



North Sea, Liberator Resources

Competent Person's Report Update 2020

For: i3 Energy plc & W H Ireland Limited

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■ 2020

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This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the 2018 SPE PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. TRACS International Limited shall have no liability arising out of or related to the use of the report.

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Qualification

TRACS International Limited was founded in 1992, and currently has over 40 petroleum engineers, geoscientists and petroleum economists working from two office locations. TRACS has extensive reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts.

The Liberator Resource evaluation was performed by senior TRACS staff with a combined 120+ years in the oil and gas industry. The team members all hold at least a bachelor's degree in geoscience, petroleum engineering or related discipline.

This assessment has been conducted within the context of the TRACS understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to the P.1987, Block 13/23d and P.2358, Block 13/23c. However, TRACS is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

It should be understood that any determination of resource volumes, particularly involving petroleum developments, may be subject to significant variations over short periods of time as new information becomes available and perceptions change. This is particularly relevant to exploration activities which by their nature involve a high degree of uncertainty.

All volumetric calculations are based on independent mapping undertaken by TRACS using data provided to TRACS. The reservoir properties input to the volumetric calculations and the associated volume uncertainty ranges are based on TRACS experience over more than 20 years of performing evaluations, and the statement on risking in this report represents the independent view of TRACS.

The resource estimates presented in this report have been prepared in accordance with reserves definitions presented in the SPE's Petroleum Resources Management System ("SPE-PRMS" summary in Appendix A), and the risking of contingent and prospective resources has been done in accordance with the LSE/AIM Guidance note for Mining, Oil and Gas Companies - June 2009 ("LSE/AIM Guidelines").

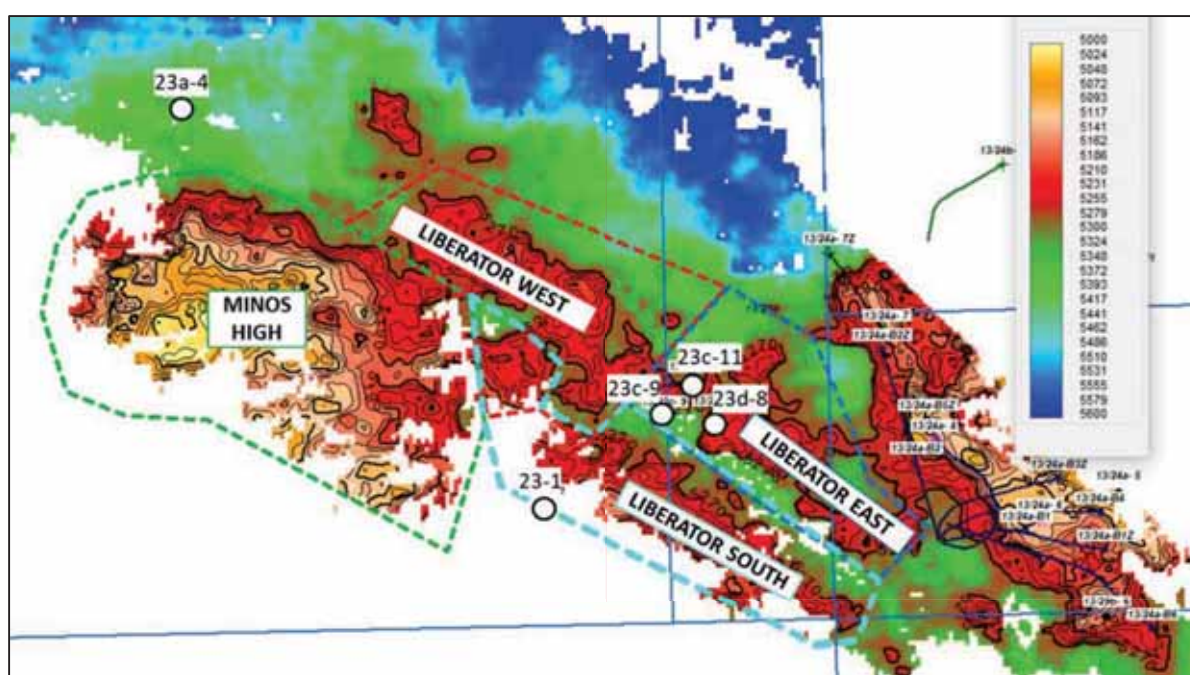
TRACS will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report and TRACS will receive no other benefit for the preparation of this report.

Neither TRACS nor the individuals who are responsible for authoring this report, nor any directors of TRACS, have at the date of this report, nor have had within the previous two years, any economic or beneficial interest (present or contingent) in i3 Energy. TRACS, the individuals responsible for authoring this report and the directors of TRACS consider themselves to be independent of i3 Energy, its directors, senior management and its other advisers.

Executive Summary

TRACS International Limited (TRACS) was commissioned by i3 Energy North Sea Limited (i3 Energy) to complete a Competent Person's Report (CPR) assessing the resource potential of the Liberator East discovery and making an assessment of the likely range of resources that may be assigned to the Liberator West and Minos High areas. The Liberator area is located 120 km north-east of Aberdeen in the South Halibut Basin of the Moray Firth Province, within Licenses P.1987, UKCS Block 13/23d, and P.2358, UKCS Block 13/23c, which are held by i3 Energy on a 100% basis.

This CPR is as an update of a previous CPR generated by TRACS International Limited in 2019 for the Liberator field ahead of a planned field development. Prior to final FDP approval and sanction, i3 embarked on a three-well drilling campaign in 2019 which included two wells on Liberator and an exploration well on the nearby Serenity prospect. The well results on Liberator were not as expected and failed to find hydrocarbons. This CPR update addresses how the underlying subsurface evaluation and classification of resources have changed in light of the new well data and newly licensed seismic data. This CPR focuses on the proven oil accumulation around the Liberator discovery well, formerly referred to as Phase 1 East (now Liberator East). An assessment of the likely prospective resource range of the Liberator West and Minos High areas (previously called Phase 1 West and Phase 2) has also been made.



i3 current Liberator area designation

The report has been prepared to be included in an appendix to the AIM admission document prepared and published in accordance with the AIM Rules for Companies of the London Stock Exchange (LSE). This CPR was prepared in compliance with the "AIM Note for Mining, Oil and Gas Companies, June 2009", as published by the London Stock Exchange. Estimates of resources are prepared in accordance with resource definitions presented in the SPE's 2018 Petroleum Resources Management System ("SPE-PRMS"). The previous Development Plan is no longer valid and there are no development plans for Liberator at the current time. No economic value or development Risk Factor has been determined.

At this stage, the calculated resources for Liberator East have been classified as "Contingent, Development Not Viable". Commerciality of a development based on the reduced recoverable volumes remaining post appraisal drilling is unlikely and has not been established; no commercial Chance of Success or Risk Factor has been assigned pending increased clarity on potential appraisal of the Liberator West and Minos High structures. Subject to funding and potential farm-out activities, i3 Energy anticipate further 2020/21 appraisal drilling on the Serenity and Liberator accumulations. The appraisal programme would focus on Serenity (two wells plus side-tracks) with an additional two-well option for the Liberator West/Minos high area. A farm-out process is ongoing with parties in i3's data room.

Block	Licence	Asset	Holder	Operator	Interest	Status	Area (km ²)	Expiry
UKCS Block 13/23d	P.1987	Liberator East	i3 Energy	i3 Energy	100%	Production (Extant)	14.6	31/12/2038 (anticipated)
UKCS Block 13/23c	P.2358	Liberator West	i3 Energy	i3 Energy	100%	Production (Extant)	187.1	30/09/2042 (anticipated)
UKCS Block 13/23c	P.2358	Minos High	i3 Energy	i3 Energy	100%	Production (Extant)	187.1	30/09/2042 (anticipated)

Summary of licensing interest

Any future development of this asset will be subject to UKCS taxation system, which will amount to 40% (Corporation Tax plus Supplementary Charge). No royalty is applicable to this licence, hence net resources are equal to gross volumes.

The unrisked contingent resource volumes for Liberator East are shown below.

LIBERATOR EAST i3 Energy Working Interest 100%, Unrisked										
Asset	Resource Category	Company Share Gross Resources				Company Share Net Resources				Risk Factor
		Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	
Liberator East, Block 13/23d	1C	1.1	0	-	1.1	1.1	0	-	1.1	N/A
	2C	5.3	2900	-	5.7	5.3	2900	-	5.7	
	3C	11.0	6500	-	12.1	11.0	6500	-	12.1	

Liberator East Resource summary

A preliminary estimate of likely range of Liberator West and Minos High Propsective resources is summarised below. Given the ongoing and immature nature of the technical work on these assets, the Low to High estimates are considered provisional.

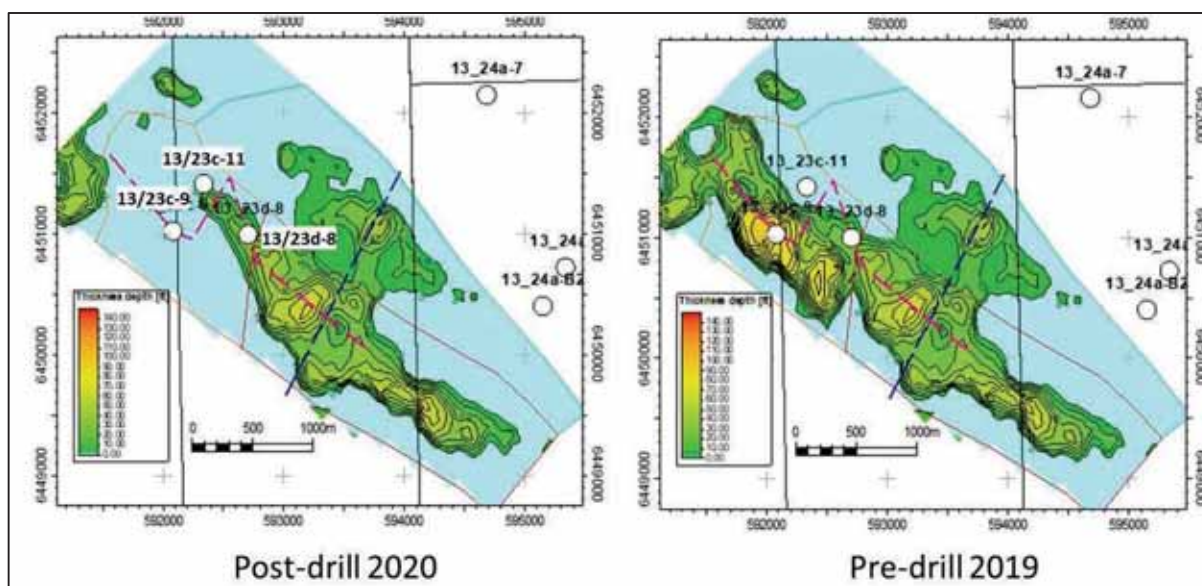
LIBERATOR WEST & MINOS HIGH i3 Energy Working Interest 100%, Unrisked										
Asset	Resource Category	Company Share Gross Resources				Company Share Net Resources				COSg
		Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	
Liberator West Block 13/23c	1U	1	-	-	1	1	-	-	1	42 %
	2U	-	-	-	-	-	-	-	-	
	3U	52	-	-	52	52	-	-	52	
Minos High, Block 13/23c	1U	5	-	-	5	5	-	-	5	42 %
	2U	-	-	-	-	-	-	-	-	
	3U	165	-	-	165	165	-	-	165	

Liberator West and Minos High Provisional Resource estimate

Liberator East Evaluation Summary

Liberator was discovered in 2013 by well 13/23d-8, which encountered a 24 foot hydrocarbon column in a high porosity - high permeability reservoir sand, with 4 feet of gas underlain by 20 feet of oil. Reservoir and fluid properties are analogous to those found in the Blake Field. The OWC at 5270 ft tvdss was clearly established from logs and MDT pressure data. The reservoir is the Lower Cretaceous Captain Sandstone reservoir, which extends as a regional northwest to southeast fairway of deep marine turbidite sand channels and associated deposits in the Moray Firth Basin. In the Liberator area, we classify the Captain sands to be part of the K50.1 unit, comparable with the reservoir sands in the Blake field. The K50.1 sand is further divided into an Upper and Lower Captain sand in Liberator East. It is the Upper Captain sand in Liberator that is hydrocarbon-bearing, i.e. proven. Where penetrated to-date in the Liberator area, the Lower Captain sand is water-bearing and MDT pressures taken in the Liberator discovery well 13/23d-8 indicate this sand is isolated on a production timescale and not connected to the regional aquifer.

Of the two wells planned on Liberator in 2019; the first was intended as a pilot hole for the first producer and the second as an appraisal well on Liberator West. The pilot hole (13/23c-9) was drilled in September 2019 and targeted the shallowest part of the Liberator Phase 1 East structure in a small culmination west of the discovery well. 13/23c-9 failed to find the Upper Captain sands and instead encountered a water-bearing interval of lower Captain Sandstones, deep to prognosis. i3 Energy then licensed the MF18 seismic data, which appeared to provide clear insight into sand distribution between the 13/23c-9 well and the Liberator discovery well 13/23c-8, just 500 m away. It was evident that the 13/23c-9 well had missed the edge of the Upper Captain sand package and it appeared that the MF18 seismic volume was more reliable for well placement. In November 2019, a second attempt was made to drill the pilot hole based on the new seismic data. Though the Upper Captain Sandstone was present in the 13/23c-11 well, it came-in deep to prognosis and was also water-bearing.



Liberator East height of oil column maps

This report deals with 13/23c-9 and -11 well results, and what impact these wells and new seismic data have had on Liberator East post-drill. Based on an integrated assessment, the uncertainties identified in the previous volumetric assessment remain significant though depth uncertainty has proved by far the most important factor. Given that the 13/23c-9 well targeted the most crestal point on the pre-drill map, the negative impact of encountering water in this region is apparent from the new map.

Following review of the new MF18 seismic data, TRACS believe the original seismic interpretation (MF10) provided an acceptable view of the subsurface geometry over the majority of the Liberator East structure, once it was corrected at the 13/23c-9 well. The MF18 interpretation represents an alternative view which has been incorporated into the volumetric range.

TRACS updated STOIP realisations reflect the impact of the revised mapping. Consistent with the previous CPR, the depth uncertainty applied remains of the order of +/-25ft within 1km of well control but will increase in the Liberator West and Minos areas which are further away. Uncertainty realisations for

reservoir properties, and the impact of a possible gas cap were carried forward unchanged from the previous CPR; a small gas cap and was assumed in the low case only.

Case	STOIIP MMstb	GIIP Solution gas Bscf	GIIP Free gas Bscf	2019 CPR STOIIP for comparison
Low	5.7	1.8	1.9	18.4
Mid	19.5	6.6	0	38.0
High	33.3	11.9	0	58.2

Liberator East; Low, Mid and High Case In-Place volumes

The updated Mid Case STOIIP is comparable with the pre-drill Low Case STOIIP estimated for the 2019 Liberator CPR.

The reduced area and height of the oil column has significant implications on the development efficiency of Liberator East. The number of development wells required is reduced from two to one, and earlier water breakthrough from the underlying water is expected, reducing the recovery factor. The reservoir simulation model was updated to reflect the new structure and sand distribution and a single, crestal, horizontal well was tested in the model. Based on the results, the previously estimated low and mid recovery factors have been reduced by 5%, leaving the high estimate as before to reflect the remaining uncertainty in sand architecture and associated production performance.

Resource volumes have been evaluated deterministically by applying low, mid and high case recovery factors to the respective low, mid and high in-place volume estimates for oil and gas. This is consistent with the evaluation approach in which recovery factors were derived from deterministic (low, mid, high) reservoir models.

Case	Oil RF (%)	Gas RF (%)	Oil Resources (MMstb)	Gas Resources (Bscf)
Low	20	0	1.1	0
Mid	27	44	5.3	2.9
High	33	55	11.0	6.5

Liberator East; Low, Mid and High Case Recovery Factors and Resource Volumes

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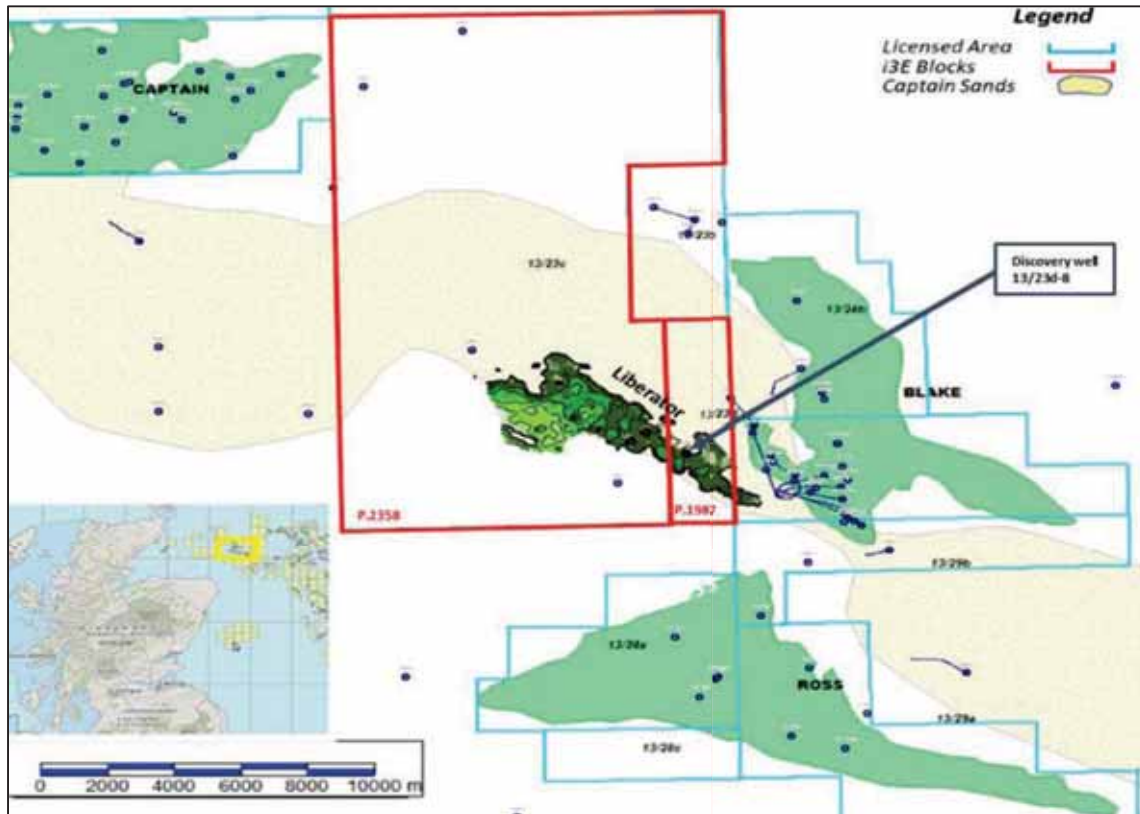


Figure 1-2 Liberator area location map

Liberator was discovered in 2013 by well 13/23d-8, which encountered a 24 foot hydrocarbon column in a high porosity - high permeability reservoir sand, with 4 feet of gas underlain by 20 feet of oil. Reservoir and fluid properties are analogous to those found in the Blake Field. The OWC at 5270 ft tvdss was clearly established from logs and MDT pressure data. i3 Energy interpret the Liberator accumulation to share a common OWC with the Blake field and the Serenity and Tain discoveries.

The reservoir is the Lower Cretaceous Captain Sandstone reservoir, which extends as a regional northwest to southeast fairway of deep marine turbidite sand channels and associated deposits in the Moray Firth Basin. In the Liberator area, i3 classify the Captain sands to be part of the K50.1 unit, comparable with the reservoir sands in the Blake field. The K50.1 sand is further divided into an Upper and Lower Captain sand in Liberator East. It is the Upper Captain sand in Liberator that is hydrocarbon-bearing, i.e. proven. MDT pressures taken in the Lower Captain Sand in the Liberator discovery well 13/23d-8 indicate that the Lower Captain water sand is isolated on a production timescale and not connected to the regional aquifer (Section 3.3 & Figure 3-7). There is uncertainty surrounding the depth and continuity of sand bodies across the Liberator area. The 2019 well results have stressed that this uncertainty has an impact at very short distances away from existing well control since the new wells are just 500 m away from the 13/23c-8 discovery well. In well 13/23a-4, some 8 km away in the west, the Captain sands are wet (below the 5270 ft OWC) and capped by a thick shale. To the southwest the sands pinch out and are completely absent in 13/23-1. It is possible that the sands encountered in 13/23a-4 are different to those observed in the Liberator East discovery area.

Prior to the 2019 drilling campaign, i3 Energy had matured the Liberator project to "Define" stage, with final FDP approval and project sanction expected Q3 2019. A phased development was planned. Phase 1 consisted of a two to three well subsea development tied back to the Ross DCA manifold and Bleo Holm FPSO. Figure 1-3 summarises the 2019 CPR map, with area designations consistent with the phase of development but also the confidence in how far away from the discovery well the results could be extrapolated northwestwards:

- Phase 1 East. The area around the discovery well extending to the saddle northwest of the well. Economically recoverable resources from this area, associated with a committed development plan, were classified as Reserves. Resources produced beyond the 2024 vessel certification were classified as Contingent Resources.

- Phase 1 West. Immediately to the NW of the Phase 1 East area continuing to a saddle just west of the A3 Appraisal well location. Resources in this area were classified as Discovered, Contingent Resources.
- Phase 2. The region around 23a-4. This area was considered undiscovered; resources are Prospective with a geological chance of success of 56%.

