North Sea, Liberator Resources

Competent Person's Report Update 2020

For: i3 Energy plc & W H Ireland Limited

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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").

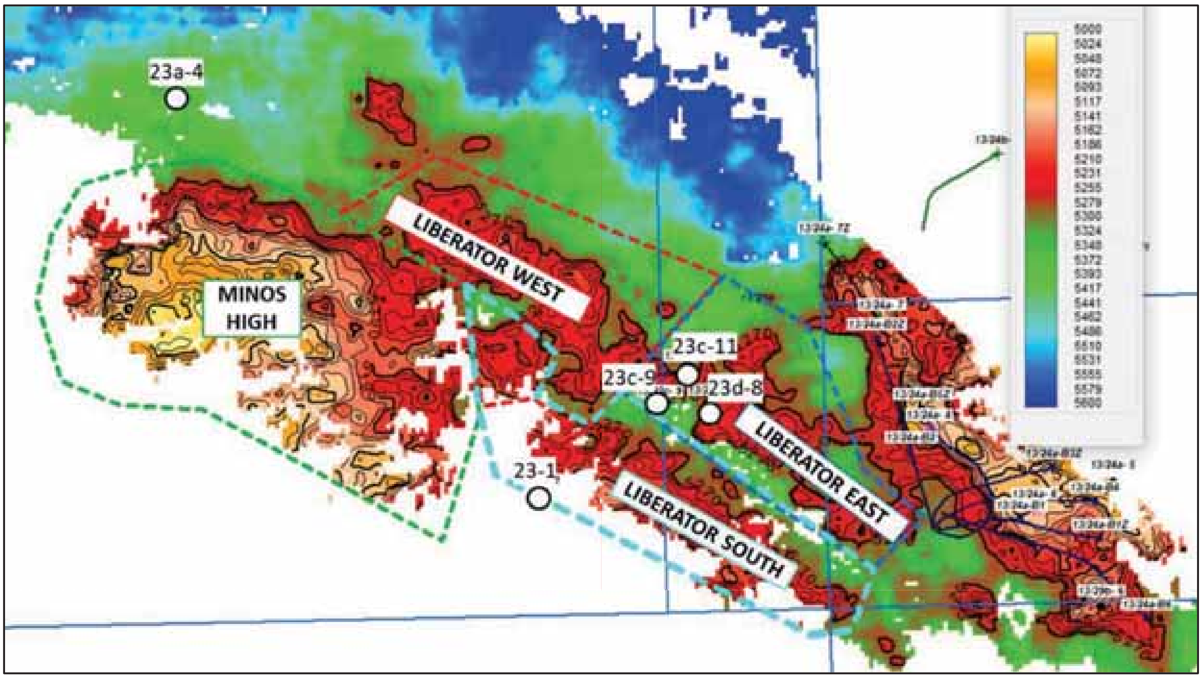
TRACS will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report and TRACS will receive no other benefit for the preparation of this report.

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 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 (km²)	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.

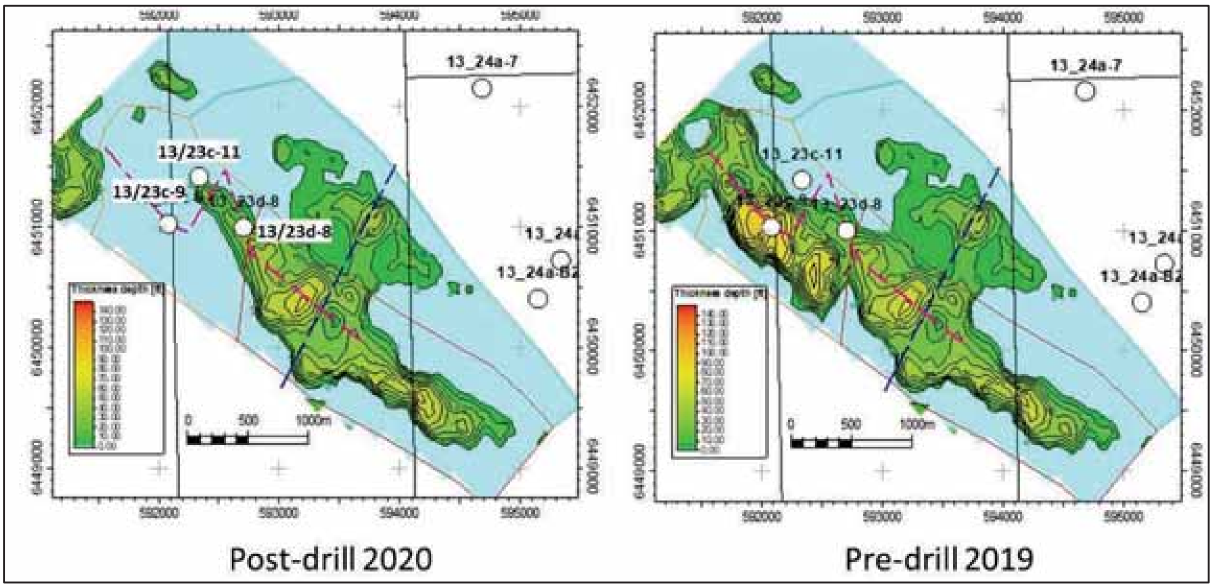
LIBERATOR WEST & MINOS HIGH i3 Energy Working Interest 100%, Unrisked										
Asset	Resource Category	Company Share Gross Resources				Company Share Net Resources				COSg
		Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	
Liberator West Block 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, 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. 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 STOIIP 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 gap 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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1 Introduction

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 in accordance with resource definitions presented in the SPE's 2018 Petroleum Resources Management System ("SPE-PRMS": Appendix A – Summary of 2018 SPE Petroleum Resource Management System Classification). The report also includes a provisional assessment of the likely range of resources that may be assigned to the Liberator West and Minos High areas. The report has been prepared to be included in an appendix to the AIM admission document prepared and published in accordance 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.

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 (Ref 1). 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 Update focuses on the proven oil accumulation around the Liberator discovery well, formerly known as Phase 1 East in the 2019 CPR but re-named Liberator East for the purposes of the current evaluation (Figure 1-1). Evaluation of other resource potential in the Liberator area is part of an ongoing evaluation and is reported separately in Section 8.

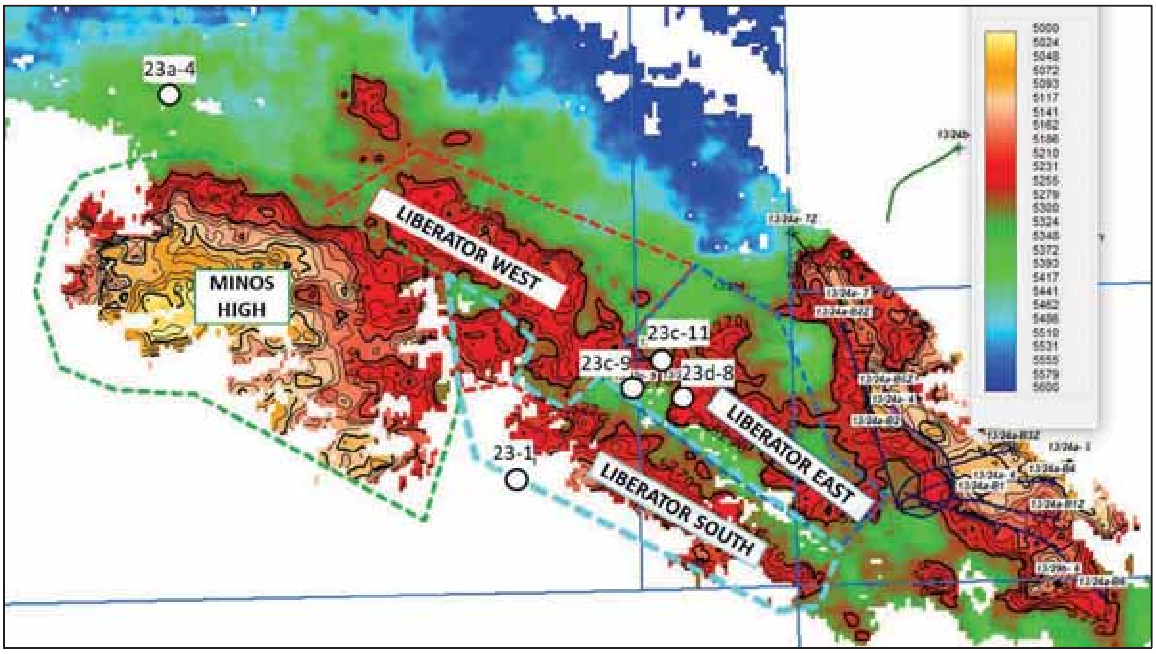


Figure 1-1 i3 current Liberator area designation

1.1 Overview

The Liberator discovery 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. The Liberator accumulation is situated between the Blake field to the north and Ross field to the south (Figure 1-2), both of which are hosted by the Bleo Holm FPSO.

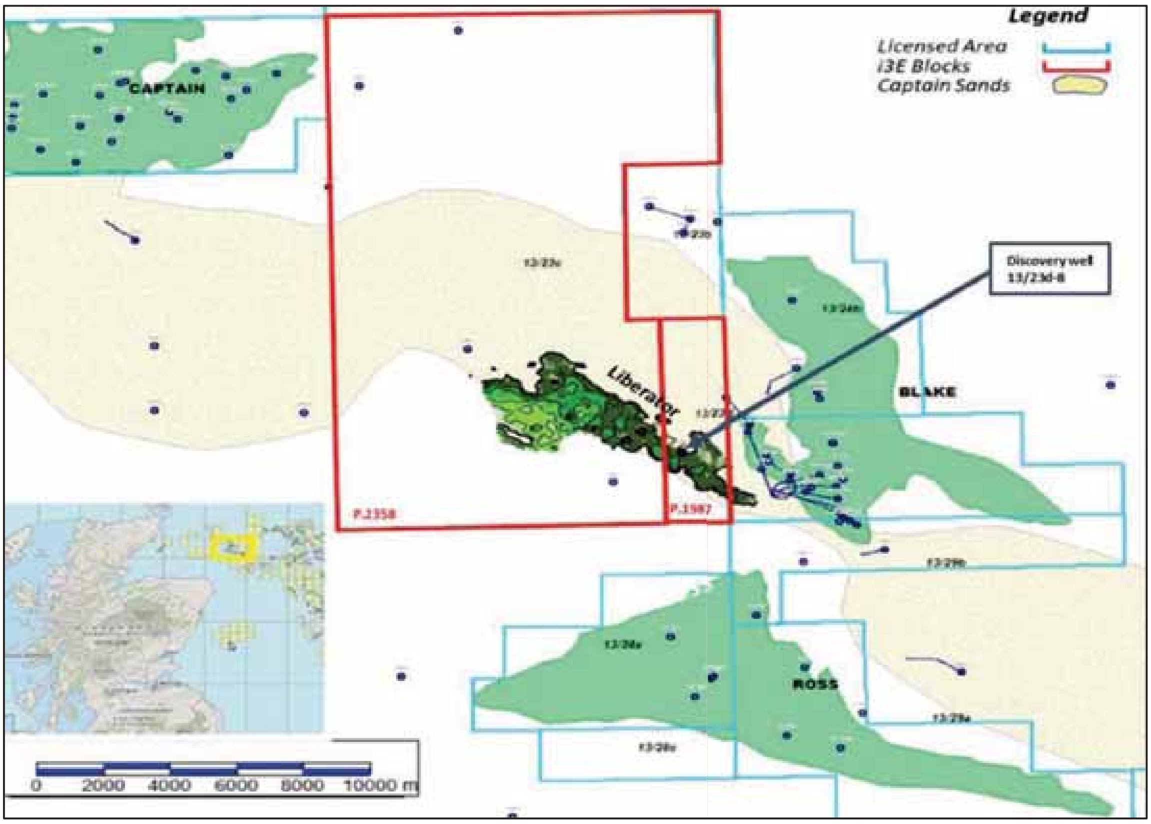


Figure 1-2 Liberator area location map

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%.

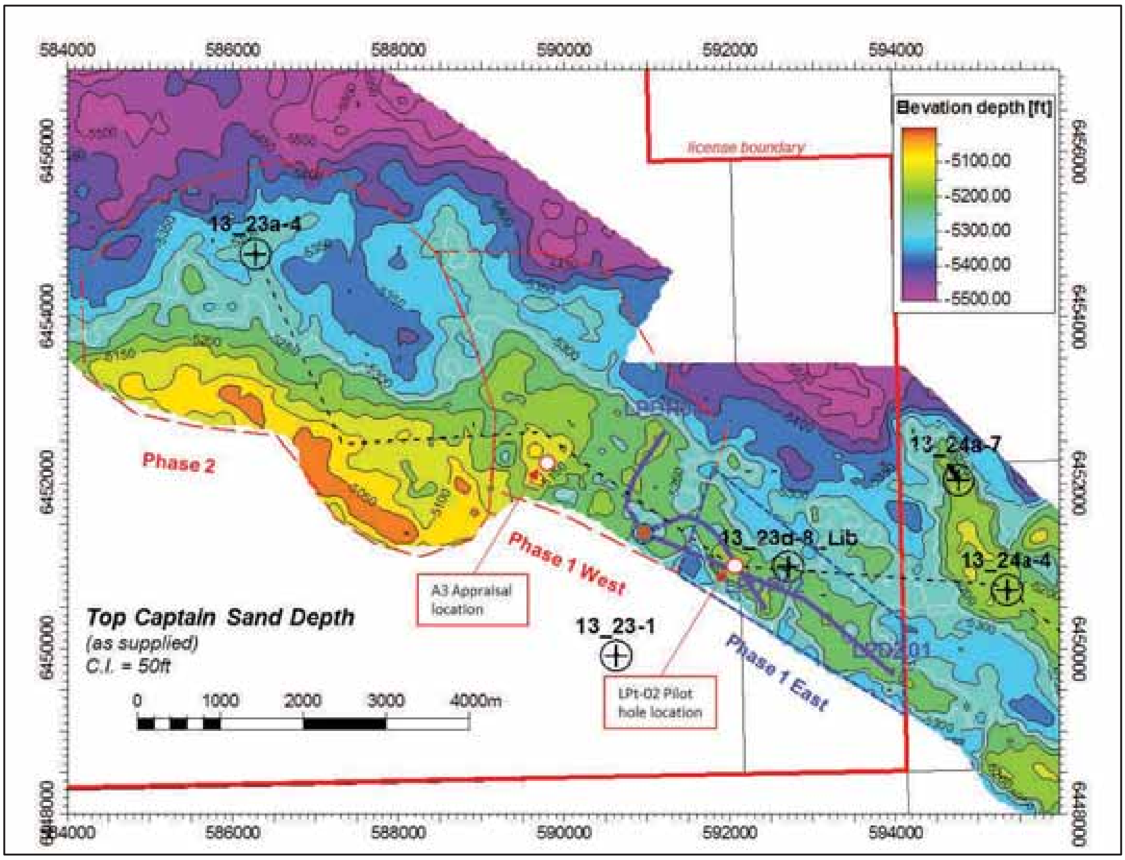


Figure 1-3 2019 development layout, appraisal well locations and area designations

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.

