Petroleum Potential of the Herodotus Basin: Applying Regional Analogues to Predict Plays and Reduce Potential Risk*

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Abstract

Within the last few years, play-opening gas discoveries in the Egyptian and Cypriot offshore and the Levantine Basin have prompted a renewed interest in the Eastern Mediterranean. While recent exploration efforts have focused on these areas, the adjacent deepwater Herodotus Basin remains almost totally unexplored. This basin, located along Egypt's northern coastline, forms a down-dip extension to the prolific Nile Delta province and probably shares multiple play elements with this basin and the Levantine Basin to the east. The forthcoming 2018 Egyptian Natural Gas Holding Company (EGAS) international bid round includes offshore acreage for thirteen blocks in the Eastern Mediterranean that will introduce new investment opportunities in this frontier region, with an additional bid round anticipated to open up another eight blocks in Egypt's Herodotus Basin during 2019.

This study evaluates the petroleum potential of the Herodotus Basin, using regional analogues from the Nile Delta and Levantine Basin to assist with play prediction and reduce potential exploration risk. Two important fairways considered are (1) the successful Oligo–Miocene clastic fairway of the Nile Delta and Levantine Basin represented by numerous major discoveries (e.g., Satis and Tamar) and (2) the Early–Middle Cretaceous carbonate fairway opened by Zohr during 2015 and subsequently extended by the Calypso discovery during February 2018. The possible extension of these plays into the Herodotus Basin was assessed by conducting a basin-scale risk assessment of the presence and effectiveness of individual play elements for each play.

Overall, basin screening suggests that the potential for technical success within the Herodotus Basin is fairly high. Maturity modeling for potential biogenic sources indicates that many proven biogenic fields in the Eastern Mediterranean lie close to or beyond the conventional biogenic gas window with reservoir temperatures as high as 85°C, suggesting effective biogenic gas charge for both play types with overburdens as great as 4000 m, diminishing charge risk for potential deep targets. However, some fundamental differences between the Herodotus and adjacent basins should be considered. Significant variations in trap geometries tied to dense normal faulting in the area, as well as an absence of the giant Syrian arc inversion structures observed in the Levantine Basin (largely resulting from fundamental differences in the

nature of the crust), suggest fields for the Oligo–Miocene clastic play are likely to be smaller than equivalent fields in nearby basins. For the Cretaceous carbonate play, the majority of the deepwater Herodotus Basin is likely not prospective because of the absence of seafloor topography over oceanic crust, inhibiting growth of shallow-water carbonates throughout the Mesozoic, and therefore preventing Cretaceous carbonate reservoir development. The lowest potential risk targets within Zohr-type plays are high relief build-ups over detached continental highs along the northeast margin of the basin that are sealed, and potentially also charged, by Oligo–Miocene mudstones.

Eastern Mediterranean as an Exploration Frontier

Although the well-established Nile Delta province is now largely considered mature for exploration, deeper-water basins of the Eastern Mediterranean remain largely underexplored. Recent exploration successes within the Levantine Basin and Egyptian and Cypriot offshore have sparked renewed interest in the Eastern Mediterranean, distinguishing it as an emerging province for frontier exploration and attracting potential future investment for deepwater exploration in the region. Play-opening discoveries include the 10 Tcf Tamar Field in 2009 (Needham, 2017), found in Early Miocene turbidites in the northern Levantine Basin, and the giant Zohr discovery, which reportedly contains 30 Tcf gas in-place (Adams, 2015), discovered within an Early Cretaceous carbonate build-up (with secondary Miocene reservoirs; Cozzi et al., 2018) in the deepwater Nile Cone area. During February 2018, the Calypso discovery was announced by ENI and contained approximately 7 Tcf in-place, extending the Zohr-type play into Cypriot waters and further fuelling interest for gas exploration within the region. During May 2018, EGAS launched the 2018 international bid round, including thirteen blocks covering a large frontier zone in the Egyptian offshore, with an additional bid round anticipated for 2019 that will introduce new investment opportunities for this frontier region (Figure 1).

To date, exploration activity in the Herodotus Basin has been limited, largely hindered by challenges such as water depths ranging from 1000 to more than 3000 m and limitations in seismic imaging beneath the Messinian salt (Morshedy et al., 2016). Nevertheless, the last few decades have seen the migration of Eastern Mediterranean exploration farther into the deep water, as well as targeting stratigraphically deeper reservoirs. In the central part of the basin, three sub-economic discoveries have been made, proving an active petroleum system is in place: LA-52 and LD-51 in subsalt Messinian sandstones of the Abu Madi Formation and Kg-45 in the Pliocene slope channel sandstones of the Kafr El Sheikh Formation (EGAS, 2012; Figure 1).

In all cases, the dominant hydrocarbon phase is reported to be dry biogenic gas. With the exception of the area flanking the Eratosthenes continental block, only one exploration well—Kiwi A-1X drilled by Statoil in 2010—has penetrated beneath the Messinian section in the Herodotus Basin; stratigraphically deeper targets remain largely untested. Although the well was dry due to the absence of a valid closure, reservoir quality sandstones were encountered in the Oligocene interval (Baer et al., 2016), indicating promising potential for an Oligocene sandstone fairway.

Play Prediction in the Herodotus Basin

Predicting plays in a frontier basin with scarce data coverage, such as the Herodotus Basin, can be challenging. Applying analogues from neighboring basins can assist with defining the petroleum system elements that are likely to be present and aid with the prediction of potential plays. For the purpose of this report, two frontier fairways with successful regional analogues were considered (i.e., proven plays in the neighboring Nile Cone and Levantine Basin to the south and east, respectively):

- A composite Oligocene–Miocene clastic fairway ranging from Rupelian to Messinian, represented by major discoveries such as Nooros in the Messinian, Temsah in the Middle Miocene, Leviathan and Tamar in the Early Miocene, and Satis in the Oligocene.
- Cretaceous-Miocene carbonate fairway opened up by the Zohr discovery in 2015 and subsequently extended in 2018 by the Calypso discovery offshore Cyprus, where the best reservoirs so far have been recorded in the Albian–Cenomanian.