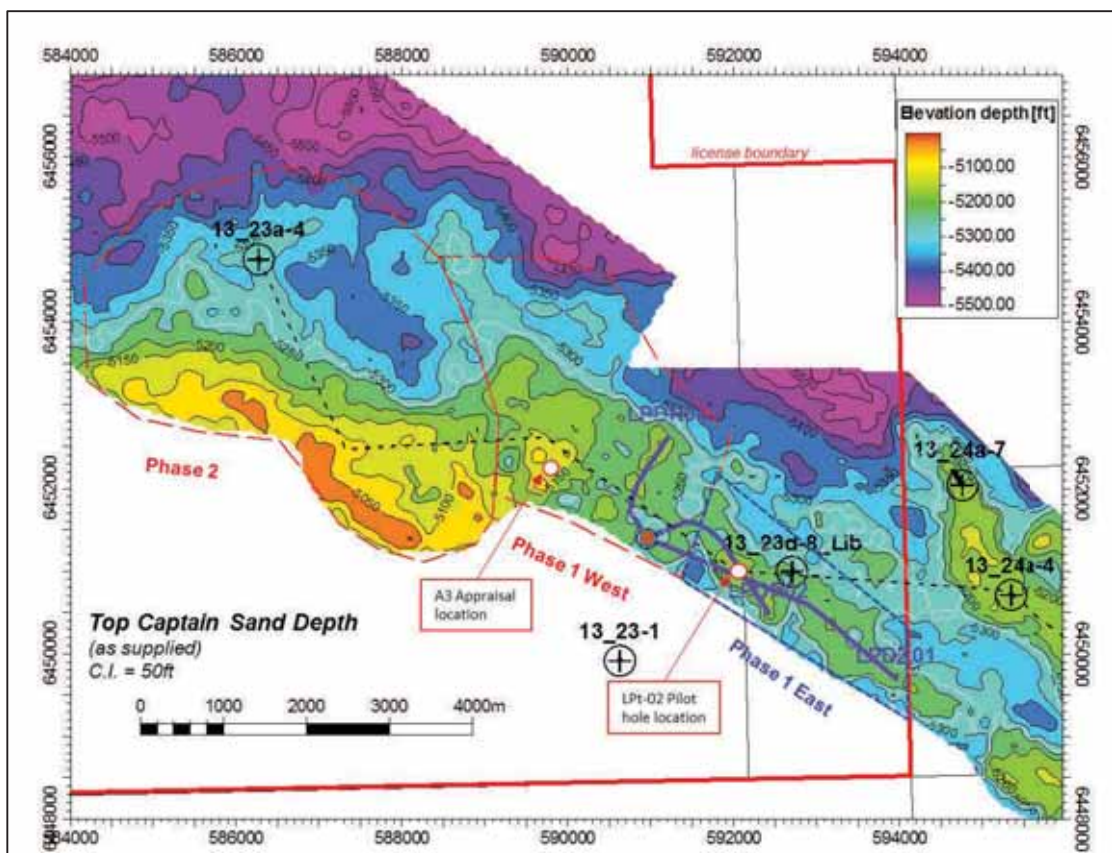


Figure 1-3 2019 development layout, appraisal well locations and area designations

Of the two wells planned on Liberator in 2019 in Phase 1; the first was intended as a pilot hole for the first producer (LP02) and the second as an appraisal well (A3) on a secondary high to the west. The pilot hole (13/23c-9) was drilled in September 2019 and targeted the shallowest part of the Liberator Phase 1 East structure in a small culmination west of the discovery well. 13/23c-9 failed to find the Upper Captain sands and instead encountered a water-bearing interval of Lower Captain Sandstones, deep to prognosis. i3 Energy then licensed the MF18 seismic data, which appeared to provide clear insight into sand distribution between the 13/23c-9 well and the Liberator discovery well 13/23d-8, just 500 m away. It was evident that the 13/23c-9 well had missed the edge of the Upper Captain sand package and it appeared that the MF18 seismic volume was more reliable for well placement, as illustrated in Figure 1-4.

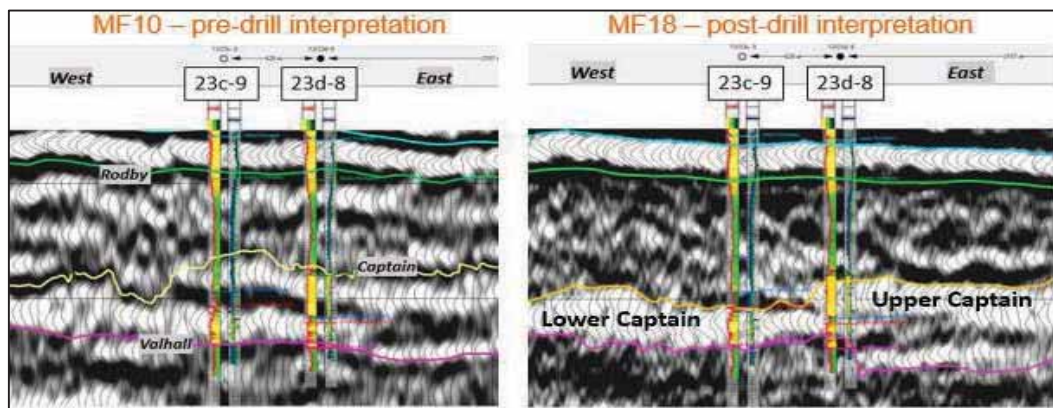


Figure 1-4 Seismic character close to the 13/23c-9 well; comparison of MF10 and MF18

There was a pause in the Liberator drilling campaign whilst the Serenity discovery well 13/23c-10 was drilled (October 2019). In November 2019, the rig returned to the Liberator area when a second attempt was made to drill the pilot hole based on the new seismic data. The plan to appraise the Liberator Phase 1 West area in the 2019 drilling campaign was shelved. Though the Upper Captain Sandstone was present in the 13/23c-11 well, it came-in deep to prognosis and was also water-bearing.

A first step in the updated CPR assessment was to determine how the two new well results and newly licensed seismic have impacted the resource classification. A revised resource classification was made based on the new well data, with reference to the revised i3 area designations illustrated previously in Figure 1-1:

- **Liberator East** (formerly Phase 1 East). The area including the discovery well (23d-8) and two latest Liberator wells (23c-9 and -11). Resources were re-classified as Discovered; Contingent Resources. Revised resources estimates (Section 7) are unlikely to be commercially viable, though this CPR does not include an economic evaluation.
- **Liberator West** (formerly Phase 1 West). Resources in this area were re-classified as undiscovered, Prospective Resources. It is unclear whether the sands in this area are Upper or Lower Captain (or both). Hydrocarbons are yet to be proven in Lower Captain sands.
- **Minos High** (formerly Phase 2). The region around 23a-4. This area remains classified as Undiscovered; Prospective Resources.
- **Liberator South**. Not yet evaluated by TRACS but classified as Undiscovered; Prospective Resources.

This CPR presents an updated resource evaluation for **Liberator East** and provides likely prospective resource ranges for Liberator West and Minos High, presented in Section 8, which will be matured through ongoing analysis of the newly-available seismic and well data.

1.2 Licence history, burdens and current status

i3 Energy hold a 100% interest in P.1987 licence, Block 13/23d and P.2358 licence, Block 13/23c. Licence P.1987 was awarded in the 27th round to Dana in 2013 on a 100% basis. The initial term was for four years commencing 1st January 2013, with a one well commitment. This commitment was fulfilled in 2013 with the drilling of the Liberator discovery well, 13/23d-8. i3 Energy acquired the licence from Dana in 2016. OGA approval was confirmed on December 8th 2016 with an obligation to "secure approval of a Field Development Plan or provide evidence of funds to drill a well by 31st December 2018."

License P.2358 was awarded to i3 Energy on October 1st 2018 following a successful bid in the 30th offshore licence round; the work programme for the initial license term of two years consists of a single well; this obligation has been met with the drilling of wells 13/23c-9 (Liberator), 13/23c-10 (Serenity) and 13/23c-11 (Liberator) in Q3/Q4 2019. The initial obligation attached to licence P.1987 for FDP approval was extended to allow for an optimised development of Liberator, which spreads across both licences.

The Liberator East discovery lies almost entirely within Licence P. 1987, though a portion (estimated 17%) extends outside the licence boundary to the southeast into the Blake partners acreage. No unitisation agreement exists relating to this extension, however based on this evaluation, the volumes are minor and in any case presently not viable for development.

Block	Licence	Asset	Holder	Operator	Interest	Status	Area (km ²)	Expiry
UKCS Blocks 13/23d	P.1987	Liberator East	i3 Energy	i3 Energy	100%	Production (Extant)	14.6	31/12/2038 (anticipated)

Table 1-1 Summary of licensing interest

1.3 Future activity

Subject to funding and potential farm-out activities, i3 Energy anticipate further 2020/21 appraisal drilling on the Serenity and Liberator accumulations. According to public statements, i3 Energy anticipate an appraisal programme that would focus on Serenity (two wells plus side-tracks) with an additional two-well option for the Liberator West/Minos high area. A farm-out process is ongoing with parties in i3's data room. No firm development plans exist at present for Liberator.

1.4 Data available

Data provided for the assessment included raw, and interpreted data, covering all required disciplines including

- Seismic data and interpretation extending over Liberator area and including the Blake field.
- Well data for exploration wells, the new Liberator wells, Liberator discovery well and selected Blake field wells.

Details of data provided are described in subsequent chapters. There were no data gaps identified which could impede TRACS in carrying out the assessment in accordance with PRMS. i3 were forthcoming with all requests for further information and clarifications.

1.5 Key uncertainties

Key subsurface uncertainties identified for the Liberator East discovery in the previous CPR (Ref 1) are listed below and are reflected in the range of input parameter values selected for volumetric estimation:

- Depth uncertainty on a low relief structure
- Fluid distribution; size and presence of gas cap
- Saturation height distribution
- Mobility of water within the transition zone
- Relative permeability
- Aquifer strength

Input assumptions for updated in place and recoverable resources are documented in further detail in subsequent chapters.

Of the uncertainties highlighted in the previous CPR, it is clear from the new well and seismic data that reservoir pick and depth uncertainty proved to be critical. There is inherent difficulty in accurately defining not only the top reservoir depth but also mapping of sand body continuity with the Captain Sandstone package, even at short distances away from well control. Though the new MF18 seismic data better imaged the sands in the -9 well, it failed to do so in the -11 well, meaning that no seismic survey is consistently reliable.

2 Geology Overview

2.1 Wells considered

The Liberator discovery well 13/23d-8 lies 2km west of the northern part of the Blake Field. Appraisal wells 13/23c-9 and 13/23c-11 were drilled some 500m to the NW of the discovery well. Other wells considered in the evaluation include exploration wells 13/23a-4, some 7km to the NW and 13/23-1 some 2km to the SW, off the axis of deposition. Some of the Blake Field development wells have also been included (Figure 2-2).

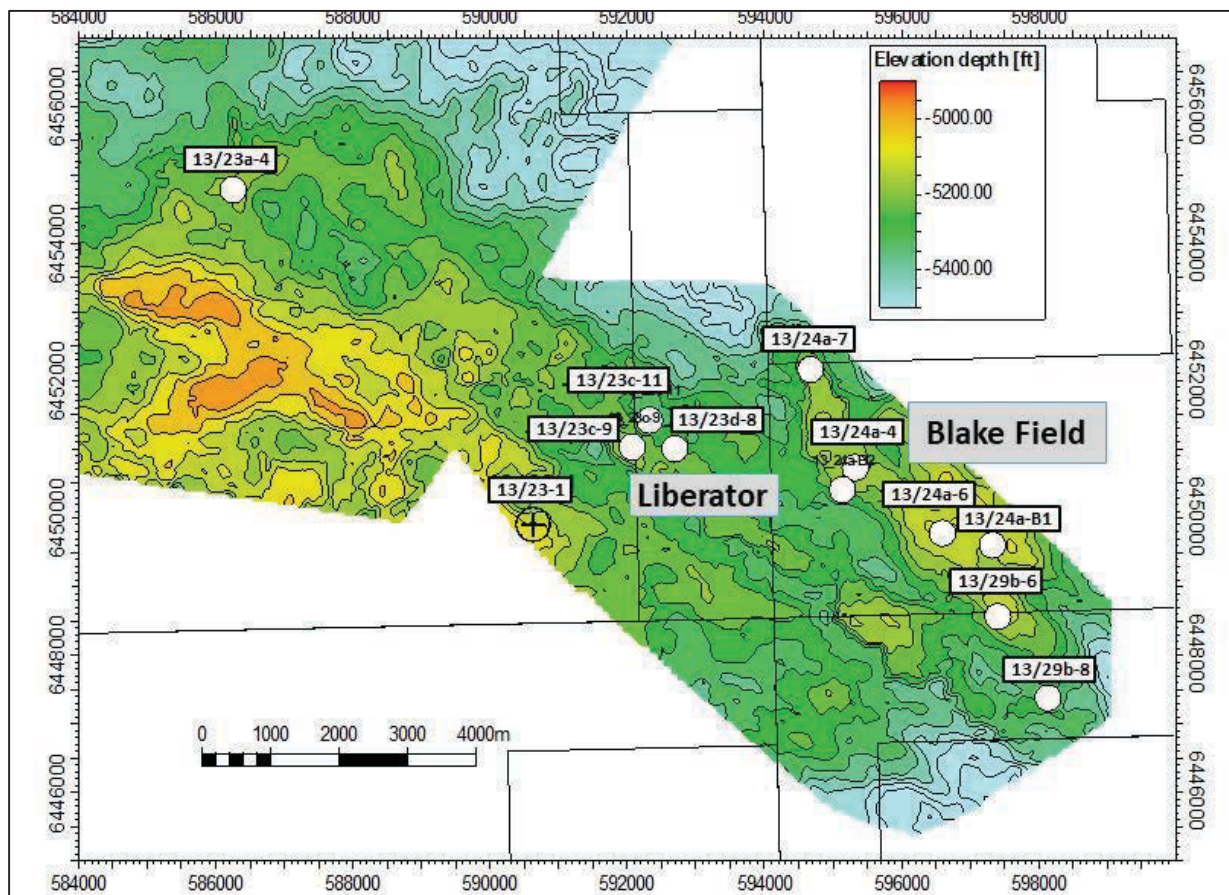


Figure 2-1 Map of Liberator-Blake area

2.2 Well correlation

The well correlation starts by picking the reliable top Rodby formation. This is a calcareous shale, often reddish coloured, covering the entire area and ranges in thickness from ~400ft at Liberator to ~250ft at the Blake Field. Below the Rodby Formation is the Carrack Formation, comprising non-calcareous shale with high GR, soft Density-Neutron and sonic response (20-50ft thick in the Liberator area). Above this is a thin unit (7-20ft thick) with harder sonic response and lower GR. This is interpreted as a silt, and very fine sand was observed in cuttings in 13c-9 ("Carrack Sandy"). Throughout the Rodby and Carrack Formations the GR, Density-Neutron and sonic logs display very similar responses in all wells (Figure 2-2). In the Liberator area, we classify the Captain sands to be part of the K50.1 unit, comparable with the reservoir sands in the Blake field. The K50.1 sand is further divided into an Upper and Lower Captain sand in Liberator East. Tracs are confident that this is a suitable correlation.

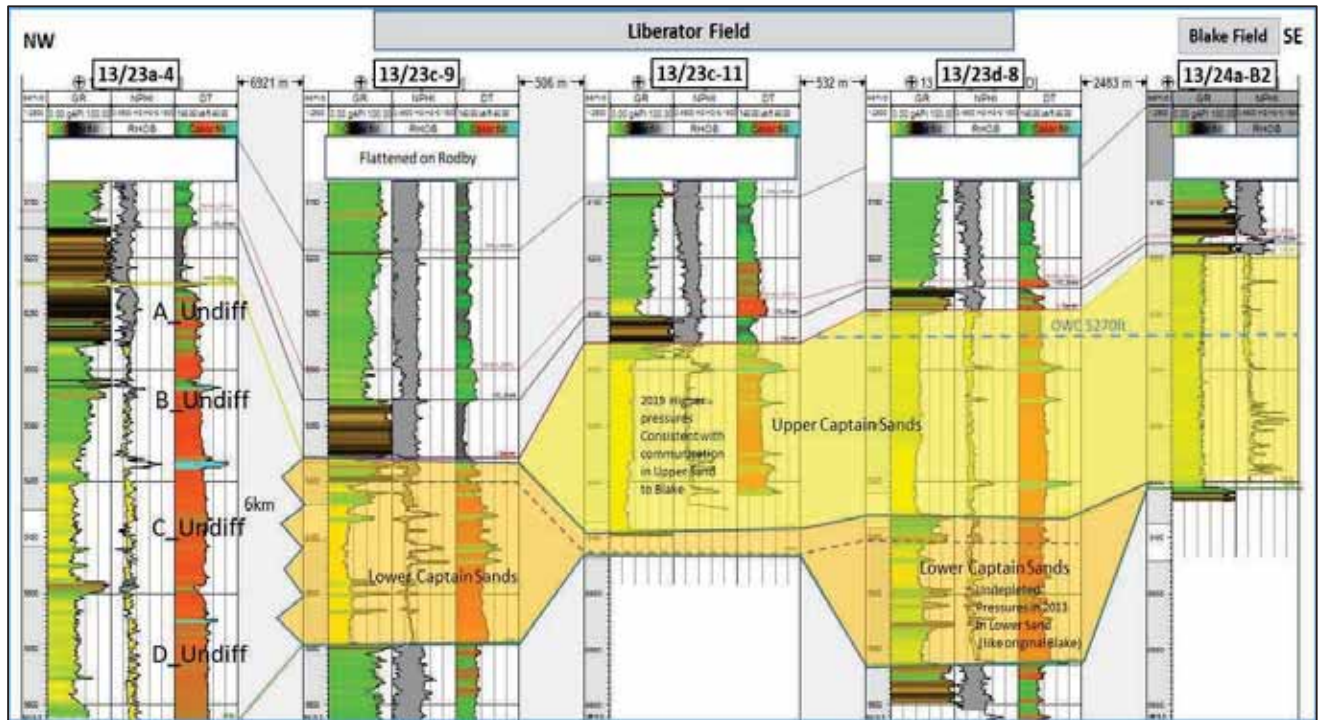


Figure 2-2 Well correlation panel

Some 7km to the NW of Liberator is the exploration well 13/23a-4. This comprises ~200ft of Rodby Formation with the Carrack shale ~40 ft thick. The shale is interpreted to be the top of the K50 time sequence, but there is no biostratigraphic data available to confirm this age. In this well the "Captain" interval can be subdivided into 4 units:

- A_undiff upper silt (non reservoir)
- B_undiff upper silty sand
- C_undiff middle blocky sand
- D_undiff lower blocky sand (lower porosity)

The exact correlation of these informal units with Liberator or Blake cannot be determined from wireline logs.

To the SW of Liberator lies the well 13/23a-1. There is no reservoir in this well, only Rodby and Valhall Formations are present. There is obviously a pinch-out of the Liberator sands in this direction.

The top reservoir sand can be clearly observed on logs. The top sand is thought to mostly coincide with the K50 sequence stratigraphic time line, although it is not known how much biostratigraphic data has been used to draw this conclusion. It occurs at various depths below the Rodby pick, being quite shallow in the Blake Field (~200ft) and deeper in the Liberator well (350ft). To the SE along the axis of the channel system, the sands occur about 350ft below Rodby, similar to Liberator. The sands are thicker to the SE, 500ft in 13/23b-8. Over the area, the top sand occurs at approximately 50% of the isochore from the Rodby to the Valhall.

Upper Captain Sands in the Liberator discovery well 13/23d-8, drilled in 2013, showed pressure depletion consistent with regional pressure drawdown in the Captain Sand aquifer (Section 3.3 & Figure 3-7). The Lower Captain Sands were seemingly at virgin pressure, consistent with Blake field pre-production pressures taken in 1998. On a production timescale therefore, the Lower Captain sand is not in communication with Upper Captain sand in the Liberator East area.

Formation pressures were also taken in the recent 13/23c-11 well and these showed an increase in aquifer pressure relative to Blake pre-production data, presumably due to communication with injectors in the Blake Field via the regionally connected aquifer. This is consistent with the 13/23c-11 Captain sand being correlated as the Upper Captain sand.

2.3 Reservoir geology

The sediments are of Lower Cretaceous age. At various times within the Aptian, thick sandstone units are developed from the Captain Field to the Blake Field and further South to the Cromarty Field. The Captain sands were deposited as massive turbidites in a NW-SE trending submarine channel system, over 100km long. Massive sands are very thickly developed in the Blake field. In the NW of the area of interest, well 13/23a-4 is in the axis of sand deposition, but to the SW, 13/23-1 is on the margin and has no sand, just a relatively thin shale.

Based on well and seismic data, together with analogue information, it is clear that more than one sand channel occurs in the wider area of interest. The dimensions of individual sand channels (width, length, thickness) are expected to be km scale, but there is uncertainty surrounding the correlation and continuity of sand bodies and the net-to-gross distribution.

Within the Liberator East area itself, it has been recognised from drilling the appraisal/pilot wells in 2019 that the Captain sand can be clearly subdivided into 2 sand bodies, informally named upper and lower. The lower sand was deposited closer to the SW margin of the channel system and the upper sand was deposited further towards the Blake Field, typical of submarine turbidite channels.

The main facies comprises high-density turbidites channels. Minor facies include silty sands and shales, probably representing off-axis lower energy deposition. A more widespread silty shale occurs at the top of the Lower Captain sand in the Liberator east area. This probably represents a time with no sand deposition allowing background distal turbidites to briefly blanket the area. The lower Captain sands contain more thin silt interbeds, which probably represent turbidite bed tops. This infers there are about 5 sand beds in the Lower Captain sand and possibly only 2 huge beds in the upper sand.

Individual sand bodies will extend from NW-SE for several km so reasonable continuity is expected from 13/23d-8 to the SE, following the same seismic event.

In the wider area it is possible that one sand channel can cut into another, as seen in the Captain field. However this has not happened significantly in the Liberator east area as the shale at the top of the Lower sand has not been disturbed - it is a pressure baffle.

There are several thin intervals of carbonate cemented sands which reduces porosity severely in about 2 to 5% of the reservoir. Based on analogue core information, these are likely to be large nodules and will not form large-scale baffles.

The bulk of the sandstones in the area including the Liberator well are well sorted, clean with high porosity (0.25 to 0.28) and permeability (1 to 2 Darcies).

2.3.1 Fluid Contacts

The Blake Field appears to share a common OWC with the Liberator discovery, at 5270ft. Since the latest two Liberator wells were water-bearing, they do not provide additional information about fluid contacts, though the results highlight that Liberator East oil pool is likely to be separate from potential accumulations further west in Liberator West or the Minos High.

In the Liberator discovery well, an interval of about 25ft of oil saturation occurs below the present OWC. This feature is similar to the wells in the Blake Field, being interpreted as a paleo-oil zone and is not counted in the STOIP.

The 4ft of gas seen in the well could be interpreted in several ways: 1. Primary or secondary gas cap across Liberator, or 2. Local tiny trap within 100m of the well (either primary or secondary). Evidence from the Blake Field was considered in the previous 2019 CPR by comparing seismic amplitude response with gas column height. The previous conclusions are carried forward to this CPR; since there is no clear seismic amplitude response over the Liberator East, the occurrence of a significant gas cap across the Liberator area is judged to be unlikely.

3 Petrophysical Evaluation

The petrophysics input for this CPR is to review the well logs and core data to support the range of reservoir properties and fluid contacts. The petrophysical data, including log analysis, was supplied as an LR Interactive Petrophysics (IP) database. Supporting data was supplied as summary presentations and the draft FDP.

