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REPORT
as of
MARCH 31, 2016
on
RESERVES and REVENUE
of
CERTAIN PROPERTIES
owned by
CARACOL PETROLEUM, LLC
in the
SOUTHERN MILUVEACH UNIT

QUALIFIED PERSONS REPORT

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REPORT as of MARCH 31, 2016 on RESERVES and REVENUE of CERTAIN PROPERTIES owned by CARACOL PETROLEUM, LLC in the SOUTHERN MILUVEACH UNIT

QUALIFIED PERSONS REPORT

FOREWORD

Scope of Investigation

This report presents estimates, as of March 31, 2016, of the extent and value of the proved, proved-plus-probable, and proved-plus-probable-plus-possible oil reserves of certain properties in which CaraCol Petroleum, LLC (CaraCol) has represented that it owns a 38.187-percent working interest with a 30.549-percent net revenue interest. The reserves estimated in this report are located in the Southern Miluveach Unit (SMU), North Slope Alaska, to be developed and operated by Brooks Range Petroleum Corporation (BRPC) from the Mustang drillsite pad. This report has been prepared to meet the requirements of the Singapore Stock Exchange. It has been prepared for disclosure on the Singapore Exchange Network by Alpha Energy Holdings Limited, the holding company of CaraCol, for public viewing and access.

At the time of the preparation of this report, CaraCol has represented that BRPC was proceeding with final design engineering and procuring long-lead equipment. Five wells have been drilled into the SMU, and all of these wells encountered the reservoir target to be developed. The last two wells were drilled in 2012 and 2014, respectively, and both are planned to be utilized in the development of SMU. Subsequent wells are scheduled to resume drilling by mid-2017.

Estimates of reserves presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. These reserves definitions are discussed in detail in the Definition of Reserves section of this report.

Reserves estimated in this report are expressed as gross, company gross, and net reserves. Gross reserves are defined as the total estimated petroleum that is recoverable from these properties after March 31, 2016. Company gross reserves are the portion of the gross reserves attributable to CaraCol's working interest. Net reserves are defined as that portion of the gross reserves attributable to the CaraCol working interest after deducting landholder and overriding royalty interests owned by others.

The table below summarizes the five leases (ADL #390680, 390681, 390690, 390691, and 390692) and licenses held by CaraCol in the SMU.

Asset Name/Country	CaraCol's Interest (%)	Development Status	License Expiration Date	License Area (acres)	Type of Deposit	Remarks
Southern Miluveach Unit, North Slope Alaska, USA	38.187% working interest, 30.549% revenue interest.	SMU development is on-going.	December 31, 2017 (see notes below).	8,960	Oil	CaraCol pays 55.263% of drilling costs.

Notes:

1. Subject to the terms and conditions of an approved plan of development, the Unit automatically terminates 5 years from the Effective Date (March 31, 2011) unless:
   - a well in the Unit area has been certified as capable of producing oil or gas in commercial quantities, in which case the Unit will remain in effect for so long as oil or gas is being produced in commercial quantities; or
   - for as long as oil or gas is being produced from within the Unit in commercial quantities and operations are being conducted in accordance with the approved plan of development; or
   - should production cease, for so long thereafter as diligent operations are in progress to restore production and then so long after as oil or gas is being produced from within the Unit in commercial quantities; or
   - exploration operations are being conducted under an approved development plan and the unit term is extended by the Commissioner of the Alaskan Department of Natural Resources. No single extension will exceed 5 years.
2. Production of oil and gas in commercial quantities is defined as production sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid.
3. On March 30, 2016, BRPC and CaraCol received approval from the State of Alaska, Department of Natural Resources, to extend the term of the Unit until December 31, 2017. Based on the development schedule provided herein, the Unit will be producing in commercial quantities before December 31, 2017, and the Unit will remain in effect for so long as commercial quantities are being produced.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that have been prepared using prices and costs specified by CaraCol and BRPC. All prices, costs, and revenue shown in this report are expressed in United States dollars (U.S.$). A detailed explanation of the future price and cost assumptions is included in the Financial Analysis section of this report.

Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated ad valorem taxes, production taxes, transportation expenses, operating expenses, and capital and abandonment costs from the future gross revenue. Operating expenses include lease and lifting expenses. Lease expenses include an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded annually over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values are reported in detail using a discount rate of 10 percent, and summarized in the appendix using discount rates of 5, 9, 12, 15, 20, 25, and 30 percent.

Estimates of oil reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Authority

This report was prepared at the request of Mr. Dean Gallegos, Chief Executive Officer of Alpha Energy Holdings Limited. CaraCol is a wholly owned subsidiary of Alpha Energy Holdings Limited.

Source of Information

Data used in the preparation of this report were obtained from CaraCol, from BRPC, and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by CaraCol with respect to its property interests, production flow tests from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report, as no production facilities are yet in place, and we are comfortable that State of Alaska well drilling and reporting guidelines are monitored by the state. DeGolyer and MacNaughton has made reasonable enquiries and exercised its judgement on the reasonable use of such data and information, and has no reason to doubt the accuracy or reliability of the information provided or extracted.

Qualified Person

DeGolyer and MacNaughton, operating from its offices at 5001 Spring Valley Road, Suite 800E, Dallas, Texas, 75244, USA, is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. Provision of professional services has been solely on a fee basis. Mr. Dennis W. Thompson, P.E., Assistant Manager of our North American Division, has supervised the evaluation. He graduated from Eastern New Mexico University with a Bachelor of Science Degree in Geology in 1973 and he earned a Master of Science Degree in Petroleum Engineering from the University of Texas at Austin in 1975. He is a Registered Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers, with 37 years of experience in the evaluation of oil and gas fields. Mr. Thompson fulfills the following criteria for a qualified person:

1. The qualified person is not a sole practitioner;
2. The qualified person producing the report is a Senior Vice President of DeGolyer and MacNaughton;
3. The qualified person and officers and staff of DeGolyer and MacNaughton are independent of Alpha Energy Holdings Limited (Alpha), Alpha directors, and substantial shareholders;

4. The qualified person and officers and staff of DeGolyer and MacNaughton do not have any interest, direct or indirect, in Alpha or its subsidiaries, and will not receive benefits other than fees paid in connection with the qualified person's report; and
5. Our fees are not contingent on the results of our evaluation.