A basin-scale risk assessment of the presence, distribution and effectiveness of individual play elements was undertaken for each of these plays using a combination of Gross Depositional Environment (GDE) maps and regional depth surfaces integrated with rock properties, organic geochemical and petroleum occurrence datasets. Table 1 shows a summary of the primary potential risks associated with each play element for the two plays.

Oligocene–Miocene Clastic Play Fairway

An Oligo–Miocene sandstone fairway is proven on both the western and eastern flanks of the Nile Delta, demonstrated by various producing gas fields in submarine slope-channel combination traps (e.g., Raven, El King, Hodoa, Satis, Atoll and Salamat fields). Furthermore, multiple major biogenic gas discoveries made in Early Miocene deep-marine fan sandstones in the Levantine Basin (e.g., Tamar) represent down-dip extensions to these slope-channel sands, suggesting an analogous play could exist in the adjacent Herodotus Basin to the west.

Reservoir

To establish reservoir presence, sand-prone turbidites for the Rupelian to Messinian interval were extracted from GDE maps to create a composite reservoir presence map for this interval. In the absence of well data coverage in the Herodotus Basin, sand distributions for GDEs were estimated using Oligo–Miocene sediment sink volume calculations for the Paleo-Nile system and offshore isopachs for the Oligo–Miocene interval (Macgregor, 2012). These exhibit two distinct lobe-shaped sediment thicks extending out into both the Herodotus and Levantine basins, separated by a thin corresponding to the Rosetta-Eratosthenes structural high (Figure 2).

During the Oligo–Miocene, a Paleo-Nile provenance is likely to have sourced reservoir-quality sandstones from the active Red Sea rift shoulders to the south, fed through slope channels in the Nile Delta area and deposited as thick basin-floor fans in the Levantine and Herodotus basins (Macgregor, 2012). The Rosetta-Eratosthenes Ridge was a positive feature that acted as a structural divide, deflecting sands into the two distinct systems. Reservoir ages for these sandstones at fields such as Tamar and Leviathan suggest that the delivery of sands eastward into the Levantine Basin was restricted to the Early Miocene. This implies that the Herodotus Basin likely became the primary focus for Nile sedimentation at periods when Nile-derived sediments were diverted away from the Levant sediment sink (e.g., Late Oligocene and Middle Miocene).

For the Levantine Basin, Early Miocene sandstone reservoirs are characteristically thick (e.g., more than 250 m of gross pay at Tamar) and have excellent reservoir qualities, with porosities exceeding 20% and permeabilities up to 500 mD at depths of approximately 4000 m (e.g., Tamar field, Needham et al., 2017). Because sandstones were likely switching between the Levantine and Herodotus arms of the system during the Oligocene and Miocene, sands with comparable reservoir extents and qualities are expected to be developed in the Herodotus Basin, extending out into distal settings at different but specific time periods.

Proven reservoir quality for Nile-derived sandstones extends down to 6000 m depth (e.g., Satis Field, Dolson et al., 2014). These extremely deep, proven reservoirs lie well above the global porosity/depth trend (Ehrenberg and Nadeau, 2005), which lends support to a steep porosity/depth gradient (i.e., a low rate of porosity loss with depth). This is likely the result of reservoirs being significantly overpressured because of rapid sedimentary burial, causing a reduction in pressure-solution and preservation of porosity. Therefore, the effects of burial are likely to have minimal impact on reservoir effectiveness across the region, considering the majority of Miocene and Oligocene sandstones fall well above the maximum 6000-m depth threshold.

Charge

Across the Nile Delta and Levantine basins, biogenic gas acts as the primary charge for many sandstone reservoirs throughout the offshore region (e.g., Gardosh and Tannenbaum, 2014). Across much of the province, thick salt has played a significant role in keeping temperatures cool during burial, lowering geothermal gradients and enabling reservoirs to stay within the biogenic window to greater depths of burial. Maturity modeling for potential biogenic sources in the Herodotus and Levantine basins indicates that, with the exception of the Messinian interval, the majority of Oligo–Miocene reservoirs are buried below the present-day biogenic gas window. However, multiple major Early Miocene discoveries in the Levantine Basin (with reservoir temperature of 78°C at Tamar (Figure 3) and potentially as high as 85°C at Aphrodite (Pujol et al., 2016; Macgregor, 2018) are charged by biogenic gas, even though these temperatures fall beneath the biogenic window. This suggests that biogenic source rocks could represent a primary charge for time-equivalent sandstone reservoirs at similar depths and temperatures in the adjacent Herodotus Basin. This scenario is dependent on gas being generated from biogenic source rocks in direct contact with the reservoir and trapped at a considerably early stage of burial (Macgregor, 2018) in shallow structures forming at or around the time of their deposition, without significant subsequent gas shrinkage or leakage. For the Herodotus Basin, this could be a viable charging mechanism, considering gravity tectonics were active during the Oligo–Miocene, setting up potential syn-sedimentary up-dip extensional and down-dip compressional trapping mechanisms.

Taking this into account, depth and temperature cut-offs taken from fields with known biogenic charge in the surrounding basins (e.g., ~4000-m reservoir depth and a calculated 85°C reservoir temperature at Aphrodite, assuming a geothermal gradient of 20–22°C; Pujol et al., 2016; Needham et al., 2017; Macgregor, 2018) were used with Oligocene–Miocene depth surfaces and regional geothermal gradient datasets (Macgregor, 2018) to generate a first-pass biogenic charge common chance map (CCM) for the Oligocene–Miocene interval. Overall screening demonstrates that across the majority of the Herodotus Basin, predicted Oligocene–Miocene reservoirs have a high likelihood of being charged by biogenic gas, provided structural and/or stratigraphic traps were in place at the time of generation.

However, aspects of this biogenic petroleum system are complex, and certain factors would benefit from further investigation to reduce potential risk. For instance, in the Early Miocene Levantine fields, basin modeling indicates that gas pools were filled during the Middle–Late Miocene, but then underwent depressuring and gas expansion during the Messinian lowstand followed by a rapid repressuring and compression during the Pliocene (Figure 3; Macgregor, 2018). A lack of significant subsequent recharge because of the elevation of reservoir temperature beyond the biogenic window is modeled to cause these closures to have only a partial gas fill in comparison to apparently higher degrees of fill in the younger reservoirs (e.g., Messinian and Pliocene fields), which would still have been in the biogenic window following Messinian salt deposition. This is supported by the work of Needham et al. (2017) in which seismic data covering the area around the Tamar Field indicates that structural closures are only ~50% full-to-spill (Macgregor, 2018). Consequently, a potential risk associated with biogenic charge in the Herodotus Basin could be that where deeper, older structures are charged before the Messinian sea level lowstand, fields might not be full-to-spill, making what could be potentially low reserve estimates in smaller structural closers even lower.

