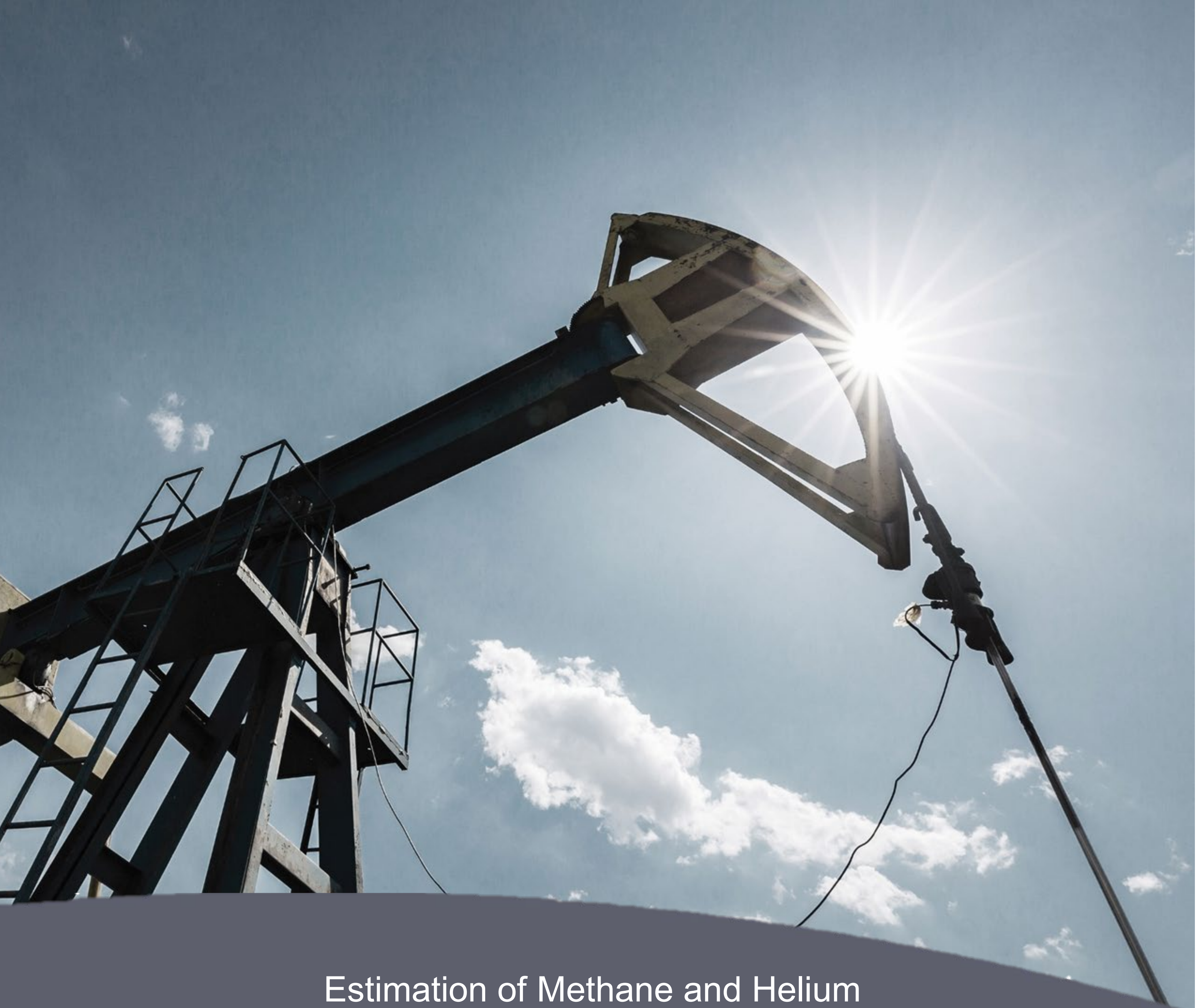

Estimation of Methane and Helium Contingent and Prospective Resources in the Motuoane Gas Project, Free State Province, Republic of South Africa, as of December 1, 2022

Prepared for D3 Energy Limited
January 2023

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Sproule

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Prepared for:	**D3 Energy Limited**	
Project No.:	25805.111137	
Distribution:	D3 Limited	
	Summary Volume	(Digital copy)
	Sproule	(Full digital copy retained)
Editor:	JLD	
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Sproule

January 30, 2023

Mr. David Casey
Executive Director – Technical
D3 Energy Limited
945 Wellington Street
West Perth WA 6005
Australia

RE: Estimation of Methane and Helium Contingent and Prospective Resources in the Motuoane Gas Project, Free State Province, Republic of South Africa, as of December 1, 2022

Dear Mr. Casey,

At the request of D3 Energy Limited ("D3"), Sproule Incorporated ("Sproule"), an independent sub-surface consultancy based in Calgary, Canada, has conducted an independent evaluation of unconventional methane and helium resources in Motuoane License, 315ER, east of the Tetra4 production right 24/04/07PR, located in the Free State of the Republic of South Africa. This geologic and engineering evaluation, based on the analysis methodology described herein, utilizes technical and economic data supplied by D3 has an effective date of December 1, 2022. This evaluation includes estimates of recoverable methane and helium volumes from Contingent Resources. Contingent Resources have commercial risk. Sproule has estimated the volumes of Contingent Resources, those volumes of gases that are discovered but are not yet considered commercially viable for extraction due to one or more contingencies. Sproule has also estimated the volumes of Prospective Resources, those volumes of gases that are undiscovered, but the likelihood of their existence can be estimated. Prospective Resources thus carry significant exploration risk. The estimates of Resources and future net revenue for individual properties may not reflect the same confidence level as estimates of Resources and future net revenue for all properties, because of aggregation. Further, estimates of Net Present Value, either discounted or undiscounted, are a calculation of the Resource value at a given date and are not a representation of the fair market value of a company or corporation owning a working interest in the project.

Resource Estimates

The independent Resource estimates and contained in this report are prepared in accordance with the Society of Petroleum Engineers (SPE) Petroleum Resources Management (PRMS) guidance and all volumes are calculated upon a standard pressure of 14.7 psia (101.325 kPa) and a temperature of 60 F (15.6 C). This study provides a Technical Value, defined as an assessment of a mineral asset's future net economic benefit at the valuation date under a set of assumptions deemed most appropriate by a practitioner excluding any premium or discount to account for market considerations. These estimates are also in accordance with both the Australian Stock Exchange (ASX) rules (specifically Listing Rule 05 for Oil and Gas Companies) and the Johannesburg SAMOG code for oil and gas reporting in conjunction with the SPE PRMS guidance and specific additional rules. Sproule's evaluation is based upon data supplied by D3, supplemented where necessary by Sproule's corporate awareness of current South African industry costs and best practices. Sustained commercial sales of methane gas from pilots located on the adjacent Tetra4 licenses and periodic measurements of the free flow gas volumes from multiple blowers, some producing for decades, allow estimation of the gas production decline rate and thus ultimate recoverable volumes of gas.

Contingent Resources are those volumes that have been discovered but either are not yet defined sufficiently to be classified as reserves or are not currently planned for development. Contingent Resources were calculated from the technically recoverable gas volumes for each type well multiplied by the number of locations in the portion of the Motuoane License classified as Contingent Resources and, in the case of helium, multiplied by a constant helium content of 4.1%. No economics were calculated for either methane or helium Contingent Resources. Similar to the Reserve categories, the 1C category of Contingent Resources has a 90% confidence the calculated volumes are technically capable of being produced, without economic consideration, the 2C category has a 50% or greater confidence level and the 3C has a 10% or greater confidence level. Estimated net methane and helium Contingent Resources are summarized in Table 1.

Table 1 - Estimated Net Methane and Helium Contingent Resources

Contingent Resources (BCF)	**1C**	**2C**	**3C**
Recoverable Gas Resource	336.65	547.45	858.03
Recoverable Methane	291.88	474.64	743.91
Recoverable Helium	13.803	22.445	35.179

Prospective Resources are, by definition, undiscovered resources. In the Virginia Production License there are areas that have not been adequately explored by well control to state that there is continuous gas columns and continuity of the gas reservoir. There is every reason to anticipate that future drilling will expand the field into these areas and there are mapped faults, sills and dykes in the area defined as the Prospective Area. These form the drillable targets for gas prospects. Net Prospective Resources were calculated volumetrically as the technically recoverable gas volumes for each type well multiplied by the number of locations in that portion of the Motuoane License classified as Prospective Resources. No economics were calculated for Prospective Resources. Estimated net methane and helium Prospective Resources are summarized in Table 2.

