Appendix A

PERMIT APPLICATION FORM

The following permit application form is designed to assist potential applicants in submitting a Ground Water Discharge Permit Application. This format is <u>not</u> mandatory but only guidance. Applicants are free to use the format they deem appropriate as long as the requirements of R317-6-6.3 of the Ground Water Quality Protection Rules are met.

MAIL TO:
Division of Water Quality
Utah Department of Environmental Quality
Salt Lake City, Utah 84114-4870

Application No.:______________________
Date Received:______________________
(leave both lines blank)

UTAH GROUND WATER DISCHARGE PERMIT APPLICATION

Part A - General Facility Information

Please read and follow carefully the instructions on this application form. Please type or print, except for signatures. This application is to be submitted by the owner or operator of a facility having one or more discharges to groundwater. The application must be signed by an official facility representative who is: the owner, sole proprietor for a sole proprietorship, a general partner, an executive officer of at least the level of vice president for a corporation, or an authorized representative of such executive officer having overall responsibility for the operation of the facility.

1. **Administrative Information.** Enter the information requested in the space provided below, including the name, title and telephone number of an agent at the facility who can answer questions regarding this application.

Facility Name: **MCW Energy Group**

Mail Address: **18653 Ventura Blvd Ste. 158, Tarzana, Ca 91356**

Facility Legal Location* County: **Uintah County, Utah**

T.__________, R.___________, Sec._________, __________1/4 of_________1/4,

Lat._________°_________'__________"N.Long.__________°__________'_________"W

4S R20E 26: E1/2, E1/2 W1/2 Sec. 23: N1/2 NE1/4, E1/2 W1/2, S1/2 SE1/4: Section 24: Lots 2-4, W1/2 E1/2, N1/2 NW1/4

*Note: A topographic map or detailed aerial photograph should be used in conjunction with a written description to depict the location of the facility, points of ground water discharge, and other relevant features/objects.

Contact's Name: **Donald Clark** Phone No.:**(718) 868-3763**
Title: **Chief Geologist – MCW Energy Group**

2. **Owner/Operator Information.** Enter the information requested below, including the name, title, and phone number of the official representative signing the application.

Owner

Name: **Vladimir Podlipskiy, Chief Technology Officer – MCW Energy Group**
Phone No.:**(323) 356 - 4768**

Mail Address: **10366 Roselle St. Suite B, San Diego, Ca 92121**
(Number & Street, Box and/or Route, City, State, Zip Code)

Operator

Name:____________________________Phone No.:(____)__________________________
(If different than Owner's above)

Mail Address:____
(Number & Street, Box and/or Route, City, State, Zip Code)

Official Representative

Name: **Donald Clark** Phone No.:**(718) 868-3763**
Title: **Chief Geologist – MCW Energy Group**

3. **Facility Classification** (check one)

[ ] New Facility
[ ] Existing Facility
[**X**] Modification of Existing Facility

4. **Type of Facility** (check one)

[**X**] Industrial
[ ] Mining
[ ] Municipal
[ ] Agricultural Operation
[ ] Other, please describe:____________________

5. **SIC/NAICS Codes: NAICS 211 Oil & Gas Extraction [211111 Crude Petroleum & Natural Gas Extraction, Petroleum from Oil Sands]**
Enter Principal 3 Digit Code Numbers Used in Census & Other Government Reports

6. **Projected Facility Life: 10 – 20 years**

7. **Identify principal processes used, or services preformed by the facility. Include the principal products produced, and raw materials used by the facility:**

See attached

8. **List all existing or pending Federal, State, and Local government environmental permits:**

		Permit Number
[ ]	NPDES or UPDES (discharges to surface water)	________
[ ]	CAFO (concentrated animal feeding operation)	________
[ ]	UIC (underground injection of fluids)	________
[ ]	RCRA (hazardous waste)	________
[X]	PDS (air emissions from proposed sources)	________
[ ]	Construction Permit (wastewater treatment) Solid	Approval in progress
[ ]	Solid Waste Permit (sanitary landfills, incinerators)	________
[ ]	Septic Tank/Drainfield	________
[X]	Other, specify________	Uintah Co., CUP

9. Name, location (Lat._____°______'______"N,Long.______°______'______"W) and description of: each well/spring (existing, abandoned, or proposed), water usage(past, present, or future); water bodies; drainages; well-head protection areas; drinking water source protection zones according to UAC 309-600; topography; and man-made structures within one mile radius of the point(s) of discharge site. Provide existing well logs (include total depth and variations in water depths).

Name	Location	Description	Status	Usage

See Attached

The above information must be included on a plat map and attached to the application.

Part B - General Discharge Information

Complete the following information for each point of discharge to ground water. If more than one discharge point exists, photocopy and complete this Part B form for each discharge point.

1. **Location (if different than Facility Location in Part A):**
   County:________________________________
   T.__________, R.__________, Sec.__________, __________1/4 of __________1/4,
   Lat.__________°__________'__________"N.Long.__________°__________'__________"W

2. **Type of fluid to be Discharged or Potentially Discharged**
   (check as applicable)

   Discharges (fluids discharged to the ground) **None – See attached**

   [ ] Sanitary Wastewater: wastewater from restrooms, toilets, showers and the like
   [ ] Cooling Water: non-contact cooling water, non contact of raw materials, intermediate, final, or waste products
   [ ] Process Wastewater: wastewater used in or generated by an industrial process
   [ ] Mine Water: water from dewatering operations at mines
   [ ] Other, specify:____

   Potential Discharges (leachates or other fluids that may discharge to the ground) – **Post processed oil sands will be returned to the Temple Mountain mine for backfill and mine remediation**

   [ ] Solid Waste Leachates: leachates from solid waste impoundments or landfills
   [ ] Milling/Mining Leachates: tailings impoundments, mine leaching operations, etc.
   [ ] Storage Pile Leachates: leachates from storage piles of raw materials, product, or wastes
   [ ] Potential Underground Tank Leakage: tanks not regulated by UST or RCRA only
   [ ] Other, specify:____

3. **Discharge Volumes**
   For each type of discharge checked in #2 above, list the volumes of wastewater discharged to the ground or ground water. Volumes of wastewater should be measured or calculated from water usage. If it is necessary to estimate volumes, enclose the number in parentheses. Average daily volume means the average per operating day: ex. For a discharge of 1,000,000 gallons per year from a facility operating 200 days, the average daily volume is 5,000 gallons.

Discharge Type:	Daily Discharge Volume (Average)	(Maximum)	all in units of
________	______	______	______
Not Applicable – see attached			
________	______	______	______

4. **Potential Discharge Volumes**
   For each type of potential discharge checked in #2 above, list the maximum volume of fluid that could be discharged to the ground considering such factors as: liner hydraulic conductivity and operating head conditions, leak detection system sensitivity, leachate collection system efficiency, etc. Attach calculation and raw data used to determine said potential discharge.

Discharge Type:	Daily Discharge Volume (Average)	(Maximum)	all in units of
________	______	______	______

Not Applicable – see attached

5. Means of Discharge or Potential Discharge (check one or more as applicable)

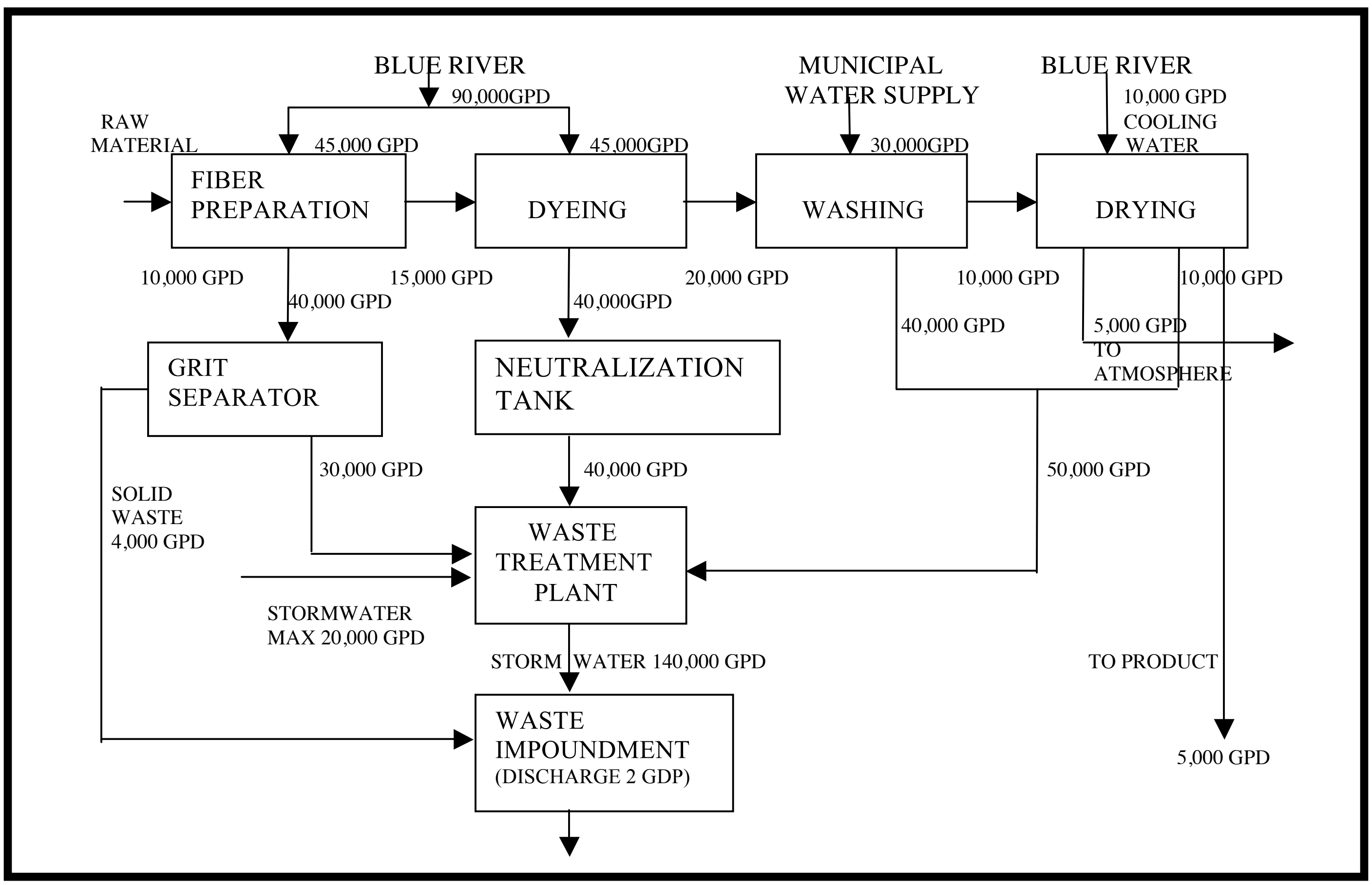
[ ] lagoon, pit, or surface impoundment (fluids)
[ ] land application or land treatment
[ ] discharge to an ephemeral drainage (dry wash, etc.)
[**X**] storage pile
[ ] landfill (industrial or solid wastes)
[ ] other, specify________________________

[ ] industrial drainfield
[ ] underground storage tank
[ ] percolation/infiltration basin
[ ] mine heap or dump leach
[ ] mine tailings pond

6. Flows, Sources of Pollution, and Treatment Technologies

Flows. Attach a line drawing showing: 1) water flow through the facility to the ground water discharge point, and 2) sources of fluids, wastes, or solids which accumulate at the potential ground water discharge point. Indicate sources of intake materials or water, operations contributing wastes or wastewater to the effluent, and wastewater treatment units. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and wastewater outfalls. If a water balance cannot be determined, provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures. See the following example.

See flow diagram in Appendix B of the attached



7. Discharge Effluent Characteristics

Established and Proposed Ground Water Quality Standards - Identify wastewater or leachate characteristics by providing the type, source, chemical, physical, radiological, and toxic characteristics of wastewater or leachate to be discharged or potentially discharged to ground water (with lab analytical data if possible). This should include the discharge rate or combination of discharges, and the expected concentrations of any pollutant (mg/l). If more than one discharge point is used, information for each point must be provided. **See attached.**

Hazardous Substances - Review the present hazardous substances found in the Clean Water Act, if applicable. List those substances found or believed present in the discharge or potential discharge. **See attached.**

Part C - Accompanying Reports and Plans

The following reports and plans should be prepared by or under the direction of a professional engineer or other ground water professional. Since ground water permits cover a large variety of discharge activities, the appropriate details and requirements of the following reports and plans will be covered in the pre-design meeting(s). For further instruction refer to the Ground Water Permit Application Guidance Document.

8. Hydrogeologic Report

Provide a Geologic Description, with references used, that includes as appropriate:

Structural Geology – regional and local, particularly faults, fractures, joints and bedding plane joints;
Stratigraphy – geologic formations and thickness, soil types and thickness, depth to bedrock;
Topography – provide a USGS MAP (7 ½ minute series) which clearly identifies legal site location boundaries, indicated 100 year flood plain area and applicable flood control or drainage barriers and surrounding land uses.

Provide a Hydrologic Description, with references used, that includes:
Ground water – depths, flow directions and gradients. Well logs should be included if available. Include name of aquifer, saturated thickness, flow directions, porosity, hydraulic conductivity, and other flow characteristics, hydraulic connection with other aquifers or surface sources, recharge information, water in storage, usage, and the projected aerial extent of the aquifer. Should include projected ground water area of influence affected by the discharge. Provide hydraulic gradient map indicating equal potential head contours and ground water flow lines. Obtain water elevations of nearby wells at the time of the hydrologic investigation. Collect and analyze ground water samples from the uppermost aquifer which underlies the discharge point(s). Historic data can be used if the applicant can demonstrate it meets the requirements contained within this section. Collection points should be hydraulically up and downgradient and within a one-mile radius of the discharge point(s). Ground water analysis should include each element listed in Ground Water Discharge Permit Application, Part B7.
NOTE Failure to analyze for background concentrations of any contaminant of concern in the discharge or potential discharge may result in the Executive Secretary's presumptive determination that zero concentration exist in the background ground water quality.
Sample Collection and Analysis Quality assurance – sample collection and Preservation must meet the requirements of the EPA RCRA Technical Enforcement Guidance Document, OSWER-9959.1, 1986 [UAC R317-6-6.3(I,6)]. Sample analysis must be performed by State of Utah certified laboratories and be certified for each of the parameters of concern. Analytical methods should be selected from the following sources [UAC R317-6-6.3L]: (Standard Methods for the Examination of Water and Wastewater, 20th Ed.,1998; EPA, Methods for Chemical Analysis of Water and Wastes, 1983; Techniques of Water Resources Investigation of the U.S. Geological Survey, 1998, Book 9; EPA Methods published pursuant to 40 CFR Parts 141, 142, 264 (including Appendix IX), and 270. Analytical methods selected should also include minimum detection limits below both the Ground Water Quality Standards and the anticipated ground water protection levels. Data shall be presented in accordance of accepted hydrogeologic standards and practice.

Provide Agricultural Description, with references used, that includes:
If agricultural crops are grown within legal boundaries of the site the discussion must include: types of crops produced; soil types present; irrigation system; location of livestock confinement areas (existing or abandoned).

Note on Protection Levels:

After the applicant has defined the quality of the fluid to be discharged (Ground Water Discharge Permit Application, Part B), characterized by the local hydrogeologic conditions and determined background ground water quality (Hydrogeologic Report), the Executive Secretary will determine the applicable ground water class, based on: 1) the location of the discharge point within an area of formally classified ground water, or the background value of total dissolved solids. Accordingly, the Executive Secretary will determine applicable protection levels for each pollutant of concern, based on background concentrations and in accordance with UAC R317-6-4.

9. **Ground Water Discharge Control Plan:**
Select a compliance monitoring method and demonstrate an adequate discharge control system. Listed are some of the Discharge Control Options available. **We believe the project qualifies for Permit by Rule under R317-6-6.2. Please see Attached.**

No Discharge – prevent any discharge of fluids to the ground water by lining the discharge point with multiple synthetic and clay liners. Such a system would be designed, constructed, and operated to prevent any release of fluids during both the active life and any post-closure period required.

Earthen Liner – control the volume and rate of effluent seepage by lining the discharge point with a low permeability earthen liner (e.g. clay). Then demonstrate that the receiving ground water, at a point as close as practical to the discharge point, does not or will not exceed the applicable class TDS limits and protection levels* set by the Executive Secretary. This demonstration should also be based on numerical or analytical saturated or unsaturated ground water flow and contaminant transport simulations.

Effluent Pretreatment – demonstrate that the quality of the raw or treated effluent at the point of discharge or potential discharge does not or will not exceed the applicable ground water class TDS limits and protection levels* set by the Executive Secretary.

Contaminant Transport/Attenuation – demonstrate that due to subsurface contaminant transport mechanisms at the site, raw or treated effluent does not or will not cause the receiving ground water, at a point as close as possible to the discharge point, to exceed the applicable class TDS limits and protection levels* set by the Executive Secretary.

Other Methods – demonstrate by some other method, acceptable to the Executive Secretary, that the ground water class TDS limits and protection levels* will be met by the receiving ground water at a point as close as practical to the discharge point.

*If the applicant has or will apply for an alternate concentration limit (ACL), the ACL may apply instead of the class TDS limits and protection levels.

Submit a complete set of engineering plans and specifications relating to the construction, modification, and operation of the discharge point or system. Construction Permits for the following types of facilities will satisfy these requirements. They include: municipal waste lagoons; municipal sludge storage and on-site sludge disposal; land application of wastewater effluent; heap leach facilities; other process wastewater treatment equipment or systems.

Facilities such as storage piles, surface impoundments and landfills must submit engineering plans and specifications for the initial construction or any modification of the facility. This will include the design data and description of the leachate detection, collection and removal system design and construction. Provide provisions for run on and run-off control.

10. **Compliance Monitoring Plan:**
The applicant should demonstrate that the method of compliance monitoring selected meets the following requirements: **We believe the project qualifies for Permit by Rule under R317-6-6.2. Please see Attached.**

Ground Water Monitoring – that the monitoring wells, springs, drains, etc., meet all of the following criteria: is completed exclusively in the same uppermost aquifer that underlies the discharge point(s) and is intercepted by the upgradient background monitoring well; is located hydraulically downgradient of the discharge point(s); designed, constructed, and operated for optimal detection (this will require a hydrogeologic characterization of the area circumscribed by the background sampling point, discharge point and compliance monitoring points); is not located within the radius of influence of any beneficial use public or private water supply; sampling parameters, collection, preservation, and analysis should be the same as background sampling point; ground water flow direction and gradient, background quality at the site, and the quality of the ground water at the compliance monitoring point.

Source Monitoring – must provide early warning of a potential violation of ground water protection levels, and/or class TDS limits and be as or more reliable, effective, and determinate than a viable ground water monitoring network.

Vadose Zone Monitoring Requirements – Should be: used in conjunction with source monitoring; include sampling for all the parameters required for background ground water quality monitoring; the application, design, construction, operation, and maintenance of the monitoring system should conform with the guidelines found in: Vadose Zone Monitoring for Hazardous Waste Sites; June 1983, KT-82-018(R).

Leak Detection Monitoring Requirements – Should not allow any leakage to escape undetected that may cause the receiving ground water the exceed applicable ground water protection levels during the active life and any required post-closure care period of the discharge point. This demonstration may be accomplished through the use of numeric or analytic, saturated or unsaturated, ground water flow or contaminant transport simulations, using actual filed data or conservative assumptions. Provide plans for daily observation or continuous monitoring of the observation sump or other monitoring point and for the reporting of any fluid detected and chemical analysis thereof.

Specific Requirements for Other Methods – Demonstrate that: the method is as or more reliable, effective, and determinate than a viable ground water monitoring well network at detecting any violation of ground water protection levels or class TDS limits, that may be caused by the discharge or potential discharge; the method will provide early warning of a potential violation of ground water protection levels or class TDS limits and meets or exceeds the requirements for vadose zone or leak detection monitoring.

Monitoring well construction and ground water sampling should conform to A Guide to the Selection of Materials for Monitoring Well Construction. Sample collection and preservation, should conform to the EPA RCRA Technical Enforcement Guidance Document, OSWER-9950.1, September, 1986. Sample analysis must be performed by State-certified laboratories by methods outlined in UAC R317-6-6.3L. Analytical methods used should have minimum detection levels which meet or are less than both the ground water quality standards and the anticipated protection levels.

11. **Closure and Post Closure Plan:** The purpose of this plan is to prevent ground water contamination after cessation of the discharge or potential discharge and to monitor the discharge or potential discharge point after closure, as necessary. This plan has to include discussion on: liquids or products, soils and sludges; remediation process; the monitoring of the discharge or potential discharge point(s) after closure of the activity.

12. **Contingency and Corrective Action Plans:** The purpose of this Contingency plan is to outline definitive actions to bring a discharge or potential discharge facility into compliance with the regulations or the permit, should a violation occur. This applies to both new and existing facilities. For existing facilities that may have caused any violations of the Ground Water Quality Standards or class TDS limits as a result of discharges prior to the issuance of the permit, a plan to correct or remedy any contaminated ground water must be included.

    Contingency Plan – This plan should address: cessation of discharge until the cause of the violation can be repaired or corrected; facility remediation to correct the discharge or violation.

    Corrective Action Plan – for existing facilities that have already violated Ground Water Quality Standards, this plan should include: a characterization of contaminated ground water; facility remediation proposed or ongoing including timetable for work completion; ground water remediation.

Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Vladimir Podolipskiy CTO
NAME & OFFICIAL TITLE (type or print)

323-356-4768
PHONE NO. (area code & no.)

SIGNATURE

2/25/15
DATE SIGNED

APPENDIX A

WATER WELL AND ROCK CORE LOGS

PROJECT: MCW Energy, NW Asphalt Ridge

ROCK CORE LOG

BORING NO. MCW-6	PROJECT NO.	LOCATION E: 614790 N: 4479484 El.: 6041	SHEET 1 OF 1
TIME START 1230	DRILLING CONTRACTOR Envirotech	DRILLING EQUIPMENT	DATE 8/17/2011
TIME STOP 1530	DRILLER Warren	DRILLING METHOD Rotary / Air	SAMPLING METHOD Cuttings @ 5 ft.
TOTAL DEPTH 180	BACKFILL MATERIAL Cuttings w/ cement	WATER FIRST ENCOUNTERD None	FINAL DEPTH TO WATER Dry Hole

DEPTH (FT)	CORE RUN (IN)	RECOV. CORE LENGTH (IN)	TOTAL CORE RECOVERY (%)	SOLID CORE RECOVERY (%)	RQD (%)	FRCT. DENSITY (# PER FT)	PENETRATION RATE (FT/HR)	SMPL. FOR TEST	GRAPHIC LOG	DESCRIPTION/LITHOLOGY/COMMENTS
										0 to 20 ft. Alluvium
10										
20										20 to 35 ft. Sandstone, silty with mudstone
30										35 to 45 ft. Mudstone, broun
40										45 to 70 ft. Shale with sandstone interbeds
50										
60										
70										70 to 75 ft. Sandstone, very fine grained, oil smell
										75 to 80 ft. Shale, dark gry., some pyrite
80										80 to 100 ft. Sandstone, very fine grained, some clay
90										
100										100 to 105 ft. Sandstone with shale, gry.
										105 tp 115 ft. Shale, dark gry.
110										115 to 120 ft. Sandstone, very fine grained, brown, oil smell
120										120 to 125 ft. Shale, sandy, gry.
										125 to 140 ft. Sandstone, very fine grained, light brown, minor bitumen
130										
140										140 to 145 ft. Shale, sandy
										145 to 165 ft. Sandstone with Shale Interbeds, minor oil smell
150										
160										165 to 180 ft. Shale, dark gry.
170										
180										
9										

LOGGED BY: James Kohler OFFICE: DATE: 8/17/2011

PROJECT: MCW Energy, NW Asphalt Ridge

ROCK CORE LOG

BORING NO.	MCW-5	PROJECT NO.		LOCATION	E: 614962 N: 4479302 Elev.: 6016	SHEET	1 OF 2
TIME START	1345	DRILLING CONTRACTOR	Envirotech	DRILLING EQUIPMENT		DATE	8/16/2011
TIME STOP	8/17 1130	DRILLER		DRILLING METHOD	Rotary / Air	SAMPLING METHOD	Cuttings @ 5 ft.
TOTAL DEPTH	300 ft.	BACKFILL MATERIAL	Cuttings, cement plug	WATER FIRST ENCOUNTERED	None	FINAL DEPTH TO WATER	Dry HOle

DEPTH (FT)	CORE RUN (IN)	RECOV. CORE LENGTH (IN)	TOTAL CORE RECOVERY (%)	SOLID CORE RECOVERY (%)	RQD (%)	FRCT. DENSITY (# PER FT)	PENETRATION RATE (FT/HR)	SMPL. FOR TEST	GRAPHIC LOG	DESCRIPTION/LITHOLOGY/COMMENTS
0										0 to 30 ft. Alluvium light tan, very fine grained with gravel
10										
20										
30										30 to 35 ft. Siltstone, brown
40										35 to 45 ft. Sandstone, very fine grained, lt. yellow
50										45 to 68 ft. Mudstone, medium brown
60										
70										68 to 72 ft. Sandstone, very fine grained, silty, light tan
										72 to 80 ft. Mudstone, brown
80										80 to 85 ft. Shale, gry. to light gry.
90										85 to 92 ft. Sandstone, very fine grained, some oil smell
										92 ft. to 100 ft. Sandstone, light gry, silty
100										100 to 125 ft. Shale (tar @ 125 ft., contamination?)
110										
120										
130										125 to 130 ft. Sandstone, very fine grained, crystalline, hard
										130 to 140 ft. Mudstone, green, sandy at bottom
140										140 to 155 ft. Sandstone. gry to greenish gry, some mudstone
150										
160										155 to 165 ft. Mudstone, red
170										165 to 175 ft. Sandstone, very fine grained, greenish gry.
180										175 to 188 ft. Mudstone, red
190										188 tp 200 ft. Sandstone, gry, mudstone @ 195
200										

LOGGED BY: ______________ OFFICE: ______________ DATE: ______________

PROJECT: MCW Energy, NW Asphalt Ridge

ROCK CORE LOG

BORING NO.	MCW-5	PROJECT NO.		LOCATION	E: 614962 N: 4479302 Elev.: 6016
SHEET	2 OF 2	DATE			
TIME START	1345	DRILLING CONTRACTOR	Envirotech	DRILLING EQUIPMENT	
TIME STOP	8/17 1130	DRILLER		DRILLING METHOD	Rotary / Air
SAMPLING METHOD	Cuttings @ 5 ft.				
TOTAL DEPTH	300 ft.	BACKFILL MATERIAL	Cuttings, cement plug	WATER FIRST ENCOUNTERED	None
FINAL DEPTH TO WATER	Dry Hole				

DEPTH (FT)	CORE RUN (IN)	RECOV. CORE LENGTH (IN)	TOTAL CORE RECOVERY (%)	SOLID CORE RECOVERY (%)	RQD (%)	FRCT. DENSITY (# PER FT)	PENETRATION RATE (FT/HR)	SMPL. FOR TEST	GRAPHIC LOG	DESCRIPTION/LITHOLOGY/COMMENTS
200										200 to 215 ft. Mudstone, dark gry to red
210										
220										215 to 225 ft. Sandstone, very fine grained, some oil smell
230										225 to 230 ft. Mudstone, red
										230 to 245 ft. Sandstone, shaley, minor oil smell?
240										
250										245 to 250 ft. Sandstone, very fine grained brown, with bitumen
										250 to 260 ft. Sandstone with shale, minor bitumen
260										260 to 270 ft. Sandstone, very fine grained, brown, with bitumen
270										270 to 275 ft. Shale, sandy
280										275 to 280 ft. Sandstone, lt. brown, some bitumen
										280 to 300 ft. Shale, Dark gry, (Mancos?)
290										
300										
310										
2										
3										
4										
5										
6										
7										
8										
9										

LOGGED BY: ____________ OFFICE: ____________ DATE: ____________

PROJECT: MCW Energy, NW Asphalt Ridge

ROCK CORE LOG

BORING NO. MCW-4	PROJECT NO.	LOCATION E: 615044 N: 4479474 Elev.: 6124	SHEET 1 OF 2
TIME START 0900	DRILLING CONTRACTOR Envirotech	DRILLING EQUIPMENT	DATE 8/16/2011
TIME STOP 1300	DRILLER Warren	DRILLING METHOD Rotary/Air	SAMPLING METHOD Cuttings @ 5 ft.
TOTAL DEPTH 220	BACKFILL MATERIAL Cuttings and Cement	WATER FIRST ENCOUNTERD None	FINAL DEPTH TO WATER None

DEPTH (FT)	DESCRIPTION/LITHOLOGY/COMMENTS
0	0 to 45 ft. Alluvium, light tan: clay with gravel
10	
20	
30	
40	45 to 55 ft. Sandstone, gray with some gravel
50	
60	55 to 70 ft. Shale, sandy, gray
70	75 to 92 ft. Sandstone, very fine grained, light brown with strong oil smell
80	
90	92 to 100 ft. Sandstone, very fine grained, black, well saturated with bitumen
100	100 to 110 ft. Shale, dark gry, minor bitumen in sample
110	110 to 120 ft. Shale, dark gry, with sandstone, minor bitumen
120	120 to 128 ft. Shale, gray
130	128 to 140 ft. Sandstone, very fine grained, trace bitumen
140	140 to 150 ft. Shale, gray
150	150 to 180 ft. Sandstone, very fine grained, silty, dark brown with oil smell
160	
170	
180	180 to 220 ft. Shale, gray (Mancos Shale?)
190	

Column headings printed on the log (no entries): CORE RUN (IN), RECOV. CORE LENGTH (IN), TOTAL CORE RECOVERY (%), SOLID CORE RECOVERY (%), RQD (%), FRCT. DENSITY (# PER FT), PENETRATION RATE (FT/HR), SMPL. FOR TEST, GRAPHIC LOG

LOGGED BY: James Kohler OFFICE: DATE: 8/16/2011

PROJECT: ROCK CORE LOG

BORING NO. MCW-4	PROJECT NO.	LOCATION		SHEET 2 OF 2
TIME START	DRILLING CONTRACTOR	DRILLING EQUIPMENT		DATE
TIME STOP	DRILLER	DRILLING METHOD	SAMPLING METHOD	
TOTAL DEPTH 220	BACKFILL MATERIAL	WATER FIRST ENCOUNTERD	FINAL DEPTH TO WATER	

DEPTH (FT)	CORE RUN (IN)	RECOV. CORE LENGTH (IN)	TOTAL CORE RECOVERY (%)	SOLID CORE RECOVERY (%)	RQD (%)	FRCT. DENSITY (# PER FT)	PENETRATION RATE (FT/HR)	SMPL. FOR TEST	GRAPHIC LOG	DESCRIPTION/LITHOLOGY/COMMENTS
200										
210										
220										
3										
4										
5										
6										
7										
8										
9										
0										
1										
2										
3										
4										
5										
6										
7										
8										
9										

LOGGED BY: James Kohler OFFICE: DATE: 8/16/2011

PROJECT: MCW Energy NW Asphalt Ridge

ROCK CORE LOG

BORING NO. MCW-1	PROJECT NO.	LOCATION E: 617035 N: 4479286 EL: 5837	SHEET 1 OF 1
TIME START 1615	DRILLING CONTRACTOR Envirotech	DRILLING EQUIPMENT	DATE 8/17/2011
TIME STOP 1730	DRILLER Warren	DRILLING METHOD rotary / air	SAMPLING METHOD cuttings @ 5 ft.
TOTAL DEPTH 60	BACKFILL MATERIAL Cuttings, cement surf.	WATER FIRST ENCOUNTERED No Water	FINAL DEPTH TO WATER Dry Hole

DEPTH (FT)	CORE RUN (IN)	RECOV. CORE LENGTH (IN)	TOTAL CORE RECOVERY (%)	SOLID CORE RECOVERY (%)	RQD (%)	FRCT. DENSITY (# PER FT)	PENETRATION RATE (FT/HR)	SMPL. FOR TEST	GRAPHIC LOG	DESCRIPTION/LITHOLOGY/COMMENTS
										0 to 25 ft. Alluvium, vfg sand, cly, gravel
1										cuttings damp 15 ft. to 20 ft.
2										
3										25 to 60 ft. Shale, weathered, lt. gry to brown
4										
5										
6										
7										
8										
9										
0										
1										
2										
3										
4										
5										
6										
7										
8										
9										

LOGGED BY: James Kohler OFFICE: DATE: 8/17/2011

WELL DRILLER'S REPORT
State of Utah
Division of Water Rights

For additional space, use "Additional Well Data Form" and attach

Rec'd 9/21/04

Well Identification

Water Right: 45-6098 WIN: 30414

Owner *Note any changes*

Anna K. Jenkins
809 North 3500 West
Vernal, UT 84078

Contact Person/Engineer: ______

Well Location *Note any changes*

S 2500 E 100 from the N4 corner of section 19, Township 4S, Range 21E, SL B&M

Location Description: (address, proximity to buildings, landmarks, ground elevation,local well #)

Drillers Activity Start Date: Sept 9 2004 Completion Date: Sept 9 2004

Check all that apply: [X] New [ ] Repair [ ] Deepen [ ] Clean [ ] Replace [ ] Public Nature of Use: ______

If a replacement well, provide location of new well. ______ feet north/south and ______ feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	30	12 1/4	Air Rotary	Wa-

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE High	PERMEABLE Low	UNCONSOLIDATED CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	CONSOLIDATED ROCK TYPE	COLOR	DESCRIPTION AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition density, plasticity, shape, cementation, consistancy, water bearing, ordor, fracturing, minerology, texture,degree of weathering, hardness, water quality, etc.)
0	15						X		X	X			Red	
15	25				X							Clay	Brown	
25	32				X							Clay	Green	
52	56				X							Clay	Gray	
56	200										X	Shale	Blue.	

Static Water Level

Date Sept-9-2004 Water Level ______ feet Flowing? [ ] Yes [X] No

Method of Water Level Measurement ______ If Flowing, Capped Pressure ______ PSI

Point to Which Water Level Measurement was Referenced ______ Elevation ______

Height of Water Level reference point above ground surface ______ feet Temperature ______ degrees [ ] C [ ] F

Dry hole

Construction Information

DEPTH (feet)		CASING			DEPTH (feet)		☐SCREEN ☐PERFORATIONS ☒OPEN BOTTOM		
FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
0	30	Steel	.250	8"		N/A			

Well Head Configuration: Well Cap Access Port Provided? ☐Yes ☒No

Casing Joint Type: Welded Perforator Used: N/A

Was a Surface Seal Installed? ☒Yes ☐No Depth of Surface Seal: 30 feet Drive Shoe? ☐Yes ☒No

Surface Seal Material Placement Method: Cement

DEPTH (feet)		SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION		
FROM	TO	SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	**Quantity** of Material Used (if applicable)	GROUT DENSITY (lbs./gal., # bag mix, gal./sack etc.)
0	30	Cement	13 Sacks	6 gal water per sack

Well Development and Well Yield Test Information

DATE	METHOD	YIELD	Units Check One GPM	CFS	DRAWDOWN (ft)	TIME PUMPED (hrs & min)
	Dry Hole					

Pump (Permanent)

Pump Description:______ Horsepower:______ Pump Intake Depth:______ feet

Approximate Maximum Pumping Rate:______ Well Disinfected upon Completion? ☐Yes ☐No

Comments

Description of construction activity, additional materials used, problems encountered, extraordinary Circumstances, abandonment procedures. *Use additional well data form for more space.*

Dry Hole

Well Driller Statement

This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name ROSS DRILLING & CONSTRUCTION INC (Person, Firm, or Corporation - Print or Type) License No. 346

Signature [signature] (Licensed Well Driller) Date Sept-18, 2004

a well record
y counties
ch 3-15-50
Recorded mv 1-14-50
r filing
checked vgh 3-15-50
No. Assigned
vgh 2-27-50
well
BM
D-4-21) 18bbb-1

Report No. 7401
Filed Dec. 10, 1949
Rec. By MV
Ret'd

PAGE ____ (Leave Blank)

Report of Well and Tunnel Driller

STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

ABANDONED

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, in compliance with Sec. 100-3-22, Utah Code Annotated, 1943. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of person, ~~company or corporation boring or~~ drilling well ~~or tunnel~~. (Strike words not needed)

   J. C. Zimmerman, Roosevelt, Utah

2. Name and address of owner of well or ~~tunnel~~ Elmer Lind (Strike Words not needed)

   Vernal, Utah Uintah County

3. Source of supply is in Uintah County; ____ drainage area (Leave blank); ____ artesian basin (Leave blank)

4. The number of approved application to appropriate water is 21199

5. Location of well or ~~mouth of tunnel~~ is situated at a point

   S. 500 ft. and E. 100 ft. from NW. Cor. Sec.18, T4S, R21E, SLM.

   (Describe by rectangular co-ordinates or by one course and distance with reference to U. S. Government Survey Corner — Copy description from well owner's approved application)

6. Date on which work on well ~~or tunnel~~ was begun 12/1/49 (Strike words not needed)

7. Date on which work on well ~~or tunnel was completed or~~ abandoned 12/7/49 (Strike words not needed)

8. Maximum quantity of water measured as flowing, pumped or ____ on completion of (Strike words not needed) well or ~~tunnel in sec. ft.~~ ____; or in gals. per minute ____ Date ____

DETAIL OF COLLECTING WORKS:

9. **WELL:** It is drilled, ~~dug, flowing or pump~~ well. Temperature of water ____°F. (Strike words not needed)

   (a) Total depth of well is 260 ft. below ground surface.

