Shell Exploration & Production

Shell Frontier Oil & Gas Inc.
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Houston Texas 77082-3101

FED EX Tracking #7948 9645 4686

March 7, 2013

Mr. Paul Daggett
Bureau of Land Management
220 East Market Street
Meeker, CO 81641

SUBJECT: Revised and updated Plan of Development (POD) for East RDD
Shell Frontier Oil & Gas Inc., Oil Shale RDD Lease #COC69166
Section 4, T2S, R98W, Rio Blanco County, Colorado

Dear Mr. Daggett:

Shell Frontier Oil & Gas Inc. (SFOGI) is submitting revised attachments to update the Plan of Development (POD) for the above-referenced RDD lease. These documents include information regarding SFOGI's proposed East Long Heater Test Project (ELHT). A summary of the changes made to the POD is provided below:

<u>TEXT</u>	
Title Page:	Added POD revision dates.
Table of Contents:	Added ELHT sections and renumbered pages
Section 1 - Introduction:	Added discussion of ELHT
Section 2 - Contact Information:	Updated with current SFOGI permit contact person
Section 3 – Location	Updated affected area acreage
Section 4 – Geology:	Incorporated information regarding ELHT
Sections 5.1 to 5.5 – Hydrology:	Incorporated information regarding ELHT
Section 6B – In Situ Development Plan:	Added drilling plan details & well specifications for ELHT
Section 7 – Reclamation:	Revised reclamation seed mix (use BLM-stipulated seed mix)
Section 10 – Lease Conversion:	Included reference to ELHT
Section 11.5 – Subsidence:	Included consideration of ELHT
Section 11.8 – Personnel and Vehicles:	Included consideration of ELHT
<u>FIGURES</u>	
Figure 15 – General Hydrostratigraphic X-sec:	Added ELHT details
Figure 36 – East RDD Facilities:	Added ELHT pad, access routes, and surface facilities
NEW FIGURES	
Figure 37a – ELHT Schematic X-Sec.:	Schematic cross-section of ELHT downhole well configuration
Figure 37b – ELHT Well Trajectories:	Plan view drawing – ELHT well trajectories
Figure 38 – ELHT Heater Well Schematic:	Downhole schematic of ELHT heater well
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APPENDICES

Appendix H – Reclamation Cost Estimate: Updated using 2013 Cost Data, added costs for ELHT

Note that the Drilling Plan, Surface Use Plan of Operations, and supporting Figures provided with the four ELHT Applications for Permit to Drill (APDs) submitted to the BLM on February 28, 2013 include the same updated information for the ELHT that has been incorporated into the attached POD Document.

If you have any questions regarding the information in this submittal, please contact Florentino Vuelvas at 281-544-7990.

Sincerely,

George K. Zimmerman
Land Administration

Attachments (POD Text, Figures, and Appendix H)

Cc: Travis Marshal - CDRMS

Attachment 1
POD Text

Shell Frontier Oil and Gas Inc.

Plan of Development
for
Research, Development and Demonstration Activities
on
Oil Shale Research, Development and Demonstration (RDD) Lease COC 69166
and
Nahcolite Preference Right Sodium Lease C-0120057

"Multi-Mineral RDD"

Submitted to:

Bureau of Land Management
White River Field Office
73544 Hwy 64
Meeker CO 81641

December 29, 2010
Updated December 2012 and February 2013 (Add ELHT Project)

ABBREVIATIONS

AMSL	above mean sea level
APCD	Air Pollution Control Division (CDPHE)
API	American Petroleum Institute. API gravity = specific gravity of liquid hydrocarbons
bbl	barrels
BLM	Bureau of Land Management
BMP	best management practices
boe	barrels of oil equivalent
bopd	barrels of oil per day
BTEX	benzene, toluene, elthybenzene, xylenes
bwpd	barrels of water per day
CDPHE	Colorado Dept of Public Health and Environment
CH_4	methane
CO_2	carbon dioxide
CSU	Colorado State University
DHT	Deep Heater Test: a Shell research project near Cathedral Bluffs
DRMS	(Colorado) Division of Reclamation, Mining and Safety
ELHT	East Long Heater Test
EIA	Environmental Impact Assessment
EIS	Environmental Impact Statement
EMT	Emergency Medical Technician
FA	Fischer assay
gpt	gallons per ton
H_2S	technically hydrogen sulfide, but used generally for all sulfur gases
HSE	health, safety and environment
ICP	in situ conversion process
LEL	lower explosive limit
MDP[o]	MDP Original: a Shell research project near Cathedral Bluffs
MDP[s]	MDP South: a Shell research project near Cathedral Bluffs
MI	mineral insulated (heater)
MIT:	Mahogany Isolation Test: a Shell research project near Cathedral Bluffs
MLRB	(Colorado) Mined Land Reclamation Board
MRP	(Shell) Mahogany Research Project
MTE	Mahogany Test Experiment
Na_2CO_3	soda ash; sodium carbonate
NIA	Notice of Intent to Abandon (permit)
O&G	oil and gas

POD	(BLM) Plan of Development
POO	(BLM) Plan of Operations
ppg	pounds per gallon
PRL	Preference Right Lease (or Preference Right Lease Area)
psi	pounds per square inch
RDD	Research, Development and Demonstration (Lease). Same as R, D &D and RD&D.
ROW	right of way
RPP	Recreation or Public Purposes
SFOGI	Shell Frontier Oil and Gas Inc.
SIA	Subsequent Report to Plug and Abandon (permit)
SIFT	Steam Injection Field Test: a Shell research project near Piceance Creek
SPCC	Spill Prevention, Control and Countermeasures Plan
SWMP	Storm Water Management Plan
TD	total depth
TDS	total dissolved solids
TI	TI bed; (tee-eye bed); a rich nahcolite unit in lower part of Saline Zone
TLQ	temporary living quarters
TVS	table value standards (see WQCC Basic Standards for Groundwater – Regulation 41)
UAA	Use Attainability Assessment
VFD	volunteer fire department
VVT	Variable Voltage Transformer
WBI	water bearing interval
WQCC	(Colorado) Water Quality Control Commission

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1 INTRODUCTION

Shell Frontier Oil and Gas Inc. (Shell) has leased approximately 149 acres of oil shale-bearing land to develop a Research, Development and Demonstration (RDD) project in a nahcolite-rich zone of the Eocene Green River Formation in the Piceance Basin, NW Colorado. The East RDD project lies on federal land managed by U.S. Bureau of Land Management (BLM) (Figure 1). The target resources include oil shale and nahcolite ($NaHCO_3$). In essence, the plan is to leach nahcolite with hot water to create permeability and recover the leachate, then heat the formation to convert kerogen and recover the oil and gas products.

Shell's Project plans are described in the "Plan of Operations for 2nd Generation ICP Project" (POO) (February 15, 2006 [15]), the "Addendum to Plan of Operation for the 2nd Generation ICP Project" (July 17, 2008 [17]), and the "Addition of No Freeze Wall Option" (November 26, 2008 [18]) (POO Addenda).

The BLM approved the "Environmental Assessment CO-110-2006-117-EA and Finding of No Significant Impact/Decision Record Site 2 COC-69166 Nahcolite Test Site (EA)" (November 9, 2006 [3]). Subsequently, Shell and BLM signed a Research Development and Demonstration Lease (RDD) for approximately 149 acres (December 10, 2008 [4]). The POO Addendum and Addition of no Freeze Wall Option were incorporated into the RDD Lease by BLM letter dated December 10, 2008.

Leases covering the RDD Project include the "Oil Shale Research, Development and Demonstration (R,D&D) Lease" number COC 69166 (December 2006 [2]), "Addendum Number 1 to the Oil Shale Research, Development and Demonstration Lease Number COC-69166, COC-69167, and COC-69194", and the "Preference Right Sodium Lease" number C-0120057 (Sodium PRL) (1992 [1]). The RDD lease term is 10 years with the option to extend 5 years upon a showing of diligence, and is convertible to a 20-year term for commercial development. It is expected that the Sodium PRL will be renewed within the working life of the RDD Project.

This POD estimates that leaching, pyrolysis, product recovery, and subsurface reclamation of the RDD Pilot Project will require 6½ to 10 years, more or less depending on the time needed to leach, pyrolyze, and reclaim the subsurface (Figure 2). This time includes ~ 7 months to drill and construct the wells, 6 to 18 months of nahcolite leaching, 5 to 12 months of construction including leach well work-overs transitioning to the heating phase, 2 to 3 years of heating, and 2½ or more years of subsurface reclamation that includes cooling and reservoir filling. Surface reclamation (not shown in Figure 2) will begin once surface facilities can be removed and will continue until the surface is returned to a beneficial post-mining land use. Ground water monitoring sufficient to demonstrate compliance with ground water numeric protection levels will close out the project. Numeric protection levels listed in this POD will be established by DRMS, the ground water implementing agency for mines in Colorado.

With RDD Pilot success, the project will be converted to commercial-sized lease of ~ 5120 acres. Terms for the conversion of the RDD Lease to a Commercial Lease, identified in Section 23 of the RDD Lease, are included in this POD.

In addition to the RDD Pilot Project, Shell is planning a Long Heater Test (East Long Heater Test [ELHT]). This test will consist of drilling three (3) horizontal heater wells, two in the Saline Zone, one in the Illite Zone, and an inclined well installed for observation and pressure relief. The objective of the ELHT is to test the tendency for hotspots to form along commercial heaters installed in a horizontal orientation. This test will also evaluate the effectiveness of installing heaters horizontally, as opposed to vertically, as is the method to be employed in the RDD Pilot Project. Therefore, the ELHT is proposed as a way to refine the heat delivery system, to more efficiently extract the resource, and is not part of the production test. However; data generated from the ELHT regarding heater deployment and performance, drilling costs, and reservoir response will all be used to supplement the vertical well data set.

This document, the Plan of Development (POD), covers requirements in Section 8 of the RDD Lease and the Oil Shale Regulations, and fulfills all other requirements of the leases, and the RDD Environmental Assessment. BLM approval is expected to be contingent on release of CSU's lease for Recreation and Public Purposes, and renewal of Shell's Sodium PRL per BLM direction. Included in the POD is a list of all associated permits, notices, licenses, etc that have been or will be submitted to fulfill local, state, and other federal requirements. All supporting documents to this Plan of Development are contained in Appendix A through Appendix J.

In October 2012, Shell met with staff from the White River Office of the Bureau of Land Management and Colorado Division of Reclamation, Mining and Safety to discuss incorporation of testing of horizontal long heaters on the East RDD lease concurrent with RDD activities described above. This updated Plan of Development replaces all earlier versions of the POD previously submitted to BLM and describes Shell's plans for incorporating testing of horizontal long heaters on the East RDD lease concurrent with previously described RDD activities.

2 CONTACT INFORMATION

Lessee:

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3 LOCATION

3.1 Location, Elevation, Acreage

The East RDD Project site is ~ 37 miles northwest of Rifle and 25 miles west-southwest of Meeker, Colorado (Figure 1). The RDD Lease encompasses the following 149.39 acres more or less, in Rio Blanco County:

Sec. 4; Lots 9, 10, 15, and 16; T2 S, R98 W; 6th P.M.

Elevation at the RDD Lease center is ~ 6,630 ft above mean sea level. The permit boundary for all permits coincides with the RDD Lease boundary; the affected area inscribes a portion of the Permit boundary plus the access road.

The affected area inside the lease covers approximately 15.36 acres. This includes 12.68 acres of active operations (drill pads, support facilities, drill cuttings pit), 2.48 acres of access roads, and 0.2 acres for the stormwater pond.

A pipeline right of way (ROW) traverses the RDD lease on the south side (Figure 3). An unimproved BLM road ("BLM Pipeline Road") along the north side of the pipeline ROW, which will be marked for emergency access only, will not be upgraded or improved. Approximately 5 acres of the RDD Lease that lie south of the Pipeline Road will remain unfenced.

Colorado State University (CSU) holds a Recreation or Public Purposes (RPP) lease with BLM covering 50 acres, more or less, for re-vegetation studies. The study plots cover parts of the RDD, most notably a series of plots inside an 8-ft tall wildlife exclusion fence. A N-S road immediately east of the exclusion fence, which links to the Pipeline ROW, will serve as emergency access for the RDD Pilot. POD approval is contingent on a Shell and CSU Agreement to terminate the RPP Lease. Shell's intent is to fence the RDD operating area with an 8 ft high game fence, tied in to the 8 ft exclusion fence in order to maintain the existing (CSU) fence.

The RDD lease area north of the BLM Pipeline Road will be fenced per BLM Gold Book Standards, to preclude livestock. An emergency access gate will be installed in this south fence at the existing N-S dirt road, which lies east of the existing CSU fenced area. Operating areas inside that fenced area will be cleared of vegetation and graveled. Topsoil will be preserved.

3.2 Shell Lands, Projects, Facilities

Shell maintains an office, parking facilities, and helipad on private land approximately ½ mile east of the East RDD. These facilities will help support the RDD project.

Shell maintains temporary living quarters (TLQ) on Corral Gulch, approximately 6 miles WNW of the East RDD. The Corral Gulch TLQ and associated structures, which presently are not occupied, will be reopened to support the East RDD Pilot and other Shell projects on private lands. The TLQ facilities include sleeping quarters, office buildings, cafeteria, warehouse, and storage yard on Shell-owned property.

The Shell Freeze Wall Test (FWT) on Corral Gulch is located on private land approximately 5 miles WNW of the East RDD. Activities at the FWT are ongoing.

Shell's Mahogany Research Project (MRP) sites on private lands near Cathedral Bluffs in the western part of the Piceance basin, approximately 7 miles WNW of the Corral Gulch Facilities, are presently undergoing reclamation. Some of the MRP facilities will be transported to the East RDD for re-use. The MRP will not be used otherwise to support the East RDD Pilot.

3.3 Ownerships, Leases in RDD Lease Area

The East RDD Lease acreage is wholly within federal BLM boundaries. The RDD lease, primary access road, and emergency access road overlap leases and rights of way of other parties (Figure 3). Following is a list of the Shell leases and the ownerships and other leases on or adjacent to the East RDD Lease.

Surface Owner / Mineral Owner/Lessor

United States of America, through the Bureau of Land Management
Meeker, Colorado

Oil Shale Research Development and Demonstration R, D&D) Lease Serial no. COC 69166
Sodium Minerals "Preference Right Sodium Lease" number C-0120057
2009-10 East Lease Appraisal Right of Way Grant COC 73947

Shell Frontier Oil and Gas Inc.
Houston, Texas 77002

Oil and Gas Lease Holder

Williams Production RMT Co.
1 Williams Center
Tulsa, OK 74172 Ph. 970-285-9377
Federal Lease Serial No. COC 60737

Recreation or Public Purposes Lease Holder – (Cancelled upon approval of December 2010 POD)

Colorado State University
William H. Farland, VP for Research
2001 Campus Delivery
Fort Collins, CO 80532-2001
Attn: Mark Paschke
Federal Lease Serial No. COC - 34329

Grazing Leases

A grazing lease overlaps the East RDD, and a separate grazing lease overlaps the access road.

Dean Mantle – Reagle Allotment CO-06026

Mantle Ranches – Square S Allotment CO-06027

3.4 Explanation of Ownerships, Leases, Easements, Rights of Way

Leases that affect unimpeded 100% access to the East RDD lease and the lease access road are described in this section along with a description of Shell facilities and projects in the vicinity.

BLM ownership and mineral rights: The East RDD Project area, access road, and proposed activities are on BLM land. Surface and subsurface mineral, oil and gas, and other natural resources are federally owned, and managed by the BLM White River Field Office in Meeker Colorado.

Shell Leases: Shell has two mineral leases and a Right of Way Access agreement with BLM for the East RDD. The oil shale RDD lease of ±149.39 acres includes the East RDD Permit area. Shell's Preference Right Sodium Lease covers ±2186.76 acres. The ROW Access Agreement covers ±4 acres, approximately 2 of which are outside the RDD Lease area. The leases and agreements include:

- "Oil Shale Research, Development and Demonstration (R,D&D) Lease" number COC 69166
- "Preference Right Sodium Lease" number C-0120057 (Sodium PRL)
- Right of Way Access Agreement number COC 73947.

The RDD lease term is 10 years with the option to extend no more than 5 years upon a showing of diligence. The RDD lease is convertible to commercial preference right lease. The Sodium PRL lease term is for 20 years, renewable upon approval by BLM. It is expected that the Sodium PRL will be renewed within the working life of the RDD Project.

Oil and gas lease: Oil and Gas (O&G) rights beneath the RDD Lease and access road are leased to Williams Production RMT Co. A gas well pad on that lease is located approximately 300 ft east of the eastern RDD Lease boundary and approximately 150 ft south of the RDD access road. This oil and gas lease overlaps the entire East RDD property and is part of a significant tight gas play in the region. The O&G target formations are several thousand feet beneath the oil shale units and are accessible to O&G production via offset drilling. Shell's RDD lease and access road are not available for O&G operations or staging.

Pipeline Easements: The two pipeline rights of way cross the project area; one crosses the southern part of the RDD and includes pipelines constructed by several companies; the other is crossed by the access road east of the RDD lease.

The site access road crosses a north-south gas flow line west of CR 24. This flow line is owned by Williams Production RMT Co. A Shell agreement to cross the Williams flow line is included in the 2009-10 East Lease Appraisal Right of Way Grant, COC 73947. That agreement required a minimal buildup of roadbed thickness to provide access across the line for heavy equipment. This access has been already constructed.

The pipeline right of way crossing the southern part of the RDD lease includes pipelines belonging to Enterprise Products Partners L.P, Colorado Gas Company (CGC), Xcel Energy, and Questar Pipeline Company. No part of this pipeline ROW will be employed for surface operations. An unimproved BLM access road parallels the pipeline ROW on the north side, and will be used by site personnel for emergency use only.

CSU RPP Lease. Colorado State University (CSU) has a ±50 acre Recreation or Public Purposes Lease (RPP) with BLM to conduct disturbed land reclamation. Much of the RPP lease overlaps the RDD lease. An agreement between Shell and CSU provides for termination of the RPP lease in consideration of research and endowment funding to CSU Foundation. Termination by the BLM of the RPP lease is a condition of the POD and other permit approvals. *Note: The December 2010 POD was approved by BLM on August 10, 2011 and the RPP lease was subsequently terminated by BLM.*

3.5 Man-made Structures within 200 ft

The lease permit boundary and adjacent man-manmade structures (Figure 3) includes several structures within 200 ft of the permit boundary. Man-made Structures within 200 ft of the Permit Boundary include:

- Shell Hydrology Cluster well pad 22-4-298[1]
- Shell Hydrology Wells 138-4-298
  Includes Uinta, A-groove, B-groove, L5, and L4 wells (5 wells total)
- Williams Gas Well
  Williams gas well Fed RGU 41-8-298
  NE NE Sec 8, T2S, R98W. Federal Lease Serial No. COC 60737
  This is a producing well.
- CSU fences
  CSU exclusion fences surrounding several areas within the East RDD permit boundary will be removed as necessary to enable access to the RDD disturbed area. Otherwise the CSU fences will be maintained to preclude large game access. POD and other approvals are contingent on an agreement with CSU to terminate the CSU RPP Lease.

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[1] Shell recognizes the distinctions between the terms "well" and "hole" as defined in CRS 33-44-101, CRS 34-32-101, and CRS 37-91-101, regarding permitting and use. This Plan of Development uses the terms less explicitly: "hole" applies generally to the drilled, unimproved feature; "well" applies generally to a hole that contains casing, equipment, or other additions or improvements.

- Grazing lease fence
  A N-S cattle fence with cattle guard crosses the Access road near CR 24. This cattle guard, erected by Shell to enable access to the appraisal and hydrology wells in 2009 was selected to withstand very heavy equipment specifically for the East RDD project.

- Gas pipelines
  Buried, natural gas pipelines of Enterprise Gas, CGC, Xcel, and Questar lie in a single ~E-W pipeline corridor crossing the southern part of the East RDD Permit area.

- Natural Gas flow line
  The RDD Access Road crosses a single natural gas flow line from various Williams gas wells ~N-S along the west side of CR 24. A letter agreement from Williams Pipeline Company gives Shell and others rights to cross gas flow lines provided sufficient crossing surfaces are constructed.

- BLM unimproved dirt road
  Unimproved dirt road along northern boundary of above-mentioned gas pipeline corridor is to be used for emergency use only. The road will not be improved or upgraded, but will be maintained as necessary.

4 GEOLOGY

4.1 Background

The East RDD Pilot site lies in the northern part of the Piceance Basin in northwestern Colorado (Hail and Smith, 1994 [9]) (Figure 4). The Piceance Basin contains the world's richest deposits of oil shale and one of the most significant occurrences of the saline mineral nahcolite, which is $NaHCO_3$ (sodium bicarbonate or baking soda). An estimated one trillion barrels of oil shale resource occurs within the Parachute Creek and Garden Gulch Members of the Green River Formation. The resource area covers 1,600 square-miles and is bounded by the Colorado River on the south, the White River on the north, the Douglas Creek Arch on the west, and the White River Uplift on the east. The in-place oil shale resource lying beneath the 149-acre East RDD tract, location for the East RDD Pilot and ELHT, is estimated to be approximately 274 million barrels, based on Fischer Assay (FA) recovery rates.

The East RDD Pilot Project is planned for the nahcolite oil shale strata of the Saline zone of the Parachute Creek Member, which exhibits very low permeability and no producible groundwater. The first stage of development is to leach nahcolite from the Saline Zone in order to establish permeability for subsequent production of oil. Nahcolite is also to be removed to lower the cost of pyrolysis. At a temperature below the kerogen pyrolysis temperature, nahcolite transforms to soda ash (Na_2CO_3). The transformation is an endothermic reaction that consumes heat which, if nahcolite is not removed previously, effectively increases the cost of heating. The second stage of development is to pyrolyze oil shale in order to produce hydrocarbon liquids and gases.

The ELHT is planned for the lower saline nahcolitic oil shale zone of the Parachute Creek Member, and for the illitic sediments near the top of the underlying Garden Gulch Member. Both development intervals are oil-shale bearing with very low permeability and effectively no free groundwater.

Portions of the following section are excerpted, abridged and adapted from Dyni, "Stratigraphy and Nahcolite Resources of the Saline Facies of the Green River Formation, Rio Blanco County, Colorado", 1974, pp. 3-16, 21 [7].

4.2 Structural Setting

The East RDD Pilot site is near the depocenter of the Piceance Basin, an intermontane asymmetric basin formed during the Laramide Orogeny (~ 60 ma). Older rocks are exposed in the surrounding uplifts -- Uinta Uplift to the north, Uncompahgre Uplift to the south, Grand Hogback Monocline and White River Uplift (Rocky Mountains) to the east, and the Douglas Creek Arch to the west. The Piceance Basin is one of several basins that are part of the Greater Green River Basin, which includes northeastern Utah and southwestern Wyoming. The Douglas Creek Arch divides the Piceance from the Uinta basin in Utah, and the Uinta Uplift divides it from the Sand Wash and Washakie Basins to the north. Together these basins comprise the Greater Green River Basin. The Colorado River runs along the southern boundary of the

Piceance Basin, cutting off the southernmost part of the Piceance Basin, and the White River bounds the basin to the north.

Locally, strata dip gently to the northeast toward basin center (Figure 5). Local strike is approximately N45W, and dip is approximately 2-3 degrees NE.

The East RDD Pilot and ELHT areas lie on the western side of a ~⅛ mile wide, northerly-trending depression. Strata traversed by wells drilled on the northeastern area of the East RDD Pilot (SAW-1 and the 138-4-298 hydrology wells) are ~ 20-25 ft lower than projected by simple layer to layer projections from the nearest wells to the west and east (Figure 5). The length of the structure is approximately 1 mile, as suggested by interpretations from local seismic sections. Several possible interpretations of the depression were considered: a graben; a primary depression on the lake floor; and sag caused by intraformational dissolution of nahcolite. All cores in the vicinity were carefully inspected for signs of fracturing, faulting, brecciation, and dissolution, any of which might indicate a need to locate the East RDD Pilot and ELHT elsewhere. As no such indications were observed, it appears that the most reasonable interpretation of the depression is as primary local topography on the original lake floor and bed thicknesses controlled by changes in primary water chemistry over broad areas and an absence of detrital input to fill the lake floor depression.

4.3 Stratigraphy and Resources

The Parachute Creek Member is a part of the Eocene Green River Formation. Within the Piceance Basin, northwest Colorado, the Parachute Creek Member comprises mostly feldspathic dolomite marlstone, kerogen, the evaporite minerals nahcolite and halite, and minor clay, quartz and calcite. Siliciclastics occur in some units along the original lake margins and decrease significantly toward basin center, which is a few miles northeast of the East RDD Pilot and ELHT project site. Most of the Parachute Creek and Garden Gulch units formed in a deep saline meromictic lake.[2] The absence of overturn of the lake waters allowed concentrated solutions to build up in the deeper lake, eventually leading to precipitation of evaporite minerals. The high salinities, great depth of water, and the anoxic conditions favored kerogen preservation.

Kerogen-rich R zones are laterally continuous through the Saline Zone, and are generally thicker due to their position within the primary depositional basin where they accumulated in or near the basin depocenter. The Saline Zone extends from the base of the R2 to as high as the lower L5 at the thickest point. The lower surface is a depositional surface that marks basin closure during early Parachute Creek time when the basin transitioned from a fresh water lake to hypersaline conditions, compared to previous (older), more open lake conditions associated with Garden Gulch time. The Saline Zone has extremely low permeability and is virtually void of water as noted in underground mine workings in the Horse Draw mine and in drill cores (USGS Project Bronco and others).

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2 A meromictic lake is a lake whose water is permanently stratified and therefore does not circulate completely throughout the basin at any time during the year

The Saline Zone and the Dissolution Surface are important controls on the basin hydrostratigraphy, ground water flow, and geochemistry. Extreme low permeability makes the Saline Zone a regional no-flow boundary for ground water. The extreme salinity of ground water in contact with the salts profoundly affects the water chemistry of waters near the Dissolution Surface.

Strata within the Piceance Basin dip generally toward basin center, with the steepest dips observed on the margins, and near horizontal beds at basin center. In the East RDD Lease area, the units dip 1 to 3 degrees to the northeast. Most strata of the Parachute Creek Member thicken toward the center of the basin, primarily due to the increase in original depositional thickness in that direction, and secondarily to progressive loss of section, from near the basin margins down dip toward the depocenter, due to dissolution of saline minerals of the Saline Zone. The illitic section of the Garden Gulch Member may thicken more toward the basin margins.

The Garden Gulch Member Illitic Interval was not deposited under the same evaporative conditions as the lower saline portion of the Parachute Creek member. A substantial decrease in the amount of nahcolite and related minerals is observed, with an increase in clastic minerals that include illite are indicative of a fresh water depositional setting contrasting with the overlying Parachute Creek Member which is indicative of a hypersaline depositional setting. The target Illite Zone for the ELHT is greater than 60% illite clay, which is the reason for the low permeability in this interval.

Although the oil shales of the Garden Gulch Member differ mineralogically and in physical character from the overlying Parachute Creek Member, the kerogen-rich oil shales of both members are vertically gradational with each other and form essentially one continuous mineral deposit.

The Green River Formation is overlain by the Eocene Uinta Formation, a predominantly siliciclastic unit; generally devoid of economic oil shale deposits. The Parachute Creek and Garden Gulch Members of the Green River Formation contain considerable kerogen-rich oil shale deposits, and are the principal units of interest for the East RDD Pilot Project and the ELHT. Organic matter that today is kerogen was mostly algae, originally, that formed in the greater Green River lakes, including the area that now comprises the Piceance Basin. With time, the deposits were compressed and dewatered by the weight of overlying sediments, and the compressed algae and associated organics formed kerogen. Mature hydrocarbons of thermogenic origin are rarely present in the Green River Formation in the Piceance Basin (Day, 2009 [6]), due to the Piceance Basin the Green River Formation not being subjected to sufficient heat and pressure heated sufficiently (i.e., buried deep enough) to convert the kerogen to hydrocarbons. Today the Parachute Creek and Garden Gulch Members remain thermally immature. Methane and CO_2, two gases that appear frequently in wells that transect the Green River Formation in the Piceance Basin are biogenic gases that represent early diagenesis associated with aging and shallow burial of the kerogen.

The stratigraphy of the Parachute Creek and Garden Gulch Members (Figure 6) in the Piceance Basin are divided into kerogen-rich (R) and kerogen-lean (L) zones. The kerogen-rich R zones are numbered, base to top, from R0 through R8, and are separated by kerogen-lean L zones, which are also numbered successively from base to top, L0 through L7. The R zones typically have low vertical permeability relative to the L zones, and form seals that preclude or limit significantly the vertical migration of groundwater.

The Uinta Formation has minor low-grade kerogen-bearing interbeds. These beds, like their R zone counterparts in the Green River Formation, form sealing units that limit vertical transmission of groundwater.

Individual fine grained clastics and marlstone strata, kerogen units, texturally distinct nahcolitic units in the Parachute Creek and Garden Gulch Members are correlative over relatively large distances, and are actually time synchronous: that is, individual distinct layers in the Parachute Creek Member can be correlated across the basin, and each formed at the same time. Such layers are interpreted to be time correlative because they are conformable with over- and underlying layers of volcanic ash (tuff) in the Parachute Creek that extend over many miles. Because tuff layers represent very short-term events in geological time, they serve as precise time markers. As the tuff layers are conformable with the over- and underlying units, it follows that the R and L zones in the Parachute Creek and Garden Gulch Members are time equivalent throughout the basin.

The Green River Formation in the Piceance Basin records a lacustrine sediment stratigraphic sequence. The depositional environment changed with time from a fresh water lake that was hospitable to aquatic life (Garden Gulch Member) to a hypersaline lake that was generally inhospitable to all organisms except algae (Parachute Creek Member). The early period of fresh water lake deposition, marked by the illite rich fine grained sediments of the Garden Gulch Member, was hospitable to fresh water fauna including clams and fresh water fish. Saline minerals began forming by evaporation of lake waters during early Parachute Creek (R2) time. Although saline minerals appear throughout the Parachute Creek Member in the Piceance Basin, the most significant thicknesses are preserved in the center of the Piceance Basin. There, saline minerals occupy strata from the R2 through the lower L5 zones. Layers with relatively high concentration of saline minerals interbedded with oil shale intervals marks the base of the Saline Zone, which is the target for the East RDD Pilot and a portion of the ELHT. The Lower Saline zone and upper Illitic Zone are primarily composed of fine grain clastic sediments, and is one of the targets for the ELHT.

The lower section of the Saline Zone contains significant accumulations of nahcolite and dawsonite ($NaAlCO_3(OH)_2$) (Figure 7). Nahcolite is considered a valuable mineral resource as a result of its high concentrations in the Piceance Basin. While high in concentration relative to most rock, dawsonite is considered a mineral of interest, but uneconomic. The upper portion of the Saline Zone includes halite beds farther basinward (northeast) but not in the RDD Pilot area. The high saline mineral content gives the Saline Zone extremely low permeability and no producible water. The Saline Zone behaves as a sealing unit that will provide natural geological containment for the East RDD Pilot and ELHT.

The Garden Gulch Member of the lower Green River Formation overlies the Eocene Wasatch Formation, which is comprised of mudstones, sandstones, coals, and conglomerates. The lowest test zone of the ELHT is separated from the Wasatch Formation by at least 200 ft of low permeability shales of the Garden Gulch Member.

The Saline Zone originally extended farther than the current limits, both laterally and vertically. Fracturing that accompanied regional uplift allowed the introduction of fresh ground water into the subsurface, displacing the native saline formation water and dissolving part of the original nahcolite and halite. Evaporite dissolution that is evident today occurred slowly over geologic time. The dissolution of saline minerals proceeded from above and from the margins of the basin, and continues today. The areas of evaporite mineral dissolution, which have higher permeability than other units, are most conspicuous in the drill core by nodule-shaped vugs and by breccias that have collapsed into open voids created by the dissolution and removal of saline mineral mass. The breccia-form permeability is prevalent for several miles updip of the Saline Zone, and for a few feet to several tens of feet immediately above the Saline Zone, more or less depending on local rock features their tendency to form breccias. Vugular porosity caused by dissolution of nahcolite nodules is found throughout the Parachute Creek, both updip and above the Saline Zone.

The dissolution of nahcolite increases TDS concentration in ground water, and yields a $Na\text{-}HCO_3$ type composition. Halite, which occurs always in association with nahcolite, also yields higher TDS content upon dissolution and yields ground water with a $Na\text{-}Cl\text{-}HCO_3$ type composition.

The so-called "Dissolution Surface" marks a level in the Saline Zone below which evaporite mineral dissolution is not observed. Significant stratal thicknesses of primary saline minerals occasionally do occur above the Dissolution Surface, and such is the case at the East RDD and ELHT area.

The lower half of the East RDD Pilot and ELHT area Parachute Creek Member oil shale section consists of low- to high-grade oil shale that contains variable amounts of nahcolite as non-bedded crystalline aggregates and nodules, as well as bedded disseminated nahcolite. Nodular and aggregate forms of nahcolite comprise about 80% of the saline facies in this area, with the remaining 20% being composed of highly continuous units of nahcolite crystals disseminated in oil shale.

ELHT operations will penetrate below the basal R4 zone of the Parachute Creek Member into the Illitic Zones L1 and R1 below. Oil shales present in the Garden Gulch Member are typically differentiated from overlying oil shales by the presence of abundant illite and occasional claystone units. The rocks are typically faintly to prominently laminated and contain sparse fish and vertebrate bone fragments and sparse to locally abundant ostracods. The section contains irregularly distributed siltstones which probably represent occasional pulses of terrigenous clastics from lake margins.

