ARA Petroleum Tanzania

Revised Resource Potential – Post 3D Seismic

Mtwara Licence – Ruvuma PSA

February 2024

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1. EXECUTIVE SUMMARY

The Mtwara Licence is operated by ARA Petroleum Tanzania Limited ("APT") (75%) with partner Ndovu Resources Limited (25%), a wholly-owned subsidiary of Aminex PLC (LON:AEX). The Licence is situated onshore Tanzania 25km from established production at Mnazi Bay (**Figure 1**). Exploration of the Mtwara Licence has, to date, resulted in the discovery of significant gas resources associated with the Ntorya-1 (2012) and Ntorya-2 (2017) discovery wells ("Ntorya Discovery"). A new 338 km^2 3D seismic survey ("Ruvuma 3D") was acquired in 2022 by APT with the aim of better defining the extent of the Ntorya Discovery prior to further appraisal drilling and approval of a field development plan to target near-term scalable production and receipt of positive cash flows. The interpretation of the Ruvuma 3D has significantly reduced uncertainty regarding the size of the Cretaceous aged Ntorya turbidite fan, the continuity of reservoir sands away from the existing wells and has helped to optimise the targets for planned appraisal wells (e.g. Chikumbi-1). In addition, the Ruvuma 3D has revealed significant exploration upside, resulting in a revised exploration portfolio containing a range of potential targets, some of which may be stacked, allowing targeting of multiple levels in a single well. A summary of the new portfolio is provided in **Table 1**.

A seismic inversion, performed by Ikon Geoscience, calibrated to the existing wells and the new Ruvuma 3D seismic dataset, focused on further derisking the lateral continuity of the main Ntorya reservoir. Static geomodelling based on the Ikon inversion has resulted in the definition of a higher confidence discovery outline area extending to an area of ca 75km^2. This area now yields a revised and matured "Development Pending" unaudited Contingent Resource estimate of 3.45 TCF Gas Initially In Place (GIIP) with associated recoverable condensate of ca 20 MMbbls. This new volumetric estimation represents a near two-fold increase on the existing audited Pmean GIIP of 1.87 TCF quoted in the Competent Person's Report prepared by RPS Energy in 2018. It is hoped that the planned Chikumbi-1 appraisal well will confirm both the geological model, the existence of additional gas charged sandstones in a shallower Unit 3 reservoir and enable a further upward revision of resource estimates.

Development activities are ongoing, and the first gas production is targeting up to 60 MMscf/day from Ntorya-1, Ntorya-2, and Chikumbi-1 via a new spur line from Ntorya to the Madimba Gas Processing Facility and onward through the existing 36" gas pipeline to industrial customers in Dar es Salaam. Tanzanian authorities have indicated that the spur line will be completed by the first half of 2025.

Contingent Resources will be matured to Reserves upon formal development approval. Further successful appraisal and development wells are expected to significantly increase production, commensurate with the enlarged gas volumes.

Considerable newly identified exploration potential is noted in plays ranging in age from Miocene to Jurassic, Pre- and Post-rift. Large structural and stratigraphic traps have the potential to host gas and oil accumulations including, *inter alia*, a large untested mass transport complex prospect ("MTC") which, in terms of structure and depth, closely resembles several of the large-scale offshore accumulations which await development. Underexplored Jurassic potential is indicated in the 2010 Likonde-1 well which was drilled on the northern edge of the Ruvuma 3D seismic dataset. Likonde-1 penetrated what is interpreted to be the down-dip periphery of a substantial untested Jurassic fan system. Oil and gas shows are noted in sands identified on

mudlogs in Likonde-1 at the levels of the Jurassic post-rift prospects in the block, suggesting the bright amplitudes up-dip of the Likonde-1 well could be potential direct hydrocarbon indicators. Overall play and prospect risking, summarised in this report, indicates a portfolio of highly attractive exploration opportunities within a low-cost onshore exploration setting and supported by a high-quality 3D seismic dataset.

The current internally aggregated block total Pmean unrisked GIIP potential is estimated at ~16.4 TCF with a risked Pmean GIIP potential of ~6.9 TCF (**Table 1**). These significant volumes indicate the Mtwara Licence offers a unique opportunity to deliver "game-changing" near-term onshore production with substantial low- cost exploration upside. Tanzania is a politically supportive country with rising energy demands and aspirations to produce cleaner fuels domestically and export to both regional and global markets (e.g. LNG).