   (b) If flowing well, give water pressure (hydrostatic head) above ground surface ____ ft.

   (c) If pump well, give depth from ground surface to water surface before pumping ____; during pumping ____

   (d) Size and kind of casing none (If only partially cased, give details)

   (e) Depth to water-bearing stratum ____ (If more than one stratum, give depth to each)

   (f) If casing is perforated, give depth from ground surface to perforations ____

   (g) Log of well Well was abandoned until 7 inch casing can be obtained; well caving in Farther drilling impossible.--0-35 yellow clay; 35-75 Black clay; 75-82 ~~white talck; 82-85 dark shale; 85-105 Coal black shale; 105-115 grey shale~~; 115-155 Black clay; 155-165 black shale; 165-180 grey shale; 180-210 white clay; 210-230 Light grey shale, trace of water; 230-260 soft grey shale; 8¼ inch hole Bottom.

   (h) Well was equipped with cap, valve, or ____ to control flow. (Strike words not needed)

(Over)

Water Right Number 45-2074

10. **TUNNEL:** It is timbered, tiled, piped, open, bulkheaded, covered or..............................
(Strike words not needed)

(a) Dimensions................; total length......................; temperature of water...............................°F.

(b) Position of water bearing stratum or strata with reference to mouth of tunnel...................

(c) Log of tunnel..

11. **GENERAL REMARKS:** (Note any general or detailed information not covered above).

STATE OF UTAH,
COUNTY OF Salt Lake } ss.

I, J. E. Zimmerman, being first duly sworn, do hereby certify that I am the driller of the aforesaid well or tunnel who furnished the foregoing statement of facts; that I have read said statement and each and all of the items therein contained are true to the best of my knowledge and belief.

/s/ J. C. Zimmerman
Driller

Subscribed and sworn to before me this 10 day of December, 19 49.

(SEAL) (SEAL)

/s/ Laurence C. Monson
Notary Public

My Commission Expires:

July 18, 1952

Form 113—5M—12-60

Examined

Recorded: B. C. T. B.

Inspection Sheet

Copied

REPORT OF WELL DRILLER
STATE OF UTAH

Application No. 455312 (A63255)

Claim No.

Coordinate No.

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:
Name Mr. Jones

Address Vernal Utah

(2) LOCATION OF WELL:
County Uintah Ground Water Basin (leave blank)

~~North~~ South 1,300 feet, ~~East~~ West 980 feet from N¼ Corner of Section 19, T. 4 S, R. 21 E SLBM ~~W USM~~ (strike out words not needed)

(3) NATURE OF WORK (check):
New Well ☑ Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐

If abandonment, describe material and procedure:

(4) NATURE OF USE (check):
Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐ Irrigation ☑ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):
Rotary ☐ Dug ☐ Jetted ☐ Cable ☐ Driven ☐ Bored ☐

(6) CASING SCHEDULE: Threaded ☐ Welded ☐
" Diam. from feet to feet Gage

" Diam. from feet to feet Gage

" Diam. from feet to feet Gage

New ☐ Reject ☐ Used ☐

(7) PERFORATIONS: Perforated? Yes ☐ No ☐
Type of perforator used

Size of perforations inches by inches

perforations from feet to feet

perforations from feet to feet

perforations from feet to feet

perforations from feet to feet

perforations from feet to feet

(8) SCREENS: Well screen installed? Yes ☐ No ☐
Manufacturer's Name

Type Model No.

Diam. Slot size Set from ft. to

Diam. Slot size Set from ft. to

(9) CONSTRUCTION:
Was well gravel packed? Yes ☐ No ☐ Size of gravel:

Gravel placed from feet to feet

Was a surface seal provided? Yes ☐ No ☐

To what depth? feet

Material used in seal:

Did any strata contain unusable water? Yes ☑ No ☐

Type of water: Depth of strata

Method of sealing strata off:

Was surface casing used? Yes ☐ No ☐

Was it cemented in place? Yes ☐ No ☐

(10) WATER LEVELS:
Static level feet below land surface Date

Artesian pressure feet above land surface Date

RECEIVED

LOG RECEIVED: JUL 06 1988 WATER RIGHTS SALT LAKE

(11) FLOWING WELL:
Controlled by (check) Valve ☐ Cap ☐ Plug ☐ No Control ☐

Does well leak around casing? Yes ☐ No ☐

(12) WELL TESTS:
Drawdown is the distance in feet the water level is lowered below static level.

Was a pump test made? Yes ☐ No ☐ If so, by whom?

Yield: gal./min. with feet drawdown after hours

Bailer test gal./min. with feet drawdown after hours

Artesian flow g.p.m. Date

Temperature of water Was a chemical analysis made? No ☐ Yes ☐

(13) WELL LOG:
Diameter of well inches

Depth drilled feet. Depth of completed well feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	REMARKS
0	70	✓										Blue

Water was unusable, well casing was pulled, well was filled with plug cement.

Work started June 1, 1988 Completed June 3, 1988

(14) PUMP:
Manufacturer's Name

Type: H. P.

Depth to pump or bowles feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Birchell Well Drilling (Person, firm, or corporation) (Type or print)

Address Rt 2 Box 2765 Roosevelt Ut

(Signed) [signature] (Well Driller)

License No. 496 Date June 23, 1988

USE OTHER SIDE FOR ADDITIONAL REMARKS

WELL DRILLER'S REPORT

B.S.
12-30-04

State of Utah
Division of Water Rights

For additional space, use "Additional Well Data Form" and attach

Well Identification

Water Right: 45-5968

WIN: 31969

Owner *Note any changes*

Bruce L. Kendall
1905 East 500 South
Vernal UT 84078

Contact Person/Engineer: ____

Well Location *Note any changes*

N 200 W 450 from the S4 corner of section 19, Township 4S, Range 21E, SL B&M

Location Description: (address, proximity to buildings, landmarks, ground elevation,local well #)

Drillers Activity Start Date: 11-24-04 Completion Date: 12-09-04

Check all that apply: ☒ New ☐ Repair ☐ Deepen ☐ Clean ☐ Replace ☐ Public Nature of Use: ____

If a replacement well, provide location of new well. ____ feet north/south and ____ feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	38	10"	Air Rotary	Air + Foam
38	60	6"	"	"

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE High	PERMEABLE Low	CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	ROCK TYPE	COLOR	DESCRIPTION AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition density, plasticity, shape, cementation, consistancy, water bearing, ordor, fracturing, minerology, texture,degree of weathering, hardness, water quality, etc.)
0	28				x			x			x	Topsoil.	Br.	
28	36	X						X					Br.	

RECEIVED
DEC 3 0 2004
WATER RIGHTS
SALT LAKE

Static Water Level

Date 12-09-04. Water Level 11 feet Flowing? ☐ Yes ☐ No

Method of Water Level Measurement M Scope If Flowing, Capped Pressure ____ PSI

Point to Which Water Level Measurement was Referenced Top of Casing. Elevation ____

Height of Water Level reference point above ground surface 2' feet Temperature ____ degrees ☐ C ☐ F

Well Log

Construction Information

DEPTH (feet) FROM	TO	CASING: CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	DEPTH (feet) FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
+2	-38.	Steel	.75.	6"	30'	35'	3/8"	5"	3-x [illegible]

☐ SCREEN ☒ PERFORATIONS ☒ OPEN BOTTOM

Well Head Configuration: McNiTor CAP. Access Port Provided? ☒ Yes ☐ No

Casing Joint Type: Welded Perforator Used: CuTTing Torch.

Was a Surface Seal Installed? ☒ Yes ☐ No Depth of Surface Seal: 28' feet Drive Shoe? ☒ Yes ☐ No

Surface Seal Material Placement Method: Poured

DEPTH (feet) FROM	TO	SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION: SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	Quantity of Material Used (if applicable)	GROUT DENSITY (lbs./gal., # bag mix, gal./sack etc.)
0	28ft.	Cement + Bentonite Hole Plug.	11 Sacks.	5 gal

Well Development and Well Yield Test Information

DATE	METHOD	YIELD	Units Check One: GPM	CFS	DRAWDOWN (ft)	TIME PUMPED (hrs & min)
12-9-04	Air Lift.	20 +	X			1 Hr.

Pump (Permanent)

Pump Description: ? Horsepower: ______ Pump Intake Depth: ______ feet

Approximate Maximum Pumping Rate: ______ Well Disinfected upon Completion? ☐ Yes ☐ No

Comments

Description of construction activity, additional materials used, problems encountered, extraordinary Circumstances, abandonment procedures. *Use additional well data form for more space.*

No casing below [illegible] as it is intended for a place for sand to go. advised customer to keep pump above 30'

Well Driller Statement

This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name INTERSTATE WATER WELLS INC (Person, Firm, or Corporation - Print or Type) License No. 606

Signature Leroy E. Kuehler. (Licensed Well Driller) Date 12-27-04.

WELL DRILLER'S REPORT

State of Utah
Division of Water Rights
For additional space, use "Additional Well Data Form" and attach

RECEIVED
APR 04 2003
WATER RIGHTS
SALT LAKE

Well Identification PROVISIONAL WELL: 01-45-002-P-01 (45-6015)

Owner *Note any changes*
DAHMS, DALE M
1084 N 1500 E
VERNAL, UT 84078

Contact Person/Engineer:

Well Location *Note any changes*

NORTH 380 feet EAST 150 feet from the W4 Corner of
SECTION 18, TOWNSHIP 4S, RANGE 21E, SLB&M.

Location Description: (address, proximity to buildings, landmarks, ground elevation, local well #)

Drillers Activity Start Date: 3-26-03 Completion Date: 3-28-03

Check all that apply: [X] New [ ] Repair [ ] Deepen [ ] Clean [ ] Replace [ ] Public Nature of Use:

If a replacement well, provide the location of the new well. ____ feet north/south and ____ feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	28'	18"	Auger	NONE

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE high	PERMEABLE low	CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	ROCK TYPE	COLOR	DESCRIPTIONS AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition, density, plasticity, shape, cementation, consistancy, water bearing, odor, fracturing, minerology, texture, degree of weathering, hardness, water quality, etc.)
0	7						X							
7	21								X					
21	28											SHALE	BLUE	

(UNCONSOLIDATED: Clay, Silt, Sand, Gravel, Cobbles, Boulder, Other; CONSOLIDATED: Rock Type)

Static Water Level

Date 3-27-03 Water Level 10' feet Flowing? [ ] Yes [X] No

Method of Water Level Measurement ________ If Flowing, Capped Pressure ________ PSI

Point to Which Water Level Measurement was Referenced Ground Level Ground Elevation (If known) ________

Height of Water Level reference point above ground surface ________ feet Temperature ________ [ ] °C [ ] °F

Construction Information

DEPTH (feet) FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	DEPTH (feet) FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
0	28'	8" Plastic	200 PSI		20'	28'	1/8" Slots	6"	4

☐ SCREEN ☐ PERFORATIONS ☐ OPEN BOTTOM

Well Head Configuration: CAP Access Port Provided? ☐ Yes ☒ No

Casing Joint Type: Glue Perforator Used: Saw

Was a Surface Seal installed? ☒ Yes ☐ No Depth of Surface Seal: 6 feet Drive Shoe? ☐ Yes ☒ No

Surface Seal Material Placement Method: Cement

Provide Seal Material description below:

DEPTH (feet) FROM	TO	SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION: SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	Quantity of Material Used (if applicable)	GROUT DENSITY (lbs./gal.,# bag mix, gal./sack etc.)
8'	28'	Gravel	2 yds	
6'	8'	Quick Gel		
0'	6'	Cement		5 Bag Mix

Well Development and Well Yield Test Information

Date	Method	Yield	Units (Check One) GPM	CFS	DRAWDOWN (ft)	TIME PUMPED (hrs & min)

Pump (Permanent)

Pump Description: ____ Horsepower: ____ Pump Intake Depth: ____ feet

Approximate maximum pumping rate: ____ Well disinfected upon completion? ☐ Yes ☐ No

Comments

Description of construction activity, additional materials used, problems encountered, extraordinary circumstances, abandonment procedures. *Use additional well data form for more space.*

Well Driller Statement

This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name Bill Jr's Rathdrum Drilling Inc. **License No.** 348

(Person, Firm, or Corporation - Print or Type)

Signature W.O. [signature] **Date** 3-28-03

(Licensed Well Driller)

WELL DRILLER'S REPORT
State of Utah
Division of Water Rights

For additional space, use "Additional Well Data Form" and attach

Well Identification

Water Right: 45-6464 WIN: 437712

Owner *Note any changes*

Keith Michael Foley Trust
Keith Michael and Aljean Snow Foley Trustees
789 West Highway 40
Vernal, UT 84078

Contact Person/Engineer: ______

Well Location *Note any changes*

N 940 E 1094 from the S4 corner of section 18, Township 4S, Range 21E, SL B&M

Location Description: (address, proximity to buildings, landmarks, ground elevation,local well #)

Drillers Activity Start Date: 5-21-14 Completion Date: 5-23-14

Check all that apply: ☒ New ☐ Repair ☐ Deepen ☐ Clean ☐ Replace ☐ Public Nature of Use: ______

If a replacement well, provide location of new well. ______ feet north/south and ______ feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	30	12 1/4	Air Rotary	NA
30	325	6 3/4	" "	"

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE High	PERMEABLE Low	CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	ROCK TYPE	COLOR	DESCRIPTION AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition density, plasticity, shape, cementation, consistancy, water bearing, odor, fracturing, minerology, texture,degree of weathering, hardness, water quality, etc.)
~~0~~	~~30~~								x			~~Cobbles~~		
0	30								x			Cobbles	Red	
30	325										x	Shale	Green	Dry hole

RECEIVED
JUL 10 2014 JH
WATER RIGHTS
SALT LAKE

Static Water Level

Date 5-23-14 Water Level N/A feet Flowing? ~~☒~~ Yes ☐ No

Method of Water Level Measurement Dry hole If Flowing, Capped Pressure ______ PSI

Point to Which Water Level Measurement was Referenced ______ Elevation ______

Height of Water Level reference point above ground surface ______ feet Temperature ______ degrees ☐C ☐F

Construction Information

DEPTH (feet)		CASING			DEPTH (feet)		☐SCREEN ☐PERFORATIONS ☐OPEN BOTTOM		
FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
0	30	Steel	.250	8					
		pulled casing							

Well Head Configuration: N/A　　Access Port Provided? ☐Yes ☐No

Casing Joint Type: ______　　Perforator Used: ______

Was a Surface Seal Installed? ☐Yes ☐No　　Depth of Surface Seal: ______ feet　　Drive Shoe? ☐Yes ☐No

Surface Seal Material Placement Method: ______

Was a temporary surface casing used? ☐Yes ☐No　If yes, depth of casing: ______ feet　　diameter: ______ inches

DEPTH (feet)		SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION		
FROM	TO	SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	**Quantity** of Material Used (if applicable)	GROUT DENSITY (lbs./gal., # bag mix, gal./sack etc.)
		pulled casing -		

Well Development and Well Yield Test Information

DATE	METHOD	YIELD	Units Check One		DRAWDOWN (ft)	TIME PUMPED (hrs & min)
			GPM	CFS		

Pump (Permanent)

Pump Description: N/A　　Horsepower: ______　　Pump Intake Depth: ______ feet

Approximate Maximum Pumping Rate: ______　　Well Disinfected upon Completion? ☐Yes ☐No

Comments

Description of construction activity, additional materials used, problems encountered, extraordinary circumstances, abandonment procedures. *Use additional well data form for more space.*

Pulled 8" Casing Used Bentonite hole plug to plug Dry hole.

Well Driller Statement

This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name ROSS DRILLING & CONSTRUCTION INC　　**License No.** 346

(Person, Firm, or Corporation - Print or Type)

Signature [signature]　　**Date** July 7, 2014

(Licensed Well Driller)

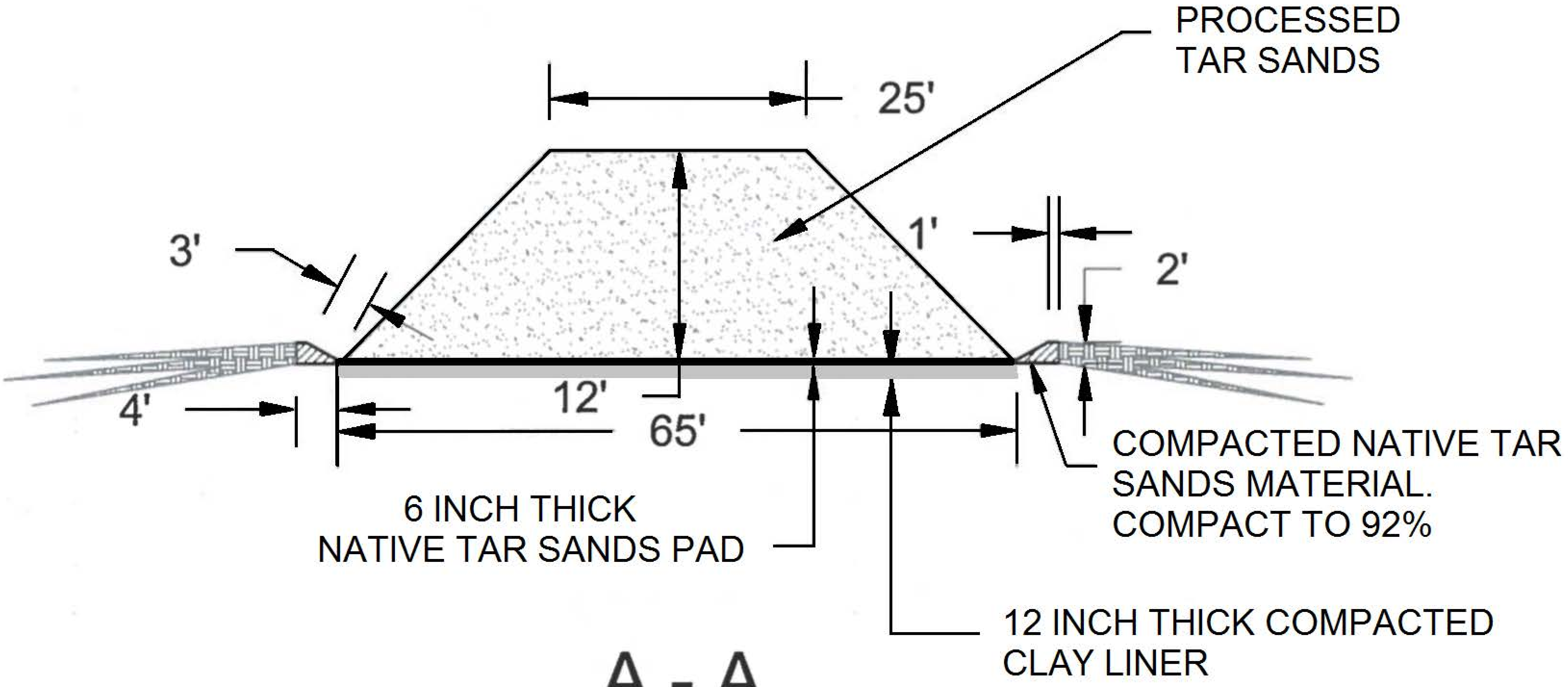
APPENDIX B

SITE PLANS

FLOW DIAGRAMS

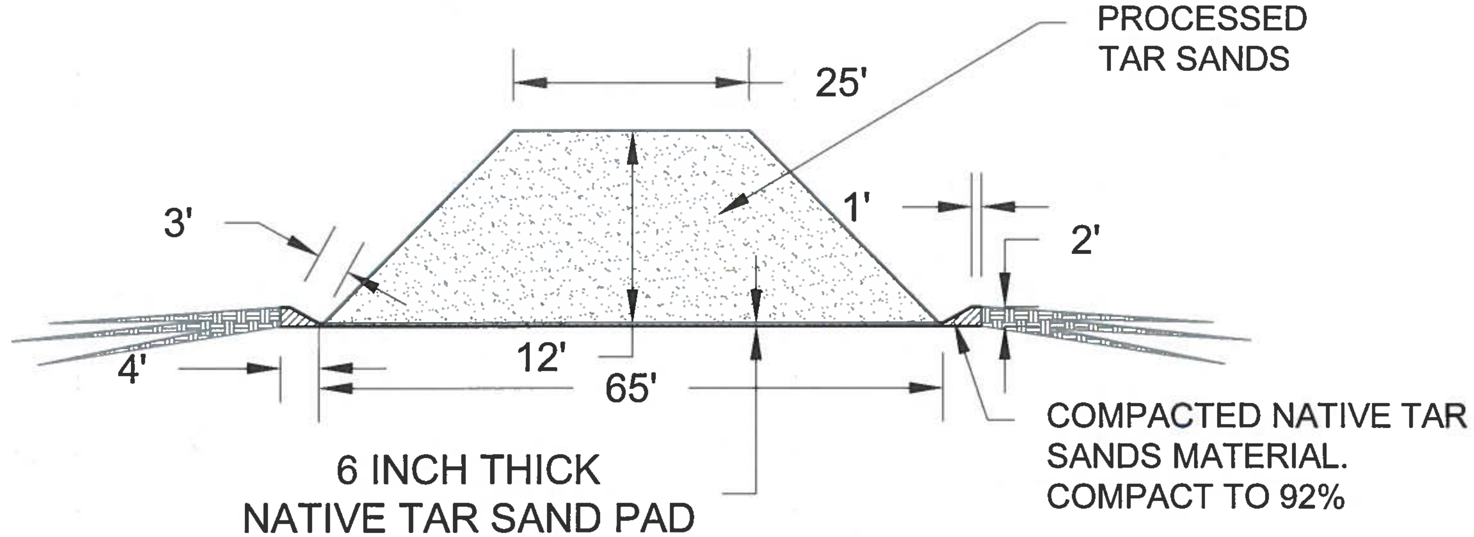
APPENDIX REDACTED

BUSINESS CONFIDENTIAL

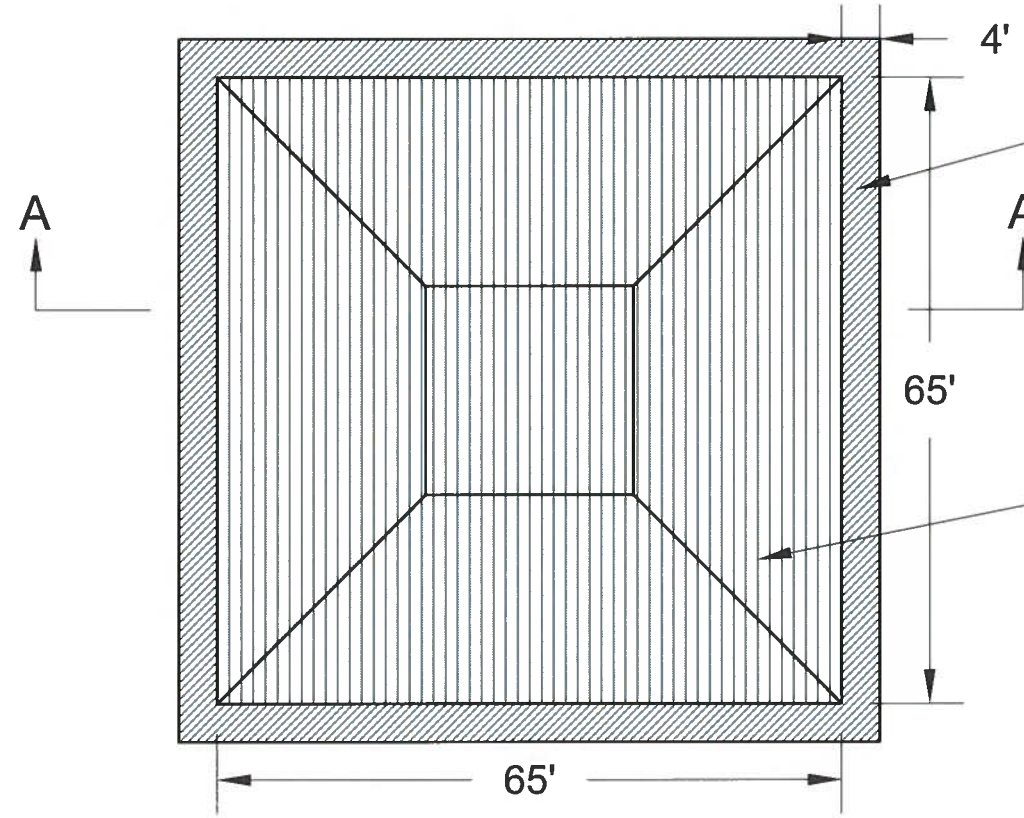


PROCESSED
TAR SANDS
25'
1'
3'
2'
12'
4'
65'
COMPACTED NATIVE TAR
SANDS MATERIAL.
COMPACT TO 92%
6 INCH THICK
NATIVE TAR SANDS PAD
12 INCH THICK COMPACTED
CLAY LINER

A - A



A - A



STOCK PILE
RETENTION AREA

REGISTERED STRUCTURAL ENGINEER
167895
TRACY D.
OSTLER
6-9-15
STATE OF UTAH

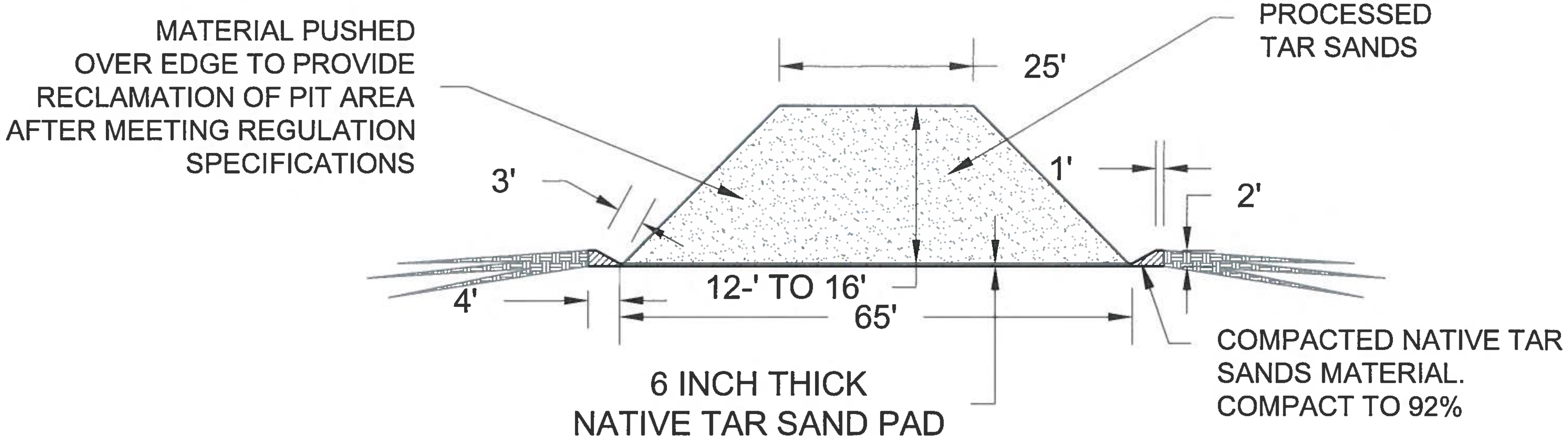
UTAH DEPARTMENT OF TRANSPORTATION
ROADWAY DESIGN

No.	DATE	BY	REMARKS
			REVISIONS

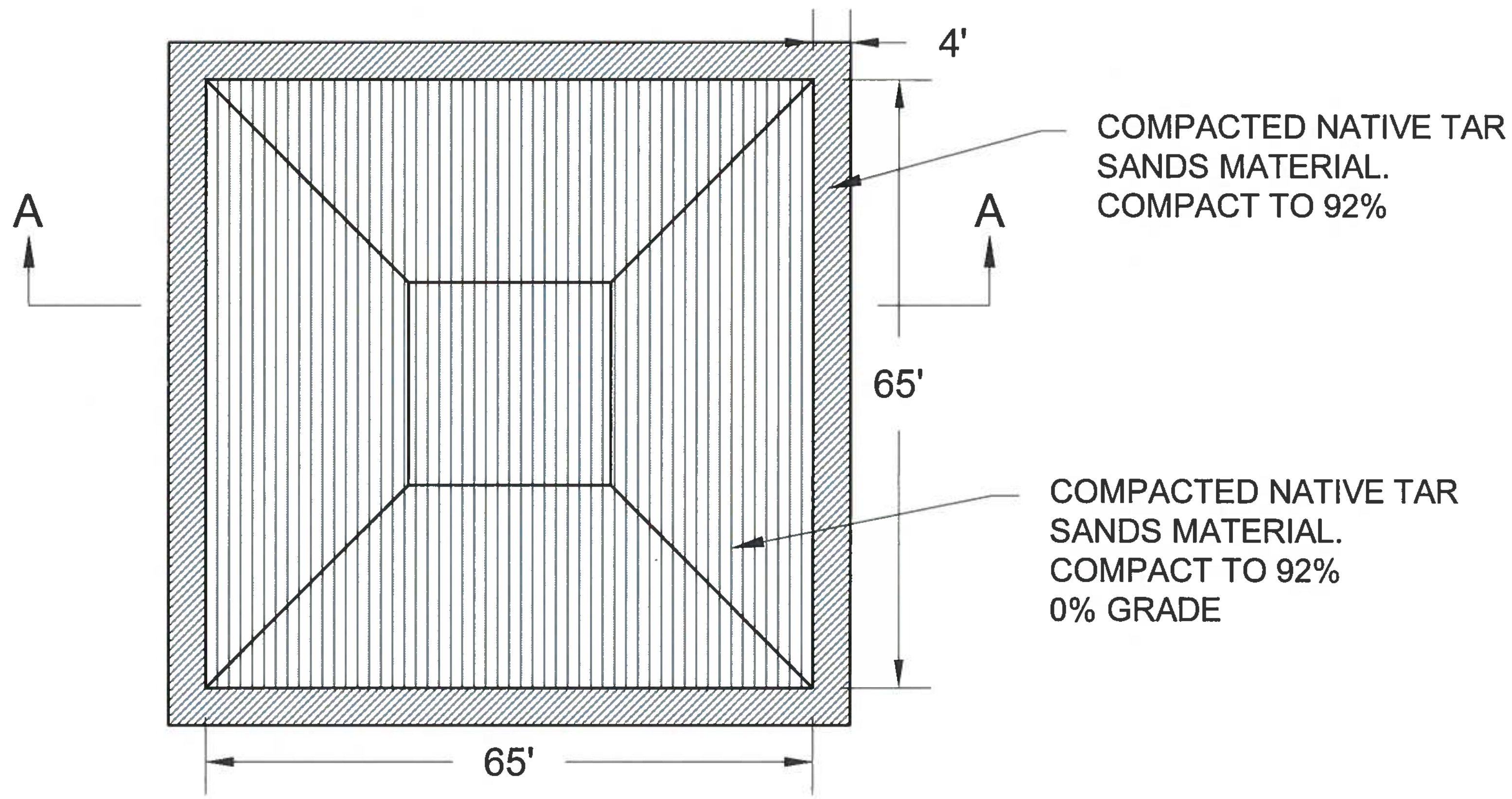
DRAWN BY ####
QC CHECKED BY ####
APPROVED
PROFESSIONAL ENGINEER
DATE

PROJECT: MCW Energy Group
Maeser Facility
PROJECT NUMBER: Processed Tar Sands
PIN
Temp Storage Area

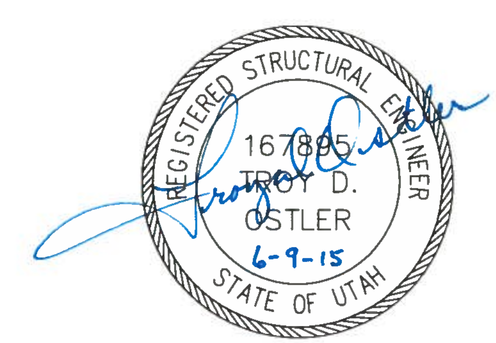
SHEET No. DT-5



A - A



MINE SITE
STOCK PILE RETENTION AREA



UTAH DEPARTMENT OF TRANSPORTATION
ROADWAY DESIGN

No.	DATE	BY	REMARKS
			REVISIONS

DRAWN BY ####
QC CHECKED BY ####
APPROVED
PROFESSIONAL ENGINEER
DATE

PROJECT: Temple Mountain Energy
Mine Site
PROJECT NUMBER: Processed Tar Sands
PIN
Retention Area

SHEET No. DT-6

New temporary pad dimensions and storm water catchment solution

At full production the plant will process 7 to 10 cubic yards an hour.

9 yd^3 x 24 hours x 27 ft^3/yd^3 = 5,832 ft^3 per day x 7 days = **40,824 ft^3 per week**

The current temporary tailing pad was designed for **17,460 ft^3**, just over 2 days of tailings at full production. If we take the tailings back to the mine site after each load of ore is delivered, this should not be a problem, but since we are resubmitting the application, we should enlarge the pad to accommodate some additional material so that we are not on such a tight schedule taking tailings back to the mine site.

If we increase the dimensions of the temporary tailings pile to the following…

Perimeter Length (**b1**) - 65 ft (assume a square base)

Height - **h1** - 32.5 ft

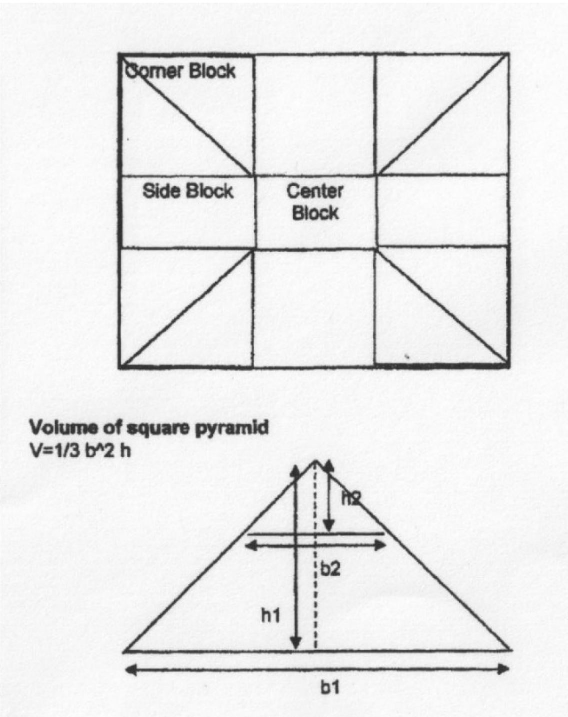
Volume V1 = $b1^2$ (h1/3) = 65^2 (32.5/3) = **45,771 ft^3**

Width of flat top (**b2**) - 25 ft

Height - **h2** - 12.5 ft.

Volume V2 = $b2^2$ (h2/3) = 25^2 (12.5/3) = **2,604 ft^3**

Volume of stockpile = V1 – V2 = 45,771 ft^3 - 2,604 ft^3 **= 43,167 ft^3,** which is a full week's storage at 9 cubic yards per hour.



