Submitted to:

Colorado and Yampa-White-Green
Basin Roundtables

Energy Development Water Needs Assessment Update

PHASE III

FINAL REPORT

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Table of Contents

List of Tables

List of Figures

Acronym List

For the purpose of this report, the following terms are defined as:

Term	Definition
the Act	Colorado Water for the 21st Century Act
af/year	acre-feet per year
AMSO	American Shale Oil
bblw/bblo	barrels of water required to produce one barrel of oil
bblo/day	Barrels of oil per day
BIP	Basin Implementation Plan
BLM	Bureau of Land Management
BRT	Basin Roundtable
CCGT	combined-cycle gas turbine
COGCC	Colorado Oil and Gas Conservation Commission
CWCB	Colorado Water Conservation Board
DOE	Department of Energy
EIS	Environmental Impact Study
gpcd	gallons per capita per day
IBCC	Interbasin Compact Committee
IPP	Identified Projects and Processes
NOSA	National Oil Shale Association
NSHI	Natural Soda Holding, Inc
OSEC	Oil Shale Exploration Company
P&M	Projects and Methods
PRL	Preference Right Lease
RD&D	Research, Development and Demonstration
RFD	Reasonable Foreseeable Development
RMP	Resource Management Plan
StateMod	State of Colorado’s Stream Simulation Model
SWSI	Statewide Water Supply Initiative
YWG BRT	Yampa-White-Green Basin Roundtable

EXECUTIVE SUMMARY

The Energy Development Water Needs Assessment, Phase III study provides updated information regarding the amount of water required to supply future oil shale and oil and gas industrial development in northwestern Colorado. This study supplements information contained in the Energy Development Water Needs Assessment Phase I (URS, 2008) and Phase II studies (AMEC, 2011) in which estimates were made regarding water demands associated with the development of energy in northwestern Colorado. The Yampa-White-Green River Basins and Colorado River Basin Roundtables initiated this work to provide updated water use estimates as part of the Basin Implementation Plan processes.

In the Phase I study, four energy sectors were addressed: natural gas, coal, uranium, and oil shale. Phase I evaluated and quantified the direct and indirect water uses associated with various levels of development (i.e., production) associated with each energy sector. The direct demands include water supplies for use in the construction, production, operations, processing, and reclamation of the resource development. Indirect demands include water uses by the new population (e.g., domestic and municipal). Phase I also quantified water use resulting from the power generation needed to supply the industries and the new population (called thermoelectric water uses in Phase I).

The Phase II study revisited the water uses for the oil shale industry and provided preliminary analysis of alternative water supply projects in the White River. Phase II updated the industry's direct water uses with new assumptions regarding power generation. Instead of coal fired generation (the technology evaluated in Phase I), Phase II developed water uses for combined cycle gas turbine technologies with significantly less water use. Phase II reported significantly reduced water demands associated oil shale development.

The Phase III study updates the water demands associated with the oil shale and natural gas and oil industries. Since 2011, Shell and Chevron have ended oil shale research in Colorado. The National Oil Shale Association is projecting significantly smaller commercial production levels. Now, instead of large in situ oil shale projects and production levels up to approximately 1.5 million barrels of oil per day the organization is providing estimates for up to approximately 500,000 barrels of oil per day production. Consequently, Phase III reports oil shale water uses that are about one-third of the volumes estimated in Phase II, however. If a very profitable industry emerges, production amounts could be significantly higher due to the size of the resources and global oil demand. Subsequently, water use would be higher. It will be important to monitor production rates and water use for future water planning as the industry develops.

The initial Phase III work revisited the Phase I water uses for the natural gas, coal, and uranium energy sectors. Since 2008, the status of oil and gas well drilling has changed, 2006 – 2008 are the historical peak years for drilling activity in Colorado, but the outlook for coal and uranium development is much the same. The Energy Subcommittee decided that the updated Phase III report would include the oil and gas sector water uses and carry forward the Phase I estimates for the coal and uranium sectors.

In Phase II, the oil shale water use estimates ranged up 120,000 acre-feet per year. The estimates reflected commercial production levels up to 1.5 million barrels of oil per day with production ramping up to the ultimate levels by 2050. The Phase II estimates significantly decreased direct water use estimates reflected industry projections of commercial production and refined water use factors. Now, in Phase III, new information indicates that the water demands for commercial oil shale industry in Colorado may be range from approximately 15,000 – 90,000 acre-feet per year.

Regarding water uses associated with oil and gas development, the Phase III water use volumes are generally equivalent to the volumes reported in Phase I. Phase III reports slightly increased direct use volumes for oil and gas. The direct uses in Phase I ranged from approximately 2,000 – 5,500 acre-feet per year. This update estimates peak year uses range from 4,400 – 6,000 acre-feet per year. The Phase I indirect demands are carried forward in this work and range from approximately 8,200 – 11,400 acre-feet per year.

1.0 INTRODUCTION

This report provides information about the amount of water that may be required to supply future energy development in northwestern Colorado. The work described in this report updates information contained in the Energy Development Water Needs Assessment Phase I (URS, 2008) and Phase II studies (AMEC, 2011). The Phase I report addressed the direct and indirect water demands associated with four energy sectors: natural gas, coal, uranium, and oil shale. Phase II updated the oil shale sector water demands and evaluated water supply projects that could assist in meeting the projected water demands of an oil shale industry. The Phase III study evaluates recent changes in oil shale research and development projects and new information associated with water uses in oil and gas well drilling and completion.

In western Colorado, the oil and gas and oil shale energy sectors have the greatest potential to significantly impact water uses in both the Colorado and Yampa-White-Green (YWG) basins. To provide the most current information for development of the BIPs, this Phase III study is a re-evaluation of these water needs. The information developed in this Phase III study will be incorporated into the draft BIPs for the Colorado and YWG basins, scheduled for delivery to the CWCB the end of July 2014. As work continues after that date, particularly with modeling of Identified Projects and Processes (IPPs), updated information will be incorporated into future drafts of the BIPs.

2.0 THE WATER SUPPLY PLANNING PROCESS

The Statewide Water Supply Initiative (SWSI) was the beginning of a variety of efforts led by the Colorado Water Conservation Board (CWCB) to address statewide water demands and water supply needs as well as ways to address any gaps in water supply. Through the SWSI process, which began in 2003, eight Basin Roundtables were formed that were comprised of stakeholders from a particular river basin representing various water use sectors such as agricultural and ranching community members, recreational/environmental interests, federal agencies, and municipal water providers. Since 2003, a variety of water supply planning reports and analyses have been completed throughout the state, including SWSI 2010, and update to the original SWSI completed in 2004. Currently the water supply conditions are evaluated through the year 2050.

After completion of SWSI, HB05-1177, the Colorado Water for the 21st Century Act (the Act), was signed into law. The Act is the basis for a permanent forum for statewide water discussions that are held under two new arrangements: nine Basin Roundtables (separate from the SWSI Basin Roundtables) and the Interbasin Compact Committee. These new arrangements are discussed below.

While these planning efforts and studies have been extremely valuable in understanding the future water needs of each basin, it became apparent that the State needed to take a more sustainable, holistic view of its water needs and how to better plan for a secure water future. To address all of these challenges facing the state, the Colorado Water Plan is currently being developed under the direction of CWCB. The Basin Roundtables are playing a critical role in this process by developing Basin Implementation Plans (BIP), which seek solutions for addressing water needs for each basin at a local level. Information contained in each BIP will be incorporated into the Colorado Water Plan to understand needs on both the basin and statewide level. Colorado's Water Plan, expected to be finalized in December 2015, will offer a path forward to provide Coloradans with water for consumptive uses while supporting healthy watersheds and the environment, robust recreation and tourism economies, vibrant and sustainable cities, and viable and productive agriculture.

2.1 Basin Roundtables

Similar to SWSI, the Act created Basin Roundtables, one in each of the eight major river basins, plus an additional Roundtable in the Denver metro area. However, Basin Roundtable membership under the Act is of a broader nature than that of SWSI, which reflects the objective of encouraging participation from a wider range of stakeholders. Designated Roundtable participants, which total over 300, include 10 at-large members, non-voting members, agency liaisons, and the CWCB board member from that basin. The Basin Roundtables are charged with facilitating discussions surrounding water management issues while promoting locally-driven decision-making processes to find water management solutions.

Using information developed in SWSI as a foundation, each Roundtable is responsible for the following:

- An assessment of basinwide consumptive water needs (municipal, industrial, and agricultural);
- An assessment of basinwide non-consumptive water needs (environmental and recreational);
- An assessment of available surface water and groundwater supplies and an analysis of available unappropriated water;
- Proposed projects or management options for meeting identified water needs and achieving water supply sustainability over time;
- Reviewing proposed projects; and
- Negotiating interbasin compacts.

Each Basin Roundtable is able to form subcommittees to encourage discussion and address specific issues before the Roundtable. These subcommittees can be formed any time a need arises, and they may be permanent or temporary. Examples of Basin Roundtable Subcommittees include, but are not limited to:

- Groundwater
- Needs Assessment
- Non-Consumptive Needs Assessment
- Water Transfers
- Project Screening
- Agriculture
- Energy

The role of the Basin Roundtable Subcommittees played a large part in the two studies discussed below.

2.2 Interbasin Compact Committee

The second arrangement created under the Act is the Interbasin Compact Committee, or IBCC. This group attempts to broaden the participation of those involved in the State's water decisions, and to facilitate interbasin negotiations. It is comprised of 27 members according to the following breakdown:

- 2 members appointed by each of the 9 Basin Roundtables;
- 6 members appointed by the Governor, who come from "geographically diverse parts of the state" and have expertise in environmental, recreational, local governmental, industrial, and agricultural matters;
- 1 member appointed by the chairperson of the Senate Agriculture Committee;
- 1 member appointed by the chairperson of the House Agriculture Committee; and
- The Director of Compact Negotiations appointed by the Governor, who chairs the IBCC.

2.3 Basin Implementation Plans (BIP)

An Executive Order was issued by Governor Hickenlooper on May 14, 2013 directing the CWCB to work with the Basin Roundtables, IBCC and other stakeholders to develop Colorado's Water Plan by December 2015. Each of the nine Basin Roundtables are responsible for developing their own BIP as coordinated by the CWCB. This information is critical to the Colorado Water Plan and will show how each basin plans to meet its future municipal, industrial, agricultural, recreational, and environmental needs, from a bottom up approach.

In western Colorado, the oil and gas and oil shale energy sectors have the greatest potential significantly impact water uses in both the Colorado and YWG basins. To provide the most current information for development of the BIPs, this Phase III study is a re-evaluation of these water needs. Further, since completion of the Phase II Energy study in January 2012, various circumstances have taken place with the energy industry that warrant revisiting the water demand estimates, specifically for natural gas and oil shale.

The information developed in this Phase III study will be incorporated into the draft BIPs for the Colorado and YWG basins, which will be delivered to the CWCB the end of July 2014. As work continues after that date, particularly with modeling of Identified Projects and Processes (IPPs), updated information will be incorporated into future drafts of the BIPs.

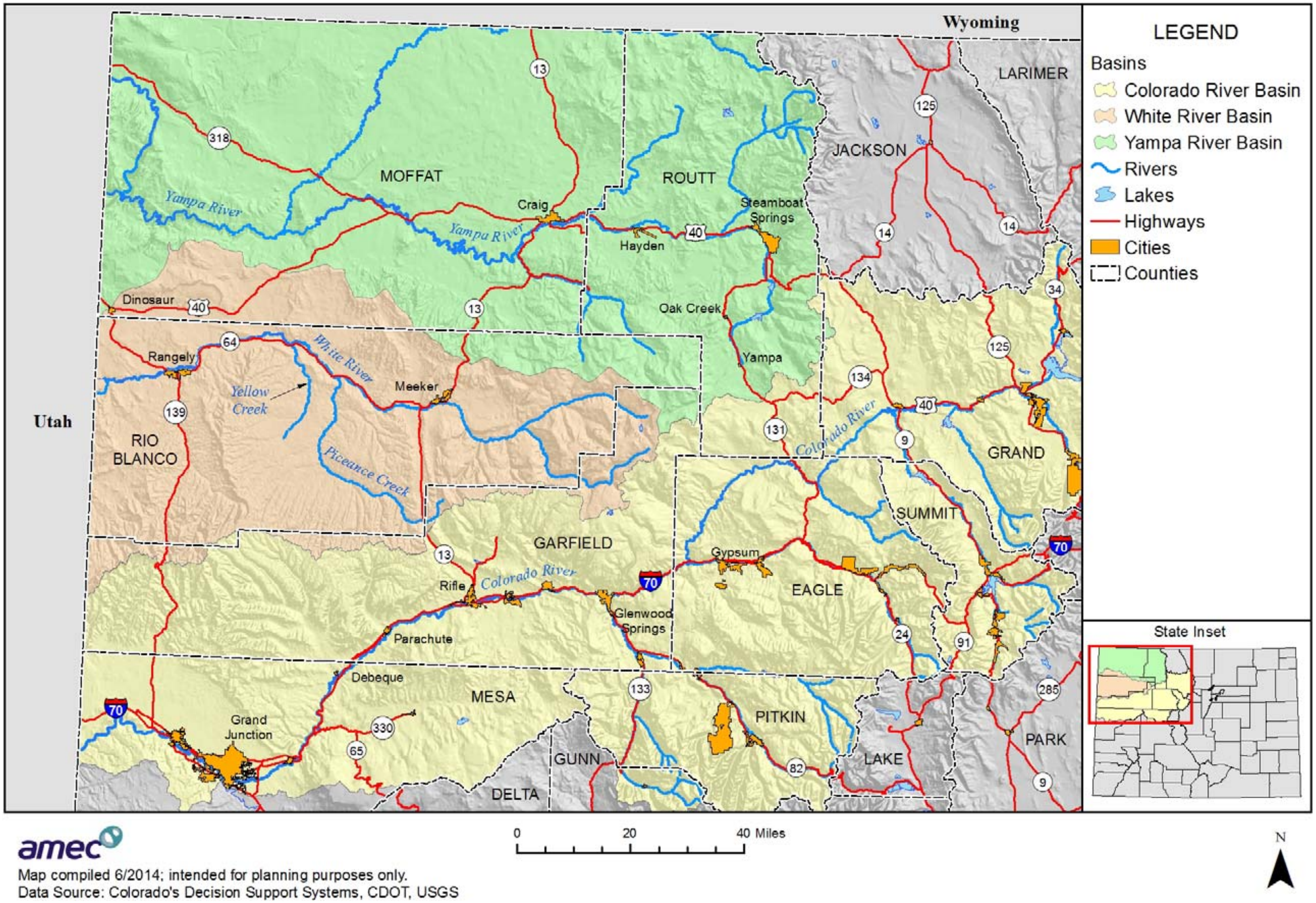
2.4 Energy Water Needs Assessments

2.4.1 Overview of Phase I Study

Phase I of the Energy Water Needs study evaluated water demands associated with the extraction and production of energy in the Colorado, Yampa, and White River Basins (Figure 2-1) for the following four sectors:

- Natural Gas
- Coal
- Uranium
- Oil Shale

Figure 2-1 Phase I Study Area



Phase I quantified direct and indirect water demands within each energy development sector. The direct demands included water for construction, operation, production, and reclamation associated with the development of the energy sector. The indirect demands include water supplies for the domestic uses by an energy-related workforce (industrial workforce and the population servicing the industry). The Phase I report also estimated water uses for thermoelectric power for each industry to supply its production technologies and the associated growth in population.

The Phase I study described assumptions on the timing and intensity of development in each of the four sectors. The estimates of timing and intensity provided a range of water use volumes and were meant to characterize water use scenarios through a planning horizon extending to 2050. The production scenarios represented three general output levels (low, medium and high) in units specific to each industry (e.g., average number of natural gas wells drilled per year or number of barrels oil from oil shale produced per day).

Table 2-1 through Table 2-3 provides the Phase I estimates for annual direct, indirect, and thermoelectric water demands for each of the energy sectors.

In part, the Phase I report concluded,

> *"…that the amount of water required for natural gas, coal, and uranium, including the amount associated with the population growth to support these industries, is significant but appears to be within the realm of water supplies available for planning and development."*

The Phase I "high production scenario" for oil shale assumed an approximately 1.5 million barrels of oil per day (bblo/day) commercial industry (comprised of 1.5 million bblo/day from in situ processes and 0.05 million bblo/day from ex situ processes). The Phase I report included the assumption that coal fired power plants would generate the electric energy required by the industry. As a result, for the high production scenario, these assumptions led to water uses associated with the thermoelectric power supplies for oil shale of approximately 240,000 acre-feet per year (af/year). The Phase I estimated direct demands for oil shale were approximately 113,000 af/year. As discussed in the next section, the Phase II Energy Development Water Needs study revised oil shale industrial water uses.

