International Journal of Science and Research (IJSR)
ISSN: 2319-7064
Impact Factor 2024: 7.101

Cambay Basin, India: Geological Review and Exploration Potential of a Moderately Explored Hydrocarbon Province

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Abstract: ***The Cambay Basin, an intracratonic rift located in northwestern India, has long been recognized as a significant onshore hydrocarbon province. Despite extensive exploration efforts since the 1950s, a substantial portion of its resource potential remains to be discovered. This review outlines the basin's tectonic evolution, petroleum system components, reservoir characteristics, and exploration history. Special emphasis is given to the syn-rift and post-rift sedimentary phases and their implications for hydrocarbon accumulation. The study also evaluates present-day challenges in data quality, seismic interpretation, and deeper depth exploration efforts. Enhanced Oil Recovery (EOR) techniques and improved reservoir management strategies are discussed as key tools for rejuvenating mature fields. The article advocates for a multidisciplinary, geologically driven exploration strategy to unlock frontier areas and improve recovery rates in alignment with global benchmarks. This paper aims to provide a comprehensive geological review of the Cambay Basin with a focus on its hydrocarbon potential, reservoir characteristics, and opportunities for future discovery and enhanced recovery.***

Keywords: Cambay Basin, Hydrocarbon Exploration, Rift Tectonics, Petroleum Systems, Enhanced Oil Recovery

1. Introduction

The Cambay Basin is a narrow, linear, sigmoidal elongated peri-cratonic rift bounded by faults and located on the western passive margin of the Indian plate[1]. It lies between the Saurashtra craton to the west, the Aravalli swell to the northeast, and the Deccan craton to the southeast (Figure 1). The basin stretches from just north of Sanchor to the Cambay Gulf in the south, where it opens into the Arabian Sea. A basement uplift in the northern region is a boundary separating the Cambay Basin from the adjacent Barmer Basin in Rajasthan[2]. Throughout its geological history, the basin has undergone several distinct phases of extensional tectonics, primarily during the Cenozoic era. The tectonostratigraphic arrangement has enabled the maturation and entrapment of hydrocarbons within the Lower Eocene source facies, which are distributed across various plays in the Middle Eocene to Lower Miocene clastic facies.

The area spans approximately 59,000 square kilometers. Since the late 1950s, the basin has undergone extensive geological studies. It stands as one of India's principal onshore hydrocarbon-producing basins. The initial success for explorers occurred in 1958 with the discovery of the Cambay field, followed by the significant Ankleswar field in 1960. This success spurred a vigorous pursuit of oil and gas exploration within the Cambay Basin. Two-thirds of the prognosticated resources have been established. While oil and gas production has remained steady, approximately one-third of the reserves have already been extracted, primarily from major fields. Around 150 oil and gas fields, including 2 giants, have been identified following the drilling of over 2500 exploration wells. The authors contend that there is considerable potential to enhance recovery rates through well-planned drilling techniques and improved recovery initiatives. Besides, exploring new oil and gas in frontier areas is an immense opportunity. Determining the remaining volume and specific locations of undiscovered oil reserves remains a pressing challenge.

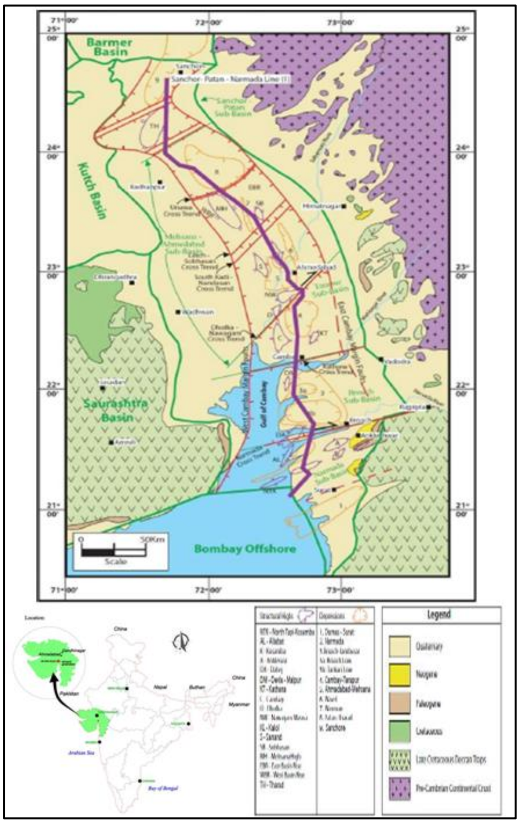

Figure 1: Cambay Basin in Western India

Numerous earlier researchers, including[3,4,5,6], have provided comprehensive descriptions of the geology, tectonics, and stratigraphy of this basin. The Cambay Basin holds a pivotal position in India's energy future, and unlocking its full potential can bridge current gaps in domestic hydrocarbon supply to an extent.

2. Tectonics and Stratigraphy

The basin was formed during the Late Cretaceous period, coinciding with the Deccan Trap volcanism, which resulted in a varied basin floor that was favorable for sedimentation during the Tertiary period. Following the extensive eruption of Deccan trap basalt, significant extensional faults developed along pre-existing basement structures. This basaltic foundation facilitated the accumulation of considerable layers of Tertiary-Quaternary sediments[7]. Two prominent tectonic lineament trends, namely the NNW-SSE Dharwarian and the ENE-WSW Satpura trends, extended into the Cambay basin (Figure 2).

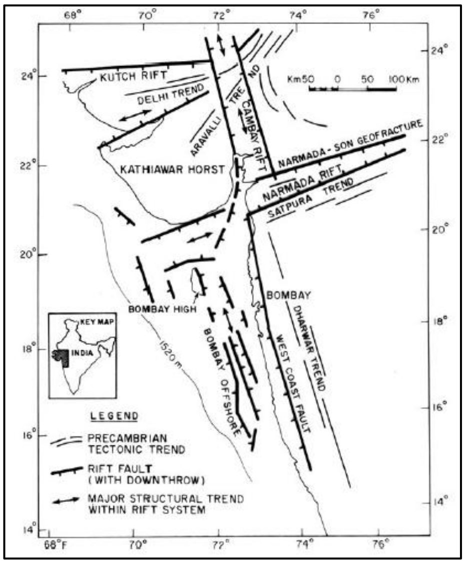

Figure 2: Cambay Basin in Western India[8]

The tectono-stratigraphic analysis of the basin reveals that before reaching its current configuration, the lithosphere experienced a period of rifting and drifting as the Indian plate separated from the Gondwana supercontinent. The initial phase of separation between Western and Eastern Gondwanaland occurred during the Late Triassic to Jurassic period, approximately 195 to 205 million years ago. The subsequent phase involved the detachment of Seychelles-India from Madagascar during the Late Cretaceous, around 93 million years ago. Ultimately, the final fragmentation of Seychelles at the Cretaceous-Tertiary boundary, approximately 65 million years ago, coincided with the Deccan volcanism and is linked to a series of rift basins along the western continental margins, among which is the Cenozoic Cambay Basin.

The uplift phases that define the Cambay Basin is partially attributed to the intricate and swift detachment of India from Africa during the Jurassic period, followed by the rifting of Madagascar and the Seychelles, and the subsequent northward movement of tectonic plates leading to the collision of the Indian plate with the Asian plate (Figure 3). The Reunion hotspot, responsible for Deccan Volcanism, initiated the rift, and multiple pulses lasted through to the Lower Eocene when the rift failed and closed[9]. The timing of India's separation from Africa and the ensuing collision have been examined by Biswas[8].

