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

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Disclaimer

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ACEC	Areas of Critical Environmental Concern
AMSO	American Shale Oil Company
BACT	Best Available Control Technology
BLM	Bureau of Land Management
BOPD	Barrels of Oil per Day
CAA	Clean Air Act
cfs	Cubic Feet per Second
DOI	Department of Interior
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EROI	Energy Return on Investment
ESA	Endangered Species Act
FLPMA	Federal Land Policy and Management Act
FWS	U.S. Fish and Wildlife Service
GHG	Greenhouse Gas
GML	General Mining Law of 1872
GPT	Gallon per Ton
ICP	In Situ Conversion Process

MLA	Mineral Leasing Act of 1920
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NOSR	Naval Oil Shale Reserve
OSEC	Oil Shale Exploration Company
PSD	Prevention of Significant Deterioration
RD&D	Research, Development and Demonstration
RMP	Resource Management Plans
ROD	Record of Decision
SIP	State Implementation Plan
SITLA	School and Institutional Trust Lands Administration
SMCRA	Surface Mining Control and Reclamation Act
SOI	Secretary of Interior
WRAP	Western Regional Air Partnership
WSA	Wilderness Study Areas
WSRA	The Wild and Scenic Rivers Act

Executive Summary

Executive summary here

Chapter 1

Introduction

The United States is home to the world's largest known oil shale deposits, 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 1.1, 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 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

[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.

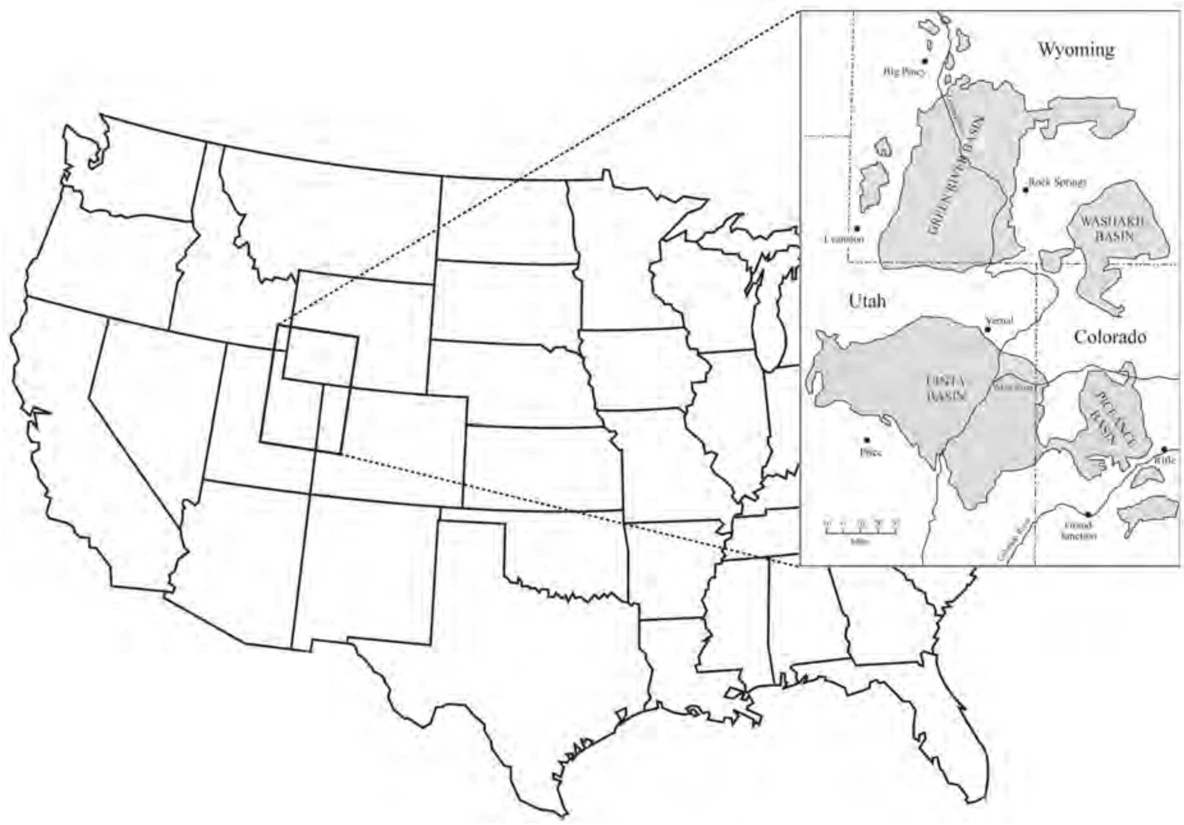
[4] Bartis et al. at 1.

[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).

benefit of developing the oil shale resource has been estimated to be as high as $500 billion over a period of 25 years.[7]

Figure 1.1: 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 chemical compounds called kerogen.[8] It is the kerogen in oil shale that, once separated from the rock through significant heat input, can be converted into liquid

[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.

[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.

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 the resource either by direct heating or 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 gallon per ton (GPT) units, meaning the number of gallons of shale 'oil' recovered from one ton of rock. Another physical variability among oil shale deposits is their surface accessibility, or, stated another way, how much overburden 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. As with overburden, the thickness of the oil shale resource may determine the appropriate extraction technology. Thinner oil shale deposits are ill suited to in situ extraction, but may be developed using either conventional mining methods or modified in situ technologies. All three characteristics, richness, accessibility and thickness, are used to evaluate the economic attractiveness of potentially developable oil shale deposits. By way of illustration, Figures 1.2, 1.3, 1.4, and 1.5 depict the varying richness, thickness and overburden attributes for the in-

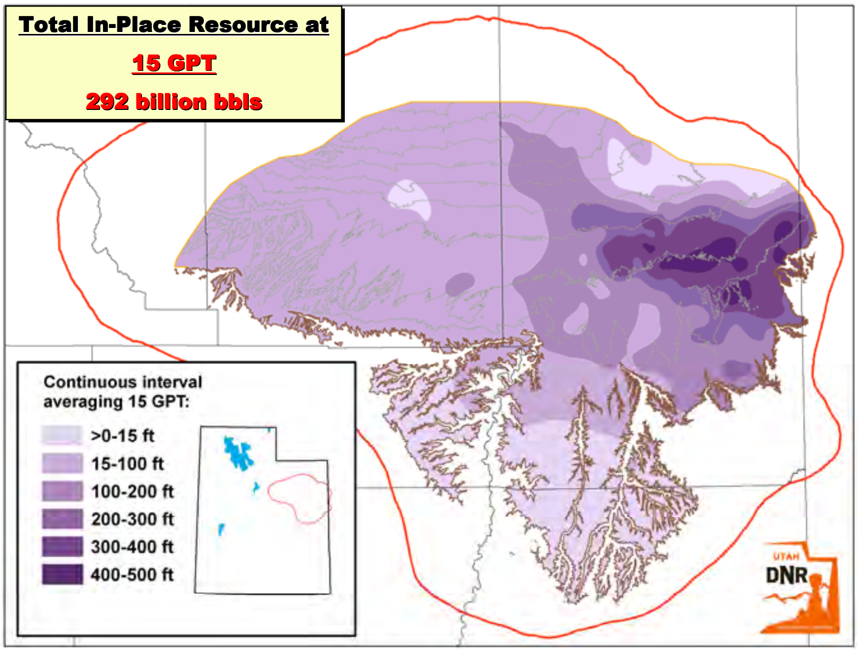
[9]U.S. Department of Energy, Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Reserves, *available at* `http://www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf`. For a discussion of oil shale uses and potential oil shale by-products *see* Oil Shale, Applications and products, `http://en.wikipedia.org/wiki/Oil_shale`.

[10]For a more detailed layperson's 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`.

[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 under lease in Utah. *See* `http://www.ecoshale.com/`.

place oil shale resource in Utah's Uinta Basin.

Figure 1.2: Total In-Place Uinta Basin Oil Shale Resource at 15 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 per day in 2007[12] and 19.5 million barrels per day in 2008.[13] In 2007 and 2008, respectively, 58%[14] and 57%[15] of that demand was met by petroleum imports from foreign countries, many of whom are not considered allies of the United States.[16] Anticipated future oil resources are similarly located, as seen

[12]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.

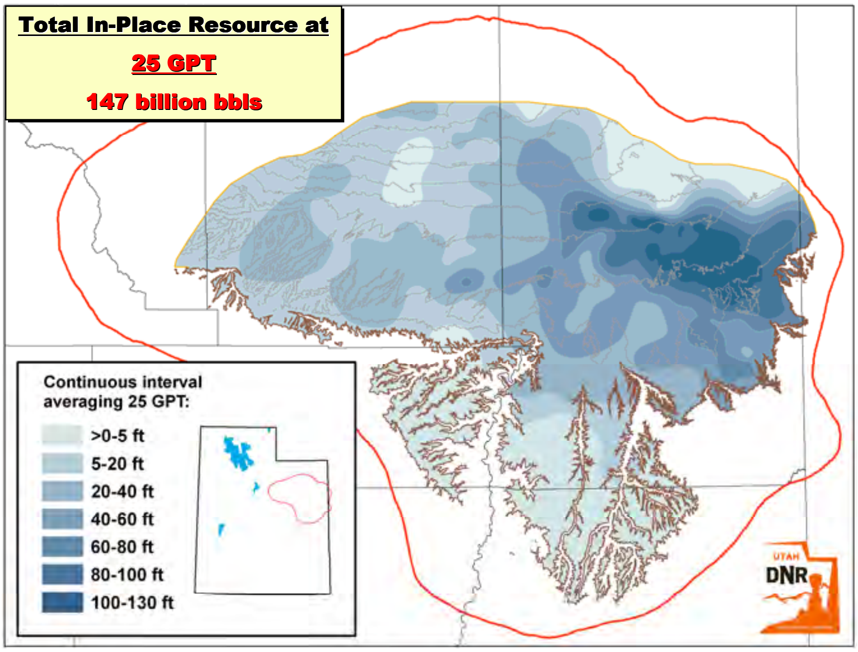
[13]Energy Information Administration, Department of Energy, Energy Explained: Use of Oil, *available at* http://tonto.eia.doe.gov/energyexplained/index.cfm?page=oil_use.

[14]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.

[15]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.

[16]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

Figure 1.3: Total In-Place Uinta Basin Oil Shale Resource at 25 GPT. Source: Michael D. Vanden Berg, Utah Geological Survey.



in Figure 1. Some analysts suggest that decreased reliance on imported petroleum products, particularly from OPEC members, could hold political benefits at the international level by prompting a drop in world oil prices and shifting the prevailing geopolitical balances of power.[17] 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. Accordingly, enhanced national, economic and energy security resulting from reduced reliance on foreign imports of petroleum products is often cited as another benefit to commercial oil shale development.[18]

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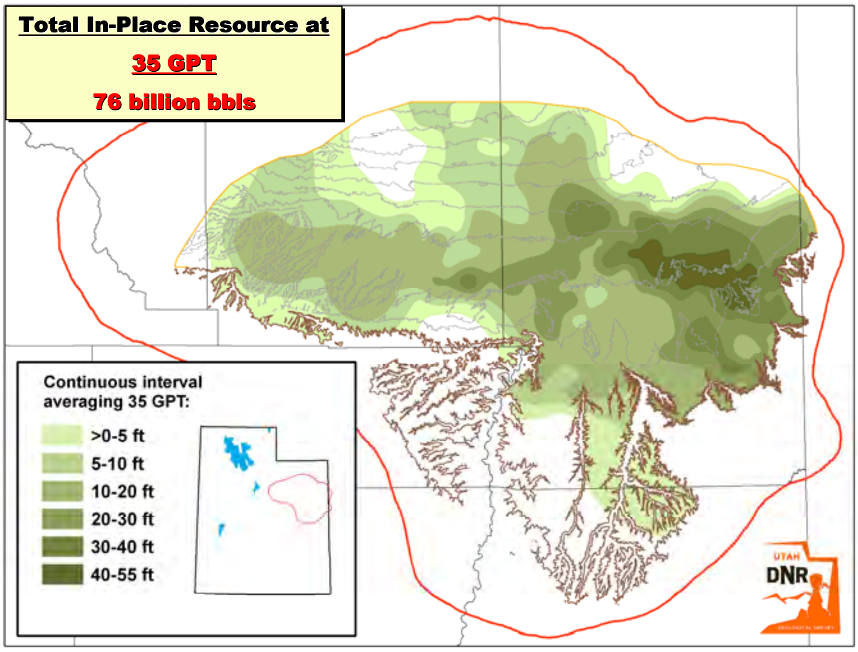
ten petroleum exporters to the United States were Canada, Mexico, Venezuela, Saudi Arabia, Nigeria, Algeria, Russia, Iraq, Angola, and Colombia. Energy Information Administration, Department of Energy, Crude oil and Total Petroleum Imports Top 15 Countries, *available at* `http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/company_level_imports/current/import.html`.

[17]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.

[18]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 1.4: Total In-Place Uinta Basin Oil Shale Resource at 35 GPT. Source: Michael D. Vanden Berg, Utah Geological Survey.



The magnitude of the domestic oil shale resource has prompted several attempts to develop a commercial oil shale industry,[19] 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 and thus gaining access to federal lands is often viewed as critical to the long-term success of commercializing the oil shale resource.[20] Estimates of the federal oil shale resource range from 60%[21] to 73%[22] to 80%[23] 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

[19]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).

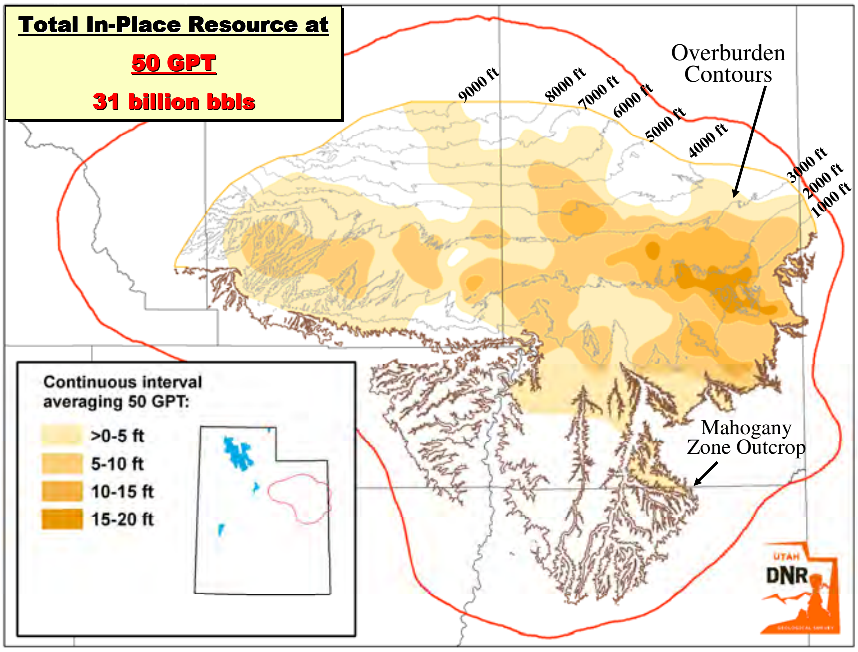
[20]*See* Utah Mining Association, Development of Utah Oil Shale and Tar Sands Resources (Oct. 2008), *available at* http://www.utahmining.org/UMA%20White%20Paper%20on%20Development%20of%20Utah%20OS%20TS.pdf.

[21]textitSee FINAL PEIS at 2-13.