Table 2-1 Phase I Annual Water Direct Demands by Industry (values in af/year)

Planning Horizon	Production Scenario		
	Low	Medium	High
Near-Term (2007 – 2017)	Natural Gas: 4,292 Coal: 1,213 Uranium: 0 Oil Shale: 720	Natural Gas: 4,880 Coal: 1,213 Uranium: 0 Oil Shale: 720	Natural Gas: 5,230 Coal: 1,213 Uranium: 62 Oil Shale: 720
Mid-Term (2018 – 2035)	Natural Gas: 4,168 Coal: 1,213 Uranium: 0 Oil Shale: 720	Natural Gas: 5,044 Coal: 1,538 Uranium: 62 Oil Shale: 8,586	Natural Gas: 5,437 Coal: 1,538 Uranium: 62 Oil Shale: 42,106
Long-Term (2036 – 2050)	Natural Gas: 3,869 Coal: 1,213 Uranium: 0 Oil Shale: 720	Natural Gas: 4,769 Coal: 1,538 Uranium: 62 Oil Shale: 17,407	Natural Gas: 5,171 Coal: 5,063 Uranium: 124 Oil Shale: 112,675

Table 2-2 Phase I Annual Indirect Water Demands by Industry (values in af/year)

Planning Horizon	Production Scenario		
	Low	Medium	High
Near-Term (2007 – 2017)	Natural Gas: 9,400 Coal: 1,100 Uranium: Negligible Oil Shale: 700	Natural Gas: 10,200 Coal: 1,400 Uranium: Negligible Oil Shale: 700	Natural Gas: 10,800 Coal: 1,400 Uranium: Negligible Oil Shale: 700
Mid-Term (2018 – 2035)	Natural Gas: 9,400 Coal: 1,100 Uranium: Negligible Oil Shale: 700	Natural Gas: 10,800 Coal: 1,400 Uranium: Negligible Oil Shale: 1,545	Natural Gas: 11,400 Coal: 1,400 Uranium: Negligible Oil Shale: 9,680
Long-Term (2036 – 2050)	Natural Gas: 8,200 Coal: 1,100 Uranium: Negligible Oil Shale: 700	Natural Gas: 10,300 Coal: 1,400 Uranium: Negligible Oil Shale: 3,920	Natural Gas: 11,100 Coal: 2,400 Uranium: Negligible Oil Shale: 21,100

Note: The tabulated values are the upper range values for each planning horizon and production scenario

Table 2-3 Phase I Annual Thermoelectric Power Generation Water Demands by Industry

Planning Horizon	Production Scenario		
	Low	Medium	High
Near-Term (2007 – 2017)	Natural Gas: 4,354 Coal: 755 Uranium: 0 Oil Shale: 18	Natural Gas: 5,230 Coal: 764 Uranium: 3 Oil Shale: 18	Natural Gas: 5,428 Coal: 764 Uranium: 3 Oil Shale: 18
Mid-Term (2018 – 2035)	Natural Gas: 5,827 Coal: 755 Uranium: 0 Oil Shale: 18	Natural Gas: 8,309 Coal: 958 Uranium: 3 Oil Shale: 6,090	Natural Gas: 9,012 Coal: 958 Uranium: 3 Oil Shale: 82,925
Long-Term (2036 – 2050)	Natural Gas: 5,049 Coal: 755 Uranium: 0 Oil Shale: 18	Natural Gas: 7,501 Coal: 958 Uranium: 3 Oil Shale: 26,316	Natural Gas: 8,220 Coal: 1,124 Uranium: 6 Oil Shale: 244,532

2.4.2 Overview of the Phase II Energy Development Water Needs Study

The Phase II study adopted the Phase I water use scenarios and demands for the natural gas, coal, and uranium energy sectors. It revised the direct, indirect, and thermoelectric water uses associated with oil shale. The Phase II study changed the assumptions for electrical power generation associated with oil shale industrial purposes. Instead of coal fired power generation, the Phase II water estimates included power generation with combined cycle gas turbines located near the production sites within the White River basin. The Phase II study estimated oil shale indirect demands from population estimates used in the Basin Roundtable BRT and IBCC processes (Harvey Economics, 2010).

The Phase II work assumed a single production scenario of 1.5 million bblo/ day from in situ technologies and 50,000 bblo/day for above ground ex situ technologies. And, instead of varying the production levels, as was done in Phase I, the Phase II study varied the water use factors for each production level. The evaluation assumed low, medium, and high water use factors for each component of process technology.

Phase II estimated indirect water use from increased population by multiplying population estimates by an estimate of per-capita daily water use. Water use due to population growth not directly employed in the oil shale industry was estimated using a per-capita daily rate of 200 gallons per capita per day (gpcd), which is the value adopted by the Phase I study, and a smaller per-capita daily water use rate of 100 gpcd was used to estimate water use by the workforce. Estimates of indirect water use in the Phase II study did not include the water required for generation of electricity to support population growth, under the assumption that this electricity will come from the grid and will not be attributable to a single generating station in the study area.

The Phase II developed water use factors for direct and indirect uses associated with commercial oil shale development. Table 2-4 shows the estimated water use volumes presented in the Phase II report. The values include direct and indirect uses.

Table 2-5 presents the water use categories and factors for in situ and ex situ processes. For the 1.5 million bblo/day insitu and 50,000 bblo/day ex situ production scenario the indirect water uses total approximately 9,500 af/year.

Table 2-4 Phase II Oil Shale Water Use Estimates for 1.5 million bblo/day In situ and 50,000 bblo/day Ex situ Oil Shale Production Levels

Scenario	Technology Mix	Unit Use (bblw/bblo)	af/year
Low			
IS-1	In situ; downhole combustion heating, off-site upgrading, low estimates.	-0.22	-16,000
AG-1	Above Ground; off site electricity, low estimate	1.45	3,400
		Total	-13,000
Medium			
IS-4	In situ; Shell ICP, on-site upgrading, low estimates.	0.77	54,000
AG-3	Above Ground; on-site electricity, on-site upgrading, low estimates	2.22	5,200
		Total	59,000
High			
IS-7	In situ; Shell ICP, on-site upgrading high estimates.	1.59	110,000
AG-6	Above Ground; on-site electricity, on-site upgrading, high estimates	4.33	10,000
		Total	120,000

Table 2-5 Phase II Estimates of Oil Shale Indirect Water Uses

Water Use Category	Production Scenario 1.5 million bblo/day in situ and 0.05 million bblo/day ex situ		
	Water use Factor In situ (bblw/bblo)	Water Use Factor Above Ground (bblw/bblo)	Estimates of Indirect Water Use for Oil Shale (af/year)
Construction and Production	0.11	0.46	8,900
Electrical Energy	0.008	0.002	570
Total			9,500

Finally, the Phase II study developed water supply scenarios and then modeled conceptual water supply projects utilizing the State of Colorado StateMod hydrological and water allocation model. The modeling indicated that yields of up to 120,000 af/year could potentially be available assuming the historical hydrology, water uses, and river administration. The modeled scenarios assumed various priority water rights, storage structures, and direct diversions from the White River (Table 2-6).

Table 2-6 Phase II Selected White River Water Supply Projects

Water Supply Project	Description
Lake Avery Enlargement Filled From Big Beaver Creek	Location: Off stream of White River on Big Beaver Creek Water Supply: Big Beaver Creek Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Lake Avery Enlargement Filled From White River	Location: Off stream of White River on Big Beaver Creek Water Supply: White River Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Wolf Creek Reservoir	Location: On the White River or off-stream of White River on Wolf Creek Water Supply: White River Capacity: 162,400 acre-feet (total decreed capacity for three conditional storage rights owned by the Colorado River Water Conservation District) Modeled Priority: 2010 Operation Assumptions: water released from Wolf Creek Reservoir would be either (1) exchanged up to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand, or (2) pumped directly from Wolf Creek Reservoir to Piceance Creek Basin to meet in-situ retort demand.

Water Supply Project	Description
New Diversion	Location: Confluence of Piceance Creek and White River Water Supply: White River Capacity: 165.05 cubic feet per second (cfs) Modeled Priority: 2010 Operation Assumptions: water diverted by this diversion would be pumped up to Piceance Creek Basin to meet in-situ retort demand.

3.0 COMMERCIAL OIL SHALE WATER DEMANDS

The direct water demands associated with the commercial oil shale industry include water for site development, operations, production processes, refining processes, electric energy generation for production processes, reclamation, and other appurtenant water uses. The indirect water uses are result from growth in population from workforce and population to service the industrial workers. This report updates the direct and indirect water demands.

As in the Phase II report, this planning considers "build-out" industrial water demands. If a commercial oil shale industry develops, then the demands will likely ramp up over 10 – 50 years. During the research and development process, until 2025 or so, water uses may amount to hundreds of acre-feet per year. If the oil shale projects prove commercially viable, then industrial direct water demands may develop to the build-out levels and this planning effort aims to portray a range in build-out levels.

Since 2011 and the completion of the Phase II study, both Chevron and Shell have ended their research efforts in Colorado oil shale. In May of 2014, the National Oil Shale Association (NOSA) provided new estimates of the scale of commercial oil shale industry and the associated direct water uses (Appendix A). Instead of commercial production levels up to 1.5 million bblo/day, NOSA indicates total oil shale production for the three states of Colorado, Utah, and Wyoming of up to approximately 500,000 bblo/day. Based on the new NOSA data, the oil shale industrial direct water uses in Colorado may range from approximately 15,000 – 30,000 af/year. Indirect water uses for a 500,000 bblo/day production scenario are approximately 7,200 af/year.

In addition, the Energy Subcommittee believes prudent water supply planning for the area includes additional water volumes to express uncertainty in the NOSA estimates. Assuming a commercial industry of up to 1.5 million bblo/day, that in situ production technologies make up 1.2 million bblo/day production and ex situ technologies at approximately 0.3 million bblo/day. This results in a net direct water use of 30,000 - 76,000 af/year and indirect water uses of approximately 13,000 af/year.

The following sections summarize the current oil shale research projects, introduces the new water use information developed by NOSA, and reports updated water use volumes for build-out of a commercial oil shale industry in Colorado.

3.1 Oil Shale Research Development and Demonstration Leases

The following paragraphs describe the oil shale research, development, and demonstration lease process and provide a general description of individual development plans as available from company websites, the Bureau of Land Management (BLM), and Department of Energy (DOE) sources.

In 2006 and 2007, the BLM awarded six "first round" oil shale research, development, and demonstration (RD&D) leases (DOE, 2012). Five leases are in Colorado, at the time, three held by Shell, one by Chevron, and one by EGL Oil Shale. The sixth first round lease was obtained by the Oil Shale Exploration Company (OSEC) and is in Utah.[1] Subsequently, American Shale Oil (AMSO) acquired the EGL Oil Shale lease and Enefit (the Estonian company) acquired the OSEC lease. In 2010, the BLM awarded two "second round" oil shale RD&D leases (DOE, 2012). Both of the second round leases are in Colorado, held by Exxon/Mobil and Natural Soda Holding, Inc (NSHI).

Since the Phase II report was published, both Chevron and Shell and stopped development of their Colorado oil shale projects. In February of 2012, Chevron announced that the company would discontinue lease

[1] Also, the Red Leaf Corporation is developing oil shale projects on private lands and State of Utah leases in Utah

activities and divest its BLM lease (Denver Business Journal, February 28, 2012). In November of 2013, Shell announced that the company was divesting its Colorado oil shale interests (Denver Post, September 24, 2013). At this time, only three companies are active on RD&D leases in Colorado: AMSO, Exxon/Mobil, and NSHI. Enefit is actively pursuing oil shale projects on its private and state leases in Utah (Energy Wire as shown on Enefit website, January 7, 2014). Redleaf is developing ex situ oil shale production processes on state School and Institutional Trust Lands Administration land in Utah (Salt Lake Tribune, January 15, 2014).

Both first and second round leases are for a period of 10-years with potential for a 5-year extension. The first round RD&D leases include 160 acres for RD&D projects with a contiguous 4,920 acre Preference Right Lease (PRL) area (Figure 3-1). The second round leases are for smaller areas and include 160 acres for RD&D projects and a contiguous 480 acre PRL. Although somewhat different in the terms and conditions, both first and second round leases require the lessees to submit operating plans, acquire permits, and show development of commercially viable technologies. If commercial viability is demonstrated, then the PRL area may be developed.

In addition to the federal oil shale leases, various energy companies and private parties own land with mineral rights in the oil shale resource areas. Figure 3-2 indicates all non-federal and non-state lands in Rio Blanco and Garfield counties associated with resource areas.

Figure 3-1 Phase II Study Regions of In Situ and Above-Ground Oil Shale Operations

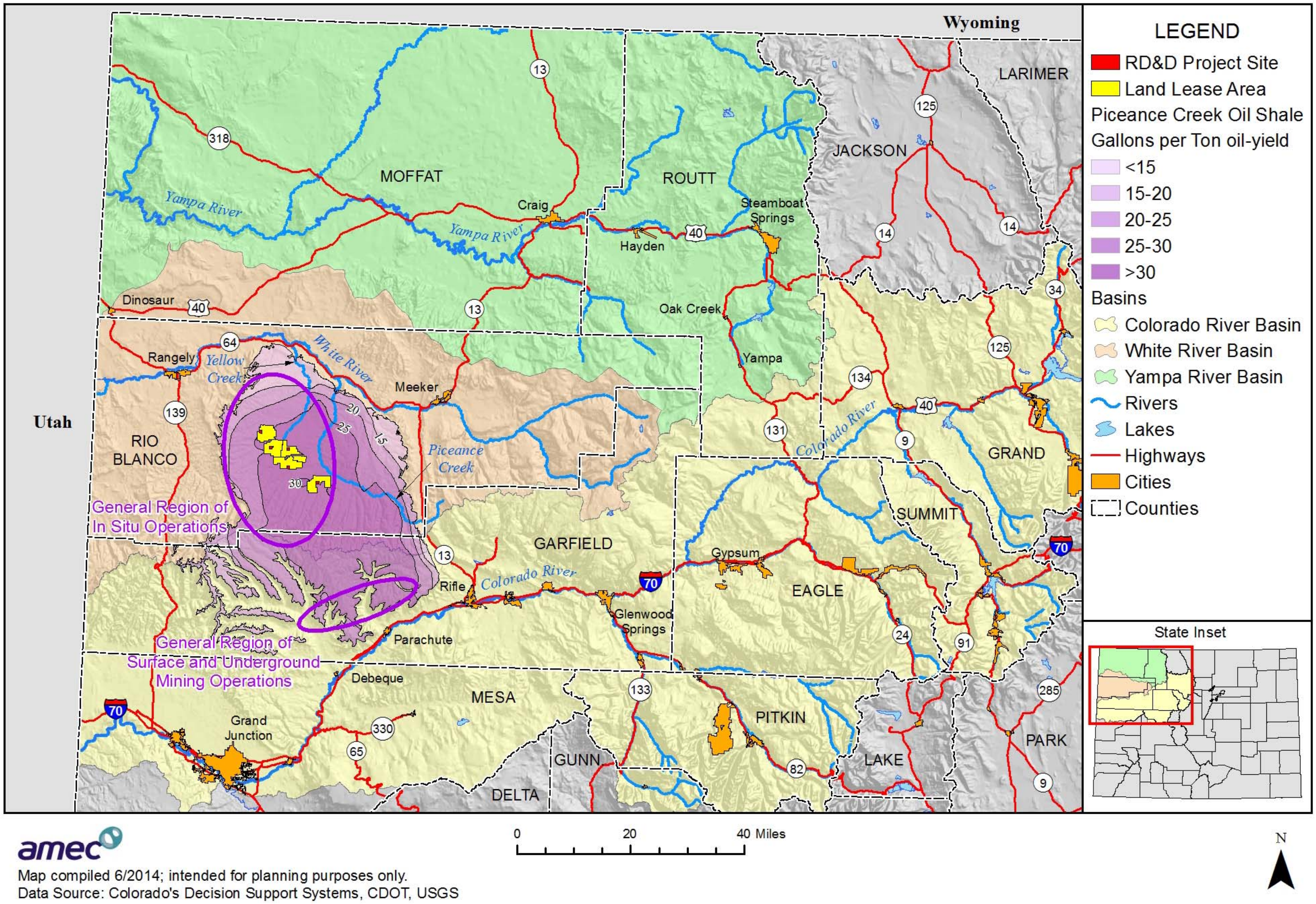
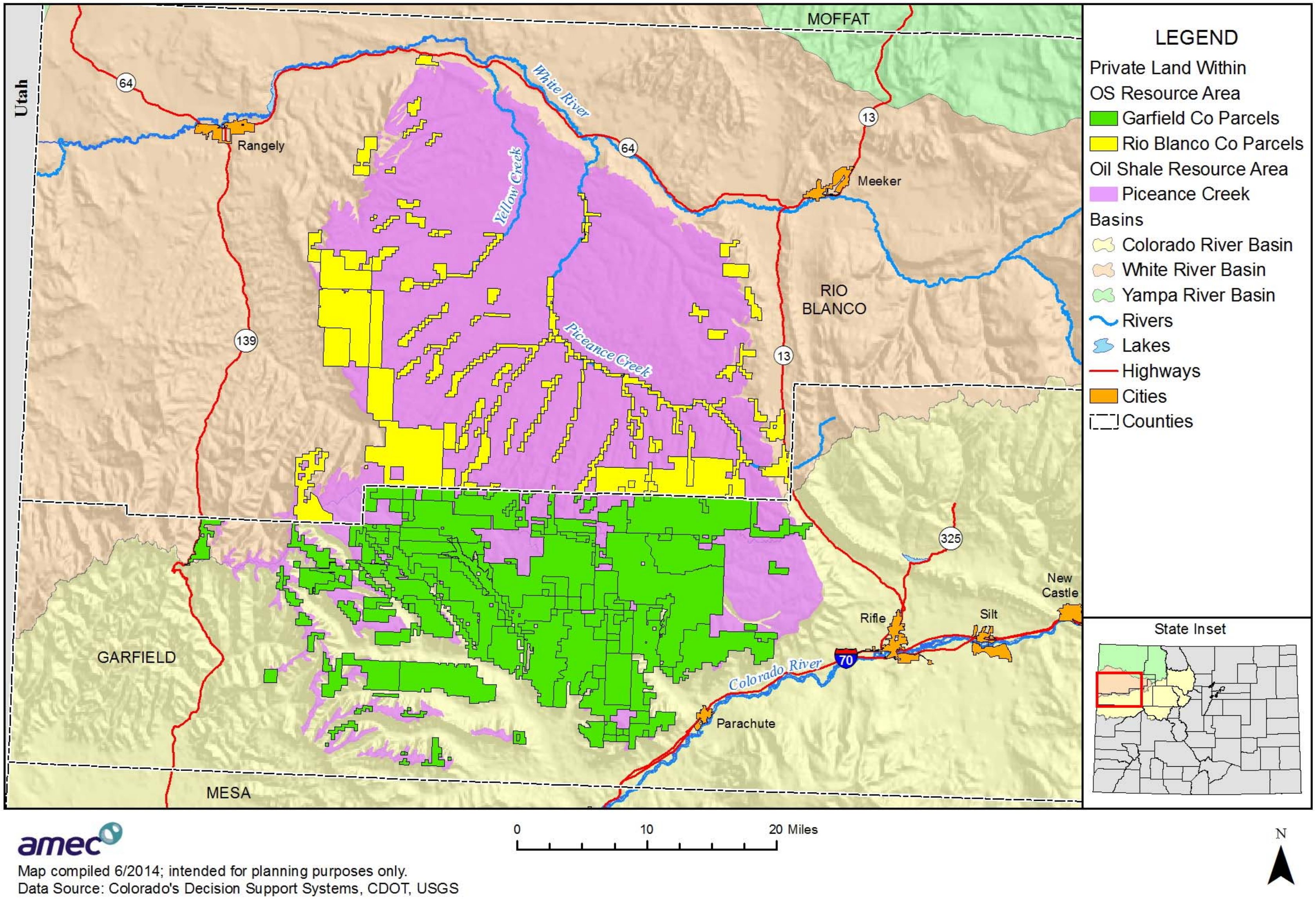


