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Report to Congressional Requesters

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ENERGY-WATER NEXUS

A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development

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GAO-11-35

October 2010

Highlights

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Highlights of GAO-11-35, a report to congressional requesters

ENERGY-WATER NEXUS

A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development

Why GAO Did This Study

Oil shale deposits in Colorado, Utah, and Wyoming are estimated to contain up to 3 trillion barrels of oil—or an amount equal to the world's proven oil reserves. About 72 percent of this oil shale is located beneath federal lands, making the federal government a key player in its potential development. Extracting this oil is expected to require substantial amounts of water and could impact groundwater and surface water. GAO was asked to report on (1) what is known about the potential impacts of oil shale development on surface water and groundwater, (2) what is known about the amount of water that may be needed for commercial oil shale development, (3) the extent to which water will likely be available for commercial oil shale development and its source, and (4) federal research efforts to address impacts to water resources from commercial oil shale development. GAO examined environmental impacts and water needs studies and talked to Department of Energy (DOE), Department of the Interior (Interior), and industry officials.

What GAO Recommends

GAO recommends that Interior establish comprehensive baseline conditions for water resources in oil shale regions of Colorado and Utah, model regional groundwater movement, and coordinate on water-related research with DOE and state agencies involved in water regulation. Interior generally concurred with GAO's recommendations.

View GAO-11-35 or key components.
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What GAO Found

Oil shale development could have significant impacts on the quality and quantity of water resources, but the magnitude of these impacts is unknown because technologies are years from being commercially proven, the size of a future oil shale industry is uncertain, and knowledge of current water conditions and groundwater flow is limited. In the absence of effective mitigation measures, water resources could be impacted from ground disturbances caused by the construction of roads and production facilities; withdrawing water from streams and aquifers for oil shale operations, underground mining and extraction; and discharging waters produced from or used in operations.

Estimates vary widely for the amount of water needed to commercially produce oil shale primarily because of the unproven nature of some technologies and because the various ways of generating power for operations use differing quantities of water. GAO's review of available studies indicated that the expected total water needs for the entire life cycle of oil shale production ranges from about 1 barrel (or 42 gallons) to 12 barrels of water per barrel of oil produced from in-situ (underground heating) operations, with an average of about 5 barrels, and from about 2 to 4 barrels of water per barrel of oil produced from mining operations with surface heating.

Water is likely to be available for the initial development of an oil shale industry, but the size of an industry in Colorado or Utah may eventually be limited by water availability. Water limitations may arise from increases in water demand from municipal and industrial users, the potential of reduced water supplies from a warming climate, fulfilling obligations under interstate water compacts, and the need to provide additional water to protect threatened and endangered fishes.

The federal government sponsors research on the impacts of oil shale on water resources through DOE and Interior. DOE manages 13 projects whose water-related costs total about $4.3 million, and Interior sponsored two water-related projects, totaling about $500,000. Despite this research, nearly all of the officials and experts that GAO contacted said that there are insufficient data to understand baseline conditions of water resources in the oil shale regions of Colorado and Utah and that additional research is needed to understand the movement of groundwater and its interaction with surface water. Federal agency officials also said they seldom coordinate water-related oil shale research among themselves or with state agencies that regulate water. Most officials noted that agencies could benefit from such coordination.

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Abbreviations

BLM	Bureau of Land Management
BOR	Bureau of Reclamation
DOE	Department of Energy
EIS	environmental impact statement
EPA	Environmental Protection Agency
INL	Idaho National Laboratory
Interior	Department of the Interior
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
OSEC	Oil Shale Exploration Company
OTA	Office of Technology Assessment
PEIS	programmatic environmental impact statement
RD&D	research, development, and demonstration
USGS	U.S. Geological Survey

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United States Government Accountability Office
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October 29, 2010

The Honorable Bart Gordon
Chairman
Committee on Science and Technology
House of Representatives

The Honorable Brian N. Baird
Chairman
Subcommittee on Energy and Environment
Committee on Science and Technology
House of Representatives

Being able to tap the vast amounts of oil locked within U.S. oil shale could go a long way toward satisfying the nation's future oil demands. Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil when heated. The Green River Formation—an assemblage of over 1,000 feet of sedimentary rocks that lie beneath parts of Colorado, Utah, and Wyoming—contains the world's largest deposits of oil shale. The U.S. Geological Survey (USGS) estimates that the Green River Formation contains about 3 trillion barrels of oil, and about half of this may be recoverable, depending on available technology and economic conditions.[1] This is an amount about equal to the entire world's proven oil reserves. The thickest and richest oil shale within the Green River Formation exists in the Piceance Basin of northwest Colorado and the Uintah Basin of northeast Utah.

The federal government is in a unique position to influence the development of oil shale because 72 percent of the oil shale within the Green River Formation is beneath federal lands managed by the Department of the Interior's (Interior) Bureau of Land Management (BLM). The Department of Energy (DOE) has provided technological and financial support for oil shale development, primarily through its research and development efforts, but oil shale development has been hampered by concerns over potential impacts on the environment, technological challenges, and average oil prices that have been too low to consistently

[1]The Rand Corporation, a nonprofit research organization, estimates that between 30 and 60 percent of the oil shale in the Green River Formation can be recovered. At the midpoint of this estimate, almost half of the 3 trillion barrels of oil would be recoverable.

justify investment. In particular, developing oil shale and providing power for oil shale operations and other activities will require large amounts of water—a resource that is already in scarce supply in the arid West where an expanding population is placing additional demands on water. Some analysts project that large scale oil shale development within Colorado could require more water than is currently supplied to over 1 million residents of the Denver metro area and that water diverted for oil shale operations would restrict agricultural and urban development. The potential demand for water is further complicated by the past decade of drought in the West and projections of a warming climate in the future. While there are also other concerns over the impacts from oil shale development, such as impacts to air quality, wildlife, and nearby communities, this report focuses on water impacts.

In response to your request, and building on our two recent reports examining the relationship between other forms of energy production and water use,[2] we examined (1) what is known about the potential impacts of oil shale development on surface water and groundwater, (2) what is known about the amount of water that may be needed for the commercial development of oil shale, (3) the extent to which water will likely be available for commercial oil shale development and its source, and (4) federal research efforts to address impacts on water resources from commercial oil shale development. Our report focuses on oil shale resources within the Green River Formation in the Piceance Basin of northwest Colorado and in the Uintah Basin of northeast Utah because these are the areas in the United States in which the industry is most interested in pursuing oil shale development due to the great thickness and richness of the deposits.

To determine what is known about the potential impacts to surface water and groundwater from commercial oil shale development, we reviewed an environmental impact statement on oil shale development prepared by BLM and various studies from private and public groups. We discussed the completeness and accuracy of these studies in interviews with federal agency officials, state agency personnel involved in regulating water quality and quantity, oil shale industry representatives, and representatives

[2]GAO, *Energy-Water Nexus: Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use*, GAO-10-23 (Washington, D.C.: Oct. 16, 2009) and *Energy-Water Nexus: Many Uncertainties Remain about National and Regional Effects of Increased Biofuel Production on Water Resources*, GAO-10-116 (Washington, D.C.: Nov. 30, 2009).

of environmental groups. We also visited oil shale demonstration projects in Colorado. To determine what is known about the amount of water that may be needed for commercial oil shale development, we conducted a comprehensive literature search for studies on water needs, contacted the authors of these studies, and assessed the reasonableness of their estimates. Our review of the literature identified several groups of activities that comprise the life cycle of oil shale production. We then tabulated the water needs identified in each study for each group of activities and expressed the total water needs for the life cycle as a range based on these numbers. To determine the extent to which water is likely to be available for commercial oil shale development and its source, we compared the total needs reflected in this estimated range to the amount of surface water and groundwater that is physically and legally available in the immediate area and to the future demands of municipalities and other industries as projected by federal and state agencies.[3] To review federal research efforts to address the impacts of commercial oil shale development on water resources, we interviewed officials at DOE, the USGS, BLM, and organizations performing the research, including universities and national laboratories, and collected and reviewed relevant documents describing their research. We also discussed areas for future water research as it relates to oil shale with 18 organizations—including the USGS, BLM, the DOE National Energy Technology Laboratory, the DOE Office of Naval Petroleum and Oil Shale Reserves, the U.S. Bureau of Reclamation, three DOE national laboratories, four state regulatory agencies in Colorado and Utah, three water experts, an industry representative, and two universities performing research—to identify gaps in current efforts.

We conducted this performance audit from September 2009 through October 2010 in accordance with generally accepted government auditing standards. These standards require that we plan and perform the audit to obtain sufficient and appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides such a reasonable basis for our findings and conclusions based on our audit objectives.

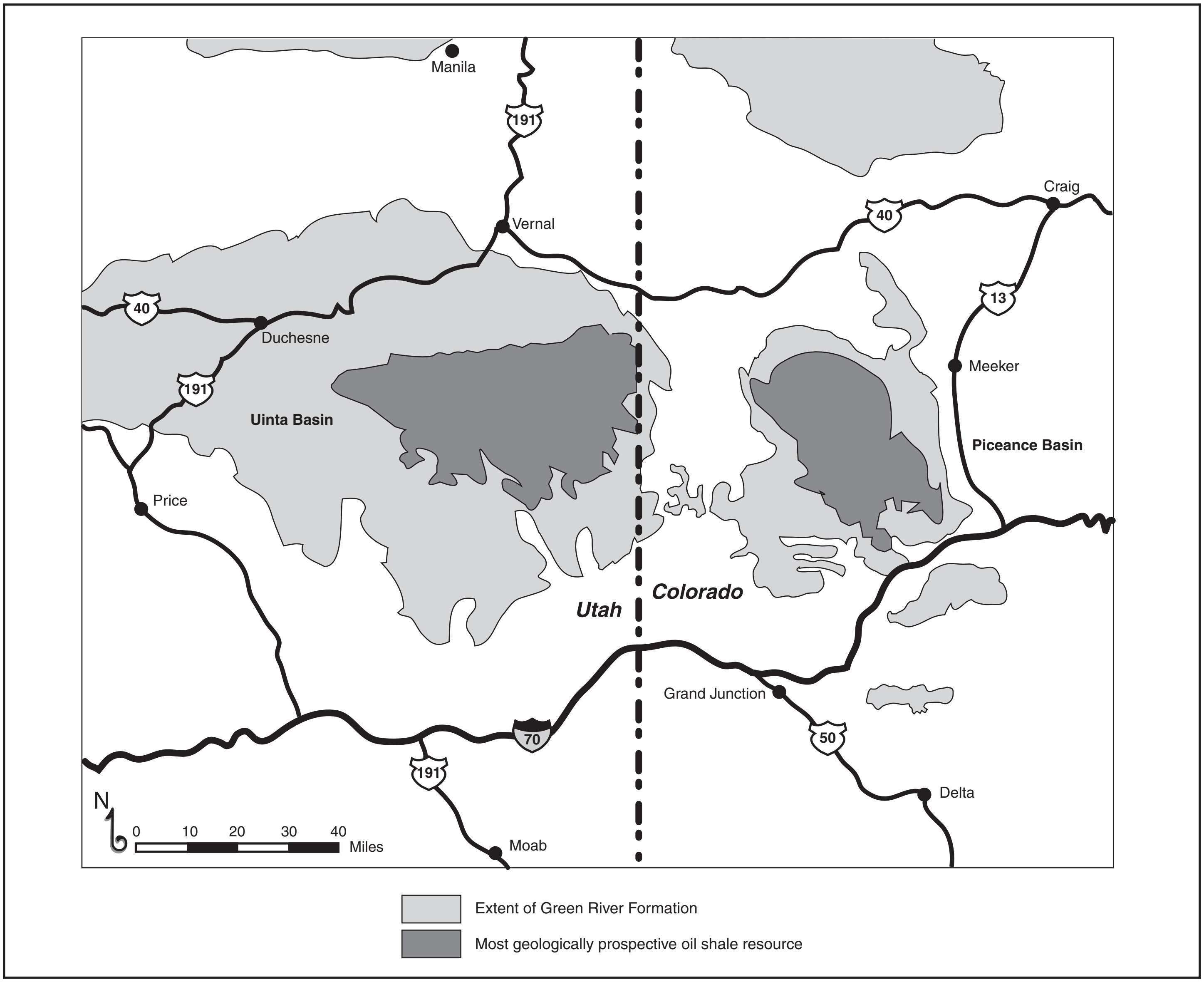
[3]Physically available, according to the state of Colorado, is the actual or observed amount of water flowing in a stream. This amount can vary from year to year, based on the amount of precipitation and snow pack. Legally available, according to the state of Colorado, is the portion of physically available flow that could be developed without injury to other water rights or compacts.

Background

Interest in oil shale as a domestic energy source has waxed and waned since the early 1900s. In 1912, President Taft established an Office of Naval and Petroleum Oil Shale Reserves, and between 1916 and 1924, executive orders set aside federal land in three separate naval oil shale reserves to ensure an emergency domestic supply of oil. The Mineral Leasing Act of 1920 made petroleum and oil shale resources on federal lands available for development under the terms of a mineral lease, but large domestic oil discoveries soon after passage of the act dampened interest in oil shale. Interest resumed at various points during times of generally increasing oil prices. For example, the U.S. Bureau of Mines developed an oil shale demonstration project beginning in 1949 in Colorado, where it attempted to develop a process to extract the oil. The 1970s' energy crises stimulated interest once again, and DOE partnered with a number of energy companies, spawning a host of demonstration projects. Private efforts to develop oil shale stalled after 1982 when crude oil prices fell significantly, and the federal government dropped financial support for ongoing demonstration projects.

More recently, the Energy Policy Act of 2005 directed BLM to lease its lands for oil shale research and development. In June 2005, BLM initiated a leasing program for research, development, and demonstration (RD&D) of oil shale recovery technologies. By early 2007, it granted six small RD&D leases: five in the Piceance Basin of northwest Colorado and one in Uintah Basin of northeast Utah. The location of oil shale resources in these two basins is shown in figure 1. The leases are for a 10-year period, and if the technologies are proven commercially viable, the lessees can significantly expand the size of the leases for commercial production into adjacent areas known as preference right lease areas. The Energy Policy Act of 2005 directed BLM to develop a programmatic environmental impact statement (PEIS) for a commercial oil shale leasing program. During the drafting of the PEIS, however, BLM realized that, without proven commercial technologies, it could not adequately assess the environmental impacts of oil shale development and dropped from consideration the decision to offer additional specific parcels for lease. Instead, the PEIS analyzed making lands available for potential leasing and allowing industry to express interest in lands to be leased. Environmental groups then filed lawsuits, challenging various aspects of the PEIS and the RD&D program. Since then, BLM has initiated another round of oil shale RD&D leasing and is currently reviewing applications but has not made any awards.

Figure 1: Location of Oil Shale Resources in Colorado and Utah



Source: Adopted from BLM.

Stakeholders in the future development of oil shale are numerous and include the federal government, state government agencies, the oil shale industry, academic institutions, environmental groups, and private citizens. Among federal agencies, BLM manages the land and the oil shale beneath it and develops regulations for its development. USGS describes the nature and extent of oil shale deposits and collects and disseminates information on the nation's water resources. DOE, through its various offices, national laboratories, and arrangements with universities, advances energy technologies, including oil shale technology. The Environmental Protection Agency (EPA) sets standards for pollutants that could be released by oil shale development and reviews environmental impact statements, such as the PEIS. The Bureau of Reclamation (BOR) manages federally built water projects that store and distribute water in 17 western states and provides this water to users. BOR monitors the amount of water in storage and the amount of water flowing in the major streams and rivers, including the Colorado River, which flows through oil shale country and feeds these projects. BOR provides its monitoring data to federal and state agencies that are parties to three major federal, state, and international agreements, that together with other federal laws, court decisions, and agreements, govern how water within the Colorado River and its tributaries is to be shared with Mexico and among the states in which the river or its tributaries are located. These three major agreements are the Colorado River Compact of 1922, the Upper Colorado River Basin Compact of 1948, and the Mexican Water Treaty of 1944.

