Depositional trends and reservoir geometries of the Early Cretaceous Lower Goru Formation in Lower Indus Basin, Pakistan: evidence from sequence stratigraphy

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Abstract
Lower Goru sand intervals of Early Cretaceous age are proven reservoirs in the Lower Indus Platform area. The delineation of reservoir geometries is of utmost importance while searching for stratigraphic and combination traps in clastic reservoirs. The data of ten wells and two 2D seismic lines from the northern part of the Lower Indus Basin are incorporated in this study. These reservoir intervals of the Lower Goru Formation are correlated in a third-order sequence stratigraphic framework to understand the depositional architecture and reservoir geometries. The Lower Goru Formation was deposited in westerly prograding river-dominated deltas developed by river system drained through the Indian Shield from east and south-east during Cretaceous time. Due to auto-cyclic switching of river distributaries, different lobes might have formed which if identified can point out the possible locations and configurations of stratigraphic and combination traps in this highly prospective area of Lower Indus Basin. The Lower Goru Formation (Barremian to Cenomanian) consists of one full second-order sequence of 20 Ma duration, having all the three fundamental system tracts in which eleven sequences of the third order, i.e. LG-1 to LG-11, were interpreted. Proven reservoir intervals of the Lower Goru Formation are concentrated in various third-order lowstand system tracts. The net sand and porosity maps of lowstand system tracts, gross depositional map and depositional cross section of the Lower Goru Formation point out the potential sites of good sandstone reservoirs and hint at the possible sand-body geometries.

Keywords Early cretaceous · Lower goru formation · Lower indus basin, Pakistan · Sequence stratigraphy · Lowstand system tracts (LST) · Reservoir horizon · Reservoir geometries

Introduction
Pakistan's Indus Basin is the largest onshore sedimentary basin, covering an area of about 138,000 square kilometres. Indus Basin is tectonically divided into Kohat-Potwar, Lower Indus, Sulaiman Fold Belt, Kirthar Fold Belt, Northern Punjab and Offshore Indus Basins (Kadri 1995; Kazmi and Jan 1997; Siddiqui 2009). Tectonically, this region is situated in the northern half of the Lower Indus Basin (Fig. 1). The Early Cretaceous succession is widespread in various parts of the Lower Indus Basin. The lithological heterogeneity in these rocks is primarily due to changes in the sediments supply and environmental conditions (Shakeel 2014). The early Cretaceous Goru Formation is lithologically divided into two parts; the term Lower Goru Formation is used for the lower sandy portion, whereas the upper part having more shales with rare sandstone is called Upper Goru Formation (Kadri 1995; Khalid et al. 2012; Shakeel 2014). The age span of the Lower Goru Formation has been reported by Integrated Exploration and Development Services (IEDS 1995) to be Barremian to Cenomanian (and occasionally Early Turonian) in the Lower Indus Basin (Badin Block area which is ~ 100 kms south of the current study area). The sandstone units of the Lower Goru Formation are of remarkable interest due to their potential of producing hydrocarbon. This interest has significantly increased during the past few years due to petroleum production and potential reservoir in the region (Ashraf et al. 2019). However, depositional...
trends, reservoir geometries, stratigraphic trapping mechanism and regional depositional cross sections tied to the well data have not been well documented and need a detailed study.

Determination of depositional trends is essential in hydrocarbon exploration because it is useful in reservoir architecture modelling and for understanding facies distribution for field development (Shakeel 2014; Radwan, 2021; Dar et al. 2021a). Geometry, heterogeneity, petrophysical properties and continuity of a reservoir depend on several phenomena including the depositional settings, provenance, diagenesis and tectonic history (Ramon and Cross 1997; Dar et al. 2021b).

Sequence stratigraphy provides a background for understanding the relationship between the stratified rocks, facies, depositional settings and relative sea-level changes (Abdel-Fattah & Slatt 2013). Sequence stratigraphy establishes the investigation of cyclic sedimentation patterns in stratigraphic sequences as they develop in response to several changes in sediment supply and depositional settings (Posamentier and Allen 1999; Abdel-Fattah & Slatt 2013; Nwaezeapu et al. 2018). Thus, the sequence stratigraphic analysis enables the detection of reservoir bodies both vertically and laterally. Relative sea-level changes permit restraining of spatial and temporal distribution and quality of the reservoir rock within the perspective of sequence stratigraphy (Abdel-Fattah & Slatt 2013; Pigott and Abdel-Fattah 2014).

Depositional systems and reservoir geometries can be identified in a better way once a valid sequence stratigraphic architecture of the area is developed. Net sand isopach maps can be used effectively to identify the reservoir geometries in the specific zones of the formation (Catuneanu et al. 2011).