[22]textit See 74 FED. REG. 56867 (Nov. 3, 2009).

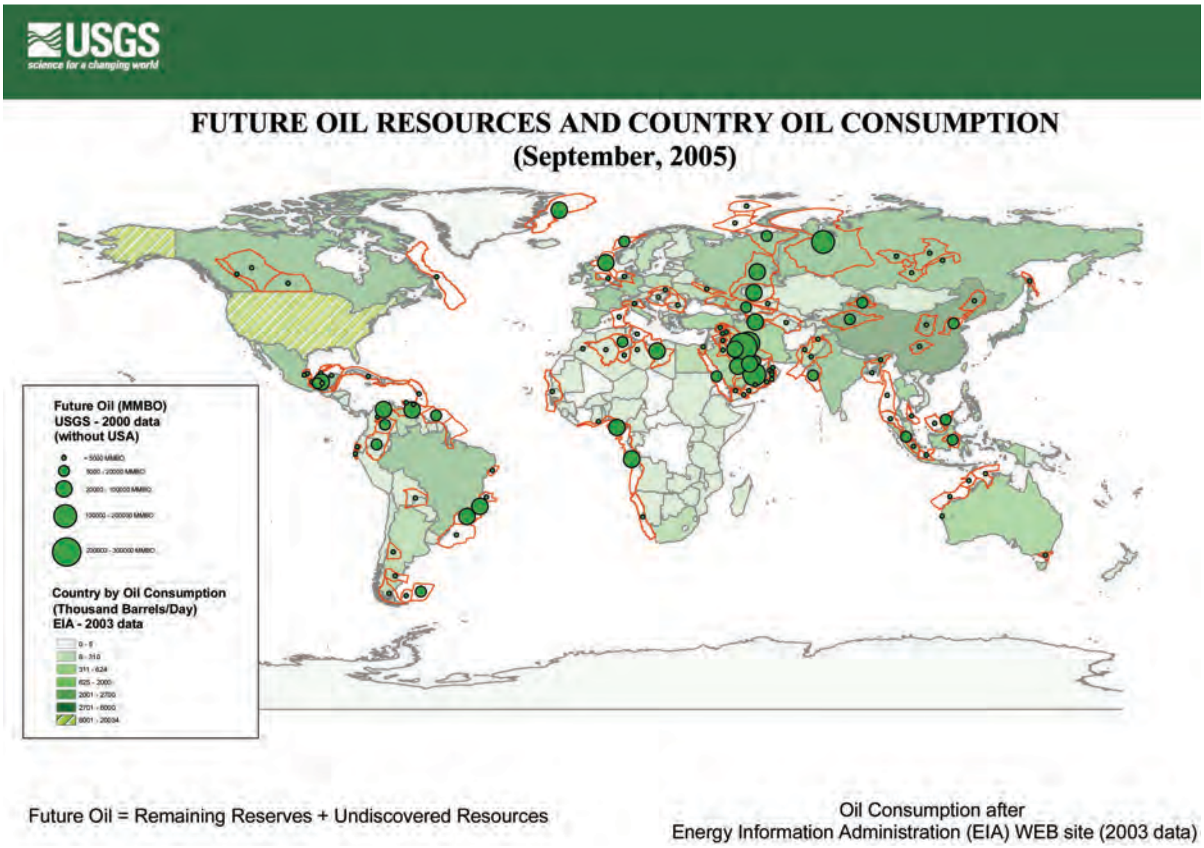
[23]*See* DEPARTMENT OF ENERGY OFFICE OF PETROLEUM RESERVES, Fact Sheet: U.S. Oil Shale Resources, *available at* http://www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf.

Figure 1.5: Total In-Place Uinta Basin Oil Shale Resource at 50 GPT. Source: Michael D. Vanden Berg, Utah Geological Survey.



or total domestic oil shale resource versus most geologically prospective oil shale resource area), and in part to the age and accuracy of the various estimates' underlying mapping data. Even at the low range of federal resource estimates, 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 even if only 60% rather than 80% of the resource is found on federal lands it 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, economical, or avoid a sprawling patchwork of development. And third, there is an abundance of privately held land in Colorado in the most geologically prospective oil shale area, but almost no state land, leaving prospective developers in Colorado who lack large private holdings to focus primarily on federal oil shale-bearing lands.

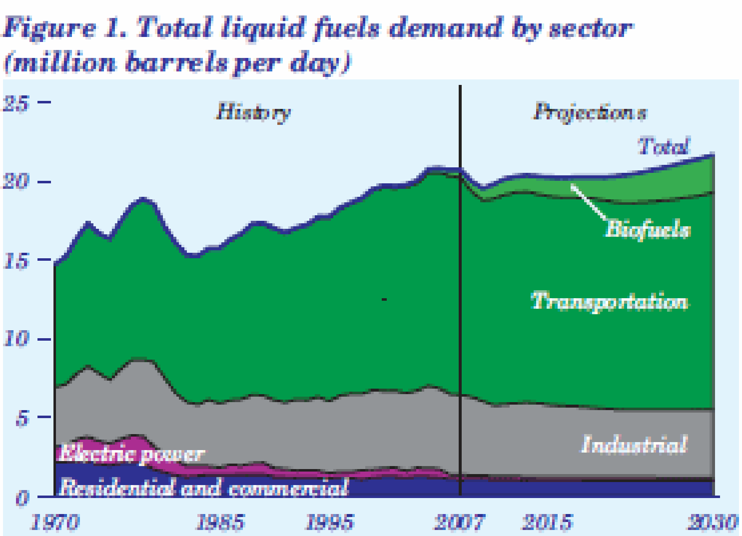
Figure 1.6: Future Oil Resources and Country Oil Consumption. Source: U.S. Geological Survey, Energy Program 2005.



The most recent federal effort to promote development of a commercial oil shale industry, the Energy Policy Act of 2005 (EPAct 2005),[24] 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."[25] EPAct 2005 made "environmentally sound"[26] exploration and development of the oil shale resource in Colorado, Utah and Wyoming a national priority; instituting a Research, Development & Demonstration (RD&D)[27] leasing program for oil shale on the public lands, mandating that the Secre-

[24] 42 U.S.C. §§ 15801 *et. seq.*
[25] 42 U.S.C. § 15927(b)(1).
[26] 42 U.S.C. § 15927(b)(2).
[27] Consistent with the mandate of EPAct 2005, the Bureau of Land Management (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

Figure 1.7: Total liquid fuels demand by sector, 1970–2030. Source: Annual Energy Outlook 2009, Energy Information Administration.



tary of Interior (SOI) complete a final programmatic environmental impact statement for a commercial leasing program for oil shale on the public lands (Final PEIS)[28] and finalize a regulatory framework for federal commercial oil shale leasing and development.[29] Under EPAct 2005, it was intended that these federal activities would, subject to consultation with affected states, tribes, and communities,[30] culminate in the Department of Interior (DOI) issuing commercial oil shale leases on the public lands.[31]

Events between 2005 and the present illustrate the intertwined complexities of realizing the policy aims of EPAct 2005 and creating a domestic oil shale industry. The scope of the Final PEIS, originally

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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).

[28] 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").

[29] 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.

[30] 42 U.S.C. § 15927(b)(3).

[31] *See* 42 U.S.C. § 15927(e).

intended to suffice as 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 scope of 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. Commerical oil shale leasing regulations were promulgated, however, those rules, along with the Final PEIS, are currently the subject of litgation,[32] and no commercial leases have been issued.

Consistent with EPAct 2005, six RD&D leases were 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. As the commercial viability of potential oil shale technologies remains unknown, so do the consumptive demands for water and energy and greenhouse gas (GHG) implications of these technologies. 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.[33] These fluctuations have provided widely shifting incentives and disincentives for investment in oil shale resource holdings and extractive technologies. In short, implementation of an oil shale leasing and development program on the public lands remains the subject of interest and discussion, but very little action.

Numerous challenges have been citd as the obstacles forestalling commercial oil shale development, including adverse environmental impacts, fluctuating oil prices, economic and regulatory uncertainties, and lack of access to federal oil shale resources.[34] 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

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

[33] 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.

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

shale leasing program on the public lands. Where possible, this report also presents potential approaches to managing these challenges and tradeoffs. This report focuses on the most geologically 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,[35] and is thought to represent the most attractive development target for commercial leasing and development of oil shale on the public lands.[36] As 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.[37]

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

[36]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. recently 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).

[37]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 also 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)[1] and the Federal Land Policy Management Act (FLPMA).[2] Summaries of these two statutes

[1] 42 U.S.C. §§ 4321 – 61.
[2] 43 U.S.C. §§ 1701 – 84.

follow.

2.1 THE NATIONAL ENVIRONMENTAL POLICY ACT

The National Environmental Policy Act (NEPA),[3] 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."[4] 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."[5] This analysis of the environmental impacts must utilize "a systematic, interdisciplinary approach,"[6] incorporating public involvement throughout the document's preparation.[7] For most major projects, the process culminates in issuance of a Record of Decision (ROD) explaining the decision.[8]

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.[9] NEPA does not apply to actions by state government (including its subdivisions), to purely private actions, or to actions where the federal agency lacks dis-

[3] 42 U.S.C. §§ 4321-4370d.
[4] 42 U.S.C. § 4321.
[5] 42 U.S.C. § 4332(2)(C).
[6] 42 U.S.C. § 4332(2)(A).
[7] 40 C.F.R. § 1506.6.
[8] 40 C.F.R. § 1505.2.
[9] 40 C.F.R. § 1508.18.

cretionary authority to deny or modify a proposal.[10] 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 the 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.[11] The question of whether the BLM took the requisite hard look in NEPA documents pertaining to oil shale management and public land management within the most geologically prospective oil shale area is currently being litigated in three federal courts.[12]

With respect to commercial oil shale leasing and development, NEPA will generally apply only to projects proposed for federal lands.[13] NEPA analysis is required at the point in time that a federal agency makes an "irretrievable commitment of resources."[14] 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.[15]

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.[16] Instead the Final PEIS identifies only which areas are open to consideration for commercial

[10] *South Dakota v. Andrus*, 614 F.2d 1190 (8th Cir. 1980)

[11] *Kleppe v. Sierra Club*, 427 U.S. 390 (1976).

[12] *See Western Watersheds Project v. Kempthorne*, (No. 08-cv-516-BLW) (D. Id. 2009),F *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).

[13] 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.

[14] *Conner v. Burford*, 848 F.2d 1441 (9th Cir. 1988).

[15] *Conner v. Burford*, 848 F.2d 1441 (9th Cir. 1988).

[16] *See* FINAL PEIS at 1-3.

leasing applications.[17] 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,[18] and a subsequent round of NEPA analysis will be required to address the reasonably foreseeable consequences of developing those leased lands.[19] A third round of NEPA analysis may be required before operational development can proceed, depending 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.[20] Each round of NEPA analysis will afford the interested public an opportunity to review and comment on each proposed action and its alternatives.[21] The BLM must review these comments, respond to substantive issues and revise its alternatives or analysis as appropriate.[22]

Many of the issues presented by commercial oil shale leasing and development will be considered in greater detail during subsequent stages of NEPA review, when more information is available. Issues such as impacts to wildlife, water resources, air quality, and overall greenhouse 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 appro-

[17] *See* FINAL PEIS at 1-3 - 1-5.

[18] OIL SHALE ROD at 38.

[19] NEPA analysis must address actions that are connected to the decision to be made. Actions are connected if they (1) 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).

[20] *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.").

[21] *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)," and 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.").

[22] 40 C.F.R. § 1503.4.

priate 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 should be managed according to the twin principles of multiple use and sustained yield.[23] "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."[24] "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."[25]

In order to meet these several 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)."[26] 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, fish and wildlife resources or other natural systems of processes, or to protect life and safety from natural hazards."[27] Based on these inventories, the BLM must develop, maintain, and revise Resource

[23] 43 U.S.C. § 1701(7).
[24] 43 U.S.C. § 1702(c).
[25] 43 U.S.C. § 1702(h).
[26] 43 U.S.C. § 1711(a).
[27] 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 at pp. ___.

Management Plans (RMPs) for the public lands it administers.[28] 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.[29]

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.[30] 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.[31] 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."[32] 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.[33] Three Colorado BLM field offices are in the process of revising their RMPs. The outcome of pending RMP challenges will be of great importance

[28] 43 U.S.C. § 1712(a).

[29] 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).

[30] OIL SHALE ROD.

[31] OIL SHALE ROD at ii.

[32] OIL SHALE ROD at 41.

[33] *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). Because RMPs constitute "major federal actions significantly affecting the quality of the human environment," NEPA requires preparation of a detailed statement describing the environmental impacts of the proposed amendments. 42 U.S.C. § 4332(2)(C). The adequacy of the environmental impact statement prepared in connection with the amendment of the Vernal RMP also is being contested in *Southern Utah Wilderness Alliance v. Allred*, (No. 1:08-cv-02187) (D. D.C. 2009).

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 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.[34] The locations of the detonations is shown in Figure 2.3. The intent was to stimulate 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 approximately 12 miles southwest of the town of Rifle.[35] Although approximately 455 million cubic feet of natural gas was produced, elevated levels of radioactivity in the gas made it unacceptable for use.[36] The test area is outside the most geologically prospective oil shale area evaluated in the Final PEIS,[37] but within an area where numerous pre-1920 land patents have

[34] *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.gov/SiteInfo/RioBlanco.aspx.

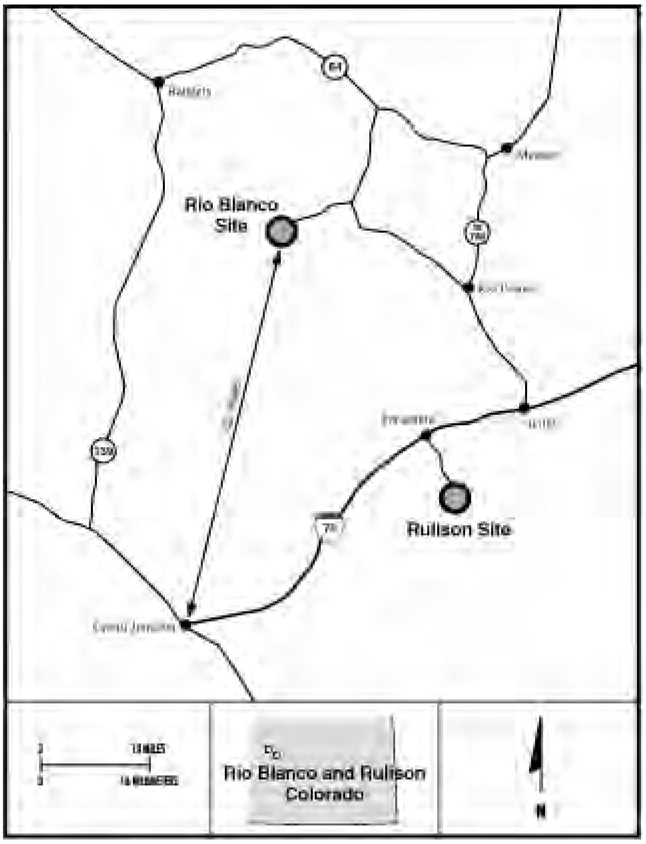
[35] U.S. Department of Energy, Office of Legacy Management, Fact Sheet: Rulison, Colorado, Site (May 2008), *available at* http://www.lm.doe.gov/land/sites/co/rulison/rulison.htm.

[36] 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).

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

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.[38]

Figure 2.1: 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 level.[39] The detonations occurred on May 17, 1973, about 30 miles southwest of the town of Meeker.[40] This is within the most geologically prospective oil shale area and near five existing RD&D leases.[41] As the Final PEIS explains:

[38]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.

