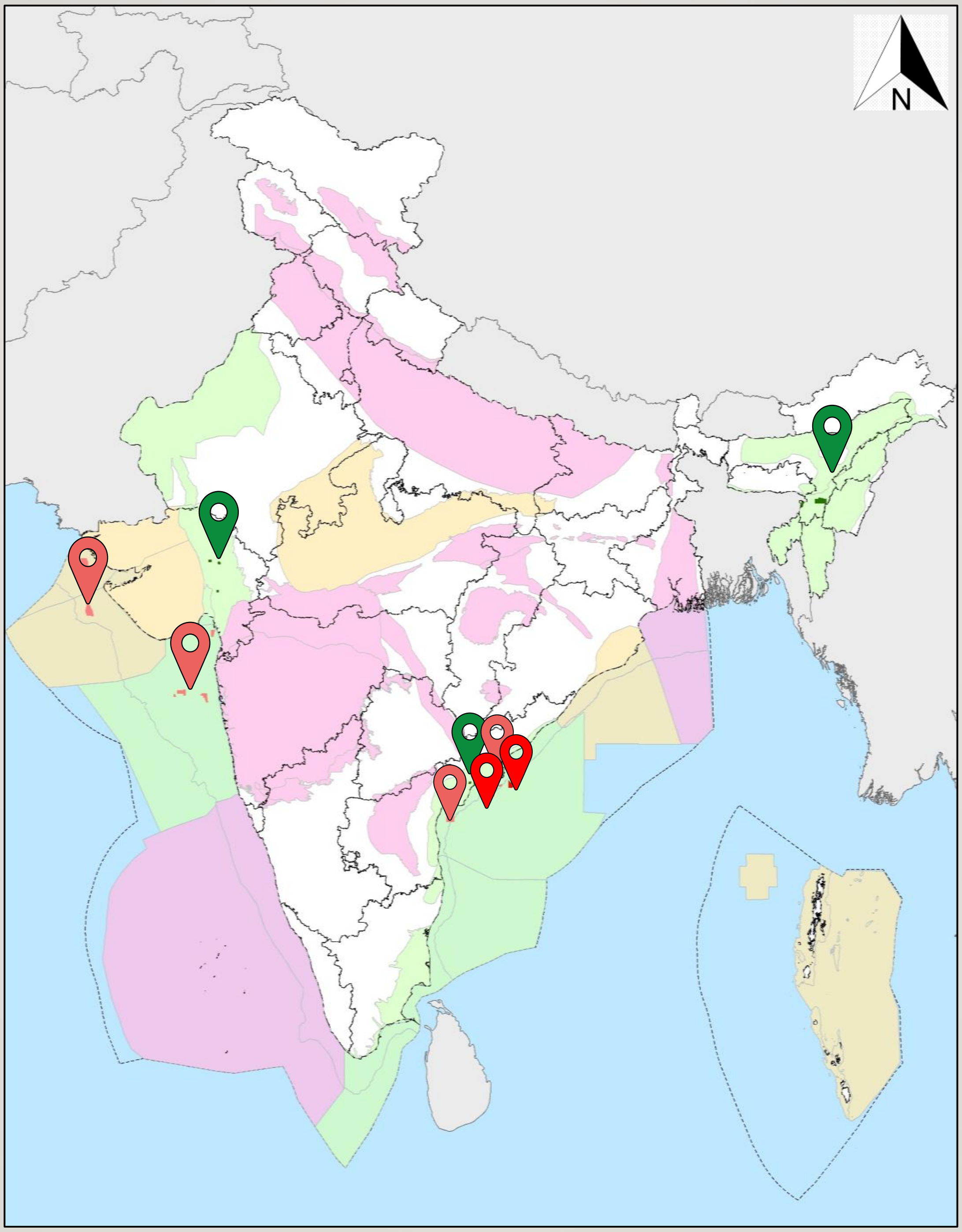
पेट्रोलियम एवं
प्राकृतिक गैस मंत्रालय
MINISTRY OF
PETROLEUM AND NATURAL GAS

सत्यमेव जयते

DGH

DIRECTORATE GENERAL OF HYDROCARBONS
(Ministry of Petroleum & Natural Gas,Government of India)

INFORMATION DOCKET



CONTRACT AREA

AA/ONDSF/ASSAM/2025

DISCOVERED SMALL FIELD BID ROUND - IV

DISCLAIMER

This document, titled Information Docket, provides a consolidated overview of the Contract Area comprising the discoveries/fields offered under the Discovered Small Fields (DSF) Bid Round-IV. This docket has been prepared based on original inputs /information received from National Oil Companies, Private Operators/JV and available at National Data Repository (NDR).

Third Parties were engaged to independently assess the information and estimate the in-place volumes. In conducting these estimations, Third Parties used the available data/information and employed assumptions, procedures and methods deemed necessary given the timeframe available for evaluation.

The accuracy and clarity of the information presented herein, including the reported hydrocarbon resources, are thus limited to the data available at the time of analysis and the verifications performed by the Third Parties during the evaluation timeframe. The findings are subject to further review and validation by bidders upon receipt of additional and clarified data/information.

Given these limitations, all bidders are hereby advised to undertake their own independent technical and commercial due diligence and conduct thorough evaluations of the data and resource potential to support informed investment and bidding decisions.

Contents

INTRODUCTION

With the extension of the DSF policy 2015, DSF Bid Round IV offers 55 small-to-mid-size oil and gas discoveries through international competitive bidding. There are 9 Contract Areas under DSF-IV spread over Cambay, Assam & Assam Arakan, Gulf of Kutch, Mumbai Offshore, Krishna Godavari Basins. Out of 55 discoveries, there are 19 onshore discoveries in 3 Contract Areas, 26 shallow water discoveries in four Contract Areas and 10 Deepwater discoveries in two Contract Areas. The discoveries have been suitably clustered in order to leverage shared resources and operational flexibility.

In terms of hydrocarbon prospectivity, the fields-on-offer lie in 5 sedimentary basins which include 8 Contract Areas in Category I basins with hydrocarbon reserves and 1 Contract Area in Category II basins with contingent resources.

Each Contract Area on offer has multiple discoveries, comprehensively described in this Information Docket to bring in all relevant subsurface facts of geo-scientific and engineering information. This technical booklet will be useful if read while working with the Data Package which would be available on sale once the Data Room is set up for viewing.

1. CONTRACT AREA DESCRIPTION

The Contract Area, titled, AA/ONDSF/ASSAM/2025 is located in the onland area of India (**Figure 1-1**) within the Assam Shelf Basin and the Assam Arakan Fold Belt Basin (AAFB) segments of the composite Assam and Assam Arakan Basin (A&AA Basin). The Contract Area has an offered area of **645.47 Sq. Km**. under this DSF Bid Round IV. The Contract Area is made up of clusters with 8 discoveries/fields viz Laxmijan-1A (LXMJ-1A), Bihubar-1 (BHBR-1), Barsilla-1 (BRSL-1), Charaideo-1 (CRDO -1), Kherem-2 (KHM-2) in the Assam Shelf and Tukbai-2 (TUKB-2), Patharia-2 (PTRA-2) & Patharia-5 (PTRA-5) in the AAFB segment and 17 additional wells and 3 sidetracks included. In the map, enclosed with the NIO (Notice Inviting Offer) Document, the Contract Area is referred to as O-3. The following **Table** 1-1 and **Figure 1-1** show the Contract Area details across the field(s) and/or cluster(s).

Table 1-1: Details of Contract Area AA/ONDSF/ASSAM/2025

Details of Contract Area AA/ONDSF/ASSAM/2025

Total Contract Area : **645.47** Sq Km

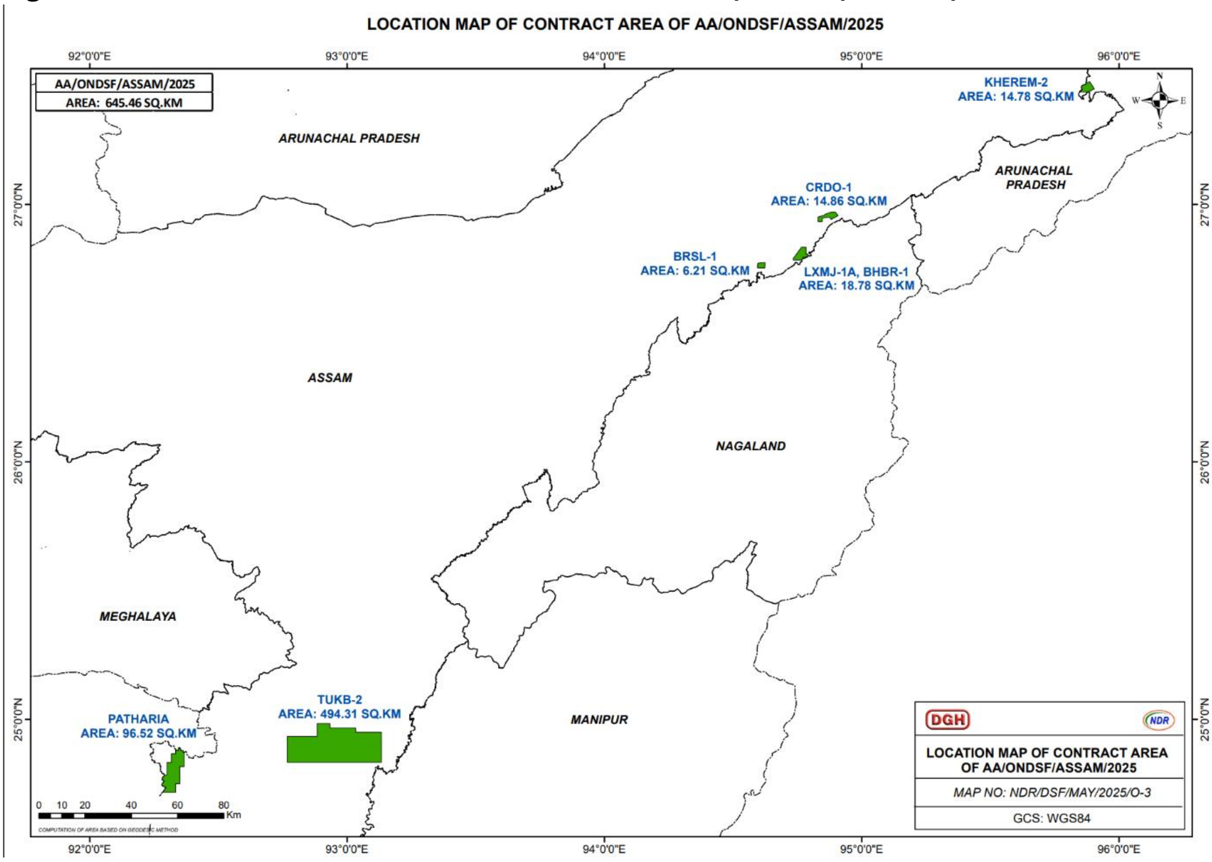
No. of Discovery Wells in Contract Area : **8**

Total No. of Wells in Contract Area : **28** (including Discovery wells)

No. of Polygons Covered in Contract Area : **6**

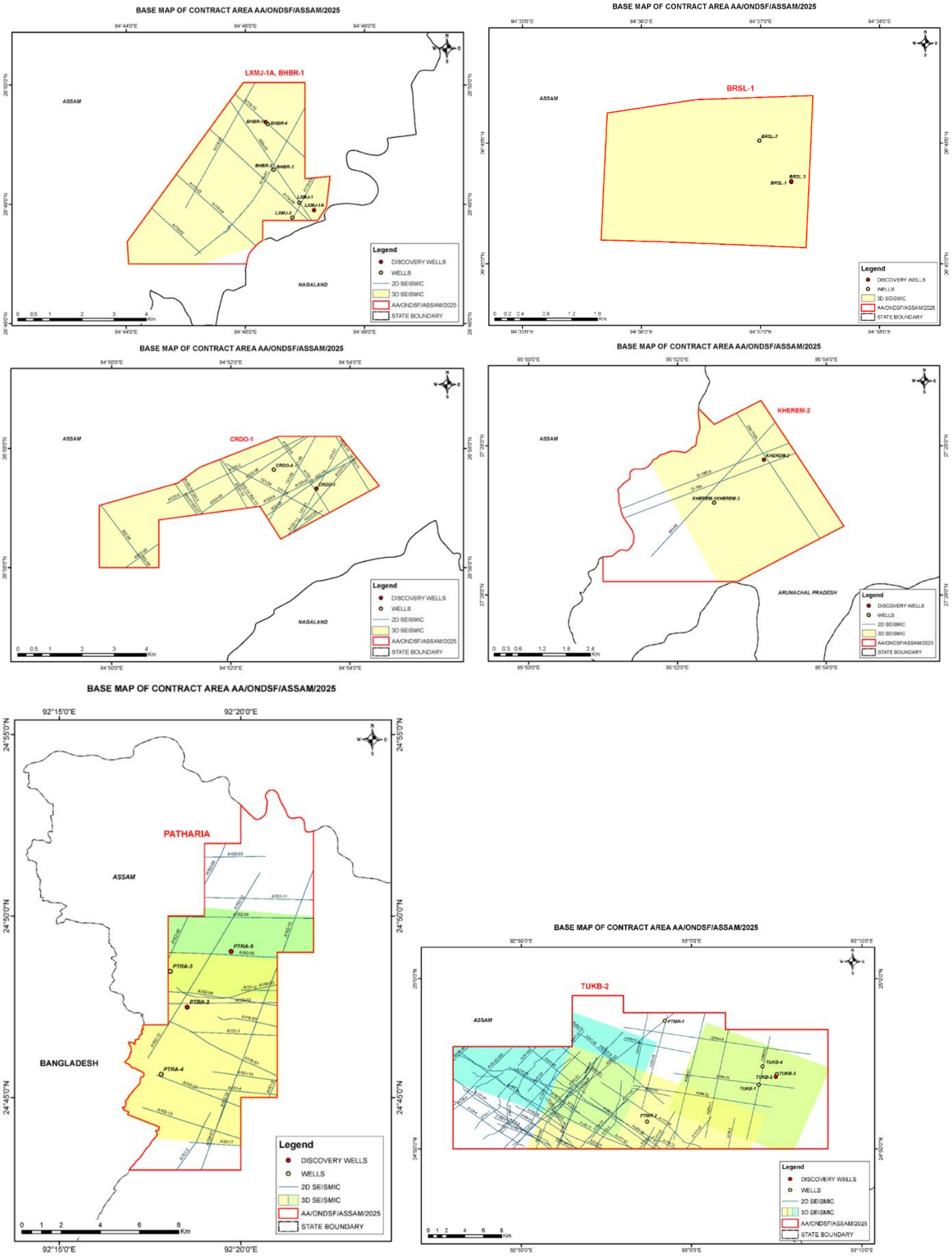
<table>
<tr><th>S. No.</th><th>Name of Polygon</th><th>Area, SqKm</th><th>No. of Discovery Wells</th><th>Total No. of Wells</th><th>O+OEG MMTOE</th><th>O+OEG (As per Erstwhile Operator) MMTOE</th></tr>
<tr><td>1</td><td>Laxmijan</td><td rowspan="2">18.78</td><td>1</td><td>2</td><td>0.96</td><td rowspan="2">0.15</td></tr>
<tr><td>2</td><td>Bihubar</td><td>1</td><td>5</td><td>0.70</td></tr>
<tr><td>3</td><td>Barsilla</td><td>6.21</td><td>1</td><td>3</td><td>1.00</td><td>0.25</td></tr>
<tr><td>4</td><td>Charaideo</td><td>14.86</td><td>1</td><td>3</td><td>3.35</td><td>3.64</td></tr>
<tr><td>5</td><td>Kherem</td><td>14.78</td><td>1</td><td>3</td><td>1.34</td><td>0.89</td></tr>
<tr><td>6</td><td>Tukbai</td><td>494.31</td><td>1</td><td>8</td><td>0.17</td><td>0.03</td></tr>
<tr><td>7</td><td>Patharia-2</td><td rowspan="2">96.52</td><td>1</td><td rowspan="2">4</td><td>0.23</td><td>0.18</td></tr>
<tr><td>8</td><td>Patharia-5</td><td>1</td><td>0.19</td><td>0.14</td></tr>
<tr><td>Total</td><td></td><td>645.46</td><td>8</td><td>28</td><td>7.94</td><td>5.28</td></tr>
</table>

Figure 1-1 : LOCATION MAP OF CONTRACT AREA OF AA/ONDSF/ASSAM/2025



The area has information of **740.87 line km of 2D** seismic data and **469.07 sq km of 3D** seismic data. There are 28 wells in the Contract Area. The following **Figure 1-2** show(s) the coverage of available seismic 2D and 3D data along with wells drilled across field(s) and/or cluster(s).

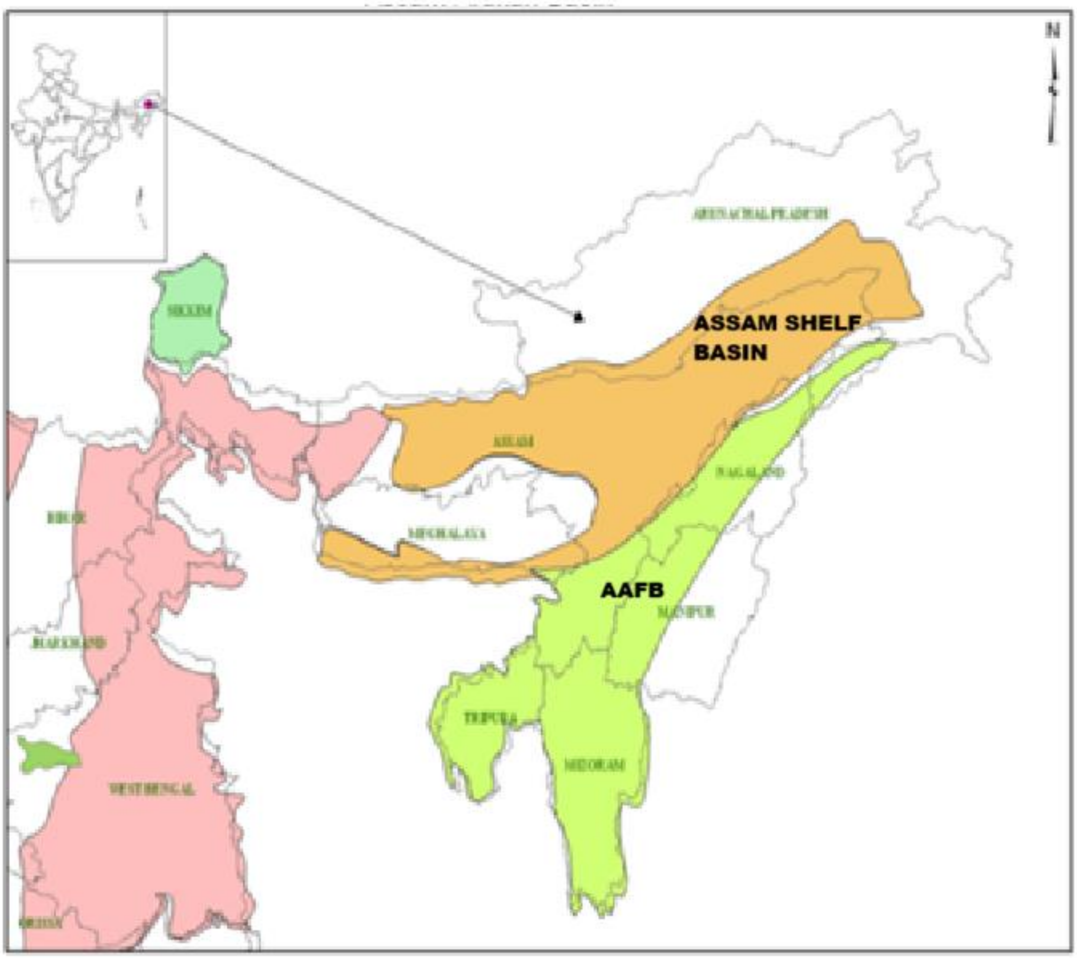
Figure 1-2 : COVERAGE OF AVAILABLE SEISMIC 2D AND 3D DATA IN AA/ONDSF/ASSAM/2025



2. PHYSIOGRAPHY AND ACCESSIBILITY OF THE AREA

The Contract Area is located in the states of Assam and Arunachal Pradesh within northeast India and encompasses discovered structures, both in the Category-I Assam Shelf Basin and the Assam Arakan Fold Belt (AAFB) Basin (**Figure 2-1)**. However, based on the tectonic history of the area the two Basins can be considered part of the composite Assam and Assam Arakan Basin (A&AA Basin). This part of India is located between the latitudes 22^{o}N and 29.5^{o}N. The Tropic of Cancer passes along the southern part of the Assam Arakan Fold Belt Basin through the states of Tripura and Mizoram. The Kherem, Laxmijan, Bihubar, Charaideo and Barsilla Fields are located in the Assam Shelf Basin while Tukbai and Patharia Fields are located in the Assam Arakan Fold Belt Basin.

Figure 2-1 : ASSAM & ASSAM ARAKAN (A&AA) BASIN



Though primarily in the plains area within the states of Assam and Arunachal Pradesh, the fields in the Assam Shelf Basin have uneven elevations ranging nearly 100m to 154m from Mean Sea Level and are mostly covered with alluvium. Being within the monsoon belt of South and South-East Asia, the region has essentially tropical climate, with high rainfall during summer (April-October) and relatively dry winter from November to March. But its location and topography, encircled on three sides by high mountain ranges and the presence of a precipitous plateau (Shillong Plateau), athwart the course of the incoming south west monsoon winds and have rendered its climate somewhat different from that of the other parts of India. The fields in the Assam Shelf Basin are well connected by motorable roads with national and state highways. The nearest railway station to the fields is Simaluguri Junction and the nearest airport is Jorhat for the Laxmijan, Bihubar, Charaideo and Barsilla Fields while for the Kherem Field, the nearest railway station is Tinsukia Junction and the nearest airport is at Dibrugarh.

The Patharia and the Tukbai Fields, falling in the state of Assam are located in the Cachar area of the Assam-Arakan Fold Belt Basin and which consists of, in the area of the fields, a series of long narrow anticlines and broad synclines in an almost N-S trend that swings north-eastward towards the northern margin. The N-S trending ridges are the northward extension of the Tripura hills running nearly up to the Barak River, which flows almost east to west parallel to the Barail Hill range. The average elevation of the Cachar Fold belt varies between 10 m and 1600 m because of the varied topography consisting of plains, hills, and valleys. Hilly terrains are present, particularly in the north and south, near the borders with the state of Mizoram and the Dima Hasao district of Assam. However, in the area of the discovered fields the ground level elevations are mostly in the range of 25 to 55 m.

This area has a humid tropical climate with annual rainfall ranging from 300-400 cm. The maximum temperature during the summer months of April-June ranges between 30°C-38°C. The monsoon lasts from May to September. Winter temperature (November, December and January) ranges from 12°C to 25°C. Guwahati is the nearest international airport while Silchar is the other connecting airport at a distance of around 60 Km. Karimganj is the nearest major town and railway station within a 10 KM radius. **Figure 2-2, Figure 2-3 and Figure 2-4** show locations of the blocks in satellite imagery.

Figure 2-2 : SATELLITE IMAGERY OF THE BLOCK AREAS:

Figure 2-3 : SATELLITE IMAGERY OF THE CHARAIDEO, LAXMIJAN, BIHUBAR AND BARSILLA AREA:

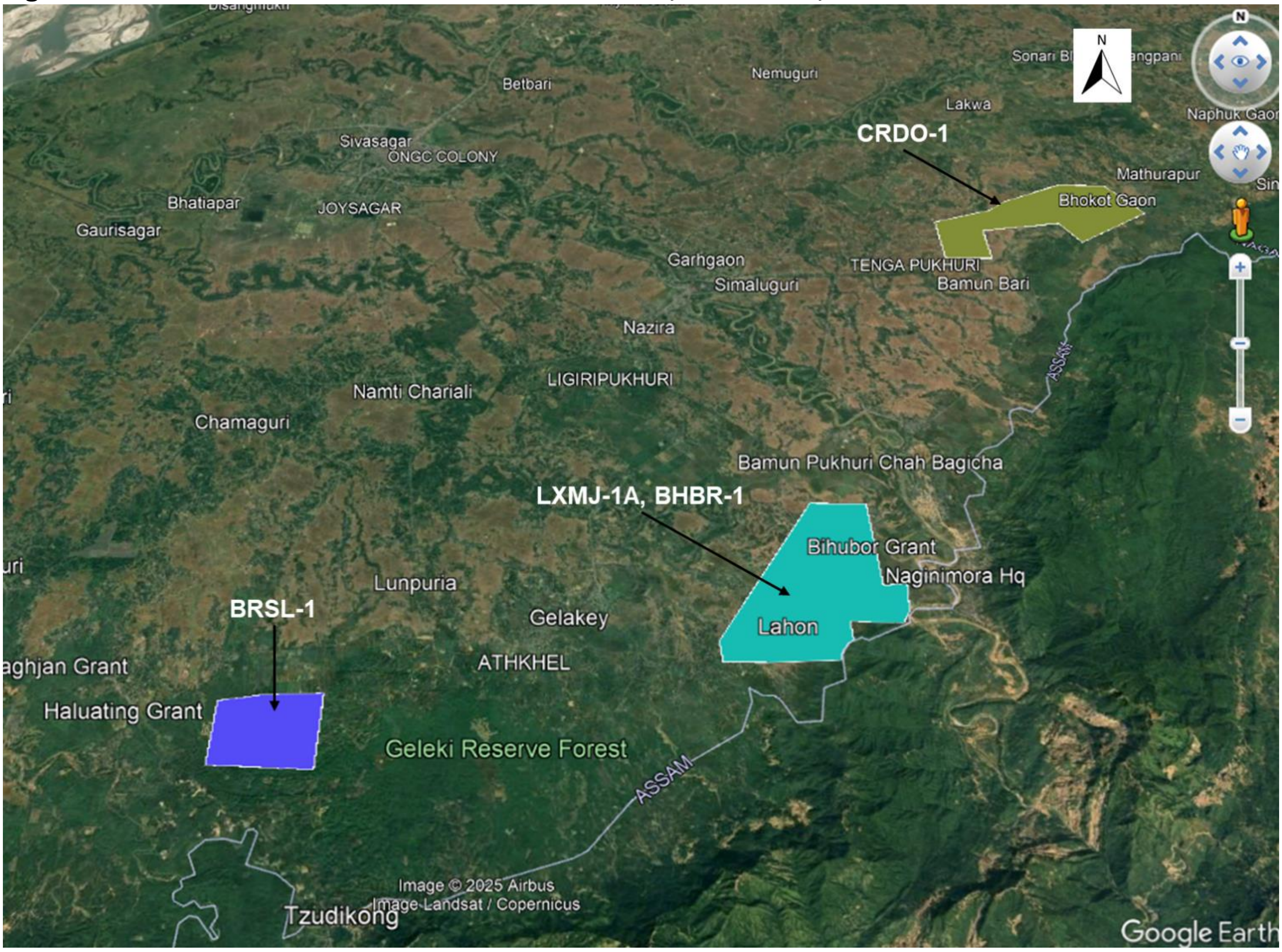
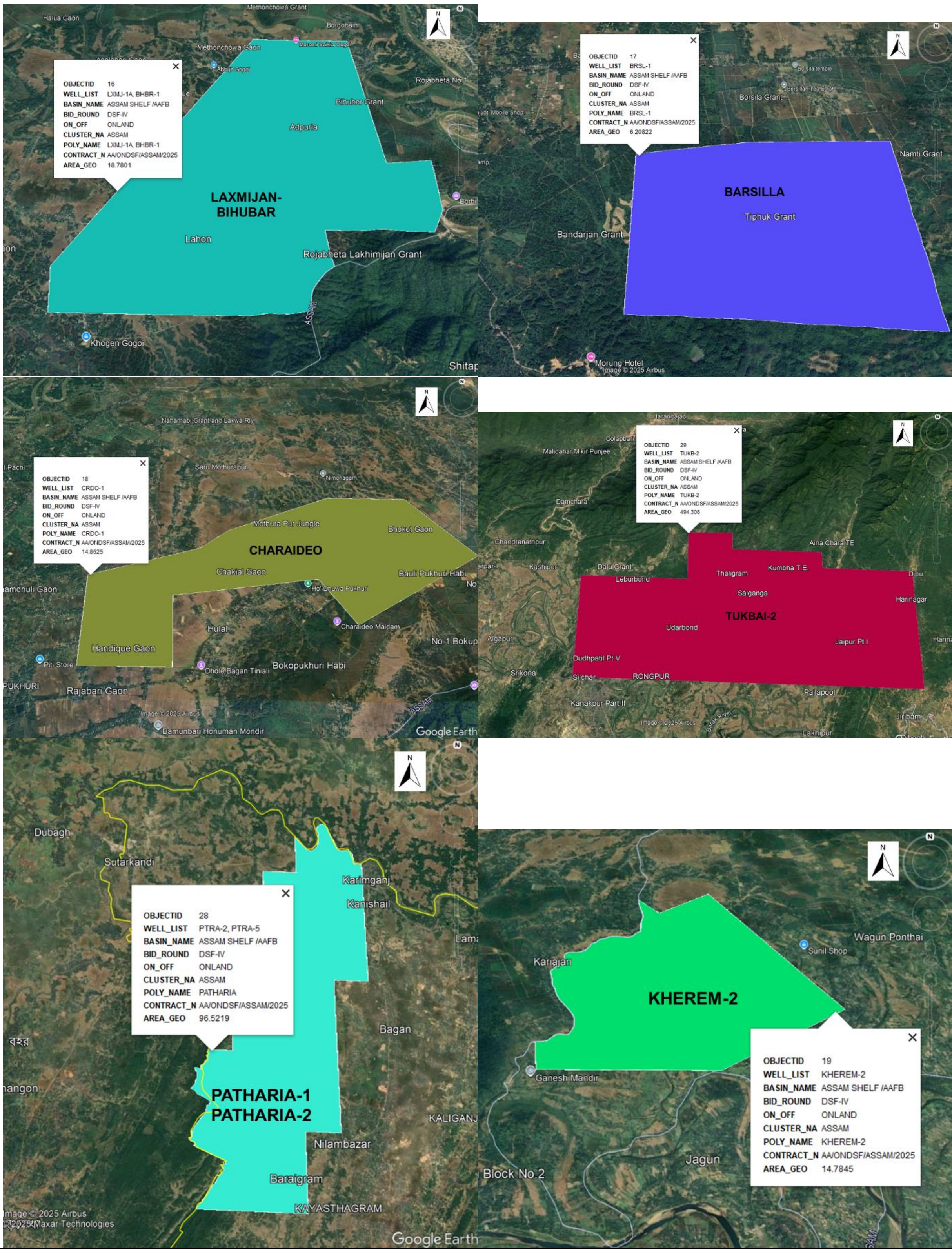


Figure 2-4 :SATELLITE IMAGERY OF THE BLOCKS SHOWN IN 6 CLUSTERS



3. RELEVANT SEDIMENTARY BASIN INFORMATION

3.1 ASSAM & ASSAM ARAKAN BASIN DESCRIPTION

The composite Assam and Assam Arakan Basin (A&AA Basin) is divided into two Category I basins viz. the Assam Shelf Basin and the Assam-Arakan Fold Belt (AAFB) Basin (**Figure 2-1**) The Assam Shelf Basin is a Category I Basin which is entirely onland, and the Basin has an area of 56,000 sq. km. containing about 7000 m thick sediments of mostly the Tertiary period. The Basin is a peri-cratonic, passive margin basin, with the signature of compressional tectonics as a result of the Himalayan orogeny. The Basin hosts a thick pile of mainly Tertiary sediments, ranging from Paleocene to Recent which overlies the Basement consisting of Granitic and Metamorphic complex. Gondwana sediments are exposed in the western extremity of Garo Hills (in the state of Meghalaya), consisting of gritty sandstones, carbonaceous shale and lenticles of coals. The Basin unconformably extends up to the northern bank of the River Brahmaputra into the foothills of the Eastern Himalayas. The Assam Shelf Basin is a petroliferous province, characterized primarily by siliciclastic deposits of the shelf margin, situated to the north-east region of Indian peninsula. and 8 plays are present within the Basement and Tertiary sedimentary section. Commercial hydrocarbon occurrences, besides in the Basement, is spread over different stratigraphic intervals ranging from the older sediments of Paleocene (Tura Sandstone) to the younger sediments of Pliocene (Girujan Formation). Several oil and gas fields have been discovered within structural, stratigraphic and strati-structural entrapment conditions. The hydrocarbon accumulations often indicate charging from multiple source sequences. The Assam Shelf Basin is still under active exploration stage.

The Assam-Arakan Fold Belt (AAFB) Basin is also a Category I Basin, implying that the Basin has significant commercial discovered in-place oil and gas. The Basin which is entirely onland has an area of 60,000 sq. km and contains a sedimentary column of more than 10,000 m thick sediments of mostly the Tertiary period. Assam Arakan Fold Belt Basin is a peri-cratonic, passive margin basin, with the signature of compressional tectonics during Himalayan Orogeny. The basin includes two distinct tectonic setting, viz. Tripura-Cachar Fold Belt and Naga- Schuppen belt. The Basin hosts a thick pile of Tertiary sediments, ranging from Paleocene to Recent which overlies the Archean Basement consisting of granitic and metamorphic rocks. The Basin is characterized primarily by siliciclastic deposits of fluvial to shelf margin setup, situated in the northeast region of Indian peninsula. It cuts through major states of the North-East region (NER) of India (Assam, Arunachal Pradesh, Nagaland, Manipur, Mizoram and Tripura). The Basin is currently under active exploration stage. In the Basin, 7 plays are present from the Eocenes to Pliocene. Commercial hydrocarbon occurrences have been mainly encountered and produced from within Miocene and Pliocene formations except for some small discoveries in Oligocene and Eocene sequences. Several gas pools have been discovered within structural closures while hydrocarbon accumulations often indicate charging from deeper sequence. The deepest Oligocene play (Renji) is yet to be thoroughly explored. All proven systems have significant risked resources

Though the Contract Area can be divided into the Assam Shelf Basin and the Assam Arakan Fold Belt (AAFB) Basin, based on the tectonic history of the area the two basins can be considered part of the composite Assam and Assam Arakan Basin (A&AA Basin). The major structural elements of the shelf–slope–basinal system of the composite Assam & Assam Arakan (A&AA) sedimentary basin is briefly described as following **(Figure 3-1).**

1. **Assam Shelf**

The salient features of the structural elements from north to south are as follows:

a) Southerly to southeasterly moving thrust sheets of younger (Miocene to Plio-Pleistocene) sedimentary rocks in the Eastern Himalayan foothills.

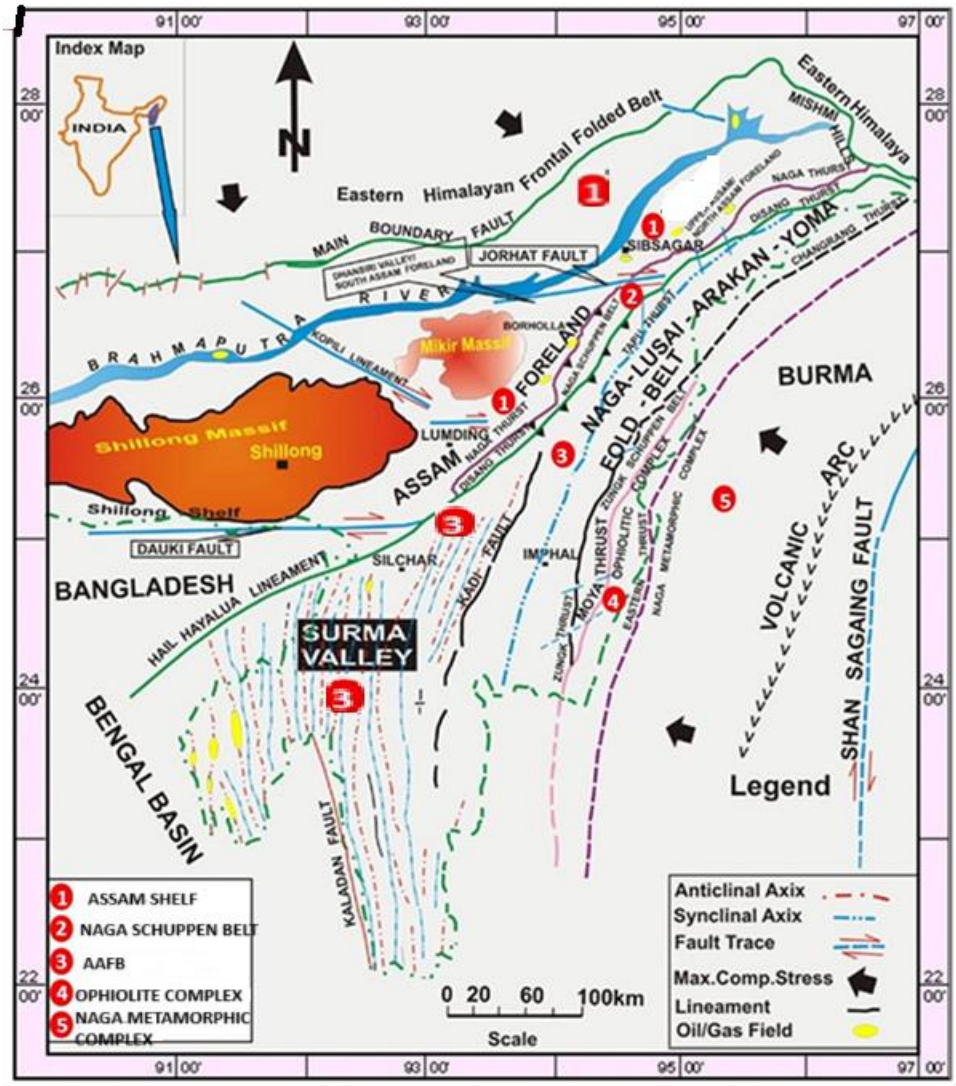
b) The Himalayan Foredeep zone, north of the River Brahmaputra, lies in the northern periphery of the foredeep and is overridden by the southerly moving thrust sheets of younger sedimentary rocks.

c) The subsurface Brahmaputra-Arch, running along the southeastern side of the River Brahmaputra in the eastern and northeastern part of the state of Assam.

d) The southeastern slope of the Assam Shelf, southeast of the Brahmaputra Arch, having local structural highs and lows, up to the Naga Thrust, and extending to beneath the Naga Schuppen belt. This element contains most of the oil fields of the Assam Shelf.

e) The Shillong Plateau and Mikir Massif, composed mostly of Precambrian granitic and metamorphic rocks. The southern slope of the Shillong Plateau exposes Gondwana, Cretaceous and Tertiary rocks.

Figure 3-1 :MAJOR STRUCTURAL ELEMENTS OF ASSAM & ASSAM-ARAKAN BASIN



2. The Naga Schuppen Zone

The Naga Schuppen Thrust Belt is a narrow, elongated zone of imbricate thrusts about 20 to 35 km wide, extending for about 200 km in a NE-SW direction. This morpho-tectonic unit which fringes the Assam-Arakan Fold Belt was formed as a result of subduction of the Indian Plate beneath the Burmese Plate. The main axis of compression is SE-NW, with the oldest Disang Thrust being of Late Eocene-Oligocene age. Thrusting continued up to Late Pliocene~~,~~ with the youngest emergent thrust, Naga Thrust, separating the foreland and the imbricate thrust zone.

3. **The Assam – Arakan Fold Belt**

This fold belt may be divided into two zones bounded by prominent thrusts, viz, (i) the Naga Fold Zone, lying in between the Disang and Tapu Thrusts and having exposures of Disang shales and Barail sediments, and (ii) the Central Flysch Zone, lying between the Tapu Thrust and Changrang – Zunki Thrust and having exposures of mainly Disang shales. The Tripura-Cachar Fold Belt and the Compressed Mizo Fold Belt are two more important zones of this structural element with the former hosting a number of hydrocarbon discoveries, primarily gas.

4. **The Zunki Schuppen belt,**

This zone contains mostly older Disang shales (Upper Cretaceous to Eocene) & occurring between the Zunki and Moya Thrusts.

5. **The Ophiolite Complex,**

Occurs in between the Moya and the Eastern Thrust. Disang shales, occurring in association with ophiolites, are somewhat metamorphosed here.

6. **The Naga Metamorphic Complex,**

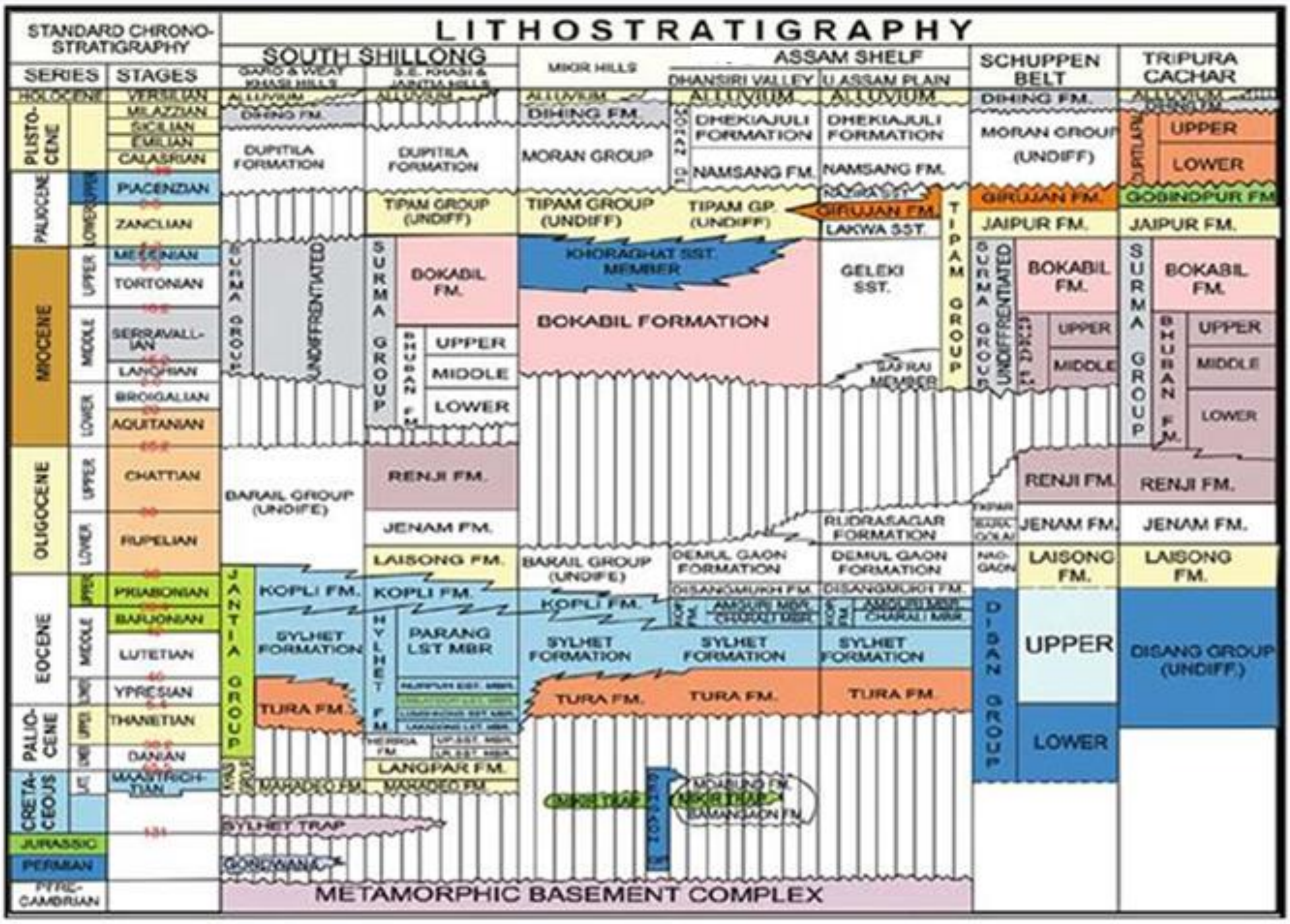
Located east of the Eastern Thrust the metamorphic complex occurs mostly to the east of the Indo-Myanmar international border.

The fields under this DSF round, located in the Assam Shelf, mostly lie close to or on the transition of the Naga Schuppen zone between the first two structural elements (please see above) of the composite Assam and Assam Arakan Basin. But the presence of Assam Shelf sediments has been established in the subsurface stratigraphic section of these fields.

3.2 ASSAM & ASSAM-ARAKAN BASIN STRATIGRAPHY

The stratigraphy of the Assam & Assam Arakan Basin (A&AA) at a few of Its structural elements is given in the **Figure 3-2.**

Figure 3-2: GENERALIZED STRATIGRAPHY OF THE BASIN



As earlier mentioned, the composite Assam and Assam Arakan Basin (A&AA Basin) consists of two basins viz. the Assam Shelf Basin and the Assam-Arakan Fold Belt (AAFB) Basin. The generalized stratigraphy of Assam Shelf Basin is as follows (**Figure 3-3 and Figure 3-4**):

Figure 3-3 GENERALIZED STRATIGRAPHY OF ASSAM SHELF BASIN

AGE	FORMATION / SAND		LITHOLOG	GROSS LITHOLOGY
Recent	Alluvium			Poorly consolidated coarse sand with sandy clays and clay.
Pliocene - Pleistocene	Namsang			Dominantly loose medium to fine grained sand with little mottled dominantly red color clay/claystone.
	Nazira Sandstone			Predominantly grey, medium grained sand with minor grey to brownish grey clay and occasionally siltstone, coal.
Miocene - Pliocene	Tipam	Girujan Clay		Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
	Lakwa Sst.	TS-1		Dominantly fine to medium grained grey sandstones with minor light grey soft clay/ claystone.
		TS-2		
		TS-3		
	Galeki Sst.	LCM+TS4		Dominantly clay/ claystone with occasional sand/ sandstones
		TS-5		Intercalation of sand /sandstone with clay /claystone and siltstone.
		TS-6		
Oligocene	Barails	Argillaceous / Rudrasagar (BCS)		Dominantly shale inter-bedded with coal and minor clay stone with Sand and siltstone
		Arenaceous / Demulgaon (BMS)		Dominantly fine to medium grained grey sandstones with some inter-bedded clay and shale.
Late Eocene	Kopili			Mainly shale (splintery) alternating with fine grained sandstone and siltstone.
Middle Eocene	Sylhet			Mainly fossiliferous limestone with shales and thin sandstone bands.
Early Eocene	Tura			Dominantly sandstone with minor shales.
Pre - Cambrian	Basement			Leucocratic granite (weathered) with essential minerals e.g. quartz and pink feldspar.

The stratigraphy and gross lithology towards the northeast of the Basin particularly in the PEL/ ML areas bearing operated primarily by Oil India Limited (OIL) is as follows,

1. Alluvium/Dhekiajuli: Consists of medium to coarse grained unconsolidated sands with thin bands of clay.
2. Namsang: Comprised of medium to coarse grained sandstone with streaks of brownish clay. Coal and carbonized wood pebbles are also abundant.
3. Girujan: Made up of mottled, brown and bluish gray clay with bands of fine to medium grained sandstone and occasionally streaks of coal.
4. Tipam: Predominantly arenaceous range and is composed of salt and pepper coloured, medium grained sandstone with bands of blue and bluish gray shale. Some coal streaks are found in the middle and lower Tipams.
5. Barail: Commonly divided into two units viz. Argillaceous and Arenaceous. The argillaceous range of Barail consists of mostly bluish gray mudstone with thin bands of fine-grained sandstone and thin streaks of coal. In some areas well developed extra bands of fine-grained sandstone ranges are found.

The arenaceous range is comprised of mostly fine to medium grained sandstone with occasionally coal streaks, calcareous mudstone and bluish gray shale.

6. Kopili: Mainly composed of alternation of dark gray splintery shales and thin bands of fine grained sandstone with coal streaks and carbonaceous shale.
7. Prang: Consists of dark gray splintery shales with bands of creamy white, brownish gray and light ray limestone and calcareous sandstone.
8. Narpuh: Thin grayish white, light gray and thin bands of creamy white limestone, splintery shales, fine grained sandstone (often calcareous and glauconitic), and abundantly siltstone characterize the Narpuh stage.
9. Lakadong+Therria: Consists of carbonaceous shale with light gray to dark gray splintery shale, bluish gray shale, fine to coarse grained saccharoidal to calcareous, glauconitic sandstone. Thin stringers of coal, white and brownish charts are mostly present in middle and lower part.
10. Langpar: Composed of mostly medium to coarse grained arkosic sandstone along with bluish shale streaks.
11. Basement: Medium to coarse grained granite containing quartz, pinkish feldspar and biotite.

The generalized stratigraphy of AAFB Basin in the Tripura-Cachar Belt is as follows (**Table 3-1**):

Table 3-1: GENERALIZED STRATIGRAPHY OF TRIPURA-CACHAR FOLD BELT AREA

AGE	GROUP	FORMATION/ MEMBER	GENERALISED LITHOLOGY
Recent to Pliestocene		Alluvium	Loose sands, silts and clays
		Dihing	Pebble beds, conglomerates and sandstones with thin beds of clay
UNCONFORMITY			
Pliocene	Dupitala	Upper	Coarse pebbly sandstone and mottled clays
		Lower	
UNCONFORMITY			
Mio-Pliocene	Tipam	Gobindpur	Variegated soft and sticky clays often silty with Sandstone
		Jaipur	Mainly Sandstone with clays and claystone
Miocene	Surma	Bokabil	Fine grained sandstone, siltstone with intervening layers of claystone.
		Upper Bhuban	Sandstone and sandy claystone and shale layers
		Middle Bhuban	Shale and occasional fine grained sandstone
		Lower Bhuban	Alternations of Sandstone and shale
UNCONFORMITY			
Oligocene to Late Eocene	Barail	Renji	Dominantly sandstone with thin shale layers
		Jenam	Shale and occasional sandstone
		Laisong	Alternations of thin sandstone and shale beds
Eocene	Disang	**Disang**	Dark grey shale with thin beds of sandstone

Petroleum System:

All the oil and gas fields, discovered till date in the Assam Shelf, are situated mostly on the southeastern slope of the Brahmaputra Arch, and almost all the major oil fields like Nahorkatiya, Lakwa, Lakhmani, Geleki, Dikom, Kathaloni etc. lie in a belt bordering the Naga Thrust. In the Dhansiri valley also, oil fields like the Borholla, Khoraghat and Nambar lie in the same belt. Along the Naga Schuppen belt, oil accumulations in the Laxmijan and the Champang Oil fields occur in that zone of the Assam Shelf which is overridden by the Naga Thrust. In the Digboi and Kharsang Oil fields, oil occurs in Tipam Sandstone and Girujan formations, respectively, overlying the Naga Thrust.

Source Rock and Hydrocarbon Generation

The important source rock sequences occur within the argillaceous Kopili Formation and in the Coal-Shale Unit of the Barail Group. The average TOC of shales in the Kopili Formation is about 2.5% and in the Barail Coal-Shale Unit is about 3.8% while within the Sylhet Formation is about 0.60%, The average TOC ranges of different formations (shale samples) are as follows (**Table 3-2**):

Table 3-2: AVERAGE TOC RANGES WITHIN THE SEDIMENTARY COLUMN IN THE A&AA BASIN

Formation / Group	Average TOC Range	Remarks
Barail (shales)	2.5% to 4.5%	Excellent source potential
Kopili (shales)	1% to 3%	Excellent source potential
Sylhet Limestone	~ 0.61%	Poor source potential
Basal Sandstone	~ 0.62%	Poor source potential

Organic matter richness of shales increases towards the Naga Thrust. In both Kopilis and Barails, the organic matter is terrestrial Type-III with varying contributions of Type-II. Barail Coal-Shale Unit in the Naga Schuppen belt also form an important source rock sequence. In the Naga Schuppen belt, in addition to above, Disang shales also possess excellent source rock characteristics with TOC around 4% and VRo varying from 0.69% to 1.94%.

Geochemical analysis of exposed sediments from the Naga Schuppen belt show a TOC range of 0.64-1.20% for Barail shales. The dominant organic matter type is structured terrestrial. Presence of amorphous (upto 60%) and extractable organic matter (upto 55%) indicates a fairly good liquid hydrocarbon generating potential. Organic matter is mainly humic and sapropelic. TAI of 2.6 to 2.75 and VRo of 0.57 to 0.67% show that the sediments are thermally mature and within the oil window. In the subthrust, the source sequences occur at greater depths and, therefore, should be in a higher state of thermal maturity. It is expected that the source sequences within the Kopili Formation and Barail Group in the subthrust would be at the peak oil generating state.

Reservoir Facies

Hydrocarbon in the Assam Shelf and the Naga Schuppen Belt occurs in sandstone reservoirs ranging in age from Upper Paleocene-Lower Eocene to Mio-Pliocene. Major accumulations occur in Upper Paleocene + Lower Eocene, Oligocene (Barail Group) and Miocene (Tipam Group) sandstones. Borholla and Champang oil fields of the Dhansiri valley and in the adjacent Schuppen Zone oil also occurs in fractured granitic Basement rocks (Precambrian) and Tura sandstones (Upper Paleocene/ Lower Eocene). In the eastern and northeastern part of the Basin, prolific hydrocarbon fields are present in the Paleocene - Lower Eocene sandstone reservoirs viz. Tengakhat, Dikom, Kathaloni, Baghjan. In the Kumchai and Kharsang Fields of Arunachal Pradesh, oil occurs in the Girujan Formation of Mio-Pliocene age and prolific gas accumulations have been discovered in sandstone reservoirs of Dirok structure within Girujan Formation. In the Khoraghat oil field of Dhansiri Valley, oil occurs in sandstone reservoirs within the Bokabil Formation (Miocene). In the Tripura-Cachar belt, the Surma Group of rocks consisting of Bhuban and Bokabil Formations of Miocene age, which are primarily sandstones, constitute the major reservoir rocks.

Seal and Entrapment

There are three well developed regional cap rocks within the Tertiary sedimentary succession; the lower one, occurring in the Upper Eocene is the argillaceous Kopili Formation, the middle one is the Barail Coal-Shale Unit and the upper one, overlying the Tipam Sandstone is the Girujan Clay. Most of the oil accumulations, discovered till date in the Upper Paleocene-Lower Eocene, Oligocene (Barail) and Miocene (Tipam Sandstone) reservoirs, occur in structural combination (fold + fault) traps developed by compressive forces during Mio-Pliocene and later times.

Most of these hydrocarbon traps, particularly those developed in post- Barail sediments, orient parallel to the Naga Thrust. Faults associated with these traps in the southeasterly sloping shelf zone in the Brahmaputra and Dhansiri valleys have NE-SW to NNE-SSW orientation. Most of the prominent faults continue upwards into post-Tipam sediments, and the rest die out in the lower part of the Tipam Group. A few of the prominent faults, particularly those near the Naga Thrust, are reverse faults. It may be mentioned that oil, generated in the Kopili and Barail source beds, accumulated in post-Barail sediments by vertical migration through such prominent faults. Oil within the Kopili Formation (composed predominantly of shales with subordinate sandstone) occurs in strati-structural combination traps, as in the Geleki Field. Oil within the Girujan Clay Formation as in the Kumchai and Kharsang Fields also occurs in combination traps, but here the control of lithology on accumulation is more than that of structure. In the Borholla Field of the Dhansiri valley and Champang Field of the neighbouring Schuppen Belt, oil accumulations occur in structurally controlled subtle trap in fractured Basement rocks. Oil accumulations within the Bokabil Formation (Middle Miocene) in the Khoraghat and Nambar Fields of the Dhansiri valley, occur in structural combination traps.

In the Tripura-Cachar belt, anticlinal folds primarily serve as the traps for hydrocarbon and these structures have been forming since Miocene. Shaly facies within Bokabil, Upper Bhuban, Middle Bhuban and Lower Bhuban of the Surma Group with regional extent have acted as seals to prevent upward migration and create favourable entrapment conditions. Abnormal pressure regime in the deeper Bhubans has also created a barrier for the upward migration of hydrocarbon.

Figure 3-4 GENERALIZED STRATIGRAPHY DEPICTING PETROLEUM SYSTEM ELEMENTS OF ASSAM SHELF BASIN

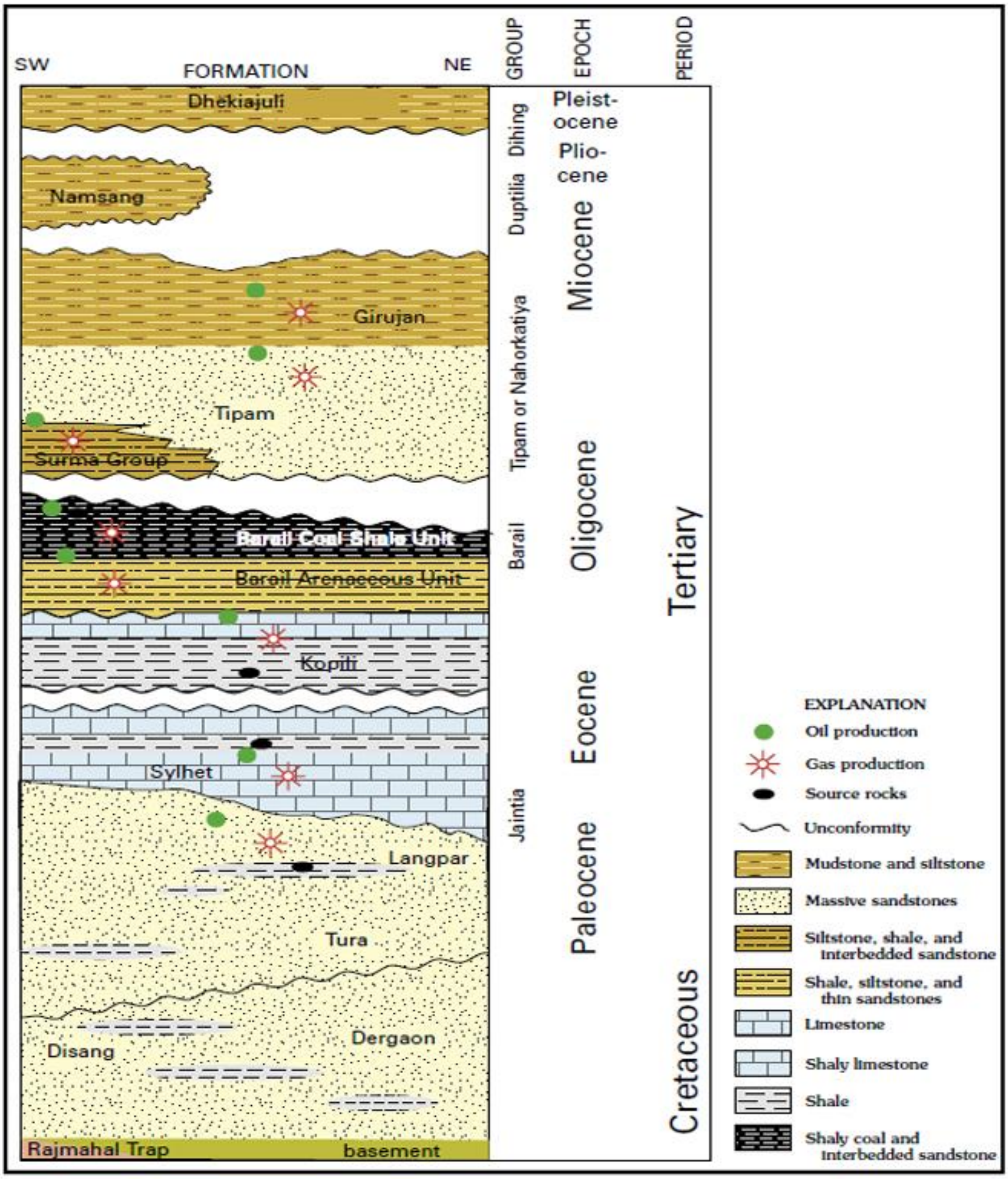
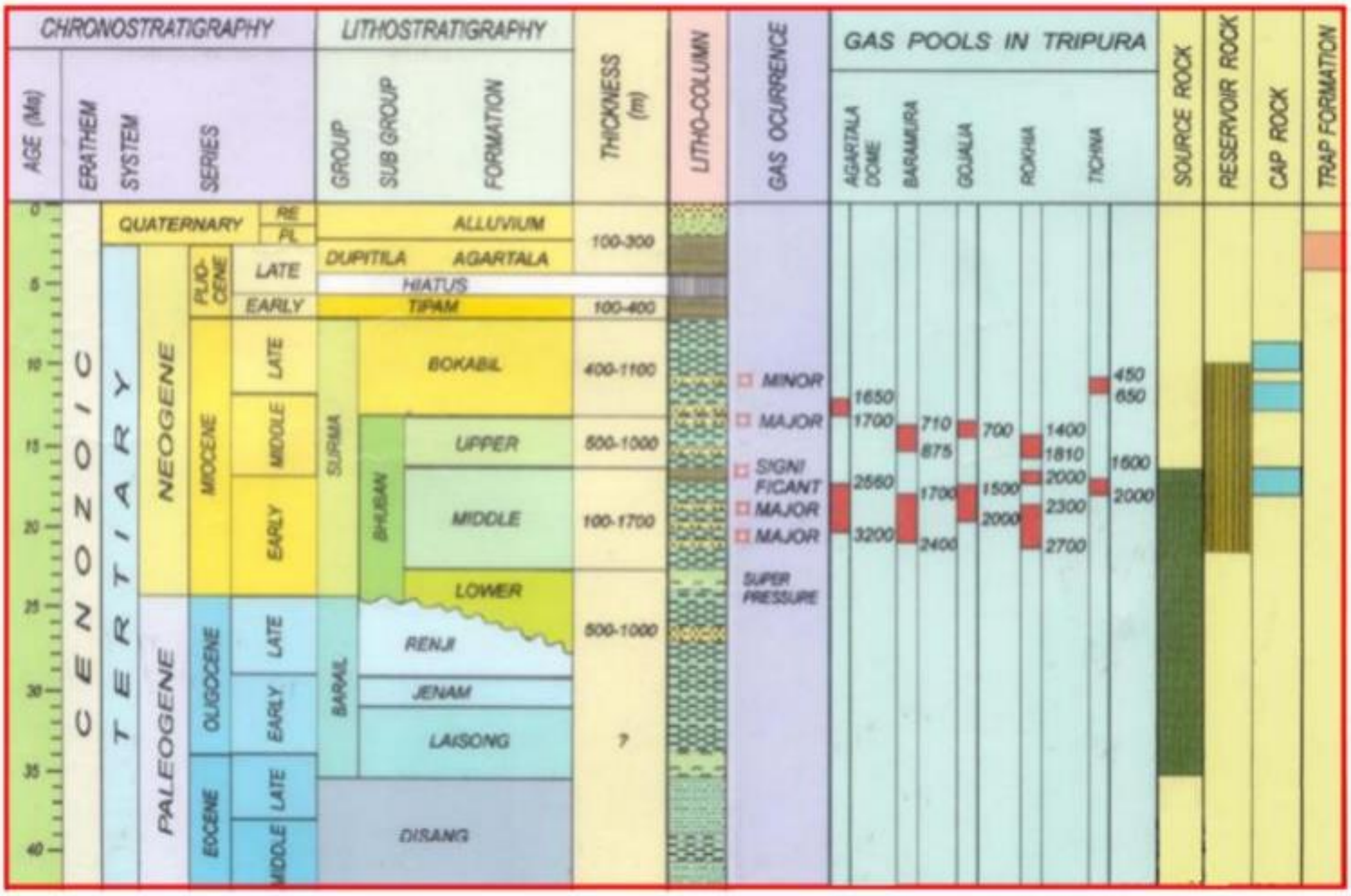


Figure 3-5 GENERALIZED STRATIGRAPHY DEPICTING PETROLEUM SYSTEM ELEMENTS OF THE AAFB BASIN



3.3 BASIN PROSPECTIVITY

The composite A&AA Basin is divided into two Category I Basins:

- The Assam Shelf Basin and
- The Assam-Arakan Fold Belt (AAFB) Basin.

The Assam Shelf Basin is spread over the state(s) of Arunachal Pradesh, Assam, Meghalaya, Nagaland and has a total hydrocarbon in-place of 2,705 MMTOE, out of which around 1,827 MMTOE has only been discovered, and this includes both commercial and sub-commercial in-place volume. The remaining 874 MMTOE, nearly 32% of total in-place is potential to be explored and discovered.

The Assam-Arakan Fold Belt (AAFB) basin has a total hydrocarbon in-place of 1,178 MMTOE, out of which around 178 MMTOE has been discovered, and it includes both commercial and sub-commercial in-place volume. The remaining 1,000 MMTOE, nearly 85% of total in-place is potential to be explored and discovered. The Basin is spread into the state(s) of Arunachal Pradesh, Assam, Manipur, Mizoram, Nagaland, Tripura.

The play-level undiscovered (risked) hydrocarbon in-place for Assam Shelf and Assam Arakan Fold Belt (AAFB) Basins is given in the Table below (**Table 3-3**):

Table 3-3: PLAY-LEVEL UNDISCOVERED (RISKED) HYDROCARBON IN-PLACE FOR ASSAM SHELF AND ASSAM ARAKAN FOLD BELT (AAFB) BASINS

PLAY	ASSAM SHELF	ASSAM ARAKAN FOLD BELT
	UNDISCOVERED (RISKED) HYDROCARBON IN-PLACE	
Cenozoic Pliocene (Girujan):	1 MMTOE	
Cenozoic Pliocene (Tipam):		124 MMTOE
Cenozoic Miocene (Tipam):	215 MMTOE	
Cenozoic Miocene (Bokabil):		191 MMTOE
Cenozoic Miocene (Upper Bhuban)		187 MMTOE
Cenozoic Miocene (Middle Bhuban)		292 MMTOE
Cenozoic Miocene (Lower Bhuban)		117 MMTOE
Cenozoic Oligocene (Barail Coal Shale):	192 MMTOE	
Cenozoic Oligocene (Barail Main Sands)	242 MMTOE	
Cenozoic Oligocene (Renji):		78 MMTOE
Cenozoic Eocene (Disang)		11 MMTOE
Cenozoic Eocene (Kopili)	46 MMTOE	
Cenozoic Eocene (Sylhet):	67 MMTOE	
Cenozoic Early Paleocene (Tura)	102 MMTOE	
Archean Basement:	9 MMTOE	

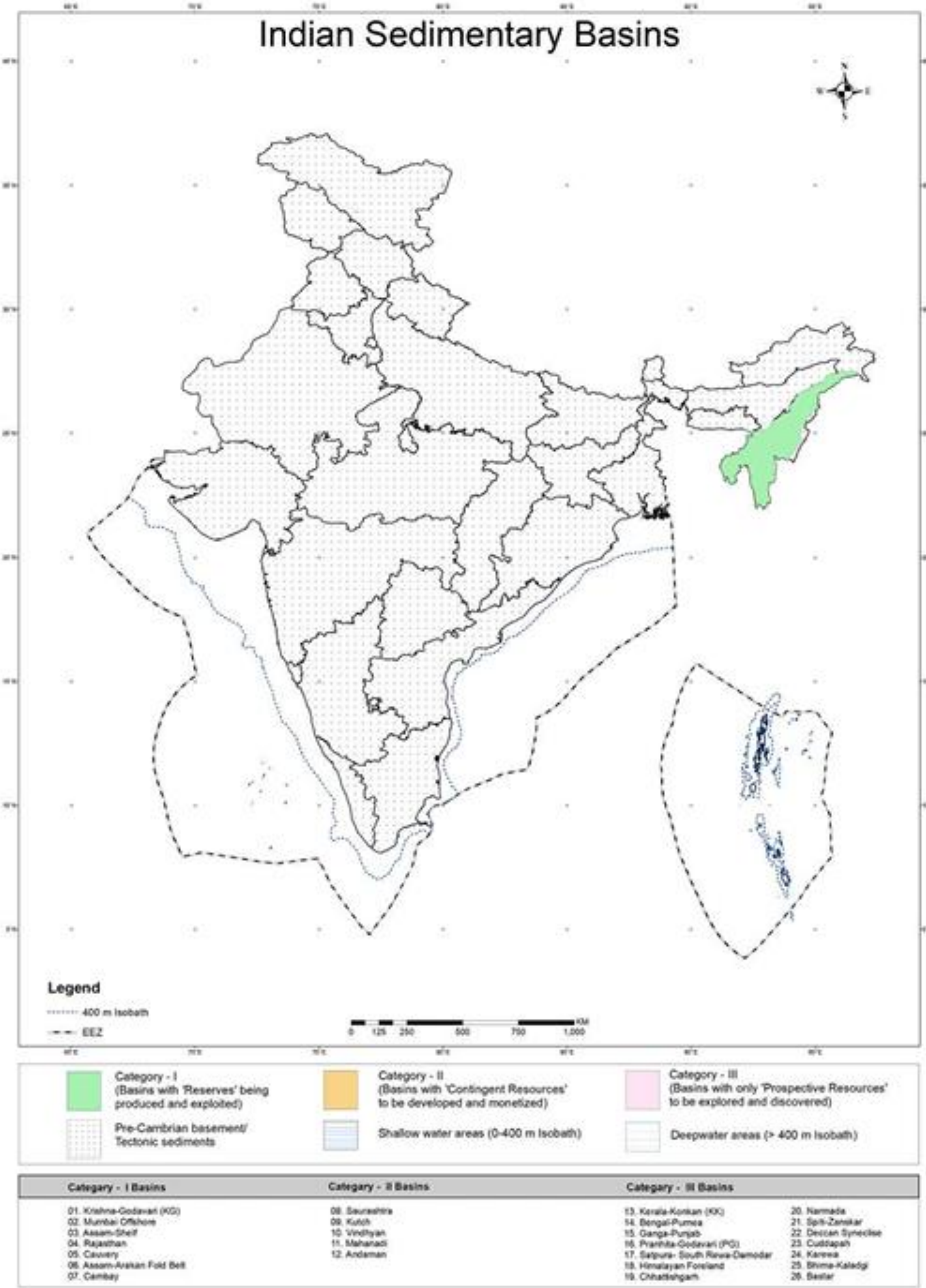
3.4 OPPORTUNITIES IN THE BASIN

The Assam Shelf and Assam Arakan Fold Belt (AAFB) Basins had been assessed earlier during a 1995-96 study under the aegis of the Directorate General of Hydrocarbons (DGH) along with 14 other sedimentary basins of India (**Figure 3-6**). In 2017, during a subsequent Hydrocarbon Resource Assessment Study, 3D PSM and Aerial Yield have been used based on the merit of adequate datasets. The 2017 resource reassessment study has incorporated 2,723 LKM of 2D seismic data, 10,995 SKM of 3D seismic data, 275 drilled well information from the Assam Shelf Basin and 15,000 LKM of 2D seismic data, 1,400 SKM of 3D seismic data, 317 drilled well information from the AAFB.

The Assam Shelf Basin is fairly explored with good seismic coverage. Geochemical, 2D/3D seismic, well data and reports are excellent while gravity data is good and magnetic data are fair. Reliability of results is excellent. 3D PSM and Trap Density method have been used to assess hydrocarbon resources due to good quality data existing throughout the basin. A major challenge is that mature source rocks lie below the thrust belt. Naga Thrust belt is the future focus for exploration. Shallow play near Naga-Schuppen belt are good targets for exploration

In the Assam Arakan Fold Belt basin gravity, well data and reports are good while magnetic, geochemical and 2D/3D seismic data are fair. Data availability is better in the Tripura-Cachar area while it is poor in rest of the basin. Reliability of results is good. 3D PSM and Trap Density method have been used in some parts to assess hydrocarbon resources due to fair data and conceptual information has been used in the rest of the basin. There is inadequate coverage of data in major part of the basin. The fact that structural traps primarily formed since Miocene, sequential restoration and migration of Thrusts is a focus area.

Figure 3-6 : REFERENCE SEDIMENTARY BASIN



4. DISCOVERY AND FIELD DESCRIPTION

The information docket is presented in a manner that each oil/gas discovery (i.e. the field) is described along with other wells, drilled and/or tested in the Contract Area. The available information of geo-scientific and engineering findings, studies and interpretations are sequentially showcased and in process, all subsurface and surface data from drilling, logging, testing and production data have been collated. Reservoir studies wherever available have been described with facts. Geological interpretations are suitably illustrated through correlations, sections and maps to bring in subsurface picture of the Contract Area. In the end, discovered hydrocarbon in-place and its recoverable contingent resources (wherever available) have been given with parameters and range of estimates.

For the sake of continuity in reading, domain contents like drilling, logging, testing, reservoir studies and geology, each field is described domain-wise into comprehensive illustration of all constituent wells and reservoirs in one go. For example, when a Contract Area has more than one discovery/field, each such discovery/field starts with a new page describing key information pertaining to drilling, logging, testing and other subsurface details.

Emphasis is given on factual presentation of data and available information on interpretations and results. Figures and pictures are extensively used for illustrations to establish a preliminary basis for field understanding and contents of data. As outlined under the disclaimer, all information contained in this report are made available by NOCs and Contractors through their specific submissions.

AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN-BIHUBAR BLOCK

4.1 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN-BIHUBAR BLOCK

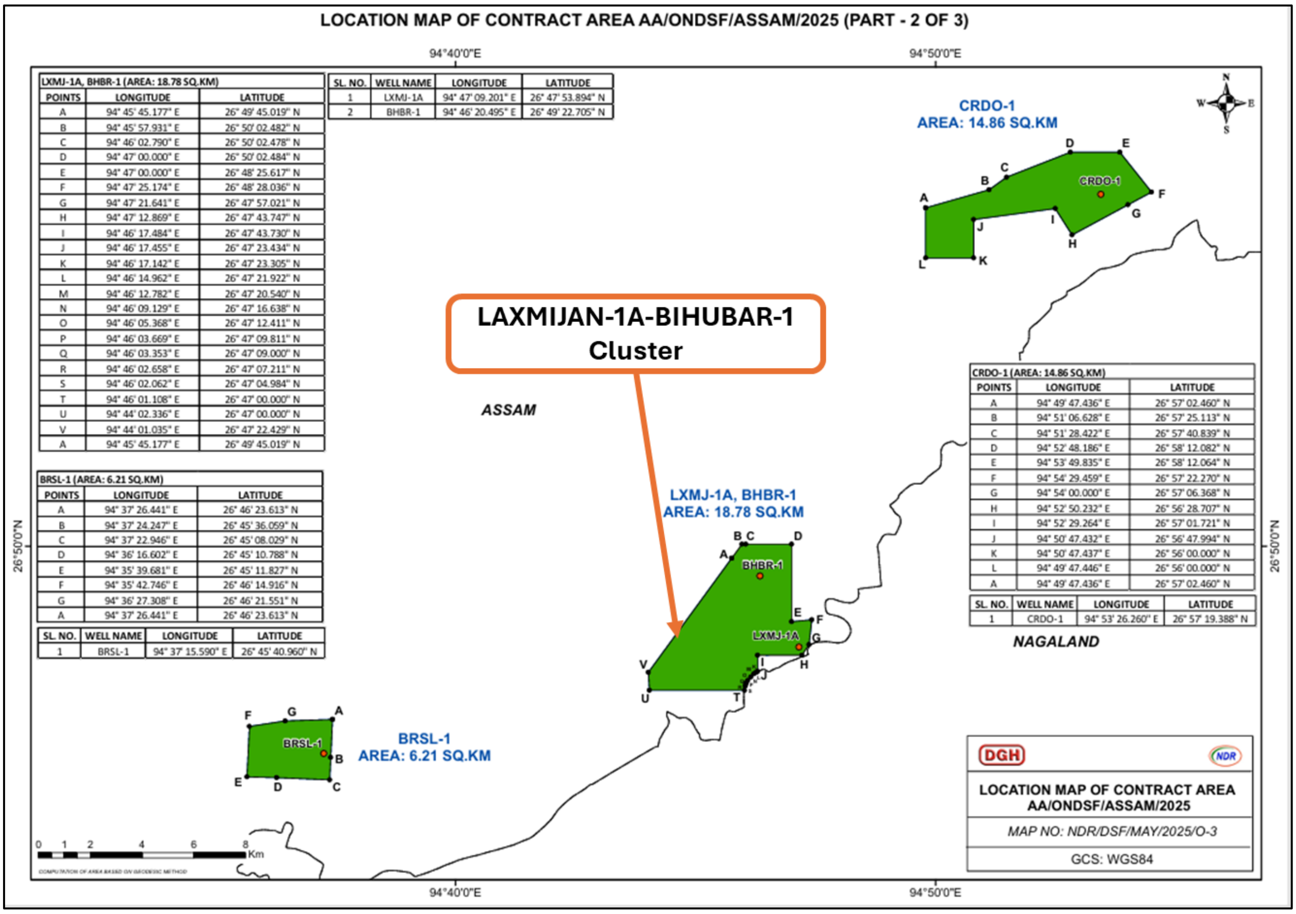
The Laxmijan-Bihubar block is located in the Assam Shelf area of the Category I composite Assam & Assam-Arakan Basin (A&AA Basin) at approximately 9-9.5 km E and ENE of the prolific onland Geleki Field within the state of Assam situated in the Assam Shelf area of the Assam & Assam Arakan Basin (A&AA Basin) in the northeast corner of India. The Bihubar Field is adjacent to the Laxmijan Field and lies to the north of it.

Laxmijan Field along with the neighbouring Bihubar Field together (**Figure 4-1**) covers an area of 18.78 sq. km under this DSF Bid Round IV. The co-ordinates of the endpoints defining the cluster boundary are tabulated below in **Table 4-1.** The area is a single area with 2 discoveries/fields (LXMJ-1A & BHBR-1) and 6 additional wells (including 1 S/T and 1 incomplete) have been drilled.

Table 4-1: COORDINATES OF BLOCK BOUNDARIES: LAXMIJAN-BIHUBAR CLUSTER

	Laxmijan-Bihubar Boundary Points		
	Area: 18.78 sq km		
	POINTS	**LONGITUDE**	**LATITUDE**
	A	94° 45' 45.177" E	26° 49' 45.019" N
	B	94° 45' 57.931" E	26° 50' 02.482" N
	C	94° 46' 02.790" E	26° 50' 02.478" N
	D	94° 47' 00.000" E	26° 50' 02.484" N
	E	94° 47' 00.000" E	26° 48' 25.617" N
	F	94° 47' 25.174" E	26° 48' 28.036" N
	G	94° 47' 21.641" E	26° 47' 57.021" N
	H	94° 47' 12.869" E	26° 47' 43.747" N
	I	94° 46' 17.484" E	26° 47' 43.730" N
	J	94° 46' 17.455" E	26° 47' 23.434" N
	K	94° 46' 17.142" E	26° 47' 23.305" N
	L	94° 46' 14.962" E	26° 47' 21.922" N
	M	94° 46' 12.782" E	26° 47' 20.540" N
	N	94° 46' 09.129" E	26° 47' 16.638" N
	O	94° 46' 05.368" E	26° 47' 12.411" N
	P	94° 46' 03.669" E	26° 47' 09.811" N
	Q	94° 46' 03.353" E	26° 47' 09.000" N
	R	94° 46' 02.658" E	26° 47' 07.211" N
	S	94° 46' 02.062" E	26° 47' 04.984" N
	T	94° 46' 01.108" E	26° 47' 00.000" N
	U	94° 44' 02.336" E	26° 47' 00.000" N
	V	94° 44' 01.035" E	26° 47' 22.429" N
	A	94° 45' 45.177" E	26° 49' 45.019" N
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	LXMJ-1A	94° 47' 09.201" E	26° 47' 53.894" N
2	BHBR-1	94° 46' 20.495" E	26° 49' 22.705" N

Figure 4-1: LOCATION MAP SHOWING THE LAXMIJAN-BIHUBAR BLOCK BOUNDARY.



A thin veneer of alluvium overlies sediments of the supra-Thrust Tipam Group and the area has an average elevation of around 120 m above MSL. The field is approachable by metalled road connected to National Highways NH 2 (erstwhile NH 37) and NH 702C. The nearest railway station is Simaluguri Junction and the nearest airport is Jorhat, about 70 kms from neighbouring Nazira Town.

The Laxmijan-Bihubar cluster Fields lie along the Naga Schuppen Zone of the Assam Shelf area in the Assam & Assam-Arakan Basin along which a number of prolific oil and gas fields are present (**Figure 4-2**).

The adjacent lying Laxmijan and Bihubar Fields have been covered by 2D seismic surveys of different vintages and part of 11 seismic lines amounting to 18.68 GLK cover both the areas. A 39.60 SKM of 3D seismic volume viz. GELEKI_PSDM_SCALE_TO_TIME covering the area and was processed by merging multiple 3D datasets, is available for the area. A seismic grid map showing the 3D coverage and 2D lines across the Block is shown **Figure 4-3**

Figure 4-2: DISTRIBUTION OF THE OIL AND GAS FIELDS ALONG THE NAGA THRUST of ASSAM SHELF BASIN

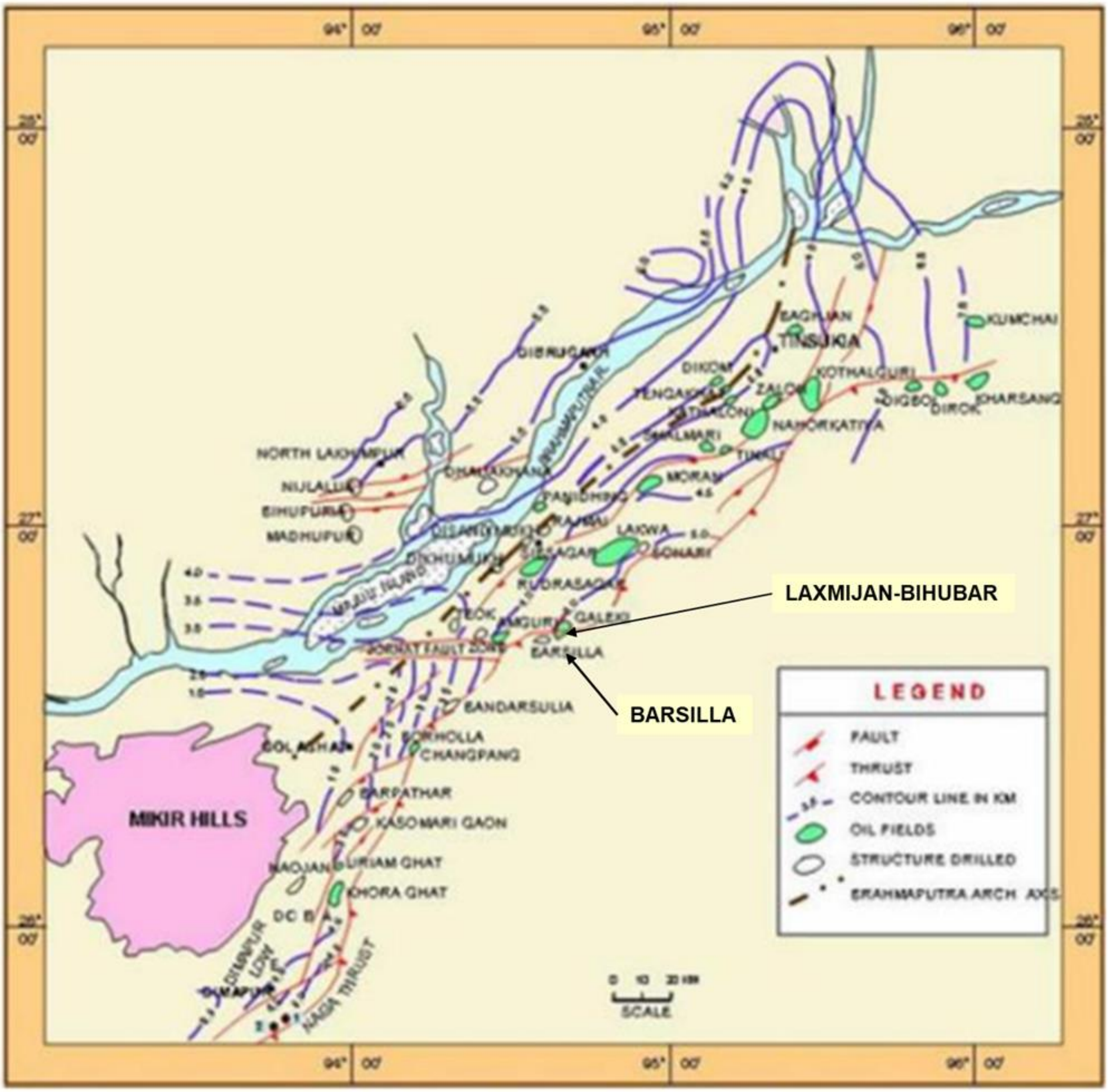
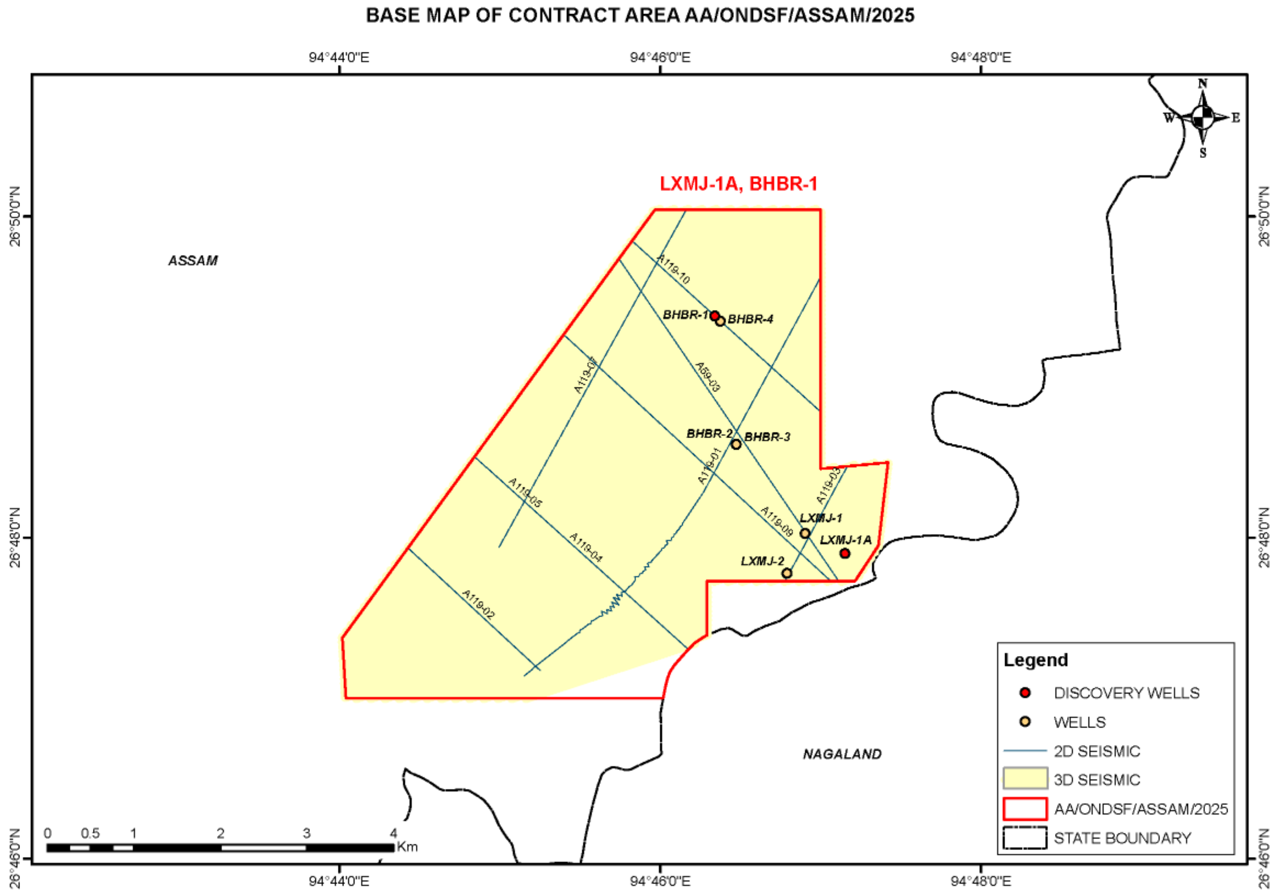


Figure 4-3: 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: LAXMIJAN-BIHUBAR



AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN FIELD

4.2 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN FIELD

The Laxmijan Field was discovered by ONGC in 1985 with the drilling of well Laxmijan-1A (LXMJ-1A) which proved to be hydrocarbon bearing in the sub-Thrust Tipam Group of Miocene age. The well produced around 10 cum of oil from the TS-5A Sand during initial testing and produced around the same quantity of oil during a workover job in the year 2007. A total of 2 exploratory wells viz. Laxmijan-1A (LXMJ-1A) and Laxmijan-2 (LXMJ-2) were drilled and completed by ONGC in a drilling campaign between 1979 and 2000 in the Laxmijan Field of the Contract Area of which well LXMJ-1A was completed as a replacement well for the well Laxmijan-1 (LXMJ-1). The available details of the well Laxmijan-1 (LXMJ-1), which was an incomplete well with only the conductor stage being drilled, however are mentioned in the following paragraphs. Laxmijan Field has been recognized as a marginal field. The main pay are the TS-5A1, TS-5A2 and TS-5B sands of Miocene age.

4.2.1 Drilling and well completion

As stated earlier, two exploratory wells have been drilled in this field, viz., Laxmijan-1A and Laxmijan-2, along with a part well (Laxmijan-1) of which drilling had to be terminated at a shallow depth. Key information of the drilled wells has been collated and presented in the tables hereunder. The adjoining figures illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

Well construction diagrams of wells, Laxmijan-1A and Laxmijan-2 are shown in **Figure 4-4**. General details of the drilled wells and their casing data are given in **Table 4-2 and Table 4-3** below:

Table 4-2: LAXMIJAN FIELD - GENERAL WELL DETAILS

Well	Laxmijan-1	Laxmijan-1A	Laxmijan-2
Area	Nazira, Assam		
Structure	Laxmijan		
Category	Exploratory	Exploratory	Exploratory
Co-ordinates	Lat: 26°47’40”	Lat:26°27’40”	Lat:26°47’44”
	Long: 94°46’30”	Long: 94°47’40”	Long: 94°47’00”
Rig	3DH	3DH-IV (Romanian type)	E-2000-IX & E-2000-VII
Target Depth	4500 m	4500 m	4850 m
Drilled Depth	1152.60 m	4479 m	4760 m
Objective	Tipam & Barail Sands	Tipam & Barail Sands	Barail Sands
Status	Abandoned due to unrecovered fish in hole (drillstring and BHA)	Discovery well. Could not be brought onto commercial production at that time due to poor cementation behind casing, nature of crude and lack of testing accessories in time. Well has been killed.	Abandoned as zones tested / interpreted to be water bearing with minor traces of oil.

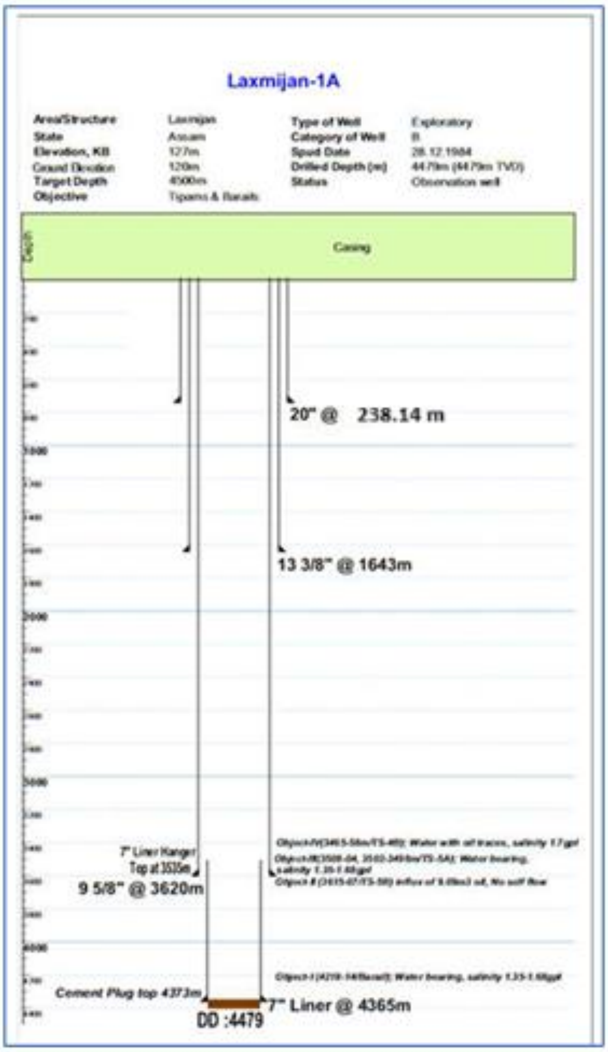
KB	126.70 m	127 m	128.0 m
Spud date	08-01-1979	20-12-1984	22-03-1997
Drilling Completion	16-03-1979	23-03-1986	11-10-2000
Production testing Completion	No production testing	25-08-1986	25-12-2000
Rig release	NA	25-08-1986	31-12-2000

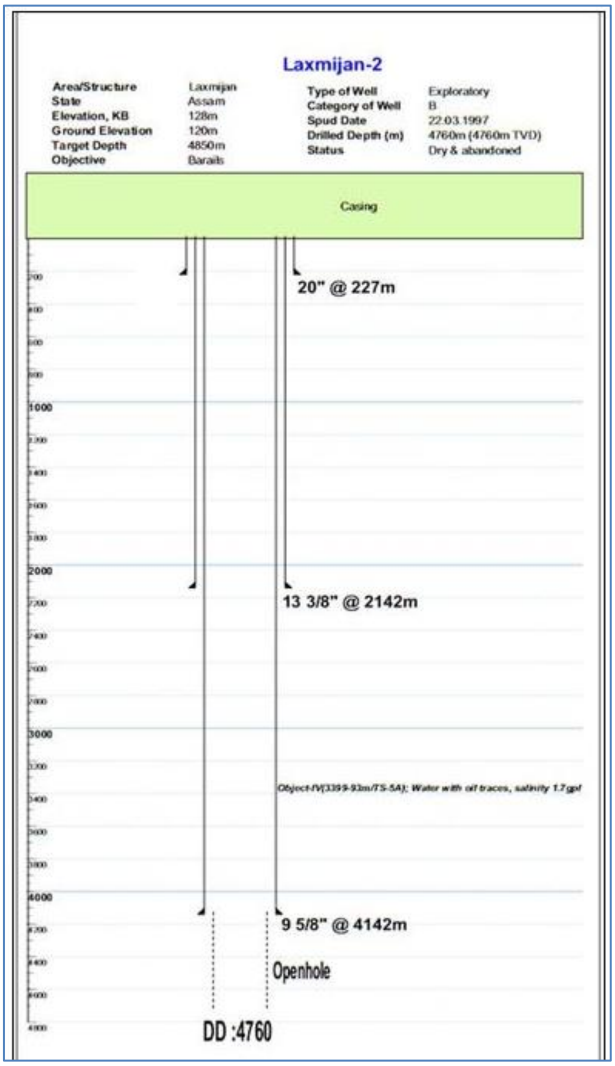
NA = Data not available

Table 4-3: LAXMIJAN FIELD - CASING DETAILS

Well	Hole Size	Casing Size	Cement Rise from Surface	Casing Shoe Depth (m)
Laxmijan-1	. 36 “	30”	Surface	21.16 m
	Other casings were not lowered due to repeated unsuccessful attempts at recovery of Fish (Drill string and BHA), following which the well was abandoned at a well depth of 1152.6 m			
Laxmijan-1A	36 “	30 “	NA	30 m
	26 “	20 “		238.4 m (short landed)
	18 ½ “	13 3/8 “		1643.4 m
	12 ¼ “	9 5/8 “		3620 m
	8 ½ “	7 “		4365 m
	6”	Casing not lowered		
Laxmijan-2	26 “	20 “	Surface	227
	17 ½ “	13 3/8 “	Not Logged	2142
	12 ¼ “	9 5/8 “	-	4142
	8.1/2”	Casing not lowered		

Figure 4-4: WELL CONSTRUCTION DIAGRAM OF WELLS LAXMIJAN-1A &2





4.2.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.2.2.1 Reports availability

The following reports are available for Laxmijan Field (**Table 4-4**).

Table 4-4: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Laxmijan-1	126.7m	08-01-79	1152.60 m	Available	Not Available
Laxmijan-1A	127m	20.12.1984	4479 m	Available	Available
Laxmijan-2	128m	22.03.1987	4760 m	Available	Available

4.2.2.2 Well logs acquired (Laxmijan Field):

Log suites recorded in Laxmijan-wells are given in **Table 4-5 and Table 4-6.** Core data recorded in the wells are given in **Table 4-7**.

Table 4-5: LOG SUITES RECORDED

Well No.	Type of log	Interval (m)
Laxmijan-1	STANDARD Caliper-Induction	90-804
Laxmijan-1A	DIL-GR-SP	31-682.7, 650-724.5,
	Inclinometer	240-1070, 500-1379, 500-635
	DIL-GR-Inclinometer	650-1457
	DIL-SP-GR-Caliper-XY Inclinometer	500-1650
	LSS	240-1650
	DIL-BCS-CDL-CNS-GR-SP-CAL	1632.9-2704.7, 3623-4107.5
	DIL-BCS-GR-SP-CAL	2700 – 3652, 4000-4365
	MEL-GR	3390- 3640
	CAL	2700-3220
	DIPMETER	1000-2100, 2500-3080, 3470-3524, 3539-3651
	NGS-LSS	2700-3657
	CDL-CNS-GR-CAL	3422-3651, 3148-3216
	DIL-HDT	4090-4367, 3625-4365
	CBL-VDL-CCL-NEUTRON	3345-4360
Laxmijan-2	DLL-GR-SP	226-2147
	DLL-MSFL-CAL-GR-SP	2141 – 3597, 3590-4137
	BCS-GR	226-2140, 2141-3597, 3590-4144.8,
	SWC-GR	2197-3767
	DSLC(SDDB)-GR	4144-4757
	AIT-MCFL-GR-SP	4144 – 4646.5

	TLD-HGNS-GR	4144 - 4757
	CBL-VDL-CCL-GR	3098-3990

Table 4-6: WIRELINE LOGS ACQUIRED

Well	Hole Size	Details of Logs recorded
Laxmijan-1	18.1/2”	Standard logs, Induction and Caliper was recorded on 19/20.02.1979 at a well depth of 800 m
Laxmijan-1A	26”	DIL-GR-SP-CAL logs recorded on 12.02.1985 at well depth of 682.7 m
		DIL-GR logs recorded on 17.02.1985 at well depth of 724.7 m
	18.1/2”	Inclinometer Survey recorded on 08.03.1985 at a well depth of 1104.0 m
		Inclinometer Survey recorded on 18.03.1985 at a well depth of 1300.0 m
		DIL-GR and Inclinometer Survey recorded on 23.03.1985 at a well depth of 1457.0 m
		Inclinometer Survey recorded on 09.06.1985 at a well depth of 639.0 m
		DIL-SP-GR-CAL and Inclinometer survey recorded on 20/21.07.1985 at a well depth of 1650.0 m
		LSS-GR logs recorded on 21.07.1985 at well depth of 1650.0 m
	12. 1/4”	DIL-SP-CAL, BCS-GR and CDL-CNS logs recorded on 30/31.08.1985 at a well depth of 2801.5 m
		DIL-SP-CAL-BCS-GR, MEL-GR-CAL, Dipmeter and BCS-GR logs recorded on 10 to 14.10.1985 at a well depth of 3634.0 m
	8.1/2”	DIL-SP-BCS and CDL-CNS-GR logs recorded on 16.11.1985 at a well depth of 4100.0 m
		DIL-SP-CAL-BCS-GR logs recorded on 30/ 31.12.1985 at a well depth of 4362.0 m
		CNL-HDT logs recorded on 01.01.1986 at a well depth of 4362.0 m
		A cased hole CBL-VDL-CCL-Neutron-GR survey was recorded on 23.03.1986 for 7” Liner.
Laxmijan-2	17. 1/2”	17.5” | DLL-GR-SP and BHC-GR logs recorded on 20.05.1997 at a well depth of 2150 m
	12. 1/4”	DLL-MSFL-CAL-GR and BHC-GR logs were recorded on 18.07.1997 and 19.07.1997 respectively at a well depth of 3599 m
		DLL-MSFL-CAL-GR, BHC-GR logs and CST-GR (SWC) were recorded from 25.08.1997 to 26.08.1997 at a well depth of 4142 m
		MDT with Pretest in 30 points. A sample was collected at a well depth of 4152 m within the Barail BCS. 1/2 litre of muddy water was collected and the resistivity of the sample was found to be 0.626 ohm-rn, salinity of the sample was 4.5 gm/lit. Salinity of mud filtrate 14.62 grn/lit
	8.1/2”	AIT-MCFL-GR-SP and DSLC (SDDB)-GR logs recorded on 10.07.2000 at a well depth of 4650 m
		AIT-MCFL-GR-SP and TLD-HGNS-GR logs recorded from 13.10.2000 to 14.10.2000 at a well depth of 4760 m
	A cased hole CBL-VDL-CCL-GR log was recorded inside the 9.5/8” casing on 23.10.2000.	
	VSP survey carried out from 27.10.2000 to 31.10.2000	

Table 4-7: CONVENTIONAL CORES

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Lakshmijan-1	CC-1	777.57-783.57 m	32 %	Sandstone

Laxmijan-1A	CC-1	3464-3472 m	75 %	Mostly Sandstone

VSP DATA

Zero offset VSP was carried out from 27.10.2000 to 31.10.2000 in the well Laxmijan-2. Recording detail are given below in **Table 4-8.**

Table 4-8: VSP RECORDED IN WELL LAXMIJAN-2

Type of VSP	Offset distance in	Depth logged interval	Receiver Interval	No. of levels
ZVSP	70 m	4000-400	25	145

4.2.2.3 Well log evaluation and initial test results (LAXMIJAN FIELD):

A petrophysical study carried out on the well LXMJ-1A located within the Laxmijan Field indicate the Barail sands both in the supra-Thrust and sub-Thrust sections to have high water saturation (80-100%) with average porosity to be around 10%.(**Figure 4-5**) The Tipam sands, except for the TS-5 sand, mostly on an average show high water saturation (80-100%) but with better porosity in the average range of 15-20%. The TS-5 Tipam sand in the range 3485 – 3525 m show water saturation of 40-60% with porosity of 13 – 16% but gradually the saturation increases downwards to 75-100% with porosity being largely consistent.

Petrophysical study carried out in well LXMJ-2 indicated the supra-Thrust and sub-Thrust Barails to be water bearing. TS-1, TS-2, TS-3, TS-5, TS-6 and Safrai sands also have been interpreted to be water bearing. In the Girujans a few sand intervals were seen to be interesting from a hydrocarbon point of view. MDT survey conducted at 4228.5 – 4232.0 m of the well indicated the mobility in the range to be low (0.1 – 1.6 md/cp) and gradient plot showed more than 1.0 gm/cc indicating the presence of water. In the range 4300 – 4303 m, low mobility (0.1 to 0.2 md/cp) was also observed. The gradient plot indicated the presence of water.

The main pay of the Laxmijan structure is the, TS-5A1, TS-5A2 and TS-5B of Miocene age. Testing of the TS-5A zone in the ranges 3504-3508 m & 3498-3502 m with additional perforations in the ranges 3514-3520 m & 3492-3498 m produced around 10 cum of oil during initial testing in well LXMJ-1A in 1986 and produced almost the same quantity of oil during a workover job in 2007.