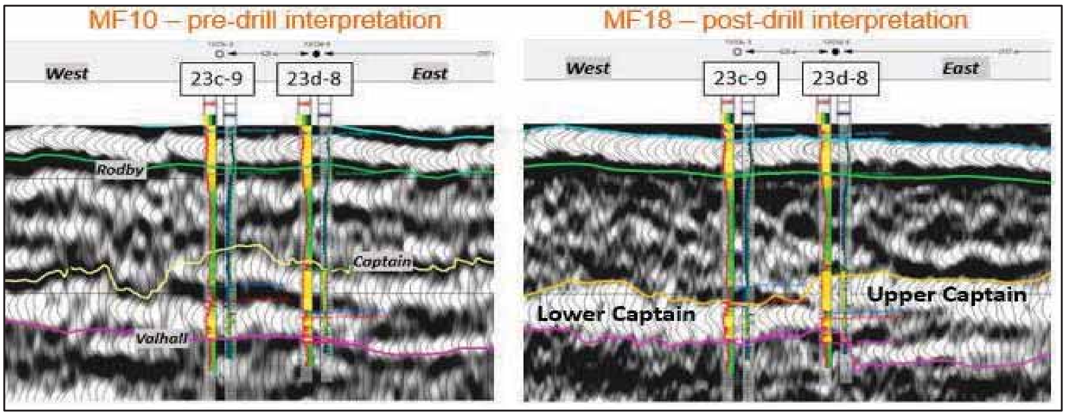


Figure 1-4 Seismic character close to the 13/23c-9 well; comparison of MF10 and MF18

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).

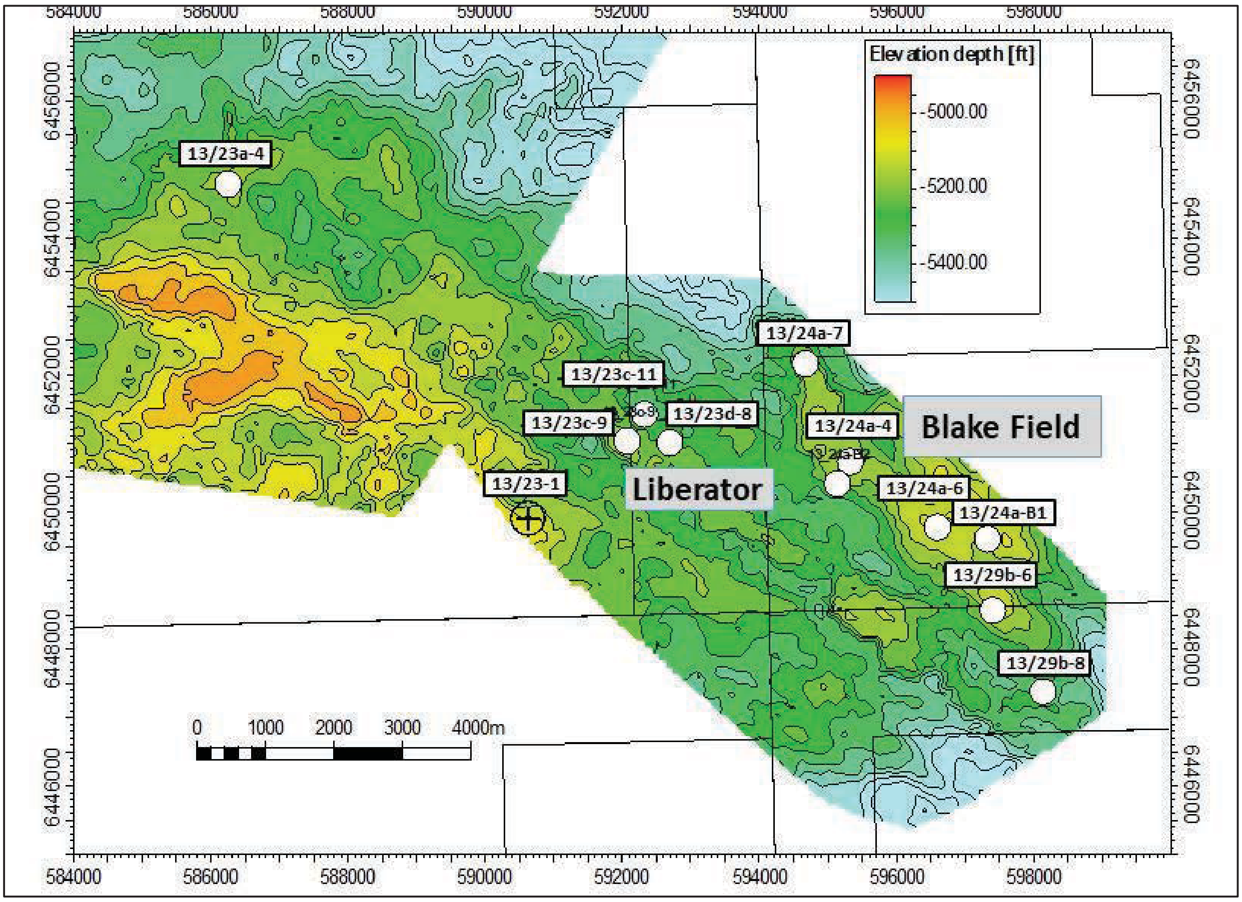


Figure 2-1 Map of Liberator-Blake area

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, 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. Tracs are confident that this is a suitable correlation.

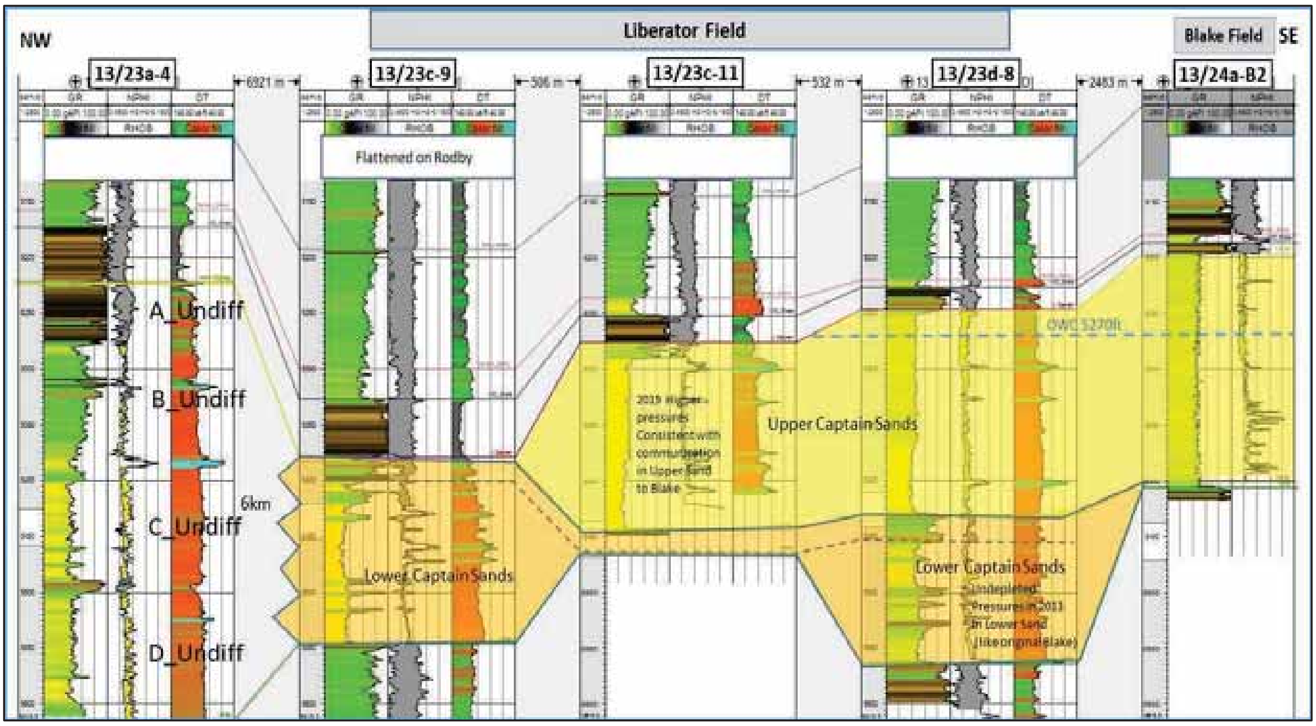


Figure 2-2 Well correlation panel

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 STOIIP.

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.

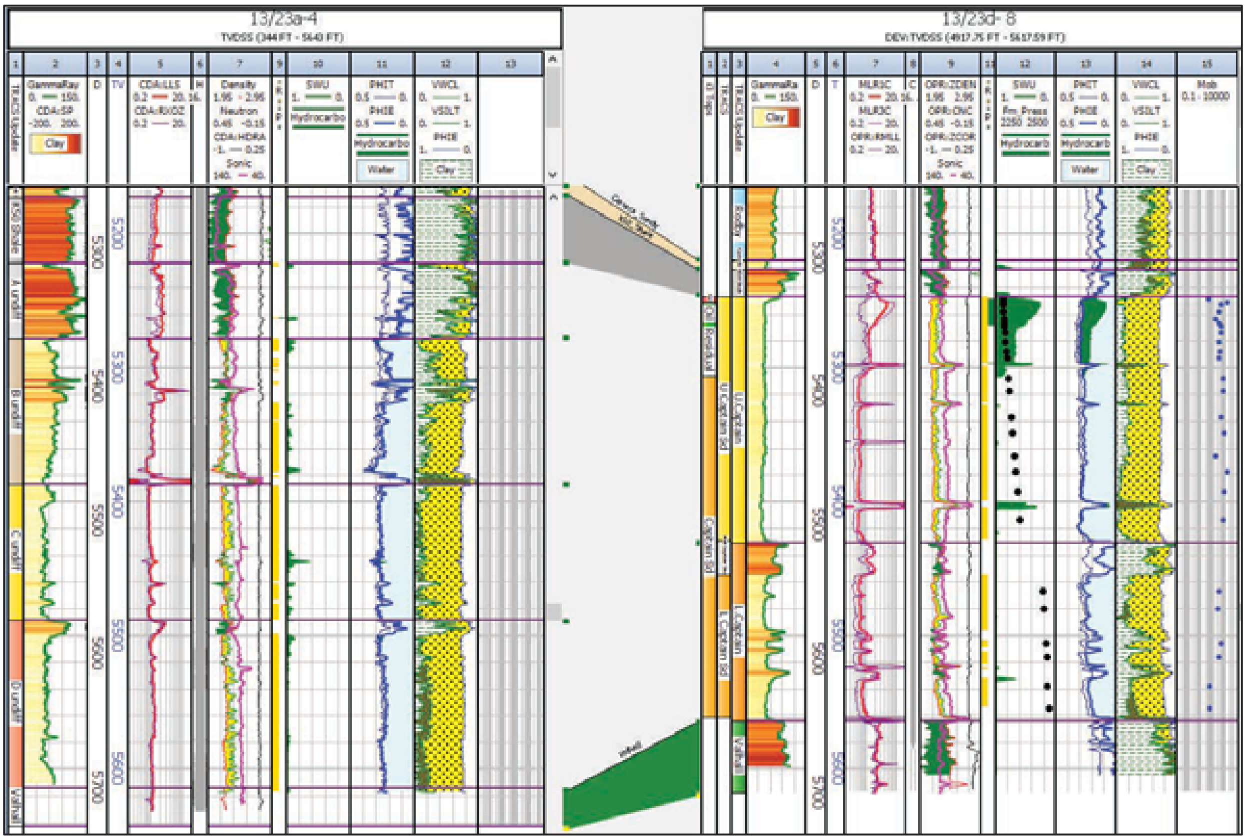


Figure 3-1 CPI for 13/23a-4 and 13/23d-8

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.

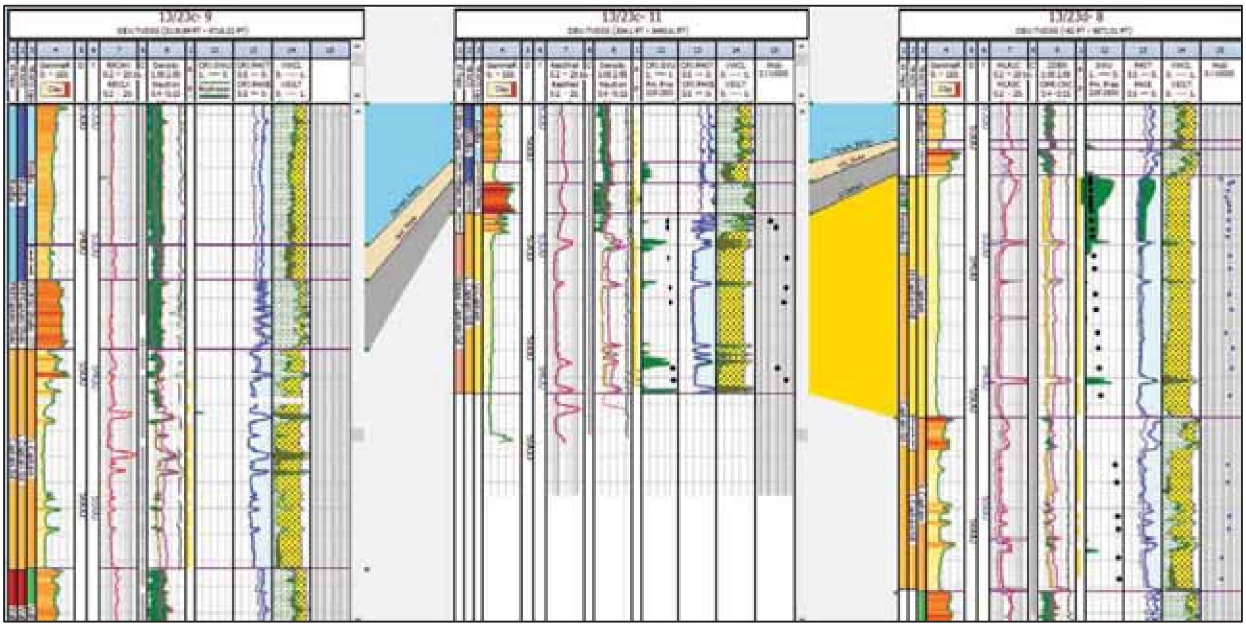


Figure 3-2 Liberator wells; logs and CPI

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).