EXECUTIVE SUMMARY

At the request of CaraCol, an evaluation has been prepared of the oil reserves, expenditures, and revenue for the interests that CaraCol has represented that it owns in the SMU of the Kuparuk River Field as of March 31, 2016. This unit is operated by BPRC in North Slope Alaska, United States. No site visit was undertaken by us.

The SMU is expected to produce oil from the Cretaceous-age Kuparuk River Formation sandstones. The reservoir has been delineated by all five of the previously drilled wells in the SMU. The wells were drilled between 2002 and 2014, and the last two wells drilled are expected to be utilized in the development of the SMU. The remaining development wells are scheduled to resume drilling operations by mid-2017. The reserves are expected to be fully developed by the middle of 2019, with production scheduled to begin in November 2017. Planned development for proved reserves will require 8 producers and 13 injectors. Planned development for proved-plus-probable reserves and proved-plus-probable-plus-possible reserves will require one more producer and two more injectors. CaraCol has represented that it owns a 38.187-percent working interest with a 30.549-percent revenue interest in the SMU.

Estimates of reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. These reserves definitions and other terms are discussed in detail in following sections of this report.

The estimated proved (1P), proved-plus-probable (2P), and proved-plus-probable-plus-possible (3P) reserves, as of March 31, 2016, expressed in millions of barrels (MMbbl), for the proposed SMU development are summarized as follows:

Category	Gross Attributable to License (MMbbl)	Net Attributable to CaraCol (MMbbl)	Change from Previous Update (percent)	Remarks
Oil Reserves				
1P	20.2	6.2	(7.5)	Approximately 30-Percent Recovery
2P	32.6	10.0	(2.0)	Approximately 35-Percent Recovery
3P	37.2	11.4	(0.9)	Approximately 40-Percent Recovery

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. All oil reserves estimated herein are considered undeveloped.

Estimated future net revenue and expenditures attributable to CaraCol's interests in the SMU, as of March 31, 2016, under the assumptions concerning prices and costs are summarized as follows, expressed in thousands of United States dollars (M U.S.$):

	1P (M U.S.$)	2P (M U.S.$)	3P (M U.S.$)
Future Gross Revenue	308,810	504,249	577,013
Ad Valorem and Production Taxes	(19,986)	(11,351)	(7,690)
Transportation Expenses	59,152	95,654	108,974
Operating Expenses	85,295	118,379	137,742
Capital and Abandonment Costs	120,372	126,665	126,666
Future Net Revenue	63,977	174,902	211,321
Present Worth at 10 Percent	34,325	88,719	100,864

Notes:
1. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.
2. Future income taxes were not taken into account in the preparation of these estimates.

DEFINITION of RESERVES

Estimates of proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. The petroleum reserves are defined as follows:

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *Proved Reserves* – Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90-percent probability that the quantities actually recovered will equal or exceed the estimate.
>
> *Unproved Reserves* – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
>
>> *Probable Reserves* – Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is

equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves – Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to estimates of proved reserves.

SOUTHERN MILUVEACH UNIT GEOLOGY and EXPLORATION DATA

The SMU encompasses approximately 12 contiguous square miles (7,680 acres) in the North Slope oil productive region of Alaska. It is located directly north of the Tarn field, south of the Palm field, and southwest of the 2M drilling pad of the Kuparuk River Unit, Kuparuk field. Five wells have been drilled into the SMU as follows: the Kuparuk River Unit 2L-03 well drilled in the south (2002), the North Tarn 1 (2011), and 1A (2012) wells situated in the center, the Mustang 1 (2012) and SMU M-02 (2014) wells drilled to the eastern side. All of these wells encountered Early Cretaceous-age Upper Kuparuk River Formation sandstones, which make up the oil development objective of the SMU and the prolific oil producer in the Kuparuk River and Palm fields.

The Kuparuk River Formation includes several sandstone and shale members above the Kingak Formation and below the Kalubik Shale Formation. The main objective oil interval includes the bioturbated shallow marine C sandstone lobe, which, where present, has a net sand true vertical thickness (TVT) of generally 15 feet to more than 50 feet in the local multi-field area. This clean and blocky sand lobe often includes siderite and glauconite components, but core data in offset wells indicate permeability of 1 to 10 millidarcys within these heteromineralogy zones. The regional Upper Cretaceous unconformity lies at the base of the C lobe. The thin-bedded progradational lower shoreface sandstones of the upper A interval of the Kuparuk River Formation lie beneath the unconformity and, where paleotopography and faulting are favorable, are preserved and contribute as an oil-bearing lower component to the overall reservoir. In the wells drilled within the SMU, the net oil varies from 17 to 25 feet TVT at an average depth of 6,035 feet true vertical depth subsea (TVDSS). Reservoir thickness in the North Tarn 1 well was estimated from mud log oil shows, since well difficulties precluded obtaining a wireline log suite. The North Tarn 1A well penetrated the reservoir within 1,000 feet of the original hole and had 17 feet TVT of net oil. The 1A well was pressure and flow tested in January 2012 and produced oil at a rate of 62 barrels per day with a very high wellbore skin value of 47.7. Average net oil thickness for the SMU is 17.5 feet TVT. Average porosity and water saturation for the SMU are 21.1 percent and 19.3 percent, respectively.

The Kuparuk River Formation in the SMU exhibits a moderately faulted undulating structure that varies from 5,900 to 6,200 feet TVDSS. A dual-direction tensional stress regime is manifested in a bimodal normal fault pattern. This is dominated by a series of north/south-trending, down-to-the-east normal faults, which are complemented by multiple northwest/southeast-trending cross faults. The displacements across these faults within the SMU may be sufficient to effect reservoir separation and cause compartmentalization. Seismic data also indicate fault separation from the 2M drilling pad development of the Kuparuk River Unit, Kuparuk field, which borders the SMU to the east and northeast. However, an initial pressure buildup test, conducted in the North Tarn 1A well, indicated that the Kuparuk C reservoir was approximately 500 pounds per square inch above the expected pressure. The elevated pressures at the North Tarn 1A well are most likely caused by the current waterflood operations in the Kuparuk River Unit and support the interpretation that the C sand is continuous between the Kuparuk River Unit waterflood injectors and the location of the North Tarn 1A well.