Following many hydrocarbon discoveries in the Lower Goru Formation from the Lower and Middle Indus basins, due to the limited understanding of subtle stratigraphic traps, major potentials remain untapped (Ahmad et al. 2004). This trapping mechanism relies on the understanding of reservoir sands’ quality. The objective of this study is: (1) to understand the depositional trends and depositional environment within the Lower Goru Formation by classifying the sequence stratigraphic surfaces; (2) to delineate the geometries of reservoir sandstone within the formation; and (3) to map the reservoir properties, i.e. porosity and permeability, against all third-order lowstand system tracts.
of the formation to identify the areas of good and poor reservoirs. This case study can be beneficial for the assessment of reservoir's depositional trends, geometry, distribution and quality variation. Mapping the stratigraphic changes of the sandstone reservoirs are beneficial for improved prediction of reservoir quality and possible stratigraphic/combination traps, increased production and long-lasting life of the field. Many risks exist for exploring stratigraphic traps, due to the unpredictable lateral distribution and the limited volume of the clastic reservoirs (Radwan et al., 2021), but sequence stratigraphic analysis supported with good quality dataset may reduce this risk. This work will hopefully provide a better understanding for exploring the non-structural and combination plays in the Lower Indus Basin and adjoining areas.

**Previous work**

The Early Cretaceous clastics (Lower Goru Formation) in the Lower Indus Basin have been studied with different perspectives by several researchers, both from the oil industry and academia. Wandrey et al. (2004) performed detailed research work on petroleum resources within the Sembar-Goru/Ghazij Composite Total Petroleum System (TPS). Sequence stratigraphic analysis of the Lower Goru Formation, Lower Indus Basin Pakistan has been performed for play fairway analysis by a few authors (e.g., Ahmad et al. 2004; Ahmad & Khan, 2010; Weihua et al. 2005). Various authors have worked for reservoir characterization using petrophysical techniques in the Lower Goru Formation (e.g., Shahid et al. 2008; Naeem et al. 2016; Hussain et al. 2017; Siyar et al. 2017; Khan & Khan 2018; Khalid et al. 2018; Qadri et al. 2019; Ali et al. 2019; Asad & Rahim 2019; Yasin et al. 2019; Dar et al. 2021a, fig. 3a). Reservoir properties of the Lower Goru Formation were analysed based on integrated analysis of seismic, well and core data by a few authors (e.g., Pervez et al. 2003; Riaz Ahmed & Ibrahim 2008; Ahmed et al. 2010; Munir et al. 2011; Ashraf et al. 2019, 2020). The impacts of diagenesis on the reservoir quality of the Lower Goru Formation have been studied (e.g., Baig et al. 2016; Dar et al. 2021a, fig. 3a).

Depositional facies were evaluated by several authors based on petrography, well cuttings and wireline log motifs for the Lower Goru Formation, Lower Indus Basin, Pakistan (e.g., Sahito et al. 2013; Nazeer et al. 2016; Dar et al. 2021a, fig. 3a). Subsurface structural analysis in the Lower Indus Basin, Pakistan, were performed with the help of seismic, image logs and wireline logs (e.g., Wasimuddin et al. 2005; Abbas et al. 2015; Khan et al. 2016; Naeem et al. 2016; Qureshi et al. 2021). Ahmad et al. (2015) identified reservoir geometries of the C-Sand member of the Lower Goru Formation in the Sawan Gas field. He discussed reservoir geometries based on well correlation panels and seismic data.

Literature review and previous research work discussed above reveal that the Lower Goru Formation has extensively been studied for its structural analysis and reservoir properties based on conventional petrophysical techniques. However, a few authors analysed it for play prediction with the help of sequence stratigraphic techniques.

**Research gap**

It is obvious from the previous work on the Lower Goru Formation (discussed above) that the regional and detailed reservoir geometries of all members of the Lower Goru Formation have never been studied. Mapping the net sands’ thickness is an effective way to identify the reservoir geometries. A similar sort of technique was used by Catuneanu et al. (2011), to identify the reservoir geometries through isopach mapping of net sands in 14 genetic units of Yegua Formation (Eocene), Gulf of Mexico. Detailed sequence stratigraphic analysis, petrophysical calculations, identifications of palaeo-environments, mapping of net sands and porosity–permeability values are required as a prerequisite to understand the reservoir geometries and their reservoir potential.

**Geological settings**

The Lower Indus Basin is bordered by the Central Indus and Sulaiman Fold-Belt Basins to the north and the Kirthar Fold-Belt Basin to the west. This region constitutes clastic and carbonate deposits ranging in age from Infra-Cambrian to recent (Fig. 2). It is situated in the "Indus Platform and Foredeep" tectonic zone, which includes several structural areas (Kazmi and Jan 1997). The structural features in this region (Indus Platform and Foredeep) are tilted blocks of faults and thrust–fault anticlines (Kazmi and Jan 1997; Nazir and Fazeelat 2014).