Source: Permit presently on file with DWQ

Bulk Density - 125 lbs/ft3

Tailings in Stockpile - 43,167 ft^3 x 125 lbs/ft^3 = 5,395,875 lbs = **2,698 tons**

Stockpile Height - 20 ft

Ideally, two trips per week would prevent the tailings pile from reaching maximum capacity, but if one trip per week was done, there would be enough storage capacity.

Concerning storm water capacity - the original temporary tailings holding pad had the capacity to hold 480 ft^3 of water in the base 10 inches of clean sand with 25% porosity.

48 ft x 48 ft x (10/12) x 0.25 = **480 ft^3 of pore space**.

A 100-year 24-hour rain event in eastern Utah will yield 2.3 inches of rain.

48 x 48 x (2.3/12) = **441.6 ft^3 of storm water**.

The new dimensions will also accommodate a 100-year 24-hour rain event…

65 ft x 65 ft x (10/12) x 0.25 = **880 ft^3 of pore space**.

A 100-year 24-hour rain event in eastern Utah will yield 2.3 inches of rain.

65 x 65 x (2.3/12) = **809 ft^3 of storm water**.

We can cheaply and easily modify the design of the base of the pad to accommodate even more water. If the berm surrounding the pad is 2 feet high, we get a total of **2,112 ft^3** of storm water storage capacity with a flat bottom. With an asphalt base, this should be more than adequate to prevent any storm water from contaminating the ground water with leachate.

Total volume = 65 x 65 x 2 x 0.25 = **2,112 ft^3** of total storm water storage space.

http://www.wrcc.dri.edu/pcpnfreq/ut100y24.gif

We can have two 100-year 24-hour rain events in the same week and still have the capacity to store all the storm water within the temporary tailings holding pad without any storm water runoff.

It should be noted that the tailings themselves have the capacity to hold even more water since they will be coming out of the dryer virtually free of any moisture. The capillary forces within the tailings after a rain storm will be quite strong and hold a significant amount of water. This was not considered in the original application since the saturated storage was adequate to hold a

100-year 24-hour rain event. It may be beneficial for us to include this information in the new application.

If we use a water holding capacity chart as a measure of the storage capacity of the tailings and use fine sand as the category of soil that the tailings are equivalent to, then each vertical foot of tailings should be able to hold 1.8 inches of rainwater via capillary forces (Table 1). Two feet of tailings will hold 3.6 inches of rain, this is more than the 100-year 24-hour rain event without taking into consideration the saturated storage capacity of the sand.

Table 1. Water holding capacity measured in inches of water per foot of soil.

Soil Type	Total Available Water, in/ft
coarse sand	0.6
fine sand	1.8
loamy sand	2.0
sandy loam	2.4
sandy clay loam	1.9
loam	3.8
silt loam	4.2
silty clay loam	2.4
clay loam	2.2
silty clay	2.6
clay	2.4
peat	6.0

Source: http://nrcca.cals.cornell.edu/soil/CA2/CA0212.1-3.php

Lastly, we should also include the fact that the temporary storage pad will also be temporary since we will be going to a system of having the dry tailings loaded directly onto trailers right from the conveyor belt in the short term future.

SPECIAL PROVISION

SECTION 02744S

OIL SAND ASPHALT (OSA)

Add Section 02744:

PART 1 GENERAL

1.1 SECTION INCLUDES

A. Products and procedures for mixing, laying, and compacting a surface course of one or more layers of oil sand asphalt comprised of raw oil sands.

1.2 REFERENCES

A. ASTM D 2950: Standard Test Method for Density of Bituminous Concrete in Place by Nuclear Methods

B. ASTM E 178: Practice for Dealing with Outlying Observations

1.3 DEFINITIONS

A. Oil Sands
  1. A mined material comprised of natural asphalt and sand.

1.4 ACCEPTANCE

A. A lot equals the number of tons of OSA placed during each production day. The Engineer may:
  1. Conduct the following tests on the placed OSA for acceptance:
    a. Obtain samples for density and thickness.
      1. Obtain one core per 250 tons, randomly as instructed, and in the presence of the Engineer within two days after the pavement is placed.(UDOT Materials Manual of Instruction Part 8-981: Random Sampling, UDOT Materials Manual of Instruction Part 8-984: Sampling Methods)
      2. Move transversely to a point one foot from the edge of the pavement if the random location for cores falls within one foot of the edge of the overall pavement section (outer part of shoulders).

3. Fill core holes with OSA or high AC content cold mix and compact.
4. Obtain one nuclear density test for each 2500 Sq. Ft. of placed OSA.

PART 2 PRODUCTS

2.1 OIL SAND

A. Use Oil Sand supplied by the owner. Load and haul oil sands from source identified by owner.

PART 3 EXECUTION

3.1 SURFACE PREPARATION

A. Locate, reference, and protect all utility covers, monuments, and other components affected by the paving operations.

B. Remove all moisture, dirt, sand, leaves, and other objectionable material from the prepared surface before placing the OSA.

3.2 COMPACTION

A. Use a small compactor or vibratory roller in addition to normal rolling at structures.

B. Operate in a transverse direction next to the back wall and approach slab.

C. Use aggressive rolling techniques to minimize risk of under-compacted OSA courses.

D. Roll surface immediately after placement.

3.3 LIMITATIONS

A. Do not place OSA on frozen base or subbase.

B. Do not place OSA during adverse climatic conditions, such as precipitation, or when surface is icy or wet.

C. Place OSA from when the air temperature in the shade and the surface temperature are above 70 degrees F.
   1. The Engineer determines if it is feasible to place OSA outside the above limits. Obtain written approval from the Engineer prior to paving.

END OF SECTION

MCW Energy
Asphalt Ridge Project
Uintah County, Utah

Attachment to Ground Water Application
Project Background, Geology, Hydrology
& Operations Description

Stantec

Prepared for:
Utah Department of
Environmental Quality
Division of Water Quality
Ground Water Section

Prepared by:
Stantec Consulting, Inc.

June 1, 2015

Table of Contents

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 ATTACHMENT TO GROUNDWATER PERMIT APPLICATION

1.1 INTRODUCTION

MCW Energy (MCW) has leased a Utah School and Institutional Trust Lands Administration (SITLA) tract west of Vernal, Utah in Maeser (previously leased by Amerisands, LLC) (see **Figure 1**). The tract contains approximately 1,138.22 acres in the following parcels:

Township 4 South (T4S), Range 20 East (R20E), Salt Lake Base & Meridian (SLB&M),
Section 23: N ½ NE ¼, E ½ W ½, S ½ SE ¼;
Section 24: Lots 2-4, W ½ E ½, N ½ NW ¼;
Section 26: E ½, E ½ W ½.

MCW plans to extract bitumen from Asphalt Ridge oil sands using a proprietary solvent process that was developed and has been used in Russia and the Ukraine. The process is designed to produce enhanced bitumen as its primary product, and clean, dry sand, suitable for construction material as a secondary product. The modular processing plant was delivered to the site and constructed in the SW¼ NE¼, Section 24, T4S, R20E, SLB&M in October 2014 (see **Figure 2**). MCW purchased oil sands from an existing mining operation to use for a pilot test of the process.

The process was proved through a pilot test in October 2014 and has been optimized through subsequent test runs throughout 2015. MCW now plans to scale up into a production operation as well as continued optimization and testing (pilot plant) operations. During the initial production phase, oil sand will be purchased from an existing operation, the Temple Mountain Mine (TME) south of Vernal, Utah. The SITLA lease has oil sands beneath it and MCW is planning to mine these oil sands in the future. All oil sands ore storage, crushing, processing, and employee support facilities will be located off Highway 121 on the MCW plant site. During the pilot test the plant employed up to 12 workers, and, during production, the plant will employ up to 18 workers. Other than a minor amount of additional traffic, there should be no impact to Highway 121 or its users.

This report has been prepared to demonstrate that the design and location of the MCW facilities ensures a very low probability that any contaminants would impact soils or groundwater as a result of the MCW pilot test or operations.

1.2 MEASURES TAKEN TO PROTECT THE ENVIRONMENT

The MCW process is designed to contain and reuse all process solutions that might be considered contaminants if released to the environment. The operation uses no process water, although the plant requires water for its boiler, dust control, and for employee sanitary purposes. Fresh water will be brought to the site by truck and stored in a tank. Sanitary waste water will be collected in a tank and trucked to a licensed disposal facility. No water or waste water will contact tar sands or any process chemicals.

Oil sands, a proprietary oil sand processing solvent, and water will be delivered to the site by truck. A front end loader will be used on-site to move stockpiled tar sands to the crusher, and to load clean, dry sand onto trucks for use on other sites. Bitumen, sanitary waste water, and sand will be trucked out of the facility. Short-term storage of feedstock and processed sand will be on DWQ permitted liners. Engineer's drawings for the proposed temporary storage pad for processed sand are in **Appendix D**. The pad has been designed to withstand long-term loading and unloading stresses. Its asphalt construction will allow for easy repair, if needed. The pad will be inspected daily for cracking or any other damage, and repaired as needed. It has also been designed to contain precipitation equivalent to two 100-year 24-hour storm events within the pore space of the processed sand, without counting the capillary action that would be created by the sand (which would increase storage capacity substantially).

Processed sand that is not sold will be trucked back to TME for permanent storage as mine backfill. These tailings will be covered in a manner that will prevent precipitation from leaching through the material and potentially reaching groundwater. Results of laboratory analyses using EPA's Synthetic Precipitation Leaching Procedure (SPLP) and dry analyses are provided later in this document. Tailings will only be stored short-term (maximum three-weeks when the plant is running a single shift) at the Maeser site and only on a liner approved by DWQ for that purpose.

The solvent used to extract bitumen from the oil sands, and the bitumen product, are stored in factory-built tanks placed within a concrete and steel containment area that would prevent any spills or ruptures from escaping into the environment. All piping is above ground where any leaks would be immediately detected and initiate a remedial response.

Processed sand will be monitored daily to ensure maximum removal of hydrocarbons. This serves the dual purpose of maximizing the plant's efficiency and leaving minimum residual product and solvent in the processed sand. A description of the process and its environmental safeguards are described separately in this Attachment.

The Maeser site is situated in a slight depression and has been graded to prevent run-on of precipitation from offsite so that it will not contact the disturbed area. Precipitation that falls on the disturbed area will remain on site due to the same topography and grading.

MCW ENERGY
ASPHALT RIDGE PROJECT
UINTAH COUNTY, UTAH

Attachment to Groundwater Permit Application
June 1, 2015

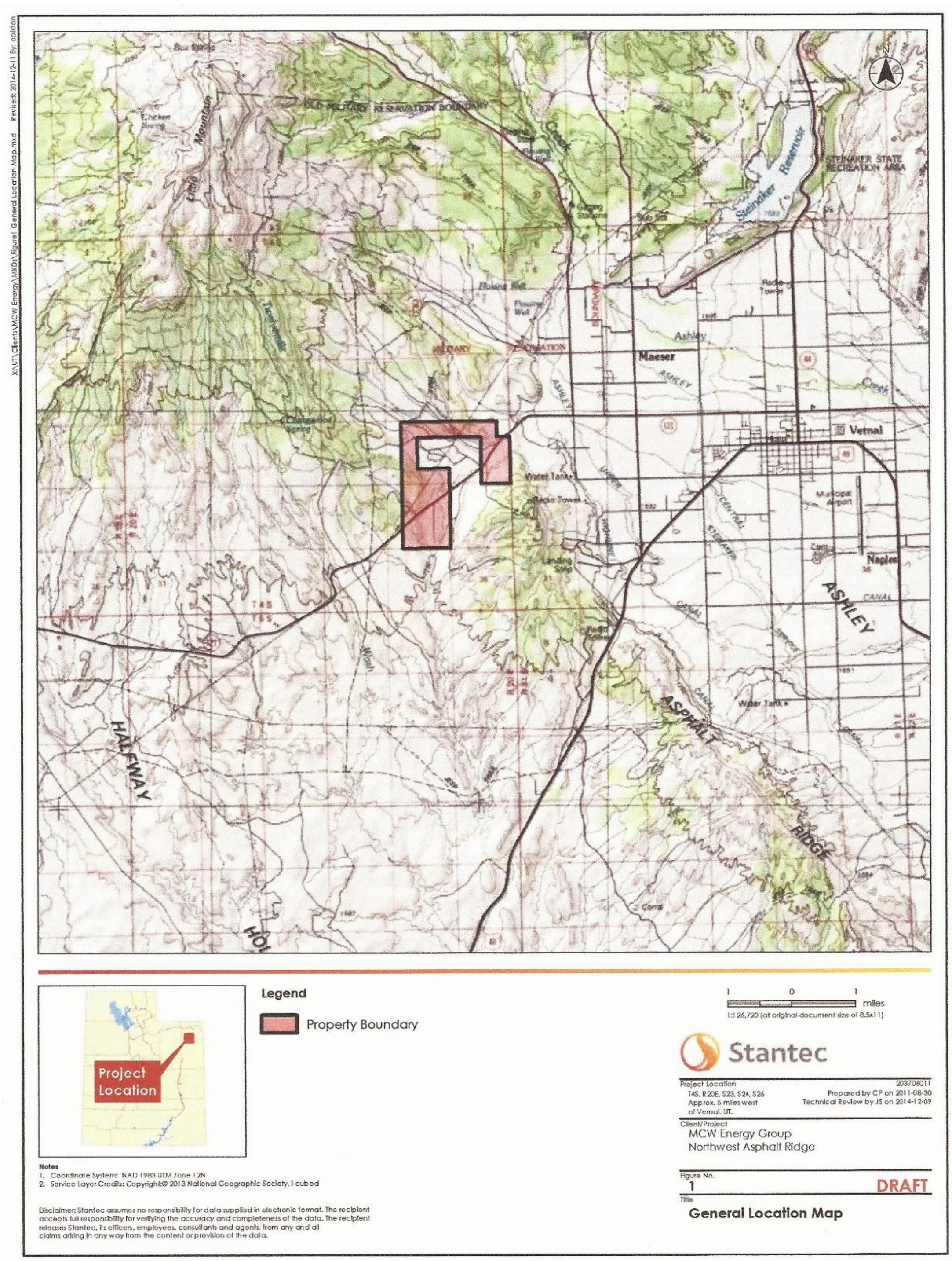


Figure 1 General Location Map

MCW ENERGY
ASPHALT RIDGE PROJECT
UINTAH COUNTY, UTAH

Attachment to Groundwater Permit Application
June 1, 2015

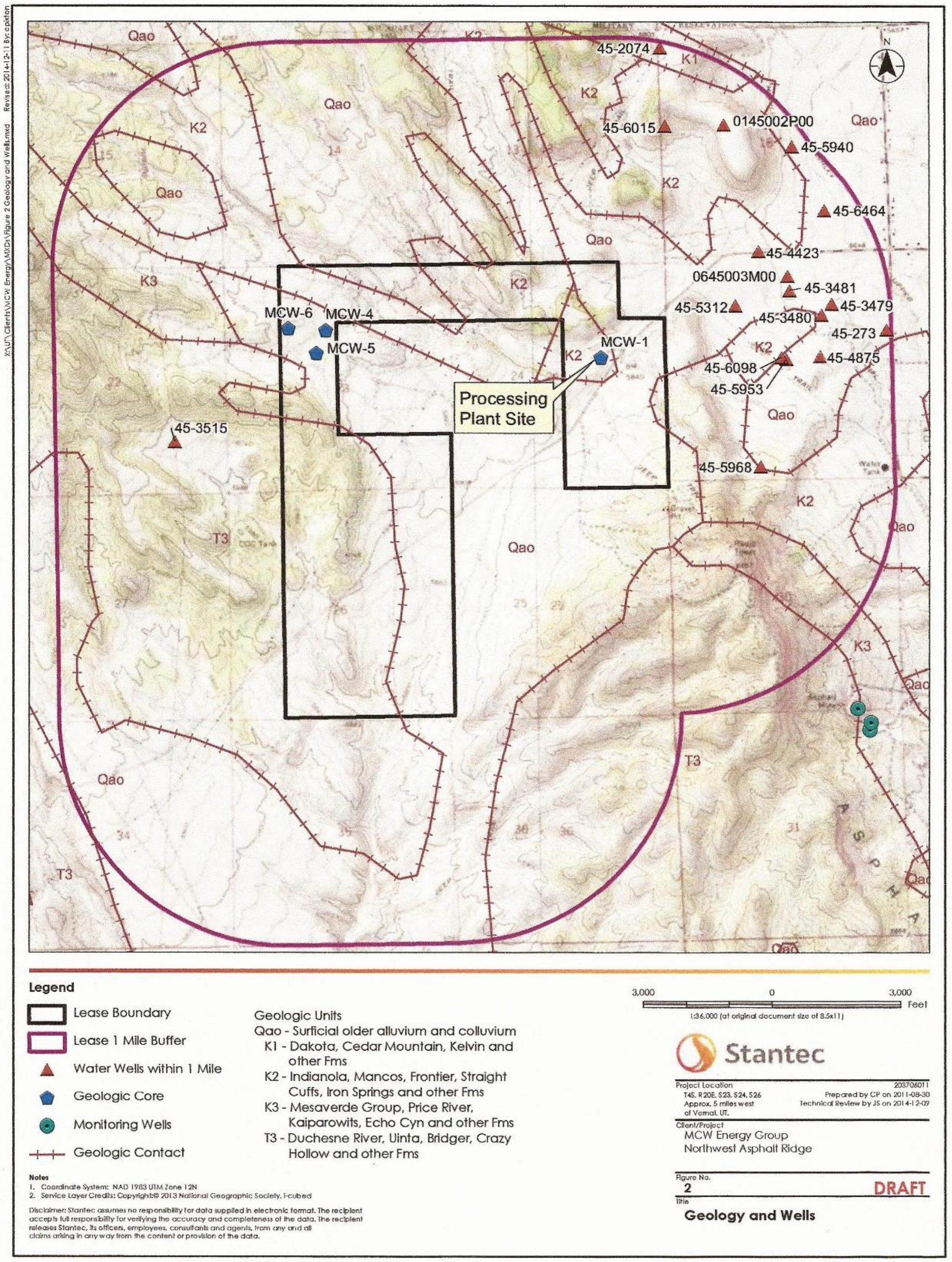


Figure 2 Geology and Wells

Stantec

1.3 ENVIRONMENTAL SETTING

The topography of the plant site (see **Figure 2**) is relatively flat with rolling hills. There are no perennial surface water features on the site; an unnamed ephemeral drainage is approximately 116 feet north of the nearest site disturbance. The vegetation in the area surrounding the NW Asphalt Ridge site includes mixed shrub/grassland communities with junipers on slopes. Temperatures range from average highs of 89.1°F in July to average lows of 5.0°F in January, and precipitation averages 8.42 inches annually including 18.5 inches of snowfall (WRCC, 2015), based on the period of record, which is 11/01/1894 to 12/31/2010.

The topographic setting of the leasehold is shown on **Figure 2**. The leasehold exhibits moderate relief with elevations ranging from 5,760 feet to over 6,200 feet on Asphalt Ridge in the southern portion of the tract. State Highway 121 between the small communities of Maeser and Lapoint traverses the tract, and most of the tract is accessible through numerous unimproved roads. A powerline also crosses through the center of the tract.

1.3.1 Geology and Landform

This section is taken largely from the "Draft Technical Report on NW Asphalt Ridge Tar Sand Deposit, Uintah County, Utah," (Report) by James F. Kohler, P.G., Utah Geosystems, dated June 12, 2011.

The NW Asphalt Ridge deposit is one of the oil sand deposits which occur in the Uinta Basin of northeastern Utah (**Figure 3**). Asphalt Ridge is a 15-mile-long northwest trending hogback, with the Tertiary Duchesne River Formation lying uncomformably on the Cretaceous Mesaverde Group (**Figure 4**). The NW Asphalt Ridge deposit is separated from the main Asphalt Ridge deposit by a series of major faults which lower the Mesaverde formation over 1,000 feet to the north (**Figure 5**).

Within the NW Asphalt Ridge deposit, Mesozoic and early Tertiary strata dip steeply to the south southwest. These strata are overlain unconformably by less steeply dipping formations of middle Tertiary age. This is shown on **Figure 4** which shows a generalized cross section across north-central Asphalt Ridge (Kayser, 1966). A section showing the stratigraphy of the NW Asphalt Ridge area is shown on **Figure 6**.

Oil sands deposits in the NW Asphalt Ridge area are found in sandstone units in the Cretaceous Mesaverde group which intertongue with the Mancos Shale of marine origin. Two sandstone units have been identified with some level of bitumen saturation. These units have been designated from oldest to youngest as the Asphalt Ridge sandstone and the Rim Rock sandstone.

Within the NW Asphalt Ridge area, the upper Cretaceous Mancos Group immediately underlies and intertongues with the sandstones of the Mesaverde Group. which consists of two distinct sections, the lower marine sandstones and the upper brackish water sandstones, si1tstones, carbonaceous shales and coals. At NW Asphalt Ridge this upper sequence has been eroded, and only the lower marine sandstones are present (Sinks, 1985). The Rim Rock Sandstone varies in thickness in the vicinity of the NW Asphalt Ridge deposit from 100 to 350 feet thick.

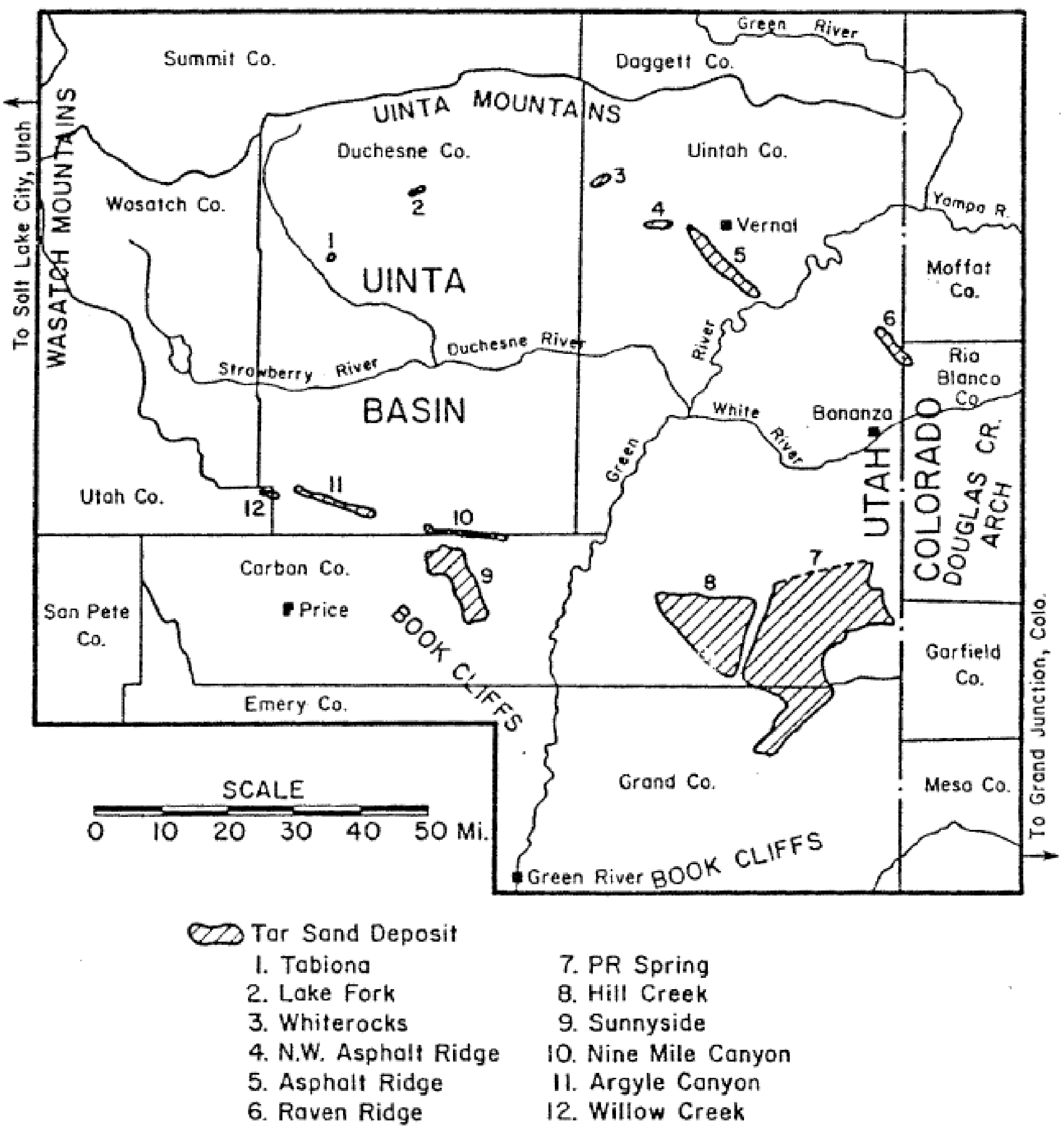


Figure 3 Uintah Basin Oil Sands Deposits

Stantec

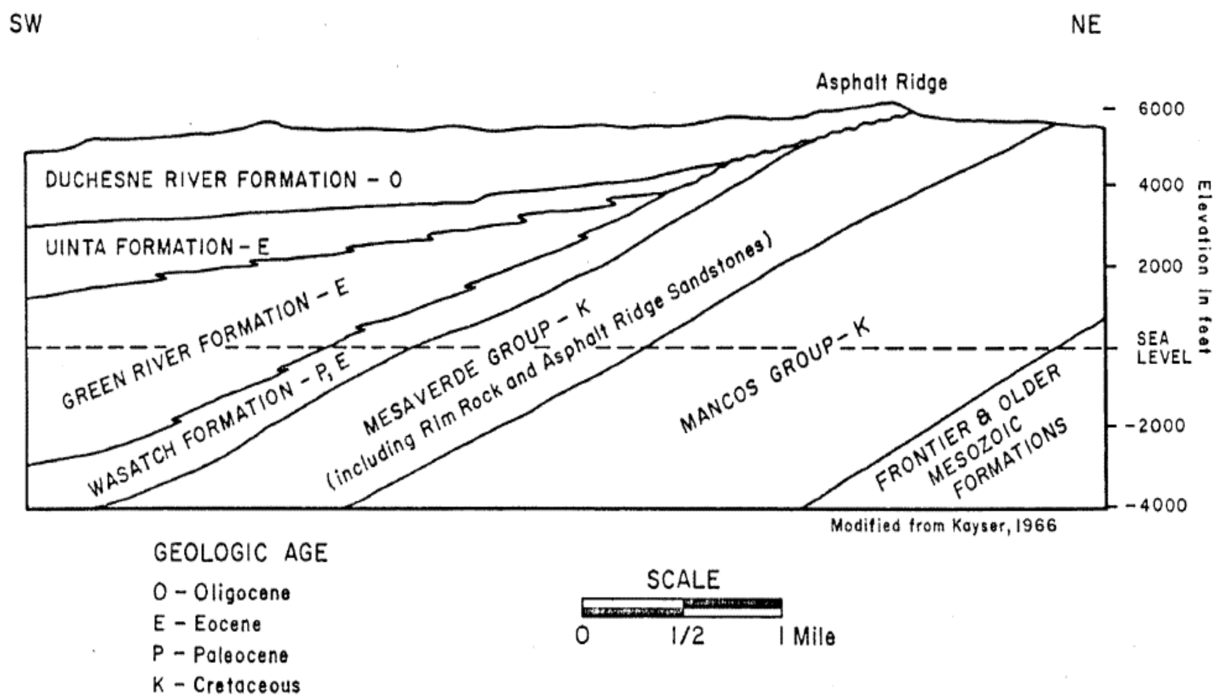


Figure 4 Generalized Cross-Section Through Asphalt Ridge (from Kayser 1966)

The middle zone of the Rim Rock Sandstone was the target reservoir for three in situ field tests conducted in August 2011 (see MCW-4, MCW-5, and MCW-6 on **Figure 2**; Core logs in **Appendix A**). An angular unconformity exists between the upper Rim Rock and the overlying Duchesne River Formation.

The third significant formation in the study area is the Oligocene Duchesne River Formation which unconformably overlies the Mesaverde Group at the NW Asphalt Ridge. This angular unconformity represents approximately 7,000 feet of missing strata (Walton, 1944). The Duchesne River formation is of fluvial origin and the lower portion formation may be saturated with bitumen in some areas (Covington, 1955a; Covington, 1963; Campbell and Ritzma, 1979). This formation, along with Quaternary alluvium, is exposed at the surface basinward from the NW Asphalt Ridge deposit.

Attachment to Groundwater Permit Application
June 1, 2015

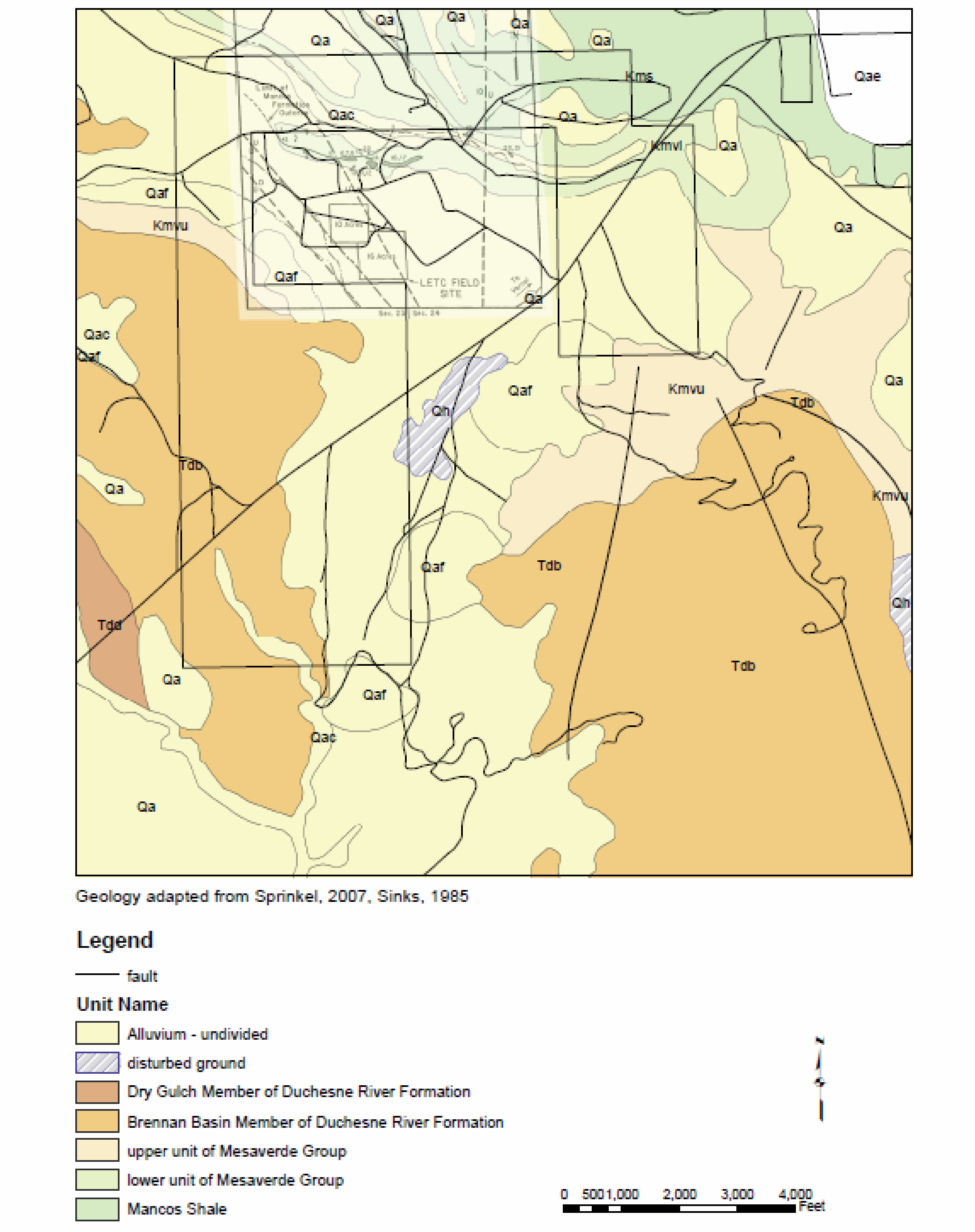


Figure 5 Bedrock Geology and Faults of NW Asphalt Ridge

Stantec

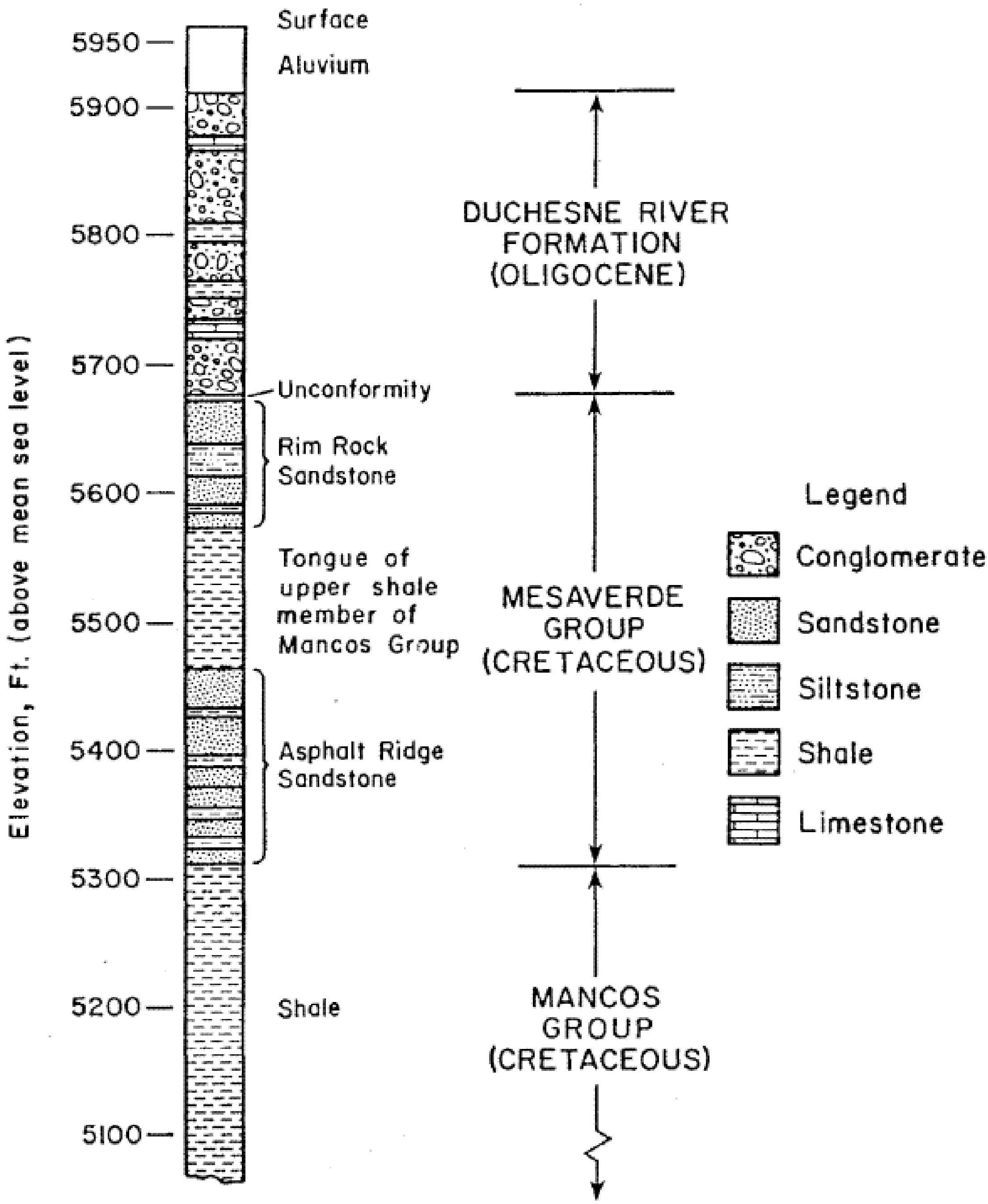


Figure 6 Stratigraphic Section of NW Asphalt Ridge (from Sinks 1985)

Asphalt Ridge is separated from Northwest Asphalt Ridge by faulting at the north end of Asphalt Ridge. Covington (1957) has estimated its displacement to be about 1,200 feet, with the downthrown side to the northwest. The Mesaverde Group dips 12-34° south southwest, while the strata overlying the unconformity between the Mesaverde Group and the Duchesne River Formation are less steep, with dips ranging 5-20° southwest (Kayser, 1966). Drilling and seismic surveys indicate that the NW Asphalt Ridge deposit is structurally complex (see **Figure 5**), with a series of NW-SE trending normal faults (Sinks, 1985). The bedrock geology of the area is shown on **Figure 6**, as are faults. Contacts are shown on **Figure 2**.

