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INTEGRATED REASSESSMENT OF HYDROCARBON POTENTIAL IN THE ABSHERON-BANK AND DARWIN BANK FIELDS, OF THE ABSHERON-PREBALKHAN STRUCTURAL THRESHOLD

(Представлено членом редакційної колегії д-ром геол. наук, доц. О.В. Шабатурою)

Background. ***The South Caspian Basin represents an exceptional geodynamic province distinguished by its extraordinary sedimentary accumulation and active petroleum systems, positioning it among the foremost hydrocarbon-bearing regions globally. Encircled by collisional orogenic belts, the basin has accommodated over 25 kilometers of sedimentary infill, more than 10 kilometers of which have been rapidly deposited within the last six million years. This accelerated subsidence and burial, under anomalously low geothermal gradients, has facilitated ongoing hydrocarbon generation at depths exceeding 8–12 kilometers. Regionally extensive anticlinal structures, interpreted as buckle folds developed above a basal detachment surface, have been delineated through the interpretation of regional-scale 2D seismic datasets. The convergence of an actively generating petroleum system, vast undrilled structural closures, and a regulatory framework conducive to foreign investment has elevated the basin's profile within the global energy sector.***

Within this tectonically complex setting, the Absheron–Prebalkhan structural zone constitutes a principal hydrocarbon province, encompassing several strategically significant fields, notably the Absheron-Bank and Darwin Bank fields. This investigation offers a rigorous, data-integrated evaluation of their hydrocarbon prospectivity, synthesizing multi-decadal exploration, production records, and subsurface geoscientific data. The Absheron-Bank field, discovered in 1951 some 25 km north of Pirallahi Island in shallow Caspian waters, and the Darwin Bank field, delineated in 1950 and sharing structural continuity with neighboring anticlinal trends, serve as focal points of this assessment.

Methods. ***Geological and geophysical analyses were conducted to evaluate reservoir properties, including stratigraphic correlations, reservoir pressures, and production performance. Core lithology and seismic data were integrated with petrophysical parameters – such as porosity, permeability, and fluid saturations – to characterize productive horizons (e.g., Kirmaki and Kala suites).***

Results. ***The results underscore substantial hydrocarbon accumulations within Lower Pliocene strata of the Productive Series. The Absheron-Bank field possesses estimated initial reserves (B+C1+C2 categories) of 6.3 million tonnes of crude oil and over 2.5 billion cubic meters of both dissolved and free gas. As of January 2022, 74 wells have been drilled, yielding 495.8 thousand tonnes of oil and approximately 1.2 billion cubic meters of gas – representing a 39.4 % recovery of extractable oil reserves.***

Conversely, the Darwin Bank field, developed through 776 wells, has produced approximately 17.9 million tonnes of oil and 1.4 billion cubic meters of dissolved gas, with nearly 80 % of extractable reserves already recovered. Current development efforts are situated in the terminal phase of the field's productive lifecycle, where diminishing well productivity and infrastructure obsolescence pose persistent operational challenges.

Conclusions. ***This study advocates for the continued implementation of reservoir pressure maintenance strategies, enhanced oil recovery (EOR) techniques, and the optimization of water injection regimes to prolong field productivity. Furthermore, it highlights the necessity of sustained geological, petrophysical, and hydrodynamic monitoring to inform adaptive field management strategies – particularly within mature, offshore domains of the South Caspian petroleum province.***

Keywords: ***South Caspian Basin, Absheron–Prebalkhan tectonic zone, hydrocarbon prospectivity, offshore oil and gas fields, reservoir characterization, Productive Series, enhanced oil recovery (EOR).***

Background

The South Caspian Basin is traditionally regarded as one of the deepest sedimentary depressions within the geodynamically active Mediterranean–Alpine mobile belt (Fig. 1). In terms of its fundamental geological attributes, it is comparable to the Black Sea and Aegean Sea basins; however, it exhibits a set of unique features that distinguish it from other analogous tectonic structures (Pogorelova, 2019; Mikhailov, 2017).

Foremost among these is the pronounced thinning of the oceanic-type crust in the central part of the basin. According to geophysical data, the depth to the Mohorovičić discontinuity beneath the South Caspian seafloor does not exceed 22–28 km. In adjacent areas – particularly near the shelf escarpments and the Absheron-Prebalkhan structural threshold – this boundary plunges to depths of 30–35 km. It is noteworthy, however, that the prevailing view concerning the ubiquitous absence of a "granitic layer" – a seismic velocity layer characterized by values of 6.0–6.3 km/s – is challenged by several researchers, giving rise to ongoing scholarly debate (Khalilova, & Seyidov, 2023).

Secondly, the basin is marked by an extraordinarily thick sedimentary cover, reaching its maximum accumulation in the central sector. Integrated evidence from marine seismic surveys, offshore drilling, and geological mapping of adjacent Azerbaijani and Turkmenian territories suggests that the South Caspian Basin has accumulated high amount of sedimentary influx (Abdulla-zada, & Vakhably, 2021; Huseynov, 2003). Its exceptional sedimentary thickness, tectonic complexity, and ongoing hydrocarbon generation at extreme depths render it a subject of continued scientific interest and industrial investment (Kerimov et al., 2015). Surrounded by collisional orogenic belts, the basin has accumulated more than 25 kilometers of sedimentary fill, of which over 10 kilometers were deposited during the last six million years. This rapid subsidence, accompanied by anomalously low geothermal gradients, has created unique conditions wherein hydrocarbons continue to be actively generated at depths exceeding 8–12 kilometers (Alizade et al., 2018; Aliyeva, 2004). Structurally, the basin is defined by large-scale anticlinal folds, interpreted as buckle structures detached from a regional décollement zone, which serve as primary traps for oil and gas accumulations. These geological attributes have collectively positioned the South Caspian Basin at the forefront of global hydrocarbon exploration (Javanshir et al., 2015; Bagirov, Minzverg, & Kondrushkin, 1975). Within this sequence, stratigraphic units of Paleogene, Neogene, and Quaternary age can be clearly delineated, the specific characteristics of which will be addressed in subsequent sections.

The third defining feature is the remarkable concordance between the present-day bathymetry of the basin and the distribution of sediment thickness. The uppermost boundary of the sedimentary fill is overlain directly by a water column exceeding 1 km in depth, thereby creating a unique, uninterrupted stratigraphic-hydrological continuum (Kerimova, 2023; Abbasov, & Guliyev, 2003).