Table 2 - Estimated Net Methane and Helium Prospective Resources

Prospective Resources (BCF)	**1U**	**2U**	**3U**
Recoverable Gas Resource	228.44	661.32	1875.35
Recoverable Methane	198.06	573.36	1625.93
Recoverable Helium	9.366	27.114	76.889

The estimated quantities of helium resources that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to estimate the existence of a commercial quantity of potentially movable helium. Prospective Resources carry significant exploration risk. All Prospective Resources volumes presented in this report are un-risked.

Statement of Risk

The accuracy of reserves, resources, and economic evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a prospect, project, or well matures and new information becomes available revisions may be required which may either increase or decrease the previous estimates. Sometimes these revisions may result not only in a significant change to the reserves, resources and value assigned to a property, but also may impact the total company reserves, resources and economic status. The independent reserves, resources and economic forecasts contained in this report were based upon a technical analysis of the available data using accepted geoscience and engineering principles. However, they must be accepted with the understanding that further information and future reservoir performance subsequent to the date of the estimate may justify their revision. It is Sproule's opinion that the independent estimated reserves, resources, economics, and other information as specified in this report are reasonable and have been prepared in accordance with generally accepted geoscience and petroleum engineering and evaluation principles. Notwithstanding the aforementioned opinion, Sproule makes no warranties concerning the data and interpretations of such data. Neither Sproule, nor any of its employees have any interest in the subject properties and neither the employment to do this work, nor the compensation, is contingent on Sproule's estimates of the resources or economic evaluations for the properties in this report. This report was prepared for the exclusive use of D3 and will not be released by Sproule to any other parties without D3's written permission (other than the stated purpose set out above). The data and work papers used in this preparation of this report are available for examination by authorized parties in Sproule's offices. Sproule gives its permission for the release of this report, for public use, by D3.

Thank you for this opportunity to be of service to D3. If you have any questions or wish to discuss any aspect of the report further, please feel free to contact either of us.

Sincerely,

Jan. 30 2023

Jeffery B. Aldrich, L.P.G.

Senior Geoscientist

Jan. 31, 2023

John Seidle, P.E.

Senior Engineer

The following Responsible Member of Sproule Incorporated certifies that our internal quality control process has been completed in accordance with our Professional Practice Management Plan.

Jan. 31, 2023

Alexey Romanov, Ph.D., P.Geo.
Senior Manager, Geoscience

Sproule

Certificate of Qualifications

Jeffrey Aldrich, L.P.G., P.Geo.

I, Jeffrey B. Aldrich, Senior Geoscientist of Sproule, 1000, 1700 Broadway Street, Denver, Colorado, USA, declare the following:

1. I hold the following degree:
   a. B.S. Geology (1977) Vanderbilt University, Nashville, TN, USA
   b. M.S. Geology (1983) Texas A&M University, College Station, Texas, USA

2. I am a licensed professional:
   a. Licensed Professional Geoscientist (P.G.) Louisiana, USA #394
   b. Licensed Professional Geoscientist (P.G.) Texas, USA # 15140
   b. Certified Petroleum Geologist (C.P.G) The American Association of Petroleum Geologists #6254

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. American Association of Petroleum Geologists (AAPG)
   c. Society of Petroleum Engineers (SPE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

.

5. My contribution to the report entitled "Estimation of Methane and Helium Contingent and Prospective Resources in the Motuoane Gas Project, Free State Province, Republic of South Africa, as of December 1, 2022" is based on my geoscience knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of D3 Energy Limited.

Jan. 30 2023

Jeffrey Aldrich, L.P.G., P.Geo.

Sproule

Certificate of Qualifications

John Seidle, P.E.

I, John Seidle, Senior Reservoir Engineer of Sproule, 1000, 1700 Broadway Street, Denver, Colorado, USA, declare the following:

1. I hold the following degrees:
   a. B.S. Aeronautical Engineering (1972) University of Colorado, USA
   b. M.S. Aeronautical Engineering (1973) Stanford, USA
   c. Ph.D. Mechanical Engineering (1981) University of Colorado, USA

2. I am a registered professional:
   a. Professional Registered Engineer (P.E.), Colorado, USA
   b. Professional Registered Engineer (P.E.), Oklahoma, USA
   c. Professional Registered Engineer (P.E.), Wyoming, USA

3. I am a member of the following professional organizations:
   a. Society of Petroleum Engineers (SPE)
   b. Society of Petroleum Evaluation Engineers (SPEE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the “Canadian Oil and Gas Evaluation Handbook” as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” as promulgated by the Society of Petroleum Engineers and incorporated into the “Petroleum Resource Management System” (SPE-PRMS).

5. My contribution to the report entitled “Estimation of Methane and Helium Contingent and Prospective Resources in the Motuoane Gas Project, Free State Province, Republic of South Africa, as of December 1, 2022” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of D3 Energy Limited.

John P. Seidle

John Seidle, P.E.

Sproule

Certificate of Qualification

Alexey Romanov, Ph.D., P.Geo.

I, Alexey Romanov, Senior Manager, Geoscience of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. Ph.D. Eng. (2007), Kazan State Technological University, Kazan, Russia
   b. M.Sc. Reservoir Evaluation and Management (2004), Heriot-Watt University, Edinburgh, UK
   c. M.Sc. (Honours), Petroleum Geology (2003), Kazan State University, Kazan, Russia

2. I am a registered professional:
   a. Professional Geoscientist (P.Geo.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Society of Petroleum Engineers (SPE)
   b. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   c. Canadian Society of Petroleum Geologists (CSPG)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

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Jan. 31, 2023

Alexey Romanov, Ph.D., P.Geo.

Sproule

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BACKGROUND

The D3 Motuoane gas project, located in the Free State Province, is approximately 250 km southwest of Johannesburg (Figure 1). The Motuoane License Application Area is near the towns of Welkom, Virginia and Hennenman.

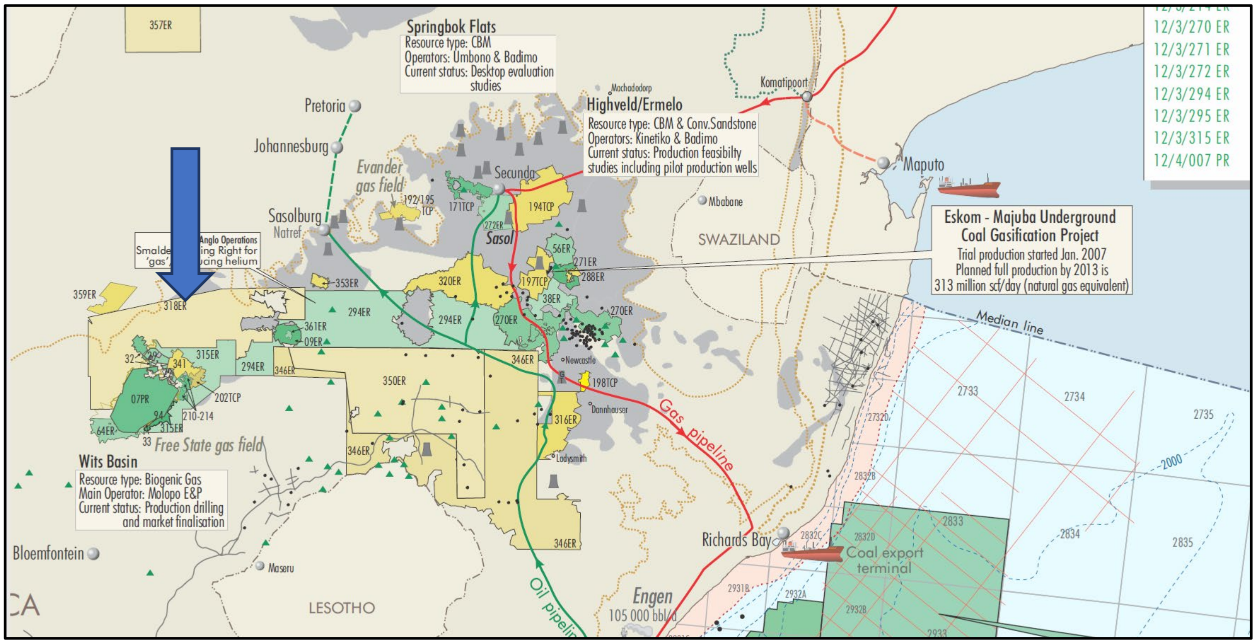

Figure 1 - Detail from the Official Lease and Rights Map from the Petroleum Agency of South Africa. 315ER is the Motuoane Exploration Right.

