Energy Science, Engineering and Technology Series

Ike S. Bussell
Editor

Oil Shale Developments

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Ike S. Bussell (Editor)
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PREFACE

This book looks at developments in oil shale which is the largest untapped domestic resource with the greatest potential to decrease our dependence on foreign oil. Over 70% of the world's oil shale resources occur in the United States. These deposits contain over 1.5 trillion barrels of shale oil. If only 800 billion of this can be recovered, that alone would supply all of our current domestic petroleum needs for the next 100 years or more. The 2005 Energy Security Act demonstrated that the US government might finally encourage the development of these valuable oil shale resources. The nation's production of crude oil has been declining since the 1970s while its demand has continued to increase, making the country increasingly dependent on imported oil. However, there are lingering questions about our ability to produce shale oil in this country. Most of these questions discussed in this book, center on key issues such as: (1) is the technology available and will it work on a large scale?; (2) can shale oil be produced profitably?; (3) can shale oil be produced in an environmentally responsible manner?; and (4) what are the socio-economic impacts going to be on the local regions where these developments occur? Oil shale requires an expensive, high-risk, long-lead-time development program and the federal government controls most of the resource. They will therefore ultimately determine whether or not shale oil is ever produced at a level sufficient to improve our economic and national security.

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Chapter 1

STATEMENT OF C. STEPHEN ALLRED, LAND AND MINERALS MANAGEMENT, U.S. DEPARTMENT OF THE INTERIOR, OVERSIGHT HEARING: OIL SHALE, SENATE ENERGY AND NATURAL RESOURCES COMMITTEE,MAY 15, 2008

Mr. Chairman and members of the Committee, thank you for the opportunity to participate in this oversight hearing to discuss the development of oil shale resources on federal lands.

I understand the key leadership role this Committee played in the development of Section 369 of the Energy Policy Act of 2005 (EPAct), directing the Department of the Interior to ready itself to meet future requests for the commercial development of oil shale on Federal lands.

This hearing comes at a particularly challenging time as oil prices are reaching record levels, and energy prices are affecting the Nation and our citizens in a number of profound ways. As energy demand continues to rise, we must focus on the need to provide for future energy supplies. The U.S. will continue to be dependent on oil for the foreseeable future, and oil shale is a domestic source that, if developed, can help to meet this demand. Total U.S. energy use will increase 19 percent and demand in China and India will double. Over the next 25 years, domestic production of all energy resources, oil, gas, coal and renewable energy, will be important to our economy. That is why this hearing is so important today.

Oil shale holds much potential for helping to address this challenge. It is imperative that the Federal Government act now to meet our future energy needs. New sources of energy take a great amount of time and private capital to develop and bring on line. With the legislative provisions concerning oil shale in EPAct 2005 Section 369(d)(2) establishing final regulations for commercial oil shale leasing, we can provide the framework for the development of an environmentally sound and economically viable oil shale industry to help meet our future energy needs. Accordingly, I would urge Congress to repeal the current prohibition on the finalization of the oil shale regulations.

Section 369 of EPAct, which builds on the oil shale research, development, and demonstration (RD&D) leasing program initiated by the Department of the Interior (DOI) in 2004, directs the Secretary to develop a Programmatic Environmental Impact Statement (PEIS) and commercial leasing regulations for oil shale. The concept is a comprehensive three-pronged approach: 1) Permit oil shale RD&D projects to ensure that oil shale technologies can operate at economically and environmentally acceptable levels prior to expansion to commercial-scale operations; 2) develop an oil shale PEIS to identify the most geologically prospective oil shale areas in Colorado, Utah, and Wyoming; and 3) develop commercial oil shale regulations that will allow companies to make investment decisions in RD&D efforts now, so that when technologically, commercially, and environmentally feasible, the Federal government is prepared to move forward to allow commercial oil shale leasing. Each of these steps builds upon the other, and each is executed in an open, public process with full consideration of social and environmental concerns.

Finlizing oil shale regulations is a critical component in realizing the potential of this vast resource. Unfortunately, the Consolidated Appropriations Act for Fiscal Year 2008 prohibits the BLM from spending FY 2008 funds to publish final regulations on oil shale. While the prohibition limits the BLM from publishing final regulations, the BLM intends to publish proposed regulations this summer. These regulations will lay out a proposed framework for potential commercial operations. However, absent the certainty that final regulations would bring, the commercial oil shale industry may not be willing to invest the necessary dollars for research, and this vast domestic resource will remain untapped at a time when our Nation is searching for ways to further its energy security.

OIL SHALE PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

The BLM published and accepted comments on a draft PEIS for the future development of oil shale and tar sands. The draft PEIS is not a leasing document, but will serve to inform land allocation decisions by analyzing the most geologically attractive oil shale areas in Colorado, Utah and Wyoming. Decisions that result from the PEIS will identify lands that may be open to receive applications for future commercial oil shale and tar sands leasing, and will amend 12 associated land use plans. Forest Service and National Park Service lands are not included in the analysis for such development at this time. It is important to note that any future leasing and development will be contingent upon the successful completion of site- and project-specific environmental analyses.

The RD&D projects will identify commercially viable technologies that can provide the basis to conduct the appropriate site-specific environmental analysis prior to leasing.

The draft PEIS was developed with the help of 14 cooperating agencies including the states of Colorado, Utah, and Wyoming, and several local governments from those states. It was published and released to the public in December 2007 for a 90-day comment period. In response to requests from the State of Colorado and others for more time, an additional 30-day comment period was granted. The public comment period ended April 21, 2008, and more than 100,000 comment documents were received and are currently being reviewed. A final PEIS is scheduled for completion late this summer, and a record of decision is scheduled for completion by the end of this calendar year. It is important to note that no leasing will occur until RD&D has produced viable technology and a leasing EIS is completed.

OIL SHALE REGULATIONS

Section 369 of EPAct also directs the Secretary to develop regulations to establish a commercial oil shale leasing program. The regulations are being developed in keeping with the overall goal of the Act, that a BLM oil shale program is to promote economically viable and environmentally sound oil shale production that augments current domestic oil production while addressing the potential effects of development on states and local communities.

The BLM plans to publish proposed regulations this summer for public review and comment that will provide the roadmap for future industry management decisions. They incorporate applicable provisions of EPAct and the Mineral Leasing Act of 1920 (MLA) that establish oil shale lease size, maximum acreage limitations, and rental rates. The proposed regulations will also address direction in EPAct to establish work requirements and milestones that ensure diligent development of leases. In addition, the proposed regulations will address the key comments received in response to the BLM's August 2006 advance notice of proposed rulemaking.

Moving forward with these regulations does not mean commercial oil shale production will take place immediately. To the contrary, with thoughtfully developed regulations, thoroughly vetted through a public process, we have only set the groundwork for the future commercial development of this resource in an environmentally sound manner. With the administrative and regulatory certainty that regulations will provide, energy companies will be encouraged to commit the financial resources needed to fund their RD&D projects, and the development of viable technology will continue to advance. Actual commercial development and production will be dependent upon the results of the RD&D efforts and more site-specific environmental evaluations.

As discussed earlier, consistent with the language in the Consolidated Appropriations Act for FY 2008, the BLM is not spending FY 2008 funds to develop and publish final oil shale regulations; however, the agency is moving forward in a thoughtful, deliberative manner to publish proposed regulations on oil shale. These proposed regulations will address much of the input already received. The publication of the proposed regulations will provide an additional opportunity for the public and interested parties to comment on the proposed regulatory framework and remain engaged on this important issue.

RD&D

The DOI has been a leader in advancing opportunities for oil shale technology RD&D on Federal lands. DOI's Oil Shale Task Force, initiated in 2004, examined options for promoting oil shale development on Federal lands, resulting in the RD&D leasing program's initiation in 2005. In 2007, the Bureau of Land Management (BLM), after a competitive process, authorized six oil shale RD&D projects on public lands in northwestern Colorado and northeastern Utah. These projects provide industry access to oil shale resources to further their efforts to develop oil shale technologies. Despite the potential for significant return, investors face challenges in the development of new technologies and uncertainty in the regulatory and administrative arena. Based on my experience in private industry, I strongly believe we need to promulgate regulations now to help alleviate some of this uncertainty, thus providing the necessary framework the companies need in order to make informed decisions to invest in oil shale development both now and in the future.

This type of research will require significant private capital, with an uncertain return on investment. Part of the wisdom of Section 369 is that it envisions the private sector will lead this investment -- not the American taxpayer. However, for this to be successful, for these companies to invest the large sums of money, a level playing field and a clear set of regulations or "rules of the road" are required. Developing a regulatory framework now will aid in facilitating a producing program in the future. Impeding the Federal Government's efforts at this stage could significantly impact our ongoing efforts to achieve greater energy security.

THE CASE FOR OIL SHALE

Declining domestic oil production leaves us vulnerable to rising energy costs. Households across America are struggling to deal with these additional costs and experts predict that the trend is set to continue. In looking beyond traditional energy resources to unconventional and alternative fuels, the Department of the Interior has a key role to play in the development of oil shale.

The potential of the U.S. oil shale resource to serve the Nation's needs is staggering. The U.S. Geological Survey estimates that the total U.S. oil shale resource in place is 2.1 trillion barrels – 1.5 trillion barrels of which is located in the Green River Basin of Colorado, Utah, and Wyoming. Even if only a fraction of this resource is ultimately recovered, it could have a significant impact on our Nation's energy supply. The Strategic Unconventional Fuels Task Force has estimated that as much as 800 billion barrels of oil equivalent could be recoverable from oil shale resources depending on technology and economics, enough to replace the oil we import for more than 180 years.

CONCLUSION

Thank you for the opportunity to testify on the progress we are making, and the challenges we face in establishing a program for the commercial development of oil shale on federal lands. As I stated earlier, any delay in finalizing these regulations may discourage private investment in much needed research and development and create a high level of uncertainty that will ultimately affect investments to advance economically viable and environmentally sound oil shale development and technology. I urge Congress to lift this ban and allow us to move forward with the public process of finalizing regulations for commercial oil shale development on federal lands.

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Chapter 2

TESTIMONY OF JAMES V. HANSEN, OIL SHALE EXPLORATION COMPANY (OSEC), MAY 15, 2008, SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

Mr. Chairman, Members of the Committee, my name is Jim Hansen and I am testifying on behalf of the Oil Shale Exploration Company, more commonly known as OSEC. I appreciate the opportunity to testify before this Committee to discuss the most critical energy source for our nation's future, oil shale.

US OIL SHALE RESOURCE

The United States is blessed with many natural resources and still has huge, untapped energy resources in its oil shale deposits. Over 70% of the world's oil shale resources occur in the United States and the richest deposits are in the Green River Formation in Colorado, Utah and Wyoming. These deposits contain over 1.5 trillion barrels of shale oil. If only 800 billion of this can be recovered, that alone would supply all of our current domestic petroleum needs for the next 100 years or more.

ELSEWHERE WORLDWIDE

Oil shale deposits are found in at least 15 other countries worldwide and some countries rely on the production of these domestic resources to meet some or all of their needs. Currently shale production is taking place in Brazil, China, Estonia and Russia and development efforts are underway in Israel, Jordan, Australia, and Morocco, as well as elsewhere.

PAST US EFFORTS

The presence of oil shale in both the western and eastern states has been known for over 100 years. Early oil shale operations in the eastern US were terminated when natural oil wells were developed in Pennsylvania in 1859. The discovery of rich oil shale in the western United States drew attention during World War I as the shortage of oil prompted exploration for unconventional fuels; there was a rush to develop these western oil shale resources and the country looked to oil shale as its future fuel supply. In 1920 the Mineral Leasing Act was passed to allow the government to lease its oil shale land at a manageable pace. Then, shortly thereafter, the vast oil deposits in west Texas and Oklahoma were discovered and oil shale lost its attraction.

During World War II, oil shale was again looked upon as the answer to our military needs and the government established an oil shale research center at Anvil Points, Colorado managed by the Bureau of Mines. Following the war, interest again waned and the Alaska oil fields and imports seemed sufficient to meet the nation's needs.

The OPEC oil embargo in 1973 again forced the nation to look at its domestic oil supplies and the government issued its first ever oil shale leases in Colorado and Utah in 1974. The Synthetic Fuels Corporation was established by the Carter administration in 1980 and it finally looked as though the nation was going to do something to diminish its reliance on imported oil. Then, the world oil prices declined in the 1980s and all of the government programs were abolished and the dozen major oil shale projects were terminated by 1985.

Between 1985 and 2005 the nation had no concerted effort to develop its major unconventional fuels, including oil shale. During this same period, Canada was developing its oil sands resources and today is producing well over one million barrels/day, much of it exported to the US. The oil sands industry of Canada is a tremendous success story and production continues to increase. If the

US had maintained its oil shale program after 1985, we would be producing shale oil in this country today.

Again, between 1985 and 2005, there was no federal oil shale program, no significant budget, no policy and no leasing of federal oil shale resources. Finally, the 2005 Energy Security Act offered industry an opportunity to lease federal research parcels of 160 acres each. Congress decided once again that it was time to consider oil shale, especially since the government controls over 80% of the western resource and nothing was going to happen unless the government made federal land available.

CURRENT US PROGRAMS

The 2005 Energy Security Act demonstrated that the US government might finally encourage the development of these valuable oil shale resources. The nation's production of crude oil has been declining since the 1970s while its demand has continued to increase, making the country increasingly dependent on imported oil and much of the foreign supply is controlled by nations unfriendly to the US. Oil shale is the largest untapped domestic resource with the greatest potential to decrease our dependence on foreign oil.

Recent reports completed by DOE and by the Unconventional Fuels Task Force, working with DOE, DOD and DOI, clearly document the value of the US oil shale resources and show that the nation, under the right government programs and leadership, could be producing up to two million barrels of shale oil by 2030.

However, there are lingering questions about our ability to produce shale oil in this country. Most of these questions center on key issues such as: (1) is the technology available and will it work on a large scale?; (2) can shale oil be produced profitably?; (3) can shale oil be produced in an environmentally responsible manner?; and (4) what are the socio-economic impacts going to be on the local regions where these developments occur?

The 2005 Energy Security Act set out to answer these questions and industry has stepped forward to cooperate. The plan is to go slow and answer those questions during an interim research program that precedes huge commercial development efforts. There were six research, development and demonstration leases signed in 2007; five of these in Colorado (three to Shell, one to Chevron and one to EGL Resources) and one in Utah (Oil Shale Exploration Company). Each of these companies has active programs underway. There are other companies working on private and state lands. Each of these projects is working to answer the same crucial questions, although their technical approaches might differ. Commercial development will not occur until investors are convinced that the risks are manageable and that the government is supportive.

So, oil shale is again garnering some attention but not nearly at the level justified. Industry is anxious to ramp up its research programs but it needs the assurance that the federal government is a willing, cooperative partner. Oil shale requires an expensive, high-risk, long-lead time development program and the federal government controls most of the resource and will ultimately determine whether or not shale oil is ever produced at a level sufficient to improve our economic and national security.

Industry was burned in the past when federal oil shale programs were discontinued and proposed leasing programs were terminated. We can’t continue to start and stop these programs. The nation can’t afford to delay any longer; it is time to make a national long-term commitment to oil shale and other unconventional fuels.

OSEC AS AN EXAMPLE

In 2007 Oil Shale Exploration Company (OSEC) was granted a BLM RD&D lease on the 160 acres surrounding the idle White River Mine site in Uintah County, Utah. The mine had been developed by Sun, Phillips and Sohio on the BLM commercial prototype oil shale leases Ua and Ub granted in 1974; when the price of oil dropped and the federal oil shale programs were abandoned in the early 1980s, the companies relinquished the leases in 1985 and the mine reverted back to the government. It has sat idle for over 20 years!

OSEC has initiated an aggressive research program at the site. Its approach is to use conventional underground mining and surface processing of the oil shale through a retort plant. This is in contrast to the in-situ technologies being researched by some of the other projects in Colorado.

In September 2007 OSEC tested 300 tons of Utah oil shale in a retort pilot plant in Calgary, Canada. The test program was very successful and OSEC is currently securing permits to reopen the White River Mine and continue its technology demonstration program, which is focused on answering remaining questions on the technology, economics and environment.

As the OSEC project matures, future expenditures will be in the hundreds of millions of dollars for research and demonstration prior to the final decision on whether or not to build a commercial plant at a scale of 50,000 barrels per day or more. As the level of the expenditures and the risks increase, OSEC, like other oil shale development groups, is asking itself where the federal government stands on oil shale.

The DOE has essentially no oil shale program at this time, even though oil shale produces excellent transportation fuels, including crucial jet fuels and diesel fuel important to the military. DOD is very interested in fuels from shale oil but is getting little direction or funding. The BLM is being told to slow down the proposed commercial leasing program and delay issuing regulations.

Before OSEC can justify more expensive research on the federal RD&D lease, it would like to know the terms of the preferential lease it might secure if its research is successful, as it believes it will be. The terms of that future commercial lease will depend on the leasing regulations, now delayed.

NEED FOR A FEDERAL OIL SHALE PROGRAM

From industry perspective, it appears as though the federal government is opposed to developing oil shale. While federal programs have assisted research and development programs for solar, wind, biomass, ethanol, coal bed methane, clean coal and so on, there is currently very little being done with the unconventional fuels (oil shale, heavy oil, tar sands, and coal-to-liquids) which have the most potential to increase our domestic supplies and improve our national and economic security.

The world oil supplies are decreasing and world demand is increasing as countries industrialize and populations grow. The US global leadership position is jeopardized by the growing power of the OPEC countries that control the world's oil supply; many of these countries are adversarial. Their control of the world oil supply and prices threatens our standard of living and our national security. We cannot afford to further delay efforts to develop our domestic oil shale resources. We have already lost the past 20 years and cannot afford to continue putting off this decision.

While we need to consider all energy supplies, including an aggressive energy conservation program, most of these will have only minor impacts on our fuels shortfall, while costing huge amounts of money and demanding extensive resources that might be better directed elsewhere. It is time to consider the 800 pound gorilla that we have been neglecting all too long, oil shale.

DOMENICI BILL

We appreciate the fact that Senator Domenici and his co-sponsors recognize the problem and are willing to address it head on. These are dire times and will only get worse if the US doesn't address the energy issue. The world is watching as the US fumbles and squanders opportunities. It is time for bi-partisan leadership to come forth and co-sponsor a program that will get us on the course to a meaningful domestic energy program that is more than fancy, feel-good window dressing. This bill can get us started in the right direction and we are prepared to offer further suggestions and assistance. It will take many years of dedicated, cooperative effort between government and industry. Industry is willing to do its part if it is assured that the government is committed and will stay the course.

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Chapter 3

TESTIMONY OF TERRY O'CONNOR, EXTERNAL AND REGULATORY AFFAIRS, SHELL EXPLORATION AND PRODUCTION COMPANY, UNCONVENTIONAL OIL, BEFORE THE UNITED STATES SENATE ENERGY COMMITTEE, MAY 15, 2008

Chairman Bingaman, Ranking Member Domenici, and Members of the Committee: I am pleased to have this opportunity to speak with you today on the topic of oil shale development in the United States.

Let me begin by discussing the broader global energy challenge that we face today. Shell believes, and our Chief Executive Officer Jeroen Van der Veer has stated, that there are three hard truths about our global energy future:

> "First, the global demand for energy is accelerating . . . not just growing, but accelerating. The reason is that China and India in particular are entering the energy-intensive phase of their development.
>
> "Second, the growth rate of supplies of 'easy oil' will struggle to keep up with growing energy demand.
>
> "And, third, increased use of coal, plus the overall dominance of fossil fuels, will cause higher CO_2 emissions, possibly to levels we deem unacceptable. More energy means more CO_2 emitted at a time when climate change looms as a critical global issue. Even though it is predicted that fossil fuels will still be a major part of the energy mix by mid-century, Shell is committed to CO_2 reduction through effective and stable regulatory frameworks. These measures should also serve to enhance energy efficiency

> and promote alternative energy." (Quoted from Jeroen van der Veer Speech - *The Resources Trilemma between Efficiency, Social Justice and Security* – St. Gallen, May 31, 2007)

The recent National Petroleum Council study on "Hard Truths" noted most of the same issues that Shell sees in our future and recommended a series of necessary actions, including:

> "Expand and diversify production from clean coal, nuclear, biomass, other renewables, and unconventional oil and natural gas; moderate the decline of conventional domestic oil and natural gas production; and increase access for development of new resources."

Oil shale is America's most concentrated fossil fuel resource and one of the largest oil resource deposits in the world. There are also oil shale deposits in Australia, China, Estonia, Jordan, Morocco and other nations. The Green River Formation covers portions of Colorado, Utah and Wyoming. According to the Rand Corporation,

> "Estimates of the oil resource in place within the Green River Formation range from 1.5 to 1.8 trillion barrels," of which between 500 billion and 1.1 trillion barrels is recoverable. They continued, "the midpoint in our estimate range, 800 billion barrels, is more than triple the proven oil reserves of Saudi Arabia. Present U.S. demand for petroleum products is about 20 million barrels per day. If oil shale could be used to meet a quarter of that demand, 800 billion barrels of recoverable resources would last for more than 400 years."

As of today, U.S. demand has passed 21 million barrels per day, on the way to 22 million barrels per day. And demand is increasing.

Clearly, this resource represents a significant strategic advantage for the United States and, if developed, would increase U.S. energy security.

Oil shale is a marlstone containing kerogen, an immature hydrocarbon laid down millions of years ago as plants and animals died and drifted to the bottom of an ancient lake that then covered large parts of Colorado, Utah and Wyoming. Left in current form, kerogen would slowly form into liquid oil and natural gas through increasing temperature and pressure over millions of years.

In the late 1970s and early 1980s, large energy companies joined forces with the U.S. government in an attempt to develop this resource in an era of significant global energy stress. The initial attempts to develop oil shale required mining the ore and heating the shale to temperatures near 1000 degrees Fahrenheit in large surface kilns called retorts. When global energy prices collapsed in the 1980s, the expensive energy and water intensive surface retorting projects were abandoned, leaving western Colorado in an economic downturn that persisted for many years. While other energy companies exited their oil shale research, Shell stayed on, although with a radically different technology.

From 1981 to today, Shell has pursued a deliberate but cautious approach to the research of new oil shale extraction technologies. Over the course of the past quarter century and more, and without seeking any financial subsidies from the U.S. government, Shell has pursued the development of a very different and unique method called In-Situ Conversion Process (ICP) technology for oil shale recovery on our privately-owned Mahogany property in Northwest Colorado. The process involves inserting heaters directly into the underground shale formation and heating the rock to roughly 700 degrees Fahrenheit. This heating causes the kerogen molecules to crack, transforming them into lighter-end hydrocarbons that then can be produced using conventional means. The heavier end of the carbon chain molecules is left behind in a solid and immobile state. We have determined that the product produced is roughly one-third gas and two-thirds light transportation liquids, with an API gravity of 36 or better.

Shell has pursued this research on our private Colorado land since 1981. We have developed and completed five complicated field tests of various heater and groundwater protection technologies. In 2005, Shell conducted its most recent field test, called the Mahogany Demonstration Project South. This field test, which followed our predicted production models very accurately, produced approximately 1800 barrels of light liquid and gas. This particular test has convinced Shell that our ICP technology indeed works. Now our challenge is to determine if it can work on a long-term, sustainable commercial basis.

Our current research efforts are focused on groundwater protection research, as Shell is committed to developing oil shale in an environmentally responsible manner. The Shell private property Freeze Wall Test (FWT) will build, dewater, stress, break and then heal an impermeable wall of groundwater ice. Although Shell's application to oil shale development is unique, freeze wall technology is not new and has been used effectively for many years in the mining and construction business. We drilled closely spaced wells to a depth of approximately 1700 feet around an area the size of a football field and circulated a super-cooled liquid through a closed pipe network down those wells to remove the heat and eventually freeze the groundwater in place creating a "wall of ice" that prevents communication of water between the heated area and lands outside the freeze wall. Then we pump out water from the inside of the ice canister we have created. As an analogy, imagine an empty barrel standing in a river.

It is not our intention to perform any heating activities inside this particular freeze wall at the current time. Rather, we will test the durability of the freeze wall and prepare the concept for deployment on our Research Development and Demonstration (RD&D) leases. The freeze wall test is absolutely critical to future Shell oil shale development plans because, unless we can clearly demonstrate both to our Board of Directors and to the various federal and state regulatory authorities that we can and will protect the precious ground waters of Colorado, we will not proceed to commercialization. You may ask, "How can Shell expect to surround an area that will reach 700 degrees Fahrenheit with a wall of ice?" The answer is that the shale is not a particularly good conductor of heat. Therefore, a small buffer zone is created around both the area to be heated and the freeze wall to prevent heat communication between the separated areas.

As our research moves forward, we are grateful to have the opportunity to perform needed tests on BLM land through the Research Development and Demonstration program created by BLM and sanctioned by Congress in Section 369 of the Energy Policy Act of 2005. The U.S. government's support for cautious and careful oil shale development in Colorado is particularly critical inasmuch as approximately 75 percent of the oil shale-rich Piceance Basin of northwest Colorado is owned by the U.S. government and managed by BLM. We thank Congress and the BLM for the creation and implementation of the RD&D program. Shell believes that the opportunity to test new technologies in the most geographically prospective areas is a smart path to a sound and sustainable oil shale development policy for the future.

In late 2006, Shell applied for and received three 160-acre RD&D leases in the Piceance Basin. Our applications proposed to test a new, energy-saving heater-type on the northern lease, to test oil shale and nahcolite recovery together on the southeastern lease, and to perform a field test simulating commercial conditions of the ICP technology on the third lease. According to the leases, each 160-acre research test pilot is surrounded by a roughly 5000-acre-sized Preference Right Lease area. If the lessee can show that it is capable of producing "commercial quantities of shale oil from the lease," the lessee will earn the right to expand the surrounding Preference Right Lease area, subject to the payment of an undetermined conversion fee (presumably to be established by regulation).

Shell hopes to perform separate pilot projects on each of the three RD&D lease areas, to evaluate differing commercial variants of the ICP technology and then to apply to convert these leases to commercial-scale oil shale development projects sometime in the middle part of the next decade.

We also thank the Department of Energy and its Unconventional Fuels Task Force. This group has conducted a number of valuable studies on the feasibility of creating an oil shale industry here in the United States. Its findings have been interesting and, in some cases, quite enlightening. If you have not had an opportunity to review these DOE studies, I encourage you to do so. We very much appreciate the assistance and encouragement of the Department of Energy and the Department of Interior and their respective divisions and agencies dedicated to responsible oil shale development. At Shell, we will live up to their charge (which is also our charge) to develop this tremendous domestic resource in an economically viable, environmentally responsible and socially sustainable way.

The BLM recently closed the comment period on the draft Programmatic Environmental Impact Statement for Oil Shale and Tar Sands. Shell submitted significant and detailed comments on the PEIS. We believe that the final PEIS and the future regulatory structure of oil shale development are critical keys to both corporate investment in research projects and the eventual development of this vast U.S. energy resource. The draft PEIS delineates the significant safeguards to both the land and the people of the Rocky Mountain west. The number of NEPA procedural tollgates set forth in the PEIS will ensure that development of oil shale takes place is a cautious and environmentally sound manner.

In sum, I would like to comment on two issues of concern to Shell and other companies involved in research and development of new technologies to develop oil shale.

First, in December 2007, Congress passed and the President signed a spending bill that included a provision that states:

> "None of the funds made available by this Act shall be used to prepare or publish final regulations regarding a commercial leasing program for oil shale resources on public lands pursuant to section 369(d) of the Energy Policy Act of 2005 (Public Law 109–58) or to conduct an oil shale lease sale pursuant to subsection 369(e) 8 of such Act."

It appears that such a moratorium may likely remain through the next fiscal year, leading us to believe that the moratorium on potential future development of America's vast oil shale resource may be intended to become permanent in nature. The extension of this moratorium may well have a chilling effect on our efforts to develop this resource in the future. Ironically, preventing BLM from issuing regulations around any oil shale regulations also could have the unfortunate effect of undermining our efforts to develop carbon minimization solutions, as they would relate to oil shale development. Major commercial scale decisions for development take years to research, design and analyze. Although we are still in the research phase of our development activities, we would be helped greatly by regulatory stability on everything from diligence requirements and royalty rates to conversion fees and operating and environmental standards in order to make informed decisions, even in the RD&D stage that will lead to responsible development.

Shell has always pursued a thoughtful and cautious approach to oil shale development in order to prevent a repeat of the past oil shale boom and bust cycle. We expect to invest substantial capital in each of our three small but rather complex RD&D projects to demonstrate that our ICP technology is economically viable, environmentally responsible and socially sustainable. The long history of unsuccessful attempts to responsibly and economically develop oil shale illustrates the significant risks for investors in research in oil shale. Lack of clarity about the economic and environmental regulations governing a potential commercial development of oil shale will add significant additional risk to our potential research investment. Shell urges Congress to allow the BLM to create such a regulatory framework.

Second, the 2007 Energy Bill contained a provision (Section 526) that prevents federal agencies from contracting to purchase fuels produced from alternative fuels if the carbon footprint of those fuels may exceed certain limits. Such a provision is not only harmful to U.S. energy security, as we already receive significant oil supply from Canadian oil sands, but also will be extremely difficult to administer as gasoline and diesel fuels are mixed from various sources in refineries. And let us not forget that our friends to the north now provide more oil to the United States than any other country on Earth. Congress should act to repeal this provision.

Shell understands that the Governor and the Colorado delegation believe that oil shale should be developed in an economically viable, environmentally responsible and socially sustainable way. At Shell, we share this desire. However, preventing the BLM from completing needed regulations or preventing the government from contracting for unconventional fuels is not the way to achieve this end. The BLM has placed a series of safeguards in the draft PEIS on oil shale to prevent uncontrolled leasing and development, including several required NEPA actions before a project can be approved. These federal safeguards are in addition to a host of stringent county, state and federal permits required from 47 separate regulatory agencies to assure protection of the environment. It is time for us to work together to make this tremendous American resource a reality of our energy security.

In closing, I would like to note that the two above-mentioned U.S. government policies will undeniably drive the United States to greater dependence on foreign sources of energy. As our domestic energy demand grows, so does our reliance on imports. It does not have to be this way. Shell understands the global energy and climate challenge. We also understand that the use of fossil-fuel-based energy will be with us for many decades into the future. Shell invests heavily in renewable energy technologies and we are committed to growing our portfolio over time, but for much of this century, oil shale can and should be a critically important bridge to a renewable energy future.

Thank you again for the opportunity to speak with you today.

Pump Jack.

Freeze Wall Test.

Northwestern Colorado.

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Chapter 4

BILL RITTER, JR., GOVERNOR OF COLORADO, TESTIMONY BEFORE THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES, OVERSIGHT HEARING: OIL SHALE RESOURCES, THURSDAY, MAY 15, 2008

Mr. Chairman, thank you for this opportunity to provide the State of Colorado's perspective on oil shale resources. Oil shale development creates significant opportunities and challenges for Coloradans, and all Americans, with respect to energy supplies, environmental protection, water resources, socioeconomic impacts, and national security. From this perspective, I thank the Committee for the time and thoughtful consideration you are giving to reviewing these issues.

Northwest Colorado is home to extraordinary oil shale resources, among the richest in the world, yielding 25 gallons of oil or more per ton of rock. The area is estimated to hold nearly 500 billion barrels of proven oil shale reserves, which is more than double the proven reserves of Saudi Arabia. Successful development of this resource could provide a substantial new source of domestic oil for the United States, which would have positive implications for our national energy policy and national security.

Even though Colorado's oil shale resources are remarkable, they have remained in the ground since their discovery over a hundred years ago. Past development attempts have failed due to a number of challenges -- technical, economic, and environmental -- that have yet to be overcome, notwithstanding billions of dollars invested by both government and industry. Just as it was 30 years ago during the last push for oil shale development, the State of Colorado is ready to do its part to help the country meet its energy needs. At the same time, we need to be thoughtful about our approach, especially in light of the magnitude of such development. In fact, if the Department of the Interior were to authorize a commercial oil shale industry in Colorado, the development would constitute the largest industrial development in the State's history – with enormous implications for all of Northwest Colorado and for the State itself.

Since coming into office nearly 18 months ago, I have followed with keen interest federal efforts to jump-start a domestic oil shale program. I have strongly supported continuation of the Research Development and Demonstration (RD&D) process, and look forward to continuing to work with the Administration, Congress, and the private sector to make that possible. Once we understand the results from this federal RD&D process and the other efforts that are being pursued on private land holdings, and once we have a clear understanding of viable technologies and the steps necessary to manage and mitigate the environmental and socioeconomic impacts of such technologies, thoughtful and meaningful regulations can be developed and a commercial federal leasing program can be put in place. Establishing a leasing program prior to understanding what technologies are viable and the implications of these technologies would be a dangerous course, with enormous risk of unintended consequences. Such a course of action would not be in the best interest of the nation and certainly not in the interest of Colorado.

This position is consistent with Colorado's previous administration which appeared before this very committee three years ago to urge caution with respect to oil shale development and noted that "oil shale technology development is still fraught with uncertainty". I would like to emphasize that the same is true today. Similarly, I have heard from many local mayors, county commissioners and citizens who support a thoughtful and measured approach to oil shale development. In addition, the Western Governor's Association has expressed in a letter to this Congress that they are "very concerned about the accelerated timetable mandated in the [Energy Policy Act] for the development of a commercial scale oil shale industry." As the Governor of Colorado, I will continue to emphasize the need to be responsible and thoughtful when it comes to oil shale development.

BACKGROUND PRINCIPLES

Colorado will play an active role in any development of the nation's unconventional fossil fuels, particularly oil shale, and has consistently articulated a desire to move forward in a thoughtful and measured manner with regard to shale. We must ensure that projects are fiscally and environmentally responsible, and that our communities are protected from any harmful boom and bust cycle such as we saw in the 1980s. As the epicenter of the oil shale resource in the United States, Colorado has the most to gain if the resource is developed responsibly and the most to lose if the risks are not managed appropriately. While a reliable, sustainable domestic oil-based resource is increasingly important, equally important, from Colorado's perspective, is the protection of the State's exceptional environment, including our water supplies, our clean air, our mountains, and our wildlife. Colorado's oil shale country also boasts a remarkably diversified economy in which agriculture, tourism, recreation, hunting and fishing, natural gas and mineral development, retirement communities, and their economic drivers co-exist in a relatively balanced and supportive way. This economic diversity grew in part out of the last energy bust, and the current energy boom should not diminish the businesses and culture that emerged from that adversity.

For Colorado, then, there is much at stake in the outcome of any federal oil shale program, including the need for thoughtful development of a commercial leasing program through leasing regulations. That is why I am here today: I am concerned that federal efforts to develop a commercial oil shale leasing program are moving forward too quickly, before public and private research efforts are completed, with necessary testing and monitoring to ensure that the impacts to air, water, wildlife, and communities are fully understood.

My testimony today will provide the Committee with background on the area of Northwest Colorado containing the nation's richest oil shale deposits -- the Piceance Basin. I will also discuss the status of the federal research and development program, and provide my perspective on pending legislation concerning federal oil shale resources and appropriate steps forward.

COLORADO'S OIL SHALE COUNTRY

Northwest Colorado is truly blessed with diverse, exceptional natural resources and a vibrant, diversified economy. While being the epicenter of oil shale country, the Piceance Basin is also home to other world-class hydrocarbon resources. Natural gas, oil, and coal -- all vital components of a national energy strategy -- are commingled in this same geographic region. This area holds centuries of clean coal reserves that are being produced at record levels, a significant oil field that has produced for decades, and trillions of cubic feet of clean-burning natural gas which are currently undergoing an unprecedented boom in development. There are currently twice as many drilling rigs operating in Colorado as there were just five years ago, and the number of active oil and gas wells statewide has increased 40 percent during this period to top 35,000 wells. In 2007, the State issued a record 6,368 oil and natural gas drilling permits -- over half of which were located in the oil shale country of Northwest Colorado's Piceance Basin -- and the Bureau of Land Management (BLM) proposes amending management plans to allow up to 17,000 new gas wells to be drilled in this region over the next twenty years.[1] In 2006, natural gas and other energy-related development accounted for 15 percent of direct and secondary employment in the region. Attached is a recent comprehensive economic study of Northwest Colorado forecasting that population in the region will double in the next 30 years due to the boom in natural gas drilling, and that an additional 50,000 people could move into the region if oil shale development were to occur.

This hydrocarbon-rich area also supports incredible wildlife resources. The Piceance Basin is home to the largest migratory mule deer herd in North America, a robust migratory elk population, one of only six greater sage-grouse populations in Colorado, populations of Colorado River cutthroat trout, and a host of other wildlife species. These wildlife resources have been built up over millennia, are part of active recovery programs, and are of long-term statewide and national economic, ecological, and aesthetic importance. Colorado's future is reliant on these resources remaining strong and healthy.

In the last twenty years, the region has developed a growing tourism industry as well as a vigorous hunting and fishing economy. In 2006, approximately 17,000 jobs were supported by the tourism industry for the region including Moffat, Rio Blanco, Garfield, and Mesa counties -- representing about 15 percent of the jobs in the area. About 20 percent of the tourism jobs in Northwest Colorado are in the outdoor recreation segment -- or about 3,400 jobs.

The region also sustains a healthy agriculture industry, a vibrant and long-standing ranching tradition, and growing retirement communities. Employment in

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[1] See Reasonable Foreseeable Development Scenario for Oil and Gas Activities in the BLM White River Field Office: Rio Blanco, Moffat, and Garfield Counties, Colorado, Executive Summary

the agriculture and ranching industry -- a 16 billion dollar industry in Colorado -- contributes between 6 percent and 15 percent of all base jobs in the counties in this region. Retirees comprise 13 percent of the population in the region, and their spending supports 11 percent of the basic jobs.

As a result of its abundance of natural resources, particularly the growth of the natural gas industry, Northwest Colorado is experiencing extraordinary changes in population and associated challenges. Housing affordability is a significant challenge to these local communities, and the capacity of local communities to absorb growth is already largely consumed. Many workers are housed in hotels and motels rather than conventional housing. Much of the transportation infrastructure in these communities is in disrepair and is being severely stressed by growth. The costs to repair infrastructure will require up-front financing, before revenues become available from traditional sources such as severance taxes, property taxes, sales taxes, and federal royalties.

This region is vitally important to Colorado's future. Everything state and federal policy makers do with regard to Northwest Colorado must protect the resources, values, and diverse economies and interests that have been embodied there for decades. We cannot simply think of this region as an area where development of one resource can supplant protection of other social, economic, and natural resources.

MOVING FORWARD WISELY ON OIL SHALE

In 2005, the Congress considered various pieces of legislation related to oil shale resources and ultimately enacted oil shale measures in Section 369 of August 2005's Energy Policy Act. Among other things, the Energy Policy Act called for a research and development leasing program for federal oil shale resources; a regional study of federal oil shale resources and the likely impacts of commercial leasing in Colorado, Utah, and Wyoming; and the adoption of final regulations establishing a commercial leasing program for federal oil shale resources.

Given the significant oil shale resource and exigent national energy interests, Colorado is committed to seeing ongoing oil shale research and development move forward. For example, Shell Exploration and Production has been a collaborative corporate leader in its efforts to develop successful *in-situ*

at 3, available at http://www.blm.gov/rmp/co/whiteriver/documents/RFD_Executuve_Sumnmary.pdf.

development technologies and we support their efforts to move forward. State officials also assisted the Department of the Interior in reviewing and narrowing the applications for these federal RD&D leases. The State is currently home to five 160-acre RD&D leases that were issued in 2006. If successful, these research and development projects could set the foundation of a subsequent commercial oil shale industry.

Construction has not yet begun on the federal RD&D leases, and none of the companies looking at Colorado's oil shale are talking about commercial development any time in the next decade. I believe that the projects on federal RD&D leases are critical in showing that new proposed technologies work, that they can be utilized economically, that they will not have unacceptable impacts on Colorado's environment, and that the resulting communities are sustainable. Colorado has consistently maintained that development of the information that will allow us to address historic challenges to development of the resource is a prerequisite to federal oil shale leasing, regulation, and development.

In March of this year, I submitted comments to the BLM on the agency's draft Programmatic Environmental Impact Statement for Oil Shale and Tar Sands Resources in Colorado, Utah, and Wyoming. That document proposes to make nearly 2 million acres of federal lands in the three states -- including nearly 360,000 acres in Colorado -- available for application for commercial oil shale leases.

Today, I reiterate the conclusion I reached after reviewing the BLM's draft document: the approach put forward by the BLM is unwise. The agency proposes to open nearly 2 million acres of federal oil shale resources to potential oil shale development, yet it lacks information about the technologies that would be used or their impacts on the environment. One is a logical consequence of the other – and we have neither at this time. The prospect of oil shale development raises a number of significant questions that must be answered before large-scale leasing goes forward:

- We do not know how much water will be needed for a large oil shale industry or how those water demands will affect other water users. The State is rapidly approaching full allocation of its Colorado River entitlements and will soon enter a new period of trading and sharing water between different users.
- We do not know what the environmental impacts will be on both surface water and ground water quality due to extraction operations, particularly when considering experimental *in-situ* technologies.

- We do not know the scope of potential impacts on wildlife. The Piceance Basin contains unique and irreplaceable habitats for a variety of species, and oil shale development could cause significant habitat loss and fragmentation that would damage important wildlife populations, including greater sage-grouse and big game species.
- We do not know the amount of energy that will be needed to process shale oil , the sources or locations of necessary power plants, the impacts such energy production would have on regional air quality and visibility, or the greenhouse gas implications.
- We do not know how the infrastructure needed to house the incoming workforce will be developed, financed and managed.
- We do not know whether the cumulative environmental and economic carrying capacities of the region have been exceeded, in light of the current natural gas development boom.

Given the information missing from the BLM's analysis, a decision to make 360,000 acres of federal land in Colorado available for oil shale leasing at this time is ill-advised. The State of Colorado, therefore, recommended selection of Alternative A, which would allow activities on federal RD&D leases to continue and potentially expand to commercial leases on over 25,000 acres of federal lands for which the RD&D lessees have preference rights. I am attaching a copy of my comments on the BLM's environmental review for the Committee's use.

For the same reasons that it is inappropriate for the BLM to make land use decisions without results from the federal RD&D leases, it is likewise inappropriate for the BLM to move forward to finalize commercial leasing regulations at this time. The BLM lacks the information necessary to finalize any comprehensive set of rules and regulations for oil shale development. These regulations will establish environmental-protection standards, set royalty rates and address bonding, establish standards for diligent development, determine the allowable size of leases, and make myriad other important decisions that will directly and significantly and irreversibly affect how oil shale development proceeds. Until the basic answers are derived from the RD&D program, establishing the rules for commercial leasing is premature. Promulgating regulations in the absence of the data from the RD&D projects will likely create an illusion of "regulatory certainty" rather than a comprehensive set of regulations that will be viable for commercial leasing and development.

Colorado is committed to working with the federal government and industry on oil shale efforts going forward. But this requires a thoughtful approach rather than a rush to premature leasing and regulatory decisions that will create legal rights and expectations before we fully understand the economic, environmental, and social implications.

