COMPETENT PERSONS REPORT OF

CONTINGENT AND PROSPECTIVE RESOURCES

AS OF

MAY 1, 2013

ATTRIBUTABLE TO CERTAIN INTERESTS

OWNED BY

MAJOR OIL INTERNATIONAL, LLC

IN CERTAIN PROPERTIES

LOCATED IN

HOT CREEK VALLEY

NYE COUNTY, NEVADA, USA

FORREST A. GARB & ASSOCIATES, INC.
INTERNATIONAL PETROLEUM CONSULTANTS

FORREST A. GARB & ASSOCIATES, INC.

INTERNATIONAL PETROLEUM CONSULTANTS
5310 HARVEST HILL ROAD, SUITE 275
DALLAS, TEXAS 75230 - 5805
(972) 788-1110 Telefax 991-3160
E-Mail: forgarb@forgarb.com

May 22, 2013

Mr. Brian McDonnell
Chief Executive Officer
Major Oil International, LLC
1208 W. Drew Street
Houston, TX 77006

Re: Competent Persons Report (CPR) Relating to the Exploration Project in Major Oil International, LLC's Area of Interest in Hot Creek Valley, Nye County, Nevada.

Dear Mr. McDonnell:

At the request of Major Oil International, LLC (Major Oil), Forrest A. Garb & Associates, Inc. (FGA) has prepared an independent, third-party assessment of the exploration project in Hot Creek Valley, Nye County, Nevada following the drilling of the Eblana #1 exploratory well. The Eblana #1 well drilled through the Tertiary Volcanics formation, but did not penetrate the Paleozoic dolomites which are prospective in this area. The objective of this assessment is to update the resource categorization, hydrocarbon volume estimates, and financial model, and make recommendations for future exploration of this Hot Creek Valley concession incorporating the results from the Eblana #1.

FGA reviewed mud logs, cased-hole logs, drilling reports, flow test data, lab testing results from the Eblana #1, and 3-D geologic modeling provided by Major Oil, along with information FGA found in the public domain. Major Oil also provided FGA with a technical report detailing their assessment of the well results, hydrocarbon estimates, and financial model.

Estimates of the hydrocarbon resources in the nine license block area (the prospect), Hot Creek Valley, Nye County, Nevada, USA are presented. Major Oil represents that it currently owns 100 percent working interest in the prospect under the terms of the exploration and production licenses issued. Major Oil holds leases in their original lease area (core area) covering approximately 20 square kilometers (sq km) and has subsequently added 68 sq km surrounding the core area. Major Oil intends to proceed with the exploration, development, and production of any commercially viable discovered hydrocarbons. Based on these representations and the results of the Eblana #1 well, FGA's evaluation includes estimated quantities of contingent resources and prospective resources in the Tertiary Volcanics covering the entire lease area. The prospective resources in the Paleozoic dolomites have not been updated in this study, but are re-stated from the previous report titled "Competent Persons Report of Prospective Resources as of January 31, 2012 Attributable to Certain Interests Owned by Major Oil International, LLC in Certain Properties Located in Hot Creek Valley, Nye County, Nevada, USA", dated February 20, 2012. The prospective resources for the Paleozoic dolomites cover only the original core area of 20 sq km. The net resource estimates are summarized in Tables 1 and 2. Net hydrocarbon volumes are net of royalties. For more detail, please refer to Tables 7 through 11.

The estimated net contingent and prospective resources in the Tertiary Volcanics formation, as of May 1, 2013, are presented in Table 1 below:

TABLE 1 – TERTIARY VOLCANICS

	Estimated Net Resources[1] (MBbl)[2]		
Resource Category	Low Estimate (P90)	Best Estimate (P50)	High Estimate (P10)
Eblana #1 Area			
Contingent			
Recoverable Oil	**8,686**	**19,256**	**33,513**
OOIP[3]	**45,301**	**107,344**	**165,286**
20 sq km Core Area Prospective[4]			
Recoverable Oil	**11,873**	**20,189**	**45,049**
OOIP[3]	**61,120**	**132,060**	**222,919**
Total Prospective[4] 88 sq km area Prospective[4]			
Recoverable Oil	**20,138**	**57,200**	**683,646**
OOIP[3]	**102,342**	**282,818**	**3,342,163**

The estimated net prospective resources in the Paleozoic dolomite formation in the original core area, as of May 1, 2013, are presented in Table 2 below:

TABLE 2 – PALEOZOIC DOLOMITES

	Estimated Net Resources[1] (MBbl)[2]		
Resource Category	Low Estimate (P90)	Best Estimate (P50)	High Estimate (P10)
Prospective[4]			
Recoverable Oil	**9,000**	**22,000**	**39,000**
OOIP[3]	**34,000**	**68,000**	**121,000**

In preparing this report FGA has relied upon, without independent verification, information furnished by or on behalf of Major Oil. This information included the property interests to be evaluated, subsurface data as it pertains to the target objectives and prospects, and various other information and technical data. All data were accepted as represented. Geologic review and estimates of the contingent and prospective hydrocarbons are based on data available as of May 1, 2013. Any distribution of this report or any part thereof must include this letter and the General Comments in their entirety.

[1] The definitions for all reserves incorporated in this study have been set forth in this report. Net hydrocarbons are net of royalties.
[2] MBbl thousands of barrels.
[3] OOIP = Original-oil-in-place.
[4] Probabilistic aggregation of Prospective Resources in multiple areas, not arithmetic summation.

Oil was tested in non-commercial quantities in the Eblana #1 well with consistent flow having a one to four percent oil cut, which may indicate an oil-water transition zone. It is also possible, but not as likely, that this area is a swept zone with no oil column updip. It is FGA's opinion that the area updip to the Eblana #1 well meets the Petroleum Resources Management System (SPE-PRMS) criteria of Contingent Resources, and the remaining quantities are categorized as Prospective Resources. As such, reserves cannot be assigned at this time; however, volumes of contingent and prospective resources were estimated by FGA. Furthermore, FGA opines that the drilling of a successful updip well is needed to transition the contingent resources into the reserves category. Success is contingent on 1) being able to get updip sufficiently in the area of the Eblana #1 to find the oil column, 2) having the presence of a trap and seal, and 3) finding primarily oil, rather than gas.

Information Reviewed for this Assessment

Various Reports and other confidential documents provided by Major Oil, including those described below:

- Kaya and Akrawi, 2013. Reserves Estimation Report Hot Creek Valley Discover Field, Nevada (Drafts April 15th, April 20th, and May 5th).
- Eblana #1 Daily Reports, Flow Test Data, and other technical data.
- Eblana #1 – Logs Listed Below
    - Lithology Strip Log (800 ft – 8,550 ft)
    - Mudlog ((950 ft – 8,550 ft)
    - RPM Pulsed Neutron Effective Porosity Log (1,000 ft – 8,000 ft)
    - RPM Provisional Gasview Saturation Analysis (4,000 ft – 8,290 ft)
    - RPM Carbon Oxygen Analysis (6,282 ft 6,310 ft; 6,361 ft 6,391 ft; 7,152 ft 7,250 ft; 7,440 ft – 7,500 ft)
- Gibson Consulting, 2009. Competent Persons Report, Gravity and Magnetics data.
- Geotech.org, 2011. Various reports regarding geochemical analogs and analysis of Hot Creek Valley.
- Richers, 2011. Competent Persons Report and update regarding 2-D seismic in Hot Creek Valley.
- Akrawi & Campagna, 2011. Various reports regarding passive seismic analogs and analysis of Hot Creek Valley.
- Probablisitic model and output provided by Major Oil.
- Major Oil financial model dated April 23, 2013.
- Various other Geophysical, geochemical, and Geological analogs and analyses of Hot Creek Valley.
- Publically available data regarding the Geology and oil production in Nevada.
- Publically available production data on analog wells in Railroad Valley.
- Actual drilling capital costs on the Eblana #1 well, including drill, complete and flow test.
- US Bureau of Land Management lease documents.
- Professional profile listing of the Major Oil technical team.

Activities and Prospect Area

Major Oil has drilled the Eblana #1 through the Tertiary Volcanics interval in an area previously identified as prospective for hydrocarbon production in Hot Creek Valley, Nye County, Nevada *(see Figure 1)*. This area is situated approximately six miles south of the Apache #24-13 (Permit #302, API # 27-023-05294), which was drilled in 1981 and abandoned. The nearest production is approximately 35 miles to the east in the adjacent Railroad Valley.

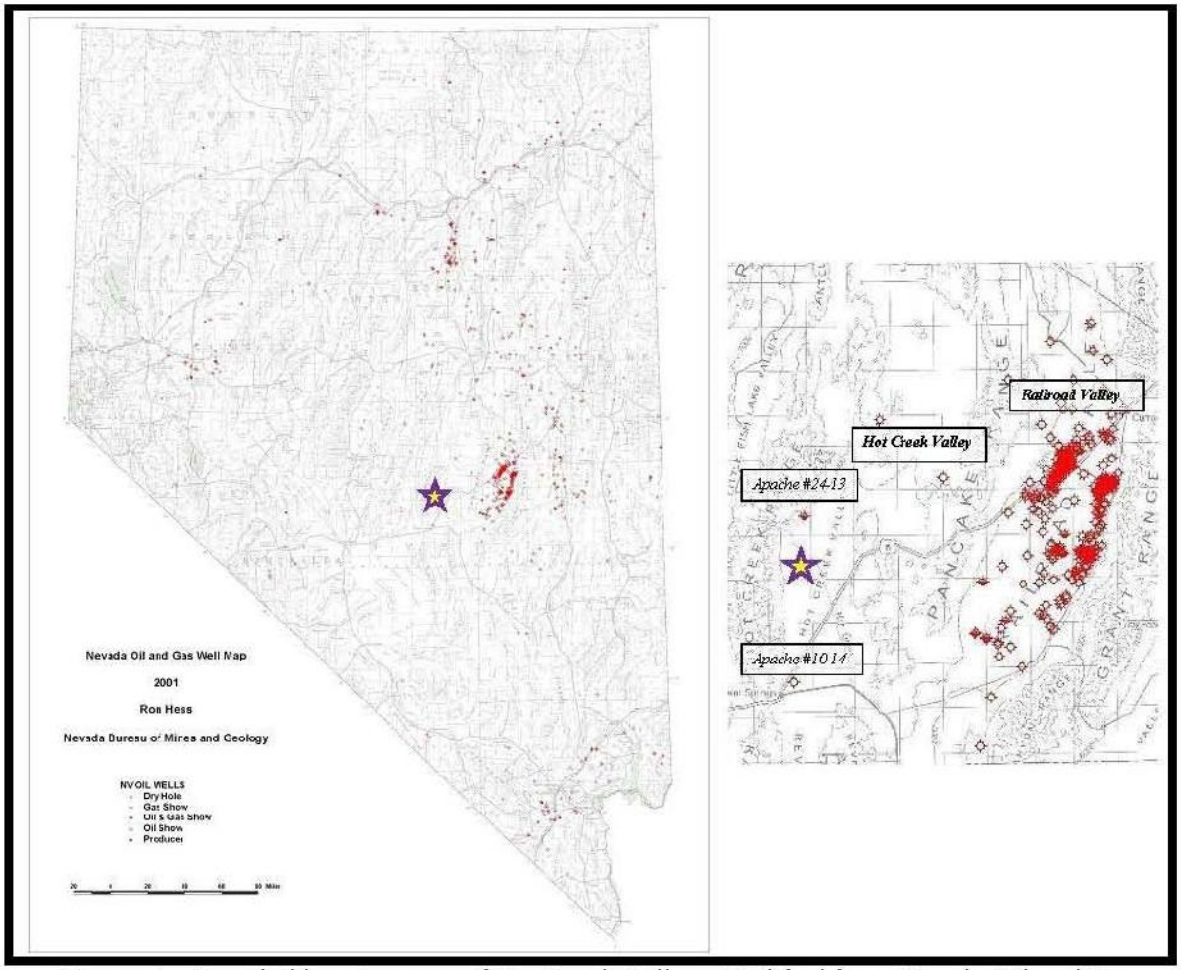


Figure 1. *Detailed location map of Hot Creek Valley. Modified from Nevada Oil and Gas Board, 2001. Note the stars, indicating Major Oil's approximate area of interest.*

Petroleum Exploration and Production in Nevada

According to the Nevada Bureau of Mining and Geology, Nevada's first exploratory well resulted in a dry hole near Reno in 1907. Few wells were drilled in Nevada from 1907 to 1954, when Shell drilled and completed the Eagle Springs #1-35 in Railroad Valley in 1954. This well became the state's first commercial producer, with initial estimates of 4 million barrels (MMBbl) of recoverable reserves. In 1976, the Trap Springs #1 became the second discovery resulting in commercial oil production, also in Railroad Valley. Later discoveries in Railroad Valley include the Eagle Springs, Bacon Flat, and Grant Springs Fields.

Production outside of Railroad Valley was established in 1982 when Amoco discovered the Blackburn field, in Pine Valley, Eureka County about 120 miles north of the nearest

production in Railroad Valley. Prior to Major Oil drilling the Eblana #1, the most recent discovery was in 1986, when Marathon drilled the Kate Spring #1, in Railroad Valley. This well had an initial flowing potential of 345 BOPD and 1,371 BWPD, and produced about 1,500 barrels of oil before being shut in due to engineering problems and the low price of oil. Oil in these fields is in the 22 to 27 deg API range.

