Source rock presence and maturity along the Northwest African (MSGBC) margin: results from a seep sample and basin modelling study

Felicia Winter[1]*, Tiago Cunha[2], Marianne Nuzzo[2] and David Gardiner[2] present the results of a basin petroleum systems model investigation combined with a surface seep geochemistry survey to address the key exploration risks of source presence and maturity.

Introduction into the Northwest African Atlantic Margin and exploration risks

In 2014 a new spotlight was thrown on the Mauritania, Senegal, Guinea Bissau and Republic of Guinea (MSGBC) offshore region with the FAN-1 discovery in Senegal. This was very quickly followed by the successful drilling of SNE-1 (now Sangomar Field). Continued exploration success yielded multiple commercial gas discoveries, such as Tortue-1, Yakaar-1 and Orca-1, but exploration activities have subsequently slowed down. In 2024 a new wildcat well will be drilled in deep-water Guinea Bissau, Atum-1 by Apus, reigniting exploration interest in this potentially prolific petroleum province. This study aims to address one of the key exploration risks of the margin, source presence and maturity.

Tectonic reconstructions demonstrate that prior to break-up in the mid-Cretaceous and the opening of the central Atlantic, the southern MSGBC Basin was juxtaposed against the prolific Demerara Plateau Guyana-Suriname margin, with the deposition of major Jurassic and Cretaceous source rock intervals. No more than 200 km separated the coastlines of modern-day Guinea and Suriname (Nemčok et al., 2016). The palaeo-tectonic reconstruc-

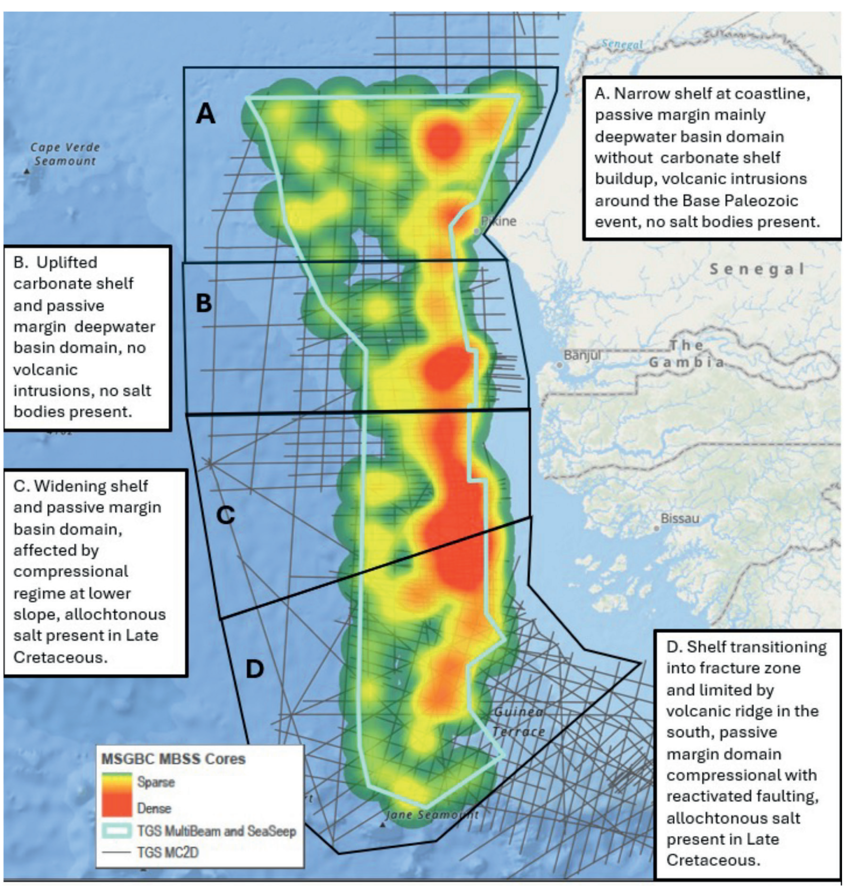

Figure 1 Data coverage of Phase 1 and 2 of the study, including regional 2D seismic offshore Senegal, The Gambia, AGC, and Guinea and the multibeam and seafloor sampling (MB&SS) data (light blue polygon). For confidentiality reasons, core locations within the MB&SS have been replaced with a 'heatmap' showing density of sample locations across the campaign area. Black polygons A-D signify main structural domains in the MSGBC basin across the margin.

[1] TGS | [2] IGI Ltd,
* Corresponding author, E-mail: Felicia.Winter@tgs.com
DOI: 10.3997/1365-2397.fb2024081

tions indicate that the deepwater MSGBC and Guyana-Suriname basins formed an axis where marine circulation was restricted, which is likely to have enabled preservation of organic matter on the seafloor to form world-class marine source rock intervals from the Barremian to Turonian. Early Jurassic syn-rift lacustrine and late Jurassic carbonate source rocks are also likely to be present in the MSGBC platform areas.

