Independent Reserve and Resource Evaluation Report

2021 UPDATE ON THE ESTIMATION OF METHANE AND HELIUM RESERVES AND RESOURCES AND ASSOCIATED ECONOMICS OF THE TETRA4 VIRGINIA GAS FIELD IN THE FREE STATE OF THE REPUBLIC OF SOUTH AFRICA

AS OF SEPTEMBER 1, 2021

SUBMITTED TO:

Renergen Limited

September 2021

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sproule.com

Sproule

November 1, 2021

Mr. Stefano Marani
Chief Executive Officer
Renergen Limited
1 Bompas Road
Dunkeld West
Johannesburg, 2196
Republic of South Africa

Re: 2021 UPDATE ON THE ESTIMATION OF METHANE AND HELIUM RESERVES AND RESOURCES AND ASSOCIATED ECONOMICS OF THE TETRA4 VIRGINIA GAS FIELD IN THE FREE STATE OF THE REPUBLIC OF SOUTH AFRICA AS OF SEPTEMBER 1, 2021

Dear Mr. Marani:

At the request of Renergen Limited (hereinafter referred to as “Renergen”), Sproule Incorporated (“Sproule”), an independent sub-surface consultancy based in Calgary, Canada, has conducted an independent update to its April 2019 assessment of the unconventional methane and helium reserves and resources in Tetra4’s Virginia Gas Field, on the production right 24/04/07PR, located in the Free State of the Republic of South Africa. This evaluation is both a geologic and an economic update, based on the analysis methodology described herein using technical and economic data supplied by Tetra4, a wholly owned subsidiary of Renergen, and has an effective date of September 1, 2021. Material changes to this report are the inclusion of the 5 newly completed wells, the initial flow testing of two wells with new “slant completions”, a more detailed sub-surface geologic model, updated CAPEX and OPEX costs, updated currency exchange rates, new gas sales agreements and an updated field development plan.

This evaluation includes estimates of recoverable methane and helium volumes from Proved Reserves including Proved Developed Producing wells (PDP), Proved Developed Non-Producing wells (PDNP’s) and Proved Undeveloped locations (PUDs). In addition to the total Proved Reserves, Probable, and Possible reserves are also estimated. Associated pre-tax net present value of future income for selected discount rates are presented for Reserves volumes. 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 Reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of Reserves 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 Reserve 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.

The independent Reserve and Resource estimates and associated economics contained in this report are prepared in accordance with the Society of Petroleum Engineers (SPE) Petroleum Resources Management (PRMS) guidance and 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 Tetra4, supplemented where necessary by Sproule's corporate awareness of current South African industry costs and best practices.

Reserve and Resource Estimates

The independent Reserve and Resource estimates presented in this report have been prepared for publication in both South Africa under the SAMOG regulatory guides and Australia using an evaluation approach for unconventional resources consistent with Society of Petroleum Engineers Petroleum Resources Management System (SPE PRMS) 2018 and the SPE 2011 PRMS guidelines (attached). The Reserve and Resource estimates contained in this report have been prepared as of September 1st, 2021 and are independently generated from the data supplied to Sproule from Tetra4. Sustained commercial sales of methane gas from pilots located on the 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.

Estimated net methane and helium Reserves and the associated net present values at discount rates specified by Tetra4 are summarized in Table 1. For the purposes of clarification, the use of the abbreviation 'MM' equates to millions of the specified currency throughout this text. Sproule has calculated the economics according to the assumptions detailed in the following report and are presented in Table 1 as both Undiscounted (NPV=0), breakeven, and at the specified discount factors. Sproule makes no recommendation as to which discount factor should be used.

Table 1: Summary of Methane and Helium Net Gas Reserves and Net Present Values at Selected Discount Rates

Virginia Gas Project – Specified Prices and Costs

	PDP	PDNP	PUDs	Total Proved (1P)	Probable	Proved + Probable (2P)	Possible	Proved+ Probable+ Possible (3P)
Methane (BCF)	0.89	17.87	196.30	215.08	281.90	406.97	193.12	600.09
Helium (BCF)	0.03	0.60	6.54	7.17	6.40	13.57	6.44	20.00
Net Present Value (MMZAR)								
Undiscounted	477	9,575	111,080	100,121	113,908	214,029	113,485	327,514
5%	265	5,362	55,357	49,121	46,402	95,523	47,653	143,176
8%	203	4,104	39,569	33,647	31,210	64,857	32,576	97,433
10%	174	3,523	32,487	26,561	24,950	51,511	26,245	77,756
15%	128	2,579	21,319	15,225	15,728	30,953	16,714	47,667
20%	101	2,026	15,094	8,835	10,910	19,745	11,599	31,344
30%	72	1,425	8,751	2,293	6,265	8,558	6,532	15,090

Due to rounding certain totals may not be consistent from one presentation to the next.

Reserves are defined by the PRMS Guidelines as follows; Proved Reserves (1P) are defined as meaning 90% or greater confidence that the volumes will be produced, Probable Reserves (2P) means there is a 50% or greater confidence of the volumes being produced and the 3P is given to the Possible Reserves that have a 10% or greater confidence of being produced.

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 Virginia Gas Field classified as Contingent Resources and, in the case of helium, multiplied by a constant helium content of 3%. No economics were calculated for either methane or helium Contingent Resources. Similar to the reserve categories the C1 category has a 90% confidence the calculated volumes being technically capable of being produced, without economic consideration, the C2 category has a 50% or greater confidence level and the C3 has a 10% or greater confidence level. Estimated net methane and helium Contingent Resources are summarized in Table 2.

Table 2: Summary of Net Methane and Helium Contingent Resources

Virginia Gas Field

Category Contingent Resources (BCF)	Low Case (C1)	Best Case (C2)	High Case (C3)
Total Gas*	141.6	267.8	409.5
Methane	127.6	241.0	368.6
Helium**	4.3	8.0	12.3

For the purposes of field design total wellhead gas volumes are reported which contain some percentages of non-commercial gases that the field pipeline system and liquifiers must be designed to accommodate.

*****Calculated at 3%***

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 Virginia Gas Field classified as Prospective Resources. No economics were calculated for Prospective Resources. Estimated net methane and helium Prospective Resources are summarized in Table 3 .

Table 3: Summary of Net Methane and Helium Prospective Resources

Virginia Gas Field

Category Prospective Resources (BCF)	Low Case (1U)	Best Case (2U)	High Case (3U)
Total Gas*	189	357	546
Methane	170	321	491
Helium**	5.7	10.7	16.4

For the purposes of field design total wellhead gas volumes are reported which contain some percentages of non-commercial gases that the field pipeline system and liquifiers must be designed to accommodate.

Calculated at 3%

***PROSPECTIVE RESOURCES**: "The estimated quantities of petroleum 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 determine the existence of a significant quantity of potentially moveable commercial gases."*

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 Renergen and will not be released by Sproule to any other parties without Renergen'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 Renergen.

Sproule

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

Sincerely,

Jeffrey B. Aldrich, L.P.G.
Senior Geoscientist

John P. Seidle, P.E.
Senior Engineer

Responsible Member Validation

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

Engineering

Meghan Klein, P.Eng.
Senior Manager, Engineering

Geoscience

Alec Kovaltchouk, P.Geo.
VP, Geoscience

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

BACKGROUND

Renergen's Tetra4's South Africa Virginia gas project, which is in the Free State Province, is approximately 250 km southwest of Johannesburg (Figure 1). Throughout this report Tetra4 is used to refer to the field operator and Renergen is used to refer to the overall license holder and project developer of the South African gas development.

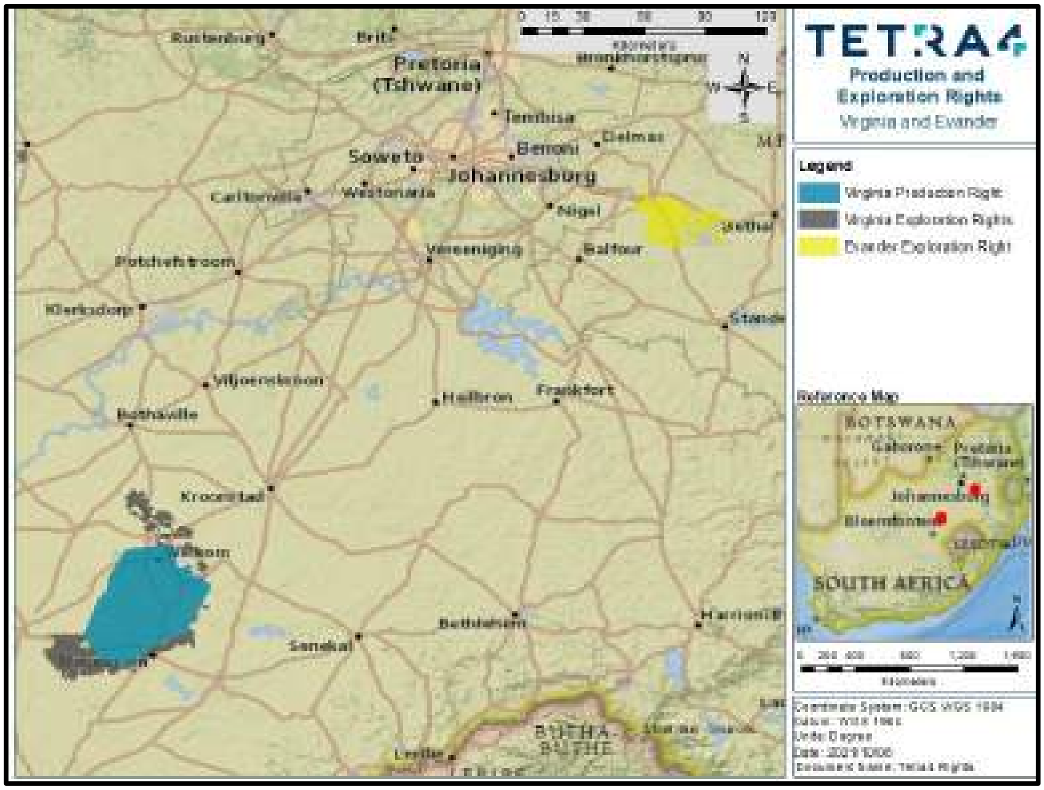

Figure 1: Location Map

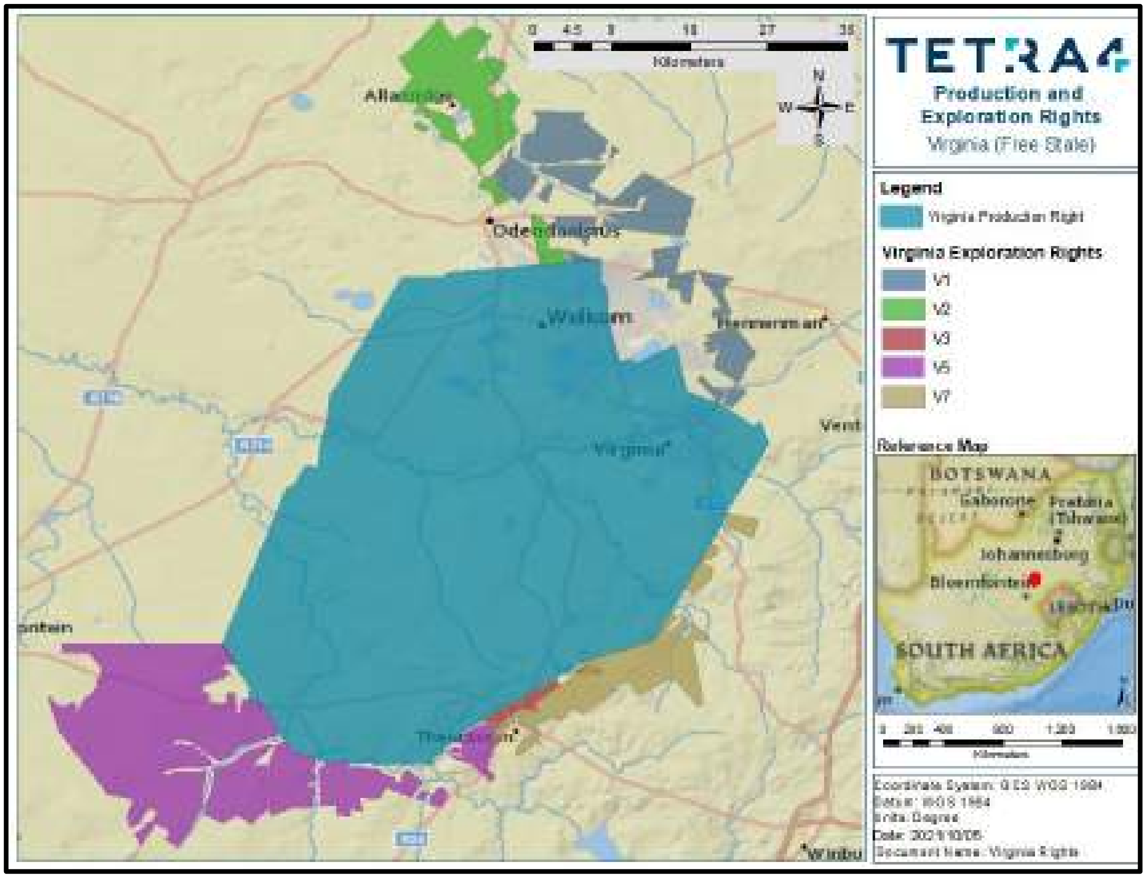

Figure 2: Permit Map

The exploration and production rights, which combined are known as the Virginia Gas Project (Figure 2), covers a large area where gas emitting boreholes have been identified from 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 capped due to dangerously high gas emission rates. Tetra4 now owns 100 percent working interest in 187,427.2189 hectares (463,147.74 acres or 1,874.27 Km^2) that currently has 18 wells currently capable of producing gas and 28 wells that are known to have produced gas in the past but are now currently capped.

The Tetra4 Production License is subject to a 5% government tax as described in the Mineral and Petroleum Resource Development Act of 2002 plus an overriding royalty interest (ORRI) paid by Renergen on certain concurrent leases that are owned by GFI Mining South Africa (GFIMSA), or Goldfields (Figure 3).

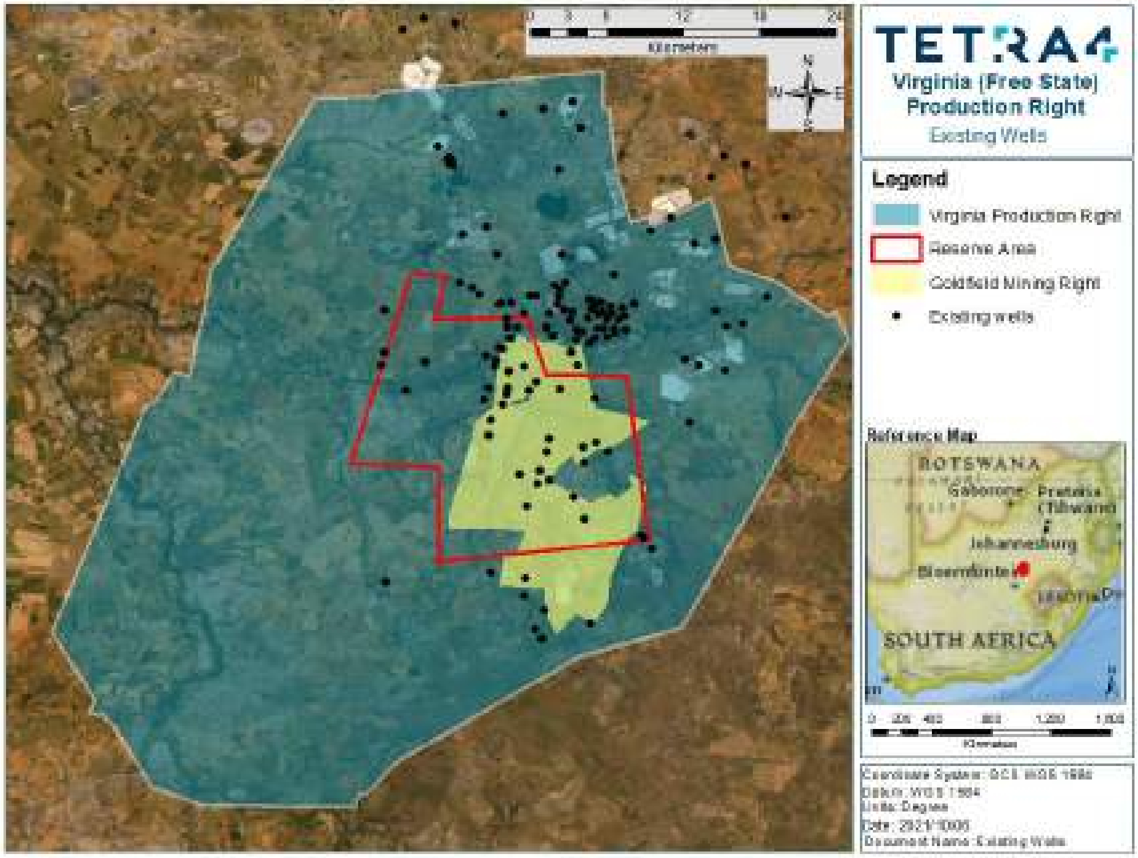

Figure 3: Map of the Tetra4 Well Control

The Goldfields ORRI is an additional 1% on top of the government tax on all wells and locations that are located within the Goldfields mining leases. These two reductions in the revenue stream, (government tax and GFIMSA ORRI) have been accounted for in the economic analysis. Sproule has not evaluated any gas volumes or economics on the Renergen exploration rights. This report only refers to the production right 24/04/07PR that has been granted in the center of the Virginia Gas Field.

GEOLOGY

REGIONAL GEOLOGY

The Virginia Gas Field Project overlies the Witwatersrand Precambrian age Supergroup of meta-sediments that host the Welkom Goldfield (Figure 4).

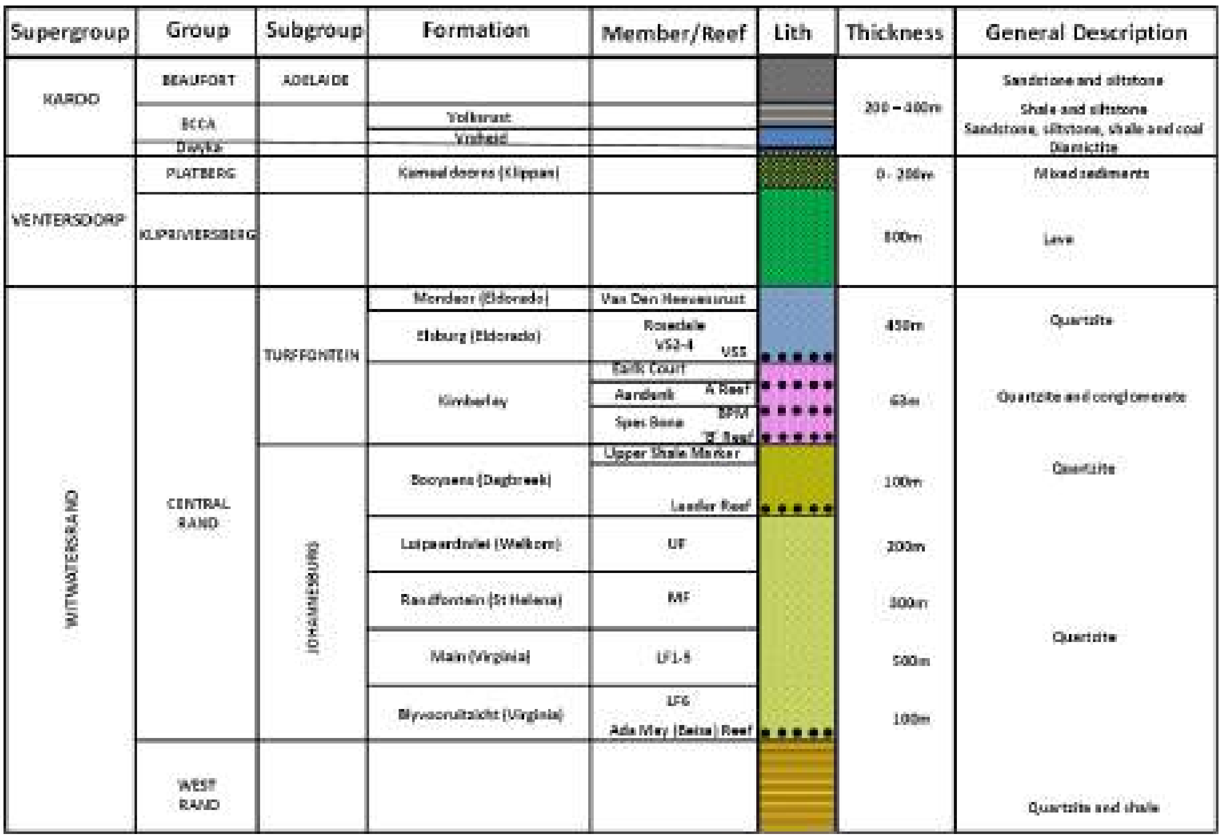

Figure 4: Stratigraphic Column (from Shango Solutions)