The most recent indication of oil in Nevada is found in Major Oil's Eblana #1, drilled in Hot Creek Valley approximately 35 miles east of the nearest production in Railroad Valley. The Eblana #1 was drilled to 8,500 feet, encountering formations similar to the producing formations in Railroad Valley, with gas shows, and non-commercial higher quality oil ranging between 28.5 deg API and 33 deg API.

Geologic Overview

Geologically, most of the state of Nevada is in the Great Basin; an area dominated by basin and range topography. *(See Figure 2).*

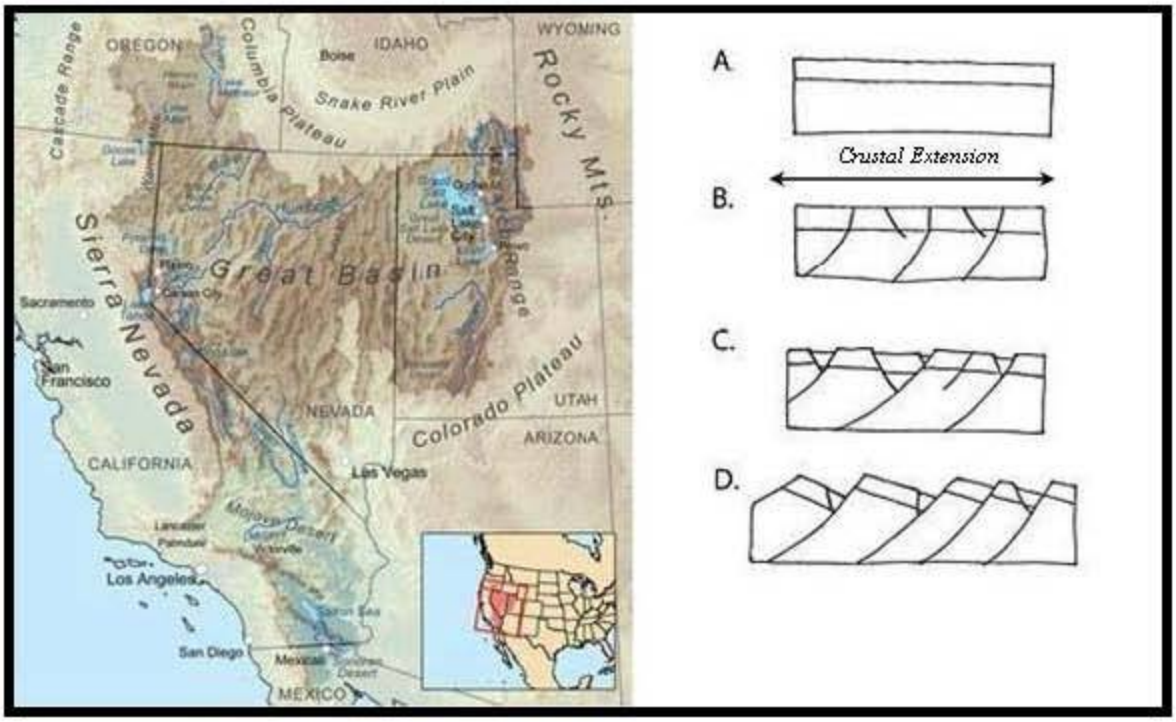


Figure 2. *On the left is a map of the Great Basin, which includes most of Nevada. On the right is a sequence of schematic diagrams showing the formation of the basin and range topography, caused by normal faulting due to crustal extension. (Source unknown.)*

Analog production in the Railroad Valley is from a series of Tertiary-age welded volcanic tuffs, which are found in the Apache #24-13 well just to the north, and are interpreted on the 2-D seismic and passive seismic covering Major Oil's core area of interest. Additional production from Railroad Valley is from Paleozoic-age dolomites. The Eblana #1 well encountered similar welded volcanic tuffs and conglomerates, which had oil shows. However the Eblana #1 did not reach the Paleozoic dolomites, which are productive in the Railroad Valley.

Structure and Stratigraphy of Hot Creek Valley

Most of Nevada, including Hot Creek Valley and Railroad Valley, is dominated by basin and range topography. This structural environment is characterized by a series of roughly parallel valleys or basins, which are each bound by one or more normal faults, often meeting at a basal detachment fault *(see Figure 2)*. The basins are downthrown blocks while the ranges are relatively upthrown. Sediments deposited in these basins can provide the components necessary for conventional hydrocarbon reservoirs. Included in these basins are depositional centers (depocenters), with thicker sediments than the surrounding area.

The basin and range topography in Hot Creek Valley and Railroad Valley are reflected as series of roughly N-S parallel valleys, bound by normal faults. Structural influences from the underlying Northern Nevada Rift are evident as basaltic andesite outcrops in the nearby Railroad Valley and structural lineaments found in magnetic and gravity data. Often times, these datasets agree with each other, and when combined with surface geology, give a clear indication of the geological significance of these features. These lineaments tend to influence production in the area. Not all faults in the Great Basin are seen on the surface, and oil reservoirs in the area are often compartmentalized by faulting or other geologic features *(Walker, 2010)*. Additional faulting not related to basin and range topography is also found. These faults often do not reach the surface, and can also influence hydrocarbon production.

In eastern Nevada, the most important source rock is the Chainman formation, deposited in the Mississippian approximately 325 million years ago. This formation outcrops to the east of Hot Creek Valley, in the Pancake Range. To the west of Hot Creek Valley, in the Hot Creek Range, the Chainman's stratigraphic equivalent, the Eleana formation, outcrops as well. Based on these outcrops, the Chainman formation is presumed to be present in Hot Creek Valley. Another potential source rock, the Eocene-age Sheep Pass, is not mentioned in the Apache #24-13 well or the Apache #10-14 well (Permit #310, approximately 10 miles to the south-southwest). The Sheep Pass is not evident in the Eblana #1, likely due to drilling problems which prevented openhole logs from being run and cores from being collected. However, if found, the high temperature gradient in Hot Creek Valley could place it in the oil generation window and provide another source of hydrocarbons.

Post Tertiary uplift created anticline and syncline structures in Hot Creek Valley. Many of these anticlinal features exposed the Chainman formation to erosion. Thus, the Chainman may not be present on top of these features. Due to this, Walker postulates that the eastern side of Major Oil's lease block contains source rock, while in the western side the source rock is likely thinner or absent *(Walker, 2010)*.

Migration paths would include permeability through some of the rocks in the area, as well as faults and fractures. Hydrocarbons migrating through these pathways could find several traps, most likely due to faulting, and seals to prevent hydrocarbons from continuing to migrate – resulting in economic hydrocarbon accumulation. Timing is best determined by drilling a well, but the nearby production in Railroad Valley along with the presence of oil and gas shows in the Apache #24-13 and the Eblana #1 wells provide evidence supporting the presence of hydrocarbons in Hot Creek Valley.

Further east from Major Oil's lease block, Hot Creek Valley is dominated by four large calderas, which represent ancient volcanoes. These volcanoes were active from approximately

25 to 32 million years ago, in the Tertiary–Oligocene ages after the Chainman formation was deposited. The heat from these volcanoes could have destroyed potential hydrocarbon generation from these source rocks which were in direct contact with the lava. However, further away, heat from these volcanoes could have sufficiently altered source rock to generate hydrocarbons in other valley fill sediments, if any are present as found in Railroad Valley. There is little indication of production in these sediments in the Apache #24-13, the Eblana #1, or the Apache #10-14 wells.

Exploration Methodology

Major Oil used a rigorous process to identify possible oil and gas accumulations in Hot Creek Valley. By starting regionally and then focusing on areas where geologic, magnetic, and gravity data indicate possible productivity, Major Oil interpreted geochemical and 2-D seismic data to further explore for hydrocarbons. Passive seismic was used to grade areas with the highest potential. Independent consultants provided Major Oil with specific expertise relevant to this area and relative to the technology. Major Oil chose to have these studies performed by independent consultants without knowledge of the leased area, to ensure the results were independent and credible. Where appropriate, statistical analysis of neighboring areas was employed to estimate depths and resources.

Each type of data is reviewed and interpreted as part of a total exploration package, and no single analysis is taken as the basis for drilling a well. However, if the studies agree, then drilling a well can be justified. At the conclusion of each phase, the decision was made to either terminate or proceed with the project. The proposal in Hot Creek Valley has survived this process, and Major Oil has tested this prospect by drilling the Eblana #1.

Geology and Production Analogs

The nearest geologic and production analog to Hot Creek Valley is the Railroad Valley, the next valley to the east, which has ten productive oil fields. These fields all possess the source, trap, and seal components critical to hydrocarbon accumulation. Hydrocarbon accumulations and field orientations in Railroad Valley have proven to be directly related to lineaments found in magnetic and gravity data. Depths on 2-D seismic were estimated from both Railroad Valley and the nearby Apache #24-13 well. In order to tie the existing and any future seismic lines to the wells, future plans include running a Vertical Seismic Profile in the Eblana #1. Passive seismic anomalies over Railroad Valley production appear similar to those in Hot Creek Valley. Passive seismic near the Apache #24-13 well coupled with mud log shows, seem to indicate it is in the transitional zone, at the western edge of a reservoir.

Satellite Imagery and Surface Geology

Satellite Imagery is often used to help with the surface geology. Major Oil found it useful in identifying the lineaments found in gravity and magnetic data, and to determine vegetation patterns, which lead to areas where geochemical analysis could be useful in prospecting for hydrocarbons in Hot Creek Valley.

Magnetic and Gravity Data and Analysis

In the Great Basin, lineaments found on publicly available magnetic and gravity data often define geologic features which can influence oil and gas production. Maps indicate that Railroad Valley features one such lineament defined as the Northern Nevada Rift. These lineaments appear to influence production as experienced in the Trap Spring and Grant Canyon oil fields. However, not all oil and gas production is directly offsetting these lineaments. Hot Creek Valley lies between the Northern Nevada Rift and an unnamed lineament to the west. When magnetic and gravity data are integrated with surface geology, the result is an excellent tool for determining regional geology, identifying important geologic features, and isolating areas that could be hydrocarbon productive. The Gibson 2009 report contains an analysis of Hot Creek Valley which integrates magnetic and gravity data with surface geology. Major Oil's area of interest has been mapped showing the lineaments, depocenters, and surface faults (see Figure 3).

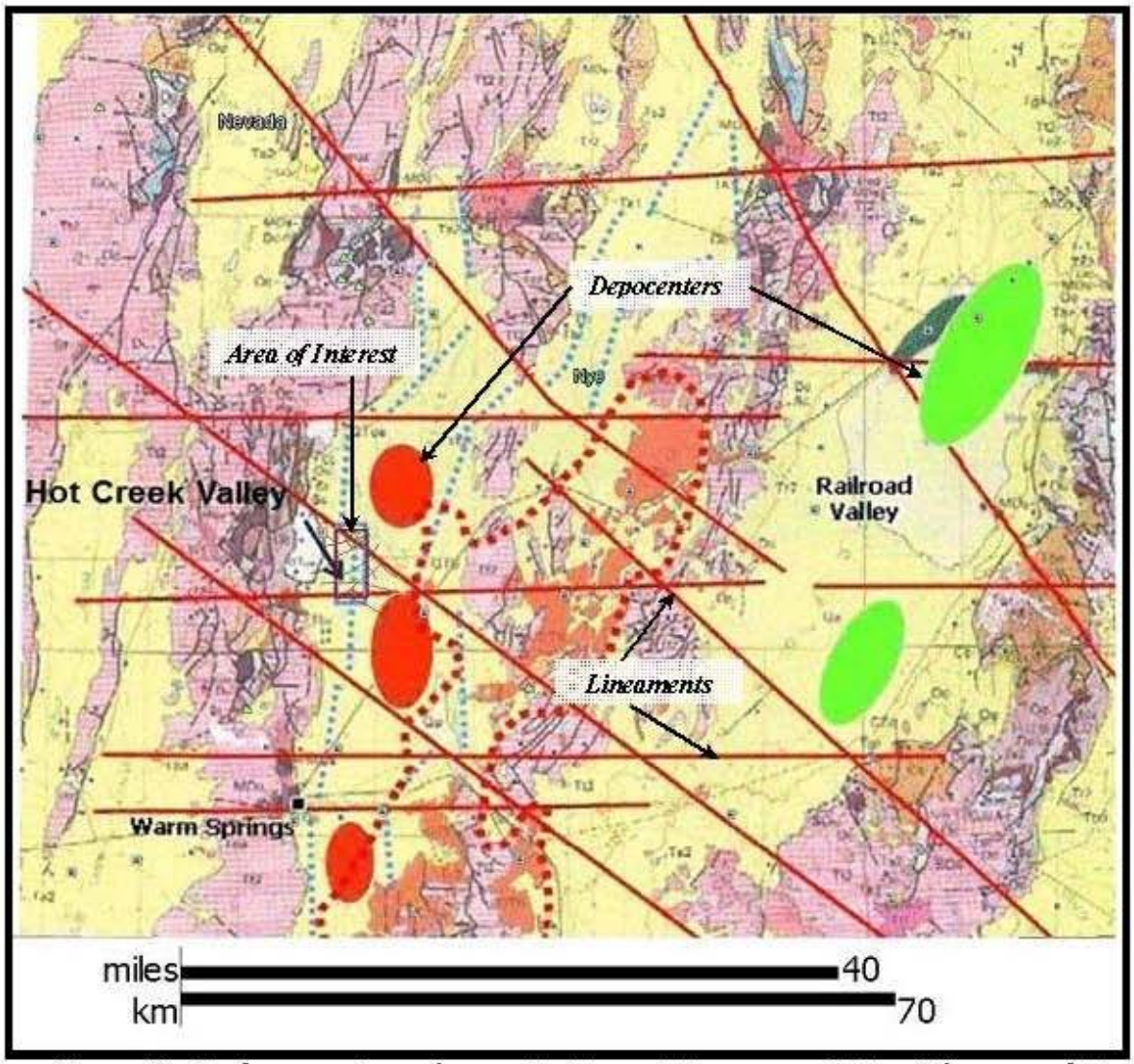


Figure 3. *Surface, gravity, and magnetic interpretations across Major Oil's area of interest. Note the lineaments and depocenters. Black lines in the area of interest represent surface faults. Other gravity maps reveal sediment thicknesses in Hot Creek Valley to be similar to the sediment thicknesses in Railroad Valley, and Major Oil lineaments in the area. Source, Major Oil, date unknown.*

Lineaments found in magnetic and gravity data analysis can often be correlated with surface geology. These lineaments have been shown to affect the presence and nature of hydrocarbon accumulations in Railroad Valley. Gibson Consulting interpreted and integrated these sets of data, determined the nature of lineaments in the Hot Creek Valley area, and how they may affect hydrocarbon accumulation based on the Railroad Valley analog. Gravity and magnetic lineaments can represent either structural or stratigraphic events. Structurally, they can represent faults, fracture zones, or folding. Stratigraphically, they can represent facies or thickness changes, or pinchouts of porous formations. Integrating surface geology helps determine the nature of a lineament and how it could affect hydrocarbon accumulation *(Gibson, 2009)*.