[39]KREITH & WRENN at 176.

[40]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.

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

> This site is not included as part of the study because the area is not on BLM-administered land . . . monitoring 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.[42]

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.[43]

[42] FINAL PEIS at 3-12.

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

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. Given the potential of these issues to significantly complicate permitting efforts, potential lessees should receive advance notice of these potential 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) that will 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 sites.[44]

`SiteInfo/RioBlanco.aspx`.

[44] Managing development near nuclear legacy sites is an active and 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."[1] 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.[2] The majority of this area (1,500 acres) would be dedicated to spent shale disposal, which would be piled 250 feet high.[3] While in situ development avoids the difficult problem of spent shale disposal, "the entire lease area will be disturbed during the 20-year [development] time frame."[4]

The anticipated breadth of disturbance distinguishes oil shale from conventional oil or natural gas development, with which extensive disturbance occurs only on portions of the lease tract. Improve-

[1] FINAL PEIS at 4-4 n. c.
[2] FINAL PEIS, 4-8 n. c.
[3] FINAL PEIS, 4-9. This figure assumes that 30% of spent shale is returned to the underground mine for disposal.
[4] FINAL PEIS, 4-11 n. c.

ments in oil and gas extraction technologies, including advances in directional drilling and consolidated drilling pads, have further allowed operators to significantly 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, coal, 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.[5] 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 oil and gas leasing occurs when the BLM inventories resources and prepares an RMP for the area(s) to be opened to leasing.[6] RMPs determine which areas are open to leasing, and for such areas, what if any additional lease stipulations are needed to protect sensitive resources.[7] 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

[5] *See* BLM Oil and Gas Leasing, http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/leasing_of_onshore.html.

[6] 43 U.S.C. §§ 1711, 1712.

[7] 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.

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.[8] 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 generally cannot prohibit the intended use once a lease is issued.[9]

As part of the leasing process, leaseholders are required to post reclamation bonds to assure adequate site restoration.[10] Following cessation of operation and production activities, the leaseholder must plug open oil and gas wells and reclaim the lease site.[11] Reclamation must begin as soon as possible after the surface is disturbed and continue until the BLM determines that successful reclamation has been achieved.[12]

3.2 FEDERAL COAL LEASING MODEL

The Surface Mining Control and Reclamation Act (SMCRA)[13] sets forth requirements for all coal surface mining on federal and state lands.[14] Mine operators must minimize disturbances and adverse im-

[8] 43 C.F.R. § 3162.3-1.

[9] *See* 43 C.F.R. § 3101.1-2. Facility relocation is generally adequate as oil and gas development does not occupy the entirety of the lease site's surface area and specific sensitive areas of the site can be avoided through directional drilling.

[10] 43 C.F.R. § 3104.1(a).

[11] 43 C.F.R. § 3162.3-4.

[12] 43 C.F.R. § 3101.1-2.

[13] 30 U.S.C. §§ 1201-1328.

[14] 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.

pacts 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.[15] Unsuitability criteria are applied prior to lease issuance,[16] either as part of the land planning process or through site-specific NEPA review for specific lease applications.[17]

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.[18] Under rules promulgated by the SOI, these four general factors give rise to 20 specific criteria.[19] In assessing unsuitability, the BLM must rely on the "best available data that can be obtained given the time and resources available to prepare the plan,"[20] and the analysis must be subject to public review and comment.[21] In practice, the BLM usually begins its unsuitability analysis by identifying coal resources with development potential and surveying these areas for constraining resources.[22]

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 invento-

[15] 30 U.S.C. § 1272(b).

[16] 43 C.F.R. § 3461.3-1(a).

[17] 43 C.F.R. § 3461.3-1(b).

[18] 30 U.S.C. § 1272(a)(3), *see also* 30 C.F.R. § 762.11(b).

[19] *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).

[20] 43 C.F.R. § 3461.2-1(b)(1).

[21] 43 C.F.R. § 3461.2-1(a)(1). Because unsuitability determinations constitute "major federal actions significantly affecting the quality of the human environment," they are subject to NEPA's environmental analysis requirements. 42 U.S.C. § 4332(2)(C). The environmental impact statement associated with the relevant RMP usually serves to satisfy this NEPA requirement. *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).

[22] *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).

ries 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.

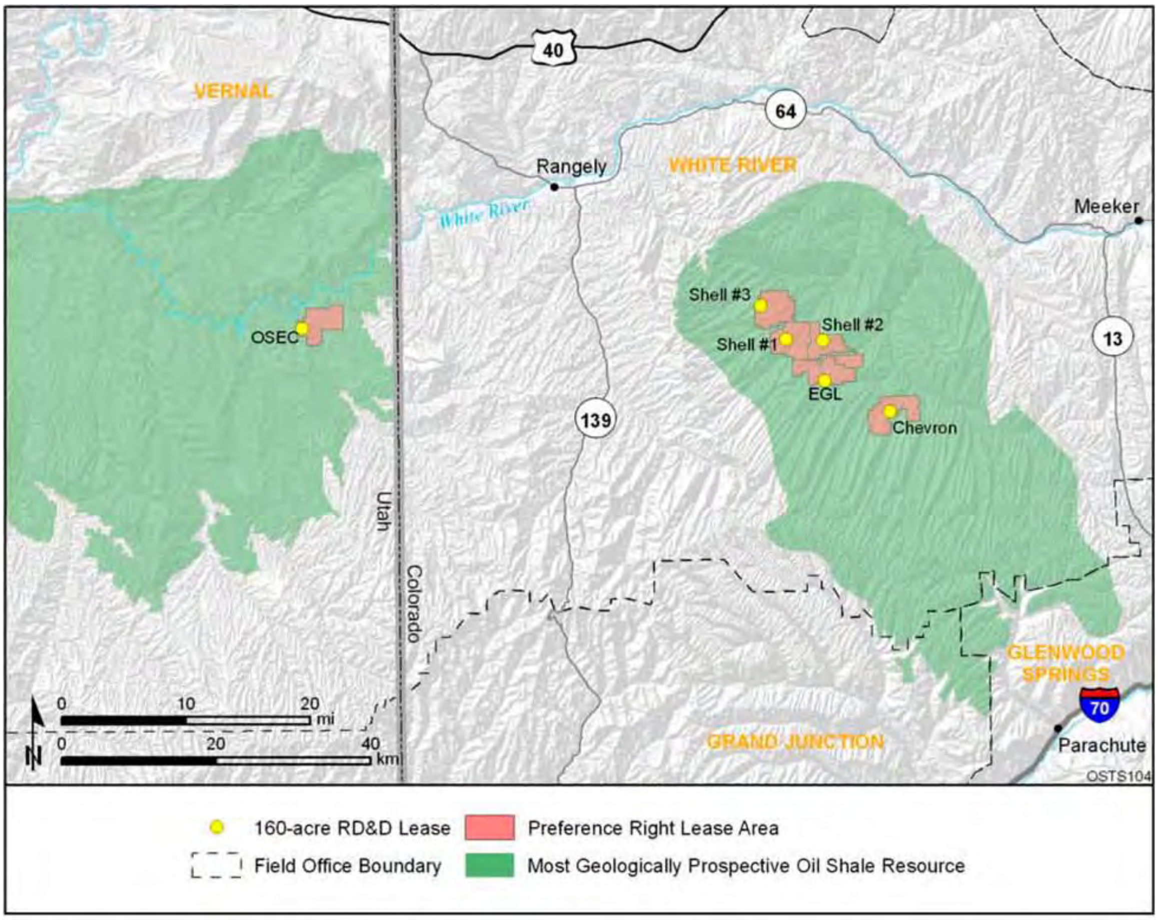
3.3 FEDERAL RD&D OIL SHALE LEASING MODEL

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.[23] 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.[24] 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.[25] The six RD&D lease sites and the associated preference acreage are shown in Figure 3.3. Additional NEPA compliance is required before an RD&D lease can be converted to a commercial lease.[26] While all six first round RD&D leases remain active, none has proceeded to commercial development.[27] Addenda to these RD&D leases were

[23] 70 FED. REG. at 33753.
[24] 70 FED. REG. at 33754.
[25] 70 FED. REG. at 33754.
[26] 70 FED. REG. at 33754.
[27] 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 completed to evaluate availability for commercial leasing. 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 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

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.[28]

Figure 3.1: Locations of the Six RD&D Lease Tracts and Associated Preference Right Lease Areas. Source: Bureau of Land Management, Final PEIS.



The BLM initiated a second round of RD&D leasing on January 15, 2009.[29] 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's RMP.

[28]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`.

[29]74 FED. REG. 2611 (Jan. 15, 2009).

office.[30]

On October 20, 2009, Secretary of the Interior Ken Salazar announced a revamped second round of RD&D lease solicitations.[31] 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.[32]

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.[33] 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.[34] 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."[35]

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[30] 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.

[31] 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.

[32] 74 FED. REG. at 56868.

[33] 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`.

[34] 74 FED. REG. at 56868.

[35] 74 FED. REG. at 56868.

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[36] and management on public lands were issued on November 18, 2008.[37] The regulations include provisions governing pre-lease exploration, leasing processes, bonding, operations, reclamation, and inspection and enforcement.[38] The regulations allow issuance of exploration licenses covering up to 25,000 acres[39] and leasing of up to 5,760 acre tracts,[40] limiting leaseholders to no more than 50,000 acres in any one state.[41] Leases are subject to a $2.00 per acre annual rental charge,[42] with production royalties starting at 5% and increasing to 12.5% over time.[43] NEPA compliance is required prior to issuance of a lease or exploration license, or approval of a plan of development.[44] 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."[45] 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

[36]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.

[37]*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.

[38]43 C.F.R. part 3900.

[39]43 C.F.R. § 3910.31(c).

[40]43 C.F.R. § 3827.20.

[41]43 C.F.R. § 3901.20.

[42]43 C.F.R. § 3903.40.

[43]43 C.F.R. § 3903.52.

[44]43 C.F.R. § 3900.50.

[45]43 C.F.R. § 3922.20(c)(9).

impacts on wildlife habitat management" before a lease can be offered for bid.[46] 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.

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.[47] Federal lands are likely to remain effectively closed to commercial oil shale development until these legal challenges are resolved.[48]

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 will be disturbed during development. Surface coal leasing regulations assume similarly complete sur-

[46] 43 C.F.R. § 3922.20(c)(7).

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

[48] 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.

face 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 to surface coal mining or oil shale development, 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 the BLMs 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 what would be at best difficult post-leasing avoidance or mitigation. Issuing commercial oil shale leases absent 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 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).[49] 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."[50] 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.[51] 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.

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 devel-

[49] 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.
[50] HANSON & LIMERICK at 12.
[51] Pub. L. 106-398 §3403.

> opment that will have tremendous adverse impacts on Colorado.[52]

In contrast to Colorado and the current posture of the federal government, Utah actively promotes oil shale development, stating that Utah is "open for business as it relates to oil shale."[53] In Utah, there are 99 active state leases conveying rights to develop oil shale on over 97,848 acres of state land.[54] 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.[55] 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."[56] 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)[57] 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.[58] 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

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

[53] 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 Basin 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."

[54] 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.

[55] UTAH CODE ANN. § 53C-1-102(2).

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

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

[58] 30 U.S.C. § 29.

$5.00 per acre for claims.[59] Patented land becomes private property and can be used for mining or other purposes.

Passage of the Mineral Leasing Act of 1920 (MLA),[60] which applies to oil shale, marked a change in course by replacing the system of location and patent with requirements that miners obtain leases before developing most minerals on federal lands and pay royalties on developed minerals. Under the MLA, mineral development could not lead to land 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),[61] provided that the claimant conducted annual labor and improvements as required under the GML.[62] Where a claimant failed to conduct required assessments or improvements, the claim would be open to relocation in accordance with federal law.[63] Passage of the MLA precludes relocation, so if a claim fails for lack of assessment work, the full interest in the property reverts to the United States and the minerals are available only through lease.[64] 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.[65] Subsequent litigation and settlements extended patents for significant additional lands,[66] 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

[59] $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).

[60] 30 U.S.C. § 181 – 287.

[61] 30 U.S.C. § 193.

[62] 30 U.S.C. § 28.

[63] 30 U.S.C. § 28.

[64] *Hickel v. Oil Shale Corp.*, 400 U.S. 48, 57 (1970).

[65] *Andrus v. Shell Oil Co.*, 446 U.S. 657, 667 (1980).

[66] *See TOSCO Corp. v. Hodel*, 611 F.Supp 1130 (D. Colo. 1985) *vacated because of settlement* at 826 F.2d 948 (10th Cir. 1987)

and richest oil shale bearing formations within Utah.[67] One prospective oil shale developer in Utah the Oil Shale Exploration Company controls more than 46,000 acres of privately owned oil shale lands.[68] 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."[69] 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.[70] The federal government has long exercised its obligations as trustee to manage the use of Indian land for mining and mineral development.[71] 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.[72]

The Secretary is further obligated to provide tribes or individual Indians "advice, assistance, and information during the negotiation of a Minerals Agreement."[73] Therefore, as a general rule, the DOI is

[67] VANDEN BERG at Plates 3 and 5.

[68] *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)

[69] 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.

[70] 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).

[71] *See* 26 Stat. 795 (1891) *codified at* 25 U.S.C. § 397 (allowing tribes, with the consent of the SOI, to lease certain lands).

[72] 25 U.S.C. § 2102(a).

[73] 25 U.S.C. § 2106.

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.[74] NOSR No. 2, covering 88,890 acres, was located in Utah's Carbon and Uintah counties.[75] The National Defense Authorization Act of 2000[76] transferred approximately 84,000 acres of NOSR No. 2 to the Ute Indian Tribe,[77] which received the land, including mineral rights, in fee simple and not subject to federal management in trust status.[78] Consequently, development of these Ute tribal lands does not require DOI approval or authorization.[79] 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.[80] (The overlay of tribal lands on the oil shale resource in Utah and the location of NOSR No. 2 are shown in Figures 3.7 and 3.8.) To date, the Ute Indian Tribe has not adopted a position on commercial oil shale development.

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,

[74] NOSRs Nos. 1 and 3 are located in Colorado and remain under federal control.
[75] Anthony Andrews, Congressional Research Service, Report to Congress, *Oil Shale: History, Incentives, and Policy* 2 (April 13, 2006).
[76] Pub. L. 106-398.
[77] Pub. L. 106-398 § 3403; *see also* Andrews at 28.
[78] Pub. L. 106-398 § 3403.
[79] "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).
[80] *See* Vanden Berg at Plates 3 and 5.

the BLM royalty rate will automatically increase annually after the first five years[81] where the SITLA royalty rate increase is discretionary.[82] 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[83] while the BLM leases contain a 20 year primary term.[84] 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."[85] 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 is important because it potentially negates the need for off-site sources of power to support commercial oil shale development, which in turn determines 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.[86] Reliance on the oil and gas royalty approach in the oil shale context may not be optimal, however, given that far more energy is required to produce and upgrade shale oil than is required to power compressors, dehydrators, and other equipment for purposes of oil and gas production.

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,"[87] and calculated "at the point of shipment

[81] 43 C.F.R. § 3903.52(b).
[82] 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).
[83] Oil Shale Lease Form 6/22/05 at § ___ .
[84] 43 C.F.R. § 3927.30.
[85] 43 C.F.R. § 3903.54(a).
[86] 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).
[87] Oil Shale Lease Form 6/22/05 at § 6.4.