Several of these source rock intervals have been proven by the drill bit in the MSGBC offshore basins in both exploration and Deep Sea Drilling Project (DSDP) wells, with the older sources inferred from biomarker and isotopic compositions of discovered oils and gases. Their presence is relevant since the borehole locations are at the shelf edge in a classic passive margin setting where there is connectivity of environments across the shelf/slope. Despite that, one of the main exploration risks is still perceived to be source rock presence and maturity, and timing of hydrocarbon generation. The overall objective of this study is to integrate geochemistry results obtained from gravity and piston cores in 2020 with regional structural mapping, well information and heat flow studies, to build an integrated Basin and Petroleum Systems Model (BPSM).

The regional thermal subsidence of this passive margin basin during the Albian to late Cretaceous period was accompanied by the deposition of interbedded shales and sands, and localised carbonates. Organic-rich marine shales, deposited in the Barremian to Albian, are the probable source for the Senegalese discovery Fan-1, which charged Albian-aged sands with 28° API oil (Clayburn, 2017). The younger Turonian and Cenomanian section exhibits additional source potential, proven by DSDP westwards in the deep oceanic basin (e.g., DSDP 367) and by exploration wells on the platform. Additionally, there are further data pertinent to demonstrating source rock presence and maturity, in the form of a multibeam and seafloor sampling survey conducted in 2020 (blue polygon in Figure 1).

Seabed sampling of hydrocarbons in the MSGBC basins and conclusions from the geochemistry analysis and interpretation

Thermogenic hydrocarbons in shallow sediments are indicators of potential seepage/micro-seepage from reservoirs and suggestive of an active petroleum system. A total of 313 shallow cores were collected across the AOI during a survey conducted by TDI-Brooks (Figure 1). The high-resolution geochemical data acquired from these seabed cores (Geomark, 2020) have been assessed for traces of migrated hydrocarbons to interpret the source and maturity of the micro-seep fluids in the regional MSGBC context.

The preliminary geochemical screening results (e.g., Total Scanning Fluorescence (TSF)), suggest that petroleum micro-seeps might be present in the MSGBC survey area. Sediment TSF intensity is an indicator of potential petroleum occurrence, and the large differences between the lowest and highest values can represent background *vs.* micro-seep signals, despite the relatively low absolute values (Figure 2).

Oil staining is supported for several samples by characteristic ratios of the saturated *vs.* aromatic *vs.* polar hydrocarbon fractions (Figure 3).

Two major factors can interfere with the identification of oil stains in sediment extracts: recent organic matter (ROM) co-extraction, and contamination by petroleum from anthropogenic sources. In both cases, 'non-seep related' organic compounds tend to overprint the weaker signal of the quantitatively minor oil stains. Our study comprises a rigorous quality check of potential oil stain samples to exclude non-seep samples. In an example sample in Figure 4 (anonymous for confidentiality reasons), the Gas Chromatogram is dominated by a C_{25+} wax contamination, but < C_{22} hydrocarbons could be related to seep oil. Oil staining is confirmed by GC-MS analysis of the hopane biomarkers distribution (Figure 4, lower panel), which suggests a carbonate-rich source rock for this sample (e.g., high $C_{29/30}$ and $C_{35/34}$ αβ-hopane ratios).

The biomarker compositions of the oils extracted from samples assessed as likely micro-seepage stains show the presence of at least two distinct source rock types, which range from carbonate-rich to marine clastic sources. Figure 5 provides an example of biomarker composition variations for potential micro-seep oils that show some samples to have source rocks

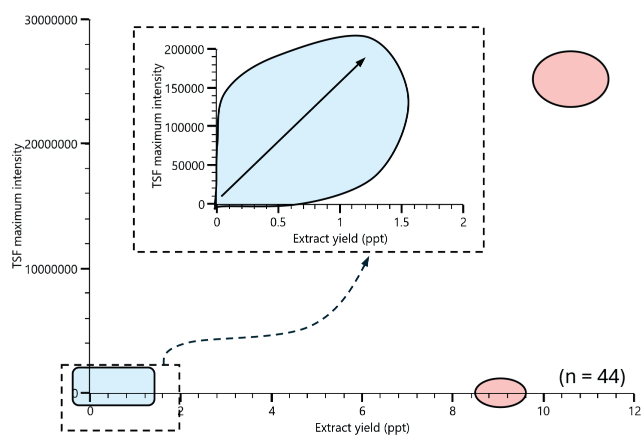

Figure 2 TSF vs Extract Yield showing the occurrence of potentially oil-stained sediment samples (red-shaded) vs background (blue-shaded). For confidentiality reasons, individual data points have been replaced with data clusters shaded areas in all diagrams.

