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Final Scientific/Technical Report
With Detailed Reports of Center-sponsored Research

UTAH HEAVY OIL PROGRAM

Submitted by:
University OF Utah
Salt Lake City, UT

Prepared for:
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Office of Fossil Energy

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Final Scientific/Technical Report

Project Period: June 21, 2006 to October 20, 2009

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ABSTRACT

The Utah Heavy Oil Program (UHOP) was established in June 2006 to provide multidisciplinary research support to federal and state constituents for addressing the wide-ranging issues surrounding the creation of an industry for unconventional oil production in the United States. Additionally, UHOP was to serve as an on-going source of unbiased information to the nation surrounding technical, economic, legal and environmental aspects of developing heavy oil, oil sands, and oil shale resources. UHOP fulfilled its role by completing three tasks. First, in response to the Energy Policy Act of 2005 Section 369(p), UHOP published an update report to the 1987 technical and economic assessment of domestic heavy oil resources that was prepared by the Interstate Oil and Gas Compact Commission. The UHOP report, entitled "A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources" was published in electronic and hard copy form in October 2007. Second, UHOP developed of a comprehensive, publicly accessible online repository of unconventional oil resources in North America based on the DSpace software platform. An interactive map was also developed as a source of geospatial information and as a means to interact with the repository from a geospatial setting. All documents uploaded to the repository are fully searchable by author, title, and keywords. Third, UHOP sponsored five research projects related to unconventional fuels development. Two projects looked at issues associated with oil shale production, including oil shale pyrolysis kinetics, resource heterogeneity, and reservoir simulation. One project evaluated in situ production from Utah oil sands. Another project focused on water availability and produced water treatments. The last project considered commercial oil shale leasing from a policy, environmental, and economic perspective.

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EXECUTIVE SUMMARY

The Utah Heavy Oil Program (UHOP) was established in June 2006 to provide research support to federal and state constituents for addressing the wide-ranging issues surrounding the creation of an industry for unconventional oil production in the United States. The research sponsored by UHOP was to focus on clarifying issues and seeking solutions to challenges for managing and utilizing these natural resources. Additionally, UHOP was to serve as an on-going source of unbiased information to the nation surrounding technical, economic, legal and environmental aspects of developing heavy oil, oil sands, and oil shale resources. UHOP was to be multidisciplinary in nature, involving faculty and students from many departments and colleges at the University of Utah and elsewhere. In the work reported here, there was involvement from the following entities at the University of Utah: College of Law, Department of Chemical Engineering, Department of Civil and Environmental Engineering, Utah Bureau of Economic and Business Research, and the Energy and Geoscience Institute. There was also participation from the Utah Geological Survey.

UHOP fulfilled its role by completing the two primary tasks listed in the 2006 Statement of Project Objectives. Task 1 had two parts: to update the 1987 technical and economic assessment of domestic heavy oil resources that was prepared by the Interstate Oil and Gas Compact Commission and to develop an on-line repository for information, data, and software pertaining to heavy oil resources in North America. Task 2 was to perform UHOP-sponsored research related to the objectives in Section 369 of the Energy Policy Act of 2005 and report on the results of the research. In addition to these two tasks, UHOP has sponsored three conferences during the project period. These conferences, the Western U.S. Oil Sands Conference and the Western U.S. Oil Sands Technology Transfer Meeting, have included speakers from government, academic institutions, and industry presenting material relating to resource characterization, production/processing, legal and environmental issues, and economic analysis of western U.S and Canadian oil sands. Attendees at the conference have consistently numbered greater than 100 with representation from government, academia, and industry.

The UHOP update report was to include publicly available information and link to data already compiled by DOE NETL, as part of their Unconventional Oil Resources Project , and by the Canadian oil sands work in Alberta. It was also to include an analysis of available resources, a discussion of the state-of-the-art production and processing technologies, and an analysis of the economics of utilization and environmental impacts. In October 2007, UHOP provided to NETL for general release to the public "A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources." The report included seven sections: Introduction, Utah Heavy Oil Program ArcIMS Map Server Interface, North American Unconventional Oil Resource, Production/Processing Technologies for Unconventional Oil Resources, Upgrading and Refining, Economic and Social Issues Related to Unconventional Oil Production, and Environmental, Legal and Policy Issues Related to Unconventional Fuel. The report represented the work of eight authors at the University of Utah. A PDF version of the report may be downloaded from http://ds.heavyoil.utah.edu/dspace/handle/123456789/4921. In addition to providing the electronic copy, UHOP printed 1000 copies of the report and distributed those copies to interested individuals, companies, government officials, and universities. Prior to release, the report was reviewed by five individuals including two individuals at NETL, UHOP's programmatic contact at DOE, a Canadian professor with expertise in oil sands processing, and an attorney who specializes in energy, natural resources, and the environment.

The second part of Task 1, the development of a comprehensive, publicly accessible online repository of unconventional oil resources in North America, began with the selection of the DSpace software platform for UHOP's digital archiving needs. DSpace, jointly developed by MIT Libraries and Hewlett-Packard Labs, is a digital repository system that captures, stores, indexes, preserves, and redistributes an organization's research data. DSpace accepts all forms of digital materials including text, images, video, and audio files. Additionally, DSpace is freely available as open source software. These characteristics made DSpace ideal for the UHOP repository, which was to be populated and sourced by all constituencies in the unconventional oil community. The DSpace repository has two portals: a text-based interface that can be accessed at http://repository.icse.utah.edu/dspace/index.jsp and an interactive map-based interface accessed at http://map.icse.utah.edu/website/uhop_ims/viewer.htm). All documents uploaded to the repository are fully searchable by author, title, and keywords through the text-based interface. To make this full text search possible, older documents that were scanned in have been processed through optical character recognition software. The interactive map interface allows users to access data in a geospatial setting. A user can search in a certain geographical location, highlight an unconventional fuel resource in that area (heavy oil, oil shale, or oil sands), and then query the repository for information related to the geographically-referenced resource. The UHOP repository was initially populated with over 1000 documents on unconventional fuels collected by the Utah Geological Survey. Additional resources were obtained from various UHOP researchers. Where possible, the repository contains the actual digital material. However, due to copyright issues, some information in the repository is only available in abstract form.

Task 2 in the UHOP Statement of Project Objectives, to develop potential research area ideas for UHOP-sponsored projects and then to perform and report on the research, was accomplished in several phases. First, each member of the UHOP Directorate (Ray Levey, Energy and Geoscience Institute; Robert Keiter, College of Law; Michael Lemmon, College of Business; Milind Deo, College of Engineering; and Philip Smith, College of Engineering) provided a list of research topics in his field of expertise that complemented other work in industry, academia, and government. This list of potential research topics was presented to NETL at the project kick-off meeting on October 26, 2006, in Tulsa, Oklahoma. After incorporating input from NETL, the list of research topics was finalized and included in a section of the internal request for proposals (RFP) that was released in October 2006. Eleven proposals were submitted by the December 2008 deadline, requesting in excess of $1.6 million in research money. A proposal review panel convened on February 15, 2007 to select projects for funding. The review panel included Philip Smith, Director of UHOP; Jennifer Spinti, Research Associate in UHOP; Brandon Lloyd, Millenium Synfuels, LLC; and Olayinka Ogunsola, DOE. The review panel was impressed with the quality and breadth of the proposals that covered the wide range of issues associated with unconventional fuel development, including technical, geological, legal, and economic issues. Five of the projects were selected for funding for a total of $600,000 in research from the solicitation. The five selected projects are listed in Table 1.

Table 1 UHOP Research Projects Selected for Funding

Title of Proposal	Principal Investigator	Affiliation	Funding Level
Analysis of Environmental, Legal, Socioeconomic and Policy Issues Critical to the Development of Commercial Oil Shale Leasing on the Public Lands in Colorado, Utah, and Wyoming under the Mandates of the Energy Policy Act of 2005	Robert Keiter Kirsten Uchitel John Ruple Michael Hogue	Wallace Stegner Center for Land, Resources and the Environment, S. J. Quinney College of Law Bureau of Economic and Business Research	$110,000
Depositional Heterogeneity and Fluid Flow Modeling of the Oil Shale Interval of the Upper Green River Formation, Eastern Uinta Basin, Utah	Md. Royhan Gani Milind Deo	Energy and Geoscience Institute Chemical Engineering	$110,000
In Situ Production of Utah Oil Sands	Milind Deo	Chemical Engineering	$100,000
Quantifying Water Availability Impacts and Protecting Water Quality while Developing Utah Oil Shale and Sands	Steven Burian Ramesh Goel Andy Hong	Civil and Environmental Engineering	$130,000
Oil Shale Pyrolysis & In Situ Modeling	Milind Deo Eric Eddings Terry Ring	Chemical Engineering	$150,000

Following is a summary of the research results obtained from the five projects listed in Table 1. Detailed final reports for all five projects are presented as appendices to this document.

1. Analysis of Environmental, Legal, Socioeconomic and Policy Issues Critical to the Development of Commercial Oil Shale Leasing on the Public Lands in Colorado, Utah, and Wyoming under the Mandates of the Energy Policy Act of 2005

This report seeks to identify the salient environmental, policy, economic and socioeconomic issues that are relevant to determining when and how a federal commercial oil shale program might be implemented. Where appropriate, this report offers conclusions and recommendations as to potential paths forward on oil shale policymaking.

If commercial oil shale development occurs on the public lands, it will be subject to a comprehensive and complex legal framework. Additionally, the Bureau of Land Management, the largest single manager of oil shale-bearing lands, operates under a" multiple use--sustained yield" mandate that requires the BLM to weigh and balance current and future needs for the various resources and resource values found on the public lands. Many of the BLM's discretionary decisions as to the proper resource balance meet with legal challenge, and this is currently the case for recent BLM decisions affecting the potential scope of oil shale development. Programmatic BLM management plan amendments have identified lands available for application for commercial leasing, but these plans also remain encumbered by legal challenges. New policies announced by the Obama Administration favor more detailed and environmentally informed decisions, which in turn may foster enhanced certainty for prospective energy developers and the public alike. In addition to federal lands, state, private and tribal interests overlie extensive and valuable oil shale resources. The public interest, the interests of the various oil shale resource owners, national energy needs and environmental impacts will all influence the course of commercial oil shale leasing and development on the public lands.

Presently, analysts and policymakers must guess at the number, size, location and technologies employed by what is as yet only a prospective oil shale industry. While much is anticipated about the tradeoffs of commercial oil shale development on the public lands, important gaps in information remain. And these tradeoffs are not solely environmental; for example, development of conventional oil and gas may be at odds with commercial oil shale development.

Making water available for a commercial oil shale industry raises several policy issues. In a region where water resources are fully allocated, potentially water intensive oil shale development will require reallocation of existing water supplies. While in theory existing water law is well suited to facilitating water right transfers, it is hampered by large unresolved claims and is of little help in answering the more basic question of what competing water uses society is willing to forego in favor of oil shale development.

The intrinsic energy demand and related air quality issues associated with producing shale oil raises policy questions as to the energy balance of oil shale development. Similarly, absent proven carbon management technologies, anticipated regulation of greenhouse gases has the potential to significantly constrain the scale and economics of commercial oil shale development.

Development of a sustainable commercial oil shale industry also faces a number of economic challenges. Will a commercial oil shale industry be likely to generate a return on investment sufficient to retain or attract capital? Can a future commercial oil shale industry effectively compete with conventional petroleum sources and emerging alternatives to liquid transportation fuels? Would commercial oil shale development provide a sufficiently broad public benefit --whether energy security or economic -- to warrant government support?

Finally, unbalanced growth is a salient feature of past episodes of rapid mineral development, including the oil shale development efforts that occurred in western Colorado in the late 1970s and early 1980s. The problems associated with "boomtown growth" are central to evaluating when and how a federal commercial oil shale leasing program might be implemented.

2. Depositional Heterogeneity and Fluid Flow Modeling of the Oil Shale Interval of the Upper Green River Formation, Eastern Uinta Basin, Utah

A detailed geological analysis was performed followed by a reservoir modeling exercise. For the geological analysis, ~300 m of cores were correlated to gamma and density logs in well P4 in the lower to middle Eocene (49.5–48.0 million years ago (Ma)), upper Green River Formation of the eastern Uinta Basin, Uintah County, Utah. In well P4, three distinct facies associations were identified that represent three phases of deposition linked to the hydrologic evolution of Lake Uinta: 1) an overfilled, periodically holomictic lake system with deposition of primarily clastic mudstones, followed by 2) a balanced-filled, uniformly meromictic lake system with deposition of primarily calcareous and dolomitic mudstones, followed by 3) an underfilled, evaporative lake system with nahcolite precipitation. The richest oil shale zones were deposited during the second depositional phase. While the studied interval is popularly known as oil "shale", this bed-by-bed investigation revealed that lithologically, thus chemically, the interval is quite heterogeneous. This complexity has significant impact on modeling strategies for oil shale exploitation.

In-situ methods are expected to have a lessened environmental impact and are likely to have lower costs than mining and surface processing. Heat transfer pathways, chemical kinetics, geomechanics, multiphase fluid flow, and process strategies add complexity to any in-situ oil shale production strategy. Understanding each of these phenomena as well as appropriate model coupling is necessary to accurately model in-situ oil shale production processes. For the reservoir modeling exercise, various in-situ oil shale production methods for this heterogeneous resource were explored using the geologic information from U059 (core P4) . The core information was converted to wt% hydrocarbon (organic matter or kerogen) and used directly in the reservoir simulation model. Results from in-situ oil shale modeling with the STARS simulator show that oil production from the Green River Formation is feasible. Challenges to achieving economic rates of recovery include porosity-permeability creation and the establishment of contiguous pathways between injectors and producers. Idealized energy efficiency and carbon footprint for an electrical conduction-type process were estimated as 3:1 net energy gain and 36 kg CO_2/barrel (bbl) oil produced respectively.

3. In Situ Production of Utah Oil Sands

The objective of this project was to evaluate and rank a variety of in-situ heavy oil production method for the production of bitumen from a representative Utah oil sand formation within the Uinta Basin. Two oil sand reservoirs located in Utah's Uinta Basin were considered for analysis: Whiterocks, a small, steeply dipping, contained reservoir containing about 100 million barrels, and Sunnyside, a giant reservoir containing over four billion barrels of oil in place. Cyclic steam stimulation, steam assisted gravity drainage, and in-situ combustion processes were considered for the production of oil from these reservoirs. Different well configurations and patterns were examined. It was found that the application of steam-based in-situ processes would be feasible but challenging for Utah oil sands. For most configurations, the steam to oil ratios were higher than five, indicating marginal economic viability. Additionally, the water production rates were high. The in-situ combustion process was simulated with and without the presence of a hydraulic fracture for a homogeneous reservoir. The nature of the combustion front was radial without the fracture and linear with the fracture. Even though the process appears feasible, rigorous evaluation with an appropriate geologic model will be necessary to determine technical and economic viability.

4. Quantifying Water Availability Impacts and Protecting Water Quality While Developing Utah Oil Shale and Sands

When project proposals were reviewed, there were three related to water availability and water quality. However, there was not enough money to fully fund all three projects. Instead, the principal investigators were asked to reduce the scope of their proposals and work in a synergistic manner to maximize their efforts within the available budget. As a results, three subparts were created for this project. The results from each of these subparts is summarized here.

Water Resources Sustainability: The goal of this project was to mitigate water resources impacts from oil shale development in the U.S. by compiling geospatial data and water use estimates to assess water availability impacts. A brief literature search was conducted to acquire publications and fact sheets on oil shale and water resources. Water resources geospatial datasets for the Uinta and Piceance Basins in Utah and Colorado were also collected to support the development of the water management model. The 50 documents obtained in the literature review were uploaded to the UHOP repository and the geospatial datasets collected and created have been incorporated into the UHOP interactive map. To update water requirements estimates, projections for urban growth, estimates of available oil shale resources, and the quantification of water requirements for the urban growth, oil shale industry, and energy generation sectors were needed. The Eastern Utah urban growth projection was based on a retrospective analysis of growth in Fort McMurray, Canada, in response to their oil sands development growth. The retrospective analysis provided a model to follow that was fine-tuned in discussions with Vernal planning department officials to arrive at a reasonable estimate of future urban growth and to generalize key characteristics of the urban demographic and growth pattern likely to influence water demand. The in-place oil shale resource estimates were based on a geostatistical analysis. Water demand estimates were made using a range of possible oil shale production rates, technologies, and urban and energy water demands. A methodology to determine water availability was also conceived. The conceptual approach identified the need to develop a water management model for the White River (a tributary to the Green River in the Colorado River Basin), to acquire and incorporate hydrologic information, and to accurately account for the current water users in the region.

Biological and Chemical Treatment of Produced Water: Produced water is composed of dispersed oil, dissolved organic compounds, production chemicals, heavy metals, naturally occurring radioactive minerals and other inorganic compounds. Every year, larger quantities of produced water go through underground injection or discharge into natural water bodies, which do not meet the requirement of sustainable development and also present a potential threat to the aquatic ecosystem. Produced water has been treated by physical (deep bed filter, gas flotation, sand filtration, activated carbon, etc.), chemical (ozonation, ion exchange, UV treatment, etc.) and biological methods respectively. However, none of those methods alone gives a substantive treatment. The long-term objective of this work is to develop an integrated treatment scheme which will employ a combination of physical, chemical and biological treatment methods to treat produced water for sustainable production in oil/gas fields. The objective in this first phase of the project was to test and refine each of the steps in the combined treatment approach. Real produced water samples (6 samples in triplicate) from ConocoPhillips were characterized using ICP-MS to identify elements present and the HACH method to identify ammonia, nitrite, nitrate, phosphorus, and COD. The identified constituents were used to simulate the composition of the synthetic produced water in the integrated treatment scheme. Naphthalene and BTEX were used as the model refractory compounds to test the treatment efficiency of advanced oxidation and biological methods. While the rate of degradation of naphthalene and BTEX in electrolytic experiments was slow and not all the contaminants were degraded, the electro-Fenton method was able to oxidize and remove the bulk of the organic compounds. The results show that up to 60 weight percent of the naphthalene and more than 99 weight percent of BTEX were removed after 8 hours of electrolysis. Furthermore, biomass from municipal sewage removed more than 95 weight percent of the naphthalene and BTEX. The bacteria responsible for the biodegradation were identified through the 16S rDNA-based cloning and sequencing technique. Both oxidation and biological treatment results are affected by volatilization as indicated by tests conducted with blanks.

Ozonation of Produced Water: Produced water from gas and crude oil production is voluminous, requiring extensive treatment before it can be safely discharged or reused. The project objectives were: 1) to treat oily wastewater such as produced water that contains dissolved and suspended oil, 2) to remove the potential for sheen formation on the water surface, 3) to render the water amenable to reuse and safe environmental release, and 4) to demonstrate bitumen extraction from oil sands. To complete these tasks, the project used a newly developed pressure-assisted ozonation technology for removing oil from water and to prevent oil sheen at the water surface. The new process is based on heightened reactions of ozone and hydrocarbon molecules occurring at the gas-liquid interface of the microbubbles. Ozonation in pressure cycles combines the advantages of microbubbles for floatation and heightened reactivity of ozone for the removal of oil from water. Ozone converts small hydrocarbons in the aqueous phase into hydrophilic organics in a short time (< 20 min). The dissolved organic acid products exhibited good biodegradability. Because the treated water contains biodegradable end products at low concentrations, safe discharge to the environment or for various reuses is possible. The new process is especially valuable for coastal discharge, as well as for energy development and water use in arid regions. Finally, the pressure-assisted HOSE process rapidly accomplished bitumen extraction from oil sands using little energy and requiring no chemical additives, demonstrating its potential as an effective oil sands process.

5. Oil Shale Pyrolysis & In Situ Modeling

When modeling in situ extraction of oil shale, the chemical reactions that detail the conversion of kerogen to oil have a first order effect on predicted oil production rates. Accordingly, the two subparts of this project focused on (1) obtaining a better understanding of oil shale pyrolysis and (2) employing a pyrolysis mechanism in a multi-physics model of in situ extraction using DC and RF heating of the deposit.

Detailed Study of Shale Pyrolysis for Oil Production: Good kinetic data are essential for accurate mathematical modeling of various ex-situ and in-situ oil shale processes. The purpose of this project was to develop a more detailed kinetic understanding of the pyrolysis of oil shale. Studies significant to the kinetic analyses of oil shale are compiled and discussed. Then, methods and experiments relating to the pyrolysis and combustion of Green River oil shale samples from Utah are presented. Kinetic analysis of both pyrolysis data from thermgravimetric analysis (TGA) and combustion data was performed using conventional and isoconversion (Friedman) methods. A reasonable match of the data was obtained by considering activation energy as a function of heating rate. For decomposition of complex materials such as kerogen, isoconversion methods are recommended. Based on the data collected, a distribution of activation energies (with conversion) was established.

While obtaining comprehensive combustion kinetic information was not one of the original project objectives, other research activities indicated that in situ combustion could be one of the processes used to generate sufficient energy for the pyrolysis process. Pyrolysis yield information was generated using ¾ inch core samples. Yields generally increased slightly with temperature in the narrow temperature window examined in this work. The highest yield was obtained in the experiment with a slow heating rate. Compositional information of the samples revealed that higher temperature processes yielded oil with higher residue. No significant difference in yield or composition was observed in experiments performed by soaking cores in water for short durations (1-10 days). Selected GC-MS analyses of the products revealed the alkene-alkane pairs typical of shale oils. Significant amounts of aromatics were also present in the oils. In general, these compounds have higher water solubilities than the paraffinic and naphthenic species in the oil. The GC-MS analyses revealed the necessity of detailed compositional analyses.

Modeling In situ Oil Shale Recovery Extraction: In situ production processes are being vigorously pursued by all the major energy companies. However, fundamental issues related to the kinetics of kerogen conversion to natural gas and light oil products and the production of the resulting oil require further multi-physics analysis to aid in situ extraction. Additionally, in situ processing is a highly energy-intensive process. Better energy utilization and efficiency is necessary to make the extraction of this resource cost effective. A multi-physics model of in situ extraction of oil shale was developed which couples kerogen pyrolysis, fluid flow, mass transfer of multiple species, heat transfer and AC (RF) and DC heating of the deposit. All physical properties used in these model equations were functions of the local chemistry of the deposit and of local temperature. A 2D slice consisting of a heating and a production well located 25 feet (7.62 m) apart, was simulated for up to 5 years. The 2D slice is a right triangle consisting of the smallest repeating unit of a hexagonal drill pattern. The model calculated the concentrations of kerogen, bitumen, oil and gas at all locations in the deposit; physical properties such as viscosity, permeability, heat capacity, thermal conductivity, electrical conductivity, dielectric constant, and loss tangent; and pressure, temperature, and thermal and pressure stresses in the deposit. The results showed that a pusher fluid, a gas in this work, was necessary to move the oil to the production well; that thermally-induced stresses did not induce fracture of the deposit; and that more uniform heating of the deposit by RF heating was beneficial to oil extraction.

FUTURE WORK

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The Utah Heavy Oil Program was terminated at the end of the project period. However, the work conducted by UHOP was phased into new programs within the Institute for Clean and Secure Energy (ICSE) in 2008. For example, the repository and interactive map are continuing to evolve as online resources for unconventional fuels, especially in Utah and the western U.S., and are supporting the work of ICSE researchers in coal, oil sands, and oil shale. Policy work continues in the areas of produced water and water availability, land use impacts, and the potential to learn from the Canadian oil sands experience as a model for development in the U.S., particularly in Utah. Another assessment is also being prepared on the supply costs and economic impact of oil shale, oil sands, and heavy oil industries where development does not currently exist. Projects related to oil shale pyrolysis, geologic characterization, and reservoir simulation have been continued, and new projects studying atomistic modeling of kerogen and porosity/permeability in pyrolyzed oil shale samples have been added. Both technical and legal projects have two overarching objects. In the area of clean oil shale & oil sands utilization with efficient CO_2 capture, the objective is to produce the research and simulation tools needed to provide efficient CO_2 capture for process equipment for production and upgrading of oil shale and oil sands and specifically to produce predictive capability with quantified uncertainty bounds for a pilot-scale, oxy-gas process heater using flameless technologies. In the area of secure liquid fuel production by in-situ thermal processing of oil shale & oil sands, the objective is to apply science, engineering, technology and economics research tools developed within ICSE to a wide variety of in-situ processes and to explore the environmental, legal and policy framework for implementation of such technologies on public and private lands.

APPENDIX A

Analysis of Environmental, Legal, Socioeconomic and Policy Issues Critical to the Development of Commercial Oil Shale Leasing on the Public Lands in Colorado, Utah and Wyoming under the Mandates of the Energy Policy Act of 2005

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

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ACEC Areas of Critical Environmental Concern
AMSO American Shale Oil Company
ANWR Arctic National Wildlife Refuge
AQRV Air Quality Related Values

BACT Best Available Control Technology
BLM Bureau of Land Management
BOPD Barrels of Oil per Day

CAA Clean Air Act
CAD Canadian Dollar
CCS Carbon Capture and Storage
CFS Cubic Feet per Second
CO Carbon Monoxide
CO_2 Carbon Dioxide

DOE Department of Energy
DOI Department of Interior

EIA Energy Information Administration
EIS Environmental Impact Statement
EOR Enhanced Oil Recovery
EPA U.S. Environmental Protection Agency
EPAct 2005 Energy Policy Act of 2005
EROI Energy Return on Investment
ESA Endangered Species Act

FEIS Final Environmental Impact Statement
FLPMA Federal Land Policy and Management Act
FWS U.S. Fish and Wildlife Service

GDP Gross Domestic Product
GHG Greenhouse Gas
GML General Mining Law of 1872
GPT Gallon per Ton

HAP Hazardous Air Pollutant

ICP In Situ Conversion Process

MLA Mineral Leasing Act of 1920
MMBbl/D Millions of Barrels per Day

NAAQS National Ambient Air Quality Standards
NEPA National Environmental Policy Act
NESHAP National Emissions Standards for Hazardous Air Pollutant
NO_x Nitrogen Dioxide
NOSR Naval Oil Shale Reserve
NSPS New Source Performance Standards

O_3 Ozone
OCS Outer Continental Shelf
OPEC Organization of Petroleum Exporting Countries
OSEC Oil Shale Exploration Company

PADD Petroleum Administration for Defense Districts
Pb Lead
PEIS Programmatic Environmental Impact Statement
PM Particulate Matter

PSD Prevention of Significant Deterioration

RD&D Research, Development and Demonstration
RMP Resource Management Plans
RMWB Regional Municipality of Wood Buffalo
ROD Record of Decision

SIP State Implementation Plan
SITLA School and Institutional Trust Lands Administration
SMCRA Surface Mining Control and Reclamation Act
SO_2 Sulfur Dioxide
SOI Secretary of Interior
SPR Strategic Petroleum Reserve

TAP Trans-Alaskan pipeline

UPEC The Utah Population Estimation Committee

WRAP Western Regional Air Partnership
WSA Wilderness Study Areas
WSRA The Wild and Scenic Rivers Act

Executive Summary

The United States is home to the largest oil shale deposits in the world. This resource is located in the Green River Formation, spreading across the states of Colorado, Utah and Wyoming. Despite the vast potential of this resource, successful commercial development has yet to occur. To date, concerted federal efforts to promote oil shale leasing and development have resulted in little visible progress.

Under the Energy Policy Act of 2005, it was intended that the Department of Interior would take several steps that would culminate in a commercial oil shale leasing and development program on the public lands. Thus far, numerous technological, environmental and economic uncertainties have impeded initiation of such a program.

This report seeks to identify the salient environmental, policy, economic and socioeconomic issues that are relevant to determining when and how a federal commercial oil shale program might be implemented. Where appropriate, this report offers conclusions and recommendations as to potential paths forward on oil shale policymaking. The aim of this report is not to advocate for or against commercial oil shale development, but rather to provide an outline of the issues and tradeoffs that should be considered in advance of any federal commercial oil shale leasing decisions.

If commercial oil shale development occurs on the public lands, it will be subject to a comprehensive and complex legal framework. Additionally, the Bureau of Land Management (BLM)—the largest single manager of oil shale-bearing lands—operates under a "multiple use–sustained yield" mandate. This mandate requires the BLM to weigh and balance current and future needs for the various resources and resource values found on the public lands. Many of the BLM's discretionary decisions as to the proper resource balance meet with legal challenge, and this is currently the case for recent BLM decisions affecting the potential scope of oil shale development. Programmatic BLM management plan amendments in Utah have identified lands available for application for commercial leasing, but these plans remain encumbered by legal challenges. Equivalent management plans within Colorado that will dictate the terms of oil shale development in that state are being revised.

Recently announced decisions by the Obama Administration to revise federal oil and gas leasing requirements by expanding pre-leasing environmental reviews do not directly impact prospective oil shale developers, but they mark the latest in a series of decisions reflecting evolving federal energy policies. These new policies favor more detailed and environmentally informed decisions, which in turn may foster greater certainty for prospective energy developers and the public alike.

Oil shale, like other energy resources, is not strictly limited to federal lands. In the case of oil shale, state, private and tribal interests overlie extensive and valuable oil shale resources. The potential value of these resources creates powerful and potentially conflicting development incentives that could lead to mismatched federal, state and tribal policies. More coordination among policymakers at each of these levels would help ensure that the public interest is met and create the framework for an economically and environmentally viable oil shale development effort.

Presently, analysts and policymakers must guess at the number, size, location and technologies employed by what is as yet only a prospective oil shale industry. While much is anticipated about the tradeoffs of commercial oil shale development on the public lands, important gaps in information remain. And these tradeoffs are not solely environmental; for example, development of conventional oil and gas may be at odds with commercial oil shale development.

Making water available for a commercial oil shale industry raises several policy issues. In a region where water resources are fully allocated, potentially water intensive oil shale development will require reallocation of existing water supplies. While in theory existing water law is well suited to facilitating water right transfers, it is hampered by large unresolved claims and is of little help in answering the more basic question of what competing water uses society is willing to forego in favor of oil shale development.

The intrinsic energy demand associated with producing shale oil raise policy questions as to the energy balance of oil shale development. Related air quality issues present substantial planning challenges for a future oil shale industry that is, at minimum, several years away. Similarly, climate change is an issue of continuing public debate and concern. Absent proven carbon management technologies, anticipated regulation of greenhouse gases has the potential to significantly alter the scale and economics of commercial oil shale development.

Development of a sustainable commercial oil shale industry also faces a number of economic challenges. Will a commercial oil shale industry be likely to generate a return on investment sufficient to retain or attract capital? Can a future commercial oil shale industry effectively compete with conventional petroleum sources and emerging alternatives to liquid transportation fuels? Would commercial oil shale development provide a sufficiently broad public benefit—whether energy security or economic—to warrant government support?

Finally, unbalanced growth is a salient feature of past episodes of rapid mineral development, including the oil shale development efforts that occurred in western Colorado in the late 1970s and early 1980s. The problems associated with “boomtown growth” are central to evaluating when and how a federal commercial oil shale leasing program might be implemented.

CHAPTER 1

INTRODUCTION

The United States is home to the world's largest known oil shale deposits. These deposits are contained in the Green River Formation, which spreads across 11 million acres of Colorado, Utah and Wyoming.[1] Estimates of the Green River Formation's in-place oil shale resource, depicted in Figure 1.0.1, range from 1.5 to 1.8 trillion barrels.[2] The recoverable oil shale resource is estimated to be between 500 billion and 1.1 trillion barrels.[3] At a mid-range estimate of 800 billion barrels, the Green River Formation contains more than three times Saudi Arabia's proven oil reserves.[4] By way of comparison, the Prudhoe Bay oil field contains 13.5 billion barrels of oil and the mean estimate of recoverable oil from the coastal plains of the Arctic National Wildlife Refuge (ANWR) is 10.4 billion barrels.[5] The dollar value of the Green River Formation's in-place oil shale resources has been estimated to be in the trillions,[6] and the potential public economic benefit of developing the oil shale resource has been estimated to be as high as $500 billion over a period of 25 years.[7]

[1] U.S. Department of Energy, Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Resources, *available at* http://www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf.

[2] BARTIS ET AL., OIL SHALE DEVELOPMENT IN THE UNITED STATES: PROSPECTS AND POLICY ISSUES, RAND CORP. 6 (2005).

[3] BARTIS ET AL. at 8–9.

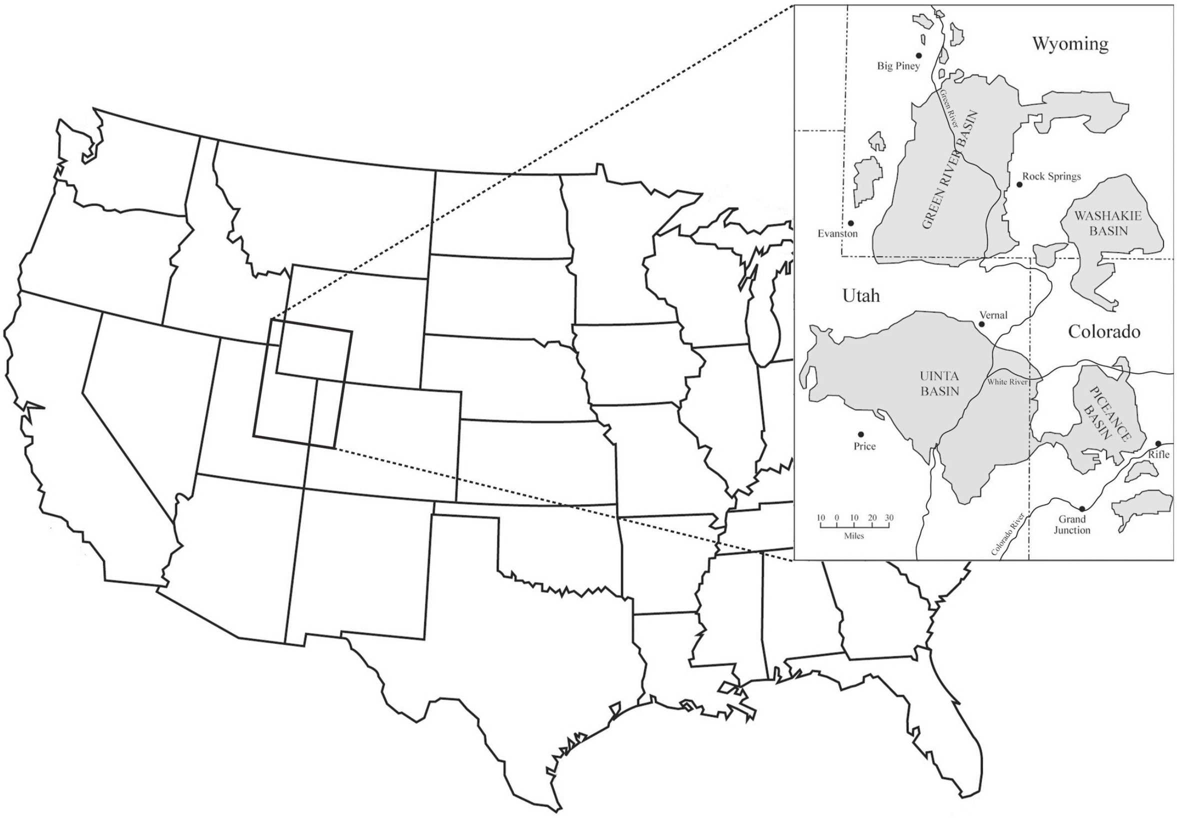
[4] BARTIS ET AL. at 1.

[5] U.S. Energy Information Administration, *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge* (May 2008) *available at* http://www.eia.doe.gov/oiaf/servicerpt/anwr/methodology.html.

[6] James T. Bartis, Policy Issues for Oil Shale Development, Testimony before the House Natural Resources Committee, Subcommittee on Energy and Mineral Resources (April 17, 2007).

[7] U.S. Department of Energy, Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Economics, *available at* http://www.unconventionalfuels.org/publications/factsheets/Oil_Shale_Economics_Fact_Sheet.pdf.

Figure 1.0.1: Green River Formation Oil Shale Resources. Source: Institute for Clean & Secure Energy.



Its name notwithstanding, oil shale does not actually contain oil; rather, oil shale is a sedimentary rock containing significant amounts of organic material known as kerogen.[8] It is the kerogen in oil shale that, once separated from the rock through significant heat input, can be converted into liquid hydrocarbons. These liquid hydrocarbons, after upgrading and refining, can be used to produce high quality jet fuel, #2 diesel fuel, and other by-products.[9]

Production processes for extracting kerogen from oil shale fall into two main categories: (1) ex situ and (2) in situ production.[10] In ex situ production, oil shale is mined, crushed, and then thermally processed at the surface. With in situ production, the oil shale is left underground and heat is applied to

[8]Kerogen is "[t]he naturally occurring, solid, insoluble organic matter that occurs in source rocks and can yield oil upon heating. Typical organic constituents of kerogen are algae and woody plant material. Kerogens have a high molecular weight relative to bitumen, or soluble organic matter. Bitumen forms from kerogen during petroleum generation. Kerogens are described as Type I, consisting of mainly algal and amorphous (but presumably algal) kerogen and highly likely to generate oil; Type II, mixed terrestrial and marine source material that can generate waxy oil; and Type III, woody terrestrial source material that typically generates gas." Schlumberger Oilfield Glossary, `http://www.glossary.oilfield.slb.com/Display.cfm?Term=kerogen`.

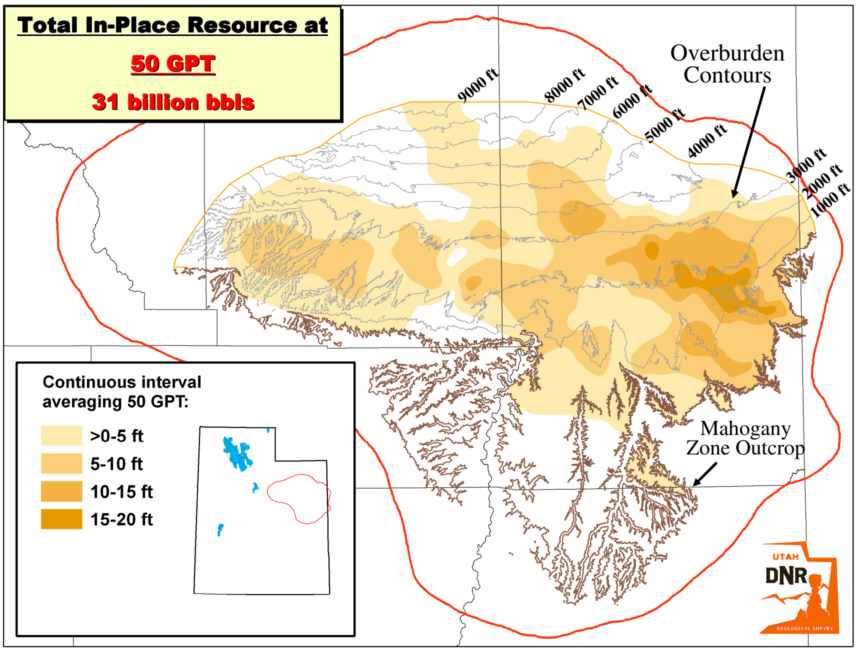
[9]U.S. Department of Energy, Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Reserves, *available at* `http://www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf`.

[10]For a more detailed description of oil shale production technologies, *see* U.S. Department of Energy, Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: Oil Shale Conversion Technology, *available at* `http://www.unconventionalfuels.org/publications/factsheets/Oil_Shale_Technology_Fact_Sheet.pdf`.

the resource either by direct heating or by performing in situ combustion. A modified version of in situ treatment also has been developed that combines aspects of both in situ and ex situ.[11]

Oil shale deposits can vary widely in richness and are commonly measured in gallons per ton (GPT), meaning the number of gallons of shale oil recovered [12] from one ton of rock. Oil shale deposits also vary in their their surface accessibility as defined by the overburden that sits atop the shale resource. The greater the overburden, the less suited the oil shale resource is to conventional mining methods due to the logistics and costs of resource extraction. Overburden, however, is necessary for in situ combustion as overburden creates needed pressure while trapping heat. The thickness of the shale resource also varies from deposit to deposit, and may determine the appropriate extraction technology. Thinner oil shale deposits are ill suited to in situ extraction, but may be developed using conventional mining methods. All three characteristics – richness, accessibility and thickness – are used to evaluate the economic attractiveness of potentially developable oil shale deposits. By way of illustration, Figure 1.0.2 depicts the varying richness, thickness and overburden attributes for the 50 GPT in-place oil shale resource in Utah's Uinta Basin.

Figure 1.0.2: Total In-Place Uinta Basin Oil Shale Resource at 50 GPT. Source: Michael D. Vanden Berg, Utah Geological Survey.



Commercial oil shale production holds several potential benefits for American consumers. The primary presumed benefit is the role oil shale could play in meeting at least a portion of the current domestic demand for petroleum products. Domestic consumption of petroleum products was 20.7 million barrels

[11] Red Leaf Resources, Inc. has developed the EcoShale In-Capsule Process, which is a modified in situ process in which the oil shale is first mined and then heated in a capsule constructed in the mining pit. The EcoShale process has been tested at the pilot scale by Red Leaf Resources on its state land lease in Utah. *See* Red Leaf Resources, Inc., Pilot Test, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=14\&Itemid=16.

[12] We will use the term "oil shale" when we mean the rock in which the kerogen is bound and "shale oil" to generically refer to a product obtained by heating the kerogen, and which, possibly after further treatment to reduce contaminants, is suitable as refinery feedstock.

per day (BOPD) in 2007[13] and 19.5 million BOPD in 2008.[14] In 2007 and 2008, respectively, 58%[15] and 57%[16] of that demand was met by petroleum imports from foreign countries, many of whom are not considered allies of the United States.[17] Anticipated future oil resources are similarly located, as seen in Figure 1.0.3. Some analysts suggest that decreased reliance on imported petroleum products, particularly from OPEC members, could hold international political benefits by prompting a drop in world oil prices and shifting the prevailing geopolitical balances of power.[18] The demand for petroleum products, particularly liquid transportation fuels, is projected to remain largely unchanged over the next two decades, as illustrated in Figure 1.0.4. Accordingly, enhanced national, economic and energy security resulting from reduced reliance on foreign petroleum imports is often cited as another benefit to commercial oil shale development.[19]

[13]Energy Information Administration, Department of Energy, Energy in Brief: How dependent are we on foreign oil?, *available at* http://tonto.eia.doe.gov/energy_in_brief/foreign_oil_dependence.cfm.

[14]Energy Information Administration, Department of Energy, Energy Explained: Use of Oil, *available at* http://tonto.eia.doe.gov/energyexplained/index.cfm?page=oil_use.

[15]Energy Information Administration, Department of Energy, Energy in Brief: How dependent are we on foreign oil?, *available at* http://tonto.eia.doe.gov/energy_in_brief/foreign_oil_dependence.cfm.

[16]Energy Information Administration, Department of Energy, Frequently Asked Questions: How dependent is the United States on foreign oil?, *available at* http://tonto.eia.doe.gov/ask/crudeoil_faqs.asp.

[17]In 2008, 74% of United States net petroleum imports came from OPEC countries and Persian Gulf countries. Energy Information Administration, Department of Energy, Frequently Asked Questions: How dependent is the United States on foreign oil?, *available at* http://tonto.eia.doe.gov/ask/crudeoil_faqs.asp. As of September 2009, the top ten petroleum exporters to the United States were Canada, Mexico, Venezuela, Saudi Arabia, Nigeria, Algeria, Russia, Iraq, Angola, and Colombia. Energy Information Administration, Department of Energy, Crude oil and Total Petroleum Imports Top 15 Countries, *available at* http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/company_level_imports/current/import.html.

[18]The extent to which oil shale production would reduce oil prices depends on the behavior of other oil producing nations and would be greater if these nations maintain current oil production levels in spite of increased shale oil production. BARTIS ET AL. at 29-30. For a more detailed discussion of the national security implications of domestic oil shale development *see* Task Force on Strategic Unconventional Fuels, America's Strategic Unconventional Fuels: Volume I - Preparation Strategy, Plan, and Recommendations (Sept. 2007) at pp. I-7 - I-13.

[19]BARTIS ET AL. at 28-29; *see also* James T. Bartis, Policy Issues for Oil Shale Development, Testimony before the House Natural Resources Committee, Subcommittee on Energy and Mineral Resources (April 17, 2007).

Figure 1.0.3: Future Oil Resources and Country Oil Consumption. Source: U.S. Geological Survey, Energy Program 2005.

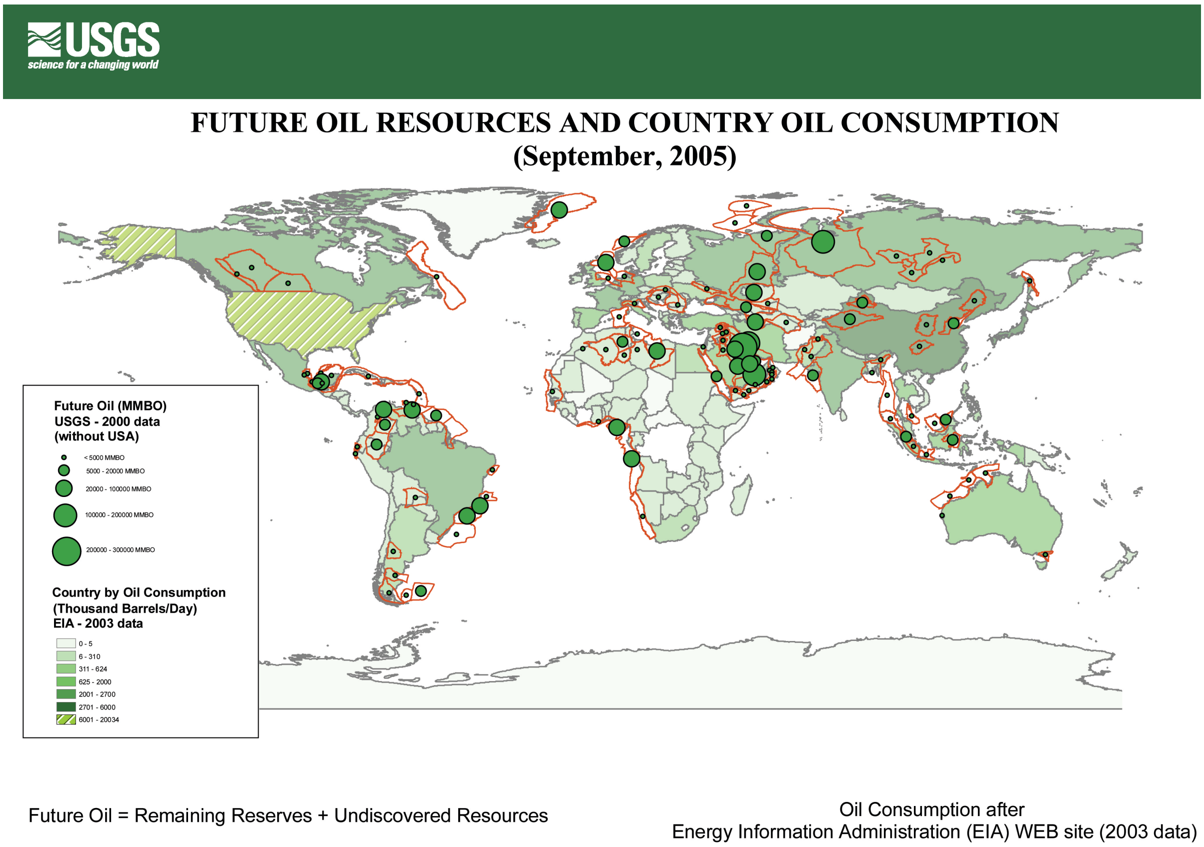
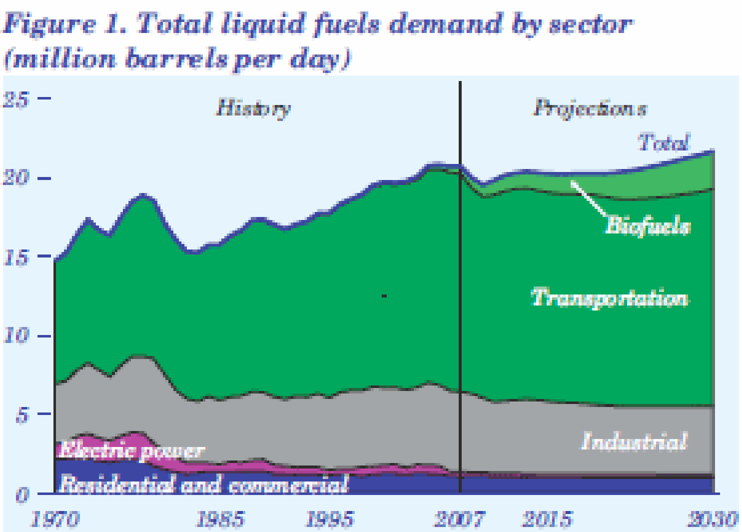


Figure 1.0.4: Total liquid fuels demand by sector, 1970–2030. Source: Annual Energy Outlook 2009, Energy Information Administration.



The magnitude of domestic oil shale resources has prompted several attempts to develop a commercial oil shale industry.[20] However, to date, none has emerged. Although the oil shale resource in the western United States underlies federal, state, private and tribal lands, the majority of recoverable oil shale deposits underlie federal lands. Thus, gaining access to federal lands is often viewed as critical to the long-term success of commercializing the oil shale resource.[21] Estimates of the federal oil shale resource range from 60%[22] to 73%[23] to 80%[24] of the total domestic oil shale resource. This disparity in estimates is due in part to differences in estimate terminologies (i.e. recoverable versus in-place or total domestic oil shale resource versus most geologically prospective oil shale resource area) and in part due to the age and accuracy of the underlying data used to make the estimates.

Even at the low end of the estimate range, federal oil shale holdings are likely to remain an essential element of long-term oil shale commercialization for several reasons. First, the federal resource represents the majority of domestic oil shale deposits and will continue to represent an attractive target for potential commercial development. Second, non-federal oil shale-bearing lands tend to be smaller, discontinuous parcels surrounded by federal lands. Because of this, even if access to non-federal lands is obtained, access to adjacent federal lands may be needed to make commercial scale development feasible and economical or to avoid a sprawling patchwork of development. Third, there is an abundance of privately held land but almost no state land in the most geologically prospective oil shale area in Colorado, leaving prospective developers who lack large private holdings to focus primarily on federal oil shale-bearing lands.

The most recent federal effort to promote development of a commercial oil shale industry, the Energy Policy Act of 2005 (EPAct 2005),[25] deemed oil shale (along with oil sands and other unconventional fuels) to be a "strategically important domestic resource[] that should be developed to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports."[26] EPAct 2005 made "environmentally sound"[27] exploration and development of the oil shale resource in Colorado, Utah and Wyoming a national priority. EPAct 2005 authorized a Research, Development & Demonstration (RD&D)[28] leasing program for oil shale on the public lands, mandated that the Secretary of Interior (SOI) complete a final programmatic environmental impact statement for

[20] For a discussion of failed attempts to develop oil shale resources, *see* ANDREW GULLIFORD, BOOMTOWN BLUES: COLORADO OIL SHALE (2003) and JASON L. HANSON & PATTY LIMERICK, UNIVERSITY OF COLORADO CENTER FOR THE AMERICAN WEST, WHAT EVERY WESTERNER SHOULD KNOW ABOUT OIL SHALE: A GUIDE TO SHALE COUNTRY (2009).

[21] *See* Utah Mining Association, Development of Utah Oil Shale and Tar Sands Resources (Oct. 2008), *available at* http://www.utahmining.org/UMA%20White%20Paper%20on%20Development%20of%20Utah%20OS%20TS.pdf.

[22] *See* FINAL PEIS at 2-13.

[23] *See* 74 FED. REG. 56867 (Nov. 3, 2009).

[24] *See* DEPARTMENT OF ENERGY OFFICE OF PETROLEUM RESERVES, Fact Sheet: U.S. Oil Shale Resources, *available at* http://www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf.

[25] 42 U.S.C. §§ 15801 *et. seq.*

[26] 42 U.S.C. § 15927(b)(1).

[27] 42 U.S.C. § 15927(b)(2).

[28] The Bureau of Land Management's (BLM) first round of RD&D leases was authorized under the Mineral Leasing Act (MLA), as amended by EPAct 2005. *see also* 70 FED. REG. 33753 (June 9, 2005). The BLM first issued RD&D leases before it began developing a commercial leasing program for oil shale. As explained by the BLM, "[b]y initiating a research, development and demonstration leasing process, the BLM can provide itself, state and local governments, and the public, with important information that can be utilized as BLM works with communities, states and other Federal agencies to develop strategies for managing any environmental effects and enhancing community infrastructure needed to support the orderly development of this vast resource. This will be valuable information for a rulemaking addressing commercial oil shale leasing." 70 FED. REG. 33754 (June 9, 2005).

a commercial leasing program for oil shale on the public lands (Final PEIS)[29] and finalized a regulatory framework for federal commercial oil shale leasing and development.[30] Under EPAct 2005, it was intended that these federal activities would, subject to consultation with affected states, tribes, and communities,[31] culminate in the Department of Interior (DOI) issuing commercial oil shale leases on the public lands.[32]

Events between 2005 and the present illustrate the intertwined complexities of realizing EPAct 2005 policy aims and creating a domestic oil shale industry. The scope of the Final PEIS, originally intended to provide the requisite environmental analysis for federal commercial oil shale leasing, was abridged due to a dearth of information about the nature and impacts of oil shale development. Ultimately, the Final PEIS was limited solely to identifying federal lands in Colorado, Utah and Wyoming that should be open to consideration for oil shale leasing.[33] Commercial oil shale leasing regulations were promulgated, however, those rules, along with the Final PEIS, are currently the subject of litgation,[34] and no commercial leases have been issued.

Six RD&D leases have been issued by the Bureau of Land Management (BLM), five in Colorado, one in Utah, and none in Wyoming. But to date, no RD&D lease has proceeded to any level of oil shale production. Fluctuating oil prices have lent further instability to oil shale development efforts, ranging from $65/barrel at the time EPAct 2005 was enacted, to an all-time high of $134/barrel in June 2008, and then back down to $76/barrel as of late November 2009.[35] These fluctuations have provided widely shifting incentives and disincentives for investment in oil shale resource holdings and in extractive technologies. In short, implementation of an oil shale leasing and development program on the public lands remains the subject of interest and discussion with very little action.

Numerous challenges have been cited as the obstacles forestalling commercial oil shale development, including adverse environmental impacts, excessive water consumption, greeenhouse gas (GHG) implications of potential oil shale technologies, fluctuating oil prices, economic and regulatory uncertainties, and lack of access to federal oil shale resources.[36] This report seeks to identify and evaluate the critical legal and economic policy issues in order to inform federal, state, tribal, and other decision makers, as well as affected citizens, of the likely challenges and tradeoffs inherent in implementing a commercial oil shale leasing program on the public lands. Where possible, this report also presents potential approaches to managing these challenges and tradeoffs. The focus is on the most geologically

[29] 42 U.S.C. § 15927(c); *see also* U.S. DEPARTMENT OF INTERIOR, BUREAU OF LAND MANAGEMENT, DRAFT OIL SHALE AND TAR SANDS RESOURCE MANAGEMENT PLAN AMENDMENTS TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT (Dec. 2007) ("DRAFT PEIS"); U.S. DEPARTMENT OF INTERIOR, BUREAU OF LAND MANAGEMENT, FINAL OIL SHALE AND TAR SANDS RESOURCE MANAGEMENT PLAN AMENDMENTS TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT ("FINAL PEIS"); U.S. DEPARTMENT OF INTERIOR, BUREAU OF LAND MANAGEMENT, APPROVED RESOURCE MANAGEMENT PLAN AMENDMENTS/RECORD OF DECISION (ROD) FOR OIL SHALE AND TAR SANDS RESOURCES TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND FINAL PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT (Nov. 2008) ("OIL SHALE ROD").

[30] 42 U.S.C. § 15927(d)(1)-(2); *see also* 73 FED. REG. 69414-487 (Nov. 18, 2008), codified at 43 C.F.R. § 3900.10.

[31] 42 U.S.C. § 15927(b)(3).

[32] *See* 42 U.S.C. § 15927(e).

[33] OIL SHALE ROD at 43.

[34] *See Colorado Environmental Coalition v. Kempthorne*, 1:09-CV-00085-JLK and 00091-JLK (D.Colo. pending).

[35] The quoted prices are the monthly or daily nearest-term ("Contract 1") futures prices for light, sweet crude delivered at Cushing, OK. *See* http://tonto.eia.doe.gov/dnav/pet/PET_PRI_FUT_S1_M.htm and http://tonto.eia.doe.gov/dnav/pet/pet_pri_fut_s1_d.htm.

[36] *See generally*, Anthony Andrews, *Congressional Research Service Report to Congress: Oil Shale: History, Incentives, and Policy* (April 13, 2006).

prospective oil shale area, which is comprised of those oil shale deposits in the Green River Formation capable of yielding at least 25 GPT that are 25 feet (or greater) in thickness,[37] and thus thought to represent the most attractive development target for commercial leasing and development of oil shale on the public lands.[38] As large, contiguous deposits of this richness and thickness are found only in Colorado and Utah, this report does not specifically address implementation of a commercial oil shale leasing program on the public lands in Wyoming.[39]

[37]This area of focus is drawn from the BLM's definition of the "most geologically prospective oil shale resources." FINAL PEIS.

[38]The rich oil shale deposits in Wyoming "are situated in thinner, less continuous layers and represent a less favorable development target, compared with the Colorado and Utah deposits." JAMES T. BARTIS ET AL., RAND CORP., OIL SHALE DEVELOPMENT IN THE UNITED STATES: PROSPECTS AND POLICY ISSUES 8 (2005). Accordingly, early efforts at commercial oil shale development, both on and off the public lands, have been thought most likely to commence in Colorado and Utah. BARTIS ET AL. at 7. Recently, however, interest in Wyoming's oil shale resources appears to have increased, with Anadarko Petroleum Corp. committing to construct Wyoming's first research and development facility on 160 acres of private land near the town of Rock Springs. *See* Jeff Gearino, *Wyoming Gets Oil Shale Project*, CASPER STAR-TRIBUNE (June 2, 2009).

[39]Although this report does not specifically discuss oil shale bearing lands within Wyoming, the issues and analysis discussed in this report are generally applicable to public lands and oil shale resources within Wyoming.

CHAPTER 2

PLANNING FOR OIL SHALE LEASING AND DEVELOPMENT ON THE PUBLIC LANDS

An array of environmental laws are relevant to planning and implementing a commercial oil shale leasing and development program on the public lands. These laws and their attendant regulatory frameworks are critical to the legal and policy context within which federal oil shale leasing decisions will occur. In addition, political and practical considerations discussed throughout this report will be essential components of any evaluation surrounding initiation of a federal commercial oil shale leasing program. At a threshold level, any commercial oil shale development on the public lands will be subject to the environmental analysis and land use planning requirements of the National Environmental Policy Act (NEPA)[40] and the Federal Land Policy Management Act (FLPMA).[41] Summaries of these two statutes follow.

2.1 THE NATIONAL ENVIRONMENTAL POLICY ACT

The National Environmental Policy Act (NEPA),[42] enacted on January 1, 1970, is in many ways the cornerstone of federal environmental law. NEPA declares it to be federal policy to "encourage productive and enjoyable harmony between man and his environment; to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man; to enrich the understanding of the ecological systems and natural resources important to the Nation."[43] NEPA is unique among federal environmental laws as it does not dictate particular outcomes. Instead, NEPA mandates a public decision-making process intended to culminate in considered, well-informed federal decisions affecting the environment.

Under NEPA "every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, [must include] a detailed statement by the responsible official on . . . the environmental impact of the proposed action."[44] This analysis of

[40] 42 U.S.C. §§ 4321 – 61.
[41] 43 U.S.C. §§ 1701 – 84.
[42] 42 U.S.C. §§ 4321-4370d.
[43] 42 U.S.C. § 4321.
[44] 42 U.S.C. § 4332(2)(C).

the environmental impacts must address the direct, indirect and cumulative effects[45] of the proposal, utilizing "a systematic, interdisciplinary approach,"[46] incorporating public involvement throughout the document's preparation.[47] For most major projects, the process culminates in the issuance of a Record of Decision (ROD) explaining the decision.[48]

NEPA applies only to federal actions. A "federal action" is one in which a federal agency has the authority to incorporate or require changes to the proposed action and includes decisions to grant a permit, use federal lands, or provide federal funding.[49] NEPA does not apply to actions by state government (including its subdivisions), to purely private actions, or to actions where the federal agency lacks discretionary authority to deny or modify a proposal.[50] While the level of detail and associated procedural requirements required in the NEPA process may vary depending on the nature of the impacts anticipated, the fundamental test of the adequacy of a particular NEPA process remains the same—whether the federal agency took a "hard look" at both the environmental consequences of the proposed action and a reasonable range of alternate means of satisfying the underlying need for the project.[51] The question of whether the BLM took the requisite hard look in NEPA documents pertaining to oil shale and public land management within the most geologically prospective oil shale area is currently being litigated in three federal courts.[52]

With respect to commercial oil shale leasing and development, NEPA will generally apply only to projects proposed for federal lands.[53] NEPA analysis is required at the point in time that a federal agency makes an "irretrievable commitment of resources."[54] Issuance of a lease generally satisfies this requirement as the lease conveys certain property rights that cannot be revoked absent the payment of just compensation.[55]

The Final PEIS for oil shale development was originally intended to provide the initial NEPA framework for a commercial oil shale leasing program. However, uncertainty regarding the number and size of facilities, as well as the technologies involved and individual facilities' location within the most geologically prospective oil shale area prevented the BLM from completing the "hard look" required under NEPA.[56] Instead, the Final PEIS identifies only which areas are open to consideration for commercial leasing applications.[57] Because the Final PEIS did not evaluate the environmental impact of leasing specific parcels of land, an additional round of NEPA analysis will be required before leases can be issued[58] in order to address the reasonably foreseeable consequences of developing those to-be-leased lands.[59] Whether a third round of NEPA analysis will be required before operational development can

[45] 40 C.F.R.§ 1508.8.
[46] 42 U.S.C. § 4332(2)(A).
[47] 40 C.F.R. § 1506.6.
[48] 40 C.F.R. § 1505.2.
[49] 40 C.F.R. § 1508.18.
[50] *South Dakota v. Andrus*, 614 F.2d 1190 (8th Cir. 1980)
[51] *Kleppe v. Sierra Club*, 427 U.S. 390 (1976).
[52] *See Western Watersheds Project v. Kempthorne*, (No. 08-cv-516-BLW) (D. Id. 2009), *Southern Utah Wilderness Alliance v. Allred*, (No. 1:08-cv-02187) (D. D.C. 2009), and *Colorado Environmental Coalition v. Kempthorne* (Nos. 1:09-CV-00085-JLK and 00991-JLK) (D. Colo. 2008).
[53] NEPA analysis may be required for projects proposed for non-federal lands where other federal approvals are required or where federal funds are expended. An example of such a NEPA trigger is requesting approval, under Section 404 of the Clean Water Act, to place fill materials in wetlands or waters of the United States.
[54] *Conner v. Burford*, 848 F.2d 1441 (9th Cir. 1988).
[55] *Conner v. Burford*, 848 F.2d 1441 (9th Cir. 1988).
[56] *See* FINAL PEIS at 1-3.
[57] *See* FINAL PEIS at 1-3 - 1-5.
[58] OIL SHALE ROD at 38.
[59] NEPA analysis must address actions that are connected to the decision to be made. Actions are connected if they (1)

proceed, depends on the amount of information regarding development operations available and considered at the time the leasing analysis is completed. To the extent possible, the BLM will tier to prior NEPA documents, focusing solely on the progressively narrower issues addressed in subsequent rounds of analysis.[60] Each round of NEPA analysis will afford the interested public an opportunity to review and comment on each proposed action and its alternatives.[61] The BLM must review these comments, respond to substantive issues and revise its alternatives or analysis as appropriate.[62]

Many of the issues presented by commercial oil shale leasing and development will be considered in greater detail during future stages of NEPA review, when more information is available. Issues such as impacts to wildlife, water resources, air quality, and GHG emissions will be thoroughly scrutinized by a wide range of interested parties. Other issues, such as optimal national and international energy strategies, whether there is a role for oil shale in the domestic energy portfolio, and the appropriate balance between energy production and environmental protection, are outside the scope of NEPA review and will need to be independently evaluated by policymakers. Addressing these national policy issues is essential to developing sound policies for commercial oil shale leasing and development.

2.2 THE FEDERAL LAND POLICY AND MANAGEMENT ACT

The Federal Land Policy and Management Act (FLPMA), enacted on October 21, 1976, sets forth the federal policy that BLM-administered public lands must be managed according to the twin principles of multiple use and sustained yield.[63] "Multiple use" means making the most judicious use of public lands for the present and future needs of the American people, "taking into account the long-term needs of future generations for renewable and nonrenewable resources, including but not limited to recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values ... without permanent impairment of the productivity of the land and the quality of the environment."[64] "Sustained yield" means "the achievement and maintenance, in perpetuity, of a high-level ... output of the various renewable resources of the public lands consistent with multiple use."[65]

In order to meet these management obligations, FLPMA directs the SOI to "prepare and maintain on a continuing basis an inventory of all public lands and their resource and other values (including, but not limited to, outdoor recreation and scenic values)."[66] Each inventory must identify and give special priority to Areas of Critical Environmental Concern (ACECs) requiring "special management attention" to "protect and prevent irreparable damage to important historic, cultural, or scenic values,

automatically trigger other actions that may require an environmental impact statement, (2) cannot or will not proceed unless other actions are taken previously or simultaneously, or are (3) interdependent parts of a larger action and depend on the larger action for their justification. 40 C.F.R. § 1508.25(a)(1).

[60] *See* 40 C.F.R. § 1502.20 ("Whenever a broad environmental impact statement has been prepared (such as a program or policy statement) and a subsequent statement or environmental assessment is then prepared on an action included within the entire program or policy (such as a site specific action), the subsequent statement or environmental assessment need only summarize the issues discussed in the broader statement and incorporate discussion from the broader statement by reference and shall concentrate on the issues specific to the subsequent action.").

[61] *See* 40 C.F.R. § 1501.7 ("There shall be an early and open process for determining the scope of the issues to be addressed and for identifying the significant issues related to a proposed action ... (a) as part of the scoping process the lead agency shall: ... (1) invite the participation of ... interested persons (including those who might not be in accord with the action on environmental grounds);" 40 C.F.R. § 1503.3(a)) "Comments on an environmental impact statement or proposed action ... may address either the adequacy of the statement or the merits of the alternatives discussed or both.").

[62] 40 C.F.R. § 1503.4.

[63] 43 U.S.C. § 1701(7).

[64] 43 U.S.C. § 1702(c).

[65] 43 U.S.C. § 1702(h).

[66] 43 U.S.C. § 1711(a).

fish and wildlife resources or other natural systems of processes, or to protect life and safety from natural hazards."[67] Based on these inventories, the BLM must develop, maintain, and revise Resource Management Plans (RMPs) for the public lands it administers.[68] RMPs essentially function as zoning plans for public lands administered by the BLM, determining what uses and protections are appropriate for areas based on existing conditions and statutory requirements (including multiple use and sustained yield principles). Preparation and development of an RMP is a public process involving input from interested members of the public, tribal governments, and state and local governments.[69]

The BLM recently completed programmatic amendments to ten RMPs governing management of lands overlaying oil shale resources for public lands spread across Colorado, Utah, and Wyoming.[70] These programmatic amendments designate certain federal lands as "available for application for commercial leasing and future exploration and development" of oil shale and tar sands resources.[71] However, the programmatic amendments do not replace individual RMPs. Instead, finalization of these programmatic amendments "only amends the decisions for oil shale ... and does not amend any of the decisions or protocols for the management of the other resource uses or values, such as air quality, wildlife, cultural resources, water quality, special resource values, etc."[72] Consequently, individual RMPs and the programmatic amendments must be read together and individual RMPs remain critically important.

Six Utah BLM field offices completed RMP revisions during late 2008. The adequacy of these revised plans is the subject of ongoing legal challenges.[73] Three Colorado BLM field offices are in the process of revising their RMPs. The outcome of pending RMP challenges will be of great importance to prospective oil shale developers because RMPs establish management practices for a wide range of resources that will directly and indirectly affect development of oil shale bearing public lands.

2.3 PROJECT PLOWSHARE

Project Plowshare represents one of several site-specific issues that policymakers will need to consider in planning for oil shale leasing on the public lands. Although Project Plowshare has not been discussed extensively in previous published analyses of commercial oil shale leasing and development, it has the potential to significantly impact planning for commercial oil shale development on the public lands.

Several decades ago, as part of Project Plowshare, the U.S. Atomic Energy Commission conducted underground nuclear detonations designed to increase natural gas production from low-permeability sandstone.[74] The locations of the detonations are shown in Figure 2.3.1. The intent was to stimulate

[67] 43 U.S.C. § 1702(a). In addition to ACECs, the BLM is also statutorily required to manage other specially designated areas on the public lands, such as wilderness, Wilderness Study Areas and Wild and Scenic Rivers. The impacts of these designated areas on future oil shale leasing and development are discussed later in this chapter.

[68] 43 U.S.C. § 1712(a).

[69] Under FLPMA and its implementing regulations, BLM land use plans "shall be consistent with State and local plans to the maximum extent [the Secretary of the Interior] finds consistent with federal law and the purposes of this Act." 43 U.S.C. § 1712(c)(9). However, the leverage afforded to the states or their subdivisions by this provision is questionable as the 10th Circuit Court of Appeals recently concluded that the Secretary's duty is discretionary and thus unlikely to create a procedural right enforceable by state or local governments. *Kane County v. Salazar*, 562 F.3d 1077, 1088 (10th Cir. 2009).

[70] OIL SHALE ROD.

[71] OIL SHALE ROD at ii.

[72] OIL SHALE ROD at 41.

[73] *Western Watersheds Project v. Kempthorne*, (No. 08-cv-516-BLW) (D. Id. 2009) (challenging adequacy of sage grouse management), and *Southern Utah Wilderness Alliance v. Allred*, (No. 1:08-cv-02187) (D. D.C. 2009) (challenging Moab, Price, and Vernal RMPs).

[74] *See generally*, FRANK KREITH AND CATHERINE B. WRENN, THE NUCLEAR IMPACT: A CASE STUDY OF THE PLOWSHARE PROGRAM TO PRODUCE GAS BY UNDERGROUND NUCLEAR STIMULATION IN THE ROCKY MOUNTAINS (1976). *See also* U.S. Dept. of Energy, Office of Environmental Management, *Rio Blanco*, *available at* http://www.lm.doe.

the flow of natural gas through fractures created by the blasts and use the blast chimney as a natural gas collection chamber. Two detonations occurred in western Colorado.

The Rulison Project detonation, which occurred on September 10, 1969, consisted of a single detonation 8,426 feet underground and approximately 12 miles southwest of the town of Rifle.[75] Although approximately 455 million cubic feet of natural gas were produced, elevated levels of radioactivity in the gas made it unacceptable for use.[76] The test area is outside the most geologically prospective oil shale area evaluated in the Final PEIS[77] but within an area where numerous pre-1920 land patents have been converted to private land. The surface property within the Rulison Site is privately owned, but the federal government retains control of the subsurface rights beginning at a depth of 6,000 feet within a 40 acre area.[78]

gov/SiteInfo/RioBlanco.aspx.

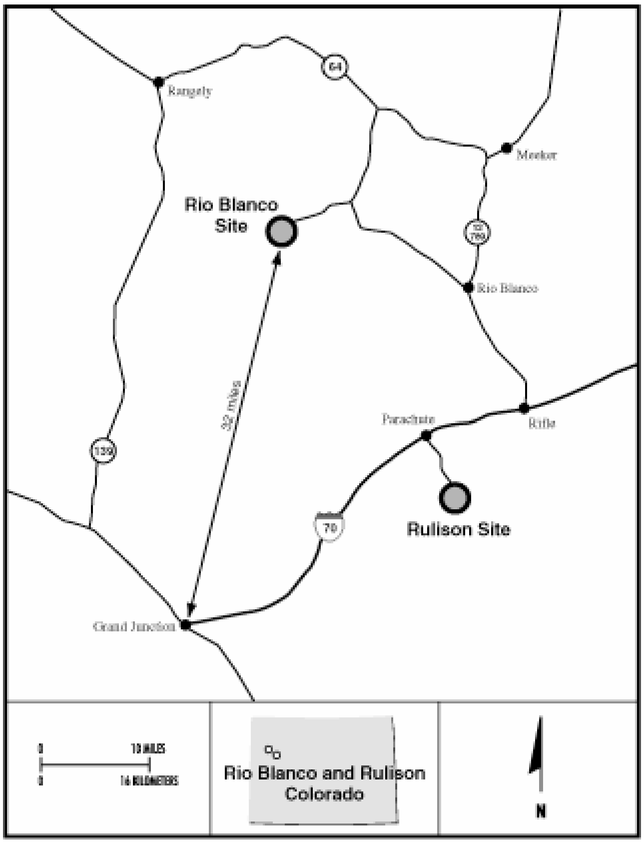
[75] U.S. Department of Energy, Office of Legacy Management, Fact Sheet: Rulison, Colorado, Site (May 2008), *available at* http://www.lm.doe.gov/land/sites/co/rulison/rulison.htm.

[76] U.S. Department of Energy, Office of Legacy Management, Fact Sheet: Rulison, Colorado, Site (May 2008), *available at* http://www.lm.doe.gov/land/sites/co/rulison/rulison.htm. Colorado reached a different conclusion. According to the Colorado Oil and Gas Conservation Commission, "flaring removed much of the gas-phase radioactive contamination from the blast site" and "radioactivity of the gas produced from the well was below levels hazardous to human health" by conclusion of the testing and flaring period. David Neslin, Colorado Oil and Gas Conservation Commission Acting Director, *Action on Application for Permits to Drill at Locations from One-Half Mile to Three Miles from the Project Rulison Blast Site* (Dec. 21, 2007).

[77] *See* FINAL PEIS at Figure 2.3-1.

[78] U.S. Department of Energy, Office of Legacy Management, Fact Sheet: Rulison, Colorado, Site (May 2008), *available at* http://www.lm.doe.gov/land/sites/co/rulison/rulison.htm.

Figure 2.3.1: Project Plowshare Detonation Sites. Source: Department of Energy.



The Rio Blanco Project involved detonation of three 30 kiloton devices in a single hole more than a mile below ground.[79] The detonations occurred on May 17, 1973, about 30 miles southwest of the town of Meeker.[80] Meeker is within the most geologically prospective oil shale area and near five existing RD&D leases.[81] As the Final PEIS explains:

> This site is not included as part of the study because the area is not on BLM-administered land . . . [M]onitoring conducted at this DOE Legacy site shows no surface contamination, and there are no surface use restrictions at the site. However, subsurface disturbance is not allowed within a 600-ft radius of the test area without U.S. government permission. Groundwater and surface water monitoring have shown no radiological contamination. The Green River Formation lies about 3,000 ft above the depth where the detonations occurred. If the BLM were to lease its bordering property for oil shale development in the future, stipulations would be included to confirm that no radioactive contamination would be mobilized.[82]

[79] KREITH & WRENN at 176.
[80] U.S. Department of Energy, Office of Legacy Management, Fact Sheet: Rio Blanco, Colorado, Site (Nov. 2007), *available at* http://www.lm.doe.gov/land/sites/co/rio/rio.htm. *See* FINAL PEIS at Figure 2.3-1.
[81] *See* FINAL PEIS at Figure 2.3-1.
[82] FINAL PEIS at 3-12.

This BLM description seems to depart from the potential risk identified by the U.S. Department of Energy, Office of Environmental Management, which states:

> Contamination was present as a result of the activities conducted on the sites in conjunction with the gas stimulation testing and gas flaring operations. At the Rio Blanco site, contamination consisted of radioactive contamination of the deep bedrock around the shot cavities; contamination of a deep zone in FCG Well No. 1, in which contaminated water from the production testing and decontamination operations was injected; possible surface contamination from the gas flaring activities; and near-surface hazardous waste contamination from the closed mud pits. Groundwater is the most likely transport medium for the deep contamination. The cleanup strategy was to characterize ground-water flow and area of contamination, assess risk, and model contaminant movement away from the shot cavities. The focus was on tritium, since it was the most mobile of the potential radiological contaminants.[83]

The site-specific NEPA analysis required for leasing near the Rio Blanco project area will almost certainly involve detailed analysis of the extent of contamination, the proposed means of development, and the potential for development to release radioactive contamination—including the potential to fracture surrounding geological structures and contribute to groundwater contamination. Potential lessees should receive advance notice of these complications before initiating the leasing process. At a minimum, past nuclear testing and associated contamination raise concerns that will increase the complexity of the subsequent NEPA analysis (conducted at the lessee's cost) and may affect the value of surrounding lease tracts. More generally, federal and state policymakers will need to evaluate how best to manage oil shale development activities proximate to the Project Plowshare legacy sites.[84]

2.4 Conclusion and Recommendations

If commercial oil shale leasing and development occurs on the public lands, it will occur within a comprehensive regulatory context that involves both planning and review of actions impacting the environment. While the requisite threshold decisions are in place for oil shale to occur, these decisions are the subject of ongoing litigation and thus do not currently provide the stable framework needed to foster commercial oil shale development.

[83] U.S. Dept. of Energy, Office of Environmental Management, *Rio Blanco*, *available at* http://www.em.doe.gov/SiteInfo/RioBlanco.aspx.

[84] Managing development near nuclear legacy sites is an ongoing concern. The Colorado Oil and Gas Conservation Commission authorizes wells within one-half to three miles of the Rulison blast site on a case-by-case basis. As of December 2007, it had authorized 13 producing wells, 40 permitted but undrilled wells, and 19 additional applications for permits to drill were pending. David Neslin, Colorado Oil and Gas Conservation Commission Acting Director, *Action on Application for Permits to Drill at Locations from One-Half Mile to Three Miles from the Project Rulison Blast Site* 2 (Dec. 21, 2007). The Commission is currently considering natural gas drilling within less than a half mile of the blast site. *See* Richard Martin, *Re-Considering Rulison, Once Again*, Colorado Energy News (July 20, 2009); Associated Press, *Colorado Regulators Discuss Gas Wells near Nuke Site*, (July 14, 2009). Drilling would involve hydraulic fracturing of surrounding rock in order to increase gas production. In situ oil shale production, like natural gas production, would involve fracturing. Policymakers will need to thoroughly analyze these proposed fractures and their ability to facilitate migration of contaminated groundwater. If there proves to be sufficient similarity between fracturing for in situ oil shale production and fracturing for natural gas production, information obtained by the Commission may help to answer some of the questions likely to arise in planning for oil shale leasing and development on the public lands.

Chapter 3

Developing an Optimal Commercial Leasing Model for Oil Shale

The nature and extent of surface disturbances associated with oil shale development vary depending on the technology utilized. The BLM assumes that for a commercial surface mine with surface retort, "the entire lease area [5,760 acres or nine square miles] would be disturbed during the 20-year [development] time frame."[85] If operations utilize surface retorting combined with an underground mine, the disturbance area would shrink to 1,650 acres (approximately 2.6 square miles) over the project's 20 year lifetime.[86] The majority of this area (1,500 acres) would be dedicated to spent shale disposal, which would be piled 250 feet high.[87] While in situ development avoids the difficult problem of spent shale disposal, the BLM anticipates that "the entire lease area will be disturbed during the 20-year [development] time frame."[88]

The anticipated breadth of disturbance distinguishes oil shale from conventional oil or natural gas development, where extensive disturbance occurs only on portions of the lease tract. Improvements in oil and gas extraction technologies, including advances in directional drilling and consolidated drilling pads, have further allowed operators to reduce the footprint of oil and gas development and avoid site-specific resource conflicts. Although the BLM's oil shale leasing regulations draw from conventional oil and gas law, an alternate regulatory model appears better suited to managing the potential scope of surface impacts associated with oil shale development. A comparison of the federal leasing models for fluid minerals, surface coal mining, and oil shale (RD&D and commercial), as well as non-federal leasing models and royalty approaches, follows.

3.1 Federal Oil and Gas Leasing Model

About half of the 700 million subsurface acres administered by the BLM are believed to contain oil and natural gas.[89] Development of these onshore federal oil and natural gas resources occurs in five phases: (1) land use planning, (2) parcel nomination and lease sales, (3) well permitting and production, (4) operation and production, and (5) plugging and reclamation. The land use-planning phase of federal

[85] Final PEIS at 4-4 n. c.
[86] Final PEIS, 4-8 n. c.
[87] Final PEIS, 4-9. This figure assumes that 30% of spent shale is returned to the underground mine for disposal.
[88] Final PEIS, 4-11 n. c.
[89] *See* BLM Oil and Gas Leasing, http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/leasing_of_onshore.html.

oil and gas leasing occurs when the BLM inventories resources and prepares an RMP for the area(s) considered for leasing.[90] RMPs determine which areas are open to leasing and what, if any, additional lease stipulations are needed to protect sensitive resources.[91] This initial determination is subject to review pursuant to the requirements contained in NEPA and other federal laws.

Once planning is completed, any member of the public may nominate lands for leasing, provided nominated parcels are identified as open for leasing in the RMP. The BLM reviews each nomination to ensure parcels are available and that stipulations from the RMP are attached before the lease is placed on sale. Nominated and approved parcels are then offered for competitive bid, and successful bidders obtain the right to explore, drill for, extract, remove, and dispose of deposits of oil and most gases found on the leased parcel.

Before commercial production can begin, the leaseholder or an operator hired by the leaseholder files an application for a permit to drill and a surface use plan of operations detailing their proposed development and associated infrastructure requirements.[92] Because the planning area covered by a typical RMP is generally large, often in excess of one million acres, RMPs tend to be general in scope and lack the site-specific detail required to begin construction. Therefore, the application for a permit to drill and the surface use plan of operations are normally subject to another round of site-specific NEPA review and analysis. At this point, the BLM can require the operators to move facilities short distances or impose short-term use restrictions to reduce resource impacts, but the BLM generally cannot prohibit the intended use once a lease is issued.[93]

As part of the leasing process, leaseholders are required to post reclamation bonds to assure adequate site restoration.[94] Following cessation of operation and production activities, the leaseholder must plug open oil and gas wells and reclaim the lease site.[95] Reclamation must begin as soon as possible after the surface is disturbed and continue until the BLM determines that successful reclamation has been achieved.[96]

3.2 FEDERAL COAL LEASING MODEL

The Surface Mining Control and Reclamation Act (SMCRA)[97] sets forth requirements for all coal surface mining on federal and state lands.[98] Mine operators must minimize disturbances and adverse impacts on fish, wildlife and related environmental values and achieve enhancement of such resources wherever practicable. SMCRA also authorizes the SOI to assess whether federal lands are unsuitable for some or all types of surface coal mining.[99] Unsuitability criteria are applied prior to lease issuance,[100] either as part of the land planning process or through site-specific NEPA review for specific lease appli-

[90] 43 U.S.C. §§ 1711, 1712.
[91] Under all leases, the BLM can require operators to move facilities by up to 200 meters and limit operations for up to 60 days; longer or more restrictive limitations must be authorized by law or included in additional stipulations in the lease. 43 C.F.R. § 3101.1-2.
[92] 43 C.F.R. § 3162.3-1.
[93] *See* 43 C.F.R. § 3101.1-2.
[94] 43 C.F.R. § 3104.1(a).
[95] 43 C.F.R. § 3162.3-4.
[96] 43 C.F.R. § 3101.1-2.
[97] 30 U.S.C. §§ 1201-1328.
[98] Most coal-mining states now have the primary responsibility to regulate surface coal mining on lands within their jurisdiction, with the federal Office of Surface Mining performing an oversight role.
[99] 30 U.S.C. § 1272(b).
[100] 43 C.F.R. § 3461.3-1(a).

cations.[101]

An area may be designated unsuitable for certain types of surface mining based on four factors: (1) incompatibility with state or local land use requirements; (2) significant damage to important historic, cultural, scientific, and esthetic values and natural systems; (3) substantial loss or reduction in long-term productivity of water supply or agriculture; and (4) natural hazards substantially endangering life and property.[102] Under rules promulgated by the SOI, these four general factors give rise to 20 specific criteria.[103] In practice, the BLM usually begins its unsuitability analysis by identifying coal resources with development potential and surveying these areas for constraining resources.[104]

An essential distinction between fluid mineral leasing regulations and surface coal mining leasing regulations is that the former model defers much of the site-specific environmental analysis until after leases have been issued. The surface coal mining regulations require comprehensive resource inventories prior to issuing leases as impact avoidance is far more difficult in the context of surface coal mining activities than fluid mineral extraction. The anticipated surface impacts associated with oil shale development are more akin to that of surface coal mining than fluid mineral exraction, and thus deferring site-specific environental analysis until after leases are issued is likely to be an ineffective means of managing the environmental impacts of oil shale leasing and development on the public lands.

3.3 FEDERAL RD&D OIL SHALE LEASING MODEL

On June 9, 2005, the BLM initiated the first round of an RD&D leasing program by soliciting nominations of 160-acre parcels of public land to be leased in Colorado, Utah, and Wyoming.[105] Parcels leased under the RD&D program are available to investigate oil shale recovery technologies and inform potential future commercial leasing decisions and regulations, building the foundation for a subsequent commercial leasing program.[106] In response to 19 nominations, the BLM issued six RD&D leases, five in Colorado and one in Utah. Each RD&D lease contains a preference right allowing conversion of the RD&D lease acreage, along with an additional adjacent 4,960 acres, to a commercial lease upon demonstration of a successful method for producing oil from shale.[107] The six RD&D lease sites and the associated preference acreage are shown in Figure 3.3.1. Additional NEPA compliance is required before an RD&D lease can be converted to a commercial lease.[108] While all six first round RD&D leases remain active, none has proceeded to commercial development.[109] Addenda to these RD&D leases were

[101] 43 C.F.R. § 3461.3-1(b).

[102] 30 U.S.C. § 1272(a)(3), *see also* 30 C.F.R. § 762.11(b).

[103] *See* 43 C.F.R. § 3461.5. SMCRA also includes criteria for designating federal lands as unsuitable for mining of non-coal minerals, but the criteria are limited to adverse impacts to urban or suburban residences. 30 U.S.C. § 1281(b).

[104] *See e.g.*, *Coal Unsuitability Report Henry Mountains Coal Field*, which is included as Appendix 8 of the U.S. BUREAU OF LAND MANAGEMENT, RICHFIELD FIELD OFFICE PLANNING AREA, PROPOSED RESOURCE MANAGEMENT AND FINAL ENVIRONMENTAL IMPACT STATEMENT (Aug. 2008).

[105] 70 FED. REG. at 33753.

[106] 70 FED. REG. at 33754.

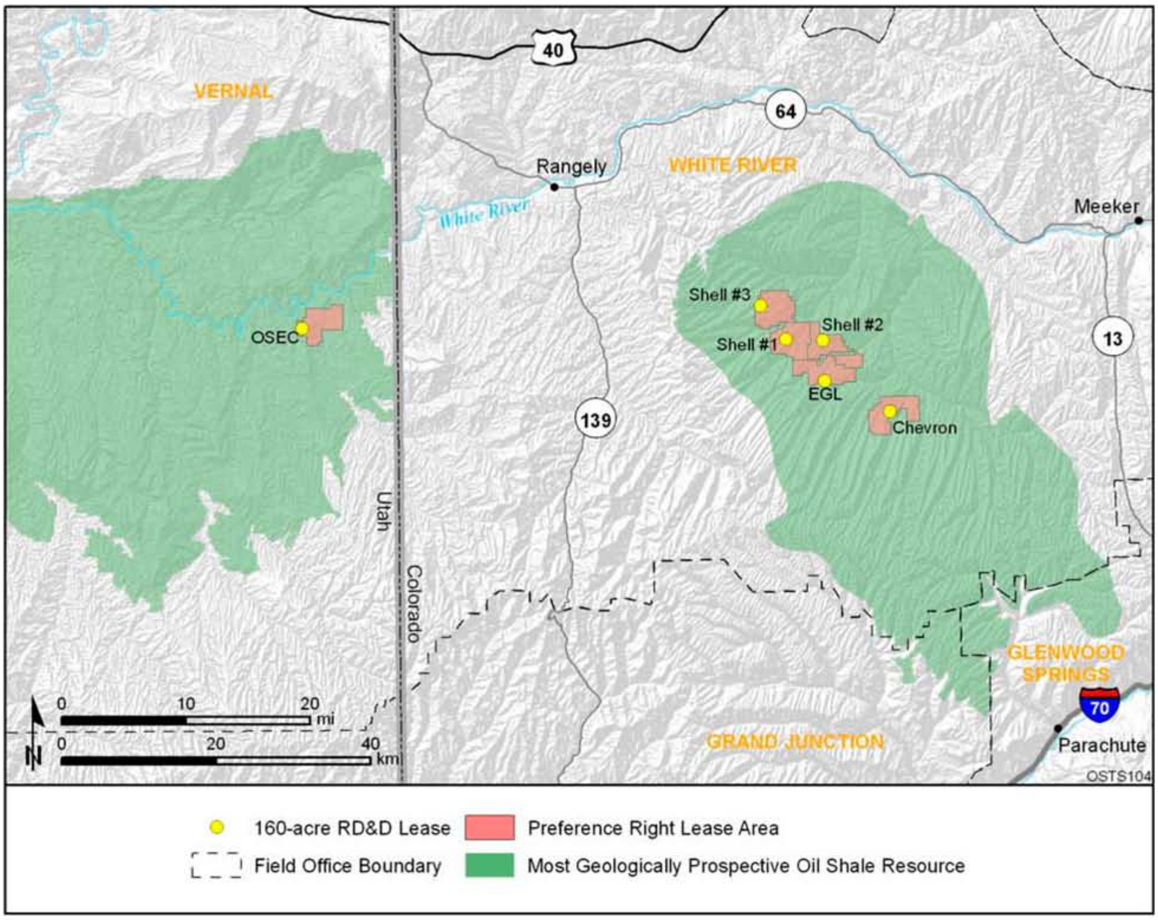
[107] 70 FED. REG. at 33754.

[108] 70 FED. REG. at 33754.

[109] Among the six active RD&D leases, the Oil Shale Exploration Company's (OSEC's) RD&D project in Utah stands in a unique position. First, it is the only RD&D project contemplating conventional mining methods and surface retorting of shale. *See* U.S. DEPARTMENT OF ENERGY, OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, SECURE FUELS FROM DOMESTIC RESOURCES: THE CONTINUED EVOLUTION OF AMERICA'S OIL SHALE AND TAR SANDS INDUSTRIES (Aug. 2008). Second, a portion of OSEC's preference area was not identified as available for application for commercial leasing in the FINAL PEIS. Portions of OSEC's preference area were excluded from the FINAL PEIS because of a potentially eligible Wild and Scenic River segment, Evacuation Creek. *See* Oil Shale ROD at 16. Although the 2008 Vernal RMP Record of Decision subsequently determined Evacuation Creek was ineligible for inclusion in the Wild and Scenic Rivers System, no

made on January 15, 2009, incorporating favorable conditions and low royalty rates, which are now the subject of investigations by the U.S. Department of Justice and DOI's Inspector General.[110]

Figure 3.3.1: Locations of the Six RD&D Lease Tracts and Associated Preference Right Lease Areas. Source: Bureau of Land Management.



The BLM initiated a second round of RD&D leasing on January 15, 2009.[111] The second solicitation departed from the 2005 model in that it increased the size of the initial lease tract from 160 to 640 acres and did not provide a preference right. The 2009 solicitation also included several less significant revisions intended to promote consistency with the BLM's recently issued commercial leasing regulations. The Obama Administration withdrew this second round of RD&D lease solicitations shortly after taking office.[112]

NEPA analysis has been completed for the leasing of these lands. Therefore, for commercial leasing to occur on the excluded segment, the BLM would also need to amend the Vernal Field Office's RMP.

[110] Letter from Ken Salazar, Secretary of the Interior, to Mary Kendall, Acting Inspector General, DOI (Oct. 19, 2009), *available at*, `http://www.doi.gov/documents/IG_Letter_RDD.pdf`.

[111] 74 FED. REG. 2611 (Jan. 15, 2009).

[112] 74 FED. REG. 8983 (Feb. 27, 2009). Congressional Republicans responded to the solicitation's withdrawal by introducing legislation that required DOI to offer an additional ten parcels for RD&D leasing under the terms of the January 19, 2009 RD&D lease offering. H.R. 2540, 111th Cong. (2009). Thus far the bill has made little progress.

On October 20, 2009, Secretary of the Interior Ken Salazar announced a revamped second round of RD&D lease solicitations.[113] This second round of RD&D leases is intended to:

> [F]ocus on the technology needed to develop the resources into marketable liquid fuels. Knowing the costs and benefits associated with the new technologies will inform the Secretary's future decisions about whether and when to move forward with commercial scale development and allow the Secretary to assess its impact on the environment, including an assessment of those impacts in light of climate change.[114]

Under this latest round of RD&D leasing, the initial lease size will be 160 acres with a preference right for an additional 480 contiguous acres becoming eligible for commercial development upon demonstration of the ability to commercially produce shale oil.[115] The new RD&D lease nominations will be reviewed by both the BLM, including a NEPA review, and an Interdisciplinary Review Team comprised of representatives from the States of Colorado, Utah, and Wyoming (as appropriate to the particular nomination) and the Departments of Defense and Energy.[116] New RD&D leases will be awarded based on the following criteria: "(1) Potential for a proposal to advance knowledge of effective technology; (2) Economic viability of the applicant; and (3) Means of managing the environmental effects of oil shale technology."[117]

Although RD&D leases have yet to yield commercially viable production technologies, they remain a tool well suited to testing new technologies and encouraging innovation. Continued utilization of RD&D leases, in some form, can help address many of the issues raised in this report.

3.4 Federal Commercial Oil Shale Leasing Model

Pursuant to the mandates of EPAct 2005, final regulations for oil shale leasing[118] and management on public lands were issued on November 18, 2008.[119] The regulations include provisions governing pre-lease exploration, leasing processes, bonding, operations, reclamation, and inspection and enforcement.[120] The regulations allow issuance of exploration licenses covering up to 25,000 acres[121] and leasing of up to 5,760 acre tracts,[122] but limit leaseholders to no more than 50,000 acres in any one

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[113] 74 Fed. Reg. 56867 (Nov. 3, 2009). When the BLM withdrew the original second round of RD&D leases it also requested comments on terms and conditions for future RD&D leases *See* 74 Fed. Reg. 8983 (Feb. 27, 2009). For a brief summary of the comments received by the BLM *see* 74 Fed. Reg. at 56868.

[114] 74 Fed. Reg. at 56868.

[115] 74 Fed. Reg. at 56868. The newly revised RD&D lease form can be found at http://www.blm.gov/wo/st/en/prog/energy/oilshale_2.html. The first and revamped second rounds of RD&D leases are compared in U.S. Department of Interior, Oil Shale DOI RD&D Second Round Fact Sheet (Oct. 20, 2009), *available at* http://www.doi.gov/documents/oil_shale_rdd_fact_sheet_001.pdf.

[116] 74 Fed. Reg. at 56868.

[117] 74 Fed. Reg. at 56868.

[118] With respect to federal lands, oil shale is considered a "leasable" mineral under the Mineral Leasing Act of 1920, 30 U.S.C. § 241, and those seeking to develop oil shale on public lands must obtain a lease from the federal government.

[119] *See* 73 Fed. Reg. 69414 – 487 (Nov. 18, 2008), codified at 43 C.F.R. § 3900. The final regulations apply to federal lands within portions of Colorado, Utah and Wyoming excluding National Parks, National Recreation Areas, lands within incorporated cities, towns and villages, and lands subject to special protections as a matter of law (e.g. Wilderness Study Areas). *See* 43 C.F.R. § 3900.10.

[120] 43 C.F.R. part 3900.

[121] 43 C.F.R. § 3910.31(c).

[122] 43 C.F.R. § 3827.20.

state.[123] Leases are subject to a $2.00 per acre annual rental charge,[124] with production royalties starting at 5% and increasing to 12.5% over time.[125] NEPA compliance is required prior to issuance of a lease or exploration license, or to approval of a plan of development.[126] Accordingly, an application to lease must include information regarding proposed technologies used to develop the tract, and a "description of the known historical, cultural, or archaeological resources within the lease area."[127] The application must also include a "description of how the proposed lease development would avoid, or, to the extent practicable, mitigate impacts on species or habitats protected by applicable state or federal law or regulations, and impacts on wildlife habitat management" before a lease can be offered for bid.[128] The regulations do not, however, specify the amount of detail required or direct the applicant to conduct surveys prior to submitting an application to lease. Nor do they articulate a clear standard regarding acceptable resource impacts. These are particularly significant omissions as very little is known about the scope of sensitive and irreplaceable resources located across much of the most geologically prospective oil shale area.[129]

On January 16, 2009, a coalition of environmental organizations filed lawsuits in Federal District Court for the District of Colorado, challenging the validity of the final leasing rule as well as the adequacy of the BLM's NEPA analysis of lands available for application for commercial oil shale leasing.[130] Federal lands are likely to remain effectively closed to commercial oil shale development until these legal challenges are resolved.[131]

A critical assessment of the current federal commercial oil shale leasing regulations must begin by considering the anticipated surface footprint of oil shale development. Consistent with the BLMs stated assumptions, federal land managers should expect that virtually the entirety of each oil shale lease tract

[123] 43 C.F.R. § 3901.20.

[124] 43 C.F.R. § 3903.40.

[125] 43 C.F.R. § 3903.52.

[126] 43 C.F.R. § 3900.50.

[127] 43 C.F.R. § 3922.20(c)(9).

[128] 43 C.F.R. § 3922.20(c)(7).

[129] These issues are discussed in greater detail in chapter 4 of this report.

[130] *Colorado Environmental Coalition v. Kempthorne*, 1:09-CV-00085-JLK and 00091-JLK (D.Colo. pending).

[131] Despite the many uncertainties regarding federal oil shale leasing and development, one notable hurdle to commercial federal oil shale development has been cleared. In 1930, President Hoover issued an Executive Order withdrawing "from lease or other disposal and reserved for the purpose or investigation, examination, and classification...the deposits of oil shale, and lands containing such deposits owned by the United States." Executive Order 5327 (April 15, 1930). Subsequent efforts modified the Executive Order to the extent necessary to permit leasing for sodium, oil and gas, "native asphalt, solid and semi-solid bitumen and bituminous rock," and limited oil shale leasing. *See* Executive Order 7038 (May 13, 1935), Executive Order 6016 (Feb. 6, 1933), Public Lands Order 2795 (Oct. 19, 1962). Until recently, however, the vast majority of federal lands containing deposits of oil shale remained subject to President Hoover's withdrawal. Acting under delegated authority (see Executive Order 10355 (May 26, 1952)), the Deputy Secretary of Interior on March 15, 2002 revoked the oil shale withdrawal with respect to approximately 900,000 acres in Moffat, Rio Blanco, Garfield, and Mesa counties, Colorado. 67 FED. REG. 11706-07 (March 15, 2002). More recently, the Assistant Secretary of Interior for Land and Mineral Management revoked the oil shale withdrawal for public lands in Utah and Wyoming, effective February 9, 2009. 74 FED. REG. 830-31 (Jan. 8, 2009). Therefore, Executive Order 5327 no longer stands as an obstacle to commercial oil shale development on public lands. On January 20, 2009, the incoming presidential administration directed executive departments and agencies to temporarily stay finalization of most pending administrative regulations and to "consider" extending the implementation date and seek further public comment regarding final rules that had yet to take effect. Memorandum from Rahm Emanuel, Assistant and Chief of Staff to newly inaugurated President Barack Obama, to the Heads of Executive Departments and Agencies, 74 FED. REG. 4435 (Jan. 26, 2009). The Memorandum applies to all "regulations" as defined by Executive Order 12866 ("'Regulation' or 'rule' means an agency statement of general applicability and future effect, which the agency intends to have the force and effect of law, that is designed to implement, interpret, or prescribe law or policy or to describe the procedure or practice requirements of an agency."). While Interior's January 8, 2009 revocation appears to fall within this definition, Interior took no further action with respect to the withdrawal revocation, leaving the revocation intact.

will be disturbed during development. Surface coal leasing regulations assume similarly complete surface disturbance and consequently require intensive pre-leasing assessments. These surveys identify, at a site-specific level, areas that are unsuitable for surface mining because of sensitive resources. In contrast, conventional oil or natural gas development occurs on only portions of the lease tract. Improvements in oil and gas extraction technologies, including the proliferation of directional drilling and consolidated drilling pads, allow operators to reduce significantly the footprint of development and avoid site-specific resources. Because of the ability to avoid sensitive sites through oil and gas facility location, oil and gas leasing regulations do not require exhaustive pre-leasing resource surveys.

While BLM leasing regulations draw from conventional oil and gas law, oil shales more expansive surface impacts appear better suited to a regulatory approach closer to that used for coal, precluding sensitive areas from leasing rather than relying on difficult post-leasing avoidance or mitigation. Issuing commercial oil shale leases absent a clear standard for comprehensive resource inventories places both lessees and the federal government at risk. Lessees run the risk that protection of previously unidentified sensitive resources will greatly increase development costs or even preclude development of portions of their lease tract. Land managers face likely challenges to the adequacy of the "hard look" required under NEPA if less than comprehensive information is considered at the leasing phase. Land managers also face takings claims if regulatory requirements reduce significantly the economic value of leased tracts. As a practical matter, comprehensive pre-leasing surveys may be necessary to withstand the almost certain NEPA challenges that will accompany commercial oil shale development. Making such surveys part of a public process, as is done for surface coal mining leases, would lead to more defensible policy and land management decision-making, while helping potential lessees realistically calculate the value and cost of development associated with available lease tracts.

3.5 NON-FEDERAL OIL SHALE LEASING MODELS

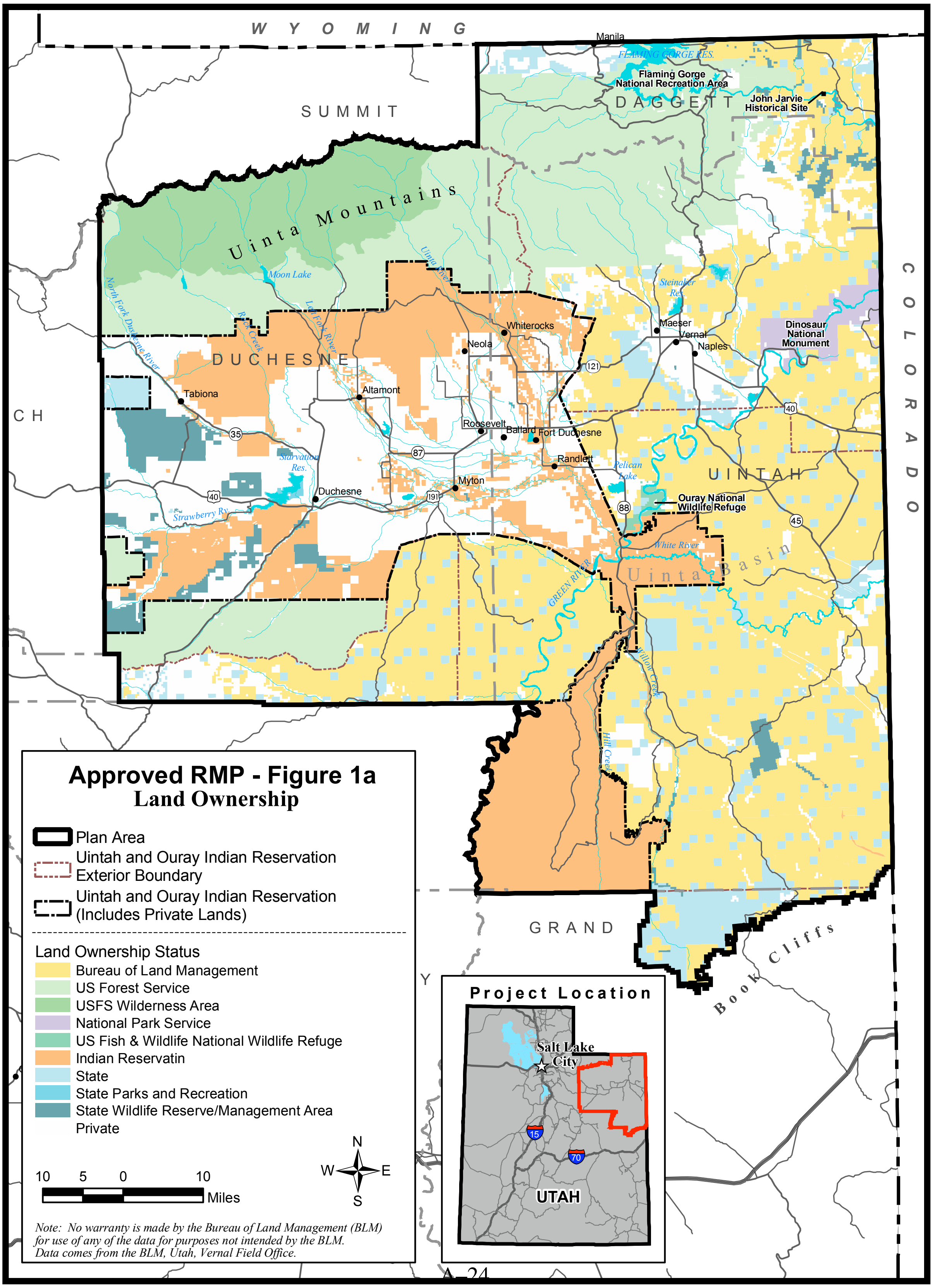
Although federal lands are home to the majority of the recoverable oil shale resources in the western United States, state, tribal and private lands also overlie extensive and valuable oil shale resources. Within Utah's Uinta Basin, tribal, state, and private interests control over 45% of 25 GPT oil shale (illustrated in Figure 3.5.1).[132] The Ute Indian Tribe controls 84,000 acres of oil shale-bearing land that was previously set aside as part of U.S. Naval Oil Shale Reserve No. 2.[133] According to a 2009 report published by the University of Colorado, "private property owners, mainly energy companies, control about 20% of the land that overlies oil shale deposits in the Piceance Basin and the associated mineral rights—enough, according to some, to get an oil shale industry off the ground without the incentive of federal leases."[134] State, private and tribal oil shale resources can be developed independent of federal land use planning and leasing regulations. Different policy perspectives on oil shale development could lead to divergent development strategies in the short term, increasing competition for scarce resources and potentially constraining future oil shale development. The three primary non-federal resource owners, and their perspectives on oil shale development, are discussed below.

[132] MICHAEL D. VANDEN BERG, UTAH GEOLOGICAL SURVEY, BASIN-WIDE EVALUATION OF THE UPPERMOST GREEN RIVER FORMATION'S OIL-SHALE RESOURCES, UINTA BASIN, UTAH AND COLORADO (2008) at 8.

[133] Pub. L. 106-398 §3403.

[134] HANSON & LIMERICK at 12.

Figure 3.5.1: Land Ownership in the Uinta Basin. Source: Bureau of Land Management, Vernal RMP ROD.



State Leases. Colorado and Utah have adopted disparate approaches to commercial oil shale development. Colorado has embraced a go-slow approach, concluding that:

> BLM must gain critical answers to many questions before any commitment to commercial leasing occurs. Equally important, BLM must similarly gain answers to such questions before any rules and regulations for commercial oil shale development can or should be finalized. Absent obtaining these answers, BLM and Colorado run the serious risk of development that will have tremendous adverse impacts on Colorado.[135]

In contrast, Utah actively promotes oil shale development, stating that Utah is "open for business as it relates to oil shale."[136] In Utah, there are 99 active state leases conveying rights to develop oil shale on over 97,848 acres of state land.[137] Leased lands are administered by the School and Institutional Trust Lands Administration (SITLA), which is mandated to maximize income for current trust beneficiaries while preserving trust assets for future beneficiaries.[138] Trust beneficiaries, as SITLA's name implies, are public schools and institutions funded by revenue generated from trust lands; "beneficiaries do not include other governmental institutions or agencies, the public at large, or the general welfare of this state."[139] SITLA, therefore, has a strong incentive to develop oil shale and limited mandate to consider competing land uses.

Private Land Leases. In addition to federal and state resources, private parties control sizeable oil shale resources. The General Mining Law of 1872 (GML)[140] was enacted to promote mineral exploration and development in the western United States. Under the GML, prospectors could locate a mining claim on federal lands open to mineral entry.[141] Once a valuable mineral was discovered and required filings made, a claim was considered valid and the claimant could mine the resource without payment of royalties to the federal government. Holders of valid claims could also "patent," or buy, the property for $2.50 or $5.00 per acre for claims.[142] Patented land becomes private property and can be used for mining or other purposes.

Passage of the Mineral Leasing Act of 1920 (MLA),[143] which applies to oil shale, marked a change in course by requiring miners to pay royalties on developed minerals and to obtain leases before developing most minerals on federal lands. Under the MLA, mineral development could not lead to land

[135] Colorado Governor Bill Ritter, Comments on DRAFT PEIS *available at* http://coloradobiomass.org/cs/Satellite/GovRitter/GOVR/1206035634228.

[136] Julie Cart, *Energy Dispute Over Rockies Riches*, LOS ANGELES TIMES (Dec. 28, 2008). Lieutenant Governor Herbert and Utah's two senators are also strong oil shale supporters. *See* Patty Henetz, *Delegation Slams Oil-Shale Moratorium: Hatch and Bennett Say One-Year Ban Hurts U.S. Energy Independence*, SALT LAKE TRIBUNE (July 2, 2008). Utah's support is reflected in Utah Code § 53C-2-414 which allows royalty reduction to encourage development of oil shale and tar sands, § 59-5-120 which creates a 10 year exemption from severance taxes for oil shale and tar sands development, § 59-13-201(3)(a)(iii) which exempts motor fuels derived from Utah oil shale or tar sands from state motor fuel taxes, and § 59-12-104(63) which creates a 10 year tax exemption for "personal property or a product transferred electronically that are used in the research and development of coal-to-liquids, oil shale, or tar sands technology."

[137] Figures are as of October 31, 2008. Statistics were compiled from data provided by the School and Institutional Trust Lands Administration (SITLA), *available at* http://168.178.199.154/publms/contents.htm. These figures reflect active leases; an additional 71 inactive leases cover over 96,281 acres.

[138] UTAH CODE ANN. § 53C-1-102(2).

[139] UTAH CODE ANN. § 53C-1-102(2)(d).

[140] Codified as amended at 30 U.S.C. § 22–54.

[141] 30 U.S.C. § 29.

[142] $5 per acre applies to "lode" or hard rock mineral claims, 30 U.S.C. § 28; $2.50 per acre applies to "placer" or unconsolidated mineral claims. 30 U.S.C. § 37. In 1897, Congress passed the Oil Placer Act, confirming that oil, gas, and oil shale were locatable minerals under the 1872 Act. 29 Stat. 526 (Feb. 11, 1897).

[143] 30 U.S.C. § 181 – 287.

ownership, as ownership of the land remained with the federal government. However, provisions of the MLA allow patenting of claims filed prior to the MLA's effective date (February 25, 1920),[144] provided that the claimant conducted annual labor and improvements as required under the GML.[145] Where a claimant failed to conduct required assessments or improvements, the claim would be open to relocation in accordance with federal law.[146] Passage of the MLA precluded relocation, instead directing that if a claim failed for lack of assessment work, the full interest in the property would revert to the United States with the minerals becoming available only through lease.[147] Many claims, however, did not fail and vast resources passed into private hands.

While a precise accounting of the amount of land patented to date remains elusive, a 1980 U.S. Supreme Court opinion addressing oil shale patents identified 349,088 acres that were successfully patented and thus transferred to private lands.[148] Subsequent litigation and settlements extended patents for significant additional lands,[149] mostly in Colorado and Utah. The largest private land blocks in Utah are in the eastern part of the most geologically prospective oil shale area and overlie some of the thickest and richest oil shale bearing formations within Utah.[150] One prospective oil shale developer in Utah, the Oil Shale Exploration Company (OSEC), controls more than 46,000 acres of privately owned oil shale lands.[151] The Exxon Mobil Exploration Company controls over 50,000 acres of private oil shale bearing land in Colorado's Piceance Basin that were acquired "primarily for development by mining and retorting."[152] These private lands can be developed, subject to applicable federal and state laws, without regard to federal or state leasing requirements.

Tribal Leases. Federally recognized Indian tribes occupy a unique position with respect to the federal government, the latter being subject to a trust obligation in the oversight of certain tribal dealings.[153] The federal government has long exercised its obligations as trustee to manage the use of Indian land for mining and mineral development.[154] Today, subject to approval by the SOI, any federally recognized tribe may:

> [E]nter into any joint venture, operating, production sharing, service, managerial, lease or other agreement … providing for the exploration for, or extraction, processing, or other development of, oil, gas, uranium, coal, geothermal, or other energy or nonenergy mineral resources … in which such Indian tribe owns a beneficial or restricted interest, or providing for the sale or other disposition of the production or products of such mineral resources.[155]

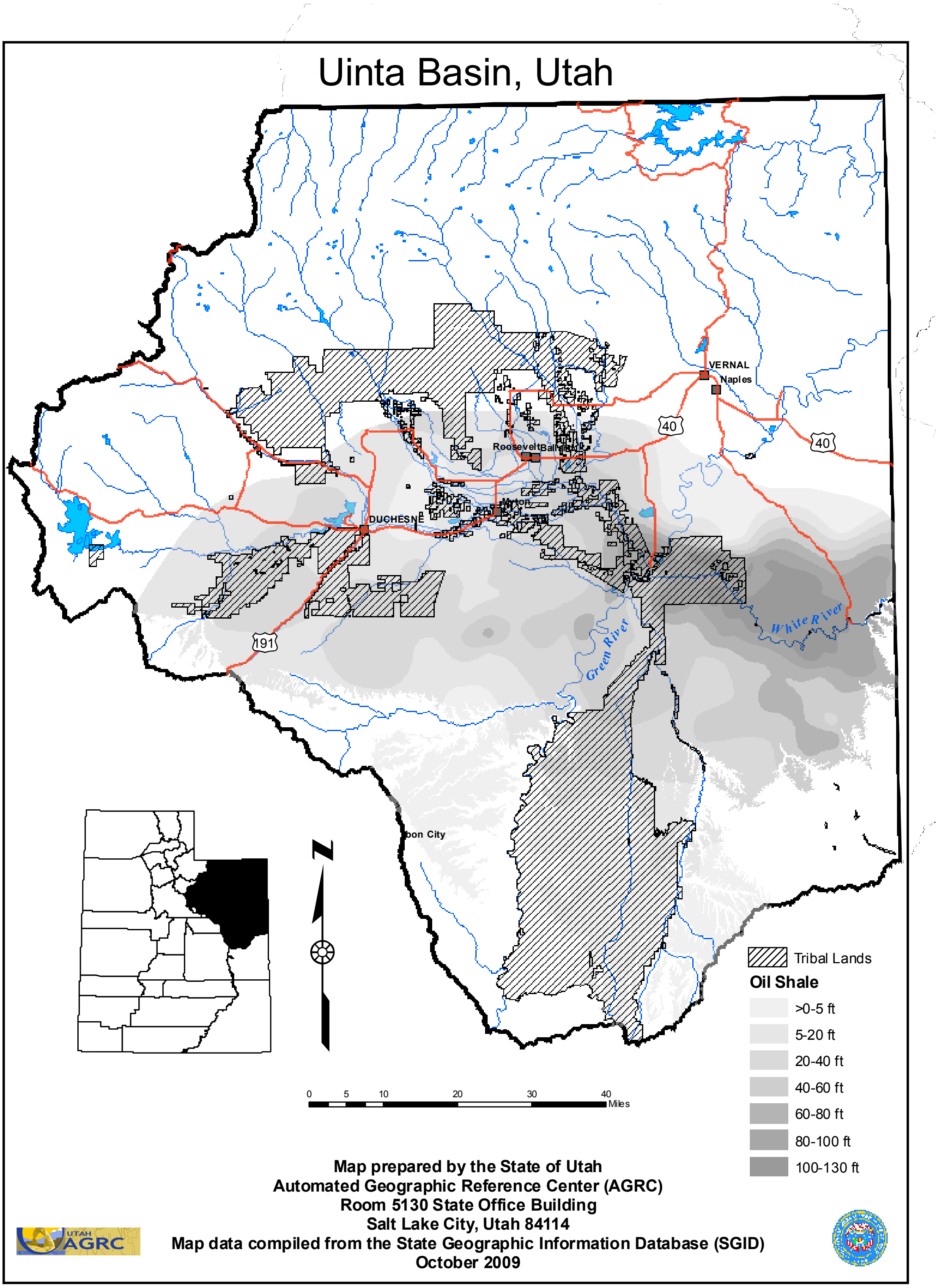
[144] 30 U.S.C. § 193.
[145] 30 U.S.C. § 28.
[146] 30 U.S.C. § 28.
[147] *Hickel v. Oil Shale Corp.*, 400 U.S. 48, 57 (1970).
[148] *Andrus v. Shell Oil Co.*, 446 U.S. 657, 667 (1980).
[149] *See TOSCO Corp. v. Hodel*, 611 F.Supp 1130 (D. Colo. 1985) *vacated because of settlement* at 826 F.2d 948 (10th Cir. 1987)
[150] VANDEN BERG at Plates 3 and 5.
[151] *See* U.S. DEPARTMENT OF ENERGY, OFFICE OF PETROLEUM RESERVES, OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, SECURE FUELS FROM DOMESTIC RESOURCES: THE CONTINUING EVOLUTION OF AMERICA'S OIL SHALE AND TAR SANDS INDUSTRIES, PROFILES OF COMPANIES ENGAGED IN DOMESTIC OIL SHALE AND TAR SANDS RESOURCE AND TECHNOLOGY DEVELOPMENT 35 (Rev. Aug. 2008)
[152] U.S. DEPARTMENT OF ENERGY, OFFICE OF PETROLEUM RESERVES, OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, SECURE FUELS FROM DOMESTIC RESOURCES at 35, 57.
[153] For a comprehensive discussion of the basis for the United State's trust obligations as well as the responsibilities contained therein *see* CONFERENCE OF WESTERN ATTORNEYS GENERAL, AMERICAN INDIAN LAW DESKBOOK (3d 2004).
[154] *See* 26 Stat. 795 (1891) *codified at* 25 U.S.C. § 397 (allowing tribes, with the consent of the SOI, to lease certain lands).
[155] 25 U.S.C. § 2102(a).

The Secretary is further obligated to provide tribes or individual Indians "advice, assistance, and information during the negotiation of a Minerals Agreement."[156] Therefore, as a general rule, the DOI is heavily involved in most decisions regarding energy development on Indian land and would likely play a major role in future plans to develop tribal oil shale resources.

Naval Oil Shale Reserve (NOSR) No. 2 represents an important exception to this general rule. In the early 20th century, with the U.S. Navy transitioning from coal to liquid fuels and concerned over fuel availability, the President of the United States issued a series of executive orders setting aside three federal oil shale reserves.[157] NOSR No. 2, covering 88,890 acres, was located in Utah's Carbon and Uintah counties.[158] The National Defense Authorization Act of 2000[159] transferred approximately 84,000 acres of NOSR No. 2 to the Ute Indian Tribe,[160] which received the land, including mineral rights, in fee simple and not subject to federal management in trust status.[161] Consequently, development of these tribal lands does not require DOI approval or authorization.[162] Oil shale deposits in what was formerly managed as part of NOSR No. 2 are typified by shallower overburden and thinner oil shale bearing formations.[163] (The overlay of tribal lands on the oil shale resource in Utah is shown in Figures 3.5.2.) To date, the Ute Indian Tribe has not adopted a position on commercial oil shale development.

[156] 25 U.S.C. § 2106.
[157] NOSRs Nos. 1 and 3 are located in Colorado and remain under federal control.
[158] Anthony Andrews, Congressional Research Service, Report to Congress, *Oil Shale: History, Incentives, and Policy* 2 (April 13, 2006).
[159] Pub. L. 106-398.
[160] Pub. L. 106-398 § 3403; *see also* Andrews at 28.
[161] Pub. L. 106-398 § 3403.
[162] "The land conveyed to the Tribe under subsection (b) shall not revert to the United States for management in trust status." Pub. L. 106-398 at § 3405(b)(3).
[163] *See* VANDEN BERG AT PLATES 3 AND 5.

Figure 3.5.2: Overlay of Tribal Lands and Oil Shale Deposits in the Uinta Basin. Source: State of Utah Automated Geographic Reference Center.



3.6 COMPETING ROYALTY MODELS

The BLM and Utah differ not only in their oil shale development philosophies but also in the terms they apply to commercial leases. Both leases contain an initial production royalty of 5% for the first five years and the potential to increase royalties by 1% annually to a maximum of 12.5%. However, the BLM royalty rate will automatically increase annually after the first five years[164] where the SITLA royalty rate increase is discretionary.[165] The primary lease terms under the BLM and SITLA models are also notably different. Post-2005 SITLA leases contain a 10 year primary lease term[166] while the BLM leases contain a 20 year primary term.[167] Both leases are renewable upon demonstration of commercially viable development.

Perhaps the most important difference between the BLM and SITLA leasing models is the federal lease provision stating that the lessee "must pay royalties on all products of oil shale that are sold from or transported off of the lease."[168] Federal leases appear not to charge royalties on oil shale or oil shale derivatives consumed on site. It appears that once operators begin retorting oil shale and producing synthetic gas, they will be able to fire retorts or generate power for their retorts and upgraders using energy from synthetic gas produced on site free of charge. This provision potentially negates the need for off-site sources of power to support commercial oil shale development, which in turn affects the need for off-site infrastructure and grid integration. This approach is consistent with federal fluid mineral leasing, which allows on-site use of produced oil or gas free of royalty charges.[169] In light of the extensive energy requirements for producing and upgrading shale oil, this policy of waiving royalties for fuel consumed on site may need to be revisited.

Whether a similar use of synthetic gas would be allowed, free of charge, under a SITLA lease is not clear. On one hand, the lessee's royalty obligation is based on "all leased substances that are sold or transported from the leased lands during a particular month,"[170] and calculated "at the point of shipment from the leased premises of the first marketable product or products produced from the leased substances and sold under a bonafide arms length contract of sale."[171] However, the lease goes on to state that "[i]t is expressly understood and agreed that none of Lessee's mining, production or processing costs, including but not limited to costs for materials, labor, overhead, distribution, transportation f.o.b. mine, loading, crushing, processing, or general and administrative activities, may be deducted in computing Lessor's royalty. All such costs shall be entirely borne by Lessee and are anticipated by the rate of royalty set forth in this Lease."[172]

The mandatory royalty escalation contained in the BLM leases should encourage timely development and discourage extended, speculative holding of undeveloped leases.[173] Whether the potentially lower production royalty, potential minimization of NEPA requirements, or other factors make SITLA

[164] 43 C.F.R. § 3903.52(b).
[165] Utah State Mineral Lease Form for Oil Shale (June 22, 2005) (Oil Shale Lease Form 6/22/05) at § 6.3 (on file with authors).
[166] Oil Shale Lease Form 6/22/05 at § 3.
[167] 43 C.F.R. § 3927.30.
[168] 43 C.F.R. § 3903.54(a).
[169] ROCKY MOUNTAIN MINERAL LAW FOUNDATION, LAW OF FEDERAL OIL AND GAS LEASES § 13.03[2] and [3] (2008); *see also* 30 U.S.C. §§ 202.100(b)(1) (royalty on oil) and 202.151(a)(2) and (b) (royalty on natural gas).
[170] Oil Shale Lease Form 6/22/05 at § 6.4.
[171] Oil Shale Lease Form 6/22/05 at § 6.1.
[172] Oil Shale Lease Form 6/22/05 at § 6.3.
[173] A report recently issued by the Government Accountability Office found that state oil and gas leases tend to encourage more rapid lease development than their federal counterparts and recommended structuring federal leases to encourage more timely development. United States Government Accountability Office, *Oil and Gas Leasing: Interior Could Do More to Encourage Diligent Development* (Oct. 2008).

leases more appealing than BLM leases remains to be seen. Similarly unknown is whether and how royalty calculations will affect the desirability of and need for infrastructure integration, and thus the specifics of oil shale planning and development.

3.7 MANAGING DEVELOPMENT OF THE OIL SHALE RESOURCE

Discussions of whether and how to pursue commercial leasing and development of oil shale focus primarily on development of federal oil shale resources. While federal lands hold the majority of the total recoverable oil shale deposits in the United States, significant portions of the richest oil shale resources are found on non-federal lands. The BLM recently estimated that roughly 1.4 million acres, or 40% of the most geologically prospective oil shale area, is managed by other entities.[174] Within the Uinta Basin, the Utah Geological Survey estimates that tribal, state, and private interests control over 45% of oil shale resources.[175] Development of these non-federal lands may be advantaged initially as such development will not be delayed by legal challenges to either the RMP amendments or oil shale leasing regulations.[176] Similarly, oil shale leasing and development on non-federal lands will not be subject to the multiple environmental impact statements that must precede oil shale development on federal lands.[177] Thus, non-federal lands may be the first to secure access to scarce resources needed for commercial oil shale production such as water, power, labor, and equipment.

Extensive non-BLM holdings present two important questions: first, should leasing and development of the oil shale resource be driven by a coordinated national policy that transcends land ownership; and second, will uncoordinated policies and leasing models adequately address environmental concerns or result in conflicting requirements that impede energy development. Given the potential pitfalls of uncoordinated action, federal, state, and tribal policymakers should endeavor to harmonize leasing and development schemes—before non-BLM leasing and development progresses to a level that constrains policy options.

If oil shale is to be developed commercially, oil shale leasing on the public lands should be treated as part of a coordinated federal energy and resource management strategy. The federal government can take the role of encouraging environmentally responsible, synergistic development by actively engaging in oil shale development policymaking. Further, policymakers should explore making public land development or financial incentives contingent upon attainment of environmental benchmarks reflecting the type of industry needed to support national energy and environmental policies rather than indirectly allowing technologies with the lowest internalized costs to squeeze out technologies that may represent a better use of federal resources.

3.8 LAND EXCHANGES

The western United States, and Utah's Uinta Basin in particular, is a jurisdictional patchwork. Because ownership of federal, state, private and tribal tracts is deconsolidated, coordinated and efficient resource management often proves difficult. In the past, land grants and exchanges provided valuable tools to con-

[174]FINAL PEIS, 2-13.
[175]VANDEN BERG at 8.
[176]On January 16, 2009, a coalition of 13 environmental organizations filed two lawsuits in the U.S. Diqstrict Court for the District of Colorado (1:2009-cv-00085 and 1:2009-cv-00091), challenging both the BLM's new oil shale leasing regulations published at 73 Fed. Reg. 69414 – 87 (Nov. 18, 2008), and the FINAL PEIS. Both cases remain pending as of the writing of this report.
[177]43 C.F.R. § 3900.50.

solidate control and improve management efficiency. Pooling and unitization also provide valuable tools in managing oil and gas resources across jurisdictional boundaries. Both of these tools have potential utility in the context of a federal oil shale leasing program.

Upon recognizing Utah's statehood, the federal government granted the State of Utah title to four sections of land in every township,[178] excluding lands reserved for permanent national purposes such as military or Indian reservations.[179] Lands granted to the state were intended to support Utah's public schools.[180] These sections encompassed one-ninth of the land within the state and were intended to support Utah's public schools. However, the sections granted were discontinuous, resulting in a checker-boarded pattern of ownership. This fragmented pattern of ownership complicates management for federal and state government agencies because jurisdiction and ownership do not follow resources, and state and federal land management objectives do not always coincide.

To address the problem of checker-boarded ownership (which is not unique to Utah), Congress authorized the exchange of federal and non-federal lands where "the public interest will be well served by making the exchange," and where the exchanged parcels are of like value.[181] Utah and the SOI have relied upon this provision to negotiate several successful land exchanges, consolidating lands into more manageable configurations. Utah continues to pursue federal land exchanges, most recently under the Utah Recreational Land Exchange Act, signed into law on August 9, 2009,[182] which exchanged SITLA lands along the Colorado River Corridor for mineral bearing lands in the Uinta Basin (illustrated in Figure 3.8.1).

The vast majority of lands included in the Utah Recreational Land Exchange Act are well south of the most geologically prospective oil shale area, but several sections that came under state control contain potentially significant oil shale resources. The state will make leasing decisions regarding these lands pursuant to state law; however, pursuant to the exchange, the SOI retains an interest in the portion of the mineral estate containing the oil shale resources equivalent to what the Secretary would obtain were such lands leased under applicable federal laws.[183]

[178] A section is normally one square mile (640 acres) in size. There are 36 sections in a township. Utah received title to sections 2, 26, 32, and 36. *See* 28 Stat. 109 § 6 (1894).

[179] 28 Stat. 109 § 6 (1894). At the time of statehood, some of the granted land had already transferred into private ownership, through homesteading laws or patents under the GML. Where sections granted to the state had previously been conveyed out of federal ownership the state obtained the right to select equivalent sections, subject to approval by the SOI. 28 Stat. 109 § 6 (1894). These are commonly referred to as "indemnity lands" or "in lieu lands." In addition, Utah secured the right to select more than 1,570,000 acres of land to support construction of its capital, schools, and institutions for disadvantaged populations. 28 Stat. 109 §§ 7, 8, and 12 (1894). These are commonly referred to as "quantity grant lands." Comprehensive surveys were slow in coming to much of the west and their absence complicated efforts to identify state and federal lands and for the state to select its in lieu lands. It was not until 1965 that Utah filed its first claim to in lieu lands, claiming title to 194 selections that totaled 157,255.90 acres in Uintah County. In 1974, the Secretary of Interior announced his intent to deny the indemnity applications, asserting the claimed lands were rich in oil shale resources and therefore disproportionately valuable when compared to the lands they were intended to replace. In 1980, the U.S. Supreme Court agreed and upheld the Secretary's decision in the case of *Andrus v. Utah*, 446 U.S. 500, 503 (1980). Following *Andrus v. Utah*, most of Utah's remaining in lieu lands were appraised and converted to a cash ledger account, allowing the state to select lands based on assessed value. Utah recently filed a selection application for 1,120 acres of geothermal lands in Iron County plus several telecommunication sites which, if approved, will exhaust the in lieu entitlement. Utah's remaining quantity grant selection rights total 4,847.17 acres and cannot be used for mineral lands. *See* Email from John W. Andrews, Associate Director/Chief Legal Counsel, Utah School & Institutional Trust Lands Administration (May 28, 2009) (on file with authors). Therefore, in lieu lands afford little opportunity to consolidate jurisdiction.

[180] 28 Stat. 109 § 6 (1894). The Enabling Act of each of the public land states admitted to the Union since 1802 has included grants of designated sections of federal lands to support public schools. *Andrus v. Utah*, 446, U.S. 500, 506 (1980).

[181] *See* 43 U.S.C. § 1716.

[182] P.L. 11-053H.R. 1275, 111th Cong. (2009).

[183] H.R. 1275, 111th Cong., § 3(f) (2009).

Although facilitation of oil shale development was not the primary purpose for the exchange, several of the sections transferred to the state are located along the southern end of the Mahogany zone where overburden is at its shallowest, making oil shale in this area much easier to access via conventional mining operations. Exchanging lands along the southern edge of the Mahogany zone outcrop could make commercial oil shale development in this area easier, both by consolidating ownership and by transferring control to Utah, which is actively pursuing commercial oil shale development. Facilitating development of shallower oil shale deposits may indirectly favor development technologies involving conventional mining methods, as limited overburden may be insufficient to trap heat and create the pressure needed to support in situ thermal processing. While exchange and consolidation may offer policymakers an opportunity to advance commercial oil shale development, such advancement would likely diminish federal control over future development of oil shale resources.

3.8.1 Logical Mining Units, Pooling and Unitization

Where land ownership cannot be reconfigured to optimize efficient development and resolve jurisdictional questions, policymakers can still encourage improved cooperation across jurisdictional lines. Assuming federal lands are made available for commercial leasing, policymakers can look to conventional energy development activities as a model in the context of oil shale leasing and development.

With respect to coal mining, federal resource managers establish logical mining units, which constitute areas of land where coal can be developed in an efficient, economical, and orderly manner as a unit with due regard for conservation of the coal and other resources.[184] Logical mining units allow the operator to consolidate development and operations requirements for federal leases and other coal tracts within the boundaries of the mine. Logical mining units also facilitate management continuity of the coal resource when geologic characteristics cross property boundaries.

The oil and gas industry uses the practice of "unitization" to combine a sufficient majority of royalty and working interests over a producing formation to facilitate exploration and development so that drilling and production over the entire reservoir may proceed in the most efficient and economic manner.[185] Under most states' unitization laws, operators are allowed to proceed despite being unable to reach agreement with all landowners, provided that a statutorily set percentage of landowners consent.[186] "Pooling" is the accumulation of smaller tracts of land or fractional mineral interests, the sum total acreage of which are required for a governmental agency to grant a well permit or assign a production quota to an operator.[187]

Pooling usually refers to bringing a well into primary production whereas unitization refers to coordinated management of the pooled resources. Voluntary pooling and unitization derive from agreements among interested parties, so there is no limitation upon their contents except possible contravention of law or public policy. Many jurisdictions authorize the state oil and gas boards to force or encourage pooling and unitizations in order to maximize state interests in efficient production.[188]

Logical mining units, pooling and unitization may be suitable tools for managing oil shale leasing and activities on the public lands depending upon whether oil shale is developed using in situ thermal processing or conventional mining operations.. Further assessment of legal tools for facilitating coordi-

[184] 30 U.S.C. § 202a; 43 C.F.R.§ 3487.
[185] *See* Nancy Saint-Paul, Summers Oil and Gas § 54.1 (3d ed. 2009).
[186] *See* Interstate Oil and Gas Compact Commission, IOGCC Model Statute and Fieldwide Unitization References 9 (no date) (as of 2000, the minimum percentage required to ratify unitization agreements ranged from 51% to 80% for IOGCC member states with forced pooling statutes).
[187] *See* Nancy Saint-Paul at § 54.1.
[188] *See* Nancy Saint-Paul at § 54.2 (discussing 11 methods of pooling or unitization).

nated oil shale resource development will be needed and, in some instances, amendments to federal or state law may be required to ensure efficient development. Policymakers should encourage early investigation and analysis of these potential means of coordinating oil shale development, beginning with the feasibility of applying state pooling and unitization laws to in situ oil shale processing.

3.9 Conclusion and Recommendations

In contrast to the federal government and Colorado, Utah is actively seeking to advance commercial oil shale development. Utah controls significant oil shale resources, roughly 150 billion barrels of shale oil equivalent.[189] These state lands, together with the considerable tribal and private lands containing oil shale, are potentially sufficient to incent development of a commercial oil shale industry independent of federal decision-making regarding oil shale development. Federal uncertainty as to whether to pursue oil shale leasing and development on the public lands may result in shifting oil shale development activities to state and private lands. Federal leadership in the planning of any future domestic oil shale industry would ensure that, if a commercial oil shale industry develops, it does so consistent with national energy and environmental objectives. As both property owner and sovereign, the federal government has various interests at stake, which include promoting energy security, deriving a reasonable financial return, and minimizing environmental problems while developing a viable commercial oil shale leasing program on the public lands.

