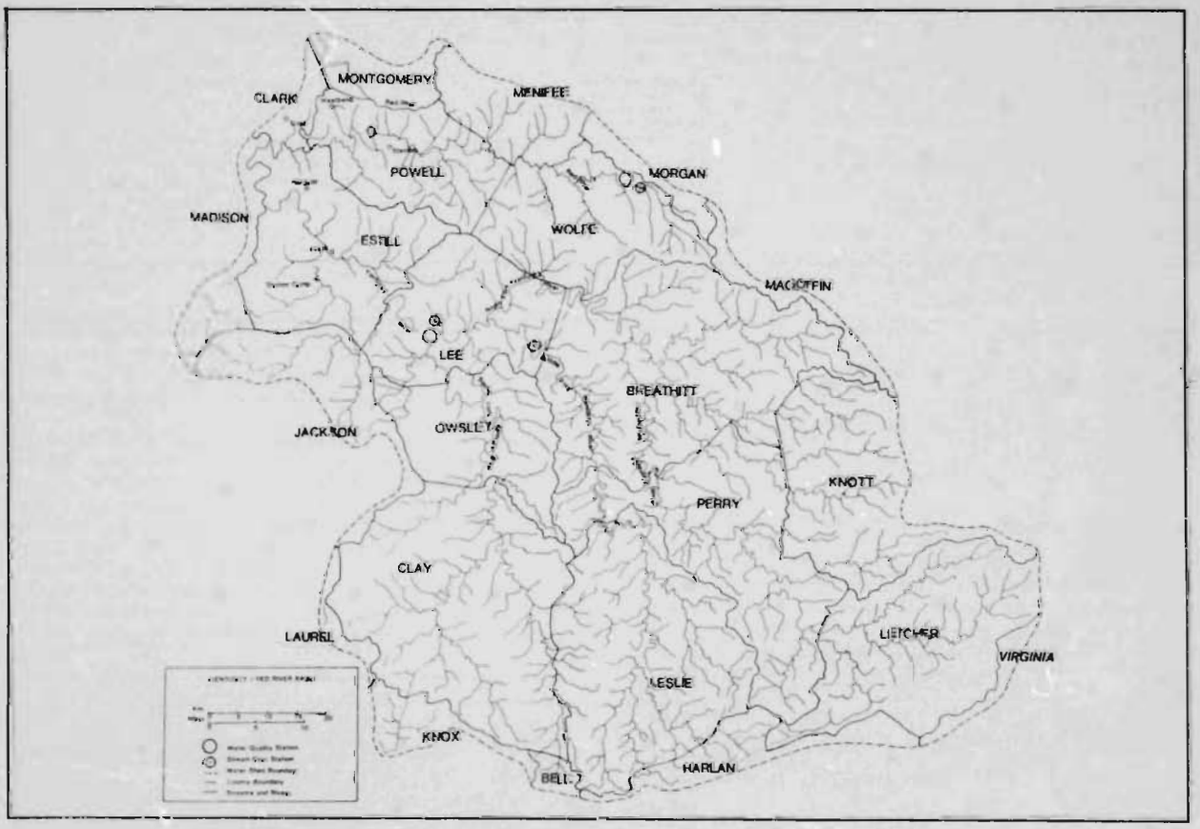

Figure 7. Kentucky River Watershed in Eastern Kentucky.

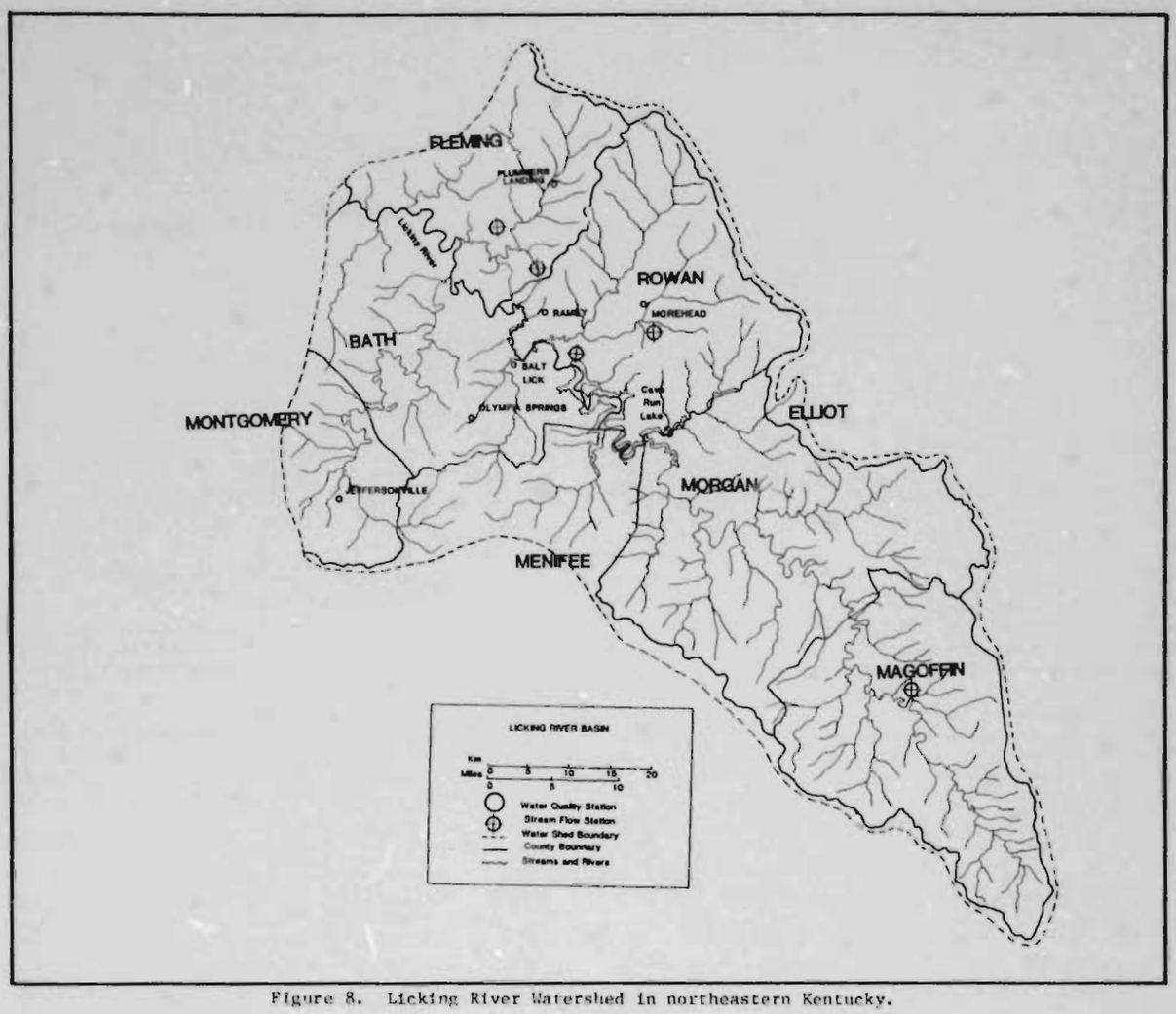

Figure 8. Licking River Watershed in northeastern Kentucky.

Suspended Sediments. Measurements of suspended sediments (also called solids or residue) showed a very wide deviation from the mean for all streams. This is because of the characteristic pattern of much higher concentrations of suspended materials at higher flows. None of the values in the streams investigated were found to be excessive except during flooding conditions.

Iron and Manganese. Iron and manganese are major indicators of acid drainage from pyrite-rich deposits. Commonly associated with discharges from surface and undergound coal mines, these metals could be found in high concentrations in effluents from oil shale mines as well. The Commonwealth of Kentucky has developed regulations for oil shale effluents which are similar to coal mining regulations and are shown in Table 3. Total dissolved iron is highest in the Red, Licking and Kentucky Rivers, reflecting possible effects of upstream coal mining. Manganese is also high in the Red and Kentucky Rivers. Although dissolved iron is low in the Salt and Rolling Fork Rivers, total iron is around 2 mg/l, a relatively high concentration. Total iron data were not available for the other streams.

Table 3. Effluent Limitations for Oil Shale Operations in Kentucky.

Parameter	Minimum Allowable	Average for 30 days
Total iron, mg/l	7.0	3.5
Total manganese, mg/l	4.0	2.0
Total suspended solids, mg/l	70.0	35.0
pH	6.0-9.0	----

Trace Metals. Concentrations of trace metals in selected streams are also summarized in Appendix A. Dissolved lead values are higher than EPA criteria for drinking water (50 mg/l) in the Red, Kentucky and Licking Rivers and considerably higher than that acceptable for aquatic life. Mercury is higher than acceptable for aquatic life, while cadmium is close

to the criteria for domestic water supply in the same streams. It is not known if these values are a result of upstream coal mining. The Rolling Fork and Salt Rivers in the western part of the oil shale region have higher values of dissolved barium and dissolved chromium than the streams to the east, but the values are well below criteria for drinking water and aquatic life.

Groundwater Resources and Quality

Groundwater data for the oil shale region are sparce to non-existent. No U.S.G.S. groundwater monitoring wells are located in our watersheds. Well yields are generally 100 to 500 gpd throughout the region with little water available on the hillsides of the Knobs. The water becomes hard at relatively shallow depths and may contain salt and hydrogen sulfide. Water quality for selected samples taken from wells in the region is given in Appendix B. Iron and sulfate concentrations are high in samples taken from shale strata as a result of pyrite. The exposure of these seams during oil shale mining could lead to acid drainage conditions similar to those experienced from coal mining.

Water Quality Impacts of Kentucky Oil Shale Development

The development of oil shale in Kentucky will present several potential water resource problems. The questions of water use and water quality cannot be separated because water diversion will, by definition, have an impact on in-stream water quality, particularly during low flow conditions. For convenience, the water impacts will be discussed separately for shale mining, shale processing, and spent shale disposal.

Mining

Surface mining methods, probably contour mining and mountain-top removal techniques, will be used to mine oil shale in the Knobs region of Kentucky. It has been estimated[19] that 80 hectares per year (200 acres per year) of surface mining will be required to support a 50,000 barrel per day commercial plant. For the prediction of the major water impacts of shale mining in Kentucky, more can be inferred from Eastern coal mining problems than from Western oil shale mining. The major anticipated problems from oil shale mining are then: 1) erosion and sedimentation, 2) hydrological modification, 3) acid drainage, and 4) other toxic chemical pollution.

When large surface areas are exposed during mining, increased amounts of sediments are eroded from the mined site. These sediments, if not controlled with sedimentation basins, can significantly increase the total suspended solids (TSS) of adjacent streams and can lead to irregular erosion and sedimentation patterns in the streams. It has been estimated that surface mining in the Appalachian region can cause an 80-fold increase in sediment load as compared with a forested area in the same region.[20]

The hydrological modification of the watershed may also indirectly change the water quality of adjacent streams. Removal of surface vegetation will lead to increased runoff during storm events and will decrease soil and groundwater storage of water. Sediment loads will then be higher during flooding conditions in adjacent streams and water recharge will be less during low flow periods. This latter effect may indirectly lead to greater concentrations of dissolved materials during low flow and may increase instream levels of toxic metals. This, by itself, could have a deleterious effect on aquatic life in the stream.

Acid drainage, typical of Eastern coal mining, will probably be a major impact of shale mining in Kentucky. Pyrite (FeS_2) is present in varying amounts in the oil shale seams with concentrations varying between 2 and 5 percent.[19] Acid drainage, in addition to contributing low pH conditions to local streams, will dissolve metals such as iron, manganese, and aluminum. As the pH recovers through natural processes in the streams, a ferric hydroxide precipitate is formed (called yellowboy in some regions) which has a toxic and smothering effect on most aquatic organisms in the stream. While measures are currently available for the control of acid drainage from active mines in Eastern coal regions, the high levels of pyrites in the shale seams and the large amounts of shale that would be mined for a commercial operation suggest that acid drainage will be one of the major water quality considerations of oil shale development in Kentucky.

Trace metals, which can be toxic to aquatic life or deleterious to water supplies, may also be present in mine runoff. Several metals, including colbalt (Co), chromium (Cr), copper (Cu), and molybdenum (Mo), nickel (Ni) and uranium (U) were found to be higher in the shales than in surrounding geological materials.[18] Some of these metals could be mobilized due to the acidic conditions that develop during mining and could be transported to local streams. Alternatively, the metals could remain in the shale matrix through retorting and become significant during the disposal of spent shale.

Processing

The retorting and upgrading of oil shale to commercial oil products may have several effects on the water quality of adjacent streams. These possible effects include 1) the direct discharge of wastewaters from various unit operations, 2) the indirect effects of water withdrawal and possible impoundments on stream water quality, and 3) possible accidental oil spills.

The products contained in various wastewaters from operations are not well known. Most oil shale developers have proposed zero-discharge of wastewaters to local surface waters, although the practicality of this scheme has not yet been fully demonstrated. Major waste streams to be expected from Eastern oil shale processes include 1) wastewater from retort operations, 2) wastewater from shale oil upgrading (if done on site), 3) wastewater from air pollution control systems, 4) blowdown from cooling systems, and 5) effluents from water treatment and sanitary wastewater systems.[6,19]

Major water quality parameters of concern from retorting and/or upgrading operations include oxygen-demand parameters (BOD, COD, TOC), total suspended solids (TSS), oil and grease, organic compounds such as phenols, amines, and mercaptans, sulfur compounds (sulfates and sulfides), ammonia and several trace metals (e.g., total and hexavalent chromium). Wastewaters and treatment options would be similar to those now employed in oil refineries.[6] Air pollution control systems could utilize water for scrubbing and/or transport of solid wastes that

contain high levels of sulfur, nitrogen compounds, and trace metals. Blowdown from cooling water concentrates all dissolved materials originally found in the feed water. Best available technology criteria for cooling tower blowdown have been developed and include alkalinity, phosphates, chromium, copper, iron, and zinc.

Spent Shale Disposal

Approximately the same mass of material that is mined for the production of shale oil must be disposed of as spent shale. The volume of the material is actually slightly greater due to physical changes that take place during crushing and retorting. The material will be stored permanently in spent shale piles, probably in the surface mines or at the head of hollows. Revegetation potential as well as the chemical characteristics of runoff and leachate from the spent shale piles are not well understood for eastern shale. Western shale studies have shown that revegetation is slow and that runoff and leachate are high in total dissoved materials and certain trace elements. Because the Eastern shale is believed to have lower cohesion and cement-life properties than Western shale, leaching of water through the shale may be more significant in the East. Materials that are in relatively high concentrations in spent Devonian shale include iron, sulfates, chromium, copper, cobalt, molybdenum, nickle, and uranium. High salinity from spent shale will not be as great a problem in the East as in the Western shale region, but spent shale piles in the East could contribute to acid drainage problems expected from mining of shale. This would result in low pH waters with high concentrations of iron, manganese, sulfur and other toxic metals. It is also possible that some organics, particularly polyaromatic hydrocarbons, could be leached from the spent shale although one study suggested that this is not a problem with spent Devonian shales.[17] Research is just beginning on the leachates from spent Devonian shale and much field and laboratory work will be required before the potential for this problem is understood.

Summary of Water Impacts

The state of knowledge of water quality impacts of Devonian oil shale developments in Kentucky is summarized in Table 4. There is a great deal of uncertainty about several aspects of oil shale operations in Kentucky, particularly with spent shale leaching and runoff and retort effluents. High probabilities are associated with the effects of oil shale mining which will cause acid drainage, sedimentation, and erosion in local streams unless significant control measures are taken. It is also probable that the large amounts of water consumed in oil shale processes will cause significant instream problems with certain water quality parameters during low flow periods. Eutrophication of streams and/or impoundments and localized oil spills may also be problems exacerbated by oil shale development in the region.

Much research needs to be done on the importance of individual parameters that can be utilized for monitoring and regulation. Table 5 summarized a preliminary list of parameters, with high and low ranking, that should be investigated in subsequent research on the water quality impacts in the Devonian oi shale region of Kentucky. The potential effluents and pollution sources must be weighed against the carrying capacities of the local streams in order to properly develop water quality standards for oil shale development in Kentucky.