The states of Colorado and Utah have regulatory responsibilities over various activities that occur during oil shale development, including activities that impact water. Through authority delegated by EPA under the Clean Water Act, Colorado and Utah regulate discharges into surface waters. Colorado and Utah also have authority over the use of most water resources within their respective state boundaries. They have established extensive legal and administrative systems for the orderly use of water resources, granting water rights to individuals and groups. Water rights in these states are not automatically attached to the land upon which the water is located. Instead, companies or individuals must apply to the state for a water right and specify the amount of water to be used, its intended use, and the specific point from where the water will be diverted for use, such as a specific point on a river or stream. Utah approves the application for a water right through an administrative process, and Colorado approves the application for a water right through a court proceeding. The date of the application establishes its priority—earlier applicants have preferential entitlement to water over later applicants if water availability decreases during a drought. These earlier applicants are said to have senior water rights. When an applicant puts a water right to beneficial use, it is referred to as an absolute water right. Until the water is used, however, the applicant is said to have a conditional water right. Even if the applicant has not yet put the water to use, such as when the applicant is waiting on the construction of a reservoir, the date of the application still establishes priority. Water rights in both Colorado and Utah can be bought and sold, and strong demand for water in these western states facilitates their sale.

Challenges to Oil Shale Development

A significant challenge to the development of oil shale lies in the current technology to economically extract oil from oil shale. To extract the oil, the rock needs to be heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. Retorting can be accomplished primarily by two methods. One method involves mining the oil shale, bringing it to the surface, and heating it in a vessel known as a retort. Mining oil shale and retorting it has been demonstrated in the United States and is currently done to a limited extent in Estonia, China, and Brazil. However, a commercial mining operation with surface retorts has never been developed in the United States because the oil it produces competes directly with conventional crude oil, which historically has been less expensive to produce. The other method, known as an in-situ process, involves drilling holes into the oil shale, inserting heaters to heat the rock, and then collecting the oil as it is freed from the rock. Some in-situ technologies have been demonstrated on very small scales, but other technologies have yet to be proven, and none has been shown to be economically or environmentally viable. Nevertheless, according to some energy experts, the key to developing our country's oil shale is the development of an in-situ process because most of the richest oil shale is buried beneath hundreds to thousands of feet of rock, making mining difficult or impossible. Additional economic challenges include transporting the oil produced from oil shale to refineries because pipelines and major highways are not prolific in the remote areas where the oil shale is located and the large-scale infrastructure that would be needed to supply power to heat oil shale is lacking. In addition, average crude oil prices have been lower than the threshold necessary to make oil shale development profitable over time.

Large-scale oil shale development also brings socioeconomic impacts. While there are obvious positive impacts such as the creation of jobs, increase in wealth, and tax and royalty payments to governments, there are also negative impacts to local communities. Oil shale development can bring a sizeable influx of workers, who along with their families, put additional stress on local infrastructure such as roads, housing, municipal water systems, and schools. Development from expansion of extractive industries, such as oil shale or oil and gas, has typically followed a "boom and bust" cycle in the West, making planning for growth difficult. Furthermore, traditional rural uses could be replaced by the industrial development of the landscape, and tourism that relies on natural resources, such as hunting, fishing, and wildlife viewing, could be negatively impacted.

In addition to the technological, economic, and social challenges to developing oil shale resources, there are a number of significant environmental challenges. For example, construction and mining activities can temporarily degrade air quality in local areas. There can also be long-term regional increases in air pollutants from oil shale processing, upgrading, pipelines, and the generation of additional electricity. Pollutants, such as dust, nitrogen oxides, and sulfur dioxide, can contribute to the formation of regional haze that can affect adjacent wilderness areas, national parks, and national monuments, which can have very strict air quality standards. Because oil shale operations clear large surface areas of topsoil and vegetation, some wildlife habitat will be lost. Important species likely to be negatively impacted from loss of wildlife habitat include mule deer, elk, sage grouse, and raptors. Noise from oil shale operations, access roads, transmission lines, and pipelines can further disturb wildlife and fragment their habitat. In addition, visual resources in the area will be negatively impacted as people generally consider large-scale industrial sites, pipelines, mines, and areas cleared of vegetation to be visually unpleasant (see fig. 2 for a typical view within the Piceance Basin). Environmental impacts from oil shale development could be compounded by additional impacts in the area resulting from coal mining, construction, and extensive oil and gas development. Air quality and wildlife habitat appear to be particularly susceptible to the cumulative affect of these impacts, and according to some environmental experts, air quality impacts may be the limiting factor for the development of a large oil shale industry in the future. Lastly, the withdrawal of large quantities of surface water for oil shale operations could negatively impact aquatic life downstream of the oil shale development. Impacts to water resources are discussed in detail in the next section of this report.

Figure 2: Typical View in the Piceance Basin of Colorado

Source: GAO.

Oil Shale Development Could Adversely Impact Water Resources, but the Magnitude of These Impacts Is Unknown

Oil shale development could have significant impacts on the quality and quantity of surface and groundwater resources, but the magnitude of these impacts is unknown because some technologies have yet to be commercially proven, the size of a future oil shale industry is uncertain, and knowledge of current water conditions and groundwater flow is limited. Despite not being able to quantify the impacts from oil shale development, hydrologists and engineers have been able to determine the qualitative nature of impacts because other types of mining, construction, and oil and gas development cause disturbances similar to impacts expected from oil shale development. According to these experts, in the absence of effective mitigation measures, impacts from oil shale development to water resources could result from disturbing the ground surface during the construction of roads and production facilities, withdrawing water from streams and aquifers[4] for oil shale operations, underground mining and extraction, and discharging waste waters from oil shale operations.

[4] An aquifer is an underground layer of rock or unconsolidated sand, gravel, or silt that will yield groundwater to a well or spring.

Quantitative Impacts of Oil Shale Development Cannot Be Measured at This Time

The quantitative impacts of future oil shale development cannot be measured with reasonable certainty at this time primarily because of three unknowns: (1) the unproven nature of in-situ technologies, (2) the uncertain size of a future oil shale industry, and (3) insufficient knowledge of current groundwater conditions. First, geological maps suggest that most of the prospective oil shale in the Uintah and Piceance Basins is more amenable to in-situ production methods rather than mining because the oil shale lies buried beneath hundreds to thousands of feet of rock. Studies have concluded that much of this rock is generally too thick to be removed economically by surface mining, and deep subsurface mines are likely to be costly and may recover no more than 60 percent of the oil shale. Although several companies have been working on the in-situ development of oil shale, none of these processes has yet been shown to be commercially viable. Most importantly, the extent of the impacts of in-situ retorting on aquifers is unknown, and it is uncertain whether methods for reclamation of the zones that are heated will be effective.[5] Second, it is not possible to quantify impacts on water resources with reasonable certainty because it is not yet possible to predict how large an oil shale industry may develop. The size of the industry would have a direct relationship to water impacts. Within the PEIS, BLM has stated that the level and degree of the potential impacts of oil shale development cannot be quantified because this would require making many speculative assumptions regarding the potential of the oil shale, unproven technologies, project size, and production levels. Third, hydrologists at USGS and BLM state that not enough is known about current surface water and groundwater conditions in the Piceance and Uintah Basins. More specifically, comprehensive baseline conditions for surface water and groundwater do not exist. Therefore, without knowledge of current conditions, it is not possible to detect changes in groundwater conditions, much less attribute changes to oil shale development.

A Number of Impacts to Water Quality and Quantity Could Be Expected from Oil Shale Development

Impacts to water resources from oil shale development would result primarily from disturbing the ground surface, withdrawing surface water and groundwater, underground mining, and discharging water from operations.

[5]Reclamation is an attempt to mitigate the adverse impacts of heating the subsurface zone, such as repeated rinsing with water to remove any residual hydrocarbons that were not economically extracted.

Ground Disturbances Could Degrade Surface Water Quality

In the absence of effective mitigation measures, ground disturbance activities associated with oil shale development could degrade surface water quality, according to the literature we reviewed and water experts to whom we spoke.[6] Both mining and the in-situ production of oil shale are expected to involve clearing vegetation and grading the surface for access roads, pipelines, production facilities, buildings, and power lines. In addition, the surface that overlies the oil shale would need to be cleared and graded in preparation for mining or drilling boreholes for in-situ extraction. The freshly cleared and graded surfaces would then be exposed to precipitation, and subsequent runoff would drain downhill toward existing gullies and streams. If not properly contained or diverted away from these streams, this runoff could contribute sediment, salts, and possibly chemicals or oil shale products into the nearby streams, degrading their water quality. Surface mining would expose the entire area overlying the oil shale that is to be mined while subsurface mining would expose less surface area and thereby contribute less runoff. One in-situ operation proposed by Shell for its RD&D leases would require clearing of the entire surface overlying the oil shale because wells are planned to be drilled as close as 10 feet apart. Other in-situ operations, like those proposed by American Shale Oil Company and ExxonMobil, envision directionally drilling wells in rows that are far enough apart so that strips of undisturbed ground would remain.[7] The adverse impacts from ground disturbances would remain until exposed surfaces were properly revegetated.

If runoff containing excessive sediment, salts, or chemicals finds its way into streams, aquatic resources could be adversely impacted, according to the water experts to whom we spoke and the literature we reviewed. Although aquatic populations can handle short-term increases in sediment, long-term increases could severely impact plant and animal life. Sediment could suffocate aquatic plants and decrease the photosynthetic activity of these plants. Sediment could also suffocate invertebrates, fish, and incubating fish eggs and adversely affect the feeding efficiency and spawning success of fish. Sedimentation would be exacerbated if oil shale activities destroy riparian vegetation because these plants often trap

[6]For a detailed discussion of the literature we reviewed and the experts to whom we spoke, see appendix I.

[7]In directional drilling, the company starts drilling a borehole on the disturbed ground surface and angles the well so that the bottom of the hole occurs below the undisturbed surface.

sediment, preventing it from entering streams. In addition, toxic substances derived from spills, leaks from pipelines, or leaching of waste rock piles could increase mortality among invertebrates and fish.

Surface and underground mining of oil shale will produce waste rock that, according to the literature we reviewed and water experts to whom we spoke, could contaminate surface waters. Mined rock that is retorted on site would produce large quantities of spent shale after the oil is extracted. Such spent shale is generally stored in large piles that would also be exposed to surface runoff that could possibly transport sediment, salts, selenium, metals, and residual hydrocarbons into receiving streams unless properly stabilized and reclaimed. EPA studies have shown that water percolating through such spent shale piles transports pollutants long after abandonment of operations if not properly mitigated. In addition to stabilizing and revegetating these piles, mitigation measures could involve diverting runoff into retention ponds, where it could be treated, and lining the surface below waste rock with impervious materials that could prevent water from percolating downward and transporting pollutants into shallow groundwater. However, if improperly constructed, retention ponds would not prevent the degradation of shallow groundwater, and some experts question whether the impervious materials would hold up over time.

Withdrawing Water for Oil Shale Operations Could Adversely Impact Surface Water and Groundwater

Withdrawing water from streams and rivers for oil shale operations could have temporary adverse impacts on surface water, according to the experts to whom we spoke and the literature we reviewed. Oil shale operations need water for a number of activities, including mining, constructing facilities, drilling wells, generating electricity for operations, and reclamation of disturbed sites. Water for most of these activities is likely to come from nearby streams and rivers because it is more easily accessible and less costly to obtain than groundwater. Withdrawing water from streams and rivers would decrease flows downstream and could temporarily degrade downstream water quality by depositing sediment within the stream channels as flows decrease. The resulting decrease in water would also make the stream or river more susceptible to temperature changes—increases in the summer and decreases in the winter. Elevated temperatures could have adverse impacts on aquatic life, including fishes and invertebrates, which need specific temperatures for proper reproduction and development. Elevated water temperatures would also decrease dissolved oxygen, which is needed by aquatic animals. Decreased flows could also damage or destroy riparian vegetation. Removal of riparian vegetation could exacerbate negative impacts on water temperature and oxygen because such vegetation shades the water, keeping its temperature cooler.

Similarly, withdrawing water from shallow aquifers—an alternative water source—would have temporary adverse impacts on groundwater resources. Withdrawals would lower water levels within these shallow aquifers and the nearby streams and springs to which they are connected. Extensive withdrawals could reduce groundwater discharge to connected streams and springs, which in turn could damage or remove riparian vegetation and aquatic life. Withdrawing water from deeper aquifers could have longer-term impacts on groundwater and connected streams and springs because replenishing these deeper aquifers with precipitation generally takes longer.

Underground Mining and In-Situ Extraction Would Permanently Impact Aquifers

Underground mining would permanently alter the properties of the zones that are mined, thereby affecting groundwater flow through these zones, according to the literature we reviewed and the water experts to whom we spoke. The process of removing oil shale from underground mines would create large tunnels from which water would need to be removed during mining operations. The removal of this water through pumping would decrease water levels in shallow aquifers and decrease flows to streams and springs that are connected. When mining operations cease, the tunnels would most likely be filled with waste rock, which would have a higher degree of porosity and permeability than the original oil shale that was removed.[8] Groundwater flow through this material would increase permanently, and the direction and pattern of flows could change permanently. Flows through the abandoned tunnels could decrease ground water quality by increasing concentrations of salts, metals, and hydrocarbons within the groundwater.

In-situ extraction would also permanently alter aquifers because it would heat the rock to temperatures that transform the solid organic compounds within the rock into liquid hydrocarbons and gas that would fracture the rock upon escape. Water would be cooked off during the heating processes. Some in-situ operations envision using a barrier to isolate thick zones of oil shale with intervening aquifers from any adjacent aquifers and

[8] Porosity is the amount of space within an aquifer that can be filled with groundwater. Permeability is the ability of a material, such as an aquifer or rock formation, to transmit liquids like water.

pumping out all the groundwater from this isolated area before retorting.[9] Other processes, like those envisioned by ExxonMobil and AMSO, involve trying to target thinner oil shale zones that do not have intervening aquifers and, therefore, would theoretically not disturb the aquifers. However, these processes involve fracturing the oil shale, and it is unclear whether the fractures could connect the oil shale to adjacent aquifers, possibly contaminating the aquifer with hydrocarbons. After removal of hydrocarbons from retorted zones, the porosity and permeability of the zones are expected to increase, thereby allowing increased groundwater flow. Some companies propose rinsing retorted zones with water to remove residual hydrocarbons. However, the effectiveness of rinsing is unproven, and residual hydrocarbons, metals, salts, and selenium that were mobilized during retorting could contaminate the groundwater. Furthermore, the long-term effects of groundwater flowing through retorted zones are unknown.

Discharge of Waste Waters from Operations Could Temporarily Impact Downstream Waters

The discharge of waste waters from operations would temporarily increase water flows in receiving streams. According to BLM's PEIS, waste waters from oil shale operations that could be discharged include waters used in extraction, cooling, the production of electricity, and sewage treatment, as well as drainage water collected from spent oil shale piles and waters pumped from underground mines or wells used to dewater the retorted zones. Discharges could decrease the quality of downstream water if the discharged water is of lower quality, has a higher temperature, or contains less oxygen. Lower-quality water containing toxic substances could increase fish and invertebrate mortality. Also, increased flow into receiving streams could cause downstream erosion. However, at least one company is planning to recycle waste water and water produced during operations so that discharges and their impacts could be substantially reduced.

[9] In Shell's original process, a ring of bore holes is drilled around the zone to be isolated. Liquid ammonia is circulated down the boreholes, which freezes the groundwater in the immediate vicinity, creating a ring of ice around the isolated zone.

Estimates of Water Needs for Commercial Oil Shale Development Vary Widely

While commercial oil shale development requires water for numerous activities throughout its life cycle, estimates vary widely for the amount of water needed to commercially produce oil shale. This variation in estimates stems primarily from the uncertainty associated with reclamation technologies for in-situ oil shale development and because of the various ways to generate power for oil shale operations, which use different amounts of water. Based on our review of available information for the life cycle of oil shale production, existing estimates suggest that from about 1 to 12 barrels of water could be needed for each barrel of oil produced from in-situ operations, with an average of about 5 barrels. About 2 to 4 barrels of water could be needed for each barrel of oil produced from mining operations with a surface retort.[10]

Oil Shale Development Requires Water throughout Its Life Cycle

Water is needed for five distinct groups of activities that occur during the life cycle of oil shale development: (1) extraction and retorting, (2) upgrading of shale oil, (3) reclamation, (4) power generation, and (5) population growth associated with oil shale development.

- *Extraction and retorting.* During extraction and retorting, water is used for building roads, constructing facilities, controlling dust, mining and handling ore, drilling wells for in-situ extraction, cooling of equipment and shale oil, producing steam, in-situ fracturing of the retort zones, and preventing fire. Water is also needed for on-site sanitary and potable uses.