The SMU was recognized by the Division of Oil and Gas of the State of Alaska on January 26, 2012, subject to the completion of additional well work and sanction by BRPC by October 1, 2012. CaraCol has represented that those requirements have been met, and that development has been ongoing. On March 30, 2016, BRPC and CaraCol received approval from the State of Alaska, Department of Natural Resources, to extend the term of the SMU until December 31, 2017. Based on the development schedule provided herein, the Unit will be producing in commercial quantities before December 31, 2017, and the Unit will remain in effect for so long as commercial quantities are being produced.

SOUTHERN MILUVEACH UNIT DEVELOPMENT

The development of the SMU from a single drillsite pad (the Mustang pad), the capital costs necessary to construct the Mustang drillsite pad, the schedule of development, and the expenses to operate were provided by CaraCol and BRPC. The development plan, the associated capital costs, and the operating expenses appeared reasonable and were accepted as presented.

As part of the overall development of the SMU, CaraCol has represented that one of the other working interest owners (with 20-percent ownership) in the project is to pay for the cost of the surface production facilities. The contractual arrangement between this surface facility working interest owner and the remaining working interest owners is similar to a purchase/lease back arrangement. Any funds accruing from the 20-percent working interest that are over and above the calculated lease payments are to be refunded to the other working interest owners. Any potential payments from the surface facility working interest owner to CaraCol have not been included in this analysis. CaraCol and the other remaining working interest owners are to pay for the cost to drill and complete the wells. Because of this arrangement, CaraCol is expected to pay 55.263 percent of the drilling and completion costs.

The proved estimate of reserves presented herein requires the drilling and completion of 8 single-lateral horizontal wells paired with 13 vertical water injection wells to effectively waterflood the targeted Kuparuk C reservoir. The proposed Mustang drill pad is located at the surface site of the existing North Tarn 1, 1A, and Mustang 1 wellbores in section 2 (Figure 1). The sections developed in the proved reserves estimate are the nine contiguous sections centered around the proposed Mustang drill pad in section 2, as well as section 25. This area is generally within a 12,000-foot drilling radius from the centralized planned drillsite pad location and also is located above the lowest known oil (LKO) depth at 6,105 feet TVDSS, which is seen in the Kuparuk River Unit 2L-03 well.

The planned proved reserves development is to orient the 8 horizontal producers and 13 vertical water injectors in a parallel direction with the dominant north-south faulting in order to minimize areas of stranded oil. Because it is unknown if these faults are sealing, each horizontal producer will be paired with one or two vertical water injectors located approximately 2,500 to 5,000 feet away so that they both lie within the same fault block. The north/south-oriented horizontal laterals are estimated to range in length between 5,000 and 8,000 feet and are estimated to cost an average of U.S.$12.4 million each. Since it is uncertain whether BRPC will be able to re-enter the Mustang 1 wellbore, extend the well horizontally, and complete it as a horizontal producer along the eastern boundary, capital has been included to re-drill the well. The rate forecast for the proved case was estimated using the BRPC full-field model. The recovery factor for the proved reserves case is approximately 30 percent of the original oil in place (OOIP) in the SMU.

The proved reserves development schedule represents the following: the gravel road and pad have already been installed; equipment procurement is underway and module fabrication is to finish by late 2016 to early 2017; module transportation to the North Slope is to begin by mid-2017 and installation to finish by the end of 2017. Functional check out and commissioning is planned for the third quarter of 2017 with an anticipated plant startup date of November 1, 2017. Development drilling is planned to resume in July 2017. The development drilling is expected to continue until May 2019.

The proposed production facilities on the Mustang pad are to be designed with a capacity of 15,000 barrels of fluid per day (BFPD). It is anticipated that initial oil production from the eight horizontal producing wells will be able to exceed the 15,000 BFPD limit. As such, the total oil production from the field is estimated to reach 15,000 barrels of oil per day (BOPD) by the first half of 2018 as the producers are completed, and remain at 15,000 BOPD throughout 2018. It is projected that water production will begin to increase after 2018 as water breakthrough occurs between the paired injectors and producers, and oil production will begin to decline as the total fluid produced remains at the production facility capacity of 15,000 BFPD.

The estimate of probable reserves presented herein requires the drilling and completion of one additional horizontal producer and two vertical injectors, in addition to those planned for the proved reserves development. These additional laterals are required to develop the Kuparuk C reservoir in the western sections of the SMU under sections 4 and 9. For the probable reserves estimate, the oil productive limits of the Kuparuk C have been extrapolated downdip an additional 50 feet below the LKO to 6,155 feet TVDSS, and the probable reserves recovery factor was increased from 30 percent, used in the proved reserves evaluation, to 35 percent. The estimate of possible reserves presented herein does not require any additional wells over that contemplated under the probable reserves development. For the possible reserves estimate, the recovery factor was increased from 35 percent used in the probable reserves evaluation to 40 percent.

Figure 1 below is a map of the SMU development plan showing the boundaries of the SMU and the locations of the proposed horizontal producers and high-angle injectors.