4.4 Nahcolite Forms and Leaching Characteristics

This section pertains only to the East RDD Pilot leaching operation. Nahcolite appears in the Parachute Creek Member in several forms (morphologies), in widely varying concentrations (Figure 9) (Dyni, 1974 [7]). Leachability of nahcolite controls the generation of leaching-induced permeability in the natural environment. The development of nahcolite leaching-induced permeability, in the unleached Saline Zone, is necessary for recovery of liquid hydrocarbons generated by ICP. Nahcolite leaching is equally important for nahcolite recovery. Three beds of rich disseminated nahcolite occur within the target section: the Greeno bed near the top of the section, the "lower Greeno" bed, and the TI bed (Figure 7). The intent is to preferentially leach the TI bed, and secondarily to leach the "lower Greeno" and Greeno beds.

Nahcolite leaching varies with the amount of mineral surface exposed to the leach fluid, and with temperature (Waldeck, et al, 1932 [21]; 1934 [22]) and pressure (Nielsen et al, 2004 [11]). An increase in any of these parameters increases the rate of nahcolite leaching; and higher temperature and pressure increase the solubility. Mineral surface area exposed to the leaching fluid (hot water in this case) is considered to have the strongest effect on rate and effectiveness of dissolution. Surface area itself is affected strongly by the nahcolite form and the percent of nahcolite that is exposed to leach fluids in the area of leach fluid circulation.

The amount of nahcolite exposed to the leaching fluid over time depends on the connectivity between individual nahcolite minerals; connectivity in turn is governed by nahcolite morphology. Nahcolite occurs in (1) microcrystalline, (2) aggregate, (3) nodular, and (4) disseminated forms (Figure 8).

Microcrystalline nahcolite tends to occur as small crystals or crystal masses in a matrix of marlstone. Individual crystals or crystal masses tend not to be connected except where nahcolite concentration in a layer is very high.

Nahcolite *aggregates* and nahcolite *nodules* typically comprise crystals visible to the eye, have irregular to round outlines, and range from less than 1 inch to more than 3 ft in diameter. Aggregate and nodular nahcolite units tend to float in a matrix of marlstone or marlstone and kerogen. Although these morphologies are laterally continuous across much of the basin, nonetheless they are not likely to leach much past the immediate area of a leach well because the matrix around the nodules and aggregates is practically insoluble relative to the nahcolite.

Disseminated nahcolite, which Dyni (1974) characterized as sparse, moderate, and densely disseminated based on the nahcolite abundance, tends to produce the richest nahcolite layers. Disseminated nahcolite occurs as a mass of crystals that are physically connected laterally, or they are segregated by relatively minor amounts of kerogen or marlstone. The TI and Greeno nahcolite beds are of the densely disseminated type; they have a high nahcolite concentration, a high crystal surface area that is laterally connected, and thus are projected to be the most leachable nahcolite bearing units.

Nahcolite clusters, nodules, and aggregates that are exposed at the drill hole interface will of course leach once hot water in injected into the open bore hole. However, the lateral progress of leaching is stemmed unless nahcolite at the face of the borehole connects laterally to more nahcolite. Disseminated and microcrystalline nahcolite forms are more laterally connected than other forms and hence are considered most readily leachable. Leaching tendency (Figure 7) favors dissolution of the rich disseminated units, namely the TI, Greeno, and "Sub-Greeno".

Core studies indicate that nahcolite layers with a particular morphology are laterally continuous over many miles. Dyni (1981 [8]) showed that nahcolite morphologies are laterally continuous over more than 9 miles north to south and 6 miles east to west in the northern Piceance Basin.

Nahcolite crystals within aggregates and nodules are typically bladed, ¼ to 1 in. long forms commonly separated from each other by paper-thin septa of oil shale. Aggregates show crude clustering and are more or less randomly oriented, while nodular crystals are arranged in a radiating rosette-like pattern.

Most of the nahcolite is colored light brown by organic (kerogen) impurities. Many aggregates and nodules are rimmed with pyrite or marcasite that alters to a soft expanded material on exposure to air.

Some units are composed of alternating oil-shale laminae and nahcolite-rich laminae. The contacts between units of disseminated nahcolite may be sharp or gradational. Despite the variations in textures vertically and the gradational nature of contacts, many units of disseminated nahcolite have remarkable lateral continuity.

During the course of heating, nahcolite present within the heated interval will decompose to soda ash ($2NaHCO_3 \rightarrow Na_2CO_3+H_2O+CO_2$). As heating progresses, nodule nahcolite is expected to expand and "fluff" in a manner described as the popcorn effect. This expansion will cause localized fracturing of the nodule and microfractures due to increase pressure in the formation adjacent to the nodules. This effect is anticipated to increase the degree of connectivity between the nodules and result in a net increase in the recoverability of sodium minerals in the nodular zones.

4.5 Estimated Resources

4.5.1 East RDD

The RDD Lease (USDOI, 2007 [19]) and the Oil Shale Regulations (USDOI, 2008 [20]) require information on the resource volume and estimated recovery. These include an estimate of the size of the resource to be affected, estimated recovery factors, maximum economic recovery (MER), and ultimate maximum recovery. For this POD, "maximum economic recovery" and "ultimate maximum recovery" are considered the same.

Recoverable resources in the target section include nahcolite ($NaHCO_3$ – sodium bicarbonate) and oil shale. Dawsonite is not of ore grade and is unrecoverable under the conditions planned for the East RDD Pilot, so is not a target of this investigation.

As indicated in consultation with the BLM, "ultimate maximum recovery" may not be required at the East RDD Pilot research because (a) the project is very small in size and (b) is of a research nature, and (c) profitability from the RDD research per se is not intended. This statement is also true for the ELHT. Ultimate maximum recovery applies to commercial projects and will be addressed in the plan for conversion to a commercial lease, assuming the RDD Pilot proves successful.

Resource estimates are based on 3-dimensional projections of the nahcolite leaching zone and the target pyrolysis zone – the leach volume and pyrolysis volume, respectively. The progress of leaching and pyrolysis are monitored by remote monitoring devices such as temperature and pressure sensors mounted in the wells. The effectiveness of leaching and pyrolysis and recovery efficiency will be evaluated upon completion of the project.

For estimating purposes, the leaching volume and pyrolysis volume each is projected based on placement of the leach and heater wells and their anticipated performance. The nahcolite leaching design assumes a circular, 40 ft ± diameter zone principally in the most readily leachable TI and Greeno nahcolite beds, with lesser leaching of nahcolite bearing units above the TI bed to the top of the open interval. The open, leaching interval is approximately 153 ft in height, including the TI bed. The TI bed will be preferentially leached while other nahcolite bearing units above the TI to the top of the heater zone will be leached less so, depending on contact with the leach solution.

The pyrolysis target zone is a hexagon of 18.48 ft radius between heater wells in the long dimension by 112 ft in height (Figure 30). The maximum affected area dimensions assume a 36.96 ft hexagonal design diameter plus ~2 ft beyond the outer heaters, for a total of ~40 ft diameter, and a heater length of 112 ft. Heating is not expected to reach optimum temperatures at the top and base of the heater, so the actual height of the heated interval will be less (Figure 35). For instance, at the MDP-South project, a Shell experiment near Cathedral Bluffs, approximately 10 miles west of the East RDD Project area, the area adjacent to the upper 10 ft of the heater reached temperatures that were 150 to more than 500 °F lower than the maximum temperatures in the deeper parts of the heater, and the lower 5 ft of area adjacent to the heaters the temperatures was up to 50 °F lower than the maximum. For resource estimating purposes however the shape and dimensions of the pyrolysis zone are considered to be a hexagon 112 ft tall by 40 ft maximum diameter.

The leach volume spans from base of the TI bed to top of the heater (base of the crown). On a layer by layer basis, the grade of nahcolite in the leach volume ranges from less than 1 to about 80 wt %, and average grade is 24 weight %. The shape of the leaching front, while expected to be more or less circular about the leach well, will not be known until leach monitoring is under way. Nahcolite leaching will continue until the leach front traverses an acceptable number of the outer heater wells, for an optimal radius of approximately 20 ft beyond the leach well. When the leach front inscribes an acceptable area in the TI bed, then leaching will be curtailed.

The plan is to pyrolyze the target volume and recover a minimum of 1,500 barrels of liquid hydrocarbons. Volatile hydrocarbons, mainly methane, will be measured at the surface and flared.

The amount of recoverable liquid hydrocarbons is affected by many factors including grade of the oil shale, heating efficiency, liquids expulsion from the matrix, production of liquids at the producer wells, matrix permeability, and charring of liquid hydrocarbons near heaters.

Oil shale grade is gauged by the Fischer Assay (FA) method, the standard assay measurement for oil shale. On a layer by layer basis, the FA grade of oil shale in the 112 ft thick target section ranges from zero to ~ 35 gallons per ton (gpt); the average FA grade is 25.3 gpt (Figure 7). Actual conversion and recovery from lab and field experiments is a fraction of the FA grade, and ranges from about 60 to about 70% of FA, more or less depending on how the volume is pyrolyzed and other physical attributes.

Considering a hexagonal pattern with 18.5 ft outer hexagon diameter by 112 ft, the FA resource is 3,904 bbls in place. Assuming that heating affects an additional 1.5 ft around the outer periphery of the heaters which leads to a total hexagon radius is 20 ft, the FA resource estimate is 4,643 bbls. At 62% recovery, which is on the conservative end of the measured recovery range, the potential recoverable resource for the design heated volume is ~2,829 bbls of oil, for a uniformly heated volume.

4.5.2 ELHT

The estimate resource recovery for the ELHT is de minimis because the ELHT has intentionally been designed to minimize hydrocarbon recovery. This is accomplished by spacing the horizontal heaters sufficiently far apart (~80-100 ft) to ensure that superposition of heating does not occur. While the East RDD Pilot production is expected to be greater than 1,500 bbls of oil, the production from the ELHT is expected to be less than 175 bbls of oil. This oil will be routed to its own separator and tanks and therefore will be kept apart from the oil produced from the East RDD Pilot to ensure clarity of results. From time to time and for short durations, the production from the two tests may need to be commingled in response to operational problems or scheduled maintenance on the one of the two separators. During such times, the cumulative production from each test will be adjusted based on the rate during the time period immediately preceeding the event.

For the East Long Heater Test, the primary objective is to test subsurface heater technology to inform on the heater design. The test is designed to minimize production, if any, from the pilot by placing the heaters far apart from each other so as to avoid thermal superposition between the heaters. This is expected to result in a small localized pyrolysis zone around each of the heaters. Predictive modeling suggests this zone to be confined to less than 2 ft radius in the vicinity of each heater. Heaters extend 1000 ft in the lateral direction. Average FA in 2 ft radius around the three heaters is 28, 35 and 29 gpt respectively. Assuming a 2ft horizontal cylinder of affected kerogen around each 1000 ft long heater, the total affected FA resource is about 1645 bbls. Only a fraction of this resource will be produced as necessary to control reservoir pressure.

The ELHT does not include a leaching phase. Heating in intervals where nahcolite is present will result in thermal decomposition to soda ash. For the test interval where the nahcolite content is ~30 %wt on average (limited to the uppermost heater), it is calculated that the approximately ~

1,200 to 1,500 tons of nahcolite will decompose to soda ash which remains in place for potential recovery.

5 ENVIRONMENTAL BASELINE

5.1 Background: Basis for Water Quality Protection

Protection of surface and ground water quality is a fundamental design premise for nahcolite leaching, oil shale pyrolysis, and reclamation. Surface water protection considerations are simple compared with ground water because the target zone is over 2,000 ft deep, and surface water is more than one and a half miles from the project. Nonetheless, surface water protection features are included in the RDD Pilot design. Likewise, ground water quality protection is also a design premise because the target zone is overlain by a series of water bearing intervals (WBI) having less than 10,000 mg/L TDS, which the Federal Safe Drinking Water Act defines as Underground Sources of Drinking Water(USDW).

The extreme low permeabilities of the Saline Zone and Garden Gulch Illite zone provide natural geological containment that precludes migration of leach fluids or ICP fluids and gases into the overlying or underlying WBI. The absence of producible water keeps the Saline Zone and Illite Zone from being an aquifer or a WBI. Wells and even mines developed in the Saline Zone fail to produce any water, even after being left open for several decades. For instance, the Horse Draw Mine, an underground mine located off Piceance Creek approximately 10 miles NE of the East RDD Pilot, at approximately the same depth, presently houses a shaft whose cap is accessible via a small tube. This deepest part of the shaft was investigated by Shell in 2009 and found to have no water after being left open since at least 1983 when it was capped, and for several years prior. The mine shaft consists of a steel collar with annular cement from surface to total depth of approximately 2,300 ft, and seals off WBIs above the saline zone. As discovered in Shell's investigation, the underground workings remain dry even after more than 40 years without any pumping from the subsurface. Hence, the Saline Zone is void of water except perhaps for nahcolite saturated pore water which, as evidenced by the lack of water in the Horse Draw Mine, is not producible. While the reasons for the low permeability and lack of water in the target zone are clear and compelling, (see Geology section) the well penetrations through the WBIs and the ground water zone must completely isolate any overlying aquifers by verifiable cemented casing (see Development Details Section). There are multiple investigations that verify the Garden Gulch is essentially dry. Chief among these are the U.S. Geological Survey (USGS), in cooperation with the U.S. Bureau of Mines (USBM), the U.S. Atomic Energy Commission (AEC), Lawrence Radiation Laboratory and CER Geonuclear Corporation, drilling program for the Colorado Core Holes 1-3 with hydraulic testing and sampling of USBM-AEC Colorado Core Hole 3.

The following sections describe the baseline hydrology and water quality of local surface streams, and of the water bearing intervals above the Saline Zone and Garden Gulch Illite Zone. This section also describes measures that will be taken to monitor water quality in surface and ground waters for the East RDD Pilot.

5.2 Surface Water Hydrology

5.2.1 Regional North Piceance Basin

The Piceance Basin is considered a closed basin in that there is no significant ground water underflow into or out of the basin. All water that enters and leaves the basin derives from direct precipitation onto the basin itself. Ground water recharge derives from direct precipitation (mostly as snowmelt) and discharges into surface streams that flow within the basin. Major surface water divides coincide generally with ground water divides. USGS gauges 09306255 and 09306222 indicate that average discharge from Yellow Creek and Piceance Creek at their confluence with the White River are approximately 1.8 and 27.1 cubic feet per second (cfs) respectively.

The primary source of stream flow in Piceance and Yellow Creeks is snowmelt, with lesser contributions from springs and seeps that discharge from shallow portions of the Uinta Formation. Precipitation from November through March is stored in snowpack at higher elevation areas of the basin. Spring snow melt produces a period of high stream flow from about March or April through June or July.

Stream flow in the headwaters of the basin during the spring runoff provides a significant source of ground water recharge to the alluvium and underlying shallow bedrock. Stream flow during the remainder of the year is maintained almost entirely by ground water discharge in the form of alluvial underflow, diffuse seepage, or springs.

Stream flow is intermittent in upland areas. Streams may lose flow due to infiltration into alluvium and may regain flow downstream where the alluvium thins and the saturated zone intersects the channel base. Summer precipitation is largely consumed by evapotranspiration so that only high intensity storms produce significant summer stream flow. Irrigation diversions from mid-March to early November mainly affect Piceance Creek stream flow; irrigation on Yellow Creek is minor.

5.2.2 East RDD Area

The East RDD 149 acre lease lies entirely in the Stake Springs Draw drainage area slightly above the confluence of Stake Springs Draw with Yellow Creek (Figure 10). All potential surface water features are ephemeral on and down topographic gradient from the East RDD Pilot location as evidenced by USGS gauging station Stake Springs Draw 093062300, which had only very sporadic, storm-related discharge for the period of record from March 1974 through September 1977 (Figure 11). Shell established a Stake Springs Draw surface water station up-stream of the USGS station (Figure 12). Quarterly monitoring at the Shell Stake Springs Draw station reported no flow during every attempt from the fourth quarter of 2004 through first quarter of 2008 (19 measurement attempts). Shell's "Use-Attainability Analysis for the Yellow Creek Drainage, Rio Blanco County, Colorado" (April 2008 [16]), presented to the Colorado Water Quality Control Commission as part of a Standards setting hearing in 2008 for Yellow Creek, reported that Stake Springs Draw was dry (Figure 13).

5.3 Ground Water Hydrology

5.3.1 Regional North Piceance Basin

The first encountered ground water in the RDD Lease area is approximately 250 ft below ground surface in the Uinta Formation. Ground water flow is not influenced by topography and the potentiometric down-gradient direction is uniformly to the northeast. Additionally, there is no alluvial ground water as the RDD site is located near the top of the local drainage divide and floored by weathered sandstone/siltstone bedrock.

The general ground water flow pattern is from the outer perimeter of the basin, where most recharge occurs, toward the center of the basin where there is discharge to the perennial streams, more active evapotranspiration, and a greater frequency of springs (see Figure 14).

A generalized stratigraphic and hydrostratigraphic section (Figure 6) shows the sodium lease monitoring intervals. A conceptual cross-section through the Piceance Basin (Figure 14 and Figure 15) demonstrates the relations between flow and discharge.

With increasing depth, the principal hydrogeologic units are stream alluvium "shoestring" aquifers, the Uinta Formation, upper Green River Formation above the R5 zone, lower Green River Formation below the R5, and the Wasatch Formation below the Garden Gulch Illite Zone. For engineering purposes, Shell has divided the upper and lower Green River Formation into additional hydrostratigraphic water bearing intervals. As noted previously, very low permeabilities and no free water characterize the lower portion of the Green River Formation consisting of the Lower Parachute Creek and Garden Gulch members. In addition, the upper Wasatch is thought to be of relatively low permeability and not able to transmit much water in the project area. Given that the EAST RDD and ELHT will be conducted in the lower portion of the Green River Formation where producible water is known to be absent, and there is substantial thickness of impermeable formation above (180-200 ft) and below (200 ft) the test intervals, communication of pyrolysis products generated during heating to either the overlying or underlying hydrostratigraphic zones is not expected.

Stream alluvium has relatively high hydraulic conductivity, is of limited extent, and exists only below and adjacent to perennial and ephemeral stream channels. The Uinta Formation extends downward generally from ground surface and is moderately transmissive due to its large saturated thickness. At the basin scale, the Uinta is conceptualized as an unconfined aquifer, with stratigraphic heterogeneity that imparts varying degrees of confinement to the deeper strata. "Tongues" of low permeability, kerogen-bearing strata exist in the lower portion of the Uinta and these provide confinement to underlying stratigraphic units and water-bearing intervals (WBIs).

Anisotropic flow conditions, which have been observed from pumping tests performed mostly in the western portion of the Basin, are projected for the East RDD Pilot area based on the strongly correlative nature of the individual beds across the basin. Marlstones of the Parachute Creek Member generally have low primary intergranular porosity. Unfractured oil shale has very low permeability. In the Upper Parachute Creek Group, secondary porosity features are dominated by fractures. In the Lower Parachute Creek Group, secondary porosity is dominated by sodium mineral dissolution features (vugs and collapse breccia). Nearly all ground water in the Green River Formation flows through the secondary porosity fractures and dissolution/collapse features as the fine-grained porous matrix is nearly impermeable. The lean zones tend to be more brittle, contain a higher degree of fracturing, and are thus much more permeable than the rich zones. As a consequence, the Green River Formation is conceptualized as a sequence of relatively transmissive lean zones, which are each confined by overlying and underlying rich zones having very low permeability. Shell has conducted extensive hydraulic testing to define the hydrostratigraphic zones, which do not always correspond with the traditional lithologic rich and lean zones (shown in Figure 6). Hydrostratigraphic seal zone R5 appears to operate regionally as a highly confining unit and this is reflected in the tendency for a large hydraulic head difference in WBIs above and below the hydrostratigraphic R5 in the region that is northwest of the East RDD Lease where the L4 and L3 units exist due to nahcolite dissolution. In addition in the extreme southwest East PRL, Yellow Creek, PRL and North PRL areas, groundwater chemistry in lean zones below the R5 differs markedly from the groundwater chemistry in WBIs higher in the stratigraphic sequence, with zones below the hydrostratigraphic R5 having much higher TDS and associated trace elements.

Based on field evidence from the Horse Draw mine and from cores collected from wells installed on or near the EAST RDD lease, the Saline Zone and the Illite Zone of the Garden Gulch Formation do not contain producible water and are considered by Shell to be hydrostratigraphic "seal" or no-flow zones.

5.3.2 East RDD Area

Multiple water level measurements have been obtained from the wells in the area (Figure 16). Figure 17 through Figure 22 show the density and temperature corrected potentiometric ground water contours of the shallowest to deepest WBIs of the Uinta through L3, respectively. The L3, which exists only in the extreme southwest portion of the East PRL, and the L4 WBIs have been corrected to fresh water equivalents using a reference point at the base of the L5 WBI so that the potentiometric surfaces can be compared to the L5 and above WBIs with respect to the potential for up flow or down flow across the regional R5 "seal." The Dissolution Surface affects ground water elevations with the extreme flattening of the contours coincident with where the base of the L4 WBI intersects this surface (Figure 21). Comparing Figures 20 and 21, an approximate 60 ft downward vertical gradient is evident between the L5 and L4 WBIs.

5.4 Ground Water Quality

5.4.1 Regional Ground Water Quality

Shell has been measuring ground water quality in Piceance Basin wells for about 10 years. Several wells were drilled on a single well pad into any or all of the water bearing intervals of the Uinta, L7, L6, L5, L4, and L3 zones. On Shell's Mahogany Fee property in the western Piceance Basin, east of Cathedral Bluffs, wells were drilled starting in 2001. Starting in 2005, Shell drilled wells on more than 30 additional pads in and near the three PRL areas associated with the three RDD sites; these sites comprise a northwesterly trending region between Duck Creek on the north and

Black Sulfur Creek on the south. Each well was sampled at least 6 times, usually on a quarterly basis, and some have been sampled quarterly for more than two years.

Ground water wells were sampled for a broad range of analytes, including at least one sample each of the full suite of regulated organics, numerous analyses of all regulated inorganics and major elements, and a single set of isotopic measurements for both stable and radiogenic isotopes including C, O, H, S, B, Sr, and radiogenic Cl. As a result of these studies, Shell has an excellent foundation to interpret the ground water chemistry.

Native ground water composition is affected most significantly by three processes: (1) nahcolite dissolution in most areas of the basin, but most evidently near the Saline Zone boundaries, (2) halite dissolution in areas mostly near basin center and downgradient, and (3) iron sulfide dissolution in shallow Uinta ground water and shallow Parachute Creek Member ground water mostly in the headwaters where the Parachute Creek is exposed. Mineral dissolution has released constituents to ground water in quantities that in some cases cause ambient ground water to exceed standards (TVS).[3] Nahcolite apparently contains trace quantities of arsenic (As), barium (Ba), boron (B), and fluoride (F); halite releases chloride (Cl); and the oxidation of iron sulfides increases sulfate concentrations. The dissolution of nahcolite and halite also has led to TDS concentrations that in some cases exceed 10,000 mg/L, which is the value below which ground water is defined by EPA as an underground source of drinking water (USDW).

The causes for concentrations in excess of ground water use standards are local and native. Industrial or other developments that could affect ground water composition are not present in the immediate area. Hence, the water chemistry as measured is considered to reflect native ground water quality. Gas drilling is prevalent in the region, and might be considered a potential source for excursions of ground water chemistry. However, based on the following observations, there is no evidence for such effects:

1. Gas wells are cased and cemented to protect water quality of shallow aquifers and to contain and thereby collect the products. Leaks or poor cementing jobs would be reflected routinely in pressure readings at these wells and, presumably, the problems would be addressed appropriately.
2. The composition of ground water in the Green River deposits is explained best by dissolution of minerals within that formation (see next section); there are no measurements that indicate external sources for the water chemistry.
3. Elevated concentrations of organic constituents that could indicate a deeper hydrocarbon source have been observed only rarely in some of the Shell hydrology wells; these are rare, and only a few have been measured in the same well more than one time.
4. Elevated concentrations of the same key regulated constituents that tend to exceed water quality standards have been reported in measurements dating to the 1970s, before gas drilling was as widespread as at present. These observations together, along with the

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[3] Table value standards are taken from Colorado Water Quality Control Commission Regulation 41, Basic Standards for Ground Water, 5 CCR 1002-41. Applicable use standards include domestic and agriculture uses.

geochemical assessment of Shell and other available water chemistry data for the basin, lead us to conclude that the water chemistry as reported is natural, and unaffected by anthropogenic features.

Oil and gas well drilling impacts on ground water, if any, are not evident. The Ca Tract, an underground oil shale retort that operated in the 1980s, lies well north of the East RDD Pilot location, and across the flow gradient, so could have no effects at the East RDD site, a deduction supported by Shell's ground water sampling.

5.4.2 East RDD Ground Water Quality

Ground water quality downgradient from the East RDD Pilot has been measured at the 138-4-298 Hydrology Pad. This pad lies at the East RDD permit boundary and will be used to demonstrate compliance with numeric protection limits, as established by the DRMS. Per guidance from the DRMS, these limits will be based on the greater of the constituent's mean concentration plus two standard deviations, or the ground water standard. Water quality has been measured in the Uinta, L7, L6, L5, and L4 water bearing units. An L3 water bearing unit is not present at the East RDD Pilot because the Saline Zone at that location is intact.

Ground water chemistry is controlled most significantly by dissolution of nahcolite in the RDD area. Several regulated constituents that tend regularly to exceed CDPHE ground water table value standards for domestic or agriculture uses appear to be derived from the weathering of pyrite in the shallower WBIs and from the dissolution of nahcolite.

Ground water quality baseline is established with at least 5 quarters of water quality measurements, per MLRB Regulations. The downgradient water quality of each WBI above the East RDD Pilot has been established for a number of wells regionally, and will be established locally prior to leaching and pyrolysis activities. There are currently four quarters of monitoring data for the Uinta, L7, L6, and L5 WBIs at the 138-4-298 hydrology pad. Select constituent water quality data for these monitoring events (Table 5.1) include data only for those parameters that exceed applicable water quality standards. In the L4 WBI, only the fourth quarter sample data are available because the L4 well was deepened after the first three quarterly sampling events. Based on these data and the DRMS criteria, preliminary numeric protection limits are proposed by Shell for constituents that tend to exceed ground water standards in the area of the East RDD (Table 5.2). These data as well as the ground water standards are presented in Table 5.3. As additional sample data are collected (minimum of five quarters), these proposed numeric protection standards will be updated and submitted to the DRMS, and may constitute changes in the proposed numeric protection levels.

The hydrology wells are purged, sampled, and analyzed following industry standard protocols using certified analytical laboratories. This includes the 138-4-298 well cluster and will eventually include the 135-4-298 L4 well, which will be drilled and sampled during the period of permit review. The 135-4-298 L4 well is being installed per the EPA UIC Program to establish baseline close to the proposed leach/pyrolysis pattern, and to serve as an "early warning" well to gauge potential impacts from the project prior to their reaching the 138-4-298 L4 well that is located farther down gradient. At least 5 quarters of baseline water quality will be collected from the 135-L4 well prior to initiation of subsurface activities that might affect native ground water quality.

Ground water analyses conducted by Shell at the MDP[o], MDP[s], MTE/DHT, and MIT projects near Cathedral Bluffs, and at numerous hydrology monitoring wells in the Shell PRL areas show that a number of inorganic compounds regularly exceed table value standards (TVS). These same constituents exceed ground water TVS in the East RDD Project Area (Table 5.1). In the RDD area, the average arsenic concentration exceeds TVS in the L6 WBI. Barium, boron, fluoride, and chloride exceed TVS in the L4 well. Fluoride exceeds TVS in all WBIs except the Uinta. All WBIs except the L4 have <10,000 mg/L TDS, which indicates they meet the criteria for underground sources of drinking water (USDW) under the federal Safe Drinking Water Act.

Values that exceed ground water use for the most restrictive (lowest value) standard for "domestic use", "drinking water use", and "agriculture use", as defined by WQCC Regulation 41, were tabulated for each WBI (Table 5.2). Values that exceed applicable standards are highlighted. The trends evident on this table are consistent with observations from other parts of the basin.

Several inorganic parameters have the potential to be affected by pyrolysis, and several organic compounds are generated by pyrolysis. For monitoring purposes, it is proposed that each of the inorganic parameters be measured directly; whereas the organics are estimated from the indicator organic compounds benzene, toluene, ethylbenzene, and xylene (BTEX). For the inorganic parameters that tend to exceed TVS, Shell proposes a set of alternate numeric protection levels (Table 5.3). For all other regulated inorganics, and for all of the regulated organic constituents, the TVS is expected to apply. These constituents will be monitored for potential WBI impacts.

Table 5.1: Water quality sample data for 138-4-298 pad wells.

Measured Concentrations of Select Constituents in 138-4-298 Pad Wells									
WBI	Sample Date	As (mg/L)	Ba (mg/L)	B (mg/L)	Cl (mg/L)	F (mg/L)	SO_4 (mg/L)	TDS (mg/L)	pH[A] (standard units)
Uinta	3/10/2010	0.0065	0.026	0.12	8	0.4*	**310**	950	7.34
Uinta	6/8/2010	0.0034	0.027	0.13	9	0.3*	**320**	980	7.08
Uinta	8/18/2010	0.003	0.023	0.12	9	0.3*	**300**	1000	6.93
Uinta	11/10/2010	0.0017*	0.023	0.12	9	0.3*	**330**	710	7.31
L7	3/10/2010	0.0095	0.028	0.31	10	**8.6**	188	850	7.88
L7	6/8/2010	0.0054	0.029	0.31	11	**9.2**	175	840	7.54
L7	8/18/2010	0.0046	0.041	0.32	10	**9.1**	148	840	7.77
L7	11/9/2010	0.0034	0.027	0.31	12	**9.6**	163	830	7.78
L6	3/10/2010	**0.0493**	0.202	0.36	10	**18.5**	33	770	8.43
L6	6/8/2010	**0.0277**	0.200	0.37	11	**19.5**	20	710	8.14
L6	8/18/2010	**0.0199**	0.215	0.38	11	**19.5**	23	750	8.34
L6	11/9/2010	**0.0167**	0.205	0.38	14	**19.6**	25	760	8.36
L5	3/10/2010	<0.0005	0.228	0.32	9	**15.8**	<1	710	8.50
L5	6/8/2010	<0.0005	0.217	0.32	10	**16.1**	1*	700	8.22
L5	8/17/2010	<0.0005	0.221	0.32	9	**15.9**	1*	700	9.04
L5	11/9/2010	<0.01	0.008*	0.31	9	**16.2**	2	700	8.44
L4	11/10/2010	<0.01	**6.51**	**8.5**	**310**	**55**	<10	45000	7.61
Ground Water Standard		**0.01**	**2.0**	**5.0 [C]**	**250**	**2**	**250**	**1.25 X Background**	**6.5 - 8.5**

Notes:

[A] Field measurement

[B] Specific conductivity not regulated

[C] Non-agriculture standard applicable due to absence of sensitive crops

Bold values exceed agriculture, drinking water, or domestic use ground water standards

* value < Practical Quantitation Limit and > Method Detection Limit

Table 5.2: Baseline ground water quality concentrations for regulated constituents that tend to exceed most restrictive ground water standard for agriculture or domestic water uses. All other regulated constituents meet ground water standards.

Measured Concentrations of Key Inorganic Constituents at NE Lease Boundary

East RDD Point of Compliance Wells - Well Pad 138-4-298

MEAN CONCENTRATIONS (mg/L)

WBI	As	Ba	B	Cl	F	SO_4	TDS
UT	0.0037	0.025	0.123	8.8	0.0	**315**	910
L-7	0.0057	0.031	0.313	10.8	**9.1**	169	840
L-6	**0.0284**	0.21	0.37	11.5	**19.3**	25	748
L-5	0	0.17	0.32	9.3	**16.0**	0.5	703
L-4[A]	0	**6.51**	**8.5**	**310**	**55.0**	0	45000

MEAN + 2 STANDARD DEVIATIONS (mg/L)

WBI	As	Ba	B	Cl	F	SO_4	TDS
UT	0.0085	0.029	0.133	9.8	0.0	**341**	1180
L-7	**0.0110**	0.044	0.323	12.7	**9.9**	203	856
L-6	**0.0578**	0.22	0.39	15.0	**20.3**	36	800
L-5	0	0.39	0.33	10.3	**16.4**	2.5	713
L-4[A]	0	**6.51**	**8.5**	**310**	**55.0**	0	45000
Groundwater Standard	**0.01**	**2.0**	**5.0 [B]**	**250**	**2**	**250**	**1.25 X Background**

Notes

[A] Only one quarter of sample data available for L-4 well

[B] Non-agriculture boron standard applicable due to absence of sensitive crops

Zero values are below laboratory detection limits

Highlighted **bold** values exceed groundwater standards

Table 5.3: Ground water numeric protection limits proposed for East RDD based on baseline ground water quality data.