Table 4. Impact Rank and Probability of Occurrence of Oil Shale Activities on Water Quality in Kentucky Devonian Shale Regions.

Impact on Water Quality	Probability of Occurrence	
	High	Uncertain
High	*acid mine drainage *erosion sedimentation *instream modification due to water withdrawal	*spent shale leachate *hydrologic modification by mining and spent shale disposal *retort and other process wastewaters
Intermediate to Low	*cooling system blowdown *water treatment and sanitary effluents	*localized oil spills *eutrophication *spent shale runoff

Table 5. Preliminary List of Parameters for Monitoring and Regulation of Oil Shale Development in Kentucky.

Ranking	Mining	Processing	Spent Shale Disposal
High Priority	pH, TSS, Fe, Mn, alkalinity/acidity, Pb, Hg, Al, SO_4	TSS, NH_3, phenols, COD, Cr, organics	Cr, Fe, Cu, Co, Mo, Ni, U, pH, SO_4
Lower Priority	nutrients (N, P), other trace metals, organics	BOD, TDS, nutrients, other trace metals	Ca, Mg, Na, K, B, Se, F, Zn, Ni, As, Cd, Hg, TDS, organics

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Appendix A

Table A1. Water Quality of Streams in and near the Oil Shale Region of Kentucky

Parameter	Salt River at Shepherdsville[1,2]	Rolling Fork near Lebanon Junction[1]	Red River at Hazel Green[3]
	Average + Standard Deviation (# of samples)		
pH	7.8 ± 0.4 (12)	7.55± 0.2 (12)	7.3 ± 0.6 (16)
Dissolved oxygen (mg/l)	10.1 (2)	----------	9.1 ± 1.6 (7)
Conductivity (umho/cm)	429 ± 86. (12)	374.0 ±35. (12)	107.0 ± 65.0 (17)
Coliform, fecal (#100/ml)	1459 ± 810 (11)	307.0 ± 6.0 (11)	----------
Calcium (mg/l)	66.0 ± 4.0 (12)	54.0 ± 2.0 (11)	7.9 ± 7.5 (17)
Magnesium (mg/l)	13.0 ± 1.0 (12)	13.0 ± 0.6 (11)	3.5 ± 3.1 (17)
Sodium (mg/l)	7.1 ± 1.2 (12)	5.8 ± 0.5 (11)	2.8 ± 1.9 (17)
Potassium (mg/l)	3.1 ± 0.4 (12)	2.5 ± 0.3 (11)	1.6 ± 0.8 (17)
Alkalinity (mg/l as $CaCO_3$)	181.0 ± 13.0 (12)	158.0 ± 6.0 (12)	26.6 ± 15.8 (17)
Sulfate (mg/l)	36.0 ± 3.0 (12)	33.0 ± 2.0 (12)	19.3 ± 18.9 (16)
Chloride (mg/l)	9.3 ± 1.1 (12)	6.5 ± 0.7 (12)	3.7 ± 2.4 (17)
Floride (mg/l)	0.2 ± 0.1 (12)	0.2 (12)	<0.1 (4)
SiO_2, dissolved (mg/l)	4.0 ± 0.5 (11)	5.6 ± 0.3 (12)	6.2 ± 1.5 (17)
Dissolved Residue (mg/l)	272.0 ± 14.0 (12)	231.0 ± 6.0 (12)	72.8 ± 29.0 (17)
Suspended Residue (mg/l)	67.0 ± 104. (11)	114.0 ± 127. (11)	65.1 ± 167.5 (16)
NO_2 + NO_3 (mg/l as N)	1.0 ± 0.1 (12)	0.6 ± 0.1 (11)	0.26 ± 0.12 (15)
NH_4 (mg/l as N)	0.1 (12)	0.1 ± 0.1 (11)	0.13 ± 0.12 (14)
N, organic (mg/l)	0.7 ± 0.1 (11)	0.4 ± 0.1 (9)	0.3 ± 0.2 (14)
N, total (mg/l)	1.7 ± 0.1 (11)	1.1 ± 0.1 (10)	0.7 ± 0.3 (15)
P, total (mg/l)	0.3 (12)	0.2 ± 0.1 (12)	0.04 ± 0.06 (15)
P, dissolved (mg/l)	0.2 (12)	0.1 (12)	----------
BOD (mg/l)	----------	----------	0.8 ± 0.6 (13)
COD (mg/l)	----------	----------	8.0 ± 8.0 (16)
Total Organic C (mg/l)	6.9 ± 1.8 (7)	5.0 ± 0.8 (7)	----------
Turbidity (NTU)	10.0 ± 4.0 (12)	20.0 ± 6.0 (12)	23.5 ± 74.0 (17)

Parameter	Kentucky River at Heidelberg[3]	North Fork Licking River near Murphysville[3]
	Average + Standard Deviation (# of samples)	
pH	7.4 ± 0.4 (11)	7.8 ± 0.2 (9)
Dissolved oxygen (mg/l)	9.8 ± 2.1 (18)	10.0 ± 2.4 (16)
Conductivity (umho/cm)	251.0 ± 145.0 (20)	324.0 ± 52.0 (18)
Coliform, fecal (#100/ml)	----------	----------
Calcium (mg/l)	16.9 ± 10.3 (19)	49.0 ± 23.0 (12)
Magnesium (mg/l)	8.2 ± 3.6 (19)	11.5 ± 2.0 (12)
Sodium (mg/l)	7.6 ± 5.7 (19)	4.0 ± 1.9 (12)
Potassium (mg/l)	2.2 ± 0.9 (19)	3.2 ± 1.5 (12)
Alkalinity (mg/l as $CaCO_3$)	39.5 ± 17.2 (18)	130.0 ± 42.0 (17)
Sulfate (mg/l)	50.5 ± 24.6 (18)	36.0 ± 5.0 (17)
Chloride (mg/l)	5.6 ± 4.0 (20)	6.0 ± 2.3 (18)
Floride (mg/l)	<0.12 (19)	0.12 ± 0.02 (18)
SiO_2, dissolved (mg/l)	5.4 ± 1.8 (20)	5.6 ± 1.9 (14)
Dissolved Residue (mg/l)	15.2 ± 57.0 (20)	219.0 ± 41.0 (17)
Suspended Residue (mg/l)	62.1 ± 69.5 (20)	90.0 ± 242.0 (18)
NO_2 + NO_3 (mg/l as N)	0.25 ± 0.15 (17)	0.78 ± 0.41 (16)
NH_4 (mg/l as N)	0.13 ± 0.10 (17)	0.17 ± 0.16 (16)
N, organic (mg/l)	0.30 ± 0.14 (17)	0.53 ± 0.52 (16)
N, total (mg/l)	0.64 ± 0.20 (17)	1.45 ± 1.00 (16)
P, total (mg/l)	0.07 ± 0.07 (17)	0.28 ± 0.81 (16)
P, dissolved (mg/l)	----------	----------
BOD (mg/l)	<1.2 ± 0.9 (17)	1.2 ± 0.7 (15)
COD (mg/l)	<9.3 ± 6.3 (20)	16.9 ± 15.2 (17)
Total Organic C (mg/l)	----------	----------
Turbidity (NTU)	25.2 ± 35.3 (20)	20.5 ± 48.6 (18)

[1]U.S.G.S. Water Resources Data for Kentucky - Report Ky-80-1, Water Year 1980
[2]not on watershed map, but adjacent
[3]Kentucky Department for Natural Resources and Environmental Protection, Division of Water Primary Station Network, Mar 1979-Sep 1980.

Table A2. Water Chemistry (Metals) of Streams in and near the Oil Shale Region of Kentucky.

Parameter, ug/l	Average + Std. Dev. (# of samples)			
	Salt River at Shepherdsville[1]	Rolling Fork near Lebanon Junction[1]	Red River at Hazel Green[2]	Kentucky River at Heidelberg[2]	North Fork Licking River near Murphysville[2]
As, total	2.3 ± 0.7 (4)	1.8 ± 0.5 (4)	2.1 ± 2.1 (12)	8.7 ± 15.2 (15)	3.3 ± 3.2 (14)
As, dissolved	2.7 ± 0.9 (3)	2.0 ± 0.7 (4)	1.5 ± 1.2 (6)	2.7 ± 2.2 (10)	2.8 ± 1.7 (9)
Ba, total	83.3 ± 16.7 (3)	87.5 ± 37.5 (4)	---	---	---
Ba, dissolved	40.0 ± 5.8 (3)	37.5 ± 4.8 (4)	16.8 ± 6.9 (8)	<24.2 ± 18.6 (10)	32.5 ± 17.7 (2)
Cd, total	1.5 ± 0.6 (4)	1.5 ± 0.6 (4)	---	---	---
Cd, dissolved	0.5 ± 0.5 (4)	1.0 ± 2.0 (4)	9.6 ± 7.2 (16)	8.1 ± 7.2 (19)	8.2 ± 5.2 (18)
Cr, total	15.0 ± 5.0 (4)	12.5 ± 2.5 (4)	2.9 ± 3.1 (15)	3.6 ± 2.3 (17)	3.5 ± 5.5 (17)
Cr, dissolved	12.5 ± 1.3 (4)	10.0 ± 0.0 (4)	1.4 ± 0.5 (13)	3.4 ± 3.4 (14)	2.0 ± 2.6 (18)
Co, total	1.0 ± 1.0 (4)	1.3 ± 1.3 (4)	---	---	---
Co, dissolved	0.5 ± 0.5 (4)	0.5 ± 0.5 (4)	---	---	---
Cu, total	11.3 ± 5.1 (4)	14.5 ± 7.5 (4)	7.2 ± 6.0 (18)	6.2 ± 3.2 (20)	6.6 ± 5.1 (17)
Cu, dissolved	10.5 ± 2.5 (4)	6.8 ± 2.3 (4)	5.1 ± 3.4 (17)	5.0 ± 4.6 (19)	8.5 ± 4.4 (18)
Fe, total	1802.0 ± 452.0 (4)	2150.0 ± 784.0 (4)	---	---	---
Fe, dissolved	33.3 ± 14.5 (3)	22.5 ± 6.3 (4)	168.6 ± 120.1 (17)	83.7 ± 77.5 (20)	89.3 ± 64.0 (18)
Pb, total	8.3 ± 2.0 (4)	11.2 ± 6.6 (4)	42.3 ± 52.2 (18)	94.6 ± 105.9 (20)	106. ± 91.0 (17)
Pb, dissolved	0.3 ± 0.3 (4)	0.5 ± 0.3 (4)	95.5 ± 92.0 (17)	94.8 ± 120.7 (19)	98.8 ± 79.6 (18)
Mn, total	107.0 ± 25.0 (4)	162.0 ± 37.0 (4)	---	---	---
Mn, dissolved	40.0 ± 10.8 (4)	41.0 ± 22.2 (4)	132.4 ± 137.5 (17)	82.0 ± 45.0 (19)	26.4 ± 11.2 (18)
Hg, total	0.1 ± 0.0 (3)	0.1 ± 0.0 (4)	1.0 ± 1.2 (18)	2.3 ± 6.5 (20)	1.3 ± 0.9 (18)
Hg, dissolved	0.2 ± 0.6 (3)	0.1 ± 0.0 (4)	0.8 ± 0.7 (15)	0.7 ± 0.4 (16)	1.3 ± 0.6 (6)
Zn, total	25.0 ± 8.7 (4)	35.0 ± 12.6 (4)	---	---	---
Zn, dissolved	11.3 ± 6.6 (4)	9.2 ± 7.1 (4)	31.1 ± 23.1 (17)	35.9 ± 40.7 (19)	26.0 ± 13.6 (18)
Ni, total	4.7 ± 0.3 (3)	3.7 ± 1.5 (4)	---	---	---
Ni, dissolved	0.7 ± 0.2 (3)	0.5 ± 0.5 (4)	4.9 + 3.3 (13)	5.2 ± 2.8 (16)	6.3 ± 2.8 (18)

[1]U.S.G.S Water Resource Data for Kentucky-Report Ky 80-1 Water Year 1980
[2]Kentucky Department for Natural Resources and Environmental Protection Division of Water -Primary Station Network March 1979-Sept. 1980.

Appendix B

Table B1. Water Quality of Selected Groundwater Samples from the Oil Shale Region of Kentucky.

Parameter	County					
	Bullitt	LaRue	Nelson	Nelson (J. Beam Distillery)	Bath (City of Salt Lick)	Fleming
Depth, ft	127-180	145	40	--	40	66
Date of Sample	May, 1964	Sep, 1952	1956	Jun, 1957	Apr, 1953	Sep, 1953
Geological Unit	350 SLRN	333 STSL	354LVLL	111 ALVM	111 AMOT	341 NALB
pH	7.4-8.2	7.5	7.3-7.5	7.4	----	----
temperature, °C	13.8	18.3	13-13.3	15.0	12.7	14.4
alkalinity, mg $CaCO_3$/l	----	134	292	123	----	----
hardness, mg $CaCO_3$/l	60-320	146	194-260	144	270	193
conductivity, umhos/cm	788-1210	298	853-915	284	1390	479
Fe, ug/l	210-850	00	130-250	150	1800	5700
Mn, ug/l	----	----	-----	----	----	----
HCO_3, mg/l	247-377	163	356-378	150	430	234
$SO_4^{=}$, mg/l	39-249	17	83-93	14	146	54
Cl^- mg/l	54-110	4.5	46-63	4	152	12
Fl^-, mg/l	0.6-1.0	0.1	0.6	----	0.1	0.2
NO_3, mgN/l	0.04-1.7	1.1	0.6-4.6	----	3.4	0.9
Ca^{++}, mg/l	----	47	40-58	33	----	----
Mg^{++}, mg/l	----	6.8	23-28	15	----	----
Na^+, mg/l	----	2.7	94-129	2.1	----	----
K^+, mg/l	----	1.5	4.2-5.9	0.8	----	----

Appendix B Continued on Next Page.

Appendix B Continued.

Parameter	County					
	Lewis	Rowan	Clark	Estill	Montgomery	Powell
Depth, ft	50	37	1600	143	40	150
Date of Sample	May 1954-Apr 1956	April 1953	1964-67	May 1968	May 1965	1951-57
Geological Unit	357BFLD	341NALB	364STPR	354LVLG	341NALB	111ALVN
pH	7.6	3.8	6.3-8.0	7.3	---	6.3-7.6
temperature, °C	13.8-15.0	----	--	---	---	14.4
alkalinity, mg $CaCO_3$/l	-----	---	318	---	----	--
hardness, mg $CaCO_3$/l	485-534	66-126	959-1360	764	400	60-75
conductivity, umhos/cm	3240-3930	252-379	13,100-17,300	9350	792	213-422
Fe, ug/l	1100-1700	440-780	--	---	2100	2600-3900
Mn, ug/l	30	---	--	---	---	---
HCO_3, mg/l	280-305	0 - 7	290-388	758	415	106-164
$SO_4^{=}$, mg/l	43-55	48-180	69-200	--	88	4.0-8.8
Cl^- mg/l	890-1110	5-20	4380-6100	2880	16	12-48
Fl^-, mg/l	0.5	0.1-0.2	0.3-0.4	1.9	0.4	0.1-0.2
NO_3^-, mgN/l	0.5	24	0.9	---	1.6	0.5-1.0
Ca^{++}, mg/l	116	-----	127-297	197	86	19
Mg^{++}, mg/l	59	-----	151-156	66	45	2.9
Na^+, mg/l	570	-----	2700-3740	1840	28	64
K^+, mg/l	17	-----	80-100	11	2.9	1.8

Leaching Studies on Kentucky Oil Shale Products

by

D.W. Koppenaal
K. Cisler, and G. Thomas
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Abstract

Laboratory leaching studies on a suite of Kentucky oil shales and their associated retorted and combusted products are described. Standardized batch extraction procedures were performed and evaluated on the basis of their leaching media composition, particle morphology, solid : liquid ratio, and contact time characteristics. Leachate composition was monitored via pH, conductivity, total organic carbon, anion (SO_4^{2-}, Cl^-, NO_3^-), cation (Na^+, K^+, Ca^{2+}, Mg^{2+}), and trace element (Ag, As, Ba, Cd, Cr, Pb, Se, Hg, and others) determinations. Illustrative results from the studies are presented and discussed in relation to their environmental impact, regulatory compliance, and applicability to field disposal conditions.