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 5 and Figure 6:

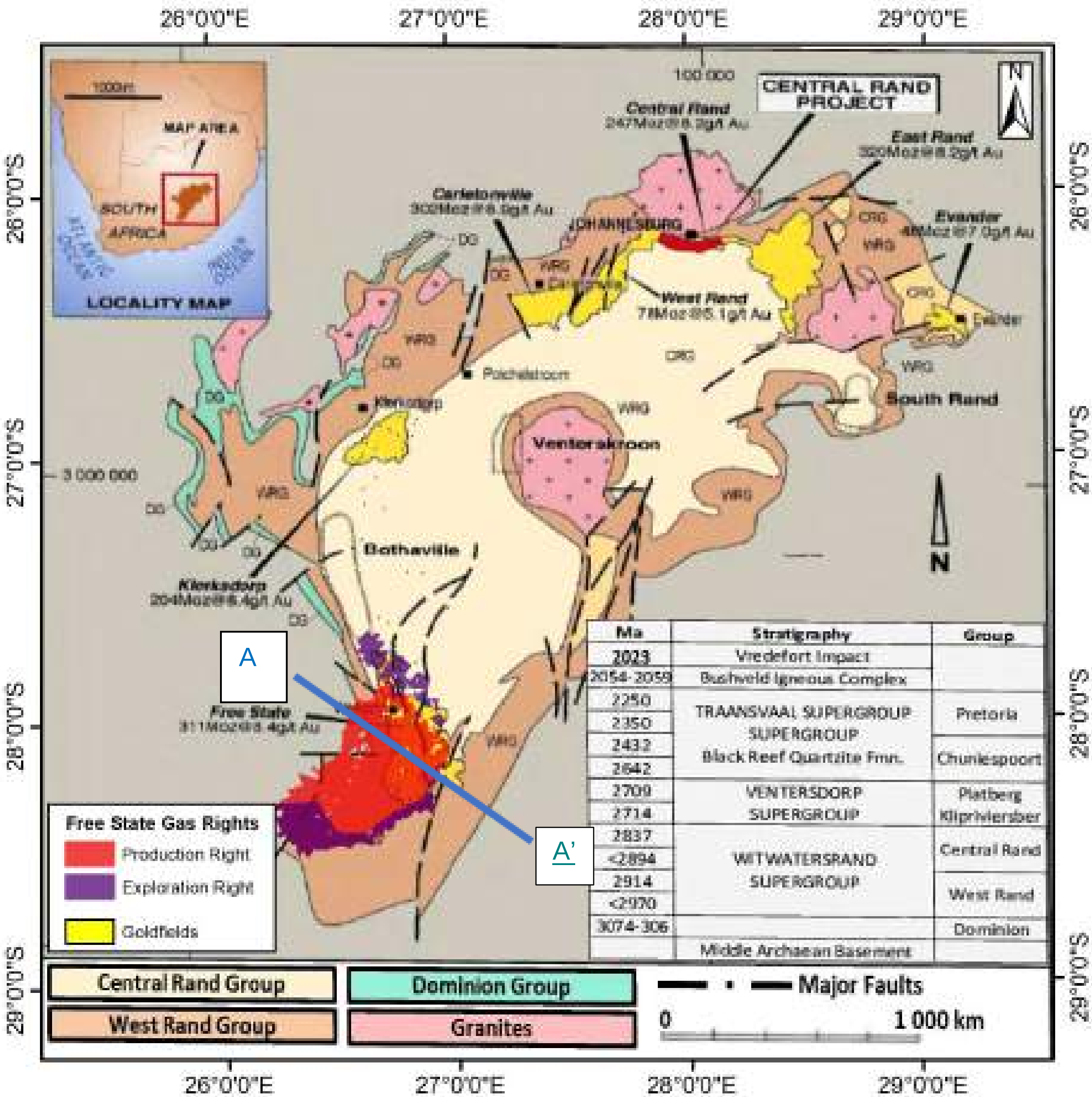

Figure 5: Regional Geologic Map of the Surface Geology

The Virginia Gas Project is Annotated in the Southwest Corner of the Map.

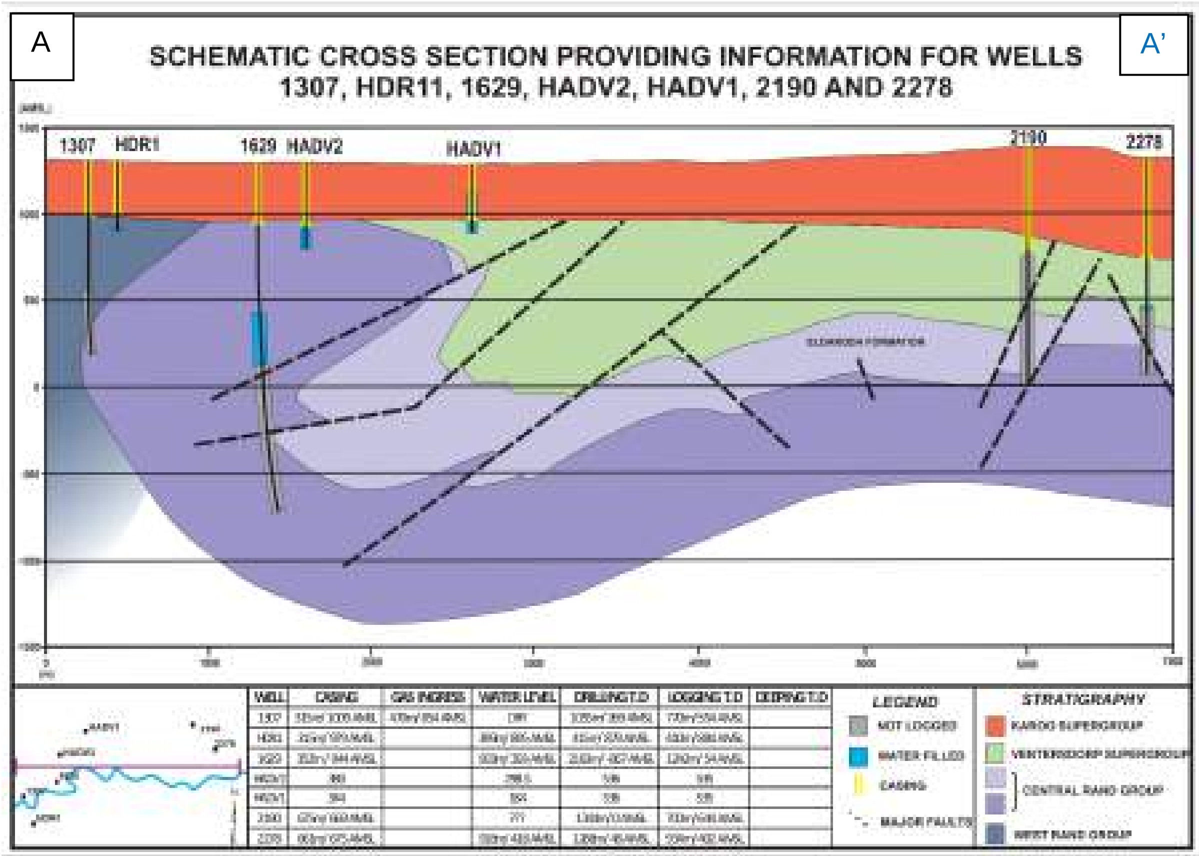

Figure 6: NW to SE Cross-Section Across the Virginia Gas Field

The known gas wells are associated with the wells intersecting the faults that penetrate the Witwatersrand Supergroup.

Unconformably overlying the Witwatersrand Supergroup is the Venterdorp 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 greenchist 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 Tetra4 license area producing methane gas for over forty years without any discernable pressure drop, however there are no quantified studies to date.

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:

> *He [Helium] 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 αparticles. …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.

EXISTING WELLS AND PRODUCTION HISTORY

HISTORIC WELLS

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.

EVALUATED WELLS

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.

2021 UPDATE AND MATERIAL CHANGES

Sproule, through a precedent company MHA Petroleum Consultants, have evaluated the Virginia Gas Project since 2007 and produced various reports in 2008, 2017, 2018, 2019, and 2020. The last four reports were contracted by Renergen and can be found on its website. This report updates the 2019 Reserve and Resource Report. There are several material changes since the 2019 report. Tetra4 entered into a turn-key drilling contract to drill several slant wells into the fractured basement. Shallow depth slant drilling for the production of gas resources is not a common practice globally and this was the first known production attempt in South Africa with an expected learning curve, which Tetra4 has demonstrated that it has managed. Tetra4's use of turn-key contract put the burden of learning on the drilling contractor and several of the initial wells did not reach the objective. Five of the last six wells were successful and the single well that was not completed was terminated due to mechanical reasons, and not for geologic failure. In the 2019 Report Sproule discussed that future slant wells could have a positive impact for Tetra4 however Sproule did not include those impacts at that time until Tetra4 could be shown to successfully drill and complete slant wells and true costs were realized, Table 4, and Figure 7, below. Those successes and costs have now been incorporated into this evaluation.

Tetra4 has analyzed the results of the drilling program and with the use of consulting geologists developed a more advanced subsurface model of the faults, fractures, sills, and dykes that represent the gas reservoir. This has allowed volumetric estimation of original gas in place for the first time. Sproule has examined and independently verified this model.

Tetra4 has provided Sproule with updated and detailed CAPEX and OPEX numbers based on actual costs and orders for equipment. Additionally, Tetra4 now has a detailed development plan, with exact co-ordinates, for the next Phase IC and Phase II drilling program which they have supplied to Sproule.

Table 4: Recent Wells Drilled by Tetra4 Used to Update this Report

Tetra4 Exploration Well Data Sheet							
			Gas Data				
Exploration Well ID	Well Type	Hole Depth (m MD)	Gas Intersected	Gas Flow (SCF/day)	CH4 (%)	He (%)	Comments
NEA02HT4	45° Horizontal	500	Yes	~108 307,86	75.7	12	The well is waterlogged and has been closed with a shut-in valve. Pressure gauge is constantly montioring the well pressure. Plans to de-water the well are being reviewed.
SWM06IT4	30° Incline	70	No	N/A	N/A	N/A	Drilling Failure - did not reach target - not Geologic Failure
T4WHM1	60° Incline	136	No	N/A	N/A	N/A	Loss of rods downhole - not Geologic failure
T4MD0001 (P2_V2)	60° Incline	331	No	N/A	N/A	N/A	Abandoned due to excessive water in the Karoo - did not reach basement
MDR1 Re-Entry	45° Incline	580.03	Yes	~194 552,67	82.5	3.15	Iinital gas intersection at 360m MD when hole was first drilled in 2015. After drilling kic-off at 347m MD for MDR1C, increase in gas flow was noted after drilling through 94mm fracture at 560m MD.
P0007	50° Incline	500	Yes	~ 136 392,98	86.65	3.4	
P0012	50° Incline	993.05	Yes	~31 680	92.7	1.9	Plans to improve gas flow are currently being reviewed.
P0010	55° Incline	750	No	N/A	N/A	N/A	Waterloss as a result of loose shales that resulted in a cavity at 331m MD. Cavity filled with cement between 321,1-331,1m
T4MD0002 (R2D2)	50° Incline	380	Minor gas show in the Karoo.	N/A	N/A	N/A	R2D2 to cement and closed. A new replacement well, called R2D2b will be drilled to intersect the gas-bearing fractures.
T4MD0003 (C3P0)	50° Incline	800	Yes	~31 680	TBD	TBD	Fluid level is between 380-392m MD. Main gas ingress depth is not known. According to the logs, gas is visible coming from the Wits directly below the Base of Karoo at 382m MD. Open fractures are associated with this contact.
T4MD0004 (P13)	Vertical	712	Yes	~2 880	94.3	0.9551	Main water ingress depth is uncertain. Fluid level is between 380-392m MD. Fractures at 575m MD but are not gas producing.

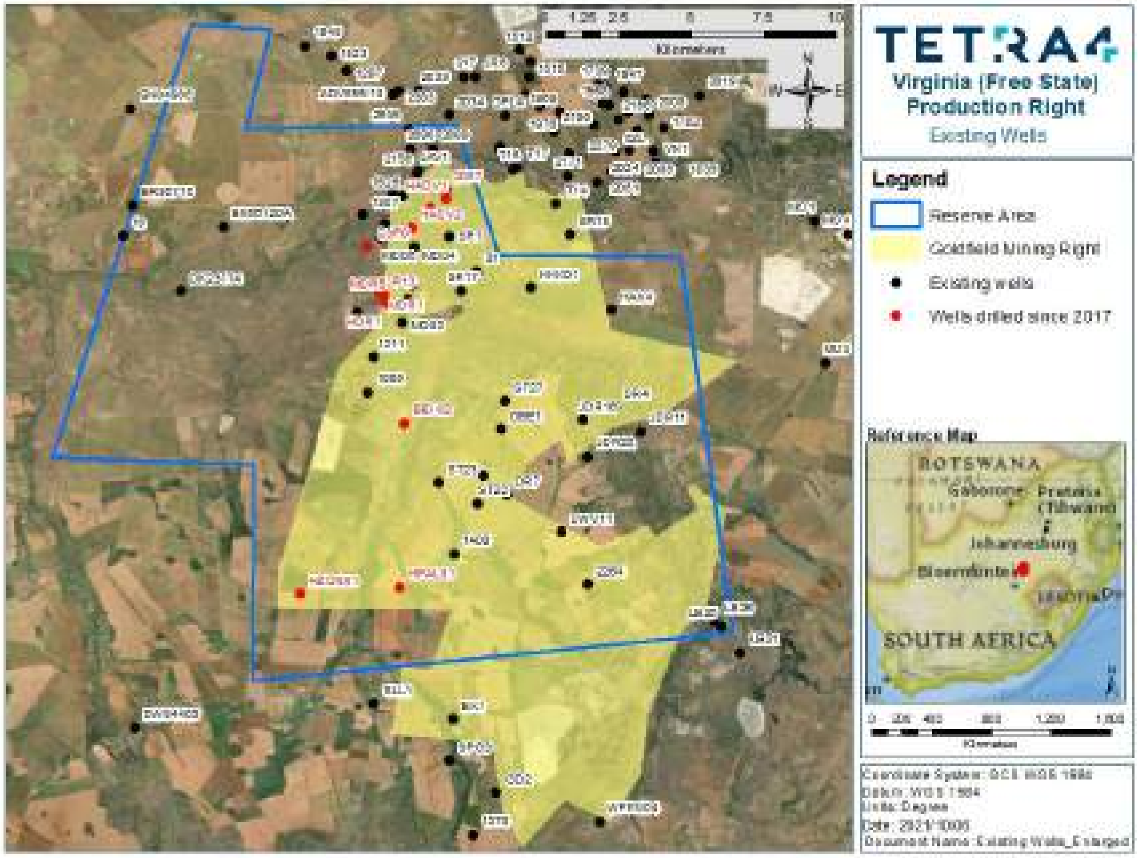

Figure 7: Enlargement of the Primary Development Area and Highlighted New Wells

It has been recognized, since before 2017, that most of the gas (both methane and helium) is found in fractures beneath the Permian Unconformity where the matrix porosity in the Ventersdorp and Witwatersrand Groups is essentially zero. The gas migration and charge are reliant on tectonically induced fracture porosity. Tetra4 has spent a large effort in mapping out the fractures and the multiple volcanic sills and dykes as gas is also associated at the margins of these features. Tetra4 has used a variety of geological methods, including remote sensing and wireline logging of wells, to map out both the fractures and the volcanics and then to verify the mapping. As a result of this work, and a shift to slant well drilling, the success rate of both intersecting fractures and\or volcanics and finding gas associated with these features has risen from an earlier 60 percent success rate to over 90 percent success rate. One of the primary keys to this improved success is Tetra4's use of satellite imagery to map vegetation stress and relate this to methane seepage along faults, Figure 8 and Figure 9, below.

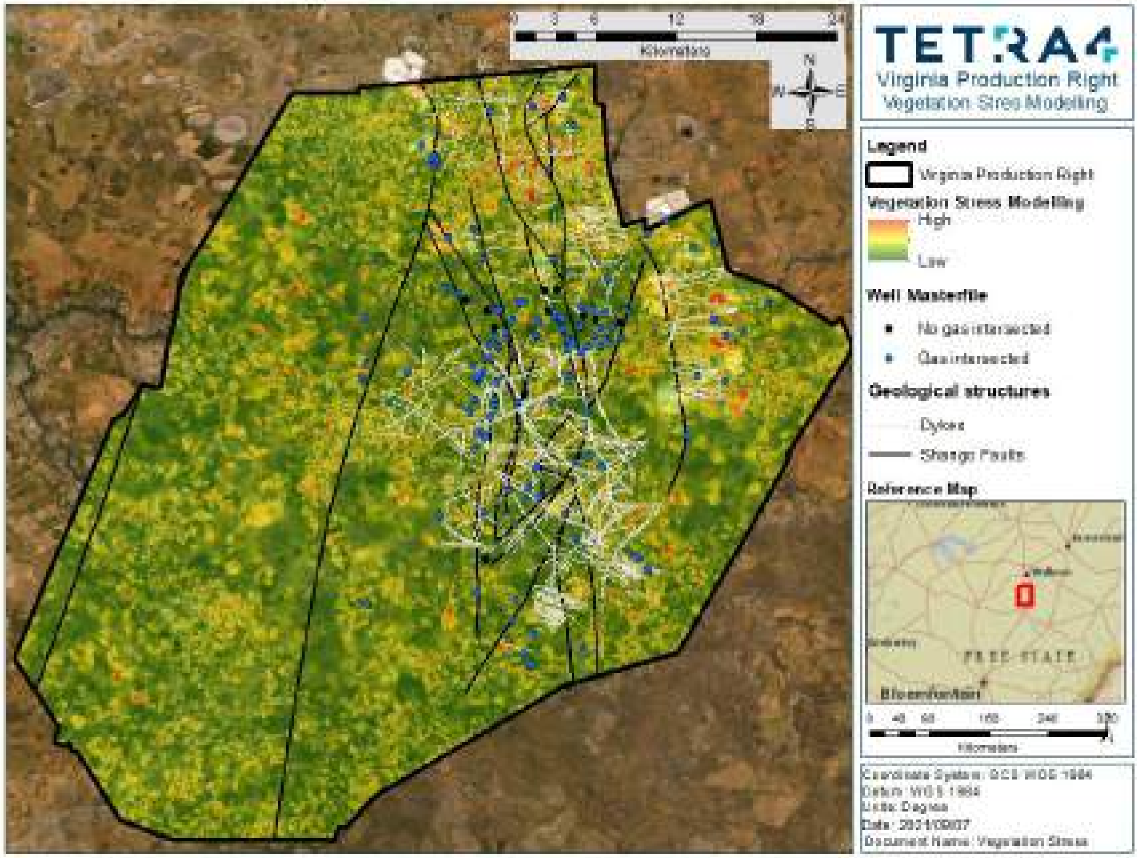

Figure 8: Production License Regional Vegetation Stress Map and Selected Known Faults and Dykes with Well Locations

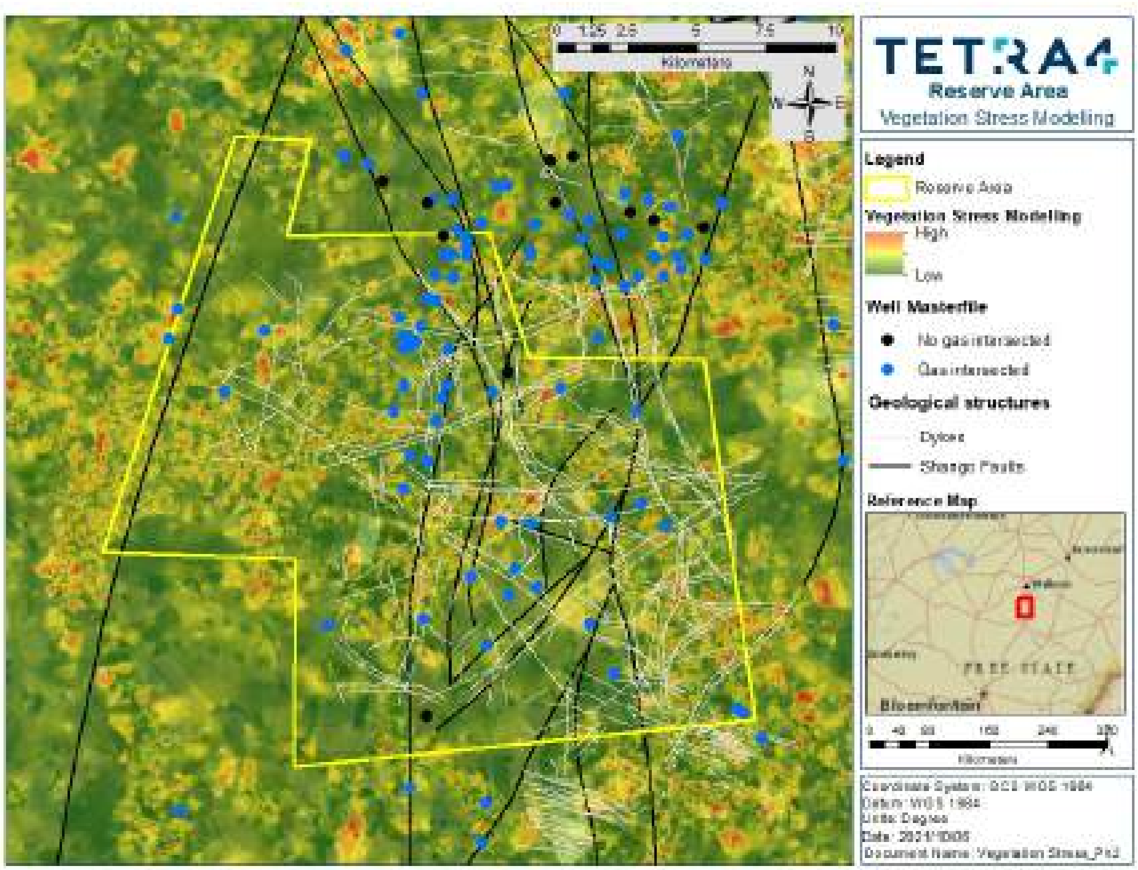

Figure 9: Enlargement of the Central Area Planned for Development

Using a methodology of targeting known faults at high vegetation stress points they have found both producible methane and helium in every targeted location.