Figure 3-2 Private Land within OS Resource Area



3.2 Oil Shale Research Development and Demonstration Plans of Operations

Currently, five energy companies or joint ventures own federal oil shale RD&D leases on BLM managed land in Colorado. As mentioned above, Chevron and Shell have discontinued research activities. AMSO, Exxon/Mobil, and Natural Soda Holdings, Inc remain active on their RD&D projects. These companies are all pursuing in situ technologies in the Piceance Basin and within the Piceance Creek and Yellow Creek drainages in the White River.

There is one federal oil shale RD&D lease on BLM managed land in Utah. Enefit American Oil Shale, Inc. is conducting research on ex situ retort technologies in Utah. The research site includes the former "Ua tract" development area. Finally, Redleaf Resources Incorporated is developing ex situ technologies on areas under private leases in Utah and owns rights to resource areas in Wyoming (http://www.redleafinc.com).

3.2.1 American Shale Oil, LLC (AMSO)

In 2007, EGL Resources obtained a 160-acre research, development, and demonstration lease in Rio Blanco County for development of oil shale technologies. In 2008, EGL was sold to IDT Corporation and the company was renamed American Shale Oil, LLC. The company is now owned 50/50 by Total and Genie Energy. Genie Energy is the operating partner through the demonstration phase of the AMSO LLC oil shale RD&D project (DOE, 2012).

EGL originally submitted the initial Plan of Operations for an in situ oil shale production process and AMSO made two major modifications to the RD&D program as a result of the preliminary research and analysis phases. The major changes relate to the target formation for initial pilot testing and modifications to the downhole heater technologies. The amended plan for operation has been approved by the BLM (DOE, 2012).

Concerns about groundwater intrusion and protection of the groundwater quality led to AMSO's decision to target deeper oil shale deposits. The modified plan includes drilling horizontal heat injection wells in the illitic oil shale zone (approximately 2,000 feet below ground surface). The illitic shale lies below the "dissolution surface" and below a nacholitic oil shale cap rock (DOE, 2012).

AMSO's RD&D phase is continuing and the Plan of Operations calls for development of the in situ conversion process, downhole burners, and demonstration of CO_2 sequestration. "Post-Application" work is set to begin in 2017. At that time AMSO will evaluate process options and engineering designs and develop permitting for the commercial project. The AMSO project timeline indicates commercial operations beginning in 2020. The commercial production is projected to ramp up to a 100,000 barrel of oil per day operation. AMSO believes that the commercial project will operate for 25 years on the approximately 8 square mile lease area (http://amso.net).

3.2.2 Enefit American Oil Company

In 2007, the BLM awarded OSEC an oil shale lease for a 160-acre research, development, and demonstration lease in Uintah County, Utah (near Vernal). The lease includes "Tract Ua" and the White River Mine which were test projects under oil shale leasing programs in the 1970's. In 2011, OSEC was acquired by Eesti Energia, the state owned Estonian energy group (Estonian Review, March 10, 2011) and organized as Enefit American Oil Company to develop the RD&D project (DOE, 2012).

Enefit intends to commercialize its Enefit 280 surface retort technology. The company is developing baseline environmental data, preparing an environmental impact study (EIS), conducting drilling and modeling/bench scale tests, and creating surface/underground mining plans. The development goals include initiating commercial oil shale production in 2020 at a level of 25,000 bblo/day and implementing a second retort to achieve full capacity of 50,000 bblo/ day by 2024 (DOE, 2012).

3.2.3 ExxonMobil

ExxonMobil is conducting research on in situ oil shale production technologies on a 160-acre RD&D tract in Rio Blanco County, Colorado (DOE, 2012). The proposed process includes hydraulically fracturing oil shale zones and filling the fractures with conductive materials and then using electricity to heat the materials. The RD&D project includes an appraisal phase followed by three experimental phases. The appraisal phase establishes the environmental baseline. The experimental phases establish the ability to install the technology in the test zone, heat the zone, and then conduct a pilot test to determine commercial viability on a field scale (DOE, 2012).

3.2.4 Natural Soda Holdings, Incorporated (NSHI)

The NSHI lease consists of 160-acres situated between the Stake Spring and Ryan Gulch drainages in Rio Blanco County, Colorado. NSHI's in situ process for extracting kerogen from oil shale utilizes high temperature water in conjunction with carbon monoxide, sodium bicarbonate, and sodium aluminate to break the chemical bonds of kerogenaceous oil shale. As with AMSO and ExxonMobil, NSHI will target the saline zone of the Parachute Creek Member (NSHI, 2011).

3.2.5 Redleaf Resources, Inc.

Redleaf Resources, Inc. has developed the EcoShale™ In-Capsule Technology which is an ex situ process that heats mined oil shale in a constructed cell at the surface. The mined oil shale is placed into a clay-lined excavation and covered with layers of impermeable clay and soil and then the shale is heated with natural gas via steel pipes. The heating results in pyrolysis and produces oil, condensate, and natural gas (http://www.redleafinc.com).

The company is projecting commercial scale projects on their current holdings in Utah will produce approximately 400 million barrels of oil over the next 20 years. That is equivalent to an average daily rate of approximately 55,000 bblo/ day. Currently, there are no plans for developing this technology in Colorado. Nonetheless, the ex situ processes are applicable to oil shale resources in Colorado that are accessible by mining.

The location of oil shale deposits and the general location of the expected in situ and above-ground development are shown in Figure 3-1.

3.3 Commercial Oil Shale Industry Direct Water Uses

In May of 2014 NOSA provided new water use estimates for the direct uses associated with potential future oil shale industry (Appendix A). Table 3-1 summarizes the new production levels, gross water use factor, net water use factor, and estimated net volumes for the "build-out" production scenario. The NOSA fact sheet indicates that the water use is associated with industry in Wyoming, Utah, and Colorado.

Table 3-1 NOSA May 2014 Fact Sheet Oil Shale Production Levels and Water Use

Technology	Production Level (bblo/day)	Gross Water Use Factor (bblw/bblo)	Net Water Use Factor (bblw/bblo)	Net Water Use Volume (af/year)
In situ	225,0000	0.6 - 1.3	0.3 – 1.0	3,180 – 10,600
Ex situ	200,000	2.4 – 2.6	1.4 – 1.6	13,200 – 15,100
Mod In situ	75,000	0.5 – 1.1	0 – 0.9	0 – 3,180
Total	500,000			16,400 – 28,900

The in situ technologies correspond to research underway by Exxon/Mobil, AMSO, and NSHI. The ex situ technology relates to Enefit (mining and surface retort) and the modified in situ technology corresponds to Redleaf's mining and cell retort.

The NOSA update indicates a production level of up to 0.5 million bblo/day, one-third of the production level assumed in Phase II. The production is about equally apportioned between in situ and ex situ plus modified in situ processes, 225,000 and 275,000 bblo/day, respectively. Their assumptions include a range (low and high) of water use factors and applying the factor to the production level and mix of technologies results in direct water use volumes of approximately 15,000 – 30,000 af/year (Table 3-2).

In addition, the Energy Subcommittee believes water supply planning for the area should include additional water volumes to express uncertainty in the NOSA estimates. For those purposes, the production levels of 1,225,000 bblo/day in situ and 275,000 bblo/day ex situ plus modified in situ result in direct water uses ranging from approximately 30,000 – 76,000 af/year (Table 3-2).

Table 3-2 Direct Water Use Phase III Production Scenarios

Production Level (bblo/day)	Production Level (bblo/day)	Net Water Use Factor (bblw/bblo)	Net Water Use Volume (af/year)
NOSA 500,000			
- In situ	225,000	0.3 – 1.0	3,180 – 10,600
- Ex situ	200,000	1.4 – 1.6	13,200 – 15,100
- Mod In situ	75,000	0 – 0.9	0 – 3,180
Total	500,000		16,400 – 28,900
1,500,000			
- In situ	1,225,000	0.3 – 1.0	17,000 – 58,000
- Ex situ	200,000	1.4 – 1.6	13,000 – 15,000
- Mod In situ	75,000	0 – 0.9	0 – 3,000
Total	1,500,000		30,000 – 76,000

Since the in situ RD&D projects are located in the White River basin, the water supplies would most likely be developed from the White River. The ex situ projects may be developed in either the White River basin (e.g., Tracts Ca and Cb) or in the Colorado River basin (e.g., Colony). For purposes of locating the direct demands, this report assumes all of the in situ demands and one-third of the ex situ plus modified in situ water uses are White River and the remaining two-thirds of the ex situ plus modified in situ water uses are in the Colorado River basin (Table 3-3).

Table 3-3 Oil Shale Direct Demands Apportioned by River Basin

Production Technology	Production Level (bblo/day)	River Basin	Net Water Use Volume (af/year)
NOSA 500,000			
- In situ	225,000	White	3,000 – 11,000
- Ex situ + Mod In situ	275,000	Colorado	13,000 – 18,000
1,500,000			
- In situ	1,225,000	White	17,000 – 58,000
- Ex situ + Mod In situ	275,000	Colorado	13,000 – 18,000

3.4 Oil Shale Indirect Water Use

The Phase I study estimated indirect water demands associated with a commercial oil shale industry. The indirect water uses result from growth in population from the energy and service workers (i.e., the new population requires domestic and municipal water supplies). In addition, the Phase I work estimated the thermoelectric water uses associated with providing electric power to the new population. The Phase II study refined estimates of oil shale indirect water use. The Phase II refined the indirect water use estimate so as to be consistent with methods used in the Statewide assessments and IBCC.

In the Phase II study, water use from increased population from development of oil shale was estimated by multiplying population estimates by an estimate of per-capita daily water use. Water use due to population growth not directly employed in the oil shale industry was estimated using a per-capita daily rate of 200 gpcd, which is the value adopted by the Phase I study. To estimate water use due to employment, a smaller per-capita daily water use rate of 100 gpcd was used to reflect the fact that oil shale workers will spend considerable time at production locations or traveling and therefore will not have any associated outdoor water use.

Estimates of indirect water use in the Phase II study do not include the water required for generation of electricity to support population growth, under the assumption that this electricity will come from the grid and will not be attributable to a single generating station in the study area (Table 3-4).

Table 3-4 Phase II Estimates of Indirect Water Use Factors for Production of Oil from Oil Shale (bblw/bblo)

Water Use Category	In situ Retorting (bblw/bblo)	Above-Ground Retorting (bblw/bblo)
Electrical Energy Workforce	0.008	0.002
Construction and Production Workforce	0.11	0.46
Total	0.118	0.462

Using the Phase II water use factors to scale indirect water use volumes associated with the Phase III production scenarios results in indirect demands of 7,200 and 12,800 af/year for the 500,000 and 1.5 million bblo/day assumptions, respectively (Table 3-5).

Table 3-5 Updated Indirect Water Uses for Commercial Oil Shale

Production Technology	Production Level (bblo/day)	Net Water Use Factor (bblw/bblo)	Net Water Use Volume (af/year)
NOSA 500,000			
- In situ	225,000	0.118	1,200
- Ex situ + Mod in situ	275,000	0.462	6,000
Total	500,000		7,200
Phase III 1,500,000			
- In situ	1,225,000	0.118	6,800
- Ex situ + Mod in situ	275,000	0.462	6,000
Total	1,500,000		12,800

4.0 NATURAL GAS AND OIL INDUSTRY WATER DEMANDS

This section updates the Phase I Energy Development Water Needs Assessment's estimates of direct water uses associated with the drilling and completion of oil and gas wells.[2] The indirect demands associated with the oil and gas industry developed in the Phase I study are carried forward and not updated in this report[3]. Since 2008, there have been important changes in drilling and completion methods and the activity in the west slope gas fields, this work evaluates the direct water uses in light of these changes.

As shown later, 2006 – 2008 represents the historical maximum drilling activity within the study area. The Energy Subcommittee wanted to know if the Phase I projections needed adjustment, factoring in the significant slowdown in drilling operations in the past several years. Also, horizontal drilling methods are becoming more common and this work investigates horizontal wells becoming a larger component of oil and gas water use estimates going forward.

This section provides estimates of water demands using water use factors (i.e., acre-feet per well) and assumptions regarding the number of wells drilled over time. The water volumes presented are the net amount of tributary water required for well drilling and completion unless otherwise noted. The summary (ref table) provides the direct water uses by river basin.

The water estimates include assumptions regarding the "peak" water demands for the planning period to 2050. The peak water demands represent an assumption for maximum number of well drilled in a future year. The historical numbers of well completions (CWCB, May 2014) and estimates of development (BLM various) inform the assumptions. Nonetheless, the range of estimates reflects the considerable uncertainties in estimating the peak rates and in the range of water volumes.

This work evaluates new information about oil and gas industrial water uses that has become available since the Phase I report. In 2011, the Colorado Oil and Gas Conservation Commission (COGCC) and CWCB published a "white paper" projecting statewide water demands for well drilling through 2015 (http://cogcc.state.co.us/). In the past several years the Bureau of Land Management has issued updated Resource Management Plans for the federal management areas in the Colorado, Little Snake, White, and Yampa River basins in Colorado (BLM, various). Finally, this report completes a precursory summary of water uses indicated on COGCC well completion forms (i.e., Form 5A) and of certain well completion records as described on FracFocus (a national voluntary participation database regarding well hydrofracturing).

4.1 Estimates of Water Use Factors

This section develops water use factors representing the net amount of tributary water required for well development/drilling and completion (unless otherwise noted).[4] The water use factor is expressed as volume of water per well. The Phase I study evaluated the various component of water use associated with gas well drilling and completions and arrived at a factor of 2.24 acre-feet per well. The following discusses the new evaluations and refinements for the oil and gas water use factors.

Water use factors vary by the type of well drilling and completion method, location, the level of development of a field or "play", operator experience, and likely, other reasons. Horizontal wells generally require more

[2] The Phase II study did not update water use estimates associated with development of the oil and gas resources.

[3] Phase I estimates are deemed to be sufficient at this time because the new production levels are expected to have about the same growth in population as were associated with the Phase I estimates..

[4] For the purposes of this reporting, the water use factor includes water for well pad construction, dust control, and other ancillary uses.

water for completion, as compared to vertical or deviated wells, because more "stages" are needed to hydraulically fracture the lengthy production zones. Net water use is less is in developed areas because recycled water (either flow back from prior completions or produced water) becomes a significant portion of the total water use. Operators adjust completion techniques based on site specific conditions and what they believe are the most effective methods.

This Phase III study includes information from the COGCC and CWCB fact sheet entitled "Water Sources and Demand for the Hydraulic Fracturing of Oil and Gas Wells in Colorado from 2010 through 2015" (Appendix B), drilling activity and water use as described in Bureau of Land Management Resource Management Plans (various BLM as listed in the references), database records downloaded from FracFocus.org (Appendix C), and information regarding water use associated with horizontal well drilling (COGCC, 2014).

The COGCC fact sheet reported gross direct water use for oil and gas well drilling on a statewide basis. The water use estimates used 2011 historical information regarding water use (from well completion records) and numbers of well starts to project statewide water demands for 2010 – 2015. The COGCC estimates of water use represent a gross water use factor of approximately 5 acre-feet per well.