The affected states, communities, and tribes are also keenly interested in the long term sustainability of such an undertaking for an array of fiscal, socioeconomic, and environmental reasons. Moreover, with important resource values at risk, as well as potential water and air quality concerns and energy policy questions, environmental groups and the general public have a clear interest in the details of oil shale leasing and development. This is particularly true given the boom and bust history of oil shale development efforts in the western United States where several of these communities survived the bust by transforming from natural resource-dependent economies to communities where new citizens and businesses are attracted to the area's scenery, open spaces, and recreational opportunities on the public lands.[190]

RD&D leases provide one avenue of ensuring that oil shale developers can develop and test a broad range of technologies. Conditioning commercial leases on specific milestones and impact assessments, whether proven initially on RD&D, state or private leases, is another avenue for opening public lands to responsible and measured oil shale leasing and development. The surface impacts associated with oil shale development are certain to be extensive regardless of the technology utilized and these impacts are best addressed under pre-lease rather than post-lease assessments. Similarly, a suitability determination similar to the analysis that precedes surface coal development would benefit the decision-making and planning processes integral to oil shale leasing and development on the public lands.

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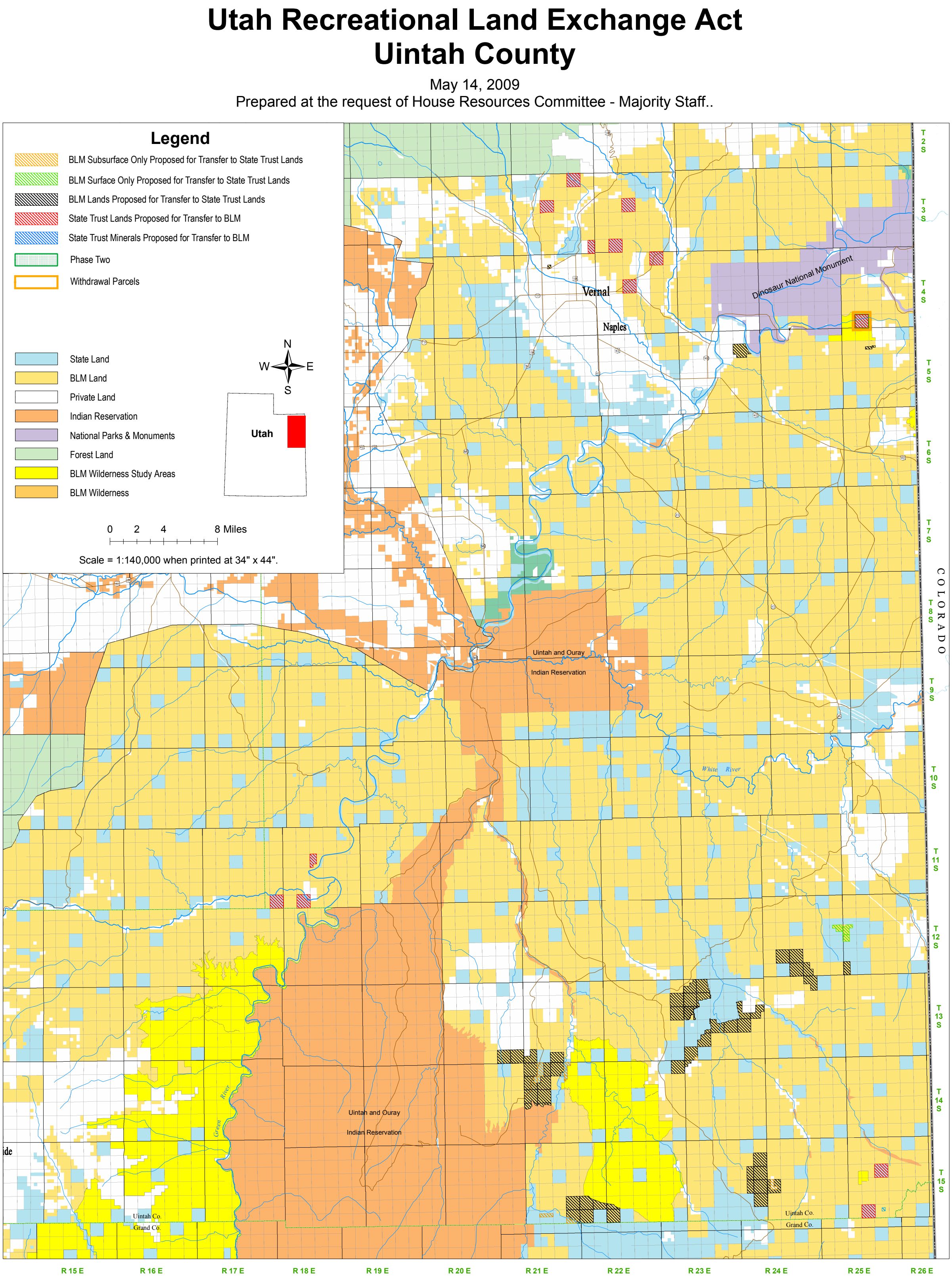
[189] *See* Vanden Berg at 1. This figure is based on the 25 GPT zone; roughly twice this amount exists within the 15 GPT zone.

[190] *See generally* Gulliford.

Figure 3.8.1: Utah Recreational Land Exchange Act Uintah County. Source: Bureau of Land Management.



CHAPTER 4

COMPETING LAND USES

FLPMA's multiple-use mandate requires the BLM to manage its resources "in the combination that will best meet the present and future needs of the American People ... taking into account the long-term needs of future generations for renewable and non-renewable resources."[191] Some lands may be used for certain uses at the exclusion of others provided the mix of outputs satisfies this broad mandate.[192] Exclusion of competing resource uses is especially relevant for oil shale development as the near total surface disturbance anticipated with oil shale development[193] is not compatible with other land uses. A related issue presented by federal commercial oil shale leasing and development is the extent to which leased public lands can be adequately reclaimed after oil shale development.

Uncertainty regarding the scale and location of oil shale development sites, as well as the technologies likely to be employed at those sites, force a certain level of generality on land use discussions. Commercial oil shale leasing and development would have a significant impact on the public lands, and the resource values competing with, and potentially displaced by, oil shale development represent noteworthy challenges to development. Where competing land uses are protected as a matter of federal law, oil shale development may be limited or precluded entirely. Even in the absence of specifically protected competing land uses, vigorous debate is likely where federal land managers exercise discretion in balancing oil shale leasing and development against other resource values and land uses.

4.1 PROTECTED MANAGEMENT AREAS

Within the most geologically prospective oil shale area, BLM managed lands are unavailable for commercial oil shale leasing where the oil shale resource coincides with legally protected lands. Thus commercial leasing will not occur in designated Wilderness Areas, Wilderness Study Areas (WSAs), existing Areas of Critical Environmental Concerns (ACECs) that are currently closed to mineral development, and Wild and Scenic Rivers.[194]

[191] 43 U.S.C. § 1702(c).
[192] 43 U.S.C. § 1702(c).
[193] *See* FINAL PEIS at 4-4 n.C and 4-8 n.C.
[194] OIL SHALE ROD at 9, 17.

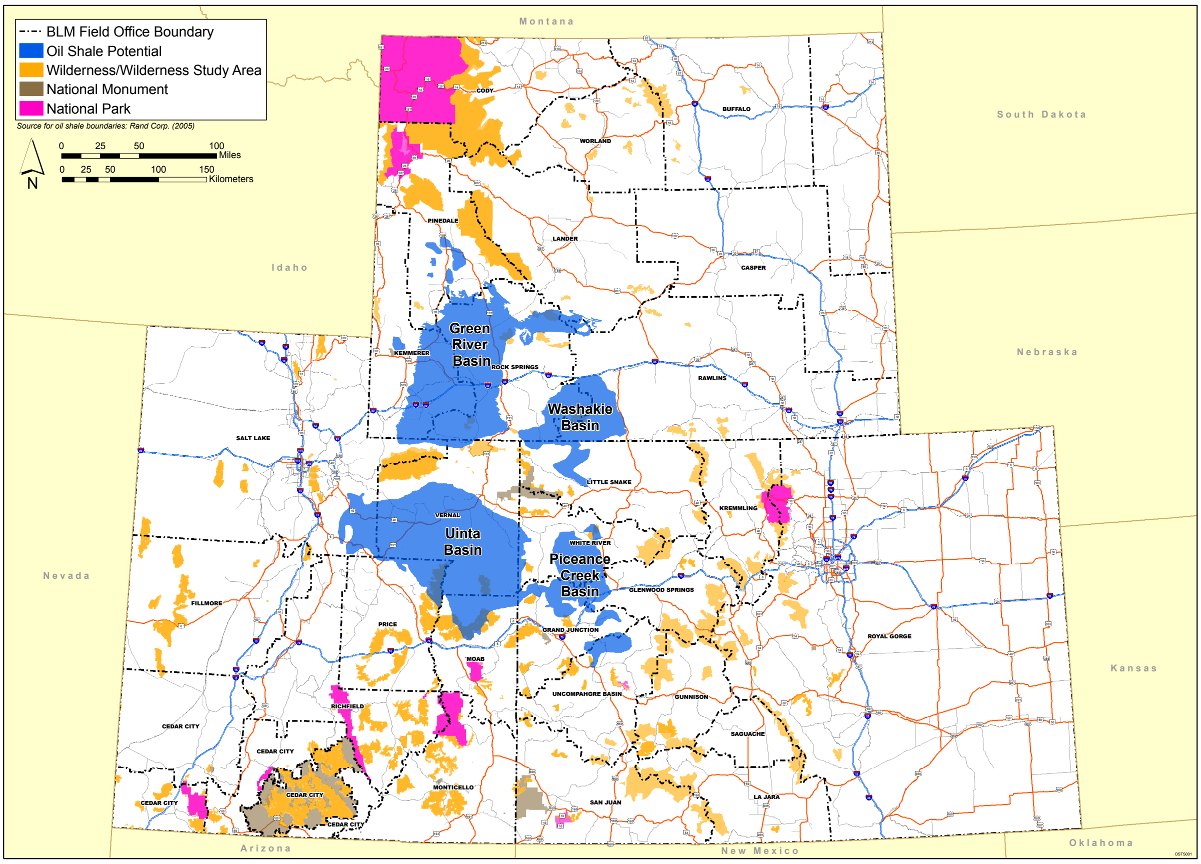
4.1.1 WILDERNESS AREAS AND WILDERNESS CHARACTERISTICS

Wilderness Areas are designated through federal legislation and subject to the protections of the Wilderness Act.[195] Wilderness Areas are "untrammeled by men, where man himself is a visitor who does not remain … retaining its primeval character and influences … affected primarily by the forces of nature, with the imprint of man's work substantially unnoticeable."[196] Unless otherwise provided by law, commercial enterprises, roads, structures, and motorized or mechanical vehicles cannot be located or operated within Wilderness Areas.[197] Under federal law, designated Wilderness Areas and WSAs within the most geologically prospective oil shale area are unavailable for mineral leasing (illustrated in Figure 4.1.1).[198] Protections afforded by the Wilderness Act and applicable to formally designated Wilderness Areas are non-discretionary, as are protections afforded WSAs created under FLPMA.[199] Once statutorily created, protections afforded to Wilderness Areas can be revoked only through further legislative action. At present, there are no formally designated Wilderness Areas or WSAs within the most geologically prospective oil shale area.

[195] 16 U.S.C. §§ 1131 – 36.
[196] 16 U.S.C. § 1131(c).
[197] 16 U.S.C. § 1133(a).
[198] *See* OIL SHALE ROD at 9, 17.
[199] 43 U.S.C. § 1782. In 2005, Utah and the BLM settled a lawsuit by, in part, stipulating that authority to designate WSAs under Section 603 had expired and that no such areas would be designated in the future. BLM did, however, retain authority to inventory areas for wilderness characteristics and manage based on this inventory. *See* Settlement Agreement Between Plaintiffs and Federal Defendants, *Utah v. Norton*, 2:96-cv-0870 B (D. Utah Sept. 9, 2005). This settlement is part of an ongoing "as applied" legal challenge. *See* First Amended Complaint for Declaratory and Injunctive Relief, *Southern Utah Wilderness Alliance v. Allred*, 1:08-cv-02187 (D. D.C. Feb. 3, 2009).

Figure 4.1.1: Oil Shale Deposits in Colorado, Utah and Wyoming. Source: Bureau of Land Management, Final PEIS.

Oil Shale Deposits in the Three-State Area



Within Utah, approximately 9,400,000 acres are currently proposed for Wilderness designation under the Red Rocks Wilderness Bill.[200] A sizeable portion of this proposed wilderness acreage coincides with existing WSAs, but large portions are subject to the BLM's discretionary management authority under FLPMA.[201] If passed, the Red Rocks Wilderness Bill could bar development of some lands along the eastern edge of the most geologically prospective oil shale area.

Wilderness character or characteristics refer to what are perceived to be untrammeled landscapes that are not legally protected. Within the most geologically prospective oil shale area, additional lands have been inventoried as possessing wilderness characteristics. While the mere existence of wilderness

[200] *See* the Red Rocks Wilderness Bill, H.R. 1925, 111th Cong. (2009). The Red Rocks Wilderness Bill was originally introduced in 1989 and has been reintroduced during each subsequent legislative session. During the 111th Congress (2009-2010), the bill claimed 155 cosponsors in the House of Representatives and 22 co-sponsors in the Senate. *See* `http://www.suwa.org/site/PageServer?pagename=work_arwaCosponsors`. Utah's current congressional delegation unanimously opposes the Bill. In an attempt to circumvent opposition, 75 members of the House of Representatives recently signed a letter formally opposing leasing of any lands subject to pending Wilderness designation legislation. *See* Letter from 75 Members of Congress to Ken Salazar, Secretary of Interior and Tom Vilsack, Secretary of Agriculture (Feb. 5, 2009) (on file with authors).
[201] 43 U.S.C. § 1712.

characteristics carries with it no protective mandate, the BLM retains jurisdiction pursuant to FLPMA to manage lands in ways that reflect the "relative scarcity of the values involved" and which emphasize wilderness characteristics.[202] The BLM's recent RMP revisions address management for wilderness character. Within the most geologically prospective oil shale area, the BLM's Vernal Field Office inventoried a number of parcels as possessing wilderness characteristics (illustrated in Figure 4.1.2).[203] Of these several parcels, the BLM elected to manage only one, a 6,680-acre parcel along the White River, specifically to protect wilderness character.[204] As a discretionary decision, management prescriptions emphasizing wilderness characteristics are subject to revision through RMP amendments. The decision to forego protection for other areas acknowledged as possessing wilderness characteristics is the subject of ongoing litigation in the Federal District Court for the District of Columbia.[205] Given the intense interest in wilderness issues, it is almost certain that discretionary decisions regarding management of areas with wilderness characteristics will be thoroughly scrutinized and may result in litigation. These political and practical realities are likely to shape the future of oil shale development even on public lands not expressly closed to leasing.

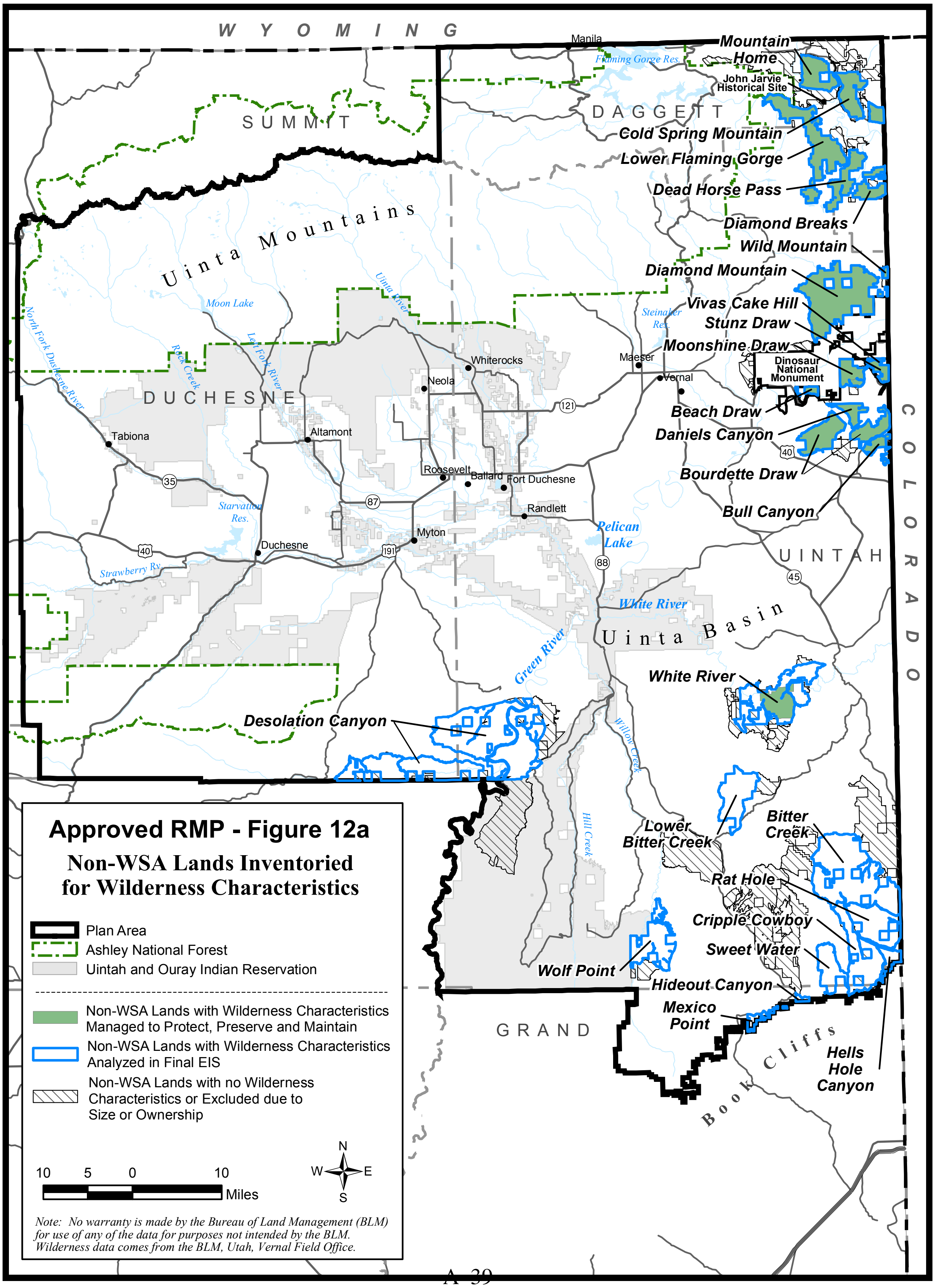
[202] 43 U.S.C. § 1712(c)(6).

[203] Inventories were conducted pursuant to Section 201 of FLPMA, 43 U.S.C. § 1711, and management is conducted pusuant to Section 202 of FLPMA, 43 U.S.C. § 1712.

[204] U.S. BUREAU OF LAND MANAGEMENT, VERNAL FIELD OFFICE, RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN (Oct. 2008) (VERNAL RMP ROD) at 28.

[205] *Southern Utah Wilderness Alliance v. Allred*, 1:08-cv-02187-RMU (D.C., pending).

Figure 4.1.2: Vernal RMP Non-WSA Lands Inventoried for Wilderness Characteristics. Source: Bureau of Land Management, Vernal RMP ROD.



4.1.2 AREAS OF CRITICAL ENVIRONMENTAL CONCERN

Under FLPMA, Areas of Critical Environmental Concern (ACECs) are "areas within the public lands where special management attention is required ... to protect and prevent irreparable damage to important historic, cultural, or scenic values, fish and wildlife resources or other natural systems or processes."[206] In developing and revising land use plans, BLM must "give priority to the designation and protection of areas of critical environmental concern."[207] Existing ACECs that are currently closed to mineral development are unavailable for commercial oil shale development.[208]

The recently revised RMP for the BLM's Vernal Field Office designated seven ACECs covering 131,700 acres (shown in Figure 4.1.3),[209] however not all of these areas are closed to mineral development.[210] None of the designated ACECs overlay areas likely to experience significant oil shale development, but several of the areas that were not brought forward for ACEC designation are within the most geologically prospective oil shale area.[211] In finalizing the RMP revisions, the BLM declined to designate 512,610 acres as ACECs, concluding in part that these areas were adequately protected by other management prescriptions.[212]

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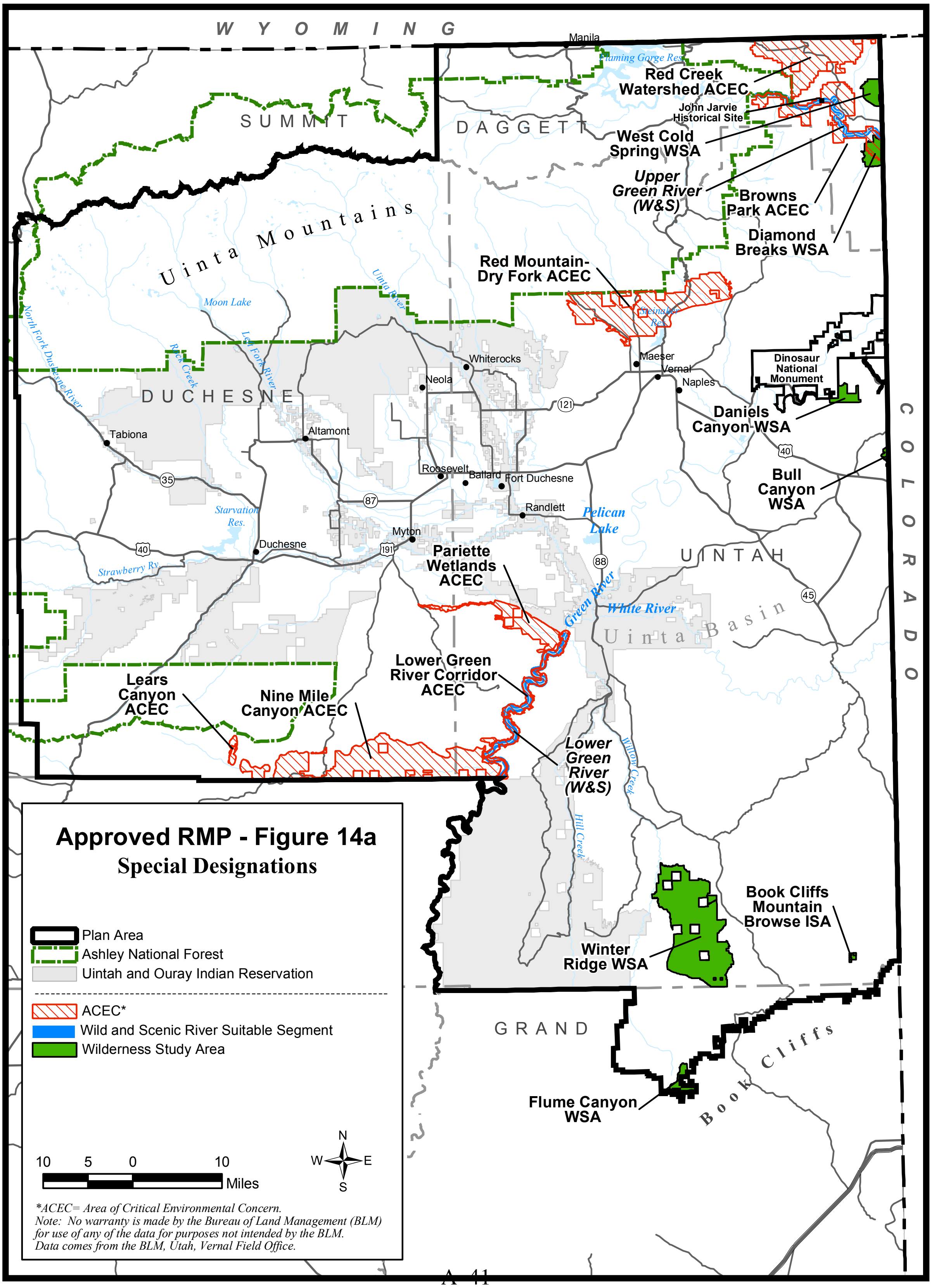
[206] 43 U.S.C. § 1702(a).
[207] 43 U.S.C. § 1712(c)(3).
[208] OIL SHALE ROD at 9.
[209] VERNAL RMP ROD 118-21.
[210] VERNAL RMP ROD at 118-21.
[211] U.S. BUREAU OF LAND MANAGEMENT, VERNAL FIELD OFFICE, PROPOSED RESOURCE MANAGEMENT PLAN AND FINAL ENVIRONMENTAL IMPACT STATEMENT (VERNAL RMP FEIS) at Figure 32.
[212] VERNAL RMP ROD at 118-21.

Figure 4.1.3: Vernal RMP Special Designations. Source: Bureau of Land Management, Vernal RMP ROD.



A coalition of environmental organizations is challenging, among other things, the BLM's decision to forego ACEC designation for eligible areas.[213] Resolution of this challenge is not a legal prerequisite to initiating a commercial oil shale leasing and development program on the public lands in Utah, although it will likely be a practical consideration for both federal land managers and prospective oil shale developers.

4.1.3 WILD AND SCENIC RIVERS

The Wild and Scenic Rivers Act (WSRA)[214] mandates that "certain selected rivers which ... possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values, shall be preserved in free-flowing condition."[215] River segments are first inventoried to determine their eligibility for designation based on their physical characteristics, then evaluated for the suitability of designation in light of management considerations and competing uses. River segments deemed suitable are normally presented for congressional action, while unsuitable segments receive no special management protection. Suitable segments are subject to interim management (roughly equivalent to the protections afforded a designated segment) while congressional action is pending.[216]

Designation as a wild or scenic river triggers preparation of a comprehensive river management plan addressing both resource protection and development.[217] In general, designation prohibits projects such as dams and diversions, as well as federally authorized actions degrading water quality, but has no bearing on private property bordering the river.[218] Designated segments are unavailable for mineral leasing.[219] Neither Colorado nor Utah have designated segments within the most geologically prospective oil shale area. However, the most geologically prospective oil shale area contains or lies in proximity to river segments under consideration for future wild or scenic designation.

In the recently approved Vernal RMP, the BLM identified two river segments as suitable for designation: the 22 mile segment of the Green River immediately west of the Colorado border upstream to a point near Flaming Gorge Dam, and a 30 mile segment of the Green River downstream of its confluence with the White River.[220] Segments considered eligible but not suitable for designation included the White River upstream of the Uinta and Ouray Reservation, all of Evacuation Creek (a tributary to the White River), and a large segment of Bitter Creek (also a tributary to the White River).[221] Since the segments were not considered suitable, no special protections are afforded. However, as with wilderness characteristics, the decision to forgo protection is being challenged[222] and development impacting these segments may generate strong public opposition and complicate development proposals.

The BLM's recently revised Moab RMP prescribes management for portions of Grand County, identifying three relevant suitable river segments, including most of the Colorado River downstream of the

[213] First Amended Complaint for Declaratory and Injunctive Relief, *Southern Utah Wilderness Alliance v. Allred*, 1:08-cv-02187-RMU (D.C., Feb. 3, 2009) at 50-51.
[214] 16 U.S.C. § 1271-1287.
[215] 16 U.S.C. § 1271.
[216] BLM Manual § 8351.52 (1992), *available at* http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/blm_manual.html.
[217] 16 U.S.C. § 1274(d)(1).
[218] 16 U.S.C. § 1278(a).
[219] OIL SHALE ROD at 9, 17.
[220] VERNAL RMP ROD at 44.
[221] VERNAL RMP FEIS at Figure 32. The White River is the largest surface water source within the most geologically prospective oil shale area.
[222] First Amended Complaint for Declaratory and Injunctive Relief, *Southern Utah Wilderness Alliance v. Allred*, 1:08-cv-02187-RMU (D.C., Feb. 3, 2009) at 48-49.

Colorado-Utah border, all of the Delores River, and portions of the Green River.[223] The U.S. Forest Service recently finalized its list of suitable segments, most of which are north of the most geologically prospective oil shale area.[224] These segments are subject to interim protections, including the effects of more distant development. For example, a large increase in demand for water and associated impoundments as well as the need for new power plants could change flow characteristics and conflict with management requirements under the WSRA.

WSRA discussions are subject to one very important caveat—protections afforded to eligible and designated segments are subject to valid, existing rights.[225] It is Utah and the BLM's position that water rights secured under the Upper Colorado River Compact are valid, existing rights.[226] These rights are senior to rights associated with suitable or even designated rivers. Under this interpretation, inclusion of a river segment in the Wild and Scenic River System will have little practical effect on oil shale development since, as Colorado River tributaries, rights to utilize these waters are already secured under the Upper Colorado River Compact. Therefore, flow protections afforded by designation would be subject to the prior existing right to all water within the basin. Whether this position prevails remains to be seen as it has not yet been the subject of political or judicial scrutiny.

4.2 WILDLIFE

The most geologically prospective oil shale area includes diverse habitats for a wide range of wildlife species. Utah's conservation database indicates that the most geologically prospective oil shale area contains important habitat for elk, mule deer, and pronghorn antelope as well as brood and winter habitat for sage grouse.[227] Crucial elk and mule deer winter range, as well as a lynx habitat linkage zone, have been identified south of the White River, as shown in Figure 4.2.1.[228] According to the Colorado Division of Wildlife, the "Piceance Basin is home to the largest migratory mule deer herd in North America, a large migratory elk population, one of only six sage-grouse populations in Colorado, conservation and core conservation populations of Colorado River cutthroat trout, and a host of other wildlife species."[229]

Prior to initiating a commercial oil shale leasing program on the public lands, policymakers (as well as prospective oil shale lessees) will need to develop a legally and politically acceptable framework that

[223] U.S. BUREAU OF LAND MANAGEMENT, MOAB FIELD OFFICE, RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN, (Oct. 2008) (MOAB RMP ROD) at 34 and Map 22.

[224] U.S.D.A. FOREST SERVICE, RECORD OF DECISION AND FOREST PLAN AMENDMENTS, WILD AND SCENIC RIVER SUITABILITY STUDY FOR NATIONAL FOREST SYSTEM LANDS IN UTAH (Nov. 2008).

[225] 16 U.S.C. §§ 1280(a), 1283(b) and 1284(f). *See also* MOAB RMP ROD at 112 and letter from Jon Huntsman, Jr., Governor of Utah to Selma Sierra, Director of Utah BLM 7 (Sept. 30, 2008) (providing the Governor's Consistency Review for the Moab Field Office's Proposed Resource Management Plan), *available at* http://governor.utah.gov/rdcc/Y2008/Comments/Governors%20Consistency%20Review%20MOAB%20RMP.pdf.

[226] *See* MOAB RMP ROD at 112-13 ("it is BLM's position that existing water rights, including flow apportioned to the State of Utah interstate agreements and compacts, including the Upper Colorado River Compact, and developments of such rights will not be affected by designation or the creation of the possible federal reserved water right.") and *see e.g.*, letter from Jon Huntsman, Jr., Governor of Utah to Selma Sierra, Director of Utah BLM 7 (Sept. 30, 2008), *available at* http://governor.utah.gov/rdcc/Y2008/Comments/Governors%20Consistency%20Review%20MOAB%20RMP.pdf("a suitability determination will have no effect on future projects, including projects reflecting 'valid existing rights' under the provisions of the Compact and other water agreements.").

[227] *See* http://atlas.utah.gov/wildlife/viewer.htm.

[228] VERNAL RMP FEIS at Figure 46.

[229] Comments of Colorado Governor Bill Ritter on DRAFT PEIS, *reprinted in* FINAL PEIS at p. 5313. Within Colorado, areas that would be open to commercial leasing under the Final PEIS include: 880 acres of important aquatic habitat; 7 acres of active bald eagle nests; 190,478 acres of elk production area; 6,506 acres of greater sage-grouse leks; 125,563 acres of greater sage-grouse production area; 78,093 acres of critical mule deer winter range; and 31,479 acres of mule deer migration corridors. FINAL PEIS at p. 5313.

ensures adequate wildlife and habitat protection while addressing the realistic impacts of commercial oil shale development. The number of special status species reflects the potential magnitude of this conflict for commercial oil shale development. As an example, Uintah County, which is most likely to experience the direct impacts of oil shale development in Utah, is currently home to 9 federally protected species, 19 species designated as state species of concern, and 5 species receiving special management in efforts to preclude the need for federal protection.[230]

As evidenced by the Uintah County example, commercial oil shale leasing and development activities are also almost certain to impact several species and their habitat, including some subject to protections under the Endangered Species Act (ESA)[231] and comparable state laws. The BLM is obligated to afford great weight to state wildlife plans and policies intended to conserve species even where ESA protections are not in place.[232] Oil shale leasing and development activities also may negatively affect state wildlife refuges and wildlife conservation efforts underway in areas proximate to the most geologically prospective oil shale area. Wildlife management represents a multi-jurisdictional challenge, and land managers will need an effective framework for proactively coordinating their wildlife management efforts from the outset of commercial oil shale leasing and development activities.

4.2.1 THE ENDANGERED SPECIES ACT

Oil shale leasing and development on the public lands is likely to impact several species subject to protections under the ESA. The ESA provides "a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, to provide a program for the conservation of such endangered species and threatened species, and to take such steps as may be appropriate to achieve the purposes of [relevant] treaties and conventions."[233] The ESA protects and aids in the recovery of imperiled species and the ecosystems upon which they depend,[234] protecting "listed" species and their habitats by prohibiting the "take" of listed animals, except under federal permit.[235] The U.S. Fish and Wildlife Service (FWS) has primary jurisdiction over listed terrestrial and freshwater organisms under the ESA.

Five factors weigh on the decision to list[236] a species: habitat degradation, overuse of the species,

[230] Utah Division of Wildlife Resources, Utah's State Listed Species by County (Feb. 10, 2009).
[231] 16 U.S.C. §§ 1531-43 (2008).
[232] FLPMA requires that the BLM's land use plans "shall be consistent with State and local plans to the maximum extent [the SOI] finds consistent with Federal law and the purposes of this Act." 43 U.S.C. § 1712(c)(9). Regulations promulgated to implement this provision expand this mandate to include not only formal land use plans, but "resource related policies and programs" adopted by states, other federal agencies, or Indian tribes. 43 C.F.R. § 1610.3-2(b). Although the extent of the BLM's obligation under the consistency provision and apparent discrepancies between FLPMA and its implementing regulations have not been fully resolved, consistency between federal and state wildlife management strategies should be evaluated prior to initiating a commercial oil shale leasing and development program on the public lands. Efforts such as the Western Governors Association's Wildlife Council, which involves collaboration across federal, state and local boundaries, may provide a model for collaborative and proactive wildlife management practices for an oil shale leasing program on the public lands. *See* `http://www.westgov.org/wga/initiatives/corridors/index.htm`.
[233] 16 U.S.C. § 1531(b).
[234] 16 U.S.C. § 1531.
[235] 16 U.S.C. § 1538(a)(1)(B). ESA listed plants are not protected from take, although it is illegal to collect or "maliciously damage or destroy" them on federal land. 16 U.S.C. § 1538(a)(2). Protection from commercial trade and the effects of federal actions do apply for plants.
[236] Under the ESA, species may be listed as either endangered or threatened: "Endangered" species are in danger of extinction throughout all or a significant portion of their range, 16 U.S.C. § 1532(6) "threatened" species are likely to become endangered within the foreseeable future. 16 U.S.C. § 1532(20). Section 4 of the ESA requires species to be listed based solely on their biological status and threats to their existence; economic impacts of a listing decision are not considered. 16 U.S.C. § 1533. The FWS also maintains a list of "candidate" species which warrant listing, but whose listing is precluded by higher listing

disease or predation impacts, the inadequacy of existing regulatory protections for the species, and other natural or human threats to the species survival.[237] Economics are not considered when making a listing determination.[238] To "take" a listed species means "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect or attempt to engage in any such conduct."[239] Through regulations, "harm" is defined as "an act which actually kills or injures wildlife. Such an act may include significant habitat modification or degradation where it actually kills or injures wildlife by significantly impairing essential behavioral patterns, including breeding, feeding, or sheltering."[240] This prohibition against a "take" applies regardless of land ownership.[241]

To avert a trend towards listing, state officials and federal land managers frequently apply protections to safeguard dwindling species and the habitat upon which they depend. These safeguards include protections imposed by state law and conservation agreements between state and federal agencies. However, the FWS cannot rely on state promises in making listing determinations; it "may only consider efforts that are currently operational, not those promised to be implemented in the future."[242]

The ESA also requires designation of "critical habitat" for listed species when "prudent and determinable."[243] Critical habitat includes geographic areas containing physical or biological features essential to the species conservation and that may need special management or protection.[244] Critical habitat may include areas that are not occupied by the species at the time of listing but are essential to its conservation.[245] Unlike the initial listing decision, an area can be excluded from critical habitat designation if the economic benefits of excluding it outweigh the benefits of designation, unless failure to designate the area as critical habitat may lead to extinction of the listed species.[246]

Section 7 of the ESA requires federal agencies to promote the conservation purposes of the ESA and to consult with the FWS, as appropriate, to ensure that effects of actions they authorize, fund, or carry out will not jeopardize the continued existence of listed species.[247] During consultation, the action agency receives a "biological opinion" or concurrence letter addressing the proposed action.[248] In the relatively few cases in which the FWS makes a jeopardy determination, the agency offers "reasonable and prudent alternatives" about how the proposed action could be modified to avoid jeopardy.[249] Under Section 7, federal agencies are required to avoid "destruction" or "adverse modification" of designated critical habitat.[250]

Section 10 of the ESA provides relief to non-federal landowners who want to develop property inhabited by listed species.[251] Non-federal landowners can receive a permit to take listed species incidental to otherwise legal activities, provided they have developed an approved habitat conservation

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priorities.

[237] 16 U.S.C. § 1533(a)(1)(A) through (E) (2008).

[238] *N.M. Cattle Growers Ass'n v. United States Fish & Wildlife Serv.*, 248 F.3d 1277, 1282 (10th Cir. 2001).

[239] 16 U.S.C. § 1532(19).

[240] 50 C.F.R. § 222.102.

[241] 16 U.S.C. § 1538(a)(1), *see also Babbitt v. Sweet Home Chapter of Communities for a Great Oregon*, 515 U.S. 687, 703 (1995).

[242] *Oregon NRDC v. Daley*, 6 F. Supp 2d 1139, 1154 (D. Or. 1998).

[243] 16 U.S.C. § 1533(a)(3)(A).

[244] 16 U.S.C. § 1532(5)(A)(i).

[245] 16 U.S.C. § 1532(5)(A)(ii).

[246] 16 U.S.C. § 1533(b)(2).

[247] 16 U.S.C. § 1536(a).

[248] 16 U.S.C. § 1536(b)(3).

[249] 16 U.S.C. § 1536(b)(3).

[250] 16 U.S.C. § 1536(a)(2).

[251] 16 U.S.C. § 1539.

plan.[252] Habitat conservation plans include an assessment of the likely impacts on the species from the proposed action, the steps that the permit holder will take to minimize and mitigate the impacts, and the funding available to carry out the steps.[253]

As applied to an oil shale leasing program on the public lands, the ESA would require consultation at the leasing phase and might require additional consultation at the development and reclamation stages of operations, depending on the level of detail available and considered at each phase.[254] Consultation would not merely require an assessment of the lease site, but an overall evaluation of the indirect and cumulative effects of commercial development on listed species and their critical habitats.[255]

While a review of each species that has the potential to impact commercial oil shale development is beyond the scope of this report, the following case studies of four Colorado River fishes, sage grouse and endemic plants present three distinctive sets of problems and are emblematic of the challenges sensitive species are likely to pose for commercial oil shale development on the public lands.

Fishes. Four species of fish[256] inhabit the major rivers running through Colorado and Utah, including large portions of the most geologically prospective oil shale area. The portion of the Green River running along the western side of the most geologically prospective oil shale area includes:

> [T]he prime spawning bar and the largest and most important floodplain rearing habitat in the entire Upper Colorado basin. This reach of river is also at the core of the largest remaining Colorado pikeminnow population, and contains key backwater habitat for this species ... Further, recent sampling has confirmed that the lower White River contains a significant number of adult Colorado pikeminnow.[257]

Common factors that imperil all four species relate to direct loss of habitat, changes in water flow and temperature, blockage of migration routes, fragmentation of habitat, and interaction with introduced fish species. According to the FWS, reservoir inundation within the Upper Colorado Basin destroyed approximately 435 miles of Colorado pikeminnow habitat.[258] Dams continue to exact a toll as streamflow regulation and associated habitat modification (including cold-water dam releases and blockage of migration corridors) pose the greatest ongoing threats to these protected species.[259]

The FWS has developed flow recommendations for some stream reaches within the Upper Colorado River Basin, identifying and describing flow timing, frequency, magnitude, and duration required by endangered fishes.[260] Flows necessary to maintain and restore habitats of the four native Colorado River

[252] 16 U.S.C. § 1539(a).

[253] 16 U.S.C. § 1539(a)(2).

[254] *See Village of False Pass v. Clark*, 733 F.2d 605, 611-12 (9th Cir. 1984) (holding additional Section 7 consultation is required where initial consultation identifies only conceptual measures and other statutes require additional information regarding development at later phases), *accord Pit River Tribe v. U.S. Forest Service*, 469 F.3d 768, 783-84 (9th Cir. 2006) (holding supplemental NEPA required for development where leasing analysis does not consider impact of development.).

[255] *Connor v. Burford*, 848 P.2d 1441, 1453-54 (9th Cir. 1988).

[256] The Colorado pikeminnow (*Ptychocheilus lucius*), the humpback chub (*Gila cypha*), bonytail chub (*Gila elegans*), and the razorback sucker (*Xyrauchen texanus*)—all of which are listed as endangered under the ESA.

[257] Comments of Joel S. Tuhy, Director of Science, Utah State Office of The Nature Conservancy (March 19, 2008), reprinted in FINAL PEIS, vol. 4, p. 4755-56.

[258] U.S. Fish and Wildlife Service, *Colorado pikeminnow (Ptychocheilus lucius) Recovery Goals: Amendment and Supplement to the Colorado Squawfish Recovery Plan* 23 (2002).

[259] *See* U.S. Fish and Wildlife Service, *Colorado pikeminnow (Ptychocheilus lucius) Recovery Goals: Amendment and Supplement to the Colorado Squawfish Recovery Plan* 22 (2002); U.S. Fish and Wildlife Service, *Bonytail* (*Gila elegans*) *Recovery Goals: Amendment and Supplement to the Bonytail Chub Recovery Plan* 18 (2002).

[260] *See generally*, U.S. Fish and Wildlife Service, *Recovery Implementation Program Recovery Action Plan* (as amended April 2, 2009).

fishes mimic the natural hydrograph and include spring peak flows and summer–winter base flows.[261] In some instances, these flow recommendations have already been incorporated into state law. Utah recently revised state policy to incorporate year-round bypass flow requirements for new appropriations and change applications along portions of the Green River.[262] The flows required to protect the four Colorado River fishes represent one of the few firm limits on oil shale development because any development that interferes with required flows (either qualitatively or quantitatively) would conflict with the ESA.

The more information available in advance of Section 7 consultation regarding flow and habitat requirements, the easier it will be to plan within ESA constraints. If new information or changed conditions call existing recommendations into question, updates should proceed at the earliest possible point. By establishing the threshold requirements for permissible development, policymakers would reduce uncertainty for industry, regulators, and the public alike.

Sage Grouse. Sage grouse habitat overlies significant oil shale resources within the Uinta Basin. Roughly half the sage grouse habitat within Utah has already been lost and populations have declined at a comparable rate.[263] Although not listed at present under the ESA, Greater Sage Grouse are currently under review for listing by the FWS.[264] If the sage grouse is listed, oil shale development will trigger both the consultation requirements of Section 7 and the prohibition against the "take" of listed wildlife species under Section 9 of the ESA. Listing of the Greater Sage Grouse will portend significant restrictions on all energy development activities in the geologically prospective oil shale area.

Independent of the ESA, the BLM is required to consider impacts to biological resources as part of its land planning process, weighing "the relative scarcity of the values involved."[265] In furtherance of this mandate and under the BLM's Special Status Species Policy, BLM State Directors may designate "sensitive" species that are native species of concern for various reasons: they "could become endangered or extirpated from a state, or within a significant portion of its distribution in the foreseeable future;" they are "under status review" by the FWS; or they are "undergoing significant current or predicted downwards trends in population or density."[266] The Greater Sage Grouse has been designated as a "sensitive" species by the BLM within the most geologically prospective oil shale area and thus will receive heightened consideration.

In December, 2008, the Western Watersheds Project filed suit in the Federal District Court for the District of Idaho, challenging the BLM's consideration of impacts to sage grouse and sage grouse habitat as part of 18 recently issued RMPs.[267] Western Watershed's suit alleges failure to satisfy both FLPMA and NEPA requirements across a 25 million acre area and seeks to compel the BLM to revisit its analysis.

[261] *See* U.S. Fish and Wildlife Service, *Colorado pikeminnow (Ptychocheilus lucius) Recovery Goals: Amendment and Supplement to the Colorado Squawfish Recovery Plan* 20-21 (2002); U.S. Fish and Wildlife Service, *Bonytail* (*Gila elegans*) *Recovery Goals: Amendment and Supplement to the Bonytail Chub Recovery Plan* 26 (2002).

[262] *See* Utah Department of Natural Resources,Division of Water Rights, *2009 Proposed Water Rights Policy Regarding Applications to Appropriate Water and Change Applications Which Divert Water from the Green River Between Flaming Gorge Dam and the Duchesne River* (Sept. 21, 2009), *available at* http://www.waterrights.utah.gov/meetinfo/m20090820/policy-upcorviMC09L.pdf.

[263] Utah Department of Natural Resources, Division of Wildlife, *Strategic Management Plan for Sage-Grouse* 6 (June 11, 2002); John W. Connelly et all., *Guidelines to Manage Sage Grouse Populations and their Habitats*, WILDLIFE SOCIETY BULLETIN, 28(4):967 (2000).

[264] Information regarding the status of the Greater Sage Grouse listing petition can be found at http://ecos.fws.gov/speciesProfile/profile/speciesProfile.action?spcode=B06W

[265] 43 U.S.C. § 1712(c)(6).

[266] BLM Manual 6840.06.E.

[267] *Western Watersheds Project v. Kempthorne*, (No. 08-cv-516-BLW) (D. Id. pending).

The outcome of this litigation will be of tremendous importance to potential commercial oil shale developers in Utah as surface resource management practices within Utah's most geologically prospective oil shale area are governed by the challenged RMPs.

In light of the intensive surface disturbance associated with oil shale development, neither policy-makers nor potential lessees should assume that conflicts between oil shale leasing and development activities and species such as the sage grouse will be amenable to design change solutions such as those typically used with oil or natural gas development. A proactive approach to managing development conflicts with sensitive species should include mandatory pre-lease surveys and buffers within suitable habitat, as well as developing and requiring effective mitigation of associated offsite and cumulative effects prior to commencement of surface-disturbing development activities. The BLM Wyoming State Director recently issued a statewide sage grouse habitat management policy detailing requisite protections and analytical requirements.[268] While not applicable in Colorado or Utah, the Wyoming policy represents the most comprehensive sage grouse management recommendations available and may be indicative of future requirements throughout the region.

Plants. The most geologically prospective oil shale area is home to several federally protected plant species as well as several species that are candidates for federal protection. ESA protections applicable to plants differ from those affecting fish and wildlife. Although the Section 9 prohibition against "taking" listed species does not apply to plants,[269] it is illegal under the ESA to:

> [R]emove and reduce to possession any such species from areas under Federal jurisdiction; maliciously damage or destroy any such species on any such area; or remove, cut, dig up, or damage or destroy any such species on any other area in knowing violation of any law or regulation of any State or in the course of any violation of a State criminal trespass law.[270]

This prohibition's reach is somewhat truncated, applying only to "areas under Federal jurisdiction," or actions in knowing violation of state law rather than applying to all areas "within the United States."[271] Nonetheless, Section 7 consultation requirements still apply and all federal agencies must

> [I]nsure that any action authorized, funded, or carried out by such agency ... is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined by the Secretary, after consultation as appropriate with affected States, to be critical.[272]

On August 18, 2009, the FWS issued a finding that a 2007 petition for ESA listing contains substantial information indicating that listing of 14 plants found within Utah may be warranted. Accordingly, the FWS will initiate a status review to determine if ESA listing is warranted.[273] Two of these species, Hamilton milkvetch (*Astragalus hamiltonii*) and flowers penstemon (*Penstemon floweersii*), are found

[268] U.S. DEPT. OF THE INTERIOR, BUREAU OF LAND MANAGEMENT, INSTRUCTION MEMORANDUM NO. WY-2010-012, GREATER SAGE-GROUSE HABITAT MANAGEMENT POLICYON WYOMING BUREAU OF LAND MANAGEMENT (BLM) ADMINISTERED PUBLIC LANDS INCLUDING THE FEDERAL MINERAL ESTATE (Dec. 29, 2009), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/resources/efoia/IMs/2010.Par.61358.File.dat/WY2010-012.pdf.
[269] *Compare* 16 U.S.C. §§ 1538(a)(1) and (a)(2).
[270] 16 U.S.C. § 1538(a)(2)(B).
[271] Compare 16 U.S.C. §§ 1538(a)(1)(B) and (a)(2)(B).
[272] 16 U.S.C. § 1536(a)(2).
[273] 74 FED. REG. 41649-62 (Aug. 18, 2009).

in Uintah County. Although specific plant location information is limited, the finding indicates that all known habitat for flowers penstemon is located on private and Ute Indian Tribe lands.[274]

Several plants overlaying portions of the most geologically prospective oil shale area are already protected under the ESA. Shrubby reed-mustard (*Glaucocarpum suffrutescens*) is a federally listed endangered plant that occurs in the Uinta Basin. The Uinta Basin hookless cactus (*Sclerocactus glaucus*) and clay reed-mustard (*Schoenocrambe argillacea*) are also found within the Basin and listed as threatened under the ESA.[275] According to the Utah Division of Wildlife, these plant species are vulnerable to disturbance associated with energy development.[276]

Graham beardtongue (*Penstemon grahamii*) is endemic to the Uinta Basin in Utah and in immediately adjacent Rio Blanco County, Colorado. The FWS identifies key threats as loss of habitat due to oil and gas exploration, drilling and field development, tar sand and oil shale mining, off-road vehicle use, domestic and wild grazers, and horticultural overuse.[277] In 2006, the FWS proposed listing Graham beardtongue as threatened under the ESA.[278] The FWS's initial critical habitat designation included five separate plant populations covering approximately 3,500 acres.[279] However, this proposed listing was withdrawn in December 2006,[280] sparking a federal lawsuit alleging that the FWS ignored sound science in failing to grant protected status to Graham beardtongue.[281] Any resolution reinstating the listing decision could impact oil shale development because Graham beardtongue is found only in oil shale bearing formations. White River beardtongue (*Penstemon scariosus var. albifluvis*), found within portions of the most geologically prospective oil shale area[282] in the Uinta Basin, as well as in Rio Blanco County, Colorado, is also a candidate for listing under the ESA.[283]

Oil shale leasing and development on the public lands poses a unique set of challenges with respect to rare plants. Development strategies invariably focus on avoidance; however, effective avoidance requires knowledge of species locations, which, throughout much of the most geologically prospective oil shale area, appears lacking. Further, the breadth of surface disturbance associated with oil shale development will make avoidance of rare plants more difficult than it would be with oil and gas development. Absent detailed knowledge of plant distribution and population sizes, regulators will have a much harder time determining whether individual plants can be lost without jeopardizing species viability. Adequate information and the flexibility to effectively avoid sensitive resources through careful siting of facilities will be crucial to concluding mandatory Section 7 consultations with non-jeopardy opinions. Policymakers should promote efforts to increase knowledge about these scarce and sensitive resources, not only inventorying known and potential habitat, but also researching the feasibility of reintroducing populations into areas subject to less development pressure. As recommended with respect to other resources, surveys should precede leasing in order to provide potential lessees an accurate assessment of potential development constraints.

[274] 74 FED. REG. at 41660.
[275] *See* Utah's Federally (US F&WS) Listed Threatened(T), Endangered (E), and Candidate (C) Plant Species, *available at* http://dwrcdc.nr.utah.gov/ucdc/viewreports/te_list.pdf.
[276] *See* http://dwrcdc.nr.utah.gov/rsgis2/Search/SearchSelection.asp?Group=PLANT\&Species=PLANT.
[277] http://www.fws.gov/mountain-prairie/species/plants/grahamsbeardtongue/.
[278] 71 FED. REG. 19,158-59 (April 13, 2006).
[279] 71 FED. REG. 3,157-96 (Jan. 19, 2006).
[280] 71 FED. REG. 76,023-35(Dec. 19, 2006).
[281] *See* Tom Wharton, *Lawsuit filed to protect Uinta Basin Flower*, SALT LAKE TRIBUNE (Dec. 17, 2008), *available at*: http://www.sltrib.com/ci_11256381).
[282] http://dwrcdc.nr.utah.gov/rsgis2/Search/Display.asp?FlNm=pensscar.
[283] *See* Utah's Federally (US F&WS) Listed Threatened(T), Endangered (E), and Candidate (C) Plant Species, *available at* http://dwrcdc.nr.utah.gov/ucdc/viewreports/te_list.pdf.

4.2.2 NATIONAL AND STATE WILDLIFE MANAGEMENT AREAS

In addition to impacting species protected under the ESA, initiating a commercial oil shale leasing and development program on the public lands has the potential to negatively impact existing national and state wildlife management areas. The Ouray National Wildlife Refuge, managed by the FWS, is located 30 miles south of Vernal in northeastern Utah, covering 11,987 acres including 12 miles of the Green River.[284] The Refuge contains several habitat types[285] and is home to a wide variety of plants (including the endangered Uintah Basin hookless cactus)[286] and wildlife.[287] Ponds at the Ouray National Wildlife Refuge are home to several aquatic species and function as nurseries for four Colorado River fishes listed as endangered under the ESA.[288]

Some leasing of state lands bearing oil shale has occurred near the Ouray National Wildlife Refuge's southern boundary where oil shale bearing formations yield, on average, 25 GPT from deposits approximately 60 to 100 feet or more in thickness.[289] These shale deposits are better suited to recovery through in situ technologies rather than conventional mining methods because area overburden generally exceeds 3,000 feet in depth.[290] Nonetheless, development of adjacent oil shale resources could negatively impact the wildlife conservation efforts of the Refuge, impacting the Refuge's ability to maintain high-quality wetland and riparian habitat.

In addition, the Utah Division of Wildlife manages two large tracts of land along the southern edge of the most geologically prospective oil shale area that were obtained as part of the Book Cliffs Conservation Initiative.[291] The Conservation Initiative respresents a partnership between the Rocky Mountain Elk Foundation, the Nature Conservancy, Utah, the BLM, and longtime ranchers and private landowners who joined forces to acquire several privately owned ranches in the Book Cliffs.[292] Under the Initiative, ranches were acquired to "[p]rotect, improve and restore watershed and soil stability, vegetative communities, forage and escape/security for big game emphasizing mule deer fall, winter and spring range."[293] In January of 2009, Initiative partners succeeded in reintroducing bison on to the public lands in the

[284]U.S. Fish and Wildlife Service, Ouray National Wildlife Refuge General Brochure, *available at* `http://www.fws.gov/ouray/brochure.html`.

[285]The Ouray National Wildlife Refuge includes numerous habitat types, among them river, riparian woodlands, wetlands, artificial impoundments, croplands, semidesert shrublands, grasslands, and clay bluffs. U.S. Fish and Wildlife Service, Ouray National Wildlife Refuge General Brochure, *available at* `http://www.fws.gov/ouray/brochure.html`.

[286]*See* U.S. Fish and Wildlife Service, Ouray National Wildlife Refuge Plant List, *available at* `http://www.fws.gov/ouray/plants.html`.

[287]Wildlife found at the Ouray National Wildlife Refuge include cottontail rabbits, jackrabbits, raccoons, porcupines, prairie dogs, beavers, badgers, muskrats, river otters, mule deer, elk, moose, bison, bears, foxes, coyotes, mountain lions, lynx, bobcats, bald and golden eagles, great horned owls, several species of hawks, and numerous waterfowl. U.S. Fish and Wildlife Service, Ouray National Wildlife Refuge Mammal List, *available at* `http://www.fws.gov/ouray/mammals.html`.

[288]The four endangered Colorado River fishes in residence at the Ouray National Wildlife Refuge are the Colorado pikeminnow (*Ptycholcheilus lucius*), the humpback chub (*Gila cypha*), the bonytail chub (*Gila elegans*), and the razorback sucker (*Xyrauchen texanus*). U.S. Fish and Wildlife Service, Ouray National Wildlife Refuge Fish List, *available at* `http://www.fws.gov/ouray/fish.html`.

[289]*See* VANDEN BERG at Plate 5.

[290]*See* VANDEN BERG at Plate 3.

[291]For a description of the early evolution of the Book Cliffs Conservation Initiative *see* Michelle Nijhuis, *Oil clashes with elk in the Book Cliffs*, HIGH COUNTRY NEWS (Apr. 13, 1998), *available at* `http://www.hcn.org/issues/128/4069`.

[292]*See* Michelle Nijhuis, *Oil clashes with elk in the Book Cliffs*, HIGH COUNTRY NEWS (Apr. 13, 1998), *available at* `http://www.hcn.org/issues/128/4069`.

[293]Utah Division of Wildlife Resources, Northeastern Region, *Phase I Habitat Management Plan, Book Cliffs Wildlife Management Area, Two Waters Unit* 7 (April 25, 2003) (on file with authors). Identical language is contained in Utah Division of Wildlife Resources, Northeastern Region, *Phase I Habitat Management Plan, Book Cliffs Wildlife Management Area, Bitter Creek Unit* 7 (April 25, 2003) (on file with authors).

Book Cliffs.[294]

Control over several thousand acres of oil shale bearing lands immediately adjacent to the Utah Division of Wildlife management areas was recently transferred to SITLA,[295] which is obligated to maximize income for trust beneficiaries and has already issued nearly 100,000 acres of oil shale leases in furtherance of its mandate.[296] These adjacent tracts and neighboring oil shale bearing lands are capable of producing at least 25 GPT oil shale from deposits roughly 40 to 60 feet in thickness with very little overburden, making these deposits well suited to conventional mining operations.[297] While not currently leased, these tracts are likely to prove highly desirable for oil shale developers. Absent effective avoidance and mitigation protocols, development of these tracts could indirectly compromise collaborative efforts to protect important wildlife habitat and will likely generate significant public interest.

4.3 Cultural and Paleontological Resources

The most geologically prospective oil shale area contains a wide range of cultural[298] and paleontological resources[299] covering an expansive period of human history and prehistory. Human populations have inhabited this area through four major prehistoric eras (Paleoindian from 11450 to 6000 B.C., Archaic from 6400 to 400 B.C., Formative from 400 B.C. to A.D. 1300, and Protohistoric A.D. 1300 to 1880), and excavated artifacts and archaeological features date back as far as twelve thousand years ago.[300] Fossilized remains of vertebrate, invertebrate, and plant life have been found in the region from the Paleocene/Early Eocene to the Middle Eocene geologic units, dating approximately 66 to 40 million years ago.[301] Dinosaur National Monument, which has yielded an immense number of large vertebrate fossils, is located less than 20 miles from the most geologically prospective oil shale area.[302] Cultural and paleontological resources are best characterized as rare, fragile and nonrenewable. The degradation or destruction of these items can irretrievably compromise their unique scientific and research value; as a result, their loss is difficult, if not impossible, to mitigate.

Although the most geologically prospective oil shale area is recognized as rich in cultural resources, the extent of these resources is not well understood. Only 7.9% of the Piceance Basin and only 5.3% of the Uinta Basin have been subject to any cultural resource surveys.[303] "o date, no comprehensive

[294]*See* Utah Division of Wildlife Resources, Wildlife News: Dreams come true – bison released in the Book Cliffs,*available at* http://wildlife.utah.gov/news/09-01/bison_release.php.

[295]Control was transferred pursuant to the Utah Recreation Land Exchange Act, P.L. 111-053 (2009). For further discussion of the implications of land exchanges under this Act *see* chapter 3

[296]Figures are as of October 31, 2008. Statistics were compiled from data provided by SITLA, *available at* http://168.178.199.154/publms/contents.htm. These figures reflect active leases; an additional 71 inactive leases cover over 96,281 acres.

[297]Vanden Berg at Plate 3.

[298]Cultural resources can be either man-made or natural physical features. Final PEIS at 3-197. Cultural resources can include "[a]rchaeological sites, architectural structures or features, traditional use areas, and Native American sacred sites or special use areas that provide evidence of the prehistory and history of a community." Final PEIS at 9-6. Cultural resources may also be "properties that are important to a community's practices and beliefs and that are necessary for maintaining the community's cultural identity." Final PEIS at 3-197.

[299]Paleontological resources are "fossilized remains, imprints, and traces of plants and animals preserved in rocks and sediments since some past geologic time."Final PEIS at 9-20.

[300]Final PEIS, 3-199. *See* Final PEIS at 3-197 - 3-210 for a description of cultural and archaeological resources throughout the most geologically prospective oil shale area.

[301]*See* Final PEIS at 3-56 - 3-61 for a description of paleontological resources throughout the most geologically prospective oil shale area.

[302]*See* http://www.nps.gov/history/museum/exhibits/dino/overview.html.

[303]Final PEIS at 3-202 and 3-205. The Final PEIS may underreport surveys within Utah as the figures quoted above do not

inventory of fossils and no systematic inventory of fossil-bearing areas on BLM-administered lands has been conducted."[304] Despite the lack of survey data, the BLM classifies 8.7% of the Vernal planning area, which contains Utah's portion of the most geologically prospective oil shale area as "high" or "very high" in its potential for fossil yields.[305]

Cultural resources are subject to a complex web of federal laws and regulations,[306] the twin focuses of which are impact avoidance and mitigation of unavoidable impacts. The legal framework protecting paleontological resources is less developed than that for cultural resources. The Final PEIS tiers to other documents for cultural and paleontological resources, stating that it:

> [O]nly amends the decisions for oil shale and tar sands resources in the 10 existing RMPs, and does not amend any of the decisions or protocols for the management of the other resource uses or values, such as air quality, wildlife, cultural resources, water quality, special resource values, etc.[307]

Management, accordingly, depends on the requirements contained in each of the RMPs covering oil shale bearing lands. On the paleontological side, the Vernal RMP requires the BLM to "[l]ocate, evaluate, and manage paleontological resources, and protect them where appropriate, ... [and e]nsure that significant fossils are not inadvertently damaged, destroyed, or removed from public ownership as a result of surface disturbances or land exchanges."[308] "Areas with significant fossils will be identified through predictive modeling and broad-scale sampling. Assessment and mitigation will be required in these areas."[309]

Under the Vernal RMP, the BLM will endeavor to "[p]reserve and protect a representative array of significant cultural resources ... Ṗreserve and conserve cultural resources by conducting activities in a way that protect [sic] values and provide [sic] for the following benefits: conservation for future use, education, interpretation, public use, and research."[310] More specific management direction emphasizes consultation with state and Tribal officials in accordance with existing legal obligations but does not specifically require pre-lease surveys or bar resource destruction.[311] An exception occurs in the Upper Willow Creek Area, which is in the south-central portion of the most geologically prospective oil shale area, where "conditional surface use" stipulations are imposed to protect cultural and archaeological resources.[312] Since it is unclear what conditions will be imposed to protect these resources, however, so prospective oil shale lessees and policymakers alike are left wanting for guidance as to specific management requirements.[313]

The likely consequences of this lack of clarity are exacerbated by the BLM's traditional reliance on the promise of best management practices designed to protect cultural resources that are discovered during resource exploration and extraction.[314] The BLM requires leaseholders to stop work immediately

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include surveys associated with linear features such as roads or pipelines.

304 FINAL PEIS at 3-55.

305 VERNAL RMP FEIS at 4-287.

306 *See e.g.*, the Antiquities Act, 16 U.S.C. §§ 470ee and 470ff, the Archaeological Resources Protection Act, 16 U.S.C. §§ 470aa-470ll, and the National Historic Preservation Act, 16 U.S.C. §§ 431-433.

307 OIL SHALE ROD at 41.

308 VERNAL ROD at 102.

309 VERNAL ROD at 103.

310 VERNAL ROD at 72.

311 VERNAL ROD at 73.

312 VERNAL ROD at 75.

313 Appendix K of the VERNAL RMP FEIS states only that "[t]o preserve the unique representation of the Archaic period, the surface disturbing activities would be subject to timing and controlled surface use stipulations." VERNAL RMP FEIS at K-3.

314 FINAL PEIS at 4-144 – 145.

upon discovery of cultural remains and to then contact the BLM for further guidance. Where sensitive cultural and paleontological resources are not quickly recognized, the BLM's protections cannot be implemented and inadvertent destruction of these resources becomes more likely.

Adequately protecting cultural and paleontological resources on the public lands, the nature and extent of which are unknown, will be an extremely challenging task in the context of the widespread surface disturbances anticipated with commercial oil shale leasing and development. The absence of systematic surveys results in an incomplete picture of the resources potentially at risk from oil shale development, undermining efforts to avoid or minimize impacts. Since avoidance will not always be possible, federal and state agencies should adopt clear, coordinated policies for mitigating unavoidable impacts, and define acceptable levels of resource loss that are sufficient to protect remaining resources; such policies will be of greatest benefit if they precede leasing.

4.4 Recreation

FLPMA directs that the "public lands be managed in a manner that will protect the quality of [various resource-based values]; and that will provide for outdoor recreation."[315] Recreational uses of the lands identified for potential oil shale development include hiking, biking, fishing, hunting, bird watching, off-road vehicle use, and camping.[316] Commercial oil shale development activities are largely incompatible with recreational land use, and "recreational land use could be precluded for those portions of the lease area depending on the technology employed."[317]

The magnitude of this impact is uncertain as the extent of hiking and off-road vehicle activities on oil shale lands has not been quantified. However, the Utah Division of Wildlife Resources maintains records of deer and elk hunters afield within each of 31 management units across the state, providing a rough barometer of recreational use. During 2007, deer hunters in the South Slope area, which extends north from the White River, logged an estimated 38,491 days in the field. For the Book Cliffs area, which extends south from the White River, deer hunters logged an estimated 2,052 days afield during 2007.[318] During 2007, elk hunters logged an additional 42,851 days afield in the South Slope area and 1,661 days afield in the Book Cliffs.[319] Recreational interest is significant and the extent to which big game hunters will be displaced by oil shale development is unclear.

The BLM estimates that approximately 2,000 boaters float the 32-mile segment of the White River downstream of Bonanza, Utah annually,[320] which flows through some of the richest oil shale deposits in Utah. River recreation outside of the most geologically prospective oil shale area is much higher, averaging 73,000 boating days on the Colorado River and 19,000 boater days on the Green River.[321] These numbers likely understate actual demand as river use is limited by permit. A significant reduction in river flows could impair recreation opportunities, both in and downstream of the most geologically prospective oil shale area.

If oil shale leases were clustered in the most geologically prospective oil shale area, the impacts of

[315]43 U.S.C. § 1701.
[316]Final PEIS at 4-20.
[317]Final PEIS at 4-20.
[318]*Utah Division of Wildlife Resources, Utah Big Game Annual Report* 21 (2007). Since portions of the Uinta Basin are subject to limited entry hunts and permits are allotted by lottery, usage statistics may understate public interest.
[319]*Utah Division of Wildlife Resources, Utah Big Game Annual Report* 77 (2007). Since portions of the Uinta Basin are subject to limited entry hunts and permits are allotted by lottery, usage statistics may understate public interest.
[320]Vernal RMP FEIS at 3-56.
[321]U.S. Department of Interior, Bureau of Land Management, Moab Field Office, Proposed Resource Management Plan and Final Environmental Impact Statement (Aug. 2008) (Moab RMP FEIS) at 3-87.

development on recreational users clearly would be intensified in those areas. Transmission line and pipeline rights-of-way would not prevent recreational use of lands other than lands physically occupied by such structures, but would likely affect the quality of the recreation experience.

4.5 Livestock Grazing

Public land grazing is regulated by the Taylor Grazing Act,[322] which seeks to reduce degradation of the public lands attributable to grazing. Under the Taylor Grazing Act, a permit is required to graze livestock on public lands.[323] While this permit confers a revocable privilege to use the public lands, it does not confer vested rights upon the grazer, nor does it give rise to a compensable property interest should the grazing privilege be revoked.[324] Initiating a commercial oil shale leasing and development program on the public lands will displace livestock grazing from lands under development. Within the Vernal planning area, active permitted livestock grazing is currently 137,897 animal unit months.[325] The extent to which commercial oil shale developemnt on the public lands will affect grazing activity is unknown.

In accordance with direction provided by DOI's Solicitor, lands within existing grazing districts are considered "chiefly valuable for grazing" under the Taylor Grazing Act and remain so until the Secretary specifically designates otherwise.[326] A determination that lands are no longer chiefly valuable for grazing is required before a grazing district can be dedicated to another purpose.[327] The Final PEIS does not rescind the "chiefly valuable for grazing" designation; therefore site-specific NEPA analysis associated with lease issuance will need to evaluate whether to re-classify lands for uses other than grazing.[328] Withdrawals from grazing that exceed 5,000 acres also require congressional notification.[329]

Commercial oil shale development would preclude grazing in those portions of the lease area undergoing active development, being prepared for a future development phase, undergoing restoration, or occupied by long-term surface facilities. Transmission line and pipeline rights-of-way would likely not prevent grazing other than on land physically occupied by such structures, but increased human activity within grazing allotments could complicate grazing management. Conflicts between grazing and mining or oil and gas development, while often heated, are routinely resolved, providing a guide as to what oil shale developers can expect.

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[322] 43 U.S.C. § 315 – 315r (2008). The DOI established the Grazing Service to administer the Taylor Grazing Act. The Grazing Service merged with the General Land Office in 1946 to form the Bureau of Land Management.

[323] *See* 43 U.S.C. § 315b; *see also* 43 U.S.C. § 1752 (reiterating the Taylor Grazing Act's requirement for grazing permits).

[324] *See* 43 U.S.C. § 315(b), stating that grazing preferences "shall not create any right, title, interest, or estate in or to the lands" belonging to the U.S. Government; *see also* 43 U.S.C. § 1752(h), stating that "[n]othing in this Act shall be construed as modifying in any way law existing on October 21, 1976, with respect to the creation of right, title, interest or estate in or to public lands or lands in National Forests by issuance of grazing permits and leases;" *see also Omaechevarria v. Idaho*, 246 U.S. 343, 352 (1918) ("Congress has not conferred upon citizens the right to graze stock upon the public lands."); *see also Swim v. Bergland*, 696 F.2d 712, 719 (9th Cir. 1983) ("license to graze on public lands has always been a revocable privilege"); *see also Osborne v. United States*, 145 F.2d 892, 896 (9th Cir. 1944) ("it has always been the intention and policy of the government to regard the use of its public lands for stock grazing … as a privilege which is withdrawable at any time for any use by the sovereign without the payment of compensation").

[325] Vernal RMP FEIS at 3-34. An animal unit month is the amount of forage needed by an animal unit (i.e., a mature 1,000-lb cow and her calf) for one month.

[326] Memorandum, Clarification of M-37008, from Solicitor, U.S. Department of the Interior to Assistant Secretaries and BLM Director (May 13, 2003) ("2003 Clarification of M-37008").

[327] 2003 Clarification of M-37008.

[328] 2003 Clarification of M-37008.

[329] 43 U.S.C. § 1714(c)(1).

4.6 Competing Mineral Development

According to the BLM, "[c]ommercial oil shale development . . . is largely incompatible with other mineral development activities and would likely preclude these other activities while oil shale development and production are ongoing."[330] Depending on the technologies used, extracting oil shale prior to oil and gas, or vice-versa, may also affect the later extraction of the other resource. The severity of the potential conflict is not well known but should be evaluated as prior fluid mineral development could disadvantage some in situ oil shale technologies. For example, prior fluid mineral development that has resulted in significant geologic fracturing or drilling could compromise groundwater management or the ability to efficiently locate wells. Similarly, fracturing for in situ oil shale development could allow natural gas to migrate by disturbing cap rock.

The potential for conflicts over mineral development is significant as large portions of the most geologically prospective oil shale area are already undergoing mineral development, most notably oil and gas exploration.[331] The Congressional Research Service reports that, subject to a margin of error of 2%, 94% of the most geologically prospective oil shale area in Colorado is already leased for oil and gas development; 83% of the most geologically prospective oil shale area in Utah is already leased for oil and gas development; and 71% of the most geologically prospective oil shale area in Wyoming is already leased for oil and gas development.[332] In the Uinta Basin, the Utah Geological Survey paints a more detailed picture of conflicting mineral rights (illustrated by Figure 4.6.1):

[330] Final PEIS at 4-18.

[331] U.S. Department of Interior, Bureau of Land Management, Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement (Dec. 2007) at 4-17 and 5-13. For a comprehensive treatment of the issues complicating oil shale development, including multiple minerals, *see* Constance K. Lundberg, *Shale We Dance? Oil Shale Development in North America: Capoeira or Funeral?*, 52 Rocky Mtn. Min. L. Inst. 13-1 (2006).

[332] Anthony Andrews, Congressional Research Service, *Developments in Oil Shale* (Nov. 17, 2008) at 15-16.

Figure 4.2.1: Vernal RMP Deer, Elk and Lynx - Winter Range/Corridor/Zone. Source: Bureau of Land Management, Vernal RMP ROD.

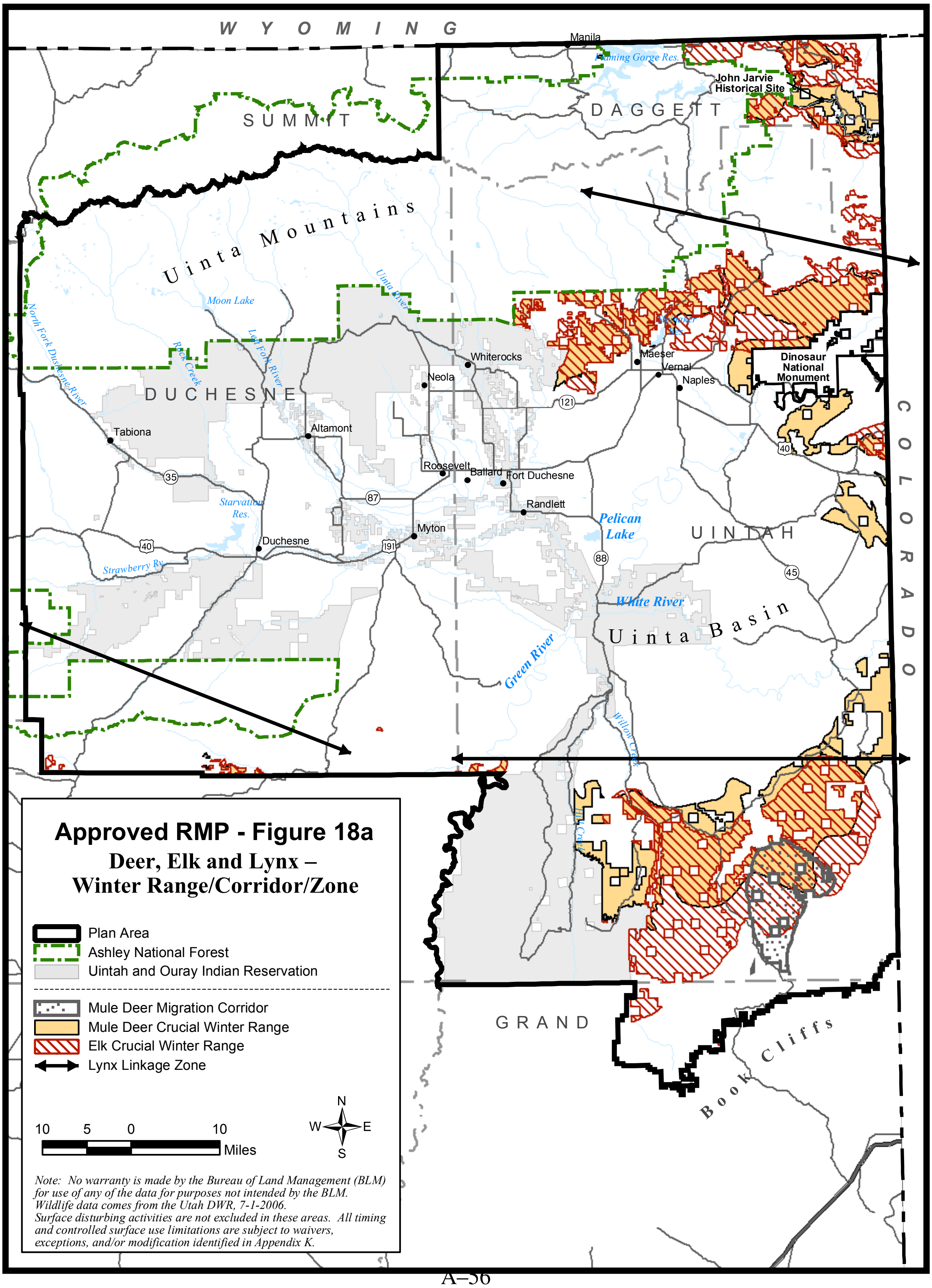
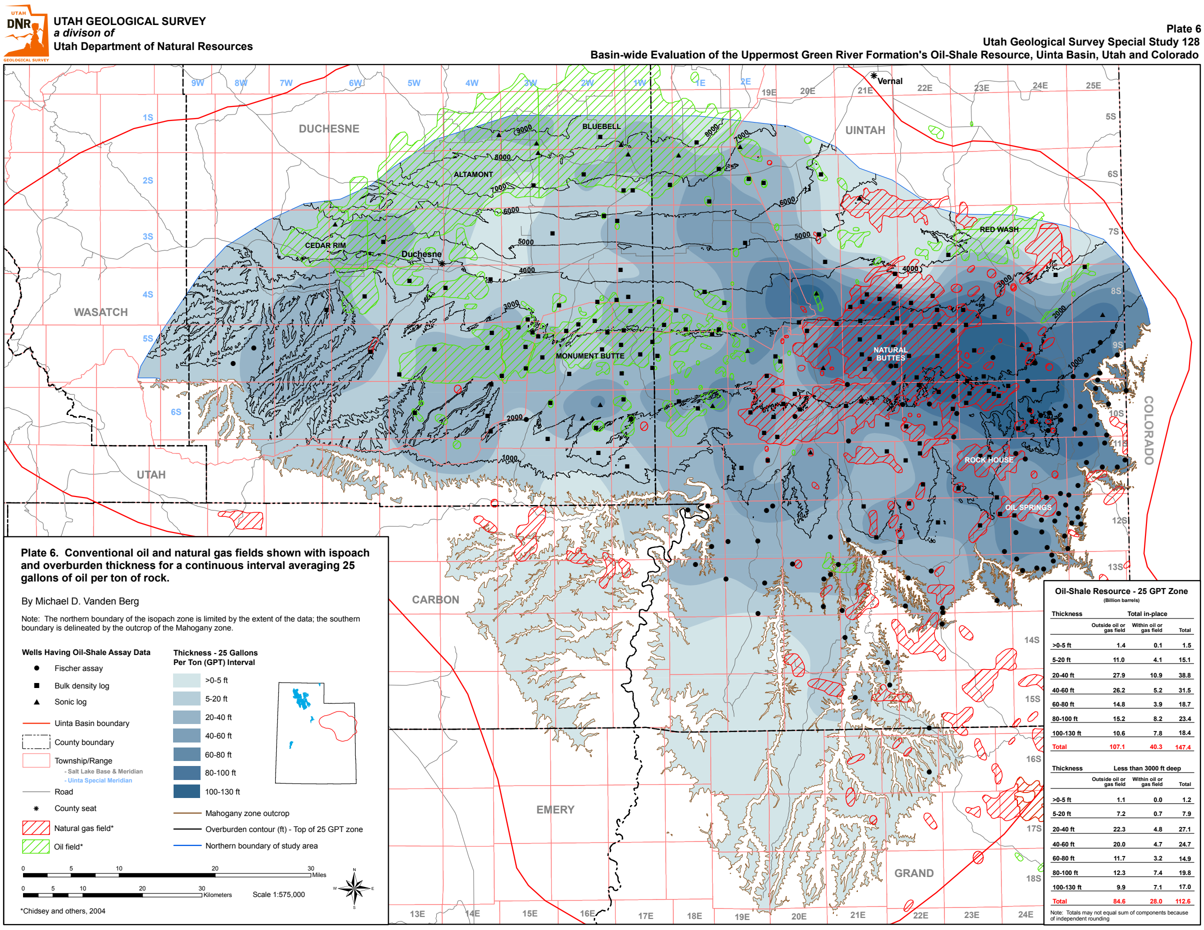


Figure 4.6.1: Basin-wide Evaluation of the Uppermost Green River Formation's Oil-Shale Resource, Uinta Basin, Utah and Colorado. Source: Michael D. Vanden Berg, Utah Geological Survey Special Study 128, Plate 6.



Thickness	Total in-place		
	Outside oil or gas field	Within oil or gas field	Total
>0-5 ft	1.4	0.1	1.5
5-20 ft	11.0	4.1	15.1
20-40 ft	27.9	10.9	38.8
40-60 ft	26.2	5.2	31.5
60-80 ft	14.8	3.9	18.7
80-100 ft	15.2	8.2	23.4
100-130 ft	10.6	7.8	18.4
Total	107.1	40.3	147.4

Thickness	Less than 3000 ft deep		
	Outside oil or gas field	Within oil or gas field	Total
>0-5 ft	1.1	0.0	1.2
5-20 ft	7.2	0.7	7.9
20-40 ft	22.3	4.8	27.1
40-60 ft	20.0	4.7	24.7
60-80 ft	11.7	3.2	14.9
80-100 ft	12.3	7.4	19.8
100-130 ft	9.9	7.1	17.0
Total	84.6	28.0	112.6

Note: Totals may not equal sum of components because of independent rounding

> A significant portion of the Uinta Basin's oil-shale resource, approximately 25% for each grade, is covered by conventional oil and gas fields. . . . In particular, the extensive Natural Buttes gas field covers a significant portion of land underlain by oil shale averaging 25 GPT, ranging to 130 feet thick, and under roughly 1500 to 4000 feet of cover. Furthermore, this field is expected to expand in size and cover more oil-shale rich lands to the east. Of the 18.4 billion barrels contained in 25 GPT rock having thicknesses between 100 and 130 feet, 7.8 billion barrels, or 42%, are located under existing natural gas fields.
>
> However, lands where the oil-shale deposits are under less than 1000 feet of cover currently do not contain significant oil and gas activity (except the Oil Springs gas field) as compared to lands with deeper oil-shale resources. The majority of planned oil-shale operations will be located on lands having less than 1000 feet of cover. This does not mean that oil-shale deposits located within oil and gas fields will be permanently off limits. In fact, most of the conventional oil and gas reservoirs are located far below the Mahogany zone. It simply demonstrates that regulators will need to recognize that resource conflicts exist and plan their lease stipulations accordingly.[333]

The potential conflict between existing mineral development and potential commercial oil shale leasing and development is well illustrated by EOG Resources' proposed Greater Chapita Wells Natural Gas Infill Project in the eastern part of Utah's Uintah County. EOG's project proposal involves drilling up to 7,028 new natural gas wells within the existing well field over the next 15 years, as depicted in Figure 4.6.2. Wells are expected to have a 40-year operational life. If approved as proposed, EOG would construct approximately 700 new well pads and expand approximately 979 existing or previously authorized well pads, resulting in approximately one pad every 20 acres. Utilizing directional drilling and multiple well bores per pad, EOG would produce bottom hole spacing of approximately one bore every 5 to 10 acres.[334]

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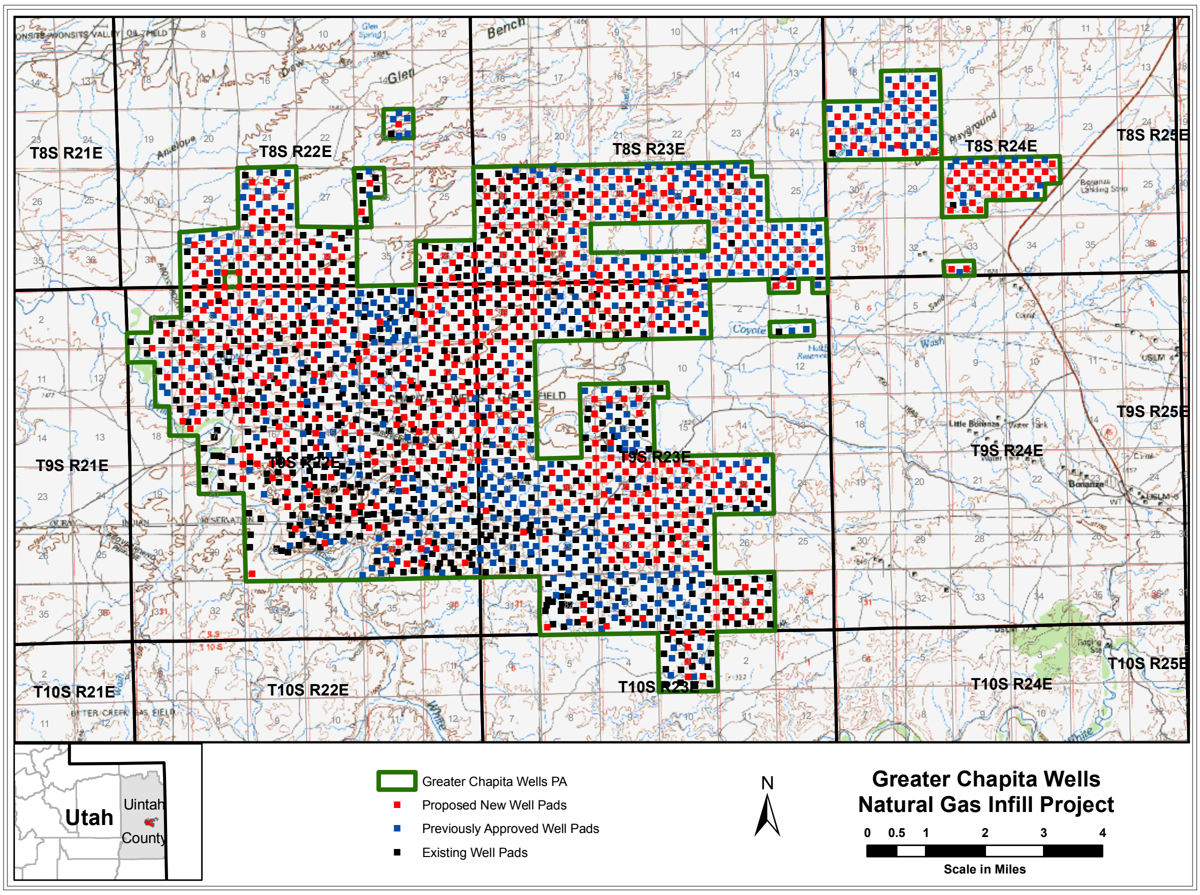
[333] VANDEN BERG at 10 (internal references omitted).

[334] *Notice of Intent to Prepare an Environmental Impact Statement for the Greater Chapita Wells Natural Gas Infill Project, Uintah County, UT*, 74 FED. REG. 46458 (Sept. 9, 2009).

Figure 4.6.2: Greater Chapita Wells Natural Gas Infill Project, Uintah County. Source: Bureau of Land Management.



The 42,027 acres comprising EOG's project area contain some of the richest oil shale resources in Utah and are within the area identified as available for application for commercial oil shale leasing under the Final PEIS. If approved as proposed, the infill project could complicate efforts to develop oil shale resources within Utah. Moreover, the 5,688 acres of anticipated surface disturbance will increase pressure on sensitive resources such as air, water, and wildlife, making permitting for additional resource impacts of oil shale development all the more difficult.

Where multiple minerals occur on private land, the situation is less problematic. The mineral estate owner can treat them as he or she wishes, contractually prescribing conditions for third party development. But because the United States operates under an array of allocation systems for different types of minerals, development of multiple minerals on the public lands poses more difficult questions.[335] While the Multiple Mineral Development Act,[336] provides some limited guidance regarding conflicts between leasable and locatable minerals, it does not apply to conflicts arising between persons interested in different leasable minerals such as oil shale and oil or natural gas:

[335] *See generally*, GEORGE CAMERON COGGINS AND ROBERT L. GLICKMAN, PUBLIC NATURAL RESOURCES LAW § 41:1 (2d ed. 2008).
[336] 30 U.S.C. §§ 521-531.

> The granting of a permit or lease for the prospecting, development or production of deposits of any one mineral shall not preclude the issuance of other permits or leases for the same lands for deposits of other minerals with suitable stipulations for simultaneous operation, nor the allowance of applicable entries, locations or selections of leased lands with a reservation of the mineral deposits to the United States.[337]

What constitutes a "suitable stipulation" under this regulation is unclear and, as there are no published court cases interpreting this provision, its application remains a matter of speculation.

The BLM's first round of oil shale RD&D leases confirm the BLM's policy of addressing multiple mineral conflicts at the leasing stage. Under the first round of RD&D leases, BLM reserves the "right to continue existing uses of the leased lands and the right to lease, sell, or otherwise dispose of the surface or other mineral deposits in the lands for uses that do not unreasonably interfere with operations of the Lessee under this lease."[338] In accordance with the recently finalized commercial oil shale leasing rules, commercial oil shale leases will contain a similar provision, allowing multiple use development so long as it "does not unreasonably interfere with the exploration and mining operations of the lessee."[339] These provisions reiterate the BLM's intention to deal with potential competing mineral conflicts on a case-by-case basis at the leasing stage or later.

Earlier federal oil and gas leases may prove less problematic for commercial oil shale development. Between 1968 and 1989, federal oil and gas leases within oil shale bearing portions of Colorado, Utah, and Wyoming contained stipulations protecting future oil shale development. These stipulations generally prevent oil and gas drilling that would result in undue waste of oil shale resources or otherwise interfere with oil shale development.[340] However, as the BLM recognizes, "[w]here these oil shale stipulations do not exist in oil and gas leases, without some accommodation being made between oil shale developers and prior lease holders, oil shale development may not be able to proceed."[341]

On Utah state lands leased by SITLA, SITLA reserves "the right to enter into mineral leases and agreements with third parties covering minerals other than the leased substances, under terms and conditions that will not unreasonably interfere with operations under this Lease in accordance with Lessor's regulations, if any, governing multiple mineral development."[342] SITLA also reserves the right to designate Multiple Mineral Development Areas and impose additional terms and conditions necessary to integrate and coordinate multiple mineral development.[343] In sum, resolution of multiple mineral development conflicts is largely committed to agency discretion, with some level of protection afforded to the first leaseholder to develop their rights.

4.7 Reclamation

Given the breadth of surface disturbance anticipated with oil shale development, reclamation will be an essential element of any commercial oil shale leasing and development program on the public lands. Lease reclamation objectives include, but are not limited to, erosion control, reshaping the disturbed area, applying topsoil, revegetating disturbed areas where "reasonably practicable," rehabilitating fisheries

[337] 43 C.F.R. § 3000.7.
[338] United States Department of the Interior, Bureau of Land Management, Oil Shale Research, Development and Demonstration (RD&D) Lease, 70 Fed, Reg. 33755.
[339] 73 Fed. Reg. 69414, 69472 (Nov. 18, 2008), *codified at* 43 C.F.R. § 3900.40.
[340] Final PEIS at 4-18.
[341] Final PEIS at 4-18.
[342] *See* Utah State Mineral Lease for Oil Shale § 2.2 ("Oil Shale Lease Form 6/22/05").
[343] *See* Utah State Mineral Lease for Oil Shale § 15 ("Oil Shale Lease Form 6/22/05").

and wildlife habitat, and isolating, removing and controlling toxic materials at the site.[344] Information regarding reclamation must be contained in the lessee's exploration plan,[345] and the lessee must post a reclamation bond sufficient to cover the estimated cost of site reclamation.[346] Required reclamation methods are not specified by rule due to uncertainty regarding the operation and the surface resources involved.[347]

A critical question for policymakers is the reclamation standard to which oil shale lessees should be held. At present, lessees are required to reclaim only to pre-development use rather than pre-development conditions.[348] Given the rugged, arid nature of much of the most geologically prospective oil shale area, very little pre-development use may have occurred. Reclaiming to accommodate either livestock grazing at extremely low densities,[349] dispersed off-road vehicle use, or oil and gas development represents a low standard of reclamation. And although the BLM's regulations require revegetating disturbed areas where "reasonably practicable," it is unclear how that standard will apply to the difficult and labor-intensive demands of revegetating a spent shale environment.

With respect to timing of the reclamation obligation, a lessee or operator must protect or reclaim surface areas no longer needed for operations "as contemporaneously as possible."[350] In describing the process of reclamation, the BLM states "[d]uring reclamation activities, which proceed continuously throughout the life of the project, waste material piles would be smoothed and contoured by bulldozers. Topsoil would be placed on the graded spoils, and the land would be prepared for revegetation by furrowing, mulching, and the like."[351] The BLM goes on to note:

> Reclamation of impacted areas would include reestablishment of vegetation on restored soils. Although revegetation of disturbed soils may successfully establish a productive vegetation cover, with biomass and species richness similar to local native communities, the resulting plant community may be quite different from native communities in terms of species composition and the representation of particular vegetation types, such as shrubs . . . . Community composition of revegetated areas would likely be greatly influenced by the species that are initially seeded, particularly perennial grasses, and colonization by species from nearby native communities may be slow. The establishment of native plant communities may require decades. Successful reestablishment of some vegetation types, such as shrubland communities or stabilized sand dunes, may be difficult and would require considerable periods of time, likely more than 20 years. Restoration of plant communities in areas with arid climates . . . such as the Uinta Basin Floor ecoregion in Utah . . . would be especially difficult and may be unsuccessful. The loss of intact native plant communities could result in increased habitat fragmentation, even with the reclamation of impacted areas.[352]

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[344] 43 C.F.R. § 3931.20(c).
[345] 43 C.F.R. § 3931.41(d).
[346] 43 C.F.R. § 3904.14(b).
[347] 73 FED. REG. 69434 (Nov. 18, 2008).
[348] 43 C.F.R. § 3931.20(a).
[349] According to the VERNAL RMP FEIS, there are 167 livestock grazing allotments within the Vernal planning area, 160 of which are open to livestock grazing. These 160 allotments include 2,237,003 acres of BLM and non-BLM managed lands, upon which 146,161 animal unit months are allocated. Actual livestock grazing use over the past 10 years averaged 78,500 animal unit months annually. This equates to one animal unit month per 28.5 acres of land. VERNAL RMP FEIS at 3-33 - 34 and Appendix J. While the planning area is broader than the most geologically prospective oil shale area, it reflects the best information available and is likely representative of grazing in oil shale bearing areas.
[350] 43 C.F.R. § 3931.20(e).
[351] FINAL PEIS at 4-53.
[352] FINAL PEIS at 4-71 (citations omitted).

The BLM's cautions are consistent with attempts to revegetate spent shale near Rifle, Colorado and in the Piceance Basin. During the early 1970s, Colorado State University, in cooperation with the U.S. Environmental Protection Agency (EPA), conducted multi-year research on spent shale revegetation and concluded that spent shales are deficient in plant-available nitrogen and phosphorus and generally too salty for plant growth. Revegetation is more successful where at least 12 inches of topsoil is placed over spent shale having low pH (8-9), the site is leached to reduce soil and shale salinity, seeded, mulched, fertilized, irrigated for multiple growing seasons, and where the site is re-leached and re-seeded as needed. Where pH is higher, more topsoil will be needed.[353] Even where this lengthy process was utilized, establishment varied both in terms of vegetation type and density, depending on site conditions such as elevation, exposure, shale texture and pH. Unwanted establishment by non-native species such as cheatgrass was also problematic, especially upon transitioning from irrigation to natural precipitation.[354] Elevated levels of zinc and molybdenum were also reported in plants grown in the spent shales, warranting further investigation.[355]

To further complicate matters:

> The area available for application for leasing … includes locations that support oil shale endemic plant species. Local populations of oil shale endemics, which typically occur in small scattered populations on a limited number of sites, could be reduced or lost as a result of oil shale development activities. Establishment and long-term survival of these species on reclaimed land may be difficult.[356]

Attempts to reestablish oil shale endemics and native plants will also struggle with the limited availability of commercially available native plants and native plant seeds. The lack of commercially available plant species that are adaptable to the oil shale region also could impose a temporary restriction on the industry's land reclamation efforts. If commercial growers were to expand their production to keep ahead of the needs, this problem could be mitigated.[357] Efforts to establish seed banks containing sufficient native plants (including endemics) would be beneficial, as would research focused on the ability to propagate or relocate endemic species, some of which may be legally protected.

Additional consideration should be given to the level of reclamation required under an oil shale leasing and development program on the public lands. Specifically, policymakers need to determine whether commercial oil shale lease tracts should be restored to pre-development conditions, pre-development uses, or reclaimed to a level able to support another set of desirable future uses. Policymakers also should evaluate reclamation objectives in the context of concurrent development of multiple mineral estates, such as oil shale and natural gas. Current reclamation obligations may force restoration only to see the site disturbed by the next round of mineral development. However, failure to complete reclamation obligations could result in forfeiture of reclamation bonds and complicate future leasing and development permitting efforts for the non-compliant lessee. Further guidance regarding transfer of reclamation obligations across successive operators could lead to more efficient development of co-located minerals and conservation of water demands associated with reclamation efforts.

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[353] H. P. Harbert and W. A. Berg, Colorado State University, Vegetative Stabilization of Spent Oil Shales (Dec. 1974) (Hartbert & Berg 1974) at 39; H. P. Harbert III and W. A. Berg, Colorado State University, Vegetative Stabilization of Spent Oil Shales: Vegetation, Moisture, Salinity, and Runoff – 1973-1976 (Feb. 1978) (Harbert & Berg 1978) at 3-8.

[354] Harbert & Berg 1974 at 39; Harbert & Berg 1978 at 3-8.

[355] Harbert & Berg 1974 at 39; Harbert & Berg 1978 at 7.

[356] Final PEIS at 6-72.

[357] Office of Technology Assessment, An Assessment of Oil Shale Technologies (June 1980) at 33.

4.8 Conclusion and Recommendations

Three major issues overshadow all others when considering initiating a commercial oil shale leasing and development program on the public lands: the lack of a coordinated strategy harmonizing development across the patchwork of land ownership; the likelihood of legal challenges to discretionary land management decisions; and the inability to rely on resource avoidance as a way to control or limit resource impacts.

As the oil shale resource overlies federal, state, tribal and private lands, policymakers need to ensure that the BLM coordinates with its state, tribal, and local governmental partners in order to avoid conflicting policies on the ground that impede effective environmental stewardship. Initiating a commercial oil shale program on the public lands presents a unique opportunity to develop an industry from scratch, in a manner consistent with national energy and environmental policies. Regardless of where oil shale development occurs, it will have a substantial footprint, and the resource values displaced by oil shale development represent significant challenges to development. Notwithstanding the panoply of complications and challenges, federal policymakers should commit to playing a leadership role in the development of any domestic oil shale industry.

Finally, policymakers must anticipate a broad expanse of disturbance with any commercial oil shale leasing program initiated on the public lands. This expansive disturbance distinguishes oil shale from oil or natural gas development, which while extensive, occurs on only portions of the lease tract. Relying primarily on a policy of avoidance to protect sensitive resources located within lease tracts is not a viable approach to managing the inevitable conflicts that will accompany implementation of a commerical oil shale leasng and development program on the public lands. Requiring comprehensive resource surveys in advance of leasing would help potential lessees evaluate the true value and cost of contemplated oil shale development associated with their potential lease tracts while helping the BLM more effectively manage for the wide-ranging resources within the most geologically prospective oil shale area.

CHAPTER 5

WATER RESOURCES

Two constants of the debate over the desirability and viability of initiating a commercial oil shale leasing program on the public lands are that water will be needed to support a commercial oil shale industry, and that there is a scarcity of water in the most geologically prospective oil shale area. This chapter[358] first reviews the legal framework for water allocation and then discusses water demand and availability for oil shale development in the most geologically prospective oil shale area, including "new" sources of water potentially available to a commercial oil shale industry and the role reserved water rights may play in developing such an industry.

5.1 REGULATING THE USE OF WATER

5.1.1 APPROPRIATING WATER UNDER STATE LAW

In Utah, and throughout the arid west, water is generally considered a public resource[359] and except for a small number of water rights obtained prior to codification of Utah's water code, water rights must be obtained through application with the Office of the State Engineer.[360] A five-part test must be satisfied before the State Engineer can issue a new water right: (1) there must be unappropriated water available; (2) the proposed appropriation cannot impair existing rights or interfere with more beneficial uses; (3) the proposed plan must be physically and economically feasible and not detrimental to the public welfare; (4) the applicant must have the financial resources to complete the proposed project; and (5) the application must be filed in good faith and not for purposes of speculation or monopoly.[361] If the test is satisfied and the application granted, the water right will prescribe the source of supply, the point of diversion, the quantity of water that can be appropriated, the rate of diversion, the nature of use allowed, the period of use, and the place of use.[362] While the process in Colorado is somewhat different, the substantive requirements affect a similar result.[363]

[358]The Water Resources chapter summarizes research published in John Ruple & Robert B. Keiter, *Water for Commercial Oil Shale Development: Moving Forward Without Knowing How Much Water is Needed or Available*, J. ENERGY & RESOURCES L. (2009) (forthcoming) and John Ruple & Robert B. Keiter, *Water for Commercial Oil Shale Development in Utah: Allocating Scarce Resources and the Search for New Sources of Supply*, J. LAND RESOURCES & ENVTL. L. (2009) (forthcoming).
[359]*See e.g.*, UTAH CODE ANN. § 73-1-1 ("All waters in this state, whether above or under the ground are hereby declared to be the property of the public.)".
[360]UTAH CODE ANN. § 73-3-1.
[361]UTAH CODE ANN. § 73-3-8.
[362]UTAH CODE ANN. § 73-3-2.
[363]*See generally*, COLO. REV. STAT. §§ 37-82-101 - 106.

When not enough water exists to satisfy all who seek the region's scarce resources the question becomes whose rights will prevail. The maxim "first in time, first in right" is the foundation of western water law.[364] Each water right has a priority date established in accordance with statutory requirements or, in the case of pre-water code rights, corresponding to the date upon which the appropriator first initiated successful and diligent efforts to put the water to a beneficial use. When demand for water exceeds available supply, those with senior rights can require full or partial curtailment of junior water users' diversions, leaving users with junior priorities with less than their allotted amount of water, or with no water at all.[365] As the value of water relates directly to its availability, senior rights are much more valuable than their junior counterparts because they provide a more certain source of supply.[366]

Consistent with a policy of encouraging development and beneficial use of water, western water law can flexibly accommodate reallocation of water rights to economically more profitable uses. Thus, water rights may be conveyed separately from the land upon which they are used.[367] Changes in the use of a water right are also allowed subject to the general rules that they cannot result in an enlargement of the water right or injury to other water users.[368] It follows that when inadequate water is available to satisfy the needs of all prospective users, markets develop and water rights are conveyed to economically more profitable uses. Historically, conversion of agricultural water rights to municipal and industrial rights has facilitated a significant amount of western expansion.

In keeping with statutory provisions encouraging economically efficient use, a wasteful use of water is not protected and appropriators are generally unable to hold water rights for future, speculative needs.[369] Thus, if a water right is not put to a beneficial use within the statutory period, it reverts back to the state and is available for appropriation.[370] These timelines may be extended where the applicant exercises due diligence in developing water rights.[371] In 2008, the Utah legislature revised the water code to exempt public water supplies from forfeiture if water is required for the reasonable needs of the public and the supplier can demonstrate a need for the water within the next 40-years based on projected

[364]UTAH CODE ANN. § 73-3-1; *see also United States v. County of Denver*, 656 P.2d 1, 12 (Colo. 1982) (noting that the doctrine of prior appropriation generally governs, in one form or another, the acquisition of water rights in the nineteen western states).

[365]Under Utah law, a senior appropriator is guaranteed the full measure of his or her appropriation before any junior claim may be satisfied. *Sanpete Water Conservancy Dist. v. Carbon Water Conservancy Dist.*, 226 F.3d 1170, 1173 (10th Cir. 2000).

[366]Until recently, Utah's water code included an important exception to this general rule whereby: "[I]n times of scarcity, while priority of appropriation shall give the better right as between those using water for the same purpose, the use for domestic purposes, without unnecessary waste, shall have preference over use for all other purposes, and use for agricultural purposes shall have preference over use for any other purpose except domestic use." UTAH CODE ANN. § 73-3-21 (2008). While this provision was never invoked by a court of law, it provoked considerable discussion and represented a potential foil to water users engaged in less preferential practices. The Utah legislature passed House Bill 241, repealing the provision effective May 11, 2010. Neither the House nor Senate committee report indicates the reason for the revocation, noting only that the amendment received a "favorable" recommendation. Reports of the House Natural Resources, Agriculture, and Environment Committee (Feb. 3, 2009) and Senate Natural Resources, Agriculture, and Environment Committee (Feb. 20, 2009).

[367]Water rights evidenced by shares of stock in a corporation are transferred as personal property in accordance with provisions of the Uniform Commercial Code. UTAH CODE ANN. § 73-1-10(2). Water rights evidenced by certificate, decree, or diligence claim are conveyed as real property. UTAH CODE ANN. § 73-1-10(1)(a).

[368]UTAH CODE ANN. § 73-3-3(2)(b).

[369]Important exemptions exist under most state permitting systems, allowing municipalities to secure senior domestic water sources sufficient to meet projected demand. While these rights must eventually be perfected through beneficial use, the timeline for right perfection is much longer. *See e.g.*, UTAH CODE ANN. § 73-3-12(2)(c). Similarly, Colorado grants conditional water rights for infrastructure-intensive water developments that may require years of planning and construction. *See* COLO. REV. STAT. § 32-92-103(6). Conditional rights allow permittees to secure water right priority in advance of development and beneficial use. In the absence of such rights, capitol acquisition costs would likely be much higher given the uncertainty associated with the underlying water right.

[370]*See e.g.*, UTAH CODE ANN. § 73-1-4(2)(a).

[371]*See e.g.*, UTAH CODE ANN. § 73-3-12.

population growth or other water use demand.[372]

The concept of relinquishment is important because many prospective oil shale developers obtained significant water rights in anticipation of the development that appeared certain in the 1970s. As the energy crises and rapid oil price increases of 1973 and 1979 gave way to falling demand and opening of the Prudhoe Bay oil field, oil prices fell and interest in commercial oil shale development evaporated. Accordingly, anticipated development did not occur and many water rights went unperfected. Companies that bet on the oil shale boom and their successors in interest hold significant water rights, the continued validity of which is subject to state law. So far, Colorado's Water Court has generally accepted water right holders' efforts as sufficient to demonstrate diligent development,[373] but the longer such rights remain contingent, the more difficult it may become to demonstrate diligent development. It should also be noted that many of the water rights obtained in anticipation of commercial oil shale development were leased to agricultural users, thus avoiding relinquishment, but necessitating a change in use if used to support future oil shale development.[374]

While converting senior irrigation rights to other purposes is a relatively common practice and does not create new demands on the system, two points deserve mention. First, irrigation rights almost invariably allow diversion of far more water than can be consumed, with excess water being used to pressurize pipes and move useable water through the irrigation system. This excess, unused water is returned to the source of supply and therefore does not represent a consumptive use. When irrigation rights are converted to other uses, only the amount of water actually consumed is available for other consumptive uses, so irrigation rights that include large diversionary components are generally much smaller in terms of allowable consumptions. This important factor was surprisingly overlooked in earlier efforts to acquire water for oil shale development.[375]

Second, when irrigation rights are converted to other uses, the previously irrigated land is taken out of agricultural production. Farms with the most valuable water rights are also the largest, oldest, and most established farms in the area. The shifts that will invariably come with commercial oil shale leasing and development on the public lands stand to fundamentally change the character of communities throughout Colorado and Utah.

5.1.2 THE ENDANGERED SPECIES ACT[376]

The most geologically prospective oil shale area includes critical habitat for at least four species of fish protected under the ESA.[377] The ESA must be considered a water resources issue as the ESA

[372] UTAH CODE ANN. § 73-1-4(2)(f)(i).

[373] *See e.g.*, *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Getty Oil Exploration Co.*, 997 P.2d 557 (Colo. 2000) (holding that under the "can and will" test, Getty "can" develop oil shale given existing technology and "will" upon changed economic considerations), *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. OXY USA, Inc.*, 990 P.2d 701 (Colo. 1999) (holding conditional water right application not filed for purposes of speculation and OXY "can" develop oil shale given existing technology and "will" upon changed economic considerations), *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Chevron Shale Oil Co.*, 986 P.2d 918 (Colo. 1999) (holding economic conditions properly considered in evaluating adequacy of efforts to perfect water rights for oil shale), *but see Bar 70 Enterprises, Inc. v. Highland Ditch Ass'n*, 694 P.2d 1253 (Colo. 1985) (holding the association failed to obtain required finding of reasonable diligence in developing its conditional water right), and *Bar 70 Enterprises, Inc. v. Tosco Corp*, 703 P.2d 1297 (Colo. 1985) (denying claimed appropriation date for conditional water right because Tosco failed to demonstrate diligent development).

[374] *See* WESTERN RESOURCE ADVOCATES at 33.

[375] UNIVERSITY OF WISCONSIN-MADISON, OIL SHALE DEVELOPMENT IN NORTHWESTERN COLORADO: WATER AND RELATED LAND IMPACTS 198-200 (1975).

[376] The impact of the ESA on oil shale leasing and development on the public lands is also discussed in chapter 3 of this report.

[377] 16 U.S.C. §§ 1531-44. The four species of Colorado River fish listed under the ESA are the Colorado pikeminnow (*Ptycholcheilus lucius*), the humpback chub (*Gila cypha*), the bonytail chub (*Gila elegans*), and the razorback sucker (*Xyrauchen*

imposes obligations on federal agencies, agency licensees and permittees, state and local governments, and private individuals that may supersede state water rights. Where such requirements exist, water resources may be available physically but not legally.

Designation of critical habitat can have a major effect on the exercise of water rights because the designation creates what can amount to a *de facto* reservation of water for species protection.[378] Utilization of state water rights is subject to the ESA's prohibition against the take of a listed species.[379] Bureau of Reclamation water delivery contracts are likewise subject to curtailment to comply with the ESA,[380] which may require federal reservoir operations to maximize species protection, thus subordinating state and federal contract water rights.[381] Under such circumstances instream flow requirements for listed species can trump water rights, including water rights apportioned by interstate compact.[382] Thus while water for listed species does not have a fixed priority date and may be unquantified, it effectively supersedes competing uses.

Complex policies are in place to protect ESA listed species (and their habitat) native to the Colorado River and its tributaries. These protections will complicate efforts to increase diversions from perennial streams within the most geologically prospective oil shale area and may preclude on-channel reservoir development. The ESA will play a critical role in future water availability and development for oil shale, as it already does elsewhere on the Colorado River.[383] Recent amendments to Utah state policy further constrain future water right changes by subjecting them to bypass flow requirements needed to protect listed fish along portions of the Green River.[384] This policy change could complicate efforts to pipe water from portions of the Green River to Utah's oil shale bearing lands.

5.2 WATER DEMANDS

Opponents of commercial oil shale leasing and development contend that the best information available demonstrates that oil shale development will require an unacceptable amount of water.[385] Oil shale proponents assert that decades of innovation have led to the development of less water intensive technologies. Both statements may actually be accurate as most published water use estimates are based on more than 30 year-old information and technologies,[386] and the actual requirements for emerging technologies are often proprietary and untested at commercial scales. The uncertainty regarding technological requirements and water demand raise questions about the net demand for water resources, creating uncertainty for oil shale developers, regulators, and policymakers.

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texanus).

[378] *See* A. DAN TARLOCK, LAW OF WATER RIGHTS AND RESOURCES § 9.29 (2008).

[379] *See United States v. Glenn-Colusa Irrigation Dist.*, 788 F.Supp 1126, 1134 (E.D. Cal. 1992) (enjoining pumping in accordance with state granted water rights where pumping was a substantial proximate cause of injury to listed salmon species).

[380] *See Klamath Water User Protection Ass'n v. Patterson*, 191 F.3d 1115 (9th Cir. 1999) and *Bartelos & Wolfsen, Inc. v. Westlands Water Dist.*, 849 F.Supp. 717, 732 (E.D. Cali. 1993).

[381] *See Carson-Truckee Water Conservancy Dist. v. Clark*, 549 F.Supp 704 (D.Nev. 1982), *affirmed in part, reversed in part* 741 F.2d 257 (9th Cir. 1984).

[382] *See* TARLOCK, LAW OF WATER RIGHTS AND RESOURCES at § 9.31.

[383] *See generally*, ROBERT W. ADLER, RESTORING COLORADO RIVER ECOSYSTEMS: A TROUBLED SENSE OF IMMENSITY (2007).

[384] *See* Utah Department of Natural Resources, Division of Water Rights, *2009 Proposed Water Rights Policy Regarding Applications to Appropriate Water and Change Applications Which Divert Water from the Green River Between Flaming Gorge Dam and the Duchesne River* (Sept. 21, 2009), *available at* http://www.waterrights.utah.gov/meetinfo/m20090820/policy-upcorviMC09L.pdf.

[385] *See e.g.*, *The Wilderness Society, Oil Shale Fact Sheet: Water Consumption and Pollution* (no date), available at http://www.wilderness.org/files/Oil-Shale-fs-water.pdf.

[386] *See e.g.*, FINAL PEIS.

Complicating matters, municipal, industrial, and agricultural water demands are also increasing. Legal and policy measures will dictate technological choices, indirectly driving water resource discussions. As observed by Senator Jeff Bingaman, Chairman of the Senate Energy and Natural Resources Committee:

> Energy production requires substantial amounts of water—this is of course a resource becoming increasingly scarce in several parts of the country. Whether it involves electricity generation or fuel production, the choice of fuel stock can dramatically influence the amount of water needed as part of the process of producing that energy. That nexus is starting to emerge in permitting decisions across the country.[387]

Jennifer Gimbel, Executive Director of the Colorado Water Conservation Board, similarly notes that "[w]hen you are dealing with water, you are dealing with our future. It's going to take choices, and it's going to take trade-offs."[388] The discussion that follows stems from this premise of trade-offs, presenting different perspective on water demands, identifying gaps in water resource policies, and where appropriate, recommending approaches for moving forward.

5.2.1 WATER FOR COMMERCIAL OIL SHALE DEVELOPMENT

Most analyses of water demand for oil shale development offer little insight to policymakers or interested stakeholders. For example, the Final PEIS relies upon DOI analysis from 1973[389] for the assumption that conventional mining with surface retorting will require from 2.6 to 4.0 barrels of water for each barrel of shale oil produced.[390] In contrast, Red Leaf Resources and Oil Tech. Inc. (formerly Millennium Synfuels), which collectively hold over 50,000 acres of state land under lease in Utah, purport to possess technologies that do not require any water for retorting.[391] Although these operators would still require water for dust suppression, reclamation, and other activities, emerging technologies appear capable of cutting water use to levels far below the projections contained in the PEIS.

Estimating water needs for in situ retorting is at least equally difficult. In situ technologies are largely proprietary, and development efforts to date are still in the experimental phase. While the Final PEIS cites a 2005 Rand Corporation study for the proposition that in situ development would require 1 to 3 barrels of water for each barrel of oil produced,[392] the Rand study relies on information from a 17 year-old report by the U.S. Water Resources Council.[393] In contrast to these figures, Chevron, a first round RD&D lessee in Colorado, claims that its in situ method "will consume less water than the quantity of groundwater pumped out of the target zone," making it "a net producer of water."[394]

Dr. Laura Nelson, Chair of the Utah Mining Association's Oil Shale and Oil Sands Committee, recently testified that estimated water use is falling rapidly as industry innovates, and currently sits at

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[387]Bingaman Hearing Statement: "Energy-Water Integration Act" (March 10, 2009), *available at* `http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail\&PressRelease_id=c87e8b22-beb6-4475-8c3c-28f02fdca42d\&Month=3\&Year=2009\&Party=0`.

[388]Chris Woodka, *Water Debate Takes on a New Ripple: Energy*, THE PUEBLO CHIEFTAIN (March 31, 2009).

[389]*See* U.S. DEPARTMENT OF INTERIOR, FINAL ENVIRONMENTAL IMPACT STATEMENT FOR THE PROTOTYPE OIL SHALE LEASING PROGRAM, Vol. 1, p. III-34 (1973).

[390]FINAL PEIS at 4-4 and 4-8.

[391]*See* SECURE FUELS FROM DOMESTIC RESOURCES, at 28-29 and 48-49.

[392]*See* FINAL PEIS at p. 4-11.

[393]BARTIS ET AL. at 50, *citing* U.S. WATER RESOURCES COUNCIL, SECTION 13(A) WATER ASSESSMENT REPORT, SYNTHETIC FUEL DEVELOPMENT IN THE UPPER COLORADO REGION (July 1981).

[394]HANSON & LIMERICK at 20.

an average of 1.5 barrels of water for each barrel of shale oil produced.[395] At that level, oil shale development might use less water than conventional oil and gas production.[396]

Colorado has raised concerns that oil shale development may increase strains on scarce water resources. Citing uncertainty regarding the extent of development and applicable technologies, Colorado treats water demands for oil shale development as unknown but potentially significant.[397] While Utah has been less specific in its discussions of water for oil shale development, past efforts to develop water resources demonstrate that it too recognizes potentially significant demand requirements.[398]

Under both NEPA and the BLM's commercial oil shale leasing regulations, future environmental reviews for oil shale leasing and development on federal lands must evaluate impacts on the quality of the human environment.[399] According to the BLM's leasing regulations, applications to lease must include a "description of the source and quantities of water to be used,"[400] and plans of development must include a narrative description of the mine or in situ operation that includes an "estimate of the quantity of water to be used and pollutants that may enter any receiving water."[401] These disclosures would help resolve questions that are today unanswerable, and enable better decisions. Developing a better understanding of the size and shape of the oil shale industry will provide the basis for extrapolating water demand estimates to include the population growth sure to accompany commercial oil shale development. As stated in the Rand Report: "Reliable estimates of water requirements will not be available until the technology reaches the scale-up and confirmation stage."[402]

5.2.2 Demand for Water Unrelated to Oil Shale Development

Utah is the second driest state in the West[403] and reliable water supplies are a practical necessity for municipal, industrial, or agricultural development. Colorado, while receiving more precipitation, is subject to similarly severe competition for scarce water resources. In light of previous shortages, water resource planners must consider not just demand directly attributable to oil shale development, but demand that will continue to increase independent of such development.

In Colorado, the population of Moffat, Rio Blanco, and Routt counties contains most of Colorado's oil shale resources and is anticipated to grow by 56% between 2000 and 2030, from 39,300 to 61,400.[404] Gross water demand within this three county area is expected to increase by 79% over the same period,

[395] Testimony before the Utah Legislature's Interim Committee on Natural Resources, Agriculture, and the Environment (June 17, 2009), *available at* `http://le.utah.gov/asp/interim/Commit.asp?Year=2009\&Com=INTNAE`.

[396] Extracting and processing domestic crude oil into gasoline is estimated to take from 3.6 to 6.9 gallons of water per gallon of gasoline produced; when Saudi Arabian crude is used, water demand is slightly less, ranging from 2.9 to 6.1 gallons of water per gallon of gasoline produced. When Canadian oil sands are used as a fuel stock, 2.6 to 6.2 gallons of water are used for every gallon of gasoline produced. M. Wu et al., Argonne National Laboratory, *Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline* (2009) at 6. Argonne's analysis includes the additional step of refining, which is not reflected in the oil shale estimates. Water use for refining averages 1.5 gallons of water per gallon of fuel produced. Upon refining, water use would average 3 barrels of water for each barrel of shale oil produced. *See id.* at 55.

[397] Colorado Water Conservation Board, Statewide Water Supply Initiative, 6-82 (Nov. 2004).

[398] *See e.g.*, U.S. Department of Interior, Bureau of Land Management, Final White River Dam Project Environmental Impact Statement (White River Dam FEIS) (May 1982). The White River Dam was proposed by Utah and would have been built on federal lands.

[399] *See* 42 U.S.C. § 4331(2)(C), 43 C.F.R. § 3900.50(b) and (c). Such disclosures are not required on state or private land absent a "major federal action" that would trigger NEPA.

[400] 43 C.F.R. § 3922.20(c)(3).

[401] 43 C.F.R. § 3931.11(h).

[402] Bartis et al. at 50.

[403] Steven E. Clyde, *Marketplace Reallocation in the Colorado River Basin: Better Utilization of the West's Scarce Water Resources*, 28 J. Land Resources & Envtl. L. 49, 50 (2008).

[404] State of Colorado, Statewide Water Supply Initiative Fact Sheet (Feb. 2006).

from 29,400 to 52,600 acre-feet.[405] Colorado believes 900 acre-feet of water can be saved through conservation, leaving 22,300 acre-feet of new depletions anticipated within the three county area. This increase in demand does not include direct and indirect demand associated with oil shale development, which remains too speculative to quantify.

The Yampa/White/Green river basin is also a target for withdrawals by water developers intent on providing water to the rapidly growing population along Colorado's Front Range. The U.S. Army Corps of Engineers is preparing an Environmental Impact Statement evaluating a proposal to divert 250,000 acre-feet of water annually from the Green River, at or immediately upstream of the Flaming Gorge Reservoir. Of the water diverted, 10% would go to users in southeast Wyoming, with the remaining 225,000 acre-feet being piped 560 miles to Colorado's Front Range.[406] This nascent proposal is generating significant public interest and opposition.[407] Other, less developed efforts to divert water from the Green River to Colorado's western slope also appear to be in the works.[408] Because the Yampa/White/Green river system flows into Utah, upstream water development would reduce water flowing into Utah.

In Utah, the State Water Plan for the Uinta Basin estimates a 40% increase in the basin's population between 1998 and 2020.[409] Municipal and industrial diversions from public suppliers within the basin are anticipated to increase from 13,140 acre-feet in 2000 to 16,900 acre-feet in 2020;[410] industrial depletions from privately held water rights are projected to increase from 11,830 acre-feet in 1996 to 23,700 acre-feet in 2050.[411] Neither set of figures includes water to support commercial oil shale development. Non-agricultural irrigation is projected to increase diversions by 770 acre-feet over the same period as irrigation related diversions falls to 790,480 acre-feet from its 1995 level of 797,610 acre-feet.[412]

Like Colorado, Utah appropriators are proposing large withdrawals from the Green River. Nuclear power proponents recently filed for rights to consume 53,600 acre-feet of water from the Green River to satisfy cooling water requirements for a proposed nuclear power plant near the town of Green River, Utah.[413] This project raises concerns over impacts to resources including instream flows and endangered fish, resulting in at least 239 formal protests with the Office of the State Engineer.[414] Oil shale developers and policymakers alike must consider that as Colorado and Utah continue to grow, scarce water supplies

[405] State of Colorado, Statewide Water Supply Initiative Fact Sheet (Feb. 2006). An acre-foot is 325,851 gallons, or enough water to cover one acre of land in twelve inches of water.

[406] Notice of Intent to Prepare Environmental Impact Statement for the Proposed Regional Watershed Supply Project in Wyoming and Colorado, 74 FED. REG. 11920 (March 20, 2009).

[407] *See e.g.*, *De-watering Wyoming*, NEW YORK TIMES (April 20, 2009), Joan Barron, *Gov: Water Diversion Potential Endangered Species Concern*, CASPER STAR-TRIBUNE (April 16, 2009), Jeff Gearino, *Water Project Draws Ire*, CASPER STAR-TRIBUNE (April 15, 2009), Jack H. Smith, *Hundreds Gather at GRHS to Protest Proposed Transbasin Pipeline*, GREEN RIVER STAR (April 15, 2009), *Corps' Look at Water Project Questioned*, DENVER POST (April 13, 2009), DENVER POST, *Concerns Raised about Wyo-Col Water Pipeline* (April 15, 2009).

[408] *See* Jack H. Smith, *Another Transbasin Diversion Project Proposed*, THE GREEN RIVER STAR (May 6, 2009).

[409] UTAH DEPARTMENT OF NATURAL RESOURCES, DIVISION OF WATER RESOURCES, UTAH STATE WATER PLAN: UINTA BASIN p. 4-1 (Dec. 1999) (figures provided in this analysis are revised to correct computational errors in the UTAH STATE WATER PLAN: UINTA BASIN).

[410] UTAH STATE WATER PLAN: UINTA BASIN at 9-14.

[411] UTAH STATE WATER PLAN: UINTA BASIN at 18-2.

[412] UTAH STATE WATER PLAN: UINTA BASIN at 9-14.

[413] Change application a35874,submitted by the San Juan County Water Conservancy District, contemplates moving the point of diversion for 24,000 acre-feet of water from the San JuanRiver. Change application a35401, submitted by the Kane County Water Conservancy District, contemplates moving the point of diversion for 29,600 acre-feet of water from Wahweap Creek in Kane County. Both applications are based on water rights secured for a coal-fired steam-generation power plant that was never built. Both applications call for 100% consumption of all water diverted.For more information on the applications and underlying rights, ***see*** `http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup`.

[414] *See* Amy Joi O'Donoghue, *Critics Say N-Plant Would Harm Ecosystem*, DESERET NEWS (May 27, 2009).

will become subject to only more intense competition.

5.3 WATER AVAILABILITY

While the actual water demands associated with commercial oil shale development are uncertain, it is clear that commercial oil shale development will require water, the amount of water required will depend upon the size of the industry that develops, and water resources in and proximate to the most geologically prospective oil shale area are already in short supply. With these factors in mind, this section identifies possible sources of water for oil shale development. In examining the questions surrounding water availability, it must be noted that the seasonal nature of surface flows means that while ample water may be readily available during spring runoff, much less water is available during winter months. Securing reliable, year-around supplies for oil shale development would therefore require a significant increase in water storage capacity.

5.3.1 THE COLORADO RIVER COMPACT

As part of the Colorado River System, waters proximate to Colorado and Utah's oil shale resources are subject to the Colorado River Compact,[415] which apportions water among the seven states that drain to the Colorado River.[416] The Compact divides the Colorado River watershed into upper and lower basins based on whether lands drain to the Colorado River at points above or below the town of Lees Ferry, Arizona.[417] (The upper and lower Colorado River basins are illustrated in Figure 5.3.1.) Under the Compact, both the upper and lower basins are entitled to annual consumptive use of up to 7,500,000 acre-feet of water.[418] The lower basin is also "given the right to increase its beneficial consumptive use of such waters by one million acre-feet per annum."[419] Additionally, Mexico is entitled to 1,500,000 acre-feet pursuant to the Treaty with Mexico.[420] Mexico's entitlement is provided out of surplus flows; when surplus flows do not exist, the obligation is met by an equal reduction in each basin's apportionment.[421]

[415] 70 Cong. Rec. 324 (1928) (Colorado River Compact). The Colorado River Compact is also codified by most of the compacting states. *See* ARIZ. REV. STAT. ANN. § 45-1302; COLO. REV. STAT. ANN. § 37-61-101; N.M. STAT. ANN. § 72-15-5; UTAH CODE ANN. § 73-12a-1; WYO. STAT. ANN. § 41-12-301. Congress officially approved the Colorado River Compact in the Boulder Canyon Project Act, 43 U.S.C. § 617l.

[416] These states are Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming.

[417] Colorado River Compact at Art. II §§ (f) and (g).

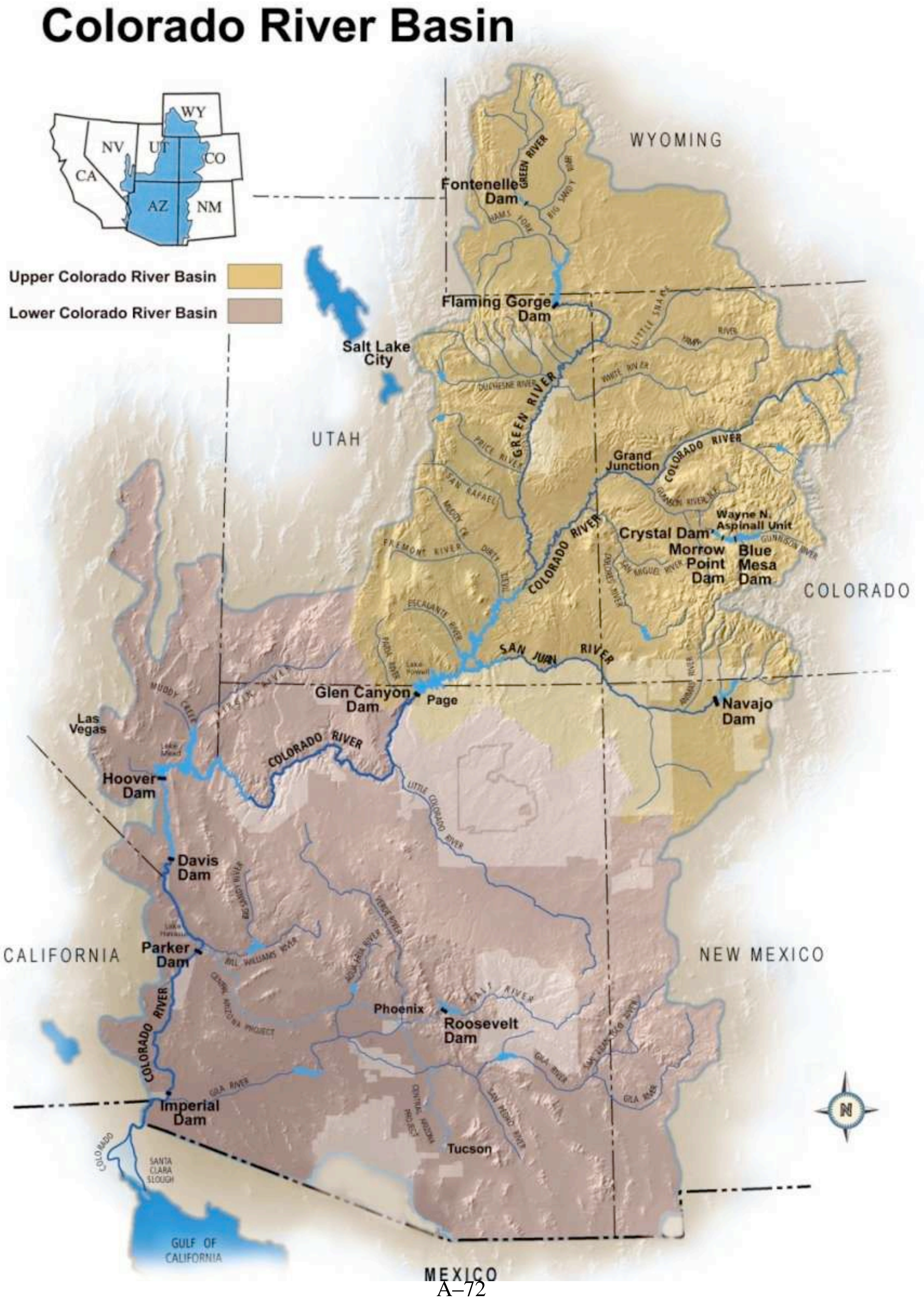
[418] Colorado River Compact at Art. III § (a).

[419] Colorado River Compact at Art. III § (b).

[420] Treaty Between the United States of America and Mexico Respecting Utilization of Waters of the Colorado and Tijuana Rivers and of the Rio Grande, Act of Feb. 3, 1944, U.S.-Mex. 59 Stat. 1219 at Art. 10.

[421] Colorado River Compact at Art. II § (c).

Figure 5.3.1: Colorado River Basin. Source: U.S. Bureau of Reclamation.



The upper basin's entitlement to 7,500,000 acre-feet annually is misleading because it must also deliver an average of 7,500,000 acre-feet of water at Lees Ferry without regard to the amount of water in the river.[422] Moreover, since surpluses are seldom available to satisfy Mexico's rights, the upper basin's share of the obligation to Mexico is an additional 750,000 acre-feet, meaning the upper basin is really obligated to deliver 8,250,000 acre-feet at Lees Ferry.[423] Finally, apportionment was based on assumed levels of flow that rarely occur. During compact negotiations it was widely believed that the Colorado River annual flows averaged at least 17,400,000 acre-feet at Lees Ferry.[424] However, estimated and gauged flow from 1906 through 2005 averaged 15,072,000 acre-feet (ranging between 5,399,000 and 25,432,000 acre-feet).[425] Recognizing the significant variability in Colorado River flows and that gauged data may not provide an accurate assessment of either variability or average flows, several studies have attempted to utilize tree-ring data to establish historic flow levels. One such widely cited 1976 study concluded that natural flows at Lees Ferry are only 13,500,000 acre-feet.[426] A 2006 update to this study determined that natural flows at Lees Ferry were higher than estimated in 1976, but still below gauged levels.[427] In light of more realistic estimates of river flows, the upper basin states' obligation to the lower basin, and obligations to Mexico, the upper basin states are left with an average annual allocation of at most 6,000,000 acre-feet, and possibly much less.[428]

Climate change, the effects of which are difficult to project, further jeopardizes water availability within the Upper Colorado River Basin. According to the National Academy of Sciences: "Based on analysis of many recent climate model simulations, the preponderance of scientific evidence suggests that warmer future temperatures will reduce future Colorado River streamflow and water supplies. Reduced streamflow would also contribute to increasing severity, frequency, and duration of

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[422]Colorado River Compact at Art. III §§ (a) and (d).

[423]Under very limited circumstances, the upper basin states' delivery obligations can be reduced to 7,480,000 acre-feet if Lake Powell's storage capacity falls below 9,500,000 acre-feet (39% of capacity) and Lake Mead is above the 1,025-foot elevation level. Delivery obligations can be reduced further to 7,0000,000 acre-feet annually if Lake Powell's storage capacity falls below 5,900,000 acre-feet (24% of capacity). U.S. DEPARTMENT OF INTERIOR, RECORD OF DECISION, COLORADO RIVER INTERIM GUIDELINES FOR LOWER BASIN SHORTAGES AND THE COORDINATED OPERATIONS FOR LAKE POWELL AND LAKE MEAD (Dec. 2007) at 50. Such shortages have not occurred during the period of operation for these two facilities but appear possible based on longer term instream flow estimates and in light of modeled instream flow reductions attributable to climate change.