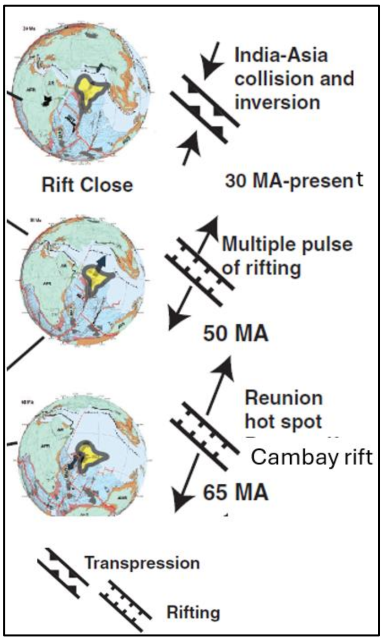

Figure 3: Cambay Basin in Western India, the rifting process

The rift geometry displays a sinusoidal basin track that generally aligns with the NNW-SSE direction. The width of the basin decreases towards the northern region, suggesting a potential reduction in rift propagation. The initiation of the rift is marked by basin-bounding extensional faults that enabled the initial subsidence alongside the uplift of the basin margins or rift shoulders. The early rift phase is characterized by subsidence dominated by faults and the deposition of fluvial systems. During the Late Paleocene to Lower Eocene period, subsidence was driven by thermal cooling and sediment loading, in addition to faulting and extensive marine transgression. The post-rift structural inversion in the Middle Miocene significantly influenced the structural entrapment of hydrocarbons generated within the basin. Shallow marine to continental sedimentation was prevalent during the Miocene-Pliocene epoch.

The stratigraphy of numerous continental rift basins exhibits a vertical progression that begins with an initial sequence of fluvial, shallow lake, or shallow-marine deposits, transitioning to a sequence characterized by deep lake or deep-marine environments[10]. The stratigraphic succession of the basin, along with the sequences in the five tectonic blocks, is illustrated in Figure 4.

Sediment deposition in this rift, similar to others, is significantly controlled by the structural geometry and the evolution of faults, both within the basin itself and along its margins. Sedimentation within the basin is primarily influenced by the prerift, synrift, and post-rift phases, which occurred concurrently, along with the interplay of local and regional sediment dispersal patterns and drainage systems. The technical basement is constituted by the basaltic floor, specifically the Deccan Trap, which dates back to the late Cretaceous-Paleocene period. The Olpad Formation is

International Journal of Science and Research (IJSR)
ISSN: 2319-7064
Impact Factor 2024: 7.101

deposited above the Deccan Trap and exhibits a gradational relationship with the Cambay Shale that overlies it. The Olpad facies were formed in environments such as alluvial fans, alluvial fan deltas, and overbank areas,

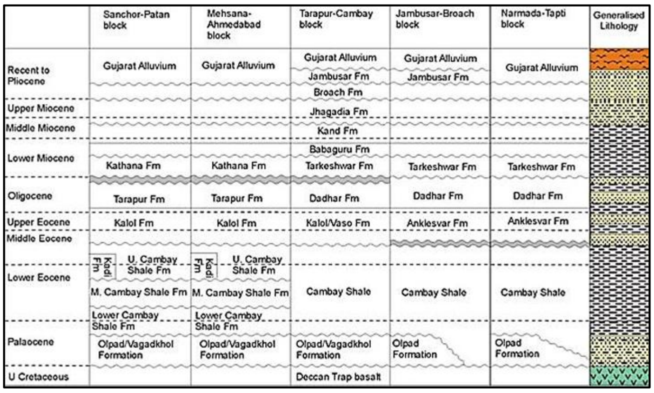

Figure 4: Stratigraphy of the Cambay Basin[11]

and lacustrine settings, characterized by volcanic wacke, sandstone, siltstone, and volcano clastic claystone, all of which have contributed significantly to hydrocarbon generation. The Synrift phase persisted into the Early Eocene, during which a substantial sequence of Cambay Shale was deposited. This shale, primarily black to dark gray, along with interspersed sand and silt, serves as the principal source of hydrocarbons in the Cambay Basin. The Cambay Shale consists of two distinct formations: the Older Cambay Shale (OCS) and the Younger Cambay Shale (YCS). The Older Cambay Shale represents the initial marine sedimentation in the basin, featuring episodes of coarser clastic deposition. In the northern region of the Cambay Basin, the Lower and Upper shaly units delineate three arenaceous members—Mandhali, Mehsana, and Chhatral—of the Younger Cambay Shale, which is comparatively shaly in the southern section of the basin. The overlying Kalol Formation, dating to the middle Eocene, is a significant hydrocarbon producer in the area and is primarily divided into two members: Sertha and Wavel. The Kalol Formation is characterized by alternating layers of thin sandstone, siltstone, shale, and coal. In certain locations, additional reservoir facies, situated above and below the coal deposits, serve as the main hydrocarbon producers.

The structural style is intimately controlled by primordial tectonic trends influenced by shear rift systems. Right lateral strike-slip faults trending northeastward break the Cambay rift into smaller sub-basins[12]. The basin is longitudinally divided into five major tectonic blocks bounded by transverse basement faults (Figure 5). The five discrete tectonic blocks or grabens with transfer zones delineating the blocks from north to south are Sanchor-Patan, Mehsana, Ahmedabad, Tarapur-Cambay, and Jambusar-Broach.

The structural evolution of the basin happened in three phases.
1) Syn-rift phase (Paleocene – Early Eocene rift stage)
2) Post-rift phase (Middle Eocene – Early Miocene stage) and
3) Late Post rift phase (Middle Miocene and younger stage).

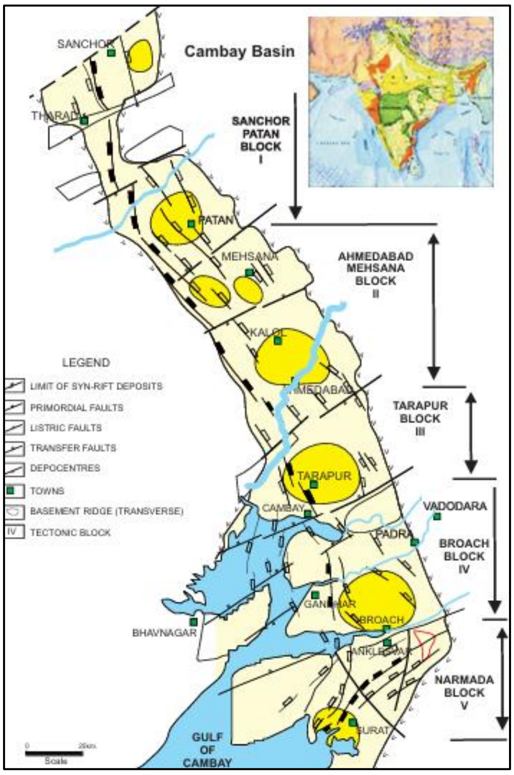

Figure 5: Tectonic map of the Cambay Basin[5]

During the Syn-rift phase, the configuration of the basin was characterized by alternating inter-basinal highs and lows. The reactivation of cross-trending faults, along with basinal uplifts, led to the formation of elevated trends (Figure 6). The basin experienced ongoing subsidence along the extensional faults. In the post-rift phase, volcanic activity completely ceased, while subsidence persisted due to the cooling of the crust and the accumulation of sedimentary loads from fluvial systems.