COLORADO PERSPECTIVES ON PENDING OIL SHALE LEGISLATIVE PROPOSALS

Finally, I would like to offer my perspective on two pieces of legislation concerning federal oil shale resources.

American Energy Production Act, S. 2958

Section 433 of the Consolidated Appropriation Act, 2008 provides that none of the funds made available by that Act can be used to prepare or publish final commercial leasing regulations or to conduct a commercial lease sale for federal oil shale resources. I support this restriction, and recently sent a letter to Congress expressing my desire that this funding limitation continue.

A provision in the American Energy Production Act would eliminate this restriction on Department of the Interior expenditures. I oppose this provision.

The oil shale funding limitation contained in the 2008 Consolidated Appropriation Act will not prevent the BLM from finalizing the Programmatic Environmental Impact Statement or preparing draft rules for oil shale leasing. Importantly, it will also not slow or prevent activities on the federal research and development leases. As I have made clear, I support a thoughtful, measured approach to oil shale, which means letting research and development activities yield meaningful results before irreparably locking up federal resources with an uncertain fate through commercial leasing.

Oil Shale and Tar Sands Leasing Act of 2008, S. 221

This legislation would eliminate some of the timing requirements of the Energy Policy Act and expand opportunities for me and other Governors from oil shale states, as well as the public, to comment on environmental reviews and proposed oil shale regulations. I support these provisions. The Energy Policy Act of 2005 sets out unreasonably ambitious deadlines for preparing regional environmental analyses and adopting leasing regulations. It should be noted that these deadlines have passed. Setting out a more responsible and realistic timeline in legislation is consistent with sound public policy.

The legislation would also direct the Department of the Interior to submit to the Congress a report on the status of activities on federal research and development leases as well as various policy issues surrounding a potential commercial leasing program. It would also call for a study by the National Academy of Sciences concerning oil shale resources, research activities, timing of commercial development activities, and positive and negative implications of such development on the environment and various resources. I strongly support these provisions. They would do nothing to slow current research and development activities, yet they would yield vital information that is now missing from the public debate about commercialization of federal oil shale resources.

Finally, the legislation would provide me and the Governors of other affected states, as well as executives of affected local governments, the opportunity to submit recommendations regarding the size, timing, or location of any proposed oil shale lease sales or with respect to any proposed development or production plans. I support these provisions as well. The State of Colorado and local governments have much at stake in commercial leasing decisions, and I support provisions giving expanded voice to their concerns.

CONCLUSION

The State of Colorado supports a thoughtful approach to oil shale development. I am encouraged by the ingenuity displayed by the companies seeking to develop new oil shale development technologies, but I am concerned by federal efforts to fast-track decisions about commercial oil shale leasing, including promulgation of leasing regulations. I continue to believe that the prudent course of action is to see the research and development program called for in the Energy Policy Act through so that accurate information might be forthcoming about the likely costs, risks, and impacts of commercial shale development activities. Then, and only then, might the federal government be assured that its rules and regulations can both encourage oil shale development while ensuring a fair rate of return for federal oil shale resources and protecting the environment and communities of Colorado.

Thank you for this opportunity to offer the State of Colorado's perspective on oil shale development.

ATTACHMENTS

- State of Colorado's statement to the Task Force on Strategic Unconventional Fuels (September 2007).
- State of Colorado's comments on BLM's Draft Oil Shale and Tar Sands Programmatic EIS (March 2008)
- Northwest Colorado Socioeconomic Analysis and Forecasts (April 2008)

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Chapter 5

STATEMENT OF STEVE SMITH, THE WILDERNESS SOCIETY, BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE, REGARDING OIL SHALE DEVELOPMENT AND RESEARCH, MAY 15, 2008

Thank you, Mr. Chairman, and members of the committee, for this opportunity to highlight some key environmental issues that must be addressed as Congress and federal land managers consider the possible development of oil shale resources in sensitive and arid western states.

My name is Steve Smith. I live in Glenwood Springs, Colorado, 30 miles from one of America's richer deposits of oil shale and within 100 miles of what is projected to be half the world's supply of oil shale. Over the past nineteen years living there, I have watched the local people, communities, and economy slowly recover and revive from what was the disaster of the last oil shale experiment in our county.

That boom-bust disaster was the result of attempts to move oil shale too quickly with artificial acceleration and unsustainable subsidies. It is essential that Congress and federal land managers learn both from the mistakes of that past and from currently evolving innovations when—cautiously—crafting or implementing oil shale policy and activities.

Basic Facts

I encourage to carefully consider three basic facts:

- Oil shale production technology still is slowly evolving. No technology—or company—is anywhere near being ready to develop oil shale at commercial scale;
- Research into the technical and environmental feasibility of various oil shale technologies is barely begun on federal lands already leased for that research;
- Companies with interest in oil shale already own or have access to extensive amounts of land containing oil shale ore; and
- The climate impacts of oil shale development—both from the use of produced fuel and from the immense amount of energy needed just to produce it—are serious concerns that must be addressed before proceeding with anything approaching commercial scale production.

Oil shale, an important *potential* resource

This possible source of fuels warrants careful consideration, both of its potential contribution and of its potential effects on other important values and resources.

As you know, various provisions of the Energy Policy Act of 2005 direct the Bureau of Land Management:

- to make federal lands selectively available for research and development activities for oil shale and tar sands resources; several such leases have been awarded;
- to analyze, through a programmatic environmental impact statement, the environmental, economic, and social impacts of potential commercial oil shale and tar sands development in three western states; preparation of that PEIS continues; and
- to adopt new regulations for commercial leasing of oil shale and tar sands, and if there is sufficient local interest and support, potentially lease federal public lands for commercial oil shale production.

That is a logical sequence –to research carefully whether public lands should be opened to oil shale development and, if so, how. The pace of that sequence, as imposed by the 2005 Act, is now proving too ambitious and too hasty.

None of the research intended on federal lands leased for that purpose have begun. Indeed, at least two of the research leasing companies with research leases have announced their intention to rewrite their original research leasing proposals or to revise their research plans.

Meanwhile, the PEIS process is moving deliberately but slowly, which is appropriate, considering the large amount of land and water potentially affected and the significant amount of key information that just is not known.

It just makes sense to take all the time needed for a thoughtful review of the research results from the preliminary research leasing program before considering any public lands leasing for commercial oil shale production—and before attempting to craft commercial leasing regulations.

Federal managers, local citizens and their leaders, and the industry itself need additional time to evaluate whether and how well the new oil shale extraction technologies work and how they could affect local economies, communities, and the natural environment so key to both.

Commercial leasing should begin, if it begins at all, *only* if and when technical difficulties of oil shale production are solved and when negative environmental and social effects of commercial development—including climate effects—are fully understood and then avoided or mitigated.

Careful research before considering commercial development
Even recent innovations in oil shale production include many very new ideas and accompanying unknowns. The BLM is currently evaluating five *in-situ* oil shale research and development proposals in Colorado, each using technology that is the first of its kind. Nowhere on the planet has large-scale oil shale development occurred using the *in-situ* techniques being considered in Colorado's Piceance Basin. For all the effort and investment it has expended, the oil shale industry is in its infancy, and each of these is a one-of-a-kind operation.

The BLM should let companies conduct extensive—and long-term—research and development activities—and carefully evaluate the results of that research—before it considers holding a commercial lease sale.

	Technology		Commenced test operations?	Time to commercial decision	Time to initial commercial operations	Time to production growth	Federal Lands (acres)
Chevron	In-situ	ICP - Hot gas frac. (suspended)	NO	10-15 years	12-16 years	>20 years	160
Shell #1	In-situ	ICP - Electrostatic heaters	NO	7-10 years	12-16 years	>20 years	160
Shell #2	In-situ	ICP - Bare electrode	NO	7-10 years	12-16 years	>20 years	160
Shell #3	In-situ	ICP - Nahcolite, then shale (suspended)	NO	7-10 years	12-16 years	>20 years	160
AMSO	In-situ	ICP - Natural gas heat source	NO	7-15 years	12-16 years	>20 years	160
OSEC	Surface retort	ATP rotary retort	NO	Unknown	12-16 years	>20 years	160
Shell Mahogany	In situ	ICP	YES	7-10 years	12-16 years	>20 years	

Interim production--This sound, cautious approach to—indeed, strategic postponement of—commercial oil shale leasing on public lands does not mean foregoing oil shale energy production. In fact, the potential resource recovery from the BLM research-and-development leases themselves is very large. According to the Plans of Operations submitted with the research lease nominations, the estimated in-place oil shale resources for the 160-acre Colorado tracts are 284 million barrels, 280 million barrels, 300 million barrels, 274 million barrels, and 356 million barrels, respectively. Thus the total resource to be conveyed in the research-and-development leasing program alone is approximately 1.5 billion barrels in place.

We note that this number does not represent the amount of oil that would be recovered, but rather the "resource in place". Because we do not yet know the potential recovery rate for the development methods proposed by research lessees, it is difficult to estimate the number of barrels that could actually be recovered. At a 70% recovery rate, which might be possible with the newer *in situ* processes, these research leases stand to deliver over 1 billion barrels of oil over their life, which would represent a substantial domestic supply.

In addition, the companies holding research leases have already nominated 4,960 acres of federal land preference rights adjacent to each of the research lease tracts. Once they demonstrate the viability of their technology, the BLM can confer the additional acres for development. Until and unless experimental leases can definitively demonstrate high rates of recovery and effective environmental protections, larger tracts should not be offered for what would be speculative commercial leasing.

Commercial leases offered later in time also will be likely to generate greater returns to the federal treasury. This view was supported by the Congressional Budget Office (CBO) when it evaluated legislative proposals to mandate large-scale oil shale and tar sand leasing in the next five years. The CBO found that because the technology to successfully develop shale has not yet been developed, bonus bids for commercial leases would be insignificant over the next five years.

In addition, CBO found that any increased receipts from early lease sales would be offset by forgone receipts from sales that would otherwise occur later, when the technology has been developed, as well as by administrative costs. Leases will simply be more valuable when potential lessees know what they will be able to do on them.

Extensive undeveloped oil shale resources are already in private hands—If oil shale and tar sands were a commercially viable resource to substitute for more traditional fossil fuels, surely some of the extensive oil shale and tar sands resources already in private hands would be under commercial development. They are not.

Oil shale and tar sands resources in private hands are extensive within the Green River Formation. For example, according to an April, 2006 Department of Energy Report, approximately 3,000,000 acres of oil shale and tar sands resources are in non-federal ownership in Colorado, Utah and Wyoming, and hold in-place reserves of approximately 360 billion barrels of oil equivalent (DOE, Office of Naval Petroleum and Oil Shale Reserves, "National Strategic Unconventional Resource Model," April, 2006, p. 6).

Several prominent companies either own outright or control large oil shale or tar sands resources, according to both federal government and industry sources. For example,

* ExxonMobil owns 50,000 acres of oil shale lands in Colorado's Rio Blanco and Garfield counties alone;
* Red Leaf Resources controls oil shale leases of about 16,500 acres on Utah state lands;
* Great Western Energy, LLC owns or controls oil shale leases on 16,500 acres of state lands in Uintah County, Utah;
* Millennium Synfuels, LLC controls approximately 34,000 acres of oil shale leases in Utah;
* Royal Dutch Shell owns 36,000 acres of oil shale lands in Rio Blanco and Garfield counties Colorado ;
* The Oil Shale Exploration Company controls over 45,000 acres of oil shale lands in Colorado.

These six companies control over 200,000 acres of oil shale and tar sands resources, but none of these companies have moved forward with any plans to commercially exploit the resources under their control.

Moreover, at least some of the oil shale resources in private hands have been characterized by the United State Geological Survey as among the richest in the Piceance Basin in terms of barrels of oil equivalent per acre. For instance, at a hearing before the Senate Subcommittee on Mineral Resources Development and Production of the Committee on Energy and Natural Resources held on October 16, 1987, regarding the patenting of 82,000 acres of old oil shale claims, testimony was presented regarding USGS estimates that 42 billion barrels of recoverable oil equivalent were present within the 82,000 acres patented. Royal Dutch Shell, though not an original patentee, acquired a substantial proportion of those 82,000 acres of patented oil shale claims, which apparently comprise the lion's share of its holdings in the Piceance Basin. Shell, though carrying out a robust research program, has not moved to commercial production of these resources. According to the same hearing record, between 1920 and 1980 the federal government issued patents on over 345,000 acres of oil shale claims in Colorado, Utah, and Wyoming. None of these claims are in commercial production.

It seems to us that before the Congress lifts the current moratorium on commercial oil shale and tar sands leasing—which could result in the imprudent transfer of additional tens of thousands of acres of oil shale and tar sands resources into the hands of companies that already posses large inventories of these resources—it should find out more about the status and nature of the extensive oil shale and tar sands resources already in private hands. The USGS likely has information in its possession describing the nature of these resources, since much of it apparently derived from patents issued prior to the late 1980s. It would be prudent for Congress to find out from the companies holding these extensive private resources why they are pressing to acquire more federal resources, when they have not found it opportune to develop that which they already possess.

Protecting the environment and climate

Even as technological improvements advance, however, researchers and policymakers must fully consider and integrate into the oil shale equation the protection of our communities, our water, our wildlife, our clean air, and the scenic beauty of this region, as well as a better understanding and avoidance of climate impacts from this potential industry.

The public lands in question, in northwest Colorado, northeast Utah, and southwest Wyoming, certainly have large energy potential. Those lands already are producing unprecedented volumes of oil, natural gas, and coal for regional and national energy needs, and they contain a very large theoretical volume of additional energy from oil shale.

Those same public lands also include integrated and critical wildlife habitat, popular hunting and other recreation opportunities, water supplies for local agriculture and communities, and astounding scenic wonders. For all its energy potential, the oil shale country must be considered in the larger context of natural and public values. Correspondingly, any energy policies affecting those lands must protect those other, more enduring and more complex values and the region's tourist- and recreation-dependent communities that relay on those natural features.

Energy inputs—The amount of energy needed, as an input, to make oil shale production work is immense. Traditional, above-ground retorts must heat mined and pulverized oil shale to 900 degrees Fahrenheit, consuming 40% of the energy value produced from the shale itself. Even in the new *in-situ* heating technique, underground electric heaters must bring the ore to 700 degrees Fahrenheit and hold there for up to four years!

The Rand Corporation's report, *Oil Shale Development in the United States, Prospects and Policy Issues*, prepared for the U.S. Department of Energy last year, notes that oil shale production of 100,000 barrels per day (less than one half of 1% of U.S. daily oil consumption), using the so-far most advanced *in-situ* underground heating retort technique, would require 1.2 gigawatts of dedicated electric generating capacity. That equates to construction of a dedicated power plant equal in size to the largest coal-fired plant now operating in Colorado. Such a plant cost of about $3 billion to build and would consume five million tons of coal each year, producing ten million tons of green house gases

A 500,000 barrels-per-day industry—the scale projected by some oil shale enthusiasts—would require five such plants, 6 gigawatts of new electric power, an amount equal to that generated from all of Colorado's existing coal-fired power plants.

Although some small amount of that electric generation might be fueled by natural gas, a by-product of the *in-situ* process, most of it likely would be fueled by the abundant coal supplies in the vicinity, prompting additional technological challenges in providing carbon sequestration and particulate air pollution control.

Water—The region underlain by oil shale is notably arid, with relatively low annual rainfall, and existing over-commitment of existing water supplies and facilities. Against that dry backdrop, the Rand report cites the Office of Technology Assessment's projection that traditional oil shale operations require between 2.1 and 5.2 barrels of water to produce one barrel of shale oil product. While the new in-situ processes may require relatively less water, the Rand report notes that "considerable volumes of water may be required for oil and natural gas extraction, post-extraction cooling, products upgrading and refining, environmental control systems, and power production."

The BLM projected in 1996 that oil shale (by traditional methods) would reduce the annual flow of the White River by up to 8.2 percent and "would result in the permanent loss or severe degradation of nearly 50% of BLM stream fisheries."

More recently, local water agencies have estimated that a 500,000 barrels-per-day oil shale industry itself would require 25,000 acre-feet of water annually, either from new sources or diverted from existing uses, noting that such supplies of water adequate for the newer oil shale extraction technologies might not be available and, even if they are, might not remain available in a changing global climate.

Additional water would be needed for domestic and municipal uses in response to significant growth in population centers near the oil shale production areas.

All of these water factors should be—and are not—thoroughly analyzed in the PEIS and other comprehensive reviews to provide information essential to decisions about the possibility and timing of commercial-scale oil shale leasing and development.

Air quality—The Rand report notes that there were no publicly available analyses regarding how modern pollution control systems could be incorporated into oil shale production facilities, and that further studies would be needed to determine the extent to which nonpoint-source air emissions (i.e. dust and off-gassing) from both surface and in-situ operations could be prevented or controlled. Rand also found that no studies of the cumulative impacts of oil shale development on air quality had been reported since the 1980s. Because so much has changed in terms of air-quality regulations, mining and process technologies, and pollution-control techniques, the earlier air quality analyses were found to be no longer relevant. Rand characterized available studies on air quality effects of oil shale development as "so out of date, it is not possible to provide an analytically based estimate of the extent to which air quality considerations will constrain the technology profile, pace of development, and ultimate size of an oil shale industry."

Additional air quality study and modeling must be completed before making decisions about commercial oil shale production.

Climate impacts—Each of these factors—energy inputs, water use, air pollution—exacerbate impacts on the global climate in a spiraling, interrelated cycle.

As energy production increases to power oil shale development, corresponding significant releases of greenhouse gases would contribute to a reduction in water supplies, either reducing the amount of water available for oil shale production and energy generation or requiring diversion of even more water from other uses.

As agriculture is by far the largest user of water in northwest Colorado, loss of irrigated cropland and soil cover may contribute further to the climate change cycle.

Increasing global temperatures would increase demand for domestic electricity consumption, either competing with power production for oil shale or requiring still more power generation, with still more greenhouse gas emissions, etc.

These dynamics stack on top of the direct climate impacts that would result from the burning of oil shale fuels themselves.

As noted, the energy required to extract oil from shale will likely result in the generation of huge quantities of green house gas emissions. The 6 new gigawatts of electricity needed to power that 500,000 barrels production level could generate up to 60 million additional tons of carbon dioxide per year—according to EPA data, that would be a 45% increase in the carbon dioxide emitted by all existing electric utility generating units in 2005 in Colorado, Wyoming, and Utah combined.

Due to the required energy inputs, the fuels derived from oil shale would have a carbon footprint that is substantially higher than conventional fuels. Researchers at the University of California reviewed the global warming contribution of the leading oil shale extraction technologies, as well as the emissions released when the fuel is burned, and found that the fuels derived from shale would lead to substantially greater carbon emissions than from conventional fuels. For example, the Alberta Tackuk Processor, an above-ground extraction technique now being pursued by Oil Sands Exploration Company (OSEC) on a federal research and development lease, produces between 37.5 and 40.8 grams of carbon equivalent per unit of delivered energy, compared to an average of 25 grams of carbon equivalent for conventional fuels.

None of these climate impact factors—primary or secondary—are adequately addressed in the current PEIS process, if addressed at all. More complete analysis of these factors must be completed before informed decisions about commercial-scale oil shale leasing or production can be honestly or effectively contemplated.

All of these factors must be thoroughly and thoughtfully analyzed in the pending programmatic EIS and used as the basis for decisions about where oil shale activities will be allowed, and where they would not be appropriate and so will *not* be allowed, and at what pace development should proceed.

Conclusion: go slow, go carefully

Oil shale holds a potential contribution to our energy supply. Researched carefully, developed prudently, and considered in the important contexts of communities, recreation, and the beauty and natural environment of these wondrous states, it might be able to make that contribution without destroying longer-term resources and values. We do not know enough at present, however, to conclude that it can be done safely or efficiently.

Congress and federal land managers should, in careful consultation with states and local communities, learn from the oil shale research leasing program *before* beginning any commercial leasing or commercial production on public lands.

The oil shale will be there when we are ready to develop it in a truly sustainable and environmentally sound manner. We should not venture too fast until we are.

I invite your questions on that document, on my comments today, and on any other opportunity that we may have to help with your work and consideration.

Thank you again for this opportunity to address the committee.

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Chapter 6

DEVELOPMENTS IN OIL SHALE*

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ABSTRACT

The Green River oil shale formation in Colorado, Utah, and Wyoming is estimated to hold the equivalent of 1.38 trillion barrels of oil equivalent in place. The shale is generally acknowledged as a rich potential resource; however, it has not generally proved to be economically recoverable. Thus, it is considered to be a contingent resource and not a true reserve. Also, the finished products that can be produced from oil shale are limited in range to primarily diesel and jet fuel. Earlier attempts to develop oil shale under the 1970s era Department of Energy (DOE) Synthetic Fuels program and the later Synthetic Fuels Corporation loan guarantees ended after the rapid decline of oil prices and development of new oil fields outside the Middle East. Improvements taking place at the time in conventional refining enabled increased production of transportation fuels over heavy heating oils (which were being phased out in favor of natural gas).

Rising oil prices and concerns over declining petroleum production worldwide revived United States interest in oil shale after a two-decade hiatus. In addition to technological challenges left unsolved from previous development efforts, environmental issues remained and new issues have

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emerged. Estimates of the ultimately recoverable resource also vary. Challenges to development also include competition with conventional petroleum production in the mid-continent region, and increasing petroleum imports from Canada. The region's isolation from major refining centers in the Gulf Coast may leave production stranded if pipeline capacity is not increased.

The Energy Policy Act of 2005 (EPAct) identified oil shale as a strategically important domestic resource, among others, and directed the Department of the Interior to promote commercial development. Since then, the Bureau of Land Management (BLM) has awarded six test leases for oil research, development, and demonstration (RD&D). The ongoing program will confirm whether an economically significant shale oil volume can be extracted under current operating conditions. If so, early commercial development may directly proceed. BLM has published a final Programmatic Environmental Impact Statement (PEIS) in which approximately two million acres of oil shale lands, out of approximately 3.54 million acres total, are identified as potentially available for commercial leasing. Draft rules for commercial leases have also been issued, and final rule making is proceeding. The lease and royalties rates proposed in the draft rules appear to compare with rates charged for similar resources, but provide no unique incentive for producing oil shale.

In a previous report, CRS framed oil shale in the perspective of national energy security and reviewed the circumstances under which policies first promoted and then ended support for earlier oil shale development. This second report takes up the progress toward commercializing oil shale development under the EPAct 2005 mandates, and offers a policy perspective that takes account of current turmoil in the energy sector.

BACKGROUND

Declining domestic production, increasing demand, and rising prices for petroleum have underscored the United States' dependence on imported oil. In response, proponents of greater energy independence have argued that the huge undeveloped oil shale resource in the Rocky Mountain region should be opened for commercial development.[1] Those concerned over repeating past mistakes and compromising the environment, however, have urged caution and deliberation in proceeding.

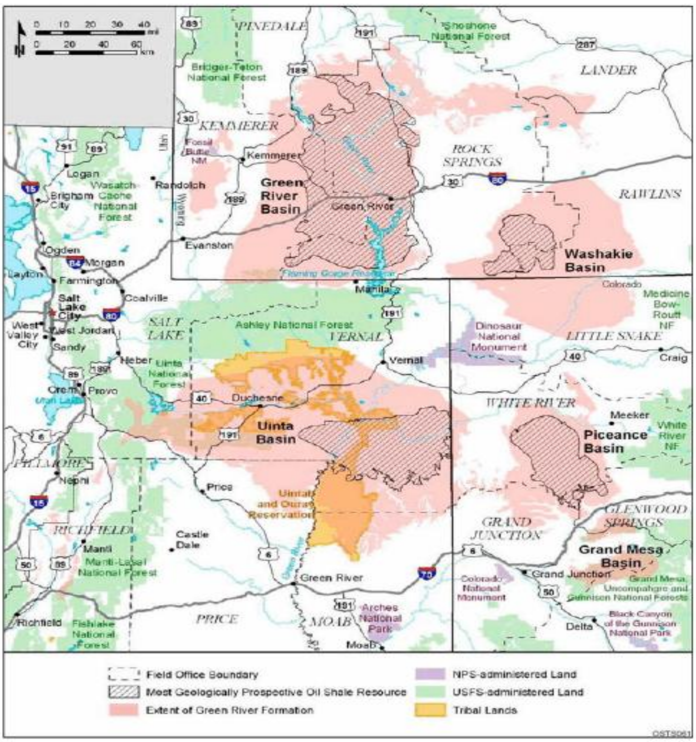
Earlier attempts to develop oil shale had received direct funding support under the 1970s era Department of Energy (DOE) Synthetic Fuels (SynFuels) program and the later Synthetic Fuels Corporation loan guarantee program. Private sector interest in oil shale all but ended after the rapid decline of oil prices and the development of new oil fields outside the Middle East in the early 1980s. Federal support ended by the mid-1980s with the commissioning of the Strategic Petroleum Reserve. Also at the time, improved refining processes enabled conversion of petroleum residuum into high-value transportation fuel. The residuum (figuratively, the bottom of the petroleum barrel) had been processed into low-value heavy heating oil, which was being replaced by cleaner burning and increasingly available natural gas. Then, as now, oil shale was considered a strategic resource. However, its strategic value more recently had been tied to producing defense-related jet fuel, which now appears to be an uncertain prospect. Oil shale shows better potential as a resource for commercial transportation fuels — jet and diesel. However, it faces regional competition from conventional petroleum resources and their wider distribution, and thus use may be constrained by infrastructure limitations. For information on the history of oil shale under the Synthetic Fuels Program refer to CRS Report RL33359, Oil Shale: History, Incentives, and Policy.

In 2005, Congress conducted hearings on oil shale to discuss opportunities for advancing technology that would facilitate “environmentally friendly” development of oil shale and oil sand resources.[2] The hearings also addressed legislative and administrative actions necessary to provide incentives for industry investment, as well as exploring concerns and experiences of other governments and organizations and the interests of industry.[3] The subsequent Energy Policy Act of 2005 (EPAct — P.L.109-58) included provisions under Title III Oil and Gas that promoted the development of oil shale, tar sands, and other strategic unconventional fuels.[4] Section 369 of EPAct directed the Department of the Interior (DOI) to offer test leases for research, development and demonstration (RD&D); prepare a programmatic environmental impact statement (PEIS); issue final rules for commercial oil shale leasing; and commence commercial leasing. EPAct also directed the Department of Defense (DOD) to develop a strategy for using fuel derived from oil shale (among other unconventional resources).

OIL SHALE RESOURCE POTENTIAL

Oil shales exist in several states in the United States. Their kerogen content is the geologic precursor to petroleum. The term shale oil is used in this report to refer to the liquid hydrocarbon products that can be extracted from the shale. The most promising oil shales occur in the Green River formation that underlies 16,000 square miles (10.24 million acres) of northwestern Colorado, northeastern

Utah, and southwestern Wyoming (figure 1). The most geologically prospective oil shale areas make up ~3.5 million acres. The Bureau of Land Management (BLM) administers approximately 2.1 million acres. Another 159,000 acres is made of BLM administered split estate lands. These are areas where the surface estate is owned by Tribes, states, or private parties, but the subsurface mineral rights are federallyowned.



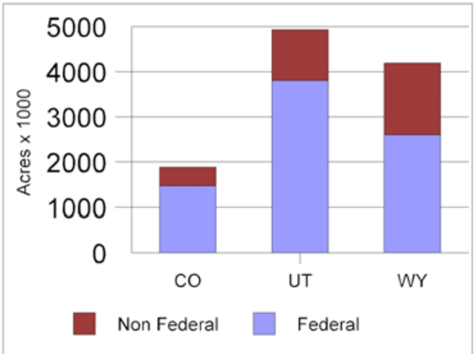
St	Geologic Basin	Basin Size	Geologically Prospective Areas: Total Area Size	BLM Administered Lands	Split Estate Lands
CO	Piceance	1,185,700	503,342	319,710	41,940
UT	Uinta	2,977,900	840,213	560,972	77,220
WY	Green River & Washakie	4,506,200	2,194,483	1,257,680	39,406
	Total Acres	8,669,800	3,538,038	2,138,361	158,566

Key: NPS: National Park Service; USFS: U.S. Forest Service

Source: Bureau of Land Management, Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement, December 2007.

Figure 1. Most Geologically Prospective Oil Shale Resources within the Green River Formation of Colorado, Utah, and Wyoming.

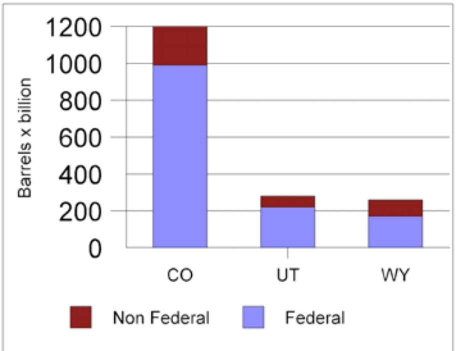
Estimates of oil shale's resource potential vary. The DOE Office of Naval Petroleum and Oil Shale Reserves estimates that ~1.38 trillion barrels of shale oil are potentially recoverable from the roughly 7.8 million acres of federal oil shales (figures 2 and 3).[5] The Rand Corporation conservatively estimates that only 800 billion barrels may be recoverable.[6] Though Utah represents the greatest areal extent of federally managed oil shale land, Colorado's shale may offer a greater potential for recovery because of the resource richness.



	CO	UT	WY
Federal	1470	3800	2600
Non Federal	415	1130	1590

Source: DOE Office of Petroleum and Oil Shale Reserves, National Strategic Unconventional Resource Model, April 2006.

Figure 2. Oil Shale Acreage.



	CO	UT	WY
Federal	990	220	170
Non Federal	210	60	90

Source: DOE Office of Petroleum and Oil Shale Reserves, National Strategic Unconventional Resource Model, April 2006.

Figure 3. Shale Oil Volume.

The amount of shale oil recoverable depends on extraction technology and resource “richness.” The richest oil shales occur in the Mahogany zone of the Green River formation and could be expected to produce more than 25 gallons/ton (~b barrel). At that richness, one acre-foot would hold 1,600 to 1,900 barrels of shale oil.[7] The Mahogany zone can reach 200 feet in thickness in the Uinta Basin of Utah, and thus could represent a technical potential of producing from 320,000 to 380,000 barrels of shale oil per acre if that volume of shale were fully exploited. The ultimate yield would depend on extraction technologies being evaluated under the RD&D program and the land area made available by the preferred leasing alternative selected in the final PEI (discussed below). The potential yield would rival the ~1,400 barrels/acre-foot yields of Canada’s oil sand.[8] It could well exceed the 50 to 1,000 barrels/acre-foot yields of North America’s now-depleted giant oil fields.[9]

As oil shales have not yet “proved” economically recoverable, they may be considered contingent resources and not true reserves. The United States’ conventional proved oil reserves amount to less than 22 billion barrels with the Arctic National Wildlife Refuge Coastal Plain potentially adding up to 17 billion barrels of oil, as estimated by the U.S. Geological Survey. In comparison, Saudi Arabia’s reserves are reportedly 262 billion barrels according to the Energy Information Administration.

CHALLENGES TO DEVELOPMENT

Oil shale has long been proposed as a source of synthetic or substitute crude oil. However, the organic content (kerogen) of oil shale is only a petroleum precursor. The extracted oil lacks the lower boiling-range hydrocarbons that make up natural gasoline, and the heavier hydrocarbons that refineries crack to make gasoline. It does yield hydrocarbons in the middle-distillate fuels boiling range — naphtha, kerosene, jet fuel, and diesel fuel. Thus, it may face challenges as a substitute for conventional crude oil. It may also face competition from conventional petroleum resources under development in the Rocky Mountain region and Canadian exports to the region.

Oil shale production continues to face unique technological challenges. The kerogen occurs in the shale as a solid and is not free to flow like crude petroleum. The shale must be heated or "retorted"to extract petroleum-like distillates. Retorting oil shale involves destructive distillation (pyrolysis) in the absence of oxygen. Pyrolysis at temperatures above 900° F is needed to thermally break down the kerogen to release the hydrocarbons. Two basic retorting processes have been used — above-ground retorting and in situ (underground) retorting. The above-ground retort is typically a large cylindrical vessel based on rotary kiln ovens used in cement manufacturing and now used by Canada's oil sands industry.[10] The in situ process involves mining an underground chamber that functions as a retort. Both concepts were evaluated under the former DOE Synfuels program.

Both in situ and above-ground retorting processes have been plagued with technical and environmental problems. A plentiful water supply is considered necessary for above-ground retorting. Above-ground retorting also depends on underground or open-pit mining to excavate the shale. While either mining method is well-practiced, the expended shale that remains after retorting would present a disposal problem. In the case of open-pit mining, overburden rock had to be removed and set aside to expose the shale. Above-ground retorts also faced frequent problems from caked-up shale, which led them to shut down frequently. Apart from the problem of sustaining controlled combustion underground, in situ retorting also caused groundwater contamination.[11]

New approaches aim to avoid the past drawbacks associated with in situ extraction methods by adapting enhanced oil recovery methods such as horizontal drilling, long term heating, and freezewall technology (a geotechnical engineering method for stabilizing saturated ground). The proposed technologies are discussed in further detail below (see RD&D Program).

Competition with Regional Resources

The Green River oil shales are located in the Rocky Mountain Petroleum Administration for Defense District (PADD 4 — figure 4). PADDs were delineated during World War II to facilitate petroleum allocation. In the past, petroleum pipeline infrastructure left PADD 4 isolated from the other districts, a situation that may slowly improve with the emphasis on new production in the region.

With recent record-high crude oil price, crude production has increased in PADD 4, as has local refining of this production. PADD 4 produced roughly 577 thousand barrels/day over 2007-2008 (table 1). An estimated 588 million barrels of undiscovered technically recoverable conventional oil and natural gas liquids are estimated to underlie the Uinta-Piceance Basin of Utah-Colorado and an additional 2.9 billion barrels are estimated to underlie southwestern Wyoming.[12] Conventional undiscovered technically recoverable resources are those hydrocarbon resources that, on the basis of geologic information and theory, are estimated to exist outside of known producing fields. They are resources that are considered producible using current technology without regard to economic profitability. Natural gas, in particular, has also been undergoing extensive development in Rifle, Colorado (the focal point for the 1980s oil shale boom and bust).

Figure 4. Petroleum Administration for Defense Districts.

The Bakken Formation, part of the larger Williston basin, is estimated to hold from 3 to 4.3 billion barrels of oil, according to a recent delineation of the U.S. Geological Survey (USGS).[13] The formation covers 529 square miles split between Montana (PADD 4) and North Dakota (PADD 2). The USGS estimate places the Bakken ahead of all other lower 48 states oil assessments, making it the largest “continuous” oil accumulation ever assessed by the USGS. A “continuous” oil accumulation means that the oil resource is dispersed throughout a geologic formation rather than existing as discrete, localized occurrences. Bakken production is increasing and is likely to add to PADD 4 production.

PADD 4 has also been a destination for oil exported from western Canada, derived from both oil sands and conventional petroleum reservoirs (figure 5).

Canada ranks as the largest crude oil supplier to the United States, exporting 1.6 million barrels per day. Subsequently, refiners in PADD 4 are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crude oils. The large discount is in reaction to aggressive Canadian crude pricing, a shortage of refinery capacity, and the lack of pipeline capacity to move the crude oil to other markets.

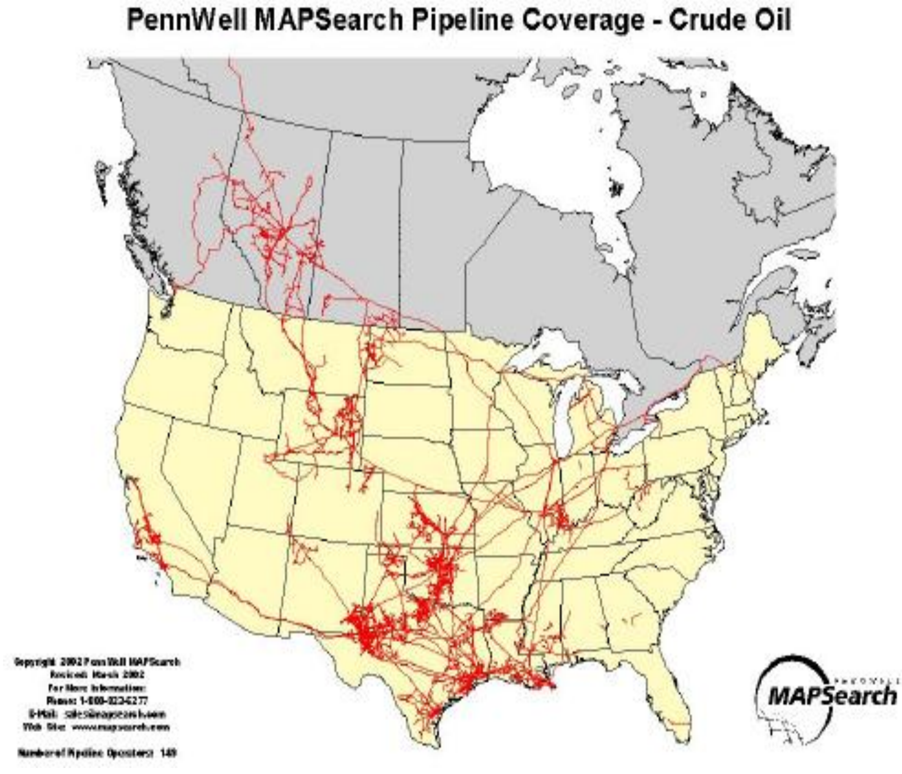


Figure 5. United States and Canada Crude Oil Pipelines.

Supply and Disposition

Supply and disposition, as tracked by the Energy Information Administration (EIA), is an indication of petroleum production, consumption and movements between districts. Over 2007-2008, PADD 4 consumed an average 682,000 barrels/day of supplied products. Refiners and blenders in the district could only produce roughly 593,000 barrels/day (table 1). Its roughly 174,000 barrels/day in distillate production placed PADD 4 behind the other districts.[14] This also left it short of meeting the regional distillate demand of 195,000 barrels/day.[15]

Table 1. Crude Oil and Petroleum Products by PADD (2007-2008)

	Supply (thousand barrels/day)					Disposition (thousand barrels/day)			
	Field Production	Refinery and Blender Net Production	Imports	Net Receipts	Adjustments	Stock Change	Refinery and Blender Net Inputs	Exports	Products Supplied
PADD 1	41	2,592	3,332	2,767	130	-47	2,507	147	6,256
PADD 2	775	3,533	1,254	2,756	208	-36	3,343	89	5,129
PADD 3	4,006	8,257	7,004	-5,446	180	-79	7,720	982	5,380
PADD 4	577	593	362	-254	-18	-4	577	5	682
PADD 5	1,448	3,019	1,516	177	153	17	2,852	209	3,235
U.S.	6,847	17,994	13,468	n.a.	653	-148	16,999	1,433	20,680

Source: EIA Petroleum Supply Annual, Volume 1, July 28, 2008.

Notes: Field Production represents crude oil production on leases, natural gas liquids production at natural gas processing plants, new supply of other hydrocarbons/oxygenates and motor gasoline blending components, and fuel ethanol blended into finished motor gasoline.

Refinery Production represents petroleum products produced at a refinery or blending plant. Published production of these products equals refinery production minus refinery input. Negative production will occur when the amount of a product produced during the month is less than the amount of that same product that is reprocessed (input) or reclassified to become another product during the same month. Refinery production of unfinished oils, and motor and aviation gasoline blending components appear on a net basis under refinery input.

Imports represents receipts of crude oil and petroleum products into the 50 States and the District of Columbia from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Net Receipts represents the difference between total movements into and total movements out of each PAD District by pipeline, tanker, and barge.

Stock Change represents the difference between stocks at the beginning of the month and stocks at the end of the month. A negative number indicates a decrease in stocks and a positive number indicates an increase in stocks.

Exports represents shipments of crude oil and petroleum products from the 50 States and the District of Columbia to foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Product Supplied approximately represents consumption of petroleum products because it measures the disappearance of these products from primary sources, i.e., refineries, natural gas processing plants, blending plants, pipelines, and bulk terminals. In general, product supplied of each product in any given period is computed as follows: field production, plus refinery production, plus imports, plus unaccounted for crude oil, (plus net receipts when calculated on a PAD District basis), minus stock change, minus crude oil losses, minus refinery inputs, minus exports.

Processing

With the increasing competition from other petroleum resources produced and refined in PADD 4, shale oil appears to faces stiff competition. However, the roughly 20,000 barrels/day distillate production shortfall could represent an opportunity. Distillate production (kero-jet fuel, kerosine, distillate fuel oil, and residual fuel oil) makes up 38% of PADD 4 refining output, compared to 42% for the United States on average (table 2). For every barrel of distillate produced, almost three barrels of crude oil must be refined. Increasing distillate production by 4% in the Rocky Mountain region could make up the distillate deficit (at the expense of cutting back on gasoline production).

Table 2. Refinery Yield by PADD (percent)

	PADD1	PADD2	PADD3	PADD4	PADD5	U.S.
Liquefied Refinery Gases	3.2	3.9	5.0	1.5	2.8	4.1
Finished Mogas	45.5	49.8	43.2	46.3	46.6	45.5
Finished Avgas	0.1	0.1	0.1	0.1	0.1	0.1
Kerosene-Type Jet Fuel	5.0	6.1	9.4	5.4	15.6	9.1
Kerosene	0.5	0.1	0.3	0.3	0.0	0.2
Distillate Fuel Oil	29.4	28.2	26.0	29.8	20.8	26.1
Residual Fuel Oil	7.2	1.7	4.1	2.6	6.3	4.2
Naphtha Petro Feed	1.1	0.9	1.9	0.0	0.0	1.3
Other Oils	0.0	0.2	2.4	0.1	0.3	1.3
Special Naphthas	0.0	0.1	0.5	0.0	0.0	0.3
Lubricants	1.0	0.4	1.7	0.0	0.6	1.1
Waxes	0.0	0.1	0.1	0.0	0.0	0.1
Petroleum Coke	3.2	4.3	6.0	3.4	5.8	5.2
Asphalt and Road Oil	5.0	5.3	1.3	8.9	1.8	2.9
Still Gas	3.9	4.2	4.3	4.2	5.4	4.4
Miscellaneous Products	0.2	0.4	0.5	0.3	0.4	0.4

	PADD1	PADD2	PADD3	PADD4	PADD5	U.S.
Processing Gain(-) or Loss(+)	-5.1	-5.8	-6.9	-3.0	-6.4	-6.3
Middle Distillate Average	43.2	37.2	44.6	38.2	43.0	42.5

Source: Table 21. EIA Petroleum Supply Annual 2007, Volume 1.

For now, the most likely option for upgrading shale oil into finished products is by conventional refining. However, shale oil does not fully substitute for conventional crude oil. A typical refinery separates middle distillates during atmospheric distillation — the first pass in the refining process — and then removes sulfur and nitrogen by hydrotreating. The remaining heavier fraction (residuum) is “cracked” then into gasoline through advanced refining processes. Shale oil consists of middle distillate boiling-range products, and a typical refinery would not be configured to crack the middle distillates into gasoline. In fact, some refineries find it more profitable to increase middle distillate production (diesel and jet fuel) at the expense of gasoline. There may be no economic rationale to crack shale oil into gasoline.