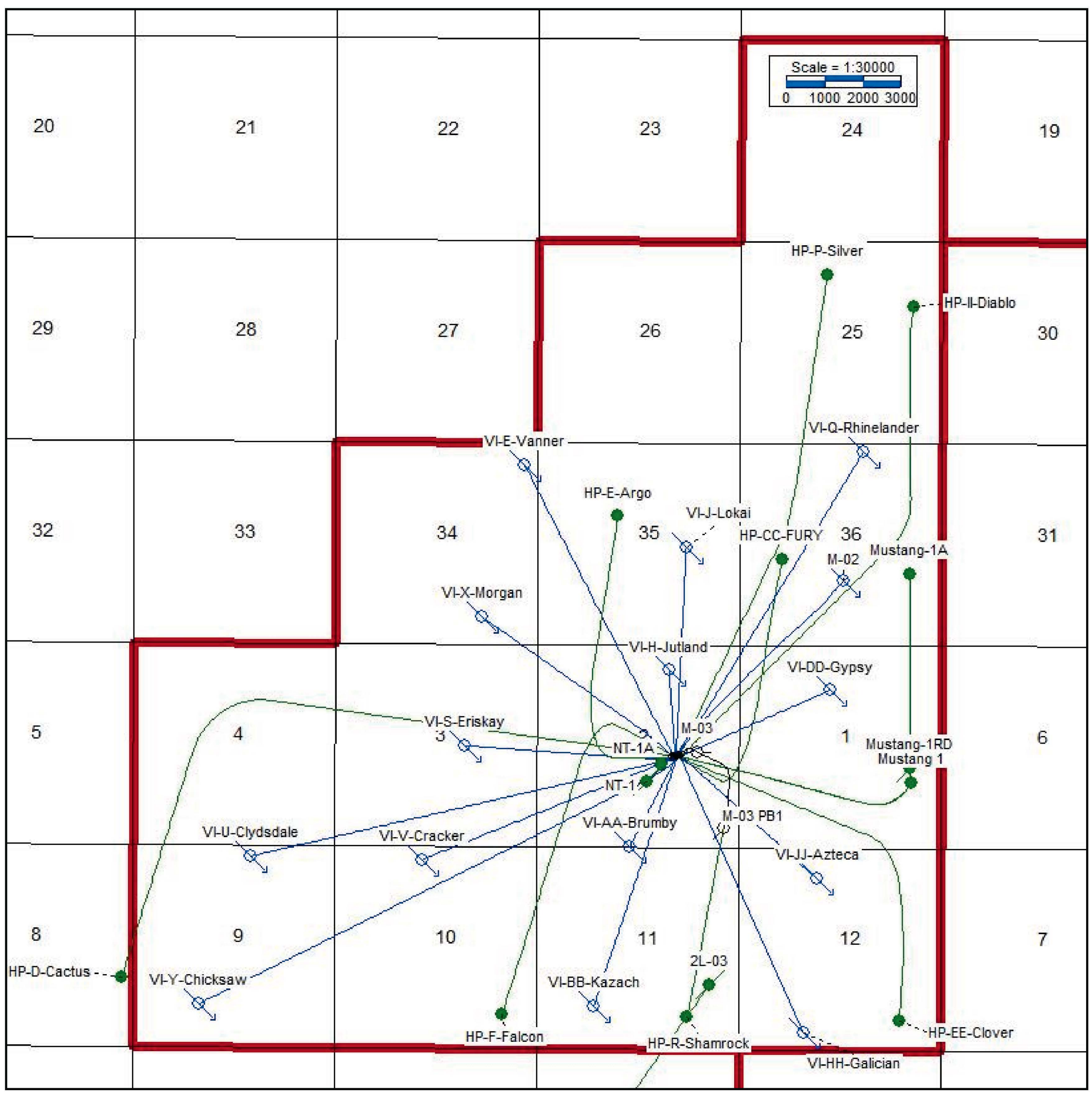

Figure 1: SMU development plan map

No gas reserves have been evaluated for this report. There are no gas sales markets available on the North Slope and all gas that is to be produced is expected to be either used as fuel or reinjected for pressure maintenance.

ESTIMATION of RESERVES

Estimates of reserves presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry were used. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by CaraCol, and the analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

The volumetric method was used to estimate the OOIP. Structure maps were prepared by BRPC and reviewed for this report to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. Simulation results prepared by a third party and provided by BRPC for this report were also used to help estimate the anticipated future recoverable volumes.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and analogous production histories in the Kuparuk C reservoir in the nearby Kuparuk River field and Palm field. An analysis of analogous reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

The estimated proved (1P), proved-plus-probable (2P), and proved-plus-probable-plus-possible (3P) reserves, as of

March 31, 2016, expressed in millions of barrels (MMbbl), for the proposed SMU development are summarized as follows:

Category	Gross Attributable to License (MMbbl)	Net Attributable to CaraCol (MMbbl)	Change from Previous Update (percent)	Remarks
Oil Reserves				
1P	20.2	6.2	(7.5)	Approximately 30-Percent Recovery
2P	32.6	10.0	(2.0)	Approximately 35-Percent Recovery
3P	37.2	11.4	(0.9)	Approximately 40-Percent Recovery

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. All oil reserves estimated herein are considered undeveloped.

Oil reserves estimated herein are those to be recovered by conventional lease separation. Oil reserves estimates included in the appendix to this report are expressed in terms of barrels (bbl), in which 1 barrel equals 42 United States gallons.

FINANCIAL ANALYSIS

Revenue values in this report were estimated using prices and expenditures provided by CaraCol and BRPC. Future prices were estimated using prices provided by CaraCol, and were considered to be reasonable. Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable or possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values for probable and possible reserves have not been adjusted to account for such risks; this adjustment would be necessary in order to make revenue values for probable and possible reserves comparable with revenue values for proved reserves.

The following assumptions supplied by BRPC were used for estimating future prices and costs.

Oil Prices

An oil price forecast based on the future monthly prices traded on the New York Mercantile Exchange (NYMEX) for crude oil on March 31, 2016, was used in estimating the future net revenue. The oil prices were not adjusted or escalated for inflation. The average annual oil prices, based on the NYMEX future prices, applied to the properties in this report were as follows, expressed in United States dollars per barrel (U.S.$/bbl):

Year	**Oil (U.S.$/bbl)**
2016	40.67
2017	44.60
2018	46.81
2019	48.52
2020	49.85
2021	50.84
2022	51.74
2023	52.27
2024 *and thereafter*	52.64

Operating Expenses, Transportation Expenses, Capital Costs, and Abandonment Costs

Operating expenses, transportation expenses, capital costs, and abandonment costs (in 2015 United States dollars) were provided by CaraCol and BRPC. Estimates of operating expenses, based on estimated future fixed and variable expenses, transportation expenses, and capital costs were held constant for the lives of the properties and were not adjusted or escalated for inflation. The costs of surface facilities are paid by a separate legal entity established for the sole purpose of financing said facilities. CaraCol has represented that it is contractually responsible for a disproportionate share of 55.263 percent of the drilling capital.