Introduction

The characterization of water generated or modified as a result of contact with various oil shale products or by-products is a necessary first step in assessing if, and to what extent, water quality problems may arise in the development of an eastern oil shale industry. The leaching (i.e. release) characteristics of raw shale, retorted shale, and other associated materials will determine the level of treatment necessary prior to water discharge, and the long range hazards such materials may present to surface and ground water quality.

In an endeavor to address this issue, a research program was developed (in conjunction with and partially financed by the Kentucky Department of Natural Resources and Environmental Protection) to evaluate the environmental and disposal characteristics of anticipated oil shale waste products. The overall project (flowsheet in Figure 1) was

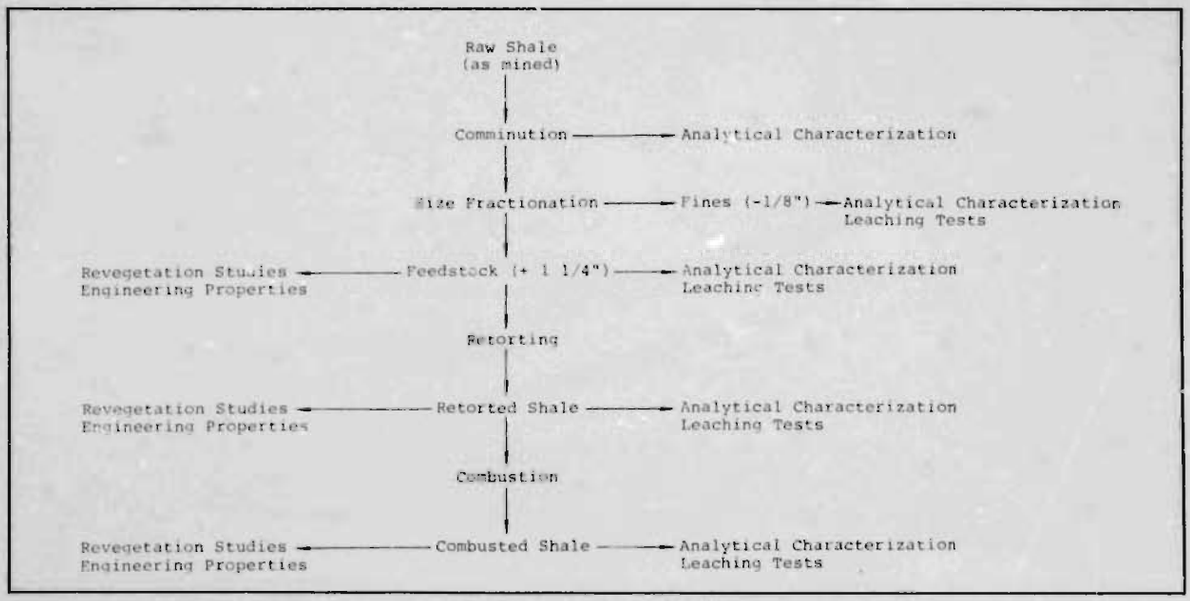

Figure 1. Project Flowsheet

designed to provide preliminary information on the engineering, revegetation, and leaching characteristics of Kentucky oil shale waste materials. Only the latter issue is addressed in this paper; the former two studies are the subject of other papers presented in this Proceedings.[1,2]

The approach taken for the leaching studies involved the utilization of several standardized batch extraction procedures for the examination of the leachability characteristics of raw, retorted, and combusted oil shale materials as well as selected soils and overburdens. Raw shale samples were taken from several Kentucky sites and processed shales from two technologies were obtained for evaluation. A description of the project in general and the leaching studies in particular is given. Illustrative results pertaining to leachate composition are presented, with discussion on the environmental impact, regulatory compliance, and extrapolation of these results to field disposal conditions.

Materials and Methodology

Sample Procurement and Preparation

Oil Shale Samples. Seven samples of approximately 1-2 tons each were extracted by backhoe from six geographic sites broadly representing the entire oil shale resource in Kentucky. Figure 2 depicts the location of each shale sample. It is evident that efforts were taken to obtain reasonable geographic and geologic distribution in the selection of sample sites. Raw, unweathered samples were obtained from existing road-cuts and/or quarries by digging well into the face of the resource. Samples of the Sunbury and Cleveland shale units were obtained in the Lewis County location. The Sunbury-Cleveland equivalent of the New Albany shale unit was obtained in the Powell County site. In Lincoln, Nelson, and Bullitt Counties the New Albany unit was sampled, and completing the sample acquisition was the Chattanooga shale unit from Russell County. In general the samples taken represented a composite of the entire vertical unit available.

IGT HYTORT Samples. Several retorted Kentucky oil shale samples were obtained from the HYTORT process developed by the Institute of Gas Technology.[3] This process involves an elevated hydrogen pressure technology to enhance shale oil recovery and has been specifically designed for Eastern oil shale utilization. The samples obtained from IGT included retorted Sunbury, Cleveland, and New Albany shales. The corresponding feed shales were not available however. Certain HYTORT samples were combusted by us as described below to simulate probable disposal material.

Soil and Overburden Samples. Soil and overburden/interburden samples were collected in order to provide baseline control conditions for certain experiments. Selected samples of these materials were examined for leachate characteristics.

Sample Preparation. The collected raw shale samples were comminuted using a convential jaw crusher to a nominal particle size range of 1 1/4 x 0". This material was subsequently size-fractionated to remove fines prior to processing, resulting in a feed stock material of 1 1/4 x 1/8" particle size.

The HYTORT samples were received in a form that required no further comminution.

The soil/interburden samples were initially ground to a particle size of 3/8 x 0". This material was further ground to -60 mesh for analytical and leaching tests.

Additional sample preparation was dependent on the particular leaching procedure used. The ASTM procedures dictate that leaching experiments be performed on the material in question in an 'as-disposed' form." Thus, the ASTM procedures

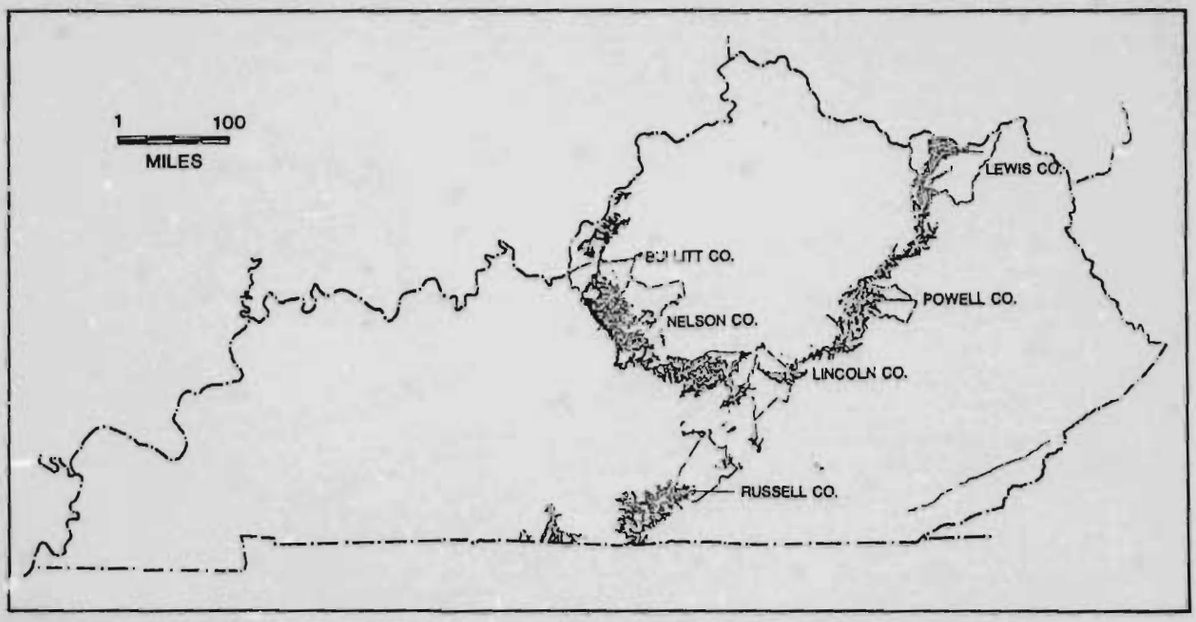

Figure 2. Kentucky Oil Shale Outcrop Diagram and Location of Project Sample Sites.

used the as-received retorted/combusted samples (i.e. particle size range slightly less than 1 1/4 x 1/8" due to particle attrition during processing). The EP procedure requires that the particle size of the sample to be leached be no greater than 9.5mm, however.[5] In this case further grinding of the feedstock, retorted, and combusted shales was necessary to meet this requirement.

Retorting Operations

Oil shale samples were retorted using a development unit scale retort facility owned and operated by Pyramid Minerals Inc. of Olive Hill, Kentucky. A schematic of the retort facility is given in Figure 3. The unit consists of a two-stage, screw-fed retort with dual water-cooled product removal condensers. Stage 1 (labeled A in Figure 3) is operated at a temperature of 250°C, while Stage 2 (labeled B) is maintained at 450°C. The unit was operated at an approximate shale feed rate of 200 lbs/hr; shale residence time was estimated to be 32 minutes. Retorted shale was removed periodically through a lock-valve and air-cooled. Liquid oil and water products were removed continuously through the condenser outlets.

The retort facility can only be considered as a first-generation experimental unit. Process control parameters (i.e. temperature, steam and shale feed rate, etc.) were manually controlled and therefore somewhat variable. Retort operation was not specifically optimized for oil recovery in these operations - the primary emphasis was the generation of sufficient quantities of retorted shale materials. Analytical results on feed and product streams indicated that the retorting runs were adequate in terms of oil yield, however.

Combustion Operations

Portions of the retorted shale were combusted to simulate oil shale products which have been processed to remove residual carbon after retorting. The combustion facility utilized was a modified coal gasification reactor located on the University of Kentucky campus. The unit consists of an 8-inch i.d., ceramic-lined reactor. Retorted shales were fed counter-current to the oxygen-rich combustion gas. The reactor temperature was maintained at 800-900°C during combustion operations.

Leaching Studies

Objectives. The primary objective of the leaching studies was the assessment of the potential environmental hazard oil shale leachates might present. This preliminary assessment was based on a thorough compositional analysis of leachates obtained from a variety of oil shale materials, and comparison of these results with recommended and/or regulatory criteria.

Secondary objectives were to obtain a framework of comparative data to evaluate procedural, geological, and technological effects on leachate composition. The use of three extraction procedures enabled intra-test comparison and evaluation with respect to test variables such as leaching media composition, sample morphology and size, contact time, and solid : liquid ratio. The application of each test to the various raw and processed oil shale materials allowed for evaluation of the effect of resource location (six counties) or type (Sunbury, Cleveland, New Albany and Chattanooga shale units), process material

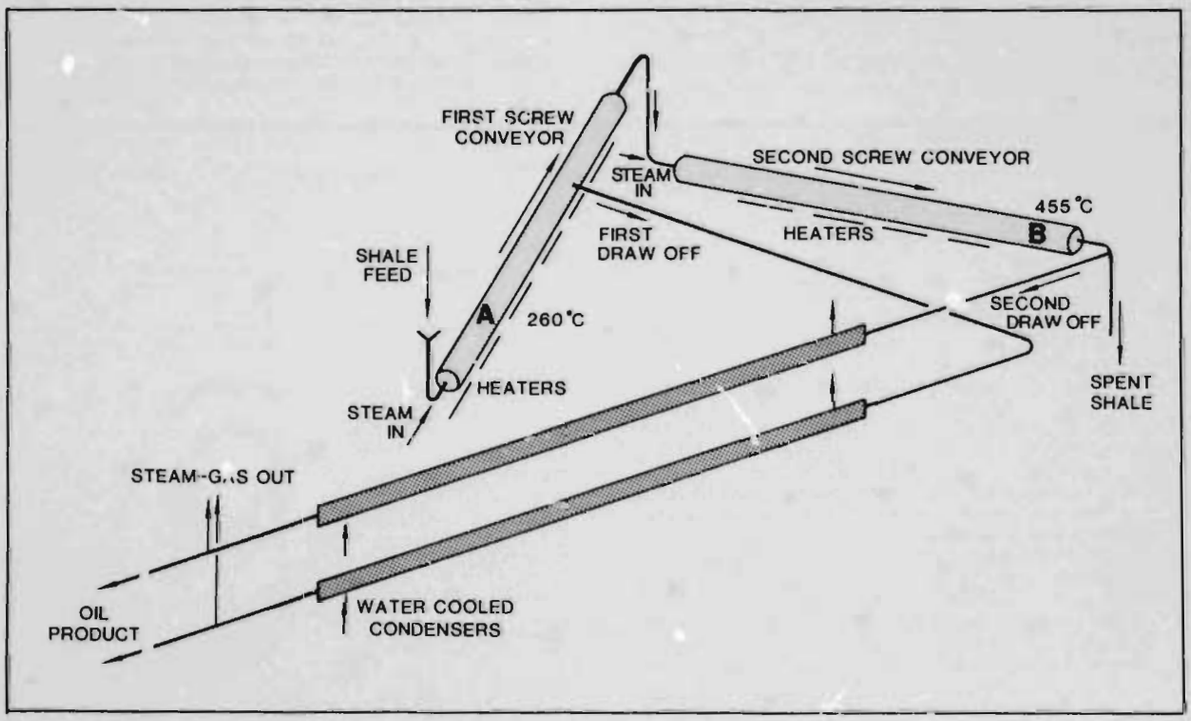

Figure 3. Pyramid Minerals Retort Schematic

(raw, retorted, or combusted) and process technology (Pyramid Minerals retort or IGT HYTORT).

Extraction Procedures. Three standardized extraction (leaching) procedures were utilized in the course of this work. All three tests were batch (alternatively referred to as static and/or shake procedures) procedures. For each test a weighed amount of solid waste material is contacted with a known amount of liquid extractant under specified control conditions. After a prescribed time period the liquid extractant is separated from the host material and analyzed for extractable waste constituents. Table 1 summarizes the conditions for each of the extraction procedures; a detailed description for each procedure is presented below.

Two extraction procedures proposed by the American Society for Testing Materials[4,5] were utilized and evaluated. As indicated in Table 1 the ASTM-A procedure dictates a distilled water extraction medium while the ASTM-B procedure utilizes a buffered (pH 4.5) acetic acid/sodium acetate medium. Both ASTM tests call for a solid : liquid ratio of 1:4, and 'as-disposed' physical form, and a test duration of 48 hours.

The third extraction procedure evaluated was the Environmental Protection Agency's Extraction Procedure (EP), as specified by the Resource Conservation and Recovery Act of 1976 (as amended)[6]. This procedure is in current use for regulatory evaluation of a material as a hazardous or non-hazardous material. The EP test prescribes a solid : liquid ratio of 1:16, a particle size of <9.5mm, and a test duration of 24 hours. The extractant used in the EP test is distilled water with dilute acetic acid added as necessary to maintain a pH of 4.8-5.2.

All extraction tests were performed using a Lab-Line Instruments, Inc. Orbit Environ-Shaker operating at an agitation rate of approximately 70 revolutions per minute.

Multi-cycle wet/dry leaching procedures. In order to more closely simulate natural precipitation/evaporation and analagous events, a multi-cycle wet/dry extraction procedure was developed and applied. With this procedure, weighed portions of the shale materials were extracted using the previously described extraction procedure(s). After the initial extraction period, the solid residual materials were collected and air dried for a minimum of 1 week, whereupon they were re-extracted with fresh extractant. This extraction-drying cycle was repeated four times, and each time the resulting leachate was collected and preserved for analysis.

16-day leaching procedures. Another experiment was designed to examine the short-term release dynamics of various elements from oil shale materials. This experiment involved the extraction (using the general guidelines of the ASTM-A procedure) of 16 separate portions of New Albany (Nelson County) shale. Each day for 16 days after the initial 48 hr. extraction period one extraction test was terminated. The appropriate analyses were subsequently performed on each leachate solution.