MCW had four geologic cores drilled in August 2011 as shown on **Figure 2**. Logs of the cores are attached in **Appendix A**. **Table 1** summarizes the logs. Groundwater was not found in any of the core holes. MCW-1 was drilled at the project site.

Table 1 Summary of Rock Core Logs in Feet Below Ground Surface (BGS)

Feature	MCW-1 (feet bgs)	MCW-4 (feet bgs)	MCW-5 (feet bgs)	MCW-6 (feet bgs)
Alluvium (Duchesne River formation?)	0-25	0-45	0-30	0-20
Mesa Verde – alternating layers, primarily of shale & sandstone	25-60	45-180	30-280	20-180
Mancos Shale		180-220	280-300	
Bitumen	None	92-120	125; 245-270; 275-280	125-140
Groundwater Encountered	None	None	None	None

1.3.2 Surface Water

There are no perennial streams within the lease area or adjacent to it. Precipitation on the plant site (see **Figure 2**), if unmanaged, would drain to an unnamed ephemeral channel that may drain to the Highline Canal. MCW is using best management practices (BMPs) related to storm water management and the Spill Prevention, Control, and Countermeasure (SPCC) plan to ensure that no sediment or contaminants reach the channel. Precipitation runoff that does not contact disturbed areas is routed around the project site. Precipitation that contacts disturbed areas is kept on site via natural topography and berms; this water either evaporates or infiltrates. The National Hydrography Dataset shows no springs within or near the one-mile buffer area around the lease (see **Figure 2**).

The lease area is in two watersheds. The eastern portion, where the processing plant is located, is in the lower Ashley Creek watershed, while the western portion is in the Twelvemile Wash basin. Both are tributary to the Green River. At a HUC 12 level, the eastern portion is in the Coal Mine

Basin-Ashley Creek watershed and the western portion is in the Middle Twelvemile Wash watershed.

The nearest gauging stations in the Ashley Creek drainage are Ashley Creek, Sign of the Maine, near Vernal, Utah (USGS 09271000) and Ashley Creek near Naples, Utah (USGS 09271400). Drainage from the processing plant area would not be measured by either station. There are no gauging stations in the Twelvemile Wash watershed. The gauging station on the Highline Canal Below Mantle Gulch near Jensen, Utah (USGS 09271070) may gauge water from the project site, but it is eight miles downstream and only operated for 36 months between June 1969 and September 1972. During that period there was no flow December through March. The highest monthly average for a single month was 11.7 cubic-feet per second (cfs) in June 1971; the highest monthly average flow for the period of record was 8.1 cfs in June, based on four years (1969-1972).

Ashley Creek near Vernal, which would be upstream of the project site, operated from 1900 to 1965. During the period of 1939 through 1965, the average annual discharge was 121.5 cfs. Peak flow for 1900-1965 was 4,110 cfs on June 11, 1965. Water quality samples were taken at irregular intervals between 1949 and 1974; the average total dissolved solids (TDS) of all 42 samples taken during that period was 140.4 mg/L.

Ashley Creek near Naples, which would be downstream from the project area (but parallel to the Highline Canal), has only a three year record of operation. Average annual discharge for water years 2001, 2002, and 2003 was 62.1 cfs, 5.28 cfs, and 19.0 cfs, respectively. Average TDS for 50 water samples taken between January 2000 and November 2003 was 1,088 mg/L.

Hood and Fields (1978) say the following of Ashley Creek:

> In Ashley Valley, the stream is almost completely diverted and part of the water is impounded. The return flow from irrigation is a slightly saline water of the calcium magnesium sulfate type.

1.3.3 Groundwater

The State of Utah defines an aquifer as "a geologic formation, group of geologic formations or part of a geologic formation that contains sufficiently saturated permeable material to yield usable quantities of water to wells and springs" (R317-6-1).

Several publications describe the local area alluvial surface layer as a fresh water aquifer where present (BLM 2008; Hood 1976; UDWR 1999). In the local area of Maeser and Vernal there are wells completed in the alluvium, but it is a relatively thin layer. As shown in **Table 1** the alluvium in the four MCW geological cores varied from 20-45 feet. **Figure 2** shows all water wells and monitoring wells within one mile of the MCW lease area that are in the Utah Division of Water Rights (UDWR) well database. **Table 2** shows which six of those wells have well logs (the well logs and the geologic rock core logs are in **Appendix A**). Four of the six wells indicate surface layers of alluvium with the depth of the alluvium being 15, 21, 30, and 36 feet. The two perfected wells (with alluvium to 21 and 36 feet) are the only wells in use within the one mile buffer of the lease area, with their uses being irrigation and stock water (they are not used for domestic supply). The two deepest wells (to 200 and 325 feet) were abandoned as dry holes. All four of the geologic core holes were dry as well, with total depths of 60, 220, 300, and 180 feet. The two water well logs that did not record alluvium at the surface described the surface layer as clay. The data in **Table 1** and **Table 2** demonstrate that groundwater at the project, if any, would be a substantial distance beneath the surface and overlain by multiple layers of shale and sandstone (MCW-1 in **Table 1**).

Table 2 Water Wells within One Mile of Leased Area (UDWR 2014)

Water Right Number	Well Log	Summary Status[1]	Priority	Uses[2]	CFS	AC FT	Well Depth (ft)
45-3515	N	T	19740521	IS	1.000	0.000	
45-2074	Y	T	19490606	I	0.000	0.000	260*
45-6015	Y	P	20030314	I	0.000	0.880	28
45-5940	N	U	20020509	I	1.000	0.000	
45-4423	N	T	19781018	DIS	0.015	0.000	
45-3481	N	T	19740108	DIS	0.015	0.000	
45-5312	Y	T	19880524	I	0.015	0.000	70**
45-3479	N	T	19740107	DIS	0.015	0.000	
45-3480	N	T	19740107	DIS	0.015	0.000	
45-273	N	T	1900	DI	0.100	0.000	
45-6098	Y	T	20040720	DIS	0.000	4.730	200***
45-4875	N	T	19810811	DI	0.015	0.000	
45-5953	N	T	20020604	DIS	0.000	4.730	
45-5968	Y	P	20020625	IS	0.000	3.512	36
45-6464	Y	A	20130221	DI	0	4.450	325***
0145002P00	N	A		NP	0.000	0.000	
0645003M00	N	A	20060609	NP	0.000	0.000	
0645003M00	N	A	20060609	NP	0.000	0.000	
0645003M00	N	A	20060609	NP	0.000	0.000	
0645003M00	N	A	20060609	NP	0.000	0.000	
0645003M00	N	A	20060609	NP	0.000	0.000	
[1] T=Terminated; P=Perfected; U=Unapproved; A=Approved							
[2] I=Irrigation; S=Stockwater: D=Domestic; NP=Non-Production Well for Heat Exchange							
* Well abandoned; ** "Water was unusable", well plugged; *** Dry hole, abandoned							
Last six wells in the table are heat exchange wells and have no well logs or information.							

The Duchesne River formation may be present below the alluvium as conglomerate. This formation is described as a key aquifer by the BLM (2008), and the Utah State Water Plan for the Uintah Basin (UDWR 1999) states the following:

> Due to the lack of unconsolidated aquifers in much of this basin, the only other groundwater source that can be developed is from consolidated or bedrock aquifers. While all geologic formations contain some water, those in the Uintah Basin which have been identified as being the best groundwater targets are the

> Browns Park, Duchesne River, Uinta, Current Creek and Morgan formations, Nugget/Navajo sandstone and Weber quartzite. These consolidated aquifers are considered the best for development.
>
> Groundwater in these consolidated formations is unconfined in locations nearest areas of recharge. Confined conditions, however, are the most common and occur in about 90 percent of the area within the basin underlain by sedimentary rocks.
>
> The circulation of groundwater in these consolidated aquifers is affected by folding and faulting, which locally will either enhance groundwater movement by fracturing or impair groundwater movement by offsetting aquifers. Local fracturing also enhances interformational leakage, which affects water quality.

The last paragraph is applicable to the MCW lease area, which contains a fault (see **Figure 5**). The area geology is described previously in the Geology and Landform section. MCW-4 and MCW-5 (see **Table 1**) are approximately 680 feet horizontal distance apart and the core logs indicate the top of the Mancos Shale is 100 feet deeper at MCW-5 than it is at MCW-4. It is unclear from the rock core logs if the Duchesne River Formation is present on the MCW lease area or if the conglomerate is graded directly into the alluvium.

Below the alluvium at the project site is weathered shale which may be an interbed of the Mancos Shale within the Mesa Verde Formation (see rock core logs in **Appendix A**). The interlocking tongues of sandstone and shale vary in thickness from less than 10 feet to 30 feet, which is a fairly thin layer to sustain an aquifer, although the sandstone beds might be connected via fracturing within the shale layers. The Mesa Verde sandstone layers are the most likely reservoirs for bitumen, and where the sandstone is saturated with bitumen it does transmit water. In the areas of the Uinta Basin where the Mesa Verde does not interbed with the Mancos Shale it is considered a key aquifer.

1.3.4 Surface and Ground Water Quality

There is very little analytical data available for either surface water or groundwater in the project area locally or within the two surface water drainages (Ashley Creek and Twelvemile Wash). As described under Surface Water above, the U.S. Geological Survey (USGS) gauging station at Ashley Creek near Vernal, which would be upstream of the project site, had water quality samples taken at irregular intervals between 1949 and 1974; the average TDS of all 42 samples taken during that period was 140.4 mg/L. For Ashley Creek near Naples, which would be downstream from the project area (but parallel to the Highline Canal), average TDS for 50 water samples taken between January 2000 and November 2003 was 1,088 mg/L.

Hood and Fields (1978) describe the water quality in Ashley Creek as follows:

> Ashley Creek above the mouth of Ashley Creek canyon yields freshwater of the calcium bicarbonate type, which, during the spring freshet is very dilute. ...In Ashley Valley, the stream is almost completely diverted and part of the water impounded. The return flow from irrigation is a slightly saline water of the calcium magnesium sulfate type.

Analytical data on groundwater in the local area is also scarce. No water quality data for groundwater were found within one mile of the project area, although for one well within the one mile buffer a 70 foot well was drilled and abandoned, with the explanation "Water was unusable" on the well log (**Table 2** and **Appendix A**). The nearest data found were for two monitoring wells at the Crown Asphalt Ridge tar sand mine south of the MCW project site which were sampled in 2005. The wells draw from an aquifer below the tar sands layer. Results of that sampling event are provided in **Table 3**. The results reflect the local geology in which layers saturated with bitumen were situated above the sampled aquifer. Bitumen consists of heavier organics which test in the range of diesel range organics (DRO) or oil and grease.

Table 3 Analytical Results from Crown Asphalt Ridge Monitoring Wells

	Benzene (mg/L)	Toluene (mg/L)	E-Benzene (mg/L)	Xylenes (mg/L)	Naphthalene (mg/L)	TPH-GRO (mg/L)	TPH-DRO (mg/L)	Oil & Grease (mg/L)
Utah Groundwater Quality Standards (Table 1 of R317-6-2.1)	0.005	1	0.7	10				
Utah Tier 1 (2008) (mg/L)	0.30	3	4	10	0.7	10	10	10
MW-2								
5/1/2005	ND	ND	ND	ND	ND	ND	ND	5.7
MW-3								
5/1/2005	0.003	0.008	0.006	0.055	0.048	0.6	4.5	32

The Environmental Protection Agency (EPA) conducted a tar sands leachate study in 1984 (Grosse and McGowan). Processed tar sands were tested separately for leachate quality using the RCRA EP Toxicity Test; the ASTM (D-3987) Method A-1 Modification (8) shake extraction test; and one other protocol. EPA came to the following conclusion:

> The initial laboratory tests conducted under this study indicate that leachates from spent tar sand may not contain significant amounts of toxic pollutants but may contain substantial amounts of sulfate and total organic carbon (TOC). Only five constituents of the specific parameters analyzed were identified as priority pollutants (e.g., those elements posing the greatest risk to health and the environment). Of the five priority pollutants tested (cyanide, mercury, nickel, arsenic, and zinc), all exhibited low concentrations. However, concentrations of sulfate and TOC were fairly high and could impact surface and/or groundwater quality. Those trace elements which were present to any significant degree were not considered to be highly toxic or deleterious to the environment.

1.4 ANALYSIS AND TREATMENT OF PROCESSED SAND

MCW was granted a limited permit-by-rule for its process pilot test. As a condition of the permit-by-rule, following processing, the EPA SPLP (Synthetic Precipitation Leaching Procedure) was performed on processed ore, and the leachate was analyzed for a number of compounds. Note that this material is typically a waste termed "tailings", but MCW's intention is to market this clean, dry sand as a secondary product useful for construction and other purposes. Processed sand that is not sold will be returned to TME for use as mine backfill. Because the material will be put to beneficial use in either case, it is not a waste product or tailings.

Per DWQ's instructions the leachate was analyzed for the following:

- BTEXN
- Oil and Grease
- Total petroleum hydrocarbons, diesel range organics (TPH-DRO)
- Total petroleum hydrocarbons, gasoline range organics (TPH-GRO)
- Total organic carbon (TOC)
- Total dissolved solids (TDS)
- pH, and
- Major ions (Na, Ca, K, Mg, Cl, SO_4, and alkalinity).
-

Table 4 shows the results of the analyses. The full lab report is attached as **Appendix E**. Although detectable levels of several organics were found, all were at low levels, well below Utah's groundwater quality numeric standard. The only exception to this was pH, which, at 10 standard units (s.u.), is more alkaline than the State standard; it should be noted that the lab flagged the pH test result due to its being processed outside the accepted holding time.

Table 4 Analytical Results from Processed Tar Sands

Compound	Reporting Limit (mg/L)	Analytical Result (mg/L)	Qualifier	Numeric Standard (mg/L) [1]
Calcium	1.00	4.90		
Magnesium	1.00	<1.00		
Potassium	1.00	<1.00		
Sodium	1.00	1.94		
Alkalinity (as $CaCO_3$)	10.0	12.9		
Bicarbonate (as $CaCO_3$)	10.0	<10.0		
Carbonate (as $CaCO_3$)	10.0	<10.0		
Chloride	0.100	0.580		
Oil & Grease	5.00	<5.00		

Compound	Reporting Limit (mg/L)	Analytical Result (mg/L)	Qualifier	Numeric Standard (mg/L) [1]
pH @ 25 °C (reported in Standard Units)	1.00	10.0	H	6.5-8.5
SGT-HEM/Non-Polar Material	5.00	<5.00		
Sulfate	0.750	4.77		
Total Dissolved Solids (TDS)	20.0	84.0	H	1200[2]
Total Organic Carbon (TOC)	1.00	31.4		
Diesel Range Organics (DRO)	0.500	0.898		
Gasoline Range Organics (GRO)	0.0200	0.149		
SVOA SPLP by GC/MS Method 8270D/1312/3510C (19 compounds reported, all below detection limit)	0.0100	<0.0100		
Benzene	0.00100	<0.00100		0.005
C5&C6 Aliphatic hydrocarbons	0	0.00778		
C7&C8 Aliphatic hydrocarbons	0.0200	<0.0200		
C9&C10 Aliphatic hydrocarbons	0.0200	<0.0200		
C9&C10 Alkyl Benzenes	0.0200	0.0286		
Ethylbenzene	0.00200	0.00522		0.7
Naphthalene	0.00200	0.00472		
Toluene	0.00200	0.0378		1
Xylenes, Total	0.00200	0.0554		10

[1] Source: R317-6-2, Ground Water Quality Standards
[2] R317-2-14, Numeric Criteria
Qualifiers: H= Sample was received outside of the holding time

The lab analyses confirm that the processed ore is essentially free of residual bitumen and processing solvents, making it a potentially saleable commodity, and posing no threat to groundwater.

1.5 PROJECT SPECIFICS

As described above, MCW plans to extract oil from Asphalt Ridge oil sands using a proprietary process that was developed and has been used in the Ukraine. The process is designed to produce bitumen as its primary product, and clean, dry sand suitable for construction material as a secondary product. A detailed project description is in **Appendix B and C**. The bitumen would be enhanced with natural gas condensate, which would increase the value of the product.

Two phases are planned for the project. The first phase, a pilot test of the process, took place in October 2014 and was used to characterize processed sand produced by the plant for its leachate chemistry. The simulated leachate from precipitation was analyzed for parameters provided by DWQ. The results are shown in **Table 4**, above. The analyses will also determine how the sands that remain after the ore is processed will be used during the second phase of the project. The second phase will be the production phase.

MCW purchased oil sands locally to use for the pilot test. To ensure that there would be no risk of leachate from the ore contaminating either soil or groundwater, an impermeable liner was constructed and permitted by DWQ. One thousand tons of purchased tar sands were stockpiled on the liner. Processed sand produced during the pilot test was placed back on the existing liner, but segregated from the unprocessed ore. Fresh processed sand was sampled as it came out of the plant for lab analysis. The samples were analyzed for residual solvent, BTEXN, Oil and Grease, TPH-DRO, TPH-GRO and other parameters as requested by DWQ (see previous section for results).

With the extraction process optimized through the pilot test, MCW will now move into the production phase, while continuing to optimize the process by testing new equipment. During the production phase, oil sands will be purchased from an existing operation, TME. Now that the processed sands have been characterized, its future use can be determined. This information and all analytical results will be shared with DWQ.

The MCW process uses no process water, although the plant will require water for its boiler and for employee sanitary purposes. Current plans are to bring fresh water to the site by truck. Sanitary waste water will be collected in a tank and trucked to a licensed disposal facility. No water or waste water will contact oil sands or any process chemicals. The plant is designed to produce bitumen as its primary product, and clean, dry sand suitable for construction material as a secondary product.

Oil sands, a proprietary oil sands processing solvent and water will be delivered to the site by truck. A front end loader will be used on-site to move stockpiled tar sands to the crusher, and to load clean, dry sand onto trucks for use on other sites. Bitumen, sanitary waste water, and sand will be trucked out of the facility.

Stormwater is routed around the plant to prevent mobilization of sediment from disturbed areas. Stored solvent, bitumen and other potential contaminants are stored in containment per spill prevention, control, and countermeasure (SPCC) regulations. MCW has obtained a small source air quality exemption from the Utah Department of Environmental Quality, Uintah County, and other agencies as required. The company will abide by all permit conditions.

A process flow diagram and site plan are attached in **Appendix B**.

2.0 SUMMARY

At the processing plant site, no groundwater was found in the surface alluvium or the upper 30 feet of the weathered shale layer underlying the alluvium. Within a mile of the MCW lease no wells are being used for domestic supply (**Table 2**). Where wells are in use they are drawing on the alluvial aquifer. All water well and geologic core logs that went below the alluvial layer were either dry (to as deep as 325 feet) or were abandoned because the water was "unusable." This combined with the presence of multiple layers of low permeability shale indicates low vulnerability of any aquifer in the project area.

By design, the MCW bitumen extraction process uses no process water and a closed loop solvent system (**Appendix B and C**). Water will only be used in the boiler as a heat transfer medium, for dust suppression (if needed), and for employee sanitary needs. All potential sources of soil or groundwater contamination are contained and potential sources of leachate (ore stockpile and processed sands) are placed on impermeable liners (**Appendix D**). Lab analyses of the processed ore show that the material would pose a *de minimis* risk to the environment (**Appendix E**). However, the processed sand will be trucked back to TME to be used as mine backfill. To eliminate the potential for leachate through the processed sand an ET cover or an impermeable cap will be placed over the material.

In summary, MCW believes that, based on its pilot test, future oil sands production operations pose a very low to negligible risk of contaminating groundwater for the following reasons:

- Groundwater within the one-mile buffer area, including the MCW lease area, has very low vulnerability based on the underlying geology and the distance (depth) to groundwater (**Table 1** and **Table 2**).
- Groundwater quality, where analyses are available, demonstrate that water beneath oil sands is of too poor a quality to be put to beneficial use, likely as a result of hydrocarbons leaching through the natural oil sands geology over many centuries (**Table 3**).
- Leachate through processed ore (sand remaining after bitumen has been removed) has demonstrated negligible risk of contaminating groundwater (**Table 4**).
- The geology at the site (i.e., bitumen-saturated sandstone) has been present for millennia, as recent samples of groundwater have demonstrated (**Table 3**); removing the bitumen may ultimately improve groundwater quality, assuming that the bitumen is currently a natural source of contamination of the groundwater.
- MCW is taking all appropriate measures to protect the environment, including isolating tailings from the environment using impermeable pads and caps (**See Groundwater Discharge Application for Temple Mountain Mine for additional processed sands permanent disposal information**); BMPs to manage stormwater from the site; and BMPs (i.e., secondary containment) to control any potential risk from chemical spills, tank failures, or other potential releases. In addition pads and processed sand will be monitored daily to ensure that all operational and environmental safeguards are operating within their design parameters.

Consequently, we believe MCW's proposed operations pose a very low to negligible probability that any contaminants will impact soils or groundwater as a result of the MCW pilot test or production operations (i.e., *de minimis* risk).

Based on the closed nature of the operations; demonstrated cleanliness of the processed sand; containment structures and BMPs to limit potential exposure of the environment to contaminants; monitoring of the containment and BMPs; and site conditions (landforms, topography, lack of surface water or near surface groundwater), MCW requests permit by rule under R317-6-6.2.

3.0 REFERENCES

Bates, Robert L., and Julia A. Jackson. 1984. Dictionary of Geological Terms, Third Edition, prepared by the American Geological Institute.

Bureau of Land Management (BLM). 2008. Proposed Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement. FES 08-32. September 2008.

Campbell, J.A., 1975b, Structural geology and petroleum potential of the south flank of the Uinta Mountain uplift, northeastern Utah; Utah Geology, v. 2, no. 2, p. 129-132.

Covington, R.E., 1957, The bituminous sandstones of the Asphalt Ridge area, northeastern Utah, in Seal, O.G., editor, Guidebook to the geology of the Uinta Basin: Intermountain Association of Petroleum, p. 172-175.

Covington, R.E., 1964, Bituminous sandstones in the Uinta Basin, in Sabatka, E.F., editor, Guidebook to the geology and mineral resources of the Uinta Basin—Utah's hydrocarbon storehouse: Intermountain Association of Petroleum Geologists, p. 227-242.

Grosse, Douglas W., and Linda McGowan. 1984. Tar Sands Leachate Study. Environmental Protection Agency (EPA) Research and Development Publication EPA-600/S2-84-113, July 1984.

Hood, James.W. 1976. Characteristics of Aquifers in the Northern Uinta Basin Area, Utah and Colorado. State of Utah Department of Natural Resources Technical Publication No. 53.

Hood, J.W., and F.K. Fields. 1978. Water Resources of the Northern Uinta Basin Area, Utah and Colorado, With Special Emphasis on Ground-Water Supply. State of Utah Department of Natural Resources Technical Publication No. 62.

Kayser, R.B., 1966, Bituminous sandstone deposits Asphalt Ridge: Utah Geological and Mineralogical Survey Special Studies 19, 62 p.

Kohler, James F. 2011. Draft Technical Report on NW Asphalt Ridge Tar Sand Deposit, Uintah County, Utah, prepared for MCW by James F. Kohler, P.G., Utah Geosystems, dated June 12, 2011

Sinks, D.J., 1985, Geologic influences on the in-situ processing of tar sand at the northwest Asphalt Ridge deposit, Utah: Laramie, U.S. Department of Energy, Western Research Institute, 81 p.

USGS. 2011. National Water Information System (NWIS) accessed online March 25, 2011 at http://waterdata.usgs.gov/nwis/nwisman/

USGS. 2010. Geographic information system (GIS) shapefile titled SGID93_WATER_SpringsNHDHighRes, obtained from the Utah Automated Geographic Reference Center downloaded from http://gis.utah.gov/agrc. Data source is the USGS, USEPA, and the US Forest Service.

Utah Division of Water Resources (DWR). 1999, Utah State Water Plan, Uinta Basin. Published December 1999 by the Utah Department of Natural Resources.

Utah Division of Water Rights (DWRi). 2011. Water rights database for Utah, accessed online September 17, 2011 at http://www.waterrights.utah.gov/wellinfo/default.asp

Western Regional Climate Center (WRCC). 2015. Accessed online at http://wrcc.dri.edu/ on February 24, 2015.

Woods et al. 2001. Ecoregions of Utah (color poster with map, descriptive text, summary tables, and photographs): Reston, Virginia, U.S. Geological Survey (map scale 1:1,175,000).

APPENDICES

MCW ENERGY
ASPHALT RIDGE PROJECT
UINTAH COUNTY, UTAH

June 1, 2015

Appendix A LOGS FOR WATER WELLS WITHIN ONE MILE AND ROCK CORES

Appendix B SITE PLAN AND FLOW DIAGRAM

Appendix C TECHNOLOGY DESCRIPTION

Appendix D ENGINEER'S DRAWINGS FOR CONSTRUCTION OF PROPOSED PROCESSED SANDS STORAGE PAD

Appendix E ANALYTICAL LAB REPORTS

Stantec

MCW Energy Group

Technology Overview

Asphalt Ridge, Uintah County, Utah

October 15, 2015

Prepared by:

Donald Clark, PhD

Chief Geologist

MCW Energy Group

10100 Santa Monica Blvd
Suite 300
Century City, CA 90067

Mobile: (718) 869-3763

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

Introduction: As a non-convention hydrocarbon resource, oil sands hold billions of barrels of oil all over the world. The world's largest oil sands deposits are found in western Canada, where over 170 billion barrels of bitumen are found close to the surface. The oil sands of western Canada are being developed using hot water (Clark hot water extraction) and steam (Steam Assisted Gravity Drainage - SAGD). Both of these technologies consume tremendous amounts of water and energy (natural gas for heating water and producing steam), emit excessive amounts of greenhouse gases and, in the case of hot water extraction, produce huge tailings ponds that are polluted with the oil that is not fully extracted from the sands. In addition to multiple environmental issues, the shortcomings and inefficiencies of these technologies result in exceptionally poor economics on a per barrel production basis.

MCW Energy Group recognized the inherent shortcomings of the hot water and steam based oil extraction technologies and developed a new technology to overcome these shortcomings that uses solvents, instead of water, to recover the oil from the oil sands.

1.1 MCW Energy Group Technology Overview: MCW Energy Group's (MCW) proprietary technology uses a chemical solvent, instead of water, to extract the oil from oil sands. MCW's solvent is composed of multiple individual components (multiple light hydrocarbons and alcohols) which, when combined to proper proportions, are capable of dissolving and recovering over 99% of the bitumen, heavy oil and other lighter hydrocarbons that are found in oil sands. This solvent contains no chlorinated compounds, or dense non aqueous phase liquids (DNAPL). MCW's technology is able to extract the oil at much lower operating temperatures (50^{oc} to 60^{oc}) than either the Clark hot water extraction, or SAGD processes. The components of MCW Energy Group's unique solvent form an azeotropic mixture that boils at a relatively low temperature (70^{oc} to 75^{oc}). This guarantees a high level of energy efficiency during the oil extraction process. MCW's proprietary design also includes exceptionally efficient heat exchange systems and distillation/rectification systems. This energy efficiency makes MCW's extraction facilities extremely economical to operate. By comparison, the Clark hot water extraction and SAGD technologies are far less energy efficient and ultimately far less economical to operate than MCW's oil extraction facilities.

MCW's oil extraction process takes place in a completely closed loop system that continuously recirculates the solvent after it has separated the bitumen and heavy oils from the oil sands. As mentioned above, the closed loop system is capable of recovering over 99% of the bitumen and oil from the oil sands making this technology very environmentally friendly. Unlike the tailings pond sands produced by the Clark hot water extraction technology, the processed sands from MCW's technology are virtually solvent and hydrocarbon free, which enables it to be either used in mine remediation operations, or sold for use as a construction aggregate. Independent laboratory analysis of the synthetic leachate produced from the MCW processed sands show extremely low levels of hydrocarbons (Appendix A).

1.2 How MCW's Technology Works. During the first stage of the oil extraction process, crushed oil sands ore is premixed with MCW's solvent in a special mixing vessel located at the top of the facility tower (Fig. 1). The resultant slurry then passes vertically downward through a pug mill that further crushes any clumps of oil sands ore allowing greater contact area between the solvent and the oil sands which helps make the recovery operation more efficient. From the pug mill, the slurry is pumped into the primary oil recovery vessel located at the base of the facility tower, where more solvent is added to the slurry and the majority of the oil and bitumen is recovered from the oil sands. The slurry is then pumped into MCW's patented, pseudo-boiling layer fluidized bed extraction column (Fig. 2). The patented internal design of the extraction column is a key reason for the exceptionally high rate of oil extraction, over 99%. The solids (mainly clean sand and clay) settle to the bottom of the extraction column while the solvent/oil mixture leaves the top of the extraction column and is deposited into a surge tank.

The solvent/oil mixture is pumped from the surge tank to the distillation column (Fig. 2). As mentioned above, the solvent/oil mixture is heated under relatively low heat conditions and the light hydrocarbon and alcohol solvent is separated from the oil by distillation. The distillation process is designed to allow some of the lighter hydrocarbons in the solvent to remain in the solvent/oil mixture in order to give the customer an oil with the specific API to meet their needs. This can range from light API oil ($>31.1^o$) medium API oil (22.3^o – 31.1^o), to heavy API oil ($<22.3^o$), depending upon the needs of the end user (purchaser). After separating the solvents from the oil, the oil is pumped into the onsite storage tanks and/or delivery trucks and shipped to the customer. All the solvent vapors produced by the distillation process are collected and contained in the closed-loop system. The solvent vapors are condensed in a chiller and then reused to recover more oil and bitumen from incoming oil sands ore (Fig. 1).

During the final stage of the operation, the clean sand is transferred from the extraction column into the drying vessel to begin the drying process (Fig. 3). The sand is heated by steam lines within the drying vessel in order to vaporize any remaining solvent in the sand. The vaporized solvent is recovered from the drying vessel, condensed in the chiller and recycled in the closed loop system. Over 99% of the solvent is recovered and recycled from the processed sand. The clean, dry sand can then be sold as a construction aggregate or used in mine remediation.

Figure 1. Conveyor belt loading oil sands ore into the premixing vessel at the top of MCW's oil sands extraction facility in Maeser, Utah, USA. The gray, horizontal structure immediately below the conveyor belt is the chiller used to condense all the vaporized solvent that is collected from the sand drying vessel. The condensed solvent is recycled through the closed loop system and reused.

Figure 2. MCW patented, pseudo-boiling fluidized bed extraction column in the foreground. The extraction column increases oil recovery to over 99%. The distillation column used for separating the solvent from the oil is in the background. All vaporized solvent is collected, condensed (see chiller in figure 1) and recycled in the closed loop system.

It is important to note that MCW has tested its technology on oil sands from different locations around the world that have very different hydrocarbon chemical compositions. MCW has found that the efficiency and consistency of their technology is not affected by differences in the chemical composition of the oil/bitumen in the oil sands. An example of the technology's efficiency and consistency, despite dramatic differences in oil/bitumen chemistry, are the results of extensive testing on oil sands samples sourced from both Utah and China (Table 1, Appendix B and C). In both cases, MCW's recovery efficiency exceeded 99%.

Figure 3. MCW oil sands drying vessel in Maeser, Utah. The processed sands are heated with steam lines in the drying vessel to vaporize any remaining solvent in the sands. All vaporized solvent is collected and condensed in the closed loop system. This process recovers over 99% of the solvent from the processed sands and reuses it to process additional incoming oil sands.

1.3 Energy Returned Over Energy Invested: By using solvents instead of hot water or steam, MCW's technology immediately realizes a dramatic reduction in the energy required to produce a barrel of oil from oil sands. MCW's process operates at relatively mild temperatures of 50^{oc} to 60^{oc}. MCW's process also employs multiple energy saving technologies to reduce energy requirements even further. A third party consultant, Chapman Petroleum Engineering, performed an extensive energy analysis of MCW's technology and determined that the combined effect of all the energy saving features of MCW's technology is a 45:1 EROEI (energy returned over energy invested) ratio (Chapman, 2011 – Appendix D). To be conservative, Chapman reduced this ratio to 22:1 to account for any unforeseen energy losses. A 22:1 EROEI compares very favorably to EROEI values of 4:1 for SAGD and 6:1 for Clark hot water extraction.

Table 1. Chemical comparison between oil sands samples sourced from Utah, USA and China

Location	Saturated Hydrocarbons	Aromatic Hydrocarbons
Utah (Asphalt Ridge)[1]	29.3%	28.4%
China[2]	61.06%	5.34%
China[3]	78.87%	4.43%

1 - Oblad, et al. (1975)
2 - Zhi-Nong Gao, Li-Bo Zeng and Fei Niu (2005) - 5 sample average
3 - MCW testing (Appendix B) - 3 sample average

2.0 MCW Extraction Costs: Based upon conservative and reasonable assumptions, the Monte Carlo simulations performed by Chapman (2011- Appendix D) determined, with a 90% confidence level, that MCW's technology processing costs will range from $22.84 to $38.87 per barrel. A second study performed by Chapman Petroleum Engineering (2012 - Appendix E) again estimated that the production costs for MCW's solvent based extraction process would range between $24.51 and $34.04 per barrel.

A recent, confidential third party analysis of MCW's technology, including a multi-day site visit at the company's 250 barrel per day plant in Maeser, Utah, confirmed that production costs for a light-sweet crude oil are $33.40 per barrel and $31.30 per barrel for oil sands having 4.75% and a 10% (weight percent) oil, respectively. A follow up report from the same third party estimated that production costs for a larger plant (2500 barrels per day) would be in the mid $20 per barrel range with significant room to reduce those costs further.

In response to the falling price of oil, Scotiabank published a comparison of the per barrel breakeven costs between various conventional Canadian light and heavy oil plays, US based tight shale plays and Canadian oil sands projects (Fig. 4) (Scotiabank, 2014). The mid-cycle breakeven costs for legacy oil sands projects are approximately $53 per barrel, $40 to $80 per barrel for SAGD and $90 per barrel for mining and upgrading new projects. In comparison to these production costs, MCW's production costs are very competitive.

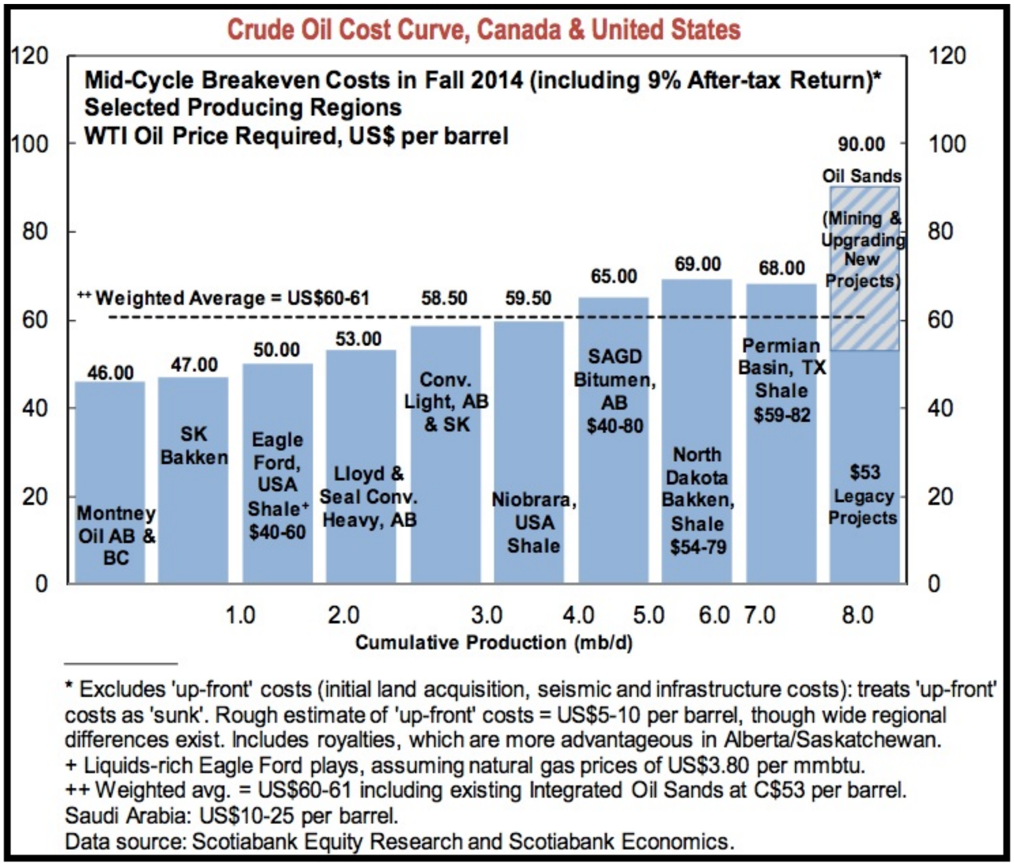


Figure 4. Comparison of breakeven costs for various tight shale plays and Canadian oil sands projects.