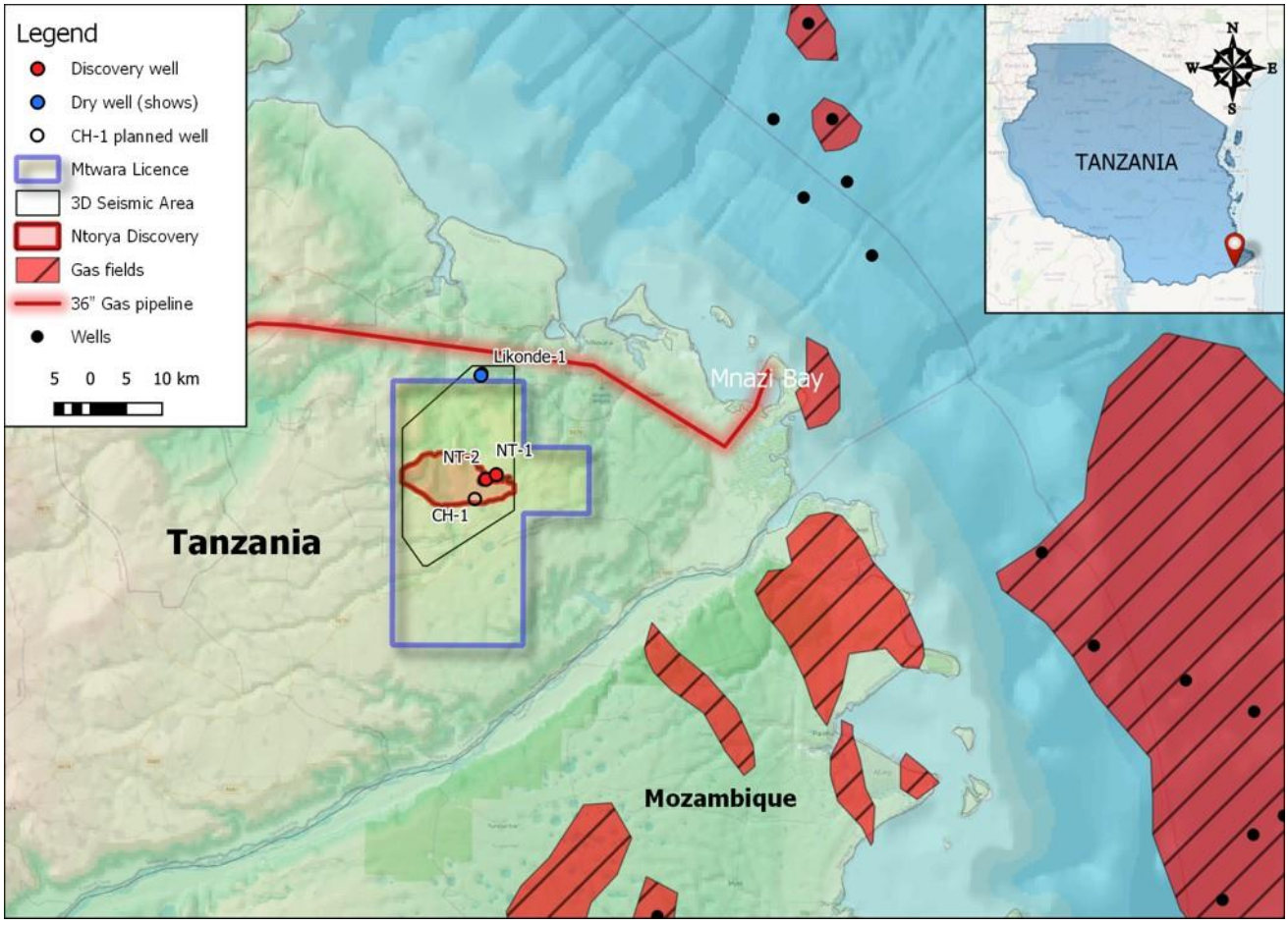

Figure 1 The Mtwara licence is located in the South of Tanzania close to the Mozambique border. Offshore gas discoveries estimated to hold > 100 TCF. ***Note that location of wells and discoveries are not accurate but digitised and modified from various sources.***

Table 1 Estimated in place and risked volumes in the Mtwara licence summarized after geological age.

Mtwara Licence	Volumes	Risk	Risked Volumes	
DISCOVERY, PROSPECTS AND LEADS	MEAN INPLACE GIIP (BCF)	AVERAGE PLAY POS	GAS MEAN GIIP (BCF)	CONDENSATE (MMbbls)
Tertiary	2,233	26%	590	4.7
Cretaceous	11,674	39%	5,768	46.1
Jurassic	2,478	26%	545	4.4
Summary of Mean Inplace Volumes	**16,385**		**6,903**	**55.2**

2. SUMMARY OF MTWARA GEOLOGY

The Ruvuma basin is one of a series of long-lived coastal basins and delta systems developed along the East African coast which host >100 TCF discovered gas reserves in multiple accumulations offshore Tanzania and Mozambique. Rifting commenced during the Late Palaeozoic and was active throughout the Permo-Triassic periods leading to the deposition of thick Karoo Group sediments which potentially include world-class source and reservoir rocks. The post-rift history of the basin from the Early Jurassic to Palaeogene periods is characterized by progressive subsidence as a passive margin sag basin. Deposition occurred during the Early Jurassic in a partially restricted marine environment allowing additional potential oil and gas source rocks to be deposited and preserved under anoxic conditions. Both the Karoo and Jurassic source rocks are now identified as being potentially mature for oil and gas generation in the Mtwara Licence.

As Madagascar separated from the African continent and moved progressively southward during the Middle Jurassic and Cretaceous periods, the enclosed basin became increasingly open to marine circulation. Large-scale fluvial and shallow marine sediment catchments developed to the west of the Mtwara Licence on the then eastern flanks of the African continent. These depositional systems which continued to develop during the Cretaceous are believed to have transported sand-rich sediments from the river and coastal systems into the newly formed basin through a series of submerged ravines which closely resemble present day onshore and offshore canyons and embayment's. From the Late Jurassic onwards, rapid thermal subsidence, vertical aggradation and major fluctuations in relative sea level resulted in the development of deep erosional channels, regional unconformities and large-scale movements of shallow and shelfal sediments into the deeper water setting. Large 100km scale turbidite fans e.g. the Ntorya Discovery and mass transport events such as the newly identified MTC Prospect demonstrate the magnitude of geological processes in the Mtwara area. Infilling of the channels with sand-rich sediments and periodic capping with deep marine shales (e.g. Ntorya-1 & -2) provided an ideal opportunity for the development of stacked stratigraphic traps with proven links to deeper sources of gas which are now being recognised by APT and its partner (**Figure 2**).

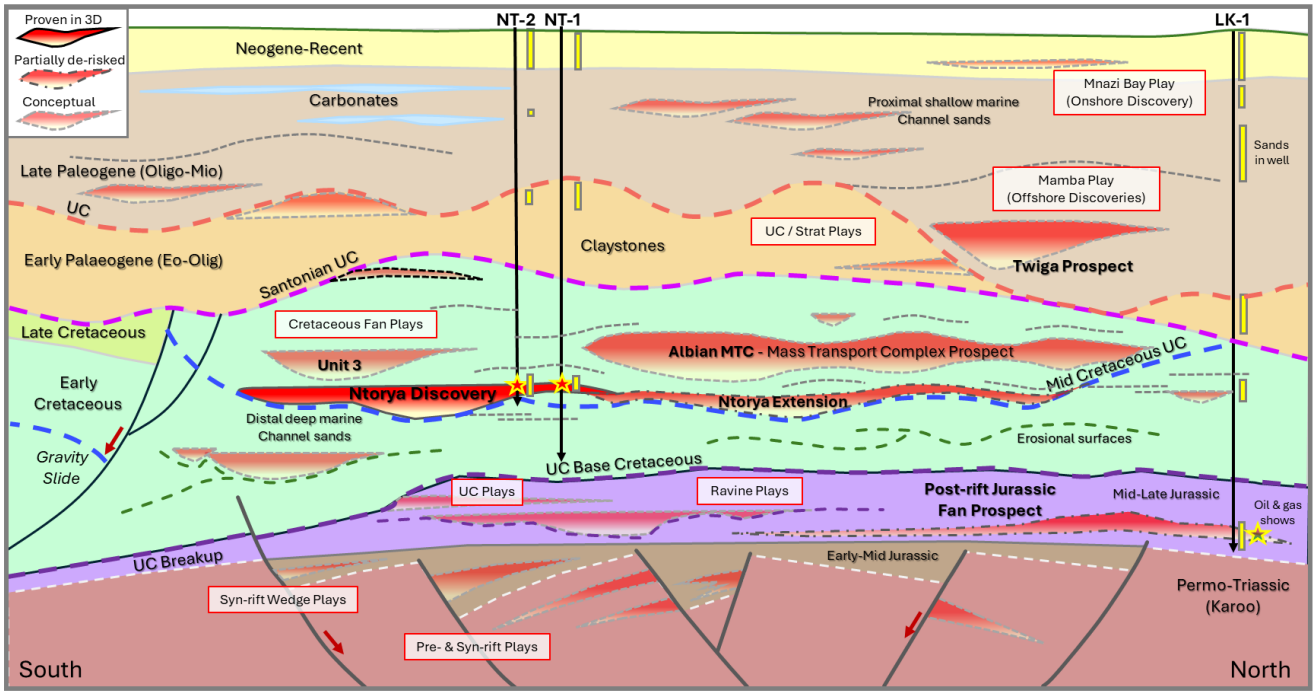

Figure 2 Conceptual geoseismic line from the new Ruvuma 3D survey through the Mtwara licence in a North-South direction illustrating the key plays and stacked prospectivity described in this report.