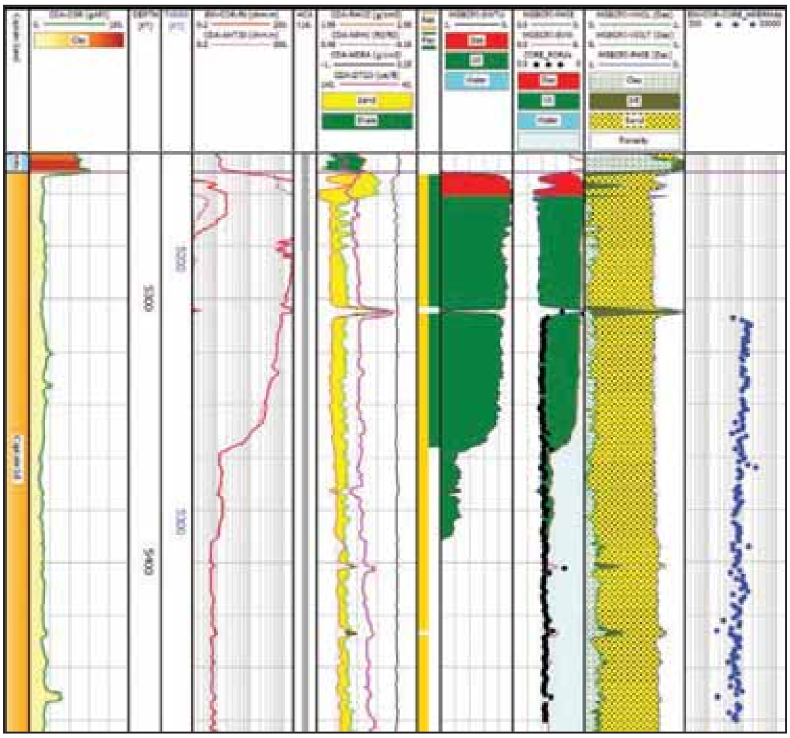


Figure 3-4 Porosity from core analysis in Blake well 13/24a-4 in close agreement with porosity from logs

3.2.3 Water saturation

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

$$Sw = \sqrt[n]{\frac{a \times Rw}{Phi^m \times Rt}}$$

Where:

- Phi is porosity (dec).
- Rw is water resistivity at reservoir temperature (for salinity of ~58kppm in this case)
- Rt 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.

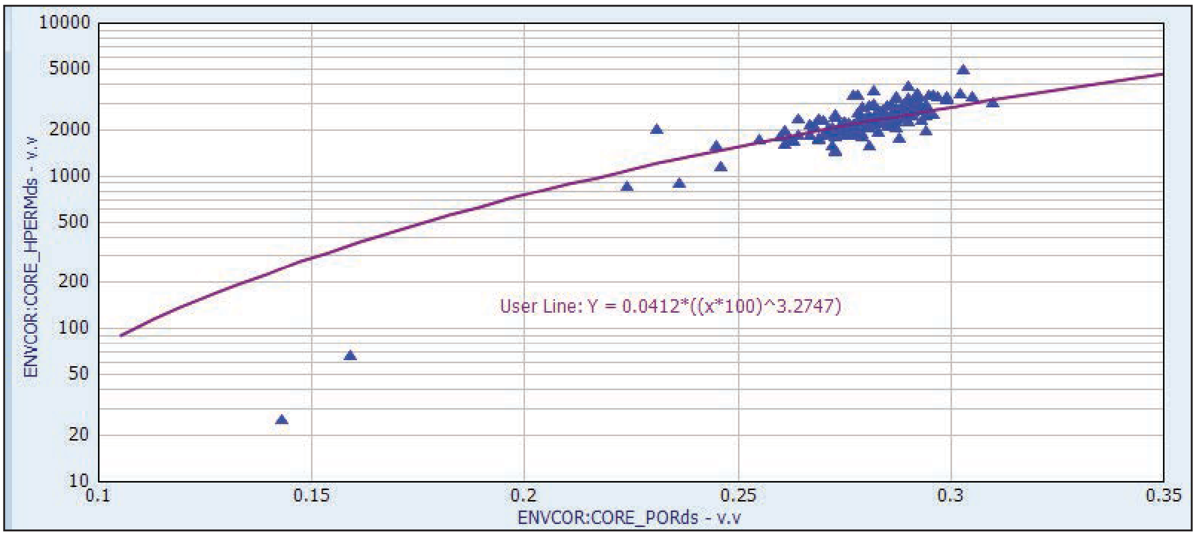


Figure 3-5 Porosity v Permeability from core in Blake well 13/24a-4

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.

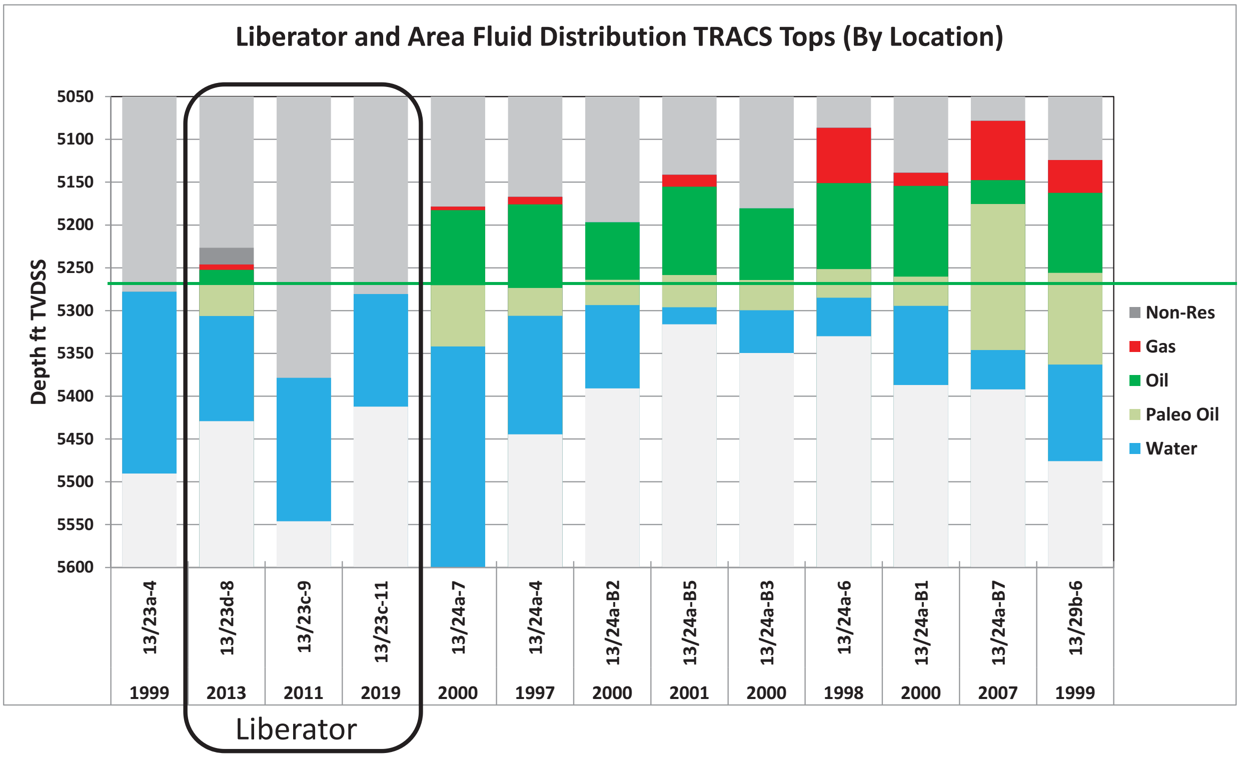


Figure 3-6 Fluid distribution in the Liberator region

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.

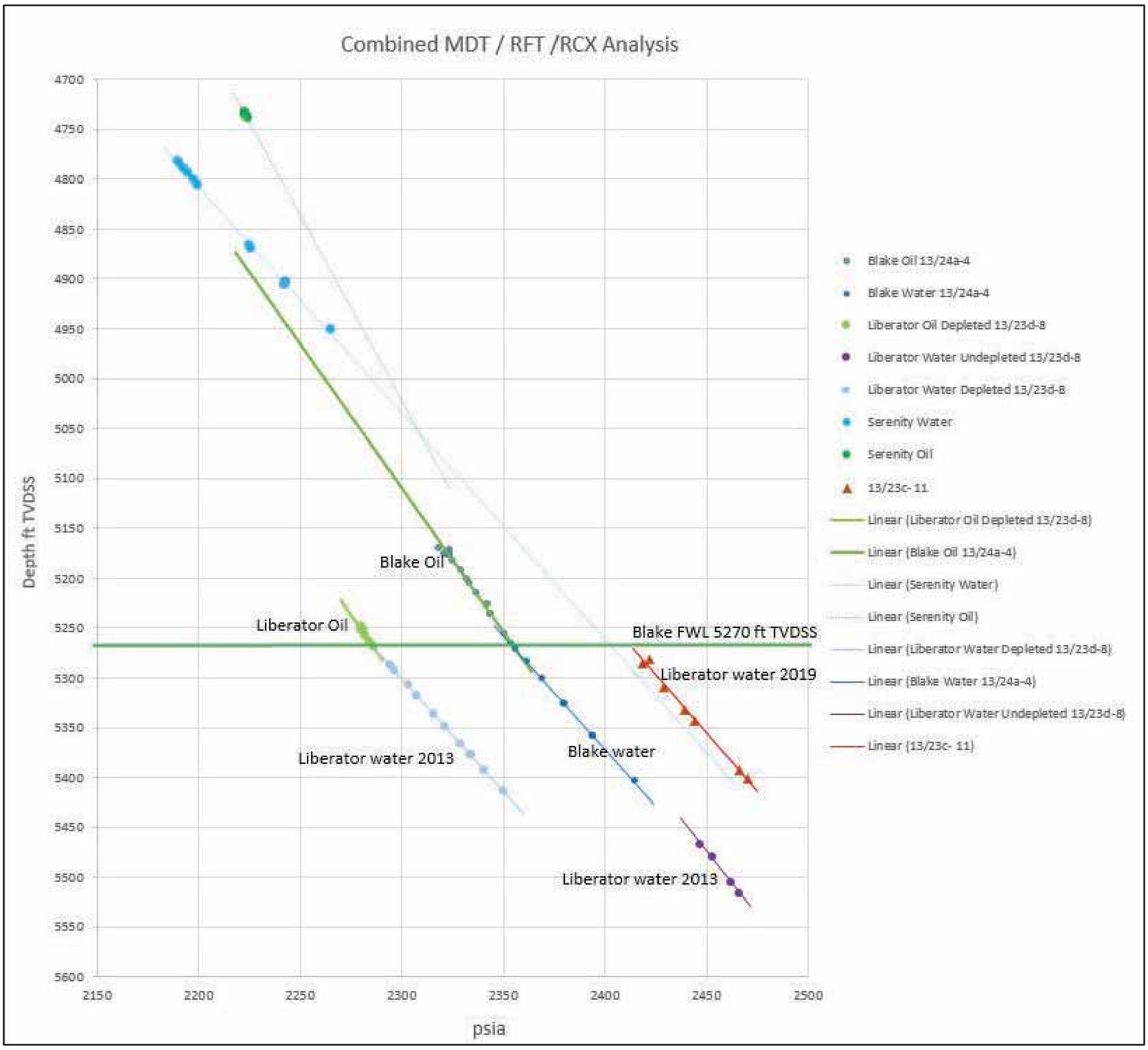


Figure 3-7 Formation pressure from Liberator and Blake Saturation vs height function

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.

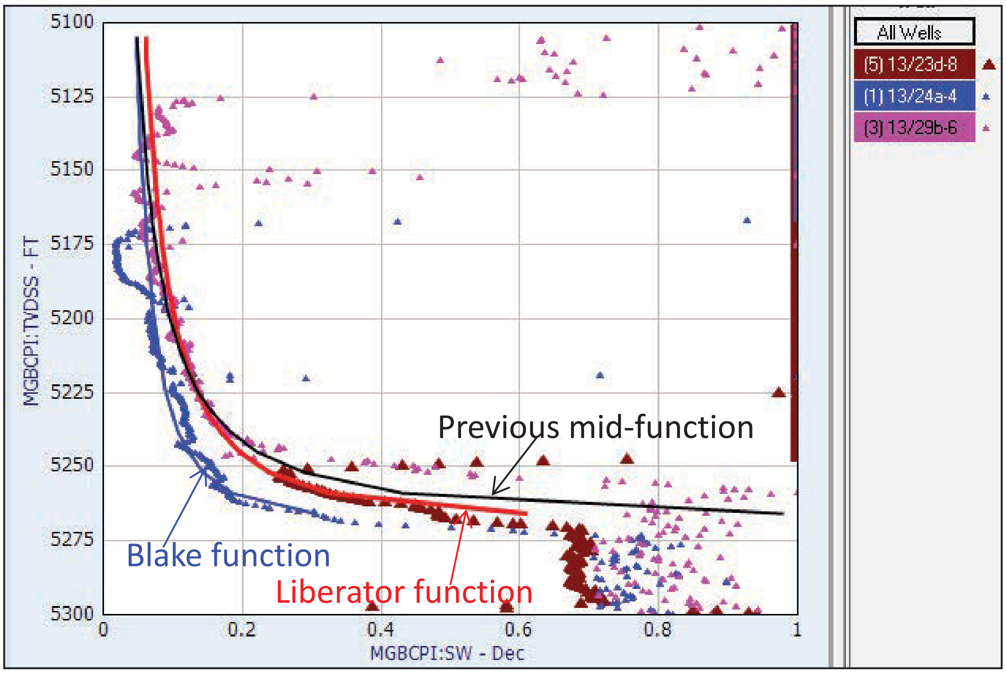


Figure 3-8 Saturation height functions displayed with Sw from logs

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.

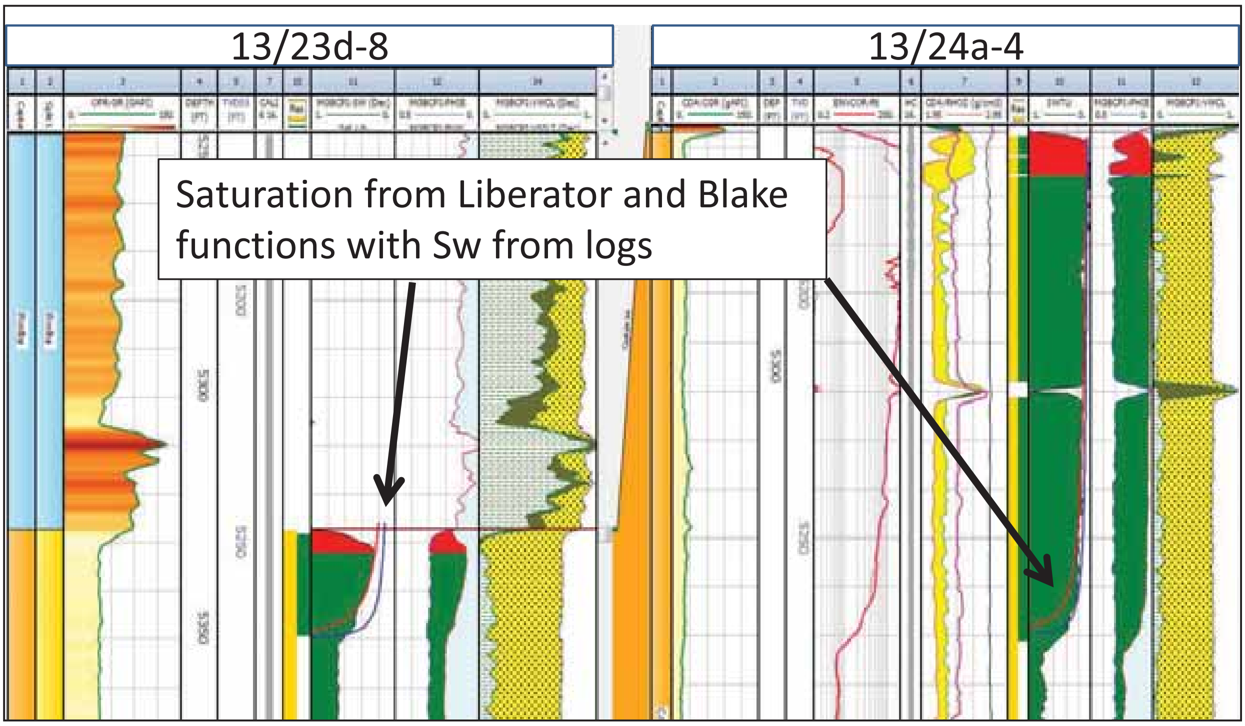


Figure 3-9 Saturation from the functions described displayed with the CPIs (Red-Liberator, Blue-Blake)

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 thought 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 ('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.