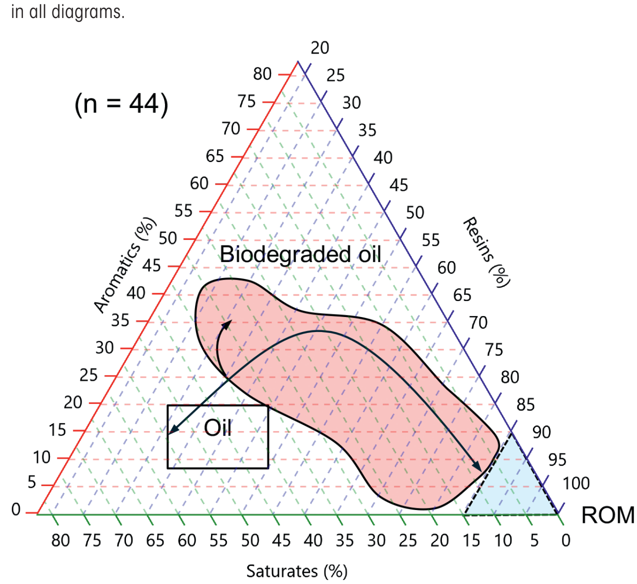

Figure 3 Hydrocarbon extract fractions showing oil and mixed oil and Recent Organic Matter (ROM) signals.

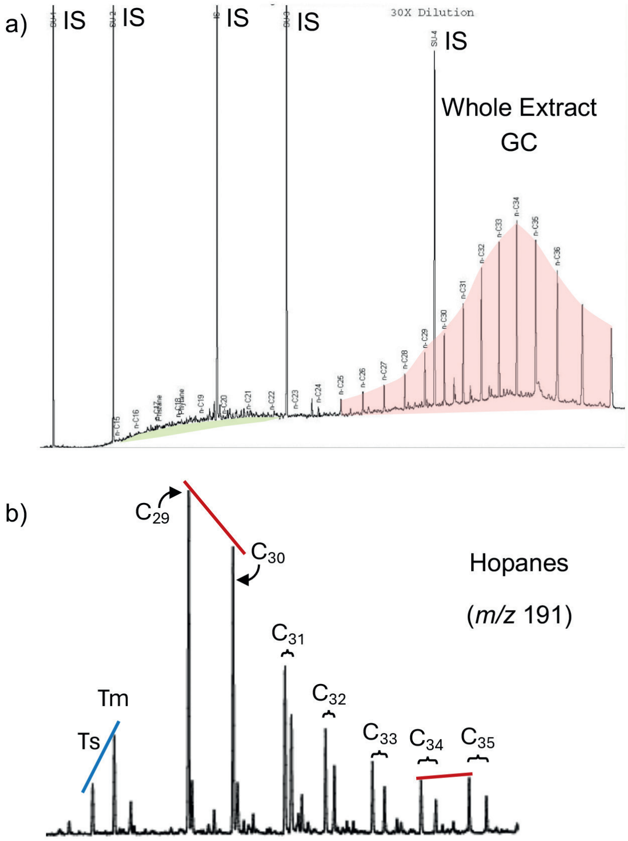

Figure 4 a) Dominant wax contamination (red-shaded) does not overprint a weaker oil signal (green-shaded) (IS = Internal Laboratory Standard). b) Hopane biomarkers distribution from GC-MS supporting identification as a carbonate-sourced oil stain. Carbon numbers reflect αβ-hopanes. Chromatograms anonymous for confidentiality e..g., high C_{29}/C_{30} αβ-hopane, high C_{25}/C_{34} αβ-hopane and presence of C_{30}-norhopane. reasons.

deposited in open to shallow marine environments and others in a marine environment with higher terrestrial contributions (e.g., higher C_{29}-steranes).

Potential oil shows have been identified in different locations across the entire AOI, including in a pockmark field, which testifies to present and/or past hydrocarbon seepage (Figure 6).

The subsequent BPSM investigation, coupled with this surface seep geochemistry survey, enables a more thorough understanding of the regional petroleum systems, complementing the information provided by the extensive structural mapping of stratigraphic burial based on seismic data.

Methods used to integrate the geochemical data with the structural mapping of the margin based on seismic interpretation and burial history

The BPSM study over the MSGBC margin is a multi-phase study:

- Phase 1 was the detailed reinterpretation of the source rock presence and maturity from geochemistry samples from the combined regional Multibeam and Seafloor Sampling (MB and SS) campaign (described above).
- Phase 2 consists of regional basin and petroleum systems modelling:
  a. 2D thermal and burial history reconstruction on four geo-seismic sections through each of the main structural basin domains, and
  b. putting this information into a coarse framework 3D temperature model based on regionally interpolated seismic surfaces.
- Phase 3 will use this regional framework integrated with the geochemistry to build detailed 3D burial history and maturation models in selected AOI using maps made from 3D seismic data. This phase will aim to update the model with data from newer exploration wells, to improve migration models.