Given the operating refineries in the PADD 4 (table 3), any one refinery might be hard pressed to expand capacity or shift production to make up the regional deficit in distillate supply. The economics of constructing and operating a shale oil plant may be uncertain but may also be outweighed by the cost of expanding operating refinery capacity. As a reference case, the CountryMark refinery in Mount Vernon, Indiana, is spending $20 million to add 3,000 barrels/day in diesel fuel capacity. The expansion will increase throughput from 23,000 barrel/day to 26,000 barrels/day.[16] CountryMark is a specialty refinery that makes diesel fuel for agriculture use.

The economic prospects of building a shale oil upgrading plant are uncertain. A new refinery has not been built in the United States since the late 1970s, as operators have found it more efficient to expand the capacity of existing refineries to yield more gasoline. Refineries increase gasoline yield by processes downstream from atmospheric distillation that crack residuum with heat, pressure, catalysts, and hydrogen. Overall refinery throughput though is limited by the atmospheric distillation capacity. A shale oil plant would process a narrower boiling range of hydrocarbons than a conventional refinery, and thus would not require the suite of complex processes. Shale oil’s high nitrogen and sulfur content was considered problematic, but the hydrotreating processes now used by refineries to produce ultralow sulfur diesel fuel can overcome that drawback. The hydrogen required for hydrotreating may be made up in part from shale oil's high hydrogen content and the lighter volatile gases devolved during processing. A less-complex facility making a limited slate of products compared to conventional refinery may prove less burdensome to permit. The approval process for new refinery construction has been estimated to require up to 800 different permits, notwithstanding anticipated legislation mandating carbon capture and sequestration.[17]

Table 3. Atmospheric Crude Oil Distillation Capacity of Operable Petroleum Refineries in PADD 4

Refinery	City	ST	Bbls/Day
Colorado Refining Co	Commerce City	CO	27,000
Suncor Energy (USA) Inc	Commerce City	CO	60,000
Cenex Harvest States Coop	Laurel	MT	55,000
ConocoPhillips	Billings	MT	58,000
ExxonMobil Refining & Supply Co	Billings	MT	60,000
Montana Refining Co	Great Falls	MT	8,200
Big West Oil Co	North Salt Lake	UT	29,400
Chevron USA Inc	Salt Lake City	UT	45,000
Holly Corp Refining & Marketing	Woods Cross	UT	24,700
Silver Eagle Refining	Woods Cross	UT	10,250
Tesoro West Coast	Salt Lake City	UT	58,000
Frontier Refining Inc	Cheyenne	WY	46,000
Little America Refining Co	Evansville (Casper)	WY	24,500
Silver Eagle Refining	Evanston	WY	3,000
Sinclair Oil Corp	Sinclair	WY	66,000
Wyoming Refining Co	Newcastle		12,500
	Total		587,550

Source: EIA, As of January, 2005.

Congress has recognized that increasing petroleum refining capacity serves the national interest and included provisions under Title III of EPAct (Subtitle H — Refinery Revitalization) to streamline the environmental permitting process. A refiner can now submit a consolidated application for all permits required by the Environmental Protection Agency (EPA). To further speed the permit's review, the EPA is authorized to coordinate with other federal agencies, enter into agreements with states on the conditions of the review process, and provide states with financial aid to hire expert assistance in reviewing the permits. Additional provisions under EPAct Title XVII (Incentives for Innovative Technologies) guarantee loans for refineries that avoid, reduce, or sequester air pollutants and greenhouse gases if they employ new or significantly improved technology. It should be noted that permitting would be a secondary consideration for new construction, if refining was an unfavorable investment.

Short of building new pipelines, expanding pipeline capacity to export either crude or refined products from the Rocky Mountain regions appears to be an apparent alternative. As shown in figure 5, PADD 4 is relatively isolated from refining centers in the Gulf Coast and does not serve the western states. To accommodate increased crude oil imports from Canada, the Mobile Pipe Line Company reversed its 858 mile crude oil pipeline that historically ran from Nederland, Texas, to Patoka, Illinois. The pipeline now takes Canadian crude oil delivered to the Chicago region to Gulf Coast refineries.

Carbon Emissions

Congress is considering various bills aimed at reducing and stabilizing greenhouse gas emission. The Energy Independence and Security Act of 2007 (EISA — P.L. 110-140) amends the Energy Policy Act of 2005 with research and development programs to demonstrate carbon capture and sequestration, and restricts the federal government's procurement of alternative fuels that exceed the lifecycle greenhouse gas emissions associated with conventional petroleum based fuels. Title II of EISA directs the EPA to establish "baseline life cycle greenhouse gas emissions" for gasoline or diesel transportation fuel replaced by a renewable fuel.[18] The Lieberman-Warner Climate Security Act (S. 3036) would have established a program to decrease emissions.

Until ongoing oil shale research development and demonstration projects are completed (discussed below), and environmental impact statements are prepared for permitting commercial development, adequate data to assess baseline emissions is not available. Greenhouse gas emissions, primarily carbon dioxide (CO_2), associated with oil shale production can originate from fossil fuel consumption, and carbonate minerals decomposition.

A 1980 analysis concluded that retorting Green River oil shales and burning the product could release from 0.18 tons to 0.42 tons CO_2/barrel of oil equivalent, depending on retorting temperatures.[19] A large portion of the CO_2 released would be due to decomposition of carbonate minerals in the shale. The analysis concluded that equivalent of 1½ to 5 times more CO_2 could be emitted by producing fuels by retorting and burning shale oil than burning conventional oil to obtain the same amount of usable energy.

An "In Situ Conversion Process" being tested by the Shell Oil Company (discussed below) is projected to emit from 0.67 to 0.81 tons CO_2/barrel of refined fuel delivered.[20] The analysis concluded that the in situ retorting process could produce 21% to 47% greater greenhouse gases than conventionally produced petroleum-based fuels.

Petroleum refining alone, accounts for approximately 0.05 tons CO_2/barrel refined of oil. In 2005, U.S. refineries emitted 306.11 million tons of CO_2 to produce 5,686 million barrels of petroleum products.[21] However, from a life-cycle perspective, these emissions do not account for the CO_2 emitted by expending fossil energy for drilling, lifting (production), and transporting crude oil by tanker ship and pipeline. The practice in some parts of the world of flaring (burning) “associated natural gas” that can’t be delivered to market also contributes to emissions.

As a benchmark, CO_2 emissions associated with Canadian oil sand production reportedly range from 0.08 tons CO_2/barrel for in situ production to 0.13 tons CO_2/barrel for mining/extraction/upgrading.[22] Starting at 0.15 tons CO_2/barrel in 1990 the oil sand industry expects to nearly halve its average CO_2 emissions by 2010 to ~0.08 tons/barrel for all processes.

Water

Depending on the depth of the oil shale and the extraction methods used, demands on water resources may vary considerably. Utah’s shallower oil shale may be more suited to conventional open-pit or underground mining, and processing by retorting. Colorado’s deeper shale may require in situ extraction. The DOE Office or Petroleum Reserves expects that oil shale development will require extensive quantities of water for mine and plant operations, reclamation, supporting infrastructure, and associated economic growth.[23] Water could be drawn from the Colorado River Basin or purchased from existing reservoirs. Oil shale has a high water content, typically 2 to 5 gallons/ton, but as high as 30 to 40 gallons/ton. In situ methods may produce “associated water,” that is, water naturally present in the shale.

EPAct 2005 Section 369 (r) is clear on not preempting or affecting state water law or interstate water compacts when it comes to allocating water. Water rights would not be conveyed with federal oil shale leases. The law of water rights is traditionally an area regulated by the states, rather than the federal government. Depending on the individual state’s resources, it may use one of three doctrines of water rights: riparian, prior appropriation, or a hybrid of the two. Under the riparian doctrine, which is favored in eastern states, a person who owns land that borders a watercourse has the right to make reasonable use of the water on that land.[24] Traditionally, users in the riparian systems are limited only by the requirement of reasonableness in comparison to other users. Under the prior appropriation doctrine, which is favored in western states, a person who diverts water from a watercourse (regardless of his location relative thereto) and makes reasonable and beneficial use of the water acquires a right to that use of the water.[25] Typically, under a prior appropriation system of water rights, users apply for a permit from a state administrative agency which limits users to the quantified amount of water the user secured under the permit process. Some states have implemented a dual system of water rights, assigning rights under both doctrines.[26]

One of the most controversial areas of oil and gas production operations today is the handling, treatment, and disposal of produced water.[27] Water produced in association with mineral extraction (including oil and gas) typically contains high levels of contaminants, and it usually must be treated before it can be safely used or discharged. As clean water is a scarce resource, treating produced water may have significant economic use, such as irrigation, washing, or even drinking. A recently completed plant in the Power River basin in Wyoming treats 30,000 barrel/day water produced from coal-bed methane (CBM) wells, and is expected to discharge 120,000 barrels/day to the basin within the next year without affecting water quality.[28]

The Produced Water Utilization Act of 2008 (H.R. 2339) would encourage research, development, and demonstration of technologies to utilize water produced in connection with the development of domestic energy resources.

Defense Fuels

EPAct Section 369 (q) directed the Department of Defense (DOD) and DOE with developing a strategy for using fuel produced from oil shale (among other unconventional resources) to help meet DOD's requirements when it would be in the national interest. EPAct Section 369 (g) also charged a joint Interior/Defense/Energy task force with coordinating and developing the commercial development of strategic unconventional fuels (including oil shale and tar sands). DOD's earlier "Assured Fuels Initiative" and later "Clean Fuels Initiative" considered oil shale, but shifted emphasis to jet fuels produced by Fisher-Tropsch synthesis from coal and gas.

Under the provisions of EPAct Section 369 (h), the BLM established the Oil Shale Task Force in 2005, which in turn published the report "Development of America's Strategic Unconventional Fuel Resources" (September 2006). The

Task Force concluded that oil shale, tar sands, heavy oil, coal, and oil resources could supply all of the DOD's domestic fuel demand by 2016, and supply upwards of seven million barrels of domestically produced liquid fuels to domestic markets by 2035.

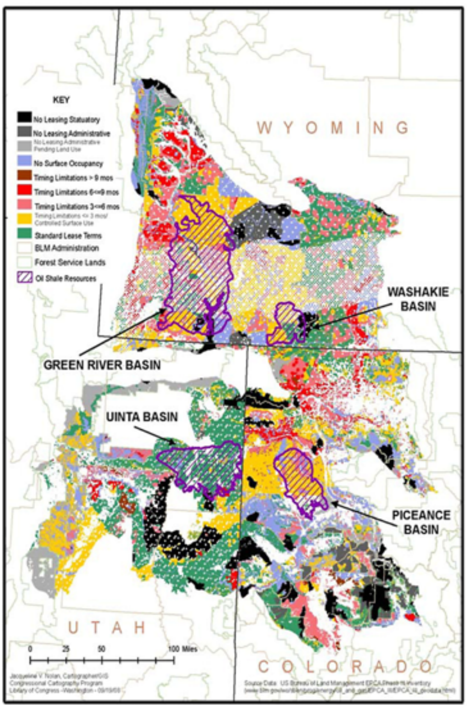
Under Section 526 of EISA 2007, DOD is restricted in buying a fuel derived from oil shale or any other unconventional fuel unless the procurement contract specifies that the lifecycle greenhouse gas emission associated with the fuel's production is less than conventional petroleum derived fuel. Section 334 of the National Defense Authorization Act for FY2009 (S. 3001), however, directs DOD to study alternative fuels in order to reduce lifecycle emissions with the goal of certifying their use in military vehicles and aircraft.

Restrictions to Leasing

EPAct Section 364 amended the Energy Policy and Conservation Act of 2000 (EPCA — 42 U.S.C. 6217) by requiring an inventory of all oil and gas resources underlying onshore federal lands, and an identification of the extent and nature of any restrictions or impediments to their development. The study areas were delineated by aggregating oil and/or natural gas resource plays within the provinces as defined by the U.S. Geological Survey (USGS) National Assessment of Oil and Gas Resources.

Certain lands within the oil shale resource areas are excluded from commercial leasing on the basis of existing laws and regulations, Executive Orders, administrative land use plan designations as noted below, or withdrawals. As a result, commercial leasing is excluded from all designated Wilderness Areas, Wilderness Study Areas (WSAs), other areas that are part of the National Landscape Conservation System (NLCS) administered by the BLM (e.g., National Monuments, National Conservation Areas (NCAs), Wild and Scenic Rivers (WSRs), and National Historic and Scenic Trails), and existing Areas of Critical Environmental Concern (ACECs) that are currently closed to mineral development. Within the oil shale areas, 261,441 acres are designated as Areas of Critical Concern (ACEC), and thus closed to developments (Colorado - 10,790; Utah - 199,521; Wyoming - 51,130). A significant portion of public land within the most geologically prospective oil shale area is already undergoing development of oil, gas and mineral resources. BLM has identified the most geologically prospective areas for oil shale development on the basis of the grade and thickness of the deposits: in Colorado and Utah, deposits that yield 25 gallons of shale oil per ton of rock or more and are 25 feet thick or greater; in Wyoming, 15 gallons/ton or more, and 15 feet thick or greater.

CRS has overlain a profile of the most geologically prospective oil shale resources of the Green River formation over maps of access categories prepared for the EPCA inventory (figure 6). The Uinta basin in Utah is shown as being subject to standard lease terms. The Piceance basin in Colorado is more subject to short term lease of less than three months with controlled surface use. Approximately 5.3 million acres (40%) of the federal land in the Uinta-Piceance study area is not accessible. Currently a total of ~5.2 million federal acres are under oil and gas lease in Colorado, ~4.7 million acres in Utah, and ~12.6 million acres in Wyoming.



State	BLM Administered Oil Shale Lands acres	Land Leased for Oil and Gas Development acres
Colorado	359,798	338,123
Utah	638,192	529,435
Wyoming	1,297,086	917,789

Figure 6. Federal Land Access for the Most Geologically Prospective Oil Shale.

In Colorado, BLM administers approximately 359,798 federal acres of the most geologically prospective oil shale deposits, of which 338,123 acres (94% margin of error is +/-2%) are already under lease for oil and gas development.[29]

In Utah, BLM administers approximately 638,192 federal acres of the most geologically prospective oil shale deposits, of which approximately 529,435 acres (83%) are currently leased for oil and gas development.[30]

In Wyoming, BLM administers approximately 1,297,086 acres of the most geologically prospective oil shale deposits, of which approximately 917,789 acres (71%) are currently leased for oil and gas development.

BLM's policy is to resolve conflicts among competing resources when processing potential leasing action. However, BLM considers the commercial oil shale development technologies currently being evaluated (see discussion below) as largely incompatible with other mineral development activities and would likely preclude those activities while oil shale development and production are ongoing. EPAct Sec. 369 (n) authorizes the Interior Secretary to consider land exchanges to consolidate land ownership and mineral rights into manageable areas.

COMMERCIAL LEASING PROGRAM

RD&D Program

EPAct Sec 369 (c) directed the Secretary of Interior to make land available within each of the States of Colorado, Utah, and Wyoming for leasing to conduct research, development, and demonstration (RD&D) of technologies to recover liquid fuels from oil shale. In a November 2004 Federal Register notice (prior to EPAct's enactment in August 2005), the BLM sought public input on the terms to be included in leases of small tracts for oil shale research and development within the Piceance Creek Basin in northwestern Colorado, the Uinta Basin in southeastern Utah, and the Green River and Washakie Basins in western Wyoming.[31] BLM followed in June 2005, with a solicitation for three nominations of parcels to be leased for research, development, and demonstration of oil shale recovery technologies in Colorado, Utah, and Wyoming.[32] BLM received 20 nominations for parcels in response to its Federal Register announcement, and rejected 14 nominations. On September 20, 2005, the BLM announced it had received 19 nominations for 160-acre parcels of public land to be leased in Colorado, Utah, and Wyoming for oil shale RD&D. On January 17, 2006, BLM announced that it accepted eight proposals from six companies to develop oil shale technologies; the companies selected were Chevron Shale Oil Co., EGL Resources Inc., ExxonMobil Corp., Oil-Tech Exploration LLC, and Shell Frontier Oil & Gas.[33] Five of the proposals will evaluate in situ extraction to minimize surface disturbance. The sixth proposal will employ mining and retorting. Environmental Assessments (EA) prepared for each proposal prepared under the National Environmental Policy Act (NEPA) resulted in a Finding of No Significant Impact. In addition to the 160 acres allowed in the call for RD&D proposals, a contiguous area of 4,960 acres is reserved for the preferential right for each project sponsor to convert to a future commercial lease after additional BLM reviews.

To date, BLM has issued six RD&D leases granting rights to develop oil shale resources on 160-acre tracts of public land (see table 4). The leases grant an initial term of 10 years and the possibility of up to a 5-year extension upon proof of diligent progress toward commercial production. RD&D lessees may also apply to convert the leases plus 4,960 adjacent acres to a 20-year commercial lease once commercial production levels have been achieved and additional requirements are met. The RD&D projects are summarized below, and locations shown in figure 7.

Table 4. RD&D Leases

Lessee	State	Locale	Technology
OSEC	UT	Vernal	Underground mining and surface retorting
Chevron	CO	Piceance Basin, Rio Blanco	In situ/ heated gas injection
EGL	CO	Piceance Basin, Rio Blanco	In situ/ steam injection
Shell	CO	Oil Shale Test Site (1); Piceance Basin, Rio Blanco	In situ Conversion Process (ICP) using self-contained heaters.
Shell	CO	Nahcolite Test Site (2); Piceance Basin, Rio Blanco	Two-Step ICP using hot water injection
Shell	CO	Advanced Heater Test Site (3); Picenace Basin, Rio Blanco	Electric-ICP using bare wire heaters

Source: Final Environmental Assessment [http://www.blm.gov/co/st/en/fo/wrfo/oil_shale_wrfo.html], [ftp://ftp.blm.gov/blmincoming/UT/VN/].

Notes: OSEC — Oil Shale Exploration Co., LLC; EGL — EGL Resources, Inc.; Shell — Shell Frontier Oil and Gas Inc.

OSEC

The Oil Shale Exploration Co., LLC (OSEC) RD&D project will evaluate developing oil shale by underground mining and surface retorting using the

Alberta-Taciuk (ATP) Process — a horizontal rotary kiln retort. The first phase would consist mainly of hauling stockpiles of oil shale to a retorting demonstration plant in Canada. The second phase would consist of moving a demonstration retort processing plant to the former White River Mine area, processing stockpiles of oil shale that are on the surface, and eventually reopening the White River Mine, and the commencement of mining of oil shale. The third phase would involve an upscaling of the retort demonstration plant, continuation of mining, and the construction of various supporting facilities and utility corridors.

OSEC currently intends to use the Petrosix process (a patented retort process) as the technology to process the mined oil shale into shale oil at the White River Mine. The Petrosix process has been under development since the 1950s and is one of the few retorting processes in the world that can show significant oil production while remaining in continuous operation. This retort technology is owned by Petrobras and has been operational in Brazil since 1992. Petrosix is an externally generated hot gas technology. Externally generated hot gas technologies use heat, transferred by gases which are heated outside the retort vessel. As with most internal combustion retort technologies, the Petrosix retort processes oil shale in a vertical shaft kiln where the vapors within the retort are not diluted with combustion exhaust. The world's largest operational surface oil shale pyrolysis reactor is the Petrosix thirty-six foot diameter vertical shaft kiln which is located in São Mateus do Sul, Paraná, Brazil. This retort processes 260 tons of oil shale per hour.[34]

Chevron

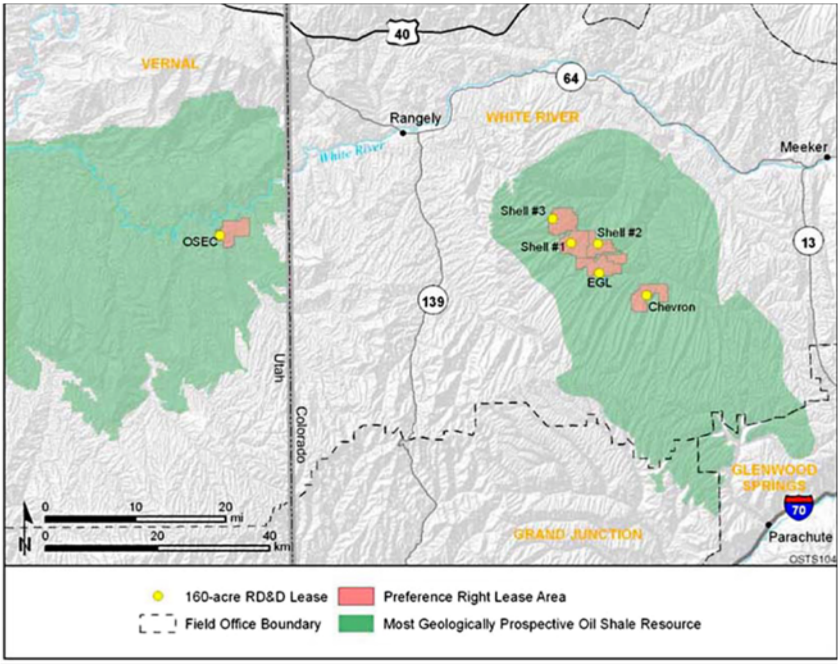
Chevron's research focuses on oil shale recovery using conventional drilling methods and controlled horizontal fracturing technologies to isolate the target interval, and to prepare the production zone for the application of heat to convert the kerogen to oil and gas.[35] The intent of the Chevron proposal is to prove an in-situ development and production method that would apply modified fracturing technologies as a means to control and contain the production process within the target interval. The use of conventional drilling methods is aimed at reducing the environmental footprint and water and power requirements compared to past shale oil extraction technologies. The project will evaluate shale oil within the oil-rich Mahogany zone, an oil shale deposit that is approximately 200 feet thick. It will be conducted in a series of seven distinct phases that would entail drilling wells into the oil shale formation and applying a series of controlled horizontal fractures within the target interval to prepare the production zone for heating and in-situ combustion.

EGL

EGL's research will gather data on oil shale recovery using gentle, uniform heating of the shale to the desired temperature to convert kerogen to oil and gas.[36] The intent of the EGL proposal is to prove an in-situ development and production method using drilling and fracturing technology to install conduit pipes into and beneath the target zone. A closed circulation system would circulate pressurized heating fluid. The methodology requires circulating various heating fluids through the system. EGL plans to test the sequential use of different heating fluids during different phases of the project. Field tests will involve introducing heat near the bottom of the oil shale zones to be retorted. This would result in a gradual, relatively uniform, gentle heating of the shale to 650-750 ºF to convert kerogen to oil and gas. Once sufficient oil has been released to surround the heating elements, EGL anticipates that a broad horizontal layer of boiling oil would continuously convect hot hydrocarbon vapors upward and transfer heat to oil shale above the heating elements. The oil shale that would be tested by EGL at the nominated 160-acre tract is a 300-foot-thick section comprising the Mahogany zone (R-7) and the R-6 zone of the Green River formation, the top of which is at a depth of approximately 1,000-feet. The affected geologic unit would be approximately 1,000 feet long and 100 feet wide.

Shell

Shell Frontier Oil and Gas, Inc. (Shell) intends to develop three pilot projects to gather operating data for three variations to in-situ hydrocarbon recovery from oil shale.[37] At the Shell Oil Shale Test (OST) site (Site 1), testing of in-situ extraction process components and systems will demonstrate the commercial feasibility of extracting hydrocarbons from oil shale. The Second Generation In-situ Conversion Process (ICP) test at Site 2 will determine the practicability of combining already developed nahcolite extraction methods with in-situ hydrocarbon extraction technology.[38] The electric-ICP (E-ICP) or advanced heater technology test at Site 3 will assess an innovative concept for in-situ heating. The sites identified by Shell overlie high grade oil shale yielding more than 25 gallons/ton of shale and a valuable nahcolite resource.



Source: Draft OSTS PEIS. December 2007.

Figure 7. Locations of the Six RD&D Tracts and Associated Preference Right Lease Areas.

Programmatic Environmental Impact Statement

EPAct Sec. 369 (d)(1) directed the Interior Secretary to complete a programmatic environmental impact statement (PEIS) for an oil shale and tar sands commercial leasing program on the most geologically prospective lands within each of the States of Colorado, Utah, and Wyoming.[39] The Notice of Availability of Proposed Oil Shale and Tar Sands Resource Management Plan Amendments To Address Land Use Allocations in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement was published September 5, 2008.[40]

In the final PEIS, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to provide the opportunity for commercial oil shale leasing. The existing resource management plans within the PEIS study area are:

Colorado[41]

- Glenwood Springs RMP (BLM 1988b, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007])
- Grand Junction RMP (BLM 1987)
- White River RMP (BLM 1997a, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007]) Utah.[42]
- Book Cliffs RMP (BLM 1985)
- Diamond Mountain RMP (BLM 1994)
- Grand Staircase!Escalante National Monument RMP (BLM1999)
- Henry Mountain MFP (1982)
- Price River Resource Area MFP, as amended (BLM 1989)
- San Rafael Resource Area RMP (BLM 1991a)
- San Juan Resource Area RMP (BLM 1991b) Wyoming.[43]
- Great Divide RMP (BLM 1990)
- Green River RMP (BLM 1997b, as amended by the Jack Morrow Hills Coordinated Activity Plan [BLM 2006b])
- Kemmerer RMP (BLM 1986)

Three alternatives to commercial leasing were presented in the draft PEIS, and in the Final PEIS, BLM selected Alternative B as the proposed plan amendment. The alternatives are:

- Alternative A — No Action Alternative. Under this alternative, approximately 294,680 acres in Colorado (White River) and 58,100 acres in Utah (Book Cliffs) are currently classified as available for leasing under existing land use plan. No amendments would be made to the plans to identify additional lands for commercial oil shale leasing.
- Alternative B. Under this alternative, BLM is designating 1,991,222 acres available for leasing by amending nine land use plans. This would include BLM-administered lands and split-estate land that the federal government owns mineral rights within the most geologically prospective oil shale areas. Land exempted by statute, regulation, or Executive Order would be excluded.
- Alternative C. This alternative would exclude additional land from commercial leasing under Alternative B, reducing the land available to 830,296 acres. The additionally excluded lands require special management or resource protection under existing land use plans. BLM administers 2,138,361 acres of the most geologically prospective oil shale

lands (table 1). Alternative B makes 93% available for leasing. As discussed below, a significant portion of these lands are already under lease for oil and gas development.

Mineral Leasing Act Amendments

Advocates of oil shale development claimed that restrictions on lease size hindered economic development. EPAct Section 369 (j) amended Section 241(a) of the Mineral Leasing Act (30 U.S.C. 241(a)) by increasing the size of an individual oil shale lease from 5,120 acres to 5,760 acres (9 square miles), but limiting the total acreage that an individual or corporation may acquire in any one state to 50,000 acres (78.125 square miles).[44] Under the act, federal oil and gas lessees may hold to 246,080 acres (384.5 square miles).

Commercial Lease Sale and Royalty Rates

EPAct Section 369 (e) directs a lease sale of oil shale within 180 days of publishing the final lease rules if sufficient interest exists in a state, and Section 369(o) directs BLM in establishing royalties and other payments for oil shale leases that: "(1) Encourage development of the oil shale and tar sands resources; and (2) Ensure a fair return to the United States."

Proposed Leasing Rules

EPAct Section 369 (d)(2) directed the DOI to publish a final regulation establishing a commercial lease program not later than 6 months after the completion of the PEIS. Now expired, Section 433 of the 2008 Consolidated Appropriations Act (P.L. 110-161) stipulated that "None of the funds made available by this Act shall be used to prepare or publish final regulations regarding a commercial leasing program for oil shale resources on public lands pursuant to section 369(d) of the Energy Policy Act of 2005 (Public Law 109-58) or to conduct an oil shale lease sale pursuant to subsection 369(e) of such Act." Section 152 of the Consolidated Security, Disaster Assistance, and Continuing Appropriations Act of 2009 (P.L. 110-329) rescinds the Section 433 spending prohibition effectively through March 2009. In the mean time, BLM published proposed regulations to establish a commercial leasing program of federally owned oil shale on July 28, 2008.[45]

In an advance notice of proposed rulemaking (ANPR), the BLM requested comments and suggestions to assist in the writing of a proposed rule to establish a commercial leasing program for oil shale.[46] Section 369(j) set the annual rental rate for an oil shale lease at $2.00/ acre. Since the statute sets the rental rate, the BLM has no discretion to revise it.

In response to ANPR, BLM received comments expressing various ideas concerning minimum production amounts and requirements ranging from no minimum production to a minimum rate of 1,000 barrels/day. BLM considers the minimum production requirement for 1,000 barrels/day too inflexible a standard because it does not allow for differences in shale quality and differences in extraction technology. A minimum annual production requirement would apply to every lease, and payments in lieu of production beginning with the 10th lease-year. The BLM would determine the payment in lieu of annual production, but in no case would it be less than $4.00/acre. Payments in lieu of production are not unique and are requirements of other BLM mineral leasing regulations, as the BLM believes they provide an incentive to maintain production. A payment in lieu of production of $4.00/acre for the maximum lease size of 5,760 acres equals a payment of $23, 040/ year.

Proposed Royalties

BLM would establish a royalty rate for all products that are sold from or transported off of the lease area. BLM recognizes that encouraging oil shale development presents some unique challenges compared to BLM’s traditional role in managing conventional oil and gas operations. BLM has not yet settled on a single royalty rate for this proposed rule, but instead proposes two royalty rate alternatives in the proposed rule, and may also consider a third alternative, a sliding scale royalty rate.

BLM assumes that the market demand for oil shale resources based on the price of competing sources (e.g., crude oil) of similar end products is expected to provide the primary incentive for future oil shale development. Additional encouragement for development may be provided through the royalty terms employed for oil shale relative to conventional oil and gas royalty terms, but BLM recognizes that such incentives must be balanced against the objective of providing a fair return to taxpayers for the sale of these resources. The range of royalty options BLM initially examined through the ANPR process are summarized in table 5.

Table 5. Proposed Options for Oil Shale Royalty Rates

Proposed Rates	Notes
12.5%	On the first marketable product
12.5%	on value of the mined oil shale as proposed in 1983
8% initial 1% annual increase 12.5 % maximum	on products sold for 10 years, similar to the rates established by the State of Utah in 1980
2% initial 5% maximum	production encouragement, infrastructure established
0%-12.5% Sliding scale	tied to time frames
0%-12.5% Sliding scale	tied to production
Sliding scale	tied to the of crude oil price
1% of gross profit before payout 25% of net profit after payout	based on old Canadian oil sands model
¢ / ton	proposed in the 1973 oil shale prototype program
% / Btu	as compared to crude oil

For comparison, the proposed standard lease terms for for oil and gas, tar sands, and coal are provided below.

Standard Federal Lease and Royalty Terms. Oil and gas in public domain lands are subject to lease under the Mineral Leasing Act of 1920, as amended (30 U.S.C. 181 et seq.) with certain exceptions.[47] All lands available for leasing are offered through competitive bidding, including lands in oil and gas leases that have terminated, expired, been cancelled or relinquished.[48] A lessee has the right to use so much of the leased lands as is necessary to explore for, drill for, mine, extract, remove, and dispose of all the leased resource in a leasehold subject to certain stipulations.[49] The maximum lease holding in any one state is limited to 246,080 acres, and no more than 200,000 acres may be held under an option. Alaska's lease limit is 300,000 acres in the northern leasing district and 300,000 acres in the southern leasing district, of which no more than 200,000 acres may be held under option in each of the two leasing districts. The annual rental for all leases issued after December 22, 1987, is $1.50/acre or fraction thereof for the first five years of the lease term and $2/acre or fraction for any subsequent year (table 6). Generally, a 12½% royalty is paid in amount (royalty-in-kind) or value of the oil and gas produced or sold on mineral interests owned by the United States.[50] A 16b% royalty is paid on noncompetitive leases. In order to encourage the greatest ultimate recovery of oil or gas, the Secretary of the Interior may waive, suspend, or reduce the rental or minimum royalty or reduce the royalty on a portion or the entire leasehold. For heavy oil leases producing crude oil less than 20° on the American Petroleum Institute (API) scale, the royalty may be reduced on a sliding scale from 12½% for 20° API to ½% for 6° API.[51]

Table 6. Federal Standard Lease and Royalty

	Lease Rate ($/acre)	Lease Terms	Royalty (percent)
Federal Oil & Gas	$1.50 to $2.00	Competitive	12½
Federal Oil & Gas		Non-competitive	$16^{2/3}$
Heavy Oil			12½ to ½
Tar Sands	$2.00	10 years	12½
Coal surface	$3.00		12½
Coal underground	$3.00		8

In special tar sand areas, combined hydrocarbon, oil and gas, or tar sand leases are offered competitive bonus bidding.[52] (The terms “tar sands” and “oil sands” are sometime used interchangeably, but here tar sands refers to resources in the United States, and oils sands to Canada.) If no qualifying bid is received during the competitive bidding process, the area offered for a competitive lease may be leased noncompetitively. Combined leases may be awarded, or leases may be awarded exclusively for oil and gas or tar sand development. Combined hydrocarbon leases or tar sand leases in Special Tar Sand Areas cannot exceed 5,760 acres. The minimum acceptable bid is $2.00/acre. Special tar sands area leases have a primary term of 10 years and remain in effect as long as production continues. The rental rate for a combined hydrocarbon lease shall be $2.00/acre/year. The rental rate for a tar sand lease is $1.50/acre for the first 5 years and $2.00/acre for each year thereafter. The royalty rate on all combined hydrocarbon leases or tar sand leases is 12½% of the value of production removed or sold from a lease.

Coal leases may be issued on all federal lands with some exceptions including oil shale.[53] Lease sales may be conducted using cash bonus — fixed royalty bidding systems or any other bidding system adopted through rulemaking procedures. The annual rental cannot be less than $3.00 per acre on any lease issued or readjusted.[54] A coal lease requires payment of a royalty of not less than 12½% of the value of the coal removed from a surface mine and a royalty of 8% of the value of coal removed from an underground mine.[55]

Private Lease Terms

Although information on lease terms for privately held oil shale is unavailable, comparison can be made with terms for private and state-owned land above natural gas-producing shales; for example, the Marcellus and Barnett shales.[56] Bonus payments and royalties received by state and private landowners in West Virginia, Pennsylvania, New York, and Texas are shown in tables 7 and 8. Rents are not included because nearly all of the information available reports on signing bonuses and royalties. Further, rents are often rolled into signing bonuses, and paid upfront or paid quarterly as a "delay rental." Rents appear to be much less significant to small landowners who lease a few acres. On state and private leases, as with federal leases, rents would be paid until production commences, at which time royalties are paid on the value of production. All Marcellus shale lessors have shown significant increases in the amounts paid as signing bonuses and increases in royalty rates. But there are still several lease sales as reported by the Natural Gas Leasing Tracking Service, that record signing bonuses in the range of $100 to $200/acre because of greater uncertainty and less interest among natural gas companies and/or the lack of information among landowners on what the land is worth.[57]

Table 7. Shale Gas Bonus Bids, Rents, and Royalty Rates on Selected State Lands

	Statutory Minimum or Standard Royal Rate	Royalty Rate Range	Bonus Bids (per acre)	Comments
West Virginiaa	12.5%	-	-	
Pennsylvaniab	12.5%	12.5-16%	$2,500	No state shale gas leases
New Yorkc	12.5%	15-20%	about $600	In many cases bonus bids were in the $25-$50 per acre range as recent as 2002. A royalty rate of 12.5% was most common.
Texas	12.5%	25%	$350-$400 (Delaware Basin)	Bonus bids ranged from $15-$600 per acre around 1999-2000 and most royalty rates were

				at 12.5%.

	Statutory Minimum or Standard Royal Rate	Royalty Rate Range	Bonus Bids (per acre)	Comments
			$12,000 (river tracts)	Bonus bids have been relatively consistent in recent times (within the past 5 years). Royalty rates were more common at 20%-25% about 5 years ago. Most state-owned lands are not considered to be among the best sites for shale gas development.

[a] Personal communication with Joe Scarberry in the WV Department of Natural Resources, October 2008.

[b]. Personal communication with Ted Borawski in the PA Bureau of Forestry, who provided information on shale gas leases on both state and private lands, October 2008.

[c] Personal communication with Lindsey Wickham of the NY Farm Bureau and Bert Chetuway of Cornell University, discussed lease sales on state and private land, October 2008.

Table 8. Shale Gas Bonus Bids, Rents, and Royalty Rates on Private Land in Selected States

	Royalty Rates Range	Bonus Bids (per acre)	Comments
West Virginiaa	12.5-18%	$1,000-$3,000	Bonus payments were in the $5 per acre range as recently as 1-2 years ago. Royalty rates were 12.5%
Pennsylvania	17-18%	$2,000-$3,000	
New York	15-20%	$2,000-$3,000	
Texas	25-28%	$10,000-$20,000	Bonus bids were in the $1,000 range around 2000-2001. Royalty rates were in the 20-25% range.

[a]. Personal communication with David McMahon, Director of the WV Surface Owners Rights Organization, October 2008.

CONCLUSION AND POLICY PERSPECTIVE[58]

Shale oil is difficult and expensive to extract and has not competed well with conventional oil supplies in the past. The major barrier has been cost, but additional barriers are potential environmental damage during development, and the cost of refining and transportation from the interior western United States.

The recent spike in crude oil price has once again stirred interest in oil shale. As in the past, however, the rapid runup in prices (to a high of $145/barrel) was soon followed by a rapid and precipitous drop in prices ($64/barrel at the time of this writing). Although the major oil companies have reaped record profits, such price volatility discourages investment in contingent resources such as oil shale. Oil price volatility has produced patterns of boom and bust for oil shale, as seen in the interest in oil shale development in the early 1980s, followed by the cancellation of Exxon's $5 billion Colony Oil Shale Project in 1982, and the cancellation of loan guarantees under the Synthetic Fuels Corporation.

Volatility in the price of oil affects all contingent or marginal hydrocarbon resources. After considerable investment in unconventional oil sand resources, Canadian producers have announced cutbacks in capital spending and are scaling back or cancelling plans for expansion altogether. While OPEC cuts oil output to prop up prices, the major and super-major oil companies continue to use an oil price of $32/barrel for their business planning. In this climate, the development of oil shale seems difficult indeed. While oil shale development faces continuous challenges, the exploration and production of conventional oil and gas grows steadily in the region.

The regional isolation of the massive oil shale deposits of western Colorado, eastern Utah, and southwestern Wyoming provides both opportunity and challenges for developing shale oil there. Shale oil is best used to produce middle distillate diesel and jet fuel, commodities in high demand in the region. Additionally, the oil and product pipeline infrastructure into and out of the region is limited, so moving shale oil to another region for refining is difficult, and importing refined product is equally difficult. This isolation provides an opportunity for shale oil as long as regional refining capacity is available.

An additional point of uncertainty is introduced by the government's changes in rules. A recent spending moratorium on finalization of the commercial leasing rules had added considerable uncertainty to oil shale development. Without a final rule, no developer could attract investors or plan for full development of the oil shale resources. The subsequent rescission of the spending moratorium now allows final rule making to be completed before the 111th Congress convenes. In the meantime, much of the land surface that might be leased for oil shale development has already been leased for conventional oil and gas development, adding further complication to the leasing process.

The oil shale boom-bust cycles are part of the cause of, and also the result of, an exodus of skilled labor and technical talent from the Rocky Mountain region. Whole communities grew up around the oil shale development of the 1980s, only to disappear again when the projects stopped. The uncertainty surrounding the viability of oil shale development, combined with competition from the conventional oil and gas industry and from other regions, makes it difficult to recruit and keep skilled labor for oil shale development.

Finally, the draft leasing rules are silent on CO2 emission requirements; and yet oil shale development may be accompanied by troublesome emission of CO2 as a result of the retorting process. Full analysis of CO2 emissions from oil shale development must wait until the research and development phase of shale oil production is completed. Such an analysis would probably be part of the environmental impact statement required for permitting commercial development. Canada’s oil sands industry has demonstrated that emission concerns may be addressed over time as technology develops.

Oil shale, along with other unconventional and alternative energy sources, will continue to struggle as long as oil prices are volatile. Sustained high oil prices will likely be required to motivate oil shale developers to make the massive investments required for ongoing production of oil from shale. Although the quantities of hydrocarbons held in oil shale is staggering, its development remains uncertain.

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Chapter 7

GEOLOGY AND RESOURCES OF SOME WORLD OIL-SHALE DEPOSITS*[1]

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ABSTRACT

Oil-shale deposits are in many parts of the world. They range in age from Cambrian to Tertiary and were formed in a variety of marine, continental, and lacustrine depositional environments. The largest known deposit is in the Green River Formation in the western United States; it contains an estimated 213 billion tons of in-situ shale oil (about 1.5 trillion U.S. barrels).

Total resources of a selected group of oil shale deposits in 33 countries are estimated at 409 billion tons of in-situ shale oil, which is equivalent to 2.8 trillion U.S. barrels of shale oil. These amounts are very conservative because (1) several deposits mentioned herein have not been explored sufficiently to make accurate estimates, and (2) some deposits were not included in this survey.

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[1] An earlier version of this report was published in Oil Shale, 2003, v. 20, no. 3, p. 193–252.

INTRODUCTION

Oil shale is commonly defined as a fine-grained sedimentary rock containing organic matter that yields substantial amounts of oil and combustible gas upon destructive distillation. Most of the organic matter is insoluble in ordinary organic solvents; therefore, it must be decomposed by heating to release such materials. Underlying most definitions of oil shale is its potential for the economic recovery of energy, including shale oil and combustible gas, as well as a number of byproducts. A deposit of oil shale having economic potential is generally one that is at or near enough to the surface to be developed by open-pit or conventional underground mining or by in-situ methods.

Oil shales range widely in organic content and oil yield. Commercial grades of oil shale, as determined by their yield of shale oil, ranges from about 100 to 200 liters per metric ton (l/t) of rock. The U.S. Geological Survey has used a lower limit of about 40 l/t for classification of Federal oil-shale lands. Others have suggested a limit as low as 25 l/t.

Deposits of oil shale are in many parts of the world. These deposits, which range from Cambrian to Tertiary age, may occur as minor accumulations of little or no economic value or giant deposits that occupy thousands of square kilometers and reach thicknesses of 700 m or more. Oil shales were deposited in a variety of depositional environments, including fresh-water to highly saline lakes, epicontinental marine basins and subtidal shelves, and in limnic and coastal swamps, commonly in association with deposits of coal.

In terms of mineral and elemental content, oil shale differs from coal in several distinct ways. Oil shales typically contain much larger amounts of inert mineral matter (60–90 percent) than coals, which have been defined as containing less than 40 percent mineral matter. The organic matter of oil shale, which is the source of liquid and gaseous hydrocarbons, typically has a higher hydrogen and lower oxygen content than that of lignite and bituminous coal.