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."[88] 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."[89]

The mandatory royalty escalation contained in the BLM leases should encourage timely development and discourage extended, speculative holding of undeveloped leases.[90] Whether the potentially lower production revenue, potential minimization of NEPA requirements, or other factors make SITLA leases more appealing than BLM leases remains to be seen.

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 underlie 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.[91] Within the Uinta Basin, the Utah Geological Survey estimates that tribal, state, and private interests control over 45% of oil shale resources.[92] Development of these non-federal lands may be advantaged initially as such development

[88] Oil Shale Lease Form 6/22/05 at § 6.1.
[89] Oil Shale Lease Form 6/22/05 at § 6.3.
[90] 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).
[91] Final PEIS, 2-13.
[92] Vanden Berg at 8.

will not be delayed by legal challenges to either the RMP amendments or oil shale leasing regulations.[93] 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.[94] 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 prsent 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 an oil shale industry develops to the point where certain technologies dominate, the federal government may be hard pressed to foster new, innovative technologies and may instead find itself on a reactive footing. This quandary can be avoided if the federal government actively engages in oil shale development policymaking, supporting alternatives that advance environmentally responsible, synergistic development. 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. If oil shale is to be developed commercially, oil shale leasing on the public lands should be

[93] On January 16, 2009, a coalition of 13 environmental organizations filed two lawsuits in the U.S. District 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.

[94] 43 C.F.R. § 3900.50.

treated as part of a coordinated federal energy and resource management strategy.

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 consolidate control and improve management efficiency. Pooling and unitization also provides a valuable tool 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,[95] excluding lands reserved for permanent national purposes such as military or Indian reservations.[96] Lands granted to the state were intended to support Utah's public schools.[97] The sections granted to the state are discontinuous, resulting in a checker-boarded pattern of ownership whereby the state owned one ninth of the land within the state. This fragmented pattern of ownership complicates management for federal and state government agencies because jurisdiction

[95] 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).

[96] 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.

[97] 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).

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.[98] 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,[99] which exchanged SITLA lands along the Colorado River Corridor for mineral bearing lands in the Uinta Basin (illustrated in Figure 3.8).

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.[100]

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

[98] *See* 43 U.S.C. § 1716.
[99] P.L. 11-053H.R. 1275, 111th Cong. (2009).
[100] H.R. 1275, 111th Cong., § 3(f) (2009).

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 for similar efforts 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.[101] 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.[102] Under most state's unitization laws, operators are allowed to proceed despite being unable to reach agreement with all landowners, provided that a statutorily set percentage of landowners con-

[101] 30 U.S.C. § 202a; 43 C.F.R.§ 3487.
[102] *See* Nancy Saint-Paul, Summers Oil and Gas § 54.1 (3d ed. 2009).

sent.[103] "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 or allowable to an operator.[104] 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 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.[105]

Future decisions as to whether oil shale developers utilize in situ thermal processing or conventional mining operations will help determine the extent to which logical mining units or pooling and unitization are suitable tools for managing oil shale leasing and development on the public lands. In situ development may present issues similar to those raised with oil and gas development if liquefaction or gasification is inconsistent with property ownership. Further assessment of legal tools for facilitating coordinated 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

[103] *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).
[104] *See* Nancy Saint-Paul at § 54.1.
[105] *See* Nancy Saint-Paul at § 54.2 (discussing 11 methods of pooling or unitization).

equivalent.[106] 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.

Federal leadership and policymaking in the area of oil shale leasing and development is also needed for other reasons. A commercial oil shale industry, given the substantial financial and technical development challenges that it faces, will require some level of assurance from the federal government that it can secure access to oil shale-rich public lands under predictable conditions. 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

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

lands.[107]

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 coal development would benefit the decision-making and planning processes integral to oil shale leasing and development on the public lands.

[107] *See generally* GULLIFORD.

Figure 3.2: Land Ownership in the Uinta Basin. Source: Bureau of Land Management, Vernal RMP ROD.

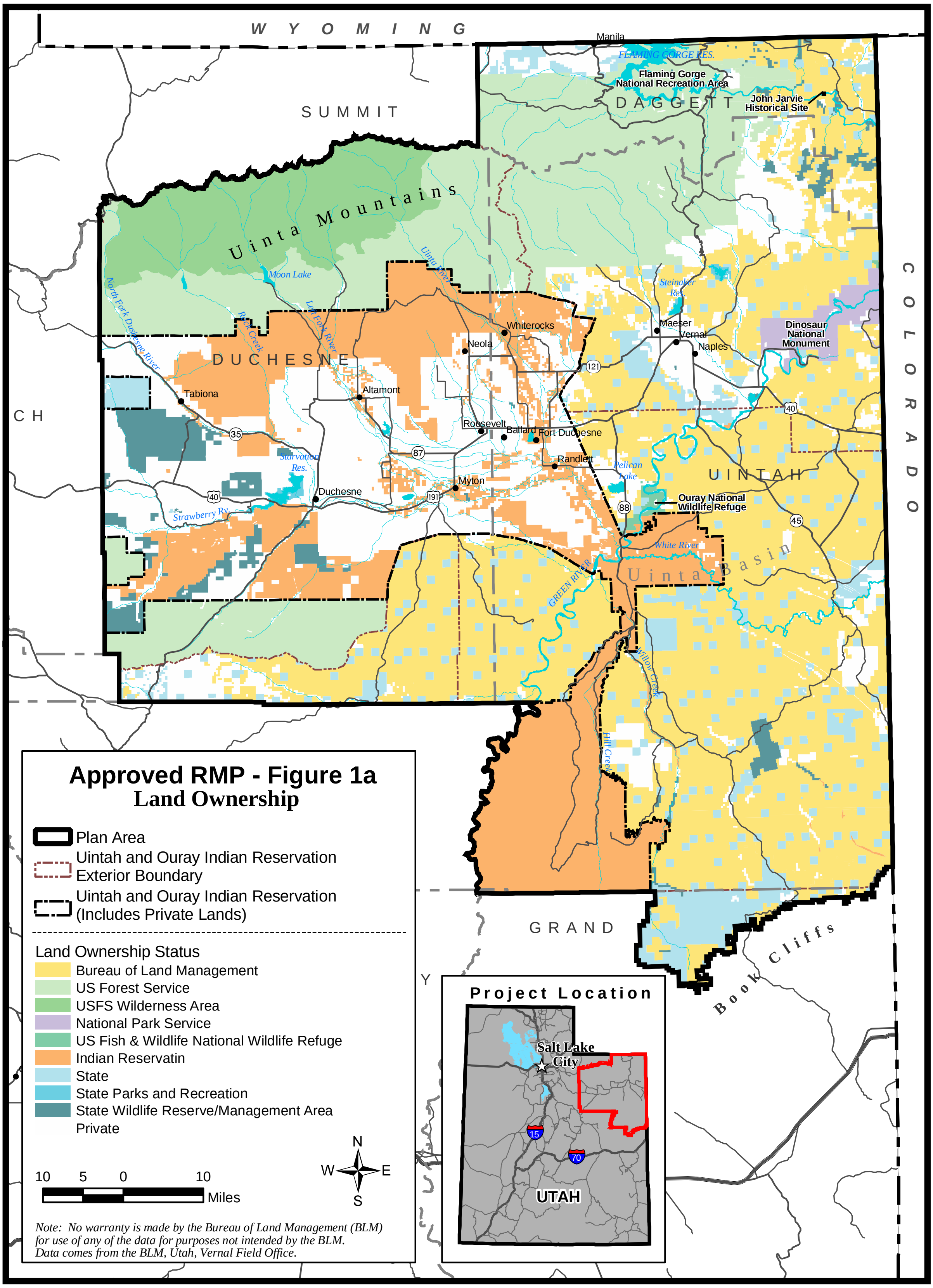


Figure 3.3: Overlay of Tribal Lands and Oil Shale Deposits in the Uinta Basin. Source: State of Utah Automated Geographic Reference Center.

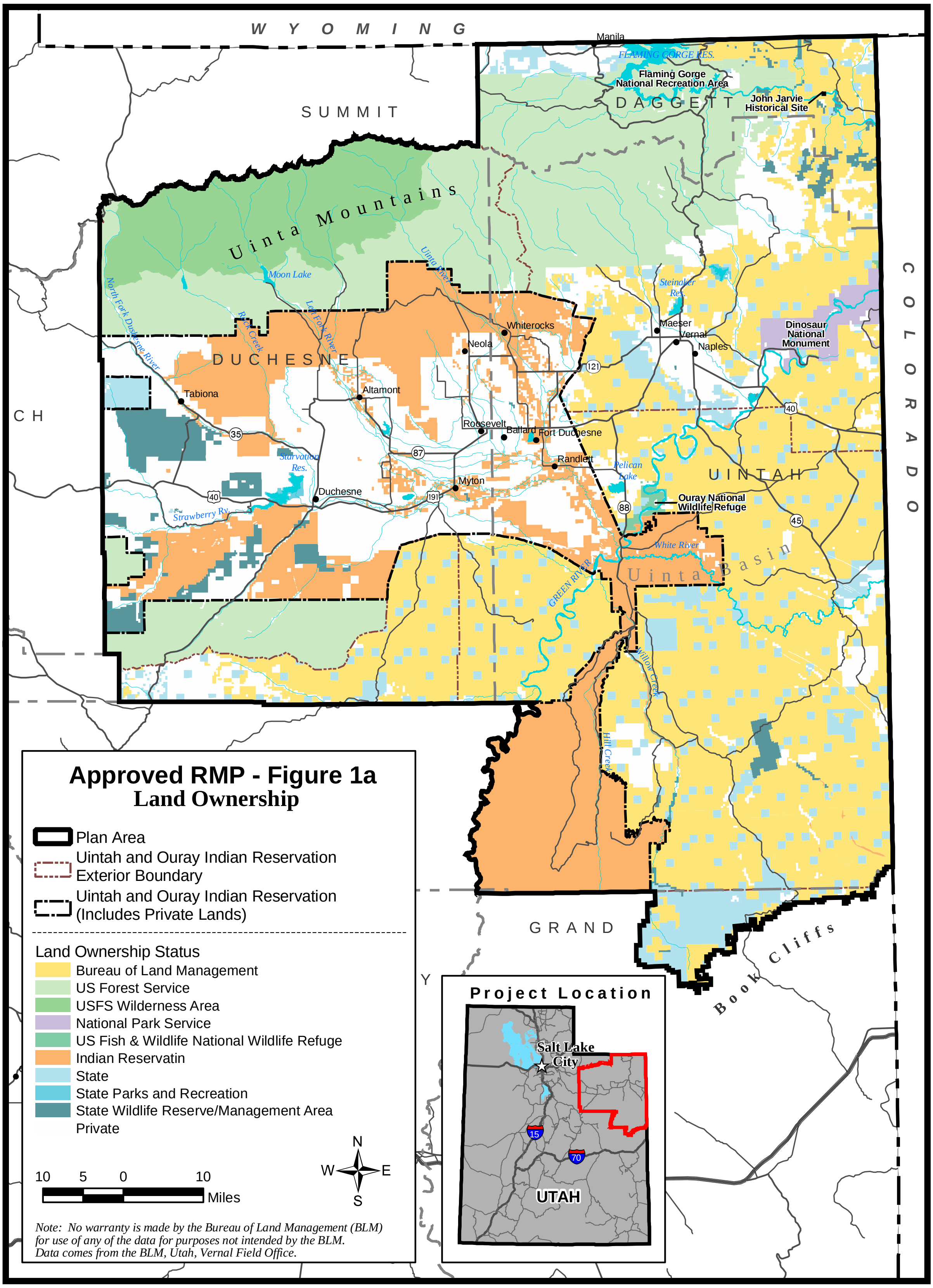


Figure 3.4: NOSR No. 2. – REPLACE WITH CRS FIGURE

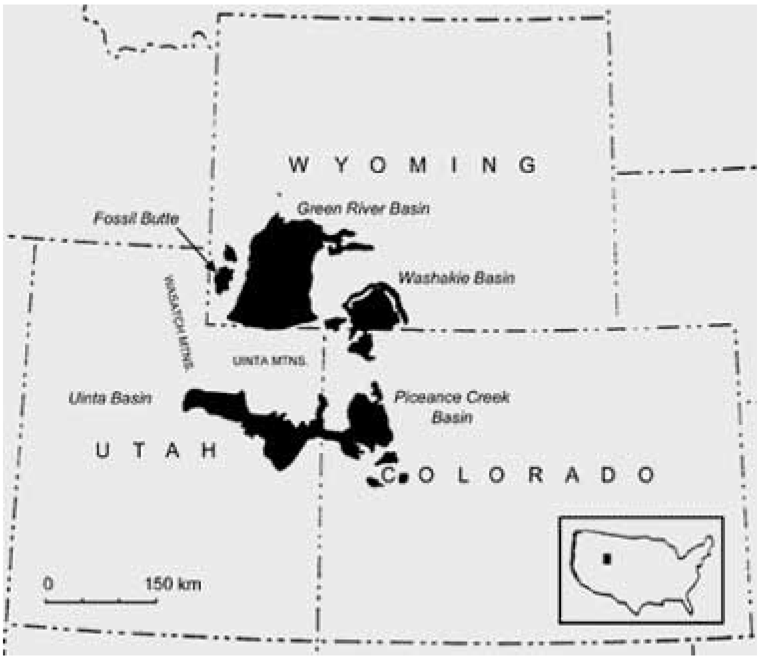
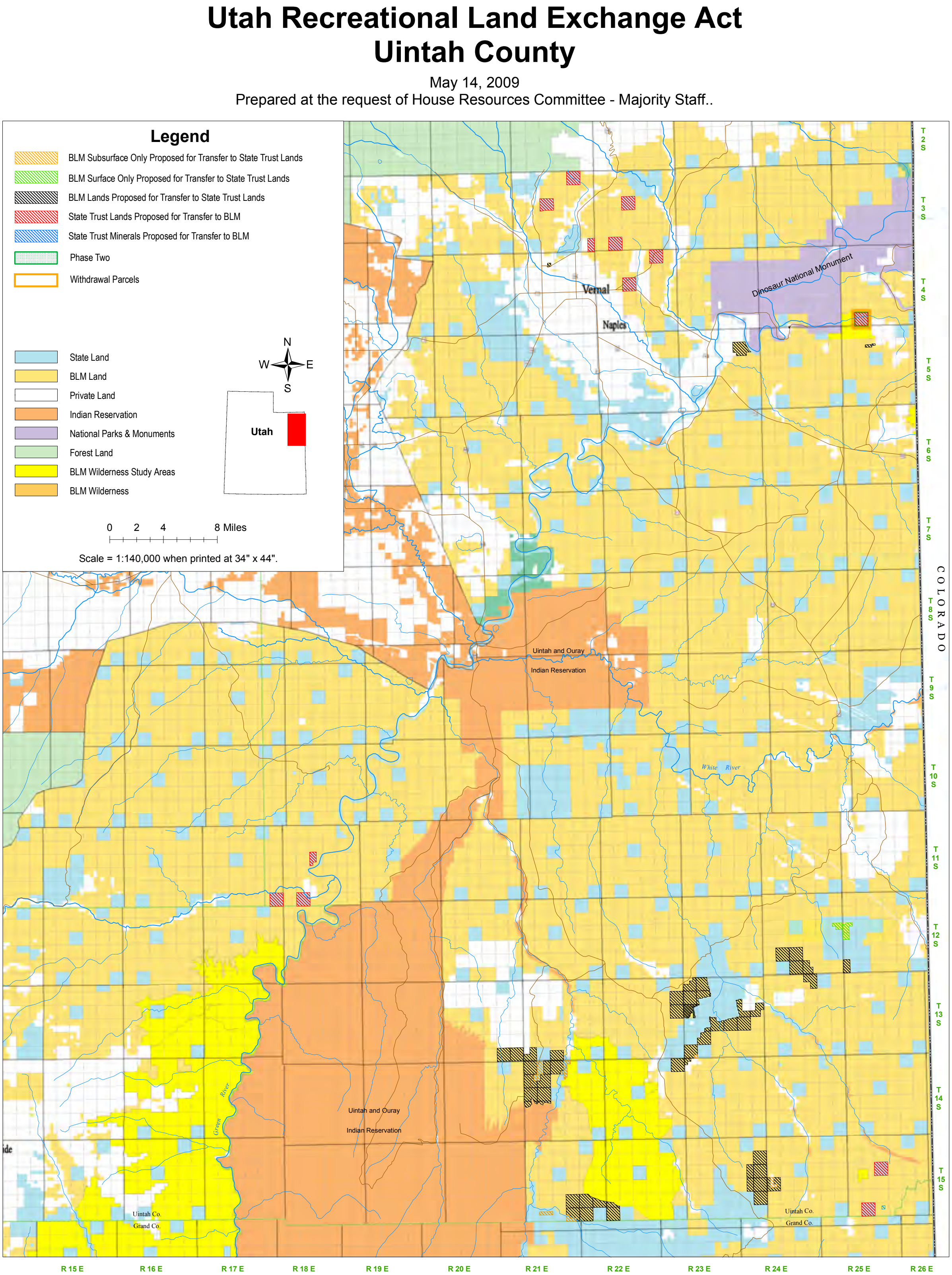


Figure 3.5: Utah Recreational Land Exchange Act Uintah County. Source: Bureau of Land Management.