In phase 2a we apply a thermo-tectono-stratigraphic basin reconstruction modelling technique using TecMod-2D (Geomodelling Solutions, GmbH; Rupke et al., 2008) to seismic transects, carefully chosen profiles in different sectors of the MSGBC basin (Figure 1 for the sectors, and Figure 7 for an example transect). The characteristic geological features and lithologies within each marked sector are considered to be largely homogenous across the sector, gradually transitioning to a different structural/lithological domain in the adjacent sector (A-D in the basemap Figure 1). TecMod-2D solves simultaneously for basin-scale

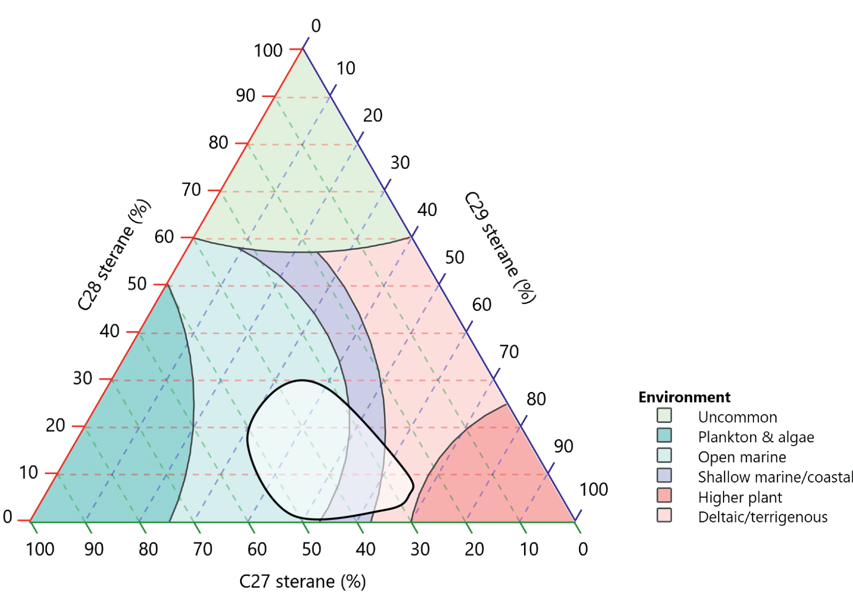

Figure 5 Plot showing the range of ratios of C_{27} vs C_{28} vs C_{29} steranes of potential oil stains identified across the AOI.

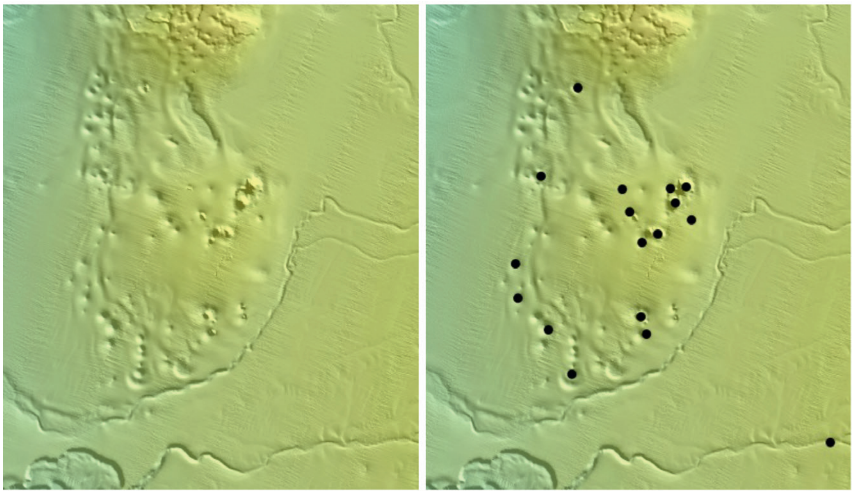

Figure 6 High resolution bathymetry shows pockmark field with cores taken at anomalies (black dots), after being high ranked based on backscatter strength, water column anomaly, and total fluorescence threshold.