The Indian Plate drifted north during the early Cretaceous, entering warmer latitudes (Jadoon et al. 1992; Kazmi and Jan 1997; Khalid et al. 2014a; Fig. 3a). On the western shelf, marine shales, calcareous and nearshore sandstones of the Lower Cretaceous Sembar and Goru formations are deposited on the Sulaiman Limestone Group over a broad erosional layer. This shelf environment persisted as regressive sandstones such as the Lumshiwal and Pab formations in the west and Tura Formation in the east (Khalid et al. 2014b). The Indian Plate continued to drift north towards the Asian plate during the Late Cretaceous, the Bengal Basin Seafloor began to form and flysch accumulated around much of the Indian Plate (Shah 2009; Fig. 3b). This was followed by a significant anomaly, which was further followed by a widespread transgressive Upper Goru Formation event. This
Fig. 2 Generalized stratigraphy of the Lower Indus Basin (modified after Iqbal and Shah 1980; Shah 2009)
transgression provided the reservoirs of the Lower Goru Formation with the regional seal (Sahito et al. 2013).

**Lithostratigraphy and depositional environment**

The Lower Goru Formation was divided into two main parts: lower sands and upper sands from bottom to top, respectively. Both the top and bottom sands are interbedded with shale beds.

The upper sands of the Lower Goru Formation are not present in the studied area. The lower sand unit (named as Massive Sands) of this formation is a proven reservoir rock in the Lower Indus Basin (Munir et al. 2011; Nazir and Fazeelat 2014). Massive Sand is overlain by Talhar Shale which is considered as a source rock. Talhar Shale is overlain by Basal Sand which is the main proven reservoir of the Lower Goru Formation also producing in the study area. Above Basal Sand are Lower Shale (having reservoir sand beds locally abbreviated as SABS, i.e. sands above basal sands), Lower Shale is overlain by Middle Sand/G Sand, and both the SABS and Middle Sands are producing in the study area. Middle sand is overlain by Upper Shale and Upper Sands (including D Sand, Jhol Shale, C Sand, Badin Shale, B Sand, Turk Shale and A Sand) from older to younger, respectively (Fig. 4).

The deposition of the Lower Goru Formation took place in the marine shelf to fluvial channels environments (Quadri and Shuaib 1986). The formation represents an overall retrogradational package of marginal marine/coastal plain to open marine shelf sediments, i.e. sand-prone facies in the basal portion and mud-prone sediments in the upper portion (Sahito et al. 2013).

The basal sand-prone interval is characterized by a suite of coastal plain—marginal marine–shoreline facies. Flavio-tidal channel/estuarine sediments along with adjacent mouth bar and upper shoreface sands are likely to have the best
reservoir potential in terms of primary depositional character (Zaigham and Mallick 2000).

Shoreface sands are modelled as linear features (sheets) running along depositional strike which was generally N-S over much of the Lower Indus Basin (Nazir and Fazeelat 2014). Tidal inlets and estuarine channel systems were generally from east to west, perpendicular to the shoreline. In the mud-prone upper portion of the Lower Goru Formation, these proximal facies progressively back step to the eastern parts of the Lower Indus Platform Basin (Figs. 5, 6).

Data set and methodology

The present study was carried out using well data (wireline logs, well cuttings, biostratigraphy) from ten wells W-03, W-05, W-06, W-08, W-09, W-15, W-21, W-23, W-28, W-29 (arbitrary well names) and two 2D seismic sections from the Lower Indus Basin (Fig. 1).

The sequence stratigraphic analysis were carried out to correlate the reservoir sands in the studied area. The available well data in the study area were correlated sequence stratigraphically adopting the regional sequence stratigraphic framework related to Hardenbol et al. (1998) scheme. The primary focus of the study was to develop a third-order sequence stratigraphic framework; however, second-order sequence stratigraphic surfaces have also been identified. The identified sequences are numbered in ascending stratigraphic order; sequences of Lower Goru Formation thus are LG-1 to LG-11. In each third-order sequence, significant surfaces, i.e. sequence boundary (SB), transgressive surface (TS) and maximum flooding surface (MFS), were identified and correlated with all wells in the study area.

After the interpretation of the well data, it was tied with 2D seismic lines. 2D seismic was utilized to interpret second-order seismic stratigraphy and depositional trends of the Lower Goru Formation. Although the quality of available seismic data was not good enough for sequence stratigraphic interpretation, it was successfully correlated with the second-order sequence, identified in the wells W-21 and W-23. Seismic reflection patterns between LG-1-SB and LG-5-TS representing regressive system tract (RST) of

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**Fig. 5** Depositional architecture of the Lower Goru Formation (along the depositional dip) interpreted based on wireline log motifs, available biostratigraphic information and drilled well cutting (facies deposited during the two hierarchical orders, i.e. second order and third order, are interpreted)
second order are showing westward prograding sequences developing down laps. Seismic surfaces between LG-5-TS and LG-9-MFS are showing transgressive system tract (TST) of second order representing a backstepping package of reflectors making onlaps over the transgressive surface, LG-5-TS. LG-9-MFS defines the end of one complete cycle of regression–transgression of second order. Above the LG-9-MFS, another cycle of regression (RST) of second order seems to be developed that makes aggrading top sets (Figs. 6, 7). This transgressive and regressive behaviour of second-order sequences of Lower Goru is also evident from a regional depositional cross section prepared based on well data (Fig. 5) and well correlation panels (Figs. 8, 9 and 10).