[424]NORRIS HUNDLEY, JR., WATER AND THE WEST: THE COLORADO RIVER COMPACT AND THE POLITICS OF WATER IN THE AMERICAN WEST (1975) at 184. *But see* ERIC KUHN, THE COLORADO RIVER: THE STORY OF A QUEST FOR CERTAINTY ON A DIMINISHING RIVER (Roundtable Ed. May 8, 2007) at 22 n.63, *available at* http://www.crwcd.org/media/uploads/How_Much_Water_05-15-07.pdf (reporting that compact negotiators believed that the Colorado River had a total supply of as much as 21.6 million acre-feet).

[425]U.S. DEPT. OF INTERIOR, BUREAU OF RECLAMATION, FINAL ENVIRONMENTAL IMPACT STATEMENT, COLORADO RIVER INTERIM GUIDELINES FOR LOWER BASIN SHORTAGES AND COORDINATED OPERATIONS FOR LAKE POWELL AND LAKE MEAD 3-15 (Oct. 2007).

[426]Charles W. Stockton and Gordon C. Jacoby, Jr., *Long-Term Surface-Water Supply and Streamflow Trends in the Upper Colorado River Basin* (1976). *See also* Eric Kuhn, *Colorado River Water Supplies: Back to the Future*, SOUTHWEST HYDROLOGY (March/April 2005) at 20.

[427]Woodhouse, C. A., S. T. Gray, and D. M. Meko (2006), *Updated Streamflow Reconstructions for the Upper Colorado River Basin*, WATER RESOURCES RESEARCH (2007).

[428]The amount of water available to the upper basin states is a mater of considerable controversy. Eric Kuhn, General Manager of the Colorado River Water Conservancy District, evaluated several scenarios for determining water available to the upper basin after satisfying delivery obligations, concluding that upper basin states should plan on a reasonable yield of 5,250,000 acre-feet. Notably, this estimate does not account for inflow reduction attributable to climate change and assumes shortages will occur in six percent of all years. *See* ERIC KUHN, THE COLORADO RIVER: THE STORY OF A QUEST FOR CERTAINTY ON A DIMINISHING RIVER 104-05 (Roundtable Ed. May 8, 2007), *available at* http://www.crwcd.org/media/uploads/How_Much_Water_05-15-07.pdf.

future droughts."[429]

While the amount of water available remains unknown, it is known how available water resources will be divided within the upper basin. The upper basin states' share of the Colorado River is apportioned according to the Upper Colorado River Compact.[430] Arizona receives 50,000 acre-feet annually; Colorado, New Mexico, Utah, and Wyoming receive 51.75%, 11.25%, 23%, and 14% of the remainder, respectively.[431] Applying these percentages to a generally accepted assumption that 6,000,000 acre-foot is available to the upper basin, Colorado and Utah's average annual consumptive rights from the Colorado River and its tributaries are 3,079,000 and 1,369,000 million acre-feet, respectively. Despite disagreement about how best to quantify water use within each state, reasonable estimates are that, during an average year, Colorado has roughly 1,000,000 acre-feet of unused appropriations under the Compact.[432] Utah has, during an average year, roughly 520,000 acre-feet of unused Colorado River apportionments.[433] Some of this water may come from the White River, but exactly how much is unclear.

5.3.2 Surface Water

The Piceance and Uinta Basins,[434] home to the richest and most extensive oil shale reserves in North America, both drain to the White River. The White River flows west from its headwaters in Colorado's Flat Tops Wilderness, crossing the border with Utah before joining the Green River. On average, the White River near the Colorado-Utah border discharges 590,100 acre-feet annually,[435] with a mean flow of 604 cubic feet per second (cfs).[436] Flows are highly variable year-to-year and season-to-season, with spring runoff swelling the river to an average discharge of 1,765 cfs during June, almost five times the average discharge experienced in December and January (350.1 and 353.5 cfs, respectively).[437] As the only major surface water source close to Utah's richest oil shale resources, the White River is of particular importance, especially considering that the financial cost of obtaining water from the White River is much lower than that of alternate sources. In fact previous oil shale development efforts depended on plans to dam the White River, declaring it the "first-choice source of water."[438]

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[429] National Research Council, Committee on the Scientific Bases of Colorado River Basin Water Management, Colorado River Basin Water Management: Evaluating and Adjusting to Hydroclimatic Variability 108-09 (2007).

[430] Pub. L. No. 81-37, 63 Stat. 31 (1949) [hereinafter Upper Colorado River Compact]. With respect to state law, the Upper Colorado River Compact is codified at Ariz. Rev. Stat. Ann. § 45-1312; Colo. Rev. Stat. Ann. § 37-62-101; N.M. Stat. Ann. § 72-15-26; Utah Code Ann. § 73-13-9; Wyo. Stat. Ann. § 41-12-401.

[431] Upper Colorado River Compact at Art. III § (a).

[432] Between 1998 and 2006, Colorado consumed an average of 2,060,000 acre-feet of Colorado River Basin water annually. *See* U.S. Department of the Interior, Bureau of Reclamation, Provisional Upper Colorado River Basin Consumptive Use and Losses Reports, *available at* `http://www.usbr.gov/uc/library/envdocs/reports/crs/crsul.html`. Given a right to consume up to 3,079,00 acre-feet annually, Colorado has roughly 1,000,000 acre-feet remaining.

[433] Between 1998 and 2006, Utah consumed an average of 848,000 acre-feet of Colorado River Basin water annually. *See* U.S. Department of the Interior, Bureau of Reclamation, Provisional Upper Colorado River Basin Consumptive Use and Losses Reports, *available at* `http://www.usbr.gov/uc/library/envdocs/reports/crs/crsul.html`. Given a right to consume up to 1,369,000 acre-feet annually, Utah should have roughly 520,000 acre-feet remaining. However, the Utah Division of Water Resources believes that less water is available, specifically only 416,000 acre-feet as of 2000. *See D. Larry Anderson, Utah Division of Water Resources, Utah's Perspective: The Colorado River* 8 (2d. ed. 2002).

[434] The Uinta Basin includes portions of eastern Utah draining to the Uinta, Duchesne, White, or Green rivers.

[435] Final PEIS at 3-81.

[436] White River Dam FEIS at 59.

[437] White River Dam FEIS at 59. Between 1923 and 1978, average monthly flows just west of the state line peaked at 2,934 cfs; monthly low flows over the same period were just 140 cfs. *Id.*

[438] Utah Energy Office, Utah Department of Natural Resources and Energy, An Assessment of Oil Shale and Tar Sands Development in the State of Utah, Phase II: Policy Analysis 27 (1982).

In 1965, Utah filed to appropriate 350 cfs and 250,000 acre-feet from the White River and its tributaries,[439] identifying the intended uses as mining, drilling, and retorting oil shale.[440] The Utah Division of Water Resources filed connected applications with the BLM, seeking authorization to construct an 11.7-mile long reservoir just west of the Colorado border. As proposed, the reservoir would have impounded 109,250 acre-feet of water and had active storage capacity of 70,700 acre-feet.[441] The Final Environmental Impact Statement for the White River Dam was issued in May of 1982, addressing availability of land for the reservoir site. Interest in the project waned when the price of oil fell and the project was never built. The low elevation and high evaporation associated with this site, coupled with endangered species concerns, make it unlikely that the project will be revived. However, some of the water rights held by the State Board of Water Resources may be available through leases from the state.[442]

Utah has also filed to appropriate significant flows from the Flaming Gorge Reservoir on the Green River, as well as from tributaries to the Green River. It appears that some water may be available from this source, though the cost of conveying it to development sites could be quite high.[443] However, under rules promulgated by the Division of Water Resources, which holds the state's water rights in Flaming Gorge Reservoir, water from the reservoir is unavailable for "a mining or gravel pit operation."[444] Mining is undefined in the rule and if interpreted to include commercial oil shale development, could limit availability of this water source.[445] Even if commercial oil shale development were deemed a permissible use, leases supporting oil shale development would be last in line under regulations that set priorities favoring domestic, municipal, agricultural, and industrial uses associated with political subdivisions.[446]

The last round of oil shale activities also prompted construction of Red Fleet Reservoir, approximately 10 miles north of Vernal. Declining oil prices and the waning prospect of economical oil shale development ushered in the demise of the oil shale industry, and as of a decade ago, about 70% of the Red Fleet water remained unsubscribed.[447] What water remains available, if any, will likely be promptly appropriated as planners anticipate growing water demands. Even if available for commercial oil shale development, conveying water from Red Fleet Reservoir to prime oil shale lands could prove prohibitively expensive. The potential to lease water from the state is of great importance because surface waters are fully appropriated throughout the area[448] and any new diversion or consumptive use

[439] UTAH STATE DIVISION OF WATER RESOURCES, WHITE RIVER DAM PROJECT: PROPOSED ACTION PLAN (REVISED) (Nov. 1980) at 3. This reflects 100% of the river's flow during low flow periods.

[440] WHITE RIVER DAM PROJECT: PROPOSED ACTION PLAN at 3.

[441] WHITE RIVER DAM FEIS at 1. The difference between capacity and active storage is attributable primarily to capacity dedicated to sediment storage.

[442] *See e.g.* water right nos. 49-304 and 49-1239, *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.

[443] Water rights held by Utah but stored in a reservoir operated by the federal government pursuant to the Warren Act, 43 U.S.C. § 523-24, are distinguishable from water rights held by the Bureau of Reclamation. The latter are subject to preferential use for irrigation under Section 9(c) of the Reclamation Act, 43 U.S.C. § 485h(c). Accordingly, municipal or industrial development may rely on water supply contracts from the Bureau of Reclamation only to the extent "it will not impair the efficiency of the project for irrigation purposes." *Id.* But, ensuring Bureau water is used for irrigation may free up state water rights for no-irrigation uses.

[444] UTAH ADMIN. CODE § R653-8-3(2)(a).

[445] Whether the rule's prohibition against use of such stored water for mining applies to commercial oil shale development is unclear as the state reportedly supported use of water from Flaming Gorge to support commercial oil shale development during the 1980s. The rule, which was promulgated in 1998, after the most recent boom-bust cycle, may reflect an important change in policy or may have been directed at more conventional mining operations.

[446] UTAH ADMIN. CODE § R653-8-3(1).

[447] UTAH STATE WATER PLAN: UINTA BASIN at p. 9-4.

[448] As of June 2009, there were 1,652 water right claims within Area 49, dating from as early as 1861. *See* Priority lists for each of the 51 drainage areas within Utah, *available at* http://www.waterrights.utah.gov/cblapps/prioritylist.exe?Startup=NOW.

within the area must be accompanied by change applications filed on existing water rights.[449]

Other important river systems and potential water supply sources for commercial oil shale development in Utah include the Duchesne River and its tributaries (including the Uinta and Lake Fork rivers), which all drain to the Green and Colorado rivers. The Green River and its tributaries are potential sources of water for oil shale development in Utah, though diversions would involve a system of pipelines and pumping that would increase costs over those associated with withdrawals from the White River.[450] The Colorado River is south of most major oil shale resources, but still important as a potential source and because changes to its tributaries will impact this highly regulated river.

The Yampa, which represents a potential source of supply for development within Colorado, is located north of the White River and flows westward, parallel to the White River before joining the Green River within Dinosaur National Monument, roughly five miles east of the Colorado-Utah border. Under the Upper Colorado River Compact, Colorado must deliver 500,000 acre-feet annually, based on a ten-year running average, to Utah as measured upstream of Dinosaur National Monument.[451] Some water may be legally and physically available from the Yampa, subject to constraints imposed by the ESA and the Law of the River.[452] But because of late priority dates, reliable water supplies would be available only during spring runoff. Accordingly, year-around uses like oil shale development would require construction of large water storage projects.[453] Notably, Shell Oil recently filed for the right to divert up to 375 cfs from the Yampa River during high flow periods.[454] Shell believes this is sufficient to fill a 45,000-acre-foot reservoir which Shell proposes to build off the main stem of the Yampa between Maybell, Colorado and Dinosaur National Monument.[455] This application has received significant opposition from local water users concerned about a potential loss of water resources as well as from those concerned about adverse impacts to protected fish species.[456] In addition to Shell's pending proposal, there are 34 conditionally decreed rights for reservoirs within Colorado's portion of the White River Basin.[457] Not all of these projects can or will be built, but they are an important indication of both the level of preparation for commercial oil shale development that has occurred to date, as well as the potential for diversions upstream of Utah.

It is unclear how much water from the White River Utah's upstream neighbors must allow to pass downstream. A recent study commissioned by Western Resource Advocates details water rights for oil shale development within western Colorado, demonstrating the extent to which the energy industry has already acquired water rights in anticipation of future development. According to the study, there are 114 proposed structures with conditional rights in Colorado's portion of the White River Basin which, if built, would enable total direct diversion of almost 5,700 cfs and total storage of over 1 million acre-feet. Energy companies also acquired senior agricultural rights and an interest in 57 ditches in Colorado's

[449] *See e.g.* Southeast Uinta Basin – Area 49, *available at* `http://nrwrt1.nr.state.ut.us/wrinfo/policy/wrareas/area49.html`.

[450] UTAH DEPARTMENT OF NATURAL RESOURCES AND ENERGY, UTAH ENERGY OFFICE, AN ASSESSMENT OF OIL SHALE AND TAR SANDS DEVELOPMENT IN THE STATE OF UTAH, PHASE II: POLICY ANALYSIS (1982) at 27.

[451] Upper Colorado River Compact at Art. XIII.

[452] The term "Law of the River" refers to the body of law that has developed around Colorado River management, including interstate compacts, Supreme Court decrees, an international treaty, and a large body of administrative law.

[453] STATEWIDE WATER SUPPLY INITIATIVE at 7-82.

[454] Tom Ross, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, THE STEAMBOAT PILOT AND TODAY, (Jan. 11, 2009).

[455] Tom Ross, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, THE STEAMBOAT PILOT AND TODAY, (Jan. 11, 2009).

[456] *See e.g.* Mark Jaffe, *Yampa River Water Plan Hits Wall of Foes*, THE DENVER POST (March 12, 2009); Melinda Dudley, *Water District Opposes Shell Oil Request*, THE STEAMBOAT PILOT AND TODAY (Feb. 28, 2009); and Collin Smith, *Moffat County Commission Acts on Shell Water Filing*, THE STEAMBOAT PILOT AND TODAY (Feb. 20, 2009).

[457] WESTERN RESOURCE ADVOCATES at 8.

portion of the White River Basin.[458] The total decreed absolute diversion rates associated with these ditches is approximately 200 cfs.[459] The development potential of these rights and diversions is unclear.

While the Colorado River Compact and Upper Colorado River Compact apportion rights between respective states, they do little to address management of interstate rivers, and no agreement is in place regarding the White River.[460] The absence of a formal agreement leaves unresolved questions as to Colorado and Utah's respective rights to the only significant surface water source flowing through the most geologically prospective oil shale area. Utah and Colorado have several options for resolving their competing claims to the White River,[461] the best of which is likely an interstate compact. But the means of resolution is of less importance than the actual resolution. Until state claims have been reduced to definite rights, the availability of water for commercial oil shale development remains uncertain. But even if commercial oil shale development does not come to pass, knowledge of their respective rights will benefit residents of both sates as they plan for growth and increasing demands for water that are unrelated to oil shale.

5.3.3 GROUNDWATER

Groundwater provides an additional potential source of water for commercial oil shale development. According to the BLM, practical groundwater withdrawal limits within the southeast Uinta Basin are approximately 20,000 acre-feet per year, but this figure appears to ignore Utah's decision to close the basin to most new water appropriations.[462] Aside from legal availability, three issues will dominate any assessment of groundwater resources.

First, groundwater that is in continuity with surface water will be regulated as surface water to ensure groundwater depletions do not result in injury to senior surface water right holders.[463] Since most shallow groundwater is hydraulically connected to surface waters such that groundwater withdrawals may reduce stream flows, shallow groundwater formations are unlikely to represent a viable water source.[464] Deeper groundwater may represent a potential source to the extent it is physically isolated from waters currently subject to beneficial use. This is most likely the case with deep, saline waters encountered during oil and natural gas production because geologic formations that trap fossil fuels may also prevent groundwater migration, and the depth and salinity makes earlier efforts to put such water to beneficial use more expensive and less desirable.

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[458] Western Resource Advocates is preparing a similar study of water rights within Utah, which should be completed in 2010.

[459] WESTERN RESOURCE ADVOCATES at 7-9.

[460] In some cases, states sharing tributary river systems have entered into compacts apportioning their respective rights and addressing common management. For example, the Upper Colorado River Compact requires Colorado to deliver an average of 500,000 acre-feet per year at a point upstream of Dinosaur National Monument. Upper Colorado River Compact at Article XIII § (a). A Memorandum of Understanding between Colorado and Utah for Pot Creek (in the Green River drainage) establishes a schedule of priorities for use in both states and defines a period before which direct flow diversions cannot be exercised, namely May 1 of each year. STATEWIDE WATER SUPPLY INITIATIVE at 4-5.

[461] The three means of resolution are an interstate compact, litigation, and legislative apportionment. For a more detailed discussion of apportionment options, *see* John Ruple & Robert B. Keiter, *Water for Commercial Oil Shale Development: Moving Forward Without Knowing How Much Water is Needed or Available*, J. ENERGY & RESOURCES L. (2009) (forthcoming).

[462] FINAL PEIS at 3-84.

[463] Groundwater ultimately bound for a surface stream is "recognized as part of the water of the stream to the same extent as though flowing upon the surface." *Medano Ditch Co. v. Adams*, 68 P. 431, 434 (Colo. 1902). Utah water law does not distinguish between surface water and groundwater and "no one can interfere with the source of supply of [a] stream, regardless of how far it may be from the place of use, and whether it flows on the surface or underground, in such a manner as will diminish the quantity or injuriously affect the quality of the water of these established rights." *Little Cottonwood Water Co. v. Sandy City*, 258 P.2d 440, 443 (1953).

[464] In Colorado, most groundwater is presumed tributary to surface water. *See Simpson v. Bijou Irrigation Co.*, 69 P.3d 50, 59-60 (Colo. 2003).

Second, salinity generally increases with groundwater depth and varies throughout the Uinta Basin.[465] While groundwater could be used for non-industrial aspects of oil shale development, such as dust abatement and reclamation, concerns over salinity increases to the Colorado River as well as trace mineral contamination warrant careful consideration. Finally, groundwater travel time varies by location and in places is very slow. As a result, the rate at which groundwater withdrawals can occur will be limited by aquifer drawdown concerns and potential interference with other water users.

5.3.4 "NEW" WATER

Four potential sources of "new" water may hold promise for future oil shale development: precipitation augmentation, water importation, utilization of water produced as a byproduct of oil or natural gas production, and water made available through advances in conservation. Of these, produced water utilization and conservation appear to be the most promising. Produced water utilization represents a rapidly evolving area of law which may reflect both a potential source of supply and a constraint on certain in situ technologies, especially where thermal processing operations would occur in groundwater-rich environments.[466] Conservation also provides a unique opportunity to increase water availability by reducing wasteful and inefficient uses. However, for conservation to provide an appreciable benefit it must be accompanied by changes to state water rights laws. Given the ever-growing demand for water that will only increase with commercial oil shale development, creative water users will invariably seek out new sources of water. These innovations are likely to represent some of the most promising areas of water resource management relevant to commercial oil shale development.

5.4 THE ROLE OF RESERVED WATER RIGHTS

Reserved water rights represent significant but as yet unquantified water rights that could play an important role in commercial oil shale leasing and development. In Utah Indian reserved rights are the most important of these reserved water rights, but similar water rights associated with upstream federal reservations also merit discussion.

5.4.1 INDIAN RESERVED RIGHTS[467]

The Uintah and Ouray Indian Reservation, established by Executive Order in 1861, is located in Utah's Uinta Basin and is home to the Northern Ute Indian Tribe.[468] According to the tribe, the Uintah and Ouray Reservation is the second largest Indian Reservation in the United States, covering over 4.5 million acres and containing approximately 1.3 million acres of trust land.[469] Under the landmark case, *Winters v. United States*, creation of federally recognized Indian reservations impliedly reserved to the Indians the water required to meet the needs of the reservation, even where water rights are not expressly

[465] *Detailed Development Plan* at 2-97 (noting shallow groundwater near the Oil Shale Exploration Company's RD&D lease appears to be of comparatively higher quality, ranging from "fresh to moderately saline").
[466] Produced water utilization will be addressed in a future report being prepared by the Institute for CLean & Secure Energy.
[467] A more detailed discussion of Indian reserved rights can be found in John Ruple & Robert B. Keiter, *Water for Commercial Oil Shale Development: Moving Forward Without Knowing How Much Water is Needed or Available*, J. ENERGY & RESOURCES L. (2010) (forthcoming).
[468] For a detailed discussion of reservation establishment and subsequent modifications *see Ute Indian Tribe v. State of Utah*, 521 F.Supp. 1072, 1092-1150 (D. Utah 1981) (involving reservation disestablishment and jurisdictional implications). While *Ute Indian Tribe* was reversed in part, the decision provides a thorough recounting of valuable, historic information.
[469] http://www.utetribe.com/.

discussed or quantified in the treaty.[470] The priority date associated with Indian reserved rights is the date upon which the reservation was created,[471] and unlike water rights granted under state law, *Winters'* rights are not subject to forfeiture or abandonment for nonuse.[472] Reserved rights claims must be satisfied by the states in which the reservation lies, and will be debited against the state's apportionment[473] under the Law of the River.

Quantification of Indian reserved rights is no simple task. Two concerns dominate resolution of Indian reserved rights: finality and objectivity. In discussing these objectives the Supreme Court concluded that "[h]ow many Indians there will be and what their future needs will be can only be guessed ... [T]he only feasible and fair way by which reserved water for the reservations can be measured is irrigable acreage."[474] In the leading case quantifying irrigable acreage, *In re General Adjudication of All Rights to Use Water in the Big Horn River System* (*Big Horn I*),[475] the Wyoming Supreme Court determined the primary purpose of the Wind River Indian Reservation was to promote agriculture among the resident tribes and that the proper measure of the tribes' reserved rights was "those acres susceptible to sustained irrigation at reasonable costs."[476] This is known as the practicable irrigable acreage standard.

The practicable acreage standard has been criticized for including projects that are unlikely to be developed.[477] Conversely, where reservations were established in particularly harsh and arid areas, little if any of the reservation may meet minimum standards of economic feasibility.[478] Accordingly, the Arizona Supreme Court rejected the practicable acreage standard, choosing instead to balance a "myriad of factors" in quantifying reserved rights.[479] The Arizona Supreme Court observed that "the essential purpose of Indian reservations is to provide Native American people with a 'permanent home and abiding place,' that is, a 'livable' environment,"[480] noting that:

> Other right holders are not constrained in this, the twenty-first century, to use water in the same manner as their ancestors in the 1800s ... [A]griculture has steadily decreased as a percentage of our gross domestic product[, and j]ust as the nation's economy has evolved, nothing should prevent tribes from diversifying their economies if they so choose and are reasonably able to do so. The permanent homeland concept allows for this flexibility and practicality. We therefore hold that the purpose of a federal Indian reservation is to serve as

[470] *Winters v. United States*, 207 U.S. 564, 577 (1908).

[471] *Arizona v. California*, 373 U.S. 546, 600 (1963) (holding the United States reserved water rights for the Indians effective as of the time reservations were created). The Uintah Valley Indian Reservation was created by Executive Order in 1861. The Spanish Fork Reservation was created by treaty on June 6, 1865. The two were subsequently combined into the Uintah and Ouray Indian Reservation. The reserved rights doctrine was extended to reservations created by Executive Order in *United States v. Walker River Irrigation Dist.*, 104 F.2d 334,336 (9th Cir 1939).

[472] *See e.g.*, *In re General Adjudication of All Rights to Use of Water in Gila River System and Source*, 35 P.3d 68, 72 (Ariz. 2001).

[473] *Arizona v. California*, 376, U.S. 340, 346 (1964) (holding water delivered to the tribes is to be applied against the total allocation for each state within which the reservation is located).

[474] *Arizona v. California*, 373 U.S. 546, 601 (1963).

[475] 753 P.2d 76 (Wyo. 1988), *judgment aff'd by evenly divided court*, 492 U.S. 406 (1989).

[476] *Big Horn I*, 753 P.2d 76, 101 (Wyo. 1988).

[477] *See* Brief of Amici Curiae Sates of Arizona et al. in Support of the Petitioner at 10, *Wyoming v. United States*, 492 U.S. 406 (1989).

[478] *See e.g.*, *State ex rel. Martinez v. Lewis*, 861 P.2d 235, 250 (N.M. Ct. App. 1993).

[479] *In re General Adjudication of All Rights to Use Water in Gila River System and Source* (*Gila V*), 35 P.3d 68, 79-80 (Ariz. 2001) (identifying five non-exclusive considerations for quantifying reserved rights: (1) the tribe's history and culture, (2) "the tribal land's geography, topography, and natural resources, including groundwater availability," (3) the reservation's "[p]hysical infrastructure, human resources, including present and potential employment base, technology, raw materials, financial resources, and capital," (4) past water use, and (5) "a tribe's present and projected future population.").

[480] *Gila V*, 35 P.3d 68 at 74 (*quoting Winters*, 207 U.S. at 565 and *Arizona I*, 373 U.S. at 599).

a 'permanent home and abiding place' to the Native American people living there.[481]

Great effort has gone into quantifying the Northern Utes' reserved rights, resulting in at least two draft settlements.[482] The most recent negotiations resulted in the Ute Indian Rights Settlement, which was then added to the federal Reclamation Projects Authorization and Adjustment Act of 1992.[483] A complementary agreement is contained in the Ute Indian Water Compact, which was codified into state law, subject to ratification by the parties.[484] The Ute Indian Water Compact, however, was not ratified by the tribe's membership.[485] While not binding, the Ute Indian Water Compact reflects years of effort involving a diverse set of parties and reportedly failed to gain ratification for reasons other than the quantity of water involved. It therefore represents a reasonable starting point for discussing the tribe's rights.

Under the Ute Indian Water Compact, the tribe would obtain the right to divert a total of 471,035 acre-feet of water annually and deplete up to 248,943 acre-feet.[486] Of this total, the tribe could divert 66,502 acre-feet from the White River and its tributaries, consuming up to 32,880 acre-feet. The remaining water rights would come from the Duchesne and Green river systems. Tribal water rights recognized under the Ute Indian Water Compact would have priority dates dating to 1861,[487] making them some of the most senior in the basin. Water allocated pursuant to the Ute Indian Water Compact would "not be restricted to any particular use, but may be used for any purpose selected by the tribe," including "sale, lease, or any other use whatsoever."[488] Furthermore, the Ute Indian Water Compact anticipates changes in the point of diversion, place of use, or nature of use, including transferring water to uses off the reservation, subject to the requirements of state law and approval of the SOI.[489] If the Ute Indian Water Compact is ratified in its current form, the Ute Indian Tribe would be in a unique position to supply water to a burgeoning oil shale industry if it were so inclined.

As extensive and well positioned as the tribe's water rights may be, they were quantified years ago based on agricultural use and potentially irrigable acreage,[490] and therefore include limits coinciding with the irrigation season. Diversionary rights are available April 10th through October 10th, and the rate of diversion varies throughout that period.[491] Since the right to use water under the settlement is seasonal in nature while the energy industry's needs are year-round, the industrial use of tribal water rights would depend on successful change applications or reservoir construction. Moreover, the exercise of Indian reserved water rights is likely subject to restrictions imposed by the ESA, which could limit the ability to divert water or construct reservoirs.[492]

[481] *Gila V*, 35 P.3d 68 at 76 (internal quotations and citations omitted).
[482] *See* Utah Laws of 1980, c. 74 §§ 1 and 2.; UTAH CODE ANN. §§ 73-21-1 and -2; and Pub. L. 102-575 at §§ 501-07.
[483] Pub. Law 102-575 at §§ 501 – 507 (Oct. 30, 1992).
[484] UTAH CODE ANN. §§ 73-21-1 and -2.
[485] *See* DANIEL MCCOOL, NATIVE WATERS: CONTEMPORARY INDIAN WATER SETTLEMENTS AND THE SECOND TREATY ERA (2002) at 177-82 (discussing the history of settlement negotiations); *see also* DANIEL MCCOOL, *The Northern Utes' Long Water Ordeal*, HIGH COUNTRY NEWS (July 15, 1991) at 8-9 and NATIVE WATERS: CONTEMPORARY INDIAN WATER SETTLEMENTS AND THE SECOND TREATY ERA at 174 (discussing concerns over potential transfer to Las Vegas and southern Nevada).
[486] UTAH CODE ANN. §§ 73-21-1 and -2.
[487] UTAH CODE ANN. § 73-21-2, Art. III.
[488] UTAH CODE ANN. § 73-21-2, Art. III.
[489] UTAH CODE ANN. § 73-21-2, Art. III.
[490] Tabulation of Ute Indian Water Rights at 10-13.
[491] Tabulation of Ute Indian Water Rights at 10-13.
[492] For a case study on the ESA's application to Indian reserved rights *see e.g. Adrian N. Hansen, Note, The Endangered Species Act and Extinction of Reserved Rights on the San Juan River* ARIZ. L. REV. 1305 (1995) at 37 (concluding enforcement of the ESA precluded new Indian water projects along the San Juan River, interfering with the tribes' ability to use their senior water rights).

Despite these challenges, tribal reserved rights have the potential to shape commercial oil shale development. The tribe's water rights would be senior to all but a handful of water rights within the basin and therefore not subject to call during times of shortage. If the tribe chooses to develop its reserved rights, water rights throughout the basin that were long considered stable will be cast into doubt, suddenly becoming quite junior. Further, if the tribe conveyed its water rights to other users for utilization off the reservation, these rights could support significant development. Continued uncertainty regarding tribal reserved rights casts a cloud over not only oil shale development, but development in general. Resolving tribal reserved rights and clarifying water development plans would be of great benefit to policymakers weighing the tradeoffs inherent in initiating a commercial oil shale leasing program on the public lands.

5.4.2 RESERVED WATER RIGHTS FOR NAVAL OIL SHALE RESERVES

Reserved water rights can be created any time the federal government reserves land and therefore are not limited to Indian reservations.[493] The priority date is generally the date upon which the reservation was created and the quantity of water reserved is the amount required to fulfill the "primary purpose" of the reservation.[494] In the early 20th century, when the U.S. Navy transitioned from coal to liquid fuels and faced concerns over fuel availability, the President of the United States issued a series of executive orders setting aside three federal oil shale reserves. NOSR Nos. 1 (36,406 acres) and 3 (20,171 acres) are located roughly 8 miles west of Rifle, Colorado. NOSR No. 2 (88,890 acres) is locates in Utah's Carbon and Uintah counties.[495]

In 1971, the United States filed a statement of claim with the Colorado Water Court, seeking confirmation of its reserved water rights for NOSR Nos. 1 and 3.[496] In amended filings, the United States asserted the right to divert 100 cfs from the mainstem of the Colorado River at the Anvil Points Diversion, near NOSR Nos. 1 or 3.[497] The Colorado Supreme Court assumed without deciding that NOSRs created a federal reserved right. The decision, however, subordinated the federal right to other state rights because of the federal government's failure to comply with state procedural requirements.[498] Therefore, while the existence of this right does not appear to be in question, its value is presumably low, absent associated storage, because of its late priority date. Nonetheless, the potential existence of reserved rights associated with the original Naval Oil Shale Reserves could affect water availability for contemporary oil shale development.

NOSR No. 2 presents a different situation. The National Defense Authorization Act of 2000 transferred NOSR No. 2 to the Ute Indian Tribe,[499] which received the land and mineral rights in fee simple and not subject to federal management in trust status.[500] It appears NOSR-2's transfer may have terminated any reserved right claim because the Act specifically states, "[e]ach withdrawal that applies to NOSR-2 and that is in effect on the date of the enactment ... is revoked to the extent that the with-

[493] *Cappaert v. United States*, 426 U.S. 128, 138 (1976). The creation of a federal reservation can expressly disclaim reserved water rights, as was the case with creation of the Grand Staircase-Escalante National Monument. *See* Sept. 9, 1996 Presidential Proclamation establishing the Grand Staircase-Escalante National Monument, *available at* 32 WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS 38 at pp. 1788-91 (Sept. 23, 1996).
[494] *United States v. New Mexico*, 438 U.S. 696, 718 (1978).
[495] Andrews at 2.
[496] *See United States v. Bell*, 724 P.2d 631, 634 (Colo. 1986).
[497] *See United States v. Bell*, 724 P.2d 631, 635 (Colo. 1986).
[498] *United States v. Bell*, 724 P.2d 631, 635 (Colo. 1986).
[499] Pub. L. 106-398; *see also* Andrews at 28.
[500] Pub. L. 106-398 § 3405(b) and (c).

drawal applies to NOSR-2."[501] The scope of the term "withdrawal," as used in the National Defense Authorization Act, warrants further investigation. If limited to prior withdrawals from mineral location and entry, reserved rights would likely remain intact. The Tribe may also be able to make a reserved rights claim independent of NOSR status as the lands were part of the Tribe's reservation before creation of the reserve.[502] The basis of the reserved right is important because it affects both the priority date and the purposes to which the water may be put to use. Under *U.S. v. New Mexico*, reserved rights for federal lands are limited to the primary purpose of the reservation,[503] thus limiting a reserved right for the NOSR to waters needed to produce oil shale from the reservation. In contrast, Indian reserved rights are normally available for more expansive purposes. The basis for the claim therefore determines how much water is available and where it can be used, as well as the priority date. Ideally, these issues will be resolved through negotiated settlement of all tribal reserved rights claims.

5.5 WATER QUALITY

Analyses of water quality as it relates to commercial oil shale leasing and development on the public lands suffer from the same uncertainties that constrain discussions of water availability.[504] Water quality issues include discharge permitting, stormwater management and non point source pollution, wastewater disposal, and salinity control. At present there is simply insufficient information regarding the number, size, and location of facilities or the associated extraction, retorting and upgrading processes to meaningfully discuss effluent streams or changes in ameliorative capacity. But in order to satisfy future environmental analysis requirements, oil shale lessees will be asked to address and evaluate the impacts that oil shale development will have on the quality of the human environment, including impacts to water quality.[505]

Under the BLM's commercial oil shale leasing rules, applications to lease federal lands for oil shale development must describe "the water treatment and disposal methods necessary to meet applicable water quality standards."[506] "If the proposed lease development would include disposal of wastes on the lease site, [the lease application must] include a description of measures used to prevent the contamination of soils and of surface ad groundwater."[507] If a lease proceeds to development, plans of development must include descriptions of the methods utilized to monitor and protect all aquifers,[508] as well as a narrative description of the mine or in situ operation that includes an estimate of the "pollutants that may enter any receiving water."[509] The plan of development must also include a narrative description of the "necessary impoundment, treatment, control, or injection of all produced water, runoff water, and drainage from workings."[510] And of course, all activities must comply with applicable laws and regulations. Although application of these rules may vary somewhat as applied to commercial oil shale developers, resolution of these issues has a long history within the oil and gas industry.

[501] Pub. L. 106-398 § 3405(c)(5).

[502] Courts have generally found that reacquired lands retain reserved water rights and most disagreements involve the priority associated with reserved rights for reacquired lands. *See* ROBERT E. BECK, ED., WATER AND WATER RIGHTS vol. § 37.02(f)(3) (2004 ed.) for a discussion of the issues associated with reacquired lands.

[503] *United States v. New Mexico*, 438 U.S. 696, 718 (1978).

[504] Water quality issues will be discussed in greater detail in a future report being prepared by the Institute for Clean & Secure Energy.

[505] *See* 42 U.S.C. § 4331(2)(C), 43 C.F.R. § 3900.50(b) and (c).

[506] 43 C.F.R. § 3922.20(c)(3).

[507] 43 U.S.C. § 3922.20(c)(6).

[508] 43 U.S.C. § 3931.11(d)(8).

[509] 43 C.F.R. § 3931.11(h)(1).

[510] 43 C.F.R. § 3931.11(h)(2).

5.6 Conclusion and Recommendations

The direct and indirect water requirements associated with commercial oil shale leasing and development on the public lands are not well defined. Changing technologies bring with them the promise of greatly reduced water usage, however, even if direct demand is much less than projected thirty years ago, indirect demand for dust suppression, revegetation, and municipal supplies will be significant, especially as competition for scarce resources increases.

While the existing water rights administrative system is flexible, and can accommodate conditional water rights and reallocations of scarce water resources, the fundamental question is what competing uses and values policymakers and the public are willing to forego in order to enable oil shale development. Several concrete steps could clarify the nature and comparative value of existing water rights independent of these policy choices. Although the White River flows through Colorado and Utah's richest oil shale resources, the extent of Colorado and Utah's respective rights to the river remain unclear. This uncertainty could be resolved by a negotiated compact specifying each state's respective water rights. Creating greater stability with respect to the extent of available water supplies and relative priorities is critical to evaluating whether adequate water supplies are available to support a development of a commercial oil shale industry. "Until state claims have been reduced to definite rights in specific quantities of water, private capital cannot afford the investment risk, states will have difficulty selling bonds, and even the federal government will not authorize projects."[511]

Further, the Ute Indian Tribe's reserved rights claims are massive and senior to those of almost every other water user within the Uinta Basin. The Ute Tribe's potential to subordinate most existing water rights creates a cloud over water users within the basin, including those supporting development of a commercial oil shale industry. Finalizing the Ute Indian Water Compact would clarify the priority of water rights within the basin and could be of particular relevance to policymakers evaluating whether and how to implement a commercial oil shale leasing program on the public lands. Unresolved issues associated with the Ute Indian Water Compact that have implications for oil shale are the extent to which water resources may be transferred to non-Indians, used for commercial and industrial purposes, used off the reservation, and resolution of potential reserved rights claims associated with NOSR No. 2.

Finally, broad water, energy, and environmental policy initiatives will indirectly influence water availability. Protection of endangered and threatened fish species will reduce the amount of water available for oil shale development. Changes in federal energy policy may make other sources of energy more desirable, reducing demand for shale oil development. Energy and environmental policy decisions will indirectly drive technologies that have comparatively more or less demand for water, impacting the economic value of water resources within the basin and with it, the profitability of shale oil development. Greater alignment of energy and environmental policy initiatives would add clarity to the water resource issues relevant to evaluating whether and how to develop a commercial oil shale leasing program on the public lands.

[511] A. Dan Tarlock et al., Water Resource Management (5th ed. 2002) at 913-14.

CHAPTER 6

AIR QUALITY

Policymakers will need to address several air quality issues in evaluating whether and how to implement a commercial oil shale leasing program on the public lands. These issues can be broadly characterized as traditional air quality issues (i.e. emission levels of criteria pollutants and anti-degradation air quality regulations under the Clean Air Act (CAA)), and emerging air quality issues (i.e. regulation of carbon and other greenhouse gases under either pending federal legislation intended to address climate change or under as yet unwritten CAA regulations). Uncertainty as to which oil shale technologies will emerge as commercially viable complicates addressing these traditional and emerging air quality issues. Should in situ oil shale technologies prevail, the magnitude of energy input required for in situ production and the source of that energy input will likely present an additional layer of policy and air quality issues. The anticipated air quality impacts resulting from commercial oil shale activities present potentially significant limiting factors on oil shale planning and development.

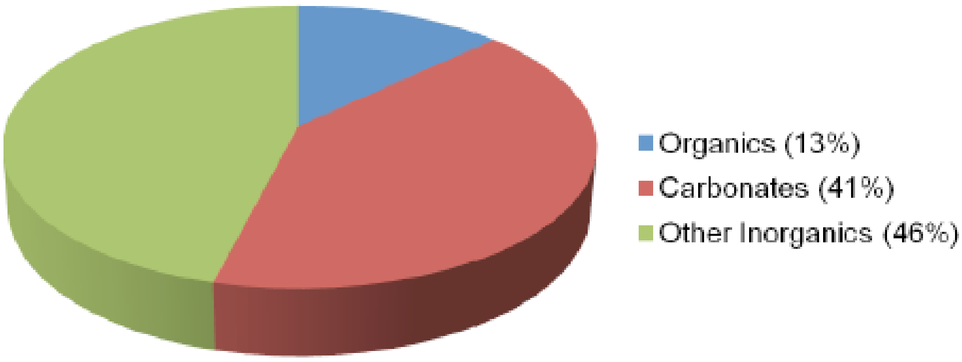
This section will first discuss the intrinsic energy demands associated with oil shale production, and then address the primary regulatory air quality issues that will accompany commercial oil shale leasing and development decisions for ex situ and in situ oil shale technologies. Then, this section presents available preliminary information from RD&D and other pilot scale oil shale activities insofar as it illuminates current technological approaches to addressing the air quality and climate management challenges inherent in commercial oil shale development.

6.1 INTRINSIC ENERGY DEMANDS OF OIL SHALE DEVELOPMENT

Commercializing oil shale energy resources presents a distinct set of energy demands and attendant air quality challenges when compared to conventional fossil energy resources. The viscosity of the oil and the porosity and permeability of a conventional oil reservoir generally allow oil to be pumped without any additional treatment of the reservoir formation.[512] The situation with oil shale is very different. Oil shale is comprised of organic material known as kerogen and inorganic material such as carbonates, silicates, and, to a lesser extent, sulfides,[513] as illustrated in Figure 6.1.1. The kerogen is bound so tightly to the inorganic elements of oil shale that the only known methods for disengaging the kerogen require heat input. This requisite thermal input, coupled with the upgrading energy demands of shale oil, contribute significantly to the overall energy footprint and associated air quality and climate impacts of commercial oil shale development.

[512] For low permeability or "tight" reservoirs, some fracturing of the rock prior to pumping may be necessary.
[513] World Energy Council, 2007 Survey of Energy Sources World Energy Council (2007) at 94.

Figure 6.1.1: "Typical" oil shale composition. Source: Adapted from World Energy Council, 2007 Survey of Energy Sources.



Given the unavoidable energy demands associated with oil shale development, initiating a commercial oil shale leasing program on the public lands presents several energy policy questions. A threshold issue is how the energy footprint of extracting oil shale compares to the energy footprint of extracting the conventional petroleum resources that oil shale is intended to augment or replace. Related to this issue are questions as to the total energy footprint of oil shale when upgrading requirements are considered, and the soundness of the underlying energy in – energy out balance of oil shale development

The Energy Return on Investment (EROI) of oil shale and conventional petroleum is a useful marker for addressing these energy policy issues. The EROI is a ratio of the quantity of energy supplied to the quantity of energy used directly and indirectly in the supply process.[514] As more accessible petroleum reserves have been depleted, the EROI for conventional petroleum in the U.S. has declined. In 1930, the EROI for conventional petroleum was >100:1; however, by 2000, the EROI for conventional petroleum was 20:1.[515] By comparison, the absolute maximum[516] EROI for oil shale is approximately 13:1,[517] indicating that the energy costs of oil shale production remain higher than even the increasing energy costs of conventional oil extraction.

In practice, the EROI for oil shale is substantially lower than 13:1. Some process estimates place potential EROI at less than 1:1, meaning that the process results in a net loss of energy.[518] Variations in the underlying energy source for the necessary thermal treatment of oil shale produce changes in oil shale's EROI. Estimates of the EROI for Shell's In Situ Conversion Process (ICP) are illustrative. Shell calculated an EROI of 3.5:1 where the thermal source for the ICP is electrical heaters powered by a 60% efficient, combined cycle gas power plant. The EROI drops to 2:1 if the same electrical heaters are powered by a standard coal-fired power plant with an efficiency rating of 35%. However, the EROI for ICP improves to 5.5:1 where the thermal source is gas-fired heaters.[519]

[514]*See* Cutler J. Cleveland; Robert Costanza; Charles A. S. Hall; Robert Kaufmann, *Energy and the U.S. Economy: A Biophysical Perspective*, SCIENCE, NEW SERIES, VOL. 225, NO. 4665 (Aug. 31, 1984) at 890-897.
[515]Cutler J. Cleveland Cutler, *Net Energy From the Extraction of Oil and Gas in the United States*, ENERGY 30 (2005) at 769-782.
[516]The absolute maximum EROI for oil shale does not allow for heat losses during production.
[517]Cutler J. Cleveland; Robert Costanza; Charles A. S. Hall; Robert Kaufmann, *Energy and the U.S. Economy: A Biophysical Perspective*, SCIENCE, NEW SERIES, VOL. 225, NO. 4665 (Aug. 31, 1984) at 890-897.
[518]Cutler J. Cleveland; Robert Costanza; Charles A. S. Hall; Robert Kaufmann, *Energy and the U.S. Economy: A Biophysical Perspective*, SCIENCE, NEW SERIES, VOL. 225, NO. 4665 (Aug. 31, 1984) Table 1.
[519]It should say Dr. Harold Vinegar, Shell Oil Company, Presentation to Utah Heavy Oil Center, University of Utah (July

The energy footprint of oil shale increases upon factoring in energy needed for the upgrading demands associated with shale oil. Conventional light crude oils have high API gravities,[520] and are readily refined into gasoline, diesel and kerosene. Shale oils typically have much lower API gravities.[521] The process of converting low API oils to higher API oils suitable as conventional refinery feedstock is known as upgrading.[522] Since shale oil is thermally produced, it is partially upgraded and may only require partial hydrotreatment for removal of nitrogen, heavy metals, and possibly sulfur.[523] Some oil shale processes yield shale oil that requires little to no upgrading.[524] But when required, this additional processing step creates a layer of air quality and greenhouse gas impacts not inherent to conventional oil production.

The energy demand attributes of oil shale should be considered in conjunction with the production potential of the oil shale resource. When evaluated on an energy density per acre basis, the oil shale resources located within the most geologically prospective oil shale area compare quite favorably with conventional petroleum from the North Slope of Alaska, oil sands from Alberta, Canada, and coal resources from Wyoming, as illustrated in Figure 6.1.2. Further, the energy density attributes (i.e. thickness and richness) of the oil shale intervals in the most geologically prospective oil shale area offer the potential for minimizing physical surface disturbance on a per barrel of oil basis when compared with other fossil fuels.

2006).

[520] API gravity refers to the American Petroleum Institute measure of crude oil density, which reflects the density of the crude relative to that of water.

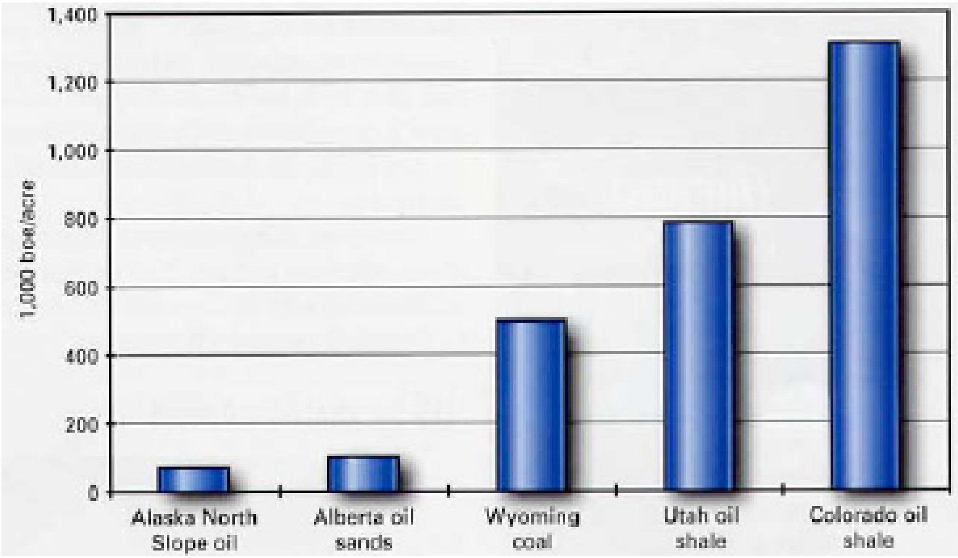
[521] *See* Anthony Andrews, Congressional Research Service, Report to Congress, *Oil Shale: History, Incentives, and Policy* (April 13, 2006) at 6-7.

[522] For a more detailed description of upgrading processes for oil shale *see* University of Utah, Institute for Clean and Secure Energy, *A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources: In Response to Energy Policy Act of 2005 Section 369(p)*, (Sept. 2007), *available at* http://repository.icse.utah.edu/dspace/handle/123456789/4921.

[523] Andrews, *Oil Shale: History, Incentives, and Policy* at 6-8.

[524] *See e.g.* Red Leaf Resources, Inc., In-Capsule Process Overview, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=8\&Itemid=14; Shell Oil, Mahogany Research Project, Doing Oil Shale The Right Way (May 2008).

Figure 6.1.2: Shale Production potential compared to other fossil fuel resources. Source: Department of Energy Office of Petroleum Reserves – Strategic Unconventional Fuels.



6.2 THE CLEAN AIR ACT AND COMMERCIAL OIL SHALE DEVELOPMENT

The Clean Air Act (CAA),[525] enacted in 1970 and subsequently amended and expanded in 1977 and 1990, authorizes the EPA to implement and enforce national air quality standards. The regulatory and permitting framework of the CAA will be germane to every phase of commercial oil shale development. The CAA and its implementing regulations are extremely complex. Because the technologies and scale of operations of a future oil shale industry are uncertain, CAA regulations are not discussed in detail in this report. Rather, this report addresses the primary regulatory issues presented under the CAA that will be broadly relevant to policymakers at the threshold stages of evaluating whether and how to develop a commercial oil shale leasing program on the public lands.

6.2.1 AMBIENT AIR QUALITY

Under the CAA, the EPA sets federal air quality standards, reviewed every five years, which apply across the country.[526] Individual states then develop local strategies for achieving these standards and submit the resulting air quality plans to the EPA for approval. A state may set more stringent air quality standards than the EPA, however, state air quality standards may not be weaker than the federal standards.[527] Delegating air quality plan development to the states was intended to assuage the inherent tensions between local economic development needs and opportunities and identifying enforceable air quality standards that were sufficiently protective of general public health.[528] Once a state's air quality

[525] 42 U.S.C. §7401 *et seq.*
[526] 42 U.S.C. §§ 7408-7410.
[527] 42 U.S.C. § 7410.
[528] *See* Holly Doremus & W. Michael Hanemann, *Of Babies and Bathwater, Why the Clean Air Act's Cooperative Federalism Framework Is Useful for Addressing Global Warming*, 50 ARIZ. L. REV. 799 (2008).

plan, termed a State Implementation Program (SIP), is approved, the state assumes responsibility for issuing permits, monitoring air quality and ensuring performance under the SIP. Under the 1990 amendments to the CAA, Indian tribes were afforded the same status as states under the CAA and consequently have the authority to develop, implement and enforce air pollution standards for Indian Country.[529] It should be noted that the term "Indian Country" refers to the jurisdictional reach of the EPA arising from its oversight responsibilities for tribal lands and, as such, is more expansive than the aggregate of individual tribal reservations. The EPA retains the authority under the CAA to develop and implement a federal plan should a state or tribe prove unable to do so.[530]

The federal air pollution standards that must be achieved under a SIP or Tribal Implementation Plan (TIP) are the National Ambient Air Quality Standards (NAAQS).[531] The EPA sets NAAQS for six ubiquitous "criteria pollutants:"[532] particulate matter (PM),[533] ozone (O_3), carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_x) and lead (Pb). The EPA sets both primary and secondary standards for these pollutants. Primary standards are intended to protect human health,[534] while secondary standards are designed to prevent environmental and property damage.[535] Table 6.2.1 lists the current NAAQS promulgated by the EPA. As illustrated by Table 6.2.1, ambient air pollutant concentrations are measured[536] using a variety of averaging time periods and ambient standards.

[529] *See* 63 FED. REG. 7254 (Feb. 12, 1998). While state and local agencies are responsible for all CAA requirements, Indian tribes exercise authority only over those CAA requirements appropriate to individual tribe's lands. For a description of the EPA's Policy for Environmental Protection ion Indian Country for Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations), *see* http://www.epa.gov/region8/tribes/Policy/r8policy.html.

[530] 42 U.S.C. §7410.

[531] 42 U.S.C. § 7409. Under the 1970 amendments to the CAA, the EPA also sets National Emission Standards for Hazardous Air Pollutants, termed NESHAPs. Under the 1990 amendments to the CAA, NESHAPs were rolled into the EPA's expanded Hazardous Air Pollutant (HAP) program aimed a limiting levels of 189 toxic air pollutants. 42 U.S.C. § 7412. The current HAPs list designates 188 toxic air pollutants, most of which are volatile organic compounds (VOCs). NESHAPs and HAPS are not addressed in this report; however a description of these regulatory programs can be found at http://www.epa.gov/apti/course422/apc4e.html.

[532] The EPA uses the term "criteria" air pollutants because the EPA regulates them by developing human health-based and/or environmentally-based criteria.

[533] PM is further delineated between PM 2.5 and PM10. U.S. ENVIRONMENTAL PROTECTION AGENCY, Particulate Matter, http://www.epa.gov/oar/particlepollution/. PM2.5 are "[f]ine particles, such as those found in smoke and haze [that] are 2.5 micrometers in diameter and smaller. These particles can be directly emitted from sources such as forest fires, or they can form when gases emitted from power plants, industries and automobiles react in the air" and PM10 are "[i]nhalable coarse particles, such as those found near roadways and dusty industries, [] larger than 2.5 micrometers and smaller than 10 micrometers in diameter." *Id.*

[534] 42 U.S.C. § 7409(b)(1).

[535] 42 U.S.C. § 7409(b)(2).

[536] Units of measure for the pollutant concentration standards are parts per million (ppm) by volume, milligrams per cubic meter of air (mg/m^3), and micrograms per cubic meter of air ($\mu g/m^3$).

Table 6.2.1: National Ambient Air Quality Standards. Source: U.S. Environmental Protection Agency. See `http://www.epa.gov/air/sulfurdioxide/`. Notes: (1) Not to be exceeded more than once per year; (2) Final rule signed October 15, 2008; (3) Not to be exceeded more than once per year on average over 3 years; (4) To attain this standard, the 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 15.0 μg/m3; (5) To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 μg/m3 (effective December 17, 2006); (6) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm (effective May 27, 2008); (7a) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm; (7b) The 1997 standard—and the implementation rules for that standard—will remain in place for implementation purposes as EPA undertakes rulemaking to address the transition from the 1997 ozone standard to the 2008 ozone standard; (7c) EPA is in the process of reconsidering these standards (set in March 2008); (8a) EPA revoked the 1-hour ozone standard in all areas, although some areas have continuing obligations under that standard ("anti-backsliding"); (8b) The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is < 1.

	Primary Standards		Secondary Standards	
Pollutant	Level	Averaging Time	Level	Averaging Time
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour (1)	None	
	35 ppm (40 mg/m^3)	1-hour (1)	None	
Lead	0.15 μg/m^3 (2)	Rolling 3-Month Average	Same as Primary	
Nitrogen Dioxide	0.053 ppm (100 μg/m^3)	Annual (Arithmetic Mean)	Same as Primary	
Particulate Matter (PM_{10})	150 μg/m^3	24-hour (3)	Same as Primary	
Particulate Matter ($PM_{2.5}$)	15.0 μg/m^3	Annual (4) (Arithmetic Mean)	Same as Primary	
	35 μg/m^3	24-hour (5)	Same as Primary	
Ozone	0.075 ppm (2008 std)	8-hour (6)	Same as Primary	
	0.08 ppm (1997 std)	8-hour (7)	Same as Primary	
	0.12 ppm	1-hour (8)	Same as Primary	
Sulfur Dioxide	0.03 ppm	Annual (Arithmetic Mean)	0.5 ppm (1300 μg/m^3)	3-hour
	0.14 ppm	24-hour (1)	0.5 ppm (1300 μg/m^3)	3-hour (1)

Regional or geographic areas that exceed a primary standard are deemed "attainment" areas and, conversely, areas that fail to meet a primary standard are "nonattainment" areas.[537]

The CAA requires operating permits, specifying acceptable emissions levels, for all major stationary sources of pollution (as defined by EPA regulations) and all hazardous air pollution sources (again as defined by EPA regulations).[538] Air quality permits are issued pursuant to SIPs, TIPs, or by the EPA. Monitoring of emissions levels to ensure compliance with the terms of air quality permits is also required.[539] Stationary sources, such as power plants, refineries and factories, are permitted under Title V of the CAA.[540] Permitting standards vary for new as compared to modified existing facilities. New or modified stationary sources are regulated according to New Source Performance Standards (NSPS)[541] and must obtain permits prior to commencing work on any construction activities or facility modifications. The EPA sets NSPS for those operational facilities that have been identified by the EPA as causing or significantly contributing to air pollution.[542]

Permitting requirements for new or modified sources depend upon whether the permittee is located in an attainment or nonattainment area. Attainment area permitting falls under the CAA's Prevention of Significant Deterioration (PSD)[543] requirements, discussed in the following section. Nonattainment area permitting requires that the permittee demonstrate an ability to offset its anticipated emissions in order to advance the area's attainment potential.[544]

Under Utah's SIP, all six criteria air pollutant standards are identical to the NAAQS.[545] Under Colorado's SIP, the standards for sulfur dioxide and lead are more stringent than the NAAQS, with the remaining criteria pollutant standards identical to the NAAQS.[546] The EPA has recently proposed tightening the standards for nitrogen dioxide, sulfur dioxide and ozone. At present the most geologically prospective oil shale area is comprised of attainment areas, with the exception of Utah County, which has been designated nonattainment for particulate matter.[547] Although ambient air quality in the most geologically prospective area is not routinely monitored, intermittent monitoring data suggests that existing levels of criteria pollutants are relatively low, with the exception of ozone.[548] Ozone results when hydrocarbons and nitrogen dioxides react with heat or sunlight. As Utah is already struggling to meet the existing ozone standard, adoption of an even more stringent level for ozone could represent a significant constraint on development of Utah oil shale resources.[549]

As noted in other chapters of this report, great uncertainty prevails as to which oil shale technologies will prove commercially viable. The scale of any future oil shale development is similarly unclear, making detailed and reliable predictions of the impacts to ambient air quality resulting from oil shale leasing and development activities on the public land extremely difficult. The BLM describes the scope

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[537]*See* 42 U.S.C. § 7502(c)(3); 40 C.F.R. § 51.114.

[538]The EPA can use its rulemaking authority to regulate additional sources under the CAA.

[539]Emissions monitoring is conducted on several timeframes, as seen in Table 6.2.1.

[540]42 U.S.C. § 7611.

[541]42 U.S.C. § 7411.

[542]*See* 40 C.F.R. §§ 60.1 – 60.759.

[543]42 U.S.C. §§ 7470-7492.

[544]*See* 40 C.F.R. § 51.165.

[545]FINAL PEIS at 3-102.

[546]FINAL PEIS at 3-102. Wyoming has adopted standards for hydrogen sulfide (H_2S), suspended sulfates, fluorides, and odors, as well as more stringent standards for SO_2. *Id.*

[547]U.S.ENVIRONMENTAL PROTECTION AGENCY, AIR NEWS RELEASE (REGION 8), *EPA finalizes nonattainment designations for Utah counties* (Oct. 8, 2009); *see also* Judy Fahys, *EPA: Cache, Tooele and Box Elder Counties now on dirty air list?*, SALT LAKE TRIBUNE (Oct. 9, 2009).

[548]Although no O3 violations have been documented, some measurements are near the 8-hour O3 standard of 157 μg/m3. FINAL PEIS 3-108.

[549]Judy Fahys, *Hitting Lower Smog Limits Will Take Joint Effort*, THE SALT LAKE TRIBUNE (Jan. 8, 2010).

of anticipated air quality impacts resulting from commercial oil shale development as:

> Temporary, localized impacts (primarily PM and SO2, with some CO and NOx emissions) would result from the clearing of the project area; grading, excavation, and construction of facilities and associated infrastructure; and mining (extraction) of the oil shale resource. Long-term, regional impacts (primarily CO and NOx, with lesser amounts of PM, SO2, and VOCs) would result from oil shale processing, upgrading, and transport (pipelines). Depending on site-specific locations, meteorology, and topography, NOx and SO2 emissions could cause regional visibility impacts (through the formation of secondary aerosols) and contribute to regional nitrogen and sulfur deposition. In turn, atmospheric deposition could cause changes in sensitive (especially alpine) lake chemistry. In addition, depending on the amounts and locations of NOx and VOC emissions, photochemical production of O3 (a very reactive oxidant) is possible, with potential impacts on human health and vegetation. Similar impacts could also occur from the additional coal-fired power plants that would be needed to supply electricity for in situ oil shale extraction.

However, as noted by the BLM in the Final PEIS, "[i]t is not possible to predict site-specific air quality impacts until actual oil shale projects are proposed and designed. Once such a proposal is presented, impacts on these resources would be considered in project-specific NEPA evaluations and through consultations with the BLM prior to actual development."[550]

Despite the dearth of detailed current oil shale development analysis, significant research was conducted by the EPA on the ambient air impacts of the oil shale development activities of the 1970s and 1980s.[551] As technologies have evolved in the intervening decades, not all of this data will be relevant for policymakers evaluating whether and how to implement a commercial oil shale leasing program on the public lands. The predominant oil shale technologies of the 1970s and 1980s were mining, either surface or underground, followed by surface retorting of the crushed shale, and modified in situ processes projects.[552] By comparison, all but one of the oil shale technologies currently being developed or tested at the pilot scale employ in situ or modified in situ processes rather than a mining and surface retorting operation.[553]

[550]Final PEIS at 4-49.

[551]*See* U.S. ENVIRONMENTAL PROTECTION AGENCY, EPA OIL SHALE RESEARCH GROUP, *Environmental Perspective on the Emerging Oil Shale Industry*, EPA-600/2-80-205a (December 1980) (detailing the key environmental issues associated with oil shale development at that time). For additional shale research reports from the 1970s and 1980s, *see* T. Thoem, E. Bates, C. Dial, E. Harris, F. Princiotta, *Status of EPA Regulatory and Research Activities Affecting Oil Shale Development*, EPA-600/D-81-009 (Feb. 1981);OFFICE OF TECHNOLOGY ASSESSMENT, UNITED STATES CONGRESS, AN ASSESSMENT OF OIL SHALE TECHNOLOGIES (June 1980); Science and Public Policy Program, University of Oklahoma, *Energy Resource Development Systems Report, Volume III: Oil Shale*, EPA 600/79 060c (March 1979) D. Myers, P. Dorset, T. Parker, *Oil Shale and the Environment*, EPA-600/9-77-033 (Oct. 1977).

[552]T. Thoem, E. Bates, C. Dial, E. Harris, F. Princiotta, *Status of EPA Regulatory and Research Activities Affecting Oil Shale Development*, EPA-600/D-81-009 (Feb. 1981). In early 1981, the EPA issued a status report on their regulatory and research activities related to oil shale development. The report listed six oil shale development projects expected to reach commercial operation by 1990: TOSCO/Colony development near Parachute Creek, CO; Union Oil development near Parachute Creek, CO; White River Project at Tracts U-a and U-b, UT; Superior Oil multi-mineral development in Piceance Basin, CO; Occidental development of Tract C-b, CO; and Rio Blanco development of Tract C-a, CO. TOSCO/Colony, Union Oil, White River Project and Superior Oil were mining and surface retorting operations; Occidental and Rio Blanco were modified in situ processes. *Id.*

[553]A DOE report published in 2007 lists 22 companies as having oil shale technologies for upstream production. Of those 22 companies, 14 are developing in situ processes and 8 are developing mining/surface retorting processes. U.S. DEPARTMENT OF ENERGY, OFFICE OF PETROLEUM RESERVES, OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, U.S. Department of Energy, *Secure Fuels from Domestic Resources: The Continuing Evolution of America's Oil Shale and Tar Sands Industries* (June 2007).

In the EPA's 1980 assessment,[554] emissions concerns for surface mining operations were particulates (PM), nitrogen dioxide (NO_x), hydrocarbons (HC), and carbon monoxide (CO). Modified in situ operations were initially anticipated to have a lower rate of particulate emissions than underground mining operations, however, data for both operations proved to be similar. Sulfur dioxide was also an area of concern for modified in situ operations. Surface retort operations had widely varying emissions of all criteria pollutants evaluated by EPA, with higher estimates dating from the early end of the research period and lower end estimates dating to 1980. Additional analysis conducted by the EPA indicated that trace metal emissions from retorting operations might also need to be controlled. Emissions data for true in situ technologies was not studied. Table 6.2.2 summarizes criteria pollutant emission estimates from the EPA's 1980 assessment. The EPA also projected the impact of atmospheric emissions on the surrounding area for a range of emissions scenarios and concluded that pollutant dispersion characterization in the Piceance Basin could be the limiting factor in the development of a commercial oil shale operation, and that strict nitrogen dioxide and sulfur dioxide controls would be needed.

Table 6.2.2: Estimated atmospheric emissions from 50,000 BOPD oil shale operation. Source: Adapted from the U.S. Environmental Protection Agency. Notes: a Data represents emissions from explosives used for blasting and from the consumption of fuel by and movement of ground vehicles; Figures are given in tonnes/day; "Handling (surface)" means "handling and storage of raw shale from a surface operation," "Handling (underground)" means "handling and storage of raw shale from an underground operation."

Type	Particulates	SO_x	NO_x	HC	CO
Surface Mine	0.8–43.2	Nil–2.6	Nil–36.0	0.1–4.2	0.7–21.6
Underground Mine	0.08–20.22	0.004–0.08	0.007–3.76	0.007–0.59	0.039–5.18
Handling (surface)	7.49	—	—	—	—
Handling (underground)	0.099–1.175	—	—	—	—
Retorting (surface)	0.68–7.81	1.11–29.0	6.2–64.16	0.27–28.25	0.43–1.91
Retorting (MIS)	0.13–0.26	0.2–2.0	—	—	—
Disposal of spent shale	0.5–0.5	—	—	—	—

6.2.2 Prevention of Significant Deterioration Permitting and Increment Availability

The PSD program further distinguished existing attainment areas as PSD Class I, II or III.[555] The PSD program was instituted in an effort to preserve existing high air quality in attainment areas by further limiting the degree of increased air pollution, termed an "increment," that could be permitted by states, tribes or the EPA. The PSD program does not contravene the NAAQS, which remain in effect as an emissions ceiling under the CAA.

[554] U.S. Environmental Protection Agency, EPA Oil Shale Research Group, *Environmental Perspective on the Emerging Oil Shale Industry*, EPA-600/2-80-205a (Dec. 1980). The air quality issues assessed by the EPA were based on a 50,000 BOPD oil shale operation. *Id.*
[555] 42 U.S.C. §§ 7470-7492.

A PSD increment represents the maximum allowable increase in the concentration of a criteria air pollutant that can be permitted above the designated baseline concentration of that air pollutant.[556] PSD baseline concentrations can be significantly more stringent than the NAAQS concentrations for the same pollutants. As a general rule, applicable PSD baseline concentrations reflect the ambient air quality for the relevant area recorded at the time that the first PSD permit application is finalized and submitted to the applicable agency.[557]

PSD Class I and II Areas are treated differently under the implementing regulations for the PSD program, with Class I Areas receiving the most stringent air quality protections, Class II Areas allowing for moderate increases in air quality degradation, and Class III Areas permitting the largest pollutant increases in attainment areas.[558] PSD Class I Areas are "areas of special national or regional natural, scenic, recreational, or historic value."[559] Federal and state land managers, as well as equivalent authorized tribal authorities, must develop Air Quality Related Values (AQRV) standards, as well as a means of evaluating impacts to those AQRV standards, for PSD Class I Areas under their management.[560] PSD permits may be denied on the ground that the permittee's activities will degrade the AQRVs of the area even where the permittee's activities would remain within the scope of available increments.

Under the PSD permitting regime, any new major source[561] of pollution seeking an air quality permit is required to utilize the Best Available Control Technology (BACT), conduct an air quality analysis, conduct an additional impacts analysis, and facilitate public involvement in the permit review and decision-making process. These permitting requirements are discussed in turn.

BACT must be installed by all PSD permittees. BACT is predicated on identification of the maximum degree of emissions control that can be achieved by the permittee.[562] Energy, environmental and economic impacts are all relevant to a BACT determination.[563] BACT is determined on a case-by-case basis, and can be met by modifying production processes or installing additional control equipment.[564] Typically BACT is reflected in an emissions limitation; however, where such a standard cannot feasibly be set, BACT can be satisfied through imposition of a design, equipment, work practice, or operational standard.[565]

The air quality analysis component of PSD permitting must show that the aggregate of the increased emissions for which permitting is sought, allowable increased emissions from other sources, and decreased emissions from existing sources will not result in a violation of either the NAAQS or applicable PSD increments.[566] A PSD air quality analysis typically involves assessing existing air quality and modeling the air quality impacts that are expected to result from the permittee's activities and associated

[556] 42 U.S.C. § 7473.

[557] 42 U.S.C. § 7479(4).

[558] U.S. Environmental Protection Agency, Press Release, *EPA Issues "Significant Deterioration" Regulations* (Nov. 27, 1974).

[559] U.S. Environmental Protection Agency, Prevention of Significant Deterioration (PSD) Basic Information, http://www.epa.gov/nsr/psd.html.

[560] 40 C.F.R. § 52.21.

[561] Existing sources of pollution located in attainment areas seeking to permit major modifications are also subject to these permit requirements.

[562] 42 U.S.C. § 7479(3).

[563] 42 U.S.C. § 7479(3); *see also In re Brooklyn Navy Yard Resource Recovery Facility*, PSD App. No. 88-10 (EPA Feb. 28, 1992); *In re World Color Press*, PSD App. No. 88-4 (EPA Dec. 13, 1990).

[564] U.S. Environmental Protection Agency, New Source Review Workshop Manual.

[565] U.S. Environmental Protection Agency, New Source Review Workshop Manual. Information on what has been required as BACT can be found in the RACT/BACT/LAER Clearinghouse database *avilable at* http://cfpub1.epa.gov/rblc/htm/bl02.cfm.

[566] *See* 42 U.S.C. § 7471.

growth (i.e. industrial, commercial and residential growth) resulting from those activities.[567] The additional impacts analysis further evaluates the expected impacts of the permittee's activities and associated growth on water quality, soil quality, existing vegetation and visibility.

The majority of the most geologically prospective oil shale is classified as PSD Class II, with the exception of the oil shale resource area immediately upwind of the Flat Tops Wilderness Area in Colorado.[568] Although the most prospective oil shale area is theoretically open to future oil shale development, significant energy development activities are already occurring or planned for the area,[569] leaving it unclear how many pollution increments will be available to a future commercial oil shale industry. Recent actions by the EPA in the context of expanded energy development underscore the challenges that are almost certain to face a future commercial oil shale industry.[570] Addressing this uncertainty in the context of planning for commercial oil shale leasing and development on the public lands presents one of the greatest challenges to development, from both the research and development and policy and regulatory sides.

Although not directed specifically at oil shale development activities, it is worth noting that the Obama Administration is revising both the PSD permit review process for new sources as well as NSPS for oil and gas operations.[571] Initially these revisions may lead to increased legal challenges to oil and gas field operations developed with multiple emissions sources. In the longer term, these revisions will likely result in more stringent air emissions permitting standards for oil and gas operations, which may prove to be a harbinger of regulations to come for any future oil shale industry.

6.2.3 Visibility & Regional Haze

Regional haze and visibility for PSD Class I Areas are regulated under the 1990 amendments to the CAA. Under the regional haze provisions of the CAA, the EPA, federal land managers,[572] states and tribes are tasked with cooperatively developing and implementing air quality plans[573] to preserve visibility at Class I Area National Parks, National Monuments, Wilderness Areas and WSAs.[574] At present, visibility in the most geologically prospective oil shale area is among the highest in the United States, excepting Alaska and Hawaii.[575]

The most geologically prospective oil shale area is in close proximity to several National Parks, National Monuments and Wilderness Areas, all of which are subject to stringent, PSD Class I Area protections under the CAA. Colorado National Monument (Colorado), Dinosaur National Monument (located in both Colorado and Utah), Flat Tops Wilderness Area (Colorado), Maroon Bells-Snowmass Wilderness Area (Colorado), Arches National Park (Utah), Bryce Canyon National Park (Utah), Canyonlands National Park (Utah), Capitol Reef National Park (Utah), Bridger Wilderness Area (Wyoming), and Fitzpatrick Wilderness Area (Wyoming) are all situated within 50 miles of the most geologically

[567] U.S. Environmental Protection Agency, New Source Review Workshop Manual; *see also In re Hudson Power 14-Buena Vista*, PSD App. Nos. 92-3, 92-4, 92-5 (EPA Oct. 5, 1992).

[568] Final PEIS at 3-108.

[569] The management challenges of multiple mineral development in the most geologically prospective oil shale area are discussed in chapter 4 of this report. *See also* Hanson & Limerick at 38-41; Bartis et al. at 38-40.

[570] *See* Hanson & Limerick at 38-41.

[571] *U.S. Environmental Protection Agency, Memorandum*, *Withdrawal of Source Determinations for Oil and Gas Industries* (Sept. 22, 2009).

[572] Participating primary federal land mangers are the BLM, the FWS, the National Park Service and U.S. Forest Services.

[573] As of January 2009, only five states (among them Colorado and Wyoming, but not Utah) had developed and submitted to the EPA adequate plans to reduce regional haze. 74 Fed. Reg. 2392 (Jan. 15, 2009).

[574] *See* 64 Fed Reg. 35714 (July 1, 1999).

[575] Final PEIS at 3-108.

prospective oil shale area.[576] The National Park Service has expressed concerns over the impacts of potential oil shale (and oil sands) development, stating:

> The following eight units of the National Park System have a very high potential for being adversely affected by cross-boundary or direct impacts from exploration and development activities in what the PEIS calls the Region of Influence: Arches, Black Canyon of the Gunnison, Canyonlands and Capitol Reef National Parks; Colorado, Dinosaur and Fossil Butte National Monuments; and Glen Canyon National Recreation Area. Numerous additional national park units in the Western United States could be adversely impacted by the regional air and water impacts likely to be generated from large scale, industrial activities associated with oil shale and tar sand development.[577]

Potential impacts to these PSD Class I Areas will be of great significance to commercial oil shale development efforts, particularly when planning the logistics and operational scale of commercial oil shale activities in the most geologically prospective oil shale area.

6.3 Climate Change and Commercial Oil Shale Development

While it is not clear what shape GHG regulation will ultimately take, it is on the horizon. Although the Obama Administration did not succeed in negotiating an internal climate agreement at the United Nations Climate Change Conference in Copenhagen,[578] the Administration appears committed to supporting regulation of GHG under the CAA if congressional action is not forthcoming.[579] At present the precise details of congressional action on climate change remain in flux. However, the EPA has taken several steps towards regulating GHG.

On April 10, 2009, the EPA published a draft regulation requiring fossil fuel suppliers, industrial gas suppliers, and direct greenhouse gas emitters to monitor and report GHG emissions above specified threshold levels.[580] That rule has now become final.[581] On April 24, 2009, acting in response to the time frame set forth pursuant to *Massachusetts v. EPA*,[582] the EPA proposed an endangerment finding identifying anthropogenic GHG as a threat to the public health and welfare.[583] On August 31, 2009, the EPA proposed a draft rule for regulating GHG emissions by very large industrial sources and, on September 30, 2009, the Obama Administration announced that such GHG regulations were proceeding.[584] A final endangerment finding with respect to GHG was released on December 7, 2009,[585] laying the groundwork for the EPA to develop NAAQS for GHG. That same month, the EPA received a petition

[576] FINAL PEIS at Table 3.5.3-3.
[577] Comments of Michael D. Snyder, Regional Director, Intermountain Region, National Park Service (April 18, 2008), reprinted in FINAL PEIS, vol. 4.
[578] *See* John M. Broder, *Many Goals Remain Unmet in 5 Nations' Climate Deal*, NEW YORK TIMES (Dec. 18, 2009).
[579] *See* Julie Eliperin, *EPA Presses Obama to Regulate Warming Under Clean Air Act,* THE WASHINGTON POST (Mar. 24, 2009).
[580] 74 FED. REG. 16448 (April 10, 2009).
[581] *See* 74 FED. REG. 56260 (Oct. 30, 2009).
[582] 549 U.S. 497 (2007).
[583] 74 FED. REG. 18886 (April 24, 2009).
[584] John M. Broder, *EPA moves to curtail greenhouse gas emissions*, THE NEW YORK TIMES (Sept. 30, 2009).
[585] U.S. ENVIRONMENTAL PROTECTION AGENCY, ENDANGERMENT AND CAUSE OR CONTRIBUTE FINDINGS FOR GREENHOUSE GASES UNDER THE CLEAN AIR ACT, *available at* http://www.epa.gov/climatechange/endangerment.html.

requesting that the EPA designate GHG as a criteria air pollutants under the CAA and impose a cap on ambient CO_2 concentrations.[586] Review of that petition is ongoing.

6.3.1 GHG Emissions Associated with Oil Shale Production

The GHG emissions associated with oil shale development are expected to be higher than those of conventional fossil energy sources, due to the inherent thermal requirements of shale oil production and upgrading. Depending upon public perception of the climate impacts of commercial oil shale development, oil shale may meet with the same criticisms as have been directed at the Canadian oil sands. Notwithstanding the substantial proportion of GHG emissions attributable to downstream combustion of the liquid fuels derived from oil sands,[587] the climate implications of oil sands production are often blamed almost exclusively on the oil sands industry rather than the end product consumer.[588]

Respected estimates of GHG emissions resulting from oil shale production are even higher than those from the Canadian oil sands.[589] The GHG footprint of various sources of liquid fuels is shown in Figure 6.3.1. The length of the bar on the horizontal axis represents the quantity of available resource while the bandwidths represent the uncertainty in GHG emissions. While the domestic oil shale resource estimated by the authors is of the same order of magnitude as both conventional oil and oil sands, projected GHG emissions from oil shale development are much higher than those from any other liquid fuel source.

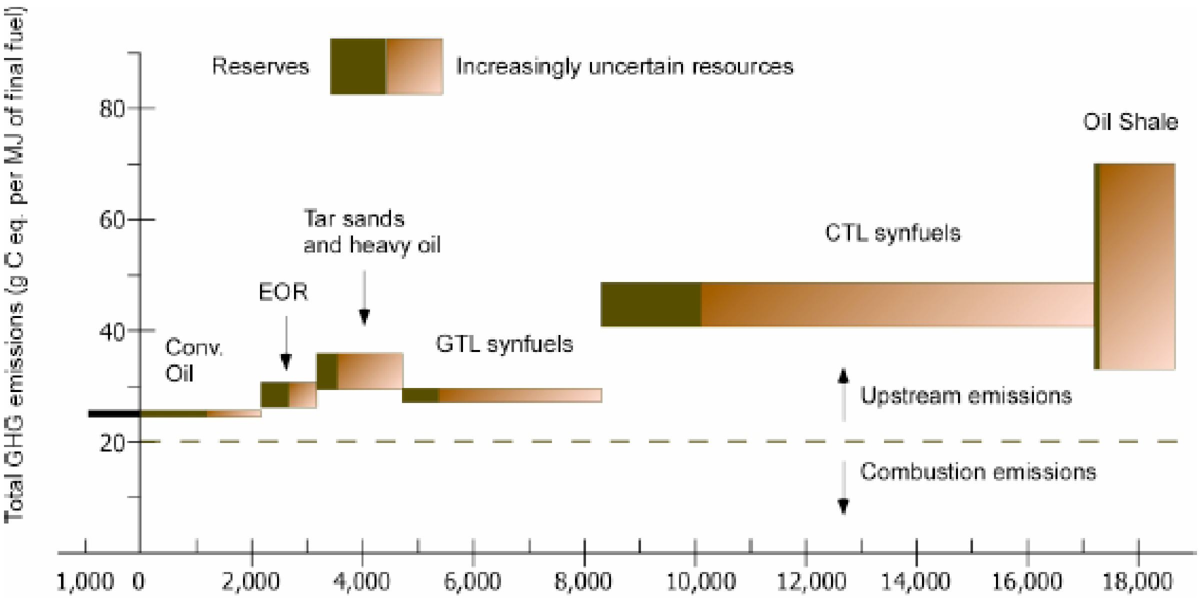
[586]Robin Bravender, *Groups Petition EPA to Set Greenhouse Gas Limits Under Clean Air Act*, THE NEW YORK TIMES (Dec. 2, 2009).

[587]In a recent report by HIS CERA, GHG gas emissions from Canadian oil sands operations (upstream + downstream production) averaged 30–70% higher than emissions from the production/refining of the average fuel consumed in the U.S. HIS CERA Special Report, *Growth in the Canadian Oil Sands: Finding the New Balance* (May 29, 2009). However, if the total life of the fuel is considered (fuel production to fuel combustion in an engine), GHG emissions from oil sands are only 5-15% higher than the average fuels consumed in the U.S. due to the large percentage of total emissions that comes from combustion of the refined products. Jay Mouawad, *Report Weighs Fallout of Canada's Oil Sands*, NEW YORK TIMES (May 18, 2009).

[588]*See e.g.*, The Pembina Institute, *Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush* (Nov. 23, 2005), *available at* http://www.oilsandswatch.org/pub/203.

[589]A. E. Farrell, A. R. Brandt, *Risks of the oil transition*, ENVIRONMENTAL RESEARCH LETTERS 1 2006, at 6.

Figure 6.3.1: Global Supplies of Liquid Hydrocarbons and Estimated Greenhouse Gas Emissions. Source: Reproduced from A. E. Farrell, A. R. Brandt, Risks of the oil transition (2006).



The primary sources of GHG emissions associated with oil shale production are the CO_2 produced to provide energy to the shale heating process, and carbonate decomposition at high retorting temperatures. A 1980 study reported the highest CO_2 emissions for retorting processes that operated above 1112°F (600°C).[590] A comparison of GHG emissions from various upstream and downstream production processes for oil shale is found in Table 6.3.1. Table 6.3.1 also shows reported wells-to-wheels GHG emissions for conventional oil and oil shale. The range of GHG emissions from surface and in situ oil shale processing are significantly higher than those reported for conventional oil, even on a well-to-wheels basis. Some reports have suggested that oil shale retorting and burning of the shale oil product could release 1.5-5 times more CO_2 than the production and burning of an equivalent amount of conventional oil.[591]

Absent either technological innovations in oil shale production methods, or the development of proven and effective methods for carbon capture and storage (CCS), the climate implications of commercial oil shale development are likely to be substantial. GHG management also presents economic issues, discussed at greater length in chapter 7 of this report. Under almost any oil shale leasing and development scenario on the public lands, the elevated carbon footprint of oil shale is likely to be of significant regulatory and economic consequence for development, and may even represent a limiting factor for that development.

[590]E. T. Sundquist, G. A. Miller, *Oil Shales and Carbon Dioxide*, SCIENCE 15 (May 1980) at 740-741.

[591]*See* Adam R. Brandt, *Converting Oil Shale to Liquid Fuels: Energy Inputs and Greenhouse Gas Emissions of the Shell In situ Conversion Process*, ENVIRONMENTAL SCIENCE AND TECHNOLOGY 42(19) (2008) at 7489-7495; E. T. Sundquist, G. A. Miller, *Oil Shales and Carbon Dioxide*, SCIENCE 15 (May 1980) at 740-741.

Table 6.3.1: GHG emissions from fuel production and fuel utilization of conventional oil, oil sands, and oil shale. Note: Estimated CO_2 emissions are measured in tons CO_2/barrel of oil. Note: Data originally reported as gCO_2e/km. For conversion, assumption for car's gas mileage was 25 miles/gallon. References: (*) Charpentier et al (**) E. T. Sundquist, G. A. Miller, *Oil Shales and Carbon Dioxide*, SCIENCE 15 (May 1980) at 740-741. (***) Adam R. Brandt, *Converting Oil Shale to Liquid Fuels: Energy Inputs and Greenhouse Gas Emissions of the Shell In situ Conversion Process*, ENVIRONMENTAL SCIENCE AND TECHNOLOGY 42(19) (2008) at 7489-7495.

Process	Sources of GHG Emissions	Est. CO_2 emissions	Source
Conventional Oil	Well-to-wheels	0.179–0.201	(*)
Oil Shale	Surface Retorting	0.18–0.42	(**)
	well-to-wheels		
	Carbonate minerals		
	production of thermal energy		
Oil Shale	Shell In Situ Conversion Process	0.67–0.81	(***)
	well-to-wheels		
	Power to supply heaters		

6.4 OVERVIEW OF CURRENT RD&D AND PILOT-SCALE MANAGEMENT STRATEGIES FOR AIR QUALITY AND CLIMATE CHANGE

.

This section summarizes the technological approaches being taken, both on federal RD&D leases and at Red Leaf Resources' pilot-scale activities on its SITLA lease, with regard to managing air quality and GHG impacts of oil shale development.

6.4.1 AMERICAN SHALE OIL

The American Shale Oil Company (AMSO) holds an RD&D lease in Colorado. AMSO has developed the patent-pending in situ Conduction, Convection, Reflux process. This technology adds heat to the oil shale formation through a horizontal well. The kerogen in the shale nearest to the well gradually heats up to its boiling point. The resulting oil vapors rise through the formation, creating heating currents. As the formation heats and hydrocarbons are released, the oil shale rubbalizes, thus forming an in situ retort. Some oil vapor is collected through a production well drilled in the retort area while the remaining vapor is left to cool, condense, and drain back to the boiling oil pool at the heating well to repeat the process.[592] In December 2008, AMSO teamed with Lawrence Livermore National Laboratory to evaluate the potential for geologic CO_2 sequestration in spent in situ retorts and other in-ground oil shale production processes.[593]

[592]See American Shale Oil, LLC, Our Plan, http://www.amso.net/Our-plan/The-plan.aspx.
[593]See D. Webb, *Carbon Dioxide Shale Solution Sought*, THE DAILY SENTINEL (March 2, 2009); Lawrence Livermore National Laboratory, News Release, *Livermore Lab and American Shale Oil team to study carbon sequestration* (Dec. 3,

6.4.2 CHEVRON

Chevron also holds an RD&D lease in Colorado. In 2006, Chevron collaborated with Los Alamos National Laboratory in 2006 on a project focused on improving the recovery of crude oil and natural gas from western U.S. oil shale.[594] This research included in situ production methods that incorporated GHG mitigation. Chevron has focused on solvent extraction rather than heat as the means of separating kerogen from the inorganic oil shale matter. The solvent, supercritical CO_2 would be injected underground at high pressures (1,000 psi) and have liquid-like properties. Kerogen would then be brought to the surface through a conventional well. This method of production would reduce energy use by eliminating the need for thermal treatment, although there will be an energy cost for pressurizing and circulating supercritical CO_2. Further, if the CO_2 binds to the rock during treatment, geologic sequestration would be achieved. Any remaining CO_2 that does not bind to the rock can be recycled and recirculated.[595]

6.4.3 SHELL

Shell holds three RD&D leases in Colorado, as well as private lands utilized for R&D activities.[596] For several decades, Shell has conducted research on an in situ oil shale production technology that is known now as ICP.[597] ICP technology "uses tightly spaced electric heaters to slowly and uniformly heat the oil shale by thermal conduction to the conversion temperature of about 650°F."[598] The heating period for a commercial project is estimated at 3-6 years and is "proportional to the square of the heater spacing and inversely proportional to the heat delivery rate."[599] The shale oil produced has a high API gravity and requires only conventional hydrotreating.[600]

The energy needs associated with the ICP technology have drawn significant criticism, with ICP often cited as evidence of the environmental follies of commercial oil shale development.[601] It has been estimated that the wells-to-wheels GHG emissions associated with commercial scale ICP activities, and the subsequent utilization of the derived shale oil, would be 21% to 47% greater than the wells-to-wheels emissions of conventional oil.[602] Shell holds a wide variety of patents for heating elements and

2008).

[594]Chevron, Press Release, *Chevron and Los Alamos National Laboratory Launch Research Project to Unlock Hydrocarbons Trapped in Oil Shale Formations*, *available at* http://www.chevron.com/news/press/Release/?id=2006-09-25.

[595]Webb, D., *Carbon dioxide shale solution sought*, The Daily Sentinel, March 2, 2009.

[596]Shell, Research, Development & Demonstration Leases, http://www.shell.us/home/content/usa/aboutshell/shell_businesses/upstream/locations_projects/onshore/mahogany/mahogany_leases.html; Shell, Freeze Wall Test, http://www.shell.us/home/content/usa/aboutshell/shell_businesses/upstream/locations_projects/onshore/mahogany/freeze_wall_technology.html.

[597]*See* National Petroleum Council, Oil Shale and Hydrates Subgroup of the Technology Task Group of the NPC Committee on Global Oil and Gas, Working Document of the NPA Global Oil & Gas Study, *Topic Paper #27: Oil Shales* (July 18, 2007); Terry O'Connor, Shell Exploration and Production- Unconventional Resources, Overview Pack (April 25, 2008), *available at* http://www.iogcc.state.ok.us/Websites/iogcc/Meetings/Midyear_Meeting/Calgary-2008/Terry-Oconnor.pdf.

[598]Fowler, T. D.; Vinegar, H. J. *Oil Shale ICP – Colorado Field Pilots.* Paper presented at the 2009 SPE Western Regional Meeting, San Jose, CA, March 24-26, 2009.

[599]Fowler, T. D.; Vinegar, H. J. *Oil Shale ICP – Colorado Field Pilots.* Paper presented at the 2009 SPE Western Regional Meeting, San Jose, CA, March 24-26, 2009.

[600]Fowler, T. D.; Vinegar, H. J. *Oil Shale ICP – Colorado Field Pilots.* Paper presented at the 2009 SPE Western Regional Meeting, San Jose, CA, March 24-26, 2009.

[601]*See e.g.*, National Resources Defense Council, Oil Shale by the Numbers: Dirty Fuels Won't Solve America's Energy Crisis (August 2008).

[602]Adam R. Brandt, *Converting Oil Shale to Liquid Fuels: Energy Inputs and Greenhouse Gas Emissions of the Shell In situ Conversion Process*, ENVIRONMENTAL SCIENCE AND TECHNOLOGY 42(19) (2008) at 7489-7495.

processes,[603] as well as one RD&D lease dedicated to research on advanced heater technologies (horizontal heating, three-phase electrical heating, natural gas heating).[604] It remains unconfirmed whether Shell would use electrical heaters should ICP progress to a commercial development technology. Shell has repeatedly stated that the size and design of any commercial oil shale development will be subject to RD&D lease activities and public opinion.[605]

6.4.4 Oil Shale Exploration Company

OSEC holds the only RD&D lease in Utah, which is also the only RD&D lease to involve ex situ technologies. OSEC's approach to oil shale development has been to utilize available "off the shelf" technologies rather than innovating new technologies.[606] Pursuant to a joint venture with Petrobas,[607] OSEC plans to use Petrobas' Petrosix process; a surface retort technology that feeds crushed oil shale into the top of the retort while recycled gases are fed into the bottom and the middle of the retort for heating the oil shale. Spent shale is discharged from the bottom while oil vapors and gases exit the top of the retort where they are cooled and cleaned. Liquid fuel and liquefied petroleum gas are produced from the oil vapors and from a fraction of the gas. The rest of the gas is recirculated back to the furnace to heat the oil shale feed.[608] Information on the air quality and GHG footprint of the Petrosix retorting process is sparse. Petrobas claims that the process has high thermal efficiency,[609] but any fixed carbon that remains on the spent shale after it exits the retort is not utilized.

6.4.5 Red Leaf Resources

Red Leaf Resources has developed and tested at pilot scale (on its SITLA lease) the EcoShale In-Capsule Process.[610] The EcoShale capsule is created in a large mined pit within oil shale ore body. The mined shale is temporarily set aside and the capsule is lined with clay. A sloped drainage system is installed at the bottom of the capsule and the mined shale is placed back in the capsule. Layered horizontally within the mined shale is a heating pipe system. A gas-fired heat source is used to heat the shale to retort temperature, producing shale oil and gas. Lower API shale oil drains to the bottom of the capsule while lighter gases and shale oil condensate are removed via the vapor recovery system at the top of the

[603] National Petroleum Council, Oil Shale and Hydrates Subgroup of the Technology Task Group of the NPC Committee on Global Oil and Gas, Working Document of the NPA Global Oil & Gas Study, *Topic Paper #27: Oil Shales* (July 18, 2007) at 10.

[604] Terry O'Connor, Shell Exploration and Production- Unconventional Resources, Overview Pack (April 25, 2008), *available at* http://www.iogcc.state.ok.us/Websites/iogcc/Meetings/Midyear_Meeting/Calgary-2008/Terry-Oconnor.pdf.

[605] *See e.g.*, Shell, Technology – In situ Conversion Process, http://www.shell.us/home/content/usa/aboutshell/shell_businesses/upstream/locations_projects/onshore/mahogany/mrp_technology.html.

[606] Gary Aho, *OSEC's White River Project*, Presentation: Utah Oil Shale Resources and Technology Update, Salt Lake City, Utah, Nov. 13, 2008, *available at http://repository.icse.utah.edu/dspace/handle/123456789/7090*.

[607] Oil Shale Exploration Company, Informational Brochure, *American Energy Independence Through Global Innovation*. Petrobas is an affiliate of the Brazilian energy company Petoleo Brasileiro SA. Mitsui and Co. Ltd, a Japanese investment and trading company, is also a party to the joint venture with OSEC. *Id*.

[608] Petrobas Refineries, The Petrosix Process, http://www2.petrobras.com.br/minisite/refinarias/petrosix/ingles/processo/index.asp.

[609] Petrobas Refineries, The Petrosix Process, Advantages, http://www2.petrobras.com.br/minisite/refinarias/petrosix/ingles/processo/proc_vantagens.asp.

[610] Red Leaf Resources, Inc., Pilot Test, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=14\&Itemid=16.

capsule. The gases produced are then used to fire the pipe burners.[611]

The EcoShale technology reduces both air quality impacts and GHG emissions. The capsule design eliminates particulate emissions (as there is no spent shale to handle or dispose of) and, due to the moderate retorting temperature of the EcoShale process, decomposition of carbonate minerals is limited, reducing CO_2 emissions. The produced shale oil requires little upgrading, further reducing overall air quality and GHG impacts. Finally, the energy required to heat the shale is generated from the retorting process itself, so after the initial heating period, the process is energy self-sufficient.[612]

6.5 Conclusion and Recommendations

As with the other resource values potentially impacted by initiating commercial oil shale leasing and development on the public lands, numerous uncertainities characterize any discussion of the effects of industrial oil shale activities on air quality and climate change. Increased air quality data-gathering and modeling would be of great benefit to policymakers and prospective oil shale developers. Meaningful evaluation of the climate change issues associated with oil shale will not be possible until a framework for GHG regulation has been finalized and the costs and available technologies for complying with such regulations are understood.

[611] *See* Red Leaf Resources, Inc., EcoShale In-Capsule Technology, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=26\&Itemid=4.

[612] *See* Red Leaf Resources, Inc., EcoShale In-Capsule Technology, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=26\&Itemid=4; Red Leaf Resources, Inc., Environmental Attributes, http://www.redleafinc.com/index.php?option=com_content\&view=article\&id=16\&Itemid=23; Red Leaf Resources, Inc., Welcome to Red Leaf Resources, http://www.redleafinc.com/#_msocom_2.

CHAPTER 7

MARKETING AND OTHER ECONOMIC CONCERNS

Apart from environmental concerns, market constraints are probably the most critical hurdle to commercial oil shale development. The economic prospects and potential regional and national role of a future oil shale industry based in the most geologically prospective oil shale area are central to determining whether and how to develop a commercial oil shale leasing program on the public lands. One threshold issue is the suitability of oil shale as a source of refinery feedstock for the production of liquid fuels such as gasoline, diesel and jet fuel, and heating and fuel oils.[613] Although shale oil would directly supply oil refiners, ultimately the demand for shale oil would be derived from the consumers of these liquid fuels. Thus issues and trends associated with public demand for these liquid fuels are relevant to commercial oil shale development. As refinery feedstock, shale oil would compete with conventional domestic and imported crude, crude produced with enhanced oil recovery methods, and remaining domestic conventional sources which are as yet unavailable for development. The status and possible contribution of these alternatives to shale oil have implications for oil shale development. A discussion of these marketing and economic challenges, along with analysis of the analagous lessons learned from the Canadian oil sands experience, follows.

7.1 DEMAND FOR LIQUID FUELS

As with conventionally produced crude oils, the immediate demand for shale oil would come directly from oil refineries, which process crude oil into products such as gasoline, diesel and jet fuel, heating oil, and fuel oil. The demand for these products, in turn, comes from their end users, among them: motorists, airlines, electric power generators, and those with oil-fired boilers or furnances.[614]

Upon upgrading (see Section 7.3), shale oil yields a synthetic crude that is best suited as a feedstock for middle distillates such as jet and diesel fuel. Through the use of more complex processes available at some refineries, it is possible, at increased cost, to convert lighter products from the heavier fractions of the upgraded crude.[615]

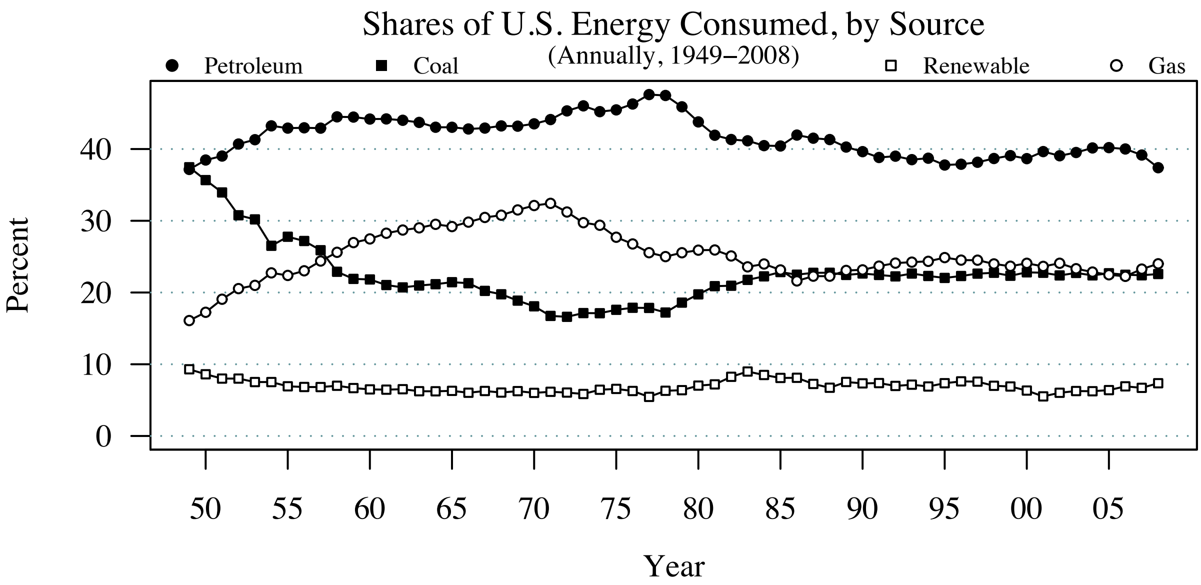
[613] We will use the term "oil shale" when we mean the rock in which the kerogen is bound and "shale oil" to generically refer to a product obtained by heating the kerogen, and which, possibly after further treatment to reduce contaminants is suitable as refinery feedstock.

[614] Section 7.3 discusses the suitability of shale oil to the production of refined products.

[615] Anthony Andrews. *Oil Shale: History, Incentives, and Policy*. Tech. rep. http://www.fas.org/sgp/crs/misc/RL33359.pdf. Congressional Research Service, 2006 and SF Culberson and PO Rolniak. "Shale Oil Likely Prospect for

The market shares of various petroleum products consumed in the U.S. per barrel of crude have changed significantly in the last few decades.[616] With an increasing number of miles-driven-by-automobile, gasoline has increased from a 39% share in 1973 to a 46% share of petroleum consumption in 2008. Consumption of residual fuel, on the other hand, dropped dramatically in the U.S. beginning in the early 1980s. Residual fuel, a fuel oil heavy enough that it must be heated prior to combustion, but which is also among the least expensive liquid fossil fuels on a BTU basis, consumed an average of 16 out of every 100 barrels of crude in the 1970s, only half as many by the end of the 1980s, and about 3 barrels per 100 in 2008.[617] Residual fuel and the heavier distillates were consumed domestically for electric power generation, but began ceding this market to coal in the 1970s. Tables 7.1.1 and 7.1.2 show, respectively, the shares over time of total U.S. consumption and production of refined petroleum products. Table 7.1.3 shows that the majority of exported products produced by U.S. refiners are heavier products which have lost market share domestically.[618]

Figure 7.1.1: Composition of U.S. Energy Sources. Data Source: Department of Energy, Energy Information Administration; Table 1.3 at http://www.eia.doe.gov/emeu/aer/overview.html



Growing demand for lighter products such as gasoline, aided slightly by a fuel tax treatment which favors gasoline over diesel, may further contribute to shale oil's disadvantage compared to conven-

Refining". In: *Oil & Gas Journal* (1981). The Salt Lake City based Red Leaf Resources states that its Ecoshale process produces feedstock for ultra-low sulfur diesel. See http://www.ecoshale.com/index.php?p_matter=process).

[616]Not suprisingly, the change in the composition of products derived from crude is more dramatic when contrasted with even earlier times. The conventional oil industry began as an attempt to find a replacement for the whale oil which was used in lamps as "light" fuel, but which in the mid 18th century was becoming scarce and expensive. It was discovered that crude oil, considered virtually useless at the time, could be distilled into a particular fraction—kerosene—that provided a superior substitute for whale oil. Now, kerosene represents only a trivial fraction of the petroleum products produced James H. Gary, Glenn E. Handwerk, and Mark J. Kaiser. *Petroleum Refining: Technology and Economics*. 5th. CRC Press, 2007.

[617]The precipitous decline of residual fuel consumption was manifestd only after the second oil crisis in the late 1970s; it was not immediately triggered by the high prices following October 1973. In Figure 7.1.2 one can see the remarkable seasonal pattern of U.S. consumption dampen considerably starting in 1980. This was due to the sharp decline in the shares of residual and heavier distillate fuels, both of which had highly seasonal consumption patterns.

[618]The large recent increase in diesel exports is of the "high sulfur" type.

Figure 7.1.2: U.S. Petroleum Consumption. Data source: *Department of Energy, Energy Information Administration*

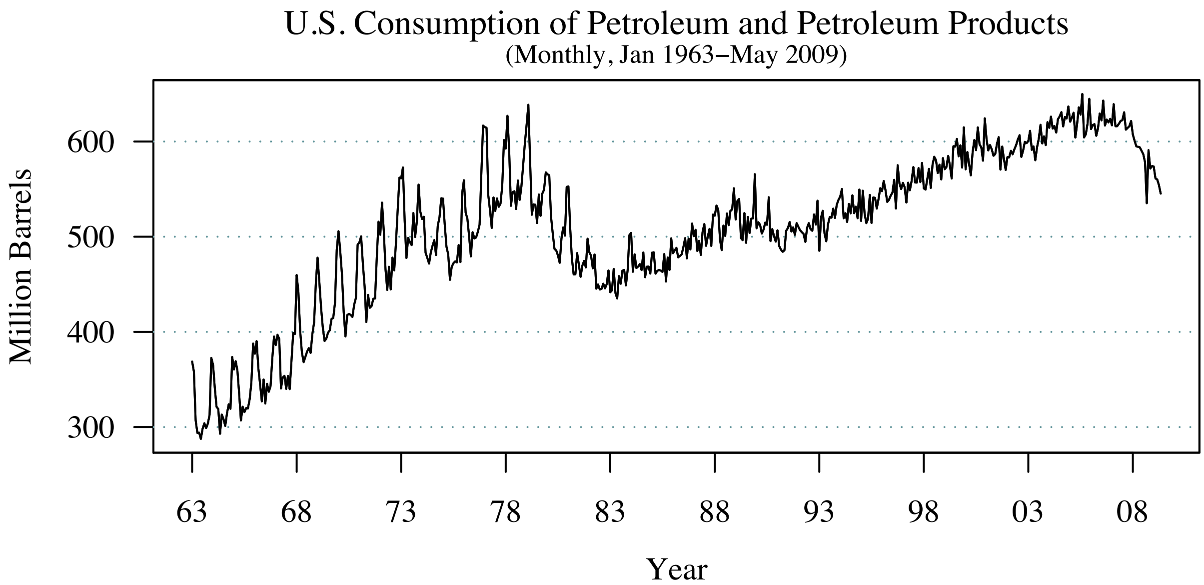


Table 7.1.1: Composition of U.S. Consumption of Refined Crude Products. Data source: *Department of Energy, Energy Information Administration*; See http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbblpd_a.htm.

Year	***Gasoline*** (%)	***Jet Fuel*** (%)	***Distillate Fuel*** (%)	***Residual Fuel*** (%)	***Total***
1973	6674 (38.6)	842 (4.9)	3092 (17.9)	2822 (16.3)	17308
1978	7412 (39.3)	858 (4.6)	3432 (18.2)	3023 (16.0)	18847
1983	6622 (43.5)	839 (5.5)	2690 (17.7)	1421 (9.3)	15231
1988	7336 (42.4)	1236 (7.2)	3122 (18.1)	1378 (8.0)	17283
1993	7476 (43.4)	1357 (7.9)	3041 (17.6)	1080 (6.3)	17237
1998	8253 (43.6)	1653 (8.7)	3461 (18.3)	887 (4.7)	18917
2003	8935 (44.6)	1578 (7.9)	3927 (19.6)	772 (3.9)	20034
2008	8989 (46.1)	1539 (7.9)	3945 (20.2)	662 (3.4)	19498

tional crude. But in many potential export markets diesel is the primary transportation fuel and is taxed more lightly than gasoline.[619] Although diesel-powered vehicles tend to consume less fuel than similar gasoline-powered vehicles, controlling emissions to an acceptable level in the U.S. has been challenging and may present a more serious obstacle to shale oil market share than the existing differential tax treatment. Shale oil's potential to contribute to diesel fuel exports is underscored by the large recent increase

[619] See Anthony Andrews. *Oil Shale: History, Incentives, and Policy*. Tech. rep. http://www.fas.org/sgp/crs/misc/RL33359.pdf. Congressional Research Service, 2006.

Table 7.1.2: Composition of U.S. Production of Refined Crude Products. Data source: *Department of Energy, Energy Information Administration*; See http://tonto.eia.doe.gov/dnav/pet/pet_pnp_refp_dc_nus_mbblpd_a.htm. Notes: (1) "NA" indicates that data was not available for the corresponding year and product (2) The difference between production (Table 7.1.2) and consumption (Table 7.1.1) does not equal exports (Table 7.1.3). This is because the U.S. imports some of the same products it exports. For example, in 2008 the U.S. exported (see Table 7.1.3) an average 355 million barrels per day of residual fuel, while importing an average 349 million BOPD.

Year	***Gasoline*** (%)		***Jet Fuel*** (%)		***Distillate Fuel*** (%)		***Residual Fuel*** (%)		***Total***
1973	6527	NA	2820	NA	971	NA	NA	NA	NA
1978	7167	NA	3167	NA	1667	NA	NA	NA	NA
1983	6338	(48.2)	817	(6.2)	2456	(18.7)	852	(6.5)	13138
1988	6956	(46.3)	1164	(7.7)	2857	(19.0)	926	(6.2)	15022
1993	7304	(46.3)	1254	(7.9)	3132	(19.8)	835	(5.3)	15787
1998	7892	(46.3)	1525	(9.0)	3424	(20.1)	762	(4.5)	17030
2003	8194	(46.9)	1489	(8.5)	3707	(21.2)	660	(3.8)	17487
2008	8548	(47.1)	1493	(8.2)	4294	(23.7)	620	(3.4)	18146

in diesel exports, rising from 138 thousand BOPD in 2005 (0.89% of total U.S. refinery yield, 3.5% of total U.S. refinery distillate yield, and 11.9% of total U.S. petroleum product exports) to 528 thousand BOPD in 2008 (3.8% of total U.S. refinery yield, 12.3% of total U.S. refinery distillate yield, and 29.3% of total U.S. petroleum product exports).[620]

Table 7.1.3: Composition of U.S. Exports of Petroleum and Petroleum Products. Data source: *Department of Energy, Energy Information Administration.*

Year	***Distillate Fuel*** (%)		***Residual Fuel*** (%)		***Petroleum Coke*** (%)		***Total***
1983	64	(8.7)	185	(25.0)	195	(26.4)	739
1988	69	(8.5)	200	(24.5)	231	(28.3)	815
1993	274	(26.5)	123	(11.9)	258	(25.0)	1033
1998	124	(13.1)	138	(14.6)	267	(28.3)	945
2003	107	(10.4)	197	(19.2)	361	(35.2)	1027
2008	528	(29.3)	355	(19.7)	377	(20.9)	1802

It is possible that changes in individual consumption preferences, possibly encouraged through public policy, could reduce the demand for liquid transportation fuels such as those potentially derived from shale oil. Preferred alternatives to liquid transportation fuels may be natural gas in the nearer term, or electric power in the farther term. Other potential liquid fuel competitors, which generally appear not

[620] As mentioned earlier, the increase in total diesel exports results from an increase in "high sulfur" diesel. As more U.S. refiners are able to produce "ultra low sulfur" diesel, diesel fuel exports may decline.

to require processing in traditional oil refineries, are "coal-to-liquids" technologies and biofuels. These longer-term challengers to the commercial viability of shale oil are speculative at present and are not considered further in this report.

7.2 The Potential Role of Oil Shale in the National Energy Portfolio

In evaluating the role and significance of an oil shale industry in the U.S., it is useful to consider the long-term trends and prospects for U.S. conventional petroleum resources. Historically, the Utah and Colorado share in the national conventional petroleum industry has been minor, however, the importance of these states to a future oil shale industry warrants a parallel discussion of the trajectory of their petroleum industries.

At this time, both the maximum size of a U.S. oil shale industry and the time-path of growth to this size, are highly uncertain. In 2005, a study by RAND stated: "Under high growth assumptions, an oil shale production level of 1 million BOPD is probably more than 20 years in the future, and 3 million BOPD is probably more than 30 years into the future." Even the low-end estimate of 1 million barrels per day equals 10 ten times the current production in Utah and Colorado combined. How much of a factor in broad national trends, such as those bearing in energy security? Assume that commercial-scale production begins in 2012, and grows at a constant arithmetic rate, eventually hiting a maximum of 1 million BOPD by 2032. How would this scale of production figure into national petroleum trends?

EIA forecasts domestic oil production of 5.7 million BOPD along with 9 million BOPD of imports by 2016, 6.0 and 8.6 million BOPD respectively for 2024, and 6.2 and 8.7 million BOPD respectively for 2032. The oil shale industry, growing as we've assumed, would reach 250 thousand BOPD by 2016, 650 thousand BOPD by 2024, and reach 1 million barrels per day in 2032. Under these assumptions, and the additional assumption that such shale oil production would not displace domestic production that would have otherwise taken place, oil shale would constitute about 4% of U.S. production in 2016, 10% in 2024, and 14% by 2032.[621] Finally, if total production also stays fixed at the levels EIA expects, in spite of this additional production coming from oil shale,[622] then due to displacement of imported oil, oil imports would be 60% in 2016, 54% in 2024, and 52% in 2032.[623] A review of recent trends in U.S., Utah, and Colorado conventional oil now follows.

In 2007, the U.S. produced 1.81 billion barrels of oil and held 21.3 billion barrels of proven reserves. Figures 7.2.1 and 7.2.2 show, respectively, the levels of U.S. proven reserves and U.S. production over time.[624] If there were no further additions to U.S. proven reserves, and the production rate remained at

[621]Details: $100 \times 0.25/(0.25 + 5.7) = 4.2\%$, $100 \times 0.65/(0.65 + 6.0) = 9.8\%$, and $100 \times 1.0/(1.0 + 6.2) = 13.9\%$.

[622]This is essentially assuming that oil consumption (which is production minus the stock change) does not increase because of oil shale production. In fact, we would expect consumption to increase and the price of crude to decrease. The reason is that the EIA forecasts are the equilibria of estimated supply and demand relations. The growing oil shale industry would "shift" the supply relation (but not the demand) so that the new equilibrium occurs at a lower price and higher quantity supplied and quantity demanded. Lastly, note that the terms "demand" and "supply" are used by EIA in a double sense: As in the equilibrium quantities supplied and demanded (e.g. in "Weekly Supply Estimates" at http://tonto.eia.doe.gov/dnav/pet/pet_sum_sndw_dcus_nus_w.htm), and, in their technical description of their energy-economic model, (see http://www.eia.doe.gov/oiaf/aeo/overview/index.html), as relations.

[623]Details: $100 \times (9.0 - 0.25)/(9.0 + 5.7) = 59.5\%$, $100 \times (8.6 - 0.65)/(8.6 + 6.0) = 54.4\%$, and $100 \times (8.7 - 1)/(8.7 + 6.2) = 51.7\%$.

[624]The pronounced jump in U.S. proven reserves which is apparent in Figure 7.2.1, was due to the recognition of the 1968 Prudhoe Bay field dicovery. The 16th largest field ever discovered, Prudhoe Bay has supplied the U.S. with a cumulative 12 billion barrels of oil, about 15% of total U.S. production over the same time (i.e. since June 1977, the date oil began flowing from Prudhoe Bay through the Trans-Alaskan Pipeline). Production at Prudhoe Bay has declined from a maximum of 1.6

1.81 billion barrels per year, this resource would be completely depleted in about 12 years ("time-until-exhaustion").

Figure 7.2.1: U.S. proven reserves. Data source: *Department of Energy, Energy Information Administration*

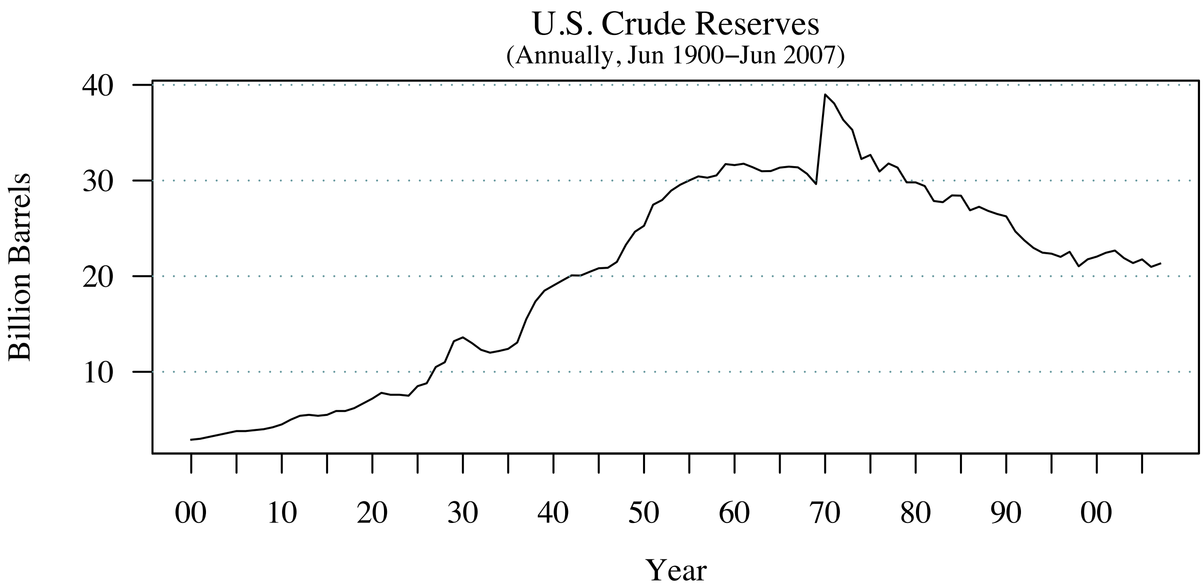
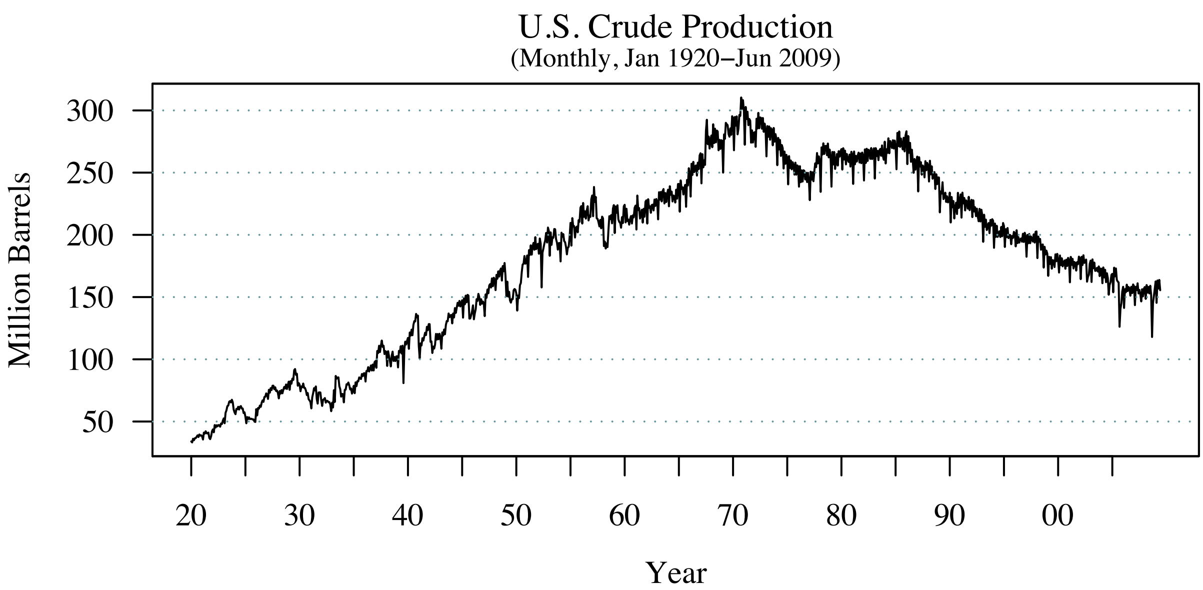


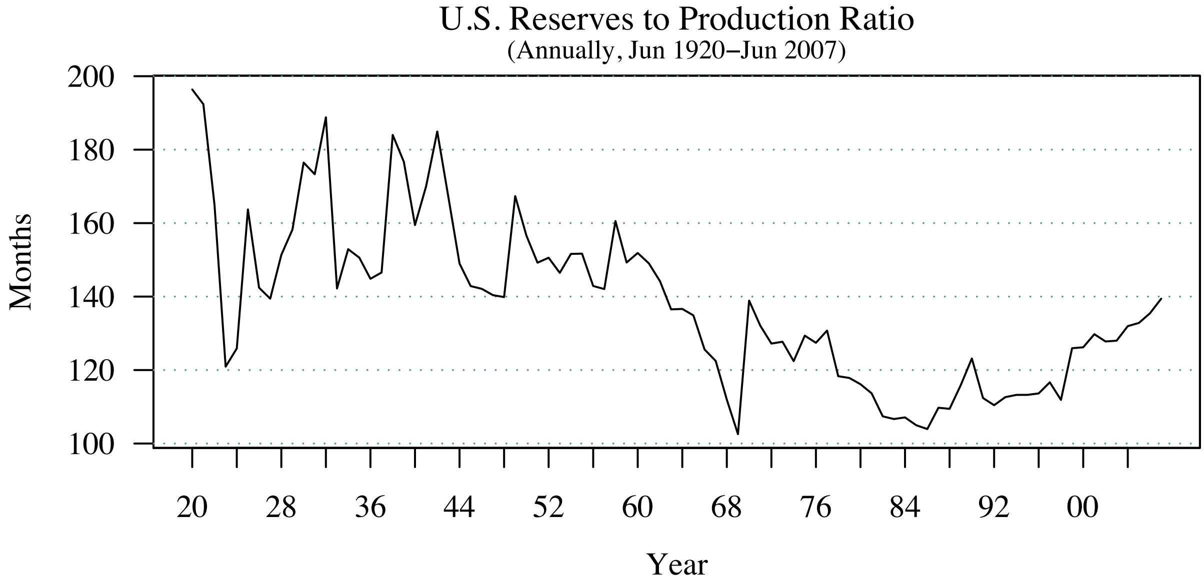
Figure 7.2.2: Oil Production in the U.S. Data source: *Department of Energy, Energy Information Administration*



million barrels per day in 1988 to its present rate of about 400,000 BOPD, now constituting roughly 7% of U.S. production.

But consider that in June 1977 the time-until-exhaustion was 11 years. That is, had there been no further increases in proven reserves, and had the production rate remained constant at its then-current level, the U.S would have run out of crude in the late 1980s. Figure 7.2.3 shows, for each year from 1920 until 2007, the ratio of then-current U.S. reserves to that year's June production.[625]

Figure 7.2.3: U.S. Reserves versus Production. Data Source: *Department of Energy, Energy Information Administration.*



New additions are one reason the U.S. has not exhausted its supplies of crude oil. Old fields have been extended, new reservoirs have been found in both old and new fields, and net revisions to previous-year estimates have nearly always been positive. Indeed, since 1977 almost 70 billion barrels of crude have been added to U.S. proven reserves.

But reserve additions are not the only explanation for the delay in time-until-exhaustion. Domestic production, following the trend of proven reserves, has suffered almost relentless declines since the early 1980s, after peaking between the late 1960s and early 1970s (see Figure 7.2.2).[626] If production had remained constant at the June 1977 level of 243 million barrels, then cumulative production from June 1977 to June 2007 would have been 88 billion barrels instead of the actual 79 billion barrels and time-until-exhaustion would have been about 7 years (80 months) instead of 12.

But since the remaining lifetime of reserves could be very small, either because reserves are small or production is large, it is a rather limited measure for assessing the status of U.S. production. This is illustrated by Figure 7.2.3, which shows that while the ratio of reserves to production has increased by about one-third since the mid-1980s, the underlying cause (as can be only be gathered from also

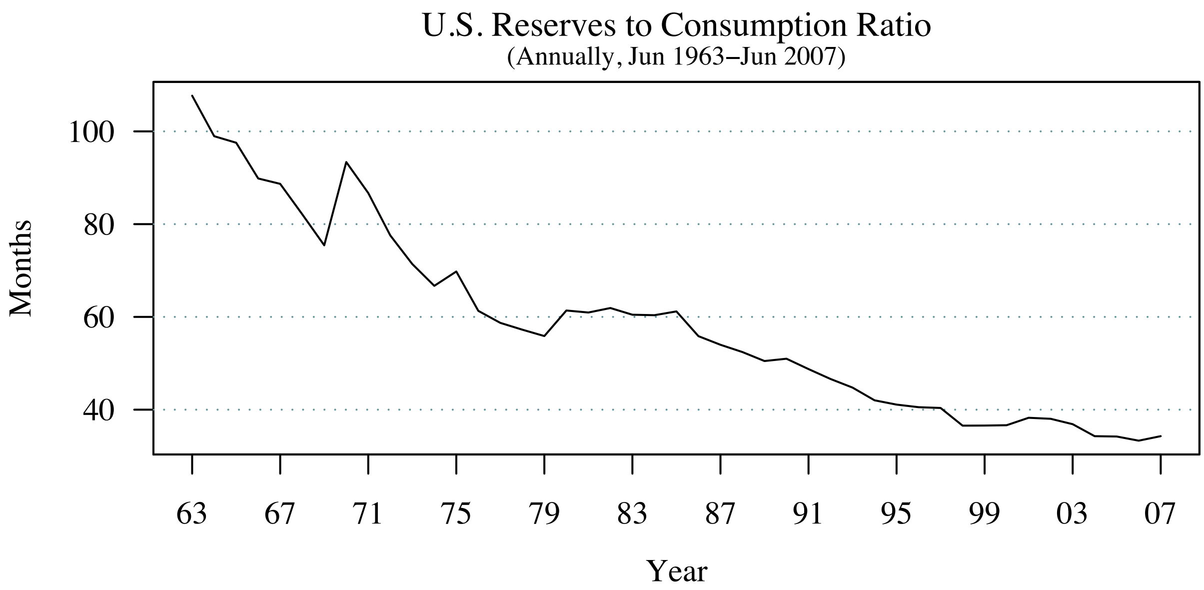
[625]The ratio of reserves current in a particular year to production during a given unit of time is the "time-until-exhaustion", given in those units of time. Proven reserves (a "stock") are cited here in billions of barrels, while production (a "flow") is given in millions of barrels per month. Since the official proven reserves statistics reported annually by EIA are dated in June, this is also the month production is noted. That is, time-until-exhaustion in year $t = \frac{\text{reserves current as of June of year } t}{\text{total June production in year } t}$.

[626]This pattern is present and perhaps more surprising in recent years (2005-2009) when prices have been historically high. But production follows exploration activity with a lag and exploration activity, as measured by the number of exploratory wells drilled, has certainly not reacted with indifference to the recently high crude prices. Thus, we expect crude production to be higher in the near future than it would have been otherwise, but still fall far short of its past peak.

observing either production or reserves (Figures 7.2.1 and 7.2.2)) is a decrease in reserves of about 25% together with a 45% decline in production over the same period.

A more pointed measure of U.S. reserves lifetime, which also speaks to U.S. self-sufficiency in crude production, is the hypothetical query of how long the U.S. could support its own consumption entirely out of its own production. In June 1977, the U.S. could have provided all its own consumption for about 5 years (59 months), while in June 2007 the U.S. could only have sustained its own consumption for a little more than half as long (34 months). Figure 7.2.4 shows, for each year from 1963 until 2007, the ratio of then-current U.S. reserves to that year's June consumption.[627]

Figure 7.2.4: Data Source: *Department of Energy, Energy Information Administration*.



While the U.S. has seen its proven petroleum reserves decline by almost 30% since reaching 29.8 billion barrels in 1980, other countries have seen their reserves increase, in some cases substantially (see Table 7.2.1). Canada has had by far the largest and most globally-substantial increase in its proven reserves, as part of its vast oil-sands resource came to be officially counted as proven reserves in 2003. Mexico, on the other hand, made large downward revisions in its proven reserves, beginning in 1999, as the result of external audits and in order to comply with the requirements of U.S. Securities and Exchange Commission disclosure regulations.[628] It is worth noting that OPEC claims reserves of 930 billion barrels, an amount equal to about 70% of world reserves. However, it is important to recognize that since not all countries use the same criteria and methods to establish reserves, comparisons between countries and even through time for the same country must be done with care.[629]

[627]This is strictly hypothetical, since consumption is not independent of production: the amount of oil consumed depends on its price, which depends on oil production.

[628]See "Drop in Pemex's revised oil reserves figure 'significant'". In: *Oil & Gas Journal* (2002), Alan Petzet. "Pemex defines 'reserves'". In: *Oil & Gas Journal* (1999), and John R. Moroney and Flory Dieck-Assad. *Energy and Sustainable Development in Mexico*. Texas A & M University Press, 2005.

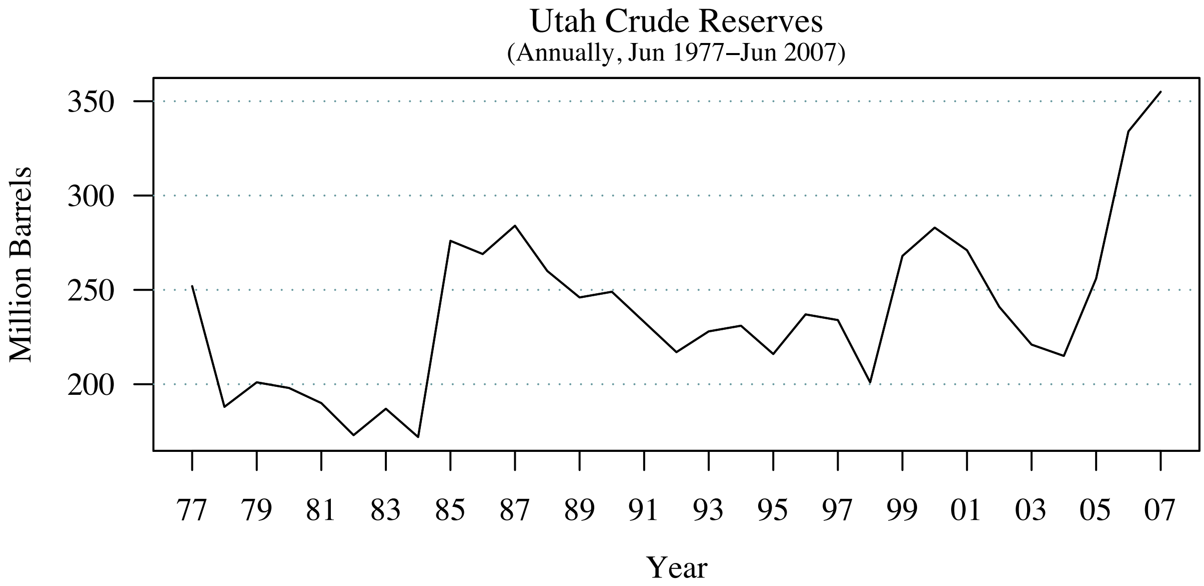
[629]See for example Bassam Fattouh and Robert Mabro. "Oil in the 21st Century: Issues, Challenges and Opportunities". In: ed. by Robert Mabro. Chapter 4: The Investment Challenge. Oxford University Press, 2006 and http://www.iags.org/n0331043.htm, the latter citing Matthew Simmons' related concern over Saudi Arabia's ability to sustain its role as the world's sole "swing producer."

Table 7.2.1: Composition of World Reserves, 1980-2009. Data Source: *Department of Energy, Energy Information Administration.*

Year	*U.S.*	%	*Canada*	%	*Mexico*	%	*OPEC*	%	*Total*
1980	29.8	4.6	6.8	1.1	31.2	4.8	425.4	66.0	644.9
1981	29.8	4.6	6.4	1.0	44	6.7	424.4	65.1	651.9
1982	29.4	4.4	7.3	1.1	56.9	8.5	426.2	63.6	670.3
1983	27.8	4.2	7.0	1.0	48.3	7.2	435.1	65.1	668.2
1984	27.7	4.1	6.7	1.0	48	7.2	438.8	65.6	668.9
1985	28.4	4.1	7.0	1.0	48.6	6.9	467.2	66.8	699.8
1986	28.4	4.1	6.5	0.9	49.3	7.0	466.1	66.5	700.5
1987	26.8	3.8	6.8	1.0	54.6	7.8	468.5	67.0	699.7
1988	27.2	3.1	6.8	0.8	48.6	5.5	661.6	74.4	889.3
1989	26.8	3.0	6.7	0.7	54.1	6.0	667.0	73.5	907.7
1990	26.5	2.6	6.1	0.6	56.3	5.6	758.1	75.6	1002.2
1991	26.2	2.6	5.7	0.6	51.9	5.2	762.0	76.3	999.1
1992	24.6	2.5	5.5	0.6	51.2	5.2	762.0	77.0	989.4
1993	23.7	2.4	5.2	0.5	51.2	5.1	765.6	76.9	996.1
1994	22.9	2.3	5.0	0.5	50.9	5.1	767.6	76.9	998.3
1995	22.4	2.2	5.0	0.5	50.7	5.1	765.1	76.6	999.2
1996	22.3	2.2	4.8	0.5	49.7	4.9	773.8	76.8	1007.3
1997	22.0	2.2	4.8	0.5	48.7	4.8	785.7	77.1	1018.5
1998	22.5	2.2	4.8	0.5	40	3.9	794.2	77.9	1020.0
1999	21.0	2.0	4.9	0.5	47.8	4.6	797.6	77.2	1032.7
2000	21.7	2.1	4.9	0.5	28.3	2.8	799.6	78.6	1016.7
2001	22.0	2.1	4.7	0.5	28.2	2.7	811.5	78.9	1028.1
2002	22.4	2.2	4.8	0.5	26.9	2.6	815.9	79.1	1031.9
2003	22.6	1.9	180.0	14.8	12.6	1.0	818.6	67.5	1213.1
2004	21.8	1.7	178.8	14.1	15.6	1.2	869.4	68.7	1265.0
2005	21.3	1.7	178.8	14.0	14.6	1.1	885.1	69.3	1277.2
2006	21.7	1.7	178.7	13.8	12.8	1.0	901.9	69.8	1292.9
2007	20.9	1.6	179.2	13.6	12.3	0.9	902.5	68.5	1316.6
2008	21.3	1.6	178.5	13.4	11.6	0.9	918.5	69.0	1332.0
2009	21.3	1.6	178.0	13.3	10.5	0.8	930.9	69.4	1342.2

In 2007, Utah produced 20 million barrels of petroleum (1.1% of U.S) and held 355 million (1.67% of U.S., 10th ranked state) proven reserves. Between January 1981 and April 2007, monthly crude oil production from Utah averaged 0.92%, but never exceeded 1.6%, of U.S. total production. Between 1977 and 2007 (the most recent year of reserve data), Utah's annual proven reserves averaged slightly less than one percent of U.S. reserves. The 355 million barrels of reserves in 2007 are a 65% increase in Utah's 215 million barrels of reserves reported in 2004 and are the result of several large positive revisions and one large acquisition. Figures 7.2.5 and 7.2.6 show the levels of Utah reserves and production over time. Figure 7.2.7 shows the ratio of reserves to production for Utah increasing over time and surpassing its highest level over the time span of the data series in 2007. This is due to a combination of generally decreasing production (as in the U.S. as a whole) and recently increasing proven reserves (unlike the U.S.).

Figure 7.2.5: Data source: *Department of Energy, Energy Information Administration.*



These attributes of Utah's oil industry are closely matched by those of Colorado. In 2007, oil production in Colorado totaled 23 million barrels (1.3% of U.S.). Between January 1981 and April 2009, monthly production averaged 1%, and never exceeded 1.25%, of U.S. production. Proven reserves, which increased 35% from 2004 (225 million barrels) through 2007 (304 million barrels), averaged 1.43% of U.S. reserves between 1981 and 2007. Figure 7.2.10 shows that, like UT, Colorado reserves-to-production are at their highest levels since 1981 (at latest). Table 7.2.2 details production and proven reserves for the U.S., Colorado, and Utah since 1981.

Since existing methods and resources could potentially bolster U.S. conventional fossil fuel supplies, and serve as a competitor to unconventional resources such as shale oil, several of the more significant among them will be presented below.

Following the trend in proven reserves, conventional petroleum production in the U.S. has been in decline for several decades. Monthly production peaked in October 1970 at 310 million barrels, and has fallen to an average 152 million barrels for the twelve months ending June 2009 (see Figure 7.2.2). Nevertheless, there are areas in the U.S. which are presently unavailable for petroleum development, but which are believed capable of substantially increasing U.S. proven reserves and eventually U.S. domestic production.

One such area is the U.S. outer continental shelf (OCS). In response to Section 357 of EPact 2005,

Figure 7.2.6: Data source: *Department of Energy, Energy Information Administration*.

