INDEPENDENT TECHNICAL REPORT ON BLOCK 2712A (PEL 107), ORANGE BASIN, OFFSHORE REPUBLIC OF NAMIBIA

Report Produced for:

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National Instrument 51-101 Report

Prepared in accordance with NI 51-101 and Forms 51-101F1, 51-101 F2 & 51-101F3

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1.0 Executive Summary

Block 2712A covers an area of 5,484 km^2 within the northwestern Orange Basin offshore the Republic of Namibia. On 26th January 2023, a petroleum agreement was awarded to Vena Gemstones and Mining Pty Ltd (subsequently re-named "Petrovena'') and Namcor Exploration and Production (Pty) Ltd ("Namcor'') for Block 2712A. On 19th July 2023, the Minister of Mines and Energy issued a Petroleum Exploration Licence No. 107 ("PEL 107'') for Block 2712A to Petrovena granting a 85% interest together with a 15% interest to Namcor. On 15th February 2024, the Ministry of Mines and Energy approved the transfer of 70% of Petrovena's interest to Westoil Limited ("Westoil"). Westoil is now the operator with a 70% participating interest with Petrovena holding a 15% interest and Namcor having a 15% interest. In December 2024, Namlith Resources Corp. ("Namlith'') purchased a 12.5% interest in Westoil which was subsequently acquired on 31st January 2025 by Supernova Metals Corp ("Supernova'') giving them an indirect effective participation interest of 8.750% in PEL 107.

Block 2712A is considered a very early-stage hydrocarbons exploration block in a proven prospective petroleum province. However, without the licencing and interpretation of the available seismic data both in and around Block 2712A being available, or new 3D seismic data having been acquired by Westoil, it is considered impossible, at the time of this report, to assess any prospective resources net to Namlith.

The PEL 107 exploration licence is situated to the north and on-trend with several significant oil discoveries, including TotalEnergies' Venus and Mangetti discoveries, Shell's Graff, La Rona, Jonker, Enigma and Lesedi fields and Galp Energia's Mopane discovery. All discoveries have proved substantial columns of light oil, condensate and in, the case of Venus and Graff, large quantities of associated gas. Exploration in the Orange Basin had historically targeted Cretaceous sequences in shallow water areas, inboard of Block 2712A. Before the large Graff and Venus discoveries in 2022, few discoveries had been made. Prior drilling had focused mainly on targets in relatively shallow water, the most notable being the Kudu gas discovery in southern Namibia (in aeolian and shallow-marine Barremian reservoirs) and the Ibhubesi gas field (in Albian-Cenomanian shallow marine fluvio-deltaic sands). Many of the recent discoveries and the unsuccessful exploration wells have demonstrated a variety of risks including the presence of gas or poor reservoir quality due to greater maturity levels of the source rocks, source of sediments, favourable (or not) depositional environments, differing characteristics of the turbidite systems and possible later diagenetic cementation.

The original Venus and Mopane discoveries remain the most attractive in terms of a possible development. Block 2712A is considered to be a close analogue of the Venus discovery on the present very limited data set due to its outboard setting in water depths of greater than 3,000 metres. Although the existing seismic data over Block 2712A is very widely spaced, it is believed to show the source rocks lying directly on the oceanic crust and within an area where sediment thickness exceeds 2,500 to 3,000 metres and with indications of the presence of Lower Cretaceous target sands. Transform faults and related fractures may represent good migration pathways from source to reservoirs/traps. Satellite oil slicks have been mapped within the limits of the blocks (HRT 2011 using RadarSat-2 Satellite images).

The overall regional setting and proximity to proven deep water hydrocarbon bearing structures indicates the potential for the presence of both reservoir sands and traps in Block 2712A. There is a large regional Barremian-Aptian source kitchen and the deep water areas like Block 2712A are considered as under explored and could provide the best chance for future oil discoveries such as Venus.

Super majors such as TotalEnergies have already proved the hydrocarbon play potential in the deep and ultra-deep waters offshore Namibia. In February 2025, TotalEnergies spudded the exploration well Marula-1X which is being drilled at the time of this report to test a prospect in 3,000 metre water depth to the southeast of the Venus discovery in a setting considered very similar to that of the Block 2712A area.

2.0 Basis of Assessment

2.1. Terms of Reference

05 Management Limited ("05 Management'') was commissioned by Namlith Resources Corp ("Namlith''), a 100% subsidiary of Supranova Metals Corp, to conduct an independent review of the hydrocarbon prospectivity and prospective resources in Block 2712A in the Orange Basin offshore Namibia. Namlith Corp is a 12.5% shareholder in the Block Operator, Westoil Limited ("Westoil''). 05 Management has prepared this Report under Canada's National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities, since Supernova is listed on the Canadian Securities Exchange (CSE). The report covers the assets of Namlith Resources Corp in offshore Namibia which comprises the Petroleum Exploration Licence (PEL) 107 awarded for Block 2712A. For this report, 05 Management has subcontracted Pioneer Oil and Gas Consulting ('Pioneer'), an independent Namibian based geological and geophysical consultancy company, to assist in the regional geological and geophysical interpretation of both the proprietary and publicly available data.

2.2. Available Data

The data and information used in the preparation of this report were provided by both Pioneer Oil and Gas Consulting ("Pioneer'') and Namlith, as a minority shareholder in Westoil, the licence operator, supplemented by public domain information. 05 Management has relied upon certain information provided by both Namlith and Pioneer Oil and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied making adjustments that in our judgment were deemed necessary. Details of the findings of our review are presented in this report. 05 Management has reviewed both Namlith's and Pioneer's technical interpretations and the assessment of prospectivity in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System 2018 (PRMS). Unless otherwise stated, the views represented in this report are with an effective date of 18th April 2025. Namlith Corp. is an exploratory early-stage company and, therefore, has no attributable prospective resources which can be considered mature enough for determination at the time of this report.

Certain information contained in this report is considered "analogous information" as defined in National Instrument 51-101 ("NI 51-101"). Such analogous information from within the Orange Basin area and outside of the Block under evaluation, has been used in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. In particular, this document has drawn extensively on information from specific analogous hydrocarbon discoveries in the Orange Basin due to the paucity of proprietary data in such early-stage exploration licences. Such information is based on public data and information obtained from the public disclosure of other parties who are active in the area, and 05 Management has no way of verifying the accuracy of such information and cannot determine whether the source of the information is independent. Such information, when presented, is intended to help demonstrate that hydrocarbons could be present in Block 2712A.

2.3. Applicable Standards

This report has been prepared in accordance with Canadian National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGEH). The National Instrument requires disclosure of specific information concerning prospects, as are provided in this Report. Any estimates of Prospective Resources prepared by 05 Management would be compliant with both Canadian National Instrument 51-101 and COGEH, and the Petroleum Resources Management System 2018 (PRMS) (resource definitions from both these standards are fundamentally the same). However, no estimates of prospective resources have been presented in this report since it is considered impossible given the present database and, therefore, 05 Management has not been engaged in this instance as an independent qualified reserves auditor (Form 51-101 F2).

3.0 Introduction

3.1 History of Petroleum Exploration in the Orange Basin

The Orange Basin straddles the offshore areas of both the Republics of Namibia and South Africa and has a long history of petroleum exploration marked mostly recently by significant discoveries. The exploration of this large sedimentary basin has occurred in three distinct periods outlined below:

Phase 1 Exploration (1960s–1980s)

In 1969–1972 Namibia initiated its first and second offshore licensing rounds, awarding several blocks to international operators and in 1974, the Kudu Gas Field (Figure 3.1.1) was discovered in Namibia's Orange Basin by a consortium including Chevron, Regent, and SOEKOR. In 1987–1988, seismic data were acquired and appraisal wells drilled in the Kudu field, confirming the presence of dry gas and minor condensate.

Phase 2 Exploration (1990s–2010s)

In 1990 -2000 Namibia launched several new licensing rounds, attracting companies like Norsk Hydro, Ranger, Sasol, Chevron, and Shell. Over 28,000 km of 2D seismic data were acquired during this period. Well 2815/15-1 was drilled in 1996 by Chevron Overseas (Namibia) Ltd in a water depth of 180m. In the early 2010s exploration wells were drilled by HRT including Wingat-1 and Murombe-1 in the Walvis Basin, and Moosehead-1 in the Orange Basin. In 2012, Chariot Oil and Gas Limited, BP and Petrobras also drilled the Kabeljou exploration well (2714/6-1) in Southern Block 2714A in the Orange Basin reaching a total depth of 3,150 metres TVDSS. While these wells did not yield commercial discoveries, they provided valuable data on source rock presence and maturity leading to continued interest in the exploration in the basin.

Phase 3 Exploration and Significant Discoveries (2020 to 2025)

In February 2022, TotalEnergies announced the drilling results of the Venus-1X well in PEL 56 which found 84 metres of net oil pay in high quality Cretaceous reservoirs in Namibia's southern Orange Basin (Figure 3.1.1). The Venus light oil discovery became the Orange basin opener proving a new basin floor fan fairway onlapping onto the Outer High ridge, creating a significant trap. Also in February 2022, Shell announced the Graff-1X discovery (PEL 39), identifying at least two reservoirs in Upper Cretaceous marine sandstone with light oil columns in high-quality channel sands in the deepwater part of the basin. In March 2023, Shell, in partnership with Qatar Energy and NAMCOR, announced the Jonker-1X discovery drilled in December 2022, 18 km to the west-north-west of the Graff discovery and in a Lower Cretaceous target, further confirming the basin's potential. Following these successes have been more discoveries (La Rona, Lesedi, Enigma and Mangetti) and some unsuccessful wells (Nara and Cullinan). The results of this drilling in the deep water Cretaceous turbidite fan sands (Figure 3.1.1) has proved multiple working petroleum system plays in the Orange Basin, offshore Namibia.

In October 2022, Chevron acquired 80% working interest in PEL 90 through a farm-in and funding a 6,600 km^2 3D seismic survey followed by the drilling of the Kapana-1X exploration well in 2024 which was recently announced as unsuccessful (January 2025).

In March 2023, Woodside entered into an option agreement to acquire a 56% interest in PEL 87 by paying for 6,800 km^2 of 3D seismic. However, after interpreting this data, Woodside recently elected (March 2025) not to take up the option of farming in and funding an exploration well. The PEL 87 licence area is notable for having a mapped giant superfan complex likely to be turbiditic and analogous to Total's Venus oil discovery directly south. This Saturn fan feature is not present in the earlier HRT 2013 Moosehead-1 well drilled in the southeast section of the block and which had no reservoir quality sands and is now believed to lie outside the fan area.

In January 2024, Galp Energia, the operator of Block 2813, Petroleum Exploration Licence (PEL) 83, (Figure 3.1.1) drilled the Mopane-1X exploration well, based on the results of a 4,000 km^2 3D seismic survey, in water depths ranging from 250 to 2,550 metres. This well found significant light oil columns in high-quality reservoir sands at two different levels, named AVO-1 and AVO-2 and was located directly north of PEL 39 where Shell made its Graff-1 light oil discovery, and directly to the west of the Kudu Gas Field. The Mopane-2X appraisal well was drilled in March 2024 and intersected further light oil columns across targets AVO-3, AVO-1, and a deeper-lying target. Importantly, the AVO-1 findings in Mopane-2X were in the same pressure regime as those in Mopane-1X, confirming lateral continuity of the reservoir over an 8 kilometre distance. In April 2024, Galp Energia subsequently announced that the Mopane complex could contain in-place hydrocarbons estimated at 10 billion barrels of oil equivalent (Bboe) or more, which would make it one of the world's largest offshore discoveries. In February 2025, Galp Energia reported a significant discovery of light oil and gas condensate in the Mopane-3X well, located 18 km southeast of the first Mopane-1X well reinforcing the estimated 10 Bboe in-place volume.

In December 2024, Sagittarius-1X was drilled immediately to the south of the Mopane discovery in PEL 85 by Azule Energy and Rhino Resources and found hydrocarbons reported in the Upper Cretaceous (phase unreported) but with no information on the reservoir. Most recently (24th April 2025), Azule Energy and Rhino Resources announced a light oil discovery with the Capricornus-1X well.

This last successful exploration period from 2022 to 2025 has positioned the Orange Basin as a global exploration hotspot with numerous exploration wells planned in 2025 and 2026. Recent announcements by Shell have caused some caution on any potential commercial development due to the reported presence of both gas and varying reservoir quality. Recent wells such as Tamboti-1X (2024) and Kapana-1X (2025) have also highlighted the risk of areas of poorer reservoir quality within the basin sands and indicate the need for more detailed work and additional drilling to better understand the areal variations in reservoir quality over the basin. Although Shell undertook a drill stem test of Graff in late April to early May, no results or information have been released although Shell in January 2025 warned that the development of PEL39 is not yet certain, writing down $400 million of expenditures.