The Liberator discovery is very close to the Blake field and is in the same formation as described in Sections 2.2 & 2.3. Data from wells in the region, including Blake, was initially included in order to understand the variations, and consistencies, in properties regionally. Subsequently the three Liberator wells have been compared with each other.

3.1 Data availability and quality

The original IP project was made up of the Liberator discovery well 13/23d-8, Blake wells and one exploration well to the west of the Liberator structure (13/23a-4). Full log analysis and interpretation parameters were included in the IP project with all input parameters and methods applied for the analysis. The two 2019 Liberator wells (13/23c-9 and -11) have been included in updated IP project from the client.

Well	Field
13/23a-4	Exploration
13/23d-8	Liberator
13/23c-9	Liberator
13/23c-11	Liberator
13/24a-4	Blake
13/24a-6	Blake
13/24a-7	Blake
13/24a-B1	Blake
13/24a-B2	Blake
13/24a-B3	Blake
13/24a-B4	Blake
13/24a-B5	Blake
13/24a-B7	Blake
13/29b-6	Blake
13/29b-8	Blake

Table 3-1 Liberator area wells

Additional data necessary for log analysis was included in the IP project including temperatures and depth in TVD and TVDSS. Core porosity and permeability are included in the IP project for Blake well 13/24a-4. MDT data was also supplied and is included in the discussion on fluid contacts.

3.2 Petrophysical interpretation

A consistent set of petrophysical interpretation has been supplied for review. The log analysis was found to be consistent with the quoted inputs and is supported by other data including porosity from core analysis and fluid pressure gradients from pressure data. The review resulted in verification of the log interpretation provided, which was then used as input going forward.

The Lower Cretaceous Captain Sand reservoir in Liberator and Blake is a high net-gross, high porosity and permeability sandstone as illustrated in Figure 3-1 CPI for 13/23a-4, which shows CPI's for the nearby exploration well and the Liberator discovery well.

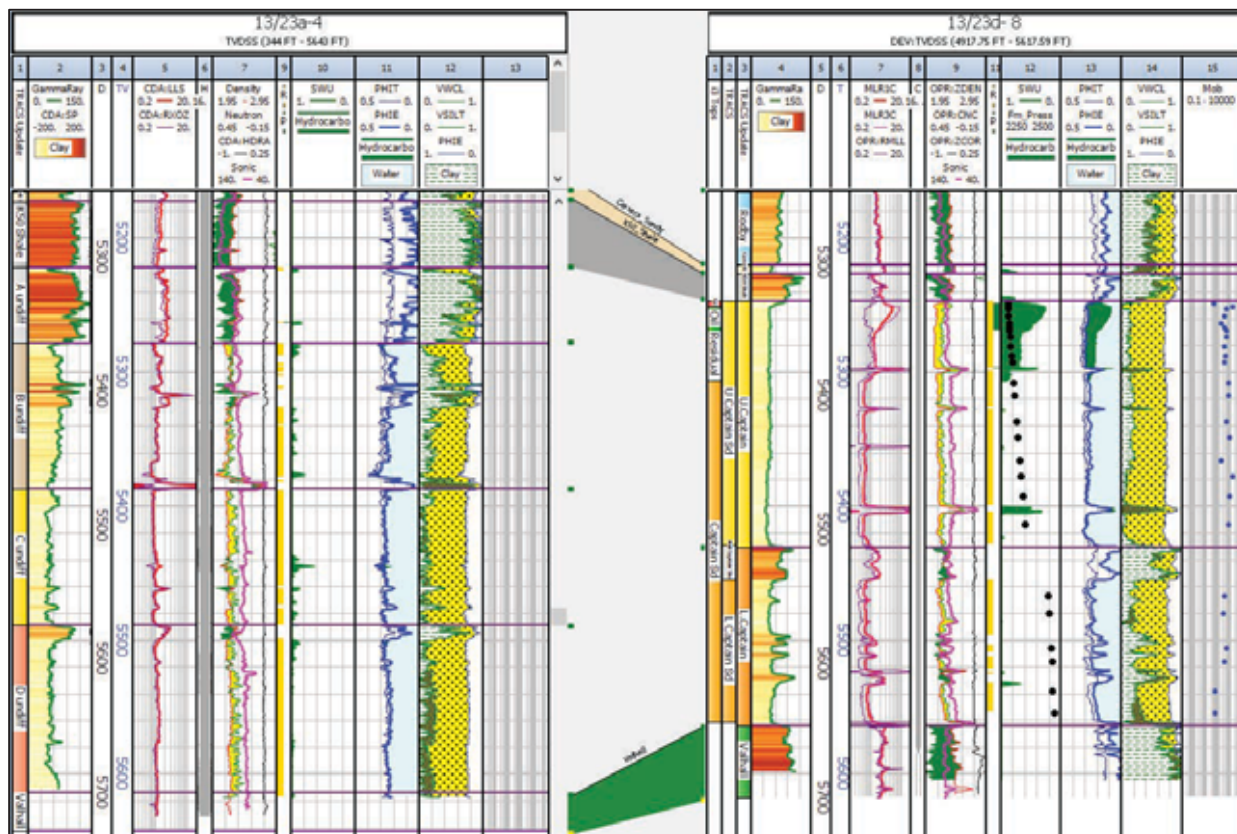


Figure 3-1 CPI for 13/23a-4 and 13/23d-8

The discovery well 13/23d-8, encountered a thick Captain sand with an Upper Captain sand separated from the Lower Captain sand by the Mid Captain shale. The well found a small gas column overlying oil.

Well 13/23a-4 found water-bearing Captain sands overlain by a thick K50 shale (which is not present in 23d-8). The sands are undifferentiated in this well and are divided into units by quality. Units C_Undiff and D_Undiff are the good quality sands and the properties from these units have been compared to the Liberator wells. There is a WUT at 5,278ft TVDss at the top of the Captain sand.

The two subsequent wells 13/23c-9 and 13/23c-11, drilled in 2019, both penetrated Captain sands deeper than the regional contact of 5,270ft TVDSS. The sands in both wells fit with this OWC since they are water-bearing (Figure 3-2). They confirm the presence and quality of the Captain sands on the Liberator structure but as described in geophysics section [Section 4] the depths of the Captain sands are uncertain.

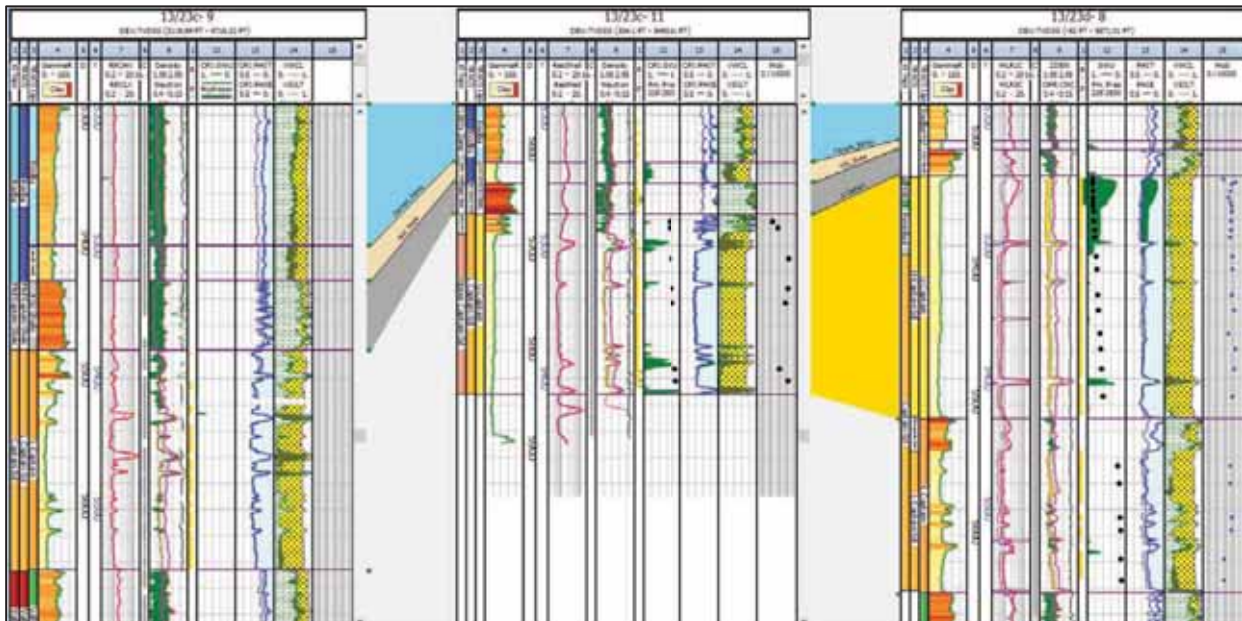


Figure 3-2 Liberator wells; logs and CPI

For reference, the formation names and colours are summarised in Figure 3-3:










Carrack_Sandy	
K50_Shale	
A_undiff	
B_undiff	
C_undiff	
D_undiff	
Valhall	
U.Captain	
L.Captain	

Figure 3-3 Liberator formation naming and colour fill

3.2.1 Vclay

Clay volume was calculated from the GR log and from the Neutron/Density (N/D) cross plot method. The results from the two methods are similar and the minimum of the two was used as input going forward.

3.2.2 Porosity

Porosity was calculated using the combination of Neutron and Density logs. Core analysis in Blake well 13/24a-4 is a close match to the porosity calculated from logs (Figure 3-4).

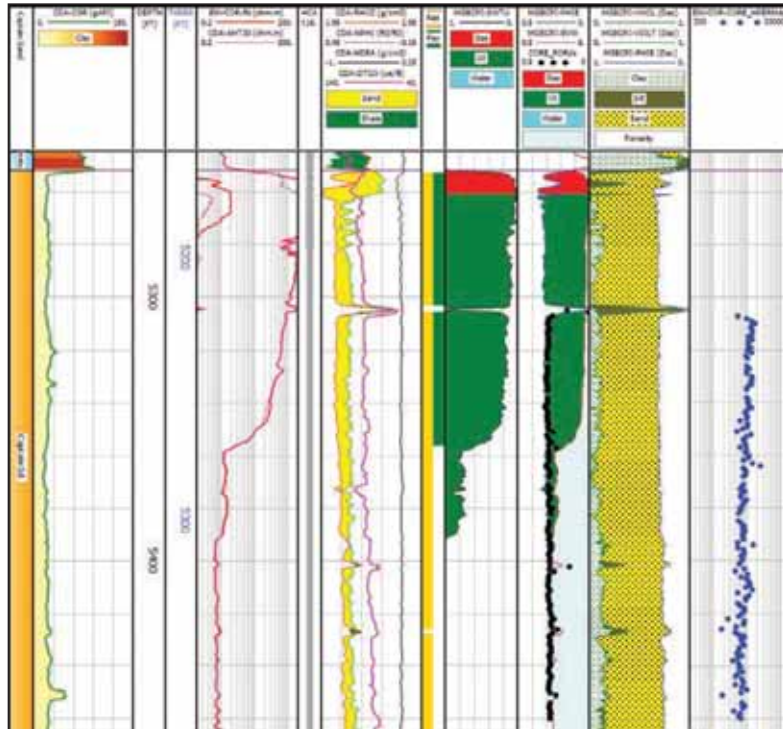


Figure 3-4 Porosity from core analysis in Blake well 13/24a-4 in close agreement with porosity from logs

3.2.3 Water saturation

Water saturation (S_w) has been calculated using the Archie equation of the form:

$$S_w = \sqrt[n]{\frac{a \times R_w}{\Phi^m \times R_t}}$$

Where:

- Φ is porosity (dec).
- R_w is water resistivity at reservoir temperature (for salinity of ~58kppm in this case)
- R_t is the true resistivity (often the deep resistivity log)

Constants a , m and n have been given the default values of 1, 2 and 2 respectively in the absence of SCAL data.

3.2.4 Permeability

As has been seen with porosity, permeability from core also varies little. A porosity/permeability graph was presented in the Liberator FDP and is reproduced in Figure 3-5 with the core data from 13/24a-4.

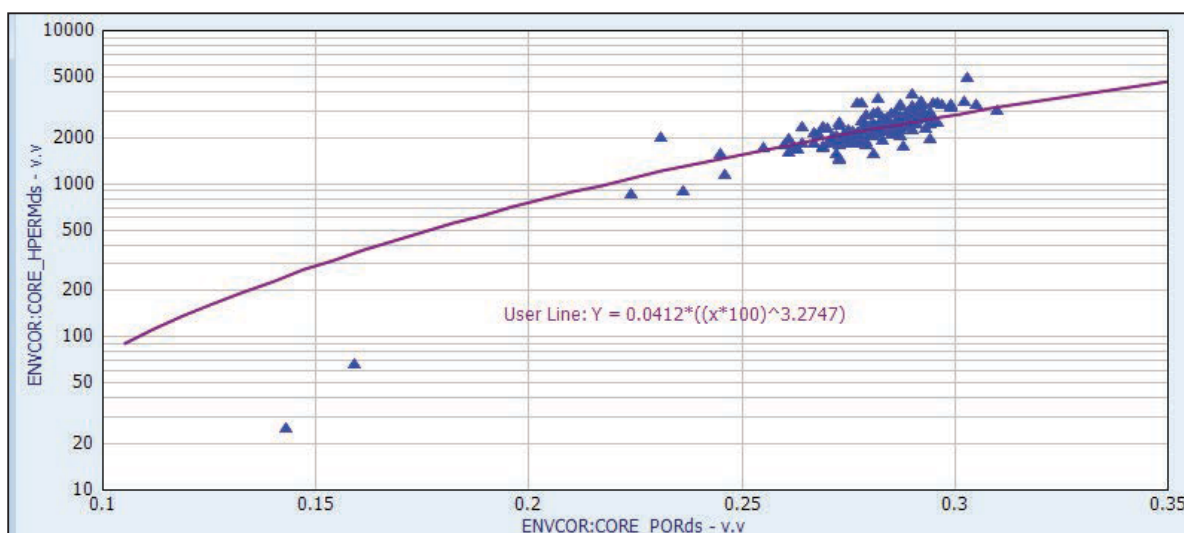


Figure 3-5 Porosity v Permeability from core in Blake well 13/24a-4

This function is fit for purpose and was used for the dynamic work.

3.2.5 Reservoir cut-offs

Figure 3-2 and Figure 3-4 illustrate that the net to gross and porosity in the Captain sand is consistently very high. The average properties calculated are quite insensitive to the cut-offs but a porosity cut-off of 20% was used along with a 50% Vsh cut-off to remove any non-net intervals.

3.3 Fluid contacts

The fluid contacts in Liberator are clearly defined from logs, pressures and fluid samples. There are some similarities with the oil-water contact depth for Blake but Liberator was expected to be a separate accumulation. The gas-oil contact seen in the Liberator well is significantly different to Blake (see Figure 3-6). The contacts in the regional wells consistently demonstrate a paleo-contact with 20% to 30% oil in the interval below the current oil-water contact. The thickness of the interval between the paleo and current oil-water contact varies illustrating some change in the structure over geological time. There is also a clear gas cap in some of the wells with the gas-oil contact showing some variation by location. The Liberator current oil-water contact from 13/23d-8 is close to the 5270ft TVDSS being carried in work to date. The Captain sands in 13/23c-11 do extend into the paleo contact depth range but do not encounter this feature.

The oil-water contact in the wells around the Liberator region is illustrated in Figure 3-6.

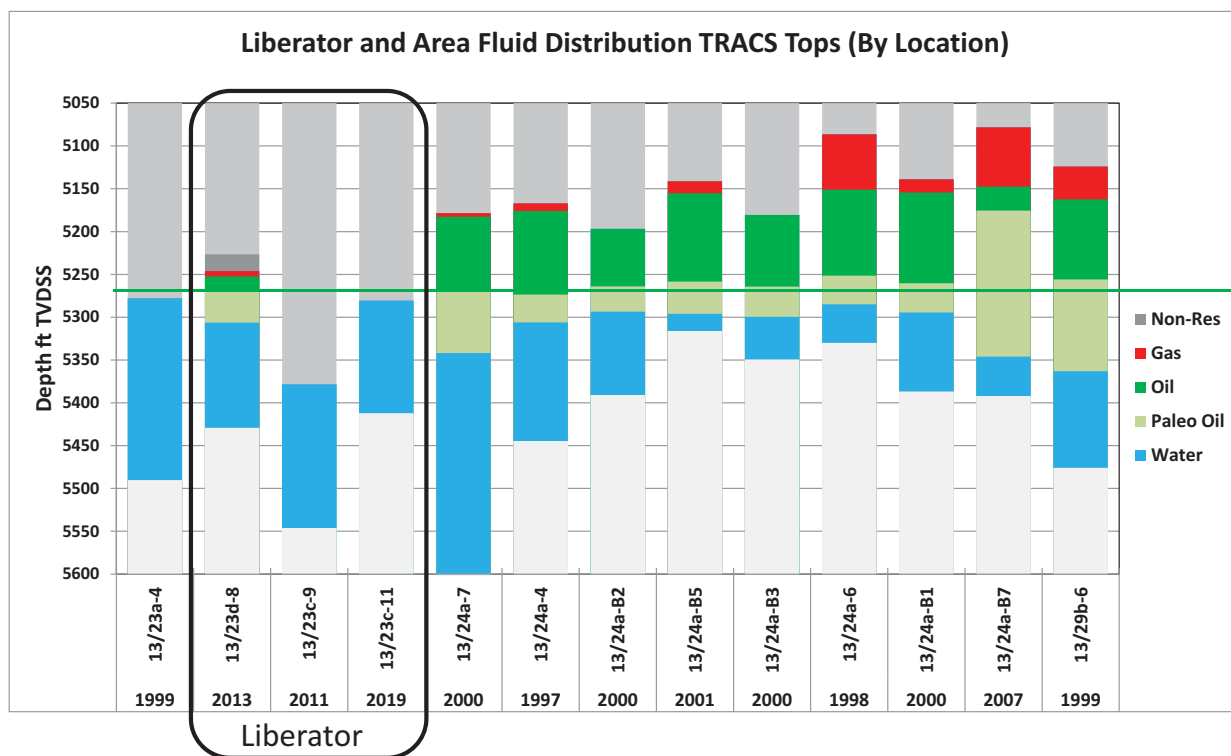


Figure 3-6 Fluid distribution in the Liberator region

The oil-water contact of 5270ft TVDSS is also supported by MDT data from the Liberator well 13/23d-8 from 2013 (Figure 3-7) though a pressure offset of 70 psi in the Upper Captain sand indicates some interference and depletion from the Blake production. Pressure data from the Upper Captain sands in 21/23c-11 in 2019 indicates that the regional pressure is now overpressured compared to Blake pre-production and is seemingly on the same regional aquifer gradient as the Serenity well pressure data (13/23c-10) acquired about a month earlier.

Pressure data from the Lower Captain sands in 13/23d-8, however, were close to the original pressure in the water leg for the Blake wells.

Gas observed in 13/23d-8 could be a result of local depletion trapped in a small culmination at the well location.

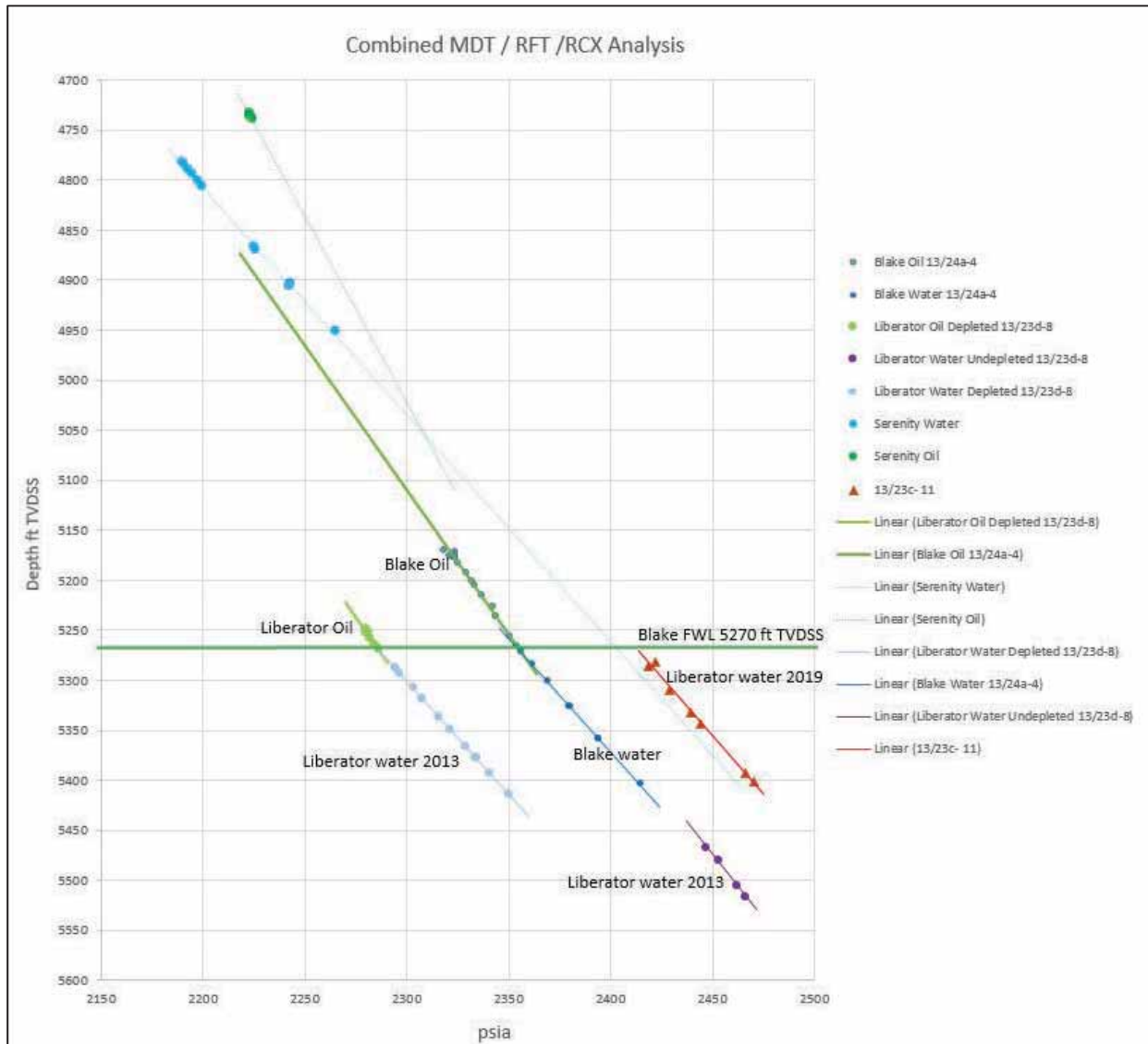


Figure 3-7 Formation pressure from Liberator and Blake Saturation vs height function

Since the Captain Sands from the 2019 wells are below the OWC they do not add anything to the saturation-Height story therefore it has not been updated.