Detailed environments of deposition were interpreted based on available well data for a well (Fig. 11) to identify depositional settings of individual clastic facies. A regional depositional cross section (proximal to distal settings) of the Lower Goru Formation was prepared based on sequence stratigraphic framework, log motifs and well cutting data from east to west (Fig. 5).

Gross depositional environment map (Fig. 12) and isopach maps of the net sands in the nine lowstand system tracts (LSTs) of each third-order sequence (Fig. 13) were prepared to know the regional depositional settings, the general direction of sediments’ influx and dispersal during the deposition of these sediments which are crucial clues for the reservoir distributions, geometries and qualities. Effective porosity and permeability were calculated in all available wells using the petrophysical technique (Table 1). Porosity maps were prepared against each lowstand system tract of the Lower Goru Formation to analyse the spatial distribution of porosity values and variation in reservoir quality across the studied area (Fig. 14).

**Results and discussion**

The primary focus of this study was to develop a third-order sequence stratigraphic framework; however, second-order sequence stratigraphic surfaces have also been identified. The second-order sequence has a time duration of 20 million years, while third-order cycles have a typical duration of approximately 2 million years (Catuneanu et al. 2011). The Lower Goru Formation consists of one and half second-order sequences, identifiable on well data (Fig. 8). The available well data in the studied area were stratigraphically associated with the regional stratigraphic sequence (Haq et al. 1987; Handford and Loucks 1993).

The Lower Goru Formation has eleven identifiable third-order sequences (LG-1 to LG-11) which are correlated in all the wells (Figs. 8, 9, 10). However, the emphasis is given to the first nine complete sequences because the principal reservoirs of the Lower Goru Formation are located within these sequences (LG-1 to LG-9) in the study area. The sequences found are numbered in ascending stratigraphic order, i.e. LG-1 to LG-9. In each third-order sequence, significant surfaces (sequence boundary, transgressive surface and maximum flooding surface) were identified. A gross
depositional facies map (Fig. 12) and a 2D depositional model (Fig. 5) were built to understand the depositional setting of the Lower Goru Formation based on well cuttings, log motifs, seismic interpretation and available literature.

### Third-order sequences

All third-order cycles in the study area are correlated (Fig. 8). The basal sequence boundary (SB), i.e. LG1-SB, was picked on the sharp-based sandstone package, marking the abrupt transition from the underlying Sembar Formation to the lowermost of the Goru Formation. Overlying sequences display well-developed third-order sequence architecture with blocky, sand-rich lowstand packages overlain by retrograding TST packages and subsequent progradational HSTs. However, these sequences become more mud-prone and fine-grained upwards in the TSTs and HSTs of the second-order sequences (Figs. 8, 9, 10 and 11).

After the deposition of Sembar Formation sequences, relative sea-level continued to rise during the latter part of Early Cretaceous till Late Cretaceous, causing an overall retrogradation of the basin margin, as evident from second-order SB (LG1_SB) to second-order maximum flooding surface (LG9_MFS) (Figs. 8, 11). This gradual and long-term base-level rise and sea-level still stand (third-order eustatic or tectono-eustatic sea-level cycles), punctuated by high-frequency fourth- and fifth-order relative sea-level fluctuations, led to the deposition of aggradational to westerly prograding clastic wedges that rarely reached the edge of the shelf built by the Sembar Formation (Munir et al. 2011). An active longshore drift and tidal influence (wave- and tide-dominated systems) restricted these sands to the south-east on the shelf where they formed a ramp that gradually deepened to the north-west (Fig. 12).

Nine third-order sequences (LG-1 to LG-9) have been focused in the region being studied. These sequences have been drilled in almost all wells of the study area except the well W-29 where the sequences from LG-1 to LG-7 are completely absent due to erosion or non-deposition while sequence LG-8 is partially deposited and sequence LG-9 is completely deposited and drilled in this well (Fig. 10). Two broad packages of third-order sequences are discussed in detail below.