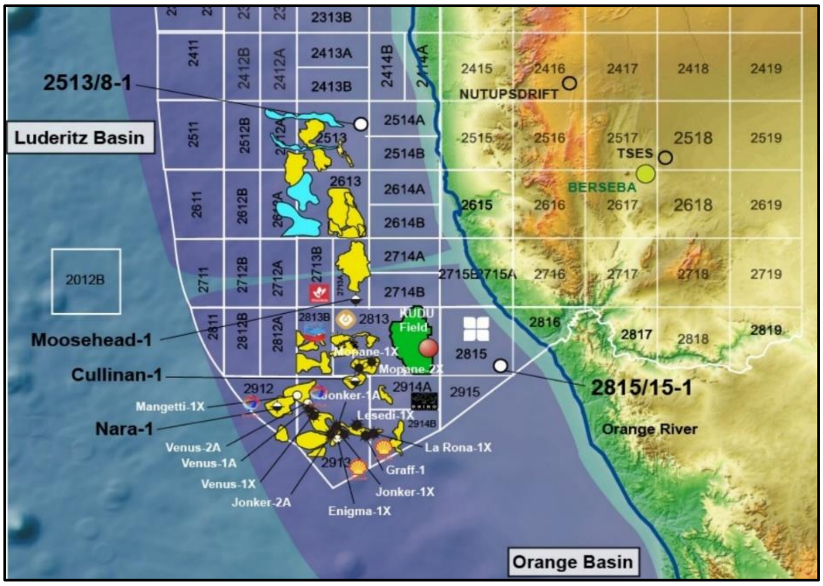

Figure 3.1.1 Licences and discoveries in the Orange Basin, Offshore Namibia (After Brazilian Petroleum Studies BPS 2023)

3.2 Asset Description

Block 2712A comprises an area of 5,484 km^2 and is located ca.230 kilometres offshore Republic of Namibia in the northwestern Orange Basin in deep to ultra-deep water depths of between 2,800 and 3,900 metres (Figures 3.2.1 and Figure 3.2.2). The Block is licenced under a petroleum agreement in 23rd January 2023 and a petroleum exploration licence (PEL) denominated as PEL 107 since the 19th July 2023. No wells have been drilled in Block 2712A and it is only covered by a sparse grid of regional 2D seismic data of varying vintages acquired between 2006 and 2023 by different companies (Figure 3.2.3).

No 3D seismic data has been acquired and there has been no drilling within the block. The nearest exploration wells are Moosehead-1 (HRT 2014) to the East, and the recent Kapana-1X (Chevron 2024). Further to the south are the Venus-1X, Mangetti-1X, Nara-1X and Tamboti-1X wells. To the east and southeast are the Mopane wells (Galp 2023-24) and Sagittarius -1X wells. Block 2712A is, therefore, considered a very early-stage exploration block in a proven prospective petroleum province.

Therefore, the report has relied on regional information provided by both the operator Westoil and Namith together with other information in the public domain. Namlith as a 12.5% shareholder in Westoil is a pure exploration company and has no prospective resources which can be attributed to it through its indirect holding in Block 2712A. However, once regional multi-client data is purchased and licenced, the available 2D legacy seismic data can be interpreted, it may be possible to define specific leads which can be identified on the existing seismic lines. This will in turn provide essential data for the planning and acquisition of a 3D seismic campaign of at least 3,000 km^2 (licence commitment).

The licence is operated by Westoil Limited with a 70% working interest with Petrovena and Namcor as non-operated partners with 15% working interest each.

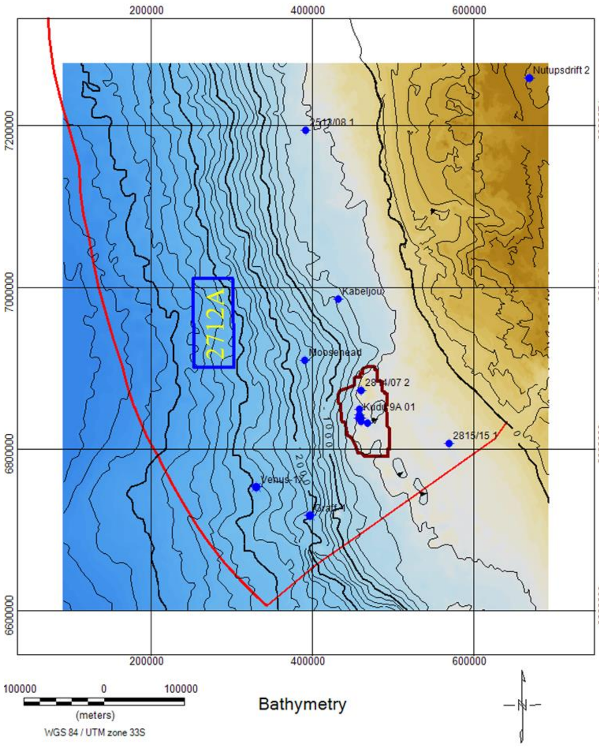

Figure 3.2.1 Bathymetry Map, Offshore Namibia (Ref. Pioneer Oil and Gas Consulting)

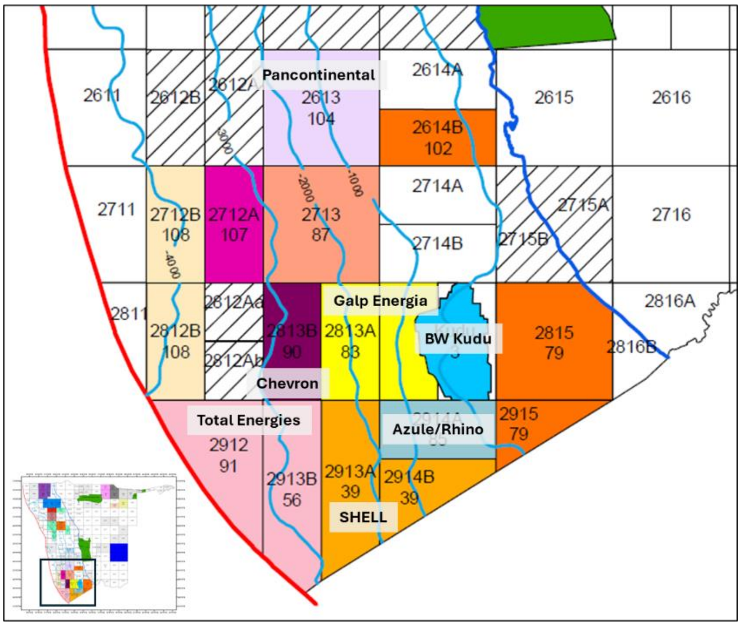

Figure 3.2.2 Orange Basin Location Map showing Block 2712A (ref. Namibian Licence Map 2025)

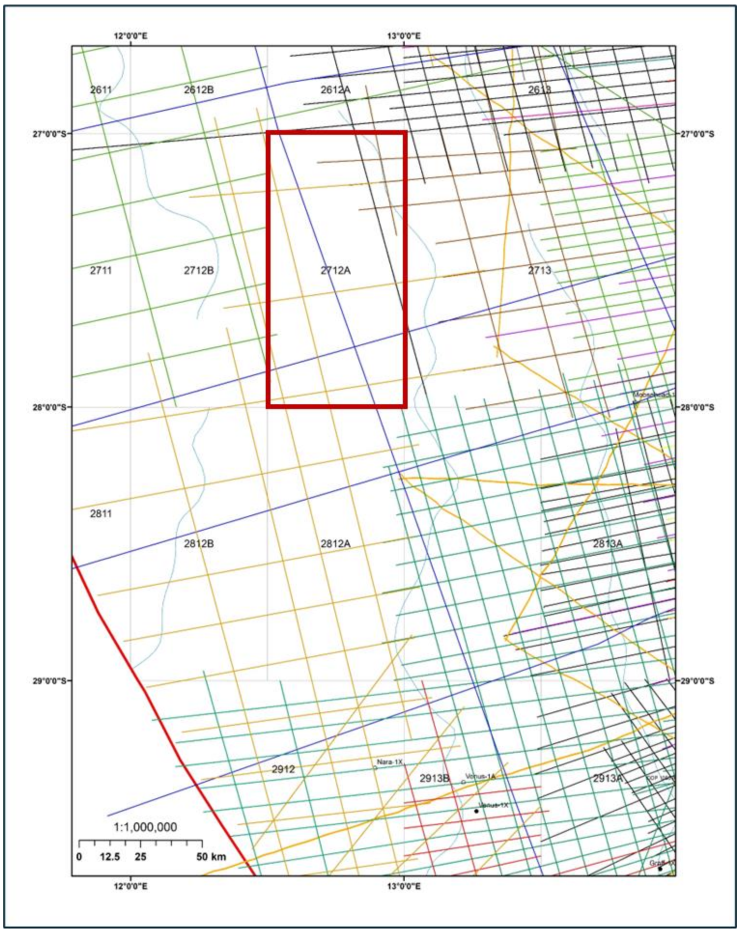

Figure 3.2.3 Existing legacy seismic grid covering Block 2712A (ref. Pioneer Oil & Gas Consulting)

4.0 Regional Information

The Orange Basin in Namibia is a sedimentary basin located offshore along the southwestern coast of Africa, extending into South Africa. Block 2712A is located in the northern part of the Orange Basin which extends as far north as the Kudu Arch in Namibia and forms part of the larger West African passive margin system. The Orange Basin gets its name from the Orange River which has provided much of the sediment supply, depositing thick sequences of clastic material and has recently become a focus for hydrocarbon exploration following recent discoveries.

Exploration for hydrocarbons in the Orange Basin has historically targeted Cretaceous sequences in shallow water areas, inboard of Block 2712A. Before the light oil Graff and Venus discoveries in 2022 in Cretaceous turbidites, few discoveries had been made. Prior drilling had focused mainly on targets in relatively shallow water, the most notable being the Kudu gas discovery in southern Namibia (in aeolian, shallow-marine Barremian reservoirs), the Ibhubesi gas discovery (in Albian-Cenomanian shallow-marine fluvio-deltaic reservoirs). The Cretaceous turbidite fans have strong seismic amplitude versus offset (AVO) signatures visible on the recent 3D seismic datasets. There is little publicly available information upon the exact calibration of these AVO responses to fluid type in the Orange Basin wells, but such high seismic anomalies are frequently indicative of the presence of gas.

Any future prospects in Block 2712A will target turbidite fan deposits of similar age and seismic response to the discoveries made by TotalEnergies and Shell to the south. Traps are generally stratigraphic traps, with siliciclastic reservoirs confined within channels, or deposited as wider turbidite fans fully encased in shales.

4.1 Regional Geology

The Orange Basin is one of four sedimentary basins along the Namibian margin and is part of the volcanic-rifted passive margin south of the Walvis Volcanic Ridge along the southern South Atlantic coast of Namibia and South Africa. The basin extends from Kudu Arch in Namibia to the Agulhas Fracture Zone in South Africa, covering approximately 160,000 km^2. The basin is fed by Africa's largest Cretaceous drainage system with more than 7,000 metres of Cretaceous sediments deposited from Paleo Orange and Oliphants rivers.

The Orange Basin is divided into two major sub-basins separated by the northwest-southeast trending Outer High basement ridge formed by tectonic uplift and located in the deep water part of the basin. This ridge feature is part of the passive margin system formed during the rifting of South America and Africa in the Late Jurassic to Early Cretaceous period. The inner sub-basin formed first, in a NW–SE direction, probably in the Neocomian and the outer sub-basin formed later, during the Aptian.

The rifting associated with the breakup of the South America and African continental plates was accompanied by significant volcanism resulting in the formation of extensive thick subaerial flood basalts that form a large area of Seaward Dipping Reflectors (SDR's) of more than 5,000 metres thickness. These SDRs are layered, wedge-shaped seismic reflectors that dip oceanward and are a direct result of the volcanic and tectonic processes during the early stages of the rifting and breakup. These SDR's form as a result of volcanic eruptions during continental breakup producing widespread flood basalts**,** which accumulate in lava flows that dip seaward due to subsidence and differential loading. New lava flows erupt overlapping older flows, creating the layered SDR sequences seen in the seismic data.

The rifting provided an environment for the young South Atlantic Ocean where restricted circulation created anoxic marine conditions in the Barremian to Aptian, allowing good quality source rock facies to develop and deposit under anaerobic conditions. In the inner sub-basin, they are referred to as the Kudu Shale Formation.