Gravity data are also used to help define the relative depth of sediments and identify structural features which can influence hydrocarbon accumulation. Together with magnetic data, weaknesses such as spacing and data quality can be addressed. Like magnetic data, gravity data are publically available and represent a good regional tool for identifying areas which could be hydrocarbon productive.

Typically in basin and range provinces, each valley undergoes sedimentary deposition, where elements such as source rocks, reservoir rocks, and seals critical to hydrocarbon accumulation can be found. Gravity data indicate that sediment thicknesses in Hot Creek Valley and Railroad Valley are similar *(Gibson, 2009)*. Lineaments in gravity and magnetic data segment both Hot Creek Valley and Railroad Valley, and have been shown to influence oil production in Railroad Valley.

Geochemical Data and Analysis

Theoretically, hydrocarbons can migrate to the earth's surface through micro-seeps. Satellite Imagery can reveal areas where vegetation may indicate micro-seeps occurring as areas with less vegetation relative to the surrounding landscape. Geochemical analysis of those areas can help determine if these micro-seepages occur.

Major Oil contracted with Geotech to provide a geochemical analog study of Railroad Valley, and apply that analog to the Hot Creek Valley. Interference from producing activities in areas such as Railroad Valley could alter geochemical analysis in the immediate area. Geochemical surveys and analyses included uncontaminated soil samples in producing areas.

These resulting studies revealed several anomalous areas in Major Oil's area of interest in Hot Creek Valley *(see Figure 4)*. The area around the Eblana #1 location shows consistency through the different types of studies. Dashed lines on this map represent surface faults. All areas are coincident with the regional geology determined by gravity, magnetic, and surface data. The area analyzed by passive seismic lies within the original 20 sq km lease area and the vast majority of the area analyzed by Gravity, Magnetic, and Geochemical data lie within Major Oil's current 88 sq km lease area.

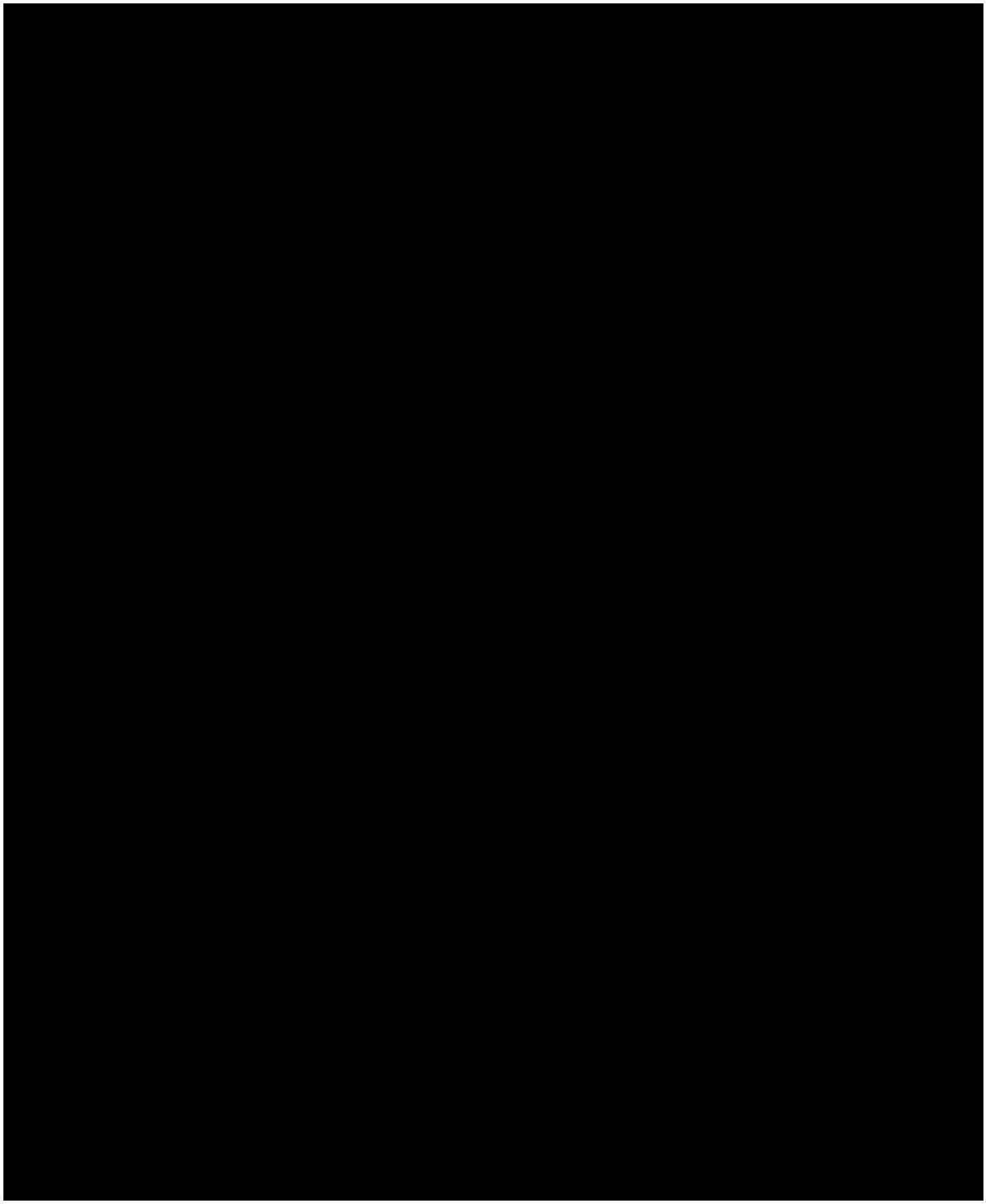


Figure 4. *Geochemical anomalies in Major Oil's 20 sq km area. (Geotech, 2011). Note the dashed lines representing surface faults.*

Seismic Data and Analysis

2-D seismic lines were shot in or near Major Oil's area of interest *(see Figure 5)*. Data from the lines are marginal, due in part to surface and geologic conditions. The older seismic line to the north (EC-APC-HC 79-4) was gathered using primacord as a source of energy. The newer line to the south (EC-APC-HC 80-10) used vibraseis as an energy source, and has better data quality *(Richers, 2010)*. Depths to markers and reflective formations were estimated from the Apache #24-13 well, but there is no direct tie-in to these seismic lines. To determine structure and better define potential traps, Major Oil plans to run a Vertical Seismic Profile (VSP) log in the Eblana #1 well to tie into the current seismic lines and a planned 2-D seismic survey in the area.

Figure 5. *White lines indicating 2-D seismic lines over Major Oil's area of interest. Well spot Eb-1 is located on shot point #160. Red polygons indicate potential pools. Red rectangle denotes original 20 sq km lease area. Yellow outline indicates current 88 sq km lease area. Source, Major Oil (2013).*

The subsurface structure shows a series of faults typical of a basin and range province, and what appears to be continuity of the producing welded tuffs found in Railroad Valley. The western side appears to be buried deeper than the eastern side. Targets identified with the seismic interpretation are coincident with a passive seismic and geochemical Anomaly. Several other possible targets for hydrocarbons have been identified in Major Oil's area of interest at depths similar to the production in Railroad Valley.

Passive Seismic Spectroscopy Data

Surface passive seismic records and spectroscopy analyzes the low frequency acoustic/seismic background noise between 0.5 – 8 Hz. Theoretically, this signal is actively emitted by the earth's movement found mainly on top of hydrocarbon reservoirs. Survey measurements are filtered and processed, and analysis is calibrated with geological and well data, and integrated with other geophysical data. Passive seismic has been used in other areas of the world to help select optimal prospect locations and reduce exploration risk.

Two Passive Seismic Spectroscopy Data (PSSD) surveys were used by Major Oil to high grade locations. PSSD has been reportedly successful in other areas of the world to directly indicate hydrocarbons and to help understand how hydrocarbons flow through a reservoir. In the past, other hydrocarbon indicators from 3-D seismic have been affected by differing geologic conditions, and it is possible that passive seismic can be affected in the same way.

Before PSSD was run over Major Oil's acreage, it was run over Grant Canyon and Hot Springs fields in Railroad Valley as well as near the Apache #24-13 well, in an attempt to calibrate PSSD to eastern Nevada. Producing activities in Railroad Valley may have an effect on PSSD analysis. PSSD indicates hydrocarbons near the Apache #24-13 well to the north, placing that well on the western edge of a prospective reservoir. PSSD analysis also indicates the potential for hydrocarbons on the eastern side of Major Oil's area of interest, coincident with the 2-D seismic and geochemical analysis *(see Figure 6)*. Other analysis places these targets coincident with surface lineament analysis *(Richers, 20011)*.

Major Oil's use of passive seismic is the first attempt to calibrate and use passive seismic as an exploration tool in Nevada. The Eblana #1 well found oil and gas coincident with the passive seismic anomaly found in two passive seismic runs over Major Oil's area of interest. However, further updip drilling is required to determine the commerciality of the resource defined by this anomaly.

FGA opines that results are mixed in the Eblana #1 well, as it tested oil, but in non-commercial quantities (low oil cut). While passive seismic remains a viable exploration tool which has added value to this project, additional tests are needed to determine its reliability in delineating the reservoir area in eastern Nevada.

Figure 6. *Eblana #1 location showing it's correlation with the RHI map (Passive Seismic), geochemical analyses, and Satellite imagery. This well was targeted to take advantage of all sets of data, which are also consistent with lineament analysis. The red dashed lines indicate 2-D seismic lines over Major Oil's area of interest. Source, Major Oil (2013).*

Control Wells and Analog Fields

As previously mentioned, there are three control wells which have been drilled in the Hot Creek Valley. The Apache #24-13 well is located approximately six miles north of the area of interest (*see Figure 1*). This well penetrated dolomites of the Devonian Nevada formation subcropping below the Tertiary Volcanics. Drilled as a wildcat exploration well, the Apache #24-13 well revealed the presence of oil on flow tests and gas was present at several intervals from 8,890 to 9,148 feet *(Geodynamics, Jan 10, 2010)*. Out of eight drillstem tests (DST's) run, seven were mechanical failures, and the eighth recovered drilling fluid. This well was abandoned. The Apache #10-14 well was drilled approximately ten miles to the south of Major Oil's lease and was also abandoned.

Major Oil drilled the Eblana #1 well in 2012 through the Tertiary Volcanic tuffs interval. Preliminary results indicate hydrocarbons in non-commercial quantities in several zones similar to the producing Tertiary Volcanics found in Railroad Valley. The Paleozoic dolomites, also

prospective in this valley, were not penetrated with this well. The Eblana #1 is discussed in more detail later in this report.

Commercial production can be found in the Railroad Valley approximately 35 miles to the east of the Hot Creek Valley where ten fields have reported oil production from 408 wells. FGA has reviewed production in these wells. Successful wells in Railroad Valley produce from the Tertiary Volcanics and Paleozoic dolomites. The Grant Canyon field in Railroad Valley is the most prolific field in Nevada. Many wells in Railroad Valley have been quite productive, with cumulative oil production from less than 100 thousand barrels (MBbl) to 2 million barrels (MBbl) per well. One of the wells producing from the Tertiary Volcanics in Railroad Valley has the distinction of being the most prolific well in the continental United States, as it produced approximately 4,000 barrels of oil per day (bopd) for over three years before declining. The reservoir drive mechanism is water drive in these fields, and thus the productivity (oil and water) remain high for the life of the well. Wells produce at a high water cut later in life. No gas sales have been reported.

The fields in Railroad Valley provide analogs for the project in Hot Creek Valley. Table 3 is a summary of production and reservoir data in the Railroad Valley. This table was provided to FGA by Major Oil in a report dated December 16, 2010, by Jerry Walker, consulting geologist. The cumulative production was updated by FGA through 2012.