- *Upgrading of shale oil.* Water is needed to upgrade, or improve, the quality of the produced shale oil so that it can be easily transported to a refinery. The degree to which the shale oil needs to be upgraded varies according to the retort process. Shale oil produced by surface retorting generally requires more upgrading, and therefore, more water than shale oil produced from in-situ operations that heat the rock at lower temperatures and for a longer time, producing higher-quality oil.

- *Reclamation.* During reclamation of mine sites, water is needed to cool, compact, and stabilize the waste piles of retorted shale and to revegetate disturbed surfaces, including the surfaces of the waste piles. For in-situ operations, in addition to the typical revegetation of disturbed surfaces, as shown in figure 3, water also will be needed for reclamation of the subsurface retorted zones to remove residual hydrocarbons. The volume of water that would be needed to rinse the zones at present is uncertain

[10]One barrel contains 42 gallons.

and could be large, depending primarily on how many times the zones need to be rinsed. In addition, some companies envision reducing water demands for reclamation, as well as for extracting, retorting, and upgrading, by recycling water produced during oil shale operations or by treating and using water produced from nearby oil and gas fields. Recycling technology, however, has not been shown to be commercially viable for oil shale operations, and there could be legal restrictions on using water produced from oil and gas operations.[11]

- *Power generation.* Water is also needed throughout the life cycle of oil shale production for generating electricity from power plants needed in operations. The amount of water used to produce this electricity varies significantly according to generation and cooling technologies employed. For example, thermoelectric power plants use a heat source to make steam, which turns a turbine connected to a generator that makes the electricity. The steam is captured and cooled, often with additional water, and is condensed back into water that is then recirculated through the system to generate more steam. Plants that burn coal to produce steam use more water for cooling than combined cycle natural gas plants, which combust natural gas to turn a turbine and then capture the waste heat to produce steam that turns a second turbine, thereby producing more electricity per gallon of cooling water. Thermoelectric plants can also use air instead of water to condense the steam. These plants use fans to cool the steam and consume virtually no water, but are less efficient and more costly to run.

- *Population growth.* Additional water would be needed to support an anticipated increase in population due to oil shale workers and their families who migrate into the area. This increase in population can increase the demand for water for domestic uses. In isolated rural areas where oil shale is located, sufficiently skilled workers may not be available.

[11]The state of Colorado has promulgated extensive regulations regarding the nature of water produced from oil and gas operations. According to Colorado state officials, the transport and use of this water offsite to oil shale operations may be restricted.

Figure 3: Shell's Experimental In-Situ Site in Colorado

Source: GAO.

Estimates of Water Needs for In-Situ Development Vary Significantly

Based on studies that we reviewed, the total amount of water needed for in-situ oil shale operations could vary widely, from about 1 to 12 barrels of water per barrel of oil produced over the entire life cycle of oil shale operations. The average amount of water needed for in-situ oil shale production as estimated by these studies is about 5 barrels. This range is based on information contained primarily in studies published in 2008 and 2009 by ExxonMobil, Shell, the Center for Oil Shale Technology and Research at the Colorado School of Mines, the National Oil Shale Association, and contractors to the state of Colorado.[12] Figure 3 shows Shell's in-situ experimental site in Colorado. Because only two studies examined all five groups of activities that comprise the life cycle of oil shale production, we reviewed water estimates for each group of activities

[12]For a complete list of the studies we reviewed and a detailed description of our methodology, see appendix I.

that is described within each of the eight studies we reviewed.[13] We calculated the minimum and the maximum amount of water that could be needed for in-situ oil shale development by summing the minimum estimates and the maximum estimates, respectively, for each group of activities. Differences in estimates are due primarily to the uncertainty in the amount of water needed for reclamation and to the method of generating power for operations.

Table 1 shows the minimum, maximum, and average amounts of water that could be needed for each of the five groups of activities that comprise the life cycle of in-situ oil shale development. The table shows that reclamation activities contribute the largest amount of uncertainty to the range of total water needed for in-situ oil shale operations. Reclamation activities, which have not yet been developed, contribute from 0 to 5.5 barrels of water for each barrel of oil produced, according to the studies we analyzed. This large range is due primarily to the uncertainty in how much rinsing of retorted zones would be necessary to remove residual hydrocarbons and return groundwater to its original quality. On one end of the range, scientists at ExxonMobil reported that retorted zones may be reclaimed by rinsing them several times and using 1 barrel of water or less per barrel of oil produced. However, another study suggests that many rinses and many barrels of water may be necessary. For example, modeling by the Center for Oil Shale Technology and Research suggests that if the retorted zones require 8 or 10 rinses, 5.5 barrels of water could be needed for each barrel of oil produced. Additional uncertainty lies in estimating how much additional porosity in retorted zones will be created and in need of rinsing. Some scientists believe that the removal of oil will double the amount of pore space, effectively doubling the amount of water needed for rinsing. Other scientists question whether the newly created porosity will have enough permeability so that it can be rinsed. Also, the efficiency of recycling waste water that could be used for additional rinses adds to the amount of uncertainty. For example, ExxonMobil scientists believe that almost no new fresh water would be needed for reclamation if it can recycle waste water produced from oil shale operations or treat and use saline water produced from nearby oil and gas wells.

[13]Shell and the URS Corporation—a contractor to the state of Colorado—conducted the two studies that examine water needs for all five groups of activities comprising the life cycle of in-situ oil shale development. For planning purposes, Shell cites 3 barrels of water needed per barrel of oil. URS estimates that 5.2 barrels of water would be needed per barrel of oil.

Table 1: Estimated Barrels of Water Needed for Various Activities per Barrel of Shale Oil Produced by In-Situ Operations

Activity	Minimum estimate	Average estimate	Maximum estimate
Extraction/retorting	0	0.7	1.0
Upgrading liquids	0.6	0.9	1.6
Power generation	0.1	1.5	3.4
Reclamation	0	1.4	5.5
Population growth	0.1	0.3	0.3
Total	**0.8**	**4.8**	**11.8**

Source: GAO analysis of selected studies.

Notes: GAO used from four to six studies to obtain the numbers for each group of activities. See table 8 in appendix I to identify the specific studies. The average for reclamation may be less useful because estimates are either at the bottom or the top of this range.

Table 1 also shows that the water needs for generating power contribute significant uncertainty to the estimates of total water needed for in-situ extraction. Estimates of water needed to generate electricity range from near zero for thermoelectric plants that are cooled by air to about 3.4 barrels for coal-fired thermoelectric plants that are cooled by water, according to the studies that we analyzed. These studies suggested that from about 0.7 to about 1.2 barrels of water would be needed if electricity is generated from combined cycle plants fueled by natural gas, depending on the power requirements of the individual oil shale operation. Overall power requirements are large for in-situ operations because of the many electric heaters used to heat the oil shale over long periods of time—up to several years for one technology proposed by industry. However, ExxonMobil, Shell, and AMEC—a contractor to the state of Colorado—believe that an oil shale industry of significant size will not use coal-fired electric power because of its greater water requirements and higher carbon dioxide emissions. In fact, according to an AMEC study, estimates for power requirements of a 1.5 million-barrel-per-day oil shale industry would exceed the current coal-fired generating capacity of the nearest plant by about 12 times, and therefore would not be feasible.[14] Industry representatives with whom we spoke said that it is more likely that a large oil shale industry would rely on natural gas-powered combined cycle thermoelectric plants, with the gas coming from gas fields within the

[14]We calculated that AMEC's estimated power requirements exceeded by over seven times the coal-fired generating capacity of northwest Colorado, which consists of this nearest plant and one other smaller plant.

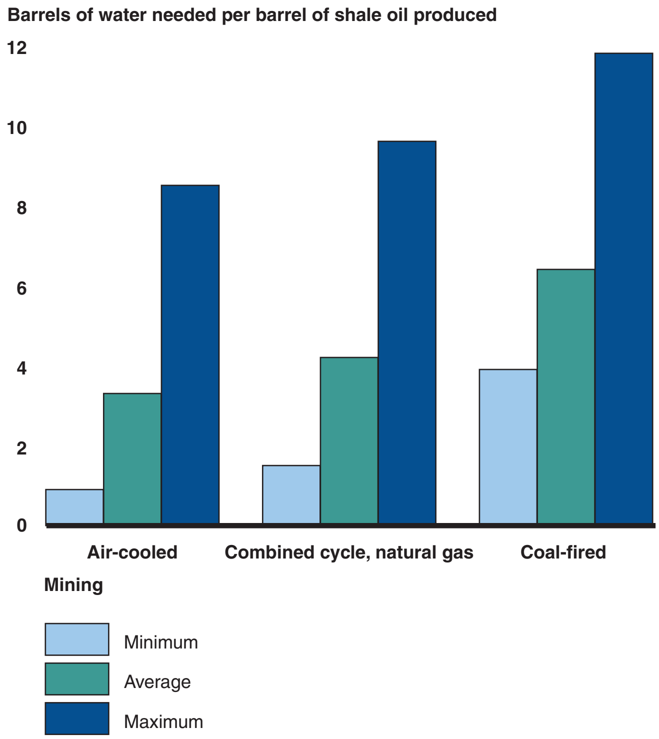
Piceance and Uintah Basins or from gas produced during the retort process. ExxonMobil reports that it envisions cooling such plants with air, thereby using next to no water for generating electricity. However, cooling with air can be more costly and will ultimately require more electricity.

In addition, table 1 shows that extracting and retorting activities and upgrading activities also contribute to the uncertainty in the estimates of water needed for in-situ operations, but this uncertainty is significantly less than that of reclamation activities or power generation. The range for extraction and retorting is from 0 to 1 barrel of water. The range for upgrading the produced oil is from 0.6 to 1.6 barrels of water, with both the minimum and maximum of this range cited in a National Oil Shale Association study.[15] Hence, each of these two groups of activities contribute about 1 barrel of water to the range of estimates for the total amount of water needed for the life cycle of in-situ oil shale production. Last, table 1 shows there is little variation in the likely estimates of water needed to support the anticipated population increase associated with in-situ oil shale development. Detailed analyses of water needs for population growth associated with an oil shale industry are present in the PEIS, a study by the URS Corporation, and a study completed by the Institute for Clean and Secure Energy at the University of Utah. These estimates often considered the number of workers expected to move into the area, the size of the families to which these workers belong, the ratio of single-family to multifamily housing that would accommodate these families, and per capita water consumption associated with occupants of different housing types.

Figure 4 compares the total water needs over the life cycle of in-situ oil shale development according to the various sources of power generation, as suggested by the studies we reviewed. This is a convenient way to visualize the water needs according to power source. The minimum, average, and maximum values are the sum of the minimum, average, and maximum water needs, respectively, for all five groups of activities. Most of the difference between the minimum and the maximum of each power type is due to water needed for reclamation.

[15]The National Oil Shale Association provided this estimate for upgrading shale oil. This range also contains data for upgrading oil from surface retorts, which we could not segregate. Conversations with an oil shale industry representative suggest that water estimates for upgrading oil derived from in-situ operations may lie toward the bottom of this range.

Figure 4: Estimated Total Barrels of Water Needed per Barrel of Shale Oil Produced by In-Situ Extraction, According to Source of Power Generation



Source: GAO analysis of selected studies.

Estimates of Water Needs for Mining and Surface Retorting Vary but Not as Much as the In-Situ Process

Estimates of water needed for mining oil shale and retorting it at the surface vary from about 2 to 4 barrels of water per barrel of oil produced over the entire life cycle of oil shale operations. The average is about 3 barrels of water. This range is based primarily on information obtained through a survey of active oil shale companies completed by the National Oil Shale Association in 2009 and information obtained from three different retorts, as published in a report by the Office of Technology Assessment (OTA) in 1980.[16] Figure 5 shows a surface retort that is operating today at a pilot plant. Because only two studies contained

[16]More information on studies we examined appears in appendix I. Experts consider some of the data within the OTA study to still be relevant because certain surface retort technologies are similar to those being tested today.

reliable information for all five groups of activities that comprise the life cycle of oil shale production, we reviewed water estimates for each group of activities that is described within each of the eight studies we reviewed.[17] We calculated the minimum and the maximum amount of water that could be needed for mining oil shale by summing the minimum estimates and the maximum estimates, respectively, for each group of activities. The range of water estimates for mining oil shale is far narrower than that of in-situ oil shale production because, according to the studies we reviewed, there are no large differences in water estimates for any of the activities.

Figure 5: Surface Retort near Rifle, Colorado

Source: Shale Technologies, LLC.

[17]The two studies that examined water needs for all five groups of activities that comprise the life cycle of oil shale development by mining and surface retorting are included in the OTA report. Both studies involve the Paraho–Direct Process. These estimates are 2.3 and 2.8 barrels of water per barrel of oil.

Table 2 shows the minimum, maximum, and average amounts of water that could be needed for each of the groups of activities that comprise the life cycle of oil shale development that relies upon mining and surface retorting. Unlike for in-situ production, we could not segregate extraction and retorting activities from upgrading activities because these activities were grouped together in some of the studies on mining and surface retorting. Nonetheless, as shown in table 2, the combination of these activities contributes 1 barrel of water to the total range of estimated water needed for the mining and surface retorting of oil shale. This 1 barrel of water results primarily from the degree to which the resulting shale oil would need upgrading. An oil shale company representative told us that estimates for upgrading shale oil vary due to the quality of the shale oil produced during the retort process, with higher grades of shale oil needing less processing. Studies in the OTA report did not indicate much variability in water needs for the mining of the oil shale and the handling of ore. Retorts also produce water—about half a barrel for each barrel of oil produced—by freeing water that is locked in organic compounds and minerals within the oil shale. Studies in the OTA report took this produced water into consideration and reported the net anticipated water use.

Table 2: Estimated Barrels of Water Needed for Various Activities per Barrel of Shale Oil Produced by Mining and Surface Retorting

Activity	Minimum estimate	Average estimate	Maximum estimate
Extraction/retorting and upgrading liquids	0.9	1.5	1.9
Power generation	0	0.3	0.9
Reclamation	0.6	0.7	0.8
Population growth	0.3	0.3	0.4
Total	**1.8**	**2.8**	**4.0**

Source: GAO analysis of selected studies.

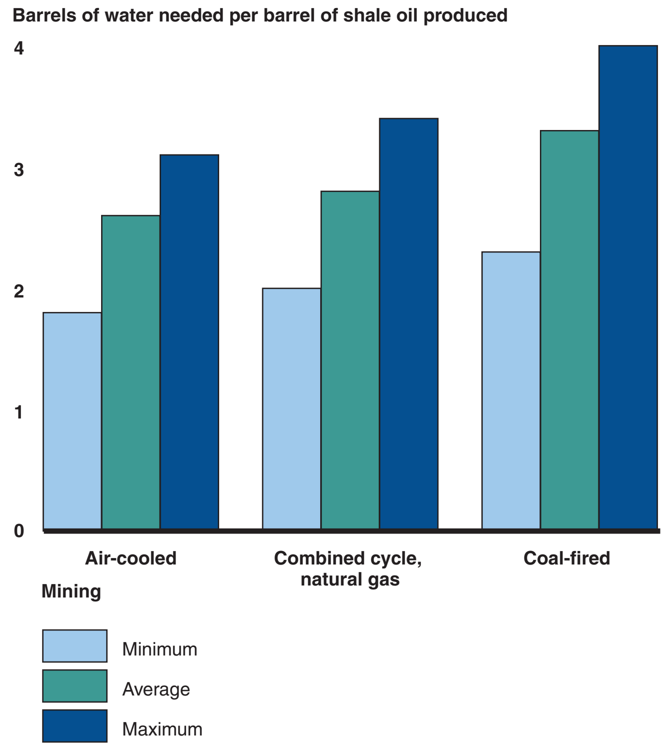
Note: GAO used from three to six studies to obtain the numbers for each group of activities. See table 9 in appendix I to identify the specific studies.