The Late Barremian-Aptian was marked by the first marine incursion across the restricted Orange Basin, resulting in the widespread deposition of marine shales. The thick marine oil-prone Barremian-Aptian source rocks have been proven in the Kudu wells and have also been penetrated at Moosehead in the Orange Basin. Mid-Aptian marks the initial progradation of the Proto-Orange delta system, which feeds the primary Aptian-Albian deep water turbidite reservoir targets at Venus-1 well. These Aptian sands are also encountered at the Kudu field (Figure 4.1.1 and 4.1.2). Open marine shales were deposited during the Cenomanian-Turonian and proven in the Moosehead and Wingat wells. Progradation of the Paleo-Orange Delta continued during the Late Cretaceous. A Santonian uplift event caused tilting of the African margin – destabilizing the shelf and triggering high erosion rates in the hinterland. The Santonian is a crucial interval for clastic reservoir deposition and was the primary reservoir target of the Graff-1 well. Rates of sedimentation increased dramatically in the Late Cretaceous. In the Campanian, growth faulting near the shelf edge resulted in the development of toe thrusts down dip to accommodate the extension. By the end of the Cretaceous, sediment input was drastically reduced meaning that there is little hydrocarbon potential in the Tertiary section in this basinal setting and the Cretaceous section remains the primary exploration play.

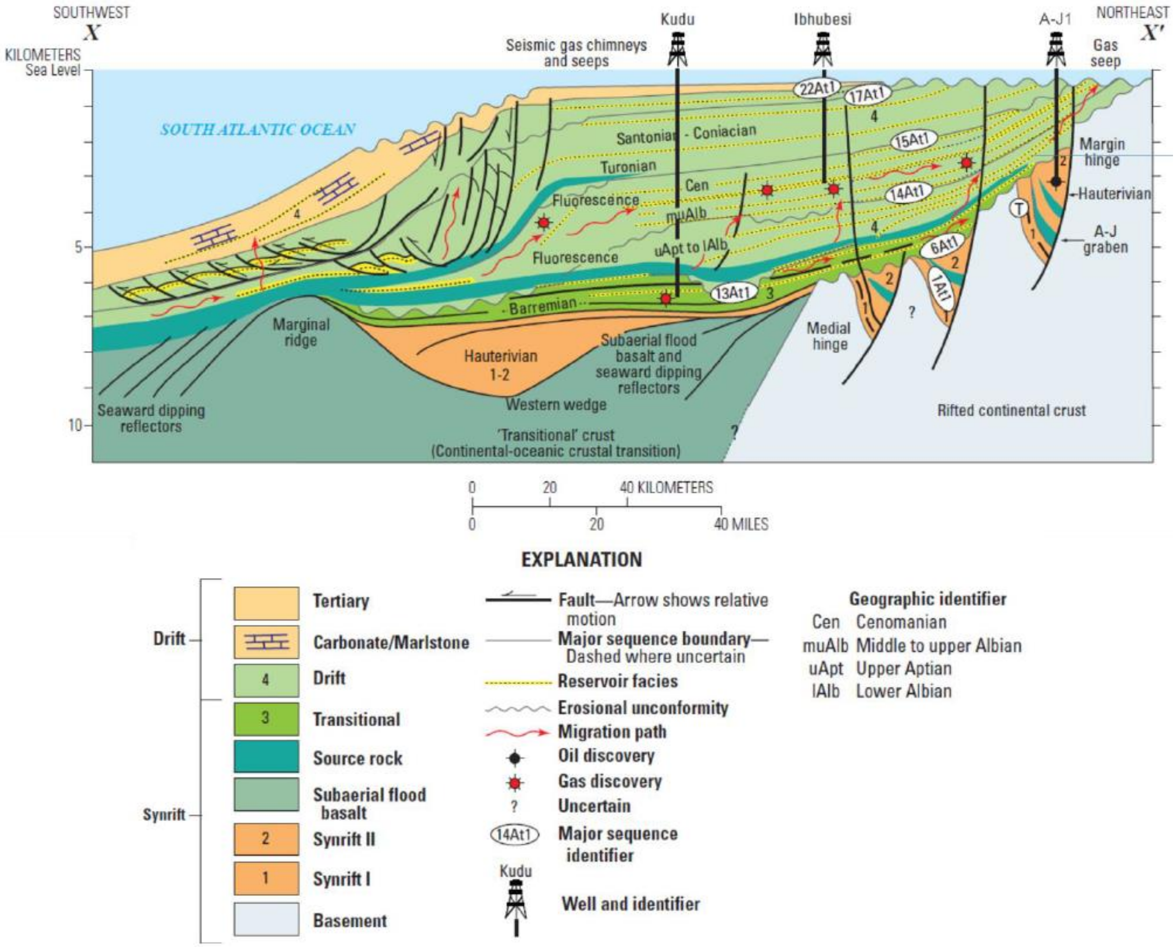

Figure 4.1.1 Schematic geological dip section for the Orange Basin showing the A-J1 half graben and the main gas discoveries (from Brownfield, 2016)

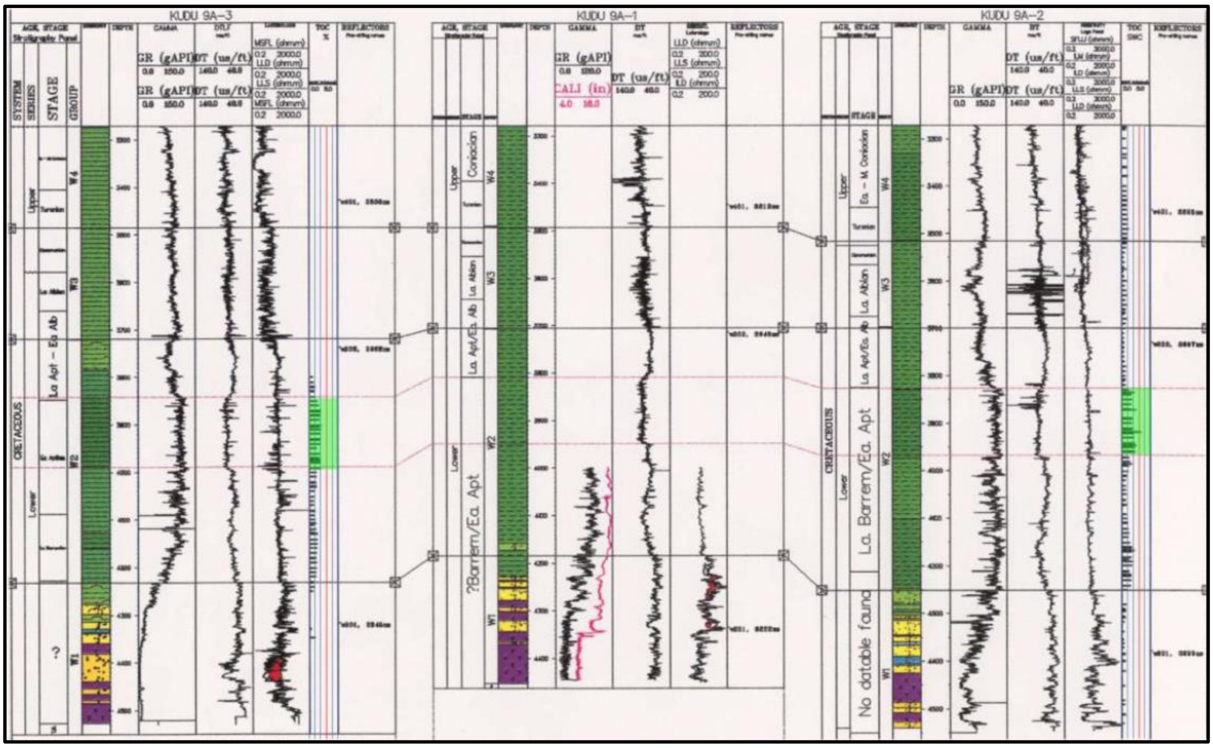

Figure 4.1.2 Well log profiles including % TOC for selected Kudu wells demonstrating the presence of 100m gross Early Aptian source rock in the Kudu Field. This source is believed to be the source for the gas (from Cole G., 2021).

A CGG Sample seismic line from the reprocessed SCOB-12 2D survey shows the volcanic nature of the Namibian margin demonstrated by the Seaward Dipping Reflectors (SDR's) together with deep water sedimentation, and Cretaceous mega-slides (Figure 4.1.3).

Figure 4.2.3 shows the typical depth converted seismic image (courtesy of TGS ref. Pioneer Oil and Gas) of the southern portion of Block 2712A. The presence of the outer high to the east represents an important feature for the trap formation represented by the pinchout over the ridge. The transition towards the ocean crust is represented by an abrupt increase in the accommodation space and deposition of sediments. This characteristic is commonly observed across the Namibian margin and creates a depocentre where the Aptian sediments (source rocks) were deposited and became mature due to the thicker overburden on top of the source rock. The depth section illustrates a favourable scenario for migration of hydrocarbons from these depo-centres to the east.

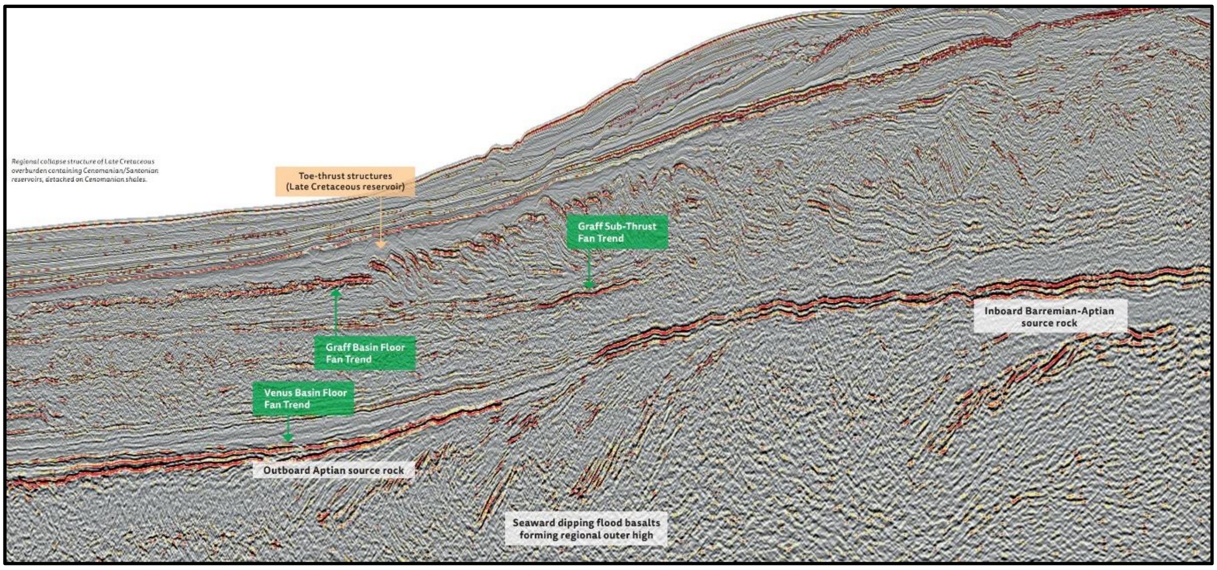

Figure 4.1.3 Structural Setting in deepwater Orange Basin, Namibia (After TGS 2022 – CGG re-processed seismic line.

4.2 Source Rocks and Charge

Interpretation of regional seismic data and well information along the Namibia and South Africa margin suggests that the Barremian–Aptian source rock is distributed over wide parts of offshore Namibia, as far north as the Walvis Ridge, and southwards into South Africa. The source rock thickness varies across the two main sub-basin depo-centres divided by the Outer High (Figure 4.1.1). The Barremian–Aptian restricted marine source rock which was proved in earlier exploration wells has a varied Total Organic Carbon (TOC) of between 1% and 14%. These TOC values are likely to be directly controlled by the occurrence of deposition of clastic sediments in the inboard areas and higher organic content in the more distal outboard areas.

Overall, based on the present available data in the public domain, the best oil-prone source rock seems most likely to be present in the outer sub-basin and at the western edge of the inner sub-basin where it is less likely to be diluted with shelf-derived clastics. 1D basin modelling at several well and pseudo-well locations offshore Namibia and South Africa based on regional well-tied seismic surfaces, a continental crust rift temperature model and a Miocene heating event in the Orange Basin (Vema hotspot) support a Late Cretaceous oil generation on the western flanks with most of the kerogen converted to oil by the mid-Tertiary times.

This wider basin modelling study, now tied in with the oil window from the Venus discovery, indicates favourable burial history for oil expulsion in the outboard, not only for the Orange Basin, but in the Lüderitz and Walvis basins to the north along the equivalent fairway trend. Mapping the potential source kitchens and the discoveries' amplitude versus offset anomalies (AVO) will be essential to understanding the play fairways of the recent discoveries, and more importantly how each specific play type works.

Early exploration studies by the operator have focussed on demonstrating the presence, quality and maturity of the Aptian source rock (Kudu Shale) which has charged all the recent deep-water discoveries in the basin. Only one exploration well, Moosehead-1X has been drilled at the time of this report in the southern part of the east bounding block 2613 (PEL 87). Moosehead-1X was drilled by Brazilian company HRT in 2013, targeting a very large carbonate feature upon a regional structural high. While the well did not encounter commercial quantities of hydrocarbons it did confirm the presence of the Kudu Shale oil source formation and a thick and effective sealing formation immediately above thought to be Saturn-aged siltstones. The Kudu Shale is interpreted to be early mature for gas generation, indicating that the formation has been potentially generative for oil within PEL 87 (Figure 4.2.1).