Proposed Numeric Protection Limits - East RDD Pilot Site							
	CONCENTRATIONS (mg/L)						
WBI	As	Ba	B	Cl	F	SO_4	TDS
UT	**0.01**	**2.0**	**5.0**	**250**	**2**	341	1138
L-7	0.0110	**2.0**	**5.0**	**250**	9.9	**250**	1050
L-6	0.0578	**2.0**	**5.0**	**250**	20.3	**250**	934
L-5	**0.01**	**2.0**	**5.0**	**250**	16.4	**250**	878
L-4	**0.01**	6.51	8.5	310	55.0	**250**	56250

Notes

TDS values based on 138-4-298 mean concentrations X 1.25

Other constituent values equal to the greater of either 1) 138-4-298 mean + 2 standard deviations of measured values (highlighted values) or 2) ground water standard **(bold values)**

5.5 Ground Water Monitoring and Response

As a means to avoid impacts to the WBIs during East RDD Pilot leaching, pyrolysis, and reclamation activities, as well as the ELHT activity, both pilots will rely on natural geologic containment of the impermeable Saline Zone below the Dissolution Surface, the impermeable Garden Gulch Illite Zone, and on verified cementing of well casings. The leaching and pyrolysis interval will be open hole completion. The annular space above the open hole section will be cased and grouted with cement to provide isolation to the overlying water bearing intervals. The casing of each well is to be pressure tested to assure casing integrity and cement bond logs and/or isolation scanner logs will be conducted to assure proper cementing, and reservoir containment relative to the overlying L4 WBI. The leaching wells, heater wells, and reclamation wells will be monitored for down hole and surface pressure and temperature with data recording. Any incident having the potential to impact the WBIs will be detected with the pressure and temperature monitoring. If monitoring detects unexpected changes, Shell will investigate, develop appropriate monitoring or response plans, and take appropriate actions as approved by the agencies. Response plans may include items such as a risk and impact assessment, ground water WBI assessment, monitoring plans, or remediation plans, as necessary.

For the East RDD, although a breach of containment is unlikely due to the low pressure that is to be maintained in the reservoir during leaching and pyrolysis, a breach if encountered would first affect the L4 WBI, which is the first WBI above the Dissolution Surface. Upward advance to any higher WBI is highly unlikely as the hydraulic gradient is downward from all succeeding aquifers above the L4. For that reason the L4 is targeted for additional monitoring. An L4 monitoring well is to be drilled approximately 60 ft downgradient (northeasterly) of the Pilot in early 2011, and at least 5 quarters of baseline data will be gathered and submitted to the agencies prior to any activities that might affect ground water quality. Owing to the location of this well closer to the leach and heater pattern, any effect on ground water would be detected earlier in this well than the 138-4-298 L4 well.

In addition to the pressure and temperature monitoring in the various Pilot wells, Shell will monitor water quality quarterly at the down-gradient 138-4-298 Pad compliance wells during Pilot activities, quarterly for one year after Pilot activities, and annually for two additional years to assure no ground water impacts.

For the ELHT, the primary focus of the test will to evaluate the tendency for hotspots to form along the heater. The three heated intervals are widely spaced to prevent superpositioning and production rates will occur only as necessary to relieve internal pressure. Given the significant over burden pressures exerted by the rock, the lack of superpositioning of the heaters and the management of pressure by flow from the heater wells and the inclined observer/producer well, the risk of any containment breach is considered negligible. By design, the location of the heated intervals for the ELHT is located upgradient of the 138-4-298 well pattern. As such, the 138-4-298 well pad and specifically the L-4 well as well as the 135-4-298-L4 well associated with the East RDD will also provide appropriate monitoring for the ELHT.

5.6 General Vegetation

The East RDD Pilot site and surrounding areas were surveyed in July of 2009 for non-native, invasive plant species (noxious weeds) and threatened or endangered, candidate, and BLM sensitive plant species. A copy of the survey report has been provided to BLM in past correspondence. There are no threatened, endangered or candidate or BLM sensitive plant species on the East RDD Pilot properties or nearby.

Three principal vegetation types occur within the East RDD Pilot site: Sagebrush shrubland type, Pinyon-Juniper Woodland type, and a Disturbed Land type. The sagebrush scrubland type consists primarily of Wyoming big sagebrush as the dominant shrub with several variations of cover, understory, and production. The type is a rolling loam ecological site on Bar D Mesa occurring primarily on the Forelle and Yamac loam soils.

The Pinyon-Juniper woodland type consists primarily of a mix of pinyon pine and Utah juniper trees with differences in tree cover and understory composition. The type is a Pinyon/Juniper woodland ecological site occurring primarily on the Rentsac channery loam soil. Areas within this type occur on the Forelle and Yamac loam soils on which pinyon and juniper trees have encroached into the adjoining sagebrush shrublands.

The Disturbed Lands type consists of several large disturbances from a major pipeline right-of-way (ROW) crossing the southern portion of the tract and from a Colorado State University (CSU) research site situated within the tract. The pipeline ROW has been reclaimed with a vegetation cover primarily of native and introduced grasses with scattered occurrences of forbs and shrubs.

The CSU research site has numerous small disturbances that are in various stages of plant succession. Many small plots occur within the research site, which appear to have been seeded with native or introduced reclamation species or both or have been allowed to naturally re-vegetate by species from adjacent areas.

5.6.1 Special Status Plant Species (T&E, Candidate, and BLM sensitive species)

The 2009 vegetation survey included a search for the presence of plants federally listed as Threatened or Endangered, Candidate species for federal listing, and BLM sensitive plant species. Special Status Species (SSS) that occur within or near areas managed by the BLM White River Field Office consist of the following:

Federally listed T&E plant species:

Dudley Bluffs bladderpod (*Lesquerella congesta*)

Dudley Bluffs twinpod (*Physaria obcordata*)

Ute ladies' tresses orchid (*Spiranthes diluvialis*)

Candidate species:

White River penstemon (*Penstemon scariosus var. albifluvis*)

BLM sensitive plant species:

- Debris milkvetch (*Astragalus detritalis*)
- Dúchense milkvetch (*Astragalus duchesne*)
- Park rockcress (*Boechera fernaldiana var. fernaldiana*)
- Tufted cryptanth (*Cryptantha caespitosa*)
- Rollins cryptanth (*Cryptantha rollinsii*)
- Ephedra buckwheat (*Eriogonum ephedroides*)
- Utah gentian (*Gentianella tortuosa*)
- Narrow-stem gilia (*Gilia stenothyrsa*)
- Piceance bladderpod (*Lesquerella parviflora*)
- Narrow-leaf evening primrose (*Oenothera acutissima*)
- Graham beardtongue (*Penstemon grahamii*)

None of the plant species listed above were observed within or near the East RDD Pilot site during the 2009 plant survey. In addition, no occurrences of any of the listed plant species have been documented on Bar D Mesa, the local geographic landform upon which the East RDD Pilot site is located. The nearest documented occurrence of any special status species are the Dudley Bluffs bladderpod and the Dudley Bluffs twinpod. Both of these species have been observed within the Ryan Gulch ACEC (BLM Area of Critical Environmental Concern) located approximately 4.25 miles east of the lease tract.

5.6.2 Invasive, Non-Native Plant Species (Noxious Weeds)

The 2009 vegetation survey included a field survey for Colorado noxious weed species. No noxious weed species from the Colorado noxious weed "List A" or "List B" were observed within the area surveyed. Common mullein (*Verbascum thapsus*), a "List C" Colorado noxious weed, is scattered within the CSU test plot area on the east side of the lease tract. Cheatgrass (*Bromus tectorum*) occurs within a few of the CSU test plots and within areas of the pipeline ROW situated near the southern boundary of the lease tract. For the most part, cheatgrass is absent from the undisturbed native plant communities on and around the lease tract.

5.7 Project Activities and Vegetation

Disturbances to vegetation during site development work could result in increased soil erosion, and will increase the potential for the growth of undesirable plant species and indirect impacts to wildlife resulting from a temporary reduction in habitat, until successful reclamation of disturbed areas is achieved following project closure. Timely interim reclamation of areas no longer needed for project-related activities, e.g. construction staging and laydown areas, is planned to reduce the impacts of site development. In addition, Shell's area-wide weed control program, which actively identifies then eliminates undesirable plants, will be implemented on the East RDD to help minimize impacts associated with the growth of noxious weeds or otherwise undesirable plants on cleared areas.

Impacts to special status plant species are not expected from project-related activities because no special status species were observed within or near the project site during the 2009 vegetation survey and no potential habitats for special status species were observed. Special status species within the Piceance Basin occur on relatively sparsely vegetated barrens of the Green River Formation; soils within the survey area are for the most part well-developed loams and sandy loams on gentle slopes. Green River Formation shale barrens do not occur within the survey area; Uinta Formation derived soils cover all of the local area, and these are not known to support any of the special status plant species identified within or near areas managed by the BLM White River Field Office.

6A. IN SITU DEVELOPMENT PLAN – EAST RDD

6A.1 Development Sequence

The East RDD Pilot (Figure 36) is to be developed in the nahcolitic oil shale section to earn Shell the exclusive right to convert the 149 acre RDD lease to a commercial oil shale lease of ±5,120 contiguous acres upon demonstration of "production in commercial quantities" and payment of a bonus based on Fair Market Value (FMV). "Production in commercial quantities" involves the following:

1. Generate sufficient permeability by hot-water leaching of the Saline Zone oil shale section to enable oil generated in the ICP phase to flow and be produced at (pumped from) the producer wells.
2. Demonstrate that ICP heating can be achieved using electric heaters in the Saline Zone at the depths proposed in this POD.
3. Produce a minimum of 1,500 barrels cumulative oil at a peak rate of greater than 10 barrels of oil per day (bopd) as defined in the Plan of Operations.

Achievement of the above thresholds requires two key project phases: the first to remove nahcolite via hot water solution mining (Figure 23) and the second deploying electric heaters to pyrolyze the leached oil shale (Figure 24). Overall Pilot development will proceed in the following stages:

1. Drilling
2. Nahcolite leaching
3. Pyrolysis (kerogen heating by ICP to produce hydrocarbons) and Production
4. Subsurface reclamation
5. Surface reclamation.

6A.2 Development Details

6A.2.1 Drilling

The RDD well pattern (Figure 25) comprises 13 heaters, 2 producers, and 6 observer wells. Several wells will be converted for dual use. All wells will be drilled, cased, and cemented prior to leaching and ICP activities. Drilling is expected to require 6 or more months.

Well heads will be converted on several wells to serve more than one purpose. The SAW-1 well, a geology appraisal well drilled in 2009, will be converted to an observer well outside the heater pattern (Figure 25). The leach well will be converted to a heater well. Two of the internal observation wells may be used for leaching if the leach front proves to be significantly anisotropic. Two or more of the heater wells may be converted for water injection following the ICP phase. The two producer wells and several heater or producer wells may be converted for recovery of steam and volatiles for the subsurface reclamation phase. Well specifications are discussed in Section 6.4.

Five hydrology monitoring wells were installed in 2009 in the northeast quadrant of the RDD Lease. These wells are being currently monitored to assess baseline water quality in the near downgradient area. An additional ground water monitor well will be drilled near the East RDD Pilot pattern, ~ 60 ft NE of the pattern. Elsewhere in the basin, Shell has drilled, tested, and sampled a considerable number of hydrology wells. These are discussed in the sections on hydrology and baseline water chemistry in this POD.

6A.2.2 Nahcolite Leaching

Nahcolite leaching facilities include an electric heater to heat fresh water, a leach well with a single tube to deliver the hot water to the reservoir and a second tube to retrieve the water, and a nitrogen blanket to help retain hot solutions in the reservoir below the casing shoe (Figure 27). Solutions will be routed to an oil/gas/water separator, as a precaution to sequester ambient gases (methane and CO_2) which are present already in the formation at ambient formation pressures.

Leach water is heated because even though nahcolite is leachable in cold water, the rate of dissolution increases significantly in hot water. Nahcolite is mined in the Piceance Basin by injection of hot water into nahcolitic formations, sometimes under pressure, and pumping the leachate to surface facilities. A similar process will be initiated at the East RDD Pilot in order to generate permeable pathways for the subsequent movement and recovery of liquid hydrocarbons from producer wells.

The nahcolite leach well is to be situated in the center of the RDD well pattern (Figure 25). (This central leach well will be converted to a heater well after leaching.) Initially, fresh water imported to the site will be circulated into the leach well to initiate water circulation. Later, water will be heated in the surface facilities and circulated to conduct nahcolite leaching (Figure 27). This water once heated will be injected into the zone of interest such that leaching is focused primarily on the TI bed. Leaching is expected to take 6 or more months.

Leaching will focus on the TI bed, with much less recovery anticipated from the Greeno bed and other nahcolite bearing units. Nahcolite solution will be recovered at the surface, transferred to holding tanks until sufficient volume is accumulated so that it may be loaded onto trucks for off-site transport. Owing to the small volume, the nahcolite solution will be disposed at an approved facility.

Following the leaching phase, the leaching well will be converted to a heater well. A construction period of approximately 5 or more months is expected to follow the leaching phase prior to initiation of the pyrolysis phase.

6A.2.3 Pyrolysis and Production

Pyrolysis facilities will include a set of electric heaters to heat the formation to convert kerogen into oil and gas and one to two producing wells (Figure 28). Each heater will be installed inside a sealed canister. Water will be released from the kerogen during the heating process. Oil and water will be pumped via the producer wells to the separator; the gases will flow in response to pressure generated as they form. At the surface, the gases will be flared, and the oil and water will be recovered from the separator and trucked off site. Diluent and fresh makeup water will be added at the surface to assist in the production of bitumen which will form during the lower temperature phases of pyrolysis.

ICP involves the gradual heating of the formation using electric heaters inserted into heater wells to gradually heat the rock over a period of time. Kerogen in oil shale converts to oil, gas, water, and coke beginning at temperatures of ~550 °F. The reaction is strongly temperature dependent, i.e. at 550 °F it takes several years for completion but only a few days at 650 °F. The produced oil is relatively light in API gravity, and after hydro-treating to remove nitrogen and other heteroatoms, it is easily refined to finished products.

The liquid hydrocarbons will be recovered at surface via two pumping wells. Gases will be separated from the oil and water, measured, and periodically sampled at the surface facilities. All produced gaseous hydrocarbons will be flared on location. Produced CO_2 and other non-combustibles will be included in the stream of gas sent to the flare and will ultimately be vented. The ICP phase of the East RDD Pilot project is expected to require 2 or more years (Figure 2).

6A.2.4 Subsurface Reclamation

Full details of subsurface reclamation are described in the Subsurface Reclamation Plan Section of this POD. A synopsis follows.

Facilities for subsurface reclamation will consist of an injection well, a production well (for gas capture), and the Separator (Figure 29). As with the pyrolysis phase, the gas from the Separator will be flared. An option exists to pump water and residual oil to the surface, via a pumping well, whereupon it will be routed to the separator. Afterwards, and after the reservoir is cooled to an average temperature below boiling point of water at formation pressure, the voids generated by leaching, pyrolysis and production will be filled with water.

Two options are considered for subsurface reclamation: (1) natural cooling and (2) water-assisted cooling. The option selected for permitting is natural cooling over a multi-year period followed by water injection into the permeable zone that will be generated by leaching and pyrolysis. Both options utilize the same equipment and well constructions. The natural cooling option is used for the reclamation cost estimate. If the water cooling option is selected, then prior to well plugging and abandonment, Shell will file a revised reclamation plan under a Notice of Intent to Abandon (NIA) or Subsequent Report Plug and Abandon (SRA), per BLM Gold Book Standards. For either option, Shell will submit a UIC permit application for injection of water, either for cooling and reservoir filling, or for reservoir cooling alone. It is emphasized that the plans for both options rely on the same well construction designs.

Upon completion of pyrolysis and recovery of liquid hydrocarbons, the pyrolyzed zone will be allowed to cool, either naturally or more quickly by slow injection of water (Figure 29). Subsurface reclamation will be considered complete once the average temperature in the reservoir falls below ~200 °F (i.e., boiling point of water at reservoir conditions). Once below ~200 °F, metal bridge plugs will be placed in each well just above the pyrolyzed reservoir, and wells will be plugged with cement above the bridge plug to approximately 3 ft below the ultimate reclaimed ground surface. Well casings will then be cut 3 or more feet below final ground surface, per BLM Gold Book Standards.

Natural cooling from an average reservoir temperature of 675 °F (Figure 26) will require ~1,000 days (~2½ years). Production of liquid hydrocarbons will continue during the initial cooling period, and continue until liquid hydrocarbons are depleted. Cooling rates are affected (increased) by: production of liquid hydrocarbons which removes thermal mass; convection around the reservoir which is assisted by circulation of ambient gases; and absorption of thermal mass by minerals in the surrounding rock, particularly nahcolite and dawsonite which have high heat capacities.

The time required for reservoir cooling can be reduced by adding water to the warm reservoir. At the depths projected for the RDD project, water injected into a reservoir above 200 °F will flash to steam if collection is done at a sufficiently low pressure. Hence, a steam collection system consisting of existing piping and surface facilities (separator) will be employed if water is used to cool the reservoir. The reclamation cost estimate anticipates natural cooling over a 2½ year period followed by filling the pyrolyzed and leached volume with water.

6A.2.5 Surface Reclamation

Surface reclamation will be completed to return the disturbed site to a beneficial post-mining land use. A synopsis of the surface reclamation plan follows. Details may be found in the Reclamation section of this POD.

After the reservoir cools, in-well equipment will be removed where feasible, and casings will be cut a minimum of 3 ft below the ground surface level projected after surface grading. Surface equipment not needed for steam recovery and oil water separation may be removed prior to or after decommissioning of the wells. Once all facilities are removed, concrete structures will be crushed on site, rebar will be removed and properly disposed off site, and concrete will be distributed evenly amongst the subsoil. Fill and cuts will be restored to approximate original contours, packed earth will be scarified, topsoil will be re-applied evenly, and the area will be re-seeded with the BLM-approved seed mix of native species.

6A.3 Size, Location, Schematics of Structures, Facilities

6A.3.1 Surface Facilities Descriptions

Surface facilities (Figure 36) include the buildings, equipment pads, liquids loading and unloading features, electrical infrastructure, tankage, wells, conveyance lines, flare, access infrastructure and other supporting features for the Pilot operation. Additional materials information is provided in the Reclamation Cost Estimate section. All of the operations infrastructure will be inside a security fence (game fence). During operations and reclamation, all access will be controlled by security guards.

For purposes of estimating the reclamation costs, buildings, and facilities with concrete foundations are considered permanent structures. These will be constructed on concrete piers with unitized footers and slab-on-grade construction. Buildings subject to product spillage have concrete stem walls for secondary containment and corner sumps for spill collection if necessary. Facilities such as the tank farm that are subject to spillage but not built on concrete floorings will be bermed and covered with artificial liners to house spills. All secondary containment structures will be sized to contain 110% of the holding capacity of the largest holding structure inside that containment structure.

6A.3.1.1 Electrical Substation

A high voltage substation, to be installed by Shell, will be placed inside the permit boundary, within the game fence. The substation will power all electric needs. The majority of surface equipment will be used in all phases – leaching, pyrolysis, and cooling – with minor variations in the equipment line-up.

Electrical service lines will be placed above ground on cable trays. Each pipe rack foundation will rest on a concrete footer.

6A.3.1.2 Control Building & DCS/MCC

The Distributed Control System (DCS) and the Motor Control Center (MCC) comprise the equipment and controls for the project facilities that occupy ~25 ft x 50 ft space. The DCS generally provides for on-site and remote monitoring and operation by more than one Operator from more than one location. [4] During operations, the DCS will be manned from the Control Room by on-site field operators who will monitor and control the facilities for operational purposes. For research purposes and technical oversight, the facility may be monitored from remote locations by researchers, operators, or others who can be in contact with field operators and other employees and contractors.

6A.3.1.3 Heater Shelter

The Heater Shelter will provide a protective shelter for the heater skid for nahcolite leaching. The concrete floor will be tied into stem walls and a corner sump. Shelter foundation is to be 50 ft x 14 ft.

6A.3.1.4 Electrical/ Instrument Building (EIB)

The Electrical/ Instrument Building (EIB) will house the transformers and controllers for the downhole electric heaters. Building exterior foundation is to be 40 ft x 20 ft.

6A.3.1.5 Separator Building

The Separator Building is to contain two separators discussed above with associated piping and instrumentation. The building will rest on a concrete floor with overflow containment capacity

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[4] Shell has employed a DCS for several years at the Freeze Wall Test (FWT) to monitor activities at that facility.

and a floor collection sump. The dual separators will provide flexibility in operations and testing. The separators will be used during leaching to capture native bitumen from the formation (not from ICP pyrolysis), during pyrolysis to separate the gas, oil and liquid streams, and during reclamation to capture residual gases. The foundation size is 20 ft x 50 ft.

6A.3.1.6 Pump Building

The Pump Building will shelter all pumps used in the process. The size is 50 ft x 20 ft.

6A.3.1.7 Tank Battery

The Tank Battery is a concrete floored open pad surrounded by a stem wall sized to contain 110% of the largest tank volume. The size is 120 ft x 55 ft.

6A.3.1.8 Flare Stack

The Flare Stack will be approximately 50 ft tall x 4 in. diameter with igniters and instruments. The Stack will be set a minimum of 150 ft from facilities, except the flare access road. A negative sloped flare line will run on an elevated line from the separator building to the flare stack.

6A.3.2 Surface Equipment Summary- Leaching Phase

6A.3.2.1 HX-202 and 203

The HX-202 and HX-203 are fin fan coolers that will be used during the leach phase to cool nahcolite leach solutions for safe effluent handling.

6A.3.2.2 Separators SEP 202 and 203

During the leaching phase, the Separators will separate gases from the liquids produced from the leach well. These will include CO_2 derived from the dissolution of nahcolite plus native CO_2, methane and any other gases that are present in the formations. The presence of two separators provides an extra measure of flexibility and redundancy. Gases separated during the leaching process will be routed to the flare for incineration.

6A.3.2.3 Pumps and Pump Building

All liquids at the surface will be transferred among various tanks, vessels, and trucks via pumps. Pump capacities and compositions are determined by the services required including water injection, produced fluid transfer, produced fluid loading (to trucks), fresh water unloading (from trucks), fresh water transfer and circulation, and flare drum recycle. All pumps will be controlled from the pump building.

6A.3.2.4 Tanks

Tankage is required for storage and transfer of the fresh water for make-up and the nahcolite laden produced water during the leach process. Tanks will be emptied when filled such that tank storage is limited to interim holding periods in the overall material transfer process.

6A.3.2.5 Flare

The flare stack, which is continuously lit, will vent CO_2 separated from the produced fluids in the separators discussed above. Free methane that is captured from the formation, prior to methane generation by pyrolysis, also will be incinerated at the flare.

6A.3.2.6 Tank Vent

Because storage tanks operate at pressures slightly higher than atmospheric, gas buildups in the vapor space need to be vented. Tank pressures will be too low to route tank gases to the flare.

6A.3.3 Surface Equipment Summary- Pyrolysis Phase

6A.3.3.1 Electric Heaters

Down hole heaters will heat the kerogen, converting it to oil and gas. This heater power and control will be supplied from the EIB, which itself is to receive power from the high voltage substation.

6A.3.3.2 HX-202 and 203

The HX-202 & 203 coolers will be used to cool the hot production stream from the wells during the pyrolysis phase.

6A.3.3.3 Separators SEP 202 and 203

The separators used in the leach phase will continue to operate during pyrolysis to separate oil, water, and vapor from the production wells. The gas will be routed to the flare.

6A.3.3.4 Pumps

The pumps may have multiple services. During pyrolysis, pump services will be used primarily for water injection, and for produced fluid loading to trucks (oil and water) and flare drum recycle. These pumps also may be used to inject diluents, scale inhibitors, corrosion inhibitors, tracer chemicals, or other chemicals into the wells. (See chemical inventory list and uses.)

6A.3.3.5 Tanks

Tankage is required for storage and handling of produced oil and water, and storage of fresh water. Tanks also may be used to store diluents and other fluids.

6A.3.3.6 Flare

The flare stack will incinerate the hydrocarbon gases from the production separators discussed above. Produced non-flammable gases (chiefly CO_2) will also be routed to the flare where they will be vented to the atmosphere. The quantities of total emissions are to be well below thresholds where controls are required, and will be regulated under an air permit from the Air Pollution Control Division of CDPHE. The flare will be operated continuously by a pilot light.

6A.3.3.7 Tank Vent

Storage tanks will operate at slightly more than atmospheric pressure during pyrolysis. Buildups in the vapor space will be vented. Liquids stored in these tanks pass first through the separators at temperatures well above ambient air temperature. Under those conditions, volatility of the produced liquids will be higher than at cooler temperatures, so most of the gases will report to the gas phase of the separator. Volatility of the produced liquids at the lower (atmospheric) temperatures in the tanks will be minimal, so the volume of vapor in the tanks will be small. The transfer of liquids to truck tanks for transport will be done under safe working conditions, based on site-wide Shell safety standards, with adequate procedures for worker safety and environmental protection.

6A.3.4 Surface Equipment Summary- Reclamation Phase

6A.3.4.1 HX-202 and 203

These coolers will cool the stream from the production wells during reclamation.

6A.3.4.2 Separators SEP 202 and 203

Separators will separate oil, water, and gas from the production wells. The gas will be routed to the flare. As water is added and reclamation progresses, the production of hydrocarbons, steam and CO_2 to the surface will diminish. Eventually as temperature falls, only water will be produced from the wells.

6A.3.4.3 Pumps

Pump services include primarily water injection, produced fluid loading to trucks (oil and water), and flare drum recycle.

6A.3.4.4 Tanks

Tankage is required for storage and handling of produced oil and water, and storage of water.

6A.3.4.5 Flare

The flare stack will incinerate the hydrocarbon gases from the production separators discussed above. Initially during the reclamation phase, some hydrocarbon gases are expected which will be flared. As reservoir temperatures cool, production of hydrocarbon gases and CO_2 are expected to rapidly decrease. The flare will be operated continuously by a pilot light, until such time that it is clear that no additional hydrocarbons will be produced and the pilot light will be extinguished.

6A.3.4.6 Tank Vent

Storage tanks operate at slightly more than atmospheric pressure. Any buildup in the vapor space will need to be vented. The pressure will be insufficient to be routed to the flare, so a vent will be used. Tank venting will be minimal at this point, perhaps limited to "breathing" due to fluctuations in daily temperatures.

6A.4 Well Construction

6A.4.1 General

The RDD Pilot utilizes five types of wells (see well construction diagrams, Figures 31-34):

- Ground water monitoring
- Leach / heater
- Heater
- Producer
- Observer.

A set of downgradient ground water monitoring wells (Pad 138-5-298) were drilled in 2009-2010. This pad includes one well each in the Uinta, L7, L6, L5, and L4 hydrostratigraphic units, and monitoring from these wells is ongoing.

Specifications for each well type are discussed in the sections following. Table 6A.1 lists the specifications for each well. Specifications listed are intended generally to provide for cement mixes to withstand both the composition (high salinity) and/or sulfate content of the wells plus the temperature fluctuations that will act on the casings and cement. Dimensions provided are for maximum pipe (casing) and drilled well dimensions, and may be decreased if feasible. Annular spaces may vary.

Table 6A.1: Well Specifications

	Casing Depths (ft)		Casing Description	Cement Design	Cement Installation Method
HEATER	Surface	60 ft	10¾", 40.5 #, H-40, STC ID:10.05"	Premium Plus + 28.5% SSA-1 11.5ppg	Cement annulus via tremmie pipe
HEATER	Intermediate	2,142 ft	7-5/8", 26.4# , J-55, STC ID: 6.969"	Premium Plus + 60% SSA-1 + 5% salt + 0.30% FWCA (11.5ppg Lead, 13.5 ppg Tail)	Mud flush, water flush, cement & displace by one plug system is used to pump cement job. Pump cement to surface.
HEATER	Canister	2,257 ft	4½", 11.6#, J-55, LTC. ID:4" + 4½" S-80 + 4", XXH, 347H Canister, Welded	N/A	N/A
LEACH/HEATER	Surface	60 ft	10¾", 40.5 #, H-40, STC	Premium Plus + 28.5% SSA-1 11.5ppg	Cement annulus via tremmie pipe
LEACH/HEATER	Intermediate	2,142 ft	7-5/8", 26.4# , J-55, STC ID: 6.969"	Premium Plus + 60% SSA-1 + 5% salt + 0.30% FWCA (11.5ppg Lead, 13.5 ppg Tail)	Mud flush, water flush, cement and displace by one plug system is used to pump cement job. Pump cement to surface.
LEACH/HEATER	Production	2,257 ft	4½", 11.6#, J-55, LTC. ID:4" + 4½" S-80 + 4", XXH, 347H Canister, Welded	N/A	N/A
PRODUCER	Surface	60 ft	10¾", 40.5 #, H-40, STC	Premium Plus + 28.5% SSA-1 11.5ppg	Cement annulus via tremmie pipe
PRODUCER	Intermediate	2,142 ft	7-5/8", 26.4# , J-55, STC ID: 6.969"	Premium Plus + 60% SSA-1 + 5% salt + 0.30% FWCA (11.5ppg Lead, 13.5 ppg Tail)	Mud flush, water flush, cement & displace by one plug system is used to pump cement job. Pump cement to surface.
PRODUCER	Production	2,320 ft	5½", 23#, L-80, FL4S Liner	N/A	N/A
OBSERVER	Surface	60 ft	7-5/8", 26.4# , J-55, STC ID: 6.969"	Premium Plus + 28.5% SSA-1 11.5ppg	Cement annulus via tremmie pipe
OBSERVER	Intermediate	N/A	N/A	N/A	N/A
OBSERVER	Production	2,280 ft	4½", 11.6#, J-55, LTC ID:4"	Premium Plus + 60% SSA-1 + 5% salt + 0.30% FWCA (11.5ppg Lead, 13.5 ppg Tail)	Mud flush, water flush, cement & displace by one plug system is used to pump cement job. Pump cement to surface.

The project comprises 21 wells for leaching, heating and observation (Figure 24) plus an array of downgradient ground water monitoring wells. Plans call for all wells to be drilled prior to the leaching phase. Wells will be drilled with directional control, with a design deviation from vertical of ~4 ft at 2,000 ft depth (~8 ft diameter). Total depth of the deepest well is projected to be <2,350 ft. The deepest will be the leach well; others will be drilled to ~2,285 ft, and some may be drilled up to 20 ft deeper than their functional depths to accommodate electrical logging tools.

Domestic use water will be transported to the site from outside sources for use in all drilling. This follows Shell's standard drilling methods for drilling in the Piceance Basin. Drilling water typically is supplied from the Meeker, Colorado public water supply. Cuttings and drilling fluids will be routed to an unlined pit or will be collected in portable tanks (frac tanks[5]) and transported to applicable offsite facilities for permanent disposal. Wells will be drilled with air mist and common water well drilling lubricants.

The leaching and heating zone will include leach, heater, hydrocarbon producer, and observer wells. Some wells will contain pressure or temperature sensors. Each will comprise a conductor casing cemented into shallow bedrock and an intermediate casing set at the top of the leaching and pyrolysis zone and cemented in place.

The heater wells form two hexagonal patterns with maximum diameter of 18.5 ft (Figure 25, Figure 30). Two producer wells flank the central heater (leach) well, and six observation wells will monitor temperature during the heating and pyrolysis phases – three inside the heater pattern and three outside.

Geological conditions at the East RDD are very well informed by the recent drilling of Shell appraisal well 135-4-298 (SAW-1 well) and 5 hydrology wells on the 138-4-298 Pad, which is approximately 500 ft northeast of SAW-1. Ground water is expected at about 250 ft depth, based on the water level in well 135-4-298 (SAW-1 well).

Wells drilled by Shell in the Piceance Basin in the past 10 years generally encountered small amounts of gas, particularly in the deeper formations. The gases contain mostly N_2 and CH_4, with lesser volumes of O_2 and CO_2 (Schatzel et al, 1987 [14]). Hydrogen and ammonia may be present. Samples collected in closed containers for up to 125 days contained up to 0.195 cm^3/g of gas.

A sulfur odor often is detected in drilling of Uinta and some of the shallow Parachute Creek wells. Although LEL (lower explosive limit) measurements are checked at all wells during drilling, and even though methane and sulfur gas occur typically, LELs have never been exceeded. When unusual gas levels are encountered, drilling is shut down and the well is allowed to vent.

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5 Frac tank is the generic term for mobile steel storage tanks used to hold liquids. Their typical use is to hold water or proppant for gas well fracturing – hence the name. Frac tanks typically have 21,000-gallon tank capacity for on-site storage of fluids. Also known as: mobile storage tank, portable tank, Baker Tank, Rhino Tank, Rain-for-Rent Tank, E-Tank, and other names. Double wall tanks can be heated for use in cold climates where regular Frac Tanks freeze.

6A.4.2 *Casing Cement Processes*

Surface (conductor) casing will be set in cement by placement of cement directly in the annulus of the conductor or by a tremmie pipe. Conductor casing cement will be Type I/II premium plus cement.

Casing in all other wells will be cemented by displacement. With the displacement method, the intermediate casing is installed to TD then lifted a few feet off bottom to create a fluid pathway between the interior and exterior of the casing. Cement is next applied inside the casing and capped with a wiper plug. Water is then added to the column above the plug, providing weight that drives the cement down the casing and up the annulus until cement returns are observed at the surface.

All wells – heater (leaching) and observers – will be cemented with Premium Plus + 60% SSA-1 (with an 11.5 lbs/gallon (ppg) lead, and a 13.5 ppg tail). Once cement returns are observed at the surface, the cement will be allowed to set for the prescribed setting time (usually 8 hours).

A cement bond log and/or isolation scanner log will be run in all wells after cementing. The cement bond log is an acoustic geophysical measurement that indicates the presence of cement as a measure of the degree of bonding in the annulus between casing and the drilled hole.

6A.4.3 *Conductor Casings*

Conductor casing will be installed at all wells. Conductors for heater (and leach) holes are 14 in., drilled to 40-60 ft depth (more or less depending on depth to bedrock) and penetrating 3 ft minimum into bedrock.