Table 2 also shows that differences in water estimates for generating power contributed about 1 barrel of water to the range of water needed for mining and surface retorting. We obtained water estimates for power generation either directly from the studies or from power requirements cited within the studies.[18] Estimates of water needed range from zero barrels for electricity coming from thermoelectric plants that are cooled by air to about 0.9 barrels for coal-fired thermoelectric plants that are cooled with water. About 0.3 barrels of water are needed to generate electricity from combined cycle plants fueled by natural gas. Startup oil shale mining operations, which have low overall power requirements, are more likely to use electricity from coal-fired power plants, according to data supplied by oil shale companies, because such generating capacity is available locally. However, a large-scale industry may generate electricity from the abundant natural gas in the area or from gas that is produced during the retorting of oil shale. Water needs for reclamation or for supporting an anticipated increase in population associated with mining oil shale show little variability in the studies that we reviewed.

Figure 6 compares the total water needs over the life cycle of mining and surface retorting of oil shale according to the various sources of power generation. The minimum, average, and maximum values are the sum of the minimum, average, and maximum water needs, respectively, for all five groups of activities.

[18]We multiplied these power requirements by the amounts of water needed to generate power as the amounts appear in GAO, *Energy-Water Nexus: Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use*, GAO-10-23 (Washington, D.C.: Oct. 16, 2009), p. 20.

Figure 6: Estimated Total Barrels of Water Needed per Barrel of Shale Oil Produced by Mining and Surface Retorting, According to Source of Power Generation



Source: GAO analysis of selected studies.

Water Is Likely to Be Available Initially from Local Sources, but the Size of an Oil Shale Industry May Eventually Be Limited by Water Availability

Water is likely to be available for the initial development of an oil shale industry, but the eventual size of the industry may be limited by the availability of water and demands for water to meet other needs. Oil shale companies operating in Colorado and Utah will need to have water rights to develop oil shale, and representatives from all of the companies with which we spoke are confident that they hold at least enough water rights for their initial projects and will likely be able to purchase more rights in the future. Sources of water for oil shale will likely be surface water in the immediate area, such as the White River, but groundwater could also be used. Nonetheless, the possibility of competing municipal and industrial demands for future water, a warming climate, future needs under existing compacts, and additional water needs for the protection of threatened and endangered fishes, may eventually limit the size of a future oil shale industry.

Oil Shale Companies Own Considerable Water Rights and Options Exist to Obtain More

Companies with interest in oil shale already hold significant water rights in the Piceance Basin of Colorado, and representatives from all of the companies with whom we spoke felt confident that they either had or could obtain sufficient water rights to supply at least their initial operations in the Piceance and Uintah Basins. Western Resource Advocates, a nonprofit environmental law and policy organization, conducted a study of water rights ownership in the Colorado and White River Basins of Colorado and concluded that companies have significant water rights in the area.[19] For example, the study found that Shell owns three conditional water rights[20] for a combined diversion of about 600 cubic feet per second from the White River and one of its tributaries and has conditional rights for the combined storage of about 145,000 acre-feet in two proposed nearby reservoirs.[21] Similarly, the study found that ExxonMobil owns conditional storage capacities of over 161,000 acre-feet on 17 proposed reservoirs in the area. In Utah, the Oil Shale Exploration Company (OSEC), which owns an RD&D lease, has obtained a water right on the White River that appears sufficient for reopening the White River Mine and has cited the possibility of renewing an expired agreement with the state of Utah for obtaining additional water from shallow aquifers connected to the White River. Similarly, Red Leaf Resources cites the possibility of drilling a water well on the state-owned lands that it has leased for oil shale development.

In addition to exercising existing water rights and agreements, there are other options for companies to obtain more water rights in the future, according to state officials in Colorado and Utah. In Colorado, companies can apply for additional water rights in the Piceance Basin on the Yampa and White Rivers. Shell recently applied—but subsequently withdrew the application—for conditional rights to divert up to 375 cubic feet per second from the Yampa River for storage in a proposed reservoir that would hold up to 45,000 acre-feet for future oil shale development. In Utah, however, officials with the State Engineer's office said that additional water rights are not available, but that if companies want

[19]Western Resource Advocates, *Water on the Rocks: Oil Shale Water Rights in Colorado* (Boulder, Colo., 2009).

[20]A conditional water right is a water right that has not yet been put to beneficial use. Its date of application establishes its priority among other water rights.

[21]An acre-foot is the amount of water that would fill an area of one acre to a depth of one foot. An acre-foot contains 325,851 gallons, or 7,758 barrels, and is roughly equal to the amount of water that a family of four will use in a year.

additional rights, they could purchase them from other owners. Many people who are knowledgeable on western water rights said that the owners of these rights in Utah and Colorado would most likely be agricultural users, based on a history of senior agricultural rights being sold to developers in Colorado. For example, the Western Resource Advocates study identified that in the area of the White River, ExxonMobil Corporation has acquired full or partial ownership in absolute water rights on 31 irrigation ditches from which the average amount of water diverted per year has exceeded 9,000 acre-feet.[22] These absolute water rights have appropriation dates ranging from 1883 through 1918 and are thus senior to holders of many other water rights, but their use would need to be changed from irrigation or agricultural to industrial in order to be used for oil shale. Also, additional rights may be available in Utah from other sources. According to state water officials in Utah, the settlement of an ongoing legal dispute between the state and the Ute Indian tribe could result in the tribe gaining rights to 105,000 acre-feet per year in the Uintah Basin. These officials said that it is possible that the tribe could lease the water rights to oil shale companies. There are also two water conservancy districts that each hold rights to tens of thousands of acre-feet per year of water in the Uintah Basin that could be developed for any use as determined by the districts, including for oil shale development.

Oil Shale Development Is Likely to Use Local Surface Water, but Groundwater Could Also Be Used

Most of the water needed for oil shale development is likely to come first from surface flows, as groundwater is more costly to extract and generally of poorer quality in the Piceance and Uintah Basins. However, companies may use groundwater in the future should they experience difficulties in obtaining rights to surface water. Furthermore, water is likely to come initially from surface sources immediately adjacent to development, such as the White River and its tributaries that flow through the heart of oil shale country in Colorado and Utah, because the cost of pumping water over long distances and rugged terrain would be high, according to water experts. Shell's attempt to obtain water from the more distant Yampa River shows the importance of first securing nearby sources. In relationship to the White River, the Yampa lies about 20 to 30 miles farther north and at a lower elevation than Shell's RD&D leases. Hence, additional costs would be necessary to transport and pump the Yampa's water to a

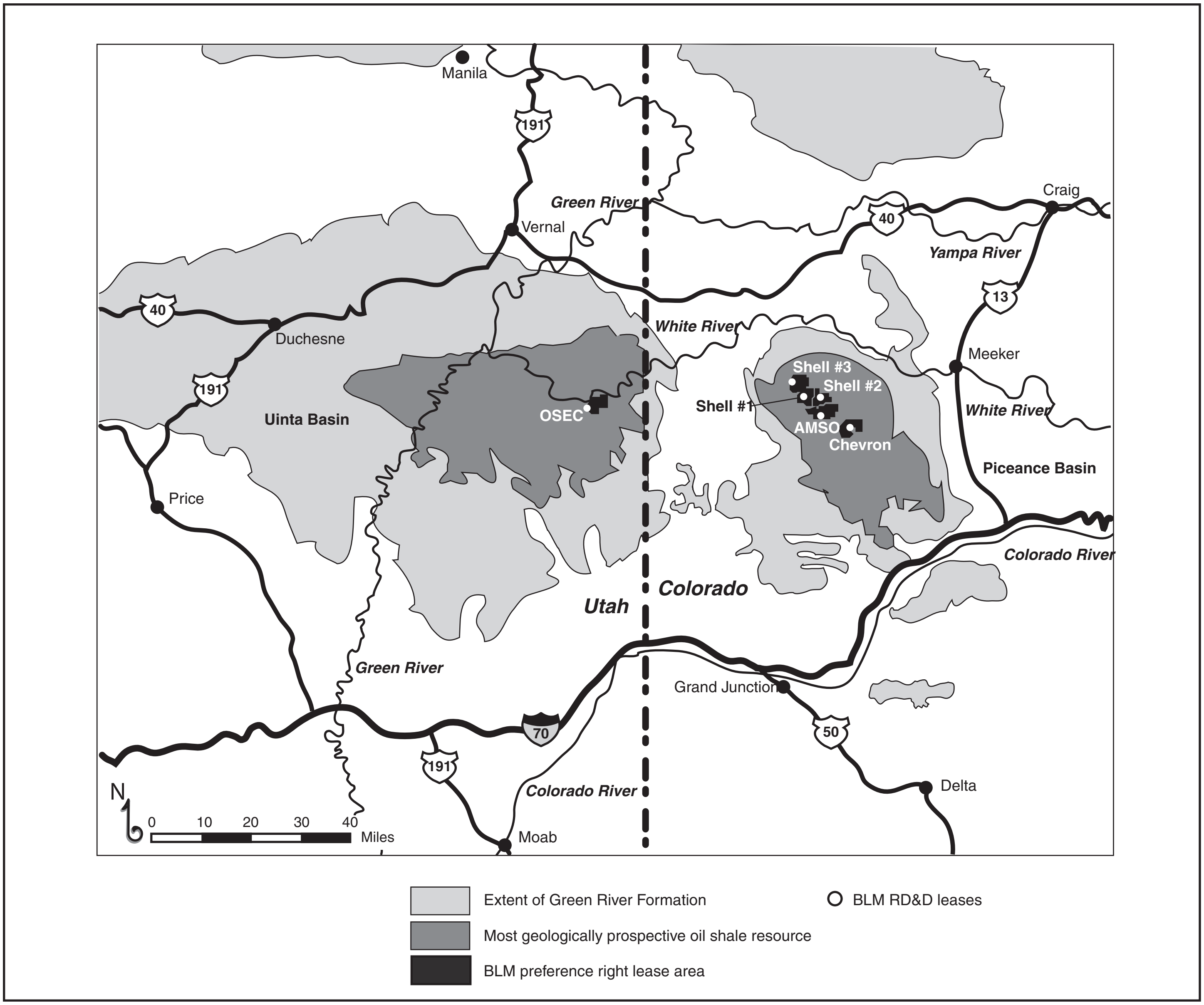
[22]An absolute water right is a water right that has been put to beneficial use.

reservoir for storage and eventual use. Shell withdrew its application citing the global economic downturn.[23]

At least one company has considered obtaining surface water from the even more distant Colorado River, about 30 to 50 miles to the south of the RD&D leases where oil shale companies already hold considerable water rights, but again, the costs of transporting and pumping water would be greater. Although water for initial oil shale development in Utah is also likely to come from the White River as indicated by OSEC's interest, water experts have cited the Green River as a potential water source. However, the longer distance and rugged terrain is likely to be challenging. Figure 7 shows the locations of the oil shale resource areas and their proximity to local surface water sources.

[23]Shell also experienced considerable formal opposition to its proposal from 25 groups, some of which was for environmental reasons.

Figure 7: Location of Rivers near Oil Shale Resources



Source: Adopted from BLM.

In addition to surface water, oil shale companies could use groundwater for operations should more desirable surface water sources be unavailable. However, companies would need to acquire the rights to this groundwater. Shallow groundwater in the Piceance and Uintah Basins occurs primarily within alluvial aquifers, which are aquifers composed of unconsolidated sand and gravel associated with nearby streams and rivers. The states of Utah and Colorado refer to these aquifers legally as tributary waters, or waters that are connected to surface waters and hence are considered to be part of the surface water source when appropriating water rights. Any withdrawal of tributary water is considered to be a withdrawal from the adjacent or nearby stream or river. Less is known about deep groundwater in the Piceance and Uintah Basins, but hydrologists consider it to be of lesser quality, with the water generally becoming increasingly saline with depth. State officials in Utah said that they consider this deeper groundwater to be tributary water, and state officials in Colorado said that they generally consider this deeper water also to be tributary water but will allow water rights applicants to prove otherwise. In the Piceance and Uintah Basins, groundwater is not heavily used, illustrating the reluctance of water users to tap this source. Nevertheless, Shell is considering the use of groundwater, and ExxonMobil is considering using water co-produced with natural gas from nearby but deeper formations in the Piceance Basin. Also, BLM notes that there is considerable groundwater in the regional Bird's Nest Aquifer in the area surrounding OSEC's RD&D lease in the Uintah Basin. In addition, representatives of oil shale companies said they plan to use water that is released from the organic components of oil shale during the retort process. Since this water is chemically bound within the solid organic components rather than being in a liquid phase, it is not generally viewed as being groundwater, but it is unclear as to how it would be regulated.

Oil Shale Development Will Likely Have to Compete with Increased Demands for Water for Other Needs and a Decreased Water Supply

Developing a sizable oil shale industry may take many years—perhaps 15 or 20 years by some industry and government estimates—and such an industry may have to contend with increased demands for water to meet other needs. Substantial population growth and its correlative demand for water are expected in the oil shale regions of Colorado and Utah. This region in Colorado is a fast-growing area. State officials expect that the population within the region surrounding the Yampa, White, and Green Rivers in Colorado will triple between 2005 and 2050. These officials expect that this added population and corresponding economic growth by 2030 will increase municipal and industrial demands for water, exclusive of oil shale development, by about 22,000 acre-feet per year, or a 76 percent increase from 2000. Similarly in Utah, state officials expect the population of the Uintah Basin to more than double its 1998 size by 2050 and that correlative municipal and industrial water demands will increase by 7,000 acre-feet per year, or an increase of about 30 percent since the mid-1990s. Municipal officials in two communities adjacent to proposed oil shale development in Colorado said that they were confident of meeting their future municipal and industrial demands from their existing senior water rights, and as such will probably not be affected by the water needs of a future oil shale industry. However, large withdrawals could impact agricultural interests and other downstream water users in both states, as oil shale companies may purchase existing irrigation and agricultural rights for their oil shale operations. State water officials in Colorado told us that some holders of senior agricultural rights have already sold their rights to oil shale companies.

Figure 8: White River near Meeker, Colorado

Source: GAO.

A future oil shale industry may also need to contend with a decreased physical supply of water regionwide due to climate change. A contractor to the state of Colorado ran five projections through a number of climate models and found that their average result suggested that by 2040, a warming climate may reduce the amount of water in the White River in Colorado by about 13 percent, or 42,000 acre-feet. However, there was much variability among the five results, ranging from a 40 percent decrease to a 16 percent increase in today's flow and demonstrating the uncertainty associated with climate predictions. Nevertheless, any decrease would mean that less water would be available downstream in

Utah. Because of a warmer climate, the contractor also found that water needed to irrigate crops could increase significantly in the White River Basin, but it is uncertain whether the holders of the water rights used to irrigate the crops would be able to secure this additional water. Simultaneously, the model shows that summer precipitation is expected to decrease, thus putting pressure on farmers to withdraw even more water from local waterways. In addition, the contractor predicted that more precipitation is likely to fall as rain rather than snow in the early winter and late spring. Because snow functions as a natural storage reservoir by releasing water into streams and aquifers as temperatures rise, less snow means that storage and runoff schedules will be altered and less water may be available at different times of the year. Although the model shows that the White River is expected to have reduced flows due to climate change, the same model shows that the Yampa is more likely to experience an increased flow because more precipitation is expected to fall in the mountains, which are its headwaters. Hence, oil shale companies may look to the Yampa for additional water if restrictions on the White are too great, regardless of increased costs to transport the water. While there is not a similar study on climate change impacts for Utah, it is likely that some of the impacts will be similar, considering the close proximity and similar climates in the Uintah and Piceance Basins.

Colorado's and Utah's obligations under interstate compacts could further reduce the amount of water available for development. The Colorado River Compact of 1922, which prescribes how the states through which the Colorado River and its tributaries flow share the river's water, is based on uncharacteristically high flows, as cited in a study contracted by the state of Colorado. Water regulators have since shown that the flow rates used to allocate water under the compact may be 21 percent higher than average historical flow rates, thereby overestimating the amount of water that may be available to share. As a result, the upstream states of Colorado and Utah may not have as much water to use as they had originally planned and may be forced to curtail water consumption so that they can deliver the amount of water that was agreed on in the compact to the downstream states of Arizona, Nevada, and California. Another possible limitation on withdrawals from the Colorado River system is the requirement to protect certain fish species under the Endangered Species Act. Federal officials stated that withdrawals from the Colorado River system, including its tributaries the White and Green Rivers, could be limited by the amount of flow that is necessary to sustain populations of threatened or endangered fishes. Although there are currently no federally mandated minimum flow requirements on the White River in either Utah or Colorado, the river is home to populations of the federally endangered

Colorado Pikeminnow, and the Upper Colorado Recovery Program is currently working on a biological opinion which may prescribe minimum flow requirements. In addition, the Green River in Utah is home to populations of four threatened or endangered fishes: the Colorado Pikeminnow, the Razorback Sucker, the Humpback Chub, and the Bonytail Chub. For this reason, agency officials are recommending minimum flow requirements on the Green, which could further restrict the upstream supply of available water.