Figure 4-5: PETROPHYSICAL RESULTS OF PROSPECTIVE ZONES IDENTIFIED IN LAXMIJAN WELLS

Well	Object	Sand	Porosity %	Sw %
Laxmijan-1A	Obj-I	BCS	6-11	80-100
	Obj-II	TS-5	13	48-70
	Obj-III	TS-5	15	50-60
Laxmijan-2	Obj-I	TS-5	12	NR

Log motifs for tested Objects of Laxmijan-1A and Laxmijan-2 are shown in **Figure 4-6, Figure 4-7, Figure 4-8, Figure 4-9, Figure 4-10 and Figure 4-11.**

Figure 4-6: LOG MOTIF OF OBJECT-I (BCS) IN WELL LAXMIJAN-1A

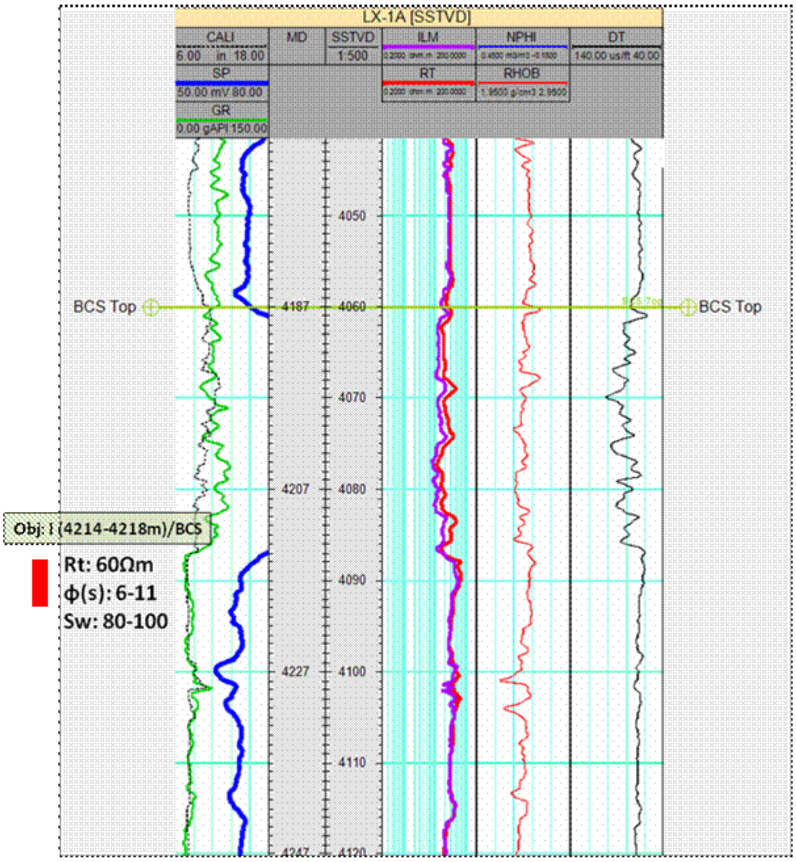


Figure 4-7: LOG MOTIF OF OBJECT-II (TS-5B) IN WELL LAXMIJAN-1A

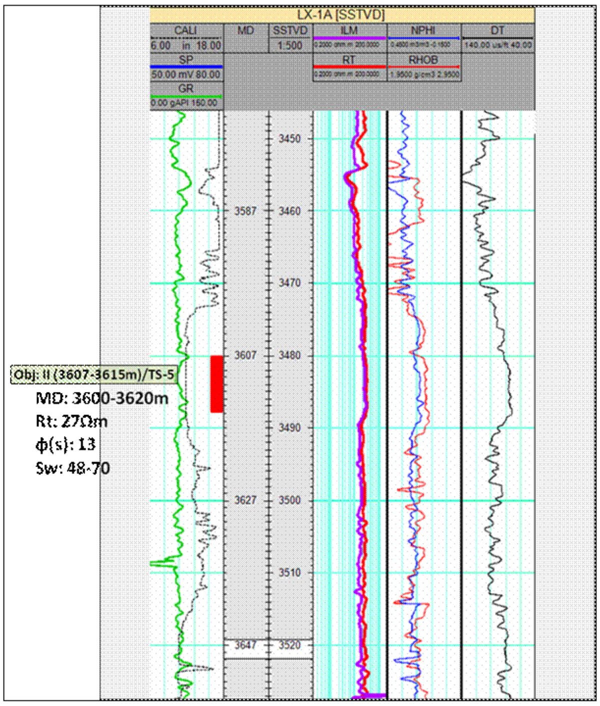


Figure 4-8: LOG MOTIF OF OBJECT-III (TS-5A) IN WELL LAXMIJAN-1A

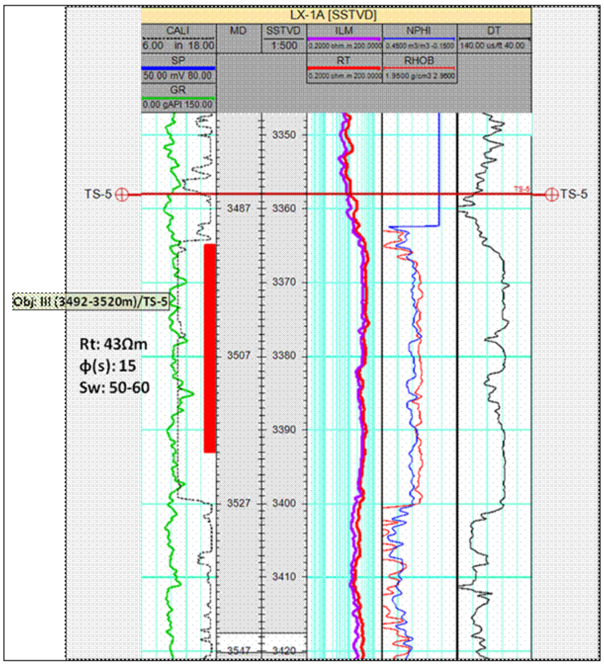


Figure 4-9: LOG MOTIF OF OBJECT-IV (TS-4B) IN WELL LAXMIJAN-1A

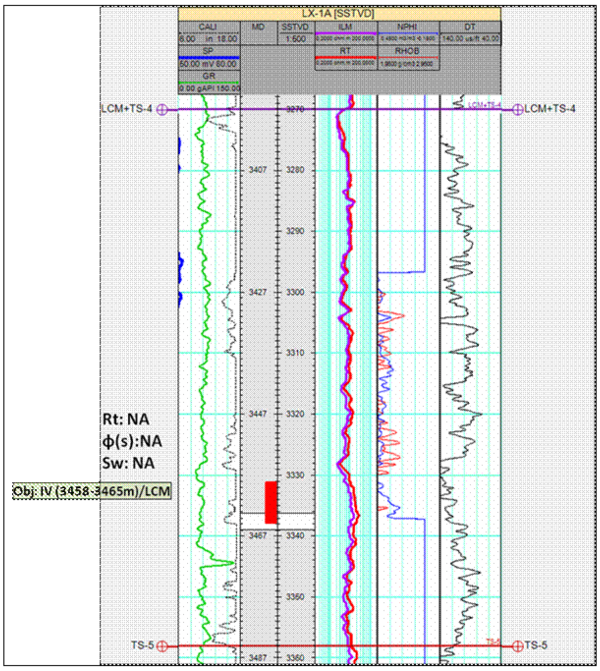


Figure 4-10: LOG MOTIF OF OBJECT-II, III & IV IN WELL LAXMIJAN-1A

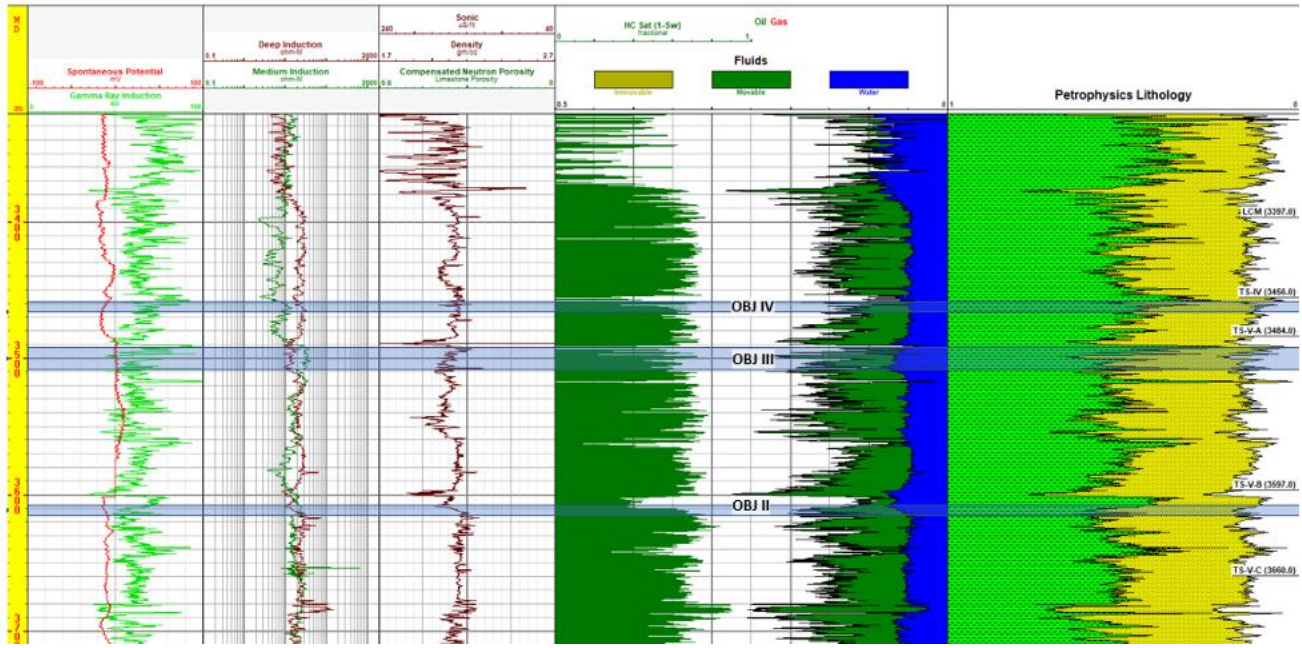
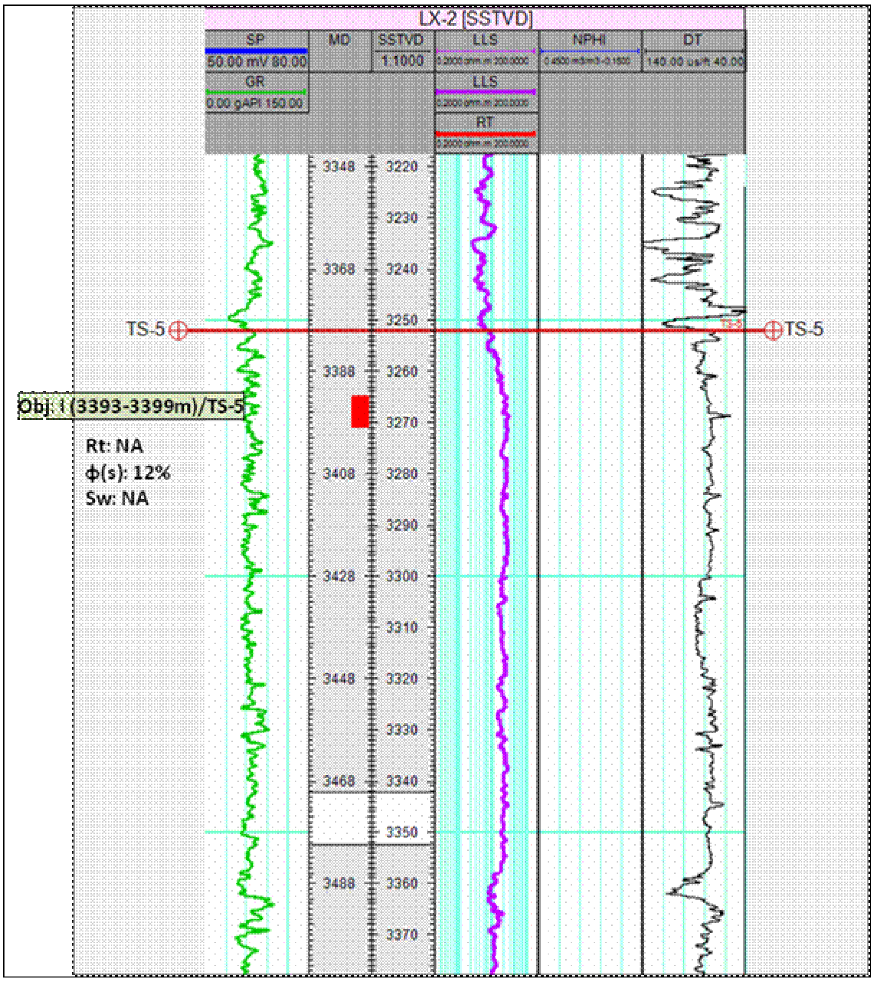


Figure 4-11: LOG MOTIF OF OBJECT-I (TS-5) IN WELL LAXMIJAN-2



4.2.3 Well testing and workover history

After the termination of drilling in well LXMJ-1 due to downhole complications, the replacement well LXMJ-1A was extensively tested.

Production testing has been carried out in wells LXMJ-1A and LXMJ-2. In well LXMJ-1A four zones have been tested, one zone in the Barail Group and three in Tipam sands of Miocene age whereas only one zone has been tested in well LXMJ-2. Detailed testing results are given in **Table 4-9.**

Table 4-9: DETAILED TESTING RESULTS OF LAXMIJAN WELLS

Well	Object	Sand	Perforation	Test Type	Flow Test Results	Status
Laxmijan-1	While drilling, drill-cuttings showed continuous golden yellow patchy fluorescence between 635 to 835 m. OH DST was carried out for the interval 793 – 797.7 m (supra-Thrust Tipam) and during which there was influx of 10 cum of water. The test was inconclusive as the chart appeared to show choking. Drilling continued but the well had to be abandoned due to unrecovered fish in hole. The well was abandoned at a depth of 1153.6 m.					
Laxmijan-1A	Obj-I	BMS	4214 – 4218 m using HSC charges @ 12 SPM	CHDST Packer set at 4174 m	No self-flow. Influx 9.27 cum of water with traces of hydrocarbon Salinity 1.35-1.68 gm/l. Final shut-in pressure = 392 ksc. ksc Plugged Back (CP).	Water bearing
	Obj-II	TS-5B	3607-3615 m using HSC charges @12 SPM	CHDST Packer set at 3535 m	No self-flow. Influx 9.16 cum of water. Salinity 1.07-1.35 gm/l. Final shut-in pressure = 361.6 ksc. Plugged Back (CP).	Water bearing
	Obj-III	TS-5A	3504-3508 m & 3498-3502 m using HSC charges @12 SPM Additional perforation 3514-3520 m &3492-3498 m using HSC charges @12 SPM (after cement job)	Conventional Testing	**No self-flow. Influx of 45m3 (10.0 cum crude oil of API gravity 31 deg** during subduing the well with mud of sp.gr 1.17 before cement repair job). Subsequently a gradient survey indicated oil upto 1060 m. Then a cement repair job was decided to be carried out. While subduing the well with mud of sp.gr 1.17 for the job, oil surfaced (10 cum crude oil of API gravity 31 degree) followed by water (salinity 2 gm/ l) After cement repair job and perforations 48 cum of influx was reported. Collected sample of oil / emulsion consisted of associated water (sal 1.92 gm/l) and oil of API gravity 28.6. While subduing the well for testing the next horizon, oil surfaced again.	Oil (Tested) Flow did not sustain possibly due to poor cementation behind casing that could not be repaired even after cement repair job. Well was subdued by placing a saline cushion of 300 m
	In 2007, Assam Company Limited carried out a Workover Operation wherein the TS-5 Sand was retested after a cement squeeze job. The test re-established the presence of oil and gas in the Sand with dominating quantity of water (~70%).					
	Obj-IV	TS-4B	3458-3465 m using PA-85	CHDST	No self-flow. Influx: 3.5 m^3 water (Sal 1.9-4.32 gm/l). However during	Water bearing

			charges @21 SPM		P/O influx of water with traces of oil was observed. Well was killed by placing a saline cushion of 300 m	
Laxmijan-2	Obj-I	TS-5A	3393-3399 m using 7” gun @ 18 SPM	CHDST	Conventionally tested in water. Poor influx. LL found at 700 m, salinity 1.17 gm/l (Technical water 0.39 gm/l) with **traces of oil** observed in sample. During the gradient survey the average gradient was 1.02 and formation pressure was recorded to be 271 ksc. The well was subdued with 1.15 sp. Gr. of mud	Water bearing with traces of oil

4.2.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/results.

Formation dynamic tests (LAXMIJAN FIELD)

MDT pressure tests recorded in LAXMIJAN wells are given in **Table 4-10 below.**

Table 4-10: AVAILABLE MDT PRESSURE DATA FROM WELL LAXMIJAN-2

Sl. No.	Horizon	Depth (m)	Hydrostatic Pressure (Psi)	Formation Pressure (Psi)	Test type
1	BCS	4151.48	8448.86	6066.42	Normal test
2	BCS	4152.00	8437.22	6066.78	Normal test
3	BCS	4152.01	8401.71	6067.02	Normal test
4	BCS	4153.00	8429.10 '	6067.69	Normal test
5	BCS	4154.00	8401.08	6068.82	Normal test
.6	BCS	4154.99	8400.37	351.67	Dry Test
7	BCS	4171.49	8428.34	15097.28	Normal test
8	BCS	4169.98	8420.40	15092.80	Normal test
9	BCS	4172.50	8422.20	6096.34	Norma! test
10	BCS	4173.98	8422.20	6091.39	Normal test
11	BCS ___	4175.01	8422.11	6092.82	Normal lest
12	BCS	4180.98	8431..86	6101.42	Normal test
13	BCS	4181.99	8430,37	6102.87	Normal test
14	BCS	4182.99	8426.11	6104.78	Normal test
15	BCS	4185.48	8429.35	6107.22	Normal test
16	BCS	4186.00	8426.36	6107.98	Normal test
17	BCS	4187.50	8427.10	6110.05	Normal test
18	BCS	4228.50	8516.08	6269.58	Normal test
19	BCS	4228.99	8510.05	6235.94	Normal test
20	BCS	4229.50	8508.17	3709.93	Dry Test
21	BCS	4230.50	8507.52	6219.77	Normal test
22	BCS	4231.00	8504.87	2845.57	Dry Test

No Pressure Transient and reservoir studies have been carried out in the field

PVT DATA INCLUDING CRUDE OIL AND GAS ANALYSIS

Analysis of oil/gas has not been carried out in Laxmijan Field. However, oil composition is available from the neighbouring Bihubar wells and is given in Table 4-11

Table 4-11: OIL COMPOSITION & RESERVOIR DATA FROM BIHUBAR WELLS.

Oil Composition & Reservoir data from Bihubar Wells

Reservoir Data

Reservoir Pr kg/cm^2	-	428
Oil saturation	-	50%
Formation vol. factor	-	1.8
Av. Porosity	-	11%
GOR m^3/t	-	280
API Gravity of oil	-	32.1
Density of Oil at 15°C gm/cc	-	0.8649
Pour Point °C	-	33

Oil Compositional characteristics

Bihubar # 2

	Int. 4300 – 4310 m (BCS)	3968 – 3970 m (BCS)
API Gr.	31.10	36.15
Pour Point	33°	27°
Water Content (v/v)	2.60	Traces
Salt Content mgm/l	13.16	10.00
Asphaltene % w/w	1.62	-
Resin % w/w	10.44	-
Wax % w/w	8.17	8.13
Initial BP °C	62	53
Distillation		
1 BP to 150 °C % w/w	18.54	20.00
150 to 250 °C % w/w	19.20	19.00
250 to 300 °C % w/w	13.41	11.00

PRODUCTION HISTORY

Subsequent to the testing phases there has been no production from the wells

WORK-OVER HISTORY

Based on a study carried out by Assam Company Limited (ACL), a Workover Operation was carried out wherein the **TS-5 Sand in well Laxmijan-1A** was retested after a cement squeeze job during 2007. The test re-established the presence of oil and gas in the Sand with dominating quantity of water (~70%)

4.2.5 Geology and Reservoir Description of Laxmijan Field:

The geology of the area has been reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure and seismic attribute maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.2.5.1 Geological correlations, sections and maps (Laxmijan Field):

The Laxmijan-Bihubar area is situated to the south of River Brahmaputra and falls along the Naga Thrust area which is part of the Naga Schuppen Belt and flanks the Assam Shelf to the northwest. Geologically, Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE, and is a narrow belt of about 100 km width, bounded by two thrust belts to the north and the southeast viz. Eatern Himalayas and the Naga Schuppen Belt, respectively. This elongated shelf extends into the sub-thrust block of Naga Schuppen Belt in SE while the Naga Schuppen Belt is also a narrow linear belt of imbricate eight to nine major thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf.

The Namdang High is an anticlinal fold exposing topmost part of Barail in its core and plunging towards Laxmijan. It is an asymmetrical fold with a gentle southeastern limb and steep northwestern limb. Laxmijan-Bihubar Fields lie on the southeastern limb of the anticline and reservoir lithology are the sands within Tipam and Barail Groups trapped in this structural setting. The seismic data of the Laxmijan-Bihubar areas and correlation of drilled wells show the presence of the structural high which has been named Laxmijan-Bihubar High. This sub-thrusted Laxmijan-Bihubar High is separated from the Geleki High towards the west- northwest by a Low. A prominent arcuate transverse fault hading southwards separates Laxmijan area from the Bihubar area. The areas are further dissected by a number of faults trending NE-SW resulting in a number of discrete blocks and culminations. Geleki Oil field to the west-northwest is updip to the Bihubar and Laxmijan structures for Barail zones. Most of the in-place oil volumes in the area are confined within multi-cycle sandstone reservoirs belonging to the sandstones of Tipam Group and the Barail Group of sediments.

The Chalimsen and Naga thrusts are two major faults which pass through the well Laxmijan-1A at 955 m and 2043m respectively. The Chalimsen thrust brings the Barails over Namsang whereas the Naga thrust brings Tipam Sandstone (TS2) over the Girujans. In the well, the sequence below the Naga Thrust, starting from Girujan Clay is a normal succession (**Table: 4.12**). In general, the stratigraphy of the sequence at Laxmijan is about 250 m downdip as compared to the Bihubar structure which itself is a subthrust succession and in turn is about 300m lower to the Geleki structure. The well Laxmijan-2 is updip to well Laxmijan-1A at all stratigraphic levels and is also traversed by the two faults in the subsurface.

The primary prospective sands of the Laxmijan Field lie within the Tipam Group of Miocene age. The sands of the Tipam Group were deposited under fluvial depositional environment with high energy conditions as braided channels during Late Miocene to Early Pliocene. The Tipam sediments overlie the distributary channels which were formed by switching channels in associated environment. of sediments deposited within Rudrasagar Formation (Barail Coal Shale Unit) of the Barail Group of Oligocene age. After the deposition of Rudrasagar Formation there had been a prominent eustatic fall due to which the younger units of Rudrasagar Formation have been eroded to form an unconformity surface. After the close of Tipam times, positive movements resulted in the emergence of land form sand. Subsequent erosions are reflected in the unconformable relations between the Tipams and overlying sediments consisting of arenaceous unit with sub equal proportion of claystone, clay and silt of Moran Group during Pliocene-Pleistocene. The Recent Alluvium constitutes the youngest stratigraphic unit in the Basin.

Geological sections, depth contour maps on reservoir top and seismic sections/ slices of the Laxmijan Field are shown in **Figure 4-12, Figure 4-13, Figure 4-14, Figure 4-15, Figure 4-16, Figure 4-17, Figure 4-18, Figure 4-19, Figure 4-20, Figure 4-21, Figure 4-22** and **Figure 4-23. Figure 4-26**

Figure 4-24 **and Figure 4-25** show the results of enhancement of reflectors using AGC 800 ms window and depth to seismic tie of the well Laxmijan-2**.**

Figure 4-12: SCHEMATIC SECTION BETWEEN BIHUBAR AND LAXMIJAN WELLS

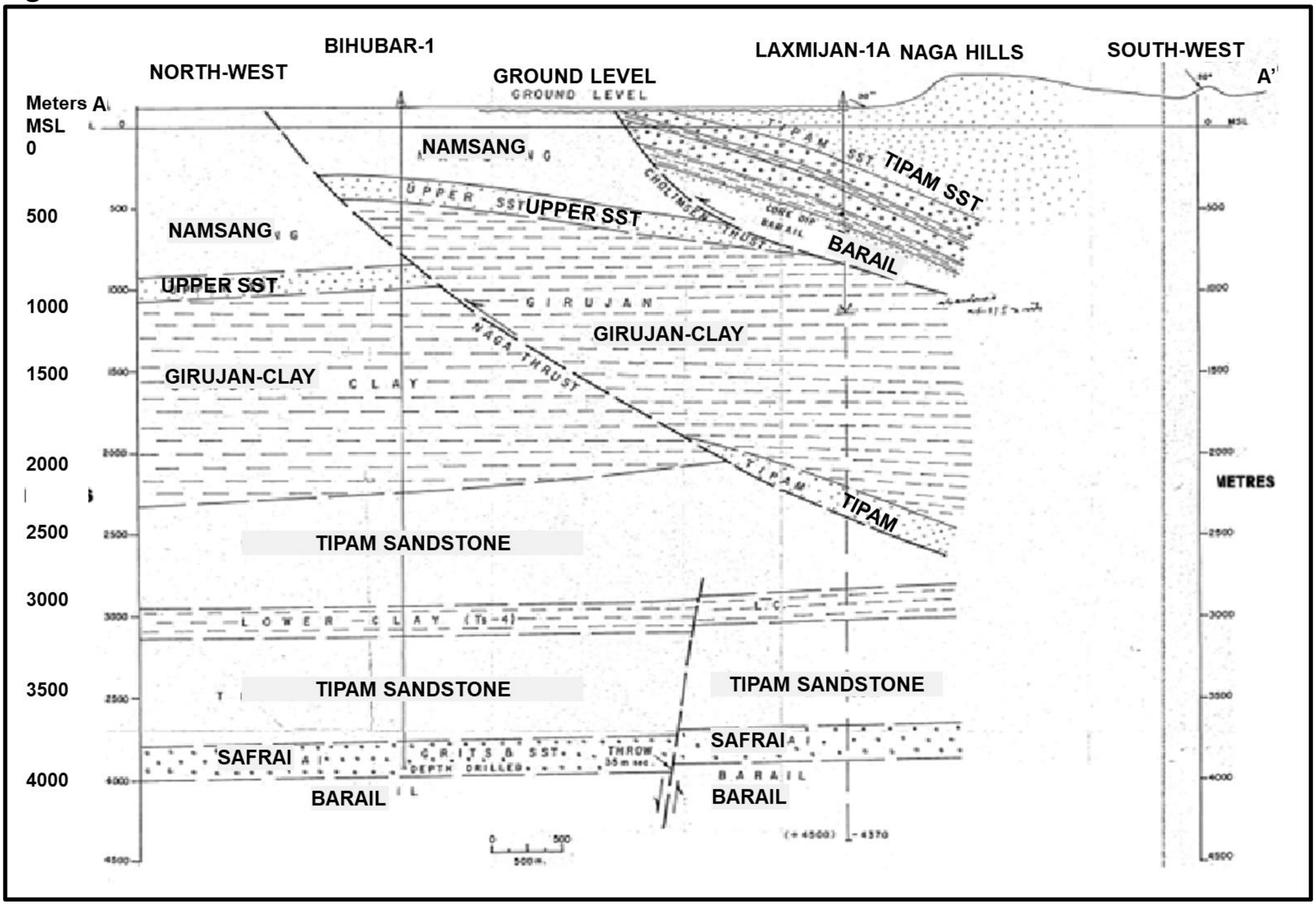


Table 4-12: STRATIGRAPHIC COLUMN ENCOUNTERED IN WELLS LAXMIJAN -1A AND LAXMIJAN-2

<table>
<tr><th>Formation/ Group</th><th>Sand</th><th colspan="2">Well Laxmijan-1A</th><th colspan="2">Well Laxmijan-2</th><th rowspan="2">Lithological Description</th></tr>
<tr><td></td><td></td><td>MD (m)</td><td>BD (m)</td><td>MD (m)</td><td>BD (m)</td></tr>
<tr><td>Alluvium</td><td></td><td>0 - 507</td><td>380</td><td></td><td></td><td></td></tr>
<tr><td>Tipam</td><td></td><td></td><td></td><td>-409</td><td>-281</td><td rowspan="2">Mainly coarse unconsolidated sand stone with chert, free quartz Fe-Mg minerals White to grey shale, gritty sandstone, med gr, with abundant dark minerals with minor coal and claystone</td></tr>
<tr><td></td><td>Safrai</td><td>507 - 634</td><td>380-507</td><td>409-534</td><td>281-406</td></tr>
<tr><td colspan="7">UNCONFORMITY</td></tr>
<tr><td>Barail</td><td></td><td>634-955</td><td>507-828</td><td>534-819</td><td>406-691</td><td>Sandstone: Dark brown carbonaceous- shale occasionally clay stone and coal</td></tr>
<tr><td colspan="7">CHOLIMSEN THRUST</td></tr>
<tr><td>Namsang</td><td></td><td>955-980</td><td>828-853</td><td>819-921</td><td>691-793</td><td>Sandstone: Variegated with free quartz.</td></tr>
<tr><td>Upper Sandstone</td><td></td><td>980-1204</td><td>853-1077</td><td>921-1154</td><td>793-1026</td><td>Sandstone with clay and minor coal</td></tr>
<tr><td>Girujan Clay</td><td></td><td>1204-1913</td><td>1077-1786</td><td>1154-1870</td><td>1026-1742</td><td>Mostly variegated claystone with siltstone/ sandstone</td></tr>
<tr><td>Tipam</td><td>TS1
TS2</td><td>1913-1988
2017-2043</td><td>1786-1861
1890-1916</td><td>1870-1997</td><td>1742-1869</td><td>Sandstone with minor claystone</td></tr>
<tr><td colspan="7">NAGA THRUST.</td></tr>
<tr><td>Girujan Clay</td><td></td><td>2043-2666</td><td>1916-2539</td><td>1997-2610</td><td>1869-2482</td><td>Monotonous variegated clay/ claystone with sandstone, silt intercalations</td></tr>
<tr><td rowspan="9">Tipam</td><td>TS1</td><td>2666-2786</td><td>2539-2659</td><td>2610-2724</td><td>2482-2596</td><td rowspan="8">Sandstone with frequent intercalation of claystone.</td></tr>
<tr><td>TS2</td><td>2786-3037</td><td>2659-2910</td><td>2724-2968</td><td>2596-2840</td></tr>
<tr><td>TS3</td><td>3050-3397</td><td>2910-3270</td><td>2968-3298</td><td>2840-3170</td></tr>
<tr><td>LCM
TS4</td><td>3397-3484</td><td>3270-3357</td><td>3298-3383</td><td>3170-3255</td></tr>
<tr><td>TS5A</td><td>3484-3582</td><td>3357-3455</td><td>3383-3486</td><td>3255-3358</td></tr>
<tr><td>TS5B</td><td>3582-3702</td><td>3455-3575</td><td>3486-3598</td><td>3358-3470</td></tr>
<tr><td>TS5C</td><td>3702-3784</td><td>3585=3657</td><td>3598-3687</td><td>3470-3559</td></tr>
<tr><td>TS6</td><td>3784-4100</td><td>3657-3973</td><td>3687-4006</td><td>3559-3878</td></tr>
<tr><td>Safrai</td><td>4100-4187</td><td>3873-4060</td><td>4006-4112</td><td>3878-3984</td><td>Coarse grained sst with polygenetic conglomerates.</td></tr>
<tr><td></td><td colspan="5">UNCONFORMITY</td><td></td></tr>
<tr><td rowspan="2">Barail</td><td>BCS</td><td>4187-4372</td><td>4060-4245</td><td>4112-4588</td><td>3984-4460</td><td>Dominantly shale with intercalation of sandstone and coal</td></tr>
<tr><td>BMS</td><td></td><td></td><td>4588-4760+</td><td>4460-4632+</td><td>Dominantly sandstone with intercalation of shale and coal</td></tr>
</table>

Figure 4-13: SEISMIC SECTION ACROSS LAXMIJAN-BIHUBAR AND GELEKI FIELDS

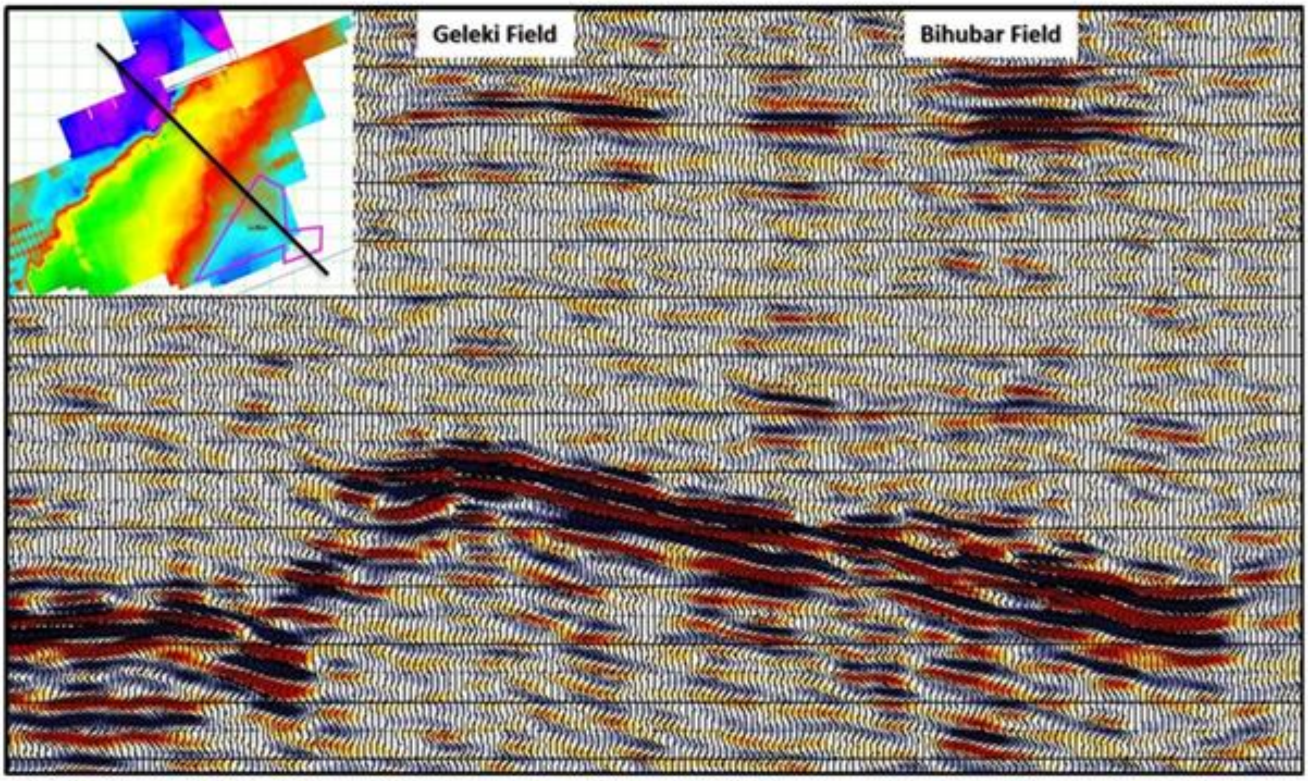
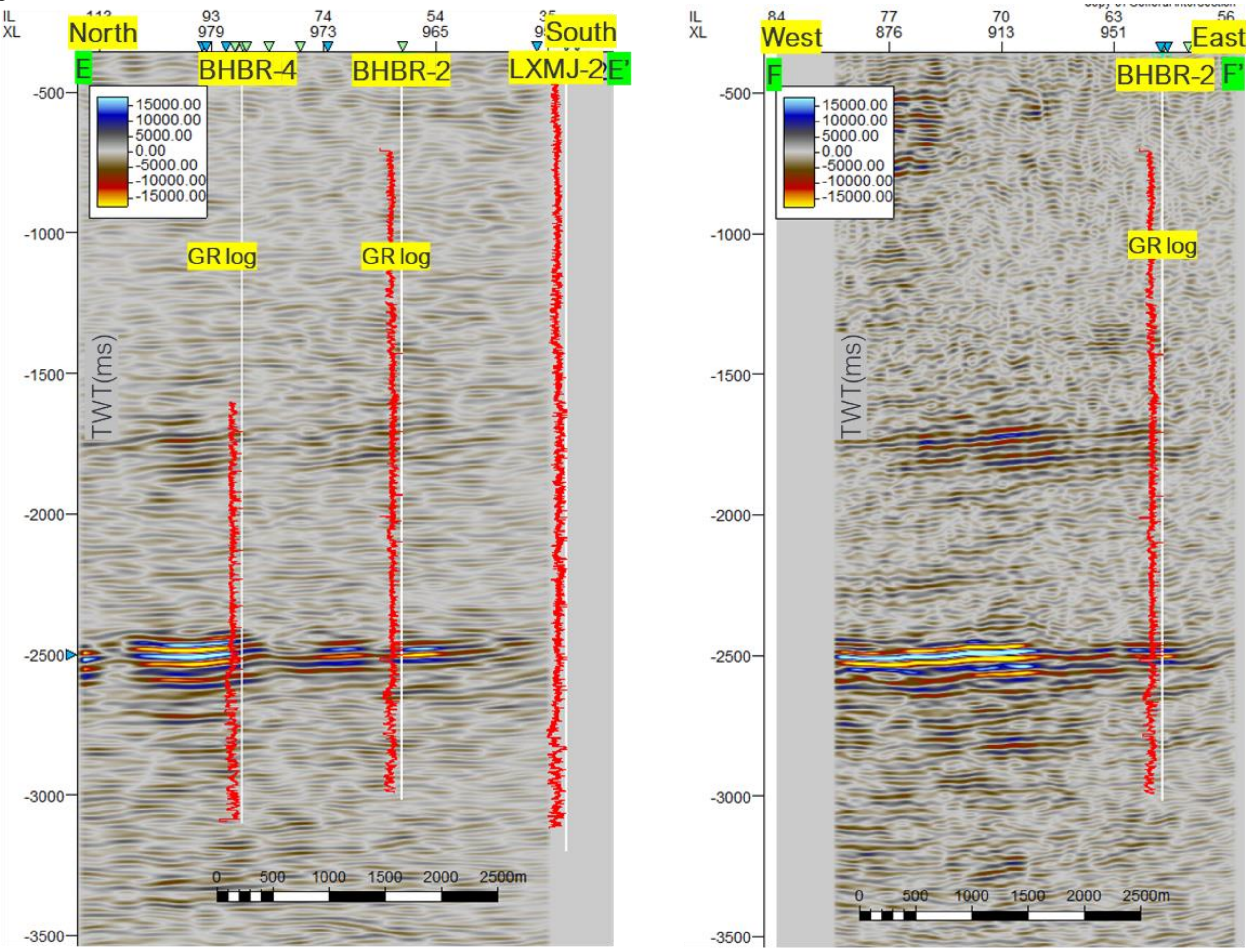


Figure 4-14: SEISMIC SECTION ACROSS WELLS LAXMIJAN-2, BIHUBAR-2 AND BIHUBAR-4



Vertical exaggeration: 2.5x
Seismic volume: 00001.GELEKI_PSDM_SCALE_TO_TIME_PSDM_SCALED_TO_TIME

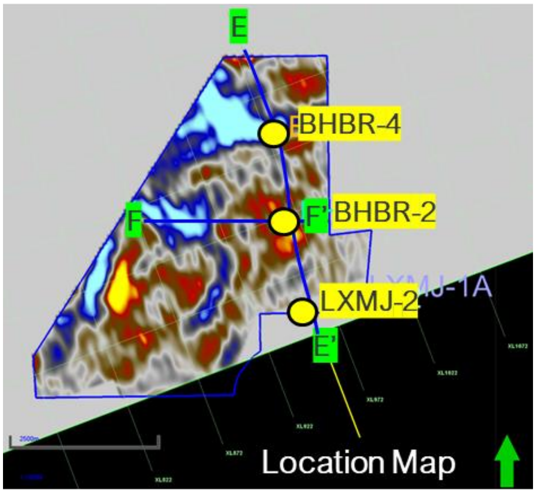


Figure 4-15: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BIHUBAR 4, 2 AND LAXMIJAN 2, 1A

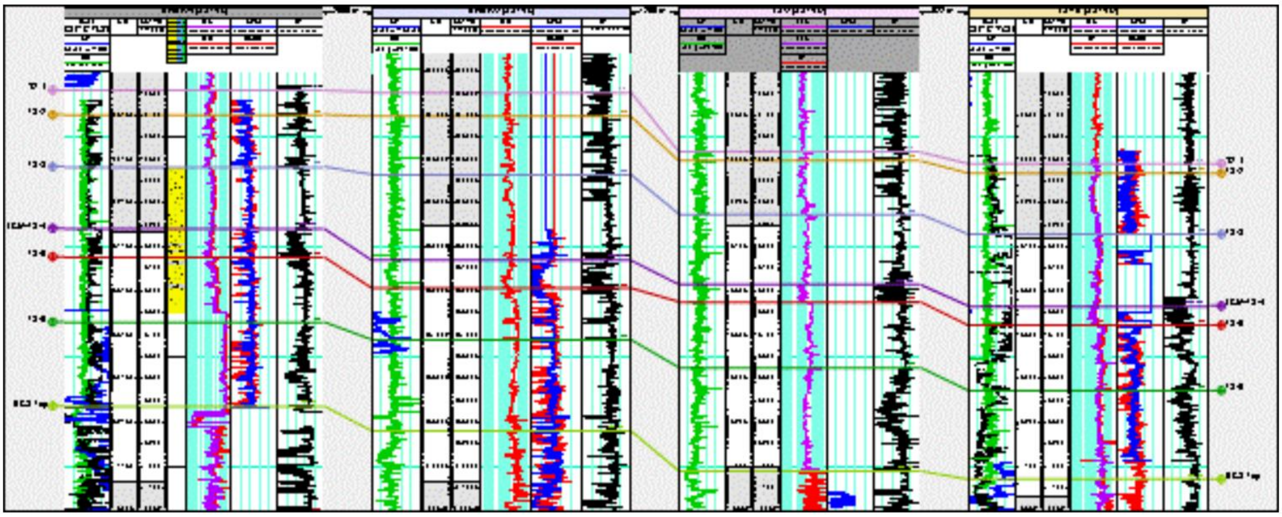


Figure 4-16: STRATIGRAPHIC (DATUM @ LCM) ELECTRO-LOG CORRELATION OF WELLS BIHUBAR 4, 2 AND LAXMIJAN 2, 1A

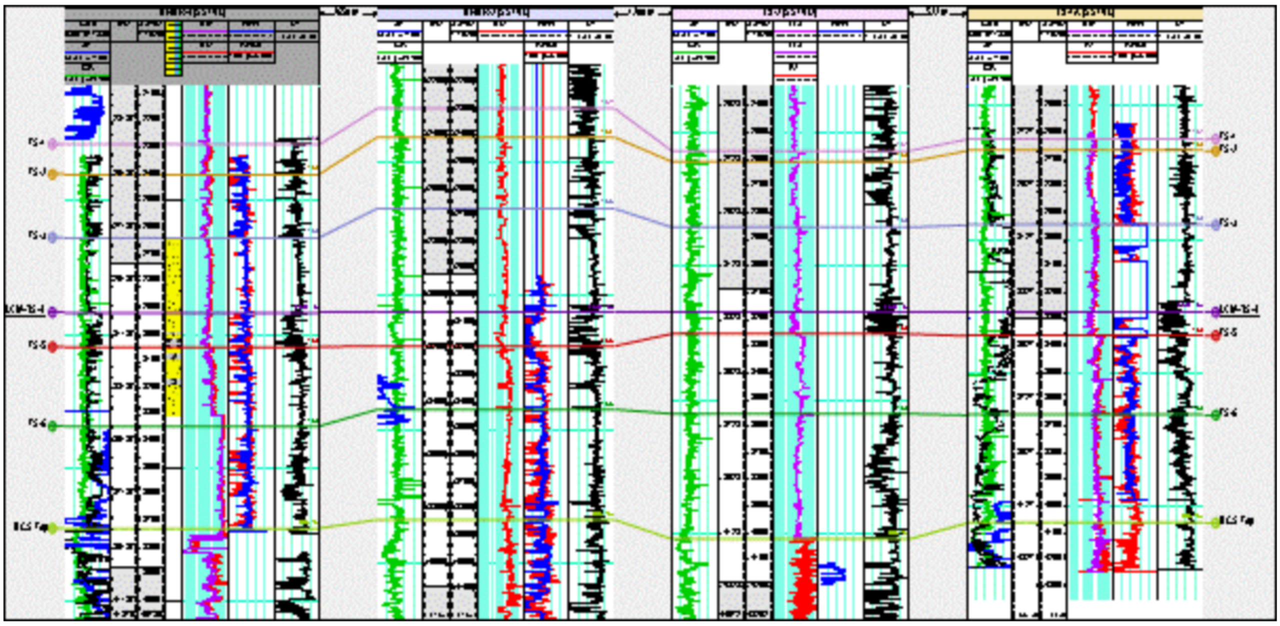


Figure 4-17: STRUCTURE MAP OF TS-II PICK SHOWING HIGHS AT WELLS LAXMIJAN 1A AND 2

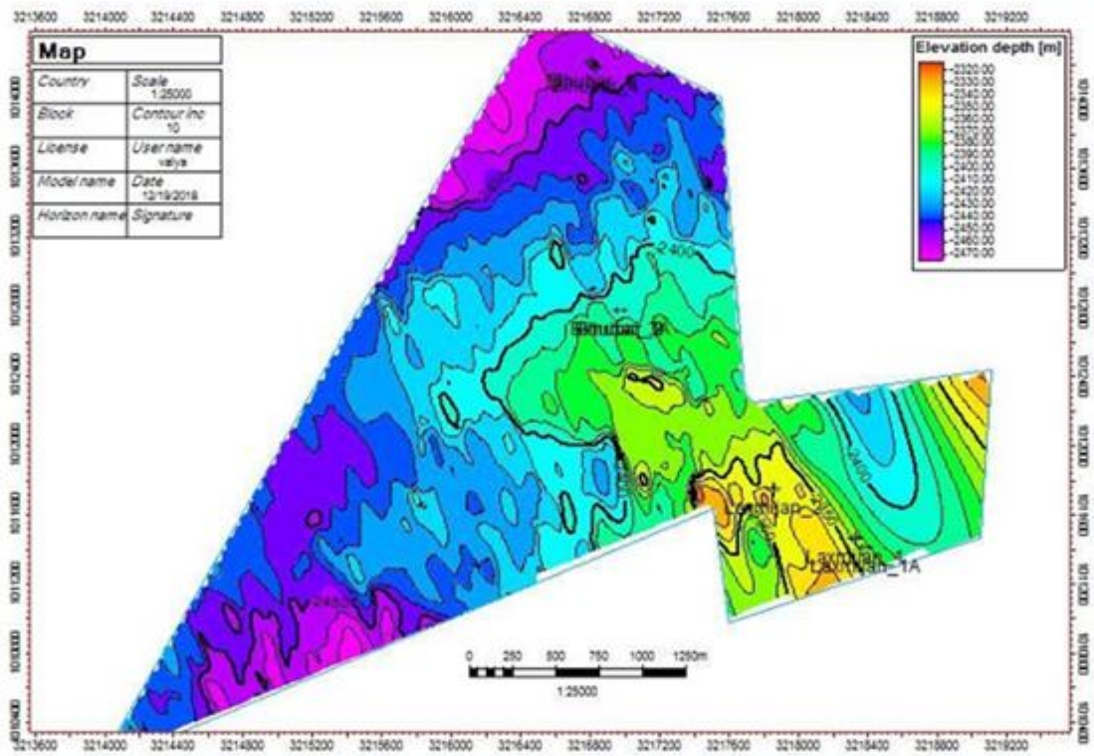


Figure 4-18: DEPTH STRUCTURE MAP AT THE TOP OF TS-5A

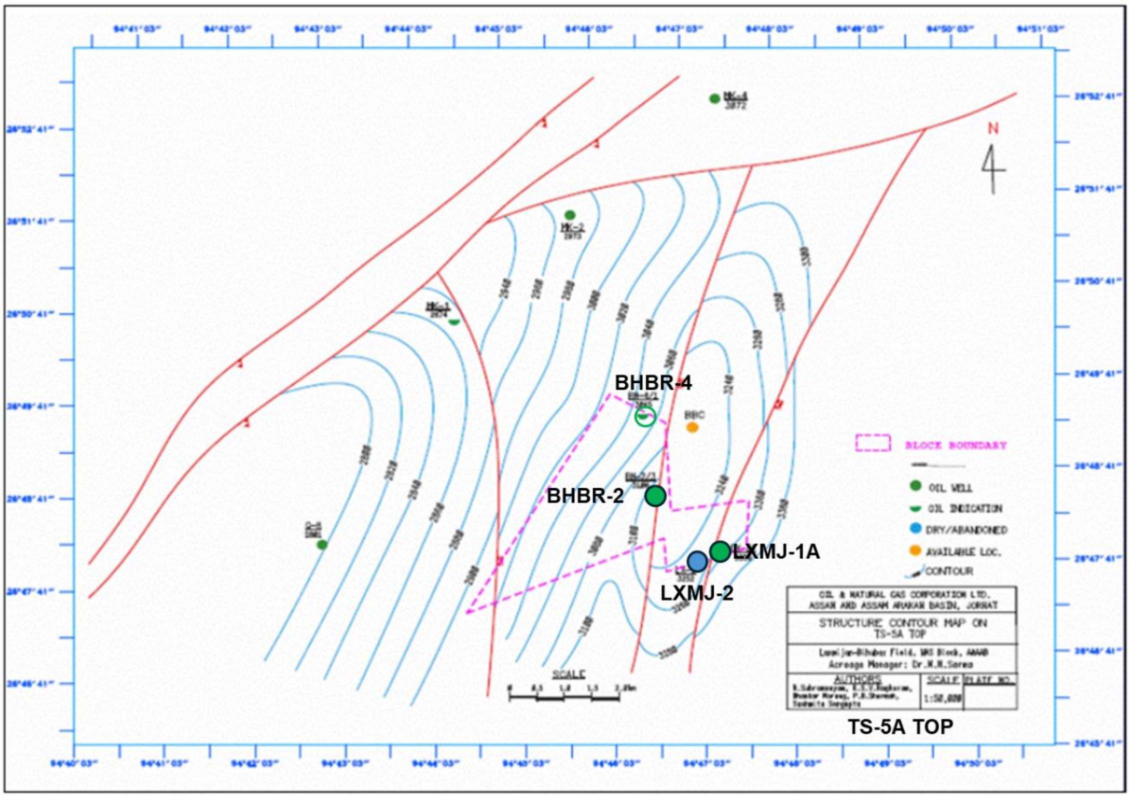


Figure 4-19: DEPTH CONTOUR MAP NEAR BARAIL BCS

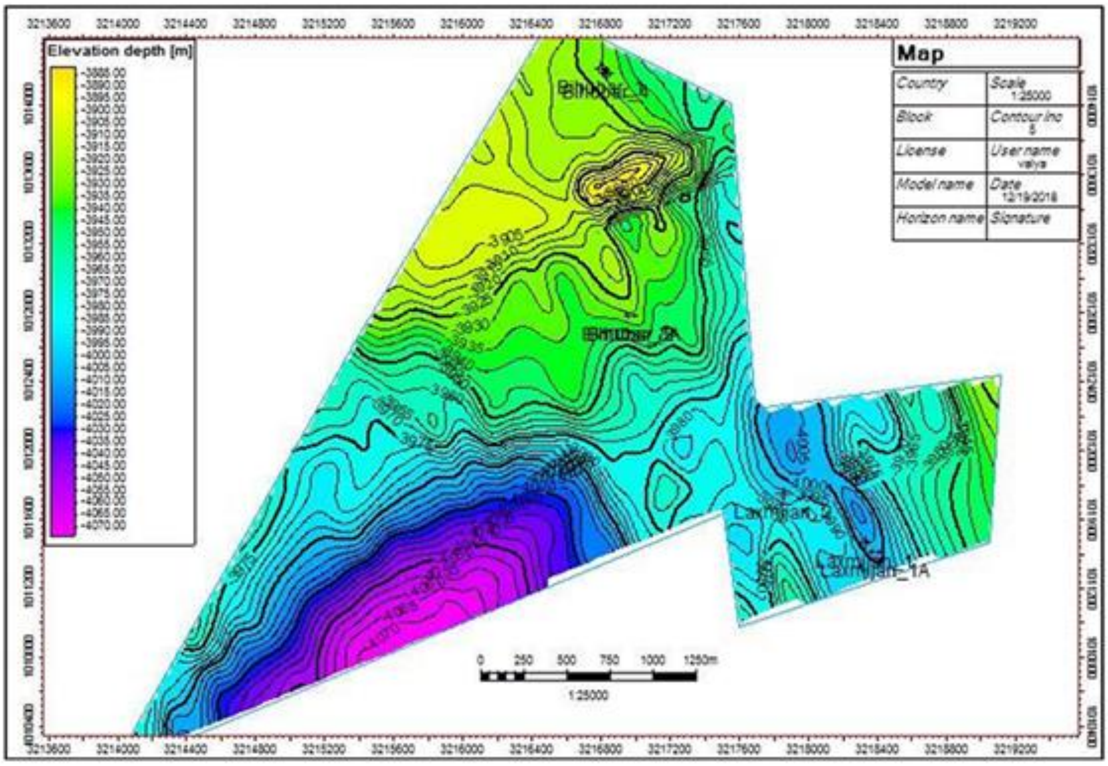


Figure 4-20: DEPTH STRUCTURE MAP AT THE TOP OF BARAIL BMS

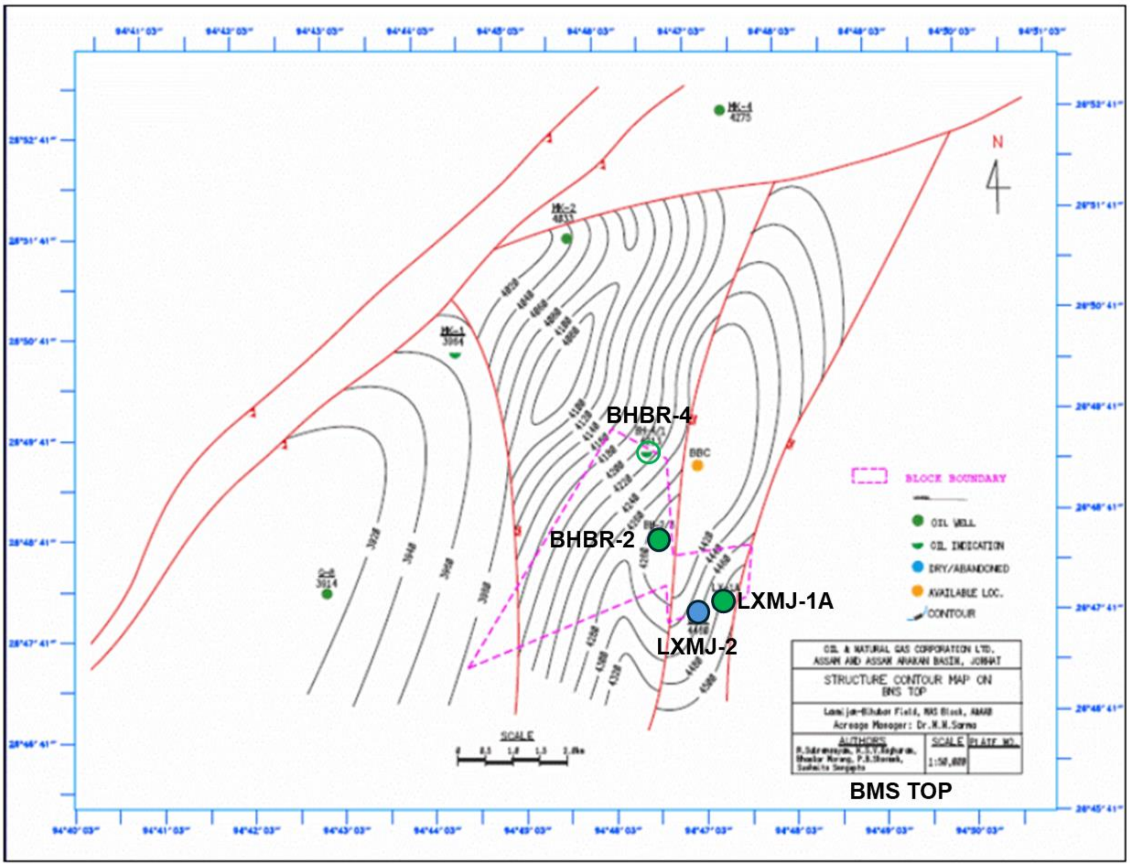


Figure 4-21: ISOPACH MAP BETWEEN TS-II AND BCS SHOWING INCREASED THICKNESS AT LAXMIJAN LEVEL TOP OF BMS

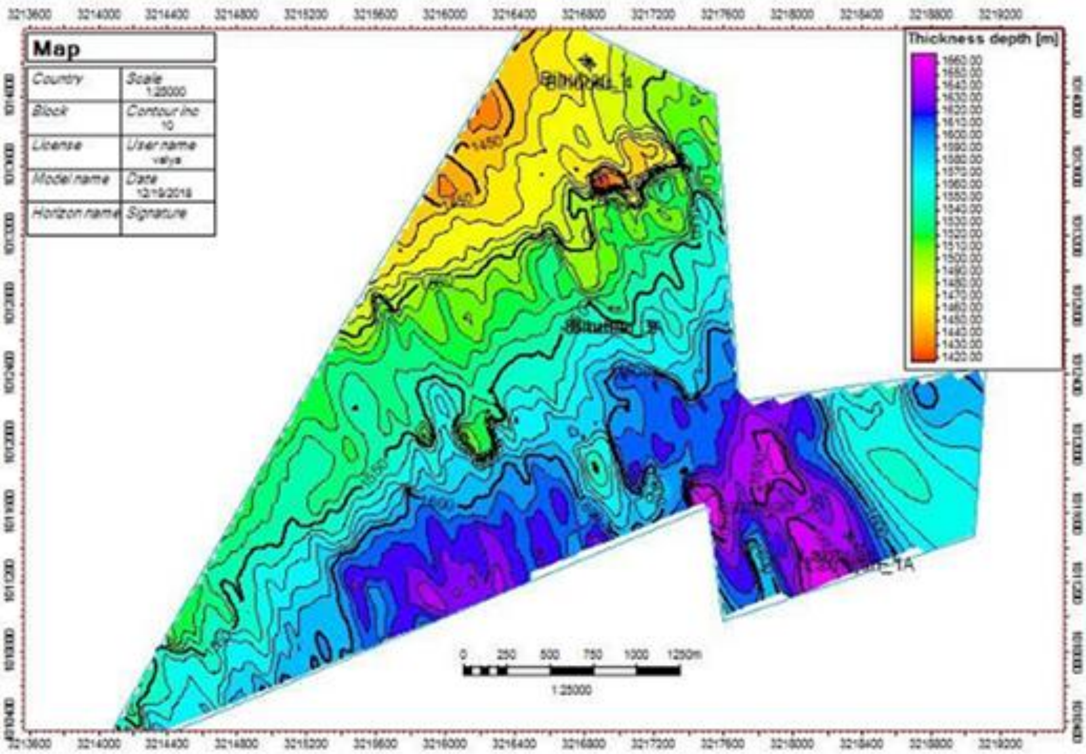


Figure 4-22: ARBITRARY LINE CONNECTING LAXMIJAN AND BIHUBAR WELLS IN THE TWO ADJACENT FIELDS

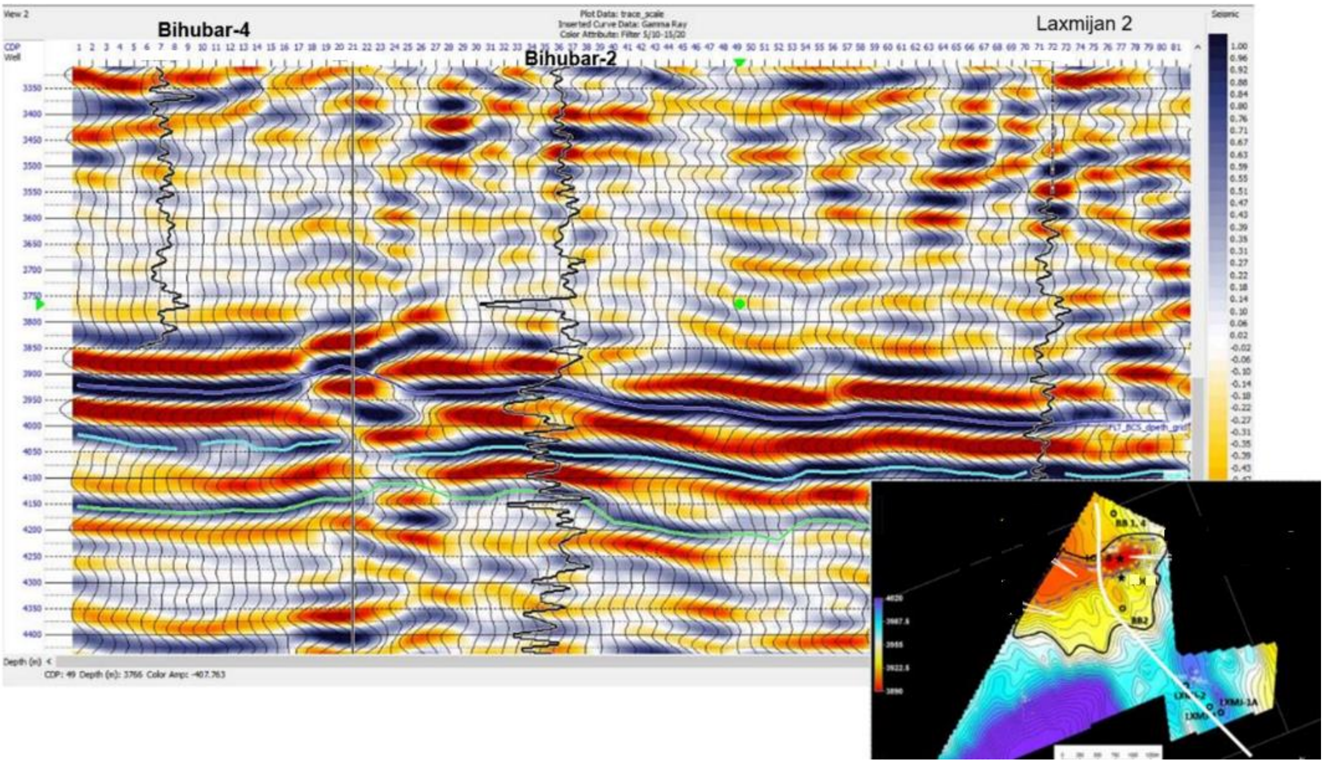


Figure 4-23: SWEETNESS ATTRIBUTE ON BCS HORIZON SHOWING INCREASED AMPLITUDE WITH DECREASED FREQUENCY

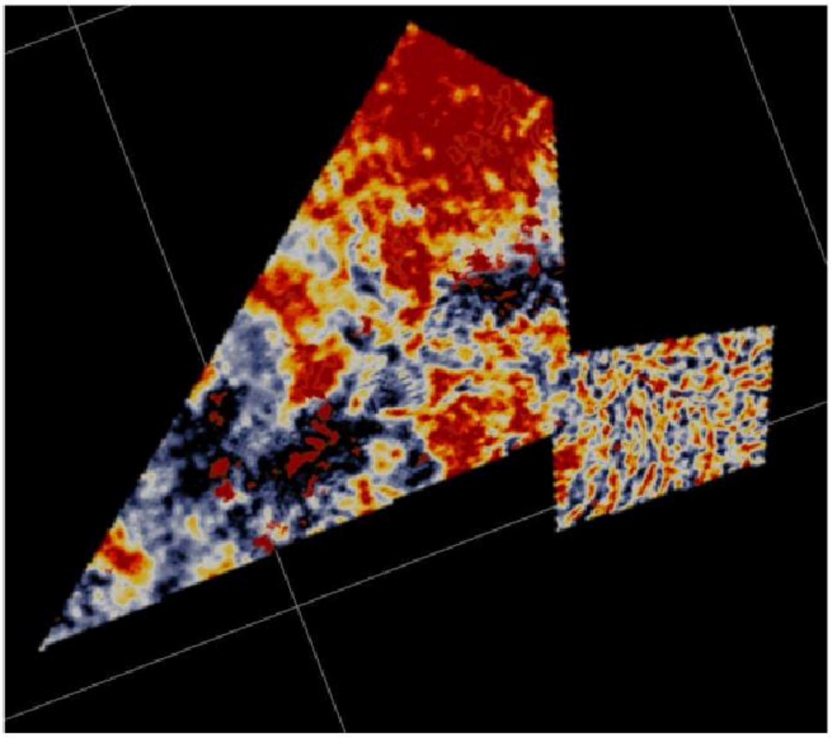


Figure 4-24: ARBITRARY LINE CONNECTING LAXMIJAN-AND BIHUBAR WELLS AND SHOWING THE INTERPRETATION OF BCS AND BMS

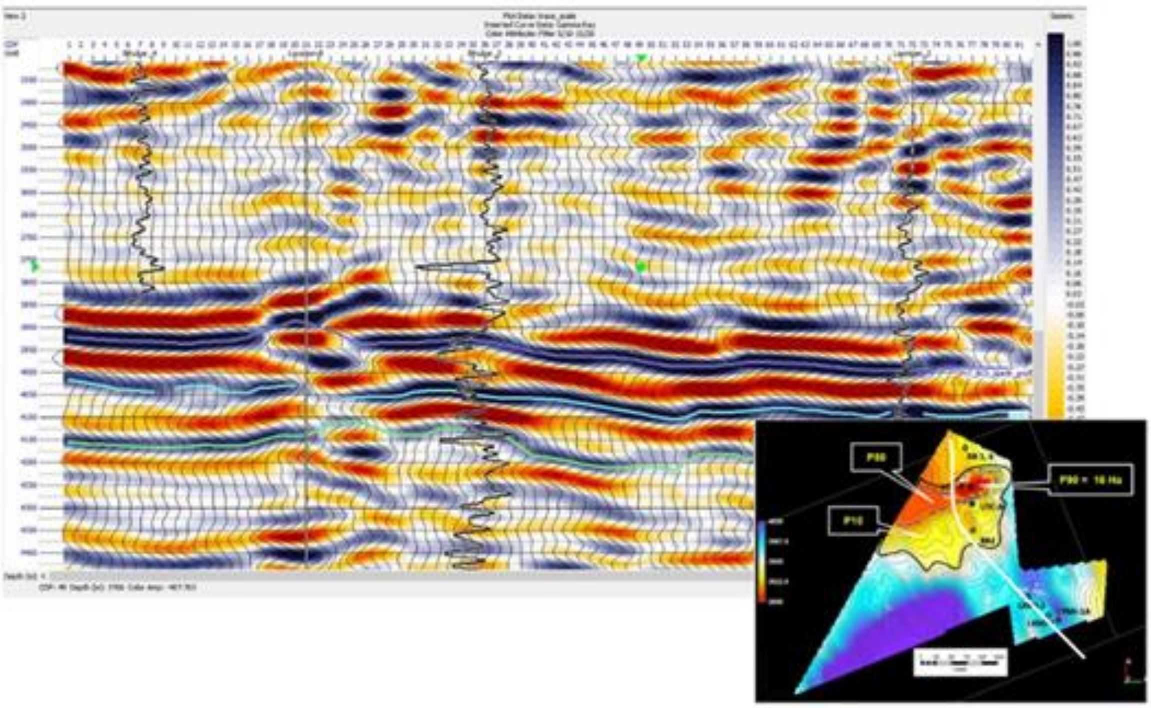


Figure 4-25: ENHANCEMENT OF REFLECTORS USING AGC 800 MS WINDOW

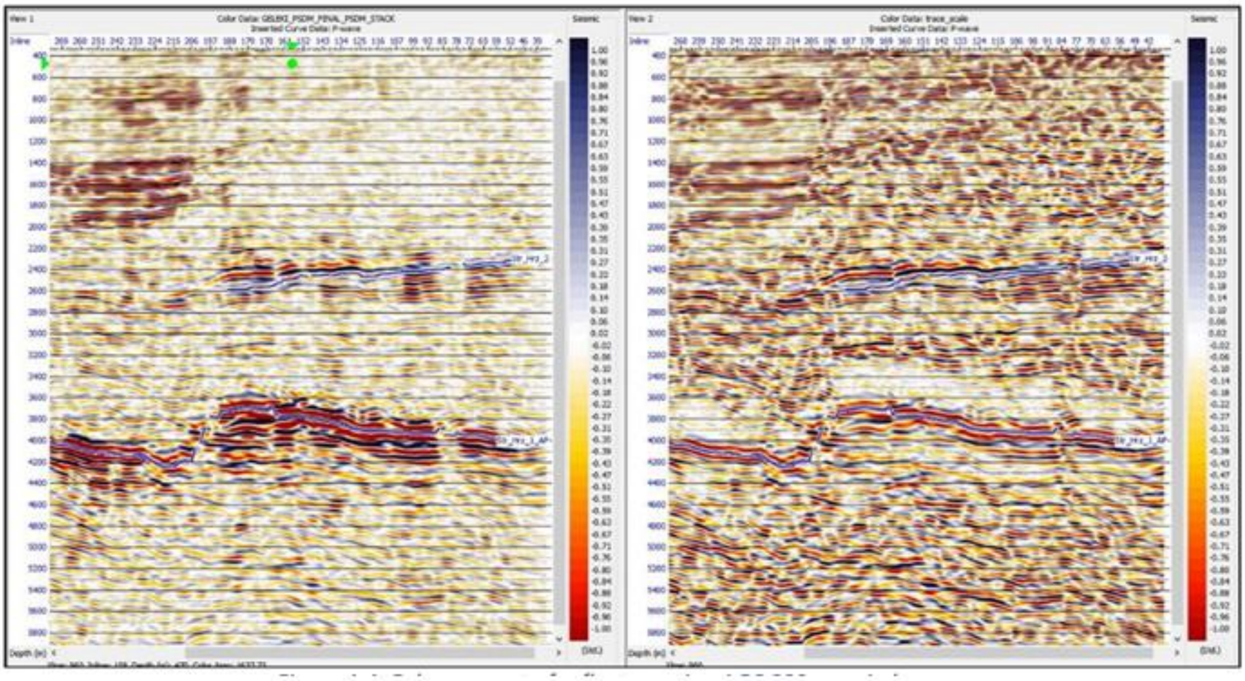
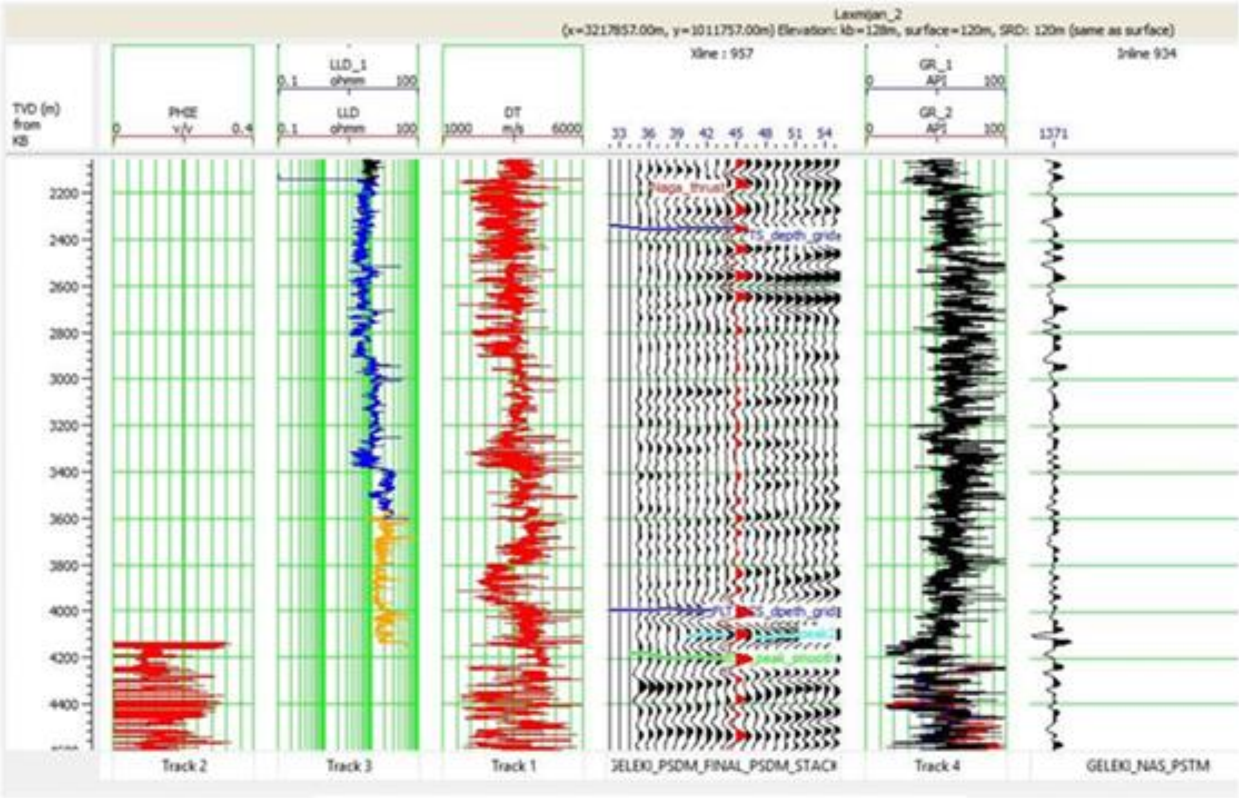


Figure 4-26: DEPTH TO SEISMIC TIE TO THE WELL LAXMIJAN-2



4.2.5.2 Reservoir parameters and hydrocarbon estimates (Laxmijan Field):

Petrophysical parameters and hydrocarbon estimates:

Table 4-13 gives the evaluation results of Laxmijan Field wells from the study

Table 4-13: DERIVED PARAMETERS FOR THE OBJECTS TESTED IN THE LAXMIJAN WELLS

Well	Object	Sand	Depth Range	Flow Test Type	Flow Test Results	Status	HC Sat	Porosity	Sw
LXM-1	Abandoned due to complications.								
LXM-1A	Obj-I	Barail	4218-4214	CHDST	Water bearing	Dry		0.07	
	Obj-II	TS-5B	3615-3607	CHDST	Water bearing	Dry		0.17	
	Obj-III	TS-5A	3508-3492	Convent-ional	Viscous Oil	Viscous Oil	57	0.15	43
	Obj-IV	TS-4B	3465-3458	CHDST	Water with traces of oil observed	Viscous Oil	57	0.13	43
LXM-2	Obj-I	TS-5A	3393-3399	Convent-ional	Water with traces of oil.	Dry			

Current hydrocarbons estimates

Initial hydrocarbons in-place have been estimated based on production testing result, reservoir parameter and Log motifs of wells Laxmijan 1A & 2. The reservoir parameters and in-place of Laxmijan Field are shown in **Table 4-14 and Table 4-15 below**.

Table 4-14: RESERVOIR PROPERTIES FOR VOLUMETRIC ESTIMATION OF LAXMIJAN FIELD

Field	Reservoir	Area	He	Phi					GOR	O+OEG
	Sand/ layer	Sq Km	m		So	Bo	API	Sp Gr	m3/ m3	MMTOE
Laxmija	TS4	0.126	5	0.168	0.43	1.47	31	0.8708	230	0.03
	TS5A1	1.004	20.2	0.142	0.43	1.48	31	0.8708	210	0.90
	TS5A2	0.282	4.8	0.142	0.25	1.48	31	0.8708	210	0.03
	TS5B	1.004	11.5	0.13	0.00	1.49	31	0.8708	125	-
										0.96

Table 4-15: HYDROCARBON IN-PLACE(2P) OF LAXMIJAN FIELD

Field	O+OEG MMTOE
LAXMIJAN	**0.96**

Erstwhile Operator-reported estimates on record:

The LAXMIJAN-BIHUBAR Cluster has a reported gas estimate of **0.15 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.2.6 Production Facility for Oil and Gas Evacuation:

X-mass tree is available at well Laxmijan-1A
The nearest surface facility to Barsilla Field is **~ 9.5 km East of Geleki Main Field**

Hydrocarbon transportation could be by tankers to the local consumers. The existing Geleki Field gathering system could serve as a good point for oil and gas delivery.

AA/ONDSF/ASSAM/2025 (A&AA) BIHUBAR FIELD

4.3 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) BIHUBAR FIELD

Well Bihubar-1 was the first well drilled on the Bihubar structure by ONGC as an exploratory well in 1975. The well was planned to be drilled to a depth of 4500 m with an objective to explore the Oligocene prospects in the Bihubar area. Though drilled to a depth of 4038 m, the well had to be sidetracked following repeated fishing in the well and the was finally abandoned at a depth of 3425m.

Of the five wells drilled on the structure, four wells viz. Bihubar -1, 3, 3A and 4 had to be abandoned either because flow tests have shown them to be mainly water bearing or due to drilling issues. Well Bihubar-1 is the discovery well in this field as during testing of the TS-5A sand of the Tipam Group of Miocene age, small quantity of oil was observed while changing over well fluid for testing a higher up sand though subsequently it showed poor influx. However, hydrocarbon, especially gas and viscous oil, was encountered in the well Bihubar-2 in the Miocene Tipam and the Oligocene Barail sands. The Bihubar Field has been recognized as a marginal field. The main pay is BMS and BCS within the Barail Group of Oligocene age. Structural entrapments are interpreted to be mainly fault closures.

4.3.1 Drilling and well completion

As stated earlier, five exploratory wells have been drilled in this field, viz. Bihubar-1 (GF), Bihubar-2 (BB-2), Bihubar-3 (BBA), Bihubar-3A and Bihubar-4 (BBD). The well Bihubar-3A was drilled as a Sidetrack well by kicking off at 755 m from the well Bihubar-3 as the testing of the sand TS1 could noy be carried out in the original well. Key information of the drilled wells have been collated and presented in the tables hereunder (**Table 4-16 and Table 4-17**). The adjoining figures illustrate the Well Construction Diagram (**Figure 4-27 and Figure 4-28**) for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

Table 4-16: GENERAL INFORMATION OF THE WELLS DRILLED IN BIHUBAR FIELD

Well	Bihubar-1	Bihubar-2	Bihubar-3	Bihubar-3A	Bihubar-4
Area	Geleki				
Structure	Bihubar				
Well	Bihubar-1 (GF)	Bihubar-2 (BB-2)	Bihubar-3 (BBA)	BB-3A (BBA)	BB-4 (BBD)
Category	Exploratory	Exploratory	Exploratory (Directional)	Exploratory (Sidetrack)	Exploratory
Co-ordinates	X: 3216837.64	X: 3217070.59	X: 3217070.59	X: 3217070.59	3216868.34
	Y: 1014174.5	Y: 1012708.79	Y: 1012708.79	Y: 1012708.79	1014150.09
Rig	3D-7	3DH-III		3DH-III	E-2000-IV
Target Depth	4500 m	4300 m increased to 4600 m	2000 m + vertical shortening	2000 m KO from 618 m of BB-3	4600 m
Drilled Depth	4038.00 m Sidetracked depth 3425 m	4485 m	2080 m	2000 m	4600 m

Objective	Released for exploration of Barail prospects in Bihubar area.	To explore the hydrocarbon potentiality of sub-Thrust Tipam and Barails	To explore the hydrocarbon potentiality of Sub-Thrust Girujans	To explore the hydrocarbon potentiality of supra-Thrust Tipams	To explore hydrocarbons of Barails
Status	Discovery well with poor influx from tested zones Abandoned	Tested zones showed presence of oil/ viscous oil with water and gas. Flow did not Sustain. Abandoned.	Incomplete Testing with fish in hole. Abandoned	Tested zones produced water. Abandoned	One zone tested water with oil. Abandoned
KB	108.92 m	112.175 m	112.175 m	112.175 m	113.71 m
Spud date	20-11-1975	15-01-1985	14-03-1987	20-10-1990	07-07-1996
Drilling Completion	-14.12.1982	19.01.1986	14.03.1987	06-12-1990	22-03-1997
Rig release	06-04-1983	09-02-1987	Rig not released as same rig to drill a sidetrack from this well	19-01-1991	01-07-1997

Table 4-17: WELL WISE CASING DETAILS

Well	Hole Size	Casing Size	Cement Rise from Surface	Casing Shoe Depth (m)
Bihubar-1	18 ½ “	14 ¾ “	Did not surface	1200 m
	13 ¾ “	9 5/8 “	2930 m	3700.31 m
	8.1/2 “	5 ½ “	2510 m	3279.20 m
Bihubar-2	26 “	20 “	Surface	98.92 m
	17 ½ “	13 3/8 “	Surface	1919 m
	12 ¼ “	9 5/8 “	2700 m	3763 m
	8.1/2”	5 ½ “	3504 m	4461 m
Bihubar-3	17.1/2 “	13.3/8“	Surface	68.12 m
	12.1/4“	9. 5/8“	Surface	532.14 m
	8. 1/2“	5. 1/2“	1750 m	2063.91 m
Bihubar-3A (BB-3A)	17 ½ “	13 3/8 “	Surface	68.12 m
	12 ¼ “	9 5/8 “	Surface	532.14 m
	8 ½ “	5 ½ “	Ist Stage: 1630 m IInd Stage: 623 m	1973.0 m
Bihubar-4 (BBD)	26 “	20 “	Surface	387.76 m
	17. 1/2“	13 3/8 “	600 m	2389 m
	12 ¼ “	9 5/8 “	1700 m	3935.27 m
	8. 1/2“	5 ½ “	3875 m	4140.77 m

Figure 4-27 : WELL PROFILE OF BIHUBAR-2

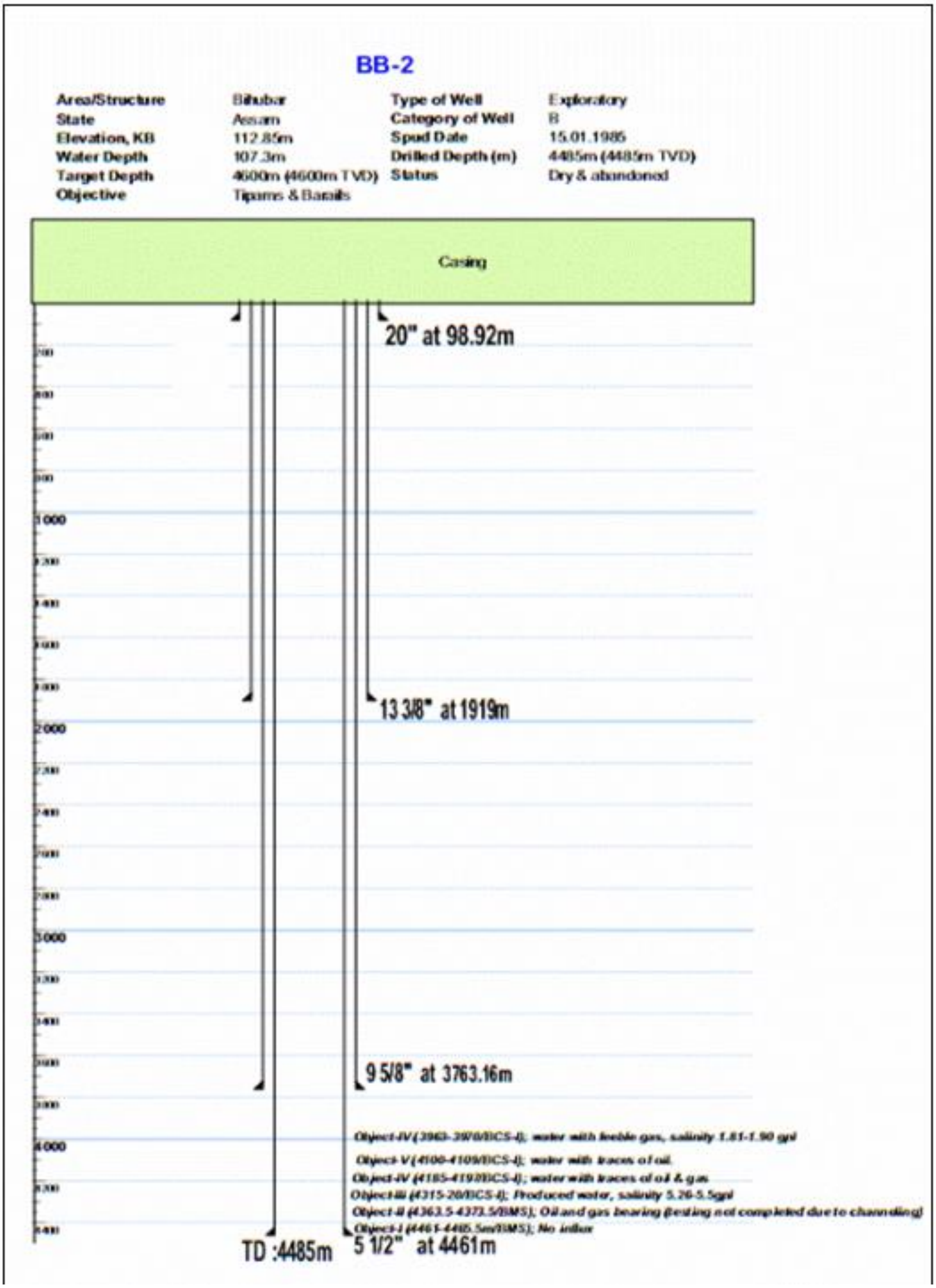
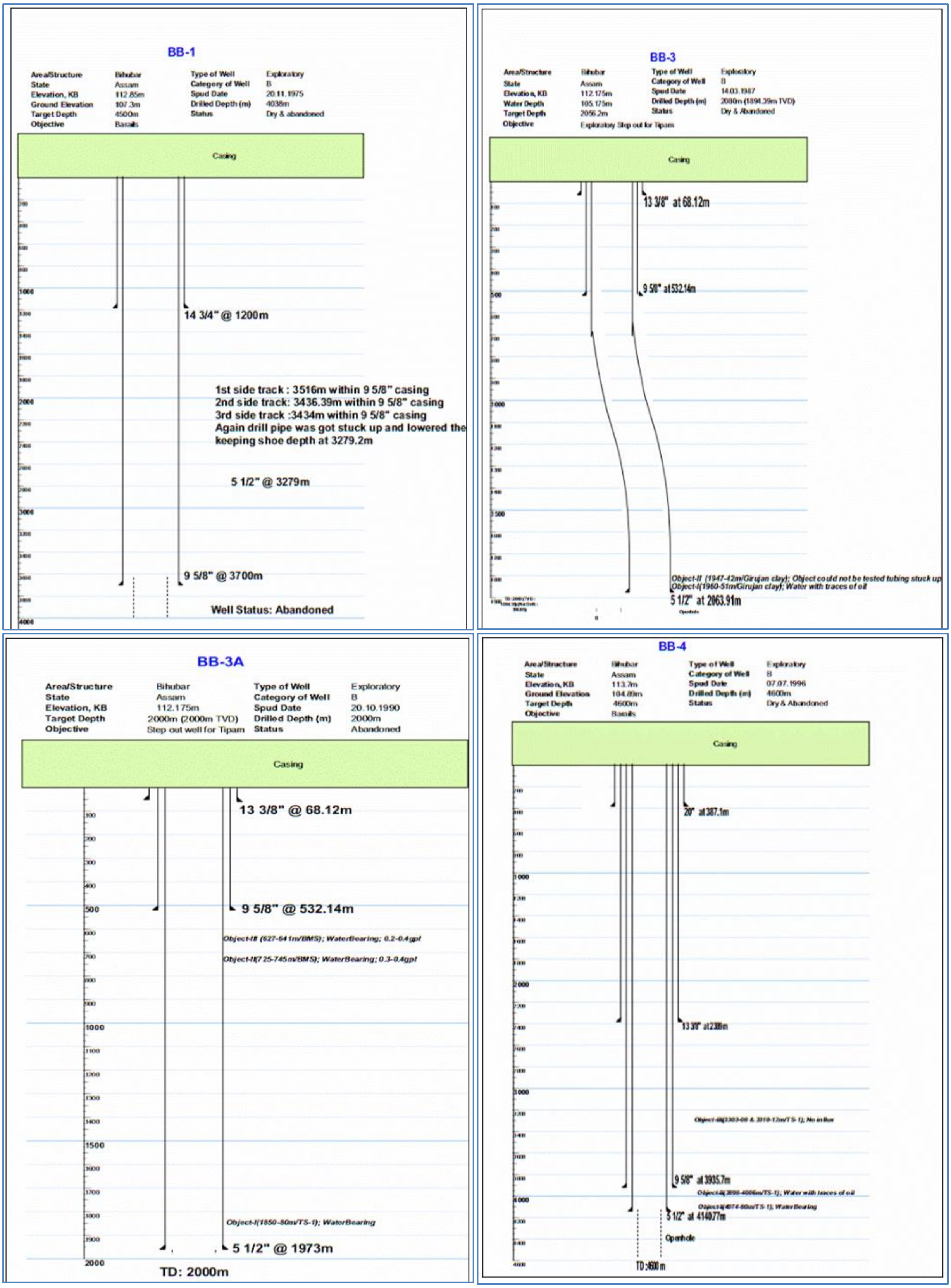


Figure 4-28: WELL PROFILE OF BIHUBAR-1, 3, 3A AND 4



4.3.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

Availability of reports, logs recorded and core data available in Bihubar wells are tabulated at **Table 4-18, Table 4-20 and TABLE 4-19.**

4.3.2.1 Availability of reports (BIHUBAR Field) :

Table 4-18: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Bihubar-1	108.92 m	20-11-1975	4038 m	Available	Available
Bihubar-2	112.175 m	15-01-1985	4485 m	Available	Available
Bihubar-3	112.175 m	14-03-1987	2080 m	Available	Available
Bihubar-3A	112.175 m	20-10-1990	2000 m	Available	Available
Bihubar-4	113.71 m	07-07-1996	4600 m	Available	Not Available

4.3.2.2 Well logs acquired (BIHUBAR Field):

TABLE 4-19: LOG SUITES RECORDED IN DRILLED WELLS

Well No.	Type of log	Interval (m)
Bihubar-1	SP, Normal, Lateral,	25-1040, 900 -1185
	SP, Normal, BKZ	2855-1200, 2900-2600, 3150-3102, 3268-2900, 3696-3200, 4020-3700
	Caliper-Inclinometer	25-1040, 1200-2750, 2900-3268, 3350-3690
	Caliper	1200-2900, 1200-3698
	Induction, Sonic, CRN	2400-2735, 2700-3612
	Thermolog	After setting of 9.5/8” Csg. with shoe @3700.31
	CBL	2450-3175, 2400-3245
Bihubar-2	DIL-SP-GR	100-1923, 3753.0-4469.6
	LSS	100-1923
	X-Y CAL	100-1923, 2400-5-3050
	Inclinometer	100-1923, 1900-3048, 1920-2056
	SP-Caliper-DIL-BCS-GR	1919-3050, 1919-3781.5, 3751-4082, 3753-4335, 4337-4386
	CDL-CNS-GR-SP	2400.5-3050, 2910-3781.5, 3778-4323

	Caliper, GR, Dipmeter,	3190-3780, 3792-4120
	CBL-VDL-CCL-GR-IT3	3100-3722
	CBL-VDL-CCL-NEUTRON-GR	3444.8-4461
Bihubar-3	DIL-SP-GR	67-544
	GR-Cal-BCS	68-542
	CDL-CNS-GR	238-545, 532-1245.1860-2072.5
	DIPMETER	59.5-541.5, 532-930, 890-2058
	Inclinometer	532-1245, 890-2058
	SP-GR-Cal-DIL-BCS	497-637, 532-1245, 1168-2067, 1800-2067
	SFT	At well depth of 636 m in 8.1/2” hole
	SP-GR-Cal-MSFL-LLD-LLS	532-1245
	SWC	At well depth of 2080 m in 8.1/2” hole
	CBL-VDL-CNL-CCL	520-2040, 1400-2028.5
Bihubar-3A	DIL--SP-GR-CAL	1986-514
	BCS	1986-514
	CDL-CNS-GR-Caliper	1986-540
	SWC	At well depth of 1986 m in 8.1/2” hole
Bihubar-4	DIL-SP	387-2397, 3250-3870
	LL-3	1550-2397
	DIL-SP	2389-3420
	BCS-CAL	2389-3407, 3250-3870
	CDL-CNS-GR	2375-3870
	SWC	At well depth of 3911 m (12.1/4” hole)
	DLL-MSFL-GR-SP-CAL	3936.9-4595.5
	CBL-VDL-GR	2900-4140

Table 4-20: WELL WISE CORE DETAILS

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Bihubar-1	CC-1	2524-2532 m	75 %	Sandstone
	CC-2	3001-3008 m	Nil	-
	CC-3	3075.55-3083.55 m	100 %	Sandstone
	CC-4	3309-3317 m	62.5 %	Sandstone
Bihubar-2	CC-1	629-633.25 m	Poor recovery	Sandstone
	CC-2	3905-3913 m	91%	Sandstone
Bihubar-3	CC-1	541-546 m	35 %	Sandstone
	CC-2	636-641 m	40 %	Sandstone
Bihubar-3A	No Conventional Cores were cut in this well.			
Bihubar-4	No Conventional Cores were cut in this well.			

4.3.2.3 Well log evaluation and initial test results (BIHUBAR Field):

Petrophysical analysis was evaluated for the objectives tested in the wells drilled in the Bihubar Field and the derived parameters are shown in **Table 4-21**.

Table 4-21: PETROPHYSICAL RESULTS OF THE PROSPECTIVE ZONES IDENTIFIED IN BIHUBAR WELLS

Well	Object	Sand	Porosity %	Sw %
Bihubar-1	Obj-I	TS-5A	14-15	77
	Obj-II	TS-4B	13	80
	Obj-III	TS-2	19	86
Bihubar-2	Obj-I	BMS	Poor Hole condition	
	Obj-II	BMS	11	62
	Obj-III	BCS	11	67
	Obj-IV	BCS	11	80
	Obj-V	BCS	8	81
	Obj-VI	Barail	9-12	63
	SFT at 4102 m gave 1 litre of mud filtrate with traces of waxy crude oil.			
Bihubar-3	Obj-I	GC	12	65-100
	Obj-II	GC	25-30	70-100
	During SFT run several attempts were made to collect sample. But no influx was observed and in most places' packer seat was not available.			
Bihubar-3A	Obj-I	TS-1	16-24	55
	Obj-II	BMS	9	76
	Obj-III	BMS	10	NR
Bihubar-4	Obj-I	BCS-III	18	NR
	Obj-II	BCS-IV	25	NR
	Obj-III	TS-5B	10	NR

NR = Not reliable

Log motifs for tested objects of wells Bihubar-1, Bihubar-2, Bihubar-3, Bihubar-3A and Bihubar-4 are shown in **Figure 4-29 through Figure 4-35**.

Figure 4-29: LOG MOTIF OF WELL BIHUBAR-1

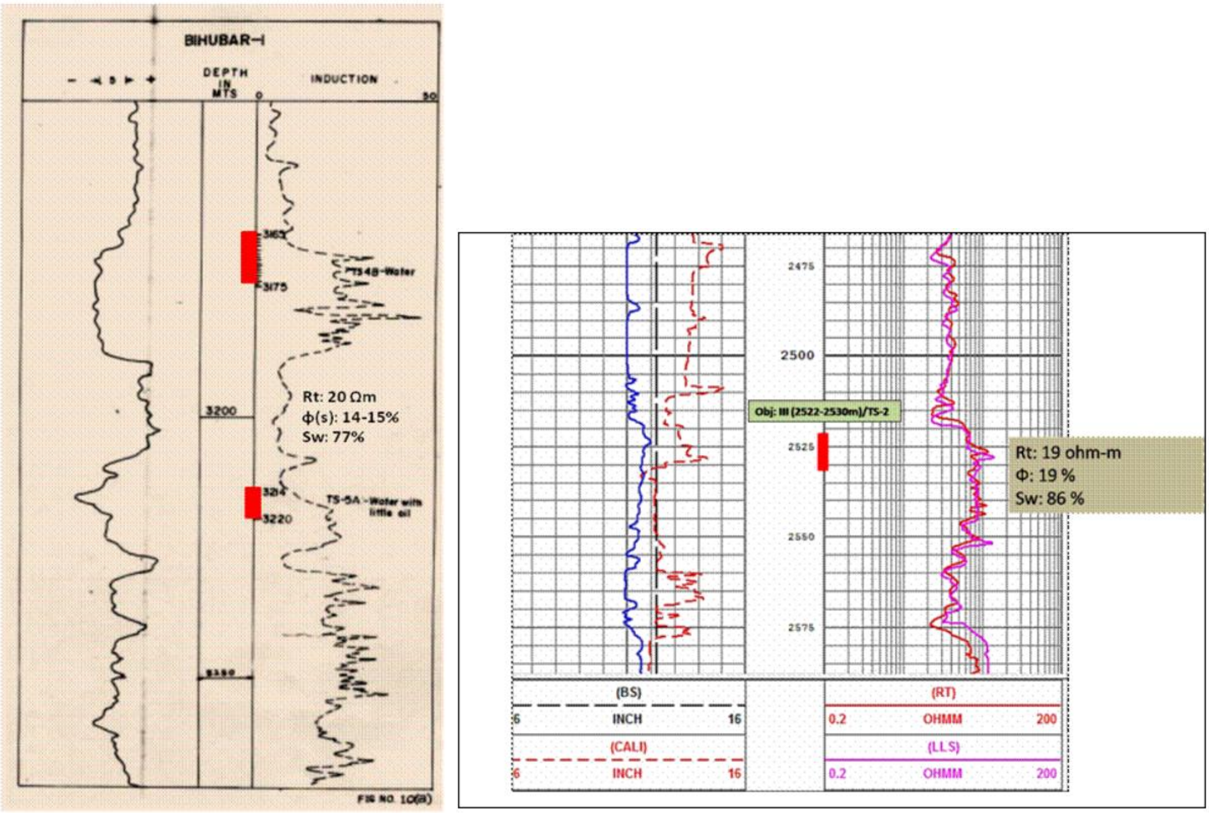


Figure 4-30: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS I, II, III & IV)

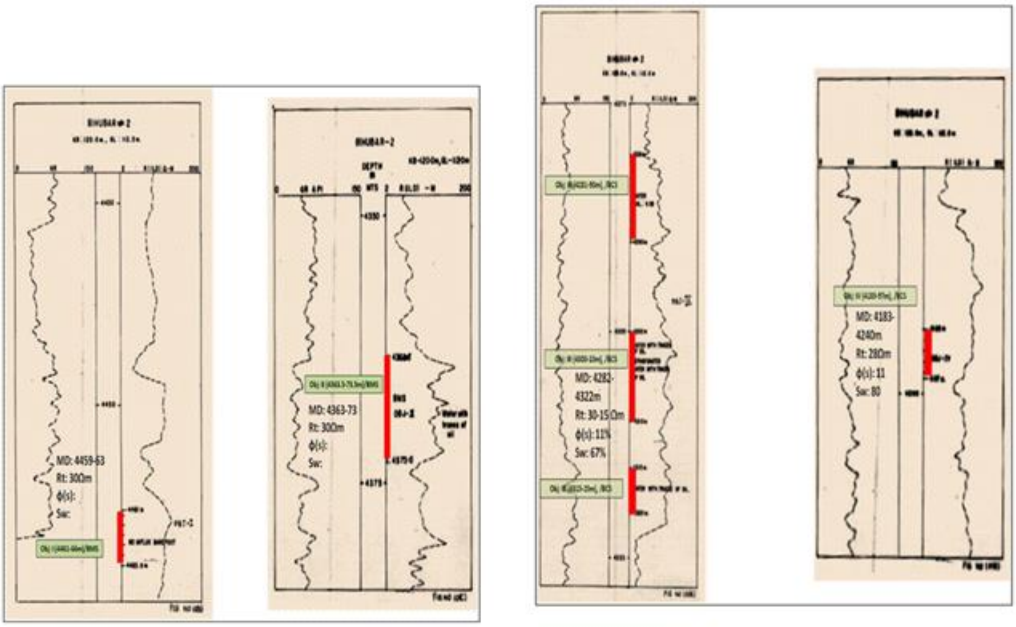


Figure 4-31: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS II & III)

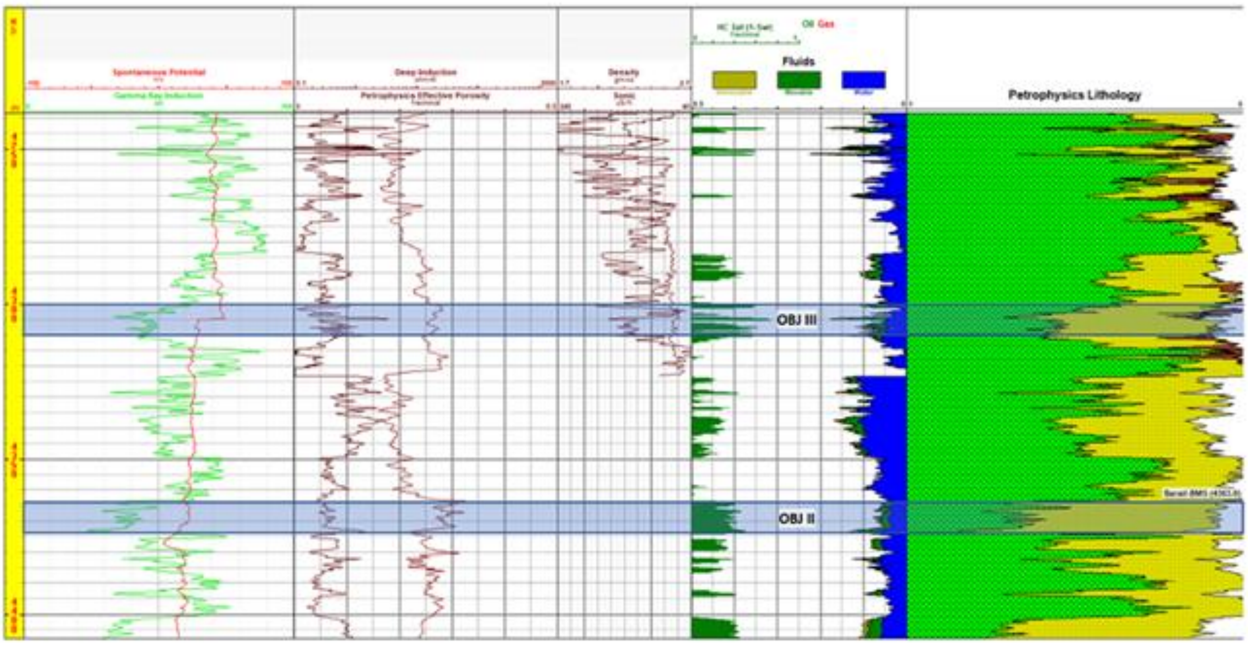


Figure 4-32: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS IV, V & VI)

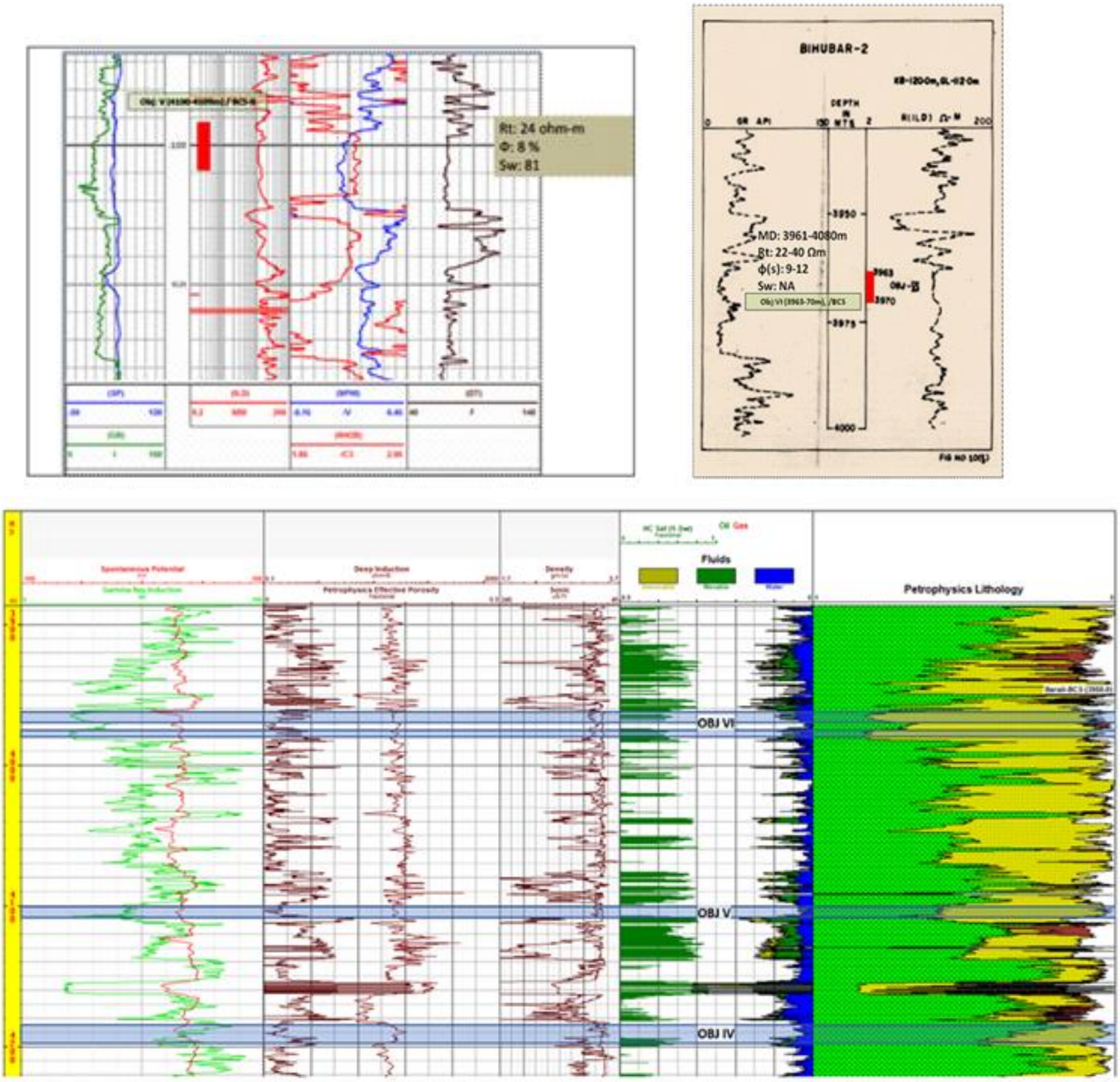
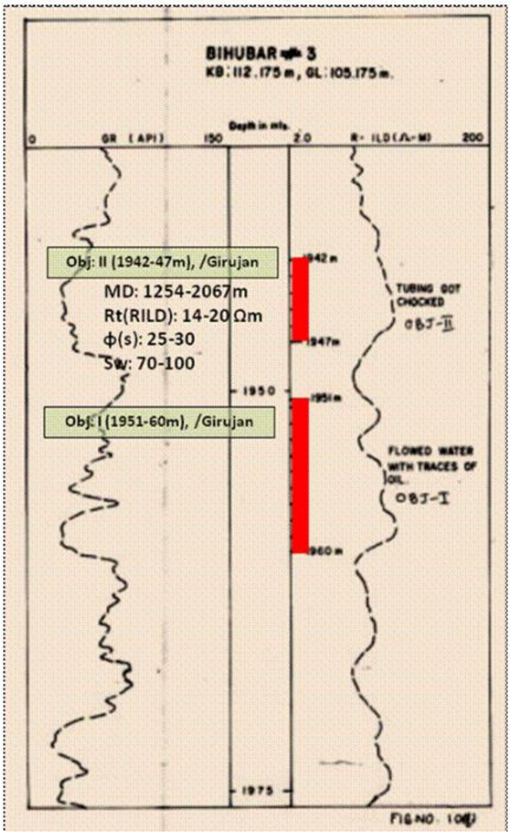


Figure 4-33: LOG MOTIF OF WELL BIHUBAR-3



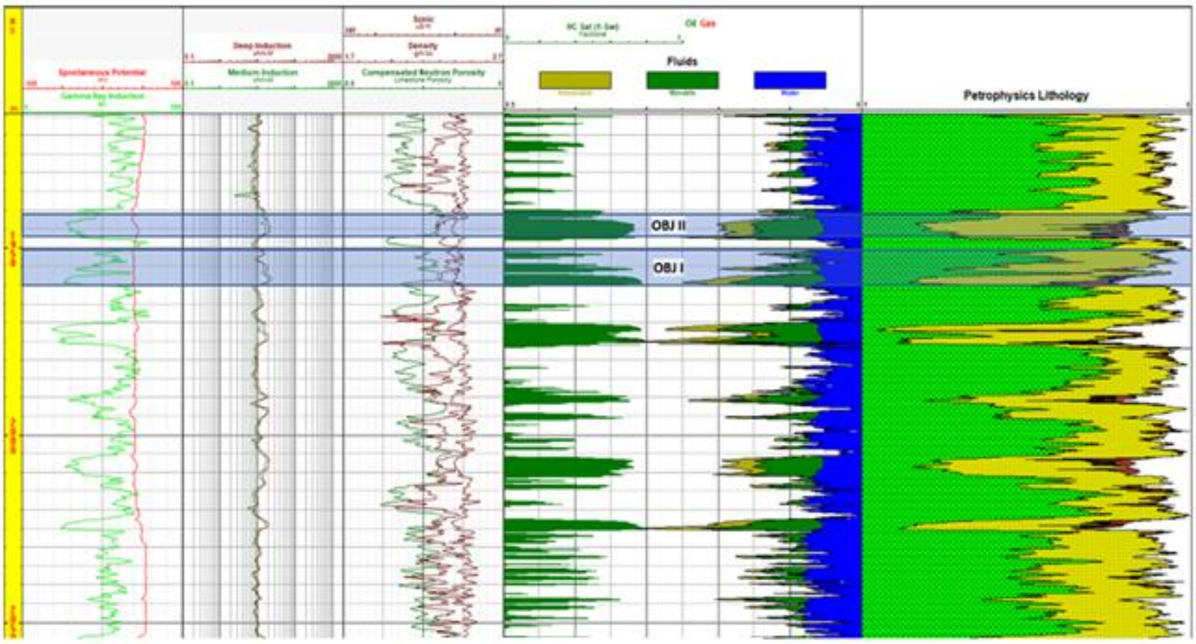


Figure 4-34: LOG MOTIF OF WELL BIHUBAR-3A

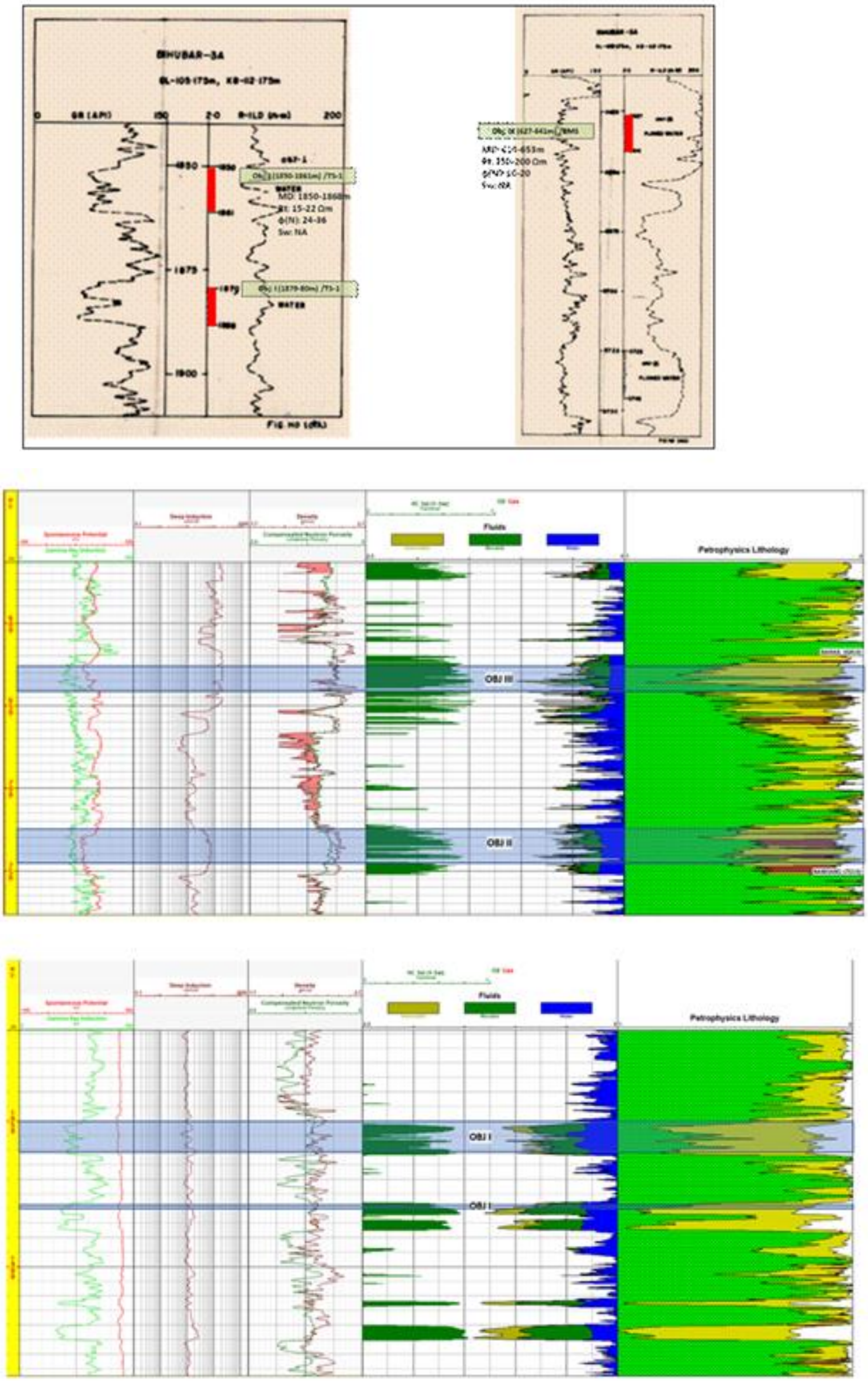
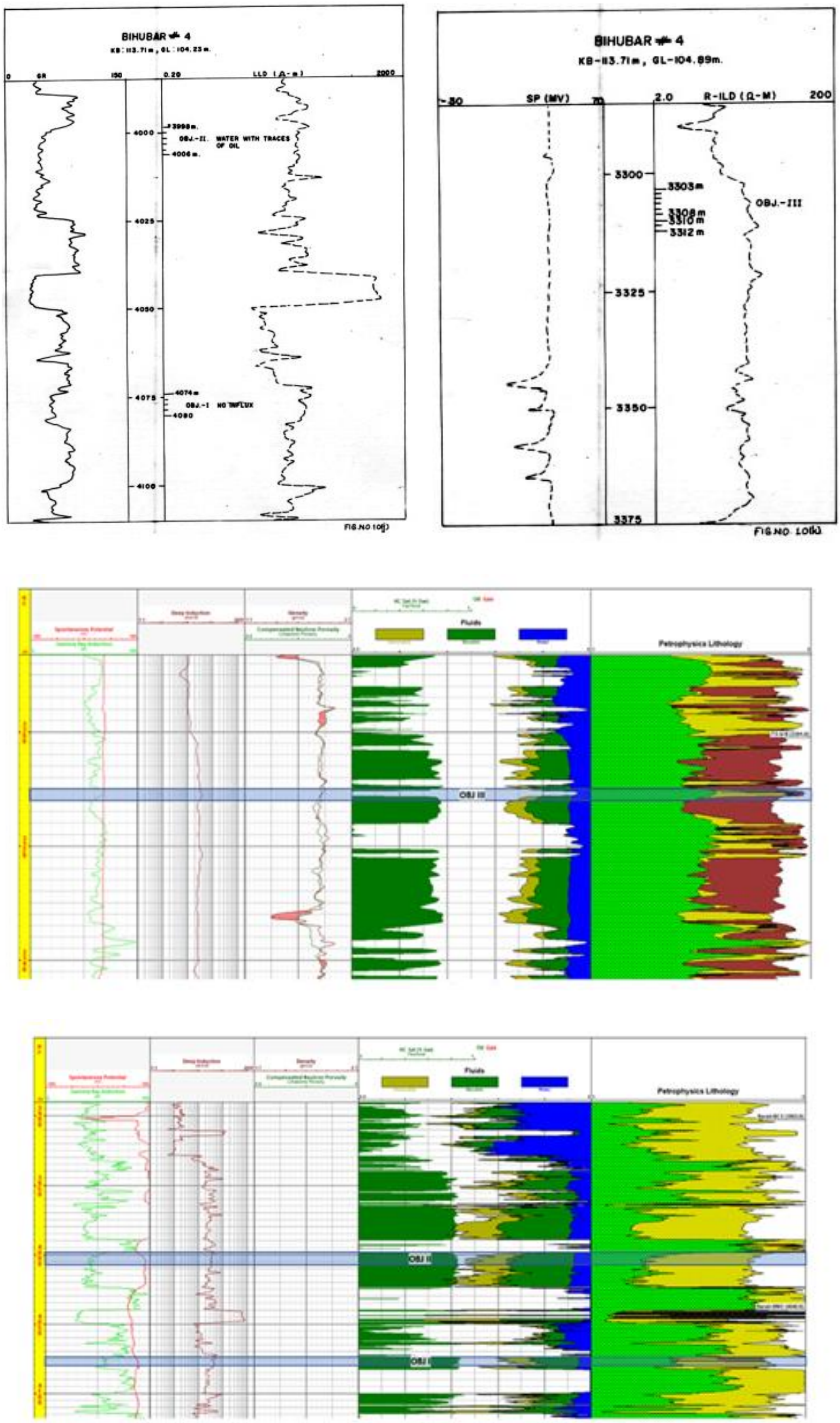


Figure 4-35: LOG MOTIF OF WELL BIHUBAR-4



4.3.3 Well testing and workover history

In Bihubar Field, 5 Exploratory wells have been drilled and tested. The well-wise/object wise testing details are given in **Table 4-22**.