Conductor casings for the heater (leaching) wells will be 10⅝ in. O.D. (40.5 lbs/ft, H-40 Grade steel, STC). Casing will be cemented from T.D. to surface with type I/II neat cement, placed in the annulus via tremmie pipe.

Conductor casings for the observer wells will be 7⅝ in. O.D. (26.4#, J-55, STC steel casing). These also will be drilled to 40-60 ft depth (more or less depending on depth to bedrock) and will penetrate a minimum of 3 ft into bedrock. Casing will be cemented from TD to surface with type I/II premium plus cement, placed in the annulus via a tremmie pipe.

Conductor casing at the SAW-1 well is installed already under separate permit and separate NOI with the MLRB.

6A.4.4 *Leach Well*

The nahcolite dissolution hole (Figure 31) will be drilled through the TI bed with additional depth to accommodate a sump up to ~50 ft deep. The leach well will later be converted to a heater well and upon conversion will become the center of a hexagon of heater wells. Nahcolite leaching will be accomplished by hot water injection via a single tubular and recovery via an adjacent tubular. Depths of the injector and producer tubular will be adjusted periodically to control leaching effectiveness. Potential upward leaching of hot water solutions into the crown will be minimized by a nitrogen blanket, which will be applied at sufficient pressure to inhibit upward movement of the leach fluid.

Drilling will be sequenced as follows. Conductor casing will be installed to ~ 40 - 60 ft depth, as described above, into a 14 in. diameter hole and cemented. A 9⅞ in. hole will be drilled to the top of the leaching and pyrolysis zone; 7⅝ in. casing (26.4#, J-55, LTC) will be placed inside and cemented by displacement to the surface.

The leach well will then be drilled through the base of the TI bed (~2,273 ft), deeper than the heater wells, with additional footage to accommodate logging tools and a cleanout sump. Within this casing, two sets of ~2⅜ in. tubulars will be installed; one set to near the base of the TI bed; the other placed approximately mid-way between the casing shoe and top of TI bed.

Leaching fluids will be injected via the shorter tubular and recovered (pumped) from the longer tubular.

6A.4.5 Heater Wells

Twelve heater wells will encircle the single leaching / heater well in the center of the heater pattern (Figure 25). The Heater well construction (Figure 32) is similar to the dissolution well, but with the addition of a thick wall sealed canister to contain the heater. (The central leach well will be converted to a heater well after leaching.) A packer will be placed inside the casing, just above the shoe so that the well will remain sealed below the packer and shoe.

6A.4.6 Producer Wells

Producer wells (Figure 33) include a 9⅞ in. hole drilled inside the surface casing to top of the heater zone with a 6½ in. open well below with a 5½ in. slotted liner for oil production drilled to TD. The 9⅞ in. hole is cased with 7⅝ in. 26.4# K-55 LTC casing and cemented to surface by cement displacement. A slotted liner will be hung from a liner hanger just above the base the shoe. The 2 ⅜ in. production tubing with an insert pump at the base will be placed in the open hole to near the base of slotted liner, ~ 42 ft above TD. Two strands of ⅛ in. capillary pressure tubes and a wired sensor will be attached to the 2⅜ in. tubing. A diluent string will be strapped also to the producer string.

6A.4.7 Observer Wells

Observer wells (Figure 34) will consist of 4½ in. O.D., 11.6#, J-55, LTC casing, cemented to surface, inside 7⅝ in. 26.4#, J-55 STC conductor casing. The observer well 4½ in. casings will be sealed at the base. Casings may be fit with any of an array of instrumentation to measure temperature, pressure or geomechanical stresses.

6A.4.8 Cuttings and Drill Water Disposal

Cuttings and drill fluids will either be routed to an unlined pit or captured by a "shale shaker" where fluids and cuttings will be segregated and cuttings transported off-site for proper disposal. Drilling fluid, which consists of domestic water mixed with formation water, will report to an unlined pit, under BLM and DRMS approvals.

6A.5 Development Methods, In Situ Methodology

6A.5.1 Operational Phases and Timeline

The East RDD Pilot will span ~ 6½ to 10 years, more or less depending on leaching progress, pyrolysis, and cooling time. Projected project initiation date may be extended depending on the time needed for permitting (Figure 2). The minimum assumes all permitting is approved by 2012; the maximum presumes longer.

6A.5.1.1 Construction and Leaching Phase

The initial drilling and primary construction phase requires ~ 8-10 months. This phase entails drilling of all wells plus construction of all the fluid heating, pumping, and product recovery units. Grading, drainage, road, and most building construction will take place during this initial construction phase.

Nahcolite leaching is expected to take ~8 - 16 months: longer if the target leach rate is lower than expected or if operational issues arise. During the leaching and recovery phase, construction outside the leach and heating well pattern will commence.

Part of the construction to support the heating phase may commence during the leaching phase. Additional time will be needed after the leaching phase to convert the leach well to a heater well, to mount the heaters, and to convert nahcolite solution collection trains to produced water collection from the separator. This construction period is anticipated to take about 6 months after leaching.

6A.5.1.2 Heating Phase

Heating of the 13 heater wells is expected to require ~ 2-years. Heating will be turned off after ~75% of the pyrolysis phase has passed. Heat flow will continue from the high temperature region near the heaters to the lower temperature regions after the heaters are off, enabling pyrolysis effects to reach the entire target resource.

6A.5.1.3 Cooling Phase

Two options are discussed for the cooling phase: natural cooling and water assisted cooling. Natural cooling is modeled to require approximately 1,000 days, while water assisted cooling may take 300 to 450 days, more or less depending on when water injection is initiated (Figure 26). The timelines (Figure 2) assume water assisted cooling.

In the initial part of the cooling phase, some time will be required to retrofit several wells, and activate the steam collection facilities. Facilities constructed and used in earlier phases will be reactivated.

6A.5.2 Development Methods

In selecting a zone to leach and pyrolyze, Shell evaluated geological features of the leach/heater zone and of the crown above the leach/heater zone. The purpose of the leach/heater zone selection is to assure isolation between the leach/heater zone and water-bearing intervals above the crown. This evaluation considered the following:

a. operating conditions
b. crown composition: i.e., thickness and composition of unleached rock between the leach/pyrolysis zone and overlying water-bearing zone; presence of fractures or faults; leaching potential
c. fracture generation potential during production: i.e., potential for the formation of leaching-induced fractures or heating-induced fractures in the crown and in laterally adjacent rock
d. heat induced changes of minerals in the crown: i.e., possible change in structural strength due to heat-induced breakdown of nahcolite especially in the lower crown above heated zone
e. static geomechanical conditions
f. production-induced changes in geomechanical conditions: geomechanical stresses induced by leaching and mass removal and those induced by heating and potential softening of the formation above the leach/pyrolysis zone.

Fresh water for leaching will be trucked to the site. The water will heated to ~ 350-400°F using surface heating facilities, then injected into the leach well and produced to the surface. Some heat loss will occur in transit; the intent is to attain an average reservoir temperature of ~300°F for leaching.[6] Leach progress will be monitored with temperature sensors in the observer wells and pressure sensors in the outer ring of heater wells.

As nahcolite solution moves up the well during production, there is a potential for clogging due to precipitation of nahcolite because of cooling and the pressure decrease in transit. Nahcolite precipitation will be controlled by maintaining concentrations below 15 wt% $NaHCO_3$ (well below nahcolite saturation, which is approximately 30 wt%). Solution concentrations will be monitored regularly at the surface by collecting solution from a bleed valve, measuring conductivity, and deriving TDS concentration by comparison with a pre-determined relationship between conductivity and TDS.

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6 The maximum temperature of 300°F, which is listed in the Commercial Nahcolite Lease, is meant to conserve oil shale resources in that lease. However, the RDD Lease for Oil Shale overrides the temperature limit as the RDD Project anticipates higher temperatures for pyrolysis, and the lease requires the recovery of both hydrocarbons and nahcolite.

The operating conditions for leaching are: (a) water injection temperature of 350°F, (b) average reservoir temperature of ~300°F, (c) reservoir pressure of ~1,310 psig, (d) water circulation rate of ~500 bwpd, (e) nahcolite concentration of the injected water not to exceed 3-4 wt%, and (f) nahcolite concentration of the return (produced) water not to exceed 15 wt%. Part of the produced water will be mixed with fresh water, so the overall production and off-site trucking of solution is expected to be approximately 350 bpd.

Hot water injected into the formation will contact nahcolite in the well and is expected to dissolve nahcolite mostly from the TI Bed. As solution circulates in the open hole, nahcolite in other units is expected to dissolve, and the pregnant solution will be produced through the other deeper tubular. The leach well design accommodates vertical movement of the injection in recovery tubes to effect better leaching.

The potential for upward migration of leach fluid through the crown will be controlled to prevent movement of high TDS solutions into overlying water bearing zones. Upward penetration of the leach fluids will be eliminated by a combination of factors including: (a) composition of strata above the proposed leach zone, which is self-limiting because it does not transmit fractures; (b) well installations and testing, which assure proper and verifiable cementing of all casings that pass through the crown; (c) application of a nitrogen blanket inside the leach well casing and upper part of the leach zone, which will hold leach solutions in the zone below the nitrogen blanket; and (d) pressure controls the leach fluid, which will be held to values below the fracture gradient. These features are clarified in the following paragraphs.

Strata above the Greeno Bed are part of the kerogen-rich R4 unit, which contains less nahcolite than the leach target interval of the Saline Zone. As a result, the potential formation of permeable channels by nahcolite leaching is limited by the low percentage of nahcolite in the supra-Greeno units and the absence of nahcolite to nahcolite connections.

Annular cement between the well and the casing further limits upward fluid migration and escape. Once each casing is installed to the top of the eventual leach/pyrolysis zone, and after the casing is cemented, a cement bond log and/or isolation scanner log will be run and inspected to assure acceptable placement of the cement. Unacceptable cement jobs will be remedied using standard practices. During operations, a nitrogen blanket will applied to the annular space between the well casing and the solution injection and recovery tubes. Nitrogen pressure will be monitored continuously to assure that the nitrogen pressure exceeds formation pressure, such that the leach fluids will move up the return tubing, rather than into the overlying crown. The nitrogen blanket will preclude contact between the circulating solution and the top of the leach reservoir, further limiting the upward migration of solution and possible penetration along the wellbore.

Nitrogen pressures and formation pressures will be monitored and controlled to remain well below the fracture gradient, which is 0.7 psi/ft. The fracture gradient estimates the pressure at each depth that would need to be applied in order to fracture the rock.

Natural fractures in the crown above the leach zone are limited to brittle units. Marlstone units are brittle, and therefore subject to fracturing, while kerogen-rich R zones are resistant to fracturing. This includes the R4 zone which makes up part of the crown. Unlike the high abundance of brittle minerals in marlstone, kerogen has a high organic content, is malleable, and thus tends not to transmit fractures.

Extensive fracture investigations conducted of cores around the East RDD Pilot show very few natural fractures. Detailed visual logs of the cores plus an array of geophysical logs and down hole video logs all fail to detect fracturing or faulting in the kerogen rich units. Fractures do occur in the marlstone rich layers, which are much more brittle. However, the crown is composed of more kerogen-rich rock than marlstone.

The space produced by nahcolite dissolution is projected to be up to ~120 ft in height, with preferential leaching forming a disc-shaped leach zone in the most readily leachable beds (the TI and Greeno beds, plus other thinner nahcolite rich beds having high leachability characteristics). If the leaching front in the TI and Greeno beds migrates preferentially along some preferred direction, the leaching front will be more elliptical. Units immediately above the TI, Greeno, and other highly leachable beds may sag into the open voids created by leaching, and minor brecciation may occur in these beds. The geometry of leached mass will be affected by the variable rates of nahcolite dissolution, which depends on nahcolite richness, morphology, and connectivity between nahcolite segregations. Nahcolite rich layers that are most susceptible to leaching will have larger leach radii than nahcolite poor layers, and leachable layers that best come into contact with the leach solutions will of course leach fastest and have the largest amount of lateral penetration.

The heating volume likely will be more uniform than the leached volume as heat will move through the area more uniformly than the leach water. The principle heat transfer mechanism is conduction. Thermal conductivities of the various minerals are similar, and laterally the layers are compositionally uniform; alternating nahcolitic and marlstone layers are continuous over several miles within the basin. Heating temperatures will increase uniformly and rapidly inside the heating pattern because of superposition of the many heaters; temperatures will increase relatively slowly outside the pattern because of the lack of superposition. The slight differences in thermal conductivities of the major phases – nahcolite, kerogen and dolomite marlstone – will have a minor effect on the radius of heating: heat transfer in kerogen for instance will be less than in marlstone by ~1 ft.

Residual nahcolite inside the heater pattern will convert above ~350°F to soda ash (Na_2CO_3), and give off water (steam) and CO_2[7]. Initially, kerogen will swell as bitumen is generated during the early, lower temperature phase of pyrolysis. With further heating, kerogen conversion will release water and liquid hydrocarbons. The overall geometry of the mass created by the conversions of nahcolite to soda ash and kerogen to hydrocarbons is projected to be a cylinder of ~20 ft radius and less than the heater height, which is 112 ft.

Conservative geomechanics modeling (Appendix A) was conducted to assess integrity of the crown above the leached and pyrolyzed volume, and to assess the risks to containment integrity.

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[7] Steam and CO_2 will report to the gas phase of the separator, at surface where steam will cool to water and CO_2 will be vented.

The risks for containment integrity include potential for active failure and for passive failure: (1) unacceptably high injection pressure during the leaching phase, which could fracture the formation and lead to *active* failure and (2) materials weakened by heating during the pyrolysis phase, which may induce tensile and shear failure in the cavern roof and wall, thus leading to *passive* failure.

The active failure risk for containment during leaching is alleviated by limiting the operating pressure below the fracture gradient of the formation. Fracture gradients have been determined by in-situ stress measurement from several sources (Bredehoeft et al 1976 [5], Prats et al 1976 [12], Maxwell 1982 [10], and Ramsey et al 2008 [13]). These indicate that the value of 0.7 psi/ft will be adequate as the upper operating pressure limit.

To assess the potential of passive failure of cavern roof and wall in the pyrolysis phase, a systematic approach that included laboratory testing, analytical estimate of material properties, and numerical modeling was adopted. The crown pillar ~20 ft thick is required to sustain the rock load above a void of the assumed shape (see Appendix A – Geomechanics). Rock up to about 10 ft above the "void" will be in tension (i.e., stress greater than zero) while rock up to about 20 ft above will show shear failure (Appendix A, Figures A-2 and A-3). Owing to the thick crown (~100-130 ft) above the pyrolyzed volume, a competent roof will be maintained above the volume generated by leaching and pyrolysis.

Progress of horizontal leaching is monitored by pressure in the heater wells, especially in the outermost heater wells. Water levels in the heater wells initially will be at the level left by drilling. The leach well will be essentially filled with water to the surface, and pressure will be applied to move leach fluids to the surface, so the leaching well pressure will be higher than the heater wells. As leaching progresses laterally and breakthrough occurs – i.e. when the leach well connects horizontally with each heater well – pressures in the wells will increase as each connects with higher pressure water from the leach well. Several heater wells will be monitored and once an adequate array of wells shows connectivity with the leach well, leaching and circulation will be cut off.

Fresh water injection will commence with cold water to assure proper circulation within the leach well, and then will be followed by injection and circulation of hot water (Figure 7). Once the reservoir is fully conditioned, water heated to ~ 350°F at the surface will be injected to attain and maintain an eventual average reservoir water temperature of ~ 300°F. Well instrumentation will include surface temperature and pressure gauges, thermocouples on the casing string, and downhole pressure monitoring gauges in selected wells, and nitrogen pressure will be monitored at the surface in the leach well.

Other wells will be instrumented with pressure and/or temperature gauges, depending on the well functions and monitoring needs. During leaching and before pyrolysis, several of the outermost heater wells in the pattern will be used to monitor pressure, which will gauge breakthrough between the leach well and the monitored heater wells. After leaching to the ±20 ft radius, heater canisters and heaters will be installed in the heater wells and the leach well. Several heaters will be instrumented with a travelling thermocouple tube between the heater canisters and wellbore. Heaters will be activated from the surface with electrical power supplied via the high voltage substation.

The in situ heaters consist of mineral insulated (MI) cables attached to an electric cable and inserted into a thick metal canister traversing the heater zone. The MI cable is similar to an electric stove burner: mineral insulation outside the cable (the burner) does not deliver an electric shock, but does heat upon application of an electric current. Electricity for the heaters will be supplied through electric power purchased commercially.

The leach well will be recompleted as a heater. The two producer wells will be completed with slotted liners. Producers will be instrumented with temperature and pressure gauges on the production string as well as in the annulus. Oil production via conventional insert rod pumps will commence once pyrolysis temperatures indicate adequate pyrolysis. Gases will be recovered at the surface from the oil/gas/water separator, and hydrocarbon gases will be flared.

If water cooling is selected for subsurface reclamation, the cooling phase will involve recompleting several outside observers as injection wells by downhole perforation. These will be instrumented with surface flow meters, temperature gauges and pressure gauges.

One rig is intended to drill the wells sequentially, with ~21 days for the leach well, ~13 days for each heater well, and ~8 days for each observer well. Each rig has a crew of 4 persons / tour. At 2 tours/day and additional directional hands, a supervisor, and well site personnel, the complete crew will total 10 workers/day. The crew will work a 14 days on / 14 days off schedule. The crews for the pyrolysis completion phase will run 7 /tour, 2 tours/day, 14 days on / 14 days off. The project anticipates ~7 days/well for a total of ~133 days to change out the well heads and install heaters. The reclamation crews should run several workers per tour at 2 tours / day on a 14-on / 14-off schedule. These crews will be housed at Shell's Corral Gulch temporary living quarters.

There are no mining features on or near the proposed RDD Pilot. Existing man-made structures including an existing gas well pad within 200 ft of the project are described in Section 3.3.

6A.5.3 Production Monitoring

Leaching will be conducted at slightly elevated pressures relative to formation pressure, in order to produce nahcolite solution to the surface. Pressure will be continuously monitored and controlled to preclude fracturing that could promote fluid migration out of the formation. Pressure increases that raise the chance for fracturing of the crown, or decreases in pressure that may indicate unexpected open space collapse, will be investigated and assessed immediately upon detection, and leaching will be curtailed if warranted by the assessment. Pressures will be maintained below the fracture gradient, which is interpreted conservatively to be 0.7 psi/ft.

Solution composition (TDS) measured at the well head and downhole temperature measured in the observation wells will be monitored to assess leaching progress. Once the progression of leaching reaches the target radius, leaching will be discontinued, or the "fresh" water injection point will be raised to a shallower rich nahcolite unit in order to best affect leaching progress. A linear to near linear relation between TDS and conductivity will be established for the leach well so that conductivity can be measured simply and frequently.

During pyrolysis, temperature will be monitored periodically and pressure will be monitored continuously. Temperature will be monitored periodically with traveling thermocouples in the observation wells. Pressure will be monitored continuously via the instrumentation in the production wells.

Pressure will be controlled by the gas production rate. Gas buildup in the reservoir would yield high sustained pressure and likely would build up by lack of production during the pyrolysis phase. The design includes a second producer to serve as a backup to provide continuous production during maintenance shutdowns and also for troubleshooting. If uncorrectable production problems develop in both producer wells, which would be an extreme condition, the heaters will be turned off. Such a condition should provide ample warning as the array of pressure and temperature sensors throughout the field provide real-time continuous monitoring of all portions of the heating and production systems.

6A.5.4 Water Consumption

Water will be consumed for drilling, leaching, dust control, reclamation, and domestic purposes (Table 6.2). Water will also be generated during pyrolysis of oil shale. Potable water from public water supplies such as Meeker, Rangely, or the RNI White River Station will be used for drilling, dust control and domestic uses. Water for leaching and subsurface reclamation is expected to be supplied from one or more locations in the basin where Shell has water rights including: (1) Corral Gulch near the FWT site (CR-242), (2) Corral Gulch immediately downstream of Water Gulch (CR-235), (3) Big Duck Creek upstream of Duck Creek (CR-445), or (4) the White River just downstream of the confluence with Yellow Creek (CRWRdYCR-311). Drilling, potable water for drinking water and other domestic uses will be provided through existing agreements with D and P Water Inc., Perry French, Meeker, Colorado, and dust control water will be hauled to the site through existing agreements with RNI/Dalbo Trucking.

Drilling is expected to require ~ 12,000 barrels of water.

Water will be consumed as needed for dust control which is highly dependent on truck traffic volume and weather conditions. Based on vehicle traffic estimates, dust control water is expected to be approximately one truck load (100 bbls) every three days during the warm seasons. Using this ratio and assuming six months of usage per year, the project is likely to consume ~ 6,000 bbls of water per year (~ 41,000 bbls for life of project).

Construction is projected to require ~ 18,000 barrels over the duration of the project. This assumes that water is consumed for concrete, earthen dikes, and engineering soils conditioning.

Potable water for drinking, cooking, showers, and facilities is hauled to the site from commercial sources. Consumption is projected at ~ 3,000 barrels over the duration of the project.

Considering all of the water required for drilling, dust control, and construction, the total estimated potable water use is ~ 63,000 barrels.

Nahcolite leaching is expected to require between ~ 30,000 and ~ 54,000 barrels of water, depending on whether one or two beds require leaching (Table 6.2). Nahcolite solutions will be hauled off site. The plan for the pilot is for each truck to deliver a load of fresh water and then haul away a load of nahcolite solution.

The current plan is to allow the heated pattern to cool naturally. If water injection is selected to accelerate the cooling, then up to ~ 7,000 barrels of water will be required. After cooling, ~ 8,000 barrels of reclamation water will be used to fill the pore spaces generated by the process.

The total volume of water consumed for leaching, cooling, and reclamation, and which will be drawn from Corral Gulch, Duck Creek or White River will range from ~ 38,000 to ~ 69,000 barrels depending on the volume of nahcolite leached, and on whether water cooling is employed. As much as 5,000 barrels of water will be produced from the heating of nahcolite, other minerals, and kerogen. This produced water will be hauled off site.

The unit water consumption figures provided above are not representative of a commercial-sized project. Commercial unit water consumption figures would be much lower in every phase of the project because aggressive water conservation and reuse measures would be utilized at commercial scales that are not appropriate at a pilot scale.

Table 6A.2: Volume and Sources of water for activities at East RDD Pilot Project

		Year								
Activity/Use	**Water Source**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total by Use Category (Minimum)**	**Total by Use Category (Maximum)**
Drilling	Meeker	12200							12200	12200
Leaching (min)	Corral Gulch, Duck Ck, White River		29500						29500	
Leaching (max)	Corral Gulch, Duck Ck, White River		53750							53750
Dust Control	Meeker	4560	6000	6000	6000	6000	6000	6000	40560	
Construction	Meeker	13700	4500						18200	
Cavity Fill (min) – Cavity fill only	Corral Gulch, Duck Ck, White River						7800		7800	
Cavity Fill (max) - water assisted cooling and cavity fill	Corral Gulch, Duck Ck, White River						14600			14600
Domestic	Meeker	365	365	365	365	365	365	365	2555	
(Production)	N/A			(2480)	(2480)				(4960)	(4960)

6B. IN SITU DEVELOPMENT PLAN – ELHT

6B.1 Development Plan

The ELHT consists of three 1000-foot long heaters installed on the East RDD lease at a pad site located adjacent to East RDD Pilot (Figure 36). The purpose of the ELHT is to test the tendency for hotspots to form along commercial mineral insulated (MI) heaters installed in a horizontal orientation. This testing supplements the data that will be generated at the East RDD Pilot by testing heaters in a nonvertical orientation and will inform Shell for future commercial design and deployment.

Testing will involve:

- Construction of a drilling pad located adjacent to and hydraulically up gradient of the 138 hydrology pad.
- Installation of three horizontal heaters in three characteristically different non-water-bearing intervals of oil shale to test heater performance. Two heaters will be installed in higher resource intervals within the Saline Zone and one heater will be installed in a high resource interval within the Illite Zone. The two heaters in the nahcolite interval will test a high nahcolite condition and a low nahcolite condition.
- Installation of deviated observer/producer well adjacent to the heater wells to provide additional pressure relief and gas production during heater testing.
- Tie in of ELHT wells to the East RDD Pilot production facilities (i.e., separator, tanks and flare system). To the extent possible, that East RDD and ELHT will utilize two distinct separators for monitoring of produced fluid volumes.
- Collection of temperature data along the entire length of the heaters during start up and ramp up of power to assess the development and severity of hotspot formation due to variation of the geothermal properties of the rock.

6B.2 Development Details

6B.2.1 Drilling

The ELHT well pattern (Figure 40) consists of three horizontal heater wells and one inclined observer/producer well to provide pressure control. In addition to heating the formation during the heating phase, heater wells will also be used to control pressure in the immediate vicinity of the heater. The surface location for these wells will be in the northeast quadrant of the East RDD lease. None of the wells will be converted for dual use and no leaching is anticipated as the main objective for the ELHT pilot is to measure the response of the reservoir to heating (principally looking for the development of heater "hot spots"). All wells will be drilled, cased, and cemented prior to heater installation and ICP activities. Figure 37a shows a subsurface view the ELHT well configuration; Figure 37b shows the ELHT well configuration in plan view.

Drilling operations will require 3 or more months. A dedicated drilling pad will be built and used for this pilot. As shown of Figure 36, the surface location of the conductors will be located less than 500 ft from the lease boundary but the downhole well trajectory during drilling will place the heated section or interval away from the property boundary in the central portion of the lease (Figure 37b). As such, the ELHT testing will not affect any resource at or near the lease boundary. Well specifications and additional construction details are discussed in Section 6B.4.

Five hydrology monitoring wells were installed in 2009 in the northeast quadrant of the RDD Lease (hydrology well pad 138) as part of the EAST RDD. Data from these wells are being collected as part of the East RDD and provide baseline water quality in the near downgradient area that is also applicable to the ELHT. An additional groundwater monitor well (135-4-298-L4) was installed near the East RDD Pilot pattern with surface location approximately 60 ft NE of the East RDD pilot pattern. Elsewhere in the basin, Shell has drilled, tested, and sampled a considerable number of hydrology wells. These are discussed in the sections on hydrology and baseline water chemistry in this POD. The existing groundwater monitoring wells associated with the EAST RDD are sufficient for monitoring during the ELHT. As such, no additional hydrology wells will be drilled as part of the ELHT.

6B.2.2 Nahcolite/Sodium Availability Assessment

It is important to assess the impact of the heating process on the viability of sodium recovery when heating near rich nahcolite beds. Only one of the three heater wells is drilled in a zone containing significant nahcolite:

- Heater 1 (2220 ft depth*) – 25.4 wt% Nahcolite (drilled near Greeno Bed)
- Heater 2 (2300 ft*) – 0.8 wt% Nahcolite
- Heater 3 (2400 ft) – 0.3 wt% Nahcolite (drilled in the illitic interval).

The ELHT pilot does not include a pre-leaching phase in which sodium is recovered. Instead, to assess the impact that heating will have on sodium recovery, Shell proposes to recover a core across the heat-affected zone near Heater 1 after the completion of the heating and production phase and prior to commencement of well abandonment activities. The core is expected to drill through (1) a virgin nahcolitic zone above the heated interval, (2) an upper nahcolite/soda ash transition zone, (3) a soda ash zone near the location of the heater, (4) a lower soda ash/nahcolite transition zone, and finally (5) a second virgin nahcolitic zone below the heated interval. Shell proposes to conduct lab testing on the core to map the location of the transition zones using the temperature fields from the reservoir model to establish the temperatures at which in situ conversion of the nahcolite to soda ash occurs. Shell further proposes to leach representative portions of the core in (1) the virgin nahcolitic zone, (2) the nahcolite/soda ash transition zone, and (3) the soda ash zone to determine the impact of heating on sodium recovery. Core previously cut from nearby wells (but never heated) can also be used in the study.[8]

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8 *Reference 135-4-298-SAW1 well.

Because of the very low nahcolite content near Heater 2 and Heater 3, no investigation on the impact that heating will have on sodium recovery is necessary and none is planned.

6B.2.3 Pyrolysis and Production

Pyrolysis facilities will consist of the three heater wells, each equipped with an electric heater installed in a canister to heat the formation which will convert the in-situ kerogen adjacent to the heater into oil and gas. Each heater will be installed with temperature monitoring instrumentation. An inclined observer/producer well will be installed through the heated interval near the heater wells to provide additional pressure relief to the formation during heating.

During the heating process water (generated by the decomposition of nahcolite to soda ash), oil and gas are released from the kerogen and surrounding matrix increasing the subsurface pyrolysis interval pressure. To maintain the pressure in the pyrolysis intervals below the formation fracturing pressure, pressure will be bled from the formation by the heater wells and the observer/producer well. To remove liquids from the pyrolysis interval, an artificial lift system will be installed in the inclined observer/producer well. Any production from the heater or observer/producer wells will flow through piping connecting the well heads to a separator located at the EAST RDD pilot. Produced gases will be flared, and the oil and water will be recovered from the separator and trucked off site. Diluent and makeup water obtained from the City of Meeker may be added to the production stream, the well casing, or well tubing (if needed) to assist in the production of bitumen which will form during the lower temperature phases of pyrolysis. Produced CO_2 and other non-combustible gases will be included in the stream of gas sent to the flare.

The heating phase of ELHT is expected to last for two or more years and is expected to run concurrently with heating at the East RDD Pilot.

6B.2.4 Subsurface Reclamation Plan

Full details of subsurface reclamation are described in the Subsurface Reclamation Plan Section of this POD. A synopsis of activities for the ELHT follows.

Upon completion of the heater test, the pyrolyzed zones will be allowed to cool naturally. Natural cooling will be considered complete when the temperature at the heater wells falls below ~200 °F (i.e., boiling point of water at reservoir conditions). Once below ~200 °F, any subsurface equipment located in the four ELHT wells between depths of approximately 2,100 ft (~80 ft below the dissolution surface) and surface will be retrieved. From a depth of approximately 2,100 ft down and in the horizontal section, the heater canister, heater, and associated instrumentation will be left in the heater wells. A metal bridge plug will be placed within the casing just above 2,100 ft TVD, and the well casing will be plugged with cement above the bridge plug to approximately 3 ft below the ultimate reclaimed ground surface. Well casings will then be cut 3 or more feet below final ground surface, per BLM Gold Book Standards.

For ELHT the radial extent of thermal disturbance is expected to be small. Based on modeling, temperatures above 550 ^{0}F are predicted to be localized to ~2-ft radius around the heaters. As there is no thermal superposition in the heated volume, natural cooling is expected to be effective and will take approximately one year for the formation to cool to less than 200 ^{0}F. Thermocouples installed along the heater canisters will be used for temperature monitoring. Abandonment of the heater wells will be completed after the temperature of the thermocouples indicates temperature along the heaters is less than 200 ^{0}F.

6B.2.5 Surface Reclamation Plan

Surface reclamation will be completed to return the disturbed site to a beneficial post-mining land use. A synopsis of the surface reclamation plan follows. Details may be found in the Reclamation section of this POD.

After the wells have been filled with cement, casings will be cut a minimum of 3 ft below the projected post grading ground surface level. Surface equipment not needed for steam recovery and oil water separation may be removed prior to or after decommissioning of the wells. Once all facilities are removed, concrete structures will be crushed on site, rebar will be removed and properly disposed off site, and concrete will be distributed evenly amongst the subsoil. Fill and cuts will be restored to approximate original contours, packed earth will be scarified, topsoil will be re-applied evenly, and the area will be re-seeded with the BLM-approved seed mix of native species.

6B.3 Size, Location, Schematics of Structures, Facilities

6B.3.1 Surface Facilities Descriptions

The ELHT includes minimal additional surface facilities as it largely ties into the existing facility for East RDD Pilot discussed in Section 6.3A. The new facilities consist of a well pad, a variable voltage transformer (VVT) skid and a ~600 ft long pipe rack enabling the tie in of the minimal production from the ELHT wells to the East RDD Pilot surface facility. The ELHT will be monitored and operated using the existing East RDD Pilot control system. All added operations infrastructure will be located inside the 8-foot tall game fence. This area is gated to prevent access by wildlife and the public. Reclamation of the minimal additional facilities at the ELHT will be consistent with the East RDD. Incremental reclamation costs for the ELHT will be calculated based on the addition of a new well pad containing three horizontal wells and one inclined well and the foundation associated with VVT, and piping connecting the ELHT to the EAST RDD surface facilities.

6B.3.1.1 VVT Station

A VVT station, to be installed by Shell, will be placed inside the permit boundary, within the game fence. The substation will power all electric needs from the VVT. The majority of surface equipment will be used in all phases – heating and cooling – with minor variations in the equipment line-up.

A buried power cable from the substation will feed the VVT; other electrical service lines will be placed above ground on cable trays. Each pipe rack foundation will rest on a concrete footer.

6B.3.2 Surface Equipment Summary - Heating Phase

During the heating phase, equipment discussed in Section 6B.3.2 will be utilized in addition to the equipment discussed in this section.

6B.3.2.1 Electric Heaters

Three horizontal, down-hole heaters will be installed to heat the kerogen within the oil shale rock. The heater performance and the reservoir response will be monitored using the installed instrumentation connected to the East RDD control system. Heaters will be positioned far enough apart such that conversion of kerogen into oil and gas will be minimal. Converted oil and gas will be managed by the observer/producer well. Heater power and control will be supplied from the EIB, which in turn, receives power from the high voltage substation via VVT.

6B.3.3 Surface Equipment Summary- Reclamation Phase

Equipment discussed in Section 6B.3.3 will also be used during the reclamation phase of the ELHT. No new equipment will be installed.