The Size of an Oil Shale Industry May Be Limited by Water Availability

Although oil shale companies own rights to a large amount of water in the oil shale regions of Colorado and Utah, there are physical and legal limits on how much water they can ultimately withdraw from the region's waterways, and thus limits on the eventual size of the overall industry. Physical limits are set by the amount of water that is present in the river, and the legal limit is the sum of the water that can be legally withdrawn from the river as specified in the water rights held by downstream users. Examining physical limits can demonstrate how much water may be available to all water users. Subtracting the legal limit can demonstrate how much water is available for additional development, providing that current water rights and uses do not change in the future. The state of Colorado refers to this remaining amount of water in the river as that which is physically and legally available.

To put the water needs of a potential oil shale industry in Colorado into perspective, we compared the needs of oil shale industries of various sizes to what currently is physically available in the White River at Meeker, Colorado—a small town immediately east of high-quality oil shale deposits in the Piceance Basin. We also compared the water needs of an oil shale industry to what may be physically and legally available from the White River in 2030. Table 3 shows scenarios depicting the amounts of water that would be needed to develop an oil shale industry of various sizes that relies on mining and surface retorting, based on the studies we examined. Table 4 shows similar scenarios for an oil shale industry that uses in-situ extraction, based on the studies that we examined. The sizes are based on industry and expert opinion and are not meant to be predictions. Both tables assume water demands for peak oil shale production rates, but water use may not follow such a pattern. For example, water use for reclamation activities may not fully overlap with water use for extraction. Also, an industry composed of multiple operations is likely to have some operations at different stages of development. Furthermore, because of the natural variability of stream flows, both on an annual basis and from year-to-year, reservoirs would need to be built to provide storage, which could be used to release a consistent amount of water on a daily basis.

Table 3: Estimated Water Needs for Mining and Surface Retorting of Oil Shale by Industries of Various Sizes

Size of industry (barrels of oil per day)	Minimum water needs (acre-feet per year)[a]	Average water needs (acre-feet per year)[b]	Maximum water needs (acre-feet per year)[c]
25,000[d]	2,400	3,500	4,700
50,000[e]	4,700	7,100	9,400
75,000	7,100	10,600	14,100
100,000	9,400	14,100	18,800
150,000[f]	14,100	21,200	28,200

Source: GAO analysis of selected studies on water needs.

[a]This scenario assumes 2 barrels of water are needed to produce 1 barrel of shale oil. All figures are rounded to the nearest 100 acre-feet.

[b]This scenario assumes 3 barrels of water are needed to produce 1 barrel of shale oil.

[c]This scenario assumes 4 barrels of water are needed to produce 1 barrel of shale oil.

[d]URS, the contractor to the state of Colorado, used this level as the minimum size for a mining operation with a surface retort.

[e]Several literature sources and oil shale companies cite this level as a reasonable commercial operation.

[f]GAO estimated industry size based on three operations of 50,000 barrels per day each.

Table 4: Estimated Water Needs for In-Situ Retorting of Oil Shale by Industries of Various Sizes

Size of industry (barrels of oil per day)	Minimum water needs (acre-feet per year)[a]	Average water needs (acre-feet per year)[b]	Maximum water needs (acre-feet per year)[c]
500,000[d]	24,000	118,000	282,000
1,000,000	47,000	235,000	565,000
1,500,000	71,000	353,000	847,000
2,000,000	94,000	470,000	1,129,000
2,500,000[e]	118,000	588,000	1,411,000

Source: GAO analysis of selected studies on water needs.

[a]This scenario assumes 1 barrel of water is needed to produce 1 barrel of shale oil. All figures are rounded to the nearest 100 acre-feet.

[b]This scenario assumes 5 barrels of water are needed to produce 1 barrel of shale oil.

[c]This scenario assumes 12 barrels of water are needed to produce 1 barrel of shale oil.

[d]One oil shale company with whom we spoke estimated that an oil shale industry could grow to this level, based on analogy to oil sands being developed in Alberta, Canada.

[e]DOE uses this level as the high end for its size estimates of an oil shale industry.

Data maintained by the state of Colorado indicate the amount of water that is physically available in the Whiter River at Meeker, Colorado, averages about 472,000 acre-feet per year.[24] Table 3 suggests that this is much more water than is needed to support the water needs for all the sizes of an industry relying on mining and surface retorting that we considered. Table 4, however, shows that an industry that uses in-situ extraction could be limited just by the amount of water physically available in the White River at Meeker, Colorado. For example, based on an oil shale industry that uses about 12 barrels of water for each barrel of shale oil it produces, such an industry could not reach 1 million barrels per day if it relied solely on physically available water from the White River.

Comparing an oil shale industry's needs to what is physically and legally available considers the needs of current users and the anticipated needs of future users, rather than assuming all water in the river is available to an oil shale industry. The amount of water that is physically and legally available in the White River at Meeker is depicted in table 5. According to the state of Colorado's computer models, holders of water rights downstream use on average about 153,000 acre-feet per year, resulting in an average of about 319,000 acre-feet per year that is currently physically and legally available for development near Meeker. By 2030, however, the amount of water that is physically and legally available is expected to change because of increased demand and decreased supply. After taking into account an anticipated future decrease of 22,000 acre-feet per year of water due to a growing population, about 297,000 acre-feet per year may be available for future development if current water rights and uses do not change by 2030. However, there may be additional decreases in the amount of physically and legally available water in the White River due to climate change, demands under interstate agreements, and water requirements for threatened or endangered fishes, but we did not include these changes in table 5 because of the large uncertainty associated with estimates.

[24]Year-to-year flows on rivers can vary significantly with annual precipitation. However, officials with the state of Colorado said that they are comfortable using average annual flows.

Table 5: Estimated Water That Will Be Physically and Legally Available in the White River at Meeker, Colorado, in 2030

	Acre-feet per year
Average historic flow, or water that is physically available today	472,000
Average water use by holders of downstream water rights	-153,000
Average physically and legally available water today	319,000
Estimated increase in municipal and industrial use by 2030	-22,000
Estimated physically and legally available supply in 2030	297,000

Source: GAO analysis of state of Colorado data.

Comparing the scenarios in table 4 to the amount of water that is physically and legally available in table 5 shows the sizes that an in-situ oil shale industry may reach relying solely on obtaining new rights on the White River. The scenarios in table 4 suggest that if an in-situ oil shale industry develops to where it produces 500,000 barrels of oil per day—an amount that some experts believe is reasonable—an industry of this size could possibly develop in Colorado even if it uses about 12 barrels of water per barrel of shale oil it produces. Similarly, the scenarios suggest that an in-situ industry that uses about 5 barrels of water per barrel of oil produced—almost the average from the studies in which power comes from combined cycle natural gas plants—could grow to 1 million barrels of oil per day using only the water that appears to be physically and legally available in 2030 in the White River. Table 4 also shows that an industry that uses just 1 barrel of water per barrel of shale oil produced could grow to over 2.5 million barrels of oil per day.

Regardless of these comparisons, more water or less water could be available in the future because it is unlikely that water rights will remain unchanged until 2030. For example, officials with the state of Colorado reported that conditional water rights—those rights held but not used—are not accounted for in the 297,000 acre-feet per year of water that is physically and legally available because holders of these rights are not currently withdrawing water. These officials also said that the amount of conditional water rights greatly exceeds the flow in the White River near Meeker, and if any of these conditional rights are converted to absolute rights and additional water is then withdrawn downstream, even less water will be available for future development. However, officials with the state of Colorado said that some of these conditional water rights are already owned by oil shale companies, making it unnecessary for some companies to apply for new water rights. In addition, they said, some of the absolute water rights that are accounted for in the estimated 153,000 acre-feet per year of water currently being withdrawn are already owned by oil shale companies. These are agricultural rights that were purchased by oil shale interests who leased them back to the original owners to continue using them for agricultural purposes. Should water not be available from the White River, companies would need to look to groundwater or surface water outside of the immediate area.

There are less data available to predict future water supplies in Utah's oil shale resource area. The state of Utah did not provide us summary information on existing water rights held by oil shale companies. According to the state of Colorado, the average annual physical flow of the White River near the Colorado-Utah border is about 510,000 acre-feet per year. Any amount withdrawn from the White River in Colorado would be that much less water that would be available for development downstream in Utah. The state of Utah estimates that the total water supply of the Uintah Basin, less downstream obligations under interstate compacts, is 688,000 acre-feet per year.[25] Much of the surface water contained in this amount is currently being withdrawn, and water rights have already been filed for much of the remaining available surface water.

Federal Research Efforts on the Impacts of Oil Shale Development on Water Resources Do Not Provide Sufficient Data for Future Monitoring

Although the federal government sponsors research on the nexus between oil shale development and water, a lack of comprehensive data on the condition of surface water and groundwater and their interaction limit efforts to monitor the future impacts of oil shale development. Currently DOE funds some research related to oil shale and water resources, including research on water rights, water needs, and the impacts of oil shale development on water quality. Interior also performs limited research on characterizing surface and groundwater resources in oil shale areas and is planning some limited monitoring of water resources. However, there is general agreement among those we contacted—including state personnel who regulate water resources, federal agency officials responsible for studying water, water researchers, and water experts—that this ongoing research is insufficient to monitor and then subsequently mitigate the potential impacts of oil shale development on water resources. In addition, DOE and Interior officials noted that they

[25]This estimate represents all of the groundwater and surface water that can be used in the Uintah Basin, but does not take into account any current withdrawals from streams and rivers.

seldom formally share the information on their water-related research with each other.

DOE Funds Research on Water Rights, Water Needs, and the Impacts of Oil Shale Development on Water Resources

DOE has sponsored most of the oil shale research that involves water-related issues. This research consists of projects managed by the National Energy Technology Laboratory (NETL), the Office of Naval Petroleum and Oil Shale Reserves, and the Idaho National Laboratory. As shown in table 6, DOE has sponsored 13 of 15 projects initiated by the federal government since June 2006. DOE's projects account for almost 90 percent of the estimated $5 million[26] that is to be spent by the federal government on water-related oil shale research through 2013.[27] Appendix II contains a list and description of these projects.

Table 6: Federal Funding for Oil Shale Research Initiated Since June 2006

Sponsoring office	Number of oil shale research projects	Federal share of funding for all oil shale research projects	Number of water-related projects	Federal share of funding for water-related projects
DOE National Energy Technology Lab	13	$15,424,702	7	$2,433,097
DOE Office of Naval Petroleum and Oil Shale Reserves	2	2,468,000	2	920,000
DOE Idaho National Lab	5	3,012,500[a]	4	965,000[a]
BLM	3	535,000	2	520,000
USGS	1	1,100,000	0	0
Total	**24**	**$22,540,202**	**15**	**$4,838,097**

Source: GAO analysis of DOE and Interior data.

[a]Numbers may contain some nonfederal funds.

NETL sponsors the majority of the water-related oil shale research currently funded by DOE. Through workshops, NETL gathers information

[26]Many research projects involve water and nonwater issues. For projects that include nonwater-related segments, we obtained estimates of the amount of the project spent on water related tasks.

[27]Most projects run for 2 to 3 years. Some have been completed, while others are still ongoing.

to prioritize research. For example, in October 2007, NETL sponsored the Oil Shale Environmental Issues and Needs Workshop that was attended by a cross-section of stakeholders, including officials from BLM and state water regulatory agencies, as well as representatives from the oil shale industry. One of the top priorities that emerged from the workshop was to develop an integrated regional baseline for surface water and groundwater quality and quantity. As we have previously reported, after the identification of research priorities, NETL solicits proposals and engages in a project selection process.[28] We identified seven projects involving oil shale and water that NETL awarded since June 2006. The University of Utah, Colorado School of Mines, the Utah Geological Survey, and the Idaho National Laboratory (INL) are performing the work on these projects. These projects cover topics such as water rights, water needs for oil shale development, impacts of retorting on water quality, and some limited groundwater modeling. One project conducted by the Colorado School of Mines involves developing a geographic information system for storing, managing, analyzing, visualizing, and disseminating oil shale data from the Piceance Basin. Although this project will provide some baseline data on surface water and groundwater and involves some theoretical groundwater modeling, the project's researchers told us that these data will neither be comprehensive nor complete. In addition, NETL-sponsored research conducted at the University of Utah involves examining the effects of oil shale processing on water quality, new approaches to treat water produced from oil shale operations, and water that can be recycled and reused in operations.

INL is sponsoring and performing research on four water-related oil shale projects while conducting research for NETL and the Office of Naval Petroleum and Oil Shale Reserves. The four projects that INL is sponsoring were self-initiated and funded internally through DOE's Laboratory Directed Research and Development program. Under this program, the national laboratories have the discretion to self-initiate independent research and development, but it must focus on the advanced study of scientific or technical problems, experiments directed toward proving a scientific principle, or the early analysis of experimental facilities or devices. Generally, the researchers propose projects that are judged by peer panels and managers for their scientific merits. An INL official told us

[28] A general description of the process DOE uses to select research proposals can be found in GAO, *Research and Development: DOE Could Enhance the Project Selection Process for Government Oil and Natural Gas Research*, GAO-09-186 (Washington, D.C.: Dec. 29, 2008).

they selected oil shale and water projects because unconventional fossil fuels, which include oil shale, are a priority in which they have significant expertise.

According to DOE officials, one of the projects managed by the Office of Naval Petroleum and Oil Shale Reserves is directed at research on the environmental impacts of unconventional fuels. The Los Alamos National Laboratory is conducting the work for DOE, which involves examining water and carbon-related issues arising from the development of oil shale and other unconventional fossil fuels in the western United States. Key water aspects of the study include the use of an integrated modeling process on a regional basis to assess the amounts and availability of water needed to produce unconventional fuels, water storage and withdrawal requirements, possible impacts of climate change on water availability, and water treatment and recycling options. Although a key aspect of the study is to assess water availability, researchers on the project told us that little effort will be directed at assessing groundwater, and the information developed will not result in a comprehensive understanding of the baseline conditions for water quality and quantity.

Interior Funds Limited Oil Shale-Related Research on Groundwater and Surface Water Resources and Monitoring

Within Interior, BLM is sponsoring two oil shale projects related to water resources with federal funding totaling about $500,000.[29] The USGS is conducting the research for both projects. For one of the projects, which is funded jointly by BLM and a number of Colorado cities and counties plus various oil shale companies, the research involves the development of a common repository for water data collected from the Piceance Basin. More specifically, the USGS has developed a Web-based repository of water quality and quantity data obtained by identifying 80 public and private databases and by analyzing and standardizing data from about half of them. According to USGS officials, many data elements are missing, and the current repository is not comprehensive. The second project, which is entirely funded by BLM, will monitor groundwater quality and quantity within the Piceance Basin in 5 existing wells and 10 more to be determined at a future date. Although USGS scientists said that this is a good start to understanding groundwater resources, it will not be enough to provide a regional understanding of groundwater resources.

[29]In January 2010, BOR initiated the *Colorado River Basin Water Supply and Demand Study* at a federal cost of $1 million. Although not directed at oil shale, this 2-year study's objective is to define and resolve current and future imbalances between the supply and demand for water within the Colorado River Basin over the next 50 years.

Gaps in Groundwater and Surface Water Data Have Been Identified by Federal and State Officials

Federal law and regulations require the monitoring of major federal actions, such as oil shale development. Regulations developed under the National Environmental Policy Act (NEPA)[30] for preparing an environmental impact statement (EIS), such as the EIS that will be needed to determine the impacts of future oil shale development, require the preparing agency to adopt a monitoring and enforcement program if measures are necessary to mitigate anticipated environmental impacts.[31] Furthermore, the *NEPA Task Force Report to the Council on Environmental Quality* noted that monitoring must occur for long enough to determine if the predicted mitigation effects are achieved.[32] The council noted that monitoring and consideration of potential adaptive measures to allow for midcourse corrections, without requiring new or supplemental NEPA review, will assist in accounting for unanticipated changes in environmental conditions, inaccurate predictions, or subsequent information that might affect the original environmental conditions. In September 2007, the Task Force on Strategic Unconventional Fuels—an 11-member group that included the Secretaries of DOE and Interior and the Governors of Colorado and Utah—issued a report with recommendations on promoting the development of fuels from domestic unconventional fuel resources as mandated by the Energy Policy Act of 2005. This report included recommendations and strategies for developing baseline conditions for water resources and monitoring the impacts from oil shale development. It recommended that a monitoring plan be developed and implemented to fill data gaps at large scales and over long periods of time and to also develop, model, test, and evaluate short- and long-term monitoring strategies. The report noted that systems to monitor water quality would be evaluated; additional needs would be identified; and relevant research, development, and demonstration needs would be recommended.