Table 4-22: PRODUCTION TESTING RESULTS OF BIHUBAR WELLS

Well	Object	Sand	Perforation Range m	Flow Test Results	Status
Bihubar-1 Abandoned	Obj-I	TS-VA	3214-3220	Poor influx. While changing over from well fluid to KCl solution for testing higher up sand, **small quantity of oil was observed**. The sand was then retested with CHDST and at a drawdown of 100 ksc fluid started flowing @300 l/hr before ceasing to flow. 3.7 cum of formation water surfaced with a maximum salinity of 2.817gm/l.	Tight sand. Water bearing with oil in traces
	Obj-II	TS-IVB	3165-3175	Approx. 42.75 cum of water was knocked by compressor application **without any trace of oil and gas.**	Poor influx
	Obj-III	TS-II	2522-2530	Not tested due to poor cement bond	Not Tested
BHBR-2 Abandoned	Obj-I	BMS	4461-4466	Poor Influx. While conditioning the hole prior to CHDST, **Gas with traces of oil was observed in the mud.** Conventionally tested Barefoot formation but very poor Influx except very feeble gas . Plugged back (BP)	Tight Sand with **traces of Gas** Bad Hole Cond+Fish
	Obj-II	**BMS**	**4364-4374**	Produced **25-30m^3 of oil, 125-130m^3 of water & continuous flow of gas**, water salinity 5.148 gm/l. Could not be tested further due to suspected channelling Plugged back (CP)	**Presence of viscous oil with gas.** Flow did not sustain. **Oil content 15%-20%**
	Obj-III	BCS	4315-4320 4300-4310	Produced 41.5m^3 of water and **3.7m^3 of oil**, water salinity 5.26-5.5gpl.	3 zones tested with **flow/recovery of water, oil and gas observed**. Poor cementation, formation damage suspected.
			4281-4290	Produced 5.5m^3 of water **traces of oil and feeble gas**. Surfaced flow –nil total influx-3.80 m^3 (**60-100 lt of oil** rest water, silty mud slurry, **feeble gas** (tested both the intervals) water salinity 2.8-4.8 gm/ll.	

			4281-4290 (Repeat)	Repeat: **Surface flow-feeble gas total influx=2.3m^3,100-150 lt of oil,**1.2m^3 of silty slurry,1.1m^3 of muddy water, water salinity 3.2-4.09gpl, formation pressure-562.5 kg/cm^2 Plugged back (BP)	
	Obj-IV	BCS	4185-4197	Muddy Water Influx of 269 cum. Salinity 1.93 gms/l to 4.094 gms/l **with traces of floating oil.** Plugged back (CP)	Water bearing **with traces of oil & gas**
	Obj-V	**BCS**	**4100-4109**	Influx of water @, 2lt/min with **traces of oil, feeble gas**, Total influx-7.79 cum, water-7.74 cum, oil-50 lt, mild flow of gas with salinity:1.87gm/l, Formation pressure-422.5 ksc	Water bearing **with traces of oil & gas**
	Obj-VI	Barail	3963-3970, 3975-3980	Influx of water @, 2lt/min **with traces of oil, feeble gas**, Total influx-7.79 cum, water-7.74 cum, oil-50 lt, mild flow of gas with salinity:1.87gm/l, Formation pressure-422.5 ksc	Water with **feeble gas,** Well abandoned by placing two cement plugs.
BHBR-3	Obj-I	Girujan Clay	1951-1960	Only Water Influx with trace oil. + Heavy Sand cut. No sustained flow. Plugged back (BP)	Water bearing
	Obj-II	Girujan Clay	1942-1947	The tubing string got choked during activation (2nd compressor application) and circulation could not be established. The tubing got stuck and could not be released (heavy formation sand cut was suspected) so the object could not be tested completely.	Unstable hole. Inconclusive Testing
BHBR-3A Abandoned	Obj-I	TS-1	1879-1880, 1850-1861	1.83m^3 of formation water with fine sand. Plugged back (BP)	Water bearing.
	Obj-II	BMS	725-745	Water bearing, sal 0.3-0.4 gpl Plugged back (BP)	Water bearing.
	Obj-III	BMS	627-641	Water bearing; sal 0.2-0.3 gpl Plugged back (CP)	Water bearing.
BHBR-4 Abandoned	Obj-I	BCS-III	4074-4080	Poor influx. Plugged back (BP)	Tight formation
	Obj-II	BCS-IV	3998-4006	Water bearing with **traces of oil.** On opening annulus to subdue the well **flow of oil up to 0.25 cum was observed which subsequently ceased**. Plugged back (BP)	Water bearing with traces of oil
	Obj-III	TS-5B	3310-3312	Poor influx; Water bearing	Water bearing

4.3.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/ results.

Formation dynamics tests (Well BIHUBAR-1)

No MDT/RFT/SFT has recorded in the Bihubar wells.

4.3.5 Geology and Reservoir Description of BIHUBAR Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.3.5.1 Geological correlations, sections and maps (BIHUBAR Field):

The Laxmijan-Bihubar area, situated to the south of River Brahmaputra, lies along the Naga Schuppen belt which is a narrow linear imbricated thrusted zone of eight to nine major thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf. The Naga Schuppen Zone flanks the Assam Shelf which is to the northwest. However, extension of the Shelf sediments in the subsurface is also established further southeast with such sediments being encountered in all the Bihubar wells. Geologically, Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE, and is a narrow belt of sediments about 100 km wide and bounded by two thrust belts to the north in the Eastern Himalayas and the southeast viz. Naga Schuppen Belt, respectively. The imbricate thrusted zone viz. Naga Schuppen belt exposes Tertiary sediments (Tipams in the Laxmijan-Bihubar area) along different thrust slices. The belt is bounded by Naga Thrust in the north west and Disang Thrust in the southeast. The overthrusts bifurcate and rejoin either with the Naga Thrust or Disang Thrust.

The Namdang High is an anticlinal fold exposing topmost part of Barail in its core and plunging towards Bihubar and Laxmijan. It is an asymmetrical fold with a gentle southeastern limb and steep northwestern limb. Laxmijan-Bihubar Fields lie on the southeastern limb of the anticline and reservoir lithology are the sands within Tipam and Barail Groups trapped in this structural setting. The seismic data of the Laxmijan-Bihubar areas and correlation of drilled wells show the presence of the structural high which has been named Laxmijan-Bihubar High. This sub-thrusted Laxmijan-Bihubar High is separated from the Geleki High towards the west- northwest by a Low. A prominent arcuate transverse fault hading southwards separates Laxmijan area from the Bihubar area. The areas are further dissected by a number of faults trending NE-SW resulting in a number of discrete blocks and culminations. Geleki oil field to the west-northwest is updip to the Bihubar and Laxmijan structures for Barail zones. Most of the in-place oil volumes in the area are confined within multi-cycle sandstone reservoirs belonging to the sandstones of Tipam Group and the Barali Group of sediments.

The Chalimsen and Naga thrusts are two major faults which pass through the Bihubar wells. The Chalimsen thrust brings the Barails over Namsang whereas the Naga thrust brings the Tipam Sandstones over the Girujans. The sequence below the Naga Thrust, starting from Girujan Clay is a normal succession. In general, the stratigraphy of the sequence at Bihubar structure is about 250 m updip as compared to Laxmijan but is about 300m lower to the Geleki structure.

The hydrocarbon reservoirs of this field occur in the sand–shale sequence of the Barail (Oligocene) section (both BCS and BMS) and Tipam sandstones. The reservoirs are defined by heterogeneous lithology of medium to fine grained tight sandstone, finely interlaminated with siltstone/shale(occasionally carbonaceous) within the Barail. The entrapment has been interpreted to be strati-structural. The Barail sediments in the area are primarily deltaic in origin where the distributary channels of the overlying Rudrasagar Formation consisting of Coal-Shale Sequence prograded over the delta front environment of the Demulgaon Formation which is also known as the Barail Main Sand (BMS) The sediments unconformably overlying the Barails belong to the Tipam Group of Miocene age which were deposited under fluvial depositional conditions in mostly high energy environment as braided channels. After the close of Tipam times, positive movements resulted in the emergence of landform sand subsequent erosion are reflected in the unconformable relations between the Tipams and overlying sediments consisting of arenaceous units with sub equal proportion of claystone, clay and silt of Moran Group during Pliocene-Pleistocene. The Recent Alluvium constitutes the youngest stratigraphic unit in the Basin. The stratigraphic column of Bihubar area is presented in a tabular form.

Seismic sections in Laxmijan-Bihubar-Geleki Fields are given in **Figure 4-36 and Figure 4-37.**

Figure 4-36: SEISMIC SECTION ACROSS LAXMIJAN-BIHUBAR AND GELEKI FIELDS

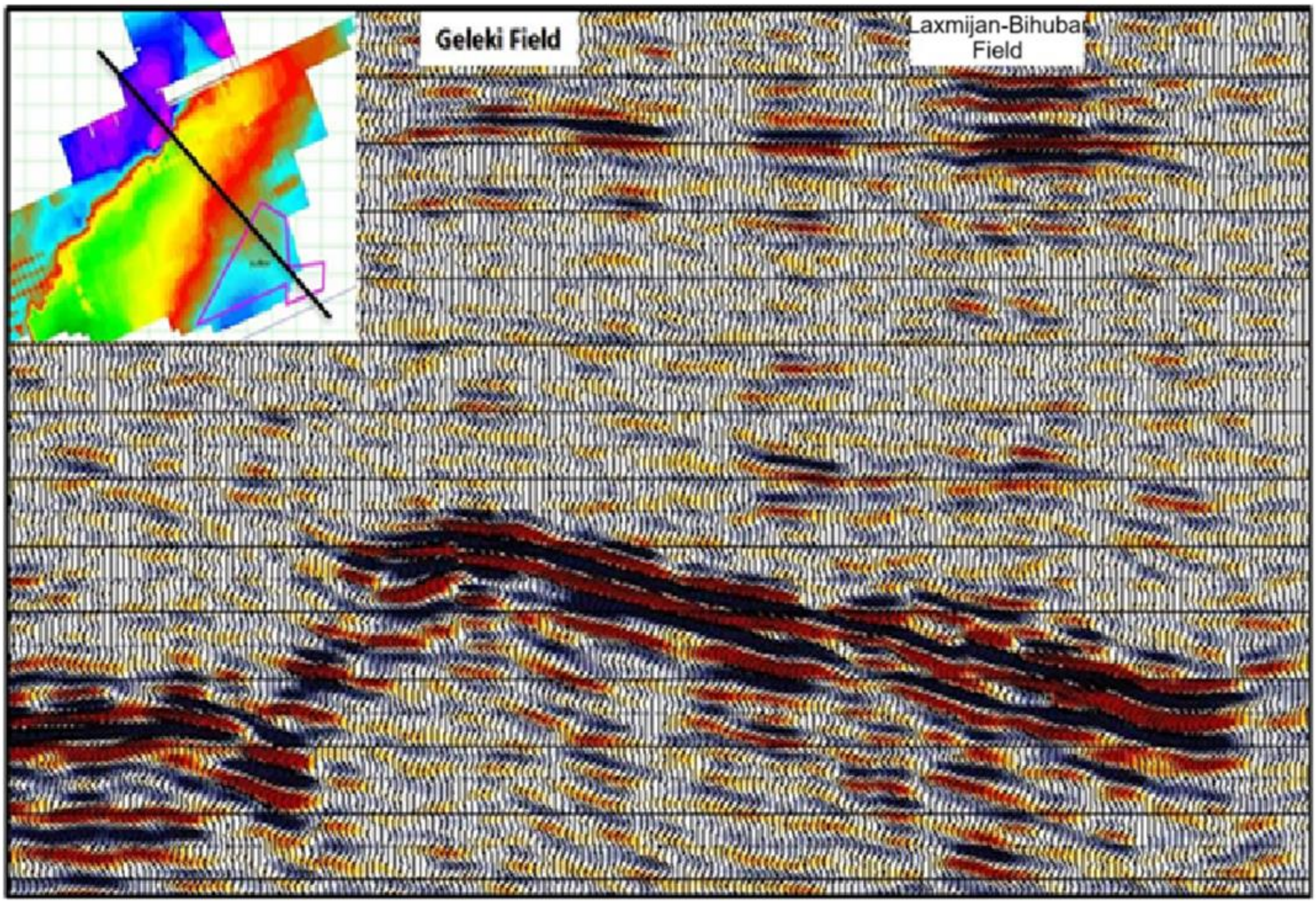
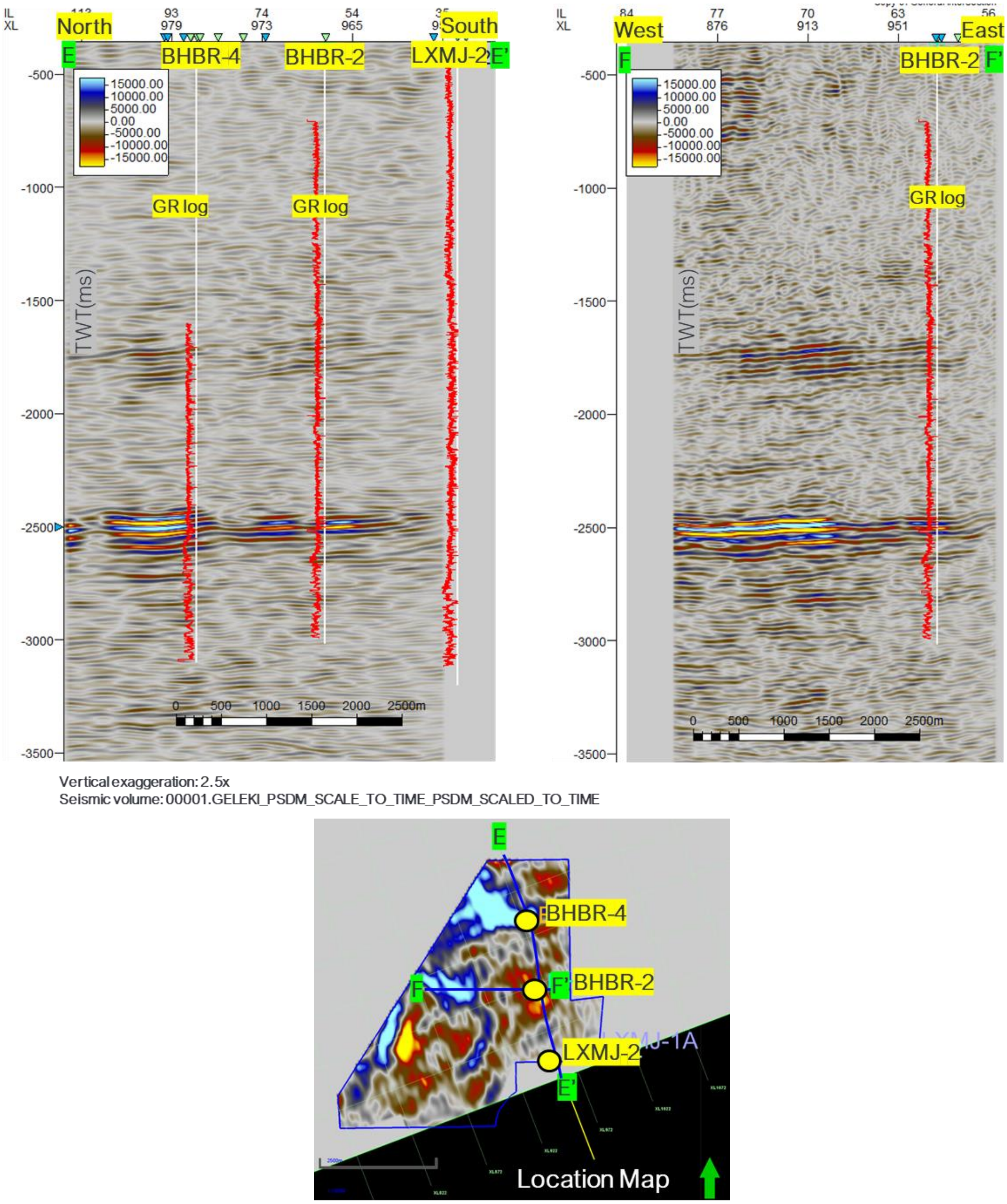


Figure 4-37: SEISMIC SECTION ACROSS WELLS BIHUBAR-2, BIHUBAR-4 AND LAXMIJAN-2



A) STRUCTURE (BIHUBAR Field):

Bihubar structure falls on eastern side of Geleki oil field. Available seismic data indicates that Bihubar structure up to the Tipam level is a northern plunging structure influenced by the Naga Thrust. The structural disposition is depicted in the depth structure contour map on top of TS-5A and BMS shown in **Figure 4-38 and Figure 4-39** respectively.

Figure 4-38: DEPTH STRUCTURE MAP ON TOP OF TS 5A

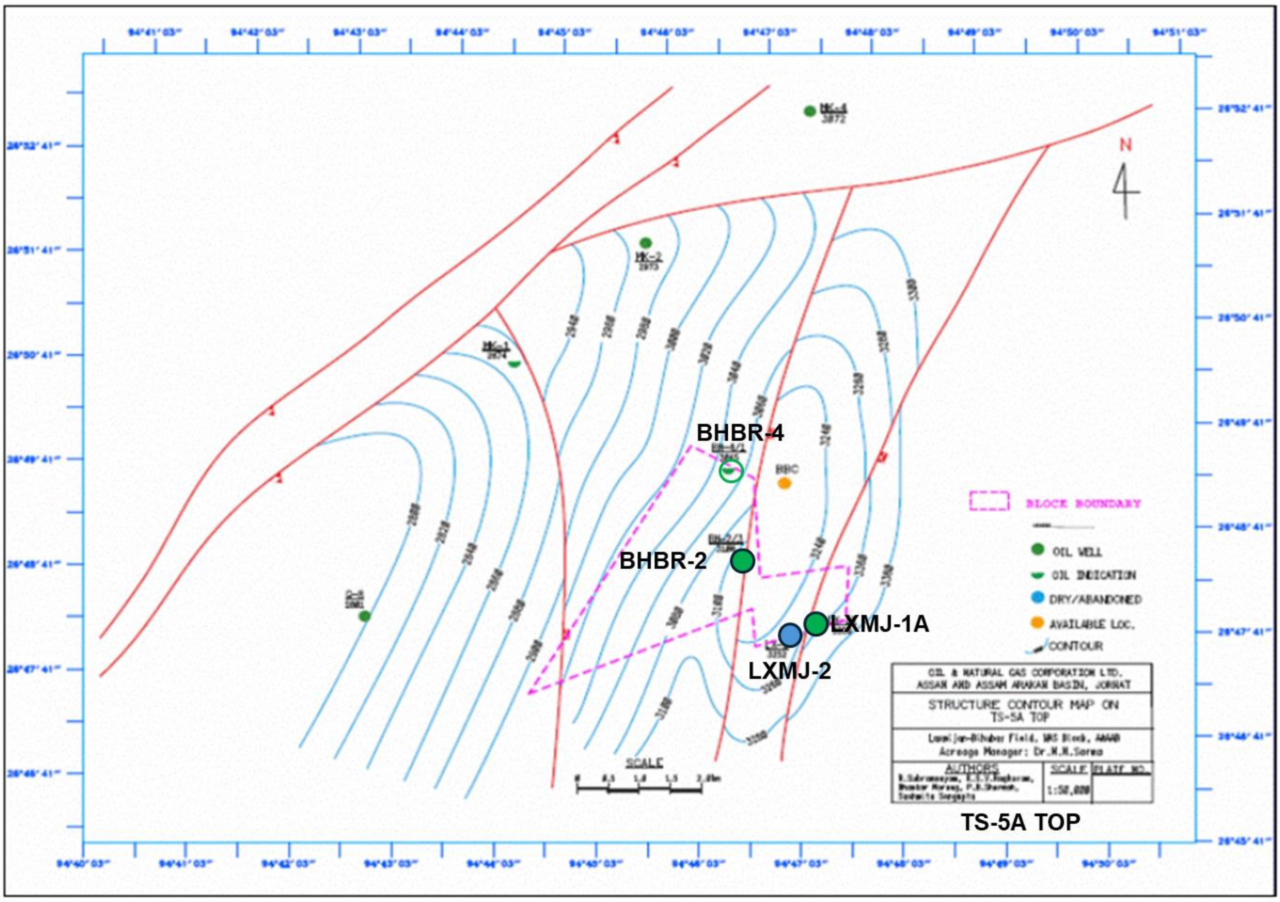
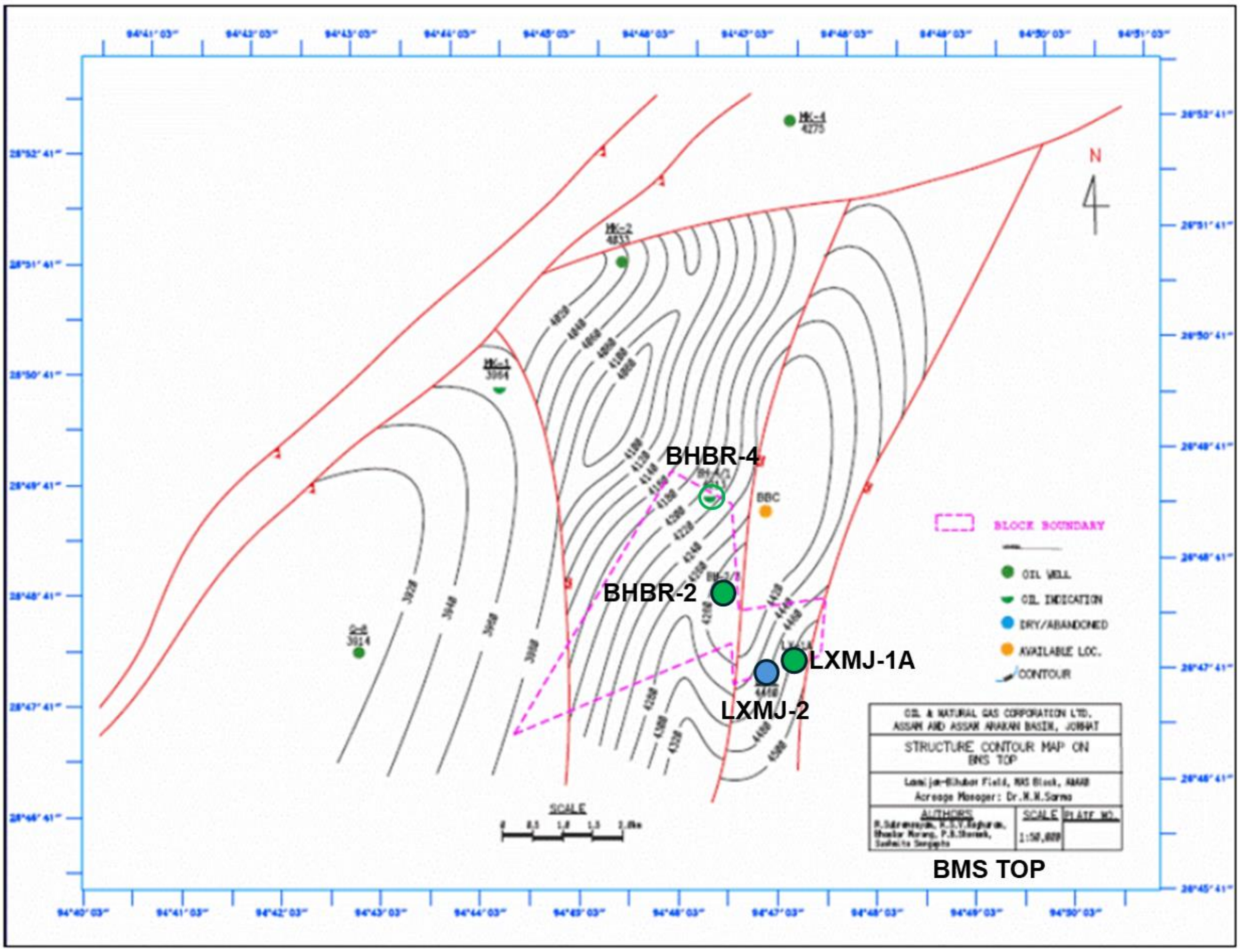


Figure 4-39: DEPTH STRUCTURE MAP ON TOP OF BMS



The NW-SE electro-log correlation profile, both stratigraphic and structural, in the Bihubar-Laxmijan area, along wells Bihubar-4, Bihubar-2, Laxmijan-2 and Laxmijan -1A is shown in **Figure 4-40 and Figure 4-41.**

Figure 4-40: STRATIGRAPHIC ELECTRO LOG CORRELATION OF WELLS BIHUBAR -4, 2 AND LAXMIJAN-2, 1A

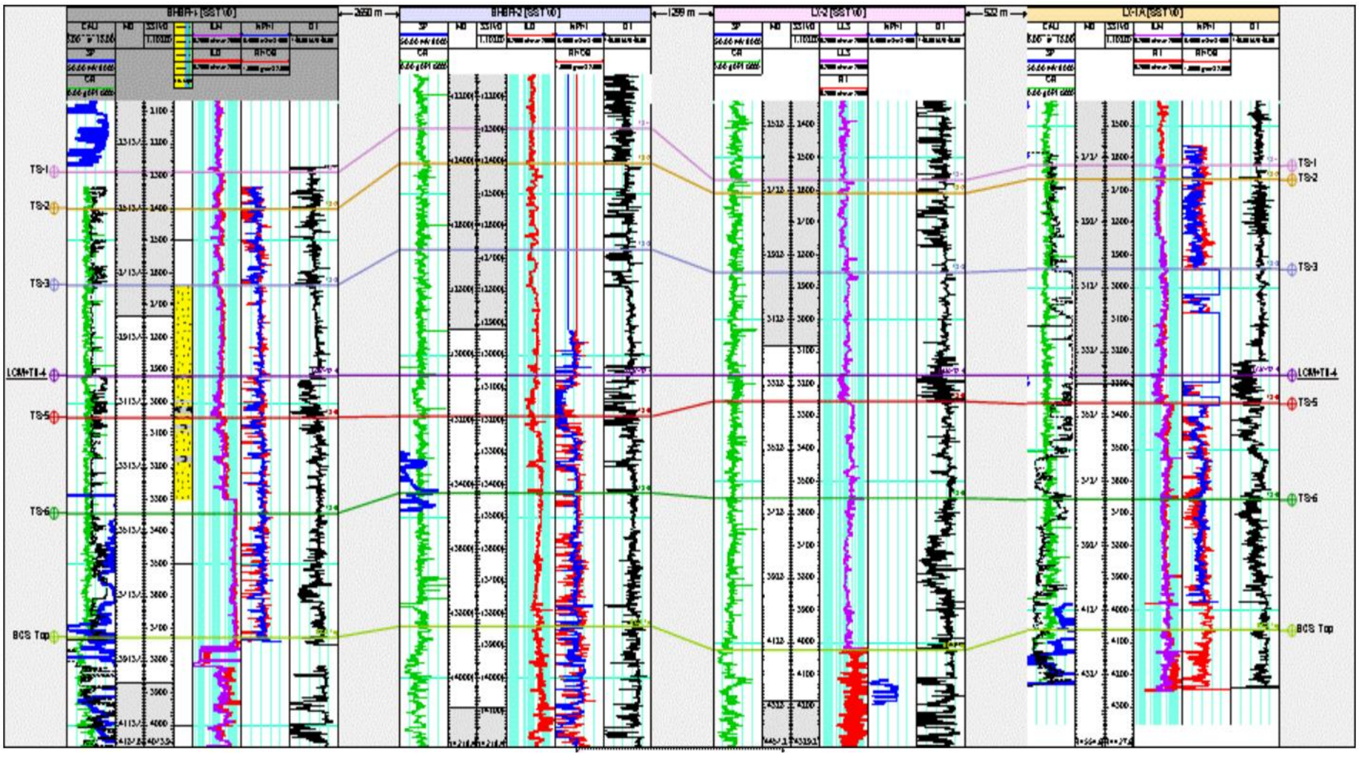
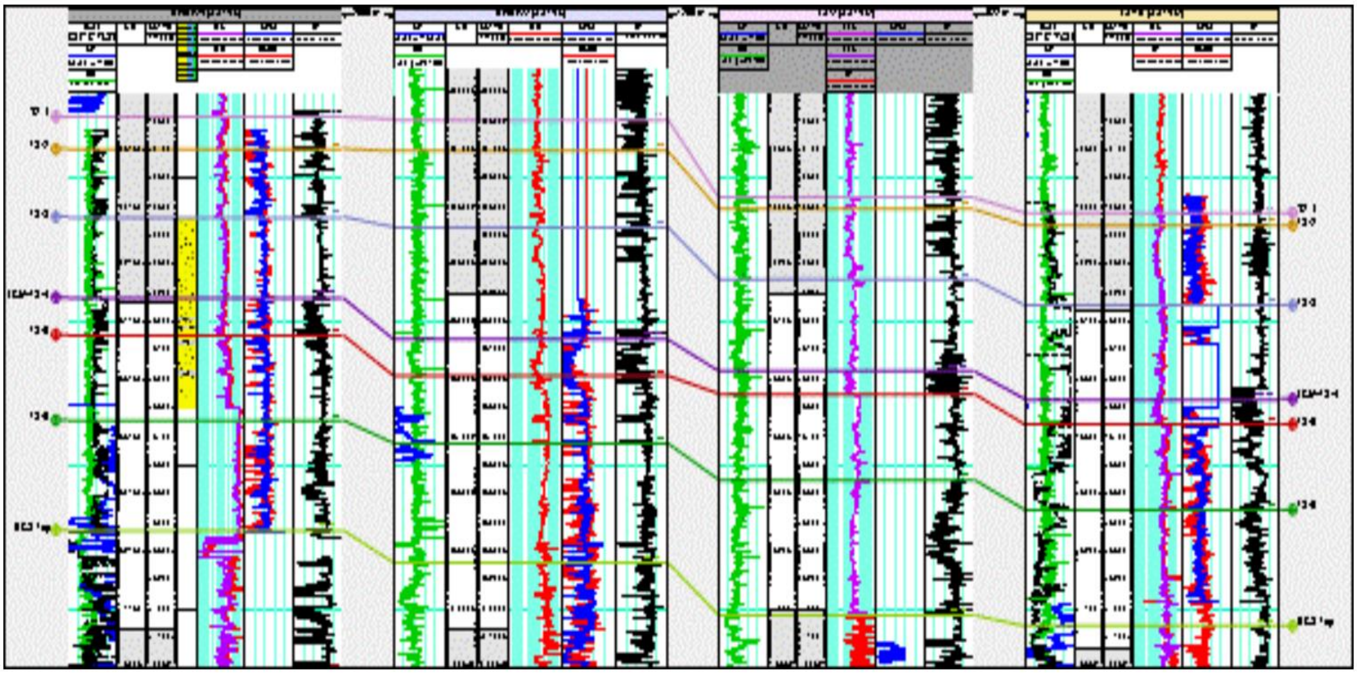


Figure 4-41: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BIHUBAR -4, 2 AND LAXMIJAN-2, 1A



Stratigraphic column of Bihubar area based on well data is depicted in **Table 4-23 below**.

Table 4-23: STRATIGRAPHIC COLUMN OF BIHUBAR AREA

GE	FORMATION/ GROUP	THICKNESS (M)	LITHOLOGICAL DESCRIPTION
Recent-Pleistocene	Alluvium	100	Unconsolidated sands with gravel, silt and minor clays
Miocene	Tipam	280	Mainly coarse unconsolidated sand with minor soft clay
	Safrai	85	Sandstone : Coarse grained Polymeric Conglomerate / coarse Sandstone
Oligocene	Barails	155	Carbonaceous shale and coal with alternations of sand & shale.
Thrust			
Plio-Miocene	Namsang	235	Sandstone / Claystone
	Upper SSt Girujan clay Tipam Sandstones	1500	Sandstone / Claystone
Thrust			
Plio-Miocene	Girujan Clay Tipam	1326	Claystone and Dominantly sandstone with intercalations of minor shale
Oligocene	Barails	690+	Sandstone, Shale, Coal

4.3.5.2 Reservoir parameters and hydrocarbon estimates (BIHUBAR Field):

4.3.6 Studies on Bihubar-Laxmijan Area

A Field development plan (FDP) for the combined Bihubar-Laxmijan cluster was prepared by Megha Engineering & Infrastructure Ltd (MEIL) in the year 2019. Two major parts in this study were recognized. The first part is geological and geophysical interpretation of the Block to better understand the petroleum system including extensive petrophysical work and to be a feeder for the second part, which is the reservoir engineering and economic reserve evaluation.

Table 4-24 shows the derived parameters for the objectives tested in the wells drilled so far. The table follows with the individual interpretation of each zone carried out by MEIL.

Table 4-24: DERIVED PARAMETERS FOR THE OBJECTS TESTED IN THE DRILLED BIHUBAR WELLS

Well	Object	Sand	Depth Range	FlowTest Type	Flow Test Results	Status	HC Sat	Porosity	Sw
BHBR-1	Obj-I	TS-VA	3214-3220	CHDST	Injectivity NIL	Dry			
	Obj-I	TS-IVB	3165-3175	CHDST	Injectivity NIL	Dry			
	Obj-III	TS-II	2522-2530	CHDST	Not tested due to poor cement bond	Not Tested			
BHBR-2	Obj-I	BMS	4461-4466	CHDST	Gas Traces. No Influx.	Bad Hole Cond+ Fish			
	Obj-II	BMS	4364-4374	CHDST	Presence of viscous crude oil with gas. Capable of self-flow oil content 15%-20%	Oil may be highly viscous. No sustained flow	38	0.11	77
	Obj-III	Barail Ch.	4310-4300	CHDST	100-150ltr of oil influx. Continuous flow of feeble gas	Oil may be highly viscous. No sustained	22	0.11	67

Well	Object	Sand	Depth Range	FlowTest Type	Flow Test Results	Status	HC Sat	Porosity	Sw
						flow			
	Obj-IV	Barail	4185-4197	CHDST	Muddy Water Influx	Dry	11	0.06	89
	Obj-V	Barail	4100-4109	CHDST	Traces of oil and feeble gas	Trace HC	19	0.08	81
	Obj-VI	Barail	3963-70, 75-80	CHDST	Traces of gas	Trace Gas	37	0.07	63
BHBR-3	Obj-I	GC	1960-1951	OHDST	Only Water Influx with trace oil. + Heavy Sandcut. No sustained flow	Dry	35	0.12	65
	Obj-II	GC	1947-1942	OHDST	Unstable hole. Test Inconclusive.	N/A	55	0.19	45
BHBR-3A	Obj-I	TS-1	1880-79, 61-50	CHDST	Water bearing	Dry	45	0.22	55
	Obj-II	BMS	745-25	CHDST	Water bearing	Dry	45	0.09	55
	Obj-III	BMS	641-627	CHDST	Water bearing	Dry	59	0.1	41
BHBR-4	Obj-I	BCS-III	4074-4080	Conventional	Water bearing	Dry	82	0.18	18
	Obj-II	BCS-IV	3998-4006	Conventional	Water bearing with traces of oil	Dry	82	0.25	18
	Obj-III	TS-5B	3312-3310	Conventional with DST packer	Water bearing	Dry	50	0.1	50

Area considered for Development in FDP:

Well Laxmijan 1A tested oil from shallower Tipam sandstone reservoir trapped below the Naga Thrust. The structure was inferred to be related to thrust drag. The closure of the structure could not be mapped due to the edge effects of 3D and very poor surface conditions. The deeper field development plan was focused on the northern part where wells Bihubar-4 and Bihubar-2 seem to have tested the downdip oil from the structure. In addition, a well for shallow target was planned to complete one of the hanging wall sheets for Barail and Tipam sands. The sheets were tested in well Bihubar-3A with water influx.

Well Laxmijan 1A was proposed for re-testing through workover. The zones proposed to be re-tested are TS-4B (3458 3465) and TS-5A (3492-3508). Two locations were proposed for drilling in the FDP for further evaluate the targets within BCS and BMS above and below the Naga Thrust. While the first well was planned to target the shallower objects, the second well was planned for the primary objects in the Barail Group.

Table 4.27: NEW DEVELOPMENT WELL LOCATIONS PROPOSED IN THE FDP

UWI	Common Well Name	Current Status	Operator	Surface X	Surface Y	3D Inline	3D Xline
LOC-A	Bihubar Location A	Location	MEIL	3217030.01	1013316.40	80	950
LOC-B	Bihubar Location B	Location	MEIL	3217028.61	1013585.66	85	954

For the Location B further studies will be required to develop well control strategies. As per the mapping of near top BCS there is a low amplitude structure that closes at the highest level 20-30 m above the drilled wells. If a single sand is used as the reservoir, we can estimate the in-place volumes as obtained in the study. As per the analyses of the data there is high possibility of encountering multiple sands within the closure.

The two tentative locations to evaluate the structural closures within upthrown fault block are shown below as **Figure 4-42**.

An Inline and Crossline through Location A is shown in **Figure 4-43 and Figure 4-44.**
Volume summary sheets for Locations A & B are given in **Table 4-25 and Table 4-26.**

Figure 4-42: LOCATIONS PROPOSED IN LAXMIJAN-BIHUBAR CLUSTER IN THE FDP

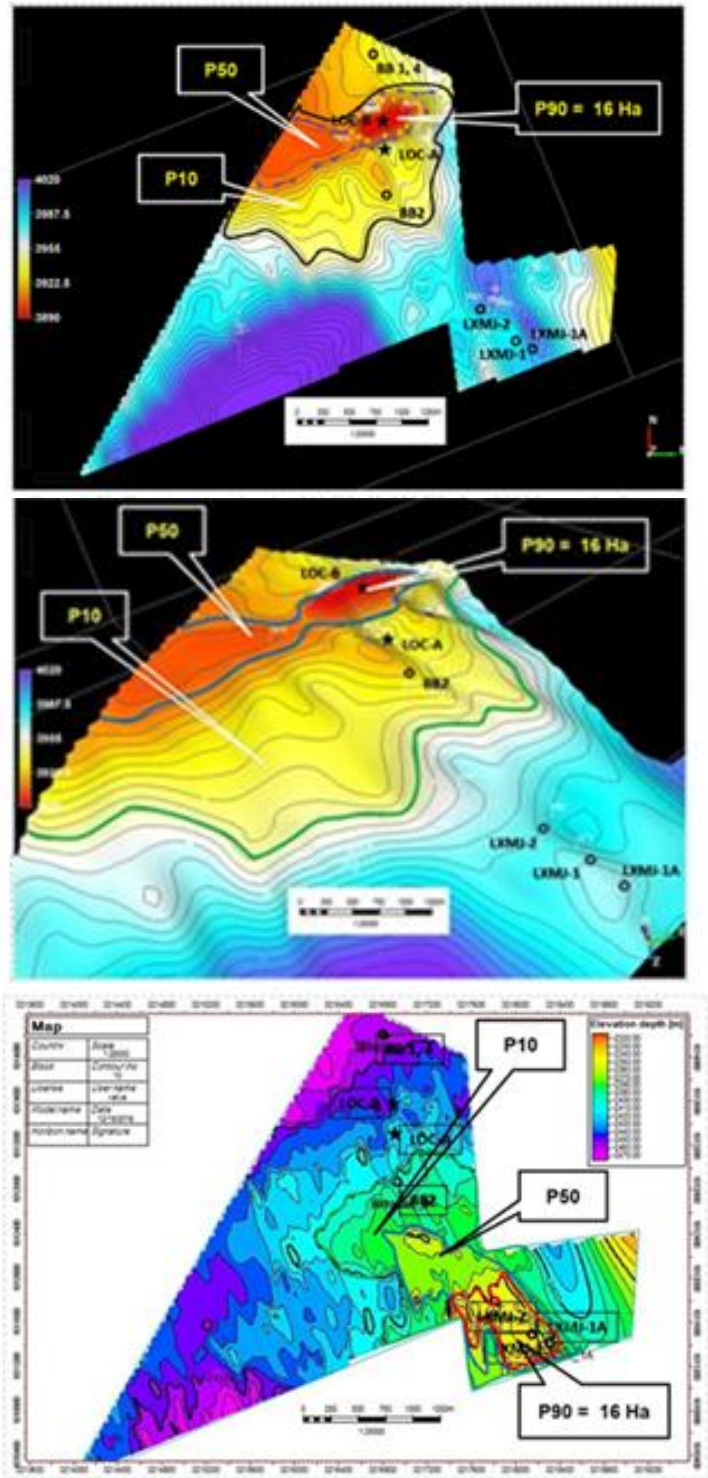
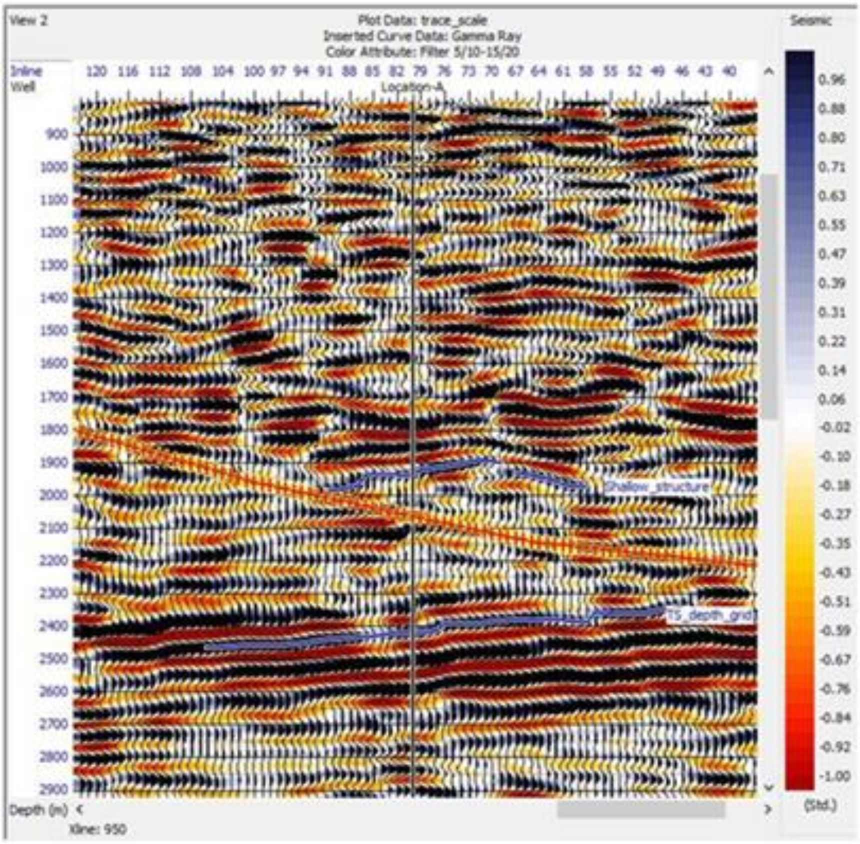


Figure 4-43: INLINE AND CROSSLINE THROUGH LOCATION A



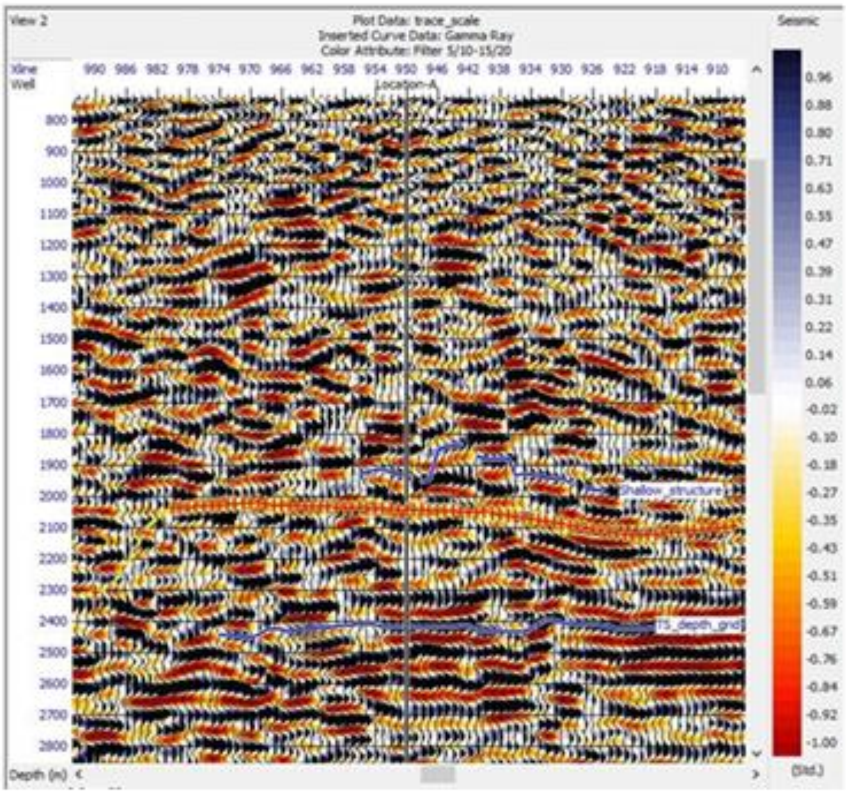
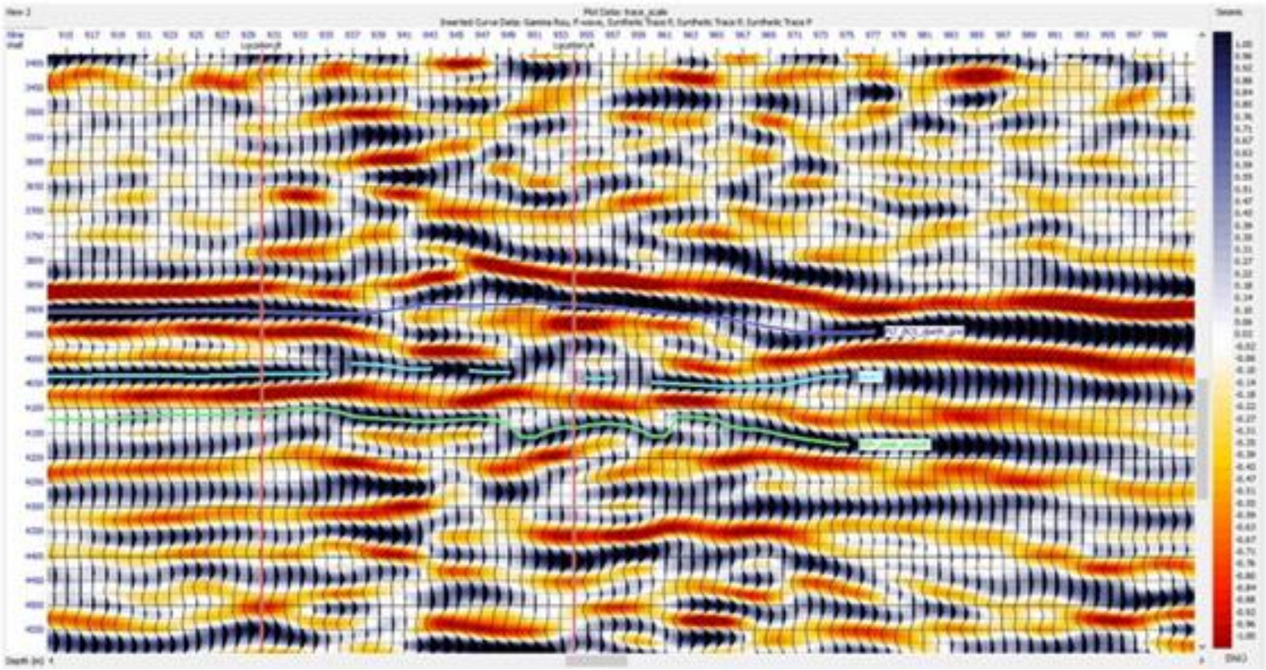


Figure 4-44: INLINE AND CROSSLINE THROUGH LOCATION B



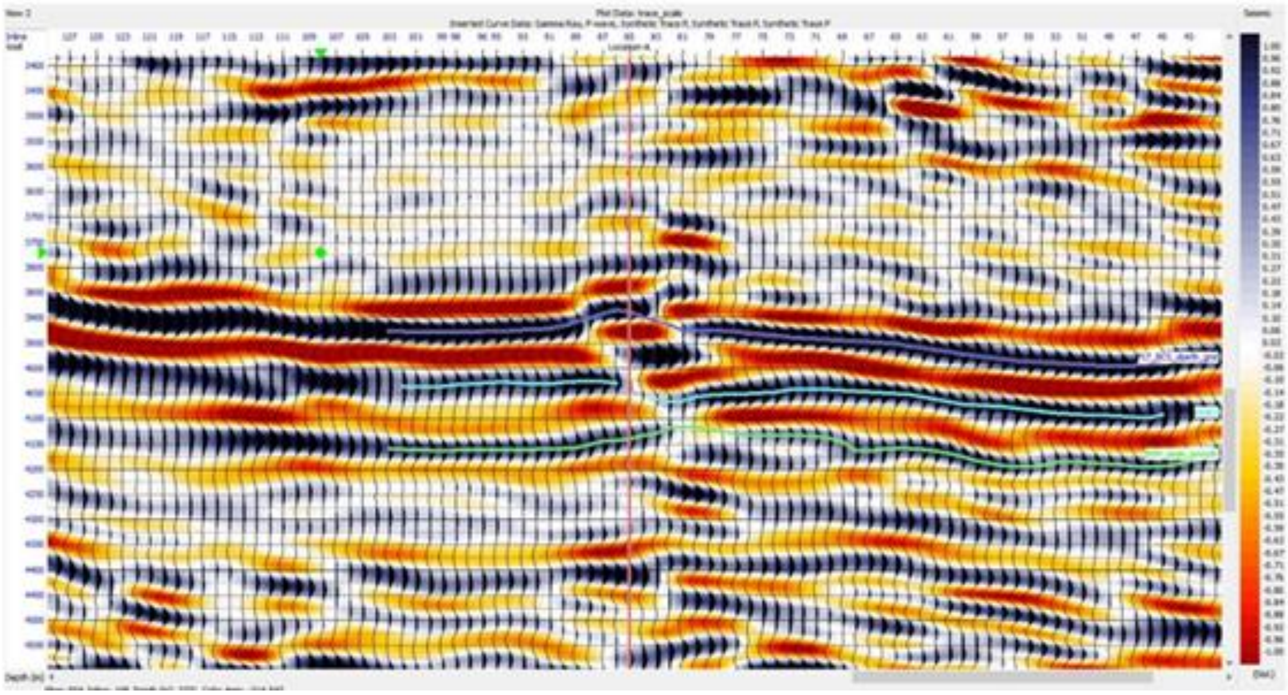


Table 4-25: Volume summary sheet for infill Location(FDP): A

Volume Summary Sheet

Hydrocarbon Type: oil

Field/Pool:	Laxmijan-Bihubar	**LOCATION:**	**Loc-A_sh**
Reservoir (Fm./Age):	**Barail**	**Lithology:**	Sandstone
Seal (Fm./Age):	**Taipam shales**	**Source (Fm./Age):**	**Miocene**
Depth (m):	**1850 m**		

A. ATTRIBUTES		*P90*	P50	*P10*	
1. Closure Area	*ha*	*8.0*	*15.5*	*30.0*	e
2. Gross Reservoir Thickness (m)		50	141.4	400	e
3. Closure Height (m)		20	28.3	40	o
4. Geometry Correction (dec.)					o
5. Corrected Res. Thickness (m)	*(equals (A2 or A3) x A4)*	20	28.3	40.	
6. Average Net / Gross (dec.)		0.2	0.32	0.5	o
7. Trap Fill (dec.)					o
8. Net Pay (m)	*(equals A5 x A6 x A7)*	*5.*	*8.9*	*15.9*	
9. Average Porosity (dec.)		0.12	0.155	0.2	e
10. Average HC Saturation (1-Sw) (dec.)		0.5	0.59	0.7	e
11. HC Volume Factor (1/ FVF)		0.9	0.92	0.95	e
12. HC Pore Volume (dec.)	*(equals A9 x A10 x A11)*	*0.0623*	*0.0847*	*0.1152*	

B. HYDROCARBONS IN-PLACE		P90	*P50*	P10	*Mean(Mz)*
1. (equals A1 x A8 x A12)	*(10^6 m3)*	**0.046**	**0.117**	**0.297**	*0.150*
(oil)	*(million bbls)*	0.29	0.74	1.9	0.94

C. RECOVERABLE HYDROCARBONS

	P90	P50	P10	
1. Recovery Factor (dec.)	0.2	0.24	0.3	e
2.				(blank)

		P90	*P50*	*P10*	*Mean*
3. (equals B1 x C1)	*(10^6 m3)*	**0.011**	**0.029**	**0.074**	**0.037**
	(million bbls)	0.07	**0.18**	0.47	0.23

D. RISKS: (dec.)	*Seal*	*Structure*	*Reservoir*	*Source*		*HCF*
	0.6	**0.7**	**0.7**	**1**	e	**0.29**

E. PREVIOUS SUCCESS RATIO: PSR =

Table 4-26: Volume summary sheet for infill Location (FDP): B

Volume Summary Sheet   Hydrocarbon Type: oil

Field/Pool: Laxmijan-Bihubar   LOCATION: Loc-B_BCS

Reservoir (Fm./Age): Barail   Lithology: Sandstone

Seal (Fm./Age): Taipam shales   Source (Fm./Age): Miocene

Depth (m) : 4100 m

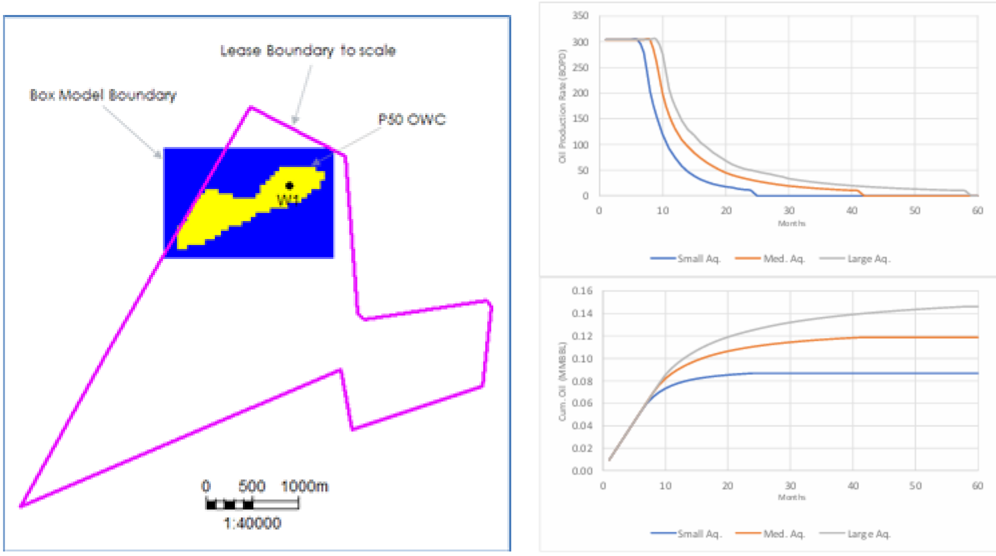
A. ATTRIBUTES		P90	P50	P10	
1. Closure Area	*ha*	*16.0*	*31.0*	*60.0*	e
2. Gross Reservoir Thickness (m)		50	141.4	400	e
3. Closure Height (m)		10	17.9	32	o
4. Geometry Correction (dec.)					o
5. Corrected Res Thickness (m)	*(equals (A2 or A3) x A4)*	10	17.9	32	
6. Average Net / Gross (dec.)		0.2	0.32	0.5	o
7. Trap Fill (dec.)					o
8. Net Pay (m)	*(equals A5 x A6 x A7)*	*2.7*	*5.7*	*11.9*	
9. Average Porosity (dec.)		0.1	0.141	0.2	e
10. Average HC Saturation (1-Sw) (dec.)		0.7	0.75	0.8	e
11. HC Volume Factor (1/ FVF)		0.9	0.92	0.95	e
12. HC Pore Volume (dec.)	*(equals A9 x A10 x A11)*	*0.0687*	*0.0979*	*0.1394*	

B. HYDROCARBONS IN-PLACE		P90	P50	P10	Mean(Mz)
1. (equals A1 x A8 x A12)	*(10^6 m3)*	0.060	0.172	0.492	*0.234*
(oil)	*(million bbls)*	0.37	1.1	3.1	1.5

C. RECOVERABLE HYDROCARBONS		P90	P50	P10	
1. Recovery Factor (dec.)		0.2	0.24	0.3	e
2.					(blank)

		P90	P50	P10	Mean
3. (equals B1 x C1)	*(10^6 m3)*	0.014	0.042	0.123	0.058
	(million bbls)	0.09	0.26	0.77	0.36

Figure 4-45: BOX MODEL FOR STUDYING SINGLE INFILL WELL BEHAVIOR WITH STOIIP OF 1.1 MMSTB AND THREE SCENARIOS OF AQUIFER SUPPORT (FDP)



One of the important parameter with uncertainty is the "tank size", i.e. the combined connected volume of the reservoir and the underlying aquifer. To assess its impact, this parameter has been sensitized with three different aquifer sizes with a BOX dynamic model (**Figure 4-45**):
Case 1 (Small Aquifer): Tank Pore Volume 5 MMRB
Case 2 (Medium Aquifer): Tank Pore Volume 22 MMRB
Case 3 (Large Aquifer): Tank Pore Volume 54 MMRB

The base case (Case-2/Medium Size Aquifer) yielded an EUR of 0.118 MMSTB, with at least two years of production. This is much lower than the EUR for the P50 case of 0.26 MMSTB obtained from a Volumetric Analysis using an RF of 24% (**Table 4-26**).

In the **Table 4-27** the expected well locations are summarized on the basis of sands that are expected to be encountered by workover at well LXMJ-1A and proposed infills Locations A & B.

Table 4-27: TARGET SANDS WITH PROMISING PARAMETERS FOR FURTHER TEST

Well	Object	Sand	Depth Range
LXMJ-1A	Obj-I	Barail	4218–4215
	Obj-II	TS-5B	3615–3607
	Obj-III	TS-5A	3508–3492
	Obj-IV	TS-4B	3465–3458
Loc A	Obj-I	TS-1	1880–1979, 1861–1850
	Obj-II	BMS	745–725
	Obj-III	BMS	641–627
Loc B	Obj-I	BMS	4461–4466
	Obj-II	BMS	4364–4374
	Obj-III	Barail Ch.	4310–4300
	Obj-IV	Barail	4185–4197
	Obj-V	Barail	4100–4109
	Obj-VI	Barail	3963–70, 3975–3980

Current Oil and Gas Volumes In-Place

Initial hydrocarbon resources have been estimated based on the production testing results, reservoir parameters and log motifs of the drilled wells. The reservoir parameters and hydrocarbon resources of Bihubar Field are tabulated in **Table 4-28 and Table 4-29 respectively**.

Table 4-28: RESERVOIR PARAMETERS & VOLUMETRIC ESTIMATION OF BIHUBAR FIELD

Field	Reser voir	Area	He	Phi	Hydrocarbon saturation		FVF		API	SPGR	GOR Sm3 /m3	O+OEG
	Sand/ layer	SKM	m		So	Sg	Bo	Z/Bg				MMTOE
Bihubar	BCS Obj-III	0.600	10	0.11	0.55	-	1.1800	-	32.1	0.8649	280	0.35
	BCS Obj-V	0.495	4.97	0.08	0.70	-	1.1800	-	32.1	0.8649	280	0.13
	BMS	0.450	7.5	0.11	0.60	-	1.1800	-	32.1	0.8649	280	0.22
												0.70

Table 4-29: HYDROCARBON IN-PLACE(2P) OF BIHUBAR FIELD

Field	O+OEG MMTOE
BIHUBAR	**0.7**

Erstwhile Operator-reported estimates on record:

A gas estimate of **0.15 MMTOE** had earlier been reported for the LAXMIJAN-BIHUBAR Cluster

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.3.7 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Bihubar Field is the **Geleki GGS** at a distance of **25 KM**

Well heads are available at wells Bihubar-2 and Bihubar-4 (abandoned).

AA/ONDSF/ASSAM/2025 (A&AA) BARSILLA FIELD

4.4 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) BARSILLA FIELD

The Barsilla Field is located at a distance of approximately 6 km SW of the prolific onland Geleki Field in the Assam Shelf area of the composite Assam & Assam-Arakan Basin (A&AA Basin) in the state of Assam situated in the northeast corner of India. The Barsilla Field covers an area of 6.21 sq. km. The coordinates of the end points defining the block boundaries are tabulated in the table below, (**TABLE 4-30**) and its location map is shown in **Figure 4-46**: Also, its location with respect to various oil and gas fields in Assam Shelf is shown on **Figure 4-47.**

The Barsilla Field has a long exploration history. Hydrocarbon indications in the Barsilla structure were reported as well as a borehole drilled by AOC several decades back. Subsequently during the field season, 1975-76, an ONGC geological field party completed a traverse mapping project in the Barsilla-Deopani foothills of Nagaland. Studies brought out some interesting stratigraphic and structural features, one of which was the identification of an anticline designated as Dashphutia anticline. During the field season 1975-76, a geophysical field party also mapped the Geleki-Deopani-Barsillla Area. They had brought out two-way time contour maps on top of Barail and TS-2 reflectors. Based on all these studies, location BRSL-1 was proposed and released with an objective of probing the Tipams and Barail prospects in the Barsilla area.

The Barsilla Field was discovered by ONGC in 1982 with the drilling of well Barsilla-1 (BRSL-1) which established the presence of oil and gas in the Tipam Group of Miocene age and BCS formation within the Barail Group of Oligocene age. Seven (7) objects were tested in the well and Object-VII (interval 1590-96 m) in supra-Naga Thrust, TS-1, produced gas and water @ 7783 m3/d (through 4.5 mm bean) with subordinate oil. Three exploratory wells viz. Barsilla-1 (BRSL-1), Barsilla-2 (BRSL-2) and Barsilla-3 (BRSL-3) were drilled by ONGC between 1982 and 2008 in the field of the Contract Area. Wells BRSL-1 and BRSL-3 have discovered hydrocarbons in the same thrust fault block, targeting deeper and shallow prospects respectively. Well BRSL-3 had been drilled to a depth of 2505.99 m to test the shallower objects which could not be tested in well BRSL-1. The well BRSL-2 was drilled on a separate fault block and was found to have poor hydrocarbon prospects.

Table 4-30: COORDINATES OF BLOCK BOUNDARIES: BARSILLA FIELD

	BRSL-1 Boundary Points		
	Area: 6.21 sq km		
	Point	**Longitude**	**Latitude**
	A	94° 37′ 26.441″ E	26° 46′ 23.613″ N
	B	94° 37′ 24.247″ E	26° 45′ 36.059″ N
	C	94° 37′ 22.946″ E	26° 45′ 08.029″ N
	D	94° 36′ 16.602″ E	26° 45′ 10.788″ N
	E	94° 35′ 39.681″ E	26° 45′ 11.827″ N
	F	94° 35′ 42.746″ E	26° 46′ 14.916″ N
	G	94° 36′ 27.308″ E	26° 46′ 21.551″ N
	A	94° 37′ 26.441″ E	26° 46′ 23.613″ N
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	BRSL-1	94° 37′ 15.59″ E	26° 45′ 40.960″ N

Figure 4-46: LOCATION MAP SHOWING THE BARSILLA BLOCK BOUNDARY.

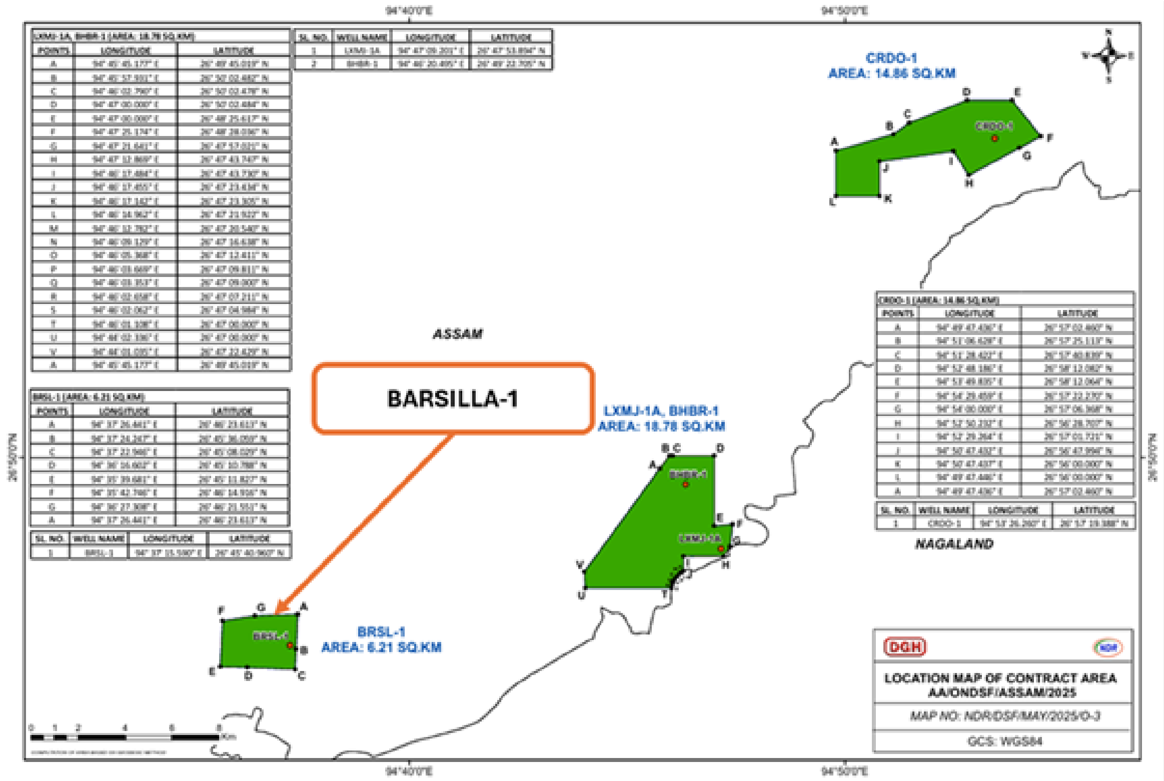
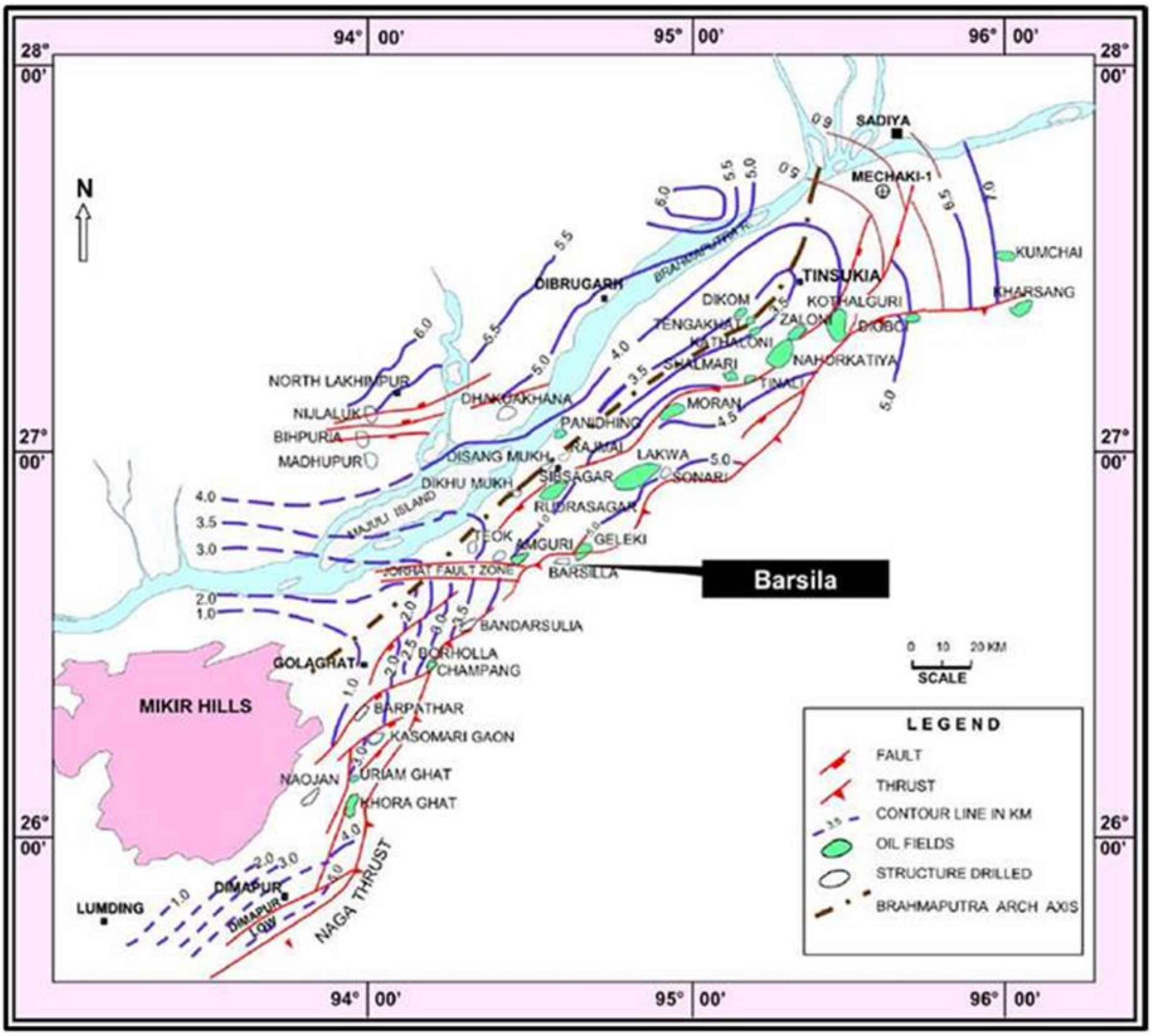


Figure 4-47: LOCATION MAP OF BARSILLA STRUCTURE WITH RESPECT TO PRODUCING OILFIELDS IN THE ASSAM SHELF BASIN

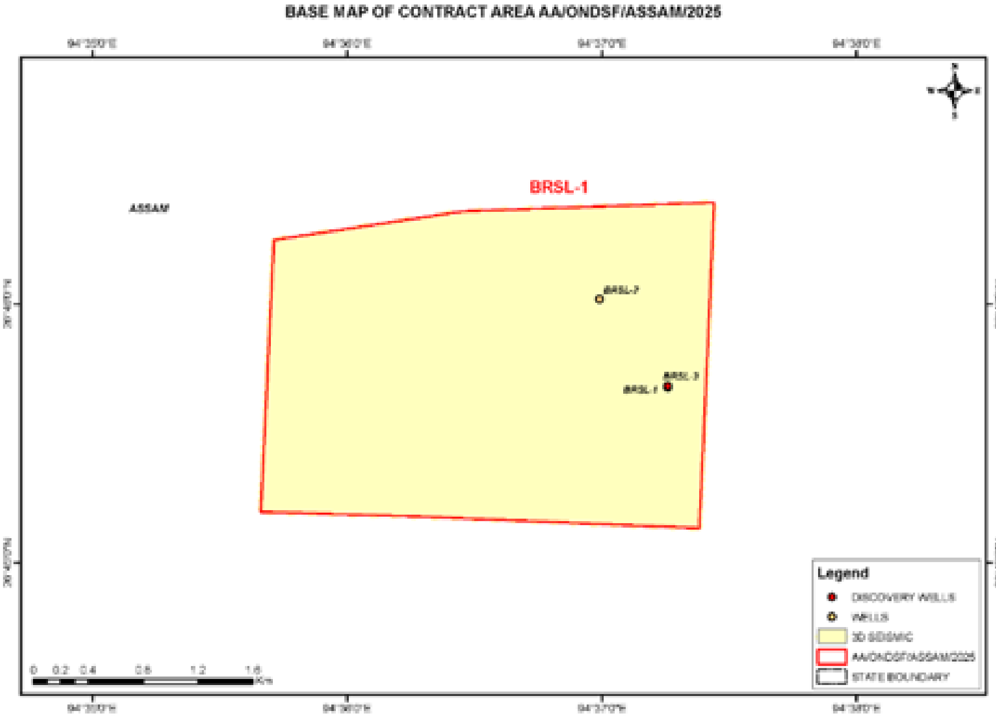


Subsequently, in response to a bidding process in 2002-2003 offered by ONGC, Assam Company Limited (ACL) qualified for the revival of three fields discovered in the A&AA Basin including the Barsilla Field and the relevant contract in this context was entered into in 2004. A number of jobs including re-interpretation of wireline logs, workover and re-testing of objects were carried out by ACL.

A veneer of alluvium overlies sediments of the supra-Thrust Tipam Group in the northern part of the Block while the Girujan Clay of the Plio-Miocene Tipam Group are exposed towards the southern part of the Block and the average elevation of the area varies between around 120 m to around 160 m above MSL. The field is approachable by roads connected to National Highways NH 2 (erstwhile NH 37) and NH 702C. The nearest railway station is Simaluguri Junction, and the nearest airport is Jorhat, about 70 kms from neighbouring Nazira Town.

Map of seismic coverage over Barsilla block with locations of drilled wells is shown in **Figure 4-48**

Figure 4-48: 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: BARSILLA FIELD



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4.4.1 Drilling and well completion

Key information of drilled wells has been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depths including well coordinates are made available in Sections through various cross-references.

In Barsilla structure. three exploratory wells (BRSL-1, 2 and 3) have been drilled so far. The well construction diagrams of wells Barsilla-1, Barsilla-2 and Barsilla-3 are shown in **Figure 4-49, Figure 4-50 and Figure 4-51** respectively.

The general well data, casing details in Barsilla wells are given in **TABLE 4-31 and TABLE 4-32**. Litho-column and stratigraphy in Barsilla wells are presented in **Table 4-33.**

Figure 4-49: WELL CONSTRUCTION DIAGRAM OF WELL BARSILLA - 1

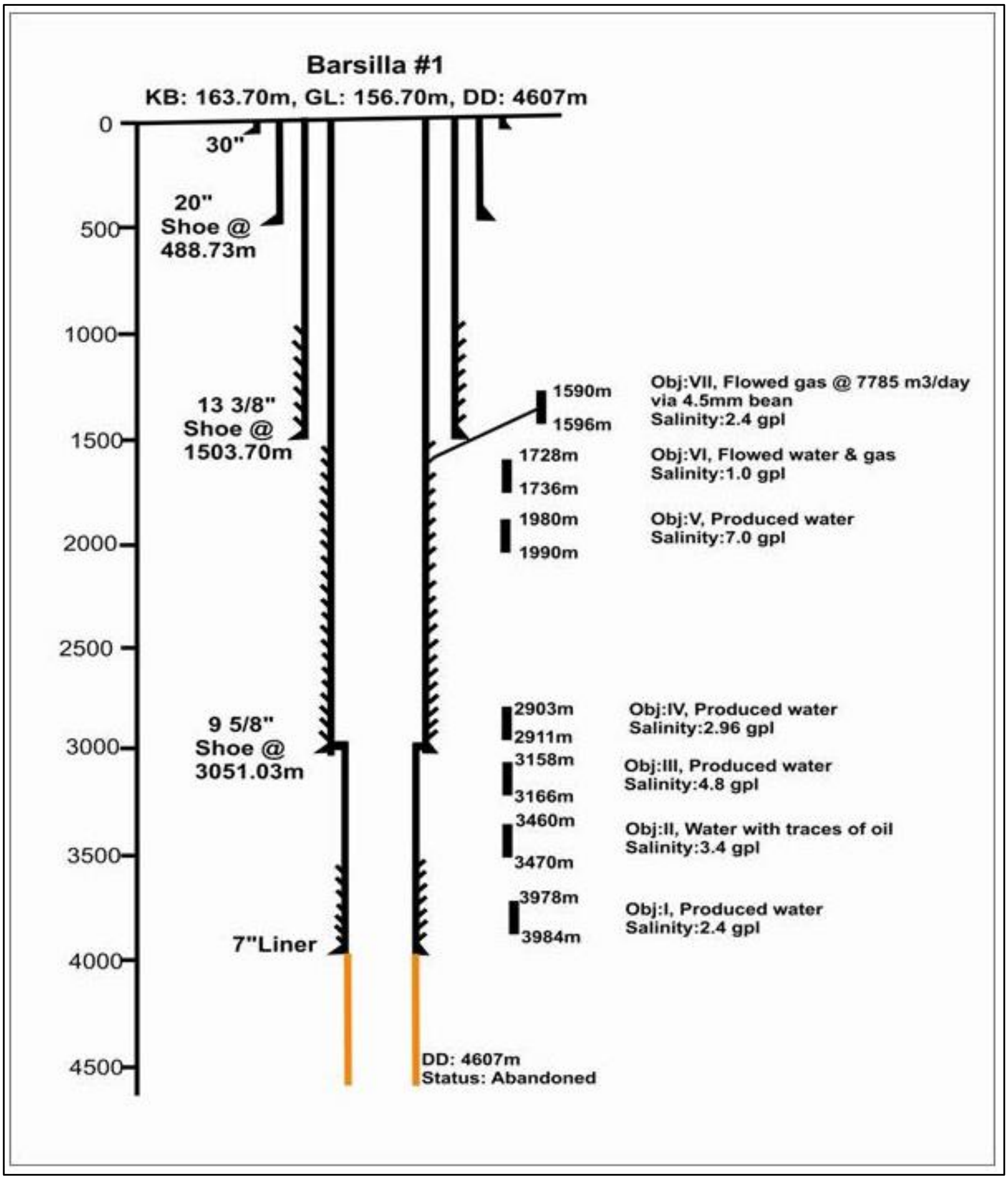


Figure 4-50: WELL CONSTRUCTION DIAGRAM OF WELL BARSILLA - 2

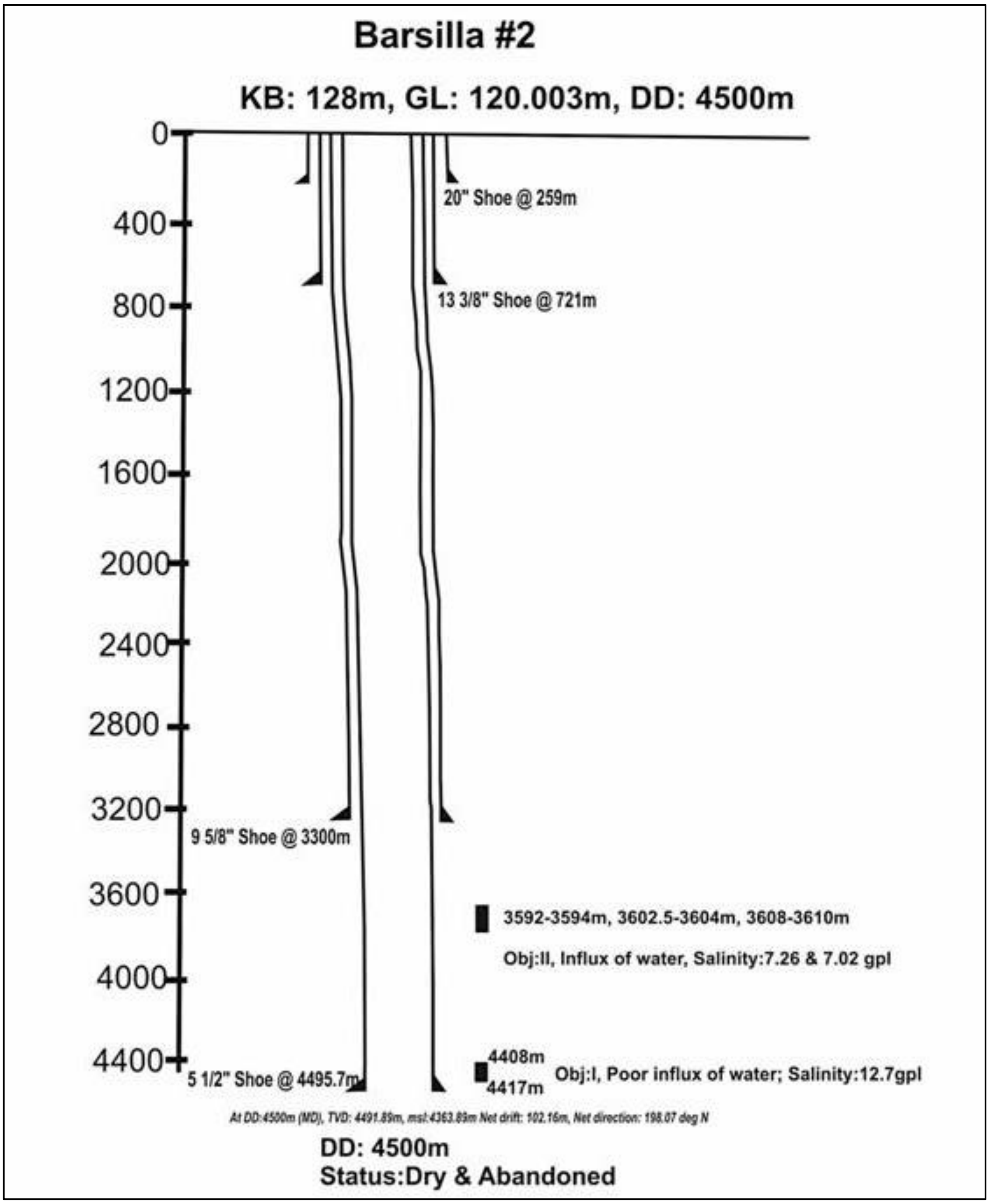


Figure 4-51: WELL CONSTRUCTION DIAGRAM OF WELL BARSILLA - 3

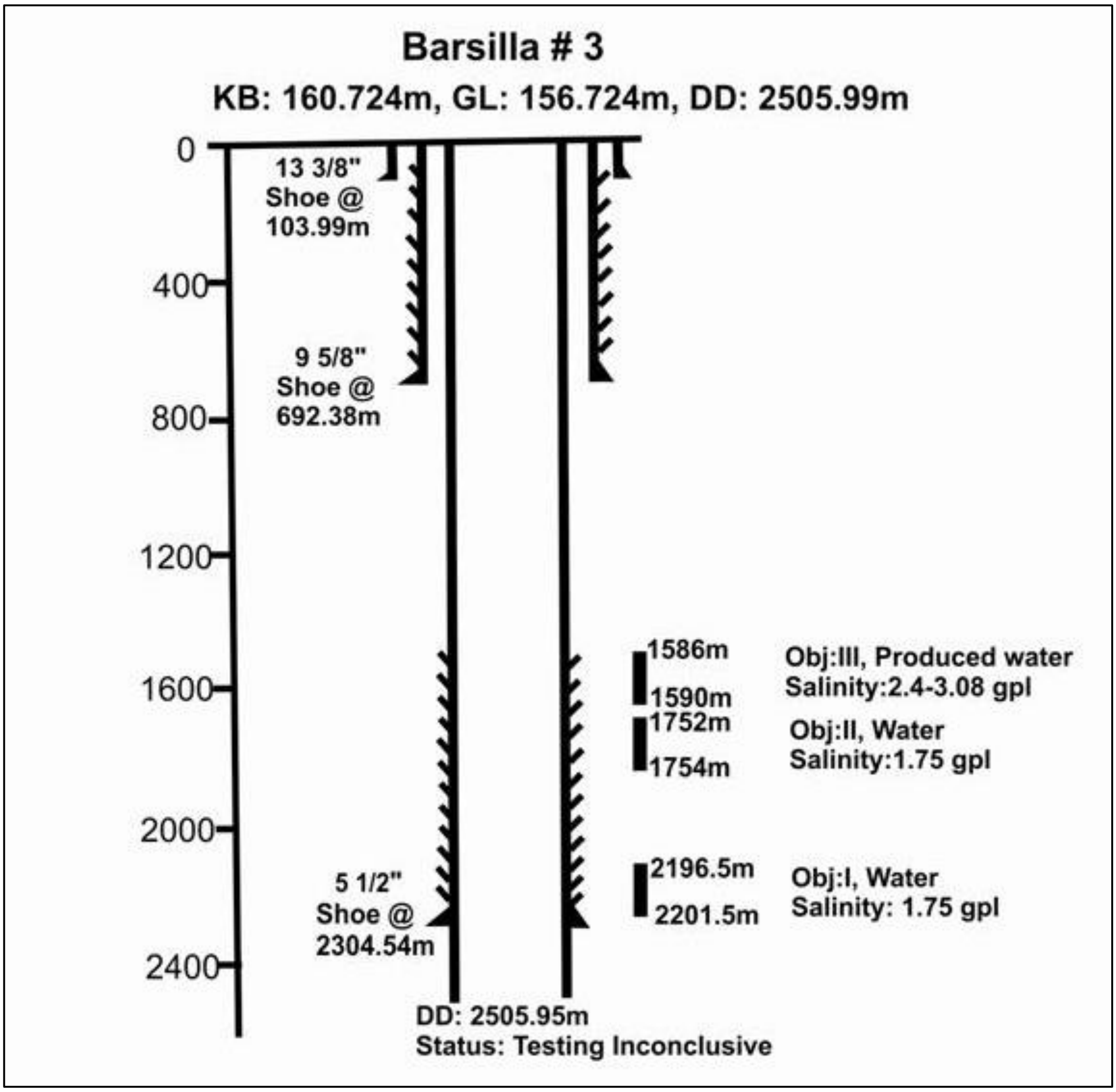


TABLE 4-31: BARSILLA FIELD - GENERAL WELL DATA

	Barsilla-1	Barsilla-2	Barsilla-3
Area	Nazira, Assam		
Structure	Barsilla		
Well	Barsilla-1	Barsilla-2	Barsilla-3
Category	Exploratory	Exploratory	Exploratory
Co-ordinates	Lat: 26^0 45’ 38.50” N	Lat: : 26^0 45’ 58.69” N	Lat: : 26^0 45’ 38.50” N
	Long: 94^0 37’ 28.00” E	Long: 94^0 37’ 11.92” E	Long: 94^0 37’ 28.00” E
Rig	3DH-IV (Rommanian)	E-1400-IV	3D-10 (Russian)
Target Depth	4000 m	4500 m	2500 m
Drilled Depth	4607 m	4500 m	2505.99 m
Objective	Supra and sub thrust Tipams and Barails & to be drilled to Basement	Tipam and Barails	Supra-Thrust Tipams and Barails
Status	**Abandoned.** Well established the presence of traces of oil and gas in sands of Tipam Group and BCS formation.	**Poor prospects & Abandoned**	**Testing inconclusive**
KB	163.42 m	128.0 m	160.724 m
Spud date	12-03-1982	17-11-2007	28-05-1984
Drilling Completion	10.01.1983	09-12-2008	22.08.1984
Production testing Completion	May, 1983	March 2009	January, 1985
Rig release	30-05-1983	07-04-2009	12-01-1985

TABLE 4-32: BARSILLA FIELD – CASING DETAILS

Well	Hole Size	Casing Size	Cement Rise to (m)	Casing Shoe (m)
Barsilla-1	36”	30 “	Surface	30.50 m
	26”	20 “	Surface	488.73 m
	17 ½ “	13 3/8 “	NA	1503.70 m
	12 ¼ “	9 5/8”	1525 m	3051.03 m
	8 ½ “	7 “Liner	NA	4000.00 m
	6”	5 ½ “	Casing not lowered	-
Barsilla-2	26 “	20 “	Surface	259.00 m
	17 ½”	13 3/8 “	600.00 m	721.00 m
	12 ¼”	9 5/8 “	600.00 m	3300.00 m
	8 ½ “	5 ½ “	600.00 m	4495.71 m
Barsilla-3	17 ½ “	13 3/8 “	Surface	103.99 m
	12 ¼ “	9 5/8 “	200 m	692.38 m
	8 ½ “	5 ½ “	1600 m (from CBL)	2304.63 m

NA = Not available

Table 4-33: STRATIGRAPHY OF BARSILA AREA BASED ON LITHO-COLUMN ENCOUNTERED IN WELL BRSL-2

AGE	FORMATION	Depth – MD (KBm) TVD(KBm) TVD MSL(m)	LITHOLOGICAL DESCRIPTION
Pliocene	Girujan Clay	Outcrop	Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
Thrust			
Recent-Pleistocene	Namsang	Surface Surface Surface	Dominantly loose medium to fine grained sand with little mottled clay
	Nazira Sandstone	302 301.97 173.97	Predominantly grey, medium grained sand with minor grey to brownish grey clay
Pliocene	Girujan Clay	647 646.89 518.89	Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom
Thrust			
Pliocene – Miocene	Girujan Clay	946 965.62 817.62	Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom
	Thrust		
	Girujan Clay	1360	Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
	Tipam Sandstone	1638 1636.37 1508.37	Massive sandstone with clay/shale alternations with minor calcareous matter in the lower part.
	Thrust		
	Tipam Sandstone	1911 1908.54 1780.54	Massive sandstone with clay/shale alternations with minor calcareous matter in the lower part.
Thrust			
Miocene	Tipam Sandstone	2510 2505.3 2377.3	Massive sandstone with clay/shale alternations with minor calcareous matter in the lower part.
	Safrai	3555 3549.92 3421.92	Dominantly medium grained grey sandstone, occasionally coarse with minor light grey soft clay.
Oligocene – Late Eocene	Rudrasagar (BCS)	3618 3612.87 3484.87	Alternations of carb. shale, coal, siltstone and fine-grained sandstone.
	BMS	3994.5 3988.05 3860.05	Mainly sandstone siltstone and minor shale with alternation of Shale and Silty Sandstone towards bottom
	Kopili	4323.5 4316.01 4188.01	Mainly Shale (splintery & water absorbing) alternating with fine grain sandstone (feebly calcareous at places) and siltstone

4.4.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.4.2.1 Well completion and log evaluation reports availability (BARSILLA Field):

Data and reports availability as well as logs acquired list are given in **Table 4-34, Table 4-35, Table 4-36, Table 4-37, Table 4-38, Table 4-39 and Table 4-40.** Core data is presented in **Table 4-41**

Table 4-34: REPORTS AVAILABLE FOR BARSILLA WELLS

Well	WCR/ FER availability	Spud date	KB	Drilled depth
BRSL-1	Both available	12-03-1982	163.42 m	4607
BRSL -2	Both available	17-11-2007	128.0 m	4500
BRSL -3	Both available	28-05-1984	160.724 m	2505.99

Table 4-35: DATA AVAILABILITY IN BARSILLA WELLS

Sl. No.	Data/Report	BRSL -1	BRSL -2	BRSL -3	Remarks
1	**Field Evaluation Report**	✓	✓	✓	available for all three wells
2	**Well Completion Report**	✓	✓	✓	available for all three wells
3	**VSP/ Checkshot**	✗	✗	✗	Not available; Sonic recorded in all wells
4	**Production Data**	✗	✗	✓	For a limited period, post workover in well BRSL-3
5	**Core Analysis**	✓	✗	✗	Coring in well BRSL-1; , but not usable for petrophysical analysis
6	**Pressure Transient Analysis**	✗	✗	✗	Not available
7	**PVT Analysis**	✗	✗	✗	Not available
9	**Workover**	✗	✗	✓	Acid treatment and revival operation performed for well BRSL -3 and reports are available
10	**Surface Facility**	✗	✗	✗	Well Barsila-3 is clustered in well-site area of well BRSL -1

4.4.2.2 Well logs acquired (BARSILLA Field) :

Table 4-36: WELL LOGS ACQUIRED (BARSILLA FIELD) :

Well	Type of Logs	Interval m
Barsila 1	SP-Normal-4M &2M	30-512, 488-1308, 1503-1860,1503-2475, 2400-2935, 4000-4600
	Mud Resistivity	Surface - 420
	Standard BKZ, Caliper, Inclinometer, Induction, Sonic	488-1510
	Inclinometer	1450-18001450-2475. 2475-2920, 3056-3430, 3400-Bottom
	BKZ, Caliper,	1503-2935
	Induction, FDC, Sonic	2475-2920
	Induction, Dipmeter, Sonic, FDC	1503-3060, 3050-4007
	Standard, BKZ,	2800-3056
	Sonic	1503-2060
	Thermolog	100-2200
	Standard, BKZ, Latero, Caliper	3051-4014
	SP, LLS, LLD. Dipmeter, FDC-CNL,GR	4003-4499
	8M, 2M, 2M(T), 1M0.4M	4000-4600
	CNL(CH), CBL-G	3125-4000, 1500-2970
Barsila 2	HRI-SP-GR-BCS-CALINCLINOMETER	227-1218
	LWD Resistivity-GR	1226-3305
	DLL-MSFL-GR-SP-CAL	720-2448, 3938-4236
	DLL-MSFL-SONIC-CAL	2400-3311
	CDL-CNS-GR-CAL	2400-3309, 4130-4493
	CAL	1800-3309
	FMI	1750 – 3292, 3320 – 3540, 4145 – 4250
	LDL-CNL-GR-CAL, NGT	720-2444, 3300-3997, 3940-4240
	SDDP - GR	720-2448
	DLL-MSFL-GR-SP-CAL-INCLINOMETER	3300-4000.8
	BHC-GR	3950-4230
	NGT-GR	3950 – 4222.5
	SDL-DSN-GR-CAL	3299 – 4236, 4489 - 4150
	Inclinometer-GR	3950 - 4219
	DLL-MSFL-SP-GR-CALNGT	4494- 4150
	DSI-GR	4500 - 3299
	CBL-VDL	3298.6 – 2280, 4460-3720
	SWC	Carried out in 12.1/4” and 8.1/2” hole (twice)
Barsila 3	DIL-BCS-CAL-SP-GR, CNL-CDS, Dipmeter,	695-110,

	Inclinometer	
	DIL-SP-GR-CDS-CNL-Dipmeter-Inclinometer	692-1385, 2461-1266
	DIL, SP, GR, BCS, CNL, CDS, Inclinometer	1275-2474
	Thermolog	575-2073
	CBL-Neutron, CCL	1550-2250, 650-1433, 1724-1754, 1428-1642.5

Table 4-37: DRILL HOLE SIZE (INCH) AND OH / CH WELL LOGS RECORDED IN WELL BARSILLA-1

	Well logs acquired (Well Barsila-1) :
Hole Size	**Log Suite Recorded**
26”	Resistivity (N, 4M,2M) – SP logs recorded on 27.08.1982 at a well depth of 510 m Mud resistivity log recorded on 24.04.1982 at a well depth of 488.73 m
17.1/2”	SP,N & 4M logs recorded on 21.05.1982 at a well depth of 1302.65 m Standard, BKZ, Caliper, Inclinometer, Induction and Sonic logs recorded on 27.05.1982 at a well depth of 1510 m
12. 1/4”	SP, N, 4M. and Inclinometer Survey recorded on 17.06.1982 at a well depth of 1860 m
	SP, N, 4M. and Inclinometer Survey recorded on 30.06.1982 at a well depth of 2468 m
	SP, N, 4M, Inclinometer, Caliper, BKZ, Latero Induction, FDC and Sonic logs recorded on 16.08.1982 at a well depth of 2909 m
	SP, N, 4M, BKZ, Inclinometer, Caliper, BKZ, Induction, FDC and Sonic logs recorded on 18.08.1982 at a well depth of 2930 m.
	Induction, Dipmeter, Sonic & FDC logs recorded on 23.08.1982 at a well depth of 3056 m
	Standard, BKZ, and Sonic logs recorded on 25/26.08.1982 at a well depth of 3056 m
	Thermolog recorded on 28.08.1962 in cased hole in the range 2200- 100 m
8.1/2”	Standard, Inclinometer logs recorded on 22/23.09.82 at a well depth of 3442 m
	Standard logs recorded on 25.09.82 at a well depth of 3449 m
	Standard, Caliper, Induction logs recorded on 13.10.1982 at well depth of 3789 m
	Standard, BKZ, Inclinometer, Caliper, and Latero logs recorded on 3/4/5.11.1982 at a well depth of 4007 m.
	Induction, Sonic & FDC logs recorded on 11.11.1982 at a well depth of 4007 m
	Dipmeter log recorded on 13.11.1982 at a well depth of 4007 m
	SP, LLS, LLD, Dipmeter, FDC-CNL-G and Gamma Ray logs recorded on 28.12.1982 at a well depth of 4502 m
	CNL(CH)/CBL-G logs recorded in the ranges 3125 – 4000 m and 1500 – 2970 m
	SP, N, 4M, 8M, 2M, 2M(T), 1M, 0.4M logs recorded on 03.03.1963 at a well depth of 4607 m

Table 4-38: LWD SURVEY WAS CARRIED OUT IN WELL BARSILLA-2

Date	Hole Size	Mode	Logs	Interval (m)
19.01.2008 to 24.03.2008	12 .1/2"	LWD	VISION Resistivity	1226-2450
28.03.2008	12. 1/2"	LWD	VISION Resistivity	2450-3305

Table 4-39: DRILL HOLE SIZE (INCH) AND OH / CH WELL LOGS RECORDED WITH WIRELINE TOOLS IN WELL BARSILLA-2:

	Well logs acquired (Well Barsila-2)

Hole Size	Log Suite Recorded
17.1/2"	HRI--SP-GR-BCS-CAL INCLINOMETER logs recorded on 29.12.2007 at a well depth of 1220 m
12.1/4"	DLL-MSFL-CAL-GR, LDL- CNL- GR- CAL - NGT Ratios and SDDP – GR were recorded on 26.03.2008 at a well depth of 2448 m
	DLL-MSFL-CAL- Sonic - GR, CDL- CNS - GR- CAL and CAL recorded on 08.05.2008 at a well depth of 3309 m
	FMI log and SWC recorded on 08.05.2008 at a well depth of 3309 m
8.1/4 "	DLL-MSFL-CAL-SP-GR, LDL- CNL- NGT- CAL logs were recorded on 07.09.2008 at a well depth of 4000 m
	DLL-MSFL-CAL-SP-GR, BHC – GR, Inclinometer-GR and NGT-GR logs were recorded on 27.10.2008 at a well depth of 4238 m
	SDL-DSN-GR-CAL and SWC surveys were recorded on 31.10.2008 and 01.11.2008 at a well depth of 4238 m
	DLL-MSFL-CAL-SP-GR, NGT and SDL- DNS - GR- CAL logs were recorded on 13.12.2008 at a well depth of 4494 m
	DSI-GR logs were recorded on 16.12.2008 at a well depth of 4494 m
	CBL-VDL and FMI logs were recorded in the ranges 3298.6 - 2280 m and 3320-3540 & 4145-4250 respectively on 17.12.2008
	SWC survey was conducted on 21.12.2008 at a well depth of 4500 m
	A cased hole CBL-VDL-CCL-GR log was recorded in the range 4460-3720 m on 13.02.2009 MDT with Pretest was not carried out in the well

Table 4-40: DRILL HOLE SIZE (INCH) AND OH / CH WELL LOGS RECORDED WITH WIRELINE TOOLS IN WELL BARSILLA-3

	Well logs acquired (Well Barsila-3)
Hole Size	**Log Suite Recorded**
12.25"	DIL- SP-GR, CDS – CNL, Dipmeter, Inclinometer logs were recorded on 20/21.06.1984 at a well depth of 692. 69 m
8.5"	DIL- SP-GR, BCS, CDS – CNL, Dipmeter, Inclinometer logs were recorded on 11/12.07.1984 at a well depth of 1391.23 m
	DIL-SP-GR, BCS, CDS – CNL and Inclinometer logs were recorded on 23/24.08.1984 at a well depth of 2505.99 m
	CBL- Neutron - CCL logs were recorded in the range 2250 - 1550 m on 04.10.1984
	Thermolog was recorded in the range 2073 – 675 m on 09.11.1984
	CBL- Neutron - CCL logs were recorded in the range 1433 - 650 m on 23.11.1984
	CBL- Neutron - CCL logs were recorded in the range 1754 - 1724 m on 06.12.1984
	CBL- Neutron – GR - CCL logs were recorded in the range 1642.5 - 1428 m on 31.12.1984

Table 4-41: BARSILLA FIELD - CORE DATA

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Barsila-1	1	1867-1875 m	68%	Sandstone
	2	2467.97-2475.22 m	79%	Sandstone
	3	3156-3164 m	98.25%	Sandstone
	4	3543-3551 m	96.5 %	Sandstone, Conglomerate and coal traces
	5	3827-3833 m	100%	Sandstone
Barsila-2	No conventional core attempted in the well			
Barsila-3	No conventional core attempted in the well			

4.4.2.3 Well log evaluation and initial test results (BARSILLA Field):

The petrophysical properties of the sands in the discovery well viz. Barsilla 1 and review of well logs of well BRSL -3 in the interval 700-1765 m before workover in July2007 is given in **Table 4-42 and Table 4-43.**

Table 4-42: PETROPHYSICAL PROPERTIES OF WELLS BARSILLA-1 & 2

Well	Sands	Top	Bottom	Av Phi %	Av Sw %
Barsilla 1	TS-1	1587.47	1608.66	18	45
	TS-2	1727.83	1739.57	15	61
	TS-5	3153.69	3189.66	15	57
	TS-5	3306.39	3313.4	16	58
	TS-6	3458.95	3482.57	16	54
	TS-6	3522.95 0	3528.59	16	56
Barsilla 2	Kopili	4402.0	4417.0	10	100
	Safrai	3592.0	3610.0	10-15	100

Table 4-43: PETROPHYSICAL PROPERTIES OF WELL BARSILLA-3

Sl No.		Interval m	Porosity %	Sw %	Remarks
1	TS-2	1745-1754	18	48	Could be hydrocarbon Bearing
2	TS-2	1223-1233	18	57	Could be hydrocarbon Bearing
3	TS-2	1194-1200	17	55	Could be hydrocarbon Bearing
4	TS-1	1065-1070	18	57	Could be hydrocarbon Bearing
5	TS-3	700-725	20	43	Could be hydrocarbon Bearing

Log motifs of the tested Objects of Barsila-1, Barsila-2 and Barsila-3 are shown in **Figure 4-52, Figure 4-53, Figure 4-54, Figure 4-55, Figure 4-56, Figure 4-57, Figure 4-58, Figure 4-59 and Figure 4-60.**