Additionally, it is possible that there could be contributions from thermogenic source rocks. Thermogenic charge of pre-salt plays is proven in the southern Nile Delta (Dolson et al., 2014), and reports of minor condensate yields at fields such as Tamar in the Levantine Basin also suggest a contribution from a thermogenic source (though it appears not to be at Zohr). Possible thermogenic source candidates include gas-prone Early Oligocene, organic-rich, deep-marine mudstones, which represent the primary source rock for fields in the southern Nile Delta and/or unproven Early and Middle Jurassic organic-rich carbonates, which could have been deposited in restricted marine lows during Jurassic rift intervals. Basin modeling indicates that although Oligocene organic-rich sediments are potentially widely distributed, they are probably immature across large parts of the basin. Exceptions to this are in the most deeply buried areas on the hanging wall side of major structures, such as north of the Nile Delta hinge line and northwest of the Rosetta Trend (Figure 4), where the maturity model exhibits the base Oligocene surface to lie within the late oil window at present day.

Seal and Trap

Within the sub-Messinian salt stratigraphy, intraformational, basinal mudstones immediately overlie reservoir horizons proven in Oligocene–Early Miocene stratigraphy in the Nile Delta and Levantine basins. Seals of a similar nature are expected across the Herodotus Basin, indicating seal presence to be of relatively low potential risk. As previously mentioned, gravity tectonics were active throughout the Herodotus Basin during the Oligo–Miocene, so there could be potential for small structural closures in up-dip rotated fault blocks and potentially larger down-dip toe thrusts and rollover anticlines, as well as stratigraphic up-dip pinchout traps near the southern basin margin. It is worth noting, however, that trap size is limited here as a function of the dense faulting in the area and a lack of compression associated with the preservation of oceanic crust to the north, so field sizes are expected to be significantly smaller compared to the broad Syrian Arc inversion structures present in the Levantine Basin.

Cretaceous and Miocene Carbonates Play Fairway

The initial discovery of a proven Cretaceous carbonate play at Zohr and the subsequent extension of this play by the Calypso discovery in 2018 have opened up the potential to extend this fairway into the surrounding deeper-water basins. The Zohr structure is composed of a 630 m thick column of reservoir-quality Early Cretaceous rudist carbonates overlain by a thinner interval of poorer-quality Miocene carbonate reservoir (with a combined net pay exceeding 400 m) and capped by an Oligo–Miocene mudstone and Messinian salt seal (Bertello et al., 2016; Cozzi et al., 2018). While the Miocene carbonate fairway is likely to be limited in extent, confined to areas on and surrounding the Eratosthenes Platform and sheltered from high Nile Delta clastic input, the Cretaceous carbonate fairway could be more extensive, considering clastic supply was significantly diminished during the Cretaceous, and rudist reef facies were prevalent across the Eastern Mediterranean and Middle East during this time (Bein, 1976; Steuber and Bachmann, 2002).

Reservoir

To establish reservoir presence, shallow-marine platform carbonates and patch-reef facies for the Aptian–Cenomanian were extracted from GDE maps to create a composite reservoir map for this interval. During the Early–Middle Cretaceous, and particularly during the Albian, rudist patch reefs grew on the Eratosthenes High, on the footwall of the Pelusium Line, on a paleo-shelf edge along the southern margin of the Levantine Basin and along the Nile Delta hinge line, as evidenced by various occurrences observed both in wells (e.g. Zohr, Cozzi et al., 2018) and outcrop (Bein, 1976; Steuber and Bachmann, 2002). This indicates that platform carbonates probably developed along the Cretaceous passive margin onto outboard highs that formed during Triassic and Jurassic rifting; further prospective targets are expected to be located along these early Mesozoic structural trends. This being the case, Cretaceous shallow platform facies are unlikely to have extended much into the basinal setting of the Herodotus Basin; indeed, the low potential risk parts of the fairway may have quite sharp fault-derived margins. Deeper in the basin, as one moves toward oceanic crust, it is expected that the Cretaceous section will have deposited in progressively deeper water that never had access to the light source necessary for rudists and other fundamental biota to develop. Therefore, potential reservoir targets are likely to be confined to the paleo-shelf area in the southern part of the basin and any detached continental blocks that may be situated along the western border of the Eratosthenes Platform in the far northeastern corner of the Herodotus Basin (Figure 5).

Limited reservoir data exist from the immediate area to test reservoir quality directly, but Early–Middle Cretaceous rudist limestones are assumed to have excellent reservoir qualities based on reports from both Zohr and Calypso. In the absence of direct data, porosity and permeability datasets for age-equivalent rudist limestones from the Zagros fold belt and the Rub Al Khali Basin were used to estimate permeability/porosity and porosity/depth relationships to establish likely depth cut-offs for reservoir effectiveness. These data confirm that the average value for the Zohr reservoir lies extremely close to the global trend for carbonate reservoirs (Ehrenberg and Nadeau, 2005), but that maximum porosities of 30% (Cozzi et al., 2018) far exceed global averages at these depths, indicating that the effects of burial are likely to have minimal impact on reservoir effectiveness, considering the majority of Cretaceous carbonate targets would likely lie above the minimum 5000 m depth cut-off. At Zohr, reservoir quality was probably enhanced by periods of subaerial exposure and subsequent karstification; therefore, larger scale build-ups situated on the longest-lived structures that remained elevated near sea level are expected to have the best reservoir potential.