METHODOLOGY

DATA SET

Tetra4 provided Sproule with driller's logs, completion reports, LAS files, gas analysis reports, production test data, and license data from the Virginia Gas Fields Project in the Free State in South Africa. In addition, Teta4 provided Sproule with shape files of its geologic interpretation of fractures, sills and dykes within the license area and remote sensing interpretation of gas migration via vegetation stress analysis.

ANALYSIS

Sproule reviewed the well data, LAS files, gas analysis reports, production test data, and historical geological data to ascertain the source of the gas, reservoir conditions, reservoir extents, Tetra4 development plans and market conditions.

VOLUMETRICS

PAST STUDIES

Past studies were referenced in the 2019 assessment and are not repeated in this report. The Virginia Gas Field has received independent 3rd Party assessments beginning in 2008, and with continued operations and increased data, the amount of certainty has increased. There is still very limited long term production data from the field with data from the HDR-1 well having the longest history, although it has been on limited production due to market constraints.

2021 ASSESSMENT

Sproule has reviewed the updated production from the HDR1 well, plus limited single test data from other wells that are not currently on production, and the data from the 2018 Tetra4 T4 WN 01 well that was drilled to test the shallow "White Sand" play towards the eastern edge of the license. Sproule has also reviewed the Tetra4 updated drilling schedule, OPEX and CAPEX costs and sales agreements in order to update the Sproule financial model.

At Sproule's suggestion, Tetra4 flow tested two new slant wells, the MDR1 and P007 wells, for two weeks in late June and early July 2021. There were several objectives of this test including understanding the completions of the new slant wells, new flow rates, and testing for possible interference between two closely spaced wells. Gas flow rates, fluid levels, and ambient pressures and temperatures were reported on a daily basis. Average gas production for the MDR1 well was 178 Mcfd (Figure 10). No water production was reported.

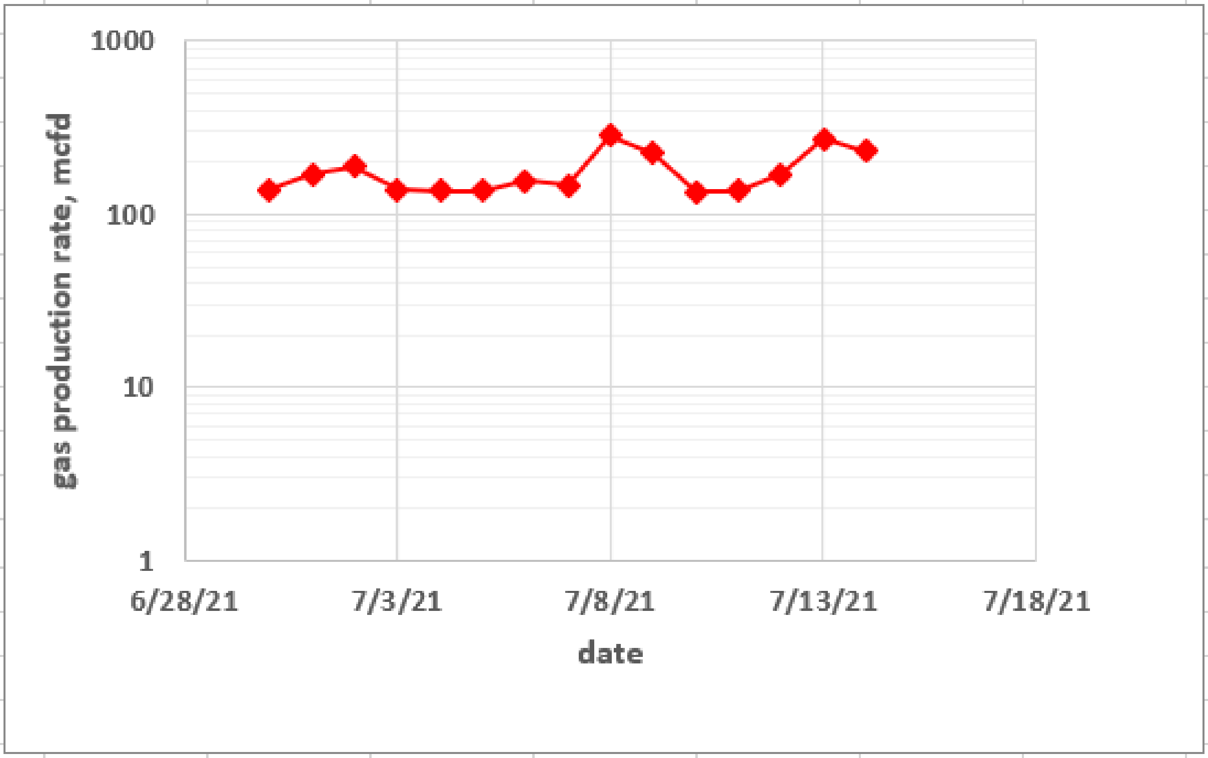

Figure 10: MDR1 Flow Test Gas Production Rate

Average gas production for the P007 well was 125 Mcfd (Figure 11). No water production was reported. For perspective, the 1P, 2P, and 3P type well plateau gas rates are 150, 260, and 380 Mcfd, respectively. Given the short duration of these flow tests, it is highly unlikely the wells were stabilized. Consequently, any gently rising or falling trends seen in reported gas production rates are not indicative of long-term behavior.

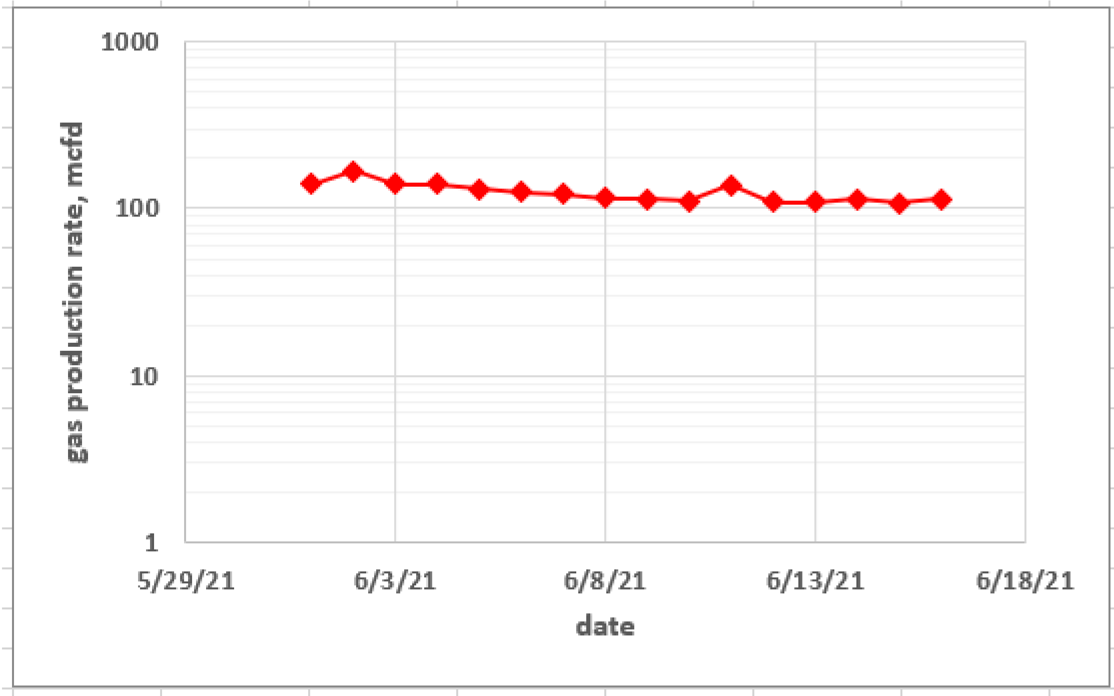

Figure 11: P007 Flow Test Gas Production Rate

Although these flow tests were short, three conclusions can be drawn from them. First, Renergen has demonstrated the ability to drill and complete slant wells, greatly increasing confidence in the gas production volumes anticipated in the current development program. Secondly, although these tests involved only two wells for brief flow tests, there is no evidence that slant wells will not be at least as productive as existing vertical completions. Finally, as these two tests were taken simultaneously from two wells within 100m of each other and, over this short period of time, neither well indicates interference so the test of rapid fracture depletion now has quantitative data. While this is not a definitive answer as to the drainage radius of the wells, it is a positive indication that rapid drawdowns do not deplete entire volumes around the borehole.

ORIGINAL GAS IN PLACE

Tetra4 has shown, by drilling and flow testing, that methane and helium are trapped in both faults and adjacent to volcanic dykes and sills within the Ventersdorp and Witwatersrand Groups. There does not appear to be any significant matrix porosity contribution to the gas volumes, at this time. Thus, this play is being developed as a fractured reservoir play within a matrix rock of zero porosity and permeability. It is likely that there will be some contribution from the matrix but at this time that contribution has insufficient data to be evaluated. In order to estimate the original gas in place ("OGIP") Sproule has used a stochastic approach using probabilistic analysis to evaluate the ranges that can be expected from the fractures and the contacts with the volcanic emplacements.

There are multiple factors that need to be assessed in the evaluation of the GIIP. The primary and most important factor is the total length of fractures and dykes/sills that exist and are planned to be drilled. Sproule, in consultation with Tetra4, has subdivided the production right into three areas for planning purposes defined as follows: the first stage of budgeted drilling and field development as the Reserve Area, areas that are extensions of the known faults with proven gas discoveries as the Contingent Resource Areas, and the rest of the production right which have known faults but limited well control as Prospective Resource Areas. These areas are shown in Figure 12.

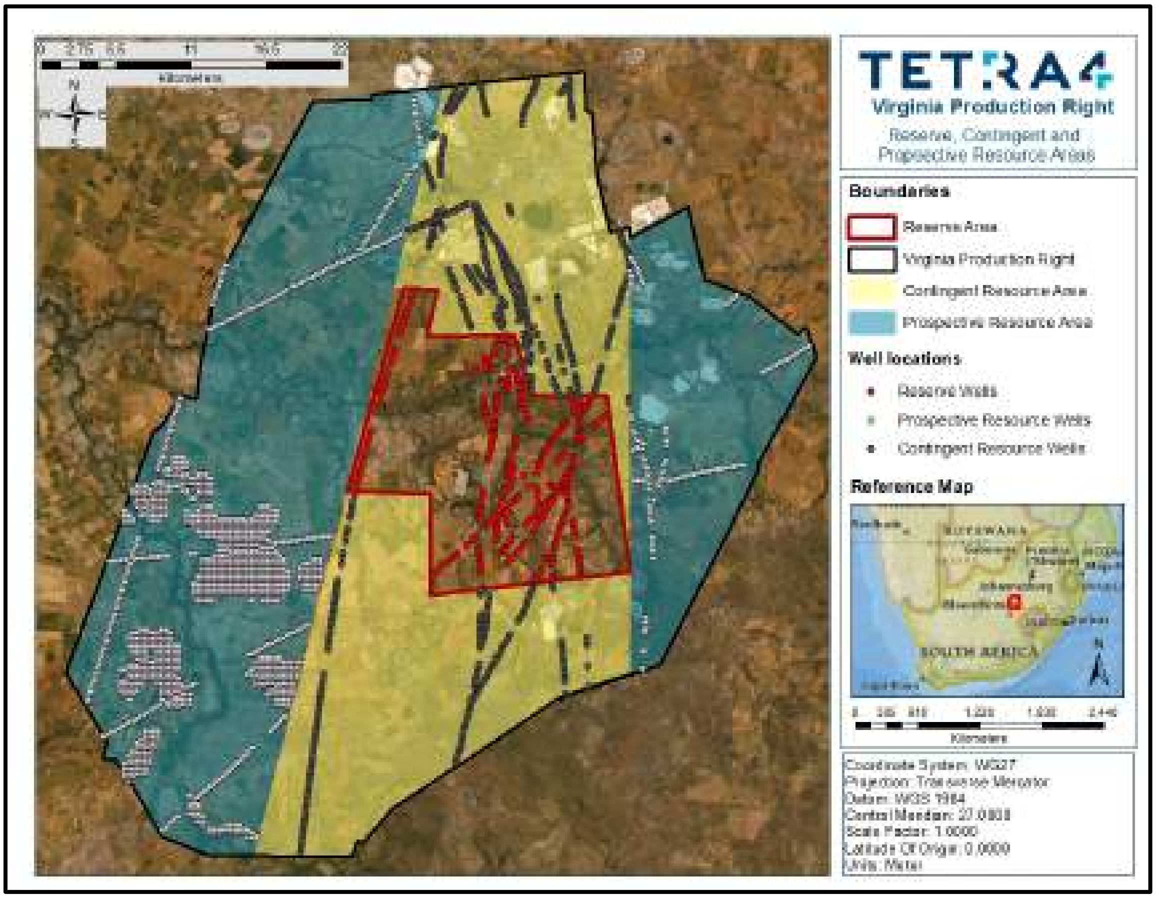

Figure 12: Map of Reserve Area (Red), Contingent Resource Area (Yellow), and Prospective Resource Area (Blue).

In the Reserve Area Sproule has evaluated both the total line meters that Tetra4 has mapped out and the more limited amount of line meters that they plan to drill on a 300m well spacing in order to evaluate the range of potential gas initially-in-place. Sproule has used the same methodology in both the Contingent and Prospective Resource areas.

A second parameter that was considered was a buffer area around any given fault or dyke that will contain additional smaller faults down to microscopic level fractures that will both hold gas and allow movement of gas to a production borehole. Figure 13 shows a photograph taken from a simple fault displacement in a quarry in the country of Turkey that illustrates the concept of multiple conjugate and smaller visible faults adjacent to the master fault. Figures 14a,b and 15a,b were taken by Jordaan Fouche, consulting geologist to Tetra4, from outcrops within the South African Karoo Basin.

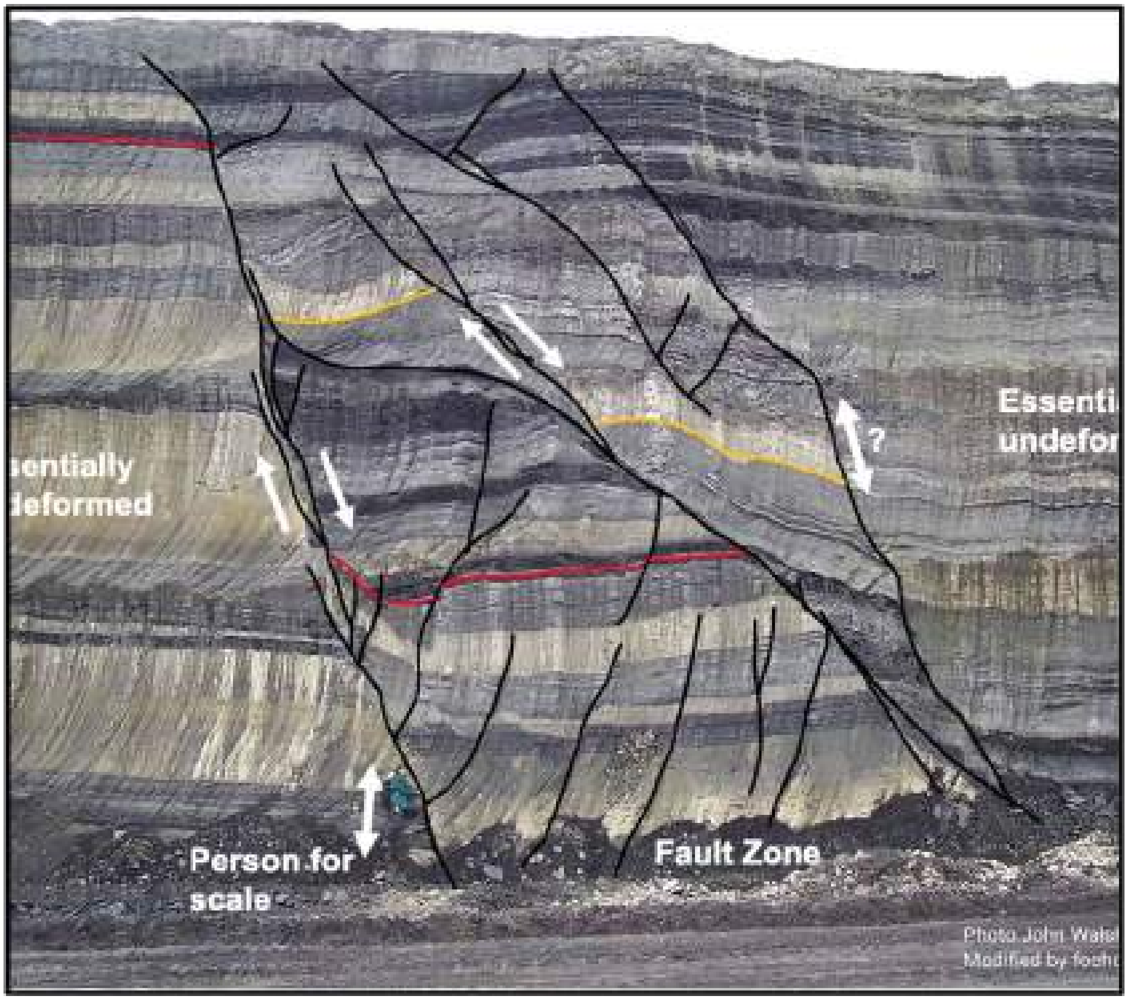

Figure 13: Photograph from a Turkish Quarry of an Example of an Extended Fault Zone

Figure 14: Photographs of an Exposed Dyke Intruding into Karoo Aged Rocks in South Africa and a Closeup Showing the Intense Fracturing of the Karoo Host Rock Near the Dyke

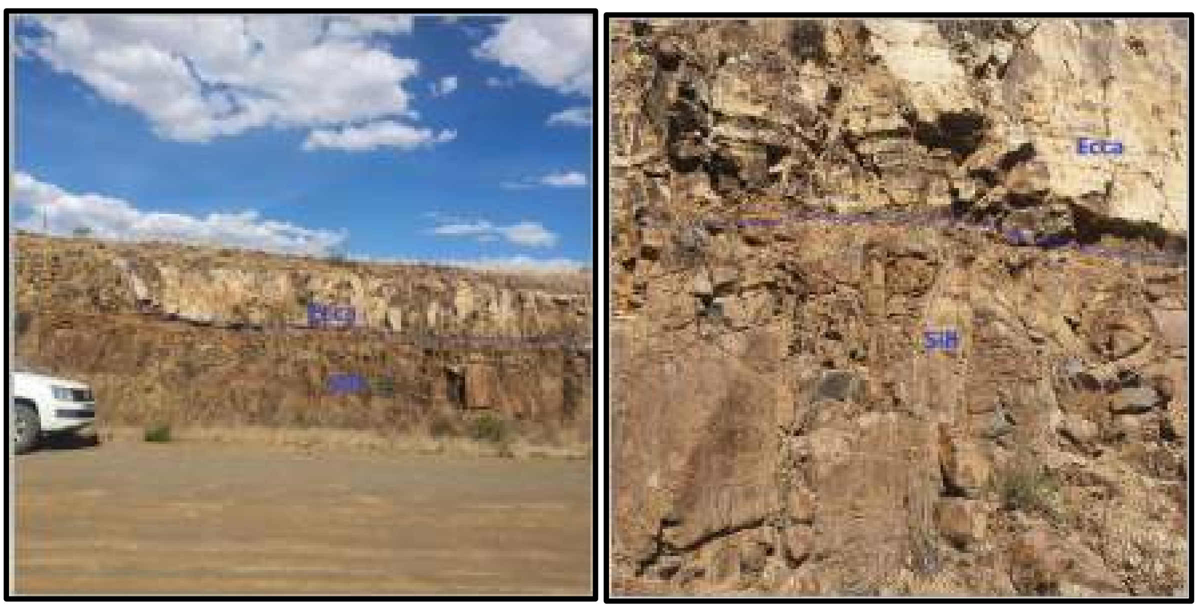

Figure 15: Photographs of an Exposed Sill Intruding into Karoo Ecca Formation in South Africa and a Closeup Showing the Intense Fracturing of the Ecca Host Rock Near the Sill

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It is established in the literature (Lorenz and Cooper, 2020) that fractured reservoirs will have a distance or area of conjugant shear fractures ("buffer zone") around the primary fault that will cover several orders of magnitude. Based on Tetra4's experiences of slant well drilling and gas shows, a range of 100-250m was used as a buffer zone around the faults and a 50m buffer zone was used around the sills and dykes.