The Moosehead-1 well, located 83 kilometres to the east of Block 2712A, proved 200 metres of the Aptian Kudu Shale (Figure 4.2.1). Figure 4.2.2 shows that the source rock (Kudu Shale) can be traced westwards from the Moosehead-1 well and across Block 2712A. Seismic images (Figure 4.2.3) show this source rock to pinch out to the west although the interval has been estimated to be at least 70 metres thick in the licence area.

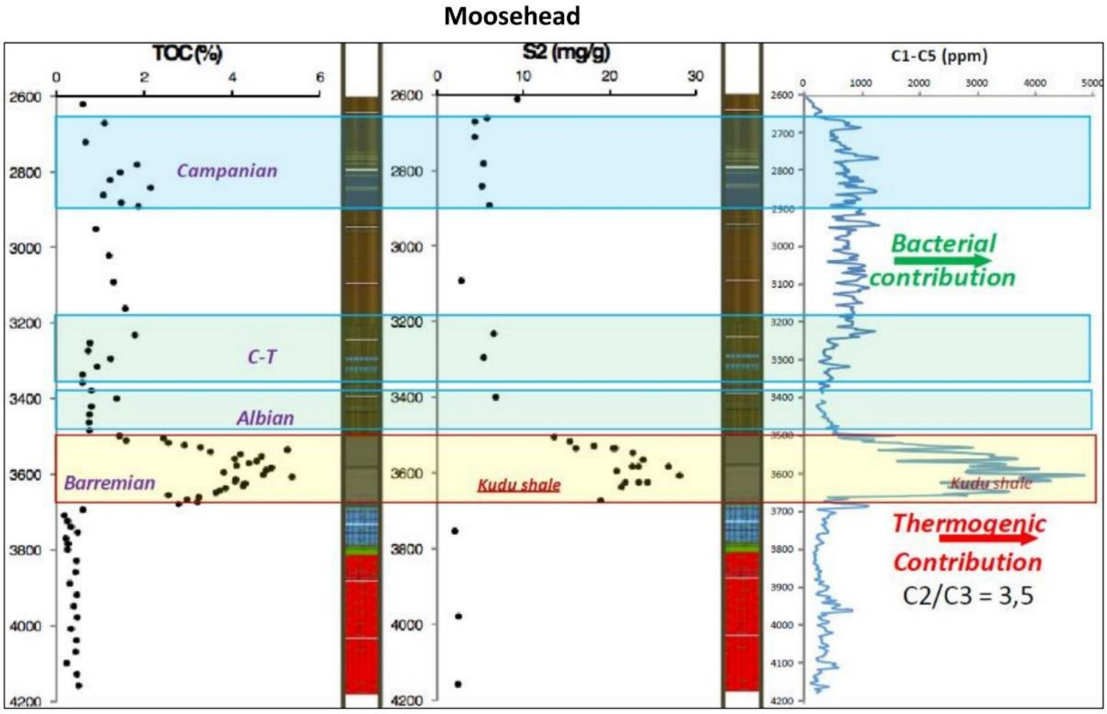

Figure 4.2.1 Kudu Shale (source rock) proven in the Mossehead-1 well (ref. Pioneer Oil and Gas – well data licenced by Westoil)

In Block 2712A, source rock maturity and presence are considered to be largely de-risked. The migration of hydrocarbons is likely to be eastwards with the source rocks dipping deeper to the west and lying directly on the oceanic crust as proven in the Venus discovery (Figure 4.2.3).

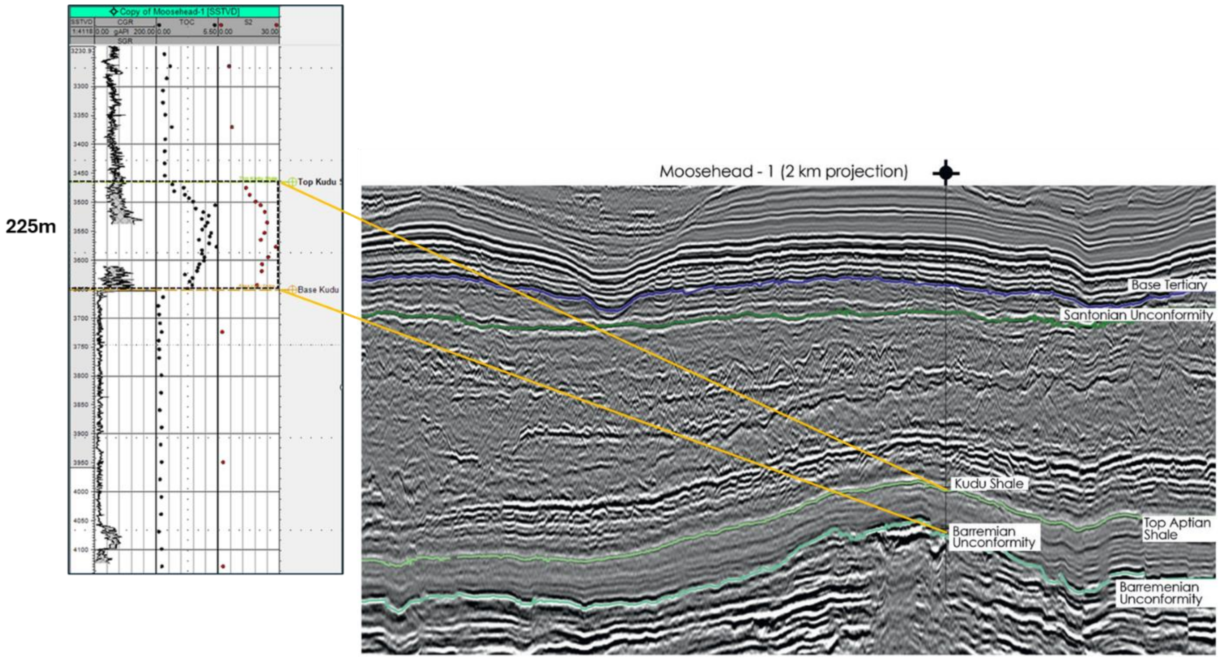

Figure 4.2.2 Seismic calibration of the Kudi Shale source rock in the Moosehead-1 well (ref. Pioneer Oil and Gas Consulting – well data licence from NAMCOR and seismic section from Eastwell D.et al 2018)

Considerable overburden thickness can be interpreted to the western side of Block 2712A in seismic line NAM-OB-2D-305 (Figure 4.2.4) and which would provide the right maturity levels required for oil generation. Pioneer have created source rock depth map (Figure 4.2.4) using different cases of documented rock densities and seismic velocities together with bottom hole temperatures extrapolated from known well data in the basin. Sediment thicknesses were estimated from the available seismic lines and the Orange Basin generally shows higher geothermal gradients in the order of 35 ^{0}C/km (Figure 4.2.5). Whilst there is limited overburden in some areas within the block, Pioneer have indicated that other sources of heat might have an influence, i.e heat from magmatic bodies could have also generated significant heat to mature the source rocks (Neumaier M et al.,2014). Pseudo maturity maps all demonstrate a positive distribution of the oil potential oil kitchens within Block 2712A and the modelling indicates that there is likely to be mature source rocks in both the south and north of the Block. Figures 4.2.6 and 4.2.7 for a cooler and hotter scenario respectively both show active source rocks are present over the block and are just entering the oil window (early mature stage) with oil generation having started.

Regional studies have confirmed the presence of satellite oil slicks over the ocean surface of Block 2712A coincident with migration pathways and the immediate area giving indications of a working petroleum system with mature source and charge (Figure 4.2.8). Migration is assumed to be in a westward's direction from a deep-water outboard kitchen area. Five different fetch areas have been identified by the operator and Pioneer (Figure 4.2.9) and potential generated hydrocarbon volumes have been estimated (Table 4.2.1). These fetch areas are believed by Pioneer capable of charging substantial volumes of hydrocarbons in possible traps in both the north and south of Block 2712A.

The recent discoveries in the southern part of the Orange Basin have now largely de-risked what was originally thought to be the largest risk in this deep-water play. It was always believed impossible to sufficiently heat a source rock which directly overlies oceanic crust. However, the gas content still remains a potential risk with some operators (Shell January 2025) referring to the presence of high gas to oil ratios (GOR) as a potential negative factor in any future development.

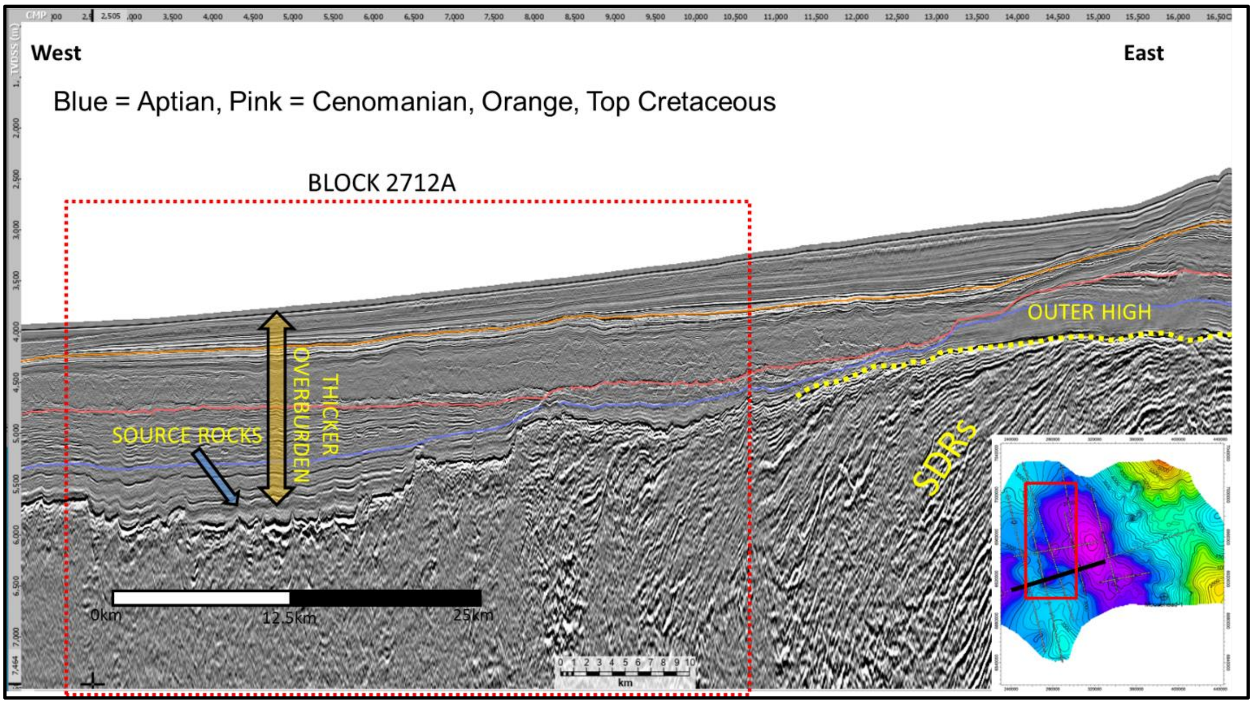

Figure 4.2.3 Typical west to east seismic line in depth showing the geological and structural character of deep-water sedimentation within Block 2712A (courtesy of TGS 2024 ref.Pioneer Oil and Gas Consulting)

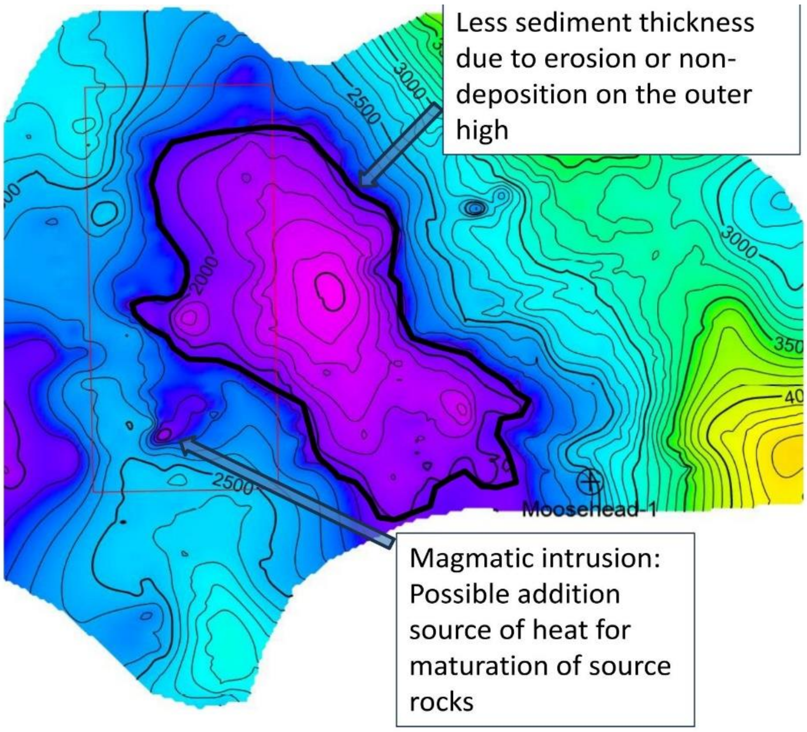

Figure 4.2.4 Indicative overburden depth map (from sea bottom to base of the drift) with a maximum seismic velocity of 2,700m/s ref. (Pioneer Oil and Gas Consulting)