Analytical Procedures

A variety of chemical constituents and parameters were monitored to evaluate leachate quality. Conductivity and pH determinations were made using classical electrometric techniques. Atomic absorption and emission methods were used for the determination of trace elements. Mercury was determined using cold vapor atomic absorption while arsenic and selenium were determined with the hydride-evolution atomic absorption technique. Graphite furnace atomic absorption was employed for the determination of lead and cadmium. A number of other trace elements (Ag, Ba, Cd, Co, Mo, Ni, Zn, Cu, V, Fe, and U) were quantitated using a Spectrametrics, Inc. Inductively-Coupled Plasma atomic emission system. Anions ($SO_4^{=}$, Cl^-, NO_3^-,

TABLE 1. Experimental Conditions for Extraction Procedures

Characteristics	Extraction Procedures		
	EP	ASTM-A	ASTM-B
Leaching Media	dist. H_2O (pH 4.8-5.2)	dist. H_2O	pH 4.5 buffer
Solid : Liquid Ratio	1:16	1:4	1:4
Test Duration	24 hr.	48 hr.	48 hr.
Particle Size	<1 cm	as disposed	as disposed

PO_4^{3-}) were screened and quantitated using ion chromatographic techniques. Finally, organic carbon in the leachate solutions was determined using a UV oxidation/non-dispersive IR method. All analytical techniques and methodology used are state-of-the-art methods and in all cases appropriate measures were taken to ensure accurate and reliable analyses.

Results and Discussion

Leachate Composition - Analysis and Comparison

Dependence on extraction procedure. Table 2 presents the leachate composition of the ASTM and EP extracts from retorted Sunbury (Lewis county) shale. Conductivity and pH results are not reported in the case of the ASTM-B procedure since this particular procedure uses a buffered leaching media that obscures any pH or conductivity contribution by the shale material. The ASTM-A and EP results for pH indicate that the retorted shale has a strong acid-producing potential, resulting in leachate pH values of 3-4 for this and most other shale materials examined. The major anion present was sulfate and therefore the obvious acid generation mechanism appears to be the oxidation of pyrite and other sulfide minerals in the shale. Results are also presented for nine trace elements of toxicological or environmental concern. Results for mercury and selenium were generally less than the detection limit of the analytical procedures used (0.5 and 5ppb, respectively) for all shale materials studied and thus will not be discussed further. The results for cadmium were surprisingly high in the case of certain samples such as the retorted Sunbury shale. However the determination of other elements such as Mo and Co revealed concentrations that were less than 1 ppm.

TABLE 2. Leachate Composition of ASTM and EP Extracts of Retorted Sunbury (Lewis County) Shale.

	Extraction Procedure		
Constituent, ppm	ASTM-A	ASTM-B	EP
pH	3.59	N/A	3.51
TOC	2.48	N/A	1.50
SO_4^{2-}	917	97	282
Cd	1.36	1.03	0.44
As	.09	<.01	.03
Se	<.005	<.005	<.005
Hg	<.001	<.001	<.001
Pb	.023	.004	.023
Mo	<.2	.21	<.2
Cr	.04	.05	.02
Ni	5.14	0.21	.02
U	0.76	0.46	0.30

Comparison of the results in Table 1 reveals a general pattern showing the EP extract being less concentrated than the corresponding ASTM extracts. This trend is not surprising considering the solid : liquid ratio (1:16 for the EP and 1:4 for the ASTM) and contact time (24 hrs. for the EP vs. 48 hrs. for the ASTM) parameters for the two procedures. Although the particle size specifications for the two procedures would predict higher concentrations for the EP procedure (due to smaller particles and therefore higher surface areas available for leaching activity) the solid : liquid ratio and longer leaching duration of the ASTM procedures apparently predominate. Our experimental data indicate that the largest single factor controlling leachate composition is the solid : liquid ratio; the larger that ratio, the more concentrated the leachate solution. This relationship will generally hold true until a solubility limit is reached.

The differences between the two ASTM procedures are less apparent in Table 2, but based on our general body of data the ASTM-A procedure results in a leachate more concentrated with respect to most elements than the ASTM-B procedure. This difference is most likely due to the buffered leaching media of the ASTM-B procedure, which maintains a leachate pH of 4.5 while the unbuffered ASTM-A leachate reaches a more acidic state which is more effective in leaching activity.

Dependence on resource location. Leachate composition data for raw, retorted, and combusted shale extracts from each of the seven site locations are tabulated in Tables 3-5. Representative data from the ASTM-A extractions are presented in these tables. The data indicate that geographic location of the shale may have some effect on leachate composition; the differences observed are attributed to localized geochemical changes in bedrock composition. The pH data for the Lewis, Powell, Lincoln, Russell, and Nelson County locations are all in the 3-4 range and are fairly consistent from one location to another. The Bullitt County site exhibits unusually high pH values of 6-7, however. This anomaly is most likely due to presence of carbonate minerals in this sample. The acid produced as a result of pyrite oxidation is neutralized by the carbonates, resulting in a much more tolerable leachate pH. Values for total organic carbon (TOC) are given in Table 3 but show no distinct geographic trend. All TOC determinations on the shale materials resulted in low TOC values indicating low solubility of organic compounds even after retorting operations. Sulfate concentrations as exhibited in Table 3 varied widely which is not entirely consistent with the pH value trend. The possibility of naturally occurring sulfates (which do not contribute to acid production) dissolving in the leaching media is under current investigation to explain this discrepancy. A very apparent disparity was found in the case of cadmium; the data of Tables 3-5 illustrate the nature and extent of the phenomenon. Cadmium concentrations were the highest in the northeastern resource locations (Lewis and Powell Counties), and dropped to negligible levels in the southern and western resource locations. The geochemical characteristics which are likely responsible for this behavior are probably related to the well known association of cadmium and zinc in minerals such as sphalerite. Further delineation of this behavior is forthcoming. Arsenic values in all

TABLE 3. Leachate Composition of ASTM-A Extracts of Raw Shale from Sampled Resource Locations.

Constituent,ppm	Resource Location					
	Lewis(S)	Powell	Lincoln	Russell	Nelson	Bullitt
pH	2.96	3.75	3.94	3.19	3.56	6.10
TOC	3.18	1.14	1.32	1.27	1.67	2.23
SO_4^{2-}	1160	216	117	120	521	150
Cd	2.85	.02	.02	.02	.05	.002
As	<.01	<.01	<.01	<.01	<.01	<.01

TABLE 4. Leachate Composition of ASTM-A Extracts of Retorted Shales from Sampled Resource Locations

Constituent,ppm	Resource Location					
	Lewis(S)	Powell	Lincoln	Russell	Nelson	Bullitt
pH	3.59	3.24	3.80	3.32	3.77	6.35
Cd	1.36	.43	.03	.04	.05	<.01
As	.09	.03	.02	<.01	.02	<.01
Ni	5.14	6.50	2.29	.78	1.7	.21
Fe	160	150	125	119	149	3.5

TABLE 5. Leachate Composition of ASTM-A Extracts of Combusted Shales from Sampled Resource Locations.

Constituent,ppm	Resource Location					
	Lewis(S)	Powell	Lincoln	Russell	Nelson	Bullitt
pH	3.79	3.86	4.10	3.73	4.20	6.73
As	.05	.02	<.01	.03	.05	<.01
Ni	5.16	2.71	1.45	3.09	1.04	<.01
Fe	175	150	9.2	228	68	0.3
U	.3	2.5	<.4	<.4	<.4	<.4
Mo	<.2	<.2	<.2	<.2	<.2	.5
Cd	1.27	.10	.02	.08	.11	<.01

leachates of Tables 3-5 are consistently low in spite of the sometimes high concentration of this element in the shale itself.

Dependence on process material. The dependence of leachate composition as a function of the material subject to leaching (i.e. raw, retorted, or combusted) is of interest since processing of the resource may result in increased or decreased release of certain elements. Comparative data on this dependence is presented in Table 6 (and may also be assimilated from Tables 3-5). Data in Table 6 is presented for the fines (material < 1/8" size), feedstock, retorted, and combusted shale materials from the New Albany Shale of Lincoln County. The effect of processing on pH is beneficial from the disposal aspect, as the leachate pH increases (acid production decreases) with a retorting-combustion processing scenario. The leachate pH increase is most likely due to the chemical changes occurring during the processing steps (reduction in the case of retorting; oxidation during combustion) which result in the conversion of acid producing sulfide minerals to less acidic forms in their respective process residues. The pH trend exhibited in Table 6 is indicative and probably underestimates the beneficial aspect of processing on acid formation since the retort and combustion methods used were somewhat crude and resulted in materials that were not fully processed from an engineering viewpoint. As indicated in Table 6, total organic carbon is highest in the fines fraction and in the retorted fraction. The combusted material exhibits the lowest organic carbon leaching potential as expected. Sulfate concentrations in the case of the Lincoln County sample are highest in the case of the retorted material but this trend was not consistent with all other analagous materials from other sites. Arsenic and cadmium differences were small and are considered negligible.

When considering the entire body of data no completely discernible trend was apparent in the release characteristics of the different process materials. This conclusion will need to be reexamined and confirmed as additional technologies are applied and analagous process materials are generated.

Dependence on process technology. Results from the ASTM-A extraction procedure using retorted Sunbury Shale from the Pyramid Minerals and HYTORT processes are presented in Table 7. The feedstock shales used for these processes were similar but not identical; this should be kept in mind during interpretation of this data. The most striking difference in results between the two leachates is the pH disparity. The Pyramid Minerals retorted shale results in an acidic leachate compared to the very basic pH of the HYTORT process. This disparity is probably due to the highly reducing conditions encountered in the HYTORT process,[3] which result in the conversion of pyrite (FeS_2) to pyrrhotite (FeS) or possibly even elemental iron, with a consequent reduction in the acid-producing potential of the HYTORT spent shales. The degree of reduction in acid producing potential is indeed surprising, however. Further investigation into the mechanism of this phenomenon is underway. The sulfate concentrations in the two leachates (Table 7) are in accordance with the observed pH trend. The higher sulfate concentration in the Pyramid Minerals retorted shale leachate seems to support the explanation presented above for the Ph trend.

Another notable disparity in these results is evident in the case of cadmium (Table 7). The cadmium concentration is significantly lower for the HYTORT leachate sample than for the Pyramid Minerals sample. As mentioned above, the raw resource material for both retort runs were from the Lewis County Sunbury Shale, although the IGT HYTORT sample was removed several years earlier than the sample taken for this study. As the corresponding raw shale material from the HYTORT run was not available from IGT, it is impossible to discount the possibility of a field sampling bias for the observed difference. In the case of the shale sample removed for this study, only the upper portion of the Sunbury unit was able to be sampled due to logistical problems at the sampling site. As the upper portion of this unit is known to be geochemically enriched with certain trace elements (7-9), an inherent but nonrepresentative bias may be present with the sample. The possibility of a localized geochemical enrichment of cadmium in this sample is being investigated.

Differences in other elemental concentrations in the leachates of the two retort technologies were generally small and not considered significant.

TABLE 6. Leachate Composition of Raw and Processed New Albany (Lincoln County) Shales

Constituent, ppm	Process Material: Fines	Feedstock	Retorted	Combusted
pH	3.56	3.94	3.80	4.10
TOC	4.09	3.32	2.06	1.12
$SO_4^{=}$	527	757	354	465
As	.017	<.010	.018	<.010
Cd	.068	.019	.032	.023

TABLE 7. Leachate Composition of Retorted Sunbury Shale from Two Retort Technologies

Constituent, ppm	Pyramid Minerals Retort	IGT HYTORT
pH	3.59	10.35
TOC	2.48	5.36
$SO_4^{=}$	917	160
Cd	1.36	<.01
As	.09	.04
Ba	.17	.06
Cr	.04	.03

The arsenic, barium and chromium data of Table 7 are indicative of this fact. As stated earlier, the re-examination, comparison, and confirmation of these results will be required as additional technologies or larger-scale processing efforts are realized.

Multi-cycle Wet/Dry Leaching Results

Typical results for the multi-cycle wet/dry leaching procedure described in the Materials and Methodology section are presented in Figures 4-7. Sunbury Shale (Lewis County) materials are used for the illustrations. Figure 4 depicts the leaching cycle behavior for cadmium in the raw feedstock shale. The relative extract concentrations shown in Figure 4 are seen to be in the order ASTM-A> ASTM-B>EP, as explained previously. It is also apparent that in all three extraction procedures a fairly rapid and predictable removal of cadmium is obtained. The leachate concentrations appear to be reaching a steady-state value by the 3rd-4th leaching cycle. A similar behavior is exhibited by cadmium in the combusted shale leachate (Figure 5) and the shale fines leachate (no figure presented). The rate of cadmium release is somewhat lower in the case of the combusted shale compared to the feedstock shale, however. The general behavior exhibited by the feedstock, fines and combusted shales is indicative of a situtation in which the surface-available material (i.e. the most readily leachable) is rapidly removed with subsequent leaching activity being controlled by intra-particle diffusion of the material from within the bulk of the solid to the surface of the solid. This diffusion process is inherently slow and thus leads to a situation in which very slow release occurs after surface-available material is removed. This behavior pattern has important disposal ramifications, for it may allow prediction of leachate concentration over time (assuming a fairly constant rate of waste disposal and a controlled disposal configuration).

Figure 6 illustrates a slightly modified behavior for cadmium in the retorted shale sample. It is evident that a concentration maximum appears on the second cycle of the experiment, as opposed to the steadily declining leachate concentration behavior exhibited by the feedstock and combusted shales. The behavior for the retorted shale is identical in all three extraction procedures; it is obviously a phenomenon peculiar to the retorted shale. A possible explanation for this behavior may involve a deactivation of surface available leaching sites for cadmium during the retorting process. This would explain the low initial value plotted in Figure 6. This deactivation is then overcome and/or modified in later leaching cycles (or upon combustion), when the leaching behavior more closely resembles that of the other shale samples.

Figure 7 supports the behavior exhibited by cadmium in the retorted shale leachate by presenting an analagous behavior for nickel. The

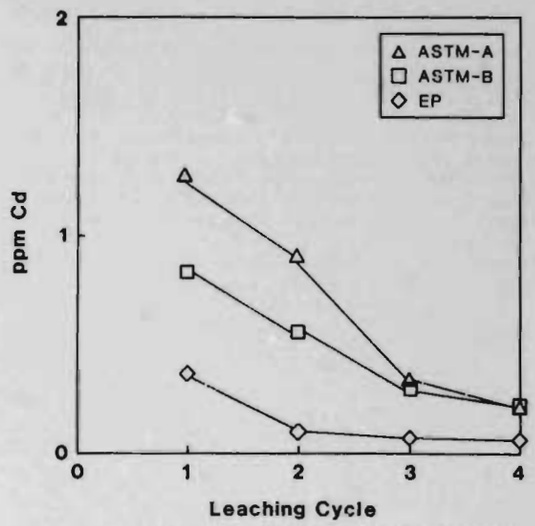

Figure 5. Multi-cycle wet/dry leaching behavior of Cd in combusted shale.

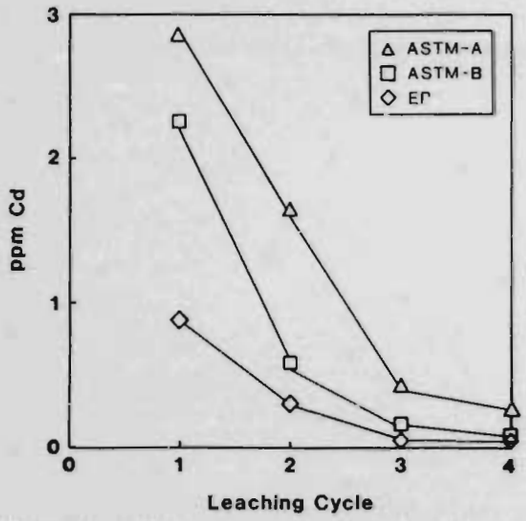

Figure 4. Multi-cycle wet/dry leaching behavior of Cd in Sunbury feedstock shale.