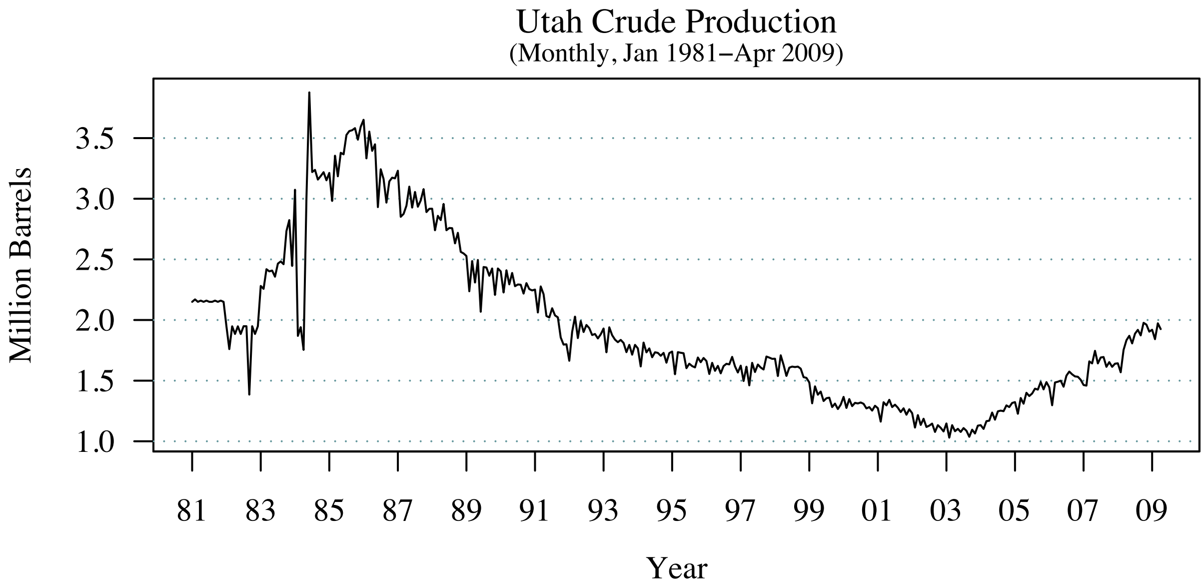
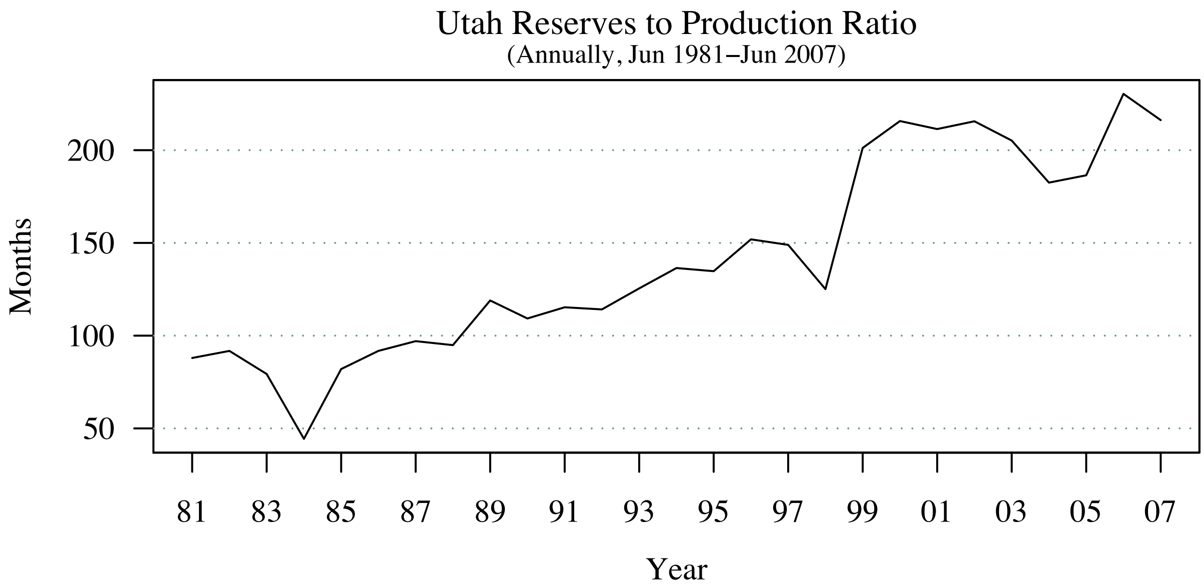


Figure 7.2.7: Data source: *Department of Energy, Energy Information Administration*.



the U.S. Minerals Management Service (MMS) provided estimates of the potential oil and natural gas resources on the U.S. OCS. Table 7.2.3 summarizes these estimates, designated as undiscovered technically recoverable resources. It is important to bear in mind that undiscovered technically recoverable resources are not proven reserves, and that substantial uncertainty exists regarding the actual levels of the resource that could be produced using conventional methods.[630] Nevertheless, to put the estimated size

[630]See *Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources*. Tech. rep. `http://www.mms.gov/PDFs/`

Figure 7.2.8: Data source: *Department of Energy, Energy Information Administration*.

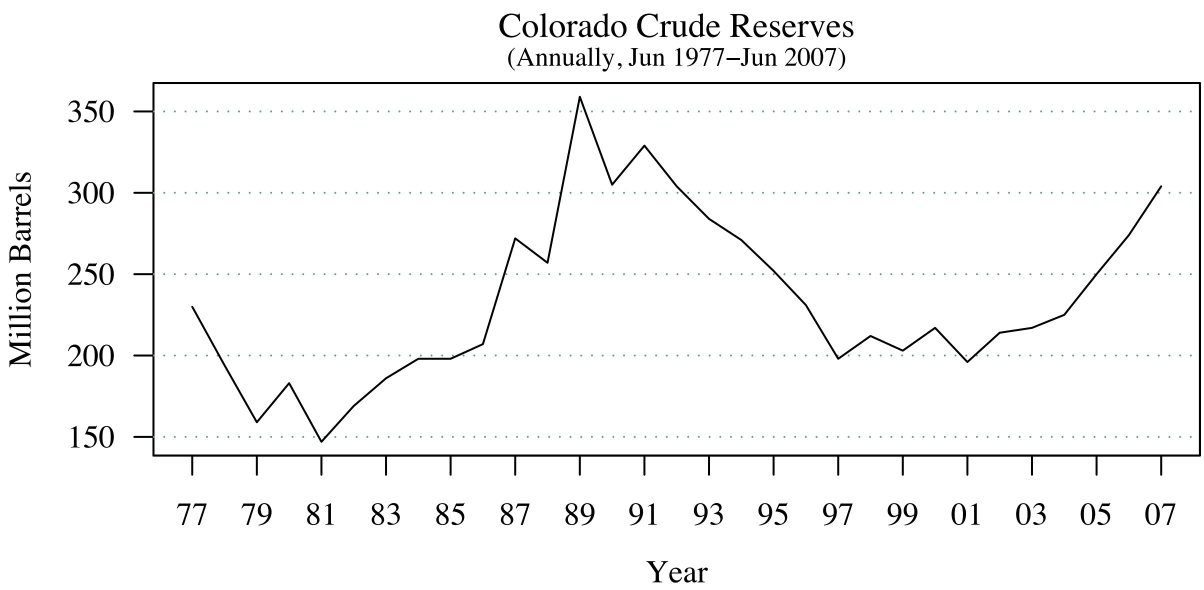
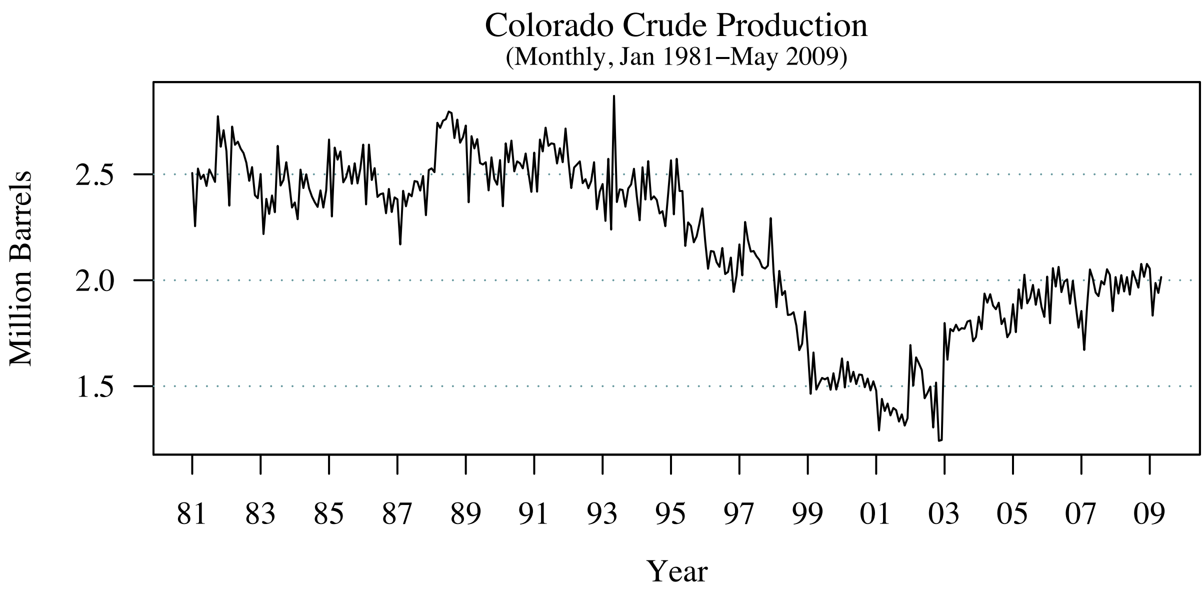


Figure 7.2.9: Data source: *Department of Energy, Energy Information Administration*.

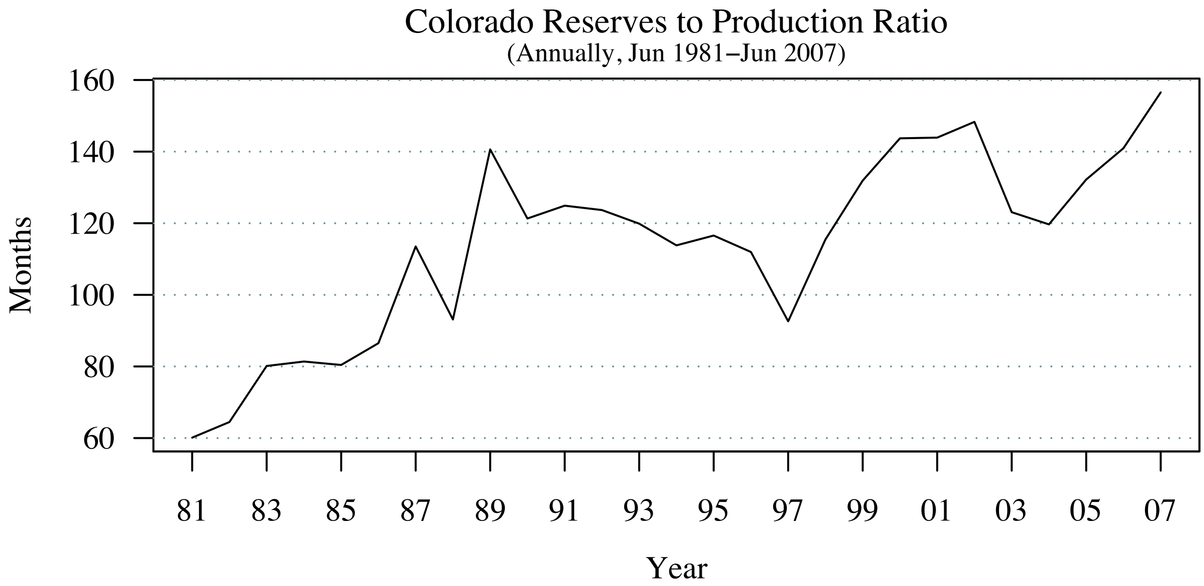


of this resource in perspective, consider that U.S. proven reserves reached a high of 39 billion barrels in June 1970, and as of June 2007 had diminished to about 21 billion barrels (see Figure 7.2.1). Also consider that if total U.S. petroleum products consumed continued its 2008 level of 7.1 billion barrels (see Figure 7.1.2 or Table 7.1.1), then this resource would represent almost 13 years of domestic supply.

In addition to oil production in new areas using well-established (though expensive in the case of

`2005EPAct/InventoryRTC.pdf`. U.S. Department of the Interior, MineralsManagement Service, 2006.

Figure 7.2.10: Data source: *Department of Energy, Energy Information Administration.*



deep-water offshore) technologies, there are emerging technologies such as enhanced oil recovery (EOR) which has the potential to unlock substantial quantities of oil from established but declining reservoirs. According to a joint study conducted by the U.S. Department of Energy (DOE) and Advanced Resources International, perhaps as much as 80–100 billion barrels (about 4–5 times current U.S. proven reserves) can be recovered using EOR technologies (see Table 7.2.4).[631]

Perhaps the most controversial of the remaining potential U.S. petroleum resources is the 19 million acre Arctic National Wildlife Refuge (ANWR), situated in northeast Alaska. Although since the status of ANWR prevents the exploratory drilling and production activity that would be necessary for an estimate as reliable as "proven reserves," the USGS believes the recoverable resource on federal lands may be in the range of 7 to 10 billion barrels, or about one-third to one-half the amount of present U.S. proven reserves. However, petroleum development in ANWR has met with significant opposition. ANWR provides habitat to a wide variety of plants and wildlife, and is considered by many to hold far greater value as a wildlife refuge than as a petroleum resource.[632]

7.3 Production, Upgrading and Refining

Production of shale oil involves heating the kerogen bound within the shale.[633] Ex situ oil shale technologies for disenaging the kerogen from the remainder of the oil shale have some operational history both

[631]See *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery*. Tech. rep. http://www.fossil.energy.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html. Department of Energy and Advanced Resources International, 2005.

[632]See M. Lynne Corn, Bernard A. Gelb, and Pamela Baldwin. *Artic National Wildlife Refuge (ANWR): Controversies for the 109th Congress*. Tech. rep. Congressional Research Service, 2006.

[633]Kerogen is a precursor to crude oil, having not yet been exposed to enough heat for enough time. Heating the kerogen greatly increases the rate of this conversion, allowing a transformation that in natural circumstances would take geologic time to take place within hours or minutes.

Table 7.2.2: U.S., Utah, and Colorado Proven Reserves and Production. Data source: *Department of Energy, Energy Information Administration.*

Year	*US Reserves*	*US Annual*	*UT Reserves*	*UT Annual*	*CO Reserves*	*CO Annual*
1981	29426	3129	190	26	147	30
1982	27858	3157	173	22	169	31
1983	27735	3171	187	30	186	29
1984	28446	3250	172	35	198	29
1985	28416	3275	276	41	198	30
1986	26889	3168	269	39	207	29
1987	27256	3047	284	36	272	29
1988	26825	2979	260	33	257	32
1989	26501	2779	246	28	359	31
1990	26254	2685	249	28	305	30
1991	24682	2707	233	24	329	31
1992	23745	2625	217	23	304	30
1993	22957	2499	228	22	284	29
1994	22457	2431	231	21	271	29
1995	22351	2394	216	20	252	28
1996	22017	2366	237	19	231	25
1997	22546	2355	234	19	198	26
1998	21034	2282	201	19	212	22
1999	21765	2147	268	16	203	18
2000	22045	2131	283	16	217	18
2001	22446	2118	271	15	196	17
2002	22677	2097	241	14	214	18
2003	21891	2073	221	13	217	21
2004	21371	1983	215	15	225	22
2005	21757	1890	256	17	250	23
2006	20972	1862	334	18	274	23
2007	21317	1848	355	20	304	23

within and without the U.S., while experience with in situ technologies is largely experimental rather than commercial. Oil shale production methods are also distinguished by the rate, time, and temperature at which heating takes place, as these parameters determine both the production rate and the hydrocarbon composition of the product. Though studies of the volume of oil in place utilize assay methods for

Table 7.2.3: Potential Oil and Gas from the U.S. Outer Continental Shelf. Data source: Minerals Management Service. Note: Oil is reported in billions of barrels and natural gas is reported in trillions of cubic feet.

Region	***Oil (billion barrels)***	***Natural Gas (Tcf)***
Alaska OCS	26.61	132.06
Atlantic OCS	3.82	36.99
Gulf of Mexico OCS	44.92	232.54
Pacific OCS	10.53	18.29
Total	85.88	419.88

Table 7.2.4: Potential Oil Available by Enhanced Oil Recovery (EOR) Techniques. See *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery*. Tech. rep. http://www.fossil.energy.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html. Department of Energy and Advanced Resources International, 2005 Note: OOIP means Original Oil in Place, and ROIP means Remaining Oil in Place (That is, OOIP minus cumulative production).

Basin/Area	***OOIP***	***ROIP***	***Technically Recoverable***
Alaska	67.3	45.0	12.4
California	83.3	57.3	5.2
Gulf Coast	44.4	27.5	6.9
Mid-Continent	89.6	65.6	11.8
Illinois and Michigan	17.8	11.5	1.5
Permian	95.4	61.7	20.8
Rocky Mountains	33.6	22.6	4.2
Texas: East and Central	109	73.6	17.3
Williston	13.2	9.4	2.7
Lousiana Offshore	28.1	15.7	5.9
Total	581.7	389.9	88.7

quantification, the shale oil product obtained depends on the heating technology employed.[634]

In ex situ production, the shale is mined, either at or beneath the surface. Such methods are established in the mining industry and appear to present few, if any, significant technical challenges.[635] After mining, the shale is crushed and then heated in a retort. In situ production involves applying the heat to the shale in formation and while it therefore does not require mining operations, it does require

[634]See Adam R. Brandt. “Converting Oil Shale to Liquid Fuels with the Alberta Taciuk Processor: Energy Inputs and Greenhouse Gas Emissions.” In: *Energy & Fuels* (2009).

[635]See James T. Bartis et al. *Oil Shale Development in the United States, Prospects and Policy Issues*. Tech. rep. http://www.rand.org/pubs/monographs/2005/RAND_MG414.pdf. The RAND Corporation, 2005.

operations to deliver the heat. Further, unlike ex situ methods, efficiency requires the shale formation occur beneath a "cap" which traps the applied heat. This typically means that in situ processes are best suited for deeply buried deposits such as those found in the Piceance Basin. Given the depth, thickness, and density variation among points in the Green River Formation, a large oil shale industry would likely see production from both in situ and ex situ methods.[636]

Shale oil may require upgrading before being sent to a refiner. Upgrading involves operations which modify the types and proportions of hydrocarbon molecules ("primary upgrading") and operations which remove contaminants like nitrogen and sulfur ("secondary upgrading"). In many proposed in situ and ex situ production configurations, the physical characteristics of the shale oil prevent it from immediately serving as refinery feedstock. In these cases upgrading would be necessary after primary heating in order to obtain a salable product. The most likely upgrading method is hydrotreating. Hydrotreating increases the hydrogen content of the shale oil, which then may command a price premium from refiners (rather than a discount) when compared to a marker crude like WTI.[637] But the extent of necessary upgrading depends on the specifics of the production process, as some processes effectively integrate a portion of what would otherwise be required as upgrading. Shell's ICP technology, for example, results in a product immediately suited as refining feedstock. Table 7.3.1 shows approximate properties of oil derived from thermally processed shale and the approximate properties present after a typical upgrading process. Arabian light crude is shown for comparison.

Table 7.3.1: Source: SF Culberson and PO Rolniak. "Shale Oil Likely Prospect for Refining". In: *Oil & Gas Journal* (1981) and *A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources*. Tech. rep. Utah Heavy Oil Program, Institute for Clean and Secure Energy, University of Utah, 2007.

	Raw Shale Oil	***Upgraded Shale Oil***	***Arabian Light Crude***
API	20–26	38	34
Sulfur, wt %	0.7	0.01	1.7
Nitrogen, wt %	1.9	0.1	0.07
Pour Point, F	70–90	0	−10
Solids, wt %	1–2	—	—
Distillate, vol % at 104–800 F	54	73	67
Distillate, vol % at 800 F +	45	26	32
Distillate, vol % at 1000 F +	7	2	17

Crude oils available to refiners differ in their chemical make-up according to the geology of where they were produced, the methods with which they were produced, and the extent of post-production processing prior to refinement. On the other hand, the product mix yielded by refining depends not only on the chemical properties of the input crude but also on the technology employed by the refiner. Refiners select input crudes based on a consideration of the acquisition costs of the crude, the mix of

[636]See James T. Bartis et al. *Oil Shale Development in the United States, Prospects and Policy Issues*. Tech. rep. http://www.rand.org/pubs/monographs/2005/RAND_MG414.pdf. The RAND Corporation, 2005.
[637]See Adam R. Brandt. "Converting Oil Shale to Liquid Fuels with the Alberta Taciuk Processor: Energy Inputs and Greenhouse Gas Emissions." In: *Energy & Fuels* (2009).

refined products which their technology can yield from this crude, and the range of prices they expect to receive from the refined products. The viability of an oil shale industry which produced feedstock would require that shale oil successfully compete against alternative feedstocks.

Since unrefined oil is of little direct use, the value of a feedstock is based upon the market-determined value of refined petroleum products together with the cost of producing these products from the given feedstock. Light, sweet crudes, for example, usually command a premium over heavy, sour crudes because they are less costly to refine into particularly valuable products such as gasoline.[638]

Though individual refiners have little influence on the price of the products they sell or the aquisition cost of their input crude, they are free to select the technologies in which they invest and use to process the crude. That is, individual refiners have an ability (albeit distinctly limited) to affect the costs of processing a given barrel of input crude into a specified slate of refined products.

For any given crude, the acquisition cost is a function of several characteristics, such as its API gravity, sulfur content, and Total Acid Number (TAN), as well as external conditions, such as refinery capacity and the market for refined products. The aggregate of these characteristics and conditions determine whether processing a particular crude oil into a typical slate of products is more or less costly for refiners as a group. The cost of a given input crude is often stated as a premium or discount to a reference crude, such as West Texas Intermediate (WTI) or Brent. This difference is called a "price differential." Typically heavier crudes, more sour crudes, or crudes with higher TAN trade at a positive price differential to WTI.[639][640]

With respect to both API gravity and sulfur content, conventional crude feedstocks have deteriorated in quality for both U.S. and PADD (Petroleum Administration for Defense Districts) IV refiners. In particular, the API of input crude to U.S. refineries has decreased from an average of 32.5 in 1985 to 30.2 in 2008, with sulfur content increasing from 0.91% to 1.47% during the same time period. Changes in PADD IV inputs were similar, with API decreasing from 36.61 to 32.44 and sulfur content increasing from 0.87% to 1.41%. Thus, PADD IV refiners then and now enjoy a higher average feedstock quality than the U.S. as a whole. (See Figures 7.3.1 and 7.3.2 respectively).

It appears that shale oil would be a low-sulfur feedstock, and thus perhaps not able to make full use of the increased refining capacity for sour crudes. Nonetheless, the general trend toward refining heavier oils, although less economic for simpler refineries lacking the capability to change the molecular structure of the petroleum inputs, probably increases the viability of a U.S. oil shale industry. Partially motivated by the growing inflow of bitumen-derived petroleum from Canadian oil sands operations and partially by high light-heavy price differentials, U.S. refiners continue to invest in "cracking" and "coking" units that offer the ability to better utilize the heavier compounds that remain after distillation. An unintended consequence of enhanced refining capabilities may be an economic environment more favorable for oil shale development.[641]

Alternatively, as continued investment in "cracking" and "coking" units creates more potential buyers of heavy feedstock, increasing demand may act to shrink the price differential that is now motivating that investment. Valero, for example, has focused its refining efforts on heavier crude streams to take

[638]The term "light" refers to the API gravity of the crude, which reflects the density of the crude relative to that of water. The New York Mercantile Exchange (NYMEX) defines a domestic light crude as having an API gravity between 37 and 42. A "sweet" crude, according to the NYMEX definition contains no more than 0.42% sulfur by weight. See http://tonto.eia.doe.gov/dnav/pet/TblDefs/pet_pri_fut_tbldef2.asp.

[639]Meaning that the price of WTI minus the price of the given crude is a positive number.

[640]See [5] for a statistical study of the relationship between observed price differentials and physical markers such as API gravity, sulfur content and TAN. The result of this study is a data-fit model in which it possible to predict the price differential of a given crude and a reference crude (Brent).

[641]See "US refinery investments align with oil sands supplies to 2015". In: *Oil & Gas Journal* (2008).

Figure 7.3.1: Data Source: *Department of Energy, Energy Information Administration.*

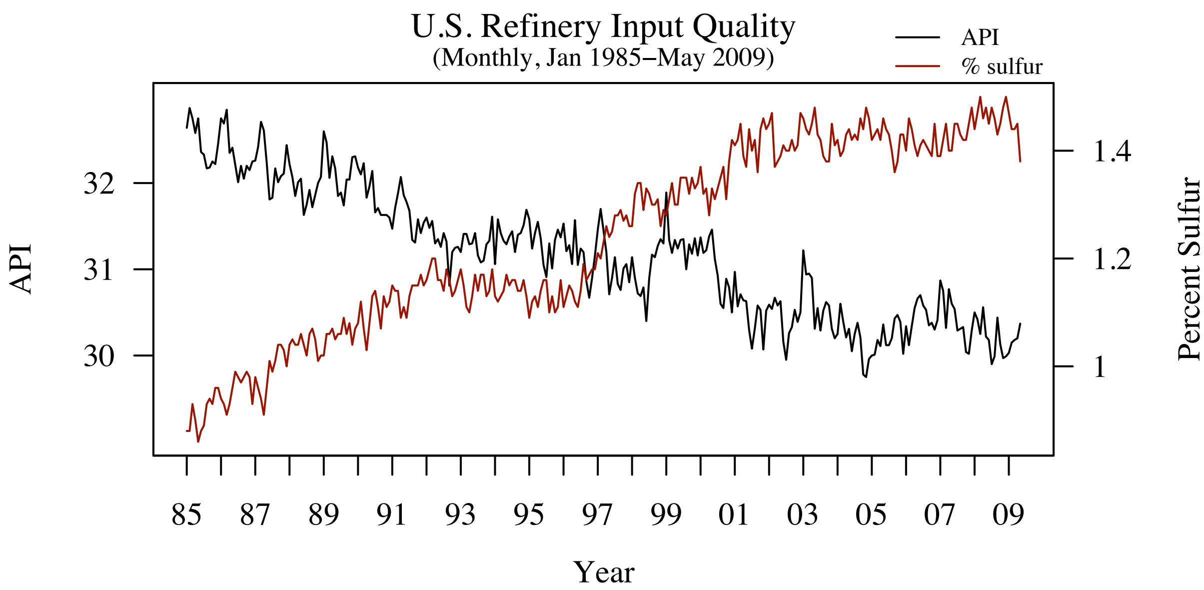
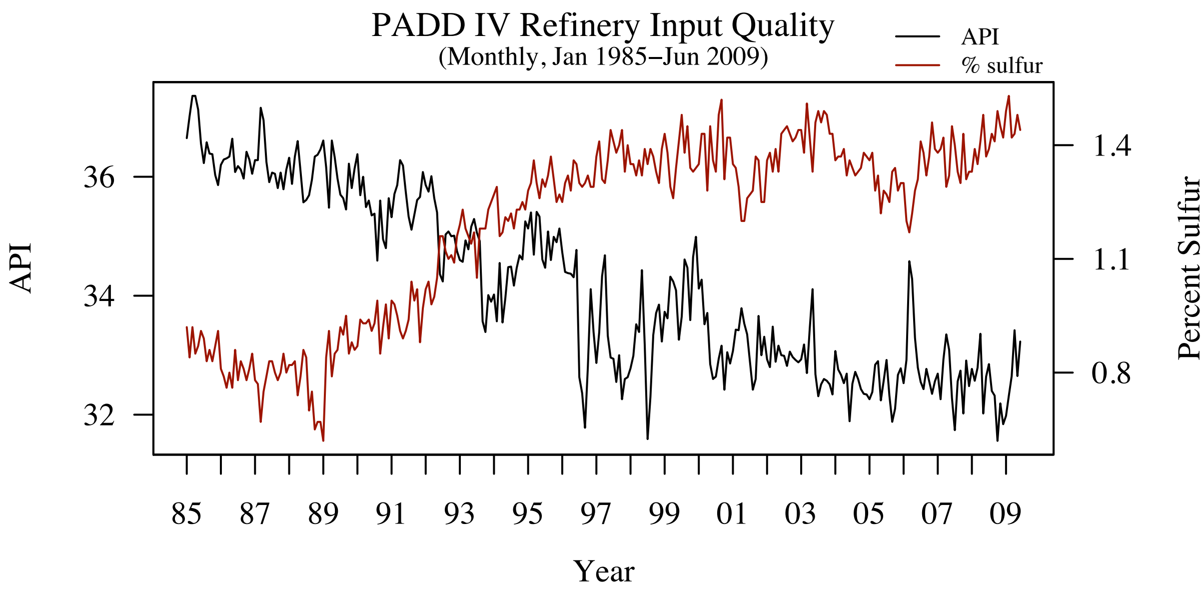


Figure 7.3.2: Data Source: *Department of Energy, Energy Information Administration.*



advantage of what it views as a long-term increase in the light-heavy price differential. But if, in fact, low margins for the providers, rather than for the refiners, leads to decreases in the supply of heavy feedstock, then this differential may close. These issues are discussed in greater detail in Section 8.5.1.

Notable challenges to the viability of a future oil shale industry are the historically high utilization rates, lack of petroleum transportation infrastructure, low rates of profit, and the further adoption of technologies that allow economic processing of lower quality crudes. In light of the low and volatile profit rate prevailing in the refining industry, it is not clear that refining capacity increases needed to accomodate an influx of shale oil feedstock will be forthcoming. The last refinery constructed in the U.S. was completed in Louisiana in 1976. Since then, smaller and simpler refineries have shut down, with increased refining capacity and capability coming from expansion and enhancement of existing facilities.[642] Table 7.3.2 shows the distribution of North American refining capacity by type. Note that although the U.S. has only 20% of world refining capacity, it has 41%, and 39% of the world's catalytic and thermal cracking capacity.

Table 7.3.2: North American Refining Capacity (barrels per calendar day) by Type, 2008. Data source: *Department of Energy, Energy Information Administration*.

Entity	***Distillation***	***Catalytic Cracking***	***Thermal Cracking***	***Reforming***
U.S.	17,443	5,965	2,427	3,699
Canada	2,041	517	139	380
Mexico	1,540	374	0	301
World	85,255	14,604	6,247	11,533

Lack of spare refining capacity poses a challenge to further development of both the conventional and unconventional petroleum industries. In spite of the reprieve provided by the ongoing recession, little excess refining capacity exists in the U.S., especially in PADD IV, the region most likely to contain a future oil shale industry (see Figures 7.3.3 and 7.3.4). PADD IV and Utah refiners in particular presently have little capacity for refining heavier oils (see Table 7.3.3). This lack of spare refining capacity has been blamed in part for the recent volatility in oil prices, which in turn have been blamed for deterring both needed investment in additional refining capacity and new development of resources such as oil shale.[643] See Figure 7.3.5 and Figure 7.3.6 for a view of the distribution of U.S. refining capacity and excess refining capacity over time.

Because present and expected future market conditions are subject to large and sudden changes, so too are price differentials. One illustration that price differentials are subject to market influences beyond those implied by the physical differences between crude streams is that Utah crude, which has historically sold approximately at par with the WTI benchmark, has increased since late 2005-early 2006 with the WTI-to-Utah price differential remaining well above its historical levels (see Figure 7.3.7 for the prices and Figure 7.3.8 for the differential).[644] A 2007 study organized by the Interstate Oil and Gas Compact Commission (IOGCC) suggests the following confluence of events as the cause of similar price deteriorations for crude streams originating in the Rocky Mountain region: growing imports from Canada, combined with very limited outlets for the increasing Rocky Mountain production stimulated by high oil prices.[645]

[642] See Bassam Fattouh and Robert Mabro. "Oil in the 21st Century: Issues, Challenges and Opportunities". In: ed. by Robert Mabro. Chapter 4: The Investment Challenge. Oxford University Press, 2006.

[643] See Bassam Fattouh and Robert Mabro. "Oil in the 21st Century: Issues, Challenges and Opportunities". In: ed. by Robert Mabro. Chapter 4: The Investment Challenge. Oxford University Press, 2006.

[644] Between 1993 and the end of 2005, Utah crude received an average monthly discount of $0.17 to WTI and the minimum and maximum average monthly discounts were −$0.64 (i.e. a premium of $0.64) and $1.43 respectively. Since 2006, Utah crude has received an average monthly discount of $7.17, with minimum and maximum average monthly discounts of $0.8 and $14.98 (all in 2009 dollars).

[645] See *Rocky Mountain Region Crude Oil Market Dynamics*. Tech. rep. Interstate Oil and Gas Compact Commission, 2007.

Figure 7.3.3: Data Source: Data source: *Department of Energy, Energy Information Administration.*

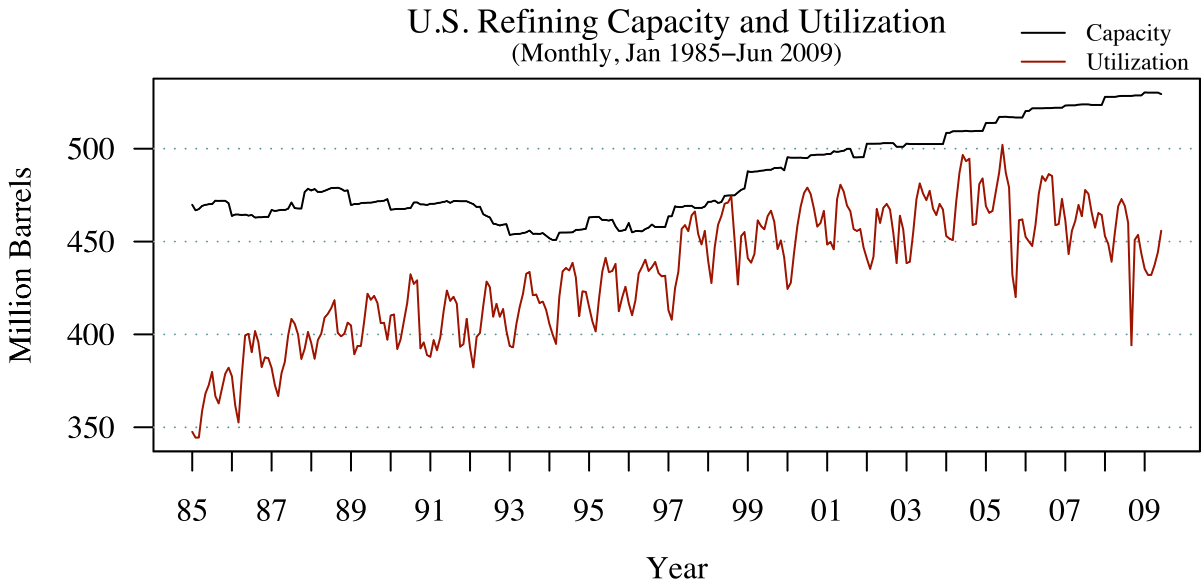
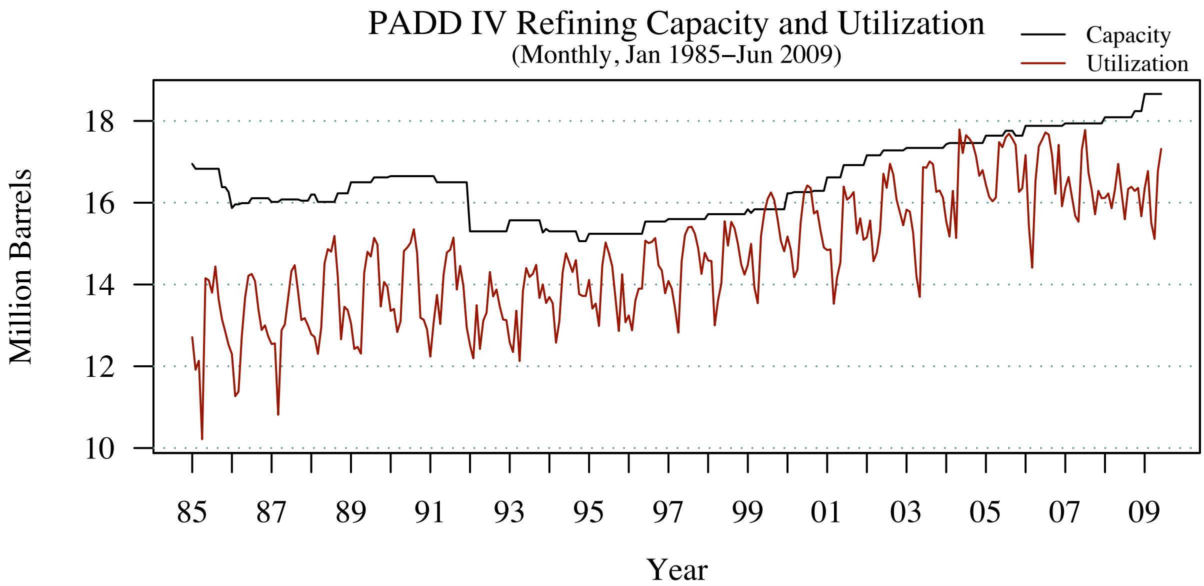


Figure 7.3.4: Data source: *Department of Energy, Energy Information Administration.*



Just as prices paid by refiners for their feedstock crude can depend upon variations in local supply (Section 7.3), petroleum prices can vary in response to changes in global supply. Thus a substantial increase in crude supply owing to development of oil shale would, at least in the short run and in the absence of compensating OPEC production cuts, be expected to lower the average price of crude. While most recent petroleum developments in the U.S. are too small to have a perceptible impact on the market prices for petroleum, and hence on their own viability, this might not be the case for a commercial oil

Table 7.3.3: PADD IV and Utah Refining Capacities by Type, 2009, barrels per stream-day and as percent of U.S. Source: *Department of Energy, Energy Information Administration*

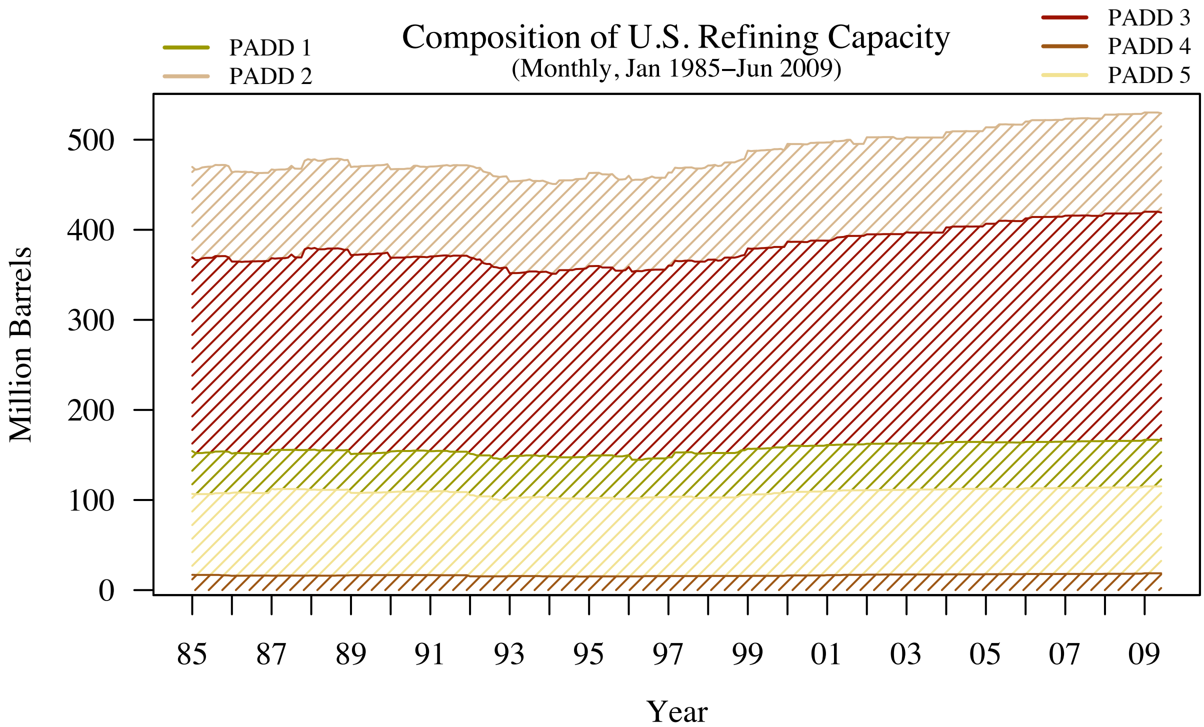
Capacities	***PADD IV*** (%)	***UT***(%)
Total Number of Operable Refineries	17	5
Operating	16	5
Idle	1	0
Atmospheric Crude Oil Distillation Capacity	660700 (3.5)	176400 (0.9)
Vacuum Distillation	249200 (2.9)	37500 (0.4)
Thermal Cracking	88100 (3.3)	8500 (0.3)
Total Coking	88100 (3.4)	8500 (0.3)
Visbreaking	0 (0.0)	0 (0.0)
Other	0 (0.0)	0 (0.0)
Catalytic Cracking—Fresh Feed	201956 (3.2)	57200 (0.9)
Catalytic Cracking—Recycle Feed	4190 (5.3)	2200 (2.8)
Catalytic Hydro-Cracking	17700 (1.0)	0 (0.0)
Distillate	17700 (3.0)	0 (0.0)
Gas Oil	0 (0.0)	0 (0.0)
residual	0 (0.0)	0 (0.0)
Catalytic Reforming	130194 (3.4)	37214 (1.0)
low pressure	47000 (2.0)	0 (0.0)
high pressure	83194 (5.8)	37214 (2.6)
Catalytic Hydrotreating/Desulfurization	559960 (3.5)	132360 (0.8)
Naptha/ reformer feed	149400 (3.4)	45400 (1.0)
Gasoline	43400 (1.8)	8500 (0.4)
Heavy gas oil	98400 (3.6)	0 (0.0)
Distillate fuel oil	253660 (4.5)	71260 (1.3)
Resdiual fuel oil	15100 (1.5)	7200 (0.7)
Fuels Solvent Deasphalting	5600 (1.5)	5600 (1.5)

shale industry of (at least) several million BOPD.

The RAND report estimates that a U.S. oil shale industry producing 3 million BOPD, might cause a 3 to 5 percent reduction in world oil prices.[646] The RAND estimate is based on studies which econometrically estimate the price-sensitivity of demand, and thus is subject to several sources of uncertainty unavoidable in statistical studies. Nonetheless, the likelihood remains that a large oil shale industry would adversely affect the price it receives for its product (even apart from widening differentials aris-

[646] See James T. Bartis et al. *Oil Shale Development in the United States, Prospects and Policy Issues*. Tech. rep. http://www.rand.org/pubs/monographs/2005/RAND_MG414.pdf. The RAND Corporation, 2005.

Figure 7.3.5: Date Source: *Department of Energy, Energy Information Administration*



ing out of more local market constraints), especially in light of current U.S. refining constraints. Further, oil shale production would not go from 0 to several million barrels per day overnight. As production ramped up, its downward influence on world oil prices would increase. Lower oil prices negatively affect not only investment in oil shale projects, but also other oil production projects like EOR.To some degree these losses would offset gains from oil shale production. For oil producers, however, lower oil prices (provided they are compatible with commercial viability) imply lower prices for domestic consumers, who are presumably the recipients of a large majority of the refined products. Assuming shale oil is produced without subsidies above and beyond what is received by other oil-producing activities, the displacement of investment in other production activities is justified. But if shale oil production required even greater subsidies than the alternatives, then the effect would be more expensive production displacing less expensive production.[647] Thus a crucial issue for shale oil production in the PADD IV region, particularly at the scale that would be necessary to make meaningful contributions to oil prices and energy security, would be the ability to gain access to refining markets outside of the region. Achieving this access would necessitate construction of new pipelines leading out of PADD IV.

Due to constraints on transportation to other markets and demand for finished products, even if "ground-to-pipeline" costs are competitive with conventional sources of crude, such costs may not accurately signal large-scale commercial viability of an oil shale industry. This is because these costs alone do not account for the total impact of industrial scale on revenue (i.e. on the price producers would receive from refiners). Further research is needed to assess in detail this regional "carrying capacity" and in what manner, how quickly, and at what cost it might be expanded.

[647] Production would be *less* expensive from the point of view of the producers, but only because part of the expense would then be borne by taxpayers.

Figure 7.3.6: Date Source: *Department of Energy, Energy Information Administration*. Note: Spare capacity has been set to 0 for those months in which utilization exceeded capacity.

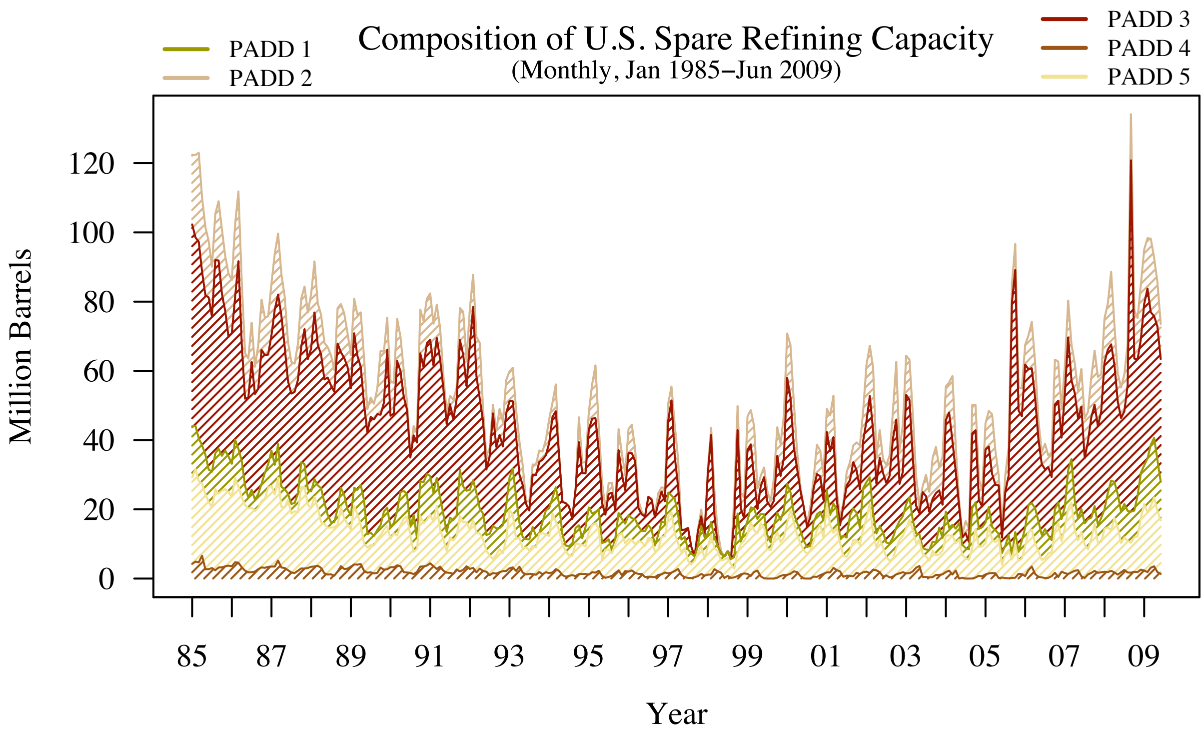
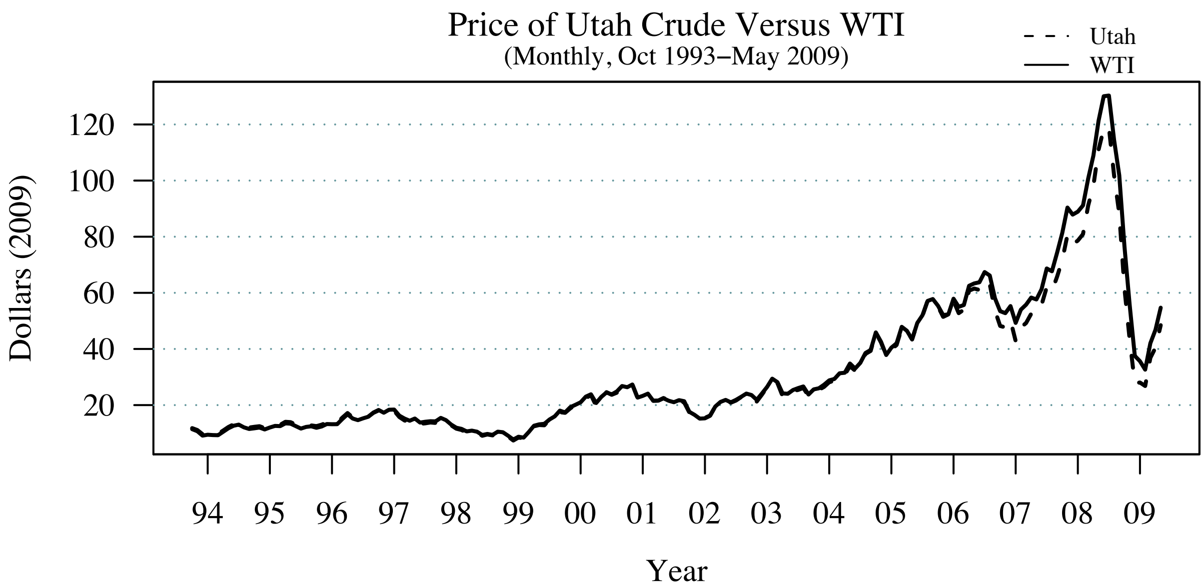


Figure 7.3.7: Data Source: *Department of Energy, Energy Information Administration*.



Transportation costs are another consideration for a commercial oil shale industry. In the Uinta

Table 7.3.4: Refined Product Yield for PADD III, IV, and U.S., percent, 2008. Source: *Department of Energy, Energy Information Administration*.

Refined Product	*U.S.*	*PADD IV*	*PADD III*
Liquified Refinery Gases	4.1	1.6	5.1
Finished Motor Gasoline	44.2	47.4	41.6
Finished Aviation Gasoline	0.1	0.1	0.1
Kerosene-Type Jet fuel	9.7	4.8	9.6
Kerosene	0.1	0.2	0.0
Distillate Fuel Oil	27.8	31.6	28.4
Residual Fuel Oil	4.0	2.2	4.0
Naptha for Petrochemical Feedstock Use	1.0	NR	1.5
Other Oils for Petrochemical Feedstock Use	1.2	NR	2.3
Special Napthas	0.3	0.0	0.5
Lubricants	1.1	NR	1.7
Waxes	0.1	0.0	0.1
Petroleum Coke	5.3	4.6	6.0
Asphalt and Road Oil	2.7	6.1	1.1
Still Gas	4.3	4.6	4.4
Miscellaneous Products	0.5	0.5	0.6
Processing Gain or Loss	-6.4	-3.8	-7.0

Basin, Low pour point oils are currently trucked to Salt Lake City refiners. Transportation costs from Eastern Utah to Salt Lake refiners are currently estimated at about $5 per barrel.[648] While entailing additional costs, transportation out of PADD IV to PADD III (in which there is presently far more spare capacity), might more than compensate with better prices (producer margins).

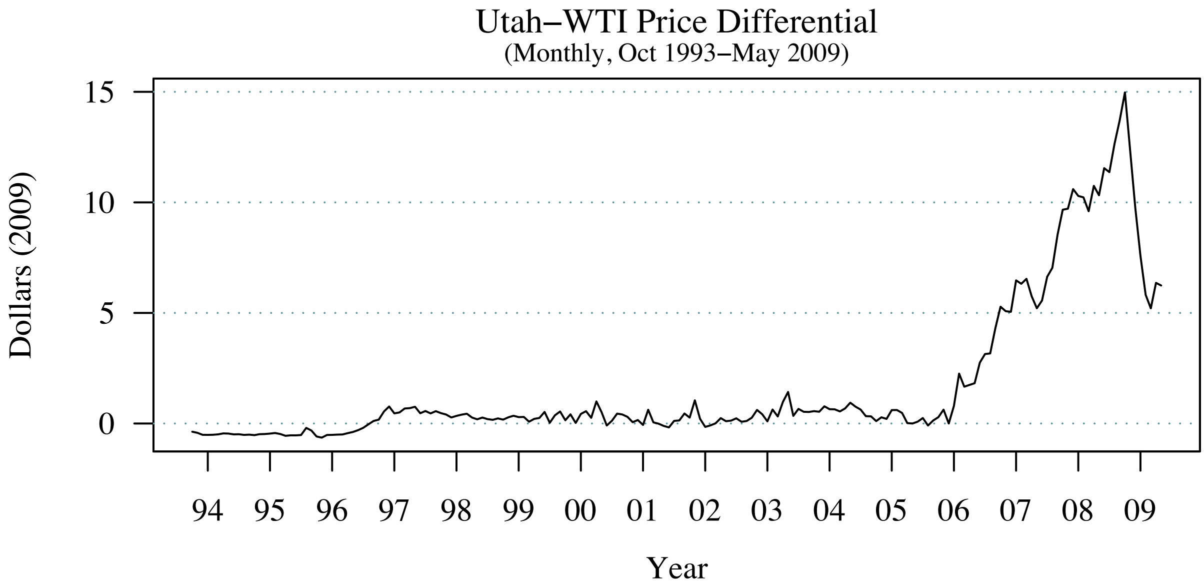
7.4 COSTS

Assessing whether and how to develop a commercial oil shale industry on the public lands requires an examination of the expected profitability of such an industry. Industry profits will reflect the difference between oil shale industry revenues (the primary challeges to which are discussed in the preceding section) and the costs of creating such an industry (along with taxes and royalties). Assesssing estimated construction and operational costs for a domestic oil shale industry is constrained by uncertainties as to viable commercial technologies and the scale of commercial oil shale operations. A broad discussion of the estimated capital and operational costs for a future oil shale industry follows.

A 2005 RAND study estimates the (then) present construction cost of a mining and surface retorting operation at "between $5 billion and $7 billion (2005 dollars) and possibly higher than that," and op-

[648] See *A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources*. Tech. rep. Utah Heavy Oil Program, Institute for Clean and Secure Energy, University of Utah, 2007.

Figure 7.3.8: Data Source: *Department of Energy, Energy Information Administration.*



erations and maintenance costs at "between \$17 and \$23 (2005 dollars) per barrel."[649] These estimates become between 5.5 and 7.75 billion and 18 and 25.5 respectively in 2009 dollars. Although these estimates are based on dated mining and retort operations, they may be a reasonable guide to the costs of development in the Utah portion of the Green River formation, where the resource is much closer to the surface and thus more amenable to such operations.

It is not clear how pertinent such estimates are for emerging processes. For example, Red Leaf Resources, which utilizes a modified in situ process on oil shale resources well-suited to traditional surface mining and retort methods, might experience significantly different costs due to the novelty of their technology. Likewise for a true in situ process, such as Shell's ICP technology. For ICP, DOE estimates that the capital costs of an 100,000 barrel-per-day operation at 8 billion dollars, with annual operating costs of 500 million dollars. These costs include the capital and operating costs for a power plant to produce the electricity needed for ICP (1.2 GW for 100,000/bbl-day). Shell has stated that the ICP process is profitable at oil prices greater than \$30 per barrel.[650]

Capital and operations costs increase if post-production hydrotreatment of the shale is required. A 1981 article by Culberson and Rolniak states that a 50,000 barrel per day hydrotreatment operation would have an approximate cost of 150 million (1980 dollars) and operations costs of about \$7.25/barrel. In 2009 dollars, these costs are about 400 million and \$19/barrel respectively.[651]

Whether produced in situ or ex situ, there will be a need to transport the product to refineries. There will also be a need to transport the refined product to markets. Although this may not be of direct concern to the producer, lack of transport options to markets will likely result in lower prices for shale oil. A large oil shale industry would require additional pipeline capacity not only within PADD IV, but outside

[649] See James T. Bartis et al. *Oil Shale Development in the United States, Prospects and Policy Issues*. Tech. rep. http://www.rand.org/pubs/monographs/2005/RAND_MG414.pdf. The RAND Corporation, 2005.

[650] See *A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources*. Tech. rep. Utah Heavy Oil Program, Institute for Clean and Secure Energy, University of Utah, 2007.

[651] See SF Culberson and PO Rolniak. "Shale Oil Likely Prospect for Refining". In: *Oil & Gas Journal* (1981).

of PADD IV, perhaps to California (PADD V) or the Gulf Coast (PADD III). Although the costs will vary considerably with the state of the macroeconomy and the level of other construction competing for similar materials and labor, estimated pipeline costs are between $600,000 per mile for a 12-inch pipe and and $3.5 million per mile for a 36-inch pipe.[652]

Adding to the already difficult task of estimating costs for a hypothetical oil shale industry is the considerable uncertainty concerning future costs of CO_2 emissions. Although CO_2 regulation of some kind may soon be a reality, the full range of options available to an oil shale developer for mitigating its emissions is not yet known. It is expected that a developer subject to emissions regulations would have an option to either pay a fee per volume of CO_2 or mitigate its emissions through carbon capture and storage (CCS). The uncertainty about future CO_2 emissions costs applies both to the potential fee and to physical mitigation costs such as for CCS.[653]

A life-cyle assessment of greenhouse gas emissions of production from leading in situ and ex situ oil shale production technologies finds that, in the case of the ATP, emissions "are 1.5–1.75 times those of conventional crude oil on a full-fuels cycle basis," while in the case of Shell's ICP, expected emissions are 21–47% higher.

A recent study by Harvard's Kennedy School of Government estimates the costs of carbon capture from a variety of electric power generating technologies. Accounting for the widely observed and acknowledged phenomenon of unit cost reduction through time, they report estimates of the cost to capture of $120—$180 dollars (2008) per ton for first of a kind plants (i.e. new plants which have not experienced over-time cost reductions) and $35—$70 dollars per ton for "Nth of a kind" operations (i.e. for plants whose design and operation can draw upon the experince of its predecessors).[654] These costs, particularly those for mature processes, are quite similar to those obtained through other studies and reported by industry.[655] Note that these costs are for capture only, not for transportation or storage.

Regarding operating experience with CCS systems, the authors state:

> Most of the technologies for CCS are already demonstrated. However, there are worldwide only four large CCS projects currently in operation, plus some smaller projects. Of these four large projects, three capture CO_2 from natural gas production (at Sleipner and Snohvit in Norway and In Salah in Algeria), and captures CO_2 from synthetic natural gas manufacture (in North Dakota). No commercial scale power plants have yet been built with CCS.

One such project is the Mongstad oil refinery, located near Bergen, Norway. This facility is undergoing two stages of construction for post-combustion CO_2 capture. By the completion of stage two (expected 2010), the facility will be capturing 1.2 million tonnes per year from its combined heat and power production and 0.8 million tonnes per year from its catalytic cracking unit, amounting to 80% of its total CO_2 production. The estimated capital cost (combined phases) is 3.5 billion dollars (−30%/+40%

[652] See *A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources*. Tech. rep. Utah Heavy Oil Program, Institute for Clean and Secure Energy, University of Utah, 2007.

[653] In the event that CO_2 emissions are taxed, the price of emissions will be clear, while with a cap and trade system the price of an emissions permit will be set by a market for such permits. A tax resolves price-uncertainty for the developer, but leaves emissions reductions uncertain, while cap and trade resolves emissions uncertainty (the "cap") but leaves the price uncertain.

[654] The authors provide several causal mechanisms. Among these are learning, improved process integration, reduced conservatism (redundancy), and economies of scale. The authors note that cost reductions are uncertain, not guaranteed; there is considerable variation in historically observed over-time cost reductions.

[655] See Mohammed A Al-Juarid and Adam Whitmore. "Realistic Costs of Carbon Capture". Discussion Paper 2009-08, Cambridge, Massachusetts: Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University, p. 49.

estimation error) and with operating costs of 1 to 1.7 billion dollars. On the basis of these, the authors estimate capture costs of between 185 and 255 dollars per ton.[656]

The authors mention EOR as a potential use of the captured CO_2 which could serve to partly offset the expense of capture as well as possibly provide a solution to the problem of storage. They estimate that for a plant which produces 10,000 tonnes of CO_2 per day, which constructs a dedicated 50 mile, 20 inch pipeline (at an assumed capital cost of 80 million dollars and operating cost of $0.12 per Mscf of CO_2), injections wells (at an assumed cost of $5 per barrel of oil recovered), and additional CCS infrastructural capital (200 million dollars), a price of oil net of taxes and royalties above $75 would be sufficient to break even on CCS expenditures.[657]

7.5 Illustration from the Ongoing Canadian Oil Sands Experience

The oil shale of the Green River Formation is often compared to Alberta's oil sands. This is partly because of the similar magnitudes of their petroleum resources, with the oil sands area containing an estimated 1.7 billion barrels of oil in place, 315 billion barrels ultimately recoverable, and 170 billion barrels of remaining proven reserves. This compares to 1.5–1.8 trillion barrels estimated in-place and approximately 800 million barrels ultimately recoverable in the Green River Formation.[658]

In 2003, when oil from the oil sands first became recognized as 180 billion barrels of proven reserves, they immediately became second in size only to Saudi Arabia's then 262 billion (267 million as of 2009) barrels.[659] Though an average 1.31 million BOPD were produced from the oil sands in 2008, production is still only very slight in comparison to the reserve base.[660][661] As illustration, consider that at the current rate of production, Alberta's oil sands would produce for about 350 years, compared to about 65 years for Saudi Arabia, which has lately produced at an average rate of approximately 10 million barrels per day.[662] Or, since current U.S. petroleum consumption is about 20 million BOPD, (7.3 billion barrels per year), another way to state the scale of the oil sands resource is that it could provide the entire current level of U.S. oil consumption for approximately 20 years.

The Canadian Association of Petroleum Producers (CAPP) states that, given the projects currently producing, projects under construction, and projects not yet started developing "at a pace similar to historical and current trends" it expects production from the oil sands to increase to 2.2 million BOPD

[656]See Mohammed A Al-Juarid and Adam Whitmore. "Realistic Costs of Carbon Capture". Discussion Paper 2009-08, Cambridge, Massachusetts: Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University.

[657]See Mohammed A Al-Juarid and Adam Whitmore. "Realistic Costs of Carbon Capture". Discussion Paper 2009-08, Cambridge, Massachusetts: Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University, p. 38.

[658]See James T. Bartis et al. *Oil Shale Development in the United States, Prospects and Policy Issues*. Tech. rep. `http://www.rand.org/pubs/monographs/2005/RAND_MG414.pdf`. The RAND Corporation, 2005.

[659]See the EIA's international petroleum reserves data at `http://www.eia.doe.gov/emeu/international/contents.html`.

[660]See *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009 at 3.

[661]With cumulative conventional production at 16 billion barrels and remaining reserves of 1.5 million, crude from the oil sands now occupies an increasingly important position in Alberta's total crude output. In 2008, Alberta produced an average 503 thousand BOPD of conventional crude. Thus the 1.31 million BOPD from oil sands operations constitutes 72% of Alberta's total "conventional plus raw bitumen" production.

[662]Thus, Alberta is currently producing from oil sands at a rate of about 0.3% of its oil sands reserves. For comparision, between 1998 and 2008, annual Saudi Arabian production averaged 1.4% of its reserves while over the same time the U.S. produced from its reserves much more rapidly at the average rate of 9.4% (note, however, that during this time Saudi reserves increased from 262 to 267 billion, while U.S. reserves declined from 21 to 19 billion.

in 2015 and 3.3 million BOPD in 2025.[663][664] If the CAPP forecast for 2025 is realized, Alberta would still be producing from its oil sands at a rate that would allow well over 100 years of production even if original proved reserves do not increase beyond their 2003 level of 180 billion barrels.[665] Furthermore, production at a rate of 3.3 million BOPD would represent only about 0.8% of proven reserves—still only slightly more than half Saudi Arabia's current rate of production out of reserves and less than one-tenth the current U.S. rate. Thus it would appear the Canadian oil sands industry has alot of room to grow.

The economic experience of the oil sands industry illustrates some of the opportunities and challenges facing development of a large-scale oil shale industry in the U.S. Although there are a number of such issues which may be relevant to planning a federal commercial oil shale leasing program (e.g. U.S. versus Albertan royalty and taxation regimes and the provincial government's early and persistent cooperative role in research and development of oil sands technology), this section focuses on the production constraints facing oil sands producers from market limitations as it seems highly likely that a rapidly growing U.S. oil shale industry would face similar challenges.

Production costs were discussed in Section 7.4. These are simply the developer's capital and operations expenses. But the economic viability of an oil shale industry is a larger issue than just the unit cost of production. In particular, any oil shale developer will need to consider the unit revenue of production. If the costs are "how much it can be produced for," then the revenue is "how much it can be sold for." In discussions of the viability of a proposed method for producing oil, it is typical to take the unit revenue as fixed and given. Then, on the basis of the given unit revenue and estimated costs, one can determine the rate of return on the project. If the implied rate of return compares favorably with other projects having similar risk, then the project could be considered viable. But the unit revenue is just the price the producer receives from the refiner; hence it increases when the price-differential decreases and decreases when the differential increases. Declining differentials benefit producers at the expense of refiners. The historical average bitumen-WTI price differential is about 50%, meaning that market value of raw bitumen is about 50% of the market value of the benchmark WTI.[666] Complex independent refiners benefit from lower bitumen-WTI differentials, while independent bitumen producers benefit from higher differentials. As stated in a recent report of the Albertan government's Energy Resources Conservation Board (ERCB):

> Project viability depends largely on the cost of producing and transporting the products and on the market price for bitumen and SCO. Other factors that bear on project economics are refining capacity to handle bitumen or SCO and competition with other supply sources in

[663] See *Crude Oil Forecast, Markets & Pipeline Expansions*. Tech. rep. Canadian Association of Petroleum Producers, 2009 at 4.

[664] A recent report by Cambridge Energy Research Associates (CERA) provides forecasts for oil sands production conditional largely on future macroeconomic circumstances. Under the circumstances least favorable to oil sands production, CERA estimates production reaching 1.8 million BOPD in 2013, but only 2.3 million BOPD in 2035. Under circumstances most favorable to long-run production, CERA forecasts production reaching 6.3 million BOPD in 2035 (forecast for 2013 not provided in this scenario). In an intermediate scenario, CERA estimates 2020 production at 2.9 million BOPD, but with stagnant demand leading to 2035 production levels of 3.0 million BOPD. See *Growth in the Canadian Oil Sands: Finding the New Balance*. Tech. rep. Cambridge Energy Research Associates, 2009.

[665] If production increased at a constant rate between its actual 2008 level of 1.31 million BOPD and its forecast 2025 3.3 million, and proven reserves did not increase from its 2008 level of 170 billion barrels, then daily production would increase by 120,000 barrels per year (annual production by 43 million per year) and cumulative production between 2008 and 2025 would be 14.3 billion barrels—6.2 billion of which due to production rate growth—leaving 156 billion barrels of reserves and $156/(3.3 \times 366/1000) = 130$ years of remaining production at a production rate equal to the 2025 level.

[666] See *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009.

U.S. and Canadian markets[667]

Citing the source of greater price differentials, ERCB states:

> Wider differentials between bitumen and Alberta light-medium are due to short-term increases in the supply of bitumen without an increase to the refinery capacity that can process this crude in North America … While seasonal variations have always existed, the bitumen/light-medium spread may be wider than heavy/light-medium for quite some time due to the lag between increasing production of bitumen without the coincident increase in upgraders and refinery capacity capable of processing bitumen.[668]

As discussed in Section 7.3, the observed values of the differential are not influenced solely by the physical properties of bitumen and WTI. Neither does the historical average of 50% represent an underlying "true" average about which the observed values fluctuate in response only to short-term factors. The value of a barrel of bitumen to a refiner is based on the net value of the refined products which it can yield.[669]

High differentials have provided an incentive for oil sands operators to seek markets beyond the U.S. To this end these are a number of pipeline projects either in planning or in works.[670] Anticipation of the subsequent increase in refining capacity for heavier crude leads ERCB to expect smaller differentials in the future:

> Forecasts for the price of heavy crude and bitumen can be estimated by applying the appropriate average differentials to the netback price of WTI at the Alberta wellhead. The ERCB expects the bitumen/light-medium differential to average 58 per cent over the forecast period. Wider differentials provide incentives for investment in additional upgrading capacity in North America. The heavy/light-medium differential is expected to remain near the five-year trend, at 68 per cent.[671]

In summary, there is an ongoing feedback between the upstream and downstream oil sands industries (much of the downstream industry being U.S.-based refiners) in which the industry-wide rate of production is constrained by the product market. A deteriorating producer's price is the signal that this market limit is being approached. This price response renders production less profitable but refining (or retail, or even end consumption, depending on the extent of integration) *more* profitable for this crude stream. The immediate affect is to encourage installation of increased capacity to refine this crude—enlarging its market. As the refining market enlarges, the limit that bears on upstream producers is pushed out and producer's prices improve. The process continues in this fashion, but is ultimately checked by the market for refined goods (e.g. gasoline).

[667] See *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009 at 57.

[668] See *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009.

[669] The "net value" is the market value of the refined products derived from the crude by way of the refining process, less the sum of the cost of the crude and processing. Thus, "net value" is the operating profit of refining a given barrel of crude.

[670] Alberta is increasing pipeline capacity by 415,000 bbl/d for the in-province market, and 2,265,000 bbl/d for the export market. Refiners in PADD III, PADD V and East Asia are the targets of some of this increase. This increase is 15% and 85% respectively. *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009. "In addition to increased crude oil pipeline capacity, the Enbridge Southern Lights pipeline and Gateway Condensate Import pipeline will be dedicated to moving 53 103 m3/d of condensate (diluent) from Chicago and from British Columbia (B.C.) to the Edmonton area, which will aid in easing the current tight supply of diluent to the oil sands."

[671] See *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*. Tech. rep. Energy Resources Conservation Board, 2009.

7.6 Conclusion and Recommendations

In time, technological processes should enable less costly production of shale oil. And, all else being equal, this of course improvesoil shale's commercial prospects.[672] But the commercial prospects of an oil shale industry will also depend greatly on the demand for liquid-fuel end-products like gasoline, diesel, and jet fuel. Though it appears unlikely that demand for these products will fall substantially in the next few decades, weaker demand for fuels—though it may provide national benefits in terms of energy security—would limit the scope of a domestic oil shale industry.[673]

Policymakers will want to be aware that there will exist a market-limit on the viable size of an oil shale industry that will likely resolve itself only slowly. The illustration of a possible production path given at the beginning of Section 7.2 is probably optimistic. In the meanwhile, policymakers might consider continuing policies like the RD&D program that allow oil shale developers to resolve some of the uncertainties that otherwise serve to inhibit the pre-commercial and technological activities needed to preserve the opportunity for future oil shale development.

[672] Some additional costs, such as for CO_2 emissions/mitigation, may be present in the future.

[673] See Section 8.2.1.

CHAPTER 8

SOCIOECONOMIC ISSUES

Any future oil shale industry in the U.S. would likely take place within the area associated with the Green River Formation. This region, encompassing northeastern Utah and northwestern Colorado, includes Moffat, Rio Blanco, and Garfield Counties on the Colorado side and Duchesne and Uintah Counties on the Utah side. This chapter surveys the socioeconomic challenges facing large-scale development of an oil shale industry in this region of northeastern Utah and northwestern Colorado. Although remote and sparsely populated at present, the potential impact of oil shale development on this region's economic and social conditions cannot be overlooked. Indeed, in many respects these conditions further the need for such analyses.

Socioeconomic issues are a particularly important concern for oil shale development for two primary reasons. First, though the imbalanced growth rates between industrial development and infrastructure such as housing, hospitals, roads, and schools are nearly ubiquitous with rapid mineral development, early, consistent, and thorough coordination between industry and government and civic groups can mitigate the imbalance and its adverse consequences. As the potential failure of infrastructural growth to keep up with industrial growth is an impediment to large-scale commercial oil shale development, it would not have been out of place alongside the market constraints addressed in the section on Marketing. This section discusses the pertinent conceptual issues and brief case studies of past developments to illustrate how these issues have developed and resolved in practice. Though only a small number of cases are discussed, they are selected to be representative members of a larger number of cases, and contain the salient features of growth of the sort that would likely accompany rapid oil shale development.

Secondly, apart from the issue of how best to manage a given rate of growth, is the question of how development should proceed. Development of an oil shale industry entails a flow of costs and benefits, some accruing directly to the industry itself, others to the public. The net value created from oil shale development to any individual, or to a group of individuals, will not necessarily agree with the aggregated net benefit. Some individuals and groups will gain more than, and possibly at the expense of, others. Thus there is likely to be a corresponding difference of opinion among the public and their representatives as to how oil shale development should proceed. The public policy question is: what rules should be set such that development proceeds equitably and with a broad consensus? Whereas balanced growth between the public and private sector ensures that development can take place at the optimal pace, careful consideration of the distribution of costs and benefits of development determines what rate is optimal.

8.1 Direct Economic Impacts of Development

The benefits to developing an oil shale industry on the scale of a few million barrels per day are potentially very large—dwarfing the benefits provided to these regions by their conventional oil and gas industry. Such benefits are in terms of the distribution of corporate profits to shareholders, and jobs created, with the attendant creation of personal income for those employed and tax revenue for the local, state and national government. The actual benefits of this sort will depend largely on the scale of the industry and the mix of technologies employed[674]. Using employment multipliers that estimate the total number of jobs created from industries of size 1–3 MMbbl/d, RAND estimates 100,000 to 300,000 jobs could be created (i.e. from direct employment, from those industries that would directly supply this industries, and from industies spurred on by the spending of wage income earned from this additional employment). As the RAND study points out, the net effect on job creation would depend on the state of the regional and macro economy.

Domestic production has opportunity costs: Resources like capital and labor that are allocated to increased domestic production are then not available for other productive activities. Even in times with high unemploment rates, some of the types of capital and labor an oil shale industry would require is specialized and could be relatively scarce. In this case, industry could get the resources it needs but only by paying an amount sufficient to outbid their alternative users.

8.2 Demographic, Social and Economic Background of the Affected Areas and Communities

Utah's population has grown steadily from an estimated 700,000 in 1950 to 2.7 million in 2008—a nearly four-fold increase in almost 60 years. This ranks Utah as the 34th most populous state, immediately ahead of Nevada and just behind Kansas. Utah ranks as the 12th largest state in terms of land area at 82,000 square miles. Hence, the population density in Utah is among the lowest in the U.S. (ranked 10th, and again between Nevada and Kansas) with an average 33 persons per square mile.

Colorado's population increased three-fold from 1,325,089 in 1950 to just over 5,010,396 in 2008. This ranks Colorado as the 22nd most-populous state; more populated than Alabama, less than Minnesota. Colorado is 8th largest in land area at 104,000 square miles; larger than Wyoming, smaller than Nevada. Colorado, with a population total nearly double Utah's but with land area about one-fourth larger, has a population density about 50% greater at 48 persons per square mile: more dense than Maine, less dense than Oklahoma.

What is not apparent in the foregoing state-level statistics is the uneven distribution of the population across each of these two states. Compared to the other lower 48 states, the western interior states exhibit far greater regional clustering of population, explained in part by access to natural resources and infrastructure. From Table 8.2 observe that Salt Lake County, Utah contains less than 1% of Utah's land area while holding almost 40% of its population.

Consider an eastern state such as Pennsylvania. Pennsylvania's two largest counties, Allegheny and Philadelphia, which contain the cities of Pittsburg and Philadelphia respectively, combine to account for 2% of the land area and 22% percent of the population of Pennsylvania[675].

Developing an oil shale industry to a scale of several million barrels per day in sparsely populated areas such as those of northeastern Utah and northwestern Colorado will be challenging for industry,

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674 Since some technologies are more labor-intensive than others and hence generate more jobs.

675 In 2000, the total populations of Pennsylvania, Philadelphia County and Allegheny County were 12,448,279, 1,448,394, and 1,281,666, with land areas 46,055, 142, and 745 square miles respectively.

Table 8.2.1: County population and population densities. Note: "Density" is given as the average number of persons per square mile.

County	*Population (2008, thousands)*	*Area (sq mi)*	*Density*
Salt Lake County, UT	1031	808	1276.0
Duchesne County, UT	16.8	3256	5.2
Uintah County, UT	30.4	4499	6.8
Denver County, CO	606.6	159	3815.1
Garfield County, CO	57	2956	19.3
Moffat County, CO	14.1	4751	3.0
Rio Blanco County, CO	6.5	3223	2.0

governments and citizens.[676]

The Utah Population Estimation Committee (UPEC)—a group organized within the Utah Governor's Office of Planning and Budget—projects Utah's total population at 3.6 million in 2020, 5.2 million in 2040, and 6.8 million in 2060.

Buried in the aggregate of State-level population data are the unique population patterns of Utah's rural counties. In the oil and gas rich Duchesne and Uintah Counties, in and out-migration dynamics are substantially influenced by the ebbs and tides of the fortunes of the oil and gas industry. The increased activity that follows high oil and gas prices attracts migrants to the area for employment, and low oil prices dampens the same activities and acts to push workers out of the county in search of other employment. See Figures 8.2 and 8.2 for trends in net in-migration to Uintah and Duchesne Counties. Salt Lake County trends are provided for reference to trends to a non-rural area.

[676] Stating that "A million b/d of shale oil production would likely lead to a population of over 250,000 in a rugged area of western Colorado that now has a population of some 11,000 in a 3-county area." (note that "now" is 1981), a 1981 article by Culberson and Rolniak further notes that "An influx of people on this scale will severely strain housing and community services. These problems can be worked but it will take a major planning and implementation effort. This will also affect the rate of development."SF Culberson and PO Rolniak. "Shale Oil Likely Prospect for Refining". In: *Oil & Gas Journal* (1981).

Table 8.2.2: State population and population densities.

State	*Population (2008, thousands)*	*Area (thousand sq mi)*	*Density*
Alabama	4661.9	50.8	91.8
Alaska	686.3	570.4	1.2
Arizona	6500.2	113.6	57.2
Arkansas	2855.4	52.1	54.8
California	36756.7	156.0	235.6
Colorado	**4939.5**	**103.7**	**47.6**
Connecticut	3501.3	4.8	729.4
Delaware	873.1	2.0	436.6
D.C.	591.8	0.1	5918.0
Florida	18328.3	53.9	340.0
Georgia	9685.7	57.9	167.3
Hawaii	1288.2	6.4	201.3
Idaho	1523.8	82.8	18.4
Illinois	12901.6	55.6	232.0
Indiana	6376.8	35.9	177.6
Iowa	3002.6	55.9	53.7
Kansas	2802.1	81.8	34.3
Kentucky	4269.2	39.7	107.5
Louisiana	4410.8	43.6	101.2
Maine	1316.5	30.9	42.6
Maryland	5633.6	9.8	574.9
Massachusetts	6498.0	7.8	833.1
Michigan	10003.4	56.8	176.1
Minnesota	5220.4	79.6	65.6
Mississippi	2938.6	46.9	62.7
Missouri	5911.6	68.9	85.8
Montana	967.4	145.6	6.6
Nebraska	1783.4	76.9	23.2
Nevada	2600.2	109.8	23.7
New Hampshire	1315.8	9.0	146.2
New Jersey	8682.7	7.4	1173.3
New Mexico	1984.4	121.4	16.3
New York	19490.3	47.2	412.9
North Carolina	9222.4	48.7	189.4
North Dakota	641.5	69.0	9.3
Ohio	11485.9	41.0	280.1
Oklahoma	3642.4	68.7	53.0
Oregon	3790.1	96.0	39.5
Pennsylvania	12448.3	44.8	277.9
Rhode Island	1050.8	1.0	1050.8
South Carolina	4479.8	30.1	148.8
South Dakota	804.2	75.9	10.6
Tennessee	6214.9	41.2	150.8
Texas	24327.0	261.9	92.9
Utah	**2736.4**	**82.2**	**33.3**
Vermont	621.3	9.2	67.5
Virginia	7769.1	39.6	196.2
Washington	6549.2	66.6	98.3
West Virginia	1814.5	24.1	75.3
Wisconsin	5628.0	54.3	103.6
Wyoming	532.7	97.1	5.5

Graphics follow which depict population levels and their growth rates for the U.S. as a whole, and for the counties of Utah and Colorado most likely to be impacted by oil shale development in the U.S. As the figures point out, economic growth is a powerful influence on regional population growth. In fact, though national population growth rates have largely broken from an early (through late 1950s) correlation with economic growth, such a linkage is still apparent more recently among regions of the U.S. considered in this report.[677] Especially prominent among the two eastern Utah counties and three western Colorado counties is the seeming dominance of energy prices in population growth. For each of these counties, note the growth rate decline (especially sharp for the western Colorado Counties which had experienced the bulk of the oil shale boom) recorded from 1982 to 1983 and again from 1983 to 1984. These declines occured during the time when the U.S. was just pulling out of the 1980–1982 recession. However, that period, and the seven or so years preceding it, saw sustained high oil prices and consequently the local economies were booming.

[677] For all graphs, filled dots indicate census years while open dots which occur before a census year (i.e. all open dots prior to year 2000) indicate an intercensal estimate and open dots which do not occur before a census year (i.e. all open dots after 2000 and until 2010) indicate a postcensal estimate. Census-year figures can be regarded as actual population counts while other-year figures are estimates of the true population characteristic. Postcensal estimates for a given year are based only on census data prior to that year, while intercensal estimates use census data from the both the immediately prior and immediately posterior census. For example, prior to 2000 census, the 1999 population estimates were based on the 1990 census (thus, these are postcensal estimates). After the 2000 census data became available, the estimates for 1999 were updated so that they became an intercensal estimate.

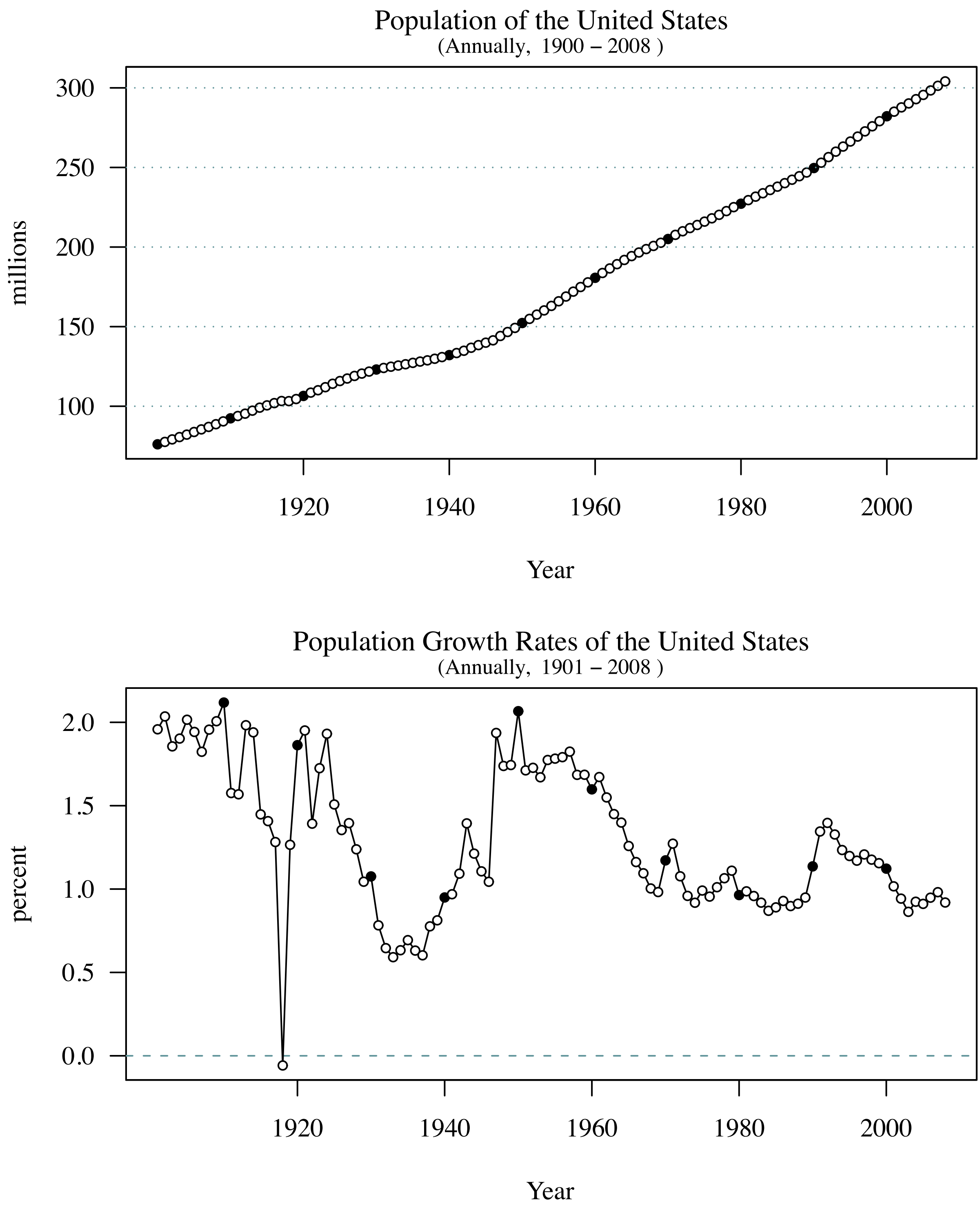


Figure 8.2.1: Data Source: U.S. Census Bureau. Note: Filled dots indicate census years (see Footnote 677). The dramatic decline in the population growth rate from 1918 to 1919 is due to the flu pandemic of 1918. Note also the growth rate declines of the Great Depression years and their rebound during the postwar economic boom.

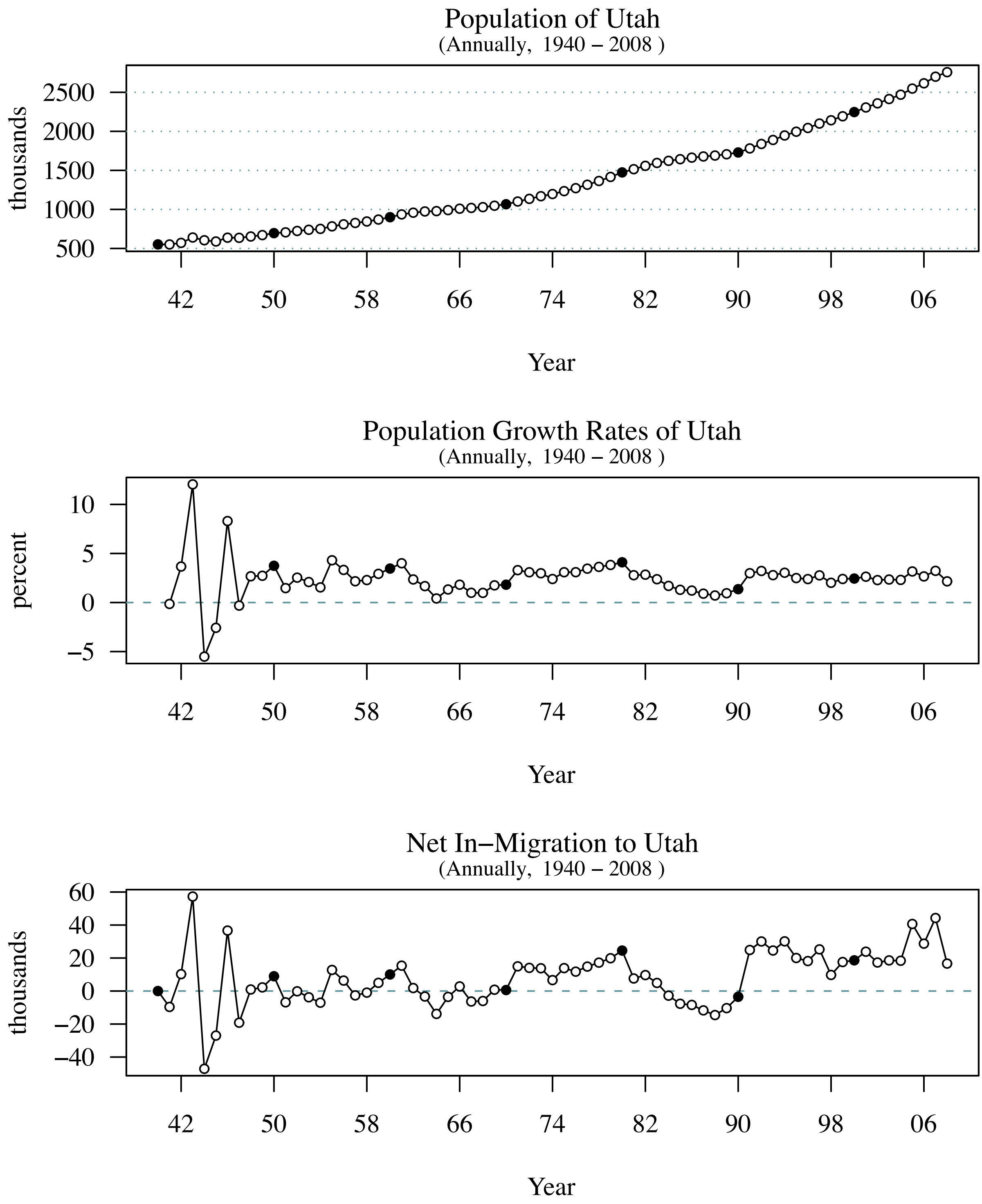


Figure 8.2.2: Data Source: U.S. Census Bureau and Utah Population Estimates Committee. Note: Filled dots indicate census years.

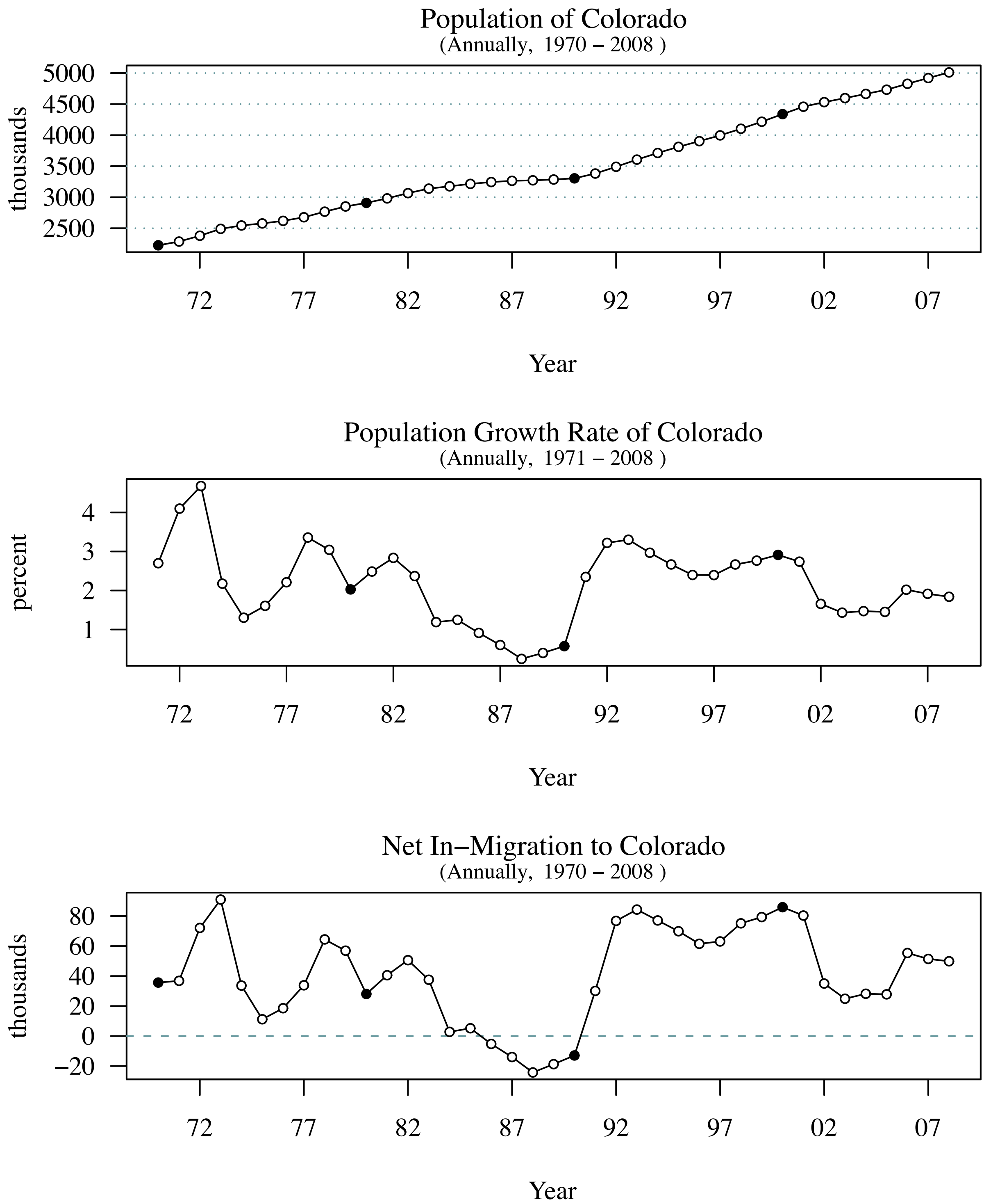


Figure 8.2.3: Data Source: U.S. Census Bureau and Utah Population Estimates Committee. Note: Filled dots indicate census years.

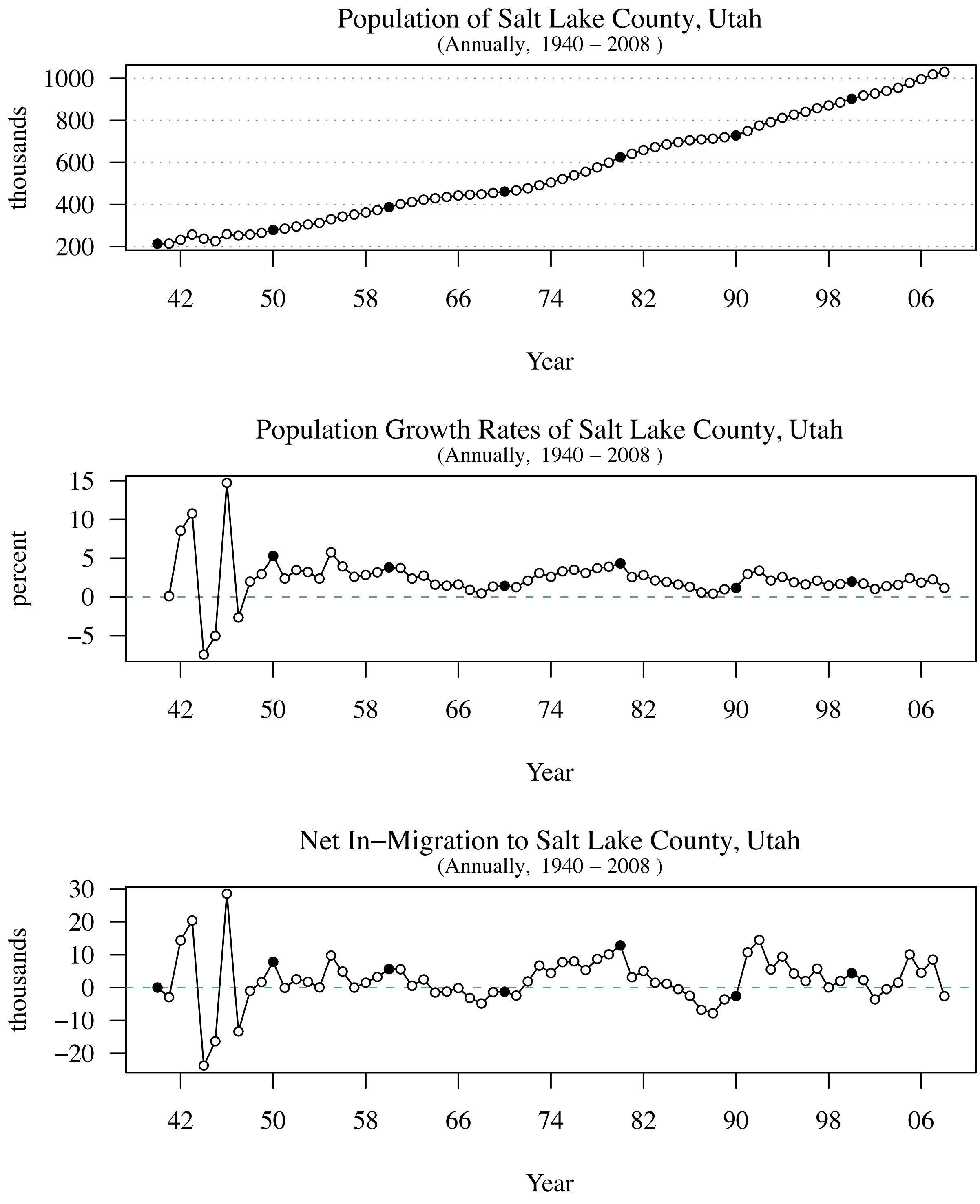


Figure 8.2.4: Data Source: U.S. Census Bureau and Utah Population Estimates Committee. Note: Filled dots indicate census years.

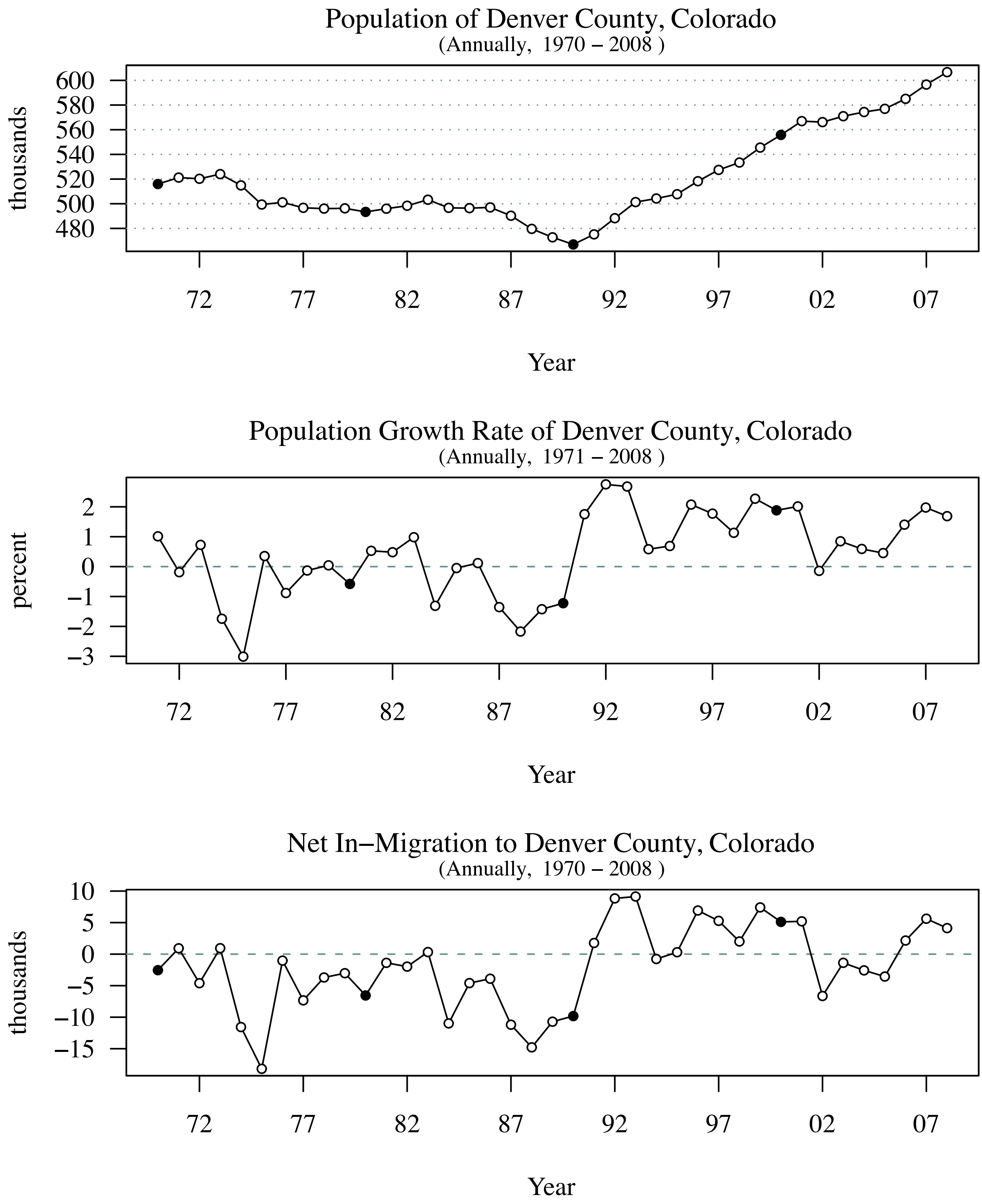
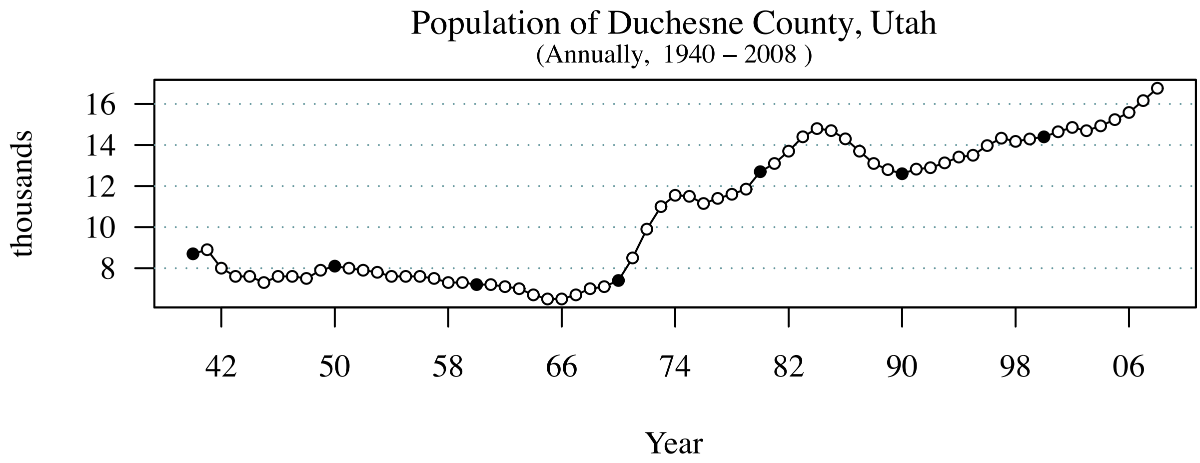
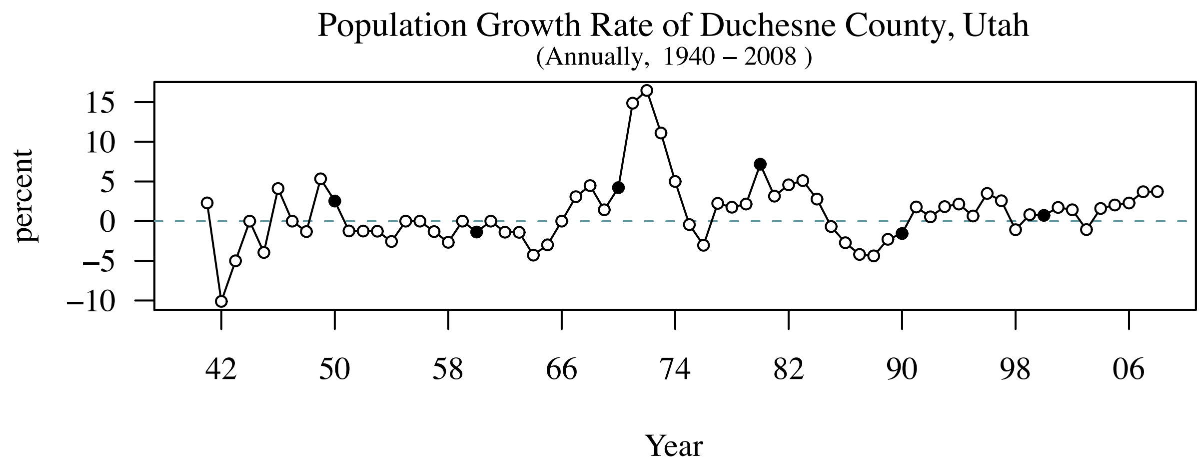


Figure 8.2.5: Data Source: U.S. Census Bureau and Colorado's State Demography Office. Note: Filled dots indicate census years.





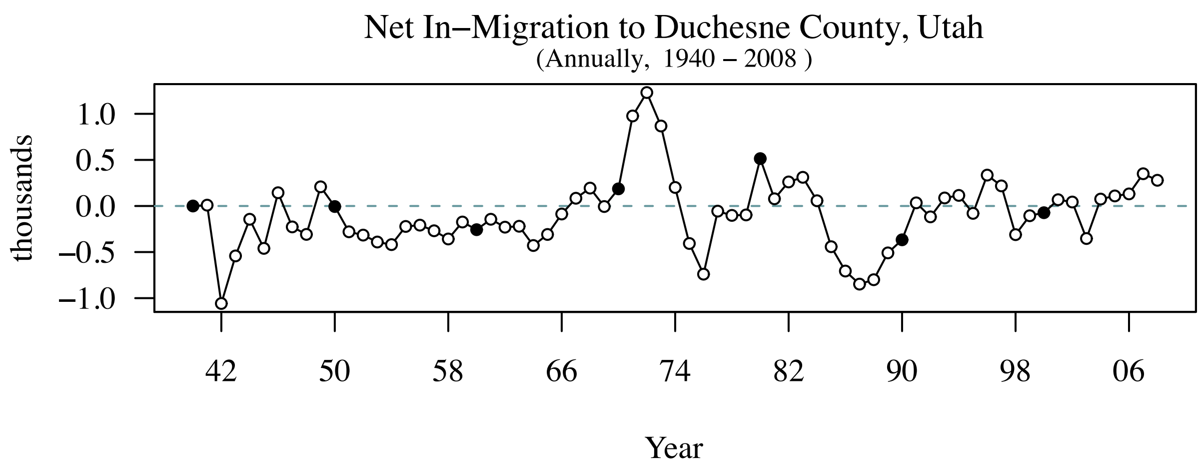


Figure 8.2.6: Data Source: U.S. Census Bureau and Utah Population Estimates Committee. Note: Filled dots indicate census years.

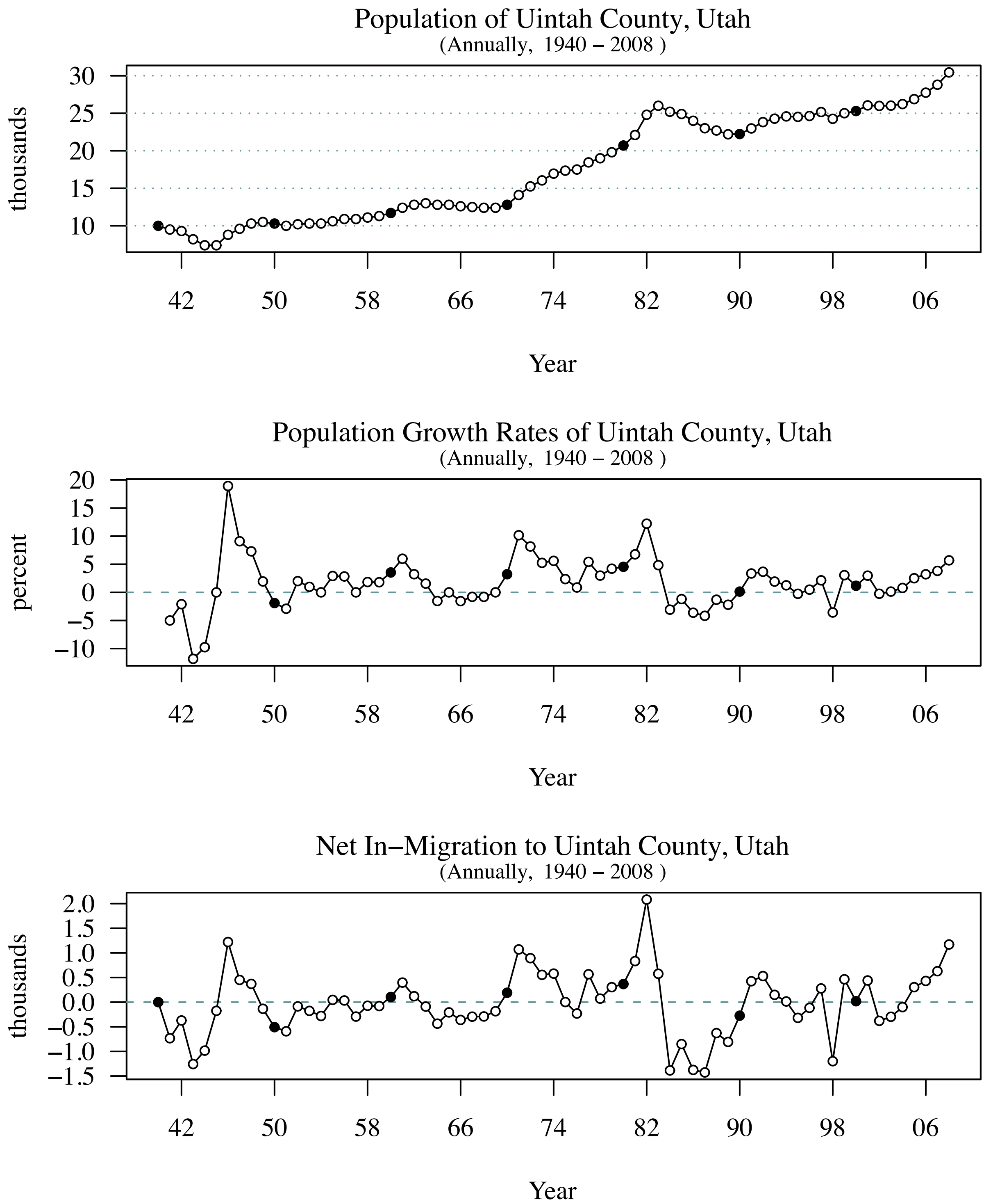


Figure 8.2.7: Data Source: U.S. Census Bureau and Utah Population Estimates Committee. Note: Filled dots indicate census years.

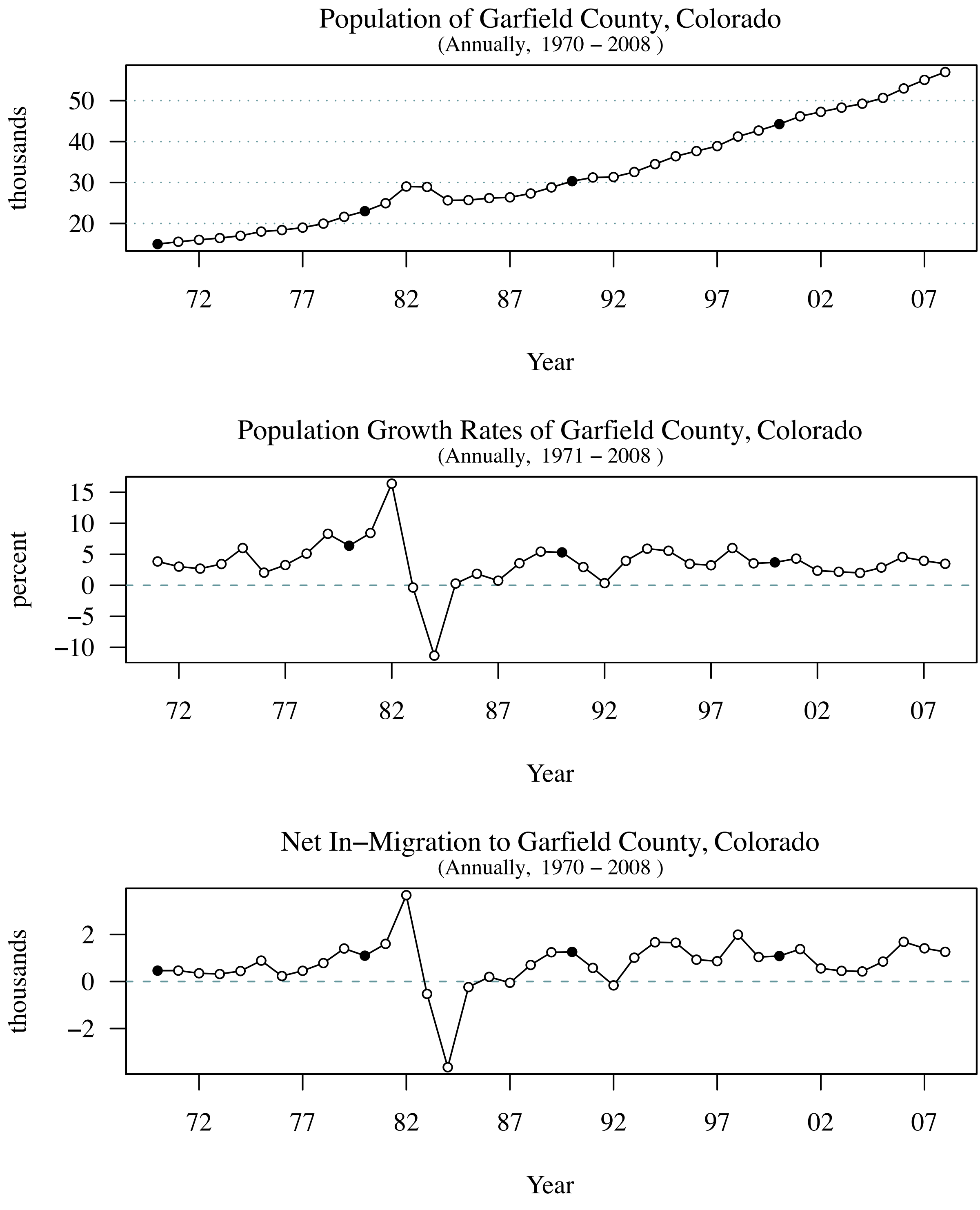


Figure 8.2.8: Data Source: U.S. Census Bureau and Colorado's State Demography Office. Note: Filled dots indicate census years.

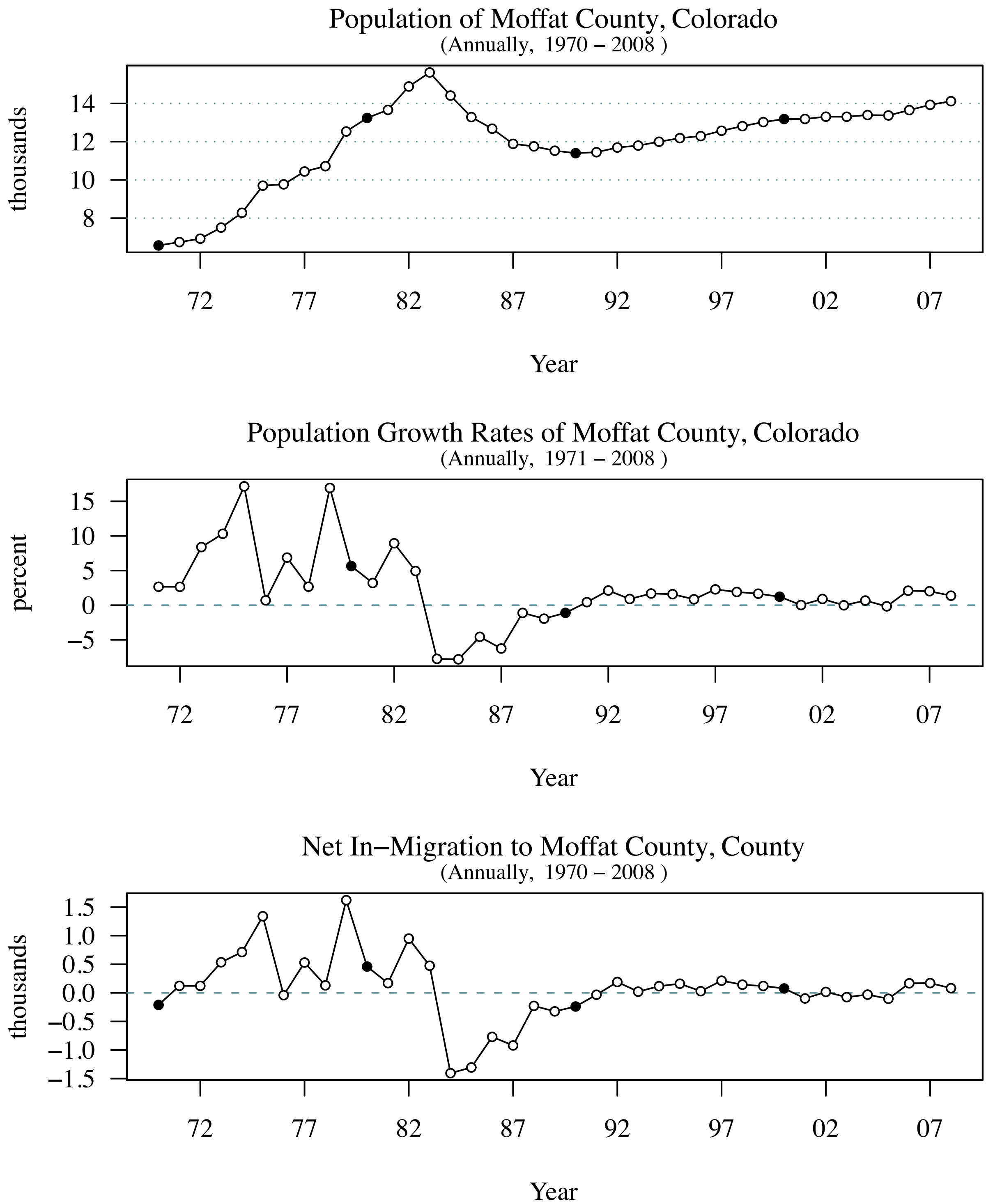


Figure 8.2.9: Data Source: U.S. Census Bureau and Colorado's State Demography Office. Note: Filled dots indicate census years.

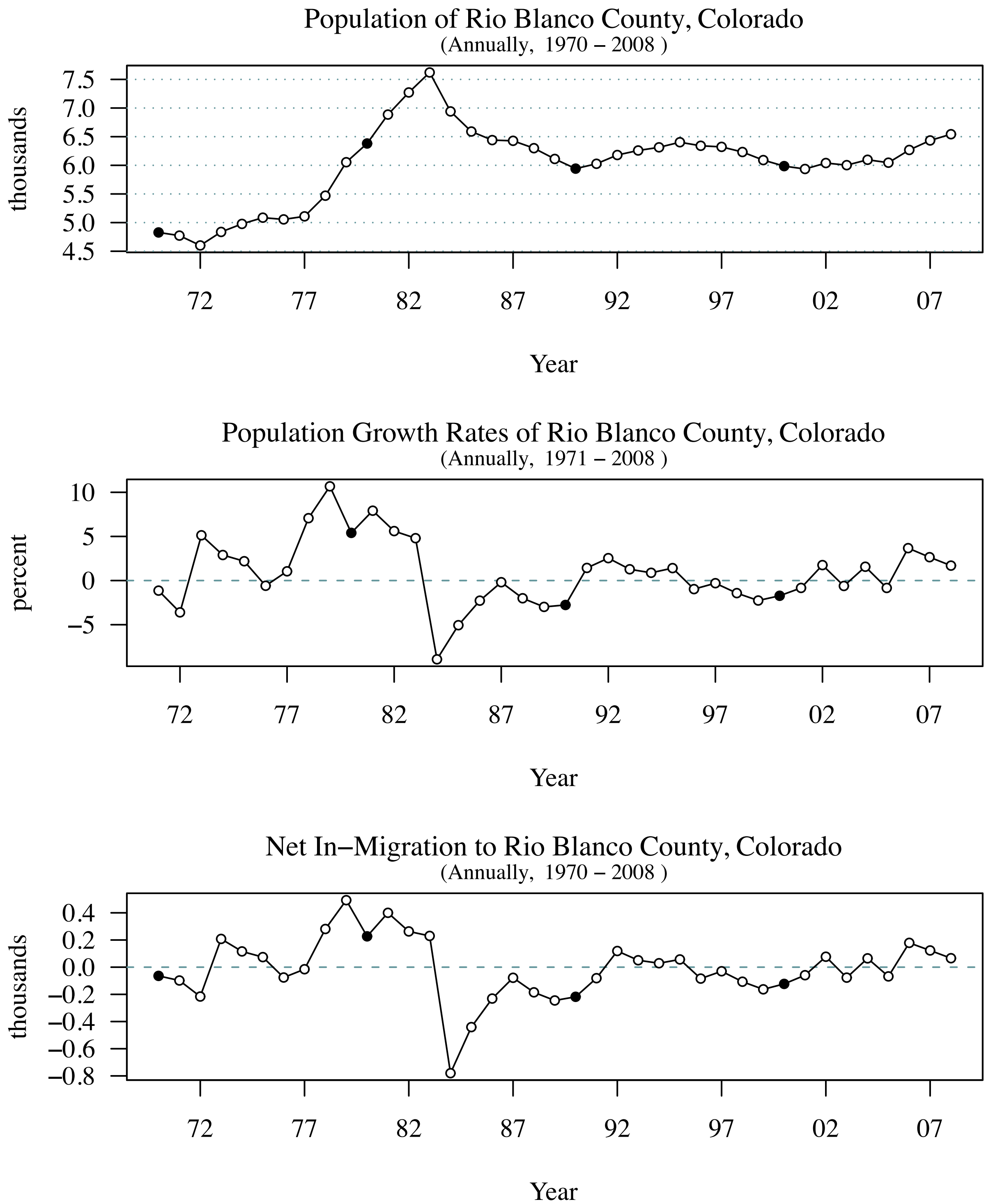


Figure 8.2.10: Data Source: U.S. Census Bureau and Colorado's State Demography Office. Note: Filled dots indicate census years.

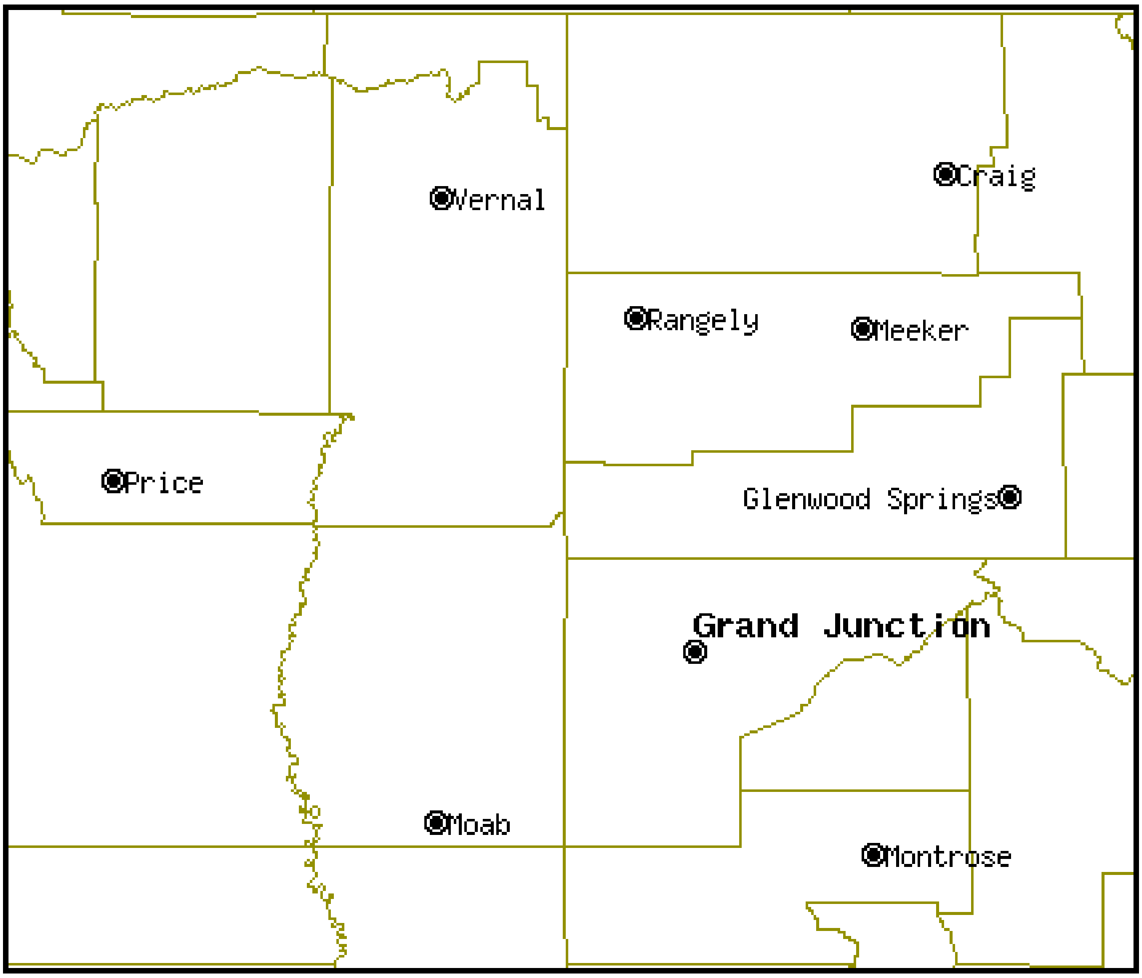


Figure 8.2.11: Map of Counties within the Most Prospective Oil Shale Area.

8.2.1 Energy Security

In the early to mid 1980s U.S. oil consumption reached its lowest level since 1973. During the same period, production from Alaska's Prudhoe Bay field was nearing its peak production of two million barrels per day and Texas production still provided over two million barrels per day.[678] Circumstances such as these enabled domestic production to provide about 70% of domestic consumption. Since then, production has declined by about 40% and consumption has increased by approximately 30%, with imported oil necessarily filling the gap. In recent years, domestic production has provided less than half of consumption.

Some observers contend that this increasing share of oil imports poses a threat to U.S. energy security substantial enough to warrant further development of domestic energy resources, including unconventional sources of liquid fuels such as oil shale. This concern over energy security arises partly from the experiences of the 1970s in which sudden increases in the price of oil ("oil shocks") following the oil embargo of 1973 and the Iranian Revolution of 1979, accompanied the macroeconomic maladies

[678] See http://tonto.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

of high inflation, low GDP growth, and a high unemployment rate.[679] All but one of the eleven U.S. recessions since World War II immediately followed a period of rapidly rising oil prices, suggesting the vulnerability posed by supply disruptions and the oil intensity of the U.S. economy.[680]

Such concerns are well-represented by the following statement from the 2004 report titled "Strategic Significance of America's Oil Shale Resources":

> The growing dependence of the United States on foreign sources for its liquid fuels has significant strategic and economic implications. The United States has been a net importer of oil for more than 50 years, and today, imports nearly 60 percent of its liquid hydrocarbon needs . . . . The U.S. Department of Energy (DOE) projects that U.S. imports may double, to 19.8 MMBbl/D by 2025. By then imports will exceed 70 percent of demand, the vast majority coming from Organization of Petroleum Exporting Countries (OPEC). As imports rise, America's vulnerability to price shocks, disruptions, and shortages will also increase.[681]

Although "dependence" could be defined in a number of ways, there are several reasonable definitions based on national energy statistics made readily and publicly available by the Energy Information Administration of the U.S. Department of Energy. Further, as in the previous quote, these measures—having in common the feature of being based on a measure of the import-share of domestic crude consumption—are often cited by analysts and other commentators. A review of trends in U.S. dependence on imported crude using these definitions follows.

The simplest of these definitionsof dependence is the ratio of gross petroleum product imports to the total U.S. consumption of petroleum products (equation 8.2.1). Because it makes use of gross imports, rather than net imports, this is referred to as "gross dependence." Changes in dependence, measured in this way, reflect both the steady rise in U.S. consumption and decline in U.S. production of petroleum. In 1982, total U.S. petroleum consumption was 5.8 billion barrels while petroleum imports totaled 1.8 billion, resulting in gross import dependence equal to 0.31 (31%). By 1995, gross dependence had risen to 49% as consumption reached 6.5 billion and imports 3.2 billion. Data for the most recent complete year (2008), shows gross dependence reaching 66%, with consumption of 7.1 billion and imports of 4.7 billion. Figure 8.2.12 illustrates the level of gross dependence since the early 1970s.

Although gross dependence is easily computed and readily understood, it does not account for the fact that the U.S. also exports refined petroleum products. For this reason, it is common to report alongside gross dependence, a modified version in which net imports—the difference between imports and exports—replaces gross imports [equation (8.2.2)]. This measure is referred to as "net dependence." Between 1990 and 2004 U.S. exports averaged 351 million barrels annually (15% of the average U.S. production over the same time) and were remarkably stable, with minimum and maximum annual exports of 343 million and 383 million barrels respectively. From 2005 to 2008, exports increased to 659 million barrels annually (35% of U.S. production), almost entirely as the result of an increase in exports of residual fuel and 15–500 PPM diesel fuel. Thus, net dependence largely parallels gross dependence until the most recent few years. In 1982, with exports of 298 million barrels, net dependence was 0.26 (26%) and rose to 44% (exports of 346 million) and 57% in 1995 and 2008 respectively.

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[679] Though the role of oil prices in the economic problems of the 1970s is still debated among experts, there appears to be a consensus that oil prices had *some* negative effect.

[680] See Stephen P.A. Brown and Hillard G. Huntington. *Estimating U.S. Oil Security Premiums*. 2009. URL: http://emf.stanford.edu/files/pubs/22528/OP68Rev.pdf and James D. Hamilton. *Causes and Consequences of the Oil Shock of 2007–08*. Working Paper 15002. 2009. URL: http://www.nber.org/papers/w15002 and the references therein for thorough discussions of oil shocks and their macroeconomic impacts.

[681] Harry R. Johnson, Peter M. Crawford, and James W. Bunger. *Strategic Significance of America's Oil Shale Resource*. Tech. rep. Volume I: Assessment of Strategic Issues. AOC Petroleum Support Services, LLC, 2004 at 1.

While both of the above measures of U.S. import dependence are reported in its Monthly Energy Review, EIA considers net import dependence to be a "more meaningful indicator of import dependence."[682] On the other hand, a further refinement, which also accounts for changes in the Nation's petroleum stock is suggested by EIA as the most appropriate of these statistics, especially when the data series are monthly rather than annually.[683] The justification for this adjustment is that had crude stocks not increased, they would have either provided for U.S. consumption—displacing the same quantity of imports—or they would have been exported—decreasing net imports. On the other hand, a draw-down on stocks conceals imports that would have been required had stock levels stayed constant (See equation 8.2.3.).

$$\text{gross dependence on } i = \frac{\text{gross imports from } i}{\text{total U.S. consumption}} \tag{8.2.1}$$

$$\text{net dependence on } i = \frac{\text{imports from } i - \text{exports to } i}{\text{total U.S. consumption}} \tag{8.2.2}$$

$$\text{net destocked dependence on } i = \frac{\text{imports from } i - \text{exports to } i - \text{change in stocks}}{\text{total U.S. consumption}} \tag{8.2.3}$$

Figures 8.2.12, 8.2.13, and 8.2.14 show trends in U.S. dependence—as measured by net dependence (See equation 8.2.2.)—on imports from all foreign sources, OPEC, and Canada respectively. Dependence on imports from foreign sources has been illustrated above for the years 1982, 1995, and 2008. Dependence on other sources, such as OPEC and Canada, is computed similarly by replacing total imports with imports solely from these other sources.

Figure 8.2.15 illustrates U.S. total import dependence as defined by gross (top line) and net dependence (bottom line). The composition of petroleum products exported by the U.S. differs significantly from the products consumed by the U.S.. Evidently it is less advantageous for refiners producing these products to instead further process them into products for domestic use. As this fact may signify some, but perhaps not complete, substitutability between U.S. exports and the imports they would presumably supplant according to the net-dependence measure, the shaded area between net and gross dependence can be seen as representing a plausible range of dependence on imported oil.

By any of the three measures, dependence on combined sources of petroleum imports has grown far more substantially than dependence on imports from OPEC member-nations. In particular, imports from Canada have nearly doubled during the same period (see Table 8.2.3), increasing from 547 thousand barrels per day in 1983 (10.8% of U.S. imports) to 2.5 million BOPD in 2008 (19.3% of U.S. imports). Though the U.S. is becoming more dependent on imported crude, a significant, growing, and potentially much larger future fraction of this import-share is coming from a stable source (Canada).

There is reason to believe that the concerns expressed at the beginning of this section are well-founded. If imported crude carries costs that are not reflected in its market price, then levels of imports may exceed the optimal level from the point of view of the U.S. as a whole. The costs of imported crude that are borne only by the purchaser are called "private costs." Additional costs are borne by others and are called "externalities." It is expected that the amount of foreign crude actually purchased completely

[682] C. William Skinner. "Measuring Dependence on Imported Oil". In: *Energy Information Administration/Monthly Energy Review* (August 1995). http://tonto.eia.doe.gov/ftproot/features/skinner1.pdf.
[683] C. William Skinner. "Measuring Dependence on Imported Oil". In: *Energy Information Administration/Monthly Energy Review* (August 1995). http://tonto.eia.doe.gov/ftproot/features/skinner1.pdf.