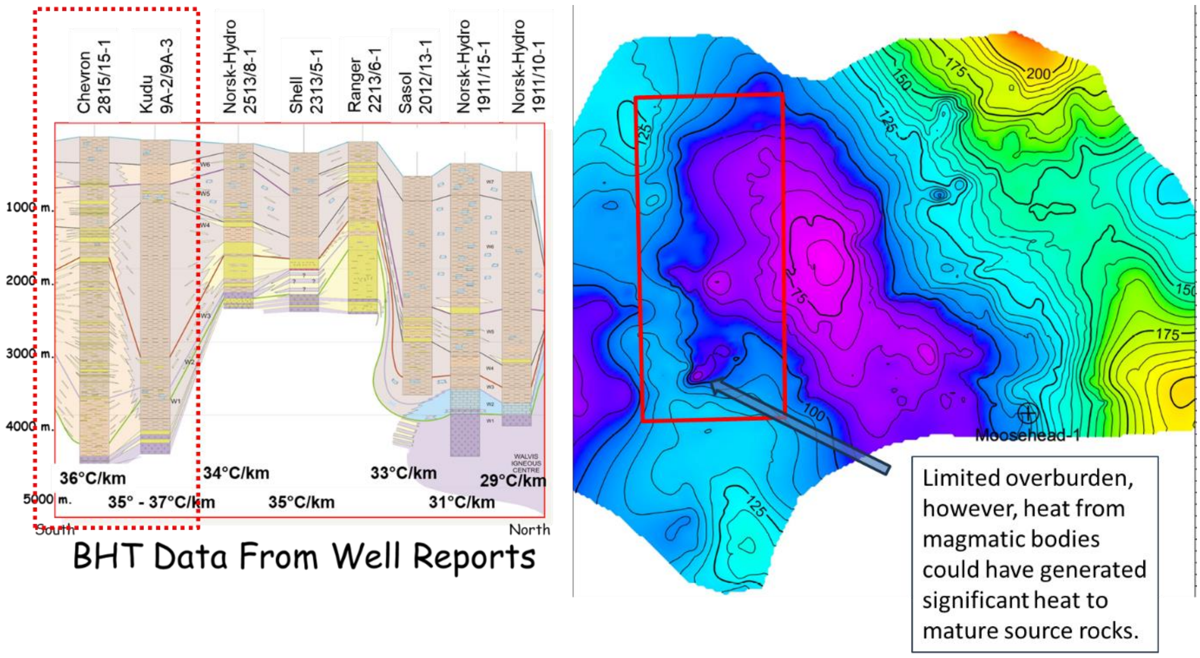

Figure 4.2.5 Predicted source rock thickness and distribution (Ref. Pioneer Oil and Gas Consulting)

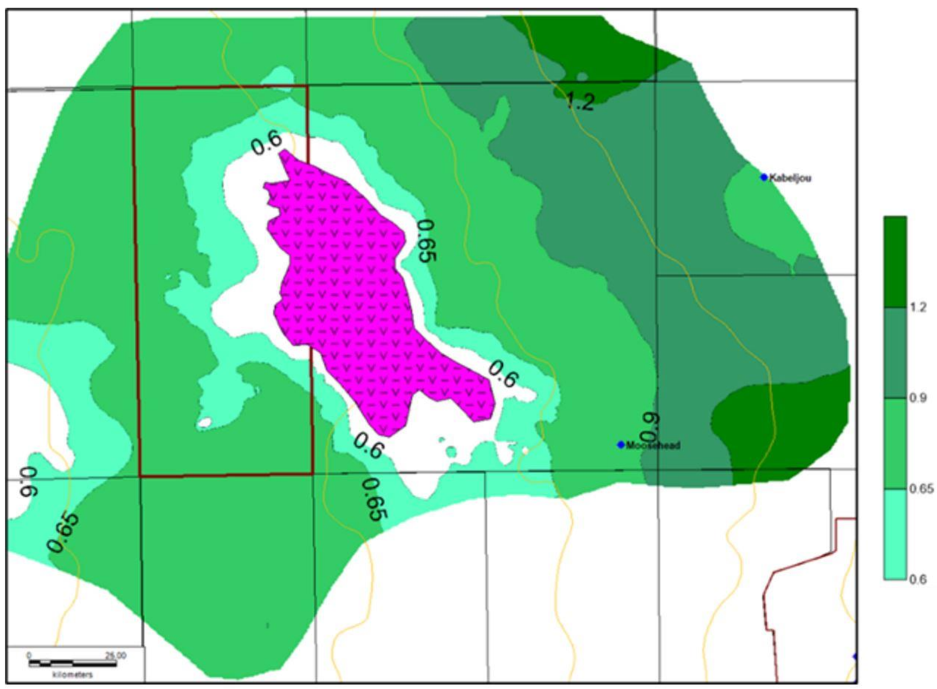

Figure 4.2.6 Calculated vitrinite reflectance (just within oil window) on a cooler temperature scenario (ref. Pioneer Oil and Gas Consulting).

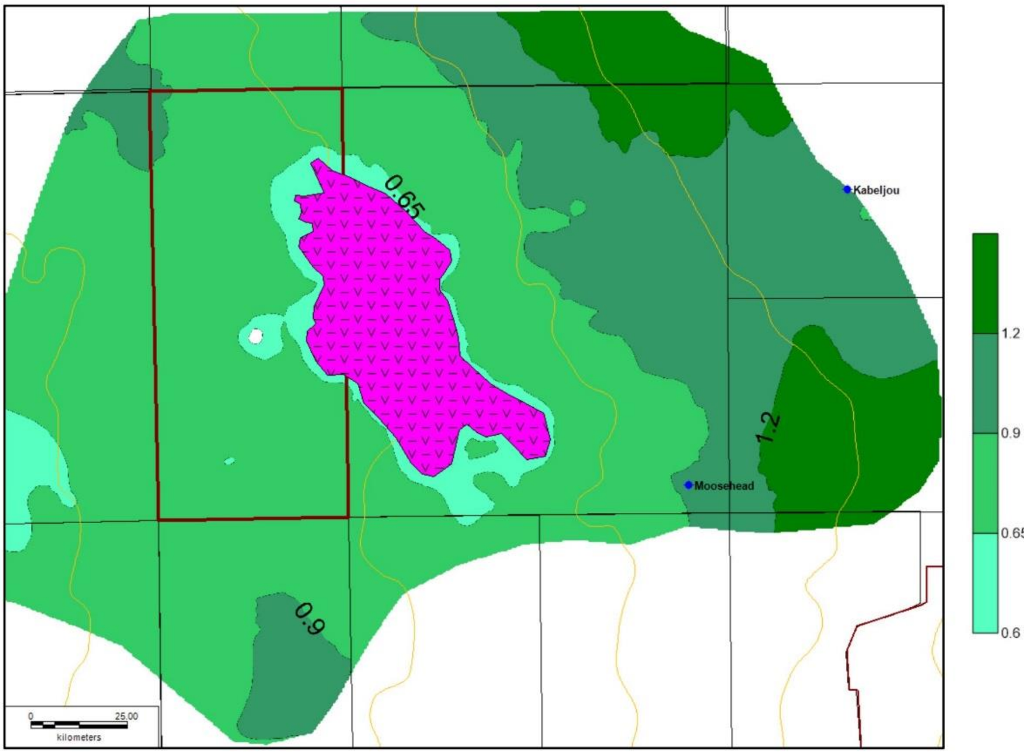

Figure 4.2.7 Calculated vitrinite reflectance (all within oil window) on a hotter temperature scenario (ref. Pioneer Oil and Gas Consulting)

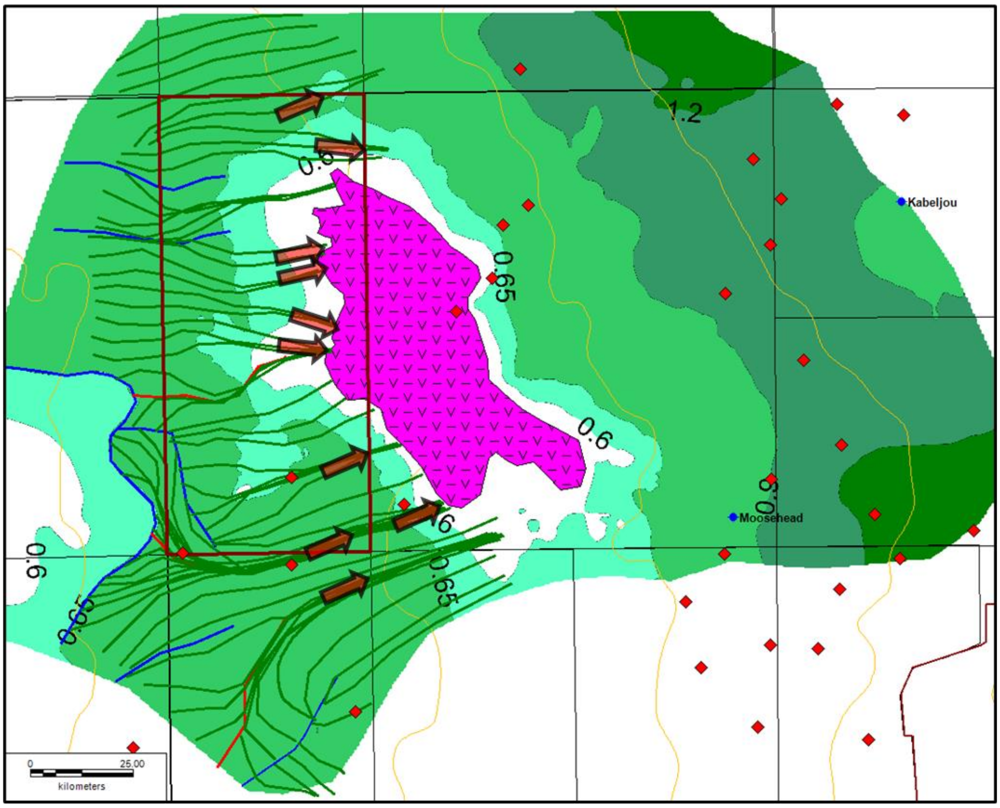

Figure 4.2.8 Satellite identified oil slicks (red) corresponding to westerly migration pathways (ref. Pioneer Oil and Gas Consulting)

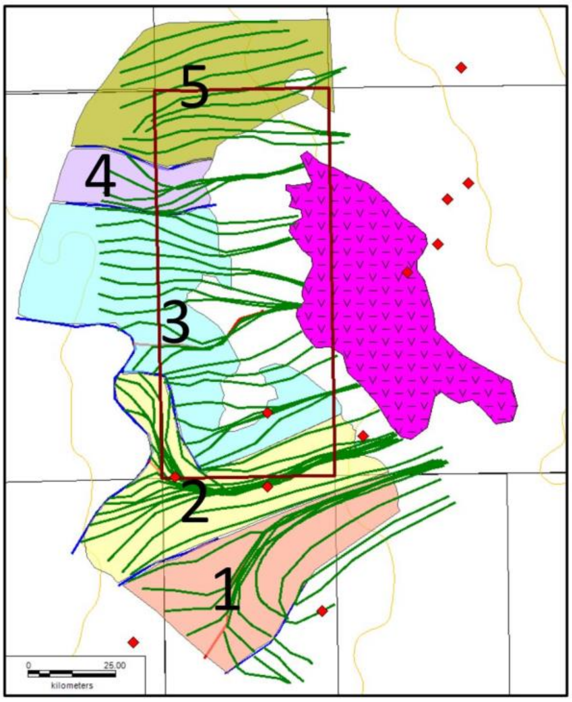

Figure 4.2.9 Fetch areas used by Pioneer Oil and Gas Consulting in the volumetric estimation of potential hydrocarbons generated

		70m		90m		110m	
Fetch area	Area (km2)	Oil expelled (mmbbl)	Gas expelled (bcf)	Oil expelled (mmbbl)	Gas expelled (bcf)	Oil expelled (mmbbl)	Gas expelled (bcf)
1	1787	27,698.50	57,720.10	35,561.30	74,160.50	43,602.80	90,600.90
2	2045	31,697.50	66,053.50	40,695.50	84,867.50	49,898.00	103,681.50
3	2879	44,624.50	92,991.70	57,292.10	119,478.50	70,247.60	145,965.30
4	598.5	9,276.75	19,331.55	11,910.15	24,837.75	14,603.40	30,343.95
5	2121	32,875.50	68,508.30	42,207.90	88,021.50	51,752.40	107,534.70
Total		146,172.75	304,605.15	187,666.95	391,365.75	230,104.20	478,126.35

Table 4.2.1 Potential volumes of hydrocarbons generated in different thicknesses of the Kudu Shale (ref. Pioneer Oil and Gas Consulting)

4.3 Reservoirs

The Orange Basin contains siliclastic deposits of varying maturity and reservoir quality. The reservoir quality is influenced by multiple factors, including sediment maturity, grain size, depositional environment, and secondary diagenetic processes.