In the Late post-rift phase, reverse separation along fault planes resulted in structural inversion, particularly pronounced in the southern region of the basin[13]. This structural reconfiguration within rift tectonics can be linked to thermal contraction and the isostatic compensation of sediments[14]. A comprehensive understanding of these three phases is crucial for elucidating the evolution of petroleum systems within the basin.

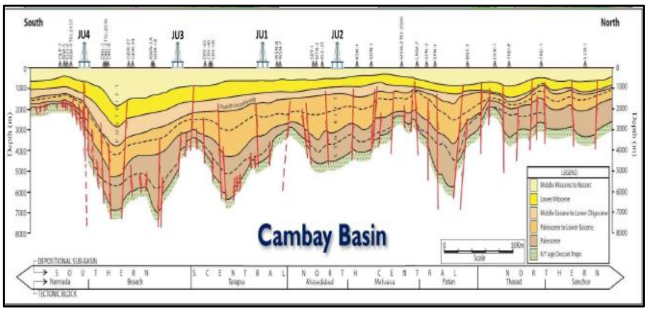

Figure 6: Geological transect from South Cambay Basin to North Cambay Basin[13]

3. Petroleum Habitat

The Cambay Basin is a rich hydrocarbon province with the maiden discovery in 1958, the Cambay gas field. Ankleswar field followed in 1960 in the Narmada-Tapti block. In the Sanchor-Patan block, small accumulations of oil were discovered from lenticular sands within the Cambay Shale. Hydrocarbon accumulations in the Ahmedabad-Mehsana block are from Tarapur, Kalol, Kadi, Cambay Shale, and Olpad formations. The prominent fields are Balol-Santhal-North Kadi- Sobhasan- South Kadi-Kalol-Sanand-Nawagam, Limbodra, and Indrora fields. The hydrocarbon accumulation in the Tarapur-Cambay block is from sands in the Tarakeshwar and Kalol formations, with noteworthy fields of Kathana, Tarapur, and Cambay. In the Jambusar-Broach block, hydrocarbons occur in sands of the Ankleswar Formation and in the Cambay Shale. Some of the significant fields are Gandhar, Nada and Pakajhan fields. Hydrocarbons occur in the sands of Tarakeshwar, Ankleswar, and Olpad formations in the Narmada-Tapti block. The prominent fields include Bhandut, Sisodra-Motawan, besides Ankleswar field.

The Cambay Basin, which originated as a rift during the Late Palaeocene due to the impingement of the Reunion Mantle Plume during and ceased rifting in the Eocene, is characterized by oil derived from Synrift shales rich in organic content[4] . Although a portion of the oil is located in Synrift reservoirs, the majority is stored in post-rift sand formations, as seen in the Ankleshwar and Gandhar fields, along with late syn-rift or post-rift clastic deposits associated with coal and shale in North Cambay[15].

3.1 Source Rocks

The Lower Eocene Cambay Shale serves as the principal source rock within the various generative depressions of the basin. Most of the troughs are local generation centres for accumulations in the adjacent highs. This formation is the most extensive, present across all tectonic blocks. It consists of a dark grey shale sequence that was deposited during the syn-rift phase. Comprehensive geochemical analyses have revealed a predominance of terrestrial organic matter characterized by Type-III kerogen. The Cambay Black Shale signifies a marine transgressive event within the basin. With thermal maturity levels ranging from approximately 0.7% to 1.5%, the shale falls within the oil, wet gas, and dry gas windows (Figure 7). The Broach depression within the Broach block represents the most extensive kitchen area for the maturation of source rocks and the generation of hydrocarbons. The oils of South Cambay are inferred to be more mature and migrated up-dip, whereas the oils of North Cambay are less mature and close to their source. Other organic-rich potential source rocks, which extend across the basin, have been identified in the Middle Eocene Kalol Formation and its equivalent as well as in the Top and base of the Paleocene Olpad Formation, besides Lr. Eocene-Oligocene Tarapur Shales in deeper areas.

Six laterally extensive sections of potential source rock, characterized by types II/III and III kerogen, are found within the lower Paleocene to middle Eocene sequences (Figure 8). These source rocks are located at the base of the middle Eocene Kalol Formation (SR4), as well as at the upper and middle sections of the middle Eocene to upper Paleocene Cambay Shale Formation (SR5 and SR6). Additionally, they are present at both the top (SR7 and SR8/9) and the base (SR11/12) of the lower Paleocene Olpad Formation[17].

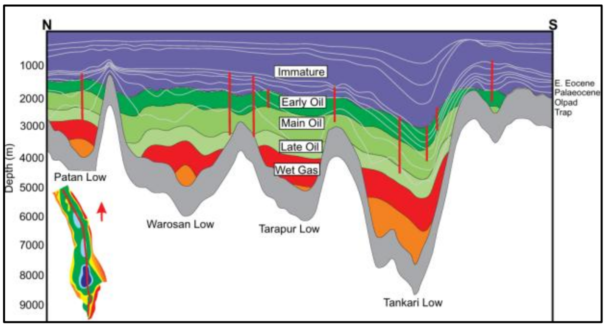

Figure 7: N-S section illustrating different lows and Source rock proclivity to oil and gas[16]

3.2 Reservoir Rocks

The reservoirs are either Sandstones or Siltstones, however, a few minor reservoirs in Fractured coals, shales, sideritic marls, and fractured Deccan Trap also occur. The reservoirs in different stratigraphy are :

- Upper Cretaceous to Paleocene: Fractured Deccan Trap and Siltstones in Olpad Formation
- Lower Eocene: sand lenses within Cambay Shale, sands, and silts in Kadi clastic wedge in Mehsana block
- Middle Eocene: Sandstones in Ankleswar Formation and Fractured coals and sandstones in Kalol Formation.
- Upper Eocene-Early Miocene: Lenticular sands in Tarapur Shales and sandstones in the younger Formations of Tarakeshwar, Dadhar, Babaguru, Kand, and Jhagadia.

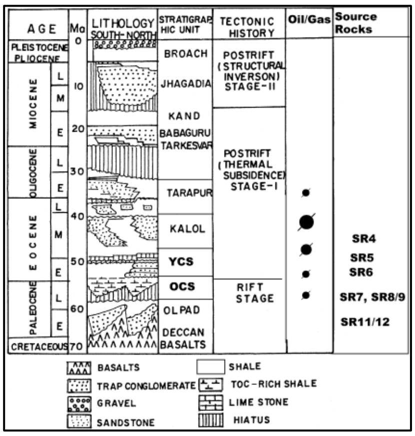

Figure 8: Stratigraphy and Source rocks occurrence in the Cambay Basin[17]

Throughout geological history, except for the early syn-rift stage, the North Cambay Basin experienced significant clastic contributions from the north and northeast, primarily sourced from the Proto-Sabarmati and Proto-Mahi rivers. Similarly, the Proto-Narmada river system was operational in the south, delivering sediments from its eastern provenance. Transverse highs significantly influenced the regulation of paleo-drainage and the distribution of sands. The major fluvial systems supplying sediments to each of the tectonic blocks emerge from the eastern margin and flow in an ENE-WSW direction[17] (Figure 9). Several faults trending NNW-SSE, NW-SE, and NE-SW regulate the channel morphology in several areas of the basin. The drainage network systems serve as indicators of ongoing fault activity.