TABLE 3
RAILROAD VALLEY RESERVOIR DATA
JERRY WALKER - DECEMBER 16, 2010

RRV Field	Year Disc.	Depth, ft	Producing Fm.	Cum. Prod... bbl of oil* (thru 2012)	Hydrocarbon Column, ft	Porosity	Permeability
Bacon Flat	1981	5,400	brecciated Devonian carbonate (landslide deposit)	1,039,759	450–	fractures, vugs, and caverns	very high
Currant	1978	7,000	Eocene Sheep Pass limestone	2,210	180	6%	low?
Duckwater Creek	1990	5,700	Tertiary volcanic: welded tuff	19,050	150?	fracture	highly variable
Eagle Springs	1954	5,800 to 6,800	Tertiary volcanic: welded tuff; Eocene Sheep Pass carbonate; Pennsylvanian Ely limestone	5,549,929	1,600+	fracture (volcanics); fracture and vug (carbonate)	variable
Ghost Ranch	1996	4,400	brecciated Paleozoic carbonate (landslide deposit)	631,743	100	fracture	high
Grant Canyon	1983	4,500	brecciated Devonian carbonate (landslide deposit)	21,322,978	900+	fractures, vugs, and cavenls	very high

Kate Spring	1986	5,200	brecciated Paleozoic carbonate (landslide deposit)	2,467,595	200	10% to 17%	moderately high?
Sand Dune	1998	6,200	Pennsylvanian limestone	137,655**	?	?	?
Sans Spring	1993	5,900	Tertiary volcanic: welded tuff	276,164	200–	fracture	high
Trap Spring	1976	2,800 to 5,000	Tertiary volcanic: welded tuff	15,142,949	1,700 to 1,800	fracture	highly variable

* *Updated by FGA thru 2012.*

** *Unable to update because data not found.*

Eblana #1 Exploratory Well

The Eblana #1 provides valuable data on the nature of the formations in the area, the analogy to Railroad Valley, and the presence of oil in the area. Formation tops as provided are listed in Table 4, and confirm the presence of many of the same formations found in Railroad Valley. The Paleozoic-age dolomites, which are productive in Railroad Valley, were not penetrated in this well.

TABLE 4
FORMATION TOPS

Formation Name	Measured Depth (Ft)	TVD (SubSea)
Valley Fill	0 (From Surface)	+5,382
Tertiary Volcanic Tuff	2,966	12,417
Tertiary "Old" Volcanic Tuff	5,952	-426
Total Depth	8,550	-2,767

Due to problems encountered while drilling the Eblana #1, Reservoir Performance Monitoring (RPM) Logs were run through casing. RPM logs measuring effective porosity, gas saturation, and other metrics were run from 4,000 feet to 8,290 feet. Carbon – Oxygen logs measuring oil saturation, water saturation, and other metrics were run from 6,280 feet to 7,500 feet at various intervals through the well. These logs proved very effective and reliable in determining reservoir properties such as effective porosity, the net amount of reservoir quality rock in an interval, and the occurrence and types of hydrocarbons. The low salinity of the formation waters encountered while drilling the Eblana #1 will make it difficult to calculate water saturation values from open hole logs planned in future wells. Water cuts in Tables 4 and 5 were taken from Eblana #1 production tests.

In clastic formations, effective porosity is normally adjusted to total porosity by adding three to five percent, depending on various factors. No study was found to have been done in volcanic tuffs, so effective porosity numbers were used in this study. However, further understanding of the lithologies through additional drilling and core data may support an adjustment of effective porosity in the future.

Major Oil perforated many intervals throughout the Tertiary Volcanic in the Eblana #1, swabbing and flow testing each one separately to determine producibility and content of the reservoir. The majority of the tests resulted in formation water with a very low oil cut and an unmeasured small amount of C1-C4 gas at the surface. Later, a hydraulic pump was utilized to achieve a constant flow rate of water and oil to surface for an extended period of time. There were five intervals which are considered to have the highest potential for oil production based on mud log shows. Flow tests were run over four of those zones, indicating good volumes of formation water and small volumes of oil. These zones are shown in Table 5. While Zones 1 and 2 were commingled, the total fluid rate was approximately 250 barrels of total fluid per day (BFPD) and an average oil cut of two percent. The fourth zone was flow tested for an extended period of time with a rate of 250 BFPD and an average oil cut of three percent. On two occasions the oil cut surged to 22 percent and 60 percent.

TABLE 5
ZONES WITH BEST POTENTIAL (CONTINGENT RESOURCES)

Zones	Mud log	Continuous Flow Tests	Log Properties
1			
2			
3			
4			
5			

There are four additional zones that showed some positive results, but appear to be of lesser quality. These zones are listed in Table 6 below.

TABLE 6
ZONES WITH LOWER POTENTIAL (PROSPECTIVE RESOURCES)

Zones		Mud Log	Swabbing Results	Log Properties
6	[redacted]			
7				
8				
9				
10	Paleozoic Dolomites	Productive in RRV; the Eblana #1 was not deep enough to penetrate this zone.		

Future plans include running a VSP log in the Eblana #1, and gathering 2-D seismic. Additional drilling updip from the Eblana #1 will help define the commerciality of this resource and provide additional data to better define the stratigraphy in this area. When combined with the structure mapping and other available data, better definition of the extent of the resource should result.

Estimated Resources

FGA uses the Petroleum Resources Management System (SPE-PRMS) published by the Society of Petroleum Engineers/World Petroleum Congresses/American Association of Petroleum Geologists/Society of Petroleum Evaluation Engineers in November 2011, as the basis for its classification of hydrocarbon volumes. An abbreviated form of the SPE-PRMS is included as Attachment 2. The SPE-PRMS defines **contingent resources** as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies". One of those contingencies is stated by the SPE-PRMS as "a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future". Major Oil has outlined a program to appraise resources updip from the Eblana #1, and exploit commercial hydrocarbons in their leasehold area.

The SPE-PRMS defines **prospective resources** as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations". The SPE-PRMS further states that these have an associated chance of discovery (geologic success) and a chance of development. Prospective Resources are exploratory in nature, carrying a high risk factor.

It is FGA's opinion that the intervals believed to be potential reservoirs in the Eblana #1 (Table 5) should be classified as Contingent Resources in the nearby area updip of the Eblana #1 well. These fall into the Project Maturity Sub-class of "Development Pending", as appraisal drilling and detailed evaluation are ongoing to confirm commerciality. Furthermore, it is FGA's opinion that all other estimated hydrocarbon volumes should be classified as Prospective Resources and, as such, carry a low level of confidence.

It is FGA's opinion that the drilling of a successful updip well is needed to transition the contingent resources into the reserves category. Success is contingent on 1) being able to get updip sufficiently in this area to find the oil column, 2) having a trap and seal, and 3) finding primarily oil, rather than gas or a small oil column with a large gas cap.

FGA estimated hydrocarbon volumes in the prospect using a probabilistic method, by defining the full range of possible values for each input parameter such as area, porosity, oil saturation, and pay thickness. These possible values were then randomly sampled to compute a full range and distribution of potential outcomes using a Monte Carlo simulation model. Well log data from the Eblana #1 well and analogs from the adjacent Railroad Valley were used in establishing the range of input values, along with geologic interpretations using passive seismic data, 2-D seismic data, and geochemistry data provided by Major Oil. The methodology used to estimate oil volumes is an appropriate and generally accepted standard protocol for estimating resources in exploratory areas. *It is FGA's opinion that the input parameters used are reasonable for this area based on the geologic and reservoir data currently available.*

Due to the uncertainty of commerciality and the lack of sufficient exploratory drilling, the resources estimated are classified as contingent and prospective resources. The possibility exists that future drilling will not result in a commercial discovery and future development, in which case there would be no future revenue. The possibility also exists that the target horizons are found to be primarily gas bearing or a small oil column with a gas cap. In this case, the economics would change significantly as gas prices are low at this time relative to oil prices, and the nearest gas pipeline is 90 miles away. The hydrocarbon quantities recovered, should they be discovered and developed, may differ significantly from the estimates presented in this report.

Estimated resource volumes are for the prospect which includes nine federal lease blocks over approximately 88 sq km, or 21,760 acres (see Figure 5). Estimates of the original oil-in-place (OOIP) and recoverable oil, as of May 1, 2013, are summarized in Tables 7 through 11 and are expressed in thousands of barrels (MBbl). Net hydrocarbon volumes are net of royalties. Following each table is a graph of the probability distribution of the estimated recoverable oil.

The contingent resources in the five primary zones around the Eblana #1 are presented in Table 7, using 50 percent of the area in the pool delineated by the hydrocarbon indicators around the well, as provided by Major Oil in Figure 6. Table 8 presents the prospective resources in the remaining four zones considered to have lower potential in the Eblana #1 area. Table 9 provides the prospective resources in the remaining 50 percent of the pool around the Eblana #1. Table 10

provides the prospective resources in the remaining areas of the original 20 sq km block which have potential oil pools delineated, as shown in Figure 6. The prospective resources estimated for the remaining 68 sq km area surrounding the original core area is presented in Table 11. Table 12 provides a summary of assets and ownership, as provided by Major Oil.

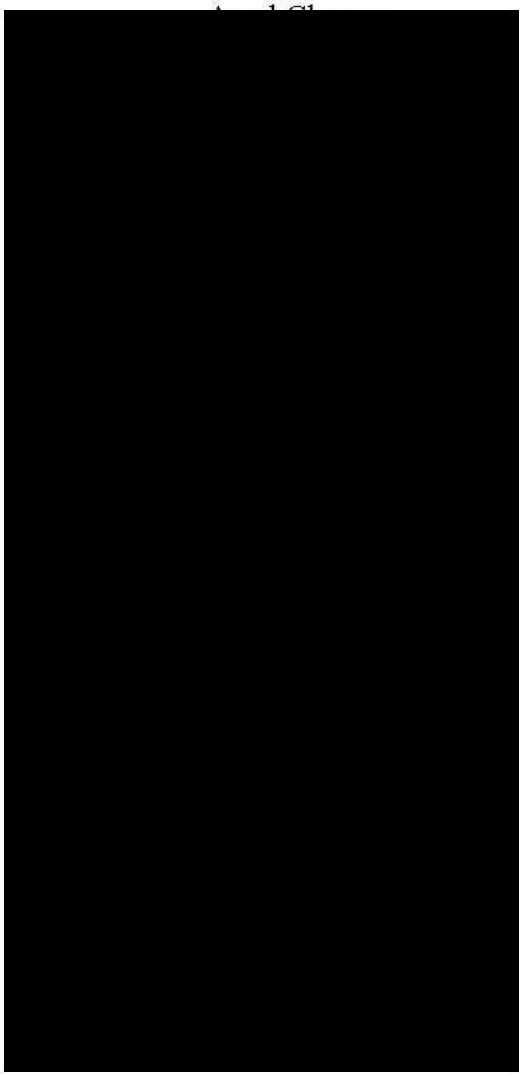


Figure 6. *Base Case resource areas as defined by Major Oil. Colored dots are passive seismic geophone locations; yellow rectangle is the 20 sq km original lease area. Source, Major Oil (2013).*

TABLE 7 – CONTINGENT RESOURCES
PRIMARY ZONES IN EBLANA #1 AREA
ORIGINAL OIL-IN-PLACE (OOIP) AND RECOVERABLE OIL
AS OF MAY 1, 2013

Target Horizon		Gross Contingent Resources (100% Working Interest) MBbl			Net Contingent Resources (87.5% Net Revenue Interest) MBbl		
		Low Estimate (P90)	*Best Estimate (P50)*	*High Estimate (P10)*	*Low Estimate (P90)*	*Best Estimate (P50)*	*High Estimate (P10)*
Tertiary Volcanics	**OOIP**	51,773	122,679	188,898	45,301	107,344	165,286
	Recoverable	9,927	22,007	38,301	8,686	19,256	33,513

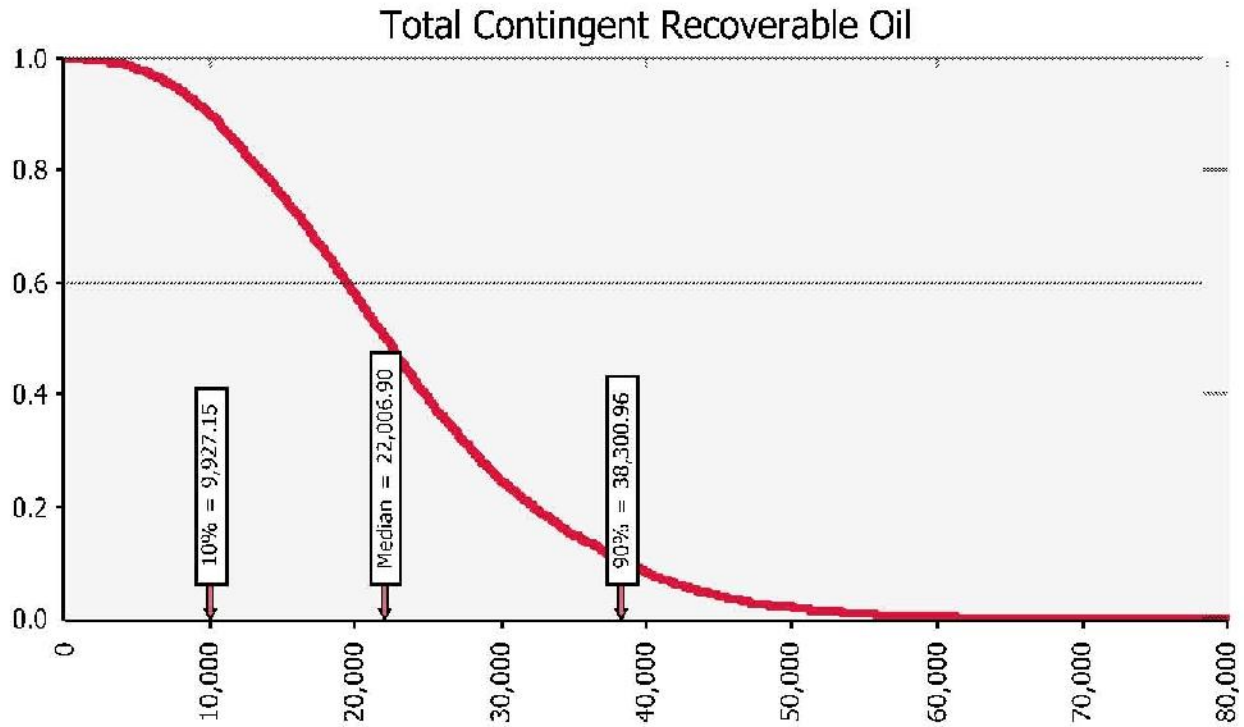


TABLE 8 – PROSPECTIVE RESOURCES
LOWER POTENTIAL ZONES IN THE EBLANA #1 AREA
ORIGINAL OIL-IN-PLACE (OOIP) AND RECOVERABLE OIL
AS OF MAY 1, 2013