High, mid and low saturation-height functions were presented in the Liberator FDP. The mid function was based on the Liberator well, 13/23d-8 (the black line in Figure 3-8). Given the pressure depletion and the higher Sw observed close to the contact in the Liberator well (which is on the edge of the structure and almost at the closest point to Blake) this is possibly a low case to carry over the whole of the Liberator structure. A slight change was made to produce a function with an improved match to the Liberator well Sw from logs (the red line in Figure 3-8). A function was also matched to the pre-production Blake Sw in 13/24a-4. This has been taken as the reference case since it represents the saturation as it was in its virgin state.

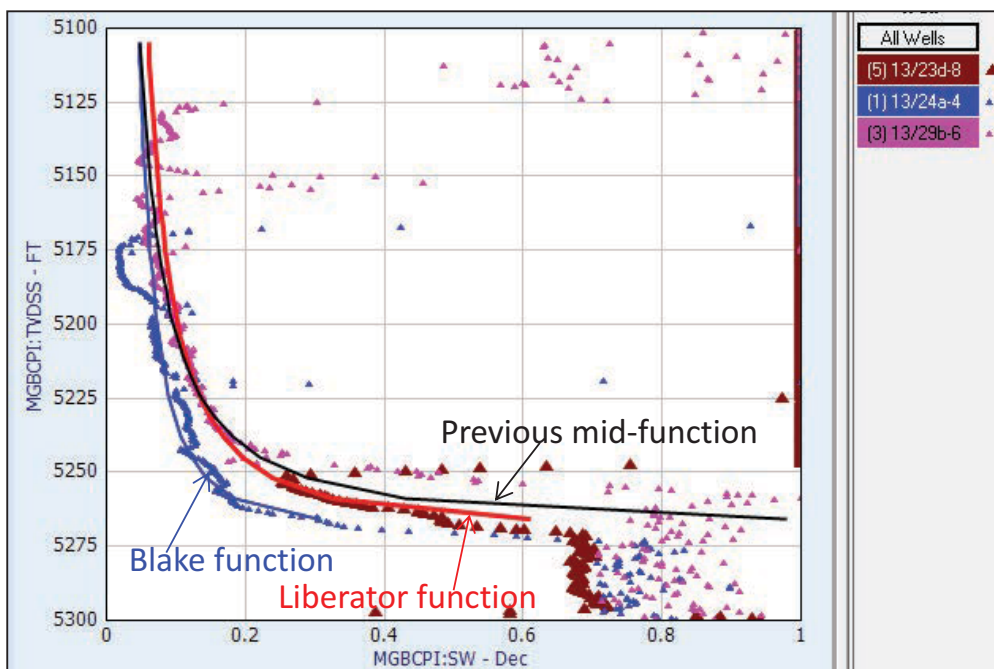


Figure 3-8 Saturation height functions displayed with Sw from logs

The Liberator and Blake saturation height functions are displayed on the CPIs for 13/23d-8 and 13/24a-4 in Figure 3-9.

The Liberator function is a good fit with the data it is matched to but is pessimistic compared to the Blake function based on a thick column, high on the structure before any production affected the fluids.

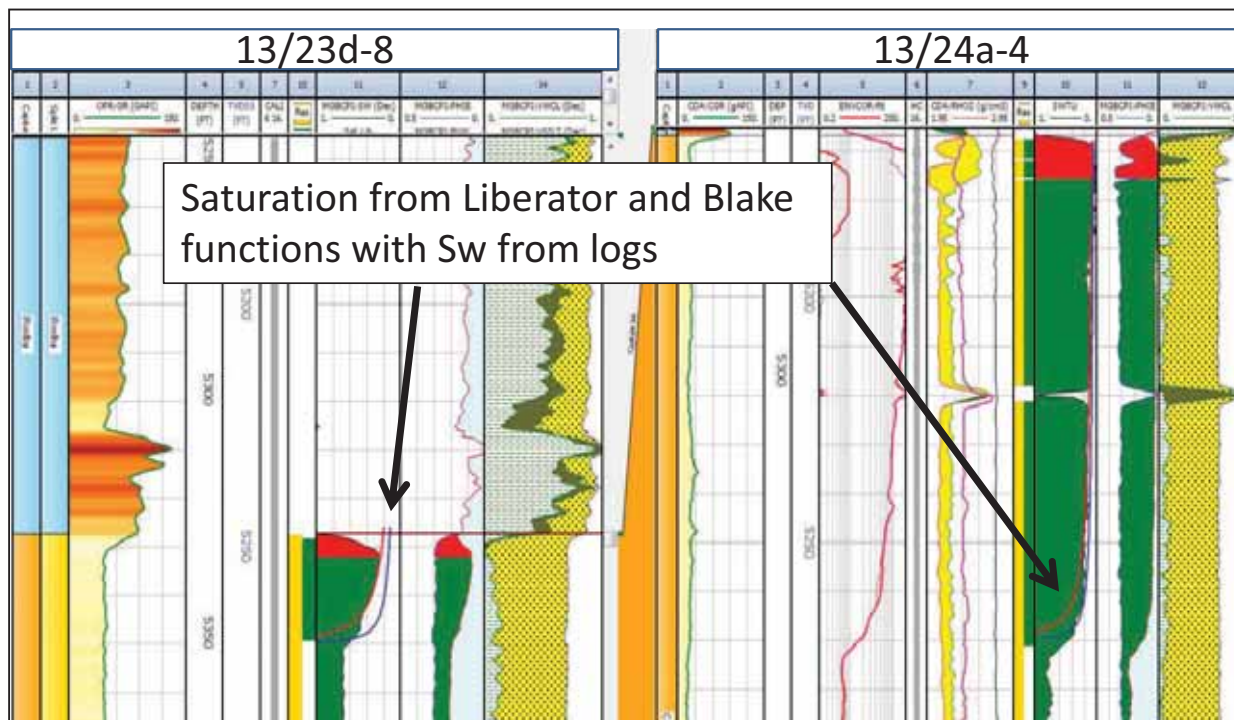


Figure 3-9 Saturation from the functions described displayed with the CPIs (Red-Liberator, Blue-Blake)

It should also be noted that the Liberator well is on the edge of the structure and only contains a relatively thin hydrocarbon column (24ft).

Considering the excellent porosity, permeability and apparent heterogeneity of the Captain Sand the transition zone as expressed on the logs is relatively thick. Intuitively one would expect a very sharp

contact in a reservoir of this quality. Given the relief of the structure, the transition zone will have an impact on the volumes calculated.

3.4 Results

As the CPIs and core analysis have illustrated, the Captain sands are of excellent reservoir quality. The Upper Captain is of slightly better quality with higher NTG and higher porosity than the Lower Captain. As described earlier the Captain Sand in well 13/23a-4 is undifferentiated though the porosity in the C and D intervals are similar to the Upper and Lower Captain Sand porosity in the Liberator wells.

Well	Zone Name	Units	Top MD	Bottom MD	Top TVDSS	Bottom TVDSS	Gross TVDSS	Net TVDSS	N/G tvdss	Av Phi Ari	Av Vcl Ari
13/23d- 8	U.Captain	ft	5329.0	5513.0	5246.7	5430.7	184.0	173.5	0.94	0.28	0.12
13/23c- 11	U.Captain	ft	5665.0	5845.6	5275.8	5412.6	136.9	104.0	0.76	0.28	0.07
13/23d- 8	L.Captain	ft	5513.0	5646.0	5430.7	5563.6	133.0	80.0	0.60	0.24	0.19
13/23c- 9	L.Captain	ft	5481.0	5648.0	5378.5	5545.5	167.0	122.2	0.73	0.26	0.15
13/23a-4	C_undiff	ft	5473.0	5575.0	5387.0	5489.0	102.0	98.8	0.97	0.27	0.08
13/23a-4	D_undiff	ft	5575.0	5700.0	5489.0	5614.0	125.0	116.0	0.93	0.24	0.08
13/23d- 8	All Zones	ft	5329.0	5646.0	5246.7	5563.6	316.9	253.4	0.80	0.26	0.14
13/23c- 9	All Zones	ft	5481.0	5648.0	5378.5	5545.5	167.0	122.2	0.73	0.26	0.15
13/23c- 11	All Zones	ft	5665.0	5845.6	5275.8	5412.6	136.9	104.0	0.76	0.28	0.07
13/23a-4	All Zones	ft	5473.0	5700.0	5387.0	5614.0	227.0	214.8	0.95	0.25	0.08

Table 3-2 Average properties in Captain sand

Average permeability from core analysis is 2331mD.

3.5 Uncertainties and sensitivities

As was previously mentioned, the volumes are sensitive to the saturation-height function given the low relief of the structure and the larger than expected transition zone. Generally all the other reservoir properties are excellent with little variation.

3.6 Conclusions and recommendations

The reservoir sand in all of the Liberator wells contains extremely good static reservoir properties similar to the Blake wells. The pressure data indicates the same oil-water contact with some interference from Blake production (possibly through the aquifer).

If cuttings or core samples are still available, mercury injection capillary pressure data would be a useful piece of data. It might be that there is some detail in the pore throat size distribution which could help to understand the nature of the transition zone.

4 Geophysical Evaluation

4.1 Data

TRACS was supplied with a Kingdom project with the following data:

- well data (various)
- TGS MF10 PSTM data – 2010 3D seismic data set ('MF10') comprising the following data types: PROCMIG, raw stack and near, mid & far stack data
- TGS MF18 PSTM data – 2018 3D seismic data set ('MF18') including the following data types: raw stack and near, mid & far stack data, IKON Vp/Vs and facies data and TrimStatics.
- Western Geco Q13Ph1 data – 2013 3D seismic data set ('Q13Ph1') comprising the PROCMIG data
- Phoenix3D Megamerge.
- various time and depth horizons/grids

The two key surveys are the MF10 survey which covers the eastern half of the structure and the MF18 survey which includes the area covered by MF10 but also extends to the northwest, Figure 4-1.

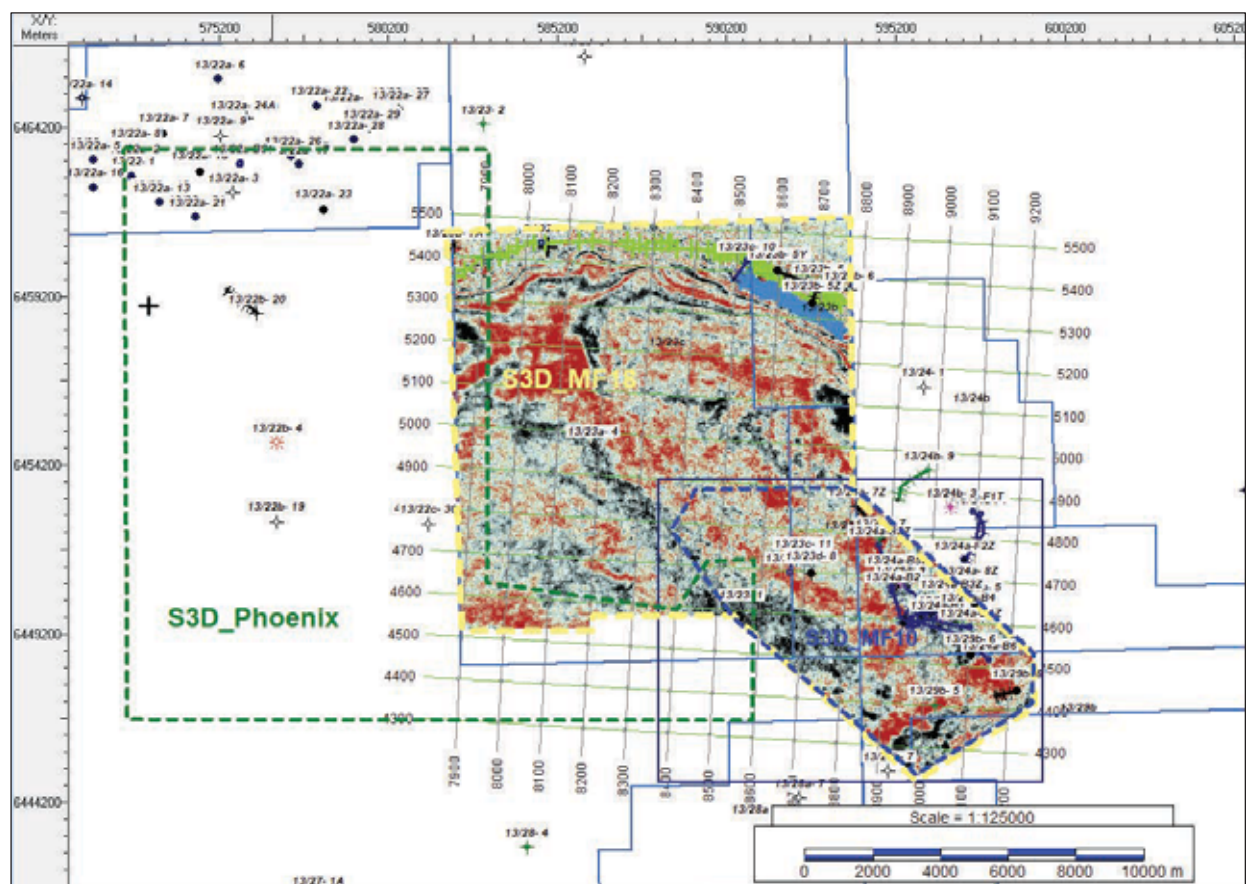


Figure 4-1 Seismic data coverage (supplied by i3 Energy)

4.2 Analysis

The objectives of the geophysical evaluation were as follows:

- review seismic interpretation over the Liberator East area
- review depth conversion and depth uncertainty over Liberator

4.2.1 Interpretation

Since the previous CPR was published, two new wells have been drilled on Liberator and a new seismic dataset (MF18) has been made available. New horizons based on the MF18 data were included in the Kingdom project and these were reviewed as part of the geophysical evaluation.

There were a number of key changes to the interpretation following the drilling of the 13/23c-9 and 13/23c-11 wells because both wells encountered unexpected results.

The 13/23c-9 well came in deeper than expected and this was the result of the original seismic data failing to image a change in sand geometry resulting in a mis-picking of the seismic data. Figure 4-2 shows Xline 4696 from both the MF10 (upper figure) and MF18 (Lower figure) datasets to show the difference in imaging between the two volumes.

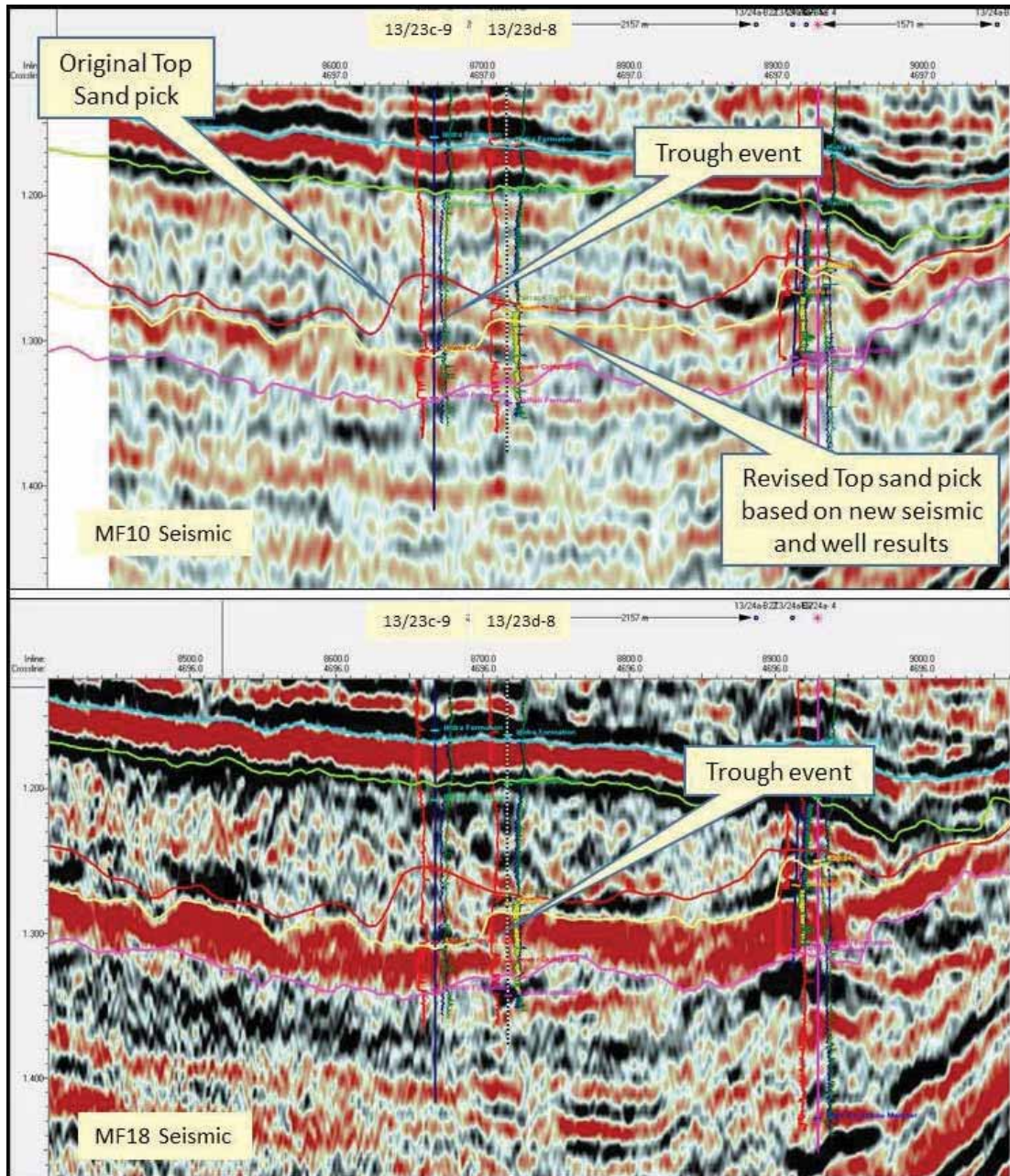


Figure 4-2 Xline 4696 showing the MF10 data (upper section) and the MF18 data (lower section) through the 13/23d-8 and 13/23c-9 well locations (For line location see Figure 4-5)

In the MF10 version (the upper image in Figure 4-2), there is a continuation of the weak peak representing the top of the K50 sequence and the following trough which was interpreted as the Upper Captain sand seen in the 13/23d-8 well. However, when the well was drilled, the Upper Captain sand was found to be

missing and the well drilled straight into the Lower Captain sand. With the new MF18 dataset (the lower image in Figure 4-2), it was possible to see that the trough that was present on the MF10 data did not extend as far as the 13/23c-9 well location.

In the Liberator East area, it has been possible to pick a weak peak that has been interpreted as the top of the Lower Sand. This can be mapped away from the wells to the east and south east and provides a mechanism for defining the distribution of the Upper Sand. It appears that the Upper Sand is present over the Liberator East area. Figure 4-3 shows a seismic line to illustrate this event.

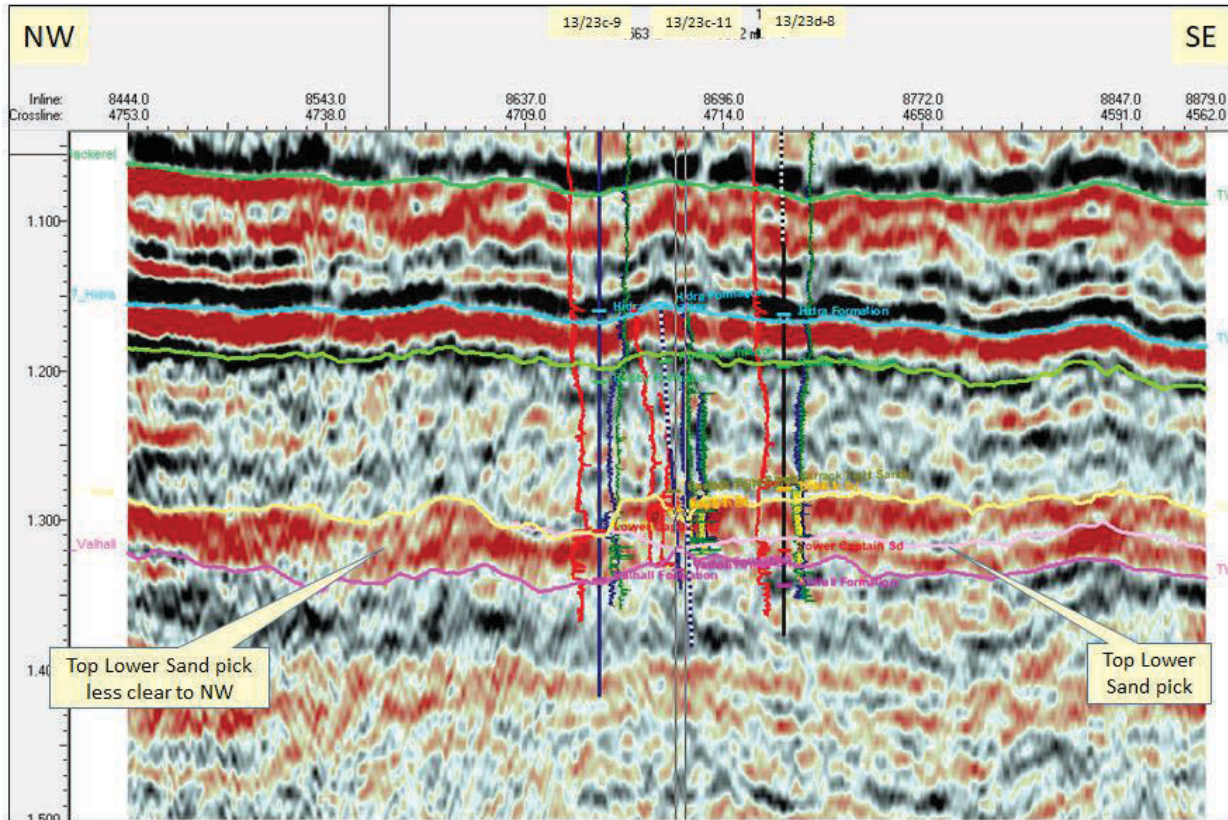


Figure 4-3 Arbitrary Line showing Top Lower Sand pick (For line location see Figure 4-5)

Further to the west and north west, this pick becomes less reliable so there is more uncertainty in these directions regarding the presence of the Upper Sand. This contributes to the uncertainties described in Section 4.2.2 below.