Figure 4-52: LOG MOTIFS OF OBJECT-I AND II OF WELL BARSILLA-1

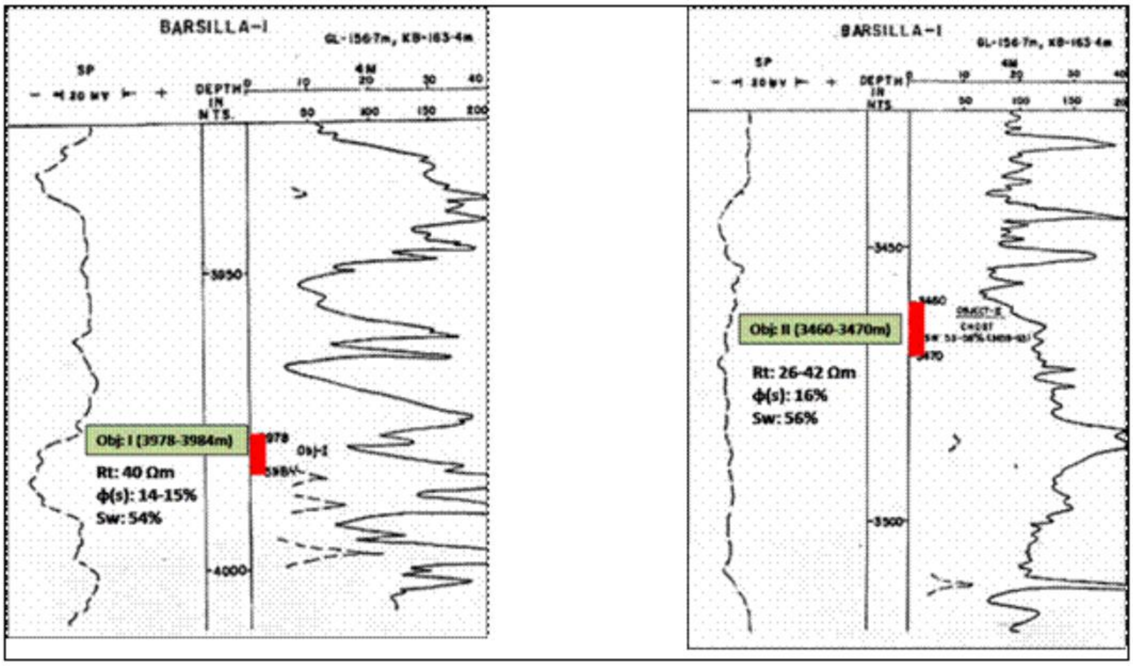


Figure 4-53: LOG MOTIFS OF OBJECT-III AND IV OF WELL BARSILLA-1

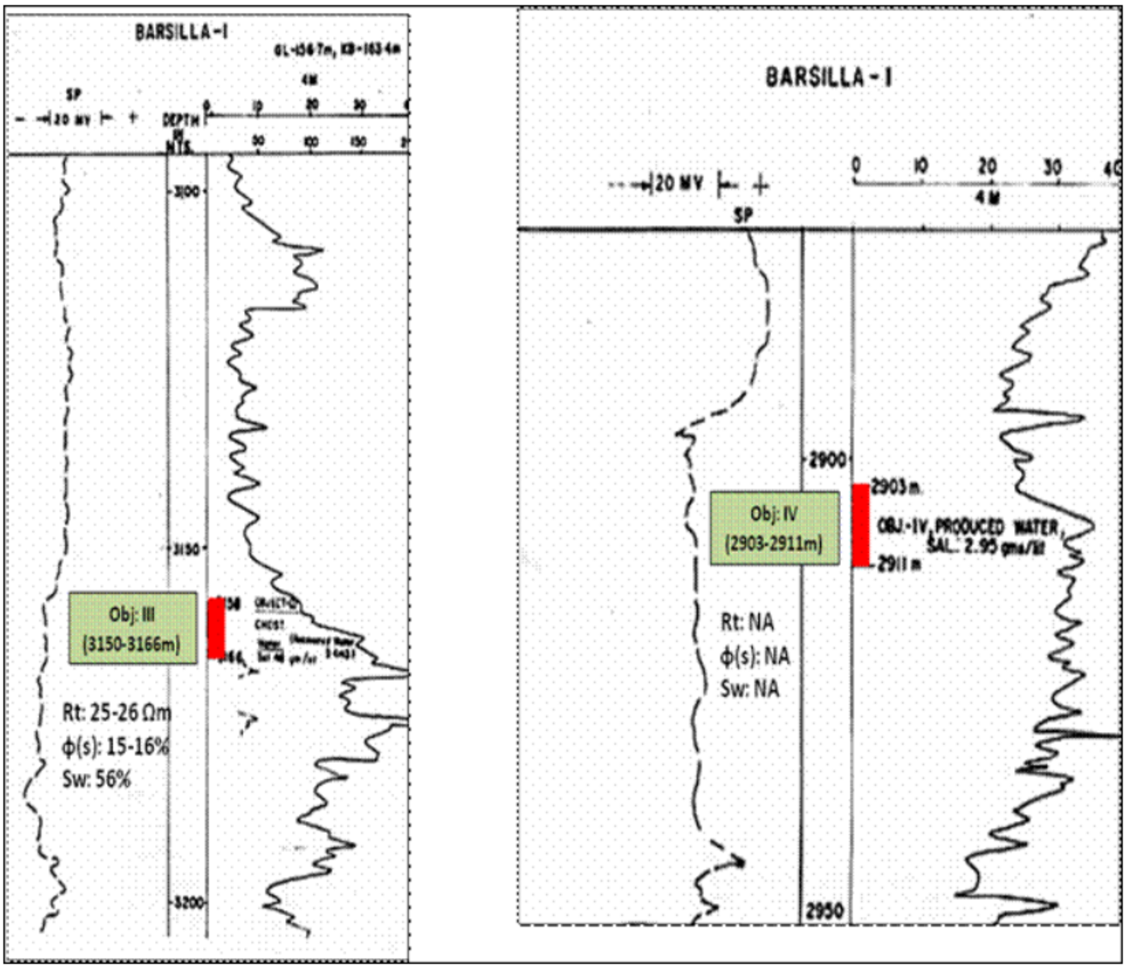


Figure 4-54: LOG MOTIFS OF OBJECT-V AND VI OF WELL BARSILLA-1

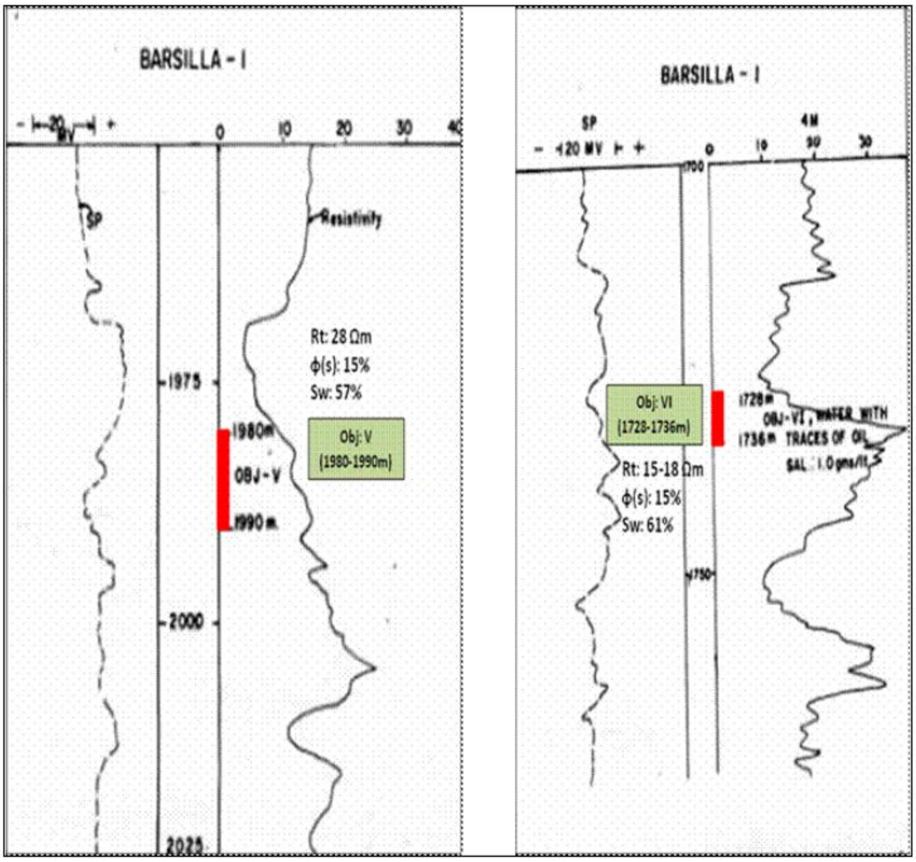


Figure 4-55: LOG MOTIFS OF OBJECT-VII OF WELL BARSILLA-1

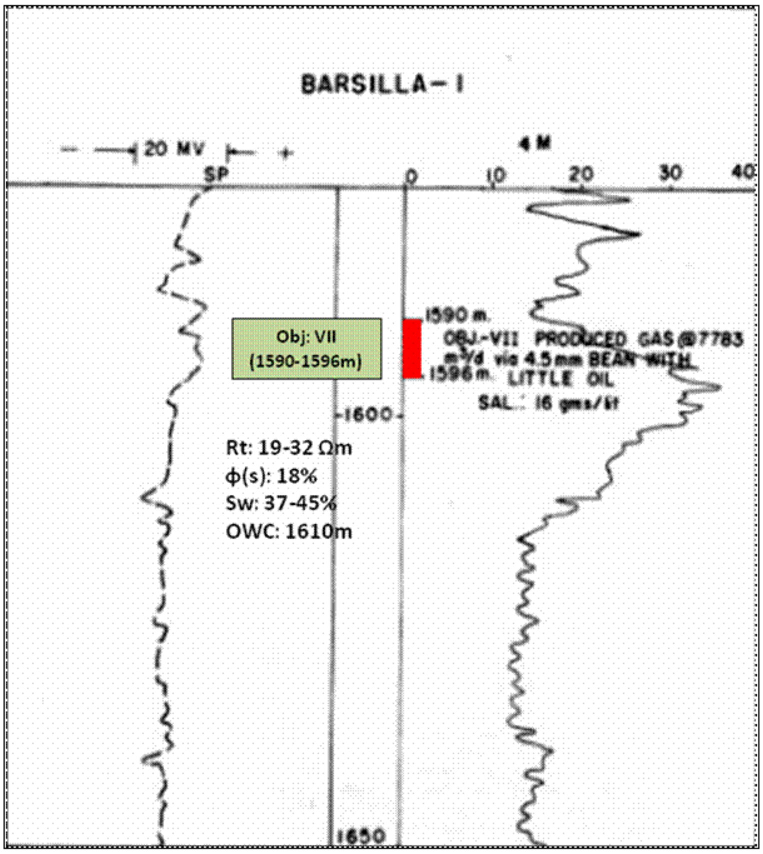


Figure 4-56: LOG MOTIFS OF OBJECT-I OF WELL BARSILLA-2

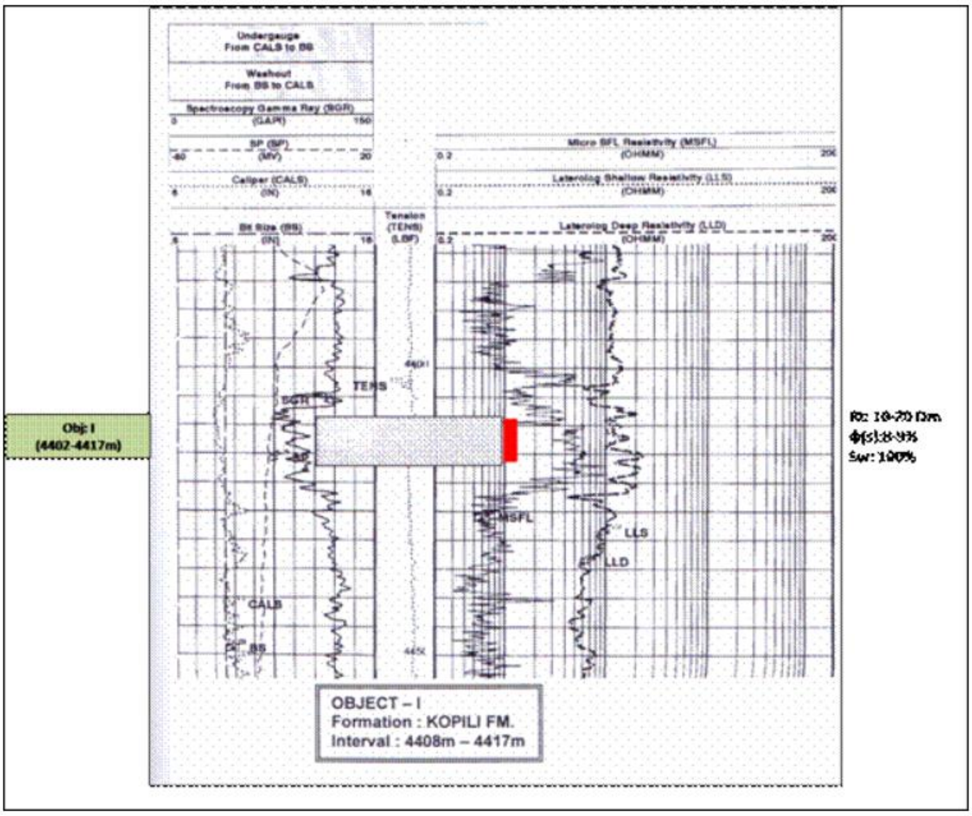


Figure 4-57: LOG MOTIFS OF OBJECT-II OF WELL BARSILLA-2

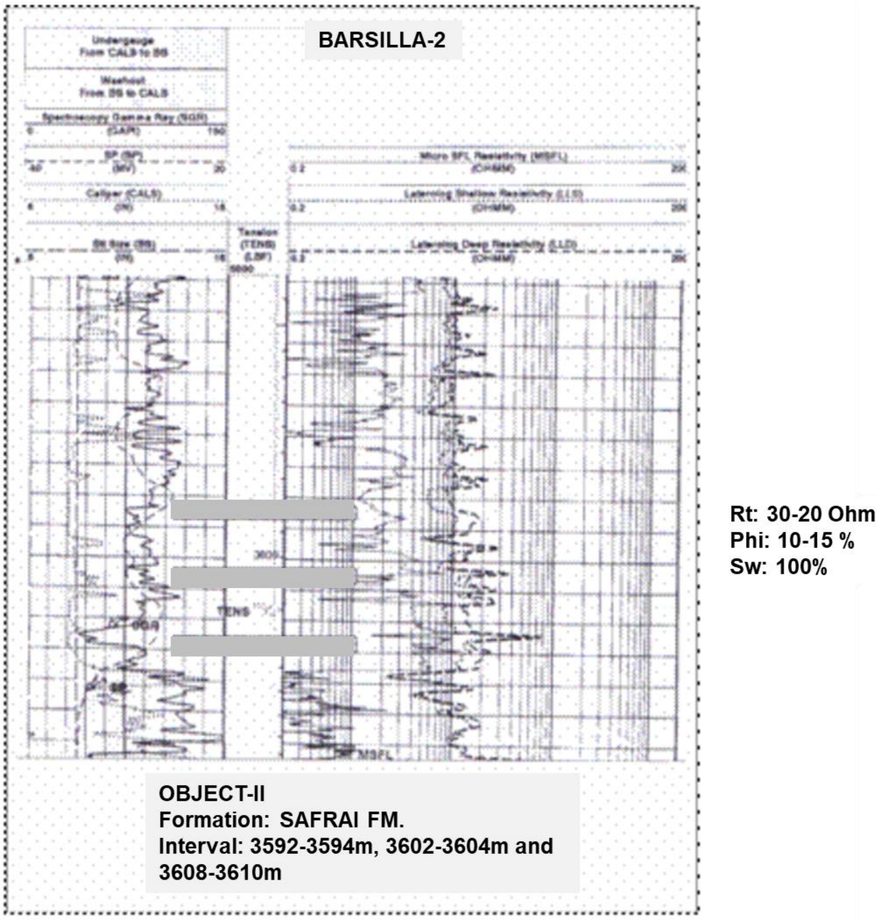


Figure 4-58: LOG MOTIFS OF OBJECT-I OF WELL BARSILLA-3

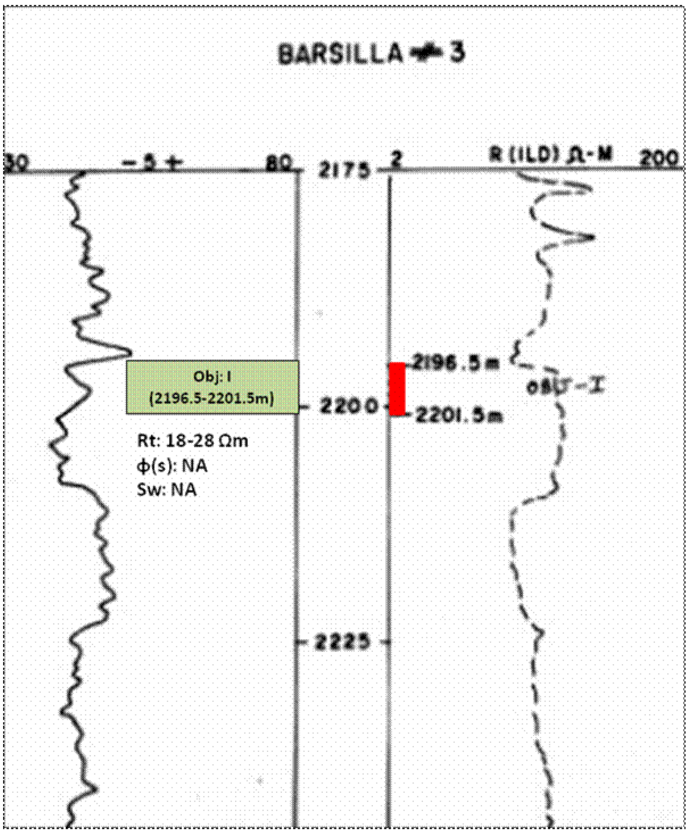


Figure 4-59: LOG MOTIFS OF OBJECT-II OF WELL BARSILLA-3

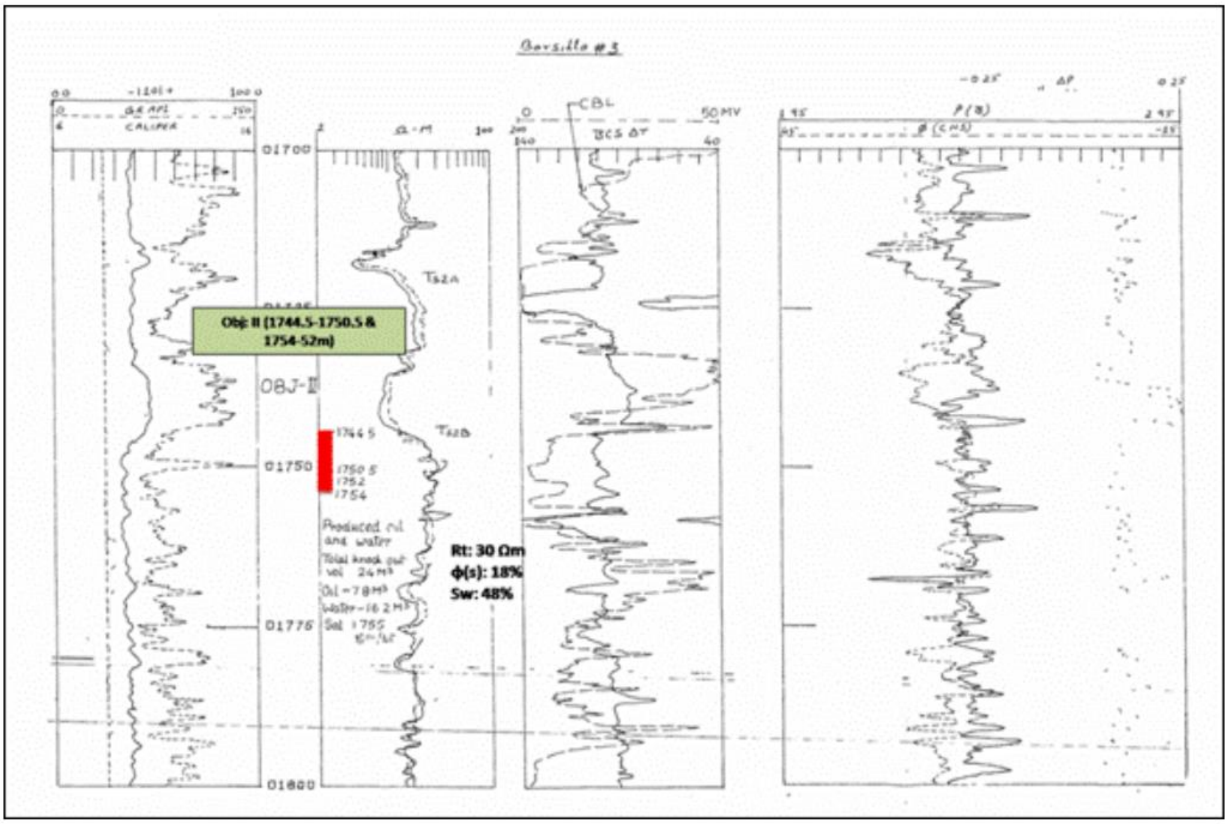
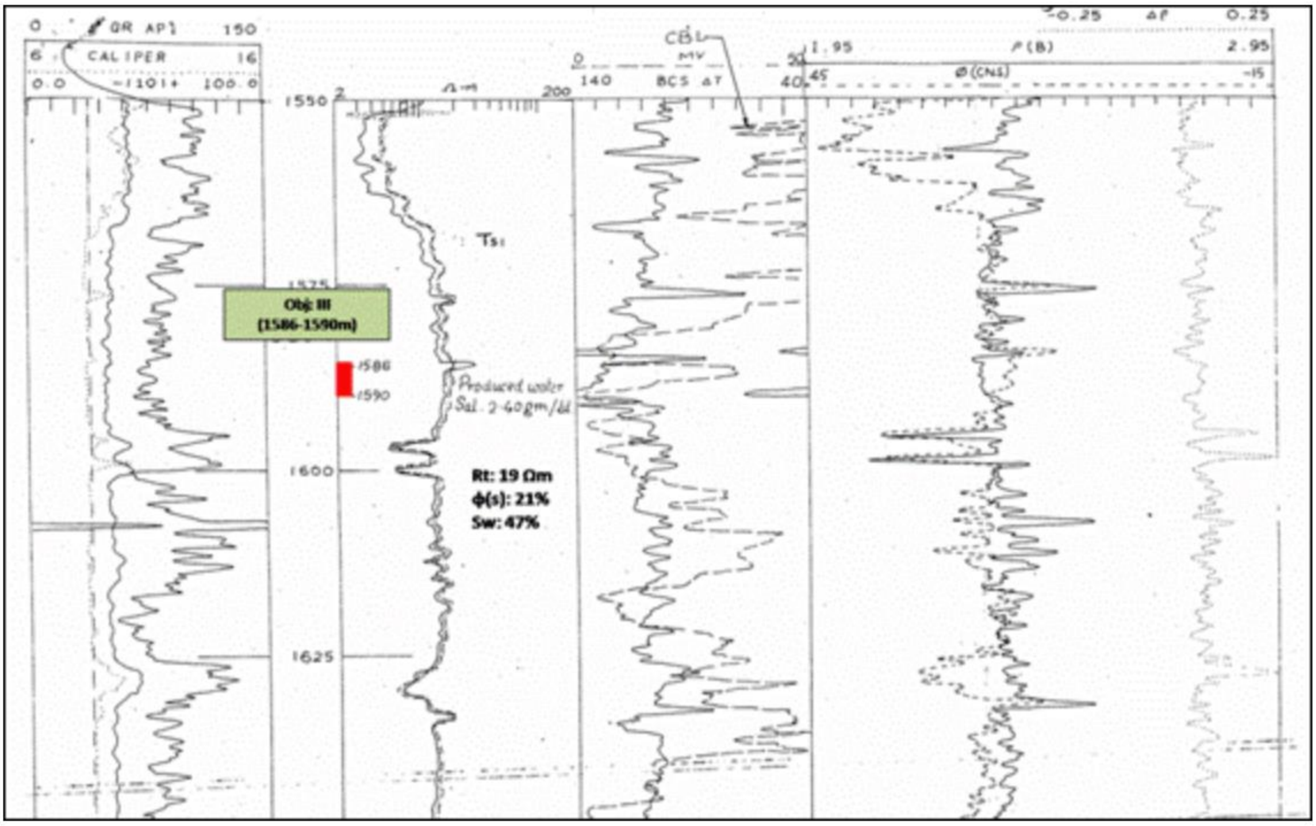


Figure 4-60: LOG MOTIFS OF OBJECT-III OF WELL BARSILLA-3



4.4.3 Well testing and workover history

Three wells, viz. BRSL -1, BRSL -2, BRSL -3, have been drilled on the Barsilla structure. Seven objects were tested in well BRSL -1 out of which Object-VII in Sand TS-1 produced gas. Two objects were tested in well BRSL -2, both of which were found to be water bearing. In well BRSL -3, three objects were tested out of which Object-II in sand TS-2 produced 7.19 cum oil during knocking out of well fluid. The results of production testing in the wells of Barsilla Field are given in **Table 4-44**.

Table 4-44: TESTING RESULTS OF BARSILLA WELLS

WELL	OBJECT	INTERVAL (M)	RESULT	STATUS
BRSL -1	I, BCS	3978-3984	Tested with CHDST Water of salinity in the range 0.1585 to 4.17 gm/l Final shut in pressure was 316 ksc	Water of salinity 2.4 GPL Plugged back (CP)
	II, TS-6	3460-3470	Tested with CHDST. Recovery of 4.806 m3 of mainly formation water with **oil in traces** Salinity in the range: 0.2381 to 3572 gm/l Final shut in pressure was 294 ksc	Water (salinity 3.4 GPL), oil in traces Plugged back (CP)
	III TS-5	3158-3166	Tested with CHDST. Water of salinity in the range3.837 to 4.832 gm/l Final shut in pressure was 298 ksc	Water of salinity 4.8 GPL Plugged back (CP)
	IV TS-3	2903-2911	Tested with CHDST. Water of salinity in the range 1.183 to 2.956 gm/l Final shut in pressure was 286 ksc	Water of salinity 2.95 GPL Plugged back (CP)
	V TS-3	1980-1990	Tested with CHDST. Water of salinity in the range 1.326 to 3.543 gm/l Final shut in pressure was 188 ksc	Water of salinity 2.9 GPL Plugged back (CP)
	VI TS-2	1728-1736	Tested with CHDST. Water of salinity in the range 0.897 to 1.075 gm/l **with traces of oil**. Final shut in pressure reading was erroneous.	Water with traces of oil. Plugged back (CP)
	VII TS-1	1590-1596	Tested with CHDST. Well became active within 10 minutes of setting packer, Well flowed vigorously with water of salinity of 1.6 gms/l and **gas @ 7783 m^3/d with** little oil.	Indication of hydrocarbon occurrence with water. Subsequently two cement plugs were placed at 1238 – 1138 m and 438 – 338 m.
	VIII TS1	Not tested due to poor cementation behind 9.5/8” casing. Was expected to produce gas as the range 1538-1546 m was the topmost part of TS1.		
BRSL -2	I (Kopili)	4402-4417	Influx of water only (salinity at 235ksc - 4.56 gm/l 260ksc -7.12gm/l, 275ksc -12.7gm/l.	Water bearing Plugged back (BP)
	II (Safrai)	3592-3594 Re-perforated 3602.5-3604	Influx of water only Salinity in the range: 7.26 gm/l -7.02 gm/l.	Water bearing. Plugged back (CP)
BRSL -3	I (TS-3)	2196.5-2201.5	Total well fluid knocked out 18 cum Influx of Water (Sal 1.755 - 2.4 gm/l)	Water (Sal 1.755 gpl) Plugged back (CP)
	II (TS2)	1754-52m & 1750.5-1744.5m Additional perforation 1744.5-1750.5m	Influx of water with oil and continuous flow of feeble gas. Total water knocked out 16.07 cum and oil knocked out **7.629 cum Sp. Gr. of oil 0.93.** Water sal 1.7555- 1.98 gm/l. No self flow.	Water with minor oil. Plugged back (CP)
	III (TS1)	1590-1586m,	Water sal 2.4-3.08 gm/l . Inconclusive testing as same sand in well Barsilla 1 had produced gas. The production of water is inferred to be due to channelling from top wherein only 2 m cement bond was observed	Inconclusive testing.

Two more objects 1490 -1595m and 1194 - 1235m in Girujan Clay and supra-Thrust TS2 showed GYF and were identified for testing. But since there was poor cement behind the casing (planned cement rise was 1100 m and actual cement top was 1584 m, the testing was kept in abeyance and the testing of the Object-Ill remained inconclusive.

Workover operation by ACL and Testing of Well Barsilla-3

On 10.07.2007, by deploying a workover rig, the well Barsilla-3 was cleared down to the cement retainer at 1765 m. Hermeticity of the casing was tested at 2500 psi and was found to be holding. Efforts were made to record CBL-VDL log but the tool could not be lowered beyond 1380 m despite repeated attempts.

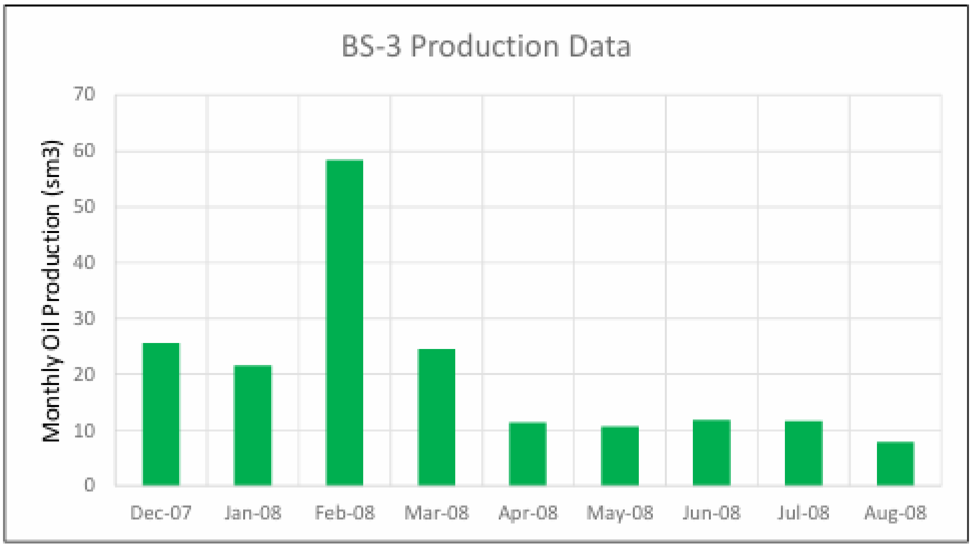
Finally, CCL-Gamma Ray tool could be lowered down to 1764 m and logs were recorded. The intervals 1742-1743m, 1753-1755 m were perforated using strip charges to carry out cement squeeze job to isolate the prospective interval. After waiting on cement, the open interval of 1586-1590m was also plugged back. The well was cleared once again down to bottom (1764m) and hermetical testing of the casing was carried out and confirmed under 2500 psi.

The interval 1744.5-1749 m (**TS2)** was perforated with use of 3.3/8" Tubing Conveyed Perforator (TCP) with 18 shots/meter. The gun was fired by hydraulic method. Subsequent activation through compressor application established flow of clean oil. However, self-flow could not be established. Repeated compressor application was conducted for activation of the well, but sustained flow could not be established.
The following were the observations after the work conducted by ACL

1) **Prolonged testing of the interval 1744.5 -1749.5 m TS2 of the Tipam Group in well BRSL -3 established the presence of water free oil but sustained surface flow could not be established**.
2) BH study established the P.I. as 0.144 M3/hr/kg/cm2 and the liquid level was steady at 700 m.
3) The reserves size calculated is around **6 MMstb of recoverable oil**

Subsequently a stimulation job was planned by IRS ONGC for reactivation of the **TS-2 sand** having swelling clay. The solvent-soak-acid job was probably carried out in the month of November 2007. Post the solvent-soak-acid job, **about 161 tonnes of oil (water free and gas free) of 18-degree API was produced by ACL from December 2007 to August 2008.** Though the acid job had helped to improve the well PI to the extent that fluid level started rising to the surface albeit slowly, sustained self-flow could not be achieved. The monthly production of the same is shown in **Figure 4-61.**

Figure 4-61: PRODUCTION DATA OF WELL BARSILA 3 FOLLOWING ACID JOB



4.4.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/ results.

Reservoir parameter of the **1744.5 Sand** in well BRSL-3 is given in **Table 4-45**

Table 4-45: RESERVOIR PARAMETER OF 1744.5 SAND OF WELL BRSL-3

I.	**Formation Name & Age**	TS-2, Miocene
2	**Depth of Formation m (MSL)**	Vertical depth- 1728m
3	**Perforation Interval (m) MSL**	1744.5 - 1749.5m
4	**Net Pay Thickness m**	5 m
5	**Formation Temperature ^{o}C**	70
6	**Initial Formation Pressure KSC**	Hydrostatic
7	**Formation Water Salinity**	~3 gms/lit
8	**Reservoir Permeability**	20 md
9	**Formation Porosity**	18 %
10	**Hole Diameter**	8-1/2”
11	**Crude Oil Viscosity at 20^{o}C**	52 cp Gas free oil
12	**Crude oil composition (specially Asphaltene, Resin and Wax content)**	Asphaltene 1.93% (w/w) Resin 21.11 % (w/w) Wax 8 % (w/w)
13	**Clay mineral content and Type**	10% montmorillonite
14	**Density at 15^{o}C**	0.9435
15	**Specific Gravity at 60^{o}F**	0.9440
16	**API Gravity**	18.4
17	**Oil Formation Volume Factor (Bo)**	1.18
18	**Solution GOR (v/v)**	50-130

Also, summary views from reservoir studies following the workover job are as follows:

• The well PI based on influx study by ACL is of the order of 0.144 m3/day/ksc. The main reason attributed to low PI is the heavy and viscous nature of the oil with expected low GOR 80 m3/m3. Due to reduction in temperature along the tubing, the viscosity increases and at around 700 m measured depth, the oil almost becomes so heavy that it refuses to surface out due to low pressure.

• The subsequent acid job to improve well PI was helpful to the extent that fluid level started rising to the surface albeit slowly, not enough to sustain self-flow.

. • It is expected that installation of a downhole heater in the tubing would heat the high viscosity oil in tubing to a temperature level of 120 degree Celsius. This will result in lightening of the oil so that it easily flows to the surface.

• In addition, an artificial lift SRP/PCP may be installed to create extra draw down that may help to achieve a sustained daily oil production rate of 15-20 m3/day.

• Solvent-soak-acid job, as formulated by IRS, could also be repeated.

• In order to improve ultimate oil recovery, suitable EOR techniques may be probed and used, if found suitable

Results of Bottomhole studies conducted in the well BRSL -3 to ascertain the influx and liquid level in the well bore are as below in **Table 4-46**:

Table 4-46: RESERVOIR STUDY IN WELL BRSL -3 DURING WORKOVER IN JULY 2007

Well No	Date of Study	Study	Pressure guage	MD, m	BHP Ksc	Remarks
Barsilla-3	24.8.2007	Influx	Electronic Memory Recorder	1700	861	PI=0.144 m3/hr/Ksc Press rise from 48 Ksc to 66.1 Ksc
Barsilla-3	26.8.2007		Mechanical Pressure Guage			LL at around 700m

Oil & Gas analysis (BARSILLA FIELD)

Due to low degree API crude with negligible dissolved gas, the oil is heavy and viscous. Analysis of gas samples taken from well BRSL-1 are given in **Table 4-47.**

Table 4-47: GAS SAMPLES ANALYSES FOR WELL BRSL-1

Barsilla-1 Object VII	Gas samples collected at 1106 hrs. on 21.5.83.	Gas Sample collected at 1600 hrs. on 21.5.1983	Gas Sample collected at 1300 hrs, on 22.5.1983.	Gas Sample collected at 1510 hrs, on 22.5.1983.
Methane	68.16	99.61	87.38	99.35
Ethane	1.2	8.39	0.33	0.68
Propane	-	-	-	-
iButane	-	-	-	-
iPentane	-	-	-	-
nPentane	-	-	-	-
Air	30.64%		12.29	-
Another sample collected on 22.05.1963 at 1050 hrs and 1430 hrs contained muddy water. The chloroform extract after evaporation gave strong fluorescence.				

4.4.5 Geology and Reservoir Description of BARSILLA Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.4.5.1 Geological correlations, sections and maps (BARSILLA Field):

A.1 Structure

Geologically, the Barsilla area overlies a thrust regime. The Barsilla structure is a doubly plunging anticline trending ENE-WSW separating the Main Naga Hills from the plains and is situated very close to the Naga Schuppen belt, which is bounded by the Naga and Disang Thrusts extending in the NE-SW direction. Barsilla anticlne is dissected by the Barsilla Thrust which separates it from the Dasphutia anticline in the north. In Barsilla anticline Girujan Clay is exposed in the axial part 'whereas Upper Sandstone forms the axial part of the Dasphutia Anticline. Based on geological data and traverse mapping done in the Borsilla-Deopani foothills of Nagaland, the anticlinal feature had been identified and named as the Dasphutia anticline.

The sedimentary section in the wells drilled in the Barsilla Field has been traversed by multiple thrusts to as many as five, leading to repetition of Girujan Clay and Tipam sand layers and encountering a huge thickness of the sediments of the Tipam Group.

A.2 Stratigraphy

In the Barsilla area, the generalized stratigraphic set-up indicates onset of shelf sedimentation during Late Palaeocene over the granitic basement after a pronounced unconformity. The Paleogene sequence was deposited on the flanks of passive continental margin as a fairly simple transgressive (Basal Tura Sandstone, Sylhet Limestone & Kopili Shales) and regressive (Barails) wedge. It was followed by the Neogene sequences (Tipam Group of sediments), consisting mainly of fresh water sandstone and fresh water clays and sand/clays alternations, which were deposited unconformably over the Barail Group of sediments after a period of non-deposition in Early Miocene. Tipam Group of sediments is overlain by the Namsang beds and Alluvium of high level terraces deposited in a fluviatile environment.

The hydrocarbon reservoir facies of this field occur in sands of the Barail section (both BCS and BMS) and Tipam section (TS-1, TS-2, TS-5 & TS-6). The sands are defined by heterogeneous lithology of medium to fine grained tight sandstone, finely interlaminated with siltstone /shale (occasionally carbonaceous) within the Barails. However, the Tipam reservoir is comparatively more arenaceous. The entrapment is strati-structural and capturing of reservoir heterogeneity is the major challenge in the field. The stratigraphic sequence encountered in well Barsilla-1 and generalized stratigraphic succession of the Barsilla Field are shown in **Table 4-48 and Table 4-49 .**

Table 4-48: STRATIGRAPHIC SEQUENCE ENCOUNTERED IN WELL BARSILLA-1

AGE	STRATIGRAPHIC UNIT	INTERVAL (M)	LITHOLOGY
Miocene	Girujan Clay	Surface – 328	Variegated mottled clay with unconsolidated sands
	Tipam Sandstone	328 - 975	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
Thrust			
Miocene	Girujan Clay	975-1035	Variegated mottled clay with unconsolidated sands
	Tipam Sandstone	1035 - 1276	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
Thrust			
Miocene	Girujan Clay	1276-1537	Variegated mottled clay with unconsolidated sands
	Tipam Sandstone	1537-2264	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
	LCM	2264-2287	Dominantly Clay/ Claystone
Thrust			
Miocene	Tipam (TS3)	2287-2670	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
	LCM	2670-2740	Dominantly Clay/ Claystone
	Tipam (TS5)	2740-2890	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
Thrust			
Miocene	Tipam (TS3)	2890-3079	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
	LCM	3079-3152	
	Tipam (TS5-TS6)	3152-3565	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
	Safrai	3565-3728	Dominantly medium grained grey sandstone, occ coarse with minor light grey soft clay
Unconformity			
Oligocene	Barail BCS	3728-4225	Predominantly consists of carbonaceous shales, grey shales, coal with fairly sorted, dark grey to yellowish grey sandstones.
	Barail BMS	4225-4405	Predominantly Sandstone, with subordinate grey shales, and sporadic coal,
Late Eocene	Kopili Formation	4405-4607	Mostly dark grey, olive greenish grey splintery shales with fine grained yellowish coloured sandstones,

Table 4-49: GENERALIZED STRATIGRAPHY OF THE BARSILLA FIELD

Age	Group	Unit	Depth Range (m)
Mio-Pliocene	TIPAM GROUP	GC	Variegated mottled clay with unconsolidated sands
		TS1	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
		TS2	
		TS3	
Barsilla Thrust			
Plio-Pliestocene		Namsang	Variegated sandstone with free quartz
		Nazira Sandstone	White to light greyish white, medium grained sandstone associated with clay and minor coal
Mio-Pliocene	TIPAM GROUP	GC	Variegated mottled clay with unconsolidated sands
		TS1	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
		TS2	
	Kharkachua Thrust		
Mio-Pliocene	TIPAM GROUP	GC	Variegated mottled clay with unconsolidated Sands
		TS1	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
		TS2A	
		TS2B	
		TS3	
		LCM	
Naga Thrust			
Mio-Pliocene	TIPAM GROUP	GC	Variegated mottled clay with unconsolidated sands
		TS2	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
		TS3	
		LCM	
		TS5	
		TS2	
		TS3	
Thrust			
Miocene	TIPAM GROUP	TS2	Mostly greenish grey, ashen grey sandstones, frequently intercalated with bluish grey, to dark grey, plastic clay/claystones
		TS3	
		LCM	
		TS5	
		TS6	
		Safrai	
Unconformity			
Oligocene	BARAIL GROUP	BCS	Predominantly consists of carbonaceous shales, grey shales, coal with fairly sorted, dark grey to yellowish grey sandstones.
		BMS	Predominantly Sandstone, with subordinate grey shales, and sporadic coal,
Late Eocene	KOPILI	Kopili	Mostly dark grey, olive greenish grey splintery shales with fine grained yellowish coloured sandstones,

A.3 Structural Correlation of Barsilla wells

In the Barsilla area, thrusts have been encountered in all the wells and are also seen in a correlation between wells BRSL-1 and BRSL-2. Due to thrust faulting, there is a repetition of sands which are found multiple times while drilling. The availability on only one structure map further constrains the possibility of finding the approximate dip and location of thrust fault at different levels. The complex structural history and repetitive sequences pose a challenge in identifying individual formation tops, faults encountered and reservoir delineation.

Based on the above correlation, a cross section showing wells BRSL-1 & BRSL-2 and BRSL-1 & BRSL-3 are shown in the following figures, viz, **Figure 4-62, Figure 4-63 and Figure 4-64.** Structure contour map~~s~~ on top of TS-1 are shown in **Figure 4-65**.

Figure 4-62: A SCHEMATIC SECTION (BETWEEN WELLS BRSL -1 & BRSL -2) SHOWN THE REPETITIVE SAND ENCOUNTERED IN THE WELL DUE TO THRUST FAULTING.

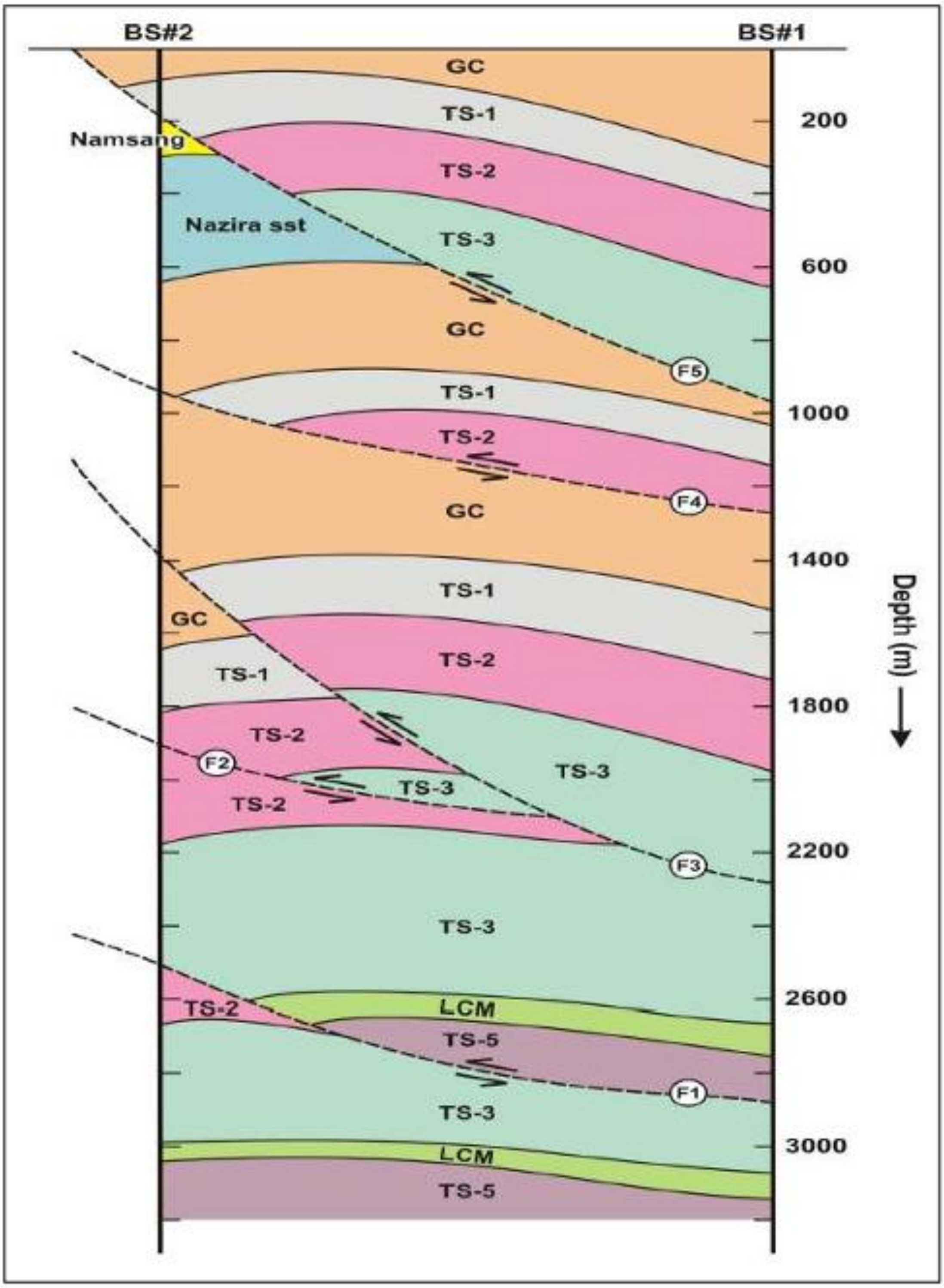


Figure 4-63: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BRSL-1 & BRSL-2

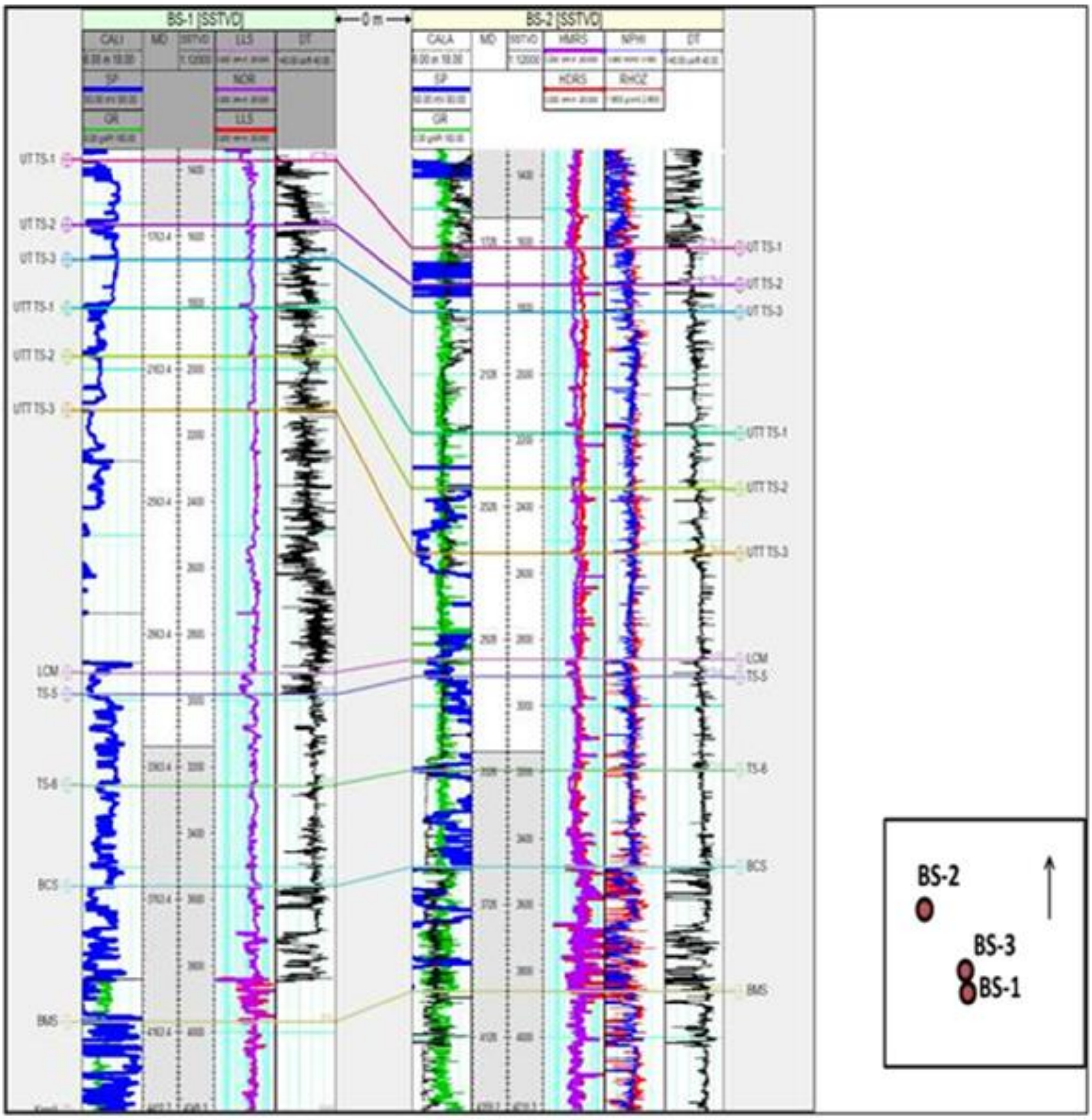


Figure 4-64: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BRSL-1 & BRSL-3

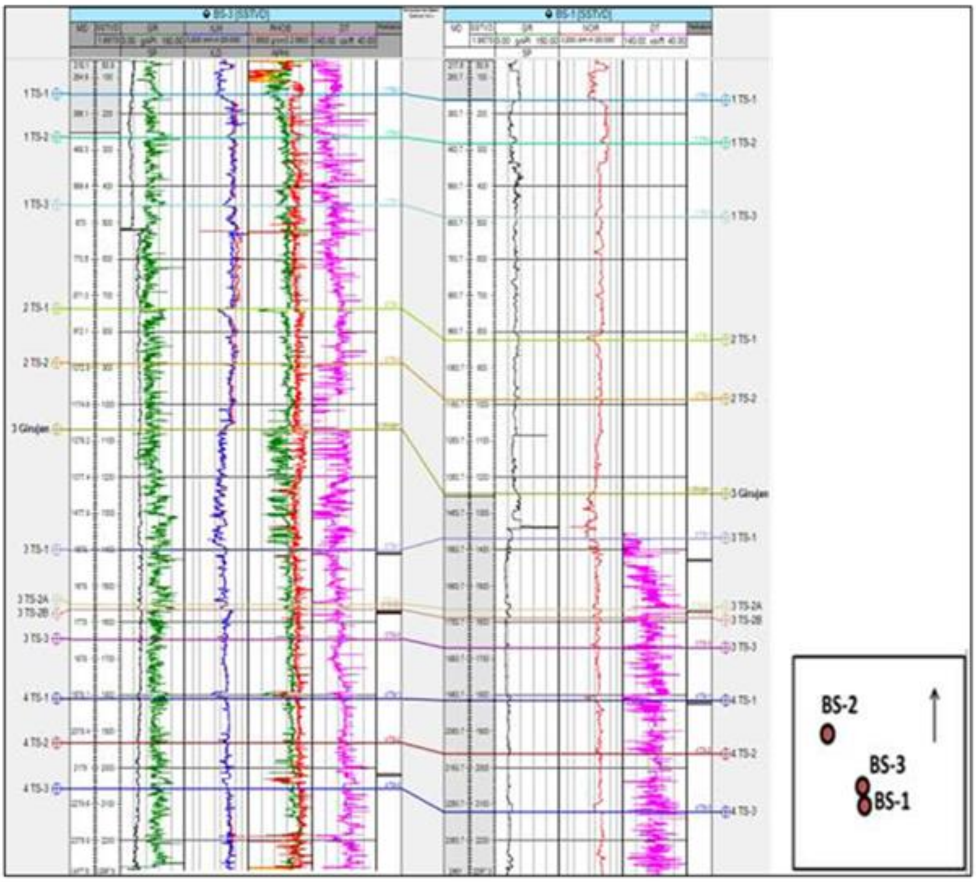
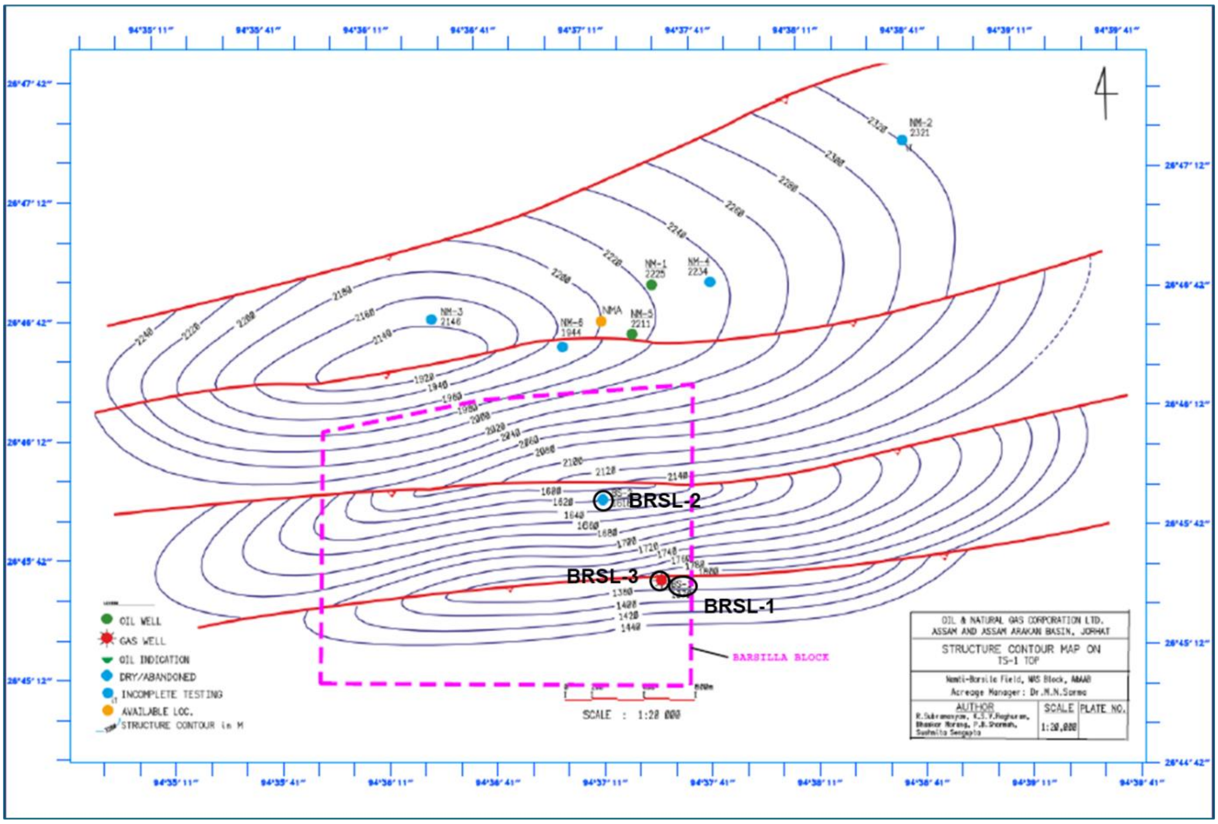


Figure 4-65: STRUCTURE CONTOUR MAP ON TOP OF TS-1 WITH DRILLED WELL LOCATIONS.



4.4.5.2 Additional Studies for BARSILLA Field

A Field Development Plan (FDP) prepared by Ramayna Ispat Pvt. Ltd, (RIPL) as part of an earlier RSC contract is available for the field. The operator performed the seismic simulation study to best answer the challenges involved in exploiting the field. The scope included a complete review of existing geophysical, geological, petrophysical, and reservoir engineering and production data. Reservoir and Pay summary of Barsilla-1, Barsilla-2 and Barsilla-3 are given in **Table 4-50, Table 4-51 and Table 4-52**

Table 4-50: RESERVOIR AND PAY SUMMARY OF WELL BRSL-1

Reservoir Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-1	1587.47	1608.66	21.19	21.19	1	0.266	0.619	0.11	5.64	2.15
	1727.83	1739.57	11.74	11.74	1	0.178	0.661	0.259	2.09	0.71
	3153.69	3189.66	35.97	20.35	0.566	0.142	0.619	0.262	2.9	1.1
	3306.39	3313.4	7.01	7.01	1	0.171	0.643	0.163	1.2	0.43
	3458.95	3482.57	23.62	15.78	0.668	0.114	0.685	0.232	1.79	0.56
	3522.95	3528.59	5.64	3.51	0.621	0.134	0.606	0.297	0.47	0.19
	Cumulative		105.17	79.57	0.757	0.177	0.635	0.208	14.09	5.14
Pay Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-1	1587.47	1608.66	21.19	18.9	0.892	0.267	0.609	0.11	5.04	1.97
	1727.83	1739.57	11.74	7.24	0.617	0.198	0.602	0.312	1.44	0.57
	3153.69	3189.66	35.97	12.34	0.343	0.158	0.577	0.23	1.95	0.82
	3306.39	3313.4	7.01	3.35	0.478	0.206	0.554	0.135	0.69	0.31
	3458.95	3482.57	23.62	6.4	0.271	0.121	0.631	0.212	0.78	0.29
	3522.95	3528.59	5.64	3.2	0.567	0.137	0.6	0.295	0.44	0.18
	Cumulative		105.17	51.44	0.489	0.201	0.6	0.193	10.33	4.14

Table 4-51: RESERVOIR AND PAY SUMMARY FOR WELL BRSL-2

Reservoir Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-2	805.28	808.48	3.2	2.74	0.857	0.278	0.497	0.382	0.76	0.38
	930.55	932.84	2.29	2.29	1	0.245	0.546	0.204	0.56	0.25
	936.04	938.63	2.59	2.59	1	0.223	0.488	0.245	0.58	0.3
	1033.12	1034.34	1.22	1.22	1	0.322	0.621	0.103	0.39	0.15
	1035.25	1037.69	2.44	2.44	1	0.339	0.586	0.214	0.83	0.34
	1040.89	1046.68	5.79	5.72	0.987	0.316	0.601	0.179	1.81	0.72
	Cumulative		17.53	17	0.97	0.29	0.565	0.225	4.93	2.15
Pay Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-2	805.28	808.48	3.2	2.29	0.714	0.279	0.446	0.379	0.64	0.35
	930.55	932.84	2.29	1.6	0.701	0.241	0.481	0.201	0.39	0.2
	936.04	938.63	2.59	2.21	0.853	0.224	0.427	0.25	0.5	0.28
	1033.12	1034.34	1.22	0.91	0.75	0.352	0.58	0.082	0.32	0.14
	1035.25	1037.69	2.44	1.9	0.78	0.36	0.565	0.2	0.68	0.3
	1040.89	1046.68	5.79	3.96	0.684	0.353	0.549	0.156	1.4	0.63
	Cumulative		17.53	12.88	0.735	0.305	0.516	0.219	3.93	1.9

Remarks: Sands in depth interval 1040.89-1046.68m, 1035.25-1037.69m, 1033.12-1034.34m and 805.28-808.48m of well BRSL -2 appears to be gas bearing as observed from Neutron-Density cross plot.

Table 4-52: RESERVOIR AND PAY SUMMARY OF WELL BRSL-3

Reservoir Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-3	706.22	725.73	19.51	17.38	0.891	0.151	0.679	0.282	2.63	0.84
	966.52	986.94	20.42	16.31	0.799	0.131	0.667	0.327	2.14	0.71
	1007.52	1013.31	5.79	5.79	1	0.136	0.711	0.28	0.79	0.23
	1044.4	1059.03	14.63	11.35	0.776	0.129	0.71	0.314	1.47	0.43
	1067.56	1078.69	11.13	7.62	0.685	0.124	0.823	0.29	0.95	0.17
	1222.4	1232.15	9.75	3.96	0.406	0.114	0.678	0.333	0.45	0.15
	1566.06	1594.41	28.35	27.13	0.957	0.15	0.721	0.265	4.06	1.13
	1744.68	1749.7	5.02	4.65	0.925	0.116	0.494	0.263	0.54	0.27
	1751.08	1754.58	3.5	2.29	0.653	0.117	0.495	0.253	0.27	0.13
	2316.94	2327	10.06	7.77	0.773	0.13	0.72	0.275	1.01	0.28
	Cumulative		128.17	104.25	0.813	0.137	0.696	0.289	14.3	4.34
Pay Summary										
Well Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
#	m	m	m	m		dec	dec	dec		
Barsila-3	706.22	725.73	19.51	6.71	0.344	0.14	0.592	0.343	0.94	0.38
	966.52	986.94	20.42	6.86	0.336	0.124	0.606	0.36	0.85	0.33
	1007.52	1013.31	5.79	1.6	0.276	0.121	0.598	0.379	0.19	0.08
	1044.4	1059.03	14.63	3.35	0.229	0.115	0.622	0.384	0.38	0.15
	1067.56	1078.69	11.13	Due to slightly higher water saturation this sands is not making the pay cutoffs,however this sands may produce hydrocarbon but with very higher water cut.						
	1222.4	1232.15	9.75	1.22	0.125	0.109	0.625	0.342	0.13	0.05
	1566.06	1594.41	28.35	4.5	0.159	0.129	0.618	0.35	0.58	0.22
	1744.68	1749.7	5.02	4.65	0.925	0.116	0.494	0.263	0.54	0.27
	1751.08	1754.58	3.5	2.29	0.653	0.117	0.495	0.253	0.27	0.13
	2316.94	2327	10.06	0.61	0.061	0.106	0.622	0.367	0.06	0.02
	Cumulative		128.17	31.78	0.248	0.124	0.584	0.336	3.95	1.64

From the Net pay and Reservoir summary of all three wells the following conclusions can be made:

- The upper part of reservoir corresponding to Girujan Clay is most likely gas bearing in well BRSL -2. There are six possible gas-bearing sands observed in Girujan Clay section of well BRSL -2 (**Figure 4-66**)
- There are a few possible oil bearing zones identified in Tipam section of wells BRSL-1 and BRSL-3 (**Figure 4-67)**. However, these layers need to be probed by acquisition of modern wireline log tools and testing.

Figure 4-66: GAS BEARING SANDS OF GIRUJAN CLAYS IN WELL BRSL-2

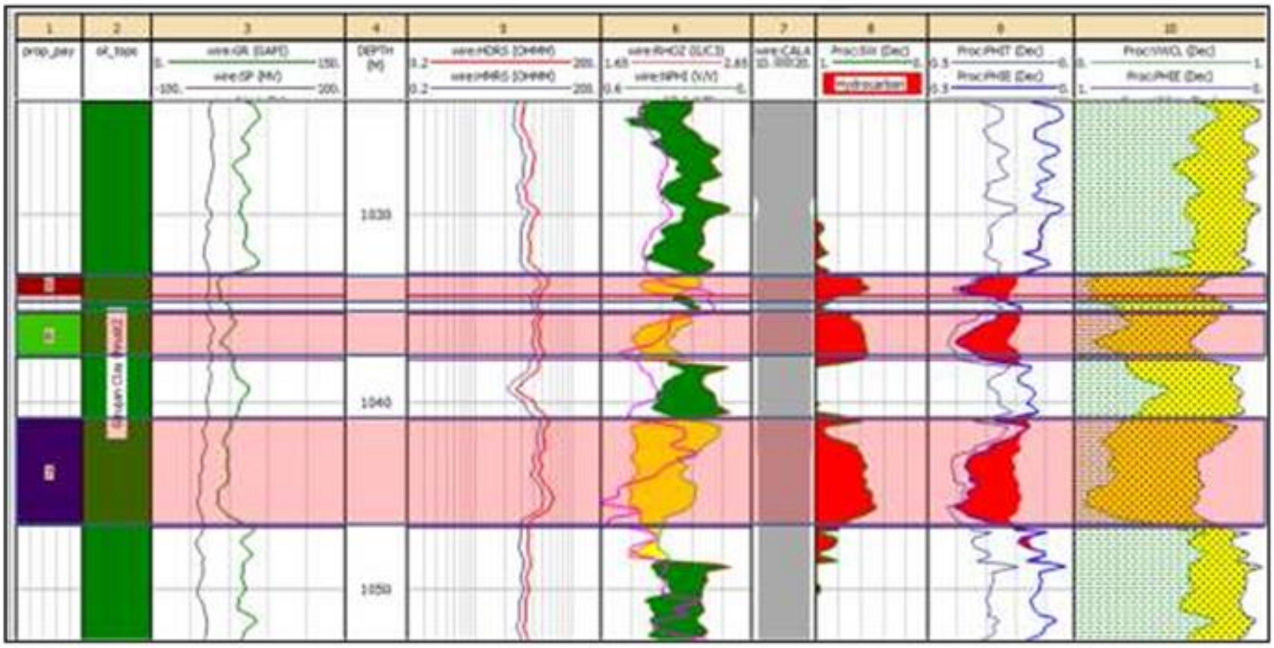
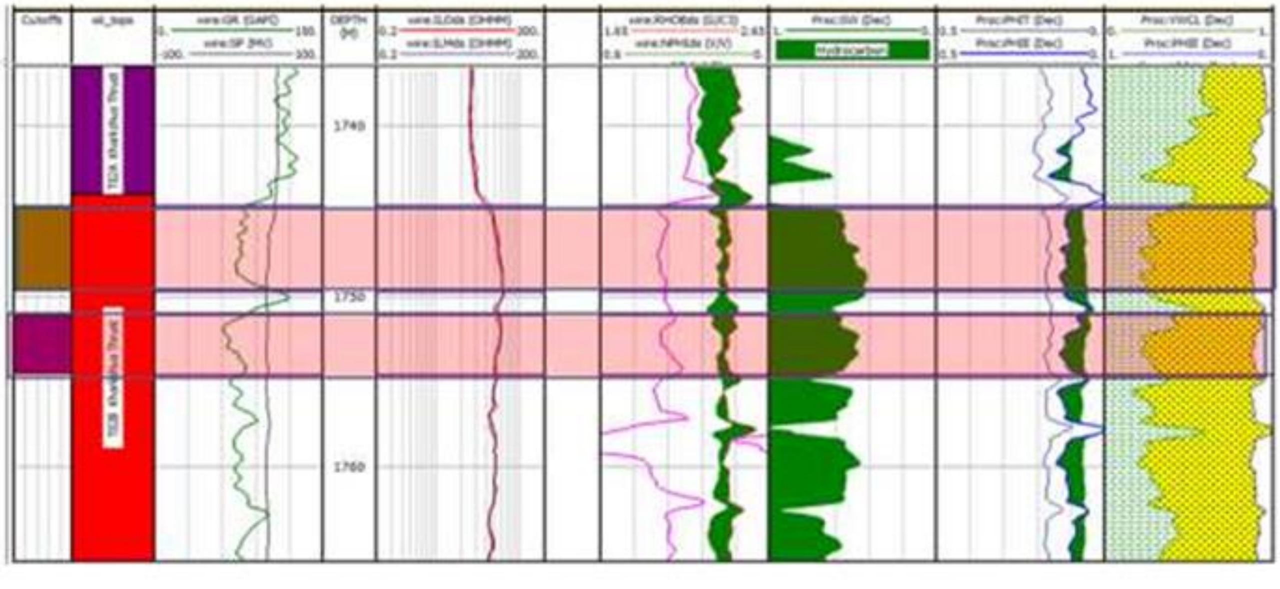


Figure 4-67: OIL BEARING SANDS OF TIPAM IN WELL BRSL -3



Parameters used to calculate hydrocarbon estimates and reserves in FDP are given in **Table 4-53, Table 4-54 and Table 4-55**.

Table 4-53: PARAMETERS FOR RESERVE CALCULATION AND RESERVE FOR ZONES-I (TS-2)

Post Workover Barsilla Zone-I (TS-2 BS-3 1744.5-1749.5m)				
		P10	**P50**	**P90**
Area	sqkm	0.35	0.29	0.32
Radius	km	0.33	0.30	0.32
H	m	5	10	15
Poro		0.12	0.15	0.18
Shc		0.4	0.5	0.55
sp gr		0.922	0.922	0.922
FVF	stb/rbbl	1.18	1.18	1.18
GOR	m3/m3	50	80	130
In place	**MMstb**	**0.45**	**1.61**	**3.53**
Reserves	**MMstb**	**0.112**	**0.194**	**0.353**
RF, %		**25**	**12**	**10**

Table 4-54: PARAMETERS FOR RESERVE CALCULATION AND RESERVE FOR ZONE-II (TS-1)

Post Workover Barsilla Zone-II (TS-1 BS-3 1590-1596)				
		P10	**P50**	**P90**
Area	sqkm	0.786	0.6	0.383
Radius	km	0.50	0.44	0.35
H	m	5	8	12
Poro		0.15	0.18	0.26
Shc		0.4	0.5	0.63
FVF	scm/rcm	150	150	175
In place	**BCF**	**1.25**	**2.29**	**4.65**
Reserves	**BCF**	**0.8**	**1.3**	**1.9**
RF, %		**65**	**55**	**40**

Table 4-55: PARAMETERS FOR RESERVE CALCULATION AND RESERVE FOR ZONE-III (GIRUJAN)

Post Workover Barsilla Zone-III (BS-3 Girujan 805-808, 848-861, 930-946 &1033-1047m)				
		P10	**P50**	**P90**
Area	sqkm	0.786	0.6	0.383
Radius	km	0.50	0.44	0.35
H	m	5	10	18
Poro		0.2	0.24	0.28
Shc		0.4	0.5	0.6
FVF	scm/rcm	90	100	100
RF%		68	42	40
In place	MMm3	28.296	72	116
Reserves	MMm3	19.2	30.2	46.3
In place	**BSCF**	**1.00**	**2.54**	**4.09**
Reserves	**BSCF**	**0.7**	**1.1**	**1.6**
RF, %		**70**	**43**	**39**

4.4.5.3 Reservoir parameters and hydrocarbon estimates (BARSILLA Field):

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Very limited production has been obtained from the field. ACL had worked over well BRSL-3 in the year 2007 and had carried out reservoir studies. No further workover has been done in any well, since 2007. Well Barsilla-3 is clustered in the wellsite area of well BRSL-1.

<u>Current Oil/ Gas In-Place estimation</u>

The reservoir parameters and in-place estimated for various sands of Barsilla Field in the current study are given in **Table 4-56 and Table 4-57** respectively.

Table 4-56: RESERVOIR PARAMETERS FOR VOLUMETRIC ESTIMATION OF BARSILLA FIELD

Reservoir	Area	He	Phi	Hydrocarbon saturation		FVF		API	SPGR	GOR	O+OEG
Sand/ layer	SqKm	m		So	Sg	Bo	Bg			Sm3 /m3	MMTOE
TS I	0.636	14	0.16	-	-	1.18		21.9	0.9222	132	-
TS IA	0.636	15	0.19	-	0.53	-	0.009	-	-	-	0.11
TS IB	0.636	8	0.18	-	0.57	-	0.009	-	-	-	0.06
TS II	0.636	8	0.16	0.505	-	1.18	-	18.5	0.9222	132	0.37
TS VA	0.636	12	0.17	-	-	1.46	-	30.3	0.8746	228	-
TS VI	0.636	14	0.17	0.42	-	1.67	-	30.7	0.8725	130	0.38
BCS	0.636	8	0.15	-	-	1.80	-	32.1	0.8649	280	-
GC	0.636	10	0.24	-	0.5		0.009	-	-	-	0.08
											1.00

Table 4-57: HYDROCARBON IN-PLACE (2P) OF BARSILLA FIELD

	O+OEG
Field	**MMTOE**
BARSILLA	**1.00**

Erstwhile Operator-reported estimates on record:

The Barsilla Field has a reported gas estimate of **0.25 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

<u>Other Prospective Resource Candidates</u>

Apart from the possible gas bearing sands in Girujan clay in well BRSL-2, several others possible hydrocarbon sands have been identified as Prospective Resource candidates, but as of now due to inadequate evidence any estimate for the same have not been made. Details of these zones are given in **Table 4-58**

Table 4-58: OTHER PROSPECTIVE RESOURCE CANDIDATES IN BARSILLA FIELD

Well Name	Depth Range	Formation/ Sand	Resistivity (Ohm.m)	Fluorescence	Test Result / Remarks
BRSL-1	3459–3510	TS-6	18–20	Poor GYF (3500–3505 m)	Tested (3460–70); Water (sal. 3.4 GPL) with traces of oil - Interpreted as Hydrocarbon Bearing during subsequent Petrophysical evaluation.
BRSL-3	1223–1233	TS-2	40–45	Dull GYF / +ve cut	Untested - Interpreted Hydrocarbon Bearing during Petrophysical evaluation.
BRSL-3	1065–1070 1044–1059 1007–1013	TS-2	30–50	N/F	Untested - Interpreted Hydrocarbon during Petrophysical evaluation.

4.4.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Barsilla Field is **Geleki Oil Field** at a distance of **6 Km.**

AA/ONDSF/ASSAM/2025 (A&AA) CHARAIDEO FIELD

4.5 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) CHARAIDEO FIELD

Charaideo Field was discovered by ONGC in 1981. ONGC has drilled 4 exploratory wells viz. Charaideo-1 (CRDO-1), Charaideo-2 (CRDO-2), Charaideo-3 (CRDO-3) and Charaideo-4 (CRDO-4) in the Charaideo area of which wells CRDO-1, CRDO-2 and CRDO-4 fall within the present Contract Area whereas well CRDO-3 falls outside the Contract Area. Well CRDO-1 was found to be oil bearing in Barail Coal Shale (BCS) unit of the Barail Group (Oligocene age) while wells CRDO-2 and CRDO-4 witnessed inflow of oil in Barail Main Sand (BMS) unit of Barail Group (Oligocene age).

The discovery well Charaideo-1 (CRDO-1) is situated about 6 km south of Lakwa Field and was drilled during the year 1981 by ONGC to explore the hydrocarbon prospects in Tipam and Barail Groups and in this well there was minor inflow of oil for a little while from the BCS unit before the flow ceased.

The well CRDO-2 was drilled in the year 2001 to a target depth of 4700 m and bottomed in BMS. The well is correlatable at all levels with the well CRDO-1. A number of hydrocarbon shows were observed during drilling in sands of the Tipam Group and Rudrasagar Formation (BCS unit of Barail Group). Conventional core recovered from Barail Coal Shale unit also indicated the presence of hydrocarbon. Subsequently, nitrogen application caused the flow of little oil and gas from the 4612 m - 4642 m zone of BMS. Other zones remain untested due to fish in hole.

The well CRDO-4 was drilled in the year 2009 as an exploratory vertical well for exploring the hydrocarbon potential of Barails (BCS & BMS). This location was proposed on the highest part of the Charaideo structure to probe its true potential. The well has been drilled down to a depth of 4708 m. The well was terminated within the BMS Formation and was sidetracked three times due to drilling complications.

On testing well CRDO-4, Object-I (4558-66m/BMS) gave poor influx of oil and the well witnessed poor influx of water. On subduing the well with mud, flow of 300 litres of oil was observed. Re-perforation of the zone again produced only 100 litres of oil during reversing out with water. It was thus concluded that the zone requires further activation by hydrofracturing. Object II (4506-02m/ BCS) tested dry with poor fluid influx. Based on results of Object-II, testing of Object III (3932-28.5m/Safrai, lying behind double casing) was cancelled. Due to poor influx, it was recommended to retest the Object-I and improve the influx after hydro-fracturing.

The area Charaideo is located onland within the Assam Shelf area and has an offered area of 14.86 sq. km. under the DSF Bid Round IV. The co-ordinates of the end points defining the block boundary are given **in TABLE 4-59 AND Figure 4-68.** Various oil and gas fields in the Assam Shelf are shown on **Figure 4-69**. A NW-SE cross section from the Eastern Himalayan foothills to Naga Hills is shown in **Figure 4-70.**

Table 4-59: COORDINATES OF THE BLOCK BOUNDARIES: CHARAIDEO FIELD

	CRDO Boundary Points		
	Area: 14.86 sq km		
	Point	**Longitude**	**Latitude**
	A	94° 49′ 47.436″ E	26° 57′ 02.460″ N
	B	94° 51′ 06.628″ E	26° 57′ 25.113″ N
	C	94° 51′ 28.422″ E	26° 57′ 40.839″ N
	D	94° 52′ 48.186″ E	26° 58′ 12.082″ N
	E	94° 53′ 49.835″ E	26° 58′ 12.064″ N
	F	94° 54′ 29.459″ E	26° 57′ 22.270″ N
	G	94° 54′ 00.000″ E	26° 57′ 06.368″ N
	H	94° 52′ 50.232″ E	26° 56′ 28.707″ N
	I	94° 52′ 29.264″ E	26° 57′ 01.721″ N
	J	94° 50′ 47.432″ E	26° 56′ 47.994″ N
	K	94° 50′ 47.437″ E	26° 56′ 00.000″ N
	L	94° 49′ 47.446″ E	26° 56′ 00.000″ N
	A	94° 49′ 47.436″ E	26° 57′ 02.460″ N
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	CRDO-1	94° 53′ 26.260″ E	26° 57′ 19.388″ N

Figure 4-68: LOCATION MAP SHOWING THE CHARAIDEO BLOCK BOUNDARY.

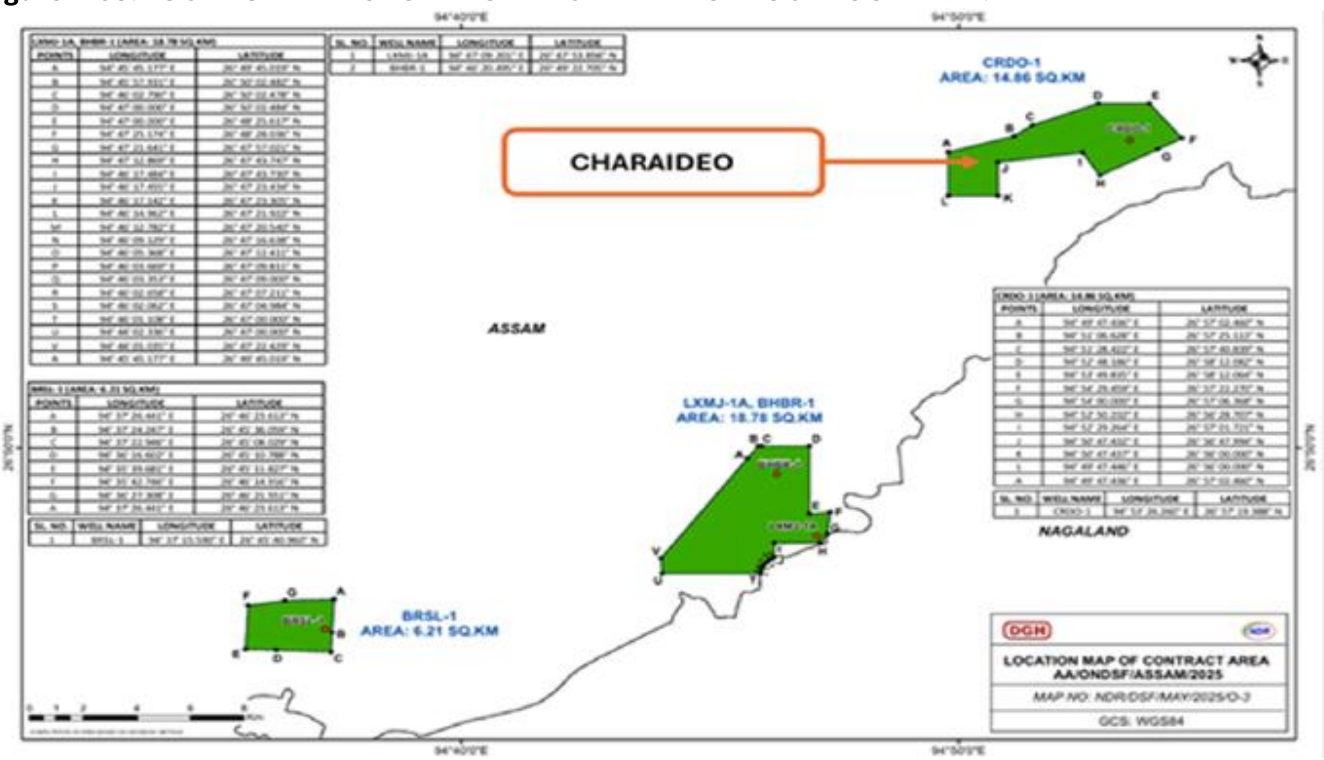


Figure 4-69: OIL & GAS FIELDS IN ASSAM SHELF.

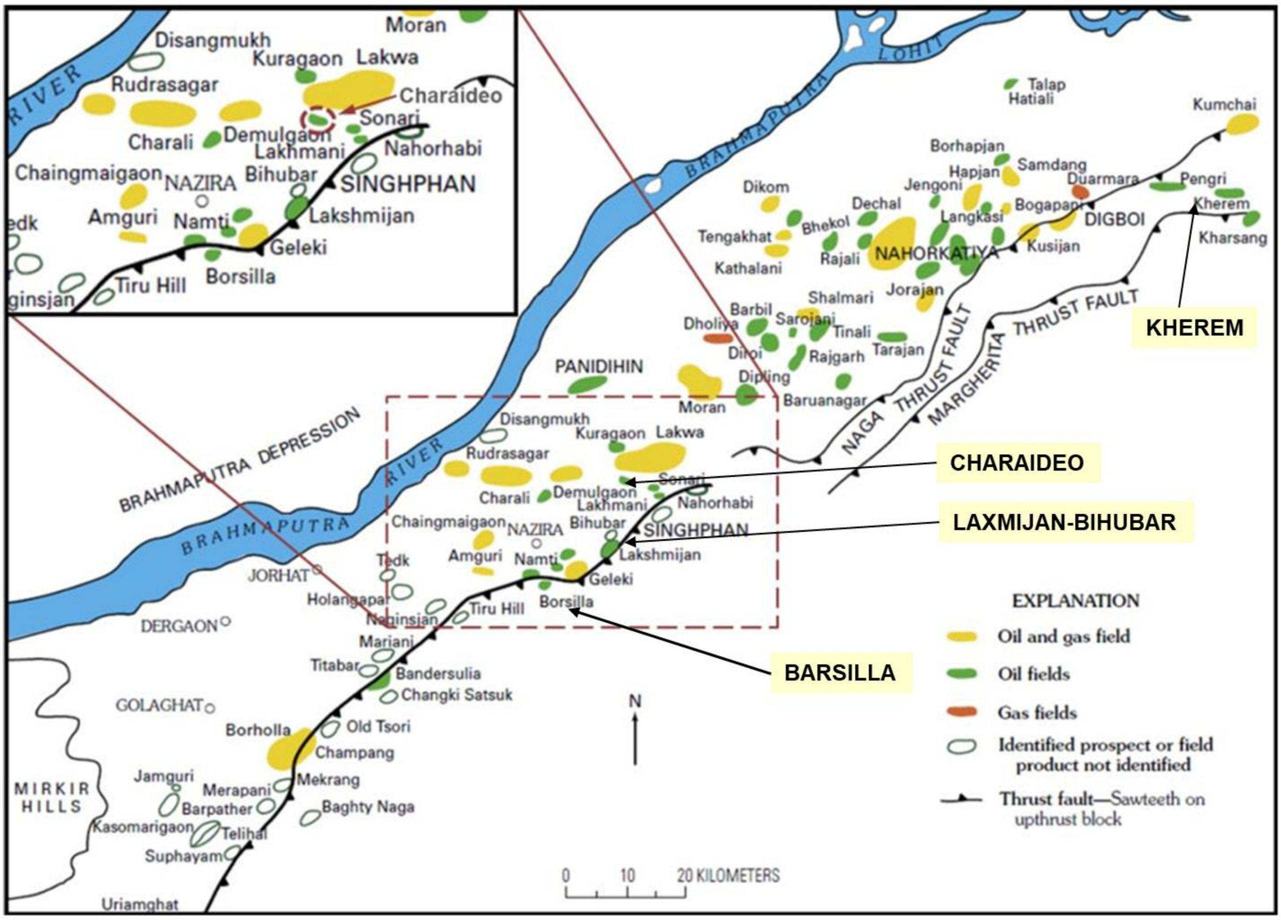
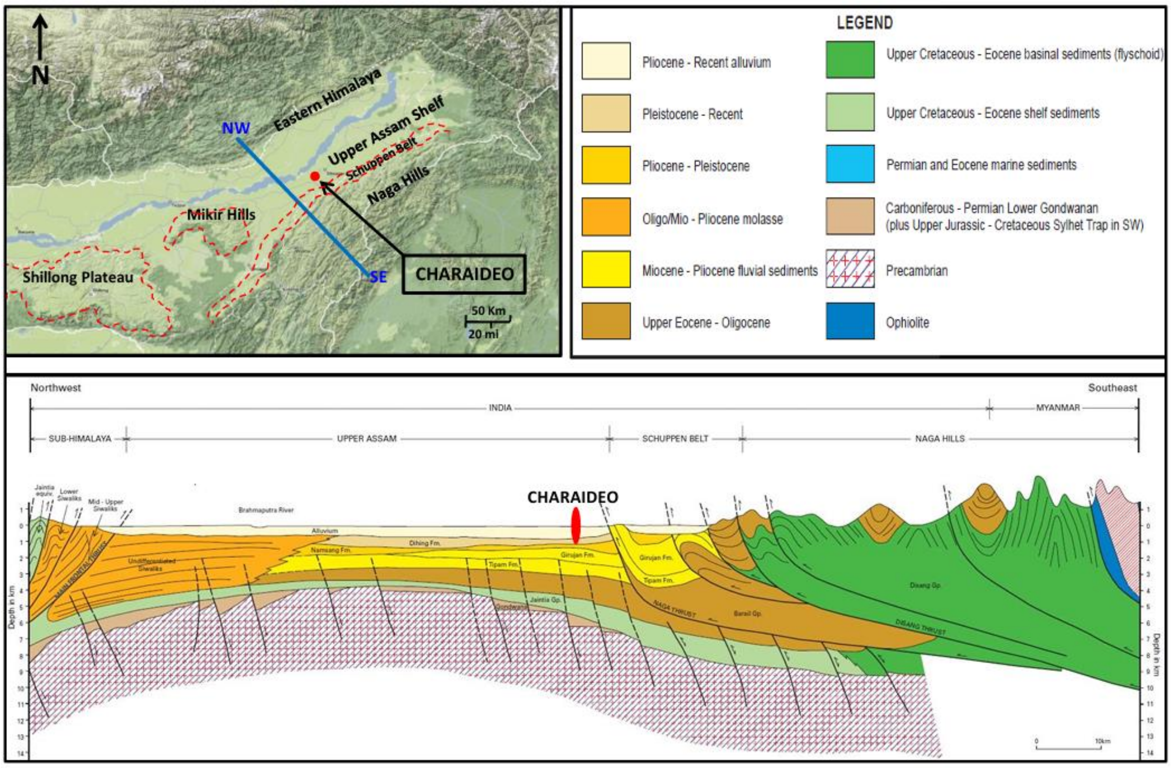


Figure 4-70: NW-SE CROSS SECTION FROM THE EASTERN HIMALAYAN FOOTHILLS TO NAGA HILLS



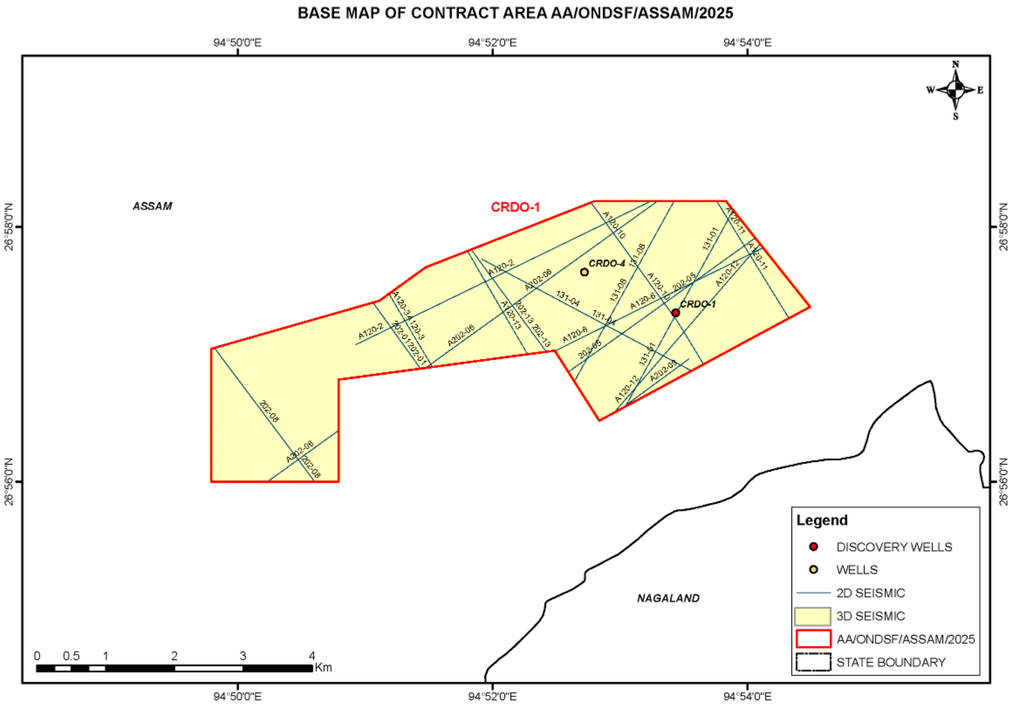
The Charaideo area is covered with alluvium and has an average elevation of 100 m above MSL. The field is well connected with National Highway 2 (erstwhile NH 37) and National Highway 702C. The nearest railway station is Simaluguri Junction and the nearest airport is Jorhat which is about 70 kms from the neighbouring Nazira Town.

In the adjoining areas, although extensive exploration has been carried out in and around Lakwa-Lakhmani area, a well-known oil field in the Assam Shelf, few exploratory locations have been drilled to the north of Santak area, i.e. south of Lakwa Field. A few structural/ stratigraphic prospects have been probed in Rajabari, Nahorhabi and Charaideo areas and are found to be hydrocarbon bearing / with indications of hydrocarbon. Apart from the Charaideo structure, one well each drilled on the Rajabari and Nahorhabi structures had indicated the presence of oil at different levels in the Barail Group of sediments.

The area has also been covered from time to time by several seismic surveys (both 2D and 3D) which include series of different vintages viz. A-42, A-44, A-57, A-117, A-120, A-131, A-185, A-186 and A-202. The earliest subsurface mapping of the area was carried out with the help of seismic investigations A-42 and A-47 based on which two exploratory locations Nahorhabi-1 and Charaideo-1 were drilled during 1981. The Chariadeo Field area is also covered with 3D seismic by the NAS (North Assam Shelf) Mega-merge volume.

The available details of seismic coverage of the block and shown in **Figure 4-71**.

Figure 4-71: 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: CHARAIDEO FIELD



4.5.1 Drilling and well completion

Key information of drilled wells has been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

As stated earlier, of the four exploratory wells drilled in this field viz. Charaideo–1 (CRDO-1), Charaideo–2 (CRDO -2), Charaideo–3 (CRDO -3) and Charaideo–4 (CRDO -4), three wells, i.e. CRDO -1, CRDO -2 and CRDO -4 fall in the block.

Well construction diagrams of wells Charaideo-1, Charaideo-2 and Charaideo-4 are shown in **Figure 4-72, Figure 4-73 and Figure 4-74** respectively.

General details of the drilled wells and casing data, recorded are given in **Table 4-60 and Table 4-61.** Litho section of the Charaideo wells is shown in **Figure 4-75.**

Figure 4-72: WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-1

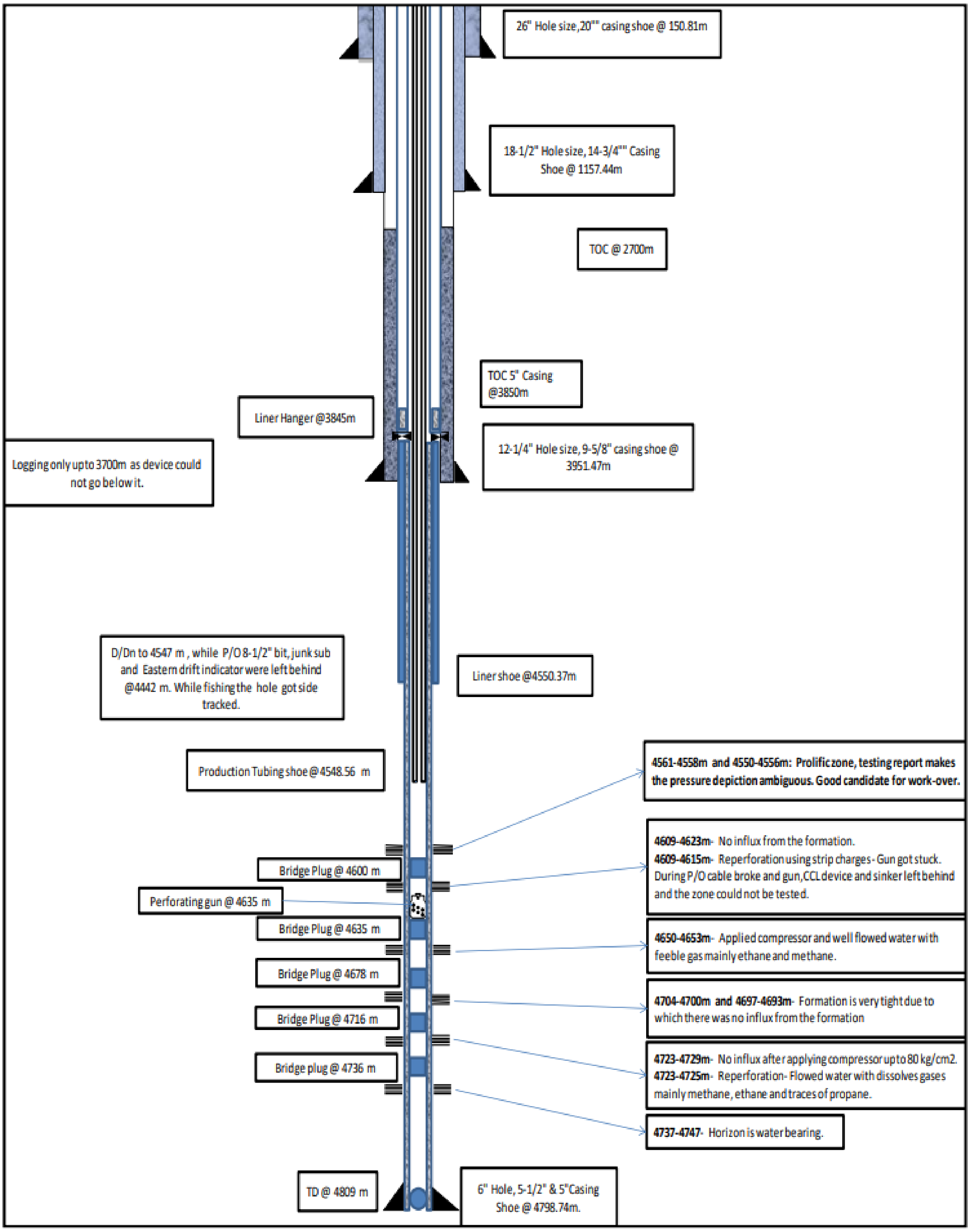


Figure 4-73 : WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-2

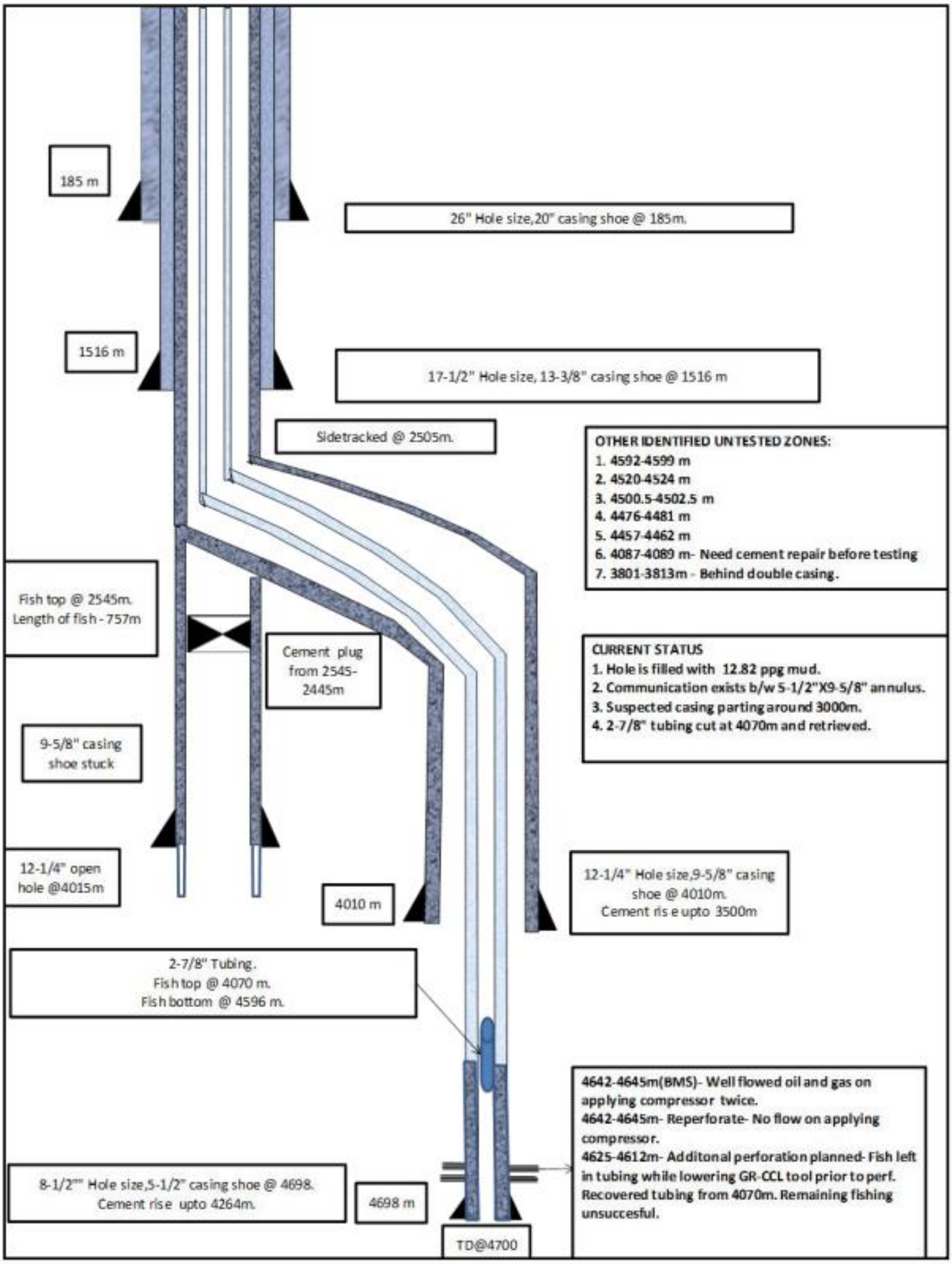


Figure 4-74: WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-4

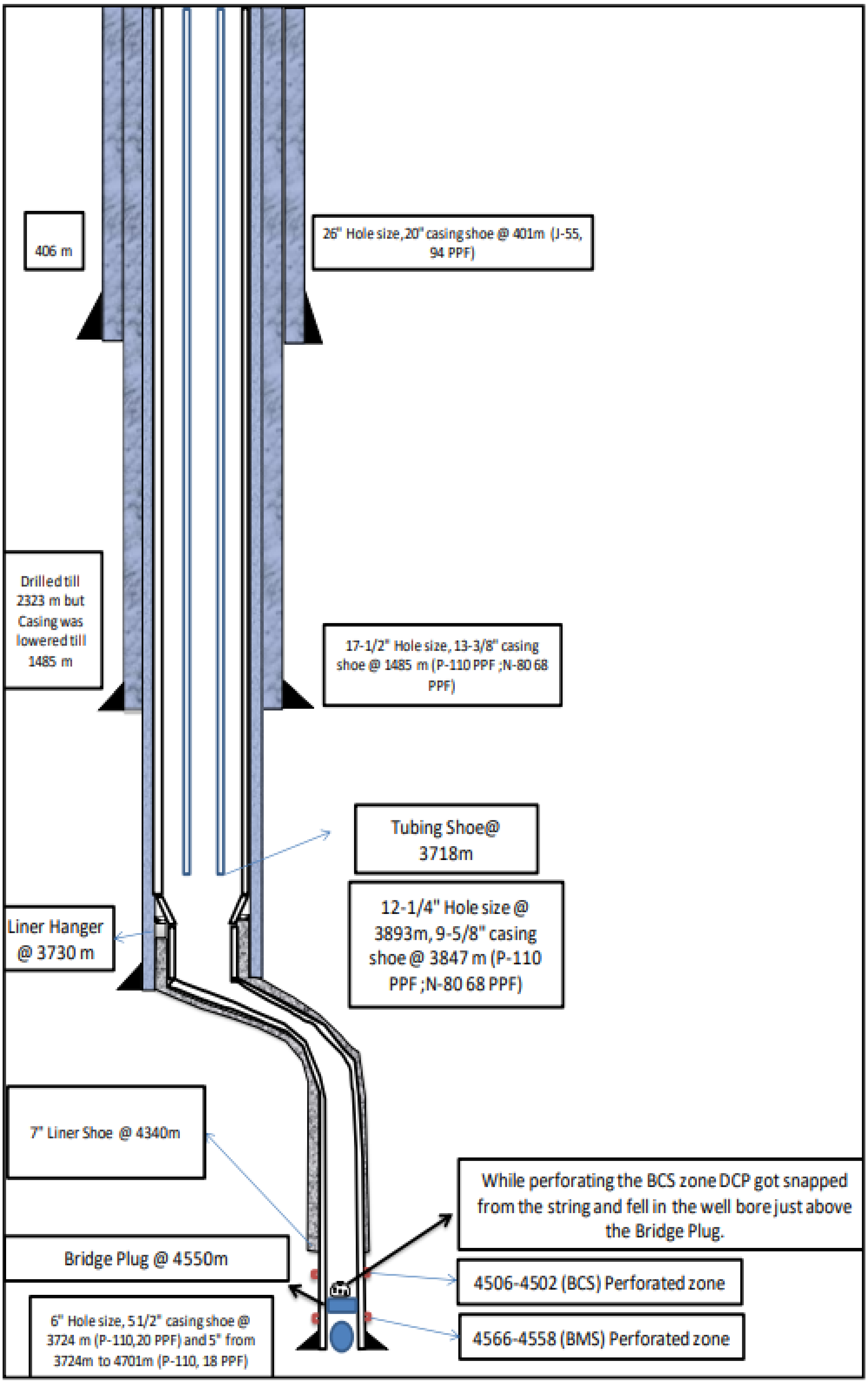


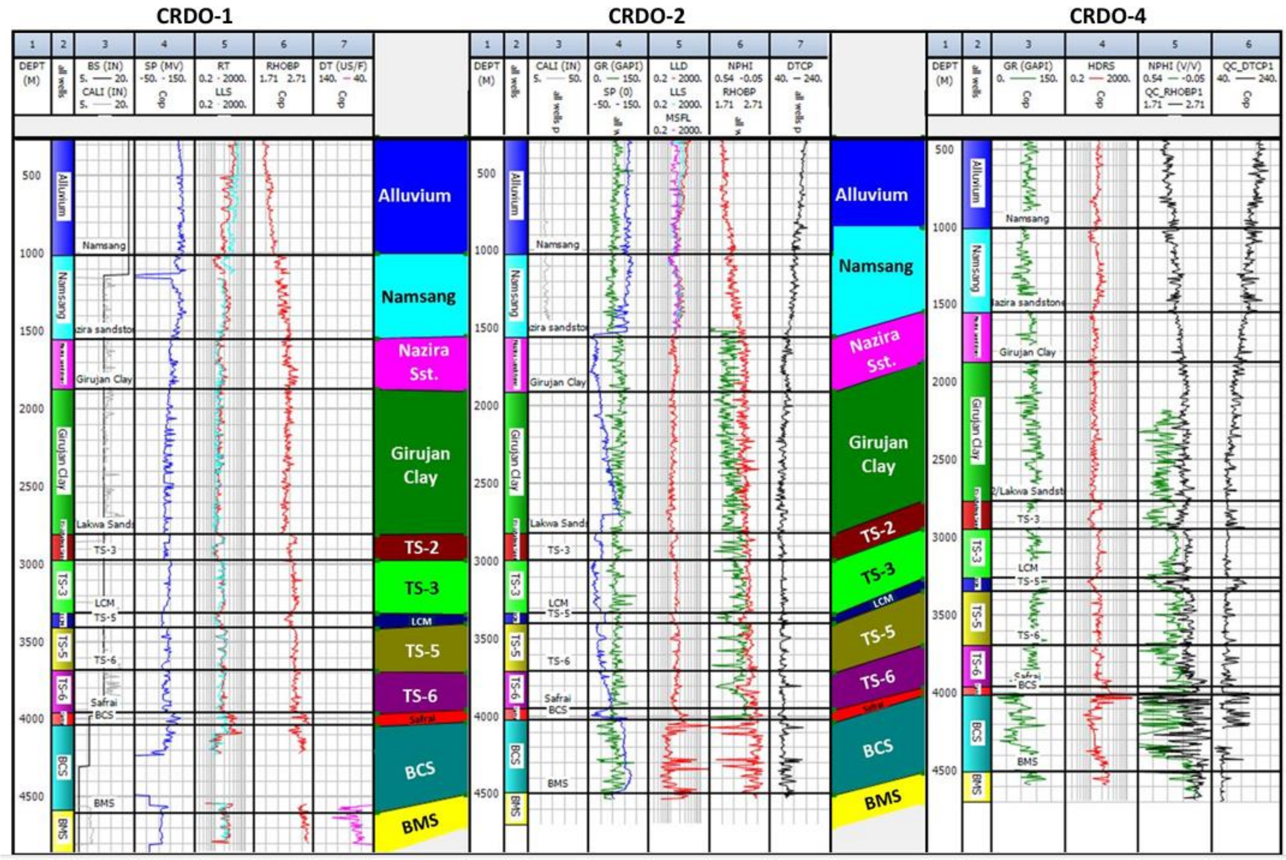
Table 4-60: GENERAL WELL DETAILS

	Charaideo-1	Charaideo-2	Charaideo-4
Area	Nazira - Assam		
Structure	Charaideo		
Well	Charaideo-1	Charaideo-2	Charaideo-4
Category	Exploratory	Exploratory	Exploratory
Co-ordinates	Latitude: 26°57’20”N	Latitude: 26°57’379”N	Latitude: 26°57’38.10”N
	Longitude:94°53’25”E	Longitude:94°53’53.52”E	Longitude:94°52’37.14”E
Rig	H-2500	E-2000-IX	E-2000-IX
Target Depth	4800 m	4900 m	4700 m
Drilled Depth	4805 m	4700 m	4708 m
Objective	Tipam and Barail Prospects	Barail BCS Formation	Barail Prospects
Status	Testing incomplete. **Flow of Oil and gas** with water for some time from BCS	Incomplete Testing due to technical reasons.	Indication of oil with negligible influx in Object-I.
KB	108.60 m	110.0 m	104.5 m
Spud date	13.08.1979	29.07.2001	24.06.2009
Drilling Completion	05.01.1982	18.10.2002	22.08.2010
Production testing Completion	August, 1982	April, 2003	November 2010
Rig release	25.08.1982	01.05.2003	18.11.2010

Table 4-61: CASING DATA

Well	Hole Size	Casing Size	Cement Rise from Surface (m)	Casing Shoe Depth (m)
Charaideo-1	36 “	30 “	Surface	30.15 m
	26 “	20 “	Surface	150.81 m
	18.½ “	14. ¾ “	Surface	1157.40 m
	12. ¼ “	9.5/8 “	2700 m	3951.47 m
	8. ½ “	7 “ (liner)	-	4550.37 to 3845.0 m
	6 “	5 “& 5 ½ “ 5.1/2”= 0 to 3741.48m 5”=3741.48 to 4798.74m	3850 m	4798.74 m
Charaideo-2	26 “	20 “	Upto Surface	185 m
	17.½ “	13. 3/8 “	-	1516 m
	12.¼ “	9. 5/8 “	-	4010 m
	8.½ “	5. ½ “	-	4698 m
Charaideo-4	26 “	20 “	Surface	401 m
	17.½ “	13. 3/8 “	600 m	1485 m (Short Landed)
	12.¼ “	9. 5/8 “	No CBL	3847 m
	8 ½ “	7 “ Liner	465 m	4340 m to 3740 m
	4 “	5½ “& 5” 5.1/2”= 0 to 3724m 5” = 3724 to 4707m	925 m	4707 m

Figure 4-75 : LITHO-SECTION INFORMATION OF THE CHARAIDEO WELLS



4.5.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.5.2.1 Well completion and log evaluation reports availability in Charaideo Field:

	WCR/ FER availability	Spud date	KB	Drilled depth
CRDO-1	Both available	13.08.1979	108.60 m	4805 m
CRDO-4	Both available	24.06.2009	104.5 m	4708 m

Lists of availability of reports , list of log suites recorded for the wells CRDO-1, CRDO-2 and CRDO-4 are given **Table 4-62, Table 4-63, Table 4-64 and Table 4-65.**

4.5.2.2 Well logs acquired Charaideo Field:

Table 4-62: CHARAIDEO-1 FIELD: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Charaideo 1	108.60 m	13.08.1979	4805 m	Available	Available
Charaideo 2	110.0 m	29.07.2001	4700 m	Not Available	Not Available
Charaideo 4	104.5 m	24.06.2009	4708 m	Available	Available

Table 4-63: LOG SUITES RECORDED

Well No.	Type of log	Interval (m)
Charaideo-1	Std. log & BKZ	151-1137, 1158-2879, 2800-3340, 1158-3440, 3952—4228,
	Caliper	151-1175.5, 1158-2870
	Inclinometer	200-1150, 1158-2850
	Sonic, Induction, SP-Normal-4M-BKZ, Inclinometer, Caliper	3952-4782
	Temperature	700-upwards, Surface to 4752
	CBL-Neutron (CH), GR	3952-4752
Charaideo-2	HRI-SP-GR-CAL-SONIC	2713-4023
	LDL-CNL-GR-CALI	1500-4020
Charaideo-4	INDUCTION–GR-SONIC	400-2315
	HRI-BCS-SP-GR-CAL- INCL	1477-2988

	SDL-DSN-GR-CAL	2174-2988
	HRI-SDLT-DSNT-GR-SP-INCL-CAL SDL-DSN-GR-CAL	2876-3838
	HRI-GR-SP-CAL	3770-3861
	SDL-DSN-GR-CAL	3800-3861
	BCDT-GR	2850-3861
	FMI-GR SWC	1520-3847
	PEX-HRLA	3847-4233
	CNL-GR	4150-4310
	CBL-VDL-GR-CAL	3741-4316, 3700-4667.8
	HRLA-MCFL-BHC-TLD-HGNS-GR-HCAL	4344.5-4407
	HRLA-MCFL-BHC-GR	4344.5-4703
	HRLA-Sonic	4344.5-4703
	CNL CH)-GR-CCL	4300-4667.8

Table 4-64: WELL CHARAIDEO-1:WELL LOGS RECORDED

Hole Size	Wireline Log Operations
18.1/2”	Standard, BKZ (Full Set) logs (Soviet Resistivity) recorded on 11/12.09.1979 at 1139.87 m
13.3/4”	Caliper and Inclinometer Surveys carried out on 11.10.1979 at well depth of 1175.5 m
12.1/2”	Standard, Caliper and inclinometer survey were recorded on 21.08.1980 at a well depth of 2890.47 m
	Standard logs recorded on 18/19.09.1980 at a well depth of 3381 m
	Standard, BKZ (full set) and Caliper survey were recorded on 17/18.10.1980 at a well depth of 3975 m
	Thermo log was recorded at a well depth of 3975 m
8.1/2”	Attempted to log the well at a depth of 4198.67 m but the tool could not be lowered below 3984 m
	Standard Logs (SP, Normal and 4 m Lateral) were recorded on 26.02.1981 at a well depth of 4220 m. Tool could not be lowered below 4200 m
	On 04.07.1981 an attempt was made to log the hole at a well depth of 4541 m but the tool could not be lowered below 4180 m.
	On 15.09.1981 an attempt was made to log the hole upto Fish Top (below 4547 m instead of calculated depth of 4442 m) but tool could not be lowered beyond 4230 m.
	On 02.11.1981 and 08.11.1981 attempts were made to log the hole at a well depth of 4547 m but the tool could not be lowered below 4228 m.
6”	Russian and GOI logs were recorded on 06/07.01 1982 at a well depth of 4809 m
	Attempt to record CBL and Neutron Gamma logs against the 7” Liner was unsuccessful on 6/7.01.1982 as the tool could not be lowered below 3700 m.