CHAPTER 4

COMPETING LAND USES

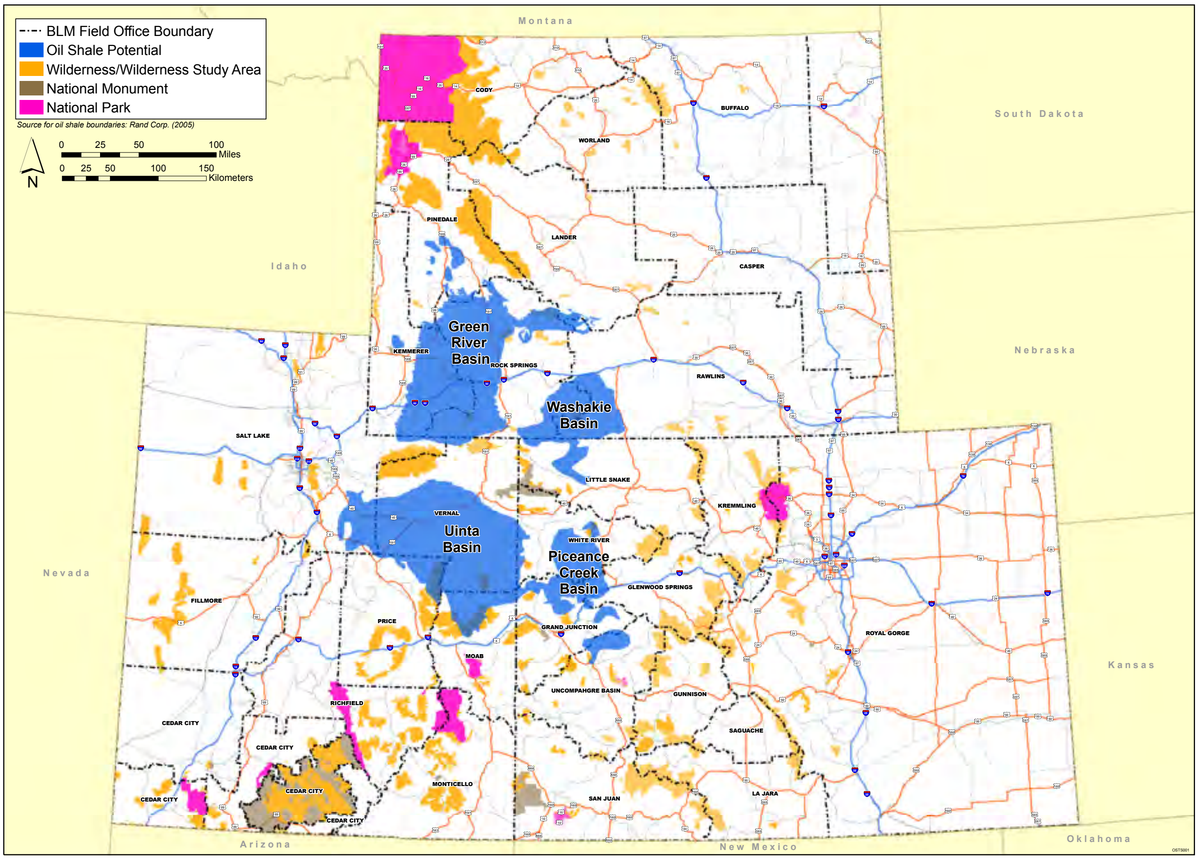
FLPMA's multiple-use mandate requires the BLM to manage its resources "in the combination that will best meet the present and future needs of the American People . . . taking into account the long-term needs of future generations for renewable and non-renewable resources."[1] Some lands may be used for certain uses at the exclusion of others provided the mix of outputs satisfies this broad mandate.[2] Exclusion of competing resource uses is especially relevant for oil shale development as the near total surface disturbance anticipated with oil shale development[3] is not compatible with other land uses. A related issue presented by 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 note-

[1] 43 U.S.C. § 1702(c).
[2] 43 U.S.C. § 1702(c).
[3] *See* FINAL PEIS at 4-4 n.C and 4-8 n.C.

Figure 4.1: Oil Shale Deposits in Colorado, Utah and Wyoming. Source: Bureau of Land Management, Final PEIS.

Oil Shale Deposits in the Three-State Area



worthy 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.[4]

4.1.1 Wilderness Areas and Wilderness Characteristics

Wilderness Areas are designated through federal legislation and subject to the protections of the Wilderness Act.[5] 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."[6] Unless otherwise provided by law, commercial enterprises, roads, structures, and motorized or mechanical vehicles cannot be located or operated within Wilderness Areas.[7] 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).[8] Protections afforded by the Wilderness Act and applicable to formally designated Wilderness Areas are non-discretionary, as are protections afforded WSAs created under FLPMA.[9] 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 within the most geologically prospective oil shale area. Within Utah, approximately 9,400,000 acres are currently proposed for Wilderness designation under the Red Rocks Wilderness Bill.[10] A sizeable portion of this proposed wilderness acreage

[4] OIL SHALE ROD at 9, 17.

[5] 16 U.S.C. §§ 1131 – 36.

[6] 16 U.S.C. § 1131(c).

[7] 16 U.S.C. § 1133(a).

[8] *See* OIL SHALE ROD at 9, 17.

[9] 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).

[10] *See* the Red Rocks Wilderness Bill, H.R. Res. 1919, 110th Cong. (2008). The Red Rocks Wilderness Bill was originally introduced in 1989 and has been reintroduced during each subsequent legislative session. During the 110th Congress (2007-2008), the bill claimed 161 cosponsors in the House of Representatives and 20 co-sponsors in the Senate; as of December 10, 2009, the Bill has 154 House co-sponsors and 22 Senate co-sponsors in the 111th Congress. *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

coincides with existing WSAs, but large portions are subject to the BLM's discretionary management authority under FLPMA.[11] 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 character or characteristics. While the mere existence of wilderness character 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.[12] 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 4.1.1).[13] 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.[14] 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.[15] 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

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).

[11] 43 U.S.C. § 1712.

[12] 43 U.S.C. § 1712(c)(6).

[13] 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.

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

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

public lands not expressly closed to leasing.

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."[16] In developing and revising land use plans, BLM must "give priority to the designation and protection of areas of critical environmental concern."[17] Existing ACECs that are currently closed to mineral development are unavailable for commercial oil shale development.[18]

The recently revised RMP for the BLM's Vernal Field Office designated seven ACECs covering 131,700 acres (shown in Figure 4.1.2),[19] however not all of these areas are closed to mineral development.[20] 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.[21] 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.[22]

A coalition of environmental organizations is challenging, among other things, the BLM's decision to forego ACEC designation for eligible areas.[23] If the challenge is successful and results in a decision to designate additional areas as ACECs that are closed to mineral development, this challenge could expand the area unavailable for oil shale leasing. Resolution of this challenge is not a legal prerequisite

[16] 43 U.S.C. § 1702(a).
[17] 43 U.S.C. § 1712(c)(3).
[18] OIL SHALE ROD at 9.
[19] VERNAL RMP ROD 118-21.
[20] VERNAL RMP ROD at 118-21.
[21] U.S. BUREAU OF LAND MANAGEMENT, VERNAL FIELD OFFICE, PROPOSED RESOURCE MANAGEMENT PLAN AND FINAL ENVIRONMENTAL IMPACT STATEMENT (VERNAL RMP FEIS) at Figure 32.
[22] VERNAL RMP ROD at118-21.
[23] 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.

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)[24] 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."[25] River segments are first inventoried as eligible 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.[26]

Designation as a wild or scenic river triggers preparation of a comprehensive river management plan addressing both resource protection and development.[27] 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.[28] Designated segments are unavailable for mineral leasing.[29] 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 desig-

[24] 16 U.S.C. § 1271-1287.
[25] 16 U.S.C. § 1271.
[26] BLM Manual § 8351.52 (1992), *available at* http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/blm_manual.html.
[27] 16 U.S.C. § 1274(d)(1).
[28] 16 U.S.C. § 1278(a).
[29] OIL SHALE ROD at 9, 17.

nation: 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.[30] 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).[31] 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[32] 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 Colorado-Utah border, all of the Delores River, and portions of the Green River.[33] 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.[34] Because these more distant segments were designated suitable, they are subject to interim protections and more distant development could indirectly impact suitable or designated river segments. 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.[35] It is Utah and the BLM's position that water

[30] Vernal RMP ROD at 44

[31] Vernal RMP FEIS at Figure 32. The White River is the largest surface water source within the most geologically prospective oil shale area.

[32] 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.

[33] 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.

[34] 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).

[35] 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

rights secured under the Upper Colorado River Compact are valid, existing rights.[36] 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 juicial scrutiny. As with wilderness characteristics, WSRA designation may represent a political constraint overshadowing the legal protections imposed.

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.[37] Crucial elk and mule deer winter range, as well as a lynx linkage zone, have been identified south of the White River, as shown in Figure 4.2.[38] 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."[39]

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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.

[36] *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.").

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

[38] VERNAL RMP FEIS at Figure 46.

[39] 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

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 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.[40]

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)[41] 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.[42] 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.

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.

[40]Utah Division of Wildlife Resources, Utah's State Listed Species by County (Feb. 10, 2009).

[41]16 U.S.C. §§ 1531-43 (2008).

[42]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.

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."[43] The ESA protects and aids in the recovery of imperiled species and the ecosystems upon which they depend,[44] protecting "listed" species and their habitats by prohibiting the "take" of listed animals, except under federal permit.[45] 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[46] a species: habitat degradation, overuse of the species, disease or predation impacts, the inadequacy of existing regulatory protections for the species, and other natural or human threats to the species survival.[47] Economics are not considered when making a listing determination.[48] 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."[49] 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

[43] 16 U.S.C. § 1531(b).

[44] 16 U.S.C. § 1531.

[45] 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. Protection of listed plants is discussed in more detail at pp ___.

[46] 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 priorities.

[47] 16 U.S.C. § 1533(a)(1)(A) through (E) (2008).

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

[49] 16 U.S.C. § 1532(19).

behavioral patterns, including breeding, feeding, or sheltering."[50] This prohibition against a "take" applies regardless of land ownership.[51]

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."[52]

The ESA also requires designation of "critical habitat" for listed species when "prudent and determinable."[53] Critical habitat includes geographic areas containing physical or biological features essential to the species conservation and that may need special management or protection.[54] Critical habitat may include areas that are not occupied by the species at the time of listing but are essential to its conservation.[55] 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.[56]

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.[57] During consultation the action agency receives a "biological opinion" or concurrence letter addressing the proposed action.[58] In the relatively few cases in which the FWS makes a jeopardy determination, the agency offers "reasonable

[50] 50 C.F.R. § 222.102.
[51] 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).
[52] *Oregon NRDC v. Daley*, 6 F. Supp 2d 1139, 1154 (D. Or. 1998).
[53] 16 U.S.C. § 1533(a)(3)(A).
[54] 16 U.S.C. § 1532(5)(A)(i).
[55] 16 U.S.C. § 1532(5)(A)(ii).
[56] 16 U.S.C. § 1533(b)(2).
[57] 16 U.S.C. § 1536(a).
[58] 16 U.S.C. § 1536(b)(3).

and prudent alternatives" about how the proposed action could be modified to avoid jeopardy.[59] Under Section 7, federal agencies are required to avoid "destruction" or "adverse modification" of designated critical habitat.[60]

Section 10 of the ESA provides relief to non-federal landowners who want to develop property inhabited by listed species.[61] Non-federal landowners can receive a permit to take listed species incidental to otherwise legal activities, provided they have developed an approved habitat conservation plan.[62] 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.[63]

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.[64] Consultation would not merely require an assessment of the lease site, but rather an overall evaluation of the indirect and cumulative effects of commercial development on listed species and their critical habitats.[65]

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.

[59] 16 U.S.C. § 1536(b)(3).
[60] 16 U.S.C. § 1536(a)(2).
[61] 16 U.S.C. § 1539.
[62] 16 U.S.C. § 1539(a).
[63] 16 U.S.C. § 1539(a)(2).
[64] *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.).
[65] *Connor v. Burford*, 848 P.2d 1441, 1453-54 (9th Cir. 1988).

Fishes. Four species of fish[66] 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 west 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.[67]

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 habitat for the Colorado pikeminnow habitat.[68] 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.[69]

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.[70] Flows necessary to maintain and restore habitats of the four native Colorado River

[66] The four Colorado River fishes are 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.

[67] 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.

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

[69] *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).

[70] *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.[71] In some instances, these flow recommendations have already been incorporated into state law; Utah is currently revising state policy to incorporate year-round bypass flow requirements for new appropriations and change applications along portions of the Green River.[72] The flows required to protect the four Colorado River fishes represent one of the few relatively 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.[73] Although not listed at present under the ESA, Greater Sage Grouse are currently under review for listing by the FWS.[74] 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

[71] *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).

[72] *See Utah Department of Natural Resources, News Release: 2009 Amended 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* (July 20, 2009), *available at* http://www.waterrights.utah.gov/meetinfo/m20090820/announcement.pdf.

[73] 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).

[74] 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

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."[75] 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, including because they "could become endangered or extirpated from a state, or within a significant portion of its distribution in the foreseeable future;" are "under status review" by the FWS; or are "undergoing significant current or predicted downwards trends in population or density."[76] Even if the Greater Sage Grouse remains unlisted, it 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.[77] 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. 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 policymakers 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

[75] 43 U.S.C. § 1712(c)(6).
[76] BLM Manual 6840.06.E.
[77] *Western Watersheds Project v. Kempthorne*, (No. 08-cv-516-BLW) (D. Id. pending).

habitat, as well as developing and requiring effective mitigation of associated offsite and cumulative effects prior to commencement of surface-disturbing development activities.