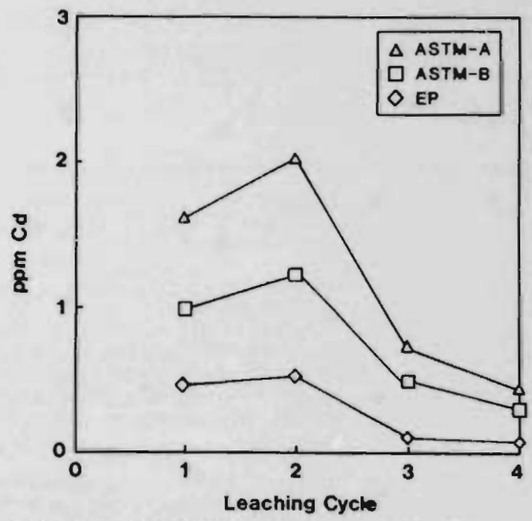

Figure 6. Multi-cycle wet/dry leaching behavior of Cd in Sunbury retorted shale.

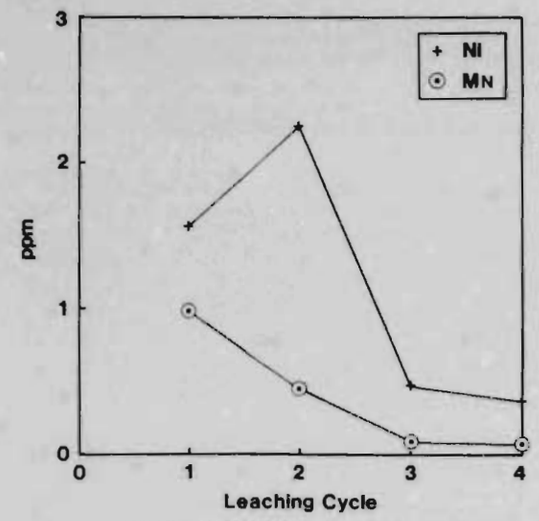

Figure 7. Multi-cycle wet/dry leaching behavior of Ni and Mn in Sunbury retorted shale.

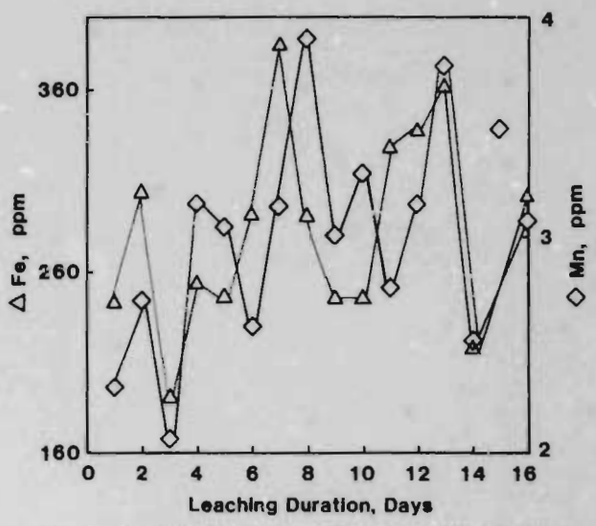

Figure 8. Release behavior of Fe and Mn during 16-day leaching experiment.

data presented for manganese illustrates that this behavior is not universal for all elements, however; the mode of behavior is apparently element dependent as well as process material dependent.

The preceding discussion and the associated figures are exemplary and are by no means all-inclusive. Many other leaching behavior patterns may be operative and additional study of these release patterns are planned.

16-Day Leaching Experiment Results

Figures 8-12 illustrate data acquired from the 16-day leaching experiment. It is immediately apparent from the figures that elemental release is accompanied by attenuation processes such as adsorption, coagulation, or precipitation. These release/attenuation phenomena account for the 'peak and valley' appearance of the plotted data (especially apparent in Figures 8 and 9). The data illustrate that leaching is a reversible process, and that the concentration of a particular contaminant may be dependent on various solution parameters such as pH, eH, ionic strength, and overall solution composition. The presence of particulate matter with its adsorption sites will also have an important effect on leachate concentration.

Data from iron and manganese concentrations over the 16-day leaching period are presented in Figure 8. The data for the two elements show a generally good correlation from day-to-day, indicating that the control mechanisms are similar for both elements. Close inspection of the data in Figure 8 reveals that certain release occurrences (Days 3-7, 9-13) are relatively slower than the subsequent depletion occurrences (Days 7-9, 13-14). It thus appears that the dissolution processes gradually build to a limiting value whereupon rapid attenuation reactions take over. The limiting value is not constant, however, as evidenced by the different peak values displayed in the figures. Release/attenuation phenomena thus appear to result from the complex interplay of various solution chemistry variables. A similar situation is present in the case of iron and sulfate, the data of which are displayed in Figure 9.

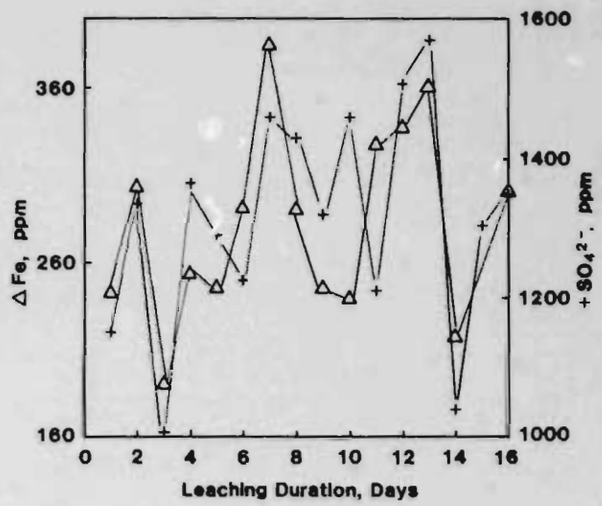

Figure 9. Release behavior of Fe and SO_4^{2-} during the 16-day leaching experiment.

Attempts to correlate the observed release behavior with the solution property of pH were generally unsuccessful. The data illustrated in Figure 10 exhibits one of the stronger pH-release correlations obtained, showing nickel concentration as a function of leachate pH. As the figure indicates, there is a general inverse relationship between nickel concentration and leachate pH. It is also notable that the release/depletion behavior of nickel is not nearly as erratic as shown for iron, manganese, and sulfate in Figures 8 and 9.

Additional data acquired from the 16-day leaching experiment are shown in Figures 11 and 12. These figures illustrate release dynamics for barium and uranium. The various release patterns for the different elements in Figures 8-12 are

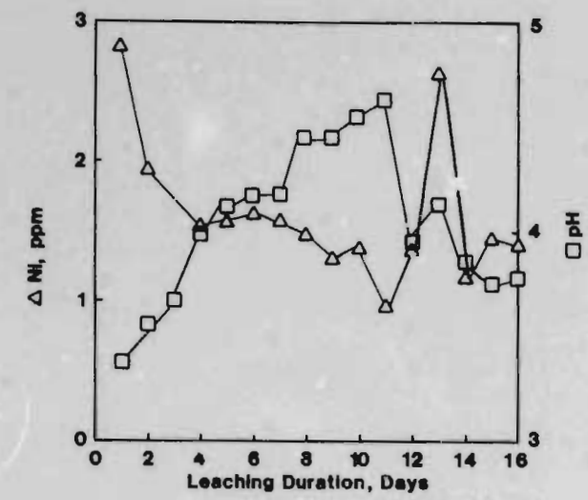

Figure 10. Correlation of Ni release with pH during 16-day leaching experiment.

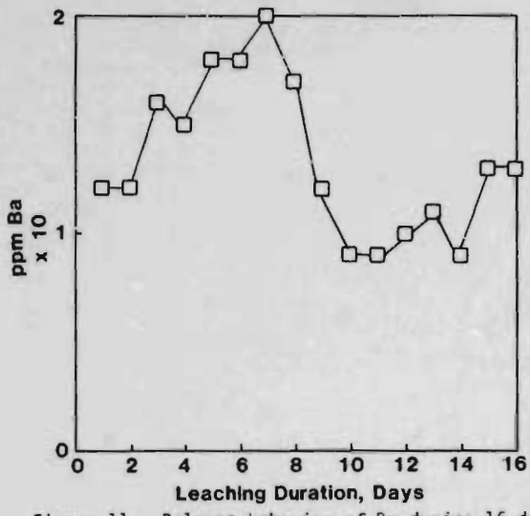

Figure 11. Release behavior of Ba during 16-day leaching experiment.

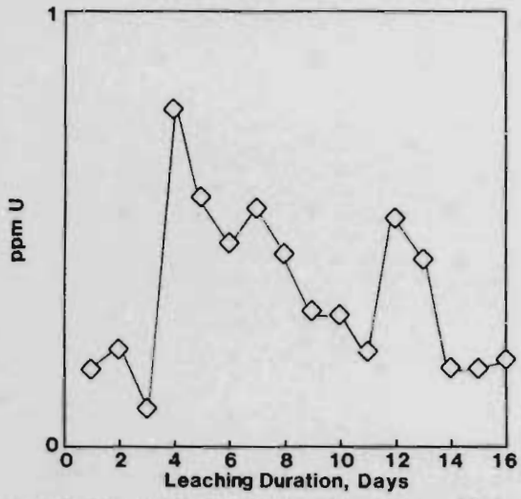

Figure 12. Release behavior of U during 16-day leaching experiment.

apparent and underline the complex chemistry that is operative even during a controlled leaching simulation.

Regulatory Compliance and Environmental Impact Considerations

Hazardous waste guidelines promulgated under the Resource Conservation and Recovery Act included specifications for maximum contaminant levels for eight elements (Ag, As, Ba, Cd, Cr, Hg, Pb and Se) in waste-derived leachates obtained via the EP extraction test. Whether the disposal of oil shale wastes will fall under the auspices of the RCRA regulations is yet to be determined, but for the purposes of this study the RCRA guidelines are assumed to be applicable and compliance with this regulation is discussed.

Data from all leachate solutions generated in this study are displayed according to element in Figures 14-21. These figures illustrate the leachate concentration distribution compared to the RCRA limit for each particular element. Results from all three (ASTM-A, ASTM-B, and EP) extraction procedures are presented in these figures even though the RCRA regulations stipulate the use of the EP procedure. Results are displayed by resource location, and within each location, values are plotted in the following order: raw, retorted, combusted ASTM-A leachates; raw, retorted, combusted ASTM-B leachates; and raw, retorted, combusted EP leachates. See Figure 13 for a legend to Figures 14-21. Values for leachate concentrations below the detection limits of the technique used are signified by a bar/dot and downward arrow. Concentrations are plotted logarithmically on the vertical scale for each element, and it is obvious that in most cases the oil shale leachates are several orders of magnitude lower in concentration than the stipulated limits. Figures 14-21 contain a wealth of information in addition to their comparison of leachate concentrations to the regulatory criteria. Information pertaining to geographic variability, process material release differences, and extraction test effects can be obtained from close inspection of the figures.

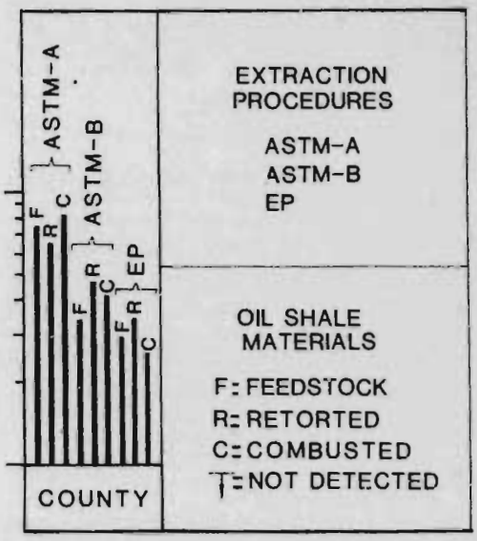

Figure 13. Legend for Figures 14-21.

Figure 14 illustrates the leachate concentration distribution for silver and compares that distribution to the RCRA limit of 5.0ppm. All samples were less than ~0.1 ppm with almost half of them containing less than detectable levels of the element. Somewhat higher levels are present in the Lewis-Cleveland and Powell county sites, but other trends are not distinctive.

Figure 15 shows the distribution obtained for arsenic. Most samples contained less than 5 ppb, the detection limit for the hydride-evolution atomic absorption technique. No samples exhibited concentrations greater than 0.1 ppm, with only a few samples being above 0.05 ppm. When compared with the RCRA limitation of 0.5 ppm, it appears that there will be little trouble in meeting the regulatory criteria.

Barium concentrations, as shown in Figure 16, were generally present at a level of 0.1 ppm, well in compliance with the 100 ppm limit established by RCRA. Detailed inspection of the figure reveals that the retorted and combusted shales exhibit slightly higher concentrations in the leachates than their associated feedstock leachates. This trend is especially apparent in the Lewis County Sunbury samples. Exceptions to this observation are also present, however.

Cadmium concentrations showed the greatest site variability in the leachate samples, with the eastern most counties (Lewis and Powell) exhibiting the highest cadmium concentrations. Concentration values range from ~.002 ppm in Bullitt County to

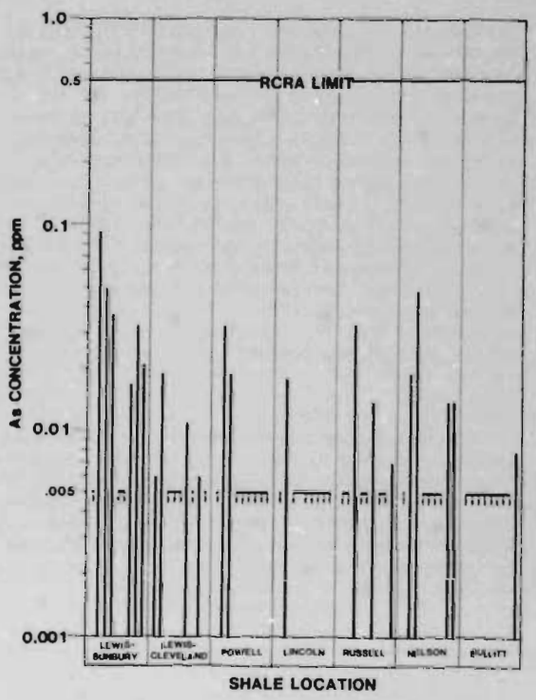

Figure 15. Distribution of As concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

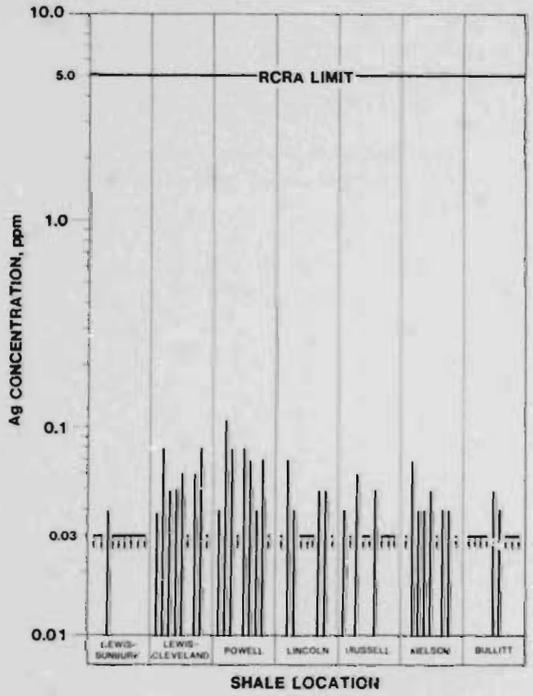

Figure 14. Distribution of Ag concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

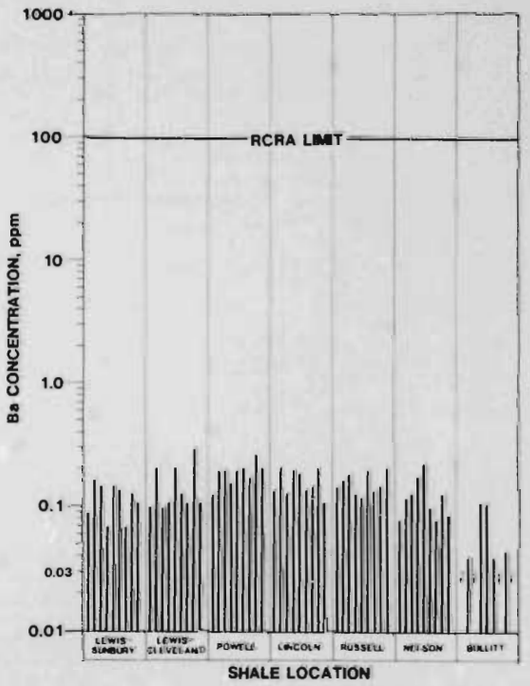

Figure 16. Distribution of Ba concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

1-2 ppm in Lewis County. Figure 17 illustrates the extent of the difference from county to county. Several values in the Lewis County samples actually approach and exceed the RCRA limit of 1.0 ppm. Upon close scrutiny it is seen that all values exceeding the limit are from the ASTM extraction tests and not the EP test upon which the RCRA regulations are based. Analyses of the bulk shale materials from Lewis County revealed cadmium concentrations of 20-30 ppm, substantially higher than the normal crustal abundance of this element. Cadmium is presumed to be associated with zinc in the mineral sphalerite in these samples. The unusually high solubility of this element is nonetheless puzzling. Additional resource work is necessary to establish the extent of this occurrence.