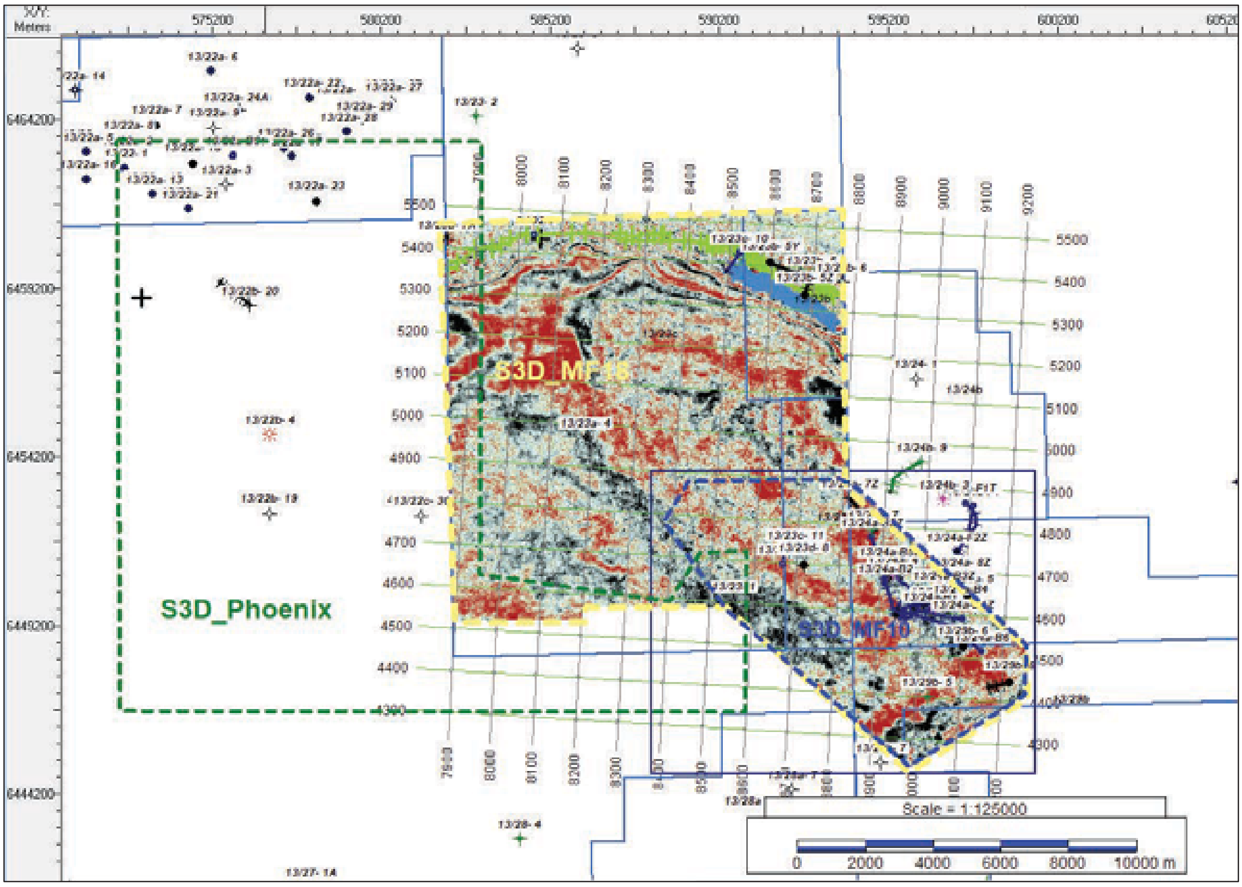


Figure 4-1 Seismic data coverage (supplied by i3 Energy)

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.

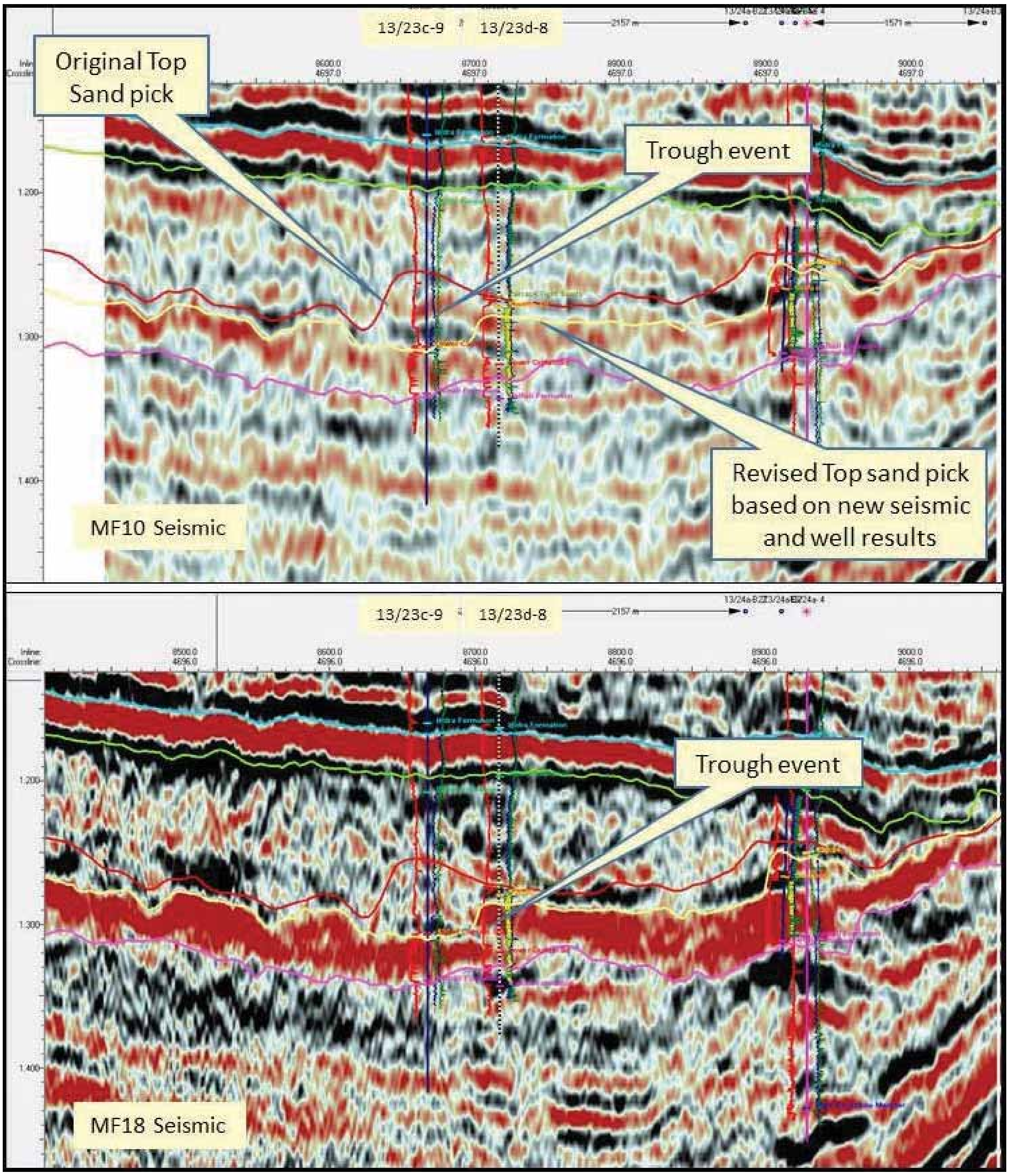


Figure 4-2 Xline 4696 showing the MF10 data (upper section) and the MF18 data (lower section) through the 13/23d-8 and 13/23c-9 well locations (For line location see Figure 4-5)

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.

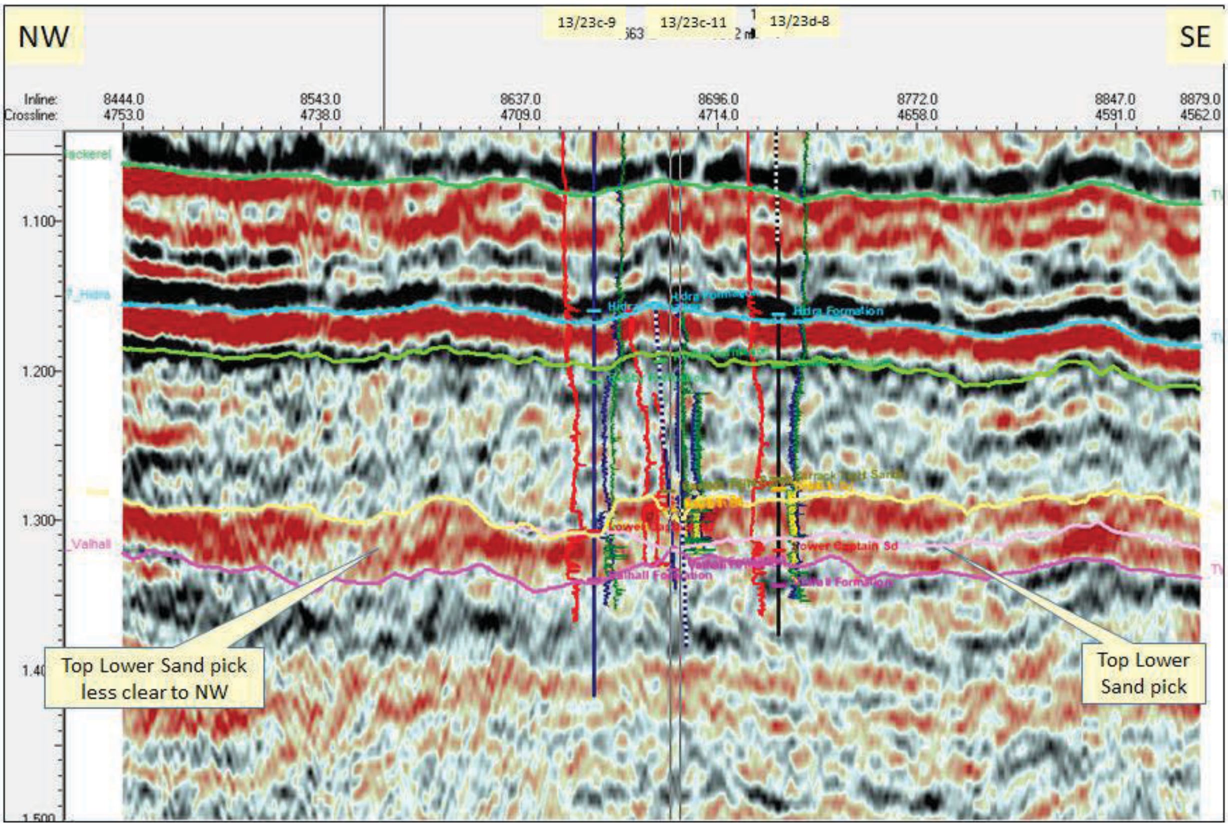


Figure 4-3 Arbitrary Line showing Top Lower Sand pick (For line location see Figure 4-5)

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.

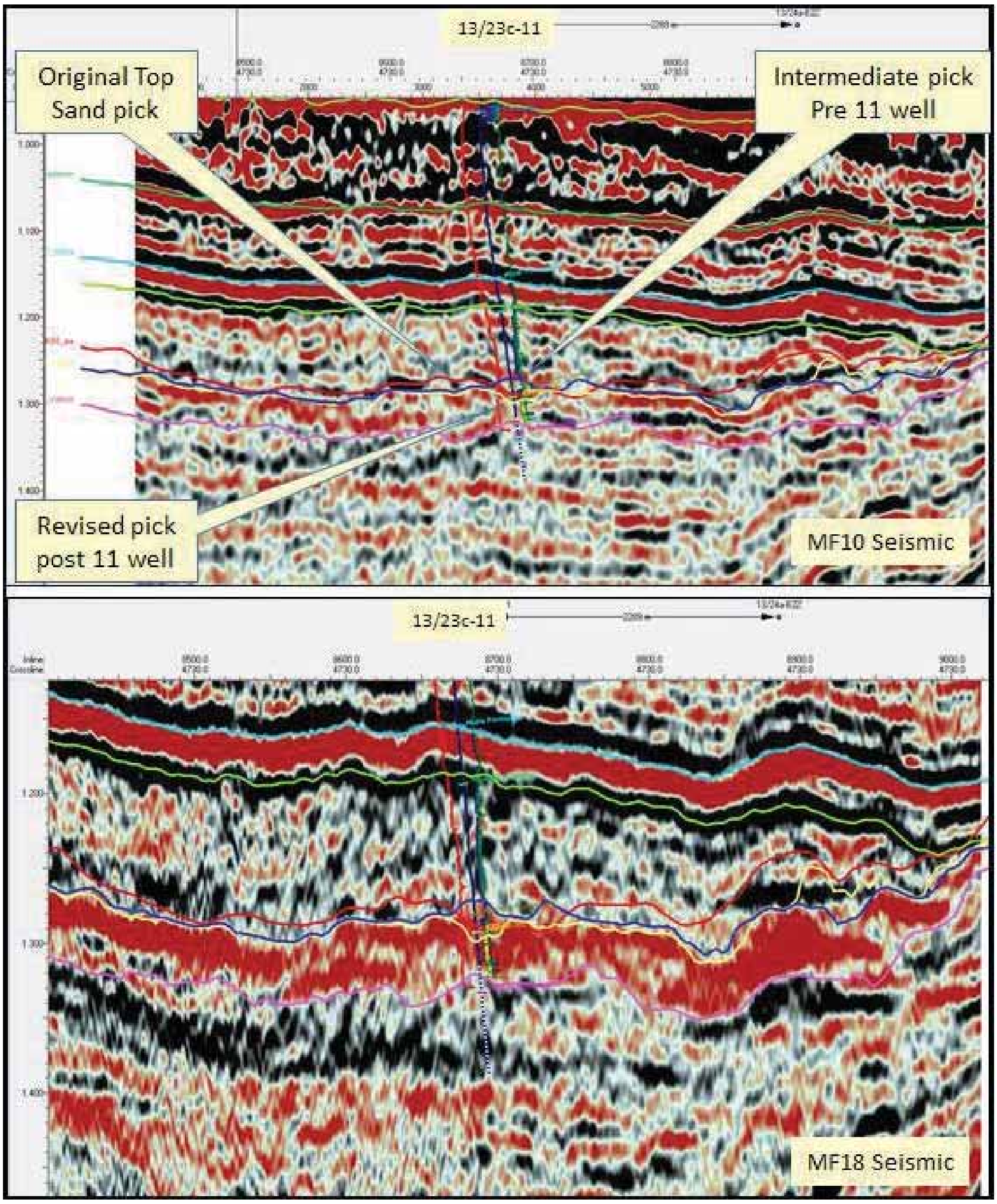


Figure 4-4 Xline 4730 showing the MF10 data (upper section) and the MF18 data (lower section) through the 13/23c-11 well location. (For line location see Figure 4-5)

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.