The fracture porosity within this entire buffer zone, not just within the few millimeters of a fault, is used to calculate gas porosity. As the rock matrix is expected not to contribute to the porosity but only the fractures, the density and spacing of the fractures is key to the estimate of the porosity. The basic model for fracture porosity (Abdassah, D., & Ershaghi, I.) is:

$\phi f=(e/(e+D))\ 100$

Where

ϕf = Fracture Porosity (%)

e = Fracture Width (cm)

D = Fracture Spacing (cm)

The fracture widths were estimated from measurements reported in literature from core measurements of fractured basement rocks, some from South Africa and others from global experience (Finley, S., & Lorenz, J. (1988), Gable, D. J., Burford, A. E., & Corbett, R. G. (1988), McCaffrey, K., Holdsworth, R., Pless, J., Franklin, B., & Hardman, K. (2020), and Cook, A.P., 1998). Fracture widths were estimated to be a Minimum of 1.00E-04 cm, Most likely of 1.00E-03 cm, and a Maximum of 1.50E-03cm. The range of estimated porosity is from a low of 0.002% to a high of 0.01% with a most likely estimate of 0.0055%.

Additionally, the height of the gas column is a parameter that has a high degree of uncertainty. Shango Solutions has produced a confidential report for Tetra4 documenting gas occurrences in gold mines within the Virginia Production License. Some of these gas occurrences have also been documented by Ward, et. al. (2004) including the Evander Gold Mine at a depth of 1,950m below surface, and the Kloof Gold Mine at depths of 3,300m and 3,400m below surface. These facts demonstrate that there is gas down to at least that level. The Beatrix Mine constructed an extraction system to capture and use the methane from depths below 830m below ground level at a rate of 1600 l/s (4.88 Mcf/d) with methane concentrations between 82% and 90%. Furthermore, the fact that the mine was able to produce methane for a substantial period of time, at commercial rates and at a depth much deeper than the depth that Tetra4 is planning to drill its wells, demonstrates there is a significant gas column that will support continued production. Sproule has used this gas-down-to of 2000 meters as the maximum gas column in its analysis and used the deepest gas below the Permian unconformity tested by vertical wells (500m) for the minimum gas column. The Most Likely gas column scenario that has been used in the stochastic realizations is 1000m.

While the production wells and the production tests have produced primarily dry gas, there can be expected to be some volume of water trapped within the fractures, even if it is immovable. This water saturation estimate ranges from 10% to 40% with a Most Likely estimate of 20%.

For the stochastic realizations, a single value of the gas expansion factor (Bg) of 0.023 was used, with a methane percentage of 80% of the total gas volume and a helium concentration of 3% by volume. No water drive is anticipated, only volumetric depletion so recovery factors from 60 to 70% were used. Using the ranges described above and using the @Risk software by Palisades a stochastic analysis of the Technically Recoverable Total Gas (which includes nitrogen, carbon dioxide as well as methane and helium), Methane Gas and Helium Gas Resources were calculated, presented inTable 5, below. Total gas volumes are important considerations in the overall field design when planning for field pipeline capacities, and inputs to the liquifiers.

Table 5: Technically Recoverable Resources from Stochastic Analysis in the Reserve Area

	P90	P50	P10
Total Gas (BCF)*	314.22	555.08	1,084.62
Methane (BCF)	251.38	444.06	867.7
Helium (BCF)	9.427	16.652	32.539

For the purposes of field design total wellhead gas volumes are reported which contain some percentages of non-commercial gases that the field pipeline system and liquifiers must be designed to accommodate.

CONTINGENT RESOURCES

Tetra4 has defined a core area that has been delineated by drilling and testing within the production license of 550.7 Km2, slightly larger than in 2019. Adjacent to that development area, to the north and to the south along strike with the delineated and mapped fault and fault zones Sproule has defined the Contingent Resource Area, (Figure 12); an area of the Production Right where gas has been discovered and wells have been flowing methane for decades however the area is outside of the Field Development Plan (FDP) that Tetra4 has put forward. Sproule has used the Tetra4 fault and fracture maps and calculated 382.97 linear kilometers of drillable reservoir in the Contingent Resources Area. Using the same parameters for the baseline OGIIP and for the Reserve Drilling spacing and EUR/well Sproule has made a stochastic calculation of the OGIP, the Technically Recoverable Total Gas volume and the Technically Recoverable Resources of Methane and Helium in the Contingent Resource Area. The Total Gas Volume and Technically Recoverable Resources are shown in Table 6, below.

Table 6: Technically Recoverable Resources from Stochastic Analysis in the Contingent Resource Area

	P90	P50	P10
Total Gas (BCF)*	152.64	286.45	512.93
Methane (BCF)	137.4	257.8	461.6
Helium (BCF)	4.6	8.6	15.4

For the purposes of field design total wellhead gas volumes are reported which contain some percentages of non-commercial gases that the field pipeline system and liquifiers must be designed to accommodate.

Using the same EUR/well as used in the reserve calculations, as shown below, and the same well spacing of 300m between wells it is estimated that Tetra4 would have at least 497 wells that it could drill in the Contingent Resource Area along known fault systems. Sproule has used a more conservative approach with 600m spacing between wells and 225 wells. Using the well parameters from the reserves (EUR Minimum of 0.9 BCF/well, a Most Likely of 1.7 BCF/well and a Maximum of 2.6 BCF/well) and an average of 90% methane and 3% helium concentration the following Contingent Resources are calculated, as shown in Table 7 below

Table 7: Contingent Resources

	C1	C2	C3
Recoverable Gas (BCF)	141.8	267.8	409.5
Recoverable Methane (BCF)	127.6	241.0	368.6
Recoverable Helium (BCF)	4.3	8.0	12.3

PROSPECTIVE RESOURCES

The areas to the east and west of the primary fault systems that are well delineated by historic blowers and by Tetra4's recent drilling program are defined as the Prospective Area. There are two areas, a western area and an eastern area that bound the Contingent and the Reserve Areas. There are known faults within these defined areas and some indications of gas however the distance between wells, the fact that some wells have water and/or minor gas shows while other wells have been blowers for over forty years indicates that there is most like some degree of reservoir heterogeneity within this area. Tetra4 has defined 50 linear kilometers of drillable fractures and over 250 linear kilometers of drillable targets on emplaced sills and dykes. Sproule has used the Tetra4 fault and fracture maps and calculated 347.4 km of drillable reservoir in the Prospective Resources Area, Figure 16, Figures 17a & b, below. Using the same parameters for the baseline GIIP and for the Reserve Drilling spacing and EUR/well Sproule has made a stochastic calculation of the GIIP, the Technically Recoverable Gas volume and the Technically Recoverable Resources of Methane and Helium in the Prospective Resource Area. Using a 300m spacing for wells Tetra4 has identified 1,158 targeted well locations for prospects within this area. Sproule has used a more conservative 900m spacing and 350 prospect wells to calculate the Prospective Resources.

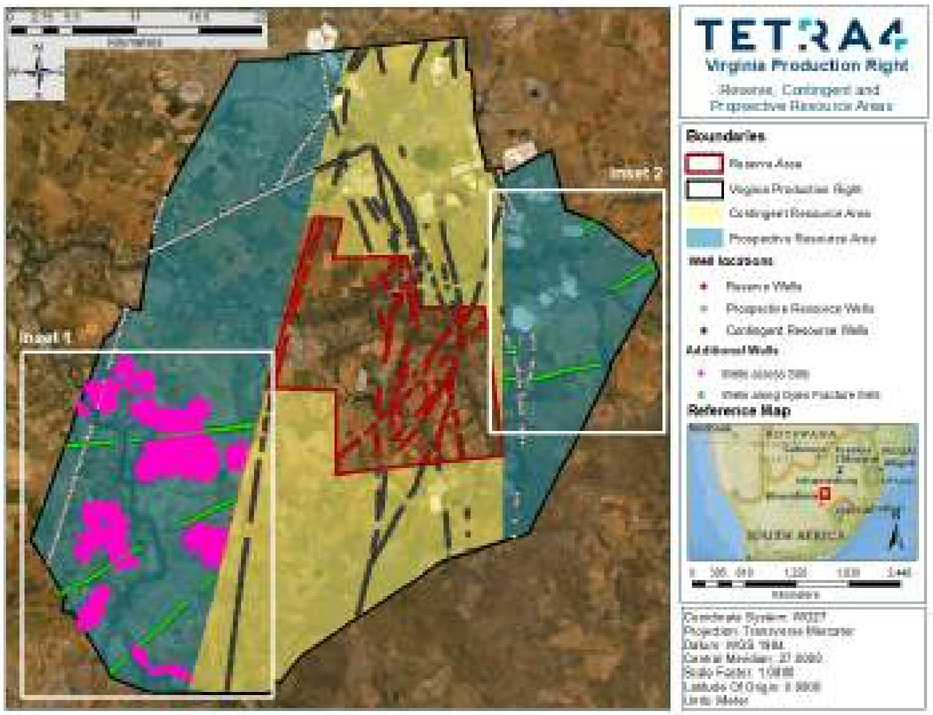

Figure 16: Tetra4 Map Showing the Prospective Area Defined Well locations Along Identified Faults, Sills and Dykes

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Figures 17a & 17b: Enlargements of the Western and Eastern Prospective Resource Areas

Sproule has chosen to use the original 60% drilling success ratio for this exploration area and the same three type curves used for the reserve and contingent resource type wells to estimate the prospective resources.Table 8, below shows the Technically Recoverable volumes for Total Gas, Methane and Helium gases and Table 9, below, shows, based on the well count, the Prospective Resources of Total Gas, Methane and Helium.

Table 8: Technically Recoverable Prospective Methane and Helium Volume Estimates of the Virginia Gas Field

	P90	P50	P10
Gas (BCF)	207.9	357.8	591.2
Methane (BCF)	187.2	322.1	532.0
Helium (BCF)	6.2	10.7	17.7

Table 9 Prospective Resources

	C1	C2	C3
Gas (BCF)	189	357	546
Methane (BCF)	170	321	491
Helium (BCF)	5.7	10.7	16.4

PROSPECTIVE RESOURCES*: “The estimated quantities of petroleum 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 determine the existence of a significant quantity of potentially moveable hydrocarbons.”*

ECONOMICS

TETRA4 OPERATING CONDITIONS AND SALES AGREEMENTS

Tetra4 operates under a Production License from the Petroleum Agency of South Africa which is subject to a 5% royalty based on wellhead price to the South African Revenue Service. An additional royalty of one percent of wellhead price is owed to the GFI Mining South Africa (GFIMSA) or Goldfields on all new wells located on their existing licenses. Sproule has taken a conservative approach and applied this additional GFIMSA royalty to all new wells although some of the Proved Undeveloped (PUD) locations will not fall withing the GFI licenses.

Tetra4 has provided Sproule with a signed Gas Sales Agreement with Linde Global Helium (Linde) for the purchase of helium gas at the price point of approximately $200/mcf escalating according to US CPI index, as shown in Figure 21, below.

Renergen has entered into a commitment letter with the Overseas Private Investment Corporation (OPIC), the United States' government development finance institution, for OPIC to provide capital assistance for the development of the helium resource, indicating the United States' government's level of interest in the Virginia Gas Project as part of the global helium supply system.

The Tetra4 field development plans call for the construction of a gas gathering system, compression facilities, the installation of the above-mentioned gas processing facilities and, as production increases, an expansion of the entire system. Sproule has reviewed Tetra4's detailed plans for abandonment and rehabilitation of the wells and all infrastructure plans that have been submitted to, and accepted by, the Petroleum Agency of South Africa (PASA). These plans meet, and in places exceed, governmental regulations for abandonment, rehabilitation, and monitoring.

ENGINEERING

SLANT WELL COMPLETIONS

Tetra4 has recently begun developing the Virginia Gas Field with "slant wells". These directional wells intersect the pay zone at angles up to approximately 45 degrees from the vertical, increasing the chances of intersecting natural fractures compared to a vertical well. Tetra4 anticipates all future wells in this project will be slant wells.

Tetra4 has drilled, completed, and placed two slant wells on production. Initial gas production rates from these two wells average 150 Mcfd, the initial rate of the vertical 1P type well, and show a shallow exponential decline similar to the Tetra4 vertical wells. However, with only two months of production history, the wells are arguably not yet stabilized and do not show a decline sufficiently clear to reliably calculate a decline rate, impacting on the accuracy of long-term production forecasts. Consequently, this evaluation assumed that the new slant well completions will be at least as productive as the historic vertical wells and utilized the vertical type wells for estimating gas production from slant wells.

TYPE WELLS

The 1P, 2P, and 3P type wells used to generate gas production forecasts for this study were developed in previous studies, some dating back to the Molopo report in 2008. All three type wells have an initial two-month plateau followed by shallow exponential declines (Figure 18 and Figure 19). Type well coefficients are given in Table 10 below.

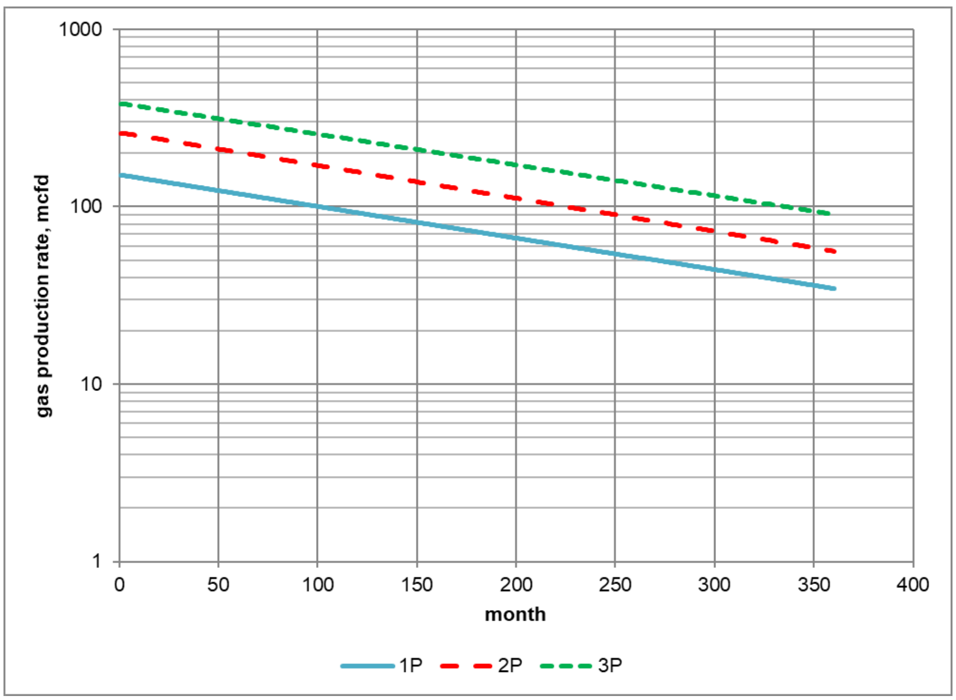

Figure 18: Type Well Gas Profiles

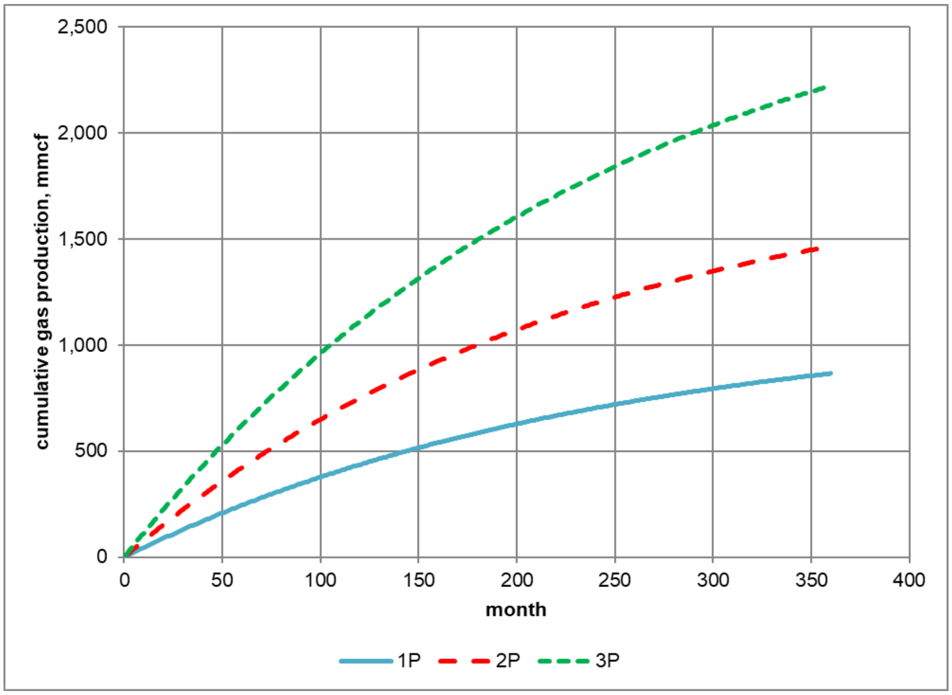

Figure 19: Type Well Cumulative Gas Production

Table 10: Type Well Coefficients

Type well category	Initial rate, Mcfd	Plateau duration, months	Effective decline rate, %/yr.	Cumulative production, Bcf	Well life, years*
1P	150	2	5.00	0.900	32.7
2P	260	2	5.00	1.652	42.3
3P	380	2	5.00	2.620	51.6

**Technical well life based on 30 Mcfd abandonment rate*

TETRA4 FIELD DEVELOPMENT PROGRAM

As of September 1, 2021, the effective date of this report, Tetra4 has two producing (PDP) wells and 23 non-producing (PDNP) wells. These PDNP wells are scheduled to be turned on production in the fourth quarter of 2021. Tetra4 plans to begin development of their acreage with 24 wells in the fourth quarter of 2021, followed by drilling 30 wells in 2022, 70 wells annually in 2023, 2024, and 2025, then a final 47 wells in 2026. This field will be fully developed by October of 2026 with 311 new wells (currently classified as PUDs), 2 PDPs, and 23 PNPs for a total well count of 336 wells. An acreage map with well locations is provided in Figure 20 below.