Figure 8.2.12: Data source: *Department of Energy, Energy Information Administration*

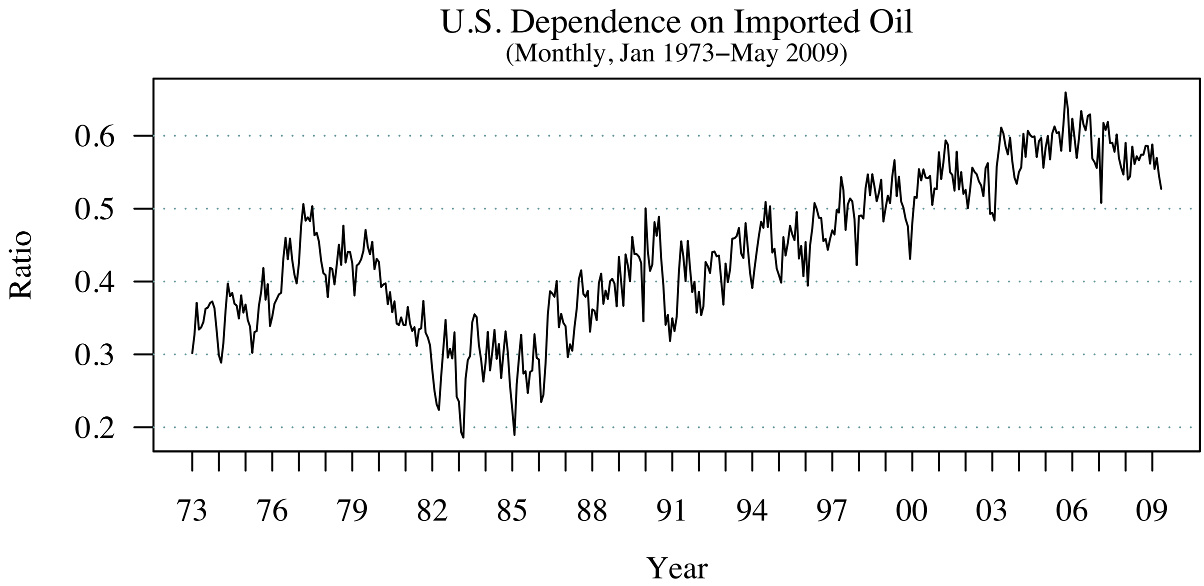
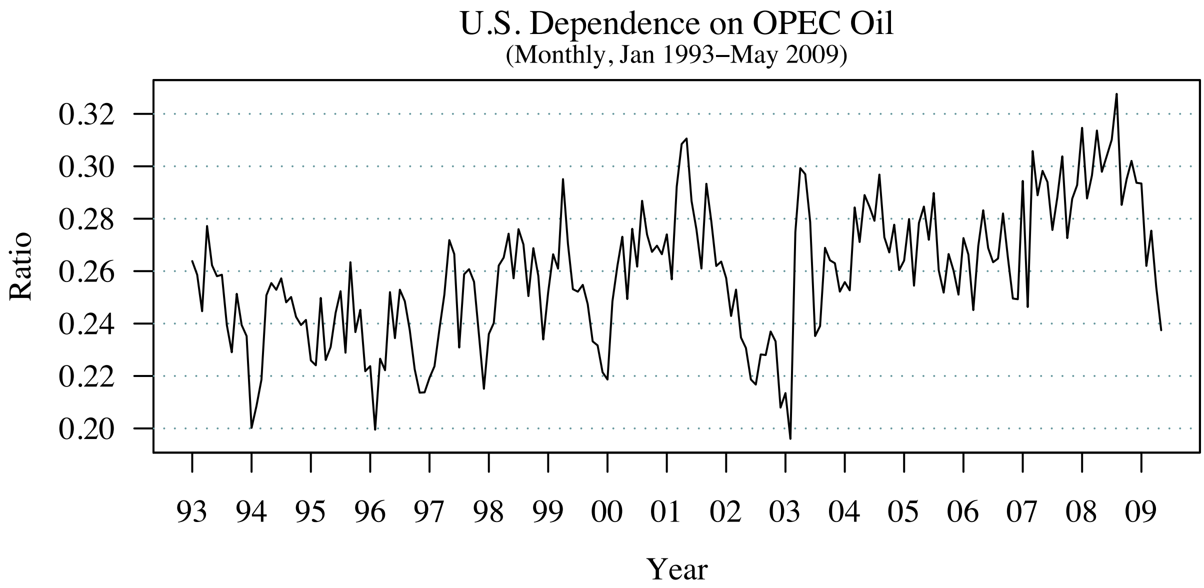


Figure 8.2.13: Data source: *Department of Energy, Energy Information Administration*



accounts for private costs, but not external costs.[684] In the literature on the economics of energy security, the external cost associated with a barrel of imported crude is called the "oil security premium:"[685]

[684]Because external costs are defined as those outside the scope of individual cost-benefit considerations, private costs—which are defined those inside the scope of such considerations—are often referred to as "internal costs."

[685]See Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/ at 2.

Figure 8.2.14: Data source: *Department of Energy, Energy Information Administration*

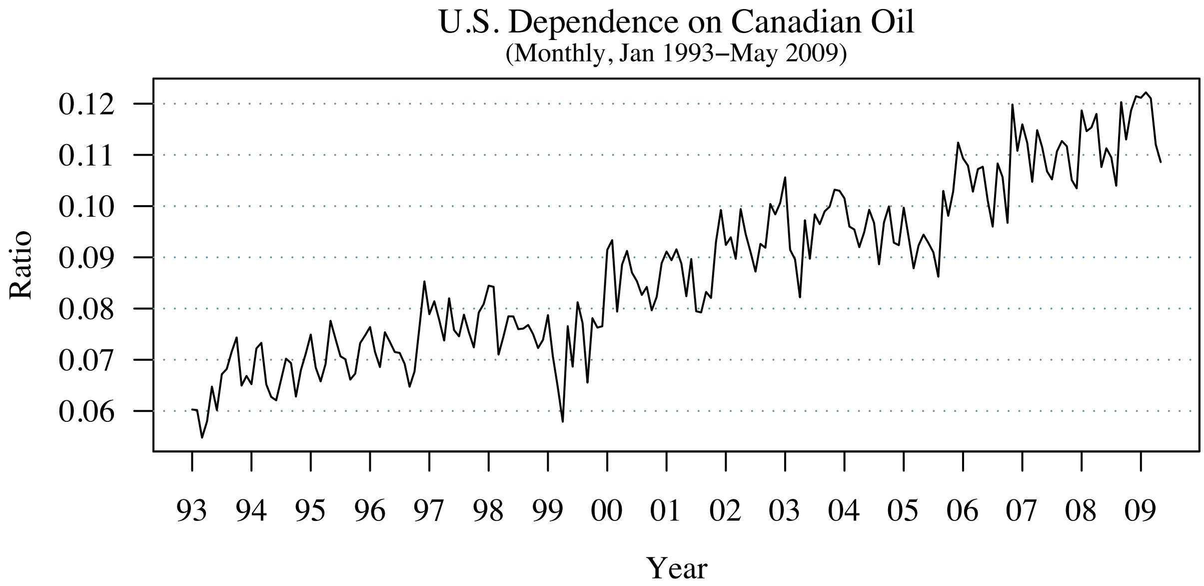
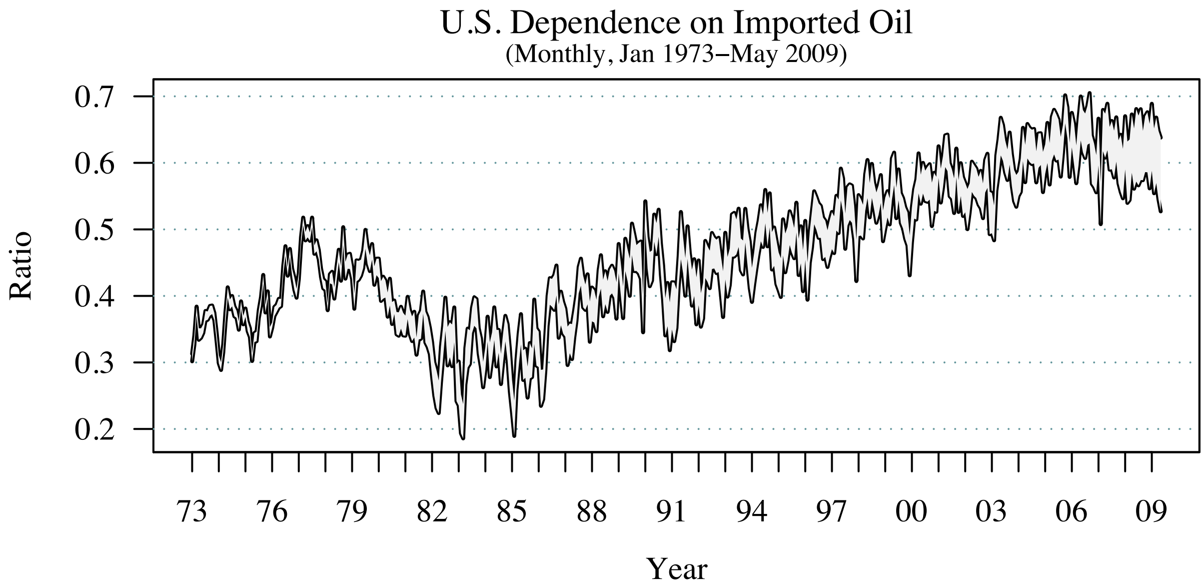


Figure 8.2.15: Data source: *Department of Energy, Energy Information Administration*. Note: Top line represents "gross dependence" and the bottom line represents "net dependence."



When buyers and sellers negotiate an oil price in the private market, they may not incorporate all of the oil security costs associated with increased oil use or imports. The oil import premium should represent the difference between the societal and private costs of purchasing one more barrel of imported oil. Some policymakers think of the premium as "hidden

Table 8.2.3: U.S. Petroleum and Petroleum Products Imports, thousand BOPD

Year	*Canada* (%)	*Mexico* (%)	*Saudi Arabia* (%)	*OPEC* (%)	*Total*
1973	547 (10.8)	826 (16.4)	337 (6.7)	2993 (47.8)	6256
1978	547 (10.8)	826 (16.4)	337 (6.7)	5751 (68.8)	8363
1983	547 (10.8)	826 (16.4)	337 (6.7)	1862 (36.9)	5051
1988	999 (13.5)	747 (10.1)	1073 (14.5)	3520 (47.6)	7402
1993	1181 (13.7)	919 (10.7)	1414 (16.4)	4354 (50.5)	8620
1998	1598 (14.9)	1351 (12.6)	1491 (13.9)	4905 (45.8)	10708
2003	2072 (16.9)	1623 (13.2)	1774 (14.5)	5162 (42.1)	12264
2008	2493 (19.3)	1302 (10.1)	1529 (11.8)	5954 (46.1)	12915

costs" because buyers and sellers do not directly see them. [686]

Recent estimates of the oil security premium follow below. It is important to be clear that the magnitude of the oil security premium is a separate issue from the tools policy-makers might employ to more closely align outcomes with the ideal outcome in which a complete account is made for internal and external costs. For instance, policies to promote conservation and improved energy efficiency, taxes on petroleum products like gasoline, tariffs on imported crude, or increased domestic production of conventional or unconventional fuels, are all potential policy options, but oil security premia alone will not indicate which are the most appropriate. Equally important, other external costs such as those associated with health or environmental degradation are not included among the external costs estimated in these studies. It is possible to devise policies which advance both particular environmental or health and energy security objectives, though policy-makers would still need to decide how much emphasis to give one one objective over another.[687]

A 1997 study conducted by Paul N. Leiby of the Oak Ridge National Laboratory is widely citedfor its estimates of plausible values for the oil security premium. There are two primary elements of this and similar studies. First, one needs to approximate the probability that a disruption of a given size will occur. This is usually done by simulation methods, perhaps augmented with expert knowledge. Second, one needs to estimate, for each type of disruption, its costs.[688] Leiby's analysis was based on supply-disruption modeling efforts undertaken at Stanford University's Energy Modeling Forum (EMF). A brief description of the EMF framework follows.

As a way of assessing the risk of future oil shocks, the Stanford Energy Modeling Forum brought together "… a working group of leading geopolitical and oil market experts. This group developed a

[686] Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/.

[687] See Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/ and Paul N. Leiby. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*. Prepared for the U.S. Department of Energy. Oak Ridge National Laboratory, 2007 for a discussion of what is and what is not included in the oil security premium, and Stephen P.A. Brown and Hillard G. Huntington. *Energy Security and Climate Change Protection: Complementarity or Tradeoff?* 2008. URL: http://emf.stanford.edu/files/pubs/22451/op63.pdf for discussion of potential tradeoffs and synergies between energy security and environmental goals.

[688] GDP loss is one definition of cost, but since GDP is income generated through production, any sort of "cost" related to the way income is spent is masked by this measure.

risk assessment framework and evaluated the likelihood of at least one foreign oil disruption over the next ten years."[689] The purpose of the working group was to identify a reasonable range of disruption scenarios—specified by magnitude and duration—and to elicit expert opinions about the plausibility of these scenarios.

It was supposed that oil-supply disruptions could originate from any one of the following four regions: Saudi Arabia, other Persian Gulf States, west of Suez (i.e. Algeria, Angola, Libya, Mexico, Nigeria, and Venezuela), and Russia and Caspian states. Countries within these categories were not distinguished in the sense that a disruption was said to originate from the region, but not from any particular country within it. Further, disruptions from the originating region were offset by excess capacity in other regions, so that instead of a gross disruption of 2 million BOPD, one gets something less than that, which is the "net disruption."[690] Running risk analysis software, their simulation-based probability estimate for a net disruption (the gross quantity of oil unavailable minus the quantity made available through offsetting production) during the next ten years of 5–10 million BOPD is 37%; for a net disruption greater than 5 million BOPD is 45%; for a net disruption greater than 10 million BOPD is 8%.

In Leiby's original study from 1997 (an era of relatively low prices) he estimated the oil security premium at $3.59 per barrel, composed of $1.03 per barrel for the costs of potential "Macroeconomic disruption and adjustment," and $2.57 per barrel for the "monopsony component" (market power).[691][692][693] In a 2007 update, which took account of the much higher oil prices compared to the mid-nineties, these are substantially higher: $13.58 (total premium), $4.68 (macroeconomic), and $8.90 (monopsony).[694][695][696]

It is worthwhile to point out here that among the energy security benefits from increased domestic production is not a greater immunity from international oil shocks. Even if the U.S. imported no oil, meeting all its consumption needs with domestic production, it would be no less vulnerable to a sudden

[689] Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/ at 11–12.

[690] The U.S. Strategic Petroleum Reserve (SPR) was not included as a resource that could provide offsetting production. The reason is that the oil import premium is meant to assess the cost to the U.S. of an oil-supply disruption. That is, the question an analysis such as this one could answer is: "Would the U.S. be justified in spending more to increase the SPR?" The answer depends on the cost to the U.S. of the sort of disruption its deployment could mitigate. Actual expenditures by the military and for the SPR are excluded from the premium estimates firstly, because these are expenditures, not mitigaged costs—the U.S. would be quite fortunate to spend exactly the amount justified by the unobservable costs—and secondly for the same reason SPR is not considered for offsets (It's the *un*-mitigated costs that form the basis for informing policy-makers how much can be justifiably spent to avoid them with options such as the SPR, or net expenditures spent on efforts to increase domestic conventional oil production or its alternatives.). See Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/.

[691] See Paul N. Leiby. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*. Prepared for the U.S. Department of Energy. Oak Ridge National Laboratory, 2007, citing Paul N. Leiby et al. *Oil Imports: An Assessment of Benefits and Costs*. Oak Ridge National Laboratory, 1997. URL: http://pzl1.ed.ornl.gov/ORNL6851.pdf.

[692] "Macroeconomic disruption and adjustment" costs are those associated with the inability of economic adjustments to occur in the manner they would if, instead of the suddenly increasing prices following a supply disruption, prices rose gradually enough that optimal adjustments could take place. The "Monopsony component" accounts for the ability of the U.S., as a buyer of imports, to affect downward pressure on the non-competitive price stemming from OPEC's market power, through reducing its purchases of imports. See Paul N. Leiby et al. *Oil Imports: An Assessment of Benefits and Costs*. Oak Ridge National Laboratory, 1997. URL: http://pzl1.ed.ornl.gov/ORNL6851.pdf at S-6–S-8.

[693] The given estimates are the midpoints of a range of estimates that span the middle 90% of the model-generated costs as ordered lowest to highest. The ranges are as follows: [$2.57–$5.64], [$1.03–$2.05], [$1.54–$3.59] (all in 2004-dollars).

[694] Paul N. Leiby. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*. Prepared for the U.S. Department of Energy. Oak Ridge National Laboratory, 2007

[695] All dollar amounts are with respect to year 2004.

[696] The corresponding 90% certainty intervals (see footnote (693)) are: [$6.71–$23.25], [$2.18–$7.81], and [$2.91–$18.40].

price increase than it would be it if it was completely import-dependent.[697][698]

As Huntington, Leiby and others point out, the "oil security issue" is larger than just the fraction of imports.[699][700] It also means that oil is important in the economy, in the sense that it is prevalent and largely without quickly deployed substitutes.[701]

In the event of an oil supply shock, such as an embargo, the immediate response to the associated price increase would be rather limited.[702] But if high prices persist long enough that they become expected well into the future, then people and businesses will shift away from purchases of long-lived oil-intensive products or capital equipment. A resident may replace their oil-burning heater with a natural-gas burning unit, or a power plant may be built to burn coal instead of fuel oil.

Of course, even a lack of ready substitutes does not, on its own, imply vulnerability to oil shocks. All else being equal, the greater oil's role in the economy, the more vulnerable the economy to an oil shock. The share of oil in national GDP is one measure (albeit limited) of the extent of oil's role in the national economy. But various researchers have found the disruptions to the national economy from past oil shocks to be larger than can be readily accounted for by oil's GDP share. This has led researchers to further investigate the pathways of oil's influence on the broader economy.[703]

There are a number of potential benefits from increasing domestic production. First, the increase in production could lead to somewhat lower average world oil prices, the amount depending on the increase in production as well as the extent of strategic export curtailement by OPEC. Secondly, U.S. production would increase the share of global supply from stable sources, reducing the likelihood and severity of a given supply shock, because less of the world's crude would be directly subject to the shock (e.g. embargo) and because this makes "oil as a weapon" less effective if used.[704] Lastly, since the U.S. is a net importer of oil, higher oil prices means that more funds flow from the U.S. to oil exporters than flows to the U.S. from those to whom the U.S. exports. Greater domestic production would reduce the payments for imports.

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[697]Up to differences in grade and transportation costs, oil is a fungible commodity. If the international price rose, but the domestic price didn't, there would exist opportunities for profits to be made by merely purchasing domestic oil and selling it on the international market. Such arbitrage would occur until the price of domestic crude reflected only its differences with international crude

[698]"Although greater domestic ethanol or ANWR production may reduce imports, this development does not protect the economy from future oil price shocks."Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/ at 10.

[699]"GDP effects may still apply for U.S. oil consumption when world oil market supplies are unstable, but that result suggests that there may be an oil consumption rather than an oil import premium component for macroeconomic externalities." See Hillard G. Huntington. *The Oil Security Problem*. 2008. URL: http://emf.stanford.edu/publications/emf_op_62_the_oil_security_problem/ at 10–11.

[700]"We acknowledge, as did others before, that oil security and dependence costs are not strictly a function of imports alone. Other attributes, such as the level of oil consumption, the oil intensity of the economy, and the structure and flexibility of oil supply and use are also important determinants of the societal economic costs of oil use. These points are well made by Toman in his comprehensive survey pieces on energy security (1993, 2002). To the extent that a reduction in oil imports is accompanied by a reduction (increase) in oil consumption, or by the introduction of technologies or fuel sources that increase (decrease) the short-run or long-run price-responsiveness of energy supply and demand, the incremental benefits to society would be greater (less) than estimated here."Paul N. Leiby. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*. Prepared for the U.S. Department of Energy. Oak Ridge National Laboratory, 2007.

[701]To make an example, the U.S. imports 100% of its bananas—is completely dependent on imported bananas according to the definitions discussed above. But because there exist many ready substitutes this dependence is not threatening.

[702]This is often phrased as: The demand for oil is relatively price-inelastic in the short-run.

[703]See e.g. Hillard G. Huntington. *The Economic Consequences of Higher Crude Oil Prices*. 2005.

[704]Crude produced from the Canadian sands is increasingly providing these as a beneficial side-effect.

8.3 ALTERNATIVES: DEMAND MANAGEMENT

In the prior chapter, supply-based alternatives were discussed, such as resources available on the outer continental shelf or through enhanced oil recovery techniques. In Section 8.2.1 of the present chapter, it was explained that the costs of imported crude could be offset either by increased domestic production of crude—domestic crude presumably supplanting imports—or reduction of overall demand for crude. This section briefly mentions the gasoline tax as an option to reduce the consumption of crude.

If one accepts at least one of the first three definitions of dependence presented in Section 8.2.1, then there are two fundamental reasons why the U.S. has become increasingly dependent on imported sources of petroleum and vulnerable to high petroleum prices: decreasing domestic production and increasing domestic consumption. For each of these two causes, a number of solutions have been proposed.

Since about 70% of the total petroleum products consumed in the U.S. is in the form of transportation fuels, lowered consumption of these fuels has proven to be an attractive target. Two of the more commonly cited proposals are: (1) decreasing fuel consumption by way of increasing fuel price, and (2) decreasing fuel consumption by way of policies, such as the CAFE standards, aimed at improving fuel efficiency.

An increase in the price consumers pay (and expect to pay in the future) for fuel is one way in which fuel consumption (and therefore "dependence") can be lowered without imposing more direct constraints, such as the rationing of the 1970s.[705] This price increase could be the result of the working out of market forces, or imposed through a tax. Implementing this increase through a gasoline tax that offset by a equal reduction in other taxes ("revenue neutral") has been proposed by N. Gregory Mankiw—chairman of former President Bush's Council of Economic Advisors—and more recently by Indiana Senator Richard G. Lugar.[706]

8.4 THE PROBLEM TRIANGLE

That socioeconomic impacts can have substantial adverse consequences for the economic viability of development appears to be long-acknowledged. As stated by John S. Gilmore in his 1976 article published by the journal *Science*:

> The problems result from the traditional, business-as-usual boom in which unmanaged growth is the cumulative result of many different corporate, governmental, and individual decisions; mostly made in total isolation from each other. ... Besides fostering conflict, this sort of boom growth almost inevitably generates a situation that causes overruns in both the time and the money required to get projects built and operating [707].

Gilmore illustrates the problem by way of a graphic he refers to as the "Problem Triangle." Gilmore's Problem Triangle, rendered in Figure 8.4 with only minor cosmetic modifications from the original,

[705] The inverse relation between the level of U.S. petroleum consumption and the price of petroleum is illustrated in Figure 7.1.2, where the drops in consumption during the high-price late 1970s and early 1980s and again in the last several years are especially apparent.

[706] See N. Gregory Mankiw. "Raise the Gas Tax". In: *Wall Street Journal* (October 20th 2006). `http://www.economics.harvard.edu/files/faculty/40_Raise_the_Gas_Tax.pdf`, A12 and Richard G. Lugar. "Raise the Gas Tax". In: *The Washington Post* (February 1st 2009), B07. Mankiw views such a tax as a means of internalizing a portion of the external costs of gasoline consumption and automobile transportation. In order to also effectively decrease the share of imports in total oil consumption, the resulting decrease in petroleum consumption would need to reduce domestic production less than imports.

[707] John S. Gilmore. "Boom Towns May Hinder Energy Resource Development". In: *Science* 191.4227 (February 1976), pp. 535–540.

describes the unbalanced growth typical of boom economies. As the population increases at boom rates, existing public services such as schools and health services typically fail to maintain levels desired by the population. The inadequacy of such services serves as a deterrent to further in-migration, creating labor shortages. Labor shortages, in turn, lead to increased wages and/or decreased labor productivity.[708]

As Gilmore states it:

> Workers and their families do not want to stay in the community and some of those who do stay are pirated back and forth among employers. Industrial employee turnover rates and absenteeism go up rapidly. It is difficult to attract and retain a satisfactory work force, whether it is a work force for building and operating a power plant or gasification plant, for operating a restaurant, or for maintaining the county's roads and bridges. Industrial productivity and profits drop.
>
> Because of declining productivity, or at least the absence of expected increases in productivity and profits, there is less money coming in to support public sector activities. In addition, social malaise or chaos causes private investors to be skeptical and unwilling to invest in commercial facilities, housing, or the other private sector needs. Insurance companies even stop writing casualty coverage in the boom towns.
>
> Thus the situation is back where it started in the problem triangle, with local services and facilities finding it even harder to keep up with increasing population and demand.

8.5 Socioeconomic impacts of past and ongoing developments

Perhaps the best indication of the sort of impacts likely to attend development of oil shale from the Green River formation is to be found in considering past booms apparently similar with respect to scale and socioeconomic features. In what follows, several cases are briefly presented which highlight the nature of the impacts, how the region prepared for or reacted to the impacts, which actions appeared to successfully mitigate adverse impacts, and where different actions might have led to further success.

As the following case studies illustrate, socioeconomic distrurbances adversely affect not only citizens and local government, but industry too.[709]

8.5.1 The Canadian Oil Sands Experience

The development of the Canadian oil sands continues to have pronounced consequences for the U.S., as crude from the oil sands has come to be a major source of U.S. supply. The oil sands have also greatly impacted the province of Alberta and the Regional Municipality of Wood Buffalo (RMWB). Although

[708] Labor productivity usually means the value of total output divided by total wages. Thus, labor productivity can decrease either because the same amount of labor-time produces less physical product (this could happen if the quality of the labor pool degrades along with the socioeconomic conditions), or because wages increase (as additional compensation becomes necessary to lure workers). Occasionally the numerator is a physical quantity, like tons of coal, and the denominator is labor hours.

[709] For example, Gilmore reports for Rock Springs and Green River, Wyoming:"Productivity (tonnage mined per man per shift) in trona (natural soda ash) mining dropped 25–40 percent between 1972 and 1973 because of labor supply problems." See John S. Gilmore and Mary K. Duff. *A Growth Management Case Study: Sweetwater County, Wyoming*. Tech. rep. University of Denver Research Institute, 1974.

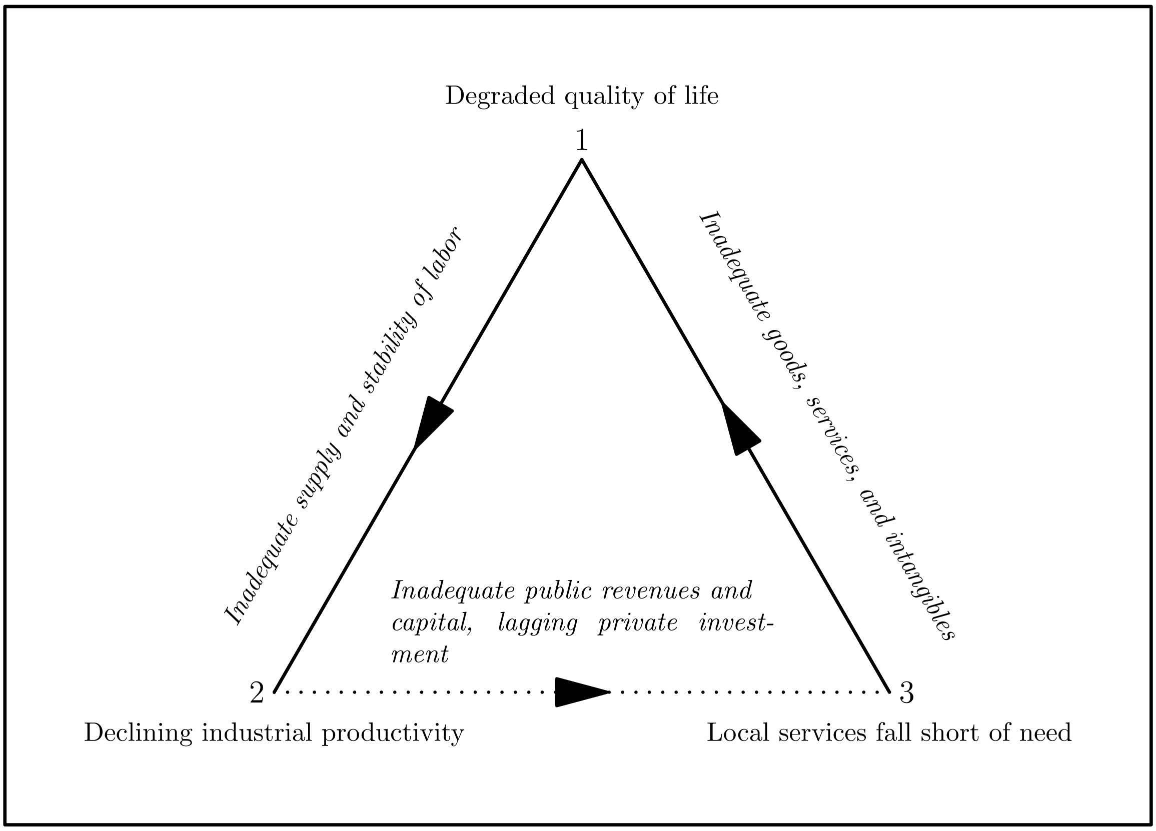

Figure 8.4.1: Gilmore's description of the dynamics of "boomtown growth" imbalances. Note: Author's replica of Gilmore's 1976 diagram. See John S. Gilmore. "Boom Towns May Hinder Energy Resource Development". In: *Science* 191.4227 (February 1976), pp. 535–540.

research and development has been on-going for nearly a century, substantial investments in production capacity have taken place only since the 1990s, with a corresponding rise in local population and socioeconomic impacts. RMWB is now experiencing many of the typical challenges of rapid growth.

Recognizing the challenges, a 2006 report issued by the Government of Alberta identified the following priorities: housing, transportation, basic municipal infrastructure—water treatment, waste water treatment and landfill; health care, education, social services, policing, and environment.[710] The report goes on to say:

> A common theme that cuts across all these specific areas is the challenge of recruiting and retaining the necessary staff to deliver key services.
>
> Although workforce shortages exist throughout Alberta, they are much more severe in the Regional Municipality of Wood Buffalo, where there is a high demand for skilled labour such as trades, technical workers, teachers, physicians, and other health care workers and a high demand for unskilled labour mainly involved in the service sector.
>
> The lack of affordable housing in Fort McMurray, the relatively isolated location, and the

[710] *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: http://alberta.ca/home/395.cfm.

> high cost of living all tend to limit the number of families that consider moving to the community and thereby contributing to the workforce.
>
> Employers in Fort McMurray experience high turnover rates. The high turnover means existing staff spend time on mentoring and recruitment, rather than other aspects of their job. It also results in a relatively new workforce with less expertise and less productivity.[711]

According to the "Regional Municipality of Wood Buffalo (RMWB) 2008 Census Report"[712], the population of Fort McMurray grew slowly during the 1980s and 1990s, increasing 9 percent from 33,576 in 1982 to 36,452 in 1999. Since 2000, population has grown much faster, increasing 72% from 42,156 in 2000 to 72,363 in 2008. The work camp population of RMWB has increased from 3,568 in 1999 to 26,284 in 2008.[713]

Almost two out of every three in the Fort McMurray population have jobs with oil companies or oil company contractors,[714] and almost one-half have jobs with an oil sands firm, or contractor. With the high oil prices and such a concentration of oil industry employment, the unemployment rate in 2006 for RMWB was 2.8%, compared to 6.1% for Canada, and 3.4% for Alberta. The oil industries average 1,315 CAD per week salary in 2005 was 80% higher than combined average for other industries.[715][716]

Cost escalation—of which high wages is a part—is a significant challenge socially and for business. There is a premium associated with building in Fort McMurray, known locally as the "Fort McMurray factor." This is due to competition with major industrial projects for labour, contractors and equipment, as well as the related high cost of living in Fort McMurray.[717]

The rapid increase in population has pushed vacancy rates on rental housing to near zero (0.37% in June 2006), rapidly increasing in the price of housing. In 2000 a 1 bedroom apartment rented for 760 CAD while a 2 bedroom rented for 895 CAD. By June 2006, these rates had jumped to 1,226 CAD and 1,387 CAD respectively[718].

8.5.2 The Trans-Alaskan Pipeline

The Trans-Alaskan pipeline (TAP) was built to transport oil from Alaska's newly discoved Prudhoe Bay field to its terminal point in Valdez—the nearest ice-free port—where it could then be shipped to refining markets.[719] The following discussion is based on testimony given by University of Alaska sociologist

[711] *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: `http://alberta.ca/home/395.cfm` at 47.

[712] See `http://www.woodbuffalo.ab.ca/business/demographics/pdf/2008_municipal_census.pdf`.

[713] See Table 8.5.1 for further detail. The "shadow population" is defined as persons present in community for a minimum of 30 days, but whose residence is elsewhere.

[714] See *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: `http://alberta.ca/home/395.cfm`.

[715] With the 2005 average exchange rate between the Canadian dollar and the U.S. dollar about 1.2 (CAD/US) 1,315 would have been approximately equal to 1600 US dollars.)

[716] *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: `http://alberta.ca/home/395.cfm`.

[717] See *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: `http://alberta.ca/home/395.cfm` at 31.

[718] *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development*. Tech. rep. Government of Alberta, 2006. URL: `http://alberta.ca/home/395.cfm` at 3–4. The report does not state whether the reported rental rates are means, medians, or other.

[719] The Prudhoe Bay field was discovered in 1968 and production commenced in June 1977, after the completion of the pipeline.

Table 8.5.1: Population and sub-populations of the Regional Municipality of Wood Buffalo since 1982. Note: Data not available for all years and sub-populations. Data Source: 2008 census, available at http://www.woodbuffalo.ab.ca/business/demographics/demographics.asp.

Year	*Pop. of Wood Buffalo*	*Work Camp Pop. (Shadow Pop.)*	*Pop. of Ft. McMurray*
1982	—	—	33576
1983	—	—	34477
1984	—	—	35352
1985	—	—	36810
1986	—	—	34444
1989	—	—	33698
1996	37222	—	34706
1999	42847	3568	36452
2000	51406	5903	42156
2002	58317	8063	47240
2004	67105	7678	56211
2005	73176	9178	60983
2006	75717	10442	61366
2007	88131	18572	65400
2008	103334	26284	72363

Michael Baring-Gould to the Mackenzie Valley Pipeline Inquiry.[720] The testimony concerns research Baring-Gould led on the socioeconomic impacts stemming from the construction of the TAP.

[720]The Canadian Government's Mackenzie Valley Pipeline Inquiry, led by Justice Thomas Berger, was charged with reviewing the possible socioeconomic and environmental impacts which might be expected to attend the construction of a natural gas pipeline proposed to run 760 miles, from gas fields in the Mackenzie River Delta at the Beaufort Sea, along the Mackenzie River, to a connection with existing pipelines in northwestern Alberta. In May 1977, three years after it had begun, the Inquiry culminated in Justice Berger's recommendation of a 10-year moratorium on construction of the pipeline to allow time to plan and set aside conservation areas along its route and to settle Aboriginal land claims. Especially noteworthy is Justice Berger's finding of little significance in the claimed economic benefits from construction of the pipeline, citing the short-term nature of such employment and a tendency for temporary economies built around construction projects to crowd out the area's traditional economy (See http://www.cbc.ca/news/background/mackenzievalley_pipeline/index.html, http://en.wikipedia.org/wiki/Mackenzie_Valley_Pipeline_Inquiry, and Paul Sabin. "Voices from the Hydrocarbon Frontier: Canada's Mackenzie Valley Pipeline Inquiry (1974-1977)". In: *Environmental History Review* 19.1 (1995), pp. 17–48). Though Berger's finding effectvely shelved the pipeline project, interest has recently resumed along with review and discussion with the Canadian Government (the National Energy Board and the Joint review Panel) and private stakeholders. The Mackenzie Gas Project, a group of "Four major Canadian oil and gas companies and a group representing the aboriginal peoples of Canada's Northwest Territories ..." states its "... goal is to have natural gas moving through the pipeline by 2010" (See http://www.mackenziegasproject.com/theProject/index.html). Not suprisingly, the project is raising reservations among environmental groups such as the Sierra Club of Canada and the World Wildlife fund of Canada who cite among their concerns the possible environmental damage and deterioration of ecosystem services associated with construction and operation of the pipeline (see http://www.sierraclub.ca/national/programs/atmosphere-energy/energy-onslaught/campaign.shtml?x=2926) and inadequate habitate protection for wildlife (see http://wwf.ca/conservation/mackenzie/).

Construction of the terminal in Valdez started in April 1974, with few preemptive actions having been taken either by citizens or government in anticipation of the impacts of sudden growth. Many Valdez residents viewed the expected changes as largely beneficial, citing creation of new jobs and a broad reinvigoration of the economy, which had largely lacked such prospects since the end of the gold rush of 1898-1899 when Valdez served as a crossing point to the Alaskan interior. Other residents expressed concern over the impact of the boom, citing cost-push inflation, increased crime, and crowding among their concerns. A seemingly wide-spread view among citizens of Valdez was that the pipeline construction activity would bring benefits, but without requiring substantial accomodation planning on the part of citizens or government.

The construction period brough dramatic demographic and economic changes. In January 1974—several months prior to the beginning of construction—the population of Valdez stood at 1,350. By July 1975, the total population had risen to 6,512, consisting of 3,500 in town and 2,672 in camps. Median per capita household head income rose from $11,940 in 1974 to $24,500 in 1975 (in 1975 dollars), while median household income rose from $16,430 to $30,600 in 1975.[721] The increase in median income was rooted in, but not limited to, high wages paid to those working on the terminal: wages rose for other occupations as well, as competition for scarce labor created a "seller's market." But the higher wages for jobs outside of pipeline work contributed only a small part of the overall increase in income.

The proportion of public employment in Valdez fell from 40% to 18% between 1974-1975, despite some pre-boom efforts to expand staff to meet expected new service demands. This was due in part to the rapid increase in construction jobs and in smaller part to government employees leaving for the higher paying private sector.

As construction went on, concern rose over the increasing cost of living brought about by the influx of high wages. These inflationary forces were driven by infrastructural constraints which could not be eased in the short term because of a combination of funding lags and construction lags. While the construction lags were due to lead times typical of public works projects such as road, water treatment, and school construction, funding lags were due to the limited financial resources of Valdez (e.g. limited bonding capacity), lagging tax revenues, and most importantly, state impact funds which could only be committed once the impact had occured (not in anticipation of the impact).[722] It was not until late 1975 that state monies were allocated and the first stage of expansion of water and sewage systems occured. Tax revenue, though it increased dramatically, naturally lagged behind the need for it. Property tax collections in Valdez increased from 1.1 million in 1974 to 4.3 million in 1976.

A survey of Valdez residents reveals a suprising sentiment, but one evidently not uncommon among residents of boomtowns, during the boom:

> In spite of acute problems and many inconveneinces associated with impact, a generally high level of satisfaction exists within valdez on the changes and progress which the community has made . . . . Among our sample of former residents, only one-third felt that the changes were worse than they had anticipated; over 40% expressed satisfaction with the developments to date and almost 25% that the community had progressed in better terms than anticipated. . . . The vast majority of older Valdez residents (75%) consider the overall

[721] These figures translate to approximately the following in terms of 2009 dollars: ... household head income rose from $48,000 in 1974 to $98,000 in 1975 ... household income rose from $66,000 in 1974 to $122,000 in 1975.

[722] See Michael Baring-Gould and Marsha Bennett. "Social Impact of the Trans-Alaska Pipeline Construction in Valdez, Alaska 1974-1975". Testimony to Mackenzie Valley Pipeline Inquiry at 12: "... a factor mentioned strongly by half of those we interviewed, was lack of support by the state government. Actual commitment of state monies for needs such as school, sewer and water expansion would come, as they did, only when impact was actually demonstrated; the first two million dollar (about 8 million 2009 dollars) impact grant was not recieved until three months after construction was initiated." Parenthetical statement added.

> changes as desirable, while at the same time they recognize the need for a more permanent population, and greater breadth and stability in the growth of their town.[723]

8.6 Conclusion and Recommendations

If commercial oil shale leasing and development occurs on the public lands, policymakers will need to effectively address numerous socioeconomic issues. Public concern over these issues will likely be significant due to the hardships of the boom and bust cycle of the last round of oil shale activity in the 1970s and 1980s. Early cooperation between the various oil shale stakeholders—industry, government and citizens—will be needed if oil shale development is to proceed to sustainable commercial levels while protecting the existing social and economic characteristics of the communities in proximity to the most geologically prospective oil shale area.

[723] Michael Baring-Gould and Marsha Bennett. "Social Impact of the Trans-Alaska Pipeline Construction in Valdez, Alaska 1974-1975". Testimony to Mackenzie Valley Pipeline Inquiry at 33.

APPENDIX B

Depositional heterogeneity and fluid flow modeling of the oil shale interval of the upper Green River Formation, eastern Uinta Basin, Utah

Final Project Report

Reporting period: June 21, 2006 to October 21, 2009

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October 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
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Project Objectives

1. Conduct a detailed sedimentological analysis of about 100 logs and a 1000-foot core to help construct realistic reservoir characteristics of the main organic-rich zones of the Green River shale in Utah.
2. Create a stratigraphic map and depositional analysis of a 40 square kilometer area in the Uinta Basin.
3. Perform a detailed, bed-by-bed investigation of lithological variations of oil shale, including distinguishing rich vs. lean zones.
4. Understand the controls and environmental conditions that led to the deposition of oil-shale rich zones.
5. Conduct a quantitative assessment of the impact of reservoir heterogeneity on production by simulating production from a realistic stratigraphic section.
6. Provide oil production rates, oil recoveries, and residual oil values for a section (around the core) in the Uinta Basin.

Summary of Project Outcomes

In this project, a detailed geological analysis was performed followed by a reservoir modeling exercise. For the geological analysis, ~300 m of cores were correlated to gamma and density logs in well P4 in the lower to middle Eocene (49.5–48.0 million years ago (Ma)), upper Green River Formation of the eastern Uinta Basin, Uintah County, Utah. In well P4, three distinct facies associations were identified that represent three phases of deposition linked to the hydrologic evolution of Lake Uinta: 1) an overfilled, periodically holomictic lake system with deposition of primarily clastic mudstones, followed by 2) a balanced-filled, uniformly meromictic lake system with deposition of primarily calcareous and dolomitic mudstones, followed by 3) an underfilled, evaporative lake system with nahcolite precipitation. The richest oil shale zones were deposited during the second depositional phase. While the studied interval is popularly known as oil "shale", this bed-by-bed investigation revealed that lithologically, thus chemically, the interval is quite heterogeneous. This complexity has significant impact on modeling strategies for oil shale exploitation.

In the project's second phase, various in-situ oil shale production methods for this heterogeneous resource were explored. In-situ methods have a lessened environmental impact and are likely to have lower costs than mining and surface processing. Heat transfer pathways, chemical kinetics, geomechanics, multiphase fluid flow, and process strategies add complexity to any in-situ oil shale production strategy. Understanding each of these phenomena as well as appropriate model coupling is necessary to accurately model in-situ oil shale production processes. Results from in-situ oil shale modeling with the STARS simulator show that oil production from the Green River Formation is feasible. Challenges to achieving economic rates of recovery include porosity-permeability creation and the establishment of contiguous pathways between injectors and producers. Idealized energy efficiency and carbon footprint for an electrical conduction-type process were estimated as 3:1 net energy gain and 36 kg CO_2/barrel (bbl) oil produced respectively.

Presentations and Papers

Peer-Reviewed Publications

Bauman, J., Huang, C. K., Gani, R. and Deo, M., 2009, Modeling In-Situ Production of Oil Shale, ACS Symposium Series, In Press.

Gallin, W., Gani', M. Royhan., Deo, Milind, Gani, Nahid D. S., and Vanden Berg, Michael, D., 2009, Lake Level Controlled Sedimentological Heterogenity of Oil Shale, Upper Green River Formation, Eastern Uinta Basin, Utah, ACS Symposium Series, In Press.

Conference Proceedings

Tiwari, P. and Deo M., 2008, Kinetics of Pyrolysis of Oil Shale and Compositions of Oils Produced, AIChE Annual Meeting Proceedings, Philadelphia, PA, November 16-21, 2008.

Presentations

Bauman, J. and Deo, M., 2009, Interaction Between Reactivity and Flow in the In-situ Production of Oil from Oil Shale, 29th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 19-23, 2009.

Tiwari, P. and Deo, M. 2009, Oil Shale Pyrolysis, Characterization and Compositional Analysis, 29th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 19-23, 2009.

Lin, C. Miller, J. Hsieh, H. Tiwari, P. and Deo M., 2009, Pore Scale Analysis of Pyrolyzed Oil Shale Cores, 29th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 19-23, 2009.

Bauman J., Huang, C. and Deo, M., 2008, In-situ Modeling of Oil Shale, AIChE Annual Meeting, Philadelphia, PA, November 16-21, 2008.

Bauman, J. Huang, C. and Deo, M., 2008, In-situ Modeling of Oil Shale, 28th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 13-17, 2008.

Tiwari, P. and Deo, M. 2008, Kinetics of Pyrolysis of Oil Shale, 28th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 13-17, 2008.

Huang, C., Gani, R., and Deo, M. 2007, In-situ Production of Oil from Oil Shale in the Greenriver Formation in the Uinta Basin, Utah, AIChE Annual Meeting, Salt Lake City, Utah, November 5-9, 2007.

Huang, C. and Deo, M. 2007, In-situ Modeling of Oil Shale Production, Pyrolysis and Waterflooding, 27th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 15-19, 2007.

Mandalaparty, P. and Deo, M. 2007, Environmental Impact of In-situ Oil Shale Processing, 27th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 15-19, 2007.

Huang, C. Gani, R. and Deo, M. 2006, In-situ Pyrolysis of GreenRiver Formation Oil Shale, 26th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 16-20, 2006.

Oh, K. and Deo, M. 2006, Evaluation of Various Oil Shale Processing Options, 26th Oil Shale Symposium, Colorado School of Mines, Golden, CO, October 16-20, 2006.

Geological Characterization

The Green River Formation in northeastern Utah, northwestern Colorado, and southwestern Wyoming (Figure 1) contains the world's largest deposit of oil shale. Estimates of recoverable resources in Utah alone range as high as 321 billion barrels (1). A recent Utah Geological Survey (UGS) report uses five key constraints to estimate Utah's potential recoverable oil shale resource at 77 billion barrels (2).

While the unconventional asset represented by the Green River Formation is obvious, sedimentology of its oil-shale bearing units is insufficiently documented, particularly in the subsurface. In outcrop, detailed investigation of oil shale lithology is hindered by weathering as evidenced by fine-grained mudstone laminations that are more clearly visible in slabbed core than in outcrop.

Previous work in the Green River Formation of the eastern Uinta Basin describes basin-margin depositional environments from outcrops, particularly for the lower and middle part of the formation (3, 4, 5), but lack information regarding subsurface lithological variation. Other work interpreting well log data without core data (6) describes the strata in this region in a scope that is temporally too broad for the objectives of this study.

This study focused on the upper Green River Formation closer to the basin center than previous work. It provides the first detailed account of subsurface sedimentology of the upper part of the Green River Formation in the eastern Uinta Basin. The study used a ~300 m thick core correlated to gamma-ray and neutron density logs to meet its objectives.

Regional Geology

As the Late Cretaceous Sevier fold-and-thrust orogeny waned during the late Campanian to early Maastrichtian, the onset of Laramide orogeny broke the broad foreland basin of the Western

Interior Seaway into a series of perimeter, axial, and ponded basins (7,8). The Uinta Basin formed as a ponded basin bounded to the west by the Sevier orogenic belt; to the south by the San Rafael, Uncompaghre, and Monument uplifts; to the east by the Douglas Creek arch; and to the north by the Uinta uplift (Figure 1). The north-south trending Douglas Creek arch separated the Uinta Basin from its time-equivalent neighbor, the Piceance Creek Basin in northwestern Colorado, and acted episodically as a hydrological barrier and as a subsumed structural saddle through the duration of deposition in these basins. The Piceance Creek Basin was, in turn, subjected to inundation from the overfilled Greater Green River Basin in southwestern Wyoming (Figure 1).

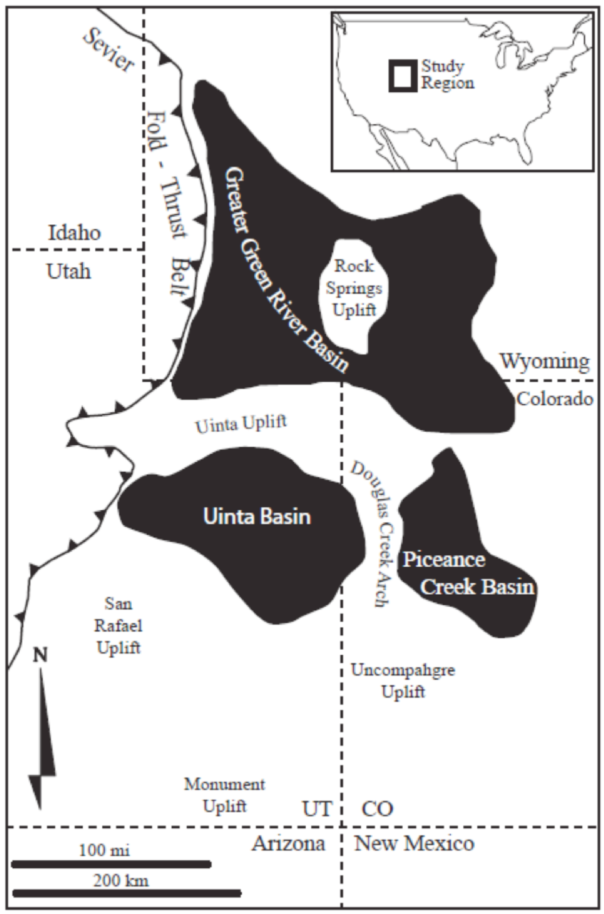

Figure 1. Location map of the study region in the western United States showing the configuration of the Laramide lacustrine basins in which the Green River Formation was deposited in the early to middle Eocene (49.5–48.0 Ma).

The Green River Formation in the Uinta, Piceance Creek, and Greater Green River Basins was deposited in the early to middle Eocene, approximately 55 Ma to 44 Ma (9,10). Ash beds from volcanism in the Absaroka Mountains episodically blanketed the region, providing datable isochrons (9). Typical of ponded basins, the Uinta, Piceance Creek, and Greater Green River Basins were at times internally drained, depositing several thousand meters of profundal-lacustrine and evaporative strata in addition to fluvial-lacustrine, paludal, and alluvial strata (7).

Study Area and Local Geology

This study focuses on the oil-shale bearing profundal-lacustrine and evaporative strata of the Green River Formation in the eastern Uinta Basin of Uintah County, located in northeastern Utah (Figure 2). The highest quality core with available correlating well logs is from well P4 (also known as U059) and is housed at the UGS Core Research Center in Salt Lake City, Utah. Core P4, located in T10S-R25E, Uintah County, was recovered from the 65 m (211 feet) to 357 m (1170 feet) depth zone, covering 292 m (959 feet) of thickness.

The present study follows marker-bed nomenclature of Remy (5) due to the prominence of these marker beds in core P4 and the precedent they set for subsequent literature (9). This nomenclature was defined in outcrops of fluvial-lacustrine and marginal lacustrine strata of Nine Mile Canyon in the south-central Uinta Basin (Figure 2). Variations on Green River Formation nomenclature in the literature and the stratigraphic position of core P4 in that system are summarized in Figure 3. In addition, this study follows the oil shale nomenclature of Vanden Berg (2), a system consisting of rich (R) and lean (L) oil-shale zones derived from Uinta Basin well log data. The richest zone, the Mahogany Zone, is found in zone R7 (2). A-Groove and B-Groove are the names for the kerogen lean zones of L7 and L6 respectively (Figure 3). These zones are identified in density logs with the Fischer Assay, which correlates the presence of kerogen in the deposits with decreased bulk density (2). Oil shale zone richness varies; yield estimates for rich zones range from 15 to 50 gallons per ton (GPT) (2).

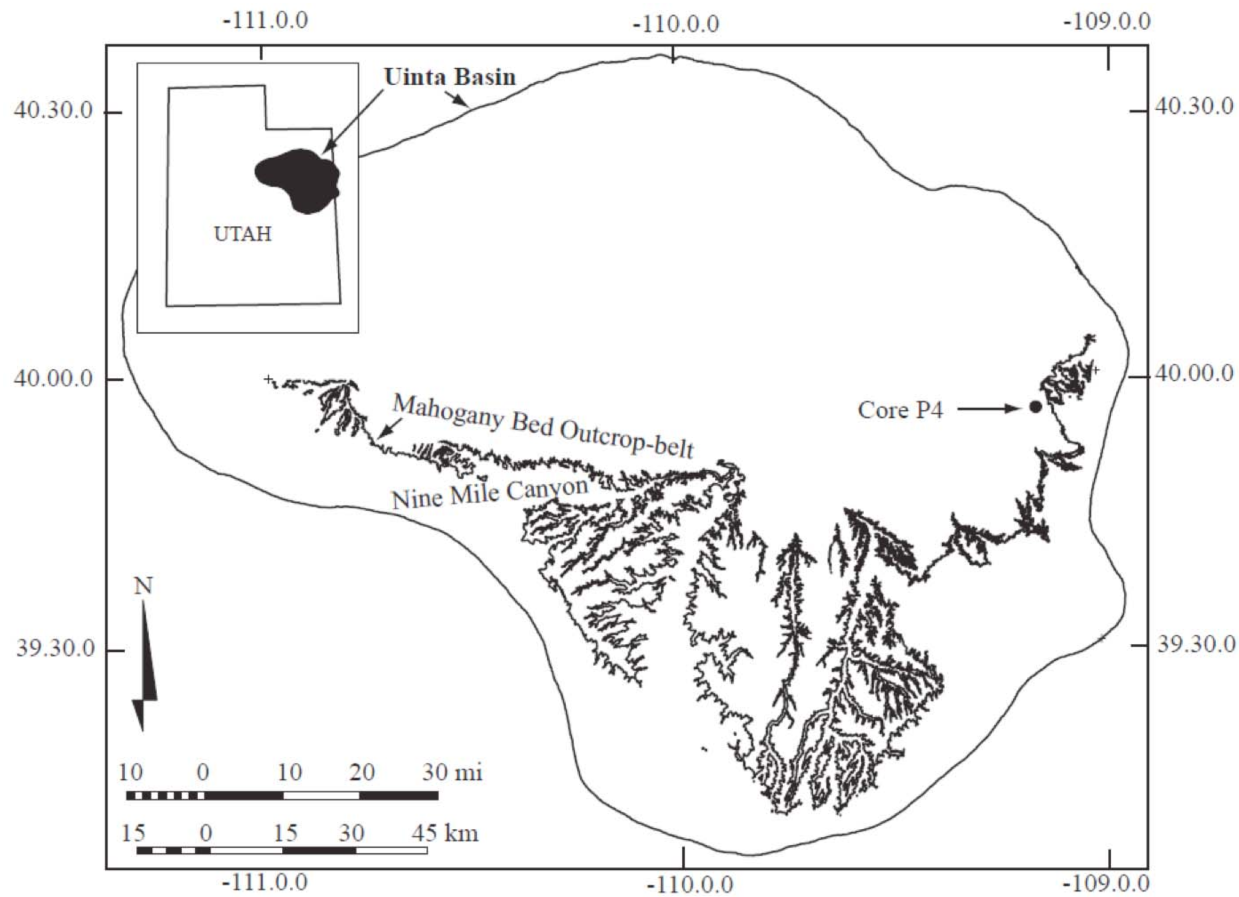

Figure 2. Location of well P4 (also known as well U059) in the eastern Uinta Basin of Uintah County, northeastern Utah. Note the location of Nine Mile Canyon, which is the site of previous outcrop-based work on the Green River Formation.

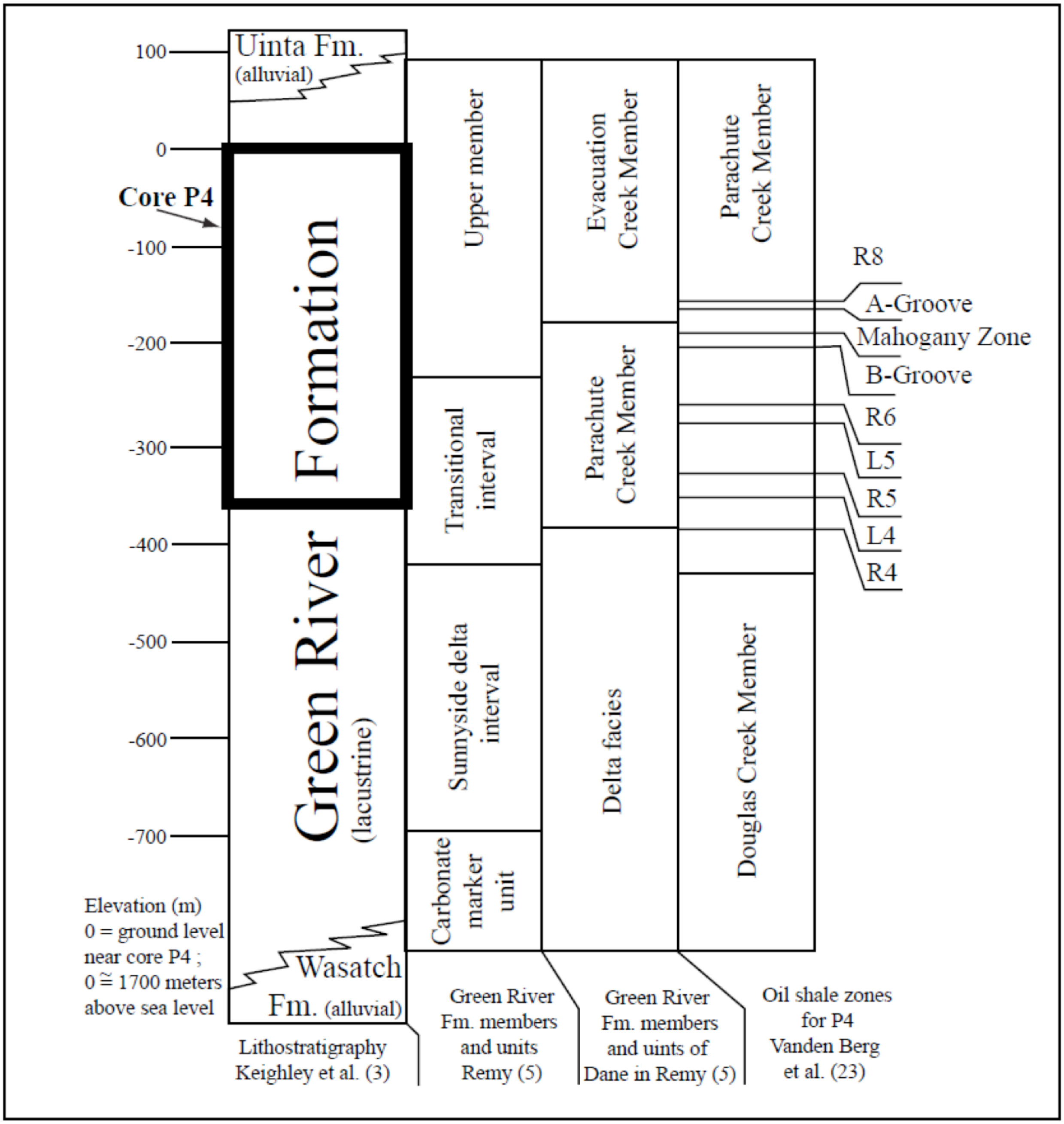

Figure 3. Stratigraphic nomenclature of Green River Formation in and around the study area. Core P4 belongs to the upper Green River Formation.

Methods

Lithology, sedimentary structures, and trace fossils (burrows) of core P4 were logged through visual investigation; HCl and a light microscope were used when necessary. Bioturbation intensity in the cores was quantified using a six-grade scale (6 being the highest) to generate a bioturbation index (BI) log (11). Photographs of key features were taken at various core depths.

Scanned images of Gamma and density well logs of P4 were acquired from UGS and digitized using NeuraLog software. The digitized logs were uploaded in Landmark's Geographix software to pick stratigraphic surfaces correlated to core P4. These surfaces, defined as gamma kicks, are regions where gradual fluctuations in gamma values lead to, or are followed by, sudden changes in gamma values.

Results

Core Sedimentology

Figure 4 shows the graphic lithological log of core P4. The six lithofacies identified can be grouped into three broad intervals. The interval lying below the base of the Mahogany Zone (>235 m depth) is characterized by the preponderance of clastic mudstone facies. The middle portion of the core (125-235 m depth) is dominated by calcareous mudstone facies. The upper portion of the core (< 125 m depth) is characterized by evaporites. Oil shale, not categorized here as facies, is unevenly distributed among the three intervals.

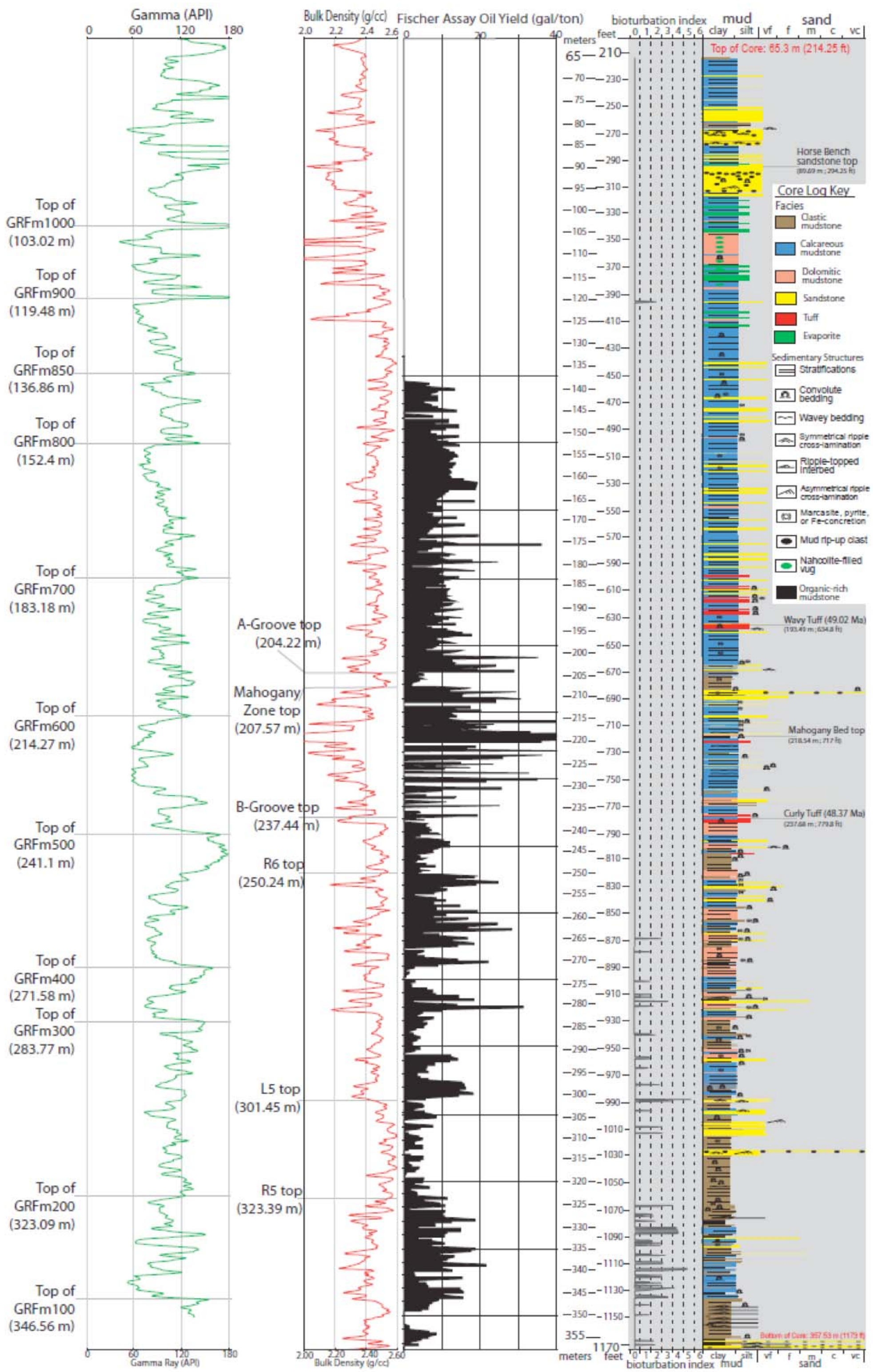

Figure 4. Geophysical, chemical, ichnological, and lithological logs for well P4 (see Figure 2 for location). Prominent marker beds, rich (R) and lean (L) oil-shale zones, and genetic stratigraphic horizons (GRFm#) are labeled.

Sandstones are also unevenly distributed throughout the core as thin beds, but two groups of thicker sandstones are found. One unnamed group lies near the base of the core. Another group, identified as the Horse Bench sandstone (5), lies near the top of the core (Figure 4).

Two main groups of tuffs are identified. The lower tuff at the base of the Mahogany Zone is the Curly Tuff. The upper tuff, approximately 18 m above the top of the Mahogany Zone, is the Wavy Tuff (5, 9).

Evaporites, identified only in the form of nahcolite, are found only above the Mahogany Zone. With the exception of current- and wave-ripples in the Horse Bench sandstone, nearly all sedimentary structures indicating lake bottom agitation appear below the Mahogany Zone.

The sedimentological description and interpretation of the oil shale and of the six lithofacies are as follows:

1. Oil Shale
    a. Description: The term oil shale is lithologically ambiguous and scientifically misleading. Hence, oil shale is not identified as a facies in this study. Lithologically, oil shale in core P4 consists of kerogen-rich intervals of calcareous and dolomitic mudstones. The kerogen richness required for a mudstone to be considered as oil shale is an economic question, not a sedimentological one. Oil shale richness is represented in the Fischer Assay log of Figure 4 by oil yield in GPT. This log shows the distribution of average rich versus lean oil shale zones throughout core P4. The Mahogany Bed of the Mahogany Zone yields up to 75 GPT in the vicinity of core P4.

       Kerogen-rich oil shale does not react as strongly with HCl as the kerogen-poor calcareous and dolomitic mudstones due to its higher kerogen to carbonate ratio. Oil shale appears distinctively dark brown to black and is finely laminated (<1 mm thick) in core P4 (Figures 5a, 5b, and 5c). Rich oil shale beds with yields greater than 20 GPT are rarely thicker than 30 cm. Oil shale is often friable with core samples tending to crack along oil-shale lamination planes.

    b. Interpretation: Interpretation of oil shale is discussed in the interpretation section of calcareous mudstones (Facies 2).

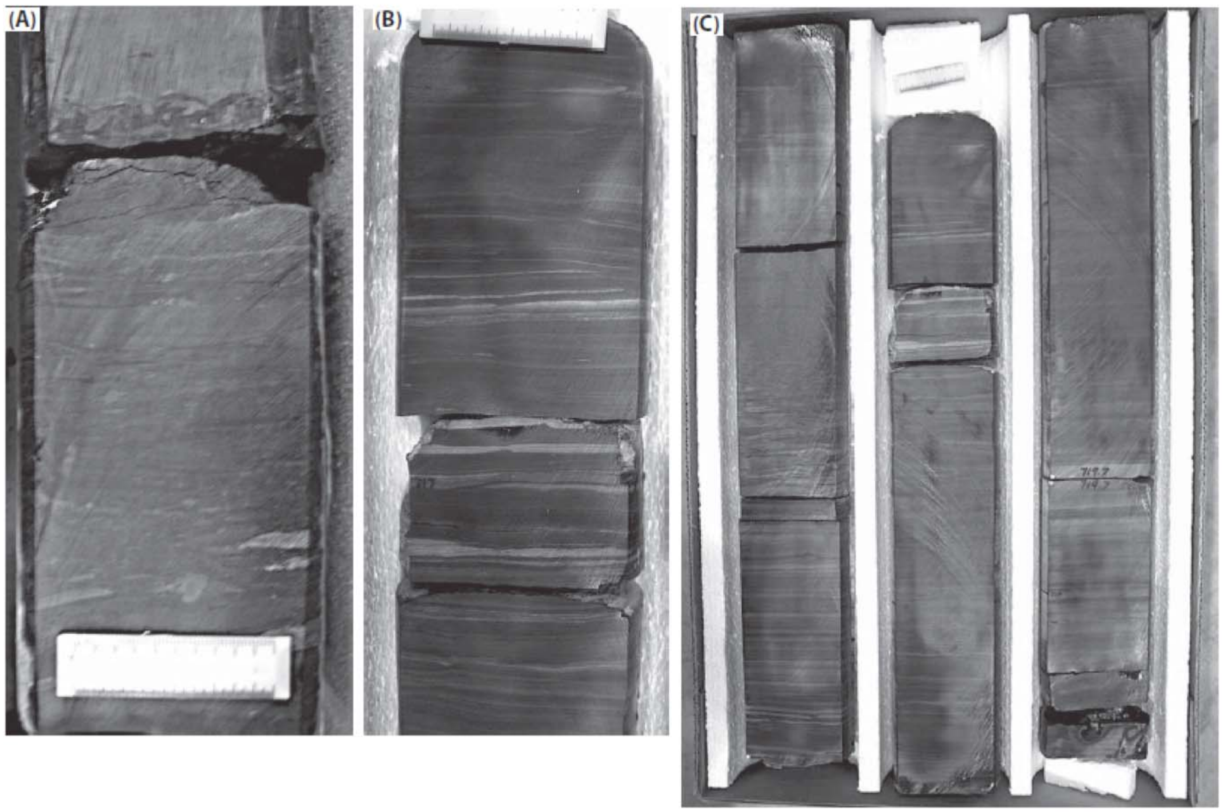

Figure 5. A) Black, organic-rich, and friable oil shale (328.88 m depth in litholog of Figure 4). B) Mahogany Bed, the richest oil shale bed in the Mahogany Zone, which is the richest oil shale zone in Green River Formation (219.46 m depth in Figure 4). Core base is bottom-right and top is upper-left. C) Details of the Mahogany Bed. Lighter interlaminations are kerogen-poor calcareous and dolomitic mudstones (218.54 m depth in Figure 4). Note that scale is 5 cm long in all photos.

2. Facies 1: Clastic mudstones
    a. Description: The clastic mudstone facies consists of clay-rich to sometimes silty, grayish-beige to dark brown, finely-laminated (<1 mm thick) mudstones (Figure 6a). Light brown, beige, and gray laminations can be similar in color to calcareous or dolomitic mudstone facies (Facies 2 and 3, respectively), but the clastic mudstone facies never fizzes under HCl. The facies is often interrupted by ripple-topped interbeds of siltstone or sandstone lenses (<2 cm thick). Additionally, it shows varying degrees of soft-sediment deformation (Figure 6b); deformation due to post-depositional mineral and nodular growth of pyrite, siderite, and possibly marcasite; deformation due to overburden strata; and deformation due to bioturbation (Figure 6c). Despite local deformations and interruptions by sand lenses, the clastic mudstone facies is most commonly horizontally laminated.

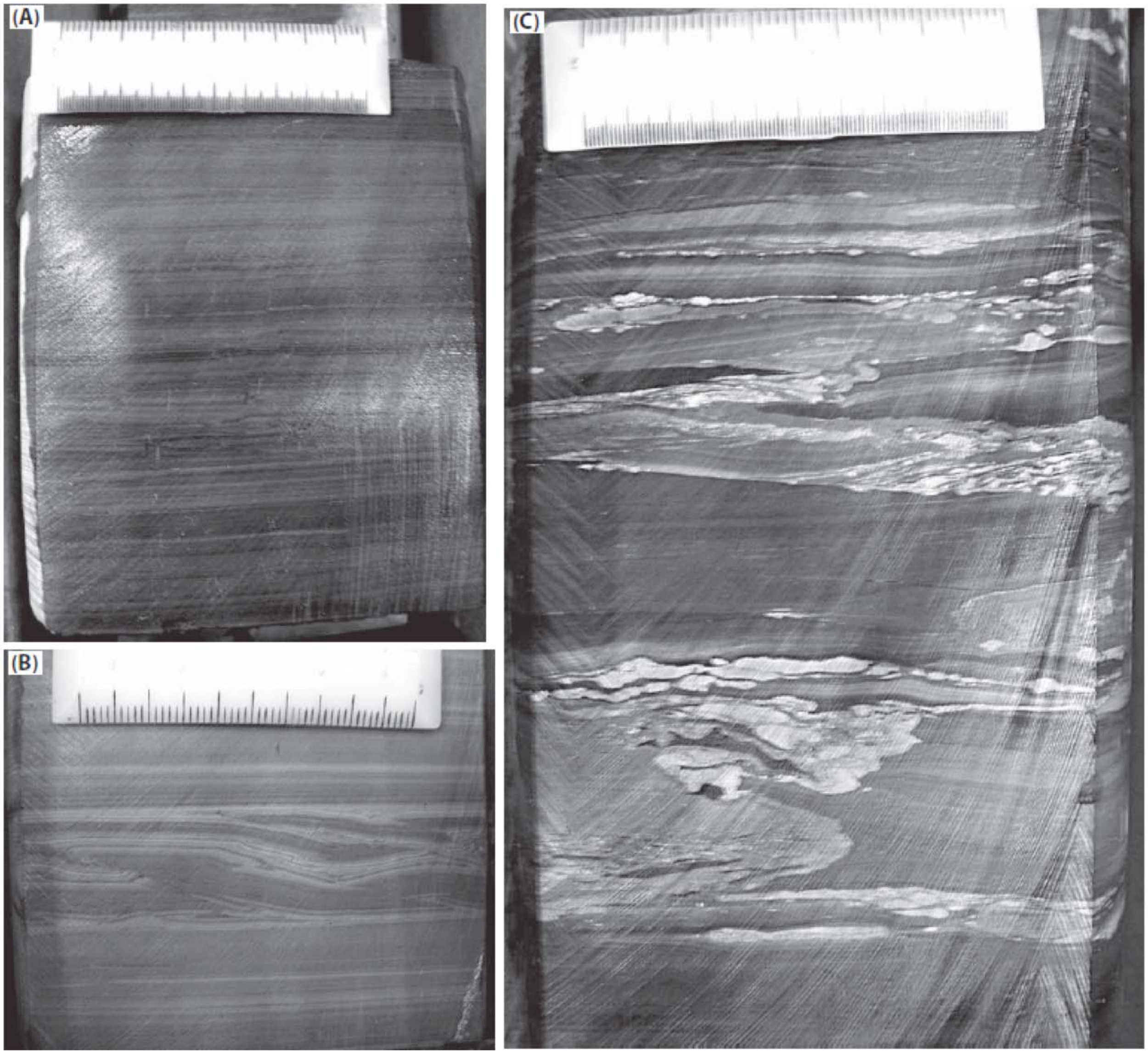

Figure 6. Clastic mudstone facies showing A) fine laminations (349.97 m depth in Figure 4), B) soft sediment deformation (316.93 m depth in figure 4), and C) deformation due to bioturbation, where burrows are filled with dolomitic mudstones (327.05 m depth in Figure 4). Note that scale is 5 cm long in all photos.

b. Interpretation: The horizontally-laminated, non-calcareous, non-dolomitic, and very fine-grained nature of the clastic mudstone facies strongly suggests the deposition of siliciclastics in the deeper part of the lake basin, likely below storm wave base. Ripple-topped interbeds of coarser materials, especially those with scoured bases and basal rip-up clasts, indicate event depositions when turbidity currents reached this distal depositional site.

3. Facies 2: Calcareous mudstones
    a. Description: The calcareous mudstone facies consists of microcrystalline, calcium carbonate-rich, yellow-beige to dark brown, finely laminated mudstones (<1 mm to 1 mm thick laminae) and reacts strongly to HCl. The richest oil shale zones are dominated by calcareous mudstone facies (Figures 7a and 7b).

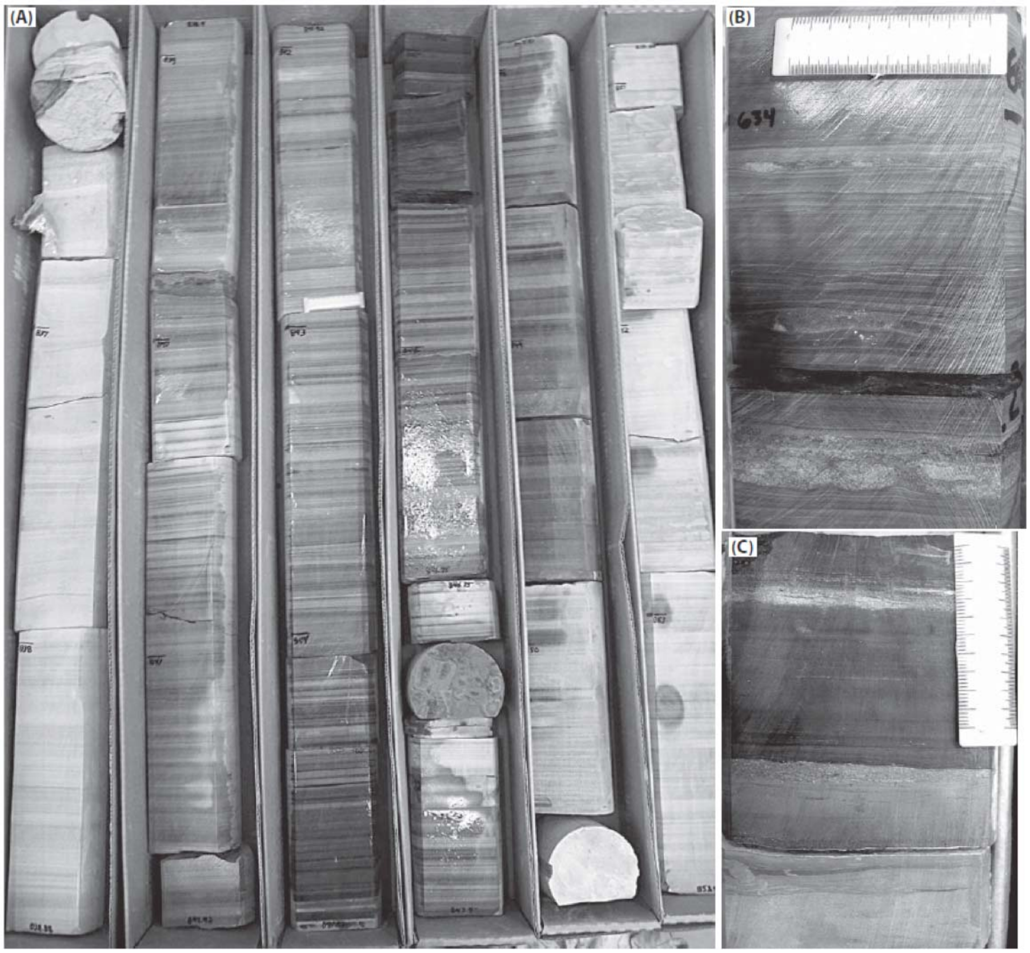

Figure 7. A) Typical calcareous-mudstone-dominated rich oil shale (259.69 –255.12 m depth in Figure 4). Lighter rocks on either end of figure are dolomitic mudstones. Gray laminated rocks are kerogen-poor vs. kerogen-rich interlaminations of calcareous mudstones. Black rocks at the middle portion are calcareous mudstones highly rich in kerogen. Each core box is ~1 m long. Core base is bottom-right and top is upper-left. B) Details of calcareous mudstone facies. Light-colored granular beds are unnamed tuffs (193.24 m depth in Figure 4). C) Bioturbated calcareous mudstones at the base of photograph, overlain by sandstone and by kerogen-rich calcareous mudstones (332.54 m depth in Figure 4). Note that scale is 5 cm long in all photos.

The calcareous mudstone facies shows evidence of local soft-sediment deformation but rarely of ripple cross-lamination or ripple-topped interbeds as does the clastic mudstone facies. Calcareous mudstone facies that is finely interlaminated with darker mudstones is difficult to distinguish from the clastic mudstone facies. However, the calcareous mudstone facies will always react with HCl while the clastic mudstone facies will not. Evidence of bioturbation is more commonly found in the calcareous mudstone facies than in other facies, although bioturbation is absent in the calcareous mudstone facies above the Mahogany Zone (Figure 7c).

b. Interpretation: Since there is no evidence of the production of calcareous shells, organic encrustations, or skeletal elements and evidence for clastic allocthonous calcium input or post-depositional precipitation is lacking, the remaining possible source for calcium in the calcareous mudstone facies is from direct precipitation from the water column (12). The association of carbonate minerals with oil shales is well documented (13) and is often characteristic of deep lacustrine basins (14).

The conditions for the deposition of the calcareous mudstone facies in association with the oil shale could be a meromictic, stratified lake with a slightly alkaline, nutrient-rich upper-layer and a high-pH, anoxic lower-layer. During seasonal algal blooms, removal of dissolved CO_2 from the water column through photosynthesis raised the upper-layer pH and allowed for the concentration of calcium and magnesium in algal sheaths. As algal blooms died, organic material was deposited in the lake bottom, where decomposition was inhibited by anoxic conditions. In this way, carbonate was deposited in association with the organic constituents of oil shale (15).

In order for the conditions to be met in which the calcareous mudstone facies were deposited rather than clastic mudstone facies, there must have been both meromictic lake conditions and some distance from the overwhelming input of clastic mudstone. Both of these conditions were met in deep water lake basins. The finely laminated nature of calcareous mudstone facies and lack of wave- or current-generated sedimentary structures further supports the interpretation of deposition of calcareous mudstone facies in deep water.

4. Facies 3: Dolomitic mudstones
   a. Description: The dolomitic mudstone facies consists of microcrystalline, light beige to light gray dolomite (CaMg(CO3)2) mudstone that reacts weakly with HCl. This facies is sometimes finely laminated (<1 mm to 1 mm thick laminae; Figure 8a) but is often deformed and may bear nodular growths of pyrite, siderite, and possibly marcasite. The lower portion of the core exhibits a more even distribution of laminated dolomitic mudstone facies in association with the rich oil shale zones, calcareous mudstone facies, and clastic mudstone facies. Near the top of the core, the

dolomitic mudstone facies is closely associated with the evaporite facies (Facies 5). It is also massive rather than laminated, deformed, and pocked by nahcolite dissolution vugs (Figure 8b). Although the dolomitic mudstone facies is generally lighter in color, it can resemble either calcareous mudstone facies or clastic mudstone facies. However, the dolomitic mudstone facies reacts weakly with HCl while the calcareous mudstone facies exhibits a strong HCl reaction and the clastic mudstone facies exhibits no HCl reaction.

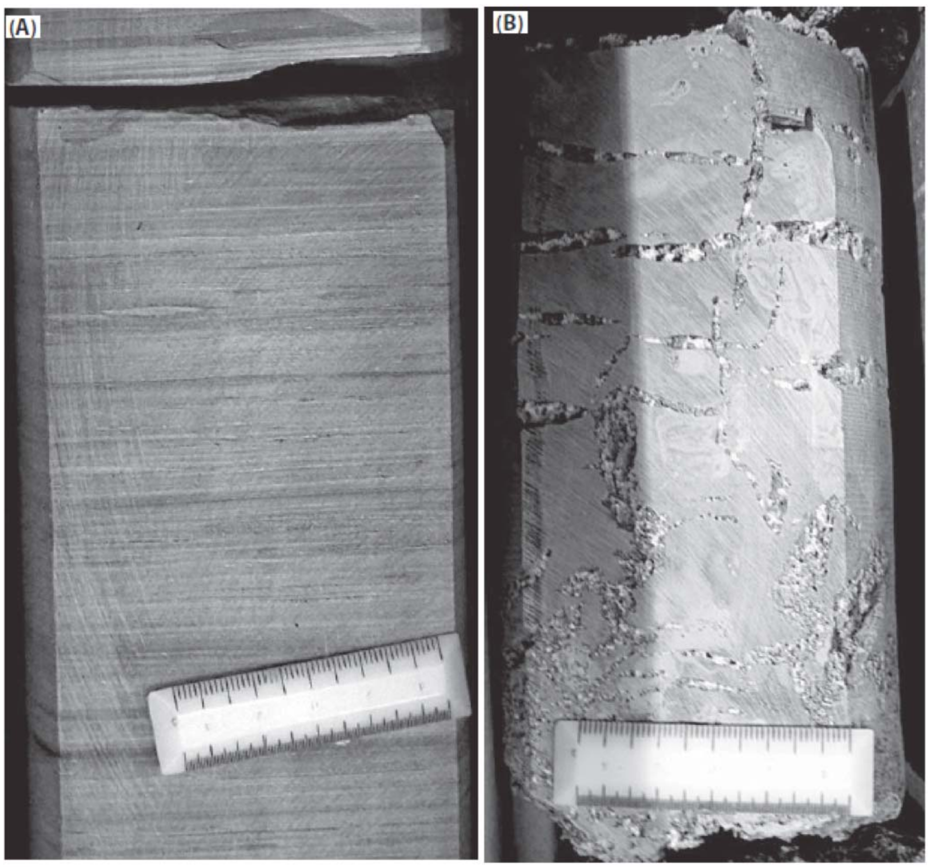

Figure 8. A) Finely laminated dolomitic mudstones (321.56 – 321.26 m depth in Figure 4). B) Massive dolomitic mudstones with nahcolite vugs (110.64 m depth in Figure 4). Note that scale is 5 cm long in all photos.

b. Interpretation: Dolomitic mudstone facies are interpreted differently for the lower and upper portions of the cores. In addition to calcium carbonate, magnesium-calcium carbonate is also found in association with oil shale (15). Certain algal blooms selectively remove magnesium from the water column for concentration in algal sheaths. The laminated dolomitic mudstone in the lower portion of the core (>235 m depth) probably formed under meromictic lake conditions similar to those that formed the calcareous mudstone facies. Slight variations in ecological conditions may have regulated the deposition of calcareous versus dolomitic mudstones.

Primary inorganic dolomite precipitate is often deposited in shallow, saline lakes (16). The association of massive dolomitic mudstone facies with evaporites in the upper portion of the core (<125 m depth) is interpreted to indicate such conditions. The perceived problematic transition from deep water carbonates to shallow water evaporites without intervening basin-margin clastics is explained in the Discussion section.

5. Facies 4: Sandstones
   a. Description: The sandstone facies consists primarily of very fine, yellow-beige to gray sandstones. This facies contains rare instances of coarser-grained sandstones found in thin (1-3 cm) intervals. While most sandstone lenses are too thin to discern visible grading patterns, some thicker (>30 cm) sandstone beds show normal grading with erosive basal-contacts and rip-up mudstone clasts (Figure 9a). Asymmetrical and symmetrical ripple cross-laminations appear locally (Figure 9b). A prominent, medium-grained, well-rounded tar sandstone layer lies at 279 m depth. Most individual sandstone beds are thin (1-3 cm) and show no ripples or graded relationship to either overlying or underlying mudstones (Figure 9c). Thicker sandstone beds below the Mahogany Zone bear limited bioturbation (Figure 9d).

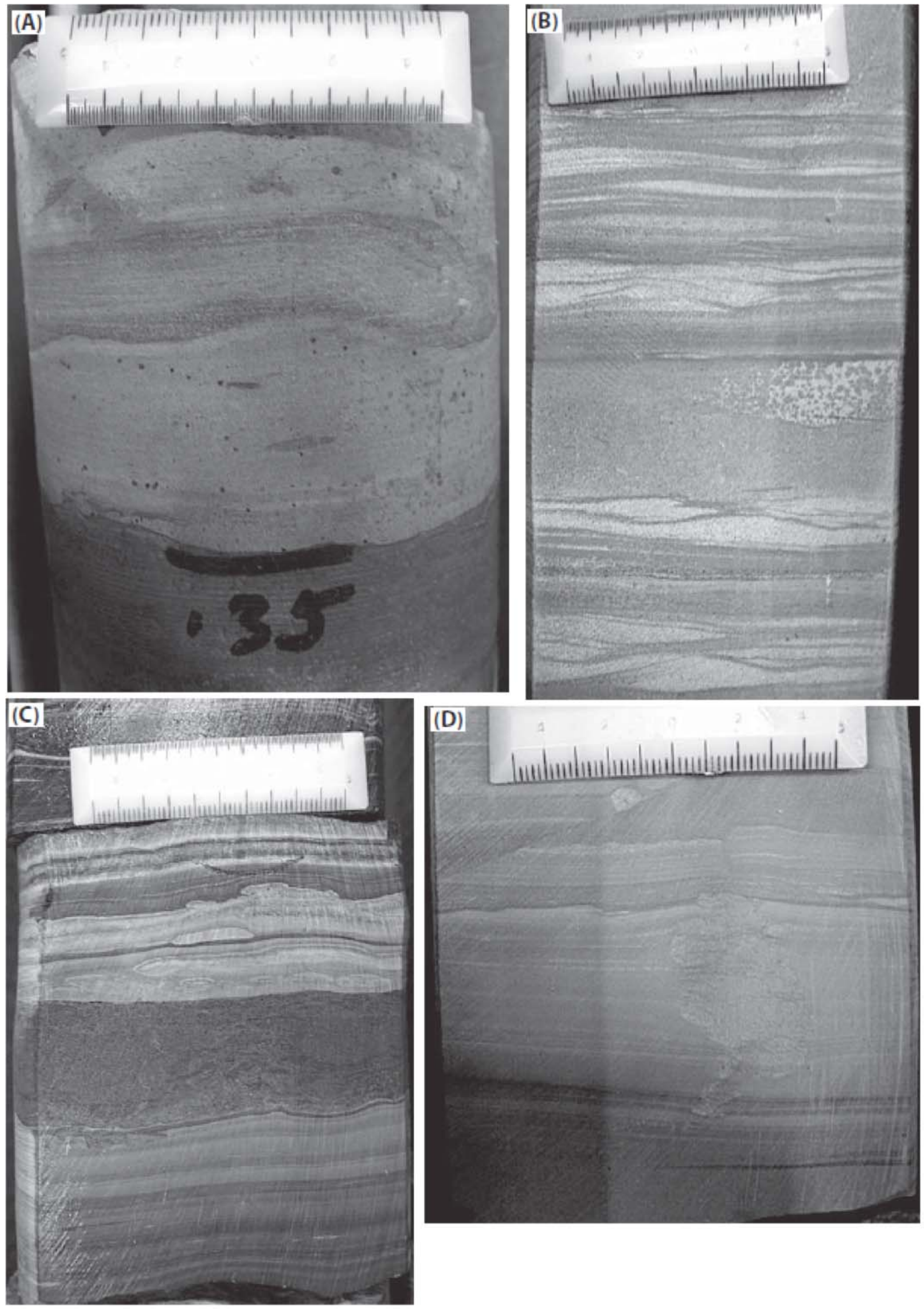

Figure 9. A) Sandstone facies (Horse Bench sandstone) with erosive basal contact and rip-up clasts (95.4 m depth in Figure 4). B) Wave ripple lamination (313.49 m depth in Figure 4). C) Sandstone bed (darker layer in the middle) with sharp lower and upper contacts, underlain by calcareous mudstones and overlain by clastic mudstones (278.89 m depth in Figure 4). D) Prominent solitary burrow in sandstone facies (278.59 m depth in Figure 4). Note that scale is 5 cm long in all photos.

In core P4, sandstones are mainly found at two stratigraphic intervals (Figure 4). The lower sandstone interval lies between ~300-315 m and the upper sandstone interval, identified as the Horse Bench sandstone (5), lies between ~80-95 m.

b. Interpretation: The deposition of sand facies in core P4 is interpreted to represent either 1) episodes of lower lake levels that brought the basin margin closer to the position of core P4, or 2) the periodic deposition of large turbidity flows capable of reaching the distal basin position of core P4. The sedimentary characteristics of the sandstone intervals indicate that most of these beds were not deposited from turbidity currents. Rather, the near absence of normal grading and the presence of oscillatory wave ripples suggest that these sandstone beds are related to periods of decreased distance between core P4 and the basin margin (i.e. decreased lake level). In the upper portion of the core, the deposition of the Horse Bench sandstone immediately following the deposition of both bedded evaporites and shallow, saline-water dolomitic mudstones suggests the onset of a wetter climate and fresher lake water conditions following a period of aridity and salinity.

6. Facies 5: Evaporite (nahcolite, NaHCO3)
   a. Description: The evaporite facies, found only above the Mahogany Zone, consists of the brown to gray, bedded precipitation of nahcolite (Figures 10a and 10b) as well as vugs filled with nahcolite (Figure 10c). No halite was observed. Nahcolite beds are generally < 3 cm thick and interbedded with calcareous mudstone facies. Beds containing nahcolite vugs can be >5 cm thick and are found mostly in massive, deformed dolomitic mudstones.

Figure 10. A) Bedding plane view of bedded nahcolite (125.58 m depth in Figure 4). B) Small nahcolite vugs (113.45 m depth in Figure 4). C) Large nahcolite vugs (122.83 m depth in Figure 4). Note that scale is 5 cm long in all photos.

b. Interpretation: The deposition of evaporites indicates conditions of shallow, saline water. Nahcolite can precipitate through shallow lake-bottom nucleation (bedded nahcolite in core P4) or as displacive intrasediment nodules (vug-filling nahcolite in core P4) (17).

Nahcolite deposits in the Green River Formation are a significant economic resource and can serve to increase the value of otherwise costly surface or subsurface oil shale mining operations (18). However, their potential assistance or detriment to in-situ electrical, air, or steam heating production of oil from oil shale is yet to be determined.

In contrast to the eastern Uinta Basin, the strata of the Piceance Creek Basin show a higher prevalence of saline water facies, including extensive nahcolite deposits, below the Mahogany Zone (9). This difference is interpreted to represent varying hydrologic gradients at different times among the Eocene lake basins. These hydrologic gradients are further explained in the Discussion section.

7. Facies 6: Tuff (zeolite sands)
    a. Description: The tuff facies consist of both biotite ash and zeolite (hydrous aluminosilicate) sands, possibly including analcime (hydrated sodium aluminosilicate) in a matrix of unidentified fused volcaniclastic mineral hash. Two large (~75 cm thick) ash beds (Figure 4) are identified as the Curly Tuff (Figure 11a) and Wavy Tuff (Figure 11b). At least 17 other distinct, unnamed tuff beds are found in the core, with thicknesses ranging from 3–12 cm (Figure 11c). The tuff beds, together with adjacent underlying and overlying beds, are characteristically highly deformed.

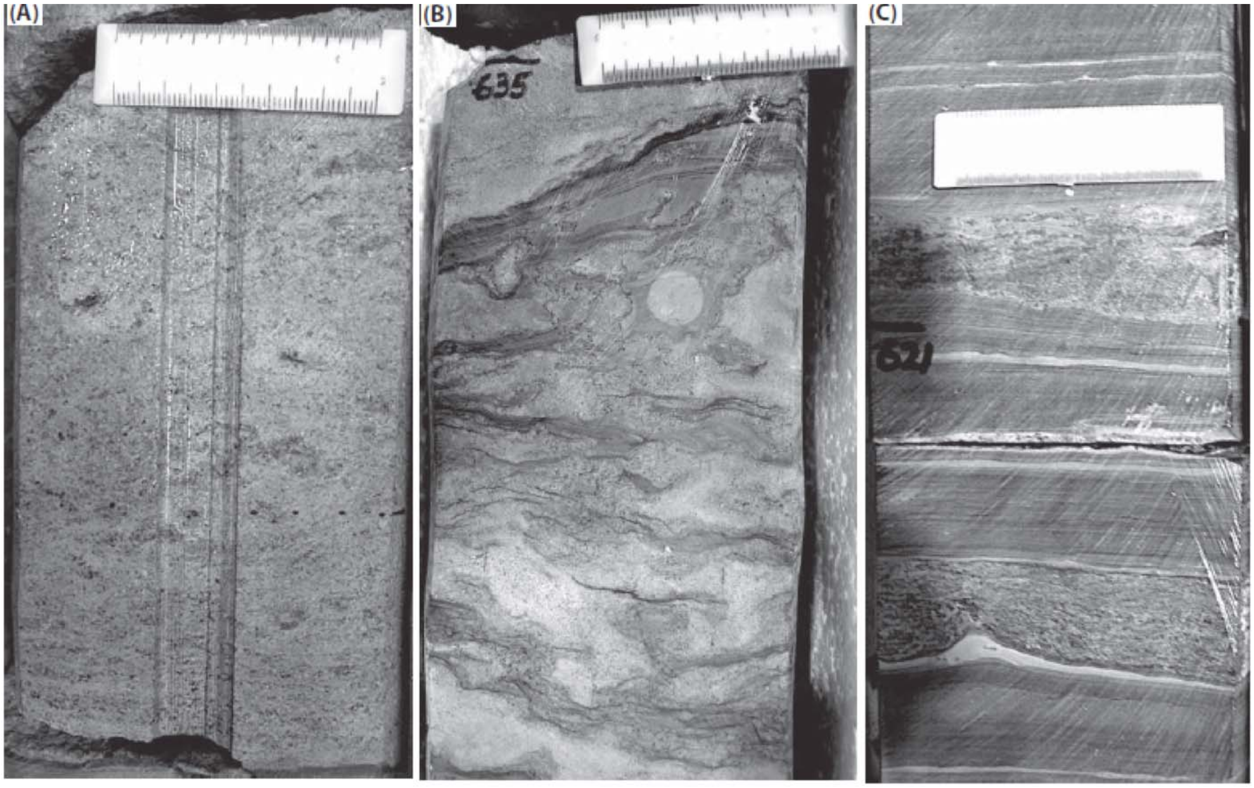

Figure 11. A) Curly Tuff (238.05 m depth in Figure 4). B) Wavy Tuff (193.55 m depth in Figure 4). C) Thin, unnamed tuff beds (189.28 m depth in Figure 4). Note that scale is 5 cm long in all photos.

b. Interpretation: As reported by Smith et al. (9), tuff ages are 49.02 ± 0.30 Ma for the Curly Tuff and 48.37 ± 0.23 Ma for the Wavy Tuff (ages are weighted means with errors of 2σ). The Absorka volcanic province in northwest Wyoming and southwest Montana and the Challis volcanic field in Idaho were active at these ages and may be the source of both Curly and Wavy Tuffs (9). Zeolites represent volcanic glass altered after deposition in highly saline or alkaline waters (19), which supports the interpretation of high alkalinity lake conditions during the deposition of calcareous and dolomitic mudstones.

Bioturbation

Bioturbation occurs almost entirely in the lower portion of the core, particularly at intervals where beds of calcareous mudstone facies alternate with beds of clastic mudstone facies (Figure 4). It is likely that the trace-making organisms periodically colonized the lake bottom during aerobic bottom-water, holomictic conditions. These trace makers were able to mine lower tiers of sediments that were deposited during anaerobic bottom-water, meromictic conditions. When stratification in water-column resumed, anaerobic bottom-water conditions precluded bioturbation. Such tiering of bioturbation is observed near the base of the core (325-350 m depth) in the BI log of core P4 (Figure 4). Tiered bioturbation controlled by bottom-water oxygen-level is well documented in the literature of marine ichnology (20).

Meromictic conditions were more prevalent farther up the core (>235 m depth) as evidenced by the onset and eventual dominance of thick intervals of calcareous mudstones. The upward-decreasing trend of clastic mudstones suggests greater distance of well P4 from the shoreline, possibly indicating greater water depth and better conditions for lake stratification. The halt of bioturbation and the increasing prevalence of calcareous mudstones above 235 m depth in core P4 further support the interpretation of deep, anoxic bottom-water conditions in the middle portion of core P4 (125-235 m depth).

Gamma Log

Eleven picks of potential genetic-stratigraphic (i.e. isochronous) surfaces were made in the upper Green River Formation from the gamma log of well P4. These eleven picks mark the top of stratigraphic units; names are abbreviated as GRFm followed by a three to four digit numeral. The stratigraphic order of GRFm picks as well as rich/lean oil shale zone picks in core P4 is shown in Figure 4. These eleven picks, coupled with six picks of rich and lean zones (2), are useful for ongoing subsurface stratigraphic correlation in the upper Green River Formation in the Uinta Basin.

The gamma log appears chaotic in the lower portion of the core, with at least two intervals of increasing-upward gamma values culminating at GRFm400 and GRFm500 (immediately below the Mahogany Zone). Above the Mahogany Zone, the gamma log shows a series of repetitive cycles of decreasing-upward gamma values with each cycle of decreasing gamma values topped by a sudden dramatic increase in gamma values. This pattern becomes less comprehensible above GRFm1000 (Figure 4).

When correlated to core sedimentology, many of the highest gamma values correspond to clastic mudstone facies (e.g., depth interval 244-250 m) while many of the lowest gamma values correspond to calcareous mudstone facies (e.g., most of the Mahogany Zone in depth interval 215-235 m). Therefore, the gamma log of core P4 can be considered as a direct measure of the relative abundance of clastic versus calcareous mudstones. This relationship, in turn, reflects the interplay of lake-level, water-depth, and lake stratification.

Two scenarios can be invoked to compare the relative abundance of clastic versus calcareous mudstones: 1) high gamma values correspond to clastic mudstones, indicating a wet climate favorable for delivering detrital-rich sediments (with K-feldspar, U, and Th) to the lake by surface runoff; low gamma values correspond to calcareous mudstones, indicating less detrital input during dry climate; or, preferably, 2) high gamma values correspond to clastic mudstones, indicating a fall in lake-level during which detrital input reaches the basin center (i.e. location of core P4); low gamma values correspond to calcareous mudstones, suggesting a rise in lake-level generating deeper, stratified water conditions with little to no input of siliciclastic fines at the basin center. Note that the second scenario is the inverse of gamma log interpretations of sand versus shale for marine and lacustrine environments (21).

Gamma signatures in the lower portion of the core (below the A-Groove) range from chaotic to bell-shaped (increasing-upward gamma). At least two bell-shaped trends, at GRFm400 and GRFm500, indicate a sudden richness of carbonate lithology (deep water facies) followed by a gradual increase in shale lithology (shallow water facies). Hence, these bell-shaped trends indicate shallowing-upward cycles, interpreted to be part of the lake system in which sediment and water supply exceeded (i.e., overfilled) or balanced (i.e., balanced-filled) with accommodation.

The gamma curve in the upper portion of the core, above the Mahogany Zone, exhibits a sawtooth pattern; high gamma values decrease gradually upward and then increase suddenly. These patterns are clear in GRFm1000, 900, 850, and 700 (Figure 4). The characteristic pattern of the gamma log exhibits aggradational to deepening-upward cycles. The persistence of deep water (i.e. calcareous mudstones) facies through the upper portion of the core coupled with the gamma signature indicates that the basin was overall a deep, balanced-filled lake system.

Discussion

Sedimentology of core P4 is interpreted to represent a depositional environment distal from the basin margin and sediment-input sources. Sedimentary structures such as current and wave ripples that were formed within a storm or fair weather wave base are only observed in limited places (the Horse Bench sandstone and other thin, scattered sandstones). However, the distance of core P4 from the shoreline varied over time, as evidenced by the three facies associations found in the core.

Excluding the volcanic input of tuff, the six facies of core P4 can be divided into three facies associations: A) relatively shore-proximal facies association (235-358 m depth) including clastic mudstones, calcareous mudstones, laminated dolomitic mudstones, and sandstones; B) deep-basin facies association (125-235 m depth) including mostly calcareous mudstones with small amounts of clastic mudstones and sandstones; and C) shallow water and evaporite facies association (60-125 m depth) including mostly sandstones, massive dolomitic mudstones, nahcolite, and some calcareous mudstones. The richest oil shale deposits are found in association B.

The models of overfilled, balanced-filled, and under-filled lake basins (22) suggest that lake-basin type is a function of sediment, water supply, and accommodation due to basin subsidence. Under conditions of continuous basin subsidence, sediment input and water supply should decrease with time, changing basin systems from overfilled to balanced-filled to under-filled.

The distinctly different facies associations of core P4 (Figure 4) resulted from changes in the lake basin system. In the lower portion of the core (> 235 m depth, facies association A), the pairing of the decreasing-upward trend in the abundance of clastic mudstone and the increasing-upward trend in calcareous mudstone is interpreted to reflect deepening conditions at core P4 in the Uinta Basin. This deepening resulted from an overfilled lake condition (excess of water and sediment input relative to accommodation; see Figure 12a. The overfilled lake condition led to a balanced-filled condition (Figure 12b) as the Uinta and Piceance Creek Basins joined. This transition is characterized by the rapid waning of clastic mudstone facies and the predominance of calcareous mudstone facies in the middle to upper portion of the core (235-125 m depth, facies association B). Balanced-filled lake conditions prevailed until evaporites deposited near the top (<125 m depth, facies association C) of the core, indicating an under-filled lake condition (Figure 12c).

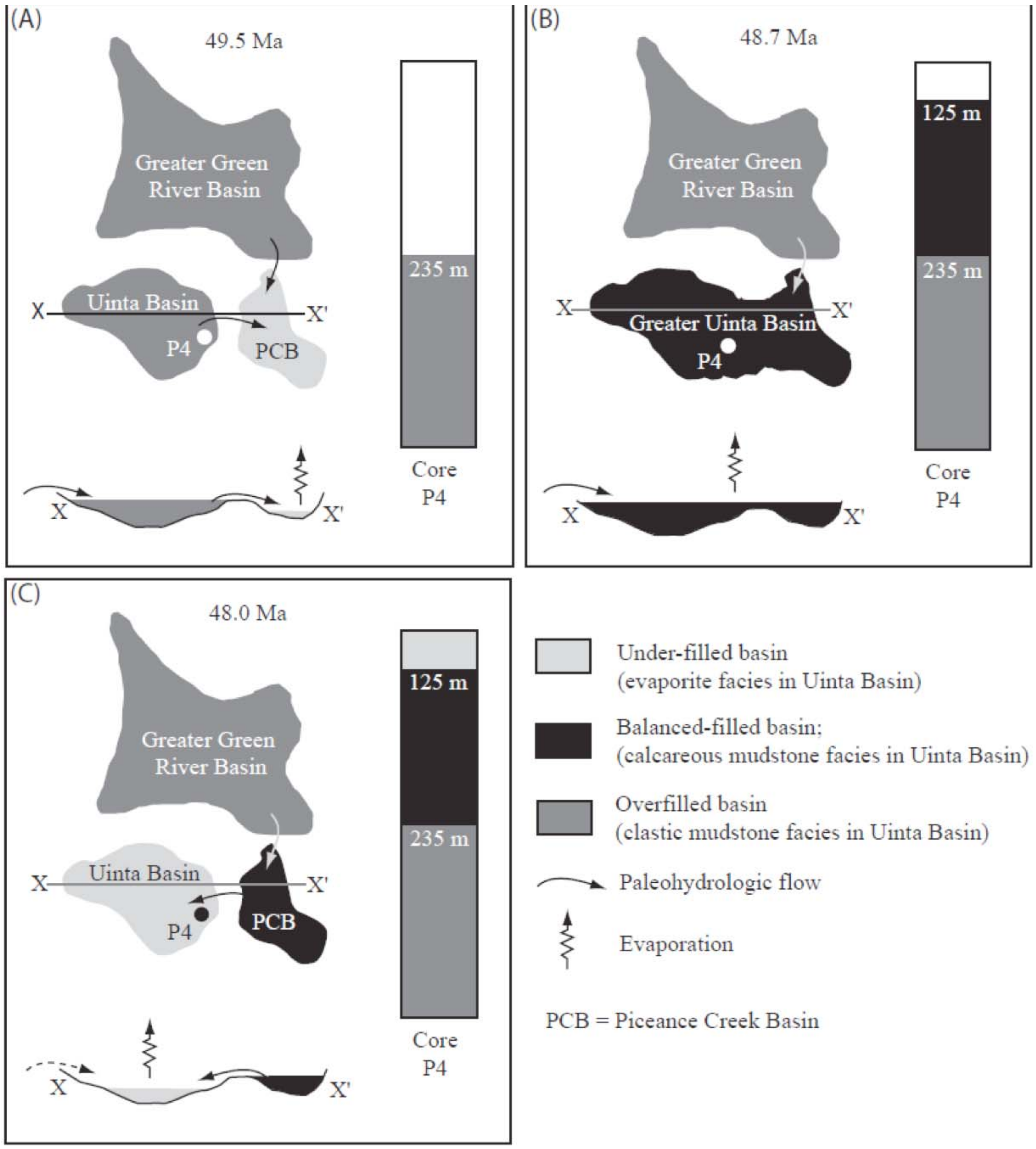

Figure 12. Lake-level evolution of Laramide basins depositing the Green River Formation, 49.5-48.0 Ma ago. Schematic cross-sections show paleohydrologic flow according to published reconstructions (9). Schematic P4 core litholog shows three facies associations deposited at each evolution stage of Lake Uinta. A) At ~49.5 Ma, the overfilled Greater Green River Lake and the Uinta Lake flow into the Piceance Creek Lake. As a terminal basin, the Piceance Creek Lake acts much as the present-day evaporative Great Salt Lake or the Dead Sea. B) At ~48.7 Ma, Uinta Lake and Piceance Creek Lake joined over a subsumed Douglas Creek arch, and balanced-filled conditions prevailed as freshwater input was proportional to evaporation rate. Under profundal, meromictic conditions, calcareous mudstones with the richest oil-shale zones were deposited at this time. C) At ~48.0 Ma, Lake Uinta became a terminal, under-filled basin, probably by tectonic alteration of watersheds, that led to evaporative conditions in the basin.

The upward-decreasing trend in the BI log and the eventual cessation of bioturbation in core P4 (Figure 4) has implications for the relationship between bioturbation and lake condtions. During the initial overfilled conditions, bioturbation is active (BI: 2-3, and up to 5). The subsequent period of balanced-filled, deeper conditions shows bioturbation decreasing and then ceasing due to the lack of oxygen (also indicated by the presence of oil shale). Bioturbation is absent through the top portion of the core where massive dolomitic mudstones and nahcolite evaporite deposits indicate hypersaline, but shallower, conditions.

The lower portion of core P4 correlates with the transitional interval of Remy (5), who describes the interval as a period of lake level transgression. At this time, the Uinta Basin was separated from the Piceance Creek Basin by the Douglas Creek arch. The prevailing hydrologic gradient led overflow waters of both the Uinta and Greater Green River Basins to flow into the Piceance Creek Basin, which served as a closed terminal basin (9); see Figure 12a. Prior to the deposition of the Mahogany Zone, the Piceance Creek and Uinta Basins were joined over the Douglas Creek arch and formed a single Lake Uinta (9); see Figure 12b. After the deposition of the Mahogany Zone, conditions reversed. The Uinta Basin eventually became the terminal basin in the hydrologic system (Figure 12c).

Oil shale was deposited in the upper Green River Formation during the deep stages of Lake Uinta. The richest oil shale zones are the Mahogany Zone, R6, and the lower portions of R8 (2, 23). These zones were deposited during the transition from the small, over-filled basin of Lake Uinta to a large, balanced-filled basin incorporating both Lake Uinta and the Piceance Creek Basin. Anoxic conditions at the bottom of Lake Uinta, obligatory for the preservation of organic materials comprising oil shale deposits, suggest that the lake was meromictic and profundal during the deposition of oil shale.

The perceived problematic transition from deep-water calcareous mudstones to shallow-water evaporites without intervening basin-margin clastic input can be explained by the deposition of terminal fan deltas. Such deltas, commonly developed at modern arid lake margins, are described by Pusca (4) in the lower part of the Green River Formation. In the terminal fan delta model during arid periods, surface runoff quickly infiltrates the arid soil or evaporates before reaching the lake. As a result, clastic sediments are deposited as sub-aerial fans, and sediment input to the lake becomes negligible. The resumption of wetter conditions would have delivered the clastic sediments of the Horse Bench sandstone to the site of core P4. Although Pusca (4) identifies terminal fan deltas in the lower part of the Green River Formation, the marginal lacustrine strata that deposited contemporaneously with the upper portion of core P4 are likely not preserved along the Uinta Basin’s southern rim due to Neogene and Quaternary erosion (8).

Conclusions

Oil shale

- Oil shale zones of the upper Green River Formation in the eastern Uinta Basin, Utah were deposited during profundal, meromictic, lacustrine conditions.
- In core P4, oil shale is a calcareous or dolomitic mudstone with high kerogen content.

Sedimentology of core P4

- Core P4 has six facies: clastic mudstones, calcareous mudstones, dolomitic mudstones, sandstones, evaporite (nahcolite), and tuff.
- The six facies are divided into three facies associations: (A) relatively shore-proximal facies association dominated by clastic mudstones (235-358 m depth), (B) deep-basin facies association dominated by calcareous mudstones (125-235 m depth), and (C) evaporating-basin facies associations, characterized by nahcolite and massive dolomitic mudstones (60-125 m depth).
- Facies associations A, B, and C were deposited in an overfilled, balanced-filled, and under-filled lake basin, respectively.
- The bioturbation index log of core P4 can be used as a proxy for bottom-water oxygen level. The BI log's upward-decreasing trend supports the interpretation of overfilled, balanced-filled, and under-filled lake basins.

Depositional history of the upper Green River Formation in the Uinta Basin (49.5 – 48.0 Ma)

- First, an overfilled, fluctuating holomictic, and siliciclastic-influenced lake system transitioned to a balanced-filled lake system as the water level rose in the Uinta Basin, subsuming the Douglas Creek arch and filling the adjacent Piceance Creek Basin.
- Second, a balanced-filled, profundal, and often meromictic lake system hosted the deposition of the richest oil shale zones during the unification of the Uinta and Piceance Creek Basins.
- Third, an underfilled, evaporitic, and terminal fan-dominated lake system commenced as the Uinta Basin separated from the Piceance Creek Basin.

Reservoir Modeling

Most large-scale oil shale processing operations involve mining and retorting at the surface. In-situ oil shale retorting is an attractive alternative to ex-situ technologies due to reduced environmental impacts from surface disturbance, water requirements, and waste management (24). However, in-situ technologies are still in the development stage and include more uncertainty, especially at large scales. Kerogen, the organic component of oil shale, is a solid that must be converted to a flowing fluid in order to be produced. With in-situ processing, the oil shale must be heated underground until the oil can flow.

In order to model any type of in-situ technology, understanding the fundamental processes is necessary. These fundamental processes include heat transfer through the reservoir, chemical kinetics of kerogen pyrolysis or combustion, geomechanics, multiphase flow, and other factors due to process variations.

Current In-Situ Processing Strategies

Shell Oil Company has been the most aggressive to this point with in-situ oil shale technology development. They have tested their InSitu Conversion Process (ICP) at a pilot scale facility on private land in the Piceance Creek Basin. The ICP consists of resistive, down hole heaters slowly supplying heat to the reservoir for a period of years. After this extended heating period, Shell reports that a high-quality oil is produced. The heating wells are arranged in a hexagonal pattern with 6 heating wells surrounding a production well. Shell is also testing a freeze wall technology that will surround the heater wells. The purpose of the freeze wall, where coolants are circulated underground to create an ice barrier, is to prevent groundwater contamination (25).

ExxonMobil is developing an in-situ oil shale extraction technology known as the Electrofrac process. First, they create hydraulic fractures in the oil shale reservoir. Next, they inject conductive material into the fractures and use resistive heating to heat the reservoir. With the Electrofrac technology, ExxonMobil maximizes heat transfer efficiency by increasing heat transfer area where the conductive material has been injected (26).

American Shale Oil (AMSO) is developing the Conduction, Convection and Reflux (CCR) process. In this process, two horizontal wells, a heater and a producer, are drilled at the bottom of the pay zone. Heat is supplied to the bottom of the reservoir, the kerogen decomposes to lighter products, and the hot vapors rise to the cooler top of the reservoir and reflux (27). This process can be engineered to create high quality oil.

The EcoShale In-Capsulation process developed by Red Leaf Resources combines the benefits of ex-situ and in-situ processing strategies. In their process, a rectangular impoundment (e.g. the “capsule”) is excavated at the surface and lined with clay. Circulation pipes attached to natural gas burners are installed into the open capsule, which is then filled with mined oil shale. The capsule is covered by native soil and overburden for environmental reclamation, and the shale in the capsule is slowly heated in-situ (28). Advantages of this strategy include that the properties in the capsule are more easily controlled than in a traditional reservoir and that heat transfer is more efficient because the previously mined shale is fragmented.

Mountain West Energy has developed their In-Situ Vapor Extraction (IVE) technology where hot methane gas is injected into the reservoir to pyrolyze the kerogen. Following pyrolysis, shale oil is produced. IVE has been successfully tested in the Naval Petroleum Reserve #3 at the Tea Pot Dome Field near Casper, Wyoming (29).

Modeling Considerations

Kerogen, the organic solid in oil shale, is insoluble in most solvents. Therefore, pyrolysis is a common method for decomposing kerogen into liquid and gaseous components. For any in-situ oil shale retort, the kerogen in the reservoir must be heated to a pyrolysis temperature of 350°C – 500°C. Heat that is supplied to the reservoir through a heating well is transferred through the reservoir by conduction and convection. Acceptable heating efficiency is essential to any successful in-situ operation. Temperature control in a reservoir is also a significant challenge due to the complexity of temperature profiles that develop as a result of kerogen pyrolysis kinetics, thermodynamics, and multiphase flow.

The chemical mechanism and kinetics of kerogen pyrolysis are uncertain. Thermal Gravimetric Analysis (TGA) is often used to measure the kinetics of oil shale pyrolysis. Typically, the oil shale is crushed to minimize any heat transfer resistance. Results from the TGA studies reported in Appendix E of this report give a distribution of activation energies, which add additional complexity to the kinetic model. The current consensus is that isoconversion models are theoretically and physically appropriate for describing kerogen pyrolysis. Kerogen structure is widely unknown and may vary significantly within and between resources. Because of this complexity, kerogen compositional behavior and decomposition mechanisms can be difficult to predict. Chemical lumping (grouping) can be used to model compositional behavior.

Combustion process options can be very attractive for oil shale production. In-situ combustion can significantly lower heat generation requirements for oil shale pyrolysis, resulting in a more efficient and economical process. Understanding coke and kerogen combustion in the reservoir is essential for engineering and predicting the behavior of this type of process.

For in-situ thermal processes, inorganic rock decomposition can also take place when temperatures are high. Carbonate rock decomposition could be a significant source of CO_2 emissions.

Geomechanics have a significant impact on the behavior of underground reservoirs. In oil shale reservoirs, the geomechanics are somewhat unique due to the thermal treatment of the rock. Evidence suggests that permeability is created as the rock is heated. Subsidence may also occur as the rock is changed and weakened due to heating.

Resource heterogeneity also has a significant role in reservoir engineering. The detailed characterization of Uintah Basin oil shale resource described in the first section of this report is an example of the type of analysis that is necessary for accurate oil shale reservoir simulations.

Flow characteristics in oil shale reservoirs can be quite complex. Depending on the process design and reservoir characteristics, models are needed to accurately represent flow characteristics. Water, oil, gas, organic solid, and inorganic solid flow behavior in an oil shale reservoir is different from that of a conventional reservoir due to the high temperatures and other factors. The geologic information from U059 (core P4) was converted to wt% hydrocarbon (organic matter or kerogen), and used directly in the reservoir simulation model.

In-situ Prototype Model

Pyrolysis of kerogen produces a complex mixture of oil, gas, and residue. For the reservoir simulations described here, the following reaction mechanism, which employs properties of lumped representative components, was used (30).

1. Kerogen → Heavy Oil + Light Oil + Gas + CH_4 + Char (capitalize Char, Coke)
2. Heavy Oil → Light Oil + Gas + CH_4 +Char
3. Light Oil → Gas + CH_4 + Char
4. Gas → CH_4 + Char
5. Char → CH_4 + Gas + Coke

All reactions were assumed to be first order, and kinetic parameters from a previous study (30) were used. The heat of reaction was assumed to be 46.5 kJ/gmole for each reaction based on similar reactions from the template input files of the thermal simulator used in the study. Overall heats of reaction of kerogen pyrolysis to oil have been reported previously (31). Detailed thermochemical studies with individual products would be necessary to assign heats of reactions of each individual reaction in the above mechanism. Sensitivity studies on the heats of reaction values showed that this parameter does not affect important production parameters in a significant manner (32).

Stoichiometry was approximated based on the molecular weights and on hydrogen to carbon ratios chosen for each component to force a mass balance. Table I lists molecular weights and two variations of the hydrogen to carbon ratio for the representative components in the kerogen pyrolysis mechanism. The first column of values for the H/C ratio is based on a mechanism and model developed by Braun and Burnham (30). The second column of values for the H/C ratio is based on the more realistic hydrogen to carbon ratio of 1.50 for Green River oil shales (32).

Table I. Representative Component Molecular Weight and Hydrogen/Carbon Ratio

Component	*Molecular Weight*	*Hydrogen/Carbon Ratio*	*Hydrogen/Carbon Ratio (Alternate)*
Kerogen	670	1.05	1.50
Heavy Oil	441	1.64	1.52
Light Oil	152	2.27	1.52
Gas	54	2.5	1.62
Methane	16	4.0	4.0
Char	12.4	0.6	0.39
Coke	12.5	0.45	0.34

Simulations were run with both columns of H/C ratios. The accuracy of the mass balance in the original kinetic model was not sufficient for the simulator, so we forced a mass balance *without* elemental balance for the first set of values. The second set of values forces a mass balance *with* an H and C elemental balance. The results for the second set of values (more rigorous) show that production rates, temperatures, produced quantities, etc., are relatively insensitive to hydrogen/carbon ratios.

It should be noted that stoichiometric coefficients used in this reaction scheme are not unique. They are simply estimated to force mass and elemental balances based on approximated molecular weights and hydrogen to carbon ratios of each representative component.

STARS, a thermal-compositional simulator coupled with chemical kinetics developed by the Computer Modeling Group, was used to solve mass and energy conservation equations with necessary constraint equations and physical models (33).

Geometry

The well geometry used in the simulations was loosely based on Shell's ICP pilot scale test (2). Six heating wells spaced 53 feet (16.2 m) apart surround one production well as shown in Figure 13. The thickness of the simulated reservoir was 50 feet (15.2 m) based on data obtained from the U059 well in the Uintah Basin (see next section for additional information). Due to symmetry, only a triangular wedge was simulated as shown in Figure 14. The results from this simulated section can be repeated to represent the field.

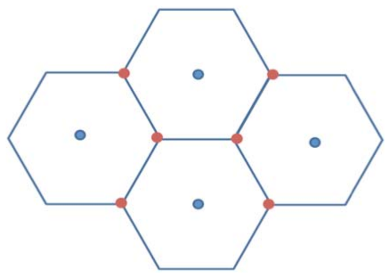

Figure 13. Aerial view of well geometry for reservoir simulations.

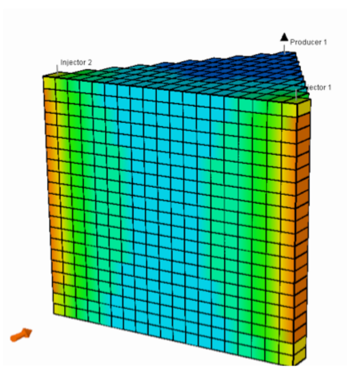

Figure 14. Simulated triangular wedge.

The triangular wedge was discretized into 21 vertical, 1-19 wide, and 1-10 length (10 blocks being the height of the triangle from an aerial view) blocks using CMG Builder.

Initial conditions

Gamma-ray log data from UGS for the U059 well (referred to as P4 in the Geological Characterization section) in the Uinta Basin (33) was used to estimate the weight percent of hydrocarbons in the oil shale (e.g. kerogen). The kerogen-rich section of the well is from 665 feet to 715 feet (202.7- 217.9 m) deep, and the kerogen weight percent varies from 12.5 wt% to 25 wt%. Table II shows the weight percent of kerogen at different depths in the well. The information in this table was used to calculate the initial kerogen volume at each depth. The remaining volume was assumed to be inorganic rock.

Table II. U059 (or P4) Well Survey Data

Depth(ft)	*wt% of HC*
665-670	12.5
671-680	12.5
681-690	14
691-694	15
695-700	16
700-710	25
710-715	16

The porosity of the initial rock was calculated for each layer. Porosities ranged from 0.3 to 0.6. To obtain these values, it was assumed that kerogen nearly filled the pore space in the rock. The initial pressure and temperature assigned to the reservoir were a constant 1000 psi and 80°F (27^0C). The values are typical of a reservoir that is about 2800 feet deep.

Production strategy

The reservoir was directly heated with two vertical injection wells to simulate resistive or burner heaters. These heaters heated uniformly from the top to the bottom of the well. Each heater supplied 50,000 BTU/day to the reservoir for a four-year time period. Production was pressure controlled by the producer. For the base case simulation described here, the following conditions were applied: BHP = 100 psi; H/C = 1.05 with associated mass balance + stoichiometry; and U059 well data.

Results

Results from this simulation are shown in the next series of figures. Cumulative oil and gas production over a four-year period is plotted in Figure 15.

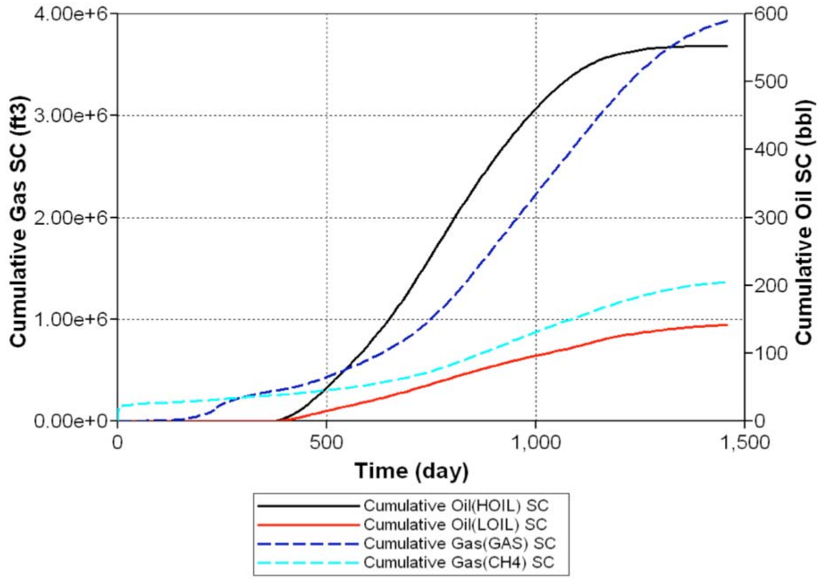

Figure 15. Cumulative oil and gas production.

No significant quantity of oil is produced prior to 400 days of heating. This time delay represents the time required to convert solid kerogen to producible oil with the given heating rate, well geometry, reservoir characteristics, and process parameters.

The oil production rates in Figure 16 show a maximum rate of approximately 1.2 bbl oil/day occurring two years after the heating is initiated. To convert to bbl oil/day/acre, the rate is multiplied by 30. Oil production rates are low, but oil production rate and quantity are a strong function of temperature history in the reservoir. With the pyrolysis kinetic parameters and mechanism used in this simulation, much of the kerogen was converted to residue and gas rather than to oil.

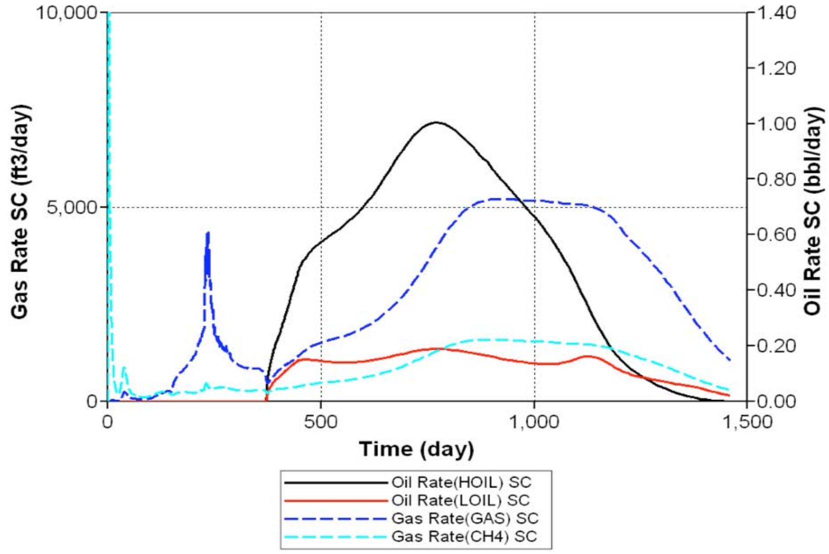

Figure 16. Oil and gas production rates.

Figure 17 shows the energy efficiency of the heating strategy. After four years, approximately 50% of the heat supplied to the reservoir is lost to overburden and underburden. To minimize such losses, changes in heating patterns, histories, and strategies are required. For example, pyrolysis could be followed by in-situ coke combustion to improve heating efficiency.

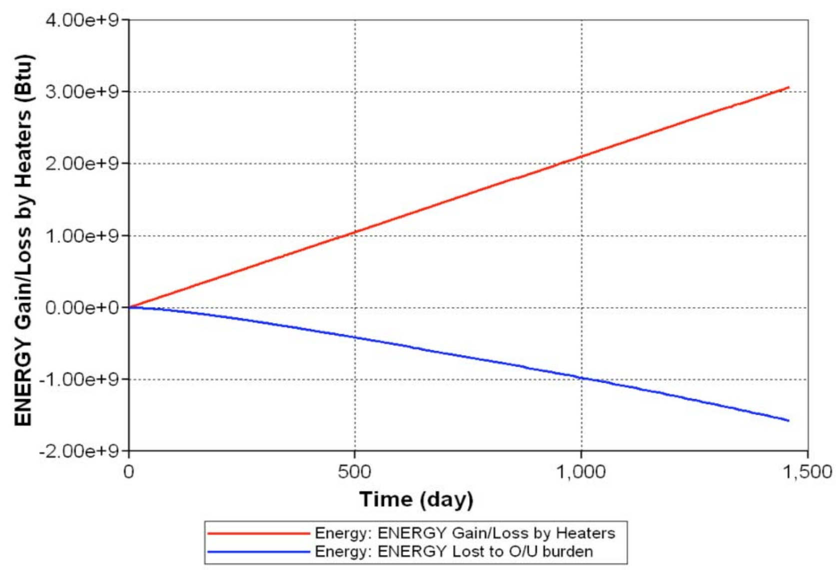

Figure 17. Energy supplied to reservoir and energy lost to under/overburden.

Figures 18, 19, 20, and 21 show a comparison of three simulated grid blocks: one near the heater (block 18, 10, 11), one far from the heater (block 10, 1, 11), and one in the middle of the section (block 14, 5, 11). In all four figures, the red line represents the location near the heater, the blue line represents the location far from the heater, and the orange line represents the location in the middle. Near the heaters (see Figure 18), the temperature rises rapidly. However, temperature changes in the other two blocks indicate that conduction through the reservoir is slow. The high temperatures near the heaters are excessive but may be required to generate a temperature gradient that results in heat conduction through the reservoir in a reasonable time. It may take up to 700 days to supply sufficient heat for pyrolysis far from the heater under these conditions. Note that the temperatures reported here are specific to the heat input strategy used in the simulations. Figure 19 shows that kerogen conversion was rapid at the high temperatures near the heater. Figure 20 shows the oil saturation versus time at different locations in the reservoir. Coking was also significant due to high temperatures near the heaters, as shown in Figure 21.

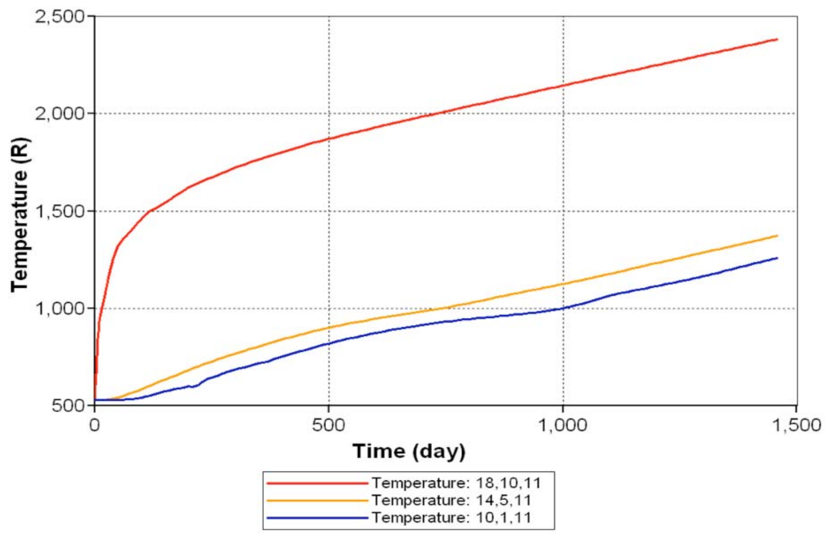

Figure 18. Temperature history comparison for three distances from heaters.

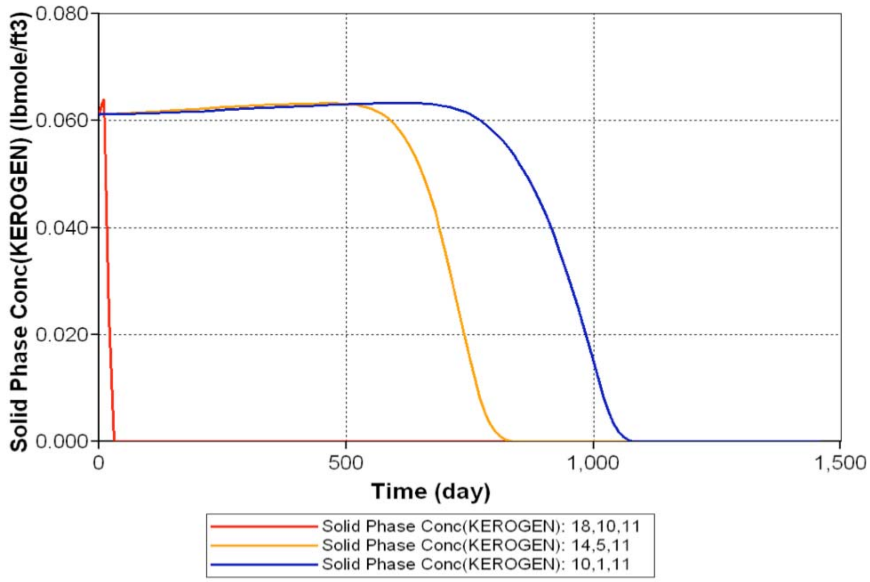

Figure 19. Kerogen concentration comparison for three distances from heaters.

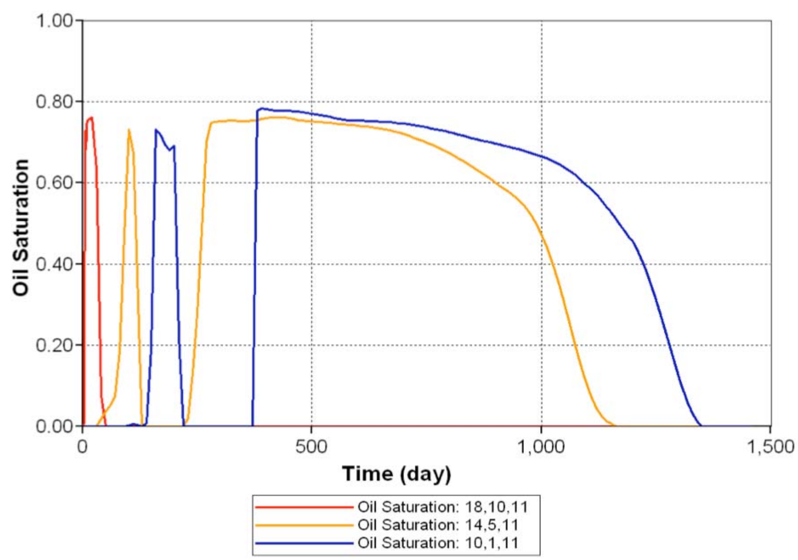

Figure 20. Oil saturation comparison for three distances from heaters.

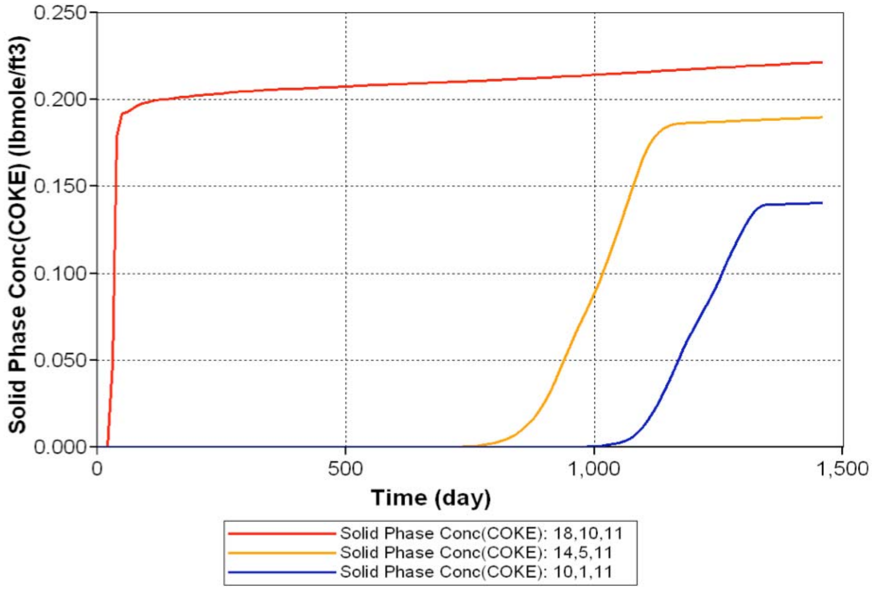

Figure 21. Coke concentration comparison for three distances from heaters.