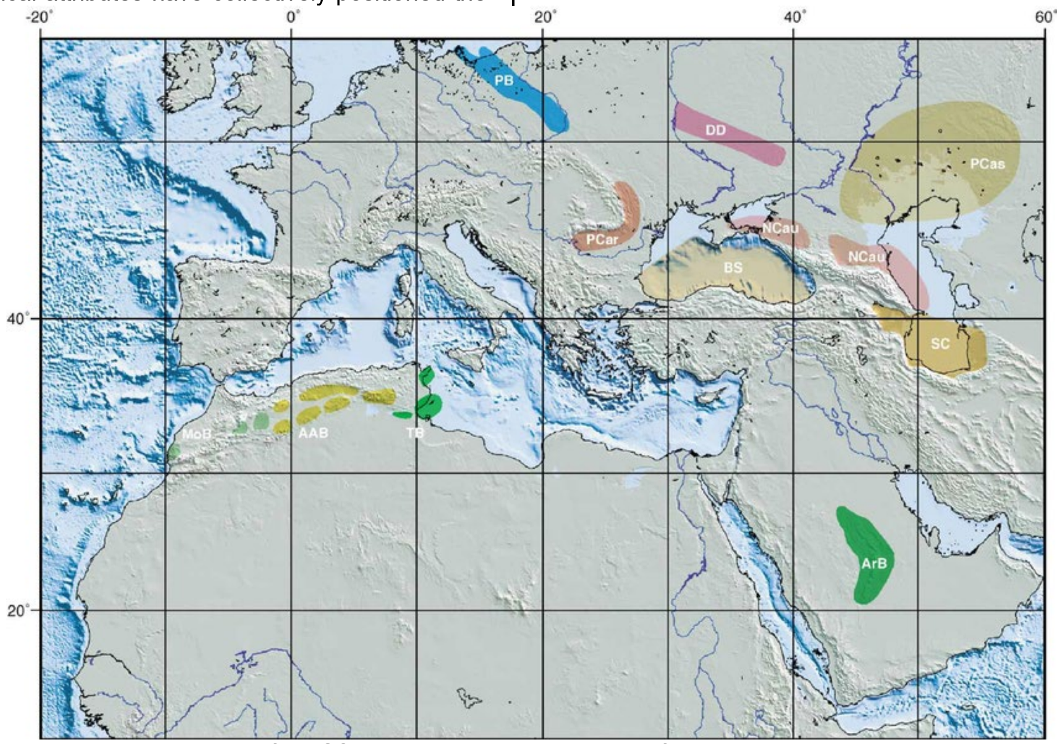

Fig. 1. Location map of the SCB within the central segment of Mediterranean–Alpine mobile belt.
PB: Polish Basin; PCar: Pre-Carpathian basins; BS: Black Sea; DD: Dniepr-Donets basin; PCas: Precaspian basin; Ncau: North Caucasus basins; SC: South Caspian basin; MoB: Moroccan basins; AAB: Algerian Atlas basins; TB: Tunisian basins; ArB: Arabian basin

Nevertheless, the South Caspian Basin is not solely defined by these primary attributes. It also exhibits a range of tectonic and morphostructural peculiarities that set it apart from other basins within the Alpine-Mediterranean orogenic system. Of particular significance is the dominance of meridionally oriented structural elements formed during the most recent tectonic phase of basin evolution. These features stand in stark contrast – both spatially and morphologically – to the older, longitudinal tectonic frameworks aligned with the Caucasian trend. Notably, Pliocene deposits within the basin and adjacent regions rest unconformably – with pronounced angular and azimuthal discordance – upon stratigraphically older formations of various ages associated with the Alpine fold belt as well as the younger Scythian and Turan platforms (Abdulla-zada, & Vakhably, 2021; Pogorelova, 2019).

In addition to this distinctly superimposed tectonic architecture, the South Caspian Basin displays a zone-like, concentric structural pattern, most vividly expressed in the regional gravitational field. This pattern is traceable at multiple depth levels through the configuration of seismic discontinuities and the behavior of reflection boundaries (Menshov, 2021; Kerimov et al., 2015).

Situated within this exceptional basin, the Absheron-Prebalkhan tectonic zone forms a prominent structural corridor extending across the western margin of the Caspian Sea. This zone hosts several offshore fields of strategic significance, with the Absheron-Bank and Darwin Bank fields representing two of the most productive and extensively studied accumulation (Fig. 2). The tectonic architecture of this region is dominated by NW–SE-trending brachyanticlinal folds, often complicated by faulting, and lateral facies variability – factors which have played a crucial role in the entrapment and preservation of hydrocarbons.

The Absheron-Bank field was discovered in 1951 during exploratory operations aimed at delineating structural highs in the shallow marine shelf zone north of Pirallahi Island. Located at the intersection of multiple anticlinal trends – including the Gosha-Dash, Gilavar, and Darwin structures – the field has since become a benchmark for evaluating Neogene petroleum systems in the region. Early production commenced following the discovery of natural gas in 1954 from the Kala formation, followed by the identification of oil-bearing intervals in 1965 within the Kirmaki suite. Detailed stratigraphic and structural studies have demonstrated that the productive intervals in Absheron-Bank are mainly confined to the lower subdivisions of the Productive Series, characterized by alternating sandstone, siltstone, and claystone units, which exhibit favorable reservoir properties and are closely associated with active source rocks (Aliyeva, 2004).

In parallel, the Darwin Bank field, discovered in 1950 and fully located offshore, lies approximately 6 kilometers northeast of Pirallahi Island and is considered a structural and genetic continuation of the Absheron-Bank – Pirallahi – Gurgan-Deniz trend. Geological exploration has shown that the Darwin structure is underlain by a thick accumulation of Pliocene sediments of the Productive Series, within which the Kirmaki and underlying Prekirmaki formations form the principal reservoir units (Abdulla-zada, & Vakhably, 2021; Aliyeva, 2021). These formations, with total thicknesses exceeding 1900 meters, have been penetrated by hundreds of wells, enabling comprehensive characterization of their porosity, permeability, and saturation regimes (Kerimov, Sharifov, & Zeynalova, 2023). The field has undergone multiple stages of development, including secondary recovery efforts such as water injection, and is currently in the late phase of production, with diminishing returns due to reservoir depletion and declining pressure support.

Despite decades of production, substantial hydrocarbon volumes remain unrecovered in both fields, necessitating a re-evaluation of their potential using updated geological, geophysical, and engineering methodologies. Reservoir modeling, petrophysical reinterpretation, and field performance analyses are essential to understanding the remaining reserves and optimizing recovery. Moreover, the operational challenges posed by offshore infrastructure degradation, complex well conditions, and fluctuating water cuts require adaptive strategies grounded in high-resolution subsurface data.

This study aims to deliver a comprehensive reassessment of the hydrocarbon potential of the Absheron-Bank and Darwin Bank fields through the integration of historical production data, reserve audits, reservoir characteristics, and development dynamics. By correlating geological structures with production history and petrophysical parameters, the research seeks to identify untapped potential within mature zones and guide future field development strategies. The findings are not only relevant for enhancing recovery in these specific fields but also offer valuable insights applicable to other structurally analogous accumulations across the South Caspian offshore region.

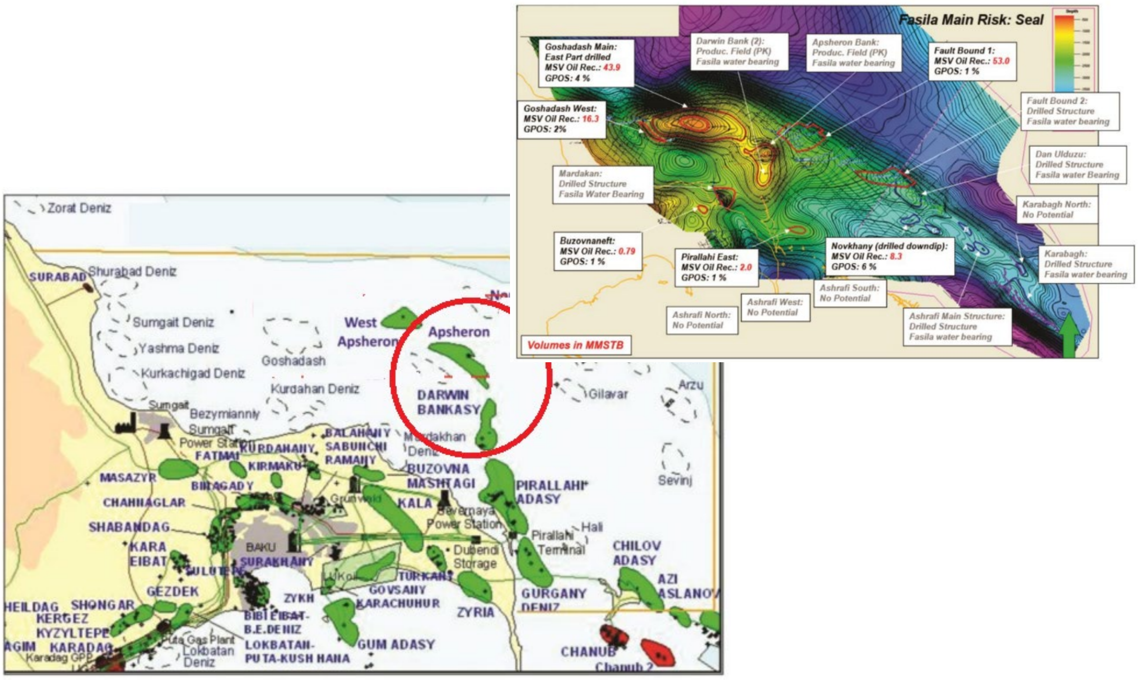

Fig. 2. Location map of Absheron-Bank and Darwin bank fields (Javadova, 2024)

Relevance of the study

The South Caspian Basin, as one of the most actively subsiding sedimentary basins globally, continues to serve as a natural laboratory for investigating complex petroleum systems. The Absheron-Prebalkhan tectonic zone, hosting the Absheron-Bank and Darwin Bank fields, offers a rare opportunity to examine reservoir behavior within mature offshore fields undergoing advanced depletion stages. This study is particularly relevant in the context of transitioning legacy fields into modern production systems by integrating geological, petrophysical, and engineering data.