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Impact Factor 2024: 7.101

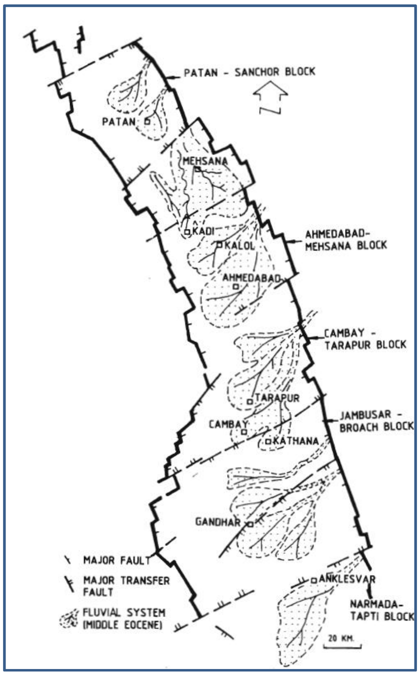

Figure 9: Tectonic blocks and major fluvial systems in the Cambay Basin[18]

3.3 Cap Rocks

A major transgression occurring from the Late Eocene to the Early Oligocene is characterized by the presence of thick Telwa shale in the southern region and Tarapur shale in the northern part of the Cambay Basin. These are the known regional primary cap rocks in the North Cambay Basin that are represented by the Tarapur Shale, which dates to the Upper Eocene-Oligocene period. In contrast, the South Cambay Basin is characterized by the Telwa and Kanwa Shales, which belong to the Middle Eocene to Oligocene age and serve as the cap rocks in that region. The end of the Early Oligocene is marked by a major regression and resulted in deposition of thin sands over Cambay, Kathana, Limbodra, and North Balol. South Cambay experienced a thick deltaic sedimentation known as Dadhar that prograded further west into the Tapti region in the western offshore.

3.4 Heat Flow

The Cambay Basin is identified as an area exhibiting elevated heat flow, with an average measurement ranging from approximately 55 to 67 mW/m^2, surpassing the regional norm [19]. The initially high heat flow experienced a decline as the rift phase ended. Within the Cambay-Kathana region, the central zone represents a relatively high heat flow area between regions of ongoing subsidence to the north and south. High heat flow values of 75–93 mW/m^2 are found in the northern Cambay basin[20]. The normal geothermal gradient is of the order of 34-40 c/km and at places it is upto 50-60 c/km.

Verma et al.[21] and Gupta et al.[19] conducted measurements of geothermal gradients in three wells located in the Cambay field, reaching a depth of 1.2 km. They determined the average heat flow at various depth intervals below 850 m to be 96.14 ± 8.36 mW/m^2. Consequently, the Cambay Basin is identified as an area of elevated heat flow, with an average heat flow ranging from approximately 41.8 to 50.16 mW/m^2, which is above the regional norm. Verma et al.[21] attributed this high heat flow anomaly to the presence of a high-temperature body that intruded into the crust during the Pliocene to Miocene epochs. However, they observed a comparatively lower heat flow of 67.72 mW/m^2 in the city of Ankleshwar, situated in the southern part of the basin. They concluded that the central region represents a zone of relatively high heat flow, positioned between areas of active subsidence to the north and south.

3.5 Entrapment

The Cambay Basin is situated at the convergence of three ancient geological trends: the Dharwarian, Satpura, and Aravalli trends, which have significantly influenced the formation of structural traps. The majority of the structures exhibit a northwest-southeast orientation, corresponding to the Dharwarian trend, while the structures within the Narmada-Tapti block are oriented east-northeast to west-southwest, in alignment with the Satpura trend (Figure 10).

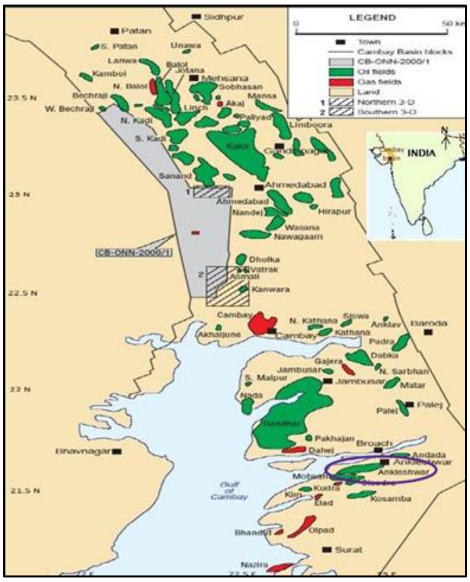

Figure 10: Trend of structures in the Cambay Basin[22]

Significant structural traps in the basin are faulted anticlinal structures, fault traps, tilted fault blocks, and narrow fault-controlled horst blocks. In most cases, the structural element plays a significant role in entrapment, except in the lenticular sands. The late post-rift structural inversion phase has given rise to several structural traps within the Middle Eocene, for example, Ankleshwar Oil Field[18].

3.6 Timing

Numerous formations within the North Cambay Basin are linked to faults associated with the basement and were formed before the principal migration phase that occurred during the Miocene epoch. In the Broach block, the primary oilfield, Gandhar, is influenced by stratigraphic controls. It is suggested that the south-easterly inclination of the northwestern limb of the Broach syncline occurred during the Miocene as a result of the subsidence of the Broach block along the Narmada fault, leading to the creation of the Gandhar trap. The structures in Narmada block, oriented ENE-WSW and associated with Satpura grain, are also

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considered to have been formed sometime during the Miocene, simultaneous with activity along the Narmada fault. Thus, the formation of traps in the Broach and Narmada blocks seems to have been coincident with the main phase of oil migration.

3.7 Petroleum Systems

The analysis of burial and thermal history suggests that a pivotal phase of hydrocarbon generation in this basin occurred during the Late Miocene. A Petroleum Event Chart has been created (Figure 11). By this period, both the trap and reservoir rock were in place, and a seal rock was deposited above the reservoirs, effectively preventing hydrocarbon loss and resulting in a viable and operational petroleum system in the region[23].The fundamental elements of the petroleum system, which include the source, reservoir, seal, and overburden rocks, were formed from the early Eocene to the present day. The key processes of generation, migration, trap formation, and accumulation took place from the Miocene epoch to the present.

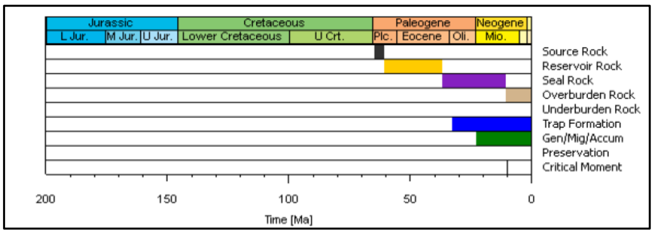

Figure 11: Petroleum systems chart of the Cambay Basin[23]

The estimated probabilities reflecting the risks associated with petroleum (Geological Chance of Success, GCOS) or probability of success (POS) are calculated by multiplying the various primary components of the petroleum system, such as the seal, trap, reservoir, and source, as they are mutually inclusive.

3.8 Exploration Resume

The discovery of the Cambay field in 1958 is a major event in the history of oil exploration in India as it put to rest the myth that India does not possess oil and gas resources outside Assam. The discovery of the giant Ankleswar oil field in 1960 gave the much-needed confidence to pursue exploration vigorously. The Gandhar field was discovered in the year 1984.