In general, the precursors of the organic matter in oil shale and coal also differ. Much of the organic matter in oil shale is of algal origin, but may also include remains of vascular land plants that more commonly compose much of the organic matter in coal. The origin of some of the organic matter in oil shale is obscure because of the lack of recognizable biologic structures that would help identify the precursor organisms. Such materials may be of bacterial origin or the product of bacterial degradation of algae or other organic matter.

The mineral component of some oil shales is composed of carbonates including calcite, dolomite, and siderite, with lesser amounts of aluminosilicates.

For other oil shales, the reverse is true—silicates including quartz, feldspar, and clay minerals are dominant and carbonates are a minor component. Many oil-shale deposits contain small, but ubiquitous, amounts of sulfides including pyrite and marcasite, indicating that the sediments probably accumulated in dysaerobic to anoxic waters that prevented the destruction of the organic matter by burrowing organisms and oxidation.

Although shale oil in today's (2004) world market is not competitive with petroleum, natural gas, or coal, it is used in several countries that possess easily exploitable deposits of oil shale but lack other fossil fuel resources. Some oil-shale deposits contain minerals and metals that add byproduct value such as alum [$KAl(SO_4)2•12H_2O$], nahcolite ($NaHCO_3$), dawsonite [$NaAl(OH)_2CO_3$], sulfur, ammonium sulfate, vanadium, zinc, copper, and uranium.

The gross heating value of oil shales on a dry-weight basis ranges from about 500 to 4,000 kilocalories per kilogram (kcal/kg) of rock. The high-grade kukersite oil shale of Estonia, which fuels several electric power plants, has a heating value of about 2,000 to 2,200 kcal/kg. By comparison, the heating value of lignitic coal ranges from 3,500 to 4,600 kcal/kg on a dry, mineral-free basis (American Society for Testing Materials, 1966).

Tectonic events and volcanism have altered some deposits. Structural deformation may impair the mining of an oilshale deposit, whereas igneous intrusions may have thermally degraded the organic matter. Thermal alteration of this type may be restricted to a small part of the deposit, or it may be widespread making most of the deposit unfit for recovery of shale oil.

The purpose of this report is to (1) discuss the geology and summarize the resources of selected deposits of oil shale in varied geologic settings from different parts of the world and (2) present new information on selected deposits developed since 1990 (Russell, 1990).

RECOVERABLE RESOURCES

The commercial development of an oil-shale deposit depends upon many factors. The geologic setting and the physical and chemical characteristics of the resource are of primary importance. Roads, railroads, power lines, water, and available labor are among the factors to be considered in determining the viability of an oil-shale operation. Oil-shale lands that could be mined may be preempted by present land usage such as population centers, parks, and wildlife refuges. Development of new in-situ mining and processing technologies may allow an oil-shale operation in previously restricted areas without causing damage to the surface or posing problems of air and water pollution.

The availability and price of petroleum ultimately effect the viability of a large-scale oil-shale industry. Today, few, if any deposits can be economically mined and processed for shale oil in competition with petroleum. Nevertheless, some countries with oil-shale resources, but lack petroleum reserves, find it expedient to operate an oil-shale industry. As supplies of petroleum diminish in future years and costs for petroleum increase, greater use of oil shale for the production of electric power, transportation fuels, petrochemicals, and other industrial products seems likely.

DETERMINING GRADE OF OIL SHALE

The grade of oil shale has been determined by many different methods with the results expressed in a variety of units. The heating value of the oil shale may be determined using a calorimeter. Values obtained by this method are reported in English or metric units, such as British thermal units (Btu) per pound of oil shale, calories per gram (cal/gm) of rock, kilocalories per kilogram (kcal/kg) of rock, megajoules per kilogram (MJ/kg) of rock, and other units. The heating value is useful for determining the quality of an oil shale that is burned directly in a power plant to produce electricity. Although the heating value of a given oil shale is a useful and fundamental property of the rock, it does not provide information on the amounts of shale oil or combustible gas that would be yielded by retorting (destructive distillation).

The grade of oil shale can be determined by measuring the yield of oil of a shale sample in a laboratory retort. This is perhaps the most common type of analysis that is currently used to evaluate an oil-shale resource. The method commonly used in the United States is called the "modified Fischer assay," first developed in Germany, then adapted by the U.S. Bureau of Mines for analyzing oil shale of the Green River Formation in the western United States (Stanfield and Frost, 1949). The technique was subsequently standardized as the American Society for Testing and Materials Method D- 3904-80 (1984). Some laboratories have further modified the Fischer assay method to better evaluate different types of oil shale and different methods of oil-shale processing.

The standardized Fischer assay method consists of heating a 100-gram sample crushed to –8 mesh (2.38-mm mesh) screen in a small aluminum retort to 500ºC at a rate of 12ºC per minute and held at that temperature for 40 minutes. The distilled vapors of oil, gas, and water are passed through a condenser cooled with ice water into a graduated centrifuge tube. The oil and water are then separated by centrifuging. The quantities reported are the weight percentages of shale oil (and its specific gravity), water, shale residue, and “gas plus loss” by difference.

The Fischer assay method does not determine the total available energy in an oil shale. When oil shale is retorted, the organic matter decomposes into oil, gas, and a residuum of carbon char remaining in the retorted shale. The amounts of individual gases—chiefly hydrocarbons, hydrogen, and carbon dioxide—are not normally determined but are reported collectively as “gas plus loss,” which is the difference of 100 weight percent minus the sum of the weights of oil, water, and spent shale. Some oil shales may have a greater energy potential than that reported by the Fischer assay method depending on the components of the “gas plus loss.”

The Fischer assay method also does not necessarily indicate the maximum amount of oil that can be produced by a given oil shale. Other retorting methods, such as the Tosco II process, are known to yield in excess of 100 percent of the yield reported by Fischer assay. In fact, special methods of retorting, such as the Hytort process, can increase oil yields of some oil shales by as much as three to four times the yield obtained by the Fischer assay method (Schora and others, 1983; Dyni and others, 1990). At best, the Fischer assay method only approximates the energy potential of an oil-shale deposit.

Newer techniques for evaluating oil-shale resources include the Rock-Eval and the “material-balance” Fischer assay methods. Both give more complete information about the grade of oil shale, but are not widely used. The modified Fischer assay, or close variations thereof, is still the major source of information for most deposits.

It would be useful to develop a simple and reliable assay method for determining the energy potential of an oil shale that would include the total heat energy and the amounts of oil, water, combustible gases including hydrogen, and char in sample residue.

Origin of Organic Matter

Organic matter in oil shale includes the remains of algae, spores, pollen, plant cuticle and corky fragments of herbaceous and woody plants, and other cellular remains of lacustrine, marine, and land plants. These materials are composed chiefly of carbon, hydrogen, oxygen, nitrogen, and sulfur. Some organic matter retains enough biological structures so that specific types can be identified as to genus and even species. In some oil shales, the organic matter is unstructured and is best described as amorphous (bituminite). The origin of this amorphous material is not well known, but it is likely a mixture of degraded algal or bacterial remains. Small amounts of plant resins and waxes also contribute to the organic matter. Fossil shell and bone fragments composed of phosphatic and carbonate minerals, although of organic origin, are excluded from the definition of organic matter used herein and are considered to be part of the mineral matrix of the oil shale.

Most of the organic matter in oil shales is derived from various types of marine and lacustrine algae. It may also include varied admixtures of biologically higher forms of plant debris that depend on the depositional environment and geographic position. Bacterial remains can be volumetrically important in many oil shales, but they are difficult to identify.

Most of the organic matter in oil shale is insoluble in ordinary organic solvents, whereas some is bitumen that is soluble in certain organic solvents. Solid hydrocarbons, including gilsonite, wurtzilite, grahamite, ozokerite, and albertite, are present as veins or pods in some oil shales. These hydrocarbons have somewhat varied chemical and physical characteristics, and several have been mined commercially.

THERMAL MATURITY OF ORGANIC MATTER

The thermal maturity of an oil shale refers to the degree to which the organic matter has been altered by geothermal heating. If the oil shale is heated to a high enough temperature, as may be the case if the oil shale were deeply buried, the organic matter may thermally decompose to form oil and gas. Under such circumstances, oil shales can be source rocks for petroleum and natural gas. The Green River oil shale, for example, is presumed to be the source of the oil in the Red Wash field in northeastern Utah. On the other hand, oil-shale deposits that have economic potential for their shale-oil and gas yields are geothermally immature and have not been subjected to excessive heating. Such deposits are generally close enough to the surface to be mined by open-pit, underground mining, or by in-situ methods.

The degree of thermal maturity of an oil shale can be determined in the laboratory by several methods. One technique is to observe the changes in color of the organic matter in samples collected from varied depths in a borehole.

Assuming that the organic matter is subjected to geothermal heating as a function of depth, the colors of certain types of organic matter change from lighter to darker colors. These color differences can be noted by a petrographer and measured using photometric techniques.

Geothermal maturity of organic matter in oil shale is also determined by the reflectance of vitrinite (a common constituent of coal derived from vascular land plants), if present in the rock. Vitrinite reflectance is commonly used by petroleum explorationists to determine the degree of geothermal alteration of petroleum source rocks in a sedimentary basin. A scale of vitrinite reflectances has been developed that indicates when the organic matter in a sedimentary rock has reached temperatures high enough to generate oil and gas. However, this method can pose a problem with respect to oil shale, because the reflectance of vitrinite may be depressed by the presence of lipid-rich organic matter.

Vitrinite may be difficult to recognize in oil shale because it resembles other organic material of algal origin and may not have the same reflectance response as vitrinite, thereby leading to erroneous conclusions. For this reason, it may be necessary to measure vitrinite reflectance from laterally equivalent vitrinite-bearing rocks that lack the algal material.

In areas where the rocks have been subjected to complex folding and faulting or have been intruded by igneous rocks, the geothermal maturity of the oil shale should be evaluated for proper determination of the economic potential of the deposit.

CLASSIFICATION OF OIL SHALE

Oil shale has received many different names over the years, such as cannel coal, boghead coal, alum shale, stellarite, albertite, kerosene shale, bituminite, gas coal, algal coal, wollongite, schistes bitumineux, torbanite, and kukersite. Some of these names are still used for certain types of oil shale. Recently, however, attempts have been made to systematically classify the many different types of oil shale on the basis of the depositional environment of the deposit, the petrographic character of the organic matter, and the precursor organisms from which the organic matter was derived.

A useful classification of oil shales was developed by A.C. Hutton (1987, 1988, 1991), who pioneered the use of blue/ultraviolet fluorescent microscopy in the study of oilshale deposits of Australia. Adapting petrographic terms from coal terminology, Hutton developed a classification of oil shale based primarily on the origin of the organic matter. His classification has proved to be useful for correlating different kinds of organic matter in oil shale with the chemistry of the hydrocarbons derived from oil shale.

Hutton (1991) visualized oil shale as one of three broad groups of organic-rich sedimentary rocks: (1) humic coal and carbonaceous shale, (2) bitumen-impregnated rock, and (3) oil shale. He then divided oil shale into three groups based upon their environments of deposition—terrestrial, lacustrine, and marine (figure 1).

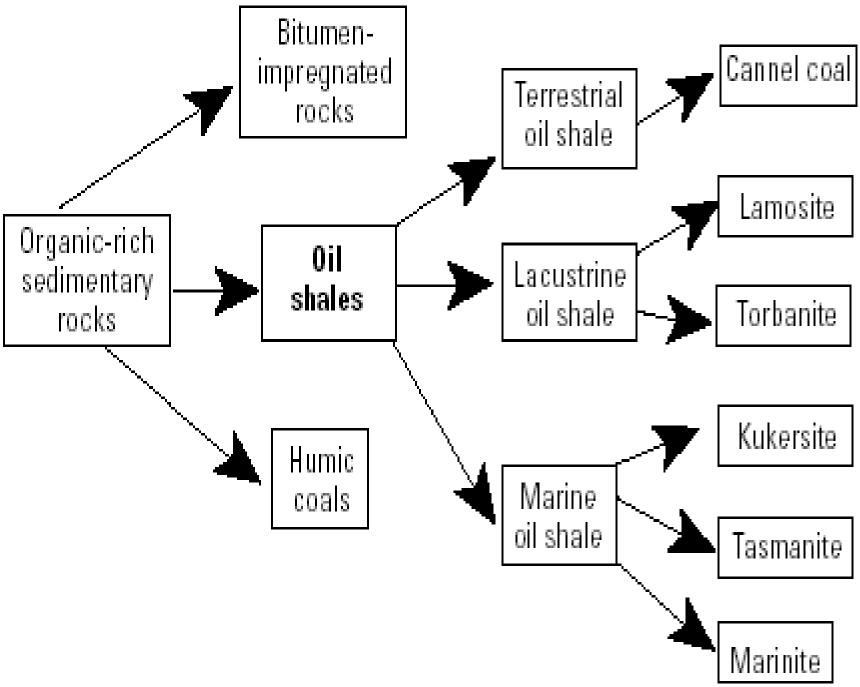


Figure 1. Classification of oil shales. Adapted from Hutton (1987).

Terrestrial oil shales include those composed of lipid-rich organic matter such as resin spores, waxy cuticles, and corky tissue of roots, and stems of vascular terrestrial plants commonly found in coal-forming swamps and bogs. Lacustrine oil shales include lipid-rich organic matter derived from algae that lived in freshwater, brackish, or saline lakes. Marine oil shales are composed of lipid-rich organic matter derived from marine algae, acritarchs (unicellular organisms of questionable origin), and marine dinoflagellates.

Several quantitatively important petrographic components of the organic matter in oil shale—telalginite, lamalginite, and bituminite—are adapted from coal petrography. Telalginite is organic matter derived from large colonial or thick-walled unicellular algae, typified by genera such as Botryococcus. Lamalginite includes thin-walled colonial or unicellular algae that occurs as laminae with little or no recognizable biologic structures. Telalginite and lamalginite fluoresce brightly in shades of yellow under blue/ultraviolet light.

Bituminite, on the other hand, is largely amorphous, lacks recognizable biologic structures, and weakly fluoresces under blue light. It commonly occurs as an organic groundmass with fine-grained mineral matter. The material has not been fully characterized with respect to its composition or origin, but it is commonly an important component of marine oil shales. Coaly materials including vitrinite and inertinite are rare to abundant components of oil shale; both are derived from humic matter of land plants and have moderate and high reflectance, respectively, under the microscope.

Within his three-fold grouping of oil shales (terrestrial, lacustrine, and marine), Hutton (1991) recognized six specific oil-shale types: cannel coal, lamosite, marinite, torbanite, tasmanite, and kukersite. The most abundant and largest deposits are marinites and lamosites.

Cannel coal is brown to black oil shale composed of resins, spores, waxes, and cutinaceous and corky materials derived from terrestrial vascular plants together with varied amounts of vitrinite and inertinite. Cannel coals originate in oxygen-deficient ponds or shallow lakes in peat-forming swamps and bogs (Stach and others, 1975, p. 236–237).

Lamosite is pale- and grayish-brown and dark gray to black oil shale in which the chief organic constituent is lamalginite derived from lacustrine planktonic algae. Other minor components in lamosite include vitrinite, inertinite, telalginite, and bitumen. The Green River oil-shale deposits in western United States and a number of the Tertiary lacustrine deposits in eastern Queensland, Australia, are lamosites.

Marinite is a gray to dark gray to black oil shale of marine origin in which the chief organic components are lamalginite and bituminite derived chiefly from marine phytoplankton. Marinite may also contain small amounts of bitumen, telalginite, and vitrinite. Marinites are deposited typically in epeiric seas such as on broad shallow marine shelves or inland seas where wave action is restricted and currents are minimal. The Devonian–Mississippian oil shales of eastern United States are typical marinites. Such deposits are generally widespread covering hundreds to thousands of square kilometers, but they are relatively thin, often less than about 100 m.

Torbanite, tasmanite, and kukersite are related to specific kinds of algae from which the organic matter was derived; the names are based on local geographic features. Torbanite, named after Torbane Hill in Scotland, is a black oil shale whose organic matter is composed mainly of telalginite derived largely from lipid-rich Botryococcus and related algal forms found in fresh- to brackish-water lakes. It also contains small amounts of vitrinite and inertinite. The deposits are commonly small, but can be extremely high grade. Tasmanite, named from oil-shale deposits in Tasmania, is a brown to black oil shale. The organic matter consists of telalginite derived chiefly from unicellular tasmanitid algae of marine origin and lesser amounts of vitrinite, lamalginite, and inertinite. Kukersite, which takes its name from Kukruse Manor near the town of Kohtla-Järve, Estonia, is a light brown marine oil shale. Its principal organic component is telalginite derived from the green alga, *Gloeocapsomorpha prisca*. The Estonian oil-shale deposit in northern Estonia along the southern coast of the Gulf of Finland and its eastern extension into Russia, the Leningrad deposit, are kukersites.

Evaluation of Oil-Shale Resources

Relatively little is known about many of the world's deposits of oil shale and much exploratory drilling and analytical work need to be done. Early attempts to determine the total size of world oil-shale resources were based on few facts, and estimating the grade and quantity of many of these resources were speculative, at best. The situation today has not greatly improved, although much information has been published in the past decade or so, notably for deposits in Australia, Canada, Estonia, Israel, and the United States.

Evaluation of world oil-shale resources is especially difficult because of the wide variety of analytical units that are reported. The grade of a deposit is variously expressed in U.S. or Imperial gallons of shale oil per short ton (gpt) of rock, liters of shale oil per metric ton (l/t) of rock, barrels, short or metric tons of shale oil, kilocalories per kilogram (kcal/kg) of oil shale, or gigajoules (GJ) per unit weight of oil shale. To bring some uniformity into this assessment, oil-shale resources in this report are given in both metric tons of shale oil and in equivalent U.S. barrels of shale oil, and the grade of oil shale, where known, is expressed in liters of shale oil per metric ton (l/t) of rock. If the size of the resource is expressed only in volumetric units (barrels, liters, cubic meters, and so on), the density of the shale oil must be known or estimated to convert these values to metric tons. Most oil shales produce shale oil that ranges in density from about

0.85 to 0.97 by the modified Fischer assay method. In cases where the density of the shale oil is unknown, a value of 0.910 is assumed for estimating resources.

Byproducts may add considerable value to some oilshale deposits. Uranium, vanadium, zinc, alumina, phosphate, sodium carbonate minerals, ammonium sulfate, and sulphur are some of the potential byproducts. The spent shale after retorting is used to manufacture cement, notably in Germany and China. The heat energy obtained by the combustion of the organic matter in oil shale can be used in the cement-making process. Other products that can be made from oil shale include specialty carbon fibers, adsorbent carbons, carbon black, bricks, construction and decorative blocks, soil additives, fertilizers, rock wool insulating material, and glass.

Most of these uses are still small or in experimental stages, but the economic potential is large.

This appraisal of world oil-shale resources is far from complete. Many deposits are not reviewed because data or publications are unavailable. Resource data for deeply buried deposits, such as a large part of the Devonian oil-shale deposits in eastern United States, are omitted, because they are not likely to be developed in the foreseeable future. Thus, the total resource numbers reported herein should be regarded as conservative estimates. This review focuses on the larger deposits of oil shale that are being mined or have the best potential for development because of their size and grade.

AUSTRALIA

The oil-shale deposits of Australia range from small and noneconomic to deposits large enough for commercial development. The “demonstrated” oil-shale resources of Australia total 58 billion tons, from which about 3.1 billion tons of oil (24 billion barrels) is recoverable (Crisp and others, 1987, p. 1) (table 1).

Australian oil-shale deposits range in age from Cambrian to Tertiary and are diverse in origin. The deposits are located in the eastern one-third of the country, including Queensland, New South Wales, South Australia, Victoria, and Tasmania (figure 2). The deposits having the best potential for economic development are those located in Queensland and include the lacustrine Rundle, Stuart, and Condor deposits of Tertiary age. The marine Toolebuc oil shale of Early Cretaceous age occupies a large area mostly in Queensland. The torbanite deposits at Joadja Creek and Glen Davis in New South Wales and the tasmanite deposits in Tasmania were mined for shale oil in the last half of the 1800s and into the early 1900s. The remaining resources of these high-grade deposits are not commercially important (Alfredson, 1985, p. 162). Some of the colourful history of the oil-shale operations at Joadja Creek is described by Knapman (1988). Glen Davis, which closed in 1952, was the last oil-shale operation in Australia until the Stuart Project began operations in the late 1990s. About 4 million tons of oil shale were mined in Australia between 1860 and 1952 (Crisp and others, 1987, their fig. 2).

Torbanite

Much of the early production of oil shale in Australia was from the torbanite deposits of New South Wales. As many as 16 deposits were exploited between the 1860s and 1960s. During the early years of mining, torbanite was used for gas enrichment in Australia and overseas, but paraffin, kerosene, and wood preserving and lubricating oils were also produced. Later, in the 1900s, torbanite was used to produce gasoline. Although the torbanite assayed as high as 480 to 600 l/t, the average feed to the retort was probably about 220 to 250 l/t. Of 30 deposits in New South Wales, 16 were commercially exploited (Crisp and others, 1987, p. 6).

Two small deposits of torbanite have been investigated in Queensland. These include the small but high-grade Alpha deposit, which constitutes a potential in-situ resource of 19 million U.S. barrels (Noon, 1984, p. 4) and a smaller deposit at Carnarvon Creek.

Tasmanite

Several companies attempted to develop the marine tasmanite deposits of Permian age in Tasmania during the early 1900s. Between 1910 and 1932, a total of 1,100 m$_3$ (about 7,600 barrels) of shale oil was produced from several intermittent operations. Further developments are unlikely unless new resources are found (Crisp and others, 1987, p. 7–8).

Table 1. Demonstrated resources of oil-shale deposits in Australia (from Crisp and others, 1987, their table 1). [ton, metric ton; l/t, liters per metric ton of rock; km, kilometer; m, meter; bbl, U.S. barrel]

					Recoverable oil	
Deposit	Age	In-situ oil (106 tons)	Yield (l/t)	Area (km)	(106 m)	(106 bbls)
Alpha	Tertiary	17	200+	10	13	80

Condor	do	17,000	65	60	1,100	6,700
Duaringa	do	10,000	82	720	590	3,700
Julia Creek	Cretaceous	4,000	70	250	270	1,700
Lowmead	Tertiary	1,800	84	25	120	740
Nagoorin	do	6,300	90	24	420	2,700
Nagoorin South	do	1,300	78	18	74	470
Rundle	do	5,000	105	25	420	2,700
					Recoverable oil	
Deposit	Age	In-situ oil (106 tons)	Yield (l/t)	Area (km)	(106 m)	(106 bbls)
Stuart	do	5,200	94	32	400	2,500
Yaamba	do	6,100	95	32	440	2,800
New South Wales						
Baerami	Permian	11	260	-	3	17
Glen Davis	do	6	420	-	4	23
Tasmania						
Mersey River	do	55	120	--	8	48
Totals		57,000			3,900	24,000

Toolebuc Oil Shale

Oil shale in the marine Toolebuc Formation of Early Cretaceous age underlies about 484,000 km2 in parts of the Eromanga and Carpenteria Basins in Queensland and adjacent States (figure 2). The oil-shale zone ranges from 6.5 to 7.5 m in thickness but yields on average only about 37 l/t, making it a low-grade resource. However, the Toolebuc Formation is estimated to contain 245 billion m3 (~1.7 trillion barrels) of in- situ shale oil. Excluding weathered oil shale from the surface to a depth of 50 m, about 20 percent (49 billion m3 or 340 billion barrels) of the shale-oil resource between the depths of 50 to 200 m could be produced by open-pit mining (Ozimic and Saxby, 1983, p. 1). The oil shale also contains potential resources of uranium and vanadium. One of the more favorable localities for oil-shale development is near Julia Creek, where the Toolebuc oil shale is near the surface and is amenable to open-pit mining. The resources of shale oil in the Toolebuc Formation suitable for open-pit mining total 1.5 billion U.S. barrels, but the oil shale is too low grade for development at present (Noon, 1984, p. 5).

The organic matter of the Toolebuc oil shale is composed largely of bituminite, liptodetrinite, and lamalginite (Hutton, 1988, p. 210; Sherwood and Cook, 1983, p. 36). The atomic hydrogen to carbon (H/C) ratio of the organic matter is about 1.1 ±0.2 with high aromaticity (>50 percent). Only 25 percent of the organic matter converts to oil by conventional retorting (Ozimic and Saxby, 1983).

Eastern Queensland

As a result of the increase in the price of crude oil related to the oil crisis of 1973–74, exploration for oil shale in Australia was greatly accelerated. Several companies identified or confirmed sizable resources of oil shale at Rundle, Condor, Duaringa, Stuart, Byfield, Mt. Coolon, Nagoorin, and Yaamba in eastern Queensland during the late 1970s and early 1980s. However, by 1986, the prices of crude oil dropped dramatically, and interest in the exploitation of oil shale diminished (Crisp and others, 1987, p. 9).

Nine Tertiary oil-shale deposits in eastern Queensland have been investigated by exploratory core drilling—Byfield, Condor, Duaringa, Lowmead, Nagoorin, Nagoorin South, Rundle, Stuart, and Yaamba (fig. 2). Most of these deposits are lamosites that were deposited in freshwater lakes located in grabens, commonly in association with coal-forming swamps.

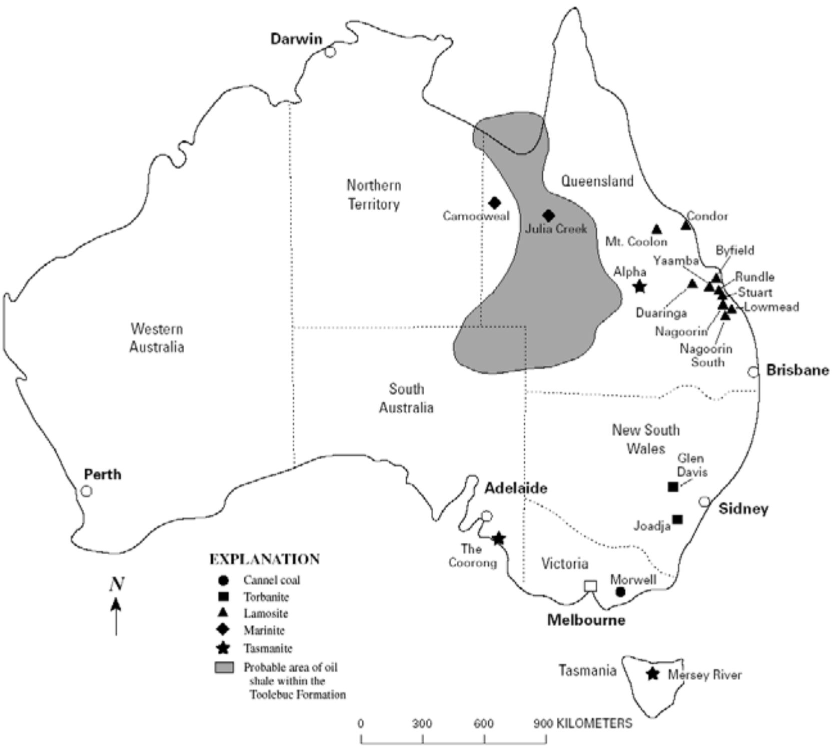


Figure 2. Deposits of oil shale in Australia. From Crisp and others (1987, their fig. 1). Area of Toolebuc oil shale from Cook and Sherwood (1989, their fig. 2)..

The mineral fraction is typically composed of quartz and clay minerals with lesser amounts of siderite, carbonate minerals, and pyrite. The sizes of the deposits range from 1 to 17.4 billion tons of in-situ shale oil with cutoff grades of around 50 l/t. Three of the largest deposits are Condor (17.4 billion tons), Nagoorin (6.3 billion tons), and Rundle (5.0 billion tons) (Crisp and others, 1987).

The Stuart oil-shale deposit, estimated to contain 3 billion barrels of in-situ shale oil, is under development by the Southern Pacific Petroleum (SPP) and Central Pacific Minerals (CPM) companies. As of February 2003, 1.16 million tons of oil shale were mined by open pit from which 702,000 barrels of shale oil were recovered by the Taciuk retorting process. Shale-oil production runs during 87 days of operation from September 20, 2003, to January 19, 2004, peaked at 3,700 barrels per day and averaged 3,083 barrels per day (SSP/CPM Dec. 2003 Quarterly Report, January 21, 2004). The Stuart operation shut down in October 2004 for further evaluation.

BRAZIL

At least nine deposits of oil shale ranging from Devonian to Tertiary age have been reported in different parts of Brazil (Padula, 1969). Of these, two deposits have received the most interest: (1) the lacustrine oil shale of Tertiary age in the Paraíba Valley in the State of São Paulo northeast of the city of São Paulo; and (2) the oil shale of the Permian Iratí Formation, a widespread unit in the southern part of the country (fig. 3).

Paraíba Valley

Two areas in Paraíba Valley totaling 86 km2 contain a reserve of 840 million barrels of in-situ shale oil as determined by drilling. The total resource is estimated at 2 billion barrels. The unit of interest, which is 45 m thick, includes several types of oil shale: (1) brown to dark brown fossiliferous laminated paper shale that contains 8.5 to 13 weight percent oil equivalent, (2) semipapery oil shale of the same color containing 3 to 9 weight percent oil equivalent, and (3) dark olive, sparsely fossiliferous, low-grade oil shale that fractures semi-conchoidally.

Iratí Formation

Oil shale of the Permian Iratí Formation has the greatest potential for economic development because of its accessibility, grade, and widespread distribution. The Iratí Formation crops out in the northeastern part of the State of São Paulo and extends southward for 1,700 km to the southern border of Rio Grande do Sul into northern Uruguay (fig. 3). The total area underlain by the Iratí Formation is unknown because the western part of the deposit is covered by lava flows.

Figure 3. Deposits of oil shale in Brazil. From Padula (1969, his fig. 1).

In the State of Rio Grande do Sul, the oil shale is in two beds separated by 12 m of shale and limestone. The beds are thickest in the vicinity of São Gabriel, where the upper bed is 9 m thick and thins to the south and east, and the lower bed is 4.5 m thick and also thins to the south. In the State of Paraná, in the vicinity of São Mateus do Sul-Iratí, the upper and lower oil-shale beds are 6.5 and 3.2 m thick, respectively (fig. 4). In the State of São Paulo and part of Santa Catarina, there are as many as 80 beds of oil shale, each ranging from a few millimetres to several meters in thickness, which are distributed irregularly through a sequence of limestone and dolomite.

Core drilling outlined an area of about 82 km2 that contains an oil-shale reserve of more than 600 million barrels (about 86 million tons) of shale-oil equivalent, or about 7.3 million barrels/km2 near São Mateus do Sul in southern Paraná. In the San Gabriel and Dom Pedrito areas of Rio Grande do Sul, the lower bed yields about 7 weight percent shale oil and contains similar resources, but the upper bed yields only 2–3 percent oil and is not considered suitable for exploitation (Padula, 1969).

The Iratí oil shale is dark gray, brown, and black, very fine grained, and laminated. Clay minerals compose 60–70 percent of the rock and organic matter makes up much of the remainder, with minor contributions of detrital quartz, feldspar, pyrite, and other minerals. Carbonate minerals are sparse. The Iratí oil shale is not notably enriched in metals, unlike marine oil shales such as the Devonian oil shales of eastern United States. Some properties of the Iratí oil shale are given in table 2.

Table 2. Average properties of Iratí oil shale mined at Sao Mateus do Sul (Petrobras, 1985, unpub. data). [Wt %, weight percent; kcal/kg, kilocalories per kilogram; l/t, liters per metric ton]

Analysis	Wt %
Moisture content	5.3
Organic carbon (dry basis)	12.7
Organic hydrogen (dry basis)	1.5
Fischer assay (dry basis)	
Shale oil	7.6
Water	1.7
Gas	3.2
Spent shale	87.5
Total sulfur (dry basis)	4.0
Gross heating value (dry basis, kcal/kg)	1,480
Oil-shale feed stock (l/t)	70–125

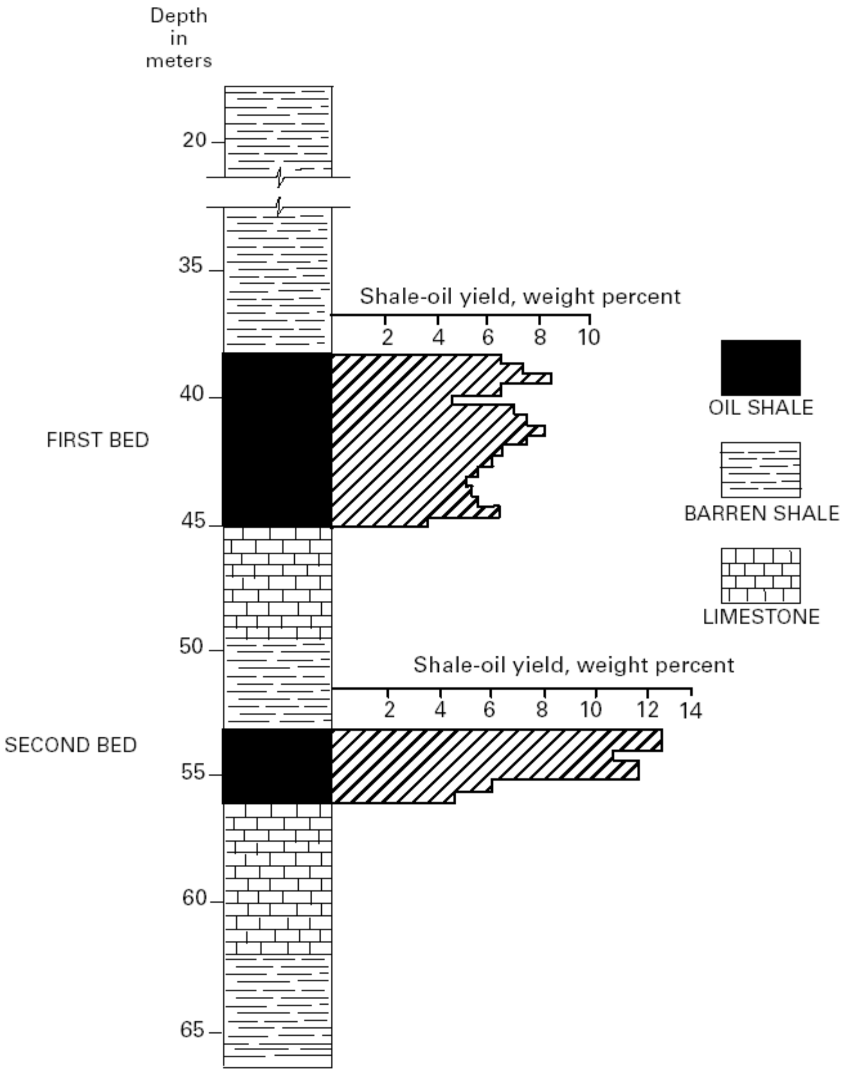


Figure 4. Typical lithologic log and shale-oil yield of the First and Second beds of the Iratí oil shale at São Mateus do Sul, Brazil. From L. Carta, Petrobras (1985, unpublished data).

The origin of the Iratí Formation is controversial. Some researchers have concluded that the organic matter is derived from a predominantly algal/microbial source in a freshwater to brackish lacustrine environment as indicated by the geochemistry of the shale oil (Afonso and others, 1994). On the other hand, Padula (1969), quoting earlier researchers, hypothesizes that the organic-rich sediments were deposited in a partially enclosed intracontinental marine (Paraná) basin of reduced salinity that was in communication with the open sea. The basin formed after the close of Late Carboniferous glaciation. Hutton (1988) classified the Iratí oil shale as a marine oil shale (marinite).

Development of the Brazilian oil-shale industry began with the establishment of the Brazilian national oil company, Petrobras, in 1954. A division of that company, Superintendéncia da Industrialização do Xisto (SIX), was charged with the development of the oil-shale deposits. Early work concentrated on the Paraíba oil shale, but later focused on the Iratí shale. A prototype oil-shale retort and UPI (Usina Prototipo do Iratí) plant constructed near São Mateus do Sul (fig. 3) began operations in 1972 with a design capacity of 1,600 tons of oil shale per day. In 1991 an industrial-size retort, 11 m in diameter, was put into operation with a design capacity of about 550 tons (~3,800 barrels) of shale oil per day. More than 1.5 million tons (~10.4 million barrels) of shale oil and other products including liquefied petroleum gas (LPG), methane, and sulfur have been produced from startup of the UPI plant through 1998.

CANADA

Canada’s oil-shale deposits range from Ordovician to Cretaceous age and include deposits of lacustrine and marine origin; as many as 19 deposits have been identified (Macauley, 1981; Davies and Nassichuk, 1988) (fig. 5 and table 3). During the 1980s, a number of the deposits were explored by core drilling (Macauley, 1981, 1984a, 1984b; Macauley and others, 1985; Smith and Naylor, 1990). Investigations included geologic studies, Rock-Eval and X-ray diffraction analyses, organic petrology, gas chromatography and mass spectrometry of the shale oil, and hydroretorting analyses.

The oil shales of the New Brunswick Albert Formation, lamosites of Mississippian age, have the greatest potential for development (fig. 5). The Albert oil shale averages 100 l/t of shale oil and has potential for recovery of oil and may also be used for co-combustion with coal for electric power generation.

Marinites, including the Devonian Kettle Point Formation and the Ordovician Collingwood Shale of southern Ontario, yield relatively small amounts of shale oil (about 40 l/t), but the yield can be doubled by hydroretorting. The Cretaceous Boyne and Favel marinites form large resources of low-grade oil shale in the Prairie Provinces of Manitoba, Saskatchewan, and Alberta. Upper Cretaceous oil shales on the Anderson Plain and the Mackenzie Delta in the Northwest Territories have been little explored, but may be of future economic interest.

Outcrops of Lower Carboniferous lacustrine oil shale on Grinnell Peninsula, Devon Island, in the Canadian Arctic Archipelago, are as much as 100 m thick and samples yield up to 387 kilograms of shale oil per ton of rock by Rock-Eval (equivalent to about 406 l/t). For most Canadian deposits, the resources of in-situ shale oil remain poorly known.

New Brunswick Oil Shale

The oil-shale deposits of the lacustrine Albert Formation of Mississippian age are located in the Moncton sub-basin of the Fundy Basin that lies roughly between St. Johns and Moncton in southern New Brunswick (no. 1 in fig. 6 and no. 9 of table 3). The principal part of the deposit lies at the east end of the sub-basin at Albert Mines about 25 km south-southeast of Moncton, where one borehole penetrated more than 500 m of oil shale. However, complex folding and faulting obscure the true thickness of the oil-shale beds, which may be much thinner.

The richest part of the sequence, the Albert Mines zone, measures about 120 m thick in one borehole, which may be double the true stratigraphic thickness because of structural complexity as noted above. The shale-oil yield ranges from less than 25 to more than 150 l/t; the average specific gravity is 0.871. Shale-oil reserves for the Albert Mines zone, which yields an estimated 94 l/t of shale oil by Fischer assay, is estimated at 67 million barrels. The shale-oil resource for the entire oil-shale sequence is estimated at 270 million barrels (Macauley and others, 1984), or about 37 million tons of shale oil.

The oil shale consists of interbedded dolomitic marlstone, laminated marlstone, and clayey marlstone. The mineral matrix is composed of dolomite, local calcite, and minor siderite with quartz, feldspar, some analcime, abundant illite, and minor amounts of smectite. The presence of dolomite and analcime, as well as the presence of overlying beds of halite, indicates that the oil shale was probably deposited in an alkaline saline lake.

The first commercial development was of a single vein of albertite, a solid hydrocarbon cutting across the oil-shale deposits, that was mined from 1863 to 1874 to a depth of 335 m. During that period, 140,000 tons of albertite were sold in the U.S. for $18/ton. A 41-ton sample sent to England in the early 1900s yielded 420 l/t and 450 m3 of methane gas/ton of albertite. In 1942 the Canadian Department of Mines and Resources initiated a core-drilling program to test the deposit. A total of 79 boreholes were drilled and a resource of 91 million tons of oil shale above a depth of 122 m was estimated. The grade of the oil shale averaged 44.2 l/t. An additional 10 boreholes were drilled by Atlantic-Richfield Company in 1967–68 to test the deeper oil shales, and still further exploration drilling was carried out by Canadian Occidental Petroleum, Ltd. in 1976 (Macauley, 1981).

Figure 5. Oil-shale deposits in Canada. Numbered deposits are keyed to table 3. Adapted from Macauley (1981). Areas in blue are lakes

Table 3. Oil-shale deposits in Canada

No. On figure	Deposit	Geologic unit	Age	Oil-shale type	Thickness (meters)	Grade (liters/ton)
1	Manitoulin-Collingwood trend, Ontario	Collingwood Shale	Ordovician	Marinite	2–6	<40
2	Ottawa area, Ontario	Billings Shale	Ordovician	Marinite	–	Unknown
3	Southhampton Island, Northwest Territories	Collingwood Shale equivalent (?)	Ordovician	Marinite	–	Unknown
4	North shore of Lake Erie, Elgin and Norfold Counties, Ontario	Marcellus Formation	Devonian	Marinite	–	Probably low
5	Norman Wells area, Northwest Territories	Canol Formation	Devonian	Marinite	≤100	Unknown
6	Gaspé Peninsula, Quebec	York River Formation	Devonian	Marinite	–	Unknown
7	Windsor-Sarnia area, southwest Ontario	Kettle Point Formation	Devonian	Marinite	10	41
8	Moose River Basin, Ontario	Long Rapids Formation	Devonian	Marinite	–	Unknown
9	Moncton sub-basin, New Brunswick	Albert Formation	Carboniferous	Lamosite	15–360	35–95
10	Antigonish Basin, Nova Scotia	Horton Group	Carboniferous	Lamosite	60–125	≤59
11	Deer Lake, Humber Valley, Newfoundland	Deer Lake Group	Carboniferous	Lamosite	<2	15–146
12	Conche area, Newfoundland	Cape Rouge Formation	Early Mississippian	Torbanite?	–	Unknown
13	Stellarton Basin, Pictou County, Nova Scotia	Pictou Group	Pennsylvanian	Torbanite and lamosite	<5–35 (in 60 beds)	25–140

No. On figure	Deposit	Geologic unit	Age	Oil-shale type	Thickness (meters)	Grade (liters/ton)
14	Queen Charlotte Islands, British Columbia	Kunga Formation	Jurassic	Marinite	≤35	≤35
15	Cariboo district, British Columbia	?	Early Jurassic	Marinite?	-	Minor oil yields
16	Manitoba Escarpment, Manitoba and Saskatchewan	Boyne and Favel Formations	Cretaceous	Marinite	40 and 30, respectively	20–60
17	Anderson Plain, Northwest Territories	Smoking Hills Formation	Late Cretaceous	Marinite	30	>40
18	Mackenzie Delta, Northwest and Yukon Territories	Boundary Creek Formation	Late Cretaceous	Marinite	–	Unknown
19	Grinnell Peninsula, Devon Island, Nunavut	Emma Fiord Formation	Mississippian	Lacustrine: lamosite?	>100	11–406

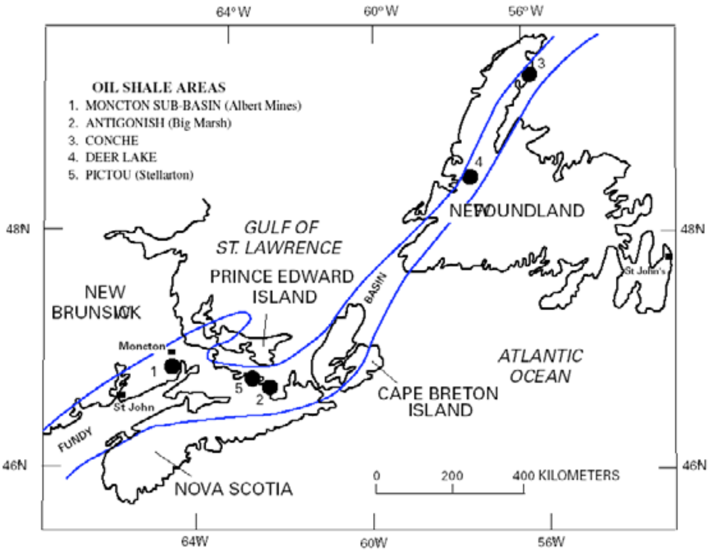


Figure 6. Oil-shale deposits in the Maritime Provinces of Canada. Adapted from Kalkreuth and Macauley (1987, their fig. 1).