Moreover, the methodological framework employed – comprising stratigraphic correlation, volumetric reserve reassessment, and performance diagnostics – serves as a model applicable to other geologically analogous offshore fields undergoing late-stage development.

Scientific novelty

1. The study introduces an advanced integrative methodology for re-evaluating mature offshore fields by synthesizing over seven decades of geological, petrophysical, seismic, and production data – constituting the most comprehensive reassessment to date of the Absheron-Bank and Darwin Bank fields.

2. The application of comparative basin analysis with analogs such as the Nile Delta and Gulf of Suez demonstrates the geodynamic and operational transferability of the workflow, affirming its relevance for petroleum provinces sharing characteristics such as rapid burial, overpressure, and structural compartmentalization.

3. The study advances a predictive conceptual framework that integrates legacy EOR interventions (e.g., pressure maintenance, dual-lateral drilling) with

modern reservoir management strategies, offering replicable guidelines for field redevelopment across analogous tectono-stratigraphic settings.

Methods

The present study is based on a comprehensive analysis of geological, geophysical, and production datasets collected from the Absheron-Bank and Darwin Bank oil and gas fields, both located within the Absheron–Prebalkhan tectonic zone of the South Caspian Basin. The methodological approach integrates historical exploration results with modern reservoir evaluation techniques to provide a refined assessment of hydrocarbon potential, reserve dynamics, and field performance.

A total of 74 wells from the Absheron-Bank field and 776 wells from the Darwin Bank field were analyzed to assess spatial distribution of hydrocarbon-bearing horizons, reservoir continuity, and production performance. These wells include exploration, development, and injection wells drilled over several decades. Structural maps, cross-sections, and borehole stratigraphic logs were used to define reservoir geometry and structural closure. The primary productive intervals include the Kirmaki suite and Kala suite in the Absheron-Bank field, and the Kirmaki, Prekirmaki, and Lower Productive Serie's suites in the Darwin Bank field (Yolchuyeva et al., 2024).

Hydrocarbon reserves were assessed using volumetric methods and categorized in accordance with the B+C1+C2 classification system for the Absheron-Bank field, and A+B+C1+C2 for the Darwin Bank field. Initial balance reserves and recoverable reserves were calculated for both oil and gas phases. Residual reserves and cumulative production were also evaluated to assess the degree of resource depletion.

Field production history was reviewed through the analysis of cumulative oil, gas, and water production data. Time series analysis of annual production rates was performed to evaluate field performance, productivity decline trends, and reservoir drive mechanisms. Current recovery factors, water cut levels, and well performance indicators were compared across development stages and geological blocks.

By combining multidisciplinary datasets and long-term operational experience, this study applies a systems-based approach to reassess the hydrocarbon potential and remaining productive life of two mature yet strategically important offshore fields in the South Caspian Basin.

Structural-tectonic setting and Stratigraphy

The Absheron-Bank field is situated on a well-defined anticlinal structure measuring approximately 10 km in length and 2.5 km in width. It lies within the convergence zone of several significant structural axes, including the Gosha-Dash, Gilavar, and Darwin anticlines. The field's geometry reflects a combination of tectonic folding and localized faulting, forming effective traps for both oil and gas (Kerimov et al., 2015; Khalilov, 2012). The shallow water depth of 2–20 meters across the field area has facilitated exploration and early-stage development.

The Darwin Bank field is located northeast of Pirallahi Island, in the shallow offshore zone of the Caspian Sea, at water depths ranging from 10 to 25 meters. It forms a structural continuation of the Absheron-Bank – Pirallahi – Gurgan-Deniz anticlinal system and shares a similar tectonic evolution. The Darwin Bank fold represents a brachyanticline trending in a submeridional direction, characterized in its southern sector by a markedly steep south-southwestern limb and a comparatively gentle north-northeastern flank. Within the northern segment of the structure, both limbs and the northern pericline exhibit a discernible flattening, resulting in a meridionally oriented, arcuate uplift whose convexity is directed westward. The structure is complicated by local tectonic disturbances, particularly in the crestal zones, which have influenced fluid migration and reservoir compartmentalization. This intricate fold morphology is indicative of the evolving geodynamic regime within the paraxial zone of the eastern-southeastern plunge of the Greater Caucasus. It further reflects the influence of pronounced tectonic stresses, predominantly of a compressional nature (Pogorelova, 2019).

The regional tectonic evolution of the area, driven by compressional stresses associated with the collision of the Arabian and Eurasian plates, has promoted vertical and lateral movements that shaped the present-day fold-and-thrust architecture.

The Darwin Bank and Absheron-Bank fields, located within the shallow-water sector of the South Caspian Basin, are typified by a thick succession of Cenozoic sediments, reflecting the region's complex tectonostratigraphic evolution. These fields lie within a zone of intense Neogene–Quaternary sedimentation and tectonic deformation, where hydrocarbon entrapment is predominantly controlled by anticlinal folding and fault-related structures. Stratigraphically, the sedimentary cover encompasses a complete section from the Paleogene–Neogene transition to the Quaternary, with the Pliocene Productive Series serving as the principal reservoir unit.

Results

The analysis of production data, geological structure, and reservoir properties from the Absheron-Bank and Darwin Bank fields provides critical insight into their current status, untapped potential, and broader relevance to hydrocarbon systems in the South Caspian Basin.

According to the B+C1+C2 classification system, the initial balance reserves of the Absheron-Bank field are estimated at 6.291 million tons of oil, 240 million m³ of dissolved gas, and 2,327 million m³ of free gas (Fig. 3). Of these, the recoverable reserves (Fig. 4) comprise 1.258 million tons of oil, 177 million m³ of dissolved gas, and 2,013 million m³ of free gas, primarily associated with the Kirmaki suite (oil-bearing) and the Gala suite (gas-bearing) (Abbasov, & Guliyev, 2003; Bagirov, Minzverg, & Kondrushkin, 1975).

Production of crude oil and liquid began to rise steadily in the early 1970s, with notable fluctuations in the 1980s and 1990s. A sharp increase is observed post-2000, peaking between 2005 and 2008, after which oil output gradually declines. The total produced liquid exhibits a similar trend, with a prominent peak slightly above 50 million m³ around 2007.

Free gas production shows a continuous upward trend starting from the mid-1980s, with a pronounced surge after 1998, reaching its maximum between 2007 and 2012. Following this period, free gas output demonstrates a consistent decline. In contrast, associated gas volumes (green line) remain comparatively low throughout the entire operational history, with minimal contribution to the overall gas output.

Overall, the production profile reflects a typical life cycle trend: an initial build-up phase, a plateau of maximum output during the 2000s, followed by a decline phase likely due to reservoir depletion and reduced well productivity (Fig. 5).

By January 1, 2022, 74 wells had been drilled, yielding 495.8 thousand tons of oil, 1,195.2 million m³ of gas, and 239.3 thousand m³ of formation water, amounting to 39.4 % depletion of recoverable oil reserves (Fig. 6).