Target Horizon		Gross Prospective Resources (100% Working Interest) MBbl			Net Prospective Resources (87.5% Net Revenue Interest) MBbl		
		Low Estimate (P90)	*Best Estimate (P50)*	*High Estimate (P10)*	*Low Estimate (P90)*	*Best Estimate (P50)*	*High Estimate (P10)*
Tertiary Volcanics	**OOIP**	5,238	36,678	87,288	4,583	32,093	76,377
	Recoverable	1,009	7,197	17,599	883	6,297	15,399

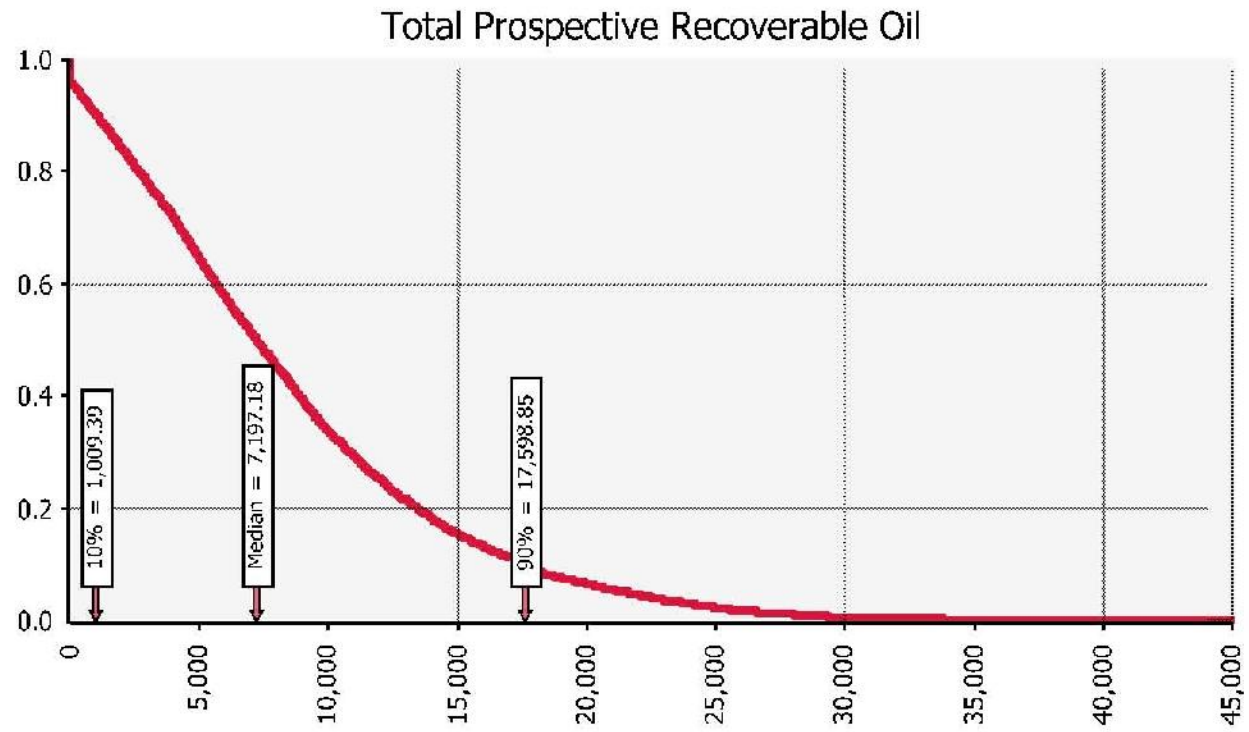


TABLE 9 – PROSPECTIVE RESOURCES
REMAINING PORTION OF EBLANA #1 POOL
ORIGINAL OIL-IN-PLACE (OOIP) AND RECOVERABLE OIL
AS OF MAY 1, 2013

Target Horizon		Gross Prospective Resources (100% Working Interest) MBbl			Net Prospective Resources (87.5% Net Revenue Interest) MBbl		
		Low Estimate (P90)	*Best Estimate (P50)*	*High Estimate (P10)*	*Low Estimate (P90)*	*Best Estimate (P50)*	*High Estimate (P10)*
Tertiary Volcanics	**OOIP**	28,799	90,240	179,361	25,199	78,960	156,941
	Recoverable	5,591	17,962	36,479	4,892	15,717	31,919

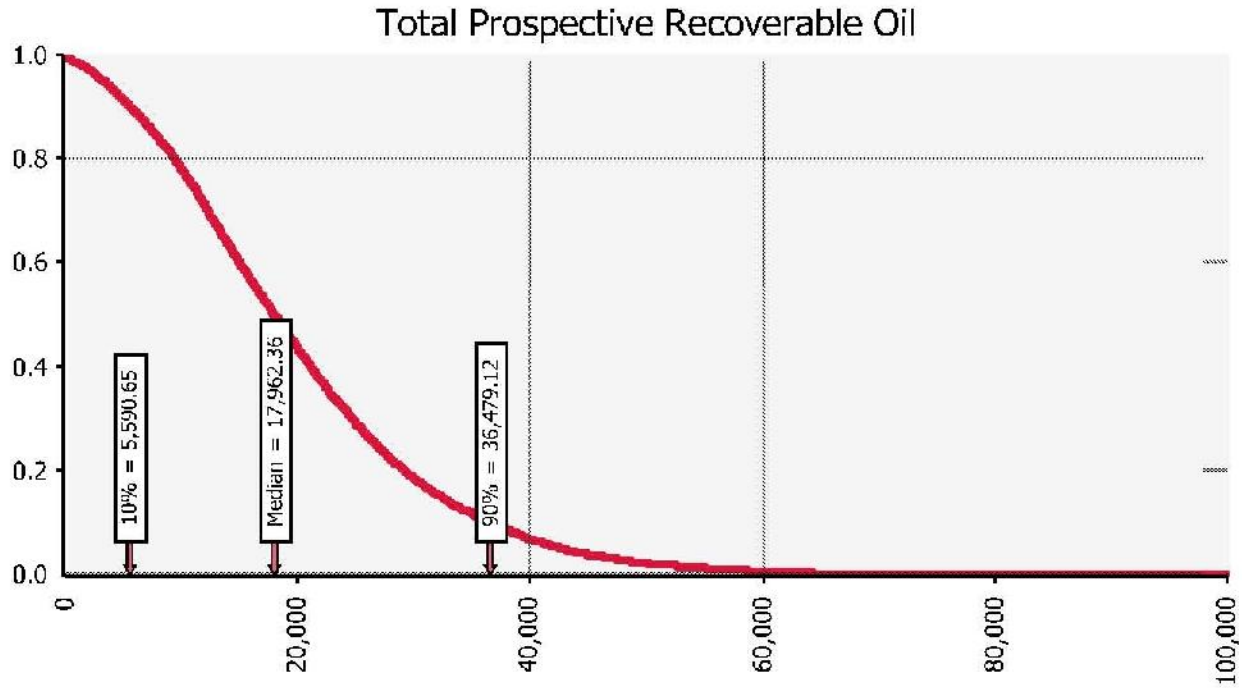


TABLE 10 – PROSPECTIVE RESOURCES
REMAINING PORTION OF ORIGINAL 20 SQ KM AREA
ORIGINAL OIL-IN-PLACE (OOIP) AND RECOVERABLE OIL
AS OF MAY 1, 2013

Target Horizon		Gross Prospective Resources (100% Working Interest) MBbl			Net Prospective Resources (87.5% Net Revenue Interest) MBbl		
		Low Estimate (P90)	*Best Estimate (P50)*	*High Estimate (P10)*	*Low Estimate (P90)*	*Best Estimate (P50)*	*High Estimate (P10)*
Tertiary Volcanics	OOIP	29,862	88,813	168,052	26,129	77,711	146,046
	Recoverable	5,723	17,794	33,783	5,008	15,570	29,560

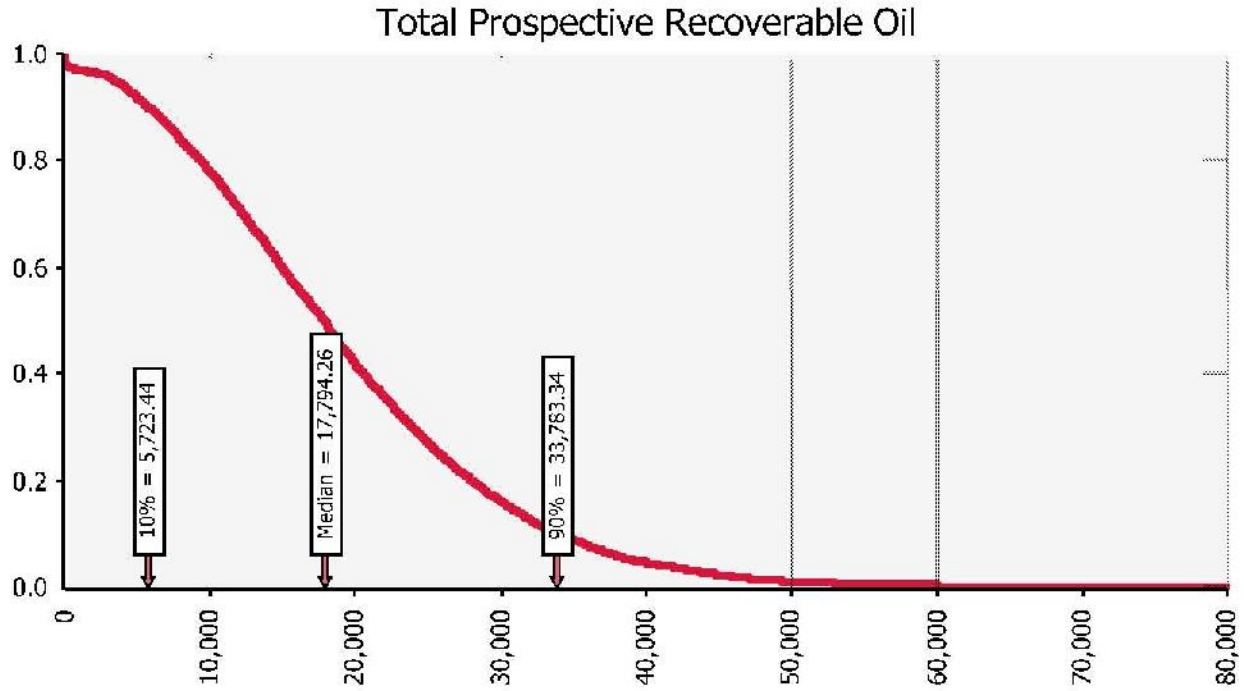
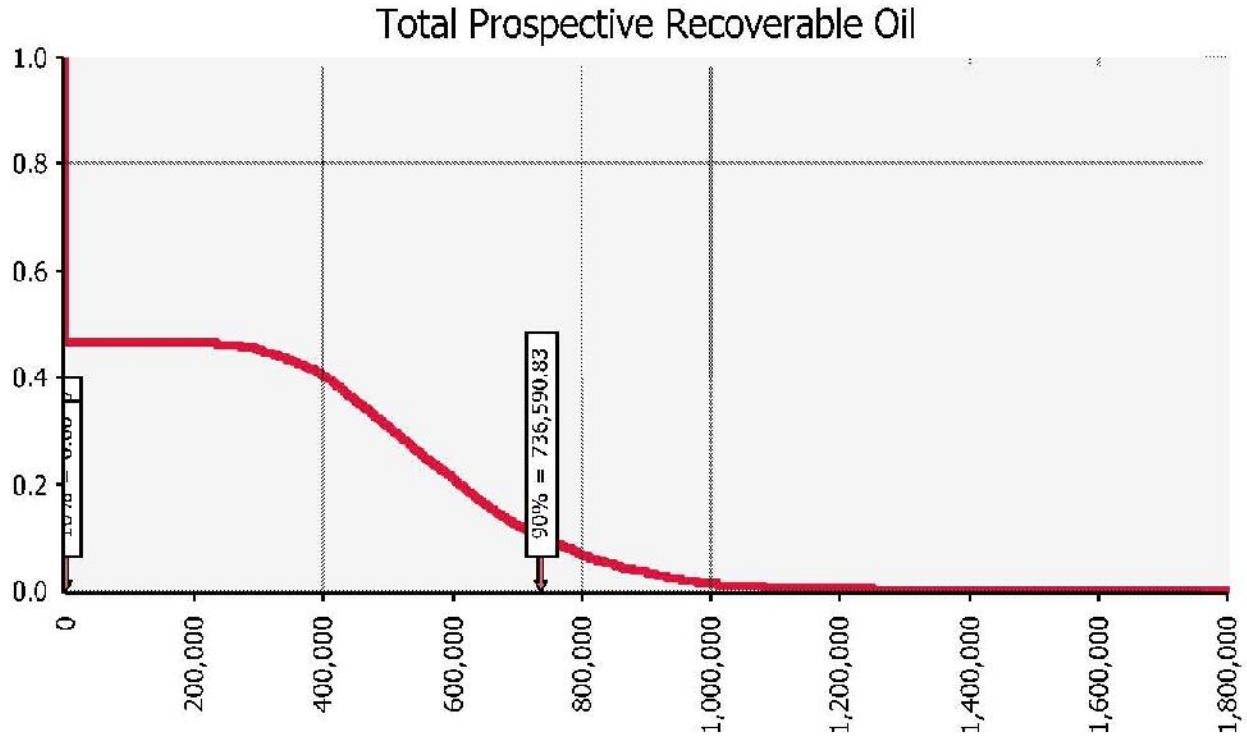