The Renergen Virginia Gas Field Production Right (07PR) lies immediately to the west of the 315ER license (Figure 1). The Virginia Gas Field was used as an analog for the style of gas trap and construction of type wells for expected well performance within the Motuoane license. This exploration right covers a large area and contains multiple gas emitting boreholes drilled as part of mineral exploration activities. Several of these boreholes are flowing gas at relatively high production rates and have been doing so for decades. Past work programs involved the cataloging and sampling of the gas emitting boreholes, a soil gas geochemistry survey, and structural mapping. The gas emitting boreholes (“blowers”) were drilled by mining companies to explore for gold in Witwatersrand formations which underlie the coal-bearing Karoo and Ventersdorp lavas. Some flowing wells were reportedly capped due to dangerously high gas emission rates. D3 now owns 100 percent working interest in 118,000 hectares (29,158,435 acres or 1,180 Km2) that currently has 8 active blowers and 6 inactive blowers. In addition, the project also has over 100 shallow wells drilled into the Permian Karoo section but are not considered for the Contingent Resources portion of this report as they do not penetrate the deeper Witswatersrand Formation and the basement faulting. The D3 Production License is subject to a 5% government tax as described in the Mineral and Petroleum Resource Development Act of 2002.

GEOLOGIC SETTING

The license is situated in the eastern part of the Greater Karoo Basin, a Permian aged large terrestrial and glacial basin in eastern South Africa (Figure 2). Within the Karoo Basin is the Ecca Group coal sequence which contains multiple thin-bedded coal seams that have some coal seam gas potential.

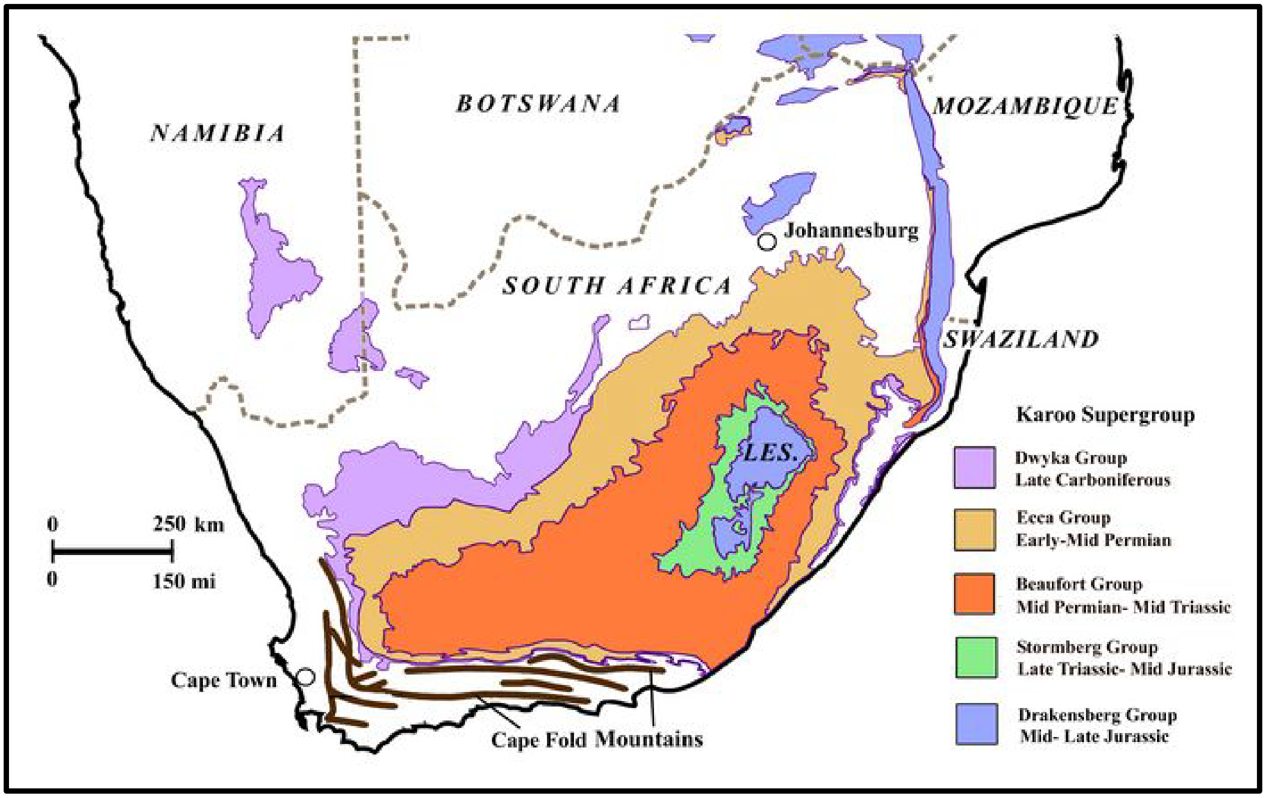

Figure 2 - The Greater Karoo Basin, from Rubridge, 1995

Below the Karoo Basin unconformably lies the Precambrian Witwatersrand Basin, which contains the Free State Gold Field Welkom (Figure 3). The Free State Gold Field is a major graben structure that is bounded on the west by the “Border” fault and on the east by the “de Bron” fault. Displacement in the order of 1000 meters is encountered along the strike of the de Bron fault. The displacement is towards the west. In certain areas the fault zone amounts to 150 m in width and is partly filled with secondary quartz and calcite with the resulting in permeability along the strike distance of the fault that varies considerably.

Geologic Map of the Central and West Rand Groups from Welkom north to Johannesburg. The D3 license lies within the red box.

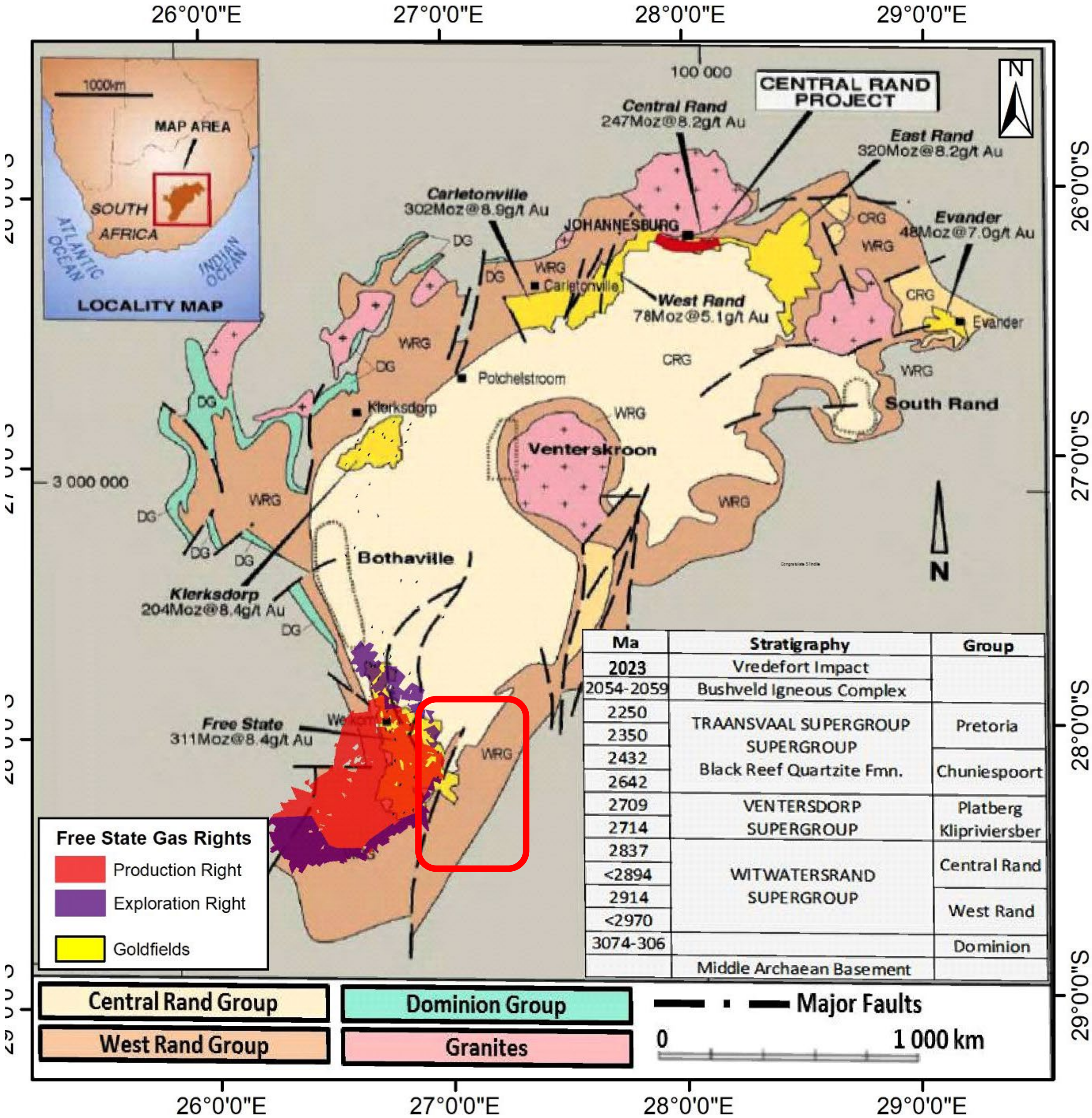

Figure 3 - Geologic Map of the PreCambrian Groups in the Witwatersrand Basin and the Gold Fields (Image from Renergen Public Reports)