Remaining reserves stand at 5.795 million tons of oil and 219.6 million m³ of dissolved gas, with recoverable quantities at 762.2 thousand tons of oil and 156.6 million m³ of dissolved gas (Fig. 7).

Despite the field's strategic location and early promise, it currently operates only five production wells, with much of its infrastructure either decommissioned or inactive. Geological and technical complications have resulted in the abandonment of 40 wells, and others are categorized as preserved, damaged, or under monitoring.

Petrophysical analysis reveals the Kirmaki suite has porosity values between 10.5 % and 33.5 %, permeability of 0.086 mD, and oil saturation up to 80 %. The Gala suite, although gas-prone, also demonstrates good porosity (~22–23 %) but slightly lower permeability. These reservoir attributes, combined with significant residual reserves, underscore the field's potential for recovery enhancement (Table 1).

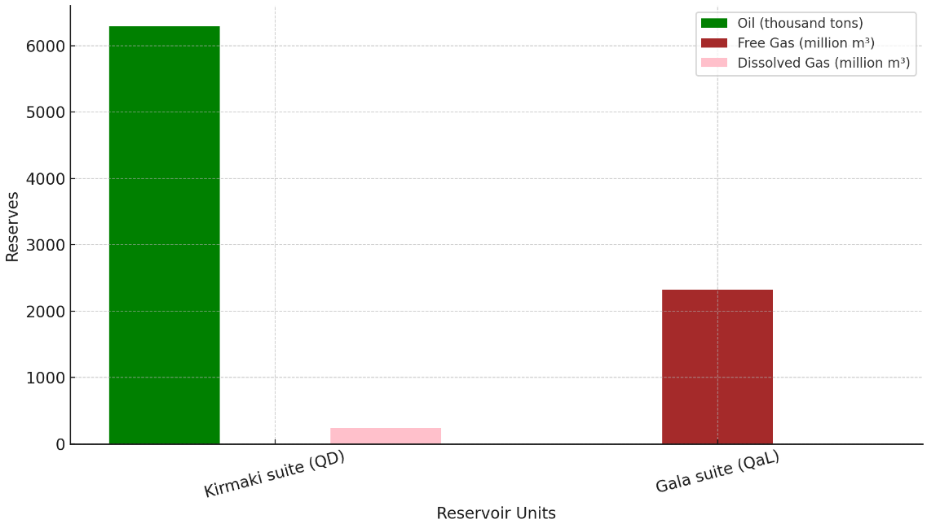

Fig. 3. Initial balance reserves of the Absheron-Bank field (B+C1+C2 category)

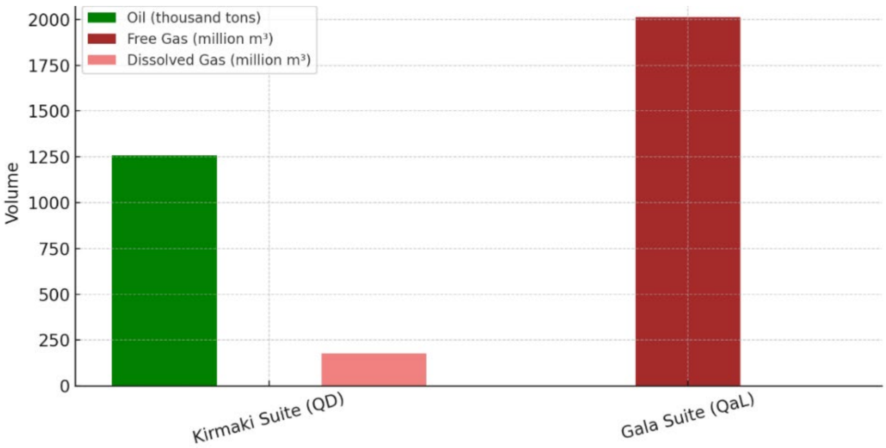

Fig. 4. Recoverable reserves of the Absheron-Bank field (B+C1+C2 category)

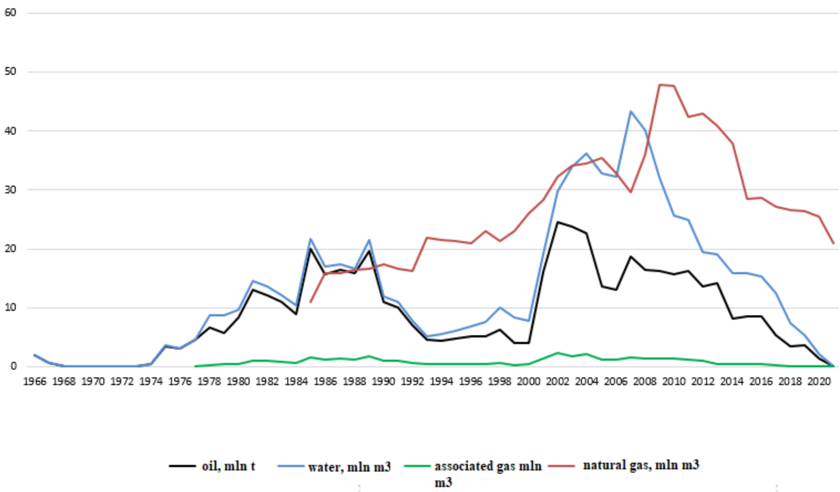

Fig. 5. Annual production indicators of the Absheron-Bank field

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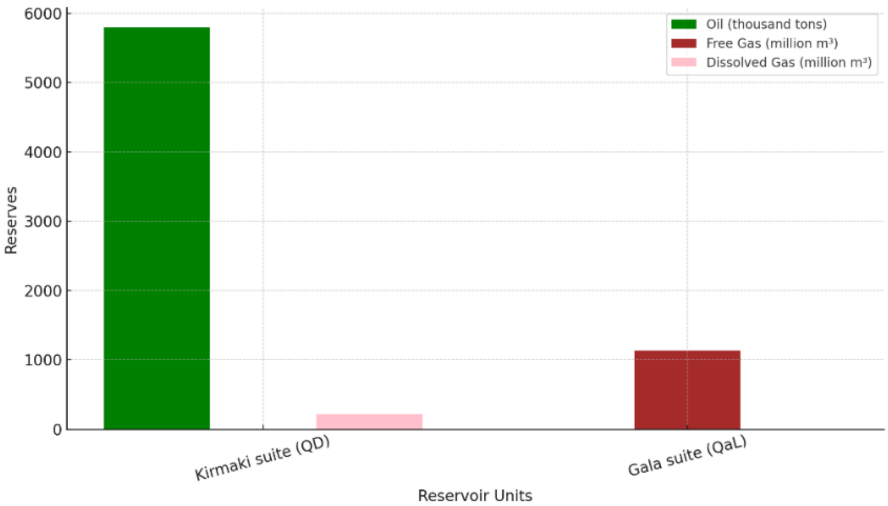

Fig. 6. Remaining balance reserves of the Absheron-Bank field (B+C1+C2 category)

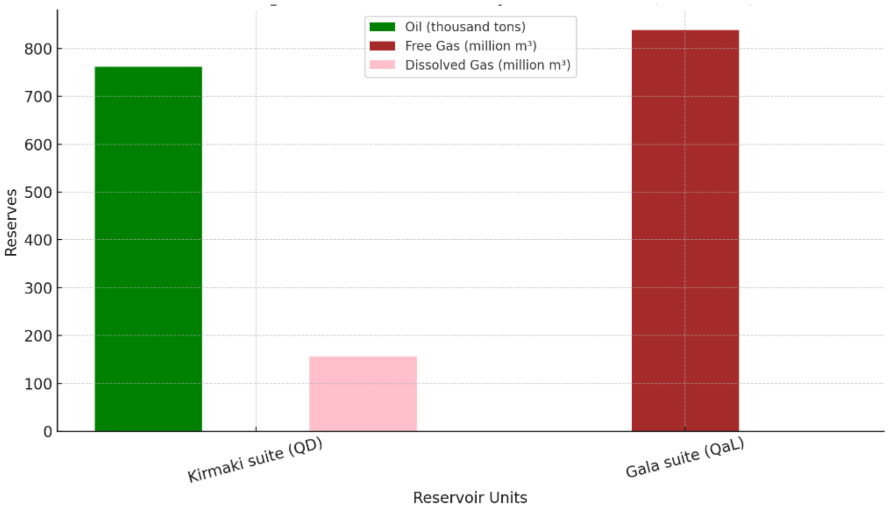

Fig. 7. Remaining recoverable reserves of the Absheron-Bank field (B+C1+C2 category)