Charge

For the offshore Nile Cone, biogenic gas has been reported as the primary charge for the Zohr Discovery (Bertello et al., 2016). Furthermore, the reported lean gas at the 2018 Calypso discovery (ENI, 2018) advocates a biogenic charge, suggesting that biogenic gas likely represents the primary source for the Cretaceous carbonate play in this region. However, the stratigraphic relationships here are unusual. At Zohr, Oligocene–

Miocene mudstones directly onlap Cretaceous carbonates so that recently generated biogenic gas from the young strata was able to migrate directly into the much older reservoir. In the absence of other primary datasets, depth cut-offs taken from the Zohr Field, and from fields with known biogenic charge in the surrounding basins (with Aphrodite being the deepest observed [Needham et al., 2017]), were used with the top Cretaceous carbonate depth surface and regional geothermal gradient dataset (Macgregor, 2018) to generate a first-pass biogenic charge CCM for the Cretaceous carbonate interval.

Over much of the region, Cretaceous build-ups likely lack the topographic relief necessary for reservoirs to communicate with Tertiary biogenic systems and thus be charged by biogenic gas. Therefore, such buildups would be dependent on the presence of unproven older thermogenic source rocks to represent prospective targets. The scarcity of observations of such thermogenic gases in the deepwater region, particularly the apparent absence of any heavy gases at Zohr, indicates that this source mechanism is of generally higher potential risk, as demonstrated on the CCCM for the Cretaceous carbonates fairway (Figure 6). Nevertheless, thermogenic charge of presalt plays is proven in the southern Nile Delta, which has been suggested (along with a primary source in the Oligocene) to have partially come from a deep Jurassic source (Dolson et al., 2014; El Diasty et al., 2015; El Belasy, et al., 2017). Additionally, reports of minor condensate yields at fields such as Tamar in the Levantine Basin suggest that there is a contribution from a thermogenic source. Overall, areas with the highest likelihood of biogenic charge and, therefore, with the lowest potential charge risk lie in the area on or surrounding the Eratosthenes platform where there is potential for biogenic charge of high relief structures in the area.

Seal and Trap

Cretaceous rudist build-ups with the highest relief, such as the Zohr and Calypso structures, are likely to be onlapped by Oligo–Miocene mudstones and potentially capped by Messinian salt, both of which have potentially low potential seal risk. However, the majority of potential build-ups likely has much lower relief and would therefore be reliant on a Late Cretaceous–Early Paleogene calcareous mudstone or chalk side-seal. Proven examples for seals of this age or lithology in the Herodotus or surrounding basins do not exist, but effective carbonate-rich seals elsewhere in the region suggest they could have sufficient sealing potential. Further, effective top- and side-seals are likely impacted in the immediate area over the Eratosthenes platform where the rapid shallowing of facies to the north and the absence of Messinian salt poses a potential elevated risk to seal.

Conclusions

A preliminary basin screening and investigation into the regional geological history of this area has demonstrated that, to some degree, we can look to the deepwater Nile Delta and Levantine basins for analogues to assess the petroleum potential of the frontier Herodotus Basin, which likely shares multiple play elements with these basins. Overall, screening suggests that the potential for technical success (i.e., discoveries that may or may not be of commercial size) in the Herodotus Basin is fairly high. However, although the Herodotus Basin shares some of its geological history with the neighboring basins, some fundamental differentiators in their structural and stratigraphic histories should be considered. Significant differences in trap geometries and an absence of the giant Syrian arc inversion structures observed in the Levantine basin, largely resulting from fundamental differences in the nature of the crust, indicate that fields in the Herodotus Basin are likely to be much smaller than equivalent play types in nearby basins. Therefore, trap size could be a potential economic risk for this basin, particularly for the

Oligocene–Miocene clastic play. More detailed seismic analysis and prospect mapping would therefore be required to analyse the potential for commercial-scale discoveries within the Oligo–Miocene clastic fairway.

Further, the presence of oceanic crust beneath much of the Herodotus Basin means that there was likely insufficient seafloor topography for shallow-water carbonates to develop during the Mesozoic, meaning the Cretaceous carbonate play is not likely viable over the deeper parts of the Herodotus Basin. However, areas where continental crust is indicated on gravity and seismic, such as the shelf area along the southern extent of the basin and to the west of the Eratosthenes High, exhibit good potential. The greatest opportunities are predicted to exist in the far northeastern sector of the basin where screening has confirmed that the Cretaceous carbonate play discovered at Zohr and subsequently extended by the Calypso discovery in 2018 has an opportunity for success. Detailed seismic facies analysis would be necessary to locate the lowest potential risk prospects, with regards to locating the highest relief build-ups along with effective seals. Additional modeling-based predictions of the limits of the biogenic kitchen and geochemical analysis of fluids might also aid the reduction of potential charge risk and in the assessment of potential deep thermogenic source rocks, which are an important element for lower relief build-ups.