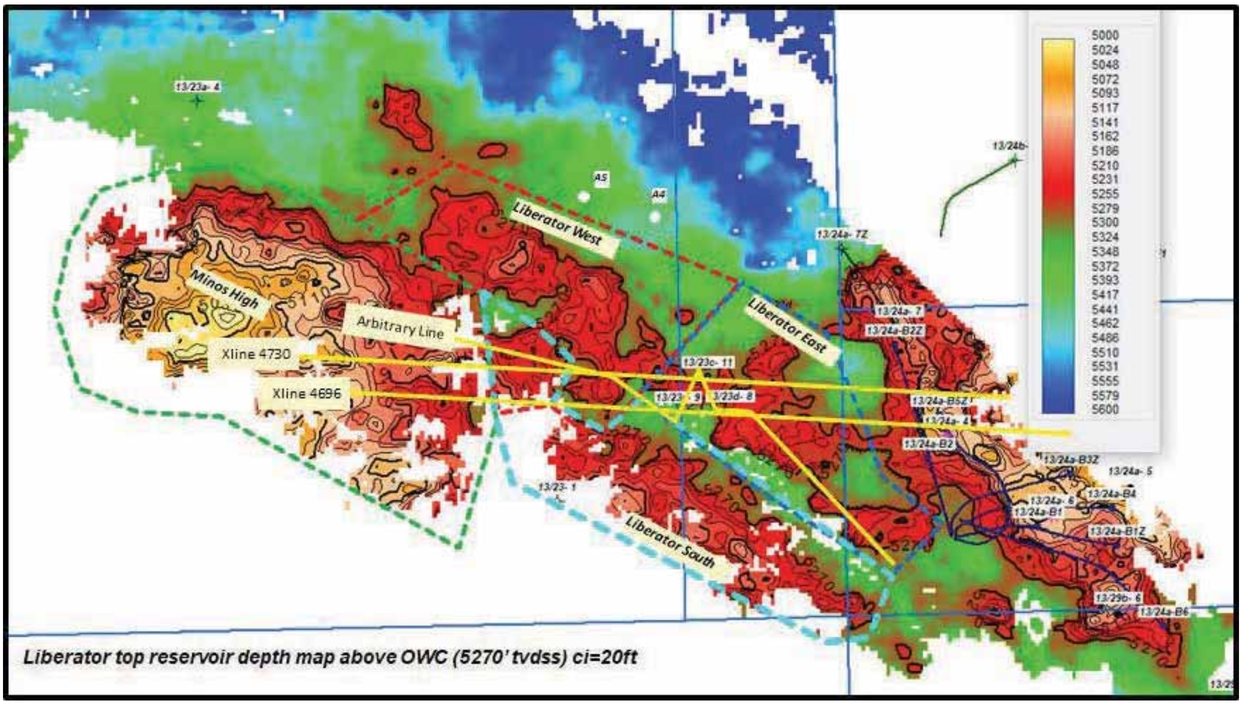


Figure 4-5 Liberator Top Reservoir depth map (Source i3 Energy)

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).

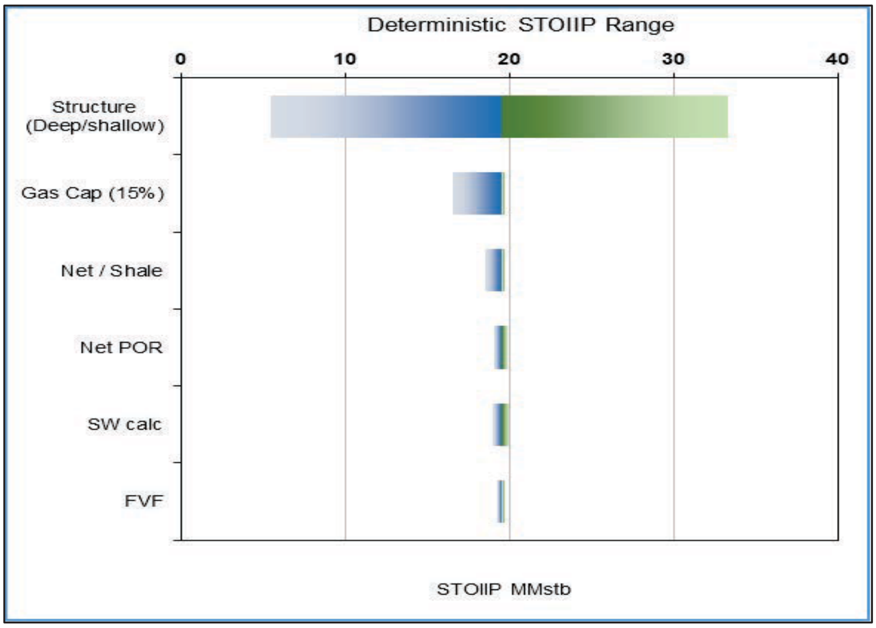


Figure 5-1 Effect on STOIIP of reservoir parameters

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).

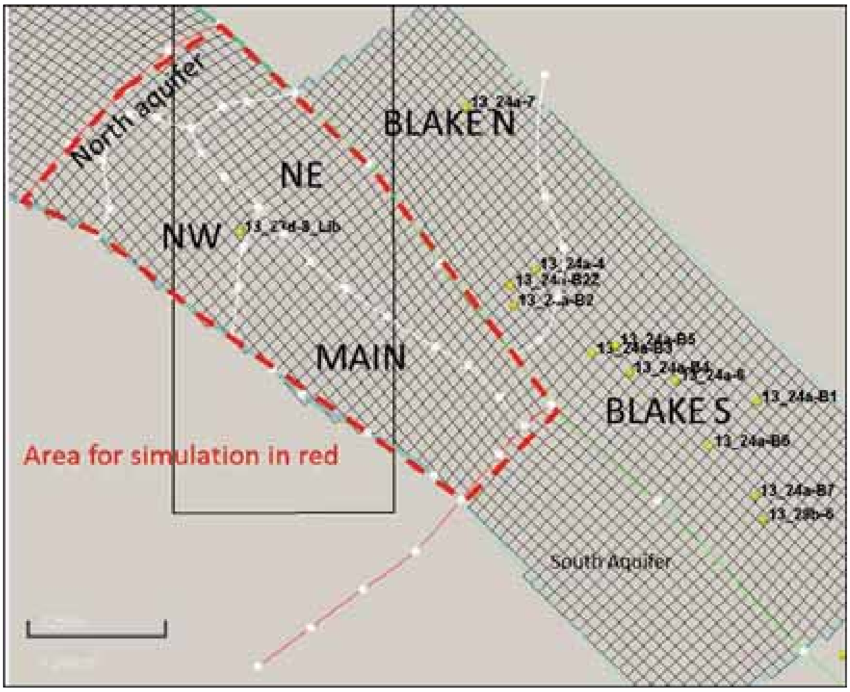


Figure 5-2 Map of modelling grid and segments

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).

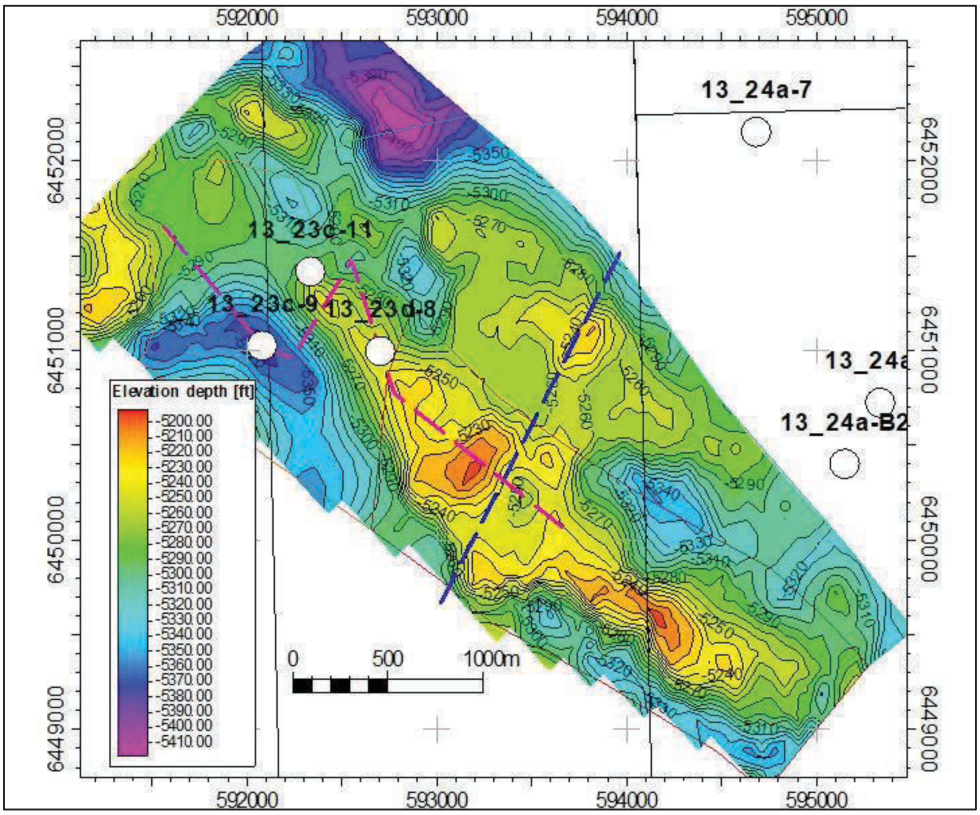


Figure 5-3 Top structure map from static model

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.

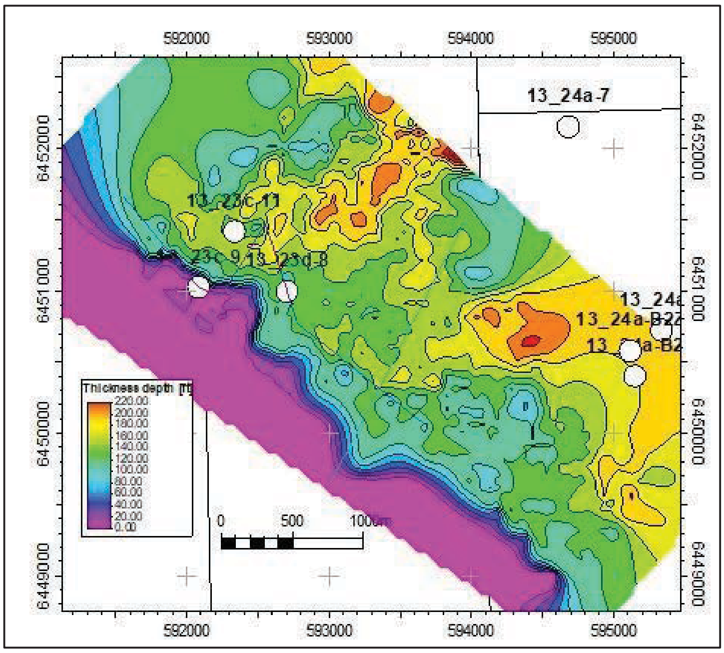


Figure 5-4 Isochore For Upper Captain Sand

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.

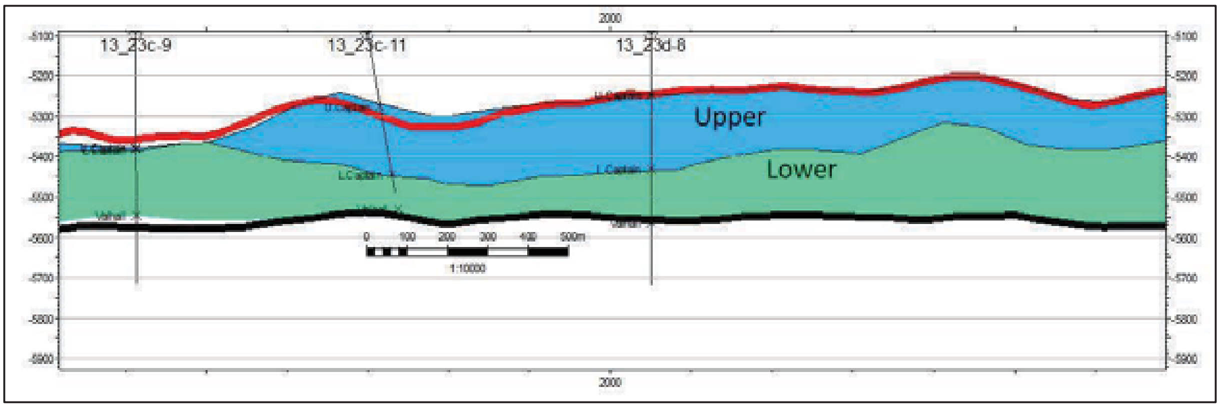


Figure 5-5 Cross Section Through the 3 Liberator Wells

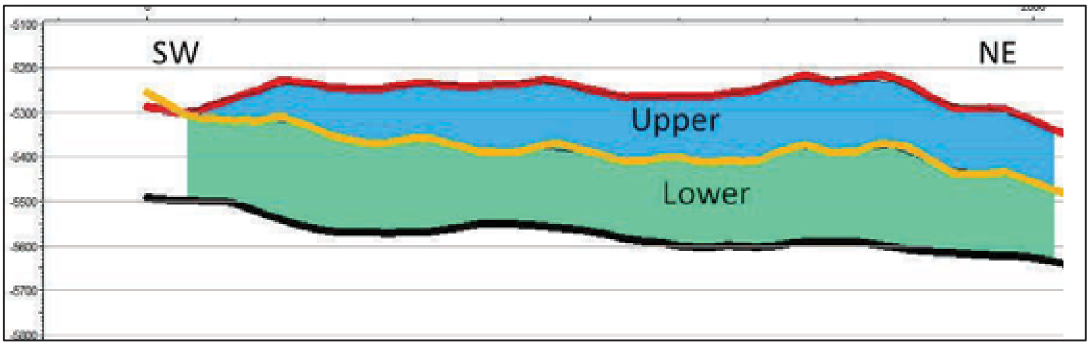


Figure 5-6 SW-NE Cross section through Liberator showing Upper and Lower sand model

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.