Table 1

Summarized the geological and physical parameters of the main production zones of the Absheron-Bank field

Reservoir Suite	Clay Content (%)	Carbonate Content (%)	Porosity (%)	Permeability (mkm²)	Oil Saturation (%)	Effective Thickness (m)	Reservoir Temperature (°C)	Reservoir Pressure (MPa)
Kirmaki suite	48	28	10.5–33.5	0.086	64–80	16.7	25–32	5.5–9.4
Gala suite	48	28	22–23	0.052	67–80	19.7	45.5	19.7

The production decline and infrastructural degradation reflect both reservoir complexity and operational limitations. Structurally, the field occupies a brachyanticlinal fold intersected by faults and characterized by lateral facies variability, which introduces compartmentalization and challenges efficient drainage. The shallow offshore setting facilitated early development, but the aging infrastructure and low productivity of remaining wells now demand a transition to selective well re-entry and enhanced oil recovery (EOR) strategies.

Discovered in 1950, the Darwin Bank field has undergone extensive drilling, with 776 wells having been completed as of 2022. Cumulative production has reached 17.93 million tons of oil and 1.43 billion m³ of dissolved gas. Water injection totaling 18.74 million m³ was carried out until 1984 to support pressure maintenance.

The principal productive intervals include the Upper and Lower Kirmaki suites (KS_{upper} subdivided into KS-1, KS-2, KS-3, KS_{lower} – KS-4, KS-5) and the Prekirmaki suite, all of which demonstrate favorable reservoir properties. Porosity values range from 24 % to 28 %, with permeability up to 300 mD – particularly in the Prekirmaki unit. Oil saturation exceeds 75 % in some horizons, confirming the reservoir's high-quality characteristics. These formations collectively represent over 5.948 million tons of remaining recoverable oil reserves under categories A+B+C1+C2 (Fig. 8, 9).

As of January 1, 2022, a total of 776 wells had been drilled in the Darwin Bank field. These wells have cumulatively produced approximately 17,934.7 thousand tons of oil and 1,426.7 million cubic meters of dissolved gas. Additionally, 7,281.3 thousand cubic meters of water have been produced, while 18,738.2 thousand cubic meters of water have been injected into the reservoir for pressure maintenance.

Despite the field's mature status, 79.8 % of the recoverable reserves under A+B+C1 have already been extracted, with current production sustained by 167 active wells. Average daily oil production per well is 2.7 tons, with a water cut of 17.5 %. The current recovery factor is 0.26, compared to an estimated ultimate recovery of 0.33, indicating potential for further exploitation through modernized development strategies (Fig. 10).

The remaining balance reserves of the field, under categories A+B+C1+C2, are currently estimated at 55,371.3 thousand tons of oil and 1,363.7 million cubic meters of dissolved gas (Fig. 12). The remaining recoverable reserves are assessed at 5,948.3 thousand tons of oil and 353.5 million cubic meters of dissolved gas (Fig. 11).

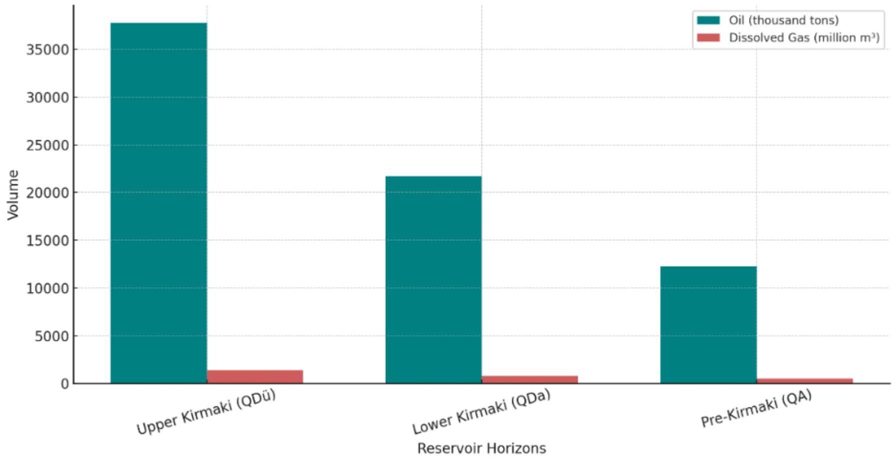

Fig. 8. The initial balance reserves in the Darwin Bank field under categories A+B+C1+C2

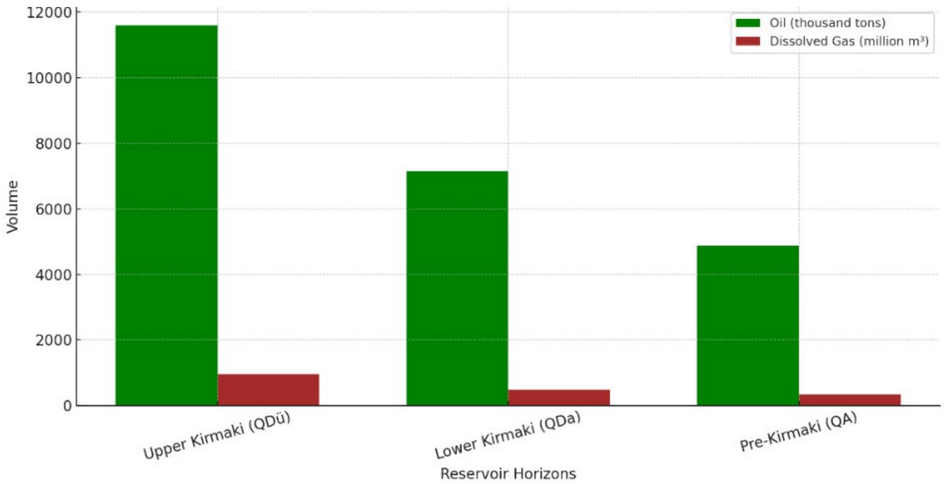

Fig. 9. The initial recoverable reserves in the Darwin Bank field under categories A+B+C1+C2