Also in September 2007, the USGS prepared for BLM a report to improve the efficiency and effectiveness of BLM's monitoring efforts.[33] The report

[30]NEPA requires all federal agencies to consider the environmental impacts of their actions and decisions. It requires an analysis and a detailed statement of the environmental impact of any proposed major federal action which significantly affects the environment.

[31]40 C.F.R. §1505.2 (c).

[32]*The NEPA Task Force Report to the Council on Environmental Quality: Modernizing NEPA Implementation* (September 2003).

[33]USGS, Colorado Water Science Center, *Regional Framework for Water-Resources Monitoring Related to Energy Exploration and Development* (Sept. 30, 2007).

noted that regional water-resources monitoring should identify gaps in data, define baseline conditions, develop regional conceptual models, identify impacts, assess the linkage of impacts to energy development, and understand how impacts propagate. The report also noted that in the Piceance Basin, there is no local, state-level, or national comprehensive database for surface water and groundwater data. Furthermore, for purposes of developing a robust and cost-effective monitoring plan, the report stated that a compilation and analysis of available data are necessary. One of the report's authors told us that the two BLM oil shale projects that the USGS is performing are the initial steps in implementing such a regional framework for water resource monitoring. However, the author said that much more work is needed because so much water data are missing. He noted the current data repository is not comprehensive and much more data would be needed to determine whether oil shale development will create adverse effects on water resources.

Nearly all the federal agency officials, state water regulators, oil shale researchers, and water experts with whom we spoke said that more data are needed to understand the baseline condition of groundwater and surface water, so that the potential impacts of oil shale development can be monitored (see appendix I for a list of the agencies we contacted). Several officials and experts to whom we spoke stressed the need to model the movement of groundwater and its interaction with surface water to understand the possible transport of contaminants from oil shale development. They suggested that additional research would help to overcome these shortcomings. Specifically, they identified the following issues:

- *Insufficient data for establishing comprehensive baseline conditions for surface water and groundwater quality and quantity.* Of the 18 officials and experts we contacted, 17 noted that there are insufficient data to understand the current baseline conditions of water resources in the Piceance and Uintah Basins. Such baseline conditions include the existing quantity and quality of both groundwater and surface water. Hydrologists among those we interviewed explained that more data are needed on the chemistry of surface water and groundwater, properties of aquifers, age of groundwater, flow rates and patterns of groundwater, and groundwater levels in wells. Although some current research projects have and are collecting some water data, officials from the USGS, Los Alamos National Laboratory, and the universities doing this research agreed their data are not comprehensive enough to support future monitoring efforts. Furthermore, Colorado state officials told us that even though much water data were generated over time, including during the last oil shale boom, little of these data have been assimilated, gaps exist, and data need to be updated in order to support future monitoring.

- *Insufficient research on groundwater movement and its interaction with surface water for modeling possible transport of contaminants.* Sixteen of 18 officials and experts to whom we spoke noted that additional research is needed to develop a better understanding of the interactions between groundwater and surface water and of groundwater movement. Officials from NETL explained that this is necessary in order to monitor the rate and pattern of flow of possible contaminants resulting from the in-situ retorting of oil shale. They noted that none of the groundwater research currently under way is comprehensive enough to build the necessary models to understand the interaction and movement. NETL officials noted more subsurface imaging and visualization are needed to build geologic and hydrologic models and to study how quickly groundwater migrates. These tools will aid in monitoring and providing data that does not currently exist.

Interior and DOE Officials Generally Have Not Shared Information on Oil Shale Research

Interior and DOE officials generally have not shared current research on water and oil shale issues. USGS officials who conduct water-related research at Interior and DOE officials at NETL, which sponsors the majority of the water and oil shale research at DOE, stated they have not talked with each other about such research in almost 3 years. USGS staff noted that although DOE is currently sponsoring most of the water-related research, USGS researchers were unaware of most of these projects. In addition, staff at Los Alamos National Laboratory who are conducting some water-related research for DOE noted that various researchers are not always aware of studies conducted by others and stated that there needs to be a better mechanism for sharing this research. Based on our review, we found there does not appear to be any formal mechanism for sharing water-related research activities and results among Interior, DOE, and state regulatory agencies in Colorado and Utah. The last general meeting to discuss oil shale research among these agencies was in October 2007, although there have been opportunities to informally share research at the annual Oil Shale Symposium, the last one of which was conducted at the Colorado School of Mines in October 2010. Of the various officials with the federal and state agencies, representatives from research organizations, and water experts we contacted, 15 of 18 noted that federal and state agencies could benefit from collaboration with each other on water-related research involving oil shale. Representatives from NETL, who are sponsoring much of the current research, stated that collaboration should occur at least every 6 months.

We and others have reported that collaboration among government agencies can produce more public value than one agency acting alone.[34] Specifically concerning water resources, we previously reported that coordination is needed to enable monitoring programs to make better use of available resources in light of organizations often being unaware of data collected by other groups.[35] Similarly in 2004, the National Research Council concluded that coordination of water research is needed to make deliberative judgments about the allocation of funds, to minimize duplication, to present to Congress and the public a coherent strategy for federal investment, and to facilitate large-scale multiagency research efforts.[36] In 2007, the Subcommittee on Water Availability and Quality within the Office of Science and Technology Policy, an office that advises the President and leads interagency efforts related to science and technology stated, "Given the importance of sound water management to the Nation's well-being it is appropriate for the Federal government to play a significant role in providing information to all on the status of water resources and to provide the needed research and technology that can be used by all to make informed water management decisions."[37] In addition, H.R. 1145—the National Water Research and Development Initiative Act of 2009—which has passed the House of Representatives and is currently in a Senate committee, would establish a federal interagency committee to coordinate all federal water research, which totals about $700 million annually. This bill focuses on improving coordination among agency research agendas, increasing the transparency of water research budgeting, and reporting on progress toward research outcomes.

Conclusions

The unproven nature of oil shale technologies and choices in how to generate the power necessary to develop this resource cast a shadow of uncertainty over how much water is needed to sustain a commercially viable oil shale industry. Additional uncertainty about the size of such an

[34]GAO, *Results-Oriented Government: Practices that Can Help Enhance and Sustain Collaboration among Federal Agencies*, GAO-06-15 (Washington, D.C.: Oct 21, 2005).

[35]GAO, *Watershed Management: Better Coordination of Data Collection Efforts Needed to Support Key Decisions*, GAO-04-382 (Washington, D.C.: June 7, 2004).

[36]National Research Council of the National Academies, *Confronting the Nation's Water Problems: The Role of Research* (2004).

[37]Subcommittee on Water Availability and Quality, National Science and Technology Council, *A Strategy for Federal Science and Technology to Support Water Availability and Quality in the United States* (Washington, D.C., September 2007).

industry clouds the degree to which surface and groundwater resources could be impacted in the future. Furthermore, these uncertainties are compounded by a lack of knowledge of the current baseline conditions of groundwater and surface water, including their chemistry and interaction, properties of aquifers, and the age and rate of movement of groundwater, in the arid Piceance and Uintah Basins of Colorado and Utah, where water is considered one of the most precious resources. All of these uncertainties pose difficulties for oil shale developers, federal land managers, state water regulators, and current water users in their efforts to protect water resources.

Attempts to commercially develop oil shale in the United States have spanned nearly a century. During this time, the industry has focused primarily on overcoming technological challenges and trying to develop a commercially viable operation. More recently, the federal government has begun to focus on studying the potential impacts of oil shale development on surface water and groundwater resources. However, these efforts are in their infancy when compared to the length of time that the industry has spent on attempting to overcome technological challenges. These nascent efforts do not adequately define current baseline conditions for water resources in the Piceance and Uintah Basins, nor have they begun to model the important interaction of groundwater and surface water in the region. Thus they currently fall short of preparing federal and state governments for monitoring the impacts of any future oil shale development. In addition, there is a lack of coordination among federal agencies on water-related research and a lack of communicating results among themselves and to the state regulatory agencies. Without such coordination and communication, federal and state agencies cannot begin to develop an understanding of the potential impacts of oil shale development on water resources and monitor progress toward shared water goals. By taking steps now, the federal government, working in concert with the states of Colorado and Utah, can position itself to help monitor western water resources should a viable oil shale industry develop in the future.

Recommendations for Executive Action

To prepare for possible impacts from the future development of oil shale, we are making three recommendations to the Secretary of the Interior. Specifically, the Secretary should direct the appropriate managers in the Bureau of Land Management and the U.S. Geological Survey to

1. establish comprehensive baseline conditions for groundwater and surface water quality, including their chemistry, and quantity in the

Piceance and Uintah Basins to aid in the future monitoring of impacts from oil shale development in the Green River Formation;

2. model regional groundwater movement and the interaction between groundwater and surface water, in light of aquifer properties and the age of groundwater, so as to help in understanding the transport of possible contaminants derived from the development of oil shale; and

3. coordinate with the Department of Energy and state agencies with regulatory authority over water resources in implementing these recommendations, and to provide a mechanism for water-related research collaboration and sharing of results.

Agency Comments

We provided a copy of our draft report to Interior and DOE for their review and comment. Interior provided written comments and generally concurred with our findings and recommendations. Interior highlighted several actions it has under way to begin to implement our recommendations. Specifically, Interior stated that with regard to our first recommendation to establish comprehensive baseline conditions for surface water and groundwater in the Piceance and Uintah Basins, implementation of this recommendation includes ongoing USGS efforts to analyze existing water quality data in the Piceance Basin and ongoing USGS efforts to monitor surface water quality and quantity in both basins. Interior stated that it plans to conduct more comprehensive assessments in the future. With regard to our second recommendation to model regional groundwater movement and the interaction between groundwater and surface water, Interior said BLM and USGS are working on identifying shared needs for modeling. Interior underscored the importance of modeling prior to the approval of large-scale oil shale development and cites the importance of the industry's testing of various technologies on federal RD&D leases to determine if production can occur in commercial quantities and to develop an accurate determination of potential water uses for each technology. In support of our third recommendation to coordinate with DOE and state agencies with regulatory authority over water resources, Interior stated that BLM and USGS are working to improve such coordination and noted current efforts with state and local authorities. Interior's comments are reproduced in appendix III.

DOE also provided written comments, but did not specifically address our recommendations. Nonetheless, DOE indicated that it recognizes the need for a more comprehensive and integrated cross-industry/government approach for addressing impacts from oil shale development. However, DOE raised four areas where it suggested additional information be added to the report or took issue with our findings. First, DOE suggested that we include in our report appropriate aspects of a strategic plan drafted by an ad hoc group of industry, national laboratory, university, and government representatives organized by the DOE Office of Naval Petroleum and Oil Shale Reserves. We believe aspects of this strategic plan are already incorporated into our report. For example, the strategic plan of this ad hoc group calls for implementing recommendations of the Task Force on Strategic Unconventional Fuels, which was convened by the Secretary of Energy in response to a directive within the Energy Policy Act of 2005. The Task Force on Strategic and Unconventional fuels recommended developing baseline conditions for water resources and monitoring the impacts from oil shale development, which is consistent with our first recommendation. The ad hoc group's report recognized the need to share information and collaborate with state and other federal agencies, which is consistent with our third recommendation. As such, we made no changes to this report in response to this comment.

Second, DOE stated that we overestimated the amount of water needed for in-situ oil shale development and production. We disagree with DOE's statement because the estimates presented in our report respond to our objective, which was to describe what is known about the amount of water that may be needed for commercial oil shale development, and they are based on existing publicly available data. We reported the entire range of reputable studies without bias to illustrate the wide range of uncertainty in water needed to commercially develop oil shale, given the current experimental nature of the process. We reported only publicly available estimates based on original research that were substantiated with a reasonable degree of documentation so that we could verify that the estimates covered the entire life cycle of oil shale development and that these estimates did not pertain solely to field demonstration projects, but were instead scalable to commercial operations. We reviewed and considered estimates from all of the companies that DOE identified in its letter. The range of water needed for commercial in-situ development of oil shale that we report ranges from 1 to 12 barrels of water per barrel of oil. These lower and upper bounds represent the sum of the most optimistic and most pessimistic estimates of water needed for all five groups of activities that we identified as comprising the life cycle of in-situ oil shale development. However, the lower estimate is based largely on estimates by ExxonMobil and incorporates the use of produced water, water treatment, and recycling, contrary to DOE's statement that we dismissed the significance of these activities. The upper range is influenced heavily by the assumption that electricity used in retorting will come from coal-fired plants and that a maximum amount of water will be used for rinsing the retorted zones, based on modeling done at the Center for Oil Shale Technology and Research.[38] The studies supporting these estimates were presented at the 29th Annual Oil Shale Symposium at the Colorado School of Mines. Such a range overcomes the illusion of precision that is conveyed by a single point estimate, such as the manner in which DOE cites the 1.59 barrels of water from the AMEC study, or the bias associated with reporting a narrow range based on the assumption that certain technologies will prevail before they are proven to be commercially viable for oil shale development. Consequently, we made no changes to the report in response to this comment.

Third, DOE stated that using the amount of water in the White River at Meeker, Colorado, to illustrate the availability of water for commercial oil shale development understates water availability. We disagree with DOE's characterization of our illustration. The illustration we use in the report is not meant to imply that an entire three-state industry would be limited by water availability at Meeker. Rather, the illustration explores the limitations of an in-situ oil shale industry only in the Piceance Basin. More than enough water appears available for a reasonably sized industry that depends on mining and surface retorting in the Piceance basin. Our illustration also suggests that there may be more than enough water to supply a 2.5 million barrel-per-day in-situ industry at minimum water needs, even considering the needs of current water users and the anticipated needs of future water users. In addition, the illustration suggests that there may be enough water to supply an in-situ industry in the Piceance Basin of between 1 and 2 million barrels per day at average water needs, depending upon whether all the water in the White River at Meeker is used or only water that is expected to be physically and legally available in the future. However, the illustration does point out limitations. It suggests that at maximum water needs, an in-situ industry in the Piceance Basin may not reach 1 million barrels per day if it relied solely on water in the White River at Meeker. Other sources of water may be needed, and our report notes that these other sources could include water in the Yampa or Colorado Rivers, as well as groundwater. Use of produced water and recycling could also reduce water needs as noted in the draft report. Consequently, we made no changes to the report in response to this comment.

[38]This research was funded by ExxonMobil, Shell, and Total Exploration and Production.

Fourth, DOE stated that the report gives the impression that all oil shale technologies are speculative and proving them to be commercially viable will be difficult, requiring a long period of time with uncertain outcomes. We disagree with this characterization of our report. Our report clearly states that there is uncertainty regarding the commercial viability of in-situ technologies. Based on our discussions with companies and review of available studies, Shell is the only active oil shale company to have successfully produced shale oil from a true in-situ process. Considering the uncertainty associated with impacts on groundwater resources and reclamation of the retorted zone, commercialization of an in-situ process is likely to be a number of years away. To this end, Shell has leased federal lands from BLM to test its technologies, and more will be known once this testing is completed. With regard to mining oil shale and retorting it at the surface, we agree that it is a relatively mature process. Nonetheless, competition from conventional crude oil has inhibited commercial oil shale development in the United States for almost 100 years. Should some of the companies that DOE mentions in its letter prove to be able to produce oil shale profitably and in an environmentally sensitive manner, they will be among the first to overcome such long-standing challenges. We are neither dismissing these companies, as DOE suggests, nor touting their progress. In addition, it was beyond the scope of our report to portray the timing of commercial oil shale production or describe a more exhaustive history of oil shale research, as DOE had recommended, because much research currently is privately funded and proprietary. Therefore, we made no changes to the report in response to this comment. DOE's comments are reproduced in appendix IV.