Source: Scotiabank Commodity Price Index, November 28, 2014.

Direct evidence of the poor economics of both the hot water and SAGD technologies comes in the form of the multiple oil sands operations that have shut down in Canada due to poor economic returns. For example, Total and partners Suncor and Occidental Petroleum shut down the Joslyn oil sands project in Canada in 2014 after spending $11 billion on the project (Globe and Mail, May 29, 2014). Mr. Andre Goffart, head of Total's Canadian division, stressed that the "*Joslyn decision is due to the project's costs, saying its technology and execution plans must improve*". The Joslyn operation first used SAGD before switching to hot water extraction. Clearly this is an acknowledgement by three major oil companies that hot water and SAGD technologies are not economically competitive in the current oil price environment.

3.0 Summary and Conclusion: The inherent shortcomings of both the Clark hot water and SAGD technologies cannot be overcome, no matter how they are modified. Their reliance on using energy in the form of heat to create hot water and steam will always have a very strong negative affect on the economics of extracting oil from oil sands. No better evidence of this is the closing of the Joslyn oil sands operation by Total, Suncor and Occidental petroleum after spending a total of $11 billion dollars on the project. Andre Goffart's public statement that the "*Joslyn decision is due to the project's costs, saying its technology and execution plans must improve*" certainly confirms the fact that new technology is needed for oil sands extraction.

By abandoning the conventional energy based methods of oil sands extraction and developing a new, proprietary solvent based technology, MCW has simultaneously addressed both the environmental problems (excessive water use, water pollution from tailings ponds, excessive energy consumption and excessive greenhouse gas emissions) and poor economics associated with hot water and SAGD extraction technologies and in doing so, has developed the "new technology" that Andre Goffart was referring to.

Recent third party analysis of MCW's technology and plant operations confirm that oil can be produced in the low $30 per barrel range and lower still if a larger plant is built, due to the efficiencies of economies of scale. This production cost is very competitive in the present oil price environment.

Additionally, the solvents used in MCW's technology (light hydrocarbons found in naturally occurring natural gas condensate liquids and alcohols) and the trace quantities of hydrocarbon compounds found in the SPLP leachate test are light non-aqueous phase liquids (LNAPL). LNAPLs are much less harmful to the ground water (they float on water due to their lower density) and the environment in general than dense non-aqueous phase liquids (DNAPL). DNAPLs are significantly more damaging to the environment, are more difficult and much more expensive to clean up if groundwater remediation is required, not only because they sink in the water column and impact deeper and larger volumes of water, but also because they are generally non-petroleum and more likely chlorinated compounds. Most chlorinated compounds are listed as hazardous wastes.

References:

Allen, E. W., 2008. Process water treatment in Canada's oil sands industry: I. Target pollutants and treatment objectives. J. Environ. Eng. Sci. **7**: 123–138

Cabrera and Silverman, 2012. Upgrade heavy oil more cost-efficiently. Hydrocarbon Processing, a division of Gulf Publishing Company.

CERI (Canadian Energy Research Institute), 2013. Canadian Oil Sands Supply Costs and Development Projects (2012 – 2046). Study no. 133, May, 2013

Chapman Petroleum Engineering, 2011. Evaluation of Oils Sands Extraction Process – September 1, 2011 NW Asphalt Ridge Area, Utah, USA. Third party consultant report prepared for MCW Energy Group.

Chapman Petroleum Engineering, 2012. Evaluation of prospective resources, NW Asphalt Ridge Area, Utah, USA. Third party consultant report prepared for MCW Energy Group.

Elliot and Kovscek, A Numerical Analysis of the Single-Well Steam Assisted Gravity Drainage Process (SW-SAGD). Stanford University research paper for the U.S. Department of Energy, Contract No. DE-FG22-96BC14994 to Stanford University

Globe and Mail, May 29, 2014 http://www.theglobeandmail.com/report-on-business/joslyn/article18914681/

Gotawala and Gates, 2011. Stability of the edge of a SAGD steam chamber in a bitumen reservoir. Chemical Engineering Science, Vol. 66, Issue 8, 15 April 2011, Pages 1802–1809.

IHS CERA, 2011. Oil Sands Technology: Past, Present, and Future.

Johnson, R., 2012. These Pictures May Give You Nightmares About The Canada Oil Sands. Business Insider, Oct. 18, 2012. http://www.businessinsider.com/photos-destructive-canada-oil-sands-2012-10?op=1#ixzz34M49zqmw

Medina, 2010, SAGD: R&D for unlocking unconventional heavy oil resources. The Way Ahead, Vol. 6, Issue 2,

MCW Energy Group press release, January 27, 2015. http://ir.mcwenergygroup.com/press-releases/detail/114/mcw-energy-group-projects-a-windfall-reduction-in-its-oil

Natural Resources Canada, 2013. Properties, Composition and Marine Spill Behavior, Fate and Transport of Two Diluted Bitumen Products from the Canadian Oil Sands. ISBN 978-1-100-23004-7

Natural Resources Canada, 2014. http://www.nrcan.gc.ca/energy/oil-sands/water-management/5865

Oblad, et al., 1975. Recovery of Bitumen from Oil-impregnated Sandstone Deposits of Utah. 68th Annual Meeting of AIChE, Los Angeles, California, November 16-20, 1975

Rapier, 2013. The Cost of Production and Energy Return of Oil Sands. Energy Trends Insider, Dec 9, 2013.

Woynillowicz, Baker and Reynolds, 2005. Oil sands fever. The Pembina Institute.

Zhi-Nong Gao, Li-Bo Zeng and Fei Niu (2005). Unusual physical and chemical characteristics of oil sands from Qaidam basin, NW China. Geochemical Journal, vol. 39 pp 121 to 130

344 Mira Loma Avenue,
Glendale, CA 91204. Telephone: 1 (800) 979-1897
Fax: 1 (866) 571-9613
Email: info@mcwenergygroup.com

TEST REPORT

DATE: September 29, 2013
Sample Origin: Asphalt Ridge, Utah
Contact: Rob Cowley/435-671-2430
Project: Analysis of the bitumen extracted from the Asphalt Ridge native oil sands ore using MCW patented extraction technology and solvent composition.
Product: Asphalt Ridge oil sands sample.
MCW Reference Number : CA-CU-092913/ES

Experimental Design Summary:

25 Lbs native oil sands ore sample has been received in MCW laboratory from Asphalt Ridge oil sands mine in Utah. Testing was performed by extracting bitumen from the oil sands sample using MCW proprietary/patented oil from oil sands extraction method. Saturation of the oil sands with bitumen has been determined by weight. Afforded bitumen/hydrocarbons were tested on API gravity and were analyzed using MS-GC and FTIR analysis methods. Every test has been repeated 3 times.

Table 1: Observations

Original Sample	**Sticky solid black oil sands sample, with specific hydrocarbon odor**
Processed Bitumen	**Thick dark viscous heavy oil with strong hydrocarbon odor**
Processed solid phase	**Clean off white sand**

Table 2 Solid phase saturation with hydrocarbons analysis before processing

Test Number	Bitumen (% by weight)	API Gravity
1	12.22	11.6
2	12.37	11.8
3	12.28	11.7

Table 3 Solid phase saturation with hydrocarbons analysis after processing

Test Number	Bitumen (% by weight)	API Gravity
1	**Less than 0.1**	**N/A**
2	**Less than 0.1**	**N/A**
3	**Less than 0.1**	**N/A**

Table 4 Analysis of the Hydrocarbons/Bitumen afforded from the oil sands

Test Number	Viscosity, CP 225 F	Viscosity, CP 320 F	Pour point, F	S (Sulfur), wt%
1	**448**	**75**	**111**	**0.37**
2	**445**	**76**	**109**	**0.33**
3	**446**	**76**	**112**	**0.34**

CONCLUSIONS

1. MCW oil from oil sands extraction technology process can be successfully applied to produce bitumen/heavy oil from the native oil sands ore with efficiency of 99.9%.

2. Analyzed samples of the Asphalt Ridge, Utah oil sands have hydrocarbon saturation in the range of 12.2% to 12.4%

3. Analyzed samples of the tailing sands afforded after hydrocarbons extraction from the native oil sands of Asphalt Ridge, Utah have shown residual bitumen/hydrocarbons content less than 0.1% by weight.

4. Asphalt Ridge bitumen has API gravity in the range of 11.6 to 11.8 and it is flow able at the temperatures higher than 120 F. It is comparable to the oil sands from Athabasca oil sands region in Alberta, Canada

5. Asphalt Ridge oil sands contains between 0.34% to 0.37% of sulfure that is a significantly less sulfur compare to the Athabasca oil sands reserves in Alberta, Canada.

Chief Technology Officer ______*Signed*_____________ Date: September 29, 2013
Vladimir Podlipskiy,

344 Mira Loma Avenue,
Glendale, CA 91204. Telephone: 1 (800) 979-1897
Fax: 1 (866) 571-9613
Email: info@mcwenergygroup.com

REPORT ON OIL SANDS SAMPLE #1 FROM CHINA

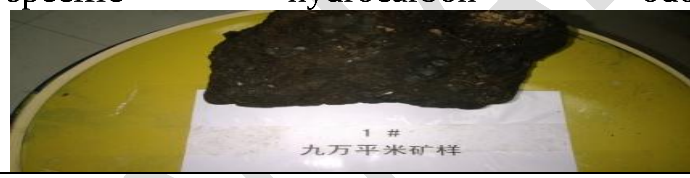
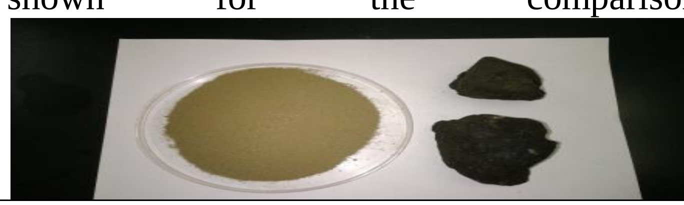
DATE:	**June 23, 2014**
Sample Origin:	KYD, China
Contact:	Elton Zeng
Project:	***Analysis of the oil sands samples from China on the oil content and applicability of MCW oil from oil sands extraction process for commercial oil production in China***
Product:	Oil sands from China. Sample #1.
MCW Reference Number:	***CA-CU-06142014/ES1***

Experimental Design Summary:

34 Lbs native oil sands ore sample has been received in MCW laboratory from China. Part of the sample # 1 has been grinded and treated with MCW patented solvent composition used in oil from oil sands extraction process in MCW production plant built in Utah, USA. Heavy oil/bitumen has been extracted, separated on different fractions and analyzed on the hydrocarbon content, type, and distribution. Saturation of the native oil sands ore with the hydrocarbons (% weight) has been determined. Afforded oil/bitumen (hydrocarbons) were analyzed using GC and FTIR/IR analysis methods. Density/API Gravity and viscosity of the afforded hydrocarbons have been determined. Combustion elemental analysis has been performed to determine the content of carbon, hydrogen, nitrogen and sulfur

in the afforded hydrocarbons. ICPMS tests have been performed to determine the heavy metal content/distribution in the afforded hydrocarbon materials. Additional testing has been performed to determine the BTU value/energy per pound for the hydrocarbon material extracted from the native oil sands ore. Processed solid tailings after the extraction were analyzed on the hydrocarbons content. Every test has been repeated 3 times. The following results have been obtained and analyzed.

Table 1: Observations

Original Sample # 1 of the oil sands from China	Large sticky solid black oil sands rocks with specific hydrocarbon odor 
Extracted hydrocarbons (Heavy Oil/Bitumen) afforded from original oil sands from China, sample # 1 using MCW process and solvent composition	Thick black viscous heavy/gummy liquid with strong hydrocarbon odor 
Asphaltene/Asphalt afforded from the hydrocarbon mixture extracted from the native oil sands ore of the sample # 1 from China	Solid powder with the specific asphalt odor 
Clean sand after hydrocarbon extraction from original oil sands from China, sample # 1	Clean dry sand after extraction. Rocks of the original oil sands before extraction have shown for the comparison. 

Total hydrocarbons content in the native oil sands ore has been determined before and after the extraction process with MCW solvent composition. The following data have been obtained.

Table 2 Total hydrocarbons content in the sample # 1 prior to the extraction

Test Number	Hydrocarbons (% by weight)
1	30.5%
2	28.6%
3	29.2%

Table 3 Total hydrocarbons content in the sample # 1 tailing after the extraction

Test Number	Hydrocarbons (% by weight)
1	Less than 0.1
2	Less than 0.1
3	Less than 0.1

Total hydrocarbons extracted from the native oil sands ore have been separated on two main fractions/compositions Asphaltene and Maltenes. The following data have been obtained.

Table 4 Hydrocarbons composition in the sample # 1 after the extraction

Test Number	Maltenes (% by weight)	Asphaltene (% by weight)
1	70.82	29.28
2	70.16	29.84
3	69.78	30.22

Additional analysis of the Maltenes hydrocarbon types have been performed and the following data have been obtained.

Table 5 Maltenes analysis results by hydrocarbon types (%wt)

Test No	Saturated Hydrocarbons	Unsaturated Hydrocarbons	Aromatic Hydrocarbons	Other Hydrocarbons
1	78.6	6.8	4.2	10.4
2	79.1	6.7	4.5	9.7
3	78.9	7.2	4.6	9.3

Viscosity and API Gravity/Density of the total hydrocarbons fraction extracted from the native oil sands ore have been determined and the following results have been obtained.

Viscosity @ 98 C	**49.52 CsT**
Density	**1.06 g/ml**
API Gravity	**1.99**

Heavy metal elemental analysis (ICPMS) has been performed on the total hydrocarbons fraction extracted from the native oil sands ore. The following data have been obtained**.**

Barium	***14.35***	***PPM***
Iron	***109.00***	***PPM***
Lead	***0.19***	***PPM***
Molybdenum	***7.40***	***PPM***
Nickel	***15 .00***	***PPM***
Strontium	***1.50***	***PPM***

Combustion elemental analysis has been performed on the total hydrocarbons fraction extracted from the native oil sands ore. The following data have been obtained (% wt)**.**

Carbon	***84.75***
Hydrogen	***10.12***
Nitrogen	***0.84***
Sulfur	***4.05***

The heating value/energy of the total hydrocarbons fraction extracted from the native oil sands ore has been determined in the closed bomb colorimeter. The following result has been obtained: ***17,900 BTU/Lbs***

CONCLUSIONS

1. Oil sands # 1 sample from China has extremely high concentrations of the hydrocarbons averaging almost 30% by weight.

2. The majority of the hydrocarbons are Maltenes with straight saturated hydrocarbon chains. Unsaturated and aromatic hydrocarbons are present in moderate rates and significant amount of Asphaltene is present.

3. MCW solvent composition and oil from oil sands extraction process are very effective when applied to produce hydrocarbons from the oil sands ore (sample # 1) from China. The efficiency of the extraction process has been 99.9% of total hydrocarbons obtained/extracted. Very high concentrations of the hydrocarbons in the native ore are making the process even more energy efficient compare to the oil sands production in Utah, USA. Expected energy return can be as high as 1 to 45 times energy invested vs. energy obtained.

4. In addition due to the very high level of the saturated hydrocarbons and Asphaltene in the hydrocarbons extracted from the sample # 1, this material is a very attractive source for the commercial hydrocarbon production. Afforded Maltenes and Asphaltene can be utilized in both oil refinery and high quality asphalt manufacturing processes. In addition the testing results have shown that with slight modification of MCW production process there is a possibility of obtaining both Maltenes and Asphaltene as two separate products of the extraction without additional separation. This approach allows using Maltenes for the oil refinery business and using the Asphaltene straight for the high quality asphalt manufacturing. MCW technology is fully compatible with Chinese sample #1 oil sands type and composition. Commercial development of this reserves would be very effective, energy efficient and economically viable. .

Vladimir Podlipskiy,
Chief technology Officer
June 23, 2014

Chapman Petroleum Engineering Ltd.

445, 708 - 11th Avenue S.W., Calgary, Alberta T2R 0E4 • Phone: (403) 266-4141 • Fax: (403) 266-4259 • www.chapeng.ab.ca

September 23, 2011

MCW Energy Group Ltd.
9701 Wilshire Blvd., 10th Floor
Beverly Hills, CA
90212

Attention: Alex Blyumkin

Dear Sir:

Re: Evaluation of Oil Sands Extraction Process – September 1, 2011
NW Asphalt Ridge Area, Utah, USA

In accordance with your authorization, we have prepared this excerpt of the September 14, 2011 Chapman Petroleum evaluation of a proprietary oil sands extraction process, for MCW Energy Group Ltd. (the "Company"), in order to determine the expected value of the Company's technology and business development plan. This evaluation has been conducted in accordance with the APEGGA Practice Standards, and utilizing our September 1, 2011 forecast prices and costs.

Our analysis has included a review of the available technical data including process component performance, ore characteristics at proposed mine site, mining and extraction costs, labor costs, and power costs etc. We have also considered the availability of product markets, and transmission facilities within economic reach of the area.

In forming our opinion of this prospect we have relied to some extent on the information presented by the Company, which, together with our independent analysis and judgment, was sufficient for us to confidently establish the nature of the project and uncertainty involved.

An economic analysis has been performed for the Company's business development plan. The plan calls for a total of 750 STB/d of processing capacity to be built by 2013. This analysis has been utilized predominantly for formulating and supporting our recommendation on the viability of the technology and project proposal. Values established do not necessarily infer the "fair market value" of this development plan. All monetary values presented in this report are expressed in terms of United States dollars.

Based on our analysis, after consideration of risks, we have concluded that the potential of this process is of sufficient merit to justify the business development plan being proposed, and we therefore recommend and support the Company's participation.

All data gathered and calculations created in support of this report are stored permanently in our files and can be made available or presented on request. We reserve the right to make revisions to this report in light of additional information made available or which becomes known subsequent to the preparation of this report. Due to the risks involved in exploring for oil and gas reserves, our assessment of the project cannot be considered a guarantee that any wells drilled will be successful.

Prior to public disclosure of any information contained in this report, or our name as author, our written consent must be obtained, as to the information being disclosed and the manner in which it is presented. This report may not be reproduced, distributed or made available for use by any other party without our written consent and may not be reproduced for distribution at any time without the complete context of the report, unless otherwise reviewed and approved by us.

We consent to the submission of this report, in its entirety, to securities regulatory agencies and stock exchanges, by the Company.

It has been a pleasure to perform this evaluation and the opportunity to have been of service is appreciated.

Yours very truly,

Chapman Petroleum Engineering Ltd.

[Original Signed By:]

C.W. Chapman

C. W. Chapman, P. Eng.,
President

[Original Signed By:]

Roy A. Collver

Roy A. Collver, P. Eng.
Petroleum Engineer

rac/lml/5441
attachments

Oil Sands Extraction Process
Economic Model and Forecast

Process Capital Costs

Average capital required to develop processing capacity is estimated at approximately \$10,000-\$12,000 per STB/d. The overall costs expected to develop the modeled plant sizes are shown in Table 1.

Process Energy and Costs – Assumptions

A probabilistic approach has been taken to determining the energy and cost requirements of the process in order to characterize the risks associated with different factors affecting the efficiency and profitability of the process.

The initial analysis focused on a 250 STB/d pilot scale operation that would be able to be moved from area to area as new ore becomes available.

Several key assumptions were made during this analysis, and they are listed below:

1. The process plant described in this analysis would be sized to handle approximately 26.5 m^3 of crushed ore per hour.

2. The process plant would operate on a 10 hour work day, and be operated every day of the year.

3. Every m^3 of raw crushed ore would consist of approximately 15% extractable hydrocarbon by volume, a conservative estimate considering higher grade ore (>20% hydrocarbon by vol.) is expected.

4. Approximately 4 parts of solvent will be needed for every part of hydrocarbon extracted.

5. A negligible amount (and value) of the solvent will be lost in the final hydrocarbon stream.

6. Electrical energy is available in sufficient quantity, at an expected price of 4.8 cents per kwh.

7. The power requirements of the process, in terms of the caloric energy of the liquid output products compared to the energy required to process the crushed ore, were doubled in the economic analysis to be approximately 20:1 to account for unexpected efficiency losses.

8. The total yearly operation of the plant for the schedule as described will require 24 workers at an average of $64,000 per year in total employment costs.

9. The costs of obtaining crushed ore will range approximately $10-$20 per m^3.

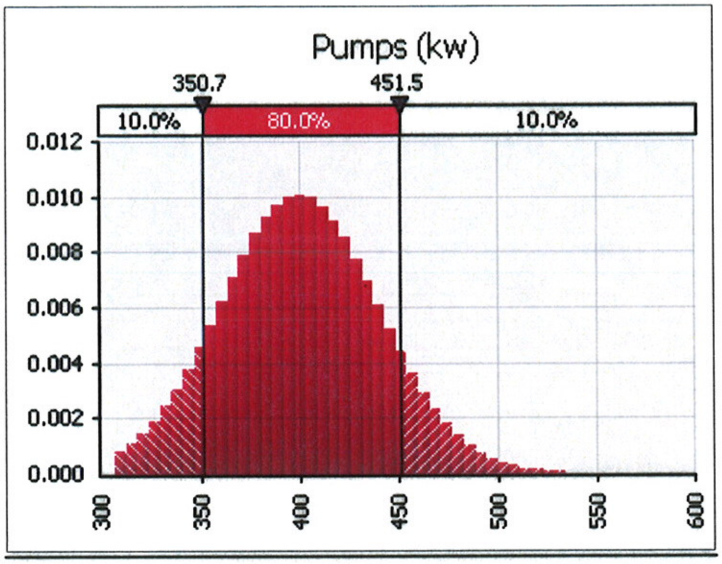
10. The equivalent of approximately 2.5% of the value of the final bitumen products will be lost due to lost solvent to the spent ore.

Energy Consumption Analysis

The following details the energy requirements estimated for a 250 STB/d ($27m^3$/hour) processing plant utilizing this process, and the probability density functions associated with the uncertainty on each component's power usage.

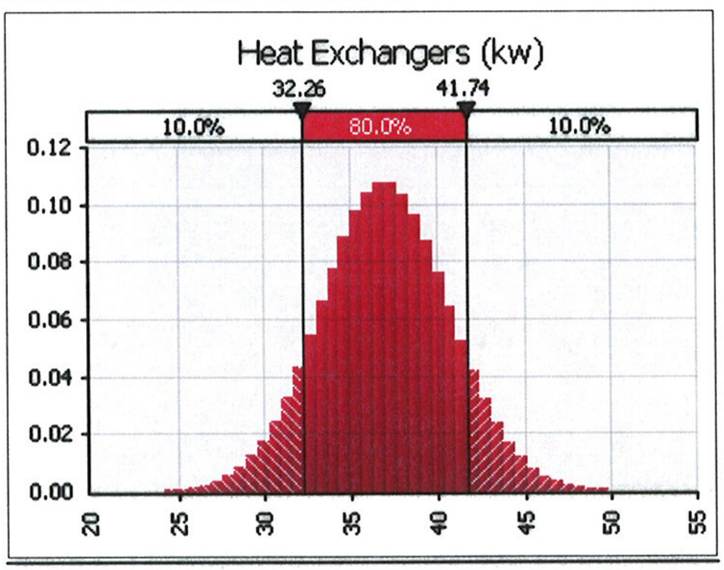
1. **Pumps** – There are 7 pumps for moving hot process water through the system, and one fixed displacement hydraulic pump for moving steam to the evaporator. The total power requirement of all the pumps is expected to be approximately 400 kw, to move approximately 2 tons of steam/hot process water through the system.

   Pump Power Req. PDF



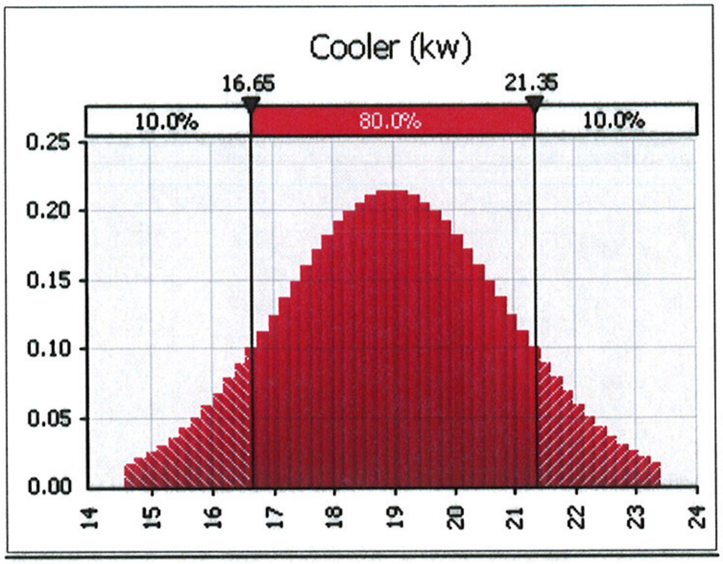
2. **Heat Exchangers –** There is one "tube and shell" style heat exchanger at the solvent heater, before the solvent enters the extractor (stage 8 on Figure 1.) The total power requirements of the heat exchanger are expected to be approximately 37 kw, which will be provided by hot process water that has cooled after the evaporator.

Heat Exchanger Power Req. PDF



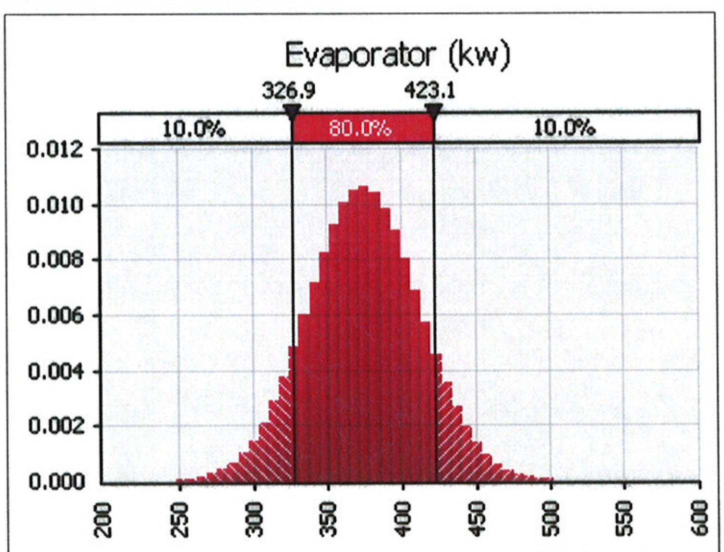
3. **Coolers –** There is one cooler to cool the solvent as it leaves the condenser (Stage 7 on Figure 1). The total power requirements of the cooler are expected to be approximately 19 kw.

Cooler Power Req. PDF



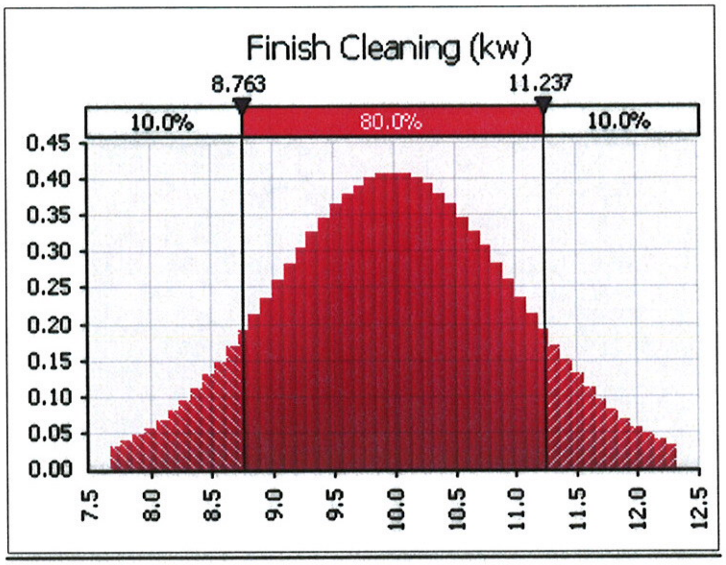
4. **Evaporator –** There is one evaporator to vaporize the solvent and hydrocarbon mixture before it enters the distillation column (stage 5 on Figure 1). The total power requirements of the evaporator are expected to be approximately 375 kw, which will be provided by steam heated by a central boiler.

Evaporator Power Req. PDF



5. **Final Cleaning –** Electric heaters will help to dry the spent ore of remaining solvent. It is expected the heaters will have fairly low power requirements, of approximately 10 kw.

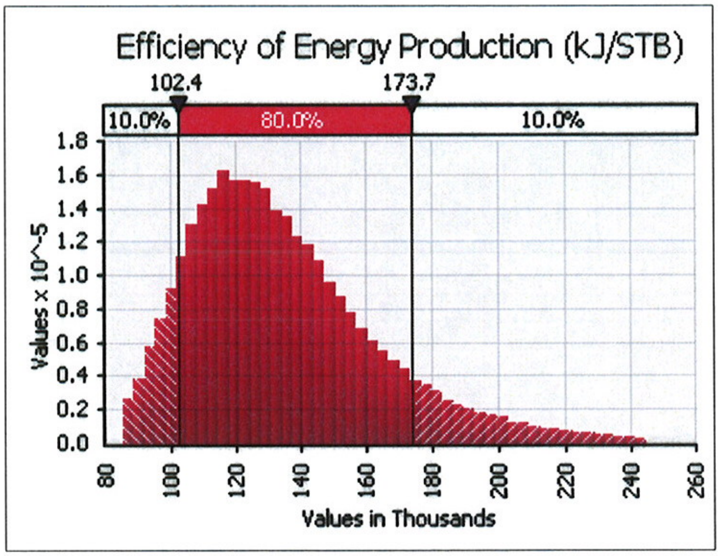
Final Cleaning Power Req. PDF

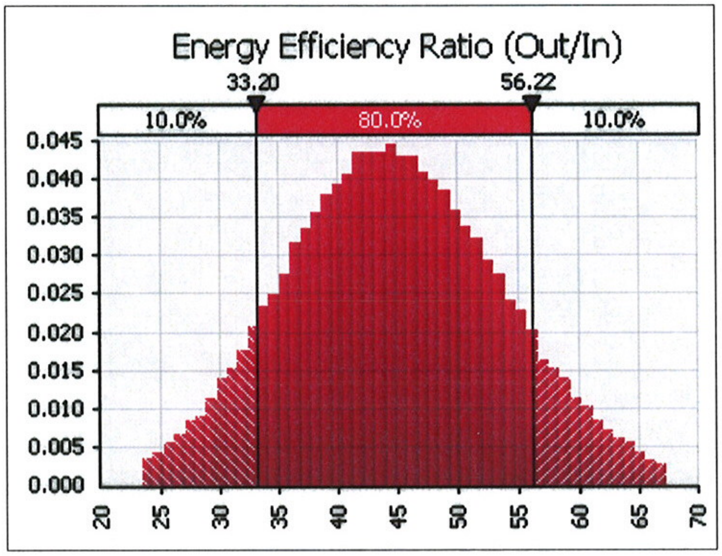


6. **Additional Operating & Contingency –** Approximately 60 kw of additional power requirements were allotted to the process for the general operation of the plant facility, as well as unexpected power requirements. The additional operating and contingency amount was expressed a definite value rather than a probability density function.

Energy Consumption Conclusions

The above probability density functions were used in a Monte Carlo simulation to generate the range of energy consumptions expected for this process.





Figures and above shows the outputs of the Monte Carlo simulation for the total energy required to generate one barrel of finished product (crude bitumen), and the ratio of energy input to energy output in liquids. Further detailed results are shown in Appendix B.

The results of the energy analysis show that this process has an expected energy requirement of 134 MJ per STB of bitumen generated, representing an energy efficiency of approximately 45 to 1 in terms of energy output to energy input (1 STB of bitumen is approximately 5,883 MJ). The reasons for this exceptional efficiency are that the process relies on the effectiveness of the solvent and fluid bed reactor to mix solvent and extract hydrocarbons. All other competing processes (that are currently commercial) utilize vast amounts of energy in the form of steam to heat the bitumen and reduce its viscosity. On this basis, this process would be expected to be economically successful and substantially better than existing competitive processes.

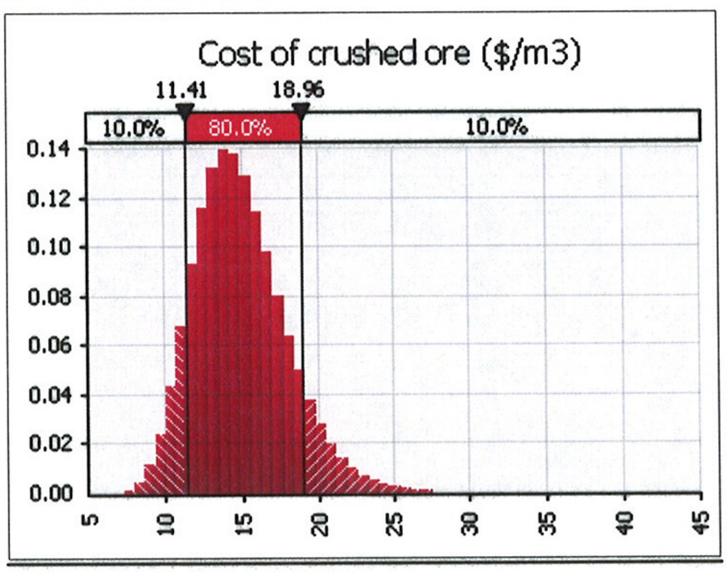
Costs Per STB Analysis

The proceeding analysis of expected energy requirements was incorporated into a statistical model of the overall processing costs per STB of hydrocarbon generated. For the sake of being conservative, the energy requirements of the process were doubled, bringing the expected energy output to input ratio to approximately 22 to 1.

The following details the significant costs associated with this process and the probability density functions that characterize the uncertainty in that variable.

1. **Raw Ore Costs –** It is assumed that the Company will have access to raw crushed oil sands ore in the Asphalt Ridge area of Utah at an average cost of between \$10-\$20/m^3. These costs are considered to be quite reasonable considering that the average costs of operators in the Athabasca oil sands are considered closer to \$10 per STB.

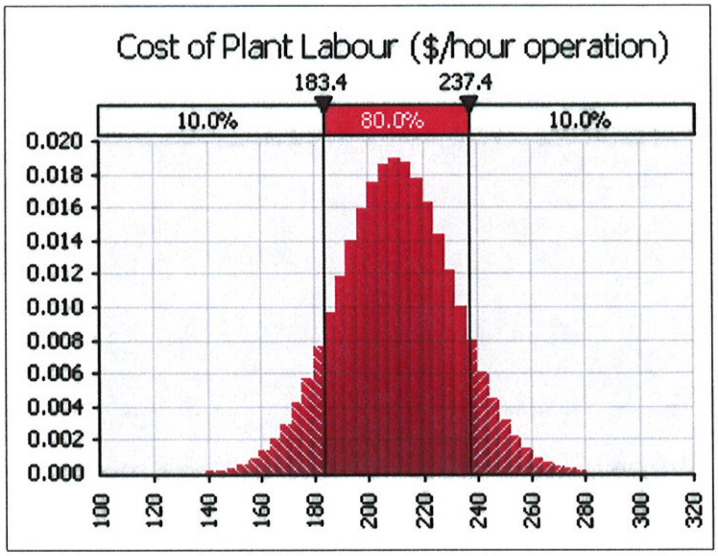
Raw Ore Costs (\$/$m^{3)}$ PDF



2. **Tons of Raw Ore Processed –** The total amount of raw ore processed per hour was expected to be constant at 27 tons, or 26.52 m^3/h.