CHINA

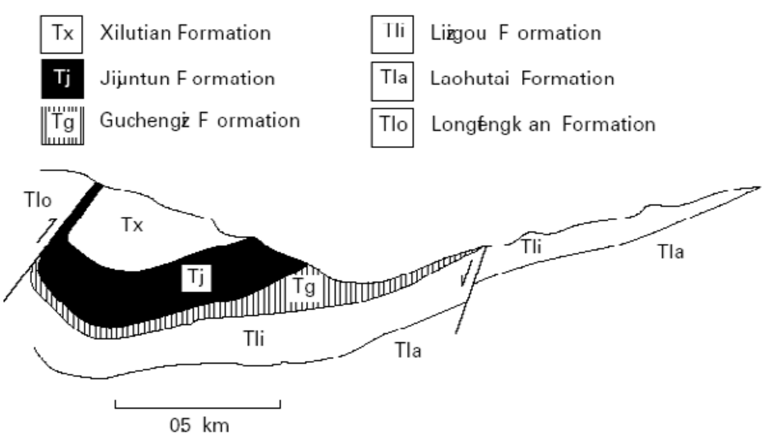
Two of China's principal resources of oil shale are those at Fushun and Maoming. The first commercial production of shale oil began at Fushun in 1930 with the construction of "Refinery No. 1;" this was followed by "Refinery No. 2," which began production in 1954, and a third facility that began producing shale oil at Maoming in 1963. The three plants eventually switched from shale oil to the refining of cheaper crude oil. A new plant for retorting oil shale was constructed at Fushun, with production beginning in 1992. Sixty Fushuntype retorts, each having a capacity of 100 tons of oil shale per day, produce 60,000 tons (about 415,000 bbls) of shale oil per year at Fushun (Chilin, 1995).

Fushun

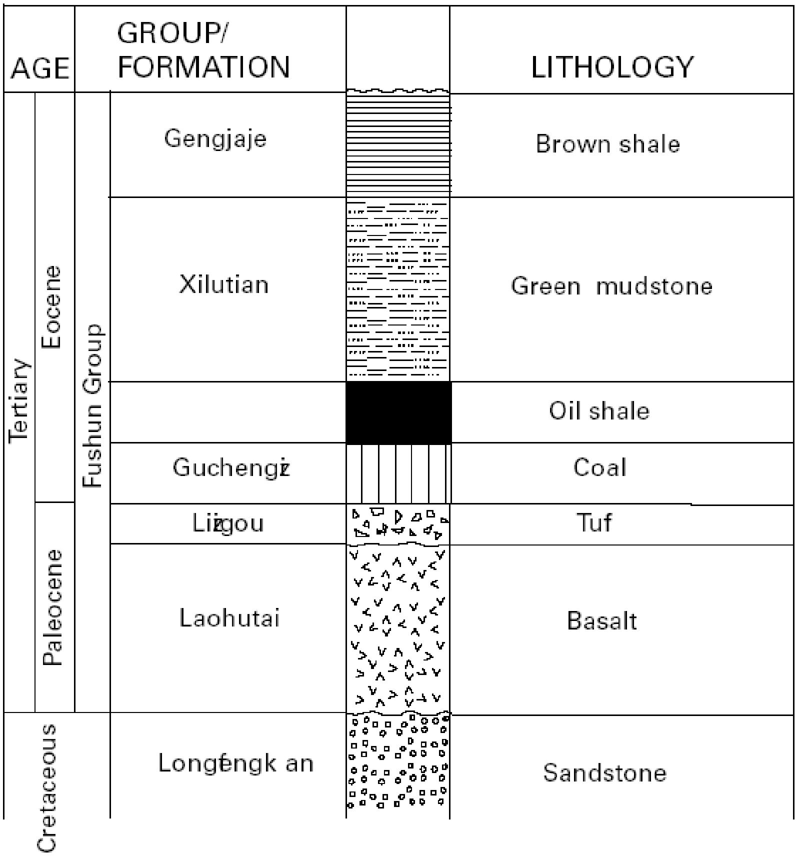
The Fushun oil-shale and coal deposit of Eocene age is located in northeastern China just south of the town of Fushun in Liaoning Province. Coal and oil shale are in a small outlier of Mesozoic and Tertiary sedimentary and volcanic rocks underlain by Precambrian granitic gneiss (Johnson, 1990). In this area, subbituminous to bituminous coal, carbonaceous mudstone and shale, and lenses of sandstone compose the Guchengzi Formation of Eocene age. The formation ranges from 20 to 145 m and averages 55 m in thickness. In the West Open Pit coal mine near Fushun, 6 coal beds are present, as well as a cannel coal 1 to 15 m thick that is used for decorative carving. The coal contains red to yellow gem-quality amber.

Overlying the Guchengzi Formation is the Eocene Jijuntun Formation that consists of oil shale of lacustrine origin. The oil shale is in gradational contact both with the underlying coal of the Guchengzi Formation and with the overlying lacustrine green mudstone of the Xilutian Formation (fig. 7). The Jijuntun Formation, which ranges from 48 to 190 m in thickness, is well exposed in the main West Open Pit coal mine where it is 115 m thick. The lower 15 m consists of low-grade light-brown oil shale and the remaining upper 100 m consists of richer grade brown to dark brown, finely laminated oil shale in beds of thin to medium thickness.

The oil shale contains abundant megafossils of fern, pine, oak, cypress, ginkgo, and sumac. Small fossil mollusks and crustaceans (ostracodes) are also present. The gradational contact between the oil shale and underlying coal indicates a depositional environment of an interior paludal basin that gradually subsided and was replaced by a lake in which the oil shale was deposited (Johnson, 1990, p. 227).



A. North-south stratigraphic cross section through the We st Open Pit coal mine (no ver tical scale).



B. Generaliz ed stratigraphic section (no scale).

Figure 7. Geologic cross section (*A*) and stratigraphic section (*B*) of the Fushun oil-shale deposit, Liaoning Province, China. From Johnson (1990, his figs. 4 and 6).

The oil yield of the shale ranges from about 4.7 to 16 percent by weight of the rock, and the mined shale averages 7 to 8 percent (~78–89 l/t) oil. In the vicinity of the mine, oilshale resources are estimated at 260 million tons, of which 235 million tons (90 percent) are considered mineable. The total resource of oil shale at Fushun is estimated at 3,600 million tons.

The West Open Pit mine is located in a tightly folded syncline (fig. 7) that trends east-west and is cut by several compressional and tensional faults. The pit is about 6.6 km long in an east-west direction, 2.0 km wide, and 300 m deep at the west end. In addition, two underground mines lie just east of the open-pit mine.

The floor of the open-pit mine is on the south limb of the syncline and dips 22–45° to the north toward the fold axis. The overturned north flank of the syncline is bounded by an east-west thrust fault that places sandstone of the Cretaceous Longfengkan Formation in contact with the Jijuntun oil shale (fig. 7).

Coal mining at Fushun began about 1901. Production increased, first under the Russians and later under the Japanese, reaching a peak in 1945, then dropped sharply and remained low until 1953 when production increased again under the first 5-year plan of the People's Republic of China.

For the first 10 to 15 years of mining coal at Fushun, oil shale was discarded with the overburden. Production of oil shale began in 1926 under the Japanese and peaked in the early 1970s with about 60 million tons of oil shale mined annually then dropped to about 8 million tons in 1978. This reduction was partly due to increased discovery and production of cheaper crude oil within China. Baker and Hook (1979) have published additional details on oil-shale processing at Fushun.

Maoming

The Maoming oil-shale deposit, of Tertiary age, is 50 km long, 10 km wide, and 20 to 25 m thick. Total reserves of oil shale are 5 billion tons, of which 860 million tons are in the Jintang mine. The Fischer assay yield of the oil shale is 4 to 12 percent and averages 6.5 percent. The ore is yellow brown and the bulk density is about 1.85. The oil shale contains 72.1 percent ash, 10.8 percent moisture, 1.2 percent sulfur, with a heating value of 1,745 kcal/kg (dry basis). About 3.5 million tons of oil shale are mined yearly (Guo-Quan, 1988). The 8-mm fraction has a heating value of 1,158 kcal/kg and a moisture content of 16.3 percent. It cannot be retorted but is being tested for burning in a fluidized bed boiler. Cement is manufactured with a content of about 15 to 25 percent of the oil-shale ash.

ESTONIA

The Ordovician kukersite deposits of Estonia have been known since the 1700s. However, active exploration only began as a result of fuel shortages brought on by World War I. Full-scale mining began in 1918. Oil-shale production in that year was 17,000 tons by open-pit mining, and by 1940, the annual production reached 1.7 million tons. However, it was not until after World

War II, during the Soviet era, that production climbed dramatically, peaking in 1980 when 31.4 million tons of oil shale were mined from eleven open-pit and underground mines.

The annual production of oil shale decreased after 1980 to about 14 million tons in 1994–95 (Katti and Lokk, 1998; Reinsalu, 1998a) then began to increase again. In 1997, 22 million tons of oil shale were produced from six room- and-pillar underground mines and three open-pit mines (Opik, 1998). Of this amount, 81 percent was used to fuel electric power plants, 16 percent was processed into petrochemicals, and the remainder was used to manufacture cement as well as other minor products. State subsidies for oil-shale companies in 1997 amounted to 132.4 million Estonian kroons (9.7 million U.S. dollars) (Reinsalu, 1998a).

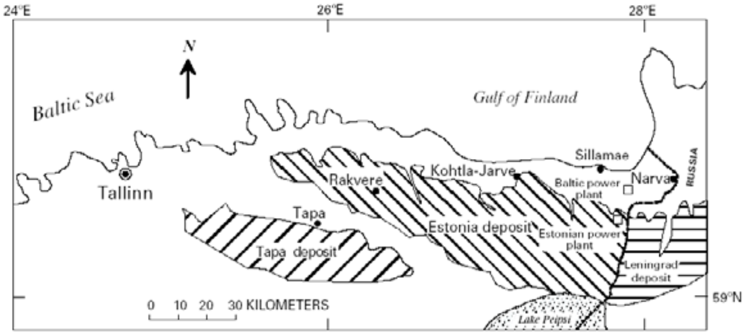
The kukersite deposits occupy more than 50,000 km2 in northern Estonia (the Estonia deposit, fig. 8) and extend eastward into Russia toward St. Petersburg where it is known as the Leningrad deposit. In Estonia a somewhat younger deposit of kukersite, the Tapa deposit, overlies the Estonia deposit (fig. 8).

As many as 50 beds of kukersite and kerogen-rich limestone alternating with biomicritic limestone are in the Kõrgekallas and Viivikonna Formations of Middle Ordovician age. These beds form a 20- to 30-m-thick sequence in the middle of the Estonia field. Individual kukersite beds are commonly 10–40 cm thick and reach as much as 2.4 m. The organic content of the richest kukersite beds reaches 40–45 weight percent (Bauert, 1994).

Rock-Eval analyses of the richest-grade kukersite in Estonia show oil yields as high as 300 to 470 mg/g of shale, which is equivalent to about 320 to 500 l/t. The calorific value in seven open-pit mines ranges from 2,440 to 3,020 kcal/kg (Reinsalu, 1998a, his table 5). Most of the organic matter is derived from the fossil green alga, *Gloeocapsomorpha prisca*, which has affinities to the modern cyanobacterium, *Entophysalis major*, an extant species that forms algal mats in intertidal to very shallow subtidal waters (Bauert, 1994).

Matrix minerals in Estonian kukersite and interbedded limestones includes dominantly low-Mg calcite (>50 percent), dolomite (<10–15 percent), and siliciclastic minerals including quartz, feldspars, illite, chlorite, and pyrite (<10–15 percent). The kukersite beds and associated limestones are evidently not enriched in heavy metals, unlike the Lower Ordovician Dictyonema Shale of northern Estonia and Sweden (Bauert, 1994; Andersson and others, 1985).

Bauert (1994, p. 418–420) suggested that the kukersite and limestone sequence was deposited in a series of east-west “stacked belts” in a shallow subtidal marine basin adjacent to a shallow coastal area on the north side of the Baltic Sea near Finland. The abundance of marine macrofossils and low pyrite content indicate an oxygenated-water setting with negligible bottom currents as evidenced by widespread lateral continuity of uniformly thin beds of kukersite.



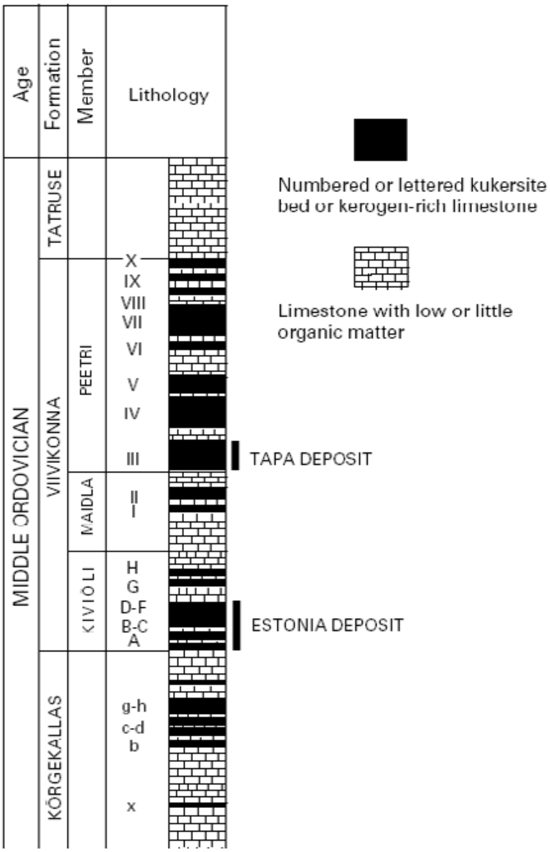


Figure 8. Location and stratigraphic section of the kukersite deposits in northern Estonia and Russia. Adapted from Kattai and Lokk (1998, their fig. 1) and Bauert (1994, his fig. 3).

Table 4. Characteristics of 10 deposits of oil shale in Israel. Data from PAMA, Ltd. (2000?).

Deposit	Overburden Thickness (meters)	Oil-shale thickness (meters)	Percent organic matter in oil shale	Oil-shale resources (tons x 106)
Nabi Musa	0–30	25–40	14–18	200
Shefela-Hartuv	25–50	150–200	14–15.5	1,100
‘En Boqeq	30–100	40–60	15.0	200
Mishor Rotem	20–150	20–150	11–17	2,260
Mishor Yamin	20–170	20–120	10–18.5	5,200
Yeroham	70–130	10–50	16.0	200
Oron	0–80	10–60	15–21	700
Nahal Zin	5–50	5–30	12–16	1,500
Zenifim	30–50	10–60	8.0	1,000
Sde Boker	50–150	15–70	15–18	3,000

Kattai and Lokk (1998, p. 109) estimated the proved and probable reserves of kukersite to be 5.94 billion tons. A good review of the criteria for estimating Estonia’s resources of kukersite oil shale was made by Reinsalu (1998b). In addition to thickness of overburden and thickness and grade of the oil shale, Reinsalu defined a given bed of kukersite as constituting a reserve, if the cost of mining and delivering the oil shale to the consumer was less than the cost of the delivery of the equivalent amount of coal having an energy value of 7,000 kcal/kg. He defined a bed of kukersite as a resource as one having an energy rating exceeding 25 GJ/m2 of bed area. On this basis, the total resources of Estonian kukersite in beds A through F (fig. 8) are estimated to be 6.3 billion tons, which includes 2 billion tons of “active” reserves (defined as oil shale “worth mining”). The Tapa deposit is not included in these estimates.

The number of exploratory drill holes in the Estonia field exceeds 10,000. The Estonia kukersite has been relatively thoroughly explored, whereas the Tapa deposit is currently in the prospecting stage.

Dictyonema Shale

Another older oil-shale deposit, the marine Dictyonema Shale of Early Ordovician age, underlies most of northern Estonia. Until recently, little has been published about this unit because it was covertly mined for uranium during the Soviet era. The unit ranges from less than 0.5 to more than 5 m in thickness (fig. 9). A total of 22.5 tons of elemental uranium was produced from 271,575 tons of Dictyonema Shale from an underground mine near Sillamäe. The uranium (U3O8) was extracted from the ore in a processing plant at Sillamäe (Lippmaa and Maramäe, 1999, 2000, 2001).

The future of oil-shale mining in Estonia faces a number of problems including competition from natural gas, petroleum, and coal. The present open-pit mines in the kukersite deposits will eventually need to be converted to more expensive underground operations as the deeper oil shale is mined. Serious air and ground-water pollution have resulted from burning oil shale and leaching of trace metals and organic compounds from spoil piles left from many years of mining and processing the oil shales. Reclamation of mined-out areas and their associated piles of spent shale, and studies to ameliorate the environmental degradation of the mined lands by the oil-shale industry are underway. The geology, mining, and reclamation of the Estonia kukersite deposit were reviewed in detail by Kattai and others (2000).

ISRAEL

Twenty marinite deposits of Late Cretaceous age have been identified in Israel (fig. 10; Minster, 1994), containing about 12 billion tons of oil-shale reserves with an average heating value of 1,150 kcal/kg of rock and an average oil yield of 6 weight percent. Thicknesses ranging from 35 to 80 m were reported by Fainberg in Kogerman (1996, p. 263) and 5 to 200 m by PAMA, Ltd. (2000?) (table 4). The organic content of the oil shales is relatively low, ranging from 6 to 17 weight percent, with an oil yield of only 60 to 71 l/t. The moisture content is high (~20 percent) as is the carbonate content (45 to 70 percent calcite) and the sulfur content (5 to 7 weight percent) (Minster, 1994). Some of the deposits can be mined by open-pit methods. A commercially exploitable bed of phosphate rock, 8 to 15 m thick, underlies the oil shale in the Mishor Rotem open-pit mine.

Utilizing oil shale from the Rotem-Yamin deposit (deposits 10 and 11 in fig. 10), about 55 tons of oil shale per hour were burned in a fluidized bed boiler to power a steam turbo-generator in a 25-megawatt experimental electric power plant operated by PAMA Company. The plant began operation in 1989 (Fainberg and Hetsroni, 1996) but is now closed. The grade of the Rotem oil shale is not uniform; the heating values range from 650 to 1200 kcal/kg.

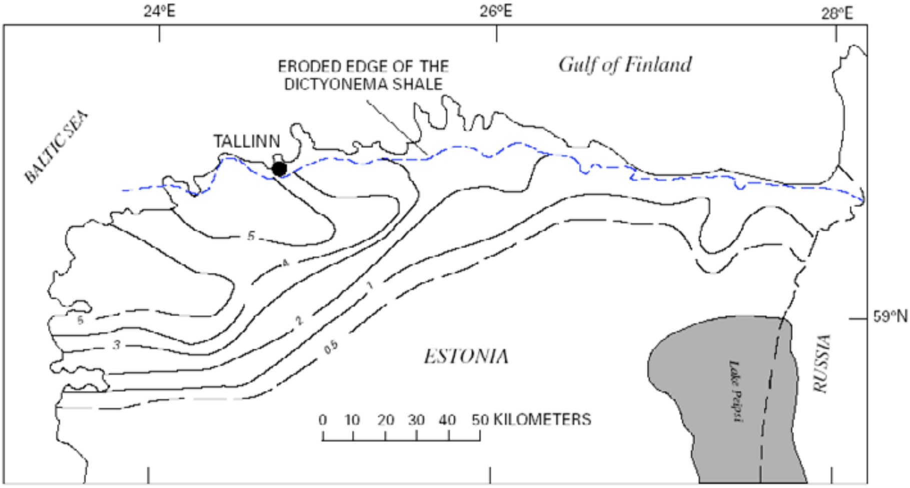


Figure 9. Isopach map of the Ordovician Dictyonema Shale in northern Estonia. From Loog and others (1996, their fig. 1). Thickness in meters.

JORDAN[3]

Jordan has few resources of oil and gas and no commercial deposits of coal. However, there are about 26 known deposits of oil shale, some of which are large and relatively high-grade (Jaber and others, 1997; Hamarneh, 1998, p. 2). The eight most important of these are the Juref ed Darawish, Sultani, Wadi Maghar, El Lajjun, Attarat Umm Ghudran, Khan ez Zabib, Siwaga, and Wadi Thamad deposits (fig. 11). These eight deposits are located in west central Jordan within 20 to 75 km east of the Dead Sea. The El Lajjun, Sultani, and Juref ed Darawish have been the most extensively explored by boreholes and many samples have been analyzed. Table 5 summarizes some of the geologic and resource data for the eight deposits.

[3] Many of the names of the Jordanian oil-shale deposits are spelled in different ways by Jordanian and other authors, probably owing to the difficulty of translating from Arabic to English. The names in this report are selected from several sources and not necessarily the best ones to use.

The Jordanian oil-shale deposits are marinites of Late Cretaceous (Maastrichtian) to early Tertiary age. A number of deposits are in grabens and some may prove to be parts of larger deposits, such as the Wadi Maghar deposit that is now considered to be the southern extension of the Attarat Umm Ghudran deposit (figure 11). The deposits listed in table 5 are at shallow depths, in essentially horizontal beds. As much as 90 percent of the oil shale is amenable to open-pit mining (Hamarneh, 1998, p. 5). The overburden consists of unconsolidated gravel and silt containing some stringers of marlstone and limestone and, in some areas, basalt. Overall, the oil shales thicken northward toward the Yarmouk deposit near the northern border of Jordan where the latter apparently extends into Syria (figure 11) and may prove to be an exceptionally large deposit—underlying several hundred square kilometers and reaching 400 m in thickness (Tsevi Minster, 1999, written commun.).

The oil shales in central Jordan are in the marine Chalk-Marl unit, which is underlain by phosphatic limestone and chert of the Phosphorite unit. The oil shales are typically brown, gray, or black and weather to a distinctive light bluish-gray. The moisture content of the oil shale is low (2 to 5.5 weight percent), whereas comparable deposits of oil shale in Israel have a much higher moisture content of 10 to 24 percent (Tsevi Minster, 1999, written commun.). Calcite, quartz, kaolinite, and apatite make up the major mineral components of the El Lajjun oil shale (figure 11), along with small amounts of dolomite, feldspar, pyrite, illite, goethite, and gypsum. The sulfur content of Jordanian oil shale ranges from 0.3 to 4.3 percent. The sulfur content of shale oil from the Jurf ed Darawish and the Sultani deposits is high, 8 and 10 percent, respectively. Of interest is the relatively high metal content of the oil shales from the Jurf el Darawish, Sultani, and El Lajjun deposits, notably Cu (68–115 ppm), Ni (102–167 ppm), Zn (190–649 ppm), Cr (226–431 ppm), and V (101–268 ppm) (Hamarneh, 1998, p. 8). Phosphate rock underlies the El Hasa deposit (deposit 3 in figure 11).

Surface water for oil-shale operations is scarce in Jordan; therefore, ground water will need to be tapped for oil-shale operations. A shallow aquifer that underlies the El Lajjun deposit, and provides fresh water to Amman and other municipalities in central Jordan, is too small in capacity to also meet the demands of an oil-shale industry. A deeper aquifer in the Kurnub Formation, 1,000 m below the surface, may be capable of providing an adequate supply of water, but this and other potential ground-water sources need further study.

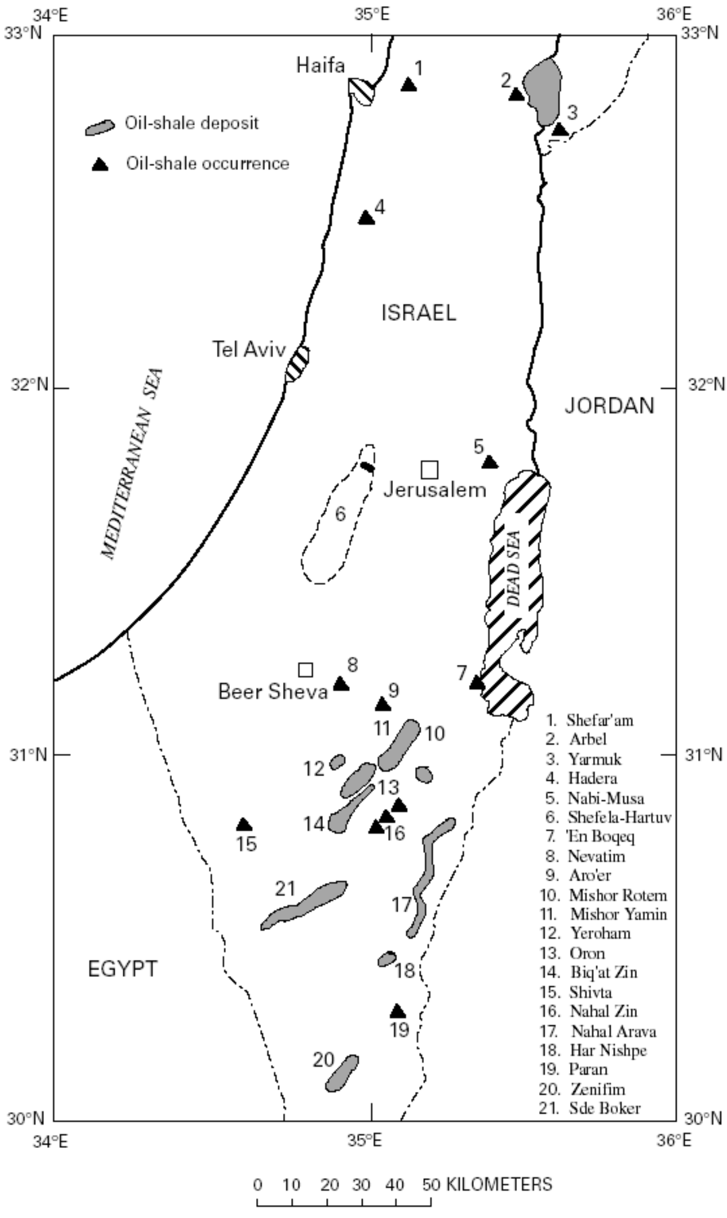


Figure 10. Deposits of oil shale in Israel. From Minster (1994, his fig. 1).

Table 5. Resource data for eight deposits of oil shale in Jordan (from Jaber and others, 1997, their table 1; and Hamarneh, 1998). Some data are rounded. [km2, square kilometers; wt %, weight percent]

Deposit	Number of boreholes	Area(km)	Overburden (meters)	Thickness of oil shale (meters)	Shale oil (wt %)	Oil shale (10 tons)	Shale oil (106 tons)
El Lajjun	173	20	30	29	10.5	1.3	126
Sultani	60	24	70	32	7.5	1.0	74
Jurf ed Darawish	50	1,500	70	31	?	8.6	510
Attarat Umm Ghudran	41	670	50	36	11	11	1,245
Wadi Maghar	21	19	40	40	6.8	31.6	2,150
Wadi Thamad	12	150	140–200	70–200	10.5	11.4	1,140
Khan ez Zabib	–	?	70	40	6.9	?	–
Siwaga	–	–	–	–	7.0	–	–
Total	–	2,385	–	–	–	64.9+	5,246+

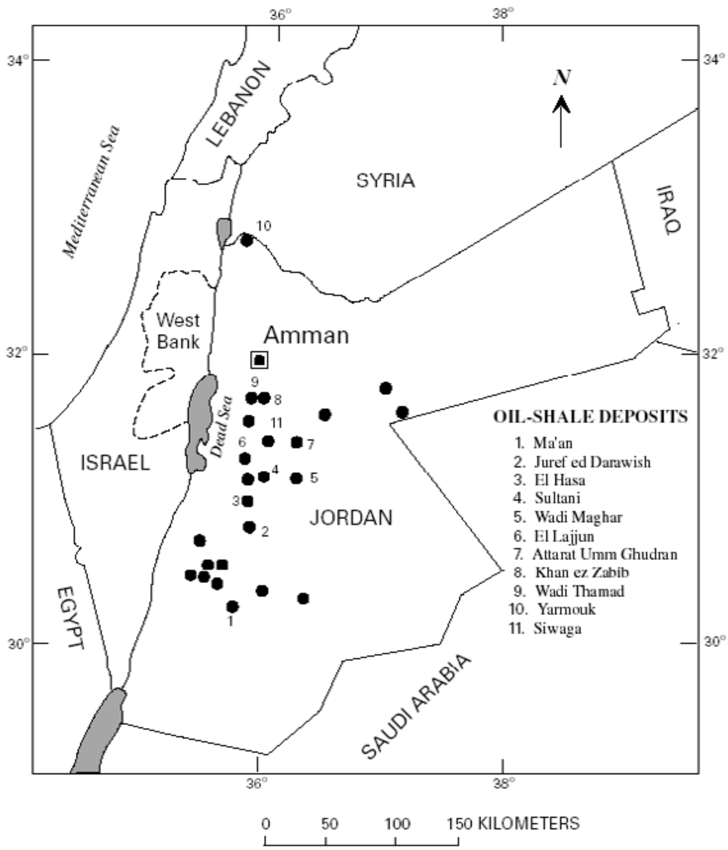


Figure 11. Oil-shale deposits in Jordan. Adapted from Jaber and others (1997, their fig. 1) and Hamarneh (1998, his figure on p. 4).

SYRIA

Puura and others (1984) described oil shales from the Wadi Yarmouk Basin at the southern border of Syria that are presumably part of the Yarmouk deposit described above in northern Jordan. The strata are marine limestones (marinites) of Late Cretaceous to Paleogene age, consisting of carbonate and siliceous carbonate shelf deposits that are common in the Mediterranean area. Fossil remains constitute 10 to 15 percent of the rock. The mineral components of the oil shales are 78 to 96 percent carbonates (mostly calcite), with small amounts of quartz (1 to 9 percent), clay minerals (1 to 9 percent), and apatite (2 to 19 percent). The sulfur content is 0.7 to 2.9 percent. Oil yields by Fischer assay are 7 to 12 percent.

MOROCCO

Oil-shale deposits have been identified at ten localities in Morocco (fig. 12), the most important of which are Upper Cretaceous marinites, not unlike those of Egypt, Israel, and Jordan. The two deposits that have been explored most extensively are the Timahdit and the Tarfaya deposits; about 69,000 analyses have been made of samples from 157 boreholes totaling 34,632 m in length and from 800 m of mine workings.

The Timahdit deposit, located about 250 km southeast of Rabat, underlies an area about 70 km long and 4 to10 km wide within a northeast-trending syncline (fig. 12). The thickness of the oil shale ranges from 80 to 170 m (fig. 13). The moisture content ranges from 6 to 11 percent, and the sulphur content averages 2 percent. Total oil-shale reserves are estimated at 18 billion tons within an area of 196 km2; oil yields range from 20 to 100 l/t and average 70 l/t. The Tarfaya deposit is located in the southwesternmost part of Morocco, near the border with Western Sahara (fig. 12). The oil shale averages 22 m in thickness and its grade averages 62 l/t. The total oil-shale resource is estimated at 86 billion tons within a 2,000-km2 area. The moisture content of the Tarfaya oil shale averages 20 percent and the sulfur content averages about 2 percent.

Phosphate rock and uranium are also associated with the Cretaceous marinites. One drill core (location uncertain) revealed a maximum P2O5 content of about 17 percent and U308 concentrations of as much as about 150 ppm.

In the 1980s several energy companies from North America and Europe conducted exploratory drilling and experimental mining and processing of Moroccan oil shale, but no shale oil was produced (Bouchta, 1984; Office National de Recherches et D’exploitation Petrolieres, 1983?).

RUSSIA

More than 80 deposits of oil shale have been identified in Russia. The kukersite deposit in the Leningrad district (fig. 8) is burned as fuel in the Slansky electric power plant near St. Petersburg. In addition to the Leningrad deposit, the best deposits for exploitation are those in the Volga-Pechersk oil-shale province, including the Perelyub-Blagodatovsk, Kotsebinsk, and the Rubezhinsk deposits. These deposits contain beds of oil shale ranging from 0.8 to 2.6 m in thickness but are high in sulfur (4–6 percent, dry basis). The oil shale was used to fuel two electric power plants; however, the operation was shut down owing to high SO2 emissions. As of about 1995, an oil-shale plant at Syzran was processing not more than 50,000 tons of oil shale per year (Kashirskii, 1996).

Russell (1990) listed the resources of 13 deposits in the former Soviet Union, including the Estonian and Leningrad kukersite deposits and the Estonian Dictyonema Shale, at greater than 107 billion tons of oil shale.

SWEDEN

The Alum Shale is a unit of black organic-rich marinate about 20–60 m thick that was deposited in a shallow marineshelf environment on the tectonically stable Baltoscandian Platform in Cambrian to earliest Ordovician time in Sweden and adjacent areas. The Alum Shale is present in outliers, partly bounded by local faults, on Precambrian rocks in southern Sweden as well as in the tectonically disturbed Caledonides of western Sweden and Norway, where it reaches thicknesses of 200 m or more in repeated sequences owing to multiple thrust faults (fig. 14).

Black shales, equivalent in part to the Alum Shale, are present on the islands of Öland and Götland, underlie parts of the Baltic Sea, and crop out along the north shore of Estonia where they form the Dictyonema Shale of Early Ordovician (Tremadocian) age (Andersson and others, 1985, their figs. 3 and 4). The Alum Shale represents slow deposition in shallow, near-anoxic waters that were little disturbed by wave- and bottom-current action.

The Cambrian and Lower Ordovician Alum Shale of Sweden has been known for more than 350 years. It was a source of potassium aluminum sulfate that was used in the leather tanning industry, for fixing colors in textiles, and as a pharmaceutical astringent. Mining the shales for alum began in 1637 in Skåne. The Alum Shale was also recognized as a source of fossil energy and, toward the end of the 1800s, attempts were made to extract and refine hydrocarbons (Andersson and others, 1985, p. 8–9).

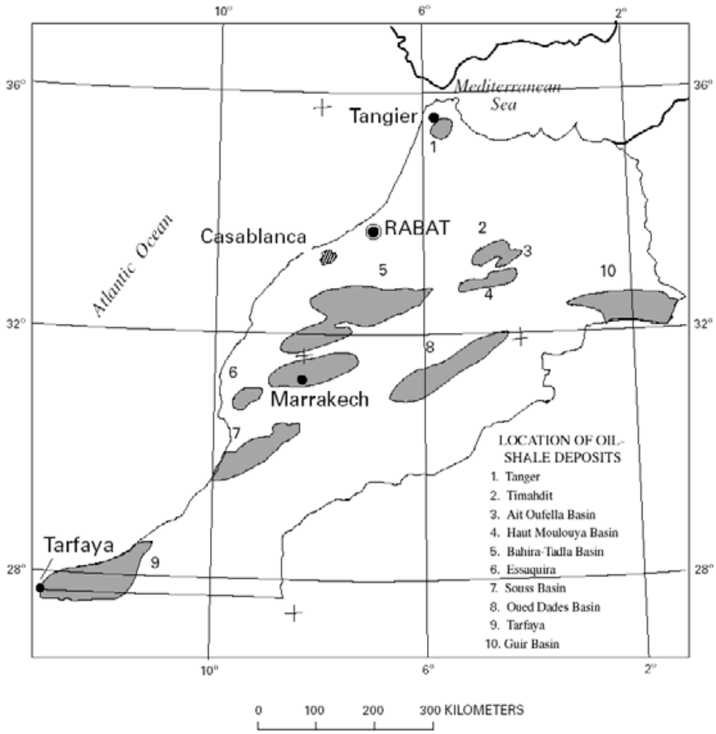


Figure 12. Oil-shale deposits in Morocco. From Bouchta (1984, his fig. 1).

Before and during World War II, Alum Shale was retorted for its oil, but production ceased in 1966 owing to the availability of cheaper supplies of crude petroleum. During this period, about 50 million tons of shale was mined at Kinnekulle in Västergötland and at Närke (figure 14).

The Alum Shale is remarkable for its high content of metals including uranium, vanadium, nickel, and molybdenum. Small amounts of vanadium were produced during World War II. A pilot plant built at Kvarntorp produced more than 62 tons of uranium between 1950 and 1961. Later, higher-grade ore was identified at Ranstad in Västergötland, where an open-pit mine and mill were established. About 50 tons of uranium per year were produced between 1965 and 1969. During the 1980s, production of uranium from high-grade deposits elsewhere in the world caused a drop in the world price of uranium to levels too low to profitably operate the Ranstad plant, and it closed in 1989 (Bergh, 1994).

Alum Shale was also burned with limestone to manufacture “breeze blocks,” a lightweight porous building block that was used widely in the Swedish construction industry. Production stopped when it was realized that the blocks were radioactive and emitted unacceptably large amounts of radon. Nevertheless, the Alum Shale remains an important potential resource of fossil and nuclear energy, sulfur, fertilizer, metal alloy elements, and aluminum products for the future. The fossil energy resources of the Alum Shale in Sweden are summarized in table 6.

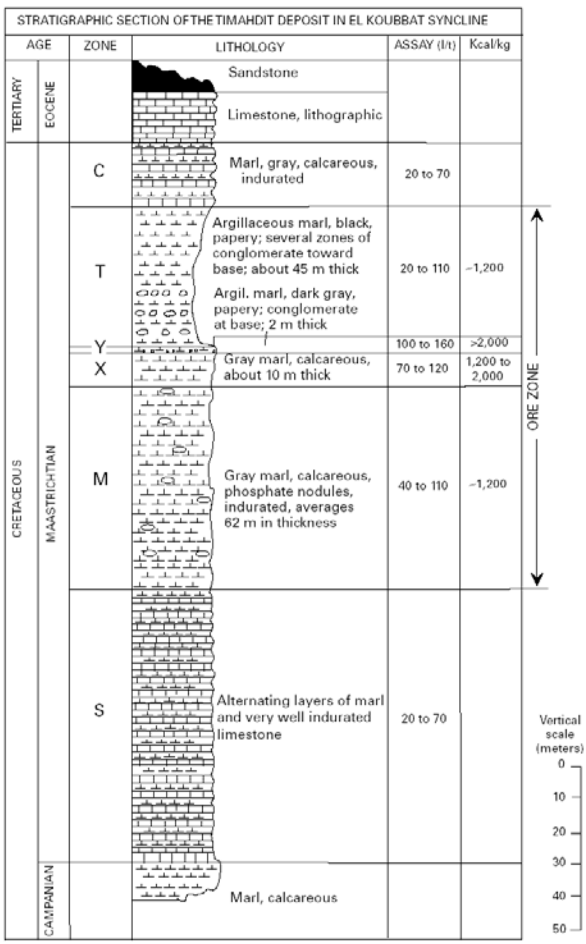


Figure 13. Generalized stratigraphic section of the Timahdit oil-shale deposit in the El Koubbat syncline, Morocco. Adapted from Office National de Recherches et

D’exploitation Petrolieres (1983?); l/t, liters per metric ton of rock; kcal/kg, kilocalories per kilogram.

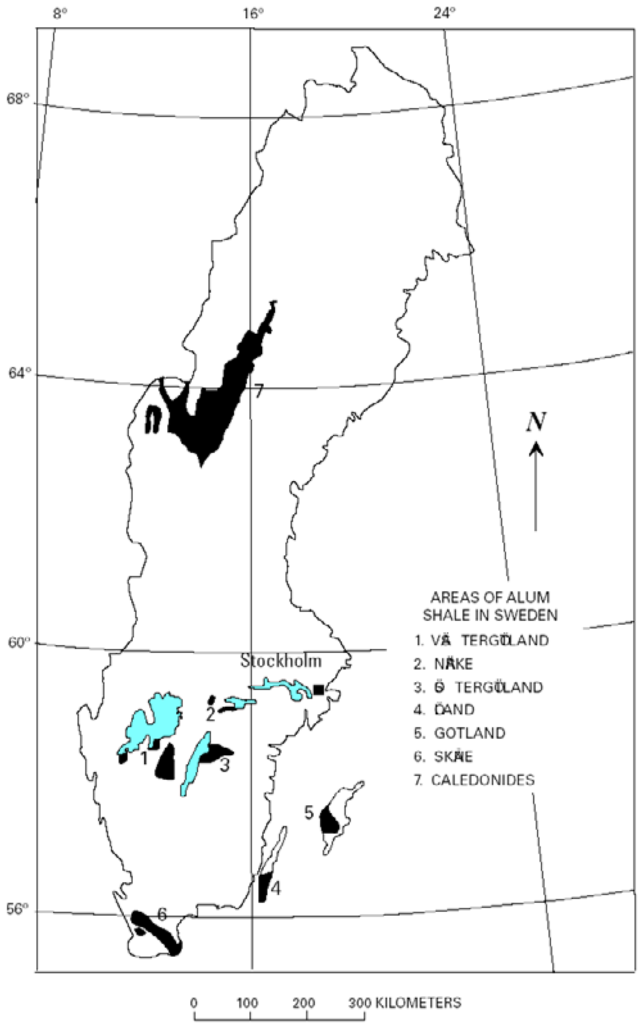


Figure 14. Map showing areas (in black) of Alum Shale in Sweden. Adapted from Andersson and others (1985, their fig. 3). Areas in blue are lakes.

The organic content of Alum Shale ranges from a few percent to more than 20 percent, being highest in the upper part of the shale sequence (figure 15). Oil yields, however, are not in proportion to the organic content from one area to another because of variations in the geothermal history of the areas underlain by the formation. For example, at Skåne (figure 14) and Jämtland in west-central Sweden, the Alum Shale is overmature and oil yields are nil, although the organic content of the shale is 11–12 percent. In areas less affected by geothermal alteration, oil yields range from 2 to 6 percent by Fischer assay. Hydroretorting can increase the Fischer assay yields by as much as 300 to 400 percent (Andersson and others, 1985, their figure 24).