ONGC carried out measurements at 12,937 gravity and magnetic stations across the Cambay Basin. The magnetic anomaly map illustrates the overall structural layout of the basin. Over 30,688 LKM of conventional data have been collected. In 1958, ONGC initiated its first exploration drilling on the Lunej structure near Cambay, which resulted in a successful discovery well that yielded oil and gas. The identification of oil in the Ankleshwar structure in 1960 significantly enhanced exploration efforts in the Cambay Basin. To date, more than 2,500 exploration wells have been drilled in the region, with 150 out of 244 prospects found to be oil and gas-bearing, including 2 giants[2].

In the basin, about 63017 LKM (2D) and 15153 sq. km (3D) of seismic surveys have been carried out, establishing a large number of structures. By 2025, over 9897 wells will have been drilled in the basin. Oil and gas pools have been discovered, accounting for two-thirds of the prognosticated resources. The continued exploration and production efforts helped attain a production of 287 MMT of oil and 87 BCM of gas to date.

4. Exploration Challenges

Exploration inherently involves risks and uncertainties, particularly when faced with limited or subpar data quality. A primary objective for every explorationist is to comprehend the uncertainties surrounding the results. Exploration activities in the Cambay Basin have advanced to a point where significant oil and gas accumulations in extensive structural traps have been identified. Current efforts are now focused on uncovering subtle structural and stratigraphic traps, as well as deeper geological plays. The acquisition of high-quality seismic data, along with thorough processing and interpretation, is crucial for identifying these traps. However, the deeper stratigraphy presents challenges, including (1) the presence of only thin reservoirs, (2) a reduction in seismic resolution with increasing depth, which complicates the mapping of these thin reservoirs, (3) a continued scarcity of drilling data of deeper stratigraphy, (4) the masking of reflections from deeper sequences by the shielding effect of Middle Eocene markers such as coals, and (5) a slow velocity gradient within the basin that complicates the differentiation between reflections from deeper layers and multiples from shallower strata. The use of seismic inversion techniques has been implemented with some degree of success, yet careful consideration of the appropriate methodologies is necessary to effectively utilize this technology.

Exploration of the syn-rift sequences has been limited due to inadequate seismic data, significant depths, elevated pressure, and poor quality of reservoir rocks known so far from scanty data. However, few wells have been drilled in the Cambay Basin because older sequences were not encouraging. The exploration of syn-rift sequences requires an integrated approach with plausible geological concepts. The availability of source rocks in the deep with substantial thickness and also the presence of cap rocks makes it imperative to search for the elusive reservoir rocks.

In a well-established area such as the Cambay Basin, the focus should be on identifying potential new pay zones, if they exist, to boost the declining production levels, despite the associated higher uncertainties. The post-rift sediments have been thoroughly investigated and are the primary contributors to production in the Basin. The search for hydrocarbons in the Synrift sediments must be actively pursued with a strong geological model. Over six decades of hydrocarbon exploration have established the Cambay Basin as the largest onshore petroliferous basin in India. Legacy exploration models have focused on structural 'highs' with reservoir facies sourced from the north, which were deposited over paleo-highs and successfully found oil and gas fields. Recent advancements in the study of half-graben rift basins prompt a reevaluation of seismic data from the west-central region of the basin, indicating the need to adopt the new model. This model could address 'Short' depositional systems characteristic of half-graben rift basins, and associated structure-controlled fan-deltas, which serve as key exploration targets within the Synrift.

4.1 Suggested Strategy

The strategy of prioritization of resources for exploration irrespective of the Synrift exploration strategy suggested in the preceding paragraph revolves around;

- Low-risk, moderate gain areas where the scope of finding more oil from brownfields exists, with new concepts leading to the area extension of heartlands. Locate extensions of prospects already delineated.
- Moderate risk- Moderate gain areas; Subtle traps, stratigraphic pods.

The periodic finding of small and medium-sized deposits near the field through an infrastructure-led exploration (ILX) demonstrates that there remains significant potential in this producing basin of our heartlands, where substantial, high-value discoveries could enhance exploration efforts even further. The incorporation of basic geological principles is a valuable approach for discovering new oil in a mature region. This reinforces the saying that the most promising locations for finding new oil are those that already have existing oil reserves.

Exploration Objectives include but are not limited to:

Patan-Sanchor Block

1) Broad alluvial fan and fan delta complex, which is laterally connected to a lacustrine or marine basin, in the Paleocene to Early Eocene succession
2) Isolated clastic bodies within the source rock, Cambay Shales.
3) Thin, discrete silt laminae within transgressive argillaceous Cambay Shale
4) Coal/Lignite as a source in the extreme northern part of the basin.
5) Lacustrine deposits in the Patan-Tharad block that are in sync with the Barmer Basin.
6) Pinchout prospects of undifferentiated Kalol and Kadi formations towards the basin margin and also towards the palaeohighs.
7) Low amplitude structural prospects of Kalol and Kadi age within the palaeo lows where the source rock potential is good.
8) Coal bed methane prospects in Sanchor-Tharad Depression.

Mehsana-Ahmedabad Block

9) Fractured shale and silt prospects within the Cambay Shale over palaeogeomorphic highs.
10) Synchronous sands of Olpad Formation over and on the flanks of paleo highs- Cambay- Olpad.
11) Fan deltas in the eastern margin of the Basin.
12) Shallow gas in the Mehsana Horst area and the plunging part of the horst in Babaguru-Kand formations.
13) Laminations in Older Cambay Shale in the rising faulted flanks of synclines in North Cambay.
14) Transfer zones are the preferred site for increased coarser clastics and hence, the locales of relatively higher quality reservoir rocks.
15) Deccan Trap accumulations on the eastern margin
16) Fractured Deccan Trap on the western margin
17) Late rift sequence may be of interest from a good reservoir point of view.

Cambay-Tarapur Block

18) Syn-rift sequences through the transfer zones and in the peripheral part of the basin margin could be viable exploration targets, because of the lesser depth of occurrence and quality of reservoir rocks.
19) Deccan Trap prospects in the eastern margin
20) The basin's greatest potential, however, lies offshore along the tidal/transition zone and beneath the shallow waters of the Cambay Gulf.
21) A series of structures associated with faulting in a productive trend and proven to be hydrocarbon-bearing.
22) Neogene plays in the Gulf of Cambay and deeper, especially for gas.
23) Deltaic sands of the Hazad Formation of Mid-Eocene age, both onshore and offshore in the Gulf of Cambay, like the Jaya field onshore.
24) Localized carbonates of Middle Eocene age fringing the western rising flank of the Gulf of Cambay.

Jambusar-Broach Block

25) Miocene inversion structures in the Navsari- Mindhola area.
26) Low resistive clays in Kand and Jambusar Formation.
27) Fan deltas in the eastern margin of the Basin.
28) Reworked sands of the Hazad delta as isolated reservoirs.
29) Discrete sand bodies in the present-day low caused by the eastward tilt of the basin
30) Deep potential hydrocarbon zones beneath producing fields and in isolated wells with shows not adequately tested to rank as discoveries.
31) Basal clastics of Olpad along the eastern margin

Narmada-Tapti Block

32) Shallow gas prospect in the Olpad- Kosamba-Ankleshwar area occurring at shallow depths.
33) Synrift prospects in the Narmada-Tapti block and Jambusar-Broach block.
34) Southern pinchout of Hazad sands in the Kosamba area
35) Deccan Trap towards the southern flank of the Ankleshwar High
36) Washover sands within the Cambay Shale towards the Olpad area.
37) Reworked sands of Haza within Hazira shale deposited as isolated bodies between the Kim and Olpad areas.
38) Low relief structural prospects within the Miocene in the Gulf and Surat-Bhandut areas.
39) Fault closures and wedge outs along the eastern margin.
40) Gas pools in Babaguru Formation.