Following the drilling of the 13/23c-9 well there was a pause whilst the Serenity well was drilled which allowed time to interpret the MF18 data in order to take advantage of the improved imaging and decide on a new location to drill at Liberator. The result was the 13/23c-11 well location which appeared on the new data to be structurally higher than originally thought. In this case however, the MF18 data did not provide an improved image and the updated pick was shown to be too high. The original interpretation, in this case, was a closer representation of the subsurface geometry. Figure 4-4 shows the MF10 data (upper image) and the MF18 data (lower figure) through the 13/23c-11 well location. There are three horizons shown; the original interpreted horizon is in red, an intermediate horizon picked before the 13/23c-11 well was drilled, in blue and the current interpretation made after the 13/23c-11 well was drilled in yellow.

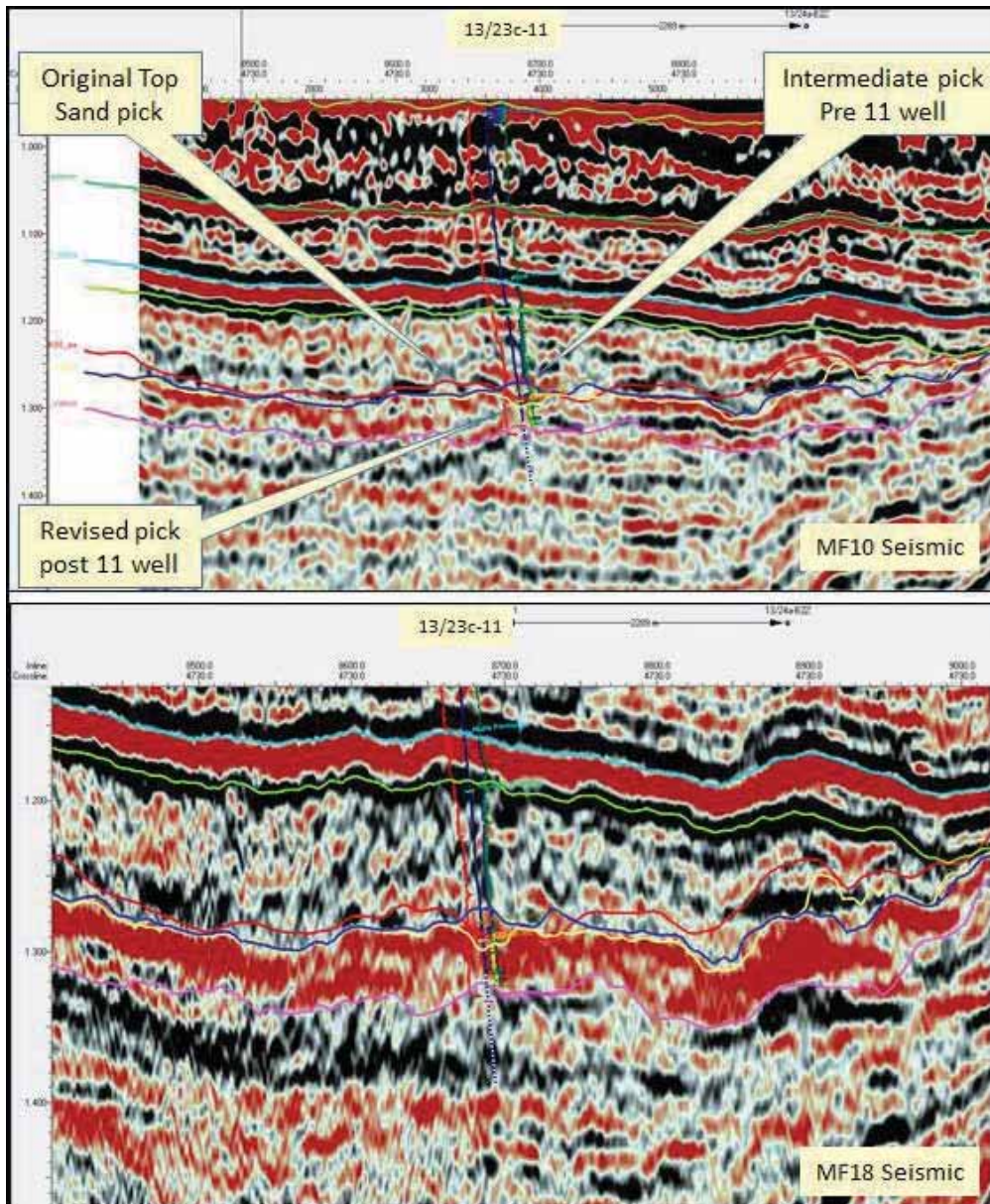


Figure 4-4 Xline 4730 showing the MF10 data (upper section) and the MF18 data (lower section) through the 13/23c-11 well location. (For line location see Figure 4-5)

Both of the seismic datasets (MF10 and MF18) appear to provide potential insights into the subsurface geometry and i3 have indicated that both will be used to enhance the interpretation of the Liberator East area. However, there are some areas of the new, MF18 interpretation which may not fully represent the top of the K50 sand. For the purposes of this review, it was decided that the original interpretation on the MF10 dataset provided an acceptable view over the majority of the Liberator East structure once it had been corrected at the 13/23c-9 well. The MF18 interpretation represents an alternative view which has been incorporated into the volumetric range.

4.2.2 Depth Conversion

The same depth conversion has been carried out for the new interpretation. In the previous CPR, this was considered to be a robust method and that view remains the case. This is despite the apparent depth errors seen at the two new wells. However, there are reasons for the depth errors which relate to the seismic picking rather than the depth conversion method as described above.

The depth uncertainty is likely to remain of the order of +/-25ft within 1km of the wells but will increase in the Liberator West and Minos areas which are further from well control and closer to the shallow channel. In these areas, the depth uncertainty is assumed to be +/-50ft.

The resulting MF18 depth map is shown in Figure 4-5.

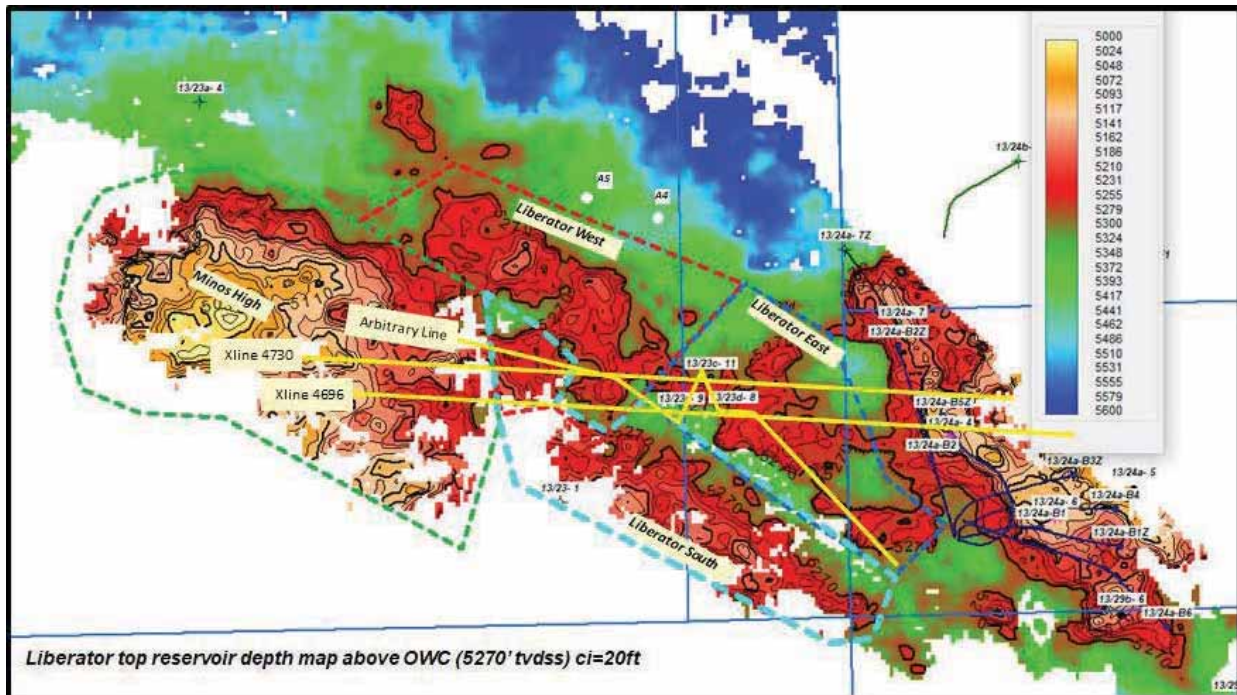


Figure 4-5 Liberator Top Reservoir depth map (Source i3 Energy)

A number of uncertainties were identified in the previous CPR and these have been shown to still be a concern. The uncertainties were considered to be made up of three elements: pick uncertainty, depth conversion uncertainty and diversion of top Captain sand from the K50 sequence boundary.

The pick uncertainty has been found to be a significant factor affecting the results of the two new wells with both the MF10 and MF18 datasets contributing to this. There are areas on both datasets where the pick steps up or down and alternative interpretations are possible for the top sand. This should be born in mind when planning new well locations.

The depth conversion uncertainty remains since, although there are reasons for the depth errors in the two wells, the other features identified in the previous CPR remain a concern. These include the shallow channel which has been identified and included in the depth conversion but the velocity of the channel fill is based on only one well so may not be representative of the whole channel. Also identified as a potential uncertainty are the small erosional features seen in the Chalk which will influence the depth estimation on what is a low relief structure at the K50 level.

The third uncertainty, relating to the changing facies of the K50 sequence, has not been affected by the new wells and remains a concern.

As previously recognised in the 2019 CPR, a combination of these uncertainties in the Liberator East area could result in a higher or lower structure which will impact the STOIIP. As before, this has been taken into account in estimating the range of STOIIP.

5 In Place Volumes

For the Liberator East, the static model was re-built with the 2 new wells and taking on board information from the MF18 seismic data. Note that the MF10 depth map remains the primary reference for top reservoir structure, though it was adjusted to account for the 13/23c-9 well result, which came in deep to prognosis and failed to encounter the oil-bearing Upper Captain Sand.

5.1 Key Uncertainties

Based on a review of the geology, seismic, petrophysics and fluids, the following are the key uncertainties affecting volumes:

- The top structure (deep or shallow with respect to the reference case).
- The significance of the 4ft gas interval seen in the discovery well. A 15% gas cap has been applied in the low case only, as per the previous CPR.

Porosity and NTG of the sand itself have a narrow range. The OWC is defined by the MDT formation pressures and hence has a small uncertainty. As for the previous CPR, pessimistic and optimistic saturation height functions were implemented in the model. But now that the hydrocarbon column height has reduced, much of the resulting structure is in the transition zone, regardless of function used. The effect on STOIIP of the uncertainties has been quantified as shown below (Figure 5-1).

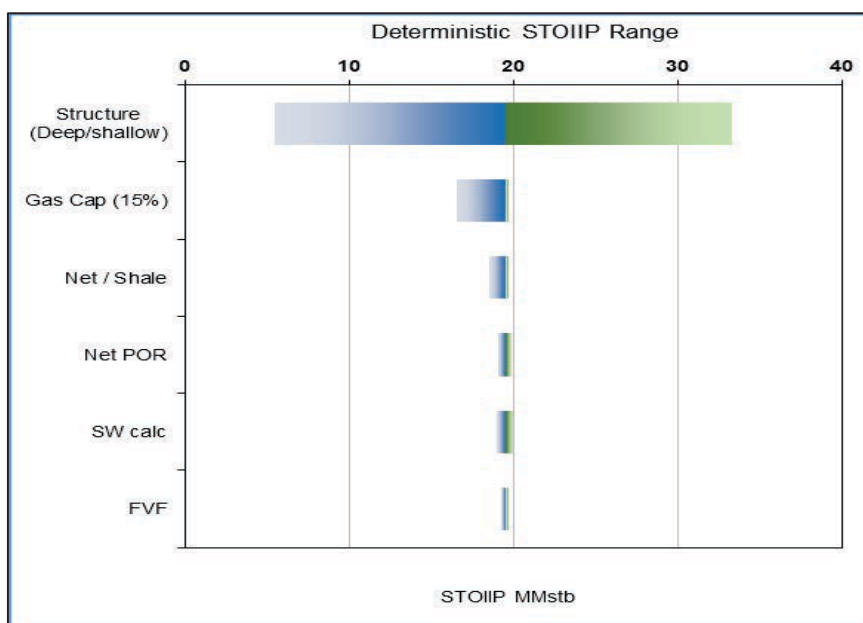


Figure 5-1 Effect on STOIIP of reservoir parameters

5.2 Static Model

The modelling was performed using Petrel 2017 software.

5.2.1 Input data

The top Upper Captain Sand corresponds to the seismic K50 in the Liberator area and in the Blake Field. The Valhall Formation is base reservoir for the entire Captain Sand package. TRACS interpreted a top Lower Captain Sand isochore.

The primary reference for top structure was the MF10 top Captain sand. The MF18 depth map was used to estimate the edge of the upper/lower sand.

The wells were loaded manually from the well location and deviation surveys provided by the client. The raw log curves and TRACS petrophysical interpretation curves were loaded from LAS files.

5.2.2 3D Grid

A cell size of 100 m was used, oriented parallel to the boundary of the Liberator area (Figure 5-2).

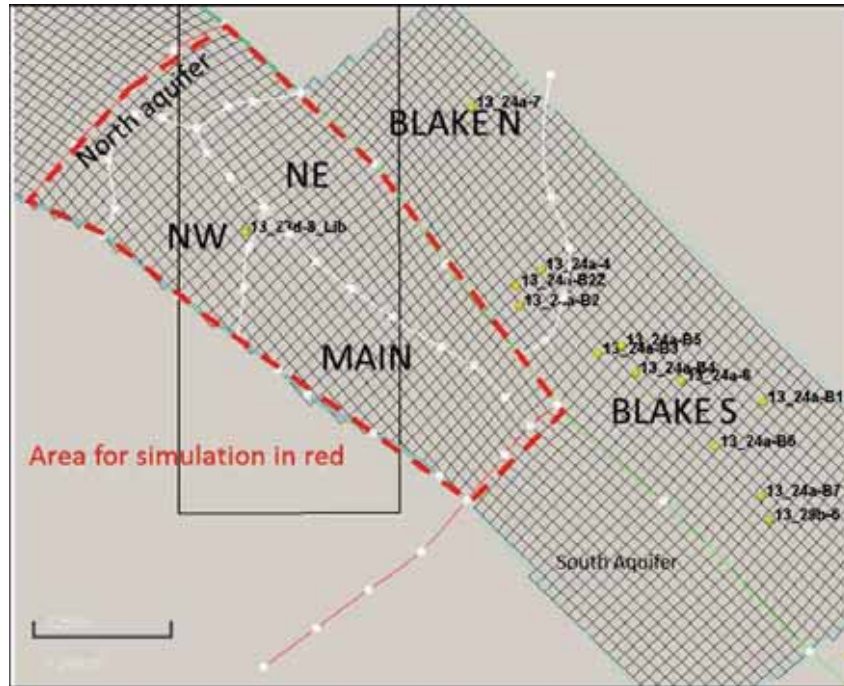


Figure 5-2 Map of modelling grid and segments

5.2.3 Horizons and top structure

The MF10 top Captain was used and updated in the area of well 13/23c-9. A patch was created from the MF18 seismic depth map and then merged together. The resulting top structure map is shown below (Figure 5-3).

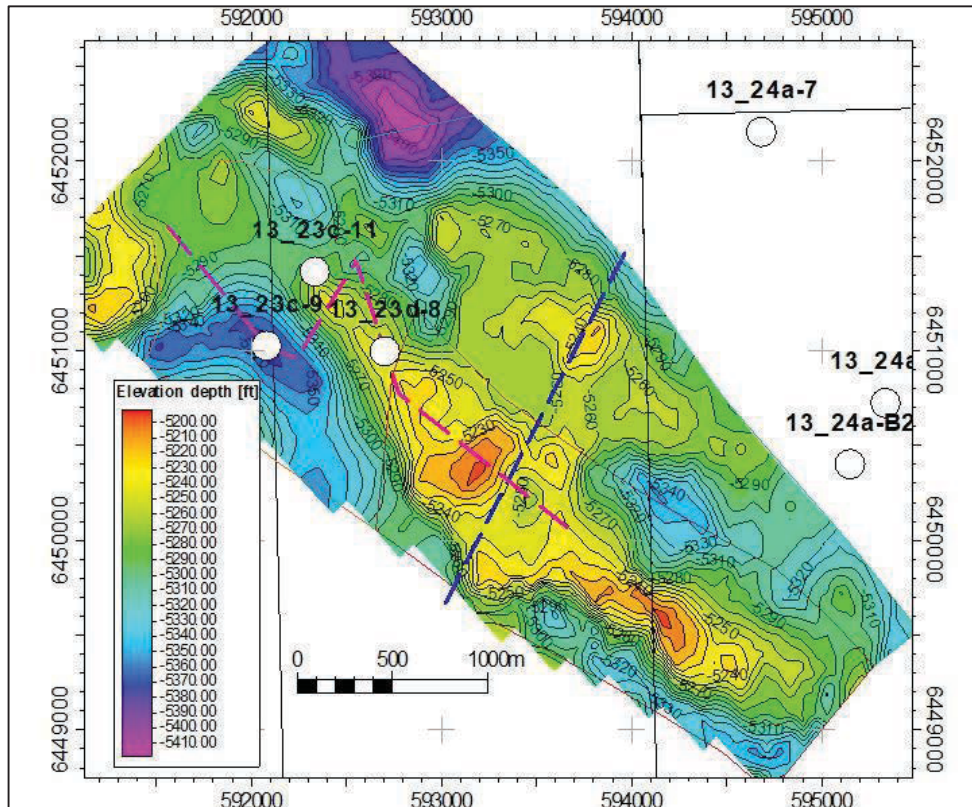


Figure 5-3 Top structure map from static model

5.2.4 Zones and Layering

Using the TRACS seismic isochore (Figure 5-4) built from the MF18 seismic interpretation, the top Lower sand depth horizon was created.

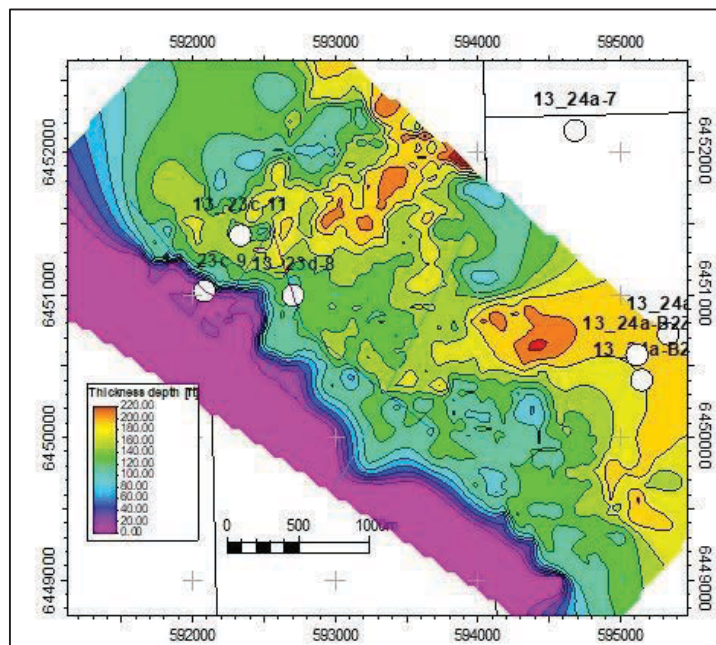


Figure 5-4 Isochore For Upper Captain Sand

The top surface was made geologically consistent with SW edge of the lower sand. The upper sand pinches out where the top structure dips SW (Figure 5-6).

The layers within the 2 zones are around 4 ft thick, suitable for simulation.

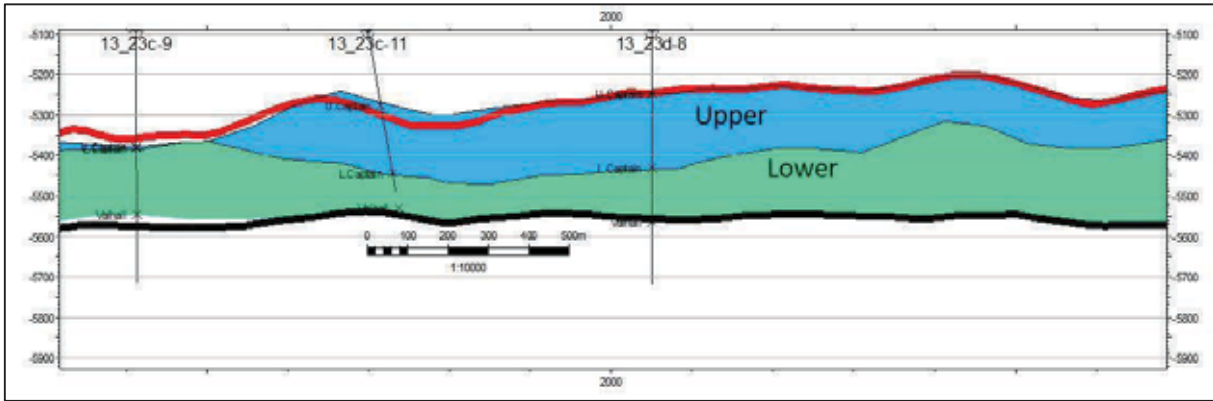


Figure 5-5 Cross Section Through the 3 Liberator Wells

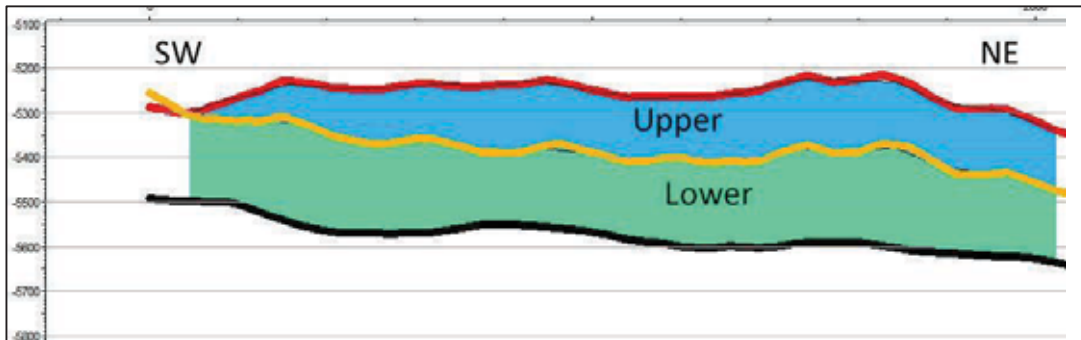


Figure 5-6 SW-NE Cross section through Liberator showing Upper and Lower sand model

5.2.5 Porosity

The porosity from all the wells was interpolated using a simple method (Figure 5-7). The upper hydrocarbon bearing interval has porosity of around 0.28 while the deeper interval of the reservoir has slightly lower porosity of 0.22.