Production Taxes and Ad Valorem Taxes

The severance tax law, SB21, in the State of Alaska is very complex. Provisions of the new law include a variety of capital, loss carry forward, and small producer tax credits. The large negative production taxes in the early years of the project are primarily due to loss carry forward credits payable under SB21 that are generated from the high capital expenditures required for the SMU development. CaraCol and BRPC have represented that each intends to apply to the State of Alaska each year, where applicable, for Alaska to purchase the applicable tax credit. Based on this representation, the value of the tax credit has been included as a negative production tax payment herein. CaraCol has represented that it is eligible for the small-producer tax credit, and at CaraCol's request, this credit has been included in the production tax calculation herein. A Crude Conservation Tax of $0.05 per barrel of net production has also been included in the production tax calculation.

Ad valorem taxes were calculated at 2 percent of the depreciated capital investment, including tangible drilling costs. As of March 31, 2016, the estimated balance for ad valorem tax purposes was $24 million.

The estimated future revenue and costs to be derived from the production and sale of CaraCol's estimated net reserves, as of March 31, 2016, for the development of the SMU are summarized as follows, expressed in thousands of United States dollars (M U.S.$):

	1P (M U.S.$)	2P (M U.S.$)	3P (M U.S.$)
Future Gross Revenue	308,810	504,249	577,013
Ad Valorem and Production Taxes	(19,986)	(11,351)	(7,690)
Transportation Expenses	59,152	95,654	108,974
Operating Expenses	85,295	118,379	137,742
Capital and Abandonment Costs	120,372	126,665	126,666
Future Net Revenue	63,977	174,902	211,321
Present Worth at 10 Percent	34,325	88,719	100,864

Notes:
1. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.
2. Future income taxes were not taken into account in the preparation of these estimates.

The appendix bound with this report includes (1) a summary projection of estimated proved reserves and revenue, (2) a summary projection of estimated proved-plus-probable reserves and revenue, and (3) a summary projection of estimated proved-plus-probable-plus-possible reserves and revenue.

SUMMARY and CONCLUSIONS

BRPC is developing certain properties located in the SMU on the North Slope, Alaska. CaraCol has represented that it owns a 38.187-percent working interest in the project. The estimated proved (1P), proved-plus-probable (2P), and proved-plus-probable-plus-possible (3P) oil reserves of the properties evaluated, as of March 31, 2016, are summarized as follows, expressed in thousands of barrels (Mbbl):

Category	Gross Oil (Mbbl)	Company Gross Oil (Mbbl)	Net Oil (Mbbl)
1P	20,169	7,702	6,162
2P	32,616	12,455	9,964
3P	37,158	14,189	11,351

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. All oil reserves estimated herein are considered undeveloped.

Estimated future net revenue attributable to CaraCol's interests in the SMU, as of March 31, 2016, of the properties evaluated under the aforementioned assumptions concerning future prices and costs is summarized as follows, expressed in thousands of United States dollars (M U.S.$):

	1P (M U.S.$)	2P (M U.S.$)	3P (M U.S.$)
Future Gross Revenue	308,810	504,249	577,013
Future Net Revenue	63,977	174,902	211,321
Present Worth at 10 Percent	34,325	88,719	100,864

Notes:
1. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.
2. Future income taxes were not taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil reserves, we are not aware of any such governmental actions which would restrict the recovery of the March 31, 2016, estimated oil reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of CaraCol. DeGolyer and MacNaughton has used all assumptions, procedures, data, and methods that it considers necessary to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

SIGNED: May 27, 2016

STATE OF TEXAS
DENNIS W. THOMPSON
55079
REGISTERED
PROFESSIONAL ENGINEER

Dennis W. Thompson, P.E.

Dennis W. Thompson, P.E.
Senior Vice President
DeGolyer and MacNaughton

PROJECTION OF ESTIMATED PROVED PRODUCTION AND REVENUE
AS OF MARCH 31, 2016
FROM CERTAIN PROPERTIES OWNED BY
CARACOL PETROLEUM, LLC

GRAND TOTAL

Year Ending Dec 31	Completions	Gross Oil Production (bbl)	Company Gross Oil Production (bbl)	Net Oil Production (bbl)
2016	0	0	0	0
2017	3	458,986	175,272	140,218
2018	8	3,984,747	1,521,649	1,217,319
2019	8	2,998,142	1,144,896	915,917
2020	8	2,384,693	910,639	728,511
2021	8	1,792,799	684,613	547,691
2022	8	1,419,551	542,082	433,665
2023	8	1,187,930	453,633	362,906
2024	8	1,020,288	389,615	311,693
2025	8	882,642	337,054	269,642
2026	8	774,170	295,631	236,505
2027	8	687,507	262,537	210,030
2028	8	617,821	235,926	188,741
2029	8	555,670	212,193	169,754
2030	8	506,301	193,340	154,673
2031	8	465,519	177,767	142,213
2032	8	432,721	165,243	132,194
2033	0	0	0	0
2034				
2035				
Subtotal		20,169,487	7,702,090	6,161,672
Remaining		0	0	0
Total		**20,169,487**	**7,702,090**	**6,161,672**
Cumulative		0		
Ultimate		20,169,487		

Year Ending Dec 31	Oil Prices ($/bbl)	Future Gross Revenue Oil ($)	Future Gross Revenue Total ($)	Ad Valorem Taxes ($)	Production Taxes ($)	Transportation Expenses ($)
2016		0	0	655,579	-15,451,648	0
2017	44.60	6,253,714	6,253,714	701,019	-262,279	1,346,091
2018	46.81	56,982,716	56,982,716	1,388,849	-12,293,852	11,686,265
2019	48.52	44,440,276	44,440,276	1,374,548	-5,702,694	8,792,800
2020	49.85	36,316,283	36,316,283	1,294,392	36,425	6,993,707
2021	50.84	27,844,594	27,844,594	1,194,820	27,385	5,257,831
2022	51.74	22,437,847	22,437,847	1,095,254	21,684	4,163,188
2023	52.27	18,969,116	18,969,116	995,686	18,146	3,483,901
2024	52.64	16,407,500	16,407,500	896,116	15,585	2,992,249
2025	52.64	14,193,981	14,193,981	796,548	13,482	2,588,568
2026	52.64	12,449,616	12,449,616	696,982	11,827	2,270,447
2027	52.64	11,055,968	11,055,968	597,410	10,503	2,016,286
2028	52.64	9,935,330	9,935,330	497,843	9,435	1,811,914
2029	52.64	8,935,865	8,935,865	398,272	8,487	1,629,641
2030	52.64	8,141,949	8,141,949	315,505	7,735	1,484,854
2031	52.64	7,486,125	7,486,125	315,504	7,112	1,365,251
2032	52.64	6,958,692	6,958,692	315,504	6,608	1,269,062
2033		0	0	0	0	0
2034						
2035						
Subtotal	50.12	308,809,572	308,809,572	13,529,831	-33,516,059	59,152,055
Remaining		0	0	0	0	0
Total	**50.12**	**308,809,572**	**308,809,572**	**13,529,831**	**-33,516,059**	**59,152,055**