### Sequence LG-1 to LG-5

The sequences from LG-1 to LG-5 fall within the second-order lowstand system tract and mostly fall within the Massive Sand unit of Lower Goru. These sequences are comparatively thicker and have more pronounced sand

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Fig. 7 Seismic section showing normal faulting and stratigraphic trends in the Lower Goru sediments across well W-23 (see Fig. 1 for the location of section B-B′)
intervals than above laying sequences. LG-1 is the bottom-most sequence of the Lower Goru Formation and its sequence boundary is marked on a sharp-based sandstone package highlighting the abrupt transition from the underlying Sembar Formation that is mostly shale (Figs. 8, 9, 10 and 11). The SB of LG-2 was placed at the base of the pronounced sand unit terminating the progradational trend of log signatures of LG-1 HST (Fig. 10). The sequence boundaries of LG-3 and LG-4 were placed at the base of the well-defined sandstones units which are interbedded with shales. The overall thickness of sequence LG-1 ranges from 129 to 22 m, LG-2 from 104 to 19 m, LG-3 from 86 to 30 m, LG-4 from 120 to 20 m and LG-5 from 165 to 74 m in the study area. According to depo-centres, the trend of paleo-transport directions of this sequence was from east and south-east (Figs. 12, 13). These five sequences have different behaviour (in terms of lateral facies changes from proximal to distal settings, i.e. southeast to north-west, respectively) in the northern part of the study area vs. the southern part of the study area. These five sequences (LG-1 to LG-5) are mostly sandier throughout the depositional dip (proximal to distal) in the northern part of the study area e.g. in wells W-15, W-09, W-08 and W-06 (Fig. 9). However, in the southern part of the study area, these sequences become more mud-prone as we move from proximal to distal settings i.e. from well W-03 to W-29 (Fig. 10).

Sequence LG-6 to LG9

The sequences from LG-6 to LG-9 fall within the second-order transgressive system tract of order Lower Goru. The LG-6 sequence was the first third-order sequence in second-order TST (backstepping) of the Lower Goru Formation (Fig. 8). The SB of LG-6 was placed at the base of the sand package having sharp contact with the underlying LG-5 HST. This sequence has pronounced shale contents.

Fig. 8 Nested architecture of depositional sequences in Lower Goru Formation (Lower Cretaceous, Lower Indus Basin). Stratigraphic cycles of two hierarchical orders, i.e. second order and third order, are interpreted. The Lower Goru Formation is occupied by 1 and a half cycles of 2nd order (LG1_SB to LG10_SB & LG10_SB to LG12_SB) and these 2nd order sequences further contain eleven sequences of 3rd order (LG1_SB to LG12_SB). An overall fining upward trend is obvious from 2nd order SB to 2nd order MFS (LG1_SB to LG9_MFS) which is then overlain by coarsening upward trend from LG9_MFS to LG10_SB. Four surfaces shown with bold lines (LG1_SB, LG5_TS, LG9_MFS, and LG10_SB) are the surfaces where 2nd and 3rd order events of similar type synchronize with each other (e.g. MFS of 2nd and 3rd order merge at LG9_MSF). Abbreviations: SB-Sequence Boundary; TS-Transgressive Surface; MFS-Maximum Flooding Surface; LST-Lowstand System Tract, TST-Transgressive System Tract, HST-Highstand System Tract. (note: correlation panel is flattened on two surfaces thus, the vertical scale of wells is variable across the panel.)
in wells W-21, W-23 and W-05 as compared to other wells which indicated that the sequence LG-6 around these wells is more distal and may be beyond the shelf edge in this area (Figs. 9, 10). The thickness of LG-6 ranges from 114 to 52 m, while of LG-7 from 133 to 28 m. The thickness of LG-8 generally ranges from 151 to 45 m in all wells except well W-29 where it is 22 m thick; it is to be noted that the bottom part of sequence LG-8 may have eroded or not been deposited in this well.

This sequence (LG-9) is widespread across the region being studied and usually includes Lower Goru Formation’s Middle Sand unit. LG-9 was the topmost part of backstepping TSTs of the second-order sequence. This third-order MSF of sequence LG-9 coincides with regional MFS of second order so marks a pronounced high gamma-ray peak (Figs. 9, 10 and 11).

**Reservoir geometries**

The proven reservoir intervals of the Lower Goru Formation have mostly been concentrated in the lowstand system tracts of third-order sequences. The gross thicknesses of the sequences give a general trend of sediment dispersal directions (AlMuhaidib et al. 2012). Thus, isopach maps of the net sands within various LSTs can give the geometries of reservoir intervals. The reservoir geometries will be naturally more reliable where data points are abundant and closely spaced compared to the areas where the data points are sparse and/or widely spaced. Isopachs maps of the net sands of all LSTs (LG-1 to LG-9) have been prepared to understand the reservoir geometries deposited within these LSTs (Fig. 13). In a regional context, the gradual basinward (to the north-west) shift of sand bodies is obvious from net sand maps of LG1_LST to LG5_LST which is due to progradation of second-order LST of the Lower Goru Formation while the landward (to the south-east) shift of sand bodies within LG6_LST to LG9_LST is due to backstepping second-order TST of the Lower Goru Formation (Fig. 13).
These net sand isopach maps of all third-order LSTs of the Lower Goru Formation reveal that the dispersal pattern of the sediments was generally from the south-east to north-west. Reservoir geometries of sand bodies in each third-order LST (lowstand system tract) are discussed below.