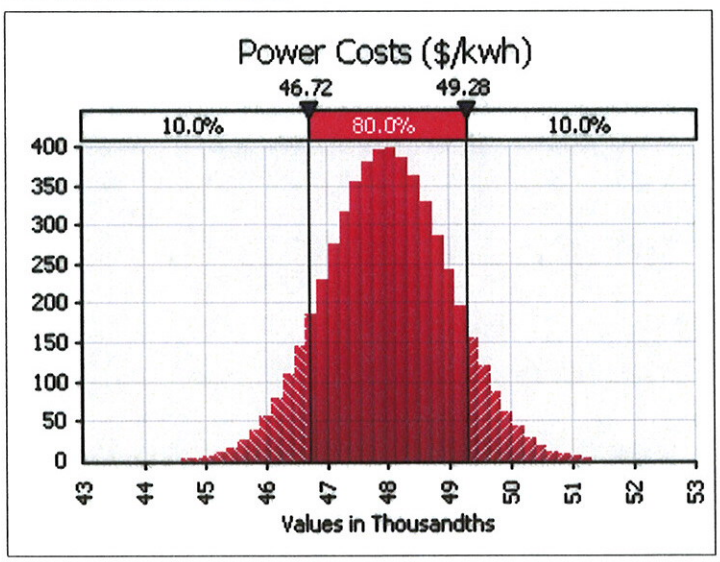
3. **Labour Costs –** It is assumed that the plant will be in operation for 10 hours per day, 365 day per year. That is expected to require 2 crews of six workers, who will on average cost $64,000 per year to employ.

Labour Costs ($/plant op hour) PDF



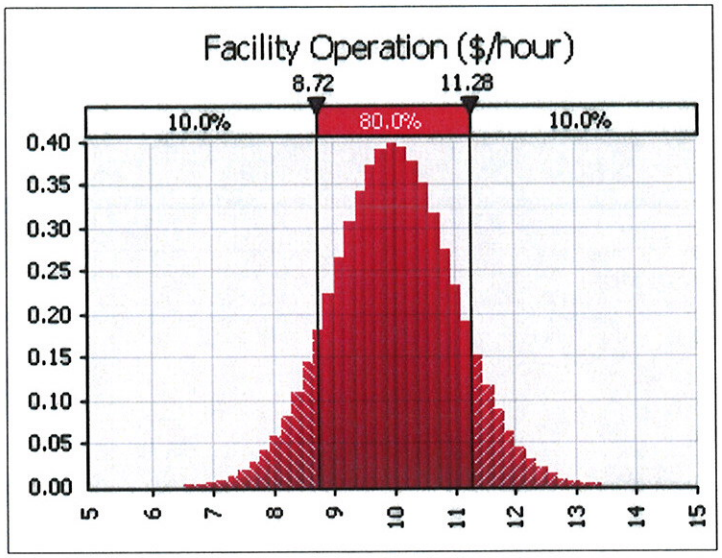
4. **Power Costs –** All power costs were based on the preceeding energy consumption analysis, and assuming an average price of electrical power of $0.048/kwh.

Power Cost ($/kwh) PDF



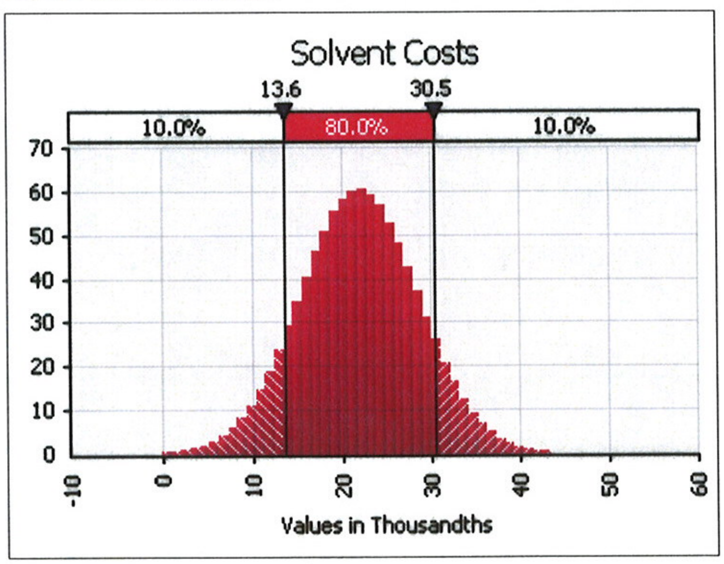
5. **Facility Operation –** An additional $10/hour was added for the costs of operating the facility, administration, custodial etc.

Facility Operation ($/h) PDF

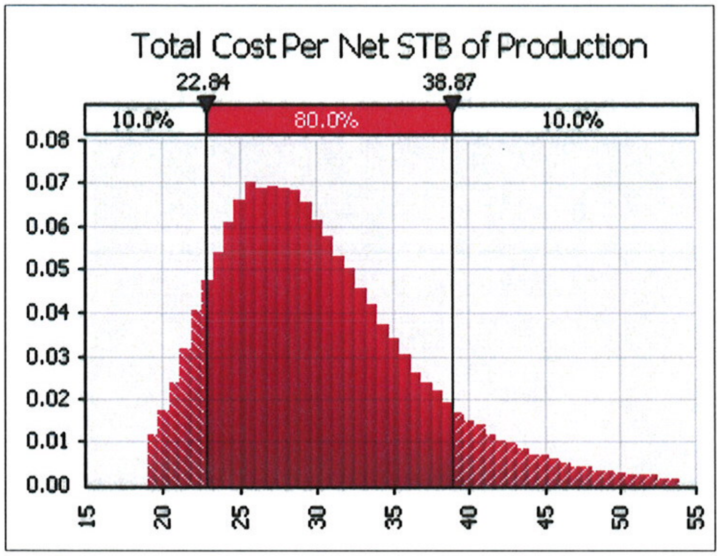


6. **Solvent Losses –** Solvent losses to the spent ore were accounted for as follows. The amount of solvent lost per STB of bitumen produced was estimated, and the cost of that solvent was also estimated (approximately 1.1 * WTI price). The value being lost as solvent in the spent ore was then deducted from the value of the bitumen output stream (Approximately 0.8 * WTI price). The PDF below shows the percentage of the bitumen value which is lost in solvent costs per STB of production.

Solvent Losses % PDF



Based on the probability density functions described above, the following range of processing costs in $ per STB was generated, as shown in Figure below.



Cost Per STB Conclusions

The overall cost per STB is conservatively expected to be in the rage of approximately $25-$40/STB. Comparatively, existing oil sands mining and extraction processes cost approximately $20/STB to produce non-upgraded bitumen, and approximately $40/STB to produce upgraded bitumen. This process is expected to be competitive with the existing hot water processes for water wet reservoirs (i.e.: Athabasca Oil Sands), and far superior for oil wet reservoirs (i.e.: Utah Asphalt Ridge).

Economic Analysis

The results of the energy analysis show that this process has an expected energy requirement of 130 MJ per STB of bitumen generated, representing an energy efficiency of approximately 45 to 1 in terms of energy output to energy input. For the cost per STB analysis, this ratio was reduced to 22 to 1, to conservatively account for unexpected energy requirements that could arise.

The ranges of processing costs were built into a statistical model predicting the value of this process to the company for their predicted development scenario.

The company plans to construct one 250 STB/d moveable pilot scale plant in the beginning of 2011 in order to demonstrate the economics of the process. At that point, the Company plans to construct 500 STB/d plants in areas with plentiful mineable oil sands ore. For the purposes of the economic forecast the value of constructing one 250 STB/d facility and one 500 STB/d facility was considered, assuming a fifteen year production life for each. It was assumed that the 500 STB/d plant would commence production in early 2013.

Per STB operating costs were further escalated by 2% per year for the first 25 years of the forecast, as is common in industry cost and economic evaluations.

Prices were estimated using the Chapman Petroleum Engineering September 1, 2011 WTI price forecast, as shown in Table 2, reduced by a factor of 0.8 based on our experience with the pricing of non-upgraded bitumen.

Probability density functions were generated for the project net present value, at 0%, 5%, 10%, 15%, and 20% discounting factors, as shown in Table 3.

Economic Conclusions

The results of the cost per STB analysis show that this process could reasonably expect to have overall processing costs of $30.10 per STB of crude bitumen generated, representing a netback of approximately $49.00 per STB. The results of the Monte Carlo simulation show there is a 90% confidence level that the per STB processing costs will fall between $22.84 and $38.87 per STB, based on conservative and reasonable assumptions of the major cost items and their variability, using the input probability distributions shown in cost analysis discussion.

The cash flows of a likely plant development scenario were modeled using the standard Chapman Petroleum Engineering September 1, 2011 price forecast, as shown in Table 2. The forecast shows bitumen sales prices approximately in the $80-$90/STB range going forward, and therefore this process is expected to be profitable.

The results of these analyses are shown in Table 3, Summary of Process Economics. Line 1 describes a 250 STB/d capacity plant costing $3,000,000, whereas line 2 shows the economics of a 500 STB/d capacity plant costing $5,000,000. The total value is a forecast assuming one 250 STB/d plant will be constructed in 2012, and another 500 STB/d plant will be constructed in 2013. The cashflow forecast for the anticipated development is shown in Table 3a, and the individual plant forecasts (250 STB/d and 500 STB/d) follow in Tables 3b and 3c.

Analysis of the statistical data used in this report shows that the primary factor influencing the cost per STB, and thus the economics of any implementation of this process, is the yield percentage of the raw oil sands. This one factor has far more impact on the potential value than any others. In addition, the actual cost the Company pays for the raw ore is important, but this factor is expected to be within manageable limits and mostly based on the depth of the mined sands.

Based on these analyses, and our experience in the economics of oil and gas projects, this process is expected to be commercially viable under a fairly wide range of conditions.

The Company intends to initially demonstrate this technology with a 250 STB/d a plant in early 2012, and then to add another 500 STB/d plant in early 2013.

The 15% discounted cashflow has been utilized as the best estimate of the net present value of the Company's technology and business plan, which our economic model shows to be 58.2 Million US$.

Table 1

Summary of Anticipated Capital Expenditures
Oil Sands Extraction Plant

September 1, 2011

MCW Energy Group Ltd.

Ashpahlt Ridge, Utah

Description	Date	Operation	Capital Interest %	Gross Capital M$	Net Capital M$
Oil Sands Extraction Plant	Dec-2011	Build 250 STB/d capacity fluidized bed oil sands processing plant	100.0000	3,000	3,000
Oil Sands Extraction Plant	Dec-2012	Build 500 STB/d capacity fluidized bed oil sands processing plant	100.0000	5,000	5,000
		Total Best Estimate		8,000	8,000

Note: **M$ means thousands of dollars.**
The above capital values are expressed in terms of current dollar values without escalation.
Unless details are known, drilling costs have been split 70% Intangible and 30% Tangible for tax purposes

Table 2
CHAPMAN PETROLEUM ENGINEERING LTD.
CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES
September 1, 2011

Date	WTI [1] $US/STB	Alberta Par Price [2] $CDN/STB	Alberta Heavy [3] $CDN/STB	Sask. Light [4] $CDN/STB	Sask. Heavy [5] $CDN/STB	B.C. Light [6] $CDN/STB	Bank of Canada Average Noon Exchange rate $US/$CDN
HISTORICAL PRICES							
2001	25.98	39.66	25.41	35.57	31.84	n/a	0.65
2002	26.09	40.63	32.20	37.67	34.57	n/a	0.64
2003	30.84	43.57	32.65	40.13	37.64	n/a	0.72
2004	41.48	52.89	37.52	48.96	45.74	n/a	0.77
2005	56.62	69.16	43.25	62.04	56.53	n/a	0.83
2006	65.91	72.88	50.40	66.77	61.23	n/a	0.88
2007	72.35	75.57	53.17	71.42	64.55	n/a	0.94
2008	99.70	102.98	83.88	98.02	92.45	n/a	0.94
2009	61.64	76.77	53.04	72.56	64.37	n/a	0.88
2010	79.42	80.56	66.58	77.02	72.79	n/a	0.97
2011 (8 mos)	98.16	104.03	76.15	93.03	83.28	n/a	1.03
CONSTANT PRICES							
the first-day-of-the-month price for the preceding 12 months [7]	92.06	95.21	73.21	86.34	78.36	92.83	1.01
CURRENT YEAR FORECAST							
2011 (4 mos)	**99.00**	98.00	81.34	93.10	88.45	95.55	1
FUTURE FORECAST							
2012	**100.00**	101.04	83.86	95.99	91.19	98.51	0.98
2013	**100.00**	101.04	83.86	95.99	91.19	98.51	0.98
2014	**100.00**	101.04	83.86	95.99	91.19	98.51	0.98
2015	**100.00**	101.04	83.86	95.99	91.19	98.51	0.98
2016	**100.00**	101.04	83.86	95.99	91.19	98.51	0.98
2017	**102.00**	103.08	85.56	97.93	93.03	100.50	0.98
2018	**104.00**	105.12	87.25	99.87	94.87	102.49	0.98
2019	**106.00**	107.16	88.95	101.81	96.71	104.48	0.98
2020	**108.12**	109.33	90.74	103.86	98.67	106.59	0.98
2021	**110.28**	111.53	92.57	105.96	100.66	108.74	0.98
2022	**112.49**	113.78	94.44	108.09	102.69	110.94	0.98
2023	**114.74**	116.08	96.35	110.28	104.76	113.18	0.98
2024	**117.03**	118.42	98.29	112.50	106.87	115.46	0.98
2025	**119.37**	120.81	100.27	114.77	109.03	117.79	0.98
2026	**121.76**	123.25	102.29	117.08	111.23	120.16	0.98
Constant thereafter							

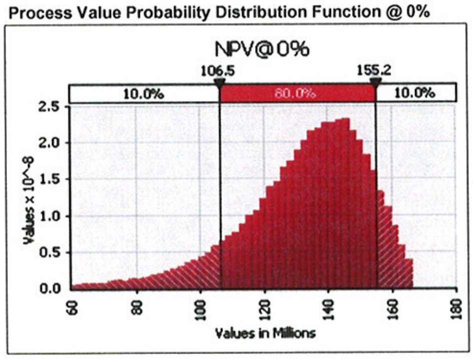
Notes:
[1] West Texas Intermediate quality (D2/S2) crude landed in Cushing, Oklahoma.
[2] Equivalent price for Light Sweet Crude (D2/S2) landed in Edmonton, Alberta is estimated from WTI US$ exchange to C$ and transportation differential of $1.00 CDN/STB.
[3] Bow River at Hardisty, Alberta (905 kg/m3, 2.1% sulphur).
[4] Light Sour Blend at Cromer, Saskatchewan (850 kg/m3, 1.2% sulphur).
[5] Midale at Cromer, Saskatchewan (880 kg/m3, 2.0% sulphur).
[6] B.C. Light at Taylor, British Columbia (825 kg/m3, 0.5% sulphur).

Table 3a

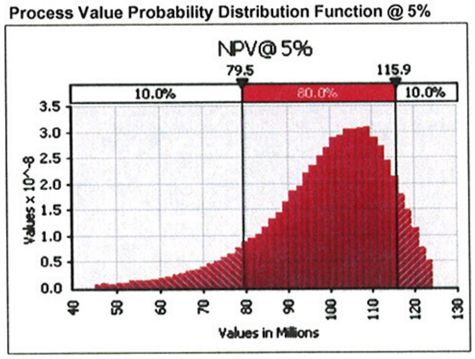
Total Oil Sands Processing Forecast
MCW Energy Group Ltd.

Year	Facility Capital (M$)	Rate	Price ($/STB)	Yearly Income ($)	Processing Costs $/STB	Costs	Net Cashflow	Net Present Value ($) 0%	5%	10%	15%	20%
2012	3,000	250	80	7305000	30.10	2,748,506	1,556,494	1,556,494	1,494,481	1,437,656	1,385,371	1,337,098
2013	5,000	750	80	21915000	30.70	8,410,429	8,504,571	8,504,571	7,776,892	7,141,134	6,582,233	6,088,174
2014		750	80	21915000	31.32	8,578,638	13,336,362	13,336,362	11,614,533	10,180,275	8,975,536	7,955,927
2015		750	80	21915000	31.94	8,750,210	13,164,790	13,164,790	10,919,154	9,135,732	7,704,404	6,544,645
2016		750	80	21915000	32.58	8,925,215	12,989,785	12,989,785	10,260,954	8,194,807	6,610,423	5,381,370
2017		750	81.6	22353300	33.23	9,103,719	13,249,581	13,249,581	9,967,784	7,598,821	5,863,158	4,574,165
2018		750	83.2	22791600	33.90	9,285,793	13,505,807	13,505,807	9,676,709	7,041,609	5,196,993	3,885,518
2019		750	84.8	23229900	34.58	9,471,509	13,758,391	13,758,391	9,388,269	6,521,182	4,603,641	3,298,487
2020		750	86.5	23695593.75	35.27	9,660,939	14,034,654	14,034,654	9,120,744	6,047,386	4,083,548	2,803,933
2021		750	88.22	24166766.25	35.97	9,854,158	14,312,608	14,312,608	8,858,456	5,606,503	3,621,236	2,382,887
2022		500	89.99	16434423.75	36.69	6,700,828	9,733,596	9,733,596	5,737,508	3,466,203	2,141,478	1,350,445
2023		0	91.79	0	37.43	0	0	0	0	0	0	0
								128,146,639	**94,815,483**	**72,371,307**	**56,768,022**	**45,602,649**

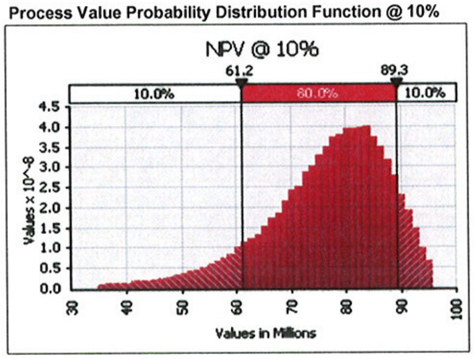
Process Value Probability Distribution Function @ 0%



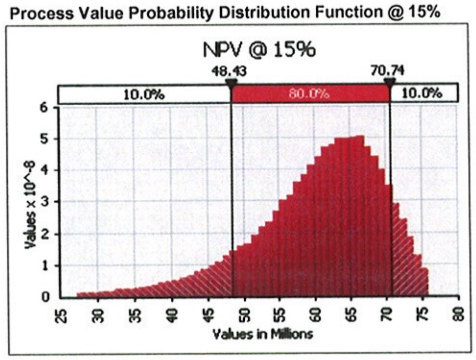
Process Value Probability Distribution Function @ 5%



Process Value Probability Distribution Function @ 10%



Process Value Probability Distribution Function @ 15%



Process Value Probability Distribution Function @ 20%

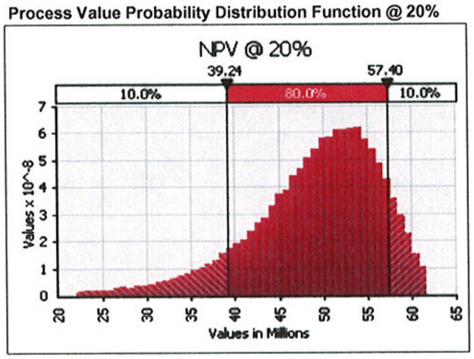
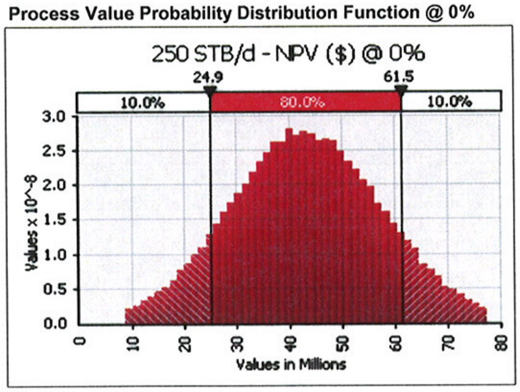


Table 3b

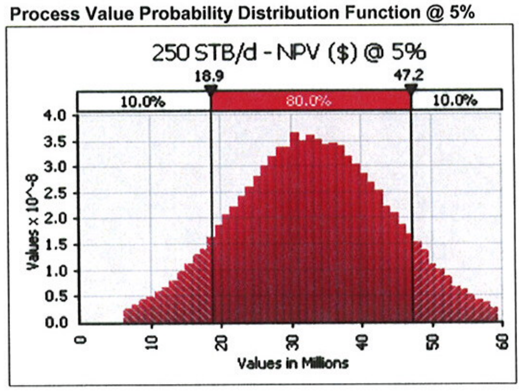
250 STB/d Oil Sands Processing Plant
MCW Energy Group Ltd.

Year	Facility Capital (M$)	Rate (STB/d)	Price ($/STB)	Yearly Income ($)	Processing Costs ($/STB)	Costs ($)	Net Cashflow ($)	Net Present Value ($) 0%	5%	10%	15%	20%
2012	3,000	250	80	7305000	30.10	2,748,506	1,556,494	1,556,494	1,494,481	1,437,656	1,385,371	1,337,098
2013		250	80	7305000	30.70	2,803,476	4,501,524	4,501,524	4,116,359	3,779,848	3,484,018	3,222,509
2014		250	80	7305000	31.32	2,859,546	4,445,454	4,445,454	3,871,511	3,393,425	2,991,845	2,651,976
2015		250	80	7305000	31.94	2,916,737	4,388,263	4,388,263	3,639,718	3,045,244	2,568,135	2,181,548
2016		250	80	7305000	32.58	2,975,072	4,329,928	4,329,928	3,420,318	2,731,602	2,203,474	1,793,790
2017		250	81.6	7451100	33.23	3,034,573	4,416,527	4,416,527	3,322,595	2,532,940	1,954,386	1,524,722
2018		250	83.2	7597200	33.90	3,095,264	4,501,936	4,501,936	3,225,570	2,347,203	1,732,331	1,295,173
2019		250	84.8	7743300	34.58	3,157,170	4,586,130	4,586,130	3,129,423	2,173,727	1,534,547	1,099,496
2020		250	86.5	7898531.25	35.27	3,220,313	4,678,218	4,678,218	3,040,248	2,015,795	1,361,183	934,644
2021		250	88.22	8055588.75	35.97	3,284,719	4,770,869	4,770,869	2,952,819	1,868,834	1,207,079	794,296
								42,175,343	**32,213,040**	**25,326,275**	**20,422,369**	**16,835,252**

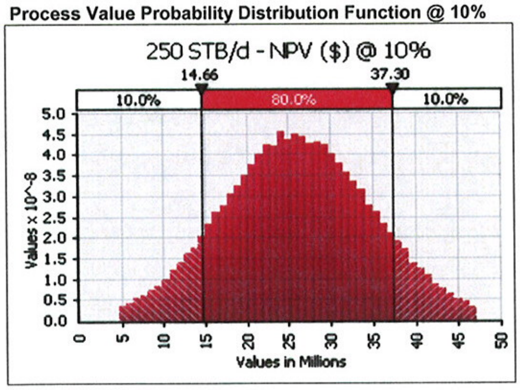
Process Value Probability Distribution Function @ 0%



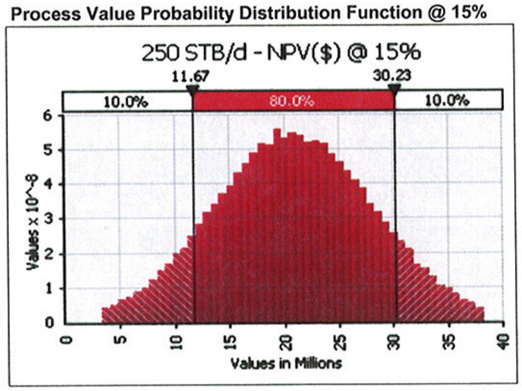
Process Value Probability Distribution Function @ 5%



Process Value Probability Distribution Function @ 10%



Process Value Probability Distribution Function @ 15%



Process Value Probability Distribution Function @ 20%

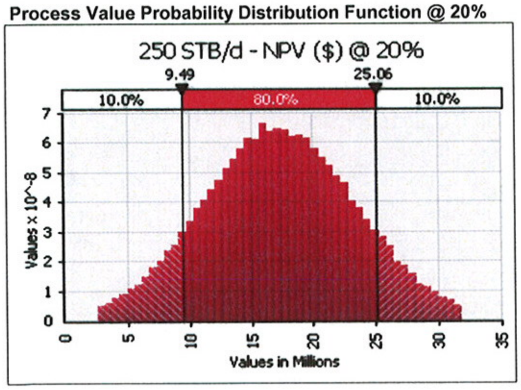
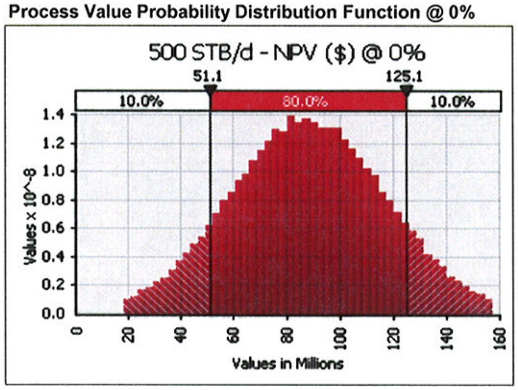


Table 3c

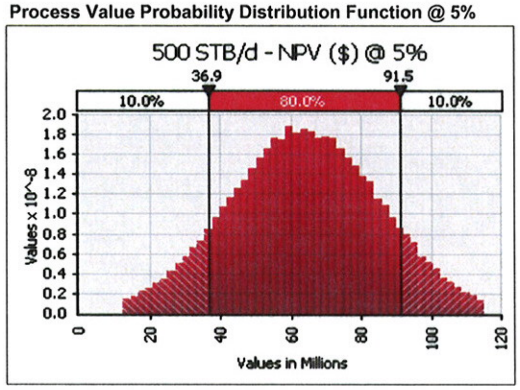
500 STB/d Oil Sands Processing Plant
MCW Energy Group Ltd.

Year	Facility Capital (M$)	Rate	Price ($/STB)	Yearly Income ($)	Processing Costs $/STB	Costs	Net Cashflow	Net Present Value ($) 0%	5%	10%	15%	20%
2012		0	80	0	30.10	0	0	0	0	0	0	0
2013	5000	500	80	14610000	30.70	5,606,953	9,003,047	9,003,047	8,232,717	7,559,696	6,968,036	6,445,019
2014		500	80	14610000	31.32	5,719,092	8,890,908	8,890,908	7,743,022	6,786,850	5,983,690	5,303,951
2015		500	80	14610000	31.94	5,833,474	8,776,526	8,776,526	7,279,436	6,090,488	5,136,270	4,363,096
2016		500	80	14610000	32.58	5,950,143	8,659,857	8,659,857	6,840,636	5,463,204	4,406,949	3,587,580
2017		500	81.6	14902200	33.23	6,069,146	8,833,054	8,833,054	6,645,189	5,065,880	3,908,772	3,049,443
2018		500	83.2	15194400	33.90	6,190,529	9,003,871	9,003,871	6,451,139	4,694,406	3,464,662	2,590,345
2019		500	84.8	15486600	34.58	6,314,339	9,172,261	9,172,261	6,258,846	4,347,455	3,069,094	2,198,992
2020		500	86.5	15797062.5	35.27	6,440,626	9,356,436	9,356,436	6,080,496	4,031,591	2,722,365	1,869,289
2021		500	88.22	16111177.5	35.97	6,569,439	9,541,739	9,541,739	5,905,637	3,737,669	2,414,158	1,588,591
2022		500	89.99	16434423.75	36.69	6,700,828	9,733,596	9,733,596	5,737,508	3,466,203	2,141,478	1,350,445
								90,971,295	**67,174,627**	**51,243,441**	**40,215,474**	**32,346,751**

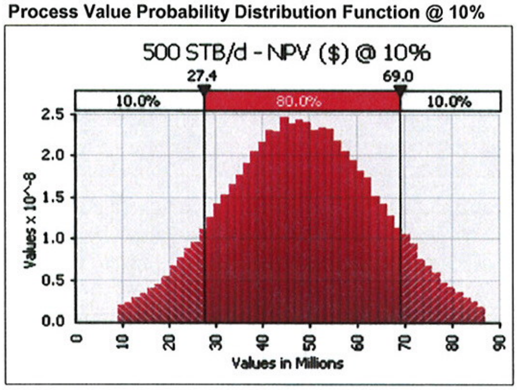
Process Value Probability Distribution Function @ 0%



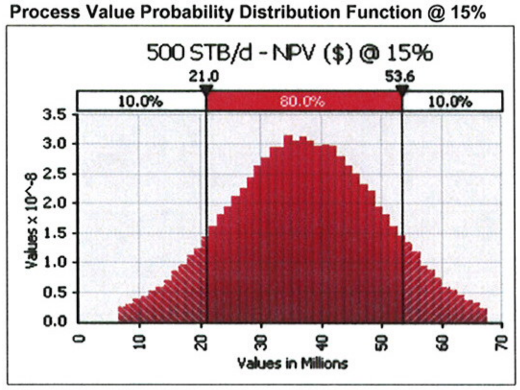
Process Value Probability Distribution Function @ 5%



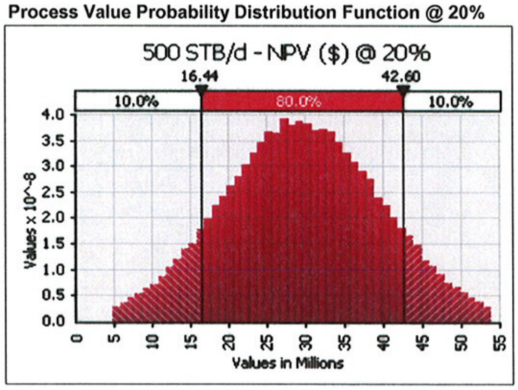
Process Value Probability Distribution Function @ 10%



Process Value Probability Distribution Function @ 15%



Process Value Probability Distribution Function @ 20%



5576

EVALUATION OF PROSPECTIVE RESOURCES

NW ASPHALT RIDGE AREA
UTAH, USA

Prepared for

MCW ENERGY GROUP LTD.

April 1, 2012
(March 31, 2012)

Chapman Petroleum Engineering Ltd.

445, 708 - 11th Avenue S.W., Calgary, Alberta T2R 0E4 • Phone: (403) 266-4141 • Fax: (403) 266-4259 • www.chapeng.ab.ca

April 4, 2012

MCW Energy Group Ltd
9701 Wilshire Blvd., 10th Floor
Beverly Hills, CA
90212

Attention: Alex Blyumkin

Dear Sir:

Re: Evaluation of Prospective Resources – April 1, 2012
<u>NW Asphalt Ridge Area, Utah, USA</u>

In accordance with your authorization, we have performed an evaluation of the prospective resources on the NW Asphalt Ridge Prospect, in Utah, USA, for MCW Energy Group Ltd. (the "Company"), in order to determine the feasibility of the Company participating in the exploration and development of this prospect under the terms proposed and determine the magnitude of the prospective resources and the economic value before and after the consideration of risk. This evaluation has been conducted in accordance with NI 51-101, Sec 5.9, pertaining to disclosure of resources, utilizing forecast prices and costs.

Our analysis has included a review of the available technical data including the geological and geophysical interpretation presented by the Company, the proposed ownership terms, information from relevant nearby wells or analogous reservoirs and the proposed program for the prospect. We have reviewed this material with respect to the estimated resources and productivity that would be expected of a successful program, the anticipated capital costs (including drilling, completion and equipment), the average operating costs in the area and expected product prices. We have also considered the availability of product markets, and transmission facilities within economic reach of the area.

In forming our opinion of this prospect we have relied to some extent on the information presented by the Company, which, together with our independent analysis and judgment, was sufficient for us to confidently establish the nature of the prospect and risks involved.

An economic analysis has been performed for the Company's interest position. This analysis has been utilized predominantly for formulating and supporting our recommendation on the project and the values established do not necessarily infer the "fair market value" of these prospective resources. All monetary values presented in this report are expressed in terms of United States dollars.

Based on our analysis, after consideration of risk, we have concluded that the potential of this prospect is of sufficient merit to justify the work program being proposed, and we therefore recommend and support the Company's participation.

All data gathered and calculations created in support of this report are stored permanently in our files and can be made available or presented on request. We reserve the right to make revisions to this report in light of additional information made available or which becomes known subsequent to the preparation of this report. Due to the risks involved in exploring for oil and gas reserves, our assessment of the project cannot be considered a guarantee that any wells drilled will be successful.

Prior to public disclosure of any information contained in this report, or our name as author, our written consent must be obtained, as to the information being disclosed and the manner in which it is presented. This report may not be reproduced, distributed or made available for use by any other party without our written consent and may not be reproduced for distribution at any time without the complete context of the report, unless otherwise reviewed and approved by us.

We consent to the submission of this report, in its entirety, to securities regulatory agencies and stock exchanges, by the Company.

It has been a pleasure to perform this evaluation and the opportunity to have been of service is appreciated.

Yours very truly,

Chapman Petroleum Engineering Ltd.

[Original Signed By:]

C.W. Chapman

C. W. Chapman, P. Eng.,
President

[Original Signed By:]

Roy A. Collver

Roy A. Collver, P. Eng.
Petroleum Engineer

rac/lml/5576
attachments

CERTIFICATE OF QUALIFICATION

I, C. W. CHAPMAN, P. Eng., Professional Engineer of the City of Calgary, Alberta, Canada, officing at Suite 445, 708 – 11th Avenue S.W., hereby certify:

1. THAT I am a registered Professional Engineer in the Province of Alberta and a member of the Australasian Institute of Mining and Metallurgy.

2. THAT I graduated from the University of Alberta with a Bachelor of Science degree in Mechanical Engineering in 1971.

3. THAT I have been employed in the petroleum industry since graduation by various companies and have been directly involved in reservoir engineering, petrophysics, operations, and evaluations during that time.

4. THAT I have in excess of 25 years in the conduct of evaluation and engineering studies relating to oil & gas fields in Canada and around the world.

5. THAT I participated directly in the evaluation of these assets and properties and preparation of this report for MCW Energy Group Ltd. dated April 4, 2012 and the parameters and conditions employed in this evaluation were examined by me and adopted as representative and appropriate in establishing the value of these oil and gas properties according to the information available to date.

6. THAT I have not, nor do I expect to receive, any direct or indirect interest in the properties or securities of MCW Energy Group Ltd. its participants or any affiliate thereof.

7. THAT I have not examined all of the documents pertaining to the ownership and agreements referred to in this report, or the chain of Title for the oil and gas properties discussed.

8. A personal field examination of these properties was considered to be unnecessary because the data available from the Company's records and public sources was satisfactory for our purposes.

[Original Signed By:]

C.W. Chapman

C. W. Chapman, P.Eng.
President

CERTIFICATE OF QUALIFICATION

I, ROY A. COLLVER, of the City of Calgary, Alberta, Canada, officing at Suite 445, 708 – 11th Avenue S.W., hereby certify:

1. THAT I am a registered Professional Engineer in the Province of Alberta, and a member of APEGGA.

2. THAT I graduated from Queen's University in Kingston, Ontario with a Bachelor of Science degree in Engineering Physics in 2005.

3. THAT I participated directly in the evaluation of these assets and properties and preparation of this report for MCW Energy Group Ltd., dated April 4, 2012 and the parameters and conditions employed in this evaluation were examined by me and adopted as representative and appropriate in establishing the value of these oil and gas properties according to the information available to date.

4. THAT I have not, nor do I expect to receive, any direct or indirect interest in the properties or securities of MCW Energy Group Ltd., its participants or any affiliate thereof.

5. THAT I have not examined all of the documents pertaining to the ownership and agreements referred to in this report, or the chain of Title for the oil and gas properties discussed.

6. A personal field examination of these properties was considered to be unnecessary because the data available from the Company's records and public sources was satisfactory for our purposes.

[Original Signed By:]

Roy A. Collver

Roy A. Collver, P. Eng.
Petroleum Engineer

EVALUATION OF PROSPECTIVE RESOURCES

NW ASPHALT RIDGE AREA UTAH, USA

Prepared for

MCW ENERGY GROUP LTD.