Year Ending Dec 31	Lease Expenses ($)	Lifting Expenses ($)	Capital and Abandonment Costs ($)	Total Expenditures ($)	Future Net Revenue Annual ($)	Future Net Revenue Cumulative ($)	Present Worth at 10 Percent Annual ($)	Present Worth at 10 Percent Cumulative ($)
2016	33,132	0	248,684	281,816	14,514,253	14,514,253	13,948,860	13,948,860
2017	2,437,469	227,856	37,523,686	41,535,102	-35,720,128	-21,205,875	-31,083,499	-17,134,639
2018	5,579,988	2,112,234	56,650,265	76,028,752	-8,141,033	-29,346,908	-7,050,454	-24,185,093
2019	3,610,695	1,972,622	13,042,106	27,418,223	21,350,199	-7,996,709	15,254,831	-8,930,262
2020	3,027,555	2,136,190	0	12,157,452	22,828,014	14,831,305	15,210,767	6,280,505
2021	3,026,178	2,205,201	0	10,489,210	16,133,179	30,964,484	9,773,138	16,053,643
2022	3,023,136	2,237,139	0	9,423,463	11,897,446	42,861,930	6,548,092	22,601,735
2023	3,019,553	2,257,095	0	8,760,549	9,194,735	52,056,665	4,599,780	27,201,515
2024	3,016,011	2,277,969	0	8,286,229	7,209,570	59,266,235	3,278,712	30,480,227
2025	3,011,734	2,282,471	0	7,882,773	5,501,178	64,767,413	2,274,183	32,754,410
2026	3,007,768	2,293,919	0	7,572,134	4,168,673	68,936,086	1,566,920	34,321,330
2027	3,003,759	2,304,379	0	7,324,424	3,123,631	72,059,717	1,067,557	35,388,887
2028	2,999,971	2,319,791	0	7,131,676	2,296,376	74,356,093	713,775	36,102,662
2029	2,995,476	2,319,461	0	6,944,578	1,584,528	75,940,621	447,849	36,550,511
2030	2,991,297	2,326,182	0	6,802,333	1,016,376	76,956,997	261,349	36,811,860
2031	2,990,692	2,331,837	0	6,687,780	475,729	77,432,726	111,508	36,923,368
2032	2,991,253	2,344,345	0	6,604,660	31,920	77,464,646	7,361	36,930,729
2033	580,822	0	12,907,152	13,487,974	-13,487,974	63,976,672	-2,605,650	34,325,079
2034								
2035								
Subtotal	51,346,489	33,948,691	120,371,893	264,819,128	63,976,672		34,325,079	
Remaining						63,976,672		34,325,079
Total	**51,346,489**	**33,948,691**	**120,371,893**	**264,819,128**	**63,976,672**		**34,325,079**	

Gross Completions

Oil	Gas
8	0

Month of Last Production: 12/2033

Interests (Percent)

Date	Working	Revenue

Present Worth Profile ($)

5.00 Percent	47,271,532
9.00 Percent	36,625,015
12.00 Percent	30,119,796
15.00 Percent	24,703,101
20.00 Percent	17,644,426
25.00 Percent	12,476,293
30.00 Percent	8,684,742

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

PROJECTION OF ESTIMATED PROVED PLUS PROBABLE PRODUCTION AND REVENUE
AS OF MARCH 31, 2016
FROM CERTAIN PROPERTIES OWNED BY
CARACOL PETROLEUM, LLC

GRAND TOTAL

Year Ending Dec 31	Completions	Gross Oil Production (bbl)	Company Gross Oil Production (bbl)	Net Oil Production (bbl)
2016	0	0	0	0
2017	3	428,400	163,592	130,874
2018	8	4,633,800	1,769,502	1,415,602
2019	9	4,292,495	1,639,168	1,311,334
2020	9	3,754,906	1,433,880	1,147,104
2021	9	2,804,844	1,071,082	856,865
2022	9	2,187,223	835,231	668,186
2023	9	1,793,915	685,039	548,031
2024	9	1,524,909	582,315	465,852
2025	9	1,320,000	504,066	403,253
2026	9	1,166,403	445,413	356,330
2027	9	1,044,899	399,014	319,211
2028	9	948,841	362,332	289,866
2029	9	864,643	330,180	264,144
2030	9	796,103	304,006	243,205
2031	9	737,565	281,653	225,322
2032	9	687,487	262,530	210,024
2033	9	637,583	243,473	194,778
2034	9	592,982	226,441	181,153
2035	9	551,501	210,600	168,481
Subtotal		30,768,499	11,749,517	9,399,615
Remaining		1,847,353	705,446	564,357
Total		**32,615,852**	**12,454,963**	**9,963,972**
Cumulative		0		
Ultimate		32,615,852		