3. NTORYA DISCOVERY UPDATED RESOURCE ESTIMATION

Status: Contingent Resources, Development Pending

The new Ruvuma 3D seismic survey has allowed APT to map the Ntorya Discovery with a higher degree of confidence than previously possible on sparse 2D data. A high confidence area of some 75km^2 is the basis for the gross rock volume inputs used to revise our internal resource estimate for the Ntorya Discovery in **Table 2**. Ongoing studies, undertaken by APT with Ikon Geoscience seeking to use seismic inversion methodologies to investigate the potential lateral extent of reservoir sand presence, have indicated that the Ntorya Discovery could cover an area of up to 180km^2. The new inversion work therefore provides considerable scope for future additional gas volumes to be present outside the main high confidence area (**Figure 3**).

The new 75km² high confidence discovery outline is mapped based on the presence of continuous high-amplitude, seismic reflections which are tied to the Ntorya-1 and Ntorya-2 discovery wells up-dip and westwards towards an inferred crestal pinchout near the western edge of the 3D survey. No significant barriers are identified within the reservoir interval on the 3D seismic volume which indicates the potential for a large continuous gas column and limited reservoir compartmentalisation. The reservoir in the Ntorya Discovery is likely defined by at least two, and possibly three to four main episodes of reservoir bearing submarine gravity flows through the Late Albian, two of which have been proven in Ntorya-1 and Ntorya-2 and referred to as “Unit 1” and “Unit 2” sands. Encountering multiple stacked sands is considered to be common in such submarine fan settings.

Based on the new Ruvuma 3D seismic dataset, the Ntorya Discovery is mapped with a gas column of 600m. Whilst APT identifies no clear gas water contact in the existing wells, some indications from previous petrophysical studies suggest a possible gas water contact towards the base of the main gas bearing Unit 1 sand in Ntorya-1.

The thickness and presence of the reservoir in the Ntorya Discovery is determined based on the two wells, Ntorya-1 and Ntorya-2 against which the Ikon Geoscience seismic inversion has been calibrated. The seismic inversion is incorporated in a new static geomodel and used to calculate the gross volume of the main sand-bearing reservoir intervals which are the basis for the Ntorya Discovery volumetric estimate quoted in this report (**Table 2**). Geophysical interpretation and amplitude extraction has been applied to the new Ruvuma 3D seismic survey. The reservoir horizons encountered in Ntorya-1 and Ntorya-2 show supporting seismic bright amplitudes associated with reservoir presence. Areas with warmest/brightest colours, on a seismic amplitude map, are reservoir sections believed to have increased calcareous cementation (as seen in Ntorya-1 and Ntorya-2) and is unrelated to a direct hydrocarbon effect. The current volumetric estimate includes only the two main reservoir units, Unit 1 and Unit 2, within the high confidence 75km² area. The near-term planned drilling of Chikumbi-1, highlighted as CH-1 in **Figure 3** and **Figure 4** aims to unlock further additional potential in a third shallower sand unit (Unit 3).

Significant overpressure was encountered in Ntorya-1 and Ntorya-2 amounting to some 1,500 psi to 1,800 psi above a hydrostatic pressure in Unit 1 and Unit 2 sands. This is considered to be consistent with a gas column of ca 600m at the apex/crest of the mapped Ntorya reservoir and therefore supports both the mapping of continuous sands and the presence of a significant gas accumulation. A dynamic reservoir simulation, undertaken by APT and designed to model conceptual full field production, shows the potential for extremely efficient drainage and future field performance with an Expected Ultimate Recovery Factor of ca 80% on a GIIP of 3.45 TCF (**Table 2**).

Table 2 Deterministic volumetric summary of the Ntorya gas discovery including recovery factor of 0.8 which is in the range of possible end of field production based on current dynamic modelling of performance.

	GIIP (inplace)	Rec. Condensate/ Oil	Rec. Gas
	BCF	MMbbls	BCF
Sum Late Albian (Unit 1 & 2)	**3,451**	**22.1**	**2,761**
Reservoir Unit 2	991	6.3	793
Reservoir Unit 1	2,460	15.7	1,968