April 1, 2012
(March 31, 2012)

TABLE OF CONTENTS

SCOPE OF REPORT

Authorization

This report has been authorized by Mr. Alex Blyumkin, COO of MCW Energy Group Ltd. The technical analysis of this property has been performed during the month of April 2012.

Purpose

The purpose of this report was to independently determine the feasibility of the Company undertaking the exploration and development of the prospective resources in the NW Asphalt Ridge area, Utah, USA, and determine the magnitude of the prospective resources and the economic value before and after the consideration of risk.

Definitions

The following definitions, extracted from Section 5.2 of the Canadian Oil and Gas Evaluation Handbook, Volume 1 – Second Edition (COGEH-1) published by the Petroleum Society of CIM, and the Calgary chapter of the Society of Petroleum Evaluation Engineers (SPEE), as specified by Canadian Securities Regulations NI 51-101. These definitions relate to the subdivisions in the resources classification framework of Figure 1 which follows and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Discovered Petroleum Initially-In-Place (equivalent to "discovered resources") is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

a) Production

Production is the cumulative quantity of petroleum that has been recovered at a given date.

b) Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.

c) Contingent Resources

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

d) Unrecoverable

Unrecoverable is that portion of Discovered or Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

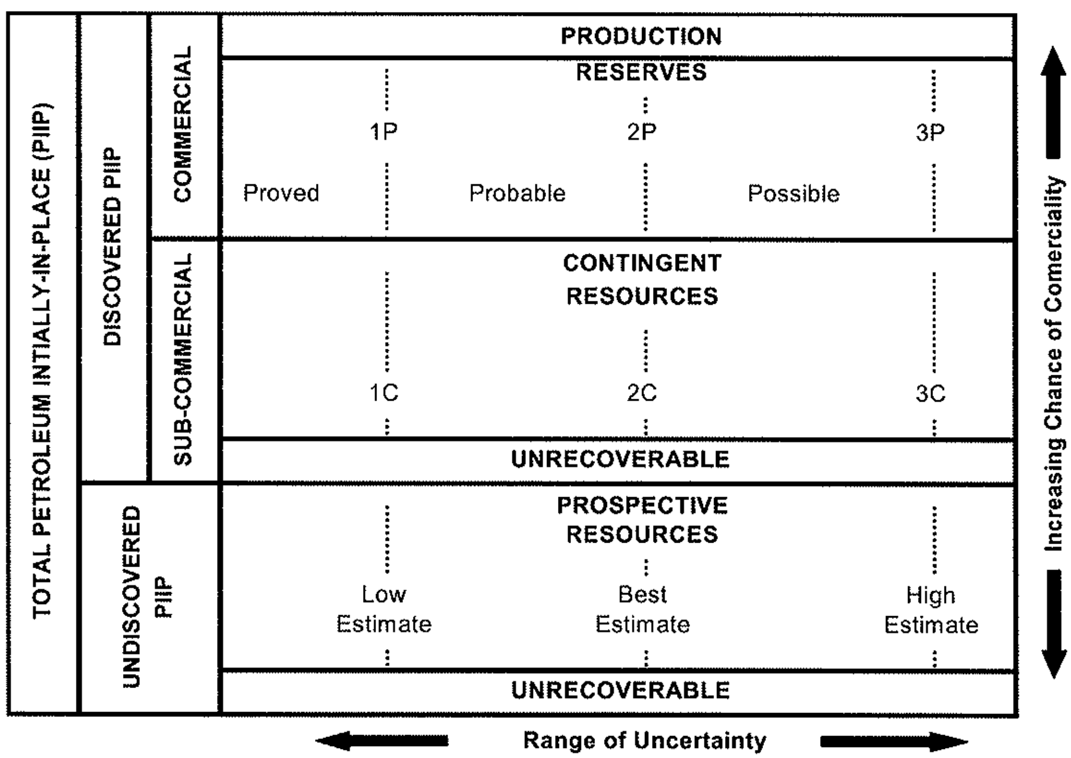
Undiscovered Petroleum Initially In Place (equivalent to "undiscovered resources") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources", the remainder as "unrecoverable".

a) *Prospective Resources*

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.

There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Figure 1 – Resources classification framework (SPE-PRMS, Figure 1.1).



Not to scale

Barrels of Oil Equivalent

If at any time in this report reference is made to "Barrels of Oil Equivalent" (BOE), the conversion used is 6 Mscf : 1 STB (6 Mcf : 1 bbl).

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Abandonment and Restoration

Abandonment and restoration costs, net of salvage, have been included in the cash flows for the final event of any particular well. The abandonment cost does not impact the economic limit and is included in the final year of production automatically by the economic software.

Attachment 1 - Product Price Forecast

CHAPMAN PETROLEUM ENGINEERING LTD.

International Price - Crude Oil & Natural Gas

HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES

April 1, 2012

Date	WTI [1] $US/STB	Brent Spot (ICE) $US/STB[2]	AECO Spot Gas [3] C$/MMBTU	Henry Hub Gas[4] $US/MMBTU	Nymex C1 $US/MMBTU	Bank of Canada Average Noon Exchange Rate $US/$CDN	Ashpalt Ridge Bitumen Sales US$/STB
HISTORICAL PRICES							
2001	25.98	24.36	5.44	N/A	N/A	0.65	20.78
2002	26.09	24.09	4.13	N/A	N/A	0.64	20.87
2003	30.84	28.40	7.03	N/A	N/A	0.71	24.67
2004	41.48	38.03	6.60	5.91	6.18	0.77	33.18
2005	56.62	55.28	8.82	8.92	9.01	0.83	45.30
2006	65.91	66.09	6.55	6.75	6.98	0.88	52.73
2007	72.35	72.74	6.47	6.97	7.11	0.94	57.88
2008	99.70	98.33	8.17	8.98	8.90	0.94	79.76
2009	61.64	62.52	3.99	3.94	3.91	0.88	49.31
2010	79.42	80.22	4.02	4.39	4.42	0.97	63.54
2011	95.03	109.67	3.63	3.99	4.03	1.01	76.02
2011 (3mos)	102.87	110.63	2.15	2.45	2.51	1.00	82.30
CONSTANT PRICES (The first-day-of-the-month price for the preceding 12 months)							
	97.67	111.11	3.35	3.67	3.74	**1.01**	78.14
FORECAST PRICE							
2012	**104.00**	108.40	2.50	2.60	2.54	**1**	83.20
2013	**102.00**	106.20	3.58	3.97	3.90	**1**	81.60
2014	**100.00**	104.00	4.12	4.65	4.58	**1**	80.00
2015	**100.00**	104.00	4.93	5.67	5.60	**1**	80.00
2016	**102.00**	106.20	5.42	6.29	6.22	**1**	81.60
2017	**102.00**	106.20	5.85	6.83	6.76	**1**	81.60
2018	**104.04**	108.44	6.18	7.24	7.17	**1**	83.23
2019	**106.12**	110.73	6.39	7.51	7.45	**1**	84.90
2020	**108.24**	113.07	6.72	7.92	7.85	**1**	86.59
2021	**110.41**	115.45	6.93	8.20	8.13	**1**	88.33
2022	**112.62**	117.88	7.04	8.33	8.26	**1**	90.09
2023	**114.87**	120.36	7.20	8.54	8.47	**1**	91.89
2024	**117.17**	122.88	7.37	8.74	8.67	**1**	93.73
2025	**119.51**	125.46	7.47	8.88	8.81	**1**	95.61
2026	**121.90**	128.09	7.69	9.15	9.08	**1**	97.52
2027	**124.34**	130.77	7.91	9.42	9.35	**1**	99.47
Constant thereafter							

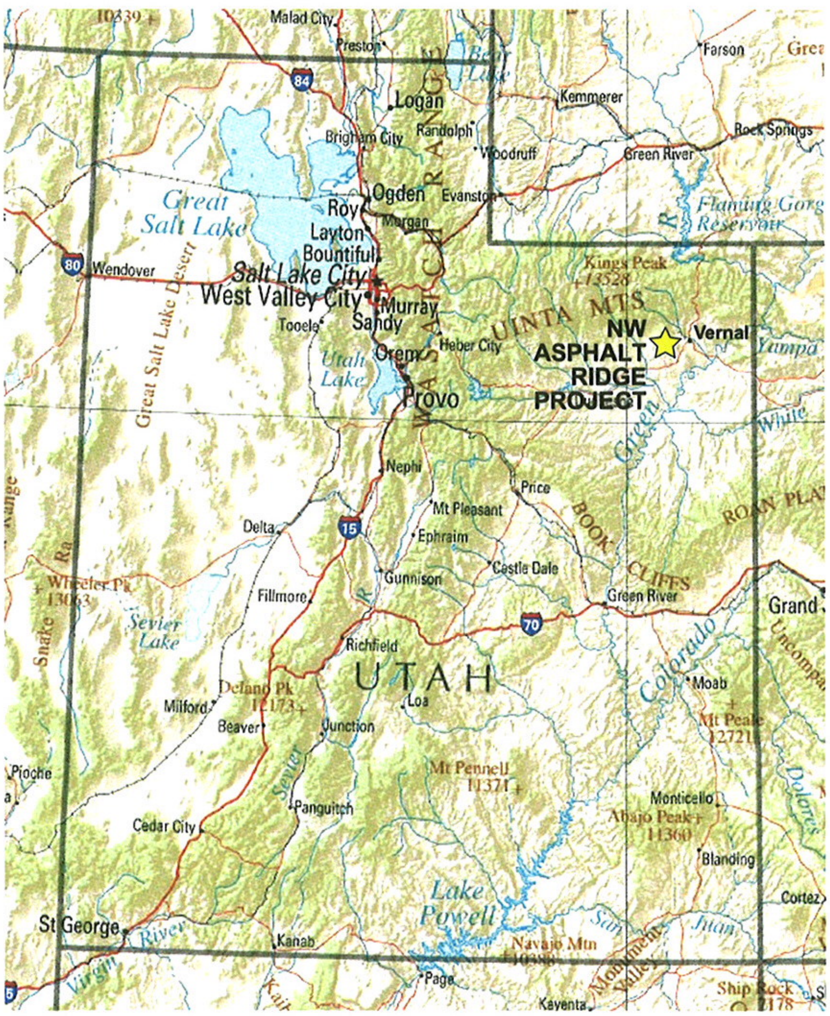
Notes:

[1] West Texas Intermediate quality (D2/S2) crude landed in Cushing, Oklahoma.

[2] The Brent Spot price is estimated based on historic data.

[3] The AECO C Spot price, which is the Alberta gas trading price

[4] Henry Hub is natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).



MCW ENERGY GROUP LTD.

NW ASPHALT RIDGE PROJECT

UINTAH COUNTY, UTAH, USA

ORIENTATION MAP

APR. 2012 **JOB No. 5576**

Chapman Petroleum Engineering Ltd.

PROSPECT SYNOPSIS

PROSPECTIVE OIL SANDS RESOURCES

NW ASPHALT RIDGE, UTAH

This Prospect Synopsis contains the information required to be disclosed under NI 51-101, Sec. 5.9. More details regarding the prospects are presented in the Report Discussion which follows.

(a) The Company has a 100% percent working interest in 1138 acres,

(b) The subject exploration lands are located in the county Uintah, Utah, approximately 3 miles west of the town of Vernal,

(c) The expected product from a successful prospect is crude bitumen between 12 API gravity,

(d) The economic and risk analysis, justifying the participation in this project is presented in the Discussion of the report and a summary of the "before and after risk" values for the Forecast Prices and Costs Case is presented below:

Project Net Value, Thousands of Dollars

	Before Risk	After Risk
Undiscounted	1,018,936,333	243,126,000
Discounted @ 5%/year	449,853,667	106,546,000
Discounted @ 10%/year	252,232,667	59,117,000
Discounted @ 15%/year	162,431,000	37,565,000
Discounted @ 20%/year	113,850,000	25,906,000

This report was prepared by a "Qualified Reserves Evaluator and Auditor" who is independent of the Company.

NW ASPHALT RIDGE

UTAH, USA

INDEX

NW ASPHALT RIDGE AREA
UTAH, USA
DISCUSSION

Ownership

The Company controls 1138 Acres of land in this area, under Oil Sands Mineral Lease ML51484. The majority of the Company lands are considered to be prospective for active oil sands mining development.

The outline of the Company lease is shown on Figure 1. Exact company lands are contained within the outline shown on the map, and are described in more detail in Table 1.

Bitumen production is subject to a constant 8% royalty rate for the first 10 years of production, escalating thereafter at 1% per year until 12.5%. There is a minimum royalty payable $10 per acre of mineral lease.

Exploration History

The bituminous sands of Asphalt Ridge and Asphalt Ridge Northwest have been known to early people and settlers of the area for quite some time. The first known use of the material was for road paving and construction during the early 1920s. In the 1930s, the first hot water extraction plant was attempted to commercially produce the oil bearing sands.

In the 1950s, two companies (Knicker-bocker Investments and W.M. Barnes Engineering Company) acquired a large block of placer mining claims and began in earnest the first drilling and evaluation program of the area. The claims were then leased to SOHIO Oil Company, which continued to expand upon the earlier evaluation program.

During the 1970s and 1980s, interest in this resource was at a high, and many companies completed extensive exploration and testing efforts around Asphalt Ridge and NW Asphalt Ridge. The Laramie Energy and Technology Center (DOE) conducted 3 in-situ experiments on the NW Asphalt Ridge deposit. The tests were conducted on an initial 10 Acre block, and then subsequently an additional 16 Acre block, in sections 23 and 24 of T4S R20E, part of the SOHIO "D" tract. In addition to the experiments, researchers drilled and analyzed numerous core holes, and studied formation outcrops where they were available. Although the in-situ experiments were largely considered failures, they did increase the knowledge of the accumulation immensely, in an area which lies immediately adjacent to Company lands.

In the late 1990s and early 2000s another pilot study was attempted in the main Asphalt Ridge formation using a solvent extraction process. After many attempts, researchers moved to a modified hot water extraction, and processed over 15,000 tones of mined oil sands material in this manner. Although this was an encouraging test, the land and facilities were sold, and the project was suspended for a period of time.

As of April 2012, the Company has completed construction of their pilot extraction plant at the site of the future mine, and have begun testing of their process on ores and samples purchased from mines in the surrounding area.

Geology

The Unita Basin primarily located in northeast Utah and shown on the map illustrated in Figure 2a, contains a number of oil sand deposits located on the margins of the basin. The basin was formed in the Late Cretaceous and early Tertiary and presently has an asymmetric configuration, with a steeply dipping side to the north and a gently sloping side to the south.

The structural axis of the Unita Basin is generally parallel to Asphalt Ridge, a prominent cuesta approximately 12 miles in length located on the northeast flank of the basin. An outcrop map of the Asphalt Ridge and NW Asphalt Ridge deposits is illustrated in Figure 2b. As also shown in the regional cross-section illustrated in Figure 2c, Cretaceous and Tertiary sandstones form bitumen saturated outcrops along the northeast side of Asphalt Ridge as well as its subsurface extension, NW Asphalt Ridge.

Structurally, Asphalt Ridge is terminated on its northwest end by a series of major crosscutting northeast trending high angle faults as shown in Figure 2b. The NW Asphalt Ridge deposit is located on the downdropped block, a monocline dipping southeast . This fault zone has apparently acted as a barrier to oil migration. While both deposits are stratigraphically continuous, one of the major bitumen bearing sandstone is saturated in the Northwest deposit and unsaturated in the Asphalt Ridge deposit.

Along Asphalt Ridge, the bitumen deposit extends downdip in the subsurface for a distance ranging from one-third to thirds-thirds of a mile from the outcropping sandstones, as indicated by the cross hatched area shown in Figure 2b.

A schematic type section of the NW Asphalt Ridge deposit is illustrated in Figure 2d. It was created from lithologic descriptions of a number of core holes drilled as part of a DOE pilot project located on the NW Asphalt Ridge deposit and shown on Figure 2b. A major angular unconformity separates the marine sediments of the Cretaceous Mancos and Mesaverde groups from the fluvial sediments of the Tertiary Duchesne River Formation. The Mesaverde Group contains two bitumen saturated sandstones, the Asphalt Ridge Sandstone and the Rim Rock Sandstone separated by a tongue of Mancos Shale. Both were deposited in a shallow marine environment.

At NW Asphalt Ridge, the Asphalt Ridge Sandstone is approximately 150 ft thick while the Rim Rock Sandstone varies in thickness from 100 to 350 feet. Unconformably overlying the Mesaverde group, is the sandstone and conglomerate rich Duchesne River Formation. This formation is approximately 250 feet in thickness and the lower portion is saturated with bitumen at NW Asphalt Ridge. A core sample from the Asphalt Ridge Sandstone has a published analysis reporting 13.4% bitumen content with an API gravity of 14.3.

Prospective Resources

The total estimated volume of Bitumen recoverable on Company lands has been estimated to be 13 MMSTB in the Low case (20.2 MMSTB bitumen in place), 20 MMSTB in the Best case (30.4 MMSTB bitumen in place), and 30 MSTB in the high case (55.6 MMSTB in place). This reflects a bitumen density of between 125 MSTB to 325 MSTB per mineable acre, as indicated by published literature regarding this deposit.

Estimates of the approximate resource size and overburden profile are based on published literature and publicly available information regarding the characteristics of the Asphalt ridge deposit, and discussions with the Company.

Productivity Estimates

In all cases it has been assumed that the Company will commence mining of their lease and producing extracted bitumen at a rate of 500 STB/d in 2013. Future upgrades to the plant and mining operation are expected to increase capacity to 1000 STB/d in 2014, and 2000 STB/d in 2015 when the operation is on full production.

Product Prices

The expected product from a successful mining operation would 8-12 API gravity crude bitumen. The forecast price for this product stream has been estimated at 80% of the WTI price, based on analogy to Canadian oil sands operations.

The 2013 estimated bitumen price is $81.60/STB.

Operating Environment

The prospective lands are located 3 miles west of the town of Vernal, in Uintah County, Utah. There are extensive oil and gas operations in this area, and several experimental mining project have been attempted on the Asphalt Ridge deposit.

There are two roads running through the middle of the lease, and the majority of the area has relatively easy, year round, access.

Capital Expenditures

Total Capital expenditures required to fully establish production on this lease have been estimated at $12,941,420 ($12,941,420 net to the Company), as shown in Table 3a.

The net capital exposure required to test these prospective resources has been estimated to be $1,866,420 ($1,866,420 net to the Company), as shown in Table 3a. The capital exposure are the estimated remaining expenses before the Company can full demonstrate the ability of the project to operate economically.

Operating Costs

Operating costs were considered to be very significant to the overall project success, and were the main parameters varied between the low, best, and high cases. In all cases, it was assumed the mining operation would proceed as follows:

1. The overall cost of mining and obtaining ore will be approximately $19.50/tonne.
2. The process plant would operate on a 10 hour work day, and be operated every day of the year.
3. Every tone of raw crushed ore would consist of approximately 14% extractable hydrocarbon by weight.
4. Approximately 4 parts of solvent will be needed for every part of hydrocarbon extracted.
5. A negligible amount (and value) of the solvent will be lost in the final hydrocarbon stream.
6. Electrical energy is available in sufficient quantity, at an expected price of 5.65 cents per kwh[1].
7. The 500 STB/d plant will require 9 workers to operate, also earning an average of $15/hour.
8. The equivalent of approximately 0.3% of the value of the final bitumen products will be lost due to lost solvent in the spent ore.
9. An average 8% royalty has been included to account for state royalties and taxes.

A complete breakdown of the operating costs assumed in each of the low, best, and high cases is presented in Table 3b.

Economics and Risk

The results of the economic analysis, before and after income tax are summarized in Table 4, and the before risk cash flows are presented in Tables 4a, 4b and 4c, for the best, low and high estimates, respectively. The before risk analysis represents the results of an assumed successful exploration and development model having parameters which are considered to be reasonable based on the information available. This is the 100% probability of success (POS) case.

A risk analysis has been performed to determine the feasibility of the Company participating in this project and to determine the after risk value before income tax, utilizing the "Expected Value" technique applied to the arithmetic average of the best, low and high estimate results, a presentation of which is shown in Figure 3.

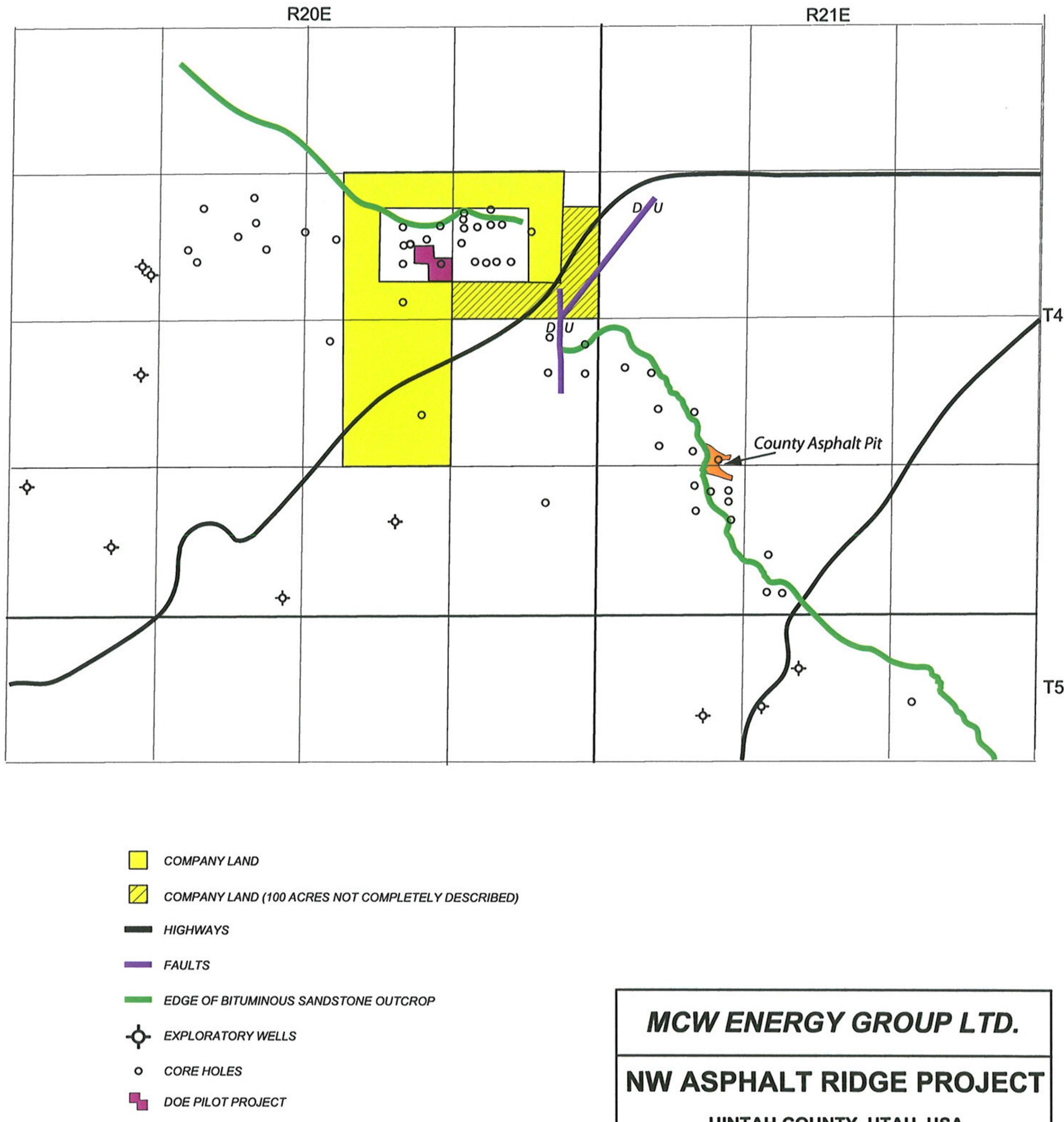
The net capital exposure (POS = 0%) for this project have been assumed to be the costs of a 24 well delineation plan, and establishing 500 STB/d of bitumen production from their mining operation and pilot extraction plant. Based on the risk analysis presented in Figure 3, the Company would require a minimum probability of success of 0.7% to participate in this project at a discount rate of 10%. As we have estimated a probability of success of 24%, the Company's participation in this project is considered feasible.

---

[1] Source – www.eia.gov

In establishing our probability of success, consideration has been given to both geological and commerciality factors. The geological factors include the four main geological components of a petroleum system needed for commercial production, source rocks available to generate hydrocarbons, reservoir rocks to accumulate hydrocarbons, a stratigraphic or structural trapping mechanism with a seal to hold hydrocarbons and a mechanism and proper geological timing allowing for hydrocarbons to migrate into the trap.

The predominant risk is the possibility that the ratio of overburden to formation thickness is not favorable enough to support mining development. In the context of an oil sands mining operation, this factor would fall under commerciality risk, in that the risk is in the per barrel production costs becoming excessive.



MCW ENERGY GROUP LTD.

NW ASPHALT RIDGE PROJECT

UINTAH COUNTY, UTAH, USA

LAND AND WELL MAP

APR. 2012 **JOB No. 5576** **FIGURE No. 1**

Chapman Petroleum Engineering Ltd.

Table 1

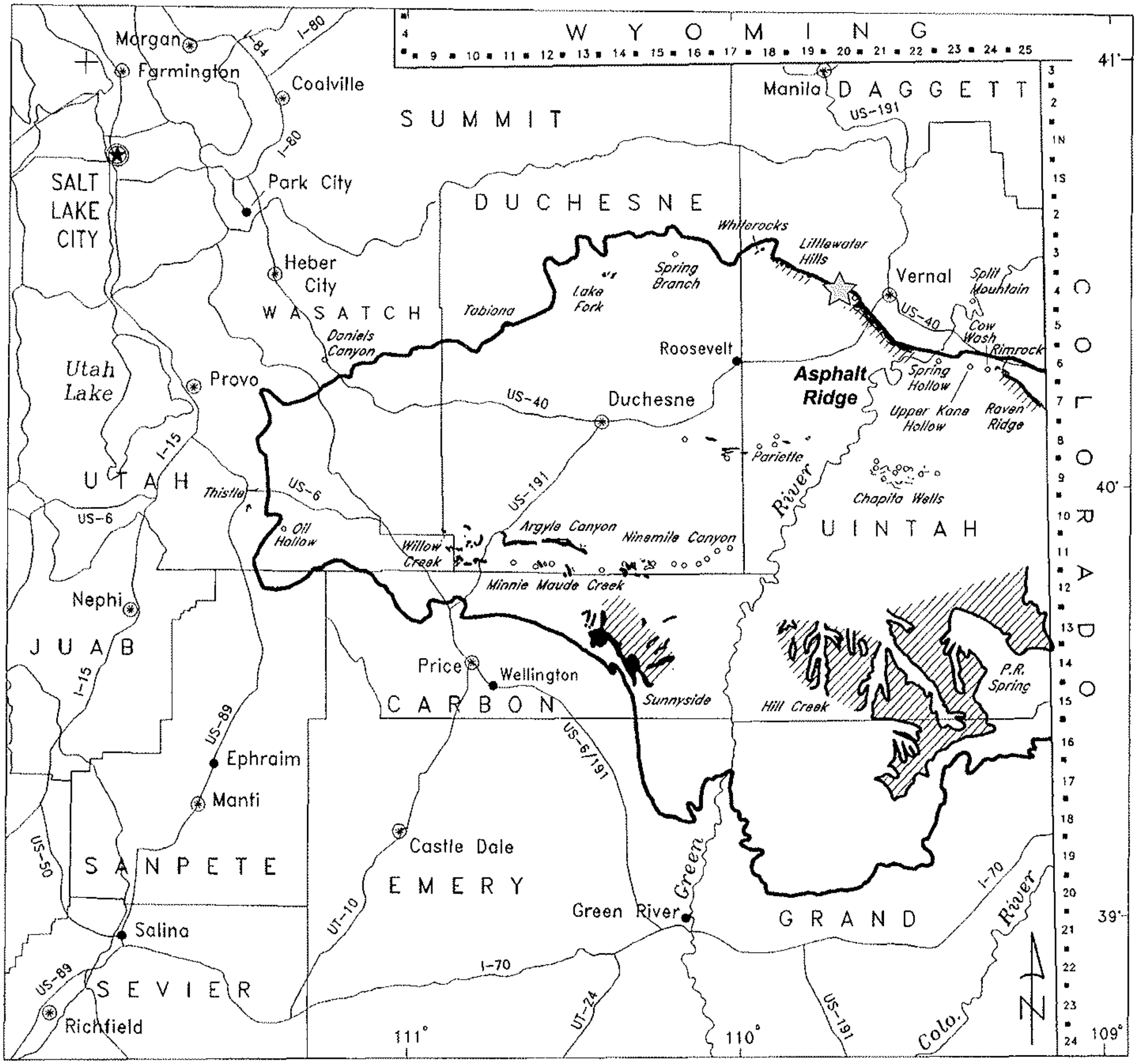
Schedule of Lands, Interests and Royalty Burdens
April 1, 2012

MCW Energy Group Ltd.

NW Asphalt Ridge, Utah

Description	Gross Acres	Appraised Interest Working %	Royalty Burdens Basic %	Royalty Burdens Overriding %
ML 51484	1,138	100.0000	[1]	-
Sec 23				
N/2 of NE/4, E/2 of W/2,S/2 of S/4				
Sec 24				
Lots 2,3,4 , W/2 of E/2, N/2 of NW/4		[2]		
Sec 26				
E/2, E/2 of W/2				
	1138			

General Notes :
[1] State production royalties begin at 8% per year for 10 years, than increase at 1% per year to a total of 12.5%
[2] Lots 2,3, and 4 are of unknown size and position, but total 100 Acres. See Fig 1



Deposit, known outcrop of bitumen-saturated rock or areas where bitumen can be projected from outcrop or core data.

Approximate edge of Uinta Basin

10 0 10 20 30 40 Miles

Area of Interest

MCW ENERGY GROUP LTD.

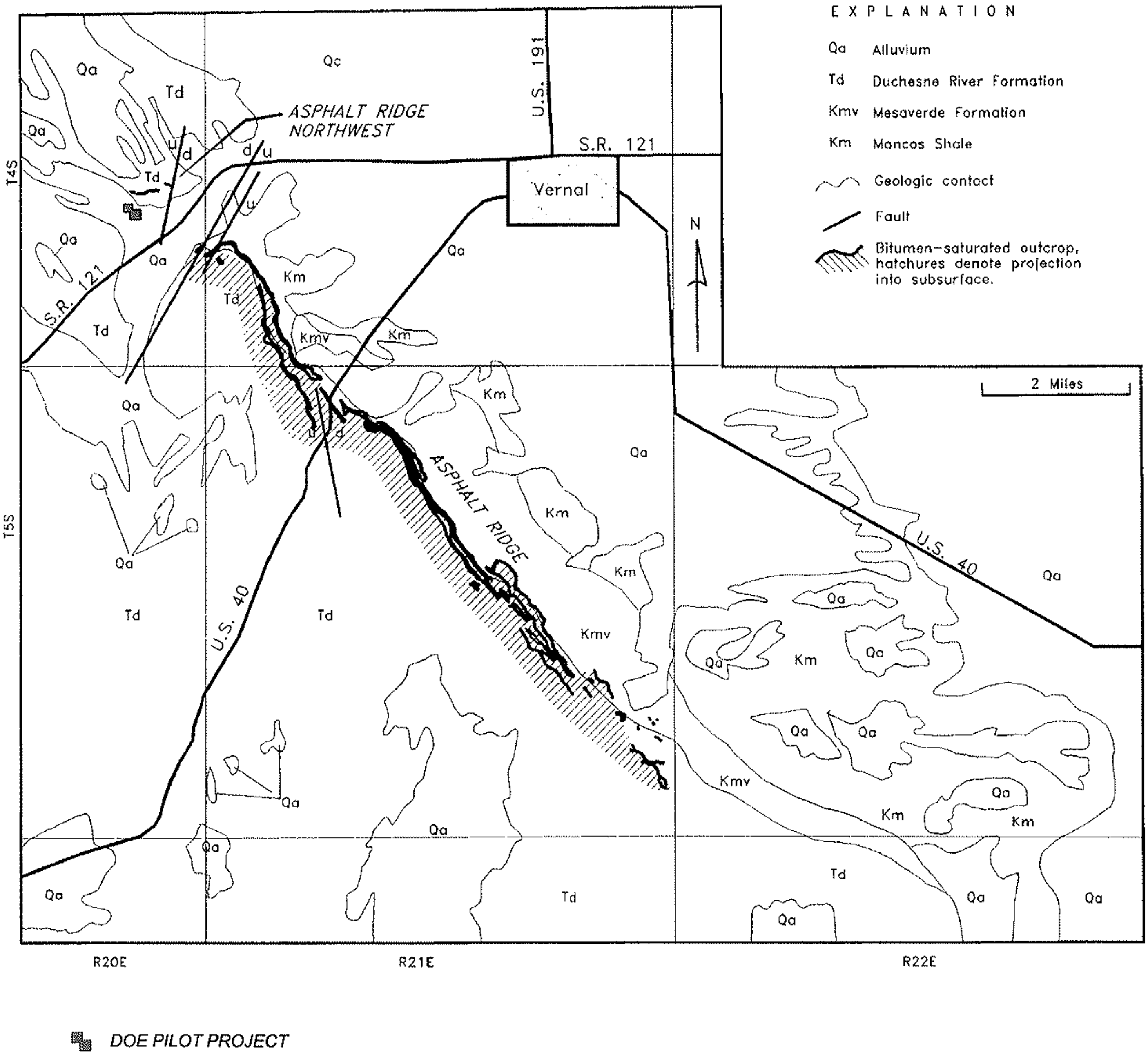
NW ASPHALT RIDGE PROJECT

UINTAH COUNTY, UTAH, USA

OIL SAND DEPOSITS MAP

APR. 2012 JOB No. 5576 FIGURE No. 2a

Chapman Petroleum Engineering Ltd.



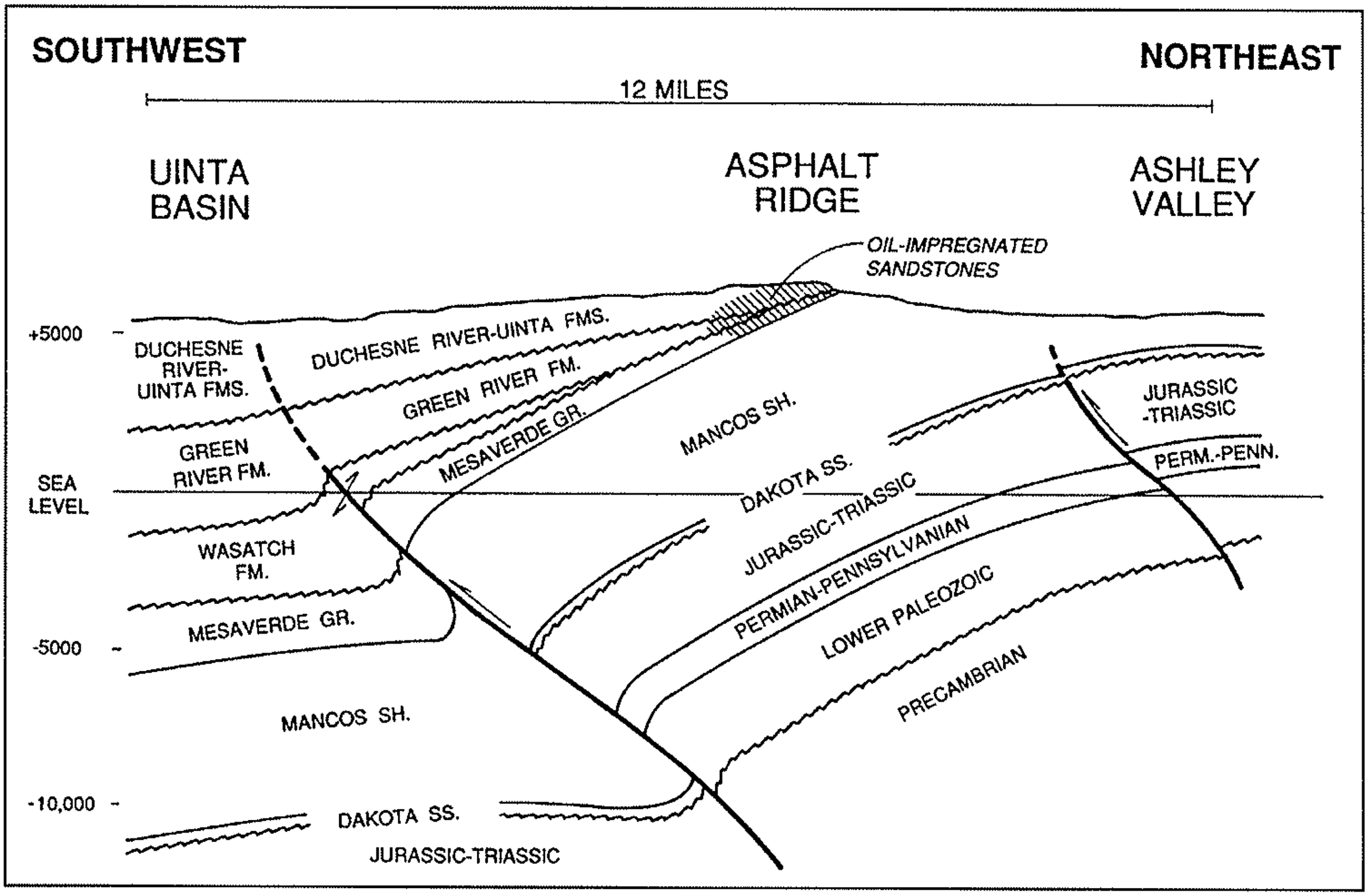
MCW ENERGY GROUP LTD.