The BLM recently updated their Resource Management Plans (RMP) in the Little Snake, Yampa, White, and Colorado River areas. The planning included analysis of oil and gas development since a primary goal of the planning is to describe the environmental impacts of these activities (and others) on federal lands. The RMPs generally describe oil and gas water uses in their analysis of alternatives, affected environment, and environmental consequences sections.

The RMPs reported water use factors for well drilling and completion in the Colorado River basin of 0.77 acre-foot per well for vertical and directional wells and a range of 1.8 – 2.1 acre-foot per wells for horizontal wells. Water use factors for well drilling and completion in the White River drainage were reported as 2.62 acre-foot per well (presumably for vertical and directional wells). The Little Snake Field Office did not include numeric water use factors.

The Phase III work reviewed well completion information as disclosed in the FracFocus.org data forms (http://fracfocus.org). The forms include entries for "Total Water Volume (gal)", well depth, well completion dates, well location coordinates, well API number, and hydraulic fracturing fluid product components. The analysis included approximately 230 wells selected to provide a cross-section of geographic area and drilling/completion methods in the Piceance and Sand Wash Basins. A summary of the data review is shown in Table 4-1.

Table 4-1 Summary of Total Water Use Disclosed on FracFocus.org for 229 Selected Wells

River Basin	No. of Wells Reviewed	Minimum Water Use (acre-feet/well)	Maximum Water Use (acre-feet/well)	Median Value Water Use (acre-feet/well)
Colorado River	158	0.28	92	5.45
Little Snake River	9	0.03	0.46	0.15
White River	35	0.02	18.5	2.9
Rangely Field	13	0.1	0.53	0.17
Yampa River	14	0.44	49	3.5
Total	229	0.02	92	4.33

This analysis considers the "Total Water Volume" reported on FracFocus to be generally reflective of gross water use volumes. The median water use value for all of the wells reviewed is 4.33 acre-feet per well. That value is comparable to the COGCC gross water use factor discussed above. While not definitive for the purposes of the Phase III study, the FracFocus data helps inform the selection of updated net water use factors.

There is relatively less data available regarding water uses for horizontal wells. The Colorado River Conservation District recently leased approximately 40 acre-feet of Elkhead Reservoir water supplies for the purpose of drilling and completing a horizontal well in Moffat County. Horizontal well drilling and completion methods required more water because significantly more "stages" may be required to hydraulically fracture the lengthy production zones. Still, horizontal wells make up a small portion of the total number of wells drilled in the Piceance basin. Consequently, these water use estimates do not explicitly account water use volumes for horizontal wells.

For the purposes of this report, the water use factors range from 1 to 3 acre-feet per well. The 1 acre-feet per well water use factor for the Colorado River indicates the overall higher proportion of water recycle and reuse that takes place in the Piceance basin fields in this area. The BLM planning in the Colorado River areas developed a water use factor of 0.77 acre-feet per well. This work rounds that number to estimate water uses in the Colorado River areas. The 3 acre-feet per well water use factor is based on Phase I value of 2.24 and considering is the water use factor from the White River Field Office RMP. The water use factors associated with the river basins are shown in Table 4-2. This work applies a water use factor of 3 acre-feet/well for drilling and completion of wells in the Yampa and Little Snake areas. This number is sufficient because even though there is a slight trend to horizontal wells, the BLM indicates that in the future the predominant development will most likely extend know gas and oil formations and fields and the overall number of horizontal wells is expected to be relatively small.

Table 4-2 Oil and Gas Well Drilling and Completion Water Use Factors by River Basin

River Basin	Acre-feet/well
Little Snake	3
White River	3
Colorado River	1

4.2 Estimates of Peak Year Drilling Activity

This section develops assumptions regarding the future peak water demands associated with oil and gas well drilling. In planning for oil and gas water supplies, the peak year is an appropriate threshold because the somewhat conservative planning goal will allow for sufficient water supplies when drilling activity is at its greatest. The peak year drilling activity comes from review of the numbers of historical numbers of well completions (COGCC, May 2014) and estimates of oil and gas development as generally characterized in the BLM RMPs. The range of estimates reflects the in estimating the peak rates and in the range of water volumes.

The COGCC publishes information regarding well drilling by county. The annual number of wells drilled in Garfield, Moffat, Rio Blanco, and Routt counties for the years 1988 – 2014 are tabulated in Appendix D. In this evaluation, the 1998 – 2014 county data was parsed by river basins; Garfield and Mesa counties represents the Colorado River basin, Rio Blanco County represents the White River basin, and the Yampa/Green/Little Snake River basins are associated with Routt and Moffat County data. Figure 4-1 through Figure 4-3 provide graphs of the annual well starts by river basin and Table 4-3 summarizes the well start data.

Figure 4-1 Annual Wells Starts for the Colorado River Area

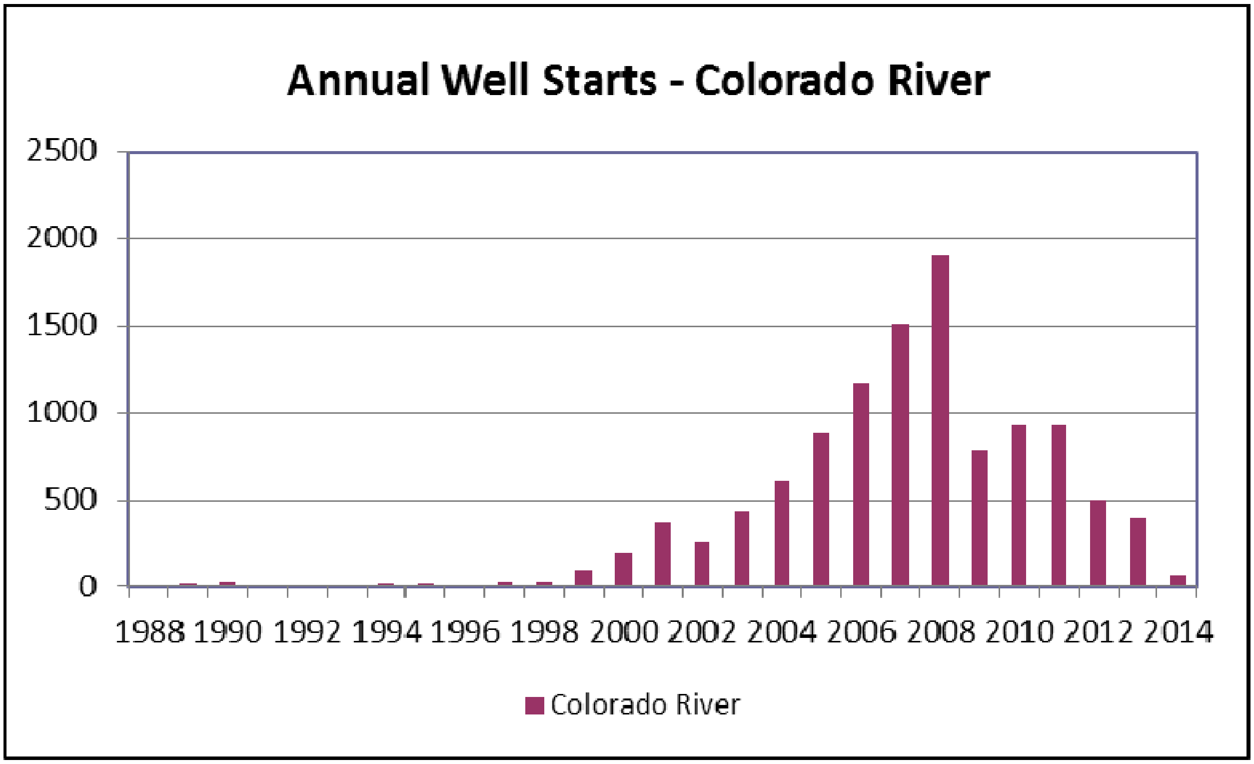


Figure 4-2 Annual Wells Starts for the White River Area

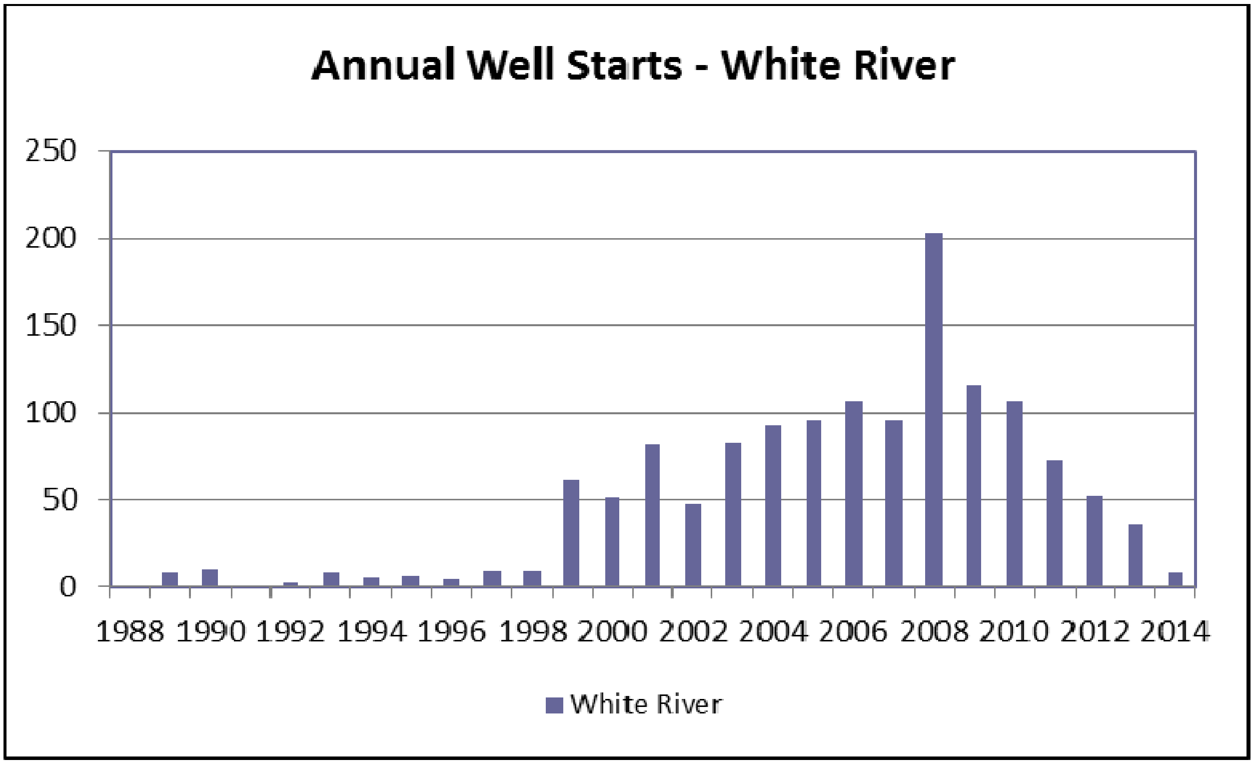


Figure 4-3 Annual Wells Starts for the Yampa/Green/Little Snake Rivers Areas

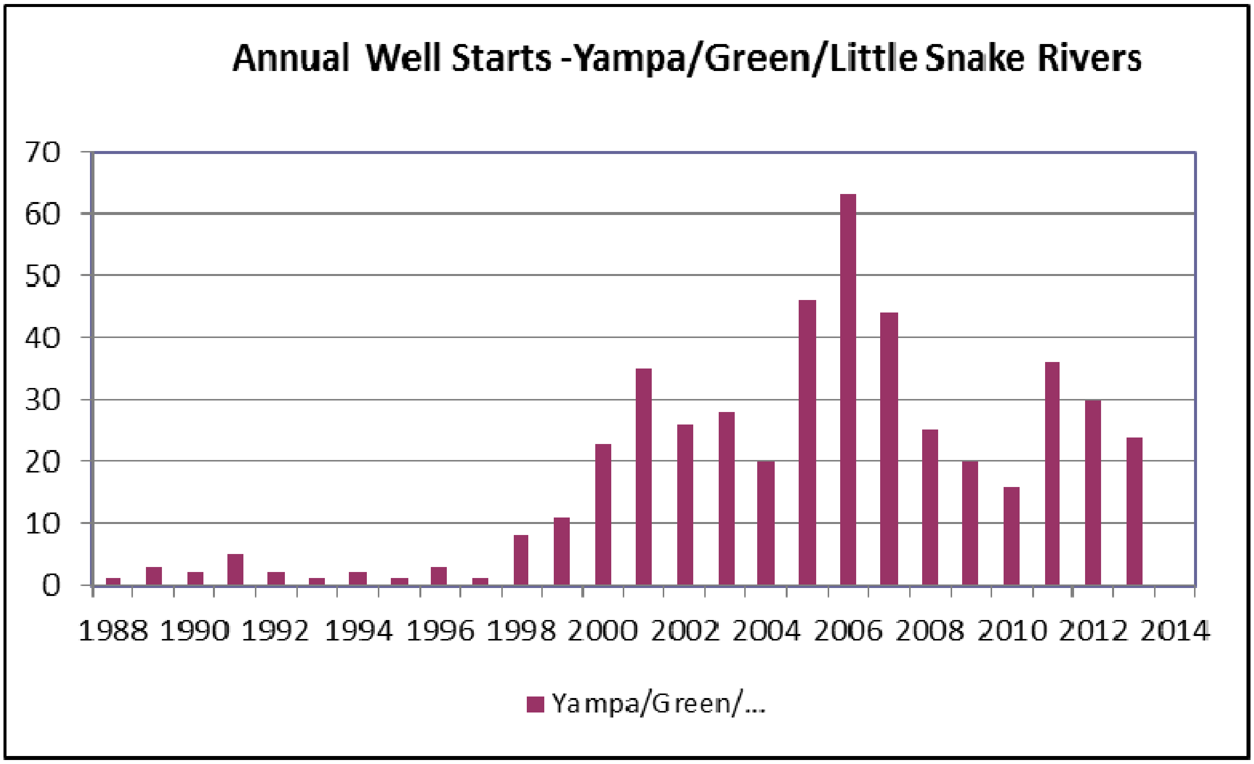


Table 4-3 COGCC Number of Annual Well Starts

County	Total No. Well Starts 1988 - 2014	Average No. Well Starts 1998 - 2014	Maximum No. Well Starts / Year
Garfield	10,323	569	1,688/2008
Mesa	844	48	222/2008
Moffat	428	24	60/2006
Rio Blanco	1375	74	203/2008
Routt	48	3	12/2001
River Basin			
Colorado River	1167	614	1,910/2008
White River	1,375	74	203/2006
Yampa/Green/ Little Snake	476	25	63/2006

The well start data indicate that the historical peak drilling activity was in 2008 for the Colorado and White River areas, with approximately 2,000 and 200 wells, respectively. The peak activity in the Yampa/Green/Little Snake area was in 2006 at approximately 65 wells. For the period from 1998 – 2014, the average number of wells starts was 614 and 203 for the Colorado and White River areas, respectively and 63 for the Yampa/Green/Little Snake area.

Looking ahead, the BLM's RMPs evaluate the impacts associated with various management alternatives and discuss future oil and gas drilling activities. One component of the BLM's process is the analysis of "Reasonably Foreseeable Development" (RFD) associated with the federal mineral estate. The analysis of the Reasonably Foreseeable Development scenario generally includes development of resources on private lands to provide a complete picture of the activity's potential impacts. The Reasonably Foreseeable Development scenario provides a baseline for federal analysis. The following describes the RFD scenario:

"This RFD scenario projects the maximum levels and types of industry activity, and the associated surface disturbance that might occur on all land ownerships in the WRFO during the twenty year period from 2009 through 2028. The RFD scenario uses the following key assumptions: 1) all potentially productive areas, except those areas designated as closed to leasing by law, regulation or executive order, are open to leasing and development; and 2) only standard lease terms and conditions would be imposed, affording minimum protections to other important resource values. These assumptions, while unrealistic, are necessary to project the maximum potential levels of development activity for environmental analysis purposes and provide full disclosure to the public."[5]

So, while the RFD scenario is <u>not</u> a projection of future activity, it helps inform assumptions on peak drilling rates through comparison to drilling activity as portrayed in the preferred alternative and to the historical data (Table 4-4).

[5] White River Field Office RFD

Table 4-4 BLM Reasonably Foreseeable Development, Number of Wells in Next 20-years

BLM Field Office	Total	No. Wells Federal	No. Wells Private	Percent Public	20-Year Annual Average (wells/year)
Little Snake River	3,031	3,031	Not reported		150
White River	17,168	13,728	3,440	80%	860
Colorado River Grand Junction	9,116	3,938	5,178	43%	450
Colorado River Valley (Glenwood)	14,792	5,768	9,024	39%	740

The Phase I Study reported direct water demands for oil and gas ranging from approximately 2,900 to 5,500 af/year. As discussed above, the Phase I water use factor is 2.24 acre-feet per well. The annual number of wells represented by the range in the Phase I assumptions is approximately 1,300 to 2,200 wells per year.

The historical maximum annual number of well starts is approximately 2,200 wells per year. The RFD 20-year average is, coincidently, 2,200 wells per year. For the purposes of this report, the peak year drilling activity estimate should be no less than 2,200 wells per year. This work includes a high end estimate of 4,300 well per year to account for increased peak drilling in future years. The drilling activity will be apportioned between the river basins based on the following percentages: Little Snake – 10%, White River – 40%, Colorado River – 50%.