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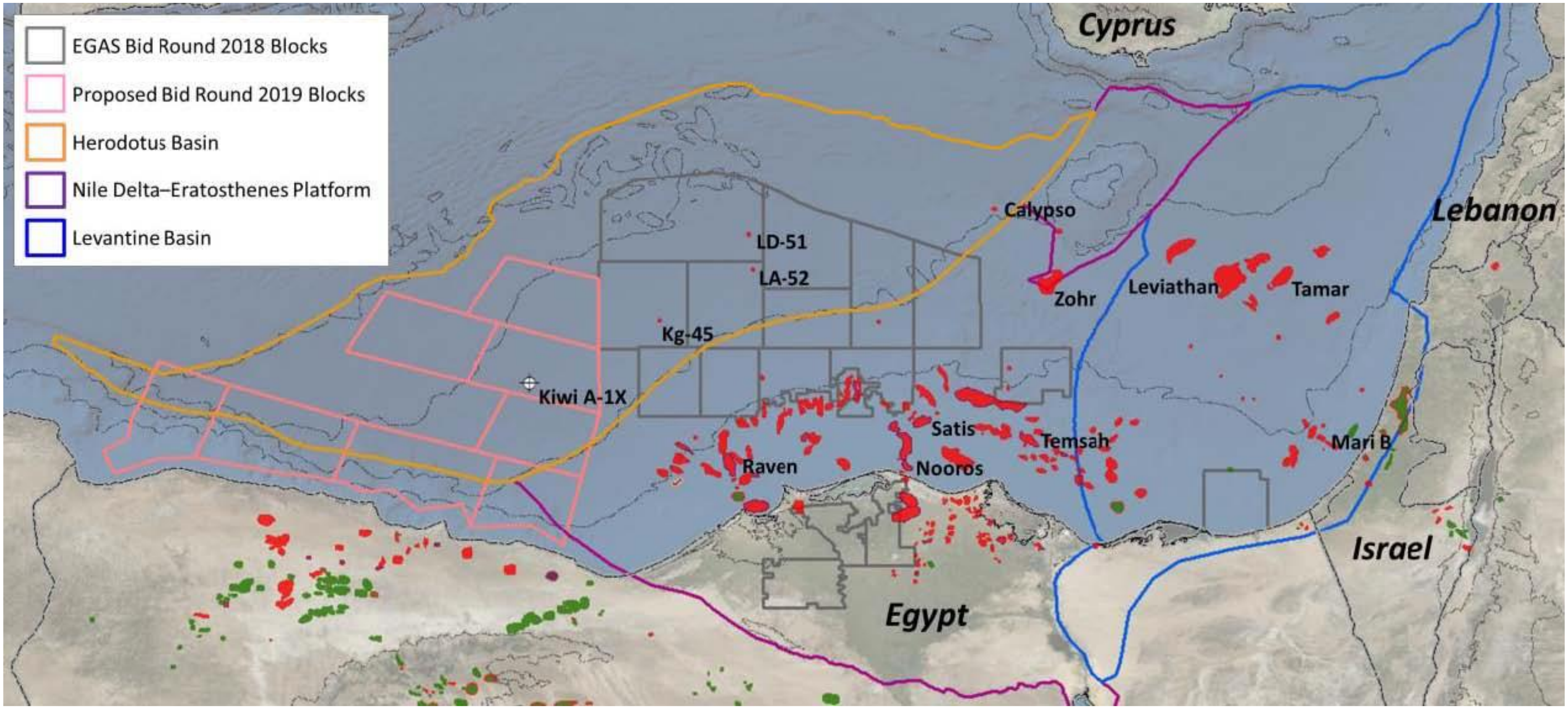

Figure 1. Location map of the Eastern Mediterranean depicting hydrocarbon fields and EGAS 2018 and proposed 2019 licence blocks. Fields, wells and outlines for the primary basins discussed are exhibited.

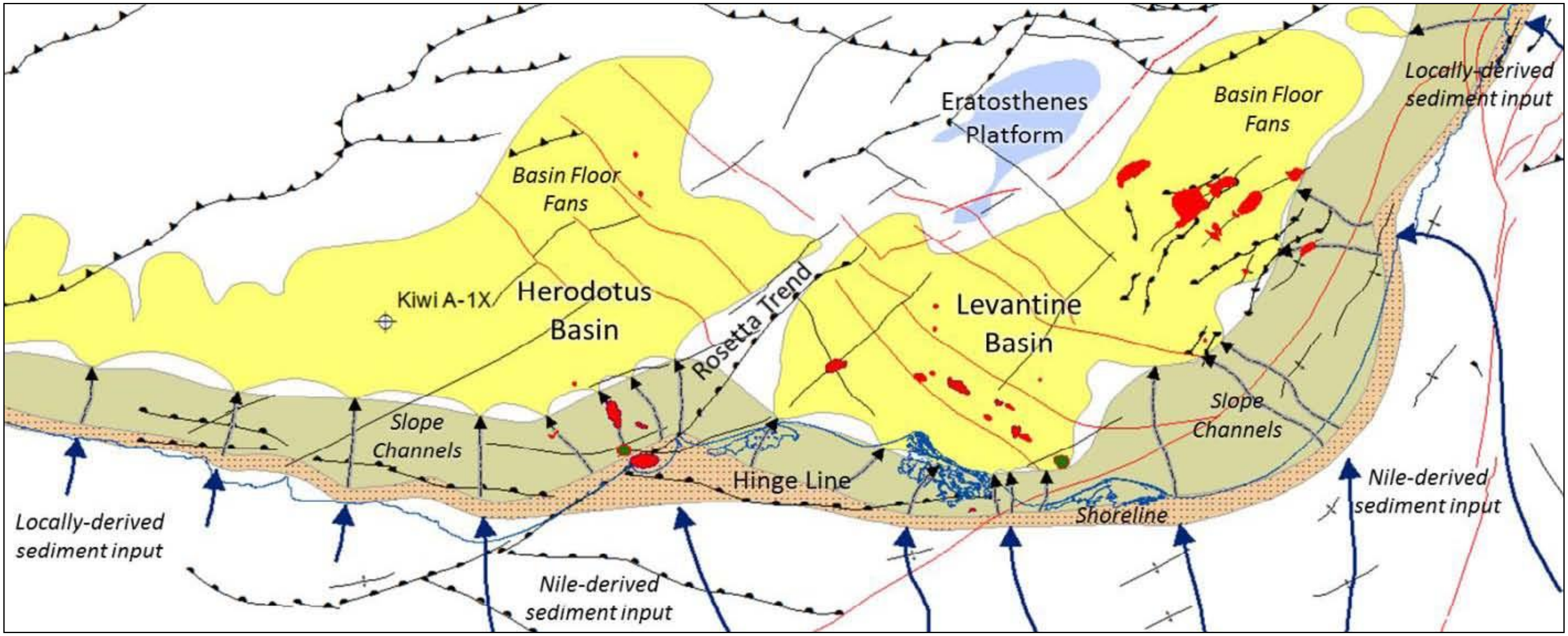

Figure 2. Composite Oligo–Miocene GDE map showing the maximum distribution of potential Oligo–Miocene reservoir sandstones based on sediment isopachs and sediment budget calculations (Macgregor 2012). High Paleo-Nile clastic input (blue arrows) was sourced from the Red Sea rift shoulders. The Rosetta-Eratosthenes Ridge remained a positive feature, deflecting sands through marine slope channels (black arrows) into the adjacent Levantine and Herodotus basins. Oil and gas fields with reservoirs in Oligo–Miocene sandstones are shown.