Table 4-65: WELL CHARAIDEO-4: WELL LOGS RECORDED

Hole Size	Wireline Log Operations
17.1/2”	INDUCTION-GR-SONIC logs recorded on 10.08.2009 at a well depth of 2323 m.
	HRI-RCS-SP-GR-CAL- INCLINOMETER survey carried out on 29.08.2009 at well depth of 2993 m
12.1/4”	SDL-DISN-GR-CAL survey were recorded on 29.08.2009 at a well depth of 2454 m m
	HRI-SDLT-DSNT-GR-SP, INCLINOMETER-CAL, SDL-DSN-GR-CAL logs recorded on 23.09.2009 at a well depth of 3875 m
	HRI-GR-SP-CAL-SOL-DSN GR—CAL, BCDT-GR surveys were recorded on 26.09.2009 at

	a well depth of 3893 m
	FMI-GR log, SWC was recorded on 27.09.2009 at a well depth of 3893 m
8.1/2”	COMPOSITE Log (PEX HRLA) logs were recorded in the ranges 4233-3847 m and 4231-3847 m on 04.01.2010 and 23.05.2010 at a well depth of 4233 m and 4245 m
	CNL-GR (Cased Hole) and CBL-VDL-GR-CCL logs were recorded on 29.07.2010 at a well depth of 4407 m.
6”	HRLA-MCFL-BHC-TLD-HGNS-GR-HCAL logs recorded on 24.08.2010 at a well depth of 4595 m
	HRIA-MCFL-BHC-GR logs were recorded on 26.08.2010 at a well depth of 4809 m
	HRLA - Sonic logs were recorded on 29.08.2010 at a well depth of 4708 m
5.1/2” Casing	CH-CNL and CBL-VDL-GR-CCL logs were recorded on 15.09.2010 at a well depth of 4708 m

Conventional & Sidewall Core Data

Conventional and Sidewall cores were recovered from well Charaideo-2 (13 cores–1 CC and 12 SWC) and well Charaideo-4 (18 cores – 1 CC and 12 SWC) from the TS-6, BCS and BMS levels (**Table 4-66**).

Table 4-66: CONVENTIONAL CORE DATA OF CHARAIDEO FIELD

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Charaideo-1	Not attempted in this well			
Charaideo-2	CC-1	4090.63-4093.4 m	61.75 %	Mainly Sandstone – The core has indicated presence of hydrocarbon. It showed GYF and +ve cut.
Charaideo-4	CC-1	3781-3790 m	Nil	-
	CC-2	4501-4508 m	67%	Sandstone with silty claystone showing fluorescence and +ve cut.

4.5.2.3 Well log evaluation and initial test results (Charaideo Field):

Petrophysical parameters obtained in the reservoir zones of Charaideo Field in the best case using the average parameter of the three wells and parameters obtained in the reservoir zones of key wells are as follows (**Table 4-67 and Table 4-68**).

Table 4-67: AVERAGE PARAMETERS OBTAINED IN THE RESERVOIR ZONES OF CHARAIDEO

Best Case - P50						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity (Frac)	Avg. Sw (Frac)
TS-5	347	0.3	0.3	0.6	0.183	0.496
TS-6	271	0.5	1.2	1.6	0.146	0.507
Safrai	51	1.3	0.7	1.9	0.178	0.533
BCS	492	8.8	7.6	16.4	0.161	0.472
BMS	194	4.4	4.1	8.5	0.167	0.456

Table 4-68: PETROPHYSICAL PARAMETERS OBTAINED IN THE TESTED ZONES OF CHARAIDEO WELLS

	Charaideo-1		Charaideo-2		Charaideo-4	
Zones	**Avg. Porosity %**	**Avg. Sw %**	**Avg. Porosity %**	**Avg. Sw %**	**Avg. Porosity%**	**Avg. Sw %**
TS-5					12-16	49.6
TS-6					11-16	85-100
Safrai					10-11	90-100
BCS	12	37	9-10	48	9-10	85-100
BMS	9-11	46	9-14	58-68	7-10	65

Hydrocarbon indications were seen in drill cuttings and core samples. Formation tops were obtained from well log data while horizons were obtained from seismic data. All these were combined to correlate the wells in the field.

<u>Well, log motif of CHARAIDEO Wells:</u>

Log motifs for tested Objects of wells Charaideo-1 are shown in **Figure 4-76, Figure 4-77, Figure 4-78, Figure 4-79, Figure 4-80 and Figure 4-81.**

Log motifs for tested Objects of wells Charaideo-2 are shown in **Figure 4-82** through **Figure 4-87**,

Log motifs for tested Objects of wells Charaideo-4 are shown in **Figure 4-88 and Figure 4-89** .

Figure 4-76: LOG MOTIFS OF OBJECT-I (BMS) IN WELL CHARAIDEO-1

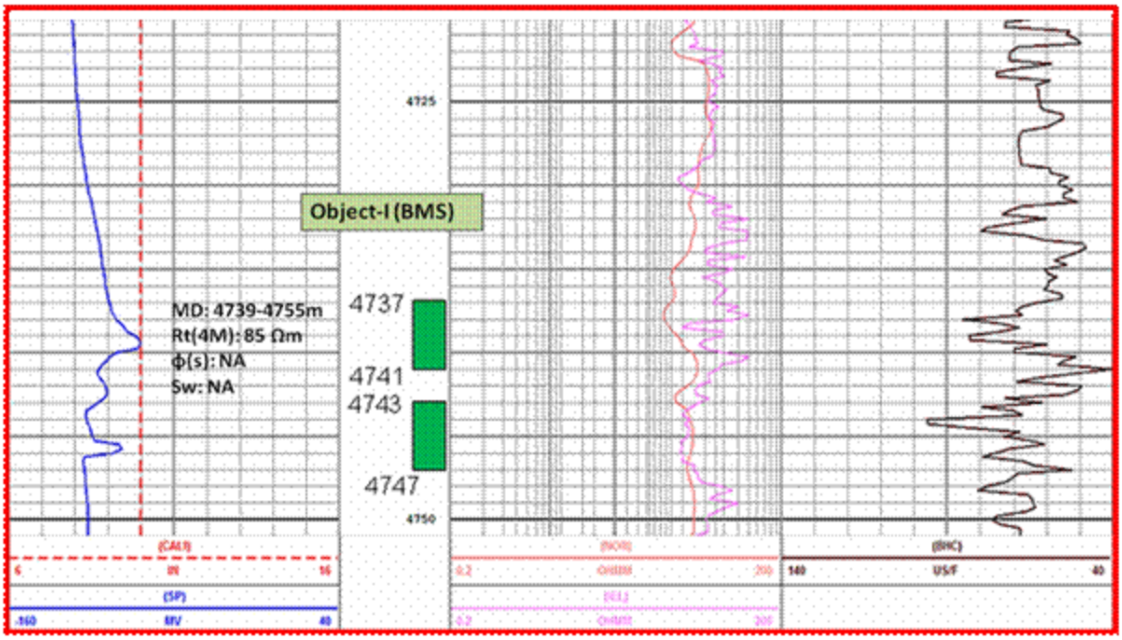


Figure 4-77: LOG MOTIFS OF OBJECT-II (BMS) IN WELL CHARAIDEO-1

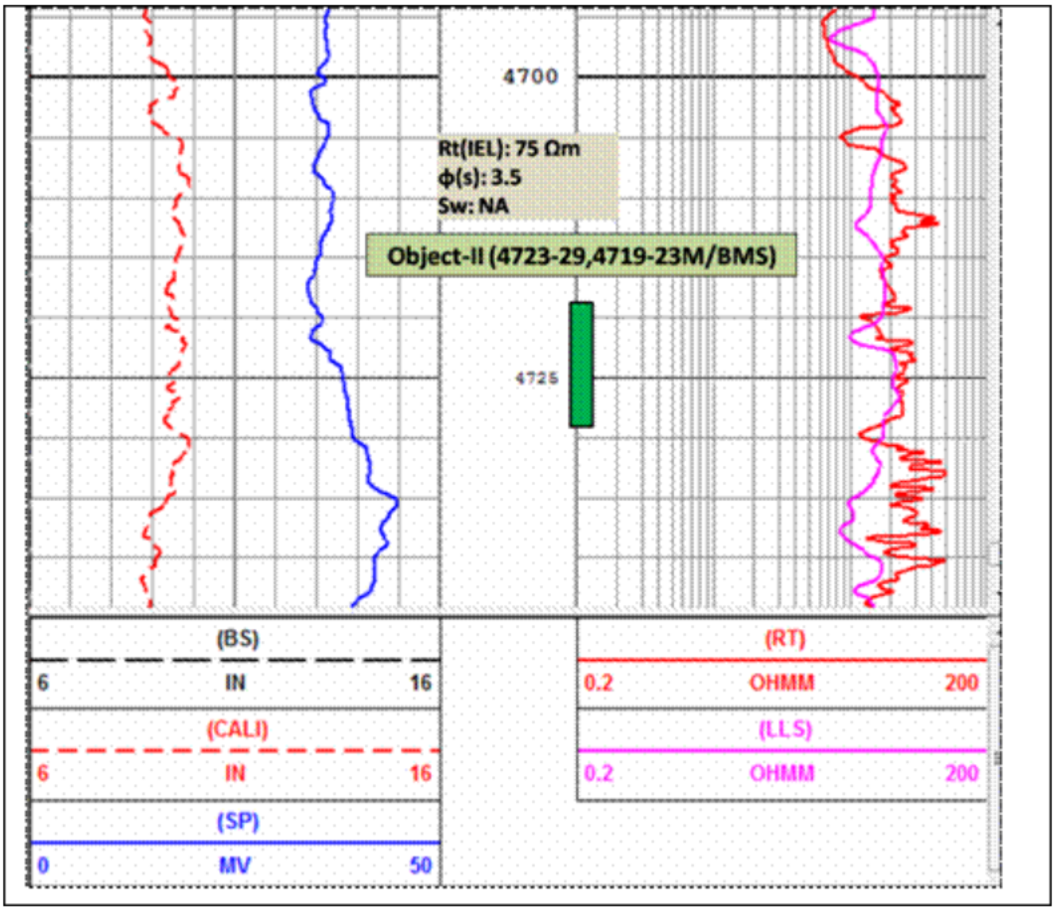


Figure 4-78: LOG MOTIFS OF OBJECT-III (BMS) IN WELL CHARAIDEO-1

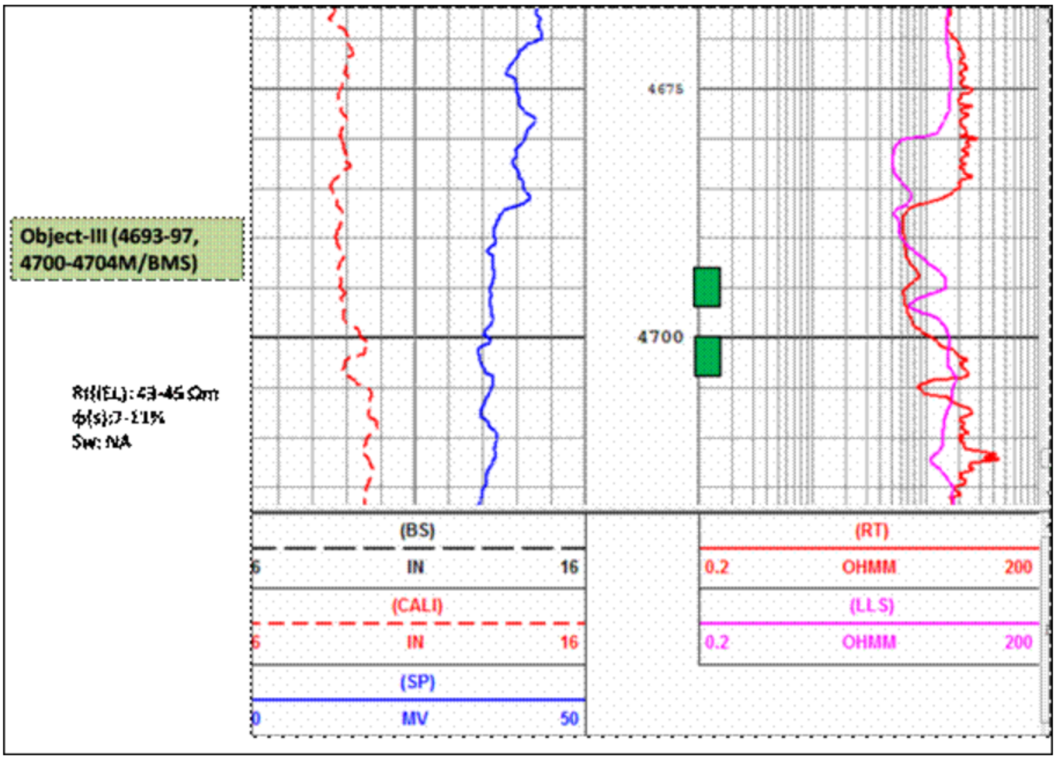


Figure 4-79: LOG MOTIFS OF OBJECT-IV (BMS) IN WELL CHARAIDEO-1

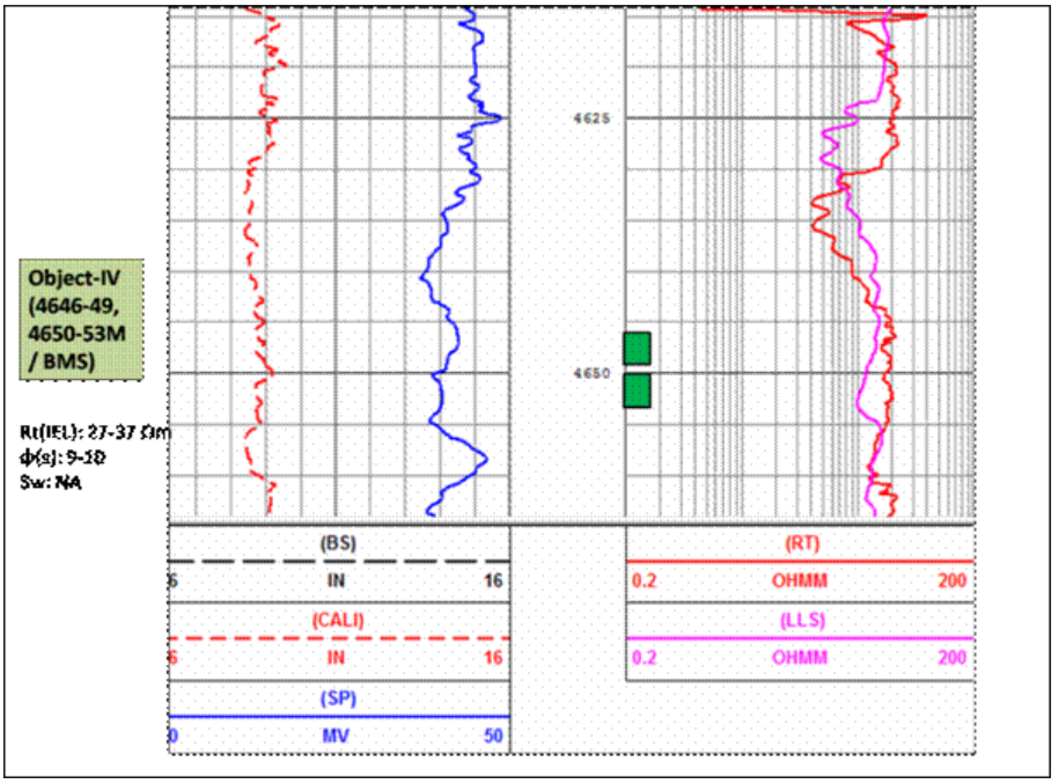


Figure 4-80: LOG MOTIFS OF OBJECT-V (BMS) IN WELL CHARAIDEO-1

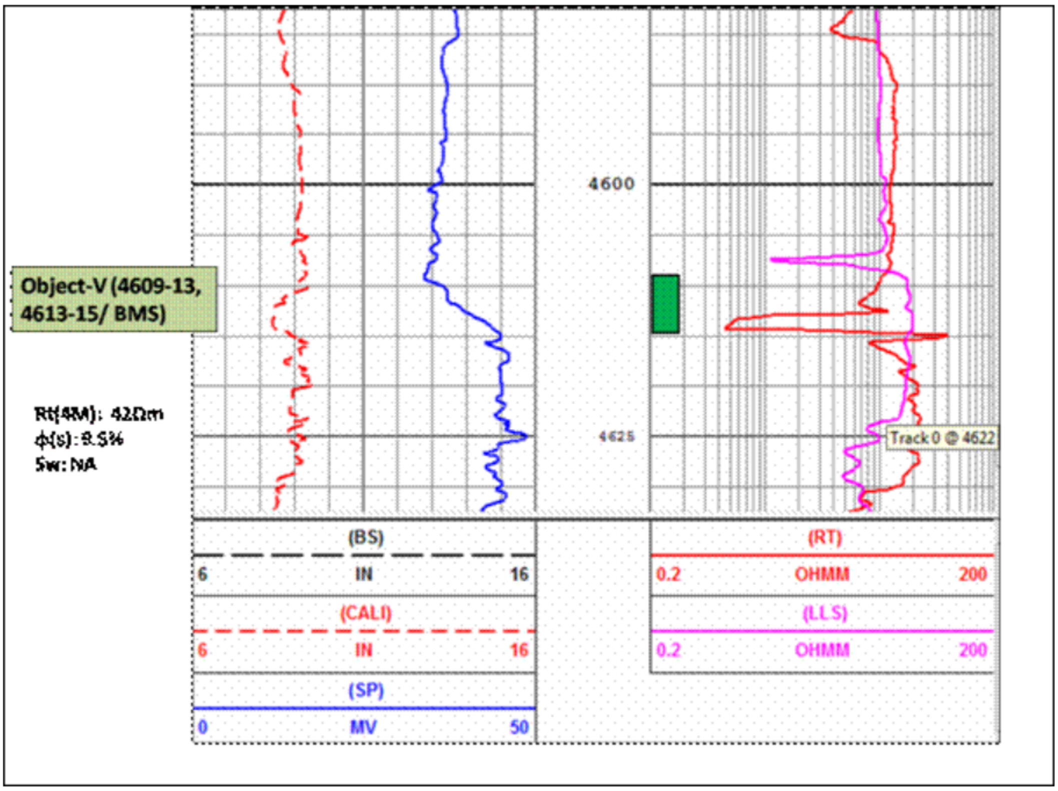


Figure 4-81: LOG MOTIFS OF OBJECT-VI (BCS) IN WELL CHARAIDEO-1

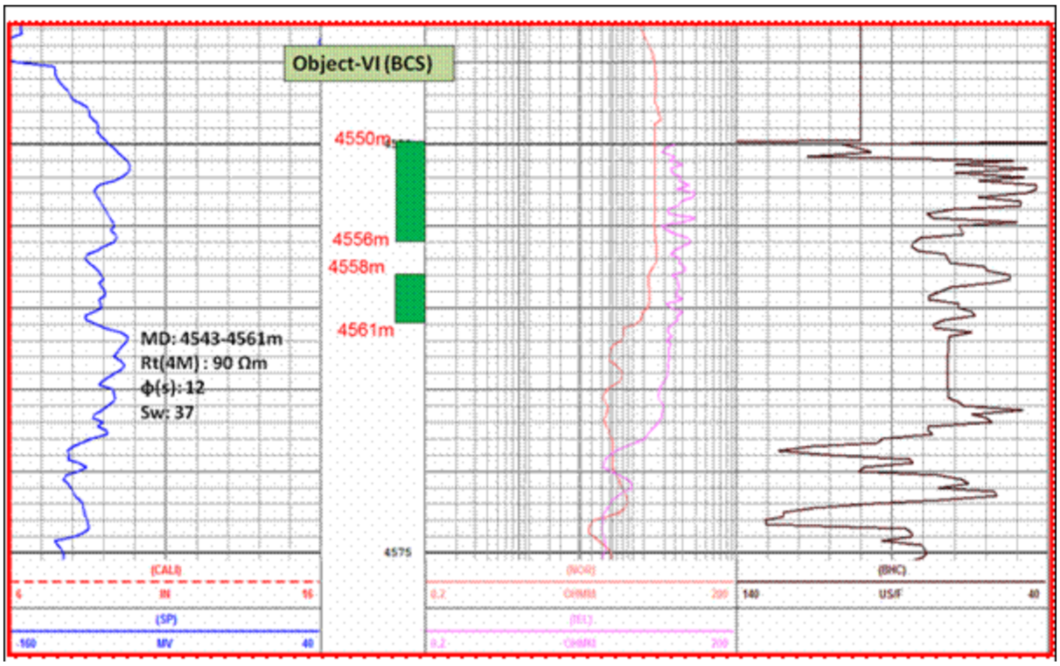


Figure 4-82: LOG MOTIF OF OBJECT-III (BMS) IN WELL CHARAIDEO-2 (Not Tested)

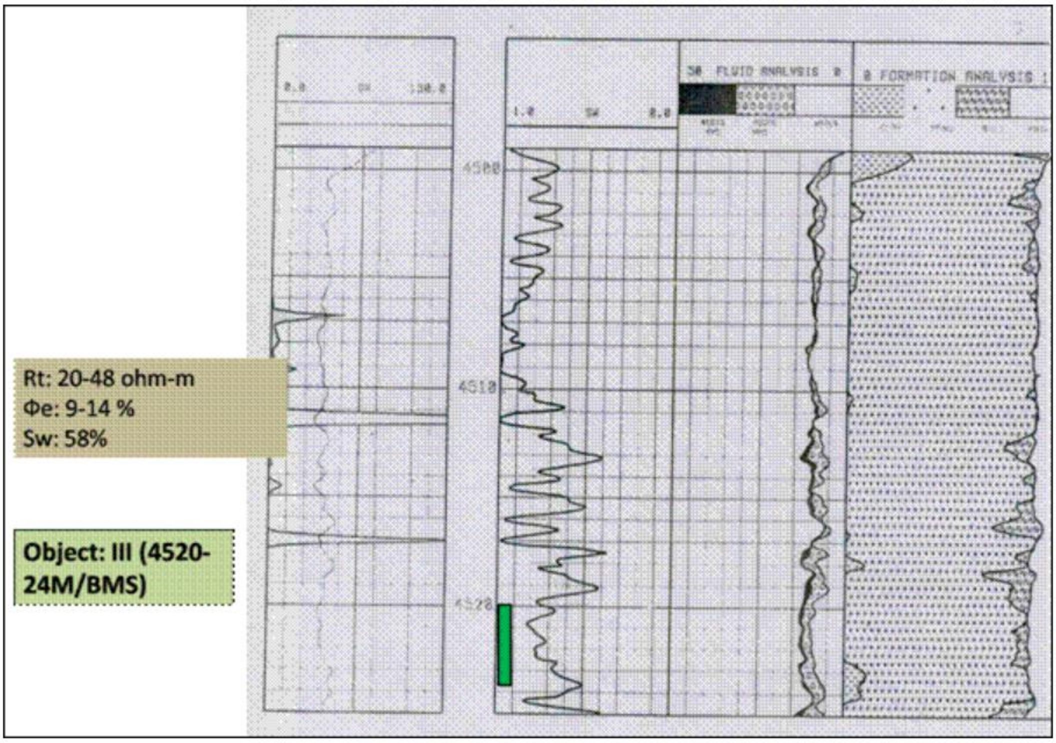


Figure 4-83: LOG MOTIF OF OBJECT-IV (BMS) IN WELL CHARAIDEO-2 (Not Tested)

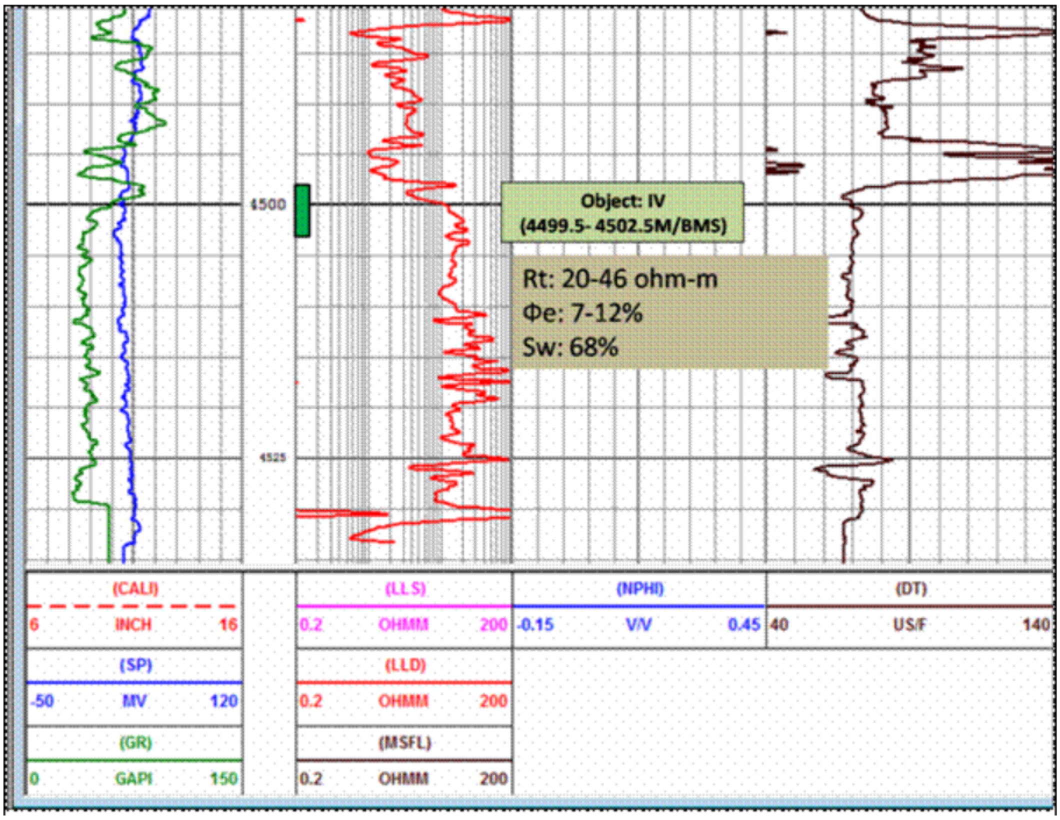


Figure 4-84: 85LOG MOTIF OF OBJECT-V (BCS) IN WELL CHARAIDEO-2 (Not Tested)

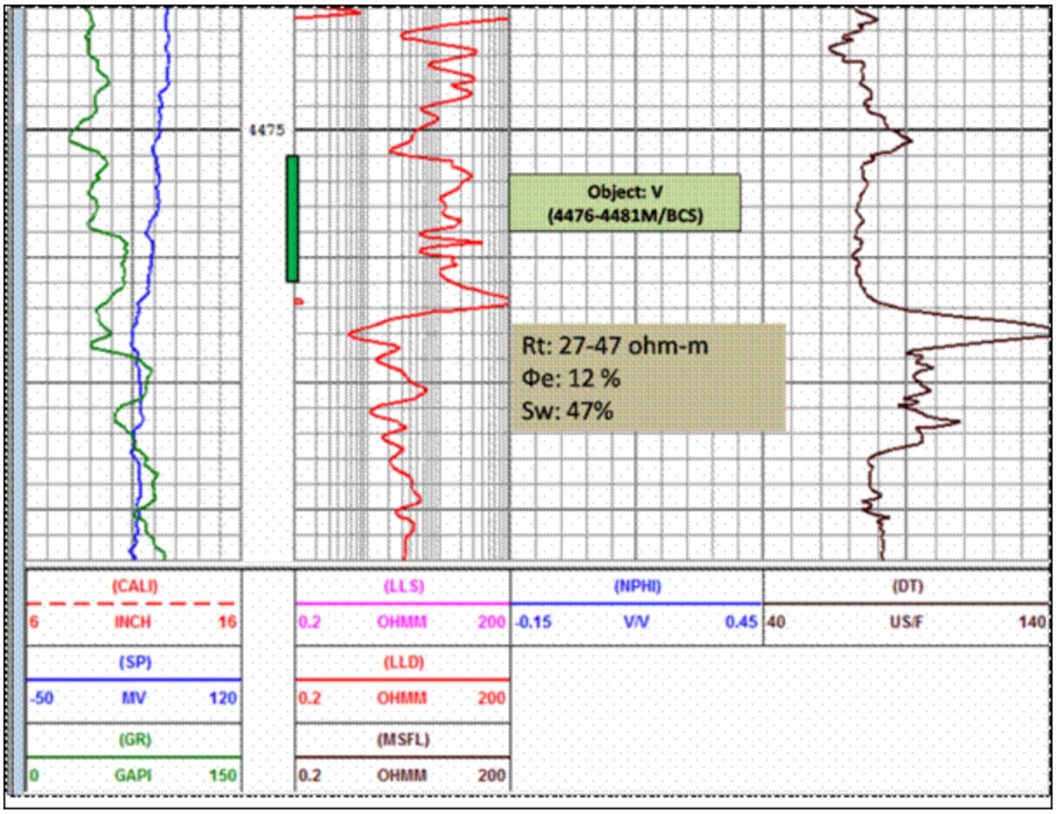


Figure 4-86: LOG MOTIF OF OBJECT-VI (BCS) IN WELL CHARAIDEO-2 (Not Tested)

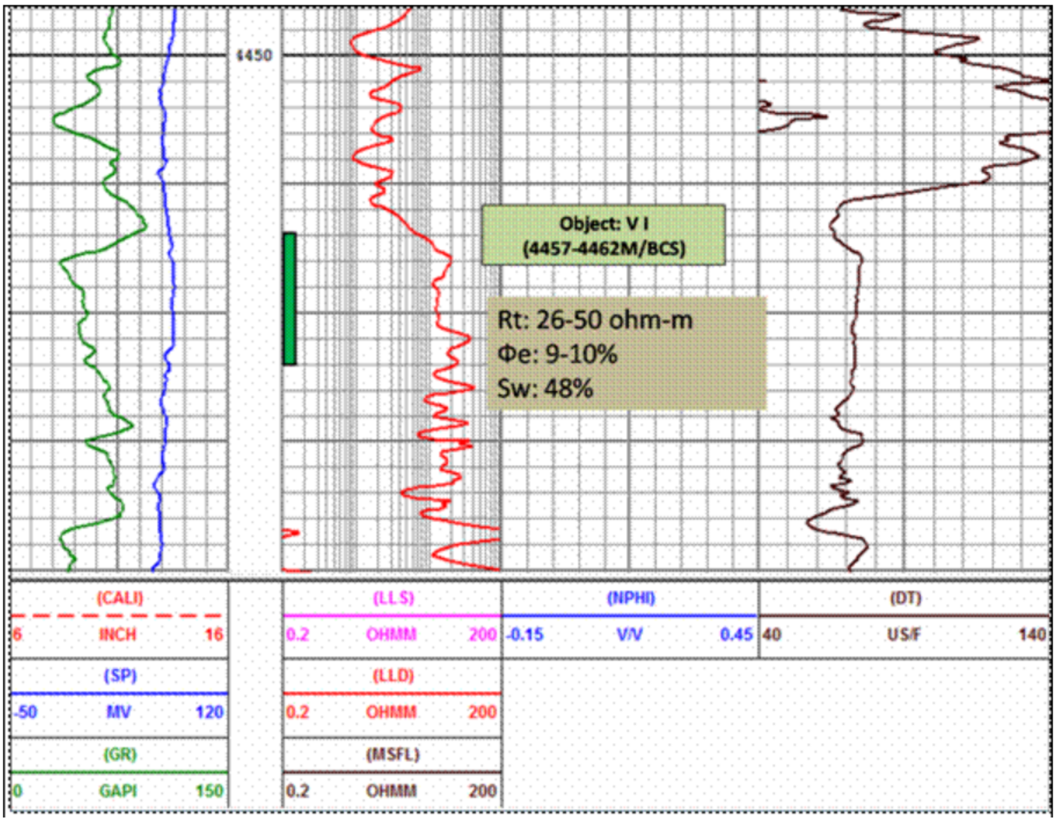


Figure 4-87: LOG MOTIF OF OBJECT-VII (BCS) IN WELL CHARAIDEO-2 (Not Tested)

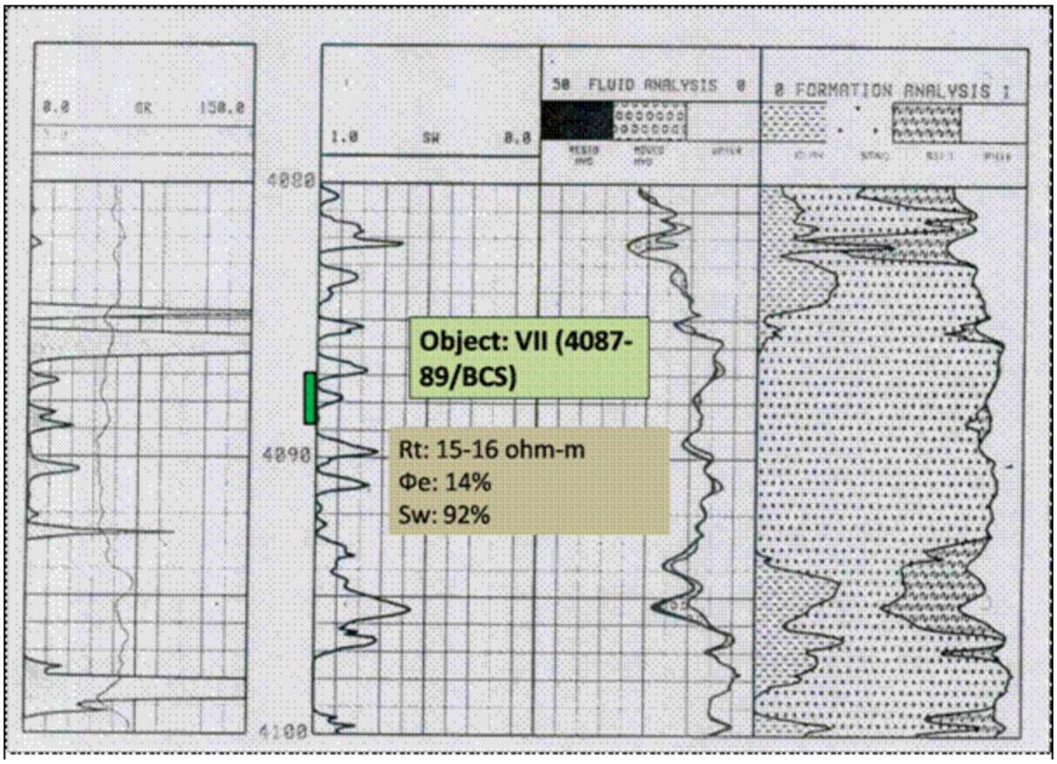


Figure 4-88: LOG MOTIF OF OBJECT-I (BMS) IN WELL CHARAIDEO-4

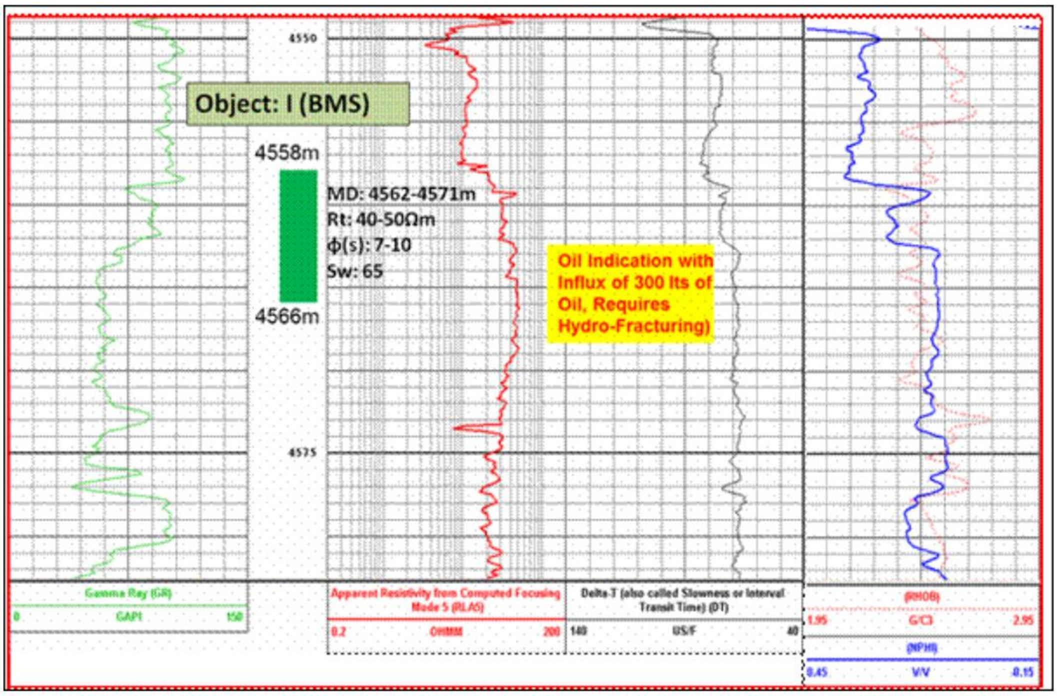
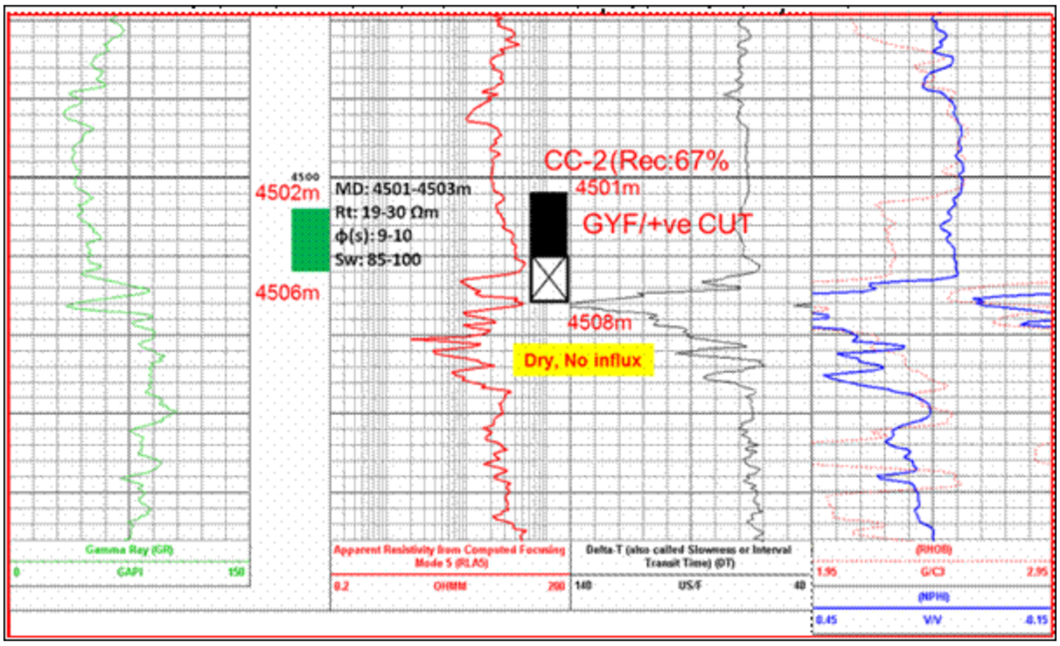


Figure 4-89: LOG MOTIF OF OBJECT-II (BCS) IN WELL CHARAIDEO-4



4.5.3 Well testing and workover history

In Charaideo Field four exploratory wells have been drilled. Out of these four wells three wells CRDO-1, CRDO-2 and CRDO-4 fall within the present block whereas well CRDO-3 falls outside the Block. The object wise detail testing results of three wells are given in **Table 4-69.** Reservoir depths of each reservoir are given in **Table 4-70.**

Table 4-69: TESTING RESULTS OF CHARAIDEO WELLS

WELL	OBJECT	INTERVAL (M)	RESULT	STATUS
CRDO#1	I, BMS	4737-4741M 4743-4747M	Chromatography on DST fluid sample showed indications of ethane and methane. No flow at surface. Plugged back (BP).	Water bearing
	II, BMS	4723-4729M 4719-23M (Addl.) 4723-25M (Reperf.)	Initially poor inflow. After reperforation self flow of water with dissolved gas @7 liters/ min Sal 3.05 gpl was observed. Plugged back (BP)	Water with dissolved gas
	III, BMS	4693-4697M 4700-4704M	Poor influx Plugged back (BP)	Tight sand with poor influx
	IV, BMS	4646-4649M 4650-4653M	Self flow of water with feeble gas. Sal 2.4 gpl. Plugged back (BP)	Water bearing with dissolved gas
	V, BMS	4609-4613M 4613-4615M (Addl Perf)	Poor influx even on additional perforation and on testing Injectivity was found to be nil. On trying to reperforate the entire range a Fish was left in hole which could not be recovered. Plugged Back (BP) after pushing down Fish to bottom	Poor influx.
	VI, BCS	4550-4556M 4558-4561M	On application of Compressor after changeover of well fluid to water poor influx was observed. However later pressure buildup was observed in the annulus. On opening the well through tubing, it flowed water **but on opening through annulus observed flow of oil/gas for few minutes. There was also a gradual increase in pressure. Subsequently the well flowed oil/ gas for 3 minutes, followed by water and then ceased.** **The well fluid was then subjected to swabbing for activation. The well flowed only gas. On further swabbing the well showed poor influx with sluggish rise in fluid level with minor oil in the swabbed fluid.**	**Oil and gas indication in BCS with poor influx**
CRDO-2	I, BMS	4642-4645M 4612-4625M (ADDL PERF)	Flowed **oil and gas** on application of compressor twice. Additional perforation was planned but while lowering GR-CCL tool prior to perforation fish was left in tubing. Recovered tubing from 4070m. Further Fishing operations unsuccessful.	Testing incomplete. **Oil indication in BMS.**
	II, BMS	4592-4599M	-Not tested due to fish-	

	III, BMS	4520-4524M	-Not tested due to fish-	
	IV, BMS	4499.5-4502.5M	-Not tested due to fish-	
	V, BCS	4476-4481M	-Not tested due to fish-	
	VI, BCS	4457-4462M	-Not tested due to fish-	
	VII, BCS	4087-4089M	-Not tested due to fish-	
CRDO-4	I, BMS	4558-4566M	While subduing the well with mud (of sp. gr.1.42), return of **300 lits of oil** followed by water was observed. After re-perforation, observed 100 lts of oil during reversing out with water. Plugged back (BP)	The object was concluded as oil bearing with poor influx. Requires hydrofracturing
	II, BCS	4502-4506M	Poor influx	Poor influx

Table 4-70: RESERVOIR SAND DEPTHS IN CHARAIDEO WELLS

Well	KB(m)	DD(m)	TS-1	TS-2	TS-3	LCM	TS-5	TS-6	Safrai	BCS	BMS
CRDO-1	108.6	4805	ND	2806	2974	3314	3410	3682	3957	4035	4585
	TVDSS		ND	2697	2865	3205	3301	3573	3848	3926	4476
CRDO-2	110	4700	ND	2819	2992	3335	3399	3708	3951	4025.7	4492
	TVDSS		ND	2708	2882	3225	3289	3597	3840	3915.7	4382
CRDO-4	104.5	4708	ND	2765	2932	3264	3345	3692	3964	4014	4507
	TVDSS		ND	2661	2828	3160	3241	3588	3960	3911	4403

4.5.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/ results.

No routine/Special core analysis data available

No Pressure Transient and Reservoir studies have been carried out

No analysis of oil/gas has been carried out

No Production has been taken.

No work over job has been carried out

Well Heads are available at well CRDO-1 and CRDO-2 and X-Mass tree at CRDO-4

FDP is available for the field.

HC was encountered in the Safrai, BCS and BMS levels and their PVT data collected are as follows (**Table 4-71**):

Table 4-71: PVT DATA FOR RESERVOIR ZONES IN CHARAIDEO WELLS

SAFRAI ZONE					
DEPTH (M)					3995
TEMP (F)					265.73
PRESSURE (Psia)					5804.7
sp gr					0.824
API GRAVITY					40.2
Black-Oil Fluid Properties Correlations This Black-oil model is consistent with Eclipse 100/200 (use field units here)					
BO model results					
API gravity of oil	API	40.22		40.22	
solution gas-oil ratio of saturated oil	Rs	1563.36	scf / stb	278.43	m3 / m3
bubble point pressure	Pb	5308.4	psia	3.660E+07	Pa
oil compressibility	Co	1.691E-05	1 / psi	2.453E-09	1 / Pa
oil formation volume factor	Bo	1.840	rb / stb	1.840	m3 / sm3
oil viscosity	Viso	0.230	cp	2.305E-04	Pas
oil density	Deno	35.43	lb / ft3	567.5	kg / m3
gas pseudo-critical pressure	Ppc	668.4	psia	4.608E+06	Pa
gas pseudo-critical temperature	Tpc	395.5	R	219.7	K
gas pseudo-reduced pressure	Ppr	8.685		8.685	
gas pseudo-reduced temperature	Tpr	1.835		1.835	
gas Z-factor	Z	1.0687		1.0687	
gas formation volume factor	Bg	3.777E-03	rcf / scb	3.777E-03	m3 / sm3
gas density	Deng	14.553	lbs / ft3	233.118	kg / m3
gas viscosity	Visg	0.0283	cp	2.826E-05	Pas
water formation volume factor	Bw	1.049		1.049	
water viscosity	Visw	0.217	cp	2.171E-04	Pas
oil-gas interfacial tension	STog	0.63	dyn / cm	6.280E-04	N / m
water-gas interfacial tension	STwg	58.68	dyn / cm	5.868E-02	N / m

BCS-I&II ZONE					
DEPTH (M)					4320
TEMP (F)					283.28
PRESSURE (Psia)					6203.1
sp gr					0.86
API GRAVITY					31.1
Black-Oil Fluid Properties Correlations This Black-oil model is consistent with Eclipse 100/200 (use field units here)					
BO model results					
API gravity of oil	API	31.14		31.14	
solution gas-oil ratio of saturated oil	Rs	1215.41	scf / stb	216.46	m3 / m3
bubble point pressure	Pb	6991.2	psia	4.820E+07	Pa
oil compressibility	Co	1.609E-05	1 / psi	2.333E-09	1 / Pa
oil formation volume factor	Bo	1.749	rb / stb	1.749	m3 / sm3
oil viscosity	Viso	0.297	cp	2.966E-04	Pas
oil density	Deno	38.04	lb / ft3	609.3	kg / m3
gas pseudo-critical pressure	Ppc	667.6	psia	4.603E+06	Pa
gas pseudo-critical temperature	Tpc	401.7	R	223.1	K
gas pseudo-reduced pressure	Ppr	9.292		9.292	
gas pseudo-reduced temperature	Tpr	1.851		1.851	
gas Z-factor	Z	1.1008		1.1008	
gas formation volume factor	Bg	3.729E-03	rcf / scb	3.729E-03	m3 / sm3
gas density	Deng	15.152	lbs / ft3	242.713	kg / m3
gas viscosity	Visg	0.0296	cp	2.958E-05	Pas
water formation volume factor	Bw	1.057		1.057	
water viscosity	Visw	0.203	cp	2.027E-04	Pas
oil-gas interfacial tension	STog	0.91	dyn / cm	9.067E-04	N / m
water-gas interfacial tension	STwg	57.79	dyn / cm	5.779E-02	N / m

BMS ZONE	
DEPTH (M)	4450
TEMP (F)	290.3
PRESSURE (Psia)	6389.7
sp gr	0.86
API GRAVITY	29.4

Black-Oil Fluid Properties Correlations

This Black-oil model is consistent with Eclipse 100/200

(use field units here)

BO model results					
API gravity of oil	API	29.41		29.41	
solution gas-oil ratio of saturated oil	Rs	1173.52	scf / stb	209.00	m3 / m3
bubble point pressure	Pb	7413.9	psia	5.112E+07	Pa
oil compressibility	Co	1.576E-05	1 / psi	2.286E-09	1 / Pa
oil formation volume factor	Bo	1.730	rb / stb	1.730	m3 / sm3
oil viscosity	Viso	0.313	cp	3.134E-04	Pas
oil density	Deno	38.61	lb / ft3	618.5	kg / m3
gas pseudo-critical pressure	Ppc	667.3	psia	4.601E+06	Pa
gas pseudo-critical temperature	Tpc	403.3	R	224.1	K
gas pseudo-reduced pressure	Ppr	9.575		9.575	
gas pseudo-reduced temperature	Tpr	1.860		1.860	
gas Z-factor	Z	1.1159		1.1159	
gas formation volume factor	Bg	3.704E-03	rcf / scb	3.704E-03	m3 / sm3
gas density	Deng	15.364	lbs / ft3	246.105	kg / m3
gas viscosity	Visg	0.0301	cp	3.008E-05	Pas
water formation volume factor	Bw	1.061		1.061	
water viscosity	Visw	0.198	cp	1.979E-04	Pas
oil-gas interfacial tension	STog	0.97	dyn / cm	9.659E-04	N / m
water-gas interfacial tension	STwg	57.46	dyn / cm	5.746E-02	N / m

Formation Dynamics Tests (CHARAIDEO FIELD)

RFT/SFT/MDT:
No RFT/SFT/MDT sampling done due to severe downhole complications.

VSP Survey:
VSP survey has been carried out in well Charaideo-2

Gas Composition Analysis (CHARAIDEO FIELD) Condensate Composition:

While the composition of the condensate from Charaideo is unknown, for any basis of design, the composition of the condensate from the nearby Amguri Field may be assumed. (**Table 4-72**).

Table 4-72: ESTIMATED COMPOSITION OF HYDROCARBONS

Charaideo Condensate (Initial) Composition	
Component	**Mole%**
Methane	0.13
Ethane	0.5
Propane	2.2
I-Butane	2.2
N-Butane	3.6
Pentanes	8.4
Hexane	9.2
Heptane	15
Octane	16.7
Nonane and higher	42.03

4.5.5 Geology and Reservoir Description of Charaideo Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.5.5.1 Geological correlations, sections and maps (Charaideo Field):

STRUCTURE

The Charaideo area is an integral part of the Assam Shelf in the A & AA Basin and is located in the fringe between two distinctive tectono-geological domains, the Assam Shelf and the Naga Schuppen Belt. Geologically, the Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE and is a narrow belt of about 100 km wide and bounded by two thrust belts to the north in the Eastern Himalayas & south-east viz. the Naga Schuppen Belt. In the southeast the elongated Assam Shelf extends into the sub-thrust block of Naga Schuppen Belt. The Naga Schuppen Belt is also a narrow linear belt of imbricate eight to nine thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf.

The Charaideo structure is a High located in the Nazira Graben, about 6 km SE of the main Lakwa High. The Naga Thrust has affected the southern part of the structure. To the west of the structure, along the strike direction, is the Rajabari Fault closure and to the East is the Mathurapur Low. About 3 km north of Charaideo structure is the Nahorhabi Fault closure. Charaideo is structurally lower at Tipam and Barail levels with respect to the Nahorhabi structure.

STRATIGRAPHY

The deepest sedimentary section encountered in the Charaideo area is the BMS section of the Barail Group of Oligocene age. A regressive phase had advanced in the area during this period when fine grained sand and shale alternations of this Formation gave way to lagoonal coal-shale alternations of the BCS unit of the Barail Group. The lower fine-grained sand and shale alternations which comprise the Barail Main Sand (BMS) was deposited in a distal delta-front environment. The overlying Barail Coal Shale (BCS) consisting of the coal-shale sequence of lagoonal facies prograded over the BMS. Distributary channels within the BCS (LBS-1, LBS-2 and LBS-3) were deposited by switching channels in associated environment. Subsequently, there was a prominent eustatic fall in the Lower Miocene due to which the younger units of BCS section were eroded to form an unconformity surface. In the Assam Shelf area, a major hiatus is observed after the deposition of the Barails as a result of block adjustment in the basin. Hiatus continued till the end of the Lower Miocene. During Upper Miocene – Lower Pliocene, Tipam Group was deposited under high energy conditions as interlaced braided channel deposits when the shelf area was tilted as a result of upliftment in the Arakan-Chin axial belt. A major transgression over the entre basin led to deposition of the Girujan Clay Formation. Post deposition of Girujans, positive movements resulting in the emergence of landforms and subsequent erosion are reflected in the unconformable relations between the Tipam Group and the overlying sediments. Lacustrine to fluvial deposits of Nazira & Namsang Formations were deposited as a result of episodic tectono-sedimentary events. The Recent Alluvium constitutes the youngest stratigraphic unit in the field. The stratigraphic column of Charaideo area is given in in **Figure 4-90 and Table 4-73**.

Table 4-73: STRATIGRAPHIC COLUMN IN CHARAIDEO WELLS

AGE	GROUP	FORMATION	AVERAGE THICKNESS (M)	LITHOLOGICAL DESCRIPTION
Recent-Pleistocene		Alluvium	900	Unconsolidated sands with gravel, silt and minor clays
Pleistocene to Pliocene	Moran	Namsang	550	Intercalated sands and mottled clay
Pliocene – Miocene	Tipam	Nazira Sandstone	350	Predominantly sandstone with minor clays
		Girujan Clay	700	Mottled and variegated clays with intercalations of silt/sandstone beds
		Lakwa Sandstone	550	Massive sandstone with clay/shale alternations
		Geleki Sandstone	650	Massive sandstone with clay/shale alternations with minor calcareous matter in the lower part.
		Safrai	80	Conglomerate/ grit topped by sandstone shale alternations.
Oligocene – Late Eocene	Barail	Barail Coal Shale Unit	550	Carbonaceous shale and coal with alternations of sandstone & shale.
		Barail Main Sand Unit	150	Dominantly sandstone with intercalations of minor shale

Figure 4-90: LITHOSTRATIGRAPHY OF CHARAIDEO AREA

AGE	FORMATION / SAND		LITHOLOG	GROSS LITHOLOGY
Recent	Alluvium			Poorly consolidated coarse sand with sandy clays and clay.
Pliocene - Pleistocene	Namsang			Dominantly loose medium to fine grained sand with little mottled dominantly red color clay/claystone.
	Nazira Sandstone			Predominantly grey, medium grained sand with minor grey to brownish grey clay and occasionally siltstone, coal.
Miocene - Pliocene	Girujan Clay			Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
	Lakwa Sst.	TS-1		Dominantly fine to medium grained grey sandstones with minor light grey soft clay/ claystone.
		TS-2		
		TS-3		
	Galeki Sst.	LCM+TS4		Dominantly clay/ claystone with occasional sand/ sandstones
		TS-5		Intercalation of sand /sandstone with clay /claystone and siltstone.
		TS-6		
Oligocene	Barails	Rudrasagar (BCS)		Dominantly shale inter-bedded with coal and minor clay stone with Sand and siltstone
		Demulgaon (BMS)		Dominantly fine to medium grained grey sandstones with some inter-bedded clay and shale.
Late Eocene	Kopili			Mainly shale (splintery) alternating with fine grained sandstone and siltstone.
Middle Eocene	Sylhet			Mainly fossiliferous limestone with shales and thin sandstone bands.
Early Eocene	Tura			Dominantly sandstone with minor shales.
Pre - Cambrian	Basement			Leucocratic granite (weathered) with essential minerals e.g. quartz and pink feldspar.

The structural disposition of the Charaideo-1 Field is depicted in the depth structure maps presented on tops of TS-2, TS-5 and BCS (**Figure 4-91, Figure 4-92 and Figure 4-93.**).The roughly NW-SE electro-log correlation profiles, both structural and stratigraphic, along all the wells of the Charaideo structure, viz. CRDO-1, CRDO-2 and CRDO-4 are shown in **Figure 4-94 and Figure 4-95** respectively. Formation tops (**Table 4-74**) were obtained from well log data while horizons were obtained using seismic data. All these were combined to correlate the wells in the field. Lithological correlation between wells CRDO-1, CRDO-2 and CRDO-4 is given in **Figure 4-96 and Figure 4-97.**

The hydrocarbon reservoirs of this field occur in the Barail section (both BCS and BMS) and Tipam section. The reservoirs are defined by heterogeneous lithology of medium to fine grained tight sandstone, finely interlaminated with siltstone /shale (occasionally carbonaceous) within the Barails. However, the Tipam reservoir is comparatively more arenaceous. The entrapment is strati-structural and capturing reservoir heterogeneity is the major challenge in the field.

Table 4-74: FORMATION TOPS ENCOUNTERED IN WELLS CRDO-1, CRDO-2 & CRDO-4

Formation/ Group	Zone	DEPTH (m MD)		
		CRDO-1 (m MD)	CRDO-2 (m MD)	CRDO-4 (m MD)
Alluvium	–	0	0	0
Namsang	–	1010	1025	1010
Nazira Sandstone	–	1550	1556	1550
Girujan Clay	–	1875	1910	1874
Tipam	Lakwa Sandstone / TS-2	2806	2819.8	2765
	TS-3	2974	2992	297.568
	LCM	3314	3335	3264
	Geleki Sandstone / TS-5	3410	3399	3346
	TS-6	3682	3708	3692
	Safrai	3957	3951	3964
Barail	BCS	4035	4025.7	4014
	BMS	4585	4492	4507
TD	–	4805	4700	4708
GE (m above MSL)		103	102	98
KB (m above MSL)		108.6	110	104.5

Figure 4-91: DEPTH STRUCTURE MAP ON TOP OF TS-2

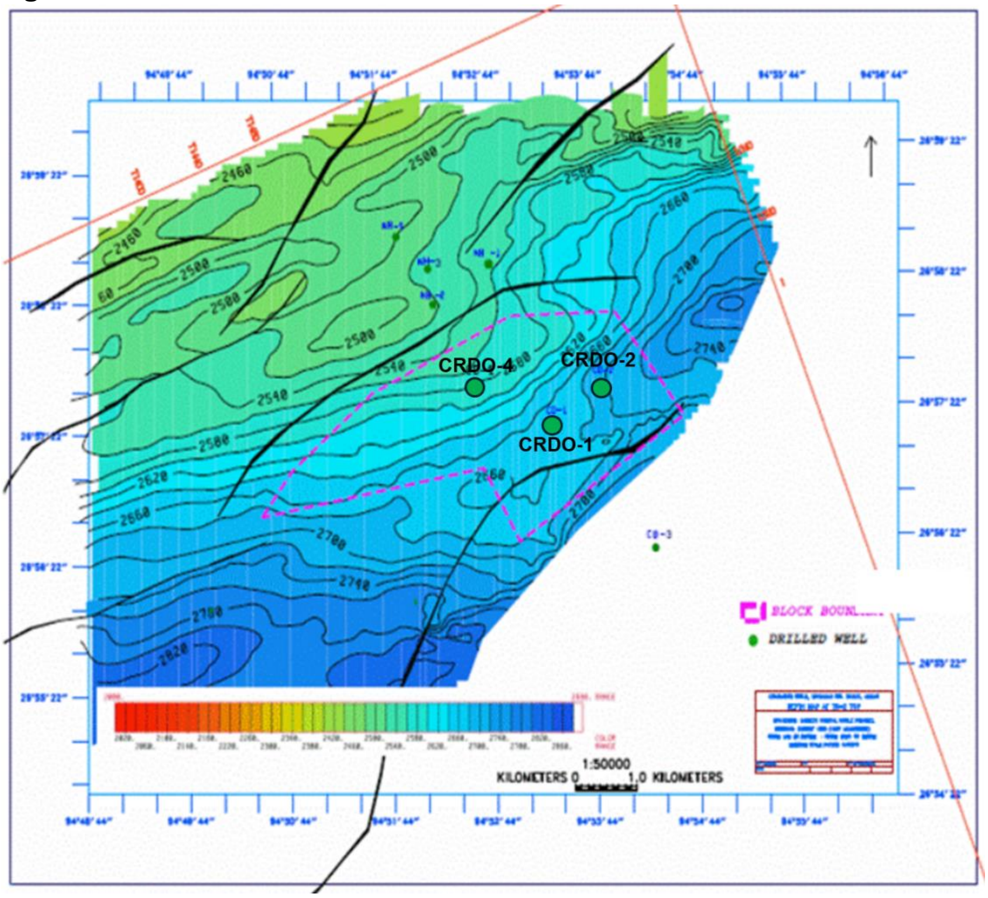


Figure 4-92: DEPTH STRUCTURE MAP ON TOP OF TS-5

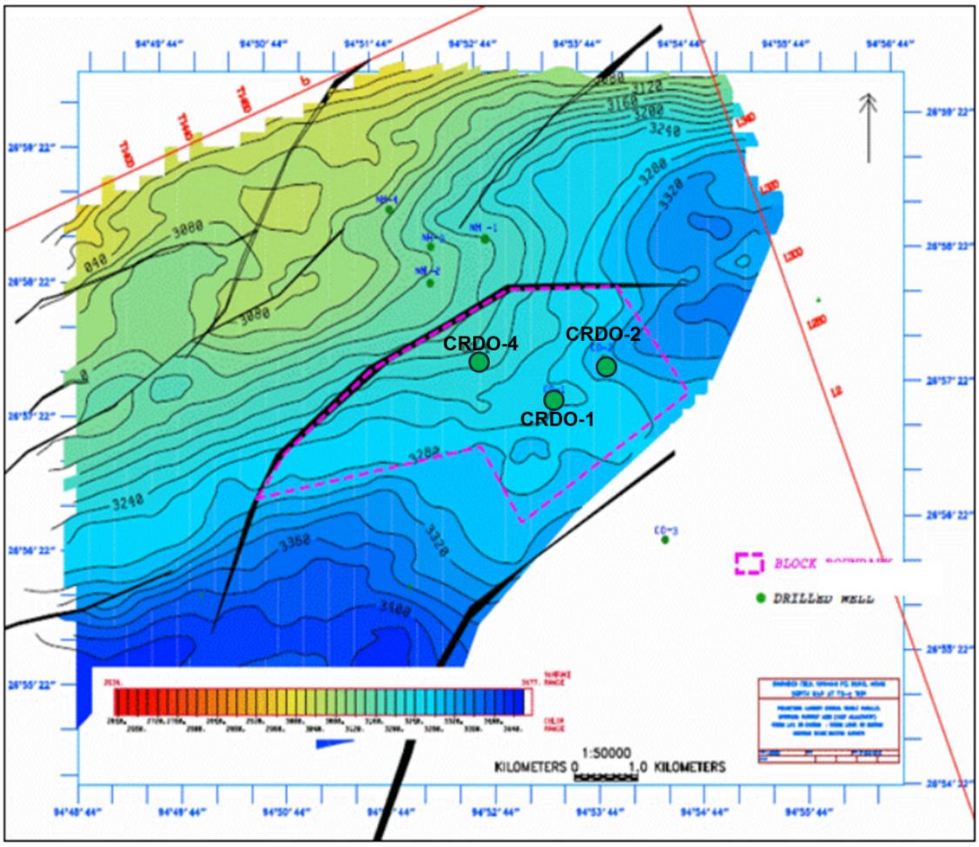


Figure 4-93: DEPTH STRUCTURE MAP ON TOP OF BCS

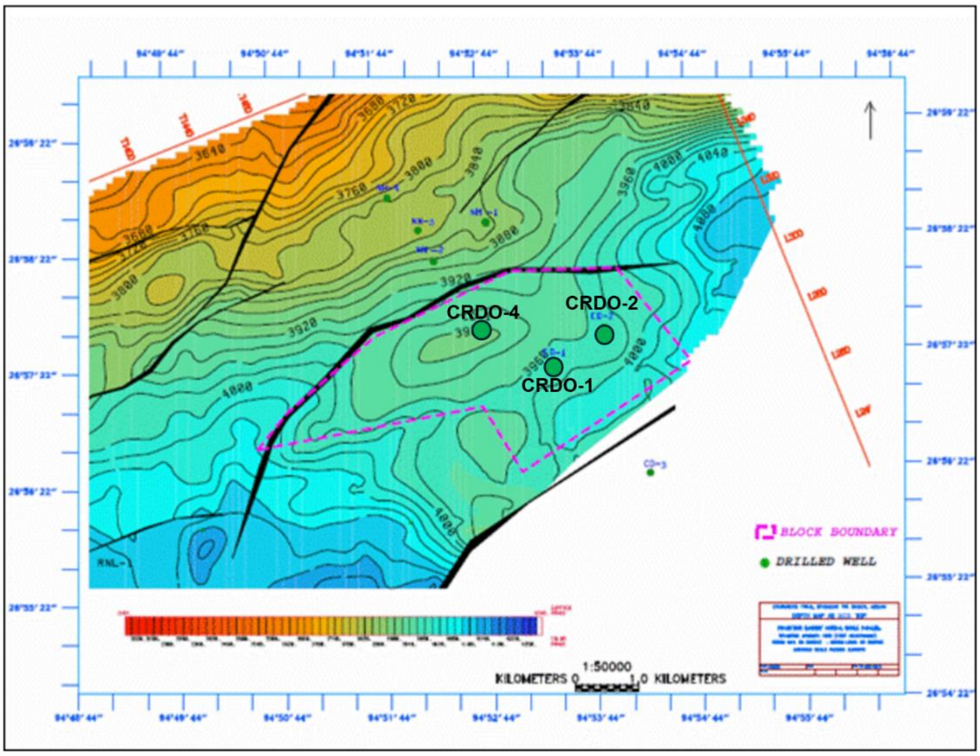


Figure 4-94: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS CHARAIDEO-4, 2 AND 1

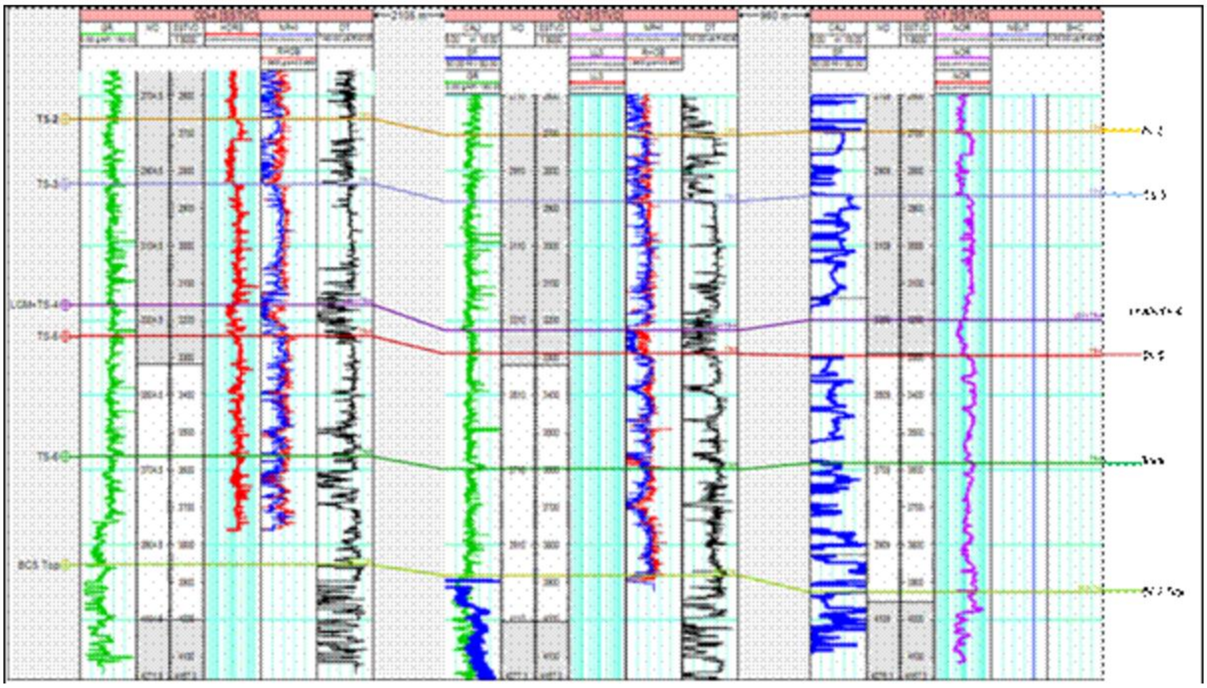


Figure 4-95: STRATIGRAPHIC ELECTRO-LOG CORRELATION (DATUM@LCM) OF WELLS CHARAIDEO-4, 2 AND 1

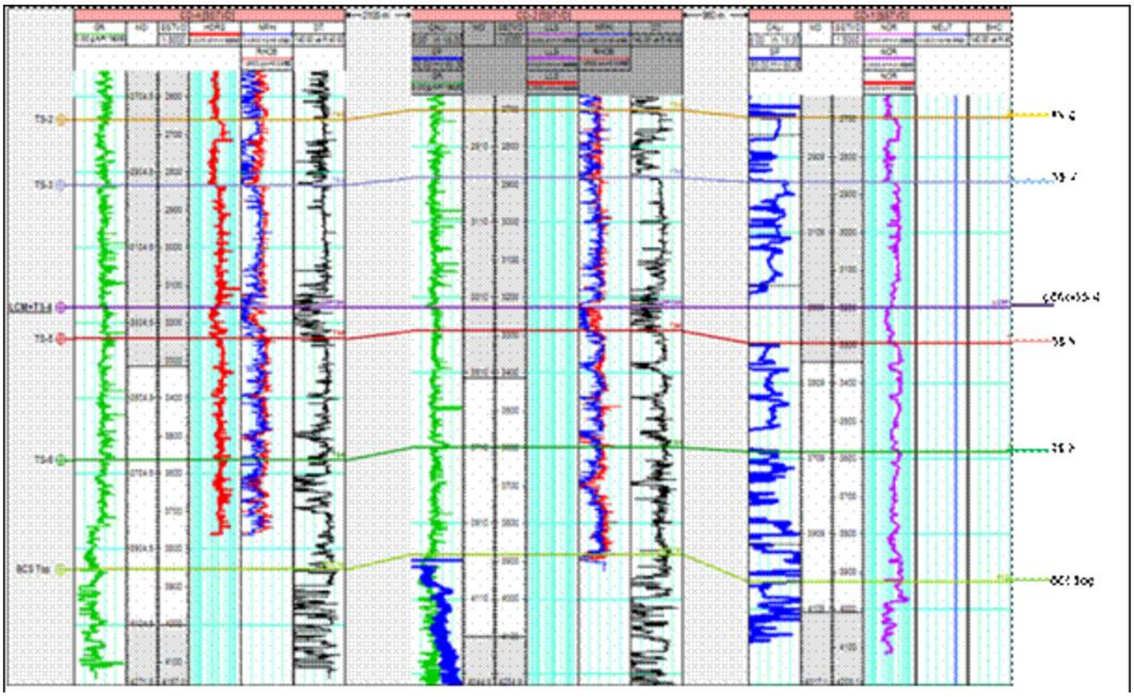
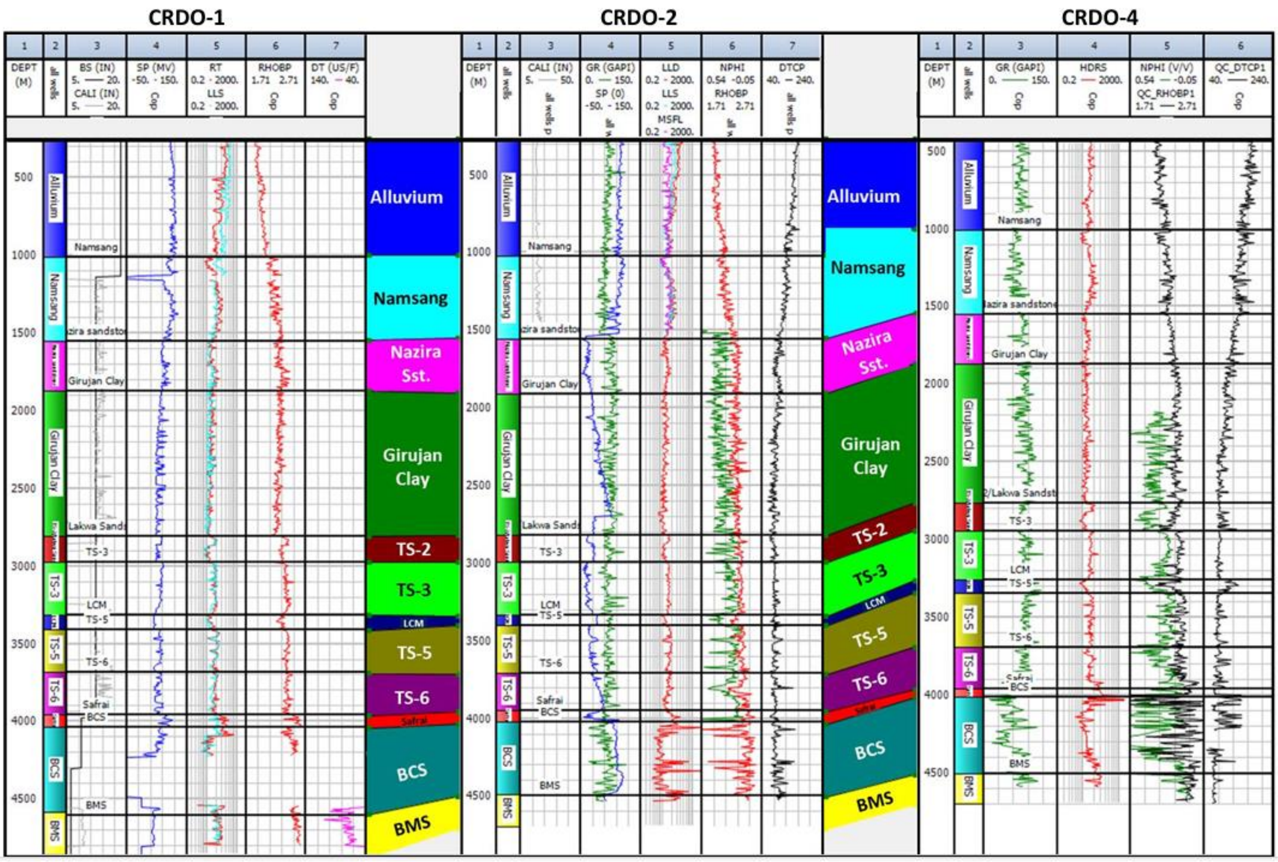


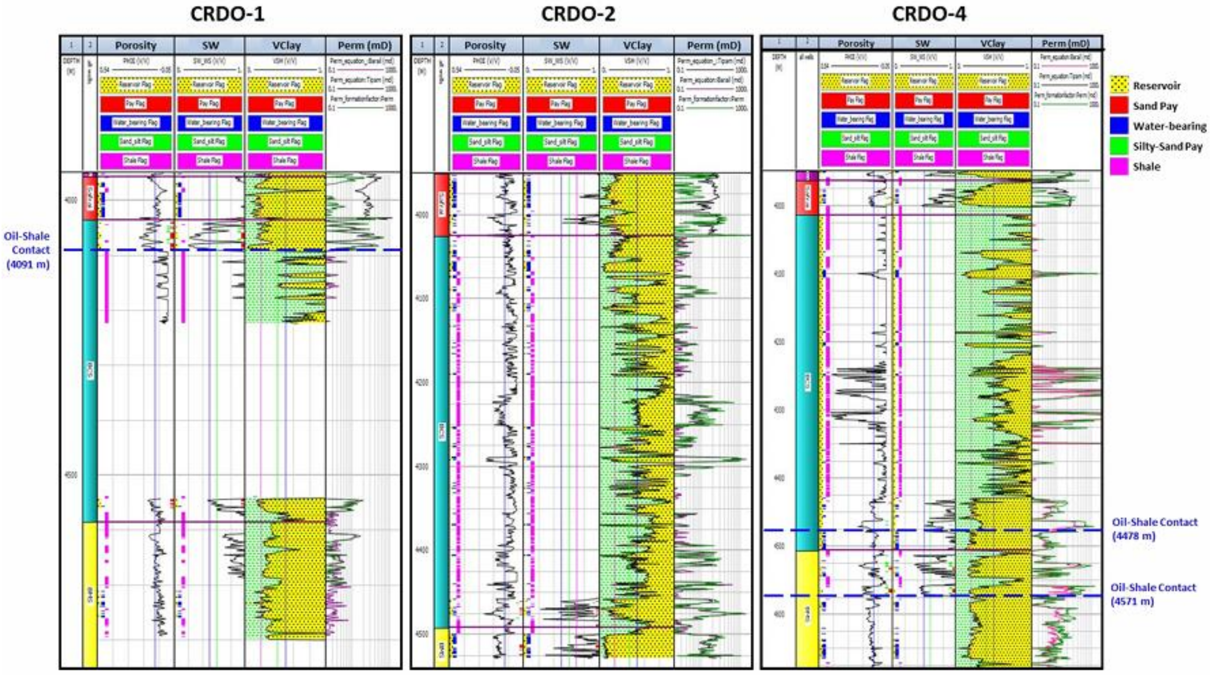
Figure 4-96: LITHOLOGICAL CORRELATION OF WELLS CRDO-1, CRDO-2 AND CRDO-4



Litho-classification and Fluid Contacts

During the well log analysis, lithology classification and net pay delineation were done in wells CRDO-1, CRDO-2 and CRDO-4. The fluid contacts for volumetric estimations were marked in the Barail sands (**Figure 4-97**)

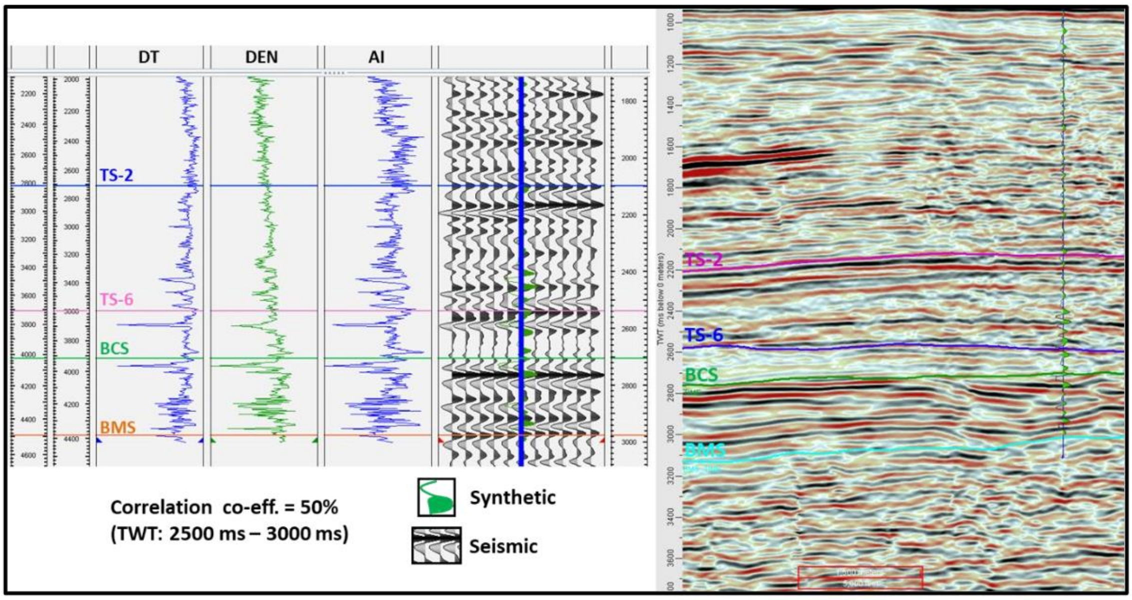
Figure 4-97: LITHO-CLASSIFICATION AND FLUID CONTACTS (BARAIL SANDS) IN WELLS CRDO-1, CRDO-2 & CRDO-4



Seismic Studies:

The area has also been covered by several seismic surveys (both 2D and 3D) from time to time which include series A-42, A44, A-57, A-117, A-120, A-131, A-185, A-186 and A-202. The earliest subsurface mapping of the area was carried out with the help of seismic investigations A-42, A-47 based on which two exploratory locations Nahorhabi-1 and Charaideo-1 were drilled in 1981. The entire area of 14.86 km^2 is covered by 3D seismic in the NAS Megamerge volume re-processed in RCC, Jorhat as shown in **Figure 4-71**.VSP was recorded in well CRDO-2 and the data is shown in **Figure 4-98.**

Figure 4-98: VSP DATA FOR WELL CRDO-2



A seismic section showing wells CRDO-1 and CRDO-4 is shown in **Figure 4-99.**

An arbitrary seismic line passing through wells CRDO-4, CRDO-1 & CRDO-2 showing the trends in the seismic data in the area is shown in **Figure 4-100**. Also, seismic transects (IL & XL) passing through the wells CRDO-1, CRDO-2 &CRDO-4 are shown in **Figure 4-101, Figure 4-102 and Figure 4-103**.

Time and Depth Structure Maps

The following time and depth structure maps of Charaideo area are shown:

- Tipam S-2 (TS-2) (**Figure 4-104**)
- Tipam S-6 (TS-6) (**Figure 4-105**)
- Barail Coal Shale (BCS) (**Figure 4-106**)
- Barail Main Sand (BMS) (**Figure 4-107)**

Acoustic impedance maps within BCS and BMS are shown in **Figure 4-108 and Figure 4-109** respectively**.** Acoustic impedance section for well CRDO-2 is shown in **Figure 4-110.**

Figure 4-99: SEISMIC SECTION OF WELLS CRDO-1 AND CRDO-4

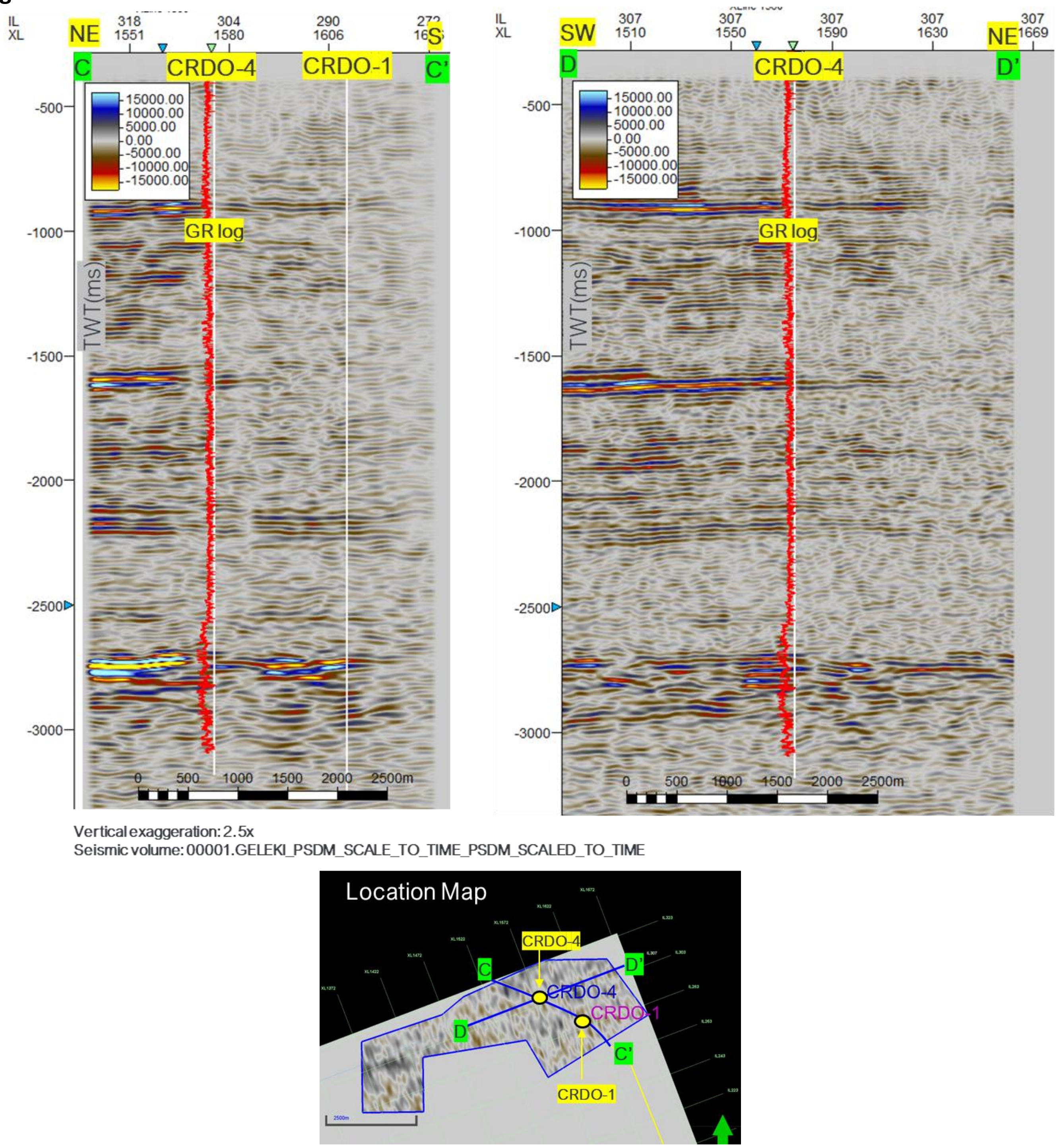


Figure 4-100: COMPOSITE LINE PASSING THROUGH WELLS CHARAIDEO 1, 2 AND 4

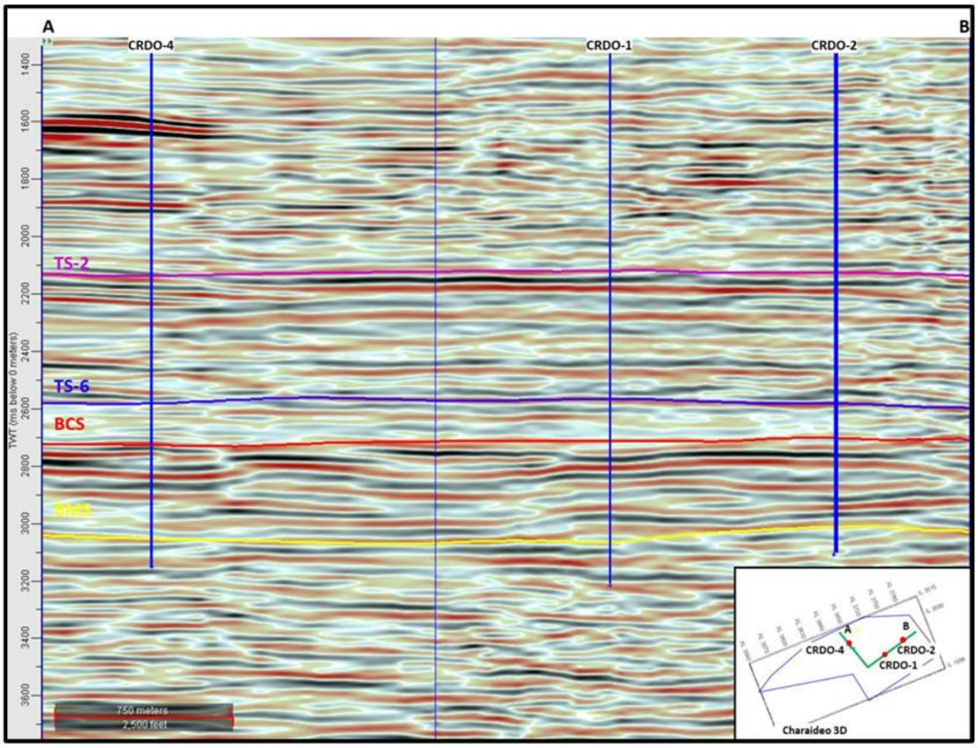


Figure 4-101: INLINE 1983 AND XLINE3728 PASSING THROUGH WELL CRDO-1

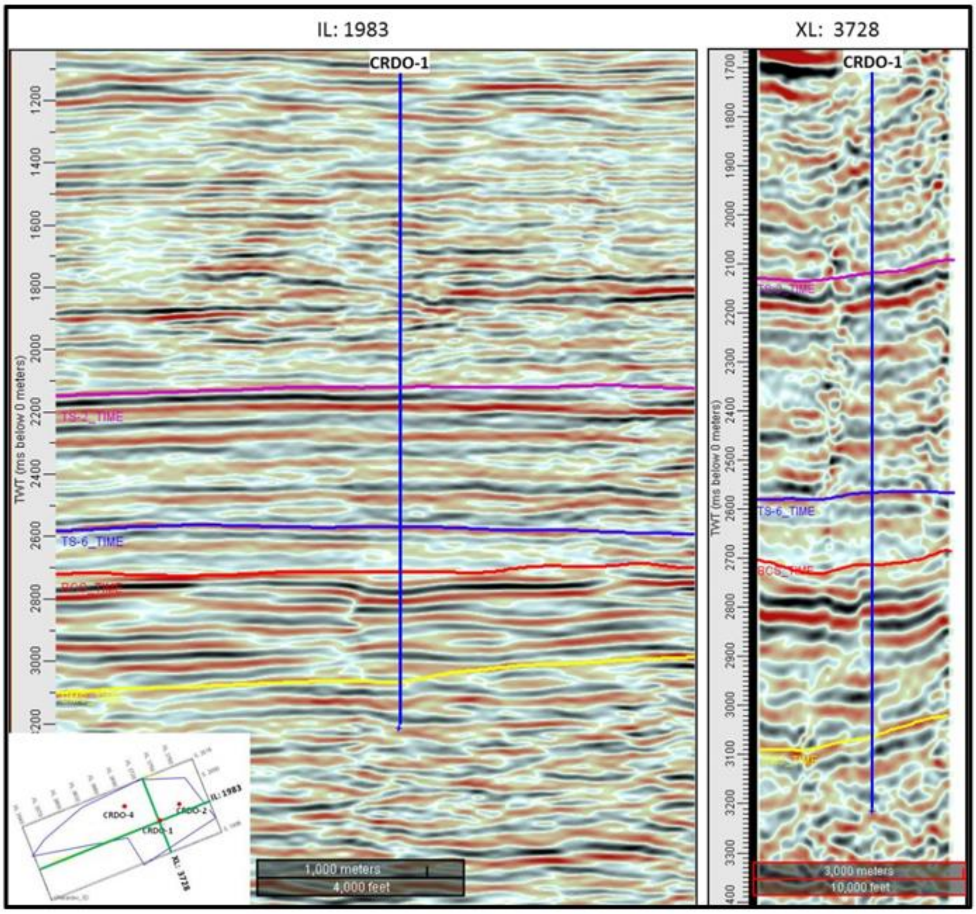


Figure 4-102: INLINE 1988 AND XLINE 3765 PASSING THROUGH WELL CRDO-2

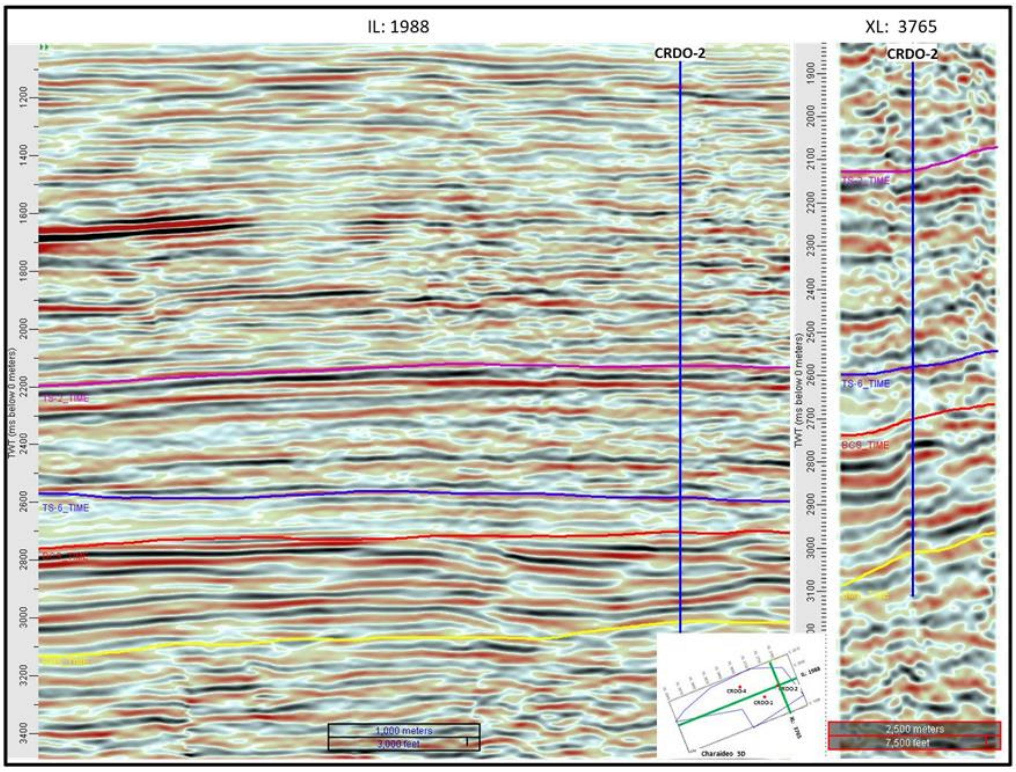


Figure 4-103: INLINE 2002 AND XLINE 3686 PASSING THROUGH WELL CRDO-4

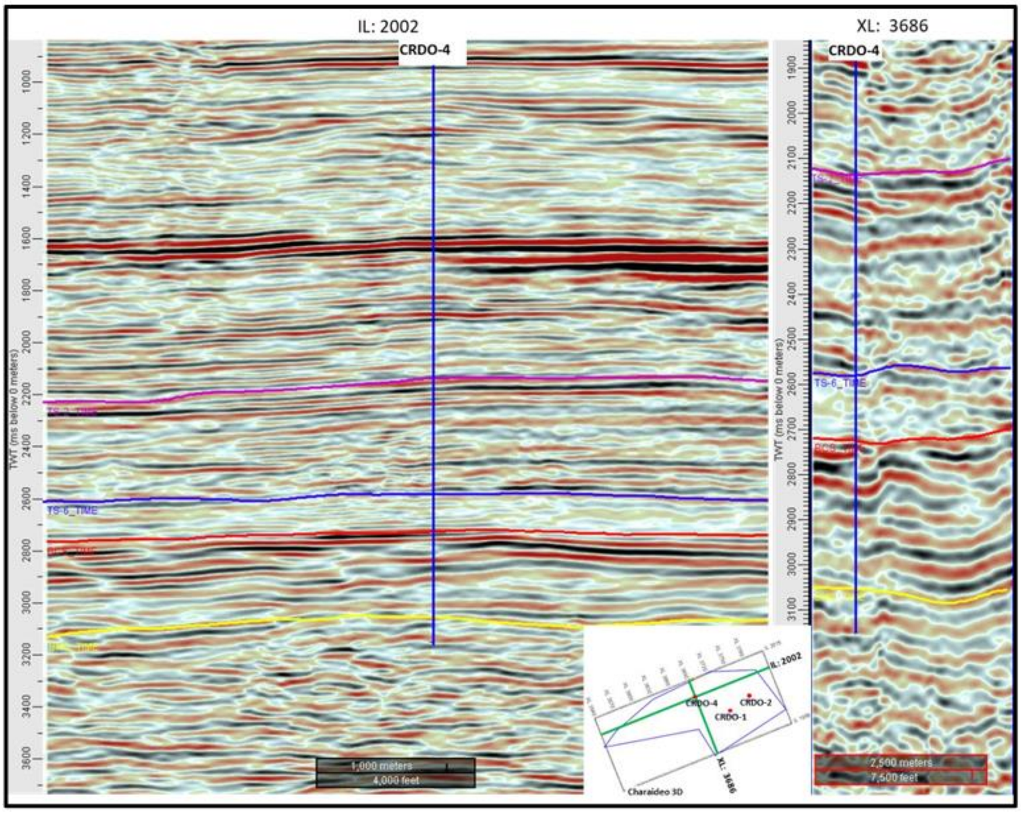


Figure 4-104: TIME AND DEPTH STRUCTURE MAP ON TOP OF TS-2

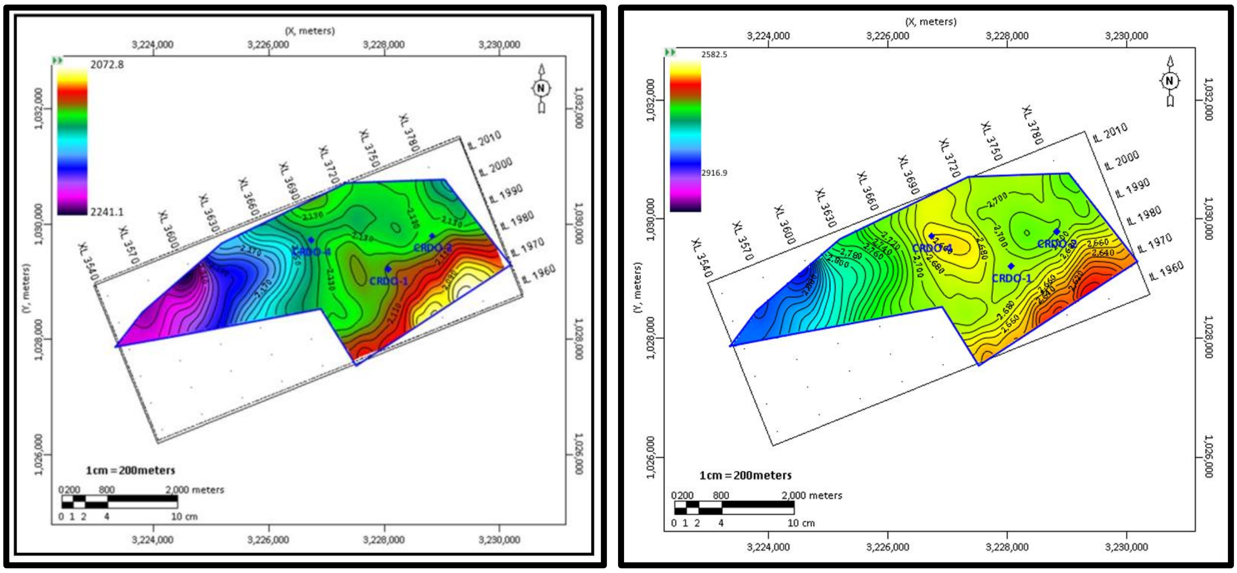


Figure 4-105: TIME AND DEPTH STRUCTURE MAP ON TOP OF TS-6

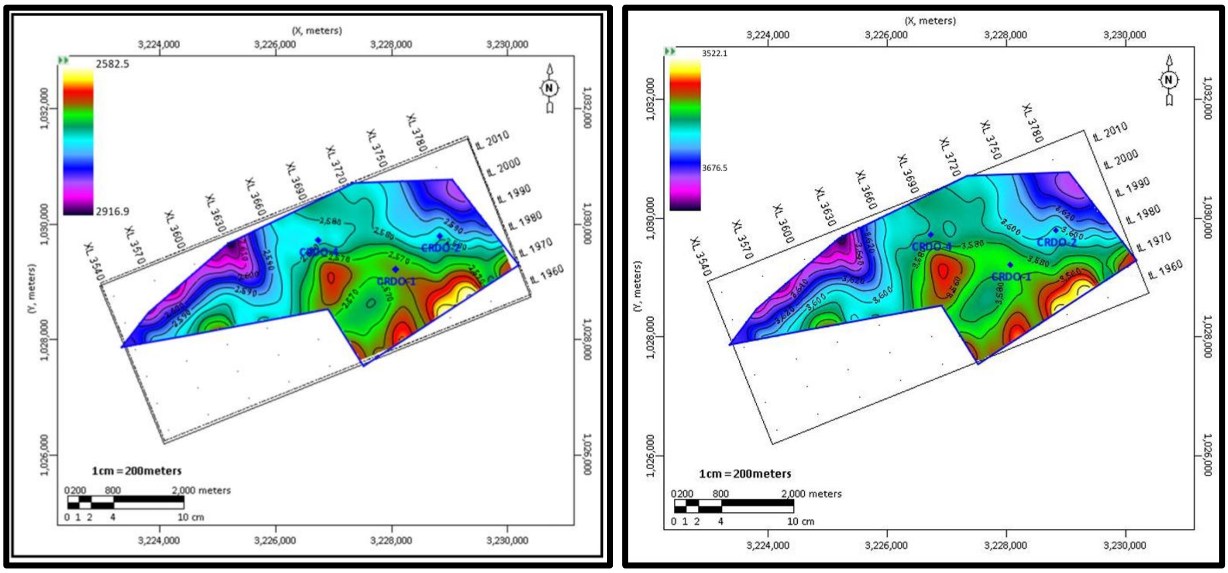


Figure 4-106: DEPTH AND TIME STRUCTURE MAP ON TOP OF BCS

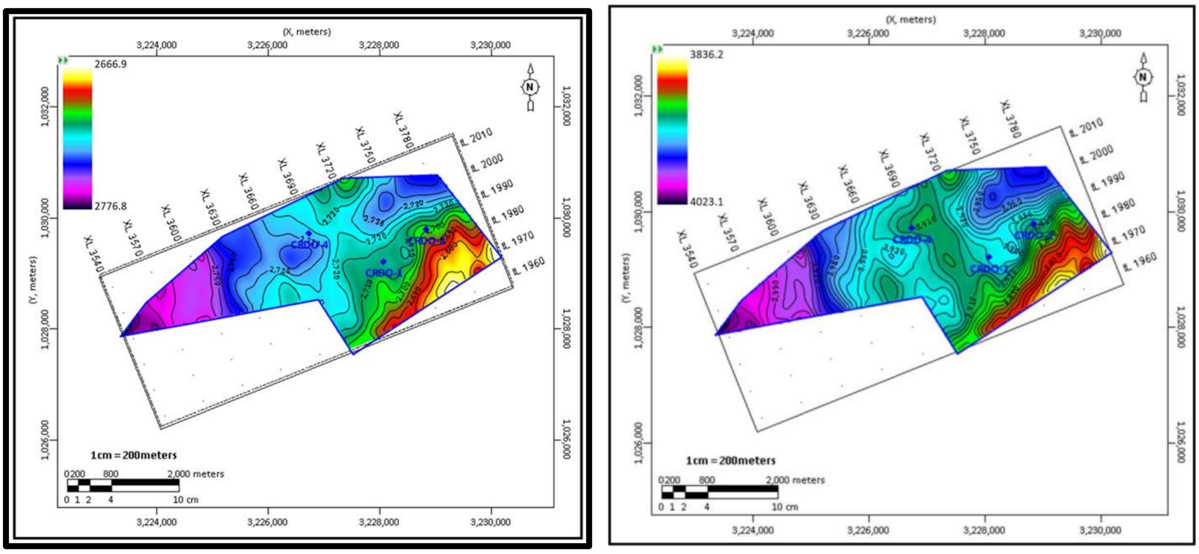


Figure 4-107: TIME AND DEPTH STRUCTURE MAP ON TOP OF BMS

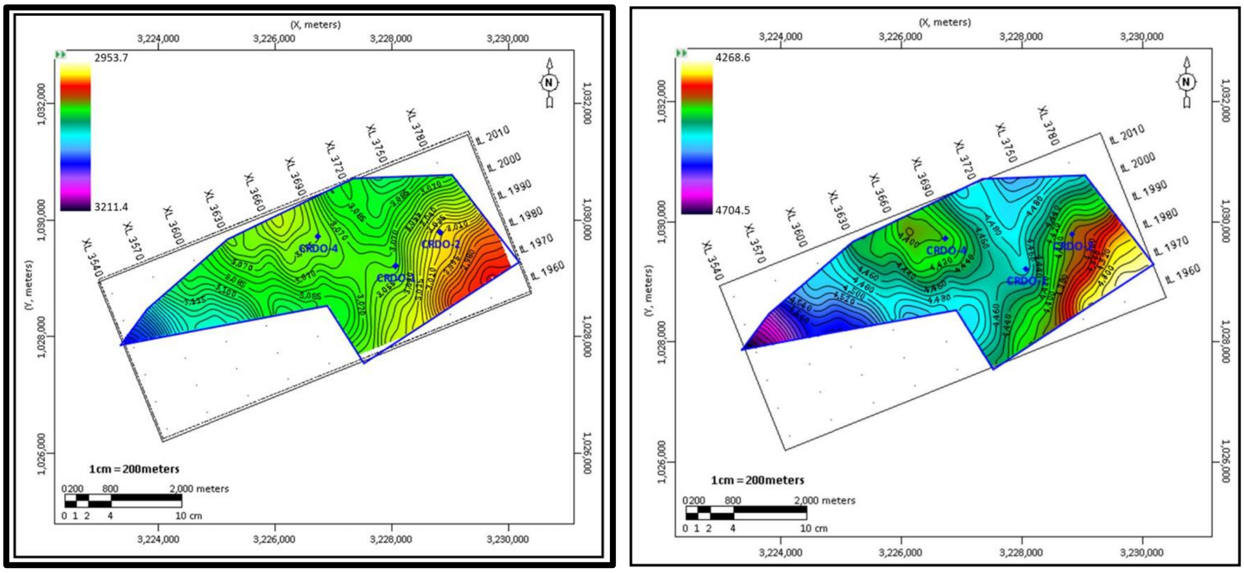


Figure 4-108: ACOUSTIC IMPEDANCE MAP WITHIN BARAIL COAL SHALE (BCS)

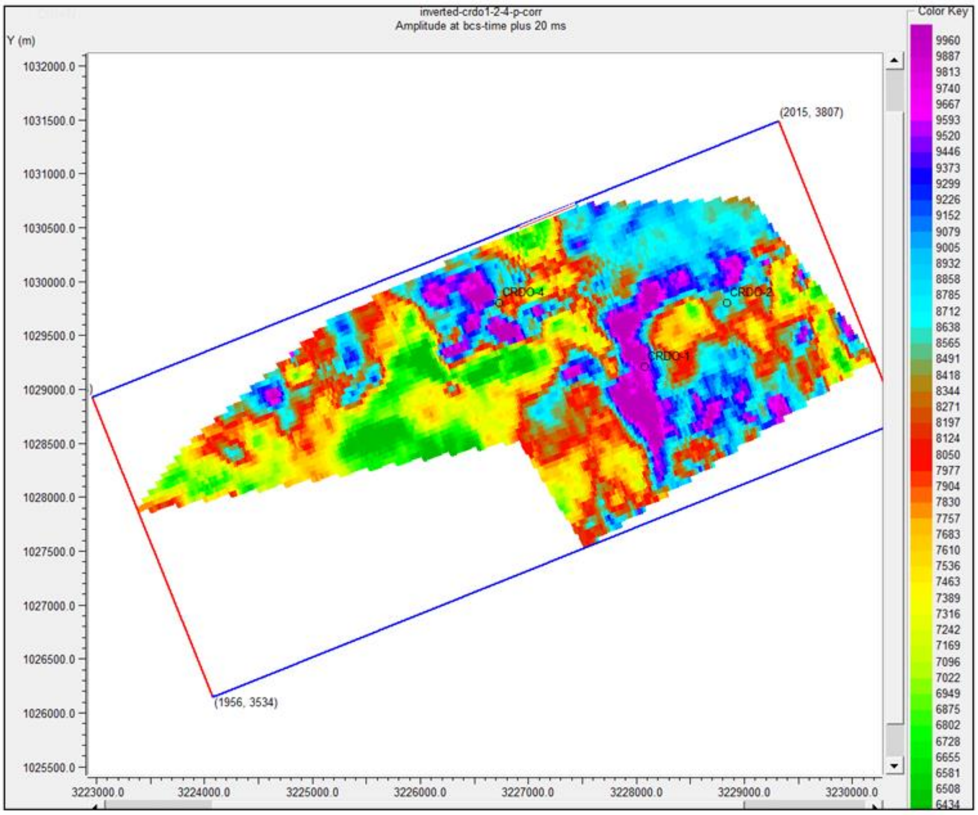


Figure 4-109: ACOUSTIC IMPEDANCE MAP WITHIN BARAIL MAIN SAND (BMS)

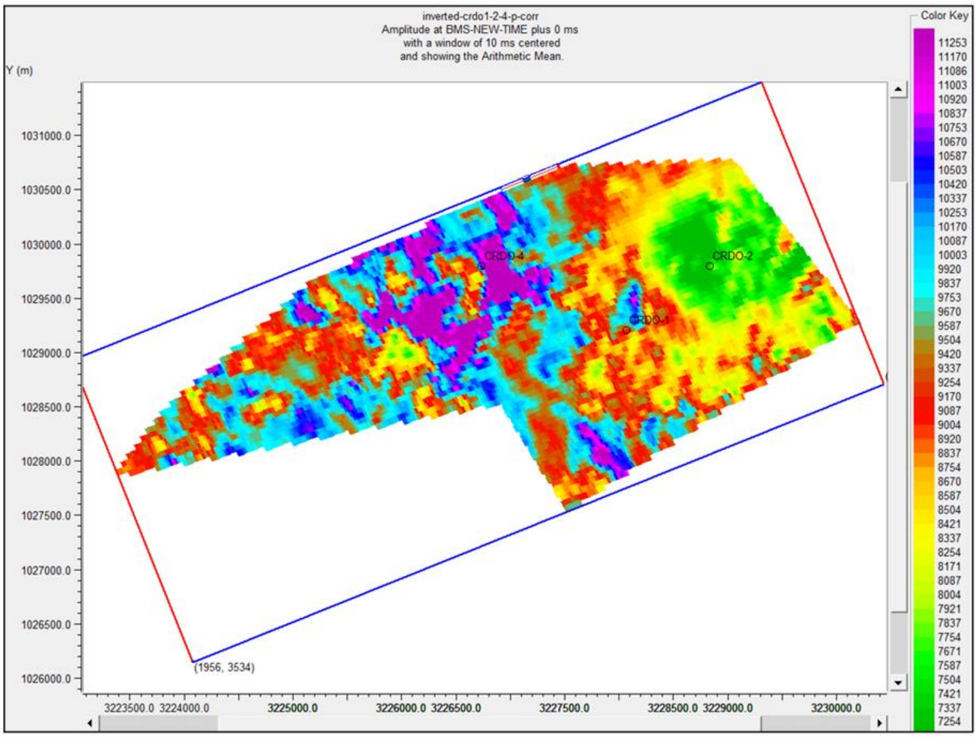
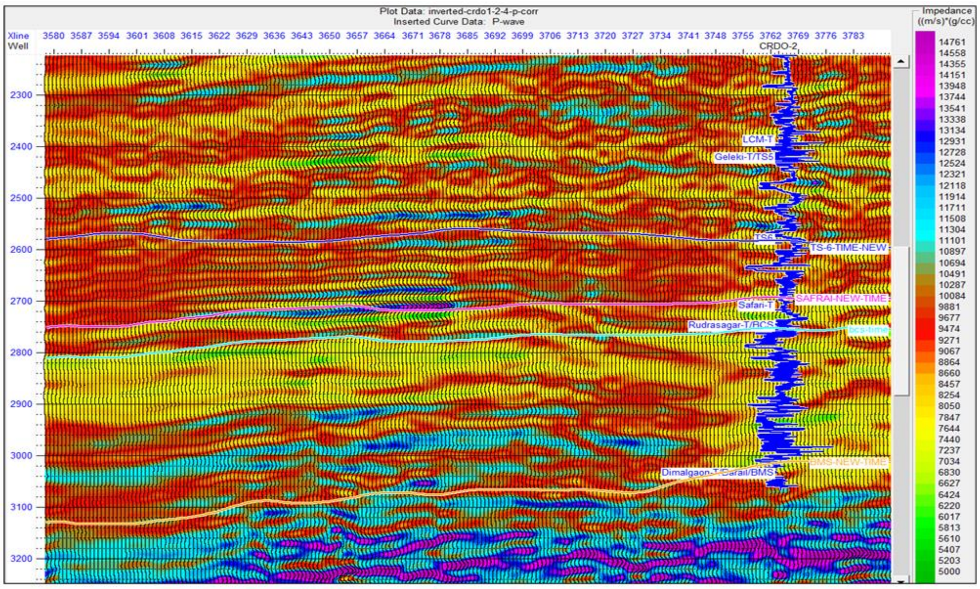


Figure 4-110: ACOUSTIC IMPEDANCE SECTION PASSING THROUGH WELL CRDO-2



4.5.5.2 Reservoir parameters and hydrocarbon estimates (CHARAIDEO Field):

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Initial oil/gas volumes have been estimated in PS category-based testing data, reservoir parameters and log motifs of drilled wells CRDO-1, 2, 4.