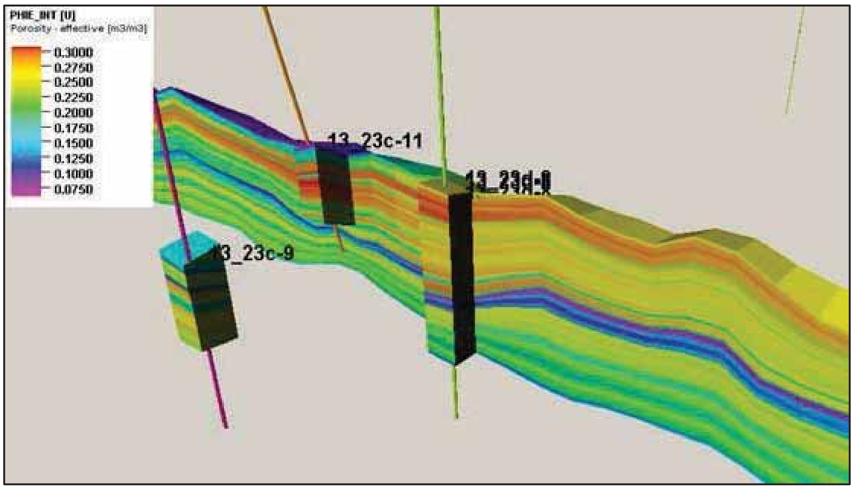


Figure 5-7 Porosity model view

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.

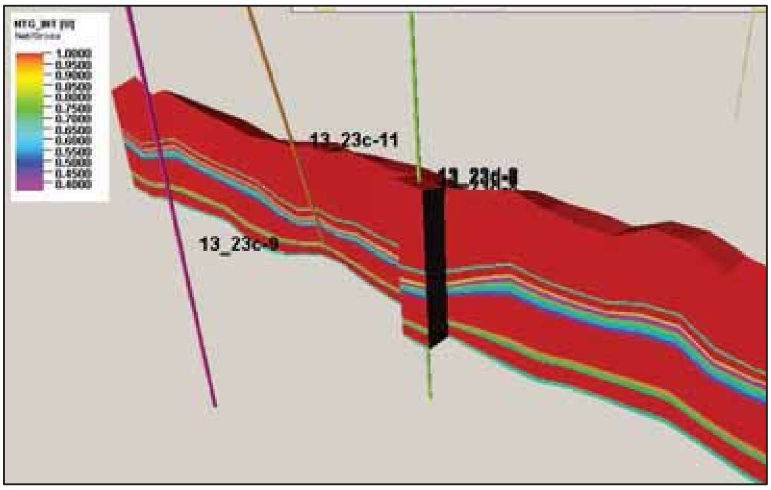


Figure 5-8 NTG model view

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).

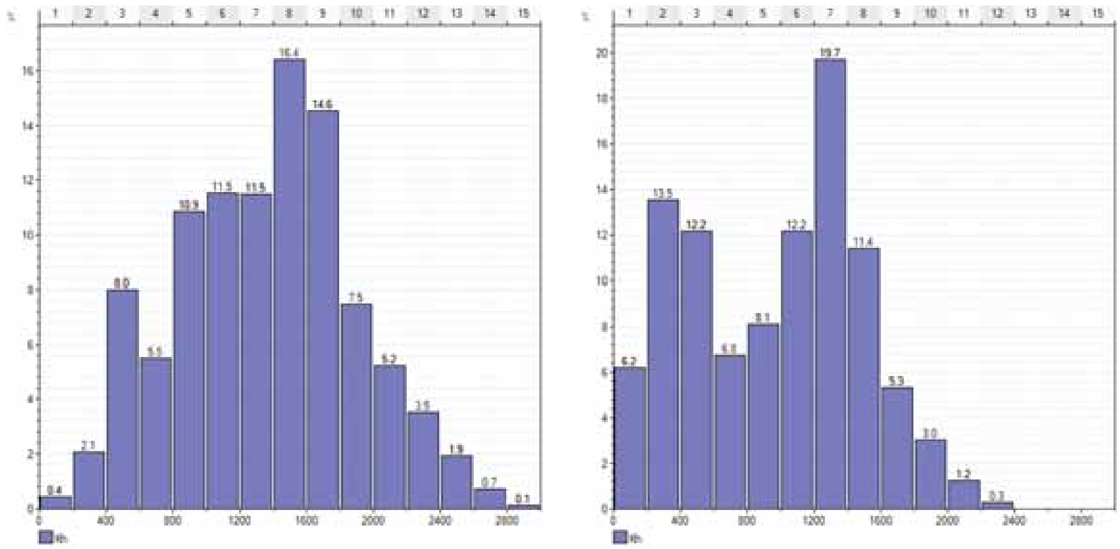


Figure 5-9 Upper and Lower Captain Sand Permeability Distribution (mD)

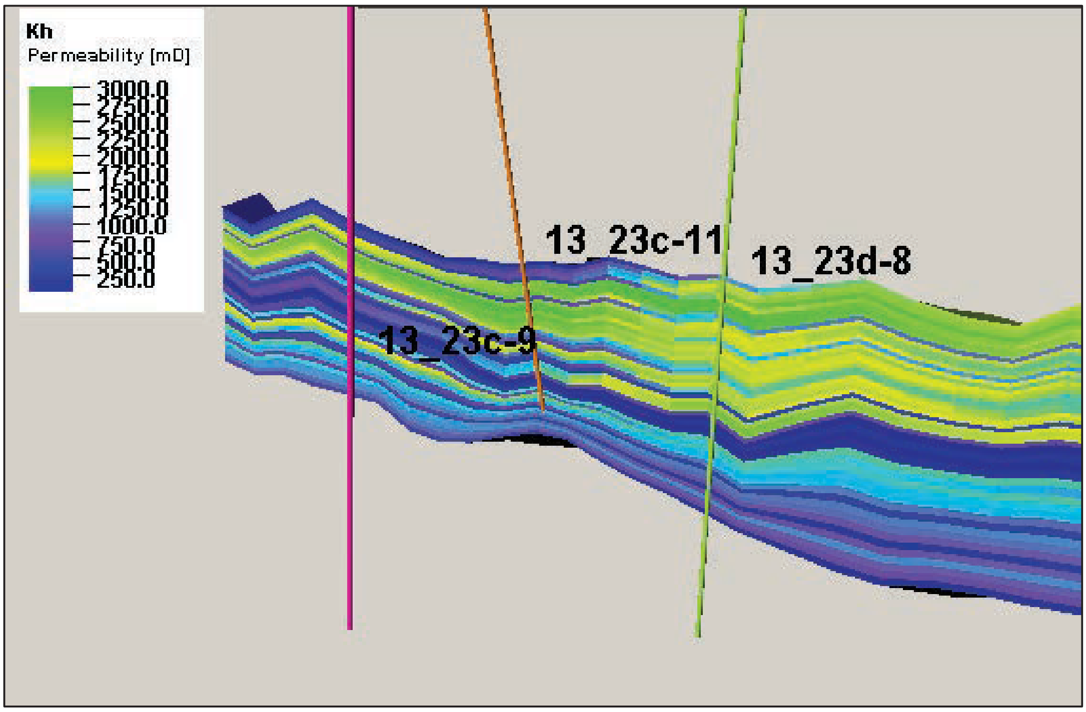


Figure 5-10 Permeability (Kh) model view

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.

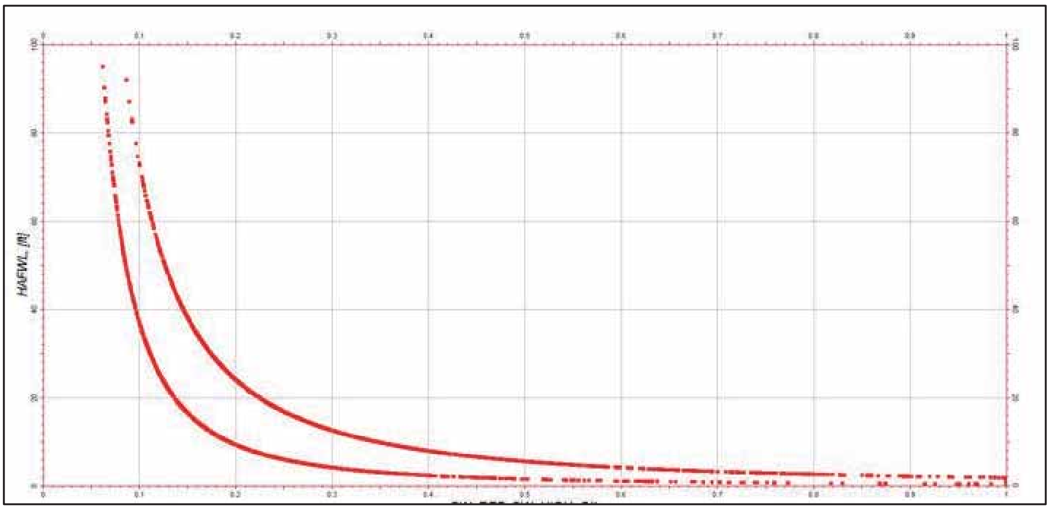


Figure 5-11 Comparison of Sw-Height functions

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).

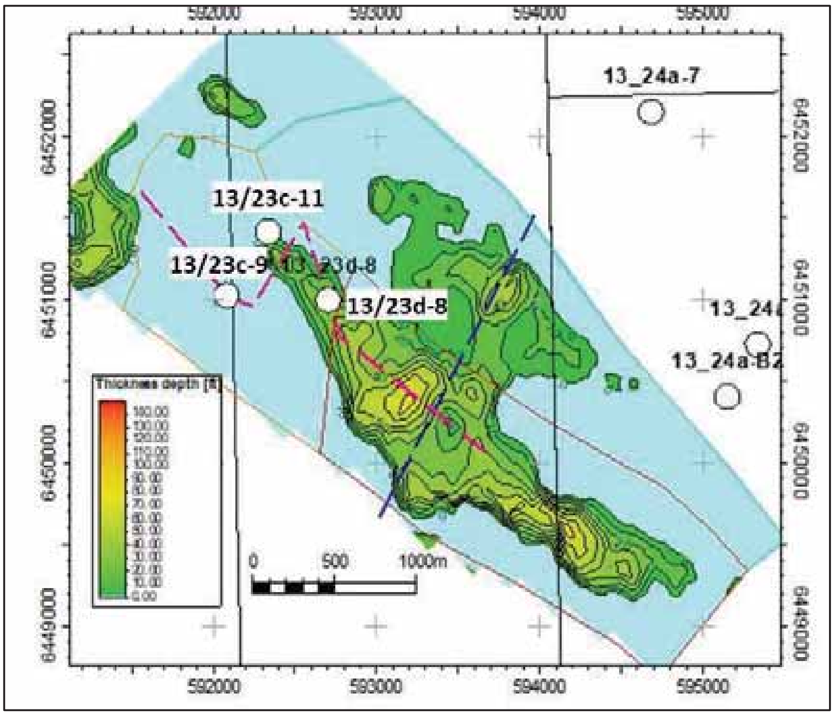


Figure 5-12 Height of oil column map from model (2020)

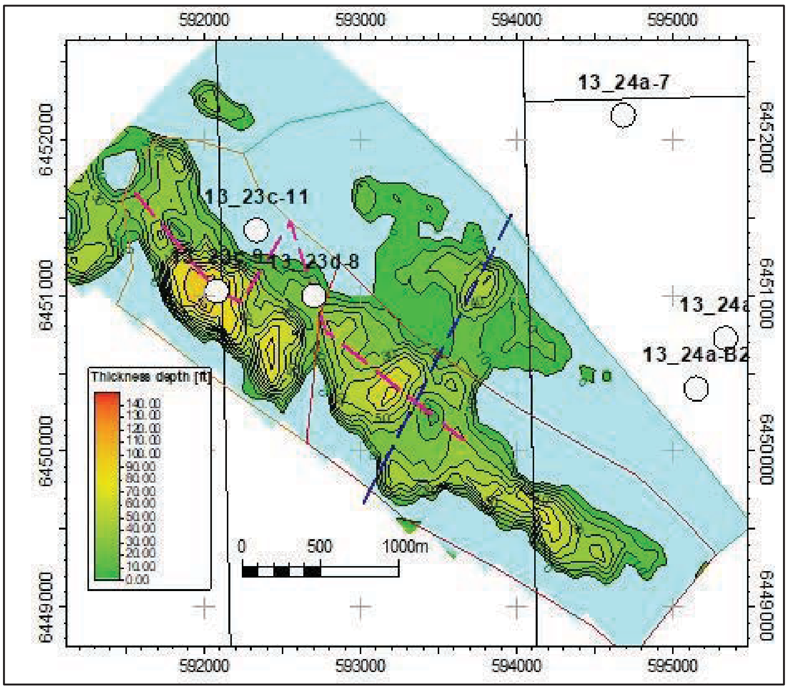


Figure 5-13 Height of Oil Column Map (pre-drill)

5.2.1 Depth uncertainty gridding

For generating shallow and deep top reservoir maps, the depth uncertainty away from the wells is estimated at $\pm$ 25ft 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.

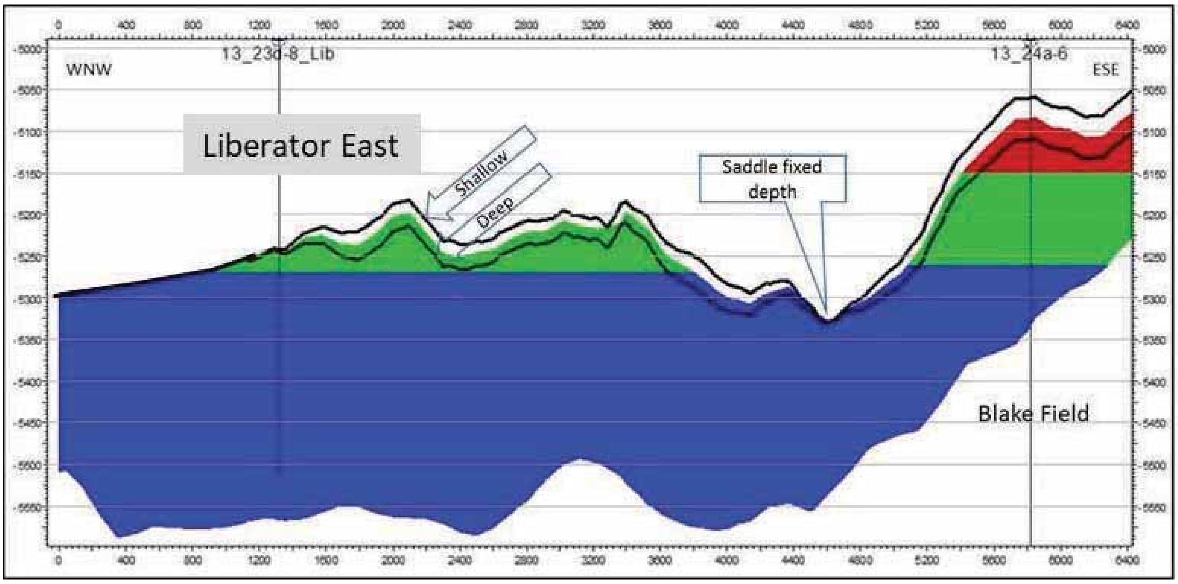


Figure 5-14 Cross Section from NW to SE showing shallow and deep top reservoir

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.