TABLE 11 – PROSPECTIVE RESOURCES
68 SQ KM AREA OUTSIDE OF ORIGINAL CORE AREA
ORIGINAL OIL-IN-PLACE (OOIP) AND RECOVERABLE OIL
AS OF MAY 1, 2013

Target Horizon		Gross Prospective Resources (100% Working Interest) MBbl			Net Prospective Resources (87.5% Net Revenue Interest) MBbl		
		Low Estimate (P90)	*Best Estimate (P50)*	*High Estimate (P10)*	*Low Estimate (P90)*	*Best Estimate (P50)*	*High Estimate (P10)*
Tertiary Volcanics	**OOIP**	0	0	3,578,490	0	0	3,131,179
	Recoverable	0	0	736,591	0	0	644,517



The comments below pertain to Tables 7 through 11:

- *Low, best, and high estimates in these tables are P90, P50, and P10, respectively.*
- *The estimates in these tables have been risked for trap and seal, structure, and thermal maturity. Ranges of uncertainties have also been applied to the input parameters.*
- *Application of any geological and economic risk factor does not equate prospective resources to contingent resources or to reserves.*
- *Recovery efficiency is applied to recoverable resources in this table.*

- *The resources presented in the tables above are based on the statistical aggregation method. The prospective resources from various areas cannot be added arithmetically.*
- *There is no certainty that any portion of the contingent or prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources evaluated.*
- *Major Oil International LLC is a 100% owned subsidiary of US Oil.*

In addition to the Tertiary Volcanics tested in the Eblana #1 well, the Paleozoic dolomites are prospective in this area. These prospective resource estimates were presented in the previous report titled "Competent Persons Report of Prospective Resources as of January 31, 2012 Attributable to Certain Interests Owned by Major Oil International, LLC in Certain Properties Located in Hot Creek Valley, Nye County, Nevada, USA", dated February 20, 2012. The best estimate volumes over the original 20 sq km core area for OOIP are 78 million stock tank barrels (MMBbl) gross and 68 MMBbl net. The best estimate volumes for recoverable oil are 25 MMBbl gross and 22 MMBbl net. These estimates were not updated for this report.

TABLE 12
SUMMARY OF ASSETS

Asset	Holder	Interest	Status	License Expiry date	License Area	Comments
Parcel 87414, 87415 Hot Creek Valley, Nevada, USA.	Major Oil International LLC	100%	Developed?	2019	21 km^2	Well Drilled
Parcels 90570, 090572 and 90514, Hot Creek Valley, Nevada, USA.	Major Oil International LLC	100%	Limited Development	2021	30.5 km^2	Acquired 2012 Limited Exploration Work done to date
Parcels 090573, 90169, 90617 and 90618 and Hot Creek Valley, Nevada	Major Oil International LLC	100%	Exploration	2021	36.6 km^2	Acquired 2012 Limited Exploration Work done to date

Refer to Attachment 4 - LEASE TERMS: Standard Bureau of Land Management Oil and Gas Stipulations.

Project Economics

Major Oil provided a financial model for FGA's review. The assumptions within the model are based on a 50-well exploration and development plan, which models only a portion of the estimated resources. FGA reviewed the assumptions used in the model and ran an independent economics study.

The modeled drilling phase is spaced out over a five-year period in this analysis. A capital investment of $206 million (MM) is included, which assumes $2.9 MM per well to drill and complete 50 producing wells, $0.6 MM per well to drill and complete ten saltwater disposal wells, $50 MM for surface equipment and pipelines, and $5 MM for 2D seismic and geological and geophysical work. The closest oil pipeline is approximately 35 miles away, thus field gathering lines and a pipeline to tie into the existing line would be required. Major Oil plans to use a major drilling company as the drilling contractor for future wells. FGA has reviewed the actual costs to drill and complete the Eblana #1, which came to $2.75 MM prior to flow testing. Future well cost estimates may decrease due to collecting less data in future wells and a learning curve that is typical in exploratory projects. However, the Eblana #1 was not fracture treated, which will probably be required. Also, the well costs may increase if Major Oil drills deeper to target the Paleozoic dolomites. FGA has not been provided a detailed cost estimate for the surface equipment or pipeline requirements and has not sought an independent evaluation. *FGA opines that the capital costs included are in the reasonable range (order of magnitude) for this exploratory project.*

The oil price in the model is based on the West Texas Intermediate (WTI) NYMEX futures strip price as of April 29, 2013, for the first five-years and held constant thereafter. A negative price differential of $5/bbl was applied to account for transportation and gravity price adjustments. Operating expenses of $10,000 per well per month were estimated. *FGA opines that the price model and operating expenses are reasonable for this project.*

The financial model projects an initial well rate of 500 barrels of oil per day (BOPD) and projects oil production and cash flow over the first 15-year period. The average oil production is approximately 350,000 bbls per well (gross) over the 15-year time frame. This financial model includes only a portion of the potential resources based on a reasonable recovery by 50 wells. The total net oil recovered in the 15-year model is 17,605,850 bbls. If more resources are found as estimated, the development will be on a larger scale.

FGA opines that the initial rate, decline rate used to time-rate the production, and the 15-year oil recovery are in the reasonable range of possibilities for this exploratory prospect. This 50-well project has an estimated present value discounted at ten percent per year of $587,583,000 for the 15-year projection. FGA agrees with the procedure and results of these economics based on the assumptions described.

Reservoir Properties, Risks and Mitigation

There are many risks and uncertainties associated with exploratory drilling for, and commercial exploitation of, oil and gas resources. Certain risks are, by their nature, defined principally by financial or legal uncertainties. Other components of risk are environmental, technological, or operational in nature. Some of these risks are completely beyond the control of the operator. However, some of these risks can be managed or influenced by the manner in which the operator conducts its business in the selection and evaluation of these prospects and in the conduct of its responsibilities in drilling and operating these properties.

Reservoir and source rock are established in the Eblana #1 by the presence of oil on flow tests. Current gaps in the understanding of structure, deposition, and migration could be determined by a future 2-D seismic survey, updip drilling, and additional mapping. Any accumulations found in Hot Creek Valley are expected to be fault bound, and future drilling will help determine if any faults are sealing in nature, thus forming a trap or compartmentalizing production. Updip drilling will also help determine the timing of oil migration through this area and the commerciality of this resource.

Based on the Railroad Valley analog, the Apache wells, and the Eblana #1 in Hot Creek Valley, the Chainman shale would be the primary source rock and the Eagle Pass shale, if present, could be a secondary source rock in Hot Creek Valley. The primary reservoir rocks include the same Tertiary Volcanics which are productive in Railroad Valley, and Paleozoic dolomites have yet to be tested in Major Oil's leasehold. Exploration should be limited to depths above the economic basement found in Railroad Valley.

The two oil samples taken in the Eblana #1 were tested to be 28.5°API gravity and 33°API gravity. This is lighter gravity oil than the 22°API to 27°API oil found in the analog Railroad Valley fields, which is a positive factor. A downside risk is the possibility of finding primarily gas production updip. The nearest gas pipeline and processing facility is approximately 90 miles away, which may make a gas discovery uneconomic due to the costs of building a pipeline *(Walker, 2010)*. In addition, gas prices are quite low relative to oil prices. FGA's analysis assumes finding an oil reservoir with little to no associated gas. If additional drilling finds primarily gas or oil with a large gas cap, the economics of the project will be quite different. Another risk is the uncertainty of being able to get updip of the Eblana #1. Although indications are that this well is in a transition zone, this could be a swept zone. There is also the risk that the structure is not present to be able to get updip or that there is not a proper trap and seal.

Observations

Upon review of the aforementioned information, the following observations can be made:

- Railroad Valley provides a good analog to Hot Creek Valley, due to its existing production and location relative to Hot Creek Valley. The oil found in the Eblana #1 well is of higher quality than the oil found in Railroad Valley.
- Gravity, magnetic, surface geology, and geochemical analysis are in agreement as to the potential for hydrocarbons in the area of interest. Areas defined with studies such as these have shown to be productive in Railroad Valley. 2-D and passive seismic are in agreement with the other data analyses and indicate anomalies with the potential of

hydrocarbons over the leasehold. Passive seismic has been used to further decrease exploration risk.

- The Eblana #1 flowed non-commercial oil and some gas on long term flow tests.
- Future plans to run 2-D seismic in the area with a direct tie in to the Eblana #1 are a reasonable approach to determine the structure in this area. Passive seismic and well results agree that oil is present in the Eblana #1, and an updip test will help determine commerciality of this resource.
- Major Oil has taken reasonable precautions to mitigate geologic risks to this project.
- FGA has estimated contingent and prospective resources in accordance with the guidelines set forth in the SPE-PRMS.

Conclusions and Recommendations

Based on the available data, FGA opines that Major Oil has used reasonable methodology while exploring for hydrocarbons in Hot Creek Valley. Further, based on outcrops to the east and to the west and the presence of oil in the Eblana #1, the Chainman shale is present in the valley and is likely the source rock. Trap types have yet to be determined, and could to be similar to those found in Railroad Valley. These conclusions are supported by available data, Major Oil's maps, results from the Eblana #1, and general knowledge of the Hot Creek Valley area. FGA believes this is still sub-categorized as a "prospect" according to the SPE-PRMS guidelines (see Attachment 3), and is sufficiently well-defined to be a viable drilling target. The potential for hydrocarbons in Major Oil's interest in Hot Creek Valley represent prospective and contingent resources, which are higher risk and exploratory in nature.

The Eblana #1 exploratory well found hydrocarbons in low saturations and non-commercial quantities in multiple zones in the Tertiary Volcanics. This well may be in an oil-water transition zone, or the zone may be swept. FGA recommends targeting a well updip of the Eblana #1 in an attempt to find the oil column. Prior to locating a future well, running a VSP in the Eblana #1 and additional seismic lines may be necessary to better determine structure.

Authority

This report was authorized by Brian McDonnell, Member of the Board, Major Oil International, LLC.

Qualifications and Independence of Report Writer

Founded in 1988, Forrest A. Garb & Associates, Inc. (FGA) is an international petroleum consulting firm providing services to the upstream oil and gas industry. FGA's expertise includes petroleum reservoir evaluation and economic analysis, as well as geological services for exploration and exploitation projects. FGA restricts it business activities to consulting services only, and does not accept contingency fees. Because the company has no hydrocarbon production and because it has no outside ownership to dictate opinions, the determinations of the firm are independent. FGA's studies are without bias and are based on the best interpretation of all available data after processing with current methods and equipment. FGA does not own operating interests in any oil, gas, or mineral properties. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. This report is based on information compiled by professional staff members of FGA, as well as consultants providing services to FGA.

FGA staff who participated in the compilation of this report includes Mr. William D. "Donnie" Harris, III, P.E., Ms. Stacy M. Light, P.E., Mr. Mike Rightmire, and Mr. John E. Cooper, C.P.G. All hold degrees in geoscience or petroleum engineering.

Mr. Harris joined FGA as President in August 1998, and became Chief Executive Officer of Forrest A. Garb & Associates in January 2002. Previously, he was a Vice President of DeGolyer and MacNaughton where he prepared and supervised engineering and reserve studies, and appraisal reports for fields in many countries. Mr. Harris holds a B.S. in Petroleum Engineering from Texas A&M University and a M.B.A from Southern Methodist University. He is a registered professional engineer in the state of Texas and is a member of the Society of Petroleum Engineers (SPE).

Ms. Light joined FGA in May 2010, and is a Senior Vice President of Petroleum Engineering. Ms. Light previously worked for ARCO Oil and Gas as a reservoir/operations engineer and crude oil risk manager. She has performed detailed production, reservoir and economic analyses for both onshore and offshore properties and supervised engineers in the same capacity. She has also performed risk management duties, trading crude oil futures and options on the New York Mercantile Exchange. Areas worked include onshore and offshore Gulf Coast, West Texas Permian Basin, Rocky Mountains, and the Mid-Continent area. Ms. Light received a B.S. in Petroleum Engineering from Texas A&M University. She is a registered professional engineer in the state of Texas and is a member of the Society of Petroleum Engineers (SPE).