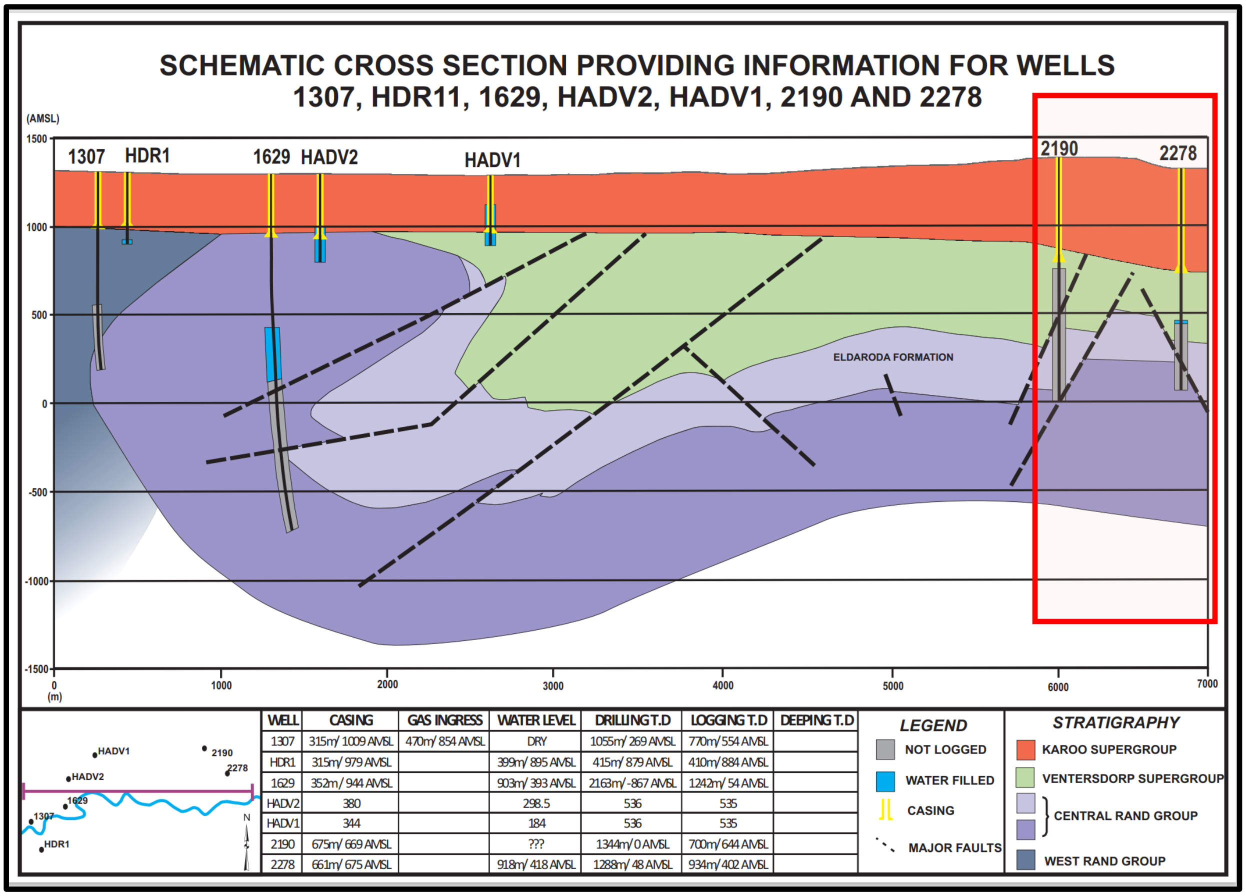

Figure 4 - West to East Cross-section Across the Virginia Gas Field and into the Motuoane License [Red Box] (Image from Renergen Public Reports)

These ‘basement’ lithologies have been tectonically flexed into a large east to west trending anticline that is in turn bisected by a large extensional graben (low area) and many faults with significant throw (offset) that extend deep into the earth’s crust, as shown in Figure 4 and Figure 5

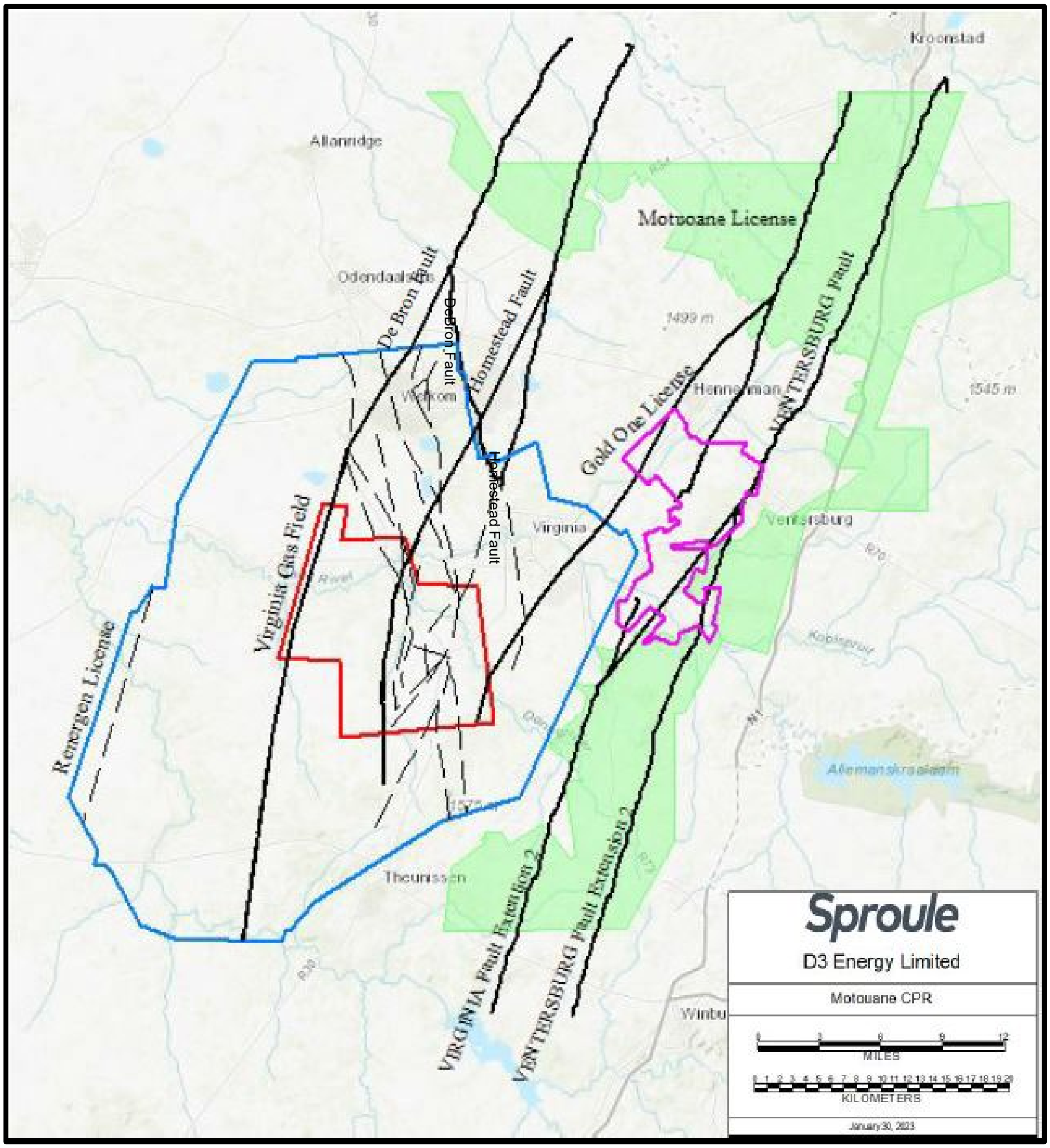

Figure 5- Map of the Major Faults from the Motuoane License (Green) into the Virginia Gas Production License and Reserve Area.