Additional simulations were run to explore the sensitivity of results to back pressure in the reservoir. Increasing reservoir pressure increases the residence time of organic components, which has compositional implications. Cumulative production results for a case with BHP = 1000 psi are shown in Figure 22. When compared to the base case simulation in Figure 15 (BHP = 100 psi), it is observed that this pressure increase caused increased oil to conversion to gases, an expected result due to the increased residence time. In addition, residue creation was greater with the higher bottom hole pressure.

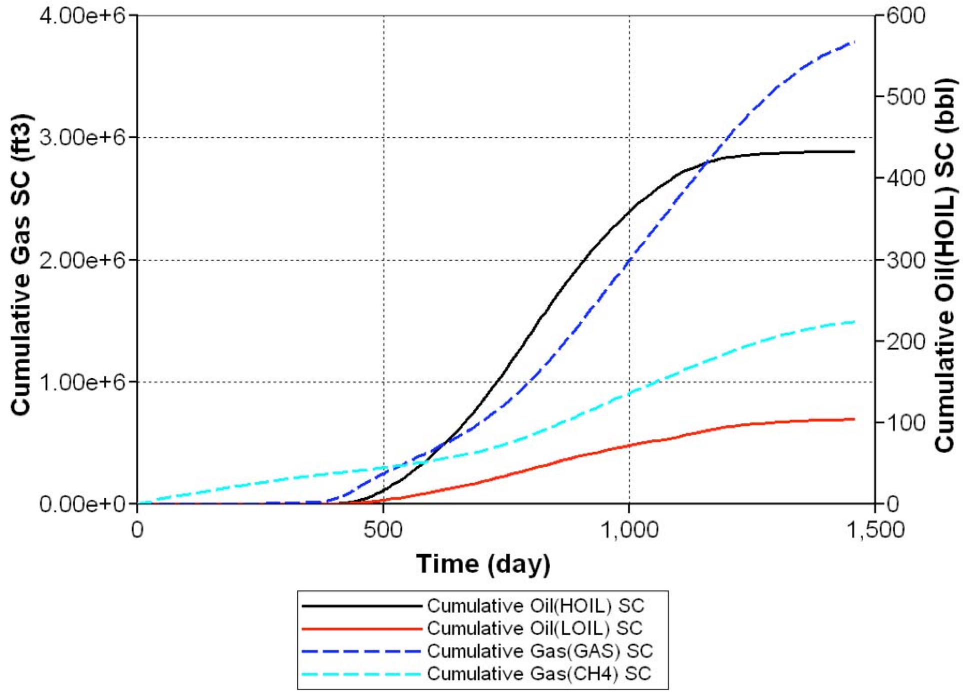

Figure 22. Cumulative oil and gas production with BHP = 1000 psi.

The net energy gain/loss was estimated for this type of process assuming the following: (1) 15 wt% kerogen in the oil shale source rock, (2) all kerogen converted to recoverable oil, (3) source rock heated from 25°C to a retort temperature of 350°C, and (4) heat of reaction for kerogen conversion of 370 kJ/kg. In this idealized estimate, 17 units of energy were produced per unit of energy required. The base case simulation results show 50% reservoir heating efficiency at the end of four years. If resistive heating is used and one assumes 36% electricity generation efficiency and 50% reservoir heating efficiency, a net energy gain of 3 units of energy out per unit of energy required is calculated. For their pilot scale ICP test, Shell estimated a net energy gain of 3 units out per unit of energy required with resistive heating supplied.

Preliminary estimates of the carbon footprint for this type of process were also calculated based on the following assumptions were made: (1) underground natural gas heating, (2) production of 33 API crude oil, and (3) the assumptions mentioned in the energy gain/loss estimate. Assuming 100% heating efficiency, 18 kg CO_2/bbl oil are emitted. If 50% heating efficiency is assumed, 36 kg CO_2/bbl oil are emitted. These estimates do not include any CO_2 emissions due to combustion inefficiency or carbonate mineral decomposition.

No estimates for water requirements were made because water is not necessarily required for in-situ oil shale conversion processes. When using resistive heating, water is required for electricity generation but is not directly required for oil shale processing.

Conclusions

A realistic geologic representation of the Green River oil shale formation was used to study the potential of an in-situ production process based on direct heating. A rigorous kinetic model was incorporated into a reservoir simulation framework. Oil production rates were low, amounting to about 40 bbl/day/acre. A significant portion of the kerogen was converted to non-condensable gas. Coke and char were also generated in the process. The net energy gain was about 3 units of energy out per unit of energy in due to significant heat losses to underburden and overburden. The net CO_2 production was about 18 kg/bbl of oil produced in an ideal situation, but under more realistic assumptions, CO_2 production increased to 36 kg/bbl. The study showed that direct heating for oil production from shale may be feasible process, but a number of technical challenges remain.

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APPENDIX C

In-situ Production of Utah Oil Sands

Final Project Report

Reporting period: June 21, 2006 to October 21, 2009

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October 2009

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Submitted by:
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Project Objectives

The objective of this project is to evaluate and rank a variety of in-situ heavy oil production method for the production of bitumen from a representative Utah oil sand formation within the Uinta Basin. Tools to be employed include a thorough survey of the geology of oil-sand intervals, a survey of various approaches described in the literature, and a numerical simulation study to test the most promising oil-extraction approaches applied to a Utah resource.

Summary of Project Outcomes

Two oil sand reservoirs located in Utah's Uinta Basin were considered for analysis: Whiterocks, a small, steeply dipping, contained reservoir containing about 100 million barrels, and Sunnyside, a giant reservoir containing over four billion barrels of oil in place. Cyclic steam stimulation, steam assisted gravity drainage, and in-situ combustion processes were considered for the production of oil from these reservoirs. Different well configurations and patterns were examined. It was found that the application of steam-based in-situ processes would be feasible but challenging for Utah oil sands. For most configurations, the steam to oil ratios were higher than five, indicating marginal economic viability. Additionally, the water production rates were high. The in-situ combustion process was simulated with and without the presence of a hydraulic fracture for a homogeneous reservoir. The nature of the combustion front was radial without the fracture and linear with the fracture. Even though the process appears feasible, rigorous evaluation with an appropriate geologic model will be necessary to determine technical and economic viability.

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Characterization of Oil Sands

Bitumen is the principal organic material found in oil sands. While the world’s largest oil sands resources are found in the province of Alberta, Canada, major oil sands resources are also found in Utah. The characteristics of bitumen in comparison to other feedstocks are shown in Table 1. While bitumen does have high densities and low heating values compared with crude oil, its hydrogen to carbon ratio is reasonably favorable when compared with other unconventional fuels.

Table 1: General characteristics of oil sand bitumen in comparison to other feedstocks.

	Crude oil	Heavy Oil	Bitumen	Kerogen
SG	0.85	0.95	0.98	1
C	86	86.5	85.1	79
H	13.6	11.5	11.3	10
N	0.2	0.5	1.6	2
S	0.2	1	1.5	1
O	0	0.5	0.5	7
H/C	1.90	1.60	1.59	1.52
Heating Value(MJ/kg)	42	38	35	34

The Utah oil sand reservoirs containing significant quantities of oil are listed in Table 2 along with a few other characteristics about the deposits.

Table 2: Some characteristics of Utah oil sand reservoirs (adapted from [1]).

Reservoir	Areal Extent (Square Miles)	Range of Gross Thickness	Oil in place (in millions of barrels)
Asphalt Ridge	20 to 25	10 to 135	800 - 1000
PR Spring	240 to 270	10 to 80	4000 - 5000
Sunnyside	35 to 90	15 to 550	3500 - 4000
Whiterocks	0.6 to 0.75	1000+	65-125

Studies in this report focus primarily on the Whiterocks and Sunnyside oil sand reservoirs. Locations of these resources can be seen in Figure 1. The Whiterocks reservoir is located in the northern section of the Uinta Basin while the Sunnyside reservoir is located on the Basin's southwest flank. The Whiterocks formation, a small, contained deposit, consists of relatively homogeneous sandstone with high viscosity bitumen [2,3]. The Sunnyside formation, one of the largest oil sands deposits in the state, is characterized by rugged terrain, uneven quality, consolidated oil sands, and very high viscosities [2,3].

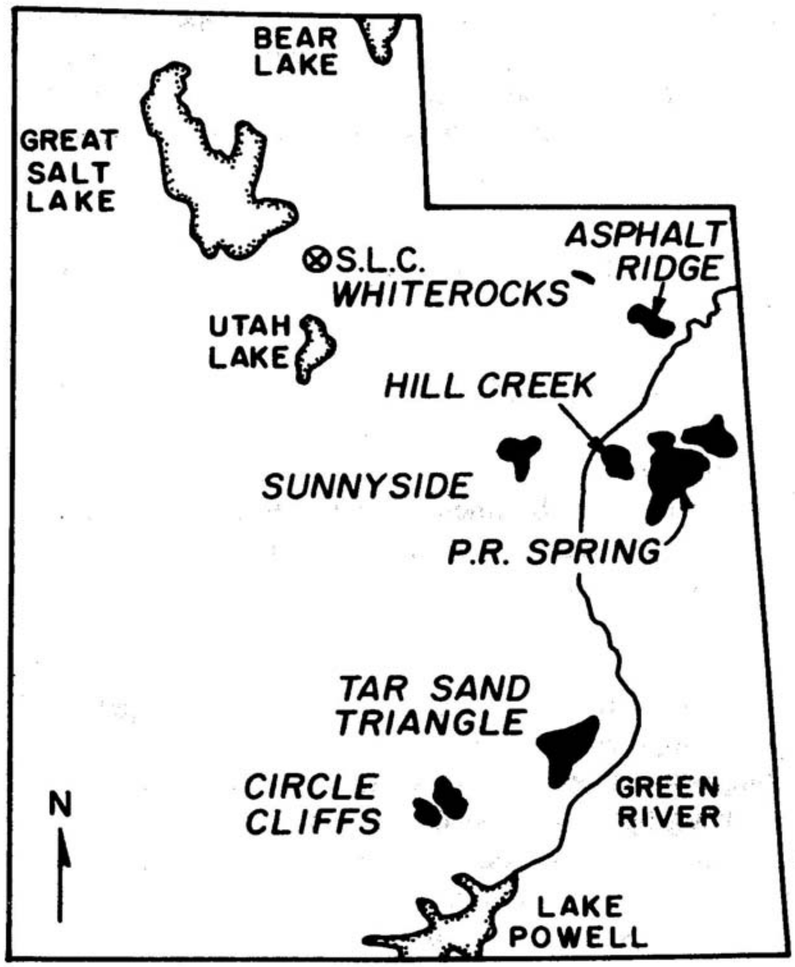


Figure 1: Locations of the prominent oil sand deposits in the State of Utah (from [2]).

General formation properties of significant Utah deposits, including the White Rocks and Sunnyside formations, are also shown in Table 2 [2]. The biggest difference between the Utah and the Canadian bitumen is that the viscosity of Utah bitumen at reservoir conditions is 30,000 to 300,000 cp, about one or two orders of magnitude larger than the Canadian bitumen. The

Sunnyside formation is characterized by ultra-high viscosity bitumen while the Whiterocks deposit contains a relatively "lighter" bitumen. Other major distinguishing features between Utah and Canadian oil sands include the higher level of sand consolidation, the lower resource quality (weight percent bitumen in the oil sand mixture) and the significant reservoir heterogeneity exhibited by Utah oils sands.

Survey of In-situ Oil Sand Production Approaches

Most large-scale oil sands production strategies involve ex-situ processes, e.g. strip mining followed by bitumen extraction [1,2]. In-situ production of oil sands bitumen offers an excellent alternative to the ex-situ processes. In addition to leaving the landscape relatively undisturbed, in situ processes allow for partial upgrading of oil sands, leaving heavier, less profitable components of the bitumen in the subsurface. Some in-situ methods use much less water and generate less CO_2 than ex-situ methods. In addition, in-situ approaches allow for the exploitation of much deeper oil sand formations—where the cost of removing the overburden is prohibitively expensive.

In-situ oil sands production is increasing in Canada. In 2007, in-situ production accounted for 41% of the 1.3 million barrels produced each day [4]. In-situ technologies might be particularly attractive for the State of Utah because of its arid climate and because of the proximity of some oil sands deposits to environmentally sensitive areas.

Steam processes, including cyclic steaming, steamdrives, and Steam-Assisted Gravity Drainage (SAGD) are the most common in-situ production processes being used globally for oil sands production. Likewise, in-situ combustion is an emerging in-situ process that has achieved some early success in Canada's vast oil sand deposits. A recently created process called Toe-to-Heel Air Injection (THAI) takes advantage of the best qualities of the SAGD and in situ combustion approaches and uses a horizontal well both to direct the combustion process and to collect the mobilized bitumen [5]. Even though these concepts are relatively simple and have been used successfully in other countries, significant challenges exist in adapting these technologies to Utah's lenticular oil sands deposits.

Cyclic steam stimulation, SAGD, and in-situ combustion are the in-situ processes considered in this report. A survey of other in-situ processes for the production of oil sands can be found in [6].

Cyclic Steam Stimulation (CSS)

Perhaps the simplest, most reliable, and most commonly practiced form of in-situ production is cyclic steam injection, also known as 'huff-and-puff' [7,8]. With this approach, steam is injected at high pressures and temperatures (550°F or higher) and is then allowed to soak. The pressure dilates or fractures the formation and the heat reduces the viscosity of the bitumen. The heated bitumen is then pumped to the surface using downhole pumps in the injection well (Figure 2). The process is repeated in a cyclical fashion until saturations become non-productive [9].

Although the cyclic steam process is simple and reliable, recoveries are relatively low (~25%) and large amounts of water are required to generate steam. Likewise, the energy to generate the required steam is expensive.

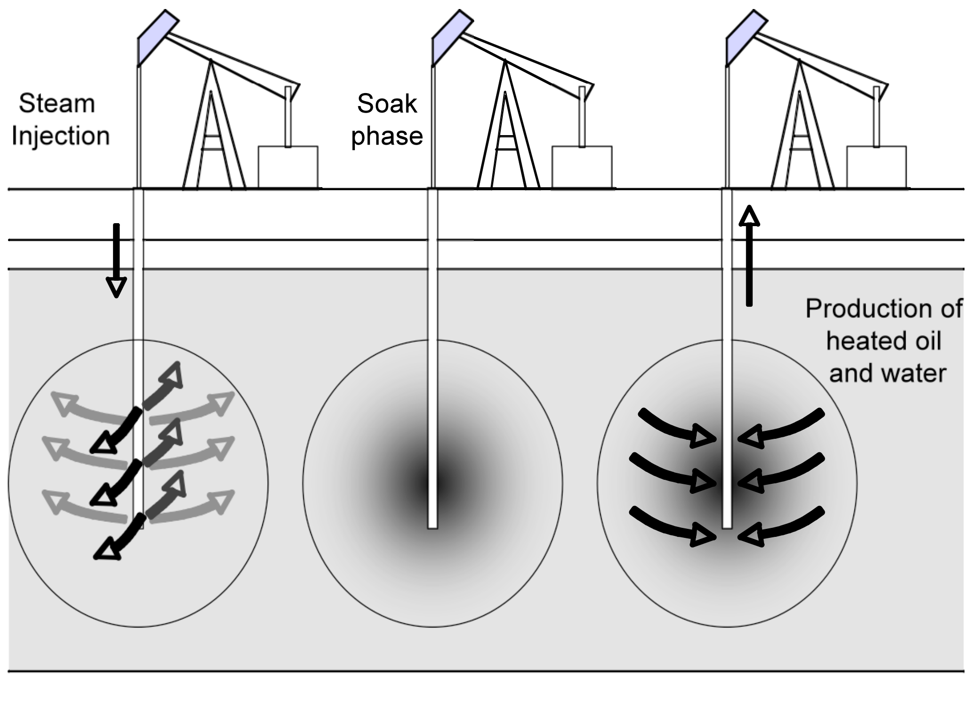


Figure 2: Schematic of the cyclic steam stimulation process showing the injection phase, the soak period and production from a single well (from [6]).

Steam Assisted Gravity Drainage (SAGD)

SAGD has become the dominant technology employed in a variety of heavy oil and bitumen recovery processes, with Canadian development leading the way. A number of oil companies are currently involved in pilot and commercial applications of the SAGD process. In SAGD, two horizontal wells are placed near the bottom of a formation as shown in Figure 3. Steam is injected through the upper well, which, due to buoyant forces, rises through the formation to create a steam chamber near the top of the formation. Steam mobilizes the bitumen by lowering its viscosity, and the bitumen then flows downward. The production well, placed about 5 m below the injection well, is used to collect the resulting condensate and the released oil, which is then pumped to the surface. Long horizontal well segments have the potential for higher oil recovery rates. SAGD is the dominant in situ technology because it utilizes the natural tendency of oil to drain by gravity into production wells and it is a relatively simple process to implement [10,11].

While the SAGD process can lead to high recoveries (up to 60 % of the oil in place) and is Economically viable, it has several disadvantages. It requires large amounts of water and the energy that is required to generate the required steam is expensive and leads to the production of large quantities of the greenhouse gas CO_2. Also, since it relies on gravity drainage, it requires comparatively thick and homogeneous reservoirs.

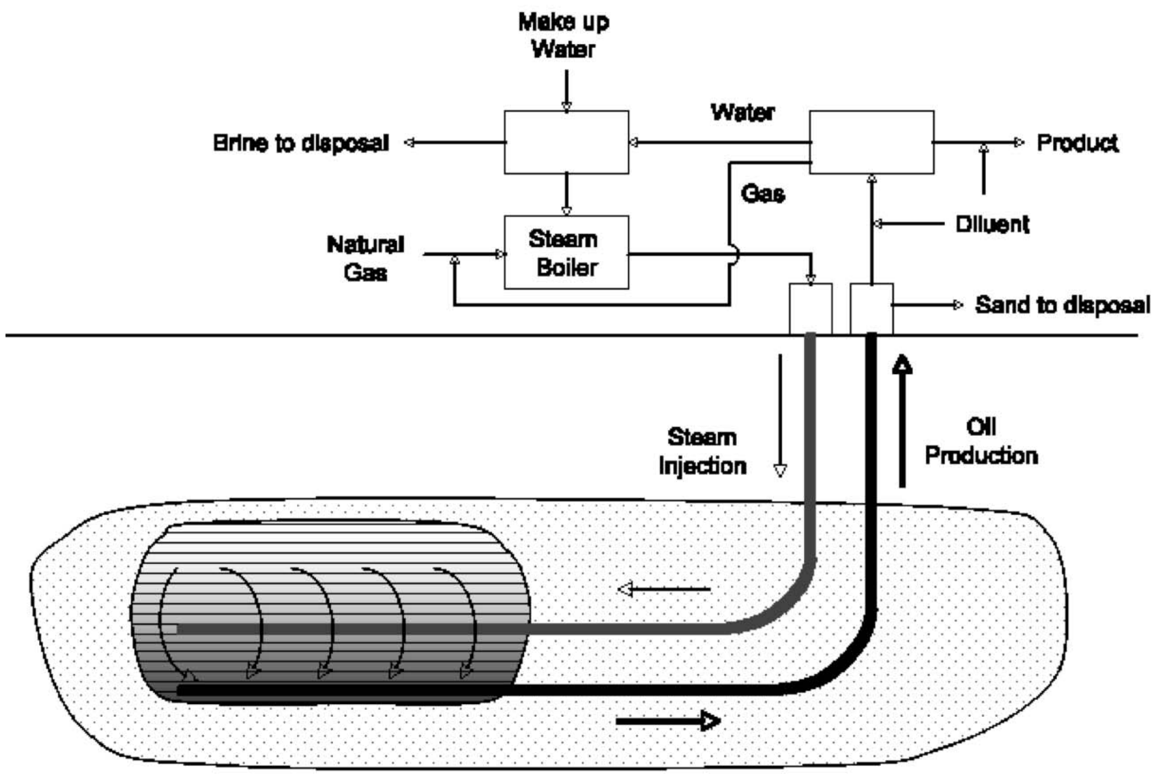


Figure 3: Schematic showing the operation of SAGD (from [6]).

In-situ Combustion

In-situ combustion is an enhanced oil recovery (EOR) technique that has been widely studied and used in the production of heavy oils since its inception in the mid-1930's [12-14]. It is a process in which air, oxygen, or oxygen-enriched air is injected into a bitumen reservoir. The air/bitumen mixture is ignited to produce a combustion zone that creates heat and causes the flow of the remaining bitumen to a collector.

In situ combustion offers the advantages of high recovery (60% or more of original oil in place), high efficiency due to self-heating of the reservoir, low cost [15] and low water use, the latter being especially attractive in arid settings such as those in Utah. The injection of pure oxygen in the place of air [16] or the injection of water to produce in situ steam [17] can both significantly improve sweep efficiencies and recoveries. However, the combustion front is difficult to control and some of the resource in place is lost to combustion. Classical in-situ combustion not expected to work well in oil sands unless some scheme is used to provide initial interwell communication and mobility to the bitumen [18].

Numerical Simulation of In-situ Production of Utah Oil Sands

Numerical simulation of these processes can give insight into the potential of the resources of interest. First, both SAGD and cyclic steam processes, loosely based on the Whiterocks resource characteristics, were modeled. Second, SAGD and a process involving steam injection with vertical wells were modeled for the Sunnyside resource. In-situ combustion was simulated with a homogeneous hypothetical resource due to complexities associated with modeling this process.

Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Processes

Whiterocks Deposit

Initial numerical simulation models of the SAGD and cyclic steam production processes based upon the Whiterocks reservoir model were constructed and run using STARS, the thermal compositional simulator developed by Computer Modeling Group, Calgary, Canada [19]. The reservoir was divided into 25 layers of varying thicknesses. These layers were categorized as: rich (r), lean (l), very lean (v), and barren (b). Properties of the various layers used in the simulation are shown in Figure 4. For example, the rich layers were assumed to have the following characteristics: vertical and horizontal permeability of 125 md, porosity of 0.3, and oil saturation of 0.6. The thickness of the 25 layers can be seen in Figure 5, which is a visualization of the permeability of the grid blocks. Red grid blocks represent rich layers, green grid blocks represent lean layers, light blue grid blocks represent very lean layers, and dark blue blocks represent barren layers. Layer 1 in Figure 4 is the layer furthest to the left in Figure 5 progressing to layer 25 as the final layer furthest to the right in Figure 5.

Layer	Category	Perm.	Por.	Sat.
1	r	125	0.3	0.6
2	l	75	0.2	0.4
3	r	125	0.3	0.6
4	b	5	0.1	0
5	l	75	0.2	0.4
6	b	5	0.1	0
7	l	75	0.2	0.4
8	b	5	0.1	0
9	v	25	0.15	0.2
10	l	75	0.2	0.4
11	v	25	0.15	0.2
12	b	5	0.1	0
13	l	75	0.2	0.4
14	b	5	0.1	0
15	v	25	0.15	0.2
16	b	5	0.1	0
17	v	25	0.15	0.2
18	b	5	0.1	0
19	l	75	0.2	0.4
20	r	125	0.3	0.6
21	v	25	0.15	0.2
22	r	125	0.3	0.6
23	b	5	0.1	0
24	l	75	0.2	0.4
25	b	5	0.1	0

Figure 4: The 25 layers used in the simulation of cyclic and SAGD processes. The categories are rich, lean, very lean and barren.

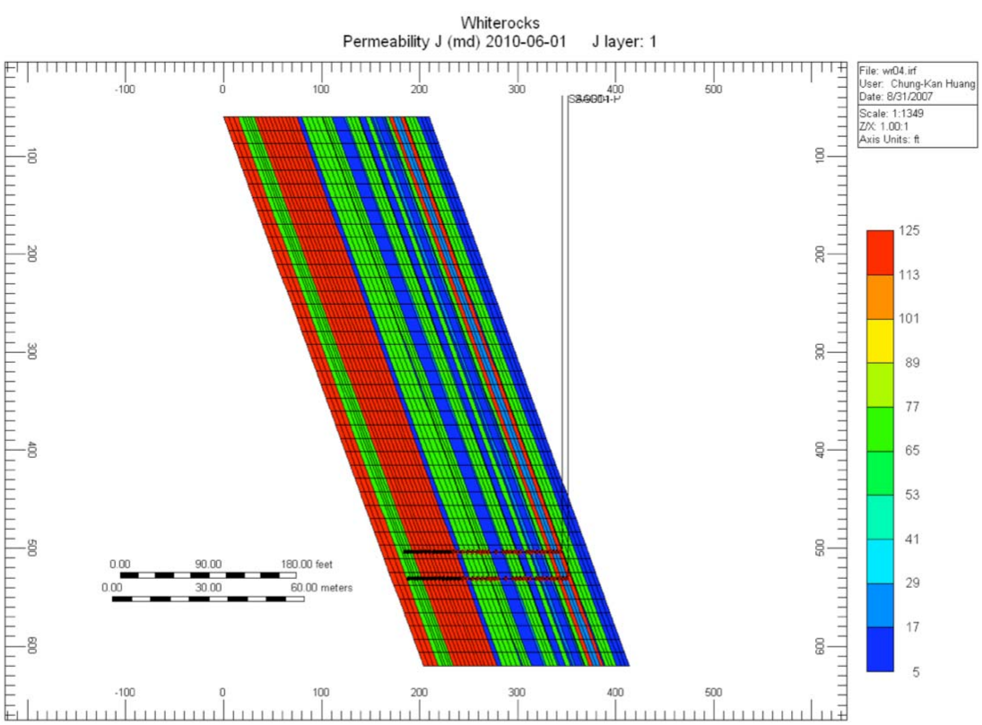


Figure 5: Model of the Whiterocks reservoir constructed in STARS.

Whiterocks is a steeply dipping reservoir (75^0). The model constructed in STARS is shown in Figure 5. It should be noted that if horizontal wells were used, they would cut across the bedding planes in almost a perpendicular manner.

The geometry and the well configurations used are shown in Figure 6. The wells were placed so that the steam chambers would be able to effectively drain oil from the reservoir. For the SAGD process, three pairs of horizontal wells, the SAGD injector and producer, were simulated. The pairs of wells alternated between a location near the bottom of the reservoir and a location and in the middle of the reservoir (290 ft. higher) as seen in Figure 6. This pattern allows for efficient heat and fluid transfer throughout the reservoir. The lower pairs of wells lie on the boundary of the simulation, so only half of each well is calculated. This boundary condition can be repeated to represent more wells in the same pattern. In the cyclic steam simulation, the same geometry and well configurations were used. However, a single vertical well was used as both the injection well and the producer. Bitumen was assumed to be highly viscous dead oil. Fluid properties for this dead oil were assumed. Three components were represented in appropriate phases: water, dead oil, and solution gas. Both types of simulations were performed on a PC. After adjustment of numerical parameters, SAGD simulations required approximately 4 hours while the cyclic steam simulations required over 46 hours.

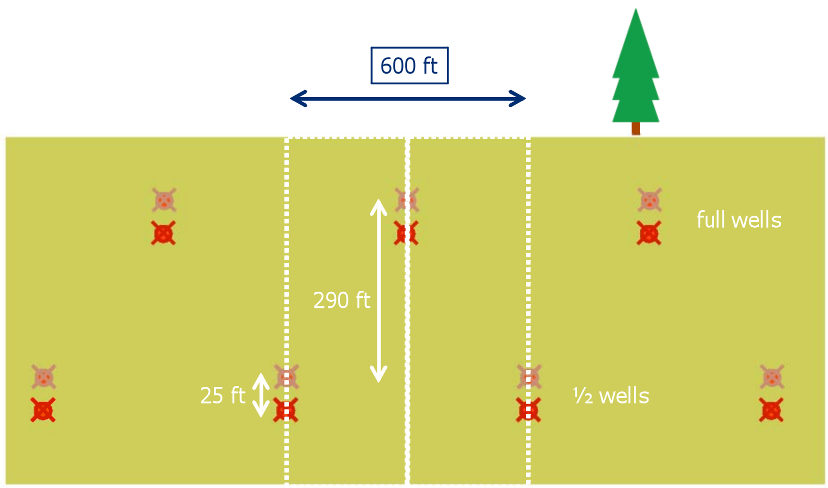


Figure 6: Geometry and well configuration used.

SAGD oil production is shown in Figure 7 and the cyclic oil production is shown in Figure 8. In both cases, substantial amounts of oil can be produced from the reservoir. Since the initial water saturation in the reservoir is significant, large amounts of water are also produced. It should be noted that the uncertainty in these simulations can be significant. The simulation results are very sensitive to the rock-fluid properties (relative permeability curves) employed in the simulation. Relative permeabilities at conditions of interest for these formations have not been measured and “typical” values were used in the simulations. Additionally, the geologic information is assembled using data from one log, so lateral variability is not accounted for. The flow properties are also approximate as they are based on limited laboratory testing.

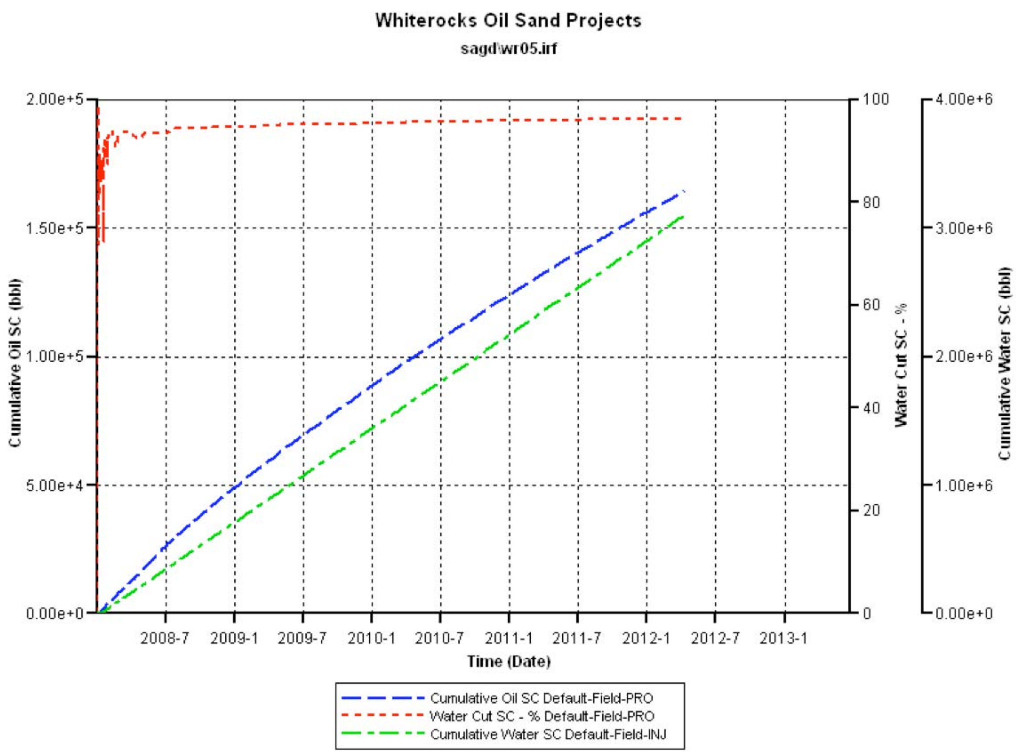


Figure 7: Oil production in Whiterocks SAGD simulations.

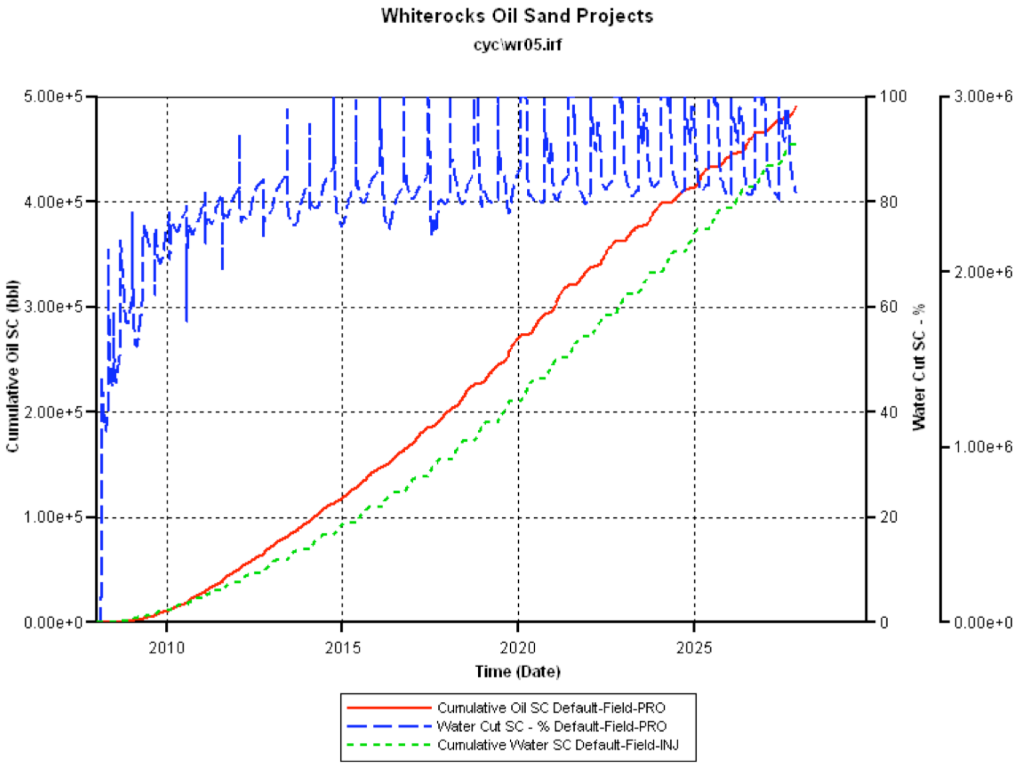


Figure 8: Oil production in Whiterocks cyclic simulations.

Steam-oil ratios (SOR) in most SAGD simulations averaged about 5-10. Initially, water was assumed to fill the remaining pore space not filled by oil in the simulations (e.g. no gas was present). This initial water saturation, in addition to the injected steam, accounts for the high water cuts. For comparison, the SOR in economic SAGD operations in Canada is about 3. With the geologic conditions employed and the assumed water saturations, it appears that the computed SORs are not very favorable for in-situ oil production in Utah.

Sunnyside Deposit Modeling

The conceptual geologic model of the Sunnyside deposit provided by Gwynn [20] and shown in Figure 9 was adapted for reservoir simulations. The thickest zones are about 90 feet in thickness, but these are interspersed with numerous thin and sometimes lean layers. This layered heterogeneous reality represents the most significant challenge to exploiting Utah oil sands resources. For the simulations, the layered geologic model was simplified by using alternating lean and rich zones as shown in Figure 10

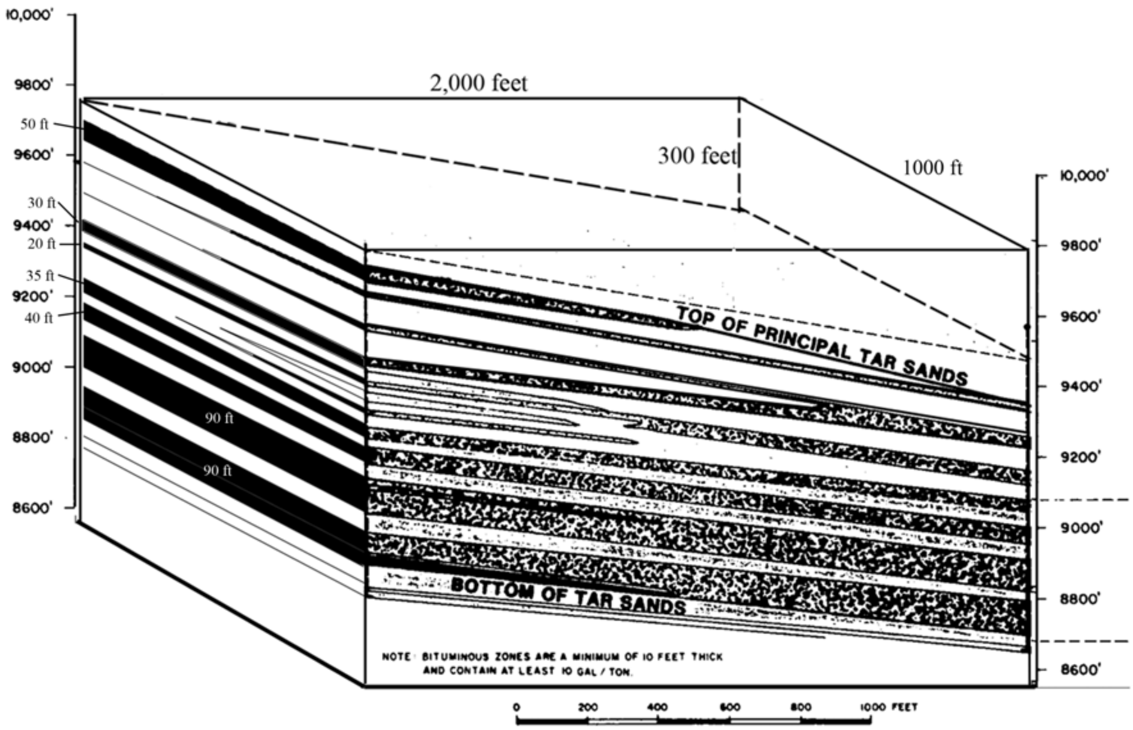


Figure 9: A geologic model of the Sunnyside deposit used in the simulations (from [20]).

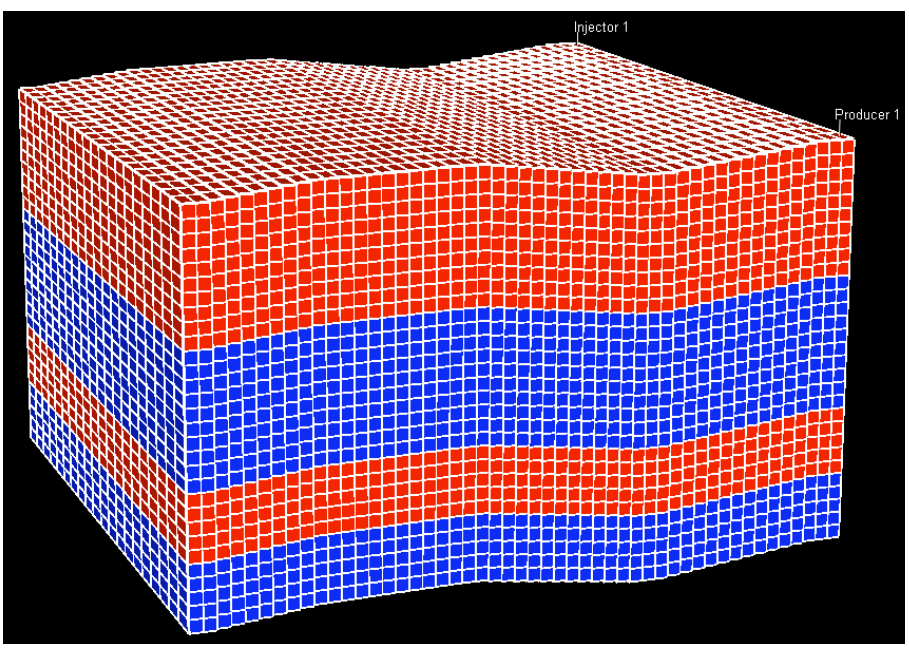


Figure 10: A small section of the Sunnyside geologic model used in the reservoir model. The model is 200 feet by 200 feet by 120 feet thick and has alternating rich and lean layers.

The well configurations used in steam injection and production are shown in Figure 8. Conditions were the same for both simulations in order to compare the performance of a SAGD process to a simpler steam flood with vertical wells. In Figure 11, the panel on the left shows a classic SAGD configuration with a horizontal well pair. The panel on the right shows a vertical injector and vertical producer configuration. The injector has been completed in only half of the formation to allow for the steam override. This injector configuration allows for more steam contact in the reservoir than if the vertical injector were completed over the entire formation. In addition to well placement, Figure 11 shows a 2D side view of the domain described in Figure 10. This geologic model is conceptual and approximate. Layers with different richness are represented with different properties but cells within layers have uniform properties. Oil saturation averages about 0.65 for the entire model. This reservoir realization represents a thick tongue in the Sunnyside formation that is sufficiently deep (500+ feet) to contain the steam chamber. A detailed characterization program (with a number of core holes over the entire deposit) will be necessary to obtain a better reservoir model and a better reservoir representation.

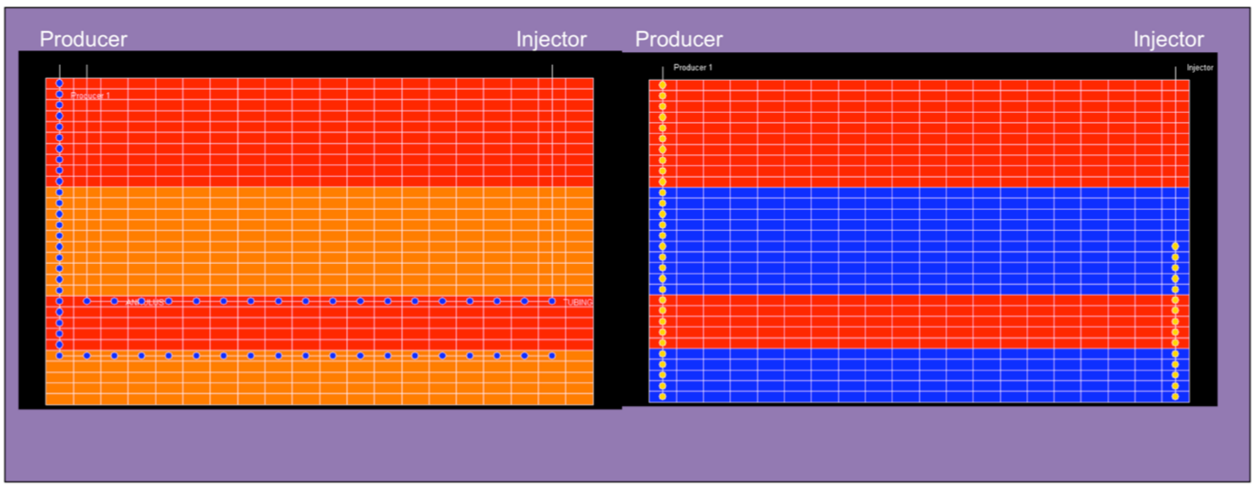


Figure 11: The horizontal and vertical well configurations used for steam injection in Sunnyside.

The horizontal well configuration consists of an injection production pair with the injector above the producer at the bottom of the reservoir. The injector in this simulation was 20 feet above the producer. The separation between these horizontal wells is partially determined by horizontal drilling capabilities. Also, it is possible to produce the injected steam before it transfers heat to the reservoir if the wells are too close to each other. In the vertical well configuration, steam is injected at the bottom half of the reservoir as illustrated by the yellow dots in Figure 11 while oil is produced from the entire cross section. These simulations required a few hours of computational time on a fast PC.

Results from the SAGD simulation, including horizontal well production and other parameters, are shown in Figure 12. Because of the high initial water saturation (0.35 average), water production was consistently high throughout the production period. Once again, SOR ranged from 5-10 throughout the simulated period.

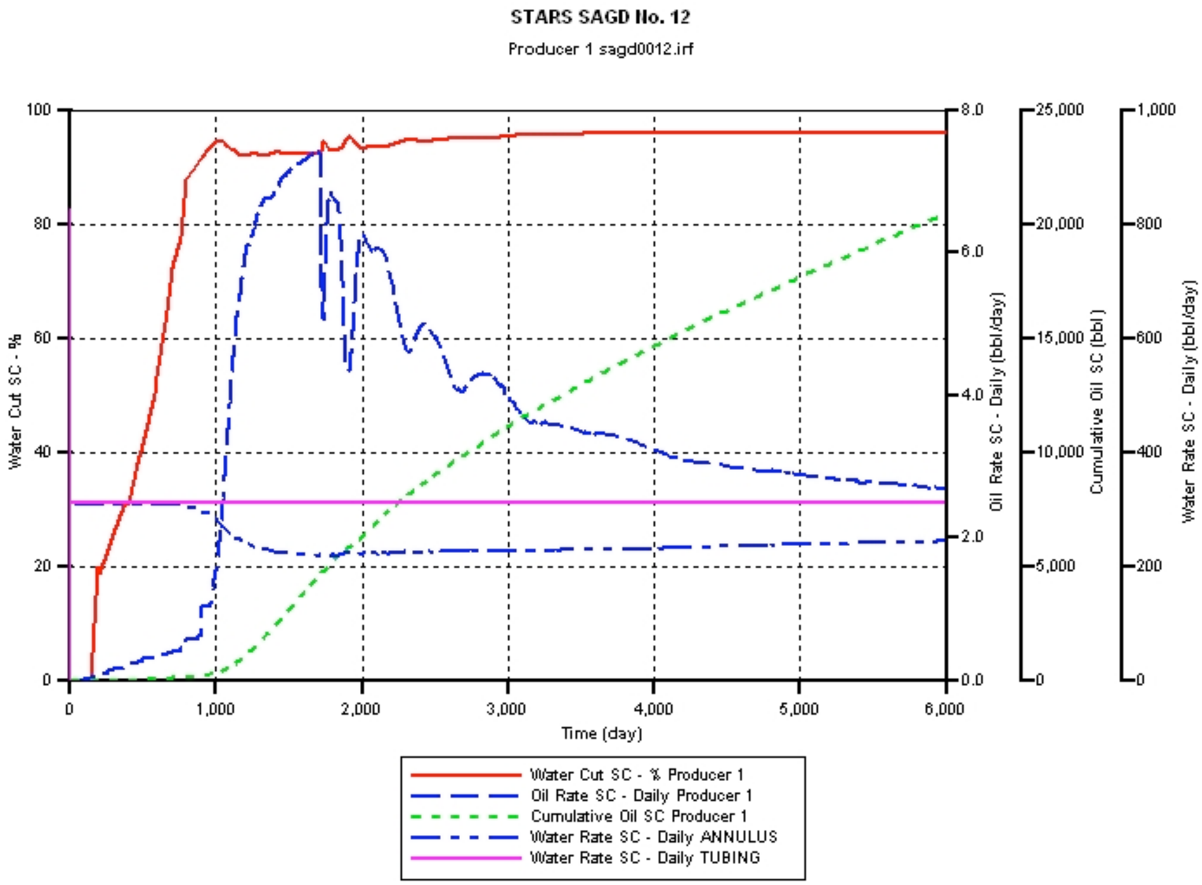


Figure 12: Production rates, cumulative production, etc. for SAGD production from Sunnyside.

The vertical well pair production is shown in Figure 13. The rates and cumulative oil production are much lower in the vertical well case than for SAGD. Heat transfer is likely insufficient from the vertical well, and the distance is too large between the injector and producer wells for economic utilization of steam. These results further demonstrate that production rates may be uneconomically low due to high oil viscosities and limited steam injectivities.

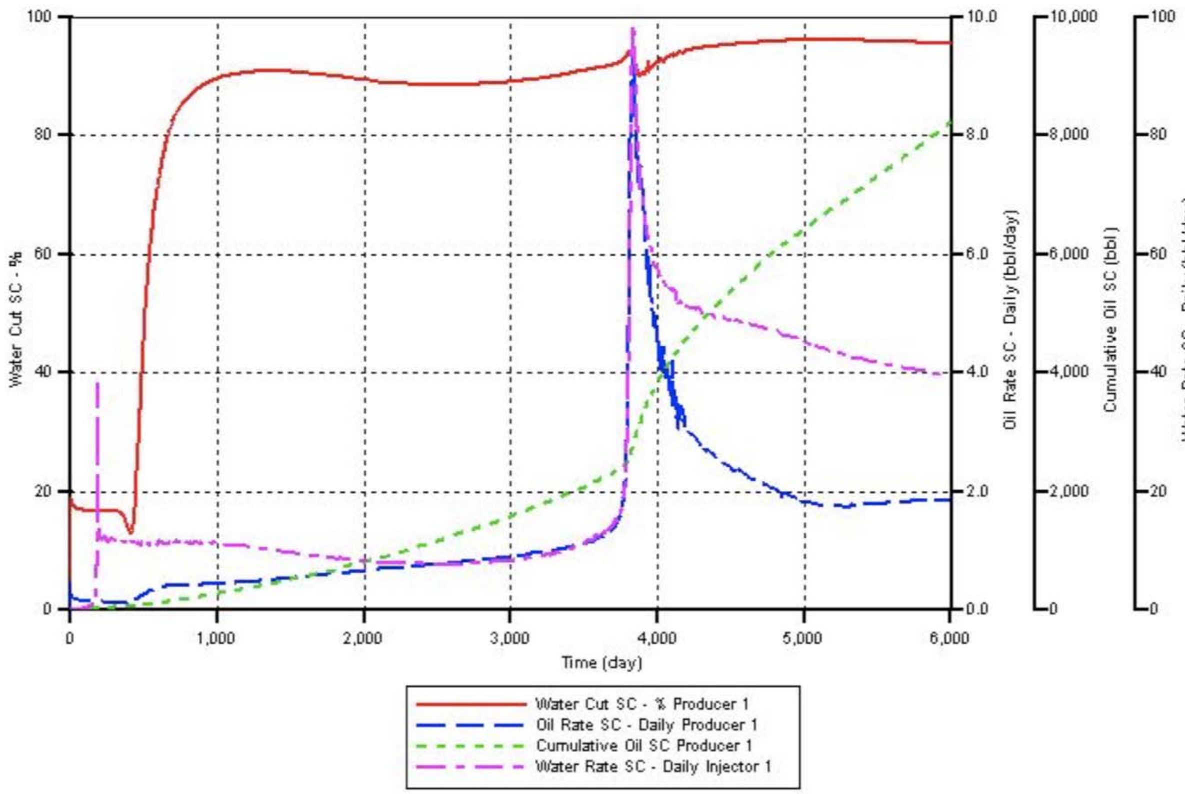


Figure 13: Oil production rates, water cut etc. for the vertical well system.

In-situ Combustion

In-situ combustion is considered a highly complicated EOR process from both a practical and a modeling standpoint. In practice, the interplay between the geological heterogeneity of the reservoir and the distribution of the hydrocarbons increases the difficulty of controlling the process. In performing simulations, chemical reaction rates, phase equilibrium calculations, and complicated rock-fluid interactions make numerical stability a challenge. The addition of fracture considerations increases the numerical difficulty since multi-scale flow regions exist in the problem. We examined the use of in-situ combustion in homogeneous media without the additional consideration of complex geology reported for the steam injection simulations in the previous section.

Injecting air in oil sand reservoirs for in-situ combustion requires reasonable permeability. Hydraulic fracturing is a logical method of creating this permeability. To study the impact of fractures and faults, an in-situ combustion simulator for complex fractured media was developed at the University of Utah. The simulator is a discrete-fracture, finite-element model for multiphase reservoir simulation that is based on models described in the late 1970s [21]. The simulator was developed using a modularization concept that divides the development of the simulator into two major modules: physical method module (PM) and the discretization module (DM). The first module provides the property data required in the reservoir model and performs the solution of the governing equations that describe the nature of the reservoir performance. The second module provides the spatial information related to the chosen discretization method.

The in-situ combustion algorithms were first tested with dry (no-water) combustion and then with wet combustion where different amounts of water were co-injected with air. Additional simulation details, including boundary conditions, inlet conditions, and reservoir characteristics, can be found in [22].

The temperature profiles along the injection path (dimensionless) are shown in Figure 14. With wet combustion. the high-temperature plateau is wider due to the effect of water evaporation and re-condensation at the front. This plateau results in better heat utilization and distribution, an additional benefit (combustion besides permeability creation) to hydraulic fracturing with in-situ

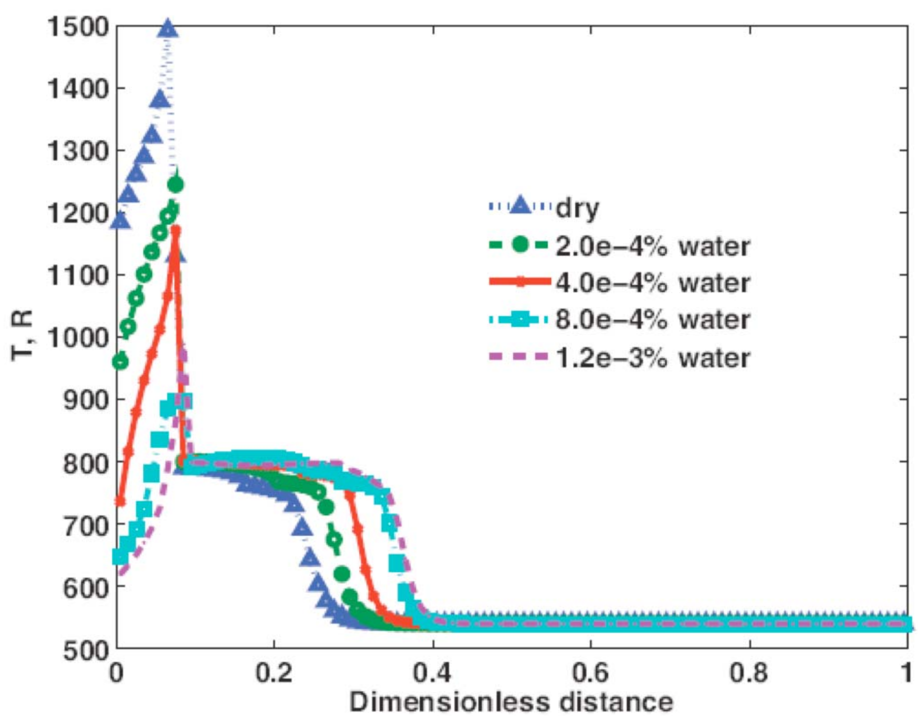


Figure 14: Comparison of temperatures profiles with dry and wet combustion.

While hydraulic fracturing is necessary to improve the air injectivity (or sometimes productivity) and sweep efficiency, the actual effect of the hydraulic fracture depends on its dimension, orientation and system of complexity. Therefore, the near-well displacement in a hydraulically-fractured in-situ combustion process was studied next. The discrete fracture model in the in-situ combustion simulator is an ideal discretization method for providing a better understanding of flow phenomena in this type of application. The domain used for the study is shown in Figure 15. A five-spot well pattern is used together with full-length and half-length fractures. Additional simulation details are found in [22].

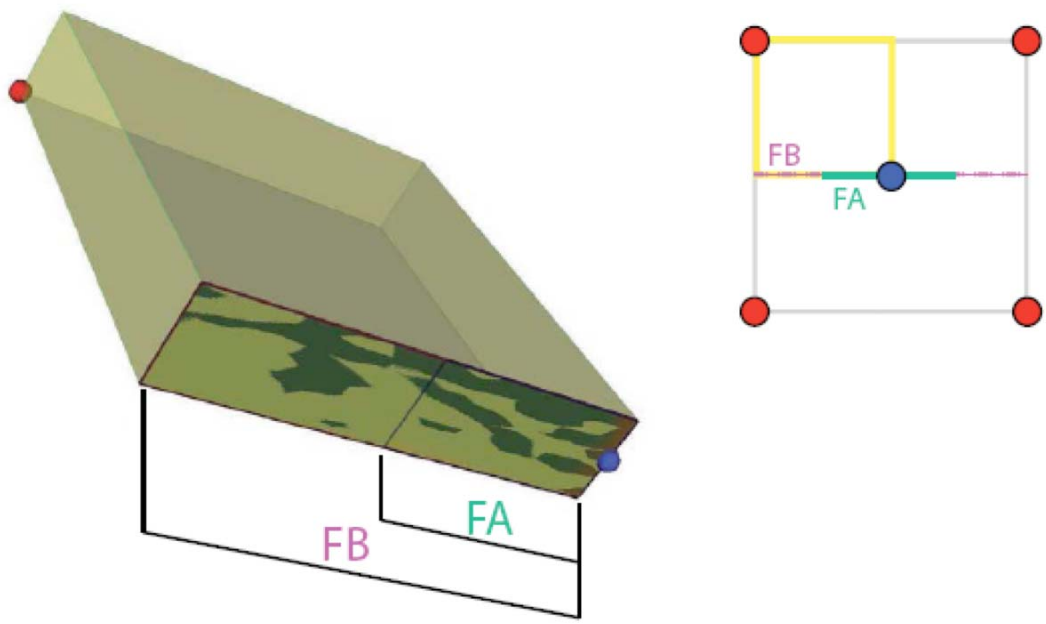
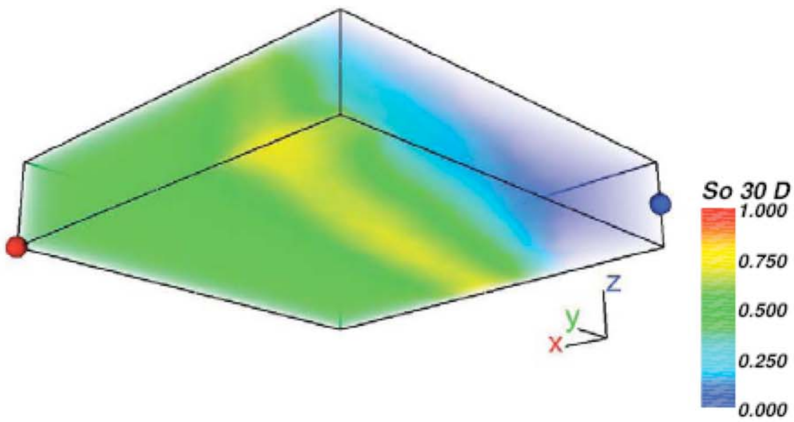


Figure 15: Domain used to study in-situ combustion in an oil sand reservoir with hydraulic fracture. The blue sphere represents the injector and the red sphere represents the producer. FA is the full-length fracture, and FB is the half-length fracture. The yellow square shows the boundary of the simulation domain (symmetry).

The oil saturation distributions with half- and full-length fractures are shown in Figure 16. The injectivity of air improves due to the presence of the fracture and the front is more linear than the front created when only a half-length fracture is present.



(a) full length

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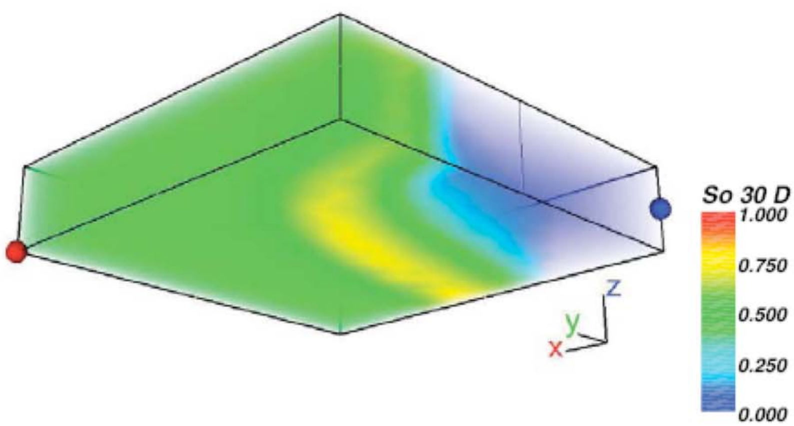

(b) half length

Figure 16: In-situ combustion with hydraulic fracture – comparison of half length and full-length fractures. It is seen that the full-length fracture creates a linear front compared to the radial front

Conclusions

The efficacy of a variety of thermally-enhanced oil recovery methods was examined for the production of oil from Utah oil sands reservoirs. Specific geologic models were used for the evaluation of steamfloods in Whiterocks and in Sunnyside. Cyclic and SAGD processes were found feasible, resulting in significant oil production. However, the water rates were high and the SOR was in the 5-10 range, making economic operation of these processes challenging. A thermal enhanced oil recovery reservoir simulator developed for fractured reservoirs was used to examine the use of in-situ combustion in the presence of hydraulic fractures. The front development and front geometry were observed to be different with hydraulic fractures.

Acknowledgements

The authors would like to acknowledge financial support for the project from the U.S. Department of Energy through the Utah Heavy Oil Program at the University of Utah under grant #00056-55800308. The steam treatment simulations were performed using STARS from the Computer Modeling Group, Calgary, Canada. The authors would like to thank CMG for granting the Academic Licenses for their suite of reservoir simulators.

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APPENDIX D

Meeting Data Needs to Perform a Water Impact Assessment for Oil Shale Development in the Uinta and Piceance Basins

A Subpart of Project

Quantifying Water Availability Impacts and Protecting Water Quality While Developing Utah Oil Shale and Sands

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

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June 23, 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
Institute for Clean & Secure Energy
155 South 1452 East Room 380
Salt Lake City, UT 84112

Project Title: Meeting Data Needs to Perform a Water Impact Assessment for Oil Shale Development in the Uinta and Piceance Basins

Principal Investigator: Steve Burian, Ph.D., P.E., Assistant Professor, University of Utah

Project Duration: Apr. 18, 2007 – Mar. 31, 2009

Project Amount: $57,718

Researchers Supported: Eric Jones (part-time hourly undergraduate researcher; fall 2007 – fall 2008), Woo Suk Han (2 months, graduate research assistant, summer 2008), Greg Nash (1 month, research scientist with EGI, spring 2008), Beth Dudley-Murphy (1 month, research scientist with EGI, summer 2008)

Project Tasks as Originally Proposed:

1. *Collect Literature and Create GIS Database of Water Resources Data*
2. *Quantify Water Requirements for Future Oil Shale Development Projections*
3. *Develop a Methodology to Assess Water Availability*

Summary of Project Outcomes:

1. The literature review produced more than 50 documents that are being incorporated into the Utah Heavy Oil Program (UHOP) Repository (http://ds.heavyoil.utah.edu/dspace/index.jsp). The geospatial datasets collected and created are being incorporated into the UHOP map server (http://map.heavyoil.utah.edu/website/uhop_ims/viewer.htm).
2. To update water requirements estimates, we needed to project urban growth, estimate available oil shale resources, and quantify water requirements for the urban growth, oil shale industry, and energy generation sectors. The Eastern Utah urban growth projection was based on a retrospective analysis of growth in Fort McMurray, Canada, in response to their oil sands development growth. The retrospective analysis provided a model to follow that was fine-tuned in discussions with Vernal planning department officials to arrive at a reasonable estimate of future urban growth and to generalize key characteristics of the urban demographic and growth pattern likely to influence water demand. The in-place oil shale resource estimates were based on a geostatistical analysis. Water demand estimates were made using a range of possible oil shale production rates, technologies, and urban and energy water demands.
3. A methodology to determine water availability was conceived. The conceptual approach identified the need to develop a water management model for the White River (a tributary to the Green River in the Colorado River Basin), to acquire and incorporate hydrologic information, and to accurately account for the current water users in the region.

Project Goal

The goal of this project was to mitigate water resources impacts from oil shale development in the U.S. by compiling geospatial data and water use estimates to assess water availability impacts.

Objectives

To meet the project goal, we (1) completed a brief literature search to acquire publications and fact sheets on oil shale and water resources, (2) collected water resources geospatial datasets for the Uinta and Piceance Basins in Utah and Colorado to support the development of the water management model, (3) studied urban growth in the Uinta Basin to improve population projections, (4) determined revised oil-yield estimates for the Uinta-Piceance Basins, (5) developed updated estimates of water demand for oil shale development in the Uinta and Piceance Basins and compared to previous estimates, (6) quantified changes to past water demand estimates for a range of development scenarios including advances in oil shale extraction technologies, alternative energy generation, and sustainable urban growth, and (7) defined a conceptual approach to assess water available for oil shale development. Summaries of the effort and outcomes of the research are described below.

Background

Currently, oil supplies more than 40% of our total energy demands and more than 99% of the fuel we use in our cars and trucks [1]. The U.S. is the largest consumer of oil in the world, consuming approximately 20 million barrels of oil a day [2]. This daily usage is increasing by 2% every year and, if the trend continues, by the year 2030 the U.S. will consume over 30 million barrels of oil a day (Figure 1). Oil production in the U.S. is insufficient to meet this need; therefore, the U.S. imports 10.4 million barrels of oil per day [1]. The demand for oil in the U.S. is increasing in concert with the general demand for energy. The national consumption of electricity per capita (residential) has increased from 3,167 kWh/person/year in 1980 to 4,223 kWh/person/year in 2001, representing an annual average increase of 48 kWh/person/year. If this trend continues, by 2030 the electricity consumption will be 5,327 kWh/person/year [2]. To successfully meet increasing energy demand and to reduce dependence on foreign oil there is a national need to develop, in an economically and environmentally sustainable manner, domestic oil resources.

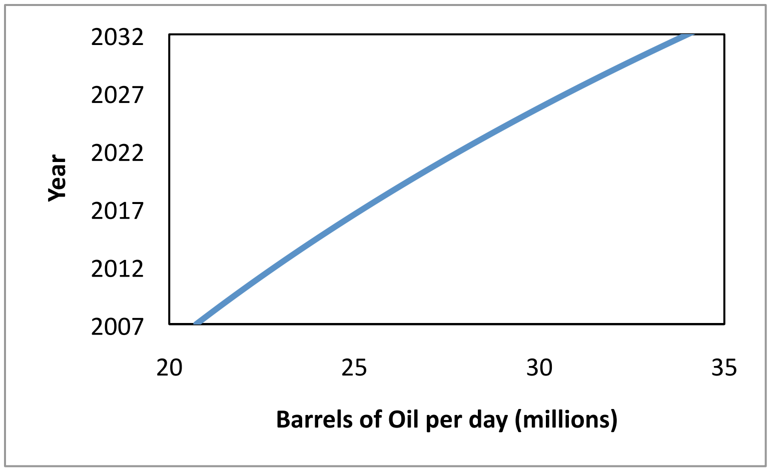

Figure 1. Annual increase of oil usage in U.S.
(Source: U.S. Department of Energy)

In the U.S., unconventional hydrocarbon resources, including heavy oil, oil sands, and oil shale, represent significant potential domestic oil sources. The U.S. Heavy Oil Database [3] estimates heavy oil in the U.S., not including Alaska, to be 84.2 billion barrels, mostly located in California. The U.S. oil sands resource is estimated at 54 billion barrels original oil in place (OOIP), in the form of bitumen [4]. The largest oil sands deposits in the U.S. are in Utah with proven reserves of 8-12 billion OOIP in the form of bitumen [5]. The Green River Formation in Colorado, Utah, and Wyoming is, volumetrically, the largest oil shale resource in the U.S. (Figure 2) with resource estimates of 1.5-1.8 trillion barrels OOIP [5]. At an estimated production rate of 5 million barrels of oil per day this source could meet more than one-quarter of the U.S. demand for more than 500 years. Figure 2 indicates the locations of deposits with different qualities as estimated by the National Energy Technology Laboratory (NETL). The dark gray areas are underlain by an estimated 10-foot thick layer of oil shale, which could potentially produce 25 to 50 gallons or more of oil per ton. The lighter brown areas are either unapprised or low-grade.

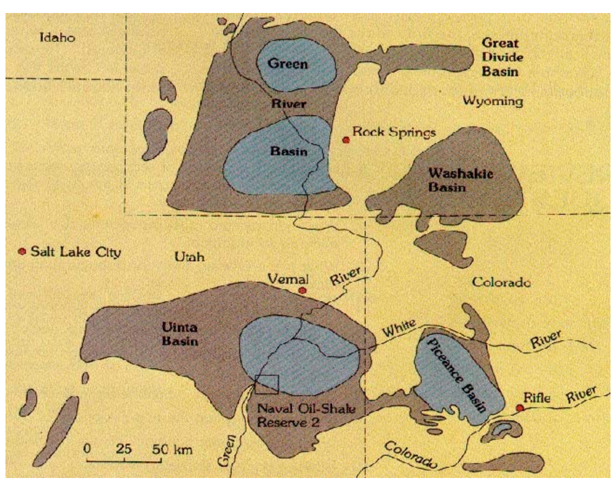

Figure 2. Location of oil shale [38].

Oil shale in the U.S., however, has not been considered a feasible source of energy to date because of many factors, including high development costs, environmental impacts, and water availability. Newer, more cost-effective technologies are still being developed; however, current cost estimates range from $10 to $95 per barrel [6]. These prices are becoming more competitive with recent and possible future crude oil prices (Figure 3); thus, there is renewed interest from industry as well as local, state, and federal governments to commercially develop this resource. Although the contents of this report have applicability to heavy oil, oil sands, and oil shale, the focus is on oil shale.

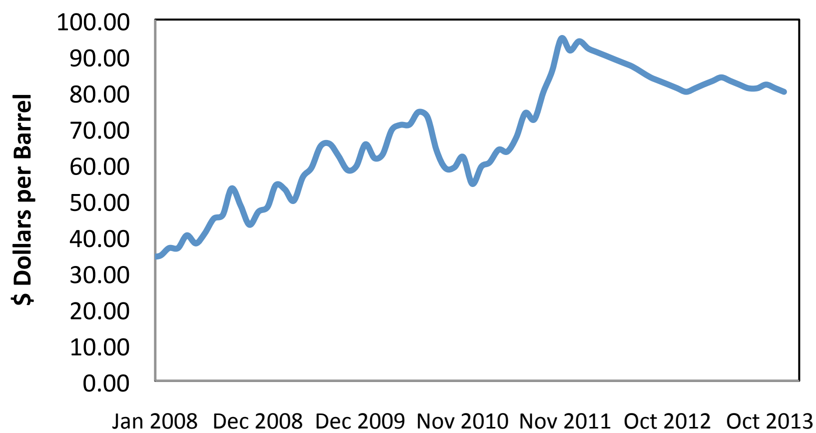

Figure 3. Crude oil price projections [2].

Oil shale is comprised of fine-grained sedimentary rock bound with kerogen [5]. When the rock-kerogen mixture is heated, petroleum-like liquids are released [7]. There are essentially two methods to develop oil shale – (1) mining and surface retorting and (2) in situ retorting. Both require water to execute the process. Mining can be subdivided into surface mining and underground mining, with underground mining having limitations of recovery rate and greater safety risk. Surface mining is more effective and can produce much higher resource extraction, although overburden deposited on the surface is an environmental concern requiring reclamation attention. Regardless of mining technique, the oil shale is crushed at the surface and retorted at 900~1000 ºF in a surface retorting plant to produce shale oil from kerogen in the rock. In order for either method to be profitable, the operating and maintenance costs for the plant should be $17 to $23 (2005 dollars) per barrel of oil produced [8]. However, estimates of cost for mining and surface retorting indicate that the price of low-sulfur, light crude oil would have to be at least $70 to $95 per barrel for an oil shale operation to be profitable [7]. An estimate of water required for mining and surface retorting processes is approximately 1 to 3 gallons water/gallon of oil produced [7].

In situ retorting during the 1970s and 1980s involved dewatering, fracturing, heating, recovering, and transporting processes [5]. A newer approach, the In Situ Conversion Process (ICP), was introduced in the early 1980s by Shell [7]. Their process involves drilling a series of boreholes into an oil shale deposit and installing underground heaters. Heaters are placed in the boreholes and the deposit is heated to 650-700ºF for 2 to 3 years, after which the oil is extracted using conventional methods. The ICP approach has resolved many of the disadvantages of mining and surface retorting. First, it reduces the potential for air and water pollution, although the issues of groundwater pollution after the freeze wall thaws out are unknown. Second, it eliminates surface destruction, although in situ processing does have a footprint [9]. Third, it has the potential to reduce costs. Estimates of ICP water requirements could not be found. However, since the process requires substantial amounts of energy to execute the heating process, water requirements will depend on the energy generation technique.

Oil shale development in the U.S. will impact water resources, especially in the semi-arid western states. To begin to re-assess the potential water resources impacts, it is necessary to review past studies, collect geospatial and environmental datasets for analysis, update estimates of population and of oil shale reserves, estimate water requirements for future oil shale industry growth, and identify water availability constraints. The beginning steps towards these needs are addressed by the research described herein. Further research is needed to provide greater breadth and depth to the analyses presented here, to develop and implement the water availability assessment framework, and to investigate possible surface water and groundwater impacts.

Task 1. Literature Search and GIS Dataset Compilation

Literature Search Summary

During the first oil shale boom in the 1970s and 1980s, a considerable amount of research was performed to address the water resources issues [8]. With the renewed interest of the past decade in unconventional oil resources, including oil shale, the research has been repeated and extended to further address the potential water resources issues associated with oil shale development. The first phase of the present project involved compiling key literature references and uploading them to the Utah Heavy Oil Program (UHOP) repository [10]. Of the approximately 50 documents (including reports, journal papers, fact sheets, and conference papers), two stand out as the key resources: reports by the Office of Technology and Assessment (OTA) [8] and the RAND Corporation [7]. The first provides an extremely detailed description of their approach to estimate the water requirements and identifies alternative approaches to supply the needed water in the western U.S. regions. The RAND report essentially updates the OTA assessment but uses an estimate of water required for oil shale extraction and processing of 1 to 3 barrels of water per barrel of oil produced compared (compared to 2-5 barrels used in the OTA estimate). The reduced amount of water was justified based on improved technologies. Key findings from the literature review included:

- From the time of the OTA report [8], the potential alternatives to supply water for oil shale development remain essentially the same, but additional sources including deep groundwater, wastewater recycle and water reuse, and new opportunities for storage and water development projects increases options and flexibility [8].
- Recent advances in produced water treatment technologies have reduced potential environmental impacts [11].
- Past failures of oil shale industry were due to reasons other than the resources [12].
- Examples of recent oil shale and oil sands production in other countries provide important information of use in assessment of water resources impacts of oil shale development in the U.S. Specific information related to water provided in the recent

literature address urban growth, demographics, and environmental impacts [e.g., 13,14,15].

- A start-up period associated with early growth of an oil shale industry must be expected. Reductions in water requirements and water resources impacts as the industry matures must also be expected based on the experiences over the last 35 years with the Alberta oil sands. Estimates of water requirements must consider the likely reductions as the industry matures.
- Advances in the 1980s and 1990s have reduced water requirements for traditional oil shale extraction and processing techniques from 2-5 barrels or water per barrel of oil to 1-3 barrels of water per barrel of oil [7].
- The Shell Oil Co. ICP has the potential to reduce (or in some cases eliminate) environmental impacts and significantly reduce the amount of water use [12], but there are new uncertainties associated with heretofore unforeseen environmental impacts (e.g., impacts to groundwater quality).
- Development of other energy industries in Utah, Colorado, and Wyoming has established a strong infrastructure backbone and new environmental technologies for the oil shale industry.
- Inclusive approach of Alberta for oil sands development could serve as a model to minimize social and cultural impacts [12].
- A geospatial approach to water management is needed to overcome the water limitations in the western U.S.
- A search of the Utah Division of Water Rights online resources indicates private owners of oil shale lands in Utah have already secured senior water rights to supply projects. The state Division of Water Resources also holds water rights for possible growth in the region. Oil shale leases on federal lands, however, will not come with water rights, and more than 80% of the Green River Formation lies on federal land.

GIS Datasets Summary

In addition to a brief literature review to give a background and provide a base level of understanding of the current state of the practice, the project team also collected GIS datasets related to oil shale and water resources in the Uinta and Piceance Basins from the Colorado Division of Water Resources, the Utah Division of Water Rights, the Utah Geological Survey, and the U.S. Geological Survey. In sum, more than 50 geospatial datasets were collected and compiled into a listing describing the datasets. The datasets describe the oil and gas resources in the Uinta and Piceance Basins and a range of water-related datasets – natural and human. The GIS data has been supplied to UHOP for upload to their map server [16]. The datasets describe the spatial distribution of the hydrography, energy resources, transportation networks, and urban population as well as the terrain and land use features of the areas. Consideration based on the data collection and literature review compilations resulted in the identification of the need to acquire environmental data and hydrologic data in time series format to help characterize the baseline environmental quality of the area.

Task 2. Revised Estimates of Water Requirements for Oil Shale Development

For this task, previous estimates of water requirements for oil shale development in the Uinta and Piceance Basins were reviewed and a new estimate was made based on recently available information and new approaches. Two new sub-tasks were needed: urban growth projection and estimate of oil shale resources.

Urban Growth Estimate

Urban growth projections can be made in a number of ways. The projection made in 1980 by OTA [8] has been used to some extent by all known estimates of water requirements for oil shale development in the Uinta and Piceance Basins. The OTA municipal population growth projection was assumed to be 5.5 times the number of employees. This was identified as an "uncertain estimate" by OTA. For our estimate, we used the 20+ year growth of the town of Fort McMurray, Alberta, Canada, to represent a reasonable model of the growth of the small town of Vernal in Eastern Utah. This growth model provided us with population projections to grow the oil shale industry from no commercial development to 2-3 million bbl/day of oil produced.

The first step of the analysis was the acquisition of aerial photos of the two cities for two periods in time. The aerial photos of Vernal, Utah were obtained for 1997 and 2006 (Figures 4 and 5), a approximately 10-year period of slow population growth in the city. Observing the photos, one notes the increase of urban areas to the east and south of the central town site in the 2006 image compared with the 1997 image. It is important to note the importance of the existing transportation corridors on the pattern of growth observed. A spatial pattern of growth (not made for this study) would likely concentrate along the same transportation corridors followed by the 10-year growth ending in 2006.

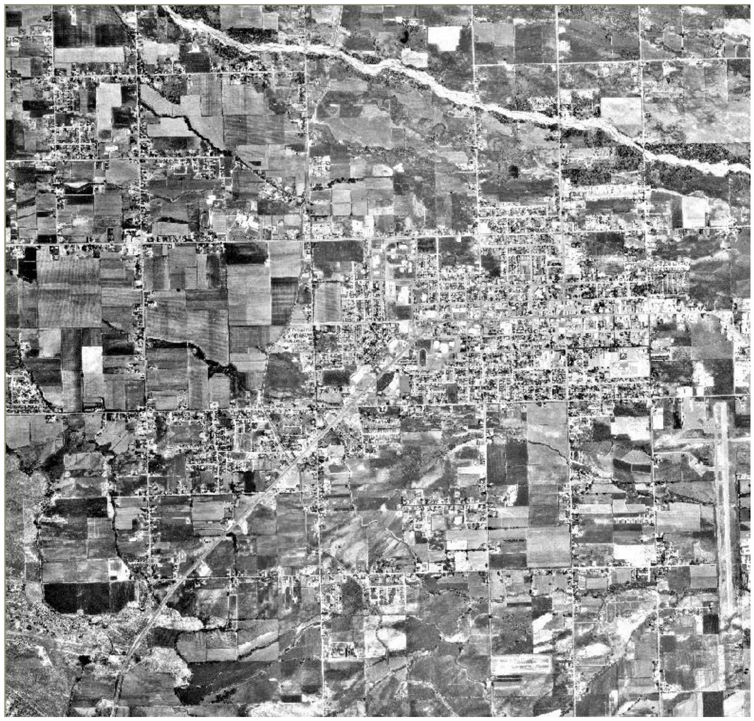

Figure 4. Aerial image of the town of Vernal, Utah collected in 1997.

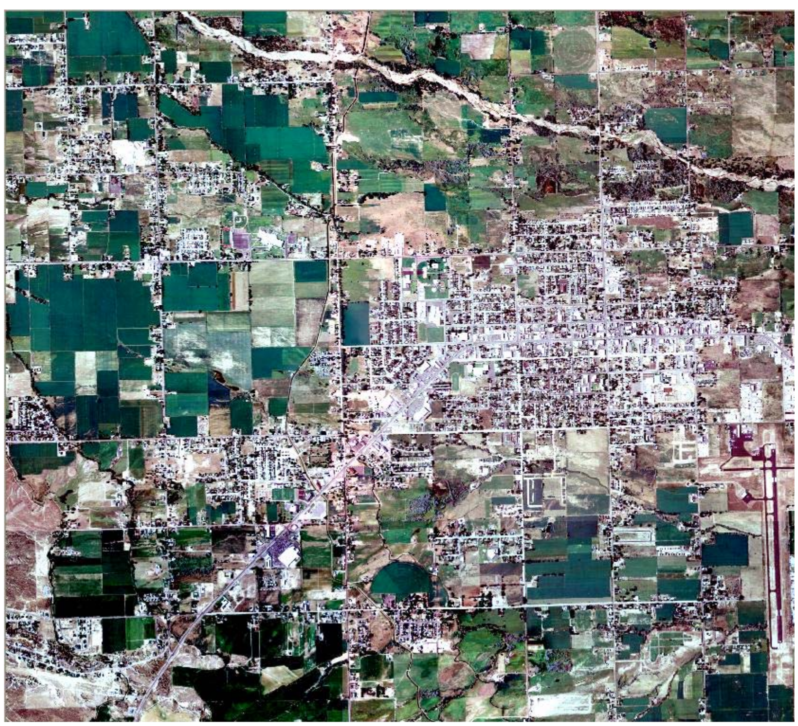

Figure 5. Aerial image of the town of Vernal, Utah collected in 2006.

Discussions with urban planners from Vernal indicated that population growth has actually been higher than the two images suggest, especially over the past 3-4 years as the energy development industry has grown. There is no significant outward growth of the city yet due to building policies and prices. Most of the people moving in to town are renting every available space and even moving into work sheds and fixing them up to simulate small cabins. There is some growth that is visible from a close study of the images, but not enough to compensate for the change in total numbers.

This housing shortage is a major problem facing Vernal. The Vernal planners suggested this trend is not due to lack of homes but a lack of affordability. In fact, homebuilding is at an all time high in the area. Single-family home building permits numbered 41 in Vernal City in 2005. This number ballooned to 61 in 2006 and 68 in the first nine months of 2007. At a meeting in Vernal in 2008 [17], a development company addressed a large gathering to discuss housing shortages and housing prices in Vernal. The key points from the meeting were the relative "lack of workforce housing for moderate-income homeowners in the community". Homes have increased in value 30 percent over the past couple of years. With the average home valued at $200,000, many first-time buyers are priced out of the market. While new construction continues, mid-range construction for lower income qualifiers has not. Some families are living in recreational vehicles and others, in their cars. A 72-year-old woman reported at the meeting that rising rents had priced her out of an apartment and forced her to stay in her car.

With the growing need, more permits have been issued for apartments and multi-unit homes. There were five city-issued building permits for multi-family housing in 2005, 12 in 2006, and 26 in 2007. Still, shortage has driven rents up from $800 just three years ago to $2,000-plus for a typical two bedroom apartment. The shortage of multi-family dwellings partly relates to city planning. Bill Johnson, impact mitigation special service's energy analyst, notes city general plans need to be adjusted in some areas to allow higher density housing [17]. All of these observations provided insight for the revised planning estimate of population growth in Vernal to support oil shale development.

To understand the urban growth issues facing Vernal and how they influence growth projections, we used the example of Fort McMurray, Alberta, Canada as an example. Fort McMurray, the most geographically proximate city to the oil sands industry, has experienced rapid urban growth driven by the development of the oil sands industry. Officials from Vernal, Utah, are well aware of the growth in Fort McMurray due to the oil sands development. In fact, they organized a visit from Melissa Blake, mayor of Fort McMurray, to learn from her experiences with a town that has grown from 6,000 to approximately 73,000 over a 20-year period. She urged the communities to have a long-term vision and to partner and cooperate with each other. She also suggested the need to weigh population projections carefully, as their growth has outpaced projections every year for the past six years.

The recent growth of Fort McMurray can be observed in Figures 6 and 7. Growth can be seen in several locations but especially in the northwest quadrant. Based on a fringe area development assessment, certain areas around Fort McMurray have been identified as being suitable for future growth. Figure 8 shows these areas in yellow.

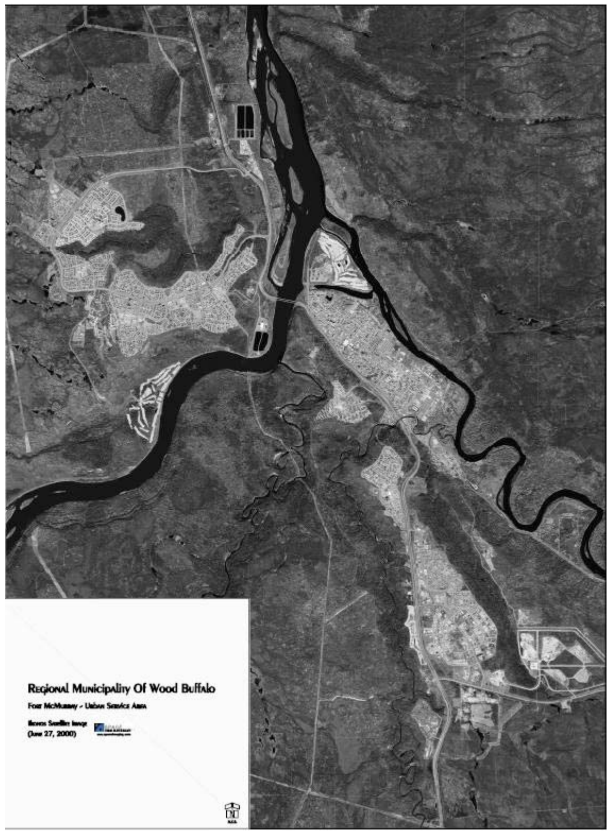

Figure 6. Aerial image of Fort McMurray, Canada, collected in 2000.

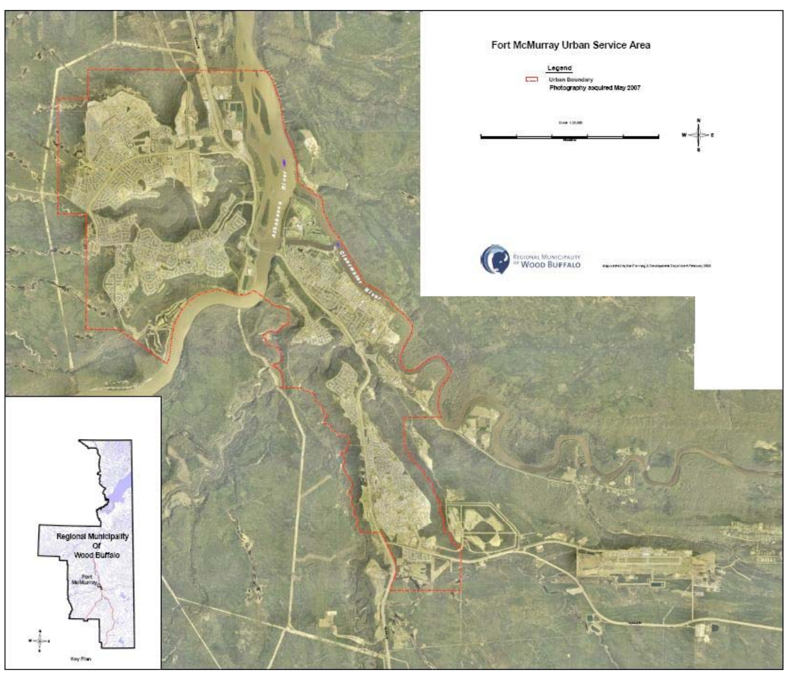

Figure 7. Aerial image of Fort McMurray, Canada collected in 2007.

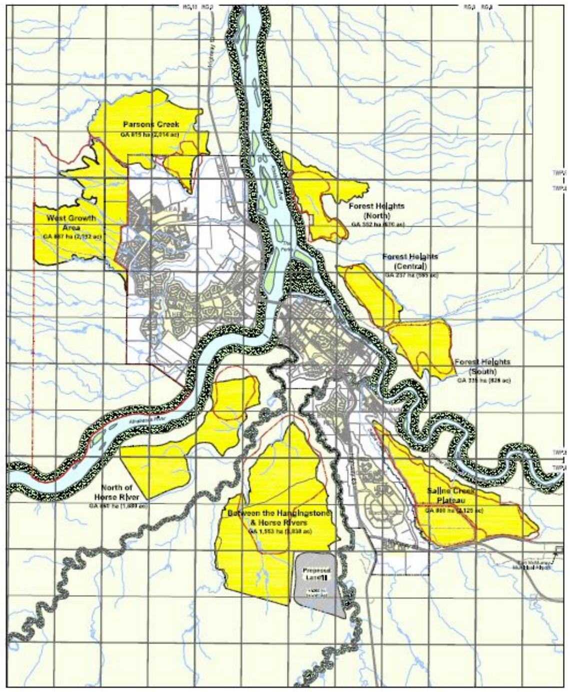

Figure 8. Identified areas for planned new urban growth in Fort McMurray.

Estimating urban growth in Vernal and the Uinta Basin area is informed based on Fort McMurray growth, but it is still not straightforward. Fort McMurray saw population increase from 6,473 in 1971 to 30,772 in 1981, spurred mostly by oil sands development. With the drop in oil prices in the early 1980s, the population remained near 30,000 – 35,000 until the end of the 1990s, when a consistent growth of ~8.5% raised the population to the present population of nearly 80,000. The population in 2005 was approximately 60,000 and the oil sands production rate was 760,000 bbl/day. In 2006, the population was 64,441 and the production rate was 1.13 million bbl/day. While these growth rates are large, they are well below the estimates made by OTA [8] and used recently by [28] and others to estimate water requirements for oil shale development. OTA [8] estimated ~100,000 new residents for a 500,000 bbl/day production rate and nearly 200,000 new residents for a 1 million bbl/day production rate. Based on the Fort McMurray growth, these estimates are high. Vernal and Uinta Basin may grow differently than Fort McMurray, but growth rates nearly two times those observed in Fort McMurray seem unlikely. Combine that with the observation in both Fort McMurray and Vernal that new residents often are temporary, live in multi-family housing, and spend significant periods of time away from the residence suggests the use of a single per capita water use amount for the entire urban population is unreasonable. Temporary residents and those living in multi-family residences use considerably less water than those living in single-family homes [18]. Also, many residents may obtain water from local sources (wells) rather than drawing from engineered municipal infrastructure systems.

Overall, caution must be exercised in making population projections. The Vernal population has already grown to more than 10,000 due to an oil and gas industry boom. Additionally, Fort McMurray Mayor Melissa Blake noted the actual population growth observed in her town was higher than projections [17]. In this case, we are making a projection expressly for estimating water requirements. **Based on the data from Fort McMurray, considerations of the likely**

demographics, and water use characteristics, we estimated the population growth rate in the Uinta and Piceance Basin to be 80,000 per 1 million bbl/day production rate. This value is slightly higher than the Fort McMurray population growth but much lower than growth estimates used in previous studies and likely provides a more reasonable estimate for the remote Uinta-Piceance Basin where growth in the region from the industry is not likely to spur additional growth.

Uinta-Piceance Oil-Yield Estimate

Another key figure to estimate water requirements for future oil shale development is an accurate estimate of crude oil yield from the oil shale resources. The amount of oil shale present will dictate the production rate and duration (and thus the water requirement rate and duration). For this study, a revised estimate of the oil yield from the Uinta and Piceance Basins (Figure 9) is made using available data for oil shale Isopach layers (the thickness of oil-shale layers), in-place oil resources (gallon of crude oil per ton of oil shale), and density of oil shale deposits. The three sources of data used to create the revised estimate are (Table 1): (1) the Utah oil shale database from the Utah Geological Survey, (2) Fischer assays of oil shale drill cores and rotary cuttings from Piceance Basin, Colorado, and (3) USGS Miscellaneous Field Study Map and Oil and Gas Investigation Maps [19].

Data Sources

The Utah Oil-shale Database [20] covers the Uinta basin, Utah. The database provides coordinates of cores, geological logs, and Isopachs of oil shale zones from the top of the Mahogany layer to the bottom of the rich oil shale layer. The in-place oil resources (gallon/ton) are calculated using the average value from the full depth of the oil shale profile in the database. For the Piceance Basin, the Fischer assays of oil-shale drill cores and rotary cuttings [21] are used to directly calculate the isopach and in-place oil resources. The USGS Miscellaneous Field Study Map (MF-958) [19] is used to estimate the in-place oil resources (gallon/ton) of the Mahogany Outcrop and the Oil and Gas Investigation Maps (OC-132 Sheet 1 to 6) [22] is used to estimate the Rich (R) and Lean (L) zones Isopach of the Mahogany Outcrop. For both basins, the oil shale density is assumed to be 2.0 g/cm^3 (2.205 short ton/m^3) based on the density measurement of Green River oil shale [23].

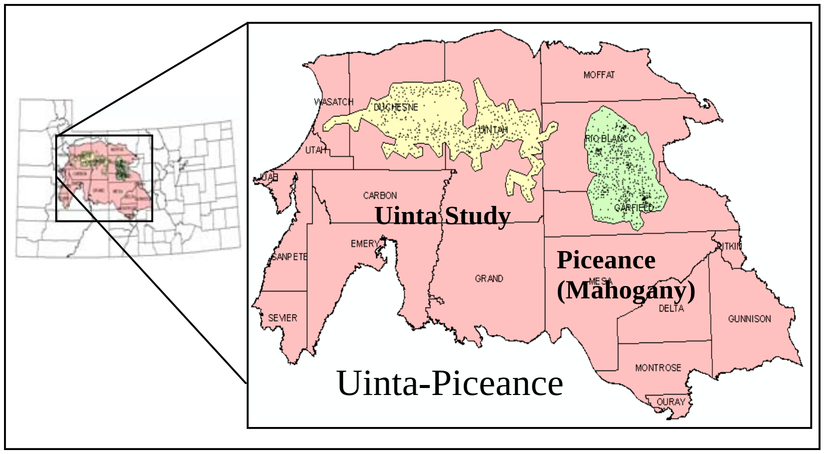

Figure 9. The Uinta (yellow) and Piceance (green) Basins are located in eastern Utah and western Colorado, respectively.

Table 1. Data sources used to estimate crude oil yields from Uinta and Piceance Basins.

Data Sources	Datasets
Utah Oil-shale database or U.S. Geological Survey Open-File Report 469	Uinta-Isopach, Uinta-In-place Oil Resources
Fischer assays of oil-shale drill cores and rotary cuttings from the Piceance Basin, or U.S. Geological Survey Open-File Report 98-483	Mahogany-Isopach Mahogany-In-place Oil Resources
U.S. Geological Survey Maps OC-132 (6 sheets) U.S. Geological Survey Maps MF958	Mahogany-Isopach (Rich and Lean) Mahogany-In-place Oil Resources
Oil Shale Technology [23]	Defined Oil-shale Density =2.0 g/cc

<u>Data Pre-Processing</u>

The Uinta Basin Isopach point features were directly derived from the Utah oil shale database (Figure 10). For the Piceance Basin, the analog USGS maps were scanned, digitized, and georeferenced (Spheroid-based Clark 1866 Geographic Coordinating System) to build the point feature shapefiles. The Piceance Basin (Mahogany Outcrop) Isopachs were digitized as polyline features from [22] including Lean (L1-L5) and Rich (R1-R5) zones and later converted to point features for processing (Figure 11). The in-place oil resources of the Mahogany Outcrop were obtained from the Fischer Assays of oil-shale drill cores and rotary cuttings [21] (Figure 12). Although the spatial reference was geographic, the derived raster (gridded) data were projected into the NAD 1983 UTM projection to facilitate the raster calculations to determine the oil yield estimates.

Figure 10. Isopachs (433 points, black) and in-place oil resources (657 points, red) of Uinta Basin study area [20].

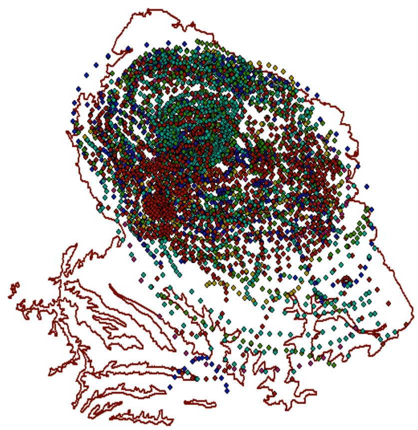

Figure 11. Point features of Isopach Rich and Lean zones in Piceance Basin Study Area (Mahogany Outcrop).

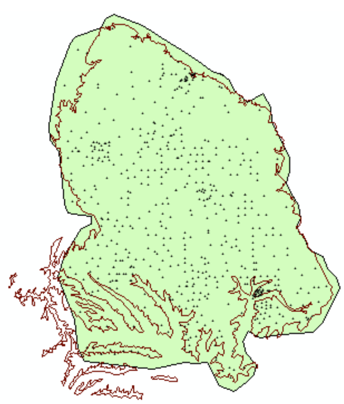

Figure 12. Isopach and in-place oil resources (587 points) of the Piceance Basin Study Area (Mahogany Outcrop) [21].

Data Processing

Standard spline interpolation in ESRI ArcGIS 9.2 was applied to the Uinta Isopach and the in-place oil resources point features to create a gridded continuous dataset (raster image) for the study area. The Piceance (Mahogany) Isopach point feature (Rich and Lean zones) was built by applying "the Feature Vertices to Points Tools" to the Isopach polylines. The point feature (output from the Feature Vertices to Point Tool) was interpolated into the raster images by spline interpolation. Analysis masks were created for the two study areas to guide the processing of the geographic information system to occur only within the designated mask boundary. The masks were set to the extent of the Isopach data, including a 3-km buffer (mask shown in green in Figure 12). The mask areas used were 2,412 mi^2 (~1.5 mil acres) and 1,530 mi^2 (~1 mil acres) for the Uinta Basin and the Piceance Basin (Mahogany Outcrop), respectively. The interpolated Isopach and in-place resource datasets were projected to the NAD 1983 UTM projection with grid cell sizes shown in Table 2.

Table 2. Grid cell sizes of interpolated raster images used in oil yield estimates.

Raster Images	Data Sources	Grid Cellsize (m x m)
Uinta Isopach	USGS Open-File Report 469	285 x 285
Uinta In-place Oil Resources	USGS Open-File Report 469	795 x 795
Mahogany Isopach	Rich and Lean Zones OC-132	309 x 309
Mahogany In-place Oil Resources	In-place oil resources MF958	318 x 318
Mahogany Isopach	USGS Open-File Report 98-483	299 x 299
Mahogany In-place Oil Resources	USGS Open-File Report 98-483	318 x 318

Raster images (output from spline interpolation) may contain errors (e.g., negative values) that must be assessed and removed from the analysis. The raster calculations needed to compute the oil yields using standard ESRI ArcGIS 9.2 Map Algebra might fail with negative values. All negative values were assigned a value of zero. An additional filter was then applied to remove in-place oil resources with less than 25 gallons/ton, a value assumed for this analysis to be the threshold for economical oil shale recovery. The crude oil yield within the oil shale layers is estimated using the following function implemented with the Map Algebra function of ESRI ArcGIS 9.2:

$$\textit{Volume of Oil Shale } (m^3) = \textit{Isopach Thickness } (m) \times \textit{Grid Cellsize } (m^2) \quad (1)$$
$$\textit{Mass of Oil Shale (ton)} = \textit{Volume of Oil-shale } (m^3) \times \textit{Density } (m^3/ton) \quad (2)$$
$$\textit{Crude Oil (gallons)} = \textit{Mass of Oil Shale (ton)} \times \textit{In-place Oil Resources (gal/ton)} \quad (3)$$
$$\textit{Crude Oil (barrels)} = \textit{Crude Oil (gallon)} / 42 \quad (4)$$

Figure 13 illustrates the oil yield calculation for the Mahogany Outcrop. The results of crude oil yield estimation are shown in the Figure 14 and Tables 3 and 4.

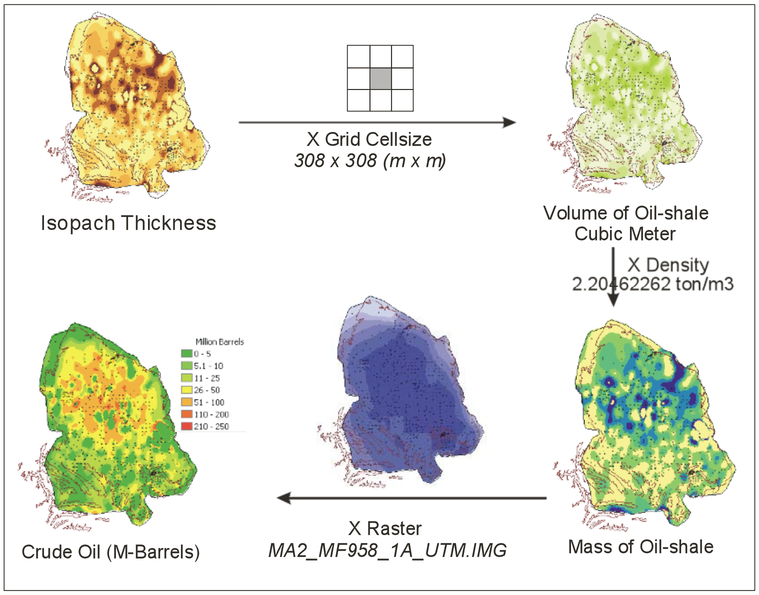

Figure 13. An example of the oil yield calculation of Mahogany Outcrop, Piceance Basin, Colorado (application of equations 1-4).

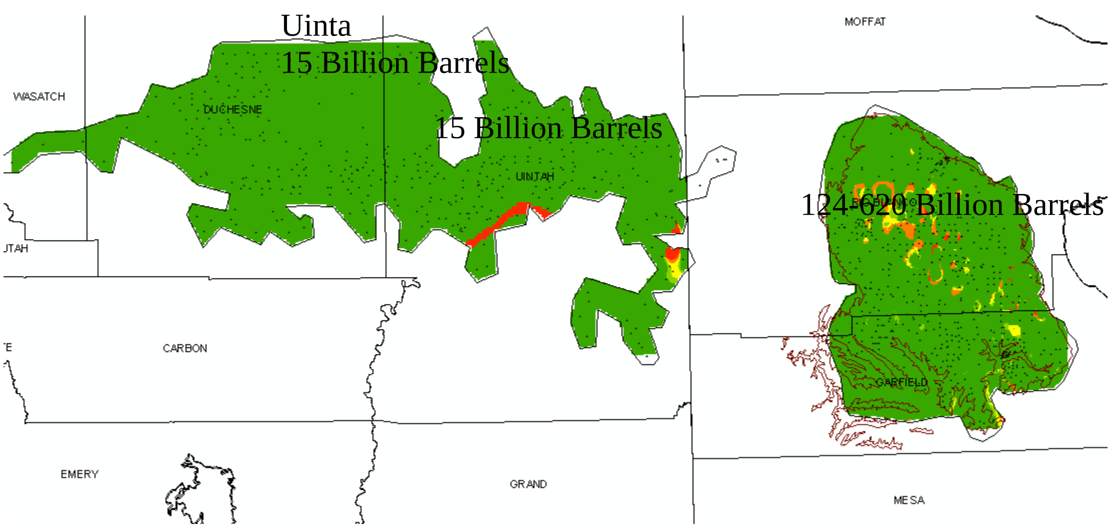

Figure 14. The estimated crude oil yield within the oil-shale Isopach of Uinta and Mahogany Areas (billion barrels) and the distribution of point features within both areas.

Table 3. Comparison of economical crude oil yield estimation from different data sources.

Data Sources	Location	Billion Barrels
USGS Open-File Report 98-483	Mahogany Outcrop, Piceance Basin Colorado	124
Rich and Lean Zones OC-132	Mahogany Outcrop, Piceance Basin Colorado	620
USGS Open-File Report 469	Uinta Basin, Utah	15
	Total Crude Oil in Both Areas	**139-635**

Table 4. Estimated crude oil yield of Uinta and Piceance Basins from other studies.

Data Sources	Location	Billion Barrels
Trudell et al. [24]	Uinta Basin, Utah (2008 mi^2)	214
Tabet [25]	Uinta Basin, Utah	499
	Mahogany Outcrop, Piceance Basin Colorado	700
Cashion [26]	Uinta Basin, Utah	321
Vanden Berg [27]	Uinta Basin, Utah and Colorado	147

The estimated crude oil yield of the Uinta Basin (Table 3), based on the economical criteria of in-place oil resources of 25 gallons/ton, is 15 billion barrels within 2,412 mi^2 (1.5 million acres). Compared with other studies (Table 4), this estimate is considerably smaller. Cashion [26] estimated 321 billion barrels, Trudell et al. [24] estimated 214 billion barrels for 2,008 mi^2 area, and Vanden Berg [27] estimated 147 billion barrels (only assuming 25 gallon/ton threshold). Additional constraints added by Vanden Berg [27] (> 5 feet thick, < 3000 feet of overburden, and no conflicts with existing oil and gas operations) produced an estimate of 77 billion barrels. There is a wide range of estimates due to the uncertainty of the input data and the assumptions made. Our study produced the smallest estimate because our assumptions and area of analysis is the most limiting, which is meant to provide a conservative estimate. The estimated oil yield from the 1,536 mi^2 (1 million acres) Piceance Basin study area (Mahogany Outcrop) varies from 124 to 620 million barrels, based on the [21] and [19], respectively. For the Piceance Basin, the estimated overall crude oil yield from this study (assuming 25 gallon/ton threshold) is similar to results from the other studies [25,28,29]. Although the area of the Piceance Basin is smaller than the Uinta Basin, the crude oil yield estimate is higher because the Piceance Basin has higher Isopach thickness and in-place oil resources (gallon/ton) [7]. Spatially, the areas of highest potential yield are located at the center of the Mahogany Outcrop in Rio Blanco County and in the Uinta Basin in central and eastern Uintah County.

Revised Estimates for Oil Shale Water Demand

Several estimates of water demand for oil shale development in the Uinta-Piceance Basin have previously been developed [7,8]. A thorough analysis by the OTA [8] in 1980 determined a 50,000 bbl/day facility would need 8,500 acre-feet/year of water and a 1 million bbl/day facility would require 170,000 acre-feet/year. One of the more recent studies, completed in 2006 [29], used some of the same information as [8] with the primary difference being an update to the water requirement for mining and retorting based on technology advancements (1-3 barrels of water /barrel of oil, changed from 2-5 barrels water/barrel of oil). The resulting water requirement estimates (Table 5) were reduced substantially. A major difference in the conclusions of the two studies is the availability of surface waters to provide the necessary water demand. The OTA report [8] concluded that surface water would be sufficient for an oil shale industry developing in the 1980s and reaching 1 million or more bbl/day oil production by 2000. Clearly, that scenario did not occur. Instead, urban development increased massively in the western U.S. and drought conditions highlighted the lower-than-expected average surface flows. Recent studies have considered altered streamflow and water scarcity in the west [7,29]. A study of the capacity of the White River in Colorado to support a 500,000 bbl/day oil shale industry in the Piceance Basin concluded the demands could be met if extractions were limited to 70,000 acre-feet/year and an additional 16,000 acre-feet/year of reservoir capacity was built [29]. Another conclusion from the more recent studies is the need for regional water management to support an oil shale industry producing more than 1 million bbl/day because the spatial and temporal impacts will extend beyond the local area.

Table 5. Previous estimates of oil shale water requirements for selected production rates [7,29].

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	1-3	21 to 63	96,000	13	34 to 76	0.04 to 0.09
1	1-3	42 to 126	177,000	24	86 to 150	0.10 to 0.17
2.5	1-3	105 to 315	433,000	58	163 to 373	0.18 to 0.42

We identified four areas we could address to improve upon previous water requirements estimates [7,8,29]: (1) population projection based on urban growth example, (2) sustainable urban development incorporating water and energy efficiency goals and representing likely demographics of new residents, (3) newer in situ technology and on-site energy generation to extract oil from oil shale resources, and (4) alternative electricity generation technologies. We also sought to incorporate energy demands for water transport and to separate the water demands into oil shale, energy generation, and urban population sectors. These updates seek to make the estimates more accurate and to provide reasonable ranges to the uncertain estimates presented in the past. In addition, by parsing the water demands into sectors, planning and decision-making can be more precise. Water requirements are first estimated for a new base case (using all the information from the previous studies and including energy generation needs for water transport). Then a series of scenarios are analyzed: population growth, sustainable urban development, oil shale extraction technology, and alternative electricity generation. Assessing the effect of the changes to water requirements caused by these scenarios is conducted by comparing the change in water requirements for each scenario to the revised base case and then combining all changes into the “optimistic scenario”. In addition, a “realistic” scenario is presented that includes the most likely scenarios (based on the project team consensus).

Base Case Scenario (Previous Study + Energy for Water Transport)

The energy demand (and associated water requirement) component that has been neglected in most previous studies is the energy required to transport water from source to use. For example, the State Water Project in California delivers 1.3 trillion gallons of water per year over a distance of 621 miles. In order to transport this amount of water, 12,400,000 MWh per year are required [30]. In China, 3.7 trillion gallons of water is transported over a distance of 683 miles requiring 5,000,000 MWh per year [31]. Although China delivers nearly three times more water over a similar distance, their transportation process requires less energy because the lift constraints are smaller. The topographic and geographical characteristics over the transport area are important. Therefore, it is critical for the spatial distribution of water sources and use locations to be identified prior to conducting an energy demand analysis. While this information is unknown, a set of assumptions can be made to produce a rough estimate of this energy demand component for the Uinta and Piceance Basins. First, one water source identified in previous studies that could supply oil shale operations in Utah and Colorado is the White River [29,32]. A conservative estimate of the distance from possible storage or diversion locations to potential oil shale extraction locations is 100 miles. The energy needed to transport water from a source to the urban population centers (e.g., Vernal, Utah and Grand Junction, Colorado) is assumed to be similar. The energy requirement for water transport in Utah is currently being determined [33]. Consequently, the outdated unit value for California (5.92 (mil kWh/day) per (MGD/mile)) must be used as a conservative estimate (1MWh/MGD).

Population Growth Scenario

Previous studies have based urban water and energy needs on estimates of population growth from OTA [8]. However, based on the analysis of the Fort McMurray growth trend (described above), an updated population increase of 80,000 for a 1 million bbl/day industry (40,000 for 500,000 bbl/day production and 200,000 for a 2.5 million bbl/day production) was used.

Oil Shale Extraction Technology Scenario

Advances to technologies are reducing the amount of water required for extraction of oil shale. Water is required to develop oil shale for power generation (in situ heating processes), retorting, refining, reclamation, dust control and other on-site demands. OTA (1980) [8] estimated 2-5 barrels of water to produce 1 barrel of oil, the U.S. Water Resources Council (1981) estimated 3 barrels of water per barrel of oil, and Bartis et al. (2005) [7] estimated 1-3 barrels of water to produce 1 barrel of oil. These estimates all include both on-site and off-site water requirements. It is clear that reliable estimates of water requirements will not be available until the technology reaches the scale-up and confirmation stage [7]. Further, these water budget estimates do not account for the potentially large quantities of water produced during extraction and processing, which may be treated and reused. For our revised estimates, we retained the range of 1-3 barrels of water per barrel of oil from [7] (except for the scenario of advances to oil shale extraction technologies described below).

An important consideration that we investigated in this study was separating on-site water requirements and off-site water requirements (for energy generation) to provide greater precision for future water management planning. To estimate the on-site water requirement range, we started with a conservative estimate from Gleick [30] of 2 barrels water used on-site per barrel of oil produced. The low end for on-site will be zero water required. This scenario may be possible if emerging in situ processing techniques that do not require copious amounts of steam/water are combined substantial water reuse. The high end of the range for off-site water requirements follows from previous estimates of water demand for energy generation. Past experiments with the Shell ICP technology used 15 to 25 boreholes per square acre with an electric heater at each borehole to heat the oil shale oil shale up to 650-700ºF for 2-3 years. Shell estimated this in-situ technique would require 250-300 kilowatt-hours (kWh) of electrical energy to extract 1 barrel of oil [7]. However, recent research developments within Shell and the experiences in the Alberta oil sands indicate energy generation will likely be provided by natural gas-fired facilities. Therefore, the low end of the off-site energy requirements will be no electric energy. The water requirement for off-site energy requirement is estimated based on the energy generation technology chosen and is described below. The high and low estimates provide the range of water requirements that can be used for planning.

Developing the water demand estimates by separating the on-site and off-site water requirements did not change the overall water demand estimates we sought for this study; therefore, we did not include the results in this report. They are relevant for the next phase of our work, which is to refine the water estimates temporally and spatially to provide more useful information for water development planners and water managers.

Sustainable Urban Development Scenario

Water consumption in U.S. cities is highly variable. However, much of this variability is based on the range of industrial, institutional, and commercial entities in a city and the wide range of outdoor water use for landscape irrigation. Indoor residential water use is fairly uniform across the U.S. at approximately 70 gallons per capita daily (gpcd). Utah has the reputation as a significant per capita water user, partially because of outdoor water use to irrigate non-native turf grass landscapes. Given that the demographics of population growth in the Uinta and Piceance Basins will likely include a significant number of temporary workers not living in single family homes with yards, the per capita water use in Utah (245 gpcd, [18]) and Colorado must be reduced to estimate future urban water use associated with growth in the major cities near to the Uinta-Piceance Basin.

The per capita water use of the urban population associated with oil shale development is based on the average per capita water use in the Salt Lake City, Utah metropolitan area, 180 gpcd for single-family residences and 58 gpcd for multifamily residences [34]. These values can be used to estimate the water requirements given future reductions due to implementation of conservation practices. The State of Utah has a stated goal of reducing water use by 25% [18]. Taking this percent reduction, we can estimate future water use to be 135 gpcd and 43.5 gpcd for single-family and multifamily residents, respectively. We can further reduce the single-family residential value by assuming the new developments are made using low-water use vegetation, which will reduce water use by approximately 35-70% [35]. Using the average water use reduction of 50%, the single-family water use under a sustainable development scenario would be 67 gpcd. An equal mix of single-family and multifamily residents can be assumed for the low end of the range to produce a per capita water demand of 55 gpcd for all population added.

In addition, previous studies based their water and energy demands on current (at that time) use rates. Our analysis will include current rates for the base case and future rates including conservation, which will provide a more realistic picture of the actual energy and water needs in the future.

Urban growth will also affect energy generation demand. The increased energy demand is estimated for this study using a combination of historical energy use data and projected energy use trends. In 1980, the Utah population was less than 1.5 million. In July 2003, the population was 2.3 million for an annual average increase of 2.1% (Figure 15). The electrical energy usage has also increased from 10,705 million kWh in 1981 to 23,205 million kWh in 2001, representing an annual average increase of 3.8% (Figure 16). Based on these numbers, Utah residential electricity consumption per capita has increased from 2133 kWh/person in 1980 to 2949 kWh/person in 2001, for an annual average increase of 39 kWh/person/year (Figure 17). Using this average annual increase, an estimate of energy consumption in 2025 (17 years has been estimated as the time to fully develop the oil shale industry [8]) is 3885 kWh/person. This value can be viewed as the high end of a range, with the low end 20% less (3108 kWh/person) based on the overall energy efficiency goal for the state of Utah in 2015 [36].

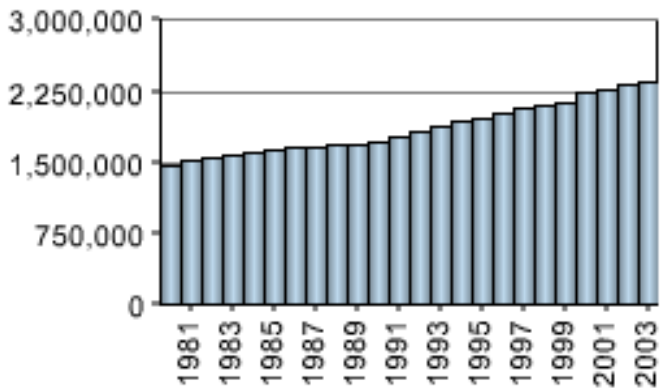

Figure 15. Utah population growth [37].

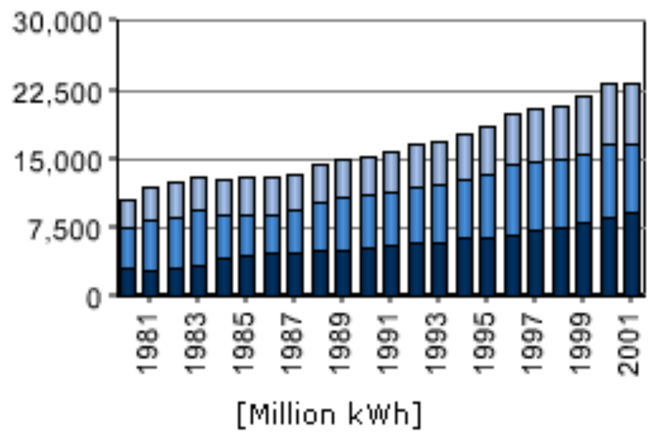

Figure 16. Electricity consumption in Utah [38].

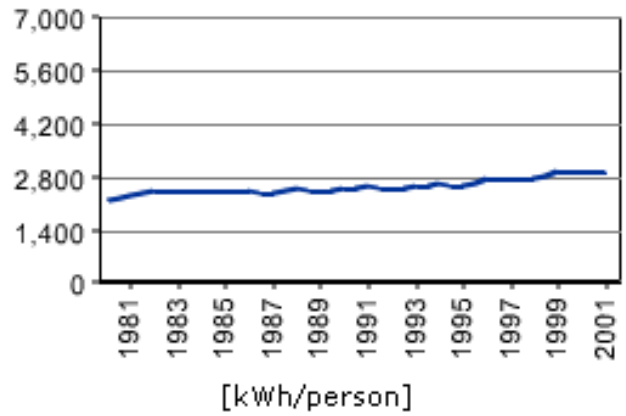

Figure 17. Utah residential electricity consumption [39].

The water requirement for the increased energy demands to support the oil shale industry and urban growth can be estimated based on the energy generation technology employed. New energy generation capacity will be needed in Western Colorado and Eastern Utah to support the oil and gas industry growth and urban growth. Currently, coal-fired power plants provide approximately 95% of the energy in Utah and 83% of the energy in Colorado. Coal-fired power plants are a reasonable assumption for future power generation to support urban growth in the Uinta-Piceance Basin. In general, coal-fired power plants consume 600 gallons of water per Mega-Watt hour (MWh) of energy produced. The National Renewable Energy Laboratory [38] estimated that in Utah, 570 gallons of water are required to produce one MWh in a coal-fired power plant. We contacted two coal-fired power plants in Utah and their consumptive water use amounts were less (450 gal/MWh and 470 gal/MWh). Therefore, we used 500 gal/MWh to be more consistent with observed water consumption at local coal-fired power generation facilities.

<u>Alternative Electric Power Generation Scenario</u>

One scenario included in the analysis was the use of alternative electric power generation capacity. There is potential to develop wind, solar, geothermal, and hydropower in or near the Uinta and Piceance Basins that could supply the oil shale industry and urban population growth. In fact, one study that considered constructing a reservoir on the White River [32] included an analysis of hydropower generation capability. Coal-fired power plants represent the high end of the range for water demand in this study. The low end is represented as a negligible water requirement to support renewable energy generation (wind, solar, geothermal, and hydropower).

<u>Realistic Scenario</u>

A “realistic” scenario was included based on the most likely combination of the scenarios described above. First, oil shale extraction technological advances (in situ processing) and the use of gas-fired power generation for in situ extraction should reduce the on-site and off-site water requirements substantially. Although water neutrality is used as a scenario above, the more likely scenario is a continued need for water on-site that cannot be provided cost effectively by reuse. It is impossible to estimate this amount until the emerging in situ technologies mature. Even if in situ processes do not require copious amounts of water, other activities at the site will require water. A reasonable expectation is that it will be less than the low end of the range (1 barrel of water per barrel of oil produced) used in previous studies. For the “realistic” scenario, a value of 0.75 barrel of water per barrel of oil is used. We feel the revised population estimates are more likely than the ones developed in 1980; therefore, they will be used for the “realistic” scenario. Future development is likely to follow more sustainable approaches, although achieving 55 gpcd is not likely. Achieving the 25% reduction is likely, which would be 135 gpcd. The urban energy efficiency goal of 20% reduction is also likely and is included in the “realistic” scenario. Although a transition to alternative energy generation is taking place, the “realistic” scenario will include the more likely case of coal-fired power plants providing electric power.

Optimistic Scenario

Finally, to determine the water requirement for a scenario where all identified water saving changes are implemented (reduced urban growth estimates, sustainable urban development, advances to oil shale extraction technology, and alternative electric energy generation), we combined the changes to produce the “optimistic scenario”.

A summary of the scenarios included in the analysis is listed in Table 6. It must be noted that the analysis presented herein is not a life-cycle assessment. The estimates for energy and water requirements are for direct and some indirect requirements that would need to be planned and managed locally. We are not factoring in the water and energy required for maintenance, to manufacture and supply chemicals, to supply food to the urban population, etc. We only consider the water requirements in the region due to activities in the region associated with oil shale development. This is an area in need of further work - to study the life-cycle water-energy demands of the oil shale industry growth.

Table 6. Scenarios for future oil shale development water demands.

Case	Conditions
1. Base Scenario (following [7,8,29])	*Population Increase:* 96,000/500,000 bbl oil, 177,000/1 mil bbl oil, 433,000/2.5 mil bbl oil *Water Demand – Oil Shale:* 1 to 3 bbl water/bbl oil *Water Demand – Urban:* 135 gpcd *Energy Demand – Oil Shale:* included above *Energy Demand – Urban:* 3885 kWh/person *Energy Demand – Water Transport:* 5.92 (mil kWh/day)/(MGD/mi), 100 mi *Water Demand – Energy Generation:* 500 gal/MWh
2. Revised Population Projection Scenario	*Population Increase:* 40,000/500,000 bbl oil, 80,000/1 mil bbl oil, 200,000/2.5 mil bbl oil *Water Demand – Oil Shale:* 1 to 3 bbl water/bbl oil *Water Demand – Urban:* 135 gpcd *Energy Demand – Oil Shale:* included above *Energy Demand – Urban:* 3885 kWh/person *Energy Demand – Water Transport:* 5.92 (mil kWh/day)/(MGD/mi), 100 mi *Water Demand – Energy Generation:* 500 gal/MWh
3. Sustainable Urban Development Scenario	*Population Increase:* 96,000/500,000 bbl oil, 177,000/1 mil bbl oil, 433,000/2.5 mil bbl oil *Water Demand – Oil Shale:* 1 to 3 bbl water/bbl oil *Water Demand – Urban:* 55 gpcd *Energy Demand – Oil Shale:* included above *Energy Demand – Urban:* 3108 kWh/person *Energy Demand – Water Transport:* 5.92 (mil kWh/day)/(MGD/mi), 100 mi *Water Demand – Energy Generation:* 500 gal/MWh
4. Oil Shale Extraction Technology Advances Scenario	*Population Increase:* 96,000/500,000 bbl oil, 177,000/1 mil bbl oil, 433,000/2.5 mil bbl oil *Water Demand – Oil Shale:* No water required *Water Demand – Urban:* 135 gpcd *Energy Demand – Oil Shale:* No water required *Energy Demand – Urban:* 3885 kWh/person *Energy Demand – Water Transport:* 5.92 (mil kWh/day)/(MGD/mi), 100 mi *Water Demand – Energy Generation:* 500 gal/MWh
5. Alternative Electric Energy Generation Scenario	*Population Increase:* 96,000/500,000 bbl oil, 177,000/1 mil bbl oil, 433,000/2.5 mil bbl oil *Water Demand – Oil Shale:* 1 to 3 bbl water/bbl oil *Water Demand – Urban:* 135 gpcd *Energy Demand – Oil Shale:* included above *Energy Demand – Urban:* 3885 kWh/person *Energy Demand – Water Transport:* No water required *Water Demand – Energy Generation:* No water required
6. Realistic Scenario	*Population Increase:* 40,000/500,000 bbl oil, 80,000/1 mil bbl oil, 200,000/2.5 mil bbl oil *Water Demand – Oil Shale:* 0.75 bbl water/bbl oil *Water Demand – Urban:* 135 gpcd *Energy Demand – Oil Shale:* included above *Energy Demand – Urban:* 3108 kWh/person *Energy Demand – Water Transport:* 5.92 (mil kWh/day)/(MGD/mi), 100 mi *Water Demand – Energy Generation:* 500 gal/MWh
7. Optimistic Scenario	*Population Increase:* 40,000/500,000 bbl oil, 80,000/1 mil bbl oil, 200,000/2.5 mil bbl oil *Water Demand – Oil Shale:* No water required *Water Demand – Urban:* 55 gpcd *Energy Demand – Oil Shale:* No water required *Energy Demand – Urban:* 3108 kWh/person *Energy Demand – Water Transport:* No water required *Water Demand – Energy Generation:* No water required

Results

The results for the 6 scenarios are presented in Tables 7 to 13. Important observations and recommendations based on the results include:

- The water requirements to support energy demand for water transport will be significant as shown by changes in water demand for the Base Scenario (Table 7) compared to previous estimates (Table 5). Nearly 10,000 acre-feet/year of water may be necessary to support electric power energy generation needs to transport the larger quantities of water (for the 1-2.5 million bbl/day operations). Not only is the energy requirement for water transport important for water, but it is also an important consideration for energy and emissions.
- The revised population growth estimates reduce overall water demand by 10,000 to 30,000 acre-feet/year (Table 8). This is a substantial quantity of water that would otherwise need to be supplied by the local water conservancy district.
- Interestingly, the reductions produced by following sustainable urban development water and energy efficiencies (Table 9) are nearly identical to reductions noted for the revised population projections scenario.
- For new oil shale extraction advances that reduce water demand to zero, the total water demand is reduced by 50% (Table 10). This is consistent with the observations of water demand for the Alberta oil sands operations where water demands are substantial. This indicates the potential impact of the oil shale industry seeking water neutrality for on-site and off-site water demands is great. **Water neutrality may be feasible through a combination of demand and supply side management actions.**
- Using alternative electric energy generation technologies (e.g., solar, wind, etc.) that do not require significant amounts of water will have a small impact (<5,000 acre-feet/year) for the 500,000 bbl/day operations, but could save more than 10,000 acre-feet/year for the larger oil shale operations (1-2.5 million bbl/day). In addition, the reduced emissions are not factored into this analysis but may be more significant.
- As would be expected, the Optimistic Scenario reduces water to a small storage requirement of less than 12,000 acre-feet/year to support the urban population. The Realistic Scenario indicates planning should account for 120,000 acre-feet/year to support the high end of the oil shale production rate (2.5 million bbl/day).

Table 7. Water demand summary for Base Case Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	1-3	21 to 63	96,000	13	35 to 79	0.04 to 0.09
1	1-3	42 to 126	177,000	24	69 to 155	0.08 to 0.17
2.5	1-3	105 to 315	433,000	59	171 to 387	0.19 to 0.43

Table 8. Water demand summary for Revised Population Projection Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	1-3	21 to 63	40,000	6	27 to 71	0.03 to 0.08
1	1-3	42 to 126	80,000	11	55 to 141	0.06 to 0.16
2.5	1-3	105 to 315	200,000	27	137 to 353	0.15 to 0.40

Table 9. Water demand summary for Sustainable Urban Development Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	1-3	21 to 63	96,000	5	27 to 71	0.03 to 0.08
1	1-3	42 to 126	177,000	10	54 to 141	0.06 to 0.16
2.5	1-3	105 to 315	433,000	24	134 to 351	0.15 to 0.40

Table 10. Water demand summary for Oil Shale Extraction Technology Advances Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	0	0	96,000	13	14	0.02
1	0	0	177,000	24	26	0.03
2.5	0	0	433,000	58	62	0.07

Table 11. Water demand summary for Alternative Electric Energy Generation Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	1-3	21 to 63	96,000	13	34 to 76	0.04 to 0.09
1	1-3	42 to 126	177,000	24	66 to 150	0.07 to 0.17
2.5	1-3	105 to 315	433,000	59	163 to 373	0.18 to 0.42

Table 12. Water demand summary for Optimistic Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	0	0	40,000	2	2	0.002
1	0	0	80,000	4	4	0.005
2.5	0	0	200,000	59	11	0.012

Table 13. Water demand summary for Realistic Scenario.

Oil Shale Production Rate (MBbl/day)	Oil Shale Water Requirement (Bbl Water Used/Bbl Oil Produced)	Oil Shale Industry Water Demand (MGD)	Projected Population Growth (People)	Urban Population Water Demand (MGD)	Total New Water Demand (MGD)	Total New Water Demand (MAF)
0.5	0.75	16	40,000	5	22	0.03
1	0.75	32	80,000	11	44	0.05
2.5	0.75	79	200,000	27	110	0.12

The oil shale extraction and processing water requirements (including energy generation water requirements) are approximately 80% or more of the total water demand. Although the other actions (sustainable development, alternative energy, etc.) can save tens of thousands of acre-feet of water per year (and are relatively low cost measures with significant additional benefits), the highest return can be gained by seeking improvements to oil shale extraction and processing that reduce water demands. The goal should be to seek water neutrality for the oil shale operations. Overall, the results of this analysis suggest water planning for oil shale development should include 32,000 acre-feet/year to support potential urban population growth meeting Utah's water efficiency goals. Water planning should also include approximately 90,000 acre-feet/year for oil shale operations (2.5 million bbl/day), assuming industrial processes minimize water use to 0.75 barrels of water/barrel of oil. The next step of the water management analysis is to identify possible water sources and analyze their ability to provide these amounts under different climate scenarios. A conceptual framework to conduct this study is described in the next section.

Task 3. Conceptual Approach to Water Availability Assessment

Given the water requirements estimates described above, the next step is to determine if the water is available. Hence, a conceptual approach to determine the availability of water was devised. The conceptual approach begins by considering the water demand in the three sectors (urban, energy, and oil shale industry) and incorporating recycle to quantify the amount available that can be treated and reused (Figure 18). The conceptual model of the system must be populated with quantities of flow and amount of reuse (based on cost) to determine the potential for water reuse to reduce the water requirements. The revised estimates of new water and reused water must then be incorporated into a water management model for the region to determine if there is enough water (in existing water rights as the basin is currently closed to new appropriation) to supply the demands. A previously identified possible source of water to support oil shale operations (and energy development in general) in Utah and Colorado is the White River. Reservoirs have been proposed for both Colorado and Utah, but the hydrologic studies to determine required storage capacities and the feasibility given current uses are based on analyses performed in the 1970s [32]. These analyses must be updated to determine the feasibility of the reservoirs given new estimates of water requirements, more streamflow records, and the possibility of climate change impacting surface flows in the river.

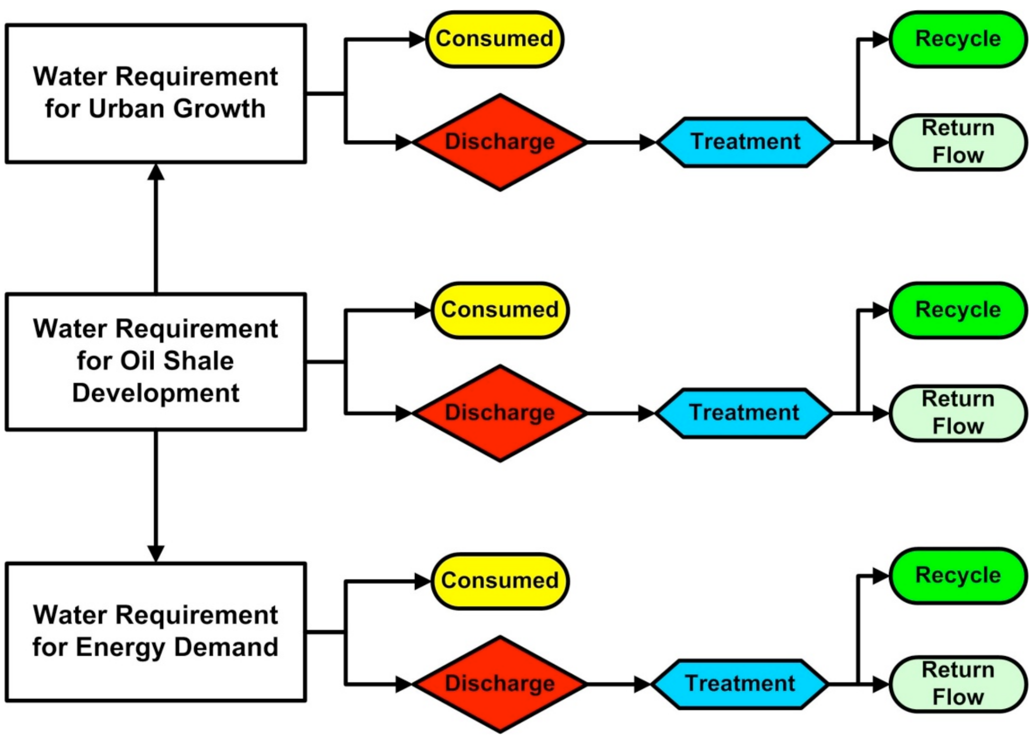

Figure 18. Conceptual diagram of a water demand, treatment, and reuse system for the three sectors of water demand.

The analyses of water availability can be performed with a water management model based on a mass balance of flows and withdraws from a water body (the White River). The proposed model for this analysis will include existing water rights information, the proposed reservoirs in Colorado and Utah, and the projected demands for urban population, energy generation, and energy development (including oil shale). A conceptual illustration of the water management model is shown in Figure 19. To implement this conceptual approach, flow data must be acquired, the existing water rights must be determined from the Utah Division of Water Rights, the water management model must be built, instream flow requirements must be defined based on habitat needs, climate change flow modifications must be estimated, and the range of water demands must be incorporated into scenarios for the study. A long-term analysis using historical streamflow records will then be conducted to determine the performance of the reservoir and optimize its size. In addition, the ability of the White River under different climate, use, and reservoir design scenarios to meet the water demands and maintain instream flows can be determined.

Summary

The outcomes of this research project were a collection of geospatial data, reports and papers related to water resources and unconventional oil development, a range of updated estimates for water requirements for oil shale development, and a conceptual approach to determining water availability and planning for water resources development to support oil shale industry growth. Updated estimates of water requirements cover a set of feasible scenarios ranging from past conditions (430,000 acre-feet/year to support a 2.5 million bbl/day operation) to an optimistic scenario (12,000 acre-feet/year to support a 2.5 million bbl/day operation). The estimate based on past conditions would be a significant challenge and cost to supply, whereas the optimistic estimate would be reasonable and a relatively small cost to develop. A realistic scenario developed by the project team was found to require 120,000 acre-feet/year to support a 2.5 million bbl/day operation. While large, this quantity of water is feasible given existing water rights on the White River. A conceptual modeling approach was outlined to determine if the range of water requirements could be provided by the White River system. The next steps were briefly described.