6B.4 Well Construction

6B.4.1 General

The ELHT Pilot utilizes two types of wells (Figures 38-39):

- Horizontal heater wells (3)
- Inclined observer / producer well (1).

The ELHT Pilot will not include additional drilling of down gradient ground water monitoring wells. Monitoring will be provided by the existing wells drilled between 2009-2010 in Pad 138-5-298 which include one well each in each hydrostratigraphic unit (Uinta, L7, L6, L5, and L4).

Specifications for each well type are discussed in the sections following. Table 6A.1 lists the specifications for each well. Specifications listed are intended generally to provide for cement mixes to withstand both the composition (high salinity) and/or sulfate content of the wells plus the temperature fluctuations that will act on the casings and cement. Dimensions provided are for maximum pipe (casing) and drilled well dimensions, and may be decreased if feasible. Annular spaces may vary depending on the final borehole and casing size selection, but will be maintained to provide sufficient space for placement of cement.

Table 6B.1: Well Specifications.

	Casing Depths (ft TVD)		Hole Size	Casing Description	Cement Design	Cement Installation Method
Horizontal Heater	Conductor	60-200 ft	17-1/2	13-3/8 in, 54.50 lbs/ft, J-55 Grade steel, STC, ID: 12.615	Premium Plus cement, 11.5 ppg, additives as required by lab test.	Cement annulus via tremmie pipe or through stab-in cementation.
	Intermediate	2,220 ft – 2,400 ft	12-1/4 in	9-5/8", 40 lbs/ft , J-55, LTC, ID: 8.835 in	Premium Plus cement, 9.5 to 11.5 ppg lead, and a 13.5 to 15.8 ppg tail, additives as required by lab test.	Mud flush, water flush, cement & displace by one plug system is used to pump cement job. Pump cement to surface.
	Heater Canister	Well TD	8-1/2 in	4-1/2", HS-70, ASTM A-606, Type 4, 0.25 WT Coiled Tubing canister containing heater and instrumentation	N/A	N/A
Inclined Producer	Surface	60-200 ft	17-1/2 in	13-3/8 in, 54.50 lbs/ft, J-55 Grade steel, STC, ID: 12.615 in	Premium Plus cement, 11.5 ppg, additives as required by lab test	Cement annulus via tremmie pipe or through stab-in cementation.
	Intermediate	2,460 ft	12-1/4 in	9-5/8", 40 lbs/ft , J-55, LTC or equivalent, ID: 8.835 in	Premium Plus cement, 9.5 to 11.5 ppg lead, and a 13.5 to 15.8 ppg tail, additives as required by lab test.	Mud flush, water flush, cement & displace by one plug system is used to pump cement job. Pump cement to surface.
	Production	Well TD	8-1/2 in	6-5/8" Slotted Liner	N/A	N/A

The project comprises three wells for heating and one well for observation and/or pressure control (Figure 37a). Plans call for all wells to be drilled prior to deploying and activating any of the heaters.

The horizontal wells (Figure 38) will be drilled with directional control from surface, with a kick off point (KOP) between 1,000 ft to 1,400 ft true vertical depth (TVD) and a build rate of 5.7°/100 ft (dog leg severity) to a maximum inclination of 90°. The horizontal section for these wells will be on the order of 1,000 ft to 1,150 ft and an inclination at well total depth (TD) between 90° and 93° to allow deploying the heaters in the formation bedding planes (up dip). The total depth of the deepest horizontal well (located at the heel) is projected to be less than 2,410 ft TVD.

The inclined well (Figure 39) will be drilled with directional control from surface with a KOP between 200 ft to 400 ft TVD with a build rate between 5° to 10°/100 ft up to an inclination of 45° which will be maintained to TD. Total depth of the inclined well is projected to be less than 2,460 ft TVD.

Fresh water will be transported to the site from the White River the City of Meeker or other available sources for use in all drilling. Cuttings and drilling fluids will be transferred to an onsite dewatering pit where the water in the cuttings will be allowed to infiltrate back to ground water. Dewatered cuttings will be transferred to rolloff boxes and transported to applicable offsite facilities for permanent disposal. Surface and intermediate hole sections will be drilled with aerated mud and loss circulation material added as required, and the horizontal section with aerated mud and loss circulation material or common water well drilling lubricant depending on the borehole stability ,studies simulations which are yet to be concluded.

The wells will be constructed with pressure or temperature sensors to monitor changes in each pyrolysis interval and in the crown above upper pyrolysis interval. Geological conditions at the ELHT are very well informed by the recent drilling of Shell appraisal well 135-4-298 (SAW-1 well), the five hydrology wells on the 138-4-298 Pad, and of the 20 ERDD wells. Ground water is expected at about 250 ft depth, based on the water level in well 135-4-298 (SAW-1 well).

Wells drilled by Shell in the Piceance Basin in the past 10 years generally encountered small amounts of gas, particularly in the deeper formations. The gases contain mostly N_2 and CH_4, with lesser volumes of O_2 and CO_2 (Schatzel et al, 1987). Hydrogen and ammonia may be present. Samples collected in closed containers for up to 125 days contained up to 0.195 cm^3/g of gas.

A sulfur odor often is detected in drilling of Uinta and some of the shallow Parachute Creek wells. Although LEL (lower explosive limit) measurements are checked at all wells during drilling, and even though methane and sulfur gas occur typically, LELs have never been exceeded. If unusual gas levels are encountered, drilling will be shut down and the well will be allowed to vent.

6B.4.2 Casing Cement Processes

Surface (conductor) casing will be set in cement by placement of cement directly in the annulus of the conductor, by a tremmie pipe or through a stab-in cementation in which a cement stinger is run and stab-in into a float shoe and pump cement into the annulus until returns are seen at surface. Conductor casing cement will be Type I/II premium plus cement.

Casing in all other sections will be cemented by displacement. With the displacement method, the casing is installed to the section TD then lifted a few feet off bottom to create a fluid pathway between the interior and exterior of the casing. Cement is next applied inside the casing and capped with a wiper plug. Displacement fluid (usually water) is then added to the column above the plug, providing weight that drives the cement down the casing and up the annulus until cement returns are observed at the surface.

All wells – horizontal heaters and observer/producer – will be cemented with Premium Plus cement and additives (as recommended by laboratory tests and simulations) which may include but are not limited to dispersant agents, antifoam material, fluid loss agents, silica flour and extender or retardant additives with a 9.5 to 11.5 lbs/gallon (ppg) lead, and a 13.5 to 15.8 ppg tail. Once cement returns are observed at the surface, the cement will be allowed to set for the prescribed setting time (usually 8 hours). Cement recipe and slurry weight may change depending on laboratory tests and simulations, however all efforts will be made and best practices applied to ensure proper zonal isolation on each interval.

A cement bond log and/or isolation scanner log will be run in each well after cementing. The cement bond log is an acoustic geophysical measurement that indicates the presence of cement as a measure of the degree of bonding in the annulus between casing and the drilled hole.

6B.4.3 Conductor Casings

Conductor casing will be installed at all wells. Conductors for both horizontal heaters and the producer / observer well will be 13-3/8 in with casing shoe located between 60 ft to 200 ft subsurface and penetrating 3 ft minimum into bedrock. Conductor casing specifications are:

- 13-3/8 in O.D. (54.5 lbs/ft, J-55 Grade steel, STC or equivalent)

Casing will be cemented from T.D. to surface with type I/II neat cement, placed in the annulus via tremmie pipe or through stab-in cementation using a cement stinger and a float shoe.

6B.4.4 Heater Wells

The main function of the horizontal heater wells is to test the tendency for hotspots to form along the heater in three subsurface environments. For this purpose, two horizontal heater wells will be drilled in the Nahcolitic Oil Shale and one horizontal heater well in the Illitic Oil Shale. All horizontal drilling will occur below the dissolution surface. The minimum horizontal section requirement for active heating in each horizontal well is 1,000 ft with an additional pocket of 125 ft - 150 ft to compensate for the expansion of the canister during the heating process.

As presented in table 6.1, horizontal heater well design (Figure 38) will consist of a 13-3/8 in conductor set into the bedrock and cemented to surface, followed by a 12-1/4 in hole drilled to the end of the build-up section (i.e. 90° inclination) to run and cement to surface a 9-5/8 in casing containing pressure transducers and bubbler tube ported to the casing ID. An 8.5 in open hole section will then be drilled along the heated interval to run a 4.5 in sealed canister from surface to well TD which contains the three phase MI heater and an instrumentation package including thermocouples and an optical fiber.

6B.4.5 Inclined Observer/Producer Well

The main function of the inclined observer/producer well is to provide monitoring and back-up pressure control of the fluids/gases generated during the heating process. This well will be drilled from the same pad as the horizontal heater wells to minimize surface disturbance. The well will be inclined at 45° inclination and will pass the deepest heater well at approximately 750 ft from the heel. The distance between the Producer / Observer well and each horizontal heater well will be between 10 ft and 15 ft subsurface.

As presented in table 6.1, Producer / Observer well design (Figure 39) will consist of a 13-3/8 in conductor set into the bedrock and cemented to surface, followed by a 12-1/4 in hole drilled through the bend section and inclined at 45° to the casing point (between 2,000 and 2,200 ft TVD) to run and cement to surface a 9-5/8 in casing string. Subsequently, an 8-1/2 in hole (inclined at 45°) will be drilled to well TD to run a 6-5/8 in slotted liner. The well will be completed with a 2-3/8 in tubing string containing a plunger lift system and instrumentation to monitor pressure and temperature at each pyrolysis interval. Instrumentation to monitor the temperature in the cap above the upper pyrolysis interval will be attached to the casing OD and cemented in place.

6B.4.6 Cuttings and Drill Water Disposal

Cuttings and drilling fluids will be transported to a temporary cuttings pit located on the EAST RDD project site. Water contained in the cuttings and drilling fluid from above the L4 will be returned to the subsurface by means of infiltration and the dewatered solids will be loaded in portable tanks and transported to applicable offsite facilities for permanent disposal.

6B.5 Development Methods, In Situ Methodology

6B.5.1 Operational Phases and Timeline

The ELHT Pilot will span ~ 4 years and is run concurrently with the East RDD Pilot. Drilling, depending on the time needed for permitting and procurement of equipment, is expected to begin in late summer 2013. From an operational perspective, the East RDD Pilot and the ELHT will be combined into a single operation.

To gain maximum R&D learnings, a ~2 year extension may be requested to study the longer term heater performance in the resource.

6B.5.1.1 Construction Phase

Pad construction of the ELHT will begin in late spring 2013 and is expected to be completed within 45 days. Drilling of the four wells at ELHT is expected to begin in late summer 2013 and is expected to require less than 120 days. Heater installation will follow and is expected to take less than 60 days. Construction of the ELHT is minimal as it will tie into the facilities constructed for East RDD Pilot. The tie-ins for ELHT to the East RDD Pilot are expected to take less than

90 days. There may be time intervals of as much as 120 days between some of these activities and some activities may overlap. Heating is expected to begin at ELHT in early 2014.

6B.5.1.2 Heating Phase

Heating of the three wells is expected to require ~2 years to gain the required information to evaluate the test. The primary purpose of the heating is to measure the response of the reservoir to heating (principally looking for the development of heater "hot spots"). Other important geomechanical and reservoir learnings are expected within the 2-year heating period.

An additional 2-year heating period may be requested to study the longer term heater performance in the resource.

6B.5.1.3 Cooling Phase

Upon completion of the heating phase, the pyrolyzed zone will be allowed to cool naturally. It is expected that natural cooling will be sufficient for the ELHT because of the relatively small volume of rock being heated. The wells will not be abandoned until the temperature at the heaters is below 200 °F.

6B.5.1.4 Coring Phase

Upon completion of the cooling phase, Shell will drill a core in the heat affected zone near heater one to assess recovery of sodium minerals as described in section 6B.2.2.

6B.5.2 Development Methods

Shell has selected three specific intervals to be heated based on the geological features of each interval. Isolation between individual heated intervals and the water-bearing zones above the crown is ensured in the selection of the heated intervals and the modeling and geomechanical analysis. In selecting the intervals to be heated, the following criteria were considered:

1. Expected operating conditions (pressure and temperature)
2. Crown thickness and composition
3. Fracture generation potential during heating
4. Possible changes in the structural strength of the crown due to heating
5. Extent of temperature and pressure front propagation during heating
6. Static geomechanical conditions
7. Heating induced changes in geomechanical conditions.

The intervals to be heated were selected to test Shell's heating technology under different subsurface conditions (i.e., kerogen richness, nahcolite and other mineral concentration, and clay content). The goal is to assess the impact of different subsurface environments on heater performance and the temperature variation along the heated section.

The top heated section has a crown thickness (distance from dissolution surface) of 180 ft. To minimize production and temperature (and consequent pressure) rise, the heated sections are placed far apart from each other (more than 50 ft) such that there is no temperature superposition between the three heated zones.

Nahcolite ($NaHCO_3$) near the upper most heater will begin to convert above ~200 °F to soda ash (Na_2CO_3), with water (steam) and CO_2[9] being released as a result of the mineral decomposition. Initially, kerogen will swell as bitumen is generated during the early, lower temperature phase of pyrolysis. With further heating, kerogen conversion will release water, gas, and liquid hydrocarbons. The volume of nahcolite converted to soda ash along the uppermost heater is estimated to be approximately 1,200 to 1,500 tons. The soda ash will remain in place and could be recovered later. The lower two heaters will be located in intervals with only minor amounts of nahcolite being present. As such, the additional volume of nahcolite converted to soda ash in these intervals is considered to be insignificant.

The ELHT predictive reservoir modeling suggests the pyrolysis zone extends to about 2 ft around the individual heaters. Minimal production is expected. The average reservoir pressures in the heated zones will be below the fracture propagation pressure. In addition, the depth of the heaters (>2,220 ft) provides sufficient crown thickness (180 ft) for containment. Hence crown integrity risks are negligible for the ELHT pilot.

6B.5.3 Production Monitoring

The heater wells and the observer/producer well will be instrumented with pressure gauges and temperature sensors. Progress of heating will be monitored by temperature sensors along each heater well. The heater package installed in each heater well consists of MI heater cables attached to an electric cable and instrumentation to measure the temperature along the heater conveyed downhole inside a metal canister. Heaters will be activated and controlled from surface with electrical power supplied via a high voltage substation.

During the ELHT oil production is estimated to be small in volume. The observer/producer will be equipped with an artificial lift system to remove accumulated liquids (oil and water). Produced liquids will be transferred by piping to a separator located at the East RDD. The volume of oil transferred from the ELHT to the East RDD will be monitored and recorded.

Conversion of nahcolite to soda ash and/or pyrolysis of the oil shale in the well will increase the pressure during the heating phase. Pressure will be controlled by the gas production rate. If reservoir pressures cannot be reduced by producing gases through the observer/producer well or the heater wells, the heaters will be shut in to prevent over pressure. If uncorrectable problems develop in observer/producer well, which would be an extreme condition, the heaters will be turned off. Such a condition should provide ample warning as the array of pressure and

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[9] Water in the form of Steam and CO_2 will report to the gas phase of the separator at the East RDD, at surface where steam will cool to water and CO_2 will be vented.

temperature sensors throughout the field provide real-time continuous monitoring of all portions of the heating and production systems.

6B.5.4 Water Consumption

The water demands of the ELHT are much lower than East RDD Pilot primarily because no leaching will be conducted at ELHT. For ELHT water will be consumed primarily for drilling which for the ELHT is expected to require 4,000 to 5,500 bbls of water.

The other water uses shown in Table 6A.2 (such as dust control, construction, and domestic purposes) will also provide coverage for the ELHT. The same water sources for the EAST RDD will be utilized at the EHLT. Drilling water will be provided from the White River and water used for cementing will be obtained from potable water supplies in the city of Meeker or other available sources.

7 RECLAMATION

7.1 Surface Reclamation Plan

7.1.1 Decommissioning of Facilities

Surface facilities associated with the East RDD Pilot and East Long Heater Test will be removed when no longer needed to support the reclamation efforts. All chemicals will be removed from the site and properly disposed. Any remaining product and wastes will be removed as well; wastes will be disposed off-site and product will be shipped for additional treatment. Storage tanks for waste and product will be triple rinsed prior to removal with the rinse water removed from the site and properly disposed. Facilities equipment will be removed for disposal or reuse, followed by demolition of buildings and other project-related structures. Concrete building foundations will be broken up and buried on-site to a minimum depth of 3 ft. below final surface grade. Rebar and demolished building materials will be hauled to a licensed landfill facility.

7.1.2 Final Regrading

Following completion of demolition of the facilities, land reclamation will begin. Soils around the above ground petroleum product storage tanks will be visually inspected for evidence of petroleum contamination and removed to licensed facilities if necessary. Existing sediment control structures will control erosion and contain runoff and sediment within the project area during reclamation. Using typical earthmoving equipment, the disturbed area will be regraded to blend into surrounding pre-construction contours. Earthmoving should be limited based upon the minimal amount of cut/fill work needed to establish the facilities areas during site development work. Regraded surfaces will be ripped to 18 inches depth to alleviate excess compaction and provide a better bond between regraded overburden and replaced topsoil.

7.1.3 Soil Replacement

Once disturbed areas have been regraded and ripped, soil material salvaged and stockpiled during site development will be evenly redistributed over disturbed areas. Redistributed soil will then be tested to determine if amendments are necessary to ensure successful establishment of planted species. Fertilizer and other appropriate amendments, if needed, will be applied after soil placement.

7.1.4 Revegetation

Following soil replacement work, disturbed areas will be revegetated with seed mix no. 2 from the 2011 BLM White River Field Office Surface Reclamation Protocol. This seed mix was stipulated for use by the BLM in the POD Approval Document dated August 10, 2011. To ensure the seed mixes are free of noxious weed species, Shell adheres to BLM Instruction Memorandum No. 2006-073 entitled "Weed-Free Seed Use on Lands Administered by the BLM". Seed material will be certified weed-free and purchased from and blended by qualified producers and dealers.

Prior to seeding, areas to be revegetated will be scarified to provide an adequate seedbed. Seed will be drilled or broadcasted. Drill seeding will be used where the machinery can be operated safely and where soil characteristics and slope allow effective operation of a rangeland seed drill. Drill rows will be oriented perpendicular to the slope in areas where such operations can be done with an adequate margin of safety. Drilled seed will be placed at an average depth of 0.5 inch. For broadcast seeding, seed will be applied uniformly over disturbed areas using typical broadcast seeding equipment. Broadcast application rates will be twice that of drill seeding rates, and areas seeded by broadcasting will be uniformly raked, chained, dragged, or cultipacked to incorporate seed to a sufficient seeding depth.

Once the seed has been applied, straw mulch will be spread and crimped over the seed or hydromulch will be spread over seeded areas using a hydromulcher. Seeding will occur in the fall with the early spring serving as an alternative should fall seeding not be completed. Following completion of seeding, woody debris cleared during initial construction will be pulled back over revegetated areas to provide wildlife habitat, protect seedlings, and to serve as flow deflectors and sediment traps for erosion control. Redistribution of woody debris will be limited to no more than 20% of total ground cover in order to meet BLM fire management objectives.

The vegetative habitat occupying the native area that will be disturbed is suited for upland drainage. The mix includes native grasses and shrubs. The two dominant plant communities in the area are sagebrush grassland and pinyon/juniper woodlands. However, pinyon/juniper woodlands are not present in the proposed disturbed area.

Table 7.1: Seed Mix No. 2 - 2011 BLM WRFO Surface Reclamation Protocol.

Species of Plant	Variety	Pure Live Seed (lbs/acre)
Western wheatgrass	Arriba	4.0
Indian ricegrass	Rimrock	3.5
Bluebunch wheatgrass	Whitmar	4.0
Green needlegrass	Lodorm	2.5
Northern sweetvetch	Timp	3.0
Sulphur flower	na	1.5
Alternates:		
Needle and thread	Critana	3.0
Scarlet globemallow	na	0.5

Following reclamation, vehicle traffic will be restricted over the area. Some limited travel may be required to conduct post reclamation monitoring of vegetation, potential subsidence, and ground water monitoring wells. The revegetated areas will be monitored for the first two years to evaluate the need for supplemental seeding and noxious weed control. Recontouring, reseeding, or other appropriate measures will address areas of erosion in the revegetated areas. Noxious weed control will occur through the use of BLM recommended procedures based on the amount and type of noxious weed present. Erosion control measures will be maintained until establishment of permanent self-sustaining groundcover of the native species specified in the seed mix (Table 7.1).

7.1.5 Management of Non-Native, Invasive Plant Species

Prior to construction, Shell will conduct a field survey to identify noxious weeds and/or other undesirable plant species within the 149 acre Permit area. Shell recognizes that areas within the 149 acre Permit boundary and the access road have been disturbed significantly by other lessees, notably for construction of pipelines and a flow line, and the CSU revegetation test plots. In addition, part of the 149 acre RDD lease is subject to grazing leases. Based on the results of the plant survey, the overlapping leases and prior disturbance, Shell will develop a treatment strategy in consultation with the BLM and the Rio Blanco County Weed Agent. Shell expects to manage weeds on all lands disturbed by Shell and by the CSU vegetation plots.

Areas disturbed by construction will be monitored for the presence of noxious or undesirable plant species and any identified infestations will be adequately controlled and/or eradicated using materials and methods approved in advance by the BLM Authorized Officer. Vehicles and equipment used for project-related activities will be required to arrive at the site clean and free of soil and vegetative debris capable of transporting weed seeds or other propagules. Interim seeding of disturbed areas will be conducted where practicable in order to prevent introduction/expansion of noxious weed infestations.

7.2 Subsurface Reclamation Plan

Upon completion of pyrolysis and recovery of liquid hydrocarbons, the pyrolyzed zone will be allowed to cool naturally, or more quickly by injection of water. Subsurface reclamation for both the East RDD Pilot and the ELHT will be considered complete once the average temperature in the reservoir falls below 200 °F, and the reservoir is filled with water. Once cooled and water filled (only for the East RDD Pilot), a metal bridge plug will be placed in each well just above the pyrolyzed reservoir, and the wells will be cemented from the bridge plug to approximately 3 ft below the ultimate reclaimed ground surface. Well casings will then be cut 3 ft or more below final ground surface; monumented with a brass marker placed in the cement at the top, and covered with soil.

7.2.1 Natural Cooling Option

Natural cooling in the EAST RDD area may require ~1,000 days (~2½ years). At the start of such reclamation, the pyrolyzed reservoir will be dry and permeable. Reservoir surfaces will be coated with chemically immobile, carbonized hydrocarbons (coke or char); boundaries of the reservoir may contain a skin of immobile tar-like bitumen. Because rock encasing the pyrolyzed reservoir is impermeable, bitumen and associated hydrocarbons will be entombed and unable to reach water bearing zones.

After the reservoir is cooled below steam temperatures, water will be injected to fill all the void spaces. Considering the variations in nahcolite and FA grades of the affected volume, it is estimated that 8,000 bbls of water will be necessary to fill the East RDD pore spaces generated by the leaching, pyrolysis and hydrocarbon production (Table 6.2). Void volumes will vary by layer, depending on the FA and nahcolite grades; the highest porosity could be ~ 38%.

The area affected by heating in the ELHT is localized, by design, near each heater due to the large spacing between the heaters. Temperatures in excess of 550^{0}F are limited to an approximately 2-ft radius around each heater well. Due to the low heated volume to surface area, natural cooling is expected to be very effective. Natural cooling of the heater wells to 200 degrees F is expected to take approximately 1 year. Reservoir surfaces will be coated with chemically immobile, carbonized hydrocarbons (coke or char); boundaries of the reservoir may contain a skin of immobile tar-like bitumen. Because rock encasing the pyrolyzed reservoir is impermeable, bitumen and associated hydrocarbons will be entombed and unable to reach water bearing zones once the four pilot wells have been filled with cement.

7.2.2 *Water Cooling Option*

Although the preferred subsurface reclamation plan calls for natural cooling, a water cooling option is described, and models are provided, to demonstrate the means of water-assisted cooling for the EAST RDD. The time required for reservoir cooling can be reduced by adding water to the warm reservoir. At the depths projected for the RDD project, water injected into a hot reservoir may flash to steam depending on reservoir temperature and pressure. If water is used to cool the reservoir, steam will be collected using the existing equipment – i.e., piping, separator, and tankage. This system also will collect residual volatile organic compounds that travel with the steam. The steam and organics thus collected will be cooled and routed to a separator where organic vapors will be separated from the liquid components (water and liquid hydrocarbons) and the gases will be flared.

To exercise the water cooling option, some of the existing wells will be converted to water injection wells, others to steam recovery wells, and the unused wells will be shut in at the surface until downhole conditions are such that these wells can be plugged and abandoned. The cooling rates (Figure 35) assume two water injection wells and five recovery wells. Additional recovery wells could lower the cooling time by adding steam recovery capacity.

The rate of water-assisted cooling is limited by the rate at which steam / hot water can be produced from the hot reservoir. As reservoir pressure is to be maintained below the fracture gradient, the water injection rate will be limited by the number and size of conduits (open wells) between the reservoir and surface. Considering those limits, it is anticipated that water can be injected into the reservoir by two injectors at ~2 gallons per minute, provided steam is recovered through two steam recovery wells.

Water-cooling is not anticipated to be used at the ELHT test area.

8 ADDITIONAL TESTING OPTIONS

8.1 Optional Tests

An array of optional tests is proposed for the East RDD property. Some are considered maintenance or operational items that do not require specific permit approval or reclamation bond. The others are options that require more advanced plans to be described in revisions to the Plan of Development. None of these optional tests are included in the Reclamation Cost Estimate, but will be bonded if implemented.

Optional tests that should not require additional POD or other permit approval or reclamation bond:

1. Post-pyrolysis coring.
2. Multiple year operation of a commercial prototype heater, including troubleshooting, repair, and possible replacement.
3. Installation of new or replacement surface equipment as required to operate heater well(s), producer wells(s), and/or leaching wells. Such equipment will be installed on existing platforms, unless covered under a POD amendment.

Optional tests that will require future permitting include

1. Additional nahcolite leaching to be conducted at other locations on the RDD to test perm/porosity development and nahcolite recovery efficiency under a variety of pressure and temperature ranges.
2. Horizontal or vertical well drilling within the commercial target interval (for heater deployment, producer deployment, or testing of advance leaching concepts).
3. Deployment of a commercial prototype heater (horizontal or vertical) within commercial target interval.
4. Deployment of a commercial prototype production piping and production equipment (horizontal or vertical) within the commercial target interval.
5. Multiple year operation of a commercial prototype production well, including troubleshooting, repair, and possible replacement.
6. Deployment of advanced leaching technology inside horizontal or vertical well.
7. Continued operation of the surface facilities equipment installed for East RDD for the purpose of handling the production from the above mentioned tests.
8. Injection of other fluids post-leach to test efficacy of alumina production from dawsonite.

9 SITE SAFETY AND EMERGENCY RESPONSE

9.1 General Procedures

Shell will operate the existing office, temporary living quarters, warehouse, and storage yard facilities, which are on Shell-owned properties in the vicinity. Access to facilities including the East RDD facilities will be controlled, and access will be limited to personnel with appropriate safety training and equipment.

Shell maintains regular training on personal protection, personal safety, site security, and environmental protections. Shell will staff the operation with medically trained first responders and first aid facilities. Personal protective equipment (PPE) is required according to job and facility needs. Field and operations personnel are required to wear steel-toed shoes/boots, sleeved shirts, long pants, and hard hats, at a minimum, and eye and hearing protection are required in specific areas. Fire retardant clothing (FRC) will be required in well drilling and hydrocarbon producing facility areas.

9.2 Fire Response Plan

9.2.1 General Fire Response

Shell maintains limited fire response and fire fighting capabilities as explained in the following. Basically, personnel are equipped to only fight incipient stage fires if in their judgment this can be done without injury to themselves or others.

Personnel may use fire extinguishers to try and extinguish small, incipient stage fires if in their judgment this can be done without injury to themselves or others.

- CO_2 extinguishers will be used on electrical fires
- Dry chemical extinguishers will be used on oil fires.

In the case of a larger fire, personnel will:

- Notify the local fire department (Dial 911)
- Protect and/or evacuate on-site personnel
- Notify Field Supervisor
- Monitor the fire and secure the area.

9.2.2 Forest or Brush Fire

The East RDD Pilot is in a region of mostly native shrubs and grasses with sparse pinyon and juniper located mostly in drainages and on north-facing slopes. Weeds are monitored and controlled at all Shell sites in the Piceance Basin, with at least yearly spraying or removal at all sites when weeds are found. Active weed management program at all sites minimizes the need for fire controls to accommodate dry weeds. Shell's existing weed management program will be expanded to include the East RDD Pilot area.

The potential for brush, range, or forest fires is assessed based on the density and type of local vegetation. Shell maintains the ability to respond to small fires that can be managed with light duty hand held equipment. Shell is not equipped to fight range fires, large operations fires, or building fires that cannot be addressed safely and adequately with hand held equipment.

In the case of larger fires, Shell procedures are to assess the nature of the fire, notify site personnel via 2-way radio, muster at pre-selected muster points, account for all personnel, notify the BLM, activate 911, and monitor or evacuate as appropriate. The following is taken from Shell's Emergency Response Plan regarding range fires.

The main concern is actions to take if wildfire threatens a facility, possibly cutting off normal egress routes. General consensus from forest fire experts is that getting out of the area is the best option as smoke and heat could be very intense. If the emergency occurred at night, the escape route might not be obvious. If a fire approaches from a north to south direction, it might be difficult to drive out on the main road. A color-coded map has been provided to operations personnel to indicate escape routes. If time permits, personnel should contact local authorities to advise of fire and indicate which evacuation route will be taken. This will allow rescuers to follow up in locating persons attempting to evacuate the site. If possible, take cell phones and/or portable radios along in each vehicle so communication can be maintained in the group.

Brush hogging shall be done during fire season months to keep vegetation cut around the complex. Mowing will be maintained around the emergency power generator equipment for a minimum distance of 100 ft. Dead, dry grass should be kept mowed to less than 6 inches.

9.3 Oil Spill Response

A Spill Prevention, Control and Countermeasures (SPCC) Plan as set out by the EPA is on file with BLM and maintained at the MRP site, and is not included here. This plan will be updated for site purposes to cover the East RDD Pilot and the ELHT. Copies of the revised SPCC will be available on request.

9.4 Medical Response, Medical Evacuation Plan

The East RDD Project will have the ability to provide First Aid, First Responder, and Ambulance transport in case of an emergency. A helipad is located at the Shell Administration Building, approximately ½ mile east of the RDD site. The roads between are improved county dirt roads that are maintained year round.

Shell presently has on site three emergency medical technicians (EMT). During operations at the East RDD Project, Shell will have on site at least one EMT per shift and provide coverage during 24 hour operations. In-house HSE (Health, Safety, and Environment) technicians will be on site during all periods or operation.

Shell EMTs at the MRP facilities are members of the Meeker Volunteer Fire Department. EMTs have First Responder status and maintain certifications through the Meeker VFD and Shell training. Most site personnel have first aid training. Shell EMTs and the Meeker VFD maintain 2-way radio contact with O&G operators and other operators in the vicinity including Encana, ExxonMobil, and others. These companies and the Meeker VFD maintain individual facilities, and are on call to share facilities and responsibility for emergency response.

Shell maintains an on-site ambulance, and a first responder truck which has transport capabilities. The ambulance, which is maintained by Shell, is owned by the City of Meeker. Local Meeker VFD affiliates also have ambulance capabilities.

10 LEASE CONVERSION PLAN

While the East RDD Pilot project is underway, Shell will collect additional environmental baseline data for the region, and develop sufficient information to support an environmental impact assessment for a potential commercial project. Internally, Shell will evaluate the technical results of the East RDD Pilot, assess the economics of a potential commercial project, and evaluate the potential environmental and socioeconomic impacts. Post-Pilot studies could require several additional years depending on the need for follow-up drilling, laboratory studies, modeling and other evaluations of the RDD project. Together, these works will provide the foundations of the required "demonstration of production in commercial quantities", as described in the RDD Lease and the Oil Shale Regulations.

The demonstration of production in commercial quantities in the Lease Conversion Application will seek to convert the 149 acre RDD lease to a commercial lease within the Preference Right Lease Area (PRLA). The PRLA covers ~ 5120 acres surrounding the East RDD Lease. Plans for a commercial scale project will accompany the Lease Conversion Application, along with a data package of environmental, engineering, socioeconomic and other information to inform an environmental impact assessment for a commercial scale project.

Shell intends to convert the entire PRL of approximately eight sections to a commercial lease. The lease conversion will rely on the technology demonstration, environmental impact assessment, and an economic assessment in sufficient detail to demonstrate production of oil shale in commercial quantities.

The Lease Conversion Application will be filed within 90 days of demonstration of production of oil shale in commercial quantities. Shell will notify BLM when the demonstration of production in commercial quantities has been achieved, and file the Lease Conversion Application within 90 days of that notice. A demonstration of production in commercial quantities scales up the technical and economic aspects of the RDD project to a commercial sized project. The demonstration is to provide the technological support that there is a reasonable expectation that oil shale can be produced profitably, at a commercial scale, by application of the demonstrated technology and other accepted extraction methods. The commercial quantities economic estimate will depend on factors such as oil and gas price, energy price, capital and operating costs, recovery efficiency, energy efficiency, anticipated heater performance, royalty rates, tax rates, prevailing rate of return discounting rate, opportunity costs, and other factors. The lease conversion plan will address disposition of oil shale within the Preference Right Lease Area, and also of nahcolite with options to preserve, produce, sell, lease, or otherwise conserve the sodium resources.