**LG-1 LST’s Reservoir geometries**

The isopach map of net sand in LG1_LST represents that the thickness of net sand ranges from 24 m in the south-east to 0 m in the north-west. Thicker net sand (>10 m) is deposited in the eastern half of the study area and represent two sand lobes which are possibly deposited by prograding fluvio-deltaic and coastal sands sources from two directions (Fig. 13a). Net sands thinning out to 0 m towards the north-west (shown with straight isopach contour lines) represent the lower shoreface to outer shelf environments (Figs. 12, 13a).

**LG-2 LST’s Reservoir geometries**

The isopach map of net sand in LG2_LST represents that the thickness of net sand ranges from 32 m in the east to 0 m in the west. Thicker net sand (>10 m) are deposited in the eastern half of the study area and represent two sand lobes. Lobe no.1 is thicker than lobe no. 2 and has has a more relative extent. Both the lobes are possibly fed by different sediment sources where lobe no. 1 has got more sedimentary influx compared to lobe no. 2. Both the lobes are deposited in fluvio-deltaic environments (Figs. 12, 13b). Net sands thinning out to 0 m towards the north-west represent the lower shoreface to outer shelf environments.

**LG-3 LST’s Reservoir geometries**

Isopach map of net sand in LG3_LST represents that the thickness of net sand ranges from 20 m in the east to 0 m in the west. Thicker net sand (>10 m) are deposited in the eastern half of the study area and represent two sand lobes having more extension along the depositional strike.
Fig. 11 Composite summary log of well W-15 showing environments of deposition (interpreted from log motifs and well cutting), lithology drilled, second-order surfaces and third-order system tracts
(NE–SW) and thus represent more or less sheet-like geometries. Lobe no.2 is thicker than lobe no. 1. Both the lobes are fed by sediment sources running from south-east to north-west direction. The elongated shape of both the lobes represents that they are dominated by coastal sand bars (Fig. 13c). Net sands thinning out to 0 m towards the north-west represent the lower shoreface to outer shelf environments.

**LG-4 LST’s Reservoir geometries**

Isopach map of net sand in LG4_LST represents that the thickness of net sand ranges from 22 m in the east to 0 m in the west. Thicker net sand (> 10 m) are deposited in the eastern half of the study area and represent two sand lobes. Lobe no.2 is thicker than lobe no. 1 and has more extension basinward (north-west) while Lobe no.1 has got a thin package of net sands and has more extension along depositional strike (NW–SE). Geometries of these lobes indicate that lob no.1 is dominated by elongated coastal
Fig. 13  Net Sand Isopach maps of third-order lowstand system tracts (LG1 to LG9 sequences) of Lower Goru Formation. Black arrows indicate the source directions while yellow fill shows the net sand thickness of more than 10 m
sand barrier bars or strand plains while lobe no. 2 is dominated by fluvio-deltaic sands with a good sedimentary influx (Figs. 12, 13d). Thinner net sands (<10 m) may be due to abundance of prodeltaic/shelf fines.

LG-5 LST’s Reservoir geometries

The net sand map of LG5_LST shows thickness variation from 48 to 4 m with the sheet-like distribution of the sand in this system tract, which ultimately shales out towards the western part of the studied area (Fig. 13e). No significant geometry evolved from the net sand maps of LG-5 LST to facilitate the stratigraphic/comination entrapment mechanism of hydrocarbon. However, further to the basinal side (north-west) this LST may have deposited basin floor fans or leveed channel complexes which if enclosed in shales may provide structure less trapping mechanism.

LG-6 LST’s Reservoir geometries

The gross thickness of LG-6 LST ranges from 13 to 63 m but net sand thickness from 0 to 34 m which is due to the onset of second-order transgression. This LST shows that the sand lobes are concentrated in the south-eastern part of the studied area (Fig. 13f). Such features are ideal venues for the development of stratigraphic/comination traps. The thickness of net sand increases south-eastward and points out that the area has possibility of good reservoir quality towards this direction.

LG-7 LST’s Reservoir geometries

The isopach map of net sand in LG7_LST reveals that its thickness decreases from east to west and ultimately shales out to the west of the studied area as evident from well W-06. The thickness of net sand in LG-7 LST ranges from 30 to 0 m. There were two closed lobes in the south-eastern part of the studied area that formed elongate and lobate features trending SE–NW (Fig. 13g). These lobes, if enclosed by prodeltaic fines of underlying LG6_HST and transgressive shales of overlying LG7_TST may provide a stratigraphic/comination trapping mechanism. Thus, these lobes need further investigation on seismic specifically thorough quantitative seismic interpretation techniques.

LG-8 LST’s Reservoir geometries

The isopach map of this LG8-LST indicates two lobes confined to the southeastern part of the study area as compared to those of LG7-LST (Fig. 13h). The net sand map of this LST indicates a negligible reservoir quality of sands in most of the wells. The thickness of net sand in LG8-LST generally ranges from 0 to 20 m. The thickness of net sand in this system tract decreases from east to west and ultimately shales out in the west of the studied area. Most wells in the western side of the studied area show zero thickness of net sand in LG-8 LST.