4.3 Horizontal Well Drilling and Completion Activity

The horizontal well drilling and completion technologies are becoming more common in the western Colorado oil and gas fields. The technology requires more water from drilling and completion because the lengthy horizontal production zone results in more “frac” stages. This work evaluated COGCC well permit data for horizontal wells. The goal of the analysis was to determine if horizontal well drilling would substantially change water use estimates for oil and gas well drilling and completion.

Table 4-5 lists the historical horizontal well starts by western slope county. The table indicates that permitting and drilling of horizontal wells is becoming more prevalent. Nonetheless, horizontal well development is a relatively small percentage of the current drilling and completion activity.

Table 4-5 Horizontal Well Activity

	Prior Years			2009		2010		2011		2012		2013		2014	
County	**Drilled**	**DA**	**PA**	**Permit**	**Spud**	**Permit**	**Spud**	**Permit**	**Spud**	**Permit**	**Spud**	**Permit**	**Spud**	**Permit**	**Spud**
Garfield	10		2	1	1	16	2	18	6	43	6	18	3	1	
Mesa	3	2		36	1	22	8	24	13	14		9	2	2	
Moffat	7	1	1	6	3	4		9	4	44	7	18	13	1	
Rio Blanco	7	2				1	1	11	2	15	2	4	5		
Routt	10	6	1							1		1			
Total	**Prior Years**			**2009**		**2010**		**2011**		**2012**		**2013**		**2014**	
Colo River	13	2	2	37	**2**	38	**10**	42	**19**	57	**6**	27	**5**	3	**0**
White River	7	2	0	0	**0**	1	**1**	11	**2**	15	**2**	4	**5**	0	**0**
Yampa River	17	7	2	6	**3**	4	**0**	9	**4**	45	**7**	19	**13**	1	**0**

Source: COGC March 17, 2014 Staff Report

Comparing the annual number of horizontal wells to the drilling activity discussed above indicates that horizontal drilling activity is a relatively small part of the overall oil and gas development. However, in the Yampa River basin in 2013, out of approximately 25 well starts, 13 were horizontal wells. Overall, the data indicates a mild trend towards more horizontal wells.

4.4 Oil and Gas Development Direct Water Use Estimates

This section estimates direct water uses using the information regarding well drilling starts and water use factors developed in the previous two sections. The water volumes depend on assumptions for the peak drilling activity. Future drilling rates in Colorado will depend on many factors and the range in the estimate represents uncertainty in projecting the future conditions.

Historical data for well drilling indicates that the peak year drilling activity in the study area is approximately 2,200 wells. For this report, the low end of the range in water uses will be 2,200 wells.[6] Generally considering rig availability and other physical and economic factors the upper range of peak year drilling activity is set at 4,000 wells.

The BLM RMPs indicate that future drilling activity will essentially follow historical patterns as known fields and reserves are drilled out. Consequently, this work apportions the areal distribution of the drilling activity within river basins based on the historical activity and results in the following percentages: Yampa/Green/Little Snake – 10%, White River – 40%, Colorado River – 50%. With these assumptions and the estimates of water use factors discussed in above, the water use volumes are shown in Table 4-6.

[6] For comparison, the drilling boom in North Dakota in 2013 included approximately 2,000 wells drilled and rig counts of about 200 rigs.

Table 4-6 Phase III Updated Oil and Gas Well Drilling and Completion Water Uses

River Basin	Reported Water Use Factor (acre-feet/well)	Annual Well Completions		Estimated Annual Water Volume (af/year)	
		Low Estimate	High Estimate	Low Estimate	High Estimate
Yampa/Green/Little Snake	3	220	300	700	900
White River	3	880	1,200	2,600	3,600
Colorado River	0.8	1,100	1,500	1,100	1,500
Total		2,200	3,000	4,400	6,000

4.5 Oil and Gas Development Indirect Water Use Estimates

The updated estimates for oil and gas industrial water uses are comparable to those estimated in the Phase I report. For that reason, this update adopts the indirect water uses for oil and gas as reported in Phase I. As shown on Table 2-2, the indirect demands associated with population growth for oil and gas range from 8,200 – 11,400 af/year.

5.0 WATER SUPPLY PROJECT ALTERNATIVES

The Phase I Energy Development Water Needs Assessment provided lists of water rights associated with industrial water use. The Phase I report did not evaluate water supply alternatives, yields or feasibility. The Phase II Energy Water Needs Assessment Study generally evaluated water supply projects that could potentially serve oil shale industrial water demands up to volumes of 120,000 af/year.

In early 2014, the Yampa-White-Green River Basin Roundtable (YWG BRT) completed the Projects and Methods Study (CDM Smith, 2014) to evaluate water supplies, demands and shortages in the region, primarily in the Yampa River. This study included an analysis of river operations considering various water supply project alternative IPPs that had been included in previous water supply planning studies performed in the basin. With the exception of an IPP associated with water supply for Peabody Coal, none of the Project and Methods alternatives addressed the direct water uses by energy development. Recently, the Rio Blanco Water Conservancy District and the Yellow Jacket Water Conservancy District have also each completed water supply project feasibility studies. The water storage and diversion projects evaluate supplies for multiple uses including energy sector direct and indirect industrial uses.

The Phase III study Scope of Work did not include evaluation of water supply alternatives. The following paragraphs provide introductory descriptions of Phase II, the P&M Study, and the water conservancy's water supply projects[7].

5.1 Energy Development Water Needs Assessment Phase II, February 2011

The Phase II study generally evaluated water supply projects that could potentially serve oil shale industrial water demands up to volumes of 120,000 af/year.[8] 4 alternatives for the White River (up to 110,000 af/year yield) and 7 alternatives for the Colorado River (up to 10,000 af/year yield) were modeled using the State of Colorado's Stream Simulation Model (StateMod) developed by the CWCB. The modeling studies considered an historical period of record from 1909 through 2006 for the White River model and an historical period of record from 1909 through 2005 for the Colorado River model. The impact of climate change has not been considered in any of the modeling scenarios.

For the White River water supply modeling, demands of up to approximately 9,200 acre-feet per month (i.e., 110,000 af/year) were fully met in every month during average and wet periods but not during dry periods. The modeled water rights included: (1) a junior diversion from the White River located at the confluence of Piceance Creek and White River; and (2) a junior storage right in Lake Avery Enlargement from Big Beaver Creek. In some months during dry periods, the above supplies alone would not be sufficient and therefore would have to be supplemented by a junior storage right in Lake Avery Enlargement from the White River to fully meet the modeled water demand.

The Phase II Study identified seven water supply projects in the Colorado River Basin.[9] The water rights represent water right priorities adjudicated in 1955 that divert from the mainstem of Colorado River in the reach from Rifle to DeBeque. The modeling results indicate that the 10,000 acre-feet annual demand in the Colorado River Basin could be fully met in every month from 1909 through 2005.

[7] The Phase I study can be referenced for summaries of water rights representing industrial uses.
[8] The study did not look at all possible water supply projects and water management scenarios that can be used to water demands in the White River and Colorado River basins. The demands may be met by water supply projects that were not tested in the study.
[9] These seven projects are described in Exxon Mobil's water rights application in Case No. 08CW199.

5.2 Projects and Methods Study

Using the StateMod water allocation modeling platform, the P&M Study evaluated baseline conditions and six modeling scenarios on a monthly time-step for the YWG Basin. The scenarios consist of a combination and range of demands (M&I, energy, agriculture, environment and recreation) various hydrology types, and the presence or absence of IPPs to assess their implications. The IPPs with an energy component that were modeled in the P&M Study include:

- Peabody-Trout Creek Reservoir
- Milk Creek Reservoir
- Lake Avery Enlargement
- Wolf Creek Reservoir
- Oil Shale Production Pipelines/Diversions

All but the first two projects above were modeled in the Phase II Study as oil shale production water supply systems. Peabody-Trout Creek was identified since Phase II as an option to meet energy development demands for coal development on Trout Creek just upstream of the confluence with the Yampa River. Milk Creek Reservoir is part of a potential supply project to meet future energy development demands, and it also includes a component to satisfy agricultural demands. As described in this Phase III study, the future energy picture for some sectors has changed since this modeling was conducted and therefore results from the P&M Study may not necessarily reflect an accurate picture of current operations in the region, particularly associated with energy development and water supply options. As a result, and because the BIPs will continue to evolve after they are submitted to the CWCB the end of July 2014, additional modeling in the YWG basin will incorporate refined information related to these energy IPPs.

5.3 Rio Blanco Water Conservancy District, White River Storage Feasibility Study, Phase I Report, May 2014

The Rio Blanco Water Conservancy District encompasses the lower White River basin in western Rio Blanco County. The District has recently completed a screening of 28 potential water storage reservoir sites and has preliminarily selected 3 sites for further investigations (Insert reference). The potential water supply projects may include 20,000 to 90,000 acre-feet of storage with the purpose of serving multiple uses including municipal growth, oil shale industrial uses, environmental water needs, and recreation.

5.4 Yellow Jacket Water Conservancy District, Water Storage Feasibility, February 2013

The Yellow Jacket Water Conservancy District encompasses the upper White River basin in eastern Rio Blanco County. The District extends from the confluence of Yellow Creek and the White River upstream to the headwaters of the White River and includes small portions of Garfield and Moffat Counties. The District has recently completed a study to form recommendations and an action plan for implementation of a specific water storage project to ensure adequate water supply for the District's municipal, agricultural, industrial, wildlife, and recreational needs (insert reference). The water storage feasibility study reviewed certain water rights and 8 potential water storage reservoir sites within the District's boundaries. The work recommended 3 reservoir sites for further investigations in subsequent phases.

6.0 REPORT CONCLUSIONS

The Energy Development Water Needs Assessment, Phase III study provides updated information regarding the amount of water required to supply future oil shale and oil and gas industrial development in northwestern Colorado. This study supplements information contained in the Energy Development Water Needs Assessment Phase I (URS, 2008) and Phase II studies (AMEC, 2011) in which estimates were made regarding water demands associated with the development of energy in northwestern Colorado. The Yampa-White-Green River Basins and Colorado River Basin Roundtables initiated this work to provide updated water use estimates as part of the Basin Implementation Plan processes.

In the Phase I study, four energy sectors were addressed: natural gas, coal, uranium, and oil shale. Phase I evaluated and quantified the direct and indirect water uses associated with various levels of development (i.e., production) associated with each energy sector. The direct demands include water supplies for use in the construction, production, operations, processing, and reclamation of the resource development. Indirect demands include water uses by the new population (e.g., domestic and municipal). Phase I also quantified water use resulting from the power generation needed to supply the industries and the new population (called thermoelectric water uses in Phase I).

The Phase II study revisited the water uses for the oil shale industry and provided preliminary analysis of alternative water supply projects in the White River. Phase II updated the industry's direct water uses with new assumptions regarding power generation. Instead of coal fired generation (the technology evaluated in Phase I), Phase II developed water uses for combined cycle gas turbine technologies with significantly less water use. Phase II reported significantly reduced water demands associated oil shale development.

The Phase III study updates the water demands associated with the oil shale and natural gas and oil industries. Since 2011, Shell and Chevron have ended oil shale research in Colorado. NOSA is projecting significantly smaller commercial production levels. Now, instead of large in situ oil shale projects and production levels up to approximately 1.5 million bblo/day the organization is providing estimates for up to approximately 500,000 bblo/day production. Consequently, Phase III reports oil shale water uses that are about one-third of the volumes estimated in Phase II, however. If a very profitable industry emerges, production amounts could be significantly higher due to the size of the resources and global oil demand. Subsequently, water use would be higher. It will be important to monitor production rates and water use for future water planning as the industry develops.

The initial Phase III work revisited the Phase I water uses for the natural gas, coal, and uranium energy sectors. Since 2008, the status of oil and gas well drilling has changed, 2006 – 2008 are the historical peak years for drilling activity in Colorado, but the outlook for coal and uranium development is much the same. The Energy Subcommittee decided that the updated Phase III report would include the oil and gas sector water uses and carry forward the Phase I estimates for the coal and uranium sectors.

In Phase II, the oil shale water use estimates ranged up 120,000 af/year. The estimates reflected commercial production levels up to 1.5 million bblo/day with production ramping up to the ultimate levels by 2050. The Phase II estimates significantly decreased direct water use estimates reflected industry projections of commercial production and refined water use factors. Now, in Phase III, new information indicates that the water demands for commercial oil shale industry in Colorado may be range from approximately 15,000 – 90,000 af/year.

Regarding water uses associated with oil and gas development, the Phase III water use volumes are generally equivalent to the volumes reported in Phase I. Phase III reports slightly increased direct use volumes for oil and gas. The direct uses in Phase I ranged from approximately 2,000 – 5,500 af/year. This update estimates peak year uses range from 4,400 – 6,000 af/year. The Phase I indirect demands are carried forward in this work and range from approximately 8,200 – 11,400 af/year.

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Appendix A NOSA Oil Shale Direct Water Use Estimates

Water use estimate 2014
National Oil Shale Association
March 2014

Oil shale developers have re-evaluated estimates of water usage. The National Oil Shale Association has analyzed the new data and produced the following information to better inform the public and decision makers about this important aspect of oil shale commercialization.

Background

Limited amounts of water will be needed to produce oil from the oil shale deposits in the Western United States. The source of the water can be from wells, surface streams and rivers, and sources not subject to appropriation or control by state agencies. The latter includes water produced in oil shale retorting, non-tributary water in the oil shale strata, water from saline geologic formations, and waste water from oil and gas operations.

In 2013 NOSA did an analysis of water usage and determined that on average an industry would consume 1.7 barrels of water per barrel of shale oil produced (Bw/Bo) or 120,000 acre feet of water per year for 1.5 million barrels per day of oil. This information compared favorably with the results of a study conducted by AMEC for the Colorado, White and Yampa River Roundtables. AMEC is an international engineering, project management and consultancy company headquartered in London, U.K. with offices in Boulder, Colorado.

The AMEC estimates were for Colorado projects only and assumed 97% insitu and 3% exsitu projects. The future may hold promise for more exsitu and modified insitu development in Colorado, as well as Utah and Wyoming, especially as we are now seeing progress in Utah with those two process approaches.

In its 2013 study, NOSA acknowledged the fact that water usage is heavily dependent upon the oil shale recovery technology, assumptions about the split between insitu and exsitu processes, and the assumed level of oil production in the future. The estimate was provided to give the public and decision makers a basis for long range planning for water needs in the region.

Some organizations have presented oil shale water usage information without the benefit of actual data from current developers. Some of that data used the extreme upper limits of hypothetical analyses. Other groups used out-of-date information from the 1970's. Lastly some organizations purposely used estimates that were well above ranges available for current technologies and accepted practices in industry to present a much distorted picture of the industry's proposed use of water. The information presented in this report is intended to supplant earlier non-fact based estimates.

New information

New information has emerged in 2014 as oil shale developers have refined their estimates. Projects have matured, and some developers have taken a new look into technologies that dramatically reduce water needs. However, estimates are still preliminary and may change as projects reach commercialization. Water usage and oil production level estimates were obtained for insitu, exsitu and modified insitu processes in Colorado and Utah. The estimates for insitu projects show the greatest reduction in overall water needs.

Assumptions

Estimates of future oil production from oil shale projects have been reduced from 1.5 million to 500,000 barrels per day in light of a more pragmatic view of what an industry might look like in 50-years for so. Estimating future levels of production is speculative at best, but decision makers need some idea of the potential for an oil shale industry, should it incrementally develop over the next decades. For this report the split of assumed production levels is 45% insitu, 40% exsitu, and 15% modified insitu in the three states.

Water required for shale oil upgrading was included in the estimates for insitu and exsitu projects, but not for the modified insitu projects. Thus 0.6 Bw/Bo was added to the modified insitu estimates given below.

Insitu figures include “intense measures” using break though technologies to reduce water consumption. Exsitu, modified insitu and upgrading estimates include water conservation measures, such as dry scrubbing and air cooling, but not to the same extent as the intense measures for the insitu estimates. Some reduction could result in the exsitu, modified insitu and upgrading figures if these same intense measures were realized. However, some developers are continuing to evaluate their water use strategies and thus a range of values is presented in the table below to reflect those differences.

Break though water use reduction technologies include low NOx burners at power plants that obviate the need for water injection for NOx control, air cooled power plants, the elimination of smaller water based cooling towers that may be distributed in the process, better recycle control, and ever increasing thermal efficiencies in power generation that reduces waste heat and the need for cooling.

Insitu water use estimates given below are for geologic deposits that do not contain mobile ground water and thus do not require water flushing or water required for ground water containment processes such as freeze walls or grouting. If in the future insitu technologies are employed in areas with mobile ground water then an additional amount of water may be required (one estimate places this additional requirement at 1.5 Bw/Bo). Current developers do not believe insitu technologies will be employed in areas with mobile ground water, but technologies are available to accommodate it.

Gross Bw/Bo is the total amount of water used on the project. Net Bw/Bo reflects the net use of water from external sources. The difference between Gross Bw/Bo and Net Bw/Bo is the amount of water produced during processing (or taken from a non-tributary source) and not from any fresh water stream, river or adjudicated well. Net Acre-Ft per year is the amount of water required from external adjudicated sources for a year of production from plants making a total of 500,000 barrels per day of shale oil at the plant gate.

The number of data points used to develop the following table was limited by the number of currently active oil shale projects.

New data

The following ranges of data are based upon the above assumptions, public documents, and input from developers.