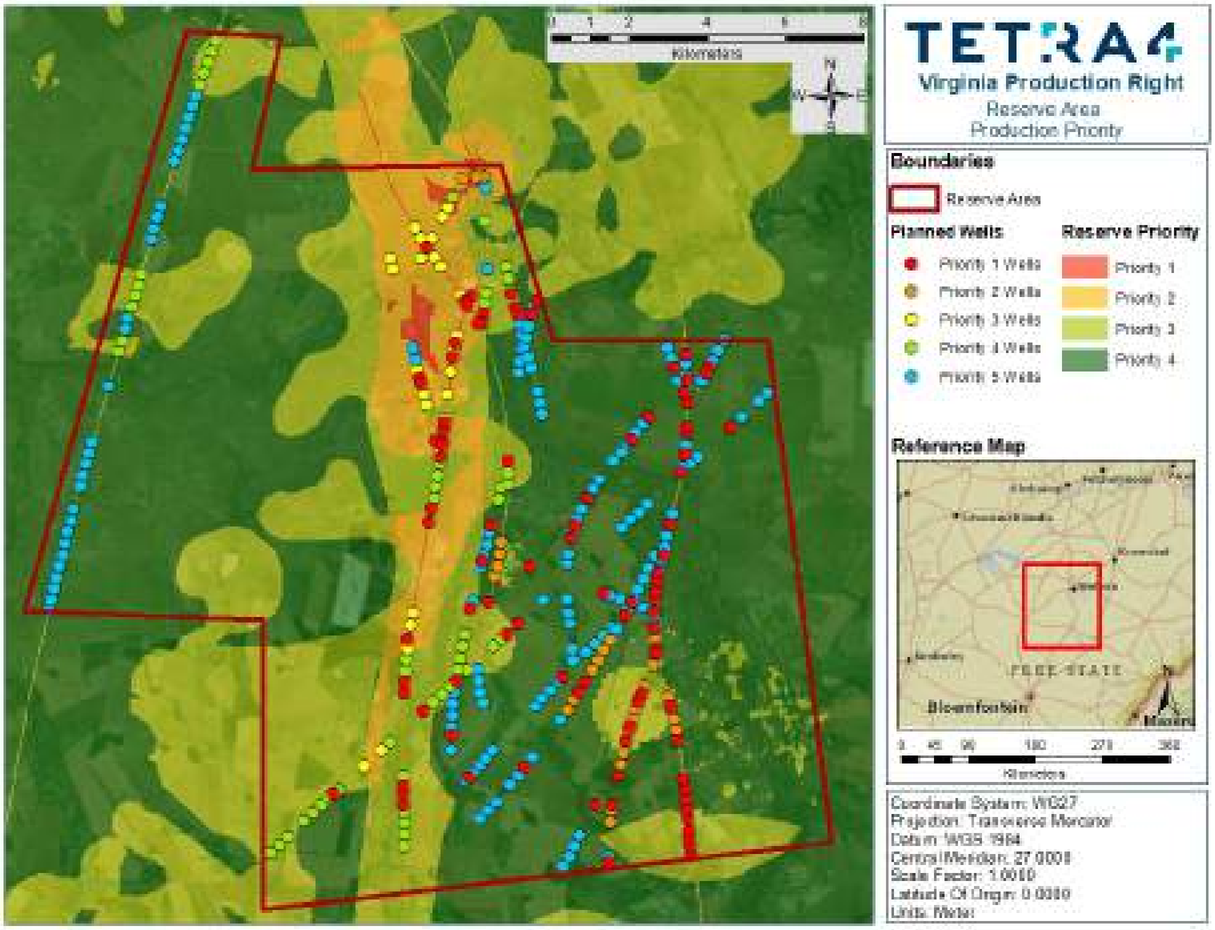

Figure 20: Tetra4 Development Reserve Area and Priority Drilling Plan

The liquefiers (a single package with both LNG and helium liquefiers) selected by Tetra4 have an inlet capacity of 44 MMcfd. As production increases with new wells coming online, Renergen plans to add additional liquefiers. Under the current development scenario, gas production for the 1P case can be treated with a single set of liquefiers over the entire project lifetime. The 2P case will require an additional set of liquefiers while the 3P case will require a total of three liquefiers over the project life; with each scenario using a slightly different sized set of liquefiers with a slightly different CAPEX cost.

A gas gathering pipeline is being constructed under a timeline to connect new wells to the liquefiers in a timely manner.

ECONOMIC PARAMETERS

CAPITAL COSTS

Sproule has reviewed Tetra4's past expenditures and future budgets. Well drilling and completion CAPEX is budgeted at 2.596 MMZAR per well (MMZAR = 1 million ZAR). As of the effective date of this evaluation, Tetra4 had drilled 6 slant wells of which 5 were producers. This dry hole risk of roughly 17% was addressed by decreasing the type well gas production rate by a factor of 0.83. Connection CAPEX is 0.5 MMZAR per well.

Pipeline capital of 2,409 MMZAR has been scheduled as payments of 225 MMZAR in September 2021 and 2,184 MMZAR in January 2022.

The number and size of the gas processing plants required for each Reserves category are tailored according to the fieldwide gas production profile for that category. The gas processing plant includes both methane and helium liquifiers. Development of the 1P Reserves assumes a single processing plant with an inlet capacity of 44 mmcfd. Capital for the 1P plant is 5,022 MMZAR and capital for connection to the electrical the grid is 124 MMZAR. Both capital expenses are scheduled for October of 2021.

Development of the 2P Reserves assumes two plants, each with a capacity of 35 mmcfd and plant and connection CAPEX of 3,995 MMZAR and 99 MMZAR, respectively. Capital is invested in October 2021 and July 2024.

Development of the 3P Reserves assumes three plants, each with a capacity of 30 mmcfd and plant and connection CAPEX of 3,424 MMZAR and 84 MMZAR, respectively, Capital is deployed in October 2021, July 2023, and January 2025.

All capital costs are escalated at 2 %/yr until they double or for 35 years, whichever occurs first, then held constant for the life of the project.

OPERATING EXPENSES

Operating expenses can have both a fixed and a variable component. Fixed plant (liquefier) operating expense varies by plant capacity and is based on an electrical cost of 0.9 ZAR/kw-hr. Fixed plant operating expense for 1P Reserves is 14 MMZAR/month. Fixed OPEX for the 2P and 3P categories is 11 MMZAR/month and 10 MMZAR/month, respectively. No variable operating expenses are assigned to the plants. Lease operating expenses (LOE's) are 3,000 ZAR per month per well fixed and 24.6 ZAR/Mcf variable. All operating expenses are escalated at 2%yr until the price doubled or for 35 years, whichever comes first, then is held constant for the life of the project.

PRICES

The initial methane price of 250 ZAR/MMbtu is escalated at 3.2%/yr, as reported in the StatsSA March 2021 Statistical Survey. The price is held constant once the initial price has doubled in 2043.

The initial helium price of 3,555 ZAR/Mcf (237 USD/Mcf) is escalated at 7.3%/yr, the sum of the average US CPI of 2.4%/yr and the 4.9% average ZAR/USD currency escalation. After doubling in 2031, the helium price is held constant over the life of the field. Monthly methane and helium prices are plotted in Figure 21 and listed in Appendix A: Methane and Helium Prices.

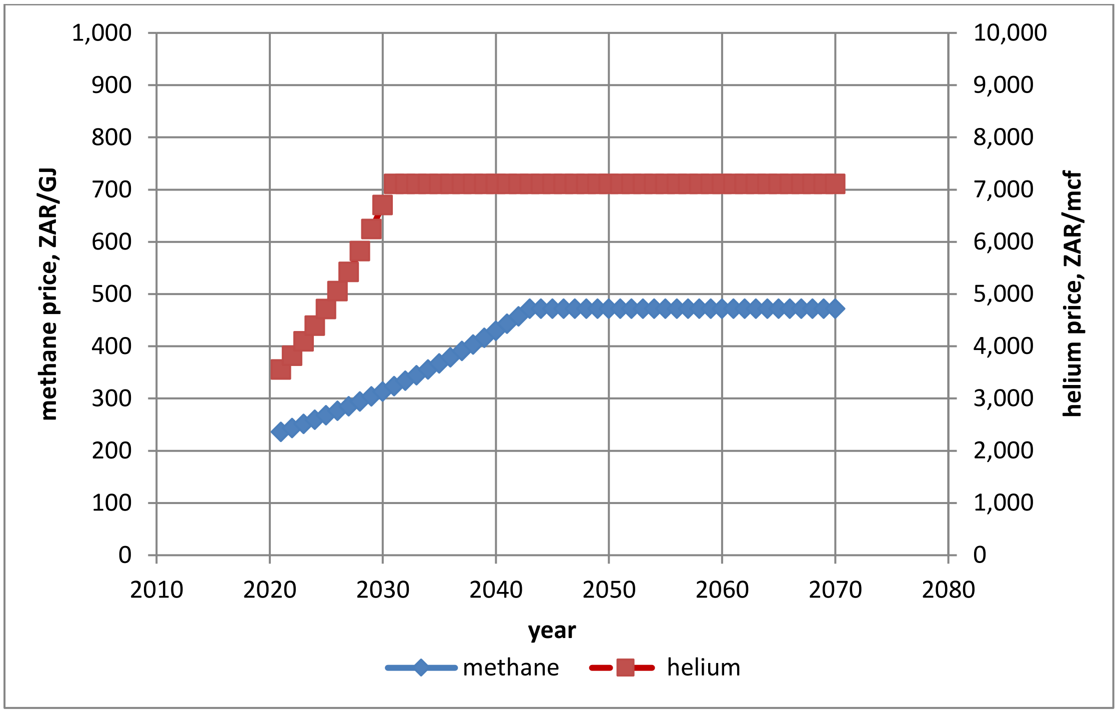

Figure 21: Methane and Helium Monthly Prices

Sproule assumed a methane BTU factor of 1.016 MMbtu/Mcf and a conversion factor of 0.948 MMbtu/GJ. Shrinkage is assumed to be zero as the Virginia gas field is fully electrified and gas measurement imbalances and surface losses are accounted for in the type well risk factors discussed above. All wells were conservatively burdened with a royalty of 3.90 ZAR/Mcf of wellhead gas. These royalties are held constant for the life of the project.

RESERVE ECONOMICS

Based on the economic parameters discussed above, reserves and economics were calculated for the Virginia Gas Field. Gross and net methane and helium reserves, based on an industry standard 10% discount rate, are shown in Table 11.

Table 11: Gross and Net Methane and Helium Reserves

1P Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
Total PDP	894	30	894	30
Total PDNP	17,873	595	17,873	595
Total PUD	196,309	6,543	196,309	6,543
Total 1P PRV	215,077	7,169	215,077	7,169

2P Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
Total PDP	894	30	894	30
Total PDNP	17,873	595	17,873	595
Total PUD	388,203	12,940	388,203	12,940
Total 1P PRV	215,077	7,169	215,077	7,169
Total Probable	191,895	6,396	191,895	6,396
Total 2P PRV+PRB	406,972	13,565	406,972	13,565

3P Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
Total PDP	894	30	894	30
Total PDNP	17,873	595	17,873	595
Total PUD	388,203	12,940	388,203	12,940
Total 2P PRV+PRB	406,972	13,565	406,972	13,565
Total Possible	193,114	6,437	193,114	6,437
TOTAL 3P PRV+PRB+POS	600,086	20,002	600,086	20,002

At the request of Tetra4, net present values associated with the reserves volumes were calculated for various discount rates. Sproule has calculated the economics according to the assumptions detailed above and have presented the economics as both Undiscounted (NPV=0, breakeven), and at various discount factors at the request of Tetra4. Sproule makes no recommendation as to preference of which discount factor to use. The results are shown in Table 1.

CONCLUSIONS

Based on analysis of technical and economic data provided by Tetra4, Sproule has independently estimated methane and helium Reserves and Resources for the Virginia Gas Field according to SPE PRMS guidance and ASX Listing Rules. Estimated Reserves and Contingent Resource gross and net methane and helium volumes are presented in Table 12. Net present values of the Reserves at requested discount rates are given in Table 1.

Table 12: Virginia Gas Field - Gross and Net Methane and Helium Reserves and Contingent Resources

Reserves Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
Total 1P	215,077	7,169	215,077	7,169
Total 2P	406,972	13,565	406,972	13,565
Total 3P	600,086	20,002	600,086	20,002

Contingent Resources Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
TOTAL C1	127,575	4,252	127,575	4,252
TOTAL C2	240,975	8,033	240,975	8,033
TOTAL C3	368,600	12,285	368,600	12,285

QUALIFICATIONS

Jeffrey B. Aldrich is a Senior Geoscientist in Sproule and is a Certified Petroleum Geologist, #6254, by the American Association of Petroleum Geologists (AAPG) and a Licensed Professional Geoscientist, #394; He is an active member of the AAPG and the Society of Petroleum Engineers (SPE). He has over thirty years as a practicing petroleum geologist/geophysicist and over twenty years of experience in oil and gas reserve evaluations. He holds a Bachelor of Science degree in Geology from Vanderbilt University and a Master's of Science degree in Geology from Texas A&M University. He is an instructor in the PetroSkills Alliance and is the Course Director for "Prospect and Play Analysis", "Evaluating and Developing Shale Reservoirs", "Unconventional Resource and Reserve Estimation", and "Coalbed Methane Reservoirs".

John Seidle is a Senior Reservoir Engineer with Sproule in Denver, Colorado. He has more than thirty-five years of experience in unconventional gas and oil reservoir engineering in domestic and international plays. His current duties include unconventional reservoir engineering, reserve studies and economic evaluations, unconventional well performance analysis, and serving as an expert witness for litigation and regulatory hearings. Dr. Seidle is an instructor for industry classes, primarily unconventional reservoirs. Privileged to work with others on over 29 technical papers, he is the author of "Fundamentals of Coalbed Methane Reservoir Engineering". John is editor and chapter author of SPEE Monograph 4, "Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs". He received a PhD in Mechanical Engineering from the University of Colorado, is a member of SPE, AAPG, and SPEE, and is a Registered Professional Engineer in Colorado, Oklahoma, and Wyoming. Unconventional reservoir experience includes USA, Canada, Australia, China, India, South Africa, New Zealand, Colombia, Mexico, France, UK, Turkey, Poland, Mongolia, Ukraine.

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APPENDIX A: METHANE AND HELIUM PRICES

The initial methane price of 249.69 ZAR/MMbtu was escalated at the South African CPI of 3.2%/year (as reported in the March 2021 StatsSA Statistical Survey) and was held constant once the initial price had doubled.

The initial helium price of 3,555 ZAR/Mcf (237 USD/Mcf) was escalated at the average US CPI of 2.4%/yr. forecast and was held constant once the initial price had doubled.

Annual methane and helium prices are listed below.

Year	Methane (ZAR/MMbtu)	Helium (ZAR/Mcf)
2021	236	3,555
2022	244	3,640
2023	251	3,728
2024	259	3,817
2025	268	3,909
2026	276	4,003
2027	285	4,099
2028	294	4,197
2029	304	4,298
2030	313	4,401
2031	323	4,506
2032	334	4,615
2033	344	4,725
2034	355	4,839
2035	367	4,955
2036	379	5,074
2037	391	5,196
2038	403	5,320
2039	416	5,448
2040	429	5,579
2041	443	5,713
2042	457	5,850
2043	472	5,990
2044	472	6,134
2045	472	6,281
2046	472	6,432
2047	472	6,586
2048	472	6,744
2049	472	6,906
2050	472	7,072
2051 +	**472**	**7,110**

APPENDIX B: RESERVE CASHFLOW SUMMARIES

Note that in this Appendix, economic parameters are denoted differently than in the main body of the report. Specific to this Appendix, all economic values, such as total net sales, direct OPEX, and discounted cash flows, are in millions of South African ZAR's and are denoted as mZAR's, not MMZAR's as used in the main report.

PIPELINE AND PLANT COSTS
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 13:06:17
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_1P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	0.000	0.000	0.000	57.024	0.000	5371.439	-5428.463	-5428.463	-5385.072
12-2022	0.000	0.000	0.000	0.000	172.212	0.000	2184.240	-2356.453	-7784.915	-7660.100
12-2023	0.000	0.000	0.000	0.000	175.657	0.000	0.000	-175.657	-7960.572	-7807.620
12-2024	0.000	0.000	0.000	0.000	179.170	0.000	0.000	-179.170	-8139.742	-7944.411
12-2025	0.000	0.000	0.000	0.000	182.753	0.000	0.000	-182.753	-8322.495	-8071.254
12-2026	0.000	0.000	0.000	0.000	186.408	0.000	0.000	-186.408	-8508.903	-8188.871
12-2027	0.000	0.000	0.000	0.000	190.136	0.000	0.000	-190.136	-8699.040	-8297.935
12-2028	0.000	0.000	0.000	0.000	193.939	0.000	0.000	-193.939	-8892.979	-8399.067
12-2029	0.000	0.000	0.000	0.000	197.818	0.000	0.000	-197.818	-9090.798	-8492.844
12-2030	0.000	0.000	0.000	0.000	201.774	0.000	0.000	-201.774	-9292.572	-8579.800
12-2031	0.000	0.000	0.000	0.000	205.810	0.000	0.000	-205.810	-9498.381	-8660.433
12-2032	0.000	0.000	0.000	0.000	209.926	0.000	0.000	-209.926	-9708.307	-8735.201
12-2033	0.000	0.000	0.000	0.000	214.124	0.000	0.000	-214.124	-9922.432	-8804.532
12-2034	0.000	0.000	0.000	0.000	218.407	0.000	0.000	-218.407	-10140.839	-8868.821
12-2035	0.000	0.000	0.000	0.000	222.775	0.000	0.000	-222.775	-10363.614	-8928.434
S TOT	0.000	0.000	0.000	0.000	2807.935	0.000	7555.679	-10363.614	-10363.614	-8928.434
AFTER	0.000	0.000	0.000	0.000	10648.506	0.000	0.000	-10648.506	-21012.120	-9623.982
TOTAL	0.000	0.000	0.000	0.000	13456.441	0.000	7555.679	-21012.120	-21012.120	-9623.982

	OIL	CH4
GROSS WELLS	0.0	0.0
GROSS ULT., MB & MMF	0.000	0.000
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	0.000
NET RES., MB & MMF	0.000	0.000
NET REVENUE, ZAR M$	0.000	0.000
INITIAL PRICE, ZAR	0.000	0.000
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	49.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	49.33
DISCOUNTED PAYOUT, YRS.	49.33
UNDISCOUNTED NET/INVEST.	-1.78
DISCOUNTED NET/INVEST.	-0.29
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	0.000

P.W. %	P.W., ZAR M$
0.00	-21012.120
5.00	-11863.251
8.00	-10229.803
10.00	-9623.980
15.00	-8801.077
20.00	-8387.851
30.00	-7955.194
60.00	-7409.128
80.00	-7208.750
100.00	-7055.402

PROVED DEVELOPED PRODUCING RESERVES
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 12:33:40
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_1P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	18.533	0.618	0.000	18.533	0.618	0.000	253.685	3555.000	6.898
12-2022	0.000	53.753	1.792	0.000	53.753	1.792	0.000	261.801	3814.521	20.907
12-2023	0.000	51.091	1.703	0.000	51.091	1.703	0.000	270.178	4092.980	20.774
12-2024	0.000	48.560	1.619	0.000	48.560	1.619	0.000	278.824	4391.768	20.649
12-2025	0.000	46.155	1.539	0.000	46.155	1.539	0.000	287.747	4712.366	20.531
12-2026	0.000	43.870	1.462	0.000	43.870	1.462	0.000	296.954	5056.370	20.421
12-2027	0.000	41.697	1.390	0.000	41.697	1.390	0.000	306.457	5425.484	20.319
12-2028	0.000	39.632	1.321	0.000	39.632	1.321	0.000	316.264	5821.545	20.225
12-2029	0.000	37.669	1.256	0.000	37.669	1.256	0.000	326.384	6246.518	20.138
12-2030	0.000	35.804	1.193	0.000	35.804	1.193	0.000	336.828	6702.500	20.059
12-2031	0.000	34.031	1.134	0.000	34.031	1.134	0.000	347.607	7110.000	19.895
12-2032	0.000	32.346	1.078	0.000	32.346	1.078	0.000	358.730	7110.000	19.269
12-2033	0.000	30.744	1.025	0.000	30.744	1.025	0.000	370.210	7110.000	18.668
12-2034	0.000	29.222	0.974	0.000	29.222	0.974	0.000	382.056	7110.000	18.090
12-2035	0.000	27.775	0.926	0.000	27.775	0.926	0.000	394.282	7110.000	17.534
S TOT	0.000	570.882	19.029	0.000	570.882	19.029	0.000	313.590	5536.394	284.377
AFTER	0.000	323.395	10.780	0.000	323.395	10.780	0.000	476.728	7110.000	230.816
TOTAL	0.000	894.278	29.809	0.000	894.278	29.809	0.000	372.585	6105.453	515.193

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	4.702	2.196	0.000	0.552	0.000	0.000	6.346	6.346	6.246
12-2022	0.000	14.073	6.835	0.000	1.614	0.000	0.000	19.293	25.638	24.080
12-2023	0.000	13.804	6.970	0.000	1.569	0.000	0.000	19.205	44.844	40.219
12-2024	0.000	13.540	7.109	0.000	1.525	0.000	0.000	19.124	63.968	54.829
12-2025	0.000	13.281	7.250	0.000	1.482	0.000	0.000	19.049	83.017	68.059
12-2026	0.000	13.027	7.394	0.000	1.441	0.000	0.000	18.981	101.997	80.042
12-2027	0.000	12.778	7.541	0.000	1.401	0.000	0.000	18.919	120.916	90.901
12-2028	0.000	12.534	7.691	0.000	1.362	0.000	0.000	18.863	139.779	100.743
12-2029	0.000	12.295	7.843	0.000	1.325	0.000	0.000	18.814	158.592	109.668
12-2030	0.000	12.060	7.999	0.000	1.288	0.000	0.000	18.771	177.363	117.762
12-2031	0.000	11.829	8.065	0.000	1.253	0.000	0.000	18.641	196.004	125.070
12-2032	0.000	11.603	7.666	0.000	1.219	0.000	0.000	18.050	214.054	131.503
12-2033	0.000	11.382	7.286	0.000	1.187	0.000	0.000	17.481	231.536	137.166
12-2034	0.000	11.164	6.926	0.000	1.155	0.000	0.000	16.935	248.471	142.154
12-2035	0.000	10.951	6.583	0.000	1.124	0.000	0.000	16.409	264.880	146.548
S TOT	0.000	179.023	105.354	0.000	19.498	0.000	0.000	264.880	264.880	146.548
AFTER	0.000	154.172	76.645	0.000	17.433	0.520	0.000	212.864	477.743	174.772
TOTAL	0.000	333.195	181.999	0.000	36.930	0.520	0.000	477.743	477.743	174.772