Unconformably overlying the Witwatersrand Supergroup is the Ventersdorp Supergroup of primarily volcanic lithologies. Many of these faults do not extend upwards beyond the upper Ventersdorp Supergroup. Above this unconformity lies the Karoo Supergroup, a Permian aged sedimentary section composed of sandstones, coal seams and carbonaceous shales. There is almost always a basal glacial deposit on top of the unconformity that separates the Karoo from the Ventersdorp known as the Dwyka Tillite. The Witwatersrand and Ventersdorp Supergroups experienced greenschist metamorphism and are both extensively fractured, due to sustained tectonic activity. The primary source of the methane gas is microbial in origin from deep within the Witwatersrand Supergroup with groundwater circulating through the large faults and coming in contact with bacteria living deep within the Archaean crust. Methane isotope studies demonstrate that very little, if any, of the methane can be attributed to the Karoo coal beds or the carbonaceous shales. Thus, the methane is a biogenic and a continuing regenerating resource. There is anecdotal evidence of historic blowers within the D3 license area producing methane gas for over forty years without any discernable pressure drop, however there are no quantified studies to date.

General Geology Structure of the Motuoane License

The Motuoane License is situated towards the east of de Bron fault. In the northern part of the Motuoane License, a major horst structure i.e. de Bron horst is present between the de Bron and Homestead faults respectively. No gold bearing sediments occur in the horst. Detailed drilling defined the eastern limit of this horst structure along the Homestead fault. East of the Homestead fault, gold bearing sediments were intersected again.

Two major fault systems, i.e. the Virginia and Ventersberg faults, occur in the eastern part of the Motuoane License. The displacement again was towards the west. Despite this major north-south striking structures several east-west faults are also present or could be extended into the Motuoane License. The east-west structures are the oldest structures in the Witwatersrand basin. Many kimberlite fissures and Karoo age dolerite dykes intruded into the younger strata along these structures. The east-west structures were right laterally displaced by north-south striking structures resulting in a very complex tectonic environment. The importance of these structures is vested in the presence of methane gas occurrence associated in or in close proximity of the structures.

HELIUM OCCURRENCE

The helium, as with almost all helium around the world, is either mantle-derived, that is from deep within the earth or from radioactive decay of radioactive minerals within the crust, and as the helium moves up along the faults, it mixes with the microbial methane in the deep subsurface. The formation and resource estimates of the helium were detailed in the Sproule 2020 report ”Evaluation of Certain Helium Prospective Resources on the Tetra4 Virginia Gas Project, Fee State, South Africa”, and in the Gilfillan and Stuart Report, 2020, which examined the origin of the helium at the Virginia Gas Field. Excerpts of the Gilfillan and Stuart report state: Helium (He) production within the Earth’s crust is primarily controlled by the radioactive decay of 235,238U isotopes of uranium and 232Th isotope of thorium and their daughter isotopes, via α particles. The helium concentration in any rock or mineral is dependent primarily on the radioelement concentration and the age of that rock or mineral (Ballentine and Burnard, 2002). The degassing of helium in the crust is controlled by two stages: (1) release from the mineral in which the noble gas was produced/trapped; and (2) transport from the site of production. He in minerals can be released to the gas phase at grain boundaries or pores by four main mechanisms: α recoil, diffusion, fracturing or mineral transformation. …Typically, concentrations of helium increase in the subsurface over time in stable continental regions, as these act as closed systems with helium either remaining within producing minerals or in the fluid within the porosity of the rocks (Holland et al., 2013). …As a result of the different release mechanisms the rate of helium release from minerals may not be constant. …The abundant evidence of severe radiation damage to the main U-bearing mineral phases in the Reef lithologies (Hiemstra, 1968) implies that the diffusion of helium into the free gas phase is likely to be on the higher end of theoretical estimates within the units beneath Renergen's Virginia prospect. …A total volume of between 2,827 to 4,772 billion cubic feet (BCF) of helium at standard temperature and pressure (STP) conditions (14.696 pounds per square inch or 1.0 atm; 101.325 kPa – the SI system standard pressure), produced since deposition of the Witswatersrand Supergroup, Dominion Group and formation of the Basement Granites. It is important to convey that only a proportion of this will be accessible from connected pore space within these rocks, and subsequent geological events since deposition may have resulted in substantial loss of this resource. The rate of recharge of the methane, and thus also the helium gas is not known.

There are nearly two thousand wellbores which have been drilled, either for water, mining assessment, or disposal, across the Welkom District over the past several decades and many tens of these wells have produced natural flammable gas (known as blowers). Data from the South Africa Council for Geosciences lists at least 136 historic wells within the production area and notes that 68 of them produced gas in the past, 18 are currently capable of producing gas (blowers), 29 have odors, and 28 are dormant.

Methane Gas Occurrences in the Free State Gold Field

The most recent evaluation of gas occurrences in proximity of the Motuoane License was done by Gold One during the evaluation of the economic potential of the A-Reef. Research on behalf of Molopo Gas in the western part of the Free State Gold Field resulted in a model whereby gas occurrence can directly be related to major tectonic structures. In order to delineate these structures (faults) a soil sampling exercise was conducted to establish whether these structures still release detectable amounts of gas. This exercise was successful in that Motuoane License's along faults could be demarcated for future drilling purposes. A similar model for gas occurrences in the Gold One area was established. A total number of 41 boreholes yielded gas of which 6 boreholes were considered as blowers. Three of the six boreholes were capped with a valve. Every one of the gas-yielding boreholes occur in close proximity of faults and diabase dikes, intersected during exploration drilling.

Potential Gas Occurrences in the Motuoane License Based on Historical Analogies

It is important to note that the number of historical boreholes drilled in or adjacent to the Motuoane License is by far outnumbered by the number of boreholes drilled towards the west. The Virginia fault in the Gold One area yielded large volumes of methane gas. The Virginia fault is present in the Motuoane License and constitutes a major gas target to be explored. The east-west striking gas-yielding fault on Gold One area can be extended into the Motuoane License. The gas potential of this fault and the one directly below it must be considered as gas targets. Very little geological information pertaining to the Ventersberg fault as a gas target is known.

Potential gas targets can be present where extensions of the east-west striking faults intersect the Ventersberg fault i.e. south of the Gold One area. This is outside the Motuoane License but must be considered as an extension into the existing Motuoane License. A major gas yielding borehole, directly in or in very close proximity of the Homestead fault occurs on the farm Nooitgedacht in the northern part of the Motuoane License. Additional work needs to be done in order to determine the aerial extent of this fault in and in areas adjacent to the Motuoane License. No major gas intersections were recorded along the strike distance of the de Bron fault. Gas targets along the de Bron fault in the western part of the de Bran horst is a possibility and need to be investigated by means of studying historical boreholes drilled in that area.

Due to the fact that the methane gas occurrences are associated with linear structures of which the widths and depths are unknown, a different approach other than the traditional calculation of average width is required. It is recommended that a method, similar to the one created by Molopo, be used for resource calculations in the Motuoane License. The Motuoane License as defined by the Hennenman and Motuoane gas areas constitutes a potential methane gas bearing area. The gas, based on previous observations, will be associated with north-south and east-west tectonic features such as the known faults. The areas affected by these faults need to be investigated, either by geophysical methods or detailed drilling. Where applicable and/or required, directional deflections can also be considered in order to demarcate the faults at depth. It should be advantageous for future research to acquire all relevant borehole data in the Motuoane License in order to define gas Motuoane Licenses prior to any drilling. A detail geophysical interpretation based an available data is also recommended.

Renergen reported that twelve wells were evaluated for the original 2008 Molopo reserves evaluation study (Burning Flame, Burning Cross, Flame 1, ML-1, Retreat, Sand, SP-3, Squatter, DBE-1, Kotze EX-1, ST23, and Tewie). Molopo drilled three additional wells in 2009 (HADV1, HADV2, and HADR1). Tetra4 took over the project and drilled 4 wells in 2016 (MDR1, MDR4, MDR5 and 2057) and in 2017 reworked an older well that had resumed flowing gas (2190). These original twelve wells were flow tested for extended periods of time which provided sufficient data that allowed Sproule to calculate three different well type curves representing a range of production profiles; a low case, an expected or best case, and a maximum case. These extended well tests and type well profiles have been used and checked against all subsequent well and test data. For the 2019 update Sproule included a new well that Tetra4 drilled in 2018, the T4 WN 01, which was drilled to test a shallow conventional sandstone play, plus 12 historic wells or vents (AD1A, SH3, P7, W1, SP8, TR3, TR4, TR5, TR6, TR7, TR8, and AL4) that were described in the publication of Hugo, P.: “Helium in the Orange Free State Gold-Field” (1963) which documented these wells and vents as far back as 1957. Using the published data and on-site verifications, as far as possible, these wells were added to the Tetra4 database. The importance of this data is twofold, A) the new well opens an additional play for Tetra4 within the lease area and B) the data from the historic wells support both the longevity of the wells and the gas composition, including the high helium concentrations.

FLUID PROPERTIES AND ANALYSIS OF THE MOTUOANE LICENSE

A total of 17 gas analyses were available for this study. The samples were fairly recent (9 in 2022, 4 in 2021, 1 in 2017, and 3 undated) and compositions were reported on an air-free basis. Average produced gas composition was 86.7% methane, 9.0% nitrogen, 4.1% helium, and 0.1% CO2 and higher hydrocarbons. Gross and net heating values were 32.4 and 29.0 MJ/m3 (0.869 and 0.778 mmbtu/mcf), respectively. Calculated gas gravity was 0.584.