The sediment maturity is considered to be the most important factor on reservoir quality in the basin with the occurrence of immature clastics coinciding with poorer reservoir characteristics. Some areas of the Orange Basin, particularly those associated with turbiditic and deltaic deposits, are reported to contain immature clastic sediments (e.g., arkosic sandstones and lithic-rich facies). These sediments tend to have a higher content of feldspar and rock fragments, leading to lower porosity and permeability compared to mature quartz-rich sands. Diagenetic processes, including chlorite cementation by carbonate and clay alteration can further reduce reservoir quality.

Higher quality reservoirs are also proven in the basin and comprise mature quartz-rich sandstones, particularly in deep water channel and fan systems. Some Cretaceous age turbidite sands have shown good reservoir potential, especially where secondary porosity has developed due to dissolution of feldspars and carbonates. The key controlling factors are (i) Provenance with the source of sediments directly affecting their mineral composition and maturity. (ii) Depositional environment as deep water fans tend to have better-sorted, higher-quality reservoirs, while deltaic systems may have more immature sediments with finer grains and higher clay content. (iii) Diagenesis - cementation and compaction play a crucial role in reservoir quality degradation. The key controlling factors are (i) Provenance - the source of sediments affects their mineral composition and maturity. (ii) Depositional environment - deepwater fans tend to have better-sorted, higher-quality reservoirs, while deltaic systems may have more immature sediments with finer grains and higher clay content. (iii) Diagenesis - cementation and compaction play a crucial role in reservoir quality degradation.

Therefore, while the Orange Basin does contain immature clastic sediments with poorer reservoir quality, it also has areas with higher-quality reservoirs, particularly in deep water turbiditic settings. These primary and secondary controls on reservoir quality have been reported in the southern Orange Basin in South Africa (Fadipe et al 2011) where the compositional maturity of the Lower Cretaceous Albian Sandstone decreases with depth and the grain angularity show a short transport distance from the source. In addition, the mineralogical and textural compositions demonstrated significant diagenesis due to high temperatures and depth of burial with the reservoirs being in a similar temperature and pressure regime as the source rocks. Fadipe found that mica and feldspar weathering gave rise to kaolinite which was followed by ductile deformation of detrital chlorite and formation of quartz overgrowths. The unrestricted movement of formation waters when the porosity and permeability was higher finally led to the formation of authigenic chlorite. This study of the A-W1 well samples in the South African part of the basin demonstrates that clay mineral alteration has played a major role in affecting the reservoir quality within the studied wells, leading to a dominance of silica and chlorite cements. The presence of chlorite within the reservoir intervals has resulted in its poor reservoir quality.

Whilst reservoir quality may be a significant risk in deeper areas with possible chlorite formation due to depth of burial, the area to the north of the Venus discovery towards Block 2712A may be characterised by both a lower heat flow and less immature volcanic clasts. To date, the reservoir presence and quality are the primary exploration risk in the deep water basin areas. Recent drilling results have demonstrated the importance of reservoir development and quality. The Tamboti-1X well drilled in 2024 on PEL 56 by TotalEnergies proved 85m of net reservoir section in lower quality Upper Cretaceous sands (also flow tested) and the Kapana-1X well drilled by Chevron and immediately adjacent to block 2712A also found poorer quality reservoir sands.

It is the reservoir quality combined with an absence of released well information which is considered to be the primary exploration risk. However, the seismic definition of channel bodies and geometry, although good, has been proven by the recent Kapana-1X and Tamboti-1X wells not to be sufficiently well understood to predict fairways of better reservoir quality. The absence of publicly available well data means that there is no understanding of the primary sedimentological factors or the post depositional diagenetic effects. Both primary reservoir quality issues as well as secondary diagenetic issues, possible related to clast immaturity giving rise to authigenic chlorite, have been publicly reported from recent deep water wells.

Block 2712A sits in the outer sub-basin seaward of the Outer High. The Outer High is clearly visible on the seismic (Figure 4.2.3) formed of the distinctive steeply dipping seaward flood basalts and mainly falling to the east of the basement ridge. However, this key seismic data has not been purchased at the time of this report and as such no conclusions can be drawn at this time without access to the data and the subsequent interpretation.

The Venus reservoir system in Block 2913B is thought to be directly sitting on top of the source rock which in turn rests on the oceanic crust. The main reservoir risk for Block 2712A is the potential for diagenetic cementation due to the high temperatures associated with the oceanic crust. For Graff and other equivalent finds, higher in the geological section, the problem of diagenetic alteration as well as gas occurrence may be less serious, as these are somewhat further away from the source rock and oceanic crust.

4.4 Hydrocarbon Play Types - Offshore Namibia

One of the main play types in the deep water outer sub-basin west of the Outer High basement ridge has been proved by the successful basin opener well, Venus-1X, which is shown in a SW-NE seismic dip line in Figure 4.4.1. The trapping mechanism of the Venus discovery is created by a basin floor fan fairway which onlaps onto the Outer High. The Outer High plays an important part in controlling reservoir and source rock distribution and deposition and is also responsible for generating other trapping configurations. Barremian-aged carbonates inboard were drowned out during the sag phase and formed carbonate platforms on the elevated Outer High.

It is likely that the Aptian reservoir sands in the Venus accumulation were sourced from the inboard basin in the east and transported across the carbonate platform on the Outer High and deposited in the outer sub-basin, ponding in the accommodation space down-dip. The Shell-operated Graff-1 discovery (Figure 4.4.2) is of Late Cretaceous age (possibly Campanian to Santonian) and is buried approximately 2.5 km below mudline. The trap appears to be a stratigraphic sub-thrust trap developed at the outboard extent of the Late Cretaceous toe-thrust structures – which developed due to episodic gravitational collapse along the margin. The Outer High has probably played an important role for this trap, acting as a backstop causing turbidite sands to pond east of the High. The Outer High also seems to control the westerly extent of the Late Cretaceous toe-thrust imbricates (Figure 4.4.2). There may be untested plays representing compressional toe-thrust structures of the Orange Basin’s gravitationally driven system and the large roll-over structures of the extensional domain inboard of the same gravity-driven system.

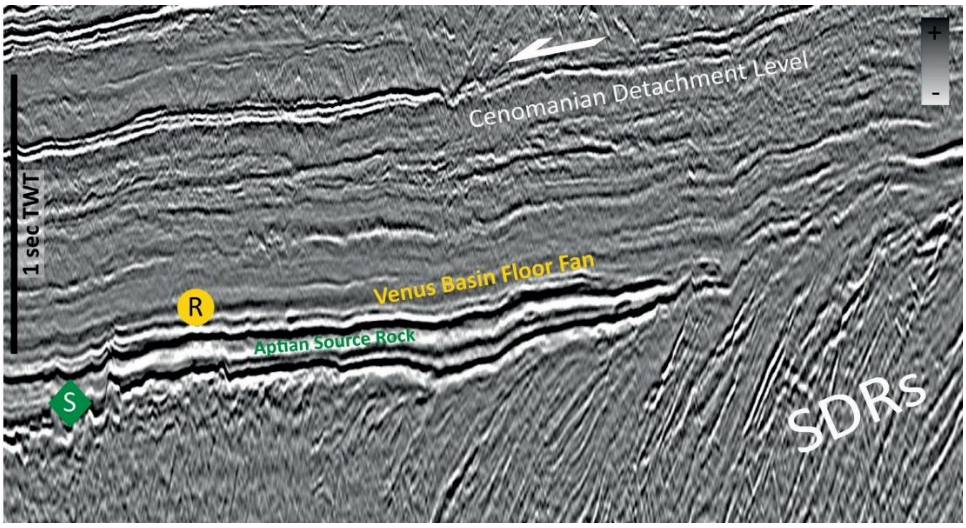

Figure 4.4.1 Southwest-Northeast dip line through the Venus structure (ref.TGS 2022)

Deep water floor fans/channels rest directly on top (or very close) of the matured Barremian-Aptian source rocks (Kudu Shale). The Kudu Shale acts as the most regional, continuous, oil-prone source rock in offshore Namibia. The Kudu shale has been drilled in Kudu wells, Moosehead, Wingat, Murombe wells. These deep water turbidite fans are immediately below the Outer High and would deposit sediments from the shelf area through channels (Figure 4.4.3).

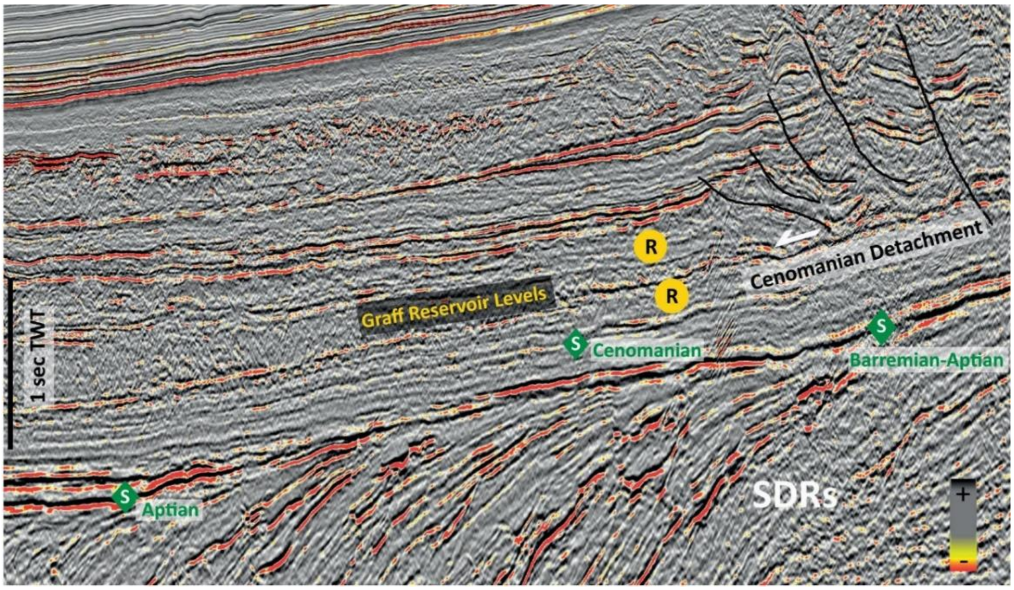

Figure 4.4.2 Southwest-Northeast dip line through the Graff discovery at the western end of the toe thrust system and the base of the collapse systems (ref. TGS 2022)

In Block 2712A, it is the outer sub basin which is of interest as it lies westward of the Outer High basement ridge. It is considered likely that future 3D seismic data over Block 2712A may demonstrate the presence and distribution of a similar deep water fan system that has been proven in the Venus discovery. It has been reported (Pioneer) that a review of the existing 2D seismic data suggests that a similar fan system to Venus may be present towards the southwestern part of the licence although this cannot be substantiated for this report. It is anticipated that any such turbidite fan systems, as in the Venus discovery, will lie directly on top of the prolific Kudu Shales which are solely responsible for the generation of hydrocarbons within the Orange basin.

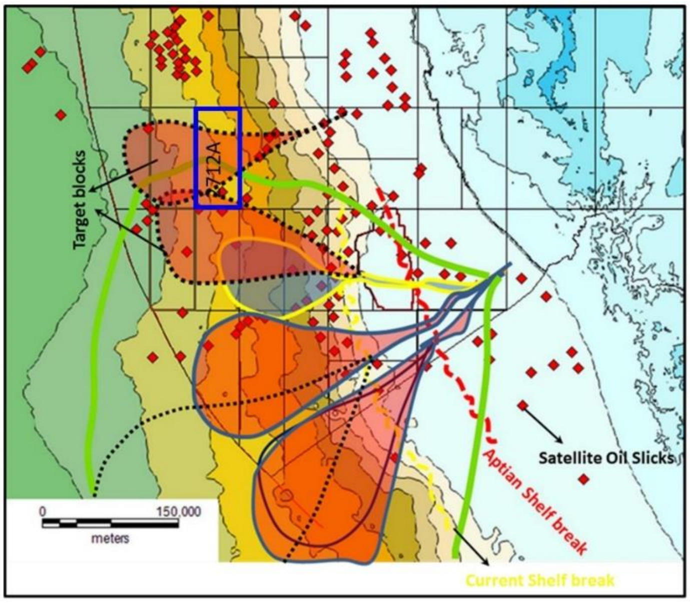

Figure 4.4.3 Schematic diagram of the Orange Basin deep water Cretacaeous turbidite fans (Supernova April 2025)

Venus lookalikes are likely to exist in other parts of deep water offshore Namibia and need regional mapping and maturity modelling of the underlying Barremian–Aptian and Cenomanian–Turonian source rocks outboard and inboard of the Outer High. It is considered that many prospective ponded sand bodies equivalent to the Venus trap type and Graff lookalikes will be found along the length of the Namibian and South African outboard fairway, surrounded by Aptian source rock, which is likely in the oil window. From the presently available data set, Block 2712A appears to be in an optimum prospective location and may represent a potentially lower temperature 'Venus play' with reduced gas risk (more oil prone) and potentially reduced chlorite cementation.