All leachates samples were found to contain less than 0.5 ppm Cr, with many samples containing less than 0.3 ppm. This observation is in agreement with the low solubility of compounds of this element. As the RCRA limit is 5 ppm, little trouble is anticipated in meeting the limit, as indicated in Figure 18.

Finally, Figures 19-21 illustrate the concentration distributions for mercury, lead, and selenium, respectively. Mercury and selenium determinations failed to find any samples with concentrations above the detection limit. Lead was found at upper concentrations of only 0.04 ppm. It thus appears that little hazard can be expected from these elements in shale leachates.

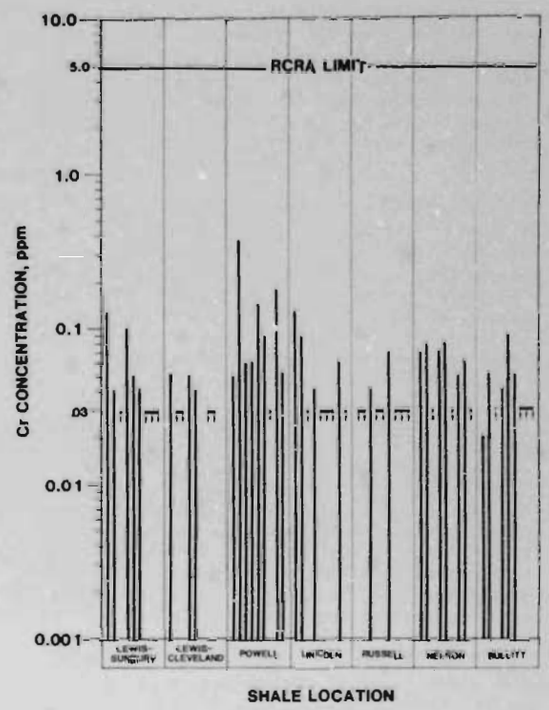

Figure 18: Distribution of Cr concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

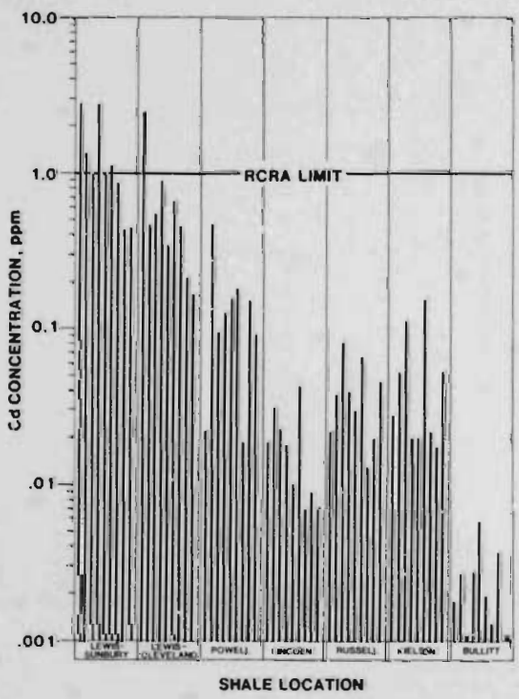

Figure 17: Distribution of Cd concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

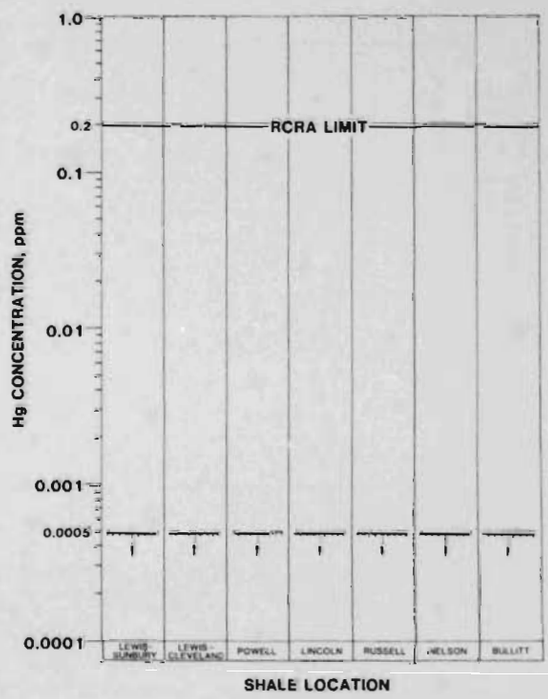

Figure 19: Distribution of Hg concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

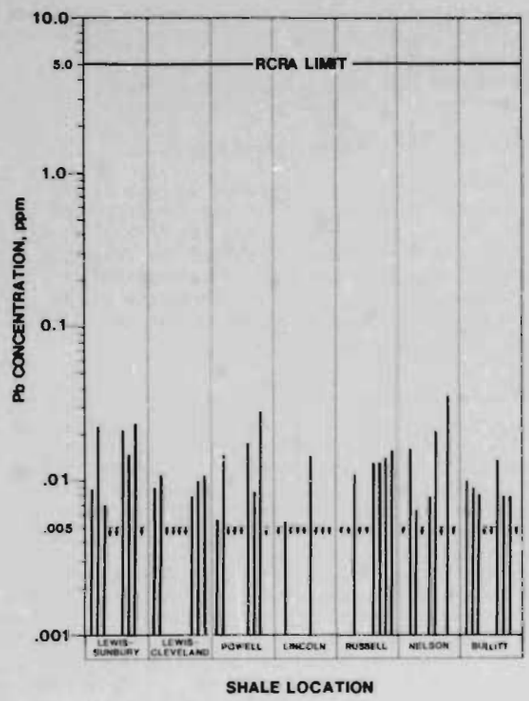

Figure 20: Distribution of Pb concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

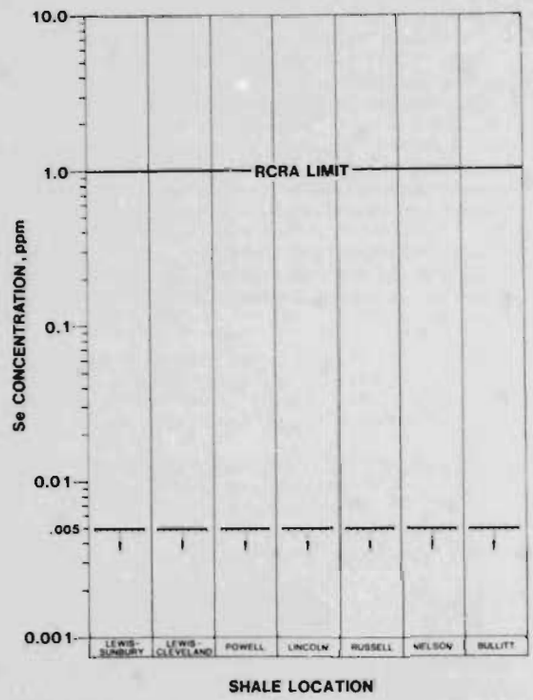

Figure 21: Distribution of Se concentrations in oil shale leachates and comparison with RCRA limit (see Figure 13 for legend).

Table 8 summarizes the data presented and numerically compares the data to the RCRA criteria for the eight stipulated elements. The table gives values for the maximum and average contaminant concentration (MCC and ACC, respectively) encountered in this study. The RCRA limitation and the number of non-compliance incidents are also tabulated. For the purpose of comparison, a 'compliance safety factor' (CSF) is defined as the ratio of the RCRA MCC to the ACC of this work. The safety factors indicate that generally large safety margins exist between the leachate concentrations and the RCRA values. The safety factor is defined so as to take into account any sample or technology related bias, and to allow some degree of freedom in applying the results to actual field conditions. It is apparent, on the basis of these results, that Ag, As, Ba, Cr, Hg, and Pb will present little trouble in meeting the regulatory requirements. The compliance safety factor for cadmium, however, is distrubingly low. The low CSF for cadmium is primarily due to the occurrence of several high concentration samples from the eastern shale sites. All things considered, however, the leachates appear to be relatively innocuous from a toxicological or environmental perspective These results agree with those of a former study concerned with western and eastern Michigan oil shales (10).

TABLE 8. Regulations Compliance Data

Element, ppm	This Work MCC	This Work Ave. CC	RCRA MCC	Non-compliance frequency	Compliance Safety Factor
As	.93	.012	5.0	0/63	420
Ba	.30	.14	100.	0/63	710
Cd	2.85	.32	1.0	7/63	3
Cr	.38	.06	5.0	0/63	83
Pb	.035	.011	5.0	0/63	460
Hg	<.0005	.0005	0.2	0/63	400
Se	<.005	.005	1.0	0/63	200
Ag	.11	.04	5.0	0/63	125

Conclusions

The data and information presented on the leaching characteristics of raw, retorted and combusted eastern shale materials is the first communication, to the authors' knowledge, concerning this important aspect of waste disposal in anticipation of eastern Kentucky oil shale utilization. The study attempted to address several pertinent questions regarding the environmental impact that may accompany the disposal of eastern shale materials, with the emphasis of this initial effort being to provide preliminary predictive information concerning leachate composition and to examine variables that may affect such composition. The data should be viewed accordingly, with proper consideration given to the limitations of the overall experimental plans. All results in this study are based on laboratory simulations of waste disposal conditions, which may only approximate conditions encountered in field disposal environ-

ments. Parameters such as pH, solid : liquid ratio, time, and agitation are recognized and controlled by the laboratory procedures. The extent to which these laboratory parameters represent field conditions depend on many factors including the weather, hydrology, and geochemistry of the disposal site and the disposal strategy employed.

Specific conclusions based on the leaching studies described herein are as follows:

- ASTM extraction procedures result in a more concentrated leachate than the EP extraction procedure. This is most likely due to the higher solid : liquid ratio of the ASTM test. The ASTM-A procedure generally results in a more concentrated leachate than the ASTM-B procedure, due to the lower pH attained in the former procedure.

- Leachate composition may change as a function of resource location. The oil shale resource appears to exhibit sufficient heterogeneity and variability to show site-to-site variations in leachate composition due to geochemical differences in the bedrock material. Specific examples are presented for pH and cadmium disparities.

- Processing of the raw oil shale via retorting or combustion has a beneficial effect in terms of acid-producing potential of the disposed material. This is due to conversion of acid-producing sulfide minerals to less acidic forms in the processed material. Little difference was found in trace element release between the different materials.

- The effect of process technology on leachability characteristics was found to be negligible in the case of trace elements but significant in terms of leachate pH using the processes examined in this study. HYTORT samples produced substantially less acidic leachates than corresponding steam retorted samples.

- Multiple-extraction tests revealed a number of release patterns that were both process material and element dependent. The general release behavior corresponds to a situation in which surface-available material is leached rapidly, with subsequent extractant concentrations reaching a steady-state level due to slow intra-particle diffusion processes.

- Time differentiated leachate concentrations were obtained using a 16-day leaching study. Results indicate a competitive release-attenuation behavior, the characteristics of which were element dependent. Solution chemistry variables undoubtably influence this behavior.

- Results of the various leaching procedures predict a generally diminutive environmental impact based on the low trace element concentrations found. Comparison of leachate trace element concentrations with probable regulatory criteria indicate that compliance can be attained in most situations. The only element which approached a non-compliance situtation was cadmium.

In conclusion, further work will attempt to clarify, confirm, and extend the results of this study to alternative processing technologies, different shale materials, and ultimately to an experimental field disposal environment.

Acknowledgements

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Eastern U.S. (Devonian) Oil Shale Industry Health Effects Studies

by

Harry G. Enoch
Kentucky Department of Energy and the
Graduate Center for Toxicology,
University of Kentucky
Lexington, Kentucky

Joyce Lockard and P.S. Sabharwal
Thomas Hunt Morgan School
of Biological Sciences
University of Kentucky
Lexington, Kentucky

Abstract. We have undertaken a study of the health effects of eastern U.S. (Devonian) oil shale. Much of the health effects research on oil shale elsewhere would be applicable to the industry in Kentucky. Since very few studies of oil shale effects are available, we have begun to examine some of the toxicological properties of raw shale oils. Using samples of eastern and western shale oils, we have measured acute toxicities in mice and genotoxicity in bacteria, mice, and animal cells (mice and human) in culture. The genotoxicity assays included measures of mutagenesis, sister chromatid exchange, sperm abnormalities, and erythrocyte micronuclei. The tests were also carried out on a coal-derived oil and a petroleum crude. In general, the results indicate that the toxic properties measured for shale oils closely resemble those of petroleum crude oil.

Introduction

During the last several years, there has been much interest in the development of the Devonian oil shale resources of the eastern United States. As with any new developing industry questions have arisen concerning the environmental and health effects of oil shale mining and retorting. Most of the potential health problems would be common to those of conventional mining and petroleum refining industries. Thus, one would expect accidental injury and death to be the major health hazards of both the mining and processing areas. In addition, there is the potential for respiratory problems due to exposure to dust and fine particulate matter. In the processing plant, exposure to irritant gases and liquids has the potential for causing skin and respiratory problems. The above are concerns largely for workers and should not be reflected in any significantly increased risks for the general public. One serious potential problem recognized early in this century is that of cancer in oil shale workers.

Cancer Studies in Oil Shale Workers

The earliest interest in the carcinogenicity of oil shale materials was in Scotland. The first Scottish oil shale plant was started in 1859 and before the end of the century it was recognized that certain oil shale fractions caused cancers in humans. This was most apparent in the spinning and weaving industry, where shale-derived oils were used as lubricants. There was a high incidence of skin and scrotum cancers among mulespinners (workers who lubricated the "mules" - spindles). In mulespinners the problem was due to direct, continuous, long-term exposure to the materials through impregnated clothing that was rarely if ever washed. The disease was found to be largely preventable by improved personal hygiene. Although the use of shale oil was associated with increased cancers, no dramatic increase was observed among workers in the Scottish retorting plants. The incidence of skin cancer among 5,000 oil shale workers observed over 20 years was less than 0.1% per year (Table 1). A study of oil shale workers in Estonia did find a significant excess of skin cancer - three-fold in men and five-fold in females. In a recent study carried out by NIOSH, 713 workers from the U.S. Bureau of Mines retort facility at Anvil Points, Colorado were examined and higher than expected mortality rates from respiratory system and digestive organ cancers were observed. The study concluded that it was not possible to attribute the cancers to oil shale exposure per se due to a stronger association between the deaths and exposure to smoking and radioactivity (from uranium mining) among the men studied.