As reservoir temperature was not reported, one was estimated from published geothermal gradients (Jones, 2018) and a depth of 374 m, the median depth of ten D3 Energy boreholes. Subsurface temperatures in this region of South Africa are relatively cool. Reported geothermal gradients range from 9 to 21 deg C/km as compared to the global average of 25 deg C/km (1.4 deg F/100 ft). Combining these gradients and the median borehole depth with an assumed surface temperature of 10 deg C gives an average reservoir temperature of 16 deg C (61 deg F).

Stabilized reservoir pressures were not available but wellhead pressures recorded during short shutins of three Bloemskraal wells were reported. These wells were shutin weekly in June and July (year unspecified but presumably 2022) and responded with rapidly rising wellhead pressures. Final reported pressures after shutins lasting “Longer than 24H” averaged 200 kPag (29.1 psig). The wells reportedly make no water and no fluid levels were reported. Pressure for a static gas column down to median borehole depth was calculated as 7.7 kPa (1.1 psi). Reported barometric pressures during the shutins averaged 87 kPa (12.6 psi). Summing the average wellhead shutin pressure, the static gas column pressure and the average barometric pressure yields a current reservoir pressure of 295 kPaa (42.8 psia).

Summing the average wellhead shutin and the static gas column pressures then dividing by the median borehole depth gives a pressure gradient of 0.56 kPa/m (0.025 psi/ft). Compared to the normal hydrostatic gradient of 9.80 kPa/m (0.433 psi/ft), this reservoir appears to be significantly underpressured.

Fluid properties of the D3 Energy produced gas mixture calculated using the reservoir gas composition, temperature, and pressure discussed above in industry standard correlations (Corredor, et al, SPE 24864; Piper, et al, SPE 26668) are given in Table 3 below.

Table 3 – D3 Energy Gas Properties at Current Reservoir Conditions of 43 psia and 61 deg F

Parameter	Value
Gas gravity	0.584
Compressibility factor, Z	0.996
Gas formation volume factor, Bg, rcf/scf	0.342
Inverse gas FVF, Eg, scf/rcf	2.92
Viscosity, μ, cp	0.0109
Compressibility, c, psi-1	0.0235

TYPE WELLS

Expected performance of D3 Energy wells was estimated with type wells published for an analogous field (Renergen/Sproule (2021) adjusted to reflect recent (Aug and Sep 2022) D3 Energy production tests. Gas production rates recorded during short-term (3 to 5 day) flow tests on three wells (Bloemskraal Nr 2 – RBD01, Bloemskraal Nr 1 – RBD03, and Nooitgedacht Major) are shown in Figure 6 below.

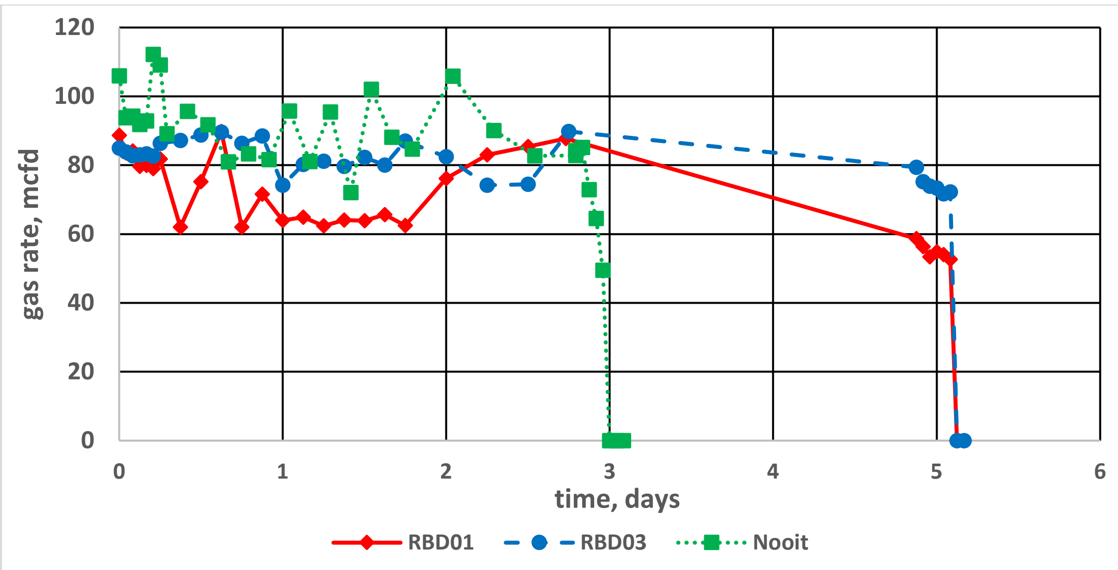

Figure 6 - Flow Test Gas Production Rates

Gas flow rates and wellhead pressures and temperatures were reported on an hourly basis, resulting in noisy plots. All three wells behaved similarly, showing gentle declines probably more reflective of wellbore transients than reservoir response. The tests were too brief to establish clear declines, precluding traditional decline curve analysis to forecast future gas production. During the tests, gas production rates varied between 58 and 97 mcfd with an average gas rate of 80 mcfd. The subject acreage directly offsets the Renergen acreage and exploits the same formation. Produced gas compositions are similar. Thus, the Renergen type wells were utilized as analogs for D3 Energy type wells.

The initial rate of the Renergen 1P type well was set to the 80 mcfd average rate seen in the flow tests and the exponential decline rate was unchanged. The 2P and 3P Renergen type wells were used without modification for the same categories of D3 Energy wells. Type well coefficients are in Table 4 below and gas production rate and 30-year cumulative gas plots follow in Figure 7 and 8, respectively.

Sproule

Table 4 - D3 Energy Type Well Coefficients

Category	Initial Rate, mcfd	Plateau Duration, months	Decline Rate, %/yr	Exponential Decline Rate, yr-1	30-Yr Cum Gas, bcf
1P	80	2	4.8	0.0492	0.462
2P	260	2	5.0	0.0513	1.465
3P	380	2	4.8	0.0492	2.223