The overall regional setting and proximity to proven deep water hydrocarbon bearing structures indicates the potential for the presence of both reservoir sands and traps in Block 2712A. However, the actual presence of such features in Block 2712A can only be confirmed after a complete interpretation of the existing 2D legacy seismic data is made.

In summary, the main proven play type is comprised of deep-water fan systems throughout northern Namibia's Orange Basin and this is the main target for Namlith's licence.

▪ **Source rock**: Aptian shales (Kudu shale) are the most regional, continuous, oil-prone source rocks offshore Namibia and has been drilled in Kudu wells, Moosehead, Wingat, Murombe wells and potentially the Venus-1. The presence of light oil found in the Graff-1X also indicates good maturity of source rocks and charge of upper Cretaceous reservoirs. The best oil-prone rock most likely in outer sub-basin (Block 2712A) and western of the inner sub-basin where it's less likely to be diluted with shelf-derived clastics. Most of the eastern half of the blocks are believed to be within the early oil windows, considering geothermal gradients of up to 33-35deg/km

▪ **Reservoir**: Deep water floor fans and channels rest directly on top of (or very close to) the matured Barremian-Aptian source rocks (Kudu shale). Reservoir source inboard basin to the east, transported across carbonate platform, ponded in outer sub-basin in accommodation space such as seen in Block 2712A. Similar systems were drilled in Venus-1 and Graff-1. Both wells confirmed the presence of reservoirs and light oil charge

▪ **Migration:** Transform faults and related fractures visible over Block 2712A may represent good migration pathways from source to reservoirs/traps.

5.0 Regional Analogue Data

The recent Venus and Mangetti light oil discoveries made by Total Energies and Qatar Energies are to the south of block 2712A in the outer sub-basin outboard of the Outer High and have given a significant interest in the prospectivity of the deep water outboard area (ca. 3,000 metres) of the Orange Basin, offshore Namibia. These discoveries are considered the best analogues for the exploration potential on block 2712A due to their similar deep water setting and their location in the outer sub-basin.

There are no well penetrations west of the Kapana-1X (Chevron) and the Mangetti (TotalEnergies) wells in the deep-water setting that characterises the 2712A block area. The Outer High plays an important role in controlling reservoir and source rock distribution and it also acts as a focus for migration and is responsible for creating many of the plays seen in the TotalEnergies and Shell acreage and is expected to be as important in Block 2712A.

The TotalEnergies operated Venus discovery is part of a basin floor fan fairway sitting on Aptian source rock in the outer sub basin, west of the Seaward Dipping Reflectors (SDR's) basin high and located outboard of the Outer High (Figure 4.4.1 and Figure 4.4.2). The Early Cretaceous reservoir sands are likely sourced from the East and transported across the carbonate platform on top of the Outer High. The Venus basin floor fan sands onlap the Outer High and 84 metres of net pay with reported light oil has been reported.

The similarity of the structural setting between the Venus proven play to the south and Block 2712A is shown in Figure 5.1. The main target play type in Block 2712A is deep water Cretaceous fan sands which overlie the Barremian to Aptian source rocks (Kudu Shale). Within the block, it is expected that similar fans will be recognised and may give rise to multiple leads following a detailed seismic interpretation of all the available 2D data. Source rock maturity and presence is considered less of a risk. Figure 5.1 is a schematic section which shows that the migration of hydrocarbons would be anticipated as being eastwards with the source rock expected to be dipping deeper to the west and lying directly on the oceanic crust as proved in the Venus-1X well.

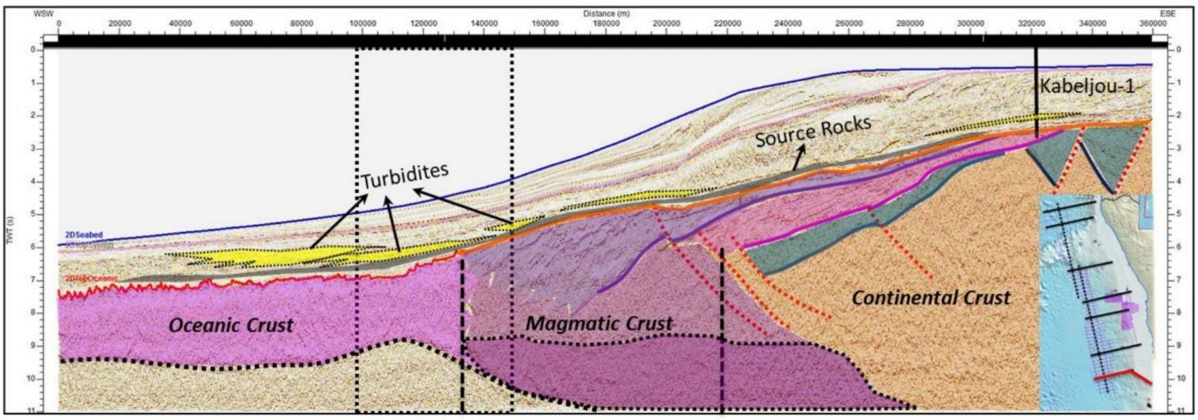

Figure 5.1 Schematic cross section showing the projected position of block 2712A (ref. Pioneer Oil and Gas Consulting)

6.0 Permit History

The ownership history of Block 2712A (PEL 107) has been provided by Namlith to 05 Management and has not been independently verified as part of this report.

On 26th January 2023 the Government of the Republic of Namibia through the Minister of Mines and Energy entered into a Petroleum Agreement with Vena Gemstones and Mining (Pty) Ltd ("Petrovena") and Namcor Exploration and Production (Pty) Ltd ("Namcor"). On July 19, 2023 the Government of the Republic of Namibia through the Minister of Mines and Energy issued Petroleum Exploration Licence No. 107 ("PEL 107") granting an 85% operated working interest to Petrovena and a 15% working interest to Namcor. Block 2712A (PEL 107) is a licence comprising 5,477 km^2, located in the Orange Basin, offshore Namibia ("Block 2712A"). PEL 107 was awarded pursuant to the Petroleum (Exploration and Production) Act, 1991 (Namibia) and governed by a Petroleum Agreement entered into by Petrovena, Namcor and the Government of the Republic of Namibia. The PEL 107 Licence, entitles the Company to apply for and receive, subject to Namibian government approval, a 25-year production licence upon successful discovery of an economically viable resource.

On 15th February 2024, the Ministry of Mines and Energy approved the transfer of 70% of Petrovena's interest and the operatorship to Westoil Limited with the remaining 30% interest in PEL 107 being owned by Petrovena (15%) and Namcor (15%). In December 2024, Namlith Resources Corp purchased a 12.5% interest in Westoil Limited ("Westoil"). On 31st January 2025, Supernova Metals Corp ("Supernova") acquired Namlith Resources which became a wholly owned subsidiary of Supernova.

7.0 Licence Activity to Date

The operator, Westoil, is intending to undertake geological and geophysical studies, including regional interpretation of the petroleum system of the Orange Basin once the data has been licenced. There is a regional grid of Multi-Client 2D seismic data acquired in different surveys from 2006 to 2019 (Figure 3.2.3) and it is recommended that this data are licenced to get a better understanding of the potential prospectivity and allow the detailed planning and optimisation of a 3D seismic data acquisition multi-client campaign in 2025. This report has relied on early reviews provided by Pioneer Oil and Gas Consulting of the available legacy seismic to provide a preliminary overview of the significant geological features within the licence area and that the elements of a working petroleum system could be present in 2712A with several potential fans being a focus of future exploration and data acquisition. However, 05 Management has not had access to any of the existing 2D seismic data so has been unable to independently verify these observations.

The future interpretation of the legacy data will provide structural definition of the block and identify any features such as transform faults which may assist migration. It is also expected that the existing seismic data may give an understanding of the regional structure and the juxtaposition of Upper Cretaceous fan reservoirs with the mature Aptian source rock (Kudu Shale). Interpretation of the legacy seismic data should also provide structural definition of the block and possibly identify the transform fault boundary between the two sedimentary basins – the Orange and Luderitz basins which appears to cross the block (Figure 3.1.1).

Pancontinental Energy, the Operator of PEL 87 acquired an extensive 3D seismic survey in 2023 (6,593 km^2) to the east and immediately adjacent to Block 2712A (PEL 107) which has reportedly shown that the 3D high resolution seismic dataset allows an understanding of the regional structure and the juxtaposition of Upper Cretaceous fan reservoirs with the mature Aptian source rock (Kudu shale). Several different potential hydrocarbon play types have also been identified, some of which exhibit apparent Amplitude vs Anomaly (AVO) effects. AVO studies can, in some cases, help the de-risking in hydrocarbon exploration drilling, and it is has been reported that the Venus and Mopane discoveries exhibit AVO anomalies as a result of hydrocarbon saturated porous reservoir sands.

Westoil has reported that it is presently planning to acquire a minimum of 3,000 km^2 of 3D seismic data in 2025 in the initial exploration period. TGS has proposed a large multiclient seismic programme across the Orange Basin and up into the Walvis Basin which includes both 2D and 3D over Blocks 2712A and 2812 (Supernova Presentation April 2025). It is understood from Namlith that Westoil intends to participate in this programme.

8.0 Resources

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGE Handbook), Block 2712A is not considered to have sufficient geological, geophysical, or engineering data to support the estimation of prospective resources as defined in Form 51-101F1.

The estimation of prospective resources requires a reasonable level of confidence in the presence of a working petroleum system, including source rock maturity, migration, reservoir quality, trap integrity, and closure. At this time, the available data for Block 2712A is insufficient to define the presence, extent, and quality of reservoir formations and to confirm valid structural or stratigraphic traps in the form of either a lead or a prospect. In addition it is presently impossible to confirm the existence and effectiveness of a migration pathway and assess the presence of a source kitchen and hydrocarbon charge. Additionally without either an interpretation of the available existing 2D legacy seismic data or subsequent acquisition of a closely spaced 3D seismic survey, it is impossible, at this time, to provide an assessment of any prospective resources net to Namlith.

Therefore, any attempt to assign prospective resource volumes would be speculative and not in compliance with the principles outlined in the COGE Handbook. Future exploration activities, including 2D seismic interpretation and the planning, acquisition and interpretation of future 3D is seismic is considered necessary to reduce geological and geophysical uncertainties and allow the definition of leads and prospects and determine whether prospective resources can be estimated in accordance with regulatory requirements.

This opinion is made in compliance with Section 5.9(2) of NI 51-101, which requires that any estimates of prospective resources must be based on sufficient reliable and supportable data.

9.0 Commercial Aspects

9.1 Regulatory Framework

Namibia's offshore basin is divided into numerous exploration blocks (Figure 9.1.1) which are really defined geographical areas offshore where petroleum exploration can be undertaken. Companies who apply for the exploration rights in these blocks have a legally binding agreement (“Petroleum Agreement’’) with the Namibian government. This petroleum agreement defines the terms and conditions under which the hydrocarbons exploration and potential production activities will be carried out. This agreement typically includes the applicable fiscal terms (royalties, taxes, production sharing, etc.), work obligations and any local content or training requirements.

After the grant of a petroleum agreement, a petroleum exploration licence (PEL) is the official government authorisation awarded to a company or consortium giving the exclusive legal right to explore for hydrocarbons within one or more blocks. The PEL is issued by Namibia's Ministry of Mines and Energy under the Petroleum (Exploration and Production) Act and together with the petroleum agreement outlines the conditions for exploration, including the duration of the licence (usually up to 10 years, with renewals), work commitments (seismic surveys, drilling etc.), financial obligations (fees, royalties, etc.) and environmental and social responsibilities.

Namibia has a well-defined regulatory framework governing petroleum exploration and production, designed to attract investment while ensuring responsible resource management. The framework is based on laws, policies, contracts, and regulatory institutions that oversee offshore oil and gas activities.

Legal and Policy Framework

The primary laws and policies governing petroleum exploration in Namibia include:

(i) The Petroleum (Exploration and Production) Act, 1991 (Act No. 2 of 1991) is the key legislation regulating petroleum exploration and production in Namibia. It provides the legal basis for granting Petroleum Exploration Licences (PELs), Petroleum Production Licences (PPLs), and Petroleum Retention Licences (PRLs) and the terms for royalties, taxation, and production-sharing arrangements together with environmental and safety regulations for exploration activities.