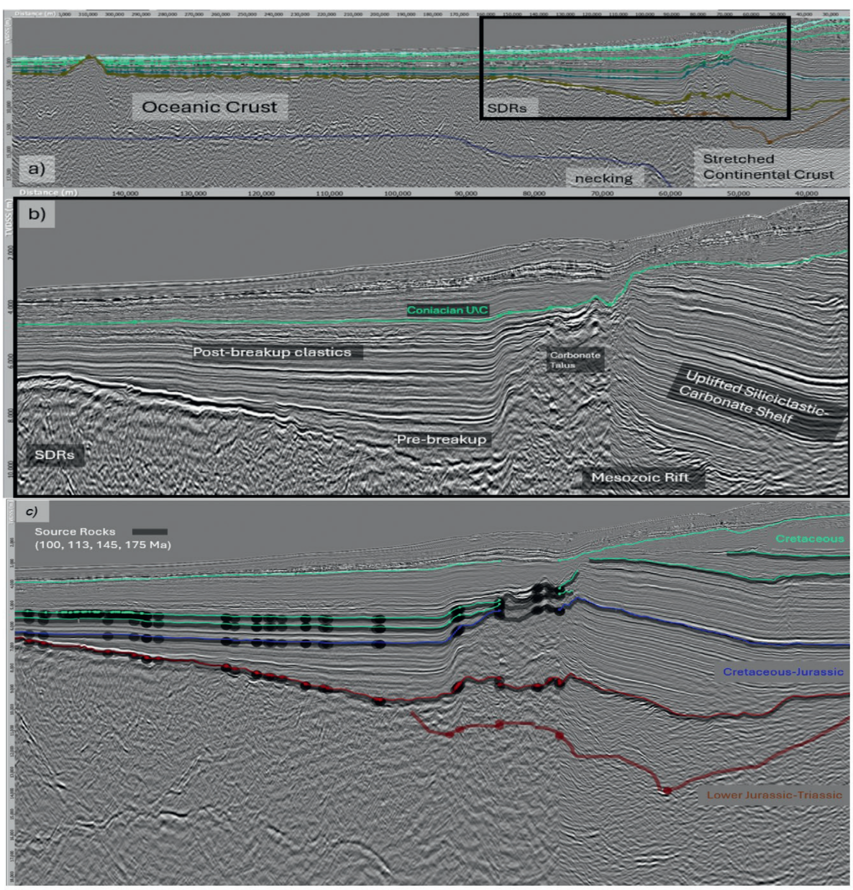

Figure 7 Example seismic transect shows the passive margin nature of the basin and is used for input into the thermal-burial modelling reconstructions (TecMod- 2D models). b) Zoom view shows details relating to changes in structure and lithology at the margin. c) Seismic section along modelled example transect (Figure 8) from Sector B (Figure 1) showing margin with modelled source rocks marked in charcoal overlay.

(e.g. sedimentation, compaction, maturation, sediment blanketing) and lithosphere-scale (e.g. crust/mantle thinning, break-up, flexure, serpentinisation) processes, and iteratively inverts for the stratigraphy.

We show here the modelling results along an example transect offshore central Senegal (Figure 8). The model accounts for a late Triassic-early Jurassic rifting event followed by break-up and thermal quiescence of the continental and oceanic lithosphere. As initial conditions, the model assumes a crustal thickness in this location of 32 km, with 20 km upper crust and 12 km lower crust, and mantle lithosphere thickness of 60 km, consistent with global geophysical models (Laske et al., 2013; Pasyanos et al., 2014), and published gravity models for the region (Zinecker, 2020). For the continental shelf, the model predicts an average geothermal gradient in the upper 3-5 km of sediments of ca. 30°C.km^{-1}, consistent with borehole data in the central and southern MSGBC. In the deep offshore, the model predicts present-day heat flow values at the surface of 40-45 mW.m^{-2}, over oceanic crust, and 45-50 mW.m^{-2}, along the continental slope-rise and the ocean-continent transition zone, that match with the recent measurements taken by TGS (TGS Heat Flow Report, 2019).

We modelled four potential source rock (SR) horizons along the transect, representative (i.e. at approximate depths) of

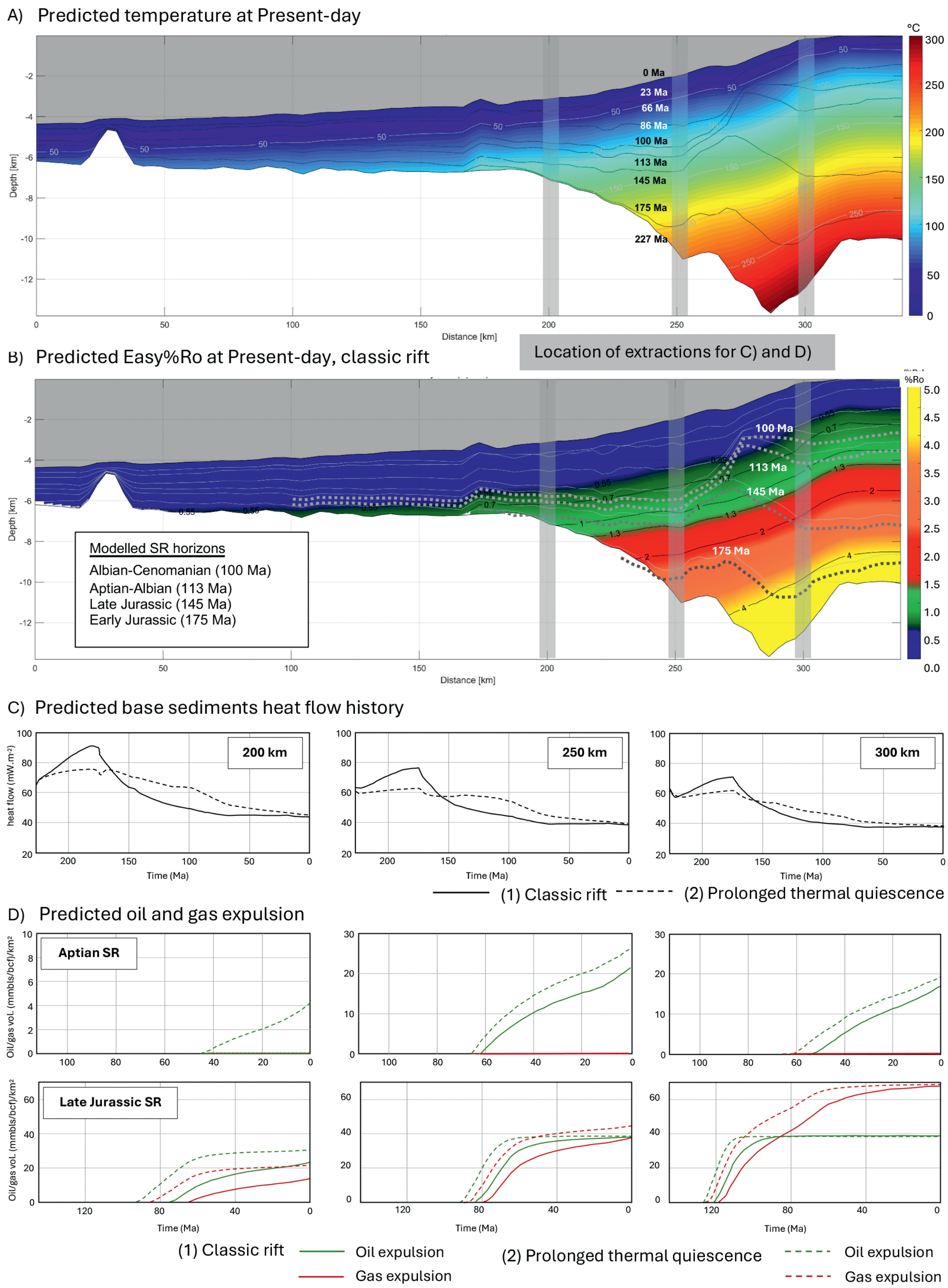

Figure 8 TecMod-2D modelling results along an example transect offshore central Senegal, in Sector B (Figure 1). A) Predicted temperature at present-day. The black lines show the margin stratigraphy, with the ages of the horizons indicated, and the light-grey contours are 50°C isotherms. B) Predicted Easy%Ro at present-day for the classic rift model with rifting between the late Triassic and the early Jurassic (see text for model description). The margin stratigraphy is depicted by the light-grey lines, where the modelled source rock (SR) horizons are highlighted by the thick dotted lines. The shaded bars mark the locations along the profile where we show the heat flow histories in (C) and predicted oil and gas expulsion in (D); at the shelf edge (300 km), the continental slope (250 km), and the continental rise, or the ocean-continent transition zone (200 km). C) Predicted base sediments heat flow through time at 200, 250 and 300 km of the profile for two modelled scenarios: (1) a classic rift model – solid lines; (2) a rift model which accounts for the possibility of prolonged thermal quiescence (see text; – dashed lines). D) Predicted oil and gas expulsion through time for two of the modelled SR horizons, in the Aptian (Type B) and the late Jurassic (Type A, sensu Pepper and Corvi, 1995), assuming software default properties (TOC=5%, HI=592 mg/gTOC) and 100 m SR thickness.

regional SRs in the MSGBC Basin: (1) top Albian (100 Ma); (2) top Aptian (113 Ma); top Jurassic (145 Ma); and (4) top early Jurassic (175 Ma). Using kerogen kinetics of organofacies after Pepper and Corvi (1995), the Aptian-Albian source horizons are classified as marine shale SRs (Organofacies B), the late Jurassic horizon as a carbonate oil-prone SR (Organofacies A), and the early Jurassic SR as a lacustrine SR (Organofacies C). As depicted in the Figure 8B, the Aptian-Albian source horizons are predicted to reach oil window maturity in the continental shelf and some sectors of the continental slope and rise. The late Jurassic source horizon is predicting dry gas mature underneath the continental shelf, and mid- to late-oil maturation between the continental slope and the Oceanic-Continental Transition Zone (OCTZ), whereas the early Jurassic horizon appears overmature to dry-gas underneath the continental shelf and slope.

We also compare the predicted heat flow (Figure 8 C) and respective implications for source maturity as well as oil and gas expulsion (Figure 8D) between two different thermal-burial models at three locations of the modelled transect. The late Triassic-early Jurassic rift model described above, as typically assumed for the MSGBC basin (e.g., Davison, 2005), and an alternative model which accounts for a much broader period of thermal quiescence of the rifted lithosphere, as predicted by recent dynamic models of rifting that couple the deformation in the lithosphere with asthenosphere dynamics and include the thermal evolution of the mid-ocean ridge (after Pérez-Gussinyé *et al*., 2024). In contrast to classical models of rifting, these models suggest that heat flow increases oceanwards during post-rift stages, and that full thermal relaxation may last over 100 Myr following rifting, due to the influence of the spreading ridge and effects of small-scale convection.

At the selected locations, the two models predict some differences in the timing and volumes of generated-expelled oil and gas. For example, at the 200 km marker east along the section, the prolonged thermal quiescence model predicts some expulsion from the Aptian/Albian SR horizon, thus extending the potential kitchen area westwards into the deep offshore and in to the OCTZ, and anticipates oil and gas expulsion from the late Jurassic SR up to ca. 20 Myr before the Classic Rift model. On the other hand, this model reduces the predicted volumes of oil and gas expulsion from the late Jurassic SR for recent times, from the Eocene onwards. Estimates of these differences have been addressed in the follow-up work (Phase 2b), where the predicted heat flow along a number of modelled profiles was built into a regional thermal-burial model over the whole of the MSGBC Basin, supported by and based on extensive regional seismic 2D mapping.

Furthermore, we get an indication of the older SRs kitchen extent based on the extrapolated burial history model, taking overburden differences along the margin into account. Based on the modelling results and sparse data on source rock geochemistry along the margin, we included these unproven but anticipated source rocks from the older rift sections which give indications of higher maturities relative to the proven younger source rocks.

In phase 3) the authors of this paper anticipate being able to show how oil migrates into a currently perceived gas province, based on the calibrated continuous model from Phase 1 and 2 combined. Recent deep-water discoveries offshore Namibia prove the validity of challenging preconceptions around source (im)maturity in the OCTZ and oceanic crust in areas of low present-day surface heat flow, as well as exploring the potential for oil in a region previously considered as only a gas province (e.g., Kudu field) (Elliott, 2024).

Having a regional-resolution 3D model for burial and thermal history is valid with a resolution of hundreds of metres over several hundred kilometres, meaning it will still be meaningful. Reason for that is the 4-7 km thick sediment overburden in the basin and the shelf due to an open and connected passive margin that reaches from north to south without major tectonic limitations for the sediment influx and, therefore, continuing subsidence. The continuous temperature and burial model across the margin enables the modelling of the maturation history of the source rock layers as encountered in wells and as mapped based on seismic character.

The next step of source rock maturation modelling (currently in process) would be to explore sensitivities around the timing of generated hydrocarbon expulsion, taking seal capacity and non-seal sequence porosity for hydrocarbon migration into account. Modelling migration on such a regional scale is not only challenging, but potentially misleading due to local elements of mistie or disruption, such as the relatively coarse cell size of the regional 3D model, relying only on 2D seismic, and the importance of smaller-scale features such as fault throw and facies changes on migration vectors.

As a result, it is envisaged that phase 3 will be run on the licence block or sub-basin scale, producing smaller 3D BPSM models, built within the larger regional modelling AOI. These can better incorporate more localised details of lithostratigraphy, seal facies and anisotropic fluid movement elements in a 3D burial model based on high-resolution 3D seismic data. Clients may wish to de-risk or quantify the risk of prospects regarding charge volumes, predicted bulk fluid properties (e.g., phase, GOR and density), and critical elements (e.g., faults).

Conclusions

The BPSM investigation combined with the surface seep geochemistry survey aims to provide a comprehensive understanding of the regional petroleum systems, complementing structural and stratigraphic mapping from an extensive seismic data coverage. The MSGBC Basin has generally good quality regional stratigraphic seals, which may explain why hydrocarbon samples are rare to come by. Hence, maximising our understanding from the existing data provides the most cost-effective and insightful way to de-risk source rock presence and maturity, to help better target areas of opportunity.

The surface geochemistry survey shows oil microseepage occuring at different locations of the MSGBC Basin. Several source rock types are involved, some having highly anoxic sulphidic characteristics, which include carbonate-rich sources, and others displaying more terrestrial features. The distribution of oil and gas microseeps may relate to source rock kerogen type and maturity. This will be further explored in Phase 3 of the study with integration with the 3D BPSM exercise.

The 2D thermal-burial modelling of a transect offshore central Senegal shows the predicted maturity of the Cretaceous and Jurassic SR horizons varying laterally along the continental shelf and slope, largely as result of sediment burial, and is in good general agreement with the known petroleum systems in the margin and available thermal calibration data (e.g., TGS Heat Flow Report, 2019). We also tested the impact of an extended period of thermal quiescence following continental rifting and break-up, as suggested by recent dynamic models of rifting (Pérez-Gussinyé et al., 2024). These models extend the potential kitchen areas for the late Jurassic-early Cretaceous SR horizons to regions of lower sediment coverage between the continental slope and oceanic basement, and may explain some discoveries in the deep offshore of the MSGBC basin. These latest thermal models may also explain the maturity of the Albo-Aptian source rock for the recent deep-water discoveries in Namibia in areas previously deemed to be immature for HC generation.

Together the integrated geochemistry and BPSM results suggest the following:

The presence of natural microseeps in different locations of the MSGBC Basin indicates that at least one source rock has reached oil maturity along much of the MSGBC margin. It is in agreement with abundant oil shows and discoveries on the platform (e.g., Dome Flore), as well as the deep offshore basin (e.g., FAN-1), indicating the presence of widespread, regional source rocks. This is consistent with well penetrations of Cenomanian to Barremian source rocks in exploration and DSDP wells.

The biomarker composition of oil stains at microseeps suggests there are at least two source rocks of distinct lithofacies on the platform, one carbonate and one clastic. Correlation to carbonate-rich source rock(s) are likely to represent an Upper Jurassic source (e.g., Brownfield, 2016).

The observation of oil stains in a pockmarks field suggests that focused hydrocarbon migration has taken place in the geologically recent past, or is ongoing. This is consistent with the BPSM results, predicting oil and gas expulsion from both the Albo-Aptian and late Jurassic SRs.

Utilising the latest rifting thermal model invoking prolonged post-rift thermal quiescence (after Pérez-Gussinyé et al., 2024) predicts oil maturity of Aptian and late Jurassic SR in the deep offshore basin along much of the MSGBC margin. Along with the presence of FAN-1, this strongly suggests the potential for regional source rock kitchens west of the slope break, and not solely relying on charge from inboard basins within the platform.

Together, the available data and modelling work suggests the MSGBC Basin contains multiple source rocks which are likely to be regionally mature, both in the platform and in the deep offshore basin westwards, and may locally have generated hydrocarbons in the recent geological past or is ongoing, significantly de-risking geologically-recent hydrocarbon expulsion as a key exploration uncertainty.

Acknowledgements

We thank our partners for the data available to this study, PGS, GeoPartners, Petrosen**,** PC Gambia, Agence de Gestion et de Cooperation entre Le Sénégal et la Guinée Bissau, and TDI Brooks.

References

Brownfield, M.E. [2016]. Assessment of undiscovered oil and gas resources of the Senegal Province, northwest Africa. U.S. *Geological Survey Digital Data Series, 69*-GG, Chap. 2, 20p.

Clayburn, J. [2018]. Realising the deep water hydrocarbon potential of Senegal. AAPG Search and Discovery Article #70345.

Davison, I. [2005]. Central Atlantic margin basins of north West Africa: Geology and hydrocarbon potential (Morocco to Guinea), *J. African Earth Sci*., **43**, 254-274, doi:10.1016/j.jafrearsci.2005.07.018.

Elliott, P. [2024]. New light oil discovery draws attention away from the Orange Basin central axis to the northern promise. *GeoExpro*, February 2024.

Geomark [2020]. *Petroleum Geochemistry of 44 Piston Core Extracts Offshore Central Africa*.31pp.

Heine, C., Zoethout, J. and Muller, R.D. [2013]. Kinematics of the South Atlantic rift. *Solid Earth*, **4**, 215-253

Laske, G., Masters., G., Ma, Z. and Pasyanos, M., Update on CRUST1.0 - A 1-degree Global Model of Earth's Crust, *Geophys. Res. Abstracts*, **15**, Abstract EGU2013-2658, 2013.

Nemčok, M., Rybár, S., Odegard, M., Dickson, W., Pelech, O., Ledvényiová, L., Matejová, M., Molčan, M., Hermeston, S., Jones, D., Cuervo, E., Cheng, R. and Forero, G. [2016]. Development history of the southern terminus of the Central Atlantic; Guyana–Suriname case study. Geological Society, London, Special Publications, **431**, 145-178.

Pasyanos, M.E., Masters T.G., Laske, G. and Ma, Z. [2014]. LITHO1.0: An updated crust and lithospheric model of the Earth. *Journal of Geophysical Research*, **119**, doi:10.1002/2013JB010626.

Pepper, A.S. and Corvi, P.J. [1995]. Simple kinetic models of petroleum formation Part 1: oil and gas generation from kerogen. *Marine and Petroleum Geology*, **12**(3), 291-321.

Pérez-Gussinyé, M., Xin, Y, Cunha, T, Ram, R. Andrés-Martínez, M., Dong, D. & García-Pintado, J.. Synrift and post-rift thermal evolution of rifted margins: a re-evaluation of classic models of extension. In Kilhams, B., Holford, S., Gardiner, D., Gozzard, S., Layfield, L., McLean, C., Thackrey, S. and Watson, D. (eds). *The Impacts of Igneous Systems on Sedimentary Basins and their Energy Resources*. Geological Society, London, Special Publications, **547**.

Rüpke, L.H., Schmalholz, S.M. Schmid, D.W. and Podiadchikov, Y.Y. [2008]. Automated thermo-tectonostratigraphic basin reconstruction: Viking Graben case study: *AAPG Bulletin*, v. **92**, p. 309-326.

Sweeney, J.J. and Burnham, A.K. [1990]. Evaluation of a simple model of vitrinite reflectance based on chemical kinetics. *AAPG Bulletin*, **74**, 1559-1570.

TDI-Brooks International Inc., 2020. SGE Interpretative Report TGS MSGBC – All Legs. *Technical Report* – 20 – 3984, 137pp.

Zinecker, M.P. [2020]. *Structural and Stratigraphic evolution of three, Mesozoic rifted passive margins: 1119 Guinea Plateau, Demerara Rise and Southern Gulf of Mexico*. PhD Thesis. Univ. of Houston (302 pp).