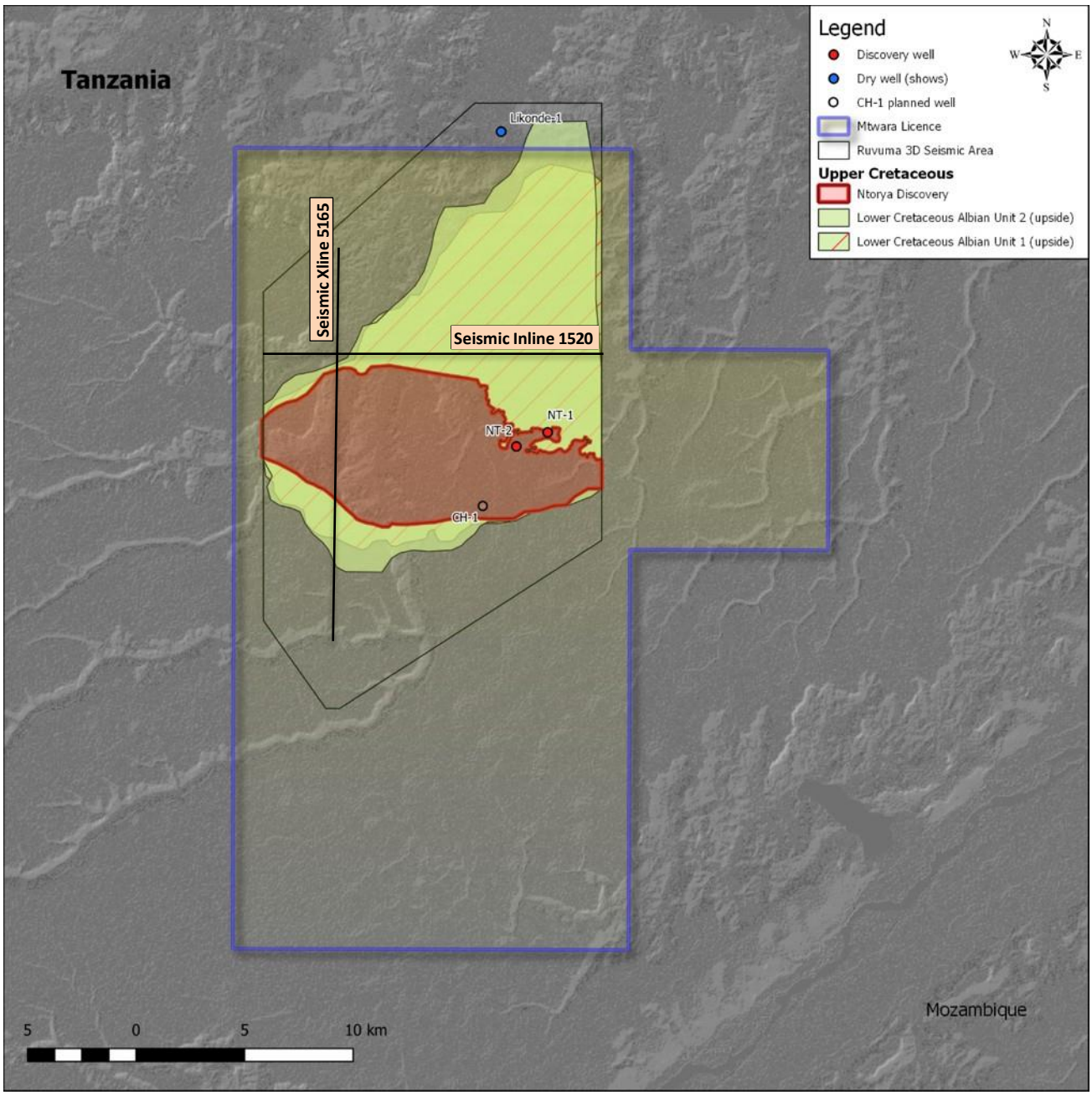

Figure 3 Ntorya Discovery (red outline) superimposed on regional Digital Elevation Model (DEM), with additional revised and extended upside for Unit 1 and Unit 2 which could be up to 180 km² in total based on the green, and green hatched areas. Annotated seismic line with reference to Figure 5 and Figure 6.

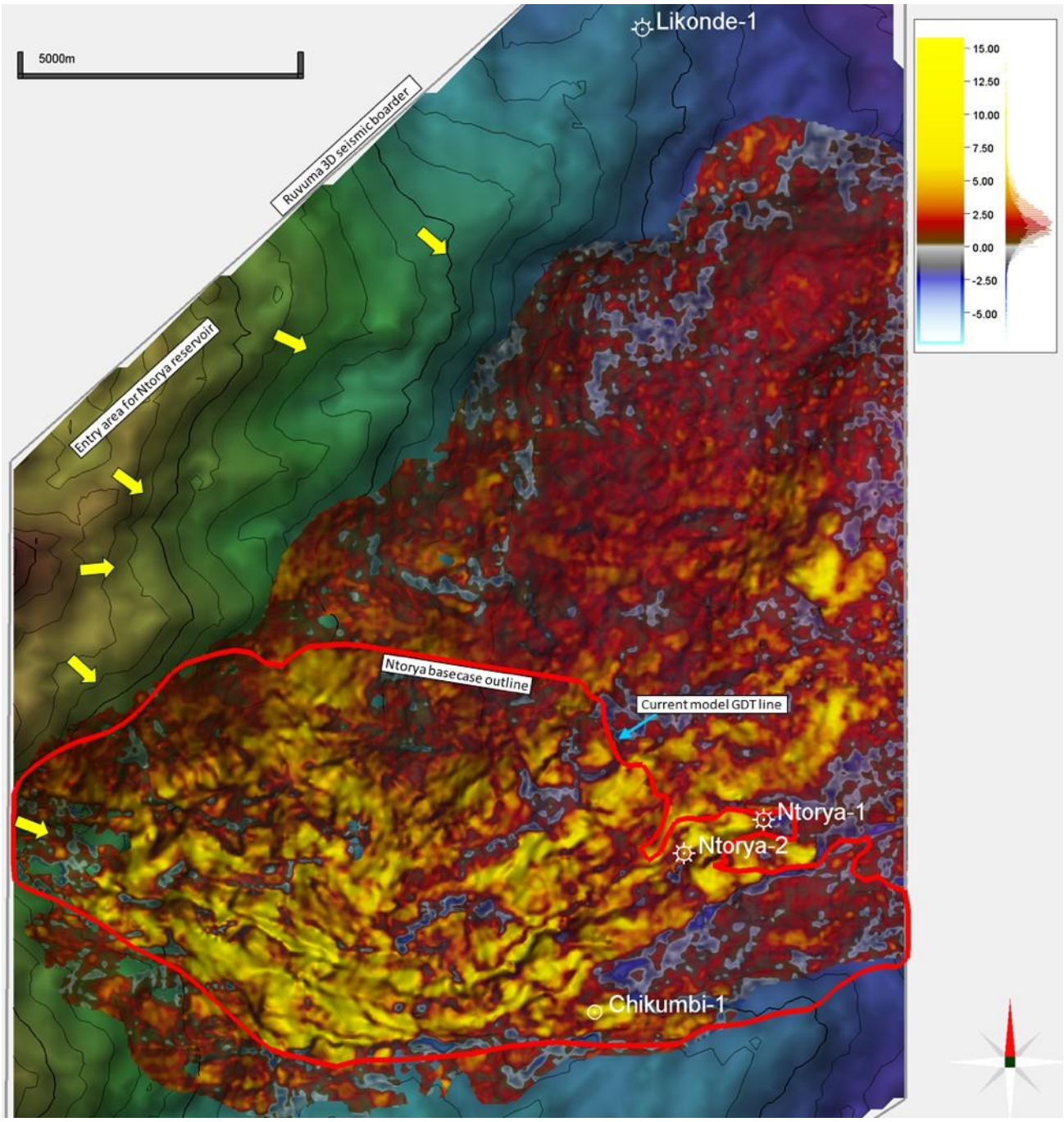

Figure 4 Example of amplitude extraction from reservoir Unit 1 in the Ntorya Discovery. Bright amplitudes are associated with reservoir and channel fairways where some cementation occurs, as proven in Ntorya-1 and Ntorya-2. Hot colors are not related to hydrocarbon effect. The general red-yellow bright colors (positive amp) are interpreted as the main reservoir depositions of the unit. Reservoir deposition is expected to enter the basin from west (yellow arrows). In red outline is the high confidence area of ca 75 km^2 for the inversion geomodel. No gas volume is included in the model below 2510 mTVDss – the base of the Unit 1 reservoir sands encountered in Ntorya-1 and representing a gas-down-to for the discovery.

4. EXPLORATION - PROSPECTS AND LEADS

The term “Prospect” refers to a potentially drill-ready structural feature mapped on 3D seismic data for which volumes have been estimated with a fair and reasonable confidence level. The term “Lead” refers to a feature or features of interest which are currently conceptually based upon initial screening of the 3D volume or for which volumetric estimations remain preliminary and liable to be updated as interpretation of the seismic data and geology are further matured.

4.1. Cretaceous Fans and Mass Transport Complex (MTC)

Thick Santonian marine shale deposits are noted as providing an excellent top seal for all of the deeper Cretaceous prospectivity that has been identified to date (**Figure 2**, **Figure 5** and **Figure 6**). The new Ruvuma 3D survey has both identified and enabled definition of a much broader portfolio of prospects and conceptual leads in the Cretaceous section. The Aptian to Turonian interval presents a number of related opportunities where stratigraphic trapping is the dominant trapping element with reservoir sandstone pinch-out and truncation invoked, in major channel infills, up-dip to the west in a similar manner to the Ntorya Discovery. The presence of porous sands encountered at similar stratigraphic levels in Likonde-1 well is seen as positive support for the lateral continuity of the Cretaceous fan facies across the extent of the Mtwara Licence.