The lease conversion plan will propose a bonus payment based on a calculation of fair market value (FMV). The FMV calculation considers, at a minimum, comparable sales in existence at the time of lease conversion, assessments based on other experimental technologies, current crude oil and natural gas pricing at the time of conversion, investment costs for a commercial operation, operating (ICP, upgrading and refining) costs, operating efficiency or extraction efficiency compared with FA values, estimated investment return timeline, profit, royalty payments, cost of electrical power, and other factors. It is understood that comparable sales for reserves developed in situ do not exist presently, and may not be available at the time of conversion as in situ conversion technology has not been applied at a commercial scale. The absence of existing commercial production using the demonstrated technology may reduce the apparent resource value where such values are estimated by assays alone as the overall valuation depends under those circumstances on modeling, professional estimates and the like.

Shell considers that production in commercial quantities involves the following technical and economic aspects related to the proposed technology:

- Demonstrate permeability generation in the Saline Zone (nahcolitic) oil shale section
- Demonstrate ICP heating success
- Produce 1,500 barrels minimum cumulative oil at a peak rate of greater than 10 bopd.

Production in commercial quantities depends on the generation of sufficient permeability to enable liquid hydrocarbons to flow to producer wells. Such permeability can be generated in a commercial project in the Saline Zone when a sufficient amount of nahcolite is removed to generate pore space for the formation to dilate into once heated, and when liquid hydrocarbon collection points are sufficiently placed and sized to produce the hydrocarbons generated by ICP.

Successful operation of heaters at the target depths is also essential to production in commercial quantities. Heater operation will be considered successful if the heaters collectively generate enough thermal mass over the duration of the project to pyrolyze oil a high enough rate and with enough efficiency to ensure the potential for profitability in a commercial sized operation.

The heating design has built-in redundancy in that even though one or more heaters may not perform, and may not be replaced, a commercial project, if sized to account for limited under performance, might still be technically sufficient to support commercialization.

The system of natural permeability and permeability enhanced by leaching, heating, and hydrocarbon production also must deliver hydrocarbons with enough efficiency to be economic in a commercial setting. Technically, this requires that economic projections based on Fischer Assay oil grades translate to acceptable levels of hydrocarbon expulsion and production in the commercial setting. The target production of 1,500 bbl liquid hydrocarbons minimum in this POD also represents a minimum expectation for a commercial project. A higher expulsion efficiency and production would improve the commercial economics.

The primary purpose of the ELHT is to measure the response of the reservoir to heating (principally looking for the development of heater "hot spots") in order to inform Shell's commercial heater design. Other important geomechanical and reservoir learnings are expected.

11 OTHER ISSUES

11.1 Temporary Abandonment Procedures

Temporary abandonment is not anticipated. As the project is a research operation, it is not designed to respond to market conditions that might otherwise call for temporary abandonment. Leaching operations can be shut in at any point by, for instance, cessation of hot water circulation during leaching or turning off the heaters during pyrolysis. Oil shale pyrolysis, however, will continue for some time after heaters are turned off; heat applied to the formation will continue to break down kerogen to form hydrocarbon gases and liquids, so some amount of production and monitoring will need to remain in place following cessation of heating. The amount of time necessary for such continued monitoring and production will depend on the amount of heat applied up to the point when heaters are turned off, production rates, and other factors that can remove heat from the formations affected by the heaters.

11.2 Treatment

There will be no on-site or off-site treatment of leach solutions, oil or gas, recovered ground water or water injected for leaching.

11.3 Control of Process Solutions and Hydrocarbon Products

Produced liquids, including nahcolite solution and hydrocarbon liquids, will be trucked to appropriate facilities off site. Gases will be flared. Loading of tanker trucks for fluid transport will take place on concrete pads that drain to a collection sump. Spills on these pads, if any, will be removed/recovered from the sumps and trucked off site to appropriate disposal facilities.

11.4 Injection

Fresh water will be trucked to the Project Site and heated for injection to leach nahcolite as part of the East RDD Pilot. Injection will take place under a UIC permit issued by EPA Region VIII.

11.5 Subsidence

Owing to the significant depth and small diameter of the leached and pyrolyzed volume, surface subsidence at the East RDD Pilot is not anticipated.

Conservative geomechanics modeling, which analyzed the stress field above a 40 ft diameter open cavern, indicates that tensional effects will be observed no higher than about 10 ft above the cavern, and total stress induced by a theoretical cavern of 20 ft radius will diminish to nil above about 40 ft above the cavern. (See section Geomechanics, Appendix A).[x] Therefore,

[x] Surface subsidence at a similar sized project that was only about 450 ft deep, the MDP[s] on Shell land near Cathedral bluffs, was less than 1 mm.

surface subsidence monitoring is not planned. Subsidence in the crown will be monitored via radioactive tags.

No surface subsidence is expected from ELHT as there will be no leaching and minimal production/mass removal.

11.6 Surface Water Pollution Control

The Project site rests atop a local hill, approximately 3 miles from the Stake Springs Draw. Except for rare springs, Stake Springs Draw is dry except during spring snow melt. All surface facilities are designed to contain fluids at the surface for later off site trucking. In the event of a spill or loss of tank containment – the only containment anticipated – the ability for pollutants to reach a stream is not feasible given the overland distance such fluids would have to travel, and the maximum volumes that may be contained on site ready for off-site trucking at any time.

11.7 Natural Resources Protections

Natural resources of the RDD area include ground and surface water, geological resources including sodium minerals and oil shale adjacent to the RDD lease, gas resources beneath the RDD Project target horizons, topsoil, and rangeland vegetation. The operations, geology and resources sections, and reclamation sections describe measures to protect these resources. Subsurface extraction and pyrolysis processes are confined and contained within the target interval. Subsurface reclamation plans provide for closure and containment of the mined (leached and pyrolyzed) interval. Natural gas resources are several thousand feet below the oil shale and sodium mineral resources, sufficiently distant from effects or leaching and pyrolysis. Surface reclamation will replace topsoil, restore drainage, and return the surface to a rangeland habitat, with fencing to remain until reclamation revegetation is self-sustaining.

11.8 Personnel and Vehicle Count

It is part of Shell's safety culture to limit driving to and from the site as well as on site as vehicle accidents are the most significant source of accidents and fatalities. Shell enables car pooling by providing car pool vans to employees who can participate. The attached tables (Table 11.1 and Table 11.2) list the number of full time personnel, and estimate vehicle trips. Table 11.2 includes shows the estimated number of trips for both the East RDD and the ELHT.

For the East RDD, vehicle trips to and from the site are estimated for trucks (tankers, haul trucks, delivery trucks, etc.) and passenger vehicles (pick-ups, sedans, and carpool vans). The estimated truck vehicle trips are subdivided into project phases including drilling, construction, leaching, pyrolysis and reclamation (Table 11.1). The totals are further segregated into water and/or oil and produced-water trucks versus all other trucks for each phase.

The total number of trucks during maximum production is estimated at 2,895 trips per year during the leach phase, and 848 trucks during the pyrolysis phase. The plan is for the same truck to be used to bring in makeup water and haul away nahcolite-rich liquor, during the leach phase, but the estimate provided assumes one truck per incoming and one truck per outgoing loads, for a worst case calculation. Truck trips during the drilling and construction phases are estimated at 1,116 and 1,352, respectively. During subsurface reclamation the yearly total is estimated at 161.

For the East RDD, the total estimated number of passenger vehicle trips and personnel required for each project phase is presented in Table 11.2. During the Operational Phase, the required personnel, consisting of Shell employees and contractors, are 25. The estimated annual number of personal vehicle trips during this phase is 4,921, an average of 13 trips per day.

Table 11.2 includes a summary of additional vehicle trips anticipated for the ELHT. For estimating purposes, the number of additional vehicle trips associated with construction, drilling, pyrolysis and reclamation of the ELHT was determined using scaling factors based on time or production rates applied to the East RDD vehicle counts.

The vehicle trips anticipated during drilling is 372 over a 2 month period, and the vehicle trips estimated for construction is 225 over a 2 month period. Leaching will not be conducted at the ELHT so accounting for additional vehicle trips is not applicable.

For the pyrolysis phase, the vehicle trip estimate is 85, which is based on 10% of the vehicle trips determined for the East RDD. A factor of 10% was used based on the ELHT being projected to produce approximately 10% of production rate for the East RDD (i.e., 1,500 barrels of oil projected for the East RDD and 150 barrels of oil projected for the ELHT). The pyrolysis phase of the ELHT will be concurrent with the East RDD so additional trips for operators to travel to and from the site was not included.

For the reclamation phase at the ELHT, the total number of vehicle trips is estimated to be 3. Reclamation of the ELHT will occur at the same time as the East RDD so minimal additional trips are anticipated.

Table 11.1: Truck Traffic Estimates – Summary

TRUCK TRAFFIC ESTIMATES

Drilling
Peak Rates East RDD- 1 Rig for 6 months period / ELHT- 1 Rig for 2 months

	Per Day	Per Week	Per 4-Wk	Annual Total:	ELHT / 2 Month
* Subtotal (Main Tank Trucks):	0.8	5.6	22.5	292	97
Subtotal (Excl. Main Tank Trucks):	2.26	15.83	63.33	823	274
TOTAL ALL VEHICLES:	3.1	21.5	85.8	1,116	372

Construction
Peak Rates East RDD- 1 year period / ELHT- 1 month

	Per Day	Per Week	Per 4-Wk	Annual Total:	ELHT / 2 Month
* Subtotal (Main Tank Trucks):	1.0	7.0	28.0	364	61
Subtotal (Excl. Main Tank Trucks):	2.71	19.00	76.00	988	165
TOTAL ALL VEHICLES:	3.7	26.0	104.0	1,352	225

Leaching
Peak Rates East RDD- 500 BWPD / ELHT- n/a

	Per Day	Per Week	Per 4-Wk	Annual Total (based on 9 mos operation):	ELHT
* Subtotal (Main Tank Trucks):	10.0	70.0	280.0	2,520	n/a
Subtotal (Excl. Main Tank Trucks):	1.49	10.42	41.69	375	n/a
TOTAL ALL VEHICLES:	11.5	80.4	321.7	2,895	n/a

NOTES
1) Plan is for the same truck to bring in makeup water and haul away rich liquor, but this assumes worst case of separate truck s for each.

Pyrolysis
Peak Rates East RDD- 13 BOPD, 16 BWPD / ELHT- 1BPOD, 1BWPD

	Per Day	Per Week	Per 4-Wk	Annual Total:	ELHT 10% ERDD
* Subtotal (Main Tank Trucks):	2.2	15.1	24.5	318	32
Subtotal (Excl. Main Tank Trucks):	1.45	10.18	40.73	529	53
TOTAL ALL VEHICLES:	3.6	25.3	65.2	848	85

NOTES
1) The same truck will be used to bring in makeup water and haul away rich liquor

Reclamation
Peak Rates East RDD- fill with 9,000 bbls / ELHT- n/a

	Per Day	Per Week	Per 4-Wk	Annual Total:	ELHT / 1 Month
* Subtotal (Main Tank Trucks):	0.4	2.5	9.8	127	0
Subtotal (Excl. Main Tank Trucks):	0.09	0.65	2.58	34	3
TOTAL ALL VEHICLES:	0.4	3.1	12.4	161	3

Table 11.2: East RDD 2012-2016 Operations Staffing and Personal Vehicle Projections

East RDD Staffing and Personal Vehicle Trip Projections 2012-2016		
Construction Phase		
	Number of Persons	Est. # of Trips per Year
Shell Supervisors Count=	5	1274
Shell Staff Count =	21	4710
Contractor Staff Count =	60	4161
Total Construction phase	86	10,144
Operational Phase		
	Number of Persons	Est. # of Trips per Year
Shell Supervisors Count=	5	260
Shell Staff Count =	16	3621
Contractor Staff Count =	4	1040
Total Operations Phase	25	4,921
Reclamation Phase		
	Number of Persons	Est. # of Trips per Year
Shell Supervisors Count=	5	0
Shell Staff Count =	7	52
Contractor Staff Count =	0	0
Total Staff Count	12	52

Assumptions:

Number of Persons - Includes fractional counts reflecting less than full-time commitment (and visits) to EAST RDD.

Est. # Trips per Year - Assumes everyone drives individually to the site as worst case (no car-pools). Assume everyone accesses the OST site via the hwy 24/91 access road, no reductions in trips for holidays or vacation days.

11.9 Public Safety and Hazards Controls

Potential hazards on the East RDD site include: (1) processing and associated transfer facilities that contain liquid hydrocarbons, (2) heated surfaces, and (3) flare gases. Public safety is assured by access restrictions, fencing, warning signs, site attendance during operations, traffic rules, setbacks (for the flare), fire breaks, and site monitoring.

Public safety is best assured by strict site access limitations, including a required sign-in/sign-out procedure and public access on a need to know basis. Visitors are required to undergo a site-specific safety orientation prior to escorted access; all visitors will be escorted. Workers including Employees and Consultants working on site are required to have task specific safety training, including emergency response training and procedures.

A game fence (8 ft height) around the operating facilities precludes inadvertent entry. A cattle fence (barbed wire) will encase the entire RDD permit area north of the pipeline ROW. Fences will be posted with "No Trespassing" signs and specific warning signs alerting would-be trespassers to potential dangers. Trespassing during operational phases will be deterred as operations will be manned during the leaching and heating phases.

A 25 ft wide firebreak inside the operations fence will be kept free of weeds and dry vegetation, and will be mowed in summer to slow or inhibit spread of range fires. In case of a fire, unaffiliated persons in the nearby area will be cautioned and led or escorted to safety in event of an evacuation.

The flare is to be situated inside the high fence, near the center of the East RDD, and at maximal distance from the site boundaries. Access will be strictly controlled. The flare area will have alarms to warn of high H_2S in the air.

Shell maintains strict adherence to local and site-specific traffic laws. Driving speeds are monitored with in-vehicle monitoring devices that record excessive speed and other potentially risky driving behaviors, and follow-ups are carried out routinely to address non-adherence. Shell does not monitor non-Shell personnel, but consultants and vendors are required to pass mandatory site safety rules, and all personnel, including Shell employees, contractors, and vendors are empowered and implored to intervene at the sight of unsafe behaviors. Cell phone use is prohibited while driving; this includes dialing, answering, talking and texting. Alcohol is prohibited from all facilities, properties, and Shell vehicles.

11.10 Other Permits

Shell will file, or has already received, several permits related to the East RDD Pilot Project. The BLM Access and RBC Driveway Permits are approved. Ground water monitoring well permits also are in place, and monitoring is ongoing.

Several major permit applications and notices are to be filed in late December 2010 to early January 2011. These include the POD, NOI, Air Quality Construction Permit, UIC permit and Rio Blanco County Special Use Permit.

Additional permits covering transport, road use, construction will be submitted as construction and transportation needs are fully known, and after the major permits have been reviewed by the agencies and adjustments are made based on the agency reviews.

An existing occupancy permit for the Corral Gulch Temporary Living Quarters will be reactivated to accommodate construction.

A number of environmental plans, surveys, and studies accompany the BLM Plan of Development. Environmental update studies will be conducted in 2011 as a condition of POD approval.

An entire list of the required permits, plans, notices, and studies associated with the East RDD Pilot are provided in the table following (Table 11.3).

Table 11.3: East RDD Project: Permits, Notices and Plans

Environmental & Access Permit, Notice, Plan	Reviewing Agency	Comments
Prospecting Notice of Intent (NOI)	DRMS	To be submitted early 2011
Plan Of Development (POD)	BLM	To be submitted early 2011
Air Quality Construction Permit	APCD	To be submitted early 2011
Special Use Permit (SUP)	RBC - PC	To be submitted early 2011
Underground Injection Control Permit (UIC)	EPA	To be submitted early 2011
Section 404 Permit	USACE	Consult USACE for direction
Water Well Permits, including Monitoring wells	SEO	To be submitted 2011
Construction - Stormwater Discharge Permit	WQCD	See POD
Operational - Stormwater Discharge Permit	WQCD	To be submitted prior to operations
Air Quality Land Development Permit	APCD	To be submitted prior to site activities
Notification of Regulated Waste Activity	HMWMD	Hazardous waste not anticipated
Above Ground Storage Tank Permit	DPS	To be permitted prior to activity
Public Land Right-Of-Way Permit	BLM	Covered by existing access road permit
Timber Removal/Fuel Wood Permit	BLM	BLM consultation. Permit not anticipated.
Operational Permits		
Occupancy Permit	RBC	Existing permit to be renewed
Building Permits	RBC	To be permitted prior to construction
Utilities Installation Permit	RBC R&B	To be permitted by Utility Service Provider
Access or Driveway Permit	RBC R&B	Existing
Hazardous Materials Transport Permit	DOT	Consult agency. Hazardous waste not anticipated
Hazardous Materials Transportation - Annual Permit	DRA, PUC	Consult agency. Hazardous waste not anticipated
Transport Permit	RBC	To be developed prior to site activities
Snow Removal Permit	RBC	To be developed prior to site activities
Environmental Plans		
Spill Prevention, Control and Countermeasure (SPCC) Plan	BLM, DRMS, RBC	See POD
EPA Risk Management Plan	EPA	
Construction Stormwater Management Plan	BLM, DRMS, RBC	See POD
Operations Stormwater Management Plan	BLM, DRMS, RBC	To be submitted prior to operations
Materials Handling and Waste Management Plan	BLM, DRMS, RBC	
Ground Water Monitoring and Response Plan	BLM, DRMS	See POD
Surface Water Monitoring Plan	BLM, DRMS	See POD
Visual Impacts Minimization Plan	BLM	See POD
Noise Management Plan	RBC	See SUP
Wild Horse Protection and Impacts Mitigation Plan	BLM	See POD
Wildlife Recovery and Replacement Plan	BLM	See POD
Cultural Resources Class III Inventory	BLM	See POD
Most Recent Noxious Weed Project Sites Survey	BLM	See POD
Raptor & Nesting Migratory Birds Survey	BLM	See POD
Special Status Species Survey	BLM	See POD
Pre-Construction Special Status Plant Species and Source Population Survey	BLM	See POD
Soil Survey	BLM, DRMS	See POD
Paleontology Class I & Class II Geologic Formation Survey	BLM	See POD
Operational		
Site Health and Safety Program	BLM	Site Document
Fire Management Plan	BLM, County	See POD
Transportation Plan	BLM, County	See SUP
Process Safety Management Plan	OSHA	Site Document

Agency Abbreviations:

APCD: Air Pollution Control Division of CDPHE

BLM: Bureau of Land Management

CDPHE: Colorado Dept of Public Health & Environment

DOT: Dept of Transportation

DRA: Dept of Regulatory Affairs

DRMS: Div of Reclamation Mining and Safety

OSHA: Occupational Safety and Health Administration

SEO: State Engineers Office

USACE: US Army Corps of Engineers

USFWS: US Fish and Wildlife Service

WQCD: Water Quality Control Division of CDPHE

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[2] BLM, December 2006, Oil Shale Research, Development and Demonstration (R,D&D) Lease, number COC 69166. Includes BLM, January 2009, Addendum Number 1 to the Oil Shale Research, Development and Demonstration Lease Numbers COC-69166, COC-69167, and COC-69194.

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[11] Nielsen, K.R., L.G. Cirotski, A.L Turner (2004) Sodium Bicarbonate Production from Hancolite; U.S. Patent 6,699,447 B1, Mar. 2, 2004.

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Attachment 2
Figures

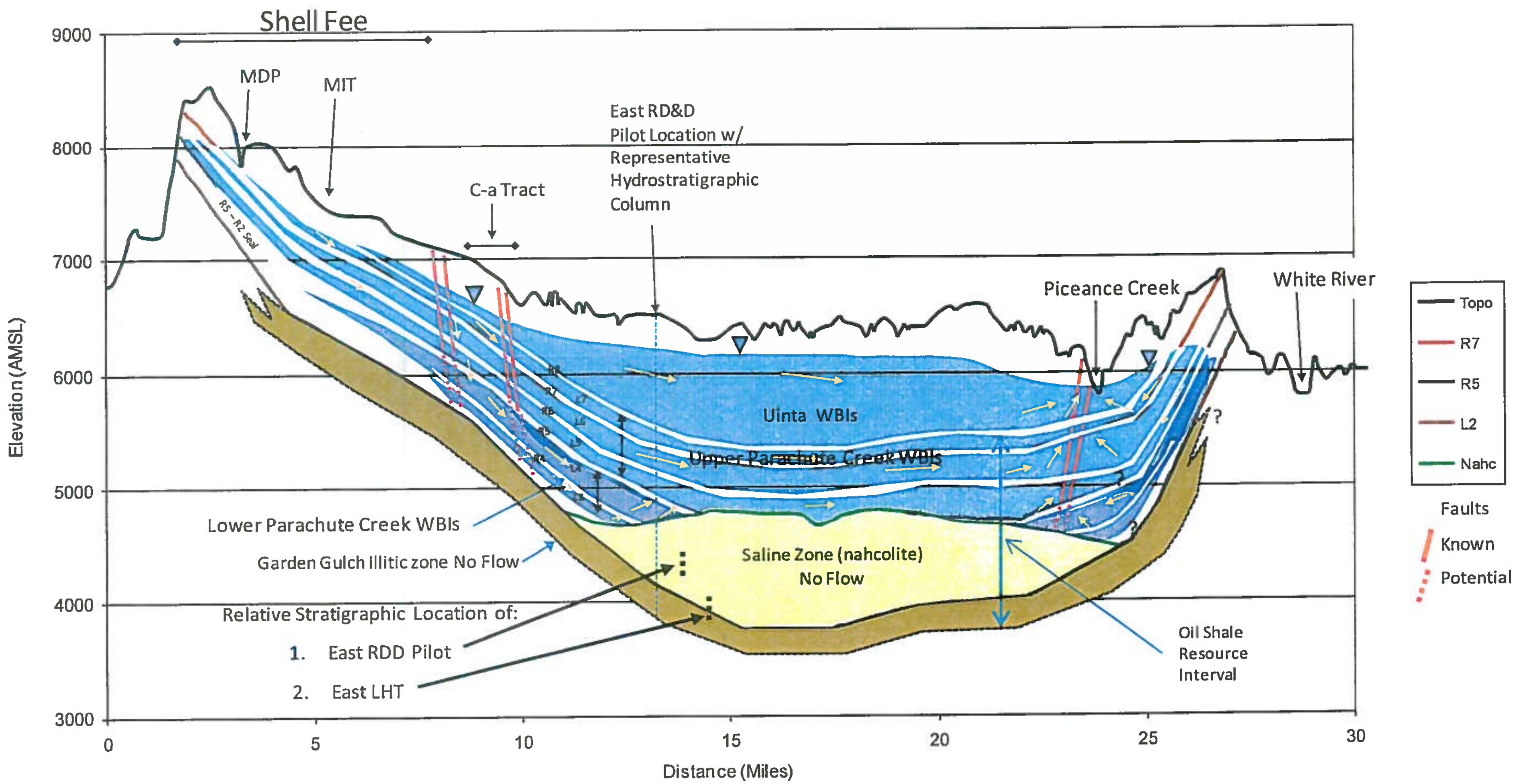


Figure 15: General hydrostratigraphic cross-section across Piceance Basin.

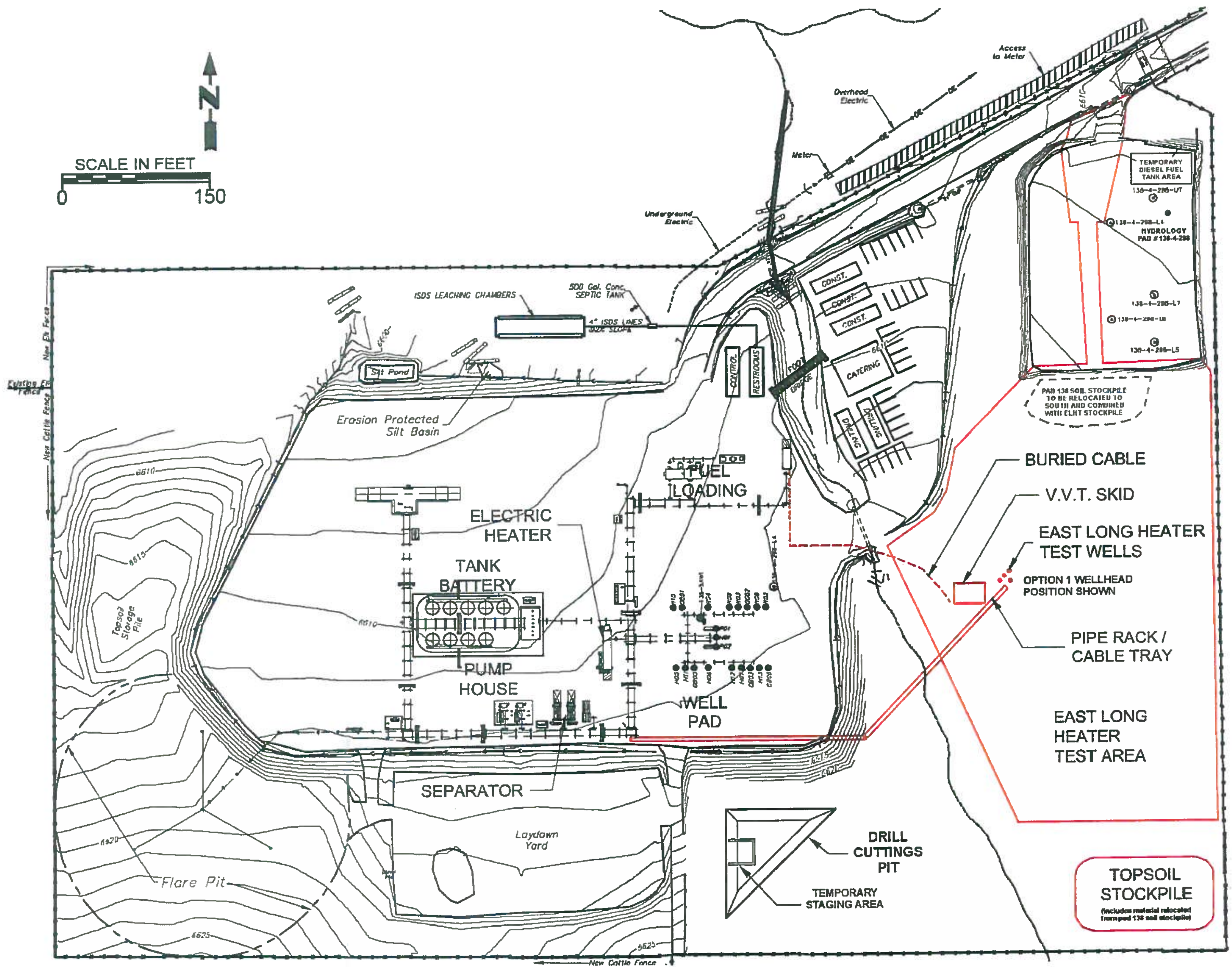
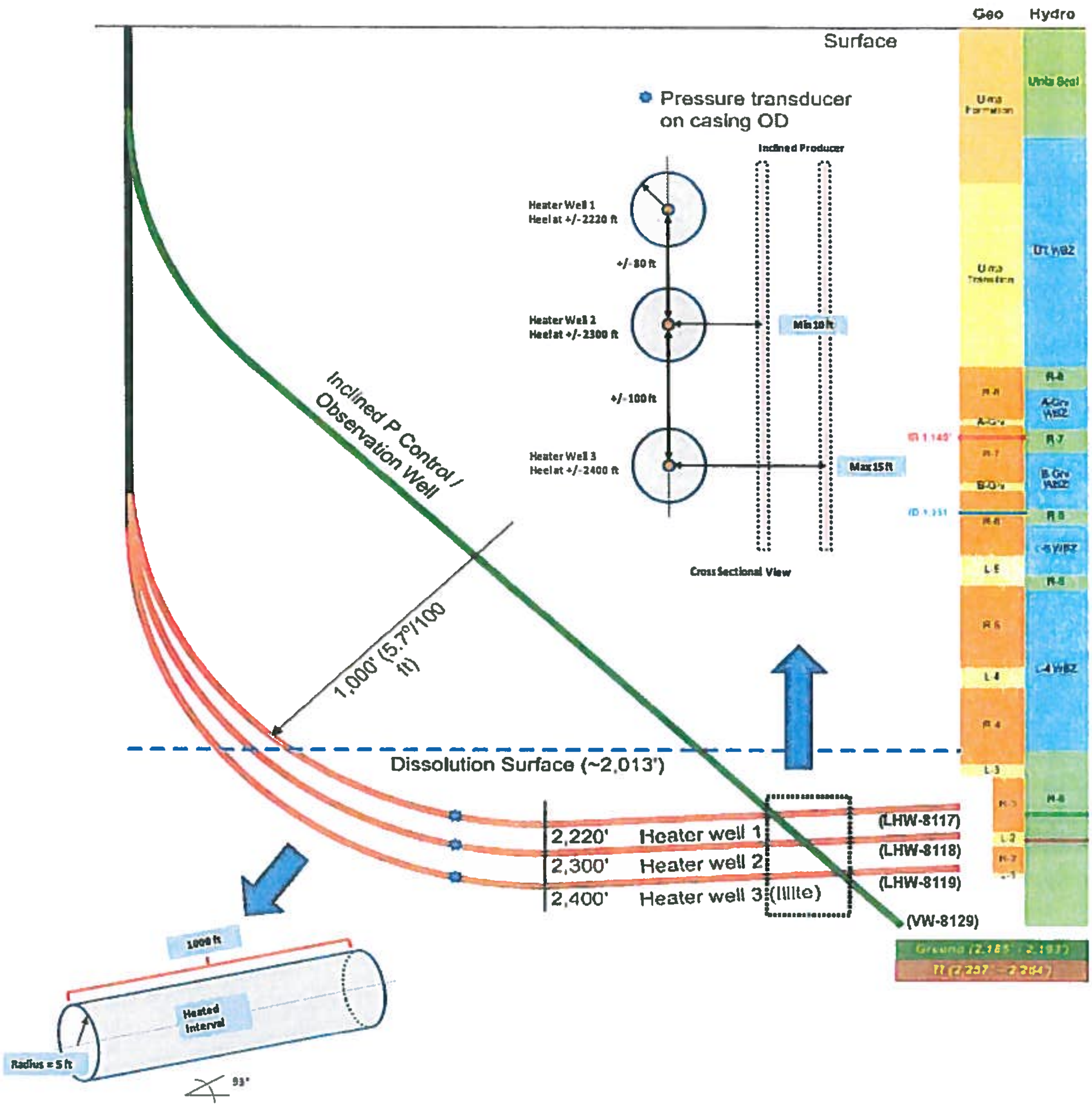


Figure 36: East RDD Facilities



Horizontal Heaters:

1. Heated Interval length: 1000 ft.
2. Inclined 3° relative to horizontal plane.
3. Heel is deepest point in well.
4. Toe approximately 52 feet above heel.

Inclined Pressure Control / Observation Well:

1. Inclined at 45° relative to vertical.
2. Distance between PC well and each Heater well: 10 ft (maximum: 15 ft).
3. Will pass deepest heater well at approximately 750 ft from the start of the heated section and 250 ft from the toe end of the heated section.