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,[78] 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.[79]

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."[80] 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.[81]

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.[82] Two of these species,

[78] *Compare* 16 U.S.C. §§ 1538(a)(1) and (a)(2).
[79] 16 U.S.C. § 1538(a)(2)(B).
[80] Compare 16 U.S.C. §§ 1538(a)(1)(B) and (a)(2)(B).
[81] 16 U.S.C. § 1536(a)(2).
[82] 74 FED. REG. 41649-62 (Aug. 18, 2009).

Hamilton milkvetch (*Astragalus hamiltonii*) and flowers penstemon (*Penstemon floweersii*), are found in Uintah County. Although specific plant locations are unknown, the finding indicates that all known habitat for flowers penstemon is located on private and Ute Indian Tribe lands.[83]

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.[84] According to the Utah Division of Wildlife, these plant species are vulnerable to disturbance associated with energy development.[85]

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.[86] In 2006, the FWS proposed listing Graham beardtongue as threatened under the ESA.[87] The FWS's initial critical habitat designation included five separate plant populations covering approximately 3,500 acres.[88] However, this proposed listing was withdrawn in December 2006,[89] sparking a federal lawsuit alleging that the FWS ignored sound science in failing to grant protected status to Graham beardtongue.[90] 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

[83] 74 FED. REG. at 41660.
[84] *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.
[85] *See* http://dwrcdc.nr.utah.gov/rsgis2/Search/SearchSelection.asp?Group=PLANT\&Species=PLANT.
[86] http://www.fws.gov/mountain-prairie/species/plants/grahamsbeardtongue/.
[87] 71 FED. REG. 19,158-59 (April 13, 2006).
[88] 71 FED. REG. 3,157-96 (Jan. 19, 2006).
[89] 71 FED. REG. 76,023-35(Dec. 19, 2006).
[90] *See* Tom Wharton, *Lawsuit filed to protect Uinta Basin Flower*, SALT LAKE TRIBUNE (Dec. 17, 2008), *available at*: http://www.sltrib.com/ci_11256381).

the most geologically prospective oil shale area[91] in the Uinta Basin, as well as in Rio Blanco County, Colorado, is also a candidate for listing under the ESA.[92]

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. Tracts that cannot be developed feasibly should not be offered for lease until adequate mitigation is shown to sufficiently offset values that would be lost.

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

[91] http://dwrcdc.nr.utah.gov/rsgis2/Search/Display.asp?FlNm=pensscar.

[92] *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.

30 miles south of Vernal in northeastern Utah, covering 11,987 acres including 12 miles of the Green River.[93] The Refuge contains several habitat types[94] and is home to a wide variety of plants (including the endangered Uintah Basin hookless cactus)[95] and wildlife.[96] 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.[97]

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.[98] These shale deposits are better suited to recovery through in situ technologies rather than conventional mining methods due to area overburden that generally exceeds 3,000 feet in depth.[99] Nonetheless, development of adjacent oil shale resources could negatively impact the wildlife conservation efforts of the Refuge. Potential indirect impacts associated with development of water from the Green River would likely pose the most significant threat to the Ouray National Wildlife 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 Conserva-

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

[94] 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`.

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

[96] 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`.

[97] 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`

[98] *See* VANDEN BERG at ___ .

[99] *See* VANDEN BERG at ___ .

tion Initiative.[100] The Conservation Initiative resulted from 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.[101] 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"[102] and in January of 2009, Initiative partners succeeded in reintroducing bison on to the public lands in the Book Cliffs.[103]

Control over the oil shale bearing lands immediately adjacent to the Utah Division of Wildlife management areas was recently transferred to SITLA,[104] 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.[105] 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, and thus are well suited to conventional mining operations.[106] 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.

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[100] 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`.

[101] *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`.

[102] 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).

[103] *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`.

[104] 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* pp. ___

[105] 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.

[106] VANDEN BERG at Plate 3.

4.3 CULTURAL AND PALEONTOLOGICAL RESOURCES

The most geologically prospective oil shale area contains a wide range of cultural[107] and paleontological resources[108] 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.[109] 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.[110] 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.[111] 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 some level of cultural resource survey.[112] And "[t]o date, no comprehensive inventory of fossils and no systematic inventory of fossil-bearing areas on BLM-

[107]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.

[108]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.

[109]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.

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

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

[112]FINAL PEIS at 3-202 and 3-205. The FINAL PEIS may underreport surveys within Utah as the figures quoted above do not include surveys associated with linear features such as roads or pipelines.

administered lands has been conducted."[113] 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.[114]

Cultural resources are subject to a complex web of federal laws and regulations,[115] 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.[116]

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."[117] "Areas with significant fossils will be identified through predictive modeling and broad-scale sampling. Assessment and mitigation will be required in these areas."[118]

Under the Vernal RMP, the BLM will endeavor to "[p]reserve and protect a representative array of significant cultural resources ... . Preserve and conserve cultural resources by conducting activities in

[113] FINAL PEIS at 3-55.
[114] VERNAL RMP FEIS at 4-287.
[115] *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.
[116] OIL SHALE ROD at 41.
[117] VERNAL ROD at 102.
[118] VERNAL ROD at 103.

a way that protect [sic] values and provide [sic] for the following benefits; conservation for future use, education, interpretation, public use, and research."[119] 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.[120] 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.[121] 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.[122]

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.[123] The BLM requires leaseholders to stop work immediately upon discovery of cultural remains and to then contact the BLM for further guidance. The difficulties of this approach are that faint soil discoloration or fire-cracked rock associated with prehistoric use may not be readily recognized as indicative of important cultural resources. Likewise, isolated bones may be difficult to identify and their precise source may be unknown. Where sensitive cultural and paleontological resources are not quickly recognized, the BLM's protections cannot be implemented and 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. Existing policies

[119] VERNAL ROD at 72.
[120] VERNAL ROD at 73.
[121] VERNAL ROD at 75.
[122] 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.
[123] FINAL PEIS at 4-144 – 145.

are not adequate to address the likely scope of impacts of oil shale development and policymakers should emphasize acquisition of information in advance of leasing. 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."[124] Recreational uses of the lands identified for potential oil shale development include hiking, biking, fishing, hunting, bird watching, off-road vehicle use, and camping.[125] 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."[126]

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 hunters afield within each of 31 management units across the state. While these management units do not correspond to the most geologically prospective oil shale area, and thus do not provide an exact measurement of use within the area, visits by deer and elk hunters provide 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

[124] 43 U.S.C. § 1701.
[125] Final PEIS at 4-20.
[126] Final PEIS at 4-20.

the White River, deer hunters logged an estimated 2,052 days afield during 2007.[127] 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.[128] 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,[129] 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 annually on the Colorado River and 19,000 boater days annually on the Green River.[130] These numbers likely understate actual demand as river use is limited by permit. Energy development could change the settings associated with river recreation and reduce the area's attractiveness to visitors. A significant reduction in flows could also impair recreation opportunities, both in and downstream of the most geologically prospective oil shale area.

If oil shale leases were clustered, the impacts of development on recreational users would be intensified where energy development dominated larger portions of lands within the most geologically prospective oil shale area. 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. The balance between energy and recreational values is likely to be bitterly contested as emphasizing one largely dispossesses the other.

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[127] *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.

[128] *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.

[129] VERNAL RMP FEIS at 3-56.

[130] 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.

4.5 LIVESTOCK GRAZING

Public land grazing is regulated by the Taylor Grazing Act,[131] 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.[132] 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.[133] 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.[134] The extent of impacts of commercial oil shale leasing on grazing activity is unknown, but significant reductions could reverberate throughout the community.

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.[135] A determination that lands are no longer chiefly valuable for grazing is required before a grazing district can be dedicated to another purpose.[136] The Final PEIS does not rescind the "chiefly valuable for grazing" designation; therefore site-specific NEPA associated

[131] 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.

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

[133] *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").

[134] 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.

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

[136] 2003 Clarification of M-37008.

with lease issuance will need to evaluate whether to re-classify lands for uses other than grazing.[137] Withdrawals from grazing that exceed 5,000 acres also require congressional notification.[138]

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 may provide a guide to what oil shale developers can expect. While often heated, these conflicts are resolved routinely and those grazing conflicts are likely comparable to those that may arise in the context of commercial oil shale leasing and development on the public lands.

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."[139] 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, or delay natural gas development until oil shale development and production is complete.

[137] 2003 Clarification of M-37008.
[138] 43 U.S.C. § 1714(c)(1).
[139] FINAL PEIS at 4-18.

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.[140] The Congressional Research Service reports that 94% of the BLM-administered land in Colorado is already leased for oil and gas; 83% of the land in Utah is already leased for oil and gas; and 71% of the land in Wyoming already leased for oil and gas.[141] In the Uinta Basin, the Utah Geological Survey paints a more detailed picture of conflicting mineral rights (illustrated by Figure 4.6):

> 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 [gallons per ton], 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

[140] 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 4-17, 5-13 (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).

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

their lease stipulations accordingly.[142]

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. 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 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.[143]

The 42,027 acres comprising EOG's project area contains some of the richest oil shale resources in Utah and is 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 because the multiple perforations are likely incompatible with conventional mining methods or in situ thermal processing. 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 not particularly 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

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

[143] *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).

questions.[144] While the Multiple Mineral Development Act,[145] 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:

> 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.[146]

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."[147] 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."[148] 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.

[144] *See generally*, George Cameron Coggins and Robert L. Glickman, Public Natural Resources Law § 41:1 (2d ed. 2008).
[145] 30 U.S.C. §§ 521-531.
[146] 43 C.F.R. § 3000.7.
[147] United States Department of the Interior, Bureau of Land Management, Oil Shale Research, Development and Demonstration (RD&D) Lease, 70 Fed, Reg. 33755.
[148] 73 Fed. Reg. 69414, 69472 (Nov. 18, 2008), *codified at* 43 C.F.R. § 3900.40.

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.[149] 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."[150]

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."[151] 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.[152]

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. As a practical matter, concurrent oil and gas and commercial oil shale development may slow the expansion of new energy development, as subsequent development of additional resources from an already-disturbed site will likely have a lower incremental impact then development of previously undisturbed sites.

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,

[149] FINAL PEIS at 4-18.
[150] FINAL PEIS at 4-18.
[151] *See* Utah State Mineral Lease for Oil Shale § 2.2 ("Oil Shale Lease Form 6/22/05").
[152] *See* Utah State Mineral Lease for Oil Shale § 15 ("Oil Shale Lease Form 6/22/05").

applying topsoil, revegetating disturbed areas where "reasonably practicable," rehabilitating fisheries and wildlife habitat, and isolating, removing and controlling toxic materials at the site.[153] Information regarding reclamation must be contained in the lessee's exploration plan,[154] and the lessee must post a reclamation bond sufficient to cover the estimated cost of site reclamation.[155] Required reclamation methods are not specified by rule due to uncertainty regarding the operation and the surface resources involved.[156]

A critical question for policymakers considering initiating an oil shale leasing program on the public lands 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.[157] 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,[158] dispersed off-road vehicle use, or oil and gas development represents a very low reclamation standard. 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."[159] In describing the process of reclamation, the BLM states "[d]uring reclamation activities, which proceed continuously

[153] 43 C.F.R. § 3931.20(c).
[154] 43 C.F.R. § 3931.41(d).
[155] 43 C.F.R. § 3904.14(b).
[156] 73 Fed. Reg. 69434 (Nov. 18, 2008).
[157] 43 C.F.R. § 3931.20(a).
[158] 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.
[159] 43 C.F.R. § 3931.20(e).

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."[160] 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.[161]

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

[160] FINAL PEIS at 4-53.
[161] FINAL PEIS at 4-71 (citations omitted).

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 re-leached and re-seeded as needed. Where pH is higher, more topsoil will be needed.[162] 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.[163] Cheatgrass emerges early, displaces native species, altering natural fire regimes, and reducing wildlife forage. Elevated levels of zinc and molybdenum were also reported in plants grown in the spent shales, warranting further investigation.[164]

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.[165]

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

[162] 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.
[163] Harbert & Berg 1974 at 39; Harbert & Berg 1978 at 3-8.
[164] Harbert & Berg 1974 at 39; Harbert & Berg 1978 at 7.
[165] Final PEIS at 6-72.

ahead of the needs, this problem could be mitigated.[166] 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.

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 con-

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

flicting 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 facing oil shale development, 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.

Figure 4.2: Vernal RMP Non-WSA Lands Inventoried for Wilderness Characteristics. Source: Bureau of Land Management, Vernal RMP ROD.

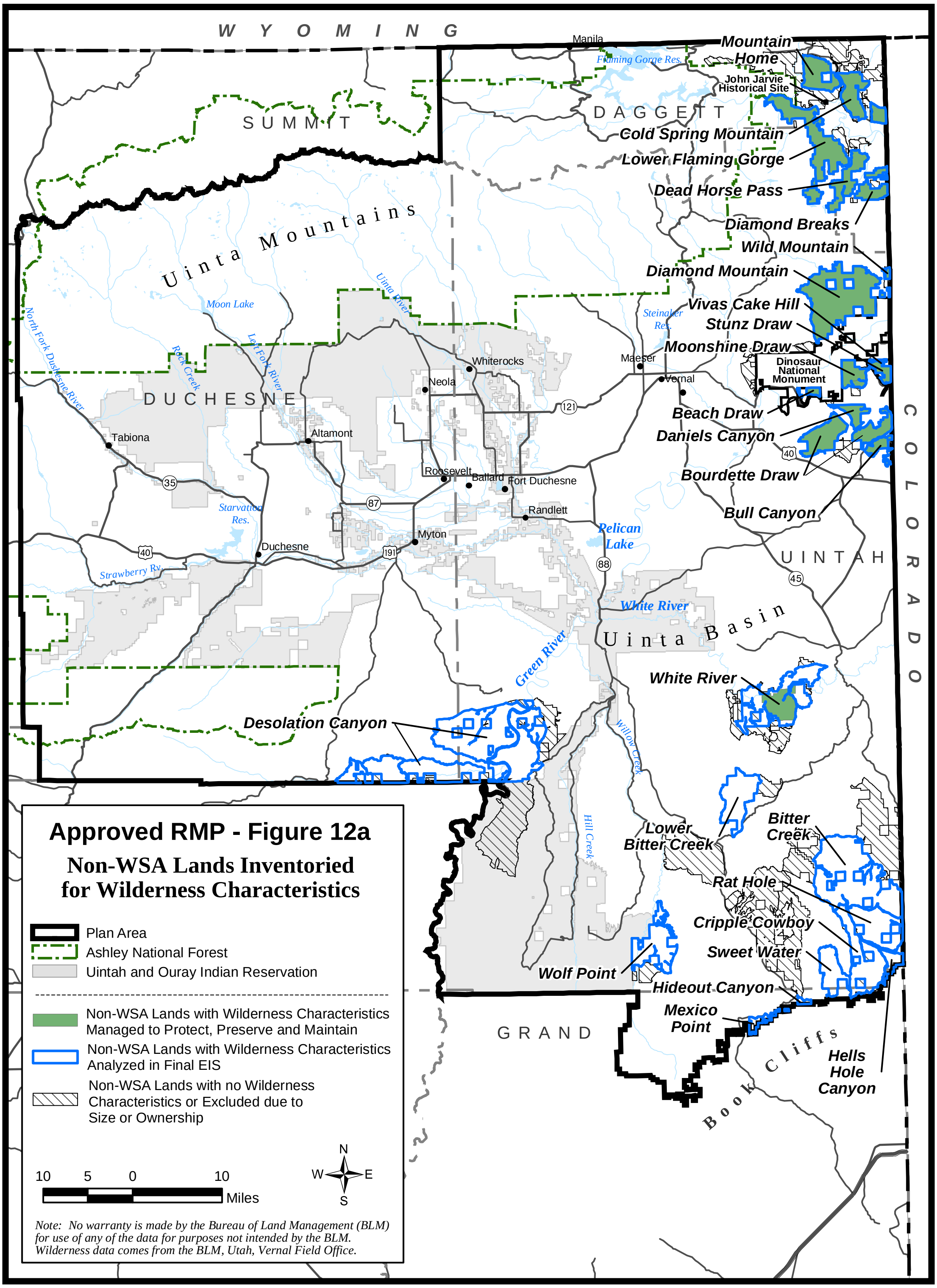


Figure 4.3: Vernal RMP Special Designations. Source: Bureau of Land Management, Vernal RMP ROD.