Efforts are currently focused on low-amplitude structural features and notable stratigraphic traps. However, there are still more nuanced lithologic and potentially deeper structural targets that need to be explored before transitioning from a continuous to a discontinuous exploration regime, such as porosity pods and tidal sand ridges. Given the complexity of the situation, there is a clear need for advanced technology, enhanced sensors, refined data processing, and innovative interpretation that incorporates a broader range of conceptual insights. Acknowledging both continuity and discontinuity is crucial for comprehending depositional systems. This understanding is key to developing accurate, near-realistic models, which can significantly advance exploration efforts.

4.2 Unlocking Frontier areas

- Mesozoic prospects in Narmada-Broach-Jambusar blocks, more specifically along the western corridor.
- The chances that Mesozoic sediments are present below the Deccan Traps are very small in the Patan block, while in other blocks it is quite favourable.
- Basin-centered gas in some of the major half grabens/grabens like Wamaj, Tarapur, Warosan, Mehmedabad, Nadripur, and Tankari synclines, etc.
- Early rift/Synrift sediments on the western depression in Mehsana Block, where Khambel-Khamboi wells tested oil.
- Tight oil/ gas in siltstone /silty shale within the deeper part of the basin in all blocks.
- Shale oil in the Cambay Shale Formation, based on maturity data, where enough migration has not taken place.
- Tarapur shale-related petroleum system in deeper parts of the basin.
- Underground coal gasification is still a future option for gas production.
- CBM of Sobhasan Coal.
- Shallow biogenic gas.

Challenges include the reservoir characterization and delineation of the fan deposit morphology of Olpad deposits, and drilling of ultra-deep wells in the Jambusar and Gandhar areas without complications to reach the targets. The silver lining is that a large number of existing low-potential wells in various fields are suitable for deepening or sidetracking for Synrift exploration of the Olpad Formation. Technological advancements and drilling expertise are crucial in accessing these regions

Currently, the primary challenge facing this basin is the exploration of hydrocarbons within the development category of small marginal field areas or the discovery of unexplored or relinquished hydrocarbon regions. The mid-Cambay basin contains numerous small marginal fields characterized by discrete sand bodies, lower net-to-gross ratios, and reduced permeability. Detecting these small and thin sand bodies using traditional seismic methods proves to be challenging. Exploration and production companies have identified several small marginal fields in the mid-Cambay basin for hydrocarbon exploration, but the success rate for locating reservoir sands remains unconvincing. Such small and marginal fields have been farmed out to private operators, and the task is onerous for them. Most recently in their quest for oil and gas in Barmer Basin, J. Dolson et al[24] have published an excellent, robust three-dimensional relief map of the basement structure from well, gravity, and magnetic data of the Cambay-Barmer Basins and surrounding areas (Figure 12).

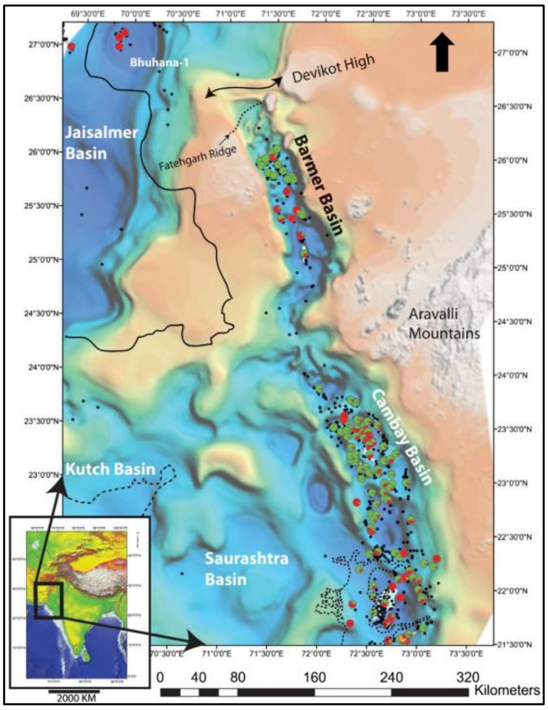

Figure 12: 3D relief map of the Basement architecture from wells, gravity, and magnetics[24]

There seems to be a Mesozoic conjugate rift west of the Cambay Basin. Wells drilled near the Cambay Basin found Mesozoic rocks, but only one tube well showed inflammable gas, with no hydrocarbon discoveries[25]. Mesozoic sediments were laid in specific conditions, but sedimentation decreased after volcanic activity. Cenozoic sediments are thinner. Overall, at present, the results for Mesozoic sections indicate limited hydrocarbon potential due to limited data. Given the limited drilling data, this area is still in the early phases of frontier exploration, and the prospects remain uncertain due to insufficient coordinated efforts.

5. Geological Insights on the Cambay-Barmer Rift Junction(Tharad-Sanchor block)

The most notable feature of India's northwest coast is the presence of Saurashtra, which functions as a craton that is not directly linked to the mainland but rather connected by a sea arm filled with deltaic sediments. Additionally, Kachchh is also seen as an island, accompanied by the Great and Little Rann, which are extensive inlets of saline water. The majority of the Rann constitutes a large gulf that has recently surfaced from the sea[26]. The second aspect that has not been entirely recognized for its importance is the characterization of the Cambay Basin. The Cambay petroliferous basin, which began forming in the lower Cretaceous period, was subsequently filled with marine sediments from the Eocene, Miocene, and Pleistocene epochs. The northern extension of the Cambay basin falls in the greater part of the delta of the Saraswati and Banas rivers in the Sanchor depression. The expansion of Cambay into the central region of Gujarat introduced maritime access to Mt. Abu and Patan. Saurashtra presents itself as a nearly circular island characterized by its radial drainage, which serves as a unique landform (Figure 13). It bears no resemblance to the Deccan trap found on the mainland and is encircled by significant deep faults on every side[27]. The drainage system of Gujarat and Saurashtra exhibits a radial pattern, which distinguishes it as an isolated island, separate from the mainland[28].