The uranium resources of the Alum Shale of Sweden, although low grade, are enormous. In the Ranstad area of Västergötland, for example, the uranium content of a 3.6-m-thick zone in the upper part of the formation reaches 306 ppm, and concentrations reach 2,000 to 5,000 ppm in small black coal-like lenses of hydrocarbon (kolm) that are scattered through the zone.

The Alum Shale in the Ranstad area underlies about 490 km2, of which the upper member, 8 to 9 m thick, contains an estimated 1.7 million tons of uranium metal (Andersson and others, 1985, their table 4). Figure 15 shows a lithologic log of a core hole drilled at Ranstad with plots of Fischer assays and uranium analyses.

THAILAND

Lacustrine oil-shale deposits of Tertiary age are near Mae Sot, Tak Province, and at Li, Lampoon Province. The Thai Department of Mineral Resources has explored the Mae Sot deposit with the drilling of many core holes. The oil shale is a lamosite similar in some respects to the Green River oil shale in Colorado. The Mae Sot deposit underlies about 53 km2 in the Mae Sot Basin in northwestern Thailand near the Myanmar (Burma) border. It contains an estimated 18.7 billion tons of oil shale, which is estimated to yield 6.4 billion barrels (916 million tons) of shale oil. The gross heating value ranges from 287 to 3,700 kcal/kg, the moisture content ranges from 1 to 13 percent, and the sulfur content is about 1 percent. The deposit at Li is probably also a lamosite but the reserves are small—estimated at 15 million tons of oil shale yielding 12–41 gallons of shale oil per ton of rock (50–171 l/t) (Vanichseni and others, 1988, p. 515–516).

TURKEY

Lacustrine oil-shale deposits of Paleocene to Eocene age and of late Miocene age are widely distributed in middle and western Anatolia in western Turkey. The host rocks are marlstone and claystone in which the organic matter is finely dispersed. The presence of authigenic zeolites indicates probable deposition in hypersaline lacustrine waters in closed basins.

Data on the shale-oil resources are sparse because only a few of the deposits have been investigated. Güleç and Önen (1993) reported a total of 5.2 billion tons of oil shale in seven deposits with their ranges in calorific values; however, the shale-oil resources of these deposits are not reported. The oilshale resources of Turkey may be large, but further studies are needed before reliable resource estimates can be made. On the basis of available data, total resources of in-situ shale oil for eight Turkish deposits are estimated at 284 million tons (about 2.0 billion bbls) (table 7).

UNITED STATES

Numerous deposits of oil shale, ranging from Precambrian to Tertiary age, are present in the United States. The two most important deposits are in the Eocene Green River Formation in Colorado, Wyoming, and Utah and in the Devonian – Mississippian black shales in the eastern United States. Oil shale associated with coal deposits of Pennsylvanian age is also in the eastern United States. Other deposits are known to be in Nevada, Montana, Alaska, Kansas, and elsewhere, but these are either too small, too low grade, or have not yet been well enough explored (Russell, 1990, p. 82–157) to be considered as resources for the purposes of this report. Because of their size and grade, most investigations have focused on the Green River and the Devonian–Mississippian deposits.

Green River Formation

Geology

Lacustrine sediments of the Green River Formation were deposited in two large lakes that occupied 65,000 km2 in several sedimentary-structural basins in Colorado, Wyoming, and Utah during early through middle Eocene time (fig. 16). The Uinta Mountain uplift and its eastward extension, the Axial Basin anticline, separate these basins. The Green River lake system was in existence for more than 10 million years during a time of a warm temperate to subtropical climate.

Table 6. Summary of the fossil energy potential of the Alum Shale in Sweden for shale containing more than 10 percent organic matter (from Andersson and others, 1985, their table 2). [wt %, weight percent; MJ, megajoules]

		Organic matter		Shale oil		
Area	Shale tons (106)	wt %	tons (106)	wt %	tons (106)	Energy in gas and coke (101 MJ)
Närke	1,700	20	340	5	85	8,800
Östergötland	12,000	14	1,600	3.5	400	41,900
Västergötland	14,000	Ў«13	1,840	0–3.4	220	53,300
Öland	6,000	12	700	2.7	170	18,000
Skåne	15,000	11	1,600	0	0	58,600
Jämtland (Caledonides)	26,000	12	3,200	0	0	117,200
Total	74,700	9,280		875		297,800

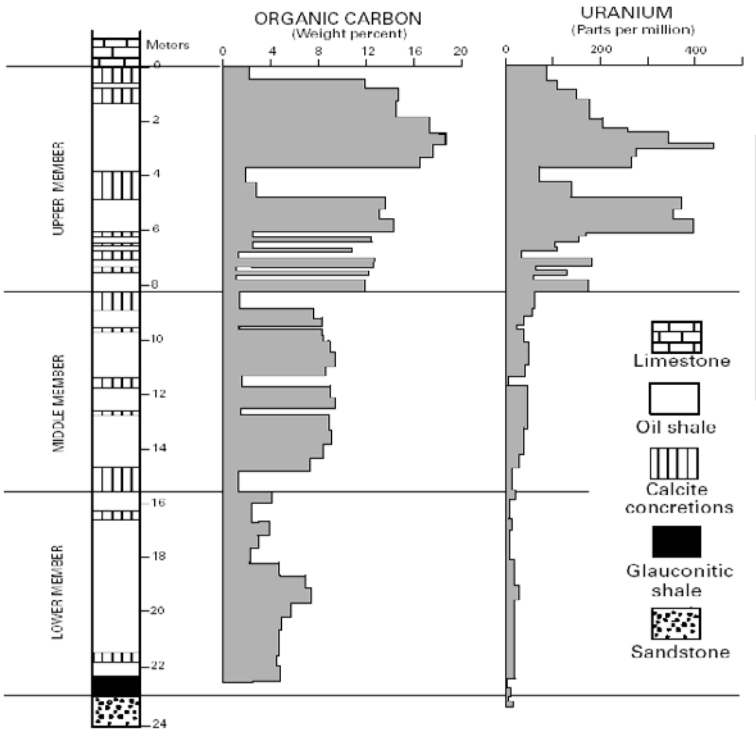


Figure 15. Lithology and plots of the abundances of organic carbon and uranium in a drill core from the Alum Shale at Ranstad, Sweden. From Andersson and others (1985, their fig. 9).

Table 7. Oil-shale deposits of Turkey. Data from Güleç and Önen (1993) and Sener and others (1995). [wt %, weight percent; kcal/kg, kilocalories per kilogram of rock; MJ/kg, megajoules per kilogram. For those deposits lacking average oil yields, an estimated yield of 5 weight percent was assumed. For deposits where two tonnages were given in the references, the larger number was used]

Deposit and province	Calorific value	Average oil yield (wt %)	Total sulfur (wt %)	Oil-shale resource (106 tons)	Shale-oil resource (106 tons)
Bahçecik (Izmit)	418–1,875 kcal/kg	–	–	100	5
Beypazari (Ankara)	3.40 MJ/kg	5.4	1.4	1,058	57
Burhaniye (Balikesir)	0–1,768 kcal/kg	–	–	80	4

Gölpazari (Bilecik)	0–1,265 kcal/kg	–	–	356	18
Göynük (Bolu)	3.25 MJ/kg	4.6	0.9	2.500	115
Hatildag (Bolu)	3.24 MJ/kg	5.3	1.3	547	29
Seyitömer (Kütahya)	3.55 MJ/kg	5.0	0.9	1,000	50
Ulukisla (Nigde)	630–2,790 kcal/kg	–	–	130	6
Total				5,771	284

During parts of their history, the lake basins were closed, and the waters became highly saline.

Fluctuations in the amount of inflowing stream waters caused large expansions and contractions of the lakes as evidenced by widespread intertonguing of marly lacustrine strata with beds of land-derived sandstone and siltstone. During arid times, the lakes contracted, and the waters became increasingly saline and alkaline. The lake-water content of soluble sodium carbonates and chloride increased, whereas the less soluble divalent Ca+Mg+Fe carbonates were precipitated with organic-rich sediments. During the driest periods, the lake waters reached salinities sufficient to precipitate beds of nahcolite, halite, and trona. The sediment pore waters were sufficiently saline to precipitate disseminated crystals of nahcolite, shortite, and dawsonite along with a host of other authigenic carbonate and silicate minerals (Milton, 1977).

A noteworthy aspect of the mineralogy is the complete lack of authigenic sulfate minerals. Although sulfate was probably a major anion in the stream waters entering the lakes, the sulfate ion was presumably totally consumed by sulfate-reducing bacteria in the lake and sediment waters according to the following generalized oxidation-reduction reaction:

$$2CH_2O + SO_4^{-2} \rightarrow 2HCO_3^{-1} + H_2S$$

Note that two moles of bicarbonate are formed for each mole of sulfate that is reduced. The resulting hydrogen sulphide could either react with available Fe++ to precipitate as iron sulfide minerals or escape from the sediments as a gas (Dyni, 1998). Other major sources of carbonate include calcium carbonate-secreting algae, hydrolysis of silicate minerals, and direct input from inflowing streams.

The warm alkaline lake waters of the Eocene Green River lakes provided excellent conditions for the abundant growth of blue-green algae (cyanobacteria) that are thought to be the major precursor of the organic matter in the oil shale. During times of freshening waters, the lakes hosted a variety of fishes, rays, bivalves, gastropods, ostracodes, and other aquatic fauna. Areas peripheral to the lakes supported a large and varied assemblage of land plants, insects, amphibians, turtles, lizards, snakes, crocodiles, birds, and numerous mammalian animals (McKenna, 1960; MacGinitie, 1969; and Grande, 1984).

Historical Developments

The occurrence of oil shale in the Green River Formation in Colorado, Utah, and Wyoming has been known for many years. During the early 1900s, it was clearly established that the Green River deposits were a major resource of shale oil (Woodruff and Day, 1914; Winchester, 1916; Gavin, 1924). During this early period, the Green River and other deposits were investigated, including oil shale of the marine Phosphoria Formation of Permian age in Montana (Bowen, 1917; Condit, 1919) and oil shale in Tertiary lake beds near Elko, Nevada (Winchester, 1923).

In 1967, the U.S. Department of Interior began an extensive program to investigate the commercialization of the Green River oil-shale deposits. The dramatic increases in petroleum prices resulting from the OPEC oil embargo of 1973–74 triggered another resurgence of oil-shale activities during the 1970s and into the early 1980s. In 1974 several parcels of public oil-shale lands in Colorado, Utah, and Wyoming were put up for competitive bid under the Federal Prototype Oil Shale Leasing Program. Two tracts were leased in Colorado (C-a and C-b) and two in Utah (U-a and U-b) to oil companies.

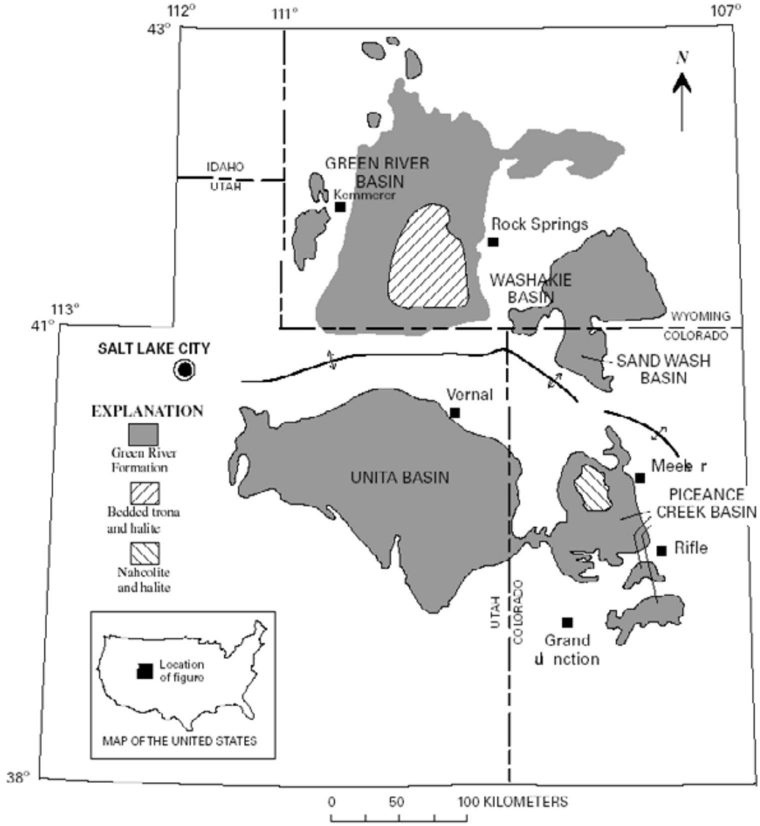


Figure 16. Areas underlain by the Green River Formation in Colorado, Utah, and Wyoming, United States.

Large underground mining facilities, including vertical shafts, room-and-pillar entries, and modified in-situ retorts, were constructed on Tracts C-a and C-b, but little or no shale oil was produced. During this time, Unocal Oil Company was developing its oil-shale facilities on privately owned land on the south side of the Piceance Creek Basin. The facilities included a room-and-pillar mine with a surface entry, a 10,000 barrel/day (1,460 ton/day) retort, and an upgrading plant. A few miles north of the Unocal property, Exxon Corporation opened a room-and-pillar mine with a surface entry, haulage roads, waste-rock dumpsite, and a water-storage reservoir and dam.

In 1977–78 the U.S. Bureau of Mines opened an experimental mine that included a 723-m-deep shaft with several room-and-pillar entries in the northern part of the Piceance Creek Basin to conduct research on the deeper deposits of oil shale, which are commingled with nahcolite and dawsonite. The site was closed in the late 1980s.

About $80 million were spent on the U-a/U-b tracts in Utah by three energy companies to sink a 313-m-deep vertical shaft and inclined haulage way to a high-grade zone of oil shale and to open several small entries. Other facilities included a mine services building, water- and sewage-treatment plants, and a water-retention dam.

The Seep Ridge project sited south of the U-a/U-b tracts, funded by Geokinetics, Inc. and the U.S. Department of Energy, produced shale oil by a shallow in-situ retorting method. Several thousand barrels of shale oil were produced.

The Unocal oil-shale plant was the last major project to produce shale oil from the Green River Formation. Plant construction began in 1980, and capital investment for constructing the mine, retort, upgrading plant, and other facilities was $650 million. Unocal produced 657,000 tons (about 4.4 million bbls) of shale oil, which were shipped to Chicago for refining into transportation fuels and other products under a program partly subsidized by the U.S. Government. The average rate of production in the last months of operation was about 875 tons (about 5,900 barrels) of shale oil per day; the facility was closed in 1991.

In the past few years, Shell Oil Company began an experimental field project to recover shale oil by a proprietary in-situ technique. Some details about the project have been publicly announced, and the results to date (2006) appear to favor continued research.

Shale-Oil Resources

As the Green River oil-shale deposits in Colorado became better known, estimates of the resource increased from about 20 billion barrels in 1916, to 900 billion barrels in 1961, and to 1.0 trillion barrels (~147 billion tons) in 1989 (Winchester, 1916, p. 140; Donnell, 1961; Pitman and others, 1989). A lithologic section and a summary of the resources by oil-shale zones in the Piceance Creek Basin are shown in figure 17.

The Green River oil-shale resources in Utah and Wyoming are not as well known as those in Colorado. Trudell and others (1983, p. 57) calculated the measured and estimated resources of shale oil in an area of about 5,200 km2 in eastern Uinta Basin, Utah, to be 214 billion barrels (31 billion tons) of which about one-third is in the rich Mahogany oil-shale zone. Culbertson and others (1980, p. 17) estimated the oil-shale resources in the Green River Formation in the

Green River Basin in southwest Wyoming to be 244 billion barrels (~35 billion tons) of shale oil.

Additional resources are also in the Washakie Basin east of the Green River Basin in southwest Wyoming. Trudell and others (1973) reported that several members of the Green River Formation on Kinney Rim on the west side of the Washakie Basin contain sequences of low to moderate grades of oil shale in three core holes. Two sequences of oil shale in the Laney Member, 11 and 42 m thick, average 63 l/t and represent as much as 8.7 million tons of in-situ shale oil per square kilometer. A total estimate of the resource in the Washakie Basin was not reported for lack of subsurface data.

Other Mineral Resources

In addition to fossil energy, the Green River oil-shale deposits in Colorado contain valuable resources of sodium carbonate minerals including nahcolite ($NaHCO_3$) and dawsonite [$NaAl(OH)_2CO_3$]. Both minerals are commingled with high-grade oil shale in the deep northern part of the basin. Dyni (1974) estimated the total nahcolite resource at 29 billion tons. Beard and others (1974) estimated nearly the same amount of nahcolite and 17 billion tons of dawsonite. Both minerals have value for soda ash (Na_2CO_3) and dawsonite also has potential value for its alumina (Al_2O_3) content. The latter mineral is most likely to be recovered as a byproduct of an oil-shale operation. One company is solution mining nahcolite for the manufacture of sodium bicarbonate in the northern part of the Piceance Creek Basin at depths of about 600 m (Day, 1998). Another company stopped solution mining nahcolite in 2004, but now processes soda ash obtained from the Wyoming trona deposits to manufacture sodium bicarbonate.

The Wilkins Peak Member of the Green River Formation in the Green River Basin in southwestern Wyoming contains not only oil shale but also the world's largest known resource of natural sodium carbonate as trona ($Na_2CO_3.NaHCO_3.2H_2O$). The trona resource is estimated at more than 115 billion tons in 22 beds ranging from 1.2 to 9.8 m in thickness (Wiig and others, 1995). In 1997, trona production from five mines was 16.5 million tons (Harris, 1997). Trona is refined into soda ash (Na_2CO_3) used in the manufacture of bottle and flat glass, baking soda, soap and detergents, waste treatment chemicals, and many other industrial chemicals. One ton of soda ash is obtained from about two tons of trona ore. Wyoming trona supplies about 90 percent of U.S. soda ash needs; in addition, about one-third of the total Wyoming soda ash produced is exported.

In the deeper part of the Piceance Creek Basin, the Green River oil shale contains a potential resource of natural gas, but its economic recovery is questionable (Cole and Daub, 1991). Natural gas is also present in the Green River oil-shale deposits in southwest Wyoming, and probably in the oil shale in Utah, but in unknown quantities. A summary of the oil shale and mineral resources of the Green River Formation in Colorado, Wyoming, and Utah is given in table 8.

Eastern Devonian–Mississippian Oil Shale

Depositional Environment

Black organic-rich marine shale and associated sediments of Late Devonian and Early Mississippian age underlie about 725,000 km^2 in the eastern United States (fig. 18). These shales have been exploited for many years as a resource of natural gas, but have also been considered as a potential lowgrade resource of shale oil and uranium (Roen and Kepferle, 1993; Conant and Swanson, 1961).

Over the years, geologists have applied many local names to these shales and associated rocks, including the Chattanooga, New Albany, Ohio, Sunbury, Antrim, and others. A group of papers detailing the stratigraphy, structure, and gas potential of these rocks in eastern United States have been published by the U.S. Geological Survey (Roen and Kepferle, 1993).

The black shales were deposited during Late Devonian and Early Mississippian time in a large epeiric sea that covered much of middle and eastern United States east of the Mississippi River (figure 18). The area included the broad, shallow, Interior Platform on the west that grades eastward into the Appalachian Basin. The depth to the base of the Devonian– Mississippian black shales ranges from surface exposures on the Interior Platform to more than 2,700 m along the depositional axis of the Appalachian Basin (de Witt and others, 1993, their pl. 1).

The Late Devonian sea was relatively shallow with minimal current and wave action, much like the environment in which the Alum Shale of Sweden was deposited in Europe. A large part of the organic matter in the black shale is amorphous bituminite, although a few structured fossil organisms such as *Tasmanites*, *Botryococcus*, *Foerstia*, and others have been recognized. Conodonts and linguloid brachiopods are sparingly distributed through some beds. Although much of the organic matter is amorphous and of uncertain origin, it is generally believed that much of it was derived from planktonic algae.

In the distal parts of the Devonian sea, the organic matter accumulated very slowly along with very fine-grained clayey sediments in poorly oxygenated waters free of burrowing organisms. Conant and Swanson (1961, p. 54) estimated that 30 cm of the upper part of the Chattanooga Shale deposited on the Interior Platform in Tennessee could represent as much as 150,000 years of sedimentation.

The black shales thicken eastward into the Appalachian Basin owing to increasing amounts of clastic sediments that were shed into the Devonian sea from the Appalachian highland lying to the east of the basin. Pyrite and marcasite are abundant authigenic minerals, but carbonate minerals are only a minor fraction of the mineral matter.

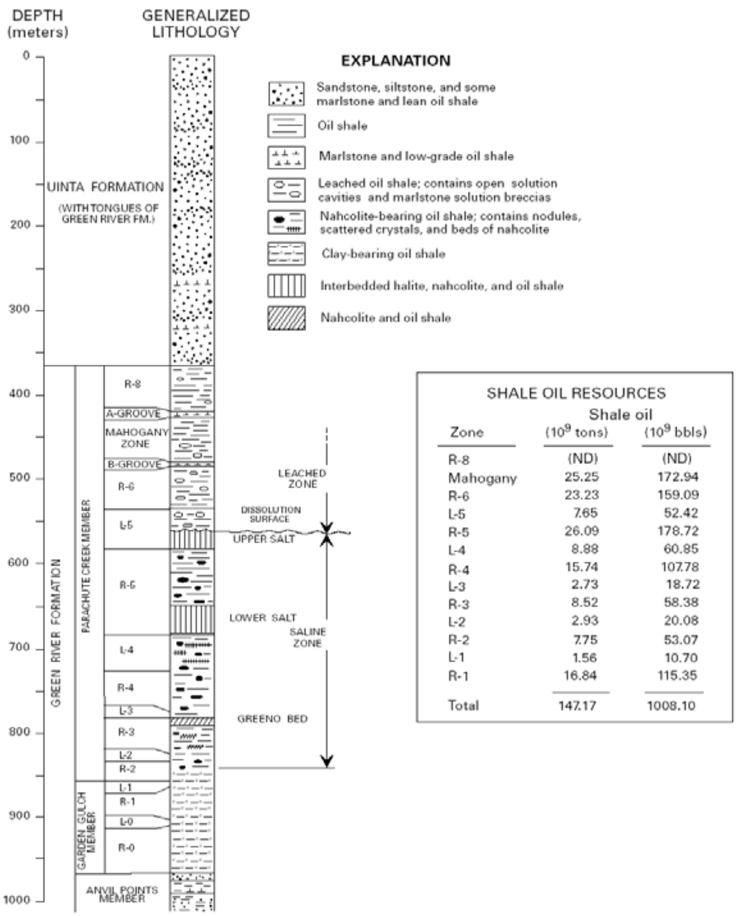


Figure 17. Generalized stratigraphic section of the Green River Formation and associated rocks in the northcentral part of the Piceance Creek Basin, northwestern Colorado, United States. Adapted from Cole and Daub (1991, their fig. 2). The shale-oil resource data, converted from U.S. barrels to metric tons, are from Pitman and others (1989).

Table 8. Summary of the energy and mineral resources of the Green River Formation in Colorado, Utah, and Wyoming, United States. Data from Donnell (1980), Culbertson and others (1980), Trudell and others (1983), Dyni (1974, 1997), Beard and others (1974), Cole and Daub (1991), Pitman and Johnson (1978), Pitman and others (1989), Wiig and others (1995), and unpublished data from the U.S. Bureau of Mines (1981). [km2, square kilometers; l/t, liters per ton; m3, cubic meters]

			Resources	
Basin	Area (km)	Federal lands (percent)	Grade (l/t)	Shale oil (10 tons)
Shale-oil resources				
Piceance Creek Basin, Colorado	4,600	791	≥63 ≥104 ≥125	147 (85)2 (49)2
Uinta Basin, Utah	~ 2,150	77	≥42	31
Green River Basin, Wyoming	~ 1,200 ~ (475)2	62	≥63 125	35.4 (1.9)2
Total	7,900			213
Other resources				
Green River Basin, Wyoming				
Trona	~ 2,800	57		115
Piceance Creek Basin, Colorado				
Dawsonite	~ 1,300			26
Nahcolite	660			29
Natural gas	>230			130x109 m3

[1] The percentage of Federal lands in the Piceance Creek Basin has been reduced by several percent from this figure owing to the transfer of a group of oil-shale placer claims to private ownership.

[2] Data included in the total figure for the basin.

Resources

The oil-shale resource is in that part of the Interior Platform where the black shales are the richest and closest to the surface. Although long known to produce oil upon retorting, the organic matter in the Devonian–Mississippian black shale yields only about half as much as the organic matter of the Green River oil shale, which is thought to be attributable to differences in the type of organic matter (or type of organic carbon) in each of the oil shales. The Devonian–Mississippian oil shale has a higher ratio of aromatic to aliphatic organic carbon than Green River oil shale, and is shown by material balance Fischer assays to yield much less shale oil and a higher percentage of carbon residue (Miknis, 1990).

Hydroretorting Devonian–Mississippian oil shale can increase the oil yield by more than 200 percent of the value determined by Fischer assay. In contrast, the conversion of organic matter to oil by hydroretorting is much less for Green River oil shale, about 130 to 140 percent of the Fischer assay value. Other marine oil shales also respond favorably to hydroretorting, with yields as much as, or more than, 300 percent of the Fischer assay (Dyni, and others, 1990).

Matthews and others (1980) evaluated the Devonian–Mississippian oil shales in areas of the Interior Platform where the shales are rich enough in organic matter and close enough to the surface to be mineable by open pit. Results of investigations in Alabama, Illinois, Indiana, Kentucky, Ohio, Michigan, eastern Missouri, Tennessee, and West Virginia indicated that 98 percent of the near-surface mineable resources are in Kentucky, Ohio, Indiana, and Tennessee (Matthews, 1983). The criteria for the evaluation of the Devonian–Mississippian oil-shale resource used by Matthews and others (1980) were:

1. Organic carbon content: ЎЭ10 weight percent
2. Overburden: ЎЬ200 m
3. Stripping ratio: ЎЬ2.5:1
4. Thickness of shale bed: ЎЭ3 m
5. Open-pit mining and hydroretorting

On the basis of these criteria, the total Devonian–Mississippian shale oil resources were estimated to be 423 billion barrels (61 billion tons); resources by State are summarized in table 9.

Table 9. Estimated resources of near-surface oil shale in eastern United States by hydroretorting. Data derived from Matthews and others (1980, their table 3). [km2, square kilometer; hectare=2.47 acres]

		Shale oil	
State	Area (km)	tons (10)	tons/hectare
Ohio	2,540	20.2	79,000
Kentucky	6,860	27.4	40,000
Tennessee	3,990	6.3	15,500
Indiana	1,550	5.8	37,000
Michigan	410	0.7	17,500
Alabama	780	0.6	7,500
Total	16,130	61.0	

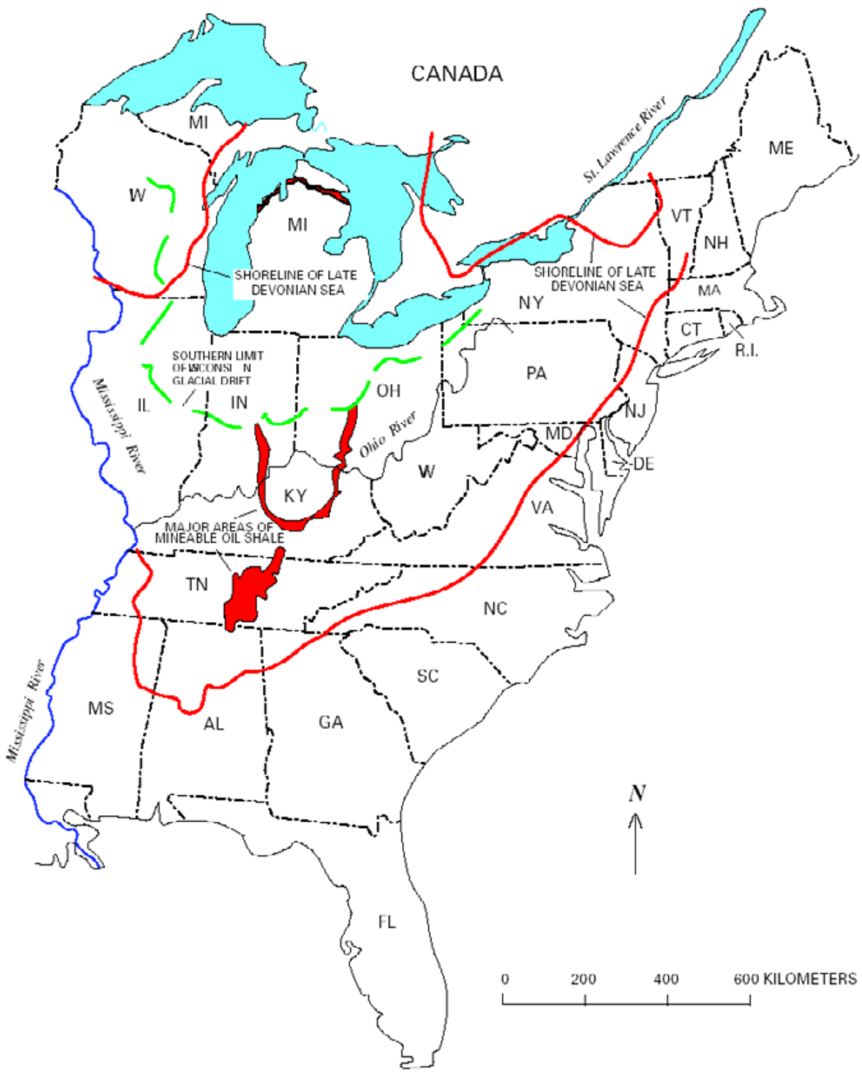


Figure 18. Paleogeographic map showing shoreline of the Late Devonian sea in eastern United States and major areas of surface-mineable Devonian oil shale. After Conant and Swanson (1961, their fig. 13) and Matthews and others (1980, their fig. 5).

SUMMARY OF WORLD RESOURCES OF SHALE OIL

Resources of shale oil for selected deposits worldwide are listed in alphabetical order by country in table 10. Individual deposits for some countries are listed under subheadings, commonly by States or Provinces.

Because of widespread use in the reporting of petroleum and shale-oil resources, quantities are expressed in terms of U.S. barrels in table 10; resources are also reported in metric tons of shale oil. Sources of information (author and date of reference) are given for most of the deposits. The data are too sparse for most deposits to differentiate between resources and reserves of oil shale.

The grade of the oil-shale resource is not indicated in the table. However, it can be assumed that most of the deposits listed will yield, by Fischer assay, at least 40 or more liters of shale oil per ton of oil shale.

For some countries, shale-oil resources of individual deposits are listed. Resources for individual deposits are shown in parentheses when they are included in the total resource figure for a country. Resource figures shown in boldface are from data reported in the literature; the associated figure in normal type was calculated for table 10.

The reliability of resource data, as indicated in the foregoing sections of this report, ranges from excellent to poor. Data for some deposits that have been explored extensively by core drilling are good, such as the Green River oil shale in Colorado, the kukersite deposit in Estonia, and some of the Tertiary deposits in eastern Queensland, Australia, are especially good in comparison to others.

A few large deposits of oil shale, such as the Toolebuc oil shale of Queensland, Australia, are too low-grade to be utilized in the near future. However, improved methods of mining and processing could change their economic status. The largest and richest known deposit by far is the Green River oil shale in western United States. In Colorado alone, the total resource reaches one trillion barrels, of which one-quarter to perhaps as much as one-third may be recoverable with mining and processing techniques available today.

Some countries having good-quality oil shale but lacking petroleum and (or) coal resources will continue to mine oil shale for transportation fuels, petrochemicals, fuel for electric power plants, building materials, and other byproducts. However, their oil-shale industries face imposing challenges from cheaper resources of crude petroleum and coal, as well as from air and water pollution problems.

Production of oil shale from several countries, for which some data are available, are shown in figure 19. World oilshale production peaked in 1980 when

47 million tons were mined, much of it in Estonia where it was used mainly for fuel in several large electric power plants.

Table 10. In-situ shale-oil resources of some world oil-shale deposits

Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Argentina		400	57	1962	
Armenia Aramus	T	305	44	1994	Pierce & others (1994)[5]
Australia					
New South Wales	P				
Queensland					
Alpha	P	80	1	1987	Matheson (1987)[6]
Byfield	T	249	36	1999	Wright (1999, written commun.)[6]
Condor	T	9,700	1,388	do	do
Duaringa (upper unit)	T	4,100	587	do	do
Herbert Creek Basin	T	1,530	219	do	do
Julia Creek	K	1,700	243	do	do
Lowmead	T	740	106	do	do
Mt. Coolon	T	72	10	do	do
Nagoorin Basin	T	3,170	454	do	do
Rundle	T	2,600	372	do	do
Stuart	T	3,000	429	do	do
Yaamba	T	4,100	587	do	Wright (1999, written commun.)[7]
South Australia Leigh Creek	Tr	600	86	1999	Wright (1999, written commun.)[6]
Tasmania					
Mersey River	P	48	7	1987	Crisp & others (1987)
Austria					

Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Belarus Pripyat Basin	D	6,988	1,000		
Brazil					
Iratí Formation	P	80,000	11,448	1994	Afonso & others (1994)
Paraíba Valley	T	2,000	286	1969	Padula (1969)
Bulgaria		125	18	1962	
Canada					
Manitoba-Saskatchewan Favel-Boyne Formations	K	1,250	191	1981	Macauley (1981, 1984a, 1986)8
Nova Scotia					
Stellarton Basin	P-IP	1,174	168	1989	Smith & others (1989)[8]
Antigonish Basin		531	76	1990	Smith & Naylor (1990)
New Brunswick					
Albert Mines	M	269	38	1988	Ball & Macauley (1988)
Dover	M	14	2	do	do
Rosevale	M	3	0.4	do	do
Newfoundland					
Deer Lake Basin	M	?	?	1984	Hyde (1984)[9]
Nunavut					
Sverdrup Basin	M	?	?	1988	Davies & Nassichuk (1988)[10]
Ontario					
Collingwood Shale	O	12,000	1,717	1986	Macauley (1986)
Kettle Point Fm	D	?	?	1986	do
Chile		21	3	1936	
China		16,000	2,290	1985	Du & Nuttall (1985)[11]
Moaming	T	(2,271)	(325)	1988	Guo-Quan (1988)

Table 10. (Continued).

Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Fushun	T	(127)	(18)	1990	Johnson (1990)
Congo, Republic of		100,000	14,310	1958	
Egypt					
Safaga-Quseir area	K	4,500	644	1984	Troger (1984)
Abu Tartur area	K	1,200	172	1984	Troger (1984)
Estonia					
Estonia deposit	O	3,900	594	1998	Kattai & Lokk (1998)[12]
Dictyonema Shale	O	12,386	1,900		
France		7,000	1,002	1978	
Germany		2,000	286	1965	
Hungary		56	8	1995	Papay (1998)[13]
Iraq					May be very large;
Yarmouk	K	?	?	1999	See Jordan
Israel		4,000	550	1982	Minster & Shirav (1982)[14]
Italy		10,000	1,431	1979	
Sicily		63,000	9,015	1978	
Jordan					
Attarat Umm Ghudran	K	8,103	1,243	1997	Jaber & others (1997)[15]
El Lajjun	K	821	126	1997	do
Juref ed Darawish	K	3,325	510	1997	do
Sultani	K	482	74	1997	do
Wadi Maghar	K	14,009	2,149	1997	do
Wadi Thamad	K	7,432	1,140	1997	do
Yarmouk	K		(Large)	1999	Minster (1999)[16]
Kazakhstan					

Kenderlyk field		2,837	400	1996	Yefimov (1996)[17]
Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Luxembourg	J	675	97	1993	Robl and others (1993)
Madagascar		32	5	1974	
Mongolia					
Khoot	J	294	42	2001	Avid and Purevsuren (2001)
Morocco					
Timahdit	K	11,236	1,719	1984	Bouchta (1984)[18]
Tarfaya Zone R	K	42,145	6,448	1984	do
Myanmar (Burma)		2,000	286	1924	
New Zealand		19	3	1976	
Poland		48	7	1974	
Russia					
St. Petersburg kukersite	O	25,157	3,600		
Timano-Petchorsk Basin	J	3,494	500		
Vychegodsk Basin	J	19,580	2,800		
Central Basin	?	70	10		
Volga Basin	?	31,447	4,500		
Turgai & Nizheiljisk deposit	?	210	30		
Olenyok Basin	€	167,715	24,000		
Other deposits	—	210	30		
South Africa		130	19	1937	
Spain		280	40	1958	
Sweden					
Narke	€	594	85	1985	Andersson & others (1985)
Ostergotland	€	2,795	400	1985	do
Vastergotland	€	1,537	220	1985	do
Oland	€	1,188	170	1985	do
Thailand					
Deposit & (Province)					

Mae Sot (Tak)	T	6,400	916	1988	Vanichseni & others (1988)

Table 10. (Continued).

Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Li (Lampoon)	T	1		1988	do
Turkmenistan & Uzbekistan					
Amudarja Basin[19]	P	7,687	1,100		
Turkey					
Deposit & (Province)					
Bahcecik (Izmit)	T	35	5	1993	Güleç & Önen (1993)[20]
Beypazari (Ankara)	T	398	57	1995	Sener & others (1995)
Burhaniye (Bahkesir)	T	28	4	1993	Güleç & Önen (1993)
Golpazari (Bilecik)	T	126	18	1993	do
Goynuk (Bolu)	T	804	115	1995	Sener & others (1995)
Hatildag (Bolu)	T	203	29	1995	do
Seyitomer (Kutahya)	T	349	50	1995	do
Ulukisla (Nigde)	T	42	6	1993	Güleç & Önen (1993)
Ukraine					
Boltysh deposit		4,193	600	1988	Tsherepovski
United Kingdom		3,500	501	1975	
United States					
Eastern Devonian	D	189,000	27,000	1980	Matthews & others (1980)21
Green River Fm	T	1,466,000	213,000	1999	This report
Phosphoria Fm	P	250,000	35,775	1980	Smith (1980)
Heath Fm	M	180,000	25,758	1980	do
Elko Fm	T	228	33	1983	Moore &

					others (1983)
Country, region, and deposit[1]	Age[2]	In-place shale-oil resources[3] (106 bbls)	In-place shale-oil resources[3] (106 tons)	Date of estimation[4]	Source of information
Uzbekistan					
Kyzylkum Basin		8,386	1,200		
Total (rounded)		2,826,000	409,000		

[1] The resources in the above table are listed by country in alphabetical order. For some countries, the deposits are listed under State or Province.

[2] The age of the deposit, when known, is indicated by the following symbols: e, Cambrian; O, Ordovician; D, Devonian; M, Mississippian Early Carboniferous); h, Pennsylvanian (Late Carboniferous); P, Permian; d, Triassic; J, Jurassic; K, Cretaceous; and T, Tertiary.

[3] The resources of shale oil are given in U.S. barrels and metric tons. Resource numbers in boldface type are from the references cited; the associated number in nonboldface type was calculated for this table. In several cases, resource numbers in parentheses are included in the total resource number for the country. To determine tons of resources from volumetric data, it is necessary to know the specific gravity of the shale oil. In some cases, this value was given in the source reference; if not, a specific gravity of 0.910 was assumed.

[4] The "date of estimation" is the publication date of the source reference. If a reference is not listed for a deposit, the resource data are from Russell (1990). A few deposits for which no resource numbers are given are still listed in the table because they are believed to be of significant size.

[5] The resource was estimated by assuming seven beds of oil shale totaling 14 m in thickness, which underlie 22 square kilometers and have an average oil-shale bulk density of 2.364 gm/cc.

[6] Shale-oil specific gravity (SG) of 0.910 was assumed. Resource data from Matheson (1987) augmented by a personal communication from Dr. Bruce Wright to Professor J.L. Qian dated March 29, 1999.

[7] McFarlane (1984) gives the Yaamba deposit as 2.92 billion in-situ barrels of shale oil.

[8] Shale oil SG of 0.910 was assumed.

[9] The west side of the basin is largely unexplored and may contain oil-shale deposits.

[10] Alginite-rich oil shale is found in the Lower Carboniferous Emma Fiord Formation at several localities in the Sverdrup Basin. On Ellemere Island the shale is geothermally overmature, but on Devon Island, the oil shale is immature to marginally mature.

[11] China's total oil-shale resources are given by Du and Nuttall (1985, p. 211).

[12] A shale-oil yield of 10 wt pct and a shale oil SG of 0.968 were used to calculate barrels of resources (Yefimov and others, 1997, p. 600). Kogerman (1997, p. 629) gives the range of oil yields of Estonian kukersite as 12–18 wt pct.

[13] Assumed a shale-oil yield of 8 wt pct and a shale-oil SG of 0.910.

[14] Fainberg and Hetsroni (1996) estimate Israel's oil-shale reserves at 12 billion tons, which equates to 600 million tons of shale oil.
[15] Shale-oil SG of 0.968 was assumed.
[16] The oil-shale deposit underlies several hundred square kilometers and reaches 400 m in thickness (Minster, 1999, written commun.).
[17] Shale-oil SG of 0.900 was assumed.
[18] Shale-oil SG of 0.970 was assumed. Occidental Oil Company made the estimate of the Timahdit resource and Bouchta estimated the Tarfaya resource; details of both estimates are in Bouchta (1984).
[19] Amudarja Basin extends across border between Turkmenistan and Uzbekistan.
[20] Güleç and Önen (1993) reported 5,196 million tons of oil shale in seven deposits but no shale-oil numbers. Graham and others (1993) estimate the Goynuk resource at 9 billion tons of oil shale. Sener and others (1995) reported 1,865 million tons of oil shale in four Turkish deposits.
[21] The Devonian oil-shale resource estimated by Matthews and others (1980) is based on hydroretorting analyses. To make these results compatible with the rest of the resource data in this table, which are based mostly on Fischer assay analyses, the resource numbers given by Matthews and others (1980) were reduced by 64 percent.

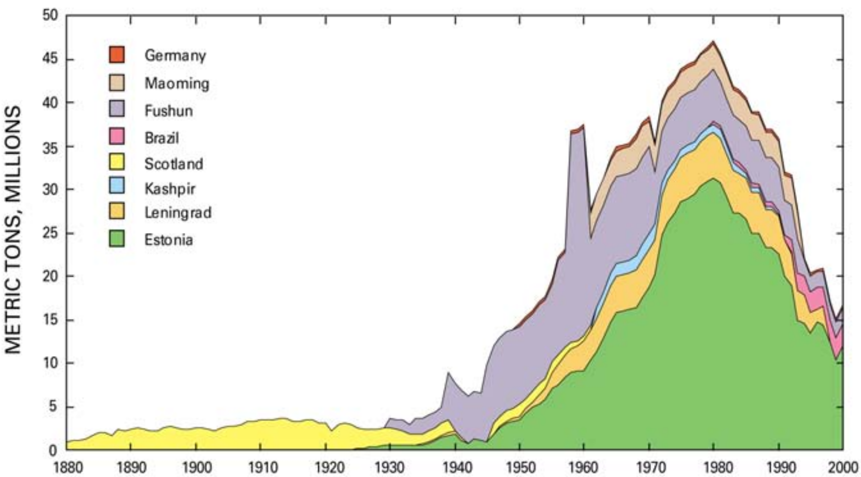


Figure 19. Production of oil shale in millions of metric tons from Estonia (Estonia deposit), Russia (Leningrad and Kashpir deposits), United Kingdom (Scotland, Lothians), Brazil (Iratí Formation), China (Maoming and Fushun deposits), and Germany (Dotternhausen) from 1880 to 2000.