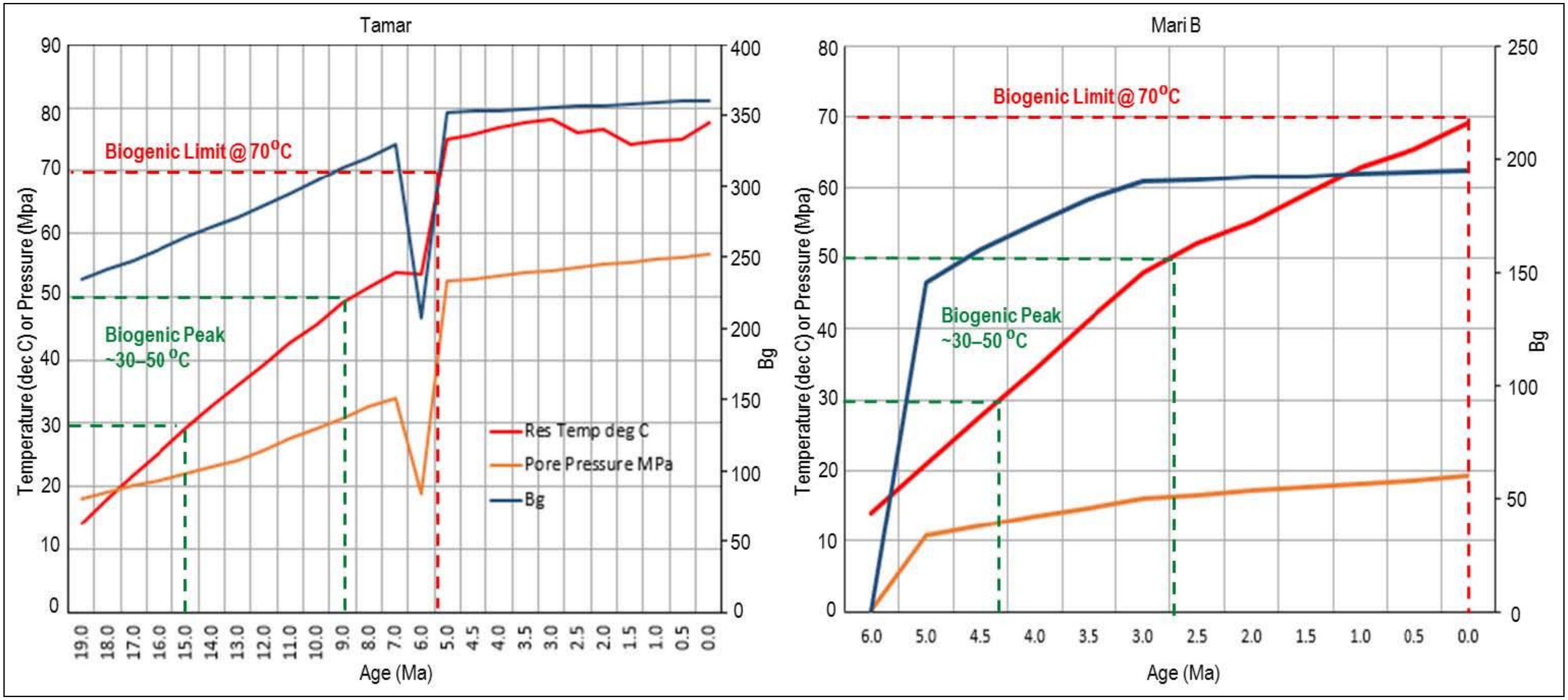

Figure 3. Early Miocene Tamar Field pressure versus temperature (PVT) history compared to PVT for younger Pliocene Mari B Field (Macgregor et al., 2018). The biogenic model predicts most generation at Tamar occurred before the Messinian lowstand, causing depressuring and gas expansion. Therefore, older fields at greater depths have a higher potential risk of not being full-to-spill, compared to younger fields such as Mari B, many of which remain within the late biogenic window at present day.