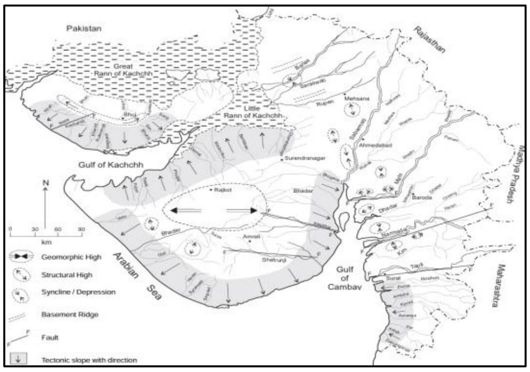

Figure 13: Drainage system of Gujarat[28]

The main takeaway is that the oil and gas prospects of the Sanchor-Patan block have remained underexplored over the last three decades after the initial thrust in the early stage exploration in the 1970s. The Patan–Sanchor–Tharad area of the Cambay Basin has previously been overlooked by exploration efforts; however, commercial discoveries in the neighboring Barmer Basin in the decade of 2001–2010 have sparked renewed interest in reassessing this region. Revisiting Sanchor-Patan with a rejuvenated exploration model is called for, given the geological and tectonic similarities with Barmer Basin. The geological objectives of both the Cambay and Barmer basins could form the targets. Tharad Ridge acts as a dividing line between the Cambay Basin and the Barmer Basin, and the NNW trending connection between the two basins. The orientation of the faults that shape these basins shifts from a northwest-southeast alignment to a northeast-southwest direction[24]. Significant depocenters are interspersed with accommodation zones (Figure 14). The Cambay-Barmer rift system, which trends from N-S to NNW-SSE, extends approximately 615 km into the Barmer Basin. There is a consistent reduction in the rift's width as one moves from south to north. In the southern region near the Gulf of Cambay, the width is nearly 100 km, gradually narrowing to about 40 km in the Sanchor block and further decreasing to approximately 35 km in the northern Barmer basin. The sediments in the major depocentres reach a maximum thickness of over 6 km. This block includes the phases of sedimentation: pre-rift, synrift, and post-rift. The correlated, comparative chronostratigraphic generalized stratigraphy is presented in figure 15[24].

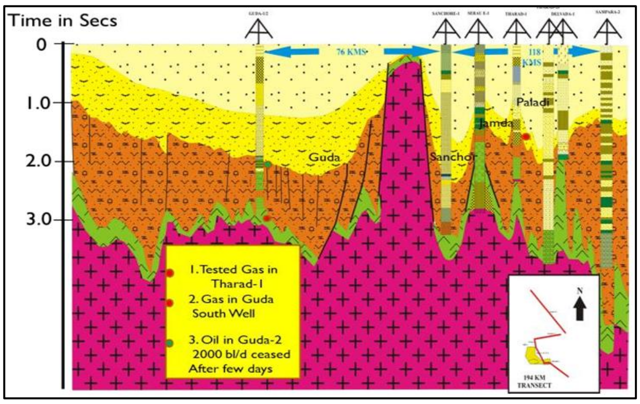

Figure 14: Seismo-geological transect connecting Cambay -Barmer Basins[29]

Additionally, it is necessary to establish the extension of the Paleocene (Olpad/Balutri Formation) level play fairway, which is present to the north in the Fategarh play within the Barmer Basin and in the south within the Olpad Play of the Patan-Cambay basin.

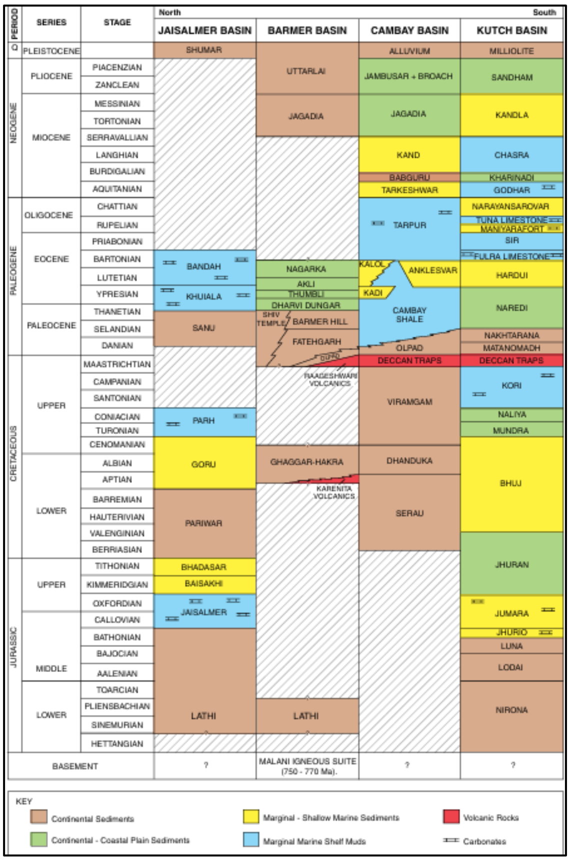

Figure 15: Stratigraphy of the Cambay -Barmer Basins[24]

6. Alternate Geological Thought Processing

Geological thought centres on the notion of process that shaped the environment of deposition through time and space. A contrarian viewpoint on the Cambay Basin suggests that the Rajasthan basin in the north and the Mumbai Offshore basin in the south is well-established Palaeogene and Neogene marine (carbonate) basins[30]. In this context, the Cambay basin may have functioned as a significant transitional lacustrine basin, where rift-related structures facilitated the formation of fan deltas at fault scarps. This process is closely associated with the widespread Kalol coals, which are characteristic of a coastal (marine) transgressive lake. This kind of innovative thinking is much required, and a dedicated pool of geoscientists would be required to rework the known into this geological thinking. Furthermore, at the inter-basinal level, particularly between the Barmer and Cambay basins, this approach may reveal the true hydrocarbon potential within the entrapment and exploration corridors and the same may be extended towards the Surat Depression in the south in Mumbai offshore Basin and in the conjugate rift of Mesozoic between the Cambay basin and the Saurashtra Basin in the west. To attain a more thorough and precise geological comprehension, it is essential to develop alternative exploration models within a regional context.

7. Exploitation Challenges

The lifecycle of an oilfield is generally divided into three primary phases: production buildup, plateau production, and declining production. Maintaining the necessary production levels throughout the lifecycle necessitates a comprehensive understanding of and the capability to manage the recovery mechanisms involved. In the case of primary recovery, which relies on the natural depletion of reservoir pressure, the lifecycle tends to be brief, with recovery factors typically not exceeding 20%. Secondary recovery, which utilizes either natural or artificial water or gas injection, achieves incremental recovery rates ranging from 15% to 25%. On a global scale, the combined recovery factors for both primary and secondary recovery fall between 35% and 45%. Enhancing the recovery factor of aging waterflooding projects by 10% to 30% could yield significant benefits[31]. To achieve this, it is essential to fall between 35% and 45%. Enhancing the recovery factor of aging waterflooding projects by 10% to 30% could yield significant benefits[30]. To achieve this, it is essential to explore methods that maximize recovery while reducing operational costs and minimizing environmental impact.

The topic of mature field development encompasses a wide range of aspects. Nevertheless, it can be categorized into two primary components: (1) well development and (2) reservoir development. The development plans may be formulated for either one or both, depending on the type of field, its history, and prospects. Technologies aimed at revitalizing mature oil fields focus on either well or reservoir applications. Once the maximum feasible number of wells for a given field has been established, various well development strategies come into play, including recompletion, stimulation, treatment, optimization of lift, data re-collection, monitoring, and the introduction of new wells. Subsequently, injectors are drilled to maintain pressure or facilitate displacement, primarily targeting secondary or tertiary recovery methods. It is essential to first ascertain the quantity and location of the target oil for any of these practices. However, re-evaluating reserves in such scenarios has consistently posed challenges due to uncertainties and the complexities involved in estimating residual oil saturation[32]**.** Identifying both the quantity and the location of the residual oil is the primary focus.