The total resource of oil shale of 409 billion tons (2.9 trillion U.S. barrels) listed in table 10 should be considered a minimum figure, because numerous deposits are still largely unexplored or were not included in this study. Further exploration will undoubtedly add many more billions of tons of in-situ shale oil to this total.

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Chapter 8

OIL SHALE: HISTORY, INCENTIVES, AND POLICY*

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ABSTRACT

Oil shale is prevalent in the western states of Colorado, Utah, and Wyoming. The resource potential of these shales is estimated to be the equivalent of 1.8 trillion barrels of oil in place. Retorted oil shale yields liquid hydrocarbons in the range of middle-distillate fuels, such as jet and diesel fuel. However, because oil shales have not proved to be economically recoverable, they are considered a contingent resource and not true reserves. It remains to be demonstrated whether an economically significant oil volume can be extracted under existing operating conditions. In comparison, Saudi Arabia reportedly holds proved reserves of 267 billion barrels.

Federal interest in oil shale dates back to the early 20th Century, when the Naval Petroleum and Oil Shale Reserves were set aside. Out of World War II concerns for a secure oil supply, a Bureau of Mines program began research into exploiting the resource. Commercial interest followed during the 1960s. After a second oil embargo in the 1970s, Congress created a synthetic fuels program to stimulate largescale commercial development of

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oil shale and other unconventional resources. The federal program proved short-lived, and commercially backed oil shale projects ended in the early 1980s when oil prices began declining.

The current high oil prices have revived the interest in oil shale. The Energy Policy Act of 2005 (EPACT) identified oil shale as a strategically important domestic resource, among others, that should be developed. EPACT also directed the Secretary of Defense to develop a separate strategy to use oil shale in meeting Department of Defense (DOD) requirements when doing so is in the national interest. Tapping unconventional resources, such as oil shale, has been promoted as a means of reducing dependence on foreign oil and improving national security.

Opponents of federal subsidies for oil shale argue that the price and demand for crude oil should act as sufficient incentives to stimulate development. Projections of increased demand and peaking petroleum production in the coming decades tend to support the price-and-supply incentive argument in the long term.

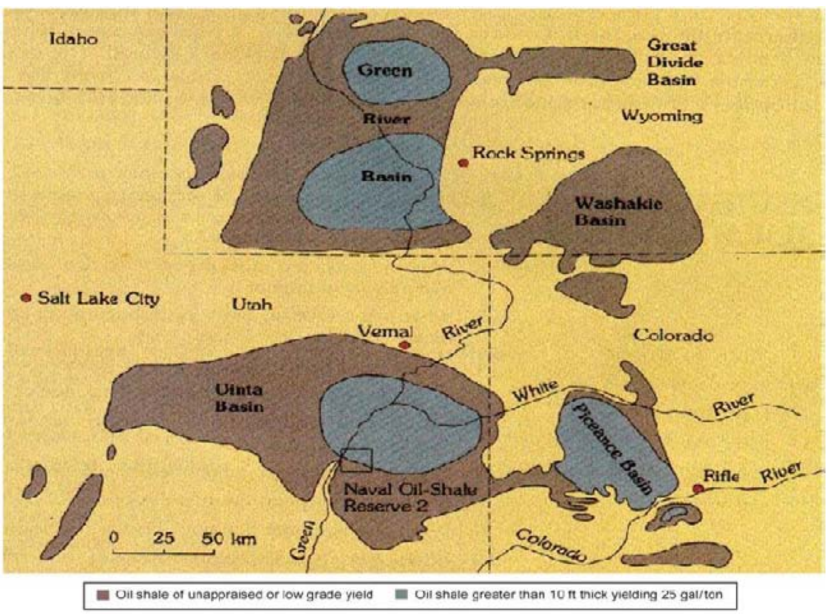
The failure of oil shale has been tied to the perennially lower price of crude oil, a much less risky conventional resource. Proponents of renewing commercial oil shale development might also weigh whether other factors detract from the resource's potential. Refining industry profitability is overwhelmingly driven by light passenger vehicle demand for motor gasoline, and oil-shale distillate does not make ideal feedstock for gasoline production. Policies that discourage the wider use of middledistillates as transportation fuels indirectly discourage oil shale development. Because the largest oil shale resources reside on federal lands, the federal government would have a direct interest and role in the development of this resource.

This report will be updated as new developments occur.

INTRODUCTION

Projections that peak petroleum production may occur in the coming decades, along with increasing global demand, underscore the United States' dependence on imported petroleum. After Hurricanes Katrina and Rita, the spike in crude oil price and the temporary shutdown of some Gulf Coast refineries exacerbated that dependency. With imports making up 65% of the United States' crude oil supply and the expectation that the percentage will rise, proponents of greater energy independence see the nations's huge but undeveloped oil shale resources as a promising alternative.[1]

Oil shales are prevalent throughout the United States. Their kerogen content is the geologic precursor to petroleum. The most promising oil shale resources occur in the Green River formation that underlies 16,000 square miles of northwestern Colorado, northeastern Utah, and southwestern Wyoming (Figure 1). Approximately 72% of the land overlying the Green River Formation is federally held.[2] The formation is estimated to contain more than 8 trillion barrels of shale oil in place; however, much of the formation has been considered too thin, too deep, or too low in yield to economically develop using older technology. The former Office of Technology Assessment (OTA) estimated in 1980 that 1.8 trillion barrels appeared marginally attractive to production, based on deposits that would yield 15 gallons per ton and were at least 15 feet thick.[3] In a more recent analysis, the portion of the formation yielding greater than 10 gallons per ton was estimated to contain 1.5 trillion barrels.[4] Because oil shales have not been proven economically recoverable, they are considered contingent resources and not true reserves.[5] By comparison, the conventional proved oil reserves of the United States are less than 22 billion barrels, and Saudi Arabia's are reportedly 267 billion barrels.[6]



Source: U.S. Geologic Survey, Circular 523 (1965), as reproduced by the U.S. Department of Energy in Strategic Significance of America's Oil Shale Resources, Mar. 14, 2005.

Note: The Green River formation may contain more than 8 trillion barrels of shale oil in place, with an estimated 1.8 trillion barrels marginally attractive to production. The United States holds proved reserves of less than 22 billion barrels of conventional crude oil, compared with Saudi Arabia's reported 267 billion barrels.

Figure 1. Distribution of Oil Shale in the Green River Formation of Colorado, Utah, and Wyoming.

In the early 20th century, three oil shale reserves were set aside on federal lands out of concern for the Navy's petroleum supply. Naval Oil Shale Reserves (NOSRs) Nos. 1 (36,406 acres) and 3 (20,171 acres) are located 8 miles west of Rifle, Colorado, in Garfield County. Reserve No. 2 (88,890 acres) in Carbon and Uintah Counties, Utah, has been transferred to the Ute Indian Tribe. NOSR No.1 has been estimated to contain more than 18 billion barrels of shale oil in place.[7] As much as 2.5 billion barrels of oil may be recoverable from shale yielding 30 gallons of oil or more per ton. NOSR No. 3 is not considered to have commercial value.

Oil shale production has faced unique technological and environmental challenges. The hydrocarbon resource is bound up in the shale and is not free to flow like petroleum. In previous attempts at production, conventional subsurface and strip mining methods were combined with high-temperature processing (retorting) to extract petroleum-like distillates. Not only was a plentiful water supply required, but certain processing methods had associated groundwater contamination issues. Unlike conventional petroleum production, wherein crude oil is shipped or piped to an established refining and distribution center, oil shale production would have required the vertical integration of resource extraction, processing, and upgrading to a finished product ready for blending and distribution. Recent interests in oil shale look to overcoming the past technical challenges associated with mining by adapting oil field production methods. Unlike conventional crude oil, oil-shale distillates make poor feedstock for gasoline production and thus may be better suited to making distillatebased fuels such as diesel and jet fuel. The cost of producing oil shale remains uncertain, especially when compared with the economic fundamentals of extracting conventional petroleum reserves.

GEOLOGY AND PRODUCTION TECHNOLOGY OF OIL SHALE

Kerogen

The first phase in organic matter's geologic transformation to petroleum is intermediate conversion to kerogen. During this low-temperature transformation — referred to as diagenesis — organically bound oxygen, nitrogen, and sulfur are released.[8] Complete transformation to petroleum occurs during catagenesis —

the prolonged exposure to temperatures in the range of 122° to 392°F, generally occurring at depths of 4,000 to 9,800 feet. The catalytic properties of the shale binding the kerogen contribute to the transformation. The threshold for intense oil generation begins at 149°F, equivalent to depths of 4,500 feet or more. Temperatures above 392°F mark the metamorphic end-state of transformation — ultimate conversion to methane gas and graphite (pure carbon).

Oil shales have not thermally matured beyond the diagenesis stage due to their relatively shallow depth of burial. Some degree of maturation has taken place, but not enough to fully convert the kerogen to petroleum hydrocarbons. The Green River oil shale of Colorado has matured to the stage that heterocyclic (ring-like) hydrocarbons have formed and predominate, with up to 10% normal- and isoparaffins (the range of hydrocarbons that includes natural gasoline).[9] In comparison, conventional crude oil may contain as much as 40% natural gasoline. The kerogen's rich hydrogen/carbon ratio (1.6) is a significant factor in terms of yielding high- quality fuels. Its 1%-3% nitrogen content, however, may be problematic in terms of producing stable fuels (petroleum typically contains less than 0.5% nitrogen), as well as producing environmentally detrimental nitrogen oxides during combustion.[10] To assess kerogen's potential for yielding hydrocarbon-like fuels, the processes of conventional petroleum refining, synthetic fuel production, and oil shale retorting are compared below.

Conventional Refining

A conventional refinery distills crude oil into various fractions, according to boiling point range, before further processing.[11] In order of their increasing boiling range and density, the distilled fractions are fuel gases, light and heavy straight-run naphtha (90°-380°F), kerosene (380°-520°F), gas-oil (520°-1,050°F), and residuum (1,050°F +). Gasoline's molecular range is C5-C10; middle-distillate fuels (kerosene, jet, and diesel) range C11-C18. Crude oil may contain 10%-40% gasoline, and early refineries directly distilled a straight-run gasoline (light naphtha) of low-octane rating.[12] A hypothetical refinery may "crack" a barrel of crude oil into two-thirds gasoline and one-third distillate fuel (kerosene, jet, and diesel), depending on the refinery's configuration, the slate of crude oils refined, and the seasonal product demands of the market.[13]

Just as natural clay catalysts help transform kerogen to petroleum through catagenesis, metallic catalysts help transform complex hydrocarbons to lighter molecular chains in modern refining processes. The catalytic-cracking process developed during the World War II era enabled refineries to produce high-octane gasolines needed for the war effort. Hydrocracking, which entered commercial operation in 1958, improved on catalytic-cracking by adding hydrogen to convert residuum into high-quality motor gasoline and naphtha-based jet fuel. U.S. refineries rely heavily on hydroprocessing to convert low-value gas oils residuum to high-value transportation fuel demanded by the market. Middle-distillate range fuels (diesel and jet) can be blended from a variety of refinery processing streams.[14] To blend jet fuel, refineries use desulfurized straight-run kerosene, kerosene boiling range hydrocarbons from a hydrocracking unit, and light coker gas-oil (cracked residuum). Diesel fuel can be blended from naphtha, kerosene, and light cracked-oils from coker and fluid catalytic cracking units. From the standard 42-gallon barrel of crude oil, U.S. refineries may actually produce more than 44 gallons of refined products through the catalytic reaction with hydrogen.[15]

From a simple crude distillation unit, a typical U.S. refinery has grown to a complex of 10 to 15 types of processes.[16] The Nelson Complexity Index, a measure of a refinery's complexity, assigns factors to the capacities of various processing units and compares them to the refinery's crude distillation unit capacity. U.S. refineries rank highest in complexity index, averaging 9.5 compared with Europe's at 6.5. The difference in complexity index reflects the 2-times greater catalytic cracking and 1½-times greater reformation capacities of U.S. refineries.[17] Although U.S. refineries have optimized to produce reformulated gasoline, European refineries yield more middle-distillate diesel fuel to meet the greater European demand for that fuel.

Synthetic Fuel Production

Synthetic fuel technology was developed in prewar Germany to address its scarce petroleum resources. An early process developed by Friedrich Bergius used a catalyst to promote the reaction of hydrogen with coal liquids to produce lowquality gasoline. During the 1960s, the Department of the Interior's Office of Coal Research sponsored research to directly liquefy Eastern coal into substitutes for natural gas and oil (synthetic liquid fuels).[18]

In a competing process developed by German scientists Fischer and Tropsch, low-temperature catalysts were used to promote hydrogen's reaction with coal gas and produce gasoline. The South African oil company Sasol later developed this technology further. Modern "gas-to-liquids" (GTL) technology based on the Fischer-Tropsch process converts natural gas to liquid fuels.

Essentially, both the Bergius and Fisher-Tropsch synthetic fuel processes build up longer chain hydrocarbons from smaller molecules. This is the opposite of hydrocracking, the refining process that breaks heavier-weight molecular chains and rings into lighter-weight molecules using hydrogen and catalysts.

Oil Shale Retorting

Oil derived from shale has been referred to as a synthetic crude oil and thus closely associated with synthetic fuel production. However, the process of retorting shale oil bears more similarities to conventional refining than to synthetic fuel processes. For the purpose of this report, the term oil-shale distillate is used to refer to middle-distillate range hydrocarbons produced by retorting oil shale. Two basic retorting processes were developed early on — aboveground retorting and underground, or in situ, retorting. The retort is typically a large cylindrical vessel, and early retorts were based on rotary kiln ovens used in cement manufacturing. In situ technology involves mining an underground chamber that functions as a retort. A number of design concepts were tested from the 1960s through the 1980s.

Retorting essentially involves destructive distillation (pyrolysis) of oil shale in the absence of oxygen. Pyrolysis (temperatures above 900°F) thermally breaks down (cracks) the kerogen to release the hydrocarbons and then cracks the hydrocarbons into lower-weight hydrocarbon molecules. Conventional refining uses a similar thermal cracking process, termed coking, to break down high-molecular weight residuum.

OTA compiled properties of oil-shale distillates produced by various retorting processes (Table 1). In general, oil-shale distillates have a much higher concentration of high boiling-point compounds that would favor production of middle-distillates (such as diesel and jet fuels) rather than naphtha.[19] Oil-shale distillates also had a higher content of olefins, oxygen, and nitrogen than crude oil, as well as higher pour points and viscosities. Above-ground retorting processes tended to yield a lower API gravity oil than the in situ processes (a 25° API gravity was the highest produced).[20] Additional processing equivalent to hydrocracking would be required to convert oil-shale distillates to a lighter range hydrocarbon (gasoline). Removal of sulfur and nitrogen would, however, require hydrotreating.

By comparison, a typical 35° API-gravity crude oil may be composed of up to 50% of gasoline and middle-distillate range hydrocarbons. West Texas Intermediate crude (a benchmark crude for trade in the commodity futures market) has a 0.3% sulfur content, and Alaska North Slope crude has a 1.1% sulfur content.[21] The New York Mercantile Exchange (NYMEX) specifications for light "sweet" crude limits sulfur content to 0.42% or less (A.S.T.M. Standard D-4294) and an API gravity between 37 and 42 degrees (A.S.T.M. Standard D-287).[22]

Oil-shale distillate has been considered a synthetic substitute for crude oil; however, its fungibility may be limited in modern refining operations. Because the kerogen contained by the shale is only a petroleum precursor, it lacks the full range of hydrocarbons used by refineries in maximizing gasoline production. Also, because of technology limitations, only hydrocarbons in the range of middledistillates (kerosene, jet fuel, diesel fuel) appear extractable.

Table 1. Properties of Oil-Shale Distillates Compared with Benchmark Crude Oils

	° API	% Sulfur
OTA Reported Oil-Shale Distillates Properties[a]	19.4-28.4	0.59-0.92
Shell ICP Oil-Shale Distillate[b]	34	0.8
Oil Tech Oil-Shale Distillate[c]	30	no report
West Texas Intermediate Crude Oil[d]	40	0.30
NYMEX Deliverable Grade Sweet Crude Oil Specification[e]	37-42	<0.42
Alaska North Slope Crude Oild	29-29.5	1.10

[a]. OTA, An Assessment of Oil Shale Technologies, Table 19, 1980.

[b.] Energy Washington Week, "Shell Successfully Tests Pilot of New In Situ Oil Shale Technology," Oct. 12, 2005.

[c.] Jack Savage, Testimony Before the Subcommittee on Energy and Mineral Resources, June 23, 2005.

[d.] Platt's Oil Guide to Specifications, 1999.

[e]. NYMEX, Exchange Rulebook, Light "Sweet" Crude Oil Futures Contract.

Both in situ and above-ground retorting processes have been plagued with technical and environmental problems. Apart from the problem of sustaining controlled combustion underground, in situ retorting suffered from the environmental drawback of causing groundwater contamination. Above-ground retorting required underground or open-pit mining to excavate the shale first. While either mining method is well-practiced, the expended shale that remained after retorting presented a disposal problem, not to mention the overburden rock that had to be removed in the case of open-pit mining. Above-ground retorts also faced frequent problems from caked-up shale, which led them to shut down. Some recent approaches have aimed to avoid these drawbacks altogether.

Shell In Situ Conversion Process. For the past five years, the Shell Exploration and Production Company has been conducting research into directly extracting oil-shale distillates on its 20,000-acre Cathedral Bluffs property near Parachute (Rio Blanco County), Colorado.[23] Unlike previously attempted in situ retorting, Shell's in situ conversion process (ICP) involves drilling holes up to 2,000 feet deep, inserting electrical resistance heaters, and heating the shale to 650-700°F over a period of months. The ICP converts the kerogen to gas and petroleum-like liquids. The process not only consumes high amounts of energy to operate the heaters, it also requires freezing the perimeter of the production zone to restrict groundwater flow. Shell Oil Company reports extracting a 34°API product consisting of a gas (propane and butane) and b liquids split 30% naphtha, 30% jet fuel, 30% diesel, and 10% slightly heavier oil. Sulfur content was 0.8% by weight.

Oil Tech Above-Ground Retorting. Oil Tech, Inc., has been developing a new above-ground retort, which it reports as having the capacity of extracting one barrel of shale-oil per ton of shale per hour.[24] The company has reported producing a low-sulfur 30° API-gravity oil consisting of 10% naphtha, 40% kerosene, 40% diesel, and 10% heavy residual oil. Starting off where past retorting attempts ended, Oil Tech intends to use previously mined oil shale that had been stockpiled.

HISTORY OF OIL SHALE DEVELOPMENT

Oil shale was originally considered as a reserve supply of crude oil to fuel U.S. naval vessels in times of short supply or emergencies. Because the largest oil shale resources reside on federal lands, the federal government historically has had a direct interest and role in encouraging the development of this resource. Potential oil-bearing lands in California and Wyoming were first set aside for withdrawal as sources of fuel for the Navy under the Pickett Act of 1910. Later, presidential executive orders created NOSR Nos. 1 and 3 in Colorado and NOSR No. 2 in Utah.

Early Synthetic Liquid Fuels Efforts

During World War II, Congress's concern for conserving and increasing the nation's oil resources prompted passage of the Synthetic Liquid Fuels Act of 1944

(30 U.S.C. Secs. 321 to 325), which authorized funds for the Interior Department's Bureau of Mines to construct and operate demonstration plants to produce synthetic liquid fuel from oil shales, among other substances.

Congress passed the Defense Production Act of 1950 (Ch. 932, 64 Stat. 798) during the Korean War to develop and maintain whatever military and economic strength was necessary to support collective action through the United Nations. The Title III program authorized governmental requisition of property for national defense and expansion of productive capacity, among other authorities. Between 1949 and 1955, the U.S. Bureau of Mines received $18 million to operate three above-ground gas combustion retorts at Anvil Points, Colorado, the site of NOSR No. 1.

Long before the United States' increasing dependence on imported crude oil become apparent, oil shale began attracting the interest of some major petroleum companies: Exxon, Occidental Petroleum, and Union Oil, among others. In 1961, the Union Oil Company began testing its "Union A" retort at Parachute Creek, Colorado. Though producing 800 barrels per day (bpd), Union shut the retort down after 18 months due to cost. In 1964, The Oil Shale Company (Tosco), Standard Oil of Ohio (Sohio), and Cleveland Cliffs Mining formed a consortium to operate the Colony Oil Shale mine. Despite producing 270,000 barrels, Tosco shut down production in 1972. Occidental Petroleum also began oil shale retorting experiments in 1972 near Rifle, Colorado, and ultimately evaluated six retorts.

Defense Department Programs

The Defense Department had become interested in oil shale as an alternative resource for producing quality jet fuel as early as 1951.[25] The U.S. Navy and the Naval Petroleum and Oil Shale Reserves Office (NPSRO) started large-scale evaluations of oil shale's suitability for military fuels in the early 1970s. Tosco was contracted to produce and process 10,000 barrels of oil-shale distillates. Development Engineering, Inc., leased the federal Anvil Points site (Naval Oil Shale Reserve 3) in 1972 and formed the Paraho Development Corporation in 1973 (a consortium of 17 energy companies). Paraho's plans included a five-year program to develop two pilot scale retorts and produce oil-shale distillates for the Navy fuel testing. Paraho initially produced 10,000 barrels of oil-shale distillates that Sohio processed into gasoline, JP-4 and JP-5 jet fuel, diesel fuel marine (DFM), and a heavy fuel oil at the Gary Western Refinery in Fruita, Colorado. Though the fuels produced were off-specification, analysis indicated that the refining process could be optimized to produce specification fuels. Paraho was awarded a follow-on contract to produce 100,000 barrels of oil-shale distillates for processing specification fuels in Sohio's Toledo Refinery. The Navy conducted extensive tests with the fuels in military and commercial equipment.

In the late 1970s, the Air Force became interested in evaluating oil shale's suitability for producing JP-4 jet fuel. Under Project Rivet Shale, in 1979, the Air Force awarded contracts to Ashland Research and Development, Suntech, Inc., and UOP, Inc., to develop technology to produce oil shale-derived JP-4 jet fuel. In 1982, over 10,000 gallons of JP-4 were processed at the Caribou Four Corners Refinery in Woods Cross, Utah, from crude oil-shale distillates produced by Geokinetics. JP-4 specification fuel was produced from other oil shale retorting techniques pioneered by Occidental, Paraho, and Union Oil. Unocal (formerly Union Oil Company) operated the Parachute Creek oil shale plant and reportedly produced 4.6 million barrels of oil-shale distillates from 1985 to 1990 for Air Force evaluation under Project Rivet Shale.[26] The Air Force generally phased out JP-4 in the early 1990s in favor of kerosene-based JP-8.

Department of Energy Synthetic Fuels Program

The Department of Energy (DOE) encouraged interest in large-scale oil shale development through its Synthetic Fuels Program. DOE initially promoted two prototype lease tracts in the Piceance Basin of Rio Blanco County, Colorado (NOSR tracts C-a and C-b).[27] Amoco later produced 1,900 barrels using in situ retorting in tract C-a, and Occidental Petroleum planned a similar effort for tract C-b.

The Interior Department Appropriations Act (P.L. 96-126) and the Supplemental Appropriations Act of 1980 (P.L. 96-304) appropriated $17.522 billion to the Energy Security Reserve fund in the Treasury Department. Of that amount, $2.616 billion was committed by the Department of Energy to three synthetic fuels projects. Two of the projects were approved under the Defense Production Act: Union Oil Company's Parachute Creek project in Garfield County, Colorado, and Exxon-Tosco's Colony oil shale project, also in Garfield County. Union Oil Company received a $0.4 billion price guarantee for the Parachute Creek Shale Oil Project, and the Exxon-Tosco Colony Oil Shale Project received a loan guarantee of $1.15 billion (applied to the 40% owned by Tosco).[28] Union Oil was expected to produce 10,400 bpd at $42.50/bbl, which, adjusted for inflation, equaled $51.20/bbl by March 1, 1985.

As an additional stimulus to producing alternative fuels — for which oil shale, among others, qualified — Congress provided a $3.00 /bbl production tax credit provision in the Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223). The credit would take full effect when crude oil prices fell below $23.50 /bbl (in 1979 dollars) and would gradually phase out as prices rose above to $29.50/bbl.

Tosco's interest in the Colony project was sold in 1979, and again in 1980, to Exxon Company for the Colony II development. Exxon planned to invest up to $5 billion in a planned 47,000 bpd plant using a Tosco retort design. After spending more than $1 billion, Exxon announced on May 2, 1982, that it was closing the project and laying off 2,200 workers.

U.S. Synthetic Fuels Corporation

The Energy Security Act of 1980 (P.L. 96-294, Title I, Part B) established the United States Synthetic Fuels Corporation (SFC) with the authority to provide financial assistance to qualified projects that produced synthetic fuel from coal, oil shale, tar sands, and heavy oils. The SFC's loan commitments would be paid from the Energy Security Reserve fund. Executive Order 12346 (Synthetic Fuels) later provided for an orderly transition of DOE's earlier synthetic fuel program to the SFC.

Between 1981 and 1984, the SFC received 34 proposals for oil shale projects in three rounds of solicitations. Only three letters of intent were ever issued. Union Oil's Parachute Creek Phase II 80,000 bpd plant was to receive a $2.7 billion funding commitment and a guarantee of $60/bbl, escalated up to $67 /bbl; another $0.5 billion in price and loan guarantees was added in October 1985 to Union's Parachute Creek Phase I. Cathedral Bluffs, a 14,300 bpd plant based on a Union Oil design, was to receive a $2.19 billion loan guarantee and a $60/bbl price guarantee. Seep Ridge Oil Shale's 1,000 bpd plant was to receive $45 million in price and loan guarantees. None of the oil shale projects that received SFC loan guarantees ever received actual funding, as Congress rescinded $2 billion originally appropriated for the Energy Security Reserve fund in the Deficit Reduction Act of 1984 (P.L. 98-369) and later abolished the SFC.

In 1984, Congress asked the General Accounting Office (GAO) to report on the progress of synthetic fuels development and to specifically respond to the question "Why have project sponsors dropped synthetic fuels projects?" GAO answered that oil had become plentiful, with about 8 to 10 million barrels per day in excess worldwide capacity, and the trend in rising oil prices had reversed after early 1981.

President Reagan's Executive Order 12287 had removed price and allocation controls on crude oil and refined petroleum products in 1981. For the first time since the early 1970s, market forces replaced regulatory programs and domestic crude oil prices were allowed to rise to a market-clearing level. Decontrol also set the stage for the relaxation of export restrictions on refined petroleum products. Oil demand had also declined, due in part to energy conservation measures and a worldwide economic recession. A more fundamental change had taken place in the way that oil commodities were traded. Prior to 1980, the price of crude oil was determined by long-term contracts, with 10% or so of internationally traded oil exchanged on the spot market.[29] By the end of 1982, more than half of the internationally traded oil was exchanged on the spot market or tied to the spot market price. The most significant change occurred in 1983, with the introduction of crude oil futures by the New York Mercantile Exchange (NYMEX). All served to undermine price setting by the Organization of Petroleum Exporting Countries (OPEC).

Tax incentives for oil shale projects had also been reduced. Some of the generous oil depreciation allowances under the 1981 Economic Recovery Tax Act (P.L. 97-48) were rescinded in 1982 by the Tax Equity and Fiscal Responsibility Act (P.L. 97-248), reducing potential project sponsors' after-tax rates of return. The House began considering a bill to abolish the SFC in 1985, and Congress terminated the Corporation the following year under the Consolidated Omnibus Budget Reconciliation Act of 1985 (P.L. 99-272). The Appendix to this report provides a more complete legislative history of the Synthetic Fuels program.

Renewed Interest in Oil Shale

In 2005, Congress conducted hearings on oil shale to discuss opportunities for advancing technology that would facilitate "environmentally friendly" development of oil shale and oil sands resources.[30] The hearings also addressed legislative and administrative actions necessary to provide incentives for industry investment, as well as exploring concerns and experiences of other governments and organizations and the interests of industry. The Energy Policy Act of 2005 included provisions under Section 369 (Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels[31]) that direct the Secretary of the Interior to begin leasing oil shale tracts on public lands and to cooperate ith the Secretary of Defense in developing a program to commercially develop oil shale, among other strategic unconventional fuels.

The Bureau of Land Management (BLM) established the Oil Shale Task Force in 2005 to address oil shale access on public lands and impediments to oil shale development on public lands. Title 30, Section 241(a) of the Mineral Lands

Leasing Act formerly restricted leases to 5,120 acres. Advocates of oil shale development claimed that restrictions on lease size hindered economic development. The Energy Policy Act amended Section 241(a) by raising the lease size to 5,760 acres and restricting total lease holdings to no more than 50,000 acres in any one state.[32]

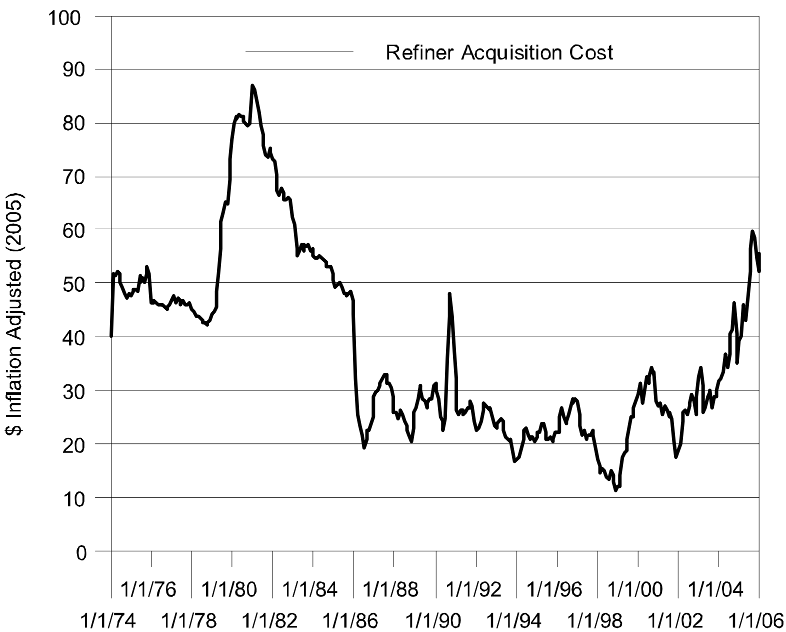
On September 20, 2005, the Bureau of Land Management announced it had received 19 nominations for 160-acre parcels of public land to be leased in Colorado, Utah, and Wyoming for oil shale research, development, and demonstration (RD&D). On January 17, 2006, BLM announced that it accepted eight proposals from six companies to develop oil shale technologies; the companies selected were Chevron Shale Oil Co., EGL Resources Inc., ExxonMobil Corp., Oil-Tech Exploration LLC, and Shell Frontier Oil & Gas.[33] Six of the proposals will look at in situ extraction to minimize surface disturbance. Each proposal will be evaluated under the National Environmental Policy Act (NEPA). In addition to the 160 acres allowed in the call for RD&D proposals, a contiguous area of 4,960 acres is reserved for the preferential right for each project sponsor to convert to a future commercial lease after additional BLM reviews.

The Energy Policy Act also identified oil shale as a strategically important domestic resource and directed DOE to coordinate and accelerate its commercial development. Section 369(q) (Procurement of Unconventional Fuels by the Department of Defense) of the act directs the Secretaries of Defense and Energy to develop a strategy to use fuel produced from oil shale to help meet the fuel requirements of the Defense Department when the Defense Secretary determines that doing so is in the national interest. The Defense Department had worked jointly with Energy on a Clean Fuels Initiative to develop, test, certify, and use zero-sulfur jet fuels from alternative resources (oil shale, among others). By eliminating sulfur, the fuels would be suitable for use in fuel cells to generate electricity and in turbine engines used in aircraft and ground vehicles. A synthetic fuel process based on Fischer-Tropsch had been considered. At the time of the President’s FY2007 budget request, DOE proposed terminating oil technology research, and the Defense Department left Clean Fuels unfunded.[34]

Since 1910, several legislation-based initiatives have attempted to promote oil shale development. (Legislation establishing the oil shale reserves and related federal programs is summarized in the Appendix of this report.) However, more recent regulatory policies (see below) appear adverse to oil shale development, at least to the wider use of middle-distillate fuels producible from oil shale.

INCENTIVES AND DISINCENTIVES TO DEVELOPMENT

The economic incentive for producing oil shale has long been tied to the price of crude oil. The highest price that crude oil ever reached — $87/bbl (2005 dollars) — occurred in January 1981 (Figure 2).[35] Exxon's decision to cancel its Colony oil shale project came a year and half later, after prices began to decline and newly discovered, less-costly-to-produce reserves came online. The price of crude oil spiked to nearly $70/bbl after Hurricanes Katrina and Rita, and the recent climb to above $67 /bbl has led to some speculation that prices may remain high indefinitely. In the Energy Information Administration's (EIA's) reference case projection, though, "the average world crude oil price continues to rise through 2006 and then declines to $46.90/bbl in 2014 (2004 dollars) as new supplies enter the market. It then rises slowly to $54.08/bbl in 2025."[36] Near-record gasoline prices have led to similar speculation, as the average price of gasoline has stayed consistently above $2 per gallon since May of 2005, and the on-highway diesel price has stayed even higher.[37] However, oil company investment decisions may be more conservatively based on making profits at the $20-$30/barrel range of just a few years ago than on projected prices. That is, high prices may not be enough of an incentive for risky developments in conventional oil, let alone oil shale.



Source: U.S. DOE EIA, World Oil Market and Oil Price Chronologies 1970-2004, Mar. 2005, at [http://www.eia.doe.gov/cabs/chron.html]; EIA Refiner Acquisition Cost of Crude Oil (for July 2005 to Jan. 2006), at [http://tonto.eia.doe.gov/dnav/pet/pet_pri_rac2_dcu_nus_m.htm].

Figure 2. Refiner Acquisition Cost of Imported Crude Oil.

Crude oil production costs vary widely by geography and reservoir conditions, and they may be more important factors now than 25 years ago as aging reservoirs decline in production. Production involves lifting the oil to the surface and the gathering, treating, and field processing and storage of the oil. The cost of production, sometimes referred to as lifting cost, includes labor to operate the wells and related equipment; repair and maintenance of the wells and equipment; and materials, supplies, and energy required to operate the wells and related equipment. In the Persian Gulf region, where a single well may produce thousands of barrels per day, production costs may be as little as a few dollars per barrel. Production costs in the United States had approached $15/bbl by 2004.[38] ExxonMobile reported production costs increases from $4½ to $5½ /bbl for its U.S. operations over the past several years.[39] In older, far less productive wells in the United States, production costs may reach more than $25/bbl.[40]

In 1998, a supply glut forced the price of crude oil down to almost $10/barrel and gasoline sold for less than $0.80/gallon in some markets. Some domestic producers charged, in a U.S. Court of International Trade suit, that oil imports had been dumped on the American market.[41] Though unsuccessful, the suit does say something further about bottom-line production costs (the crude oil price equivalent that producers could not compete below) and the production costs that oil shale may need to compete against. For several years preceding the price drop, crude oil ranged from $20 to $30/bbl.

The perception that oil shale serves as a crude oil substitute overlooks the limited fungibility of the middle distillates that are extractable — they make poor feedstock for gasoline production. That does not necessarily prevent oil-shale distillates from being used as gasoline feedstock, but additional energy and hydrogen are needed to crack them. The loss may be even greater considering the lower fuel efficiency of spark-ignition engines that use gasoline, compared with compression ignition engines that use diesel distillate fuels.

Other incentives or disincentives may include the cost and size of an oil shale processing facility, conventional refining profitability, and the cost and availability of refined commodities. Certain environmental and tax regulations that act as incentives to using gasoline in light-duty vehicles discourage middle-distillate diesel fuel use, and thus oil-shale distillates as substitute motor fuels.

The Cost of Constructing an Oil Shale Facility

A reliable cost estimate for producing oil shale has proved challenging, if not controversial. The cost of resources extraction had depended on whether conventional underground or strip-mining methods were employed. Because there was a considerable experience in mining, reliable cost estimates could be developed. A second variable — the cost of constructing and operating an oil shale facility — had to be accounted for separately. The former OTA estimated in 1979 that a 50,000 bpd oil shale facility (based on above-ground retorting technology) would have required an investment of $1.5 billion and operating costs of $8 to $13/bbl. Using the Nelson-Farrar Cost Indexes to adjust refinery construction and operation costs to 2004 dollars, the investment would be equivalent to $3.5 billion, with operating costs of $13 to $21/bbl.[42] This excludes the cost of shale extraction.

In comparison, the cost of building a new conventional refinery has been estimated to range between $2 and $4 billion as recently as 2001.[43] The cost of operating a refinery (marketing, energy, and other costs) averaged ne arly $6/bbl during 2003-2004, as reflected in the difference between gross and net margins (where the gross margin reflects the refiner's revenue minus the cost of crude oil).[44]

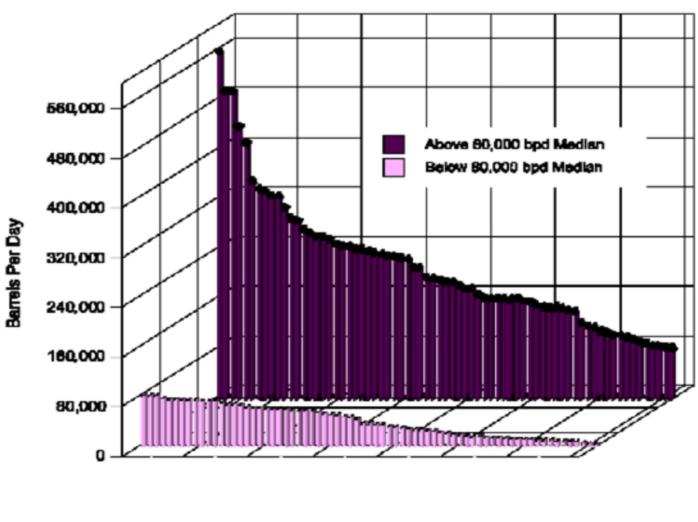
An oil shale facility may not be directly comparable to a refinery in terms of construction costs, though some processes, such as hydrotreating, may be common to both. If oil field-based technologies such as Shell's proposed ICP are successfully adapted to resource extraction, facility costs could be reduced, but operating costs could increase given the energy-intensive aspect of the technology.

Under the U.S. Air Force Project Rivet Shale, Union Oil's Parachute Creek Phase I project produced 4.6 million barrels of oil-shale distillates from 1985 to 1990 at a cost of $650 million; roughly the equivalent of $141/bbl, or $3.52/gal. (wholesale). Since Rivet Shale produced a jet fuel equivalent, a comparison might be made with the price of jet fuel at the time. In comparison, a refiner's crude oil acquisition costs ranged from a less $15/bbl to $27/bbl in nominal dollars over that same time period.[45] The spot market price for kerosene-based jet fuel rose from less than $0.40/gal in 1985 to more than $1.10/gal by 1990.

The Rand Corporation recently estimated that a "first-of-kind" surface retort facility might cost $5-$7 billion, with operating costs of $17 to $23/bbl in 2005 dollars. Rand projects that a crude oil equivalent of West Texas Intermediate would need to be at least $70 to $95/bbl for such an operation to be profitable.[46] Shell Oil believes that in situ conversion can be profitable, producing oil-shale distillates at $25/bbl once steady-state production is reached.[47] The disparity in estimates demonstrates the controversy over the issue. It should be noted that Rand refers to the older retorting technology that relied on mining methods for resource extraction, whereas Shell's estimate is based on oil field-based technology for resource extraction.

The Ideal Size for an Oil Shale Facility

As domestic crude oil production declined through the 1970s, many marginally profitable and often smaller refineries were closed or idled.[48] Of the 324 refineries operating 1981, 142 refineries currently remain operating. However, they represent a crude distillation capacity of approximately 17.5 million bpd, compared with 14.5 million bpd in the mid 1980s, and range in size from 557,000 bpd (ExxonMobile's Baytown, Texas refinery) to 1,707 bpd (Foreland Refining Corp's refinery in Eagle Springs, Nevada).[49] The median capacity (half above and half below) of all operating refineries is approximately 80,000 bpd (Figure 3). The 71 refineries above the median capacity are responsible for 85% of the current overall U.S. production (14.8 million bpd). The trend toward larger refineries reflects the economic efficiency gained by increased scale. (For further information on refining, refer to CRS Report RL32248, Petroleum Refining: Economic Performance and Challenges for the Future, by Robert L. Pirog.)



Source: EIA Annual Energy Outlook, Table 38, Capacity of Operable Petroleum Refineries by State, 2005.

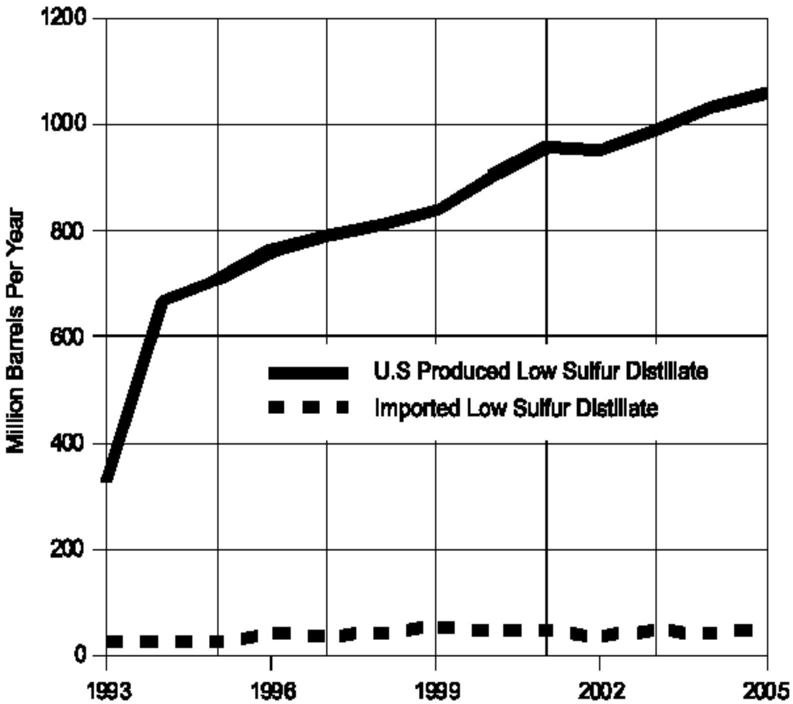
Figure 3. Refinery Capacity Distribution Above and Below Median 80,000 BPD Size.