Carcinogenicity of Oil Shale Materials

Animal studies have shown that crude shale oil, shale coke, and shale tar are all carcinogenic. The site of increased risk in almost all cases is skin and this has been associated with the presence of polycyclic aromatic hydrocarbons in these materials. Benzo(a)pyrene has frequently been used as a surrogate measure for this class of compounds. The benzo(a)pyrene concentration is very low in raw oil shale and spent shale (Table 2)

Table 1

Epidemiology Studies of Cancer in Oil Shale Workers

Location	Group	Findings
Scotland	Weavers/spinners	Increased incidence of skin and scrotum cancers.[1]
	Retort workers	5,000 oil shale workers between 1900-29, observed approximately 5 skin cancers per year.[2]
Estonia	Retort workers	A study of 2,003 Estonian oil shale workers between 1959-75 found a significant excess of skin cancer (three-fold for males, five-fold for females).[3]
U.S. (Anvil Points, CO)	Retort workers	Examined 713 oil shale workers (1947-69), found increased incidence of cancers of respiratory organs, which, however, could not be attributed to exposure to oil shale materials.[4]

[1]Leitch (1924), Twort and Ing (1928)

[2]Scott (1922)

[3]Purde and Etlin (1979)

[4]Costello (1980)

and, correspondingly, these materials have not been found to be carcinogenic in lifetime studies in mice (skin) or in hamsters (lung) (Coomes, 1979). Common soils may display higher benzo(a)pyrene concentrations than raw or spent shales. Many foods contain higher benzo(a)pyrene levels than oil shale. These include smoked meats, charcoal-cooked or broiled meats, vegetable oils, and others (Table 2).

However, what is true for oil shale - the rock - does not hold for shale oil - the liquid. In the retorting process, the organic matter in the shale is exposed to high temperatures that result in the formation of appreciable levels of polycyclic aromatic hydrocarbons. For example, a crude Colorado shale oil produced by the Tosco II retort process contained 3,200 ppb benzo(a)pyrene

Table 2

Benzo(a)pyrene Content of Oil Shale and Natural Materials

Material	BaP Content ppb
Raw Oil Shale (Colorado)	14
Spent Shale (Tosco II process)	28
Eastern U.S. Soils	
Forest	1,300
Garden	90
Plowed Field	900
Well-done Steak	up to 50

BaP - benzo(a)pyrene, ppb - parts per billion

SOURCE: Coomes (1978)

(Table 3). This material was also carcinogenic in skin-painting experiments in mice. The benzo(a)-pyrene contents and the carcinogenic potencies of raw shale oils are similar to those of crude petroleum. In addition to polycyclic aromatic hydrocarbons crude shale oils also contain primary aromatic amines, e.g., naphthylamine (Pelroy and Petersen, 1979; Epler et al., 1979), which are known to be human carcinogens. Hydrotreatment, or catalytic hydrogenation, results in decreased levels of benzo(a)pyrene in shale oil and a correspondingly lower carcinogenic potency (Table 3).

Table 3

BaP Content and Skin Carcinogenicity of Shale Oil Products*

Material	BaP Content ppb	No. of Tumors/ No. of mice
Raw Shale Oil (Tosco II)	3,200	39/50
Hydro-Treated Shale Oil		
0.25% N	800	5/50
0.05% N	690	
Libyan Crude Oil	1,320	
Asphalt	10,000-100,000	

BaP - benzo(a)pyrene, ppb - parts per billion

*R.M. Coomes (1978)

Eastern Oil Shale Study

Based on the previous findings on the potential health hazards of oil shale, we have undertaken a

preliminary study on the toxicity of eastern U.S. (Devonian) oil shale. We began by examining the comparative genotoxicity of crude unfractionated eastern shale oil in several bioassay systems. These included bacterial mutagenesis in Salmonella, sister chromatid exchange in vitro in human lymphocytes and in vivo in mouse bone marrow, production of abnormal sperm in mice, and the formation of micronuclei in mouse blood cells. The comparative samples included a western U.S. shale oil, a coal-derived oil, and a crude petroleum, as well as control chemicals of known activity.

One can reasonably ask: if cancer is the concern, why didn't we measure carcinogenesis? There are several reasons. First, cancer tests are very costly (up to $300-500,000 per chemical) and time-consuming (up to 5 years to complete). Such tests are obviously not well adapted for testing large numbers of samples. Furthermore, there are other endpoints of concern for synthetic liquid fuels. In addition to carcinogenesis, these materials can also be mutagenic (capable of inducing inheritable changes in DNA) and teratogenic (capable of causing abnormal development). All of these can be the result of damage to the genetic material: chromosomes or DNA, and together may be classified as genetic hazards or genotoxicity.

A large number of bioassays have been developed to measure DNA damage. These tests are rapid (many require only 3-7 days) and inexpensive (may cost less than $1,000 per sample). Several of these tests have the added advantage of showing a high degree of correlation with carcinogenicity. For example, approximately 90% of the chemical carcinogens tested in the Salmonella assay (Ames test) were mutagens (McCann et al., 1975).

Test Materials and Methods

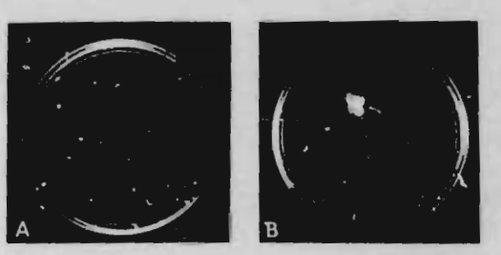
The eastern U.S. (Devonian) shale oil sample was provided by the Institute for Mining and Mineral Research, University of Kentucky. The raw shale oil was obtained from a sample of Sunbury shale, Lewis County, Kentucky. The oil was prepared using a small retort owned by Pyramid Minerals and described by D. Koppenaal et al. (elsewhere in this volume).

A group of Comparative Research Materials (CRM) was obtained from the Fossil Fuels Research Material Repository at Oak Ridge National Laboratory. These included a coal-derived oil (CRM-1), a crude western U.S. shale oil (CRM-2), and a petroleum crude oil (CRM-3). The purpose of our preliminary study was to determine the direction of our future research in this area. In drawing conclusions from this work it must be kept in mind that none of the synthetic liquid fuels tested are actually representative of any commercial products.

The bioassay methods are described in detail elsewhere (Lockard et al., 1981).

Ames Test Results

The Ames test derives its name from Dr. Bruce Ames, who developed the mutant strain of Salmonella typhimurium used in the assay. The mutant strain of this bacteria will not grow unless the amino acid, histidine, is supplied in the growth medium. The wild type Salmonella makes its own histidine. About 100 million bacteria are spread on an agar plate which is then incubated for several days. Very few colonies grow on the plates unless a chemical mutagen is added (Figure 1, A and B). These chemicals cause mutations back to the wild type, or revertants, which can grow in the absence of histidine. Some mutagens, called promutagens, require alteration before they are active. These are detected in the Ames assay by the addition of a metabolic activating system from liver. Benzo(a)-pyrene is an example of a promutagen.



AMES TEST

AGAR PLATES WITH SALMONELLA COLONIES: (A) UNTREATED CONTROL, (B) TREATED WITH MUTAGEN

SISTER CHROMATID EXCHANGE

CHINESE HAMSTER OVARY CELLS TREATED WITH (C) SOLVENT CONTROL, (D) CHEMICAL MUTAGEN

FIGURE 1

The results of the mutagenicity studies are shown in Table 4. All samples were tested in two strains of Salmonella: TA98 which detects frame-shift mutagens and TA100 which detects base substitution mutagens. The synthetic liquids, in contrast to crude petroleum, were most active in TA98 and required the metabolic activating system for maximal activity. The eastern U.S. shale oil sample had very weak activity and was significantly lower than western U.S. shale oil. Several different eastern shale oil samples were tested and had similar activities (not shown). The eastern versus western difference could be a result of their different chemical characteristics, however, a number of samples of each (prepared in a similar fashion) must be tested before any quantitative conclusions may be drawn. The eastern shale oil has a mutagenic potency that more resembles that of the crude petroleum than that of the coal-derived oil. The eastern shale oil actually has less activity than the crude petroleum in TA100. Our results with the comparative liquid fuels agree very well with the values obtained by others (Table 5). This table also shows the literature values obtained with other materials in mutagenicity studies. Included for comparison are

two chemical carcinogens, benzo(a)pyrene and 2-aminoanthracene. The eastern shale oil mutagenic potency differs from 2-aminoanthracene by nearly 5 orders of magnitude, and it is about 360,000-fold less than the natural fungal toxin, aflatoxin B1.

Table 4

Mutagenicity Data (Revertants/mg) for Natural and Synthetic Fuels in Ames Salmonella Assay*

Sample	TA98 +S9	TA98 -S9	TA100 +S9	TA100 -S9
Eastern Shale Oil	64	14	26	28
Western Shale Oil	212	50	111	37
Coal-Derived Oil	2,730	160	918	343
Petroleum Crude Oil	38	29	93	91

*Results are the average of 3 plates each for strains TA98 and TA100 in the presence and absence of the rat liver microsomal activating mixture (S9). The results have been corrected for the spontaneous (solvent control) reversion rates - these were (revertants/plate): 32 and 41 for TA98 plus and minus S9; 95 and 113 for TA100 plus and minus S9.

Table 5

Comparison of Mutagenicity of Various Substances in the Ames Salmonella Assay

Sample	Revertants/mg in TA98 This Study	Literature
Eastern Shale Oil	64	--
Western Shale Oil	212	178-650[1,3]
Coal-Derived Oil	2,730	1,000-27,000[1-3]
Petroleum Crude Oil	38	0-241[1]
Used Crankcase Oil	--	650[4]
Benzo(a)pyrene	--	114,000[3]
2-Aminoanthracene	--	5,430,000[3]
Aflatoxin B1	--	23,000,000[5]
Cigarette Smoke Condensate	--	18,200 rev/cigarette[5]

[1]Guerin et al. (1981)

[2]Kimball and Munro (1981)

[3]Mahlam (1981)

[4]Hermann et al. (1980)

[5]McCann et al. (1975)

Sister Chromatid Exchange Results

The sister chromatid exchange assay is based on a technique that allows differential staining of the two sister chromatids, one light and one dark, as shown in Figure 1C. Exchanges between the two chromatids are visible and may be quantified. Certain chemicals greatly increase the numbers of exchanges as seen in Figure 1D. This is a very sensitive assay for the detection of DNA damage. It has the advantage of using animal cells, which may be more relevant for human toxicity than bacteria.

Our results in three different sister chromatid exchange systems were disappointing: none of the liquid fuels tested showed any sister chromatid exchange activity. This suggests that these sister chromatid exchange assays are less sensitive in detecting DNA damage than the Salmonella Ames assay. Similar results were observed in all three sister chromatid exchange systems (Table 6). In the first system, human lymphocytes were grown in culture and exposed to the test materials in the growth media. Only the control chemical, benzo(a)pyrene showed any sister chromatid exchange activity. The second system was the same as the first except that a metabolic activating system, S9, was added. This assay had a much higher sensitivity for benzo(a)pyrene, but there was no sister chromatid exchange activity for the liquid fuels. Similar results were observed in the third system, in which mice were injected intraperitoneally with test material and after 24 hours the bone marrow cells were examined for sister chromatid exchanges.

Table 6

Sister Chromatid Exchange Results for Natural and Synthetic Fuels in Various Test Systems

Sample	Human Lymphocytes *in vitro* with no Activation	Human Lymphocytes *in vitro* with Activation*	Mouse Bone Marrow *in vivo*
Eastern Shale Oil	-	-	-
Western Shale Oil	-	-	-
Coal-Derived Oil	-	-	-
Petroleum Crude Oil	-	-	-
Benzo(a)pyrene	+	+	+

*Using Rat Liver Microsomal Preparation (S9)

Results in Other Test Systems

Each of the synthetic fuels and the petroleum crude were also tested for the induction of micronuclei and abnormal sperm in mice. In both tests the materials were injected i.p. and after the animals were sacrificed abnormal sperm and micro-

nuclei in erythrocytes were examined microscopically. In both cases, small dose-dependent increases were observed, however, the increases were not statistically higher than background control levels. A summary of these and other results are shown in Table 7 along with a comparison of the results obtained by others. Two of our systems are common with those previously tested: the results in Salmonella are in agreement; in the sister chromatid exchange system, no common samples were tested, but the basic fraction of synthetic crude oils was active. None of the unfractionated materials we tested had any sister chromatid exchange activity. This may suggest that sensitivity may be improved by fractionating and concentrating these materials. Masking of the activity in crude mixtures is also possible. The sensitivity of these assays should be tested after fractionation of the complex mixtures.

We also tested the acute toxicity of the fuel samples in male mice after single and multiple intraperitoneal injections (Table 8). Except for crude petroleum, only insignificant differences were observed between single and multiple injections. Coal-derived oil was the most toxic; the toxicity of the shale oil samples was similar to that of crude petroleum.

Table 8

Acute Toxicity of Fuel Samples in Mice

Sample	Approximate LD_{50} Dose (g/kg of body weight)	
	1 injection, i.p., 24 hrs	5 injections, i.p., 5 days
Eastern Shale Oil	3.9	5.3
Western Shale Oil	4.1	2.6
Coal-Derived Oil	1.6	1.0
Petroleum Crude Oil	9.0	2.6

i.p. - intraperitoneal

Table 7

Mutagenesis of Synthetic Fuels in Various Test Systems*

Test System	Literature**			This Study		
	Basic Fraction	Neutral Fraction	Crude Synfuel	Eastern Shale Oil	Other Fuels	BaP
Mutations						
Salmonella	+	+	+	+	+	+
E. coli	+	+	NT			
Yeast	+	+	NT			
Drosophila	+	-	NT			
Sister Chromatid Exchanges						
Human Leukocytes	+	+?	NT	-	-	+
Mouse Bone Marrow				-	-	+
Abnormal Sperm						
Mouse sperm				+?	+?	+
Micronuclei						
Mouse Erythrocytes				+?	+?	+
Chromatid Aberrations						
Human Leukocytes	T	+?	NT			
Thioguanine Resistance						
Hamster Ovary	+	NT	NT			

*NT(not tested), +(mutagenic), +?(possibly positive), -(not mutagenic), T(toxic), BaP(benzo(a)pyrene).

**Kimball and Munro (1981), Table 5.18.

Conclusions

For complex materials it appears that the Ames test is more sensitive than the sister chromatid exchange, the sperm abnormality, or the erythrocyte micronuclei assays. Our studies indicate that the level of mutagenic activity of eastern U.S. shale oil more closely resembles that of crude petroleum than that of coal-derived oil. This finding is in agreement with earlier findings on benzo(a)pyrene levels and carcinogenicity in these materials.

Although the single sample of eastern shale oil had less mutagenic activity than the western shale oil sample, little significance can be placed in the result. The same degree of variation might be found in different eastern shales. Multiple samples, eastern and western, need to be prepared by the same process (retort) and tested. It would also be desirable to test shale oils produced by various retort processes from a single oil shale sample. These might include, for example, a Fischer assay oil, a hydrotreated oil, and an oil prepared by the HYTORT process. In the HYTORT process the shale is subjected to a high-pressure hydrogen atmosphere during retorting. The studies on HYTORT could be particularly pertinent in view of what is known regarding the reduction of polycyclic aromatic hydrocarbon concentrations and carcinogenicity via catalytic hydrogenation reactions.

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Synthetic Fuels from Eastern Oil Shale

by

Dr. Kirit C. Vyas
Davy McKee Corporation
Cleveland, Ohio 44131

Mr. Gary D. Aho
The Cleveland-Cliffs Iron Company
Rifle, Colorado 81650

Dr. Thomas L. Robl
Institute for Mining & Minerals Research
University of Kentucky
Lexington, Kentucky 40512

Introduction

This is a summary of a Final Report (Project NC-5477, Federal Grant No. DE-FG-4480R410185) prepared for the Kentucky Buffalo Trace Area Development District, Maysville, Kentucky, in January 1981.

The main objectives of this study were to make a resource assessment, a mining study, and a process economic evaluation of oil shale in Lewis and Fleming Counties, Kentucky. Two surface retorting processes, Paraho and HYTORT, were selected, and the process and economic analyses were made for a 30,000 tons/day oil shale retorting facility. The results of this investigation are presented in this report.