Throughout the lifespan of a field, several pivotal decisions are made. An accurate and continuously updated geological and reservoir model serves as the foundation for these decisions. Key considerations include acquiring new data, assessing economic feasibility, designing the type and size of facilities, determining the number and placement of development wells, and identifying bypassed reserves for infill drilling. The drilling and production of new wells generate a substantial amount of additional data. Moreover, ongoing seismic acquisition and reprocessing efforts remain focused on refining model geometries. As technological advancements and innovative interpretation methods emerge, they must be rigorously tested. The development of an integrated model necessitates sustained and collaborative engagement between geoscientists and engineers.

7.1 Enhanced Oil Recovery

Enhanced Oil Recovery (EOR) techniques have gained prominence since the late 1990s; however, they currently account for less than 4% of total production. Various EOR methods, including Thermal (In-situ Combustion), Chemical (Polymer, Micellar, Alkali, Alkali-Surfactant, and Alkali-Surfactant-Polymer, Gas Injection (Miscible/Immiscible using hydrocarbon and non-hydrocarbon gases such as N_2 and CO_2, and Microbial (for EOR and flow assurance), are being utilized. In the heavy oil region of the North Cambay Basin, the in-situ combustion method has been in operation for thirty years, yet recovery remains sub-optimal, indicating potential for process improvement. Effective reservoir monitoring is crucial to these initiatives, allowing for timely corrective actions. The recovery factor is closely linked to reservoir heterogeneities, the characteristics of deposition environments, drive mechanisms, fluid properties, pool size, and depth. Reservoir management practices further shape these intrinsic features. It is promising to observe that the reserve replenishment ratio consistently exceeds expectations.

Air injection or in situ combustion (ISC) is among the earliest thermal enhanced oil recovery (tEOR) techniques assessed in highly viscous oil reservoirs across the globe[33]. In situ combustion(ISC) is a method employed to target heavy oil reservoirs (with an API gravity of less than 20.0°). This method works in two ways: it heats the oil to reduce viscosity and injects gas to increase reservoir pressure(Figure 16). The ISC process in the Balol Santhal fields of Mehsana block is both successful in enhancing oil production and recovery[35]. The adoption of ISC technology led to a decrease in water-cut and an enhancement in the production rate. Cyclic steam stimulation(CSS) of heavy oil in the Lanwa field has been introduced and has started paying dividends. There is also scope for deriving value from the flue gases generated out of the ISC process in the heavy oil belt of Mehsana. Mehsana Asset also puts an example of reservoir management by ongoing recent trends of EOR processes (ISC, Polymer Flooding) in heavy oil fields and exploitation of tight & lensoidal sands in all light oil fields[36].

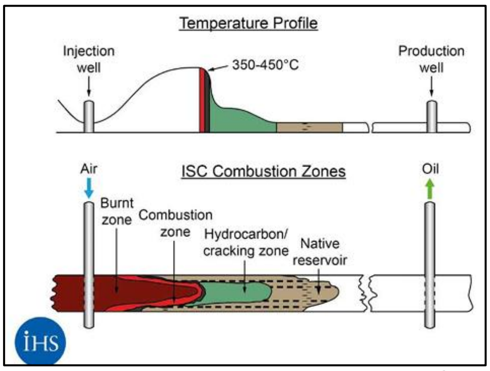

Figure 16: Schematic of ISC process [34]

Utilizing Enhanced Oil Recovery (EOR) in established fields may present a more appealing option for operators seeking quicker production boosts, especially when contrasted with the extended timelines associated with new exploration and development initiatives. While cost remains a significant concern for the implementation of EOR, advancements in

Paper ID: SR25421073254 DOI: https://dx.doi.org/10.21275/SR25421073254

International Journal of Science and Research (IJSR)
ISSN: 2319-7064
Impact Factor 2024: 7.101

efficiency and technical expertise could enhance its viability. Considering cost efficiencies, the chemical flooding technique was employed at the Bechraji field. Although Bechraji field experienced an unsuccessful ISC pilot in 2002, a chemical flood enhanced oil recovery (EOR) pilot project was carried out in 2015. The results from the chemical flood operation were promising, and it is now thought that a comprehensive development plan for full implementation is being evaluated[29].Chemical flooding can be utilized across a wide variety of field types, and it is this adaptability, along with additional cost savings, which enhances the appeal of the technique.

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Research by ONGC's Institute of Reservoir Studies and The Energy and Resources Institute (TERI) has created special microbes that can improve oil production from stripper wells[37]. These microbes can survive high temperatures, pressures, and salinity. Successful tests happened in Gujarat oil fields using the Huff & Puff method for microbial injection and improved oil production from stripper wells.

7.2 Improved Oil Recovery

Improved Oil Recovery (IOR) strategies framed to enhance recovery and production are in vogue in the basin, commencing with revisiting the field geological and reservoir models (static and dynamic). Mature field development practices can be divided into two major groups: (1) well engineering and (2) reservoir engineering strategies, including:

a) Infill drilling recovery mechanism. Determining the optimal placement of wells in mature fields is crucial, necessitating precise mapping of the distribution of remaining oil resources.
b) Initiation/Modification of water injections. The enhancement of well placement, the management of subsurface uncertainties, and a decision-making framework regarding the operational status of a well as either a producer or an injector.
c) Enhanced oil recovery through in situ combustion techniques in heavy oil fields
d) Horizontal wells with a high angle and high drift, along with ultra-short radius drainage holes, and
e) Bypassed reserves identification.
f) To enhance the volumetric sweep efficiency by realigning the injection and production wells.

7.3 Production Enhancement

Production enhancement consists of optimizing productivity from a given mature oil or gas field employing a cost-effective, structured approach to identify and resolve production anomalies. This requires dedicated well intervention and workover services. Production, sustenance, and enhancement are through a continuous process of:

a) Artificial Lift optimization
b) Massive hydraulic fracturing
c) Well-bore chemical stimulation in heavy oil fields
d) Paraffin intervention in light oilfields
e) Flue gas utilization in heavy oil fields under ISC
f) Unique flue gas shut off in the heavy oil belt.
g) Improved sand control measures and
h) Improved sick well treatments.
i) Polymer chemical flooding.

A 30% increase in oil production was achieved through unconventional and innovative techniques in the heavy oil field "Lanwa," characterized by an oil viscosity of 1000-1500 cP and supported by an active edge water drive[38]. The unconventional methods employed include Water Shut Off (WSO) with a gravel pack installation, aquifer management utilizing flue gas trapping, optimization of air injector-producer combinations in areas affected by In-Situ Combustion (ISC), and the restoration of productivity in six horizontal wells through foam treatments using coiled tubing. These initiatives were undertaken by reassessing current practices and enhancing the technical understanding of the field.

It is evident that nearly all the major oil fields, despite having reached maturity, still possess a significant quantity of recoverable oil. The outcomes of these initiatives regarding incremental oil production are promising and contribute to an increase in oil output, signifying a significant change from previous methodologies[39]. The enhanced growth rate in production is anticipated to boost ultimate recovery in alignment with global benchmarks and expedite the development of brownfield sites of the Cambay Basin.

8. Perspective

The Cambay Basin has positioned itself as a vital hydrocarbon province with vast, unrealized potential over the years. This review highlights its complex tectonic setting, prolific petroleum systems, and history of successful exploration and production. However, deeper structural and stratigraphic prospects and subtle traps remain underexplored. As the industry shifts toward maximizing recovery, the application of advanced seismic technologies, integrated geological models, and enhanced recovery strategies becomes indispensable. Future efforts must focus on revisiting mature fields with refined exploration and development models and exploring frontier areas to fully unlock the basin's potential.

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