<u>Petrophysical parameters and hydrocarbon estimates:</u>

Petrophysical Studies of conventional cores from well CRDO-4, CC-2, Sample ID: 104 is given in **Table 4-75.**

Table 4-75: PETROPHYSICAL STUDIES OF CORE SAMPLE OF WELL CRDO-4,

Petrophysical Studies of CDAC, CC-2, Sample ID: 104	**Date of Receipt of Sample: 16.02.2010**
Source of collection:	**Core Library, RGL; Sibsagar**
Well No./Area	CDAC
UWI	E-CRDO-4
Core No.	CC-2
Core interval (m)	4501-4508 m
Core Recovery	67 %
Formation/ Group	Barail
Lithology	Sandstone (Fine grained)

Test Results							
Sl. No.	**Plug No.**	**Bulk Density (g/cc)**	**Effective Porosity (%)**	**Grain Density (g/cc)**	**Bulk Density (g/cc)**	**Permeability K gas (md)**	**K∞ (md)**
1	1H	4501.05	11.1	2.8	2.49	0.693	0.573
2	2H	4501.26	9.3	2.68	2.43	0.916	0.858
3	3H	4501.52	12.2	2.78	2.44	0.933	0.847
4	4H	4501.7	6.2	2.72	2.56	0.185	0.114
5	5H	4501.94	8.9	2.74	2.5	0.860	0.790
6	6H	4502.34	9.8	2.76	2.48	0.486	0.337

The Lowest Known Hydrocarbon (LKH) depths encountered as per FDP in each reservoir zone for each well are given in **Table 4-76**. The reservoir parameters for BCS (shallow and deep), and BMS to calculate In-place volumes were obtained using the average values of the 3 wells (**Table 4-77, Table 4-78 and Table 4-79).** The areas for the calculations were used from the maps shown in the following figures. (**Figure 4-111, Figure 4-112 and Figure 4-113**). Corresponding Net Pay maps of BCS Shallow, BCS Deep, BMS in CRDO-2 and BMS in CRDO-4 are shown in (**Figure 4-114, Figure 4-115, Figure 4-116 and Figure 4-117**) respectively.

Table 4-76: LOWEST KNOWN HYDROCARBON (LKH) DEPTHS ENCOUNTERED IN CHARAIDEO WELLS

Zones	CRDO-1			CRDO-2			CRDO-4		
	Contact	Depth (MD)	Depth (TVDSS)	Contact	Depth (MD)	Depth (TVDSS)	Contact	Depth (MD)	Depth (TVDSS)
TS-6	LKO	-	-	LKO	-	-	LKO	3956.5	3852
Safrai	LKO	-	-	LKO	4010		LKO	4000	3896
BCS-Shallow	LKO	4091.6	3983	LKO	-	-	LKO	-	-
BCS-Deep	LKO	4556.6	4448	LKO	4482	4372	LKO	4478.5	4374
BMS	LKO	-	-	LKO	4576	4466	LKO	4571.5	4467

Table 4-77: PETROPHYSICAL PARAMETERS OBTAINED IN WELLS CRDO-1, CRDO-2 AND CRDO-4

CRDO-1						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.0	0.0	-	-
BCS	550	12.6	6.9	19.4	0.160	0.351
BMS	272	0.0	0.0	0.0	-	-
TOTAL	**1447**	**12.6**	**6.9**	**19.4**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.1	0.1	0.190	0.569
BCS	550	18.5	17.2	35.8	0.147	0.419
BMS	272	0.0	0.0	0.0	-	-
TOTAL	**1447**	**18.5**	**17.4**	**35.9**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.1	0.1	0.190	0.569
BCS	550	20.4	27.8	48.1	0.139	0.465
BMS	272	0.0	0.2	0.2	0.116	0.699
TOTAL	**1447**	**20.4**	**28.0**	**48.4**	**-**	**-**

CRDO-2						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	0.5	0.0	0.5	0.264	0.446
BCS	467	3.2	0.0	3.2	0.171	0.377
BMS	208	2.3	0.0	2.3	0.172	0.375
TOTAL	**1301**	**6.0**	**0.0**	**6.0**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	2.0	0.0	2.0	0.214	0.515
BCS	467	5.6	2.4	8.1	0.158	0.449
BMS	208	5.0	0.0	5.0	0.165	0.472
TOTAL	**1301**	**12.7**	**2.4**	**15.1**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	3.2	0.6	3.8	0.203	0.581
BCS	467	7.0	4.4	11.4	0.151	0.499
BMS	208	8.1	0.0	8.1	0.167	0.539
TOTAL	**1301**	**18.3**	**5.0**	**23.3**	**-**	**-**

CRDO-4						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	0.5	0.3	0.8	0.183	0.421
TS-6	271	0.0	1.8	1.8	0.152	0.426
Safrai	51	0.2	1.1	1.2	0.134	0.473
BCS	492	0.0	0.3	0.3	0.256	0.458
BMS	194	7.2	9.8	16.9	0.175	0.423
TOTAL	**1355**	**7.8**	**13.3**	**21.0**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	0.9	0.8	1.7	0.183	0.496
TS-6	271	1.4	3.5	4.9	0.146	0.507
Safrai	51	1.8	1.8	3.7	0.130	0.516
BCS	492	2.3	3.1	5.3	0.179	0.547
BMS	194	8.2	12.2	20.4	0.168	0.439
TOTAL	**1355**	**14.6**	**21.3**	**36.0**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	1.4	3.5	4.9	0.170	0.604
TS-6	271	4.0	5.6	9.6	0.141	0.575
Safrai	51	4.9	2.3	7.2	0.127	0.570
BCS	492	3.7	9.8	13.4	0.172	0.602
BMS	194	9.8	14.6	24.4	0.161	0.465
TOTAL	**1355**	**23.6**	**35.8**	**59.4**	**-**	**-**

Table 4-78: PETROPHYSICAL PARAMETERS OBTAINED IN THE RESERVOIR ZONES.

Low Case - P_{90}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.2	0.1	0.3	0.183	0.421
T_6	271	0.0	0.6	0.6	0.152	0.426
Safrai	51	0.2	0.4	0.6	0.199	0.460
BCS	492	5.3	2.4	7.6	0.196	0.395
BMS	194	3.2	3.3	6.4	0.173	0.399

Best Case - P_{50}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.3	0.3	0.6	0.183	0.496
T_6	271	0.5	1.2	1.6	0.146	0.507
Safrai	51	1.3	0.7	1.9	0.178	0.533
BCS	492	8.8	7.6	16.4	0.161	0.472
BMS	194	4.4	4.1	8.5	0.167	0.456

High Case - P_{10}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.5	1.2	1.6	0.171	0.604
T_6	271	1.3	1.9	3.2	0.141	0.575
Safrai	51	2.7	1.0	3.7	0.173	0.573
BCS	492	10.3	14.0	24.3	0.154	0.522
BMS	194	5.9	4.9	10.9	0.148	0.568

Table 4-79: NTG Values Obtained for Calculating P50 Case Volumes

3 WELL AVERAGES - CHARAIDEO									
Zones	Thickness Gross (m)	Sand Gross (m)	Silty Sand Gross (m)	Shale Gross (m)	Sand Gross (%)	Silty Sand Gross (%)	Shale Gross (%)	NTG Sand	NTG Silty Sand
BCS_Shallow	56.00	8.69	17.83	29.48	0.00	8.08	14.80	15.5%	31.8%
BCS_Deep	30.67	10.75	0.56	16.42	2.93	4.90	2.19	35.1%	1.8%
BMS	50.00	20.37	0.84	13.79	15.01	6.63	6.10	40.7%	0.0%

Figure 4-111: P90, P50 & P10 CASE POLYGONS FOR BCS-SHALLOW

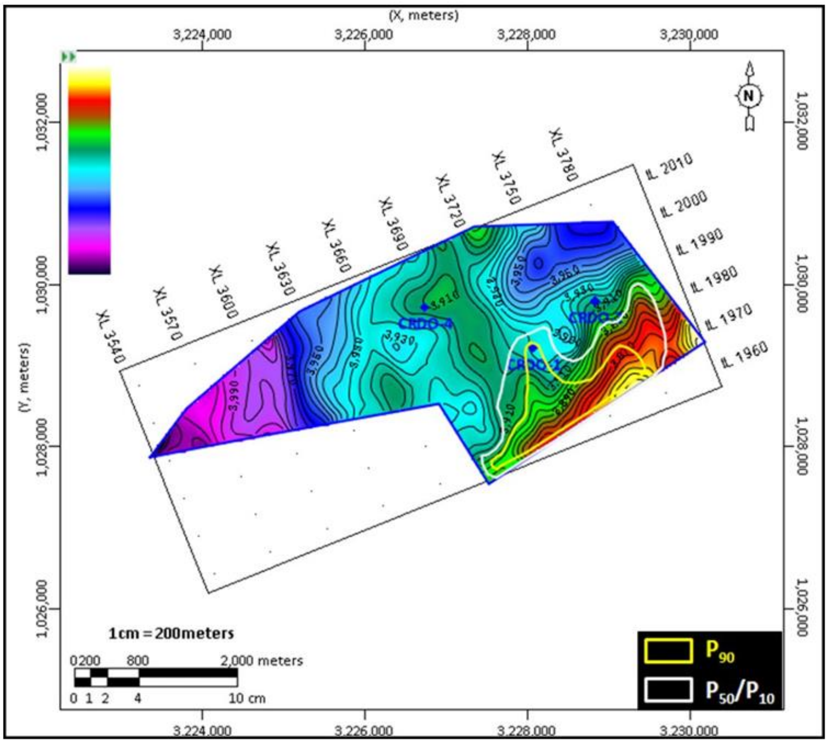


Figure 4-112: P90, P50 & P10 CASE POLYGONS FOR BCS-DEEP

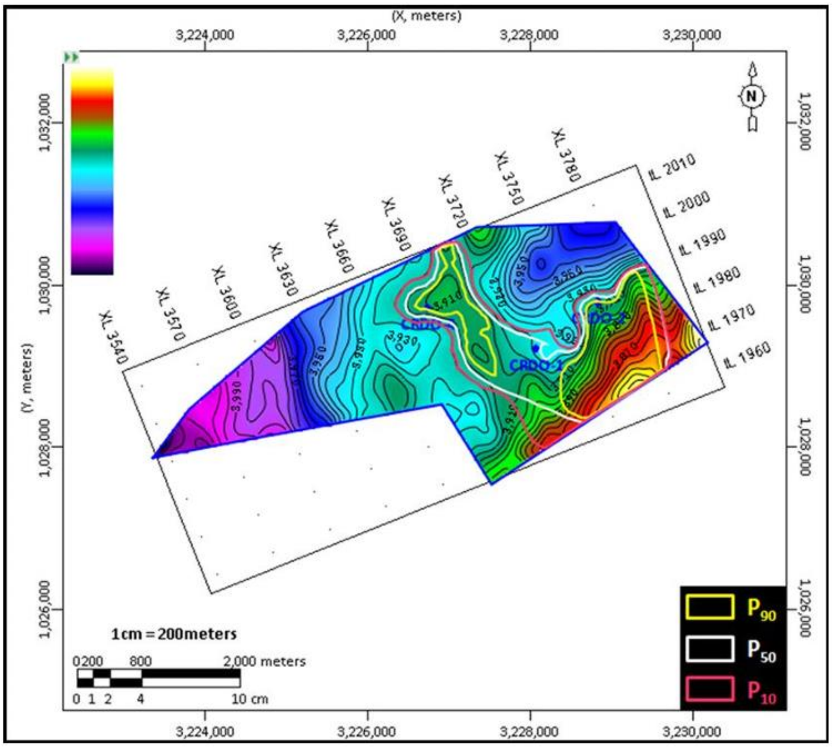


Figure 4-113: P90, P50 & P10 CASE POLYGONS FOR BMS

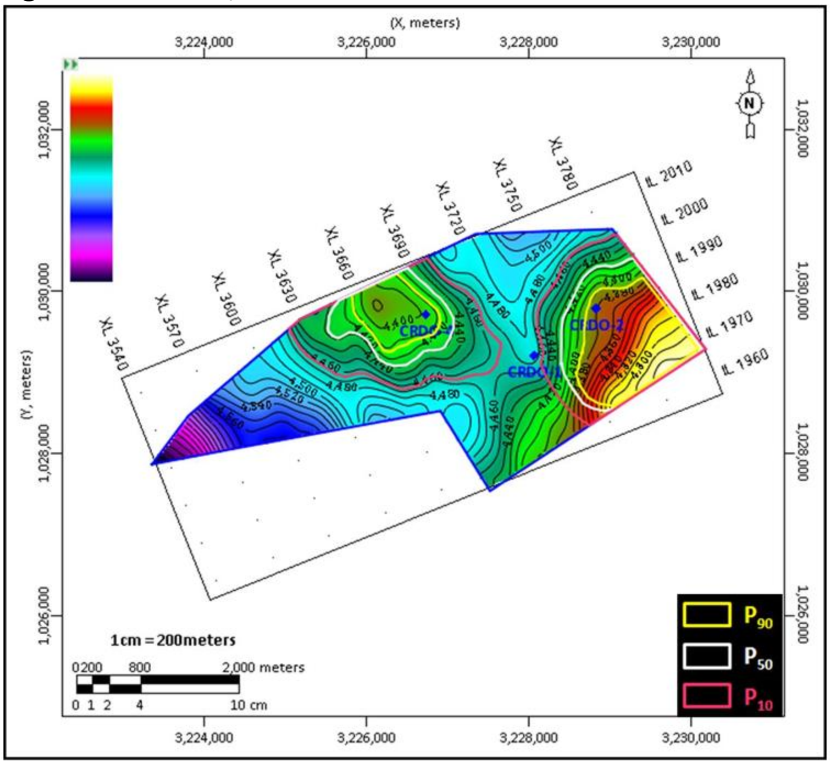


Figure 4-114: PAY THICKNESS MAP (P50 CASE) FOR BCS-SHALLOW

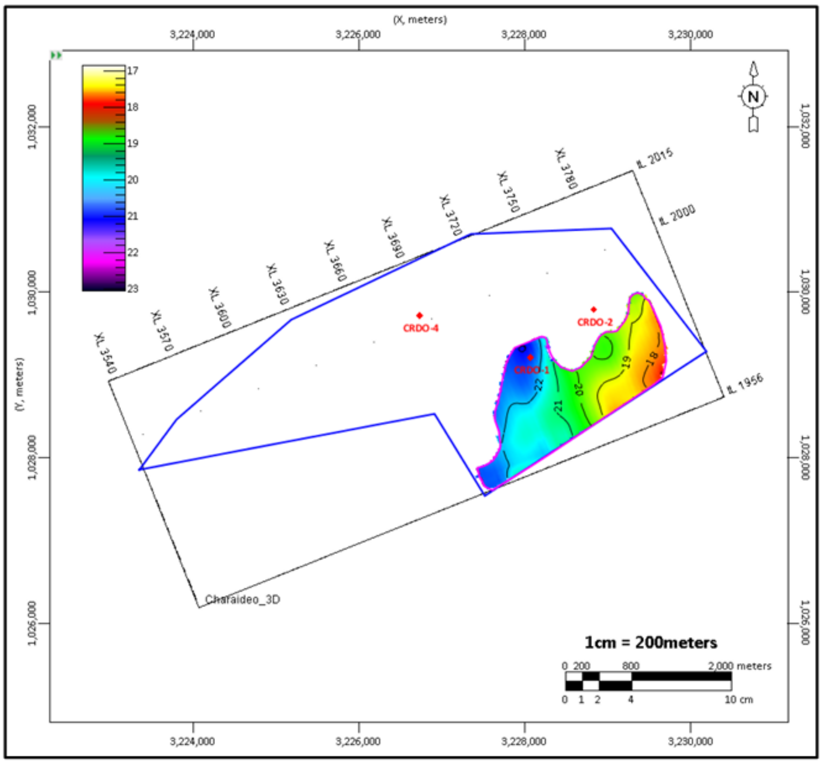


Figure-57: Pay thickness map (P_{50} case) for BCS-Shallow

Figure 4-115: PAY THICKNESS MAP (P50 CASE) FOR BCS-DEEP

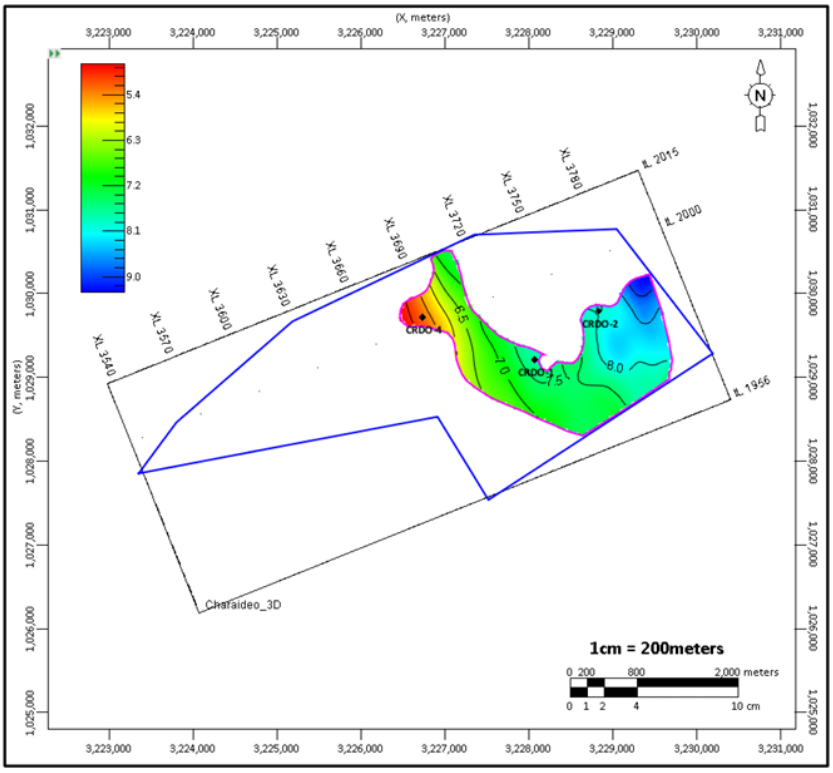


Figure 4-116: PAY THICKNESS MAP (P50 CASE) FOR BMS (WELL CRDO-2)

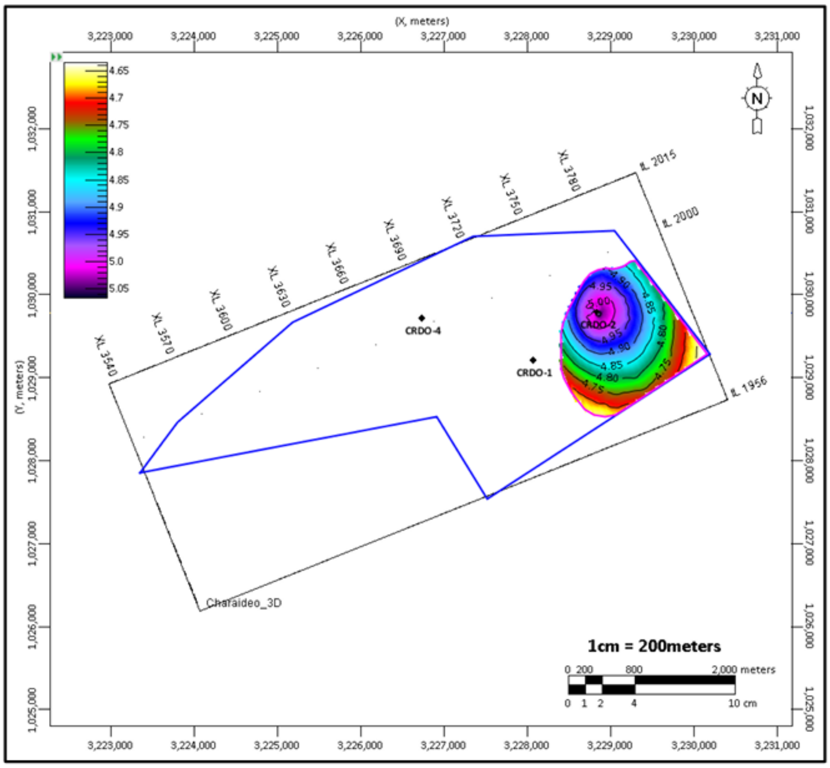
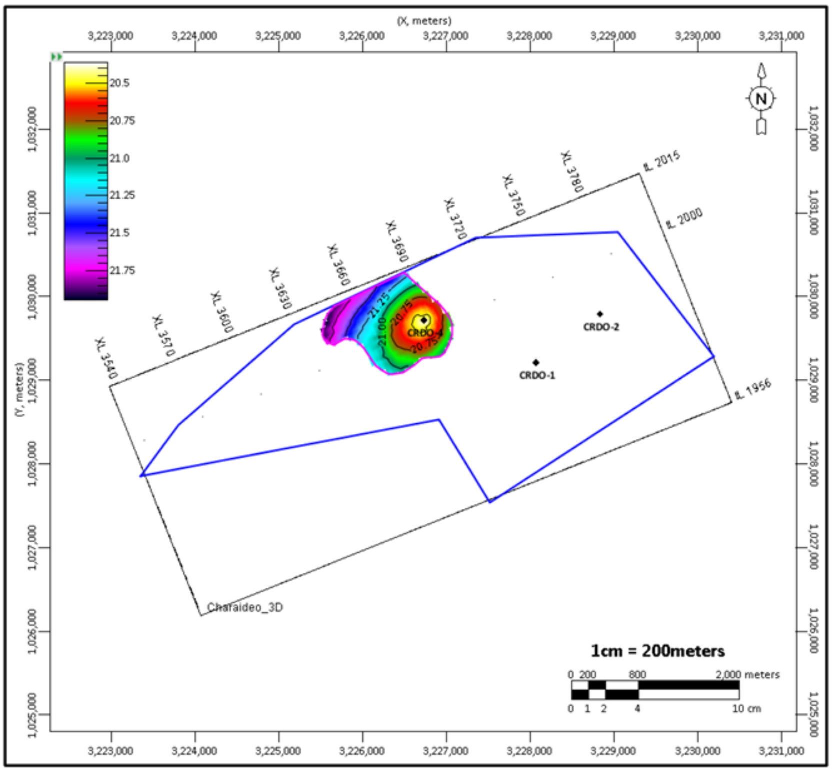


Figure 4-117: PAY THICKNESS MAP (P50 CASE) FOR BMS (WELL CRDO-4)



4.5.5.3 Estimation of In-Place Volumes and Reserves

In-place volumes and EUR have been estimated by using the polygons derived from the given maps and various petrophysical parameters for each reservoir level and the In-Place Volumes for Charaideo Field are tabulated below.

Current Oil/ Gas In-Place and Reserves estimation

The reservoir parameters and in-place are given in **Table 4-80 and Table 4-81**.

Table 4-80: RESERVOIR PARAMETERS FOR VOLUMETRIC ESTIMATION OF CHARAIDEO FIELD

Reservoir	Area	He	Phi	Hydro-carbon	FVF V/v	API	SPGR	GOR	OIIP	GIIP
Sand/ layer	SqKM	m		So	Bo			Sm3/ M3	MMstb	MMm3
BCS Shallow (CRDO-2)	2.354	15.0	0.12	0.53	1.75	31.1	0.87	210	8.1	269
BCS Deep	3.020	4.0	0.11	0.53	1.75	31.1	0.87	210	2.5	85
BMS CRDO-2	2.906	2.4	0.14	0.55	1.83	32.5	0.8628	210	1.9	62
BMS CRDO-4	2.570	10.5	0.14	0.55	1.83	32.5	0.8628	210	7.1	238
									19.6	**654**

Table 4-81: HYDROCARBON IN-PLACE(2P) CHARAIDEO FIELD

Field	O+OEG MMTOE
CHARAIDEO	**3.35**

4.5.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Charaideo field is **21 km. NE of main Geleki field and approx. 3 km. south of Lakwa field**

AA/ONDSF/ASSAM/2025 (A&AA) KHEREM FIELD

4.6 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) KHEREM FIELD

The Kherem field is located in the Ningru Extension PML in the district of Changlang in Arunachal Pradesh and is about 74 km N.E. of Duliajan in the district of Dibrugarh. The Kherem field covers an area of 14.78 Sq. Km and is bounded by the points ABCDEFG as shown in **Figure 4-118**.

The presence of a significant structure at the Pengri-Bordumsha area of the Ningru Extension PML of Arunachal Pradesh was indicated by 24-fold seismic data (21.275 LKM) acquired during 1985-87. The seismic interpretation revealed the presence of a broad asymmetrical anticline plunging towards the east at the Supra-thrust Girujan level, which appears to be the easternmost extension of the Digboi anticline. The axial plane of the anticline runs almost parallel to the Naga thrust. The northern limb of the anticline dips steeply (avg. 30-40^0) as compared to the southern limb, where dips are gentle (5-15^0).

Structurally, the area is characterized by the presence of the eastern extension of the Naga Thrust, which, however, manifests mainly in the sub-surface. The east-north-east trending thrust fault is prominent below the Dhekiajuli and divides the area into two structural blocks (segments), the southern hanging wall region and the northern foot wall blocks, which are also referred to as supra-thrust and sub-thrust, respectively. The Kherem and Kumchai fall into the supra-thrust region to the south, whereas the North Kumchai area is on the sub-thrust block to the north. Hydrocarbon has already been established in the supra-thrust block in Kumchai and Kherem areas.

Till date, three exploratory wells have been drilled in this area, viz., well Kherem-1 in 1992, well Kherem-2 in 1993 and well Kherem-3 in 1994. Drilling of well Kherem-1 started in 1992 but could not be completed due to down-hole drilling complications. The well Kherem-3 was drilled as a replacement for well Kherem-1. Neighbouring oil and gasfields to the Kherem Field can be seen in **Figure 4-120.**

A map showing the 2D-3D seismic coverage in the Kherem field is shown in **Figure 4-119**.

The Kherem-2 area is located onland within the Upper Assam Basin and has an offered area of 14.78 sq. km (**Figure 4-118**) under this DSF Bid Round IV. The area is a single area with 1 discovery/field (Kherem-2) and 2 additional wells. The coordinates of the block boundaries are given in **TABLE 4-82**.

Table 4-82: COORDINATES OF THE BLOCK BOUNDARIES: KHEREM

KHEREM Boundary Points		
Area: 14.78 sq km		
Point	**Longitude**	**Latitude**
A	95° 52′ 17.100″ E	27° 28′ 29.982″ N
B	95° 52′ 29.681″ E	27° 28′ 17.239″ N
C	95° 53′ 07.302″ E	27° 28′ 36.469″ N
D	95° 54′ 14.133″ E	27° 26′ 55.354″ N
E	95° 52′ 48.607″ E	27° 26′ 10.832″ N
F	95° 51′ 00.000″ E	27° 26′ 10.732″ N
G	95° 51′ 00.000″ E	27° 26′ 30.584″ N
A	95° 52′ 17.100″ E	27° 28′ 29.982″ N
Point G → A follows the state boundary between Assam & Arunachal Pradesh.		

Figure 4-118 : LOCATION MAP SHOWING THE KHEREM BLOCK BOUNDARY.

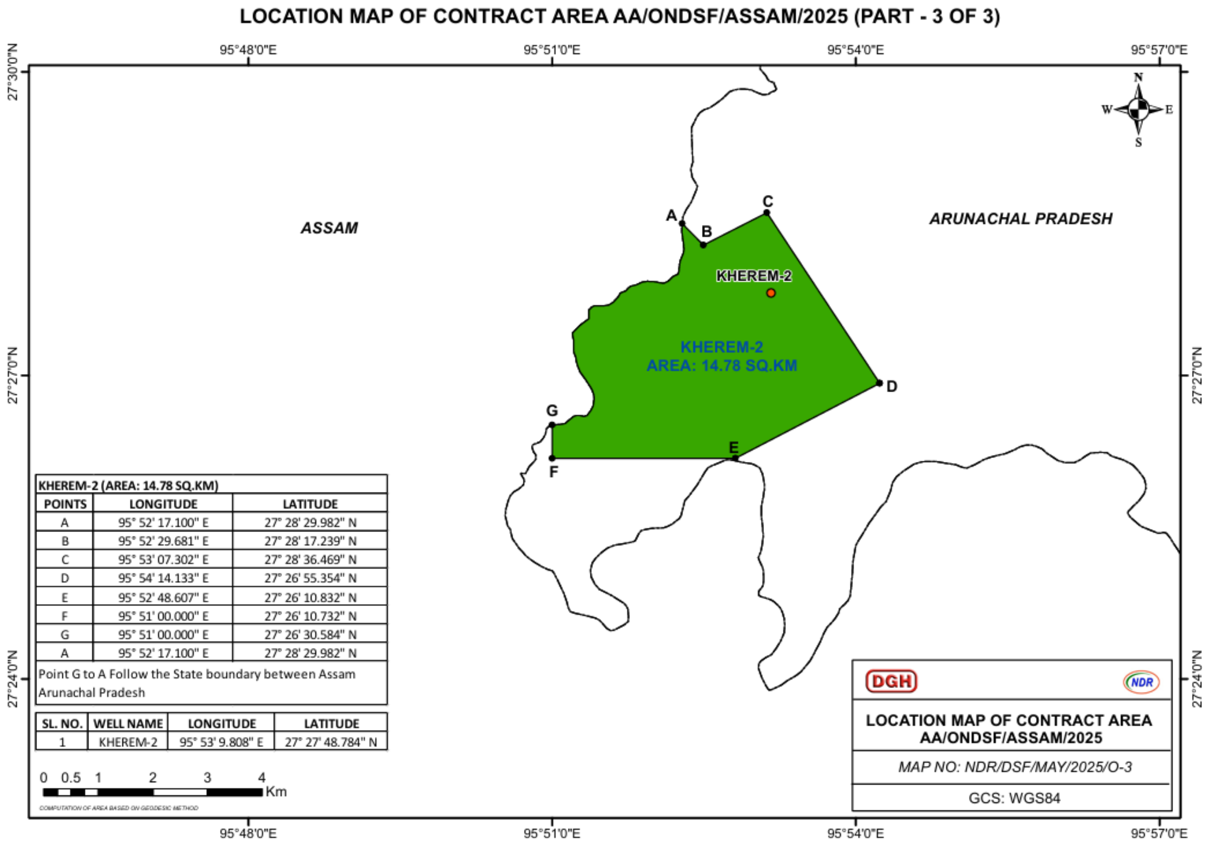


Figure 4-119 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: KHEREM

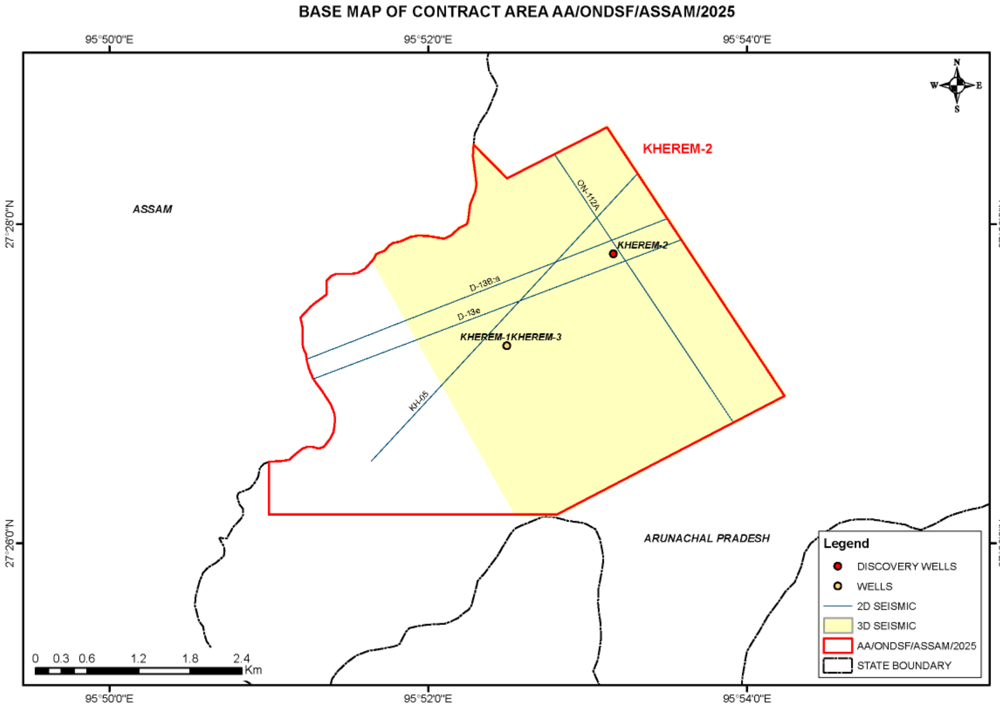
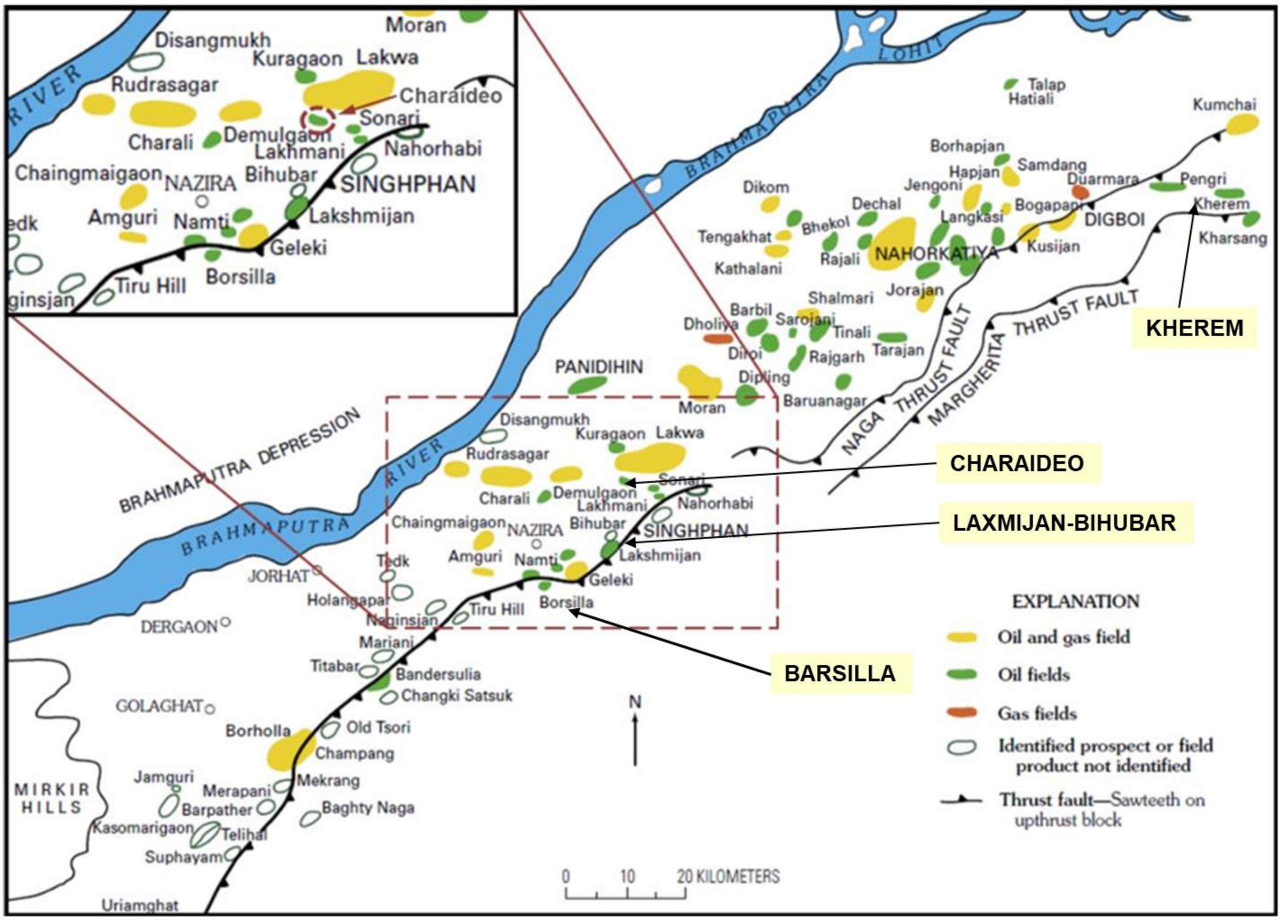


Figure 4-120 : SURROUNDING OIL AND GAS FIELDS.



4.6.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth, including well coordinates are made available in Sections through various cross-references.

Till date, three exploratory wells have been drilled in this field as Kherem-1, 2, and 3. Well Kherem-1 could not be completed due to fish in hole (Bit+ drill collars and drill pipes) and a substitute well, Kherem-3, was drilled and tested. General Information about the wells, viz, Well details are given in **Table 4-83** and the Well Construction Diagram of wells Kherem-2 & 3 are given in **Figure 4-121 and Figure 4-122.**

Figure 4-121 :.WELL PROFILE OF KHEREM-2 :

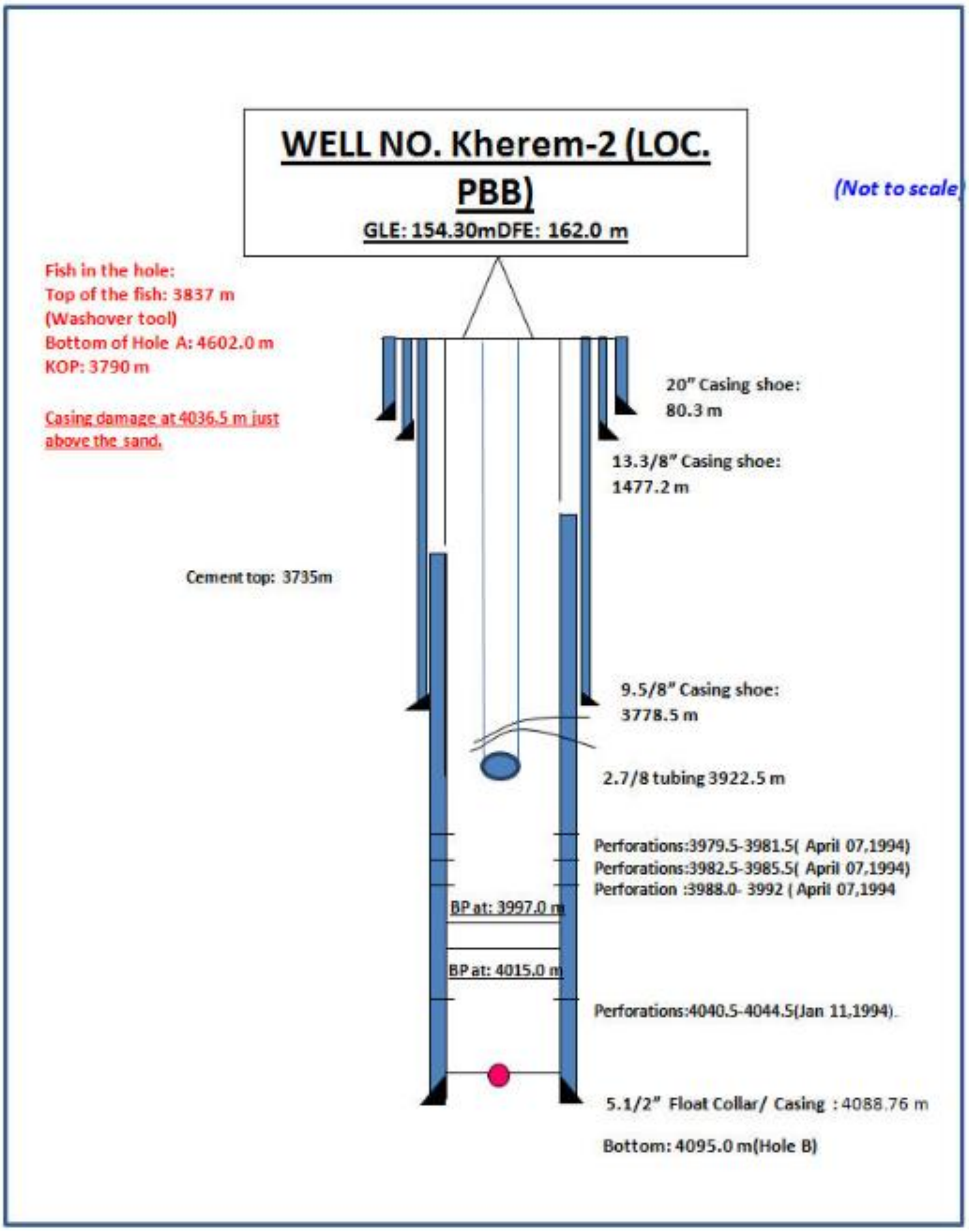


Figure 4-122 :.WELL PROFILE OF KHEREM-3 (ACTUAL)

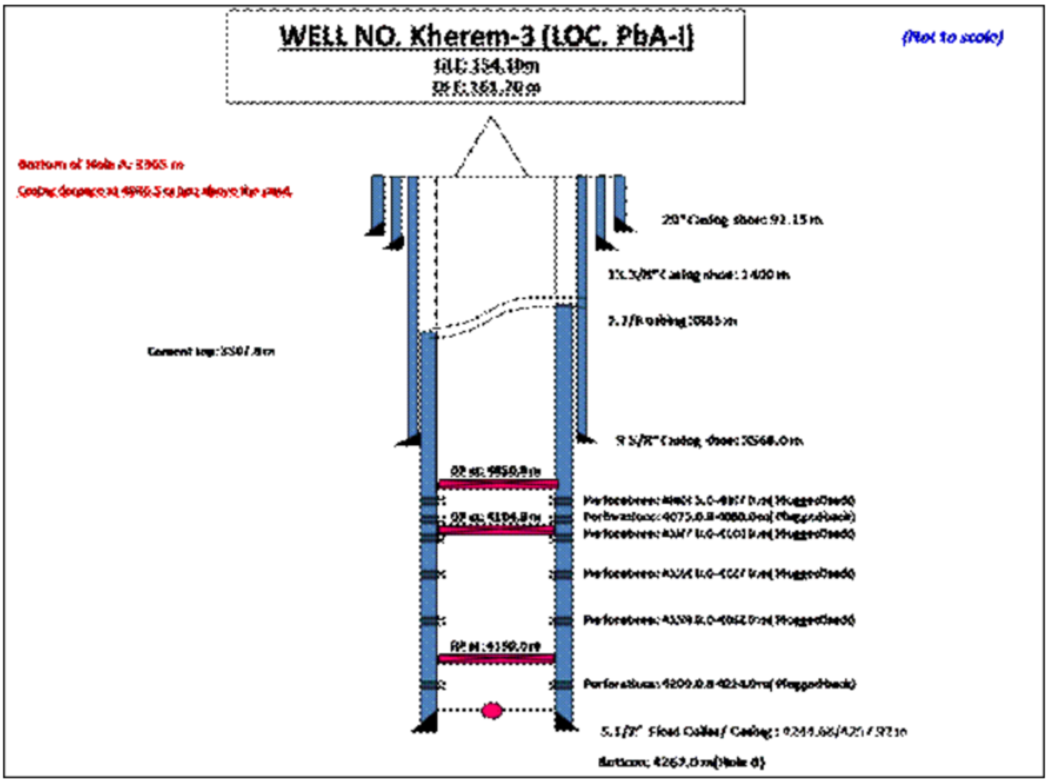


Table 4-83: GENERAL WELL WISE INFORMATION OF KHEREM FIELD:

Well Name	KHEREM-1	KHEREM-2	KHEREM-3
Category and Classification	Exploratory	Exploratory	Exploratory
Area/ Structure	Kherem	Kherem	Kherem
District & State	Lohit District, Arunachal Pradesh	Lohit District, Arunachal Pradesh	Lohit District, Arunachal Pradesh
Coordinates	Lat: 27°27'14.148" N Long: 95° 52' 29.666" E	Lat: 27° 27' 8.784" N Long: 95° 53' 9.808" E	Lat: 27° 27' 14.148" N Long: 95° 52' 29.666" E
Objective	Girujan	Girujan	Girujan
Target Depth (m)	3700	5000	4300
Drilled Depth (m)	4301	4095	4247
Logger's depth(m)	4282	4092	4262
Hydrocarbon Shows	nil	Oil	Gas
Core details	64 sidewall core samples recovered from 2109-4272m	21 sidewall core samples recovered from 3837-4061m	No sidewall cores were taken in this well
DF Elevation (m asl)	161.70	162.00	161.71
Ground level (m asl)	154.10	154.30	154.09

Well profile			
Spudded on	10.08.1991	29.01.1993	07.08.1994
Drilling completed on	04.04.1992	19.12.1993	29.05.1995
Production testing started on	22.05.1992	03.01.1994	19.06.1995
Production testing completed	04.06.1992	02.06.1994	09.09.1995
Initial Status of Well	Abandoned complicated downhole problem.	Produced @ 18 klpd clean oil (API 40°). ceased to flow due to the ingress of sand / clay / contaminated cement, owing to casing damage at 4036.5 m	The well produced intermittently condensate (API 44.8°) and a small amount of gas.
Current Status of Well	Abandoned	Shut in	Plugged back

4.6.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of the tested/ interesting zone of key wells are also appended.

4.6.2.1 Well completion and log evaluation reports availability (KHEREM Field) :

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Kherem-1	161.70 m	10-08-1991	4301.00 m	Available	Not Available
Kherem-2	162.00 m	29-01-1993	4095.00 m	Available	Not Available
Kherem-3	161.71 m	07-08-1994	4247.00 m	Available	Not Available

4.6.2.2 Well logs acquired (KHEREM Field) :

The list of logs acquired in Kherem wells is given in **Table 4-84.**

Table 4-84: LOG ACQUIRED IN KHEREM WELLS

Well Kherem-1	
Services	**Depth Range (m bdf)**
DIL-GR-SP	1200.0 – 3472.0
	100.0 – 4244.0
CDL-CNL-GR-CAL	100.0 – 3475.0
	3800.0 – 4224.0
DT-GR	100-1200
	2780.0 – 3474.0
	3400.0 – 4224.0

Well Kherem-2	
Services	**Depth Range (m bdf)**
DIL-GR-SP	1479.0 – 3700.5
LDL-CNL-GR-CAL	2000.0 – 3794.2
DLL-MSFL-GR-SP	3778.5 – 4255.5
DLL-GR-SPCAL	3918.0 – 4397.0
LDL-CNL-GR-CAL	3925.0 – 4254.5
LSS-GR	3918.0 – 4397.0

Well Kherem-3	
Services	**Depth Range (m bdf)**
DIL-SP=CAL	1300.0 – 3025.0
DLL-SP-GR	3575.0 – 4175.0
CDL-CNL-GR	3575.0 – 4175.0

4.6.2.3 Well log evaluation and initial test results (KHEREM Field):

Testing details of wells Kherem-1, Kherem-2 and Kherem-3 are given in **Table 4-85.** Log motifs of Kherem wells are placed at **Figure 4-123, Figure 4-124, Figure 4-125, Figure 4-126 and Figure 4-127**

Table 4-85: EVALUATION AND INITIAL TESTING DETAILS OF KHEREM WELLS

Interval (mbdf)	Formation (+ Zone, if specified)	Gross (m)	Net(m)	Phi	Sw
KHEREM-1					
2102-Bottom / 2034.73-Bottom	Girujan (2728.5-2742 mbdf)	14.5	11.0	0.27	-
	Initial testing results: Tested the 2729m Sand in the range 2730.0 -2733.0 m (within 9.5/8" casing), the well gave inflow of mainly formation water. Due to complicated downhole problems (Fish), the interesting Lower Girujan Sands encountered in the well could not be tested, and subsequently, the well was abandoned.				
KHEREM-2					
2183-Bottom / 2112.49-Bottom	Girujan (4037.5-4049.0 mbdf)	12	7	0.24	-
	Initial testing results: Tested the 4038 m sand in the interval 4040.5-4044.5m, the well produced clean oil at the rate of 18-24 klpd (API-40^0) through 7.5 mm bean at FTHP of 56-99 kg/cm^2 and then ceased to flow due to ingress of sand/clay/contaminated cement owing to casing damage at 4036.5 m just above the sand.				
	Girujan (3978.0-3994.0 mbdf)	16	11.0	0.18	-
	Initial testing results: Tested the 3978 m sand in the intervals 3979.5-3981.5m, 3982.5-3985.5m, and 3988.0-3992.0m, the well flowed at the rate of around 30 klpd with water (Oil-68%, API-39.4^0) through 3.5 mm bean with FTHP of 154.9 kg/cm^2. Due to lack of infrastructural facilities to produce on a regular basis, the well was killed with 100 lbs/cft mud on safety consideration during a W/O carried out in April' 04.				
KHEREM-3					
2103-Bottom / 2032.74-Bottom	Girujan (4206.5-4225.0 mbdf)	10	5		
	Initial testing results: Tested the 4207 m sand in the interval 4209.0-4214.0m. After prolonged testing, the well intermittently produced condensate (API-44.8^0). Plugged back to test higher up.				
	Girujan (4158.5-4162.0 mbdf)	6	3		
	Initial testing results: Tested the 4159 m sand in the interval 4159.0-4162.5m. After prolonged testing, the well displaced a little amount of gas. Hence plugged back.				
	Girujan (4123.0-4131.0 mbdf)	5	2		
	Initial testing results: Tested the 4123 m sand in the interval 4124.0-4127.5m. After prolonged testing, the well displaced little amount of condensate. Hence plugged back.				

Figure 4-123 :.WELL LOG MOTIF OF KHEREM-1 :

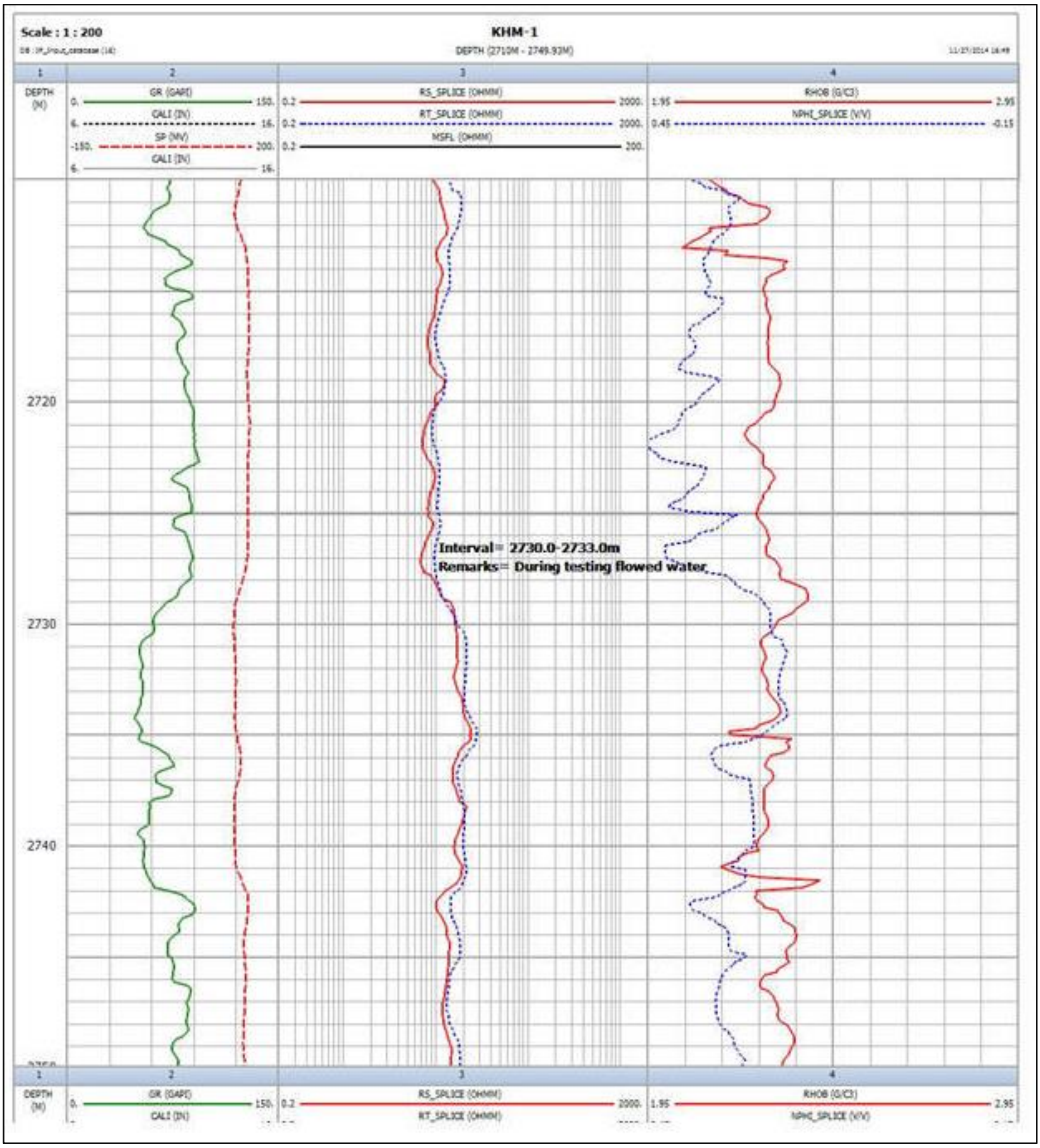


Figure 4-124 :.WELL LOG MOTIF OF KHEREM-2(3950-4018M) :

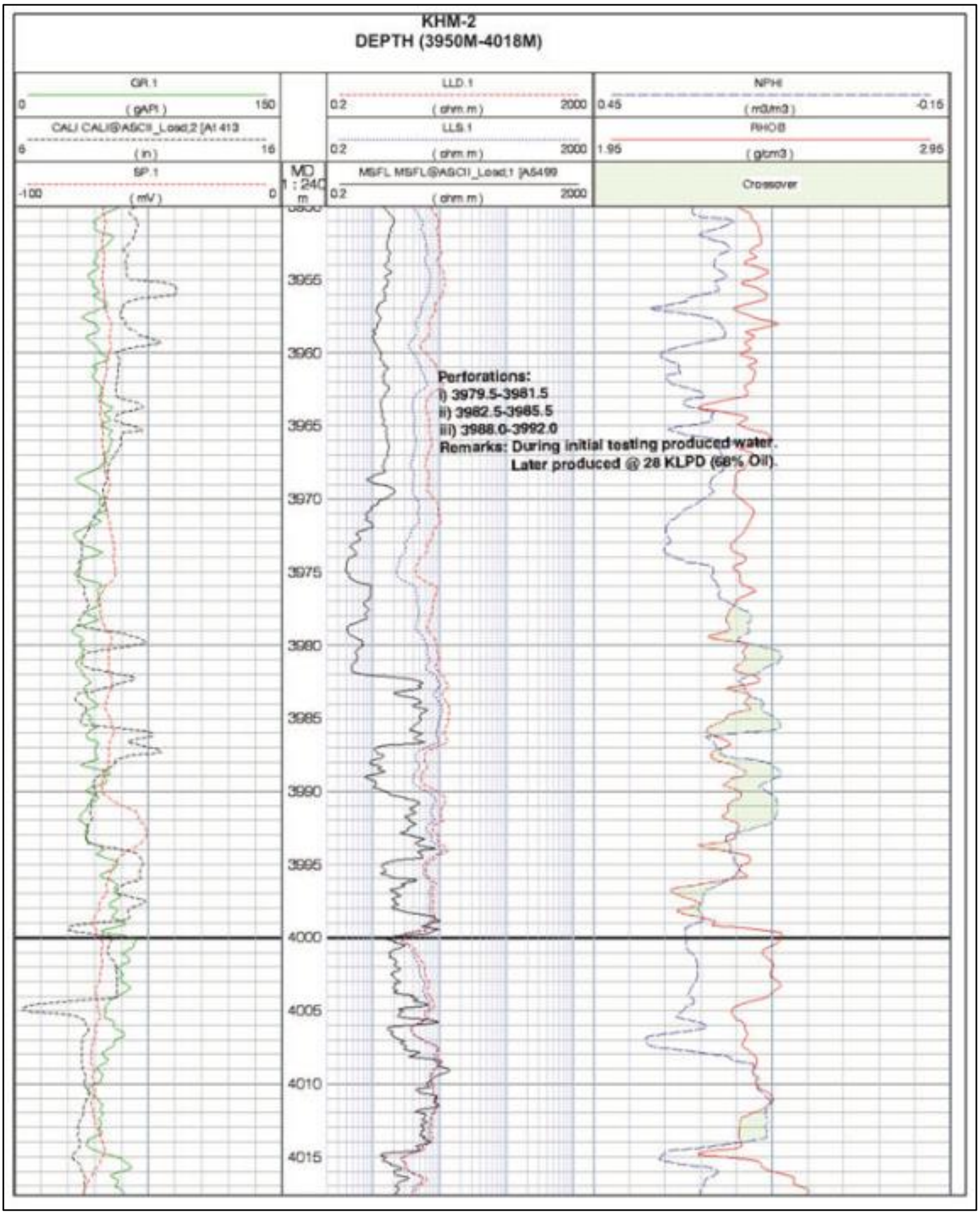


Figure 4-125 :. WELL LOG MOTIF OF KHEREM-2 (4020-4080M):

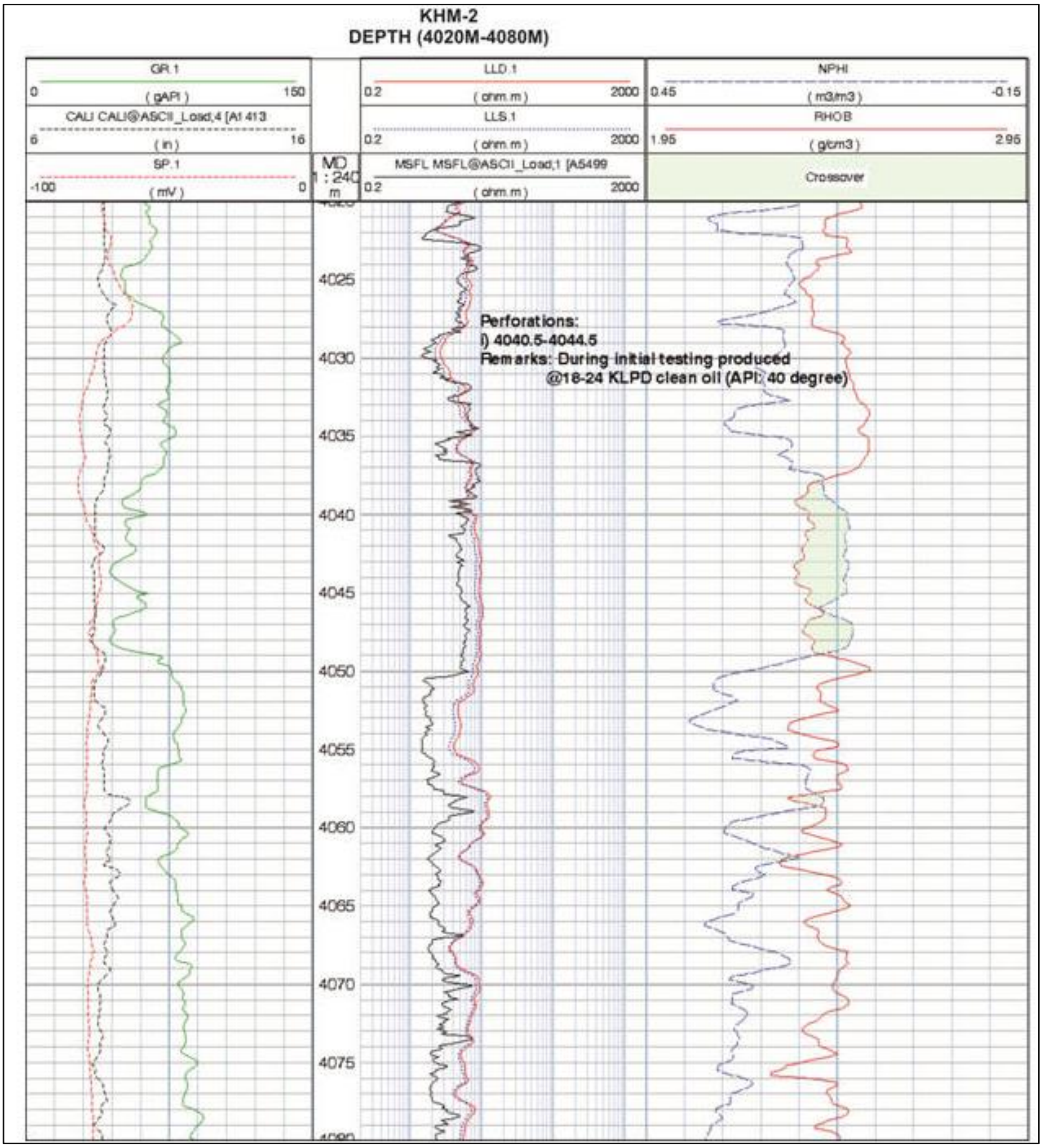


Figure 4-126 :. WELL LOG MOTIF OF KHEREM-3 (4063.5-4080M):

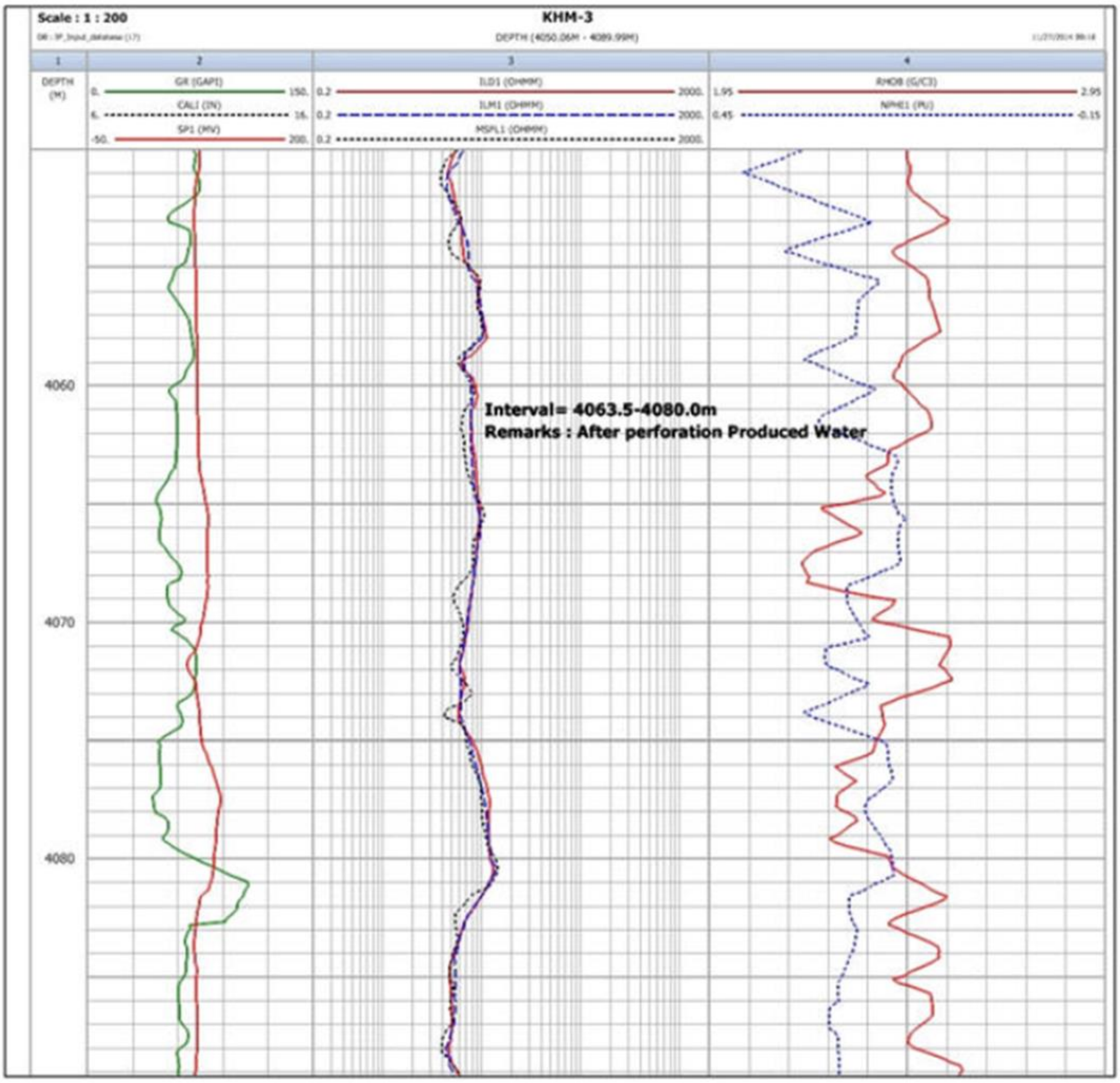
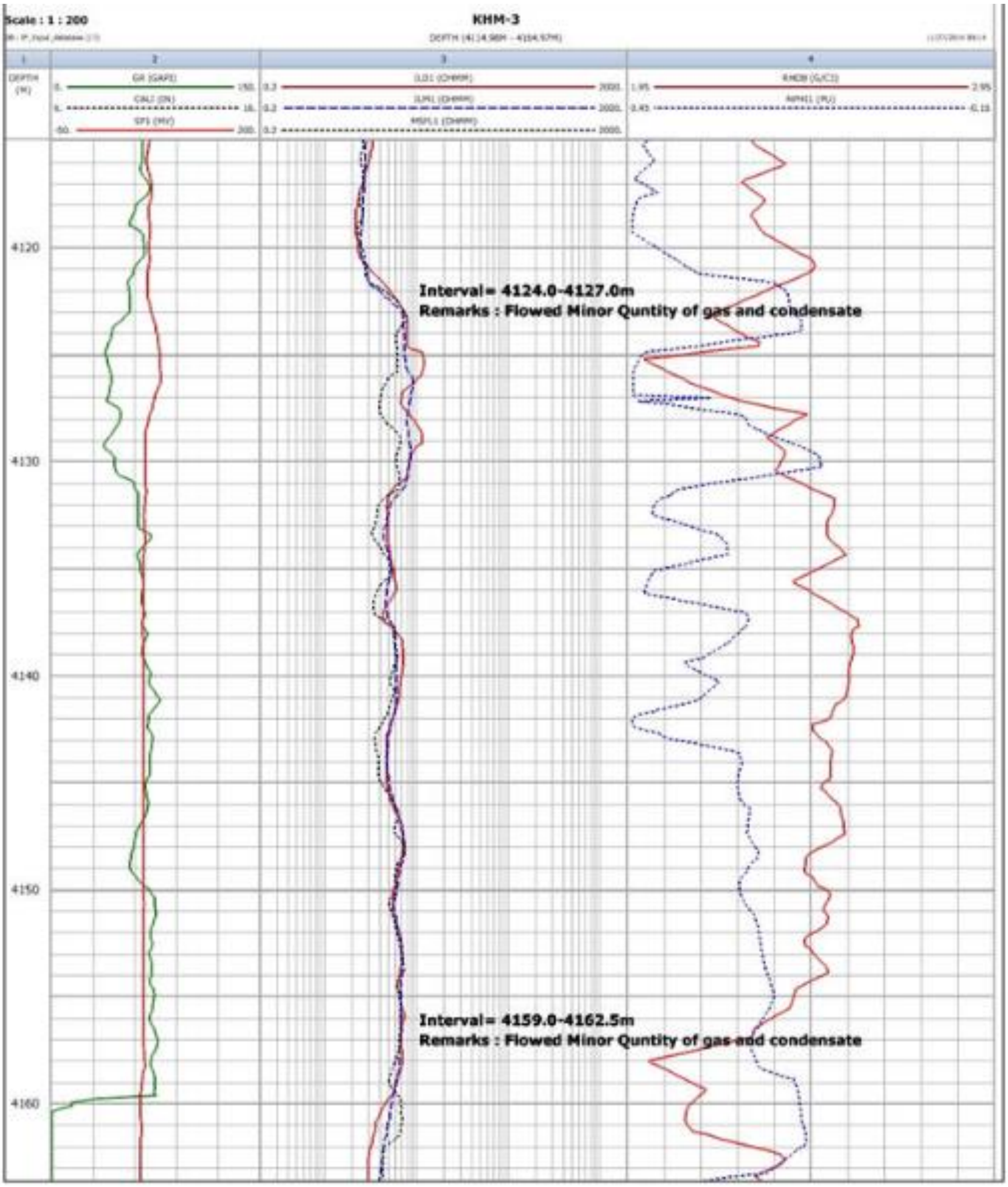


Figure 4-127 :. WELL LOG MOTIF OF KHEREM-3 (4124-4127M):



4.6.3 Well testing and workover history

Well Kherem-1:

Well Kherem-1 was drilled up to 4282m but could not be completed due to complicated downhole problems consisting of a 1303 m Fish containing BHA and drill pipe left in the hole. Prospect below 4000 m could not be tested due to a Cement plug placed above the fish top. Only one object at 2729 m Girujan Sand was tested, which gave inflow of formation water (Salinity of 300 ppm). The well was abandoned due to Fish.

Well Kherem-2:

The well was completed in 'B' hole at 4095 m with 5.1/2" oil string casing shoe at 4088.8 m after abandoning 'A' hole at 4602 due to stuck drill string. Initially, the 4037-m Girujan Sand was tested through perforations in the range 4040.5-4044.5 m in salt solution during January 1994. The well produced clean oil at the rate of **18 - 26 KLPD** (API 40°) with minor water and varying GOR of 2000 to 11000 cum/kl. The well ceased to flow on 05.03.94 due to the ingression of sand/clay/contaminated cement in the tubing. The well was then killed with 120 lbs/cft mud. CBL-VDL recorded showed casing damage at around 4036.5 m (above the sand top). A bridge plug was set at 4015 m to plug back the 4037 m Sand.

The 3978-m Girujan Sand was tested through the perforations in the ranges 3979.5-3981.5 m, 3982.5-3985.5 m, and 3988.0-3992.0 m in 90 lbs/cft mud in April '94. The sand gave inflow of mainly water, including 1 kl of floating oil (API 39.8°). Production of water from this sand was contrary to expectation and was considered to be from the Lower Sand (4007-m Sand). CBL-VDL indicates poor cement bonding with formation. Based on CBL-VDL and CCL logs, another bridge plug was set at 3997 m in order to plug back the possible casing leak.

Following setting of the plug the well produced mainly formation water with floating oil and solids during well testing from 07.05.94 - 11.05.94. Thereafter, production behavior improved and the well started producing at the average rate of 28 KLPD (oil - 68%) through 3.5 mm bean with FTHP of 155-211 kg/sq.cm and in range of **30 - 40 m3/d (Oil** 60% of 39.4° API, Water 40%) through 2.5 mm bean with FTHP of 154.9 kg/cm².

Due to lack of infrastructural facilities to produce on a regular basis, the well was killed with 100 lbs/cft mud for safety considerations during a workover carried out in April 2004.

Well Kherem-3:

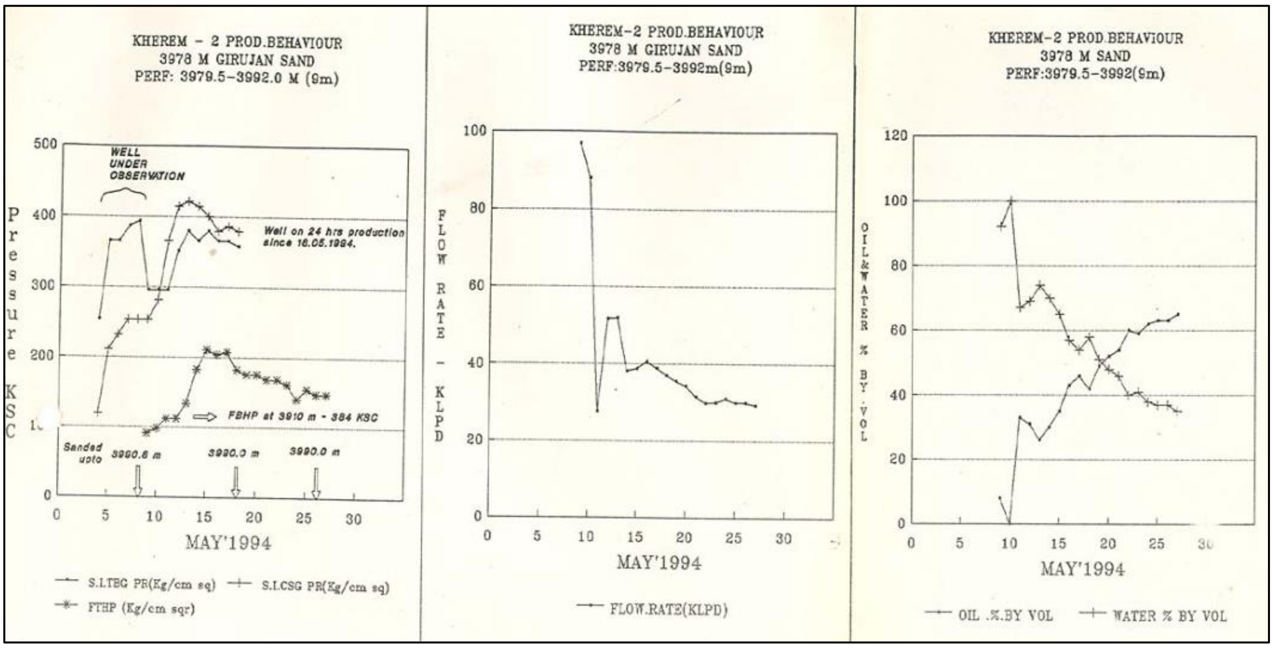
In well Kherem-3, during prolonged testing of 4207 m Girujan sand in June-July 95, the well produced intermittently condensate (44.8 Deg. API) and little amount of gas. Plugged back 4207 m Girujan sand to test higher up 4159 & 4123 m sands. During testing of 4159 & 4123 m sands, the well displaced a small amount of gas and condensate. Hence, plugged back. On testing the 4063 m sand, it produced only water. As the hole size against the higher up sand ranges is very large and the co-relatable (depth-wise) sand ranges have been tested in well Kherem-2, it was decided not to test the higher up sand ranges. Hence, the well was plugged back and kept closed.

The detailed production testing results of the wells of the Kherem block are given in the following **Table 4-86**. Production behaviour during Kherem-2 testing is shown in **Figure 4-128**.

Table 4-86: PRODUCTION TESTING DATA OF KHEREM WELLS

Well No.	DATE	PER.TOP	PER.BOT	REMARKS
KHEREM-1				
KHEREM-1	19-May-92	2730	2733	Abandoned well. Prospects below 4000 m could not be tested due to complicated downhole problems.
KHEREM-2				
KHEREM-2	11-Jan-94	4040.5	4044.5	Produced at the rate of 18-26 klpd clean oil (API 40 deg.) during testing and then ceased to flow due to the ingress of sands / clay / contaminated cement owing to casing damage at 4036.5 m just above the sand.
KHEREM-2	07-Apr-94	3979.5	3981.5	On perforating the sand produced @ 28 KLPD (68% Oil) through 3.5 mm bean with FTHP of 155-211 kg/sq.cm. Subsequently, the well was killed partially with 70lbs/cft. CaCl2(to control pressure for smooth rig down operation) due to lack of infrastructural facilities to produce on regular basis.
KHEREM-2	07-Apr-94	3982.5	3985.5	
KHEREM-2	07-Apr-94	3988	3992	
KHEREM-3				
KHEREM-3	29-Jun-95	4209	4214	During prolonged testing in June-July;95, the well produced **condensate (44.8 Deg. API) intermittently and little amount of gas.**
KHEREM-3	28-Jul-95	4159	4162	During prolonged testing of 4159 & 4123 m sands, the well displaced **little amount of gas and condensate**
KHEREM-3	30-Jul-95	4159.5	4162.5	
KHEREM-3	12-Aug-95	4124	4127	
KHEREM-3	05-Aug-95	4159	4162	
KHEREM-3	22-Aug-95	4107	4110	
KHEREM-3	30-Aug-95	4075	4078	
KHEREM-3	02-Sep-95	4063.5	4066.5	
KHEREM-3	05-Sep-95	4077	4080	
KHEREM-3	05-Sep-95	4064	4067	

Figure 4-128 :. PRODUCTION BEHAVIOUR OF KHEREM-2 IN GIRUJAN SAND



4.6.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

The shut-in bottom hole pressure data recorded in the well are given below **Table 4-87.** Oil and Gas sample analysis results are given in **Table 4-88, Table 4-89, Table 4-90 and Table 4-91**.

No PVT was carried out in Kherem-2.

No oil/gas has been produced from the field (Commercial Production has not commenced). No Workover job has been carried out in the drilled wells.

Table 4-87: SBHP DATA OF THE WELLS OF KHEREM BLOCK

Well No.	Recording Date	Measured Depth (m)	Pressure at Measured Depth (kg/cm2)
KHM-2 (4037m sand)	12-Jan-94	3881.9	656.4
KHM-2 (3977 m Sand)	31-May-94	3918.4	553.3
KHM-3	30-Jun-95	4005.9	654.6

Table 4-88: OIL ANALYSIS OF SURFACE OIL COLLECTED FROM KHEREM-2

Fluid Analysis Oil	**Kherem-2**
Crude Oil Date Collection	**8.4.1994**
Water (%)	**30.0**
Tests on dry sample	
Specific Gravity at 60°	0.8313
API Gravity (°)	38.7
Pour Point (°)	30.0
% Distilled under 180°C	37.0
Scotch set point of residue	45.0
Correlation Index	31.4
Characterization Factor	11.7

NOTE: Detailed study of the gas samples collected at the time of well kick at 3981 m (in A-hole) has been analysed, and the results are tabulated below

Table 4-89: GAS COMPOSITION OF TUBING HEAD SAMPLES OF KHEREM-2

Kherem-2 Gas Composition of Tubing Head Samples			
Source	**Tubing head**	**Well head**	**Tubing head**
Date	18.1.1994	18.1.1994	19.1.1994
Time	11.30 hrs.	1400 hrs.	03.18 hrs.
	% Volume		
Methane	86.634	86.844	86.586
Ethane	7.935	8.078	7.749
Propane	2.986	3.091	2.934
i-Butane	0.563	0.573	0.573
n-Butane	0.637	0.784	0.767
Pentane	0.211	0.283	0.344
Hexane	-	0.125	0.17
Nitrogen	1.034	0.127	0.869
Carbon dioxide	-	-	-
Gas gravity (Calculated)	0.649	0.654	0.655
Gas gravity (measured)	-	0.649	-
Gross Calorific value (Calculated)	10213.9	10410.9	10333.9
Net Calorific value (Calculated)	9237.5	9418.8	9348.9

Table 4-90: GAS COMPOSITION OF BOTTOMS UP SAMPLES OF KHEREM-2

Kherem-2 A-hole: Results of Gas Analysis													
Date	**Depth (m)**	**Source of collection**	**Component percentage**										**Gas Gravity (calculated)**
			N2	**C_1**	**C_2**	**C_3**	**iC_4**	**nC_4**	**iC_5**	**nC_5**	**C_{6+}**	**CO2**	**With N2**
9.6.1993	3981	Bottoms up	94.940	4.461	0.322	0.077	0.014	-	-	-	-	0.186	0.951
9.6.1993	3981	Bottoms up	95.185	3.977	0.352	0.083	0.014	-	-	-	-	0.389	0.954
9.6.1993	3982	Bottoms up	26.472	61.191	6.280	2.430	0.473	0.571	0.814	0.212	0.282	1.275	0.781
			Component percentage without N_2										
			N2	**C_1**	**C_2**	**C_3**	**iC_4**	**nC_4**	**iC_5**	**nC_5**	**C_6+**	**CO2**	**Without N2**
			-	88.160	6.360	1.520	0.277	-	-	-	-	3.683	0.641
			-	82.596	7.310	1.720	0.290	-	-	-	-	8.084	0.698
			-	83.221	8.541	3.300	0.643	0.777	1.107	0.288	0.384	1.739	0.708

Table 4-91: GAS COMPOSITION ANALYSIS OF KHEREM-3

Kherem-3 Gas Analysis	
	Mole %
Date	25.7.1995
Methane	89.69
Ethane	6.27
Propane	2.03
i-Butane	0.36
n-Butane	0.45
Pentane	0.25
Hexane	0.35
Nitrogen	0.48
Carbon dioxide	0.12
Gas gravity (Calculated)	0.34
Gas gravity (measured)	

4.6.5 Geology and Reservoir Description of KHEREM Field:

The geology of the area has been comprehensively reviewed using correlations, sections, and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude, and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.6.5.1 Geological correlations, sections, and maps (KHEREM Field):

The 2D seismic interpretation revealed the presence of a broad asymmetrical anticline plunging towards the east at the Supra-thrust Girujan level, which appears to be the easternmost extension of the Digboi anticline. The axial plane of the anticline runs almost parallel to the Naga thrust. The northern limb of the anticline dips steeply (avg. dip 30-40^0) as compared to the southern limb, where dips are gentle (5-15^0).

Structurally, the area is characterized by the presence of the eastern extension of the Naga Thrust, which, however, manifests mainly in the sub-surface. The east-north-east trending thrust fault is prominent below the Dhekiajuli and divides the area into two structural blocks (segments), the southern hanging wall region and the northern foot wall blocks, which are also referred to as supra-thrust and sub-thrust, respectively. The Kherem and Kumchai fall in the supra-thrust region to the south, whereas the North Kumchai area is on the sub-thrust block to the north. Hydrocarbon has already been established in the supra-thrust block in Kumchai and Kherem areas.

The first well in the structure, i.e., Kherem well no. 1 was drilled in 1992 to the depth of 4301m in "A' hole (4146 m in “B” ho!e) had encountered a number of promising Girujan sands, especially, below 3900m that showed positive indication of the presence of hydrocarbon as per the gas reading, drill cutting/side wall core fluorescence, and wire line log evidences. Owing to fish in the hole, none of the prospective Girujan sands could be tested in the well.

The presence of producible oil in Girujans in Kharsang and Kumchai areas and indications of the presence of hydrocarbons in the well Kherem-1 have encouraged drilling of well Kherem-2, which encountered a number of prospective sand ranges within the Girujans. The Well Kherem-2 encountered around 18m of net pay, which tested oil.

The following figures illustrate the structure, distribution, and seismic character in and around the Kherem discovery:

A) Time/Depth structure maps close to the top of Tipam and Girujans, **at Figure 4-129, Figure 4-130, Figure 4-131 and Figure 4-132**

B) Isopach maps of Base Dhekiajuli to close to Tipam Top and Base Dhekiajuli to close to Girujan Top **Figure 4-133 and Figure 4-134**

C) Integrated seismic amplitude map close to Tipam top, superimposed on depth contour map of reflector close to Tipam top, and Integrated seismic amplitude map close to Girujan top, superimposed on depth contour map of reflector close to Girujan top are placed at **Figure 4-135 and Figure 4-136**

D) Synthetic seismogram of well Kherem-2 (using VSP data of Kherem-2), **Figure 4-137**

E) Seismic sections in Kherem-1 & 2 at **Figure 4-138**

Figure 4-129 :. TWT CONTOUR MAP CLOSE TO TIPAM TOP

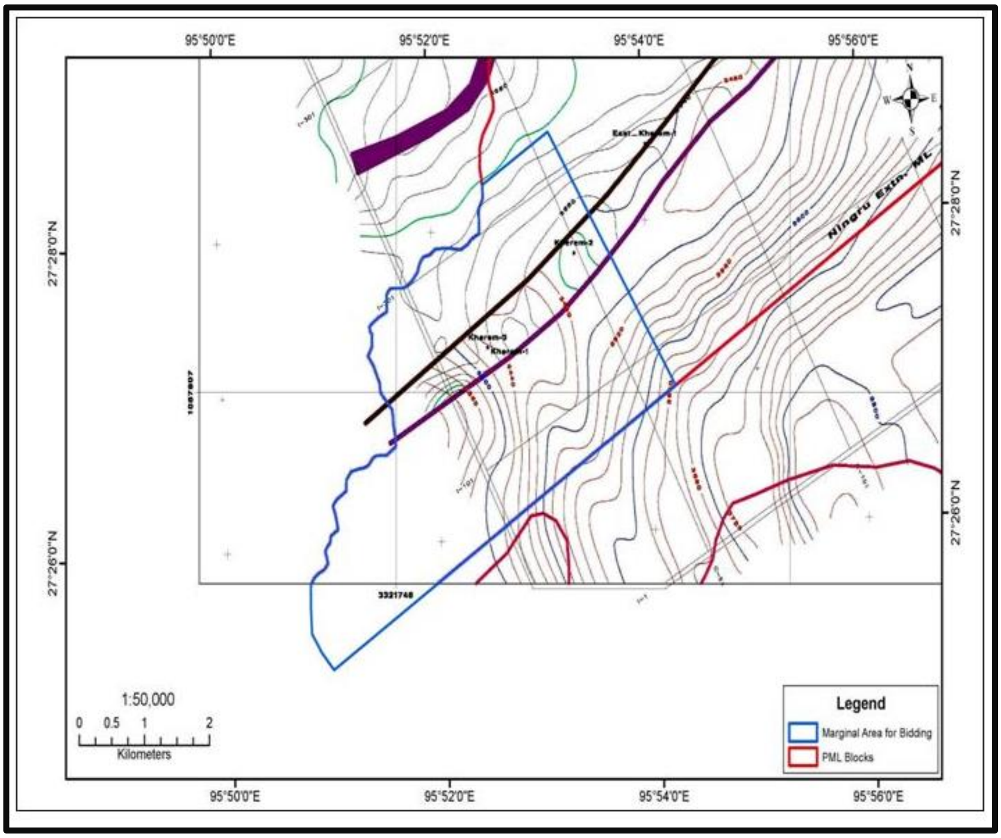


Figure 4-130 :. TWT CONTOUR MAP CLOSE TO GIRUJAN TOP

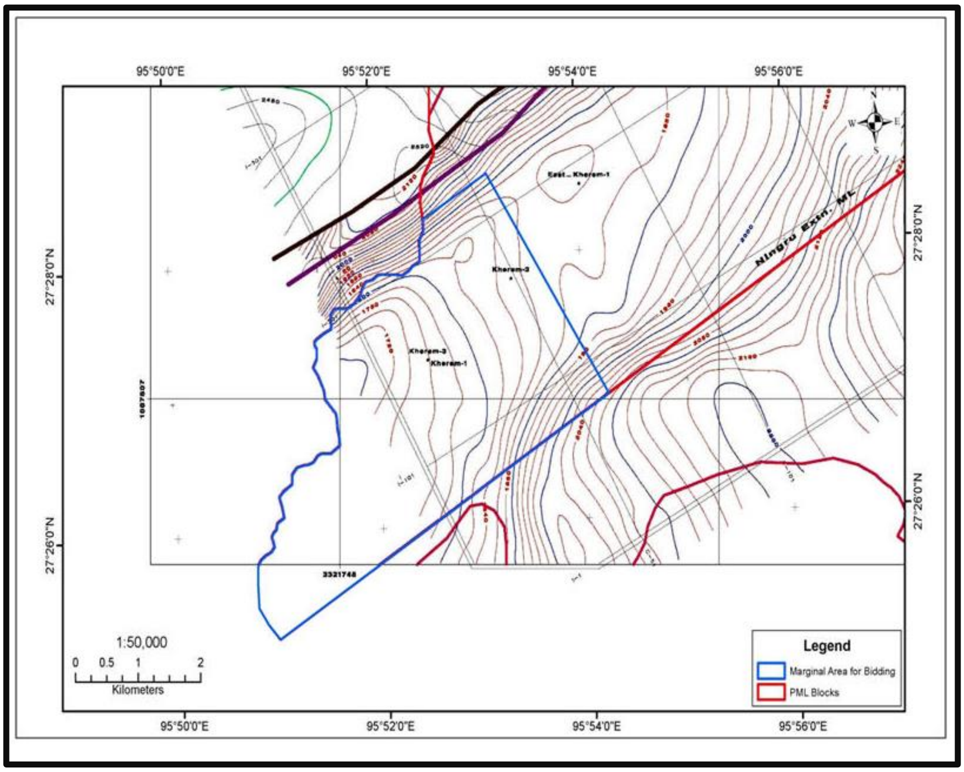


Figure 4-131 :. DEPTH CONTOUR MAP CLOSE TO TIPAM TOP

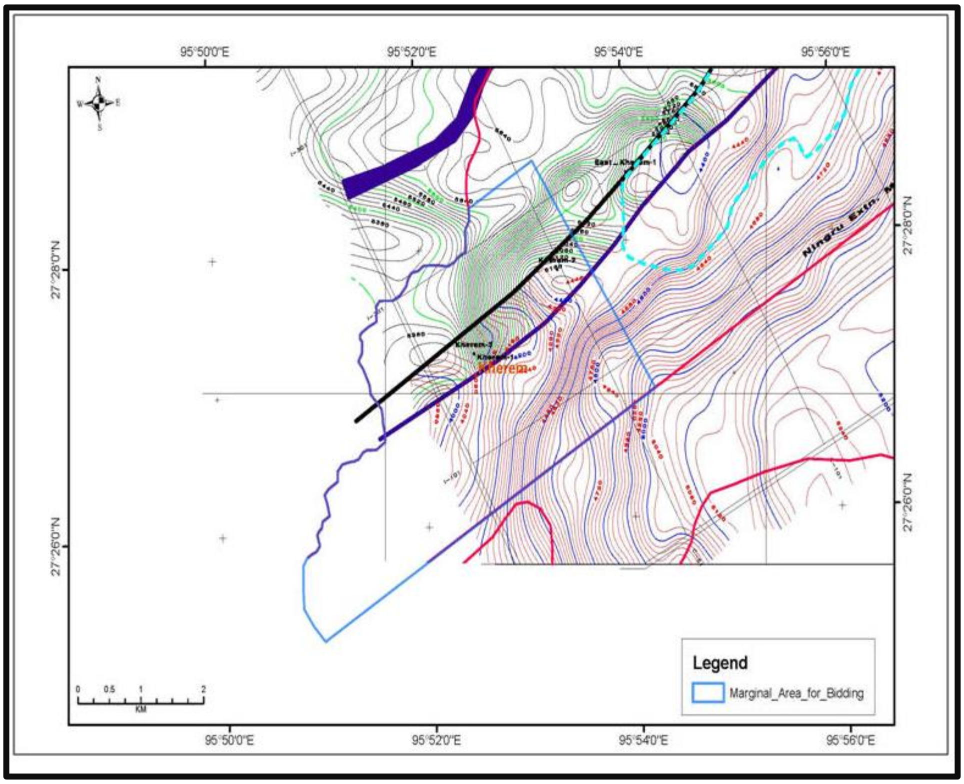


Figure 4-132 :.DEPTH CONTOUR MAP CLOSE TO GIRUJAN TOP

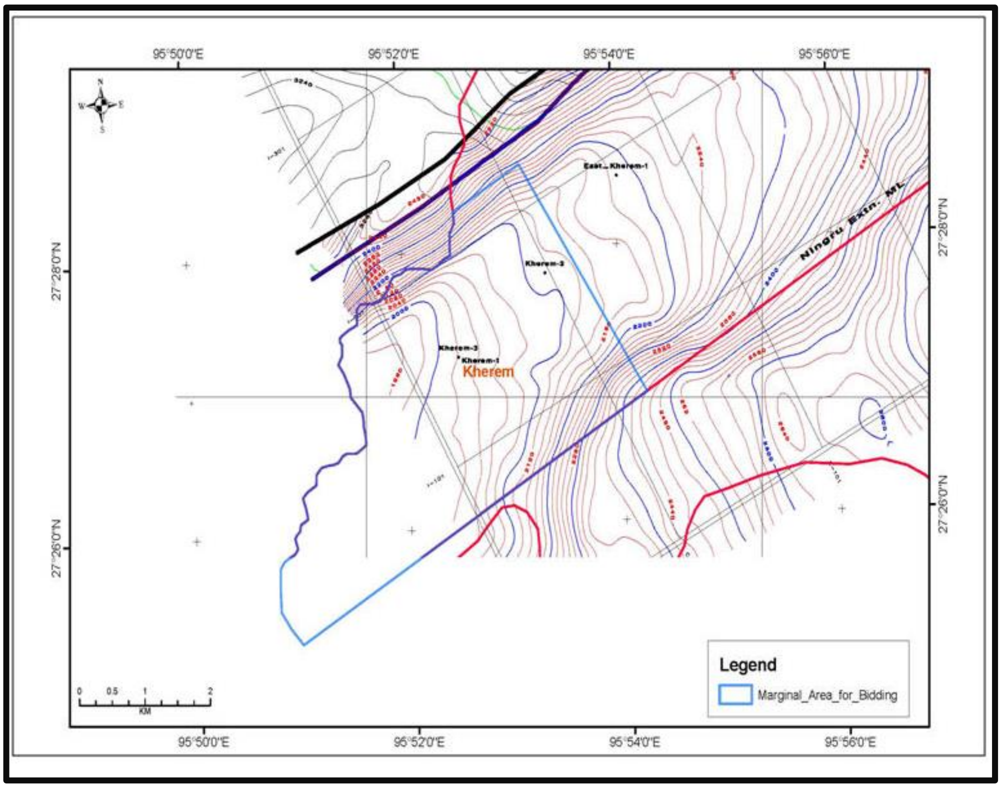


Figure 4-133 :.ISOPACH MAP OF BASE DHEKIAJULI TO CLOSE TO TIPAM TOP

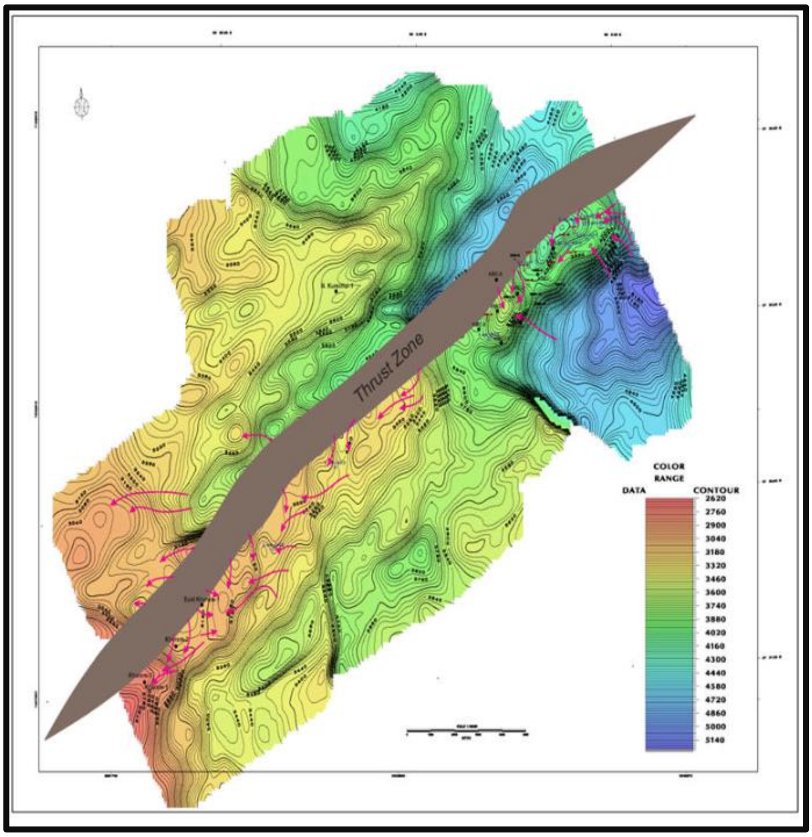


Figure 4-134 :.ISOPACH MAP OF BASE DHEKIAJULI TO CLOSE TO GIRUJAN TOP

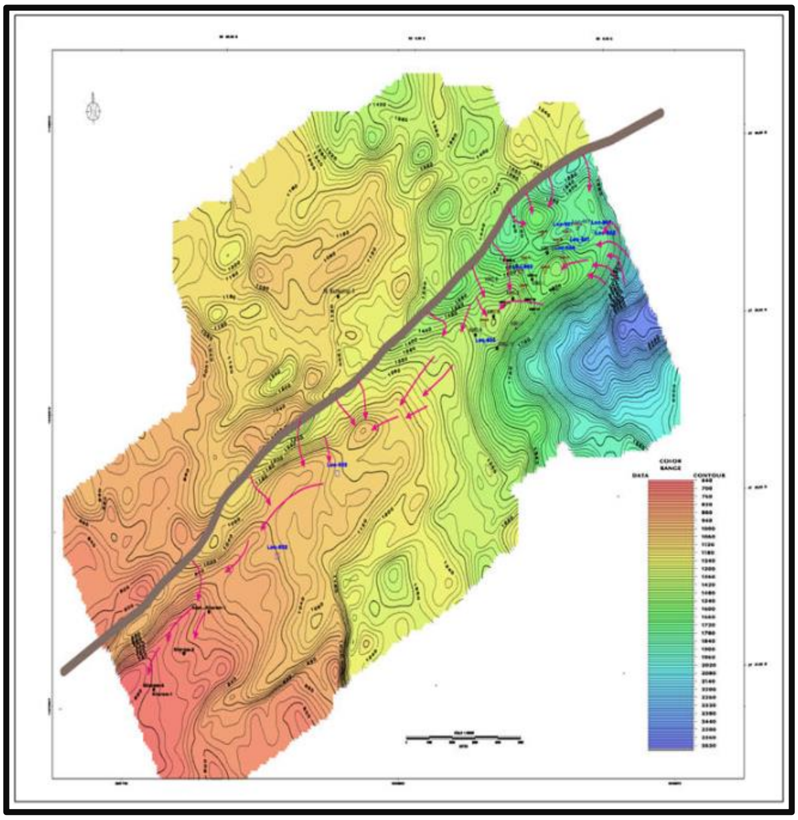


Figure 4-135 :.SEISMIC AMPLITUDE MAP CLOSE TO TIPAM TOP:

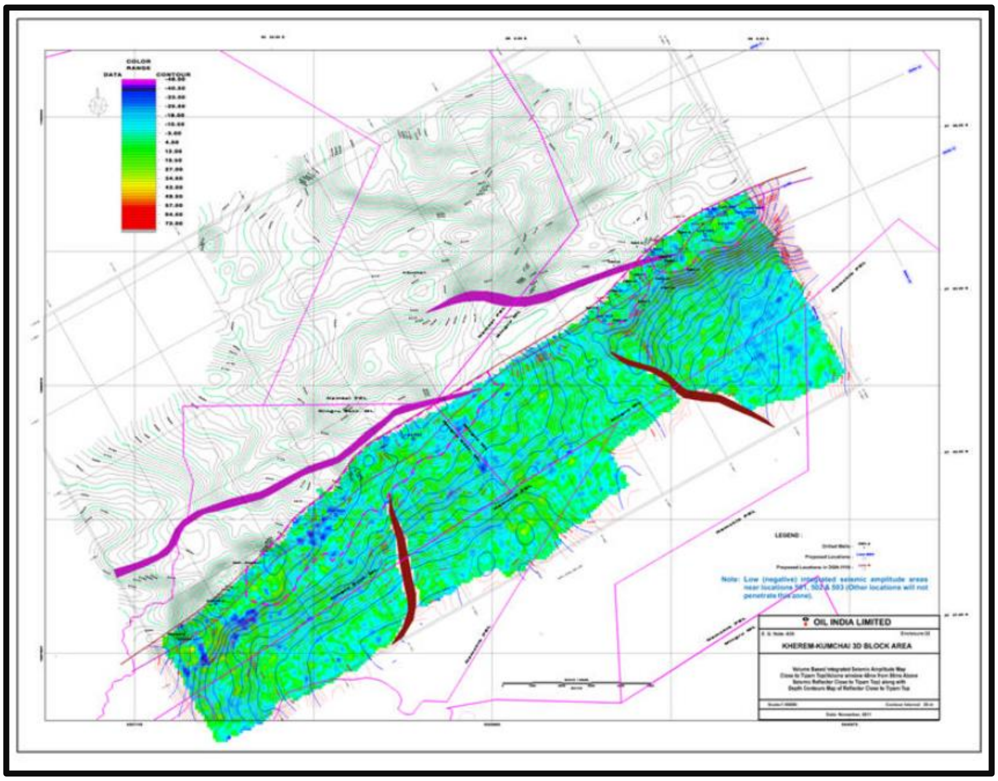


Figure 4-136 :.SEISMIC AMPLITUDE MAP CLOSE TO GIRUJAN TOP

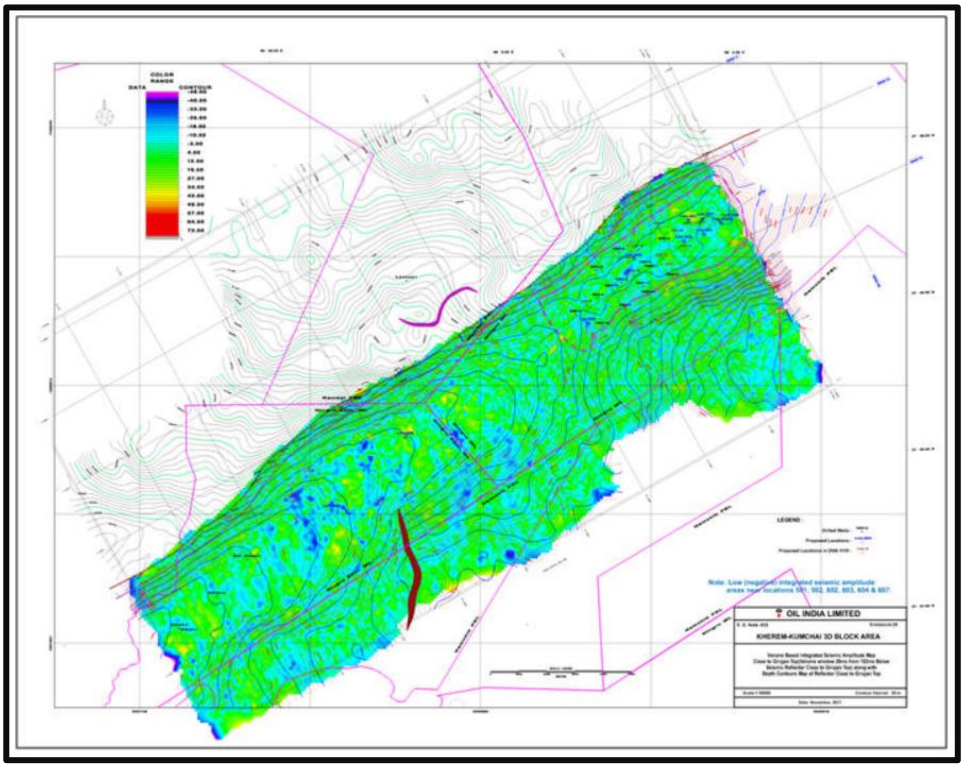


Figure 4-137 :. SYNTHETIC SEISMOGRAM OF WELL KHEREM-2

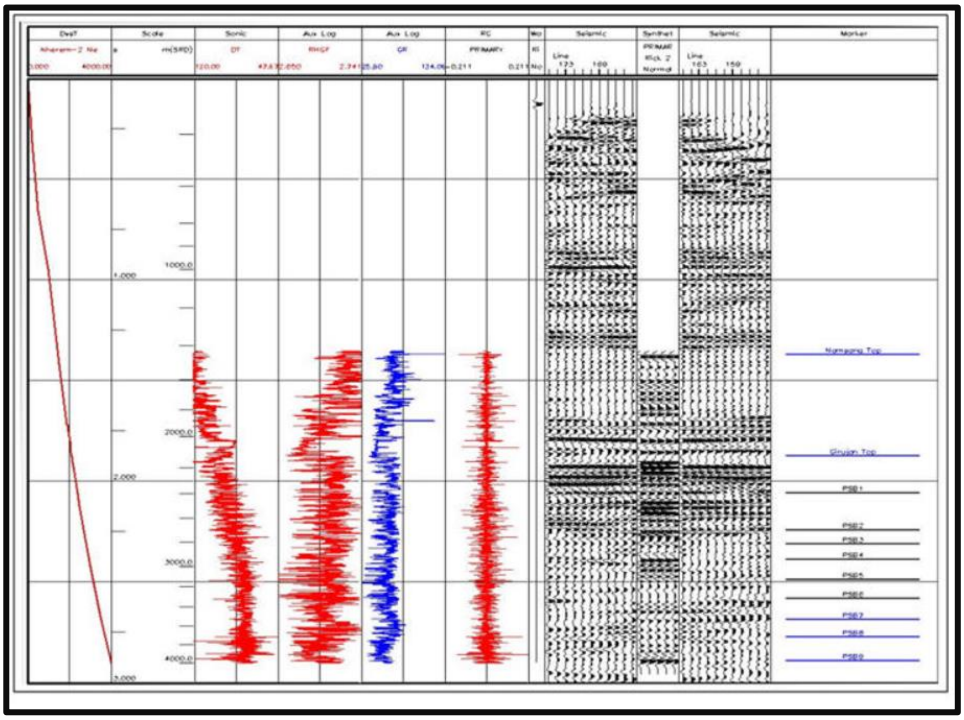
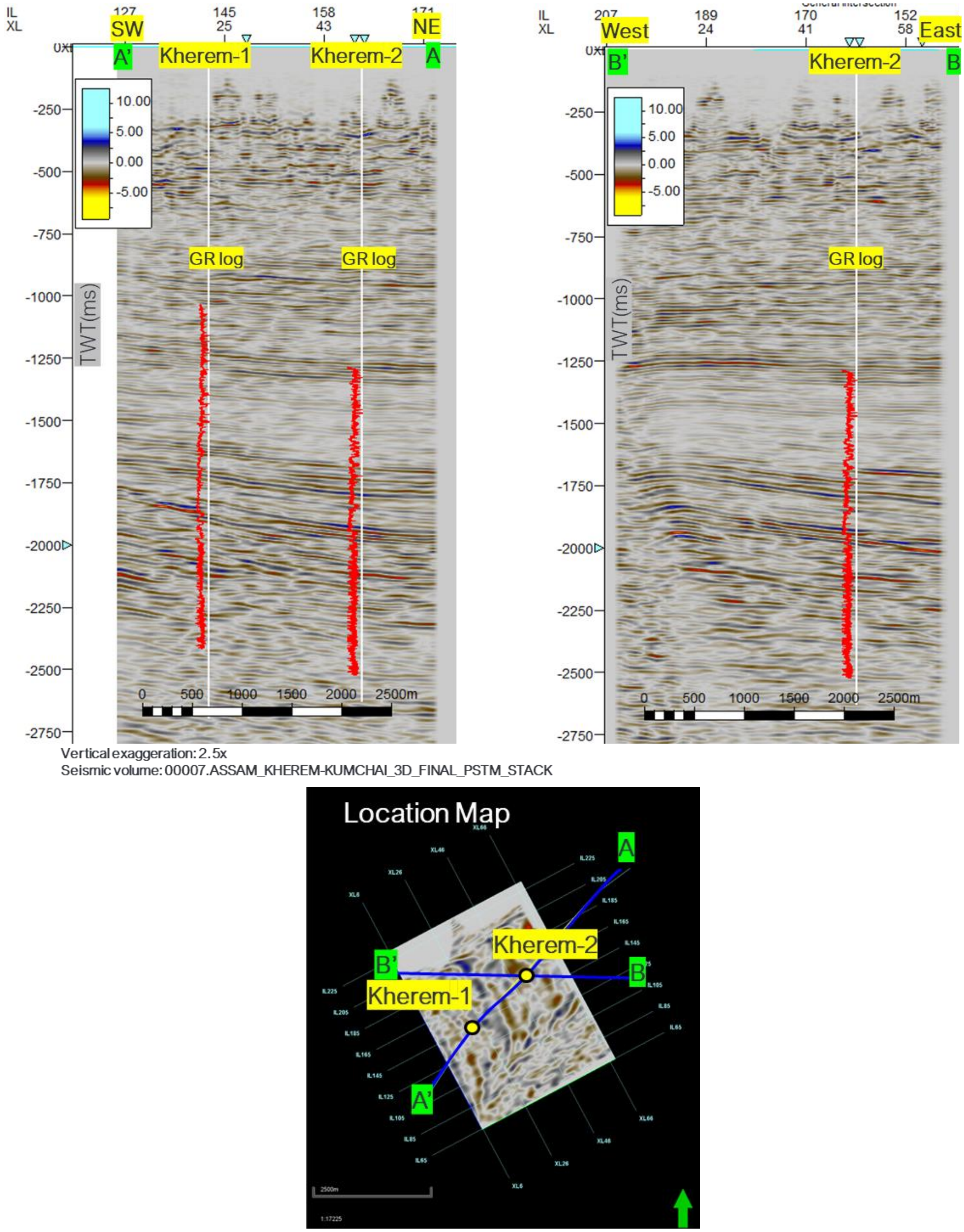


Figure 4-138 :.SEISMIC SECTIONS IN KHEREM-1 &KHEREM 2



Stratigraphic sequence encountered in Kherem wells is given in **Table 4-92**

Table 4-92: WELL WISE STRATIGRAPHY; KHEREM-1 (FORMATION TOPS ARE PROVIDED BASED ON DRILL-CUTTINGS AND CORRELATION FROM WELL KUMCHAI-1)

Formation	Top (m KB) MWD	Thickness (m)
Well Kherem-1		
Alluvium/Dhekiajuli	Surface	937.4
Namsang	945	1157
Girujan	2102	2199+
Well Kherem-2		
Alluvium/Dhekiajuli	Surface	977.38
Namsang	985	1197
Girujan	2183	2419+
Well Kherem-3:		
Alluvium/Dhekiajuli	Surface	937.4
Namsang	945	1158
Girujan	2103	2159+

4.6.5.2 Reservoir parameters and hydrocarbon estimates (KHEREM) Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

The reservoirs of the Kherem field comprise of sandstone with shale intercalations. Porosity development is good (average 14%). Oil-Water Contact not encountered. The Girujan sands have a gross pay thickness of 27m and net pay thickness of 18m. Oil reserves for Kherem-2 and Gas Volume for Kherem-3 are being estimated by fixed acreage method, hence, no isopay map has been prepared. Reservoir parameters for estimating in-place oil & gas reserves are given in **Table 4-93** and **Table 4-94** below.