By comparing with isopach maps of net sand of LG7-LST (Fig. 13g), it is obvious that the zero line moves more towards the east in LG8-LST. This fact supports the transgression of second order, which is moving younger third-order sequences of the Lower Goru Formation towards proximal sides of the basin.

LG-9 LST’s Reservoir geometries

The net sand thickness of LG-9 LST ranges from 0 to 12 m in the study area. The isopach map of the net sands in LG-9 LST shows the deposition of elongate bodies (Fig. 13i). Two main fluvially dominated deltaic lobes exist in the studied area that shows the sediment influx from east and south-east. One of the lobes which are confined to the southern part of the study area has a very narrow and restricted part of sand bodies that are more than 10 m thick while the rest of the lobe’s area is shale out to the north-west.
Fig. 14 Porosity maps showing the spatial variation of effective porosity in the third-order lowstand system tracts (LG1 to LG9 sequences) of Lower Goru Formation
Reservoir analysis

The reservoir quality of the sand bodies (in third-order lowstand system tracts) was analysed through the calculation of their porosities and permeabilities (Table 1). The available wireline logs’ data were utilized to calculate effective porosities and permeabilities using petrophysical techniques. The porosity data of each lowstand system tract (LST) were mapped to analyse the spatial distribution and variations in reservoir quality across the studied area (Fig. 14). There is a general decrease in the porosities of sand bodies from proximal (SE) to distal settings (NW) while local anomalies in the porosities have been caused by facies changes (Fig. 14a to i). These LSTs have porosities that range from 1 to 26% and permeability ranges from 0.03 mD to 30 mD (Table 1). Considering porosity values of 8% and more to be representing the good quality reservoirs, the following observations were made:

LG-1 LST’s Reservoir quality

LG1-LST is the lowermost part of the second-order LST of the Lower Goru Formation (Fig. 8). Porosity values in the sands of LG1-LST range from 6 to 12% while permeability from 0.5 to 30 mD. Good porosity values are confined to the central part of the study area where deltas and upper shoreface environments seem to have preserved the good quality reservoir sands (Fig. 14a). The porosity values in the vicinity of the well W-15 are about 6% which may have been caused by mixed facies deposited in fluvial/deltaic flood plains while porosities taper out to almost 0% to the western part of the study area (around well W-06) may have been caused by the outer shelf fines.

LG-2 LST’s Reservoir quality

LG2-LST has a porosity range of 4–15% with permeability from 0.1 mD to 5 mD. Good porosity values are confined to the south and north-east of the study area (Fig. 14b) and coincide with the sand geometries (lobe-01 and lobe-02) shown in Fig. 13b. Porosity values of more than 10% are also concentrated in the distal settings of the study area, i.e. around the W-06 well. Both the lobes have good porosity values owing to the fluvio-deltaic environments while good porosities around the well W-06 are caused by outer shelf turbidites.

LG-3 LST’s Reservoir quality

The range of porosity values in LG3-LST fall between 4 and 13% while permeability from 0.1 to 25 mD. A higher permeability value of 25mD in the W-09 well owes to the facies deposited as prograding deltaic sands. The permeability values of 10 mD calculated in W-08 and W-06 wells may have been caused by sand facies deposited in delta front and outer shelf turbiditic environments, respectively. The porosity map of LG3-LST reveals that the good porosity values are confined to the central part of the study area (Fig. 14c). The porosity values around the well W-06 are about 8% owing to the turbiditic sands while the porosity value to the west of the well W-06 decreases gradually due to shelf fines.

LG-4 LST’s Reservoir quality

The porosity values in LG4-LST range from 9 to 17% while permeability from 1 to 30mD. The higher permeability value of 16mD and 30mD found in the wells W-15 and W-09, respectively, are identified by fluvial channel sands based on well log motifs. There is a general rise in the porosity values from 9% in the south-east (around the well W-15) to 17% in the north-west, i.e. around the well W-06. Further to the west (across well W-06) porosity values decrease owing to the marine sediments (Fig. 14d).

LG-5 LST’s Reservoir quality

LG5-LST is the uppermost part of the second-order LST of the Lower Goru Formation (Fig. 8). Porosity values in this system tract range from 10 to 14% with permeability values from 0.3 mD to 30 mD. The higher permeability values of 25 mD and 30 mD are found in W-06 and W-15 wells, respectively. These higher values of permeabilities in both wells may be correlated with the facies identified as outer shelf turbidites and fluvial channels, respectively. Porosity values of ~ 14% in the proximal part of the study area (SE) drop to ~ 10% in the central part of the study area (Fig. 14e) and again rise to 14% towards the distal part in the west (in well W-06). Further to the west, the porosity values decrease gradually, representing outer shelf settings.