Several Cretaceous prospects have been included in the revised portfolio including the Mass Transport Complex Prospect (“MTC”) (which is illustrated in **Figure 2**, **Figure 5** and **Figure 6**) and provides some highly anticipated exploration upside. The occurrence of large-scale accumulations in mass transport deposits is well documented offshore Tanzania and Mozambique in stratigraphically younger intervals e.g. Mafia mega-slide. Considering the overall prograding nature of the stable passive margin setting, the younger offshore deposits are invoked as direct analogues for the Albian MTC Prospect.

Risk assessments of Cretaceous prospects are detailed in **Table 3** and **Figure 9** are based on the new 3D seismic interpretation together with geological and petrophysical evaluation of available well control in the area (Ntorya-1. Ntorya-2 and Likonde-1)**.**

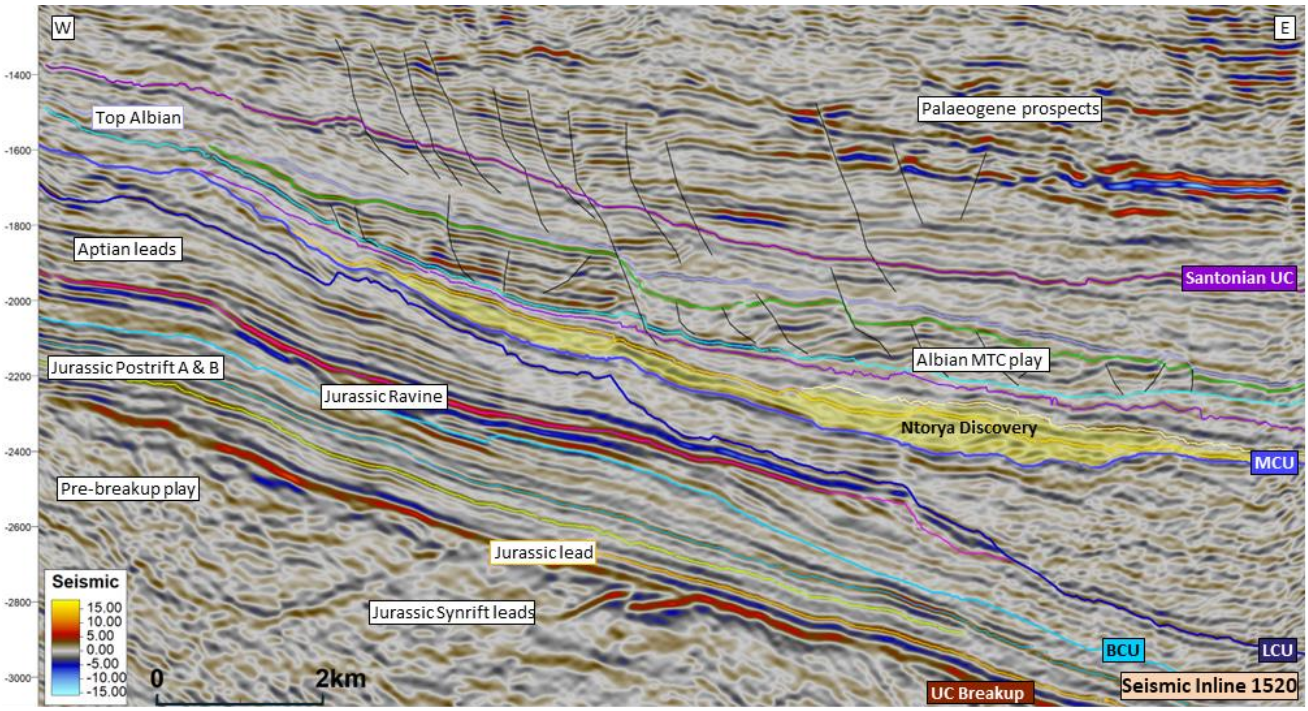

Figure 5 Ruvuma 3D Seismic Time Section (TWT) – inline 1520 showing the Ntorya Discovery in addition to multiple levels of prospectivity including the newly recognised Albian play Mass Transport Complex "MTC" prospect defined as a characteristic seismic interval in the new high-resolution Ruvuma 3D. Highlighted are unconformities (Breakup, BCU – Base Cretaceous Unconformity, LCU – Lower Cretaceous Unconformity, MCU – Middle Cretaceous Unconformity and Santonian Unconformity), Ntorya Discovery, prospect-, leads- and play levels.

4.2. Jurassic Turbidite Fans and Delta

The Jurassic sequence is mapped in detail over the new 3D seismic where two new prospects and two new conceptual leads are mapped. The two prospects (Postrift A & B) are mapped with high confidence in the Ruvuma 3D and exhibit distinctive amplitude characteristics which are interpreted to represent marine fan deposits e.g. **Figure 7**. Direct hydrocarbon seismic indicators may be present where the amplitude signatures are significantly elevated above general background values e.g. when compared against areas where there is sand in the Likonde-1 well but no significant measurable gas saturations. Each fan extends over an area of 10's km² and is represented by a main lobate toe deposit which, in the case of the northernmost fan, is linked directly to a westerly reservoir catchment by a ca 1km wide continuously mapped channel. The southern of the two mapped lobes is distinct as a separate prospect, but in contrast to the northern fan, the feeder channel has not been preserved potentially aiding up-dip trapping. Oil and gas shows were noted in sandstones in the Likonde-1 Jurassic interval which, when combined with strong indications of fan geometries significantly derisks these prospects.