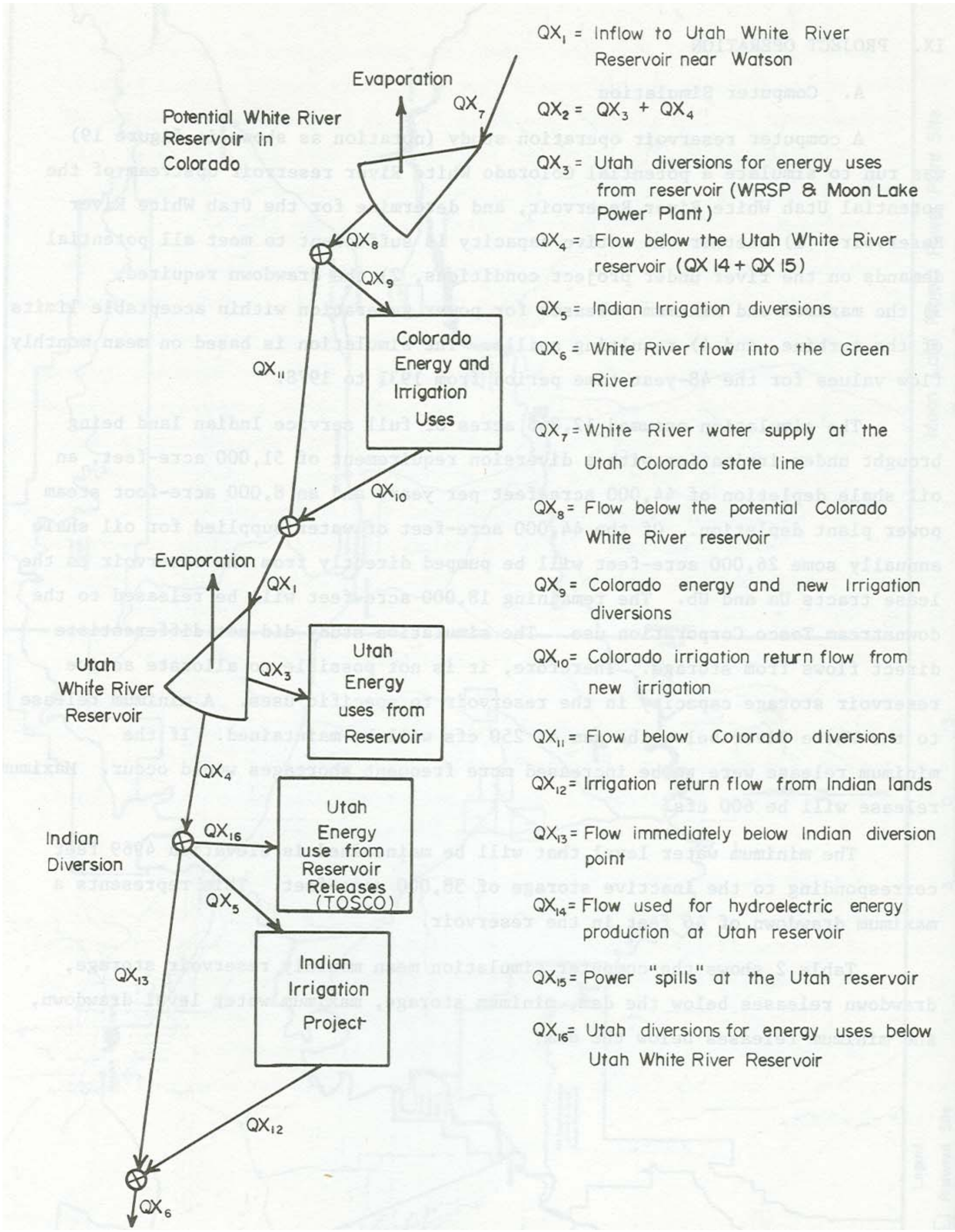

Figure 19. Diagram of White River water management modeling framework [32].

This initial research indicated the need for additional work. Specifically, the following are recommended as extensions of this work:

- Improved demand estimates with spatial and temporal resolution to permit precise water development planning to be performed
- Determination of infrastructure needs and life-cycle cost estimates
- Assessment of life-cycle water and energy demands and environmental impacts
- Compilation and assessment of existing water rights in the Uinta Basin
- Compilation of geospatial environmental quality data to establish baseline conditions

- Creation of a water management model to assess infrastructure planning on water in basins
- Creation of surface and groundwater quantity and quality models

Summary of Publications/Presentations Resulting from this Project

Burian, S., Jones, E., and Kalyanapu, A. (2009). "Impacts of energy development in Utah on water resources availability." *Journal of American Water Resources Association*, to be prepared for submission in fall 2009.

Jones, E. (2009). "Feasibility of White River to meet water requirements to support energy development in the Uinta Basin." MS thesis, Department of Civil & Environmental Engineering, University of Utah (in progress, to be completed fall 2009).

Burian, S. Jones, E., Hong, A., Goel, R., Li, L., Cha, Z., Dudley-Murphy, B., and Nash, G. (2009). "Oil shale development in Western U.S.: Water resources challenges and solutions." American Water Resources Association Spring Specialty Conference, Anchorage, Alaska, May 1-4.

Burian, S. Jones, E., Hong, A., Goel, R., Li, L. (2009). "Water management for oil sands and oil shale development in Utah: Challenges and solutions." Western U.S. Oil Sands Conference, Salt Lake City, Utah, Feb. 27, 2009.

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Goel, R., Burian, S., Hong, A., Nash, G., and Murphy, B. (2007). "New approaches to treat produced water and perform water availability impact assessments for U.S. Oil Sands and Oil Shale Development." 2007 American Institute of Chemical Engineers Annual Conference, Salt Lake City Utah, November 4-9.

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APPENDIX E

Integrated Treatment of Produced Water by Chemical and Biological Unit Operations

A Subpart of Project

Quantifying Water Availability Impacts and Protecting Water Quality While Developing Utah Oil Shale and Sands

Final Project Report

Reporting period: June 21st, 2006 to October 21st, 2009

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Department of Civil & Environmental Engineering
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October 7th, 2010

DOE Award Number: DE-FC26-06NT15569

Submitted by:
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Project Objectives:

The long-term and ultimate objective of this work is to develop an integrated treatment scheme which will employ a combination of physical, chemical and biological treatment methods to treat produced water. Real produced water from ConocoPhillips was tested for different constituents, which were used to simulate the composition of the synthetic produced water in the integrated treatment scheme. For the small batch test, naphthalene and BTEX were used as the model organic contaminants present in the produced water. The electro-Fenton method was used to oxidize and remove the bulk of the organic compounds and metals followed by a membrane-assisted bioreactor treatment to produce treated water of the highest quality. The objective in this first phase of the project was to test and refine each of the steps in the combined treatment approach.

Specific objectives include:

1) Evaluate each individual process and document its treatment efficiency and adequacy, which will generate important design and kinetics parameters for individual processes.

Task 1-1: Characterize produced water received from operators

Task 2-1: Evaluate process parameters for electro-Fenton process

Task 2-2: Biological degradation kinetics of organics (BTEX and naphthalene)

Task 2-3: Identification of bacteria using cloning and sequencing

2) Conduct at least one complete test of the whole lab-scale reactor system.

Task 3-1: Design of the complete treatment train and demonstration of the integrated treatment approach. Based on the design parameters obtained from the previous experiments, flow rates and organic loadings will be designed for the continuous system.

Project Outcomes:

Produced water samples (6 samples in triplicate) from ConocoPhillips were characterized using ICP-MS to identify elements present and the HACH method to identify ammonia, nitrite, nitrate, phosphorus, and COD. Naphthalene and BTEX were used as the model refractory compounds to test the treatment efficiency of the electro-Fenton and biological methods respectively. The results show that up to 60 weight percent of the naphthalene and more than 99 weight percent of BTEX were removed after 8 hours of electrolysis respectively. Furthermore, biomass from municipal sewage removed more than 95 weight percent of the naphthalene and BTEX. The bacteria responsible for the biodegradation were identified through the 16S rDNA-based cloning and sequencing technique. Both oxidation and biological treatment results are affected by volatilization as indicated by tests conducted with blanks.

Presentations and Papers:

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1. Introduction and Problem Statement

1.1 Introduction

Water generated along with oil, gas, and coal bed methane production is commonly known as produced water, formation water, or oilfield brine [1]. Produced water represents the largest waste stream volume in production operations on most offshore platforms [2]. According to the American Petroleum Institute (API), about 20, 18 and 14 billion barrels (bbl) of produced water were generated by U.S. onshore operations in 1985, 1995 and 2002 respectively, showing a decreasing tendency for produced water generation over time. Although it was not easy to get an accurate estimate of produced water generated offshore, a rough estimate of 175 million bbl per year indicates that production volumes are several orders of magnitude less than the onshore generated produced water [3]. With rapid expansion in the development of fossil energy resources to meet the ever-increasing demand for energy and the maturation of oil and gas fields, the U.S. Geological Survey (USGS) notes that the generation of produced water is undergoing a significant increase. Furthermore, the U.S Department of Energy has forecasted the current levels of 250 million bbl of produced water per day to increase to 312 million bbl per day by 2015.

The composition and the physical and chemical properties of produced water are complex and can vary considerably depending on the geographic location of the operation, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced [3]. Generally, produced water is composed of dispersed oil, dissolved organic compounds, production chemicals, heavy metals, naturally occurring radioactive minerals and other inorganic compounds. The salt concentration of produced water may range from a few parts per thousand to that of a saturated brine [4]. Major organic compounds in produced water of particular concern include BTEX (benzene, toluene, ethyl benzene, and xylene), polycyclic aromatic hydrocarbons (PAHs), phenols and organic acids. In addition to these natural components, produced waters may also contain chemical additives used in drilling and production operations and in the oil/water separation process. The presence of these chemicals can affect the oil/water partition coefficient, toxicity, bioavailability, and biodegradability of produced water [5].

1.2 Problem Statement

Since produced water is associated with oil, gas or coal bed methane production, handling and disposal of this water is one of significant issues. Effective treatment of produced water is a critical environmental requirement that demands immediate attention. From the properties given above, produced water can be defined as a mixture of hazardous pollutants such as heavy metals, salinity, inorganic nutrient species (ammonia, nitrate, phosphorus, etc.), BTEX, PAHs and many other organic compounds from the oil or gas field. Each category of these components requires a feasible and economic treatment approach. Furthermore, the concentration of these contaminants will vary in produced water from one place to another. Hence, it is conceivable to employ a treatment scheme specific to a given produced water. The ultimate objective of this work was to test and refine a treatment method which employed a combination of physical, chemical and biological treatment approaches.

2. Literature Review

Treatment processes for produced water that have been commercially used in past decades in the oil and gas industry have focused mainly on the removal of oils and greases, scale control, and suspended solids and brine volume reduction. But with more stringent regulations and a focus on enabling higher value uses of produced water such as irrigation, livestock watering, groundwater recharge, and habitat restoration, greater attention is being paid to treatment processes with improved capabilities in the removal of contaminants and in water conditioning [6]. In addition to oil, grease and suspended solids removal targets, treatment objectives are now emphasizing the removal of organic compounds such as BTEX and PAHs.

Current produced water treatment processes can be broadly classified into: (a) established processes; (b). recently-deployed processes; and (c) emerging technology [6, 7]. The established processes have been used for many decades in the oil and gas industry, are well understood, and have been of proven value and performance in their application. Examples of such processes include an API separator, deep bed filtration, gas flotation, and sand filtration for suspended solids removal and de-oiling; aeration/sedimentation for iron removal and suspended solids control; and activated carbon treatment for the adsorption of organic contaminants. Recently-deployed processes encompass unit processes that have been applied on a commercial scale mostly within the last decade. Treatment methods in this category include precipitation and ion exchange for softening (i.e. removal of calcium and magnesium) and iron control; water conditioning (chemical additions and ion exchange); and freeze-thaw evaporation for the desalinization of produced water. The "emerging technology" category covers unit processes that have been piloted or are in the experimental stage of development for application to produced waters. These processes are not yet fully operational at full scale with the numbers of facilities that would classify the process as a commercial practice in the oil and gas industry. Processes belonging to this category include attached film biological processes that can tolerate elevated salinities; reverse osmosis and electrodialysis for demineralization of produced water; and chemically-enhanced ultra-filtration for improved removal of soluble oils.

Though biodegradation is the major decomposition pathway for organic compounds in aquatic environments, full-scale biological treatment of produced water from offshore operations is still not widely used. Furthermore, treatment of onshore produced water has not been reported yet. The importance of biodegradation in the overall removal of organic compounds in produced water depends primarily on the persistence of the majority of the organic compounds and the selection of bacteria in the local microbial community that are able to degrade specific organic compounds in produced water. In areas where large volumes of produced water have been discharged continuously for a long period of time, the microbial community would normally be well adapted for biodegradation of organic compounds from produced water [8]. Biodegradation experiments performed with produced water from the North Sea [9] provide some information about the marine environmental fate of organic compounds of produced water. Many medium molecular weight organic compounds and phenols are biodegraded by indigenous microorganisms in seawater, whereas some higher molecular weight organic compounds are less biodegradable and remain in the water for a longer time [8].

3. Research Approach

3.1 Experimental plan, results and discussion for each task

3.1.1 Identify different contaminants in produced water

Methodology: Triplicate produced water samples from six different locations were obtained from ConocoPhillips and were analyzed using Inductively Coupled Plasma Mass Spectrometry (ICP-MS). The samples were also analyzed for nutrients (Table 1), heavy metals (Table 2) and elements (Table 3). Due to confidentiality of the site details, we could not get much information about the sampled sites.

Results: The results of various sample analyses are shown in Tables 1, 2 and 3. All samples offered good chemical oxygen demand (COD), indicating the presence of oxidizable organics. A surprising observation was the presence of nitrite nitrogen in all samples, possibly from partial nitrification under anaerobic conditions or nitrite leaching from the aquifer. Among metals, chromium, iron and selenium were present in high concentrations in all samples. All samples tested positive for mercury, with samples from Howell A301S and Howell A#300 showing particularly high concentrations of mercury. From Table 3, it is also evident that the water samples contained high amounts of sodium and chloride, possibly due to the presence of sodium chloride as a source of salinity. Based on those results, the synthetic produced water will be made to simulate the realtime produced water and used to test the treatment efficiency of membrane bio-reactor and integrated treatment scheme.

Table 1. Average COD, ammonia, nitrite, nitrate and phosphorus concentration of the produced water samples (units: mg/L)

Name of the Sample	COD	NH_3-N	NO_2	NO_3-N	DP
COM A#300S	59±29	8.2±0.3	31.5±7.1	0.3±0.5	3.3±0.4
HOWELL D#350S	31±2	5.3±1.8	28.1±4.0	0.4±0.2	3.1±0.6
HOWELL G#300	63±30	6.1±1.8	41.4±16.7	0.5±0.4	3.2±0.6
HOWELL D#351	102±66	8.2±3.5	22.1±16.1	0.5±0.7	2.6±1.9
HOWELL A#301S	72±69	5.1±1.8	33.6±16.6	0.5±0.7	3.8±1.3
HOWELL A#300	42±10	7.1±1.4	26.2±15.8	0.1±0.1	2.3±0.5

Table 2. Average heavy metal concentration of the produced water samples (units: μg/L)

Name of the Sample	Cr	Fe	As	Se	Ag	Hg	Pb
COM A#300S	3.8±1.7	263.0±80.6	1.8±1.8	2.2±0.4	0.1±0.0	1.1±1.2	0.1±0.1
HOWELL D#350S	4.0±1.5	175.6±78.7	3.8±0.2	2.7±1.0	0.0±0.1	0.4±0.4	2.8±3.9
HOWELL G#300	3.5±0.6	124.9±49.6	2.4±1.1	2.2±0.1	0.1±0.1	1.4±1.8	0.1±0.1
HOWELL D#351	4.4±1.6	151.5±4.9	1.9±1.1	2.2±0.2	0.2±0.3	1.3±0.6	0.2±0.2
HOWELL A#301S	3.8±0.6	331.7±82.5	2.0±1.5	3.9±3.6	0.0±0.0	9.5±13.4	0.3±0.4
HOWELL A#300	2.9±0.5	162.8±24.3	2.0±1.8	2.0±0.2	0.0±0.1	5.5±4.3	0.0±0.1

Table 3. Average elemental concentrations in the produced water (units: mg/L)

Name of the Sample	Na	Mg	K	Ca	Ga	Sr	Ba	B	P	S	Cl	Br	I
COM A#300S	4514.0±687.3	16.6±0.8	13.1±2.6	15.7±4.5	3.6±3.9	7.6±2.2	12.8±6.8	3.4±0.7	2.3±0.6	3.3±0.9	5761.1±5287.7	14.9±3.7	6.3±5.9
HOWELL D#350S	4535.9±192.2	15.9±2.7	11.0±0.7	16.3±3.3	4.2±4.7	6.8±1.1	10.0±2.1	2.6±0.1	2.3±1.1	4.4±3.4	682.7±6105.6	24.3±9.5	8.2±3.8
HOWELL G#300	5176.1±602.5	19.4±3.4	19.3±4.6	27.2±2.4	6.5±6.9	9.5±2.1	16.8±2.6	2.0±0.2	2.2±1.3	4.4±0.8	8976.1±8519.1	22.8±4.5	11.6±7.2
HOWELL D#351	4494.6±2467.2	13.1±10.0	40.2±42.1	16.6±7.9	5.6±6.8	6.8±4.0	12.2±7.3	2.3±1.1	2.1±1.6	3.5±0.2	8062.1±7690.4	27.2±11.7	15.5±5.0
HOWELL A#301S	5599.9±1838.3	21.1±4.4	11.1±1.5	16.7±3.1	2.9±3.2	8.0±1.5	7.7±1.6	2.0±0.2	2.3±1.4	3.6±0.6	5766.3±3866.1	22.7±5.3	15.6±12.2
HOWELL A#300	5769.4±3138.7	19.7±7.3	34.3±21.0	22.5±10.6	6.8±8.8	7.6±3.7	13.2±10.8	2.2±0.9	2.0±1.4	5.2±1.9	9766.8±9522.2	21.4±3.7	19.9±16.8

3.1.2 Electrolytic and advanced oxidation of organics present in the produced water

This task investigated the electrolytic and the chemical oxidation of organics present in the produced water. Based on the literature, we identified that the primary organics of concern are PAH and BTEX compounds, although other aliphatic organics are also present.

Methodology: All analytical grade chemicals and naphthalene were purchased from Mallinckrodt Chemicals, NJ. Benzene (C_6H_6), toluene (C_7H_8), ethyl benzene (C_8H_{10}), and p-xylene (C_8H_{10}) were bought from Fisher Scientific, IL. Ferrous sulfate ($FeSO_4$) of analytical grade purity was purchased from Sigma-Aldrich, MO. Hydrogen peroxide solution containing 30% H_2O_2 was obtained from EMD Chemicals Inc, NJ.

The electrode assembly in the present study was identical to the assembly used in Goel et al [10]. It consisted of a stainless steel plate cathode (Type 304, 3# polish, 0.07 cm thickness from Metal Supermarket, Salt Lake City, UT) and a titanium anode with a mixed metal oxide coating (Eltec Systems Corp., Chardon, OH) held together by nylon screws. The electrodes were 3.2×6.4 cm and separated by a distance of 1.4 cm. Titanium screws and nuts were used as current connectors, which were connected to the copper wires and finally to a power source (HP Model E3612A, Agilent Technologies Inc., Englewood, CO) for both the anode and cathode. The connection between the copper wires and titanium screws was sealed with an air-drying polyurethane coating (Measurements Group lnc, Raleigh, NC).

The reactor used in the electrolytic experiments was a 500 ml amber-colored bottle. Holes were drilled through the bottle cap to run the wires connected to the electrodes. A needle was pushed through the cap to keep the system under atmospheric pressure. The schematic of the system is shown in Figure 1. During each experiment, 500 ml of solution containing 10 mg/l BTEX or naphthalene and 0.01 mol/l SO_4^{2-} as electrolyte was transferred to the reactor. The pH was adjusted to the required value by adding diluted acid or base at the beginning of each experiment. Tests were performed under different current densities and pH values. Previous research showed that a retention time of about 8 hours was sufficient for electrolytic degradation of naphthalene [10], so experiments were conducted for 8 hours.

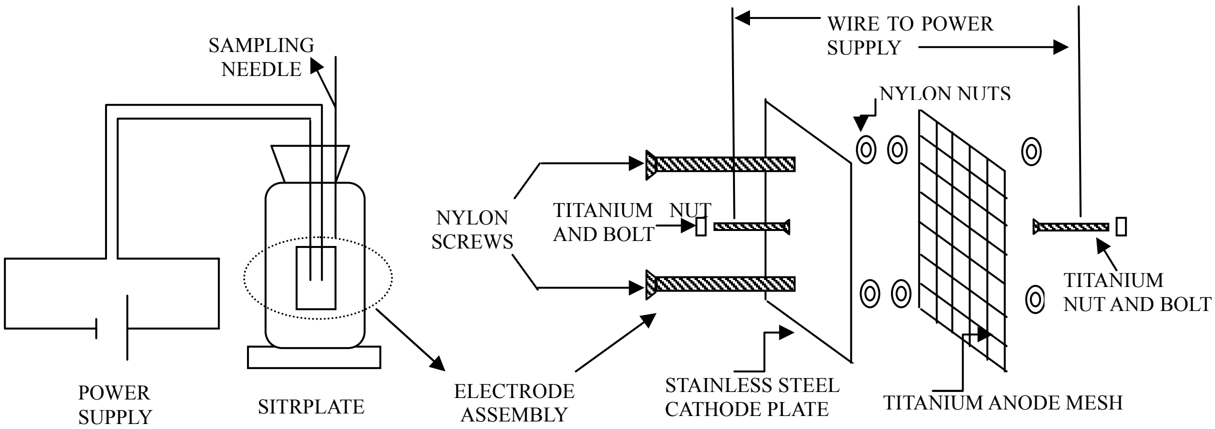

Figure 1: Schematic of the laboratory electrolytic batch reactor and the electrode assembly.

Control and gas stripping experiments with no active electrodes were also performed. Gas stripping experiments were performed to investigate the contribution of volatilization to the disappearance of model compounds during the electrolytic aeration. By using Faraday's law and the idea gas law, the flow of the gas produced at the anode and cathode was determined to be 0.4 l/d for a current of 25 mA. A 10 cm long needle was used for gas delivery, which was maintained at a constant flow as calculated above by using a gas flow meter through the cap of the reactor. The gap between the needle and the cap was sealed with an air-drying polyurethane coating. For each electrolysis and gas stripping test, 500 ml test solution was transferred to the reactor. The same mixing speed as that employed in the electrolytic degradation tests was obtained with a magnetic stirring bar and plate. Samples for model compound analysis were withdrawn and measured as described in the following paragraphs.

Chemical oxidation of naphthalene and BTEX was performed through hydroxyl radical-mediated reaction. Hydroxyl radical was generated in-situ using Fenton's and electro-Fenton's reaction. Oxidation experiments were also performed using hydrogen peroxide, a known strong oxidant. Fenton's experiments were conducted with hydrogen peroxide concentrations of 3 and 12 mg/L and a ferrous ion concentration of 30 mg/L. Experiments with only hydrogen peroxide were also performed with 12 mg/L of hydrogen peroxide. To get the desired hydrogen peroxide concentration, 30% by weight hydrogen peroxide solution (Sigma Aldrich Company Inc.) was used. Ferrous ion solution was added using a using a stock solution prepared by adding 1.49 g $FeSO_4 \cdot 7H_2O$ in 100 ml DI H_2O at a pH of 3. System pH was adjusted immediately by adding 0.5 N H_2SO_4 or 0.5 N NaOH. Samples were drawn from the bottle periodically for GC-FID analysis by using a long needle and syringe.

Compounds (naphthalene and BTEX) were analyzed on an Agilent gas chromatograph equipped with FID detector, MS detector, Chrompack capillary column (Select 624 CB D_f 1.8 µm, FS 30m × 0.32 mm ID), and a manual sampler with a 100 µm PDMS coated SPME fiber assembly (Supelco, Bellefonte, PA). A solid phase extraction technique was used for naphthalene and BTEX. The sample adsorption time with the SPME fiber was 10 minutes in agitate mode and the desorption time was 2 minutes followed by a one minute waiting period. The analysis was performed in splitless mode with an injection temperature of 250°C, isothermal oven temperature of 180°C, and detector temperature of 275°C.

Results:

Electrolytic oxidation of naphthalene and BTEX: Naphthalene solution was electrolyzed under different currents at two pH levels as shown in Figure 2 (a) (pH 4) and (b) (pH 7). All results in this and subsequent figures are reported on a mass basis (c/c_0) and mean values are based on triplicate measurements. In the figures within this report, mean values based on triplicate measurements are plotted. The bars represent the standard deviation of the triplicate measurements and provide an indication of replication uncertainty. Uncertainty introduced by the volatilization effect can be approximately quantified by the results from the blank experiments. Under all conditions, around 60% naphthalene was removed after 8.5 hours of electrolysis through various mechanisms (volatilization, electrolytic oxidation, adsorption etc.). Based on the results shown in Figure 2, it can be concluded that naphthalene degradation rates were insensitive to current density and independent of system pH, which is consistent with our previous work [10]. During the blank experiment, around 20% naphthalene loss was observed, which might be due to volatilization or adsorption on the surface of the electrode.

Electro-coagulation, electro-flotation and electro-oxidation are three mechanisms which are commonly reported to be responsible for the contaminant loss in electrochemical systems [11]. In this research, no electro-coagulation or electro-flotation in the form of turbidity or settling solids was observed. Anodic oxidation of aromatics, in which organic compounds can be either mineralized into carbon dioxide and water or some other intermediates, has been reported by previous researchers [12, 13]. In this experiment, air stripping and anodic oxidation most likely contribute to the removal of naphthalene from the aqueous phase under electrolytic conditions.

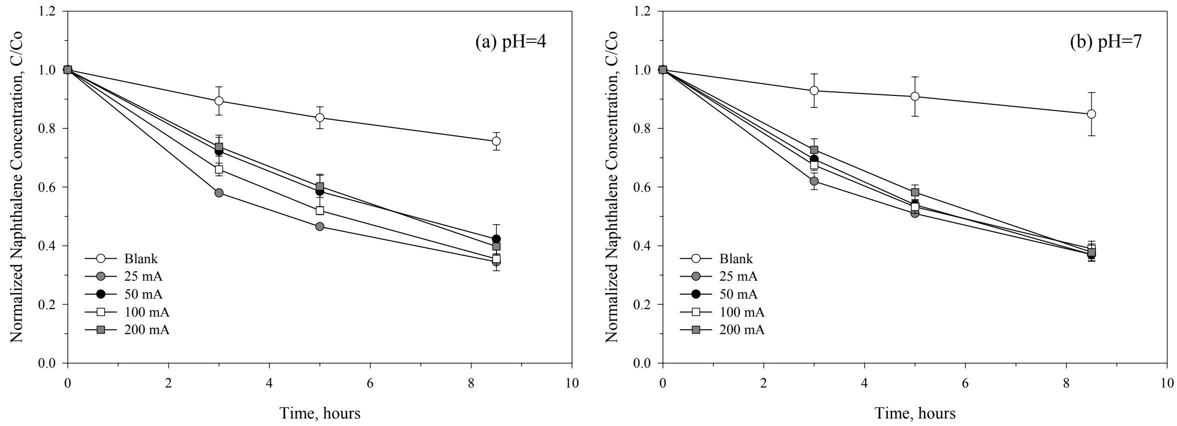

Figure 2: Electrolytic naphthalene degradation under different currents: (a) pH 4; (b) pH 7.

BTEX represents a mixture of benzene, toluene, ethyl benzene and xylene. Hence, the degradation of these four organics was monitored during BTEX degradation experiments. Table 4 depicts the results of electrolytic degradation of BTEX under different current intensities. The blank batch shows the fate of BTEX compounds under current and air sparging conditions. The disappearance of BTEX in the blank and air sparging experiments indicate losses due to volatilization. The air volume that was supplied during the air sparging experiments was equivalent to the gases produced during the electrolytic experiments. Greater volatilization occurred at higher air flow values. The removal of BTEX compounds in the electrolytic batch experiments exceeded removal in the blank and air sparged batches, indicating that the electrolytic degradation contributed to BTEX degradation to some extent. For example, at 500 mA current intensity, all BTEX compounds disappeared, whereas on a mass basis 43% of the benzene, 52% of the toluene, 74 % of the ethyl benzene, and 70% of the xylene were removed in the batch that was sparged with air equivalent to 500 mA current. These results indicate that approximately 50% of the benzene and toluene and 30% of the ethyl benzene and xylene were removed through electrolytic oxidation using a 500 mA current.

Table 4. Results of gas stripping and electrolysis of BTEX solution within 8 hours.

Experiment	Benzene removal (%)	Toluene removal (%)	Ethyl benzene removal (%)	Xylene removal (%)
Blank (no air purging and current)	0	16	48	52
Air purging equivalent to 25 mA	0	19	40	46
25 mA	9	28	57	63
Air purging equivalent to 200 mA	21	30	52	57
200 mA	16	54	74	78
Air purging equivalent to 500 mA	43	52	74	70
500 mA	100	100	100	100

Fenton's reaction-assisted oxidation of naphthalene and BTEX: The rate of degradation of naphthalene and BTEX in electrolytic experiments was slow, and not all the contaminants were degraded in these experiments. Furthermore, volatilization contributed significantly to contaminant loss. An alternative to electrolysis is to use Fenton's reaction to destroy many of the hazardous organic pollutants, converting them into into harmless compounds such as carbon dioxide, water, and inorganic salts [14]. The main mechanism for Fenton's reaction is the generation of highly reactive oxidant hydroxyl radicals, which can oxidize most of the pollutants [15, 16]. We tested naphthalene and BTEX degradation using Fenton's reaction at two different concentrations of hydrogen peroxide and two different pH conditions. Degradation was also evaluated using hydrogen peroxide as the sole oxidant.

The degradation of naphthalene by hydrogen peroxide and Fenton's reagent under different pH conditions is shown in Figure 3 (a) (pH 4) and (b) (pH 7). Some of the points in the figure have a normalized value greater than 1.0, which might be caused by the equipment (gas chromatograph) error. The naphthalene levels remained constant in the presence of hydrogen peroxide at both pH values, which is consistent with the study of Tuhkanen and Beltran [17]. Almost 99% and 96% naphthalene removal was observed with Fenton's reagent at high hydrogen peroxide concentrations (10~12 mg/l) at pH 4 and 7 conditions respectively. At low hydrogen peroxide (2~3 mg/L) concentrations, 84% and 68% naphthalene removal were observed at a pH 4 and 7 respectively. Low pH was beneficial for the removal of naphthalene, consistent with Lin et al., who reported that low pH was beneficial for the removal of phenol during electrolytic oxidation and Fenton's reaction [11]. Low pH is known to be beneficial for the generation of hydroxyl radicals since hydrogen peroxide and ferrous ion are stable when the system pH is below 5 [18, 19].

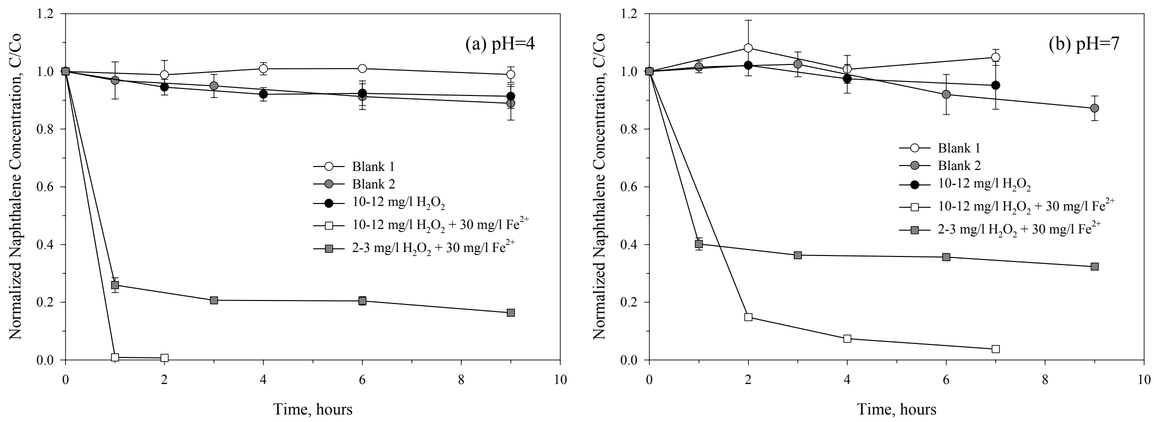

Figure 3: Naphthalene degradation using hydrogen peroxide and Fenton's reagent at (a) pH 4 and (b) pH 7.

BTEX degradation using hydrogen peroxide and Fenton's reaction at pH of 7 is shown in Figure 4. The blank batch accounted for contaminant removal by evaporation. In the blank experiment, benzene and toluene concentrations are greater than 1. The source of this error is undetermined and requires further experimentation. This error is not considered in evaluating the results of these experiments. About 10% benzene (10.0 mg/L to ~9.0 mg/L) and 25% toluene (10.0 mg/L to 7.5 mg/L) each were removed by hydrogen peroxide and Fenton's reagent (Figure 4 a and b). Furthermore, the removal efficiencies for benzene and toluene were insensitive to the addition of ferrous iron and hydrogen peroxide doses. For ethyl benzene and xylene, 30-50% removal was achieved (Figure 4c and d) with less than 10% removal resulting from volatilization based on the blank experiment. Hydrogen peroxide alone could also oxidize 40% ethyl benzene and xylene, while the addition of ferrous iron could increase 10% removal efficiency by forming hydroxyl radicals through Fenton reaction.

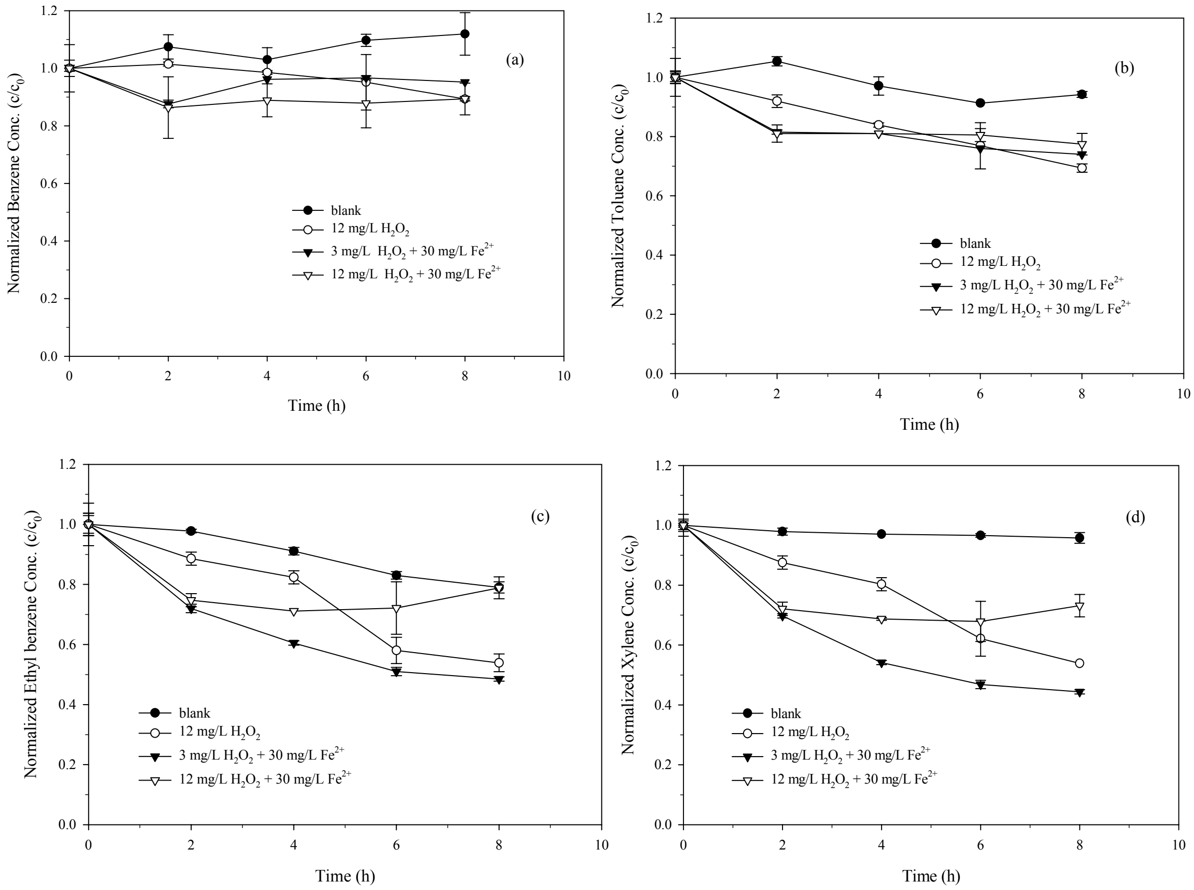

Figure 4: BTEX degradation using hydrogen peroxide and Fenton reagent at pH 7: (a) benzene, (b) toluene, (c) ethyl benzene and (d) xylene.

Figure 5 shows BTEX degradation using hydrogen peroxide and Fenton’s reaction at pH 4. Hydrogen peroxide alone did not have any significant affect on benzene and toluene. Almost 30% removal through volatilization and 20% removal through oxidation were observed for xylene and ethyl benzene with 12 mg/L hydrogen peroxide alone. All BTEX compounds showed some degree of removal in Fenton’s reaction using a lower dose of hydrogen peroxide (3 mg/L).

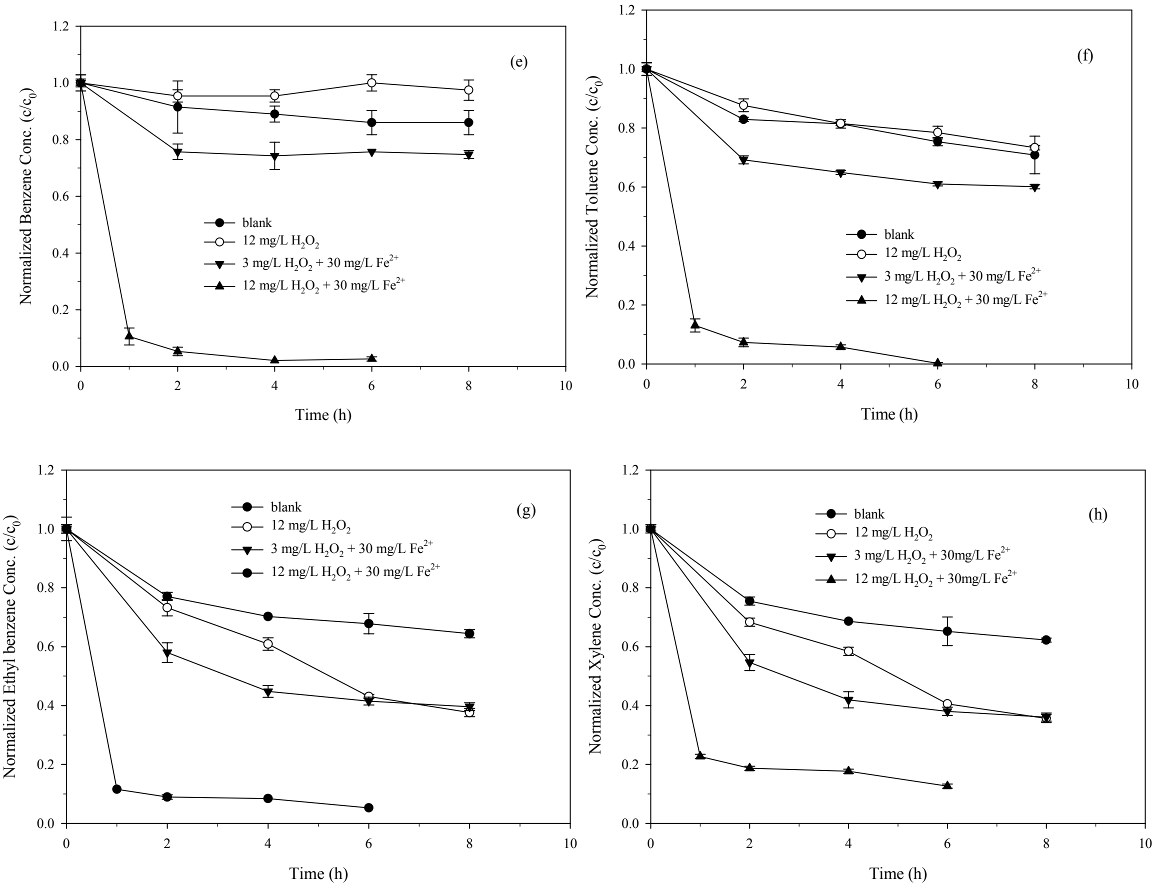

Figure 5: BTEX degradation using hydrogen peroxide and Fenton’s reagent at pH 4: (a) benzene, (b) toluene, (c) ethyl benzene and (d) xylene.

However, significant degradation of all BTEX compounds was observed under Fenton’s reaction at higher concentrations of hydrogen peroxide (12 mg/L). Results show that 97% of the benzene, 99% of the toluene, 95% of the ethyl benzene, and 88% of the xylene were removed, consistent with the previous naphthalene experiment in this research and with the results achieved by Lin et al. [11], who reported that the degradation rate of phenol decreased when the pH was increased from 3 to 9. The addition of 30mg/L of ferrous ion thus improved the removal efficiencies for benzene, toluene, ethyl benzene, and xylene by 87%, 74%, 45% and 38% respectively when compared to removal efficiencies by volatilization and oxidation by hydrogen peroxide.

3.1.3 Biological oxidation of naphthalene and BTEX

Methodology: Seed sludge was taken from the Central Davis wastewater treatment plant in Salt Lake City, Utah. Aerobic cultures were grown in amber-colored bottles with a continuous oxygen supply, a carbon source and mineral nutrients. To enrich the biomass to degrade naphthalene or BTEX, these compounds were added directly into the batch tests without mixing them into any solvent. The batch was then allowed to run for 3~4 days. At the end of this period, the biomass was allowed to settle and the supernatant was decanted and analyzed for the presence of naphthalene or BTEX. Total and volatile solids (TSS and VSS) were measured periodically. Tables 5 and 6 show the composition of mineral media and carbon sources used in enrichment batches.

Table 5. Mineral medium used in the biodegradation experiment

Mineral medium NO.	Components (per liter solution)	Ref.
#1	0.2 g $MgSO_4$, 0.02 g $CaCl_2$, 1.0 g KH_2PO_4, 1.0 g $(NH_4)_2HPO_4$, 1.0 g KNO_3 and 0.05 g $FeCl_3$	[20]
#2	0.7 g KH_2PO_4, 1 g K_2HPO_4, 0.4 g NH_4Cl, 0.05 g $CaCl_2$, 0.03 g $MgSO_4$, 0.2 g $NaHCO_3$, 0.01 g NaCl, 0.055 mg $CuCl_2{\cdot}H_2O$, 0.148 mg $ZnCl_2$, 0.022 mg $NiCl_2{\cdot}6H_2O$ 0.022 mg, $FeSO_4{\cdot}7H_2O$ 0.88 mg, $Al_2(SO_4)_3{\cdot}18H_2O$ 0.135 mg, $MnCl_2{\cdot}4H_2O$ 0.282 mg, $CoCl_2{\cdot}6H_2O$ 0.056 mg, $Na_2MoO_4{\cdot}2H_2O$ 0.032 mg, H_3BO_3 0.049 mg	[21]

Table 6. Feed of different reactors for the biodegradation experiment

NO.	Reactor Name	Volume (mL)	Carbon source	Mineral medium	Feed time
1	N+G	500	Naphthalene (0.6 g/per week) + Glucose (0.6 g/per week)	#1	Mon., Fri.
2	N only	500	Naphthalene (0.6 g/per week)	#1	Mon., Fri.
3	B+G	1000	BTEX (6 ml each/per week) + Glucose (0.6 g/per week)	#2	Mon., Wed., Fri.
4	B only	1000	BTEX (6 ml each/per week)	#2	Mon., Wed., Fri.

* G, N and B stand for glucose, naphthalene and BTEX respectively.

The biodegradation batch experiment was performed as follows. First, 190 ml of 10 mg/L stock solution was added to each of two test reactors (control and biodegradation) containing nutrients as listed in Table 5. The biomass was washed and concentrated 5 times by centrifugation. After that, 10 ml of the concentrated biomass was added into the biodegradation reactor, and 10 ml DI water was added to the control reactor for the purpose of measuring the volatilization. Finally, oxygen was supplied periodically to all the reactors. Samples were taken and immediately measured by a SPME GC_FID method as described in section 3.1.2.

Results:

Biological degradation of naphthalene: For naphthalene tests, two sets of enrichment batches were started, one with naphthalene as the sole carbon source and the other with naphthalene and glucose as the carbon sources. Both batches received an identical charge of trace nutrients. The average total solids concentration in the naphthalene-only batch was 2.7±0.9 g/l and the same concentration in the naphthalene and the glucose batch was 4.7±1.1 g/l based on two-year monitoring. The volatile suspended solids concentrations, which represent the size of the bacterial population, were 2.4±0.8 and 4.1±0.9 g/l in the naphthalene-only and naphthalene plus glucose batches respectively.

After a sludge enrichment period of approximately 600 days, two sets of experiments were performed with each of the two sludges. In the first set, the control batch, the naphthalene solution was subjected to air sparging. In the second set, biodegradation of naphthalene was tested. The performances of all these batches are shown in Figure 6.

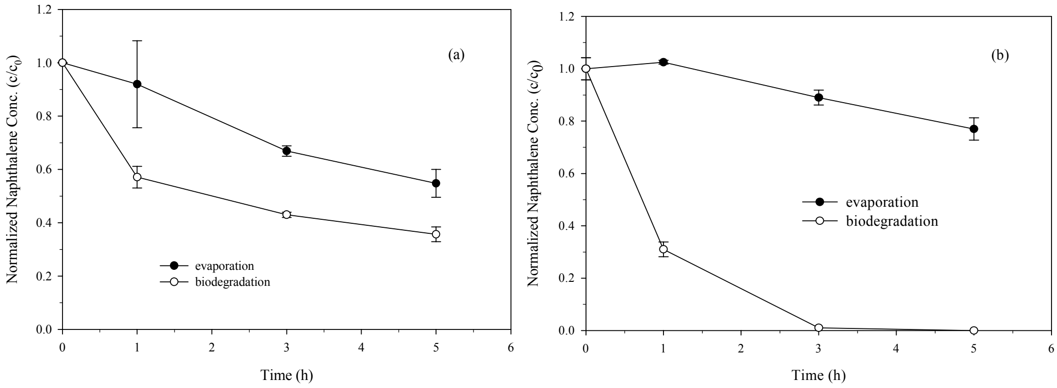

Figure 6: Biodegradation of naphthalene by bacteria enriched with: (a) naphthalene plus glucose as carbon source; (b) naphthalene only as carbon source.

In the batches performed with the naphthalene and glucose enriched biomass (Figure 6 (a)), 45% and 65% naphthalene removal from the bulk liquid occurred in the control and the active biomass-containing batch respectively. Likewise, in the batches performed with the biomass enriched with the naphthalene-only carbon source, 15% and 99% naphthalene removals from the bulk liquid occurred in the control and the active biomass-containing batches respectively. The difference in blanks between the two sets of experiments was caused by a difference in air purging rates. Higher air purging rates lead to greater volatilization. These results show that naphthalene-degrading bacteria were enriched in both batches and that the naphthalene-enriched bacteria were able to degrade naphthalene more efficiently than the bacterial community that was enriched with both naphthalene and glucose as the carbon source.

<u>*Biological degradation of BTEX:*</u> The average TSS and VSS in the batch containing BTEX as

the only carbon source were 1.1±0.4 g/l and VSS 1.0±0.3 g/l respectively. Likewise, in the batch containing glucose and BTEX, the average TSS and VSS were 2.8±0.9 g/l and 2.0±0.5 g/l respectively. Figure 7 shows biodegradation results for all four compounds present in BTEX with biomass enriched using BTEX and glucose as carbon sources. Under these conditions, 29% and 88% of the benzene, 48% and 99% of the toluene, 61% and 99% of the ethyl benzene and 60% and 95% of the xylene were removed in the blank batches and the batches containing active bacteria respectively.

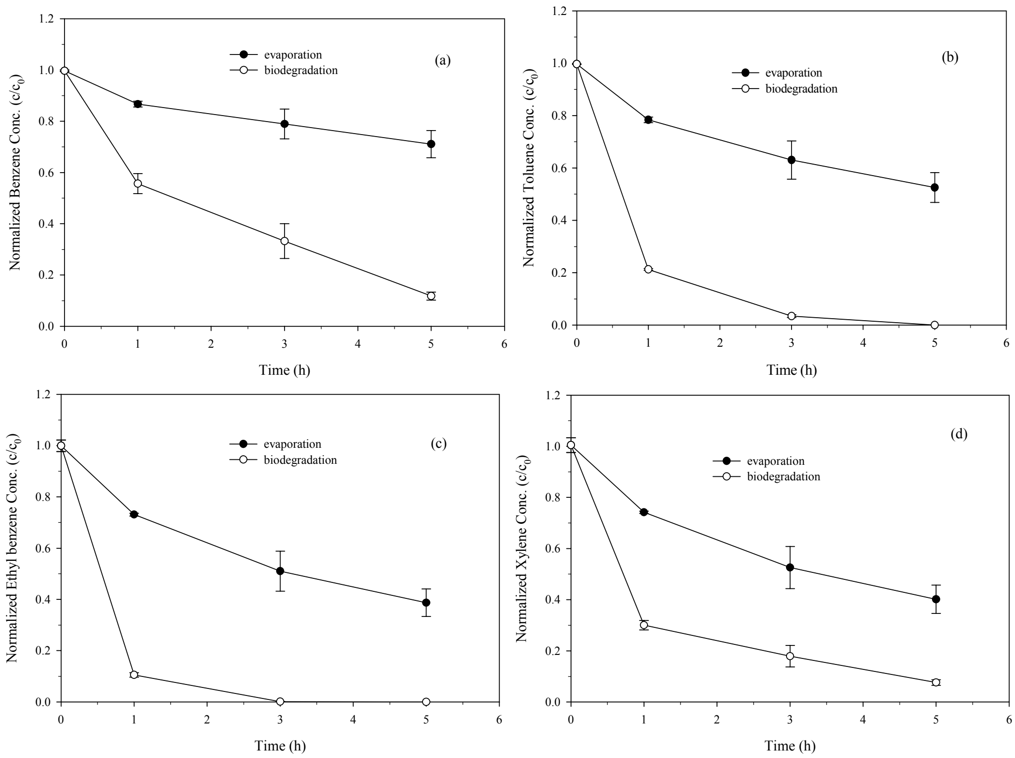

Figure 7: Biodegradation of BTEX by bacteria enriched by BTEX plus glucose: (a) benzene; (b) toluene; (c) ethyl benzene; (d) xylene.

The biodegradation results of BTEX compounds with the biomass enriched with BTEX as the only carbon source are shown in Figure 8. Under these conditions, 34% and 54% of the benzene, 50% and 86% of the toluene, 64% and 86% of the ethyl benzene and 63% and 83% of the xylene were removed in the blank batches and the batches containing active bacteria respectively.

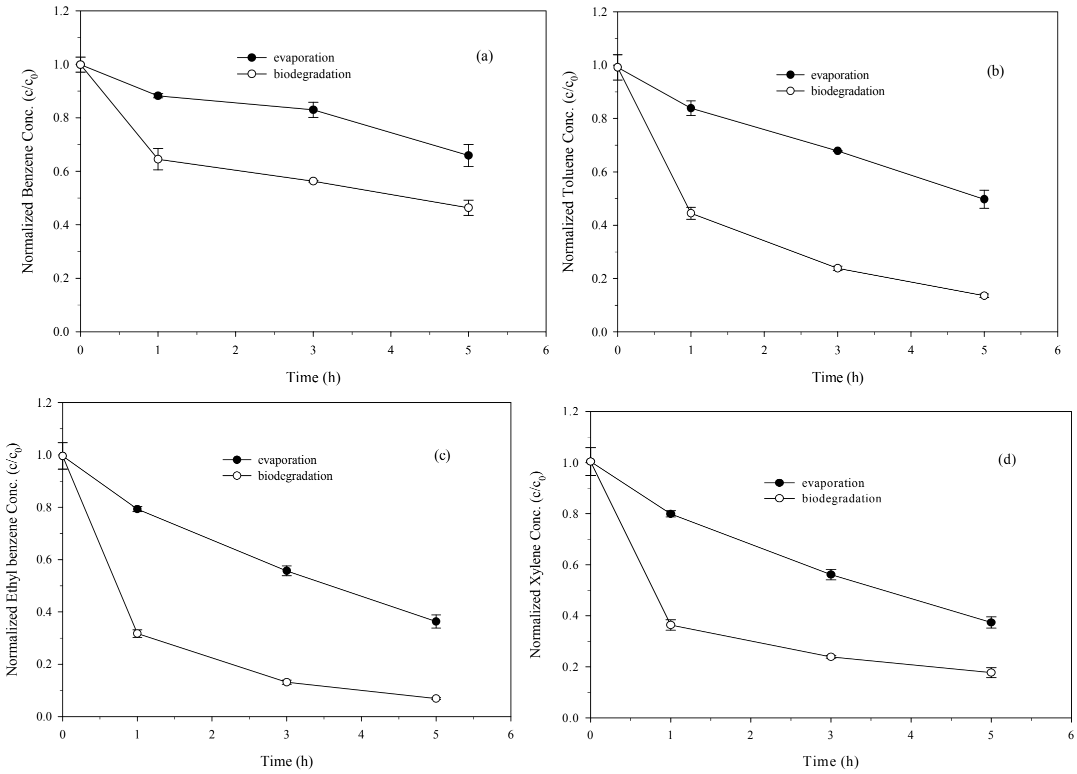

Figure 8: Biodegradation of BTEX by bacteria enriched by BTEX only: (a) benzene; (b) toluene; (c) ethyl benzene; (d) xylene.

BTEX removal was identical in the blank batches containing the two different biomasses. However, removal of BTEX compounds in the BTEX-only biomass batches was lower than in the batches containing biomass enriched with BTEX and glucose. In case of the naphthalene biodegradation experiments, more naphthalene was degraded in the batches containing the biomass enriched with naphthalene as only carbon source than in the batches containing the biomass enriched with naphthalene and glucose as carbon sources. This observation suggests that biomass responsible for naphthalene biodegradation does not require any acclimatization with glucose and could use naphthalene as the sole carbon source. On the other hand, biomass responsible for BTEX biodegradation performs better following acclimatization with glucose, indicating the diversity within physiological characteristics of both representative biomasses.

3.1.4 Identification of bacteria using cloning and sequencing

Methodology: Genomic DNA was extracted from the sludge sample using the UltraClean Soil DNA Kit (Mo Bio Lab. Inc.) as per vendor instructions. A polymerase chain reaction (PCR) was performed using universal bacteria 16S rDNA forward primer 8F (5'-AGAGTTTGATCCTGGCTCAG-3') and a universal reverse primer 1492R (5'-GGTTACCTTGTTACGACTT-3'). The amplified PCR product was verified by 1% agarose gel electrophoresis and purified using a QIAquick gel extraction kit (Qiagen, Valencia, California). The purified DNA fragments were then cloned into a competent cell of *E. coli* using a TOPO TA Cloning® Kit (Invitrogen, CA) following the manufacturer's instructions. Clones were randomly picked and were grown in kanamycin (50 μg/mL) containing LB broth. Plasmid DNA was extracted from the clones using the Wizard plus Miniprep DNA purification system (Promega, WI) and subjected to further screening. A sequencing reaction was carried out using the Big Dye sequencing kit (Applied Biosystems) with 8F as the forward primer, and the products were purified using Cleanseq (Agencourt Biosciences, MA). The products were run on an automated DNA sequencer (ABI model 3730 96-capillary sequencer, Applied Biosystems, California). The retrieved sequences were compared and identified with available 16S rDNA sequences downloaded from publicly available databases (RDP II and NCBI BLAST).

Results: Table 7 lists the details of 48 clones and their identities that were picked for the biomass enriched with naphthalene and glucose as carbon sources. Similarly, Table 8 shows results of cloning performed on the biomass from the naphthalene-only batch. In both biomasses, the genus *Pseudomonas* dominated the reactors as revealed by cloning and sequencing. These results indicate that *Pseudomonas* species are primarily responsible for naphthalene degradation. The next dominant group of bacteria in both reactors was related to the genus *Burkholderia*. Other genus such as *Terrimonas, Niastela, gp3, Rhodanobacterium* and *Pirellula* were also present in the reactors, although in low numbers. Through this cloning and sequencing effort to identify the bacteria responsible for the degradation of naphthalene and BTEX, we can learn better management strategies for the operation of bioreactors.

Table 7. Identification of the bacteria enriched by naphthalene and glucose as the carbon sources

Phylum	Class	Order	Family	Genus	No. of Clones
Proteobacteria	Gammaproteobacteria	Pseudomonadales	Pseudomonadaceae	*Pseudomonas*	16
Proteobacteria	Betaproteobacteria	Burkholderiales	Burkholderiaceae	*Burkholderia*	8
Bacteroidetes	Sphingobacteria	Sphingobacteriales	Crenotrichaceae	*Terrimonas*	4
Bacteroidetes	Sphingobacteria	Sphingobacteriales	Flexibacteraceae	*Niastella*	4
Proteobacteria	Deltaproteobacteria	Bdellovibrionales	Bdellovibrionaceae	*Bdellovibrio*	2
Planctomycetes	Planctomycetacia	Planctomycetales	Planctomycetaceae	*Pirellula*	2
Acidobacteria	Acidobacteria	Acidobacteriales	Acidobacteriaceae	*Gp3*	2
Proteobacteria	Gammaproteobacteria	Xanthomonadales	Xanthomonadaceae	*Rhodanobacter*	1
Bacteroidetes	Flavobacteria	Flavobacteriales	Flavobacteriaceae	*Chryseobacterium*	1
Proteobacteria	Gammaproteobacteria	Enterobacteriales	Enterobacteriaceae	*Enterobacter*	1
Proteobacteria	Gammaproteobacteria	Enterobacteriales	Enterobacteriaceae	*Klebsiella*	1
OP10				*OP10_genera_ incertae_sedis*	1
Proteobacteria	Deltaproteobacteria	Bdellovibrionales	Bacteriovoracaceae	*Bacteriovorax*	1

Table 8. Identification of the bacteria enriched by naphthalene as the only carbon source

Phylum	Class	Order	Family	Genus	No. of Clones
Proteobacteria	Gammaproteobacteria	Pseudomonadales	Pseudomonadaceae	*Pseudomonas*	17
Proteobacteria	Betaproteobacteria	Burkholderiales	Burkholderiaceae	*Burkholderia*	12
Bacteroidetes	Sphingobacteria	Sphingobacteriales	Flexibacteraceae	*Niastella*	6
Bacteroidetes	Sphingobacteria	Sphingobacteriales	Crenotrichaceae	*Terrimonas*	3
Acidobacteria	Acidobacteria	Acidobacteriales	Acidobacteriaceae	*Gp3*	3
Proteobacteria	Alphaproteobacteria	Sphingomonadales	Sphingomonadaceae	*Sphingomonas*	2
Planctomycetes	Planctomycetacia	Planctomycetales	Planctomycetaceae	*Pirellula*	1
Bacteroidetes	Flavobacteria	Flavobacteriales	Flavobacteriaceae	*Chryseobacterium*	1
Proteobacteria	Gammaproteobacteria	Xanthomonadales	Xanthomonadaceae	*Fulvimonas*	1

4. Summary

In summary, produced water is composed of dispersed oil, dissolved organic compounds, production chemicals, heavy metals, naturally occurring radioactive minerals and other inorganic compounds. Every year, larger quantities of produced water go through underground injection or discharge into natural water bodies, which do not meet the requirement of sustainable development and also present a potential threat to the aquatic ecosystem. Produced water has been treated by physical (deep bed filter, gas flotation, sand filtration, activated carbon, etc.), chemical (ozonation, ion exchange, UV treatment, etc.) and biological methods respectively. However, none of those methods alone gives a substantive treatment. An integrated process including physical, chemical and biological methods is proposed in our project to treat the produced water for sustainable production in the oil/gas fields. Naphthalene and BTEX were used as the model compounds of the complex organics in the produced water. Both naphthalene and BTEX were effectively removed by advance oxidation and biological methods. Preliminary results show the potential for an integrated treatment process to enhance the sustainable use of water in oil/gas fields. Enriched biomasses performing naphthalene and BTEX degradation were found to be physiologically and metabolically diverse based on their presence/absence of glucose as a carbon source. Cloning (16S rDNA-based) and sequencing revealed that *Pseudomonas* was the dominant genus in the naphthalene-degrading biomass.

The results show that chemical, physical, and biological treatment approaches are potentially capable of treating produced water such that the water can be reused. These results also suggest that issues such as volatilization during treatment and the effects of coupling in an integrated treatment scheme need to be addressed.

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APPENDIX F

Bitumen Extraction and Treatment and Reuse of Process Water

A Subpart of Project

Quantifying Water Availability Impacts and Protecting Water Quality While Developing Utah Oil Shale and Sands

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

Andy Hong
Department of Civil and Environmental Engineering
University of Utah

April 13, 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
Institute for Clean & Secure Energy
155 South 1452 East Room 380
Salt Lake City, UT 84112

Project Title: Bitumen Extraction and Treatment and Reuse of Process Water

Principal Investigator: Andy Hong, Ph.D., P.E., Professor, University of Utah

Project Duration: Apr. 18, 2007 – Mar. 31, 2009

Project Amount: $20,455

Student(s) supported:
Xiaoxiao Cai (4.5 months; Fall 2007)
Zhixiong Cha (1 month, Spring 2008)

Project Tasks as Originally Proposed:

1. Treatment of Naphthenic Acids (1st – 9th month)
2. Design of Modular Wastewater Treatment Units (6th-9th month)
3. Improved Extraction of Bitumen from Tar Sands of Utah (10th–22nd month)

Project Tasks Performed:

Various project tasks were performed and reported in quarterly progress reports submitted throughout the project period.

Summary of Project Outcomes:

1. Treatment of naphthenic acids – The task of treatment of naphthenic acids, a class of contaminants in the produced water ,was not completed as the original proposed project and budget were significantly reduced. The original proposal was submitted by S. Burian (PI) & A. Hong (Co-PI) for $123,000 with student support over 2 years, but was reduced to $20,455 with 6 months of student support for this subproject and $57,718 for S. Burian's subproject.
2. Treatment feasibility of produced water – Data collection was completed and the results were reported at various conferences. A manuscript is being prepared and near completion for a refereed journal publication.
3. Treatment of a Midwest refinery wastewater – Data collection was completed and results were reported at various conferences.
4. Bitumen extraction - Preliminary results were obtained on extraction of bitumen from oil sands.
5. Design of a new modular wastewater treatment - Designs are possible with the produced water and refinery wastewater treatment results already gathered in items 2 and 3 above. The PI plans to fine-tune the new designs in the near future.

Project Summary

Produced water from gas and crude oil production is voluminous, requiring extensive treatment before it can be safely discharged or reused. This project has used a newly developed pressure-assisted ozonation technology to remove oil from water and prevent oil sheen at the water surface. The new process is based on heightened reactions of ozone and hydrocarbon molecules occurring at the gas-liquid interface of the microbubbles. The treated water contains biodegradable end products at low concentrations, making it possible for safe discharge to the environment or for various reuses. The new process is especially valuable for coastal discharge, as well as for energy development and water use in arid regions.

Background Information

Produced water is brought to the surface during gas and crude oil production. As many as ten barrels of water are produced per barrel of oil, resulting in billions of barrels of produced water each year. Produced water contains organic compounds such as aromatics, aliphatics, organic acids, phenols, and others. Generation of offshore produced water has also been increasing due to dwindling production from onshore shallow oil reservoirs. The release of inadequately treated produced water can result in oil sheen at the water surface, and its oil content can adversely impact ecosystems and aesthetics.

Produced water contains dispersed and dissolved oils that are difficult to address with any single treatment approach. Existing techniques based on gravitational force (flotation, hydrocyclone, centrifugation), membrane filtration, adsorption, electrodialysis, and biodegradation have drawbacks including their inability to meet regulatory requirements, high costs, maintenance issues, long treatment time, and others. Presently, technologies that are economically and technically effective are needed to rehabilitate produced water for sound disposal to the environment as well as for potential reuse.

Project Objectives

The objectives were: 1) to treat oily wastewater such as produced water that contains dissolved and suspended oil, 2) to remove the potential of sheen formation on water surface, 3) to render them amenable to reuse and safe environmental release, and 4) to demonstrate bitumen extraction from oil sands. These objectives have been modified from the original scope, as explained in the project outcomes above.

Experimental Setup

Pressure-assisted ozonation was carried out in a stainless steel reactor (Figure 1). The pressure reactor has an internal diameter of about 15 cm and a working volume of about 1.5 L. It features a gas vent and a pressure gauge at the top, an inlet and outlet at the bottom, and a magnetically coupled stirrer to provide agitation of the slurry. To start, the reactor was loaded with produced water at a desired volume (100–1,000 mL). Each pressure cycle began with the compression stage when the valve was opened to allow the O_3/air mixture driven by a compressor (GAST) at 5 L min^{-1} into the closed reactor chamber through a gas diffuser plate located inside the reactor bottom. The gas passed through the liquid and pressurized the headspace to a designated pressure (e.g., 690 kPa or 100 psi); once the designated pressure was reached, the pressure was released via rapid venting by opening the solenoid valve at the reactor top. The time for compression to reach 690 kPa depended on the headspace volume, e.g., 100 s for 1,300 mL of headspace or 40 s for 670 mL of headspace, and other factors such as gas flow rate; the time for decompression varied with gas venting rate but was typically completed in seconds. The pressure cycles could be repeated as many times as prescribed. Experiments were at room temperature (20±2°C). Figure 1 also shows formation of microbubbles in a transparent column resulting from decompression.

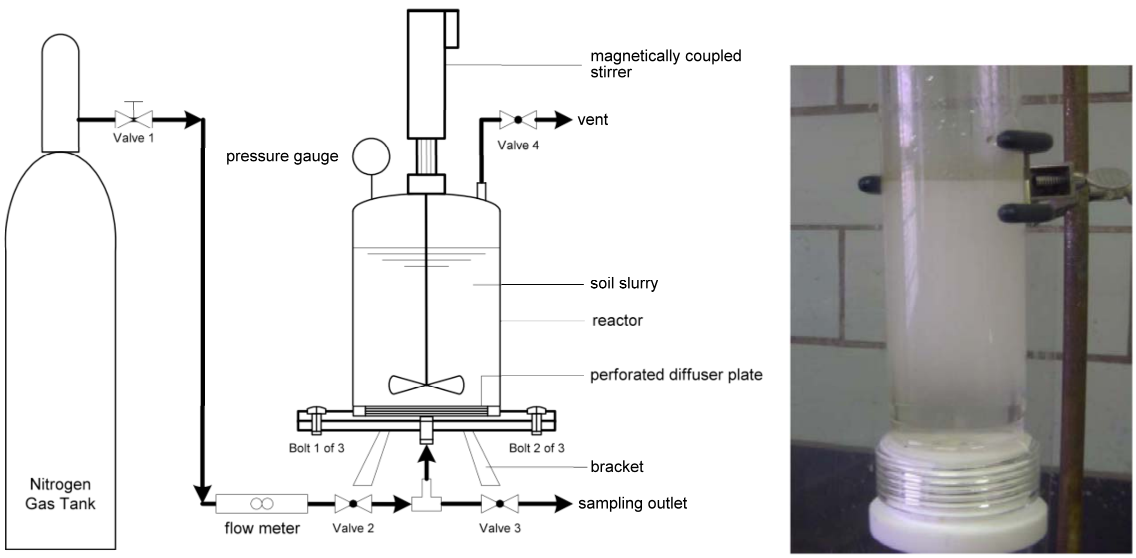


Figure 1. Reactor for pressure cycles (microbubbles shown in column).

Produced water was artificially prepared by mixing Rangely Crude oil with distilled water (1.5 mL oil in 2 L water), vigorously agitating the mixture at 500 rpm for 30 min, and then allowing the mixture to sit for 30 min. Chemical oxygen demand (COD), biochemical oxygen demand (BOD), turbidity, and pH of the spiked water were monitored before and after treatment. Sand filtration was performed following ozonation treatment (sand particle size of 0.25 – 0.42 mm; depth of 10 cm; superficial velocity 6 cm/min); the filtrate was subject to hexane extraction and solid phase extraction (SPE) method, and organic contents from the hydrophobic and hydrophilic portions, respectively, were analyzed and delineated by gas chromatography/mass spectrometry (GC/MS).

Project Findings

Key project findings are as follows:

1) *Removal of hydrocarbon contents from water by ozonation in pressure cycle*
Results shown in Table 1 reflect decreasing total COD, increasing dissolved COD, and increasing BOD_5/COD ratio as the number of pressure cycles is increased. This result suggests removal of total oil content and conversion of oil into soluble forms by ozone with increased biodegradability of the aqueous contents. The increased hydrophilic (dissolved) content in the treated water is shown in Figure 2. While aeration in pressure cycles removes total oil contents, it does not effect changes in dissolved contents or biodegradability of the treated water.

Table 1. Hydrocarbon removal by ozonation in pressure cycles (PC).

	No. Cycle (#)	Flow rate (L/min)	Compression Time to P=150 psi (s)	pH	Total COD (mg/L)	Dissolved COD (mg/L)	BOD_5/ COD
Control				6.9± 0.1	325± 34	48±4	0.45
PC / air	10	10	15	6.9±0.1	142±23	42±7	0.45
	20	10	15	6.8±0.1	99±6	45±4	0.45
	30	10	15	6.9±0.1	84±7	39±4	0.46
PC / ozone	10	10	15	6.2±0.2	152±17	50±7	0.48
	20	10	15	6.1±0.2	124±18	54±5	0.54
	30	10	15	5.1±0.3	123±12	69±7	0.57

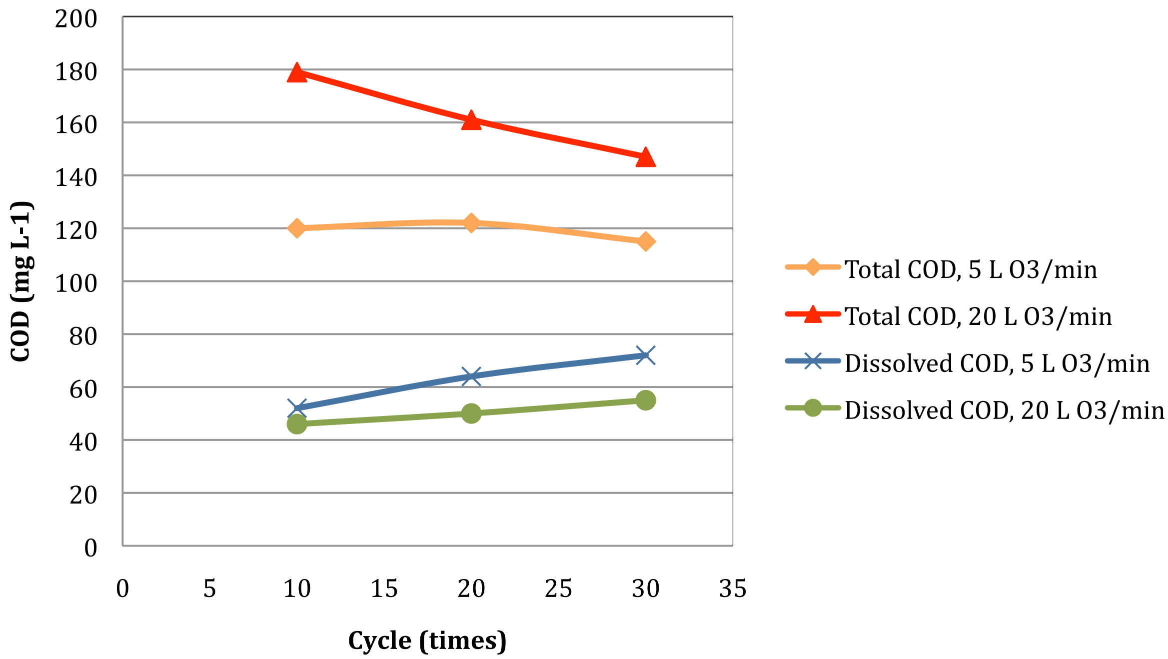


Figure 2. Hydrophilic products generated during treatment of produced water.

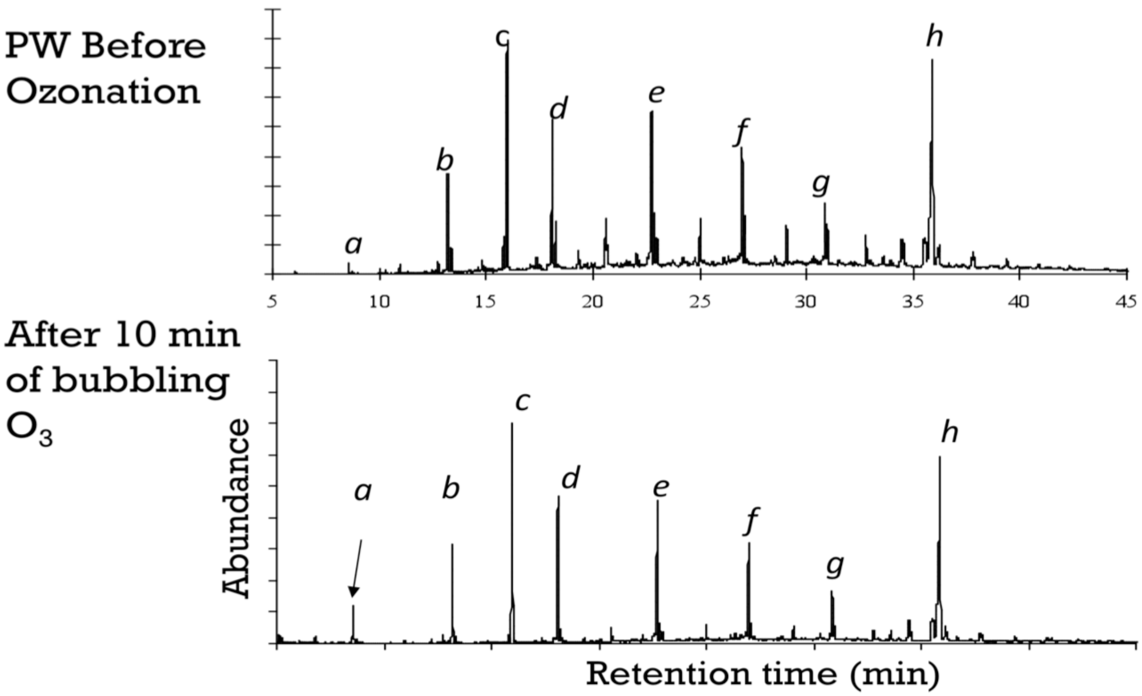
2) *Ozonation and sand filtration remove suspended oil and eliminate sheen*
   Results of Table 2 show that the sequential treatments of ozonation followed by rapid sand filtration rapidly remove a significant portion of the suspended oil. When the combined process is repeated once, suspended oil is further removed, as evidenced by a low turbidity of 2-4 NTU (nephelometric turbidity units). As a result, sheen formation is prevented. Figure 3 shows the produced water before and after treatment.

Table 2. Results of ozonation of produced water followed by sand filtration (SF).

	Flow rate (L/min)	Turbidity (NTU)	Total COD (mg/L)	Dissolved COD (mg/L)	Oil Sheen (1 h)	Oil Sheen (1 d)
Control		196± 13	325± 34	48±4	Y	Y
PC / air	10	98± 11	142±23	42±7	Y	Y
PC / ozone	10	101±10	152±17	50±7	Y	Y
10 cy PC/air + SF 20 cy PC/air + SF	10	79±8	112±11	38±5	Y (50%)	Y
10 cy PC/O_3 + SF	10	21±4	73±14	48±3	N	Y (50%)
10 cy PC/O_3 + SF + 10 cy PC/O_3 +SF	10	3.8±1.1	58±11	51±7	N	Y (25%)
10 cy PC/O_3 +SF + 20 cy PC/O_3 +SF	10	2.1±0.3	59±8	55±6	N	N

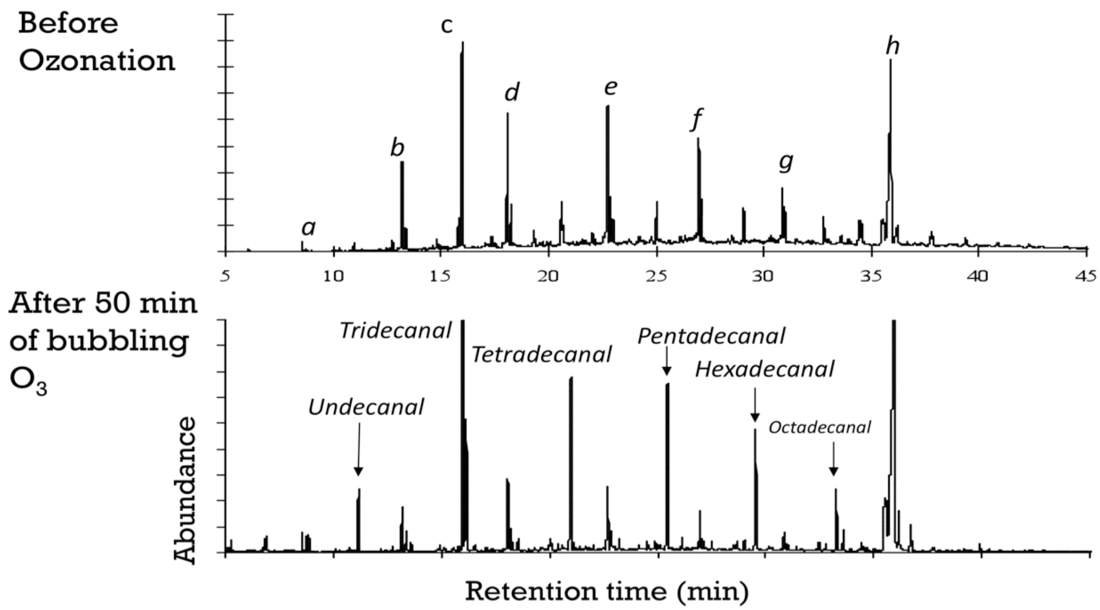
Figure 3. Visual results of ozonation in pressure cycles followed by sand filtration. Left: before treatment; Right: after treatment with 10 cycles of PC/O_3 + SF and 20 cycles of PC/O_3 + SF (gas flow rate of 5L/min).

3) *Removal of suspended oil by flotation and filtration of the coagulated oil*
Regular ozonation (i.e., conventional bubbling ozone) reacts with oil very slowly and thus is not effective in oil removal. Figures 4a and 4b show little change in the oil content after prolonged regular ozonation. However, when ozonation in executed in pressure cycles (Figure 5), the reactivity of hydrocarbons with ozone in the microbubbles is heightened, resulting in conversion of hydrophobic oil to polar hydroxyl and carboxylic groups that enable the oil droplet coagulation and removal by sand filtration.



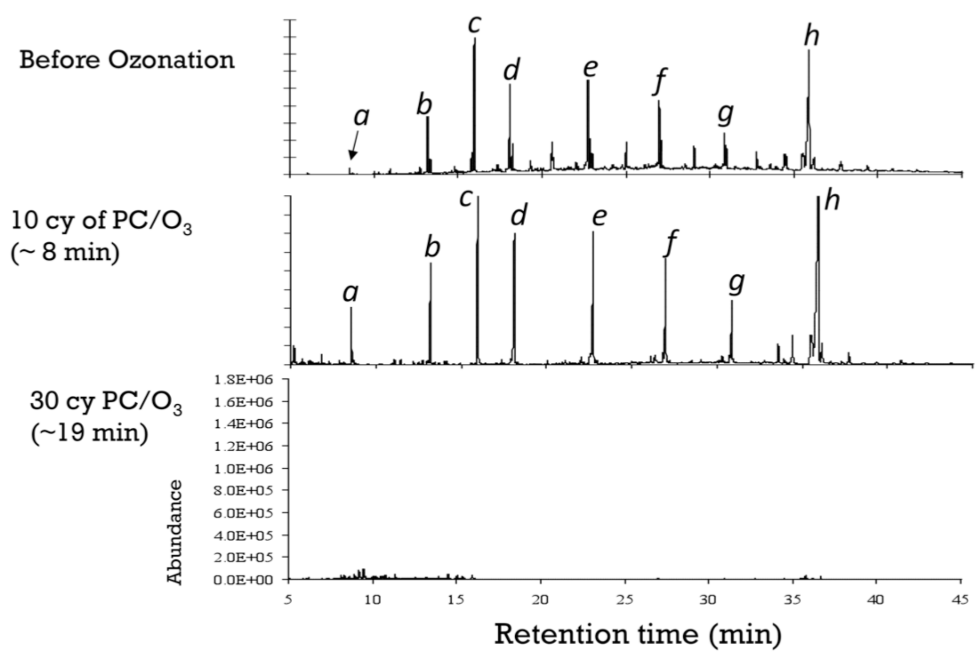
a: 1-Dodecene, *b*: 1-Tetradecene, *c*: Phenol, 2,4-bis [1,1-dimethyethl]-, *d*: 1-Hexadecene, *e*: 1-Octaadecene, *f*: 1-Nonadecene, *g*: 1-Decosene, *h*: Diethylene glycol dibenzonate

Figure 4a. GC/MS Analyses - Hexane-extractable hydrocarbons in produced water before and after 10 minutes of regular ozonation.



a: 1-Dodecene, *b*: 1-Tetradecene, *c*: Phenol, 2,4-bis [1,1-dimethyethl]-, *d*: 1-Hexadecene, *e*: 1-Octaadecene, *f*: 1-Nonadecene, *g*: 1-Decosene, *h*: Diethylene glycol dibenzonate

Figure 4b. GC/MS Analyses - Hexane-extractable intermediates before and after 50 minutes of regular ozonation.



a: 1-Dodecene, *b*: 1-Tetradecene, *c*: Phenol, 2,4-bis [1,1-dimethyethl]-, *d*: 1-Hexadecene, *e*: 1-Octaadecene, *f*: 1-Nonadecene, *g*: 1-Decosene, *h*: Diethylene glycol dibenzonate

Figure 5. GC/MS Analyses – Products with increasing number of pressure cycles.

4) *Sheen prevention occurs via conversion of the trace hydrophobic suspended oil into hydrophilic dissolved oil*
Suspended oil is the main cause for sheen formation. Once suspended oil is converted to hydrophilic, dissolved hydrocarbons, sheen is effectively prevented. Figure 6 shows increased hydrophilic products in the treated produced water, which do not form sheen. A plethora of aliphatic acids, esters, phenols, and heterocyclic organics were extracted from the treated produced water and identified by GC/MS.

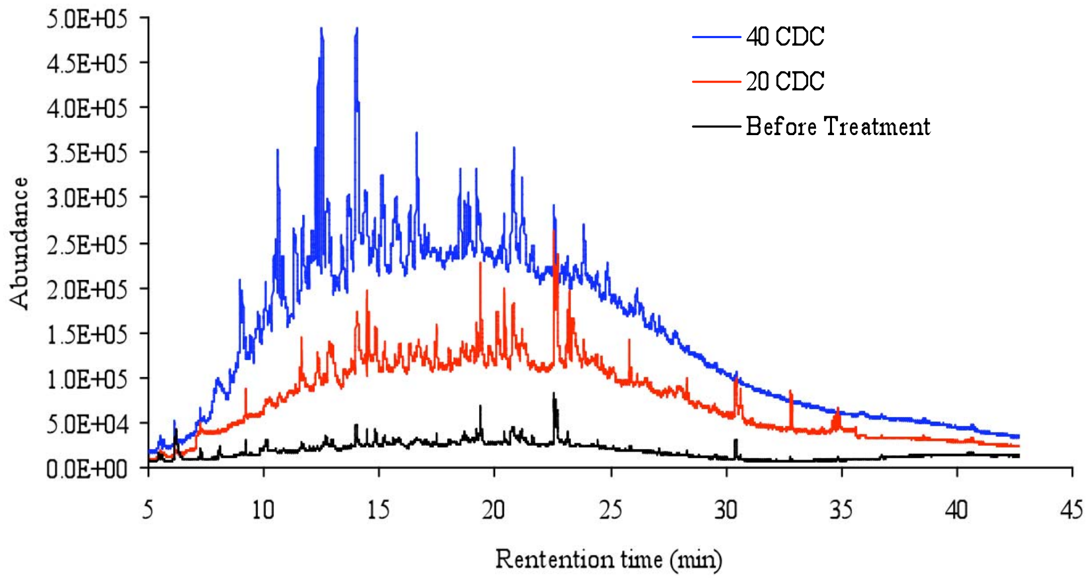


Figure 6. GC/MS Analyses – Hydrophilic products in treated produced water.
Note: CDC = cyclic compression/decompression

5) *Biodegradable, hydrophilic products in treated water*
Table 3 shows biodegradability of products in the treated produced water under different conditions. The BOD_5/COD ratio of 0.6 would suggest the dissolved, hydrophilic products remaining in the treated water are highly biodegradable and could be processed by municipal wastewater treatment systems.

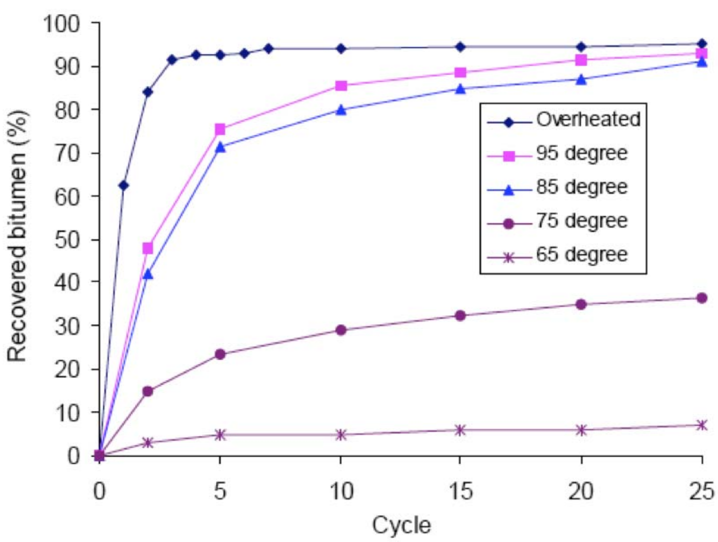
Table 3. Test for biodegradability of treated produced water.

	Flow rate (L/min)	COD (mg/L)	Dissolved COD (mg/L)	BOD_5/ COD	COD after biological treatment (48 hours), (mg/L)	BOD_5/COD after biological treatment
CDC ozone 10 cycles	5	120±9	52±4	0.48	12±3	
CDC ozone 20 cycles	5	122±6	64±4	0.55	17±4	
CDC ozone 10 cycles + SF + 10 CDC ozone + SF	10	58±11	51±7	0.55	13±4	0.05
CDC ozone 10 cycles + SF + 20 CDC ozone + SF	10	59±8	55±6	0.58	12±3	0.05
CDC ozone 10 cycles + SF + 20 CDC ozone + SF	5	65±7	57±3	0.61	4±4	0
CDC ozone 10 cycles + SF + 20 CDC ozone + SF	20	73±11	45±4	0.58	7±3	0

6) *Extraction of bitumen from oil sands*

The heightened oil sands extraction (HOSE) process is a new approach to hot water extraction of bitumen from oil sands; the rapid pressure cycles employed in the technology significantly reduce the required contact time of tar sands by hot water. Due to enhanced bitumen exposure, lower water temperatures can be used for higher yields, resulting in energy savings that more than compensate for the minimal energy expended in compression with air. Figure 7 shows an oil sands sample before and after bitumen extraction via the HOSE process under the specified conditions. The process resulted in spent sands (with low organic content at <5%) and collected bitumen (>95% recovery). The process was tested at a low water-to-sands ratio of 0.5 (v/v) at different temperatures. The results, shown in Figure 8, demonstrate an extraction dependence on process parameters of temperature and number of pressure cycles. The process accomplished bitumen release and collection in a single step without the use of caustics or disinfectants. The spent sands readily settled through the water column.

Figure 7. Left picture: Asphalt Ridge oil sands, Utah, containing 12±1.7% bitumen by weight. Right picture: Depleted and settled oil sands (beaker) and extracted, separated bitumen (canister) (Conditions: 85°C, 100 psi, 20 cycles).



Solid to Water Ratio = 0.5:1 (v/v)

Figure 8. Extraction of oil sands with pressure cycles of air (P = 150 psi).

Conclusions

Based on the laboratory results, we conclude the following:

- Ozonation in pressure cycles combines the advantages of microbubbles for floatation and heightened reactivity of ozone for removal of oil from water.

- Ozone converts small hydrocarbons in the aqueous phase into hydrophilic organics in a short time (< 20 min).

- Coarse sand filtration in a two-stage ozonation- filtration process quickly removes a large amount dispersed and coagulated oil in the produced water. The sand bed can be regenerated thermally and redeployed.

- The dissolved organic acid products show good biodegradability. They do not form sheen and are expected to readily biodegrade in the environment.

- The pressure-assisted HOSE process rapidly accomplishes bitumen extraction from oil sands using little energy and requiring no chemical additives, demonstrating its potential as an effective, green process.

Summary of Project Publications

Z. Cha, A. Hong, C.F. Lin (2009). "Pressure-assisted ozonation of produced water." Near completion for submission to review and journal publication.

Z. Cha, A. Hong. Pressurized Ozone Treatment of Produced Water and Overheated Water Extraction of Oil Sands. Western U.S. Oil Sands Technology Transfer Meeting, February 22, 2008, Salt Lake City, UT

Steven J. Burian, Ramesh Goel, Andy Hong, Liang Li, Eric Jones, Zhixiong Cha, Beth Dudley-Murphy, and Greg Nash. Oil Shale Development in the Western United States: Water Resources Challenges, Impacts and Solutions. EWRI Conference, April 2008.

Andy Hong, Zhixiong Cha, Cheng-Fang Lin, Angela Lin. Pressure-Assisted Ozonation for Rehabilitation of Produced Water. 19th Annual AEHS Meeting and West Coast Conference on Soils, Sediments, and Water, March 9-12, 2009, San Diego, CA.

R. Goel, S. Burian, A. Hong, G. Nash, D. Murphy. New Approaches to Treat Produced Water and Perform Water Availability Impact Assessments for U.S. Oil Sands and Oil Shale Development. 2007 Annual Meeting, Salt Lake City, UT.

Zhixiong Cha, Andy Hong "Heightened Ozonation Treatment Of Produced Water," AIChE Annual Meeting, November 4-9, 2007, Salt Lake City, UT.

Z. Cha, X. Cai, R. Levey, and A. Hong "Pressure-Assisted Ozonation of Produced Water and Process Water of Oil Shale," 27th Oil Shale Symposium, October 15-17, 2007, Colorado School of Mines, Golden ,CO.

Zhixiong Cha; P.K.Andrew Hong "Heightened Ozonation Treatment of Produced Water for Removal of Hydrocarbons and Prevention of Oil Sheen Formation," ACS 62nd Northwest Regional Meeting, June 17-20, 2007, Boise, ID.

Z. Cha, A. Hong "Treatment of Produced Water by Heightened Ozonation Treatment for Removal of Hydrocarbons and Prevention of Oil Sheen Formation." 2007 AWWA Spring water Quality Symposium, May 10, Salt Lake City, UT.

APPENDIX G

Detailed Study of Shale Pyrolysis for Oil Production

A Subpart of Project
Oil Shale Pyrolysis and In Situ Modeling

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

Milind Deo, Eric Eddings and Pankaj Tiwari
Department of Chemical Engineering
University of Utah

April 21, 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
Institute for Clean & Secure Energy
155 South 1452 East Room 380
Salt Lake City, UT 84112

Project Objectives

1. Conduct comprehensive analysis of oil shale pyrolysis data and kinetic models found in the literature.
2. Obtain data on the pyrolysis of Green River shale from Utah, including detailed compositional information.
3. Compare the data generated for shale with Asphalt Ridge oil sands data. We used Asphalt Ridge rather than the Sunnyside oil sands in the original proposal because of the activity on this deposit and because the samples were readily available.
4. Perform GC-MS analyses to identify compounds that may have high water solubility and may pose environmental concerns.
5. Examine different options for describing the pyrolysis process and make recommendations concerning the level of detail necessary in compositional data to describe the complex reactions that are occurring.

Summary of Project Outcomes

Studies significant to the kinetic analyses of oil shale are compiled and discussed in this report. Methods and experiments relating to the pyrolysis and combustion of Green River oil shale samples from Utah are then presented. Kinetic analysis of both pyrolysis and combustion data was performed using conventional and isoconversion (Friedman) methods. A reasonable match of the data was obtained by considering activation energy as a function of heating rate. For decomposition of complex materials such as kerogen, isoconversion methods are recommended. Based on the data collected, a distribution of activation energies (with conversion) was established. While obtaining comprehensive combustion kinetic information was not one of the original project objectives, other research activities indicated that in situ combustion could be one of the processes used to generate sufficient energy for the pyrolysis process. Pyrolysis yield information was generated using ¾ inch core samples. Yields generally increased slightly with temperature in the narrow temperature window examined in this work. The highest yield was obtained in the experiment with a slow heating rate. Compositional information of the samples revealed that higher temperature processes yielded oil with higher residue.

No significant difference in yield or composition was observed in experiments performed by soaking cores in water for short durations (1-10 days). Selected GC-MS analyses of the products revealed the alkene-alkane pairs typical of shale oils. Significant amounts of aromatics were also present in the oils. In general, these compounds have higher water solubilities than the paraffinic and naphthenic species in the oil. The GC-MS analyses revealed the necessity of detailed compositional analyses. Thermogravimetric analyses of the pyrolysis of Asphalt Ridge oil sands were performed and the signatures were found to be very different from oil shale pyrolysis. Detailed study of the oil sands pyrolysis kinetics was deferred because the process was thought to be significantly different from oil shale pyrolysis.

Presentations and papers

The work covered in this report had been presented in two conferences

1- 28th Oil Shale Symposium, Colorado School of Mines, "Isothermal and Non-isothermal Kinetic Analyses of Mahogany Oil Shale with TGA", *Pankaj Tiwari, Kyeongsok Oh and Milind Deo*, **2008.**

2- 2008 AIChE Annual Meeting, Philadelphia, "Kinetic of Oil Shale Pyrolysis and Oil Composition", *Pankaj Tiwari and Milind Deo*, **2008.**

Introduction

The oil shale industry is going through a revolution of sorts. After the oil crisis in the 1970s, a great deal of effort was spent on research and development and on pilot scale technologies. Extensive research was conducted with on-surface and in-situ production methods. Even though some large pilot underground retorting operations were performed, the on-surface (mining and processing) methods were closest to full-scale (~10,000 barrels/day) commercial implementation. The oil price collapse in the early and mid-1980s led to the total discontinuation of oil shale research and development programs. In recent years, in-situ production methods have seen a significant revival due to technological advances. With these methods, the slow thermal pyrolysis of the organic matter in shale leads to a light oil product that does not require additional thermal upgrading.

Good kinetic data are essential for accurate mathematical modeling of various on-surface and in-situ oil shale processes. The purpose of this project was to develop a more detailed kinetic understanding of the pyrolysis of oil shale. Progress toward this goal is summarized in this report, including isothermal and non-isothermal kinetics of the pyrolysis of the Green River oil shale using thermo gravimetric analyses (TGA). Detailed compositions of the shale oil obtained under various conditions are also presented.

Literature Survey

Oil shale can be a viable alternative source for fast-depleting natural sources of petroleum. The term oil shale covers a wide variety of compact, laminated, sedimentary rocks containing organic material embodied in an inorganic material matrix. The organic portion of the shale, also known as kerogen, undergoes chemical decomposition on thermal heating or pyrolysis to produce a liquid substance (shale oil). Because of the chemical composition of the oil produced, moderate to significant upgrading (nitrogen removal, hydrogen addition) may be required to convert the oil into a refinery feedstock. However, due to the very complex nature of the organic matter, the unraveling of the kinetics has not been straightforward. The yield and quality of the pyrolysis products depend on the source material (geological variability), the temperature-time history, pressure and presence of other reactants such as water, hydrogen, etc.

The main constituent of the organic part of the shale is kerogen which, in some publications, is approximated as $C_{200}H_{300}SN_5O_{11}$. Rich oil shale contains about 10 wt %p kerogen. The kerogen portion of the organic matter is insoluble in ordinary solvents for petroleum and, upon the application of heat, may yield some or all of the following products: gas, oil, bitumen and organic residue (fixed carbon). Oil shales also contain a small percentage of bitumen, which is the benzene-soluble organic material naturally present in the oil shale. Although pure kerogen has not been isolated, it is not considered to be a chemical compound of fixed composition and properties. Rather, it is a heterogeneous mixture of organic matter derived from material such as spore exines, algae, resins, cuticles and woody fragments.

Liquid condensed from the gases evolved during thermal treatment, uncondensed gases and carbonaceous coke are the primary products of kerogen decomposition. Extent of this decomposition, product yields, and the kinetics of the reaction depend on the heating rate and the temperature. Pyrolysis, which is carried out in an inert atmosphere, is likely to exhibit different characteristics than combustion, which is carried out in the presence of air. Some investigations have led to the conclusion that the kerogen exhibits properties of pyrobitumen and, upon heating, decomposes by a consecutive reaction into bitumen. Upon subsequent heating, this bitumen decomposes or cracks into the decomposition products of oil, gas, and a carbonaceous residue (benzene insoluble portion of the kerogen remaining in the spent shale). Further, the reaction rate has generally been treated as first order with respect to the concentration (weight fraction) of kerogen in the formation of bitumen and also first order with respect to pyrolysis of bitumen in the subsequent formation of oil and gas.

The reported literature on oil shale retorting is extensive and covers different approaches used in the compositional analysis of materials (raw shale, products formed, and spent shale), the development of mechanisms and kinetic parameters for retorting of oil shale in different environments, and the effects of retorting conditions on oil yield and compositions. **Hubbard and Robinson (1950)** [1] studied three Colorado oil shale samples at different temperatures (350^o-525^oC) at atmospheric pressure in the absence of oxygen. The samples were extracted (removal of naturally present bitumen) and only insoluble organic material in the oil shale was studied. It was reported that kerogen decomposition to bitumen is a first order reaction; formation of bitumen is proportional to the amount of kerogen present. **George et al. (1966)** [2] reported data from the pyrolysis of oil shale (Piceance Creek Basin in the Green River formation, marlstone) at different temperatures (331^o-500^{o}C), pressures (atmospheric and 1000 psig) and reaction duration (13-550 hours) using natural gas as the heating medium. The crude oil produced was found to have a low pour point and high specific gravity. They concluded that evidence of H_2S formation during the experiment was an indicator of initial kerogen decomposition as well as complete conversion of organic matter. Decomposition of organic matter to products was determined to be a two-step process; the heat of reaction for initial product evolution was 26.7 kcal, while for the long-term, slower, continuing product formation, an activation energy of 20.5 kcal/mol was calculated. **Allred (1966)** [3] **c**ritically re-examined Hubbard and Robinson data for Colorado oil shale and proposed a new mechanism to explain the production of fluid hydrocarbon from insoluble organic matter in oil shale. Allred anticipated that the rate determining reaction was a *logistic or autocatalytic* function. He divided the conversion versus temperature curve into three regions and explained the different rate controlling steps at different temperature segments. **Braun and Rothman (1975)** [4] analyzed the Hubbard and Robinson data more accurately by taking into account an initial thermal induction period. It was reported that the decomposition of kerogen is the rate-controlling step at temperatures above 760K (487^{o}C), while the decomposition of bitumen is the rate-controlling step below 760K. The activation energy of 44.56 kJ/mol for the first step indicates that the decomposition of kerogen involves the breaking of relatively weak chemical bonds, while the activation energy of 177.6 kJ/mol for the consecutive reaction indicates that the decomposition of bitumen involves the breaking of much stronger chemical bonds.

Campbell (1978) [5] used isothermal and non-isothermal methods to investigate the kinetics of oil generation during decomposition of Colorado oil shale by TGA. The non-isothermal method gave an apparent activation energy of 219.4 kJ/mol and a frequency factor of $2.81 x 10^{13}$ s^{-1}, and the process was found to be first order. **Burnham et al. (1982)** [6] reviewed oil yield and kinetic results for western (Colorado Mahogany zone) and eastern (Sunbury and Ohio) oil shales for conditions ranging from those encountered during in-situ processing to those in fluidized bed retorting. They concluded that oil yields from eastern shale are much more sensitive to pyrolysis conditions than western shale. The hydrocarbon generation from eastern oil shale was roughly twice as fast as that from the Colorado oil shale. **Thakur and Nuttall (1987)** [7] considered Moroccan oil shale for a kinetics study of thermal decomposition by isothermal (325^{o}-475^{o}C) and non-isothermal (1, 2, 5 10, 20, 50^{o}C/min) TGA. They analyzed the non-isothermal weight loss data by using three models: the Chen and Nuttall model (integral method), the Coast and Redfern model (graphical method) and the Anthony and Howard model (Gaussian distribution). The first two methods assume a single first order rate equation to describe the decomposition reaction while the third method assumes multiple parallel first order reactions. They also analyzed the isothermal TGA data using the integral method. Analyzing non-isothermal and isothermal TGA measurements together, they noted that the thermal decomposition of Moroccan oil shale involves two consecutive reactions with bitumen as an intermediate. Further, **Galan and Smith (1983)**[8] determined the influence of transport effects (heat and mass) on the observed rate of thermal decomposition of Colorado oil shale kerogen (Anvil Point mine) in a TGA-type apparatus. They concluded that if the particle size was greater than about 0.4 $\times 10^{-3}$ m and if more than two to three layers of particles were present, transport of heat and mass through intra-particle, particle to bulk fluid, and inter-particle interactions all influenced the rate.

A number of researchers have derived a relatively simple but effective kinetic expression for oil evolution during pyrolysis of Green River and other oil shales: single first order kinetics for slow and moderate heating rates and consecutive first order or single pseudo nth order kinetics for rapid isothermal pyrolysis (Leavitt et al., 1987). However, it is desirable to derive kinetic models that are more fundamental and are transferable to different kerogens over a wider range of pyrolysis conditions. To determine detailed kinetics of oil evolution, to maximize the oil yield, and to minimize the coking and cracking, it is necessary to understand the entire process mechanism and to account for the shift of the rate controlling step during the process with changes in retorting conditions. To accomplish this objective, **Burnham and Happe (1984)** [9] reported NMR analyses of five Green River shale oil (liquid) samples generated under widely different pyrolysis conditions and qualitatively proposed a kerogen decomposition mechanism with possibilities for secondary reactions (explained below). The proposed mechanism predicted aromaticity and yield of liquid product during pyrolysis. **Chalesworth (1985,** published two papers on the dependence of oil products on time/temperature history [10] and proposed a set of mechanisms [11] to explain oil quality as a function of time/temperature history during pyrolysis. Gas chromatographic analyses with a flame ionization detector for pyrolyzed products were reported as alkene and alkane ratios; the shift in hydrocarbon compositions was explained with the proposed mechanism. The types of temperature-dependent mechanisms that occur during pyrolysis were classified as: 1-Diffusion controlled reactions, 2-Phase boundary controlled processes, 3-Nucleation controlled processes, 4-Reaction with nucleation and linear growth of nuclei, and 5-Processes governed by nucleation and bulk growth of nuclei.

Scaling up and extrapolation from laboratory experiments to commercial scales generally requires a kinetic model that can properly describe the effects of temperature (heating rate), pressure, residence time, and gas composition on oil yield and composition. A kinetic model that can accurately calculate yields, compositions and rate of evolution must account for the effect of pressure on shale oil evolution and evaporation and its relationship to oil cracking and coking, also known as secondary pyrolysis reactions. Secondary reactions are very important and depend not only on pressure but also on temperature and flow rate of sweep gas (residence time of liquid products). Cracking and coking have a direct impact on oil yield and compositions and on the quality of the liquid and gas products distribution. **Burnham and Singleton (1983)**[12] reported oil yield, compositions, and rate of evolution from Green River oil shale (Anvil Point mine) for heating rates from 1^{o}-$100^{o}C/h$ and pressures of 1.5 and 27 atm. They concluded that higher pressure and lower heating rates during pyrolysis cause a decrease in oil yield.

Pyrolysis of shale in fixed bed and fluidized bed reactors, postulation of oil formation mechanisms and explanations of the dependency of yield on decomposition conditions and on kinetic parameters are also reported in the literature. For example, the operation of a fluidized bed reactor for Colorado oil shale pyrolysis and the derivation of subsequent kinetic parameters were reported by **Braun and Burnham (1986)** [13].

Kerogen is classified on the basis of H/C and O/C atomic ratios (Van Krevelen diagram). The Mahogany oil shale is rich in H/C atomic ratio and falls in the type I category. A global model for the generation of oil and gas from petroleum source rocks was presented by **Braun and Burnham (1993)** [14]. This model consists of 13 chemical species and 10 reactions and incorporates alternative mechanistic pathways for type I and type II kerogens. Pyrolysis was proposed and simulated for typical geological conditions.

Commercialization of oil shale pyrolysis will not occur based only on the knowledge of kinetic parameters and of a mechanism/model of product formation. Other physical (permeability, porosity, density, etc.) and chemical properties (pour point, composition distribution, heat of reaction) of raw shale, products, and spent shale are also needed to accurately predict and control both the product distribution yields and the mass and energy balances. **Muehlbaur and Burnham (1984)** [15] derived simple equations for estimating the heat of combustion of raw shale using thermo-chemical estimates and linear regression of experimental data. They found that the heat of combustion can be reasonably estimated with an exothermic term that accounts for the combustion of organic matter and a constant that accounts for pyrite combustion, carbonate decomposition, and glass formation. They reported a mean value of 5209 kJ/kg for the heat of combustion of raw Green River oil shale.

Because oil shales have differing origins and geological environments, resulting in differing compositions (H/C ratio, organic content, and mineral matter composition), it is not surprising that they behave differently when subjected to pyrolysis conditions. **Torrente and Galan (2001)** [16] pyrolyzed Spanish oil shale (Puetrollano) using different particle size distributions. They did not observe significant effects of heat and mass transport on the kinetic parameters. The activation energies reported for isothermal and non-isothermal kinetic analyses were 150 kJ/mol and 167 kJ/mol respectively. Similarly, **Shyuan and Changtao (2003)**[17-18] and **Qian et al. (2007)** [19] performed pyrolysis experiments with different Chinese oil shales and concluded that the rate of thermal decomposition could be one or two stages depending on the type of oil shale. Similar conclusions were reported for a Pakistani oil shale by **Williams and Ahmad (1999)** [20] and for a Jordanian oil shale by **Jaber and Probert (2000)** [21].

In this study, kinetic data from Mahogany oil shale are obtained using TGA. We report isothermal (300^o-600^{o}C) and non-isothermal (0.5^o- 50^{o}C/min) decompositions of crushed Mahogany Oil Shale (crushed to 100 mesh) with TGA in N_2 (pyrolysis) and air (combustion) environments. Data obtained from TGA experiments are analyzed in detail. Different mathematical approaches for both isothermal and non-isothermal cases are used to determine the kinetic parameters (activation energy, E_a and the pre-exponential factor, A) with the assumption of first order reaction. For isothermal experiments, the data are fit using the integral method; for non-isothermal analyses, kinetic data are derived using four different methods, namely, a direct Arrhenius plot, the integral method, the Friedman approach and the maximum rate method. The quality of the fit when using the first order assumption and values of the kinetic parameters differ depending on the mathematical method employed. In this report, results from several samples are covered in detail. The tradeoff between E_a and A is also considered. To analyze the product compositions at different temperatures, experiments were performed with cylindrical cores with N_2 as sweep gas. The liquid product (condensed vapor) obtained was analyzed using gas chromatography to identify the oil compositions and concentrations.

This study differs from the earlier Mahogany oil shale work of Burnham and various collaborators in several important ways. First, these earlier researchers did not obtain TGA data over such a wide range of operating conditions. Second, specific Mahogany oil shale data is generated in this study with the intent of using it for scaleup in the next phase of the project. Data on the kinetics of combustion over a wide range of operating conditions is also a new contribution from this work.

Experimental Procedure

Thermo Gravimetric Analysis (TGA)

Mahogany oil shale was crushed and screened to 100 mesh-size particles and then dried for four hours to remove any moisture (there was no significant weight loss during drying). To study the reaction kinetics, a TGA instrument (TA Instruments Q-500) was used for the entire temperature range of kerogen decomposition in both N_2 (pyrolysis) and air (combustion) environments. TGA experiments for both isothermal (300^o-600^{o}C) and non-isothermal (0.5^o - 50^{o}C/min) decomposition of the crushed and dried oil shale samples (20-30 mg) were performed. For the pyrolysis experiments, the flow rate of N_2 was kept constant at 60 ml/min as was the purging time. For the combustion experiments, the TGA setup was identical with the exception that the purge gas was switched from N_2 to air. The size of the particles used along with other conditions employed were specifically designed to eliminate heat and mass transfer effects during pyrolysis. For isothermal experiments (Tables 1 and 2), the thermal induction time period (time to heat the shale from ambient temperature to the actual retorting temperature) was kept as low as possible by employing heating rates of 100^{o}C/min, which was the maximum allowable rate in the instrument. The total time for the isothermal experiments was five hours. The thermal induction period under different isothermal conditions, is listed in Tables 1 and 2. Decomposition of the organic matter during the induction period was not considered, but a correction factor (explained below) is used to eliminate induction effects.

Table 1. Isothermal TGA data for N_2 environment (pyrolysis) and data analysis using the integral method.

Temp	*Time*	*Initial weight*	*Isothermal condition*		*Correc-tion factor*	<u>*Integral Method*</u>			
^{o}C	*min*	*mg*	*time min*	*wt loss %*	*X*	*1/T kelvin*	*R^2*	*K*	*lnK*
300	720	26.75	3.33	0.83	0.091	0.0017	0.51	0.009	-7.13
350	240	26.69	3.82	1.25	0.087	0.0016	0.88	0.005	-5.40
400	240	22.64	4.36	1.79	0.082	0.0015	0.96	0.031	-3.47
450	240	24.68	4.96	3.99	0.060	0.0014	0.81	0.297	-1.21
500*	240	25.00	5.59	10.71					
550*	180	23.95	6.3	11.62					
600*	30	24.10	6.96	12.11					

*Isothermal analyses cannot be performed at these temperatures, since most of the organic material decomposes before this temperature is attained

Table 2. Isothermal TGA data for air environment (combustion) and data analysis using the integral method.

Temp	*Total time*	*Initial weight*	*Isothermal condition*		*Corre-ction factor*	<u>*Integral Method*</u>			
^oC	min	mg	time min	wt loss %	*X*	1/T *kelvin*	R^2	K	lnK
300	240	23.64	2.70	0.73	0.093	0.0017	0.87	0.036	-3.31
350	240	23.39	3.82	1.86	0.081	0.0016	0.87	0.191	-1.65
400	240	23.24	4.31	3.15	0.068	0.0015	0.84	0.873	-0.14
450	180	32.16	4.88	5.68	0.043	0.0014	0.86	2.801	1.03

The non-isothermal experiments (Tables 3 and 4) were performed to 1000^{o}C, the highest temperature possible in the instrument. The mass and temperature measurements in the instrument were calibrated. Excellent reproducibility was observed in the mass loss curves as shown in Figure 1. The combustion experiments were performed with the same TGA set up with N_2 as purge gas for the first five minutes followed by air for the rest of the experiment.

Figure - 1: Thermogravimetric analysis (TGA) of Green River oil shale. This analysis was performed to ensure reproducibility.

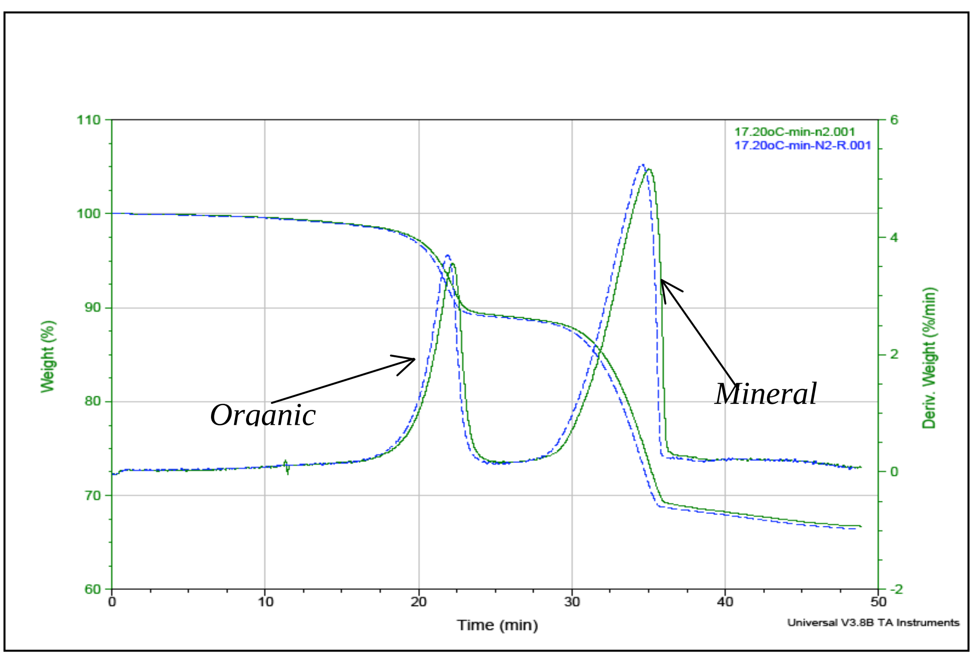


Table 3. Analysis of the non-isothermal TGA pyrolysis data using the differential method.

Heating rate	*Initial wt*	*Analysis Criteria* *Start*		*End*		*Maximum*		*Differential Method*				
β	*mg*	*T* *°C*	*wt % Loss*	*T* *°C*	*wt % Loss*	T_{max}, *°C*	*wt % Loss*	R^2	*slope*	*Intercept*	E_a *kJ/mol*	*A* min^{-1}
0.5	22.64	255.6	1.32	421.6	8.02	392.7	6.48	0.96	9351	10.8	77.74	24510
1	28.64	269.6	1.16	437.6	7.48	398.3	5.79	0.95	9002	10.07	74.84	23624
2	26.90	280.0	1.33	456.4	8.43	414.1	6.52	0.96	10379	11.8	86.29	266505
5	25.97	348.9	2.17	474	9.41	432.2	7.17	0.97	14873	17.93	123.65	3E+08
10	38.45	349.7	1.74	490	9.67	445.6	7.26	0.97	14905	17.54	123.92	4E+08
20	29.49	371.6	1.58	504	10.68	460.1	7.92	0.97	17757	21.00	147.63	3E+10
50	22.37	377.3	1.43	530.6	11.13	477.0	7.89	0.96	17218	19.56	143.15	2E+10

Table 4. Non-isothermal TGA data for air environment (combustion) - Two peaks.

Heating rate	*Initial weight*	*First Peak* *Start*		*End*		*Maximum*		*Second Peak* *End*		*Maximum*		*weight loss*
β	*mg*	*T* *°C*	*wt % Loss*	*T* *°C*	*wt % Loss*	T_{max} *°C*	*wt % Loss*	*T* *°C*	*wt % Loss*	T_{max} *°C*	*wt % Loss*	*%*
0.5	18.68	179	0.67	311.3	8.16	279.9	5.20	396.4	12.91	340.2	10.80	12.91
1	20.26	199.1	0.59	323.8	7.95	294.1	5.29	400.3	13.02	354.4	10.74	13.02
2	19.98	201.9	0.49	339.1	7.56	305.9	4.80	421.5	12.29	367.1	9.93	12.29
5	30.56	211.4	0.44	358.5	7.46	323.8	4.68	459.6	12.72	392.2	10.13	12.72
10	34.98	216.5	0.02	374.9	7.69	337.1	4.82	499.4	13.13	409.5	10.18	13.13
20	21.69	215.5	0.38	389.2	7.58	341.1	4.10	504.6	13.07	425.9	10.13	13.07
50	30.22	227.7	0.42	395.3	6.81	351.4	4.03	522.9	13.03	450.4	10.20	13.03

Pyrolysis of Cylindrical Oil Shale Core Samples

The production of oil from shale by thermal decomposition is a complex process. The numerous chemical compounds in the kerogen and the sequence of pyrolysis reactions (parallel and series reactions) that occur during decomposition are unknown. Hence, the formulation of a set of equations for the rate of decomposition that covers all simultaneously occurring reactions is a difficult task. There is a possibility that finite heat and mass transfer rates may affect the observed or global rate. In our preliminary work, we used cylindrical core samples (3/4” diameter and 9” long) of the Mahogany oil shale (similar to those used for TGA analyses). Pyrolysis experiments were performed with a 55 ml/min flow rate of N_2 under isothermal conditions (300^o-400^{o}C with a 100^{o}C/min ramp rate during the induction period). A schematic diagram of the experimental setup used is shown in Figure 2. The duration of the experiments was 24 hours (Table 5). A few experiments were repeated to assess reproducibility. The vapor condensate (yield of shale oil) was collected in condensers (two condensers in series at -6^{o}C).

Figure – 2: Schematic diagram of the pyrolysis experimental setup for core samples.

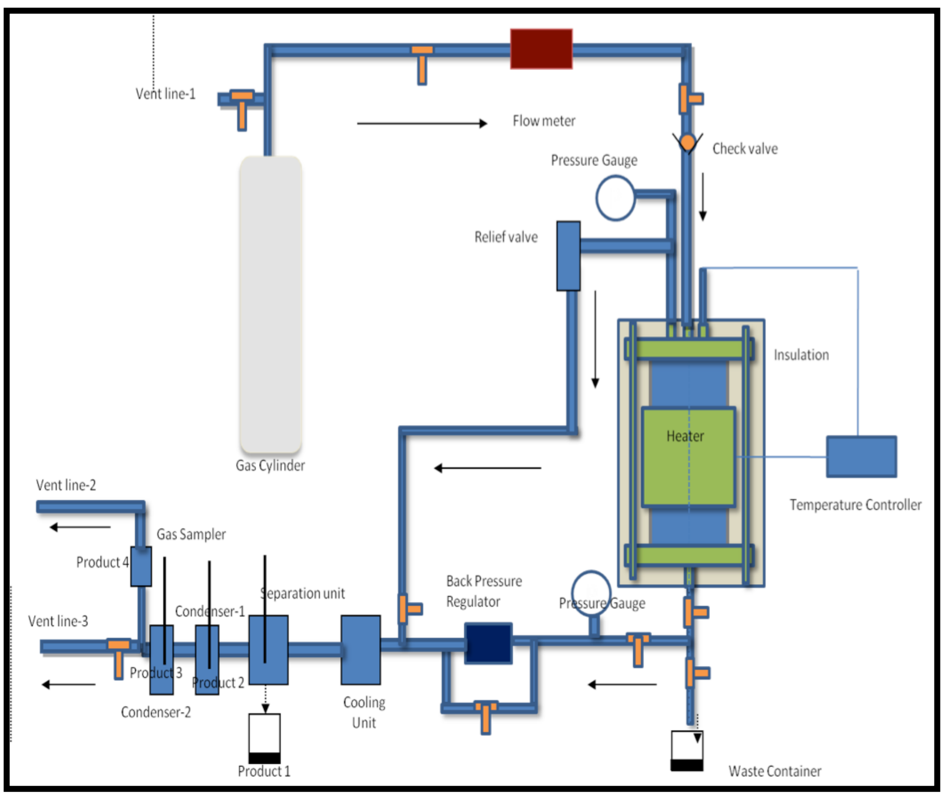


Table 5. Experimental conditions and yield information for core samples pyrolysis.

Expt no	*Temperature ^{o}C*	*Oil Shale weight gm*	*Spent shale weight gm*	*Weight loss %*	*Shale oil (Yield) %*
		Experiment with Swagelok Reactor			
1	$300^{o}C$	51.36	46.17	10.11	6.56
2	$350^{o}C$	47.44	40.8	14.00	6.74
3	$400^{o}C$	58.12	45.38	21.92	10.28
4	$300^{o}C$	57.76	53.65	7.12	5.67
5	$350^{o}C$	55.41	48.42	12.62	4.83
6	$400^{o}C$	52.47	44.71	14.79	6.97
7*	$400^{o}C$	31.5322	26.04	17.42	11.91
8	$200^{o}C$	33.57	33.60	No oil generation (7 days)	
		Experiment with Tube Reactor			
9§	$450^{o}C$	250.08	205.00	18.02	8.31

*Equilibrate at $130^{o}C$ then used $1^{o}C$/min ramp rate to reach $400^{o}C$ and hold for 24 hr at $400^{o}C$

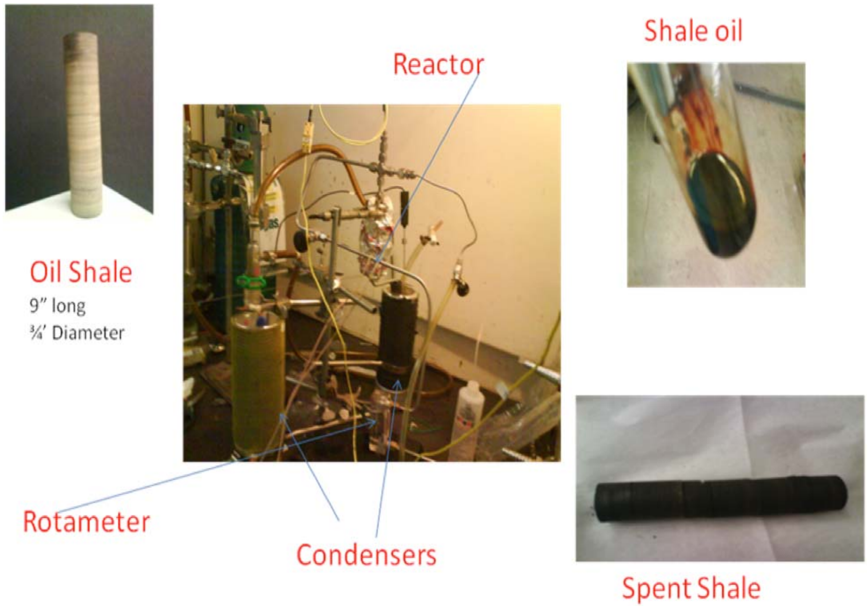
§Other identity used for this sample is -4th Expt- (chunk big pieces of oil shale were used)

Table 6. Gas chromatography (Agilent GC -6890) operating conditions (ASTM -5307).

<table>
<tr><td rowspan="3">Cool on Column GC-6890</td><td>Oven</td><td>$40^{o}C$ Initial temp</td><td>$10^{o}C$/min ramp rate</td><td>$410^{o}C$ Final temp</td><td>10 min hold</td></tr>
<tr><td>Column</td><td>1ml/min He flow rate</td><td colspan="2">Inlet - Tracked oven typed</td><td>10 Psia</td></tr>
<tr><td>Detector</td><td>FID</td><td>40 ml/min H_2 flow rate</td><td>450 ml/min Air flow rate</td><td>$350^{o}C$ Detector temp</td></tr>
</table>

Photographs of the reactor, the raw sample, the shale oil, and the spent shale are seen in Figure 3. The shale oil product was analyzed by gas chromatography (GC-6890 Agilent) to quantify the hydrocarbon compositions. The ASTM-5307 procedure with minor modifications was followed. The operating conditions of the GC (cool on-column injection) are shown in Table 6. The ASTM standard of normal alkanes (C_{12}- C_{60}) was used to perform the simulation distillation analysis (SIMDIS).

Figure – 3: Images of the small reactor section, raw sample and products.



Kinetic Expression- Mathematical Models

There are two modes where kinetic parameters can be conveniently derived, isothermal (constant temperature), and linear heating (constant heating rate, non-isothermal). Since the chemical structure of kerogen is complex and not well established, rates of thermal decomposition have been interpreted by simple overall reactions. It was noted in the earlier literature survey that kerogen is a cross-linked, high molecular weight solid. During pyrolysis, bonds are broken, leading to bitumen formation; this bitumen subsequently decomposes to products. However, in this TGA study, only one peak was observed in the organic decomposition temperature range for the N_2 environment in both isothermal and non-isothermal cases (Figures 4 and 5). Consequently, a single stage decomposition was assumed in deriving kinetic rate expressions.

Figure -4: Isothermal TGA curves in the N_2 environment (pyrolysis). Weight loss increases and the maximum rate shifts to higher temperatures as temperatures increase.

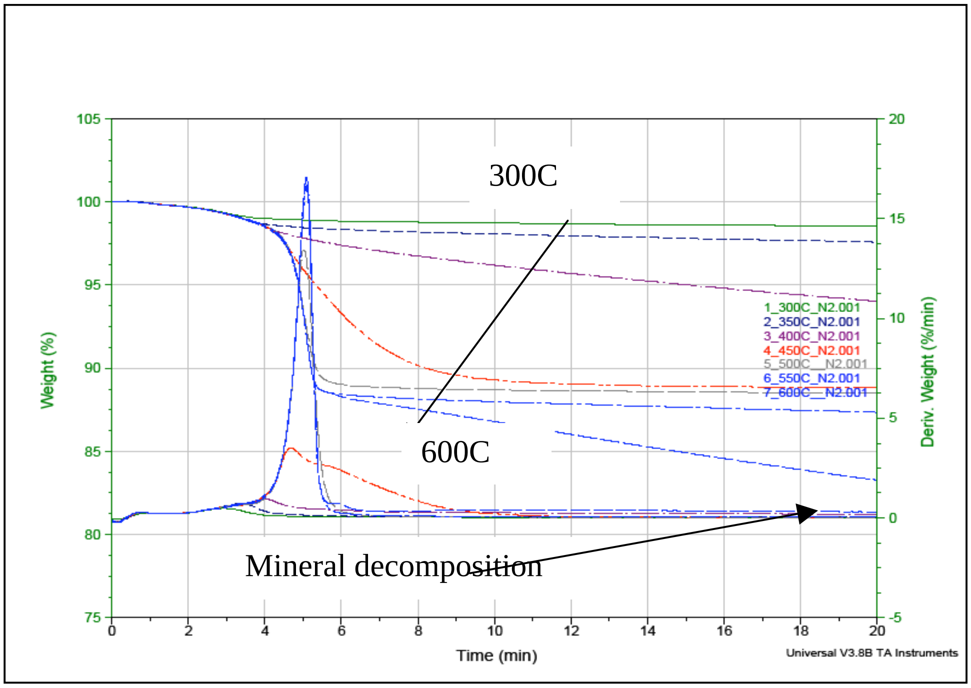
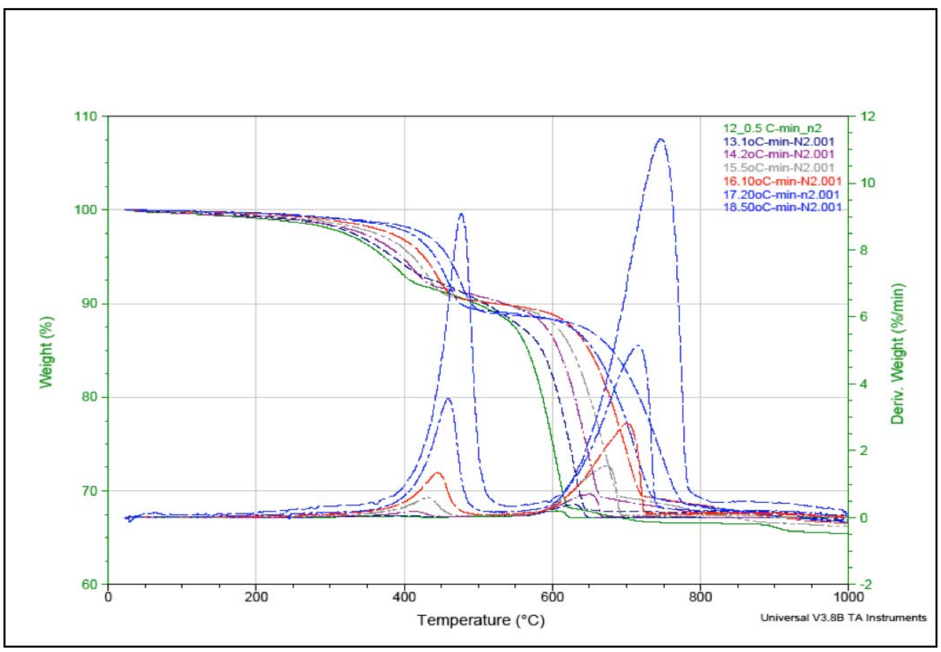


Figure - 5: Non-isothermal TGA pyrolysis curves. Rates go from 0.5°C/min to 50°C/min.



In contrast, for TGA experiments conducted in the air environment, two peaks were detected in organic decomposition temperature regions for all isothermal and non-isothermal experiments, (Figures 6 and 7). Thus, both the single stage and two stage decomposition mechanisms were examined in deriving the combustion kinetic parameters.

Figure -6: Isothermal TGA curves in air environment (combustion).

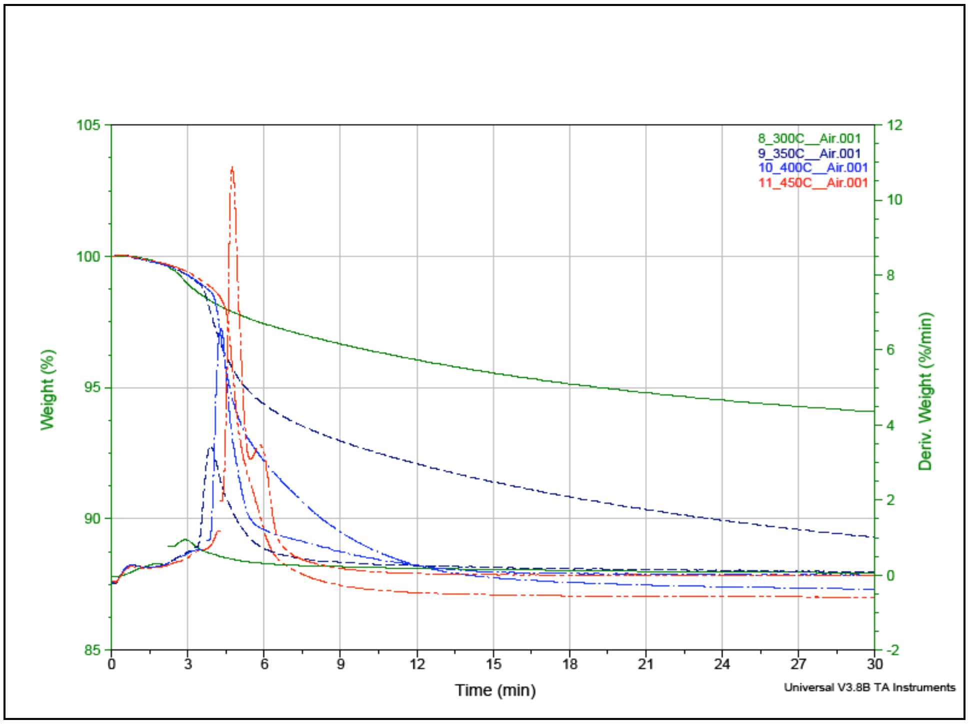
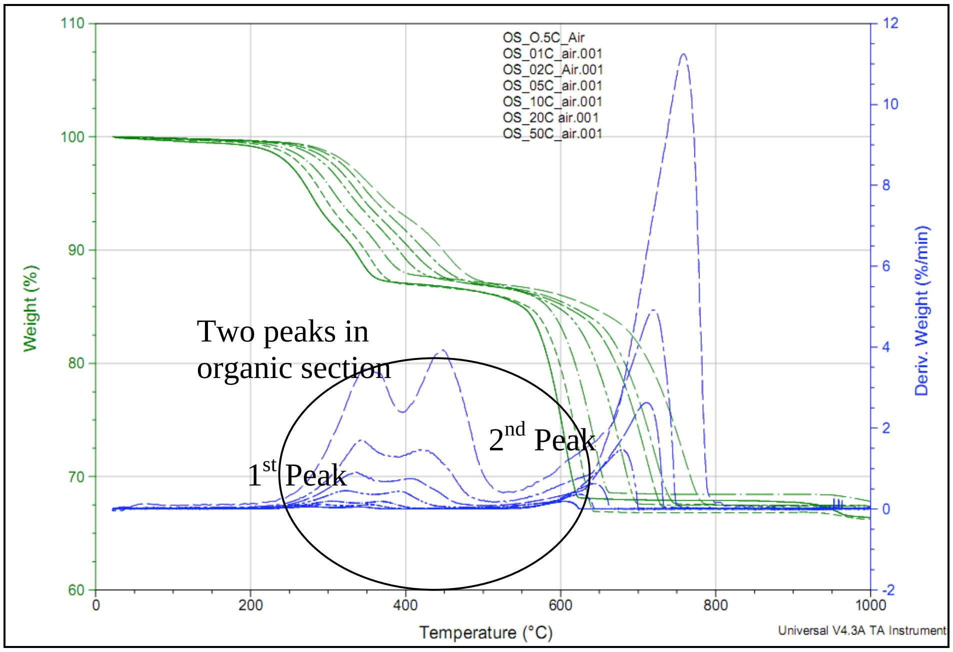


Figure -7: Non-isothermal TGA combustion curves. Rates go from 0.5°C/min to 50°C/min.



The simple mechanism for the organic decomposition of kerogen to oil shale is

$$\text{Kerogen} \longrightarrow \text{Products}$$

For the pyrolysis data, a single step mechanism with a first order reaction model was used in the analysis. For the combustion (air) data, a reaction model consisting of two successive first order (series) reactions was used to analyze the data. The reaction was assumed to be of the form

$$\text{Kerogen} \longrightarrow \text{Bitumen} \longrightarrow \text{Products}$$

with bitumen representing all the intermediate products.

As some earlier test experiments with TGA (up to 1000°C) indicated, 10-12 wt % of the oil shale was organic. Thus, all the isothermal data were normalized on the basis of the presence of 10 wt/wt % of shale being kerogen. The conversion of kerogen to product is defined as,

$$\alpha = \frac{W_0 - W_t}{W_0 - W_\infty} \tag{1-a}$$

or $$\alpha = \frac{W_0 - W_t}{W_0 \cdot X} \tag{1-b}$$

where,

W_0 = Initial weight of the sample (mg),

W_t = Weight of the sample at time t (mg),

W_∞ = Weight of the sample at the end of the experiment (mg),

X = Percent of the organic matter decomposing over the experimental period. This is a correction factor which deducts the amount decomposed during the thermal induction time and considers weight loss as a function of the total potential organic loss.