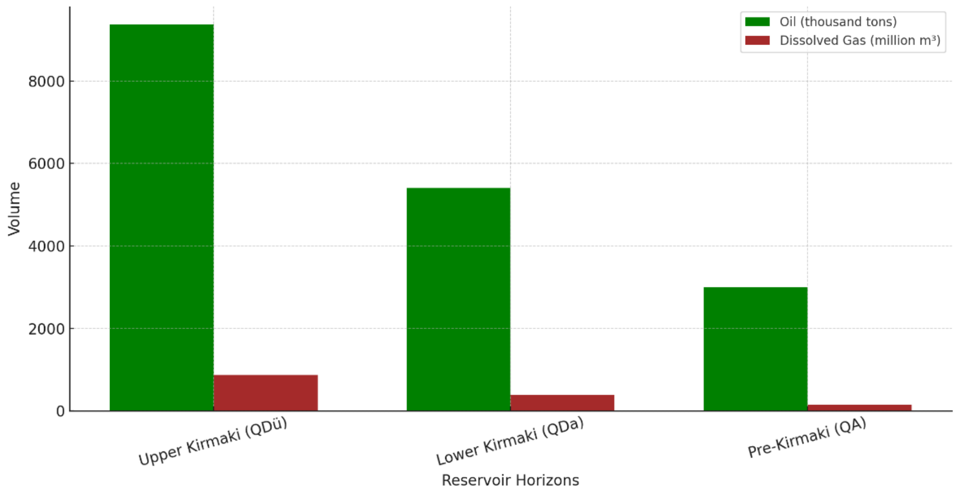

Fig. 10. Cumulative Production by Horizon in the Darwin Bank Field

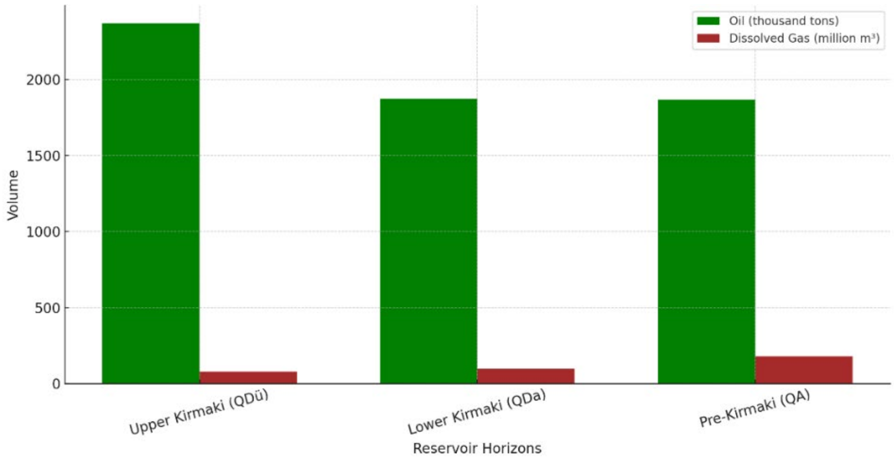

Fig. 11. Remaining Recoverable Reserves by Horizon in the Darwin Bank Field (Categories A+B+C1+C2)

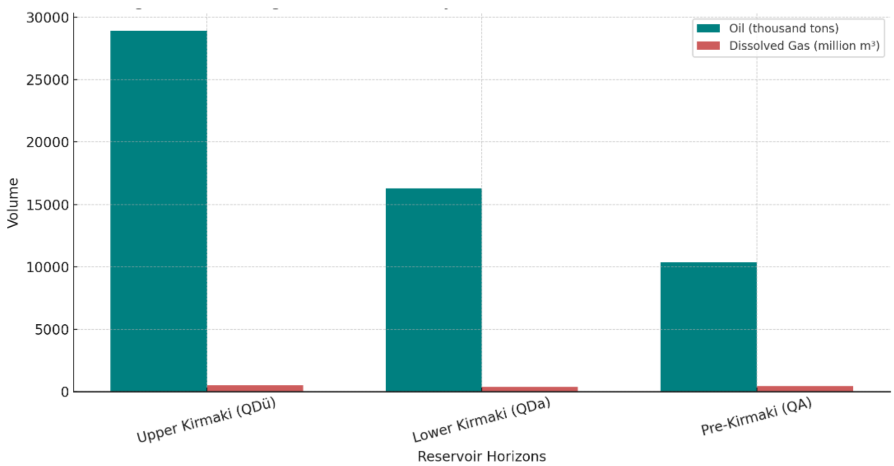

Fig. 12. Remaining Balance Reserves by Horizon in the Darwin Bank Field (Categories A+B+C1+C2)

As of 2022, the Darwin Bank field maintained an operational well stock comprising 182 wells, of which 167 wells were actively producing, while 15 wells were classified as inactive. A total of 517 wells have been decommissioned over the field's operational history due to a combination of geological and technical factors: 35 wells were abandoned for unfavorable geological conditions, 439 wells due to technical failures, and 43 wells were cancelled following post-drilling evaluations. In addition, 3 wells are currently under conservation, 20 wells are being monitored for integrity or potential re-entry, and 52 wells remain out of service due to extensive damage to hydro-technical infrastructure.

Field-level data indicate that the average daily oil production per well is approximately 2.7 tons, with an average liquid production rate of 4.0 tons per well. These relatively modest values are indicative of the field's advanced production maturity and reservoir energy depletion, further compounded by infrastructure aging.

The development of the Darwin Bank field commenced in 1950, reaching peak performance metrics by 1964, after which production entered a phase of gradual decline. Currently, the field is considered to be in Stage IV of development, characteristic of late-life fields with declining production rates and increasing operational challenges. A notable rejuvenation phase began in 2009, marked by the commissioning of new offshore platforms (Nos. 660, 670, 720, 740, and 620). This initiative led to the drilling and completion of 90 additional wells, significantly improving production efficiency and extending the field's productive capacity.

Nevertheless, deterioration of offshore platforms and associated hydro-technical infrastructure has periodically disrupted field operations. In response, a series of major repair and rehabilitation efforts have been undertaken. Since 2014, 12 wells previously rendered non-operational due to structural damage have been successfully restored, while in 2020, three wells were reactivated using dual-lateral drilling techniques, reflecting the application of modern well engineering to improve reservoir access and drainage efficiency.

Despite ongoing operational constraints related to marine logistics and seasonal weather conditions, hydrodynamic and geophysical monitoring programs remain active, facilitating real-time assessment of reservoir conditions and supporting informed decision-making for field management.

To mitigate declining reservoir pressure, a water injection program was initiated in 1955 using wells Nos. 37, 38, 39, and 41. Over the course of the program, 56 injection wells were drilled and operated, targeting multiple reservoir intervals. However, declining injection efficiency led to the program's suspension in 1984. During its active period, a total of approximately 18.74 million cubic meters of water were injected into the reservoir system (Fig. 13), contributing to improved displacement efficiency and temporary stabilization of oil output.

To identify the causes of production decline and enhance oil recovery in the Darwin Bank oil field, a series of geological interventions are being carried out. These efforts require a comprehensive understanding of the physical properties of the reservoir, including porosity, permeability, and hydrocarbon saturation, as well as the physicochemical characteristics of the reservoir fluids and gases (Table 2).

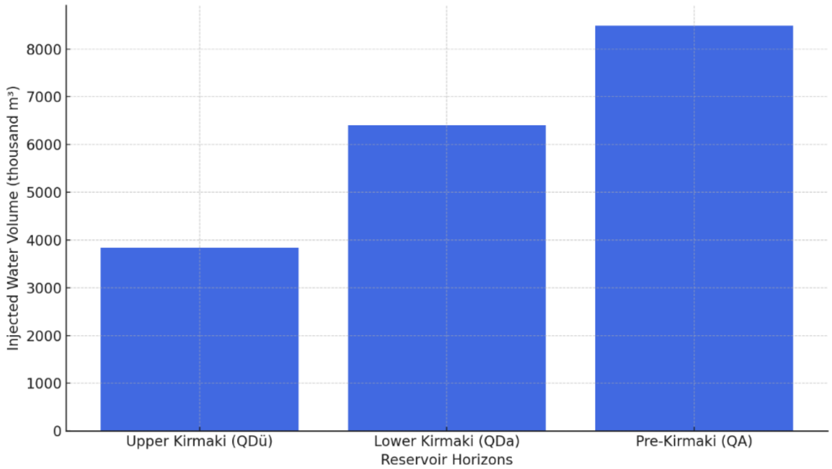

Fig. 13. Total volume of water injected into the individual horizons of the Darwin Bank field

Table 2

Summarized the geological and physical parameters of the main production zones of the Darwin Bank field

Reservoir Horizon	Clay Content (%)	Carbonate Content (%)	Porosity (%)	Permeability (mD)	Oil Saturation (%)	Effective Thickness (m)	Reservoir Temperature (°C)	Reservoir Pressure (MPa)
Upper Kirmaki (KS_{upper})	30.7	10.3	24–26	240	72–75	16.3	32	9
Lower Kirmaki (KS_{lower})	31.3	8.8	26	235	75	10.3	34	9.5
Pre-Kirmaki (PKS)	24.6	9.0	26–28	300	75–78	13.7	36	11

The Darwin Bank structure forms part of a meridionally aligned, arcuate uplift, with a steeply dipping southern limb and a gently inclined northern flank. This geometry reflects the impact of compressional stresses associated with the broader Arabian – Eurasian collision zone. Local tectonic disturbances, especially in crestal zones, have created reservoir compartmentalization, influencing pressure regimes and recovery efficiency.