Figure 37a: Schematic Cross-Section of ELHT Well Configuration

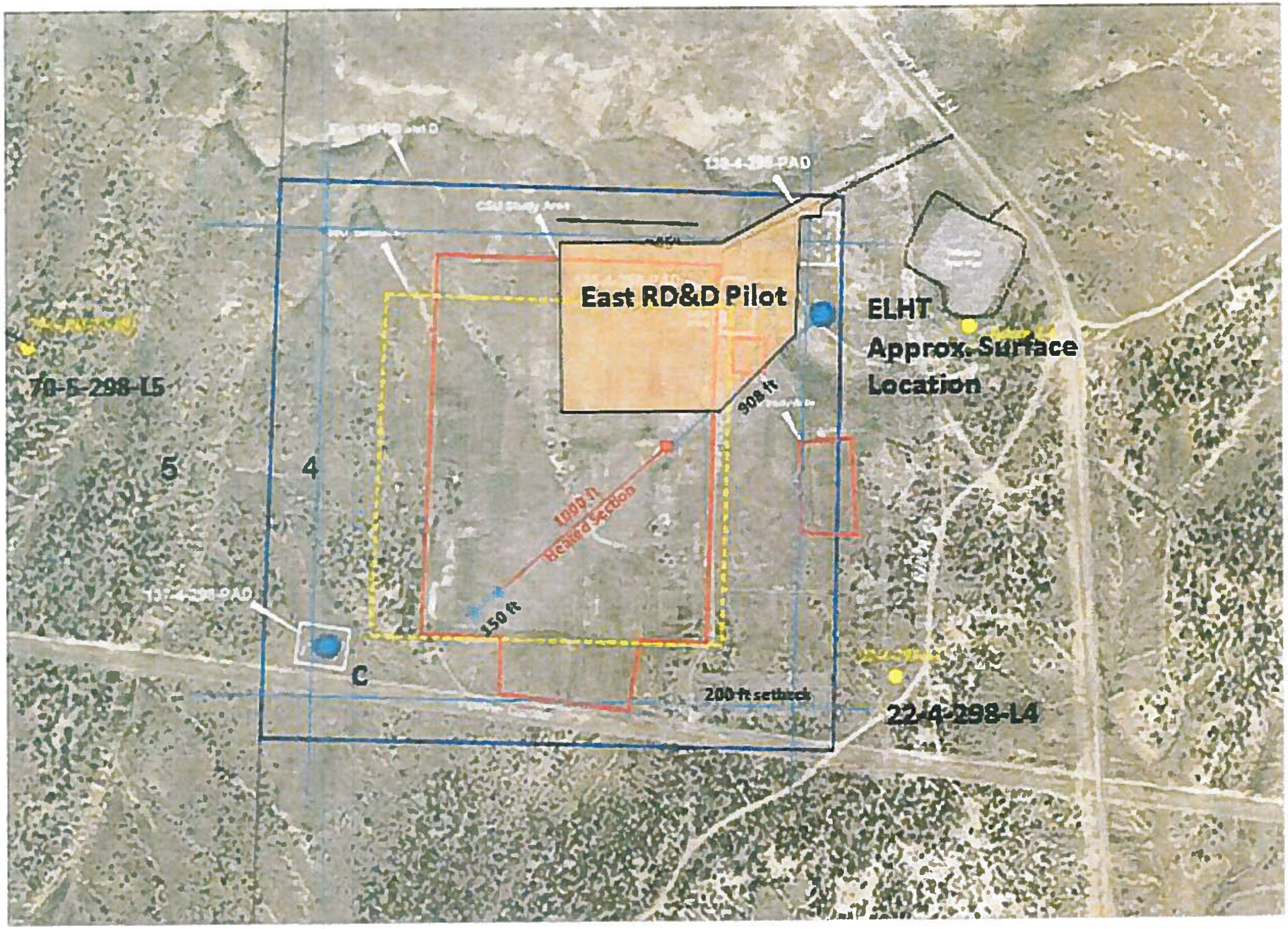
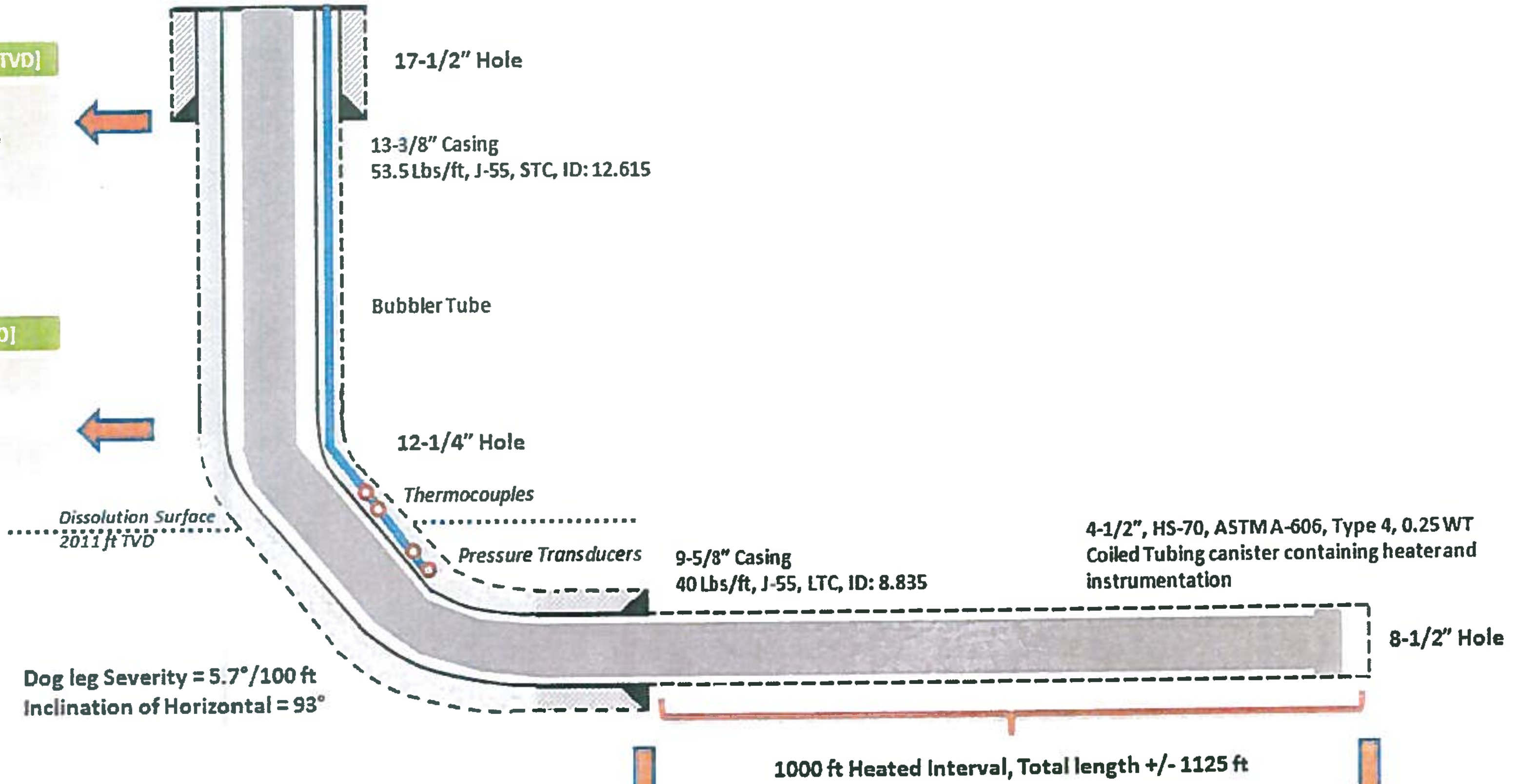


Figure 37b: Plan View of ELHT Well Trajectories



Well	Conductor [ft TVD]
HW-1	60 to 200
HW-2	
HW-3	

Well	KOP [ft TVD]
HW-1	1217
HW-2	1297
HW-3	1397

Well	9-5/8" Casing - heel [ft TVD]
HW-1	2220
HW-2	2300
HW-3	2400

Well	Well TD – Toe [ft TVD]
HW-1	2160
HW-2	2240
HW-3	2340

WELL NUMBER DESIGNATIONS:	
Working	Final for ERDD
HW-1	LHW-8117
HW-2	LHW-8118
HW-3	LHW-8119

Figure 38: Schematic Diagram of an ELHT Horizontal Heater Well

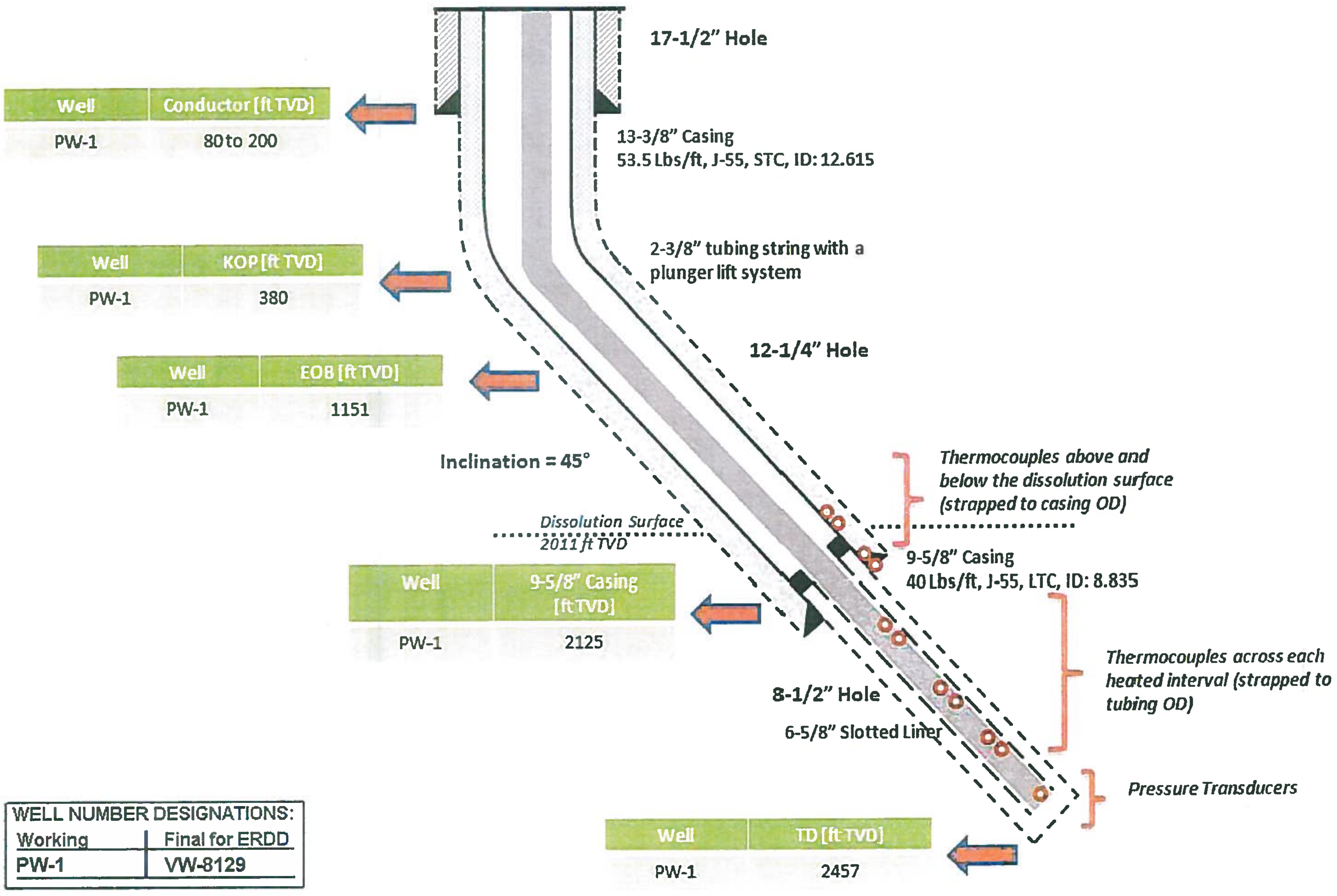


Figure 39: Schematic Diagram of the ELHT Inclined Observer / Producer Well

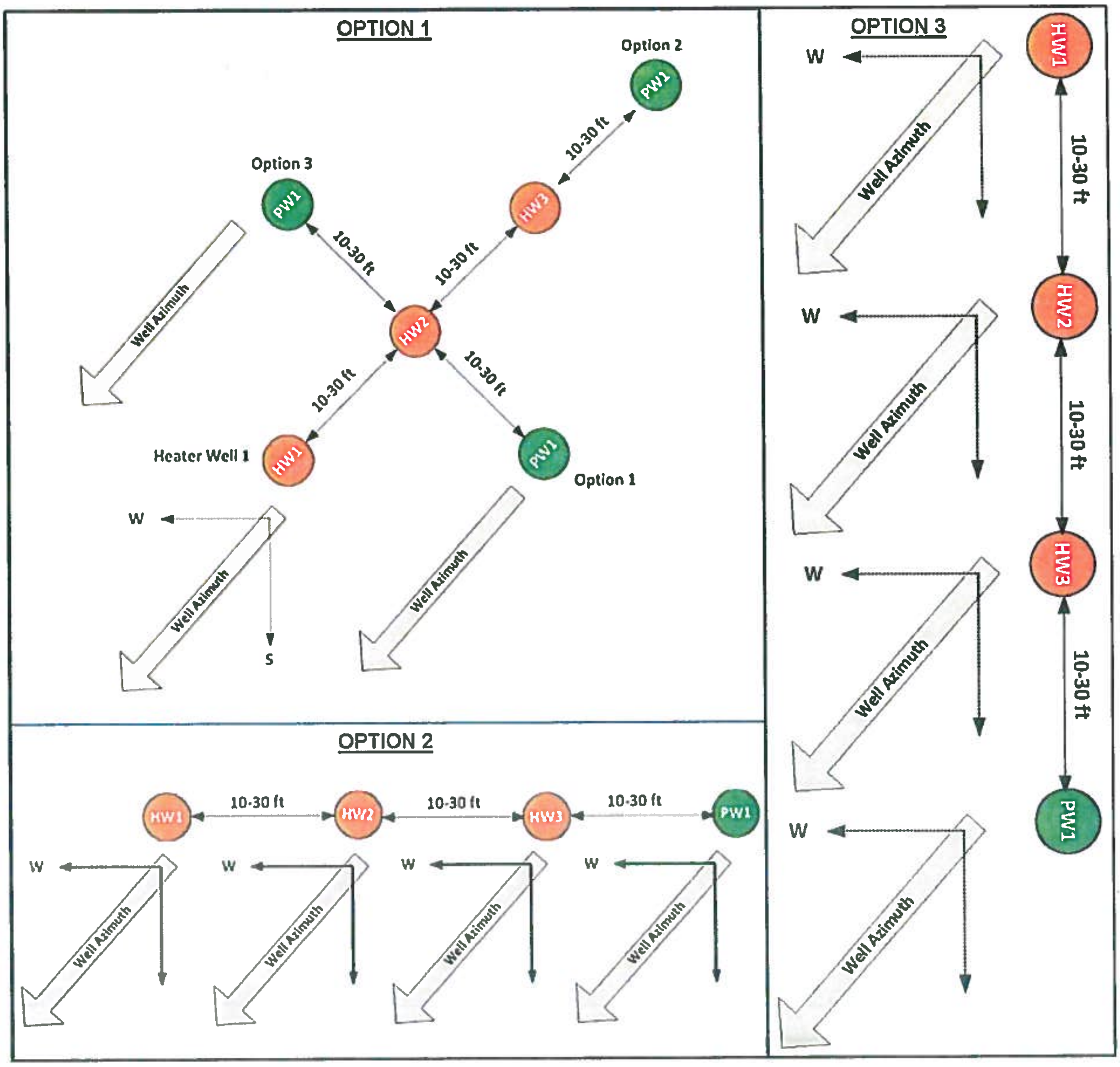


Figure 40: ELHT Wellhead Position

Attachment 3
Appendix H

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

COVER SHEET

Site East RD&D Pilot Project **Date** March 6, 2013

NOI # P-2010-026

General Cost Summary

Contract work for final reclamation:

Structural demolition	$274,890
Borehole plugging and abandonment	$1,835,844
Storm water pond backfill	$1,248
Site regrading	$45,766
Access road regrading	$8,868
Ripping	$10,601
Soil replacement	$20,720
Revegetation - Pinyon/Juniper ridgetop areas	$15,962
Revegetation - Mid-slope areas	$36,475
Revegetation - Upland drainage areas	$5,521
Mobilization & demobilization	$45,388
Job superintendent	$24,045
Subtotal:	$2,325,327

Regulatory agency administrative expenses and O & M costs:

DRMS Minerals Program bond processing cost	$500
Subsurface reclamation	$544,109
DRMS Minerals Program project administration fee	$143,497
Subtotal:	$688,106

Total estimated bond amount:	$3,013,433
Additional bond for future modifications:	$0
Grand total bond amount:	$3,013,433

Shell Frontier Oil & Gas Inc.
FINANCIAL WARRANTY CALCULATION
GENERAL COST SUMMARY BY WORK CATEGORY

Site East RD&D Pilot Project **NOI #** P-2010-026 **Date** March 6, 2013

WORK CATEGORY	DIRECT UNIT COST	UNIT OF MEASURE	UNIT COST WITH O & P	QUANTITY	TOTAL COST	PERCENT OF TOTAL
Overhead & Profit (O & P):						
Liability ins. @ 2.02%						
Perf. bond @ 1.55%						
Profit @ 10.00%						
Total = 13.57%						
Subsurface reclamation:						
Test pad	na	na	$544,109	1	$544,109	18.06%
				Total=	**$544,109**	**18.06%**
Demolition:						
Structures & facilities	na	na	na	na	$274,890	9.12%
	na	na	na	na	na	na
				Total=	**$274,890**	**9.12%**
Borehole P&A*:						
	na	na	na	21	$1,835,844	60.92%
** Surface casing removal cost included*						
			Total=	21	**$1,835,844**	**60.92%**
Earthwork:						
Regrading	$0.867	LCY	$0.984	56,782.96	$55,883	1.85%
Ripping	$607.72	Acre	$690.19	15.36	$10,601	0.35%
Soil replacement	$0.71	LCY	$0.804	25,762.71	$20,720	0.69%
				Total=	**$87,204**	**2.89%**
Revegetation:	$3,322.44	Acre	$3,773.30	15.36	**$57,958**	**1.92%**
Mobilization/Demob.:	$39,964.77	Job	$45,388	1	**$45,388**	**1.51%**
Supervision:	na	Job	$24,044.51	1	**$24,045**	**0.80%**
DRMS admin. costs:						
Bond processing fee	na	Job	$500	1	$500	0.017%
DRMS 5% admin. Expense	na	Job	$143,497	1	$143,497	5.00%
				Total=	**$143,997**	**5.017%**
Total estimated bond amount:					$3,013,433	100.00%
Additional bond for future modifications:					$0	0.00%
Grand total bond amount:					$3,013,433	100.00%

Shell Frontier Oil & Gas Inc.

TABLE 1 - FINANCIAL WARRANTY CALCULATION - EAST RDD NOI - MODIFICATION #3 - ELHT

COST SUMMARY

Site East RD&D Pilot Project **Date** March 6, 2013 **File** P-2010-026

Direct costs

Task No.	Description	Acres	Equipment	No. Units	Task Hours	Direct Cost
1	Structural demolition	na	Demo. crew	3	326.29	$242,044
2	Borehole P&A	na	Drill rig + crew	3	467.42	$1,616,486
3	Storm water pond backfill	na	Cat D8T - SU	3	1.87	$1,099
4	Site regrading	na	Cat D8T - SU	3	68.70	$40,298
5	Access road regrading	na	Cat D8T - SU	3	13.31	$7,809
6	Ripping	na	Cat D8T - SU	3	15.37	$9,335
7	Soil replacement	na	Cat 623G	2	40.31	$18,244
8a	Revegetation - Pinyon/Juniper ridgetop areas	3.91	Rev. crew	2	3.91	$14,055
8b	Revegetation - Mid-slope areas	9.82	Rev. crew	2	9.82	$32,117
8c	Revegetation - Upland drainage areas	1.63	Rev. crew	2	1.63	$4,861
9	Mobilization/demobilization	na	Transport rigs	27	4.00	$39,965
10	Subsurface reclamation	na	na	na	na	see below
	Totals:	15.36			952.64	$2,026,312

Indirect costs

Contractor's overhead & profit (O & P):

Liability insurance:	2.02%	of direct	$40,932
Performance bond:	1.55%	of direct	$31,408
Job superintendent:	per SUPERINTENDENT Tab		$24,045
Profit:	10.00%	of direct	$202,631
Reclamation contract amount (direct + O & P):	$2,325,327	Total O & P:	$299,015

Agency administrative costs:

CDRMS bond processing cost: - Corporate surety $500

Miscellaneous administrative costs:

Subsurface reclamation per SUBSURFACE Tab $544,109

DRMS Minerals Program project administration fee: 5% statutory $143,497

Total indirect costs: **$987,121**

Minimum required bond coverage Total: **$3,013,433**

Additional bond for future modifications 0.00% add-on Total: $0

Grand total bond amount **$3,013,433**

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

DEMOLITION & DISPOSAL - 2 PAGE ESTIMATING FORM

Site East RD&D Pilot Project | **Date** March 6, 2013 | **Task no.** 1

MEANS Location Adjustment (applies to Means-sourced costs only) — City nearest project site listed in Means: Glenwood Springs; Year: 2013

Location adjustment - Eqp. & labor: 80.90%; Materials: 101.80%

Number of demolition crews used: 3

ITEM DESCRIPTION	DIMENSIONS	METHOD OR CATEGORY OF DEMOLITION	QUANTITY	UNIT	UNIT COST*	SOURCE CODE	TOTAL COST**	TASK HOURS
25Kv Substation - superstructure + gutting	39'L x 27'W x 16'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	16,848	CF	$0.1811	M-02 41 16.13 w/mod.	$2,468.29	3.04
- concrete pad	39'L x 27'W x 6"T	Concrete floor, 6 in., disposal in excavated pit - 200 ft. push	1,053	SF	$1.2257	M-02 41 13.17 w/mod.	$1,044.15	1.58
- pad foundation - caisson type (no footer)	12 @ 2 ft. dia. X 12 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	12	EA	$65.10	CRG,CDOT,CHB, Means	$781.15	0.80
- security fence - chain link	49 ft. x 37 ft. perimeter, 8 ft. high	Fence removal, chain link, posts & fabric, 8-10 ft. high	172	LF	$2.93	M-02 41 13.60 1700	$407.70	1.03
Cable tray #1 - substa. to control bldg. - superstructure	82'L x 3'W x 1.5'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	369	CF	$0.1811	M-02 41 16.13 w/mod.	$54.06	0.07
- concrete cable tray foundation caissons (20 ft. ctrs)	5 x 2 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	10	EA	$65.10	CRG,CDOT,CHB, Means	$650.96	0.50
- concrete footer (NA - caisson foundations only)	na	na	na	na	na	na	$0.00	0.00
Control building - superstructure + gutting	36'L x 10.5'W x 25'H	Comm. bldg., disposal in excavated pit - 200 ft. push (CSNX)	9,450	CF	$0.1438	M-02 41 16.13 w/mod.	$1,099.54	1.70
- entryway and stairs (2 sets)	35'L total x 5'W x 5'H	Comm. bldg., disposal in excavated pit - 200 ft. push (CSNX)	875	CF	$0.1438	M-02 41 16.13 w/mod.	$101.81	0.16
- concrete floor	36'L x 10.5'W x 6"T	Concrete floor, 6 in., disposal in excavated pit - 200 ft. push	378	SF	$1.2257	M-02 41 13.17 w/mod.	$374.82	0.57
- concrete foundation - caisson type	14 @ 2 ft. dia. X 12 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	14	EA	$65.10	CRG,CDOT,CHB, Means	$911.35	0.70
- concrete footer (NA - caisson foundation only)	na	na	na	na	na	na	$0.00	0.00
Cable tray #2 - substa. to test pad - superstructure	608'L x 3'W x 1.5'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	2,736	CF	$0.1811	M-02 41 16.13 w/mod.	$400.83	0.49
- concrete cable tray foundation caissons (20 ft. ctrs)	32 x 2 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	64	EA	$65.10	CRG,CDOT,CHB, Means	$4,166.16	3.22
- concrete footer (NA - caisson foundations only)	na	na	na	na	na	na	$0.00	0.00
Electrical instr. bldg.- superstructure + gutting	38'L x 7.5'W x 16'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	4,560	CF	$0.1811	M-02 41 16.13 w/mod.	$668.06	0.82
- concrete floor	38'L x 7.5'W x 6"T	Concrete floor, 6 in., disposal in excavated pit - 200 ft. push	285	SF	$1.2257	M-02 41 13.17 w/mod.	$282.60	0.43
- concrete foundation - caisson type	4 @ 2 ft. dia. X 12 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	4	EA	$65.10	CRG,CDOT,CHB, Means	$260.38	0.20
- Electrical conduit - EIB to pipe rack	100' total length	Electrical conduit demolition, no. 2 - 4 in. diameter	100	LF	$0.6633	CRG, CDOT, CHB	$66.33	0.12
Air compressor skid	12'L x 5'W x 6'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	360	CF	$0.1811	M-02 41 16.13 w/mod.	$52.74	0.06
- concrete foundation (NA - skid mounted)	na	na	na	na	na	na	$0.00	0.00
- piping - compressor to N2 rack	Total 30' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	30	LF	$6.09	M-02 41 13.46 0200	$147.80	0.22
N2 rack skid	12'L x 5'W x 6'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	360	CF	$0.1811	M-02 41 16.13 w/mod.	$52.74	0.06
- concrete foundation (NA - skid mounted)	na	na	na	na	na	na	$0.00	0.00
- piping - N2 rack to test pad	Total 160' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	160	LF	$6.0900	M-02 41 13.46 0200	$788.29	1.19
Boiler building - superstructure + gutting	20'L x 13'W x 25'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	6,500	CF	$0.1811	M-02 41 16.13 w/mod.	$952.27	1.17
- concrete floor	20'L x 13'W x 8"T	Concrete floor, 8 in., disposal in excavated pit - 200 ft. push	260	SF	$2.2298	M-02 41 13.17 w/mod.	$469.02	0.71
- concrete foundation/stem wall	66' perimeter x 8"T x 2'H	Concrete wall, 8 in., disposal in excavated pit - 200 ft. push	132	SF	$5.08	M-02 41 16.17 w/mod.	$542.92	0.85
- concrete footer, strip type	66' perimeter x 1.5'T x 2.5'H	Concrete footer, 1.5' x 3', disposal in excavated pit - 200 ft. pus	66	LF	$10.36	M-02 41 16.17 w/mod.	$553.38	1.22
Pipe rack #1 - test pad to boiler bldg. - superstructure	27'L x 6'W x 2'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	324	CF	$0.1811	M-02 41 16.13 w/mod.	$47.47	0.06
- concrete cable tray foundation caissons (20 ft. ctrs)	3 x 2 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	6	EA	$65.10	CRG,CDOT,CHB, Means	$390.58	0.30
- concrete footer (NA - caisson foundations only)	na	na	na	na	na	na	$0.00	0.00
Piping - test pad	Total 150' L x 4'W x 2'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	1,200	CF	$0.18	M-02 41 16.13 w/mod.	$175.80	0.22
Pipe rack #2 - boiler bldg. to loadout - superstructure	752'L x 6'W x 2'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	9,024	CF	$0.1811	M-02 41 16.13 w/mod.	$1,322.05	1.63
- concrete cable tray foundation caissons (20 ft. ctrs)	40 x 2 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	80	EA	$65.10	CRG,CDOT,CHB, Means	$5,207.70	4.03
- concrete footer (NA - caisson foundations only)	na	na	na	na	na	na	$0.00	0.00
Fin Fan cooler building - superstructure	37'L x 25'W x 25'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	23,125	CF	$0.1811	M-02 41 16.13 w/mod.	$3,387.90	4.17
- concrete floor	37'L x 25'W x 8"T	Concrete floor, 8 in., disposal in excavated pit - 200 ft. push	925	SF	$2.2298	M-02 41 13.17 w/mod.	$1,668.64	2.54
- concrete foundation - caisson type	16 @ 2 ft. dia. X 12 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	16	EA	$65.10	CRG,CDOT,CHB, Means	$1,041.54	0.81
- piping - Cooler bldg. to pipe rack	Total 12' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	12	LF	$6.09	M-02 41 13.46 0200	$59.12	0.09
Separator building - superstructure	38'L x 38'W x 25'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	36,100	CF	$0.1811	M-02 41 16.13 w/mod.	$5,288.78	6.50
- concrete floor	38'L x 38'W x 8"T	Concrete floor, 8 in., disposal in excavated pit - 200 ft. push	1,444	SF	$2.2298	M-02 41 13.17 w/mod.	$2,604.88	3.96
- concrete foundation/stem wall	152' perimeter x 8"T x 2'H	Concrete wall, 8 in., disposal in excavated pit - 200 ft. push	304	SF	$5.08	M-02 41 16.17 w/mod.	$1,250.36	1.95
- concrete footer, strip type	152' perimeter x 2.0'T x 3.0'H	Concrete footer, 2' x 3', disposal in excavated pit - 200 ft. push	152	LF	$13.82	M-02 41 16.17 w/mod.	$1,699.27	3.75
- piping - Separator bldg. to pipe rack	Total 12' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	12	LF	$6.09	M-02 41 13.46 0200	$59.12	0.09

ITEM DESCRIPTION	DIMENSIONS	METHOD OF DEMOLITION	QUANTITY	UNIT	UNIT COST*	SOURCE CODE	TOTAL COST**	TASK HOURS
Pump building - superstructure	48'L x 24'W x 25'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	28,800	CF	$0.1811	M-02 41 16.13 w/mod.	$4,219.31	5.19
- concrete floor	48'L x 24'W x 8"T	Concrete floor, 8 in., disposal in excavated pit - 200 ft. push	1,152	SF	$2.2298	M-02 41 13.17 w/mod.	$2,078.13	3.16
- concrete foundation wall	144' perimeter x 8"T x 2'H	Concrete wall, 8 in., disposal in excavated pit - 200 ft. push	288	SF	$5.08	M-02 41 16.17 w/mod.	$1,184.55	1.85
- concrete footer, strip type	144' perimeter x 2'T x 3'H	Concrete footer, 2' x 3', disposal in excavated pit - 200 ft. push	144	LF	$13.82	M-02 41 16.17 w/mod.	$1,609.83	3.56
- piping - Pump bldg. to pipe rack	Total 12' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	12	LF	$6.09	M-02 41 13.46 0200	$59.12	0.09
Flare system - piping - pipe rack #1 to flare stack	158'L x 4" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 3/4-4 in. diameter	165	LF	$2.89	M-02 41 13.46 0100	$385.77	1.10
- piping "T" supports - above grade portion	8 @ 3'W x avg. 5'H structural steel or pipe	Welded steel pipe, 4 in. diameter	64	LF	$7.46	M-02 41 13.33 3200	$386.25	3.20
- piping "T" support foundations - caisson type	8 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	8	EA	$65.10	CRG,CDOT,CHB, Means	$520.77	0.40
- flare stack superstructure	Assume 4" diameter x 50'H with guy wires	Radio tower, self supported, 60'H	1	EA	$1,480	M-02 41 13.78 0700	$1,197.32	8.80
- flare stack guy wire foundations	4 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	4	EA	$65.10	CRG,CDOT,CHB, Means	$260.38	0.20
Pump for flare system	4'L x 2'W x 6'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	48	CF	$0.1811	M-02 41 16.13 w/mod.	$7.03	0.01
- concrete pad	4'L x 2'W x 12"T	Concrete floor, 12 in., disposal in excavated pit - 200 ft. push	8	SF	$3.3447	M-02 41 13.17 w/mod.	$21.65	0.03
- concrete footer, strip type	12' perimeter x 1.5'T x 3'H	Concrete footer, 1.5' x 3', disposal in excavated pit - 200 ft. pus	12	LF	$10.36	M-02 41 16.17 w/mod.	$100.61	0.22
- piping - Pump skid to flare line	Total 20' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	20	LF	$6.09	M-02 41 13.46 0200	$98.54	0.15
Truck loadout - superstructure	96'L x 25'W x 25'H	Comm. bldg., disposal in excavated pit - 200 ft. push (CSNX)	60,000	CF	$0.1438	M-02 41 16.13 w/mod.	$6,981.24	10.81
- concrete floor	96'L x 25'W x 12"T	Concrete floor, 12 in., disposal in excavated pit - 200 ft. push	2,400	SF	$3.3447	M-02 41 13.17 w/mod.	$6,494.15	9.88
- concrete foundation wall	242' perimeter x 12"T x 1'H	Concrete wall, 12 in., disposal in excavated pit - 200 ft. push	242	SF	$7.63	M-02 41 16.17 w/mod.	$1,493.02	2.33
- concrete footer, strip type	242' perimeter x 2'T x 3'H	Concrete footer, 2' x 3', disposal in excavated pit - 200 ft. push	242	LF	$13.82	M-02 41 16.17 w/mod.	$2,705.41	5.98
Pump for truck loadout	4'L x 2'W x 6'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	48	CF	$0.1811	M-02 41 16.13 w/mod.	$7.03	0.01
- concrete pad	4'L x 2'W x 12"T	Concrete floor, 12 in., disposal in excavated pit - 200 ft. push	8	SF	$3.3447	M-02 41 13.17 w/mod.	$21.65	0.03
- concrete footer, strip type	12' perimeter x 1.5'T x 3'H	Concrete footer, 1.5' x 3', disposal in excavated pit - 200 ft. pus	12	LF	$10.36	M-02 41 16.17 w/mod.	$100.61	0.22
- piping, pump skid to truck loadout	Total 20' L x 4-6" dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	20	LF	$6.09	M-02 41 13.46 0200	$98.54	0.15
Tank battery - vertical tanks - superstructure	10 steel tanks @ 12' diameter x 20'H each	Small surface tank removal, 15,000 - 30,000 gal. (EA)	10	Tank	$5,153.2500	M-02 65 10.30 w/mod.	$41,689.79	26.67
- stairs/catwalk	2 @ 25'L x 3'W x 5'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	750	CF	$0.1811	M-02 41 16.13 w/mod.	$109.88	0.14
- concrete containment pad	115'L x 58'W x 12"T	Concrete floor, 12 in., disposal in excavated pit - 200 ft. push	6,670	SF	$3.3447	M-02 41 13.17 w/mod.	$18,048.33	27.45
- concrete containment curb wall	346' perimeter x 8"T x 3'H	Concrete wall, 8 in., disposal in excavated pit - 200 ft. push	1,038	SF	$5.0841	M-02 41 16.17 w/mod.	$4,269.31	6.67
- concrete containment footer	346' perimeter x 2.0'T x 3.0'H	Concrete footer, 2' x 3', disposal in excavated pit - 200 ft. push	346	LF	$13.8188	M-02 41 16.17 w/mod.	$3,868.07	8.54
- tank surface inlet/outlet piping to pipe rack	240'L x 4-6"dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	240	LF	$6.0900	M-02 41 13.46 0200	$1,182.43	1.78
- tank vent piping	337'L x 4-6"dia. insulated steel pipe	Steel pipe demo. only, with insulation, 5-10 in. diameter	337	LF	$6.0900	M-02 41 13.46 0200	$1,660.33	2.50
Perimeter fence - 8 ft. H chain link	8 ft. high chain link fence	Fence removal, chain link, posts & fabric, 8-10 ft. high	3,895	LF	$2.9300	M-02 41 13.60 1700	$9,232.59	23.34
Primary entrance gate - 8 ft. H x 28 ft. W chain link	2 gate halves, each 8 ft. H x 14 ft. L	Gate removal, chain link, each gate 14 ft. wide	2	EA	$86.5000	M-02 41 13.62 0300	$139.96	0.36
Secondary entrance gate - 8 ft. H x 28 ft. W chain link	2 gate halves, each 8 ft. H x 14 ft. L	Gate removal, chain link, each gate 14 ft. wide	2	EA	$86.5000	M-02 41 13.62 0300	$139.96	0.36
Lease boundary fence - 3-strand barbed wire	3-strand barbed wire (wildlife friendly per BLM	Fence removal, barbed wire, 3 strand	10,230	LF	$1.3200	M-02 41 13.60 1600	$10,924.41	63.44
Emergency exit gate - 4 ft. H x 12 ft. W chain link or eq	1 gate, 4 ft. H x 12 ft. L	Gate removal, chain link, each gate 10 ft. - 12 ft. wide	1	EA	$81.5000	M-02 41 13.62 0200	$65.93	0.17
Access road culverts - #1 - primary drainage crossing	5 ft. dia. CMP x 51 ' L	Buried pipe removal, CMP type - 60 in. diameter	51	LF	$21.8814	M-02 41 13.40 w/mod.	$902.80	1.60
- culvert #2 - drainage to pond under loadout loop road	2 ft. dia. CMP x 35' L	Buried pipe removal, CMP type - 24 in. diameter	35	LF	$11.1554	M-02 41 13.40 w/mod.	$315.87	0.43
Debris disposal - non-haz. non-concrete bldg. material	Estimated at 10% intact bldg. vol. (8,144 cy)	Loading and 65 mile haul, no salvage - Cat 953C track loader	814	CY	$25.0916	CRG, CDOT, CHB	$20,424.58	13.38
Dump fees	Tonnage estimated at 75% of CY volume	Rifle, CO dump fees (WMI) - General non-haz. debris - per Ton	611	Ton	$62.2400	WMI Rifle, CO	$38,028.64	0.00
CSU Test Plot fencing - Deer fence #1	8 ft. high coarse wire mesh on wood posts	Fence removal, chain link, posts & fabric, 8-10 ft. high	4,770	LF	$2.9300	M-02 41 13.60 1700	$11,306.66	28.58
- Cattle fence in SE sector	4 ft. high coarse wire mesh	NA - Fence will be removed during site construction	na	na	na	na	na	na
- Deer fence #2	8 ft. high coarse wire mesh on wood posts	Fence removal, chain link, posts & fabric, 8-10 ft. high	1,300	LF	$2.9300	M-02 41 13.60 1700	$3,081.48	7.79
ELHT pipe rack - test pad to rack tie-in - superstr.	460'L x 6'W x 2'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	5,520	CF	$0.1811	M-02 41 16.13 w/mod.	$808.70	0.99
- concrete cable tray foundation caissons (20 ft. ctrs)	23 x 2 @ 2 ft. dia. X 6 ft. L	Caisson footer, 2.0 ft. diameter, 9 - 12 ft. long, buried in place	46	EA	$65.10	CRG,CDOT,CHB, Means	$2,994.43	2.31
- concrete footer (NA - caisson foundations only)	na	na	na	na	na	na	$0.00	0.00
ELHT Variable Voltage Transformer (VVT) skid	30'L x 20'W x 15'H	Plant or mill, disposal in excavated pit - 200 ft. push (PSNX)	9,000	CF	$0.1811	M-02 41 16.13 w/mod.	$1,318.53	1.62
- concrete foundation (NA - skid mounted)	na	na	na	na	na	na	$0.00	0.00
ELHT cable tray (NA - buried cable)	na	na	na	na	na	na	$0.00	0.00
						TOTALS:	$242,044	326.29

NOTES:

* Most unit costs (column F) are developed from MEANS Site Work & Landscape Cost Data and other Means sources, unadjusted for location. Data source codes beginning with "M-" indicate Means-sourced data.