Technology	Shale Oil B/D	Gross Bw/Bo	Net Bw/Bo	Net Acre-Ft/Yr
Insitu	225,000	0.6 – 1.3	0.3 – 1.0	3,180 - 10,600
Exsitu	200,000	2.4 – 2.6	1.4 – 1.6	13,200 – 15,100
Mod Insitu	75,000	0.5 – 1.1	0.0 – 0.9	0 – 3,180
Total	500,000		0.7 – 1.2	16,400 – 28,900

Summary

Different assumption would have resulted in different estimated external water needs for a future oil shale industry. For instance, if the split between technologies was adjusted more toward insitu processing the estimates would go down. Conversely, if exsitu technologies tend to prevail the estimates would go up, but only if based upon current preliminary estimates for those technologies. The intensity of water conservation measures could also reduce exsitu figures, but conversely insitu usage might go up if developers base their use of water based upon its cost and its availability via owned water rights. The need for and water use estimates for upgrading shale oil is another variable. Early projects may find markets for raw shale oil, and some technologies require little or no upgrading before marketing to a refinery.

Oil shale is not yet even a fledgling industry. More precise information will be developed as years go by. But for now a range of Bw/Bo of 0.7 to 1.2 (16,000 to 29,000 acre feet per year for 500,000 barrels per day of marketable shale oil) is considered reasonable. 29,000 acre feet per year of water is less than 1% of the water that flows annually from the Colorado River into Lake Powell, about 5% of the trans-mountain diversion of water from the Western Slope of Colorado to the Front Range.

Actual water consumption, that is only an estimate today, will be well known by the time the industry gets off the ground and production reaches commercial levels. At that time regulators, proponents, opponents, and other stakeholders will be able to judge the overall benefits that will result from the use of water by an oil shale industry. There are many competing demands for the water resources in the western United States, and judging the highest and best use is a challenge for decision makers and the public. However, the benefits of oil shale development include strengthening domestic energy security, providing tax revenues, developing needed transportation fuels, providing much needed and well-paying long term employment, and providing a strong boost to local and regional economic development.

Industry strives to develop oil shale in economically sound and environmentally and socially responsible ways. The importance of water resources in oil shale country is well-recognized by the companies, who are striving to reduce projected water consumption as they continue development.

The National Oil Shale Association (NOSA) is a not-for- profit organization. Its mission is to educate the public about oil shale, and dispel misconceptions about the resource by presenting factual technical information. NOSA carries out its mission by communicating with the public through a web site (www.oilshaleassoc.org), fact sheets, presentations and position papers. The NOSA web site has a link to a new brochure titled OIL SHALE –ENERGY TO FUEL OUR FUTURE. The site also has a YouTube link to an educational video OIL SHALE - A VITAL DOMESTIC ENERGY RESOURCE.

NOSA supports a U.S. national strategy that encourages responsible development of oil shale and other domestic sources of energy. The membership of NOSA includes companies involved in oil shale development, non-profits and individuals.

Definitions

Oil shale as discussed in this paper is a huge domestic energy deposit in the Green River formation located in the states of Colorado, Utah and Wyoming. Oil shale also exists in many other places in the world. In some countries shale oil has been produced commercially for decades. Oil and gas are produced from oil shale when the rock is heated to from 600 to 900 degrees Fahrenheit. Oil shale is sometimes confused with oil and gas that occurs in shale rocks in a liquid and gaseous form that would better be termed tight oil, liquid rich shale, and gas shale.

Oil may be produced from oil shale by insitu, exsitu or modified insitu methods. Heating is accomplished underground in the insitu method with technologies similar to the recovery of oil and gas by conventional means through wells drilled into the oil shale. Exsitu methods employ mining and surface processing in equipment called retorts. Modified insitu technologies employ mining and then use insitu methods for heating and recovery.

Bw/Bo is a measure of how much water is required to produce a barrel of shale oil at the plant gate of an oil shale production facility. A barrel is 42 gallons. Gross Bw/Bo and Net Bw/Bo are defined in the text above the chart.

An acre-foot of water is a measure of volume used frequently in water parlance and is equivalent to 325,900 gallons, 7,758 barrels or 43,560 cubic feet. 500,000 barrels per day is equivalent to 23, 540 acre feet per year.

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Appendix B COGCC Water Sources and Demands for the Hydraulic Fracturing of Oil and Gas Wells in Colorado from 2010 through 2015

Water Sources and Demand for the Hydraulic Fracturing of Oil and Gas Wells in Colorado from 2010 through 2015[1]

Recently, questions have been raised about the quantity of water that will be needed for the hydraulic fracturing of oil and gas wells in Colorado. This report is intended to address these questions.

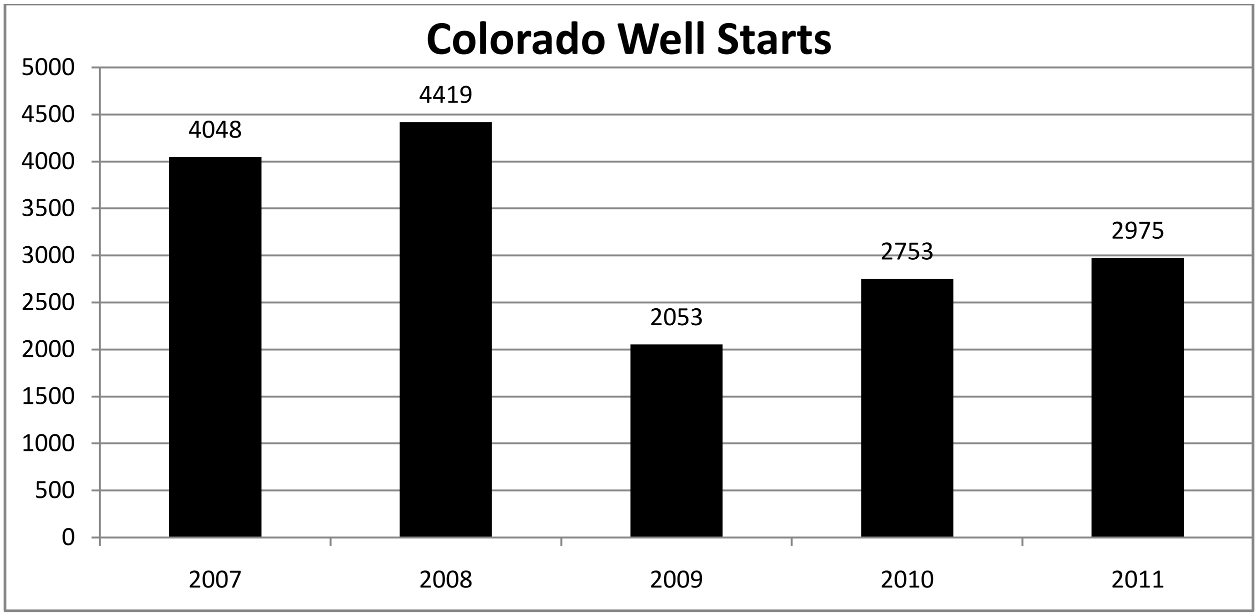
Hydraulic fracturing is the process of creating small cracks, or fractures, in underground geological formations to allow oil and natural gas to flow into the wellbore and thereby increase production. To fracture the formation, special fracturing fluids are injected down the well bore and into the formation under high pressure. These fluids typically consist of approximately 90% water, 9.5% sand, and 0.5% chemicals. The volume of fluids used for this purpose depends upon a variety of factors, including the well type and the formation depth and geologic composition. For example, horizontal wells require more water than vertical or directional wells (because of the length of the borehole that will be fracture stimulated), and deeper shale formations require more water than shallower coal bed methane formations. Hydraulic fracturing has been used in Colorado to increase the production of oil and gas wells since the 1970s, and in recent years most Colorado oil and gas wells have been hydraulically fractured.

The following pages will examine the current and projected water demands for hydraulic fracturing in Colorado, compare those demands to the amount of water that is used for other purposes in Colorado, identify potential sources of water for hydraulic fracturing, and summarize the legal and administrative requirements for using those sources.

Projected Water Demands for Hydraulic Fracturing in Colorado During the Period from 2010 Through 2015

The pace and type of oil and gas well construction in Colorado and other states depend upon a variety of factors that are difficult to predict or control. These factors include national and regional economic conditions, oil and gas prices, capital availability, corporate strategies, and technological innovations. The variability in these factors is reflected in recent well starts in Colorado, which increased from 2007 to 2008, decreased from 2008 to 2009, and then increased again from 2009 to 2010 and from 2010 to 2011:

[1] Jointly prepared by the Colorado Division of Water Resources, the Colorado Water Conservation Board, and the Colorado Oil and Gas Conservation Commission



The various factors that influence oil and gas development, and the resulting variations in development activity, make it extremely difficult to predict future development levels. Nevertheless, the Colorado Oil and Gas Conservation Commission has attempted to predict such development during the period of 2010 through 2015 for the purpose of quantifying the amount of water that could be used for hydraulic fracturing during these years. These predictions are tentative, general, and should be used with caution. They are based upon the following assumptions, which may or may not prove accurate:

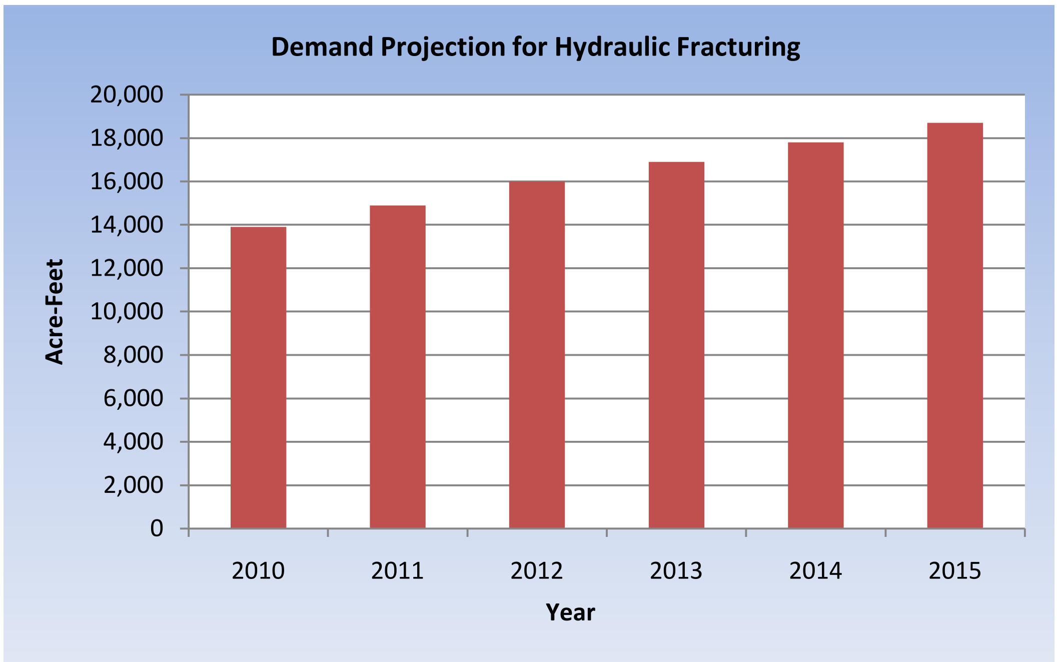
- The demand for new gas wells will remain relatively flat.
- The number of drilling rigs in the state will remain relatively flat.
- The number of wells drilled will remain relatively flat because of rig count.
- The number of horizontal oil wells drilled will increase approximately 20% each year.
- The number of vertical wells drilled will decrease proportionally with the increase in horizontal wells drilled.

Based upon these assumptions, the Colorado Oil and Gas Conservation Commission estimates that during the period from 2010 through 2015 hydraulic fracturing will require the following volumes of water:

Projection of Annual Demand for Hydraulic Fracturing (Acre-Feet[2])[3]					
2010	2011	2012	2013	2014	2015
13,900	14,900	16,100	16,900	17,800	18,700

[2] One acre-foot is approximately equal to 326,000 gallons.
[3] The demands for hydraulic fracturing are based on actual numbers of wells constructed for the years 2010 and 2011 and estimated numbers of wells to be constructed for the following years based on a county-specific projection. The amount of water demand was determined using the number of wells, using vertical or horizontal construction practices, multiplied by an amount of water required for hydraulic fracturing per well. The amount of water required per well is based on reported data.

Regional geology dictates how wells will be drilled, either vertical or horizontal, and the volume of water that will be necessary to provide the most effective fracture stimulation treatment (frac). Frac water volumes have been calculated by predicting the number of new vertical and horizontal wells to be drilled in each county. Completion records were then evaluated to determine a typical water volume used in 2011 completions for each type of well construction in the county. The number of vertical and horizontal wells was multiplied by the typical water volume used in order to predict a total county water use. All of the county volumes were summed to determine the statewide use.



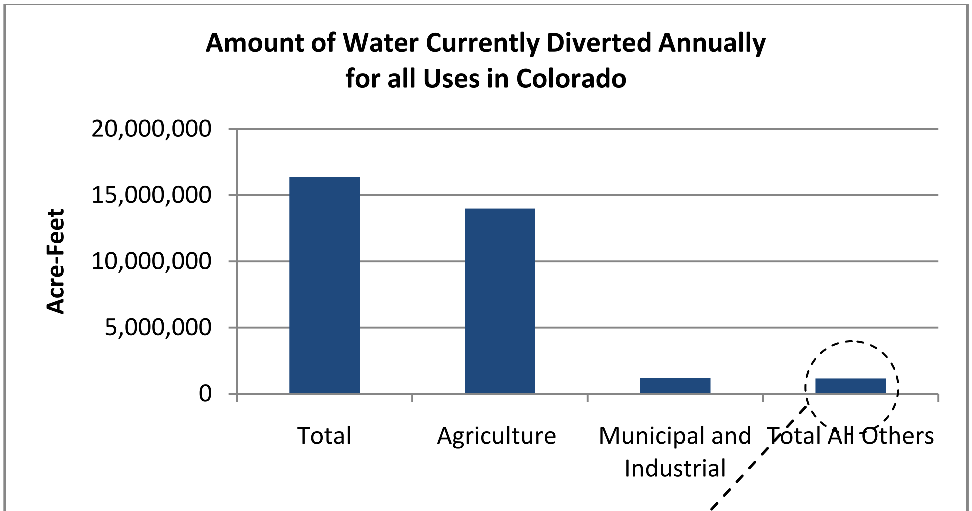
Water Demands in Colorado

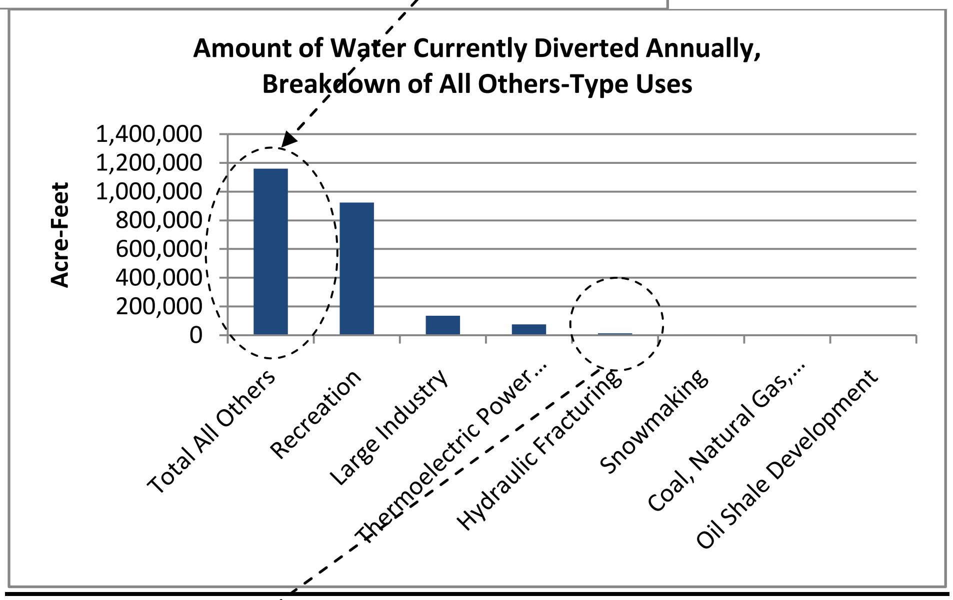
The table below shows the amount of water currently diverted for beneficial use for all uses in Colorado on an average annual basis. It is important to note that water use in Colorado varies significantly on a year to year basis, and the projected increase in demand for hydraulic fracturing is well within Colorado's current year to year variation. This table is broken down into three categories. The third category, "Total All Others", is then further broken down into seven categories, including hydraulic fracturing.