	OIL	CH4
GROSS WELLS	0.0	2.0
GROSS ULT., MB & MMF	0.000	1005.554
GROSS CUM., MB & MMF	0.000	111.276
GROSS RES., MB & MMF	0.000	894.278
NET RES., MB & MMF	0.000	894.278
NET REVENUE, ZAR M$	0.000	333.195
INITIAL PRICE, ZAR	0.000	253.685
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	49.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	477.743
5.00	265.262
8.00	203.231
10.00	174.772
15.00	128.544
20.00	101.551
30.00	72.140
60.00	40.780
80.00	32.668
100.00	27.727

PROVED DEVELOPED NON-PRODUCING RESERVES
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 12:33:41
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_1P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	254.447	8.482	0.000	254.447	8.482	0.000	253.685	3555.001	94.701
12-2022	0.000	1101.472	36.716	0.000	1101.472	36.716	0.000	261.801	3814.521	428.419
12-2023	0.000	1046.399	34.880	0.000	1046.399	34.880	0.000	270.178	4092.981	425.477
12-2024	0.000	994.078	33.136	0.000	994.078	33.136	0.000	278.824	4391.766	422.699
12-2025	0.000	944.374	31.479	0.000	944.374	31.479	0.000	287.747	4712.366	420.082
12-2026	0.000	897.156	29.905	0.000	897.156	29.905	0.000	296.954	5056.369	417.626
12-2027	0.000	852.298	28.410	0.000	852.298	28.410	0.000	306.457	5425.485	415.330
12-2028	0.000	809.683	26.989	0.000	809.683	26.989	0.000	316.264	5821.548	413.194
12-2029	0.000	769.199	25.640	0.000	769.199	25.640	0.000	326.384	6246.515	411.215
12-2030	0.000	730.739	24.358	0.000	730.739	24.358	0.000	336.828	6702.501	409.393
12-2031	0.000	694.202	23.140	0.000	694.202	23.140	0.000	347.607	7109.998	405.835
12-2032	0.000	659.492	21.983	0.000	659.492	21.983	0.000	358.730	7109.997	392.879
12-2033	0.000	626.518	20.884	0.000	626.518	20.884	0.000	370.210	7109.999	380.427
12-2034	0.000	595.192	19.840	0.000	595.192	19.840	0.000	382.056	7109.997	368.457
12-2035	0.000	565.432	18.848	0.000	565.432	18.848	0.000	394.282	7110.000	356.947
S TOT	0.000	11540.682	384.689	0.000	11540.682	384.689	0.000	314.157	5555.396	5762.683
AFTER	0.000	6333.151	211.105	0.000	6333.151	211.105	0.000	475.564	7110.001	4512.774
TOTAL	0.000	17873.832	595.794	0.000	17873.832	595.794	0.000	371.347	6106.232	10275.457

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	64.549	30.152	0.000	7.438	0.000	11.500	75.764	75.764	74.092
12-2022	0.000	288.366	140.053	0.000	32.431	0.000	0.000	395.988	471.752	440.137
12-2023	0.000	282.714	142.763	0.000	31.468	0.000	0.000	394.009	865.761	771.242
12-2024	0.000	277.173	145.525	0.000	30.536	0.000	0.000	392.162	1257.923	1070.836
12-2025	0.000	271.741	148.341	0.000	29.634	0.000	0.000	390.448	1648.371	1342.003
12-2026	0.000	266.414	151.212	0.000	28.760	0.000	0.000	388.866	2037.237	1587.520
12-2027	0.000	261.193	154.138	0.000	27.915	0.000	0.000	387.416	2424.653	1809.885
12-2028	0.000	256.073	157.120	0.000	27.096	0.000	0.000	386.097	2810.750	2011.346
12-2029	0.000	251.054	160.160	0.000	26.304	0.000	0.000	384.911	3195.661	2193.930
12-2030	0.000	246.134	163.259	0.000	25.538	0.000	0.000	383.855	3579.516	2359.461
12-2031	0.000	241.309	164.526	0.000	24.796	0.000	0.000	381.040	3960.556	2508.839
12-2032	0.000	236.580	156.300	0.000	24.078	0.000	0.000	368.802	4329.357	2640.276
12-2033	0.000	231.943	148.485	0.000	23.383	0.000	0.000	357.044	4686.402	2755.954
12-2034	0.000	227.397	141.060	0.000	22.711	0.000	0.000	345.746	5032.147	2857.789
12-2035	0.000	222.940	134.007	0.000	22.061	0.000	0.000	334.886	5367.034	2947.459
S TOT	0.000	3625.581	2137.102	0.000	384.149	0.000	11.500	5367.034	5367.034	2947.459
AFTER	0.000	3011.817	1500.957	0.000	298.754	5.980	0.000	4208.039	9575.075	3523.808
TOTAL	0.000	6637.398	3638.058	0.000	682.903	5.980	11.500	9575.074	9575.075	3523.808

	OIL	CH4
GROSS WELLS	0.0	23.0
GROSS ULT., MB & MMF	0.000	17873.832
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	17873.832
NET RES., MB & MMF	0.000	17873.832
NET REVENUE, ZAR M$	0.000	6637.398
INITIAL PRICE, ZAR	0.000	253.685
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	31.75
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.04
DISCOUNTED PAYOUT, YRS.	0.04
UNDISCOUNTED NET/INVEST.	833.62
DISCOUNTED NET/INVEST.	310.61
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	9575.074
5.00	5362.425
8.00	4104.012
10.00	3523.807
15.00	2579.109
20.00	2026.956
30.00	1425.318
60.00	783.800
80.00	617.959
100.00	517.049

PROVED UNDEVELOPED RESERVES
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 12:33:53
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_1P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	81.304	2.710	0.000	81.304	2.710	0.000	253.685	3555.000	30.260
12-2022	0.000	1354.339	45.145	0.000	1354.339	45.145	0.000	261.801	3814.521	526.772
12-2023	0.000	3373.037	112.435	0.000	3373.037	112.435	0.000	270.179	4092.983	1371.514
12-2024	0.000	6018.902	200.630	0.000	6018.902	200.630	0.000	278.824	4391.767	2559.340
12-2025	0.000	8532.512	284.417	0.000	8532.512	284.417	0.000	287.747	4712.363	3795.482
12-2026	0.000	10599.446	353.315	0.000	10599.446	353.315	0.000	296.955	5056.373	4934.045
12-2027	0.000	10739.260	357.976	0.000	10739.260	357.976	0.000	306.457	5425.481	5233.311
12-2028	0.000	10202.298	340.077	0.000	10202.298	340.077	0.000	316.264	5821.545	5206.388
12-2029	0.000	9692.194	323.073	0.000	9692.194	323.073	0.000	326.384	6246.512	5181.460
12-2030	0.000	9207.580	306.919	0.000	9207.580	306.919	0.000	336.828	6702.500	5158.500
12-2031	0.000	8747.210	291.574	0.000	8747.210	291.574	0.000	347.606	7109.994	5113.675
12-2032	0.000	8309.847	276.995	0.000	8309.847	276.995	0.000	358.730	7110.003	4950.420
12-2033	0.000	7894.346	263.145	0.000	7894.346	263.145	0.000	370.210	7109.992	4793.528
12-2034	0.000	7499.634	249.988	0.000	7499.634	249.988	0.000	382.056	7109.993	4642.697
12-2035	0.000	7124.654	237.488	0.000	7124.654	237.488	0.000	394.282	7109.999	4497.666
S TOT	0.000	109376.552	3645.886	0.000	109376.552	3645.886	0.000	328.850	6041.474	57995.059
AFTER	0.000	86932.480	2897.751	0.000	86932.480	2897.751	0.000	478.173	7109.999	62171.775
TOTAL	0.000	196309.024	6543.637	0.000	196309.024	6543.637	0.000	394.976	6514.654	120166.834

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	20.626	9.634	0.000	2.416	0.000	82.100	-54.256	-54.256	-53.731
12-2022	0.000	354.567	172.205	0.000	40.391	0.000	104.153	382.228	327.971	296.623
12-2023	0.000	911.322	460.192	0.000	102.287	0.000	222.634	1046.593	1374.564	1168.654
12-2024	0.000	1678.215	881.122	0.000	185.940	0.000	227.087	2146.311	3520.876	2801.227
12-2025	0.000	2455.202	1340.278	0.000	268.871	0.000	228.819	3297.792	6818.668	5084.710
12-2026	0.000	3147.554	1786.491	0.000	340.806	0.000	140.972	4452.264	11270.931	7889.951
12-2027	0.000	3291.126	1942.191	0.000	352.583	0.000	0.000	4880.737	16151.669	10691.342
12-2028	0.000	3226.617	1979.772	0.000	342.288	0.000	0.000	4864.102	21015.771	13229.383
12-2029	0.000	3163.377	2018.081	0.000	332.324	0.000	0.000	4849.137	25864.909	15529.591
12-2030	0.000	3101.372	2057.127	0.000	322.682	0.000	0.000	4835.817	30700.726	17614.944
12-2031	0.000	3040.585	2073.087	0.000	313.353	0.000	0.000	4800.325	35501.052	19496.804
12-2032	0.000	2980.993	1969.433	0.000	304.326	0.000	0.000	4646.102	40147.153	21152.623
12-2033	0.000	2922.567	1870.959	0.000	295.592	0.000	0.000	4497.934	44645.089	22609.906
12-2034	0.000	2865.281	1777.412	0.000	287.143	0.000	0.000	4355.552	49000.641	23892.775
12-2035	0.000	2809.121	1688.542	0.000	278.971	0.000	0.000	4218.693	53219.332	25022.374
S TOT	0.000	35968.524	22026.525	0.000	3769.973	0.000	1005.765	53219.332	53219.332	25022.374
AFTER	0.000	41568.784	20603.007	0.000	4229.770	80.860	0.000	57861.145	111080.464	32487.008
TOTAL	0.000	77537.313	42629.530	0.000	7999.743	80.860	1005.765	111080.473	111080.464	32487.008

	OIL	CH4
GROSS WELLS	0.0	311.0
GROSS ULT., MB & MMF	0.000	196309.008
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	196309.008
NET RES., MB & MMF	0.000	196309.008
NET REVENUE, ZAR M$	0.000	77537.305
INITIAL PRICE, ZAR	0.000	278.577
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	36.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.48
DISCOUNTED PAYOUT, YRS.	0.49
UNDISCOUNTED NET/INVEST.	111.44
DISCOUNTED NET/INVEST.	42.22
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	111080.448
5.00	55357.051
8.00	39569.928
10.00	32487.031
15.00	21319.328
20.00	15094.601
30.00	8751.580
60.00	3027.618
80.00	1886.230
100.00	1299.260

TOTAL PROVED (1P) RESERVES
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 13:09:45
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_1P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	354.284	11.809	0.000	354.284	11.809	0.000	253.685	3555.000	131.859
12-2022	0.000	2509.564	83.652	0.000	2509.564	83.652	0.000	261.801	3814.521	976.099
12-2023	0.000	4470.526	149.017	0.000	4470.526	149.017	0.000	270.179	4092.982	1817.766
12-2024	0.000	7061.541	235.385	0.000	7061.541	235.385	0.000	278.824	4391.767	3002.687
12-2025	0.000	9523.042	317.435	0.000	9523.042	317.435	0.000	287.747	4712.364	4236.095
12-2026	0.000	11540.472	384.682	0.000	11540.472	384.682	0.000	296.954	5056.372	5372.092
12-2027	0.000	11633.255	387.776	0.000	11633.255	387.776	0.000	306.457	5425.481	5668.960
12-2028	0.000	11051.613	368.387	0.000	11051.613	368.387	0.000	316.264	5821.546	5639.806
12-2029	0.000	10499.062	349.969	0.000	10499.062	349.969	0.000	326.384	6246.512	5612.813
12-2030	0.000	9974.123	332.471	0.000	9974.123	332.471	0.000	336.828	6702.500	5587.952
12-2031	0.000	9475.443	315.848	0.000	9475.443	315.848	0.000	347.606	7109.994	5539.405
12-2032	0.000	9001.685	300.056	0.000	9001.685	300.056	0.000	358.730	7110.003	5362.569
12-2033	0.000	8551.608	285.054	0.000	8551.608	285.054	0.000	370.210	7109.993	5192.623
12-2034	0.000	8124.048	270.802	0.000	8124.048	270.802	0.000	382.056	7109.993	5029.244
12-2035	0.000	7717.861	257.262	0.000	7717.861	257.262	0.000	394.282	7109.999	4872.146
S TOT	0.000	121488.128	4049.605	0.000	121488.128	4049.605	0.000	327.383	5992.925	64042.119
AFTER	0.000	93589.024	3119.636	0.000	93589.024	3119.636	0.000	477.992	7109.999	66915.369
TOTAL	0.000	215077.152	7169.241	0.000	215077.152	7169.241	0.000	392.919	6479.011	130957.492

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	89.877	41.983	0.000	67.430	0.000	5465.039	-5400.609	-5400.609	-5358.466
12-2022	0.000	657.006	319.093	0.000	246.649	0.000	2288.393	-1558.944	-6959.554	-6899.260
12-2023	0.000	1207.840	609.926	0.000	310.981	0.000	222.634	1284.150	-5675.403	-5827.505
12-2024	0.000	1968.928	1033.756	0.000	397.171	0.000	227.087	2378.428	-3296.976	-4017.519
12-2025	0.000	2740.224	1495.869	0.000	482.740	0.000	228.819	3524.536	227.560	-1576.482
12-2026	0.000	3426.995	1945.097	0.000	557.415	0.000	140.972	4673.702	4901.262	1368.642
12-2027	0.000	3565.097	2103.869	0.000	572.035	0.000	0.000	5096.935	9998.197	4294.193
12-2028	0.000	3495.225	2144.583	0.000	564.685	0.000	0.000	5075.123	15073.320	6942.406
12-2029	0.000	3426.726	2186.085	0.000	557.771	0.000	0.000	5055.043	20128.362	9340.344
12-2030	0.000	3359.566	2228.385	0.000	551.282	0.000	0.000	5036.669	25165.031	11512.366
12-2031	0.000	3293.724	2245.678	0.000	545.211	0.000	0.000	4994.196	30159.227	13470.281
12-2032	0.000	3229.177	2133.398	0.000	539.549	0.000	0.000	4823.027	34982.253	15189.201
12-2033	0.000	3165.891	2026.730	0.000	534.287	0.000	0.000	4658.335	39640.588	16698.497
12-2034	0.000	3103.842	1925.398	0.000	529.417	0.000	0.000	4499.826	44140.413	18023.901
12-2035	0.000	3043.012	1829.132	0.000	524.932	0.000	0.000	4347.213	48487.625	19187.950
S TOT	0.000	39773.131	24268.982	0.000	6981.555	0.000	8572.944	48487.625	48487.625	19187.950
AFTER	0.000	44734.767	22180.606	0.000	15194.463	87.360	0.000	51633.549	100121.158	26561.606
TOTAL	0.000	84507.902	46449.590	0.000	22176.018	87.360	8572.944	100121.174	100121.158	26561.606

	OIL	CH4
GROSS WELLS	0.0	336.0
GROSS ULT., MB & MMF	0.000	215188.448
GROSS CUM., MB & MMF	0.000	111.276
GROSS RES., MB & MMF	0.000	215077.168
NET RES., MB & MMF	0.000	215077.168
NET REVENUE, ZAR M$	0.000	84507.910
INITIAL PRICE, ZAR	0.000	276.400
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	49.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	4.27
DISCOUNTED PAYOUT, YRS.	4.87
UNDISCOUNTED NET/INVEST.	12.68
DISCOUNTED NET/INVEST.	4.22
RATE-OF-RETURN, PCT.	39.52
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	100121.149
5.00	49121.489
8.00	33647.368
10.00	26561.630
15.00	15225.903
20.00	8835.256
30.00	2293.845
60.00	-3556.931
80.00	-4671.894
100.00	-5211.365

TOTAL PROVED + PROBABLE (2P) RESERVES
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 13:31:38
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_2P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	413.907	13.797	0.000	413.907	13.797	0.000	253.685	3555.000	154.050
12-2022	0.000	3502.745	116.758	0.000	3502.745	116.758	0.000	261.801	3814.520	1362.398
12-2023	0.000	6944.084	231.469	0.000	6944.084	231.469	0.000	270.178	4092.980	2823.541
12-2024	0.000	11475.409	382.514	0.000	11475.409	382.514	0.000	278.824	4391.768	4879.529
12-2025	0.000	15780.217	526.007	0.000	15780.217	526.007	0.000	287.747	4712.372	7019.445
12-2026	0.000	19407.902	646.930	0.000	19407.902	646.930	0.000	296.954	5056.366	9034.375
12-2027	0.000	20200.868	673.362	0.000	20200.868	673.362	0.000	306.457	5425.486	9844.019
12-2028	0.000	19190.912	639.697	0.000	19190.912	639.697	0.000	316.264	5821.546	9793.401
12-2029	0.000	18231.380	607.713	0.000	18231.380	607.713	0.000	326.385	6246.517	9746.521
12-2030	0.000	17319.854	577.328	0.000	17319.854	577.328	0.000	336.828	6702.503	9703.346
12-2031	0.000	16453.891	548.462	0.000	16453.891	548.462	0.000	347.606	7110.000	9619.038
12-2032	0.000	15631.181	521.040	0.000	15631.181	521.040	0.000	358.730	7110.000	9311.971
12-2033	0.000	14849.650	494.988	0.000	14849.650	494.988	0.000	370.210	7109.999	9016.847
12-2034	0.000	14107.160	470.239	0.000	14107.160	470.239	0.000	382.056	7109.992	8733.139
12-2035	0.000	13401.822	446.728	0.000	13401.822	446.728	0.000	394.282	7110.004	8460.346
S TOT	0.000	206910.976	6897.032	0.000	206910.976	6897.032	0.000	328.374	6025.450	109501.964
AFTER	0.000	200061.056	6668.700	0.000	200061.056	6668.700	0.000	483.504	7110.002	144144.843
TOTAL	0.000	406972.032	13565.732	0.000	406972.032	13565.732	0.000	404.634	6558.599	253646.799

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	105.002	49.048	0.000	57.465	0.000	4412.403	-4315.818	-4315.818	-4282.704
12-2022	0.000	917.022	445.376	0.000	239.971	0.000	2288.393	-1165.966	-5481.784	-5462.582
12-2023	0.000	1876.142	947.399	0.000	347.561	0.000	222.634	2253.346	-3228.438	-3581.570
12-2024	0.000	3199.622	1679.912	0.000	492.392	0.000	4486.052	-98.915	-3327.353	-3666.523
12-2025	0.000	4540.703	2478.740	0.000	635.982	0.000	228.819	6154.641	2827.288	596.411
12-2026	0.000	5763.263	3271.114	0.000	763.772	0.000	175.157	8095.450	10922.739	5698.244
12-2027	0.000	6190.702	3653.318	0.000	804.901	0.000	0.000	9039.113	19961.852	10886.462
12-2028	0.000	6069.388	3724.026	0.000	788.371	0.000	0.000	9005.033	28966.885	15585.251
12-2029	0.000	5950.440	3796.088	0.000	772.520	0.000	0.000	8973.998	37940.883	19842.146
12-2030	0.000	5833.811	3869.543	0.000	757.333	0.000	0.000	8946.026	46886.912	23699.982
12-2031	0.000	5719.477	3899.566	0.000	742.791	0.000	0.000	8876.246	55763.157	27179.758
12-2032	0.000	5607.377	3704.594	0.000	728.879	0.000	0.000	8583.090	64346.247	30238.712
12-2033	0.000	5497.485	3519.366	0.000	715.580	0.000	0.000	8301.267	72647.516	32928.272
12-2034	0.000	5389.731	3343.398	0.000	702.879	0.000	0.000	8030.260	80677.773	35293.508
12-2035	0.000	5284.099	3176.237	0.000	690.762	0.000	0.000	7769.576	88447.353	37373.923
S TOT	0.000	67944.260	41557.721	0.000	9241.158	0.000	11813.459	88447.353	88447.353	37373.923
AFTER	0.000	96730.374	47414.469	0.000	18472.819	89.960	0.000	125582.066	214029.435	51511.136
TOTAL	0.000	164674.634	88972.190	0.000	27713.976	89.960	11813.459	214029.418	214029.435	51511.136

	OIL	CH4
GROSS WELLS	0.0	346.0
GROSS ULT., MB & MMF	0.000	407083.296
GROSS CUM., MB & MMF	0.000	111.276
GROSS RES., MB & MMF	0.000	406972.032
NET RES., MB & MMF	0.000	406972.032
NET REVENUE, ZAR M$	0.000	164674.666
INITIAL PRICE, ZAR	0.000	277.868
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	49.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	3.87
DISCOUNTED PAYOUT, YRS.	4.19
UNDISCOUNTED NET/INVEST.	19.12
DISCOUNTED NET/INVEST.	5.92
RATE-OF-RETURN, PCT.	53.64
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	214029.599
5.00	95523.602
8.00	64857.051
10.00	51511.116
15.00	30953.959
20.00	19745.749
30.00	8558.274
60.00	-1047.797
80.00	-2786.349
100.00	-3610.978