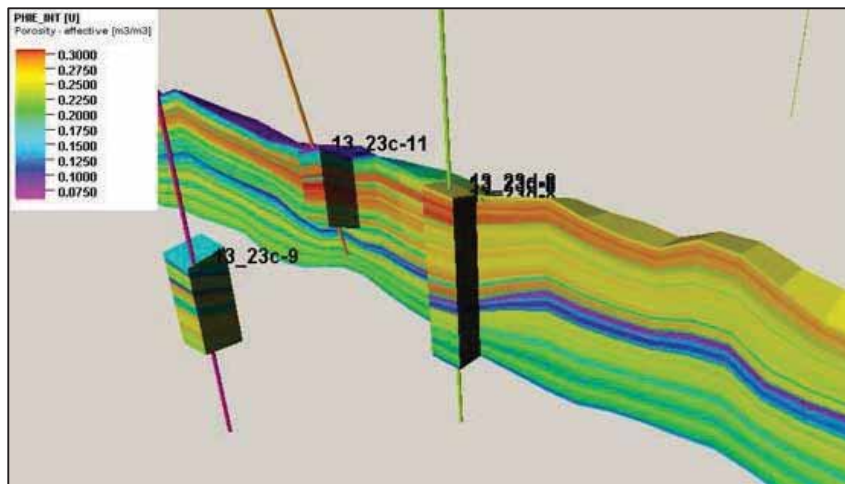


Figure 5-7 Porosity model view

5.2.6 NTG

The NTG was interpolated across the model (Figure 5-8) and this resulted in a low NTG at the top of the Lower sand as expected.

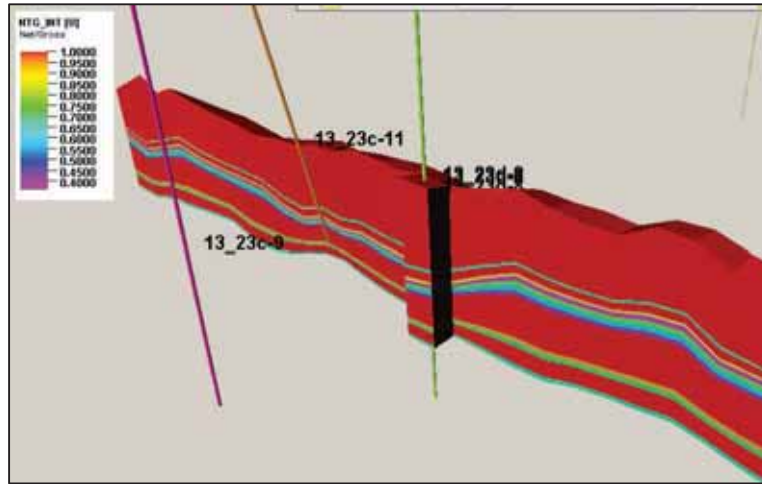


Figure 5-8 NTG model view

5.2.1 Permeability

For permeability, the function for the Blake core was used:

$$Kh = 0.0412 * PHIE^{3.2747}$$

(Porosity is in percent in the i3 Energy formula. This was converted to decimal in Petrel formula)

This gives a permeability distribution mostly above 1 Darcy, decreasing with depth due to slight porosity reduction (Figure 5-9 & Figure 5-10).

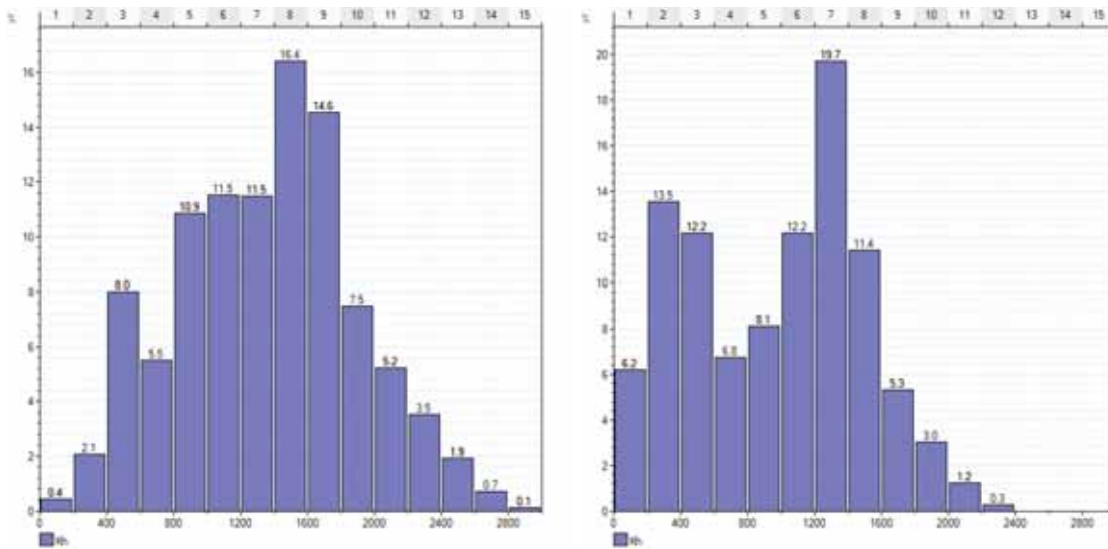


Figure 5-9 Upper and Lower Captian Sand Permeability Distribution (mD)

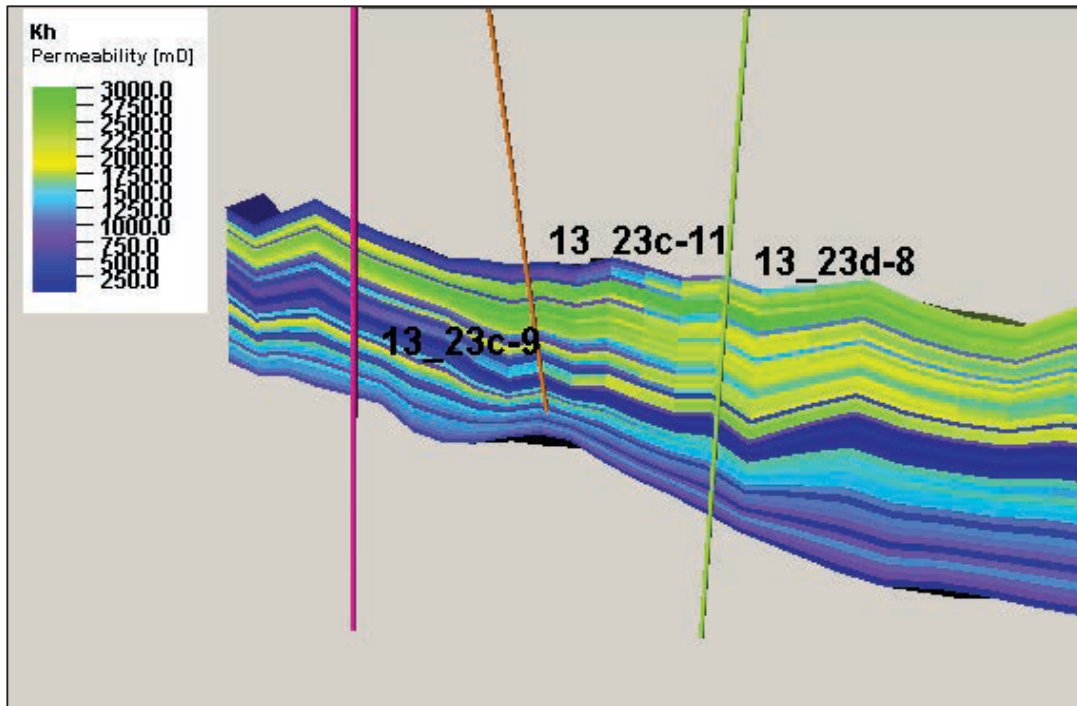


Figure 5-10 Permeability (Kh) model view

5.2.1 Saturation

The saturation was modelled using 2 functions: one from the 24ft column in the Liberator well itself and one using log data from the >100ft column in the Blake Field, 13/24a-4 (see Section 3.3).

Liberator: $Sw = 1.466 / (HAFWL^{0.622})$

Blake: $Sw = 0.61 / (HAFWL^{0.5})$

The Blake well is in the north (closest to Liberator) and the whole oil column can be defined with a relatively short transition zone, as expected in these Darcy sands. Hence the Blake function (left in Figure 5-11) was used for the reference case.

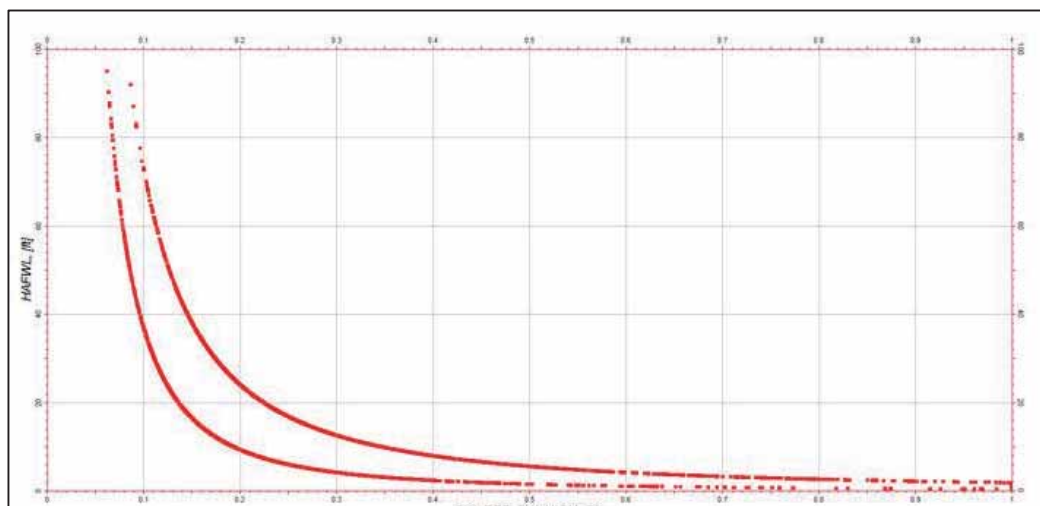


Figure 5-11 Comparison of Sw-Height functions

The resulting height of oil column from the model is shown below (Figure 5-12). The NW segment around 13/23c-9 is now in the water leg compared with the pre-drill map from 2017 (Figure 5-13).

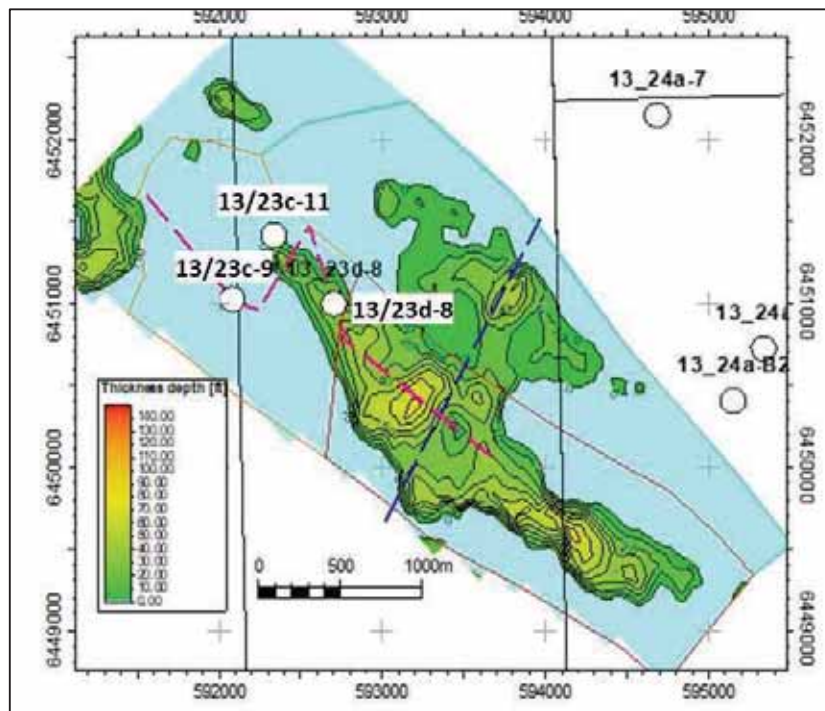


Figure 5-12 Height of oil column map from model (2020)

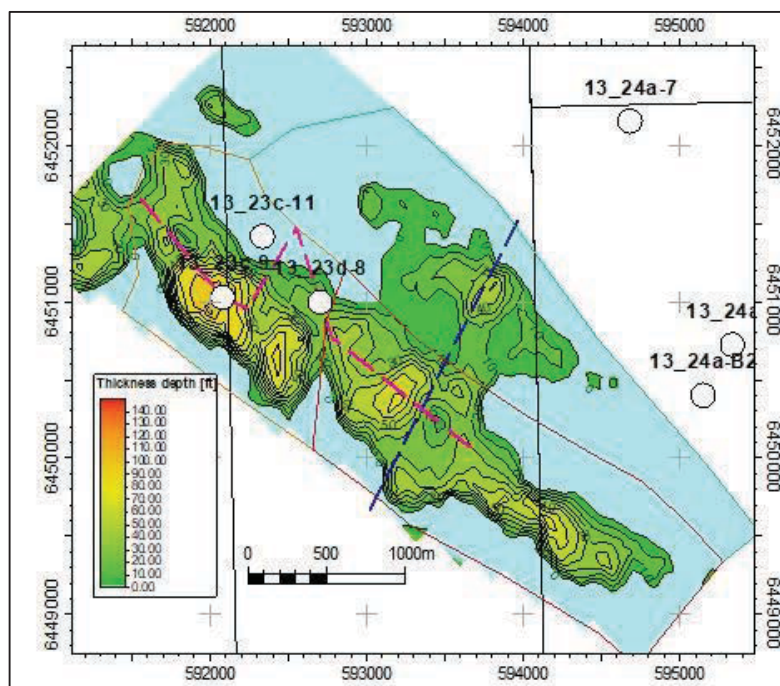


Figure 5-13 Height of Oil Column Map (pre-drill)

5.2.1 Depth uncertainty gridding

For generating shallow and deep top reservoir maps, the depth uncertainty away from the wells is estimated at ± 25 ft at a radius of 800m (Figure 5-14). The saddle with the Blake Field and the western edge were not changed during this process. The surfaces were generated in Petrel and corresponding shallow and deep grids were built with the same internal properties. Sw was regenerated.

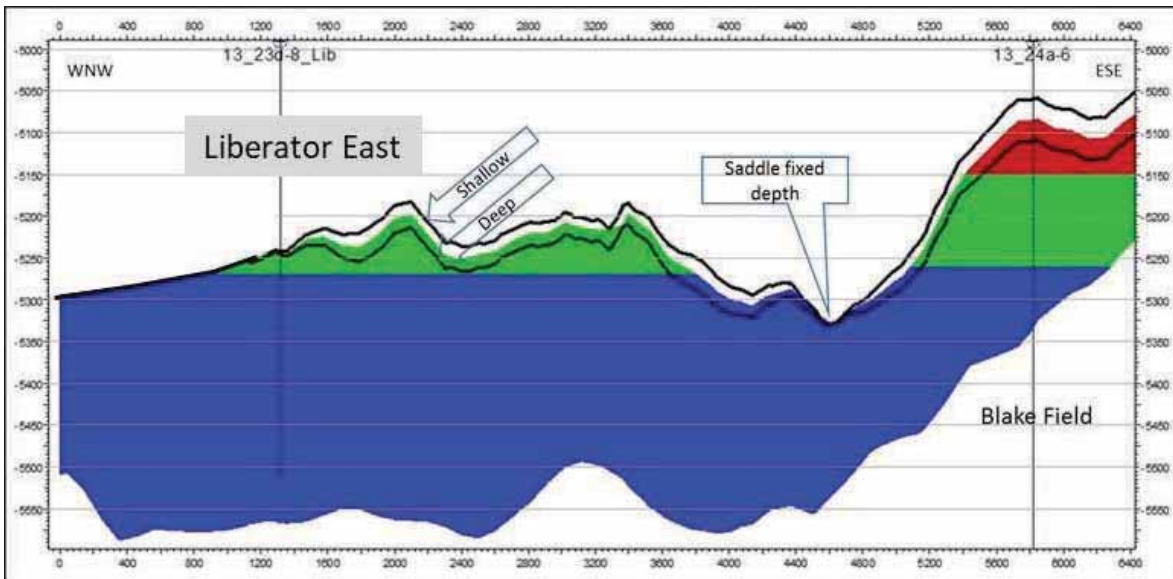


Figure 5-14 Cross Section from NW to SE showing shallow and deep top reservoir

5.3 STOIIP evaluation

The deterministic calculations were done in the 3 Petrel 3D grids, for low, mid and high cases, which are summarised in Table 5-1.

STOIIP	Structure	Gas cap	Sw calc
Low	DEEP	15%	LIB 23/13d-8
Mid	REF Depth	No	Blake 13/24a-4
High	SHAL	No	Blake 13/24a-4

Table 5-1 Summary of STOIIP inputs

An FVF of 1.157 RB/stb based on PVT analysis from the Liberator well (and similar to Blake Field) has been used for all cases. NTG, porosity and permeability are modelled by the same method for all cases.

Solution GIIP has been calculated using the measured solution GOR of 341 scf/stb from the 13/23d-8 downhole samples. A variation of +/-5% in this GOR value has been used to estimate the low and high GIIP cases.

Estimates for STOIIP by case are summarised in Table 5-2.

Case	STOIIP MMstb	GIIP Solution gas Bscf	GIIP Free gas Bscf
Low	5.7	1.8	1.9
Mid	19.5	6.6	0
High	33.3	11.9	0

Table 5-2 Liberator East Low, Mid and High case In-Place Volumes

The oil volume is entirely in the upper sand in all cases. The Liberator East discovery lies almost entirely within Licence P. 1987, though a portion (estimated 17%) extends outside the licence boundary to the southeast into the Blake partners acreage.

6 Reservoir Engineering

6.1 Data review

Since the new wells drilled on the structure failed to find hydrocarbons, no new production test or fluid data are available. For the previous CPR, the pressure data and PVT report on downhole samples of the Liberator discovery well 13/23d-8 were reviewed. When the reservoir fluid samples were taken in Nov 2013, the reservoir had a small gas cap and a thin oil column of 20 ft with a GOR of 341 scf/bbl and bubble point pressure of 2278 psia. The MDT pressure data from well 13/23d-8 indicated that the reservoir pressure was about 70 psi lower than the pre-production trend, probably due to aquifer depletion by the Blake production. No SCAL data or production data exist.

6.2 Dynamic Model

An Eclipse simulation model was constructed to support the 2019 CPR to estimate low, mid, and high recovery factors and forecasts for the Liberator Phase 1 (East) Development. This model has been updated, based on the newly acquired data, with the new, best estimates of structure and static properties to determine the implications of the substantially reduced hydrocarbon column on recovery. It was recognised that the reduced in-place volumes would likely fail to support an economic development, and that the potential for extremely rapid breakthrough of the underlying water might further reduce the viability of development (the post-drill, 2020, and pre-drill, 2019 maps of oil column thickness are shown in Figure 5-12 and Figure 5-13 respectively).

Based on this assertion, and the limited oil volume produced in the best estimate case, the full uncertainty range was not explored through simulation. Instead, the best estimate case was used to update the previous CPR recovery factor range for the Phase 1 East area, with the smaller hydrocarbon column encountered. This is a similar approach to that used for the 2019 resources assessment of Phase 1 West and Phase 2 recovery factor estimation (now Liberator West and Minos High, see Section 8), for which high level assessment recovery factors were developed using a 1-well simulation of the Phase 1 East area.

No (range of) forecasts have been generated as no viable development is foreseen, and economics have not been run.

A single horizontal well, with a 4200 ft MD lateral was designed to thread the crest of the "Main" (and most viable) accumulation in the SW of the structure (see Figure 6-5).

6.2.1 Grid

The grid and rock properties were exported from the updated static model, with X-Y grid dimensions of 100 x 100 m. Z-direction layer thicknesses varied from approximately 4 to 5 ft for layers 1 to 30 and 9 to 10 ft for layers 31 to 50. The finer layering in the upper part of the model captures the thin oil column and fluid contact, including a palaeo-contact, above which residual oil saturations exist, reducing water mobility. The total number of active cells was 36760.

As for the previous model, the kv/kh permeability ratio was set to 0.8, informed by Blake Field core data.

A cross-section through the model, from NW to SE along the crest penetrated by the producer well is shown in Figure 6-1. No gas cap is included in this mid-case model.