OTA's reference case 50,000 bpd oil shale facility would have been typical for refinery capacities in the late 1970s, but compared with current capacities, it might appear undersized. However, in terms of matching middle-distillate output, an oil shale facility requires a the capacity of a conventional refinery. Since U.S. refineries yield at most 47% motor gasoline vs. 33% middle-distillates, a 50,000 bpd oil shale facility today (producing middle distillates exclusively) would match the distillate output of a 150,000 bpd conventional refinery.[50] This suggests that relatively smaller oil shale production facilities could be as effective as a larger conventional refinery when it comes to producing middle distillates.

The complicated permitting process has been an argument against building a new refinery and for expanding an existing refinery's capacity instead. The approval process for new refinery construction has been estimated to require up to 800 different permits.[51] An oil shale facility's considerably less complexity would appear to have an inherent advantage over a conventional refinery when it comes to permitting. Congress recognized that increasing petroleum refining capacity serves the national interest and included provisions in the Energy Policy Act of 2005 (Title III, Subtitle H — Refinery Revitalization) to streamline the environmental permitting process. A refiner can now submit a consolidated application for all permits required by the Environmental Protection Agency (EPA). To further speed the permit's review, the EPA is authorized to coordinate with other federal agencies, enter into agreements with states on the conditions of the review process, and provide states with financial aid to hire expert assistance in reviewing the permits. Additional provisions under Title XVII (Incentives for Innovative Technologies) of the act guarantee loans for refineries that avoid, reduce, or sequester air pollutants and greenhouse gases if they employ new or significantly improved technology. Permitting would be a secondary consideration for new construction, if refining was an unfavorable investment.

Competing with Imported Distillates

Between 1993 and 2005, low-sulfur middle distillate production in the United States tripled from 328 million barrels to 1,058 million barrels, but some imports were still needed to satisfy demand (Figure 4). The current 55 million barrels per year of imports is the equivalent of 150,000 bpd in production, or three oil shale plants on the scale of OTA's reference case 50,000 bpd facility.



Source: EIA Petroleum Navigator, U.S. Refinery Production of Distillates 15-500 ppm Sulfur, and U.S. Distillates 15-500 ppm Sulfur Imports, at [http://tonto.eia.doe.gov/dnav/pet/hist].

Figure 4. Imported Crude Oil and Refined Products.

Like U.S. refineries, European refineries also began to optimize for gasoline production in the early 1990s, only to see the European demand shift toward middledistillate diesel fuel due largely to European tax incentives (discussed below) that favor diesel fuel use. Excess gasoline now produced by these refineries is exported to the U.S. market. Diesel fuel is forecast to make up 68% percent of European consumption by 2010.[52] How European refineries respond to an increased diesel fuel demand will likely affect gasoline exports to the United States, particularly if the refineries shift their optimization more toward diesel than investing capital in additional diesel capacity. Both diesel and gasoline exports to the U.S. market could be reduced. U.S. refineries appear to have little excess capacity to make up both the gasoline and diesel loss, leaving some opportunity for oil shale to make up the distillate loss.

Assuming that U.S. refineries yield a middle-distillates, actual refining capacity on the order of 1 million bpd would have been required. In terms of oil shale production, three 50,000-bpd plants processing 1,867 million tons of oil shale (yielding 15 to 30 gallons per ton) could be required to fill the possible gap in domestic supply.

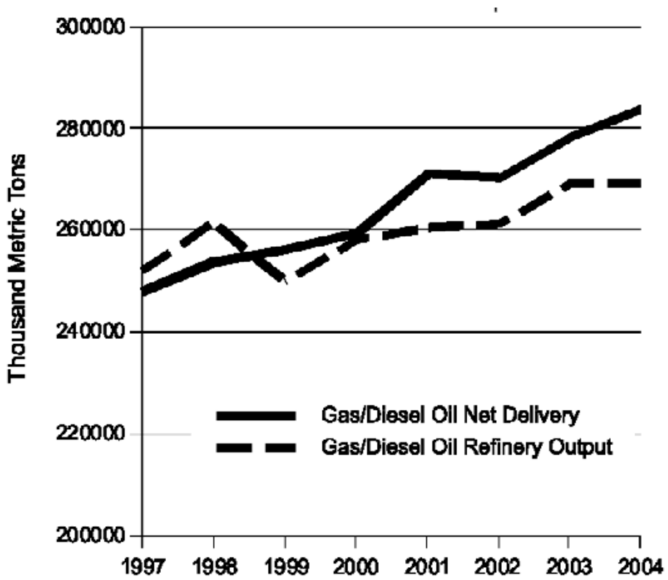
Regulatory Disincentives

Apart from economic reasons, some regulatory policies may discourage the production and use of oil-shale distillate fuels. Both gasoline and diesel fuel are subject to Clean Air Act regulations and federal motor fuel taxes. Both regulations and taxes are more lenient towards gasoline use. In comparison, European Union (EU) environmental standards and tax regulations are more lenient towards diesel fuel and consequently have stimulated its broader consumption. Since oil-shale distillates could substitute for diesel fuel, any regulatory bias toward gasoline could act as a disincentive to oil shale production.

Diesel Vehicle Demand. Passenger vehicles and light-duty trucks (under 8,500 lbs. gross vehicle weight) create the primary demand for transportation fuel in the United States. However, nearly 22% of the transportation fuel demand is for diesel, primarily in heavy-duty on- and off-road vehicles (semi-tractor trucks, earthmoving equipment, and railroad locomotives). Light-duty diesel trucks and passenger vehicles make up a smaller (but uncertain) percentage of the diesel demand, based on the lower number of miles private vehicles drive annually compared with commercial vehicles. Light-duty vehicles do, however, make up slightly more than half of the on-road diesel vehicles sold. Though overall, light-duty diesel vehicles have made up only 5% of the total light-duty vehicles sold recently (~349,000 light-duty diesel trucks and ~30,000 diesel passenger vehicles versus 16.9 million total light-duty vehicles sold in 2004).[53] The EIA sees a slower growth of light-duty diesel vehicles in the United States than in Europe.[54] In contrast to U.S. sales of light-duty diesel vehicles, new diesel passenger vehicle registration in Europe rose from 22.3% in 1998 to 48.25% in 2004.[55] The effect of increased diesel registration can be seen in the increased refinery output and net deliveries of diesel reported for European members of the

Organization of Economic Co-operation and Development (OECD) by the International Energy Agency (IEA).[56] (See Figure 5.)

Assuming that a separate diesel fuel for light-duty diesel vehicles will not be created, the EIA projects that U.S. refiners are unlikely to see the impact of a developing light-duty diesel vehicle market in the next decade. Given EIA's projection, the opportunity for oil-shale distillates as diesel substitutes would appear similarly limited in the United States.



Source: International Energy Agency, Monthly Oil Survey, 2000 through 2005.

Figure 5. Net Deliveries vs. Refinery Output of Gas/Diesel Oil for OECD Europe.

CO, NOx, and PM Emissions. Compared with spark-ignition (gasoline) engines, compression-ignition (diesel) engines characteristically emit lower amounts of carbon monoxide (CO) and carbon dioxide (CO2), but they emit higher amounts of nitrogen oxides (NOx) and particulate matter (PM). NOx is the primary cause of ground-level ozone pollution (smog) and presents a greater problem, technically, to reduce in diesel engines than PM.

The CO, NOx, and PM emissions for gasoline and diesel engines are regulated by the 1990 Clean Air Act amendments (42 U.S.C. 7401-7671q) Tier 1 and 2 Emission Standards. Under Tier 1, the NOx standard had been 1.0 gram/mile for diesel passenger and light-duty trucks, versus 0.4 grams/mile for gasoline vehicles.

The Tier 2 standards that started taking effect in 2004 are fuel-neutral. Regardless of the fuel, a fleet of vehicle models manufactured in a given year must average 0.07 grams/mile for NOx emissions. A particular vehicle model may qualify in a unique emission “bin” (the maximum allowable is 0.2 grams/mile), as long as the fleet of models meets the average NOx emission standard. Other pollutants are similarly regulated.

Since diesel engines inherently produce more NOx and PM than gasoline engines, producing more diesel vehicles raises the fleet emission average and thus limits the total number of vehicles a manufacturer can sell in the United States. This in turn limits the demand for diesel vehicles, which thus limits the opportunity for oil-shale distillates. The U.S. Tier 2 NOx emissions standards are more stringent than the EU’s current Euro 4 standards of 0.4 grams/mile for diesel cars and 0.6 grams/mile for light-duty diesel trucks. Tier 2 PM-emission standards of 0.01 to 0.02 grams/mile are also more stringent than Euro 4 PM-emissions of 0.04 grams/mile.

The Tier 2 CO-standard of 4.2 grams/mile is significantly less stringent than the Euro 4 standard of 0.8 grams/mile for diesel passenger cars and 1.2 grams/mile for light-duty diesel trucks. Tier 2 favors gasoline over diesel in this case.

The EU is moving toward taxing cars on the basis of CO2 emissions (which favors diesel).[57] This move is in response to the Kyoto Protocol on climate change, which seeks to limit CO2 emissions, a treaty that the United States signed but did not ratify.

Should oil-shale distillates substitute for diesel, Tier 2 limits on CO, NOx, and PM emissions would continue to apply, as the standard is fuel-neutral. However, the emission characteristics of oil-shale distillates (similar to diesel) have not been the subject of documented research.

Ultra-Low Sulfur Diesel. By mid-2006, new U.S. standards for ultra-low sulfur diesel (ULSD) take effect under a 2001 rule issued by the EPA.[58] Diesel fuel sulfur content must be reduced to no more than 15 parts-per-million (ppm) from the current 500 ppm (established by a 1993 rule that reduced the level from 5,000 ppm). However, to account for pipeline contamination, refiners may have to produce diesel fuel with a sulfur content as low as 7 ppm; a four-year phase-in period allows for 20% of the highway diesel produced to meet the current limit.

The EIA estimates the marginal cost of producing ultra-low sulfur diesel to range from 2.5¢ to 6.8¢ per gallon, depending on whether supply falls short of demand or consumers bid up the price.[59] EIA projects the ULSD rule to require total refinery investments ranging from $6.3 to $9.3 billion. As the energy content of ULSD is somewhat less than 500 ppm diesel, fuel efficiency may be affected (increasing fuel consumption and therefore demand).

The sulfur content of oil-shale distillates is comparable in weight percentage to crude oil (Table 1). U.S. refiners were able to meet the current 500 ppm requirement by increasing the existing capacity of their hydrotreatment units and adding new units. However, refineries may face difficulty in treating diesel to below 500 ppm. The remaining sulfur is bound in non-hydrocarbon, multi-ring thiophene-type compounds that prove difficult to hydrotreat because the molecular ring structure attaches the sulfur on two sides. Although these compounds occur throughout the range of petroleum distillates, they are more concentrated toward the residuum end. So, the problem is compounded when residuum is cracked to increase gasoline production. Improved hydrotreatment technology since the 1980s has increased sulfur removal and provided a means to removing oil-shale distillate’s excessive nitrogen content (desirable in terms of producing stable fuels with low NOx emissions).

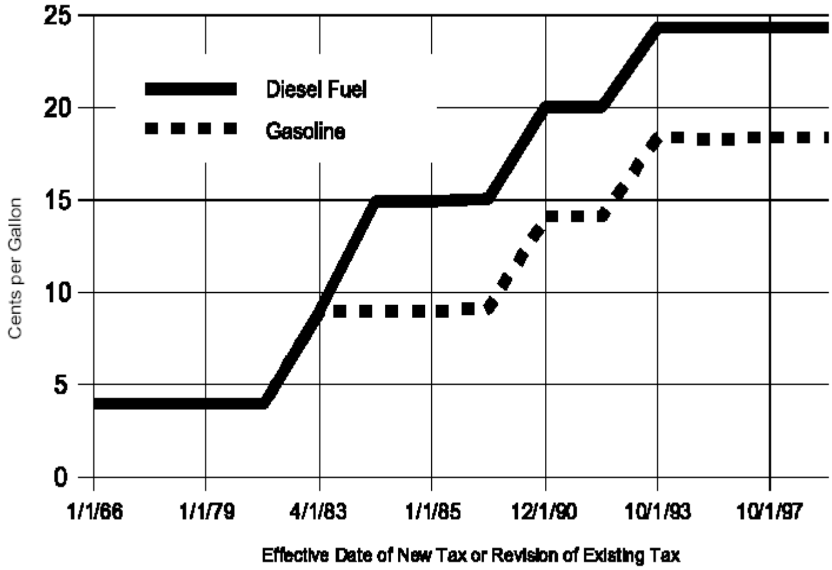
Whereas conventional refineries may be able to further upgrade hydrotreatment capacity by retrofitting, an oil shale processing plant would be designed and built from the ground up with necessary capacity. However, many refineries either produce the hydrogen needed for hydrotreating or purchase it from vendors that operate near established refining centers. An oil shale facility may require the addition of a steam reforming process to convert natural gas to the hydrogen needed.

Refiners’ response to the ULSD rule ultimately affects diesel supply and thus price. As increased diesel fuel prices are likely to erode the lower operating-cost advantage of diesel engines over gasoline, the incentive for purchasing light-duty diesel vehicles would be less, in keeping with EIA’s projection of a slow growth in light-duty diesel vehicles over the next decade. On the other hand, a decline in diesel demand would offer even less incentive to produce oil-shale distillates for light-duty vehicles.

Fuel Tax

The U.S. federal tax rate on motor fuel currently favors gasoline over diesel fuel by 6¢ per gallon (18.4¢ and 24.4¢, respectively).[60] Both gasoline and diesel tax rates began increasing after the mid-1980s, but diesel increased at a faster rate (Figure 5). The higher diesel fuel tax is essentially a user fee paid by heavy-duty trucks to offset the higher road damage they cause than lighter duty vehicles. Where motor fuel taxes are applied to transportation infrastructure improvements in the United States, they are a source of general revenue for the 15 EU member states.

Overall, motor fuel taxes are significantly higher in the EU, ranging from the equivalent of $3.28/gallon (742/1,000 liters at an exchange rate of $1.17: 1) for diesel and gas in the United Kingdom, to as low as 253/1,000 liters) ($1.12/gallon) for diesel in Luxemburg. Except for the United Kingdom, diesel fuel is taxed on average 62¢/gallon(140/1,000 liters) less than gasoline.[61].



Source: U.S. DOT, "Federal Tax Rates on Motor Fuels and Lubricating Oil," Table Fe-101a.

Note: The U.S. federal tax rate on motor fuel currently favors gasoline over diesel fuel by 6¢ per gallon. European Union states (except UK) tax diesel fuel on average (62¢/gallon less than gasoline).

Figure 6. Diesel vs Gasoline Fuel Tax.

In December 2005, the average end-use prices of gasoline in France and Germany were $5.26/gallon and $6.08/gallon, respectively (1.170/liter and 1.226/liter), compared with $2.17/gallon in the United States — with automotive diesel averaging $3.89/gallon and $4.23/gallon in France and Germany, respectively (0.865/liter and 0.941/liter), compared with $2.45/gallon in the United States.[62] The end-use price difference in the two fuels appears to correlate with the increasing registration of diesel cars in the EU. With higher crude oil prices, the fuel savings advantage of diesel cars should become even more compelling.

Diesel fuel demand is "regulatory driven" to an extent. Motor fuel taxes that favor diesel over gasoline offer one means of redirecting demand, but the tax differential may need to be significantly higher than the current 6¢ per gallon differential favoring gasoline. Raising motor fuel taxes above the current federal level runs counter to current policy. In the aftermath of Hurricane Katrina, when gasoline prices surged above $3 per gallon, some states suspended or considered suspending taxes on gasoline. However, advocates of energy conservation argued that the higher gasoline prices conserved fuel by discouraging driving, thus the motor fuel tax should have remained or even increased. If higher motor fuel tax stimulates the demand for more fuel-efficient vehicles, as the European experience suggests, the inherent fuel efficiency offered by a diesel passenger vehicle becomes more apparent, if not desirable. This in turn could act as an additional incentive for producing diesel or alternatives such as oil-shale distillates.

Policy Perspective and Consideration

Federally sponsored research to develop fuel substitutes from oil shale dates back the U.S. Synthetic Liquid Fuels Act of 1944 out of World War II concerns for oil supplies. Later, in response to the oil embargos of the 1970s, Congress created the Synthetic Fuels Corporation. National security had been a motivating concern (i.e., to aid the prosecution of the war and to contend with foreign actions that interrupt energy supplies). As newly discovered, less-costly-to-produce petroleum reserves entered production in the early 1980s, the economic and operating conditions of oil shale production became unfavorable. As commercial interests backed out of projects, Congress terminated synthetic fuel development. Various commercial attempts to exploit the resource met with limited success. Technological developments that transformed petroleum refining efficiency, and the discovery of new petroleum reserves, shifted private sector interest away from oil shale resources.

The global demand-driven petroleum supply cycle, if true to history, is likely to exhibit periods of surplus and shortage. Periods of surplus fit well with the just-intime supply model that seeks to hold down inventory costs by minimizing stocks on hand. Proponents of the self-correcting petroleum market theory may argue that supply interruptions are temporary and that price spikes signal customers to reduce consumption. Opponents may argue that reduced consumption is not an option during a national security crisis and that there ought to be a “just-in-case” contingency in place, such as oil shale. While the threat from future OPEC-like embargoes appears unlikely, the President’s goal “to replace more than 75 percent of our oil imports from the Middle East by 2025" indicates continuing concern.[63]

Recent high crude oil prices renewed interest in oil shale, prompting Congress to include provisions in the Energy Policy Act of 2005 promoting the lease and development of federal oil shale holdings. The Act also identified oil shale as a strategically important domestic resource and directed the Energy Department to coordinate and accelerate its commercial development.

The misconception persists, however, regarding oil shale’s fungibility as a crude oil substitute. It doesn’t effectively replace crude oil as a gasoline feedstock. Thus, policies that attempt to foster oil shale development come into conflict with regulatory policies that favor gasoline as transportation fuel. The best use of the resource appears to be as feedstock for producing middle-distillate fuels. Regulatory policies that are acting to discourage wider use of middle-distillate fuels thus may be acting as a disincentive to oil shale production. Congress may wish to consider whether a special case should be made for oil shale, and whether to exempt the middle-distillate fuels produced from regulatory policies that restrict their wider use as transportation fuels.

The President’s FY2007 budget request would terminate the Energy Department’s oil technology research, and the Defense Department’s initiative to develop clean fuels from oil shale (among other resources) appears unfunded.[64] Whether oil shale can be economically produced, even given the current high cost of conventionally recovered petroleum, remains unclear. However, without a long-term concerted effort to produce oil shale, either through a federal- or private sector-sponsored enterprise, the economic viability will remain questionable. The expectation of initial high unit costs should be weighed against the offset in demand for imported products and the effect on lowering price that competition brings.

APPENDIX: LEGISLATIVE HISTORY

The Pickett Act of 1910 initially authorized withdrawal of potential oil-bearing lands in California and Wyoming as sources of fuel for the Navy. Executive orders later created three Naval Petroleum and Oil Shale Reserves between 1912 and 1927 by setting aside federal lands believed to contain oil as an emergency reserve.

The U.S. Synthetic Liquid Fuels Act of 1944 (30 USC Secs. 321 to 325) authorized $30 million over five years for "the construction and operation of demonstration plants to produce synthetic liquid fuels from coal, oil shales, agricultural and forestry products, and other substances, in order to aid the prosecution of the war, to conserve and increase the oil resources of the Nation, and for other purposes." The act also authorized the Interior Secretary to construct, maintain, and operate plants producing synthetic liquid fuel from coal, oil shale, and agricultural and forestry products. The Bureau of Mines received $87.6 million for an 11-year demonstration plant program.

The Defense Production Act of 1950 (Ch. 932, 64 Stat. 798), enacted during the Korean War, was intended to develop and maintain whatever military and economic strength necessary to support collective action through the United Nations. The diversion of certain materials and facilities from civilian to military use required expansion of production facilities beyond the levels needed to meet civilian demand. Section 303 of Title III (Expansion of Production Capacity and Supply) authorized the President "extraordinary" procurement power to have liquid fuels processed and refined for government use or resale, and to make improvements to government or privately owned facilities engaged in processing and refining liquid fuels when it would aid the national defense. In 1980, Congress added provisions (P.L. 96-294) that related to preparing for terminated or reduced availability of energy supplies for national defense needs. Section 305 of the act authorized the President to purchase synthetic fuels for the purpose of national defense. Executive Order 12242 then directed the Secretary of Defense to determine the quantity and quality of synthetic fuel needed to meet national defense needs for procurement.

The Naval Petroleum Reserves Production Act of 1976 (P.L. 94-258), in reference to Naval Petroleum Reserve No. 4 in Alaska, defined petroleum to include crude oil, gases (including natural gas), natural gasoline, and other related hydrocarbons, oil shale, and the products of such sources.

The Department of Energy Organization Act of 1977 (P.L. 95-91) transferred control of the Naval Petroleum and Oil Shale Reserves from the Navy to the Department of Energy.

The United States Synthetic Fuels Corporation Act of 1980 (P.L. 96-294)[65] amended the Defense Production Act by establishing the U.S. Synthetic Fuels Corporation (SFC) "to improve the Nation's balance of payments, reduce the threat of economic disruption from oil supply interruptions, and increase the Nation's security by reducing its dependence on foreign oil." The corporation was authorized to provide financial assistance to qualified projects that produced synthetic fuel from coal, oil shale, tar sands, and heavy oils. Financial assistance could be awarded as loans, loan guarantees, price guarantees, purchase agreements, joint ventures, or combinations of those types of assistance. An Energy Security Reserve fund was also established in the U.S. Treasury and appropriated $19 billion to stimulate alternative fuel production. Executive Order 12242 (1980) directed the Secretary of Defense to determine the quantity and quality of synthetic fuel needed to meet national defense needs for procurement under the Defense Production Act. Executive Order 12346 (Synthetic Fuels) of 1982 revoked EO 12242 and provided for an orderly transition of synthetic fuel responsibilities from the Department of Energy to the United States Synthetic Fuels Corporation.

The Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223) ostensibly provided revenue to maintain the Energy Security Reserve fund. The Internal Revenue Code was amended to impose an excise tax on windfall profits of domestic producers of taxable crude oil. A production tax credit of $3.00 (1979 dollars) per barrel of oil equivalent was provided to stimulate oil shale development. The House conference report (H. Rept 96-817) projected $227.3 billion in total revenue from the tax after 1988. In the Windfall Profit Tax Account established to hold the revenue, 15% had been allocated for energy and transportation. In 1983, the Congressional Budget Office estimated that the revenue would only reach 40% of the conference report's projection and only 20% by 1988, as the price of crude oil had been lower than projected. Congress repealed the windfall profit tax in 1988 (P.L. 100-418).

The House began considering a bill to abolish the SFC with the Synthetic Fuels Fiscal Responsibility Act of 1985 (H.R. 935). The Energy and Commerce Committee debate of the bill (Rept. 99-196) linked abolishing the Corporation to reducing the federal deficit and viewed purchasing oil for the Strategic Petroleum Reserve as a far more cost effective defense against another embargo by OPEC than subsidizing synthetic fuels. The minority view noted that as late as 1983, the Department of Defense had certified that synthetic fuel was needed to meet national defense needs under Executive Order 12242. In September 1985, the Senate Committee on Appropriations report (S.Rept. 99-141) recommended increasing the Department of Energy Oil Shale Program budget and reaffirmed the goal of oil shale reserves supplying petroleum during a national emergency. Support for the SFC could not be sustained, and Congress terminated it under the Consolidated Omnibus Reconciliation Act of 1985 (P.L. 99-272). Remaining obligations were transferred to the Treasury Department, and the duties of the Chairman of the SFC Board were transferred to the Secretary of the Treasury.

The Department of Energy Organization Act of 1977 (P.L. 95-91) transferred Navy control of the NOSRs to the Department of Energy. The National Defense

Authorization Act of 1998 (P.L. 105-85) transferred NOSR Nos. 1 and 3, located near Rifle, Colorado, from the Department of Energy to the Bureau of Land Management. The National Defense Authorization Act of 2000 (P.L. 106-398) transferred NOSR No. 2 in Utah to the Ute Indian Tribe.

The Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005[66] declares the strategic importance of domestic oil shale resources and their development. The act directs the Secretary of the Interior to commence commercial leasing of oil shale on public lands and to establish a task force in cooperation with the Secretary of Defense to develop a program for commercially developing strategic unconventional fuels, including but not limited to oil shale. Section 2398a. (Procurement of Fuel Derived from Coal, Oil Shale, and Tar Sands) directs the Secretary of Defense to develop a strategy to use fuel produced from oil shale to help meet the fuel requirements of the Department of Defense when the Secretary determines that doing so is in the national interest.

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[13] The term “crack spread” refers to the 3-2-1 ratio of crude-gasoline-distillate. The crack spread and the 3-2-1 crack is a hypothetical calculation used by the New York Mercantile Exchange for trading purposes.
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Chapter 9

OIL SHALE MANAGEMENT RULE

United States Government Accountability Office

December 2, 2008

The Honorable Jeff Bingaman, Chairman

The Honorable Pete V. Domenici, Ranking Minority Member
Committee on Energy and Natural Resources
United States Senate

The Honorable Nick J. Rahall II, Chairman

The Honorable Don Young, Ranking Minority Member
Committee on Natural Resources
House of Representatives

Subject: Department of the Interior, Bureau of Land Management: Oil Shale Management–General

Pursuant to section 801(a)(2)(A) of title 5, United States Code, this is our report on a major rule promulgated by the Department of the Interior, Bureau of Land Management (BLM), entitled "Oil Shale Management–General" (RIN: 1004-AD90). We received the rule on November 17, 2008. It was published in the Federal Register as a final rule on November 18, 2008, with a stated effective date of January 17, 2009. 73 Fed. Reg. 69,414.

The final rule sets out the policies and procedures for the implementation of a commercial leasing program for the management of federally-owned oil shale and associated minerals located on federal lands. In doing so, this final rule implements section 15927 of title 42, United States Code. This rule also provides for these leases to incorporate the standard components of a BLM mineral leasing program, including work requirements and milestones to ensure diligent development of leases and other standard components of a BLM mineral leasing program.

Enclosed is our assessment of the BLM's compliance with the procedural steps required by section 801(a)(1)(B)(i) through (iv) of title 5 with respect to the rule. Our review indicates that BLM complied with the applicable requirements.

If you have any questions about this report or wish to contact GAO officials responsible for the evaluation work relating to the subject matter of the rule, please contact Michael R. Volpe, Assistant General Counsel, at (202) 512-8236.

signed
Robert J. Cramer
Associate General Counsel

Enclosure
cc: Ted R. Hudson
Acting Division Chief, Regulatory Affairs
Bureau of Land Management
Department of the Interior

REPORT UNDER 5 U.S.C. § 801(A)(2)(A) ON A MAJOR RULE ISSUED BY DEPARTMENT OF THE INTERIOR, BUREAU OF LAND MANAGEMENT ENTITLED "OIL SHALE MANAGEMENT–GENERAL" (RIN: 1004-AD90)

(I) Cost-Benefit Analysis

The Bureau of Land Management (BLM) analyzed the costs and benefits of this final rule. BLM notes that this rule has the potential to generate net economic benefits to the United States by allowing for the development of our vast domestic oil shale resources, but that there is substantial uncertainty about the magnitude and timing of these benefits. BLM estimates that the net present value of the potential monetary costs and benefits considered in this analysis will be approximately $13.6 billion using a 7-percent discount rate, $28.5 billion using a 3-percent discount rate, and $1.8 billion using a 20-percent discount rate.

(II) Agency Actions Relevant to the Regulatory Flexibility Act, 5 U.S.C. § § 603-605, 607, and 609

BLM determined that this final rule will not have a significant economic impact on a substantial number of small entities.

(III) Agency Actions Relevant to Sections 202-205 of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. § § 1532-1535

BLM determined that this final rule does not contain any mandates on state, local, or tribal governments and that the overall impact on the private sector does not exceed $100 million.

(IV) Other Relevant Information or Requirements under Acts and Executive Orders Administrative Procedure Act, 5 U.S.C. § § 551 Et Seq.

BLM promulgated this final rule using the notice and comment procedures found in the Administrative Procedure Act. 5 U.S.C. § 553. On November 22, 2004, BLM requested public comments on the potential for oil shale development at certain locations. 69 Fed. Reg. 67,935. BLM published a notice of intent to prepare a Programmatic Environmental Impact Statement (PEIS) on December 13, 2005, made the draft PEIS available for comment on December 21, 2007, and made the final PEIS available on September 5, 2008. 70 Fed. Reg. 73791; 72 Fed. Reg. 72,751; 73 Fed. Reg. 51,838.

On August 25, 2006, BLM published an advance notice of proposed rulemaking requesting comments and subsequently extended the comment period on September 26, 2006. 71 Fed. Reg. 50,378, 72 Fed. Reg. 56,085. BLM received 48 comments in response to the advance notice. On July 23, 2008, BLM published the proposed rule. 73 Fed. Reg. 42,926. BLM received over 75,000 comment letters on the proposed rule from individuals, federal and state governments and agencies, interest groups, and industry representatives. BLM responded to those comments in the final rule. 73 Fed. Reg. 69,416–69,448.

Paperwork Reduction Act, 44 U.S.C. §§ 3501–3520

This rule contains an information collection requirement entitled “Parts 3900–3930–Oil Shale Management–General.” The Office of Management and Budget (OMB) reviewed this requirement and assigned it OMB Control Number 1004-0201. BLM estimates that the total annual hour burden for this requirement to be 1,794 hours and that there will be processing and cost recovery fees of $526,652.

Statutory Authorization for the Rule

BLM promulgated this final rule under the authority of sections 351–359 of title 30, section 15927 of title 42, and sections 1701–1787 of title 43, United States Code. National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. sections 4321–4370f BLM prepared an environmental assessment for this final rule and found that this rule does not constitute a major federal action significantly affecting the quality of the human environment under the Act.

Executive Order No. 12,630 (Takings)

BLM determined that this final rule is not a government action capable of interfering with constitutionally protected property rights and that a takings assessment is not required.

Executive Order No. 12,866

BLM determined that this final rule is economically significant under the Order because it will have an effect of $100 million or more on the economy. This final rule was reviewed by the Office of Management and Budget.

Executive Order No. 12,988 (Civil Justice Reform)

BLM determined that this final rule will not unduly burden the judicial system and that it meets the requirements of the Order.

Executive Order No. 13,132 (Federalism)

BLM determined that this final rule will not have a substantial direct effect on states, the relationship between the federal government and states, or on the distribution of power and responsibilities among the levels of government.

Executive Order No. 13,175 (Consultation and Coordination with Tribes)

BLM determined that this final rule may include policies that have tribal implications under the Order. BLM consulted with potentially affected tribes on the proposed rule.

Executive Order No. 13,211 (Energy)

BLM determined that the rule will likely increase energy production and will not have an adverse effect on the supply, distribution, or use of energy.

Executive Order No. 13,352 (Cooperative Conservation)

BLM determined that this final rule will not impede facilitating cooperative conservations; takes appropriate account of and considers the interests of persons with ownership or other legally recognized interests in the land or other natural resources; properly accommodates local participation in the federal decision making process; and provides that the programs, projects, and activities are consistent with protecting public health and safety.

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Chapter 10

WATER RIGHTS RELATED TO OIL SHALE DEVELOPMENT IN THE UPPER COLORADO RIVER BASIN*

Cynthia Brougher
American Law Division

ABSTRACT

Concerns over fluctuating oil prices and declining petroleum production worldwide have revived interest in oil shale as a potential resource. The Energy Policy Act of 2005 (P.L. 109-58) identified oil shale as a strategically important domestic resource and directed the Department of the Interior to promote commercial development. Oil shale development would require significant amounts of water, however, and water supply in the Colorado River Basin, where several oil shale reserves are located, is limited. According to news reports, oil companies holding water rights in the region have not exercised those rights in decades, which has allowed other water rights holders to use the water for agricultural and municipal needs. Because of the nature of the water rights systems in the relevant states, these users might face significant limitations in their future use of water from the Basin if the oil companies exercise their rights. This report will provide a brief overview of water rights in Colorado, Utah, and Wyoming, including changes that may be made to currently held water rights and the possibility for abandonment of unused water rights.

* This is an edited, excerpted and augmented edition from CRS Report RS22986, dated November 18, 2008.

Concerns over the price of oil and supply of petroleum have revived interest in alternative energy supplies, including the development of oil shale to help address energy needs in the United States.[1] The process used to develop oil shale resources requires a plentiful water supply. According to news reports, oil companies currently hold senior water rights in the states where oil shale reserves are located.[2] As explained below, appropriation of water in these states is based on a priority system, under which water rights holders have seniority over other water rights holders who acquired rights later. These senior rights reportedly have not been exercised for decades, allowing junior water rights holders to use the water.[3] Because of the nature of the water rights systems in the relevant states, junior water rights holders might face significant limitations on their future use of water from the Basin if the oil companies exercise their rights. This report will provide a brief overview of water rights in Colorado, Utah, and Wyoming; changes that may be made to currently held water rights; and the possibility for abandonment of unused water rights.

WATER RIGHTS IN THE COLORADO RIVER BASIN GENERALLY

The law of water rights is traditionally an area regulated by the states, rather than the federal government. Individual states may choose the system under which water rights are allocated to water users.[4] Western states, including Colorado, Utah, and Wyoming, generally follow the prior appropriation doctrine of water rights, often referred to as “first in time, first in right.” These states typically are drier and experience regular water shortages. The prior appropriation system allows water users to acquire well-defined rights to certain quantities of water by designating senior and junior rights to avoid uncertainty during times of water scarcity.

Under the prior appropriation doctrine, a person who diverts water from a watercourse and makes reasonable and beneficial use of the water acquires a right to use of the water.[5] The user’s location relative to the watercourse (whether upstream, downstream, adjacent, or remote) does not affect the ability to obtain a water right. Typically, under a prior appropriation system of water rights, users apply for a permit from a state administrative agency which manages the acquisition and transfers of such rights. The prior appropriation system limits users to the quantified amount of water the user secured under the permit process with a priority based on the date the water right was conferred by the state. The user's right that was appropriated first (the senior water right) is considered superior to later appropriators' rights to the water (the junior water right). Appropriators fill their needs according to the order in which they secured the right to the water and not based on the available quantity. Therefore, in times of shortage, junior rights holders could be without the water they need.

COLORADO BASIN STATES' LAWS AFFECTING WATER RIGHTS

The issues regarding water rights in the Colorado River Basin arise from the fact that a limited supply of water is sought after by many different users. Junior rights holders who use waters from the Basin to meet agricultural and municipal interests potentially are limited by what oil companies, as senior rights holders, use. These junior rights holders have been able to use water to fill their needs for decades, while senior rights holders have not used the water. The dispute over a possible water shortage when both groups wish to use water likely will raise questions about the nature and administration of water rights, whether existing water rights may be amended to account for the changed circumstances, and the options available for users who seek to claim unused water rights from other users.

Water rights typically are established through an administrative permit system of the state in which the water is being appropriated. Water rights seekers must file an application with the proper state administrative organization, which dates the seniority of the water right. State law provides that the water is the property of the state, but a water right is considered an individual's property right in the priority of the use of the state's water.[6] The specific nature of water rights may vary depending on the state. For example, in Colorado, water rights can be either absolute or conditional.[7] Absolute rights are assigned to users who have diverted water and put the water to beneficial use, whereas conditional water rights allow the user to maintain the priority of the right he intends to acquire until the diversion is complete.[8] In other words, a user with an absolute right has fulfilled all the requirements necessary to acquire a right to the water. A user with a conditional right has asserted an intention to acquire a right but has not yet fulfilled all of the requirements necessary to do so, and that right is conditioned on the completion of all requirements. Utah law provides that water rights become real property only when the application has been perfected under the required legal process, meaning that title of the right is properly filed with the state.[9]

Wyoming issues permits to applicants for water rights, which allow the user time to construct and complete a project to put water to a beneficial use.[10] The water right is not considered permanent until the process is complete and may be disputed or removed until that time. In the context of oil shale in the Colorado River Basin, oil companies hold both absolute and conditional rights for water in Colorado. The nature of the rights held could influence the future use of the water and may provide a basis for junior rights holders to challenge the continuing validity of the senior rights holders' rights.

Both junior and senior rights holders may seek to alter certain water rights if circumstances of water use change. For example, in Colorado, senior rights holders may seek to convert their conditional rights to absolute rights, as discussed. Other state laws provide for water rights to be altered as circumstances change. Junior or senior rights holders may seek to change the geographic or purpose parameters set at the time they acquired their rights. Water rights generally are allocated based on a specific point of diversion, location of use, and purpose of use. In order to change the point from which water is diverted from its source or to change the place or purpose of use, a water right holder must apply to the appropriate state office for approval.[11] The state office considering the change may consider factors such as whether the change would exceed historical levels and whether other users' vested water rights would be impaired by the change.[12]

Junior rights holders may seek to secure water by acquiring the rights of senior rights holders under the water rights transfer process in each state. In Colorado, a water right may be bought, sold, or leased to other entities if the transfer is filed with the appropriate state office and the transfer would not injure the vested rights of another user.[13] Similarly, Utah water law provides that a water right may be bought or sold if the transfer is approved by the state.[14] Under Wyoming law, a water right attaches to the lands or the place of use in the permit rather than to an individual.[15] Water rights may be transferred only if included in the sale of land, or by petition for a change in place of use to the appropriate state office.

Senior rights holders may lose their rights if those rights are not used. Conditional rights in Colorado require rights holders to demonstrate continuous efforts in developing the water right on a regular basis.[16] Other water rights also may be lost under certain circumstances according to state law. If senior rights holders lose their rights, the water supply available for junior rights holders to fill their needs would increase. In Colorado, a water right may be considered abandoned if it is not used for a 10-year period and there is an intent to abandon.[17] In Utah, water rights may be abandoned or forfeited.[18] For a water right to be abandoned, there must be intent to abandon by the user and there is no time requirement. For a water right to be forfeited, the water right must not be used for a five-year period. In Wyoming, abandonment may take three forms.[19] First, the user may voluntarily abandon the water right. Second, one user may allege that another user's right has been abandoned because the other user has not used the right for a five-year period and that reactivation of that right would injure the user's right. Third, the state may allege an abandonment if the water is not put to beneficial use for a five-year period and reallocation would serve the public interest. Water rights that are lost under these processes revert to the state and may be appropriated in the future.

THE LAW OF THE RIVER AND INTERSTATE WATER ALLOCATION

State water laws govern the allocation of water within the state, but water resources rarely are confined to state boundaries. Rather, like the Colorado River Basin, water basins spread across several states. As a result, states often compete for resources from shared basins, and the competition often leads to water disputes between states in regions with shared water resources.[20] Interstate water disputes may be resolved in various manners. Two of the most common methods are equitable apportionment in the U.S. Supreme Court[21] and interstate compact negotiated by the parties and approved by Congress.[22] The Colorado River Basin is no exception to the likelihood of disputes and is subject to a number of judicial decisions and interstate compacts, commonly referred to as the Law of the River.

The Law of the River governs the waters of the Colorado River Basin in addition to regulation by the individual states in which water rights are allocated. The Law of the River is a collection of laws and agreements that govern the distribution of the water throughout the Basin as a whole.[23] Because the Colorado River Basin includes seven states, which have varying needs and all draw upon the same resources, a series of court decisions, statutes, interstate compacts, and international treaties address the use and management of Colorado River water.[24] The laws and agreements that form the Law of the River attempt to allocate the waters of the Colorado River Basin among the states, providing broad parameters for the distribution of the Basin's waters. Thus, the Law of the River would not govern individual water rights directly, but it would place limits on the water available for allocation by each state.

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[4] Depending on the individual state's resources and historical development, it may use one of three doctrines of water rights: riparian, prior appropriation, or a hybrid of the two. Under the riparian doctrine, a person who owns land that borders a watercourse has the right to make reasonable use of the water on that land. Rather than having appropriated quantities of water per user, users must share the water resources and reduce their usage proportionally in times of shortage. See generally A. Dan Tarlock, Law of Water Rights and Resources, ch. 3, "Common Law of Riparian Rights."
[5] See generally id. at ch. 5, "Prior Appropriation Doctrine."
[6] Colo. Const. art. XVI, §§ 5-6; Utah Code Ann. § 73-1-1 (2007); Wyo. Stat. Ann. § 41-3-101 (2007).
[7] Colo. Rev. Stat. § 37-92-301 (2007).
[8] Conditional rights holders must demonstrate reasonable diligence in completing the diversion every six years in order to maintain the conditional water right. Upon completion of the diversion, the user may apply for an absolute water right, which would have a priority dating back to the date of the conditional right. Id.
[9] Utah Code Ann. § 73-1-10. The distinction of a real property right from a personal property right affects the options available to water users regarding transferability. As real property, perfected water rights must be conveyed by deed to the new holder.
[10] See Wyo. Stat. Ann. § 41-4-501 et seq.
[11] Colo. Rev. Stat. § 37-92-302; Utah Code Ann. § 73-3-3; Wyo. Stat. Ann. §§ 41-3-104, 41-3-114.
[12] See, e.g., Colo. Rev. Stat. § 37-92-302.
[13] Strickler v. Colorado Springs, 16 Colo. 61 (1891).
[14] Utah Code Ann. § 73-1-10.

[15] Wyo. Stat. Ann. § 41-3-323.
[16] Colo. Rev. Stat. § 37-92-301.
[17] Colo. Rev. Stat. § 37-92-103(2). Conditional rights may be considered abandoned if the user does not demonstrate the reasonable diligence required by state law. See Colo. Rev. Stat. § 37- 92-301.
[18] Utah Code Ann. § 73-1-4.
[19] See Wyo. Stat. Ann. § 41-3-401.
[20] At least 47 states and the District of Columbia have been involved in interstate water disputes. See Documents on the Use and Control of the Waters of Interstate and International Streams: Compacts, Treaties, and Adjudications, H.R. Doc. No. 319, 90th Cong. 2d Sess. (1968). An online collection of interstate compacts can be accessed at [http://ssl.csg.org/compactlaws/ comlistlinks.html].
[21] The U.S. Supreme Court has original jurisdiction to hear disputes between states. U.S. Const., Art. III, § 2, cl. 1. If a state pursues litigation against non-state parties, as occurred in the Apalachicola-Chattahoochee-Flint dispute, the case must be initiated in lower courts, and only reaches the Supreme Court as a final appeal.
[22] Generally, an interstate compact, which creates a binding agreement between two or more states, requires congressional approval in addition to approval by the states involved in the agreement. U.S. Const., Art. I, § 10, cl. 3.
[23] Some of the laws and agreements that comprise the Law of the River include the Colorado River Compact of 1922, the Boulder Canyon Project Act, the Mexican Water Treaty of 1944, the Upper Colorado River Basin Compact of 1948, the Colorado River Storage Project of 1956, the Colorado River Basin Project Act of 1968, and the U.S. Supreme Court decision in Arizona v. California.
[24] The Colorado River Basin states include Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming.

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