The conversions for the isothermal experiments in both pyrolysis and combustion were calculated using equation (1-a) and the values of the correction factors applied are shown in Tables 1 and 2. The correction factor was calculated based on the assumption of 10% of the organic material in the oil shale samples. Equation (1-b) was used for the calculation of non-isothermal conversions based on the start and end criteria for weight losses (Tables 3 and 4).

Assuming first order reaction, the rate law model equation can be combined with an Arrhenius dependency on temperature, leading to the general expression for the decomposition of a solid given by **Blazek (1973)**[22].

$$\frac{d\alpha}{dt} = A \cdot \exp\left[\frac{-E_a}{R \cdot T}\right] \cdot (1 - \alpha) \tag{2}$$

where,

A = Frequency (pre-exponential) factor (min^{-1}),

E_a = Activation energy ($kJ \cdot mol^{-1}$),

R = Gas constant (8.314 kJ·mol $^{-1}$·K^{-1}),

T = Temperature (K).

In the analysis of the data from the isothermal experiments, the value of X, the correction factor for thermal induction, is not fixed. Non-isothermal TGA offers certain advantages over the classical isothermal method because it eliminates the errors introduced by the thermal induction period. Non-isothermal analysis also permits a rapid scan of the whole temperature range of interest.

Isothermal Analysis

- **Integral method**

The integral form of equation (2) can be written as

$$\ln(1-\alpha) = -k \cdot (t - t_0) \qquad (3)$$

where k is the specific rate constant and t_o is the time at the start of the constant-temperature period (when the isothermal condition reached). In this study, the thermal induction period is eliminated from the kinetic analysis. Correspondingly, the W_∞ is corrected by X. The normalized conversions versus time curves are shown in Figures 8 and 9.

Figure - 8: Normalized conversion in isothermal TGA experiments for N_2 environment (pyrolysis).

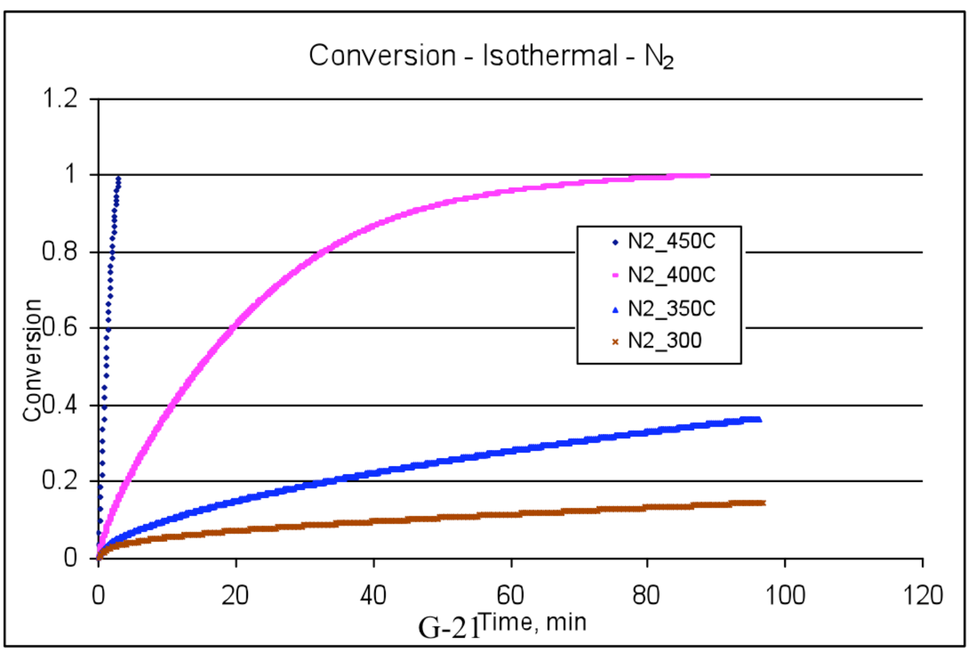
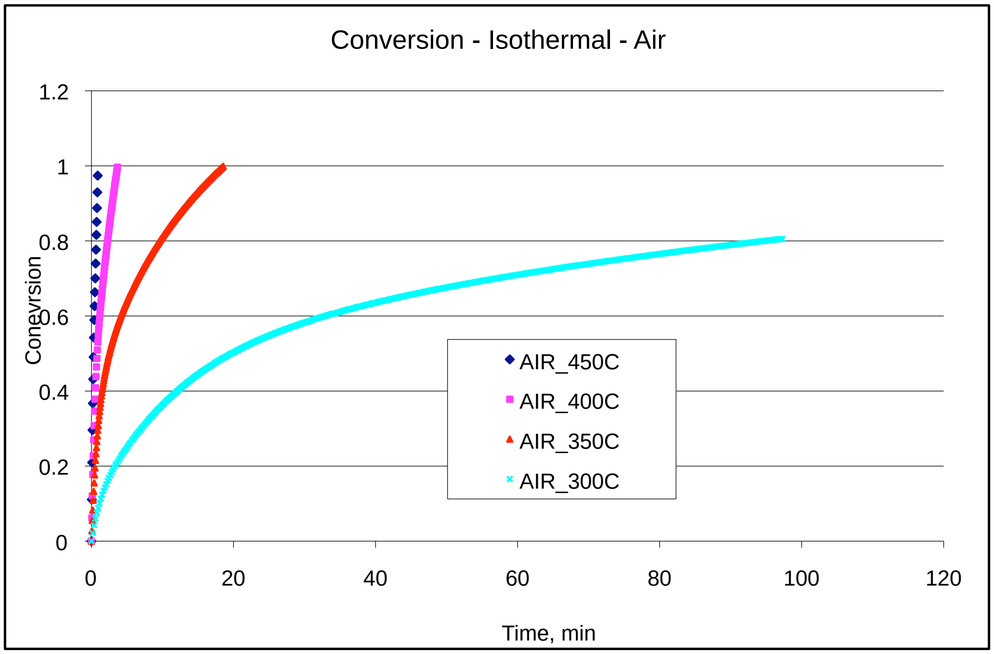


Figure - 9: Normalized conversion in isothermal TGA experiments for air environment (combustion).



Application of the integral method to the isothermal data (Figures 10 and 11) and the corresponding Arrhenius plots (Figures 12 and 13) can be used to obtain frequency factors and activation energies. The plots shown are for both the pyrolysis (N_2), and combustion (air) experiments.

Figure - 10: Analysis of kinetic data using the integral method for 1st order isothermal TGA pyrolysis experiments.

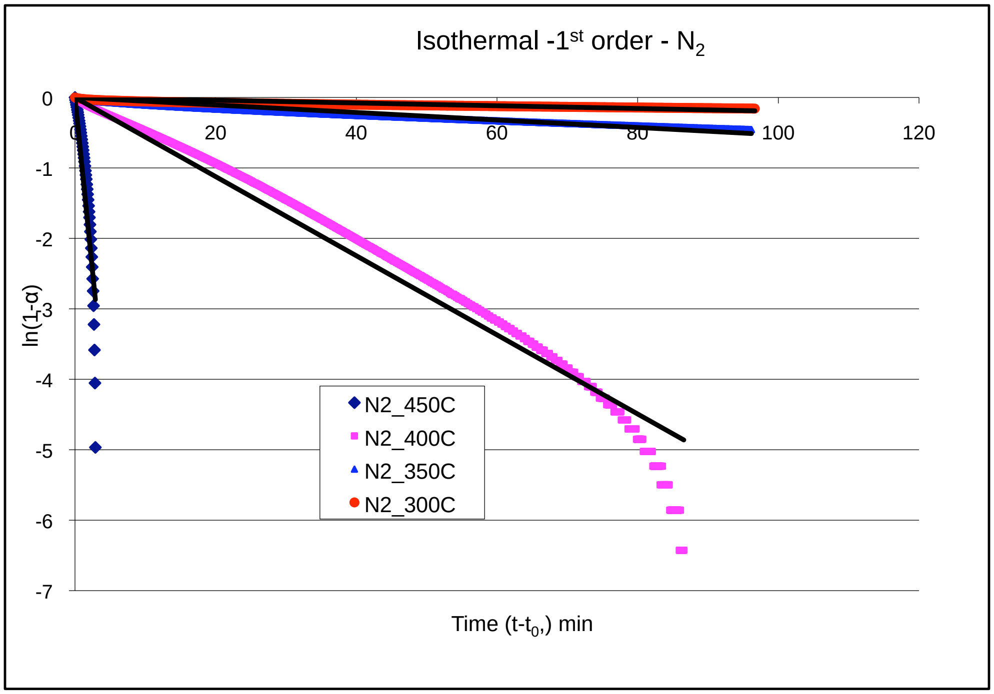


Figure - 11: Analysis of kinetic data using the integral method for 1st order isothermal TGA combustion experiments.

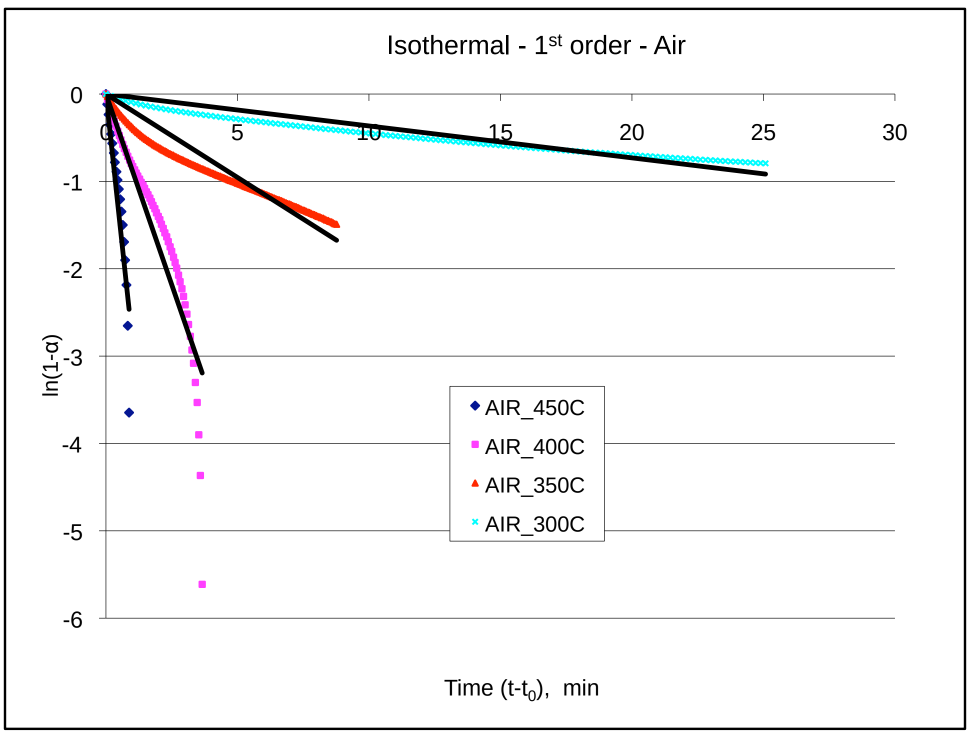


Figure- 12: Arrhenius plot for 1st order isothermal TGA pyrolysis experiments: (E_a = 134.77 kJ/mol and A = 1.2E+09 min^{-1}).

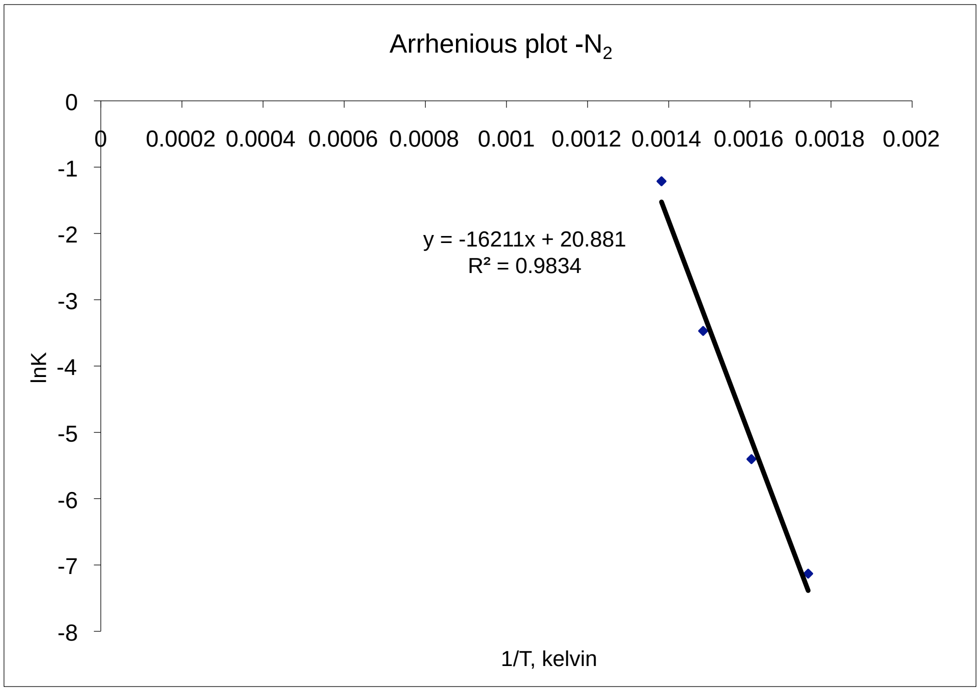
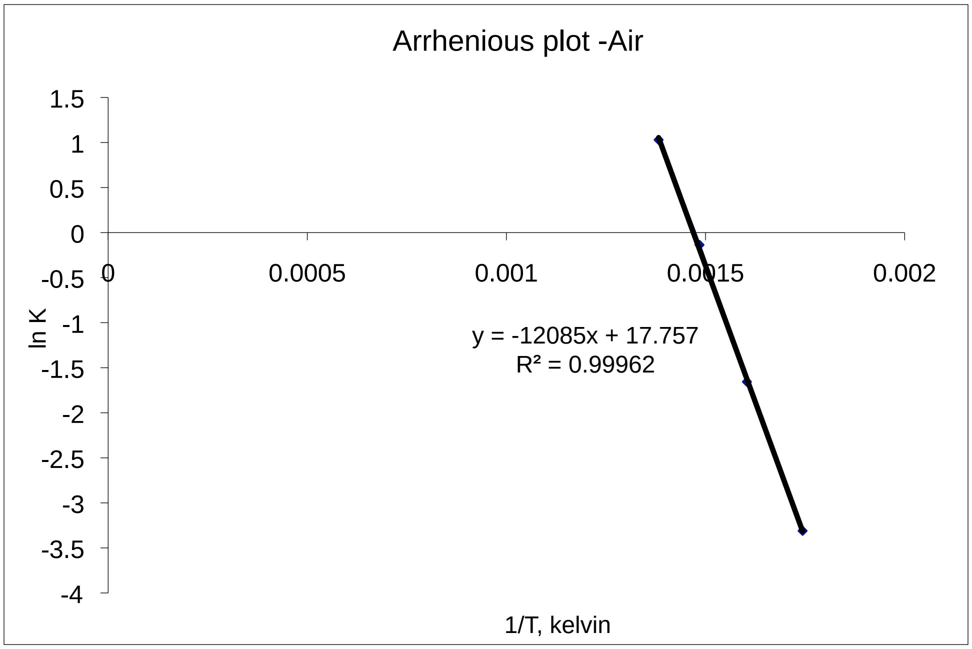


Figure - 13: Arrhenius plot for 1st order isothermal TGA combustion experiments: (E_a = 100.47 kJ/mol and A = 5.1E+07 min^{-1}).



Non-isothermal Analysis

The non-isothermal TGA curves for N_2 and air environments are shown in Figures 5 and 7. The experimental conditions and analysis criteria to obtain kinetic parameters such as start time, maximum point, and end point are summarized in Tables 3 and 4. On the basis of criteria chosen for the analysis, the conversion data were normalized from zero to one with respect to temperature (Figures 14 and 15). A single step mechanism is applied to the pyrolysis data while both single step and two step mechanisms are evaluated for the kinetics of combustion.

Figure - 14: Normalized conversion for non-isothermal TGA pyrolysis data.

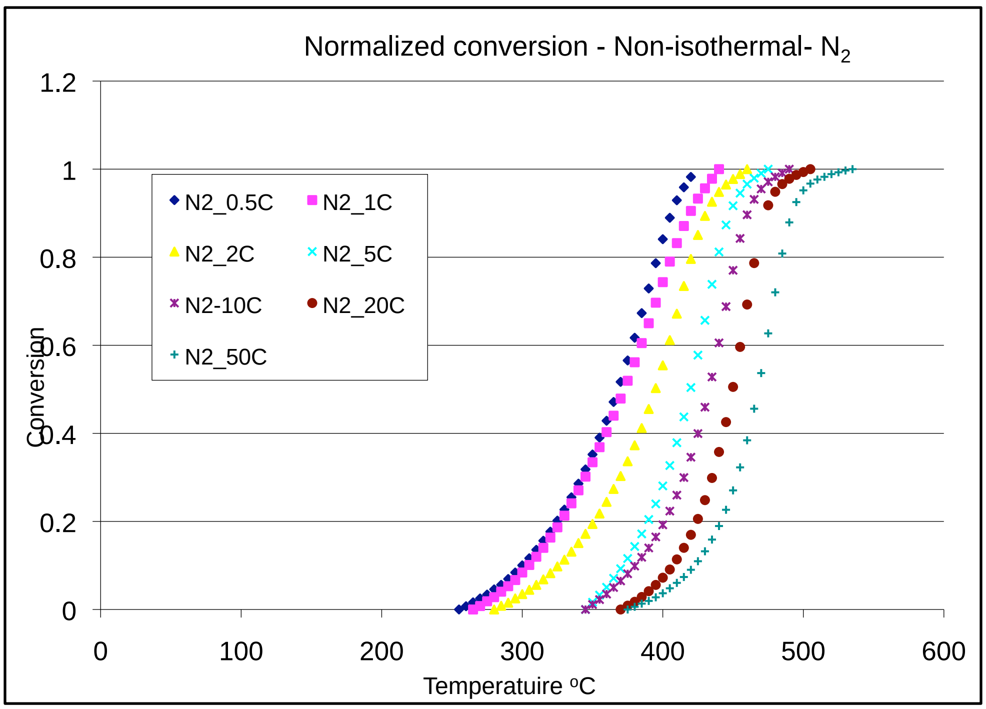
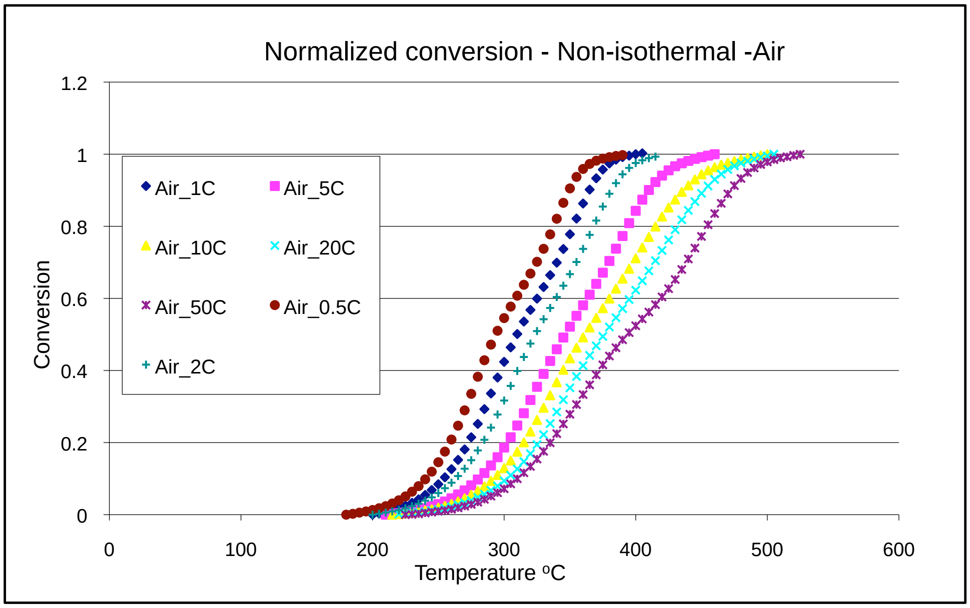


Figure - 15: Normalized conversion for non-isothermal TGA combustion data.



-Differential (Direct Arrhenius plot) method

The kinetic rate expression for non-isothermal experiments with Arrhenius dependency can be derived by introducing a heating rate (β) in equation (2)

$$\frac{d\alpha}{dT} = \frac{A}{\beta} \cdot \exp\left[\frac{-E_a}{R \cdot T}\right] \cdot (1-\alpha) \tag{4-a}$$

where $\beta = \frac{dT}{dt}$.

Rearranging the above equation yields,

$$\ln\left[\frac{1}{(1-\alpha)}\right] \cdot \frac{d\alpha}{dT} = \ln\left[\frac{A}{\beta}\right] - \left[\frac{-E_a}{R \cdot T}\right] \tag{4-b}$$

If the model is correct, the plot of $\ln\left[\frac{1}{(1-\alpha)}\right]\frac{d\alpha}{dT}$ versus 1/T should be a straight line, and values of E_a and A can be obtained from this line.

Figure 16 and Table 3 show the kinetic information obtained for N_2 data from this method. Once again, the air environment data are fit to both the single step (Figure 17 and Table 7) and two step mechanisms (Figures 18 and Table 8).

Figure - 16: Analysis of non-isothermal TGA pyrolysis data using the differential method.

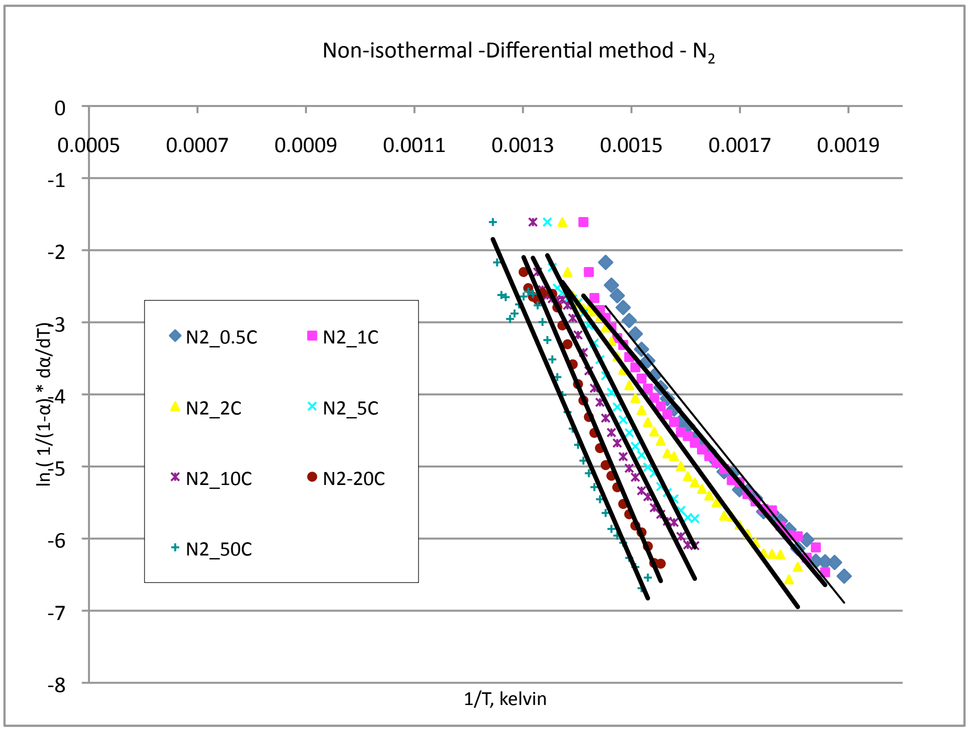


Table 7. Analysis of the non-isothermal combustion data assuming a single step mechanism using the differential method.

β	R^2	*slope*	*Intercept*	E_a	*A*	*lnA*
°C/min				*kJ/mol*	min^{-1}	
0.5	0.97	7548	9.18	62.76	4876	8.49
1	0.97	7985	9.65	66.38	15553	9.65
2	0.98	7738	8.84	64.34	13850	9.53
5	0.98	7576	7.98	62.99	14692	9.59
10	0.97	6981	6.56	58.04	7107	8.86
20	0.97	7331	6.90	60.95	19935	9.90
50	0.96	7254	6.49	60.31	33201	10.41

Figure - 17: Analysis of non-isothermal TGA combustion data (single-step) using the differential method.

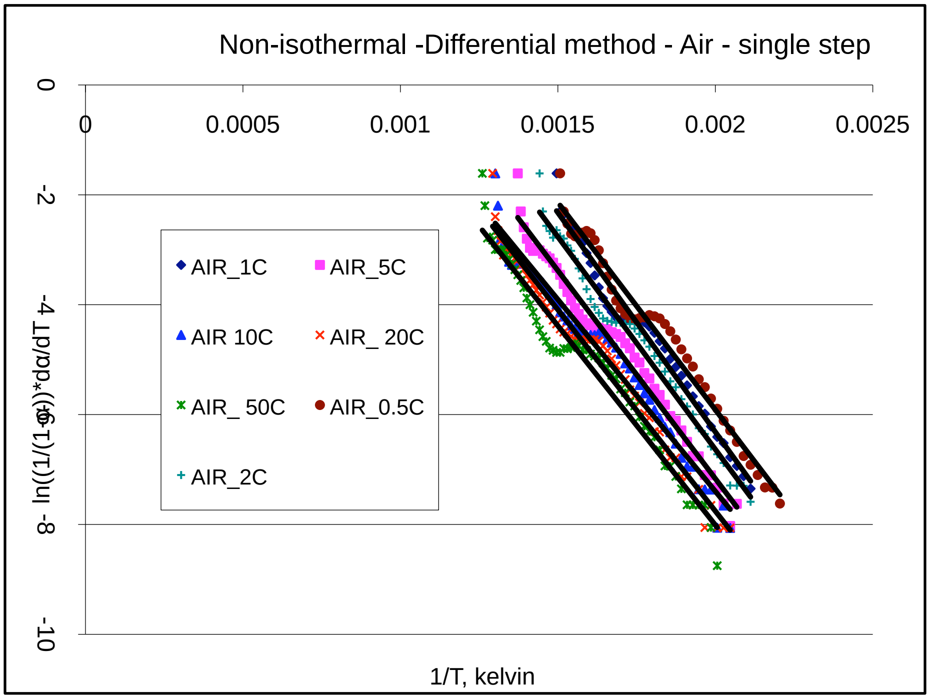
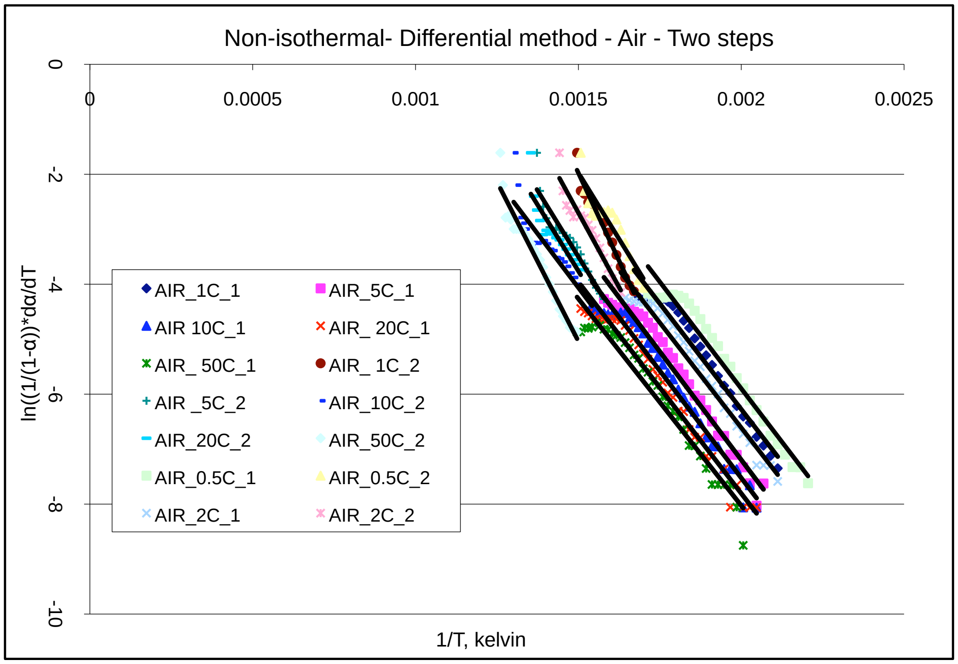


Table 8. Analysis of the non-isothermal combustion data assuming a two-step mechanism using the differential method.

	First peak area					*Second peak area*				
β	R^2	*slope*	*I**	E_a	*A*	R^2	*slope*	*I**	E_a	*A*
$^oC/min$				*kJ/mol*	min^{-1}				*kJ/mol*	min^{-1}
0.5	0.96	7762	9.62	64.53	7581	0.87	9639	12.48	80.14	1E+05
1	0.96	7690	9.10	63.93	8997	0.97	12220	17.11	101.6	3E+07
2	0.97	7641	8.67	63.52	11668	0.93	10835	13.35	90.08	1E+06
5	0.97	7875	8.55	65.46	25958	0.9	9617	10.92	79.95	3E+05
10	0.96	7797	8.06	64.82	31958	0.85	7842	7.69	65.19	22064
20	0.96	7695	7.58	63.97	39353	0.79	9615	10.66	79.94	9E+05
50	0.94	7525	7.02	62.56	56107	0.95	11607	12.37	96.50	1E+07

* I - intercept

Figure - 18: Analysis of non-isothermal TGA combustion data (two-step) using the differential method.



- Integral method

The non-isothermal kinetic equation (Equation 2) can be separated in terms of overall conversion and temperature for a specific constant heating rate (β) and constant frequency (pre-exponential) factor.

$$\int_0^{\alpha} \frac{d\alpha}{(1-\alpha)} = \frac{A}{\beta} \cdot \int_{T_\circ}^{T} \exp\left[\frac{-E_a}{R \cdot T}\right] dT \tag{5}$$

Equation 5 can be rearranged as,

$$\ln\left[\frac{-\beta \cdot \ln(1-\alpha)}{R \cdot T^2}\right] - \ln\left[1 - \frac{2R \cdot T}{E_a}\right] = \ln\left[\frac{A}{E_a}\right] - \left[\frac{-E_a}{R \cdot T}\right] \tag{6-a}$$

This approach was developed by **Chen and Nuttall (1979)**.[23] The value of E_a and A can be obtained by repeated least square fits of the equation to the experimental data. First, by using an approximate value of E_a on left hand side of the equation as a linear function of 1/T, $-E_a$/R and A/E_a are calculated using the slope and intercept of the resulting line. The value of E_a thus obtained is used successively on the left hand side until no more improvement in the value of E_a is achieved. A simpler form of the integral method, known as the **Coats and Redfern (1964)** [24] method, can be used for the same equation but does not require any iteration.

$$\ln\left[\frac{-\ln(1-\alpha)}{T^2}\right] = \ln\left[\frac{A \cdot R}{E_a \cdot \beta}\right] - \left[\frac{-E_a}{R \cdot T}\right] \tag{6-b}$$

If the model is correct, fitting the conversion data along with temperature versus 1/T, as shown in the left hand side function of the above equation, results in a straight line from which E_a and A can be obtained for different heating rates.

The Coats and Redfern method was adapted to analyze the TGA data in both environments. Non-isothermal kinetic data for N_2 are shown in Figure 19 and Table 9. A single step mechanism (Figure 20 and Table 10) and a two step mechanism (Figure 21 and Table 11) are used to fit the air data.

Table 9. Kinetic parameters using the integral method for the analysis of the pyrolysis data.

β	R^2	*slope*	*Intercept*	E_a *kJ/mol*	*A ,min*$^{-1}$
0.5	0.98	10837	3.71	90.09	222253.59
1	0.97	10708	3.30	89.02	290903.36
2	0.98	11818	4.46	98.25	2044218.8
5	0.99	18441	13.2	153.31	4.982E+10
10	0.99	17276	11.08	143.63	1.121E+10
20	0.99	22780	18.02	189.39	3.052E+13
50	0.99	21283	15.15	176.94	4.042E+12

Figure - 19: Analysis of non-isothermal TGA pyrolysis data using the integral method.

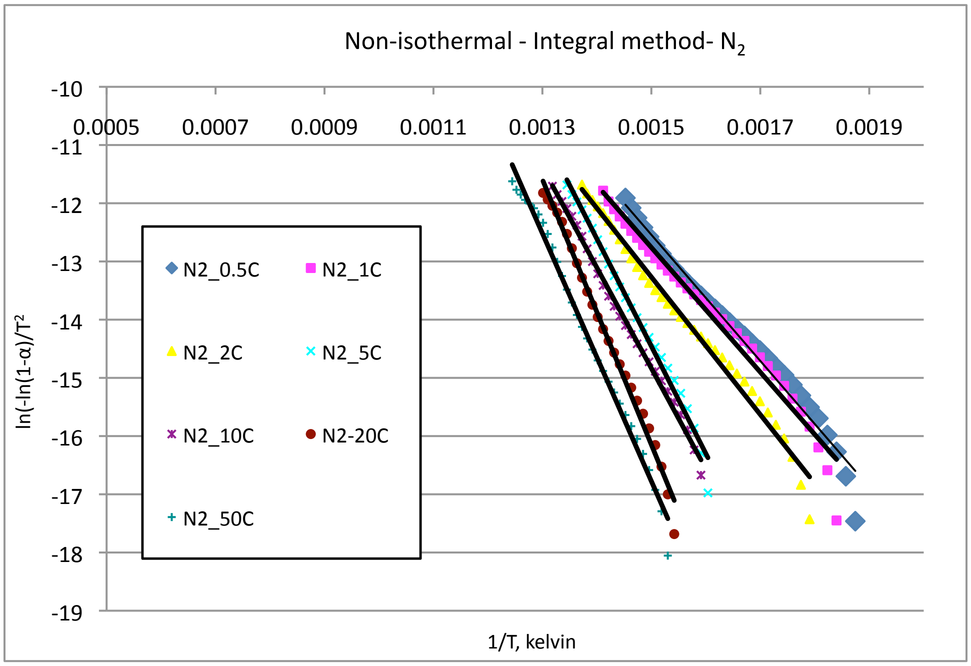


Table 10. Kinetic parameters for the non-isothermal single-stage combustion.

β	R^2	*slope*	*Intercept*	E_a, *kJ/mol*	*A*, min^{-1}
0.5	0.97	9109.9	2.75	75.73	71408.3
1	0.97	9606.4	3.17	79.86	228658
2	0.97	9311.3	2.28	77.41	182669
5	0.97	9008.3	1.10	74.89	136058
10	0.96	8463.0	-0.23	70.36	66892.6
20	0.97	8529.3	-0.39	70.91	115150
50	0.95	8514.5	-0.75	70.79	199596

Figure - 20: Analysis of non-isothermal TGA combustion data using the integral method with a single-step mechanism.

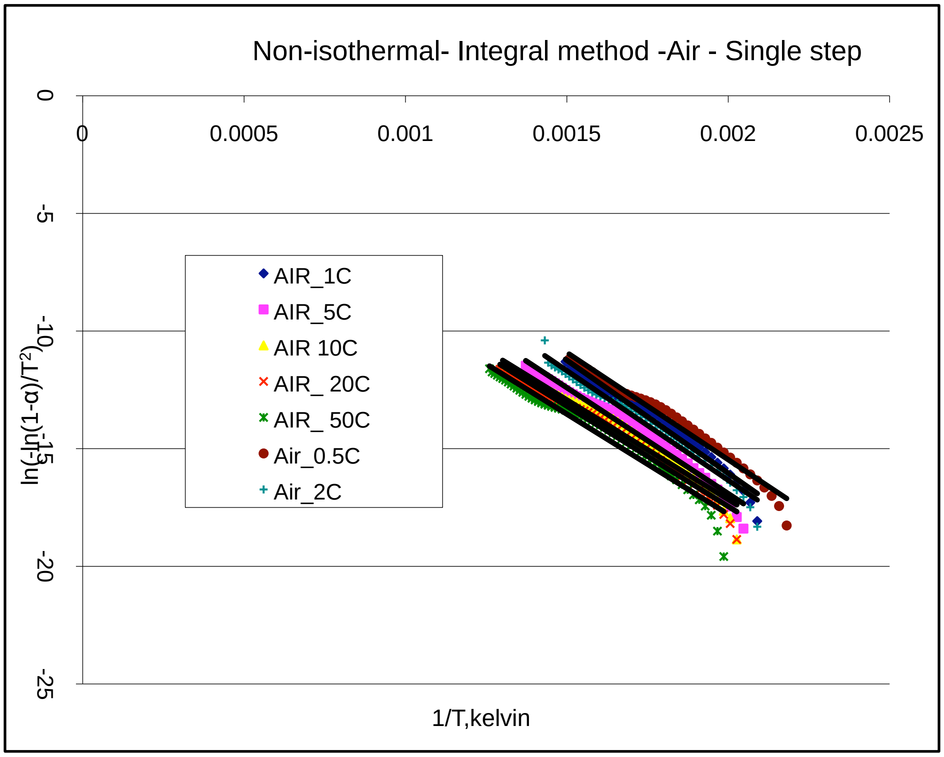
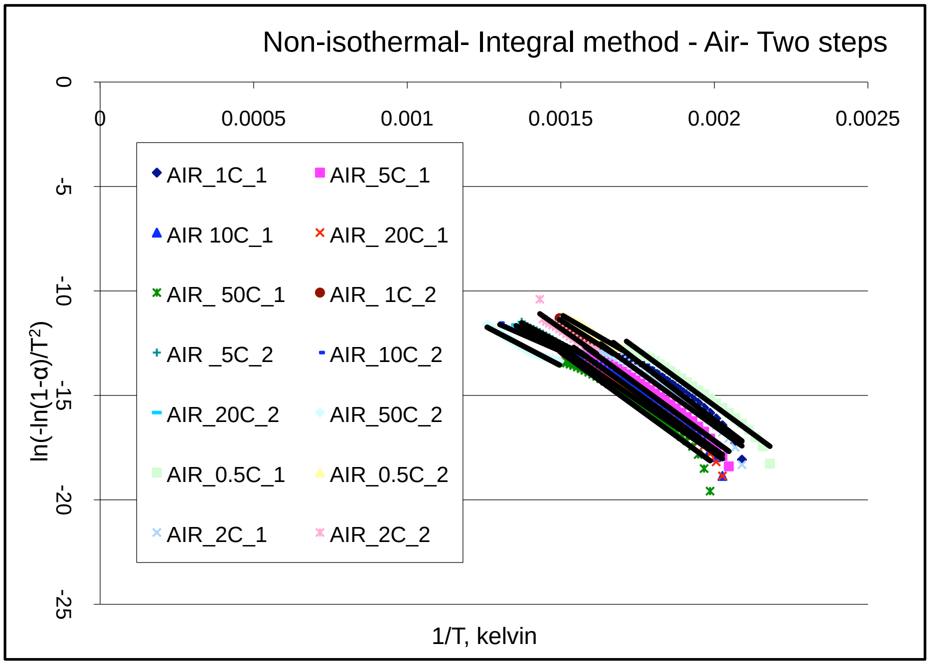


Table 11. Kinetic parameters for the non-isothermal two-stage combustion.

β	*First peak*					*Second peak*				
	slope	*I**	R^2	E_a	*A*	*slope*	*I**	R^2	E_a	*A*
0.5	10762	6.03	0.97	89.48	2E+06	8536.6	1.68	0.99	70.97	22955
1	11251	6.327	0.96	93.54	6E+06	9357.3	2.62	0.98	77.8	1E+05
2	10623	4.782	0.97	88.32	3E+06	10354	3.73	0.90	86.08	9E+05
5	10714	4.25	0.96	89.08	4E+06	7703.2	-0.95	0.99	64.04	14891
10	10612	3.65	0.97	88.23	4E+06	6410.4	-3.26	0.99	53.30	2441
20	10110	2.45	0.98	84.05	2E+06	7101.9	-2.04	0.99	59.05	18305
50	10688	3.10	0.95	88.86	1E+07	7674.0	-2.06	0.97	63.80	48544

* I - intercept

Figure - 21: Analysis of non-isothermal TGA combustion data using the integral method with a two-step mechanism.



-Friedman method

The **Friedman (1964)** [25] procedure assumes successive first order reactions and is based on the conversion data rather than on heating rates.

$$\ln\left[\frac{d\alpha}{dt}\right] = \ln[A \cdot (1-\alpha)] - \left[\frac{E_a}{R \cdot T}\right] \tag{7}$$

Non-isothermal data can be analyzed at a specific conversion point (α) for all heating rates. Then, if the data agrees with the model, the plot for $\ln(\frac{d\alpha}{dt})$ versus 1/T will give a straight line. The slope and intercept will give E_a and A respectively. The Friedman approach for TGA data is summarized in Figure 22 and Table 12 for pyrolysis and in Figure 23 and Table 13 for the combustion data.

Table 12. Kinetic parameters – distribution of activation energies as a function of conversion obtained using the Friedman approach for the pyrolysis of oil shale.

Conversion A	*Slope*	*Intercept*	R^2	E_a, *kJ/mol*	*A*, min^{-1}	*lnA*
0.05	12767	16.49	0.98	106.14	15283636	16.54
0.1	14197	18.57	0.98	118.03	1.3E+08	18.68
0.2	16912	22.46	0.98	140.60	7.1E+09	22.68
0.3	19417	25.93	0.98	161.43	2.62E+11	26.29
0.4	21671	28.99	0.98	180.17	6.55E+12	29.50
0.5	24326	32.55	0.99	202.24	2.75E+14	33.248
0.6	26110	34.82	0.99	217.08	3.34E+15	35.74
0.7	28020	37.10	0.99	232.95	4.33E+16	38.31
0.8	27740	36.16	0.99	230.63	2.53E+16	37.77
0.9	25843	32.356	0.98	214.85	1.13E+15	34.66
0.95	27102	33.17	0.99	225.32	5.09E+15	36.17

Figure - 22: An isoconversion approach (Friedman method) for the analysis of non-isothermal pyrolysis of oil shale.

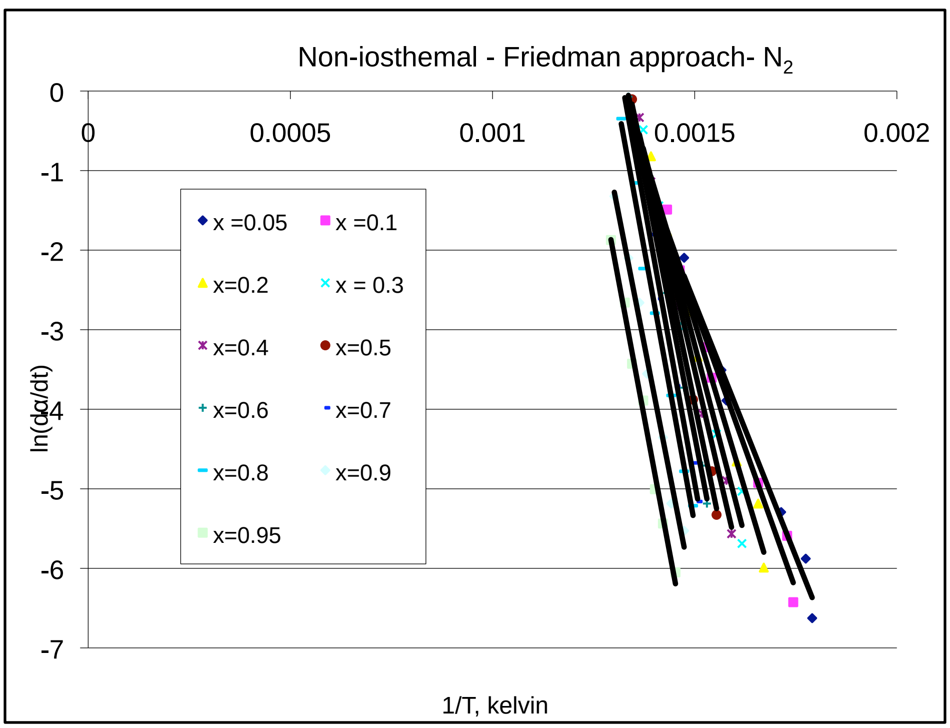
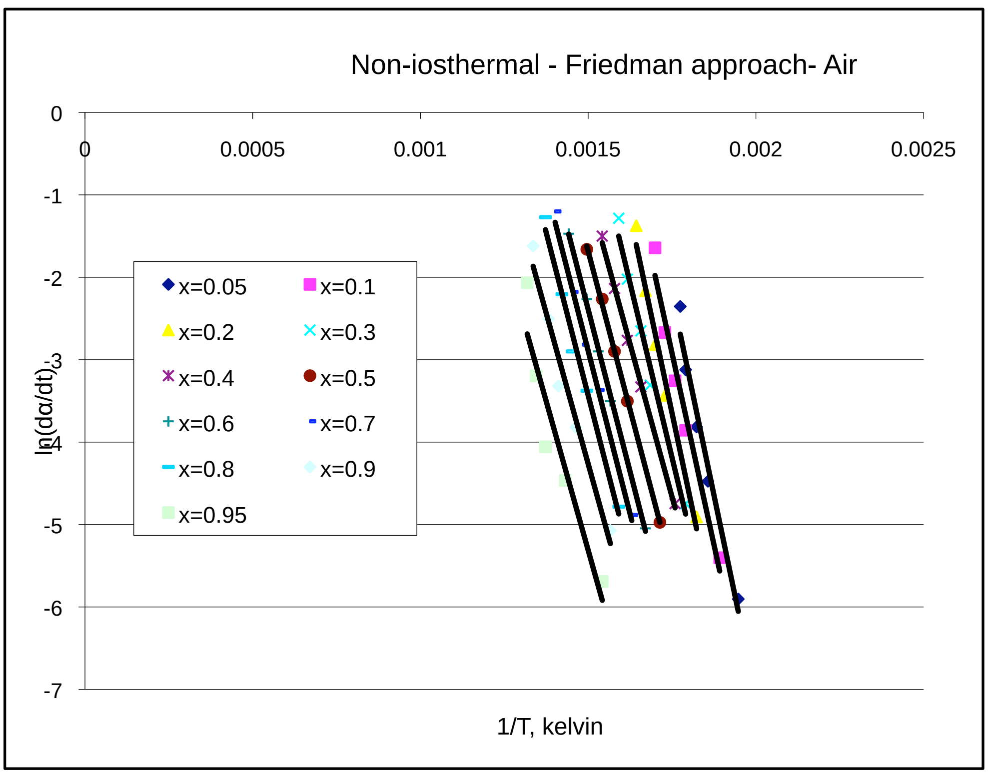


Table 13. Kinetic parameters – distribution of activation energies as a function of conversion obtained using the Friedman approach for the combustion of oil shale.

Conversion α	*Slope*	*Intercept*	R^2	E_a, *kJ/mol*	*A*, min^{-1}	*lnA*
0.05	19458	31.84	0.97	161.77	7.1E+13	31.89
0.1	18585	29.60	0.97	154.52	8E+12	29.70
0.2	19177	29.91	0.98	159.44	1.2E+13	30.13
0.3	16911	25.40	0.98	140.6	1.5E+11	25.76
0.4	14820	21.27	0.99	123.21	2.9E+09	21.78
0.5	15384	21.39	0.99	127.90	3.9E+09	22.08
0.6	15753	21.24	0.99	130.97	4.2E+09	22.15
0.7	15833	20.85	0.99	131.64	3.8E+09	22.06
0.8	15789	20.25	0.98	131.27	3.1E+09	21.86
0.9	14615	17.65	0.968	121.51	4.7E+08	19.96
0.95	14447	16.36	0.88	120.11	2.5E+08	19.35

Figure - 23: An isoconversion approach (Friedman method) for the analysis of non-isothermal combustion of oil shale.



-Maximum rate method

The maximum rate method is a mathematical tool that uses the maximum rate of the reaction (decomposition) at a point (temperature). The maximum rate is obtained by ensuring that the following condition is satisfied.

$$\frac{d\alpha^2}{dT^2} = 0 \tag{8}$$

Thus, for a first order reaction (n = 1), equation (4) will lead to the following form,

$$\ln\left[\frac{\beta}{T_m{}^2}\right] = \ln\left[\frac{A \cdot R}{E_a}\right] - \left[\frac{E_a}{R \cdot T_m}\right] \tag{9}$$

Here, T_m is the temperature at the maximum reaction rate and α_m is the conversion at that condition. These values can be obtained from weight loss curves for the same sample at different constant heating rates. The apparent E_a and apparent A can be determined by linear slope and intercept, respectively. Using the derivatives of percent weight loss data obtained from TGA (normalized conversions) to apply this method, kinetic parameters are derived from results for pyrolysis (Figure 24) and for the two peaks in air (Figures 25 and 26).

Figure - 24: Kinetic parameters using the maximum rate method for the pyrolysis of oil shale: (E_a = 78.2846 kJ/mol and A = 1.03E+06 min^{-1}).

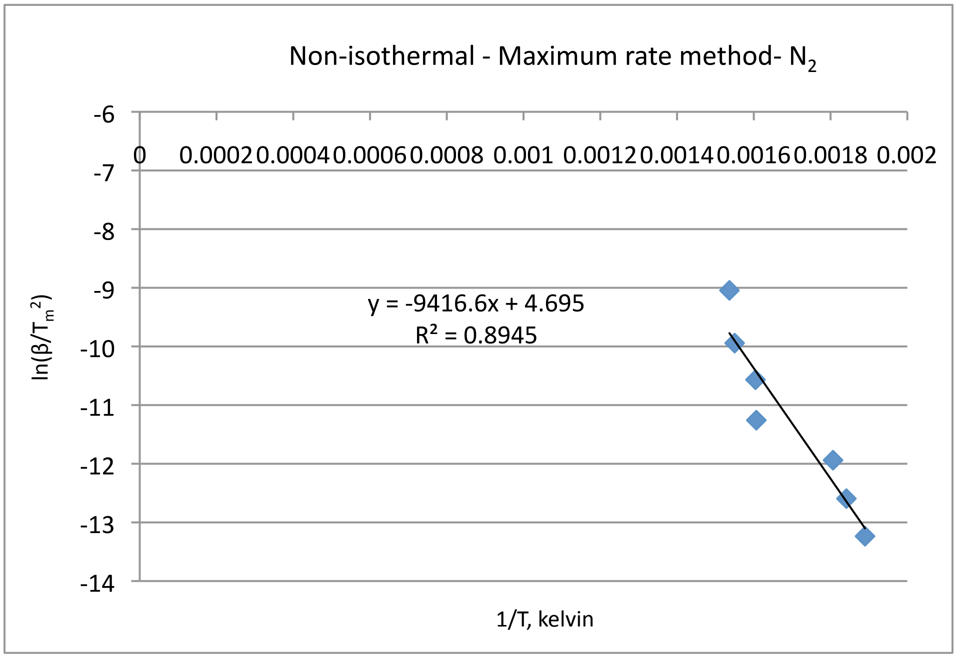


Figure - 25: Kinetic parameters using the maximum rate method for the combustion of oil shale (first peak): (E_a = 182.47567 kJ/mol and A = 3.517E+15 min^{-1}).

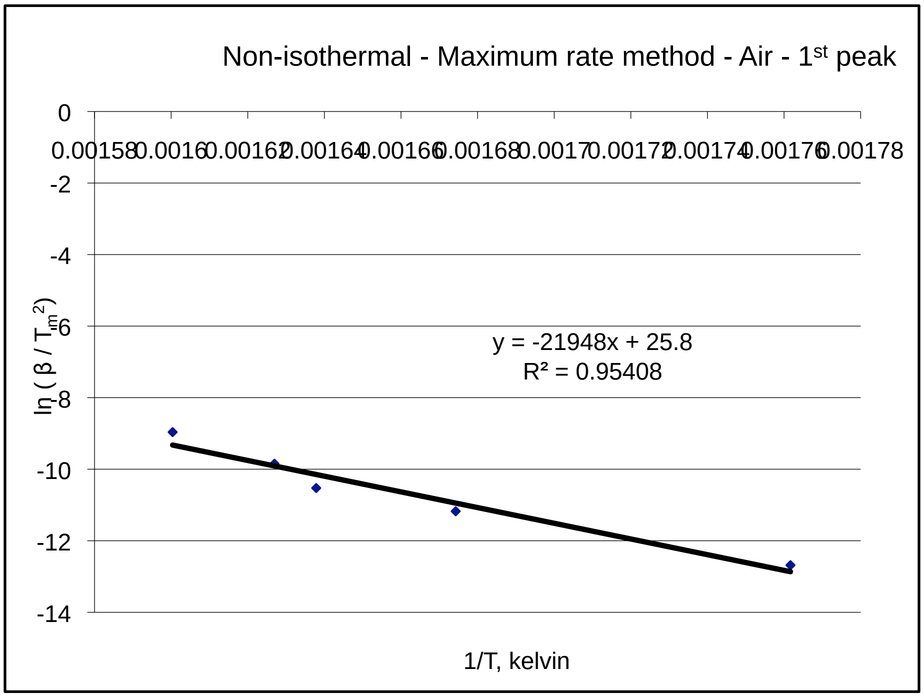
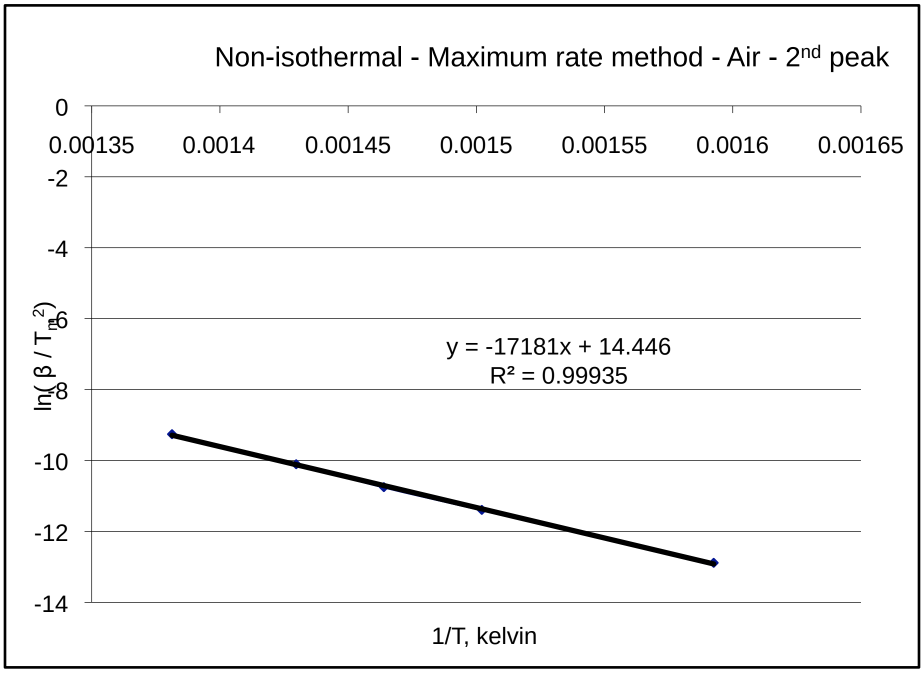


Figure - 26: Kinetic parameters using the maximum rate method for the combustion of oil shale (second peak): (E_a = 142.842834 kJ/mol and A = 3.23E+10min^{-1}).



Results and Discussion

TGA Curve- Crushed Samples

The total extractable kerogen content in Mahogany oil shale was about 10-12 % of the total weight. There was no significant weight loss observed during preheating, confirming the absence of moisture content in the sample. This result was confirmed in TGA experiments, where there was neither peak detection nor weight loss below 150^{o}C. Reproducibility was confirmed through several experiments, an example of which was shown in Figure 1. There were two derivative peaks in all non-isothermal experiments, corresponding to organic and carbonate decompositions. The carbonate decomposition commenced at 525^{o}C or above, depending upon the heating rate, and resulted in a total weight loss of about 25-30%. We also observed that the maximum rate shifts to higher temperatures as the heating rate increases from 0.5 to 50^{o}C/min. This difference is due to shorter exposure time to a particular temperature at faster heating rates (Figures 5 and 7).

In the N_2 environment, only one peak was present in the 300^{o}-550^{o}C temperature range, indicating that only one significant reaction or process occurs in this range. In the air environment, there were two peaks in the same temperature range, indicating that there may be two reactions occurring simultaneously. The mechanism of the formation of intermediates may be significantly different in the two environments, with the pyrolysis intermediate forming relatively quickly.

As a result of these findings, two possible mechanisms were examined.

1. A single step mechanism involving Kerogen → Products. (N_2 environment)
2. A two step mechanism represented as Kerogen → Bitumen → Products. (Air environment)

-**Isothermal experiments**

For isothermal experiments, the data were fit for the integral method. The kinetic data obtained were summarized in Tables 1 and 2 .The values for E_a and A in the N_2 environment were 134.78 kJ/mol and 1.2E+09 min^{-1} respectively, while in the air environment these values were 100.47 kJ/mol and 5.1E+07 min^{-1}.

-**Non-isothermal experiments**

TGA data were analyzed in the range of organic weight loss (10-12%) and conversion profiles were normalized from zero to one. The temperature at which the weight derivative starts to rise was chosen as the zero conversion point, and the temperature at which the weight derivative returned to the base line was the end point (complete conversion of the organic part). Four different methods were used to derive the kinetic parameters. For the same sample, the goodness of the fit and the values of the kinetic parameters differ depending on the mathematical method used. For example, the activation energies derived from four different methods in the N_2 environment were: 74-147 kJ/mol for the differential method, 89-189 kJ/mol for the integral method, 106-233 kJ/mol for the Friedman approach, and 78 kJ/mol for the maximum rate method.

The air data were analyzed with all non-isothermal methods for both the single step and two step mechanisms. The choice of the mechanism depends on the method of analysis employed. For example, the differential method produced a better fit than the integral method for the two step concept, while the opposite trend was observed for the single step mechanism. The maximum rate method was applied to air data for both peaks separately, and the resultant analysis indicates that the activation energy is greater for the first reaction (182.5 kJ/mol) than the second reaction (143 kJ/mol).

In the air environment, observation of two peaks in the TGA data is not enough information to propose a mechanism. It is also necessary to identify the composition of the intermediates and their series and parallel reaction combinations. Thus, in the next phase of the project, the air data will be re-analyzed after performing additional core sample experiments and composition analysis of intermediates and products at different temperatures.

The pyrolysis kinetic parameters determined using the non-isothermal analysis vary depending on the method used. The activation energies at different heating rates from differential and integral methods (Figure 27) increase with heating rate from 0.5°C/min to 20°C/min with a slight decrease at 50°C/min. It has been argued in the literature that these conventional approaches are not appropriate for finalizing the activation energies for the intrinsic decomposition of complex materials such as kerogen[26-28]. The conversion-based Friedman approach for pyrolysis, which falls within the general category of isoconversion methods, shows an increase in activation energy with conversion followed by a decrease after 70 % conversion (Figure-28).

Figure - 27: Activation energies for the pyrolysis of oil shale using conventional methods.

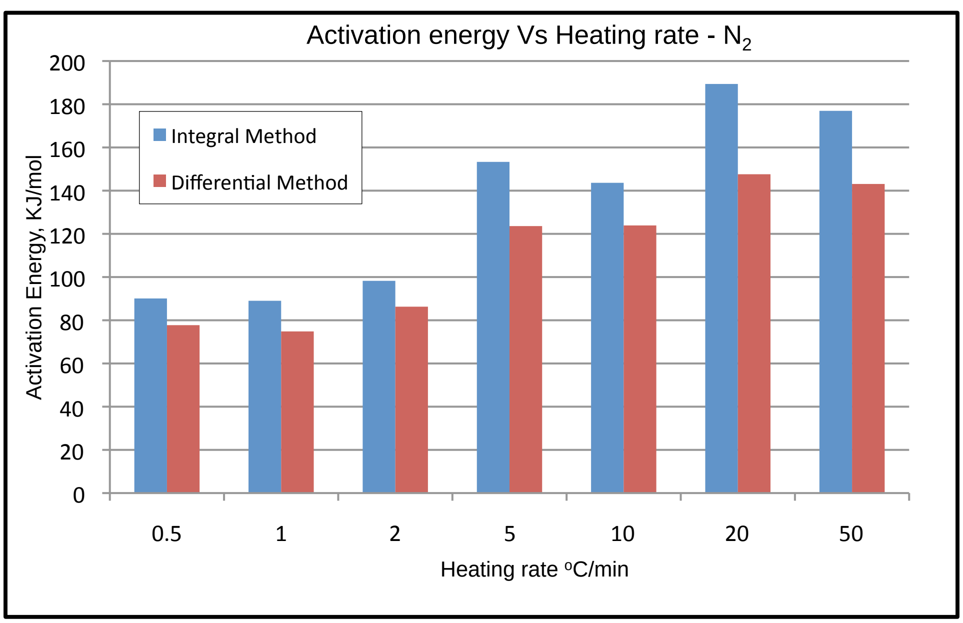
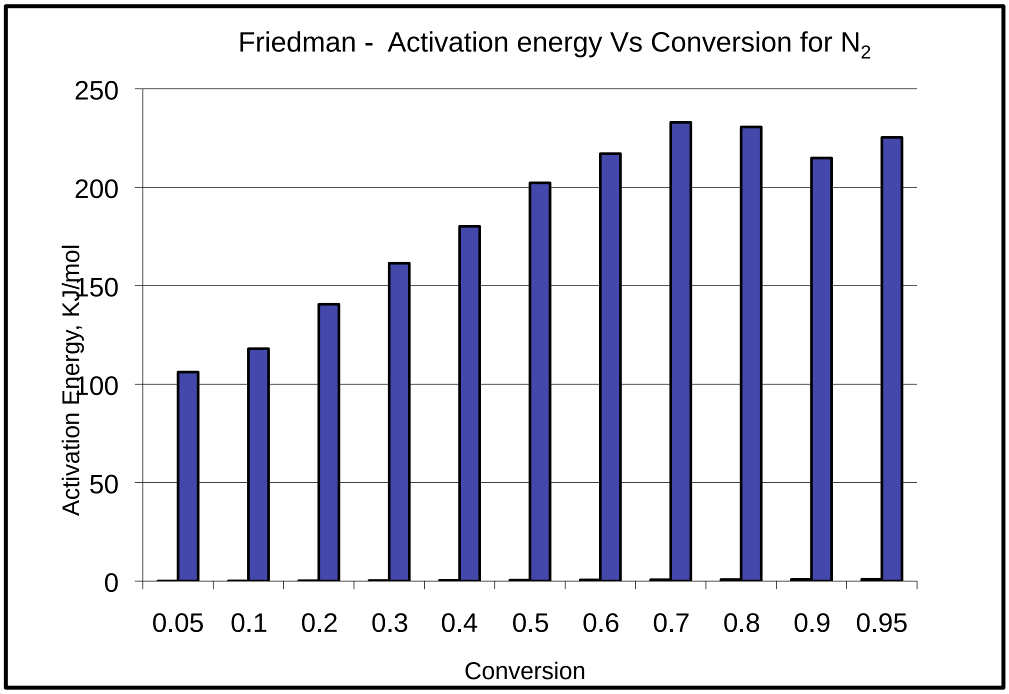


Figure - 28: Activation energy versus conversion for the pyrolysis of oil shale by the Friedman approach.



The goodness of fit for the kinetic parameters obtained from differential and integral methods are examined by replotting ln k versus 1/T data. Differential (Figure 29) and integral (Figure 30) methods both appear to fit the data well and both support the concept of a single step mechanism and a first order reaction for the pyrolysis of Mahogany oil shale. However, the slope is different for different heating rates, which creates a fundamental question regarding the application of these concepts to deriving kinetic parameters for complex reactions like kerogen decomposition.

Figure - 29: Goodness of the fit using the differential method – pyrolysis.

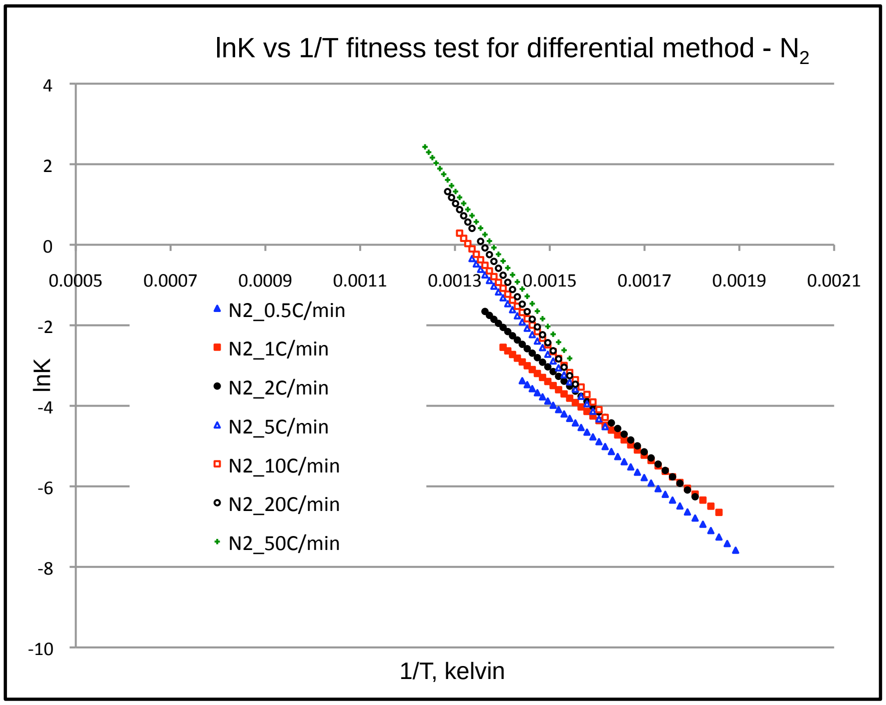
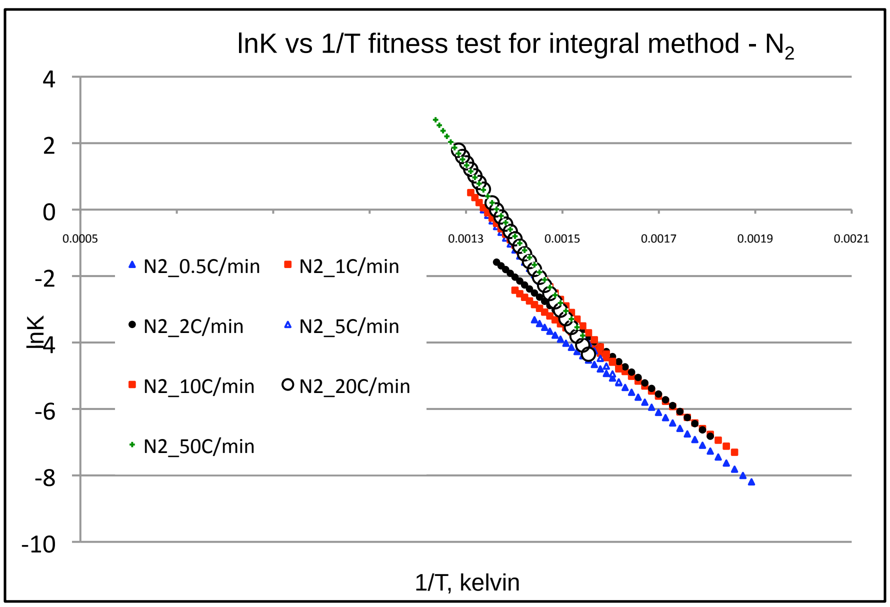
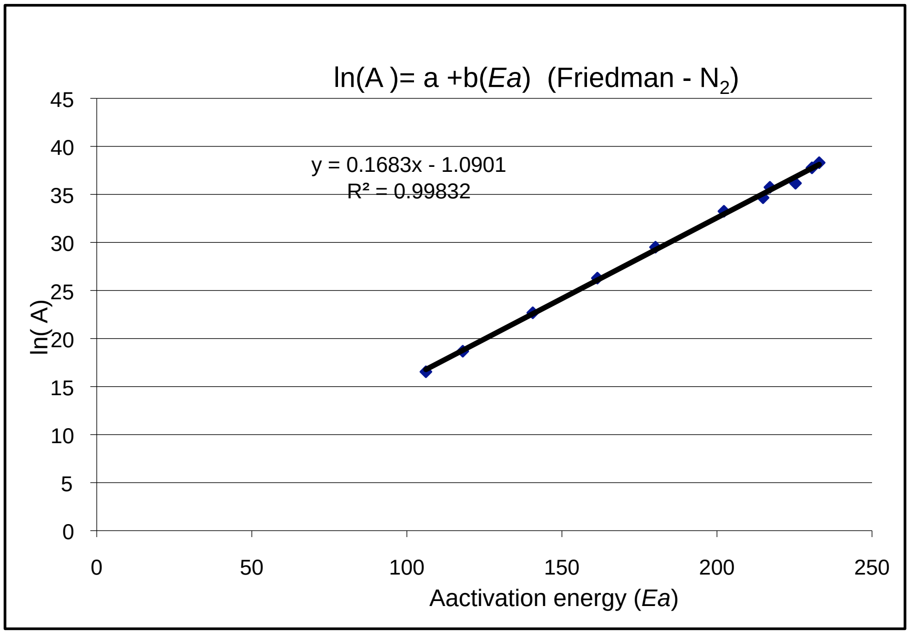


Figure - 30: Goodness of the fit using the integral method – pyrolysis.



The isoconversion methods are specifically designed to address deficiencies in variable heating rate analyses. The kinetic parameters derived in this work are consistent with those observed by others for Green River oil shale. In these types of distributions, there is typically a linear relationship between logarithm of A and E_a. The Friedman distribution provides a relationship with the best linear fit (Figure 31).

Figure - 31: Tradeoff between activation energy and pre-exponential factor for the pyrolysis kinetic data obtained by the Friedman approach.



Comparison of the Kinetics Data with Previously Published Studies

A wide range of activation energies have been reported for the pyrolysis of Green River oil shale from Colorado and Utah. Published values for kinetic parameters values are based on both the single and two step mechanisms. Reported activation energies for pyrolysis with the single step assumption are 85.69 kJ/mol[2], 219.4 kJ/mol [5] and 213.18 kJ/mol.[29] When a two-step mechanism was used, the reported activation energy for the first step is 44.6 kJ/mol and for the second step is 177.7 kJ/mol.[4] **Leavitt et al. (1987)** [30] proposed the two parallel reactions theory of the kerogen decomposition and obtained activation energies of 191.02 kJ/mol (above 350^{o}C) and 86.94 kJ/mol (below 350^{o}C). The activation energies using single step isothermal or nonisothermal conventional kinetic analyses obtained in this study range from about 80-200 kJ/mol. These values are consistent with those reported earlier.

In a series of papers, Burnham et al. established that for a material as complex as kerogen, distribution of activation energy models (isoconversion methods) are most logical, both physically and from the point of view of mathematical fits (see [26]). For Kuskerite shales, considered a "standard" because of reproducibility, the activation energies ranged from 210-234 kJ/mol. The values of activation energies reported in this work of about 110-233 kJ/**mol are slightly lower at lower conversions. The data are reproducible and the models fit the data well.

Core Sample Pyrolysis

The experimental conditions and oil yields obtained during pyrolysis experiments of cylindrical oil shale core samples (3/4" diameter and 9" long) were summarized in Table 5. The amount of the vapor condensate (yield of shale oil) in the condensers and the total weight loss increased with increasing temperature. Experiment 8, carried out at 200^{o}C for 7 days, produced no observable shale oil in the condensers. Experiment 7, with a low heating rate (1^{o}C/min) and a final temperature of 400^{o}C, produced the maximum amount of recoverable oil (11.91% of total oil shale).

Chromatograms of the shale oils, produced at different isothermal temperatures and collected without further treatment, are shown in Figures 32 and 33. It is seen that oil compositions shift toward lighter carbon numbers as the isothermal pyrolysis temperature increases. The ASTM standard sample was used to obtain the retention time for the normal alkanes (SIMDIS analysis). Based on this information, chromatograms were classified and quantified in terms of normal alkanes, non-normal alkanes and residue.

Figure – 32: Chromatographs for produced oil from pyrolysis of core samples at different temperatures.

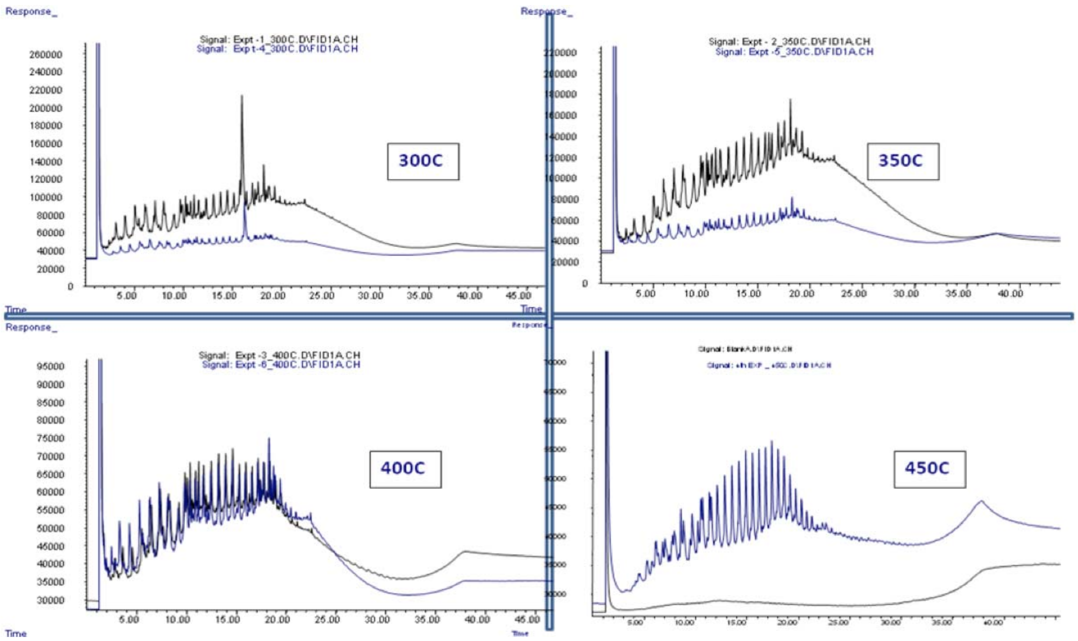
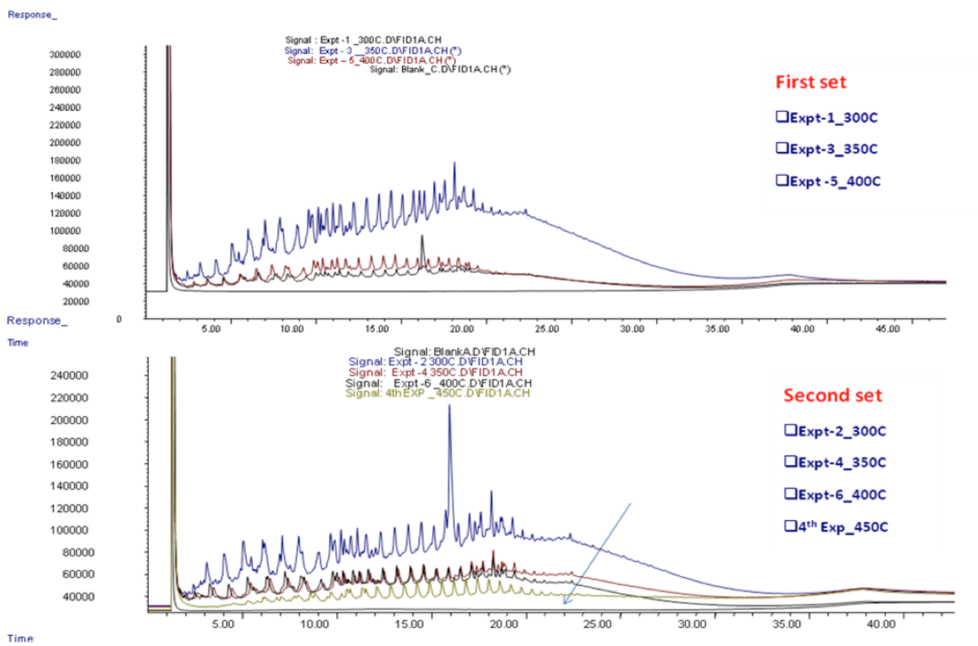


Figure – 33: Comparison of the **c**hromatographs for produced oil from pyrolysis of core samples at different temperatures (shift towards lighter components at higher temperature). The ‘4^{th} Exp’ in the legend stands for the experiment conducted with the tube reactor (Number 9 in Table 5).



The percentages of both types of alkanes and of residues for different shale oils are shown in the Figures 34 and 35 and Table 14. Figure 36 shows the chromatogram and SIMDIS analysis for experiment 7.

Table 14. Percents of n-alkane, non-n-alkane and residue in oil samples.

Expt no	*Temperature ^{o}C*	*Residue%*	*non_n_alkane %*	*n_alkane%*	*Total*
1	300 ^{o}C	7.85	41.22	51.01	100.09
2	350 ^{o}C	30.43	33.35	35.61	99.40
3	400 ^{o}C	21.69	35.80	42.54	100.04
4	300 ^{o}C	13.87	36.65	49.51	100.05
5	350 ^{o}C	14.15	39.56	46.38	100.10
6	400 ^{o}C	18.07	39.88	42.14	100.11
4th Expt	450 ^{o}C	36.02	33.39	30.76	100.17
7	400^{o}C (1^{o}C/min)	11.77	39.24	48.99	99.90

Figure – 34: Normal alkanes, non-normal alkanes and residue % in the oil samples – Set_1.

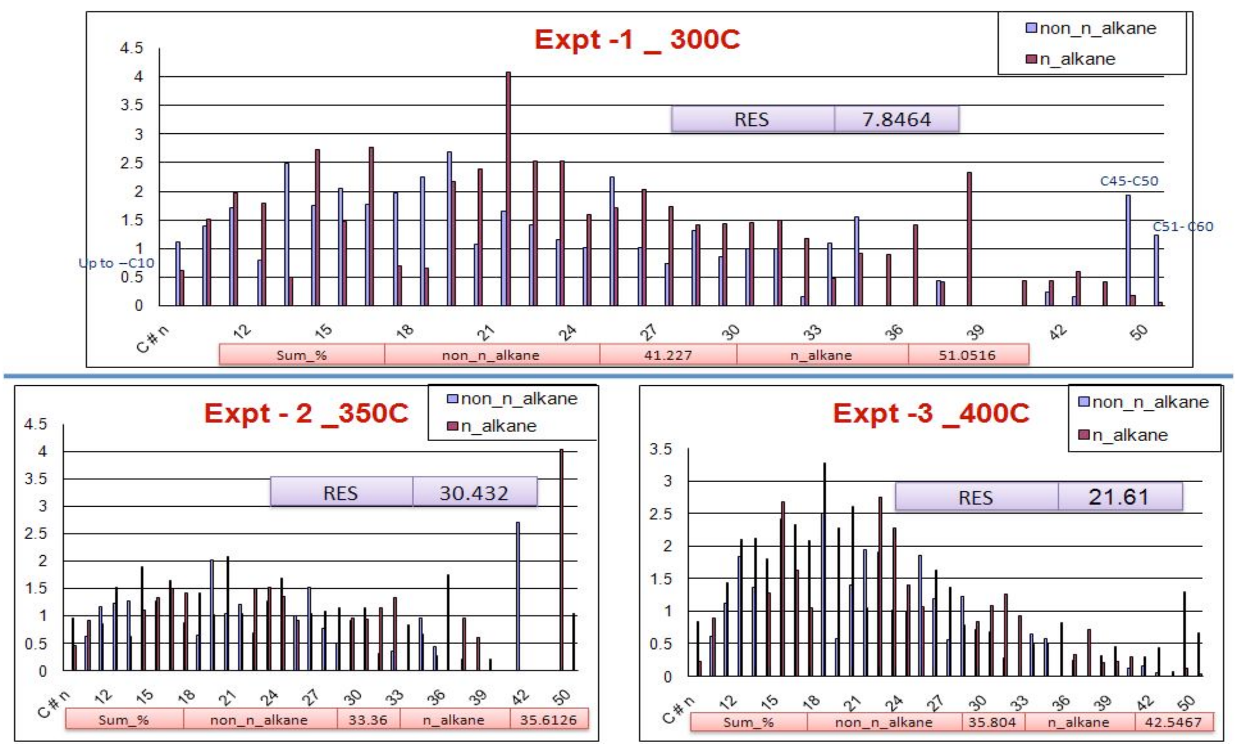


Figure – 35: Normal alkanes, non-normal alkanes and residue % in the oil samples – Set_2.

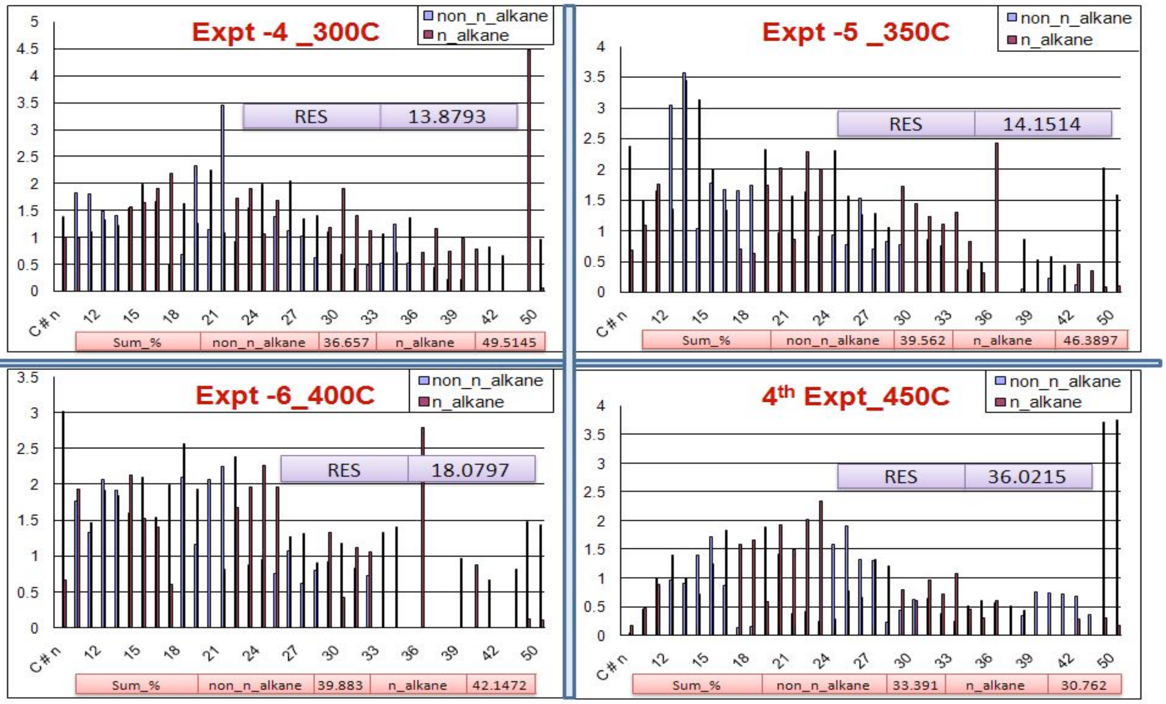
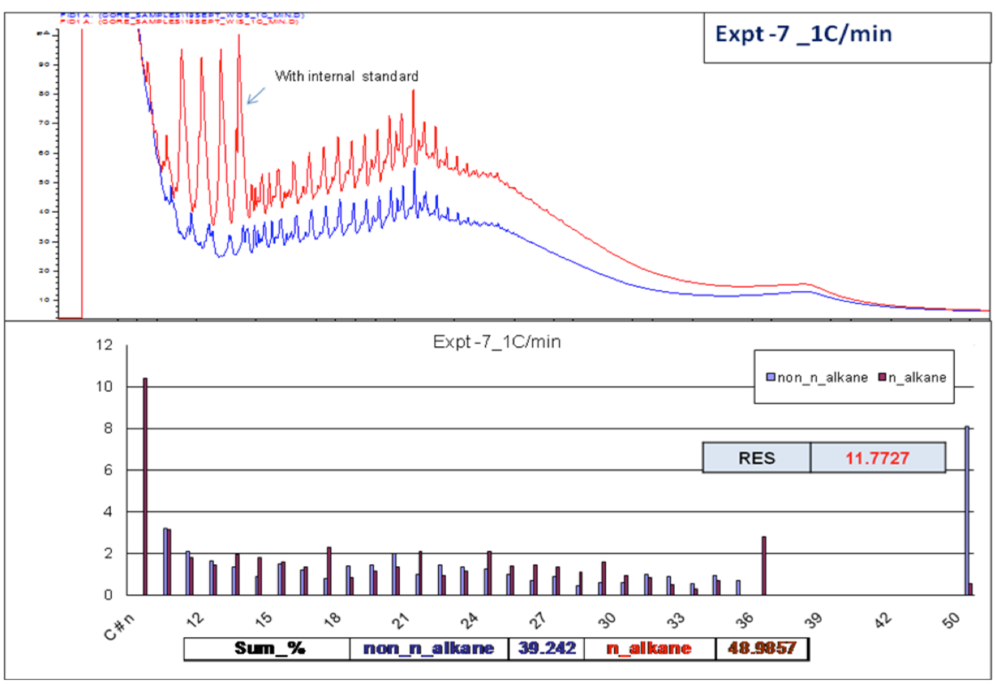
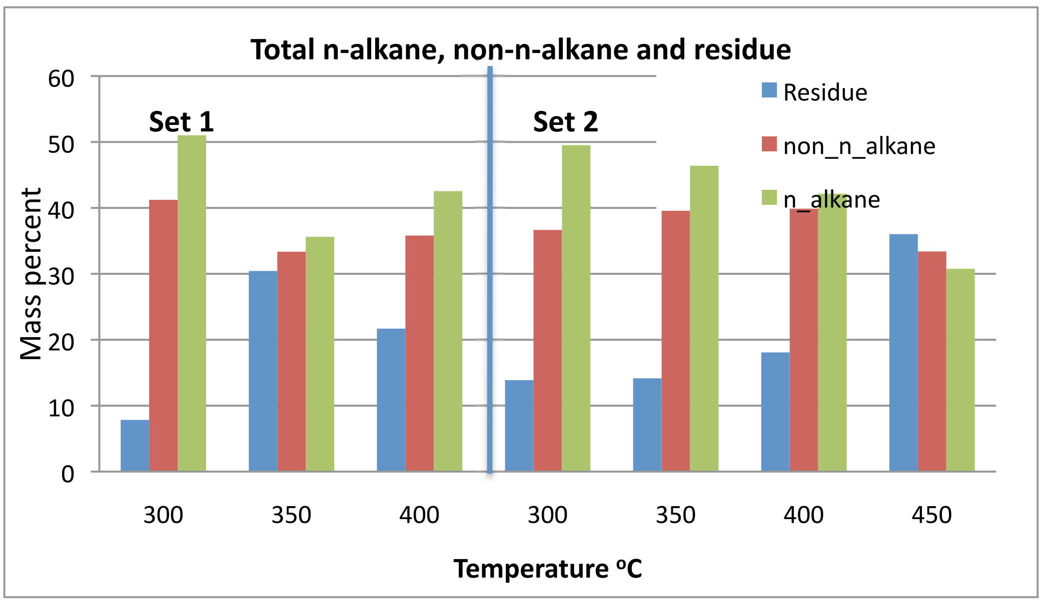


Figure – 36: Chromatogram and normal alkanes, non-normal alkanes and residue % in the oil sample from pyrolysis of core at 1°C/min.



Two data sets with compositional comparisons are plotted in Figure 37. The second data set shows that more residue (C60+) was observed at higher temperatures (13.87%@300^{o}C, 18.07%@400^{o}C). In addition, the second data set shows alkane to non-alkane ratios decrease as temperature increases. No clear trend is present in the first set. We believe the second set is more representative of the trends that are expected compositionally. The analyses are being repeated to verify the trends.

Figure - 37: Percents of n-alkane, non-n-alkane and residue in shale oil samples produced at different temperatures.



One of the objectives of this project was to determine if the products of pyrolysis are significantly different when the shale has been in contact with water for several days. An expanded chromatogram of the products from hydrous pyrolysis is shown in Figure 38. In this experiment, the core was soaked in water for 24 hours prior to the pyrolysis run (conducted at 400°C). The figure shows alkene-alkane pairs starting at carbon number 10. Alkenes are not present in crude oils. A similar chromatogram of the non-hydrous pyrolysis sample is shown in Figure 39. There is no discernible difference in the composition of the two samples.

Figure - 38: Expanded chromatogram of a product from hydrous (24 hours water soaked) pyrolysis.

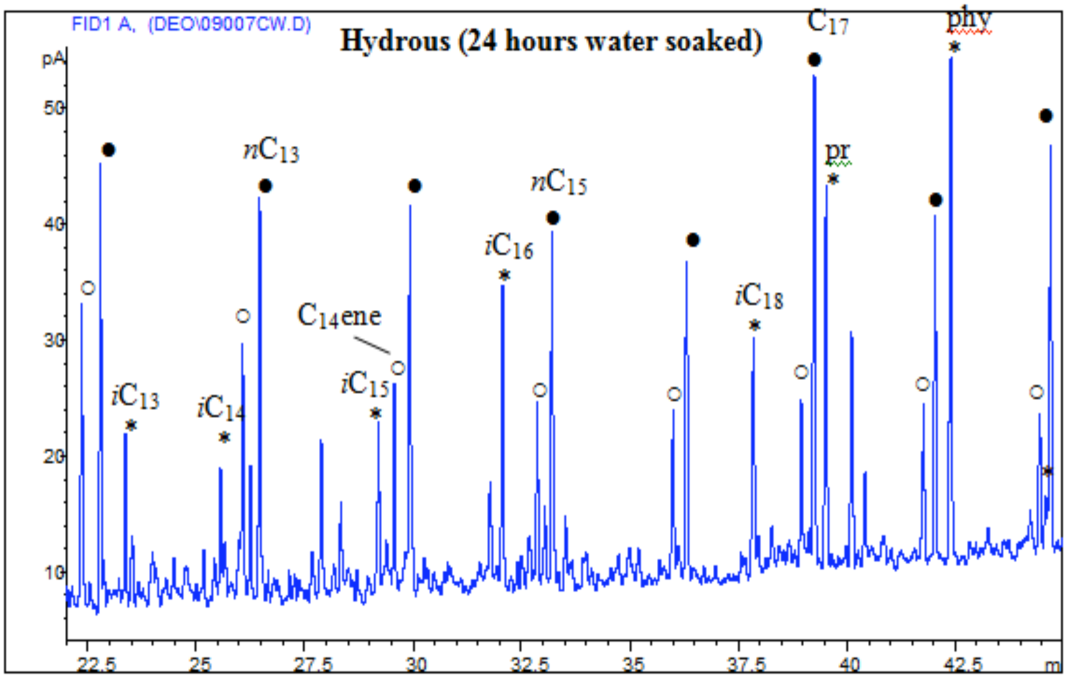
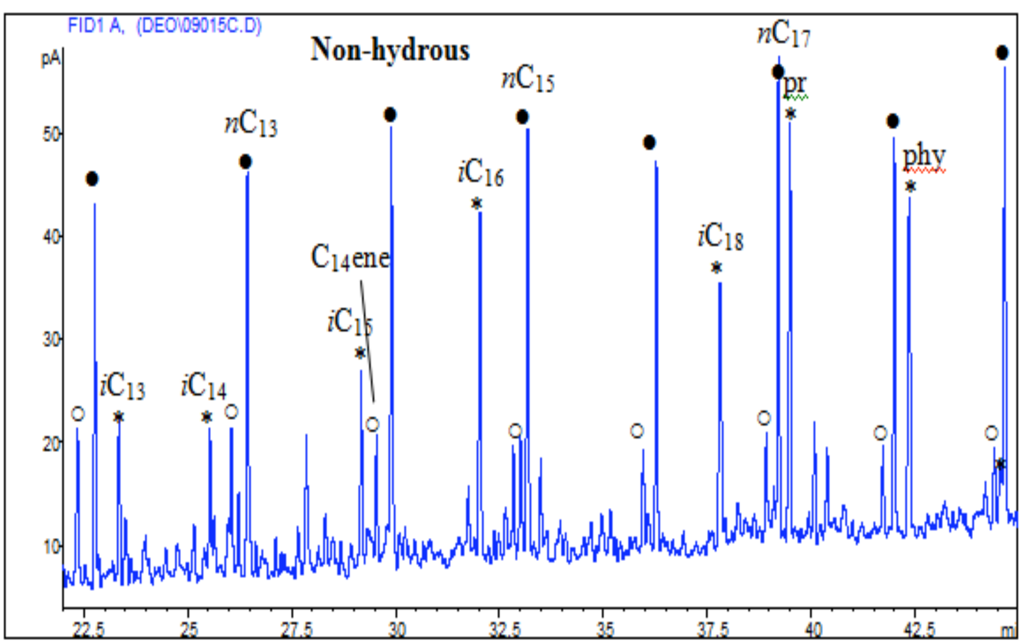
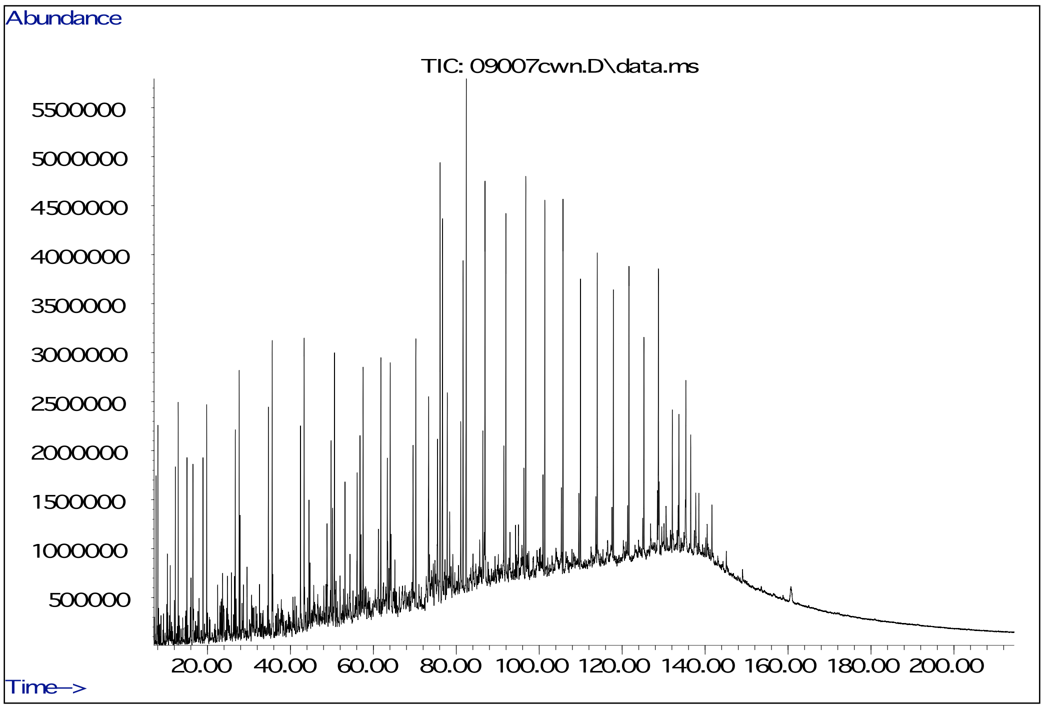


Figure – 39: Expanded chromatogram of a product from non- hydrous pyrolysis.



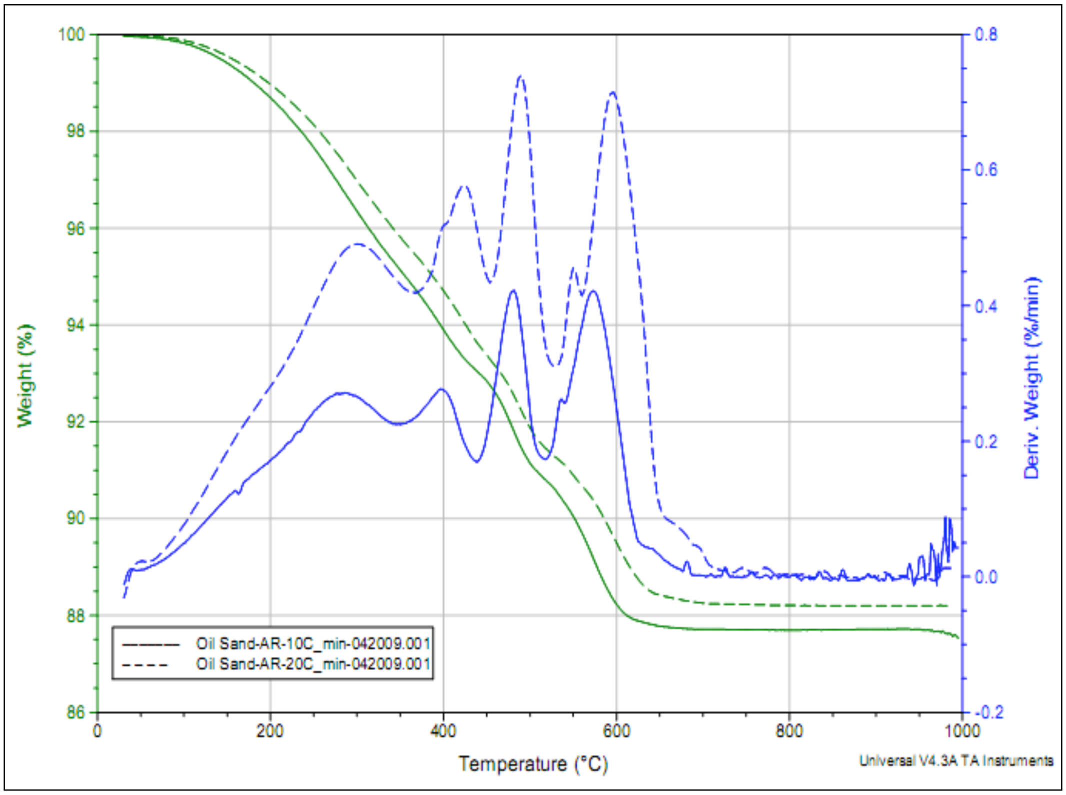
Further GC-MS analysis revealed the presence of a number of aromatic homologous series in the oils (Figure 40). These aromatic species are likely to have higher solubilities in water. We are following up on the implications of these findings in our examination of the pyrolysis process on water compositions of surrounding aquifers.

Figure – 40: GC-MS chromatogram (TIC) of a product from hydrous pyrolysis (24 hours water soaked).



The non-isothermal TGA curves for Asphalt Ridge oil sand pyrolysis at 10^oC/min (31.474 mg of original sample) and 20^oC/min (31.478 mg of original sample) are shown in Figure 41. There is a continuous weight loss with temperature increase from 100^oC to 650^oC. The weight derivative data show four significant peaks over the 1000^oC temperature range. The first peak may correspond to the presence of water in the sample (however, this peak starts at near 100^0C and spreads to 350^oC). The curves indicate that the nature of pyrolysis with oil sands is different from oil shale. More detailed comparison of these two feedstocks was deferred to the next phase of the project.

Figure – 41: Non-isothermal TGA curves for Asphalt Ridge oil sand pyrolysis at 10°C/min (31.474 mg) and 20°C/min (31.478 mg) heating rates.



Summary

In this work, TGA data on the Mahogany oil shale from Utah and yields and compositions of oils obtained by pyrolyzing oil shale cores at various temperatures were reported. The TGA data was reported for both pyrolysis and combustion processes. The pyrolysis processes were characterized by single-stage decomposition of kerogen while the combustion processes were interpreted to consist of two stages. As the heating rate increased, the maximum decomposition rate for pyrolysis shifted to higher temperatures. Total organic weight loss was in the 10-12% range. There was no appreciable moisture in the samples. Kinetic parameters were derived using isothermal experiments and non-isothermal experiments conducted over a range of heating rates. The parameters were calculated using a variety of techniques and were found to be in the range reported for Green River shales from Colorado and for other shales around the world. In the interpretation of non-isothermal data, different conventional techniques yielded activation energies that increased with heating rate. An isoconversion method (Friedman) was used to obtain a distribution of activation energies with conversion. The distribution obtained was similar to those reported for other complex materials and for oil shale. In the core pyrolysis experiments, the yields increased slightly with temperature but more residue was produced. The alkane/non-alkane ratio also decreased at higher temperatures, indicating possible secondary cracking and polymerization. Highest yields were obtained at low heating rates. The pyrolysis behavior of oil sands was observed to be different from oil shale based on TGA analyses.

In the next phase of this project, simulated distillation analyses of the oils will be used to create compositional representation of the product. The TGA kinetic model will be integrated with this information and combined with a heat and mass transfer model to create a model for pyrolysis in the core. This work will provide a methodology for scaling up kinetic and compositional data for practical applications (retort modeling or reservoir modeling).

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APPENDIX H

Modeling In Situ Oil Shale Extraction

A Subpart of Project
Oil Shale Pyrolysis and In Situ Modeling

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

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June 17, 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
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Project Objectives

The objective of this work is to develop a highly-coupled, multi-phenomenon modeling capability based upon the Comsol® multi-physics software package for *in situ* oil shale extraction using various heating technologies, including conduction, DC resistive heating and radio frequency heating, various pushing fluids and geometries for their delivery, and production of both liquid and gas products from the deposit.

Project Outcomes

A multi-physics model of *in situ* extraction of oil shale has been developed which couples fluid flow, mass transfer of multiple species, heat transfer and AC (RF) and DC heating of the deposit. All physical properties used in these model equations are functions of the local chemistry of the deposit and of local temperature. After overcoming significant numerical difficulties, a 2D slice consisting of a heating and a production well located 25 feet (7.62 m) apart has been simulated for up to 5 years. The 2D slice is a right triangle consisting of the smallest repeating unit of a hexagonal drill pattern. The model calculates the concentrations of kerogen, bitumen, oil and gas at all locations in the deposit; physical properties such as viscosity, permeability, heat capacity, thermal conductivity, electrical conductivity, dielectric constant, and loss tangent; and pressure, temperature, and thermal and pressure stresses in the deposit. The results show that a pusher fluid, a gas in this work, is necessary to move the oil to the production well, that thermally-induced stresses do not induce fracture of the deposit, and that more uniform heating of the deposit by RF heating is beneficial to oil extraction.

Presentations and Papers

Jon Wilkey, "Multiphysics Modeling *in situ* Oil Shale Extraction," Undergraduate Research Oportunities Presentation at the University of Utah, summer 2008.

Introduction

A conservative estimate of the total world in-place oil shale resources is 2.9 trillion barrels (Dyni, 2003) of which 2.0 trillion barrels, constituting the bulk of the oil shale resource worldwide in both quantity and quality, are in the western United States encompassing the Piceance Basin and the Uinta Basins. The Rand report (Bartis et al., 2005) puts the range of recovery at 500 billion to 1.1 trillion barrels depending on the percent recoverable and accessibility. There are six BLM oil shale Research Development and Demonstration (RD&D) leases in Colorado and Utah, five of which are *in situ* production. *In situ* processes are also being vigorously pursued by all the major energy companies (see Table 1). However, fundamental issues related to the kinetics of kerogen conversion to natural gas and light oil products and the production of the resulting oil require further multi-physics analysis to aid *in situ* extraction. *In situ* processing is a highly energy-intensive process. Better energy utilization and efficiency will be necessary to make the extraction of this resource cost effective. Since water is scarce in this part of the United States, the use of large amounts of steam as a pushing fluid will be difficult, making water conservation another important aspect of *in situ* processing.

Table 1. *In situ* Processing Methods Under Investigation by Major Oil Companies in Colorado's Piceance Basin and Utah's Uinta Basin. Data from (Parkinson, 2006).

Company	Heating Method	Pushing Fluid	*In situ* Containment
Raytheon and CF Technologies, Inc	Radio Frequency heating	Supercritical CO_2	?
Chevron Shale Oil Company	Hot CO_2	CO_2	?
Exxon Mobil	Either hot fluids or electric current directed into deposit	Hot fluids	?
Shell Frontier Oil & Gas, Inc.	Electrical resistance heaters and 3 phase AC electric heaters	In-situ methane	Ice-wall
Shell Frontier Oil & Gas, Inc	Pressurized hot water	Steam	Ice-wall
EGL Resources, Inc.	Superheated steam or heat transfer fluid	Steam/water	?
Phoenix Wyoming	Microwaves	In-situ methane	?
Petro Probe	Hot gases	Gas	?
IEP	Waste heat from solid oxide fuel cell; fuel cell will use produced gases to make electricity for sale	In situ methane	?

? unknown

The basic concept of *in situ* oil shale extraction is to 1) isolate the oil shale structure to be extracted, 2) sink various production wells to allow liquid and gaseous products to be removed from the oil shale structure, 3) sink various wells to provide access to the oil shale structure for various methods of heating and/or pushing fluids and 4) turn on the heating method and /or pushing fluids and remove product from the producing wells. Reservoir isolation may occur naturally due to impervious formations surrounding the oil shale deposit. Other options include the installation of isolation walls made from cement using naturally occurring faults or of ice walls (Parkinson, 2006). The production wells are placed in the appropriate locations so that heating profiles and pushing fluids drive the oil shale extraction products to the production wells.

The placement geometry is different depending upon the liquid/gas product distribution and the heating methods used. For 3-phase AC reactance heating, a Texas 5-spot pattern or a triangular pattern is often used for the heating wells (Shell, 2006). With today's directional drilling, however, even horizontal production wells are possible, e.g. Steam Assisted Gravity Drainage (SAGD) production of oils sands in western Canada. The modeling effort allows the various reservoir and well geometries to be modeled for heating by various methods, pushing with various fluids, and production of both liquid and gas products. The model for this work is a highly coupled multi-physics model run on Comsol® multi-physics software.

Model Description

The multi-physics model consists of the simultaneous solution of several equations with the coupling of the physical properties used in these equations (e.g. temperature, pressure and concentration) to the results computed from these equations. Table 2 lists the equations solved and shows the extent of equation coupling in the model.

The most important equations used to model *in situ* extraction of oil shale are the chemical reactions that take kerogen to oil and gas. A simplified overall rate equation taken from Hubbard and Robinson[1]

$$\text{Kerogen} \xrightarrow{k1} \text{Bitumen} \xrightarrow{k2} \text{Oil + gas} \qquad [1]$$

has been used in this model. This model assumes a sequential series mechanism with first order irreversible rate constants given by:

k_1 = 0.0706 [1/s] exp(-1.696e5[J/mol]/R_gT)
k_2 = 115.673[1/s] exp(-5.677e4[J/mol]/R_gT)

The overall reaction has a temperature-dependent heat of reaction that, based on the mass of kerogen reacted, is given by[2]:

H_{rxn} = (320.07*T[1/K]-114093)[J/kg]

For all modeling conditions used, this reaction heat is endothermic above 357 K.

<u>Governing Equations</u>

The governing equations for the multi-physics simulation include:

Darcy's Law

$$u = \frac{-\kappa}{\eta_f \phi}\left(\nabla P - \rho_f g \vec{e}_z\right) \qquad [2]$$

where u is the fluid velocity vector, κ is the permeability, η_f is the fluid viscosity, φ is the porosity of the deposit, ρ_f is the fluid density, g is the acceleration due to gravity and e_z is the unit vector in the direction of the gravity force. The gradient of pressure is determined from the methane gas

[1] Hubbard, A.B. and Robinson, W.E., USBM Rpt. Inv. 4744(1950)
[2] ibid

pressure at any location in the deposit. The presence of methane gas is due to kerogen pyrolysis (equation [1]) or to the flow of the pusher fluid.

Table 2. Modeled Multi-Physics Phenomena and Equation Couplings.

Phenomenon/Medium	Equation	Coupling
Fluid flow		
Oil	D'arcy's Law	1) Viscosity as a function of temperature 2) Pressure driving flow is due to decomposition of bitumen to gas 3) Porosity is function of reaction conversion & convection
Gas	D'arcy's Law	1) Viscosity as a function of temperature 2) Pressure driving flow is due to decomposition of bitumen to gas 3) Porosity is function of reaction conversion & convection
Pusher Fluid	D'arcy's Law	1) Viscosity as a function of temperature 2) Pressure driving flow is due to applied pressure & decomposition of bitumen to gas 3) Porosity is function of reaction conversion & convection
Mass Transfer		
Kerogen/Bitumen	Convective Mass Transfer	1) Reaction is function of temperature 2) Porosity is a function of reaction & convection
Oil	Convective Mass Transfer	1) Velocity from D'arcy's Law for convection 2) Reaction is function of temperature 3) Diffusion coefficient is function of temperature
Gas	Convective Mass Transfer	1) Velocity from D'arcy's Law for convection 2) Reaction is function of temperature 3) Diffusion coefficient is function of temperature
Heat Transfer		
Deposit	Conduction/Convection Radiation Boundary Condition	1) Chemical reactions are heat source 2) Velocity from D'arcy's Law (oil & gas) for convection 3) Thermal conductivity is function of local chemistry & temperature 4) Density is function of local chemistry & temperature 5) Heat capacity is function of local chemistry & temperature
DC Resistance Heating		
Deposit	Electrical Conduction equation	Electrical conductivity is function of local chemistry & temperature
RF Heating		
Deposit	Wave equation	Dielectric constant & electrical conductivity are functions of local chemistry & temperature

Convective Mass Transfer

$$\frac{\partial C_i}{\partial t} + u \bullet \nabla C_i + \nabla \bullet (- D_i \nabla C_i) = R_i \qquad [3]$$

where C_i is the molar concentration of species i, D_i is the diffusion coefficient for species i, and R_i is the reaction rate for species i.

Convective/Conductive Heat Transfer

$$\rho_l C_{pl}\left(\frac{\partial T}{\partial t} + u \bullet \nabla T\right) + \nabla \bullet (- k_l \nabla T) = Q_{rxn} + Q_{RF} \qquad [4]$$

where ρ_l is the local density of the deposit, C_{pl} is the local heat capacity of the deposit, k_l is the local thermal conductivity of the deposit, Q_{rxn} is the heat of reaction. Q_{RF}, the RF heating rate, is given by

$$Q_{RF} = 2\pi\ f\ \nabla E^2 \varepsilon_o\ \varepsilon_r \tan\delta \qquad [5]$$

where f is the frequency, ∇E is the electric field, ε_o is the permittivity of free space, ε_r is the relative dielectric constant and tan δ is the loss tangent. If a DC current is applied to the deposit, Joule heating replaces RF heating, given by $Q_{Joule} = \nabla E^2 / \sigma$ where σ is the electrical conductivity of the deposit.

Electrical Conduction Equation

$$\nabla \bullet (\sigma \nabla V) = 0 \qquad [6]$$

where V is the voltage and σ is the electrical conductivity of the deposit.

RF Equation (Wave Equation)

$$\nabla \bullet (\nabla E) + k^2 E = 0 \qquad [7]$$

where E is the amplitude of the wave's electrical potential and k, the wave propagation constant, is given by

$$k = \sqrt{j\omega\sigma - \omega^2 \varepsilon_o \varepsilon_r} \qquad [8]$$

where j is the imaginary number, ω is the frequency angular frequency [$\omega = 2\pi$ f] and σ is the electrical conductivity of the deposit. A coupled orthogonal magnetic field also governed by the wave equation is solved in this model. The relative magnetic permeability of the deposit is assumed to be 1.0 for this model since no other data was available.

Physical Properties

Most of the local physical properties are determined from concentrations of rock, kerogen, bitumen, oil and gas that occur locally in the deposit at any given time using a simple molar mixing rule. Each individual property is given by a temperature dependent function that is determined from either first principles or from a best fit of temperature dependent data (e.g.

viscosity of oil) for the material[3]. Since the pressures may be large, the compressibility of oil is considered and a virial coefficient equation of state is used for the gas (assumed to be methane).

Electrical properties for the deposit, including electrical conductivity, relative dielectric constant and tan δ, are available as a function of frequency and temperature but not in a clean form as the data does not account for the temperature-dependent chemistry of the deposit. As a result, average properties are used for the electrical properties of the deposit except for the electrical conductivity, which is assumed to be a function of carbonaceous residue left behind after the kerogen decomposition.

Mechanical properties of the oil shale as a function of temperature are not readily available. As a result, the mechanical properties at room temperature are used in this model to determine the failure strength, Young's modulus (Y), Poisson's ratio (υ) and the thermal expansion coefficient (α). Thermally induced stress is generated elastically due to the temperature difference from the initial temperature of the deposit, T_o, as calculated by[4]:

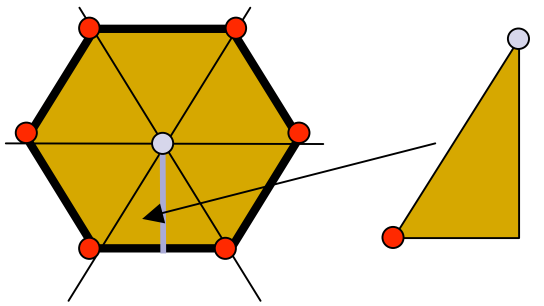
$$\Sigma_{thermal} = \varphi Y \alpha \, (T_o - T)/(1-\upsilon) \qquad [9]$$

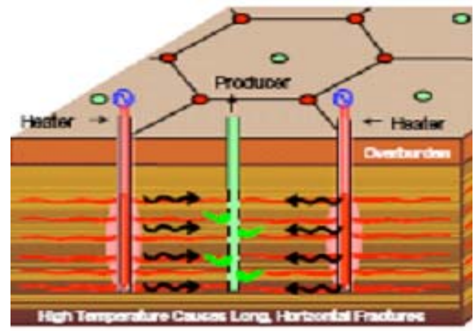
Model Geometry

The system investigated consists of one-half of a 2D slice of a triangular drill pattern as shown in Figure 1. The model geometry consists of a heating well at one end and a production well at the other end of the 25 ft (7.62 m) hypotenuse of a right triangle. The production wells consist of concave, rounded off surfaces through which the heat flux and the production fluxes flow. To facilitate numerical stability, the right angle has also been rounded off to a convex surface. A view of the computational mesh with 9393 elements for this model geometry is shown in Figure 2.

[3] Rajeswar, K., Nottenburg, R. and Dubow, J., Review Thermophysical Properties of Oil Shale," J. Mat. Sci. 14, 2025-52(1979).
[4] Ring, T.A., "Fundamentals of Ceramic Powder Processing and Synthesis," Academic Press, 1999.

- Hexagon heating drill pattern with production well at center used as representative extraction geometry
- symmetry simplifies geometry





Boundary Conditions
  Symmetry
  Constant Temp.
  Convective Flux

Figure 1. Model geometry.

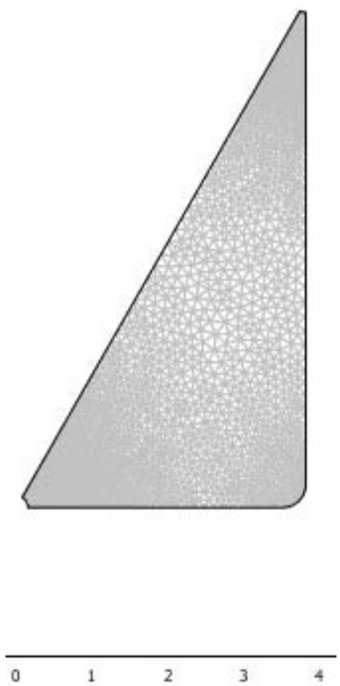


Figure 2. Mesh for model geometry (scale in meters).

<u>Initial and Boundary Conditions</u>

Initially the oil shale deposit is filled with kerogen at 9% weight (12 gal/ton Fischer assay) with no bitumen, oil or gas present. Kerogen content varies in deposits from low values to high values; values typical for economically viable commercial operations are in the ~25 gal/ton range and higher. We have used 12 gal/ton as an initial condition for the deposit because higher values gave numerical instabilities in the model.

When the kerogen decomposes, it is assumed that 63% becomes oil and 24% becomes gas with the balance being a carbonaceous deposit left behind. Initially, the deposit has a temperature of 400K and a down hole pressure of 10 atm.

The boundary conditions are symmetry conditions for all of the boundary walls except the heating (lower left corner in Figure 2) and production (upper corner in Figure 2) wells. At the heating well (when used), a time dependent heat flux is used to soften the boundary conditions; the heat flux increases to 500 W/m^2 over a time period of 10 hrs using an exponentially rising function. In other cases, a constant wall temperature at the heating well is used as a boundary condition. In these cases, the wall temperature increases from 400K to 1000K over a time period of 10 hours using an exponentially rising function to soften the boundary condition. When a DC electrical current is used for heating, it is passed between the heating and production wells. The voltage on the heating well surface is increased to 1,000 Volts over a time period of 10 hours using an exponentially rising function, and the production well is grounded. When an AC (RF) electrical signal is used for heating, the antenna is a dipole consisting of the heating and production wells with an external current of 2,200 A/m^2. When a pusher fluid is used, the pusher fluid, methane, is applied at the heating well, with pressure increasing to 100 atm over a time period of 10 hours using an exponentially rising function.

Computational Platform

Simulations were performed on a Windows XP64 quad core computer with four 18.6 GHz Intel Xeon E532 CPUs and 10 GB RAM. Calculations on the 9393 element grid with 76,536 degrees of freedom were performed with a relative tolerance of 0.01 and an absolute tolerance of 0.001. The computational times for simulating 5 years of heating were typically from several days to a week.

Results and Discussion

Model results are given for a series of cases where the heating is done by thermal conduction, electrical conduction or electrical induction both with and without a pusher fluid.

Conductive Heating with and without Pusher Fluid

With the wall of the heating well being heated by a 500 W/m^2 heat flux, the temperature of the deposit comes up to temperature slowly over a period that exceeds 5 years (43,800 hrs). The temperature (surface color), pressure (contours) and velocity (vectors) at the end of a 5-year heating period without pusher fluid are shown in Figure 3. The temperature has reached almost 1000K near the heating well and progressed through the deposit, but temperatures above 600K have not arrived at the production well. Pressure contours are barely visible and cover a very narrow range around that of the initial deposit pressure. The velocity vectors are very small.

Figure 3. Temperature, pressure and velocity profiles at the end of a 5-year heating cycle with heating due to thermal conduction.

Without pusher fluid, the amount of oil that has left the deposit is negligible as shown in Figure 4. With pusher fluid, the temperature profile is not significantly changed from that shown in Figure 3, but the amount of oil that has left the deposit is significantly larger as seen in Figure 4. This result suggests that convection is not significant in moving the heat around the deposit as the velocity vectors are small for both cases. In the case with the pusher fluid, the oil is being pushed ahead of the pusher fluid, albeit slowly. The amount of gas that has left the deposit is also negligible over the 5 year time period with and without pusher fluid; both cases provide only 10^{-8} weight fraction of gas at the production well (not shown). The deposit in the region of the production well in both cases is essentially plugged against gas flow by kerogen and oil filling the pores in the deposit, thus severely reducing gas permeability.

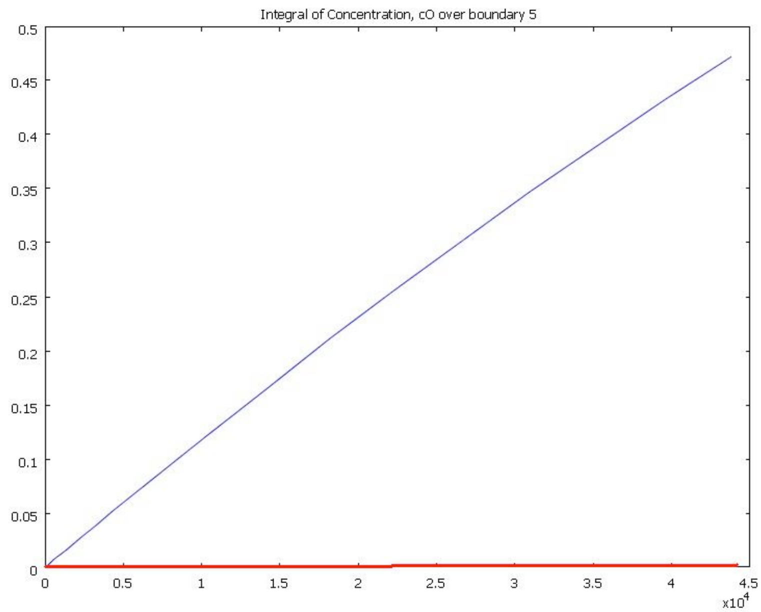


Figure 4. Oil concentration (weight %) at the producer well as a function of time (hrs) covering a period of 5 yrs (43,800 h). Red line – without pusher fluid or with constant heating well temperature boundary condition, Blue line – with pusher fluid.

An example of the thermally induced stress on the deposit is shown in Figure 5. The figure shows results for the same case as Figure 3 but after only 2,016 hrs (84 days) of heating. The temperature distribution (not shown) shows that only a small portion of the deposit next to the heating well has become hot; most of the balance of the deposit remains cold. The thermal stress is negative or compressive and is as high as 2.2 MPa (deep blue color at heating well). According to Pariseau[5], the compressive strength of the deposit is 10.1 MPa, so the formation will not fracture due to the thermal stresses developed during heating.

[5] Pariseau, W.G., *"Rock Mechanics,"*

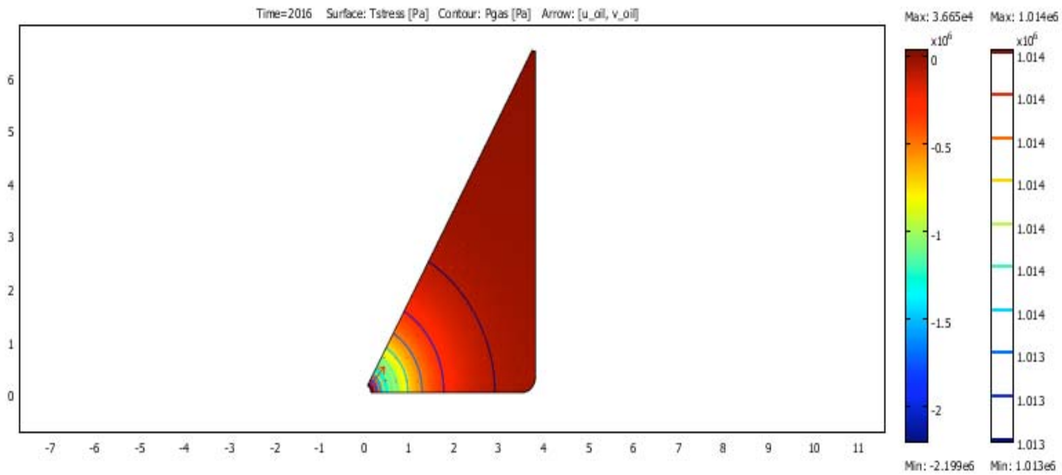


Figure 5. Thermal stress (color) and pressure (contours) on the deposit, both in units of Pa.

Using a constant 1000K wall temperature boundary condition at the heating well, the initial heat flux is 6 times greater than the 500 W/m^2 flux applied in the previous case, resulting in faster heating of the deposit. The temperature (surface color), pressure (contours) and velocity (vectors) after a little more than 1 year of heating are shown in Figure 6. In contrast to Figure 3, Figure 6 shows a zone near the heating well encompassing approximately one-half of the deposit volume that is near a uniform temperature of 1000K. The other half of the deposit volume near the production well is at a low temperature. The flow of oil to the production well is again blocked by the kerogen that has not decomposed near the production well as shown by the velocity vector arrows in Figure 6 and by the production well concentration of oil shown in Figure 4.

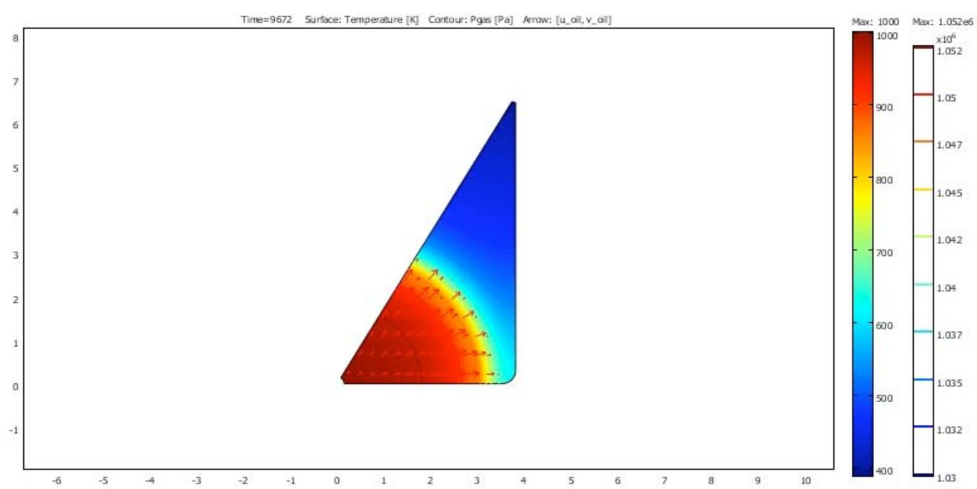


Figure 6. Temperature, pressure and velocity profiles at the end of a 403 d (9672 hr) heating cycle with heating by the application of a 1000K heating well temperature.

DC Joule Heating of Deposit

With the application of electrical current to the deposit, the nascent conductivity of the deposit should act like a resistor and heat the deposit via Joule heating. After the kerogen has decomposed, a carbonaceous char with a much higher conductivity is left behind. This higher conductivity should then move the resistive zone to where the kerogen has not yet decomposed. After 5 years of applying 1,000 volts DC to the deposit, the temperature profile, shown in Figure 7, indicates that there is essentially no heating taking place. Consequently, there is no oil or gas production from the deposit (not shown).

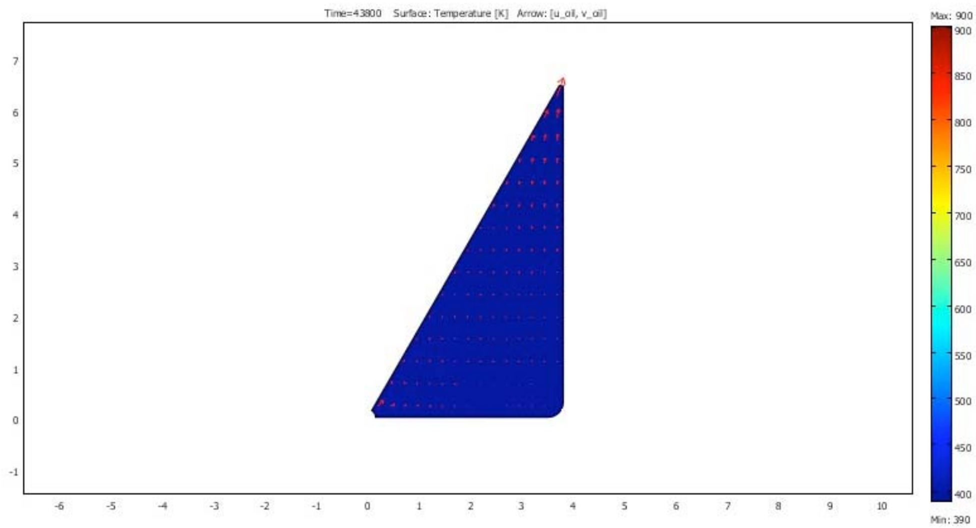


Figure 7. Temperature, pressure and velocity profiles at the end of a 5-year heating cycle with heating by the application of 1,000 volt DC to the deposit.

Combination of Conductive Heating and DC Joule Heating of Deposit

The heating profile obtained by combining conductive heating (Figure 3) with DC heating (Figure 7) is shown in Figure 8. There is no substantial difference between the heating profile in Figure 8 and that shown in Figure 6, indicating that Joule heating in combination with thermal conduction heating of the deposit is not significant, even when the kerogen residue is significantly more electrically conductive than the kerogen.

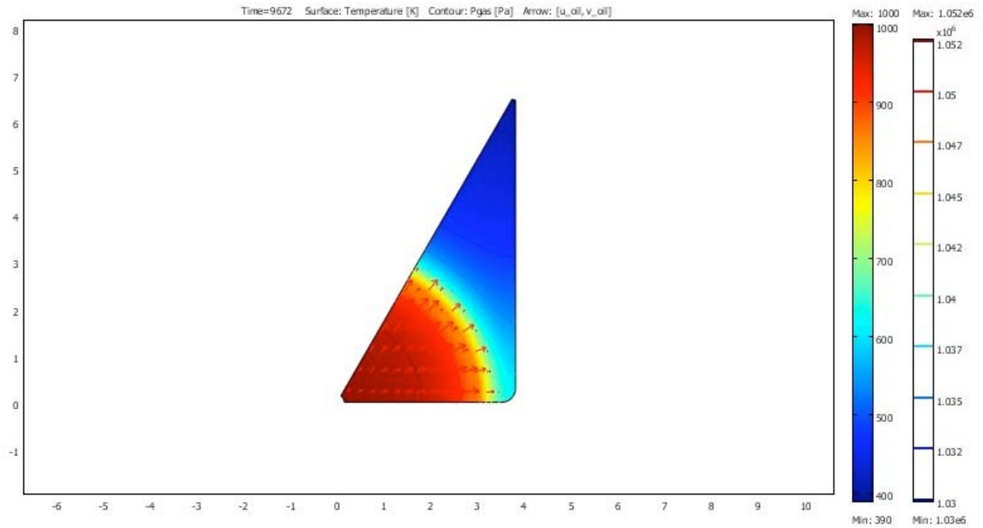


Figure 8. Temperature, pressure and velocity profile at the end of a 403 d (9,672 hr) heating cycle with heating by the application of a 1,000K heating well temperature and 1,000 volts DC at the heating well.

RF Heating of the Deposit

Results from simulations of RF heating using the quasi-static approach with a frequency of 628 MHz and an external current of 2200 A/m^2 are shown in Figure 9. A very different heating profile is observed with heating in the center of the triangular zone where the electric field is highest due to the dipole antenna consisting of the two well casings. While the maximum temperature is only 665K, more of the deposit is heated to this temperature, causing the oil to move toward the production well with larger velocity vectors than with any other method of heating. Again, the area near the production well is cooler and will restrict the flow of oil, but not as severely as with conductive heating (Figures 3 and 6). From Figure 9, it is clear that oil flows to both wells so that both could be used as producer wells with RF heating. The thermal stress after 5 years of RF heating is shown in Figure 10. The maximum thermal stress is a compressive 0.97 MPa, which is well below the compressive strength of the oil shale deposit (10.1 MPa). Hence, micro-cracking is not predicted to occur in the deposit.

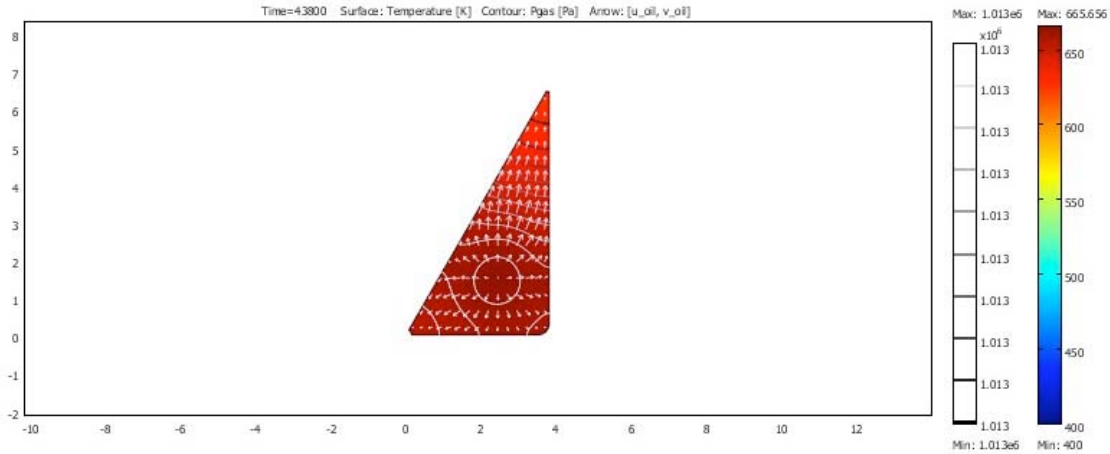


Figure 9. Temperature, pressure and velocity profiles at the end of a 5-year heating cycle with heating by the application of 628 MHz RF with 2,200 A/m^2 external current to the deposit.

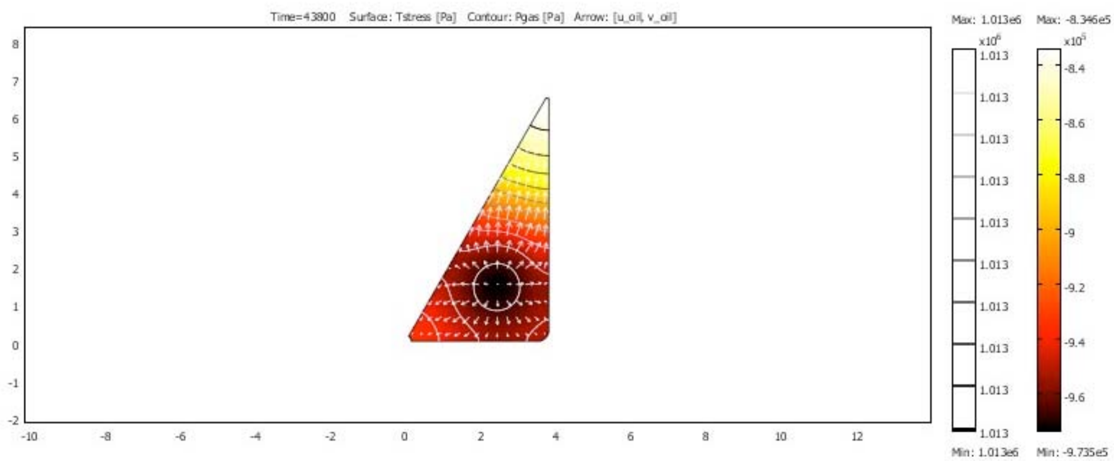


Figure 10. Thermal stress (color) and pressure (contours) on the deposit, both in units of Pa, at the end of a 5-year heating cycle with heating by the application of 628 MHz RF with 2,200 A/m^2 external current to the deposit.

Conclusions

A multi-physics model of *in situ* extraction of oil shale has been developed which couples fluid flow, mass transfer of multiple chemical species, heat transfer, and AC (RF) and DC heating of the deposit. All physical properties used in these model equations are functions of changing local chemistry and temperature. The results show that a pusher fluid is necessary to move the oil to the production well for conductive heating of the deposit. Thermally induced stresses do not induce fracture of the deposit with any forms of heating considered in this work, but higher heat loads, especially in the case of conductive heating, will cause micro-cracking of the deposit. RF heating promotes the more uniform heating of the deposit, which is beneficial to oil extraction and lowers the thermal stresses in the deposit for a given overall heating rate.

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