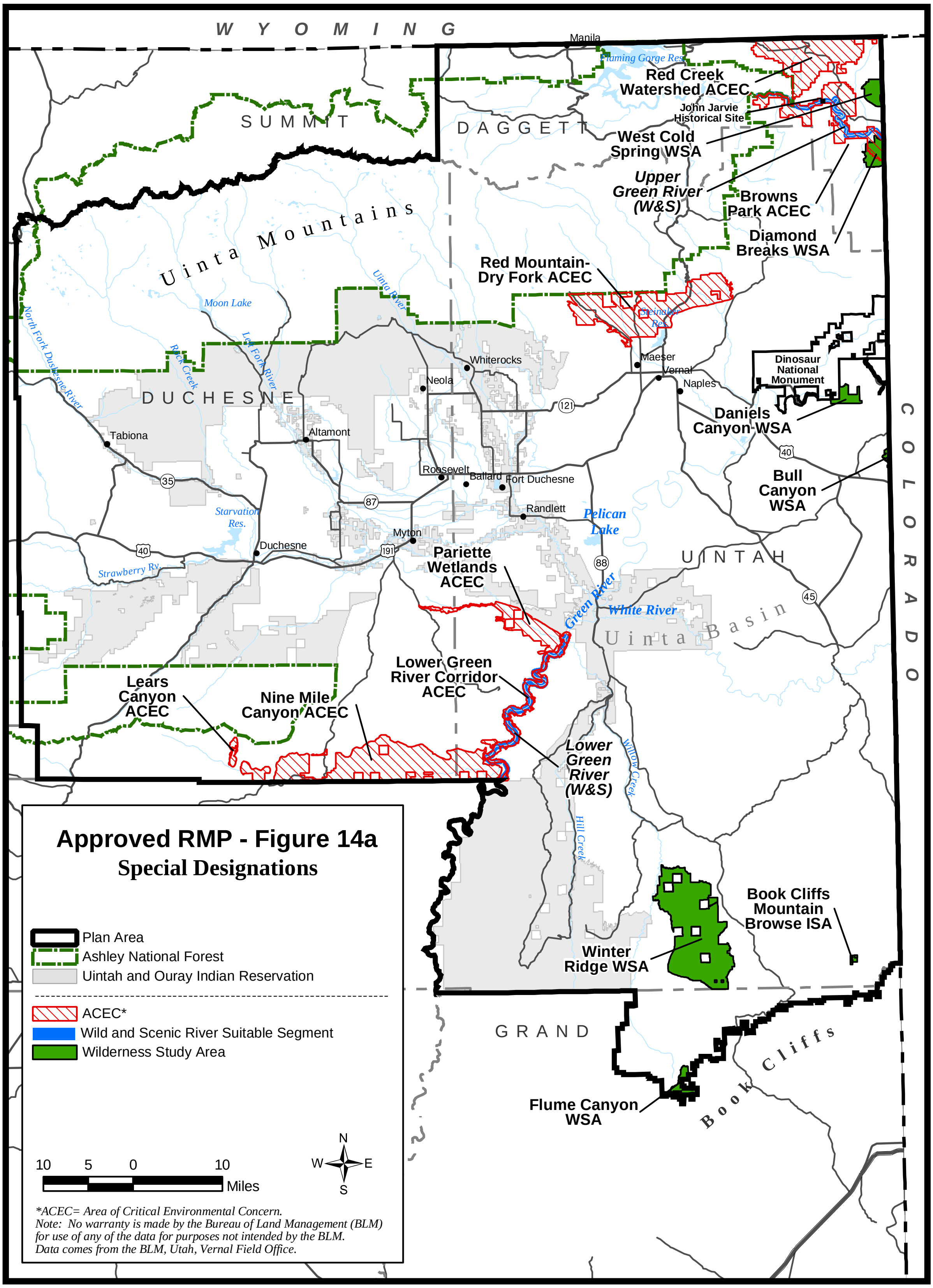


Figure 4.4: Vernal RMP Deer, Elk and Lynx - Winter Range/Corridor/Zone. Source: Bureau of Land Management, Vernal RMP ROD.

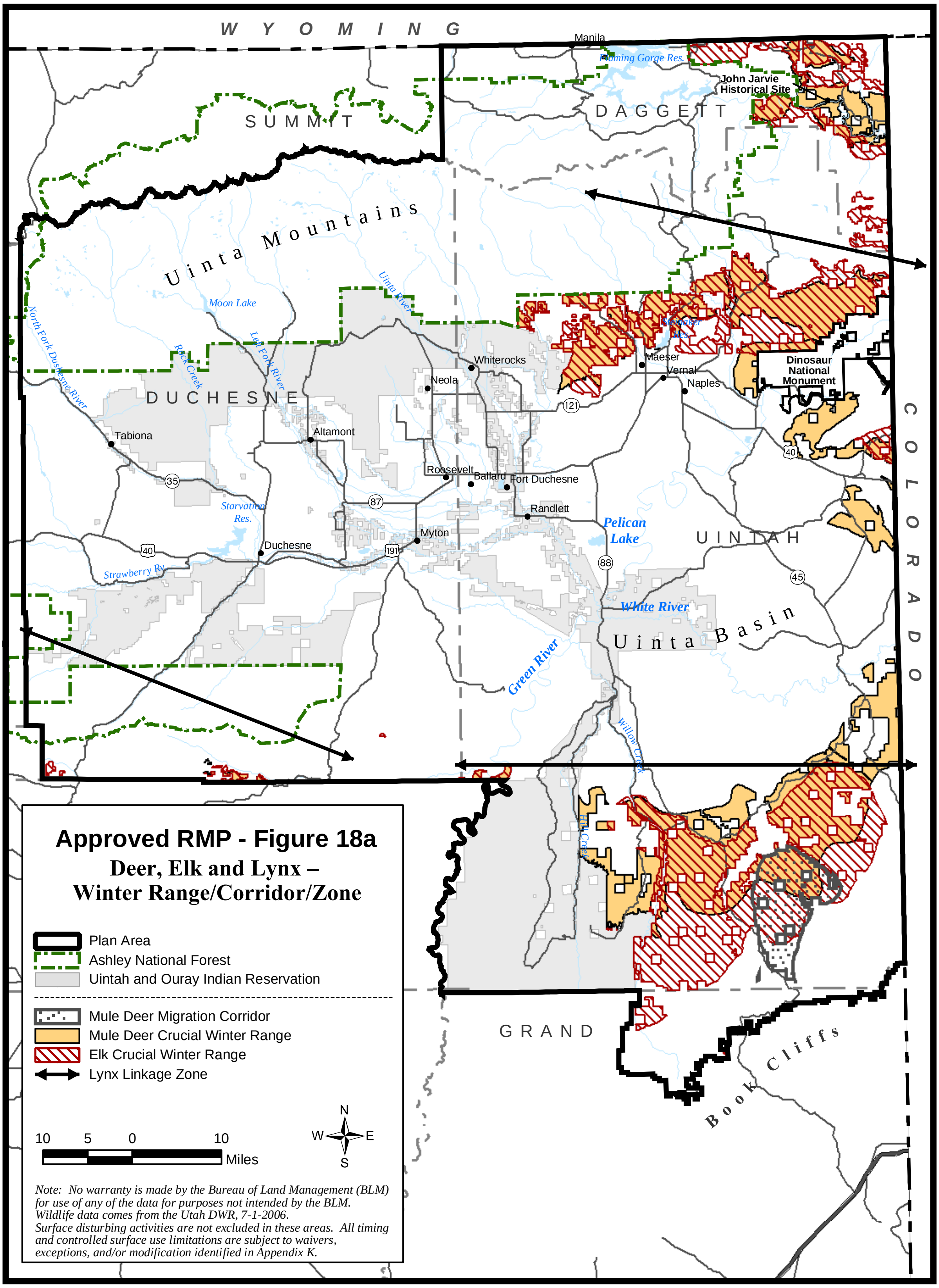


Figure 4.5: Basin-wide Evaluation of the Uppermost Green River Formation's Oil-Shale Resource, Uinta Basin, Utah and Colorado. Source: Michael D. Vanden Berg, Utah Geological Survey Special Study 128, Plate 6.

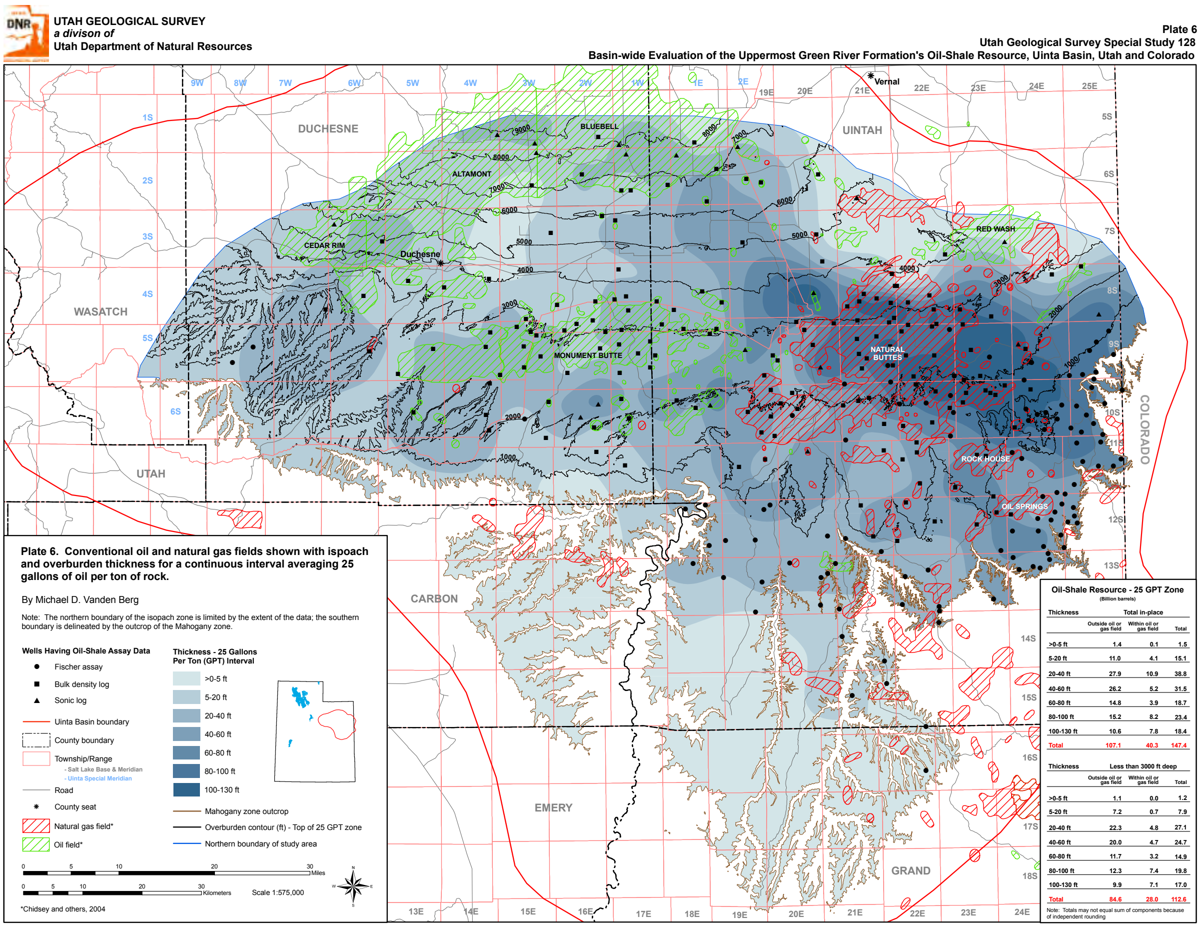
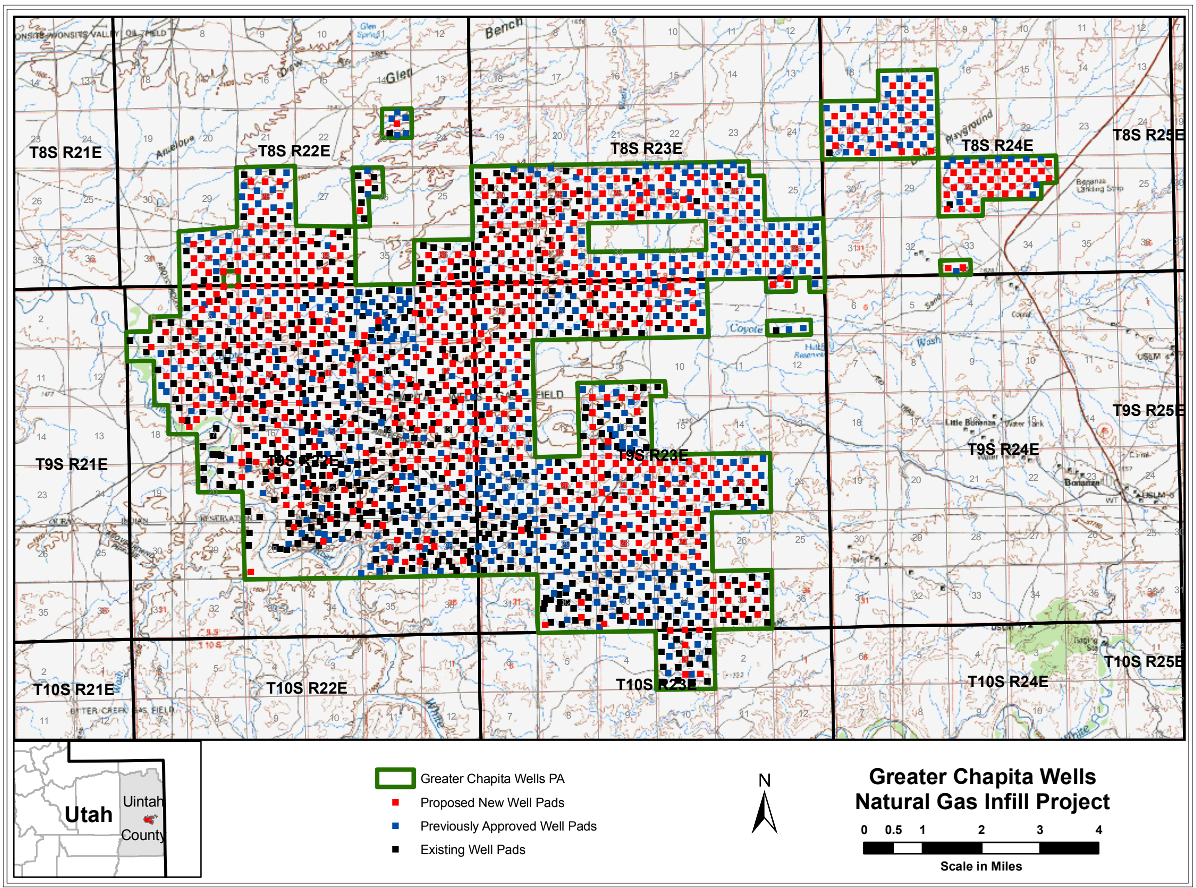


Figure 4.6: Greater Chapita Wells Natural Gas Infill Project, Uintah County. Source: Bureau of Land Management, EIS for the Greater Chapita Wells Natural Gas Infill Project.