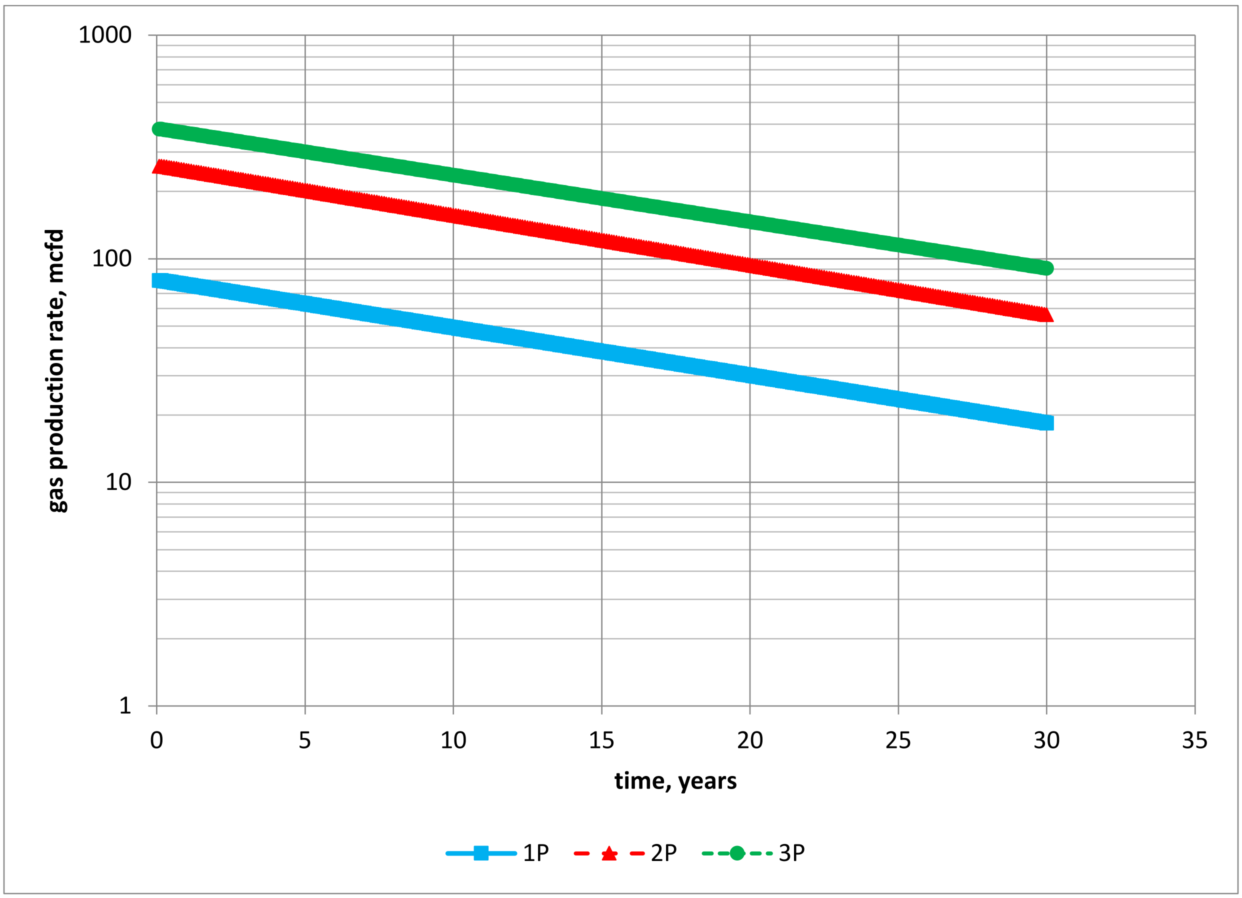

Figure 7 - D3 Energy 1P, 2P and 3P Gas Production Type Wells

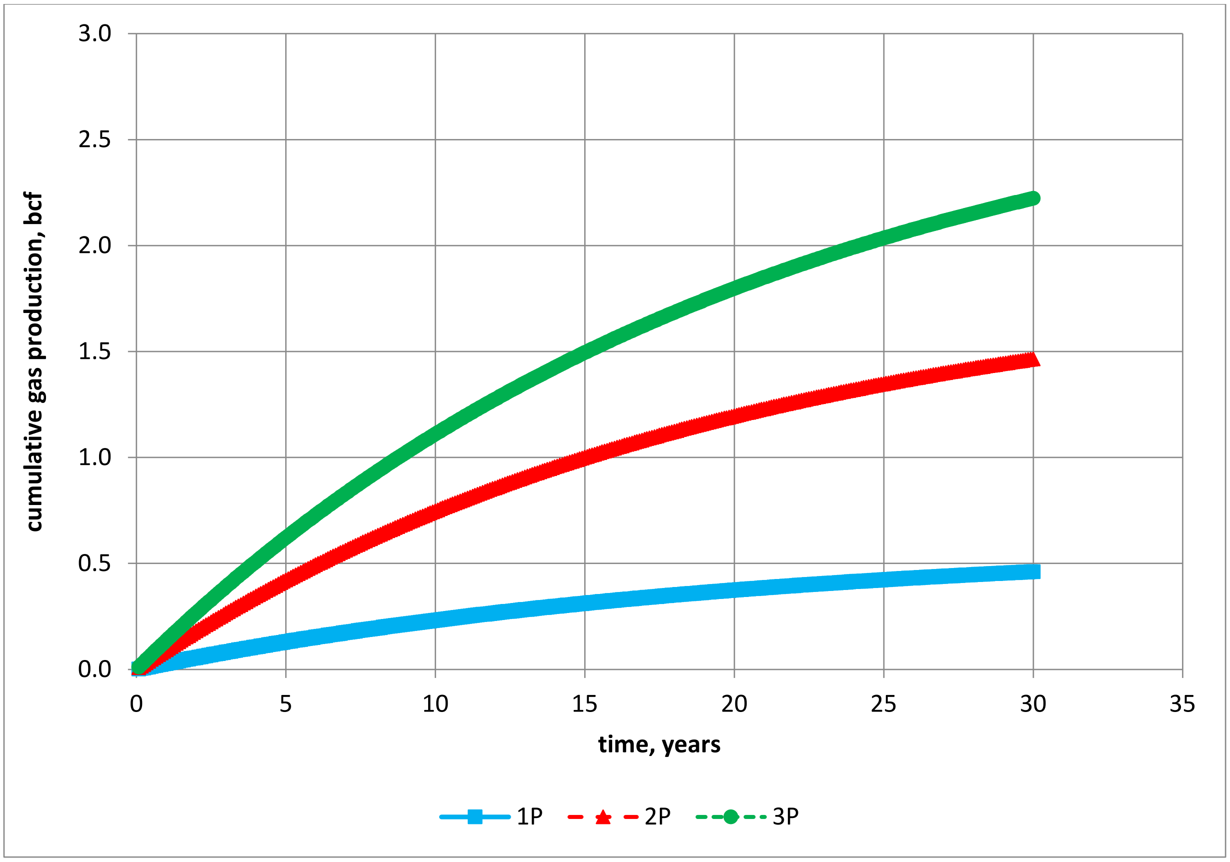

Figure 8 - D3 Energy 1P, 2P, and 3P Type Well Cumulative Gas Production

While Renergen has published, based on well tests, a planned 300m well spacing, the optimal well spacing on the subject acreage has yet to be determined. Sproule has chosen the 300m well spacing as the most likely well spacing with a range from 200 meters to 400 meters to capture the drainage uncertainty. The analysis has used the total mapped length of faults within the licensed block, with a 25% uncertainty range, to determine the number of wells to be used for the stochastic analysis.

The map below shows the lengths of the known faults (in red) that were used to calculate the Contingent Resources. These faults have been mapped into the Renergen Virginia Gas Field where there are productive wells with gas reserves.

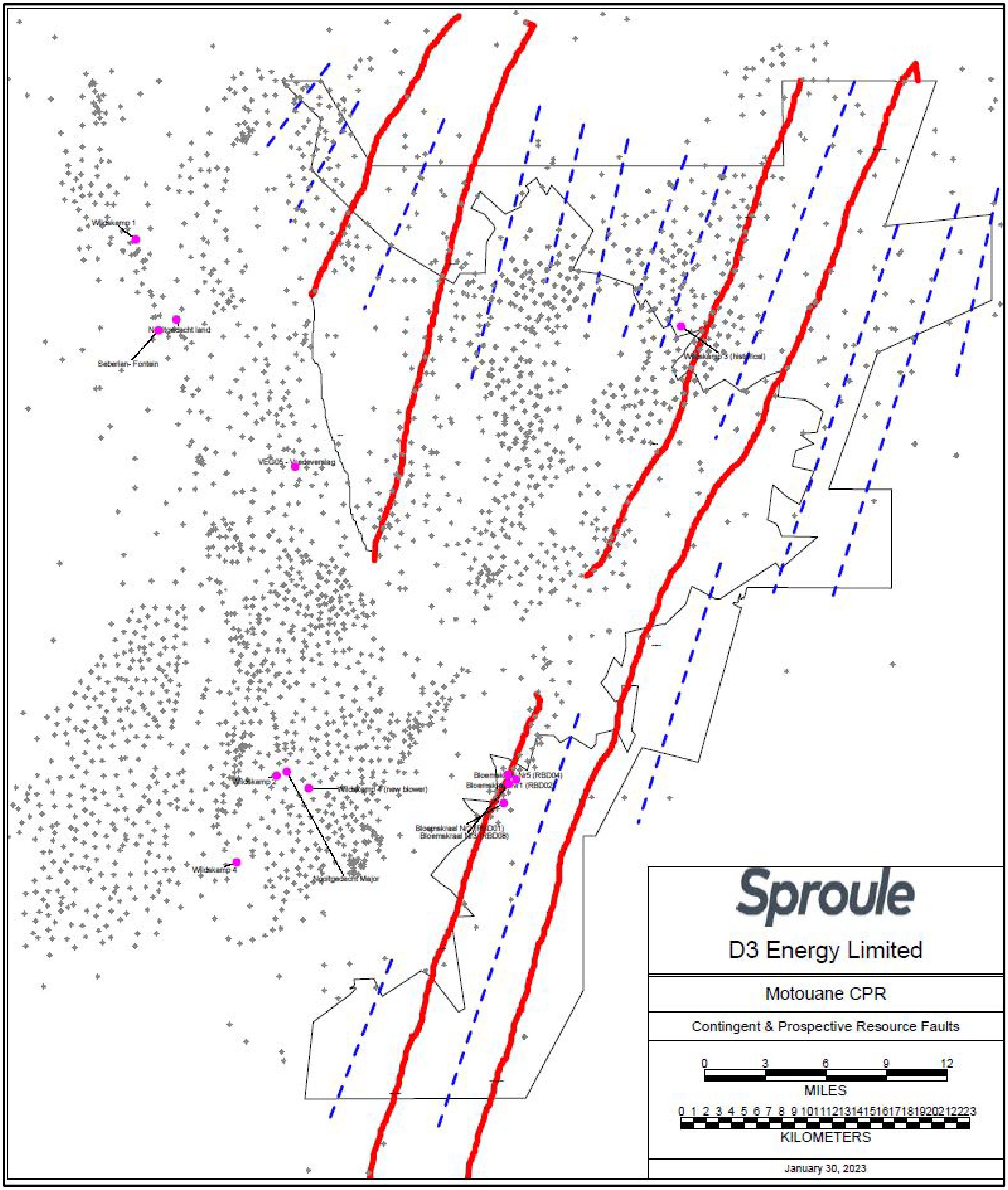

Figure 9 - Contingent Resource Faults (Red Lines) and Prospective Resource Faults (Blue Dashed Lines). Evaluated blowers are in purple dots.