As agreed with your office, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, Secretaries of the Interior and Energy, Directors of the Bureau of Land Management and U.S. Geological Survey, and other interested parties. In addition, the report will be available at no charge on GAO's Web site at http://www.gao.gov.

If you or your staff have any questions about this report, please contact one of us at (202) 512-3841 or gaffiganm@gao.gov or mittala@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. Key contributors to this report are listed in appendix V.

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and Environment

Appendix I: Scope and Methodology

To determine what is known about the potential impacts to groundwater and surface water from commercial oil shale development, we reviewed the *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 (PEIS)* prepared by the Bureau of Land Management in September 2008. We also reviewed environmental assessments prepared on Shell Oil's plans for in-situ development of its research, demonstration, and development (RD&D) tracts in Colorado and on the Oil Shale Exploration Company's (OSEC) plan to mine oil shale on its RD&D tract in Utah because these two companies have made the most progress toward developing in-situ and mining technologies, respectively. In addition, we reviewed the Office of Technology Assessment's (OTA) 1980 report, *An Assessment of Oil Shale Technologies; the Rand Corporation's 2005 report, Oil Shale Development in the United States; and the Argonne National Laboratory's 2005 report, Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations.* Because the PEIS was the most comprehensive of these documents, we summarized impacts to groundwater and surface water quantity and quality described within this document and noted that these impacts were entirely qualitative in nature and that the magnitude of impacts was indeterminate because the in-situ technologies have yet to be developed. To confirm these observations and the completeness of impacts within the PEIS, we contacted the Environmental Protection Agency, the Colorado Division of Water Resources, the Colorado Water Conservation Board, the Division of Water Quality within the Colorado Department of Public Health and Environment, the Utah Division of Water Resources, the Utah Division of Water Quality, and the Utah Division of Water Rights—all of which have regulatory authority over some aspect of water resources. To ensure that we identified the range of views on the potential impacts of oil shale development on groundwater and surface water, we also contacted the U.S. Geological Survey (USGS), the Colorado Geological Survey, the Utah Geological Survey, industry representatives, water experts, and numerous environmental groups for their views on the impacts of oil shale on water resources. To assess the impacts of oil shale development on aquatic resources, we reviewed the PEIS and contacted the Colorado Division of Wildlife and the Utah Division of Wildlife Resources.

To determine what is known about the amount of water that may be needed for commercial oil shale development, we searched the Internet and relevant databases of periodicals using the words "oil shale" together with "water use." We also searched Web sites maintained by the Bureau of Land Management (BLM), USGS, and the Department of Energy (DOE) for information on oil shale and water use and interviewed officials at these agencies to determine if there were additional studies that we had not identified. We also checked references cited within the studies for other studies. We limited the studies to those published in 1980 or after because experts with whom we consulted either considered the studies published before then to be adequately summarized in OTA's 1980 report or to be too old to be relevant. We included certain data within the OTA report because some of the surface retort technologies are similar to technologies being tested today. We did not consider verbal estimates of water needs unless companies could provide more detailed information. The 17 studies that we identified appear in table 7.

Table 7: Studies on Water Use for Oil Shale Development Initially Identified by GAO

Bartis, et al. *Oil Shale Development in the United States: Prospects and Policy Issues*. Rand Corporation, 2005.
Boak, Jeremy and Earl Mattson. *Water Use for In-Situ Production of Shale Oil from the Green River Formation*. Presented at the 29th Oil Shale Symposium, Colorado School of Mines, October 20, 2009.
Bureau of Land Management. *Oil Shale Research, Development, and Demonstration Project*. Environmental Assessment CO-110-2006-117-EA. Prepared to analyze a proposal by Shell Frontier Oil and Gas, Inc., 2006.
Bureau of Land Management. *Oil Shale Research, Development and Demonstration Project*, White River Mine, Uintah County, Utah. Environmental Assessment UT-080-06-280. Prepared to analyze a proposal by the Oil Shale Exploration Company, April 2007.
Bureau of Land Management. *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 (PEIS).* September 2008.
Dudley-Murphy, Beth, et al. *Meeting Data Needs to Perform a Water Impact Assessment for Oil Shale Development in the Uinta and Piceance Basins, Appendix D in Utah Heavy Oil Program: Final Scientific/Technical Report.* Institute for Clean and Secure Energy, October 2009.
Harding, Benjamin. AMEC Earth and Environmental. *Energy Development Water Needs Assessment and Water Supply Alternatives Analysis.* Presented at the Promise and Perils of Oil Shale Symposium sponsored by the Natural Resources Law Center at the University of Colorado at Boulder, February 5, 2010.
Mangmeechai, Aweewan. *Life Cycle Greenhouse Gas Emissions, Consumptive Water Use and Levelized Costs of Unconventional Oil in North America.* Ph.D. dissertation, Carnegie Mellon University, August 2009.
Mangmeechai, Aweewan et al. *Life Cycle Consumptive Water Use of U.S. Oil Shale.* Presented at the International Society for Industrial Ecology, Boston, Massachusetts, September 29-October 2, 2009.
National Oil Shale Association. "NOSA Evaluates Oil Shale Water Usage." *Oil Shale Update,* vol. II, issue I (September 2009).
Office of Technology Assessment. *An Assessment of Oil Shale Technologies.* June 1980.
Shell Frontier Oil and Gas, Inc. *Plan of Operations, Oil Shale Test Project.* February 15, 2006.
Thomas, Michele Mosio, et al. ExxonMobil Upstream Research. *Responsible Development of Oil Shale.* Presented at the 29th Oil Shale Symposium, Colorado School of Mines, October 2009.
URS Corporation. *Energy Development Water Needs Assessment (Phase I Report).* Glenwood Springs, Colorado, September 2008.
Veil, J. A. and M.G. Puder. *Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations, Argonne National Lab.* October 2006.
Western Resource Advocates. *Water on the Rocks: Oil Shale Water Rights in Colorado.* Boulder, Colorado, 2009.
Wilson, C, et al. Los Alamos National Laboratory. *Assessment of Climate Variability on Water Resource Availability for Oil Shale Development.* Presented at the First Western Forum on Energy and Water Sustainability, School of Environmental Science and Management, University of California, Santa Barbara, March 22-23, 2007.

Source: GAO.

Note: While this table includes all the studies we initially identified, we describe further in this section of the report how we identified data within these studies that sufficiently met our quality criteria to be included in the range of water estimates.

For further analysis, we divided the studies into two major groups—in-situ extraction and mining with a surface retort. We dismissed a combination of mining and in-situ extraction because most of these technologies are more than 30 years old and generally considered to be infeasible today. The single company that is pursuing such a combination of technologies today—Red Leaf Resources— has not published detailed data on water needs. After reviewing these studies, we found that most of the studies did not examine water needs for the entire life cycle of oil shale development. As such, we identified logical groups of activities based on descriptions within the studies. We identified the following five groups of activities: (1) extraction and retorting, (2) generating power, (3) upgrading shale oil, (4) reclamation, and (5) population growth associated with oil shale development. We did not include refining because we believe it is unlikely that oil shale production will reach levels in the near- or midterm to justify building a new refinery.

To characterize the water needs for the entire life cycle of oil shale development, we identified within each study the water needs for each of the five groups of activities. Except for OTA's 1980 report, which is now 30 years old, we contacted the authors of each study and discussed the estimates with them. If estimates within these studies were given for more than one group of activities, we asked them to break down this estimate into the individual groups when possible. We only considered further analyzing water needs for groups of activities that were based on original research so as not to count these estimates multiple times. For example, original research on water needs for extraction and retorting may have analyzed mine plans, estimated water needs for drilling wells, estimated water needs for dust control, and discussed recycling of produced water. Original research on water needs for population growth may have discussed the number of workers immigrating to a region, their family size, per capita water consumption, and the nature of housing required by workers. On the other hand, estimates of water needs that were not based on original research generally reported water needs for multiple groups of activities in barrels of water per barrel of oil produced and cited someone else's work as the source for this number. We excluded several estimates that seemed unlikely. For example, we eliminated a water estimate for power generation that included building a nuclear power plant and water estimates for population growth where it was assumed that people would decrease their water consumption by over 50 percent. We also excluded technologies developed prior to 1980 that are dissimilar to technologies being considered by oil shale companies today. We checked mathematical calculations and reviewed power requirements and the reasonableness of associated water needs. For power estimates that did not include associated water needs, we converted power needs into water needs using 480 gallons per megawatt hour of electricity produced by coal-fired, wet recirculating thermoelectric plants and 180 gallons per megawatt hour of electricity produced by gas-powered, combined cycle, wet recirculating thermoelectric plants. Air-cooled systems consume almost no water for cooling. Where appropriate, we also estimated shale oil recoveries based the company's estimated oil shale resources and estimated water needs for rinsing retorted zones based on anticipated changes to the reservoir.

We converted water requirements to barrels of water needed per barrel of oil produced. For those studies with water needs that met our criteria, we tabulated water needs for each group of activities for both in-situ production and mining with a surface retort. The results appear in tables 8 and 9. We estimated the total range of water needs for in-situ development by summing the minimum estimates for each group of activities and by summing the maximum estimates for the various groups of activities. We did the same for mining with a surface retort. We also calculated the average water needs for each group of activities.

Table 8: Studies GAO Examined That Contained Original Research on Water Requirements for Groups of Activities Representing the Complete Life Cycle for the In-Situ Production of Oil Shale[a]

Study	Extraction and retorting	Power	Reclamation	Upgrading liquids	Population growth
BLM, PEIS					X
Dudley-Murphy et al., table 6, scenarios 2 and 6[b]					X
NOSA, report and personal communication[c]	X	X	X	X	
Boak and Mattson, report and personal communication[d]	X	X	X		
ExxonMobil	X	X	X	X	
URS[e]	X	X	X	X	X
AMEC[f]		X			

Study	Extraction and retorting	Power	Reclamation	Upgrading liquids	Population growth
Shell EA, plan of operation and personal communication[g]	X	X	X	X	X

Source: GAO analysis of selected studies.

[a]An “X” in the column indicates that we analyzed the water estimate in this study for this group of activities. We do not list quantitative water estimates for these groups of activities because some of these data are confidential.

[b]This study did not differentiate estimates for in-situ extraction from estimates for mining with a surface retort.

[c]This study was a confidential survey of multiple companies. Since we did not have access to the identities of the respondents or their individual answers, we could not exclude their estimates if they appear elsewhere in this table. The National Oil Shale Association published the survey results as total water needs being 1.7 barrels of water plus 0.6 to 1.6 barrels of water for upgrading liquids per barrel of oil produced. The upgrading estimate is for both in-situ and mining with a surface retort. Water for power generation and population growth is not included. We estimated water needs for power based on the average of the survey responses to power requirements. We estimated water needs for extraction and retorting and for reclamation based on the average of the survey responses. “Personal communication” indicates that we supplemented information in the study by contacting the author for more information.

[d]We included estimates for site water (water for extraction and retorting and reclamation) between the 25 percent and 75 percent cumulative probability levels. According to the author, about 90 percent of the site water is needed for reclamation. “Personal communication” indicates that we supplemented information in the study by contacting the author for more information.

[e]We could not separate water needs for upgrading liquids from extraction and retorting. The water needs for power are based on coal-fired plants.

[f]The purpose of this study is to update water requirements in the URS report. Preliminary data were presented by Benjamin Harding at the Promise and Perils of Oil Shale Symposium on February 5, 2010. Water needs for power are based on combined-cycle natural gas plants. The final study, which is expected to examine water needs for all groups of activities, will not be publicly available until October 2010.

[g]Shell cites a total of 3 barrels of water for each barrel of oil produced as appropriate for planning purposes. We estimated individual water needs for each of the five groups of activities by examining parameters discussed in Shell’s EA and Plan of Operations in light of revised data provided verbally by Shell. Our estimates for individual groups of activities, based on Shell’s revised data, add up to about 3 barrels of water. “Personal communication” indicates that we supplemented information in the study by contacting the author for more information.

Table 9: Studies GAO Examined That Contained Original Research on Water Requirements for Groups of Activities Representing the Complete Life Cycle for an Oil Shale Mine with a Surface Retort[a]

Study	Extraction and retorting and upgrading liquids[b]	Power	Reclamation	Population growth
BLM, PEIS				X
Dudley-Murphy, table 6, scenarios 2 and 6[c]				X
NOSA, report and personal communication[d]	X	X	X	
URS		X		X
OTA, Paraho-Direct process developed by WPA/DRI	X	X	X	X
OTA, Paraho-Direct process developed by McGee-Kunchal	X	X	X	X
OTA, Paraho-Indirect process developed by McGee-Kunchal	X	X		X
Oil Shale Exploration Company	X[e]	X[e]		

Source: GAO analysis of selected studies.

[a]An "X" in the column indicates that we analyzed the water estimate in this study for this group of activities. We do not list quantitative water estimates for these groups of activities because some of these data are confidential.

[b]We could not differentiate extraction and retorting from upgrading liquids in many of these studies.

[c]This study did not differentiate estimates for in-situ extraction from estimates for mining with a surface retort.

[d]This study was a confidential survey of multiple companies. Since we did not have access to the identities of the respondents or their individual answers, we could not exclude their estimates if they appear elsewhere in this table. The National Oil Shale Association published survey results as total water needs being 2 barrels of water plus 0.6 to 1.6 barrels of water for upgrading liquids per barrel of oil produced. The upgrading estimate is for both in-situ and mining with a surface retort. Water for population growth is not included. We estimated water needs for extraction and retorting and for reclamation based on the average of the survey responses. We estimated water needs for power based on the average of the survey responses to power needs. "Personal communication" indicates that we supplemented information in the study by contacting the author for more information.

[e]Although we reviewed these estimates, we excluded them from our analysis because we do not believe they are scalable to a commercial operation. They were moderately higher than the other estimates but not unreasonable, and they serve as a check on the upper limit for these two groups of activities.

To determine the extent to which water is likely to be available for commercial oil shale development and its source, we compared the total needs of an oil shale industry of various sizes to the amount of surface water and groundwater that the states of Colorado and Utah estimate to be physically and legally available, in light of future municipal and industrial demand. We selected the sizes of an oil shale industry based on input from industry and DOE. These are hypothetical sizes, and we do not imply that an oil shale industry will grow to these sizes. The smallest size we selected for an in-situ industry, 500,000 barrels of oil per day, is a likely size identified by an oil shale company based on experience with the development of the Canadian tar sands. The largest size of 2,500,000 barrels of oil per day is based on DOE projections. We based our smallest size of a mining industry, 25,000 barrels of oil per day, on one-half of the smallest scenario identified by URS in their work on water needs contracted by the state of Colorado. We based our largest size of a mining industry, 150,000 barrels of oil per day, on three projects each of 50,000 barrels of oil per day, which is a commonly cited size for a commercial oil shale mining operation. We reviewed and analyzed two detailed water studies commissioned by the state of Colorado to determine how much water is available in Colorado, where it was available, and to what extent demands will be placed on this water in the future.[1] We also reviewed a report prepared for the Colorado Water Conservation Board on future water availability in the Colorado River.[2] These studies were identified by water experts at various Colorado state water agencies as the most updated information on Colorado's water supply and demand. To determine the available water supply and the potential future demand in the Uintah Basin, we reviewed and analyzed data in documents prepared by the Utah Division of Water Resources.[3] We also examined data on water rights provided by the Utah Division of Water Rights and examined data collected by Western Resource Advocates on oil shale water rights in Colorado. In addition to reviewing these documents, we interviewed water

[1]CDM, *Statewide Water Supply Initiative*, a report contracted by the Colorado Water Conservation Board, November 2004; and CDM *Colorado's Water Supply Future: State of Colorado 2050 Municipal and Industrial Water Use Projections*, a report contracted by the Colorado Water Conservation Board, June 2009.

[2]AECOM *Colorado River Water Availability Study (Draft Report)*, a report contracted by the Colorado Water Conservation Board, March 2010.

[3]Utah Division of Water Resources, *Utah's Water Resources: Planning for the Future* (May 2001); *Municipal and Industrial Water Supply and Uses in the Uintah Basin (Data Collected for Calendar-Year 2005)* (December 2007); and *Utah State Water Plan, Uintah Basin* (December 1999).

experts at the Bureau of Reclamation, USGS, Utah Division of Water Rights, Utah Division of Water Resources, Utah Division of Water Quality, Colorado Division of Natural Resources, Colorado Division of Water Resources, Colorado River Water Conservation District, the Utah and Colorado State Demographers, and municipal officials in the oil shale resource area.