Background

Oil shale exists in the western as well as the eastern states of the U. S. The shales in the west have higher oil yields per ton (20-30 gal/ton) than in the east (10-20 gal/ton). The organic carbon content of both the shales is similar, but the western shales contain more hydrogen. Because of the higher hydrogen content, on an average the western shales' Fischer Assay oil yields are higher than the eastern shales'. However, it is important to recognize that the overall energy content of both the shales is similar but in the case of eastern shales, higher amounts of by-products such as gas, coke, and steam/electricity are produced when compared with western shales.

The recent rapid OPEC oil price increases have raised the value of oil to a level where the production of shale oil from eastern shale is beginning to receive commercial attention. Comparatively larger amounts of by-products produced while retorting eastern shales may not be a big disadvantage, as eastern oil shale deposits are much closer to markets than western oil shale deposits. Factors that have encouraged interest in eastern oil shale include the vastness of the resource and its closeness to markets and supporting infrastructure. Also, the availability of mining, operating and construction labor, abundant water resources, and the shales' location in an industrial area, add significantly to the commercial feasibility of developing this resource. In addition, the eastern shales that cropout in Kentucky, Ohio, and Tennessee are located on privately held land and can be mined economically. The socioeconomic impact of an oil shale project is far less on the eastern United States than the western United States.

The U. S. Geological Survey has estimated the total "known resources" of Devonian eastern oil shale at 400 billion barrels, and the "probable extensions of known resources" at an additional 2600 billion barrels, including both deep and surface deposits. These estimates are based on Fischer Assay test results.

Resource Assessment

The resource assessment work included core drilling, geological mapping, sample analysis, shale characterization, reserve estimating, and mine site selection.

The ten cores were drilled along the oil shale outcrop, and 7 1/2-minute geologic quadrangle maps and field notes were used to determine the quality and quantity of oil shale in Lewis and Fleming Counties, Kentucky. The pertinent geologic strata consist of (from top to bottom) the Borden Formation (series of siltstones and shales), the Sunbury Shale (oil-bearing black shale), the Berea Sandstone (shaly siltstone), the Bedford Shale (silty shale), the Ohio Shale (oil-bearing black shale), the Bisher Limestone (dolomite), and the Crab Orchard Shale.

The Ohio Shale is divided into (top to bottom) the Cleveland Member (50-65 feet thick), the Three Lick Bed (12-20 feet thick), and the Huron Member (135-208 feet thick). The Ohio ranges from approximately 200-300 feet in thickness in the study area, thinning from north to south and from east to west. The Sunbury ranges from 15 to 20 feet in thickness throughout most of the area. These two oil shales are separated by the Berea Sandstone and Bedford Shale, which combined are approximately 100-120 feet thick in northern Lewis County, decreasing southward to 30-35 feet in Fleming County.

Chemical determinations of the shales and associated strata include C, H, N, S, major element oxide, and trace elements. Carbon concentration in the oil shales averages 11.42, 9.04, and 5.61% in the Sunbury, Cleveland, and Huron intervals, respectively. The concentration

decreases from top to bottom in the Cleveland and increases from top to bottom in the Huron. The carbon data define two economic zones in the oil shales. These are the entire Sunbury Shale and a high grade zone (HGZ) in the Cleveland, which extends from the top of the unit to a point where the carbon drops below 8%. The Cleveland HGZ is 30 feet in thickness and averages 11.11% C. Hydrogen averages 1.2% in both the Sunbury and Cleveland HGZ and increases by about 15% in the Sunbury from north to south. Fischer Assay values for the Sunbury and Cleveland HGZ average 10.3 and 11.9, respectively, for all the cores and range from 9.2 to 11.6 gal/ton and 10.8 to 13.0 gal/ton, respectively. Oil yield increases in a north to south direction in the study area. Sulfur averages 3.54% and 2.57% in the Sunbury and Cleveland HGZ, respectively, and is principally pyritic in nature.

The shales are siliceous (approximately 66% SiO_2, 16% Al_2O_3), low in calcium (1.0%), and high in potassium (4.3%), which indicates a significant quartz content, a low carbonate mineral content, and a clay content that is probably illitic in nature. The chemistry of the shales is highly consistent among the cores, with coefficients of variation only slightly greater than analytic variability for many elements.

Several trace elements occur in interesting, but probably sub-economic concentrations. These are (with average values for the Sunbury and Cleveland HGZ) Cu (108, 106 ppm), Cr (218, 213 ppm), Mo (365, 124 ppm), Ni (282, 146 ppm), V (1533, 1024 ppm), U (37, 20 ppm), and Zn (1126, 622 ppm). Sulfur and trace element concentrations are low in potential overburden materials, indicating that they probably would not be a source of pollution during mining.

Rock mechanics tests indicate the oil shales to have compressive strengths in the 10,000 to 13,000 psi range. Ash fusion testing indicates the shales to be refractory with a temperature of 1240°C (2260°F) recorded for the initial ash deformation. Bulk densities of the economic oil shale intervals average 2.28 g/cm^3 (142 lb/ft^3). Total volatile hydrocarbon yields from the shales range from 30-530 cm^3/kg (1-17 ft^3/ton) indicating that gassy mine conditions may be encountered in underground shale mines.

Shale reserves, for the economic shale intervals of the study (i.e., Sunbury and Cleveland HGZ) were calculated by overburden category on a 7 1/2-minute quadrangle map basis for those quadrangles where the shale could be recovered by surface mining. A total reserve of 5.2 million acre-feet or 16.4 billion tons of shale, conservatively representing 4.4 billion barrels of oil, were found. Of this, 6.7 billion tons, representing 1.3 billion barrels of oil, are in a configuration with less than a stripping ratio of 2.5:1 overall. Most of the shale in the latter category lies in eastern Fleming and southwestern Lewis Counties.

Mining

The mining study can be categorized into major categories: 1) evaluate the technical and economic aspects of recovering both the Sunbury and Ohio Shale, and 2) determine capital, operating, and maintenance costs (±25%).

This study is based on ridge-top strip mining with an overall stripping ratio of 2:1. The detail mining study was made to supply 30,000 tons/day of primary crushed (-12") oil shale to a surface retorting facility. However, the Paraho and HYTORT require 33,600 tons/day and 37,500 tons/day of shale, respectively. Therefore, the cost of mining in the case of Paraho and HYTORT was obtained by increasing the cost of 30,000 tons/day by 12% and 25%, respectively. Costs cover all mining functions based on ridge-top strip mining, primary crushing and conveying to the retort, processed shale disposal, and land reclamation. The proposed mine and retort are located in Fleming County in northeast Kentucky, approximately one mile north-northeast of Plummers Landing.

For the selected site, the Sunbury and Ohio shales give oil yields of about 12 to 14 gallons per ton. Mining will take place in two separate locations, initially at Pea Ridge and later at North Ridge. Based on an 80% recovery factor, each reserve area will yield an estimated total of 137,000,000 tons of ore over a 10-year life, providing for a 20-year total life-of-mine. Stripping ratios are calculated at 1.5 for the Pea Ridge reserve and 1.9 for the North Ridge reserve.

A three-year period is required (for design engineering and construction) prior to start of production mining at Pea Ridge. For a 30,000 tons per day mine, preproduction development costs are estimated at $5,872,000 and preproduction capital costs at $65,104,000.

Except for the service building and the crude ore transfer station at the retort, new facilities will be constructed for the North Ridge area, commencing in year +8. Production mining at North Ridge will start in year +11. Preproduction development costs are estimated at $7,440,000 and preproduction capital at $36,052,000 for a 30,000 tons per day mine facility.

Operating costs for both reserve areas are estimated to be $0.88 per ton for shale and stripping. Based on shale only, estimated operating costs are $2.19 per ton at Pea Ridge and $2.54 at North Ridge. These costs do not include any capital associated cost.

Mining operations will employ conventional equipment, i.e., diesel-powered drill rigs, electric and diesel-powered hydraulic shovels, and 85-ton end-dump haulage trucks feeding a toothed single-roll primary crusher. Crusher feed will be scalped -48", +12" material. Crusher product will be conveyed to the retort facility. Processed shale will be conveyed from the retort to the primary crusher area for either direct loading into ore trucks, or stockpiled for transport to a disposal site near the mining face. Haulage road maintenance will require a portable crushing plant, scrapers for distributing road material, and road graders. Scrapers will also be used for topsoil stripping as well as topsoil spreading for land reclamation. A service building will provide office, warehouse, and changeroom facilities for 72 salaried and 345 hourly personnel along with maintenance and repair shops.

Process-Economic Evaluation

The main objective of this section was to select two suitable processes for retorting eastern oil shale for detail process analysis to develop ±25% capital cost. Based on the preliminary process evaluation, Paraho and HYTORT processes were selected for detailed process and economic analysis. Paraho is a low pressure process and produces shale oil about 90-95% of Fischer Assay yield. The HYTORT process oil shale is retorted at a high pressure in the presence of hydrogen and produces more shale oil than Fischer Assay yield. In the retort, about 46% of the organic carbon in the shale was converted to shale oil and this oil yield came out to be about 116% of Fischer Assay yield. Also it is important to note that the oil yield in the HYTORT process is directly related with the organic carbon content of shale rather than Fischer Assay yield. In comparison with the HYTORT process, Paraho has a simple process configuration.

Paraho

The Paraho retort was developed by Paraho Development Corporation by modifying vertical kiln technology. Paraho has developed direct heated and indirect heated mode retorts for western shale and the combination heated retort (CH retort for eastern oil shale.

The Paraho retort is a refractory-lined, vertical kiln, in which a moving bed of crushed oil shale flowing downward through a kiln is contacted countercurrently with an upward flow of hot gases having an adequate heat content to heat shale to about 1000°F to retort the organic constituents in the shale. Temperatures near the top of the retort are controlled so that the oil vapor is condensed in the gas stream as an entrained oil mist and oil is recovered in the oil recovery system. The retorted eastern oil shale, high in carbon content, is passed through a dynamic seal and goes to the combustor where the leftover carbon is burned, the shale cooled and discharged by grate at the bottom of the retort. The hot flue gas generated in the combustor is used in heating the recycle gas for retorting and then it is passed through a boiler to generate a high pressure steam for in-plant use and power generation.

This grass roots plant is designed for a 30,000 tons/day retorting capacity. In addition to raw shale, the plant requires about 2000 gpm of makeup water, 1066 tons/day of crushed limestone, and 428,600 scfm of air. This plant produces about 8132 bbl/day shale oil, 2282 bbl/day light oil, 14,473 scfm of high Btu gas, and about 48.3 mw of excess power. About 44.2% of the input energy is recovered as liquid products, 14.8% as high Btu gas, and 8% as excess power. This plant requires about 65 acres or 2300' x 1200' land area.

HYTORT

The HYTORT retort was developed by the Institute of Gas Technology (IGT). The HYTORT process concept is based on direct, noncatalytic hydrogenation of kerogen at high pressure and controlled heat-up rates.

The HYTORT retort is a refractory-lined, high pressure, vertical vessel in which a moving oil shale flowing downward through the retort is contacted countercurrently with an upward flow of hot gases. As this retort is operated at about 550 psia, high pressure raw shale feeding and spent shale removal systems are required. The shale is progressively heated to retorting temperatures of 1200°, and the heat required for retorting is supplied by combusting part of the hydrogen stream with oxygen and raising its temperature to 1450°. The retorted shale is cooled using the hydrogen-rich stream in the bottom section of the retort. The cooled spent shale is removed from the retort through lock hoppers. The retort top gases contain oil mist, and vapors are recovered in the oil recovery system.

This grass roots plant is designed for a 30,000 tons/day retorting capacity. In addition to raw shale, the plant requires about 4100 gpm of makeup water, 565 tons/day oxygen, 45.3 mw electric power, and 269,700 scfm of air. The plant produces about 10,217 bbl/day of shale oil and 104 tons/day of anhydrous ammonia. About 44.9% of the input energy is recovered as liquid product. This plant requires about 65 acres or 2300' x 1200' land area.

Economic Analysis

Based on the detailed process analysis ±25% capital cost was developed for these projects. The initial plant investment costs for the Paraho and HYTORT are $504 million and $695 million, respectively. These costs are for the grass roots plant and include mining, material handling, retorting, oil recovery, facilities to meet environmental standards, and all the necessary off-sites. Total initial capital required for the Paraho and HYTORT projects is $647.2 million and $890.3 million, respectively (Table 1).

The gross annual operating costs for the Paraho and HYTORT processes are $63.1 million and $86.1 million, respectively (Table 1). The consumable costs include the costs of catalyst for chemicals, water, electricity, and operating and maintenance supplies. The labor and overhead costs include the costs of operating and maintenance, labor, payroll burden, general and administration. The net annual operating costs are $10.6 million and $74.1 million, respectively, for the Paraho and HYTORT projects.

Cash flow analysis was made several different ways, and some of the results are presented in Table 2. At 100% equity, the Paraho project provides a return of about 12% at $40/bbl shale oil price and provides about 14% return at $50/bbl shale oil price. The HYTORT project, at 100% equity, provides about 12% return at $60/bbl shale oil price and provides about 14% return at $70/bbl shale oil price. For the Paraho project further cash flow analysis was made assuming 75% debt at 12% interest and 25% equity. The return on equity at $40/bbl shale oil price is about 24% on a pass-through basis.

Conclusions

The following conclusions can be drawn from this study:

- About 4.4 billion barrels of oil can be recovered from oil shale of Lewis and Fleming Counties, Kentucky. The shale reserves having an overall stripping ratio of less than 2.5:1, represent about 1.3 billion barrels of oil.

- A 30,000 tons per day retorting plant can produce about 10,000 bbl/day of shale oil.

- Total capital required for the grass roots Paraho plant facility, having a capacity to retort 30,000 tons per day of eastern oil shale, will be about $647 million and the HYTORT plant having the same capacity will require about $890 million. The initial plant investment costs for Paraho and HYTORT are $504 million and $695 million, respectively.

- For the same return on equity, the Paraho process is cheaper than the HYTORT process by about $20/bbl.

- For Paraho process, for a 75% debt @ 12% and 25% equity cash flow analysis, the return on equity at $40/bbl shale oil price is about 24%.

- Based on these results, it can be con-

Table 1. Capital and Operating Costs
30,000 Tons/Day Eastern Oil Shale Plant
(4th Quarter 1980 Dollars)

A. Capital Cost ($MM)

	Paraho		HYTORT	
	Initial	Deferred*	Initial	Deferred*
Total Direct Cost	382.5		539.7	
Professional Services, Field Indirects, Insurance, etc.	122.0		155.3	
Plant Investment Cost	504.5	-----	695.0	-----
Working Capital	17.4		21.8	
Interest During Construction	125.8+		173.5+	
Start-up Cost	Expensed++		Expensed++	
Total Capital	647.7	126.1	890.3	140.8

B. Operating Cost ($1000)

Consumables	23,614	39,525
Labor & Overhead	23,556	24,571
Taxes & Insurance	15,908	21,955
Total Gross Operating Cost	63,078	86,051
By-Product Credit	(52,499)	(11,946)
Net Operating Cost	10,579	74,105

* Additional investment from year 2 to 20
\+ On the 75% of the initial plant investment @ 12% interest
++ Expensed at 50% of the first year's revenue

Table 2. Economic Analysis
30,000 Tons/Day Eastern Oil Shale Plant

	Paraho		HYTORT	
	Stand-Alone Venture	Pass-Through Venture	Stand-Alone Venture	Pass-Through Venture
A. 100% Equity				
Selling Price - $/bbl	Internal Rate of Return %			
40	11.4	12.1	5.7	5.9
50	13.7	14.4	8.8	9.1
B. 75% Debt @ 12%/25 @ Equity				
Selling Price - $/bbl	Return on Equity			
40	10.4	24.1		
50	18.2	30.8		
C. 100% Equity				
Return on Equity %	Selling Price - $/bbl			
12	42.50	39.70	61.90	58.00
14	51.80	48.20	72.00	68.40

cluded that the production of shale oil from eastern oil shale is commercially feasible.

It is important to note that the main objectives of this study were to make a preliminary resource assessment and to develop +25% capital costs for mining and retorting facilities. To firm up this conclusion, it is essential to make a detailed resource assessment and a detailed process analysis to develop ±15% capital cost. Also a detailed environmental assessment should be made in the next phase.

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