Mr. Rightmire joined FGA in December 2007, and is a Senior Vice President of Petroleum Engineering. Mr. Rightmire previously worked for ARCO Alaska and ARCO Exploration & Production Technologies as a reservoir and operations engineer and most recently for Pinnacle Technologies as a senior engineer and project manager. His work experience includes over 25 years of operations and reservoir engineering assignments, reservoir engineering research and applications development work, and fracture stimulation engineering. Mr. Rightmire holds a B.S. in Petroleum Engineering from Texas A&M University, a B.S. in Biological Science from the University of Alaska Anchorage, and is a member of the Society of Petroleum Engineers (SPE).

Mr. Cooper joined FGA in 2007, as a Senior Geologist. Mr. Cooper received his Bachelor's degree in Geology from the University of Louisiana - Lafayette, an MBA from Tulane University, and a Masters of Management in Information Services from the University of Dallas. He was employed at Great Southern Oil and Gas, Innex Energy, and Hunt Petroleum in various geological and technical positions, and is experienced in log analysis, geological interpretations, and reserves evaluations using the latest technologies. Mr. Cooper is a member of the American Association of Petroleum Geologists (Certified Petroleum Geologist #6049), the Society of Economic Geophysicists, and the Dallas Geological & Geophysical Society.

Except for providing independent interpretation services on a fee basis, FGA has no interest or commercial arrangement in connection with the areas that are the subject of this report. Neither FGA, its directors, employees, or company associates hold any commercial interest in Major Oil, LLC, nor have any vested interest or any rights to subscribe to any interest in any properties or concessions, or on any adjacent properties and concessions held by Major Oil, LLC.

The only commercial interest FGA has in relation to Major Oil is the right to charge professional fees to Major Oil at normal commercial rates, plus normal overhead costs, for work carried out in connection with the investigations reported herein. The payment of these professional fees is not dependent either on listing success or any project financing.

All opinions, interpretations, and conclusions presented herein are opinions based on inferences from geological, geophysical, and other interpretations provided by Major Oil International, LLC. The report represents FGA's best professional judgment and should not be considered a guarantee of results.

FGA certifies that this report is accurate to the best standards of geological and engineering interpretation and analysis, given the limitations of the scope of this project. Any distribution of this report or any part thereof must include this letter and the General Comments in their entirety.

FGA assumes the information provided for review to be true and accurate. Our staff conducted no independent well tests, property inspections, geological or geophysical interpretations, or audits of completions as part of this review.

FGA is an independent firm of geologists and petroleum engineers. Neither the firm nor its employees own any interest in the properties studied, nor have we been employed on a contingency basis. We appreciate this assignment. Should you have any questions, please do not hesitate to contact us.

Sincerely,

Forrest A. Garb & Associates, Inc.

Forrest A. Garb & Associates, Inc.
Texas Registered Engineering Firm F-629

JEC/SML

LIST OF ATTACHMENTS

1. **Economic Model**
2. **Petroleum Resources Management System (SPE-PRMS)**
3. **Prospect Technical Evaluation Stage**
4. **Lease Terms**
5. **Company Profile**

ATTACHMENT 1

Economic Model

Date: 5/16/2013 2:56:02PM
Partner : All Cases
Retrieval Code :
Reserve Cat. : Resources Undeveloped
Location :
Archive Set : EGA2013

ECONOMIC PROJECTION

Nevada Hot Creek Prospect
Hot Creek Valley Model - 30 Wells
Discount Rate : 10.00
As of : 5/1/2013

Case : Hot Creek Valley Model - 30 Wells
Type : LEASE CASE
Field : Hot Creek Valley
Operator : Major Oil
Reservoir : Tertiary Volcanics
Co., State : Nye, NV
API No. :

Est. Cum Oil (Mbbl) : 0.00
Est. Cum Gas (MMcf) : 0.00
Est. Cum Water (Mbbl) : 0.00

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2013	24.88	0.00	21.77	0.00	88.15	0.00	1,919.12	0.00	0.00	0.00	41,200.00	-39,280.88	-38,720.94
2014	1,027.63	0.00	899.17	0.00	84.72	0.00	76,177.56	0.00	600.00	0.00	41,200.00	34,377.56	-8,936.52
2015	2,158.40	0.00	1,888.60	0.00	82.47	0.00	155,749.78	0.00	1,800.00	0.00	41,200.00	112,749.78	82,461.31
2016	2,758.36	0.00	2,413.57	0.00	80.71	0.00	194,796.98	0.00	3,000.00	0.00	41,200.00	150,596.98	193,648.19
2017	3,125.53	0.00	2,734.84	0.00	79.60	0.00	217,697.49	0.00	4,200.00	0.00	41,200.00	172,297.49	309,365.35
2018	3,049.01	0.00	2,667.89	0.00	79.22	0.00	211,350.00	0.00	5,400.00	0.00	0.00	205,950.00	435,569.75
2019	1,715.93	0.00	1,501.44	0.00	79.22	0.00	118,944.05	0.00	6,000.00	0.00	0.00	112,944.05	498,617.60
2020	1,043.38	0.00	912.95	0.00	79.22	0.00	72,324.28	0.00	6,000.00	0.00	0.00	66,324.28	532,236.76
2021	709.46	0.00	620.78	0.00	79.22	0.00	49,178.33	0.00	6,000.00	0.00	0.00	43,178.33	552,119.60
2022	520.24	0.00	455.21	0.00	79.22	0.00	36,061.86	0.00	6,000.00	0.00	0.00	30,061.86	564,699.98
2023	400.66	0.00	350.58	0.00	79.22	0.00	27,773.05	0.00	6,000.00	0.00	0.00	21,773.05	572,981.71
2024	320.54	0.00	280.47	0.00	79.22	0.00	22,218.83	0.00	6,000.00	0.00	0.00	16,218.83	578,588.88
2025	262.03	0.00	229.27	0.00	79.22	0.00	18,162.99	0.00	6,000.00	0.00	0.00	12,162.99	582,410.82
2026	219.45	0.00	192.02	0.00	79.22	0.00	15,211.84	0.00	6,000.00	0.00	0.00	9,211.84	585,042.34
2027	186.96	0.00	163.59	0.00	79.22	0.00	12,959.91	0.00	6,000.00	0.00	0.00	6,959.91	586,849.94
Rem.	83.37	0.00	72.95	0.00	79.22	0.00	5,779.19	0.00	2,962.01	0.00	0.00	2,817.18	680.08
Total 15.2	**17,605.85**	**0.00**	**15,405.12**	**0.00**	**80.25**	**0.00**	**1,236,305.27**	**0.00**	**71,962.01**	**0.00**	**206,000.00**	**958,343.25**	**587,530.01**
Ult.	17,605.85	0.00											

Major Phase : Oil
Initial Rate : 1,000.00 bbl/month
Abandonment : 13,456.41 bbl/month
Initial Decline : -11,136.255 %/year b = 0.00
Initial Ratio : 0.000 Mcf/bbl
Abandon Ratio : 0.000 Mcf/bbl
Abandon Day : 6/30/2028

Eco. Indicators

Return on Investment (disc) : 4.475
Return on Investment (undisc) : 5.652
Years to Payout : 2.52
Internal Rate of Return (%) : 165.43

	Initial	1st Rev.	2nd Rev.
Working Interest :	1.00000000	0.00000000	0.00000000
Revenue Interest :	0.87500000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	5.00% :	741,915.70	PW	20.00% :	388,152.63
PW	8.00% :	643,438.50	PW	30.00% :	269,884.91
PW	10.00% :	587,530.01	PW	40.00% :	194,549.25
PW	12.00% :	538,059.18	PW	50.00% :	143,895.68
PW	15.00% :	473,931.75	PW	60.00% :	108,357.88

ATTACHMENT 2

Petroleum Resources Management System
(SPE-PRMS)

World Petroleum Council

Petroleum Resources Management System

Sponsored by:

Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
World Petroleum Council (WPC)
Society of Petroleum Evaluation Engineers (SPEE)

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discoverec and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

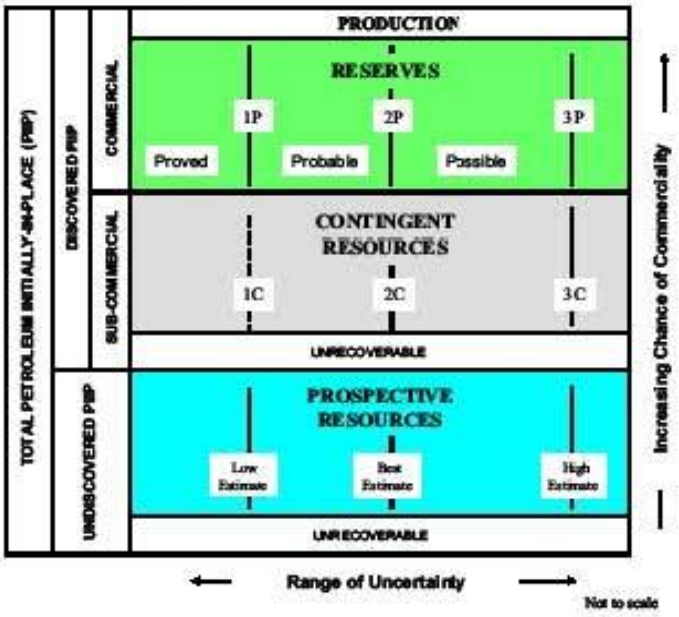


Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TERM	DEFINITION
Best Estimate	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
High Estimate (Resources)	With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Low/Best/High Estimates	The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.
Low Estimate	With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes).
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. SPE convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Estimate	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.

ATTACHMENT 3

Prospect Technical Evaluation Stages

Attachment 3 - Prospect Technical Evaluation Stages

A prospect can often be subcategorized based on its current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.

Prospect — A prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources.

Lead — A lead is less well defined and requires additional data and/or evaluation to be classified as a prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a Pg equal to or less than 0.05 to reflect the inherent technical uncertainty.

Play — A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

ATTACHMENT 4

Lease Terms
Major Oil International, LLC

FORREST A. GARB & ASSOCIATES, INC.

Attachment 4 - Lease Terms.

LEASE TERMS: Standard Bureau of Land Management Oil and Gas Stipulations

Sec. 1. Rentals - Rentals must be paid to proper office of lessor in advance of each lease year. Annual rental rates per acre or fraction thereof are:

(a) Noncompetitive lease, $1.50 for the first 5 years; thereafter $2.00;
(b) Competitive lease, $1.50; for the first 5 years; thereafter $2.00;
(c) Other, see attachment, or as specified in regulations at the time this lease is issued.

If this lease or a portion thereof is committed to an approved cooperative or unit plan which includes a well capable of producing leased resources and the plan contains a provision for allocation of production, royalties must be paid on the production allocated to this lease. However, annual rentals must continue to be due at the rate specified in (a), (b), or (c) rentals for those lands not within a participating area. Failure to pay annual rental, if due, on or before the anniversary date of this lease (or next official working day if office is closed) must automatically terminate this lease by operation of law. Rentals may be waived, reduced, or suspended by the Secretary upon a sufficient showing by lessee.

Sec. 2. Royalties - Royalties must be paid to proper office of lessor. Royalties must be computed in accordance with regulations on production removed or sold. Royalty rates are:

(a) Noncompetitive lease, 12 1/2%
(b) Competitive lease, 12 1/2 %
(c) Other, see attachment; or as specified in regulations at the time this lease is issued.

Lessor reserves the right to specify whether royalty is to be paid in value or in kind, and the right to establish reasonable minimum values on products after giving lessee notice and an opportunity to be heard. When paid in value, royalties must be due and payable on the last day of the month following the month in which production occurred. When paid in kind, production must be delivered, unless otherwise agreed to by lessor, in merchantable condition on the premises where produced without cost to lessor. Lessee must not be required to hold such production in storage beyond the last day of the month following the month in which production occurred, nor must lessee be held liable for loss or destruction of royalty oil or other products in storage from causes beyond the reasonable control of lessee. Minimum royalty in lieu of rental of not less than the rental which otherwise would be required for that lease year must be payable at the end of each lease year beginning on or after a discovery in paying quantities. This minimum royalty may be waived, suspended, or reduced, and the above royalty rates may be reduced, for all or portions of this lease if the Secretary determines that such action is necessary to encourage the greatest ultimate recovery of the leased resources, or is otherwise justified. An interest charge will be assessed on late royalty payments or underpayments in accordance with the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) (30 U.S.C. 1701). Lessee must be liable for royalty payments on oil and gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator, or due to the failure to comply with any rule, regulation, order, or citation issued under FOGRMA or the leasing authority.

Sec. 3. Bonds - A bond must be filed and maintained for lease operations as required under regulations.

Sec. 4. Diligence, rate of development, unitization, and drainage - Lessee must exercise reasonable diligence in developing and producing, and must prevent unnecessary damage to, loss of, or waste of leased resources. Lessor reserves right to specify rates of development and production in the public interest and to require lessee to subscribe to a cooperative or unit plan, within 30 days of notice, if deemed necessary for proper development and operation of area, field, or pool embracing these leased lands. Lessee must drill and produce wells necessary to protect leased lands from drainage or pay compensatory royalty for drainage in amount determined by lessor.