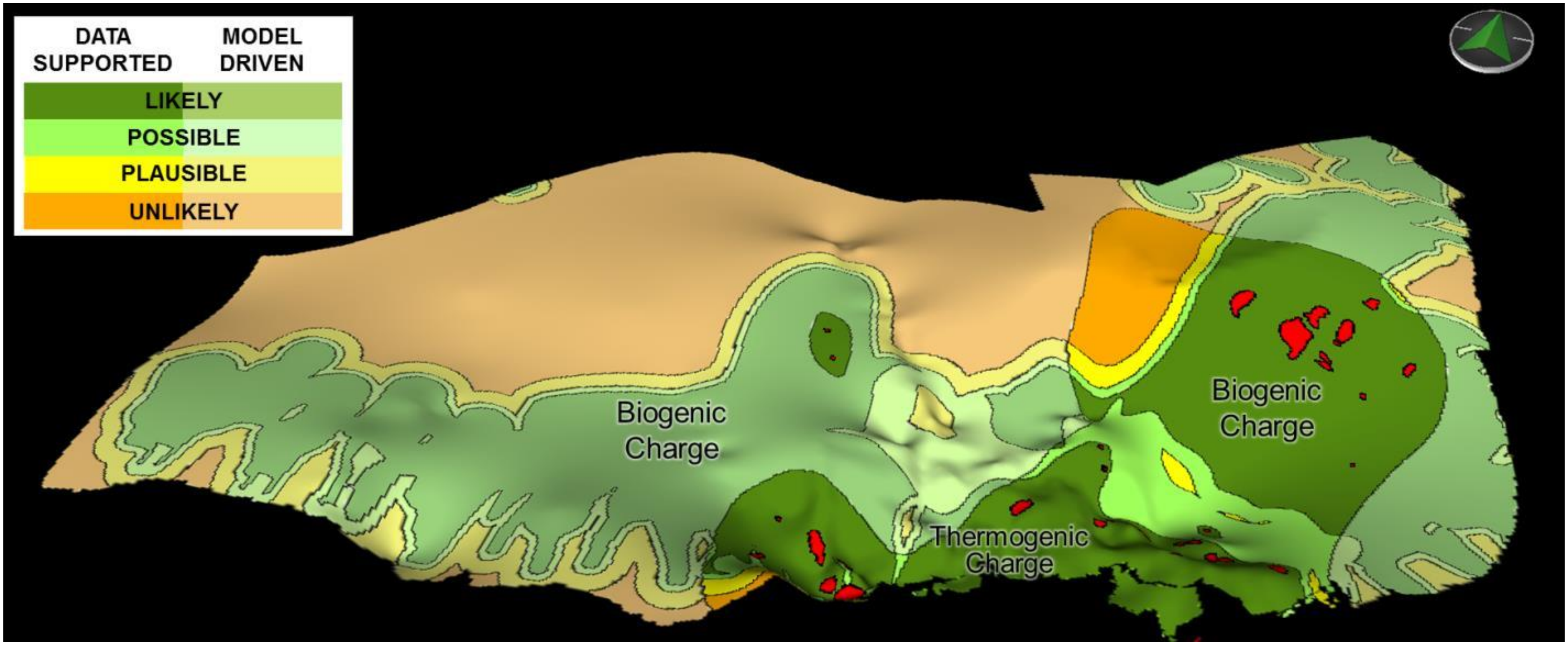

Figure 4. Final combined common chance map (CCCM) for the Oligo–Miocene Clastic Fairway in the Eastern Mediterranean draped over a top Oligocene structural framework surface. The CCCM was generated by combining biogenic charge common chance map (CCM), Early Oligocene charge CCM, Oligo–Miocene reservoir presence and effectiveness CCM, and intraformational Oligo–Miocene shales seal presence CCM outputs. Oil and gas fields with Oligo–Miocene sand reservoirs are presented.

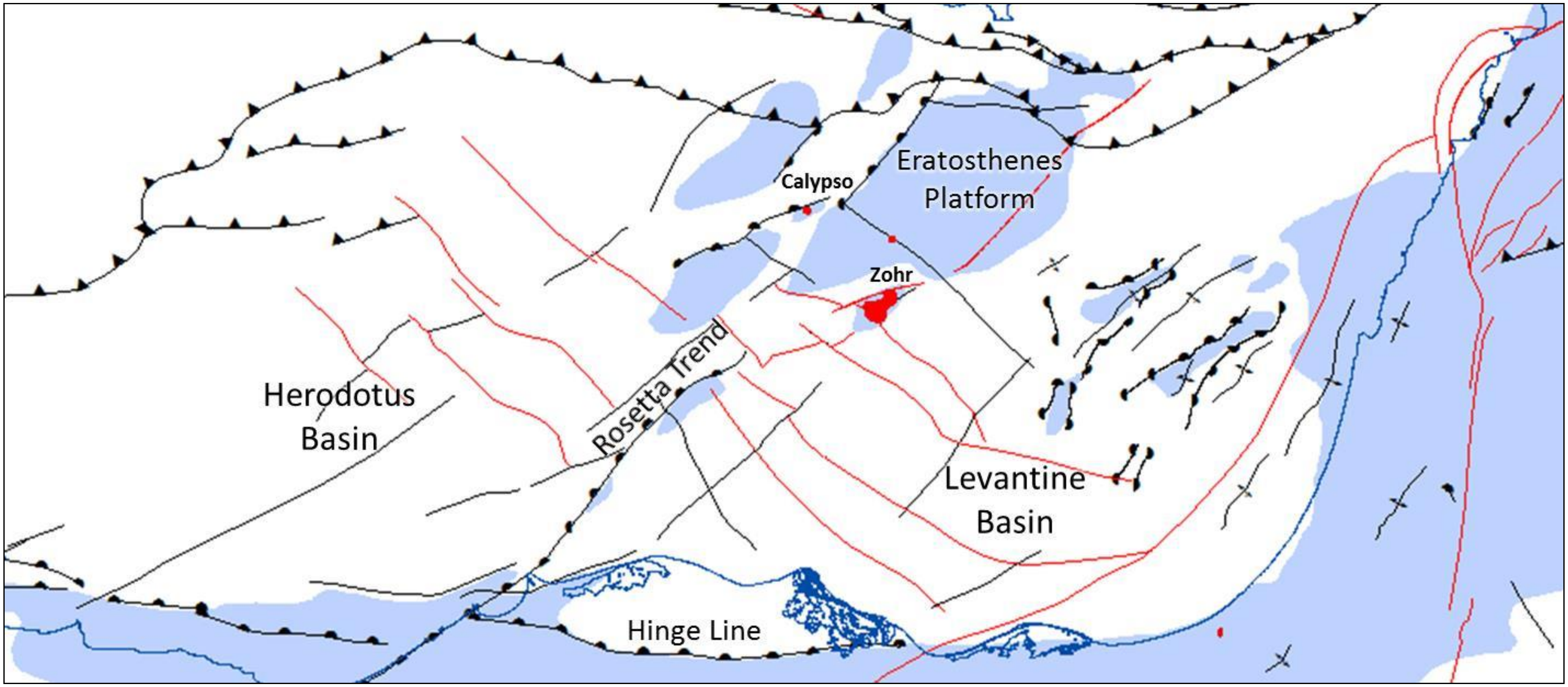

Figure 5. Simplified Middle Cretaceous GDE map showing maximum distribution of predicted carbonate reservoirs (pale blue). Cretaceous rudist build-ups were most likely seeded onto paleohighs on the seafloor over inherited Tethyan structural elements. Oil and gas fields with Cretaceous carbonate reservoirs are presented.