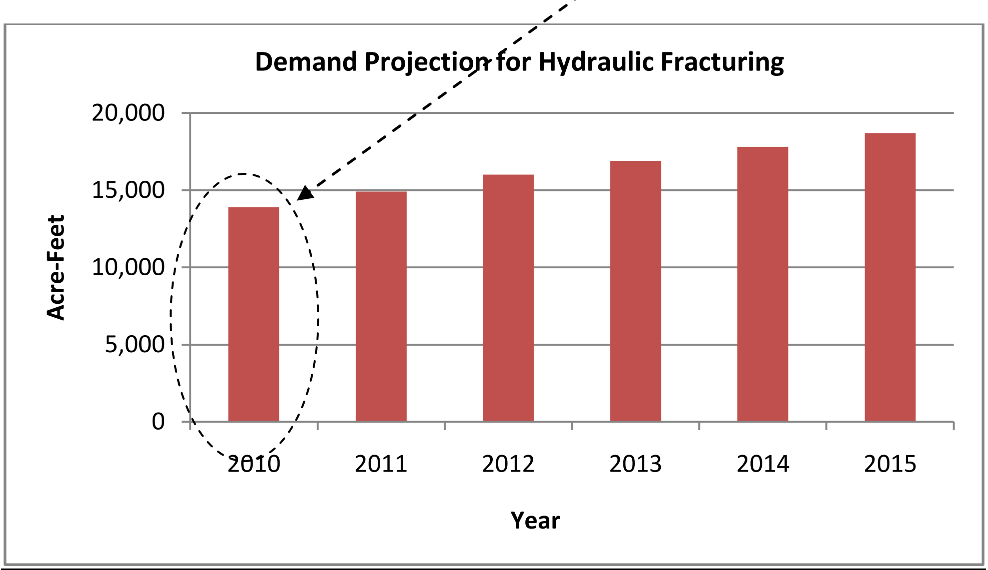
Sector	2010 Use (Acre-Feet/Yr)[4]	Percent of State Total
Total	**16,359,700**	
Agriculture	13,981,100	85.5%
Municipal and Industrial	1,218,600	7.4%
Total All Others	1,160,000	7.1%
Breakdown of "All Others"		
Total All Others	**1,160,000**	
Recreation	923,100	5.64%
Large Industry	136,000	0.83%
Thermoelectric Power Generation	76,600	0.47%
Hydraulic Fracturing	13,900	0.08%
Snowmaking	5,300	0.03%
Coal, Natural Gas, Uranium, and Solar Development	5,100	0.03%
Oil Shale Development	0	0.00%

The graphs on the following pages indicate that the amount of water currently used for hydraulic fracturing in Colorado is a small portion of the total amount of water used. In 2010, it reflected slightly less than one-tenth of one percent of the total water used. In 2015, it is projected to increase by 4,800 acre-feet to slightly more than one-tenth of one percent of the total water used.

[4] The estimated values for Current Annual Use are based on diversion records from the Colorado Division of Water Resources. For some categories, those amounts are further apportioned consistent with 2010 Statewide Water Supply Initiative data from the Colorado Water Conservation Board.


Amount of Water Currently Diverted Annually for all Uses in Colorado
Acre-Feet
20,000,000
15,000,000
10,000,000
5,000,000
0
Total
Agriculture
Municipal and Industrial
Total All Others


Amount of Water Currently Diverted Annually, Breakdown of All Others-Type Uses
Acre-Feet
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Total All Others
Recreation
Large Industry
Thermoelectric Power...
Hydraulic Fracturing
Snowmaking
Coal, Natural Gas,...
Oil Shale Development


Demand Projection for Hydraulic Fracturing
Acre-Feet
20,000
15,000
10,000
5,000
0
2010
2011
2012
2013
2014
2015
Year

Potential Sources of Water for Hydraulic Fracturing

Several sources of water are available for hydraulic fracturing in Colorado. Because Colorado's water rights system is based in the prior appropriation doctrine, water cannot be simply diverted from a stream/reservoir or pumped out of the ground for hydraulic fracturing without reconciling that diversion with the prior appropriation system. Like any other water user, companies that hydraulically fracture oil and gas wells must adhere to Colorado water laws when obtaining and using specific sources of water for this purpose.

Below is a discussion of the sources of water that could potentially be used for hydraulic fracturing. The decision to use any one source is dependent on the ability to satisfy the water rights obligations and will also be driven by the economics associated with that source.

<u>Water transported from outside the state</u>
An Operator may transport water from outside of the state. As long as the transport and the use of the water carries no legal obligation to Colorado, this is an allowable source of water from a water rights perspective.

<u>Irrigation water leased or purchased from a landowner</u>
A landowner may have rights to surface water, delivered by a ditch or canal, that is used to irrigate land. An Operator may choose to enter into an agreement with the owner of the water rights to purchase or lease a portion of that water. This is allowable, however, in nearly every case, the use of an irrigation water right is likely limited to irrigation uses and cannot be used for Well Construction. To allow its use for Well Construction, the owner of the water right and the Operator may apply to change the water right through a formal process. (See "Change of Water Right" below.)

<u>Treated water or raw water leased or purchased from a water provider</u>
An Operator may choose to enter into an agreement with a water provider to purchase or lease water from the water provider's system. Municipalities and other water providers may have a surplus of water in their system before it is treated (raw water) or after treatment that can be used for Well Construction. Such an arrangement would be allowed only if the Operator's use is compliant with the water provider's water rights.

<u>Water treated at a waste water treatment plant leased or purchased from a water provider</u>
An Operator may choose to enter into an agreement with a water provider to purchase or lease water that has been used by the public, and then treated as waste water. Municipalities and other water providers discharge their treated waste water into the streams where it becomes part of the public resource, ready to be appropriated once again in the priority system. But for many municipalities a portion of the water that is discharged has the character of being "reusable." As a result, it is possible that after having been discharged to the stream, it could be diverted by the Operator to be used for Well Construction. Such an arrangement could only be exercised with the approval of the Division of Water Resources' Division Engineer and would be allowed only if the water provider's water rights include uses for Well Construction.

<u>New diversion of surface water flowing in streams and rivers</u>
In most parts of the state, the surface streams are "over appropriated," that is, the flows do not reliably occur in such a magnitude that all of the vested water rights on those streams can be satisfied. Therefore, the only time that an Operator will be able to divert water directly from the

river is during periods of higher flow and lesser demand. Those periods do occur but not necessarily reliably or predictably.

Ground water diverted from wells completed in tributary formations ***outside*** Designated Ground Water Basins ("Designated Basins")
An Operator may choose to enter into an agreement with the owner of a well outside of the Designated Basins to divert the well's water for Well Construction, or to divert additional water for Well Construction. However, most existing wells will be located in parts of the state where the surface streams are over appropriated. In those locations, because of the wells' relatively junior water rights, the well is actually a diversion structure only and not a source of appropriated water. Instead, all water withdrawn by the well must be withdrawn according to a plan that acknowledges the impact of the well's pumping on the over-appropriated stream and an accompanying plan for replacing that water to the stream to correct for the depletive impact. Therefore, the complexity of using the well to divert ground water for Well Construction will be primarily a result of the need to develop a plan for replacing depletions to the stream system. (See "Augmentation Plans" below.)

Ground water diverted from wells ***inside*** Designated Basins
An Operator may choose to enter into an agreement with the owner of a well inside the Designated Basins to divert the well's water for Well Construction. If the well's water right allows Well Construction as a use and there are no other restrictions on its use, this is a viable source of water. However, the water right for most wells in the Designated Basins generally does not include an allowance for oil and gas well construction purposes. If there is a question as to whether some other term in the well's water right can be construed as an allowance for Well Construction, since these terms are usually ambiguous, the Division of Water Resources will evaluate them on a case-by-case basis to determine whether the intent of that term could have been for Well Construction purposes. If the well's water right does not allow for Well Construction, the owner of the well and the Operator may apply to change the water right through a formal process. (See "Change of Water Right" below.)

Ground water diverted from wells completed or to be completed in nontributary aquifers
An Operator may choose to enter into an agreement with a landowner to divert nontributary ground water from the aquifer underlying the landowner's land. The most recognizable occurrence of nontributary ground water is the water in the **Dawson, Denver, Arapahoe, and Laramie-Fox Hills aquifers** of the **Denver Basin** situated along the Front Range of Colorado. This is permissible and can be done through the issuance of a well permit. In most cases there are no restrictions on the types of use allowed for nontributary ground water if it is not already subject of a decree or a well permit. There are, however, limits to the amount of water that may be withdrawn in a given period of time. Specifically, the amount of water that may be withdrawn from a piece of land under consideration is the amount of ground water calculated to be contained in the aquifer underlying that land; and no more than one percent of the amount calculated may be withdrawn annually (many will recognize this limitation as the basis for the term: "100-year aquifer life"). This withdrawal limitation would be applied to any well permit that allows the use of Well Construction and it is the exact same limitation that would be applied to wells that would withdraw the water for domestic, commercial, agricultural, or other uses. The amount of water currently being withdrawn for all uses from the bedrock aquifers of the Denver Basin is estimated to be 350,000 acre-feet annually.[5]

[5] According to the *Citizens Guide to Denver Basin Groundwater*, 2007, produced and distributed by the Colorado Foundation for Water Education.

Produced Water

An Operator may choose to use water produced in conjunction with oil or gas production at an existing oil or gas well. The water that is produced from an oil or gas well falls under the administrative purview of the State Engineer's Office and as a result is either nontributary, in which case, it is administered independent of the prior appropriation system; or is tributary, in which case, the depletions from its withdrawal must be fully augmented if the depletions occur in an over-appropriated basin. The result in either case is that the produced water is available for consumption for other purposes, including Well Construction. The water must not be encumbered by other needs and a proper well permit must be obtained by the Operator before the water can be used for Well Construction. The exception to this permitting requirement is the allowance in Section 37-90-137(7), C.R.S., whereby produced water from a nontributary formation using a non-coal-bed methane operation may be applied to uses associated with Well Construction without a well permit.

Reused or Recycled Well Construction Water

For all of the different sources listed above that are used for Well Construction, the water right in question must contain provisions that allow the water to be fully consumed. Under that scenario, water that is used for well construction of one well may be recovered and reused in the construction of subsequent wells.

The COGCC encourages reuse and recycling of both the water used in Well Construction and the water produced in conjunction with oil or gas production. Reuse and recycling of water is covered in COGCC Rule 907 MANAGEMENT OF E&P WASTE, which describes the process for submitting a plan to the COGCC for review and approval. In the Piceance Basin several of the larger operators have constructed pipelines and use trucks to convey produced and already used water and other fluids to their centrally located water management facilities. At these facilities the water is treated so that it can be reused for drilling and completing new wells.

Explanation of Terms

Change of water right

In Colorado, a water right may be changed to allow for uses other than those originally granted to the water right and the water right can keep its original priority date. However, whether it is a water right inside or outside of the Designated Basins, such a change of use must be done through a formal process with notice to other water users. While the standards vary for each individual situation, in each case the change process is meant to ensure there will be no increase in use of the water right over what the water right allows or what has historically been done. Further, the change must include provisions to ensure that other owners of vested water rights are not impacted by a change to the system as a result of the change of water right. For designated ground water in the Designated Basins, the change of water right will be accomplished through an application to the Colorado Ground Water Commission according to the Designated Basin Rules [2-CCR-410-1]. Outside the Designated Ground Water Basins, the change of water right may be accomplished through an application to the water court or an application to the State Engineer for temporary approval of a substitute water supply plan pursuant to 37-92-308 and the State Engineer's Policy No. 2003-2, or an Interruptible Water Supply Agreement pursuant to 37-92-309.

Augmentation plans

In Colorado, water may be diverted when the result is a depletive effect on the stream system even though the diverter does not a have a water right with the priority to do so, as long as the diverter obtains formal approval of a plan to offset the depletive effect on the stream with a source of replacement water. Such a plan is called an augmentation plan. The plan must acknowledge the depletive effect of the diversion on the stream, including consideration of the amount of the depletion as well as the time and location of the depletion. Then the plan must identify a source of water that has been obtained to replace those depletions to ensure that no party with a senior vested water right will be injured. Approval to operate the augmentation plan may be accomplished through an application to the water court or an application to the State Engineer for temporary approval of a substitute water supply plan pursuant to 37-92-308.

Appendix C Summary of Selected Well Completion Reports from FracFocus.org

Appendix C - Phase III Energy Development Water Needs Assessment Well Completion Information from FracFocus.org

API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-045-20789-00-00	Colorado River	Garfield	gas	7995	30081198	92.32	1
05-045-20792-00-00	Colorado River	Garfield	gas	8987	24030946	73.75	2
05-077-10204-00-00	Colorado River	Mesa		6300	22592514	69.34	3
05-077-10100-00-00	Colorado River	Mesa	gas	7696	20274786	62.23	4
05-077-10163-00-00	Colorado River	Mesa	gas	10912	20271216	62.21	5
05-077-10200-00-00	Colorado River	Mesa		6300	20065500	61.58	6
05-077-10150-00-00	Colorado River	Mesa	gas	7349	17643612	54.15	7
05-045-20326-00-00	Colorado River	Garfield	gas	12350	17605308	54.03	8
05-077-10112-00-00	Colorado River	Mesa	gas	8684	14542836	44.63	10
05-077-10063-00-00	Colorado River	Mesa	gas	8880	12011160	36.86	14
05-045-20793-00-00	Colorado River	Garfield	gas	11198	11915568	36.57	15
05-045-20642-00-00	Colorado River	Garfield	gas	11240	11661510	35.79	16
05-045-21030-00-00	Colorado River	Garfield		0	10573080	32.45	18
05-045-18701-00-00	Colorado River	Garfield	gas	7258	8055978	24.72	19
05-077-10102-00-00	Colorado River	Mesa		12602	8047031	24.7	20
05-045-20659-00-00	Colorado River	Garfield		0	8035272	24.66	21
05-045-20641-00-00	Colorado River	Garfield		0	7995330	24.54	22
05-045-20644-00-00	Colorado River	Garfield		0	7994910	24.54	23
05-045-18694-00-00	Colorado River	Garfield	gas	7439	7968156	24.46	24
05-045-19845-00-00	Colorado River	Garfield	gas	12006	7966938	24.45	25
05-045-18696-00-00	Colorado River	Garfield	gas	7393	7752150	23.79	26
05-045-18702-00-00	Colorado River	Garfield	gas	7230	7722120	23.7	27
05-045-18695-00-00	Colorado River	Garfield	gas	7319	7679934	23.57	28
05-045-18704-00-00	Colorado River	Garfield	gas	7293	7290738	22.38	29
05-045-18693-00-00	Colorado River	Garfield	gas	7076	7268814	22.31	30
05-045-20025-00-00	Colorado River	Garfield	gas	14067	6827226	20.95	31
05-045-18691-00-00	Colorado River	Garfield	gas	7552	6797448	20.86	32
05-045-18692-00-00	Colorado River	Garfield	gas	7393	5416501	16.62	34
05-045-21031-00-00	Colorado River	Garfield		0	5409180	16.6	35
05-045-21039-00-00	Colorado River	Garfield		0	5363610	16.46	36
05-045-18703-00-00	Colorado River	Garfield	gas	7428	5345130	16.4	37
05-045-18706-00-00	Colorado River	Garfield	gas	7455	5273310	16.18	38
05-077-10210-00-00	Colorado River	Mesa		11521	5171586	15.87	39
05-045-18700-00-00	Colorado River	Garfield	gas	7288	5137188	15.77	40
05-045-19825-00-00	Colorado River	Garfield	gas	12208	5108964	15.68	41
05-045-18705-00-00	Colorado River	Garfield	gas	7309	5080278	15.59	42
05-045-18697-00-00	Colorado River	Garfield	gas	7219	5066124	15.55	43
05-045-21944-00-00	Colorado River	Garfield		8601	4848018	14.88	44
05-045-21335-00-00	Colorado River	Garfield		7442	4794930	14.72	45
05-045-20261-00-00	Colorado River	Garfield	gas	9684	4755660	14.6	46
05-045-18698-00-00	Colorado River	Garfield	gas	6984	4693038	14.4	47
05-045-21333-00-00	Colorado River	Garfield		7416	4668048	14.33	48

Appendix C - Phase III Energy Development Water Needs Assessment Well Completion Information from FracFocus.org