The EUR/well published by Renergen of 0.462, 1.465, and 2.223 BCF/well were used for the stochastic inputs to determine the technically recoverable volumes of gas listed in the Table below.

Table 5 – Estimated Net Methane and Helium Contingent Resources

Contingent Resources (BCF)	1C	2C	3C
Recoverable Gas Resource	336.65	547.45	858.03
Recoverable Methane	291.88	474.64	743.91
Recoverable Helium	13.803	22.445	35.179

The blue dashed lines are mapped out Prospective faults. The known, mapped faults have a consistent distance of 7,620 meters between the faults. Prospective fault distances of ½ that distance were used to map out additional prospective fault lengths. This was used as the 2U case. The 1U case was estimated at 33% of that length and the 3U case at 160% of the 2U case for a lognormal distribution of reservoir area. All other factors were kept identical as the Contingent Resource case to create a stochastic distribution for the 1U (P90) \ 2U (P50) \ and 3U (P10) cases.

Table 6 – Estimated Net Methane and Helium Prospective Resources

Prospective Resources (BCF)	1U	2U	3U
Recoverable Gas Resource	228.44	661.32	1875.35
Recoverable Methane	198.06	573.36	1625.93
Recoverable Helium	9.366	27.114	76.889

The estimated quantities of helium resources that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to estimate the existence of a commercial quantity of potentially movable helium. Prospective Resources carry significant exploration risk. All Prospective Resources volumes presented in this report are un-risked.

CONTINGENCIES

The contingent resources that Sproule has evaluated for this report have several contingencies before the gas volumes can be considered as reserves.

1) D3 needs to demonstrate the ability to operate successful wells, drilled to the Witswatersrand, intersecting known faults, setting production strings of casing, and flow testing multiple wells for extended periods of time.
2) D3 will need to take multiple gas samples and correctly analyze them for gas contents and BTU contents.
3) D3 will need to validate reservoir pressures and well deliverability.
4) D3 will need to develop a field development plan that will include a gas sales plan, gas gathering and processing and a drilling schedule to which the company has committed to and budgeted.

POTENTIAL UPSIDE

Sproule has not evaluated, in this report, the Coal Seam Gas (CSG) also known as CBM potential of the block. There are scores of wells that have reported intersecting Karoo aged coals and the operator has supplied an amalgamated map of total coal thickness within the block. There is sufficient thickness, over 100 meters of total coal, in the northern portion of the license to potentially support a CSG development program however Sproule was not given any direct access to coal desorption, adsorption, thermal maturity or other basic data needed to assess the prospectivity of the CSG potential.

APPENDIX A - PETROLEUM RESOURCES MANAGEMENT SYSTEM

2.0 Classification and Categorization Guidelines

2.0.0.1 To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification *system* shown in Figure 1.1. These guidelines reference this classification system and support an evaluation in which projects are “classified” based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are “categorized” to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project’s recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity’s commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.

B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.

C. Evidence to support a reasonable time-frame for development.

D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).

E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.

F. Evidence that the necessary production and transportation facilities are available or can be made available.

G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.1.3 Project Status and Chance of Commerciality

2.1.3.1 Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

2.1.3.2 As a project moves to a higher level of commercial maturity in the classification (see Figure 1.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

A. The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.

B. Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

2.1.3.3 There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

2.1.3.4 Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

2.1.3.5 Project Maturity Sub-Classes

2.1.3.5.1 As Figure 2.1 illustrates, development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

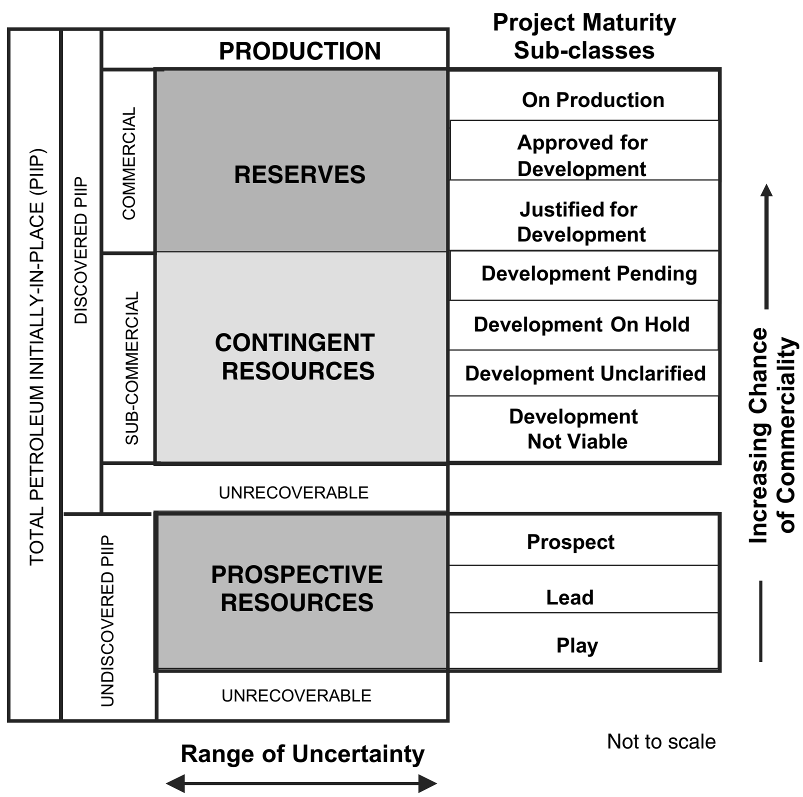

Figure 2.1—Sub-classes based on project maturity

2.1.3.5.2. Maturity terminology and definitions for each project maturity class and sub-class are provided in Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

2.1.3.5.3 Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

2.1.3.5.4 Projects that are classified as Reserves must meet the criteria as listed in Section 2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

2.1.3.5.5 Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

2.1.3.5.6 Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

2.1.3.5.7 Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

2.1.3.5.8 For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure 2.1 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

2.1.3.5.9 For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

2.1.3.6 Reserves Status

2.1.3.6.1 Once projects satisfy commercial maturity (criteria given in Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (Table 2 provides detailed definitions and guidelines):

A. **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.

    1. **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

2. **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.

B. **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

2.1.3.6.2 The distinction between the “minor costs to access” Developed Non-Producing Reserves and the “significant investment” needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

2.1.3.6.3 Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see Section 3.1, Assessment of Commerciality).

2.1.3.6.4 Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section 2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

2.1.3.6.5 Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

2.1.3.7 Economic Status

2.1.3.7.1 Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

A. **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section 2.1.2.

B. **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

2.1.3.7.2 The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project’s commerciality.

2.1.3.7.3 For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

2.1.3.7.4 The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section 2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best-estimate case.

2.1.3.7.5 The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

2.1.3.7.6 Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).

B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.0.3 There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

2.2.0.4 Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as "split classification."

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.1.6 While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

2.2.2.8 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

A. **Proved Reserves** are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. 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% probability that the quantities actually recovered will equal or exceed the estimate.

B. **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% probability that the actual quantities recovered will equal or exceed the 2P estimate.

C. ***Possible Reserves*** are those additional Reserves that 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 (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand-alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

2.2.2.9 One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

2.2.2.10 A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

2.2.2.11 It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see Section 4.2, Resources Assessment Methods). If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

2.3 Incremental Projects

2.3.0.1 The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure 1.1), with preference for applying project maturity sub-classes (Figure 2.1). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section 2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

2.3.0.2 An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

2.3.0.3 Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see Section 2.1.2, Determination of Commerciality).

2.3.1 Workovers, Treatments, and Changes of Equipment

2.3.1.1 Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section 2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

2.3.1.2 Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

2.3.2 Compression

2.3.2.1 Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

2.3.3.1 Technical and commercial analyses may support drilling additional producing wells to reduce the well spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and accelerating production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

2.3.4 Improved Recovery

2.3.4.1 Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

2.3.4.2 Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

2.3.4.3 The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

2.3.4.4 Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

2.4 Unconventional Resources

2.4.0.1 The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in-place characteristics, extraction method applied, or degree of processing required.

A. Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

B. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

2.4.0.2 For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

2.4.0.3 Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

2.4.0.4 The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

2.4.0.5 A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also Section 3.1.2 Economic Criteria).

APPENDIX B - REFERENCES

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