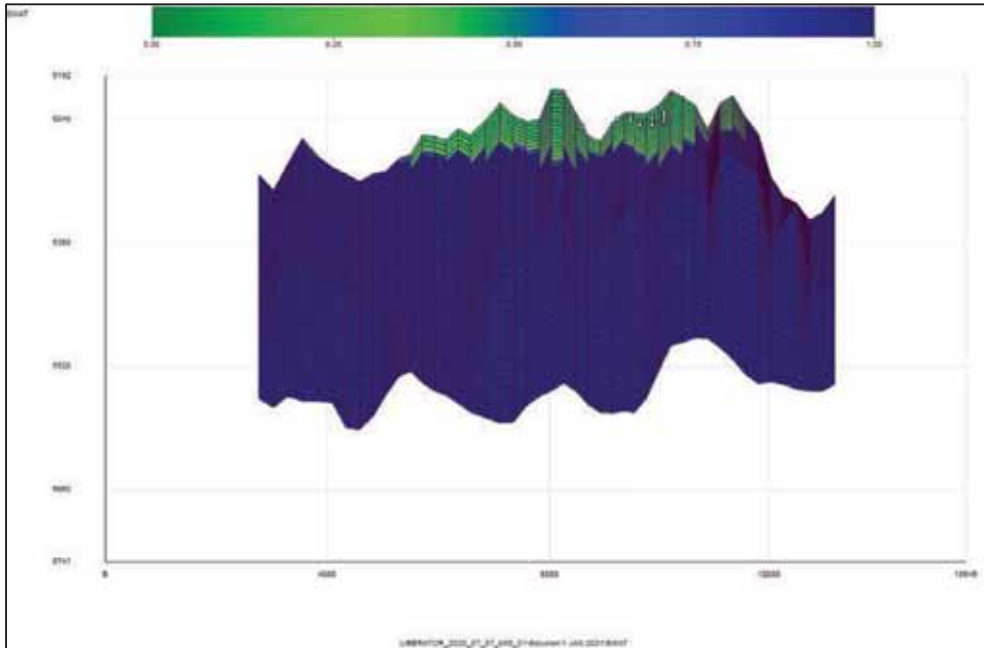


Figure 6-1 Liberator East E100 Model Vertical X-Section NW-SE along Crest

As with the previous model, the residual oil saturations between the present day and palaeo-OWC were incorporated as a transmissibility multiplier of 0.2.

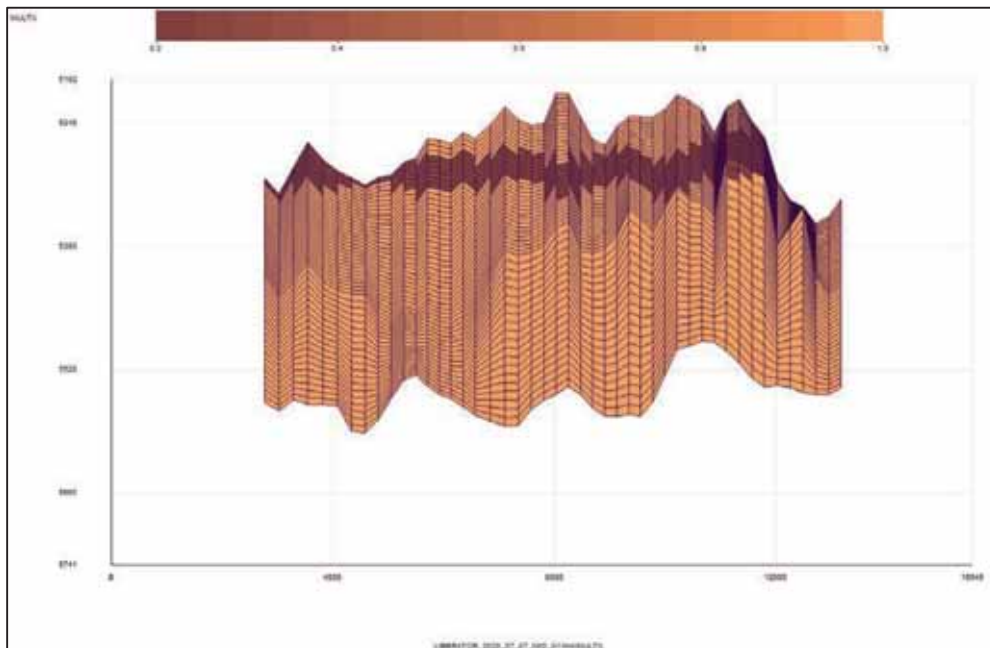


Figure 6-2 Palaeo Oil Zone Transmissibility Multiplier

6.2.2 PVT and Relative Permeability

Fluid properties were taken from the previous model which are based on data from the Liberator discovery well.

Oil Properties		
Reservoir temperature	°F	140
Reservoir pressure	psia	2315
Oil gravity	API	30.5
Pb	psia	2278
GOR	scf/bbl	341
Bo	v/v	1.16
Oil viscosity		
Reservoir pressure	cp	1.91
Bubble point pressure	cp	1.9

Table 6-1 Liberator oil properties

The water, rock and total compressibility assumed for the aquifer were as for the previous simulation model:

- Cr: 5.0E-06 (1/psi)
- Cw: 3.0E-06 (1/psi)
- Ct: 8.0E-06 (1/psi)

The water/oil relative permeability curves based on the Blake SCAL measurements provided (Figure 6-3) were applied in dynamic models as follows (MID Case in Figure 6-3):

- Corey parameters: No=2.0; Nw=2.0; Krow=1.0
- Residual oil and water end point: Sorw=30%, Krw=0.2

A generic gas/oil relative permeability with Sgc of 0.05 was applied to all E100 models. The three-phase rel perm model used is the default Eclipse model.

The irreducible oil saturation of 30% was based on the Paleo oil saturation in the well logs of Blake and Liberator wells.

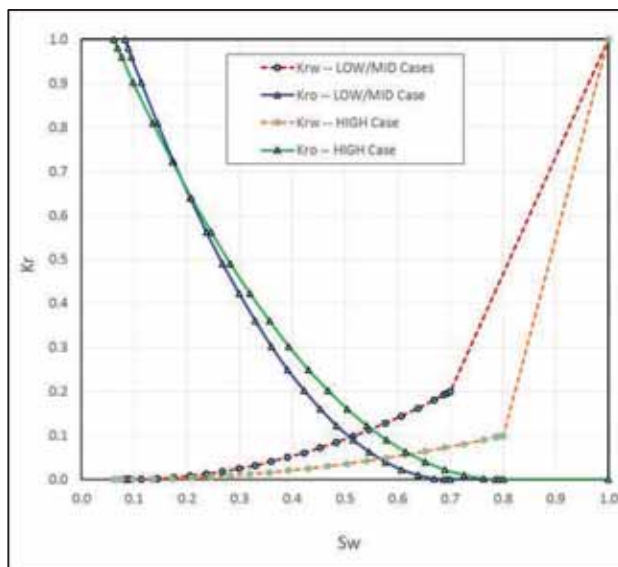


Figure 6-3 Relative permeability curves for Low, Mid and High cases

6.2.3 Saturation-height Function and Initialisation

The model was initialised with the EQUIL keyword using capillary pressure tables matching the Blake well Saturation-Height function, as used for the STOIIIP evaluation with the static model. Initial reservoir pressure was assumed to be 2285 psia at a datum of 5270 ft tvdss at the OWC.

6.2.4 Regions and Aquifer Models

The four regions adopted in the static model and in the previous simulation modelling study were used.

Region 1: NW, previously a viable oil volume but STOIIIP reduced to 0.3 MMstb with new structure means no well target.

Region 2: NE, connecting to Blake, minor STOIIIP

Region 3: SW, Main target area for production

Region 4: North, connecting to aquifer support in the north (minor STOIIIP)

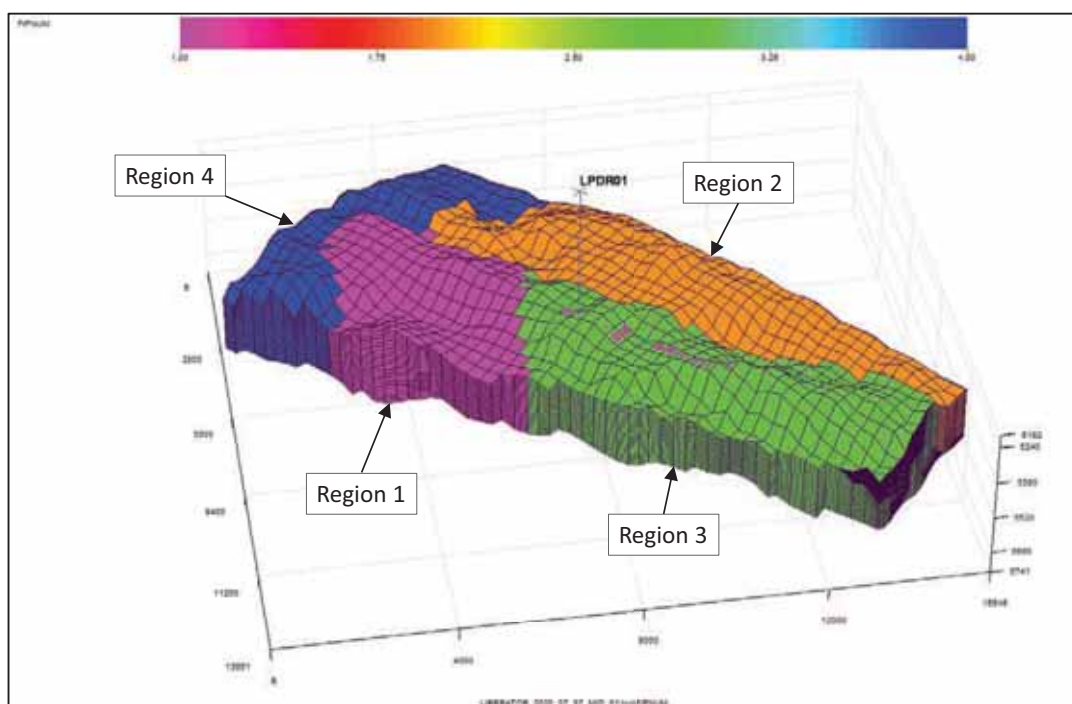


Figure 6-4 E100 Liberator Model STOIIIP Regions

Aquifers were attached, as for the previous mid-case model, on the NW, NE, and SE boundaries of the model. Sand continuity to the NW is questionable based on the latest geological interpretation, however no sensitivity was carried out on this hypothesis. The greatest aquifer support is expected to come from the SE, towards Blake.

6.2.5 STOIIIP

The initial oil-in-place volumes by region are shown in Table 6-2, with a comparison to the previous, 2019, model. Static modelling gives a slightly lower overall volume, however this was considered to be a minor issue within the context of the purpose of the modelling, and the model was not tuned to replicate the static volumes.

Case	Region				Development Area (excluding R4)
	1	2	3	4	
2020 Model	0.78	3.72	16.81	1.39	21
2019 Mid-Case	16.59	4.32	17.53	3.12	38

Table 6-2 Liberator East STOIIIP by Region and Development Area

It can be seen that the developable STOIIP has approximately halved compared to the previous model, as a result of the deeper top oil-bearing sand. Region 3 is the only viable production target area.

No free GIIP has been modelled in this realisation.

6.2.6 Production Well

A single horizontal well as designed to thread the crestal part of Region 3 in a NW-SE orientation, aiming to maximise reservoir contact whilst maximising stand-off from the OWC (see Figure 6-5).

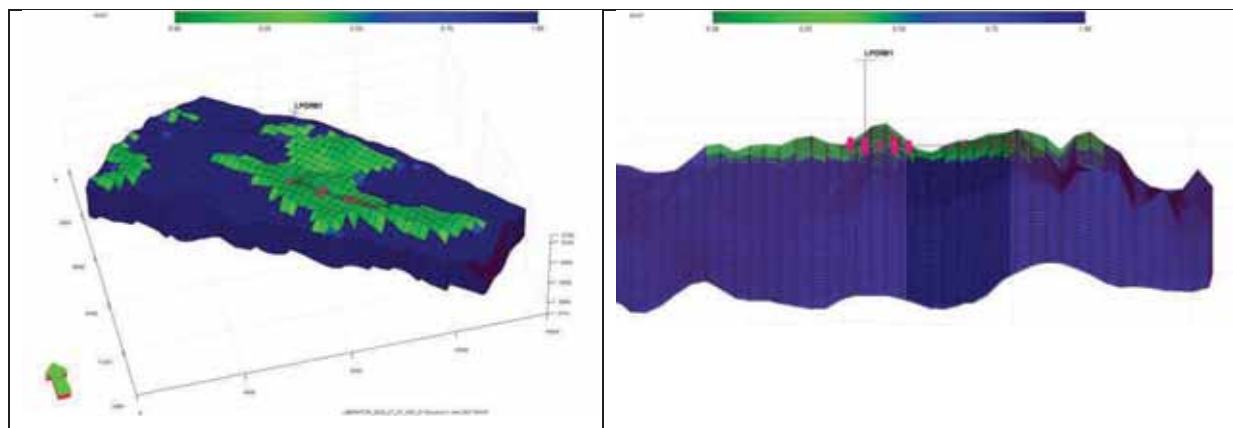


Figure 6-5 Liberator East Simulation Well Location

6.3 Forecasts

6.3.1 Schedule and well controls

The prediction run start date was 01/01/2021; forecasts were run to 01/01/2043. Controls were based on the 2019 modelling, in turn based on information provided by the client. The schedule and well controls applied to the dynamic models are listed below:

- 01/01/2022, LP1 onstream
 - Max. oil rate: 10000 stbd
 - Max. liquid rate: 20000 stbd
 - Max. pressure drawdown: 15 psi
 - THP: 523 (psia)
 - VLP table (provided by i3E)
 - Gas lift gas rate: 2 MMscf/day
 - Well Uptime: 0.86

Although maximum rate constraints are high, the drawdown is limited to minimise coning of water into the well.

6.3.2 Forecast Results

Initial oil rate is high at the target rate of 20,000 bbl/d, but as observed with the 2019 simulation, the aquifer and bottom water response is not strong enough to fully support pressure. Depletion occurs and the reservoir drops below bubble point, causing an increase in GOR and drop in production rate. Water influx also occurs almost immediately through coning with the low stand-off.

The forecast cumulative production to 2043 is 6.2 MMstb, which represents a recovery factor of 29%.

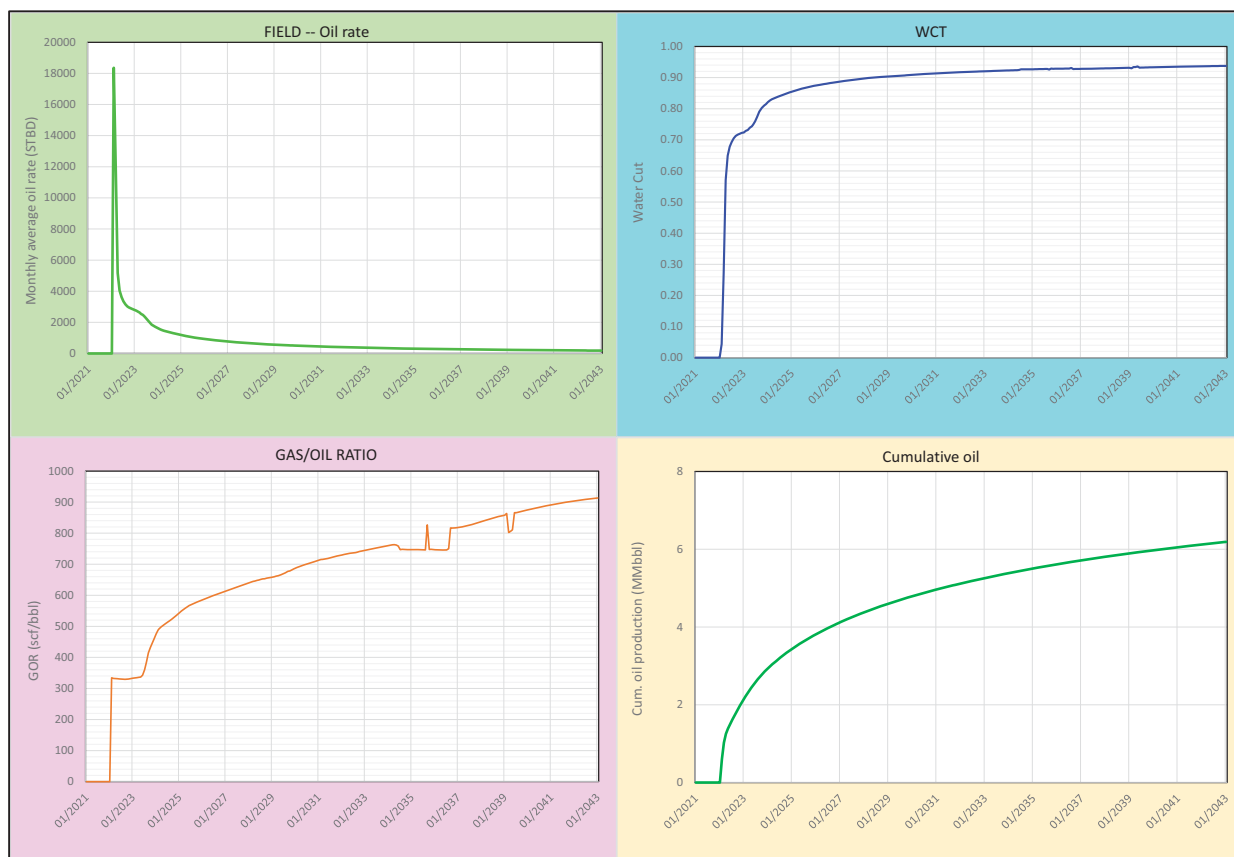


Figure 6-6 Predicted oil rate, WCT, GOR and Cum. oil

6.3.3 Recovery comparison with 2019 Simulation

The results of the 2020 simulation model (mid-case parameters) are compared with the 2019 simulation work in the tables below for oil (Table 6-3) and gas (Table 6-4).

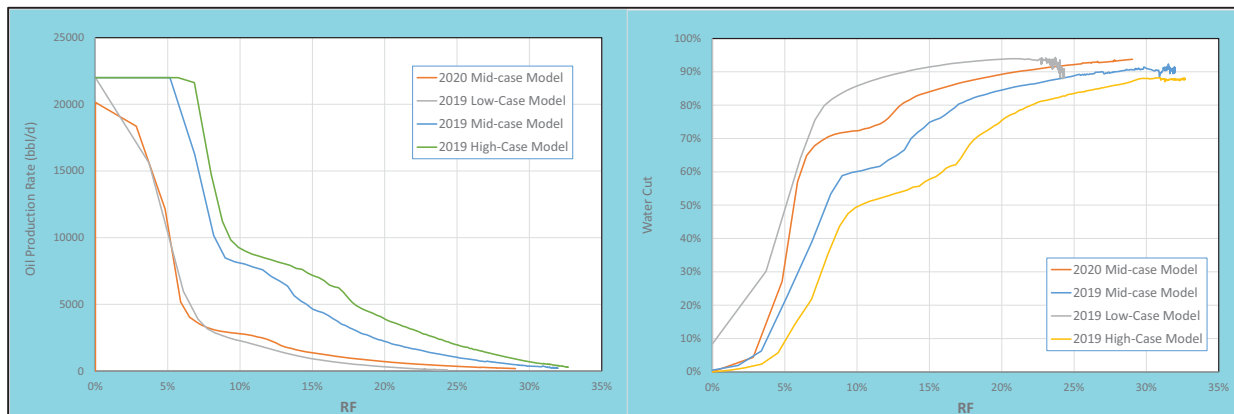
E100 Model	STOIP (Phase 1 Areas)	Cum oil (@01/01/2041)			RF
		LP1	LP2	Total	
2020	21	6.2	N/A	6.2	29%
2019 Low	18	1.6	2.7	4.3	24%
2019 Mid	38	5.8	6.2	12.0	31%
2019 High	58	9.9	8.6	18.6	32%

Table 6-3 Forecast Recoverable Oil of Liberator East

E100 Model	Phase 1 area			Cum. gas (@01/2041) Bscf	RF
	Free GIIP Bscf	Dissolved GIIP Bscf	Total Bscf		
2020	0	7.26	7.26	3.19	44.0%
2019 Low	0.304	6.26	6.57	3.74	57.0%
2019 Mid	0	13.09	13.09	7.51	57.3%
2019 High	0	19.81	19.81	11.17	56.4%

Table 6-4 Forecast recoverable gas of the Liberator Phase 1 development

It can be seen that the oil and gas recovery factors are lower than the previous mid-case model. Comparison of recovery performance shows that oil production rate actually declines more in line with the previous Low-case model.



6.4 Recovery Factor Range

A comparison of simulation forecasts between a mid-case realisation of the updated reservoir model to incorporate the 23/13-9 and -11 wells, and the 2019 model, shows that some reduction in recovery factor is likely as a result of the reduced oil column. In place volume is nearly halved compared to the previous model, however the recovery factor from a single well shows only a slight reduction in ultimate recovery factor (32 to 29%). The overall performance to achieve this recovery is significantly worse, however, and it is likely that economic factors will terminate production prior to achieving the simulated value.

Taking into consideration the overall uncertainty still remaining and the results of the simulation, it is considered that the low and mid case recovery factors should be reduced by 5%, but the high case should be maintained to reflect the overall spread of potential outcome.

Case	RF %	Comments
Low	20%	Reduce by 5% for smaller oil column, and significant simulated recovery at low oil rate
Mid	27%	Reduce previous RF by 5% for smaller oil column, 29% in new model but significant simulated recovery at high water cut low oil rate
High	33%	2019 modelling high case – upside dependent on favourable further data / appraisal

Table 6-5 Oil Recovery factor range, Liberator East

A gas recovery factor range of 0%, 44%, 55% is proposed; the low case recognises the fact that a sales gas steam may not be viable, dependent on the development plan. The mid-case number comes from the 2020 simulation and the 55% from the 2019 simulation work.

7 Resource Estimation

7.1 Classification of Resources

This evaluation addresses only the discovered volumes in the Liberator East (formerly Phase 1 East) area. The volumes documented for this area in the previous, 2019, assessment, were classified partly as reserves, forecast up to production vessel recertification in 2024, and thereafter as Contingent Resources, Development not Viable. The assignment of reserves was based on an economic evaluation of a development using assumptions and forecasts of production, capex and opex prior to the drilling of wells 13/23c-9 and -11. The Capex requirement for facilities (tie-back to Bleo Holm FPSO) and well costs associated with this plan (in total more than £100 million) plus FPSO Opex costs, clearly render the present volumes uneconomic, and with no alternative plan, the entire volumes have now been classified as Contingent, Development not Viable.

Gas resources have been documented based on a range of simulated recovery factors, however since a new development plan has not been made, it is uncertain whether a sales gas stream is viable. The low case (1C) has been set to 0.

A commercial chance of success factor (COSc) or Risk Factor have not been estimated at this stage. Further appraisal is required in the Liberator area (Liberator West & Minos High) to determine the likelihood of a combined development.

7.2 Estimated Resources

Category	Oil MMstb	Gas Bscf	MMboe
1C	1.1	0.0	1.1
2C	5.3	2.9	5.7
3C	11.0	6.5	12.1

Table 7-1 Liberator East Resources

8 Preliminary Assessment of Liberator West and Minos High

8.1 Overview

The latest area definition map provided by i3 Energy divides the Liberator area into four regions. Liberator East includes wells 23d-8, 23c-9 and 23c-11 and is described fully in Sections 1-7 of this report. Liberator West and the Minos High are the focus of the assessment in this Section. Liberator South is not yet evaluated and was not previously defined in the 2019 Liberator CPR (Ref 1). It will be considered later as part of the ongoing TRACS evaluation of the Liberator area but is considered to carry a low geological chance of success (COSg) and is not discussed further in this report.