Sec. 5. Documents, evidence, and inspection - Lessee must file with proper office of lessor, not later than 30 days after effective date thereof, any contract or evidence of other arrangement for sale or disposal of production. At such times and in such form as lessor may prescribe, lessee must furnish detailed statements showing amounts and quality of all products removed and sold, proceeds there from, and amount used for production purposes or unavoidably lost. Lessee may be required to provide plats and schematic diagrams showing development work and improvements, and reports with respect to parties in interest, expenditures, and depreciation costs. In the form prescribed by lessor, lessee must keep a daily drilling record, a log, information on well surveys and tests, and a record of subsurface investigations and furnish copies to lessor when required. Lessee must keep open at all reasonable times for inspection by any representative of lessor, the leased premises and all wells, improvements, machinery, and fixtures thereon, and all books, accounts, maps, and records relative to operations, surveys, or investigations on or in the leased lands. Lessee must maintain copies of all contracts, sales agreements, accounting records, and documentation such as billings, invoices, or similar documentation that supports costs claimed as manufacturing, preparation, and/or transportation costs. All such records must be maintained in lessee's accounting offices for future audit by lessor. Lessee must maintain required records for 6 years after they are generated or, if an audit or investigation is underway, until released of the obligation to maintain such records by lessor. During existence of this lease, information obtained under this section will be closed to inspection by the public in accordance with the Freedom of Information Act (5 U.S.C. 552).

Sec. 6. Conduct of operations - Lessee must conduct operations in a manner that minimizes adverse impacts to the land, air, and water, to cultural, biological, visual, and other resources, and to other land uses or users. Lessee must take reasonable measures deemed necessary by lessor to accomplish the intent of this section. To the extent consistent with lease rights granted, such measures may include, but are not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures. Lessor reserves the right to continue existing uses and to authorize future uses upon or in the leased lands, including the approval of easements or rights-of-way. Such uses must be conditioned so as to prevent unnecessary or unreasonable interference with rights of lessee. Prior to disturbing the surface of the leased lands, lessee must contact lessor to be apprised of procedures to be followed and modifications or reclamation measures that may be necessary. Areas to be disturbed may require inventories or special studies to determine the extent of impacts to other resources. Lessee may be required to complete minor inventories or short term special studies under guidelines provided by lessor. If in the conduct of operations, threatened or endangered species, objects of historic or scientific interest, or substantial unanticipated environmental effects are

observed, lessee must immediately contact lessor. Lessee must cease any operations that would result in the destruction of such species or objects.

Sec. 7. Mining operations - To the extent that impacts from mining operations would be substantially different or greater than those associated with normal drilling operations, lessor reserves the right to deny approval of such operations.

Sec. 8. Extraction of helium - Lessor reserves the option of extracting or having extracted helium from gas production in a manner specified and by means provided by lessor at no expense or loss to lessee or owner of the gas. Lessee must include in any contract of sale of gas the provisions of this section.

Sec. 9. Damages to property - Lessee must pay lessor for damage to lessor's improvements, and must save and hold lessor harmless from all claims for damage or harm to persons or property as a result of lease operations.

Sec. 10. Protection of diverse interests and equal opportunity – Lessee must pay, when due, all taxes legally assessed and levied under laws of the State or the United States; accord all employees complete freedom of purchase; pay all wages at least twice each month in lawful money of the United States; maintain a safe working environment in accordance with standard industry practices; and take measures necessary to protect the health and safety of the public. Lessor reserves the right to ensure that production is sold at reasonable prices and to prevent monopoly. If lessee operates a pipeline, or owns controlling interest in a pipeline or a company operating a pipeline, which may be operated accessible to oil derived from these leased lands, lessee must comply with section 28 of the Mineral Leasing Act of 1920. Lessee must comply with Executive Order No. 11246 of September 24, 1965, as amended, and regulations and relevant orders of the Secretary of Labor issued pursuant thereto. Neither lessee nor lessee's subcontractors must maintain segregated facilities.

Sec. 11. Transfer of lease interests and relinquishment of lease – As required by regulations, lessee must file with lessor any assignment or other transfer of an interest in this lease. Lessee may relinquish this lease or any legal subdivision by filing in the proper office a written relinquishment, which will be effective as of the date of filing, subject to the continued obligation of the lessee and surety to pay all accrued rentals and royalties.

Sec. 12. Delivery of premises - At such time as all or portions of this lease are returned to lessor, lessee must place affected wells in condition for suspension or abandonment, reclaim the land as specified by lessor and, within a reasonable period of time, remove equipment and improvements not deemed necessary by lessor for preservation of producible wells.

Sec. 13. Proceedings in case of default - If lessee fails to comply with any provisions of this lease, and the noncompliance continues for 30 days after written notice thereof, this lease will be subject to cancellation unless or until the leasehold contains a well capable of production of oil or gas in paying quantities, or the lease is committed to an approved cooperative or unit plan or communitization agreement which contains a well capable of production of unitized substances in paying quantities. This provision will not be construed to prevent the exercise by lessor of any other legal and equitable remedy, including waiver of the default. Any such remedy or waiver

will not prevent later cancellation for the same default occurring at any other time. Lessee will be subject to applicable provisions and penalties of FOGRMA (30 U.S.C. 1701).

Sec. 14. Heirs and successors-in-interest - Each obligation of this lease will extend to and be binding upon, and every benefit hereof will inure to the heirs, executors, administrators, successors, beneficiaries, or assignees of the respective parties hereto.

ATTACHMENT 5

Company Profile

FORREST A. GARB & ASSOCIATES, INC.

INTERNATIONAL PETROLEUM CONSULTANTS
5310 HARVEST HILL ROAD, SUITE 275, LB 152
DALLAS, TEXAS 75230 – 5805
(972) 788-1110 Fax (972) 991-3160
E-Mail: forgarb@forgarb.com
Web Site: www.forgarb.com

We are pleased to present this profile of Forrest A. Garb & Associates, Inc. (FGA). FGA is an international petroleum engineering and geologic consulting firm staffed by experienced engineers and geologists. Collectively our staff has more than a century of world-wide experience. FGA has no outside ownership. And the firm has no direct or contingent participation in oil or gas ventures. There are no conflicts of interest or concerns about maintaining the confidentiality of our client's data. The company is dedicated to providing the highest level of integrity, technology, and service.

FGA expertise includes:

- Exploration and Prospect Evaluations
- Reserve Estimation and Evaluation Studies
- Fair Market Value Analyses
- Economic and Market Analyses
- Forensic Engineering and Expert Witness Testimony
- Reservoir Engineering
- Regional and Detailed Geological Studies
- Numeric Simulation Studies
- Special Computer Applications
- Pressure Transient Test Design, Supervision, and Evaluation
- Reservoir Characterization
- Geostatistical Studies
- Oil & Gas Production Environmental Studies
- Minerals Evaluations
- Petrophysical Analyses

OUR SENIOR STAFF

Mr. Forrest A. Garb, Founder, Chairman of the Board and Chief Engineer Emeritus, with more than 50 years of practical petroleum industry experience, was a staff member and then a principal of a major consulting firm for over 30 years, serving as president and chief operating officer of this firm for the last 14 of those years. During his tenure, he supervised or prepared over 12,500 assignments varying from simple evaluations to complex reservoir simulations. Using this experience as a base, he assembled the best work system offered to the oil and gas industry. The use of state of the art computers and office equipment, together with an experienced staff, ensures economic service to the client.

Mr. William D. Harris III, P.E., joined FGA in August 1998, and is now the Chief Executive Officer. Previously, he was a Vice President with DeGolyer and MacNaughton where he prepared and supervised engineering studies and reserve and appraisal reports for fields in many countries. Mr. Harris holds a B.S. in Petroleum Engineering from Texas A&M University and a M.B.A. from Southern Methodist University. He is a member of the Society of Petroleum Engineers and is a registered professional engineer in the state of Texas.

Mr. John Cooper, Senior Geologist, joined Forrest A. Garb & Associates, Inc. in 2007. Mr. Cooper received his Bachelor's degree in Geology from the University of Louisiana - Lafayette (formerly the University of Southwestern Louisiana) and holds an MBA from Tulane University. He was employed at Great Southern Oil and Gas, Innex Energy, and Hunt Petroleum in various geological and technical positions, and is experienced in log analysis, geological interpretations, and reserves evaluations using the latest technologies. Mr. Cooper is a member of the American Association of Petroleum Geologists, the Society of Economic Geophysicists, and the Dallas Geological & Geophysical Society.

Mr. Gerald K. Ebanks, Senior Geologist, received his M.A. degree in geology from the University of Texas at Austin and has more than 35 years of experience in petroleum geology. He was employed with Mobil Oil Corporation, and subsequently with Ray Holifield and Associates, and PXI, Incorporated, in various geological positions. Mr. Ebanks is a member of the American Association of Petroleum Geologists, Dallas Geological Society, Houston Geological Society, and is a certified petroleum geologist.

Ms. Stacy M. Light, P.E., Senior Vice President Petroleum Engineering, joined Forrest A. Garb & Associates, Inc. in May 2010 as a reservoir engineer. Ms. Light previously worked for ARCO Oil and Gas as a reservoir/operations engineer and crude oil risk management director. She performed detailed production, reservoir and economic analyses for both onshore and offshore properties, and supervised engineers in the same capacity. She also performed risk management duties, trading crude oil futures and options on the New York Mercantile Exchange. Areas worked include onshore and offshore Gulf Coast and the mid-continent area. Ms. Light received a B.S. in Petroleum Engineering from Texas A&M University and is a registered professional engineer in the state of Texas and a member of the Society of Petroleum Engineers (SPE).

Mr. Claude M. (Mike) Rightmire, Senior Vice President Petroleum Engineering, joined Forrest A. Garb & Associates, Inc. in December 2007, as a reservoir engineer. Mr. Rightmire previously worked for ARCO Alaska and ARCO Exploration & Production Technologies as a reservoir and operations engineer and most recently for Pinnacle Technologies as a senior engineer and project manager. His work experience includes over 25 years of operations and reservoir engineering assignments, reservoir engineering research and applications development work, and fracture stimulation engineering. Mr. Rightmire holds a B.S. in Petroleum Engineering from Texas A&M University, a B.S. in Biological Science from the University of Alaska Anchorage, and is a member of the Society of Petroleum Engineers (SPE).

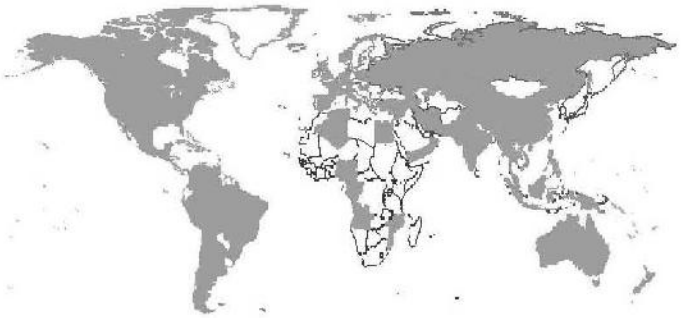
Ms. Sandra W. Wall, Senior Vice President Petroleum Engineering, joined Forrest A. Garb & Associates, Inc. in August 2006. Ms. Wall previously worked for Texas Eastern Corp., Exploration and Production Division, and Transwestern Pipeline Company as a reservoir engineer and project manager. She performed detailed reservoir and economic analyses for both onshore and offshore properties, ran 3D computer simulation studies for massive hydraulic

fracturing, water floods, and CO2 floods, and coordinated the development of exploration projects. Areas worked include onshore and offshore Gulf Coast, Alaska North Slope, Rocky Mountains, offshore California, offshore Australia, Indonesia, and North Sea. Ms. Wall holds a B.S. in Petroleum Engineering from Texas A&M University, a M.B.A. from Houston Baptist University, and is a member of the Society of Petroleum Engineers (SPE).

THE COMPANY

Forrest A. Garb & Associates, Inc. (FGA) is a consulting firm comprised of professional petroleum engineers, geologists, and technical support personnel with diversified backgrounds in all phases of the petroleum and energy industries. The group prides itself in offering the highest level of ethics, state of the art technology, and prompt dedicated service to our clients.

FGA professionals have extensive experience in the world's important hydrocarbon producing areas, including North and South America, the Middle East, Australia, New Zealand, Indonesia, Turkey, North Africa, Russia, China, Thailand, Myanmar, West Africa, India, the North Sea, Alaska, and Mexico.



The firm offers a complete range of geological and engineering services - from screening exploration prospects and designing development drilling projects to estimating reserves, forecasting future production, and presenting economic analyses. Major financial institutions accept the validity of our studies, particularly in the areas of reserve estimation and appraisal. The fair market value analysis technique developed by FGA is being applied by some of industry's largest players.

Major integrated and independent oil and gas companies have used our estimates of future production rates and available hydrocarbon resources to design facilities, and to establish contract terms.

FGA is a leader in the development and application of computers to the daily requirements of petroleum engineering. Mainframe programs, hand-held computer programs, and personal computer systems designed by Mr. Garb have been installed in many major integrated oil company offices around the world.

Associations with facilities design, seismic interpretation, petrology, and environmental firms, renowned in their own right, enable the FGA organization to offer a complete service to its clients under one master contract.

Because the company has no hydrocarbon production and because it has no outside ownership to dictate opinions, the determinations of the firm are independent. Its studies are without bias and are based on the best interpretation of all available data after processing with "state of the art" methods and equipment.

FGA restricts its activities exclusively to consultation; it does not accept contingent fees nor does it own operating interests in any oil, gas, or mineral properties. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies.

The entire FGA staff is dedicated to providing each client with a personalized and cost-efficient approach to serve their individual needs.