Since 2009, new offshore platforms and 90 additional wells have significantly enhanced field performance. Dual – lateral drilling and the rehabilitation of wells with previously damaged infrastructure have restored production capacity. Nevertheless, logistical limitations, aging platforms, and diminishing pressure support highlight the need for a systematic redevelopment strategy focused on targeted EOR, structural modeling, and real-time reservoir monitoring.

The results from both fields underscore the importance of structural configuration and facies architecture in controlling hydrocarbon entrapment and recovery in the South Caspian Basin. The influence of fold-thrust tectonics, inherited structural trends, and meridional reactivation patterns have resulted in reservoirs with variable compartmentalization and uneven saturation distribution.

The continued existence of significant remaining reserves, particularly in the Darwin Bank field, highlights the limitations of traditional development practices and the need for updated approaches. This includes the application of reservoir simulation, 3D seismic reinterpretation, and modern EOR methods tailored to specific reservoir conditions.

These fields serve as valuable analogs for structurally similar accumulations in the region. Their production history and evolving development challenges offer important lessons for the management of mature fields across the Caspian Sea and other tectonically active offshore basins.

In conclusion, the combined results and interpretation of this study reaffirm the strategic relevance of both the Absheron-Bank and Darwin Bank fields. Through integrated geological reassessment, reservoir modeling, and infrastructure modernization, their productive life can be extended, and recovery maximized in alignment with contemporary energy strategies.

Comparative basin analysis

The hydrocarbon systems of the Absheron-Bank and Darwin Bank fields share several geological and operational characteristics with other mature offshore accumulations, both within the South Caspian Basin and in structurally and tectonically analogous basins globally. Comparative analysis enhances the broader applicability of this study and supports the refinement of development strategies in similar geological settings.

Within the South Caspian Basin, the Guneshli and Bulla-Deniz fields serve as prominent analogs. Like Absheron-Bank and Darwin Bank, these fields are located on compressional anticlinal structures formed during the Neogene-Quaternary tectonic phase and are associated with the prolific Productive Series (Middle Pliocene). The Guneshli field, Azerbaijan's most productive offshore field, exhibits similar challenges, including heterogeneous reservoirs, declining pressure, high water cuts, and aging infrastructure (Alizade et al., 2018). Secondary recovery methods such as water and gas injection, coupled with horizontal well drilling, have been applied with mixed success – lessons directly transferable to the continued development of the Darwin Bank field.

The Bulla-Deniz field, predominantly gas-bearing and also hosted within a brachyanticlinal structure, further reinforces the value of tectonically controlled traps and overpressured clay sequences as key elements of South Caspian petroleum systems (Khalilov, 2012). Reservoir compartmentalization and crestal faulting observed at Bulla-Deniz mirror structural complications are documented at Darwin Bank, emphasizing the need for high-resolution seismic imaging and stratigraphic modeling to inform well placement and pressure management.

Beyond the Caspian region, structural and stratigraphic parallels can be drawn with the Nile Delta Basin (Eastern Mediterranean) and the Gulf of Suez (northeast Africa). In the Nile Delta (Fig. 14), Neogene deltaic sequences deposited in rapidly subsiding settings overlie mobile shale and salt layers, forming anticlinal and faulted traps with strong stratigraphic control (Dolson et al., 2001). The combination of overpressured systems, complex sediment architecture, and compartmentalized reservoirs resembles the geological configuration of the South Caspian's offshore fields. Technological applications such as 3D seismic inversion, dynamic reservoir modeling, and geosteering in the Nile Delta have enabled more effective exploitation of deep and compartmentalized reservoirs, offering a model for potential adoption in Azerbaijan's offshore sector.

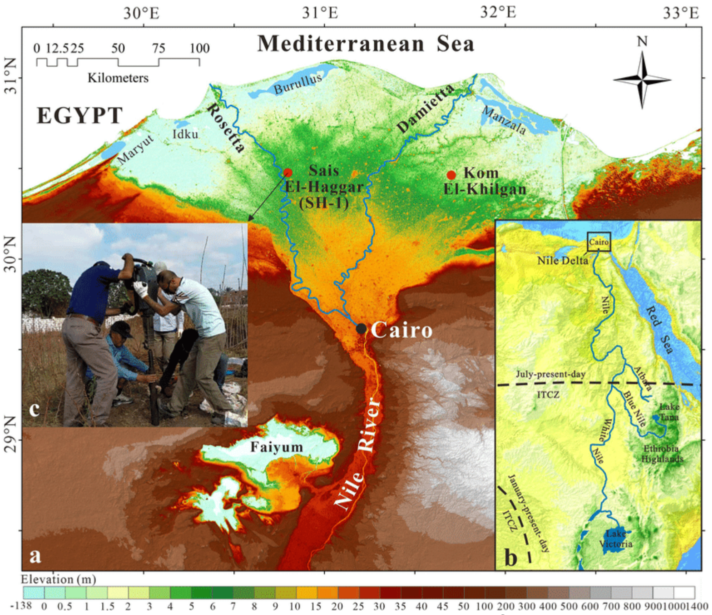

Fig. 14. Map of the Nile Delta and the Nile River Basin ((delta images were formed by authors with SRTM open source at: https://srtm.csi.cgiar.org/)

Similarly, the Gulf of Suez (Fig. 15), a mature rift basin, exhibits a long production history from faulted anticlinal traps formed by extensional tectonics, with Miocene and pre-Miocene reservoirs. Despite tectonic divergence in origin, the Suez Basin shares operational challenges with the South Caspian, including mature infrastructure, water encroachment, and enhanced oil recovery demands. EOR practices employed in the Gulf of Suez – such as steam flooding, surfactant-polymer injection, and infill horizontal drilling – can inform potential interventions in the late-stage development of the Absheron-Bank and Darwin Bank fields (Said et al., 2014; El Diasty, & El Beialy, 2015).

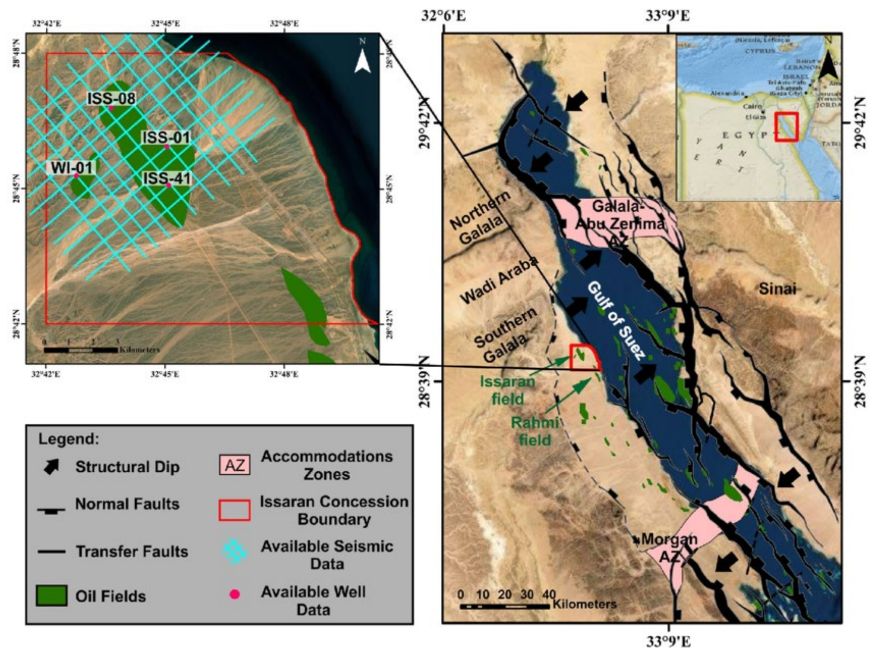

Fig. 15. A generalized structural map of the Gulf of Suez rift (Isaac, & Abu El Ata, 2023)

Overall, the comparative analysis underscores the value of cross-basin knowledge transfer. Lessons from analogous fields – both regional and global – highlight the importance of adaptive field management strategies grounded in integrated geoscientific and engineering approaches.