Table 4-93: RESERVOIR PARAMETERS OF KHEREM FIELD

Parameters	Oil (Girujan Kherem-2)	Gas (Girujan Kherem-3)
Area, SqKm	**0.385**	**1.3279**
Thickness, m	18	10
Porosity	0.20	0.18
Shc	0.65	0.65
FVF, rm3/sm3	1.18	0.003
GOR, m3/m3	245	
Oil API, sp gr	38.7 /0.8313	
OOIP, MMstb	4.8	
GIIP, MMm3	187	518

Table 4-94: 2P HYDROCARBON IN-PLACE KHEREM FIELD

Field	O+OEG MMTOE
KHEREM	**1.34**

Erstwhile Operator-reported estimates on record:

The field, Kherem has a reported oil and gas estimate of **0.89 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.6.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Kherem field is **Bordumsa Terminal, ~ 18 Km**

The wells Kherem- 2 and 3 are fitted with well head spool. No other production facilities are available in this area. The nearest production facility available is at Bordumsa Terminal, which is 18 km from Kherem field.

AA/ONDSF/ASSAM/2025 (A&AA) TUKBAI-2 FIELD

4.7 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) TUKBAI-2 FIELD

The location TUKB -3A (side-track) in Tukbai structure, falling in Sector V-C PEL block, is located at a distance of 400m towards 342^0 from well TUKB-2. Before drilling this location, the well TUKB-3 (TKAC) was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Based on the results, the location TUKB-3(Sidetrack) was released to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 with a target depth of 900m (TVD) and planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218^0 at 811 m TVD MSL (top of gas sand). Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.

The Tukbai anticline is located in the Sector VC-PEL Block of the Cachar Fold Belt Area. The structure is situated in the north-eastern part of Cachar. It trends in NNE-SSW direction and extends into the North Cachar hills. This anticline is flanked by the Labak syncline in the west and a narrow Diksha syncline in the east. The axes of both the synclines have been faulted. The Tukbai anticline is dissected by a number of NE-SW trending cross faults. The structure is a broad SSW plunging anticline with gentle dips at the plunge part and steep dips at the core of the anticline.

Disang shale is exposed at the core of the anticline. The structure was mapped in detail with the seismic survey. Interpretation of 3D and 2D seismic data in and around the Tukbai area reveals that the structural style is largely controlled by the NNW-SSE trending reverse faults on the west and NNE-SSW trending reverse/normal faults on the east. All the faults mapped in the sub-surface can elegantly be correlated to the surface faults. A number of second-generation SW-NE trending cross faults have also been identified on different time slices.

Cachar area is part of the frontal thrust and fold belt of the Assam-Arakan geosyncline. The basin is influenced by three tectonic movements in E-W, NE-SW, and N-S directions and is represented by trends of the Dauki fault, Naga thrust belt, and Arakan fold belt. The area has a huge sedimentary cover of approximately 10-11 km. This consists of alternating sandstone, siltstone, shale, and claystone beds ranging in age from Eocene to Recent, belonging to the Disang, Barail, Surma, Tipam, and Dupitila groups. These were deposited in this sub-basin under varying environmental conditions, from marine to marginal marine to fluvial.

So far, four wells, TUKB-1/1A, 2, 3/3A & 4 were drilled on this structure.

The well **TUKB-1** was drilled in 2003 to a depth of 3701m (3711m loggers' depth) to probe the hydrocarbon potential of Bhuban, Renji, and partly Jenam Formation. Based on analysis of well data, including electro logs, lab data, etc., a thrust was envisaged in the Renji Formation at 3185m. In the up-thrust section, the well has penetrated 452 m of Bokabil, 803 m of Upper Bhuban, 1105m of Middle Bhuban, 706 m of Lower Bhuban, and 119m of Renji Formation. In the sub thrust section, 465m thickness of Lower Bhuban and 61m thickness of Renji have been encountered. The Jenam Formation is not encountered up to 3700m in this well. A number of sand bodies have developed in this well, and six objects have been identified for testing. Barring objects IV, V, and VI, which could not be tested due to complications leading to well abandonment, three objects were tested. Object: I (3587-3582 m) In Sub thrust Lower Bhuban, Object II (3175-3173 m) In Lower part of Renji Formation, Object III (3104-3100m,3095-3093m) both Up thrusts. However, all these objects were proved to be water bearing with no hydrocarbon show. Due to inordinate delay and complications in fishing of 2 7/8" tubing which fell inside the well leading to abandonment of the well TUKB-1 without testing of Object-IV (3065-3052m), Object-V (2843-2833m, 2830-2828m and 2825-2823m) and Object-VI (2413-2402m), a side-tracked well (TUKB-1A) was drilled through this well and remaining equivalent objects were tested later. As the three objects tested, viz. I, II, and III were proved to be dry, this well was declared as dry and abandoned.

The **TUKB-2** well in the Tukbai structure was drilled with an objective to explore hydrocarbon leads obtained in well TUKB-1 in Up-thrust Middle, Lower Bhuban, and Renji formations. The well was spudded on 29.03.2010 and drilled up to 2387m on 04.07.2010 against the target Depth of 3500m. It penetrated through the Bokabil formation (310m) and has penetrated Upper Bhuban (700m), Middle Bhuban (1140m), and Lower Bhuban (237m+). Target depth could not be achieved due to complications at shallow depth, followed by toppling of the rig, and further drilling of the well has been terminated. So, the hydrocarbon potential of the well could not be ascertained at the expected zones underneath. Considering the above, the well was declared abandoned with the status "Abandoned due to Complication". .

The well **TUKB-3 (TKAC)** is located at a distance of 400m towards 342^0 from well TUKB-2 and was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Therefore, it was sidetracked to TUKB-3A.

The well TUKB-3A was released as an exploratory “B” category location with an objective to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 well (at the depth of 854.5 m - 868 m). It was planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218^0 at 811 m TVD MSL (top of gas sand). Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.

The well **TUKB-4 (TKAD)** was drilled with an objective to explore the hydrocarbon potential of the Upper Bhuban formation. It was spudded on 26.04.2016 and drilled as a vertical well with a target depth of 1200m. As no zone of interest was found, the target depth was revised to 1755m to encounter sands in the Middle Bhuban Formation. During drilling, the well penetrated through Bokabil and Upper Bhuban and was terminated within the Middle Bhuban formation. Based on the log evaluation of the present well, all the sand layers developed in Bokabil, Upper Bhuban, and Middle Bhuban Formations are interpreted as water bearing. As no prospective zone could be identified from hydrocarbon point of view in all Formations, the well was abandoned without lowering the production casing.

The discovery area, Tukbai-2, is located onland within the Assam-Arakan Fold Belt (AAFB) Basin and has an offered area of 494.31 sq. km. under this DSF Bid Round IV. The area is a single area (**Figure 4-139**) with 1 discovery/field (TUKB-2), and 5 additional wells (+2 S/T). Surrounding wells of TUKB-2 are shown **Figure 4-141**

2D-3D surveyed area in Tukbai block is shown in **Figure 4-140**

The coordinates of the block boundaries are given in **Table 4-95**.

Table 4-95: COORDINATES OF THE BLOCK BOUNDARIES: TUKBAI

	Tukbai Boundary Points		
	Area: 494.31 sq km		
	Point	**Longitude**	**Latitude**
	A	92° 56′ 00.000″ E	24° 59′ 00.000″ N
	B	92° 56′ 00.000″ E	24° 58′ 00.000″ N
	C	93° 02′ 00.000″ E	24° 58′ 00.000″ N
	D	93° 02′ 00.000″ E	24° 57′ 00.000″ N
	E	93° 08′ 00.000″ E	24° 57′ 00.000″ N
	F	93° 08′ 00.000″ E	24° 50′ 00.000″ N
	G	92° 46′ 00.000″ E	24° 50′ 00.000″ N
	H	92° 46′ 00.000″ E	24° 56′ 00.000″ N
	I	92° 53′ 00.000″ E	24° 56′ 00.000″ N
	J	92° 53′ 00.000″ E	24° 59′ 00.000″ N
	A	92° 56′ 00.000″ E	24° 59′ 00.000″ N
SL No.	**Well Name**	**Longitude**	**Latitude**
1	TUKB-2	93° 04′ 57.360″ E	24° 54′ 13.695″ N

Figure 4-139 :.LOCATION MAP SHOWING THE TUKBAI BLOCK BOUNDARY.

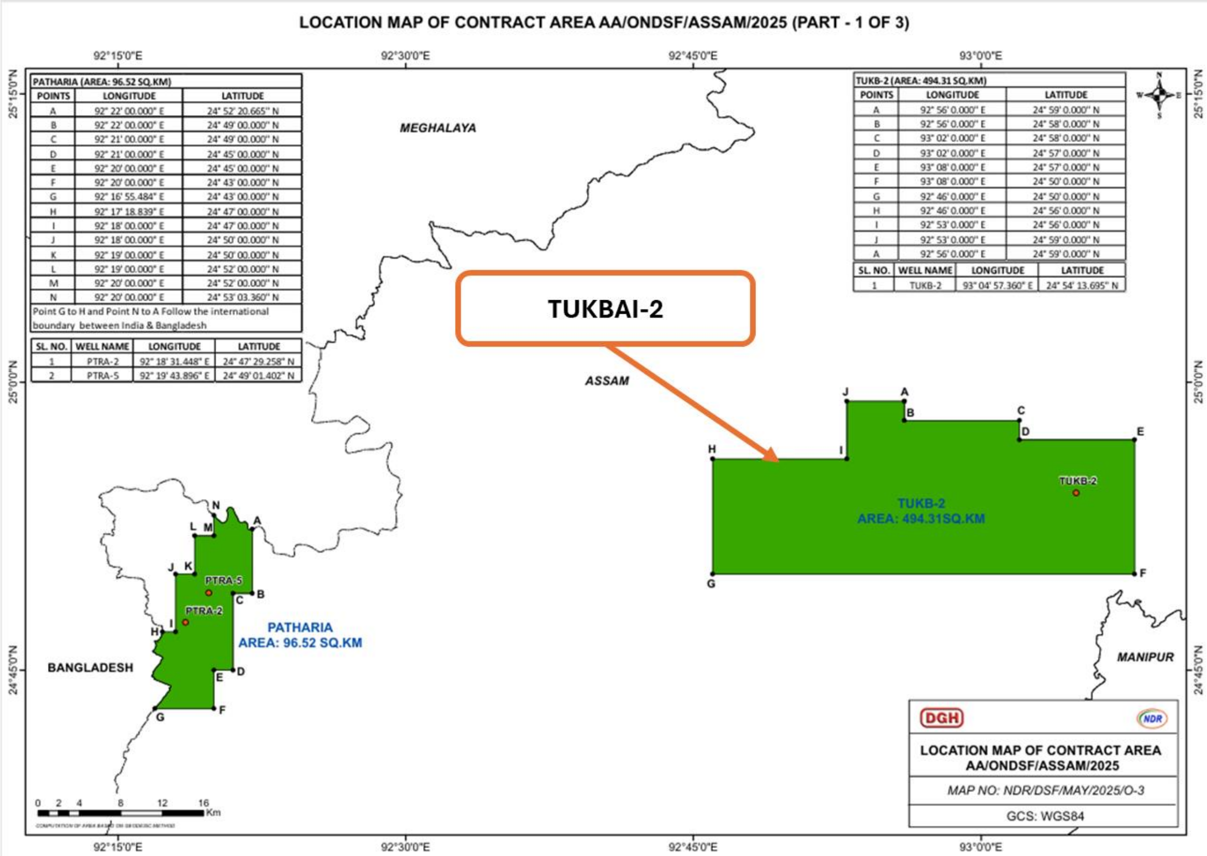


Figure 4-140 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: TUKBAI-2-

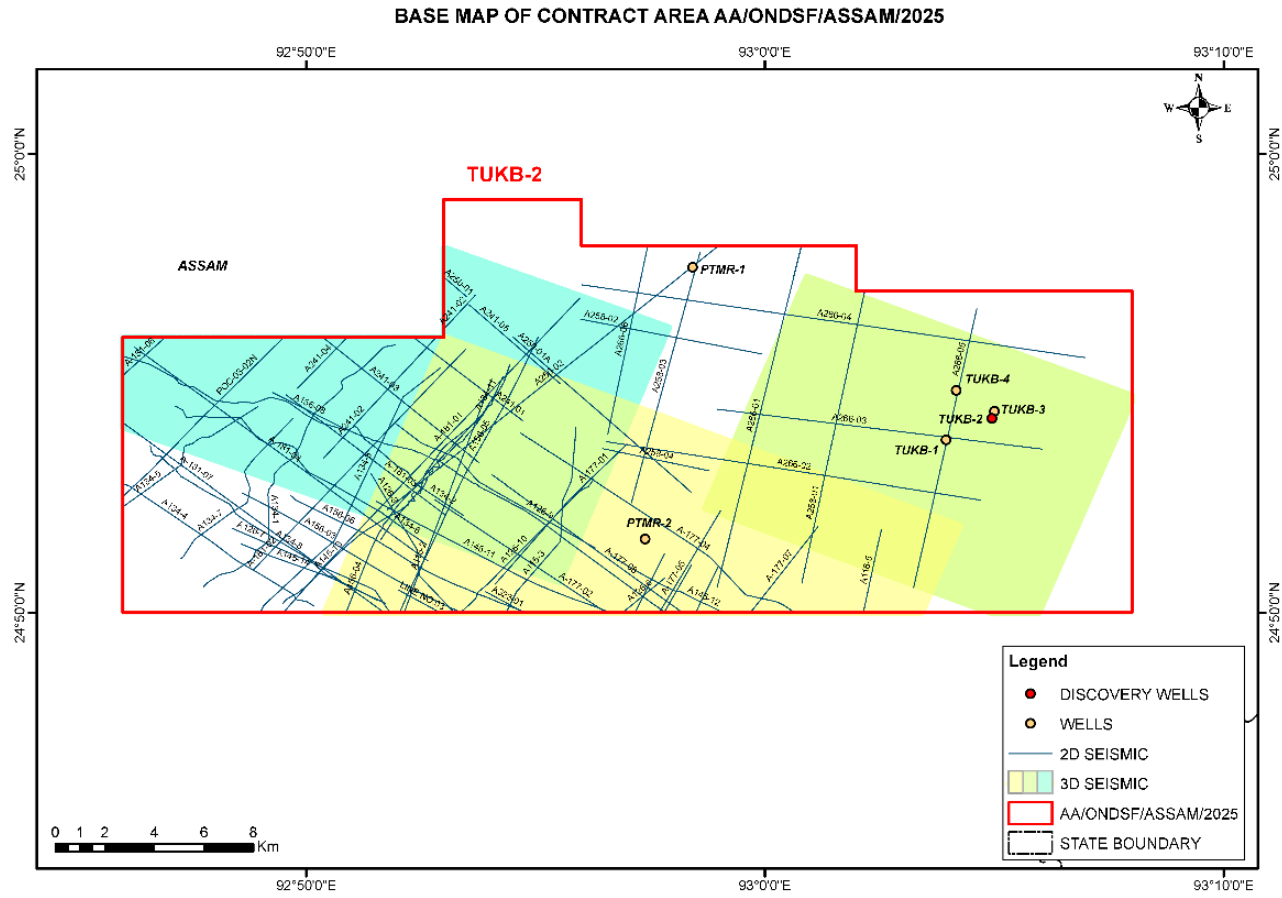
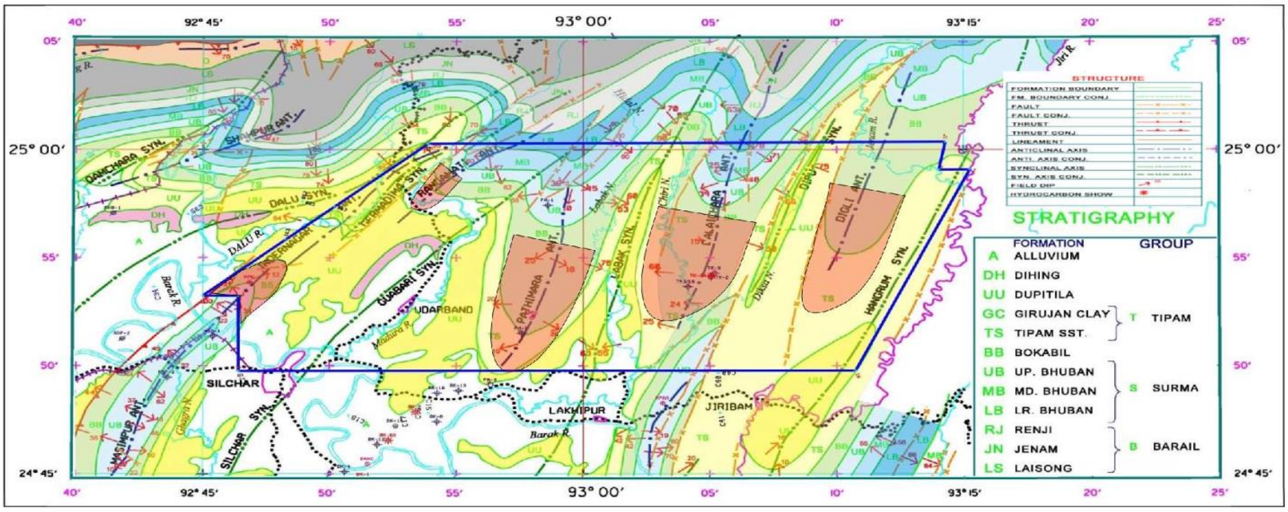


Figure 4-141 :.SURROUNDING OIL AND GAS FIELDS :



4.7.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates, are made available in Sections through various cross-references.

Figure 4-142 shows the well construction diagrams of TUKB-2 and TUKB-3A.

Figure 4-143 shows the litho section of TUKB-2

Figure 4-142 :.WELL PROFILE OF TUKB-2 (WITH LITHOLOGY) & TUKB-3A:

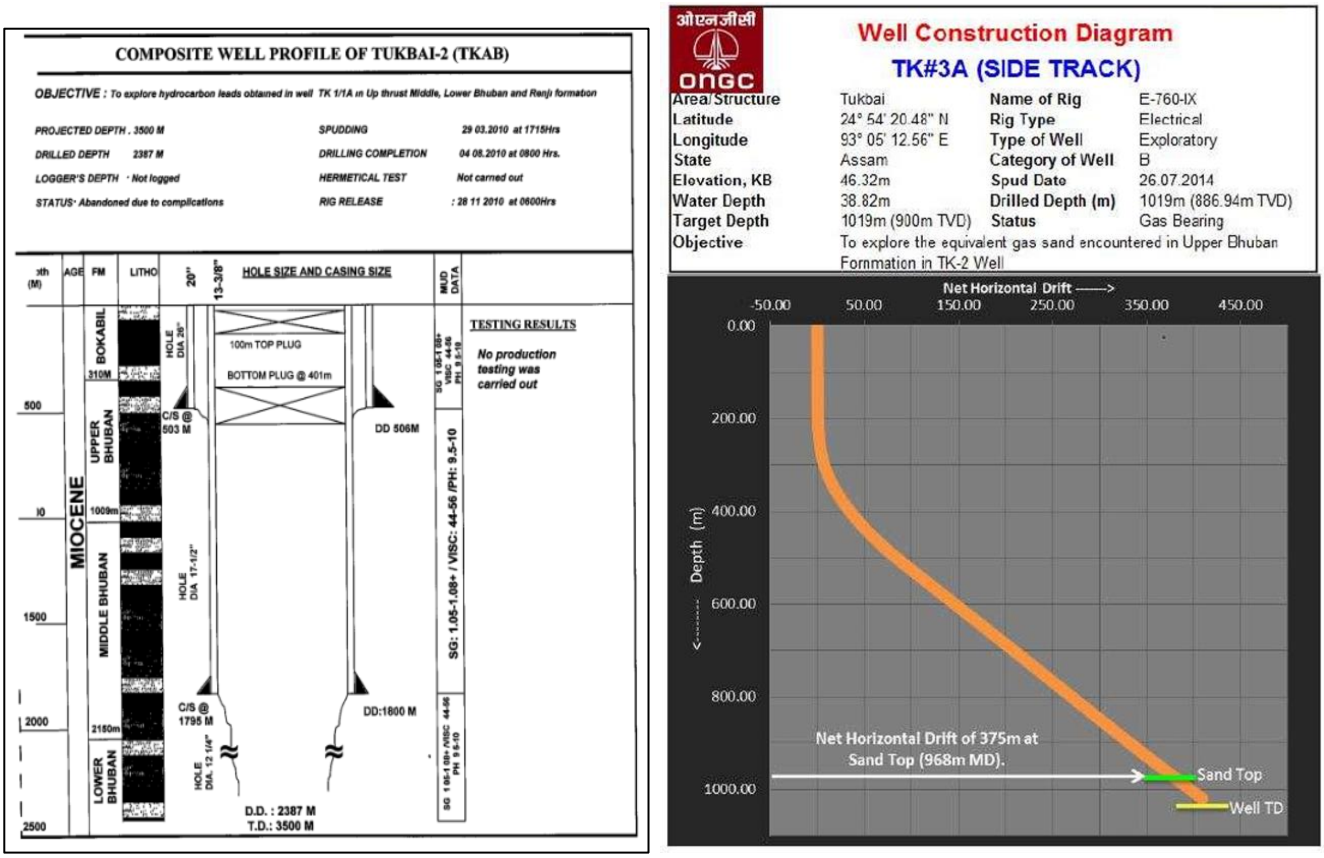
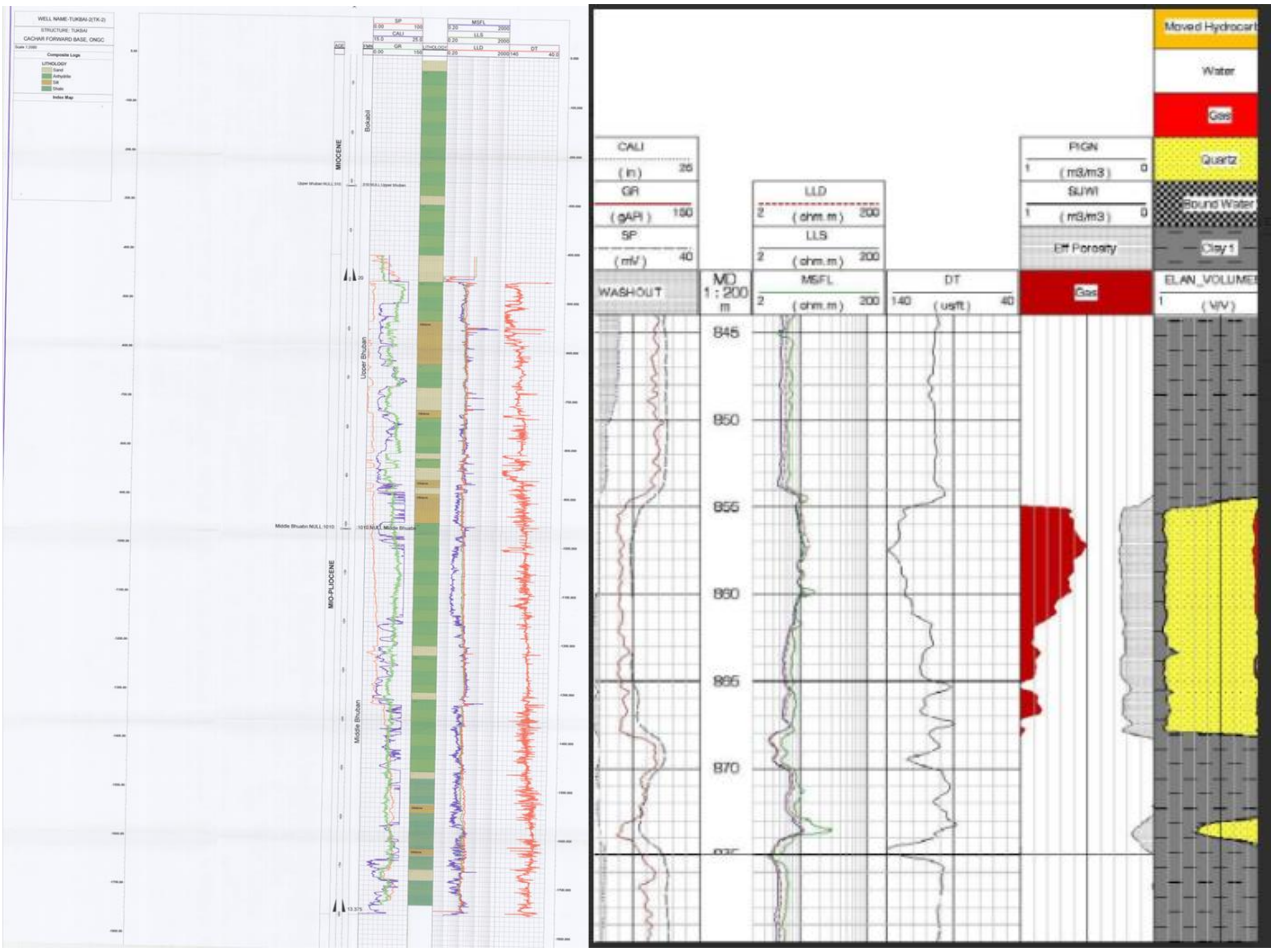


Figure 4-143 :.LITHO-SECTION INFORMATION OF TUKB-2:



4.7.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked, and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.7.2.1 Well completion and log evaluation reports availability :

Well	WCR/ FER availability	Spud date	KB	Drilled depth
TUKB-2	Both available	29.03.2010	43.15m	2387 m
TUKB-3A	Both available	26.07.2014	46.32 m	1019 m

4.7.2.2 Well logs acquired (TUKB-2, 3 & 3A) :

Well logs acquired in Tukbai field are listed in **Table 4-96.**

Conventional core details, MDT pressure tests, and samples taken during MDT are given in **Table 4-97, Table 4-98 and Table 4-99.**

Table 4-96: WELL LOGS ACQUIRED IN TUKBAI WELLS

Sl No.	Hole Size	Date of Recording	Logs Recorded	Interval (m)	Remarks
			TUKB-2		
	17 ½”	07.07.2010	SP-GR-DLL-MSFL-CAL	1797.5-502.2	**HLS**
			SONIC-GR	1797.5-502.2	
			TUKB-3		
	12 ¼”	24.04.2014	DLL-MSFL-GR-SP-CAL, LDL-CNL-GR, BHC-IDT-GR	150-499	
	8 ½”	13.05.2014	PEX-HRLS, DSI, FMI	498-998 494-1006 498.5-1005	
	8 ½”	14.05.2014	MDT	19 pretests, 6 samples	
			TUKB-3A		
1			Perforation @ 4 SPF		For cement squeeze job
2	8 ½”	08.08.2014 to 14.08.2014	**LWD logs** GR-CALL-RESISTIVITY-DENSITY-NEUTRON	218-1005	Sidetrack from 223.5m.
3	5 ½"casing	21-Aug-2014	CBL-VDL-CCL-GR @0 PSI.	990-700	
4		21-Aug-2014	CBL-VDL-CCL-GR @700 PSI.	990-800	
5			Perforation @6 SPF		Object-1

Conventional Cores:

No Conventional cores were taken in wells TUKB-2 & 3A . Details of conventional cores taken in TUKB-3 are given below (Table **4-97**):

Table 4-97: CONVENTIONAL CORES IN TUKB-3

Well: Tukbai-3 (TKAC)					
Conventional Cores					
Sl No	**Core No**	**Interval**	**Recovery**	**Gross Lithology**	**Hydrocarbon Shows**
1	CC1	814–820 m	379 cm (63.17%)	Claystone with interbedded Sandstone and minor Coal	NF/NC
2	CC2	843–850.6 m	591.1 cm (77.78%)	Claystone with Sandstone intercalations	NF/NC

Sidewall Cores:
No SWC attempted in TUKB-2, 3 & 3A.

SFT/MDT
MDT was not carried out in TUKB-2 & 3A. Details of MDT recorded in TUKB-3 are as given below (**Table 4-98 and Table 4-99**).

Table 4-98: MDT IN TUKB-3

Pretest / Sample Inspection Sheet — **TABLE-IV**

Field	Tukbai	Tukbai	Date(s) of Logging	14-May-14
Well	TKAC		Logging Interval	
Toolstring	LEH-EDTC-EDTA-PC-MS_1-SC_2-SC_1-LFA-PO-PS_1-HY_1--BN		Run	MDT-LFA-GR
Engineer	Shubhang/Phani		Witness	MR Vijay Singh
Mud	KCL PHPA POLYOL		Client	ONGC
Rig	E-760-IX		Files forwarded to Resv Engg.	Ankit Agarwal

Remarks	CQG used for all pressure measurements							Pretest Codes:				
	Total:	19	G=Good	15		D=Dry	1		L=Lost Seal	3	S=Super-charged	0	Not Attempted

Pretest	File	MD (m)	TVD (m)	Res. Cell Temp (DegF)	Mud Pressure (psi)		Equivalent MP in ppg	Last BUP (psia)	Formation Pressure (psia)	Equivalent FP in ppg	Mob.	Pretest Type	Pretest Rate (cc/min)	Pretest Volume (cc)	Pretest Code	Remarks (Please mention all the details including anomolous events)
					Before	After										
Main Pretests																
1	3	648.50	648.50	108.1	1039.0	1039.4	9.4	938.8	938.8	8.5	109.1	Volumetric Drawdown	60,60,60	5,5,5	G	
2	4	650.50	650.50	108.2	1042.6	1042.5	9.4	942.2	942.2	8.5	96.9	Volumetric Drawdown	60,60	10,5	G	
3	5	671.70	671.70	108.3	1076.4	1076.4	9.4	971.7	971.7	8.5	43.0	Volumetric Drawdown	60,60	10,5	G	
4	6	673.70	673.70	108.3	1079.3	1079.3	9.4	974.5	974.5	8.5	133.4	Volumetric Drawdown	60,60,60	10,5,5	G	
5	8	663.00	663.00	109.0	1060.2	1061.5	9.4	959.3	959.3	8.5	64.8	Volumetric Drawdown	60,30,30	10,5,5	G	
6	9	661.80	661.80	109.3	1058.3	1058.4	9.4	1057.8	-	-	-	Volumetric Drawdown	30,60	5,5	L	
7	10	664.00	664.00	109.3	1061.7	1061.7	9.4	1061.6	-	-	-	Volumetric Drawdown	60,30	10,5	L	
8	12	661.60	661.60	108.3	1056.1	1056.0	9.4	1055.8	-	-	-	Volumetric Drawdown	60,30	10,5	L	
9	13	666.50	666.50	108.7	1063.8	1063.6	9.4	964.5	964.5	8.5	47.8	Volumetric Drawdown	60,30	10,5	G	
10	14	898.00	898.00	109.6	1435.2	1435.3	9.4	1305.6	1305.6	8.5	10.7	Volumetric Drawdown	60,30	10,5	G	
11	15	902.00	902.00	116.4	1438.9	1438.7	9.4	1310.9	1310.9	8.5	7.5	Volumetric Drawdown	60,30	10,5	G	
12	16	903.50	903.50	116.0	1440.8	1439.8	9.4	1404.7	-	-	4.9	Volumetric Drawdown	60,30	10,5	D	
13	17	899.20	899.20	116.2	1432.2	1432.4	9.3	1308.1	1308.1	8.5	5.8	Volumetric Drawdown	30,30	5,5	G	
14	19	700.20	700.20	109.4	1108.1	1108.0	9.3	1012.0	1012.0	8.5	88.6	Volumetric Drawdown	60,60	10,5	G	
15	20	694.50	694.50	110.0	1098.3	1098.4	9.3	1004.0	1004.0	8.5	40.2	Volumetric Drawdown	60,60	10,5	G	
16	21	610.50	610.50	110.3	961.2	961.3	9.2	885.1	885.1	8.5	91.7	Volumetric Drawdown	60,60	10,10	G	
17	22	607.50	607.50	108.8	955.9	955.9	9.2	880.8	880.8	8.5	27.7	Volumetric Drawdown	60,60	10,10	G	
18	25	544.70	544.70	104.8	849.6	849.4	9.1	786.5	786.5	8.5	156.5	Volumetric Drawdown	60,60	10,10	G	
19	26	535.50	535.50	105.4	834.3	834.7	9.1	773.4	773.4	8.5	75.4	Volumetric Drawdown	60,60	10,5	G	

Table 4-99: MDT SAMPLES IN TUKB-3

Well: Tukbai-3 (TKAC) MDT Sample Data						
Sl. No.	**Depth (m)**	**Resistivity**	**Temp**	**Sal**	**pH**	**Volume Collected (ml)**
1	698.5	0.444 Ωm	77.5°F	12288	9	450
2	672.5	0.832 Ωm	77.5°F	7605	9	450
3	664	0.414 Ωm	77.5°F	14625	9	450
4	646.5	0.485 Ωm	77.8°F	12870	9	450
5	606.5	0.425 Ωm	78.5°F	13455	9	450
6	548.5	0.500 Ωm	77.8°F	12820	9	450

VSP

VSP was carried out in TUKB-3 only.

4.7.2.3 Well log evaluation and initial test results:

Results of formation evaluation and Initial testing details of zones are given in the table below (**Table 4-100**).

Table 4-100: FORMATION EVALUATION AND INITIAL TESTING DETAILS (TUKB-3A)

<table>
<tr><th colspan="7">Tukbai Formation Evaluation</th></tr>
<tr><th>Interval (mMDRT/mTVDSS)</th><th>Formation
(+ Zone, if specified)</th><th>Gross(m)</th><th>Net(m)</th><th>Phi</th><th>Sw</th><th></th></tr>
<tr><td rowspan="2">391-1005 / 341-830,
(976-980 mMDRT)</td><td>Upper Bhuban</td><td>4.0</td><td>3.6</td><td>0.23</td><td>0.81</td><td></td></tr>
<tr><td colspan="6">Initial testing results: Not tested. Remarks: Water Bearing</td></tr>
<tr><td>(972.4-976 mMDRT)</td><td>Upper Bhuban</td><td>3.6</td><td>3.6</td><td>0.20</td><td>0.59</td><td></td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>(969.8-972 mMDRT)</td><td>Upper Bhuban</td><td>2.2</td><td>2.2</td><td>0.21</td><td>0.47</td><td></td></tr>
<tr><td rowspan="2">(968-969.2 mMDRT)</td><td>Upper Bhuban</td><td>1.2</td><td>1.2</td><td>0.15</td><td>0.73</td><td></td></tr>
<tr><td colspan="6">Initial testing results: On initial testing, the interval 968-972m has produced gas at the rate of 9700 m3 /day through 5mm bean (FTHP 57.26 ksc) and 13000 m3 /day through 6mm bean (FTHP52.27 ksc).</td></tr>
</table>

Log motifs of TUKB-2 and TUKB-3A are placed at **Figure 4-144 and Figure 4-145** respectively.

Figure 4-144 :.WELL LOG MOTIF OF TUKB-2 :

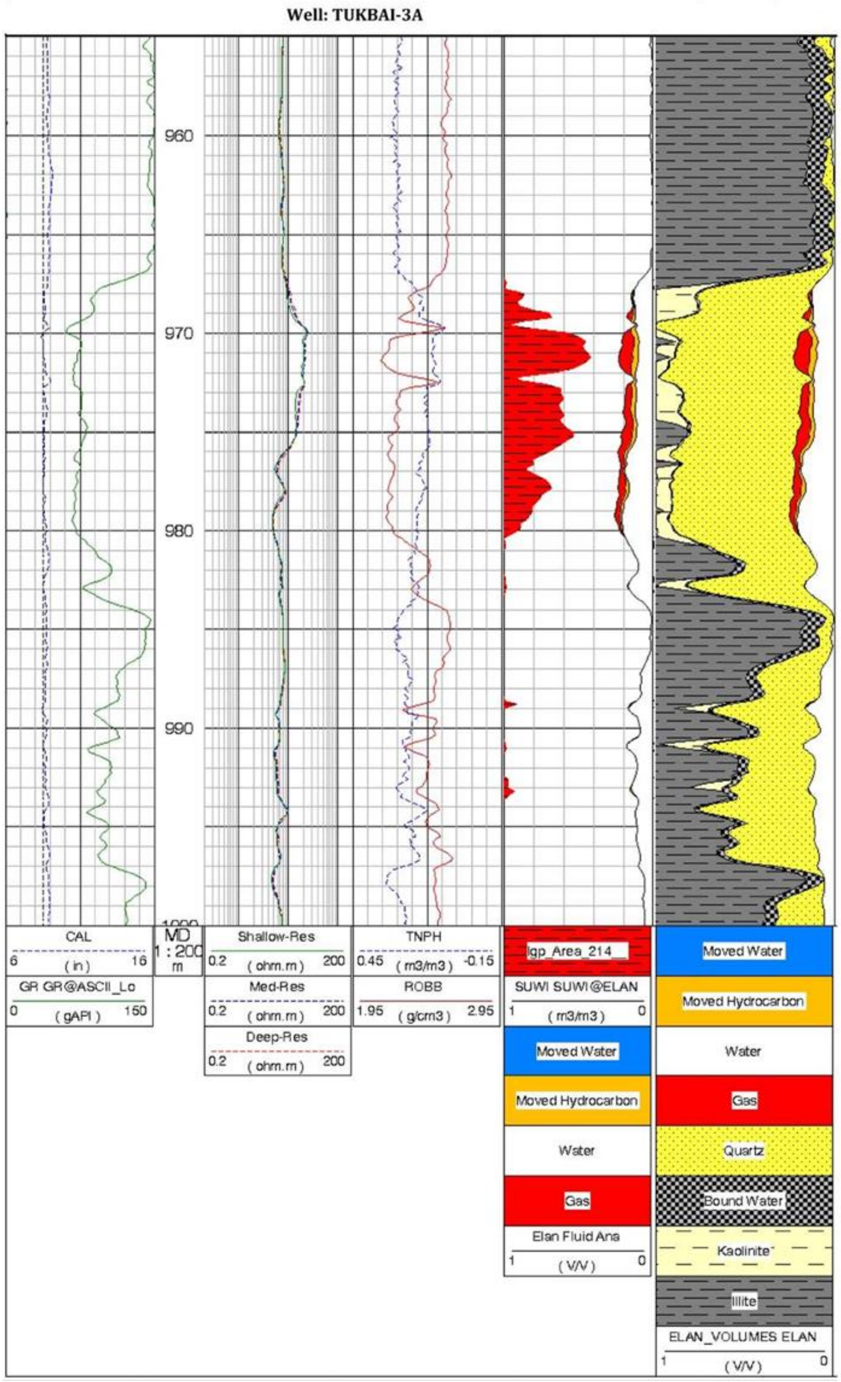
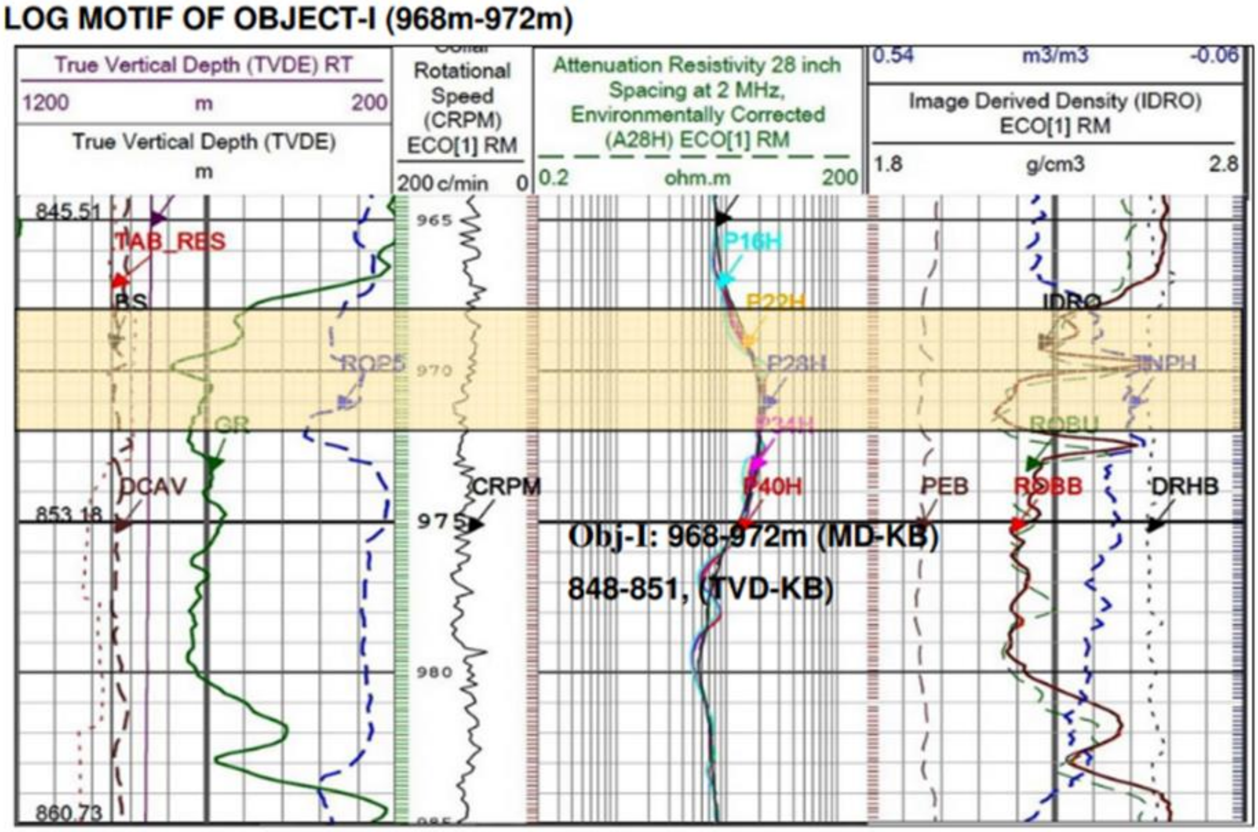


Figure 4-145 :.WELL LOG MOTIF OF TUKB-3A :



4.7.3 Well testing and workover history

The objective sand was encountered at 968m- 982m (847.5 m- 860m TVD) in Upper Bhuban. Object-I in the interval 968 m-972m MD (848 m- 851m TVD) was perforated @ 6spf, and on production testing , the object has produced gas with a flow rate of 12,900scmd through 6mm bean (FTHP/CHP: 64/60Ksc). The well is temporarily abandoned with a provision for re-entry. Testing Details are given below in **Table 4-101.**

Table 4-101: WELL TESTING RESULTS OF TUKB-3A

Well Testing Results of TUKB-3A				
Object	**OBJ - I**			
Interval (m)	**968-972m, Upper Bhuban**			
Perforation type		Conventional, 6spf		
Activation Type		On activation by applying compressor up to 50 ksc, well became active and flowed gas		
Bean (mm)	3mm	4mm	5mm	6mm
Flow Rate- Gas M3/d	4000	6200	9700	13000
Flow rate-water	---	---	---	---
GOR	--	--	--	--
FTHP (KSC)	61.77	67	57.26	52.27
Salinity (gpl)	---		---	---
Density	---		---	---
Status	**FBHP: 63.38 kg/cm2 (6mm bean) at 850m** **SBHP: 68.08 kg/cm2** **Gas Well, temporarily abandoned with provision for Re-entry**			

4.7.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, are collated and presented under various data genres. However, in the present context, there is no such analysis/study available/accessible at the time of writing this report, except for bottom hole pressure measurements. The bottom hole pressures recorded in the well are as given below in **Table 4-102**.

Table 4-102: STATIC AND FLOWING BOTTOMHOLE PRESSURE IN TUKB-3A

BHS in TUKB-3A						
Date	**Type of Study**	**Bean Size (mm)**	**Qg (m3 /d)**	**THP (Kg/Cm2)**	**BHP at Datum (850m) (Kg/Cm2)**	**BH Grad. (Kg/Cm2 / 10m)**
05-Sep-14	FBHP	6	12,900	52.27	63.38	0.22
06-Sep-14	FBHP	3	4,000	61.77	66.10	0.12
07-Sep-14	SBHP	-	-	64.20	68.08	0.05
08-Sep-14	FBHP	4	6,200	-	65.72	-
09-Sep-14	SBHP	-	-	-	68.08	-
09-Sep-14	FBHP	5	9,700	57.26	63.92	0.11

4.7.5 Geology and Reservoir Description of TUKB-2 Field:

The geology of the area has been comprehensively reviewed using correlations, sections, and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude, and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.7.5.1 Geological correlations, sections, and maps (TUKB-2 Field):

This structure was mapped in detail with the help of both 2D and 3D seismic data. Interpretation of seismic data reveals that the structural style is largely controlled by the NNW-SSE trending reverse faults on the west and NNE-SSW trending reverse/normal faults on the east. All the faults mapped in the sub-surface can elegantly be correlated to the surface faults. A number of second-generation SW-NE trending cross faults have also been identified on different time slices.

Tukbai anticline is a part of the frontal fold belt of the Tripura-Cachar-Chittagong fold system. The structure is situated in the north-eastern part of Cachar. It trends in NNE-SSW direction and extends into the North Cachar hills. This anticline is flanked by the Labak syncline in the west and a narrow Diksha syncline in the east. The axes of both the synclines have been faulted. The Tukbai anticline is dissected by a number of NE-SW trending cross faults. This structure is a broad SSW plunging anticline with gentle dips at the plunge part and steep dips at the core of the anticline.

5.3 m of gas pay has been encountered at the well location at a depth of 801 m.

Based on the analysis of drill cutting samples and characters of electro logs recorded in the wells TUKB-2 and TUKB-3/3A, the following stratigraphic boundaries were envisaged (**Table 4-103**).

Table 4-103: STRATIGRAPHIC SEQUENCES IN TUKB-2 AND TUKB-3A

Formation	Age	Interval (m)	Thickness (m)	Lithology
TUKB-2				
Bokabil	Mio-Pliocene	0- 310	310	Mainly clay/claystone with sandstone alterations
Upper Bhuban	Miocene	310 - 1010	700	Mainly sandstone with clay/claystone alterations .
Middle Bhuban		1010 - 2150	1140	Shale interbedded with thin sandstone .
Lower Bhuban		2150 – 2387 +	237 +	Mainly sandstone with shale alterations
TUKB-3				
Bokabil		0 - 385		Mainly Clay/Claystone and shale layers with intercalations of sand
Upper Bhuban		385 - 896		Thick sandstone separated by thin shale layers
Middle Bhuban		896 - 998+		Mainly Clay/Claystone intercalated with thin shaly sand layers

TUKB-3A				
Bokabil	Mio-Pliocene	Surface - 245	245	Mainly claystone with minor sandstone alternations.
Upper Bhuban	Miocene	245 – 1019	642	Mainly sandstone with a few claystone alternations

The well has been correlated with its nearby wells Tukbai-2 and Tukbai-3. The correlations at various stratigraphic and pay levels are given below (**Table 4-104**):

Table 4-104: STRATIGRAPHIC AND PAY LEVEL CORRELATION OF TUKBAI WELLS

FORMATION	CORRELATION LEVEL	Tukbai-2	Tukbai-3	Tukbai-3A
		KB: 43.15 Vertical MD(MSL)	**KB: 46.32 Vertical MD(MSL)**	**KB: 46.32 Inclined Well MD(MSL)**
Bokabil	Formation Top	Logs not recorded	0 (0)	0 TVD: 0 (0)
	Formation Bottom		385 (339)	387 TVD: 387 (341)
Upper Bhuban	Formation Top	< 503 Logs recorded upto 503m only	385 (339)	391 TVD: 387 (341)
	Objective Sand Top	855 (812)	NOT DEVELOPED	968 TVD: 848 (802)
	Objective Sand Bottom	868 (825)		980 TVD: 857 (811)
	Formation Bottom	1002 (959)	896 (850)	1000+ TVD: 876+ (830+)
Middle Bhuban	Formation Top	1002 (959)	896 (850)	NOT DRILLED
	Formation Bottom	1380+ (1337+)	998+ (951+)	

Note: The depths given in parentheses are TVD-MSL depths.

A) In Tukbai-2, no logs were recorded in Bokabil, and the well was terminated within the upper Bhuban formation; hence, correlation could be carried out at the Upper Bhuban level.

B) In Tukbai-3A, drilling was terminated within the Upper Bhuban formation; hence, the top of Middle Bhuban (Bottom of Upper Bhuban) could not be correlated.

Based on the Log analysis and geological data, the following conclusions were drawn (TUKB-3A):

- Top of the Upper Bhuban is encountered at 391m (341 MSL).
- Porous sand developed within the Upper Bhuban formation in the interval 968-984m and is interpreted as gas bearing with an estimated gas-water contact at 976m.
- All other sands developed in the Upper Bhuban formation are interpreted as water bearing.

Upper Bhuban Formation Interval: 968-972m was identified for testing.

Geological cross-section of Tukbai area and the structural correlation of Tukbai wells are shown in **Figure 4-146 and Figure 4-147.**

Figure 4-146 :.GEOLOGICAL CROSS-SECTION OF THE TUKBAI AREA:

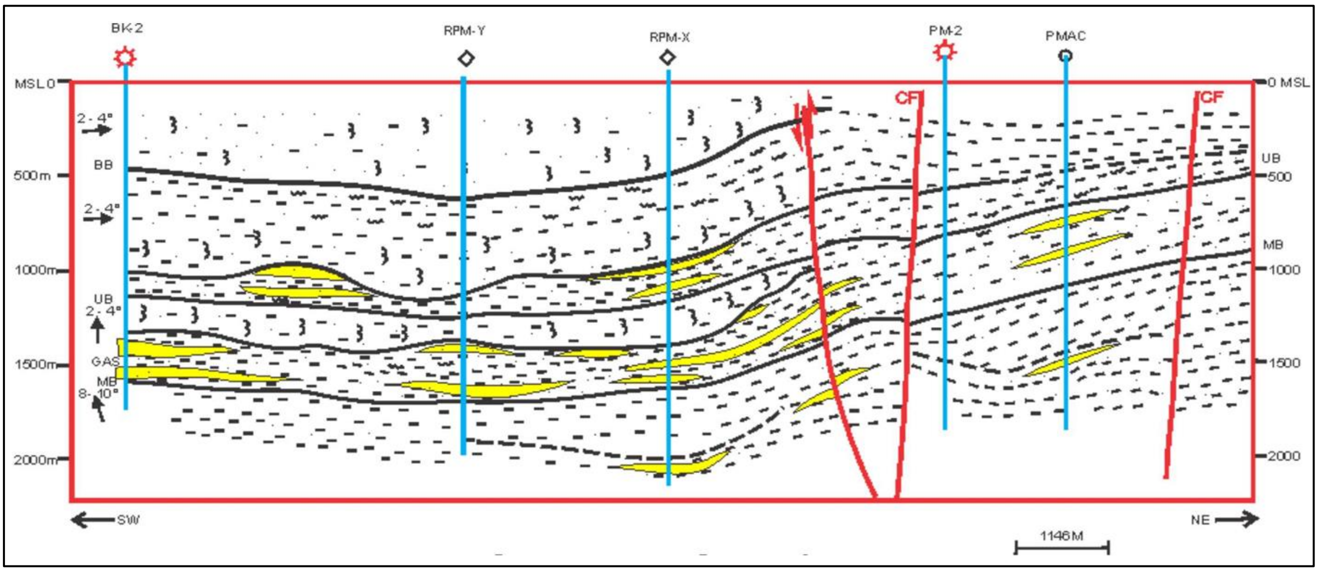
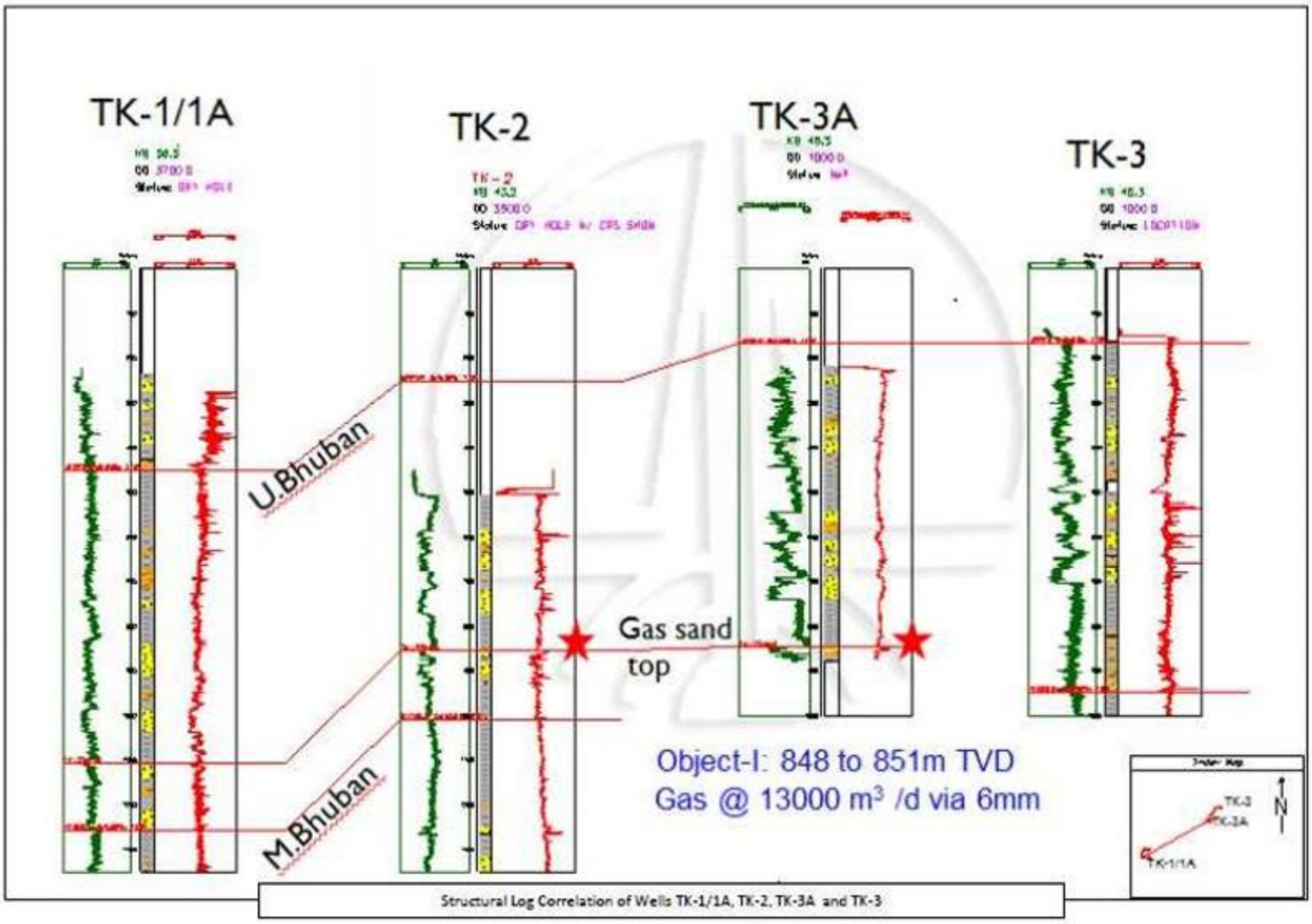


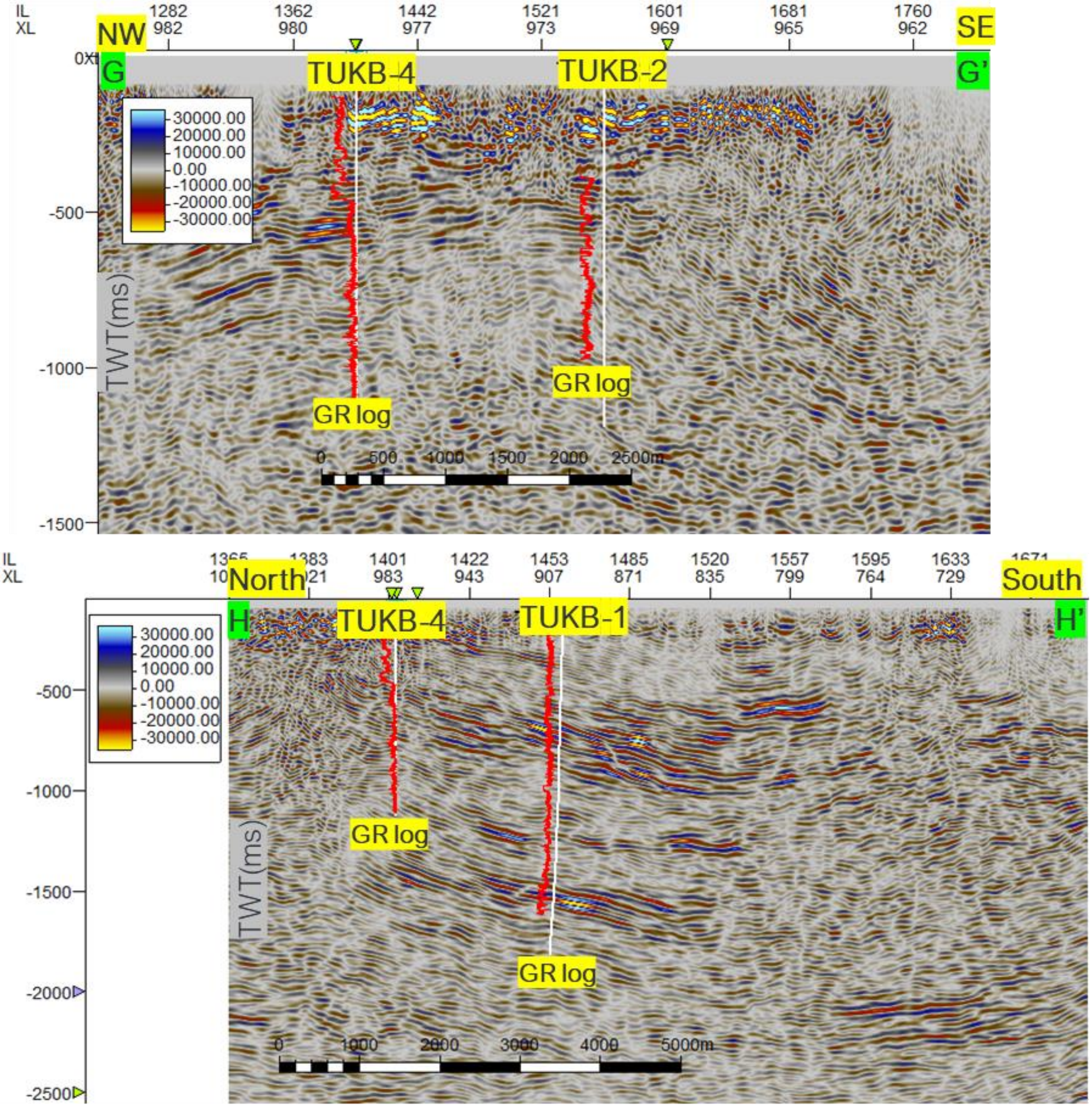
Figure 4-147 :.STRUCTURAL CORRELATION OF TUKBAI WELLS :



Structural Log Correlation of Wells TK-1/1A, TK-2, TK-3A and TK-3

Sesmic crossections of Tukbai wells are shown in
Figure 4-148 **and Figure 4-149**. Time structure and Net sand/Pay maps of Tukbai field are shown in **Figure 4-150 and Figure 4-151.**

Figure 4-148 :.SEISMIC SECTIONS ALONG THE TUKBAI WELLS:



Vertical exaggeration: 2.5x
Seismic volume: 00003.AAFB_TUKBAI_A302-A303_POST_MIG_STK_FINAL_POSTM_STACK_

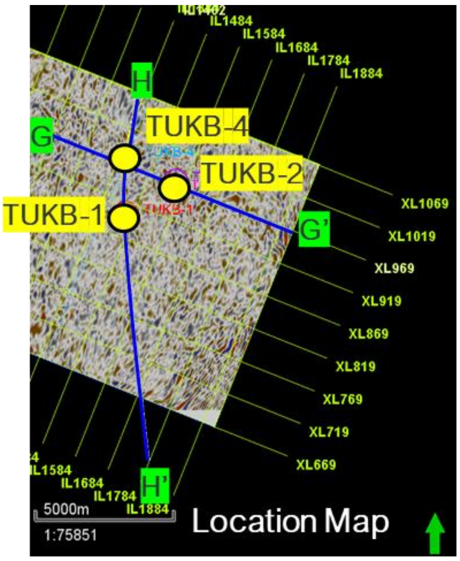
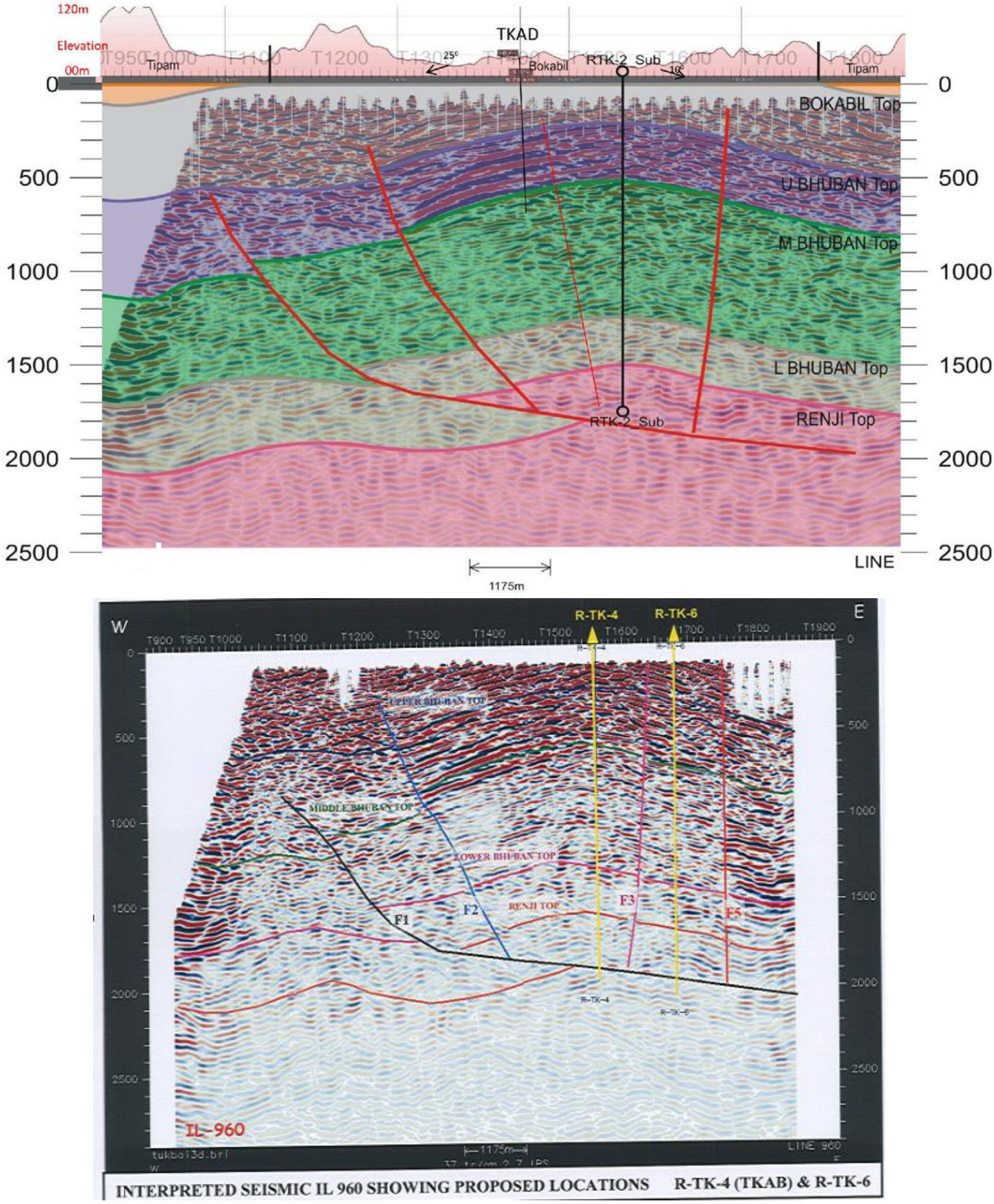


Figure 4-149 :. SEISMIC SECTIONS ALONG THE TUKBAI WELLS:



3D seismic data of series A302 and A303, acquired in 2007-08, were interpreted thoroughly to map the Tukbai Structure. Lithostratigraphic correlation between TUKB-2 and TUKB-3 primarily indicated that the gas sand in Upper Bhuban Formation in the interval 854.5-868m in well TUKB-2 has been shaled out in well TUKB-3. To target the above gas sand, well TUKB-3 was planned to deviate along 218 deg. with a net drift of 409.10m at target depth of 1019m. Two gas sands were expected at TVD 630m and 868m from the electro log correlation.

Figure 4-150 :.TIME STRUCTURE MAP OF UPPER BHUBAN IN TUKBAI AREA:

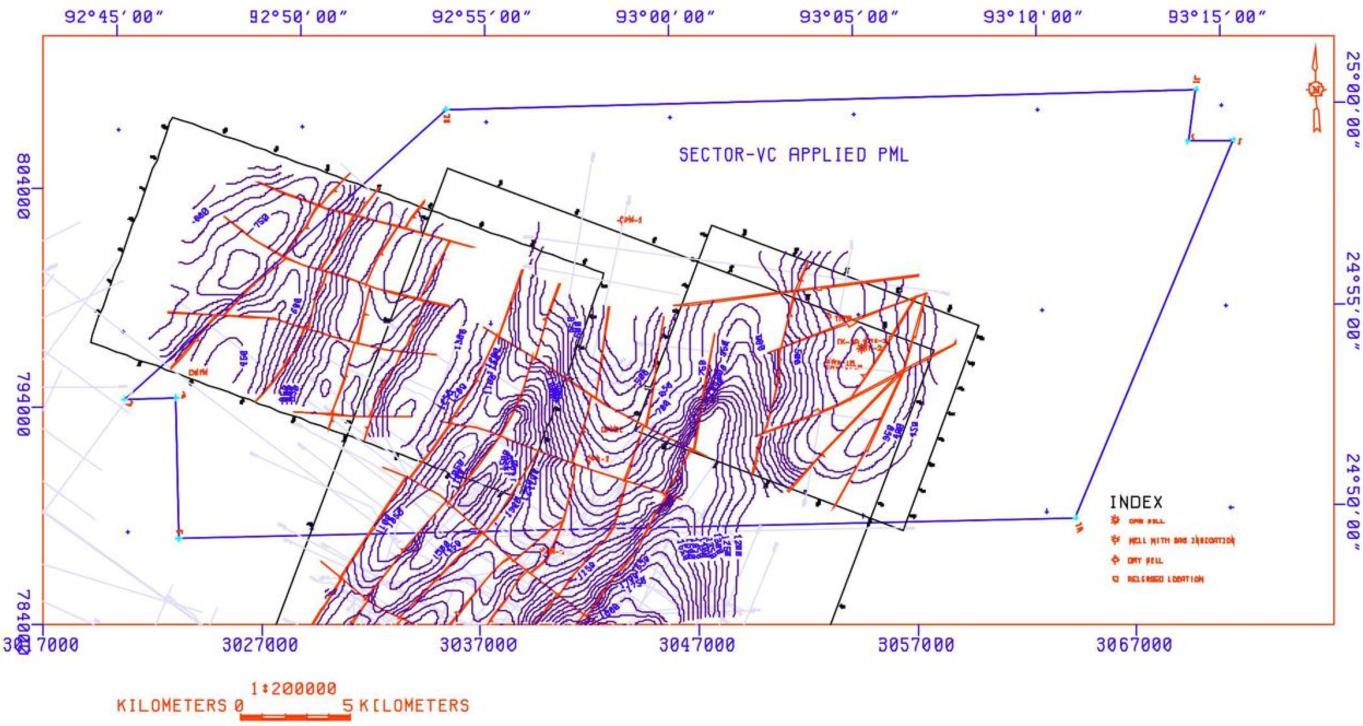
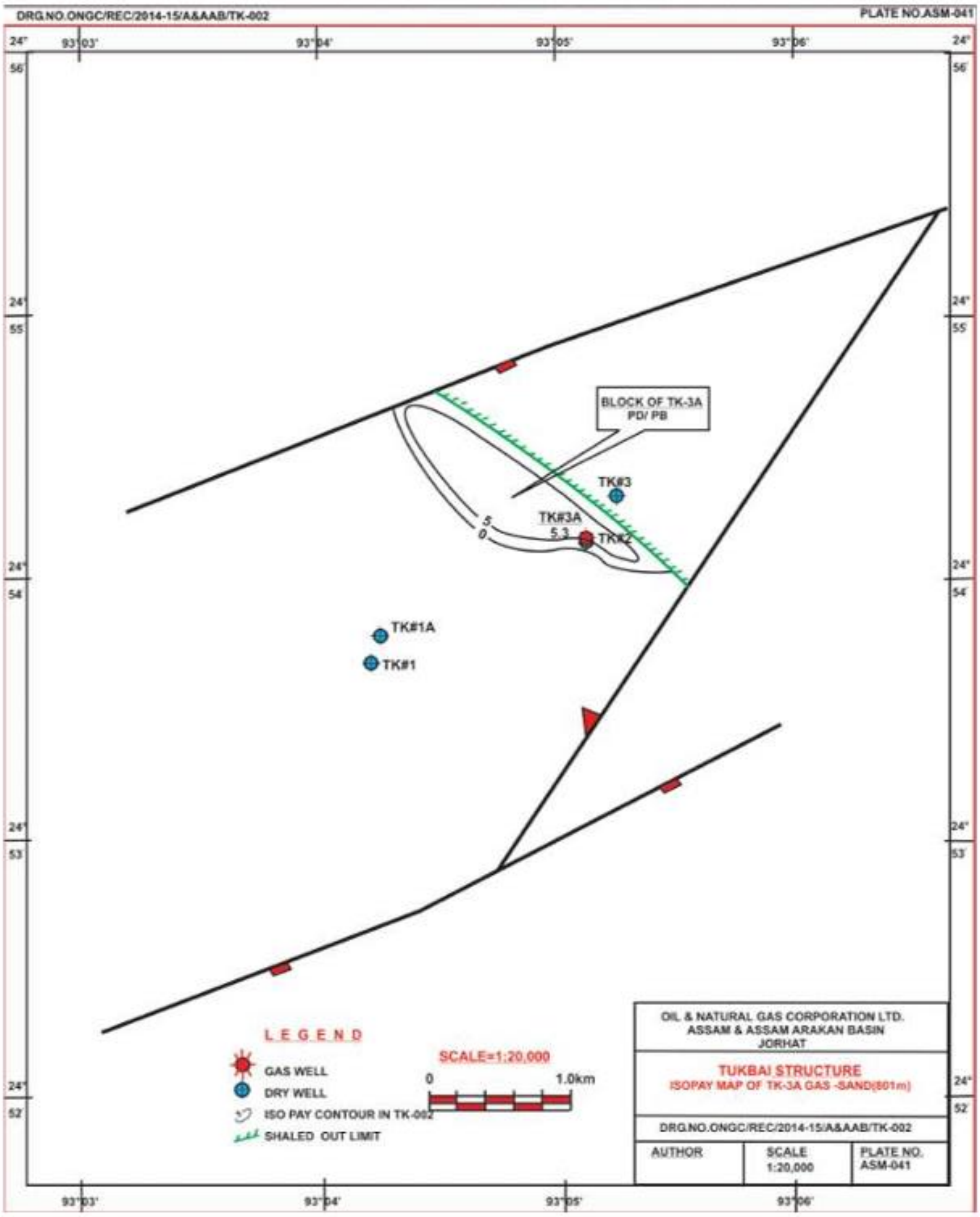


Figure 4-151 :.NET SAND/ PAY MAP OF UPPER BHUBAN IN TUKBAI AREA:



4.7.5.2 Reservoir parameters and hydrocarbon estimates TUKBAI Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Average reservoir properties and petrophysical parameters and in-place for Tukbai are given in **Table 4-105, Table 4-106 and Table 4-107.**

Table 4-105: AVERAGE RESERVOIR PARAMETERS WITH GLOBAL CUT-OFF: PHIMIN >=3%, SWMAX<=90%

Formation: Bhuban											
			Net Reservoir Parameters				Net Pay Parameters				
Top MD (m)	Bottom MD (m)	Gross Thick ness (m)	Thick ness (m)	Poro sity (m3/ m3)	Clay Vol Fraction (m3/m3)	Wtr Satn	Thick ness (m)	Poro sity (m3/ m3)	Clay Vol Fraction (m3/m3)	Wtr Satn	Remarks
968.00	**969.20**	1.20	1.20	0.15	0.26	0.73	1.20	0.15	0.26	0.73	Shaly H/C
969.80	**972.00**	2.20	2.20	0.21	0.09	0.47	2.20	0.21	0.09	0.47	H/C
972.40	**976.00**	3.60	3.60	0.20	0.14	0.59	3.60	0.20	0.14	0.59	H/C
976.00	**980.00**	4.00	4.0	0.23	0.09	0.81	3.60	0.23	0.09	0.81	Water

Table 4-106: PETROPHYSICAL PARAMETERS TUKBAI FIELD:

Reservoir	**Upper Bhuban**	**Upper Bhuban**	**Upper Bhuban**	**Upper Bhuban**
Interval, m	**(976-980)**	**(972-976)**	**(970-972)**	**(968-969)**
Area: sq.km	0.7854	2.35	2.35	2.35
Thickness, m	3.6	3.6	2.2	1.2
Porosity:	0.23	0.20	0.21	0.15
Hydrocarbon saturation:	0.19	0.41	0.53	0.27
Formation volume factor:	0.004	0.004	0.004	0.004
Gas In Place, MMm3		173	144	29
Remarks:	Water Bearing	H/c	H/c flowed gas	

Table 4-107: HYDROCARBON IN-PLACE (2P) TUKBAI FIELD

Field	O+OEG MMTOE
TUKBAI	0.17

Erstwhile Operator-reported estimates on record:

The Tukbai Field has a reported gas estimate of **0.03 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.7.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to the Tukbai field is **Banaskandi GCS (28 km)**

AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 BLOCK

4.8 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA BLOCK

The Patharia structure geographically falls in both Indian and Bangladesh territories. It is the westernmost structure developed in the Karimganj district of Assam on the Indian side, and bounded in the west and southwest by the Indo-Bangladesh border. Geologically, the structure forms a part of the frontal folded part of the Assam Arakan belt. It is bounded in the west by the Juri syncline of Bangladesh and in the east by the Nilambazar syncline. The Patharia structure is a tightly folded, doubly plunging, asymmetrical anticline trending NNE-SSW from Karimganj in the north to Dashgram in the south. The structure runs with a sinuous axial trend over a length of 50 km with an average outcrop width of 9 km through Cachar, Tripura, and Bangladesh. Only the northern plunge area, a part of the eastern limb, and the southern plunge area fall in the Indian territory. The rest of the structure is in Bangladesh. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault with downthrow towards the east is seen in the eastern flank.

The Patharia area is located onland within the Assam-Arakan Fold Belt (AAFB) Basin and covers an area of 96.52 Sq. Km under this DSF Bid Round IV. The area is a single area with 2 discoveries/fields (PTRA-2 & PTRA-5) and 2 additional wells. The coordinates of the block boundaries are given in **Table 4-108**. Location and Seismic coverage in this block is shown in (**Figure 4-152**) and **Figure 4-153.**

Table 4-108: COORDINATES OF THE BLOCK BOUNDARIES: PATHARIA

	Patharia Boundary Points		
	Area: 96.52 sq km		
	Point	**Longitude**	**Latitude**
	A	92° 22′ 00.000″ E	24° 52′ 20.665″ N
	B	92° 22′ 00.000″ E	24° 49′ 00.000″ N
	C	92° 21′ 00.000″ E	24° 49′ 00.000″ N
	D	92° 21′ 00.000″ E	24° 45′ 00.000″ N
	E	92° 20′ 00.000″ E	24° 45′ 00.000″ N
	F	92° 20′ 00.000″ E	24° 43′ 00.000″ N
	G	92° 16′ 55.484″ E	24° 43′ 00.000″ N
	H	92° 17′ 18.839″ E	24° 47′ 00.000″ N
	I	92° 18′ 00.000″ E	24° 47′ 00.000″ N
	J	92° 18′ 00.000″ E	24° 50′ 00.000″ N
	K	92° 19′ 00.000″ E	24° 50′ 00.000″ N
	L	92° 19′ 00.000″ E	24° 52′ 00.000″ N
	M	92° 20′ 00.000″ E	24° 52′ 00.000″ N
	N	92° 20′ 00.000″ E	24° 53′ 03.360″ N
Note: The segments G→H and N→A follow the international boundary between India & Bangladesh.			
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	PTRA-2	92° 18′ 31.448″ E	24° 47′ 29.258″ N
2	PTRA-5	92° 19′ 43.896″ E	24° 49′ 01.402″ N

Figure 4-152 :.LOCATION MAP SHOWING THE PATHARIA BLOCK BOUNDARY.

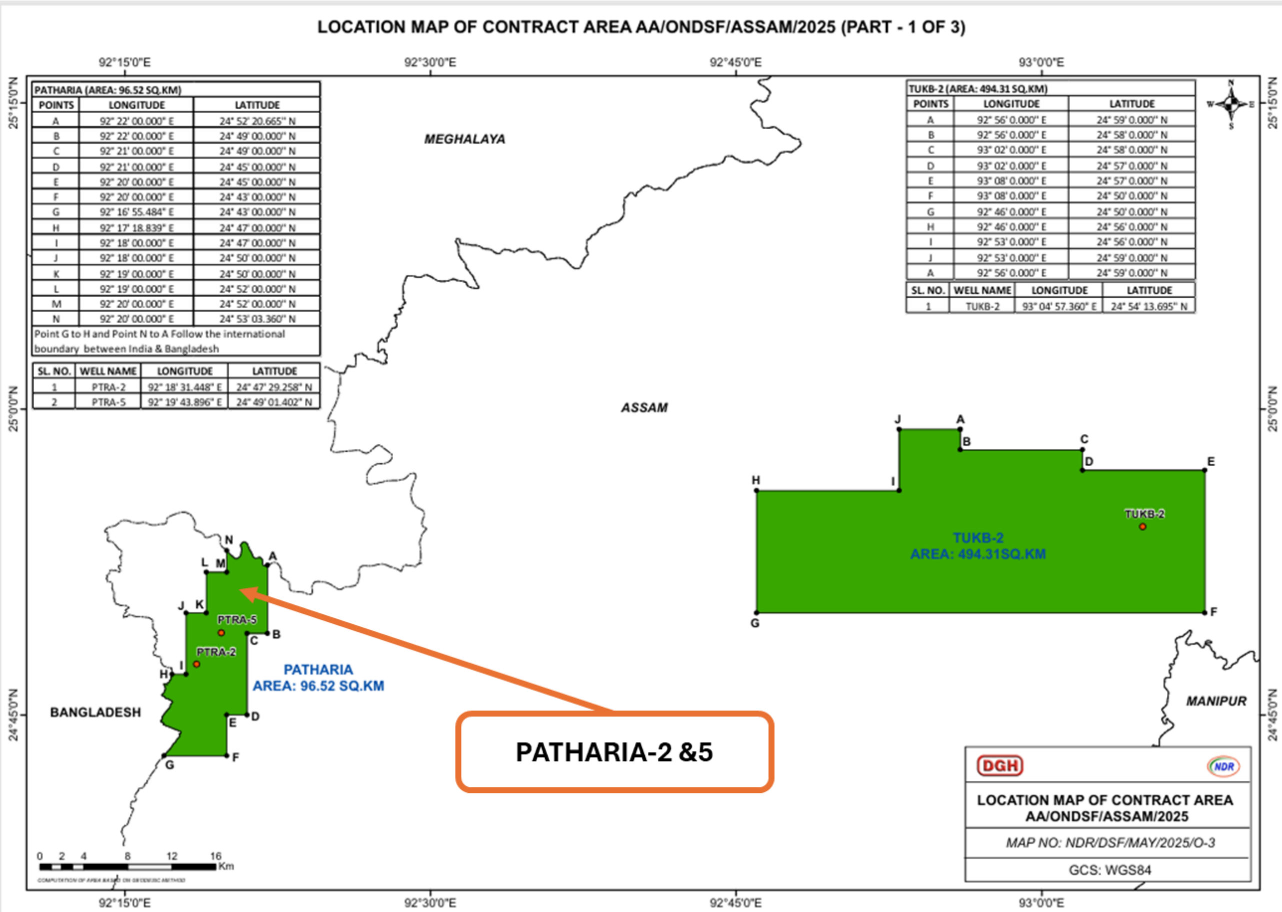
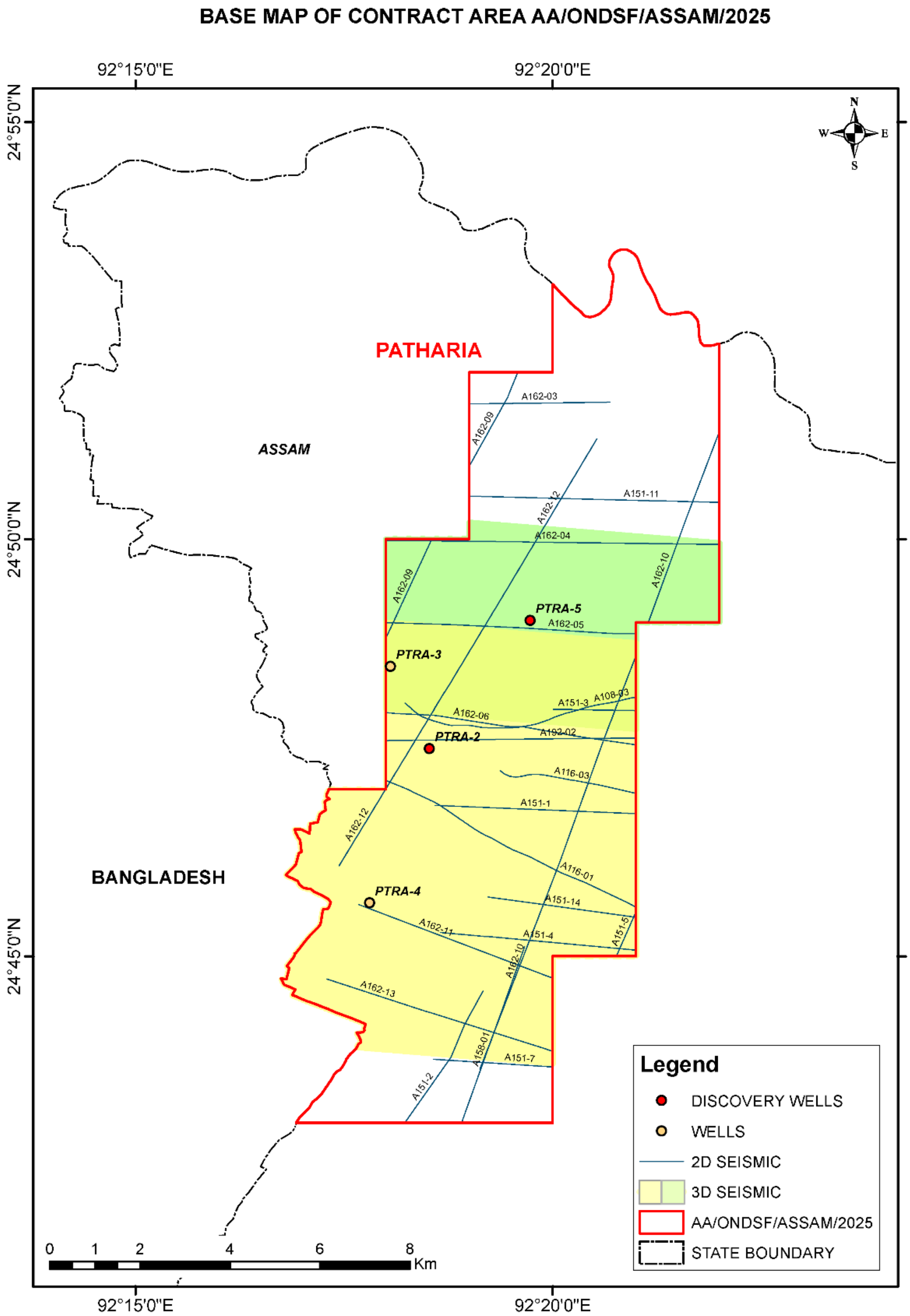


Figure 4-153 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: PATHARIA-



AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 FIELD

4.9 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 FIELD

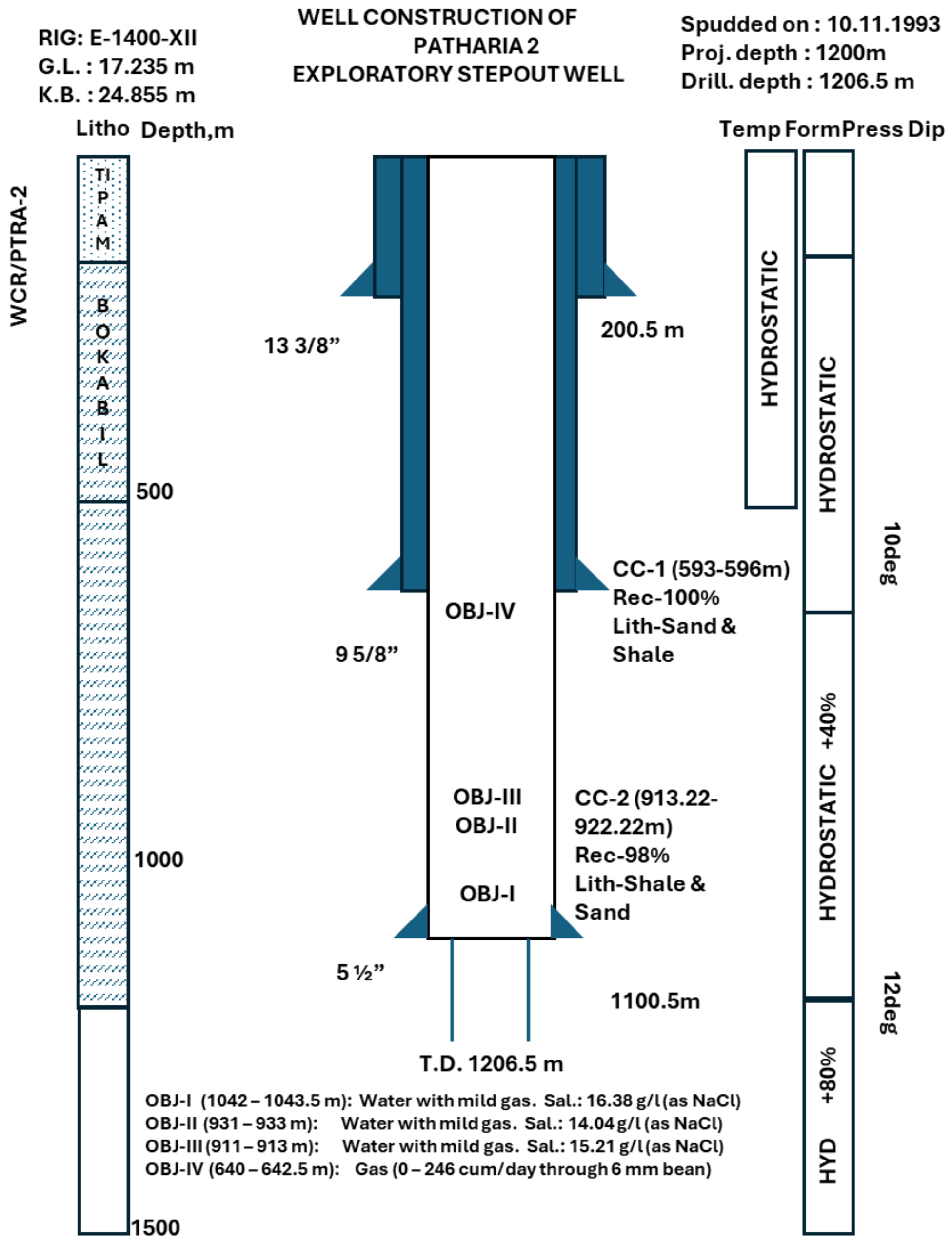
The well Patharia-2 was drilled in 1993-1994 with an objective to test the Bokabil sands. It is located on the eastern flank of the northern plunge of the Patharia anticline, just 5 metres NNE of Patharia well-1. During the drilling of Patharia-1, the presence of gaseous hydrocarbons was noticed in the drilled interval of 590-1149m. The interesting zone could not be tested since these are behind two casings. Hence Patharia-2 was proposed to test the Bokabil sands.

4.9.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates are made available in Sections through various cross-references.

Well diagram for PTRA-2 is shown in **Figure 4-154.**

Figure 4-154 :.WELL PROFILE OF PTRA-2:

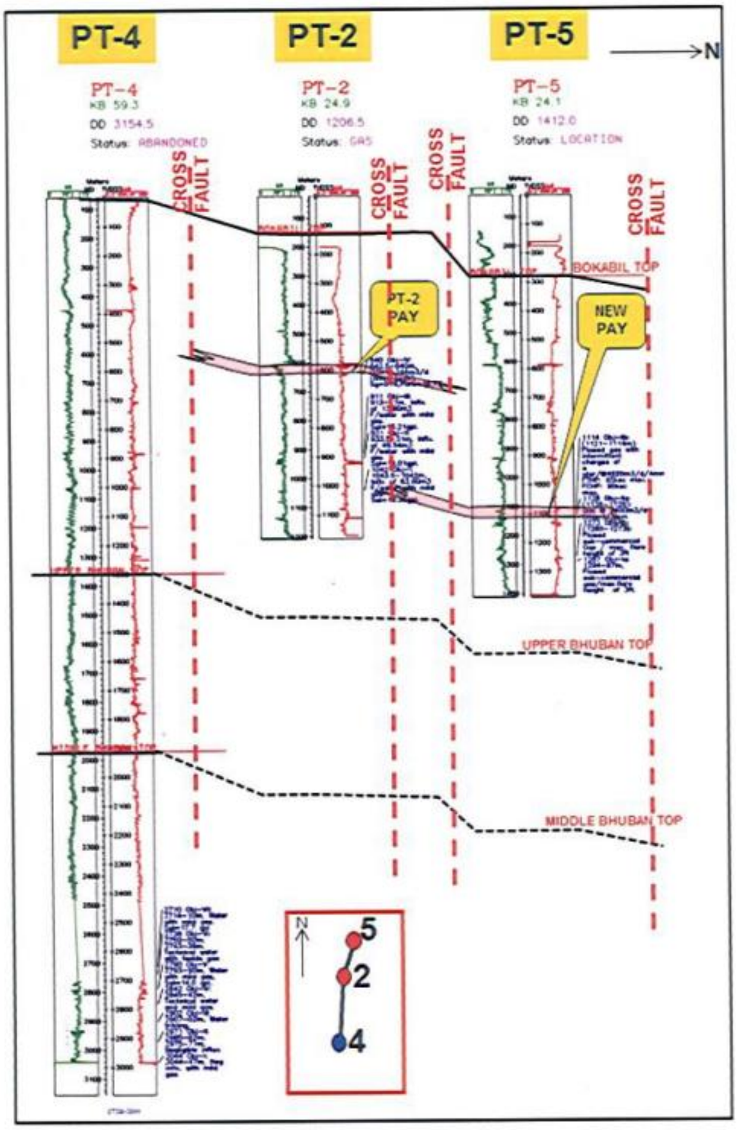


LITHO-SECTION INFORMATION OF PTRA-2 :

The following stratigraphic boundaries are envisaged, based on the lithological character of cutting/core samples and interpretation of wireline logs recorded in well PTRA-2. Electro Log Correlation of Well Patharia-4, Patharia-2, and Patharia-5 is given in **Figure 4-155.**

Group	Formation	Age	Interval (m)	Thickness (m)	Lithology
Tipam	Tipam Sandstone	Mio-Pliocene	Surface - 948	948	Dominantly sandstone with subordinate clay and claystone
Surma	Bokabil	Miocene	948 - 2173,5+	1225.5+	Mainly claystone and shale with thin interbedded siltstone and sandstone

Figure 4-155 :.ELECTRO LOG CORRELATION OF WELL PATHARIA-4, PATHARIA-2, AND PATHARIA-5:



4.9.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Reports (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.9.2.1 Well completion and log evaluation reports availability (Patharia-2) :

WCR/ FER availability	Spud date	KB	Drilled depth
Both available	10.11.1993	24.9 m	1206.5 m

4.9.2.2 Well logs acquired (PTRA-2) :

Log suites recorded in Patharia-2 are listed in **Table 4-109.**

Table 4-109: LOGS AQUIRED IN PATHARIA-2

DATE	Drill hole size(inch)	LOGS RECORDED	INT. LOGGED		DRILLED DEPTH	LOGGER DEPTH	Temp DegC
			From	To			
28.12.93	12 ¼	RUN-1					
		1.DLL-MSFL-SP-GR	611.9	200	612M.	612.7M.	44.4
		2.LDL-CNL-GR	612.0	200			
		3.BHC-SONIC	610.5	200			
27.1.94	8 ½	RUN-2					
		1.DLL-MSFL-SP-GR	1197.0	600	1200M.	1206.5 M.	61.3
		2.LDL-CNL-GR	1205.0	600			
		3.BHC-SONIC	1204.0	600			
28.01.94		CST RUN-1 (Attempted 21, Recovered 18					

4.9.2.3 Well log evaluation and initial test results (PTRA-2):

Petrophysical properties and Initial testing of Patharia-2 are given in **Table 4-110**. Details of the core data acquired in this well is given in the following paragraph below, and a log motif of PTRA-2 is shown in **Figure 4-156.**

Table 4-110: PETROPHYSICAL PROPERTIES AND INITIAL TESTING OF PATHARIA-2

Interval (mMDRT/mTVDSS)	Formation (+ Zone, if specified)	Gross(m)	Net(m)	Phi	Sw
480-1200 / 455.15-1175.15	Bokabil_Miocene(640-642.5 mMDRT)	5.0	3.5	0.19	0.49
Initial testing results: Tested interval 640-642.5m flowed gas @ 10,246m3/d gas through 3mm bean. FTHP: 10-12KSC					

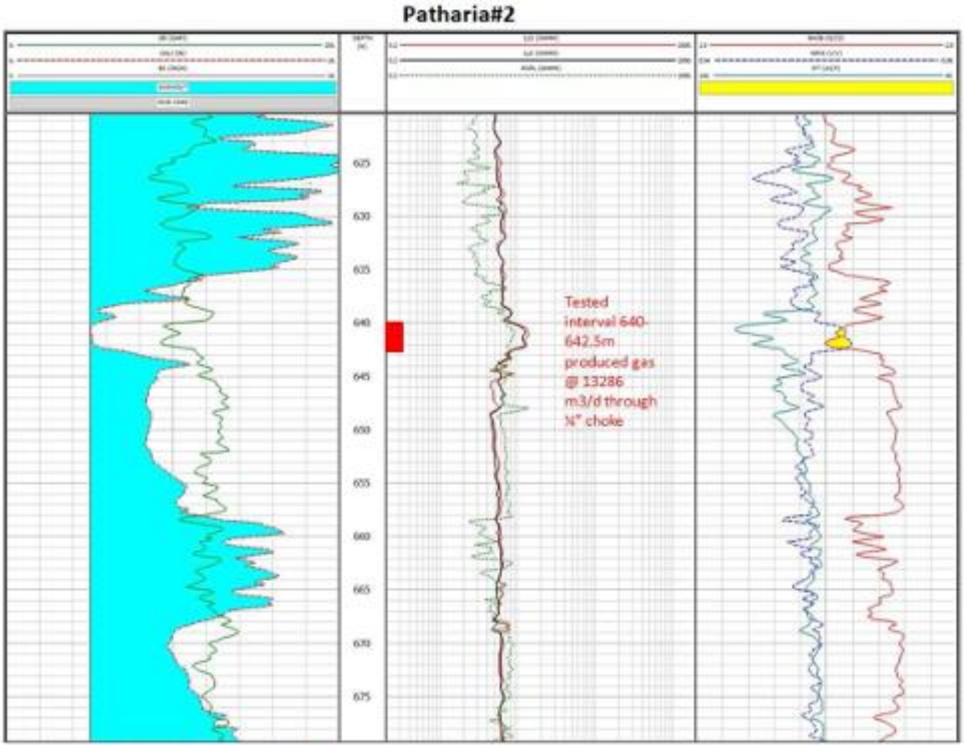
Core Data:

Two conventional cores were cut in intervals 590.0-596.00 (Rec 100%) and 913.22-922.22 (Rec 98%). A total of 21 side wall cores were shot and recovered in the interval of 614-1141m.

Conventional Core Data:

Core	Interval (m)	Recovery (%)	Formation	Lithology	Dip (^{0})
CC-1	590 – 596	100	Bokabil	Interbedded Sandstone and shale	5 - 12
CC-2	913.22 – 922.22	98	Bokabil	Shale with minor Sandstone	10 - 12

Figure 4-156 :.WELL LOG MOTIF OF PTRA-2 :



4.9.3 Well testing and workover history

The following four objects were tested in Patharia-2.

Object I (1042-1043.5m),

Object II (931-933.5m) and

Object-III (911.0-913.0m) produced water with feeble flow of gas.

Object IV (640-642.5m) flowed gas @ 10,246m3/d gas through 6 mm bean. FTHP: 10- 12 KSC (142.23psi).

The details of the well testing of all the Patharia wells are given in **Table 4-111.**

Table 4-111: DETAILS OF WELL PRODUCTION TESTING IN PATHARIA WELLS

Well	Obj. No.	Interval (m)	Formation	Testing Results
	In Bokabil Formation, a few gas bearing sands in the interval 479-481m, 483-486m, 613-620 m, 639-642m, 913-919m, 1071-1075 m, and 1138-1142m were identified, but could not be tested. 3 Objects in Upper Bhuban were tested by CHDST in 9⅝" casing. 5½" casing was not lowered due to lack of interesting zone below 9⅝" casing shoe at(2487.25m).			
PTRA-1	I	2035-2032	U. Bhuban	Influx of 5.7 m3 of mud/ filtrate. Maximum sal -3.46 gpl as NaCl. Reservoir pressure 345 Kg/Cm2
	II	1995-1989	U. Bhuban	Surface flow of gas with influx of 2.4 m3 of formation water. Maximum sal 8.19 gpl. Reservoir pressure 326 Kg/Cm2
	III	1940-1936	U. Bhuban	Influx of 5 m3 of formation water. Maximum sal. 14.63 gpl. Reservoir pressure 309 Kg/Cm2
PTRA-2	I	1042.0-1043.5	Bokabil	Yielded 63.60 m3 of water with mild gas. Salinity : 16.38 gpl (as NaCl). STHP : 55 Kg/ cm2, SCHP : 65 Kg/ cm2
	II	931.0-933.5	Bokabil	Yielded 49.54 m3 of water with mild gas. Salinity : 14.04 gpl (as NaCl). FTHP : 10 Kg/ cm2, SCHP : 40 Kg/ cm2
	III	911.0-913.0	Bokabil	Yielded 13.90 m3 of water with mild gas. Salinity : 15.21 gpl (as Nacl). STHP : 55 Kg/ cm2, SCHP : 62 Kg/ cm2
	IV	640.0-642.0	Bokabil	Produced **11761 m3/ day** of gas through 20/64” bean, FTHP: 56.892 psi. wtr traces Produced **10246 m3/ day** of gas through 16/64” bean, FTHP: 142.23 psi. wtr traces Produced **9804 m3/ day** of gas through 12/64” bean, FTHP: 156.453 psi. wtr traces Produced **8531 m3/ day** of gas through 10/64” bean, wtr traces. FTHP: 227.568 psi.
PTRA-3	Abandoned due to drilling complications			
PTRA-4	I	3047-3044	L. Bhuban	No/ Negligible influx with mild gas. Salinity of bottom sample is 572 ppm.
	II	2985-2982 2975-2971	L. Bhuban	No/ Negligible influx. Salinity of bottom sample is 580 ppm.
	III	2907-2902	L. Bhuban	Water trickling
	IV	2845-2842	M. Bhuban	No influx. Only technical water with mild gas on activation.
	V	2793-2790	M. Bhuban	Water with mild gas. Max influx 1.46m3 of water. Max sal of bottom sample is 14000ppm. Object concluded as having poor permeability.

	VI	2759-2750 2743-2738	M. Bhuban	Technical water with feeble flow of gas Object concluded as having No/ Negligible influx.
	VII	2714-2710	M. Bhuban	Water with mild gas on activation. Max Sal at 110 Kg/cm2 & 17740ppm. Object concluded due to poor permeability and negligible influx.
PTRA-5	Ia	1294-1287	Bokabil	Flowed sub-commercial Gas (max. 3ft flare height)
	Ib	1280-1273	Bokabil	Flowed sub-Commercial Gas (max. 3ft flare height)
	IIa	1136-1128	Bokabil	Flowed Gas @ 9400m3/d/3mm/ with little water in surges. FTHP: 44KSC at the time of flow measurements. After 30Hrs Shut-In STHP:109KSC / SCHP: 90KSC.Flowed Gas for 10days continuously, pressure not stabilized. Salinity: 21,000ppm as NaCl
	IIb	1121-1114	Bokabil	Flowed Gas @ 3160m3/d/3mm/ and 4820m3/d/4mm with little water in surges. FTHP: 67/65KSC at the time of flow measurements. After 49 Hrs. Shut In STHP: 114KSC/ SCHP: 98KSC. Flowed Gas for 21days continuously pressure not stabilized. Salinity: 24570ppm as NaCl.

4.9.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

Gas composition analysis (PTRA-2)

Gas composition analyses of Patharia-2 gas samples are given in **Table 4-112**

Table 4-112: GAS COMPOSITION ANALYSIS (PTRA-2)

1.	LAB SL. NO.	**G 48/94**	**S 69/94**
2.	WELL NO.	PTRA-2	PTRA-2
3.	OBJECT	IV	IV
4.	DEPTH (m)	612.5 - 640	612.5 - 640
5.	SAMPLING POINT	CHK. MANIF.	SEPARATOR
6.	FMP (Kg/Cm^2)	29.0	16.0
7.	CHP (Kg/Cm^2)	33.0	20.0
8.	DATE OF COLLECTION	17-04-94	08-05-94
S.NO.	**COMPONENTS**	**VOLUME %**	**VOLUME %**
1.	METHANE	96.15	93.10
2.	ETHANE	1.73	0.39
3.	PROPANE	0.37	0.07
4.	i-BUTANE	0.08	0.00
5.	n-BUTANE	0.00	0.00
6.	i-PENTANE	0.00	0.00
7.	n-PENTANE	0.00	0.00
8.	HEXANE PLUS	0.00	0.00
9.	CARBON DIOXIDE	0.05	1.65
10.	N_2 & O_2	1.62	4.79
	CALORIC VALUE (NET) K Cal/m^3	8150.00	7829.00

	SPECIFIC GRAVITY (AIR = 1)	0.5743	0.5823

Pressure build-up study (PTRA-2)

No transient/pressure build-up studies were carried out.