TOTAL (3P) PROVED + PROBABLE + POSSIBLE
TETRA4 VIRGINIA METHANE
AND HELIUM GAS FIELD
REPUBLIC OF SOUTH AFRICA
AS OF SEPTEMBER 1, 2021

DATE : 10/15/2021
TIME : 13:54:52
DBS : SPROULE
SETTINGS : SET0921_ZAR
SCENARIO : SPR0921_3P

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 09/2021

--END-- MO-YEAR	GROSS OIL ---MBBLS--	GROSS CH4 ---MMCF--	GROSS HELIUM ---MMCF--	NET OIL ---MBBLS--	NET CH4 ---MMCF--	NET HELIUM ---MMCF--	NET OIL PRICE --ZAR/BBL-	NET CH4 PRICE --ZAR/MCF-	NET HELIUM PRICE --ZAR/MCF-	TOTAL NET SALES ---MZAR---
12-2021	0.000	478.950	15.965	0.000	478.950	15.965	0.000	253.685	3555.001	178.258
12-2022	0.000	4586.216	152.874	0.000	4586.216	152.874	0.000	261.801	3814.519	1783.815
12-2023	0.000	9642.510	321.417	0.000	9642.510	321.417	0.000	270.178	4092.982	3920.755
12-2024	0.000	16290.548	543.018	0.000	16290.548	543.018	0.000	278.824	4391.769	6927.007
12-2025	0.000	22606.222	753.541	0.000	22606.222	753.541	0.000	287.746	4712.368	10055.830
12-2026	0.000	27931.070	931.036	0.000	27931.070	931.036	0.000	296.954	5056.370	13001.923
12-2027	0.000	29111.738	970.392	0.000	29111.738	970.392	0.000	306.457	5425.482	14186.353
12-2028	0.000	27656.264	921.875	0.000	27656.264	921.875	0.000	316.264	5821.547	14113.411
12-2029	0.000	26273.440	875.782	0.000	26273.440	875.782	0.000	326.384	6246.521	14045.843
12-2030	0.000	24959.810	831.993	0.000	24959.810	831.993	0.000	336.828	6702.509	13983.616
12-2031	0.000	23711.848	790.395	0.000	23711.848	790.395	0.000	347.607	7109.993	13862.104
12-2032	0.000	22526.292	750.875	0.000	22526.292	750.875	0.000	358.730	7110.007	13419.579
12-2033	0.000	21399.950	713.332	0.000	21399.950	713.332	0.000	370.210	7110.006	12994.280
12-2034	0.000	20329.968	677.666	0.000	20329.968	677.666	0.000	382.056	7109.995	12585.407
12-2035	0.000	19313.500	643.783	0.000	19313.500	643.783	0.000	394.282	7110.014	12192.255
S TOT	0.000	296818.336	9893.943	0.000	296818.336	9893.943	0.000	328.643	6034.321	157250.437
AFTER	0.000	303268.512	10108.952	0.000	303268.512	10108.952	0.000	484.681	7110.000	218863.272
TOTAL	0.000	600086.848	20002.896	0.000	600086.848	20002.896	0.000	407.501	6577.941	376113.725

--END-- MO-YEAR	NET OIL SALES ---MZAR---	NET CH4 SALES ---MZAR---	NET HELIUM SALES ---MZAR---	TOTAL TAX ---MZAR---	DIRECT OPER EXPENSE ---MZAR---	ABANDONMENT COST ---MZAR---	EQUITY INVESTMENT ---MZAR---	FUTURE NET CASHFLOW ---MZAR---	CUMULATIVE CASHFLOW ---MZAR---	CUM. DISC. CASHFLOW -@10% MZAR-
12-2021	0.000	121.502	56.756	0.000	52.839	0.000	3827.605	-3702.186	-3702.186	-3674.365
12-2022	0.000	1200.675	583.140	0.000	251.543	0.000	2288.393	-756.120	-4458.306	-4477.937
12-2023	0.000	2605.198	1315.554	0.000	406.702	0.000	3801.597	-287.547	-4745.853	-4735.432
12-2024	0.000	4542.196	2384.808	0.000	615.891	0.000	227.087	6084.029	1338.177	-104.905
12-2025	0.000	6504.860	3550.963	0.000	823.167	0.000	3952.371	5280.295	6618.471	3443.017
12-2026	0.000	8294.250	4707.662	0.000	1007.371	0.000	175.157	11819.384	18437.855	10892.003
12-2027	0.000	8921.499	5264.843	0.000	1065.524	0.000	0.000	13120.817	31558.672	18422.983
12-2028	0.000	8746.672	5366.742	0.000	1039.814	0.000	0.000	13073.603	44632.277	25244.690
12-2029	0.000	8575.240	5470.592	0.000	1015.045	0.000	0.000	13030.789	57663.066	31425.929
12-2030	0.000	8407.161	5576.438	0.000	991.192	0.000	0.000	12992.422	70655.492	37028.696
12-2031	0.000	8242.400	5619.706	0.000	968.232	0.000	0.000	12893.876	83549.372	42083.475
12-2032	0.000	8080.846	5338.726	0.000	946.137	0.000	0.000	12473.444	96022.815	46528.901
12-2033	0.000	7922.474	5071.795	0.000	924.886	0.000	0.000	12069.365	108092.178	50439.287
12-2034	0.000	7767.195	4818.205	0.000	904.457	0.000	0.000	11680.941	119773.118	53879.779
12-2035	0.000	7614.967	4577.305	0.000	884.823	0.000	0.000	11307.437	131080.552	56907.489
S TOT	0.000	97547.141	59703.230	0.000	11897.620	0.000	14272.211	131080.552	131080.552	56907.489
AFTER	0.000	146988.564	71874.642	0.000	22339.185	89.960	0.000	196434.133	327514.718	77756.547
TOTAL	0.000	244535.706	131577.872	0.000	34236.805	89.960	14272.211	327514.685	327514.718	77756.547

	OIL	CH4
GROSS WELLS	0.0	346.0
GROSS ULT., MB & MMF	0.000	600198.208
GROSS CUM., MB & MMF	0.000	111.276
GROSS RES., MB & MMF	0.000	600086.912
NET RES., MB & MMF	0.000	600086.912
NET REVENUE, ZAR M$	0.000	244535.689
INITIAL PRICE, ZAR	0.000	278.261
INITIAL N.I., PCT.	0.000	100.000

LIFE, YRS.	49.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	3.11
DISCOUNTED PAYOUT, YRS.	3.36
UNDISCOUNTED NET/INVEST.	23.95
DISCOUNTED NET/INVEST.	7.30
RATE-OF-RETURN, PCT.	67.72
INITIAL W.I., PCT.	100.000

P.W. %	P.W., ZAR M$
0.00	327514.587
5.00	143176.942
8.00	97433.485
10.00	77756.596
15.00	47667.282
20.00	31344.783
30.00	15090.854
60.00	1165.414
80.00	-1346.588
100.00	-2534.799

APPENDIX C: PETROLEUM RESOURCES MANAGEMENT SYSTEM

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how resources volumes are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), the Society of Petroleum Engineers (SPE) published definitions for all reserves categories in 1987. In the same year, the World Petroleum Council (WPC), then known as the World Petroleum Congress, independently published reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by supplemental application evaluation guidelines (2001), standards for estimating and auditing reserves information (2001, revised 2007), and a glossary of terms used in resources definitions (2005). In 2007, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) was issued and subsequently supported by the Society of Exploration Geophysicists (SEG). The document is referred to by the abbreviated term SPE-PRMS, with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated. In 2011, the SPE/WPC/AAPG/SPEE/SEG published Guidelines for the Application of the PRMS (referred to as Application Guidelines).

The PRMS definitions and the related classification system are now in common use internationally to support petroleum project and portfolio management requirements. PRMS is referenced for national reporting and regulatory disclosures in many jurisdictions and provides the commodity-specific specifications for petroleum under the United Nations Framework Classification for Resources (UNFC) to support petroleum project and portfolio management requirements. The definitions provide a measure of comparability, reduce the subjective nature of resources estimation, and are intended to improve clarity in global communications regarding petroleum resources.

Technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with related organizations to maintain the definitions and guidelines to keep current with evolving technology and industry requirements.

This document consolidates, builds on, and replaces prior guidance. Appendix A is a glossary of terms used in the PRMS and replaces those published in 2007. It is expected that this document will be supplemented with industry education programs, best practice reporting standards, and future updates to the 2011 Application Guidelines.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language far communicating bath the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

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

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

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

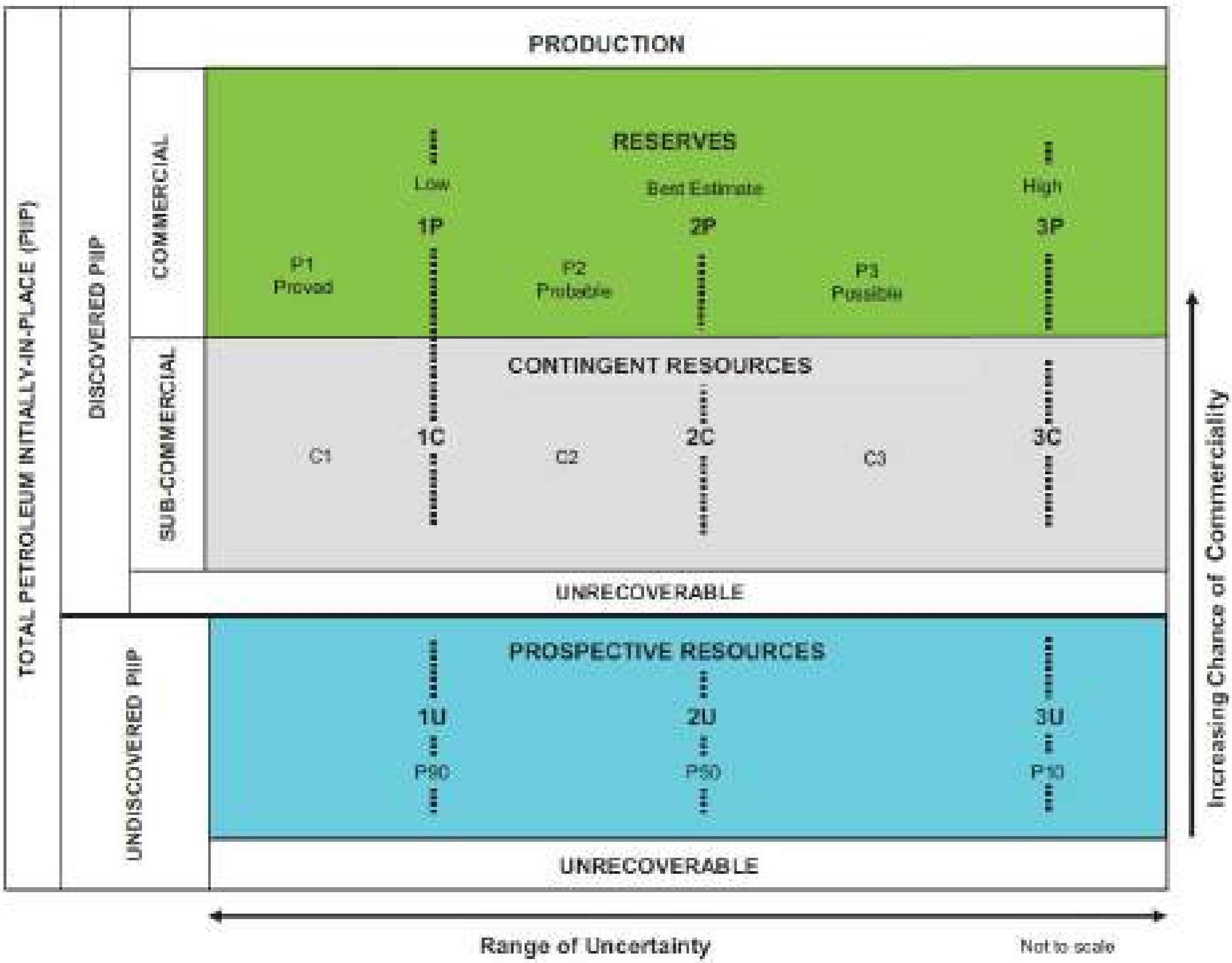

Figure 1.1—Resources classification framework

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, Pc, which is the chance that a project will be committed for development and reach commercial producing status.

1.1.1.5 The following definitions apply to the major subdivisions within the resources classification:

A. Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. Discovered PIIP is the quantity of petroleum that is estimated. as of a given date, to be contained in known accumulations before production.

C. Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. **1**. 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 satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be subclassified based on project maturity and/or characterized by development and production status.

B. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be subclassified based on project maturity and/or economic status.

C. Undiscovered PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. Unrecoverable Resources are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. Estimated Ultimate Recovery (EUR) is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. Technically Recoverable Resources (TRR) are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

1.1.0.9 Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

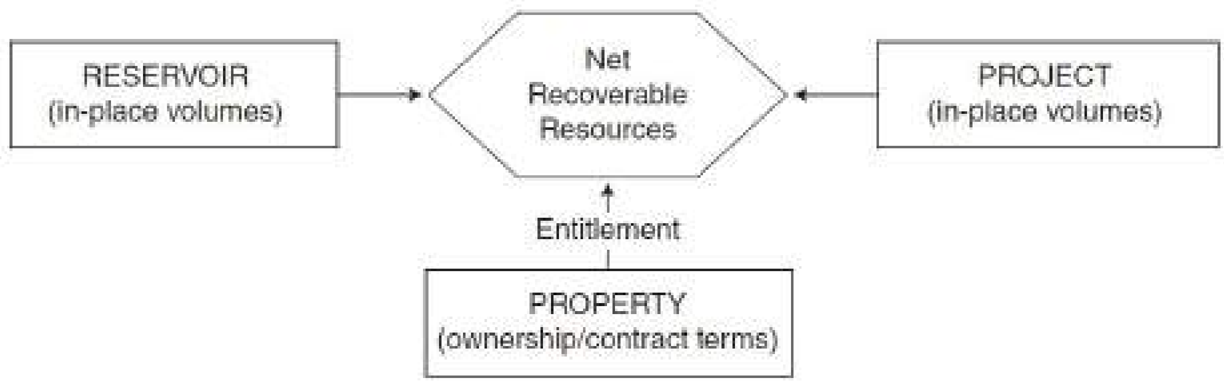

Figure 1.2—Resources evaluation

1.2.0.3 The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of Investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

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1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

1.2.0.9 The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see

Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

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, Pc (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, C02) 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, Pc, 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," *Pg*.

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

2.1.3.3 There must be a high degree of certainty in the chance of commerciality, *Pc*, for Reserves to be assigned; for Contingent Resources, *Pc*= *Pd*; and for Prospective Resources, *Pc* is the product of *Pg* and *Pd*.

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 subclassified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

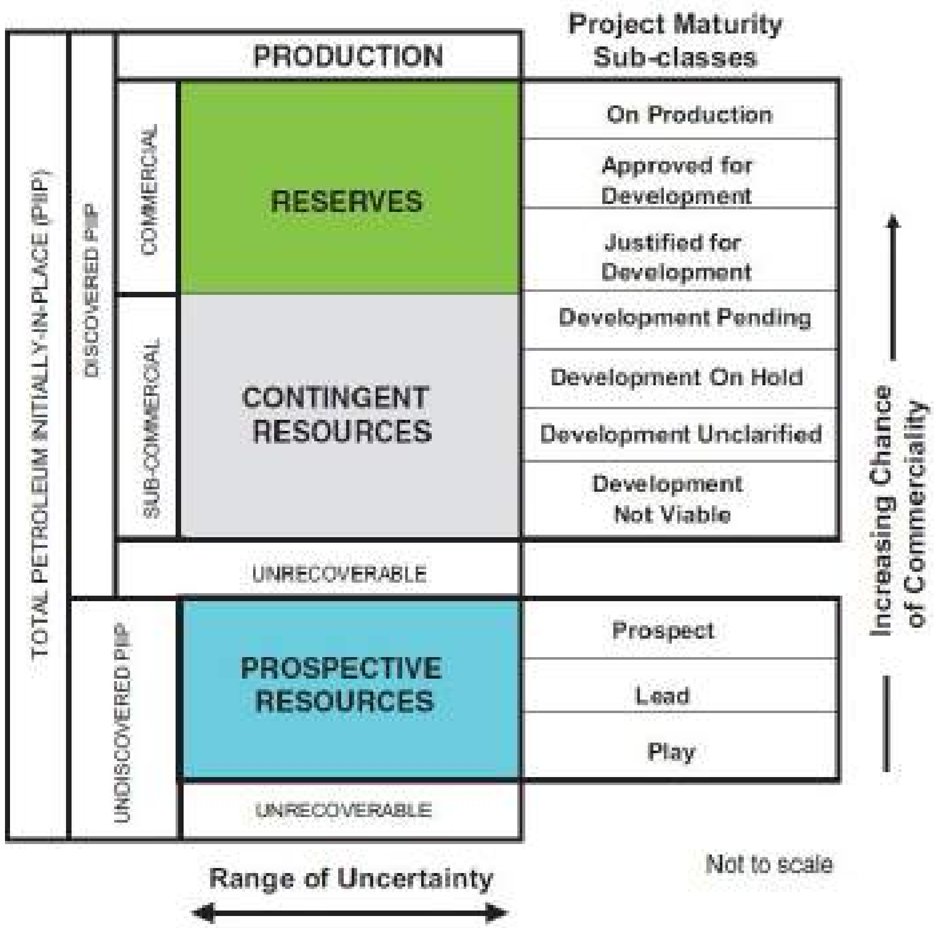

Figure 2.1—Sub-classes based on project maturity

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, *Pg*, and chance of development, *Pd*, which together determine the chance of commerciality, *Pc*. 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 subclass.

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 (1 P, 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 (JP) 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). Standalone 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).

3.0 Evaluation and Reporting Guidelines

3.0.0.1 The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" in this document refers to the presentation of evaluation results within the entity conducting the evaluation and should not be construed as replacing requirements for public disclosures established by regulatory and/or other government agencies or any current or future associated accounting standards.

3.0.0.2 Reserves and resources evaluations are based on a set of defined conditions that are used to classify and categorize a project's expected recoverable quantities. The defined conditions include the factors that impact commerciality, such as decision hurdle rates; commodity prices; operating and capital costs; technical subsurface parameters; marketing, sales route(s); environmental, governmental, legal, and social factors; and timing issues. These factors are forecast for the project over time, and evaluators must clearly identify and document the assumptions used in the evaluation because these assumptions can directly impact the project quantities eligible for classification as Reserves or Resources. A project with Contingent Resources may not yet have all defined conditions addressed, and reasonable assumptions should be made and documented.

3.0.0.3 Hydrocarbon evaluations recognize production and transportation practices that involve methods of extraction other than through the flow of fluids from wells to surface facilities, such as surface mining of bitumen or in-situ conversion processes.

3.1 Assessment of Commerciality

3.1.0.1 Commercial assessments are conducted on a project basis and are based on the entity's view of future conditions. The forecast commercial conditions, technical feasibility, and the entity's decision to commit to the project are several of the key elements that underpin the project's resources classification. Commercial conditions include, but are not limited to, assumptions of an entity's investment hurdle criteria; financial conditions (e.g., costs, prices, fiscal terms, taxes); partners' investment decision(s); organization capabilities; and marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., cash flow analysis, historical costs, comparative market values, key economic parameters) (see Section 2.1.2, Determination of Commerciality). The guidelines herein apply only to assessments based on cash-flow analysis. Moreover, modifying factors that may additionally influence investment decisions, such as contractual or political risks, should be recognized so the entity may address these factors if they are not included in the project analysis.

3.1.1 Net Cash-Flow Evaluation

3.1.1.1 Project-based resource economic evaluations are based on estimates of future production and the associated net cash-flow schedules for each project as of an effective date. These net cash flows should be discounted using a defined discount rate, and the sum of the future discounted cash flows is termed the net present value (NPV) of the project. The calculation shall be based upon an appropriately defined reference point (see Section 3.2.1, Reference Point) and should reflect the following:

A. The forecast production quantities over identified time periods.

B. The estimated costs and schedule associated with the project to develop, recover, and produce the quantities to the reference point, including abandonment, decommissioning, and restoration (ADR) costs, based on the entity's view of the expected future costs.

C. The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods, taking into account any sales contracts or price hedges specific to a property, including that portion of the costs and revenues accruing to the entity.

D. Future projected production- and revenue-related taxes and royalties expected to be paid by the entity.

E. A project life that is limited to the period of economic interest or a reasonably certain estimate of the life expectancy of the project, which is typically truncated by the earliest occurrence of either technical, license, or economic limit.

F. The application of an appropriate discount applicable to the entity at the time of the evaluation.

3.1.2 Economic Criteria

3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic. Production from the project is economic when the revenue attributable to the entity interest from production exceeds the cost of operation. A project's production is economically producible when the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the economically producibility determination. A project is commercial when it is economic and it meets the criteria discussed in Section 2.1.2.