API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-045-15911-00-00	Colorado River	Garfield		9470	4665008	14.32	49
05-045-18699-00-00	Colorado River	Garfield	gas	7407	4648938	14.27	50
05-045-14109-00-00	Colorado River	Garfield		0	4391647	13.48	51
05-045-21941-00-00	Colorado River	Garfield		8796	4343976	13.33	52
05-045-19142-00-00	Colorado River	Garfield		8906	4284521	13.15	53
05-045-19027-00-00	Colorado River	Garfield	gas	8635	4257288	13.07	54
05-045-19511-00-00	Colorado River	Garfield	gas	5850	4221630	12.96	55
05-045-21939-00-00	Colorado River	Garfield		8822	4164006	12.78	56
05-045-20470-00-00	Colorado River	Garfield	gas	7572	4055161	12.45	57
05-045-19120-00-00	Colorado River	Garfield	gas	11956	4015830	12.32	58
05-045-19509-00-00	Colorado River	Garfield	gas	5662	3909780	12	59
05-077-09701-00-00	Colorado River	Mesa		8942	3909119	12	60
05-045-20542-00-00	Colorado River	Garfield		6673	3834641	11.77	61
05-045-15910-00-00	Colorado River	Garfield		9581	3739490	11.48	62
05-045-21395-00-00	Colorado River	Garfield	gas	6011	3724373	11.43	63
05-045-19118-00-00	Colorado River	Garfield	gas	12095	3536820	10.85	65
05-045-20182-00-00	Colorado River	Garfield	gas	8553	3270372	10.04	66
05-077-10188-00-00	Colorado River	Mesa		7408	3215909	9.87	67
05-077-10103-00-00	Colorado River	Mesa	gas	8000	3131328	9.61	68
05-045-20148-00-00	Colorado River	Garfield	gas	8359	3106676	9.53	70
05-077-10085-00-00	Colorado River	Mesa	gas	9345	3092242	9.49	71
05-045-20478-00-00	Colorado River	Garfield	gas	7609	3085824	9.47	72
05-045-20173-00-00	Colorado River	Garfield	gas	8599	3028242	9.29	74
05-045-19507-00-00	Colorado River	Garfield	gas	5861	3019758	9.27	75
05-077-10099-00-00	Colorado River	Mesa		0	2944555	9.04	77
05-045-19527-00-00	Colorado River	Garfield	gas	5478	2771622	8.51	80
05-077-10101-00-00	Colorado River	Mesa	gas	8000	2760132	8.47	81
05-077-10104-00-00	Colorado River	Mesa	gas	8000	2746348	8.43	82
05-045-18536-00-00	Colorado River	Garfield	gas	6669	2685690	8.24	84
05-045-20184-00-00	Colorado River	Garfield	gas	9698	2450784	7.52	87
05-045-17879-00-00	Colorado River	Garfield	gas	6692	2366054	7.26	89
05-045-20481-00-00	Colorado River	Garfield	gas	7587	1970098	6.05	92
05-045-17286-00-00	Colorado River	Garfield	gas	6147	1945024	5.97	93
05-045-18260-00-00	Colorado River	Garfield	gas	9970	1908253	5.86	94
05-045-17290-00-00	Colorado River	Garfield	gas	6161	1880980	5.77	95
05-045-19634-00-00	Colorado River	Garfield	gas	7691	1799961	5.52	96
05-077-09440-00-00	Colorado River	Mesa	gas	7230	1798440	5.52	97
05-045-19444-00-00	Colorado River	Garfield	gas	6750	1795189	5.51	98
05-045-17283-00-00	Colorado River	Garfield	gas	6190	1776942	5.45	99
05-045-18439-00-00	Colorado River	Garfield	gas	6181	1735696	5.33	101
05-045-16292-00-00	Colorado River	Garfield	gas	6238	1628463	5	102
05-045-19535-00-00	Colorado River	Garfield	gas	7607	1614031	4.95	103

Appendix C - Phase III Energy Development Water Needs Assessment Well Completion Information from FracFocus.org

API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-045-18339-00-00	Colorado River	Garfield	gas	9179	1593054	4.89	105
05-045-18344-00-00	Colorado River	Garfield	gas	8946	1547711	4.75	106
05-045-16275-00-00	Colorado River	Garfield	gas	6300	1543398	4.74	107
05-045-15732-00-00	Colorado River	Garfield	gas	6280	1539933	4.73	109
05-045-18069-00-00	Colorado River	Garfield	gas	7196	1423266	4.37	111
05-045-21209-00-00	Colorado River	Garfield	gas	7311	1421178	4.36	112
05-045-16291-00-00	Colorado River	Garfield	gas	6384	1417471	4.35	113
05-045-16291-00-00	Colorado River	Garfield	gas	6384	1417471	4.35	114
05-045-18997-00-00	Colorado River	Garfield	gas	12199	1387680	4.26	116
05-045-16280-00-00	Colorado River	Garfield	gas	6313	1356382	4.16	117
05-045-17299-00-00	Colorado River	Garfield	gas	6206	1351290	4.15	118
05-045-20001-00-00	Colorado River	Garfield	gas	9201	1320017	4.05	119
05-045-21550-00-00	Colorado River	Garfield		8900	1298379	3.98	120
05-045-21208-00-00	Colorado River	Garfield	gas	7236	1289652	3.96	121
05-045-19442-00-00	Colorado River	Garfield	gas	6793	1272077	3.9	123
05-045-15865-00-00	Colorado River	Garfield	gas	6133	1254335	3.85	124
05-045-19532-00-00	Colorado River	Garfield	gas	7478	1230409	3.78	125
05-045-17692-00-00	Colorado River	Garfield	gas	8830	1175248	3.61	126
05-045-20523-00-00	Colorado River	Garfield		9907	1162479	3.57	127
05-045-18104-00-00	Colorado River	Garfield	gas	9236	1138068	3.49	128
05-045-20056-00-00	Colorado River	Garfield	gas	8727	1126145	3.46	129
05-045-19433-00-00	Colorado River	Garfield	gas	6754	1114797	3.42	130
05-045-16294-00-00	Colorado River	Garfield	gas	6330	1110350	3.41	131
05-045-22157-00-00	Colorado River	Garfield		13764	1108923	3.4	132
05-045-21771-00-00	Colorado River	Garfield		9907	1084637	3.33	133
05-045-19781-00-00	Colorado River	Garfield	gas	8037	1080559	3.32	134
05-045-18421-00-00	Colorado River	Garfield	gas	9367	1070978	3.29	135
05-045-18055-00-00	Colorado River	Garfield	gas	8923	1063042	3.26	136
05-045-17585-00-00	Colorado River	Garfield	gas	6719	1054888	3.24	138
05-045-19850-00-00	Colorado River	Garfield	gas	7636	1052818	3.23	139
05-045-21861-00-00	Colorado River	Garfield		8444	1047060	3.21	141
05-045-19836-00-00	Colorado River	Garfield	gas	7557	1045030	3.21	142
05-045-20912-00-00	Colorado River	Garfield	gas	11429	1042842	3.2	143
05-045-19538-00-00	Colorado River	Garfield	gas	7624	1009980	3.1	144
05-045-21551-00-00	Colorado River	Garfield		8042	1009062	3.1	145
05-045-21795-00-00	Colorado River	Garfield		9973	1006767	3.09	146
05-045-19503-00-00	Colorado River	Garfield	gas	8871	998507	3.06	147
05-045-19499-00-00	Colorado River	Garfield	gas	8994	994145	3.05	148
05-045-20067-00-00	Colorado River	Garfield	gas	8758	987581	3.03	149
05-045-19745-00-00	Colorado River	Garfield	gas	7011	984712	3.02	150
05-045-17890-00-00	Colorado River	Garfield	gas	6726	977594	3	151
05-045-19987-00-00	Colorado River	Garfield	gas	9128	966903	2.97	152

Appendix C - Phase III Energy Development Water Needs Assessment Well Completion Information from FracFocus.org

API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-045-18835-00-00	Colorado River	Garfield	gas	7178	965472	2.96	153
05-045-19718-00-00	Colorado River	Garfield	gas	7023	960081	2.95	154
05-045-19835-00-00	Colorado River	Garfield	gas	7610	958999	2.94	155
05-045-21767-00-00	Colorado River	Garfield		9945	948590	2.91	156
05-045-20104-00-00	Colorado River	Garfield	gas	8747	941513	2.89	158
05-045-22130-00-00	Colorado River	Garfield		5278	933528	2.87	159
05-045-18023-00-00	Colorado River	Garfield	gas	9076	930667	2.86	160
05-045-16288-00-00	Colorado River	Garfield	gas	6283	927082	2.85	161
05-045-19017-00-00	Colorado River	Garfield	gas	8081	918657	2.82	162
05-045-17888-00-00	Colorado River	Garfield	gas	6736	894963	2.75	163
05-045-20079-00-00	Colorado River	Garfield	gas	8747	886465	2.72	164
05-045-21712-00-00	Colorado River	Garfield	gas	6395	885869	2.72	165
05-045-17887-00-00	Colorado River	Garfield	gas	6706	872464	2.68	166
05-045-19783-00-00	Colorado River	Garfield	gas	8195	856993	2.63	167
05-045-21714-00-00	Colorado River	Garfield	gas	6434	855614	2.63	168
05-045-18202-00-00	Colorado River	Garfield		8793	810362	2.49	169
05-045-06572-00-00	Colorado River	Garfield	gas	8605	799302	2.45	170
05-045-20912-00-00	Colorado River	Garfield	gas	11429	757255	2.32	171
05-045-21201-00-00	Colorado River	Garfield	gas	7157	755171	2.32	172
05-045-20280-00-00	Colorado River	Garfield	gas	5280	722175	2.22	174
05-045-12907-00-00	Colorado River	Garfield	gas	7400	689152	2.12	176
05-045-20912-00-00	Colorado River	Garfield	gas	11429	623462	1.91	177
05-045-20277-00-00	Colorado River	Garfield	gas	5426	557516	1.71	179
05-045-19500-00-00	Colorado River	Garfield	gas	9007	535096	1.64	181
05-045-20276-00-00	Colorado River	Garfield	gas	5250	515420	1.58	182
05-045-10976-00-00	Colorado River	Garfield		0	506710	1.56	183
05-045-15257-00-00	Colorado River	Garfield		6327	492793	1.51	184
05-077-08765-00-00	Colorado River	Mesa	gas	4999	461811	1.42	185
05-045-15187-00-00	Colorado River	Garfield		6338	453780	1.39	186
05-045-13648-00-00	Colorado River	Garfield	gas	9618	377345	1.16	187
05-077-09725-00-00	Colorado River	Mesa	gas	6235	287029	0.88	189
05-045-19854-00-00	Colorado River	Garfield		9946	83217	0.26	212
05-081-07644-00-00	Little Snake River	Moffat	gas	9520	149028	0.46	195
05-081-07624-00-00	Little Snake River	Moffat	oil	6798	128394	0.39	200
05-081-07641-00-00	Little Snake River	Moffat	oil	6668	100464	0.31	207
05-081-07645-00-00	Little Snake River	Moffat	gas	9431	96331	0.3	208
05-081-07284-00-00	Little Snake River	Moffat	gas	8353	50024	0.15	219
05-081-06980-00-00	Little Snake River	Moffat	gas	8478	25056	0.08	225
05-081-06979-00-00	Little Snake River	Moffat	gas	8545	20133	0.06	226
05-081-07409-00-00	Little Snake River	Moffat	gas	8810	15124	0.05	227
05-081-07365-00-00	Little Snake River	Moffat	gas	8510	9849	0.03	228
05-103-11886-00-00	White River	Rio Blanco		10365	6020826	18.48	33

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API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-103-11744-00-00	White River	Rio Blanco	gas	11046	3563174	10.94	64
05-103-11888-01-00	White River	Rio Blanco		8596	3047787	9.35	73
05-103-11081-00-00	White River	Rio Blanco	gas	14490	3007134	9.23	76
05-103-11507-00-00	White River	Rio Blanco	gas	12284	2917557	8.95	78
05-103-11457-00-00	White River	Rio Blanco	gas	12713	2869830	8.81	79
05-103-11602-00-00	White River	Rio Blanco	gas	10390	2700642	8.29	83
05-103-11085-00-00	White River	Rio Blanco	gas	12535	2583200	7.93	85
05-103-11852-00-00	White River	Rio Blanco	gas	10654	2516053	7.72	86
05-103-11352-00-00	White River	Rio Blanco	gas	11595	2380479	7.31	88
05-103-11434-00-00	White River	Rio Blanco	gas	12348	2248291	6.9	90
05-103-11534-00-00	White River	Rio Blanco	gas	13723	2003726	6.15	91
05-103-11869-00-00	White River	Rio Blanco	gas	12753	1756884	5.39	100
05-103-11885-00-00	White River	Rio Blanco	gas	4138	1598058	4.9	104
05-103-11959-00-00	White River	Rio Blanco		11925	1541106	4.73	108
05-103-11636-00-00	White River	Rio Blanco	gas	12227	1433589	4.4	110
05-103-11601-00-00	White River	Rio Blanco	gas	9012	1409826	4.33	115
05-103-11910-00-00	White River	Rio Blanco		5696	947355	2.91	157
05-103-11517-00-00	White River	Rio Blanco	gas	12569	697868	2.14	175
05-103-10538-00-00	White River	Rio Blanco	gas	8289	615343	1.89	178
05-103-11931-00-00	White River	Rio Blanco	gas	15866	258609	0.79	190
05-103-11908-00-00	White River	Rio Blanco	oil	7716	224515	0.69	191
05-103-11603-00-00	White River	Rio Blanco	gas	4335	158277	0.49	193
05-103-11908-00-00	White River	Rio Blanco	oil	9045	140868	0.43	198
05-103-09992-00-00	White River	Rio Blanco	gas	7200	130578	0.4	199
05-103-11891-00-00	White River	Rio Blanco	oil	4626	126827	0.39	201
05-103-11890-00-00	White River	Rio Blanco	oil	4592	125819	0.39	202
05-103-08096-00-00	White River	Rio Blanco		0	119179	0.37	203
05-103-11908-00-00	White River	Rio Blanco	oil	8386	113097	0.35	204
05-103-11892-00-00	White River	Rio Blanco	oil	4647	106246	0.33	205
05-103-10343-00-00	White River	Rio Blanco	gas	7904	95112	0.29	209
05-103-09268-00-00	White River	Rio Blanco	gas	6990	76860	0.24	214
05-103-09167-00-00	White River	Rio Blanco	gas	6870	76230	0.23	215
05-103-10295-00-00	White River	Rio Blanco		7150	40866	0.13	222
05-103-11908-00-00	White River	Rio Blanco	oil	7747	7804	0.02	229
05-103-11501-00-00	White River Rangely	Rio Blanco	oil	6846	173032	0.53	192
05-103-11502-00-00	White River Rangely	Rio Blanco	oil	6600	158108	0.49	194
05-103-11951-00-00	White River Rangely	Rio Blanco	oil	5646	102290	0.31	206
05-103-11855-00-00	White River Rangely	Rio Blanco	oil	6886	86348	0.27	210
05-103-11858-00-00	White River Rangely	Rio Blanco	oil	6795	84809	0.26	211
05-103-11870-00-00	White River Rangely	Rio Blanco	oil	6910	82985	0.25	213
05-103-11914-00-00	White River Rangely	Rio Blanco	oil	6623	56693	0.17	216
05-103-11866-00-00	White River Rangely	Rio Blanco	oil	6439	55318	0.17	217

Appendix C - Phase III Energy Development Water Needs Assessment Well Completion Information from FracFocus.org

API Number	River Basin	County	Prod Type	True Vertical Depth (ft)	Total Water Volume (gal)	Total Water Volume (af)	Overall Rank (out of 229 records)
05-103-11922-00-00	White River Rangely	Rio Blanco	oil	6760	50799	0.16	218
05-103-11913-00-00	White River Rangely	Rio Blanco	oil	6661	49479	0.15	220
05-103-07089-00-00	White River Rangely	Rio Blanco	oil	6560	44411	0.14	221
05-103-07461-00-00	White River Rangely	Rio Blanco		0	40732	0.13	223
05-103-05559-00-00	White River Rangely	Rio Blanco		0	32530	0.1	224
05-081-07780-00-00	Yampa River	Moffat		12578	16000670	49.11	9
05-081-07727-00-00	Yampa River	Moffat	gas	11902	14439788	44.32	11
05-081-07726-00-00	Yampa River	Moffat	gas	10604	12665352	38.87	12
05-081-07729-00-00	Yampa River	Moffat	gas	11079	12188301	37.41	13
05-081-07737-00-00	Yampa River	Moffat		11442	11342137	34.81	17
05-081-07784-00-00	Yampa River	Moffat		12471	3109928	9.54	69
05-081-07679-00-00	Yampa River	Moffat		7475	1283284	3.94	122
05-081-07658-00-00	Yampa River	Moffat		3500	1062852	3.26	137
05-081-07722-00-00	Yampa River	Moffat	oil	0	1048417	3.22	140
05-081-07719-00-00	Yampa River	Moffat		3200	749229	2.3	173
05-081-07654-00-00	Yampa River	Moffat	oil	0	553316	1.7	180
05-081-07336-00-00	Yampa River	Moffat	oil	0	297198	0.91	188
05-081-07692-00-00	Yampa River	Moffat		0	146882	0.45	196
05-107-06248-00-00	Yampa River	Routt	oil	0	142372	0.44	197

Appendix D COGCC Well Start Summary

Appendix D - Phase III Energy Development Water Need Assessment

Annual Well Starts by County - Compiled from COGC March 17, 2014 Staff Report

County	Total 1988 - 2014	Average 1998 - 2014	Max. No. Well Starts	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Garfield	10323	569	1688	3	12	24	8	3	4	15	13	7	28	19	94	190	351	245	417	585	799	1005	1304	1688	768	910	880	497	389	65
Mesa	844	48	222	1	2	2	4	1		7	2	1	1	4	4	2	12	12	13	25	89	156	209	222	14	11	40	4	6	
Moffat	428	24	60	1	2	1	2	1	1	2	1	3	1	8	10	18	23	25	28	19	40	60	42	25	18	15	34	26	22	
Rio Blanco	1375	74	203	1	8	10	1	3	8	6	7	5	9	9	62	51	82	47	83	92	95	107	95	203	116	107	72	52	36	8
Routt	48	3	12		1	1	3	1							1	5	12	1		1	6	3	2		2	1	2	4	2	
River Basin	Total 1988 - 2014	Average 1998 - 2014	Max. No. Well Starts																											
Colorado River = Mesa + Garfield	11167	614	1910	4	14	26	12	4	4	22	15	8	29	23	98	192	363	257	430	610	888	1161	1513	1910	782	921	920	501	395	65
White River = Rio Blanco	1375	74	203	1	8	10	1	3	8	6	7	5	9	9	62	51	82	47	83	92	95	107	95	203	116	107	72	52	36	8
Yampa/Green/Little Snake River = Routt + Moffat	476	25	63	1	3	2	5	2	1	2	1	3	1	8	11	23	35	26	28	20	46	63	44	25	20	16	36	30	24	0