** Total cost column includes location adjustment for MEANS-sourced unit costs - equipment & labor component. Location adjustment for materials is not applicable to demolition work items in most cases.
Totals calculated for items utilizing non-MEANS unit costs are based on use of local equipment & labor rates (CRG, CDOT, DRMS) and so do not utilize the MEANS location adjustment.

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

BOREHOLE PLUGGING AND ABANDONMENT

Site East RD&D Pilot Project Date March 6, 2013 Task no. 2

Task Seal all open boreholes per regulatory requirements.

Borehole Description	Abandonment Task or Activity	Dia. (in.)	Length (ft.)	Quantity	Unit	Unit Cost	Data Source**	Total Cost	Task Hours
		Open/Cased	TD						
East RDD heater hole #1	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #2	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #3	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #4	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #5	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #6	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #7	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #8	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #9	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #10	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #11	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #12	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD heater hole #13	East RDD heater hole (stuck heater), 2285 ft. TD	12.25 / 7.125	2,285	1	hole	$52,511.15	SEPCO	$52,511	52.82
East RDD producer hole #1	East RDD producer hole, 2342 ft. TD - Bridge plug	9.875 / 7.125	2,342	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD producer hole #2	East RDD producer hole, 2342 ft. TD - Bridge plug	9.875 / 7.125	2,342	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #1	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #2	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #3	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #4	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #5	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD observer hole #6	East RDD observer hole, 2285 ft. TD - Bridge plug	7.625 / 7.125	2,285	1	hole	$42,856.33	SEPCO	$42,856	37.09
East RDD ELHT heater holes	East RDD ELHT heater hole, 2600 ft. TVD	8.50 / 8.835	2,307 avg.	3	hole	$177,359.39	SEPCO	$532,078	309.06
East RDD ELHT ob./prod.hole	East RDD ELHT observer/producer hole, 2200 ft. TVD	8.50 / 8.835	2,460	1	hole	$54,051.95	SEPCO	$54,052	57.36
Surface casing removal	Casing removal - 15.00 to 20.0 in. dia. pipe	15 in. - 20 in.	na	21	hole	$231.47	CRG/CDOT 2012	$4,861	52.50
			TOTALS:	21				$1,616,486	1,402.27

** Refer to BOREHOLE DATA worksheet for detailed unit cost breakdown.

Total job hours - single drill team basis: 1,402 No. drill teams used: 3 **NET JOB HOURS:** 467.42

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

DOZER WORK

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 3

Task Backfill and regrade storm water pond

Equipment

Base model: Cat D8T - SU

Blade type: Semi-Universal Blade width (ft.): 12.92

Attachment: Multi-shank ripper Type: Adjustable parallelogram

State: Colorado County: Rio Blanco Labor zone: 1

Hourly cost							
			Ownership:	$63.00	Horsepower:	310
Operating - dozer:	$92.10	Utilization:	100%	$92.10	Weight-dozer:	42.43
Operating - ripper:	$6.84	Utilization:	0%	$0.00	-blade:	5.28
			Operator:	$40.43	-ripper:	5.37
			Total:	$195.54	Total (UST):	53.08

Volume 1,322 CCY Swell: 1.164 Final: 1,538.53 LCY

Material description: Decomposed rock - 50% Rock, 50% Earth

Derivation: Assume 105 ft. L x 85 ft. W disturbance (0.205 acre), avg. 4 ft. thickness to be regraded.

Production Average push distance: 100 feet

Unadjusted production: 852.6 LCY/hr* *per Caterpillar Performance Handbook Edition: 39

JOB CONDITION CORRECTION FACTORS*			FACTOR*	
Material consistency:	Compacted fill or embankment		0.900	
Operator skill:	Average		0.750	
Dozing method:	General		1.000	
Visibility:	Average daytime conditions		1.000	
Job efficiency:	1 daytime shift per day (50 min. hour)		0.833	
Spoil pile:	Finish dressing - rough finish		0.800	
Push gradient:	5.00%	(pos. grade = uphill push; neg. = downhill)	0.900	
Site altitude:	6,615	feet	1.000	
Material weight (lbs/LCY):	2,900	Decomposed rock - 50% Rock, 50% Earth	0.793	(2300 lb. default)
Blade type:	Semi-Universal		1.000	
		Net correction:	0.321	

Adjusted production: 273.75 LCY/hr
Work team size: 3 Dozer(s)
Work team production: 821.25 LCY/hour

Job totals

Job time: 1.87 **Hours**
Job unit cost: $0.714 **per LCY**
Job cost: $1,099

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

DOZER WORK

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 4

Task Regrade site (excluding pond and access road)

Equipment

Base model: Cat D8T - SU

Blade type: Semi-Universal Blade width (ft.): 12.92

Attachment: Multi-shank ripper Type: Adjustable parallelogram

State: Colorado County: Rio Blanco Labor zone: 1

Hourly cost

				Ownership:	$63.00	Horsepower:	310
Operating - dozer:	$92.10	Utilization:	100%		$92.10	Weight-dozer:	42.43
Operating - ripper:	$6.84	Utilization:	0%		$0.00	-blade:	5.28
				Operator:	$40.43	-ripper:	5.37
				Total:	$195.54	Total (UST):	53.08

Volume 40,914 **CCY** Swell: 1.123 Final: 45,931.75 LCY

Material description: **Decomposed rock - 25% Rock, 75% Earth**

Derivation: Assume 2 ft. layer regraded over disturbed area (12.68 ac.)

Production

Average push distance: 150 feet

Unadjusted production: 634.3 LCY/hr* *per Caterpillar Performance Handbook Edition: 39

JOB CONDITION CORRECTION FACTORS*			FACTOR*	
Material consistency:	**Compacted fill or embankment**		0.900	
Operator skill:	**Average**		0.750	
Dozing method:	**General**		1.000	
Visibility:	**Average daytime conditions**		1.000	
Job efficiency:	**1 daytime shift per day (50 min. hour)**		0.833	
Spoil pile:	**Finish dressing - rough finish**		0.800	
Push gradient:	5.00%	(pos. grade = uphill push; neg. = downhill)	0.900	
Site altitude:	6,615	feet	1.000	
Material weight (lbs/LCY):	2,650	Decomposed rock - 25% Rock, 75% Earth	0.868	(2300 lb. default)
Blade type:	Semi-Universal		1.000	
		Net correction:	0.351	

Adjusted production: 222.87 LCY/hr

Work team size: 3 Dozer(s)

Work team production: 668.62 LCY/hour

Job totals

Job time: 68.70 **Hours**

Job unit cost: $0.877 **per LCY**

Job cost: $40,298

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

DOZER WORK

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 5

Task Regrade site access road.

Equipment

Base model: Cat D8T - SU

Blade type: Semi-Universal Blade width (ft.): 12.92

Attachment: Multi-shank ripper Type: Adjustable parallelogram

State: Colorado County: Rio Blanco Labor zone: 1

Hourly cost							
			Ownership:	$63.00	Horsepower:	310
Operating - dozer:	$92.10	Utilization: 100%		$92.10	Weight-dozer:	42.43
Operating - ripper:	$6.84	Utilization: 0%		$0.00	-blade:	5.28
			Operator:	$40.43	-ripper:	5.37
			Total:	$195.54	Total (UST):	53.08

Volume 8,002 CCY Swell: 1.164 Final: 9,312.67 LCY

Material description: Decomposed rock - 50% Rock, 50% Earth

Derivation: Assume 2 ft. layer regraded over disturbed area (2.48 ac.)

Production

Average push distance: 125 feet

Unadjusted production: 726.3 LCY/hr* *per Caterpillar Performance Handbook Edition: 39

JOB CONDITION CORRECTION FACTORS*			FACTOR*
Material consistency:	Compacted fill or embankment		0.900
Operator skill:	Average		0.750
Dozing method:	General		1.000
Visibility:	Average daytime conditions		1.000
Job efficiency:	1 daytime shift per day (50 min. hour)		0.833
Spoil pile:	Finish dressing - rough finish		0.800
Push gradient:	5.00%	(pos. grade = uphill push; neg. = downhill)	0.900
Site altitude:	6,000	feet	1.000
Material weight (lbs/LCY):	2,900	Decomposed rock - 50% Rock, 50% Earth	0.793 (2300 lb. default)
Blade type:	Semi-Universal		1.000
		Net correction:	0.321

Adjusted production: 233.20 LCY/hr

Work team size: 3 Dozer(s)

Work team production: 699.60 LCY/hour

Job totals

Job time: 13.31 **Hours**

Job unit cost: $0.838 **per LCY**

Job cost: $7,809

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

RIPPING WORK - AREA METHOD

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 6

Task Rip all regraded surfaces to a depth of 18 inches prior to soil replacement

Equipment

Base model: Cat D8T - SU

Blade type: Semi-Universal — Blade width (ft.): 12.92

Attachment: Multi-shank ripper — Type: Adjustable parallelogram

State: Colorado — County: Rio Blanco — Labor zone: 1

Hourly cost

				Ownership:	$63.00	Horsepower:	310
Operating - dozer:	$92.10	Utilization:	100%		$92.10	Weight-dozer:	42.43
Operating - ripper:	$6.84	Utilization:	100%		$6.84	-blade:	5.28
				Operator:	$40.43	-ripper:	5.37
				Total:	$202.38	Total (UST):	53.08

Quantities 15.36 acres — Rip depth: 1.50 feet — Final volume: 37,171.20 BCY or CCY

Derivation: Site = 12.68 acres, road = 2.48 acres, pond =0.2 acres. Total disturbed area = 15.36 acres

Production

Unadjusted production

Ripping depth:	1.50	feet/pass
Ripping width*:	7.08	feet/pass
Ripping length:	300.00	feet/pass
Machine speed:	88.00	feet/min.
Maneuver time:	0.25	min./pass
Production per acre:	0.800	acres/hr
Unadjusted production:	1,934.91	cu.yds./hr

JOB CONDITION CORRECTION FACTORS*	FACTOR
Job efficiency: 1 daytime shift per day (50 min. hour)	0.833
Site altitude: 6,615 feet	1.000
Net correction:	0.833

* per Cat Handbook

Adjusted production

	1,611.78	CY/hour per machine
Work team size:	3	Machine(s)
Work team production:	4,835.33	CY/hour

2 pass coverage? (enter "yes" or "no"): yes — Final work team production: 2,417.67 CY/hour

Job totals

Job time:	15.37	hours
Job unit cost:	$0.251	per CY
Job cost:	$9,335	

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

SCRAPER WORK

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 7

Task Replace stockpiled soil material over disturbed areas (site + access road + pond)

Equipment

Base model: Cat 623G Type: Single engine elevating

State: Colorado County: Rio Blanco Labor zone: 1

Hourly cost

Operating: $120.11 Utilization: 100%

Ownership:	$72.49	Horsepower:	365
	$120.11	Max. cap. (cy):	23.00
Operator:	$33.67	Weight (UST):	41.35
Total:	$226.27		

Volume 23,022 CCY Swell: 1.119 Final: 25,762.71 LCY

Material description: Earth - Loam

Derivation: Assume 12 inch replacement depth over disturbed areas (15.36 ac. less TS piles @ 1.09 ac.)

Production

Hauling capacity:

Material description:
Earth - Loam

Rated payload:	55,200	LBS
Material weight:	2,100	LBS/LCY
Payload capacity:	26.29	LCY
Struck volume:	18.00	LCY
Heaped volume:	23.00	LCY
Average volume:	20.50	LCY
Adjusted capacity:	20.50	LCY

Cycle time:

	HAUL	RETURN	
Distance:	700	700	feet
Grade resistance:	2.00%	-2.00%	*Road condition description for rolling resistance:*
Rolling resistance:	8.00%	8.00%	Soft, rutted dirt, no maintenance or water, 4" tire penetration
Total resistance:	10.00%	6.00%	
Max. attainable speed:	659	1,982	per Cat Handbook rimpull & retarder curves
Weight to power ratio:	377.81	226.58	lbs/hp
Acceleration / deceleration factor:	0.977	0.680	per Church's Excavation Handbook

Load time*:	0.90	min.
Haul time**:	1.09	min.
Maneuver & spread time*:	0.70	min.
Return time:**	0.52	min.
Total cycle time:	3.21	min.

*per Cat Handbook
**includes acceleration / deceleration adjustment

no

Unadjusted production: 383.58 LCY/hr per scraper***

***(per scraper pair on push-pull models)

Job condition correction factors:

Site altitude: 6,615 feet Altitude adjustment*: 1.000

Job efficiency: 1 daytime shift per day (50 min. hour) 0.833

Net correction: 0.833

Adjusted production: 319.52 LCY/hr per scraper

Work team size: 2 Scraper(s) NOTE: Min. 2 scrapers required on push-pull models (add increments of 2)

Work team production: 639.04 LCY/hour

Job totals Job time (hours): 40.31 Job unit cost ($/LCY): $0.708 **Job cost:** $18,244

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FINANCIAL WARRANTY CALCULATION

REVEGETATION

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 8a

Task Revegetate Pinyon pine / Utah juniper ridge top community (est. 1.43 ac. + 100% of 2.48 acre road area = 3.91 ac. total) using BLM Native Seed Mix No. 3 with modifications.

Fertilizing

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	6-6-6	800	lb	$0.19	$149.60
Application:	Tractor towed spreader, 12 ft. spread				$34.41
				Total/acre:	$184.01

Tilling

Description	Cost/acre
Disc harrowing, 6" deep	$101.49
Total/acre:	$101.49

Seed application Method: Broadcast seeding Total/acre: $275.18

Seed mix

	Species	Rate - PLS lbs/acre*	Native or Introduced	Warm or Cool S.	Seeds/sq. ft.*	Cost PLS/acre*
	Western Wheatgrass - Rosanna	2.00	Native	Cool	5.97	$15.00
	Bluebunch Wheatgrass - Secar	2.00	Native	Cool	6.43	$44.00
	Thickspike Wheatgrass - Critana	2.00	Native	Cool	7.07	$20.00
	Indian Ricegrass - Nezpar	2.00	Native	Cool	6.47	$32.00
	Saltbush, Four Wing - Southern Origin	1.00	Native	NA	1.38	$60.00
	Sweetvetch, Utah/Northern (or Chainpod)	1.00	Native	NA	1.54	$80.00
	Junegrass	1.00	Native	Cool	52.80	$34.87
(alt. for Hood's phlox)	Prostrate alfalfa (Truvois) Pre-inoc.	2.00	na	na	9.64	$8.30
	Bitterbrush, Antelope	1.00	Native	NA	0.31	$80.00
	Snakeweed	1.00	Native	NA	21.81	$126.23
	Sagebrush, Wyoming Big	2.00	Native	NA	118.27	$320.00
	Total/acre:	17.00			231.69	$1,640.80

* Seeding rate, seeds/sq. ft. & item cost listed on drill seeding basis. Total cost/acre doubled if non-drill seeding method used.

Mulching

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	Straw, delivered - per ton basis	2	ton	$129.15	$258.30
Application:	Power mulcher				$95.40
	Crimping, with tractor				$72.07
				Total/acre:	$425.77

Nursery stock

Description	Plants/acre	Stock type & size	Mat. $	Planting $	Cost/acre
Pine, Pinyon	10	Container, 1 gallon	$23.53	$10.39	$339.20
Total/acre:	10			Total/acre:	$339.20

Weed control

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	2,4D @ 2 lb/acre rate	1	acre	$19.75	$19.75
Application:	Non-aquatic area, truck spray, noxious sp.				$65.82
				Total/acre:	$85.57

Production

Estimated no. acres/hour: 0.50
Job hours - 1 crew basis: 7.82 No. crews: 2 job hours: 3.91

Job totals

Number of acres: 3.91 Cost/acre: $3,052.02 Initial job cost: $11,933.40
Estimated failure rate: 20% Cost/acre: $2,712.82 Replanting cost: $2,121.43
Replanting work items: Fertilizer, tilling, seeding, mulching, weed control Total job cost: $14,055

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

REVEGETATION

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 8b

Task Revegetate mid-slope community (est. 9.68 ac.) Using BLM Native Seed Mix No. 2 with modifications

Fertilizing

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	6-6-6	800	lb	$0.19	$149.60
Application:	Tractor towed spreader, 12 ft. spread				$34.41
				Total/acre:	$184.01

Tilling

Description	Cost/acre
Disc harrowing, 6" deep	$101.49
Total/acre:	$101.49

Seed application Method: Broadcast seeding Total/acre: $275.18

Seed mix

	Species	Rate - PLS lbs/acre*	Native or Introduced	Warm or Cool S.	Seeds/sq. ft.*	Cost PLS/acre*
	Western Wheatgrass - Rosanna	2.00	Native	Cool	5.97	$15.00
	Indian Ricegrass - Rimrock	1.00	Native	Cool	3.24	$15.00
	Bluebunch Wheatgrass - Secar	2.00	Native	Cool	6.43	$44.00
	Thickspike Wheatgrass - Critana	2.00	Native	Cool	7.07	$20.00
	Needlegrass, Green - Lodorm	1.00	Native	Cool	4.16	$10.00
	Globemallow, Munroe	0.50	Native	NA	9.18	$103.31
	Junegrass	1.00	Native	Cool	52.80	$34.87
(alt. for Hood's phlox)	Prostrate alfalfa (Truvois) Pre-inoc.	2.00	na	na	9.64	$8.30
(Fremont's not avail.)	Penstemon, Rocky Mountain	1.00	Native	NA	15.67	$50.00
	Sagebrush, Wyoming Big	2.00	Native	NA	118.27	$320.00
	Snakeweed	1.00	Native	NA	21.81	$126.23
	Rabbitbrush, Rubber	1.00	Native	NA	14.90	$80.00
	Total/acre:	16.50			269.14	$1,653.42

** Seeding rate, seeds/sq. ft. & item cost listed on drill seeding basis. Total cost/acre doubled if non-drill seeding method used.*

Mulching

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	Straw, delivered - per ton basis	2	ton	$129.15	$258.30
Application:	Power mulcher				$95.40
	Crimping, with tractor				$72.07
				Total/acre:	$425.77

Nursery stock

Description	Plants/acre	Stock type & size	Mat. $	Planting $	Cost/acre
None					
Total/acre:	0			Total/acre:	$0.00

Weed control

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	2,4D @ 2 lb/acre rate	1	acre	$19.75	$19.75
Application:	Non-aquatic area, truck spray, noxious sp.				$65.82
				Total/acre:	$85.57

Production

Estimated no. acres/hour: 0.50
Job hours - 1 crew basis: 19.64 No. crews: 2 job hours: 9.82

Job totals

Number of acres: 9.82 Cost/acre: $2,725.44 **Initial job cost:** $26,763.82
Estimated failure rate: 20% Cost/acre: $2,725.44 **Replanting cost:** $5,352.76
Replanting work items: Fertilizer, tilling, seeding, mulching, weed control **Total job cost:** $32,117

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

REVEGETATION

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 8c

Task Revegetate upland drainage community (est. 1.43 ac. + 100% of storm water pond area at 0.20 ac. = 1.63 ac. total) using BLM Native Seed Mix No. 4 with modifications.

Fertilizing

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	6-6-6	800	lb	$0.19	$149.60
Application:	Tractor towed spreader, 12 ft. spread				$34.41

Total/acre: $184.01

Tilling

Description	Cost/acre
Disc harrowing, 6" deep	$101.49

Total/acre: $101.49

Seed application Method: Broadcast seeding Total/acre: $275.18

Seed mix

Species	Rate - PLS lbs/acre*	Native or Introduced	Warm or Cool S.	Seeds/sq. ft.*	Cost PLS/acre*
Western Wheatgrass - Rosanna	2.00	Native	Cool	5.97	$15.00
Needle and Thread	2.00	Native	Cool	6.29	$150.00
Thickspike Wheatgrass - Critana	2.00	Native	Cool	7.07	$20.00
Indian Ricegrass - Nezpar	2.00	Native	Cool	6.47	$32.00
Sand Dropseed	1.00	Native	Warm	119.38	$7.50
Slender Wheatgrass - Pryor	1.00	Native	Cool	2.96	$5.85
Great Basin Wildrye - Magnar	1.00	Native	Cool	3.10	$14.00
Sagebrush, Mountain or Basin Big	2.00	Native	NA	105.60	$320.00
Rabbitbrush, Rubber	1.00	Native	NA	14.90	$80.00
Greasewood	1.00	Native	NA	6.89	$54.00
Prostrate alfalfa (Truvois) Pre-inoc.	2.00	na	na	9.64	$8.30
Total/acre:	17.00			288.27	$1,413.30

* Seeding rate, seeds/sq. ft. & item cost listed on drill seeding basis. Total cost/acre doubled if non-drill seeding method used.

Mulching

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	Straw, delivered - per ton basis	2	ton	$129.15	$258.30
Application:	Power mulcher				$95.40
	Crimping, with tractor				$72.07

Total/acre: $425.77

Nursery stock

Description	Plants/acre	Stock type & size	Mat. $	Planting $	Cost/acre
None					

Total/acre: 0 Total/acre: $0.00

Weed control

	Description	Units/acre	Unit	Cost/unit	Cost/acre
Materials:	2,4D @ 2 lb/acre rate	1	acre	$19.75	$19.75
Application:	Non-aquatic area, truck spray, noxious sp.				$65.82

Total/acre: $85.57

Production

Estimated no. acres/hour: 0.50
Job hours - 1 crew basis: 3.26 No. crews: 2 job hours: 1.63

Job totals

Number of acres: 1.63 Cost/acre: $2,485.32 **Initial job cost:** $4,051.07
Estimated failure rate: 20% Cost/acre: $2,485.32 **Replanting cost:** $810.21
Replanting work items: Fertilizer, tilling, seeding, mulching, weed control **Total job cost:** $4,861

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

EQUIPMENT MOBILIZATION & DEMOBILIZATION

Site East RD&D Pilot Project **Date** March 6, 2013 **Task no.** 9
Task Haul reclamation equipment to and from job site
State Colorado **County** Rio Blanco **Labor zone** 1

Small transport rig: 25-ton lowboy (6x4 on-hwy 400hp diesel tractor w/25-ton folding gooseneck drop-deck trailer).
Total hourly cost: $98.73

Medium transport rig: 50-ton lowboy (6x4 on-hwy 400hp diesel tractor w/50-ton folding gooseneck drop-deck trailer).
Total hourly cost: $122.46

Large transport rig: 100-ton lowboy (6x4 on-hwy 400hp diesel tractor w/100-ton folding gooseneck drop-deck trailer).
Total hourly cost: $131.53

Non-roadable equipment

Make & model	Weight in U.S. tons	Ownership cost/hr. ea.	Lowboy cost/hr ea.	Number of units	Haul trip cost/hour	Return trip cost/hour	DOT permit cost/trip
Cat TL642	10.1	$10.61	$98.73	3	$328.03	$296.19	$0.00
Broderson IC-200-2F	14.1	$9.99	$98.73	3	$326.15	$296.19	$0.00
250 cfm air comp.	1.6	$3.57	$98.73	3	$306.91	$296.19	$0.00
20 kw gen. set	0.6	$2.09	$98.73	1	$100.83	$98.73	$0.00
Cat D5K XL - VPAT	11.2	$15.22	$98.73	1	$113.95	$98.73	$0.00
Cat D8T - SU	53.1	$63.00	$131.53	3	$583.61	$394.60	$0.00
Cat 311D LRR	14.0	$18.38	$98.73	3	$351.34	$296.19	$0.00
Cat 324D L	27.3	$31.12	$122.46	3	$460.75	$367.38	$0.00
Cat 953D	17.1	$26.70	$98.73	1	$125.43	$98.73	$0.00
Cat 963D	23.2	$37.65	$98.73	2	$272.76	$197.46	$0.00
Cat 623G	41.4	$72.49	$122.46	2	$389.90	$244.92	$0.00
Revegetation	20.0	$20.00	$98.73	2	$237.46	$197.46	$0.00
				Subtotals:	$3,597.13	$2,882.77	$0.00

Roadable equipment

Make & model	Total cost/hr ea.	Number of units	Haul trip cost/hour	Return trip cost/hour
Generic lt. duty pickup, 4x4, 1-ton, crew cab	$56.41	1	$56.41	$56.41
Generic flatbed truck, 4x2, 30K GVW	$50.38	1	$50.38	$50.38
Generic 15-18 cy, 6x4 haul truck	$104.73	25	$2,618.17	$2,618.17
Generic water tanker, on-highway, 3,500 gal.	$65.55	1	$65.55	$65.55
Drill rig	$510.00	3	$1,530.00	$1,530.00
Fuel tanker, 4x2	$57.19	1	$57.19	$57.19
Lube truck, 4x2	$65.92	1	$65.92	$65.92
		Subtotals:	$4,443.61	$4,443.61

Haul distance & time

Nearest town or city (probable location of contractor's equipment yard): Rifle, Colorado
Total haul distance: 60 miles
Average speed: 40 mph

Haul rig cycle time

	Non-roadable equipment	Roadable equipment	
Haul time =	1.50	1.50	hours
Return time =	1.50	1.50	hours
Loading time =	0.50	NA	hours
Unloading time =	0.50	NA	hours
Subtotals =	4.00	3.00	hours

No. transport rigs used: 27

Job totals

Non-roadable equipment mob/demob cost*: $26,633.92
** two round trips with lowboy rig*
Roadable equipment mob/demob cost**: $13,330.84
***one round trip, no lowboy rig*

Total job time: 4.00 hours **Total job cost:** $39,965

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

SUBSURFACE RECLAMATION COSTS

Site: East RDD Pilot Project

Date: March 6, 2013

Task no.: 10

Lab analytical costs:

Analytical suite	Cost	Suite description
BETX	$58	BETX
Benzene	$58	Included as part of BTEX analysis
Expanded	$430	BETX + selected metals, Inorganics & semi-VOA's
Temperature	$0	NA - temperature monitoring transducer only

Assumptions:

1 - Natural cooling of the pyrolyzed reservoir is expected to take 2 years after cessation of production.
2 - Two years of reservoir temperature monitoring necessary during post-production cooling phase.
3 - Five years of ground water monitoring at pad 138-4-298. Includes two years of initial monitoring during post-production cooling phase followed by three years of additional monitoring required to demonstrate compliance with ground water quality standards.
4 - Reservoir voids filled with water using SFOGI-owned water hauled from private well in Corrral Gulch.

Monitoring costs:

Manpower:

Operator:	$51,200	Per technician per year
	0.5	1/2 time technician
	$25,600	Total per year

O & M:

Pumps & controllers:	$35,840	Monitoring well pumps & equipment
Electricity (portable generator):	$6,338	Power for well pump operation only
Waste disposal:	$10,240	Waste water from monitoring wells only
Reporting:	$25,600	
	$78,018	Total per year

Monitoring:

	YEAR	# WELLS	PARAMETERS	# SAMPLES/YR	COST/YR
Observer wells:	1	6	Temperature	4	$0.00
	2	6	Temperature	4	$0.00
Hydrology pad 138-4-298:	1	5	Expanded	4	$8,600.00
	2	5	Expanded	4	$8,600.00
	3	5	BTEX	2	$580.00
	4	5	BTEX	2	$580.00
	5	5	BTEX	2	$580.00

Reservoir filling costs:

Water truck - 3,500 gal. capacity:

Cost of water*: $0.00 /gal. Total gallons: 378,000 Total water cost: $0.00

Cost of hauling*: $65.55 /hour Gallons/load: 3,500 Hours/load: 1.00

Total hauling time (hours): 108.00 Total hauling cost: $7,079.14

Total reservoir filling cost: $7,079.14

* Water hauled from SFOGI-owned well in Corral Gulch using diesel powered on-highway water truck.

Total job cost:

YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	FILL RESERVOIR
$112,218	$112,218	$104,198	$104,198	$104,198	$7,079

Total: $544,109

Shell Frontier Oil & Gas Inc.

FINANCIAL WARRANTY CALCULATION

JOB SUPERVISION COSTS - 1 PAGE ESTIMATING FORM

Site East RD&D Pilot Project **Date** March 6, 2013

Task No.	Description	Acres	Equipment or crew	Number of units	Total task hours	CPM charting	Net task hours
1	Structural demolition	na	Demo. crew	3	326.29	all to net	326.29
2	Borehole P&A	na	Drill rig + crew	3	na	see note*	0.00
3	Storm water pond backfill	na	Cat D8T - SU	3	1.87	all to net	1.87
4	Site regrading	na	Cat D8T - SU	3	68.70	all to net	68.70
5	Access road regrading	na	Cat D8T - SU	3	13.31	all to net	13.31
6	Ripping	na	Cat D8T - SU	3	15.37	all to net	15.37
7	Soil replacement	na	Cat 623G	2	40.31	all to net	40.31
8a	Revegetation - Pinyon/Juniper ridgetop areas	3.91	Rev. crew	2	3.91	all to net	3.91
8b	Revegetation - Mid-slope areas	9.82	Rev. crew	2	9.82	all to net	9.82
8c	Revegetation - Upland drainage areas	1.63	Rev. crew	2	1.63	all to net	1.63
9	Mobilization/demobilization	na	Transport rigs	27	4.00	all to net	4.00
10	Subsurface reclamation	na	Water truck	1	na	see note **	0.00
	Totals:	15.36				Net job hours:	485

** NOTE: Direct borehole sealing cost already includes charges for supervision. See BOREHOLE DATA sheet for more information.*

*** NOTE: No job supervision required for periodic monitoring and reservoir filling activities (1-person job).*

Job supervisor cost/hour

Vehicle description: Lt. duty pickup, 4x4, 3/4 ton

Cost breakdown:

Supervisor labor cost/hour:	$44.22	per CDOT	($2.00/hr above highest trade on job)
Vehicle ownership cost/hour:	$3.05	per CRG	
Vehicle operating cost/hour:	$9.14	per CRG	
Percent vehicle utilization:	25%	Rationale:	Minimal driving time (compact job site)
Adjusted vehicle cost/hour:	$49.55		

Job total **Total project supervision cost:** **$24,045**