Year Ending Dec 31	Oil Prices ($/bbl)	Future Gross Revenue Oil ($)	Future Gross Revenue Total ($)	Ad Valorem Taxes ($)	Production Taxes ($)	Transportation Expenses ($)
2016		0	0	658,377	-15,451,648	0
2017	44.60	5,836,978	5,836,978	714,945	-263,769	1,256,390
2018	46.81	66,264,310	66,264,310	1,415,505	-12,408,073	13,589,775
2019	48.52	63,625,952	63,625,952	1,429,454	-2,950,506	12,588,812
2020	49.85	57,183,150	57,183,150	1,388,002	57,354	11,012,201
2021	50.84	43,563,014	43,563,014	1,318,600	42,841	8,225,904
2022	51.74	34,571,908	34,571,908	1,249,200	33,410	6,414,579
2023	52.27	28,645,604	28,645,604	1,179,799	27,403	5,261,101
2024	52.64	24,522,432	24,522,432	1,110,399	23,293	4,472,177
2025	52.64	21,227,249	21,227,249	1,041,002	20,162	3,871,230
2026	52.64	18,757,201	18,757,201	971,602	17,817	3,420,766
2027	52.64	16,803,279	16,803,279	902,201	15,960	3,064,428
2028	52.64	15,258,551	15,258,551	832,800	14,495	2,782,715
2029	52.64	13,904,525	13,904,525	763,399	13,206	2,535,779
2030	52.64	12,802,328	12,802,328	693,998	12,162	2,334,771
2031	52.64	11,860,965	11,860,965	624,602	11,268	2,163,094
2032	52.64	11,055,648	11,055,648	555,202	10,503	2,016,228
2033	52.64	10,253,132	10,253,132	485,801	9,738	1,869,872
2034	52.64	9,535,887	9,535,887	416,400	9,059	1,739,068
2035	52.64	8,868,814	8,868,814	346,999	8,422	1,617,413
Subtotal	50.49	474,540,927	474,540,927	18,098,287	-30,746,903	90,236,303
Remaining	52.64	29,707,744	29,707,744	1,268,891	28,219	5,417,825
Total	**50.61**	**504,248,671**	**504,248,671**	**19,367,178**	**-30,718,684**	**95,654,128**

Year Ending Dec 31	Lease Expenses ($)	Lifting Expenses ($)	Capital and Abandonment Costs ($)	Total Expenditures ($)	Future Net Revenue Annual ($)	Future Net Revenue Cumulative ($)	Present Worth at 10 Percent Annual ($)	Present Worth at 10 Percent Cumulative ($)
2016	33,258	0	248,684	281,942	14,511,329	14,511,329	13,946,051	13,946,051
2017	2,437,412	212,670	37,523,684	41,430,156	-36,044,354	-21,533,025	-31,359,174	-17,413,123
2018	5,589,653	2,300,352	56,650,264	78,130,044	-873,166	-22,406,191	-1,248,920	-18,662,043
2019	3,902,366	2,182,194	19,259,210	37,932,582	27,214,422	4,808,231	19,466,437	804,394
2020	3,036,464	2,240,559	0	16,289,224	39,448,570	44,256,801	26,275,060	27,079,454
2021	3,032,184	2,214,895	0	13,472,983	28,728,590	72,985,391	17,398,120	44,477,574
2022	3,028,173	2,195,115	0	11,637,867	21,651,431	94,636,822	11,915,022	56,392,596
2023	3,024,167	2,175,533	0	10,460,801	16,977,601	111,614,423	8,491,526	64,884,122
2024	3,020,437	2,162,027	0	9,654,641	13,734,099	125,348,522	6,243,241	71,127,363
2025	3,016,184	2,136,901	0	9,024,315	11,141,770	136,490,292	4,603,268	75,730,631
2026	3,012,205	2,117,901	0	8,550,872	9,216,910	145,707,202	3,461,675	79,192,306
2027	3,008,236	2,099,090	0	8,171,754	7,713,364	153,420,566	2,633,569	81,825,875
2028	3,004,530	2,086,142	0	7,873,387	6,537,869	159,958,435	2,029,147	83,855,022
2029	3,000,321	2,061,980	0	7,598,080	5,529,840	165,488,275	1,559,995	85,415,017
2030	2,996,375	2,043,729	0	7,374,875	4,721,293	170,209,568	1,210,856	86,625,873
2031	2,992,440	2,025,659	0	7,181,193	4,043,902	174,253,470	942,887	87,568,760
2032	2,988,757	2,013,247	0	7,018,232	3,471,711	177,725,181	735,957	88,304,717
2033	2,984,590	1,990,012	0	6,844,474	2,913,119	180,638,300	561,373	88,866,090
2034	2,980,677	1,972,480	0	6,692,225	2,418,203	183,056,503	423,725	89,289,815
2035	2,976,774	1,955,122	0	6,549,309	1,964,084	185,020,587	312,947	89,602,762
Subtotal	60,065,203	38,185,608	113,681,842	302,168,956	185,020,587		89,602,762	
Remaining	12,472,099	7,655,506	12,983,526	38,528,956	-10,118,322	174,902,265	-883,560	88,719,202
Total	**72,537,302**	**45,841,114**	**126,665,368**	**340,697,912**	**174,902,265**		**88,719,202**	

Gross Completions Oil	Gross Completions Gas
9	0

Month of Last Production: 12/2040

Interests (Percent) Date	Working	Revenue

Present Worth Profile ($)	
5.00 Percent	123,301,219
9.00 Percent	94,585,050
12.00 Percent	78,264,940
15.00 Percent	65,263,531
20.00 Percent	48,967,515
25.00 Percent	37,360,260
30.00 Percent	28,906,434

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

PROJECTION OF ESTIMATED PROVED PLUS PROBABLE PLUS POSSIBLE PRODUCTION AND REVENUE
AS OF MARCH 31, 2016
FROM CERTAIN PROPERTIES OWNED BY
CARACOL PETROLEUM, LLC

GRAND TOTAL

Year Ending Dec 31	Completions	Gross Oil Production (bbl)	Company Gross Oil Production (bbl)	Net Oil Production (bbl)
2016	0	0	0	0
2017	3	428,400	163,592	130,874
2018	8	4,633,800	1,769,502	1,415,602
2019	9	4,305,695	1,644,209	1,315,367
2020	9	3,850,996	1,470,574	1,176,459
2021	9	2,983,917	1,139,463	911,571
2022	9	2,386,960	911,505	729,203
2023	9	1,990,355	760,053	608,043
2024	9	1,711,683	653,638	522,911
2025	9	1,494,526	570,713	456,570
2026	9	1,329,444	507,672	406,138
2027	9	1,197,288	457,207	365,765
2028	9	1,091,938	416,976	333,581
2029	9	998,625	381,344	305,075
2030	9	922,257	352,181	281,745
2031	9	856,757	327,168	261,734
2032	9	802,076	306,287	245,030
2033	9	749,988	286,397	229,118
2034	9	704,821	269,149	215,319
2035	9	662,561	253,011	202,409
Subtotal		33,102,087	12,640,641	10,112,514
Remaining		4,055,579	1,548,698	1,238,958
Total		**37,157,666**	**14,189,339**	**11,351,472**
Cumulative		0		
Ultimate		37,157,666		