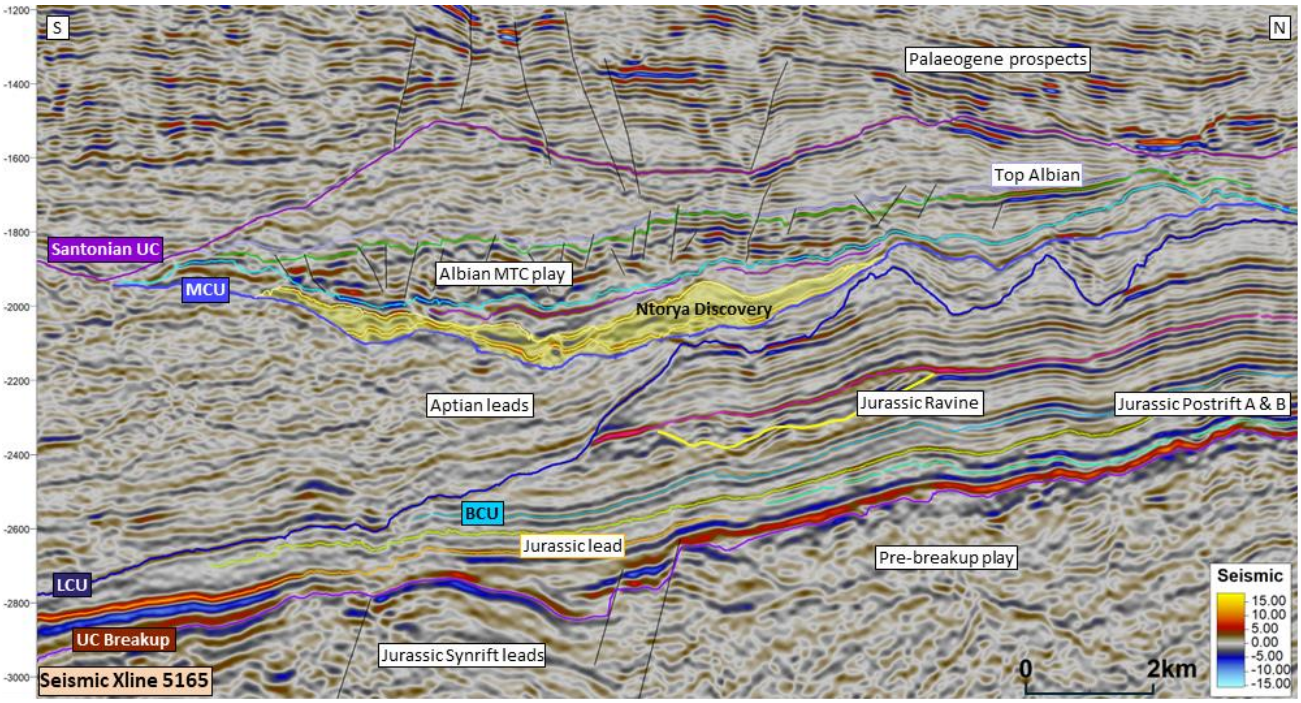

Figure 6 Ruvuma 3D Seismic Time Section (TWT) – xline 5165 showing the Ntorya Discovery in addition to multiple levels of prospectivity including. Highlighted are unconformities (Breakup, BCU – Base Cretaceous Unconformity, LCU – Lower Cretaceous Unconformity, MCU – Middle Cretaceous Unconformity and Santonian Unconformity), Ntorya Discovery, prospect-, leads- and play levels.

In addition, a newly identified delta sequence has been defined by APT as a regional lead that extends towards the northwest corner of the current licensed area (see outline in **Figure 8**). Within the delta lead, seismic has enabled the mapping of an internal sequence that is interpreted to be a ravine deposit with a possible pinch out towards the north. This feature has been mapped as a distinct prospect and is referred to as the "Ravine Prospect" (**Figure 2**, **Figure 5** and **Figure 6**). The Ravine Prospect is situated within the Delta lead and indicates a regression sequence within the Delta lead. Risk assessments of Jurassic prospects are detailed in **Table 3** and **Figure 9** are based on the new seismic interpretation together with geological and petrophysical evaluation of available local well penetrations (Ntorya-1. Ntorya-2 and Likonde-1)**.**

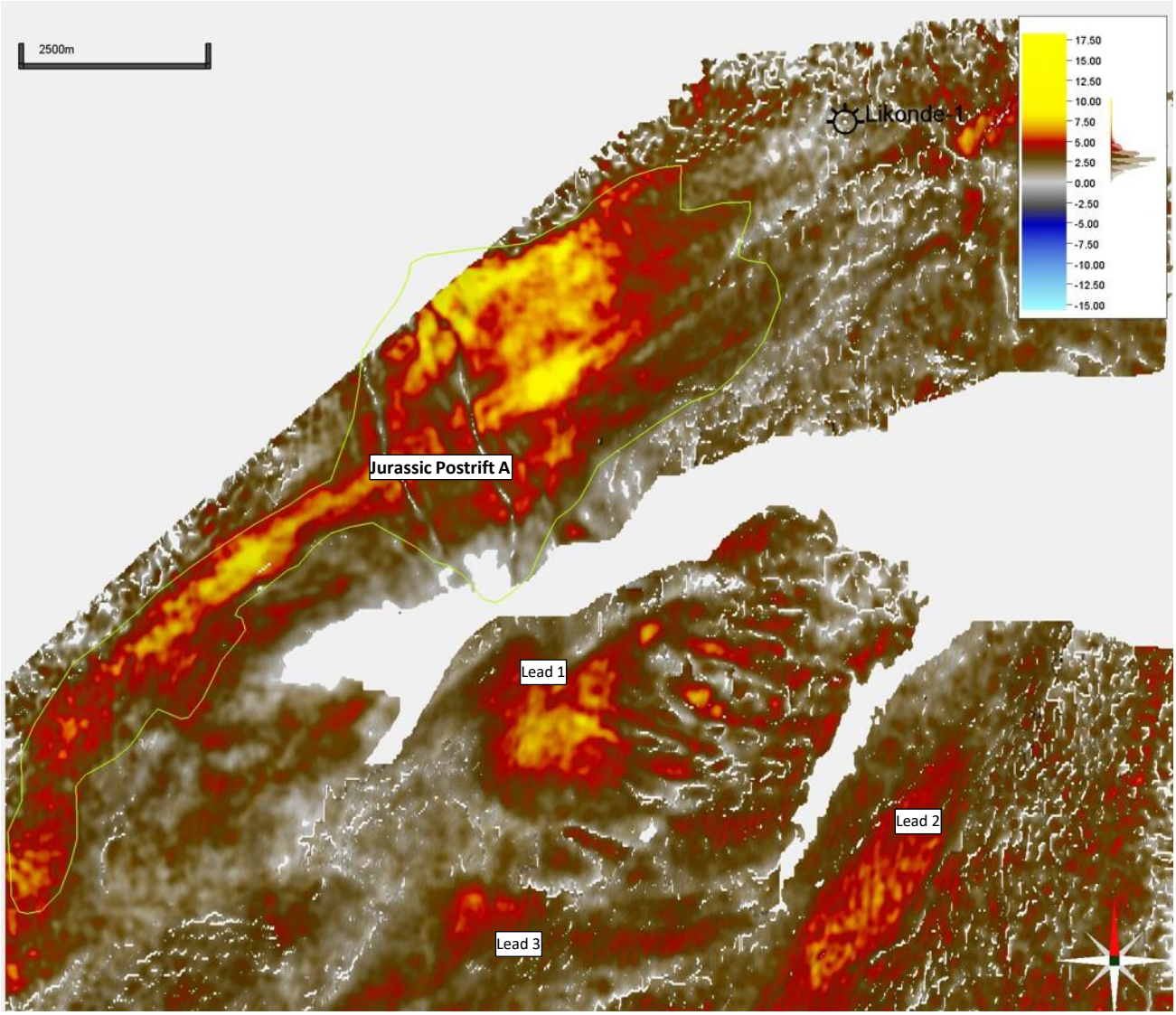

Figure 7 Example of an amplitude driven play in the Jurassic (Jurassic Postrift A), up-dip of Likonde-1 well. Oil shows are present in the Jurassic section in Likonde-1. Other leads, at the same level, are annotated on the map.