4.9.5 Geology and Reservoir Description of PTRA-2 Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.9.5.1 Geological correlations, sections and maps (PTRA-2 Field):

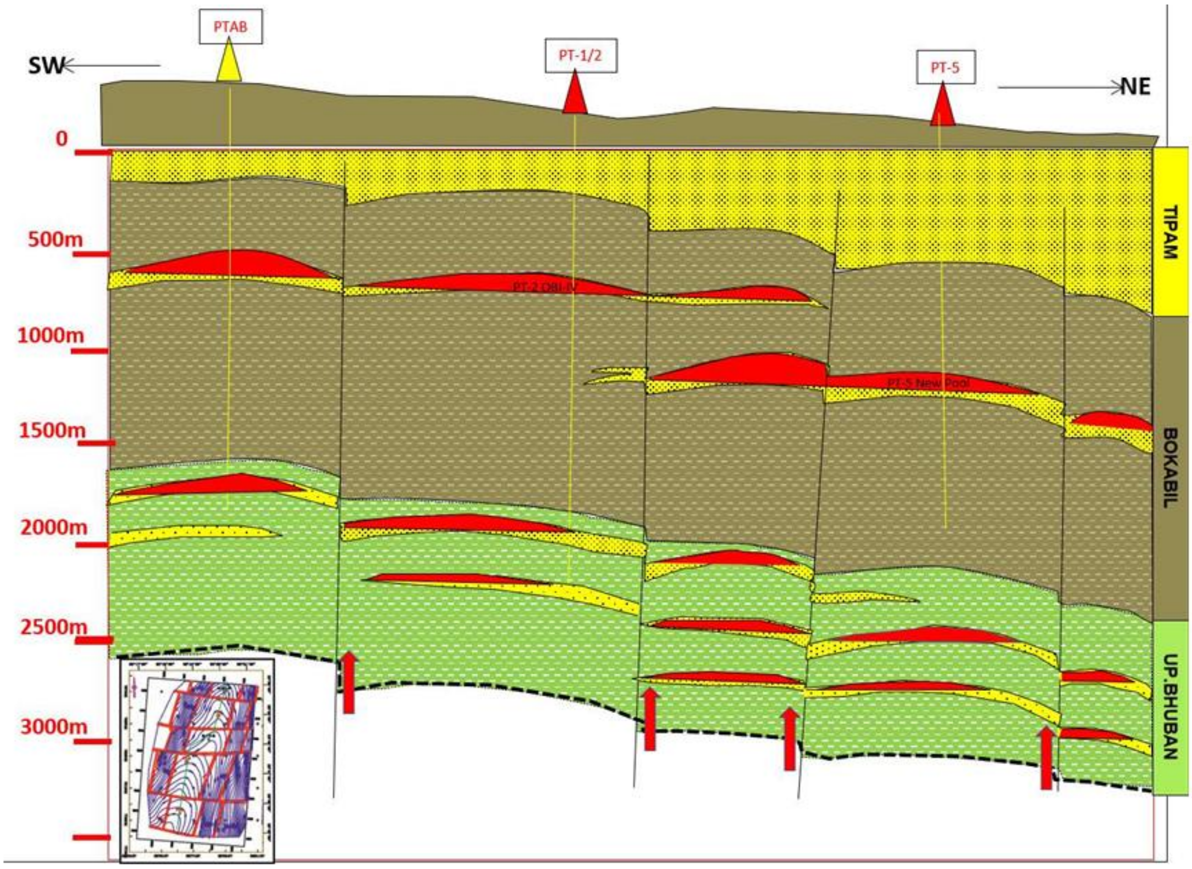
The Patharia Structure falls in the Cachar Fold Belt. Patharia Anticline is the westernmost structure in the Cachar Fold Belt. It is bounded by the Indo-Bangladesh border in the west and south-west, Nilambazar Syncline in the east, and Adamtila Gas field in the south-east. It is a tightly folded, doubly plunging, NNE-SSW trending, from Karimganj in the north to Dashgram in the south. The central crest part of the structure lies in Bangladesh, and only the northern and southern plunging parts of the anticline are present in India.

In the northern plunge, the eastern limb is steeper than the western one, whereas the reverse is the case to the south. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault downthrown towards the east is seen in the eastern flank. Patharia is the structurally highest uplifted structure in the Surma Trough. A thick sequence of Neogene section is exposed in the Patharia structure. These formations are, from top to bottom - Dupitlla, Girujan Clay, Tlpam, Bokabil, and Bhuban. Tipam and Bokabil Formations are exposed in the Cachar part, whereas Middle Bhuban is exposed in the core of the doubly plunging anticline in the Bangladesh part. The northern plunge of the Patharia anticline exhibits prograding updip sand bodies from NE-SW, which form favourable locales for trapping hydrocarbons.

The seismic Inline 650 and 590 show an anticlinal structure bounded by faults. Seismic maps have brought out longitudinal and transverse faults, which have created compartments in the plunging part. These compartments are proven gas-bearing blocks.

Around 2.5 m of gas pay has been encountered at the well location within Bokabil.

Figure 4-157 :.GEOLOGICAL CROSS-SECTION OF THE AREA:



Following is the stratigraphic succession penetrated in the well (**Table 4-113**). Geological cross-section in Patharia area is shown in **Figure 4-157.** Seismic section, depth structure map, and net sand/Pay map are shown **in Figure 4-158, Figure 4-159 and Figure 4-160.**

Table 4-113: STRATIGRAPHIC SUCCESSION PENETRATED IN THE WELL PTRA-2

AGE	FORMATION	INTERVAL (m.)	DRILLED THICKNESS	TRUE THICKNESS
Mio Pliocene	Tipam Sst.	0 - 158	158 m	147 m
Miocene	Bokabil	158 - 1205.5(+)	1056.5(+)	1033(+)

Figure 4-158 :.SEISMIC SECTION ALONG THE WELLS :

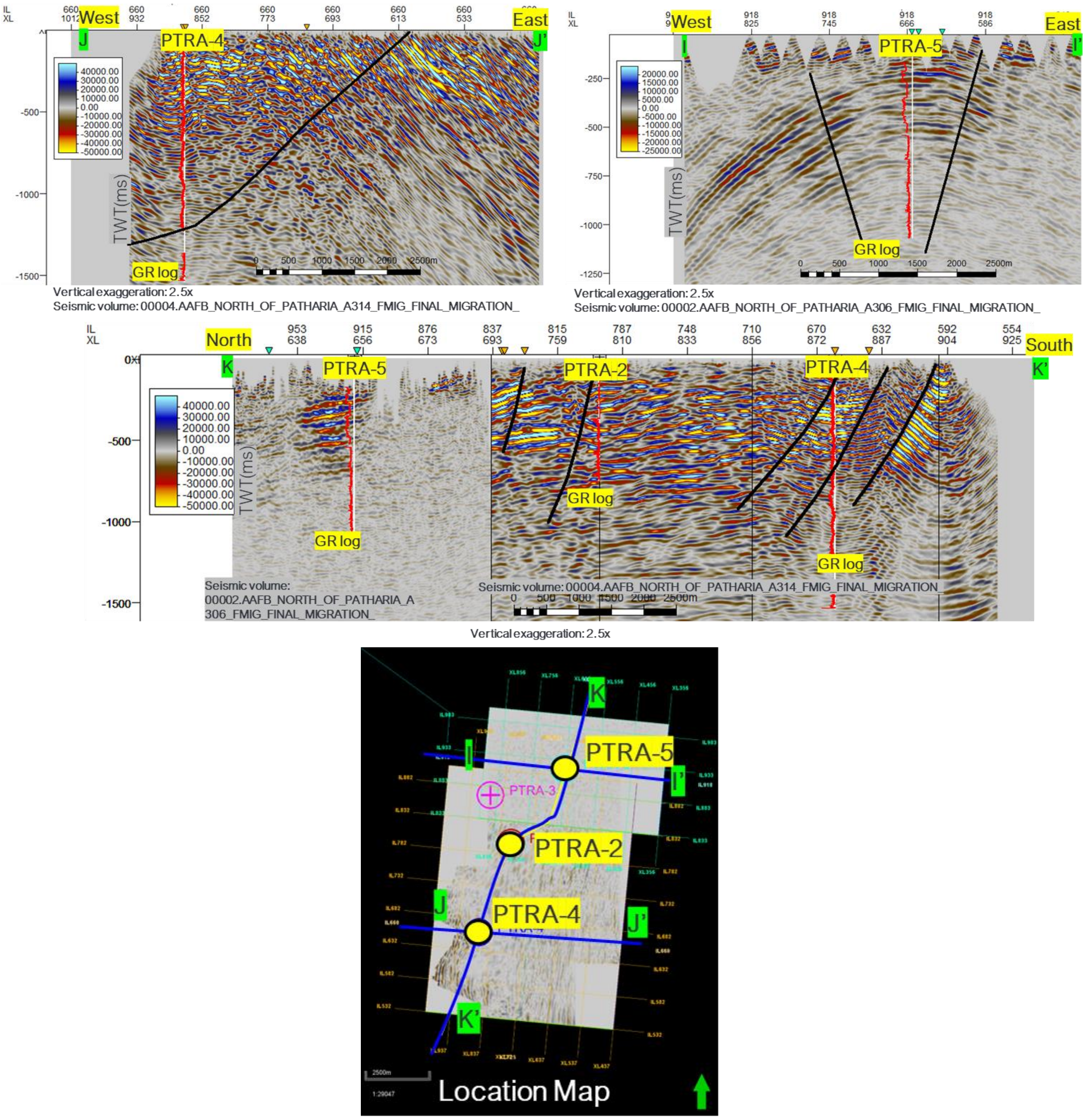


Figure 4-159 :.DEPTH STRUCTURE MAP OF BOKABIL :

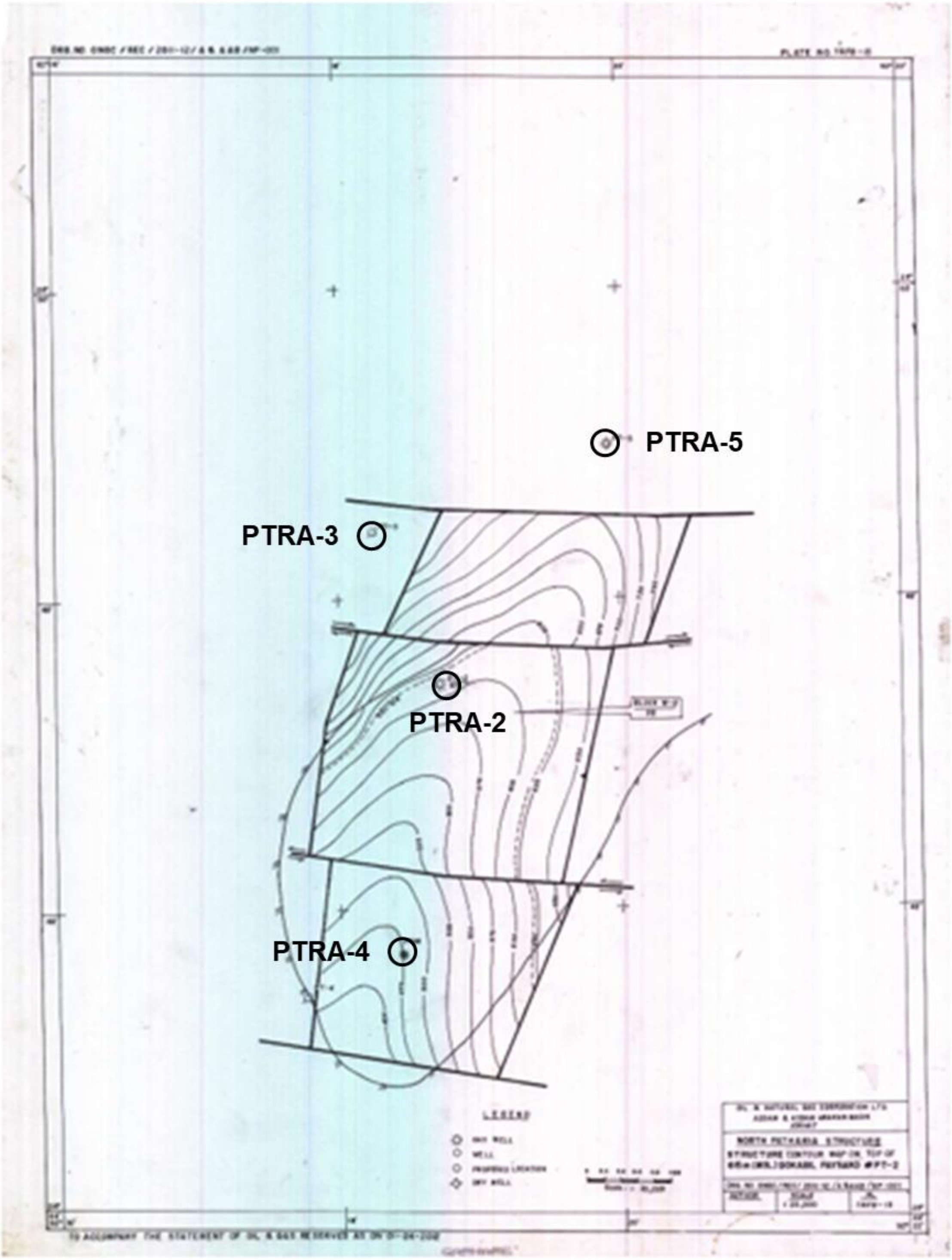
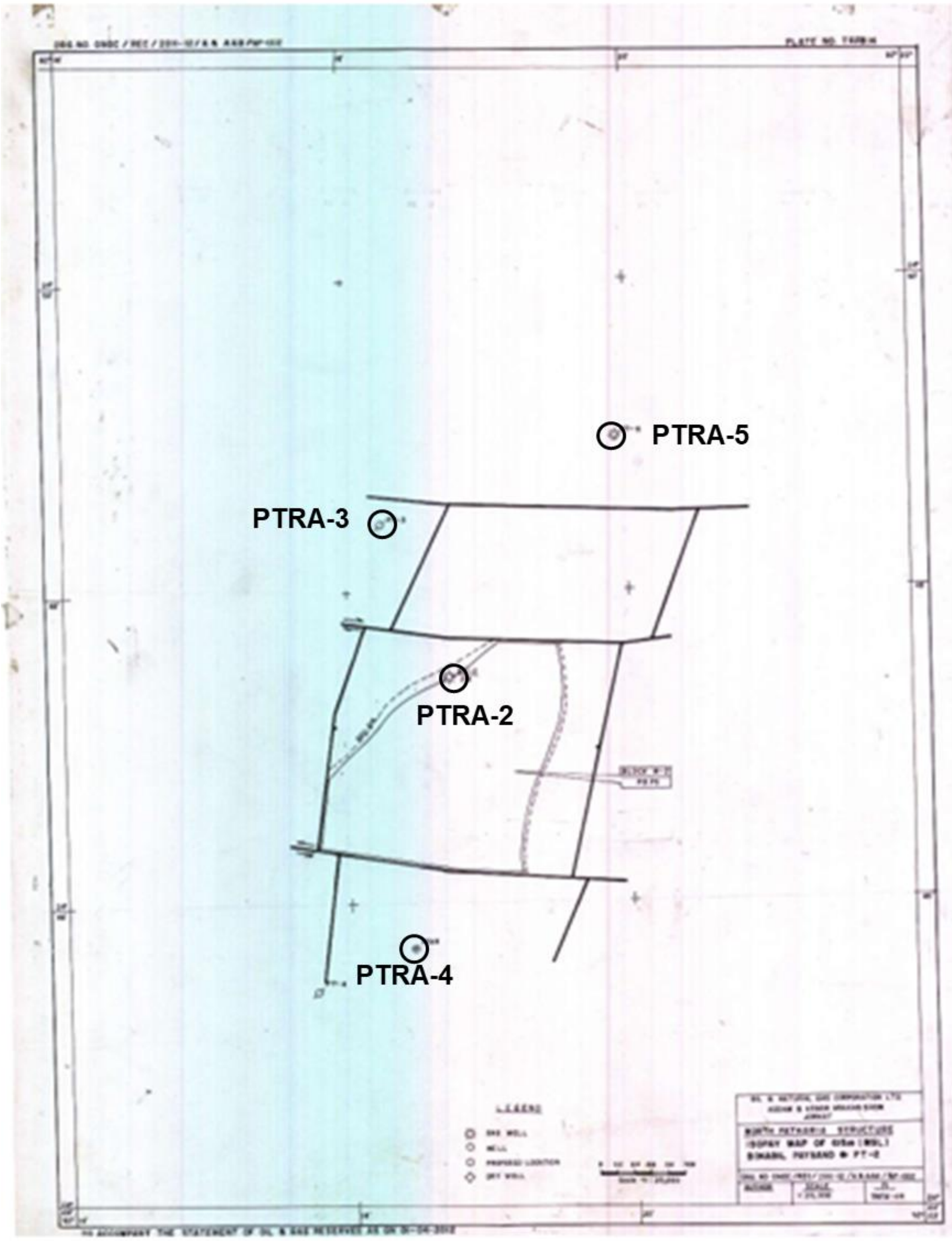


Figure 4-160 :. NET SAND/ PAY MAP OF BOKABIL :



4.9.5.2 Reservoir parameters and hydrocarbon estimates (PTRA-2) Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Petrophysical parameters and hydrocarbon estimates:

The petrophysical properties of the sands in Patharia-2 field and in-place are given in **Table 4-114 and Table 4-115.**

Table 4-114: PETROPHYSICAL PARAMETERS PATHARIA-2 FIELD

Petrophysical parameters and hydrocarbon estimates Patharia-2 Field	
Reservoir: Bokabil_Miocene (640 – 643 m)	
Area:	5.0 sq.km (map based)
Thickness:	3.5 m
Porosity:	0.19
Hydrocarbon saturation:	0.51
Formation volume factor:	0.00742

Table 4-115: HYDROCARBON IN-PLACE (2P) PATHARIA-2 FIELD

Field	Initial In-place
	O+OEG MMTOE
PATHARIA-2	0.23

Erstwhile Operator-reported estimates on record:

The field, Patharia-2, has reported gas estimate of **0.18 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant a possible revision of the currently reported estimates.

4.9.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Patharia field is **Banaskandi GCS (88KM)**

AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-5 FIELD

4.10 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-5 FIELD

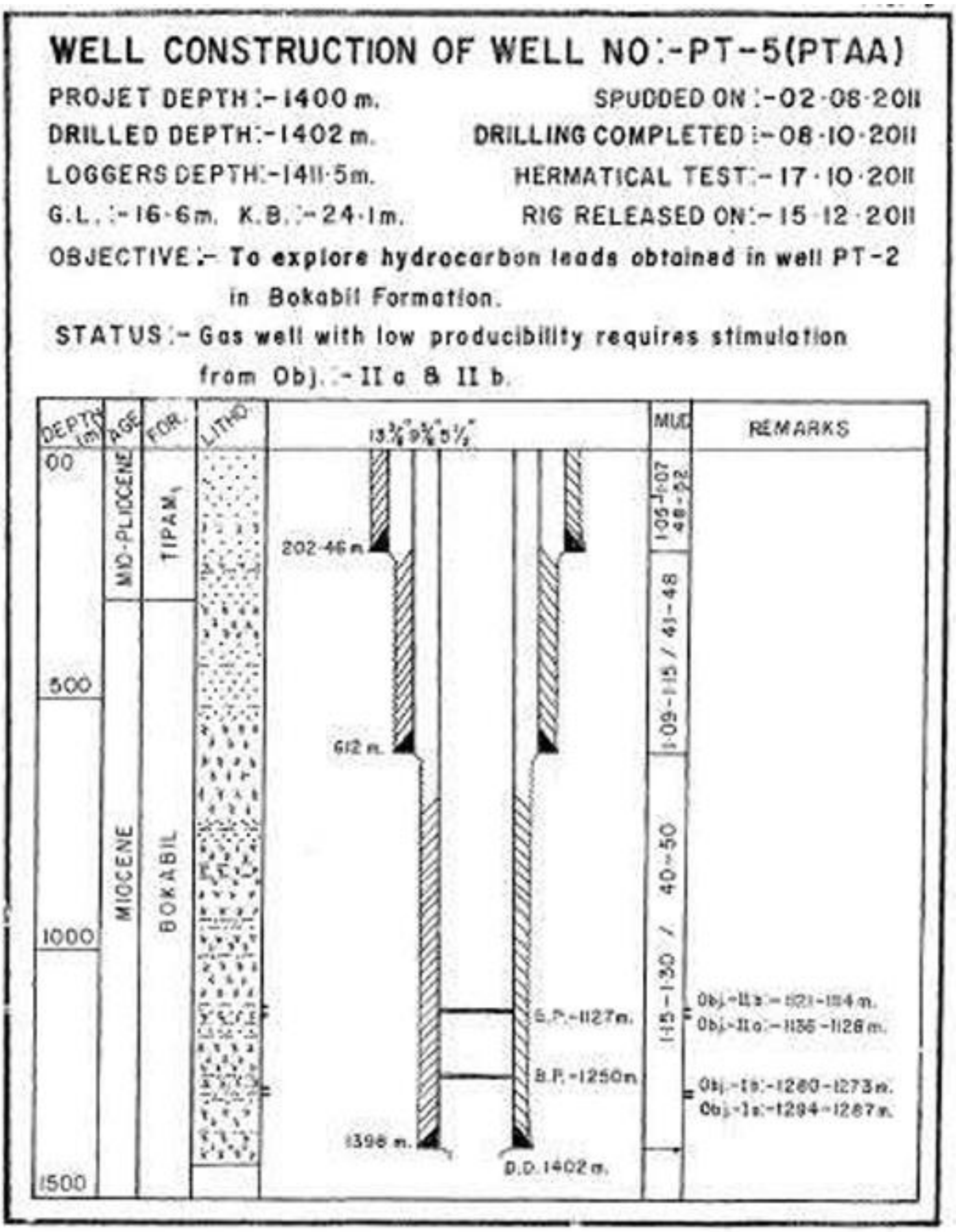
The exploratory location PTAA (Patharia-5) was proposed in 2010 to explore the hydrocarbon leads obtained in well PTRA-2 in the Bokabil Formation. The well is located in the northern plunge of the Patharia anticline, which is flanked by the Juri Syncline of Bangladesh to the west, Nilambazar Syncline to the east, and Adamtila Structure to the southeast. The central crest of the structure lies in Bangladesh, and only the northern and southern plunges are present in India.

4.10.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates, are made available in Sections through various cross-references.

Well diagram of Patharia-5 is given below in **Figure 4-161**,

Figure 4-161 :.WELL PROFILE OF PATHARIA-5 :



4.10.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.10.2.1 Well completion and log evaluation reports availability (PTRA-5) :

WCR/ FER availability	Spud date	KB	Drilled depth
Both available	02.08.2011	24.1 m	1402 m

4.10.2.2 Well logs acquired (PTRA-5) :

Details of Electrologs recorded in Well PTRA-5 are tabulated below in **Table 4-116.**

Table 4-116: LOGS RECORDED IN PTRA-5

Section	Run-	Date of Recording	Logs Recorded	Interval (m)
12¼"	1	18-Sep-2011	DLL-MSFL-INCL-GR-SP-CAL	605-201.65
	2	19-Sep-2011	SDL-DSNL-CAL CSNGR	612.38-201.65 601.74-201.65
	3	19-Sep-2011	WSTT-GR	608.1-201.65
	4	19-Sep-2011	XRMI-GR	611-201.65
8½"	1	7-Oct-2011	DLL-MSFL-INCL-GR-SP-CAL	1282.3-612.9
	1	11-Oct-2011	DLL-MSFL-INCL-GR-SP-CAL	1409.9-1150
	2	11-Oct-2011	SDL-DSNL-CAL CSNGR	1410.4-612.9 1401.2-612.9
	3	11-Oct-2011	WSTT-GR	1407.73-612.9
	4	11-Oct-2011	XRMI-GR-CAL	1411.5-612.9
9⅝" casing	5	12-Oct-2011	CBL-VDL-CCL-GR	612.2-300

Section	Run-	Date of Recording	Logs Recorded	Interval (m)
5½" casing	1	24-Oct-2011	CBL-VDL-CCL-GR (0 psi) CBL-VDL-CCL-GR (700 psi)	1373-580 1330-1080

Conventional Cores:
No conventional core collected.

Side Wall Cores:
24 side wall cores collected in the 12 ¼" section on 21sep2011. No SWC was attempted in the 8 ½" section due to poor hole condition.

Zero-offset VSP
Zero-offset VSP was recorded from 1356m to 376m @ 20m intervals on 21-Oct-2011. SSW-offset VSP was recorded from 1360m to 660m @ 20m intervals on 22-Oct-2011. ESE-offset VSP could not be recorded due to malfunctioning of the Geotelemetry unit of the VSP tool. (**Table 4-117**)

Table 4-117: VSP RECORDED IN PTRA-5

MD (m)	TVD (m)	X Offset (m)	Y Offset (m)	Two Way Time (ms)	Subsea TVD
376	376	0	0	368	-351.9
396	396	0	0	386	-371.9
416	416	0	0	402	-391.9

4.10.2.3 Well log evaluation and initial test results (PTRA-5):

Petrophysical properties and Initial testing of Patharia-5 are given in **Table 4-118** . Log motifs of PTRA-5 are shown in **Figure 4-162, Figure 4-163, Figure 4-164, Figure 4-165 and Figure 4-166.**

Table 4-118: PETROPHYSICAL PROPERTIES AND INITIAL TESTING RESULTS OF PATHARIA-5

<table>
<tr><th>Interval
(mMDRT/mTVDSS)</th><th>Formation (+ Zone, if specified)</th><th>Gross(m)</th><th>Net(m)</th><th>Phi</th><th>Sw</th></tr>
<tr><td rowspan="8">300-1411.5 /
275.9-1387.4</td><td>Bokabil_Miocene(1287-1294 mMDRT)</td><td>7</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td colspan="5">Initial testing results: Interval 1287.0 - 1294.0 m was tested as Object-Ia. During activation with compressor, well flowed mild gas (flame height 1-2 ft) with water of salinity 18720 ppm</td></tr>
<tr><td>Bokabil_Miocene(1273-1280 mMDRT)</td><td>7</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td colspan="5">Initial testing results: Interval 1273.0 -1280.0 m as Object-Ib was tested. On activation with compressor, well flowed mild gas (flame height 1.5 ft) with water of salinity 18135 ppm</td></tr>
<tr><td>Bokabil_Miocene(1128-1136 mMDRT)</td><td>8</td><td>4.0</td><td>0.12</td><td>0.65</td></tr>
<tr><td colspan="5">Initial testing results: Object-IIa in the interval 1128.0 -1136.0 m was tested. During activation with compressor, well flowed mild gas (flame height 4 – 12 ft) intermittently with water of salinity varying from 16401- 17572 ppm and Qg @ 2500 scmd.</td></tr>
<tr><td>Bokabil_Miocene(1114-1121 mMDRT)</td><td>7</td><td>3.5</td><td>0.14</td><td>0.64</td></tr>
<tr><td colspan="5">Initial testing results: The sand interval 1114.0 - 1121.0 m was tested as Object-IIb. During activation with the compressor, well flowed mild gas (flame height 3-4 ft) intermittently with water of salinity 18135- 19305 ppm.</td></tr>
</table>

Figure 4-162 :.WELL LOG MOTIF OF PATHARIA-5 BOKABIL :

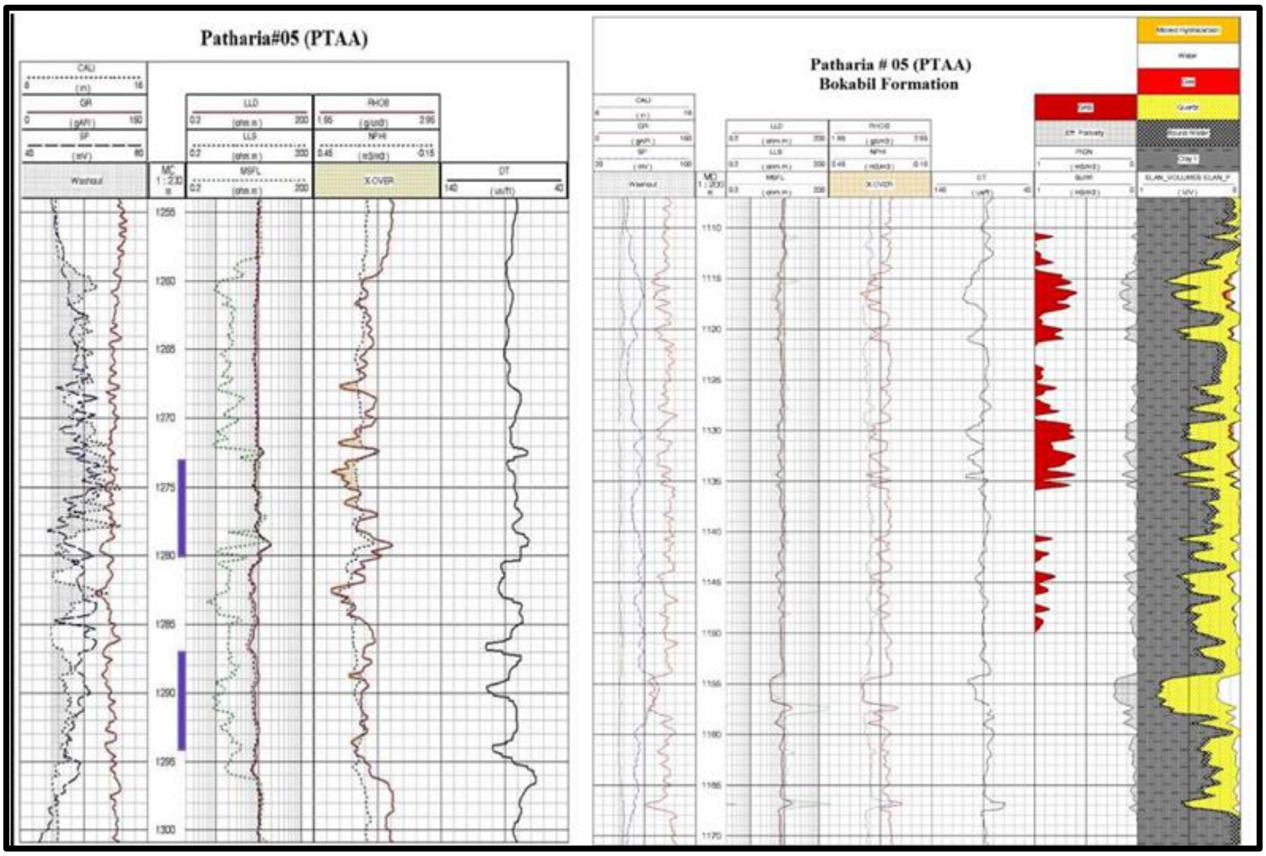


Figure 4-163 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IA

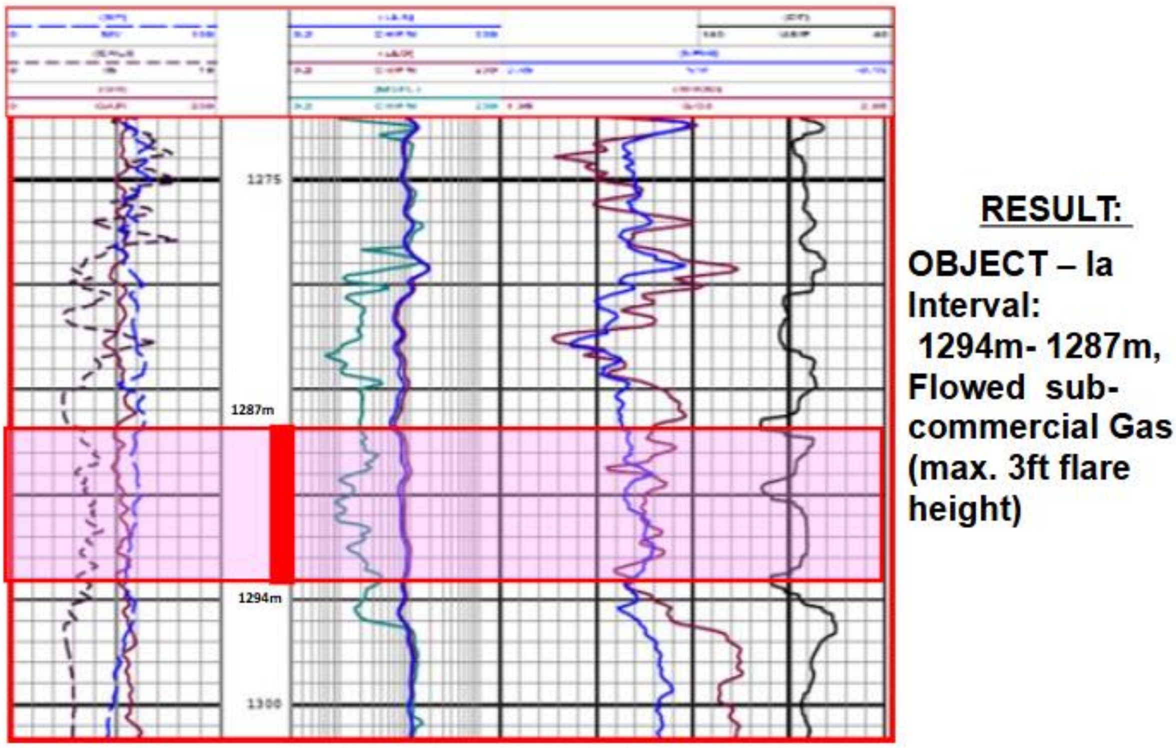
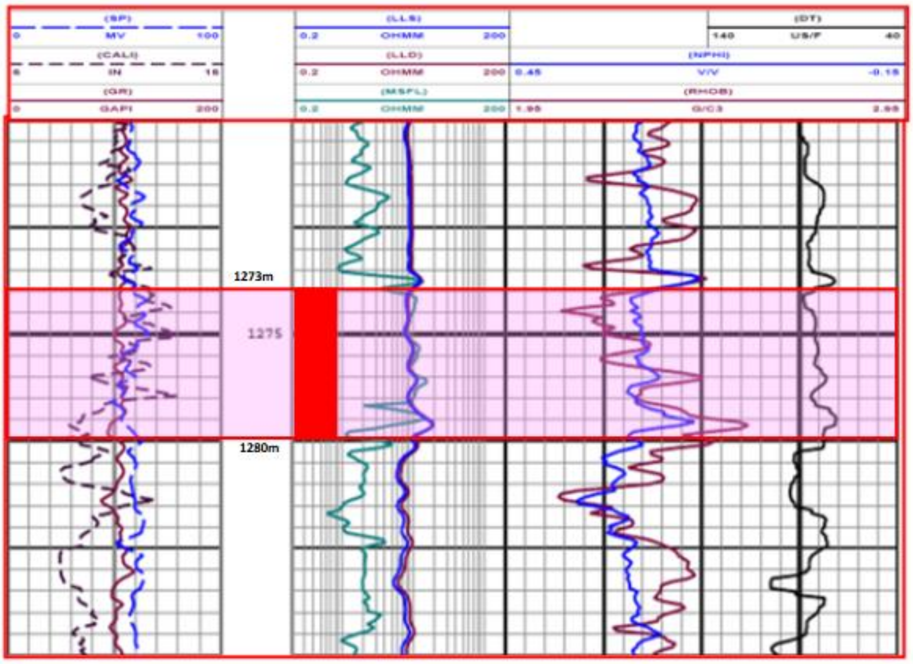


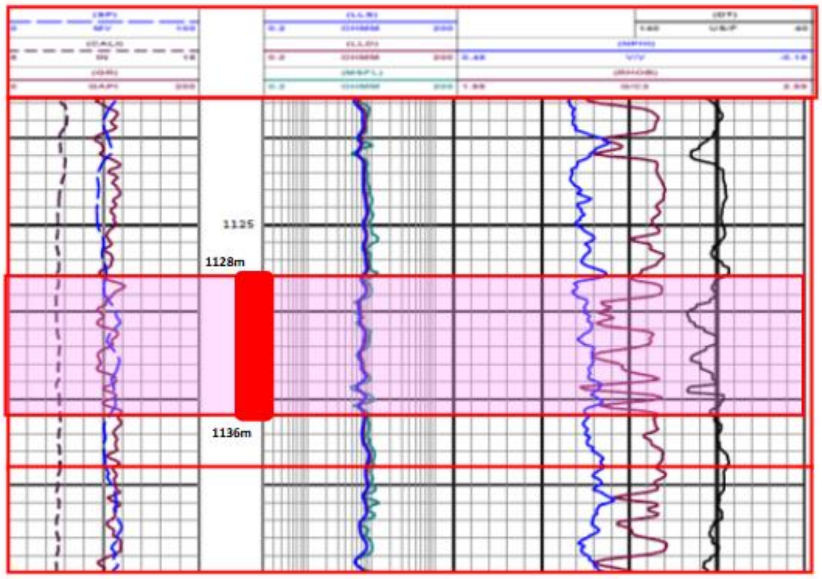
Figure 4-164 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IB



RESULT:

Object-Ib
Interval:
1280m -1273m,
Flowed sub-Commercial Gas
(max. 3ft flare height)

Figure 4-165 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IIA

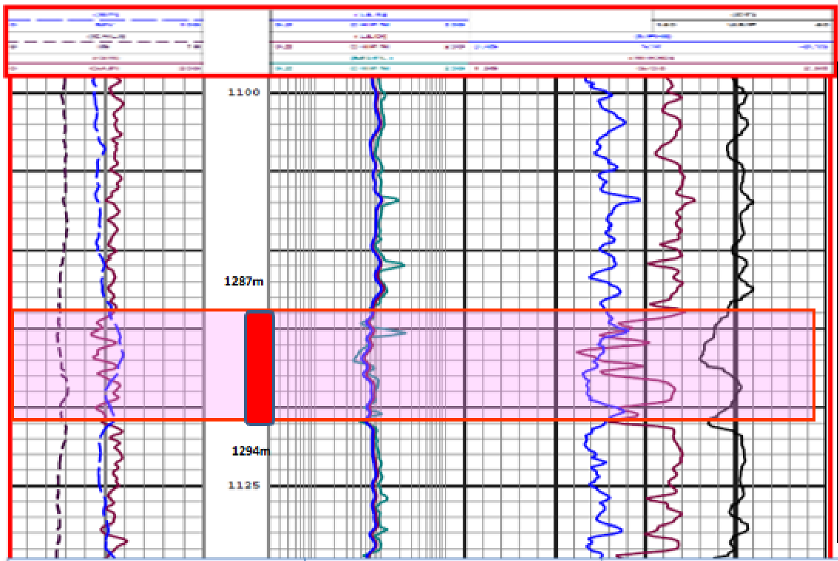


RESULT:

OBJ: IIa
INT:1136m-1128m,
FLOWED GAS WITH LITTLE WATER IN SURGES/ 3mm BEAN/ @9,400m3/d, MAX FTHP:44KSC.
After 30Hrs shut in STHP:109KSC/ SCHP: 90KSC.
Flowed gas for 10days continuously, pressure not stabilized.

Bean Size	FTHP (KSC)	Qg (m3/d)	Qw (m3/d)
3mm	44 (Max.)	9,400	Little water in surges
Note: Pressure not stabilized. Flow measurements were carried out after 49hrs shut-in.			

Figure 4-166 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IIB



RESULT:

OBJECT:IIb
Interval: 1121-1114m
FLOWED GAS WITH Little water in surges/4 & 3mm/ 4820 & 3160m3/d; FTHP:67/65KSC max/ 4/3mm.
After 49hrs Shut In: STHP:114 KSC/ SCHP 98 KSC.
Flowed gas for 21days continuously, pressure not stabilized.

Bean Size	FTHP (KSC)	Qg (m3/d)	Qw (m3/d)
3mm	67 (Max.)	3,160	Little water in surges
4mm	65 (Max.)	4,820	
Note: Pressure not stabilized. Flow measurements were carried out after 49hrs shut-in.			

4.10.3 Well testing and workover history

The sand layer interval 1287-1294 m was tested as Object-Ia. During activation with compressor, well flowed mild gas (Flame height 1-2 ft) with water of salinity 18720 ppm.

The interval 1273-1280 m was tested as Object Ib. On activation with compressor, well flowed mild gas (flame height 1.5 ft) with salinity 18135 m.

Object-IIa (1128-1136m), on activation with compressor, flowed mild gas (Flame height 4-12 ft) with water of salinity varying from 16401-17572 ppm and Qg @ 2500 scmd.

The sand interval 1114.0-1121m was tested as Object-IIb. During activation with compressor, well flowed mild gas (Flame height 3-4ft) intermittently with water of salinity 18135-19305 ppm.

Well was declared as low producible gas well, requiring stimulation.

Testing details in wells PTRA-1, PTRA-2, PTRA-3, PTRA-4 and PTRA-5 in **Table 4-119.**

Table 4-119: TESTING DETAILS IN WELLS PTRA-1, PTRA-2, PTRA-3, PTRA-4 AND PTRA-5

Well	Obj. No.	Interval (m)	Formation	Testing Results
	In Bokabil Formation, a few gas bearing sands in the interval 479-481m, 483-486m, 613-620 m, 639-642m, 913-919m, 1071-1075 m, and 1138-1142m were identified, but could not be tested. Three Objects in U.Bhuban were tested by CHDST in 9⅝" casing. 5½" casing was not lowered due to lack of interesting zone below 9⅝" casing shoe at (2487.25m).			
PTRA-1	I	2035-2032	U. Bhuban	Influx of 5.7 m3 of mud/ filtrate. Maximum sal -3.46 gpl as NaCl. Reservoir pressure 345 Kg/Cm2
	II	1995-1989	U. Bhuban	Surface flow of gas with influx of 2.4 m3 of formation water. Maximum sal 8.19 gpl. Reservoir pressure 326 Kg/Cm2
	III	1940-1936	U. Bhuban	Influx of 5 m3 of formation water. Maximum sal. 14.63 gpl. Reservoir pressure 309 Kg/Cm2
PTRA-2	I	1042.0-1043.5	Bokabil	Yielded 63.60 m3 of water with mild gas. Salinity : 16.38 gpl (as NaCl). STHP : 55 Kg/ cm2, SCHP : 65 Kg/ cm2
	II	931.0-933.5	Bokabil	Yielded 49.54 m3 of water with mild gas. Salinity : 14.04 gpl (as NaCl). FTHP : 10 Kg/ cm2, SCHP : 40 Kg/ cm2
	III	911.0-913.0	Bokabil	Yielded 13.90 m3 of water with mild gas. Salinity : 15.21 gpl (as Nacl). STHP : 55 Kg/ cm2, SCHP : 62 Kg/ cm2
	IV	640.0-642.0	Bokabil	Produced 11761 m3/ day of gas through 20/64” bean, FTHP: 56.892 psi. wtr traces Produced 10246 m3/ day of gas through 16/64” bean, FTHP: 142.23 psi. wtr traces Produced 9804 m3/ day of gas through 12/64” bean, FTHP: 156.453 psi. wtr traces Produced 8531 m3/ day of gas through 10/64” bean, wtr traces. FTHP: 227.568 psi.
PTRA-3	Abandoned due to drilling complications			

PTRA-4	I	3047-3044	L. Bhuban	No/ Negligible influx with mild gas. Sal of bottom sample is 572 ppm.
	II	2985-2982 2975-2971	L. Bhuban	No/ Negligible influx. Sal of bottom sample is 580 ppm.
	III	2907-2902	L. Bhuban	Water trickling
	IV	2845-2842	M. Bhuban	No influx. Only technical water with mild gas on activation.
	V	2793-2790	M. Bhuban	Water with mild gas. Max influx 1.46m3 of water. Max sal of bottom sample is 14000ppm. Object concluded as having poor permeability.
	VI	2759-2750 2743-2738	M. Bhuban	Technical water with feeble flow of gas Object concluded as having No/ Negligible influx.
	VII	2714-2710	M. Bhuban	Water with mild gas on activation. Max Sal at 110 Kg/cm2 & 17740ppm. Object concluded due to poor permeability and negligible influx.
PTRA-5	Ia	1294-1287	Bokabil	Flowed sub-commercial Gas (max. 3ft flare height) with water. Self flow of technical water @150 lt/hr
	Ib	1280-1273	Bokabil	Flowed sub-Commercial Gas (flare height of 1 foot and reached upto 3 feet.) with water. Self flow of technical water followed by gas with a flame height
	IIa	1136-1128	Bokabil	Flowed Gas @ **9400m3/d**/3mm/ with little water in surges. FTHP: 44KSC at the time of flow measurements. After 30Hrs Shut-In STHP:109KSC / SCHP: 90KSC.Flowed Gas for 10days continuously, pressure not stabilized. Salinity: 21,000ppm as NaCl
	IIb	1121-1114	Bokabil	Flowed Gas @ **3160m3/d**/3mm/ and **4820m3/d**/4mm with little water in surges. FTHP: 67/65KSC at the time of flow measurements. After 49 Hrs. Shut In STHP: 114KSC/ SCHP: 98KSC. Flowed Gas for 21days continuously pressure not stabilized. Salinity: 24570ppm as NaCl.

4.10.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

Formation dynamics tests (PTRA-5)

16 pressure tests were attempted in the 12 ¼" section from 19-21 Sep 2011. No RDT pressure tests were attempted in the lower 8 ½" section due to gas bubbling and intense well activity, (**Table 4-120**)

Eight RDT samples were attempted and collected in the 12 ¼" section from 19-Sep-2011 to 21-Sep-2011. No RDT sampling was attempted in the lower 8 ½" section due to gas bubbling and intense well activity. (**Table 4-121**)

Table 4-120: RDT PRESSURE TESTS IN PTRA-5

Sr. No.	Depth (m)	Temp (°C)	Hydrostatic Pressure (psi) Before	Hydrostatic Pressure (psi) After	Pore Press. (psi)	Statistical Validity (%)	Exceeding Stability
1	209.97	100.6	347.18	347.44	306.41	45.2	Excellent Stability
2	243	102.1	400.26	400.6	353.13	54.3	Excellent Stability
3	247.99	101.6	415.55	415.07	359.85	11.3	Excellent Stability
4	254.98	101.3	425.65	425.34	366.82	17.9	Excellent Stability
5	289	104.3	491.83	491.57	417.61	37.9	Excellent Stability
6	381.98	101.2	629.74	629.43	549.01	79.2	Excellent Stability
7	386.99	101.6	635.88	635.9	556.04	70.1	Excellent Stability
8	392.99	101	649.87	649.24	565.64	24.5	Excellent Stability
9	399.01	101.6	656.4	656.17	572.91	11.4	Excellent Stability
10	415.02	101.7	681.44	681.71	595.64	62.4	Excellent Stability
11	419.79	104.4	712.22	712.04	601.4	39.9	Excellent Stability
12	461.02	105	782.23	780.83	660.17	12.7	Excellent Stability
13	470.01	101.7	773.11	773.17	673.56	95.1	Excellent Stability
14	496.04	104.8	839.41	839.37	709.82	45.5	Excellent Stability
15	525.19	104.4	891.85	891.18	751.56	61.6	Excellent Stability
16	531.04	101.3	876.68	876.53	759.78	129	Excellent Stability

Table 4-121: DETAILS OF RDT SAMPLES OF PTRA-5

Stn	Depth (m)	Pressure (psia)	Temp. (°F)	Spherical Mobility (md/cp)	Water Analysis Salinity (ppm as NaCl)	Water Analysis pH	Gas Analysis (% mole) CH_4	Gas Analysis (% mole) CO_2	Gas Analysis (% mole) N_2
1	243*	352.66	101.3	644.93	351	9.0	-	0.413	99.587
2	289	417.61	104.3	373	585		-		100
3	382*	548.09	101.6	73.06	819	8.5		0.898	99.102
4	393*	564.25	100.9	6977.33	819	9.0	4.496	0.691	94.814
5	419.5	601.4	104.4	399	761	10.0	6.651	0.436	92.913
6	461	660.12	105	127	878	9.0	-	0.207	99.793
7	496	709.82	104.8	45.5	1404	9.0	5.287	0.311	94.402
8	525.5	751.56	104.4	61.6	819		2616	1046	96.338

Side wall cores:

24 SWCs were recovered, which show gross lithology as sandstone with NF/NC. Tipam formation is of no interest from hydrocarbon point of view. On the basis of log evaluation and gas indications during drilling, four intervals in the Bokabil formation were identified for production testing.

The following objects were tested in well PTRA-5 (**Table 4-122**): -

Table 4-122: IDENTIFIED ZONES FOR PRODUCTION TESTING IN PTRA-5

Object	Interval (m)	Formation	R (Ωm)	N (%)	S (%)	Perforation Density (SPM)
I A	1295*-1287	Bokabil	6-8	19-22	60	18
I B	1280-1273	Bokabil	7-8	18-21	63	18
II A	1136-1128	Bokabil	8-10	19	68	18
II B	1121-1114	Bokabil	8-9	19	72	18

*In order to avoid casing collar, the interval of Object-IA was modified to 1294-1287m.

4.10.5 Geology and Reservoir Description of PTRA-5 Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.10.5.1 Geological correlations, sections and maps (PTRA-5 Field):

The Patharia Structure falls in the Cachar Fold Belt. Patharia Anticline is the westernmost structure in the Cachar Fold Belt. It is bounded by the Indo-Bangladesh border in the west and south-west, Nilambazar Syncline in the east, and Adamtila Gas field in the south-east. It is a tightly folded, doubly plunging, NNE-SSW trending, from Karimganj in the north to Dashgram in the south. The central crest part of the structure lies in Bangladesh, and only the northern and southern plunging parts of the anticline are present in India. In the northern plunge, the eastern limb is steeper than the western one, whereas the reverse is the case to the south. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault downthrown towards the east is seen in the eastern flank. Patharia is the structurally highest uplifted structure in the Surma Trough. A thick sequence of Neogene section is exposed in the Patharia structure. These formations are, from top to bottom - Dupitlla, Girujan Clay, Tlpam, Bokabil, and Bhuban. Tipam and Bokabil Formations are exposed in the Cachar part, whereas Middle Bhuban is exposed in the core of the doubly plunging anticline in the Bangladesh part. The northern plunge of the Patharia anticline exhibits prograding updip sand bodies from NE-SW, which form favourable locales for trapping hydrocarbons.

The seismic Inline 650 and 590 show an anticlinal structure bounded by faults. Seismic maps have brought out longitudinal and transverse faults, which have created compartments in the plunging part. These compartments are proven gas-bearing blocks.

Around 6.5 m of gas pay has been encountered at the well location in two sand ranges within Bokabil.

Seismic sections along the wells, Geological cross-section of the area, Time structure map of BOKABIL and BHUBAN, Depth structure and net sand maps of BOKABIL, and Bokabil thickness map of Patharia field are given in **Figure 4-167, Figure 4-168, Figure 4-169, Figure 4-170 and Figure 4-171.**

Figure 4-167 :SEISMIC SECTIONS ALONG THE WELLS

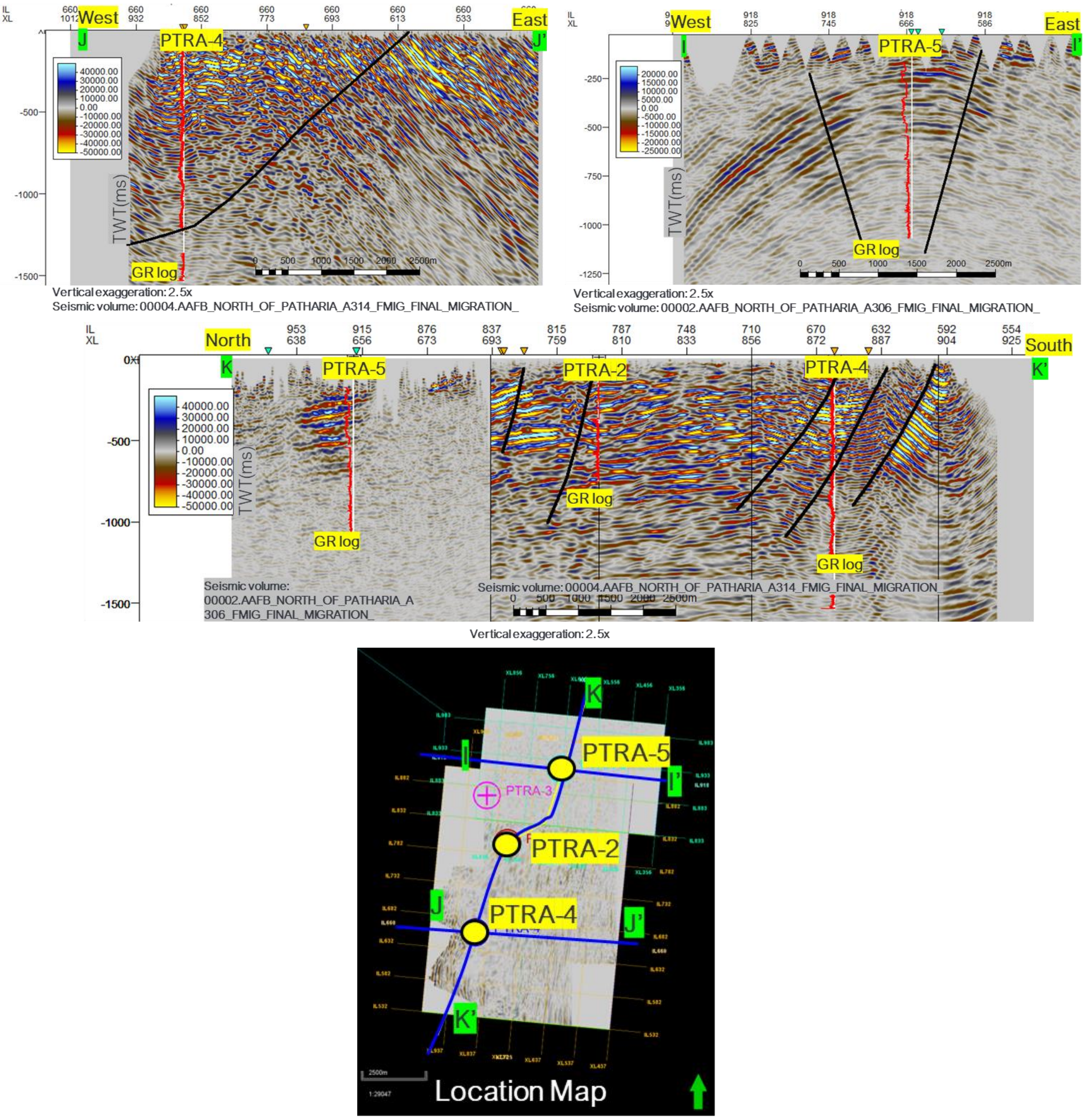


Figure 4-168 : GEOLOGICAL CROSS-SECTION OF THE AREA:

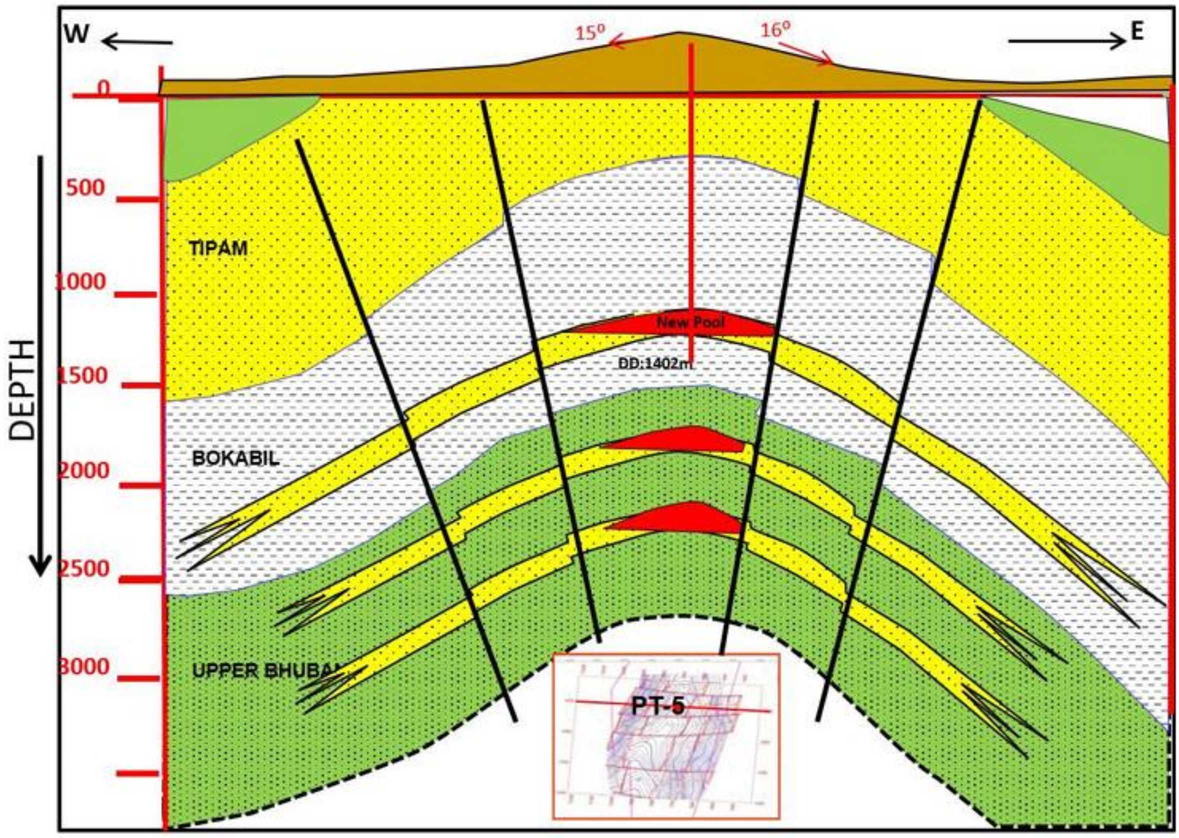


Figure 4-169 :TIME STRUCTURE MAP OF BOKABIL AND BHUBAN

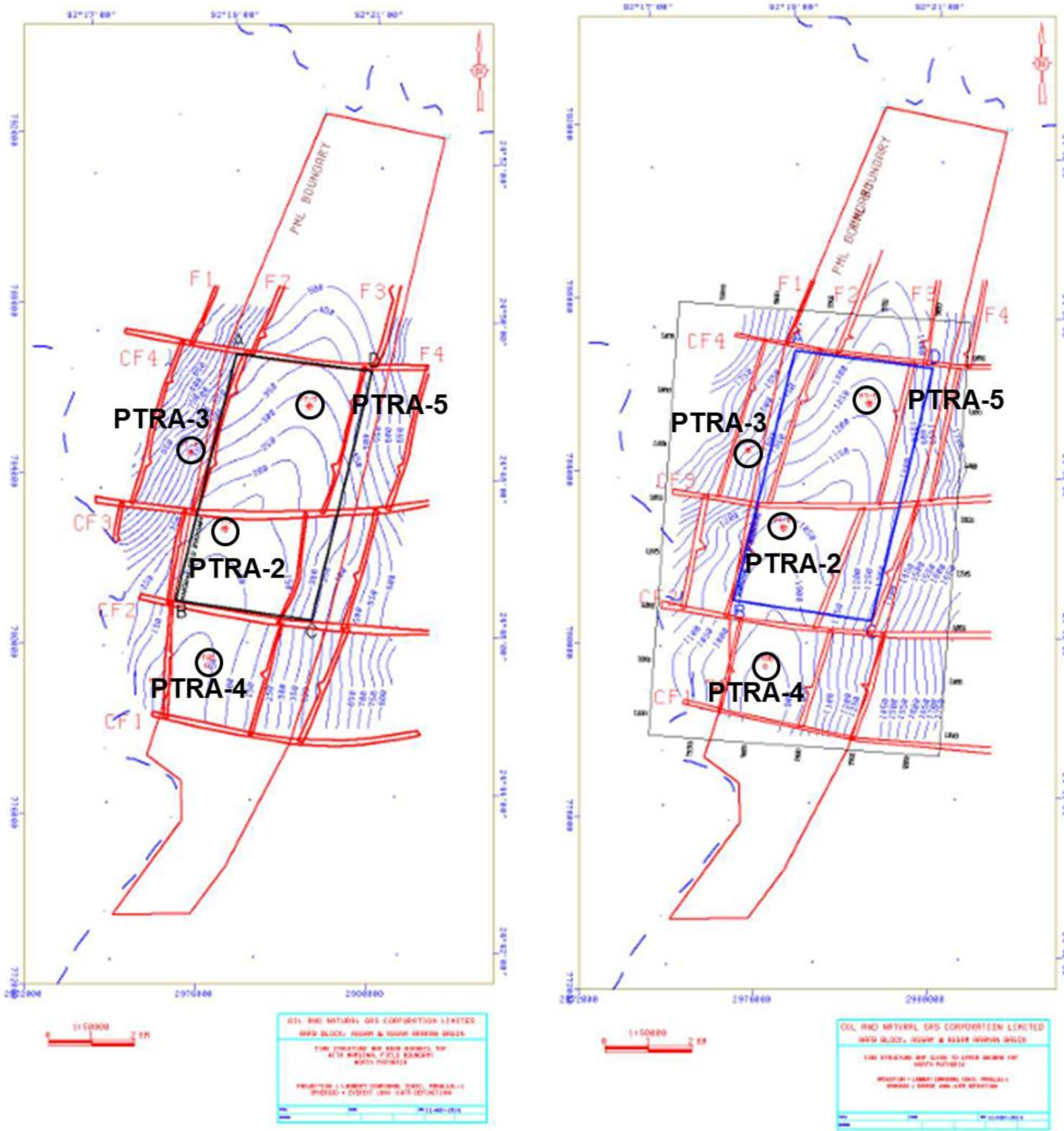


Figure 4-170 :DEPTH STRUCTURE MAP OF BOKABIL

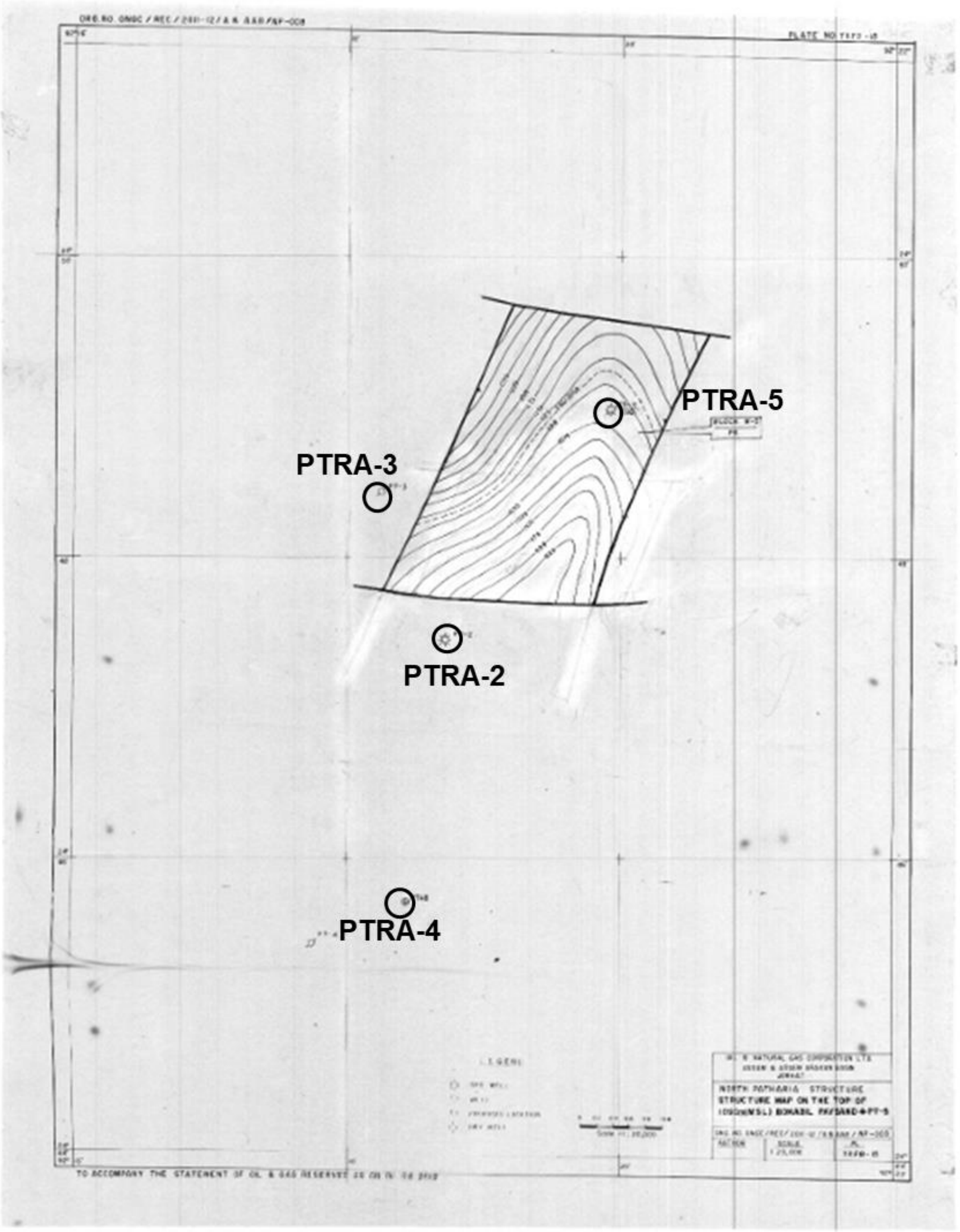
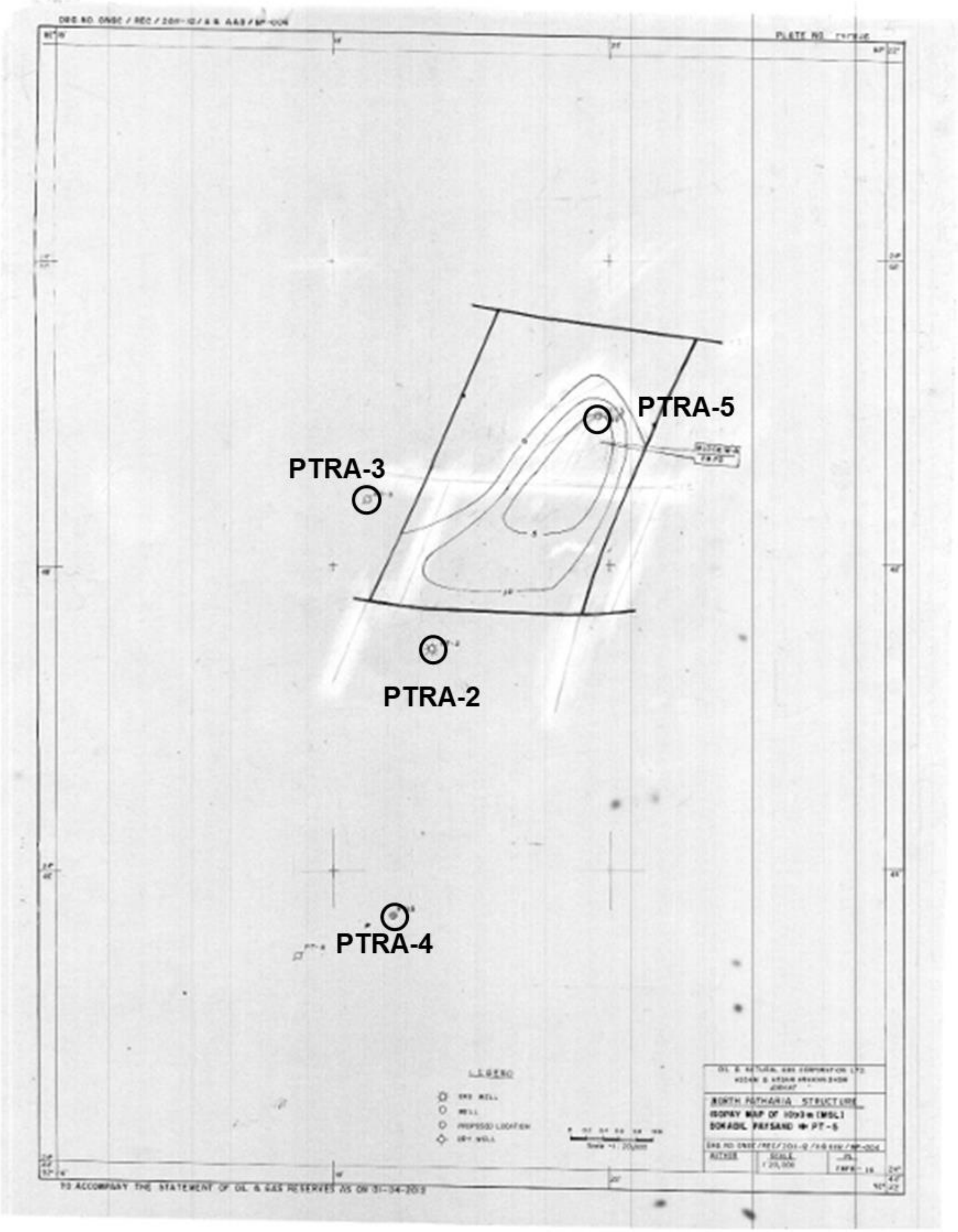


Figure 4-171 :NET SAND/ PAY MAP OF BOKABIL



STRATIGRAPHY (PATHARIA-5) field:

Based on the cutting sample analysis of the master log and the characters of electro log recorded, the following stratigraphic boundaries are envisaged in this well. The well PTRA-5 was drilled down to 1411.5m (logger's depth), and electro log was recorded from 1411.5m.

Stratigraphic sequence encountered in PTRA-5 and its correlation with nearby wells on the basis of cutting samples and electrolog data are given below in **Table 4-123, Table 4-124** and **Figure 4-172.**

Table 4-123: STRATIGRAPHIC SEQUENCE IN PTRA-5

Group	Formation	Age	Interval (m)	Thickness (m)
Tipam	Tipam	Mio-Pliocene	0-300	300
Surma	Bokabil	Miocene	300-1411.5+	1111.5+

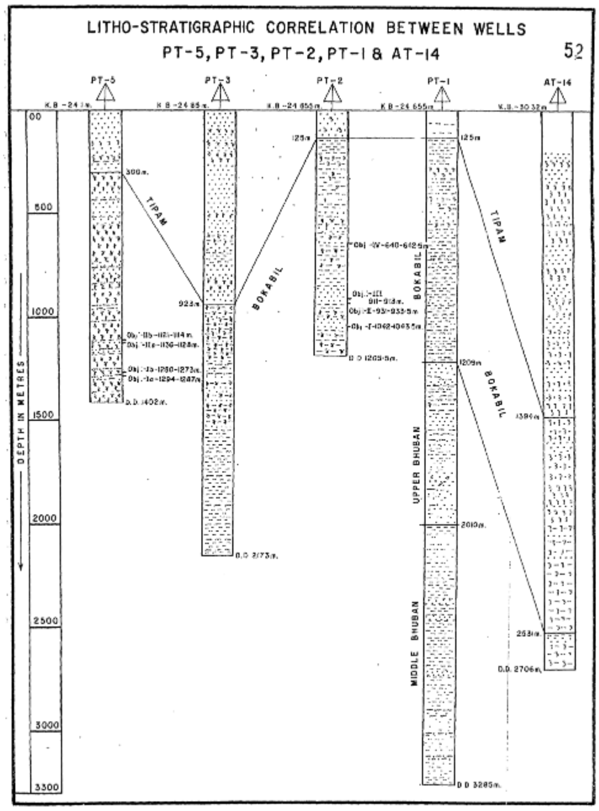
STRATIGRAPHIC Correlation in Patharia field (PTRA-1, PTRA-2, PTRA-3, PTRA-4 and PTRA-5):

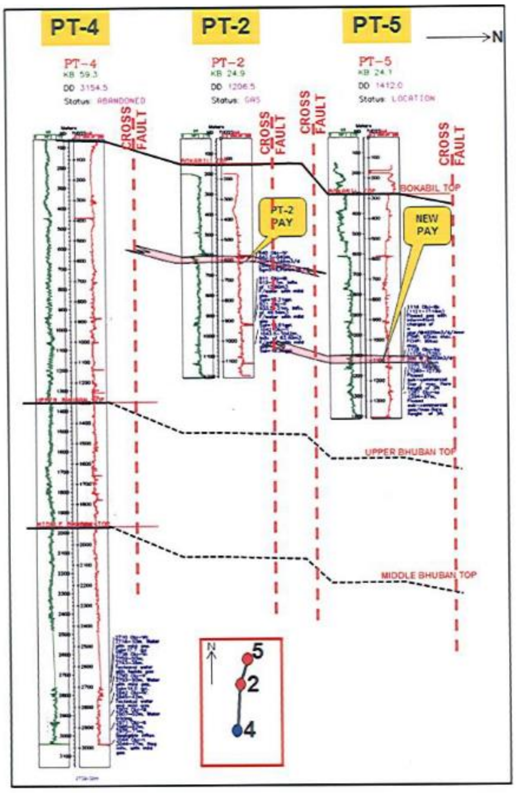
Table 4-124: STRATIGRAPHIC CORRELATION IN PATHARIA FIELD

Formation/ Well	PTRA-5	PTRA-2	PTRA-1	PTRA-3	AT-14
Tipam	Surface-300m	Surface - 150m	Surface - 150m	Surface - 948m	Surface - 1394m
Bokabil	300m-1411.5+m	150m-1206.5+m	150m-1234m	948m-2173.5+m	1394m-2531m

Logs show that the development of sandy facies is better in the well PTRA-5 in the Bokabil Formation compared to PTRA-2.

Figure 4-172 :. STRATIGRAPHIC CORRELATION IN PATHARIA FIELD





4.10.5.2 Reservoir parameters and hydrocarbon estimates (PTRA-5) Field

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Petrophysical parameters and hydrocarbon estimates:

The petrophysical properties of the sands in Patharia-5 field and in-place are given in **Table 4-125 and Table 4-126**.

Table 4-125: PETROPHYSICAL PARAMETERS AND VOLUMETRIC ESTIMATES

Formation	Reservoir	Object	Interval (m)	Map Area SqKM	Thickness m	Porosity %	Shc	FVF rm3/scm3	GIIP MMm3
Miocene	**Bokabil**	**IIa**	1136-1128	**4.1**	4.0	0.12	0.35	0.00742	92.8
Miocene	**Bokabil**	**IIb**	1121-1114	**4.1**	3.5	0.14	0.36	0.00742	97.5
									190.3

Table 4-126: HYDROCARBON IN-PLACE (2P) PATHARIA-5 FIELD

Field	O+OEG MMTOE
PATHARIA-5	**0.19**

Erstwhile Operator-reported estimates on record:

The field, Patharia-5, has reported a gas estimate of **0.14 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the current reported estimates

4.10.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Patharia field is **Banaskandi GCS (88KM)**

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4.11 STATUS OF ADDITIONAL WELLS IN AA/ONDSF/ASSAM/2025 CONTRACT AREA

The Contract Area is a single area with 8 discoveries/fields (LXMJ-1A, BHBR-1, BRSL-1, CRDO-1, KHEREM-2, PTRA-2, PTRA-5 and TUKB-2) and 20 additional wells. The status of the additional well(s) has been described field-wise in the following section. Where reports/information were not available/accessible at the time of writing this report, the same may be enquired with NDR later.

LAXMIJAN field:	
LXMJ-2	The well LAXMIJAN-2 (LJE) is an exploratory test well on Laxmijan Structure. The well has been drilled upto a depth of 4760 m with an objective to explore Barail formation. Well was spudded on 22.03.97 and was drilled vertically upto the depth of 4142 M. Drilling was suspended on 06.09.97 as the rig was deputed for Bangladesh operation. Again, the drilling was resumed after finishing the Bangladesh operation on 10.02.2000. The well was drilled vertically upto the target depth i.e. 4757 m and rig was released on 25.12.2000.Open hole log data was acquired in five stages covering the stratigraphic units Girujan Clay Section, Tipam, Surma, Barail and other sequences. No conventional core was cut in this well. On the basis of available geological informations and by correlation with Laxmijan-1A, only one object was identified for production testing in TS-5A. On testing Object-1 in the interval 3393-3399 m flowed water.
BIHUBAR field:	
Bihubar 2	Bihubar 2 is the second exploration well drilled South East of Bihubar-1 on Bihubar structure to know the hydrocarbon prospects of Tipams and Barails. The Bihubar structure is located close to Naga thrust Northeast of Geleki field. The target depth (extended) for this well was 4600 m depth; but the well had to be terminated at the depth of 4485 m (driller's depth) due to some technical problem. This well has crossed two thrusts viz., Cholsima and Naga thrusts at depths of around 750 and 1950 m respectively as per geological information. The earlier well Bihubar-1 was drilled down to Barails, but this well also had to be abandoned at the depth of 4020 m due to technical complications and no zone could be tested either in Tipams or in Barails. However, Tipam Sands were interpreted as water bearing and a few layers in Barails were interpreted as hydrocarbon bearing on the basis of well logs.
Bilhubar-3 (BMA)	Bilhubar-3 (BMA) is an exploratory step out well for the sand body within the Girujan Clay which could not be tested in Bilhubar-2 as it was behind double casing. It has been drilled upto a depth of 2067 M with a vertical shortening 55.83 M at 1792.0 M. The well has deviated from 756.0 M. The interval 623.0-640.0 M (Log Depth) in Barail Main Sand appeared hydrocarbon bearing. Conventional core in the interval 616.0-641.0 M shows bright GYF and +ve cut. Electrolog correlation with Bihubar-2 shows that the sands in the interval 1740.0-TD of Bihubar-3 is equivalent of 1854-1950 M in Bihubar-2, characterised by GYF in SWC, but structurally lower by 30 M at 1940.0 M. These sands appear to be within Girujan Clay Section. Thrusts viz Cholingen and Naga are crossing at depths 755.0 M and 1705.0 M respectively. In Girujan Clay sands the intervals 1959-1954 M, 1947-1943 M showing comparatively lower water saturations than the underlying intervals, needed testing. The interval 1902-1905 M in Girujan Clay appears hydro-carbon bearing (Sw - 50%). Two objects were tested conventionally (1960–1951m. & 1947m.–1942m.) **Obj-I: 1959.0-1954.0 M**, produced **water** (salinity = 0.1053–0.2924 gm/lit.) with traces of oil—the oil probably be dead oil, coming from invaded zone, which was spotted while the drill string got stuck at the final depth. **Obj-II: 1947.0-1943.0 M**, testing could not be completed due to complications (tubing got choked and later on stuck due to heavy sand cut) arose during testing. **Obj-III**: 1905.0-1902.0 M, Not tested **Obj-IV: 640.0-623.0 M**. Not tested It was decided to drill a vertical well (Bihubar-3A) from the same location as BMA.

Bihubar-3A	Bihubar-3A is an exploratory step out well for Tipam Sand 1 and was drilled upto 1986 M (log depth). Correlation with Bihubar-2 indicates that the sand for which the well was drilled, may be a part of Girujan Clay and may not belong to Tipam Sand 1. Although the uncertainties in the estimation of Sw makes the interpretation of fluid nature difficult, a few zones were recommended for testing on the basis of GIF in the present as well as in Bihubar-2 and Bihubar-3 and comparison of apparent formation water resistivity. These zones were tested; namely, (i) 1879-1888 & 1850-1864 (ii) 725-745 M and (iii) 620-641 M and all the three-zone yielded water.
Bihubar-4	The well Bihubar-4 was spudded on 7-7 1996 and drilled down to 3374m Drilled down to 3910m. Three objects were released and tested in Barails and Tipams as follows: Object I: 1879-1900 m in Barails was found to be water bearing. Object II: 1395-1420m in pre-Barails water with traces of oil and Object III: 1240-1300 & 1210-1215 m in Tipam was water bearing. The well is abandoned as dry.
BARSILLA field:	
Barsilla-2 (BRSL-2)	The well Barsilla-2 (BRSS-2) is 'B' category exploratory well, drilled on the Barsilla anticline with the objective to explore the hydrocarbon potential of Tipams and Barails. The well has been drilled to a planned target depth of 4500m. The well is located to the north of exploratory well BRSL-1 at a distance of about 424m & is at structurally highest position at TS-5 level. Another exploratory well BRSL-3 drilled from surface position of BRSL-1 with a drift of 163m at 2425m in direction 282.4°N was drilled up to Tipams. The well BRSL-3 drilled in year 1984 up to Tipams, the testing of object in Tipam sand was inconclusive. In the nearby well BRSL-1 drilled in year1983, the Barails & Kopili were devoid of hydrocarbons but a number of zones within Tipam section-TS-6, TS-5A, TS-3, TS-2 produced water. One zone in TS-1 produced gas @ 7788M^3/d along with formation water but the testing was not taken as conclusive. In BRSL-2, 12 ¼" & 8 ½" section up to 3682m were drilled using LWD for the first time in Assam. The open hole logs were also run in these sections along with special logs. The comparison of two data shows that resistivity recorded with LWD to be nearer to true resistivity of the formations whereas exposure of open hole to the mud system over a long period of drilling time, the conventional open hole logs were more affected by deep invasion which might have resulted in missing potential zone like Tipam sand TS-3 based on uncorrected apparent resistivity. The 12 ¼"section up to 3306m & 8 ½" section in interval from 3306-3682m were drilled with LWD. The open hole conventional wire line Logging surveys were conducted in 17 ½", 12 ¼" (two stages) and 8 ½" (three stages). Against the objective formations, DSI, FMI were also run. In BRSL-2, on the basis of log interpretation, four intervals in Girujan were interpreted to be gas bearing. The TS-1 sand in the interval 1642-1660m & two intervals 3650-3653m, 3939-3944m in BCS formation are also interpreted as hydrocarbon bearing. One object in Kopili in the interval 4408-4414m was recommended for testing in preliminary log interpretation report. Although Girujan sands have good gas potential but were not tested as Girujan was not objective in this well. Testing of two objects in Kopili & Safrai formations were approved. The object-I: 4408-4417m in Kopili gave poor influx of water. The object II: 3604-3602.5m & 3592-3594m in Safrai also gave poor influx of water only. The well status is tested dry.
Barsilla-3 (BRSL-3)	Barsilla-3 was drilled on an anticline which was well defined in the upthrust block of doubly plunging Barsilla anticline. The well was spudded on 28th May 1984 and drilling was carried out to 2505 m as a deviated well with horizontal drift of 165.572 m towards N 77.56° W (282.44°) at 2425 m (planned drift 80 m towards 275°). Production casing could not be cemented properly due to mechanical shut down during cementing job. Three objects were tested. **Object-I** (interval 2196.5–2201.5 m) produced only water of **water** salinity 1.755 gm/lt.

	After repairing, **Object-II** in the interval (1754–1752 m and 1744–1750.5 m) was perforated. A total of 24 m³ of fluid (comprising **water, oil** (7.19 m³)) **with feeble gas** was knocked out while on activation. This interval did not attain self flow even after long time activation. The **Object-III** in the interval 1590–1586 m was tested and produced **water with minor oil** and gas (water salinity 1.755 gm/lt). Water production is suspected to be due to channeling and repairs are required to test Object-III conclusively. There is two other objects worth testing but need repairs. Workover rig required for repairing and testing. Status: Inconclusive testing in Object-III and status undecided.
CHARAIDEO field:	
CRDO-4	The well CRDO-4 was spudded on 24.06.2009 and was drilled down to 4708m (TD) against the targeted depth of 4700m. The well was terminated within the BMS Formation and was sidetracked three times due to drilling complications. During the course of drilling, hydrocarbon shows were observed in sands of Tipam Formation (TS-6), Rudrasagar Formation and Demulgaon Formation. The well CRDO-4 is correlatable with nearby wells CRDO#2 & CRDO-3 of Charaideo structure and NH#02 & NH#03 of Nahorkatia structure. At the top of LBS-II, well CRDO-4 is structurally down by 133m and 176m respectively from wells NH-02 and NH-03. At the top of BMS, well CD-04 is structurally up by 45m wrt CRDO-1. In the neighboring wells, object testing remained somewhat inconclusive (BCS & BMS respectively) due to technical reasons. Oil and gas indications were observed in BCS (Obj-VI) sand of CRDO-1 and BMS (Obj-I) sand of CRDO-2. The third well of Charaideo i.e. CRDO-3 (CDAA_Z) has flowed oil (intermittently) from Safrai Formation. All the sand layers developed within Girujan clay as well as all the Tipam layers (TS-2, TS-3, TS-4, TS-5 and TS-6; TS-1 not developed in this area) are interpreted water bearing. BCS Formation encountered in CRDO-4 well is mainly shale/coal alternations with highly washed out/bad-hole sections. The sand units LBS-II and LBS-I are interpreted either silty/poor reservoir facies or water bearing. The BMS sand encountered at 4558m (-4453.5m) is interpreted hydrocarbon bearing with OWC at 4571m (-4466.5m). GYF/+ve cut was observed in the interval 4570-4605m in the cutting samples during drilling. Conventional core recovered in the interval 4501-4508m shows GYF/+ve Cut. **On testing CRDO-4, Object-I (4566-58m/BMS) gave poor influx of oil. During activation observed 300LT of oil while subduing the well.** **Object II (4506-02m/ BCS) tested dry with no fluid influx.** Based on results of Obj-II, Object III (3932-28.5m/Safrai, lying behind double casing) was cancelled. **Due to poor influx it was recommended to retest the Object-I and improve the influx after Hydro-fracturing.**
KHEREM field:	
KHEREM-1	The well was drilled to explore the HC in Mio-Pliocene turbidite fans and the underlying Paleogene banded events. The well was drilled down to 3150 m against the target of 3800 m. **No hydrocarbons were encountered.** **Abandoned.**
KHEREM-3	Replacement well drilled at the plinth of Kharem 1.The well was drilled down to 2550 m against the target depth of 4000 m to explore turbidite fan prospects of Mio-Oligocene & Eocene sediments. During prolonged testing 4207 m sand in June-July 95 the well produced intermittently condensate (44.8 Deg. API) and little amount of gas. During prolonged testing

	of 4159 & 4123 m sand, the ell displaced little amounof gas and condensate. On testing 4063 m sand, it produced only water. As the hole size against the higher up sand ranges are very large and the correlatable (depth-wise) sand ranges of interest have been tested in KHM 2, it was decided not to test the higher up sand ranges. Hence it was not appraised and plugged back.
TUKBAI field:	
TUKB-1 & 1A	The well Tukbai-1 was drilled in 2003 to a depth of 3701m (3711m loggers' depth) to probe the hydrocarbon potential of Bhuban, Renji, and partly Jenam Formation. On the basis of analysis of well data, including electro logs, lab data etc, a thrust has been envisaged in the Renji Formation at 3185m. In the up-thrust section, the well has penetrated 452 m of Bokabil, 803 m of Upper Bhuban, 1105m of Middle Bhuban, 706 m of Lower Bhuban, and 119m of Renji Formation. In the sub thrust section, 465m thickness of Lower Bhuban and 61m thickness of Renji have been encountered. The Jenam Formation is not encountered up to 3700m in this well. A number of sand bodies have developed in this well, and six objects have been identified for testing. Barring the objects IV, V and VI which could not be tested due to complications leading to well abandonment, three objects were tested. **Object: I** (3587-3582 m) In Sub thrust Lower Bhuban, **Object II** (3175-3173 m) In Lower part of Renji Formation, **Object III** (3104-3100m,3095-3093m) Both Up thrusts. However, **all these objects were proved to be water bearing with no hydrocarbon show** Maximum water salinities obtained from objects I, II and III were 210.8 ppm, 263 ppm and 234.87 ppm as NaCl. Due to inordinate delay and complications in fishing of 2 7/8" tubing which fell inside the well leading to abandonment of the well TUKB-1 without testing of Object-IV (3065-3052m), ObjectV (2843-2833m,2830-2828m and 2825-2823m) and Object-VI (2413-2402m), a side-tracked well (TUKB-1A) was drilled through this well and remaining equivalent objects were tested later. As the three objects tested viz: I, II and III were proved to be dry, this well was declared as dry and abandoned.
TUKB-2	The well TUKB-2 in the Tukbai structure of Sector VC-PEL was drilled with an objective to explore hydrocarbon leads obtained in well TUKB-1/ 1A in Up- thrust Middle, Lower Bhuban and Renji formationThe well was spudded on 29.03.2010 and drilled up to 2387m on 04.07 2010 against the target Depth of 3500m. It penetrated through Bokabil formation (310m) and has penetrated Upper Bhuban (700m), Middle Bhuban (1140m) and Lower Bhuban (237m+). Target depth could not be achieved due to complication at shallow depth followed by **toppling of rig and further drilling of the well has been terminated. So, hydrocarbon potential of the well could not be ascertained at the expected zones underneath.** Considering the above, the well has been declared abandoned with the status "Abandoned due to Complication".
TUKB-3 & 3A	The location TUKB -3A (side-track) in Tukbai structure, falling in Sector V-C PEL block, is located at a distance of 400m towards 3420 from well TUKB-2. Before drilling this location, the well TUKB-3 (TKAC) was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Based on the results, the location TUKB-3(Sidetrack) was released to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 with a target depth of 900m (TVD) and planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218 degree at 811 m TVD MSL (top of gas sand). **Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.**
TUKB-4	The well Tukbai-4 (TKAD) was drilled with an objective to explore hydrocarbon potential of Upper Bhuban formation. It was spudded on 26.04.2016 and drilled as a vertical well with a

	target depth of 1200m. As no zone of interest was found, target depth was revised to 1755m, to encounter sands in Middle Bhuban Formation. During drilling the well penetrated through Bokabil and Upper Bhuban and was terminated within Middle Bhuban formation. Based on the log evaluation of the well, all the sand layers developed in Bokabil, Upper Bhuban and Middle Bhuban Formation are interpreted as water bearing. MDT was attempted in 8.5" section and carried out 17 pre-tests. Out of which13 pertest reported as tight. Only one water sample could be collected at 1217m with salinity 24.8 gpl and formation pressure 125. 30ksc. As no prospective zone could be identified from hydrocarbon point of view in all the Formations, the well was **abandoned without lowering production casing.**
PATHIMARA-1 (PTMR-1)	The well Pathimara-1 (PTMR-1) drilled down to the depth 3000m against the target depth of 3000m and bottomed in Jenam Formation. Maximum total gas content of 1.09% was recorded in MLU at depth 2158m. Maximum total gas 1.15% was recorded at 1190m in MLU during drilling. milky fluorescence and mild +ve cut were observed in SWC. On the basis of log evaluation, **four objects** in lower bhuban formation were tested conventionally and all are proved to be **water bearing**. In view of testing results, the well has been declared as "dry and abandoned".
PATHIMARA-2 (PTMR-2)	The well pathimara-2 (PTMR-2) was drilled as an exploratory "B" category well with a target depth of 2750m to explore clastic reservoir within upper and middle Bhuban formations. The well was drilled down to the depth of 2955m against extended target depth of 2950m and terminated in lower bhuban formation. No HC shows were observed during drilling. However, based on log evaluation two objects were tested in lower bhuban formation. Only feeble gas was observed in object-I (2848-2850m, 2851-2854m). Object-I was reperforated but **no indication of gas or any influx** observed. Based on testing results well has been declared as "Abandoned with gas indication".
PATHARIA field:	
PATHARIA-3 (PTRA-3)	The well Patharia-3 was planned at a target depth of 3750m but had to be prematurely abandoned at a drilled depth of 2173.5m due to drilling complications. The objective was to explore the hydrocarbon potential of the Surma Group. The well was spudded in Tipam Formation and encountered the Bokabil formation from 948m onwards. **Indication of gas were noticed at 2173.5m in Bokabil formation** however complications in the well started thereafter and well was Abandoned.
PATHARIA-4 (PTRA-4)	The well Patharia-4 is located on the western flank of patharia anticline, and drilled upto a depth of 3154.5m against the target depth of 3500m with an objective to explore the hydrocarbon prospectivity of the Surma group. After 3154.5 m due to drilling complications, the well was side-tracked upto 3065m (side-tracked). The well was spudded in Tipam sandstone formation and ended in lower Bhuban formation. The well encountered stratigraphic thickness of 125m of Tipam, 1142m of Bokabil, 639m of Upper Bhuban, 996m of Middle Bhuban, and 252.5m of Lower Bhuban formations. A Total of **7 objects; 3 in Lower Bhuban and 4 in Middle Bhuban formations were tested**, **none of which yielded hydrocarbons due to poor permeability and absence of good quality reservoir facies. The well was declared dry and Abandoned..**

5. DATA PACKAGE INFORMATION

This information docket for the Contract Area, titled, AA/ONDSF/ASSAM/2025 is available with Data Package, which includes seismic data, well data and well completion and other reports. Apart from seismic and well data, the Contract Area has 48 reports. Given below is the detail of datasets that are available in the Data Package.

5.1 Well, Seismic Data and Reports Availability

5.1.1 Well Data:

SL. No.	Well Name	Longitude	Latitude	CRS
1	LXMJ-1A	94° 47' 09.201" E	26° 47' 53.894" N	WGS84 UTM 46N
2	BHBR-1	94° 46' 20.495" E	26° 49' 22.705" N	WGS84 UTM 46N
3	BRSL-1	94° 37’ 15.590” E	26° 45’ 40.960” N	WGS84 UTM 46N
4	CRDO-1	94° 53’ 26.260” E	26° 57’ 19.388” N	WGS84 UTM 46N
5	KHEREM-2	95° 53’ 09.808” E	27° 27’ 48.784” N	WGS84 UTM 46N
6	TUKB-2	93° 04’ 57.360” E	24° 54’ 13.695” N	WGS84 UTM 46N
7	PTRA-2	92° 18’ 31.448” E	24° 47’ 29.258” N	WGS84 UTM 46N
8	PTRA-5	92° 19’ 43.896” E	24° 49’ 01.402” N	WGS84 UTM 46N

5.1.2 Seismic 2D data:

Contract Area: AA/ONDSF/ASSAM/2025

DSF-IV CONTRACT AREA	Line segment name	Processing type	FSP/CDP	LSP/CDP	Length (Km)	CRS
AA/ONDSF/ASSAM/2025	D-13e	FINAL_MIGRATION	2	2074	4.1346	WGS84 UTM 46N
	ON-112A	FINAL_MIGRATION	1	451	3.6209	WGS84 UTM 46N
	D-13B:a	FINAL_PSTM_STACK	1	2015	4.0714	WGS84 UTM 46N
	KH-05	MIGRATION_STACK	1	373	4.3242	WGS84 UTM 46N
	A120-6	FINAL_MIGRATION	62	505	3.0925	WGS84 UTM 46N
	A120-3	FINAL_MIGRATION	62	381	1.2028	WGS84 UTM 46N
	A120-2	FINAL_MIGRATION	57	630	4.3728	WGS84 UTM 46N
	A120-13	FINAL_MIGRATION	64	407	1.6891	WGS84 UTM 46N
	A120-12	FINAL_MIGRATION	64	581	3.1045	WGS84 UTM 46N
	A120-11	FINAL_MIGRATION	64	405	1.9426	WGS84 UTM 46N
	A120-10	FINAL_MIGRATION	63	402	2.7686	WGS84 UTM 46N
	A119-05	REPROCESSED_FINAL_PSTM_STACK	1	483	3.1361	WGS84 UTM 46N
	A119-04	REPROCESSED_FINAL_PSTM_STACK	1	483	3.1361	WGS84 UTM 46N
	A119-03	REPROCESSED_FINAL_PSTM_STACK	1	653	1.4703	WGS84 UTM 46N
	A119-01	REPROCESSED_FINAL_PSTM_STACK	2	694	6.2818	WGS84 UTM 46N
	A119-10	FINAL_MIGRATION	68	436	2.7739	WGS84 UTM 46N
	A119-09	FINAL_MIGRATION	68	620	3.9615	WGS84 UTM 46N
	A119-07	FINAL_MIGRATION	68	642	4.3478	WGS84 UTM 46N
	A119-02	FINAL_MIGRATION	56	391	1.9688	WGS84 UTM 46N
	A59-03	FINAL STACK	44	225	4.3534	WGS84 UTM 46N
	A202-09	FINAL_MIGRATION	1	1052	1.1716	WGS84 UTM 46N
	A202-06	FINAL_MIGRATION	1	1236	1.1849	WGS84 UTM 46N
	A202-06	FINAL_MIGRATION	1	1236	3.8726	WGS84 UTM 46N
	131-08	FINAL_STACK	1	818	2.9202	WGS84 UTM 46N
	131-04	FINAL_STACK	1	536	3.1676	WGS84 UTM 46N
	131-01	FINAL_STACK	1	824	3.1765	WGS84 UTM 46N
	202-13	FINAL_MIGRATION	1	734	1.7743	WGS84 UTM 46N
	202-08	FINAL_MIGRATION	42	644	2.3374	WGS84 UTM 46N
	202-05	FINAL_MIGRATION	825	1930	3.1126	WGS84 UTM 46N
	202-01	FINAL_MIGRATION	1	657	1.1402	WGS84 UTM 46N
	A192-02	FINAL_STACK	1	2985	5.0545	WGS84 UTM 46N
	A162-13	FINAL_STACK	8	791	4.8396	WGS84 UTM 46N
	A162-12	FINAL_STACK	2	883	1.9339	WGS84 UTM 46N
	A162-12	FINAL_STACK	2	883	8.8383	WGS84 UTM 46N
	A162-11	FINAL_STACK	10	807	4.2484	WGS84 UTM 46N
	A162-10	FINAL_STACK	8	1235	9.6828	WGS84 UTM 46N
	A162-10	FINAL_STACK	8	1235	4.47	WGS84 UTM 46N
	A162-09	FINAL_STACK	2	865	2.381	WGS84 UTM 46N
	A162-09	FINAL_STACK	2	865	2.2969	WGS84 UTM 46N
	A162-06	FINAL_STACK	11	957	5.1123	WGS84 UTM 46N
	A162-05	FINAL_STACK	11	805	5.0601	WGS84 UTM 46N
	A162-04	FINAL_STACK	114	985	6.7373	WGS84 UTM 46N
	A162-03	FINAL_STACK	2	867	2.8425	WGS84 UTM 46N
	A158-01	FINAL_MIGRATION	58	2239	4.1106	WGS84 UTM 46N
	A151-7	FINAL_STACK	6	612	2.4167	WGS84 UTM 46N
	A151-5	FINAL_STACK	1	2254	1.0672	WGS84 UTM 46N
	A151-4	FINAL_STACK	55	860	3.9763	WGS84 UTM 46N
	A151-3	FINAL_STACK	58	968	1.6736	WGS84 UTM 46N
	A151-2	FINAL_STACK	1	1085	3.3453	WGS84 UTM 46N
	A151-14	FINAL_STACK	58	478	3.0232	WGS84 UTM 46N
	A151-11	FINAL_STACK	1	1786	5.0541	WGS84 UTM 46N
	A151-1	FINAL_STACK	94	1023	4.0685	WGS84 UTM 46N
	A116-03	REPROCESSED_FINAL_POSTM_STACK	1	1049	2.8399	WGS84 UTM 46N
	A116-01	REPROCESSED_FINAL_POSTM_STACK	1	1273	5.8	WGS84 UTM 46N
	A108-03	REPROCESSED_FINAL_POSTM_STACK	24	1405	4.9083	WGS84 UTM 46N
	A126-9	FINAL_STACK	104	817	8.9356	WGS84 UTM 46N
	A126-8	FINAL_STACK	104	1154	6.5118	WGS84 UTM 46N
	A126-7	FINAL_STACK	106	1154	6.8437	WGS84 UTM 46N
	A126-6	FINAL_STACK	97	971	2.0842	WGS84 UTM 46N
	A126-10	FINAL_STACK	182	1176	7.2994	WGS84 UTM 46N
	POC-03-02N	RAW_MIGRATION_STACK	1119	2679	8.707	WGS84 UTM 46N
	LINE NO:04	FINAL_PSTM_STACK	1451	6066	2.0234	WGS84 UTM 46N
	LINE NO:03	FINAL_PSTM_STACK	1494	4919	1.7841	WGS84 UTM 46N
	LINE NO:02	FINAL_PSTM_STACK	1497	6109	2.6183	WGS84 UTM 46N

DSF-IV CONTRACT AREA	Line segment name	Processing type	FSP/CDP	LSP/CDP	Length (Km)	CRS
AA/ONDSF/ASSAM/2025	A116-5	FINAL_STACK	151	985	3.4367	WGS84 UTM 46N
	A134-11	FINAL_STACK	167	754	8.0684	WGS84 UTM 46N
	A134-8	FINAL_STACK	100	975	10.921	WGS84 UTM 46N
	A134-7	FINAL_STACK	52	527	7.4577	WGS84 UTM 46N
	A134-6	FINAL_STACK	104	995	11.555	WGS84 UTM 46N
	A134-5	FINAL_STACK	293	921	6.649	WGS84 UTM 46N
	A134-4	FINAL_STACK	414	1462	8.6335	WGS84 UTM 46N
	A134-3	FINAL_STACK	232	1188	12.027	WGS84 UTM 46N
	A134-2	FINAL_STACK	54	1531	14.884	WGS84 UTM 46N
	A134-1	FINAL_STACK	149	1155	13.039	WGS84 UTM 46N
	A323-04	PSDM_SCALED_TO_TIME	1451	6066	2.0234	WGS84 UTM 46N
	A323-01	PSDM_SCALED_TO_TIME	1509	4348	1.6531	WGS84 UTM 46N
	A258-04	FINAL_STACK	5	330	4.0233	WGS84 UTM 46N
	A258-03	FINAL_STACK	1	780	10.384	WGS84 UTM 46N
	A258-02	FINAL_STACK	5	552	6.8179	WGS84 UTM 46N
	A-177-08	FINAL_STACK	1	1224	8.9008	WGS84 UTM 46N
	A-177-07	FINAL_STACK	1	687	4.2931	WGS84 UTM 46N
	A-177-05A	FINAL_STACK	1	323	1.5471	WGS84 UTM 46N
	A-177-05	FINAL_STACK	1	591	4.6881	WGS84 UTM 46N
	A-177-04	FINAL_STACK	1	1102	12.577	WGS84 UTM 46N
	A-177-02	FINAL_STACK	1	1137	7.7765	WGS84 UTM 46N
	A-177-01	FINAL_STACK	1	603	7.4313	WGS84 UTM 46N
	A258-01	FINAL_MIGRATION	1	1084	12.012	WGS84 UTM 46N
	A266-06	FINAL_STACK	1	764	7.747	WGS84 UTM 46N
	A266-05	FINAL_STACK	2	916	11.502	WGS84 UTM 46N
	A266-04	FINAL_STACK	168	1666	18.791	WGS84 UTM 46N
	A266-03	FINAL_STACK	41	1014	12.094	WGS84 UTM 46N
	A266-02	FINAL_STACK	1	1123	13.983	WGS84 UTM 46N
	A266-01	FINAL_STACK	1	1176	14.09	WGS84 UTM 46N
	A145-14	FINAL_STACK	100	540	5.5053	WGS84 UTM 46N
	A145-13	FINAL_STACK	100	987	11.905	WGS84 UTM 46N
	A145-12	FINAL_STACK	106	982	4.7582	WGS84 UTM 46N
	A145-11	FINAL_STACK	100	1659	9.6604	WGS84 UTM 46N
	A156-08	FINAL_STACK	100	2012	17.082	WGS84 UTM 46N
	A156-06	FINAL_STACK	100	1806	9.9341	WGS84 UTM 46N
	A156-05	FINAL_STACK	109	1916	12.196	WGS84 UTM 46N
	A156-04	FINAL_STACK	1	1909	11.826	WGS84 UTM 46N
	A156-03	FINAL_STACK	121	2008	9.3613	WGS84 UTM 46N
	A156-01	FINAL_STACK	100	1168	2.1692	WGS84 UTM 46N
	A250-02	FINAL_MIGRATION	1	1364	16.17	WGS84 UTM 46N
	A250-01A	FINAL_MIGRATION	1	710	9.0704	WGS84 UTM 46N
	A250-01	FINAL_MIGRATION	1	474	1.1408	WGS84 UTM 46N
	A241-05	FINAL_MIGRATION	1	362	4.608	WGS84 UTM 46N
	A241-04	FINAL_MIGRATION	1	566	2.751	WGS84 UTM 46N
	A241-03	FINAL_MIGRATION	1	687	7.6721	WGS84 UTM 46N
	A241-02	FINAL_MIGRATION	1	689	6.3742	WGS84 UTM 46N
	A241-02	FINAL_MIGRATION	1	689	1.7964	WGS84 UTM 46N
	A241-01	FINAL_MIGRATION	1	1194	5.2261	WGS84 UTM 46N
	A-181-07	FINAL_MIGRATION	1	1587	12.262	WGS84 UTM 46N
	A-181-06	FINAL_MIGRATION	1	1270	2.1897	WGS84 UTM 46N
	A-181-04	FINAL_MIGRATION	1	1111	13.782	WGS84 UTM 46N
	A-181-03	FINAL_MIGRATION	1	614	7.613	WGS84 UTM 46N
	A-181-02	FINAL_MIGRATION	1	948	11.83	WGS84 UTM 46N
	A-181-01	FINAL_MIGRATION	1	1402	16.697	WGS84 UTM 46N
	A115-3	FINAL_MIGRATION	4	2129	7.985	WGS84 UTM 46N
	A115-3	FINAL_MIGRATION	104	2231	8.166	WGS84 UTM 46N
	A115-2	FINAL_MIGRATION	105	2133	9.9338	WGS84 UTM 46N
					740.87	

5.1.3 Seismic 3D Data:

AA/ONDSF/ASSAM/2025 Contract Area:

00001.GELEKI_PSDM_SCALE_TO_TIME_PSDM_SCALED_TO_TIME_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00001.GELEKI_PSDM_SCALE_TO_TIME_PSDM_SCALED_TO_TIME_.sgy

Point	Inline	Crossline	Easting	Northing
1	23	200	659341.38	2957974.00
2	324	200	653988.25	2972059.00
3	324	1678	688565.81	2985198.50
4	23	1678	693918.94	2971113.75

00002.AAFB_NORTH_OF_PATHARIA_A306_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00002.AAFB_NORTH_OF_PATHARIA_A306_FMIG_FINAL_MIGRATION_.sgy

Point	Inline	Crossline	Easting	Northing
1	833	356	435754.00	2742326.00
2	1002	356	436155.44	2746534.75
3	1002	905	429318.69	2747186.75
4	833	905	428918.22	2742978.00

00003.AAFB_TUKBAI_A302-A303_POST_MIG_STK_FINAL_POSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00003.AAFB_TUKBAI_A302-A303_POST_MIG_STK_FINAL_POSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	669	884	497793.00	2750702.00
2	1070	884	501523.00	2760014.00
3	1070	1920	513552.28	2755194.50
4	669	1920	509822.47	2745883.50

00004.AAFB_NORTH_OF_PATHARIA_A314_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00004.AAFB_NORTH_OF_PATHARIA_A314_FMIG_FINAL_MIGRATION_.sgy

Point	Inline	Crossline	Easting	Northing
1	532	437	434030.81	2734926.25
2	908	437	434924.12	2744289.75
3	908	1012	427763.81	2744972.50
4	532	1012	426871.34	2735608.25

00005.AAFB_INDRANAGARRANGAMATI_A309_PSTM_FINAL_PSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00005.AAFB_INDRANAGARRANGAMATI_A309_PSTM_FINAL_PSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	1	100	475216.06	2754444.75
2	221	100	479215.75	2764699.50
3	221	841	496486.00	2757962.00
4	1	841	492485.00	2747708.00

00006.AAFB_TUKBAI-PATHMARA_A312-313_PSDM_SCALE_PSDM_SCALED_TO_TIME_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00006.AAFB_TUKBAI-PATHMARA_A312-313_PSDM_SCALE_PSDM_SCALED_TO_TIME_.sgy

Point	Inline	Crossline	Easting	Northing
1	406	171	483818.00	2746507.00
2	883	171	488254.00	2757585.00
3	883	1800	507169.00	2750008.00
4	406	1800	502732.38	2738931.75

00007.ASSAM_KHEREM-KUMCHAI_3D_FINAL_PSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00007.ASSAM_KHEREM-KUMCHAI_3D_FINAL_PSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	65	3322095	782720.56	3038007.00
2	215	3322095	782798.69	3042007.00
3	215	3326395	787075.62	3043163.25
4	74	3326399	787016.00	3039560.00

5.2Data Package Cost

The Data Package contains seismic (2D and/or 3D) and well data along with reports. The cost of the Data Package of this Information Docket (AA/ONDSF/ASSAM/2025 Contract Area) comes to be USD 9,990. This cost is as per the current data policy of NDR at the time of writing this report and subject to changes if data rates or policy framework are revised.

COST OF DATA PACKAGE FOR DSF-IV BLOCKS								
S.No.	Contract Area on offer	AREA (SQ KM)	NIO Map reference no.	Total Wells	2D Seismic (LKM)	3D Seismic (SKM)	No. of Reports	FINAL COST in USD($)
1	AA/ONDSF/ASSAM/2025	645.47	O-3	28	740.87	469.07	48	**9070**

6. CONTRACT AREA SUMMARY

Contract Area name: **AA/ONDSF/ASSAM/2025**

NIO map reference no.: **O-3**

Geographical area: **ASSAM Onshore**

Number of field(s)/discoveries: **8**

Number of well(s): **28**

Total area: **645.47 Sq. Km**.

Seismic 2D data: **740.87 Line Km**.

Seismic 3D data: **469.07 Sq. Km**.

Report(s) available: **48**

Hydrocarbon In-Place (2P) O+OEG: **7.94 MMTOE**

Data package cost: **USD 9,070**

7. CONCLUSIONS

The information docket has been prepared from the geoscientific and engineering data sets, made available by NOCs. The work has been primarily accomplished with all requisite data/information pre-processed using various in-house interpretation software. Desktop publishing applications of documents, spreadsheets and images including Google maps have also been extensively used.

The 8 discoveries, which are lying unpursued and holding contingent resources/ reserves are potential to be further developed/commercially produced. This booklet will be a useful supplement to the Data Package of the corresponding Contract Area. Such data represent 2D/3D seismic, well logs and reports on key information from various field operations pertaining to drilling, logging, testing and production. The total data package on offer under this bid round includes 740.87 LKM 2D seismic, 469.07 SKM 3D seismic, and 28 well data. The Data Package will be hosted in Data rooms for viewing and for sale from National Data Repository (NDR) to the interested investors/ bidders.

Though, the docket mentions estimated hydrocarbon, it indicates extent and order of hydrocarbon pool size. DGH strongly recommends that bidders must have their own understanding and independent assessment of resource base to support any forward bidding decision.

सत्यमेव जयते

पेट्रोलियम एवं
प्राकृतिक गैस मंत्रालय
MINISTRY OF
PETROLEUM AND NATURAL GAS

DGH

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