Year Ending Dec 31	Oil Prices ($/bbl)	Future Gross Revenue Oil ($)	Future Gross Revenue Total ($)	Ad Valorem Taxes ($)	Production Taxes ($)	Transportation Expenses ($)
2016		0	0	659,367	-15,451,648	0
2017	44.60	5,836,978	5,836,978	719,820	-264,131	1,256,390
2018	46.81	66,264,310	66,264,310	1,424,803	-12,409,855	13,589,775
2019	48.52	63,821,618	63,821,618	1,448,293	-2,953,705	12,627,525
2020	49.85	58,646,488	58,646,488	1,416,976	58,825	11,294,008
2021	50.84	46,344,264	46,344,264	1,357,936	45,576	8,751,081
2022	51.74	37,728,996	37,728,996	1,298,896	36,463	7,000,355
2023	52.27	31,782,407	31,782,407	1,239,857	30,404	5,837,212
2024	52.64	27,525,995	27,525,995	1,180,816	26,147	5,019,939
2025	52.64	24,033,839	24,033,839	1,121,777	22,830	4,383,070
2026	52.64	21,379,112	21,379,112	1,062,732	273,062	3,898,927
2027	52.64	19,253,889	19,253,889	1,003,692	65,024	3,511,347
2028	52.64	17,559,709	17,559,709	944,653	16,680	3,202,379
2029	52.64	16,059,136	16,059,136	885,612	15,255	2,928,718
2030	52.64	14,831,046	14,831,046	826,572	14,087	2,704,750
2031	52.64	13,777,712	13,777,712	767,528	13,087	2,512,652
2032	52.64	12,898,372	12,898,372	708,488	12,254	2,352,287
2033	52.64	12,060,743	12,060,743	649,449	11,456	2,199,528
2034	52.64	11,334,409	11,334,409	590,408	10,764	2,067,065
2035	52.64	10,654,792	10,654,792	531,368	10,122	1,943,123
Subtotal	50.61	511,793,815	511,793,815	19,839,043	-30,417,303	97,080,131
Remaining	52.64	65,218,767	65,218,767	2,825,965	61,941	11,894,000
Total	**50.83**	**577,012,582**	**577,012,582**	**22,665,008**	**-30,355,362**	**108,974,131**

Year Ending Dec 31	Lease Expenses ($)	Lifting Expenses ($)	Capital and Abandonment Costs ($)	Total Expenditures ($)	Future Net Revenue Annual ($)	Future Net Revenue Cumulative ($)	Present Worth at 10 Percent Annual ($)	Present Worth at 10 Percent Cumulative ($)
2016	33,302	0	248,684	281,986	14,510,295	14,510,295	13,945,057	13,945,057
2017	2,437,632	212,670	37,523,686	41,430,378	-36,049,089	-21,538,794	-31,363,361	-17,418,304
2018	5,590,072	2,300,352	56,650,265	78,130,464	-881,102	-22,419,896	-1,255,301	-18,673,605
2019	3,903,214	2,182,194	19,259,211	37,972,144	27,354,886	4,934,990	19,566,462	892,857
2020	3,037,767	2,240,559	0	16,572,334	40,598,353	45,533,343	27,031,453	27,924,310
2021	3,033,955	2,214,895	0	13,999,931	30,940,821	76,474,164	18,731,569	46,655,879
2022	3,030,409	2,195,115	0	12,225,879	24,167,758	100,641,922	13,296,547	59,952,426
2023	3,026,870	2,175,533	0	11,039,615	19,472,531	120,114,453	9,737,462	69,689,888
2024	3,023,605	2,162,027	0	10,205,571	16,113,461	136,227,914	7,323,541	77,013,429
2025	3,019,819	2,136,901	0	9,539,790	13,349,442	149,577,356	5,514,484	82,527,913
2026	3,016,306	2,117,901	0	9,033,134	11,010,184	160,587,540	4,134,640	86,662,553
2027	3,012,803	2,099,090	0	8,623,240	9,561,933	170,149,473	3,264,232	89,926,785
2028	3,009,563	2,086,142	0	8,298,084	8,300,292	178,449,765	2,575,709	92,502,494
2029	3,005,821	2,061,980	0	7,996,519	7,161,750	185,611,515	2,020,037	94,522,531
2030	3,002,340	2,043,729	0	7,750,819	6,239,568	191,851,083	1,599,969	96,122,500
2031	2,998,872	2,025,659	0	7,537,183	5,459,914	197,310,997	1,272,809	97,395,309
2032	2,995,656	2,013,247	0	7,361,190	4,816,440	202,127,437	1,020,708	98,416,017
2033	2,991,954	1,990,012	0	7,181,494	4,218,344	206,345,781	812,567	99,228,584
2034	2,988,507	1,972,480	0	7,028,052	3,705,185	210,050,966	648,902	99,877,486
2035	2,985,070	1,955,122	0	6,883,315	3,229,987	213,280,953	514,319	100,391,805
Subtotal	60,143,537	38,185,608	113,681,846	309,091,122	213,280,953		100,391,805	
Remaining	24,366,484	15,046,507	12,983,526	64,290,517	-1,959,656	211,321,297	471,866	100,863,671
Total	**84,510,021**	**53,232,115**	**126,665,372**	**373,381,639**	**211,321,297**		**100,863,671**	

Gross Completions Oil	Gross Completions Gas
9	0

Month of Last Production: 12/2044

Interests (Percent)

Date	Working	Revenue

Present Worth Profile ($)	
5.00 Percent	143,631,866
9.00 Percent	107,969,852
12.00 Percent	88,347,131
15.00 Percent	73,041,317
20.00 Percent	54,249,459
25.00 Percent	41,115,745
30.00 Percent	31,672,660

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM