Conjugate Basins, Tectonics and Hydrocarbons (CBTH) Project – Phase VIII (2026-2029)

Submitted
by:

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Project background and major objectives

The CBTH Project, or "Conjugate Basins, Tectonics and Hydrocarbons Project" began with the financial support of a consortium of oil companies on September 1, 2005 and has operated continuously for the past 21 years within seven three-year phases identified as I (2005-8), II (2008-11), III (2011-14), IV (2014-17), V (2017-2020), VI (2020-2023), and VII (2023-2026). This proposal requests funds to continue the consortium for Phase VIII, which would begin on September 1, 2026, and extend for three years through August 31, 2029.

For Phases I-IV, the consortium's previous title was "Caribbean Basins, Tectonics and Hydrocarbons (CBTH) Project," which was changed to "Conjugate Basins, Tectonics and Hydrocarbons (CBTH) Project" for Phase V in 2017.

CBTH Phase VIII will focus on identifying deepwater hydrocarbon accumulations along: 1) orthogonally-rifted-passive margins of northwest Africa and their conjugates in eastern Canada in the Central Atlantic Ocean; 2) obliquely-rifted-passive margins of Trinidad, Guyana-Suriname, and Brazil and their conjugates in west Africa in the Equatorial Atlantic Ocean; 3) orthogonally-rifted margins of eastern Brazil and Uruguay and their conjugates in Gabon, Angola, and Namibia in west Africa in the South Atlantic Ocean.

Personnel, project management, and reporting to sponsors

As in previous phases of this study (2005-2026), the proposed CBTH Phase VIII will be led by Dr. Paul Mann at The University of Houston (UH) and staffed by BS, MS, and PhD-level students and post-doctoral researchers at the UH Department of Earth and Atmospheric Sciences, who are employed by the CBTH Project. As of May 2026, the staff of the CBTH Project includes project leader Mann, project consultant Jeff Storms, senior researchers Sharon Cornelius and Jose Gorosabel, PhD students Kenneth Shipper, Daniel Maya, Ruth Beltran, Jumoke Akinpelu, Melania Maqway, Matthew McAllen, and MS students Estefani Ruiz and Conor Cahill.

All personnel will work on various CBTH-funded projects in our expanded study area. Resumes and research details for all current researchers involved with CBTH are posted on our website: https://cbth.uh.edu/proj_res.php

To provide annual summaries of project results to sponsors, the CBTH Project hosts a one-day CBTH year-end meeting (YEM) in early October each year of the project (next year-end meeting tentatively scheduled for Thursday, October 8, 2026). During this day-long meeting, CBTH researchers will summarize progress for the year in a series of oral presentations. Scheduled discussion periods will allow sponsors to provide feedback on completed work and offer suggestions for future work.

The meeting is held in person, but we can also schedule online follow-up meetings to reach international sponsors and their affiliates outside the Houston area. We also organize a luncheon for our sponsor representatives and CBTH personnel at each annual IMAGE meeting. This luncheon provides a good opportunity for sponsors to meet with the CBTH Project and learn more about our presentations at the meeting, which is the primary conference for most CBTH researchers at UH.

Finally, we can schedule in-person office visits with companies in the Houston area and arrange online meetings with companies outside the Houston area. For these visits, we report only on areas of immediate interest using CBTH personnel who are

actively working in those areas. Our company visits can be completed in as little as 1.5 to 2 hours.

Cost of CBTH Phase VIII

The total cost of the three-year CBTH Project Phase VIII is $216,000 per sponsor. We will require a three-year financial commitment from all CBTH Phase VIII sponsors with a minimum annual fee of $72,000 US due by August 15 of each year, starting with year one of the project in September 2026. These costs include both support for the original work done during the three years of Phase VIII, as well as curating and maintaining the GIS database acquired over the previous 21 years of the CBTH study. Our main costs include salaries for researchers and student researchers, computer hardware and maintenance, annual software costs, website maintenance and services, registration and travel to meetings, and publication expenses.

Data sources

As with the previous CBTH Project phases, CBTH Phase VIII data sources include 2D and 3D seismic data, well data, outcrop data, previous publications on the region, and original seismic and well data provided with permission by the sponsoring companies or government agencies.

As we have done in previous phases of the study, CBTH Phase VIII will continue to respect the conditions on the use of the donated data set by our data partners, which for CBTH Phase VIII will include TGS, Geoex-MCG, ANP, and Viridien.

Project deliverables

The CBTH Phase VIII study will integrate our seismic interpretation and well correlations across the entire region to produce crustal, structural, isopach, and paleogeographic maps, which we make available to our sponsors in digital format. Since the start of Phase V in 2017, we have provided sponsors with map products derived from our interpretations. Since the start of Phase VII in 2023, we have also begun including full-lithosphere 3D basin models generated with the newly developed ExCaliber software from Xplorlab (https://www.xplorlab.io/).

These quantitative basin models based on calculations of standard thermal stress (STS) provide our sponsors with an assessment of the maturity of the primary source rock intervals in our various study areas. All our models are validated using drilling results from those areas, including bottom-hole temperatures (BHTs) and Rock-Eval Tmax data. In addition, we are developing new methodologies to create source rock quality maps and to build expulsion and migration models, which will also be a major focus during Phase VIII. Our 3D basin modeling approach represents an efficient and cost-effective way for our sponsors to screen extensive, rifted-passive margins and focus their exploration efforts on areas with high-quality and mature source rocks.

Supporting materials used to constrain these basin models are delivered to sponsors for integration into their in-house databases. These include: (1) an integrated, regularly-updated, and user-friendly **GIS database** accessible via Geopost and secure FTP; (2) **structural and stratigraphic maps of key seismic surfaces** in the region; (3) our original **interpretations of seismic data and well data**; (4) **student and researcher poster and oral presentations** from international meetings including the annual SEG-

AAPG IMAGE that is usually held in Houston, the Fall meeting of the American Geophysical Union (AGU), the Africa conference of the Houston Geological Society held in Houston every two years, and other meetings such as the annual, regional ICE meetings of AAPG; (5) access to the **complete archive of CBTH publications from 2005 to present**, including in-progress publications; (6) access to the **CBTH sponsor website**, which provides real-time updates on project deliverables throughout the year; (7) **expanded-abstract format annual reports** to sponsors for years 1 and 2; and (8) a **large-format, map-based atlas** for year 3 of Phase VIII.

Web-based delivery of map products

During Phase V in 2018, CBTH partnered with Geopost Brazil and Katalyst Data Management to develop a web-based application, built on the ArcGIS Online platform, that enables sponsors to visualize CBTH annual release data in a web browser, eliminating the need to load the data into their own ArcGIS systems. The interface is user-friendly and regularly updated throughout the year.

Over the past eight years, CBTH personnel have been working with Geopost to populate our online data portal (https://uh.geopostenergy.com/) with all CBTH deliverables since the start of Phase I in 2005. During this process, we worked to ensure that all relevant materials were posted in the highest quality possible, often going back to the original thesis and publication files to ensure that figures and maps were posted at the highest available resolution.

We have also worked to eliminate redundancy by consolidating outdated materials, merging datasets, and meticulously comparing materials to our ongoing CBTH Contributions List (https://cbth.uh.edu/contributions.php) posted on our website. By maintaining a high level of quality control, workers at CBTH and Geopost are ensuring that this data portal is the most streamlined version of the CBTH database yet.

Following our focus on basin modeling since Phase VII, we are developing a new basin modeling database that will also be available on the Geopost platform for sponsors during Phase VIII. This new database will include all the necessary inputs for sponsors to run their own 3D basin models that include: geochemical data, crustal parameters, temperature controls, 1D models, well tops, paleo-water-depth models, and lithological composition of the main megasequences.

The additional costs for the CBTH use of the Geopost online platform are now included in the annual membership cost for the CBTH Project. For continuing sponsors, credentials are generated and distributed by Geopost following each annual sponsor meeting. All current and previous data releases remain available via our secure FTP server. With Geopost, a user can open a geographic window, easily display the many categories of CBTH data for this area, and then download various files, including thesis and publication PDFs, raster grids, and vector data such as wells, seismic locations, seeps, basement terranes, and much more. Finally, we offer new and continuing sponsors assistance with the display and interpretation of these data as part of our company visits and online meetings.

Role of publications in the CBTH Project

As CBTH is a research consortium at the Department of Earth and Atmospheric Sciences of the University of Houston, publication plays a key role in both the

professional development of the post-doctoral researchers and BS, MS, and PhD-level students. Publications also allow more integration of our work with studies being done by research groups both at other universities and in exploration groups at oil companies.

Our CBTH-supported theses at UH are organized into chapters, with each chapter being written as a stand-alone publication. This thesis style makes all our studies more comprehensible to sponsors. Chapters submitted for publication undergo an intensive peer-review process by experts in their field, which greatly improves the overall quality of the work.

Goals of Phase VIII of the CBTH Project (2026-2029)

The primary scientific goal of CBTH Phase VIII is to continue developing an integrated, lithosphere-scale understanding of how rifted-passive margins and their conjugate margins evolve and how their tectonic, crustal, and thermal histories control petroleum system development. Building on more than two decades of work, Phase VIII will consolidate CBTH's transition from regional structural and stratigraphic analysis to fully quantitative, 3D basin modeling that integrates plate tectonic reconstructions, crustal architecture, heat-flow history, and source-rock geochemistry with hydrocarbon generation, expulsion, and migration.

Although initially focused on the Gulf of America and the Caribbean (Phases I-V), Phase VIII targets two mega-regions, the Equatorial and South Atlantic margins, in addition to conjugate studies in the Central Atlantic areas of Morocco and Nova Scotia, Newfoundland and Labrador (Fig. 1). By structuring Phase VIII around these two mega-regions, CBTH aims to transform a large collection of high-quality regional studies into a unified, predictive framework for conjugate margin petroleum systems. Together, the Equatorial and South Atlantic provide complementary natural laboratories for testing the roles of basement inheritance, rift style, volcanic versus non-volcanic margin development, and lithospheric thermal evolution in controlling hydrocarbon generation and charge. This regional scale of geologic and geophysical synthesis is necessary to build the quantitative, lithosphere-scale basin that we will continue to develop in Phase VIII.

A central and ongoing theme of CBTH Phase VIII is the study of rifted and conjugate margins as natural laboratories for understanding the tectonic and thermal controls on petroleum systems. These studies directly address one of the major scientific questions motivating Phase VIII: *How do inherited basement grain and crustal architecture influence rifting style and structural development, and how do these factors in turn control source rock distribution, maturation pathways, and hydrocarbon prospectivity?* (Mann, 2022).

Recent CBTH presentations comparing "look-alike" conjugate systems emphasize both similarities and contrasts in rift style, volcanic versus non-volcanic margin development, source rock distribution, and stratigraphic architecture (Beltran and Mann, 2023; Shahriar and Mann, 2023; Shipper and Mann, 2023; Gorosabel-Araus and Mann, 2024a,b; Maya and Mann, 2025). Phase VIII builds directly on this foundation by shifting from margin-scale qualitative comparisons to fully integrated, quantitative basin modeling frameworks that explicitly incorporate crustal structure, heat-flow evolution, and lithosphere dynamics.

To achieve this objective, Phase VIII focuses on deepwater exploration and basin modeling of two principal mega-regions: the Equatorial Atlantic and the South Atlantic, which are the focus of major deepwater oil and gas discoveries over the past decade.
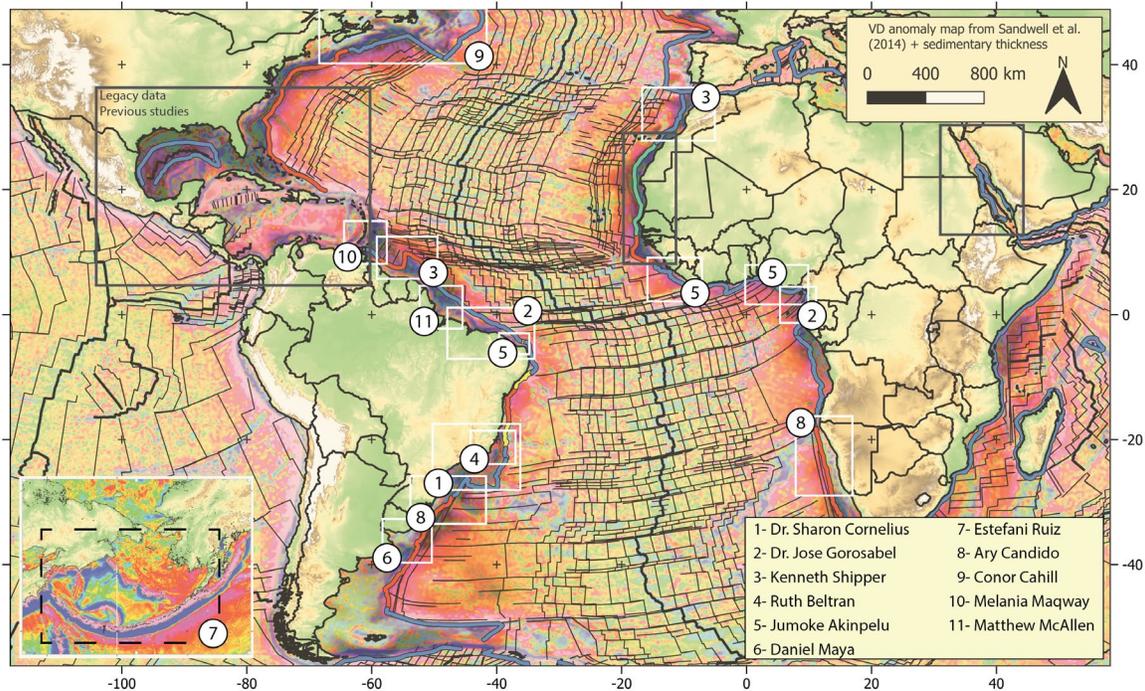
Figure 1. *Location of the study areas (numbered, white boxes) during Phases VII and VIII of the CBTH Project and the researchers involved in each of these studies. The large black box is our legacy area of previous CBTH studies in the Gulf of America and the Caribbean. All previous data from the legacy area is available online to sponsors.*

Legacy data from the Gulf of America and the Caribbean Sea

Since its inception in 2005, CBTH has built a comprehensive global database of rifted and conjugate margin systems that encompass the Central, Equatorial, and South Atlantic Ocean, and legacy regions of previous work in the Caribbean and Gulf of Mexico (Phases I-VII) (Fig. 1). This long-term effort has generated a rich legacy dataset that includes seismic interpretation, gravity and magnetic modeling, crustal structure, stratigraphy, and petroleum system analysis. The accumulated and curated knowledge from our previous studies provides the scientific foundation for Phase VIII and ensures that new research in Phase VIII is based on an internally consistent regional framework.

Completed studies of the Gulf of America conjugate margins include the MS thesis by Steier (2018) and the PhD studies and subsequent publications by Lin (2018), Lin et al. (2019), Liu et al. (2019), Kenning (2020), Kenning and Mann (2020a,b), Kenning and Mann (2021), Liu (2021), Hasan and Mann (2021), Hasan (2022), Bugti (2022), and Bugti and Mann (2023). These studies documented the shared structural inheritance and stratigraphic evolution of the northern Yucatán margin and the northeastern Gulf of America. These theses and their derived conference presentations and peer-reviewed publications (https://cbth.uh.edu/contributions.php) in leading

geoscience journals establishes a benchmark for understanding how pre-rift basement architecture and rift-related deformation influence post-rift basin development, thermal evolution, and petroleum systems.

Regional mapping of basement type, structure, stratigraphy, and hydrocarbon plays of the Nicaraguan Rise, Colombian Basin, and Venezuelan Basin has been developed through a series of PhD studies and associated publications (Alvarez, 2014; Ott, 2015; Sanchez, 2015; Leslie and Mann, 2016; Carvajal, 2017; Torrado, 2018; Carvajal and Mann, 2018; Sanchez et al., 2019; Torrado et al., 2019; Carvajal et al., 2020; Leslie, 2020; Leslie and Mann, 2020; Tillman and Mann, 2020; Romito and Mann, 2020). Collectively, these studies demonstrate that inherited crustal blocks, tectonostratigraphic terranes, and basement heterogeneity exert first-order control on source rock families, basin architecture, and petroleum system development.

Similarly, Ramos (2024) and Ramos and Mann (2023) integrate gravity and magnetic data, seismic reflection data, basin modeling, and seismic tomography to quantify the tectonic controls on hydrocarbon generation and migration in accretionary and collisional settings, focusing on the South Caribbean and Panama deformed belts. These studies extend CBTH's legacy beyond passive margins and highlight the importance of convergent-margin processes for understanding petroleum systems in structurally complex regions.

These legacy datasets and previous studies form a cumulative, internally consistent knowledge base that is unparalleled in its geographic scope and tectonic diversity. They enrich the CBTH GIS database and provide critical calibration points for crustal models, plate reconstructions, and basin modeling workflows. Phase VIII will leverage this legacy by integrating new regional studies in the Equatorial and South Atlantic Oceans.

Overview of proposed work for Phase VIII

Proposed work for Phase VIII in Trinidad and the Barbados accretionary prism and links to previous studies in the Caribbean

Our only area of Caribbean research area in Phase VIII will focus on basin modeling in Trinidad and the Barbados accretionary prism (Fig. 2). This Caribbean effort will build directly on previous work in the Caribbean region, including the Nicaraguan Rise and the Caribbean margins of Colombia and Venezuela.

The complex, three-way interaction between Trinidad, the Barbados accretionary prism, the South American passive margin, and the Caribbean arc is critical for understanding the petroleum systems of Trinidad and Tobago and their linkage to the hydrocarbon-rich and undeformed passive margin of Guyana and Suriname (Alvarez, 2014; Gomez, 2018; Gomez et al., 2018; Alvarez et al., 2021a,b; Gomez et al., 2021; Moore, 2022). Our previous basin modeling in Guyana-Suriname provides the geological framework for evaluating the source rocks, structural styles, and hydrocarbon charge in the deformed Trinidad area. The Trinidad basin modeling study will also benefit from Kenneth Shipper's ongoing 3D basin modeling study along the Guyana margin described below.

Proposed work for Phase VIII on conjugate margins of the Equatorial Atlantic in Brazil and West Africa

CBTH has developed a growing body of structural, stratigraphic, and basin modeling studies on the conjugate margins of northeastern South America and central Africa. A key foundational study of northwest Africa is the completed PhD study by Zinecker (2020) and the PhD work by Upal Shahriar (now in review), which established the regional tectonic and stratigraphic framework of the Senegal and Mauritanian margins and their conjugate relationships with North America.

The primary objective of Phase VIII in this region is to construct, for the first time, a continuous, margin-scale basin model of the entire South American Equatorial Atlantic, extending 3500 km from Trinidad to the Potiguar Basin in northeastern Brazil, including new potential regions like French Guyana (Fig. 2). This effort will utilize the results of ongoing and newly initiated doctoral and postdoctoral projects along the conjugate margins of the Equatorial and South Atlantic (Fig. 1).

This study will develop tectono-sedimentary models of the margin to define better the ages of rifting, continental breakup, and marine incursions, as well as source rock characterization of syn-rift and early post-rift intervals, including source-quality mapping and 3D modeling. (Gorosabel-Araus and Mann, 2024a,b; Gorosabel-Araus et al., 2024a,b; Gorosabel-Araus et al., 2025a,b). The final products for this study will include UEP maps of the main source rock intervals and thermal stress and expulsion maps.

On the South American margin, our proposed work for Phase VIII will include:

- Ongoing PhD research by Kenneth Shipper on 3D basin modeling of the Guyana–Suriname margin (Shipper et al., in press-a) (Figs. 1, 2A).
- A new project in Trinidad by PhD student Melania Maqway, to develop a 3D basin model for Cenomanian-Turonian source rocks in the complex transition zone between the Barbados accretionary prism, the South American passive margin, and the Caribbean arc. Trinidad is the deformed equivalent of the Guyana margin so this 3D model will investigate the mature play fairways of the Cenomanian-Turonian source rocks in this deformed area (Figs. 1 and 2A). Previous work from the CBTH group by Alvarez et al. (2021) and Gomez et al. (2021) mapped the deformed zone in the offshore areas and correlated these structures to the onshore area of Trinidad and Tobago.
- A new project by PhD student Matthew McAllen in the Foz do Amazonas region, which is a transitional zone from the Guyana-Demerara margin to the basins of Equatorial Brazil that includes the belt of prolific Cenomanian-Turonian source rocks we have studied in Guyana-Suriname. This project will also integrate data from French Guiana, which provides a continuous, geographic link between the Foz do Amazonas study and the study area of PhD student Kenneth Shipper in Guyana (Shipper et al., in press-a) (Figs. 1, 2A).
- Ongoing basin modeling and crustal studies by Dr. Jose Gorosabel in the Barreirinhas (conjugate of the Tano Basin in the Ivory Coast and Ghana)**,** Ceará, and Potiguar basins of Equatorial Brazil (Figs. 1, 2A).

- Ongoing research by PhD student Jumoke Akinpelu in the Potiguar Basin of Equatorial Brazil that builds on her completed work on its conjugate margin in Nigeria and the Niger Delta (Figs. 1, 2A).
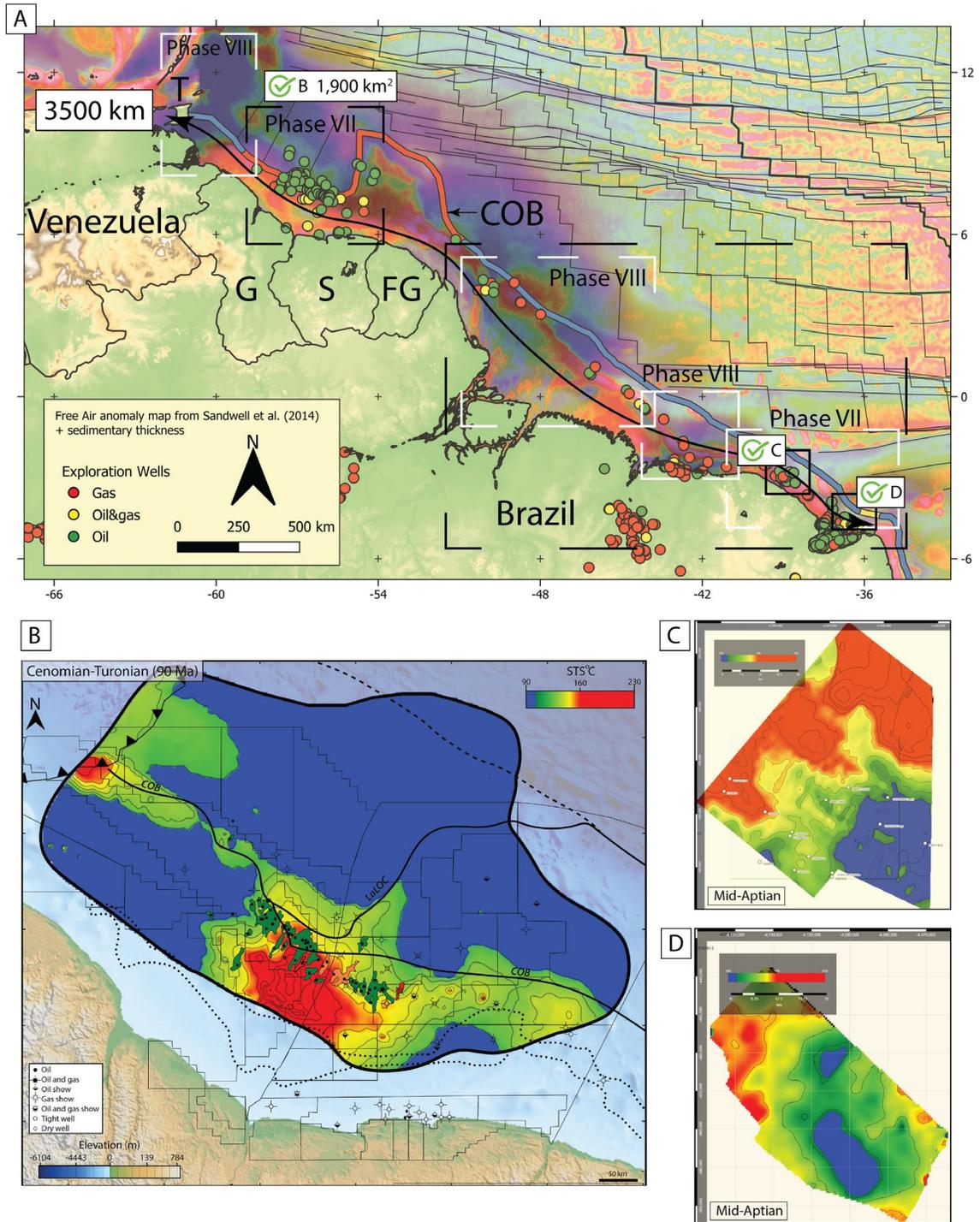

Figure 2. A. *Equatorial Atlantic megaregional overview with white boxes showing areas of active research in the current Phase VII and the proposed Phase VIII. Blue and red lines indicate the continent-ocean boundary (COB) for non-volcanic and volcanic*

*margins, respectively, as determined in our previous studies. The effect of changing margin type on hydrocarbons is a major goal of the proposed Phase VIII. **B**. 3D Basin model of the Guyana – Suriname margin from Shipper et al. (in press). Red indicates Cenomanian-Turonian source rocks mature for gas; light green indicates the same source rocks mature for oil. Known oil fields in the Miracle Mile area of Guyana are shown in dark green, with black dots indicating productive wells. Blue color indicates immaturity. **C-D**. 3D Basin model of the Ceara Basin (C) (Gorosabel-Araus et al., 2025a,b) and Potiguar Basin (D) (Akinpelu, manuscript in progress) deepwater region. Color code for both maps is the same as shown on the map in A.*

On the African conjugate margins, Phase VIII will integrate:

- The completed work of PhD student Upal Shahriar on the Guinea Plateau–Mauritania margins, which provides critical constraints on volcanic versus non-volcanic rift segmentation (Shahriar, manuscript in progress)
- A new, regional 3D basin modeling project by PhD student Jumoke Akinpelu covering the entire Liberian margin that complements her completed studies of the adjacent area of the Niger Delta (Akinpelu, manuscript in-progress)
- Previous and ongoing basin modeling work by Dr. Jose Gorosabel in Ghana and Equatorial Guinea (Gorosabel and Mann, 2025)

Together, these studies will enable CBTH to test how basement inheritance, rift segmentation, and crustal type control source rock development, thermal evolution, and petroleum system efficiency across the continuous and obliquely-rifted Equatorial Atlantic margin. This integrated approach supports Phase VIII's broader objective of developing quantitative 3D basin models that link conjugate-margin evolution to hydrocarbon generation, expulsion, and migration at the regional scale.

Proposed work for Phase VIII on South Atlantic rifted, conjugate margins

CBTH has also developed an extensive and mature body of work on South Atlantic conjugate margins. The completed PhD study by Reuber (2017) and subsequent publications (Reuber and Mann, 2019; Reuber et al., 2019) used deep-penetration ION (now TGS) seismic lines to establish a tectono-stratigraphic framework for the Austral South Atlantic margins of Brazil and West Africa, and to provide one of the earliest, systematic conjugate-margin syntheses in this region as discussed in the review paper by Mann (2022). These early studies by Reuber were extended by Romito (2021) and Romito and Mann (2022), who investigated the crustal structure of the Camamu-Almada basins of northeastern Brazil. A parallel PhD study by Zhang (2021) studied the adjacent area of the Sergipe-Alagoas Basin.

Ongoing studies include work by Dr. Sharon Cornelius and Ruth Beltran (PhD in progress), who are developing regional geophysical and basin-modeling analysis for the entire Campos–Santos–Espírito Santo rift system and its prolific hydrocarbon plays (Cornelius, 2025a, b; Beltran et al., 2025; Beltran and Mann, 2026). These CBTH studies will continue into Phase VIII, integrating gravity and magnetic interpretation, seismic stratigraphy, geochemical analysis, and basin modeling to resolve the links between crustal architecture, rifting evolution, and petroleum system development.

Phase VIII will expand this South Atlantic, 3D basin model southward to include the Pelotas Basin (Ary Candido, PhD in progress) and the offshore Uruguay margin (Daniel Maya, PhD in progress; Miller, MS, 2025). The PhD study by Daniel Maya in Uruguay integrates deep-water 2D and 3D seismic interpretation and basin modeling in collaboration with ANCAP in Uruguay (Maya and Mann, 2025). These southern margins have become a primary focus of CBTH due to their relevance to recent giant discoveries in Namibia and their importance as analogs for frontier deepwater exploration along volcanic rifted margins.

The ultimate goal for the South Atlantic in Phase VIII is to produce an integrated, continuous, basin-scale model extending 4000 km from Uruguay to the Espírito Santo Basin (Fig. 3). The new PhD study by Ary Candido in the Pelotas Basin of southern Brazil will fill the gap between our studies of the Santos (Cornelius, in press), Campos (Beltran and Mann, 2026), and the work being completed by PhD student Daniel Maya in Uruguay (Maya and Mann, 2025).
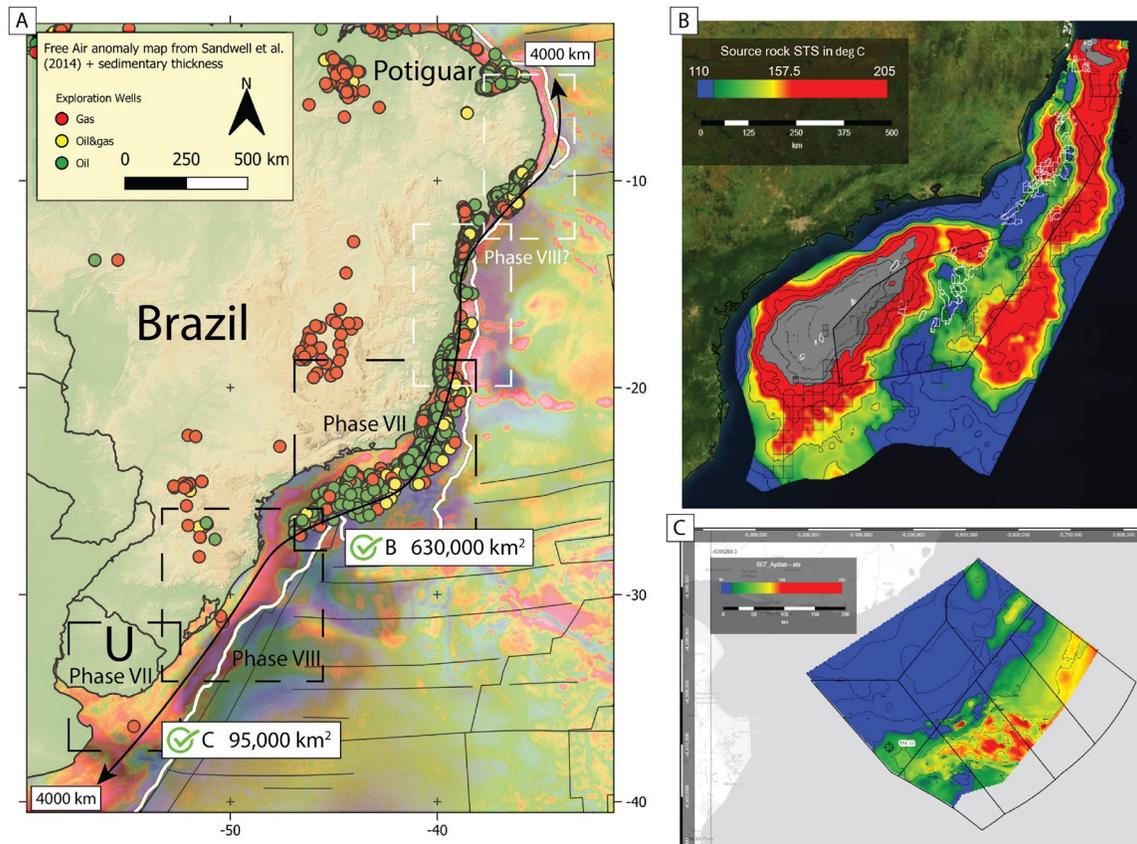
Figure 3. *A. South Atlantic megaregion overview.* *B. 3D Basin model of the Santos-Campos-Espirito Santo Basins.* *C. 3D Basin model of the Uruguayan margin.*

Proposed work for Phase VIII on the Central and North Atlantic rifted, conjugate margins

Phase VIII will expand CBTH activities into the Central and North Atlantic through projects in offshore Morocco, its conjugate margin in Nova Scotia, and the northeastern Canadian margin of Newfoundland and Labrador. Ongoing and planned

work by Kenneth Shipper and Jose Gorosabel in Morocco will integrate crustal structure, seismic interpretation, and f modeling to improve understanding of the thermal evolution of this non-volcanic rifted margin and its implications for source rock maturation and hydrocarbon charge. These studies have shown that the play fairway of mature, Jurassic source rocks extends 140 km onto late Jurassic oceanic crust (Shipper et al., in press-b). This work by the group in northern Morocco builds on a completed MS thesis and publication by Tarek Galhom (Galhom, 2020; Galhom et al., 2022).

In parallel with this work in northwest Africa, a new project in Newfoundland and Labrador, led by MS student Conor Cahill under the supervision of Mann and Gorosabel, will focus on the northeastern Canadian margin. Beyond basin modeling, this study will emphasize detailed analyses of source rock distribution, maturation history, and hydrocarbon expulsion along strike, in relation to variations in crustal type, sediment thickness, paleo-water depth, and thermal regime. As in Morocco (Shipper et al., in press), we are observing maturity trends that extend tens of kilometers onto Jurassic oceanic crust.

Proposed work for Phase VIII on plate tectonic reconstructions in critical areas

CBTH has continued its long-standing effort to improve regional-scale plate tectonic reconstructions and paleogeographic frameworks. Building on the Pacific-derived origin of the Caribbean Plate, Alejandro Escalona, Ian Norton, and co-workers developed regional plate models for the Gulf of Mexico, Caribbean, and northern South America that has been widely applied in paleogeographic studies (Escalona et al., 2021a). For the Caribbean region, these reconstructions were further refined using PaleoGIS software in AAPG Memoir 123 (Escalona et al., 2021b).

A major objective of Phase VIII is to more fully integrate the CBTH GIS database with these plate reconstructions to strengthen kinematic constraints on basin evolution, sediment routing, and thermal history. Recent and ongoing studies by Shipper (PhD in progress) and Akinpelu (PhD in progress) aim to improve the GPlates-based reconstructions in critical areas, including the Guyana–West Africa conjugates and the Equatorial Atlantic (Shipper and Mann, 2024; Akinpelu and Mann, 2025).

Proposed work for Phase VIII on 3D basin modeling at mega-regional scales

A major methodological advance of Phase VII and a central theme of Phase VIII is the application of full-lithosphere basin modeling using the ExCaliber software developed by Jean-Marie Laigle and Andrew Pepper (https://www.xplorlab.io/).

Phase VIII will expand these applications of the ExCaliber modeling software by integrating basin modeling with detailed crustal structure, lithosphere-wide gravity inversion, radiogenic heat production maps, and transient post-breakup heat flow. Kenneth Shipper has applied these approaches to the Guyana–Suriname (Shipper et al., 2025; Shipper and Mann; 2025) and Moroccan margins (Shipper, 2024, 2025), Senior Scientist Dr. Sharon Cornelius to the Espírito Santo–Campos–Santos system (Cornelius, 2025a,b), and Senior Researcher Dr. Jose Gorosabel to the Rio Muni Basin of Equatorial Guinea (Gorosabel-Araus, 2024) and the Ceara Basin in Brazil (Gorosabel-Araus et al., 2025a,b). These modeling studies demonstrate the power of thermal stress modeling as a physically consistent alternative to basin modeling approaches based solely on vitrinite reflectance, as the thermal stress method incorporates crustal type, paleo-water depth,

sediment thickness, organofacies distribution, and heat flow history into a unified framework.

Phase VIII will further extend these methods by incorporating the effects of small-scale mantle convection and transient post-rift heat flow, thereby strengthening the physical basis of regional basin models. This work directly addresses one of the central goals of upcoming Phase VIII research: *To move beyond maturity assessment based on vitrinite reflectance and move toward quantitative prediction of hydrocarbon expulsion, migration pathways, and charge risk at the mega-regional scale.*

Flexural modeling and cross-sectional restorations will continue to constrain uplift, erosion, and subsidence histories in both passive and collisional settings. Previous flexural studies in the Llanos Basin (Campos and Mann, 2015), the Putumayo Basin (Pachon-Parra et al., 2020), and the Caribbean plate interior (Romito and Mann, 2020) provide a foundation for new applications in Phase VIII, along with ongoing flexural work by Kenneth Shipper on the Guyana–Suriname margin and on subducting oceanic crust beneath the Lesser Antilles and northeastern Caribbean (Shipper and Mann, 2024). These flexural studies are critical for evaluating the timing and efficiency of hydrocarbon kitchen development, migration, and trap formation.

Focus areas and deliverables: Trinidad and Tobago

Extending understanding of Guyana-Suriname into Trinidad and the Barbados Prism
The Guyana–Suriname Basin and offshore Trinidad and Tobago can be treated as jigsaw pieces within a regionally connected Equatorial Atlantic petroleum system, in which Cretaceous marine source rocks, lithospheric thermal structure, and large-scale migration pathways straddle major crustal boundaries. In the Guyana–Suriname margin, integration of the following data types allows prediction of standard thermal stress (STS) and maturity across both Aptian and Cenomanian–Turonian source rock intervals. This is achieved by inputting crustal thickness, LAB geometry, radiogenic heat production (RHP), seismic, gravity, and geochemical data within a full-lithosphere, transient 3D basin model.

Rock-Eval data from Demerara Plateau deepwater exploration wells and ODP sites indicate organic-rich marine mudstones (TOC up to 6%, HI 200–600 mg HC/g TOC, organofacies B) with ultimate expellable potential (UEP) reaching 126 mmboe/km² along the shelf–slope transition (Staatsolie, 2026). Our 3D model for Guyana-Suriname shows the Cenomanian–Turonian oil window concentrated in Blocks 52 and 58, diminishing northward, whereas the deeper source rock Aptian interval remains mature farther east and north into distal Suriname (Blocks 63–64) (Fig. 2B). This predicted pattern of maturation explains Lower Cretaceous discoveries such as Keskesi East-1 well. Our model predicts reduced thermal maturity increases the risk of vertical migration into shallower Cretaceous reservoirs in the westernmost areas of offshore Suriname. Most Stabroek fields fall within the oil–gas condensate window, implying either a migration lag or an earlier charge from the maturation of deeper Aptian source rocks (Fig. 2B).

Extending this model-tested and calibrated Guyana–Suriname thermal framework links these proven source kitchens with frontier areas of offshore Trinidad and Tobago's ultra-deepwater domain along the Barbados Accretionary Prism and eastern abyssal plain (Fig. 2B). Over 20,000 line-km of regional 2D seismic across the southeastern Caribbean,

combined with 51,677 km² of dense seismic in Guyana–Suriname, enables construction of a merged 3D petroleum systems model that reconstructs burial and temperature history, expulsion timing, and the maximum vertical migration height across the merged domain. Stratigraphic correlation between the locally exposed Naparima Hill Formation in Trinidad and the deeply buried Canje Formation of Guyana, previous studies of oil geochemistry (e.g., Royston-1, Donohue et al., 2022), and UEP estimates for Turonian–Coniacian intervals (up to ~6 mmboe/km² per interval in Trinidad datasets) all indicate regional continuity of Late Cretaceous marine source facies.

Beneath the Barbados prism, thickened Cretaceous sections are cut by toe-thrusts and back-thrusts that may act as migration conduits that potentially charging Cenozoic clastic reservoirs derived from the Orinoco system analogous to Guyana's prolific deepwater plays of the "Miracle Mile" (Price et al., 2021). By applying full-lithosphere transient thermal modeling and UEP maps constrained by rock-eval pyrolysis data across the merged area, our 3D models will directly delineate kitchen extent, maturity limits, and charge risk, providing a predictive framework to evaluate the magnitude and extension of the Guyana "Miracle Mile" into deepwater Trinidad and Tobago (Fig. 2B).

Phase VIII deliverables for Trinidad and Tobago and the Barbados prism
As mapping is now well underway for this focus area, our goal is to complete a 3D basin model to understand hydrocarbon generation. Completing the 3D basin model will require the following steps:
1) Integration of previous crustal models with mapping of main stratigraphic sequences and source rock evaluation.
2) Study of the geothermal gradient based on well data (BHTs, Tmax, and vitrinite reflectance) and previous work by other groups.
3) Determination of paleo-water depths based on inverting variation as paleo-water depth of tectonic subsidence from a 3D tectonic subsidence model following the methodology of McKenzie (1978).
4) Geochemical characterization of the margin based on well data, including the calculation of the Ultimate Expellable Potential (UEP).
5) Thermal stress modeling of the basin using the ExCaliber software.
6) Identification of the main kitchens and timing for hydrocarbon generation and expulsion.
7) Determination of the oil migration front from an assumed percolation saturation of 2%, average porosity of 10%, formation volume factor of 1.5, and modeled oil expulsion.

Our goal for this area for Phase VIII is to produce the following deliverables:
1) Grids of the main sedimentary sequences, including the top basement, Moho, and gravity-inverted LAB.
2) Geochemical characterization of potential source rocks using well data from the basins and regional data from previous work.
3) Source quality maps based on geochemical data and paleo-depositional environments.
4) 1D basin modeling of pseudowells, including STS and expelled hydrocarbons.

5) 2D mapped basin modeling, including standard thermal stress (STS) maps based on calculated radiogenic heat production (RHP) and expelled hydrocarbons maps.

Focus areas and deliverables: the Guyana-Suriname margin

Current level of understanding

The Guyana–Suriname margin is characterized by along-strike variability, transitioning from a non-volcanic rifted margin offshore Guyana to a volcanic margin beneath the Demerara Plateau offshore Suriname (Trude et al., 2023). This along-strike transition affects the transient lithospheric thickness, basal heat flow, and variations in source rock maturation. To model these controls on hydrocarbons, we integrate regional seismic interpretation with gravity inversion results to constrain crustal thickness, Moho depth, and lithosphere–asthenosphere boundary (LAB) geometry across the basin. These data are incorporated into a transient, full-lithosphere 3D basin model that predicts the spatial distribution of standard thermal stress (STS). The model is calibrated using temperature data from regional wells and validated against the locations of wells with petroleum discoveries along the margin.

Modeled standard thermal stress at the Cenomanian–Turonian interval indicates that thermal maturity to the oil window extends across Blocks 52 and 58 but diminishes northward of Block 66 (Fig. 2A). This pattern mirrors the distribution of established discoveries and suggests that the proven play fairway has greater thermal maturity than the northernmost offshore Suriname blocks at this stratigraphic level.

In contrast, modeled STS at the Aptian interval shows thermal maturity to the oil window extending farther east and north into Blocks 63 and 64, in addition to the areas where maturity is established at the Cenomanian–Turonian level (Fig. 2B). This deeper, older source interval therefore, represents a viable alternative charge scenario for the Lower Cretaceous, as indicated by the Keskesi East-1 discovery, and may provide a path for future exploration success in distal offshore Suriname.

Our thermal modeling places most fields within the Stabroek Block of Guyana in the oil–gas condensate window (Fig. 2B). The apparent discrepancy between this elevated maturity and the dominance of oil accumulations along the highly productive "Miracle Mile" of Guyana reflects either vertical migration lag or charge from a deeper Aptian source rock interval that entered the oil window earlier in the basin's history.

Phase VIII deliverables for the Guyana-Suriname area

For the Guyana-Suriname area, we have completed the regional mapping of the seismic grid and ties to wells, a 3D crustal model, and 1D basin modeling (Fig. 2B). This modeling includes gravity inversion of the LAB and the creation of RHP maps that characterize along-strike variations in basement types, based on our compilation of onshore geologic maps showing basement rock types in coastal areas.

The preliminary 3D basin models will be improved in Phase VIII by creating new paleo-water-depth and source-rock-quality maps, including Ultimate Expellable Potential maps derived from geochemical data from wells and paleo-depositional environments.

During Phase VIII, we will provide sponsors with the following deliverables for the Guyana-Suriname margin:

1) Seven key grids of the main sedimentary sequences, including top basement, Oxfordian, Aptian, Albian, Maastrichtian, Paleogene, and Neogene.
2) Crustal thickness grid from French Guiana to Venezuela, including Trinidad and its offshore area.
3) Source quality maps based on geochemical data and paleo-depositional environments.
4) 1D basin modeling of pseudowells, including STS and expelled hydrocarbons.
5) 2D mapped basin modeling, including standard thermal stress (STS) maps based on calculated radiogenic heat production (RHP) and expelled hydrocarbons maps.
6) Oil migration front maps based on the 3D STS modeling and the geochemical characterization of the margin.

Focus areas and deliverables: the Liberia and Harper Basins, West Africa

Current level of understanding

The Liberia and Harper offshore basins are located northwest of the West African Equatorial Transform Margin (WATM) and were deformed by the opening of the Central Atlantic Margin beginning in the Late Jurassic and continuing during the Early Cretaceous (Fig. 1). The Monrovia Fracture Zone bounds the Liberia Basin to the north, and the Greenville Fracture Zone bounds it to the south, separating it from the Harper Basin across the Liberia high (Bennet and Rusk, 2002; Cooper and Liu, 2010) (Fig. 1).

Exploration efforts in the Liberia Basin had limited success, with hydrocarbons discovered at various stratigraphic levels but in non-commercial quantities. The primary reservoir targets are Albian and Upper Cretaceous sandstones, analogous to those found in other basins along the WATM. The anoxic environment in the WATM between the late Albian and the Turonian provided ideal conditions for source rock preservation within the syn-rift system and early passive margin sequences (Wagner and Pletsch,1999; Morgan, 2003). The Harper Basin remains a frontier area that has been less explored and untested by exploration wells (GeoExPro, 2020).

For these two areas, we will integrate the interpretation of an extensive seismic reflection grid, well data, gravity and magnetic data, and 3D basin modeling, using the same methods described above. The goal of this study is to understand the controls on fairways, petroleum systems, and hydrocarbon types in the Liberia and Harper basins.

Phase VIII deliverables for the Liberia and Harper Basins

The final objective of this study will be to complete a 3D Excalibur basin model for the sedimentary sections of the Liberia and Harper basins. The basin modeling work will require constructing a full-lithosphere thermal transient model that integrates mapped source rock intervals, downhole temperatures, subsidence, stratigraphy, overburden thickness, source rock characteristics, crustal type, and crustal thickness, and establishing thermal stress trends. Deliverables for the Liberia Basin will include:

1) Maps of the Moho and continent-ocean boundary, which is apparent on the seismic reflection data, and the thickness of the sedimentary section based on integration of gravity and magnetic modeling.
2) Maps of the main sedimentary sequences from a grid of 2D seismic reflection lines with ties of the main stratigraphic units to surrounding wells.
3) The geochemical characterization of source rocks is based on regional data from published sources, including the organofacies classification of the primary source rock intervals.
4) Basin modeling for the main potential source rocks using the method of standard thermal stress (STS) maps that are constrained using estimates of radiogenic heat production (RHP), along with maps of expelled hydrocarbons for the Aptian-Albian and Turonian-Cenomanian source rock intervals.
5) 1D basin modeling of pseudo-wells, including volumetric estimates of their expelled hydrocarbons.
6) The integration of crustal thickness, heat flow, and paleo-water depth data into basin models
7) Predictive maps of source rock play fairways and timing for the hydrocarbon generation and expulsion based on the 3D ExCaliber basin model.

Focus areas and deliverables: Equatorial Brazil

Current level of understanding
CBTH is developing an integrated understanding of the Brazilian Equatorial Margin, based on work carried out during Phase VII in the Barreirinhas, Ceará, and Potiguar basins (Gorosabel-Araus and Mann, 2024b; Gorosabel-Araus et al., 2025a,b) (Fig. 2). These completed and ongoing studies have combined seismic interpretation, crustal-structure analysis, geochemical data, and basin modeling to establish a coherent regional framework for the tectonostratigraphic and petroleum system evolution of this margin. As a result, CBTH has developed a solid foundation of geological, geophysical, and geochemical constraints that can be directly applied to a continuous, margin-scale basin model.
3D basin models for the Potiguar and Ceará basins by Dr. Jose Gorosabel and Jumoke Akinpelu are nearing completion and provide new and important constraints on burial history, thermal evolution, source rock maturation, and hydrocarbon generation (Gorosabel-Araus, 2025a). In parallel, first-year, PhD student Matthew McAllen is initiating a new project in the Foz do Amazonas area that extends the CBTH study area westward into one of the least explored but most geologically significant segments of the margin. Together with ongoing and previous work in the Barreirinhas Basin, these four basins (Foz do Amazonas, Barreirinhas, Ceará, and Potiguar) define a continuous, 3500-km-long transect along the Brazilian Equatorial Margin that is ideally suited for integrated regional basin modeling (Fig. 2A).
Results presented by CBTH at several international conferences over the past three years have demonstrated that this margin contains exceptionally high-quality source rocks formed during two key intervals (Gorosabel-Araus, 2025b). The older source rock interval corresponds to Valanginian–Barremian lacustrine source rocks deposited during the earliest syn-rift stages that have been documented by deepwater wells in the eastern

area of the equatorial margin. This older source rock interval exhibits excellent organic richness and hydrocarbon-generating potential (Spigolon, 2003). The younger source rock interval corresponds to Aptian marine source rocks deposited during the regional marine transgression that affected the entire Brazilian Equatorial Margin and formed a laterally extensive source rock fairway.

Phase VIII of the CBTH Project will now focus on the variations in rift architecture, crustal structure, burial history, and heat flow along strike in this area of the proto-Equatorial Atlantic Ocean. Phase VIII will merge the nearly complete basin models of Ceará and Potiguar with ongoing studies in Barreirinhas and the newly initiated project in Foz do Amazonas Basin. These combined map areas will provide the first continuous, 3D basin model of the entire Brazilian Equatorial Margin (Fig. 2A). We will then use this 3D model as the basis for generating basin-wide source rock quality maps, Standard Thermal Stress (STS) maps, expelled hydrocarbons maps, and first-order migration front reconstructions. All of these deliverables will be constrained by geochemical data from wells and interpreted paleodepositional environments.

Phase VIII deliverables for Equatorial Brazil

The primary objective of our Phase VIII research in the Equatorial Brazil region will be to complete a continuous, 3500-km-long basin model along the entire margin (Fig. 2A). This basin model will be accomplished with these objectives:

1) Seismic interpretation and mapping of the main stratigraphic sequences.
2) Identification of potential source rock intervals (Valanginian-Barremian and Aptian) and geochemical characterization based on well data.
3) Integration of previous crustal models based on refraction data and inversion of gravity data.
4) Study of the current geothermal gradient based on well data (BHTs, Tmax, and Vitrinite Reflectance).
5) Determination of paleo-water depths and paleo-depositional environments.
6) Application of new AI modules in PaleoScan to interpret facies on 3D seismic (only Potiguar and Ceara Basins)
7) Thermal stress modeling of the basin using ExCaliber software.
8) Identification of the main kitchens and timing for hydrocarbon generation and expulsion.

We propose the following deliverables for the Brazilian Equatorial Margin:

1) Grids of the main sedimentary sequences and the lithosphere structure, including gravity inverted LAB and Moho.
2) Geochemical characterization of potential source rocks based on well data of the margin and regional data from the conjugates in Africa.
3) Source quality maps based on well data and interpreted paleo-depositional environment, including the Ultimate Expellable Potential.
4) 2D mapped basin modeling, including standard thermal stress (STS), expelled hydrocarbons, and migration maps.
5) 1D basin modeling of pseudowells, including STS and expelled hydrocarbons.

Focus areas and deliverables: the Campos-Santos basins, Brazil

Current level of understanding of the Campos Basin

During Phase VII, PhD student Ruth Beltran improved our understanding of the subsurface tectonic evolution, salt-related structural styles, and petroleum systems of the Campos rifted-passive margin of Brazil, using: 1) 32,309 km^2 of pre-stack, depth-migrated (PSDM) 3D seismic reflection and marine gravity and magnetic data provided by TGS; 2) 40,520 km of pre-stack depth migrated (PSDM) 2D seismic reflection data provided by TGS; 3) publicly-available satellite free-air gravity and Earth magnetic anomaly dataset; 4) well data provided by the Brazilian Agency of Petroleum (ANP), and 5) publicly-available cross-sections, seismic profiles, and industry wells.

The Ruth Beltran PhD study is divided into three chapters that focus on the ultra-deepwater (2.4-3.2 km) Campos Basin. In Chapter 1, she defined the crustal structure and tectonic evolution of the Campos Basin rifted-passive margin by integrating 2D and 3D seismic reflection mapping of the basement with gravity and magnetic modeling. Results from the first part of the study characterized the crust beneath the Marginal rift, which consists of a <60 km wide zone of 7 -5 km thick, highly stretched continental crust with magmatic additions that is adjacent to oceanic crust of Albian age. This work has been completed and published in the journal *Tectonics* (Beltran and Mann, 2026).

Ruth Beltran is now working on a balanced structural cross-section based on a 240 km-long TGS seismic reflection line. She will then use this balanced structural cross section to evaluate the timing of continental rifting in the Campos Basin and the kinematic control of the overlying deformation on the salt body and the passive margin section. The balanced cross-section reveals active faulting during the Barremian, accompanied by syn-tectonic sedimentation, with the thickest sedimentary sections controlled by half-grabens. Rifting is diachronous with older normal faults located near the South American continent and younger, normal faults located in the seaward direction. Some early fault blocks are eroded by an intra-Barremian unconformity, revealing a period of tectonic quiescence and erosion during the early stages of rifting. Some normal faults were reactivated during the upper Barremian and lower Aptian sag phases that controlled the deposition of freshwater and brackish lake sediments.

During Phase VIII, we will use information on crustal structure, faulting, and tectono-stratigraphy as inputs to generate a 3D basin model to elucidate regional hydrocarbon maturity trends across the Campos Basin. Modeling will also predict the timing of the oil charge from the known, upper Barremian source rocks located in the deeply buried, syn-rift and sag sections of the ultra-deepwater Campos Basin. Results from the third part of the Ruth Beltran study that is based on the 1D basin models, show that the pre-salt stratigraphic units could reach the top of the oil window at a depth of ~4 km. For the post-salt section located in the deepest mini basins of the Marginal rift, the post-salt stratigraphic unit could reach the top of the oil window at a depth of ~4 km.

Current level of understanding of the Santos Basin

During CBTH Phase VII, Dr. Sharon Cornelius completed two phases of 3D basin modeling for the entire Santos-Campos-Espirito Santo combined salt basin as part of a separate project. Phase 1 included seismic mapping of 17 chronostratigraphic surfaces

between the seafloor and the top of the MOHO, paleo-water depths for each surface, heat flow calculated from borehole bottom-hole temperatures and seafloor measurements seaward of well control, and detailed lithology for each chronostratigraphic unit per well. Required lithological units were the percentages of organic matter, clay, quartz, carbonates, evaporites, and volcanics (if any).

Phase 1 modeling was based upon derived products from 37 1D basin models (from 37 actual wells), including radiogenic heat production. The resulting crustal mapping showed the three main structural elements: the Interior rift zone, the Exterior rift zone, and the External high between the two rift zones. Phase 1 3D modeling was only for the presalt source rock, and the resulting Standard Thermal Stress (STS) map showed a few small areas of thermal immaturity along the External high, with a large area of thermal immaturity across the southeastern extension of the External high in southern Santos. However, the flanks of the External high leading into the rift zones on either side of this raised structure showed mature oil, allowing three-way closure against the structure.

Phase 2 modeling incorporated geochemical data from 84 presalt wells provided by ANP. This new dataset allowed the creation of 91 1D basin models based on 91 wells and basin-wide mapping of the UEP for both oil and gas produced from Barremian, Aptian, and Albian source rocks.

The UEP map shows potential for oil discoveries in the southeastern extension of the External High in the southern Santos Basin, and along the Cabo Frio High in southern Campos. The primary fetch area in Santos Basin has already is downdip from the BP Bumerangue discovery well, 1-BP-13-SPS. The secondary fetch area of the Campos Basin has produced an oil discovery well plus three successful field development wells drilled by the Petrobras/BP consortium. Both fetch areas accommodate updip oil migration from the surrounding External high flanks.

Phase VIII deliverables for the Campos-Santos basins

The aim of Phase VIII is to generate a 3D basin model for Barremian/Aptian source rocks. Basin modeling will predict the timing of the oil charge from the known, upper Barremian source rocks located in the deeply buried, syn-rift and sag sections of the ultra-deepwater Campos Basin. Deliverables for this study will include:

1) Key grids of ten (10) main stratigraphic surfaces: 1) Moho surface based on 3D gravity model, 2) top basement, 3) pre-rift section of early Barremian age, 4) base of the sag sequence, 5) base salt, 6) top salt, 7) top Albian, 8) top Cretaceous, 9) top Paleogene, and 10) sea bottom. Using these surfaces, crustal thickness and isopach maps of salt, syn-rift, and sag sequences will be generated.
2) Geochemical characterization of potential source rocks for the pre-salt and post-salt sequences based on well data, provided by the Brazilian National Agency of Petroleum, Natural Gas, and Biofuels (ANP).
3) Stratigraphic units and the percentage of shale, sandstone, limestone, salt, and volcanic rocks will be organized as a spreadsheet for each formation
4) Geothermal gradient based on well data (BHT, Tmax, and Vitrinite Reflectance).

5) Determination of paleo-water depths.
6) Source rock characterization, organofacies, and ultimate expelled potential.
7) 2D and 3D maps for standard thermal stress (STS).
8) Present-day temperature maps, expelled maps, and vitrine (%Ro) equivalent maps.

For the Santos-Campos-Espirito Santo 3D basin modeling project, deliverables for Phase VIII will include:

1) Quantified lateral variation in source UEP within an evolving Cretaceous-Cenozoic paleogeographic context. These paleo UEP estimates will allow us to quantify charge flux and migration losses, defining effective lateral migration pathways for both drilled and undrilled prospects.
2) Microfossil paleo reports included in the ANP well data will be compiled to show the age of the salt deposition and compare it with the recently published U-Th-Pb isotopic age of pre-salt sediments.

Focus areas and deliverables: Uruguay-Pelotas Basin, Brazil

Current level of understanding
Magma-rich margins have long been considered high-risk targets for hydrocarbon exploration because most syn-rift deposits are volcanic and therefore lack source rock potential (Mann, 2022). Following the latest discoveries in Namibia (Orange Basin – 11 BBOE proposed), exploratory interest has increased for the Pelotas (Brazil), Punta del Este (Uruguay), Salado, and Colorado (Argentina) basins (Fig. 3).
Successful plays in Namibia involve Aptian-Barremian source rock and Cretaceous reservoirs within turbidite fan systems, sealed by deep-water shales. In this region, the Lower Cretaceous source rock intervals were deposited directly above the volcanic SDRs.
Previous work has highlighted similarities between the conjugate margins of Namibia and South America, suggesting the presence of potential source intervals in a setting similar to that of the Orange Basin. This interpretation is not only based on the structural evolution of both conjugate margins but also on the identification of potential source rocks in seismic data (e.g., Eastwell et al., 2018; Rodriguez et al., 2022).
After a preliminary basin analysis (Maya and Mann, 2025), PhD student Daniel Maya identified several key areas that reveal the hydrocarbon potential of this focus area:

1) The structural evolution framework is consistent with the deposition of source rock intervals during the Aptian-Barremian, as observed in other South Atlantic basins.
2) Previous works have identified and mapped a well-developed Cretaceous turbidite fan system that may act as a potential reservoir (Zalan et al., 2022; Miller, 2025).
3) Based on geothermal gradients calculated from the bottom-simulating reflector (BSR) (Morales et al., 2017), previous authors have estimated hydrocarbon generation at the South American margin (Uruguay-Argentina).

4) There is good seismic reflection control over the deeper crustal structure and the continent-ocean boundary from refraction lines and deeply penetrating seismic reflection transects (Reuber and Mann, 2019).

In this focus area, two of the three wells were drilled in shallow water, and only one was drilled in the deep region of the margin (Raya-1). Unfortunately, the objective of this well was an Oligocene turbidite fan lobe, and the deeper targets, including the Aptian-Albian and Upper Cretaceous ones, remained untested by this well.

Phase VIII deliverables for the Uruguay-Pelotas Basin
The main objective of this study will be to complete comprehensive basin model to better understand hydrocarbon generation in the deepwater area of the basin. The accomplishment of these objectives will complete this:

1) Seismic interpretation and mapping of the main stratigraphic sequences (Maya and Mann, 2025).
2) Identification of potential source rock intervals based on their seismic character and thickness estimation.
3) Geochemical characterization of source rocks based on regional data from available sources, including the organofacies classification of the main intervals.
4) Integration of previous crustal models with newer data.
5) Study of the current geothermal gradient based on available data.
6) Determination of paleo-water depths.
7) Thermal stress modeling of the basin with Trinity-Genesis software.
8) Identification of the main kitchens and timing for the hydrocarbon generation and expulsion.

To achieve these objectives, CBTH is working with our data providers to secure access to additional seismic data in the region. Using these data, we will produce the following deliverables:

1) Grids of the main sedimentary sequences and the characterization of the basement and Moho.
2) Geochemical characterization of potential source rocks based on regional data from previous works and available sources.
3) 2D mapped basin modeling for the main potential source rocks, including standard thermal stress (STS) maps based on constant radiogenic heat production (RHP) and expelled hydrocarbons maps for the Aptian-Barremian and Turonian-Cenomanian.
4) 1D basin modeling of pseudowells, including STS and expelled hydrocarbons.

Focus areas and deliverables: Uruguay-northern Argentina

Current level of understanding

The volcanic margins of Uruguay and northern Argentina have been extensively studied during Phase VII, with the creation of a 3D crustal model covering 362,200 km^2 using regional magnetics, gravity, high penetration 2D and 3D seismic, and producing structural and isopach maps of the Moho, basement, top volcanic syn-rift, crustal thickness, sedimentary thickness, and volcanic syn-rift thickness (Maya and Mann, 2025).

The complex structural setting in offshore Uruguay, which was previously postulated to have a gap in SDRs was challenged and imaged as a continuous SDR belt, with high deformation in the SDR section produced by the clockwise rotation of the Salado microplate by 15 degrees, creating a 60 km wide offset in the Rio de la Plata region and a 109 km wide offset on the northern side of the Falkland Islands (Maya and Mann, 2025).

The integration of this 3D crustal model with shallower seismic and well data served to create detailed structural maps for the sedimentary overburden along the Uruguay margin: 6294 km of 2D seismic data, 22,984 km² of 3D seismic data, and well data from Uruguay, the Falkland Islands, and the Namibia margin: Raya, Gaviotin, Lobo, DSDP 361, DSDP 511, DSDP 327, DSDP 530, Mossehead, Wingat, Murombe, Darwin East-1, Sea Lion 14/10-5, Sea Lion 14/10-4, and Sea Lion 14/10-2 wells. This has been used to understand the organofacies based on the classification of Pepper and Corvi (1995b, 1995a) from Aptian-age (123-110 Ma) source rock and Cenomanian-Turonian-age (100-88 Ma) source rock signatures in the South Atlantic.

Although the final 3D basin modeling of this margin will be complete during Phase VIII, preliminary results indicate potential for oil expulsion from Aptian source rocks, with more limited potential for Cenomanian-Turonian source rocks, which might have been affected by clastic deposition. By integrating Paleoscan into our 3D seismic, detailed spectral decomposition and attributes will be used to identify sedimentary depositional features, sweet spots, source rock intervals, and seals with great precision.

Based on all this information, an AVO seismic analysis and a novel seismic inversion method will be applied during Phase VIII using Omovie and Castagna (2019, 2020) to characterize the TOC along the source rock extension and have a synthetic measurement. Our simultaneous seismic inversion seeks to accurately estimate P-wave velocity (VP), S-wave velocity (VS), and density (ρ) to predict the fluid and lithological properties of our reservoir levels using the Castagna et al. (1985) methodology for clastic silicate rocks (Hampson and Russell, 2013).

Phase VIII deliverables for Uruguay-northern Argentina

This project aims to conduct a comprehensive hydrocarbon assessment of the Uruguay margin by applying all available methodologies and integrating traditional seismic mapping, basin modeling using Excalibur, and new geophysical approaches to develop a robust framework for identifying attractive areas for further exploration.

1) 3D crustal model including key crustal surfaces: LAB, Moho, Basement
2) Volcanic synrift surfaces and thickness in Uruguay.
3) Cretaceous and Cenozoic sedimentary mapping in 2D and 3D seismic offshore Uruguay

4) Well data geochemical compilation from Namibia and the Falkland Islands
5) Detailed subsidence, bottom hole temperatures, and maturity for 1D basin models
6) 3D maturity modeling for source rock intervals, including the internal intervals of the Aptian source rock
7) Determined paleo-water depth and paleo depositional environments using spectral decomposition
8) Source rock identification by seismic signature, applying seismic attributes and spectral decomposition.
9) Oil expulsion 3D map created using the Aptian geochemical signature from the surrounding areas and its conjugate
10) 3D general migration oil front for the Aptian source rock intervals
11) Characterized TOC bearing intervals for source rock discrimination
12) Integrated AVO studied along the 3D seismic volumes
13) Lithology prediction based on geophysical response

Focus areas and deliverables: Newfoundland and Labrador

Current level of understanding
The Mesozoic–Cenozoic rifted–passive margins of Newfoundland and Labrador remain highly prospective despite mixed exploration results. Exploration began in the 1960s, with activity intensifying after the discovery of the giant Hibernia field in 1979. Since then, most drilling has focused on the Jeanne d'Arc Basin, which hosts the major producing fields of Hibernia, Hebron, Terra Nova, White Rose, and North Amethyst. Together, these fields have produced more than 2.3 billion barrels of oil and 3.8 Tcf of gas, with remaining reserves of about 1.3 BBO. Additional discoveries such as Mizzen, Harpoon, and Bay du Nord in the Flemish Pass Basin demonstrate that large petroleum systems exist along this margin. In contrast, other areas such as the Orphan Basin and the Labrador Margin have seen limited exploration success, and recent wells drilled between 2020 and 2024 encountered shows but failed to achieve commercial discoveries, discouraging further activity (Nalcor Energy, 2020; Oilco, 2022).

Geologically, the Orphan Basin, Jeanne d'Arc Basin, and Flemish Pass Basin share a complex two-phase rift history (Nalcor Energy, 2018). The first phase occurred during the Jurassic–Early Cretaceous, related to the east-west separation of the North American and Iberian plates, and formation of oceanic crust in the Central Atlantic Ocean. This older rifting and the formation of oceanic crust were followed by a Late Cretaceous northeast-southwest-oriented rift phase associated with the opening of the Labrador Sea, which reactivated earlier basement structures.

This two-phase, tectonic evolution led to the development of regionally extensive source rocks, including Late Jurassic source intervals and organic-rich deposits associated with Early and Late Cretaceous oceanic anoxic events (OAEs). These source rocks have been identified in both industry wells and IODP sites, and previous studies demonstrate that they reached sufficient maturity for hydrocarbon generation in parts of the Orphan Basin (Tucholke et al., 2004; Norris et al., 2014). The lack of large discoveries in this basin is therefore more likely related to migration inefficiencies or trap-and-seal failures rather than to the absence of a viable petroleum system.

Along the Labrador margin, exploration began with the discovery of shallow-water gas fields in the 1970s and 1980s, but activity has since slowed and stalled (Oilco, 2022).

Importantly, the deepwater outer rift zone remains virtually unexplored, with no deepwater wells drilled to date. This region formed during the Aptian-Maastrichtian rifting event associated with the opening of the Labrador Sea between North America and Greenland. Wells on the proximal Labrador margin document high-quality Early Cretaceous source rocks, with equivalent rift-related events affecting the conjugate Greenland margin. This rift setting suggests that regionally extensive source rocks were deposited along the Labrador Margin and may have reached thermal maturity in deeper parts of the basin.

The Newfoundland and Labrador margins represent a mature petroleum province in terms of our geological understanding, but remain an underexplored region in terms of exploration success outside the Jeanne d'Arc and Flemish Pass basins. The presence of proven, mature source rocks, multiple rift phases, and large unexplored deepwater domains all indicate that the remaining exploration potential is significant. A basin-scale reassessment that integrates source-rock distribution, maturation history, expulsion efficiency, and migration pathways is therefore critical for explaining past exploration outcomes and identifying new, higher-confidence opportunities along this margin.

After conducting a preliminary analysis of the basin, we have identified key supporting data that are needed to better establish the Labrador and Orphan Basins as a promising hydrocarbon province.

1) The structural evolution framework and tectonic reconstructions of the Newfoundland and Labrador margins indicate that potential source rock intervals were deposited during the Jurassic period only in Newfoundland only (Fig. 2) and during the Early and Late Cretaceous periods. This observation is consistent with the history of their source rocks on the conjugate margins of Greenland (Dam et al., 2020) and in other productive basins of Eastern Newfoundland (Nalcor Energy, 2018).

2) Exploration wells and previous studies in Newfoundland and Labrador have also successfully identified and mapped favorable depositional environments (Dafoe et al., 2017) that host reservoir intervals above potential source rocks (Opdyke et al., 2019; Le Guerroué et al., 2020).

3) Our post-mortem analysis of the wells in the Orphan Basin suggests that the absence of commercial hydrocarbon accumulations may be linked to migration issues and/or trap-related problems that are specific to the locations of these wells.

4) Additionally, we have gained a solid understanding of crustal structure and the continent-ocean boundary through ongoing CBTH-supported studies in the North Atlantic.

We observed remarkable similarities between the Labrador and Newfoundland margins and other highly productive oil and gas provinces studied by CBTH that include:

1) The paleo-depositional environments of the Aptian-Turonian sequences in the Labrador Sea resemble those of the opening of the Equatorial Atlantic, as studied by Gorosabel-Araus and Mann (2024b).
2) The concentration of gas discoveries along the proximal margin in Labrador is similar to that found in other prolific basins, such as the Campos-Santos in Brazil and the Orange Basin in Namibia, where successful prospects are located in the outer rift zones at deepwater depths. This success may be attributed to a combination of greater overburden and higher crustal heat contributions.

Given these factors, we consider the Labrador and Newfoundland margins as a region of high interest for future hydrocarbon exploration.

Phase VIII deliverables for Newfoundland and Labrador

The primary objective of this study is to develop a comprehensive, quantitative basin model for the Labrador and Newfoundland margins that will more effectively constrain areas of mature source rocks that have charged undiscovered hydrocarbon fields. Our approach to basin modeling in the CBTH Project involves utilizing ExCaliber software to create a full-lithosphere thermal model that integrates mapped source rock intervals, downhole temperatures, subsidence, stratigraphy, overburden thickness, source rock characteristics, crustal type, and crustal thickness. By integrating these data, we can map trends in thermal stress that influence the maturity of source rocks.

Thermal stress refers to the standard temperature that a source rock must reach at a heating rate of 2 °C/Myr to achieve a level of kerogen degradation comparable to that at the actual temperature in the sedimentary basin (Pepper and Corvi, 1995a,b). CBTH will leverage ExCaliber's advanced AI capabilities to perform these calculations across margin-scale areas.

This project will also include the following objectives:

1) Crustal and structural analysis of the basin based on potential fields with a definition of structural domains and the COB.
2) 3D inversion of the Moho and LAB.
3) Basement characterization, including the onshore and offshore RHP maps.
4) Study of the current geothermal gradient based on BHTs compiled from exploration wells and heat flow measurements.
5) Geochemical characterization of source rocks based on regional data from available sources, including the organofacies classification of the main intervals (Pepper and Corvi, 1995a,b; Pepper, 2019) and the Ultimate Expelled Potential (UEP).
6) Recovery of original TOC and HI values based on the kinetic reconstruction of the main source intervals.
7) Creation of UEP maps based on the geochemical characterization and the paleo-depositional environment maps.
8) ExCaliber thermal stress, expulsion, and migration modeling of the basin.

9) Modeling will provide detailed maps of the main kitchens and timing for the hydrocarbon generation and expulsion. These model predictions are validated by comparison with spare wells, including dry holes and wells with oil and gas shows.

We will produce the following products from this study of the Labrador and Newfoundland rifted-passive margins, which would also be provided to OilCoNL:

1) Data grids of the 3D inverted Moho and LAB.
2) Geochemical characterization of potential source rocks based on regional data from previously published and publicly available sources, including organofacies classification and plots of Ultimate Expelled Potential (UEP), and source quality maps.
3) 1D basin modeling of pseudowells, including standard thermal stress (STS) and predicted volumes and types of expelled hydrocarbons.
4) 2D mapped basin modeling for the main potential source rocks, including STS maps based on constant radiogenic heat production (RHP) and expelled hydrocarbons maps for the well-established Jurassic, Aptian-Barremian, and Turonian-Cenomanian source rock intervals.

Focus areas and deliverables: the Morocco-Nova Scotia conjugate margin

Current level of understanding of Morocco
Our completed study of the Moroccan salt basin by Hasan (2022) of the Central Atlantic Ocean interprets a grid of ~8474 line-km of pre-stack, depth-migrated, 2D seismic reflection profiles, publicly available gravity and well data, and 2D gravity models. Gravity modeling and seismic interpretation reveal a ~750 km-long, 50-80 km-wide marginal rift that forms a basement low overlying a zone of rifted continental crust. The marginal rift parallels the modern coastline of Morocco and crosscuts the east-northeast orogenic and Mesozoic rift grain of northwestern Africa.

Calibrations of downhole temperature measurements from the Tantan-1 and DSDP-416 offshore wells were used to constrain 1D and map-based thermal-maturity models to quantify the hydrocarbon potential of source rocks ranging in age from Triassic to Late Cretaceous (Shipper et al., in press). Calibration of downhole temperature measurements from the Tantan-1 within the thinned, continental crust of the marginal rift and the DSDP-416 wells on oceanic crust of the Central Atlantic shows that the geothermal gradient in the marginal rift is 29 °C/km and the gradient in the oceanic crust is 23 °C/km. However, variation may occur due to the limited number of calibration wells.

Modeling shows that the absence of radiogenic heat in the oceanic crust results in lower geothermal gradients and can explain the immaturity of source rocks in these deepwater areas, placing them in the early oil window. Deeply buried Triassic and Jurassic source rocks are mature for petroleum generation along the southern ~400 km-long segment of the marginal rift, as validated by a compilation of offshore well and show locations. Late Cretaceous - Base Cenozoic uplift and erosion of the margin were observed as a major angular unconformity and break in vitrinite reflectance from wells in

the offshore area. The absence of Early Cretaceous deltaic deposits in the 350 km-long northern marginal rift segment explains why Cretaceous source rocks have remained immature in this area with less sedimentary overburden (Shipper et al., in press-b).

Following the initial PhD dissertation by Hasan (2022), we have largely completed this study, as shown in Shipper et al. (in press-b). However, we will continue compiling information from this area for the input data needed for basin modeling. We would also like to compare the Morocco model with the proposed model described above for its conjugate margin in Nova Scotia.

Current level of understanding of Nova Scotia

Exploration activities at the Nova Scotia margin date back more than 50 years, with 200 wells drilled and the discovery of in-place reserves of ~2.1 BBOE (billion barrels of oil equivalent). However, only 29 wells have been drilled since 1998, resulting in only one commercial gas discovery in 1998, the Deep Panuke, with a total production of 45 MBOE before its abandonment in 1999. Preliminary post-mortem analyses indicated that the extension and maturation of source rock intervals were the main cause of the exploration failure. However, previous work by Beicip-Franlab (2023), carried out by the Nova Scotian government to assess the exploration potential of the margin, notes a lack of geological understanding of the exploration plays as the main reason for the lack of discoveries. Their post-mortem analysis highlighted some of these causes:

1) Poor reservoir properties, including poor porosity related to calcite cements formed in the Jurassic carbonate paleoenvironments or related carbonate debris in potential sandstone reservoirs.
2) Poor reservoirs outside the main deltaic area.
3) Poor reservoir distribution within carbonate areas.
4) Lack of effective seal at some prospects.
5) Possible migration issues away from the fairway of mature source rocks.
6) Poor trap integrity is related to failures of fault seals.
7) Seismic attributes revealed that many deep-water wells were not drilled in the main sand fairway.

After our preliminary basin analysis, we have defined some key points that may transform Nova Scotia into a more promising hydrocarbon province:

1) Presence of a deepwater and largely unexplored marginal rift adjacent to oceanic crust that is similar to rifts observed in the Gulf of Mexico (Liu, 2021; Hasan and Mann, 2021; Hasan et al., 2022). Its conjugate rift in Morocco is salt-filled, with sub-salt wells.
2) Areas of Late Jurassic oceanic crust overlain by Late Jurassic and early Cretaceous clastic rocks with promising source rock intervals.
3) Presence of regional source rocks (Olson et al., 2019) in the deepwater area, which include:
   a. Lower Cretaceous – Aptian MFS: Type III with an average TOC of 2%.

      b.   Upper Jurassic – Tithonian MFS: Type II-III with an average TOC of 3%.
      c.   Middle Jurassic – Misaine-Callovian MFS? Evidence limited to one well, unknown extension. Type II-III with an average TOC of 2%.
      d.   Early Jurassic – Sinemurian-Pliensbachian-Toarcian? Source complex inferred by analogy to source rock intervals identified on the conjugate margins (Portugal and Morocco). Type II with an average TOC of 5%.

4) Presence of good reservoirs that include:
      a.   Mic Mac Upper Jurassic delta sequence in the northeastern margin.
      b.   Jurassic carbonate banks.
      c.   Lower Cretaceous delta sequences.
      d.   Cretaceous deep-water turbidite system.
5) Presence of regional seals of the system.

Phase VIII deliverables for the Morocco-Nova Scotia conjugate margin

Based on our experience on the conjugate Moroccan margin, the main objective for this focus area will be to conduct comprehensive basin modeling to better understand the basin's hydrocarbon generation, particularly in the marginal rifts of the margin. We propose the following preliminary objectives:

1) Use of grids derived from the Beicip-Franlab (2023), based on the seismic interpretation after the biostratigraphic analysis and the well-seismic tie.
2) Geochemical characterization of source rocks based on available data and previous works.
3) Refinement of previous crustal models and delimitation of the continent-ocean boundary and the marginal rifts.
4) Determination of an improved geothermal gradient based on available data.
5) Determination of paleo-water depths.
6) Thermal stress modeling of the basin using the Trinity-Genesis software.
7) Identification of the main kitchens and timing for hydrocarbon generation and expulsion.

Finally, deliverables for Morocco and the Nova Scotian Margin will include:

1) 2D mapped basin modeling for the main potential source rocks, including standard thermal stress (STS) maps based on constant radiogenic heat production (RHP) and expelled hydrocarbons maps for the Aptian-Barremian and Turonian-Cenomanian.
2) 1D basin modeling of pseudowells, including STS and expelled hydrocarbons.

Summary

In summary, CBTH Phase VIII seeks to advance understanding of the rifted margins of the Central, Equatorial, and South Atlantic oceans by developing 3D regional basin models at regional scales along the Canadian, American, and African conjugate margins. These models are built from careful, systematic compilations of crustal

structure, gravity inversions of the lithosphere, radiogenic heat production maps, transient post-breakup heat flow, and mapping of 2D and 3D seismic reflection data grids. Each margin is different, beginning with its non-volcanic versus volcanic rifted-margin heritage.

The efforts at discovering and developing the 16 BBO Miracle Mile of Guyana and Suriname (Price et al., 2021) have shown that establishing the stratigraphy of the deepwater passive margin and determining the maturity trends of play fairways of key source rock intervals, including the Aptian-Albian and Cenomanian-Turonian, can guide more systematic exploration in the deepwater areas of these margins. Our preliminary modeling results in Morocco (Shipper et al, in press-b), Guyana-Suriname (Shipper et al., in press-a), Campos-Santos, Brazil (Cornelius et al., in press), and Equatorial Guinea in West Africa (Gorosabel et al., 2025) have revealed these deepwater maturity trends. Our goal in Phase VIII is to model crustal and mantle processes that control margin-scale predictions of hydrocarbon generation, expulsion, migration, and charge risk.

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Appendices

The following articles by CBTH researchers have been recently published or are currently in-press with the GeoExPro online magazine. Please visit our website or LinkedIn profile for more information as these articles are published over the next few months.

- "New modelling study reveals a petroleum system overlying oceanic crust offshore Equatorial Guinea" by José Miguel Gorosabel-Araus, Paul Mann, and Andrew Pepper (now available online)
- "3D basin modeling incorporating presalt geochemical data reveals new exploration areas in Santos and Campos Basins, offshore Brazil" by Sharon Cornelius, Kenneth Shipper, Paul Mann, and Andrew Pepper (in press)
- "Jurassic Petroleum System confirmed by observed oil front offshore Morocco" by Kenneth Shipper, Paul Mann, José Miguel Gorosabel-Araus, and Andrew Pepper (in press)
- "Guyana-Suriname margin: New basin modeling study predicts spatial variation in charge risk" by Kenneth Shipper, Paul Mann, and Andrew Pepper (in press)

Appendix I: New modelling study reveals a petroleum system overlying oceanic crust offshore Equatorial Guinea

José Miguel Gorosabel-Araus and Paul Mann, Department of Earth and Atmospheric Sciences, University of Houston, Andrew Pepper, This Is Petroleum Systems
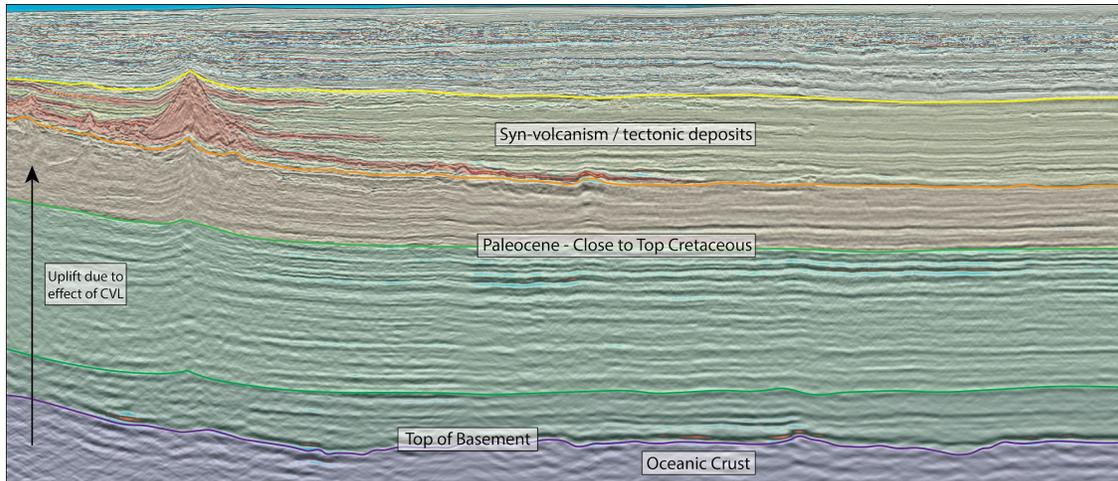
Representative dip section across the deepwater Douala–Rio Muni Basin showing key stratigraphic boundaries and the structural influence of the Cameroon Volcanic Line (CVL). Seismic data courtesy of Geoex MCG.

The deepwater Douala-Rio Muni Basin (DRMB) is a non-volcanic, Mesozoic-Cenozoic rifted passive margin located offshore in Equatorial Guinea (EG), West Africa. Commercial oil and gas fields have been discovered on the shelf and slope of EG include the Ceiba and Okume fields, charged by Lower Cretaceous source rocks on thinned, continental crust, or the Zafiro and Alen-Aseng fields, which are charged by Paleogene source rocks that overlie oceanic crust of Aptian age. In comparison, the deepwater region of the DRMB east of the Cameroon Volcanic Line (CVL) has yet to yield any major discoveries.

Our analysis of seismic, gravity, magnetic, and geochemical data, was integrated in a full-lithosphere 3D basin model, revealing a mature, potentially prolific Cretaceous petroleum system extending across oceanic crust, with its potential influenced but not handicapped by the higher thermal history of the adjacent CVL.

Full lithosphere models to predict the heat flow

Our study area is located east of the CVL, a 1,700 km long linear chain of volcanic origin ranging in age from the Eocene to the present. The CVL has influenced the crustal, stratigraphic, and thermal structure of the Gulf of Guinea since its origin in the Paleogene. We combine five 3D seismic surveys covering approximately 7,600 km² (provided by Geoex MCG, along with 2D seismic lines, regional well data provided by Viridien Group), and gravity and magnetic surveys to create a full-lithosphere model. A

newly developed gravity inversion technique enabled us to improve the accuracy of the depth to the Moho and the Lithosphere – Asthenosphere Boundary (LAB), revealing zones of mantle upwelling and increased thermal gradients beneath the deepwater region. These thermal anomalies closely align with the elongated, deep-rooted magmatic activity along the CVL and are a critical factor in assessing hydrocarbon generation in the deepwater area.
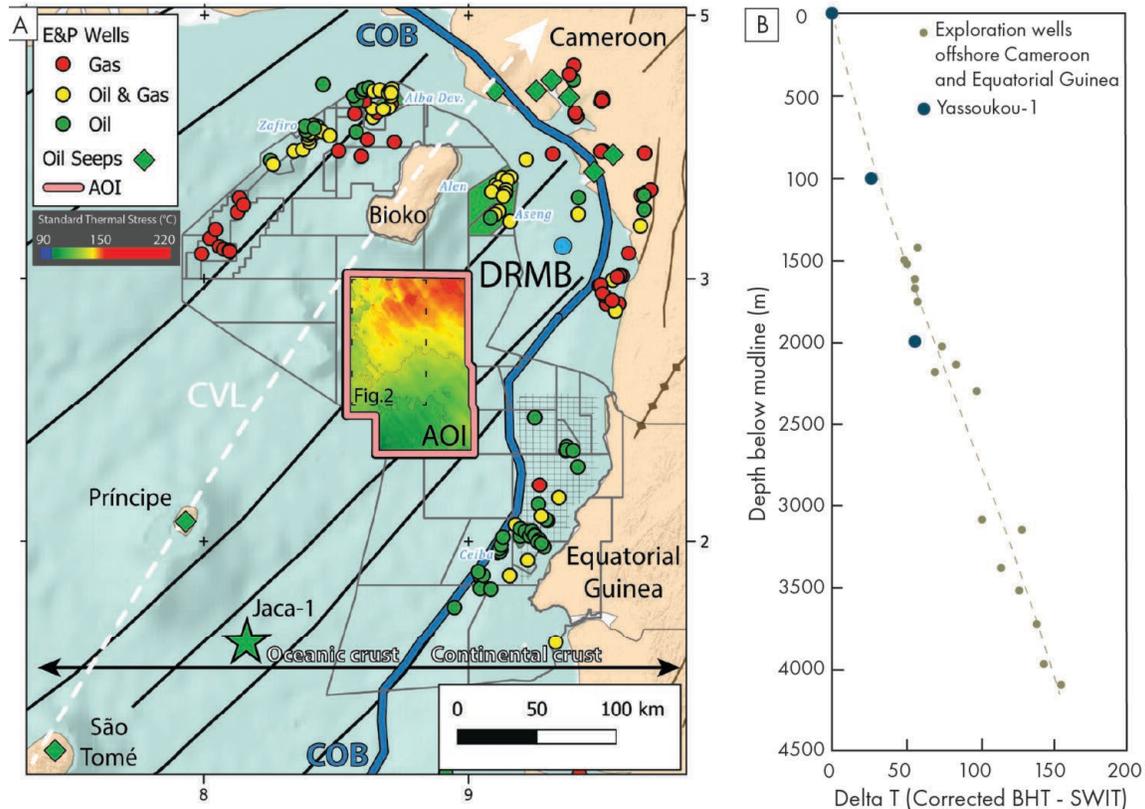
Figure 1A: Detailed map of the study area showing exploration and production blocks, exploration wells, and the distribution of oil and gas seeps in the deepwater Douala–Rio Muni Basin (DRMB). 3D models completed using the software ExCaliber are shown for the area of interest (AOI). COB, Continental-oceanic boundary. B: Corrected bottom hole temperatures (BHTs) plotted as ΔT versus depth below mudline, illustrating regional geothermal gradient trends. Well data shown in Figure 1 were provided courtesy of CGG Services (UK) Ltd (part of the Viridien Group). For data access and licensing of the Viridien GeoVerseTM database, contact GeoVerse.Support@viridiengroup.com.

Seismic clues to reservoir and seal potential

Seismic interpretation allowed the extraction of key attributes (RMS, sweetness) to identify deepwater fans and play fairways within the Albian-Campanian interval. In particular, the Santonian-Campanian channelized turbidites and basin-floor fans capped by thick mudstone packages form stacked reservoir-seal pairs. In several areas, these systems are folded or uplifted as a result of volcanic doming along the CVL. Such structural overprints also create combination traps as a potential drilling target.

Source rock potential of the region

Rock-Eval pyrolysis data from exploration wells on the shelf and upper slope of Cameroon and Equatorial Guinea (e.g., Campo R-1, Kribi E-1), combined with deepwater reference sites (e.g., DSDP 530A), allowed us to characterise and model source rock potential and compare it with the conjugate rifted margin in the Sergipe area of northeastern Brazil. The resulting source rock characterisation indicates that the Albian and Cenomanian-Turonian intervals are the primary Cretaceous source rocks in the deepwater area of the DRMB.

These organic-rich, marine clay-rich mudrocks typically contain over 2 % total organic carbon, with Hydrogen Index values between 200 and 400 mg HC/g TOC. Thermal restoration indicates original HI values in the 300 – 600 range, as observed for prolific conjugate analogues in the Sergipe Basin of Brazil. Seismic data show stratigraphic continuity between drilled source rocks on the shelf and slope to predicted source rocks in the deepwater area of the DRMB.

Figure 2: Seismic interpretation of potential reservoir intervals in the Albian–Cenomanian section. A: Structural map of a surface interpreted at the base of the Santonian-Campanian turbidite complex. B: RMS attribute map extracted along the Albian–Cenomanian surface, highlighting localized high-amplitude anomalies interpreted as potential sand-rich turbidite systems within a predominantly fine-grained, deepwater setting. C-D: Seismic interpretation of potential reservoir intervals within the Albian–Cenomanian section. A: Dip and strike seismic lines showing attribute responses (e.g., RMS) and highlighting depositional geometries of turbidite systems within the interval. Seismic data courtesy of Geoex MCG. For data access and licensing, please contact Geoex MCG at www.geoexmcg.com.

Hydrocarbon generation on oceanic crust

Our basin models were calibrated using corrected bottom-hole temperatures (BHTs) from regional wells and 1D pseudowells, which constrained the burial history, maturation, and oil and gas expulsion of the area. The results indicate a consistent southwest-to-northeast increase in the thermal stress gradient, aligning with the lithospheric structure of the CVL and a larger sedimentary input entering the basin along a NE – SW trend. This northeastward rise in the thermal gradient is supported by

exploration data from the Jaca-1, Ceiba, Zafiro, and Alen-Aseng fields over a distance of 600 km.

The deepwater source rock intervals are present within the transitional zone from oil to gas-condensate expulsion windows across the study area. 3D models confirm significant oil and gas generation, with the northeastern sectors exhibiting more advanced maturation and potentially higher gas-oil ratio (GOR) accumulations. This proposed directional trend to the northeast of higher gas-oil ratios fits with the production at the Zafiro and Alen-Aseng fields.

Significance of the EG petroleum system

By integrating seismic, geophysical, geochemical, and thermal modeling, this study proposes a working Cretaceous petroleum system developed above oceanic crust of Aptian age.

Given the presence of hydrocarbon seeps on São Tomé and Príncipe and shows in the Jaca-1 well drilled in 2023, the DRMB's deepwater sector east of the CVL provides a promising exploration target. The next steps include constraining the thermal and crustal framework and identifying the optimal trap and migration pathways.

The implications of this study go beyond Equatorial Guinea. The DRMB shares a similar history of rifting and depositional history with its conjugate in the Sergipe-Pernambuco Basin of northeast Brazil. Insights from our research can guide deepwater exploration approaches in both regions of the South Atlantic, especially in frontier oceanic areas that are often overlooked.

Appendix II: 3D basin modeling incorporating presalt geochemical data reveals new exploration areas in Santos and Campos Basins, offshore Brazil

Sharon Cornelius, Kenneth Shipper, and Paul Mann, Department of Earth and Atmospheric Sciences, University of Houston, Andrew Pepper, This Is Petroleum Systems

This four-year 3D Earth modeling project includes detailed seismic mapping of 17 surfaces between the seafloor and the top of the Moho, using a detailed grid of both 2D and 3D seismic data from TGS covering 592,00 square kilometers across the combined areas of the Santos, Campos, and Espirito Santo salt basins. The TGS dataset includes ION data recorded to a depth of 40 km and allows detailed mapping of the Moho and constrains the depth to the top of crystalline basement, which can be validated by other seismic profiles. Geopost Energy Brazil, a division of Katalyst Data Management, provided hundreds of well data wireline logs and mud logs. ANP provided geochemical data for 84 presalt wells covering all three basins. The ANP dataset also included paleontological reports that helped estimate paleo-water depths for each chronostratigraphic unit in each well.
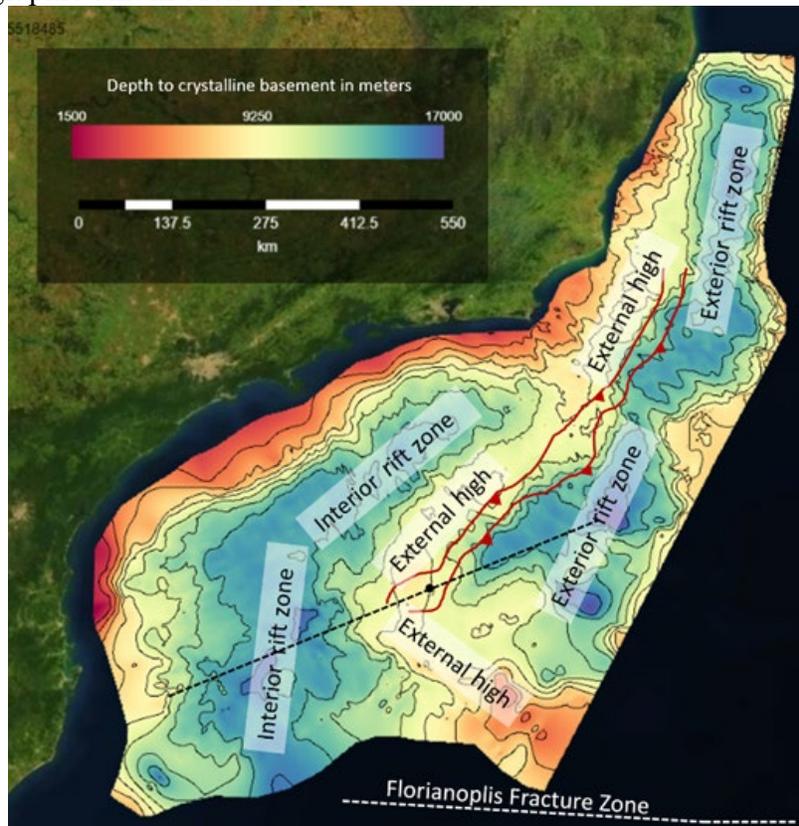

Figure 1. Depth to the crystalline basement map for the study area, showing the three main structural features: the Interior rift zone, the External high, and the Exterior rift zone. The seaward-dipping basin faults are shown in red with the BP Bumerangue

discovery well, shown by the black dot. The black dashed line is the location of the arbitrary line through the 3D model in Figure 3. The Florianopolis Fracture Zone separates the non-volcanic Santos, Campos, and Espirito Santo combined basin from the volcanic Pelotas Basin.

Assembling the data for basin modeling

We corrected Bottom-hole temperatures (BHTs) and uploaded them to the ExCaliber Earth modeling software from Xplorlab. Detailed lithological content was extracted from the mudlogs by calculating the percen-tages of clay found in shale, sandstone, and marl for each chronostratigraphic unit per well were calculated. Similarly, the percentage of quartz was calculated in shale and sandstone. In addition, the percentages of carbonate, organic matter. evaporite, and volcanic rocks present in each chronostratigraphic unit were calculated. These ANP wells were reasonably distributed throughout the study area, except in southern Santos, which has become an area of intense exploration interest due to BP's big discovery in the Bumerangue block, announced last August. Seven more wells in southern Santos were added to the project for heat flow and lithological data, even though they did not have geochemical data. We also compiled data in the form of organic carbon and pyrolysis data, including the hydrogen index (HI) and Tmax. All of these accumulated and derived lithologic data were gridded on a per chronostratigraphic-unit basis and then uploaded into ExCaliber, where values of radiogenic heat production (RHP) were inverted for 91 well locations. Crustal RHP and thickness are important in understanding and predicting variations in the thermal profile across the two rift zones given their large sediment thicknesses. The resulting 91 1D basin models, along with derived RHP values at each well, were then uploaded into ExCaliber for 3D basin modeling.
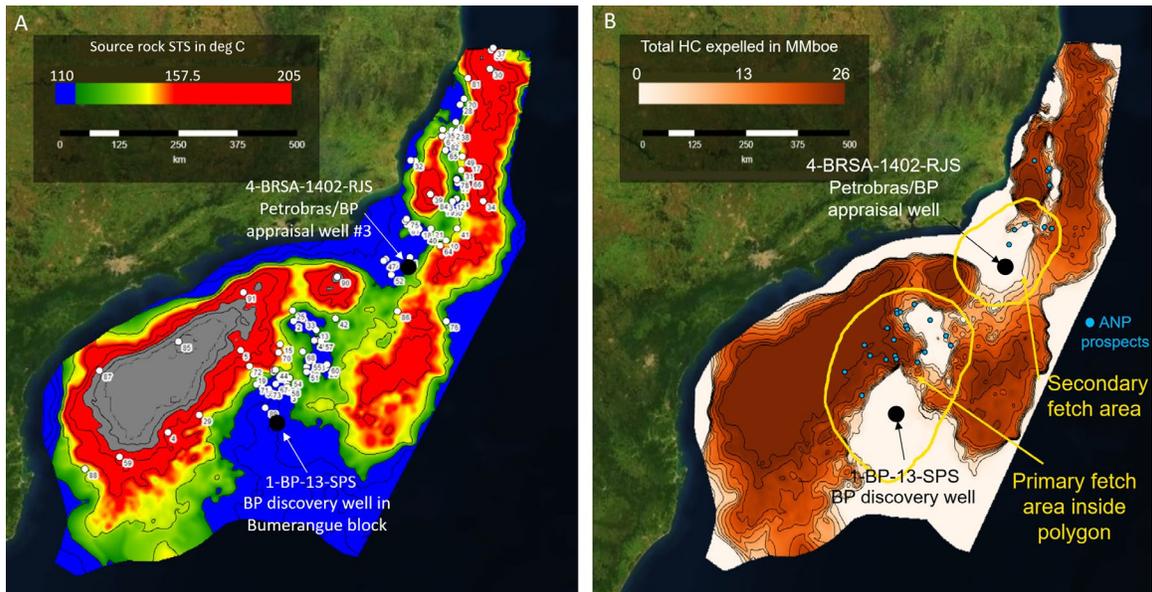

Figure 2A *is an STS map of the presalt Aptian source rock penetrated at the 91, numbered well locations. The STS color bar is shown for a typical Organofacies C lacustrine kerogen: blue indicating immaturity for oil expulsion, green indicates oil expulsion, yellow indicates the oil-to-gas transition, and red indicating the dry gas expulsion window. The*

BP discovery well 1-BP-13-SPS location is shown along the southeastward extension of the External high, as is the location of the third appraisal well 4-BRSA-1402-RJS for the Petrobras/BP Consortium along the Cabo Frio high. Note that both oil wells are located within a predicted thermally immature area shown in blue. Also note that both immature areas shown in blue are located on structural highs surrounded by two oil expulsion kitchens, i.e., they require lateral migration. **Figure 2B** *is an intensity map of the total oil and gas expelled (mmboe/km^2) from the presalt Albian source rock. It is a summation of the total oil and the total gas expelled (mmboe/km^2) from the presalt Albian source rock. The map provides a summary of the total oil and the total gas expelled for the fetch areas shown.*

Output included predictions for three different source rock intervals: the Barremian (which often contains interbedded volcanic units), the Aptian presalt (Organofacies C associated with lacustrine facies), and the Albian postsalt (Organofacies A or B associated with marine carbonate or shale facies). Standard thermal stress (STS) maps were generated for all three-source rock interval mid-points. The most important of these is the presalt Aptian source rock map. The combined Aptian and Barremian oil and gas production, loosely termed "presalt", currently supplies about 80% of Brazil's total oil and gas production per ANP. Based on our work with well data, a rough estimate for the Aptian contribution to this presalt total production would be 85 to 90% at the present time.

In terms of exploration implications, the UEP map shows potential for oil discoveries in the southeastern extension of the External high in southern Santos, and along the Cabo Frio High in southern Campos.
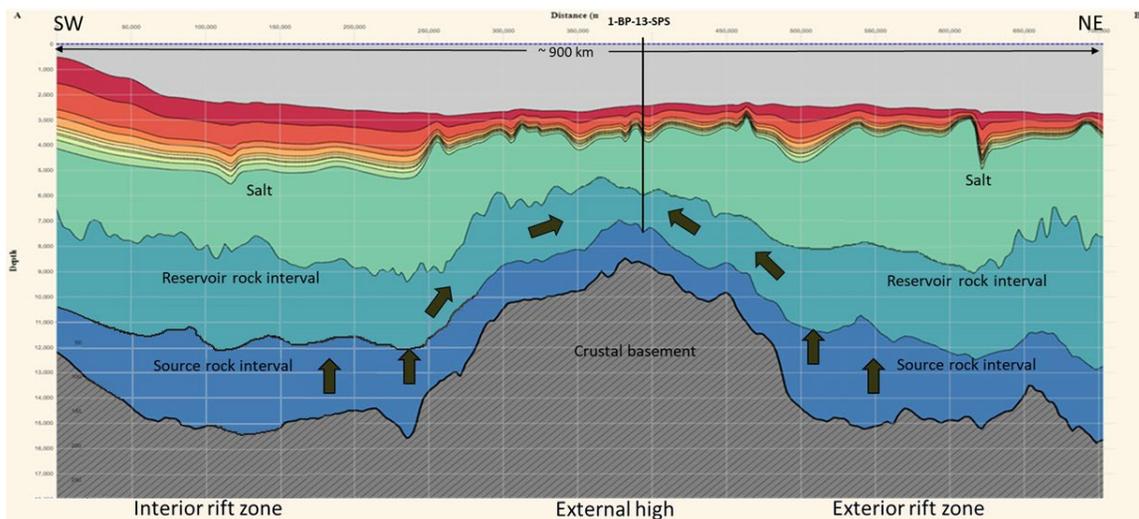

Figure 3. Arbitrary line through 3D basin model along strike, going from the Interior rift zone across the External high, passing through BP's discovery well 1-BP-13-SPS location, and then to the Exterior rift zone. The image is greatly exaggerated vertically: the depth scale is 18 km while the horizontal scale is 900 km. Black arrows indicate upward migration of oil from the Interior rift zone to the west and the Exterior rift zone to the east into potential reservoirs along the crest of the External high. Not shown are

two major crustal faults extending from the basement up into the overlying salt, located approximately 50 km on either side of this well and the arbitrary line location (see Figure 1).

Next step: quantify source potential and secondary migration

The most significant outcome of this 3D basin modeling is that not all oil found on the external high was locally expelled: there is significant migration up the flanks of the external high from the adjacent Interior and Exterior rift zones.

Our ongoing work is to quantify lateral variation in source Ultimate Expellable Potential (UEP) within an evolving Cretaceous-Cenozoic paleogeographic context. These paleo UEP estimates will allow us to quantitively address charge flux and migration losses to define effective lateral migration pathways to drilled and undrilled prospects.

Appendix III: Jurassic Petroleum System confirmed by observed oil front offshore Morocco

Kenneth Shipper, Paul Mann, and José Miguel Gorosabel-Araus, Department of Earth and Atmospheric Sciences, University of Houston, Andrew Pepper, This Is Petroleum Systems)

Source potential of the Moroccan offshore margin

The Central Atlantic margin of Morocco is a non-volcanic, Mesozoic–Cenozoic, rifted- passive margin extending over 3,500 km from the Strait of Gibraltar in northern Morocco to northern Mauritania. Exploration since the 1960s has been largely unsuccessful, with widely-spaced wells targeting Lower Cretaceous turbidites and Jurassic carbonates along the shelf, slope, and deepwater basin. To de-risk this underexplored margin, we summarize our 3D basin model for Jurassic and Cretaceous source rock intervals that is validated by our compilation of exploration and DSDP wells that overlie both rifted continental crust and the adjacent, Jurassic oceanic crust. Primary source rocks include the Late Jurassic (Oxfordian, Acme A158) with an ultimate expellable potential (UEP) of 4.5 mmboe/km2 as calculated from rock-eval pyrolysis data is (Fig. 1). This UEP is supported by previous DSDP documentation in 1976 of an active, vertical oil migration front at site 416 overlying Jurassic oceanic crust.
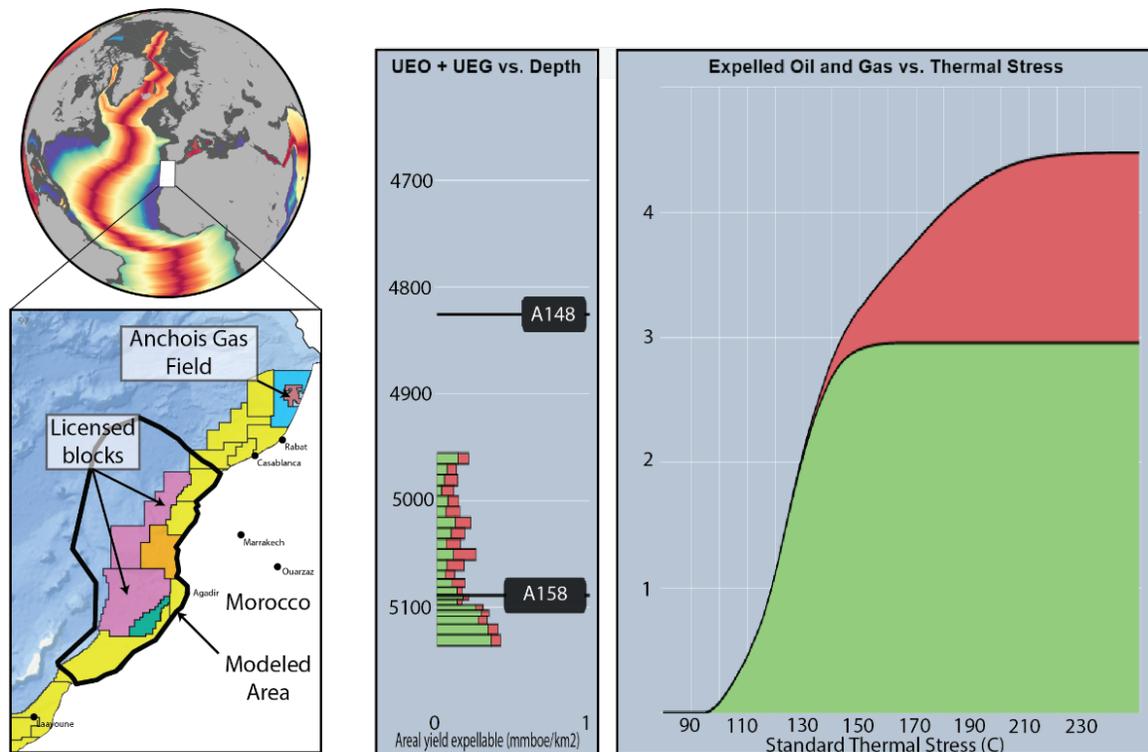

Figure 1. Present-day UEP for Oxfordian and Tithonian source rocks ultimate expellable potential (UEP) of 4.48 mmboe/km² using pre-expulsion HI across the distal offshore domain at Mazagan-1. Modeled Subsurface Thermal Stress (STS) maps for Tithonian and

Oxfordian source rocks assuming Organofacies A kinetics. Blue areas indicate thermal stress below the oil expulsion window (<110 °C), green in the oil expulsion window, yellow the oil-to-gas window transition; and red in the gas expulsion window. Tithonian sources are mature only within the Agadir and TanTan deltas; the Oxfordian oil-expulsion window extends beyond the COB, supporting widespread deepwater prospectivity from a charge perspective.

Full-lithosphere thermal modeling of the offshore Moroccan margin

We compiled multiple data types on the crustal structure, thermal regime and petroleum system construct our 3D basin model spans the rifted, continental crust and the adjacent oceanic crust. These data include regional 2D seismic data, free-air gravity (Sandwell et al., 2014), and well data from TanTan-1, Mazagan-1, DSDP 416 and 547. A 3D gravity inversion refined depth variations of Moho and constrained the transition in the dip direction from 30–40 km-thick continental crust to thinned transitional crust of the necking zone to 5–6 km-thick Jurassic oceanic crust. The marginal rift is 80–150 km wide with 1-10 km of sedimentary fill and is expressed as a margin-parallel gravity low that is interrupted by an orthogonal gravity high corresponding to the plunging, seaward extension of the High Atlas Mountains of coastal Morocco.

Our thermal modeling incorporated corrected borehole temperature, lithology, and Tmax data to predict Standard Thermal Stress (STS). A key model constraint was the observed oil expulsion levels of stress ~133 °C for Oxfordian source rocks at Mazagan-1. UEP models based on restored Corg and hydrogen index (HI) revealed the presence of the Late Jurassic (158 Ma) and Aptian (148 Ma) global acmes of high-quality source rocks. 3D full-lithosphere transient thermal modeling using ExCaliber software (developed by Xplorlab) simulated burial, maturation, and expulsion histories using a constant radiogenic heat production (RHP) of 0.58 µW/m3 that was measured at the TanTan-1 on rifted, continental crust. RHP remains a source of error for the area of rifted, continental crust as values would vary across the margin.