(ii) The Model Petroleum Agreement which serves as the standard template for negotiations between the Namibian government and oil companies. It outlines the fiscal terms (royalties, taxes, profit-sharing) and obligations for local content and corporate social responsibility (CSR).

(iii) Petroleum Income Tax Act, 1991 (Act No. 3 of 1991) which establishes the tax regime for petroleum operations with a tax rate of 35% on taxable income from petroleum activities.

(iv) Environmental Management Act, 2007 (Act No. 7 of 2007) which requires Environmental Impact Assessments (EIAs) before any petroleum exploration activities and provides for environmental monitoring and reporting.

(v) Namibian Upstream Petroleum Local Content Policy which promotes local industry participation by requiring companies to source goods and services from Namibian suppliers, setting employment targets for Namibians in petroleum projects and supporting training and skills development in the oil and gas sector.

Licencing Awards and Process

The Namibian government, through the Ministry of Mines and Energy and the Namibian Petroleum Commission (Namcor), issues several different types of petroleum licences.

(i) Petroleum Exploration Licence (PEL) which grants exclusive rights to explore for oil and gas within a defined offshore or onshore area and is valid for four years initially, with two possible renewals of two years each and requires minimum exploration commitments (seismic studies, drilling, etc.).

(ii) Petroleum Retention Licence (PRL) is granted when a company discovers oil or gas but needs additional time for feasibility studies and is valid for up to five years (renewable).

(iii) Petroleum Production Licence (PPL) is granted if a commercial discovery is made and the operator wants to develop the field and is valid for 25 years, with a possible 10 year renewal. Royalties and taxes will be payable.

Companies apply for a PEL through the Ministry of Mines and Energy, providing a work programme financial guarantees, and environmental plans. Following an acceptance of the application, the company negotiates a Petroleum Agreement with the government and once approved, the licence is granted.

9.1 Fiscal Regime

Namibia uses a combination of royalties, corporate income tax, and additional profit tax to generate revenue from petroleum exploration.

- Royalties**:** 5% of gross production revenue.
- Corporate Income Tax**:** 35% on taxable profits.
- Additional Profit Tax**:** A sliding scale tax applied if the project achieves high profitability.
- State Participation**:** Namcor, the state oil company, may take an equity stake in petroleum projects.

In Namibia, all rights in relation to the exploration for, the production and disposal of, and the control over petroleum vest in the State. The Petroleum (Exploration and Production) Act 2 of 1991 (Namibia), together with the Petroleum (Taxation) Act 3 of 1991 (Namibia) are the principal laws regulating the granting and transfer of petroleum licences to explore for and produce petroleum within the Republic of Namibia. Prior to a petroleum licence being granted, the Petroleum (Exploration and Production) Act 2 of 1991 (Namibia) requires that the Namibian Minister of Mines and Energy enter into a petroleum agreement with the licence applicant containing the terms and conditions applicable to such licence and possible future licences, including production licences. On 26th January 2023, the Minister of Mines and Energy entered into the Petroleum Agreement with Petrovena, resulting in Namlith acquiring an 8.75% indirect ownership in the Namibia Licence through their 12.5% ownership in Westoil.

On the 22nd March 2025, it was announced that with immediate effect, the management of Namibia's oil and gas sector will directly fall under the Office of the President and not, as previously, under the Ministry of Mines and Energy in a move aimed at maximising national benefits from the emerging industry. It is unclear at this time how this policy change will directly impact the management of existing petroleum agreements such as PEL 107.

Under the Petroleum Agreement, Petrovena was granted an 85% working interest in Block 2712A, with NAMCOR holding the remaining 15% working interest. The key terms of the Petroleum Agreement are summarized below.

9.2 Exploration Periods

The Petroleum Agreement for Block 2712A covers an eight-year exploration work programme subdivided into three sub periods with defined minimum expenditure commitments.

Initial Exploration Period (4 years, subject to possible one-year extension on ministerial approval)

Phase 1 - January 2023 to January 2026 (3 years) with the following work commitments:

Geological and geophysical studies on the licence area, including a regional interpretation of the petroleum system of the Orange Basin.

Purchase and interpretation of the existing 2D seismic data within the licence area and immediate surrounding licences.

Acquisition of a minimum of 3,000 km^2 of 3D seismic data.

Processing and interpretation of the new 3D seismic data.

Complete in-depth seismic studies such as attribute analysis and AVO.

Prospect evaluation, resource estimate and prospect ranking.

Decision to drill one exploration well and enter Phase 2 or drop the licence.

Phase 2 - January 2026 to January 2027 (one year) with the following work commitment

Drill 1 exploration well to a total depth as agreed with Namcor and the Ministry of Mines and Energy

Minimum expenditures for the Initial Exploration Period, as set out in the Petroleum Agreement, of total US$ 12,000,000 for the Phase 1 and US$ 50,000,000 for the Phase 2. Additionally, the Company is required to spend US$ 300,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibian citizens. This training obligation is structured with US$ 210,000 being paid to the Namibian Petroleum Training and Educational Fund and the remaining US$ 90,000 is to be paid in connection with the in- house training in the field of oil and/or gas exploration.

First Renewal Exploration Period (2 Years, subject to possible one-year extension)

Post drill data analysis

Drill 1 exploration well.

Minimum expenditures for the First Renewal Period, as prescribed by the Petroleum Agreement, total US$ 50,000,000. Additionally, the Company is required to spend US$ 300,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibian citizens, of which US$ 210,000 is to be paid to the Namibian Petroleum Training and Educational Fund and the remaining US$ 90,000 is to be paid in connection with the in- house training in the field of oil and/or gas exploration.

Second Renewal Exploration Period (2 Years, subject to possible one-year extension)

Post drill data analysis.

Drill 1 exploration well.

Minimum expenditures for the Second Renewal Period, as prescribed by the Petroleum Agreement, total US$ 50,000,000. Additionally, the Company is required to spend US$ 300,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibian citizens, of which US$ 210,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$

90,000 is to be paid in connection with the in-house training of Namibians in the field of oil and/or gas exploration.

Other Material Provisions

The Company is required to pay to the Government of Namibia an annual licensing fee ranging from NAD$ 60 to NAD$ 150 per km^2 of the Namibia Licensed Property, depending on the applicable stage of exploration. Should the Namibian Minister of Mines and Energy grant a production licence over any part of the Namibia Licensed Property (as further described below), the annual licensing fee will increase to NAD$1,500 per km^2 to which such production licence relates.

In accordance with the Petroleum Agreement, the Company must relinquish 50% of the exploration area covered by the Namibia Licence at the end of the Initial Exploration Period (19th July 2027). In determining the relinquished area, any areas of the Namibia Licensed Property that have been identified as potentially productive are excluded from the relinquishment requirements.

In the event the exploration work at the Namibia Licensed Property leads to the discovery of an economically viable petroleum reservoir, the Company may, pursuant to the terms of the Petroleum Agreement, make an application for a production licence. Within six months after making such application, subject to the provisions of the Petroleum Act (Namibia), the Namibian Minister of Mines and Energy may grant to the Company a 25- year production licence. The Company is required to pay to the benefit of the Government of Namibia on a quarterly basis, a 5% production royalty based on the market value, as determined in accordance with the provisions of the Petroleum Agreement, of any natural gas or crude oil produced under a production licence granted pursuant to the Petroleum Agreement. An incremental three-tiered Additional Profits Tax (“APT”) is charged on the after-tax net cash flow from petroleum operations in the Namibia Licensed Property. Exploration, development and operating expenditures, as well as royalty and corporate income tax, are all fully deductible in the year they are paid in the computation of the APT net cash flow for the year. APT will only be paid if the petroleum operations in the Namibia Licensed Property earn an after-tax real (i.e. inflation-adjusted) rate of return of 15%. The second and third tiers of APT become payable once the profitability level exceeds 20% and 25% respectively. The first-tier rate of APT is established in the legislation (through a formula) at 25%. The incremental second and third tier APT rates are determined in the Petroleum Agreement, and in the case of the Company, are 30.5% and 32.5%, respectively.

9.3 Work Commitments and Work Programme

The operator, Westoil, has not yet licenced any legacy multi-client 2D seismic data (Figure 3.2.3) over Block 2712A. It is also recommended that additional multi-client 2D seismic data in both Block 2712A and the surrounding blocks is also purchased in order to be able to develop an understanding of the structuring and anticipated slope fans with line tie backs to the south near the existing discoveries. Following a detailed interpretation of this 2D seismic data which is a Phase 1 work commitment, it will then be possible to plan the optimum acquisition grid for the initial exploration period commitment of 3,000 km^2 of 3D seismic data later in 2025 under a multi-client agreement reportedly under negotiation with TGS (Source Namlith). 05 Management has not seen any documentation or details of the time schedule and the proposed grid which is understood to include both 2D and 3D seismic data over Block 2712A.

An EIA is required to be submitted prior to acquiring a 3D seismic survey and needs approval from the Ministry of the Environment. There is also a short weather window due to the sea state in which such surveys are acquired which is in the summer months between December and March. Given the need for the acquisition of the available data and a regional 2D interpretation followed by the 3D seismic planning and getting EIA clearance, it is envisaged that Westoil, as block operator, may need to apply for a one year extension in case the multi-client programme is either delayed or fails to get enough sponsors to underwrite the acquisition programme or does not include Block 2712A.

10.0 Declarations

10.1 Terms of Engagement

This report, any advice, opinions, or other deliverables are provided pursuant to the engagement letter agreed to and executed by 05 Management and Namlith (100% subsidiary of Supernova Metals) in March 2025.

This report has relied solely upon data and information from Westoil Limited and Namlith Resources Corp. and also Pioneer Oil and Gas Consulting supported by any information already in the public domain.

10.2 Qualifications

05 Management is an independent oil and gas advisory firm. All of the 05 Management and Pioneer Oil and Gas Consulting staff engaged in this assignment are professionally qualified geoscientists and all have in excess of 20 years relevant experience. 05 Management was founded in 2005 to provide independent advice to companies associated with the both the oil and gas industry and natural resource exploration. Since inception, 05 Management has completed numerous assignments worldwide for investment banks, funds, governments, oil and gas and resource companies. 05 Management has extensive experience throughout Africa giving it valuable insights into the petroleum systems and resource settings.

The preparation of this report has been managed by Mr Christopher Pitman who is a director of 05 Management. Mr Pitman is a Fellow of the Geological Society of London (FGS) and holds a B.Sc (Hons) (Geology), University of Wales (Aberystwth), 1979, and an M.Sc (Sedimentology), Reading University, 1982. Mr Pitman has over 40 years' experience in the sector and is a qualified reserves auditor and technical expert who is independent of the reporting issuer (Supernova) for the purposes of the Canadian Securities Exchange (CSE).

10.3 Standard

Any reserves and resources would be reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

10.4 Limitations

The evaluation of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

This report, due to the early stage of exploration in the Orange Basin, and in Block 2712A has only considered the technical factors and risks in the exploration for hydrocarbons. The absence of any commercial decisions or a FID (Final Investment Decision) by any of the Operators such as Shell, Total Energies and Galp Energia means that no comments on the potential commerciality of any discoveries or analogue play types can be made at the time of this report.

10.5 Independence

05 Management can state that it is entirely independent with respect to Namlith, Supernova Metals and Westoil and confirms that there is no conflict of interest with any party or shareholder involved in the assignment. The independence of 05 Management is in full compliance with all the definitions outlined in Section 1.1 of the NI 51-101. Furthermore, 05 Management, as the reporting entity, has not previously worked for any of the above parties prior to this report in a consulting or advisory role. Pioneer Oil and Gas Consulting has, however, undertaken consultancy studies for Petrovena including attendance in the Namcor data room and therefore cannot be considered independent under Section 1.1 of the NI 51-101. Additionally Pioneer have disclosed that they intend to enter into a long term consultancy agreement to provide technical geological and geophysical services to Westoil. In this report, Pioneer have solely provided technical interpretation and regional knowledge upon which 05 Management has relied upon to give an independent opinion of Namlith's assets.

Under the terms of engagement between 05 Management and Namlith/Supernova Metals, 05 Management (and Pioneer) will receive agreed professional fees, with no part of the renumeration contingent on the conclusions reached, or the content or future use of this report. Except for these fees, 05 Management has not received and will not receive any financial or other benefit whether direct or indirect, in connection with the preparation of this report.

The 05 Management staff involved in the preparation of any data and subsequent interpretations in this report can confirm that they do not have any material interests in Namlith, Supernova, Westoil or in Block 2712A (including working interest partners) described herein.

10.6 Copyright

This document is protected by copyright laws. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of 05 Management.

10.7 Authorisation for release

This Report is authorised for release by Mr Christopher Pitman, 05 Management Director, dated 25th April 2025.

Christopher N Pitman

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