Discussion and conclusions

This comprehensive reassessment of the Absheron-Bank and Darwin Bank oil fields within the South Caspian Basin highlights the complex interplay of tectonic structure, stratigraphy, and reservoir dynamics that govern hydrocarbon accumulation and recovery in this geologically unique region. Both fields, situated within the Absheron–Prebalkhan tectonic corridor, are characterized by thick Neogene successions, well-developed brachyanticlinal structures, and highly heterogeneous reservoir properties shaped by prolonged compressional tectonics and rapid sedimentation.

The Absheron-Bank field, with its relatively modest scale and limited drilling infrastructure, has yielded a total of 495.8 thousand tons of oil and 1,195.2 million cubic meters of natural gas since discovery. Approximately 39.4 % of the recoverable oil reserves have been produced, with current field operations constrained by aging infrastructure and limited active well stock. The Kirmaki and Gala suites remain the principal productive units, characterized by moderate porosity and permeability, and still contain significant residual reserves that may be amenable to enhanced recovery techniques.

In contrast, the Darwin Bank field exhibits a substantially larger resource base and development history, with cumulative production reaching nearly 18 million tons of oil and over 1.4 billion cubic meters of dissolved gas. Despite entering the final stage of its production life cycle, the field retains approximately 5.95 million tons of recoverable oil and over 353 million cubic meters of dissolved gas. The primary productive horizons – Prekirmaki, Kirmaki (upper and lower), and Gala suites – demonstrate favorable reservoir parameters, including high porosity (up to 28 %) and permeability (up to 300 mD), particularly in the Prekirmaki unit. However, field performance continues to be challenged by structural compartmentalization, water encroachment, and infrastructure degradation.

The methodology and interpretative framework developed in this study extend beyond the immediate scope of the South Caspian region. The integration of historical production records, reservoir diagnostics, and tectono-stratigraphic interpretation can be adapted for other mature offshore fields located in structurally complex and tectonically active basins. Examples include the Nile Delta, Gulf of Suez, and parts of the Gulf of Mexico, where analogous compressional regimes, rapid sedimentation, and compartmentalized reservoirs exist. Therefore, the results of this study can contribute to broader global practices in revitalizing mature hydrocarbon assets under similar geological and operational constraints.

In conclusion, the combined results and interpretation of this study reaffirm the strategic relevance of both the Absheron-Bank and Darwin Bank fields. Through integrated geological reassessment, reservoir modeling, and infrastructure modernization, their productive life can be extended, and recovery maximized in alignment with contemporary energy strategies.

Authors' contribution: Murad Abdulla-zada – writing, investigation, methodology, formal analysis, conceptualization Tamella Zahidova: data curation, investigation; formal analysis, visualization. Rufat Shahbazov: investigation, visualization, data curation, supervision.

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КОМПЛЕКСНА ПЕРЕОЦІНКА ВУГЛЕВОДНЕВОГО ПОТЕНЦІАЛУ РОДОВИЩ АПШЕРОН БАНКА ТА ДАРВІН БАНКА НА АПШЕРОНСЬКО-ПРИБАЛХАНСЬКОМУ СТРУКТУРНОМУ ПОРОЗІ

В с т у п . ***Південнокаспійський басейн є винятковою геодинамічною провінцією, що вирізняється надзвичайною потужністю осадового чохла та активними нафтогазоносними системами, що дає змогу віднести його до провідних нафтоносних регіонів світу. Оточений колізійними орогенними поясами, басейн акумулював понад 25 км осадових порід, з яких понад 10 км було відкладено протягом останніх шести мільйонів років. Така інтенсивна субсіданція й занурення відбувалися за умов аномально низького геотермічного градієнта, що сприяло триваючому формуванню вуглеводнів на глибинах понад 8–12 км. Регіонально поширені антиклінальні структури, інтерпретовані як складчасті згини, утворені над базальною площиною відриву, виявлено завдяки регіональній 2D-сейсморозвідці. Поєднання активної генерації вуглеводнів, наявності великих неосвоєних структурних пасток і сприятливого інвестиційного середовища підвищує стратегічне значення басейну в глобальному енергетичному секторі.***

У межах цієї тектонічно складної зони Апшеронсько-Предбалханський структурний поріг є однією з ключових нафтогазоносних провінцій, що охоплює низку стратегічно важливих родовищ, зокрема родовища Апшеронського банку та Банку Дарвіна. Це дослідження представляє цілісну, інтегровану з даними оцінку їхнього вуглеводневого потенціалу на основі багаторічних розвідок, історичних показників видобутку та геонаукових даних про надра. Родовище Апшеронського банку відкрито у 1951 р. за 25 км на північ від острова Піраллахи, а родовище Банку Дарвіна – у 1950 р.; обидва мають тектонічну спорідненість з прилеглими антиклінальними структурами та є центральними об'єктами цього аналізу.

М е т о д и . ***Для оцінки характеристик колекторів проведено геолого-геофізичні дослідження, що включали стратиграфічну кореляцію, аналіз пластових тисків та продуктивності. Дані кернового матеріалу та сейсморозвідки інтегрувалися з петрофізичними параметрами – пористістю, проникністю, насиченням флюїдами – з метою характеристика продуктивних горизонтів (зокрема, кірмакинського та калинського ярусів).***

Р е з у л ь т а т и . ***Результати вказують на наявність значних скупчень вуглеводнів у нижньопліоценових відкладах Продуктивної серії. Початкові запаси родовища Апшеронського банку за категоріями B+C1+C2 оцінюються у 6,3 млн т нафти та понад 2,5 млрд м³ розчиненого й вільного газу. Станом на січень 2022 р. пробурено 74 свердловини, які забезпечили видобуток 495,8 тис. т нафти та близько 1,2 млрд м³ газу, що становить 39,4 % від оцінених вилучених запасів нафти.***

Родовище Банку Дарвіна, розробка якого здійснювалася через 776 свердловин, дало близько 17,9 млн т нафти та 1,4 млрд м³ розчиненого газу, при цьому було вилучено майже 80 % прогнозованих вилучених запасів. Поточні роботи зосереджено на завершальному етапі продуктивного циклу родовища, коли спостерігається зниження дебітів та зношеність інфраструктури, що створює експлуатаційні труднощі.

В и с н о в к и . ***Дослідження підкреслює необхідність подальшого впровадження заходів підтримки пластового тиску, застосування методів підвищення нафтовилучення (EOR) та оптимізації режимів закачування води з метою продовження терміну ефективної експлуатації родовищ. Також наголошується на важливості безперервного геологічного, петрофізичного та гідродинамічного моніторингу для реалізації адаптивного управління розробкою, особливо в умовах зрілих шельфових об'єктів Південнокаспійської нафтогазоносної провінції.***

К л ю ч о в і с л о в а : ***Південнокаспійський басейн, Апшеронсько-Предбалханська тектонічна зона, нафтогазовий потенціал, шельфові родовища, характеристика колекторів, Продуктивна серія, підвищення нафтовилучення (EOR).***

Автори заявляють про відсутність конфлікту інтересів. Спонсори не брали участі в розробленні дослідження; у зборі, аналізі чи інтерпретації даних; у написанні рукопису; в рішенні про публікацію результатів.

The authors declare no conflicts of interest. The funders had no role in the design of the study; in the collection, analyses or interpretation of data; in the writing of the manuscript; or in the decision to publish the results.