Source rock potential of the deep marine Moroccan margin

Jurassic and Early Cretaceous shales exhibit variable organic richness (TOC = 0.5–7%) and hydrogen index (HI = 138–608 mg HC/g TOC). Restoration of organic richness to its pre-expulsion level is constrained by Tmax data at Mazagan-1. The Oxfordian (158 Ma) source rock acme consistently shows the highest source potential, with restored HI values up to 958 capable of oil generation, Corg up to 0.35, and expulsion of 3.4 mmbo/km². 3D basin modeling indicates that Oxfordian source rocks expelled hydrocarbons extensively across both rifted continental and Lower Jurassic oceanic domains. Our 3D modeling uses organofacies A and kinetic relationships to fit to the oil migration front observed at DSDP 416. This fit requires an 18 mmboe/km2 higher UEP than observed at Mazagan-1. We predict that expelled hydrocarbons migrated vertically through Jurassic–Cretaceous sequences and laterally along salt-bounded minibasin structures as observed for the oil migration front observed at DSDP 416.
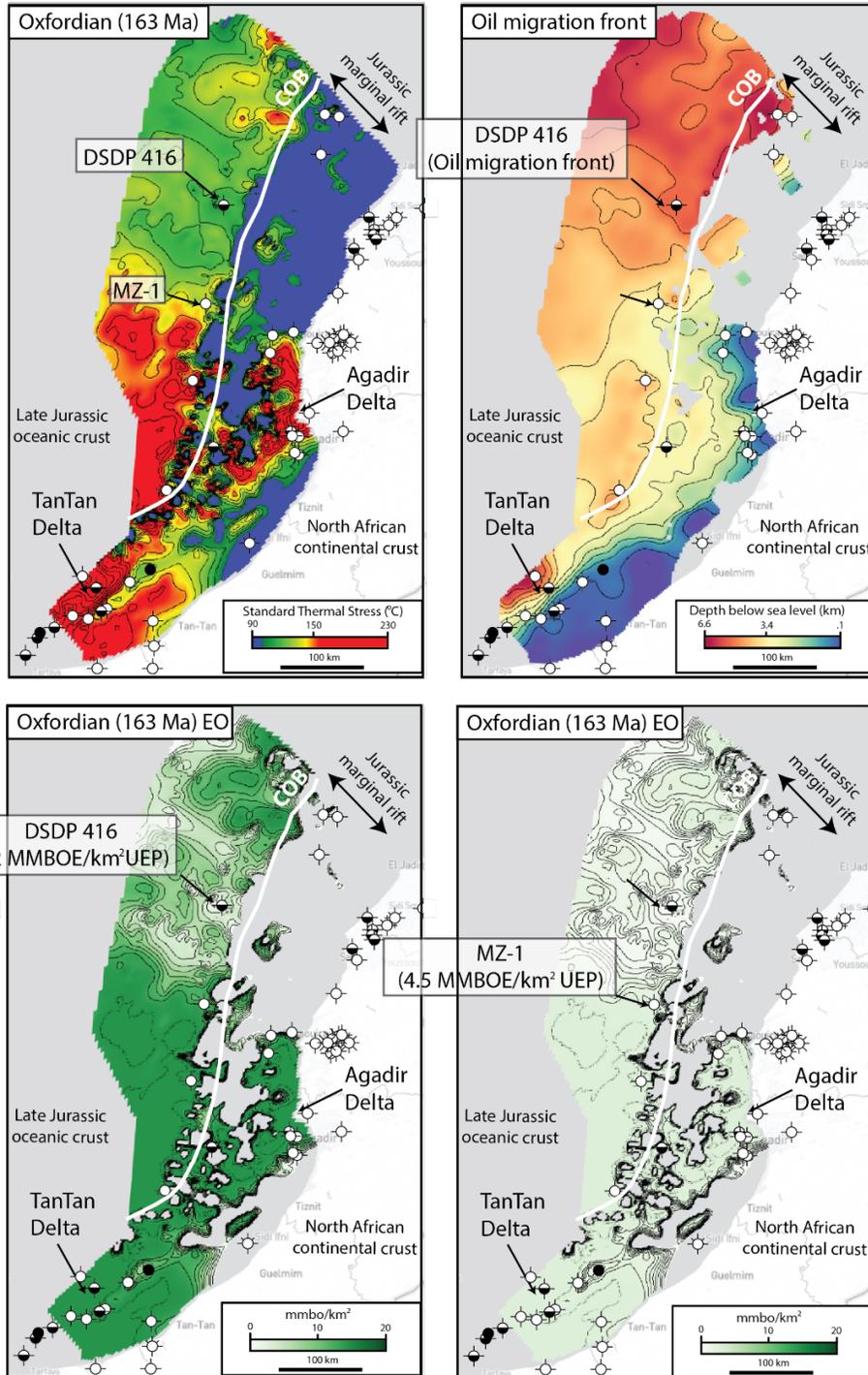
Figure 2A: Modeled Subsurface Thermal Stress (STS) maps for Oxfordian source rocks assuming Organofacies A kinetics. The Oxfordian oil-expulsion window extends beyond the continent-ocean boundary and supports widespread deepwater prospectivity from a charge perspective. B: Predicted oil migration front of Oxfordian source rocks extending from DSDP 416 throughout modeled area. C: Expelled oil maximum using 22 mmboe/km² UEP from DSDP 416. D: Expelled oil minimum using 4.5 mmboe/km² from rock-eval pyrolysis data at MZ-1.

Extended play fairway shown from modeled thermal stress

Modeled STS maps show that source rocks younger than the Tithonian reach sufficient thermal stress to expel oil above the zone of rifted, continental crust underlying the Agadir and TanTan deltas, while the Oxfordian source rock reaches the oil expulsion window across wide areas of the deepwater, Late Jurassic oceanic crust (Fig. 2). All known oil and gas shows observed in previous exploration wells overlie or are within a 2 km distance of areas of source rocks with elevated STS. Thermal stress in the 3D basin model matches measured BHT/TMax data at TanTan-1, DSDP 416 and MZ-1. The oil migration front and thermal stress maps align spatially with observed hydrocarbon shows and are consistent with our conclusion that an active petroleum system overlies both the rifted continental and the adjacent area of Upper Jurassic oceanic crust along the Moroccan margin.

Significance of the Moroccan Petroleum System

This study provides new evidence for a Jurassic petroleum system overlying the transition from rifted, continental crust to Upper Jurassic, oceanic crust. Our kinetic models completed for the Jurassic reveal an expelled oil up to 20 mmbo/km2 in the distal offshore, known from direct sampling at DSDP well 416 on Upper Jurassic oceanic crust. Oxfordian source rocks have high organic content, restored HI, and modeled thermal stress across both rifted continental and oceanic crust. The observed oil migration front at the immature DSDP 416 increases the hydrocarbon prospectivity of overlying Cretaceous reservoirs in areas with increased thermal stress. The combination of high thermal stress of source rocks, extensive sealing intervals, and structural complexity generated by salt tectonics establishes the Moroccan offshore as a frontier basin with significant hydrocarbon potential.

Appendix IV: Guyana-Suriname margin: New basin modeling study predicts spatial variation in charge risk

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The Guyana–Suriname Basin is a Mesozoic rifted–passive margin along the northeastern coast of South America that has emerged as one of the most prolific deepwater, hydrocarbon provinces of the past decade. Since the Liza-1 discovery in 2015, the central play fairway, or "Golden Lane", has been established by more than 54 commercial oil wells over a distance of 170 km along the margin of Guyana and projected over a distance of 82 km along the margin of neighboring Suriname. Production from the Golden Lane has increased to 900 thousand barrels per day and is sourced primarily from an Albian-Coniacian marine source. Despite the remarkable discovery of the Golden Lane in Guyana, the eastward extension of the play fairway into offshore Suriname remains uncertain, with recent Suriname wells, such as Caiman-1, failing to encounter commercial hydrocarbons (Fig. 1).
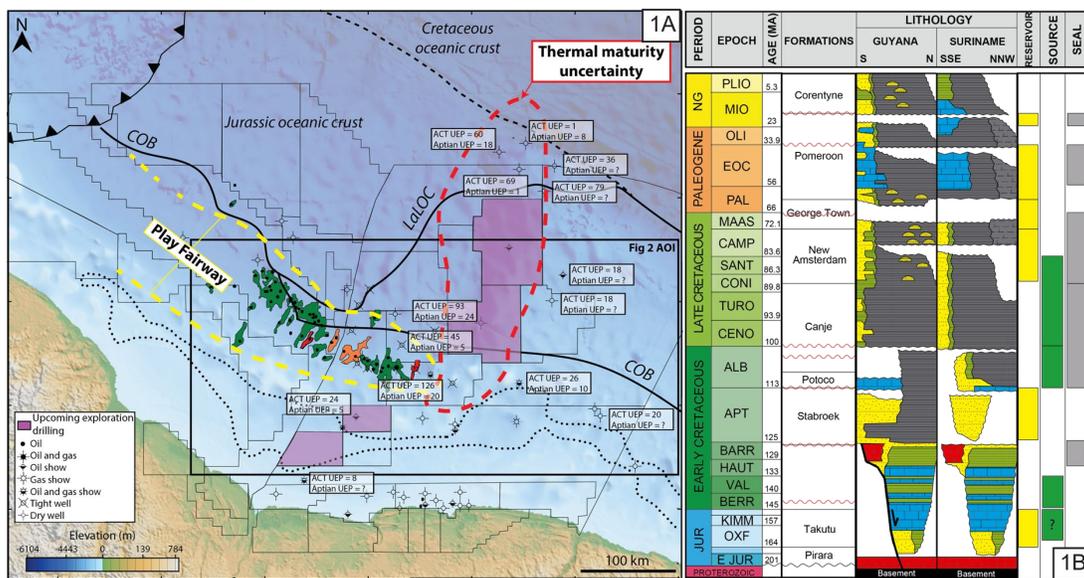

Figure 1A: Detailed map of the study area showing exploration and production blocks, distribution of oil and gas fields, and the dotted marginal rift. The public ultimate expellable potential (UEP) values in mmboe/km2 for both the Cenomanian-Turonian (ACT) and Aptian intervals are shown for key wells from offshore Suriname. Higher UEP follows the Cretaceous, paleo-shelf-slope trend highlighted in red. B: Stratigraphic column of the Guyana and Suriname, deepwater margins with petroleum system elements highlighted.

Full-lithosphere thermal modeling of the Guyana–Suriname margin

The Guyana–Suriname margin is characterized by along-strike crustal variability with the Golden Lane of Guyana underlain by a 23-km-thick, non-volcanic, obliquely-

rifted margin and the adjacent margin of Suriname underlain by the 25-km-thick and seaward-protruding, Demerara volcanic plateau, that formed as a Late-Jurassic-Cenozoic hotspot track conjugate to the Guinea Plateau in Senegal, west Africa. This crustal transition straddles the maritime boundary between Guyana and Suriname and profoundly affects lithospheric thickness, Moho topography, radiogenic heat flow, and ultimately source rock thermal stress.

Our full-lithosphere 3D basin model is calibrated using temperature data from 7 wells and predicts the spatial distribution of standard thermal stress (STS), resulting from variable burial histories and lateral changes in crust-lithosphere heat flow.

Source rock potential of the shelf-slope along the Demerara Plateau

We compiled published Rock-Eval pyrolysis data from exploration wells, including NCO-1, ANA-1A, and GNV-1, on the present shelf and upper slope along the western flank of the Demerara Plateau, with pyrolysis data from deepwater wells from five sites drilled in 2003 during Leg 207 of the Ocean Drilling Project in the area adjacent to the Demerara volcanic plateau.

Multiple source rock Acmes in both the Aptian-Lower Albian and Upper Albian-Santonian (pre- and post-breakup, respectively) source rocks contain Organofacies B kerogen in marine clay-dominated mudstones containing up to 6% total organic carbon. Hydrogen Index values range from 200 to 600 mg HC/g TOC. This organic richness translates into a truly world-class ultimate expellable potential (UEP) of up to 126 mmboe/km² along the paleo shelf–slope transition, decreasing basinward and approximately 19 mmboe/km² across the shelf, ultimately tapering to zero at the paleo-shoreline (Fig. 1).

STS trends and play fairway extent

Modeled STS at the Albian-Coniacian level indicates the oil expulsion window (>110O STS; blue-green boundary) extends across Blocks 52 and 58 of the western, offshore Suriname area, but diminishes northward of Block 66 in the northwestern area of the seaward-protruding, Demerara volcanic plateau (Fig. 2A). The location of this modeled oil expulsion window is supported by the distribution of established discoveries in the easternmost Golden Lane at blocks 52 and 58 and indicates that the northernmost offshore area of Suriname that is 41 km northeast of these two blocks has significantly lower thermal stress. In comparison, the modeled STS at the Aptian level (Fig. 2B) shows the oil expulsion window extending 120 km east and north into Blocks 63 and 64.

Our thermal model beneath the Golden Lane predicts the observed patterns of lower GOR oil fields to the NW of Stabroek (e.g. Liza), becoming increasingly high GOR with vapor phase accumulations near the maritime boundary, then becoming more oil-prone again in the SE of the Suriname trend (e.g. Grand Margu).

Implications for charge and migration risk in offshore Suriname

Most oil fields along the Golden Lane are associated with STS values exceeding 120 °C, whereas several frontier areas offshore Suriname fall well below this value. The lower modeled STS across the distal offshore Suriname suggests an increased risk of vertical migration to charge shallower Cretaceous reservoirs.

The success of recent and unreleased drilling results from offshore Suriname, including Macaw-1 and Araku Deep-1, along with three upcoming wells in Block 52,

will determine the vertical migration risk of decreased thermal stress for modeled source rock intervals. Success in these future wells would support the eastward extension of the petroleum system into deepwater Suriname and substantiate the role of Aptian source rocks in charging distal plays.
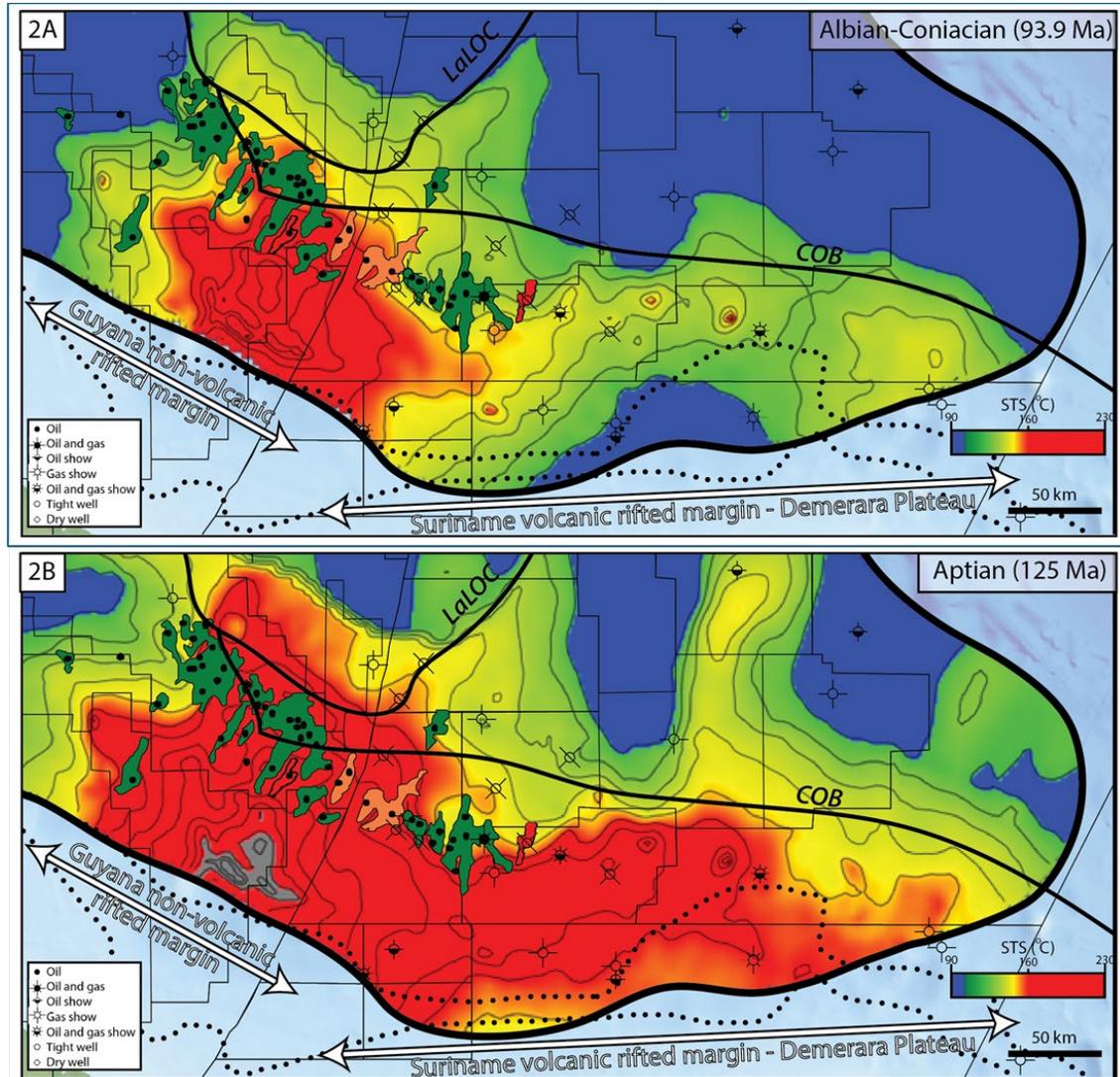

Figure 2A: STS of the Albian-Coniacian Organofacies B source rock. Blue indicates immaturity, green indicates the oil expulsion window up to the typical ~ 3000 scf/bbl liquid-vapor transition in yellow, and red indicates the dry gas window. B: STS of the Aptian Organofacies B source rock. GNV, Araku, and Sloanea aren't Albian-Coniacian sourced based on our thermal stress modeling. We interpret GNV oil shows to be Aptian-sourced.

Significance for exploration along the Guyana–Suriname margin

By integrating geochemical datasets within a full-lithosphere 3D basin modeling framework, this study delineates the kitchen limits at the Aptian and Albian-Coniacian source rock levels known over a distance of 245 km in the offshore area of Guyana-Suriname, and including the possible northeastern extension of the Golden Lane in

deepwater Suriname. While the Albian-Coniacian play fairway terminates within Blocks 52 and 58, the presence of deeper Aptian source rocks could potentially expand the prospective area into the distal offshore of the Demerara volcanic plateau, Suriname. Exploration success beyond the Golden Lane of Guyana will therefore depend on vertical migration capable of overcoming reduced thermal stress in the distal offshore of Suriname.

Our basin modeling provides a predictive framework for assessing exploration risk across Suriname's offshore blocks and highlights the importance of integrating lithospheric-scale thermal controls with stratigraphic and structural analysis in frontier deepwater basins.