4.3. Tertiary Canyons and Channel Infills

Based on current petrophysical evaluation, the lower Tertiary (Paleogene) section in Likonde-1 encountered approximately 97m of net reservoir sands, deposited above the Base Tertiary Unconformity with good average porosity of 17%. No hydrocarbons were encountered, and the Likonde-1 well is interpreted to have penetrated a reservoir lacking trapping potential. APT can identify potential hydrocarbon migration routes which could deliver a gas or oil charge to these shallower reservoir levels, in particular, where the Santonian shales thin or are faulted along the eastern edge of the Ruvuma 3D dataset. A Paleogene sand interval was not encountered in either the Ntorya-1 or Ntorya-2 wells indicating lateral pinch-out or shale-out of the sands at these well locations. Such features may contribute to the formation of as yet unexplored traps away from the Likonde-1 well and most likely updip to the west where two leads have been identified (**Figure 2**, **Figure 5** and **Figure 6**).

Two speculative Paleogene leads have been identified and named Twiga South & Twiga North (**Figure 8**). Work is ongoing to define the updip pinchouts and mature our understanding of these features. Additional conceptual prospectivity is noted to be associated with shallow water sand bar and channel deposits in the shallower Oligo-Miocene sections which host the proven Mnazi Bay producing gas field some 30km east of the Mtwara licence. Efforts will be made to identify potential traps at these levels in order to expand the prospect portfolio and mitigate the risks of encountering shallow gas whilst targeting deeper well objectives.

The range of prospective resources are illustrated in the bubble plot in **Figure 9**. There is a clear trend developed with better understood lower risk targets and newer less well understood prospects. It is hoped that further geological studies, including inversion of the Jurassic section based on modelled hydrocarbon presence and valuable data already available from Likonde-1, can help to reduce uncertainty and perceived geological risk for prospects such as the Jurassic Postrift A & B prospects and the MTC in the upper Albian, and in so doing mature some of the larger but higher risk prospects and leads up the risked resource trend.

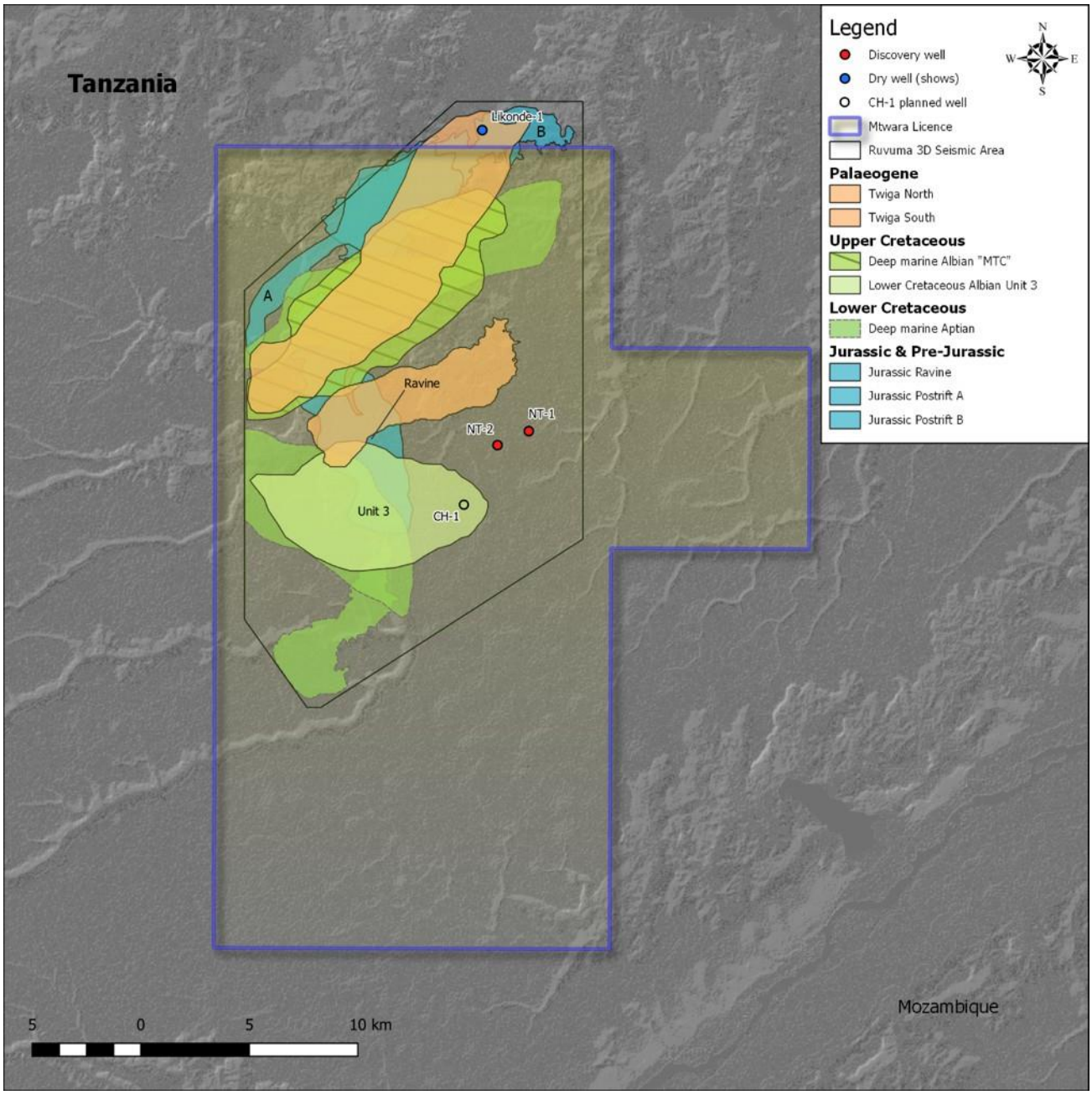

Figure 8 Combined map showing key outlines of mapped opportunities in the Mtwara licence from ongoing seismic interpretation work. Outlines are superimposed on a regional Digital Elevation Model (DEM).