There is a gradual shift of higher porosity values from proximal settings (east) to the distal settings (west) from LG1-LST to LG5-LST, respectively. This shift may have been caused by an overall progradation of second-order LST of the Lower Goru Formation.
LG-6 LST’s Reservoir quality

LG6-LST is the first LST (of third order rank) at the base of the second-order TST of the Lower Goru Formation (Fig. 8). This LST has a porosity variation of 6–15% with a permeability range of 0.05–16 mD. A higher permeability value of 16 mD is encountered in well W-15 where the said LST is composed of sand facies deposited in the fluvial channel and deltaic environments (Fig. 5, 11) with an effective porosity of about 13%. The well W-15 is also producing hydrocarbons from the fluvial channel sands of LG6-LST. The porosity map of LG6-LST (Fig. 14f) reveals that there is a gradual decrease in the porosity values from proximal settings (SE) to the distal settings (NW).

LG-7 LST’s Reservoir quality

LG7-LST has a porosity range from 9 to 20% with permeabilities from 0.04 mD to 21 mD. Higher permeability values of 15 mD and 21 mD are encountered in W-15 and W-23, respectively, and seem to be preserved in sand facies deposited in fluvial channels at the base of said LST. Porosity map of LG7-LST (Fig. 14g) reveals that there is a gradual decrease in the porosity values from proximal settings (SE) to the distal settings (NW) owing to fluvio-deltaic settings and outer shelf settings, respectively.

LG-8 LST’s Reservoir quality

LG8-LST has porosity values ranging from 4 to 18% with permeability values from 0.04 to 25 mD. The higher permeability values of 20 mD and 25 mD are found in W-09 and W-23 wells, respectively. The facies identified (based on log motifs) in W-09 and W-23 wells belong to the delta front and fluvial channels/delta plain, respectively, thus owing to higher permeability values. Porosity value of ~4% in proximal part (SE) of the study area rise to ~18% in the central part of the study area (Fig. 14h) and again drops gradually to lower values towards distal part (NW).

LG-9 LST’s Reservoir quality

LG9-LST is the uppermost LST of second-order TST of the Lower Goru Formation (Fig. 8). This LST has a porosity variation of 1–26% with a permeability range of 0.03–13 mD. Higher permeability values of 10 mD and 15 mD are found in W-15 and W-09 wells, respectively. LG9-LST in said wells is composed of sand facies deposited in delta front and fluvial channel environments with effective porosity of 10% and 16%, respectively. Porosity map of LG9-LST (Fig. 14i) reveals that there is a gradual increase in the porosity values from proximal settings (SE) towards the central part of the study area in well W-08, across which the porosity values drop towards the distal settings (NW).

Conclusions and recommendations

The Lower Goru Formation (Barremian to Cenomanian) in the Lower Indus Basin was deposited in westerly prograding river-dominated deltas developed by river system drained through the Indian Shield from east and south-east during Cretaceous time. Due to auto-cyclic switching of river distributaries, different lobes have formed which identified the possible locations and configurations of stratigraphic and combination traps in this highly prospective area of Lower Indus Basin.

The Lower Goru Formation in the studied area consists of one full second-order sequence of 20 Ma duration, having all the three fundamental system tracts which have eleven sequences of the third order (LG-1 to LG-11, bottom to top); however, first nine sequences (LG-1 to LG-9) were focused as they include the sandy reservoir part of the Lower Goru Formation. These nine third-order sequences have proven reservoirs in their LSTs. These LSTs have porosities ranging from 1 to 26% and permeability ranging from 0.03 to 30 mD. Good values of porosities and permeabilities are preserved in the sand facies deposited in the proximal settings, i.e. fluvial channels and deltaic lobes, while lower porosities and permeabilities are found in the facies deposited in distal settings (outer shelf and marine) except for turbiditic sands having good reservoir properties. The LSTs net sand maps supported with depositional map and 2D facies model (cross section) point out the potential sites of good sandstone reservoirs and hint at the possible sand-body geometries. It is recommended that all these potential sites should be further investigated using advanced geophysical techniques like seismic attribute analysis and quantitative seismic analysis.
Terminology and abbreviations used

Sequences identified in Lower Goru Formation are named as LG-1, LG-2…., LG-11, where LG is used for Lower Goru Formation. These sequences are of third-order sequences in which LG-1 is the oldest and LG-11 is the youngest sequence.

For reservoir quality description the term “net sand” craves up the sand beds’ thickness from the sand shale succession in a lowstand system tract measured from gamma-ray log based on a sand baseline.

Other abbreviations used are as follow:

- Sequences and Sequence order (third order),
- SB (sequence boundary),
- TS (transgressive surface),
- MFS (maximum flooding surface),
- LST (lowstand system tract),
- TST (transgressive system tract),
- HST (highstand system tract).

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Declarations

Conflict of interest The authors declare that they did not receive support from any organization for the submitted work and they have no competing interests.

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