To identify federally funded research efforts to address the impacts of commercial oil shale development on water resources, we interviewed officials and reviewed information from offices or agencies within DOE and the Department of the Interior (Interior). Within DOE, these offices were the Office of Naval Petroleum and Oil Shale Reserves, the National Energy Technology Laboratory, and other DOE offices with jurisdiction over various national laboratories. Officials at these offices identified the Idaho National Laboratory and the Los Alamos National Laboratory as sponsoring or performing water-related oil shale research. In addition, they identified experts at Argonne National Laboratory who worked on the PEIS for BLM or who wrote reports on water and oil shale issues. Within Interior, we contacted officials with BLM and the USGS. We asked officials at all of the federal agencies and offices that were sponsoring federal research to provide details on research that was water-related and to provide costs for the water-related portions of these research projects. For some projects, based on the nature of the research, we counted the entire award as water-related. We identified 15 water-related oil shale research projects. A detailed description of these projects is in appendix II. To obtain additional details on the work performed under these research projects, we interviewed officials with all the sponsoring organizations and the performing organizations, including the Colorado School of Mines, University of Utah, Utah Geological Survey, Idaho National Laboratory, Los Alamos National Laboratory, Argonne National Laboratory, and the USGS.

To assess additional needs for research and to evaluate any gaps between research needs and the current research projects, we interviewed officials with 14 organizations and four experts that are authors of studies or reports we used in our analyses and that are recognized as having extensive knowledge of oil shale and water issues. The names of the 14 organizations appear in table 10. These discussions involved officials with all the federal offices either sponsoring or performing water-related oil shale research and state agencies involved in regulating water resources.

Table 10: Agencies Contacted by GAO for Opinions on Research Needs

BLM
DOE Office of Naval Petroleum and Oil Shale Reserves (DOE NPOSR)
DOE National Energy Technology Laboratory (DOE NETL)
Bureau of Reclamation
USGS
Idaho National Laboratory
Los Alamos National Laboratory
Argonne National Laboratory
University of Utah
Colorado School of Mines
Colorado River Water Conservation District
Colorado Division of Water Resources
Utah Division of Water Quality
Colorado Geological Survey

Source: GAO.

Appendix II: Descriptions of Federally Funded Water-Related Oil Shale Research

Research title	Sponsoring organization	Performing organization	Total federal cost	Federal cost related to water
Water Related Issues Affecting Conventional Oil & Gas Recovery and Oil Shale Development	DOE NETL	Utah Geological Survey	$688,223	$688,223[a]
GIS Water Resource Infrastructure for Oil Shale	DOE NETL	Colorado School of Mines	883,972	883,972[a]
Support for GIS Water Resource Infrastructure for Oil Shale	DOE NETL	Idaho National Laboratory	261,769	261,769[a]
Utah Center for Heavy Oil Research FY06[b]	DOE NETL	University of Utah	1,442,376	122,809c
Institute for Clean and Secure Energy FY08[b]	DOE NETL	University of Utah	873,340	154,937[c]
Institute for Clean and Secure Energy FY09[b]	DOE NETL	University of Utah	2,585,715	161,227[c]
Institute for Clean and Secure Energy FY10[b]	DOE NETL	University of Utah	3,044,800	160,160c
Carbon and Water Resources Impacts from Unconventional Fuel Development in the Western Energy Corridor	DOE NPOSR	Los Alamos National Lab	1,968,000	820,000[d]
Western Energy Corridor Initiative (support for Los Alamos)	DOE NPOSR	Idaho National Laboratory	500,000	100,000[e]
Dynamic Impact Model and Information System to Support Unconventional Fuels Development	Idaho National Laboratory	Idaho National Laboratory	600,000f	250,000[e,f]
Generation and Expulsion of Hydrocarbons from Oil Shale	Idaho National Laboratory	Idaho National Laboratory	1,050,000f	90,000[e,f]
Near Field Impacts of In-Situ Oil Shale Development on Water Quality	Idaho National Laboratory	Idaho National Laboratory	612,500f	612,500[e,f]
Nuclear Pathways to Energy Security	Idaho National Laboratory	Idaho National Laboratory	75,000f	12,500[e,f]
Common Data Repository and Water Resource Assessment for the Piceance Basin, Western Colorado	BLM	USGS	110,000	110,000[a]
Water: Groundwater Monitoring in Piceance Basin and Yellow Creek Basin	BLM	USGS	410,000	410,000[a]
Total	**15 projects**		**$15,105,695**	**$4,838,097**

Source: DOE and Interior agencies and offices.

[a]Entire award is considered water-related due to the nature of the project.

[b]The University of Utah received four separate awards, each covering a broad array of oil shale research over multiple years. The awards included some water-related work. Examples of projects include (1) Meeting Data Needs to Perform a Water Impact Assessment for Oil Shale Development in the Uintah and Piceance Basins, (2) Effect of Oil Shale Processing on Water Compositions, and (3) New Approaches to Treat Produced Water and Perform Water Availability Impact Assessments for Oil Shale Development.

[c]DOE NETL provided this estimate of the water-related portion of the award.

[d]Los Alamos National Laboratory provided this estimate of the water-related portion of the award.

[e]Idaho National Laboratory provided this estimate of the water-related portion of the award.

[f]According to Idaho National Laboratory, some funding may be nonfederal, but it provided no details.

Appendix III: Comments from the Department of the Interior

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, DC 20240

TAKE PRIDE IN AMERICA

OCT 15 2010

Mr. Mark Gaffigan
Director, Natural Resources and Environment
Government Accountability Office
441 G Street, N.W.
Washington, D.C. 20548

Dear Mr. Gaffigan:

Thank you for the opportunity to review and comment on the Government Accountability Office (GAO) draft report entitled, *ENERGY-WATER NEXUS: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development* (GAO-11-35). The Department of the Interior (DOI) generally concurs with GAO's findings and recommendations. The report focused on the research and coordination efforts of the Bureau of Land Management (BLM) and the United States Geological Survey (USGS) related to oil shale development.

The BLM and USGS continue to collaborate and collect baseline data in the Piceance Basin and to design and implement a groundwater and surface water monitoring network. Within the Piceance Basin, natural gas and oil development is occurring along with oil shale research and development activities. The USGS has compiled water quality data and continues to analyze groundwater and surface water to provide a baseline water quality assessment and identify data gaps and redundancies. This information can be used to understand current conditions, inform future monitoring in the basin, and as part of the evaluation performed under regulatory processes involved in the approval of large-scale commercial oil shale development.

The report recommends that the USGS and BLM "establish comprehensive baseline conditions for groundwater and surface water quality, including their chemistry, and quantity in the Piceance and Uintah Basins to aid in the future monitoring impacts from oil shale development in the Green River Formation." Implementation of this recommendation is underway. The USGS efforts for surface-water monitoring provide surface water quantity and quality monitoring at sites within these basins. A more comprehensive effort would include a work plan for gathering additional surface-water quantity data, groundwater monitoring, aquifer testing, and water-quality monitoring. In addition, the USGS Data Repository project, referred to in the report, will be used to better define data gaps in the baseline groundwater and surface water quality and quantity data currently existing for the Piceance and Uintah Basins.

The GAO next recommends that the BLM and USGS "model regional groundwater movement and the interaction between groundwater and surface water, in light of aquifer properties and the age of groundwater, so as to help in understanding the transport of possible contaminants derived from the development of oil shale." The BLM and USGS are working on shared needs for regional groundwater modeling. The Department agrees that data compilation and regional modeling should be performed prior to the approval of large-scale oil shale development. Modeling of the impact to regional groundwater and groundwater/surface water interaction requires accurate estimation of potential water use from the various oil shale development technologies as well as accurate baseline hydrologic information. The six new Research, Development and Demonstration (R, D&D) leases on Federal land in Colorado and Utah will allow industry to test various technologies to determine if production can occur in commercial quantities, and to develop an accurate determination of potential water use for each technology. Interior will then assess the economic and technological challenges involved with the R, D&D projects.

The third recommendation is for the BLM and USGS to "coordinate with the Department of Energy and state agencies with regulatory authority over water resources in implementing these recommendations, and to provide a mechanism for water-related research collaboration and sharing of results." Both bureaus are also working to improve such coordination. Currently, the bureaus are coordinating with state and local regulatory authorities in the many arenas of oil shale development and will build greater collaboration. As the results of the R, D&D leases become known, non-proprietary information will be shared within the Department and with Department of Energy.

If you have any questions, please contact LaVanna Stevenson-Harris, BLM Audit Liaison Officer, at 202-912-7088, or Rebecca Bageant, USGS Audit Liaison Officer, at 703-648-4328.

Sincerely,

Rhea S. Suh
Assistant Secretary
Policy, Management and Budget

Appendix IV: Comments from the Department of Energy

Department of Energy
Washington, DC 20585

October 19, 2010

Mr. Mark E. Gaffigan
Director
Natural Resources and Environment Team
U.S. Government Accountability Office
441 G Street, NW, Mail 2T23A
Washington, DC 20548

Dear Mr. Gaffigan:

Thank you for the opportunity to review the Government Accountability Office (GAO) draft report entitled, "*Energy-water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development.*" Enclosed pleased find the U.S. Department of Energy's comments on the draft report.

If you have any questions or comments please contact Mr. David F. Johnson, Deputy Assistant Director, Office of Petroleum Reserves, of my staff at (202) 586-4733.

Sincerely,

James J. Markowsky
Assistant Secretary
Office of Fossil Energy

Enclosure:
DOE Comments on Draft GAO Report

Printed with soy ink on recycled paper

Department of Energy Comments On GAO Draft Report:
"Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Oil Shale Development (GAO-11-35)"

The following comments are based on comments received from Idaho National Laboratory (INL), Los Alamos National Laboratory (LANL), and the Office of Petroleum Reserves (OPR):

1. **The Department of Energy (DOE) recognizes the need discussed in the Report for a more comprehensive and integrated cross-industry/government approach for determining water requirements, availability, and impacts associated with oil shale development (see for example Report *Highlights*). Recognition of this need, as well as a potential solution, are discussed in the *Strategic Plan* described by Citation 25, a document that was prepared by representatives from industry, national laboratories, universities, and Federal, state, and local governments. Consideration should be given to including appropriate aspects of the *Strategic Plan* in the Report.**
2. **Water requirements for oil shale in-situ technologies are overstated, and water available for an oil shale industry and all other uses is understated (see pages 17-21 and 25-36, and Tables 1, 3, 4, and 5, and Figure 4).**

   Water Requirements: The two primary in-situ processes are by Exxon Mobil Exploration Company (Exxon) and Shell Exploration and Production Company (Shell).
   - Exxon -- Exxon reports that life cycle water requirements are 1-2 barrels of water per barrel of oil produced, taking into account aggressive water conservation technologies (like utilizing produced water/process waste water, via water treating and recycling; using air cooled power generation; using natural gas instead of water for upgrading; and using natural gas instead of coal for power generation.)[1, 4, 7, 9]
   - Shell -- Shell representatives have stated publicly that life cycle water requirements have been studied, and that for planning purposes they are using 3 barrels per barrel, based on using aggressive water conservation technologies. They have also stated that ultimately they should be able to improve on this number.[2, 4, 20]
   - The Report dismisses water treating and recycling because the technologies have not been shown to be commercially viable (see page 16 of the Report). Challenges for oil shale are well within the bounds of commercially viable water treating/recycling technologies currently in operation in other industries in the U.S.; and, as such, the private sector is clearly planning to use them.[1, 3, 4, 7, 20]
   - The Report dismisses the use of produced water due to State-imposed legal limitations (see page 16 of the Report). Utilizing produced water for oil shale production is well within the bounds of how produced water is currently being used under these same limitations in the oil and gas and other industries in the U.S.; as such, the private sector is clearly planning to utilize produced water (within imposed legal limitations).[1, 3, 4, 6, 7, 20]
   - Thus, the water requirements range should be 1-3 barrels per barrel, not 0.8-12, as shown. The 12 barrel per barrel figure is based on a controversial report that was completed without sufficient industry input.[6] The primary complaint was that the URS report did not properly take into account aggressive utilization of water conservation technologies. The report has been reworked by AMEC Earth & Environmental Corporation (AMEC) with private industry input, and a draft of the AMEC report has

10/12/2010

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been publicly released showing a life cycle high number of 1.59 barrels per barrel. The AMEC report addressed comments received from National Oil Shale Association (NOSA), which incorporated comments from Exxon and Shell. [4, 5, 6, 7, 9, 20]

- On the basis of the foregoing, the Report should be revised to more fully describe water conservation technologies, with associated adjustments for in-situ water requirements.

Water Availability – The Report provides an analysis showing how using just the water available on the White River at Meeker would limit the size of an oil shale industry (see pages 32-36, and Tables 3, 4, and 5.). This implies that the size of an industry for the entire 3-State Green River Formation is limited by water available at Meeker. In actuality, water to support the entire industry would be drawn from *many* locations within the Upper Colorado River Basin. The Report should be revised to show how water available from the *entire* basin might limit a 3-State oil shale industry. Numerous data sources on Upper Colorado water flows are publicly available. See Citations 8, 9, 10, and 21.

3. **The Report gives the impression that all oil shale technologies are speculative, and that proving them to be commercially viable will be difficult, requiring a very long period of time, with uncertain outcomes (see pages 7 and 10). This is not an accurate represent-action of the state of the technologies, or of the expected timing of first commercial production. The Report should be revised to address these issues.**
   - Advanced oil shale technologies have been under research for many years at a cost of billions of dollars. Much has been accomplished -- for some technologies; all, or almost all, technical questions impeding commercialization have been answered. [11, 12, 13, 14]
   - The great majority of the components of the various oil shale technologies are not new; most have been in use in the oil and gas and other industries in the U.S. and elsewhere for many years -- e.g., mining, heating formations, fracturing formations, oil and gas production, environmental mitigation, upgrading, transporting, refining, etc. Much of the oil shale challenge is to integrate these components for oil shale in a manner that is economically and environmentally sustainable. This has been the primary focus of all of the research undertaken to date. Although this endeavor is very capital intensive, it is not technically difficult, and expectations have been generally optimistic, evidence of which is the billions of private research and development (R&D) dollars committed to date. The biggest obstacles to investment in the development of a viable oil shale industry in the U.S. have not been the state of the technology, but rather the regulatory uncertainty, and lack of access to resources on Federal lands in the western U.S. [11, 12, 13, 14, 22, 23, 25]
   - Red Leaf Resources Inc (Red Leaf): The Report dismisses Red Leaf because it has not formally published detailed data on water needs (see page 50).
     - Red Leaf is a small start-up company that is funded with private capital. As such, it is not focused on publishing. In 2009, Red Leaf successfully completed a large field pilot/semi-works demonstration project. Based on this success Red Leaf has been funded to design and construct a 30,000 barrels per day commercial project that is due to begin operation within 2-3 years. Engineering is in progress. In order to permit its demonstration and commercial projects, detailed water studies were completed. Results have been presented at conferences and symposia. [15, 16, 18]

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- Red Leaf's extraction process requires almost no water, and it is potentially applicable to any near-surface deposits, an enormous resource target. [15, 16, 18]

- Oil Shale Exploration Company's (OSEC) surface retort technology has been in commercial operation in Brazil since 1992, and is proven there. Production capacity is about 4,600 barrels per day.[10, 17]
  - All that remains for OSEC to do is adapt the technology as needed to make it economic to operate in the U.S. regulatory environment.
  - OSEC completed a feasibility study in 2009 which found no need for a demonstration project and estimated operating costs to be $29-35 per barrel. [10, 17]
  - OSEC is designing a 12,500 barrel per day commercial plant that is funded and expects to begin operation in 2016, expanding to 50,000 barrels / day by 2027. [10, 17]
  - The OSEC technology is potentially applicable to any near-surface or mineable deposits, an enormous resource target. [10, 17]
- There are several other technologies that are also promising, especially the technology by Enshale Inc.[19]
- The Report should be revised to more fully address Red Leaf, OSEC, and other technologies.
- The Report should also more fully reflect the extensive history of oil shale research in the U.S., including ongoing public and private efforts. [11, 24, 25]

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FOOTNOTES/CITATIONS

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Appendix V: GAO Contacts and Staff Acknowledgments

GAO Contacts

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