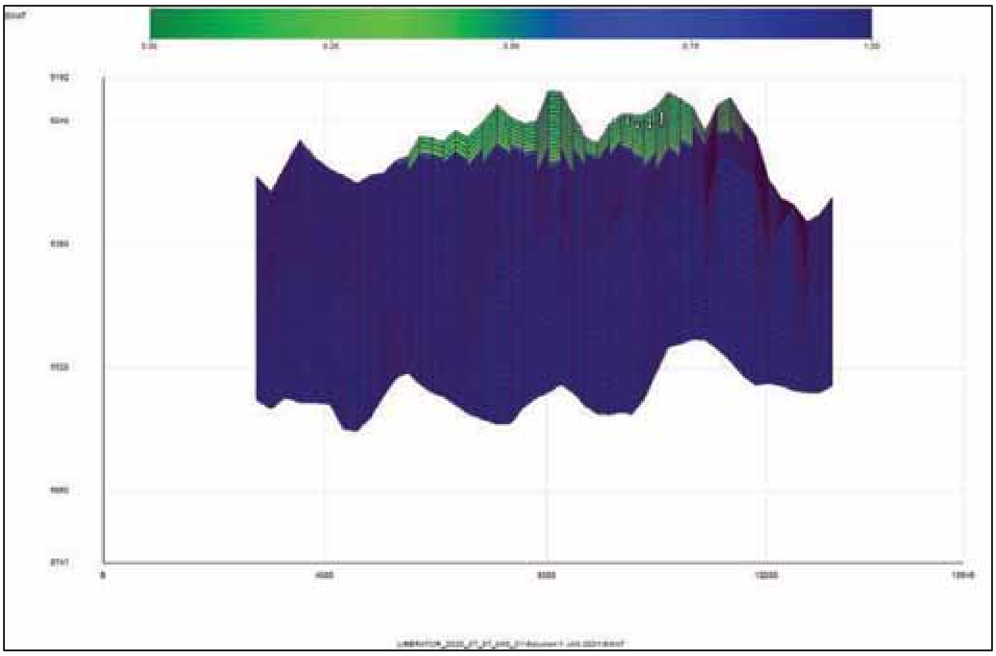


Figure 6-1 Liberator East E100 Model Vertical X-Section NW-SE along Crest

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.

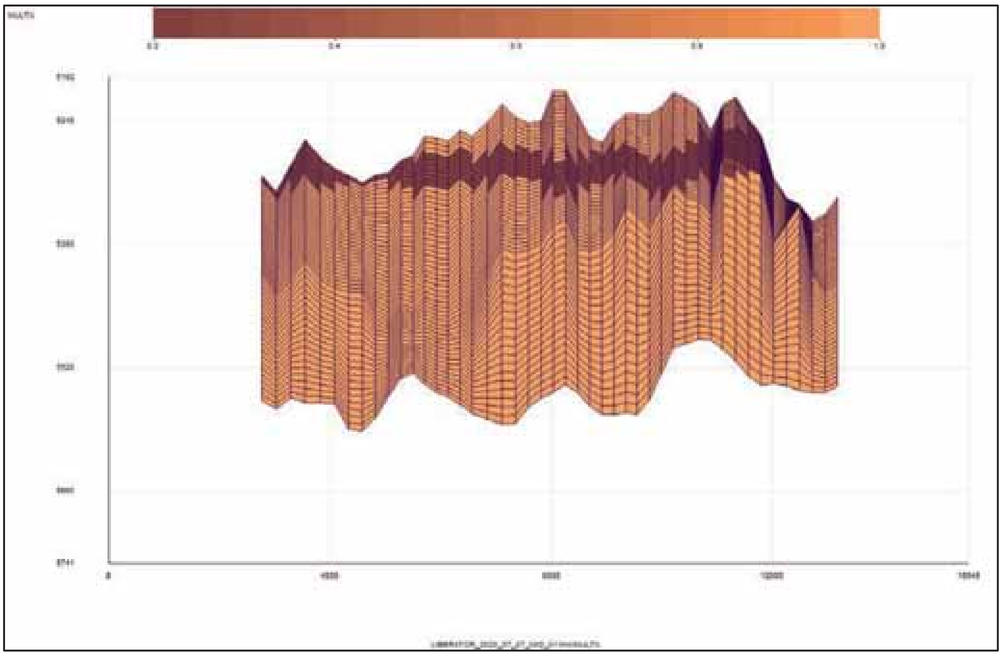


Figure 6-2 Palaeo Oil Zone Transmissibility Multiplier

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	ºF	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.

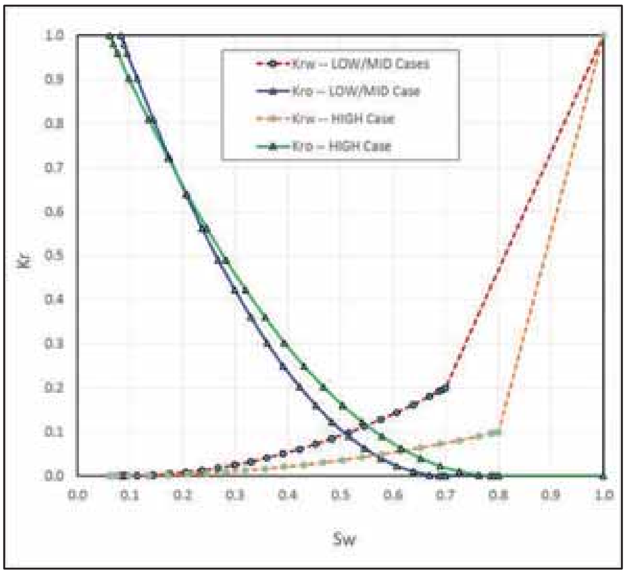


Figure 6-3 Relative permeability curves for Low, Mid and High cases

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 STOIIP 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 STOIIP reduced to 0.3 MMstb with new structure means no well target.

Region 2: NE, connecting to Blake, minor STOIIP

Region 3: SW, Main target area for production

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

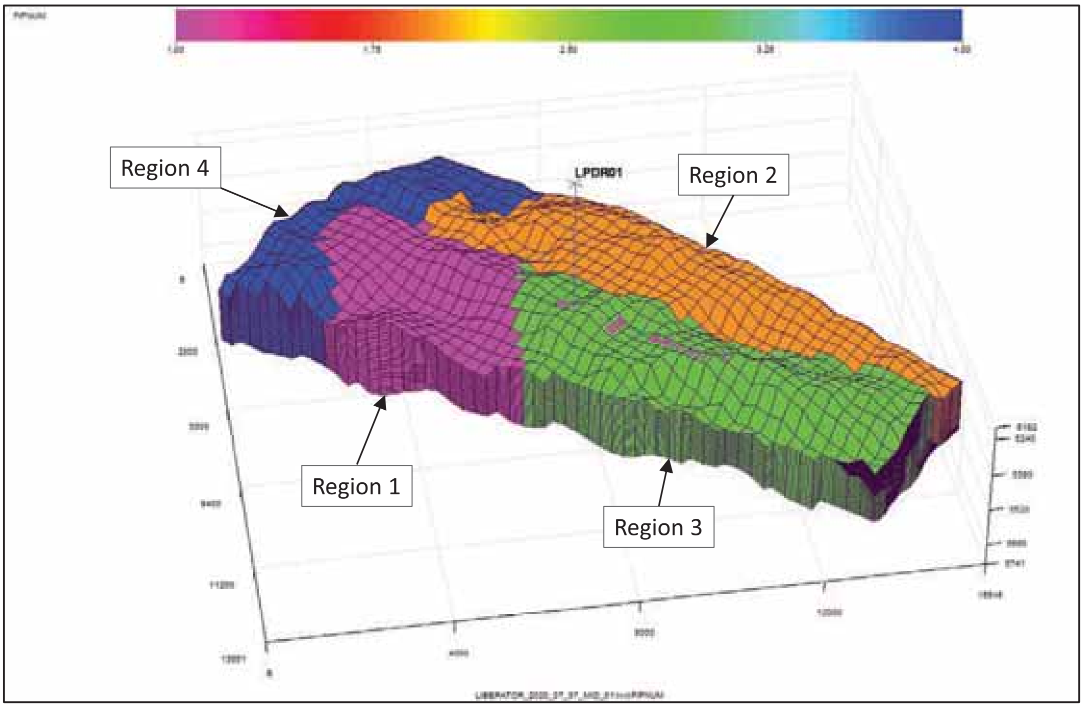


Figure 6-4 E100 Liberator Model STOIIP Regions

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 STOIIP

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 STOIIP 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).

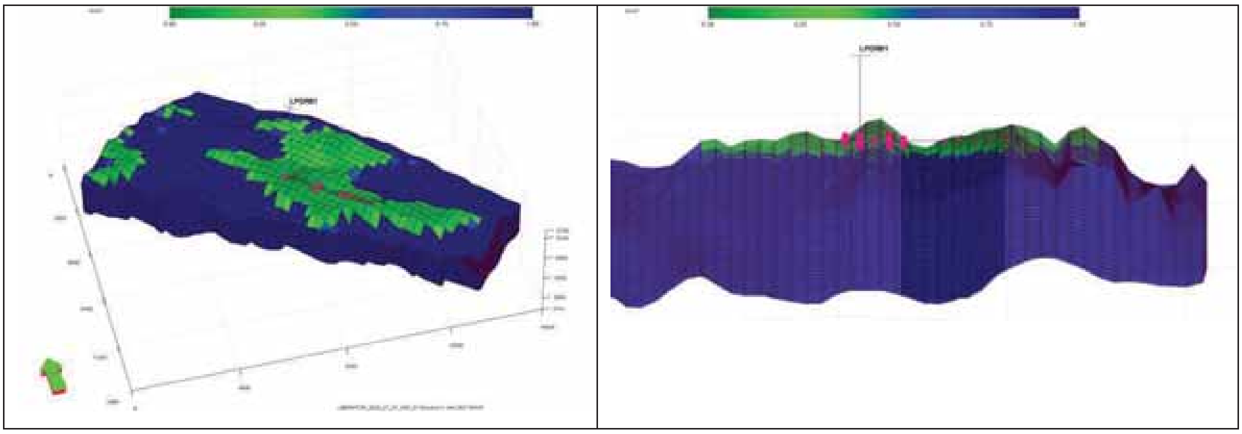


Figure 6-5 Liberator East Simulation Well Location

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. Tthe 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%.

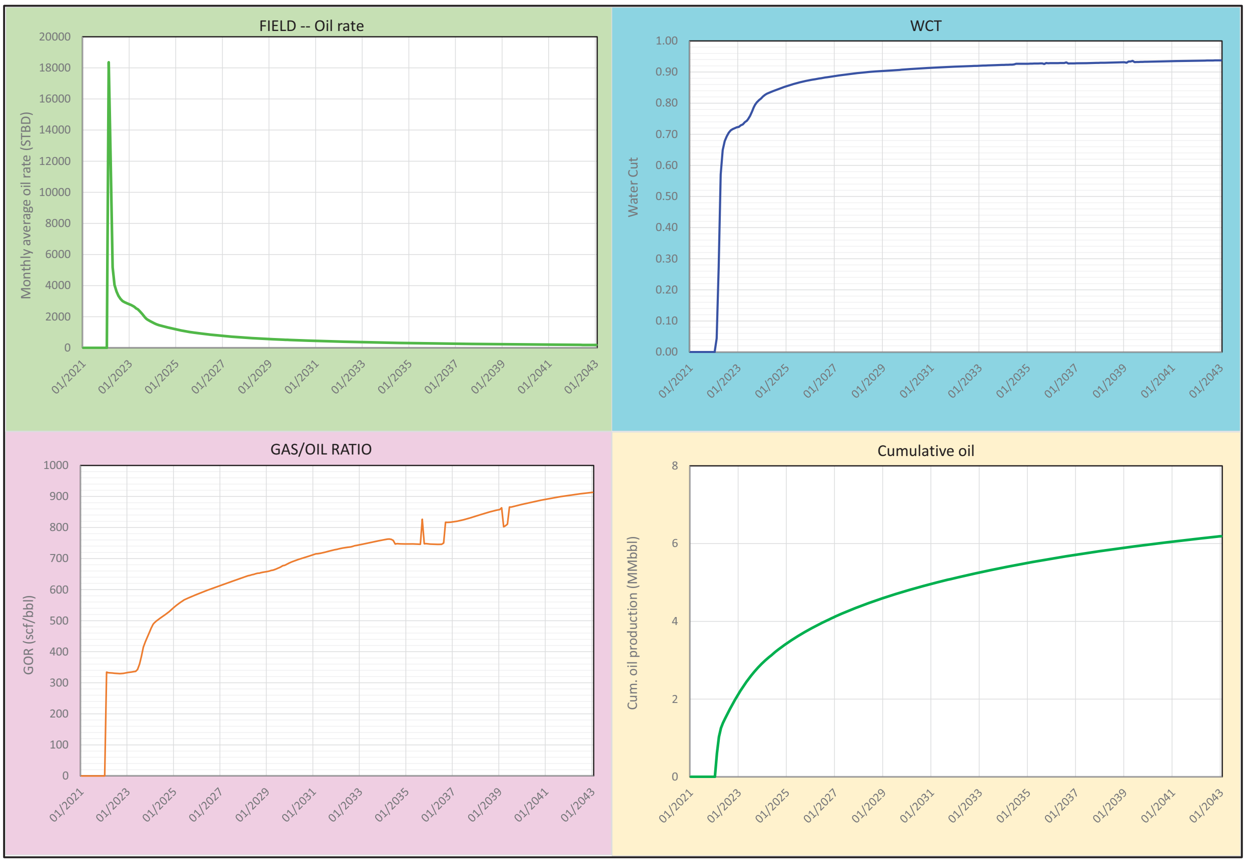


Figure 6-6 Predicted oil rate, WCT, GOR and Cum. oil

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).