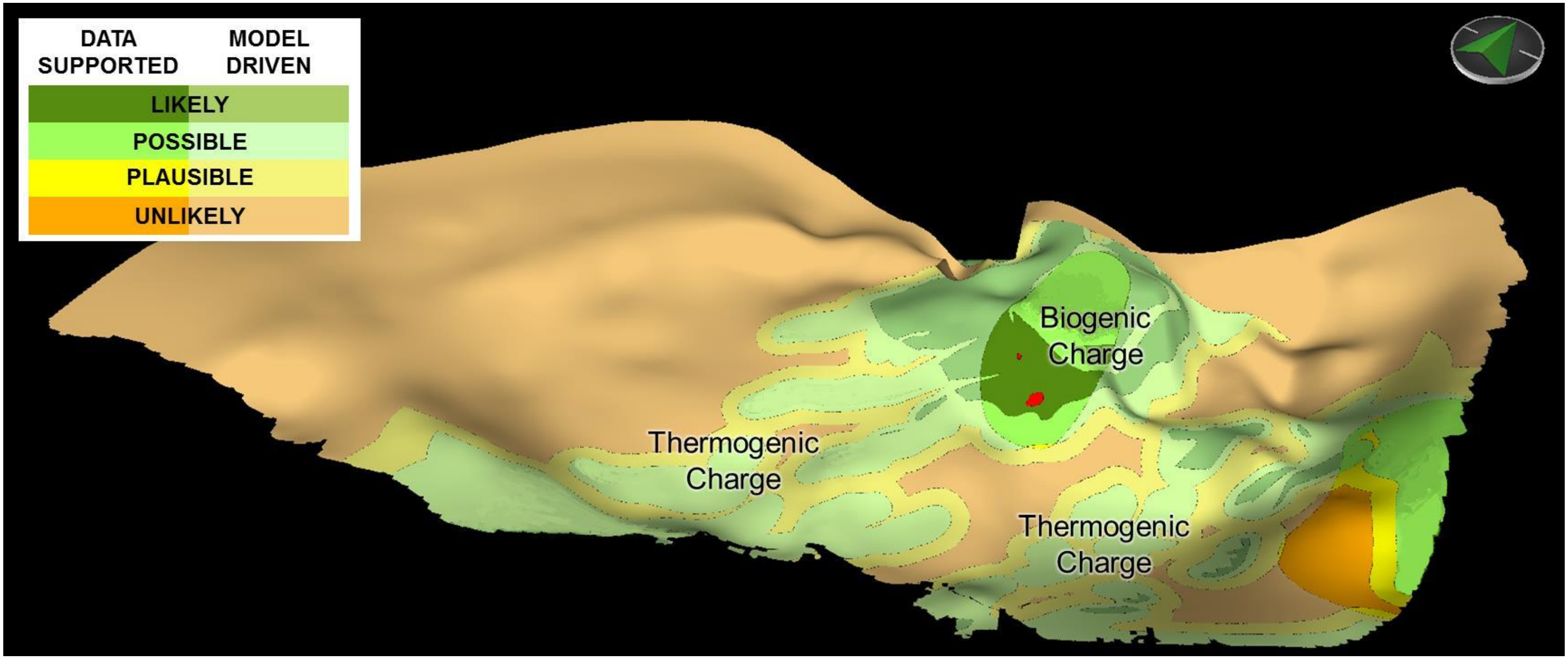

Figure 6. Final CCCM for the Cretaceous carbonates fairway in the Eastern Mediterranean draped over a top Cretaceous structural framework surface. The CCCM was generated by combining biogenic charge CCM, Jurassic charge CCM, Cretaceous reservoir presence and effectiveness CCM, and Late Cretaceous–Early Paleogene Calcareous mudstone seal presence CCM outputs. The locations of the Zohr gas field and subeconomic Onesiphoros gas pool are presented.

	HERODOTUS BASIN		NILE DELTA / ERATOSTHENES HIGH		LEVANTINE BASIN	
Play Element Risks and Uncertainties	**Oligo–Miocene Basin Floor sands in combination traps**	**Early Cretaceous Limestones in carbonate build-ups**	**Oligo–Miocene Basin Floor sands in combination traps**	**Early Cretaceous Limestones in carbonate build-ups**	**Oligocene–Miocene Basin Floor sands in combination traps**	**Early Cretaceous Limestones in carbonate build-ups**
Charge (Source Presence and Migration)	Biogenic (P); gas-prone Oligocene thermogenic (PA); Jurassic thermogenic (U)	Biogenic for high relief build-ups (P); thermogenic for low relief build-ups (U)	Gas-prone Oligocene thermogenic (P)	Biogenic for high relief build-ups (P)	Biogenic (P)	Jurassic? thermogenic (U) Low risk in south- oil in Yam wells
Source Rock Maturity	Late biogenic window (PA); Late oil mature Oligocene (south) (PA); Gas mature Jurassic (U)	Late biogenic window (PA); Gas mature Jurassic (U)	Late oil mature Oligocene; generating gas due to high Type III content (P)	Late biogenic window (P)	Late biogenic window (P), possible early thermogenic gas top-up	Gas mature Jurassic (U)
Reservoir Presence	Oligocene (P) and Messinian (P) sandstones	Cretaceous rudist-rich carbonates (P)	Oligocene–Messinian sandstones (P)	Cretaceous rudist-rich carbonates (P)	Early Miocene sandstones (P)	Cretaceous rudist-rich carbonates (PA)
Reservoir Quality	Good reservoir quality reported in Oligocene sandstones in Kiwi A-1X well.	Cretaceous section at Calypso reported to have very good reservoir quality	Oligocene to Miocene sandstone reservoirs, porosities > 20% and high permeabilities at depths of up to 6000m	30% maximum porosity reported at Zohr	Oligocene to Miocene sandstone reservoirs, porosities > 20% and permeabilities > 500 mD at depths of 3500m	Good from Zohr reports, but buildups buried much deeper – could affect reservoir quality
Seal	Oligocene–Miocene intraformational mudstones (PA)	Oligocene mudstone (P), Messinian salt (P) Cretaceous carbonate (U)	Oligocene–Miocene intraformational mudstones (P)	Oligocene mudstone (P), Messinian salt (P) Cretaceous carbonate (U)	Oligocene–Miocene intraformational mudstones (P)	Cretaceous carbonate (U)
Trap Presence and Volume	Reservoirs in combination traps based on seismic data. Expected trap size is smaller than in Levantine	One large buildup (Calypso), further ones predicted over inherited structural trends	Proven Oligo-Miocene sandstone reservoirs in combination traps	One large buildup known at Zohr, further ones predicted over inherited structural highs	Proven Oligocene to Miocene sandstone reservoirs in Syrian Arc structures.	Buildups interpreted on rifted highs on seismic (e.g. beneath Leviathan) over large region.

		Low Risk	Medium Risk		High Risk
P: Proven					
PA: Proven Analogue	**High level of certainty, based on data control**	Likely	Possible	Plausible	Unlikely
U: Unproven	**Low level of certainty, based on data control**	Likely	Possible	Plausible	Unlikely

Table 1. Summary of the primary potential risks and uncertainties associated with the Cretaceous carbonate and Oligocene–Miocene clastic play fairways for the Herodotus Basin compared to proven (and frontier) analogues in the Nile Delta and Levantine Basin.