NW ASPHALT RIDGE PROJECT

UINTAH COUNTY, UTAH, USA

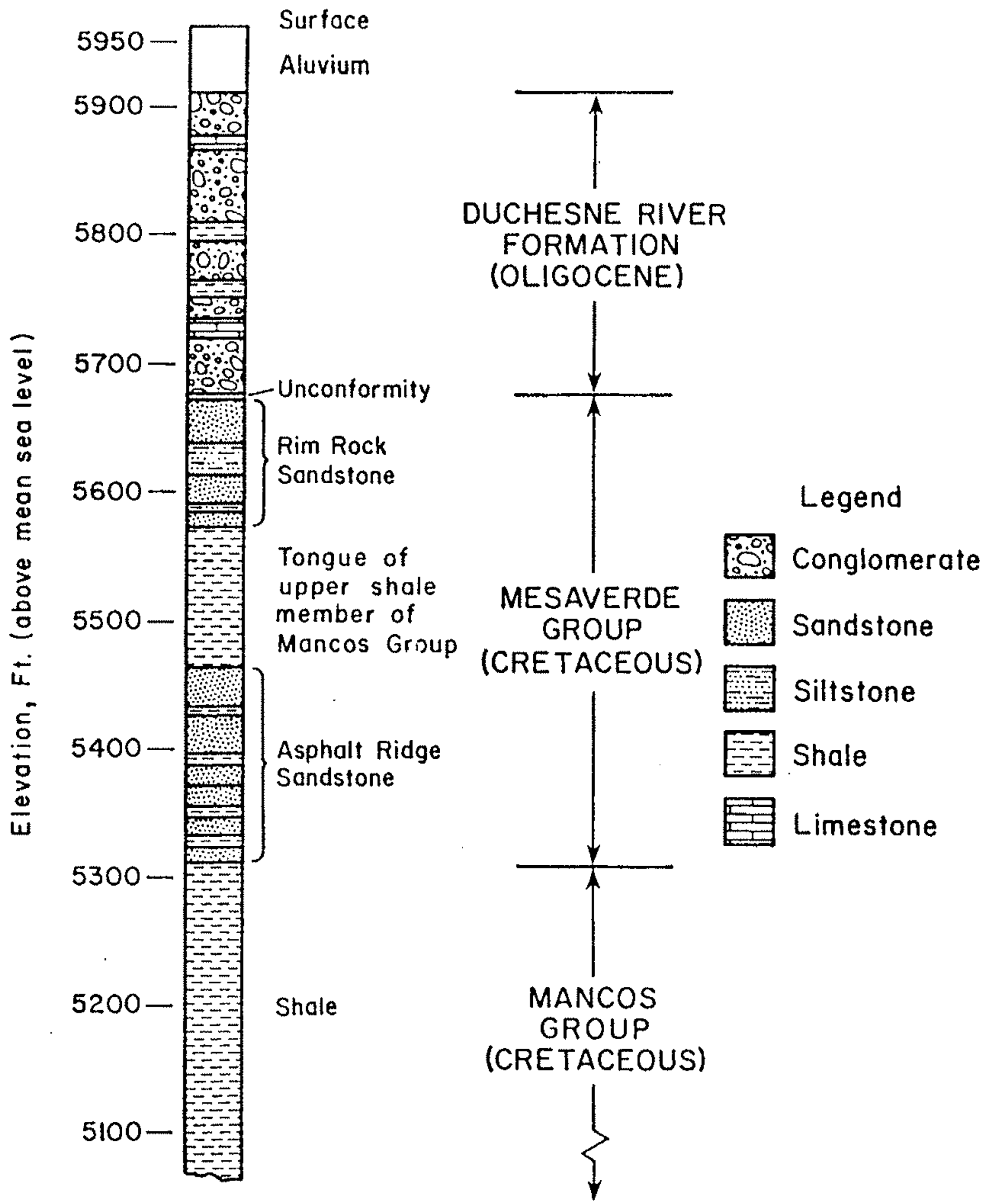
OUTCROP MAP

APR. 2012 JOB No. 5576 FIGURE No. 2b



MCW ENERGY GROUP LTD.
NW ASPHALT RIDGE PROJECT **UINTAH COUNTY, UTAH, USA** **REGIONAL CROSS SECTION**
APR. 2012 JOB No. 5576 FIGURE No. 2c

Chapman *Petroleum Engineering Ltd.*



MCW ENERGY GROUP LTD.

NW ASPHALT RIDGE PROJECT

UINTAH COUNTY, UTAH, USA

GENERALIZED STRATIGRAPHIC SECTION

APR. 2012 **JOB No. 5576** **FIGURE No. 2d**

Chapman *Petroleum Engineering Ltd.*

Table 2

Summary of Gross Prospective Resources
April 1, 2012

NW Asphalt Ridge, Utah

Description		Avg. Net Pay Thick. m	Overburd/Form Ratio	Overburden Volume m3	Oil Sands Volume m3	Development Area ha [1]	Bitumen Grade [3] % Vol	Recoverable Bitumen Resources STB	Original Bit. In Place STB [2]
Prospective Resources									
Best Estimate									
ML 51484	Rim Rock & Duchesne River	50.00	1.10	23,321,143	21,201,039	42	15.0%	20,000,000	217,112,003
	Total Best			**23,321,143**	**21,201,039**	**42**		**20,000,000**	**217,112,003**
Low Estimate									
ML 51484	Rim Rock & Duchesne River	35.00	1.50	22,147,514	14,765,009	42	14.0%	13,000,000	141,846,508
	Total Best			**22,147,514**	**14,765,009**	**42**		**13,000,000**	**141,846,508**
High Estimate									
ML 51484	Rim Rock & Duchesne River	80.00	0.90	26,832,565	29,813,961	37	16.0%	30,000,000	370,537,818
	Total Best			**26,832,565**	**29,813,961**	**37**		**30,000,000**	**370,537,818**

Table 3a

Summary of Anticipated Capital Expenditures
Exploration & Development

April 1, 2012

MCW Energy Group Ltd.

NW Asphalt Ridge, Utah

Description	Date	Operation	Capital Interest %	Gross Capital $	Net Capital $
Prospective Resources					
Dry and Abandoned					
Asphalt Ridge, Utah	2012	Surveying and lease preperation	100.0000	65,420	65,420
Asphalt Ridge, Utah	2012	24 cored delineation wells	100.0000	576,000	576,000
Asphalt Ridge, Utah	2012	2 Excavators + Salvage	100.0000	125,000	125,000
Asphalt Ridge, Utah	2012	2 Track Loaders + Salvage	100.0000	400,000	400,000
Asphalt Ridge, Utah	2012	Plant Start-up Costs	100.0000	500,000	500,000
Asphalt Ridge, Utah	2012	Infrastructure and Roads	100.0000	200,000	200,000
				1,866,420	**1,866,420**
Best/Low/High Estimate					
Asphalt Ridge, Utah	2012	Surveying and lease preperation	100.0000	65,420	65,420
Asphalt Ridge, Utah	2012	24 cored delineation wells	100.0000	576,000	576,000
Asphalt Ridge, Utah	2012	2 Excavators	100.0000	250,000	250,000
Asphalt Ridge, Utah	2012	2 Track Loaders	100.0000	800,000	800,000
Asphalt Ridge, Utah	2012	Infrastructure and Roads	100.0000	200,000	200,000
Asphalt Ridge, Utah	2013	2 Excavators	100.0000	250,000	250,000
Asphalt Ridge, Utah	2013	2 Track Loaders	100.0000	800,000	800,000
Asphalt Ridge, Utah	2013	Bitumen Extraction Plant Expansion	100.0000	2,500,000	2,500,000
Asphalt Ridge, Utah	2013	Infrastructure and Roads	100.0000	200,000	200,000
Asphalt Ridge, Utah	2013	4 Excavators	100.0000	500,000	500,000
Asphalt Ridge, Utah	2013	4 Track Loaders	100.0000	1,600,000	1,600,000
Asphalt Ridge, Utah	2013	Bitumen Extraction Plant Expansion	100.0000	5,000,000	5,000,000
Asphalt Ridge, Utah	2013	Infrastructure and Roads	100.0000	200,000	200,000
		Total		**12,941,420**	**12,941,420**

Note: **M$ means thousands of dollars.**
The above capital values are expressed in terms of current dollar values without escalation.
Unless details are known, drilling costs have been split 70% Intangible and 30% Tangible for tax purposes

Table 3b
Per STB Processing Cost Analysis - 500 STB/d plant
Janaury 1, 2012
MCW Energy Group Ltd.

***Assume 14% extractable oil

56	tons raw ore processed per hour
27.91625125	m3 of raw ore processed per hour
49.30576	STB of hydrobarbon produced per hour
197.22304	STB of solvent utilized per hour
0.0005	% of solvent lost to spent ore per STB of solvent used
0	% solvent lost to hydrocarbon stream per STB of solvent used

2 tons water steam generated per hour

Solvent Losses

0.09861152	Solvent lost to spent ore
0	Solvent lost to hydrocarbon stream
0.09861152	STB solvent lost per hour

10 Hour Standard Work Day
37 MJ/l energy density of bitumen

Energy Requirements	kw	
Pumps	800	400
Heat Exchangers	74	37
Cooler	38	19
Evaporator	750	375
Finish Cleaning	20	10
Operating + Contingency	120	60

Energy Production		
Total Bitumen Production (STB/h)	49.30576	
Lost Solvent in Spent Ore (STB/h)	- 0.09861152	
	49.2071485	
Total Energy Productin (litres)	7824.32	
Energy Production Per Hour (kJ/h)	289,499,840	
Total Energy Consumption Per Hour (kJ/h)	6,487,200	
Efficiency of Energy Production (%)	97.76%	43.62632
Efficiency of Energy Production (kJ/STB)	131,571	

Economic Analysis		
Cost of crushed ore ($/tonne)	19.5	
Cost of Plant Labour ($/hour operation)	135	
Power Costs ($/kwh)	0.0565	$/kwh Electricity price - www.eia.com
Facility Operation ($/hour)	10	
Solvent Costs	0.3%	

Solvent costs are shown as the equivalent percentage of the final product which would be given up to pay for the lost solvent costs

Cost Analysis		
Total Raw Ore Cost ($/h)	1092	
Total Labour Costs ($/h)	135	
Power Costs ($/h)	101.813	
Facility Operation ($/h)	10	
Solvent Loss Reduction Fraction	99.7%	
Total Production Per Hour	49.30576	
Total Production Per Hour Subtracting Solvent Loss	49.1701692	
Total Cost Per Hour	1338.813	
Total Best Estimate Cost Per Net STB of Production	**27.23**	($/STB)
Total Low Estimate Cost Per Net STB of Production	**34.04**	($/STB)
Total High Estimate Cost Per Net STB of Production	**24.51**	($/STB)

"net" means after deduction of the costs of solvent

Forecast Prices & Costs

Table 4
Summary of Company Prospective Resources and Economics
Before Income Tax
April 1, 2012
(as of March 31, 2012)

MCW Energy Group Ltd.

Asphalt Ridge, Uintah County, Utah, USA

Description	Resources Bitumen STB Gross	Resources Bitumen STB Net	Cumulative Cash Flow (BIT) - US$ Undisc.	Discounted at: 5%/year	Discounted at: 10%/year	Discounted at: 15%/year	Discounted at: 20%/year
BEFORE RISK							
Best Estimate							
Asphalt Ridge Oil Sands (Rim Rock,Duchesne River)	20,000,000	17,845,000	969,516,000	465,339,000	264,829,000	170,209,000	118,888,000
Low Estimate							
Asphalt Ridge Oil Sands (Rim Rock,Duchesne River)	13,000,000	11,720,000	508,333,000	299,596,000	191,491,000	130,721,000	94,010,000
High Estimate							
Asphalt Ridge Oil Sands (Rim Rock,Duchesne River)	30,000,000	26,596,000	1,578,960,000	584,626,000	300,378,000	186,363,000	128,652,000
Arithmetic Average							
Asphalt Ridge Oil Sands (Rim Rock,Duchesne River)	**21,000,000**	**18,720,333**	**1,018,936,333**	**449,853,667**	**252,232,667**	**162,431,000**	**113,850,000**
AFTER RISK							
Arithmetic Average After Risk							
Asphalt Ridge Oil Sands (Rim Rock,Duchesne River)	**5,040,000**	**4,492,880**	**243,126,000**	**106,546,000**	**59,117,000**	**37,565,000**	**25,906,000**

Gross resources are the total of the Company's working and/or royalty interest share before deduction of royalties owned by others.

Net resources are the total of the Company's working and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

Columns may not add precisely due to accumulative rounding of values throughout the report.

Table 4a

EVALUATION OF: Asphalt Ridge, Utah - Prospect Best Estimate

ERGO v7.43 P2 ENERGY SOLUTIONS PAGE 1
GLOBAL : 03-APR-2012 5576
EFF:01-APR-2012 DISC:01-APR-2012 PROD:01-JAN-2013
RUN DATE: 4-APR-2012 TIME: 14:12
FILE: Outa1PB.DAX

WELL/LOCATION - Asphalt Ridge Oil Sands (Rim Rock & Duchesne River)
EVALUATED BY -
COMPANY EVALUATED - MCW Energy Group Ltd.
APPRAISAL FOR -
PROJECT - FORECAST PRICES & COSTS

UNIT FACTOR - 100.0000 %
TOTAL RESERVES - 20000 MSTB
PRODUCTION TO DATE - N/A
DECLINE INDICATOR - EXPONENTIAL
TOTAL CAPITAL COSTS - 13162 -M$-

INTEREST

AVG WI 100.0000%

ROYALTIES/TAXES

U.S.

Year	# of Wells	Price $/STB	Oil MSTB Pool STB/D	Pool Vol	Company Share Gross	Company Share Net
2012	0	83.20	.0	0	0	0
2013	1	81.60	500.0	183	183	168
2014	1	80.00	1000.0	365	365	336
2015	1	80.00	2000.0	730	730	672
2016	1	81.60	2000.0	730	730	672
2017	1	81.60	2000.0	730	730	672
2018	1	83.23	2000.0	730	730	672
2019	1	84.90	2000.0	730	730	672
2020	1	86.59	2000.0	730	730	672
2021	1	88.33	2000.0	730	730	672
2022	1	90.10	2000.0	730	730	672
2023	1	91.90	2000.0	730	730	664
2024	1	93.74	1985.9	725	725	652
2025	1	95.61	1958.0	715	715	636
2026	1	97.52	1930.4	705	705	620
SUB				9262	9262	8449
REM				10738	10738	9396
TOT				20000	20000	17845

COMPANY SHARE FUTURE NET REVENUE

Year	Company Share Future Revenue (FR) Oil -M$-	SaleGas -M$-	Products -M$-	Total -M$-	Royalties State -M$-	Royalties Other -M$-	Wellhead Taxes Sev -M$-	Wellhead Taxes Ad-val -M$-	Oper Costs Fixed -M$-	Oper Costs Variabl -M$-	FR After Roy&Oper -M$-	Proc& Other Income -M$-	Capital Costs -M$-	Aband Costs -M$-	Future Net Revenue Undiscounted Annual -M$-	Undiscounted Cum -M$-	10.0% Annual -M$-	10.0% Cum -M$-
2012	0	0	0	0	0	0	0	0	0	0	0	0	1891	0	-1891	-1891	-1825	-1825
2013	14892	0	0	14892	1191	0	0	0	0	5069	8632	0	11271	0	-2639	-4531	-2342	-4167
2014	29200	0	0	29200	2336	0	0	0	0	10340	16524	0	0	0	16524	11993	13330	9163
2015	58400	0	0	58400	4672	0	0	0	0	21095	32633	0	0	0	32633	44626	23933	33096
2016	59568	0	0	59568	4765	0	0	0	0	21516	33286	0	0	0	33286	77912	22192	55288
2017	59568	0	0	59568	4765	0	0	0	0	21947	32856	0	0	0	32856	110768	19914	75202
2018	60759	0	0	60759	4861	0	0	0	0	22386	33513	0	0	0	33513	144281	18466	93668
2019	61974	0	0	61974	4958	0	0	0	0	22833	34183	0	0	0	34183	178464	17123	110790
2020	63212	0	0	63212	5057	0	0	0	0	23290	34865	0	0	0	34865	213329	15877	126667
2021	64479	0	0	64479	5158	0	0	0	0	23756	35565	0	0	0	35565	248894	14723	141390
2022	65770	0	0	65770	5262	0	0	0	0	24231	36277	0	0	0	36277	285171	13653	155043
2023	67084	0	0	67084	6038	0	0	0	0	24716	36331	0	0	0	36331	321502	12430	167473
2024	67945	0	0	67945	6794	0	0	0	0	25032	36118	0	0	0	36118	357620	11234	178707
2025	68327	0	0	68327	7516	0	0	0	0	25174	35637	0	0	0	35637	393258	10076	188783
2026	68713	0	0	68713	8246	0	0	0	0	25316	35151	0	0	0	35151	428409	9036	197819
SUB	809892	0	0	809892	71619	0	0	0	0	296701	441571	0	13162	0	428409		197819	
REM	1068169	0	0	1068169	133521	0	0	0	0	393540	541107	0	0	0	541107		67010	
TOT	1878061	0	0	1878061	205141	0	0	0	0	690242	982679	0	13162	0	969516		264829	

NET PRESENT VALUE (-M$-)

Discount Rate	.0%	5.0%	8.0%	10.0%	12.0%	15.0%	20.0%
FR After Roy & Oper.	982679	477799	338229	276656	230819	181463	129622
Proc & Other Income.	0	0	0	0	0	0	0
Capital Costs	13162	12459	12072	11827	11591	11254	10734
Abandonment Costs ..	0	0	0	0	0	0	0
Future Net Revenue .	969516	465339	326157	264829	219228	170209	118888

COMPANY SHARE

	1st Year	Average	Royalties	Oper Costs	FR After Roy&Oper	Capital Costs	Future NetRev
% Interest	100.0	100.0					
% of Future Revenue.			10.9	36.8	52.3	.7	51.6

PROFITABILITY

COMPANY SHARE BASIS	Before Tax
Rate of Return (%)	253.0
Profit Index (undisc.)	73.7
(disc. @ 10.0%) .	22.4
(disc. @ 5.0%) .	37.3
First Payout (years)	2.0
Total Payout (years)	2.0
Cost of Finding ($/BOE)	.66
NPV @ 10.0% ($/STB)	13.24
NPV @ 5.0% ($/STB)	23.27

Table 4b

EVALUATION OF: Asphalt Ridge, Utah - Prospect Low Estimate

ERGO v7.43 P2 ENERGY SOLUTIONS PAGE 1
GLOBAL : 03-APR-2012 5576
EFF:01-APR-2012 DISC:01-APR-2012 PROD:01-JAN-2013
RUN DATE: 4-APR-2012 TIME: 14:13
FILE: Outa2PL.DAX

WELL/LOCATION - Asphalt Ridge Oil Sands (Rim Rock & Duchesne River)
EVALUATED BY -
COMPANY EVALUATED - MCW Energy Group Ltd.
APPRAISAL FOR -
PROJECT - FORECAST PRICES & COSTS

UNIT FACTOR - 100.0000 %
TOTAL RESERVES - 13000 MSTB
PRODUCTION TO DATE - N/A
DECLINE INDICATOR - EXPONENTIAL
TOTAL CAPITAL COSTS - 13162 -M$-

INTEREST

AVG WI 100.0000%

ROYALTIES/TAXES

U.S.

Oil MSTB

Year	# of Wells	Price $/STB	Pool STB/D	Pool Vol	Company Share Gross	Company Share Net
2012	0	83.20	.0	0	0	0
2013	1	81.60	500.0	183	183	168
2014	1	80.00	1000.0	365	365	336
2015	1	80.00	2000.0	730	730	672
2016	1	81.60	2000.0	730	730	672
2017	1	81.60	2000.0	730	730	672
2018	1	83.23	2000.0	730	730	672
2019	1	84.90	2000.0	730	730	672
2020	1	86.59	2000.0	730	730	672
2021	1	88.33	2000.0	730	730	672
2022	1	90.10	2000.0	730	730	672
2023	1	91.90	2000.0	730	730	664
2024	1	93.74	1969.3	719	719	647
2025	1	95.61	1909.1	697	697	620
2026	1	97.52	1850.8	676	676	594
SUB				9209	9209	8402
REM				3791	3791	3317
TOT				13000	13000	11720

COMPANY SHARE FUTURE NET REVENUE

Year	Company Share Future Revenue (FR) Oil -M$-	SaleGas -M$-	Products -M$-	Total -M$-	Royalties State -M$-	Royalties Other -M$-	Wellhead Taxes Sev -M$-	Wellhead Taxes Ad-val -M$-	Oper Costs Fixed -M$-	Oper Costs Variabl -M$-	FR After Roy&Oper -M$-	Proc& Other Income -M$-	Capital Costs -M$-	Aband Costs -M$-	Future Net Revenue Undiscounted Annual -M$-	Undiscounted Cum -M$-	10.0% Annual -M$-	10.0% Cum -M$-
2012	0	0	0	0	0	0	0	0	0	0	0	0	1891	0	-1891	-1891	-1825	-1825
2013	14892	0	0	14892	1191	0	0	0	0	6337	7364	0	11271	0	-3907	-5798	-3467	-5292
2014	29200	0	0	29200	2336	0	0	0	0	12927	13937	0	0	0	13937	8139	11244	5952
2015	58400	0	0	58400	4672	0	0	0	0	26370	27358	0	0	0	27358	35497	20064	26016
2016	59568	0	0	59568	4765	0	0	0	0	26898	27905	0	0	0	27905	63402	18605	44620
2017	59568	0	0	59568	4765	0	0	0	0	27436	27367	0	0	0	27367	90769	16587	61208
2018	60759	0	0	60759	4861	0	0	0	0	27984	27914	0	0	0	27914	118683	15381	76589
2019	61974	0	0	61974	4958	0	0	0	0	28544	28472	0	0	0	28472	147156	14262	90851
2020	63212	0	0	63212	5057	0	0	0	0	29115	29040	0	0	0	29040	176196	13224	104075
2021	64479	0	0	64479	5158	0	0	0	0	29697	29624	0	0	0	29624	205820	12264	116339
2022	65770	0	0	65770	5262	0	0	0	0	30291	30217	0	0	0	30217	236037	11372	127711
2023	67084	0	0	67084	6038	0	0	0	0	30897	30150	0	0	0	30150	266187	10315	138026
2024	67377	0	0	67377	6738	0	0	0	0	31031	29608	0	0	0	29608	295795	9209	147235
2025	66623	0	0	66623	7329	0	0	0	0	30685	28610	0	0	0	28610	324405	8089	155324
2026	65879	0	0	65879	7906	0	0	0	0	30342	27632	0	0	0	27632	352037	7103	162427
SUB	804786	0	0	804786	71035	0	0	0	0	368552	365199	0	13162	0	352037		162427	
REM	377131	0	0	377131	47141	0	0	0	0	173693	156296	0	0	0	156296		29065	
TOT	1181917	0	0	1181917	118177	0	0	0	0	542246	521495	0	13162	0	508333		191491	

NET PRESENT VALUE (-M$-)

Discount Rate	.0%	5.0%	8.0%	10.0%	12.0%	15.0%	20.0%
FR After Roy & Oper.	521495	312056	239117	203318	174803	141975	104744
Proc & Other Income.	0	0	0	0	0	0	0
Capital Costs	13162	12459	12072	11827	11591	11254	10734
Abandonment Costs ..	0	0	0	0	0	0	0
Future Net Revenue .	508333	299596	227045	191491	163212	130721	94010

COMPANY SHARE

	1st Year	Average	Royalties	Oper Costs	FR After Roy&Oper	Capital Costs	Future NetRev
% Interest	100.0	100.0					
% of Future Revenue.			10.0	45.9	44.1	1.1	43.0

PROFITABILITY

COMPANY SHARE BASIS	Before Tax
Rate of Return (%)	205.5
Profit Index (undisc.)	38.6
(disc. @ 10.0%) .	16.2
(disc. @ 5.0%) .	24.0
First Payout (years)	2.2
Total Payout (years)	2.2
Cost of Finding ($/BOE)	1.01
NPV @ 10.0% ($/STB)	14.73
NPV @ 5.0% ($/STB)	23.05

Table 4c

EVALUATION OF: Asphalt Ridge, Utah - Prospect High Estimate

ERGO v7.43 P2 ENERGY SOLUTIONS PAGE 1
GLOBAL : 03-APR-2012 5576
EFF:01-APR-2012 DISC:01-APR-2012 PROD:01-JAN-2013
RUN DATE: 4-APR-2012 TIME: 14:13
FILE: Outa3PH.DAX

WELL/LOCATION - Asphalt Ridge Oil Sands (Rim Rock & Duchesne River)
EVALUATED BY -
COMPANY EVALUATED - MCW Energy Group Ltd.
APPRAISAL FOR -
PROJECT - FORECAST PRICES & COSTS

UNIT FACTOR - 100.0000 %
TOTAL RESERVES - 30000 MSTB
PRODUCTION TO DATE - N/A
DECLINE INDICATOR - EXPONENTIAL
TOTAL CAPITAL COSTS - 13162 -M$-

INTEREST

AVG WI 100.0000%

ROYALTIES/TAXES

U.S.

Oil MSTB

Year	# of Wells	Price $/STB	Pool STB/D	Pool Vol	Company Share Gross	Company Share Net
2012	0	83.20	.0	0	0	0
2013	1	81.60	500.0	183	183	168
2014	1	80.00	1000.0	365	365	336
2015	1	80.00	2000.0	730	730	672
2016	1	81.60	2000.0	730	730	672
2017	1	81.60	2000.0	730	730	672
2018	1	83.23	2000.0	730	730	672
2019	1	84.90	2000.0	730	730	672
2020	1	86.59	2000.0	730	730	672
2021	1	88.33	2000.0	730	730	672
2022	1	90.10	2000.0	730	730	672
2023	1	91.90	2000.0	730	730	664
2024	1	93.74	1992.0	727	727	654
2025	1	95.61	1976.2	721	721	642
2026	1	97.52	1960.5	716	716	630
SUB				9282	9282	8467
REM				20718	20718	18129
TOT				30000	30000	26596

COMPANY SHARE FUTURE NET REVENUE

Year	Company Share Future Revenue (FR) Oil -M$-	SaleGas -M$-	Products -M$-	Total -M$-	Royalties State -M$-	Royalties Other -M$-	Wellhead Taxes Sev -M$-	Wellhead Taxes Ad-val -M$-	Oper Costs Fixed -M$-	Oper Costs Variabl -M$-	FR After Roy&Oper -M$-	Proc& Other Income -M$-	Capital Costs -M$-	Aband Costs -M$-	Future Net Revenue Undiscounted Annual -M$-	Undiscounted Cum -M$-	10.0% Annual -M$-	10.0% Cum -M$-
2012	0	0	0	0	0	0	0	0	0	0	0	0	1891	0	-1891	-1891	-1825	-1825
2013	14892	0	0	14892	1191	0	0	0	0	4563	9138	0	11271	0	-2133	-4024	-1893	-3717
2014	29200	0	0	29200	2336	0	0	0	0	9308	17556	0	0	0	17556	13532	14163	10446
2015	58400	0	0	58400	4672	0	0	0	0	18987	34741	0	0	0	34741	48273	25478	35924
2016	59568	0	0	59568	4765	0	0	0	0	19367	35435	0	0	0	35435	83708	23625	59549
2017	59568	0	0	59568	4765	0	0	0	0	19755	35048	0	0	0	35048	118756	21243	80792
2018	60759	0	0	60759	4861	0	0	0	0	20150	35749	0	0	0	35749	154505	19698	100490
2019	61974	0	0	61974	4958	0	0	0	0	20553	36464	0	0	0	36464	190969	18265	118755
2020	63212	0	0	63212	5057	0	0	0	0	20964	37192	0	0	0	37192	228160	16936	135691
2021	64479	0	0	64479	5158	0	0	0	0	21383	37938	0	0	0	37938	266098	15706	151396
2022	65770	0	0	65770	5262	0	0	0	0	21811	38698	0	0	0	38698	304796	14564	165960
2023	67084	0	0	67084	6038	0	0	0	0	22247	38800	0	0	0	38800	343596	13275	179234
2024	68155	0	0	68155	6816	0	0	0	0	22602	38738	0	0	0	38738	382334	12049	191283
2025	68964	0	0	68964	7586	0	0	0	0	22870	38508	0	0	0	38508	420841	10888	202171
2026	69784	0	0	69784	8374	0	0	0	0	23143	38268	0	0	0	38268	459109	9837	212008
SUB	811811	0	0	811811	71839	0	0	0	0	267700	472272	0	13162	0	459109		212008	
REM	2060910	0	0	2060910	257614	0	0	0	0	683446	1119851	0	0	0	1119851		88370	
TOT	2872721	0	0	2872721	329453	0	0	0	0	951146	1592122	0	13162	0	1578960		300378	

NET PRESENT VALUE (-M$-)

Discount Rate	.0%	5.0%	8.0%	10.0%	12.0%	15.0%	20.0%
FR After Roy & Oper.	1592122	597085	392858	312204	255616	197618	139386
Proc & Other Income.	0	0	0	0	0	0	0
Capital Costs	13162	12459	12072	11827	11591	11254	10734
Abandonment Costs ..	0	0	0	0	0	0	0
Future Net Revenue .	1578960	584626	380786	300378	244026	186363	128652

COMPANY SHARE

	1st Year	Average	Royalties	Oper Costs	FR After Roy&Oper	Capital Costs	Future NetRev
% Interest	100.0	100.0					
% of Future Revenue.			11.5	33.1	55.4	.5	55.0

PROFITABILITY

COMPANY SHARE BASIS	Before Tax
Rate of Return (%)	273.1
Profit Index (undisc.)	120.0
(disc. @ 10.0%) .	25.4
(disc. @ 5.0%) .	46.9
First Payout (years)	2.0
Total Payout (years)	2.0
Cost of Finding ($/BOE)	.44
NPV @ 10.0% ($/STB)	10.01
NPV @ 5.0% ($/STB)	19.49

Figure 3

MCW Energy Group Ltd.
Asphalt Ridge Oil Sands, Uintah County, Utah, USA
Prospect Analysis (Arithmetic Average)

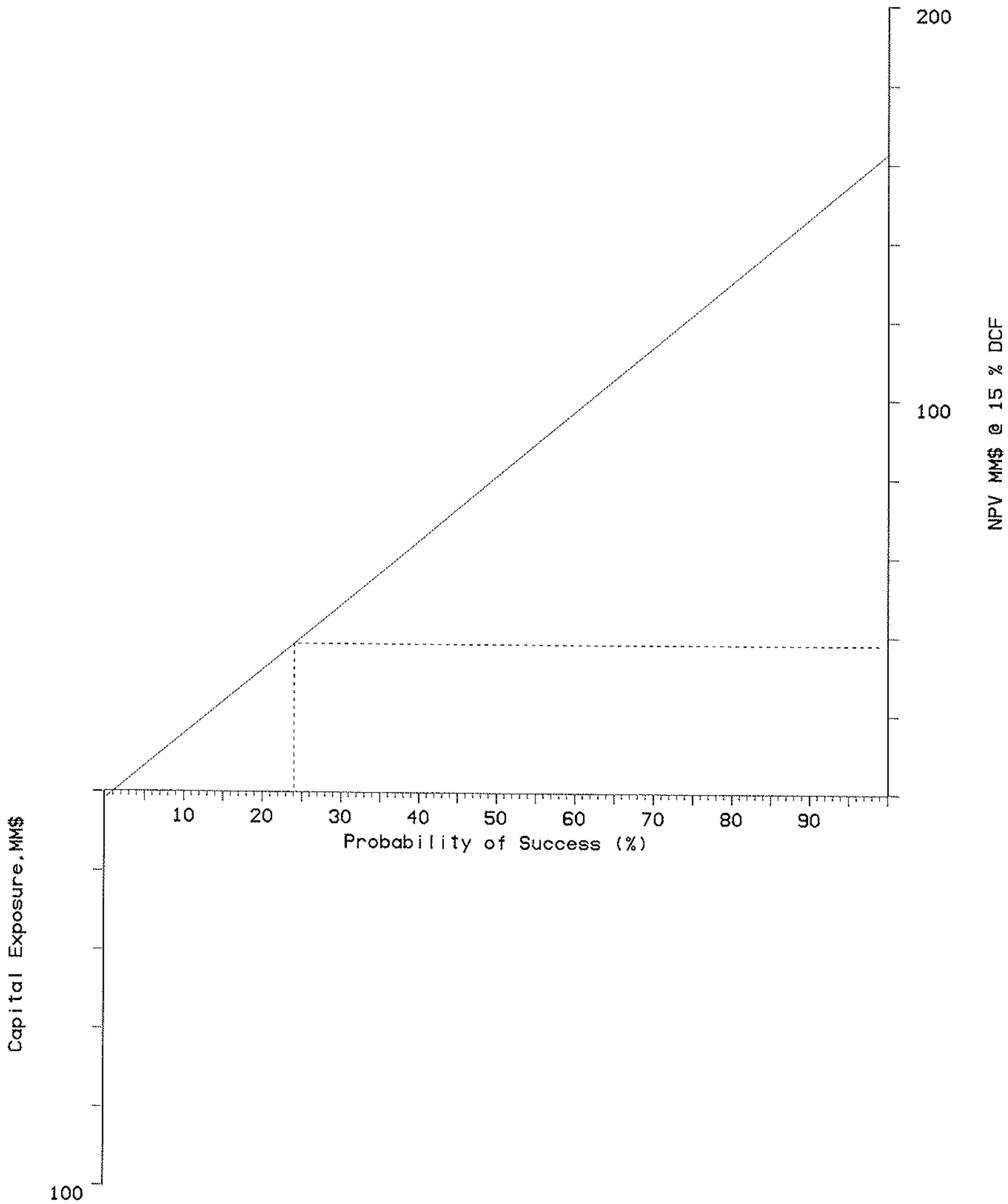


Figure 3
(cont'd)

MCW Energy Group Ltd.
Asphalt Ridge Oil Sands,Uintah County,Utah,USA
Prospect Analysis (Arithmetic Average)

ECONOMIC PARAMETERS

Net Capital Exposure, M$	**1,866**
Risk Components, POS	%
Source	100
Reservoir	60
Trap/Seal	100
Timing/Migration	100
Geological Success	**60**
Commerciality Factor	40
Commercial Success	**24**

TOTAL VALUES

Discount Rate, %	undisc.	5	10	15	20
Unrisked Value, M$	1,018,936	449,854	252,233	162,431	113,850
Risked Value, M$	243,126	106,546	59,117	37,565	25,906
Minimum Prob. of Success Req'd, %	0.2	0.4	0.7	1.1	1.6