3.1.2.2 Economic viability is tested by applying a forecast case that evaluates cash-flow estimates based on an entity's forecasted economic scenario conditions (including costs and product price schedules, inflation indexes, and market factors). The forecast made by the evaluator should reflect and document assumptions the entity assesses as reasonable to exist throughout the life of the project. Inflation, deflation, or market adjustments may be made to forecast costs and revenues.

3.1.2.3 Forecasts based solely on current economic conditions are estimated using an average of those conditions (including historical prices and costs) during a specified period. The default period for averaging prices and costs is one year. However, if a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified. In developments with high well counts and a continuous program of activity, the use of a learning curve within a resources evaluation may be justified to predict improvements in either time taken to carry out the activity, the cost to do so, or both, if confirmed by operational evidence and documented by the evaluator. The confidence in the ability to deliver such savings must be considered in developing the range of uncertainty in production and NPV estimates.

3.1.2.4 All costs, including future ADR liabilities, are included in the project economic analysis unless specifically excluded by contractual terms. ADR is not included in determining the economic producibility or for determining the point the project reaches the economic limit (see Section 3.1.3, Economic Limit). ADR costs are included for project economics but are not included in judging economic producibility or determining the economic limit (see Section 3.1.3, Economic Limit). ADR costs may also be reported for other purposes, such as for a property sale/acquisition evaluation, future field planning, accounting report of future obligations, or as appropriate to the circumstances for which the resource evaluation is conducted. The entity is responsible for providing the evaluator with documentation to ensure that funds are available to cover forecast costs and ADR liabilities in line with the contractual obligations.

3.1.2.5 Figure 3.1 illustrates a net cash-flow profile for a simple project. The project's cumulative net cash flow exceeds the ADR liability, thereby satisfying the economic viability required to consider a project's quantities as Reserves. The project's economic production (i.e., economic producibility) is truncated at the economic limit when the maximum cumulative net cash flow is achieved, before consideration of ADR.

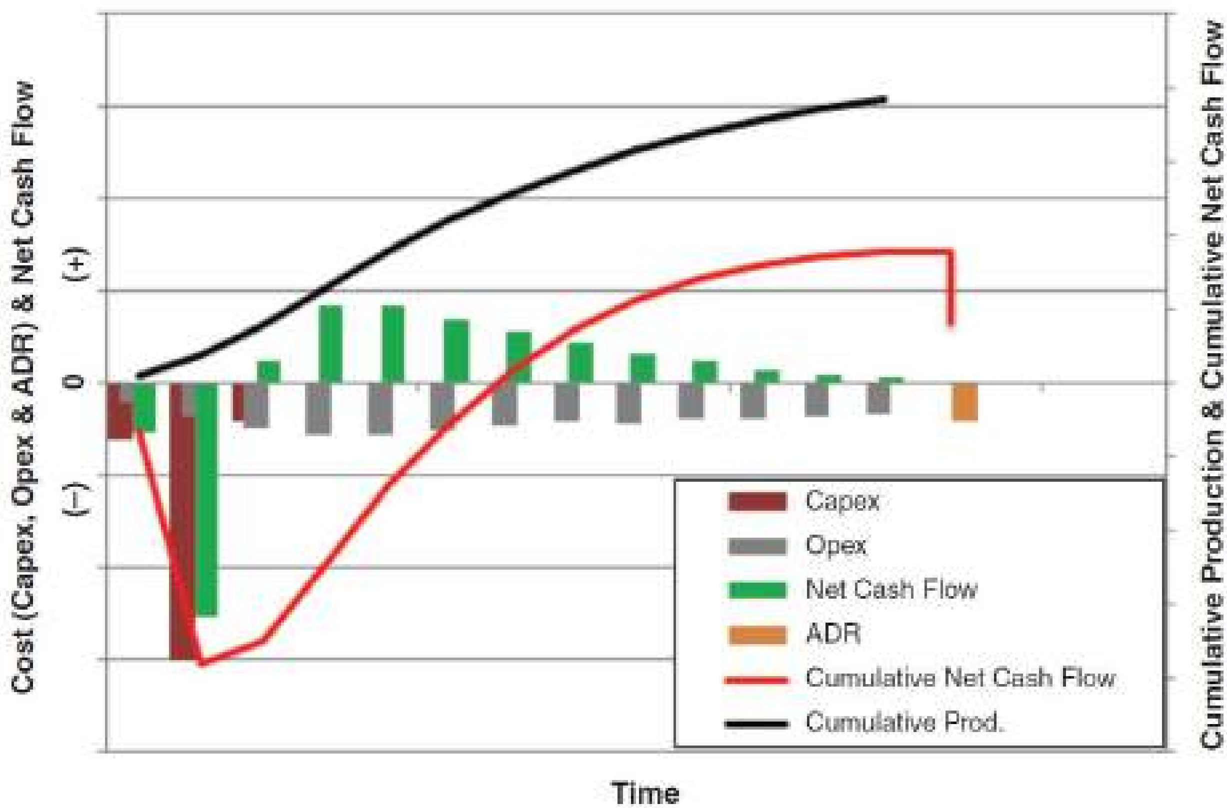

Figure 3.1—Undeveloped project economic forecast

3.1.2.6 Alternative economic scenarios may also be considered in the decision process and, in some cases, may supplement reporting requirements. Evaluators may examine a constant case in which current economic conditions are held constant without inflation or deflation throughout the project life.

3.1.2.7 Evaluations may also be modified to accommodate criteria regarding external disclosures imposed by regulatory agencies. For example, these criteria may include a specific requirement that, if the recovery were confined to the Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on the definition of current conditions or defined criteria with which to evaluate Reserves.

3.1.2.8 There may be circumstances in which the project meets criteria to be classified as Reserves using the best estimate (2P) forecast but the low case is not economic and fails to qualify for Proved Reserves. In this circumstance, the entity may record 2P and 3P estimates and no Proved Reserves. As costs are incurred in future years (i.e. become sunk costs) and development proceeds, the low estimate may eventually become economic and be reported as Proved Reserves. Some entities, according to internal policy or to satisfy regulatory reporting requirements, will defer reclassifying projects from Contingent Resources to Reserves until the low estimate case is economic.

3.1.3 Economic Limit

3.1.3.1 The economic limit is defined as the production rate at the time when the maximum cumulative net cash flow occurs for a project. The entity's entitlement production share, and thus net entitlement resources, includes those produced quantities up to the earliest truncation occurrence of either technical, license, or economic limit.

3.1.3.2 In this evaluation, operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes, but for purposes of calculating the economic limit, should exclude depreciation, ADR costs, and income tax as well as any overhead that is not required to operate the subject property. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated nonhydrocarbons (see Section 3.2.4, Associated Non-Hydrocarbon Components).

3.1.3.3 For a given project, no future development costs can exist beyond the economic limit date. ADR costs are not included in the economic limit calculations, even though they may be reported for other purposes.

3.1.3.4 Interim negative project net cash flows may be accommodated in periods of development capital spending, low product prices, or major operational problems provided that the longer-term cumulative net-cash-flow forecast determined from the effective date becomes positive. These periods of negative cash flow will qualify as Reserves if the following positive periods more than offset the negative.

3.1.3.5 In some situations, entities may choose to initiate production below or continue production past the economic limit. Production must be economic to be considered as Reserves, and the intent to or act of producing sub-economic resources does not confer Reserves status to those quantities. In these instances, the production represents a movement from Contingent Resources to Production. However, once produced such quantities can be shown in the reconciliation process for production and revenue accounting as a positive technical revision to Reserves. No future sub-economic production can be Reserves.

3.2 Production Measurement

3.2.0.1 In general, all petroleum production from the well or mine is measured to allow for the evaluation of the extracted quantities' recovery efficiency in relation to the PIIP. The marketable product, as measured according to delivery specifications at a defined reference point, provides the basis for sales production quantities. Other quantities that are not sales may not be as rigorously measured at the reference point(s) but are as important to take into account.

3.2.0.2 The operational issues in this section should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development.

3.2.1 Reference Point

3.2.1.1 Reference point is a defined location within a petroleum extraction and processing operation where the produced quantities are measured or assessed. A reference point is typically the point of sale to third parties or where custody is transferred to the entity's midstream or downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

3.2.1.2 The reference point may be defined by relevant accounting regulations to ensure that the reference point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to the delivery specifications at a defined price. In integrated projects, the appropriate price at the reference point may need to be determined using a netback calculation.

3.2.1.3 Sales quantities are equal to raw production less non-sales quantities (those quantities produced at the wellhead but not available for sales at the reference point). Non-sales quantities include petroleum consumed as lease fuel, flared, or lost in processing, plus non-hydrocarbons that must be removed before sale (including water). Each of these may be allocated using separate reference points but, when combined with sales, should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of many engineering calculations (e.g., material balance and production performance analysis) based on total reservoir voidage. Substances added to the production stream for various reasons, such as diluents added to enhance flow properties, are not to be counted as Production, sales quantities, Reserves, or Resources.

3.2.2 Consumed In Operations (CIO)

3.2.2.1 CiO (also termed lease fuel) is that portion of produced petroleum consumed as fuel in production or plant operations before the reference point.

3.2.2.2 Although Reserves are recommended to be sales quantities (see Section 1.1), the CiO quantities may be included as Reserves or Resources; when included these quantities must be stated and recorded separately from the sales portion. Entitlement rights for the fuel usage must be in place to recognize CiO as Reserves. Flared gas and oil and other petroleum losses must not be included in either product sales or Reserves but once produced are included in produced quantities to account for total reservoir voidage.

3.2.2.3 The CiO quantities must not be included in the project economics because there is neither a cost incurred for purchase nor a revenue stream to recognize a sales quantity. The

CiO fuel replaces the requirement to purchase fuel from external parties and results in lower operating costs. All actual costs for facilities-related equipment, the costs of the operations , and any purchased fuel must be included as an operating expense in the project economics.

3.2.3 Wet or Dry Natural Gas

3.2.3.1 The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed reference point. Thus, for gas that is sold as wet gas, the quantity of the wet gas would be reported, and there would be no reporting of any associated hydrocarbon liquids extracted downstream of the reference point. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

3.2.3.2 When liquids are extracted from the gas before sale and the gas is sold in dry condition, then the dry gas quantity and the extracted liquid quantities, whether condensate and/or natural gas liquids (NGLs), must be accounted for separately in resources assessments at the agreed reference point(s).

3.2.4 Associated Non-Hydrocarbon Components

3.2.4.1 In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the reference point. Correspondingly, the accounts will reflect the value of the petroleum product at the reference point. If it is required to remove all or a portion of non-hydrocarbons before delivery, the Reserves and Production should reflect only the marketable product recognized at the reference point.

3.2.4.2 Even if an associated non-hydrocarbon component, such as helium or sulfur, removed before the reference point is subsequently separately marketed, these quantities are included in the voidage extraction quantities (e.g., raw production) from the reservoir but are not included in Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the project's economic evaluation.

3.2.5 Natural Gas Re-Injection

3.2.5.1 Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. Gas can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In cases where the gas has no transfer of ownership and with a development plan that is technically and commercially mature, the gas quantity estimated to be eventually recoverable can be included as Reserves.

3.2.5.2 If injected gas quantities are included as Reserves, these quantities must meet the criteria in the definitions, including the existence of a viable development, transportation, and sales marketing plan. Gas quantities should be reduced for losses associated with the re-injection and subsequent recovery process. Gas quantities injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas quantities purchased for injection and later recovered are not classified as Reserves.

3.2.6 Underground Natural Gas Storage

3.2.6.1 Natural gas injected into a gas storage reservoir, which will be recovered later (e.g., to meet peak market demand periods) should not be included as Reserves.

3.2.6.2 The gas placed in the storage reservoir may be purchased or may originate from prior native production. It is important to distinguish injected gas from any remaining native recoverable quantities in the reservoir. On commencing gas production, allocation between native gas and injected gas may be subject to local regulatory and accounting rulings. Native gas production would be drawn against the original field Reserves. The uncertainty with respect to original field quantities remains with the native reservoir gas and not the injected gas.

3.2.6.3 There may be occasions in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the re-injected gas could be included with the native reservoir gas as Reserves.

3.2.6.4 The same principles regarding separation of native resources from injected quantities would apply to underground liquid storage.

3.2.7 Mineable Oil Sand

3.2.7.1 Mineable oil sands that meet the criteria listed in Section 2.1.2 can be considered as a potentially economic material and therefore Reserves. Mining operations may result in mined materials being stockpiled rather than processed. Stockpiled mined oil sands should be included in Reserves only when the project to recover and blend the stockpile has achieved technical and commercial maturity. The project's quantities are not included in Production until measured at the reference point.

3.2.8 Production Balancing

3.2.8.1 Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of Production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because participants may need to lift their production in parcel sizes or cargo quantities to suit available shipping schedules agreed upon by the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas quantities sold from being equal to the entitlement share within a given time period.

3.2.8.2 Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the entity and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in

Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

3.2.9 Equivalent Hydrocarbon Conversion

3.2.9.1 The industry sometimes simplifies communication of Reserves, Resources, and Production quantities with the term "barrel of oil equivalent" (BOE). The term allows for consolidation of multiple product types into a single equivalent product. In instances where natural gas is the predominate product, liquids may be converted to gas equivalence (i.e. one thousand cubic feet (MCF) volume= 1 McfGE (MCF gas equivalent)).

3.2.9.2 Oil, condensate, bitumen and synthetic crude oil can be summed together without conversion (i.e., 1 bbl volume = 1 BOE). NGLs may need to be converted, depending on the actual composition. Natural gas must be converted to report on a BOE basis.

3.2.9.3 The presentation of Reserve or Resources quantities should be made in the appropriate units for each individual product type reported (e.g. barrels, cubic meters, metric tonnes, joules, etc.). If BOE's or McfGE's are presented, they must be provided as supplementary information to the actual liquid or gas quantities with the conversion factor(s) clearly stated.

3.3 Resources Entitlement and Recognition

3.3.0.1 While assessments are conducted to establish estimates of the total PIIP and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral lease owners (lessors) and contractors (lessees) and is generally referred to as entitlement.

3.3.0.2 Evaluators must ensure that, to their knowledge, the recoverable resource entitlements from all participating entities sum to the total recoverable resources.

3.3.0.3 The ability for an entity to recognize Reserves and Resources is subject to satisfying certain key elements. These include (a) having an economic interest through the mineral lease or concession agreement (i.e., right to proceeds from sales); (b) exposure to market and technical risk; and (c) the opportunity for reward through participation in exploration, appraisal, and development activities. Given the complexities of some agreements, there may be additional elements that must be considered in determining entitlement and the recognition of Reserves and Resources.

3.3.0.4 For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be ·recognized" in external disclosures. For national interests, the reporting of 100% quantities without concession agreement constraints is typically specified.

3.3.1 Royalty

3.3.1.1 Royalty refers to a type of entitlement interest in a resources project that is free and clear of the costs and expenses of development and production to the royalty interest owner as opposed to a working interest where an entity has cost exposure. A royalty is commonly retained by a resources owner (lessor/ host) when granting rights to a producer (lessee/contractor) to develop and produce the resources. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production in-cash or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. In either case, royalty quantities must be deducted from the lessee's entitlement to resources so that only net revenue interest quantities are recognized.

3.3.1.2 In some agreements, production taxes imposed by the host government may be referred to as royalties. These payment obligations are expressed in monetary terms and are typically linked to production rates, quantities produced, cost recovery, the value of production (price sensitive), or the profits derived from it. These payments are not associated with an interest retained by the lessor/host. Thus, such payment obligations are effectively a production tax instead of a royalty. In such cases, the production and underlying resources are controlled by the lessee/contractor who may (subject to contractual terms and/or regulatory guidance) elect to report these obligations as a tax without a corresponding reduction in lessor/ contractor's entitlement.

3.3.1.3 Conversely, if an entity owns a royalty or equivalent interest of any type in a project, the related quantities can be included in resources entitlements and should not be included in entitlements of others.

3.3.2 Production-Sharing Contract Reserves

3.3.2.1 Production-sharing contracts (PSCs) of various types are used in many countries instead of conventional tax-royalty systems. Under the PSC terms, producers have an entitlement to a portion of the production. This net entitlement. often referred to as entitlement, occurs when a net economic interest is held by an entity and is estimated using a formula based on the contract terms incorporating costs and profits. The terms of the PSC provide the remuneration to the host government/lessor that would be accomplished by the royalty in other agreements.

3.3.2.2 Ownership of the production is retained by the host government; however, the contractor may receive title to the prescribed share of the quantities when produced or at point of sale and may claim that share as their Reserves.

3.3.2.3 Risk service contracts (RSCs) are similar to PSCs, but the producers may be paid in cash rather than in production. As with PSCs, the Reserves claimed are based on the entity's economic interest as risk is borne by the contractor. Care needs to be taken to distinguish between an RSC and a pure service contract. Reserves can be claimed in an RSC, whereas no Reserves can be claimed for pure service contracts because there is insufficient exposure to petroleum exploration, development, and market risks and the producers act as contractors.

3.3.2.4 Unlike conventional tax-royalty agreements, the cost recovery system in production-sharing, risk-service, and other related contracts typically reduce the production share and hence Reserves entitlement to a contractor in periods of high price and increase quantities in periods of low price. While this ensures cost recovery, it also introduces significant price-related volatility in annual Reserves estimates under cases using a constant case. The terms governing cost recovery in a particular PSC may require special treatment of items such as taxes, overhead, and ADR to determine entitlement.

3.3.2.5 The treatment of taxes and the accounting procedures used can also have a significant impact on the Reserves recognized and production reported from these contracts.

3.3.3 Contract Extensions or Renewals

3.3.3.1 As production-sharing or other types of agreements approach the specified end date, extensions may be obtained through contract negotiation, by the exercise of options to extend, or by other means.

3.3.3.2 Reserves cannot be claimed for those quantities that will be produced beyond the expiration date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the status of renewal negotiations and historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term must be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

3.3.3.3 Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for quantities that will be produced beyond those specified in the current agreement or that do not have a reasonable expectation to be included in either contract renewals or future agreements.

APPENDIX D: SPROULE PRE-2020 WELL DATABASE

Well Name	UWI	Label	Easting	Northing	RL	Hole Angle	Total Depth
HDR 1	VR1239	HDR01	27610.29	3112421.65	1294.00	90.00	484.00
Burning Cross	VR1187	1307	27976.60	3111368.30	1287.60	90.00	1092.33
EX 1	VR0512	EX01				90.00	
Highpipe	VR0846	2057	25854.40	3108505.80	1323.17	90.00	1627.00
HZON 1	VR2352	HZON01				90.00	
MDR 5			27251.00	3111658.50	1219.52	90.00	350.00
ML 1	VR1126	1370	24573.00	3132720.10	1410.95	90.00	1237.75
Retreat	VR0091	DW54403	34874.40	3129059.80	1372.37	90.00	513.70
ST 23	VR0588	ST23	25671.90	3120629.30	1340.77	90.00	1866.95
SPG 3 \ Lucky	VR1162	SPG03	25320.90	3130173.80		90.00	
Squatter	VR0848	2089	25852.40	3109095.80	1317.36	90.00	1750.60
Tewie-1400	VR0453	1400	25187.60	3123069.80	1357.15	90.00	1459.55
Burning Flame	VR0854	2190	22134.50	3108509.20	1344.08	90.00	1411.40
DBE 1	VR0489	DBE1	23747.20	3118794.80	1344.99	90.00	1090.00
SP 3	VR1026	SAP11	16593.40	3101476.40	1362.54	90.00	
Flame 1	VR0858	2278	21345.50	3109501.80	1335.32	90.00	1287.50
Sand	VR1191	1629	26806.60	3110762.90	1296.20	90.00	2163.24
BN 56120A	VR0037	Dumidi	32288.30	3111882.80	1300.10	90.00	356.00

For additional information an expanded electronic version is available.

APPENDIX E: ABBREVIATIONS

This appendix contains a list of abbreviations found in Sproule reports, as well as a table comparing Imperial and Metric units. Two conversion tables, used to prepare this report, are also provided.

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BOE	barrels of oil equivalent
bopd	barrels of oil per day
bwpd	barrels of water per day
Cr	Crown
DCQ	daily contract quantity
DSU	drilling spacing unit
FH	Freehold
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
LPG	liquid petroleum gas
M	Millions
MMZAR	Millions of South African ZAR's
m	thousands
mcfd	thousands of cubic feet per day
Mcfpd	thousands of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	'new' Crown
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OC	'old' Crown
ORRI	overriding royalty interest
P&NG	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
TCGSL	TransCanada Gas Services Limited
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	million		M (10^6)	million
B (10^9)	one billion		T (10^{12})	one billion E
T (10^{12})	one trillion		(10^{18})	one trillion G
			(10^9)	one milliard
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
Mcfpd	thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	barrels		m^3	cubic metre
Mbbl	thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			
Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Sproule

Conversion Factors — Imperial to Metric

barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F)	x 0.03743222	= megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $/$m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t) pounds
(lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)