CHAPTER 5

WATER RESOURCES[1]

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 section 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.

[1]The Water Resources section 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).

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[2] 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.[3] 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.[4] 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.[5] While the process in Colorado is somewhat different, the substantive requirements affect a similar result.[6]

When not enough water exists to satisfy all who seek the region's scarce resources the question becomes one of whose rights will prevail. The maxim "first in time, first in right" is the foundation of western water law.[7] 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

[2]*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.)".

[3]UTAH CODE ANN. § 73-3-1.

[4]UTAH CODE ANN. § 73-3-8.

[5]UTAH CODE ANN. § 73-3-2.

[6]*See generally*, COLO. REV. STAT. §§ 37-82-101 - 106.

[7]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).

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.[8] 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.[9]

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.[10] 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.[11] 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.[12] Thus, if a water right is not put to a beneficial use within the statutory period, it reverts back

[8]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).

[9]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).

[10]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).

[11]UTAH CODE ANN. § 73-3-3(2)(b).

[12]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

to the state and is available for appropriation.[13] These timelines may be extended where the applicant exercises due diligence in developing water rights.[14] 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 population growth or other water use demand.[15]

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,[16] 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

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.

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

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

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

[16] *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).

in use if used to support future oil shale development.[17]

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.[18]

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[19]

The most geologically prospective oil shale area includes critical habitat for at least four species of fish protected under the ESA.[20] The ESA must be considered a water resources issue as the ESA 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

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

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

[19] The impact of the ESA on oil shale leasing and development on the public lands is also discussed at pp. ___

[20] 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 texanus*).

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.[21] Utilization of state water rights is subject to the ESA's prohibition against the take of a listed species.[22] Bureau of Reclamation water delivery contracts are likewise subject to curtailment to comply with the ESA,[23] which may require federal reservoir operations to maximize species protection, thus subordinating state and federal contract water rights.[24] Under such circumstances instream flow requirements for listed species can trump water rights, including water rights apportioned by interstate compact.[25] 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.[26] Pending amendments to state policy, if approved, could further constrain future water right changes by subjecting them to bypass flow requirements needed to protect listed fish along portions of the Green River.[27] This policy change could

[21] *See* A. Dan Tarlock, Law of Water Rights and Resources § 9.29 (2008).

[22] *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).

[23] *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).

[24] *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).

[25] *See* Tarlock, Law of Water Rights and Resources at § 9.31.

[26] *See generally*, Robert W. Adler, Restoring Colorado River Ecosystems: A Troubled Sense of Immensity (2007).

[27] *See Utah Department of Natural Resources, News Release: 2009 Amended 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* (July 20, 2009), *available at* http://www.waterrights.utah.gov/meetinfo/m20090820/announcement.pdf.

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.[28] 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,[29] 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.

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.[30]

Jennifer Gimbel, Executive Director of the Colorado Water Conservation Board, similarly notes

[28] *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.

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

[30] 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.

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."[31] 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[32] 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.[33] 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.[34] Although these operators would still require water for dust suppression, reclamation, and other activities, emerging technologies appear capable of cutting water use by 80% or more from 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,[35] the Rand study relies on information from a 17 year-old report by the U.S. Water Resources Council.[36] 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

[31] Chris Woodka, *Water Debate Takes on a New Ripple: Energy*, THE PUEBLO CHIEFTAIN (March 31, 2009).
[32] *See* U.S. DEPARTMENT OF INTERIOR, FINAL ENVIRONMENTAL IMPACT STATEMENT FOR THE PROTOTYPE OIL SHALE LEASING PROGRAM, Vol. 1, p. III-34 (1973).
[33] FINAL PEIS at 4-4 and 4-8.
[34] *See* SECURE FUELS FROM DOMESTIC RESOURCES, at 28-29 and 48-49.
[35] *See* FINAL PEIS at p. 4-11.
[36] 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).

groundwater pumped out of the target zone," making it "a net producer of water."[37]

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 an average of 1.5 barrels of water for each barrel of shale oil produced.[38] At that level, oil shale development would use less water than conventional oil and gas production.[39]

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.[40] 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.[41]

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.[42] According to the BLM's leasing regulations, applications to lease must include a "description of the source and quantities of water to be used,"[43] 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."[44] These disclosures would help resolve questions that are today unanswerable, and enable better decisions. Developing a better understanding

[37] HANSON & LIMERICK at 20.

[38] 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`.

[39] 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* 4 (2009).

[40] COLORADO WATER CONSERVATION BOARD, STATEWIDE WATER SUPPLY INITIATIVE, 6-82 (Nov. 2004).

[41] *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.

[42] *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.

[43] 43 C.F.R. § 3922.20(c)(3).

[44] 43 C.F.R. § 3931.11(h).

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."[45]

5.2.2 Demand for Water Unrelated to Oil Shale Development

Utah is the second driest state in the West[46] 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.[47] Gross water demand within this three county area is expected to increase by 79% over the same period, from 29,400 to 52,600 acre-feet.[48] 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

[45] BARTIS ET AL. at 50.

[46] 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).

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

[48] 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.

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.[49] This nascent proposal is generating significant public interest and opposition.[50] Other, less developed efforts to divert water from the Green River to Colorado's western slope also appear to be in the works.[51] 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.[52] 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;[53] 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.[54] 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.[55]

Like Colorado, Utah appropriators are proposing large withdrawals from the Green River. Nuclear power proponents recently filed for rights to consume 29,600 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,

[49] 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).

[50] *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).

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

[52] 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).

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

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

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

Utah.[56] 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.[57] Oil shale developers and policymakers alike must consider that as Colorado and Utah continue to grow, scarce water supplies 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, surface waters proximate to Colorado and Utah's oil shale resources are subject to the Colorado River Compact,[58] which apportions water among the seven states that drain to the Colorado River.[59] 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

[56] Patty Henetz, *Utah Nuclear Power Proposal Has a Powerful Thirst*, SALT LAKE TRIBUNE (April 6, 2009).

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

[58] 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.

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

of Lees Ferry, Arizona.[60] (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.[61] The lower basin is also "given the right to increase its beneficial consumptive use of such waters by one million acre-feet per annum."[62] Additionally, Mexico is entitled to 1,500,000 acre-feet pursuant to the Treaty with Mexico.[63] 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.[64]

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.[65] 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.[66] 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.[67] However, estimated and gauged flow from 1906 through 2005 averaged 15,072,000 acre-feet (ranging between 5,399,000 and

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

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

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

[63] 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.

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

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

[66] 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.

[67] 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).

25,432,000 acre-feet).[68] 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.[69] A 2006 update to this study determined that natural flows at Lees Ferry were higher than estimated in 1976, but still below gauged levels.[70] 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.[71]

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 future droughts."[72]

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 appor-

[68] 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).

[69] 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.

[70] Woodhouse, C. A., S. T. Gray, and D. M. Meko (2006), *Updated Streamflow Reconstructions for the Upper Colorado River Basin*, Water Resources Research (2007).

[71] 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.

[72] 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).

tioned according to the Upper Colorado River Compact.[73] 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.[74] 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.[75] Utah has, during an average year, roughly 520,000 acre-feet of unused Colorado River apportionments.[76] 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,[77] 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 and eventually the Colorado River. On average, the White River near the Colorado-Utah border discharges 590,100 acre-feet annually,[78] with a mean flow of 604 cubic feet per second (cfs).[79] 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

[73] 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.

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

[75] 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.

[76] 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).

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

[78] FINAL PEIS at 3-81.

[79] WHITE RIVER DAM FEIS at 59.

June, almost five times the average discharge experienced in December and January (350.1 and 353.5 cfs, respectively).[80] 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."[81]

In 1965, Utah filed to appropriate 350 cfs and 250,000 acre-feet from the White River and its tributaries,[82] identifying the intended uses as mining, drilling, and retorting oil shale.[83] 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.[84] 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.[85]

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

[80] 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.*

[81] 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).

[82] 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.

[83] White River Dam Project: Proposed Action Plan at 3.

[84] White River Dam FEIS at 1. The difference between capacity and active storage is attributable primarily to capacity dedicated to sediment storage.

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

this source, though the cost of conveying it to development sites could be quite high.[86] 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."[87] Mining is undefined in the rule and if interpreted to include commercial oil shale development, could limit availability of this water source.[88] 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.[89]

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.[90] 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[91] and any new diversion or consumptive use within the area must be accompanied by change applications filed on existing water rights.[92]

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[86] 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.

[87] Utah Admin. Code § R653-8-3(2)(a).

[88] 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.

[89] Utah Admin. Code § R653-8-3(1).

[90] Utah State Water Plan: Uinta Basin at p. 9-4.

[91] 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.

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

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.[93] 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.[94] Some water may be legally and physically available from the Yampa, subject to constraints imposed by the ESA and the Law of the River.[95] 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.[96] Notably, Shell Oil recently filed for the right to divert up to 375 cfs from the Yampa River during high flow periods.[97] 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.[98] This application has received significant opposition from

[93] 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.

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

[95] 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.

[96] Statewide Water Supply Initiative at 7-82.

[97] Tom Ross, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, The Steamboat Pilot and Today, (Jan. 11, 2009).

[98] Tom Ross, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, The Steamboat Pilot and Today, (Jan. 11, 2009).

local water users concerned about a potential loss of water resources as well as from those concerned about adverse impacts to protected fish species.[99] In addition to Shell's pending proposal, there are 34 conditionally decreed rights for reservoirs within Colorado's portion of the White River Basin.[100] 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 portion of the White River Basin.[101] The total decreed absolute diversion rates associated with these ditches is approximately 200 cfs.[102] 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.[103] The absence of a formal agreement leaves unresolved questions as to

[99] *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).

[100] Western Resource Advocates at 8.

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

[102] Western Resource Advocates at 7-9.

[103] 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.

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,[104] 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.[105] 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.[106] 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.[107]

[104]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).

[105]FINAL PEIS at 3-84.

[106]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).

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

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.

Second, salinity generally increases with groundwater depth and varies throughout the Uinta Basin.[108] 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.[109] 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

[108] *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").
[109] Produced water utilization will be addressed in a future report being prepared by the Institute for CLean & Secure Energy.

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[110]

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.[111] 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.[112] 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 discussed or quantified in the treaty.[113] The priority date associated with Indian reserved rights is the date upon which the reservation was created,[114] and unlike water rights granted under state law, *Winters'*

[110] 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. (2009) (forthcoming).

[111] 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.

[112] http://www.utetribe.com/.

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

[114] *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).

rights are not subject to forfeiture or abandonment for nonuse.[115] Reserved rights claims must be satisfied by the states in which the reservation lies, and will be debited against the state's apportionment[116] 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."[117] 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*),[118] 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."[119] 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.[120] Conversely, where reservations were established in particularly harsh and arid areas, little if any of the reservation may meet minimum standards of economic feasibility.[121] Accordingly, the Arizona Supreme Court rejected the practicable acreage standard, choosing instead to balance a "myriad of factors" in quantifying reserved rights.[122] The Arizona Supreme Court observed that "the

[115]*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).

[116]*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).

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

[118]753 P.2d 76 (Wyo. 1988), *judgment aff'd by evenly divided court*, 492 U.S. 406 (1989).

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

[120]*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).

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

[122]*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.").

essential purpose of Indian reservations is to provide Native American people with a 'permanent home and abiding place,' that is, a 'livable' environment,"[123] 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 a 'permanent home and abiding place' to the Native American people living there.[124]

Great effort has gone into quantifying the Northern Utes' reserved rights, resulting in at least two draft settlements.[125] 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.[126] A complementary agreement is contained in the Ute Indian Water Compact, which was codified into state law, subject to ratification by the parties.[127] Neither of these complementary acts, however, was ratified by the tribe's membership.[128] 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.

[123] *Gila V*, 35 P.3d 68 at 74 (*quoting Winters*, 207 U.S. at 565 and *Arizona I*, 373 U.S. at 599).
[124] *Gila V*, 35 P.3d 68 at 76 (internal quotations and citations omitted).
[125] *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.
[126] Pub. Law 102-575 at §§ 501 – 507 (Oct. 30, 1992).
[127] UTAH CODE ANN. §§ 73-21-1 and -2.
[128] *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).

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.[129] 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 as early as 1861,[130] 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."[131] 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.[132] 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,[133] 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.[134] 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.[135]

[129] UTAH CODE ANN. §§ 73-21-1 and -2.

[130] UTAH CODE ANN. § 73-21-2, Art. III.

[131] UTAH CODE ANN. § 73-21-2, Art. III.

[132] UTAH CODE ANN. § 73-21-2, Art. III.

[133] Tabulation of Ute Indian Water Rights at 10-13.

[134] Tabulation of Ute Indian Water Rights at 10-13.

[135] 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

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.[136] 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.[137] 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.[138]

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the ESA precluded new Indian water projects along the San Juan River, interfering with the tribes' ability to use their senior water rights).

[136] *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).

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

[138] Andrews at 2.

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.[139] 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.[140] 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.[141] 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,[142] which received the land and mineral rights in fee simple and not subject to federal management in trust status.[143] 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 withdrawal applies to NOSR-2."[144] 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.[145] The basis of the reserved right is important because it affects both the priority date

[139] *See United States v. Bell*, 724 P.2d 631, 634 (Colo. 1986).
[140] *See United States v. Bell*, 724 P.2d 631, 635 (Colo. 1986).
[141] *United States v. Bell*, 724 P.2d 631, 635 (Colo. 1986).
[142] Pub. L. 106-398; *see also* Andrews at 28.
[143] Pub. L. 106-398 § 3405(b) and (c).
[144] Pub. L. 106-398 § 3405(c)(5).
[145] 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. §

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,[146] 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.[147] 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 and retorting 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.[148]

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."[149] "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."[150] If a lease proceeds to development, plans of

37.02(f)(3) (2004 ed.) for a discussion of the issues associated with reacquired lands.

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

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

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

[149] 43 C.F.R. § 3922.20(c)(3).

[150] 43 U.S.C. § 3922.20(c)(6).

development must include descriptions of the methods utilized to monitor and protect all aquifers,[151] 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."[152] 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."[153] 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.

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 sufficiently flexible to accommodate conditional water rights and creative 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 and should 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

[151] 43 U.S.C. § 3931.11(d)(8).
[152] 43 C.F.R. § 3931.11(h)(1).
[153] 43 C.F.R. § 3931.11(h)(2).

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."[154]

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 is a cloud over all water users within the basin, including those supporting development of a commercial oil shale industry. Finalizing the Ute Indian Water Compact should be a high priority, and it should clearly articulate the extent to which water resources may be transferred to non-Indians, used for commercial and industrial purposes, and used off the reservation, and whether it resolves 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 can add greater clarity to the water resource issues relevant to evaluating whether and how to develop a commercial oil shale leasing program on the public lands.

[154] A. DAN TARLOCK ET AL., WATER RESOURCE MANAGEMENT (5th ed. 2002) at 913-14.

Figure 5.1: Colorado River Basin. Source:.