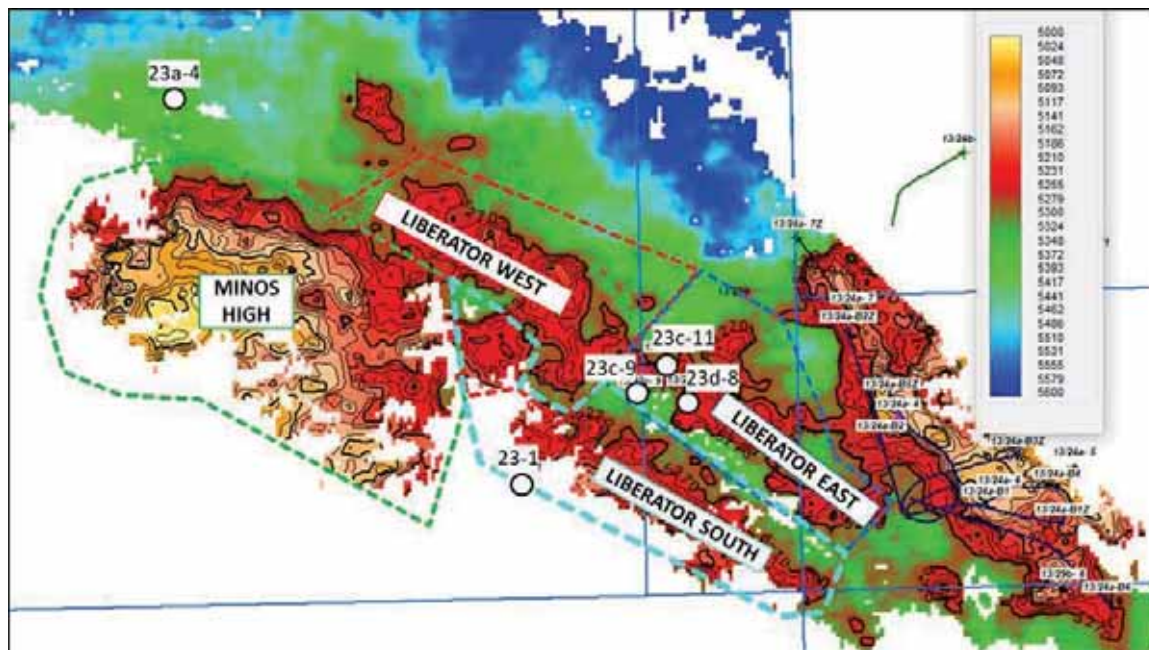


Figure 8-1 i3 current Liberator area designation

A revised resource classification was made based on the new well data, with reference to the revised i3 area designations illustrated above in Figure 8-1.

- Liberator West (formerly Phase 1 West). Resources in this area were previously described as Contingent Resources but are re-classified as Undiscovered; Prospective Resources. The 2019 Liberator wells 13/23c-9 and -11 have identified water between Liberator West culmination and the proven Liberator East oil pool. It is unclear whether the sands in this area are Upper or Lower Captain (or both). Hydrocarbons are yet to be proven in Lower Captain sands.
- Minos High (formerly Phase 2). The region around 23a-4. This area remains classified as Undiscovered; Prospective Resources.
- Liberator South. Not yet evaluated by TRACS but classified as Undiscovered; Prospective Resources.

8.2 Key Uncertainties

The following static and dynamic subsurface uncertainties were previously identified as significant for the Liberator West and Minos High areas in the 2019 Liberator CPR:

Static Uncertainties

- Depth (seismic) uncertainty (deep or shallow with respect to the reference case)
- Reservoir distribution (sand continuity)
- Fluid distribution, depth of the oil water contact and size and presence of gas caps

Dynamic Uncertainties

- Mobility of water within the transition zone
- Relative permeability

- Aquifer strength

Each factor was considered within the range of input parameter values selected for volumetric estimation as outlined in the 2019 Liberator CPR. Figure 8-2 highlights the depth uncertainty realisations previously implemented. There was assumed to be ± 50 ft departure from the reference case depth map at distances 2km away from well control.

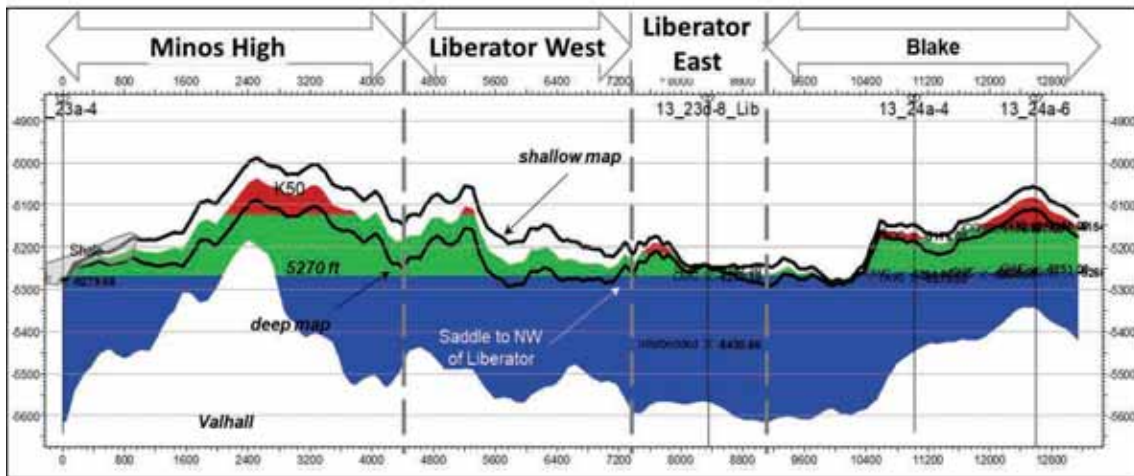


Figure 8-2 Illustration of top structure

The wide recovery factor range implemented in the 2019 CPR (20-50%) accounted for variation in hydrocarbon column thickness, and sand continuity and extent (impacting aquifer size). Generally, the average column height increases north-westward. The high case is analogous to the Blake field. The low case was derived from a low case simulation of the Liberator discovery area, which reflected a thin hydrocarbon column, high vertical permeability and thick high quality sand below the oil column, resulting in coning of water and reduced sweep despite optimum well placement and low drawdown.

8.2.1 Impact of new well and seismic data

Based on a preliminary assessment, the uncertainties identified in the previous volumetric assessment remain significant. The new 2019 well results and seismic have highlighted seismic pick uncertainty, i.e. the difficulties in accurately defining not only the top reservoir depth but also mapping of sand body continuity with the Captain Sandstone package, even at short distances away from well control. The 13/23c-9 well found a water-bearing Lower Captain sand that, based on correlation with the water-bearing Lower Captain sand in the Liberator discovery well (13/23d-8), is not in pressure communication with the regional dynamic aquifer.

The key conclusions and implications for Liberator West and the Minos High are:

- Seismic uncertainty means it is unclear which sands are present in Liberator West and the Minos High areas. Though it is possible that the proven, oil-bearing Upper Captain sands are universally present to the west of the Liberator well, it appears equally possible that Lower Captain sands (or other sands) are present over a wider area. Water-bearing Lower Captain Sands are present in the Liberator discovery well 13/23d-8 and the 2019 Liberator well 13/23c-11.
- Seismic depth uncertainty remains a key uncertainty. However, preliminary evaluation suggests the previous assumption of ± 50 ft at 2km away from well control adequately captures the range.
- Pressure data from the Lower Captain sand in 13/23d-8 shows it is not connected to the regional dynamic aquifer. This will potentially impact assumptions on aquifer size and Recovery Factor for volumetric scenarios where the Lower Captain sand is assumed present. There is also a risk that Lower Captain Sands are not charged (isolated from migration as not connected to the regional aquifer).

In the 2019 Liberator CPR, TRACS already considered the possibility that the sands encountered in 13/23a-4 are different to those observed in the Liberator area. The 13/23a-4 and 13/23d-8 wells are 8 km apart and both seismic and well-based correlations show how challenging it is to confidently correlate in the Minos High and Liberator West area (Figure 8-3 & Figure 8-4).

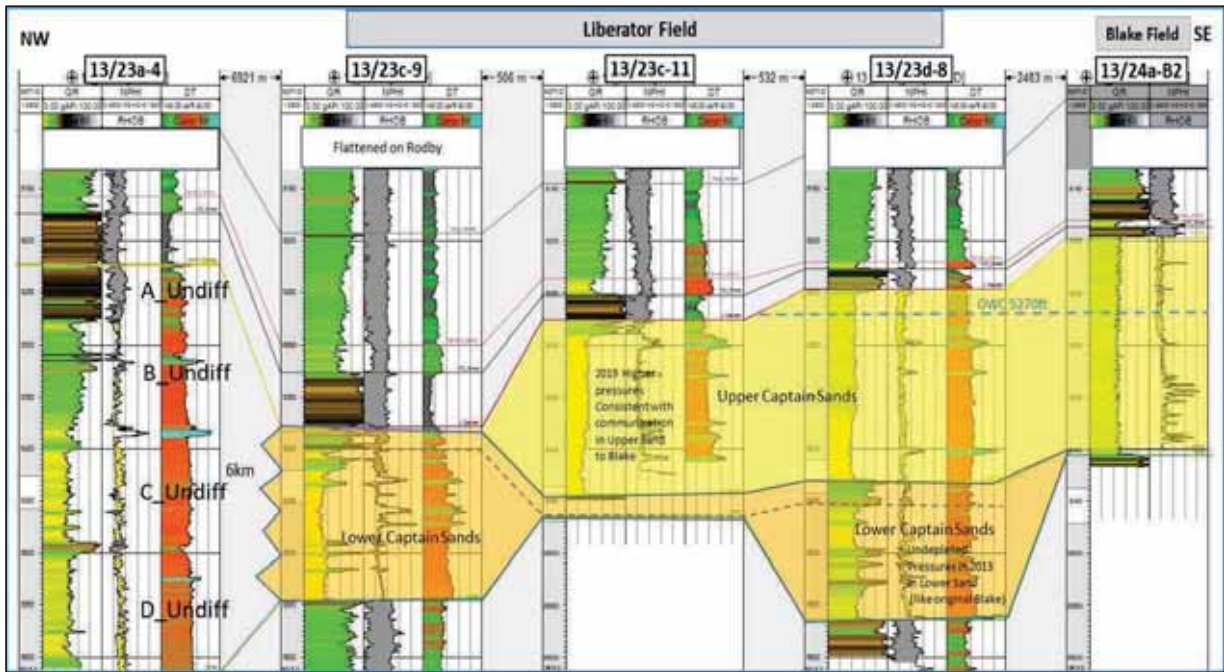


Figure 8-3 Well correlation panel

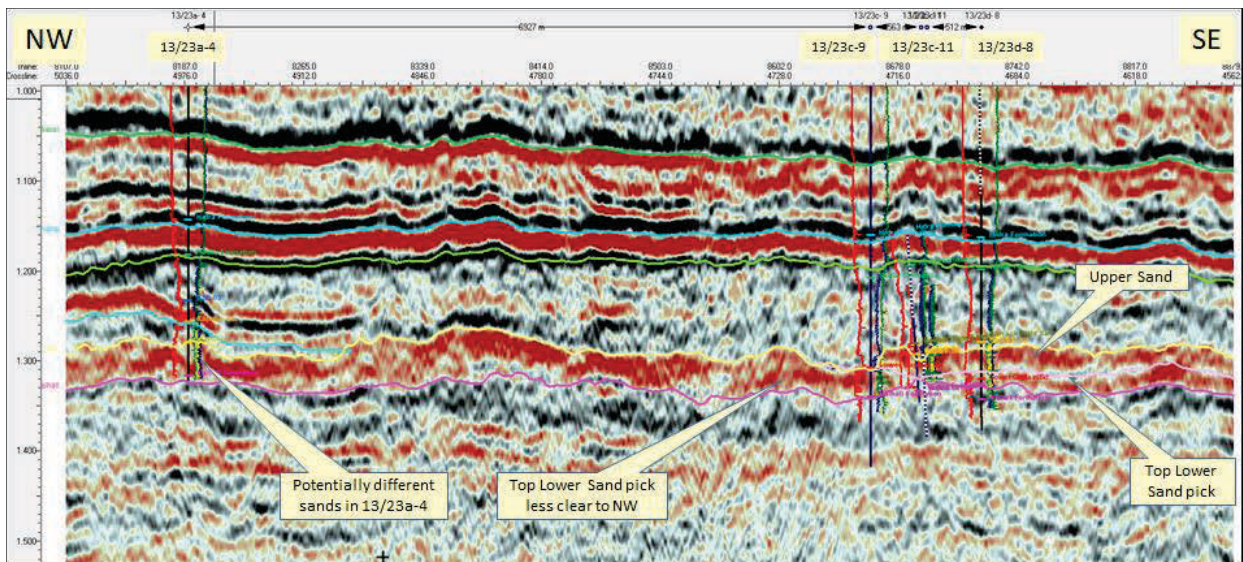


Figure 8-4 Seismic correlation

8.3 Preliminary Re-assessment of Resource Range

Based on a preliminary re-evaluation of the Liberator West and Minos based on the new seismic and well data, the following resource low-high range is suggested. At this stage of the analysis, nothing has been determined that invalidates the low-high range presented in the 2019 CPR, and so this is maintained. It should be stressed that TRACS have not yet fully re-evaluated these areas and that final estimates may change once the current work is matured.

Case	STOIIP MMstb		Recovery Factor	Scenario	Resources MMstb	
	Liberator West	Minos High			Liberator West (Prospective Resources)	Minos High (Prospective Resources)
Low	4	26	20 %	Liberator Simulation Low Case	1	5
High	103	329	50 %	Blake field type RF	52	165

Table 8-1 Provisional resource range, Liberator West and Minos High

The Low and High Case STOIIP are unlikely to materially change with further analysis on the present data set compared to the 2019 CPR since the previous input parameters are considered sufficiently wide to have captured the range in uncertainty in depth of top structure, position of the OWC and sand distribution. The Recovery Factor range accounts for uncertainties including variation in hydrocarbon column thickness, and sand continuity and extent (impacting aquifer size). Generally, the average column height increases north-westward. The high case is analogous to the Blake field. The Low Case was derived from a low case simulation of the Liberator discovery area, which reflected a thin hydrocarbon column, high vertical permeability and thick high quality sand below the oil column, resulting in cusping of water and reduced sweep despite optimum well placement and low drawdown. The previously implemented Recovery Factor range is deemed sufficiently wide for the purposes of high level preliminary assessment. Going forward, however, consideration will be given in a low case for more limited aquifer size and strength, based on geological evaluation of continuity within the Captain Sands, resulting in potential disconnection from the regional aquifer.

A provisional geological change of success (COS_g) is also presented here for both Liberator West and Minos High:

$COS_g = 42%$: A combination of Trap 75%, Reservoir presence 75%, Charge 75%

Compared to the previous 2019 CPR, an additional charge risk is considered, given that the Captain sands here could be different to the Liberator East discovery area (Lower Captain, or other), not connected to the regional aquifer and potentially isolated from charge.

9 References

1. TRACS International Limited: North Sea, Liberator Field Competent Person's Report Update 2019, September 2019

10 Glossary of Terms

\$	US Dollars	HCDT	Hydro-Carbon Down To
%	percent	HCWC	Hydro-Carbon Water Contact
°C	Degrees Celcius	IRR	Internal Rate of Return (from MOD cashflows)
2D	Two Dimensional	JV	Joint Venture
3D	Three Dimensional	K	Permeability
API	American Petroleum Institute	km	Kilometre
AVO	Amplitude Variation with Offset	km ²	Square kilometres
Av Phi	Average Porosity (from log evaluation)	m	metre
Av Sw	Average water Saturation (from log evaluation)	Mbbls	thousand barrels of oil (unless otherwise stated)
bbls	Barrels	Mboe	thousand barrels of oil equivalent
Bscf	Billion standard cubic feet of natural gas	Mbopd	thousand barrels of oil per day
bfpd	Barrels of fluid per day	Mcf	thousand cubic feet
boe	barrels of oil equivalent	Mcfd	thousand cubic feet per day of natural gas
boepd	barrels of oil equivalent per day	MD	Measured Depth
bopd	barrels oil per day	mD	milli Darcies
bpd	barrels per day	MM	million
bwpd	barrels of water per day	MMbbls	million barrels of oil
Cali	Caliper	MMstb	million stock-tank barrels of oil
Capex	capital expenditure	MMbo	million barrels of oil
CGR	Condensate Gas Ratio	MMboe	million barrels of oil equivalent
cm ³	cubic centimetre	MMcf	million cubic feet of natural gas
m ³	cubic metre	MMscfd	million cubic feet of natural gas per day
COCS	Chance of Commercial Success	MOD	Money Of the Day
CPI	Computer Processed Interpretation (of logs)	N/G	Net to Gross
CT	Corporation Tax	Neu	Neutron log
Den	Density log	NFA	No Further Activity
D res	Deep resistivity log (deep investigation)	NPV	Net Present Value
DST	Drill Stem Test	OBC	Ocean Bottom Cable
DT	Sonic log	ODT	Oil Down To
E & A	Exploration & Appraisal	OML	Oil Mining Licence
ft	feet	Opex	operating expenditure
FTHP	Flowing Tubing Head Pressure	OPL	Oil Prospecting Lease
FWL	Free Water Level	OUT	Oil Up To
G & G	Geological and Geophysical	OWC	Oil Water Contact
Gas sat	Gas saturation	P & A	Plugged and Abandoned
GDT	Gas Down To	p.a.	per annum
GIIP	Gas Initially In Place	P10	10% probability of being exceeded
GOR	Gas to Oil Ratio	P50	50% probability of being exceeded
GR	Gamma Ray log	P90	90% probability of being exceeded
GRV	Gross Rock Volume	POS	Possibility Of Success
GUT	Gas Up To	ppm wt	Parts per million by weight
GWC	Gas Water Contact	PRMS	Petroleum Resource Management System

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PSC	Production Sharing Contract	ss	subsea
psi	pounds per square inch	STOIIP	Stock Tank Oil Initially In Place
psia	pounds per square inch absolute	Sw	water Saturation
PV	Present Value	Swavg	average water Saturation
PVT	Pressure Volume Temperature	Sxo	water Saturation in invaded zone
RF	Recovery Factor	TD	Total Depth
RFT	Repeat Formation Tester	tvd	true vertical depth
RROR	Real Rate of Return (from RT cashflows)	tvdss	true vertical depth subsea
RT	Real Terms	tvt	true vertical thickness
SG	Specific Gravity	TWT	Two-Way Time
SMT Kingdom	a PC-based interpretation workstation	WI	Working Interest
SPE	Society of Petroleum Engineers		
sq km	square kilometres		
S res	Short resistivity log (shallow investigation)		

Appendix A – Summary of 2018 SPE Petroleum Resource Management System Classification

The following table has paragraphs that are quoted from the 2018 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure A 1 shows the recommended resources classification framework.

Class/Sub-class	Definition
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclassified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Table A 1 Summary of 2018 SPE Petroleum Resources Classification

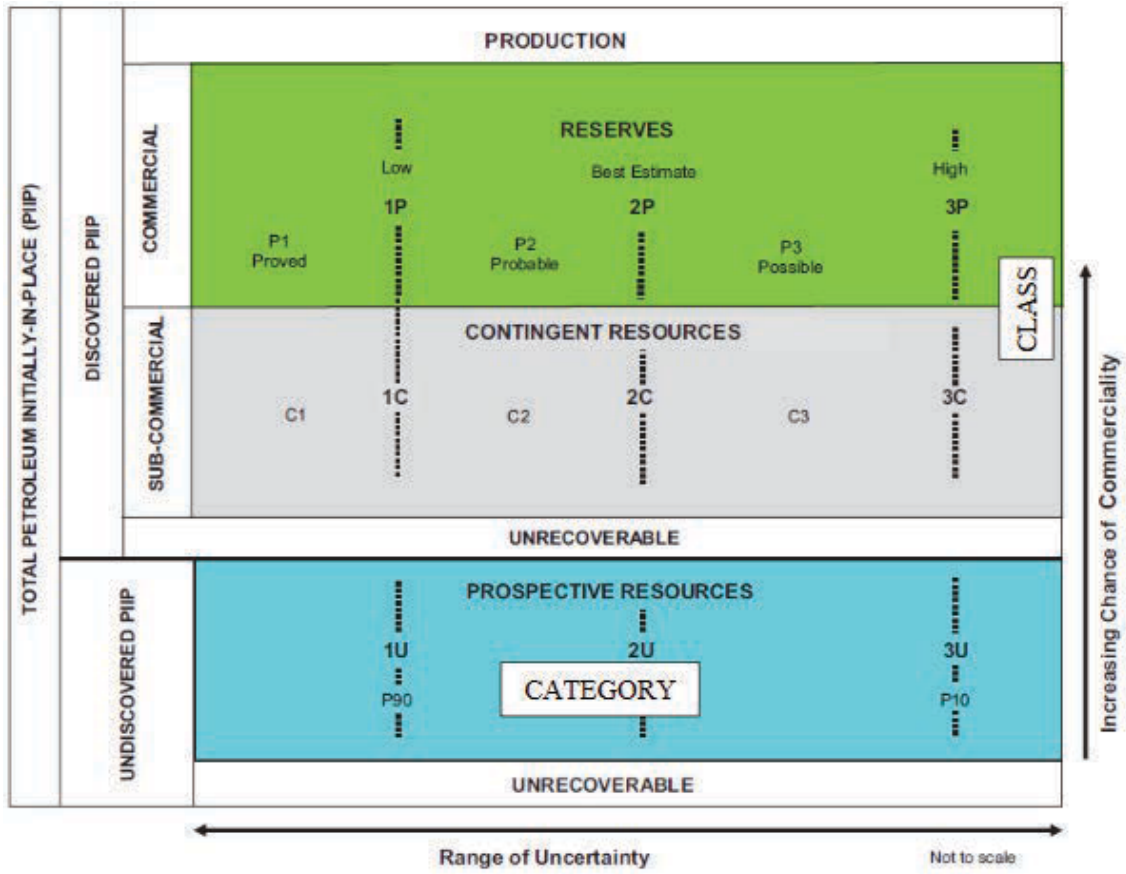


Figure A 1 SPE PRMS Petroleum Resources Classification Framework