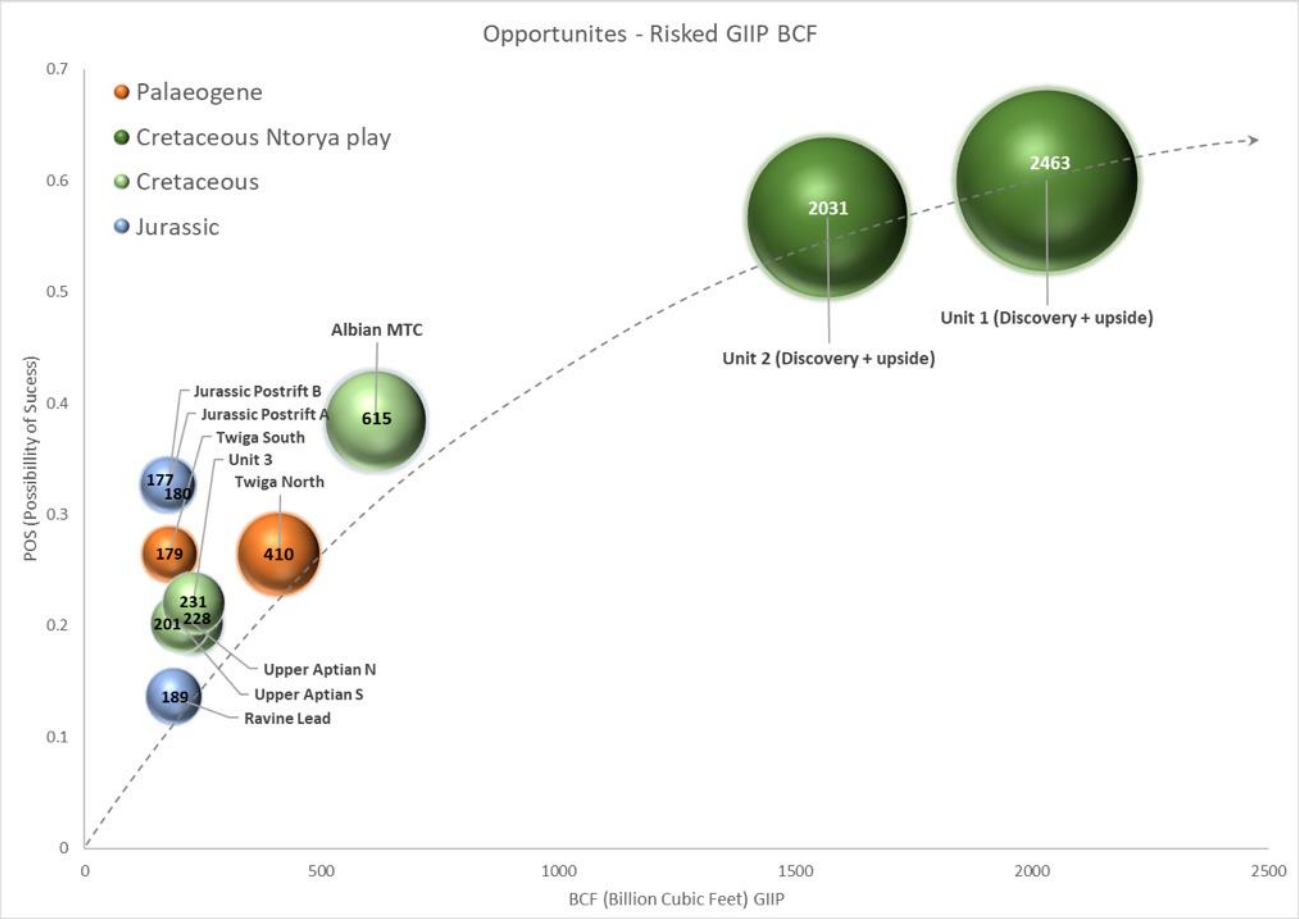

Figure 9 Bubble diagram showing the Pmean risked volumes vs POS for individual opportunities in the respective play types in the Mtwara Licence. See also Table 3 for summary.

5. CONCLUSIONS

- Interpretation of the new Ruvuma 3D seismic survey has resulted in a significantly better understanding of the resource potential of the Mtwara Licence and the Cretaceous Ntorya Discovery leading to a revision of APT's internal resource estimates and derisking of planned appraisal and development activities which are scheduled to commence upon the imminent award of a Development Licence for the Ntorya Discovery.
- A range of new exploration opportunities have been identified within the Ruvuma 3D survey associated with potentially stacked structural and stratigraphic plays in the Jurassic, Cretaceous and Tertiary intervals. Some of the undrilled features are supported by potential direct hydrocarbon indicators within the seismic response.
- A portfolio of drill-ready prospects have been mapped in detail with the resulting preliminary APT volumetric estimates being aggregated to yield a new combined estimate of Pmean prospective resources for the Mtwara Licence of ~16.4 TCF GIIP, and corresponding to an estimate of ~6.9 TCF risked Pmean GIIP (**Table 1** and **Table 3**).
- The bubble plot in **Figure 9** illustrates the relative size and associated geological risk for each of the main mapped prospects showing a clear path towards success as the ongoing exploration process is matured and various uncertainties and risks are better understood. Other leads which are currently being considered are expected to follow a similar trajectory as they are added to the portfolio. Additional prospectivity may be added from conceptual plays in the pre-breakup section (**Figure 2**, **Figure 5** and **Figure 6**).
- In a success case, significant volumes of associated condensate are expected to be produced based on the results of Ntorya-1 and Ntorya-2 as shown in **Table 1**. With expected low processing costs and available existing markets, the condensate could provide a low-cost, high margin supplementary revenue stream for the project.
- The onshore Mtwara Licence, the Ntorya Discovery and the new exploration portfolio all have the potential to make a substantial and material near-term contribution to the Tanzanian energy market and offer the opportunity to yield a faster, cleaner and more efficient route to success for all stakeholders.

Table 3 Estimated in place and risked volumes in the Mtwara licence.

Mtwara Licence	Volumes				Risk					Risked	Risked
DISCOVERY, PROSPECTS AND LEADS	INPLACE VOLUMES GIIP (BCF)				STRUCTURE	SEAL	RESERVOIR	CHARGE	POS	GIIP (BCF)	CONDENSATE MMbbls
	P90	P50	P10	MEAN							
Tertiary											
Twiga South	400	654	916	**679**	100%	55%	80%	60%	**26%**	179	1.4
Twiga North	880	1,484	2,109	**1,554**	100%	55%	80%	60%	**26%**	410	3.3
Cretaceous											
Ntorya Unit 1 (Discovery + upside)	1,624	3,232	5,364	**3,519**	100%	100%	70%	100%	**70%**	2,463	19.7
Ntorya Unit 2 (Discovery + upside)	1,443	3,149	5,023	**3,385**	100%	100%	60%	100%	**60%**	2,031	16.2
Ntorya Unit 3	344	962	1,717	**1,048**	70%	80%	40%	100%	**22%**	231	1.8
Upper Albian "MTC"	691	1,509	2,379	**1,601**	100%	80%	60%	80%	**38%**	615	4.9
Upper Aptian N	363	1,007	1,848	**1,126**	70%	70%	55%	75%	**20%**	228	1.8
Upper Aptian S	322	885	1,592	**995**	70%	70%	55%	75%	**20%**	201	1.6
Jurassic											
Ravine Lead	805	1,307	1,870	**1,385**	55%	60%	55%	75%	**14%**	189	1.5
Jurassic Postrift A	265	514	895	**552**	85%	60%	80%	80%	**33%**	180	1.4
Jurassic Postrift B	268	511	859	**541**	85%	60%	80%	80%	**33%**	177	1.4
Summary of Inplace Volumes				**16,385**						**6,903**	**55.2**

All estimates are those of the operator and are deemed fair and reasonable based on the currently available database.
The presence of hydrocarbons does not guarantee future commerciality.