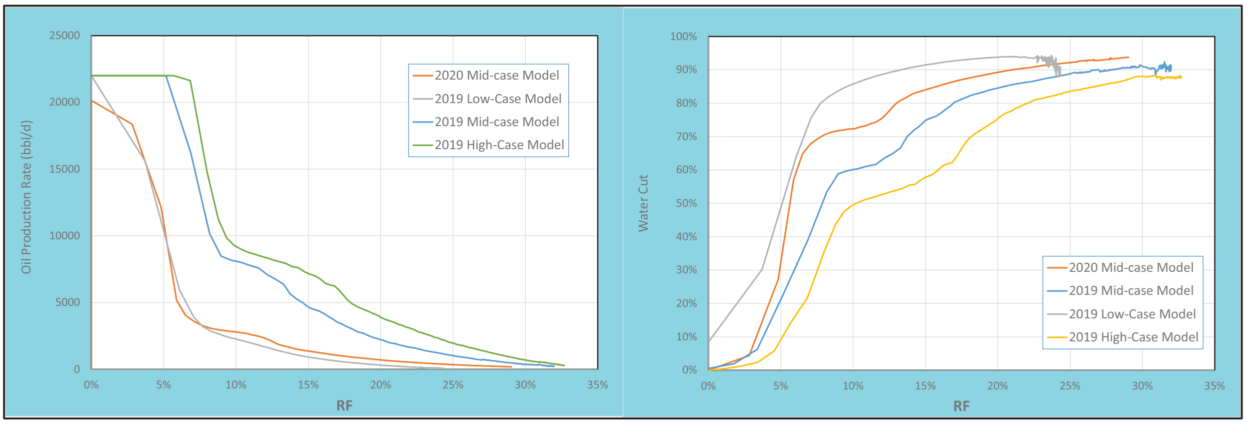
E100 Model	STOIIP (Phase 1 Areas)	Cum oil (@01/01/2041)			RF
		LP1	LP2	Total	
2020	21	6.2	N/A	6.2	29%
2019 Low	18	1.6	2.7	4.3	24%
2019 Mid	38	5.8	6.2	12.0	31%
2019 High	58	9.9	8.6	18.6	32%

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.

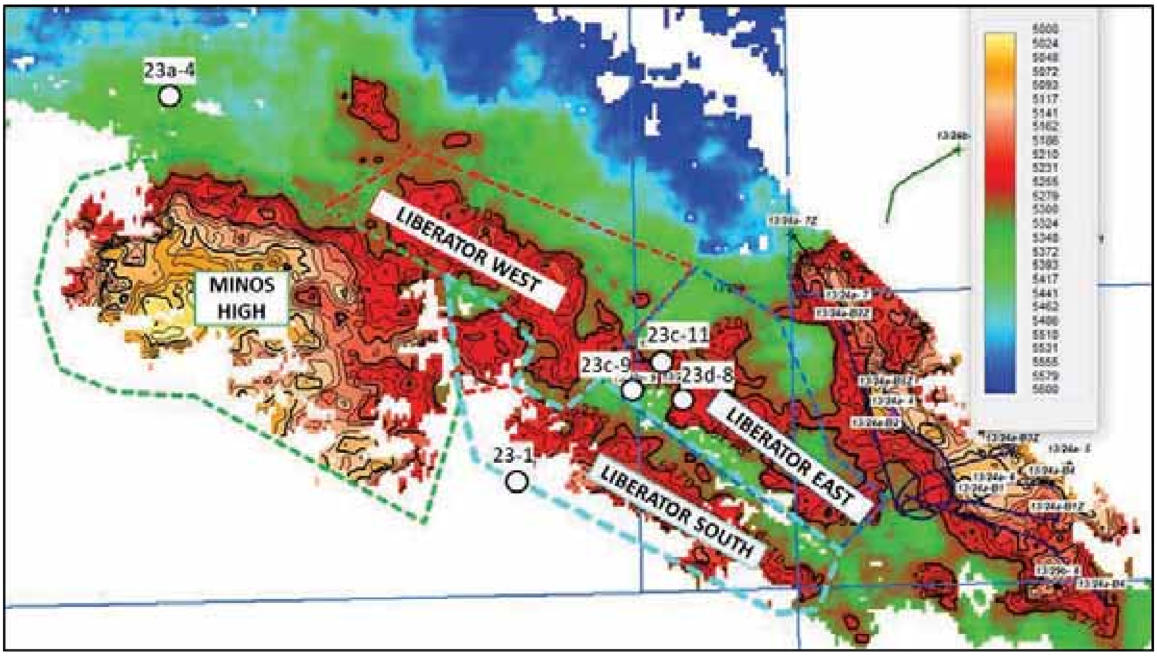


Figure 8-1 i3 current Liberator area designation

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 ±50ft departure from the reference case depth map at distances 2km away from well control.

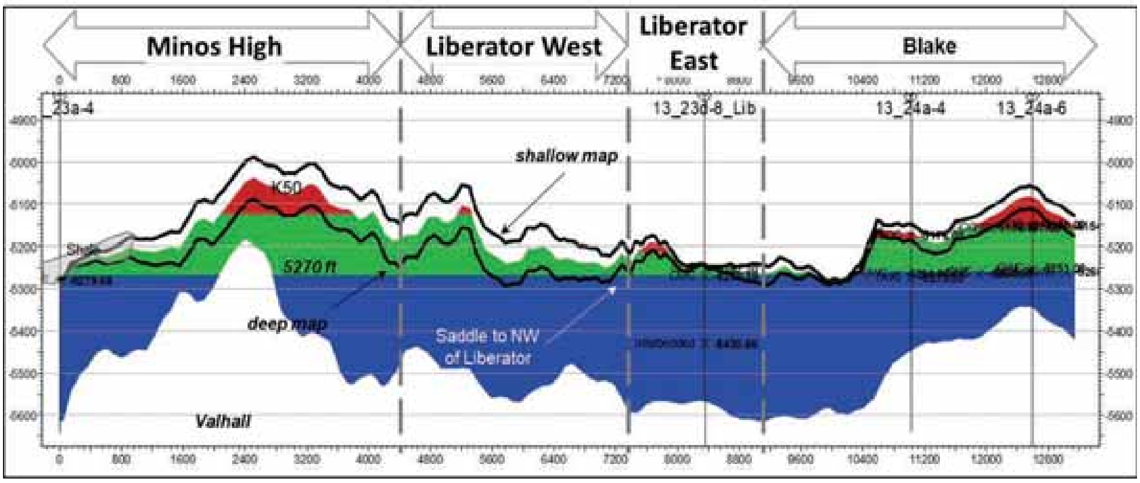


Figure 8-2 Illustration of top structure

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 ±50ft 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).

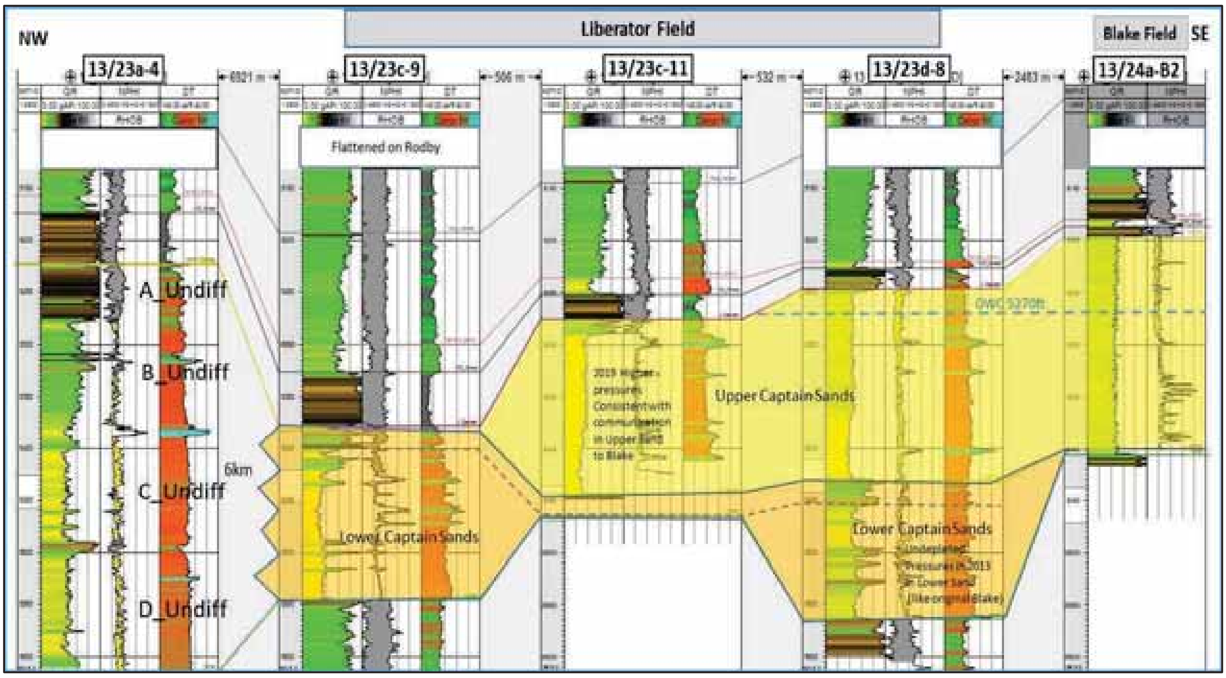


Figure 8-3 Well correlation panel

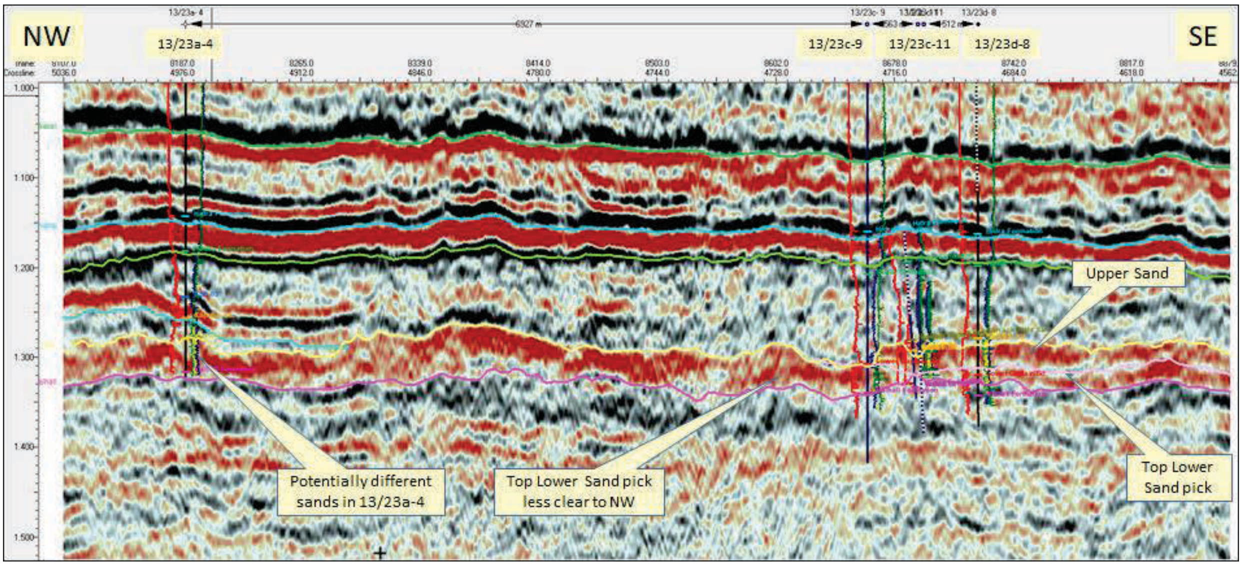


Figure 8-4 Seismic correlation

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.

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

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

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 Unclarified	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

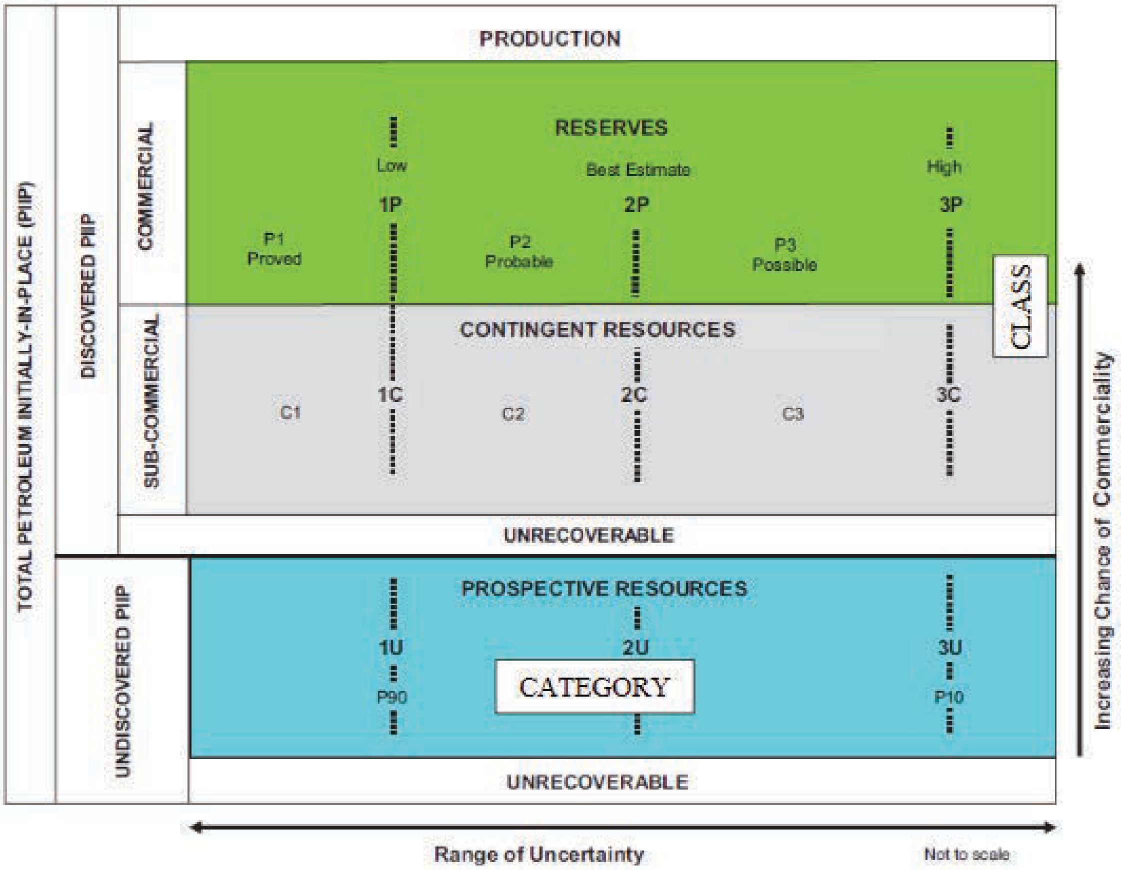


Figure A 1 SPE PRMS Petroleum Resources Classification Framework

North Sea, Serenity Discovery

Competent Person's Report 2020

For: i3 Energy plc & W H Ireland Limited

Jill Marriott, Liz Chellingsworth, Emma Saundry, Jackie Mullinor, Ed Stephens, Jerry Hadwin, Mike Wynne

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.

Status: Final

Date: [redacted] 2020

Revision: 03

Prepared by: Jill Marriott

J. Marriott

Project Manager — Jill Marriott

Approved by: Jerry Hadwin

Reviewer — Jerry Hadwin

Authorised for release by — Jill Prabucki

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 Serenity Discovery 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.

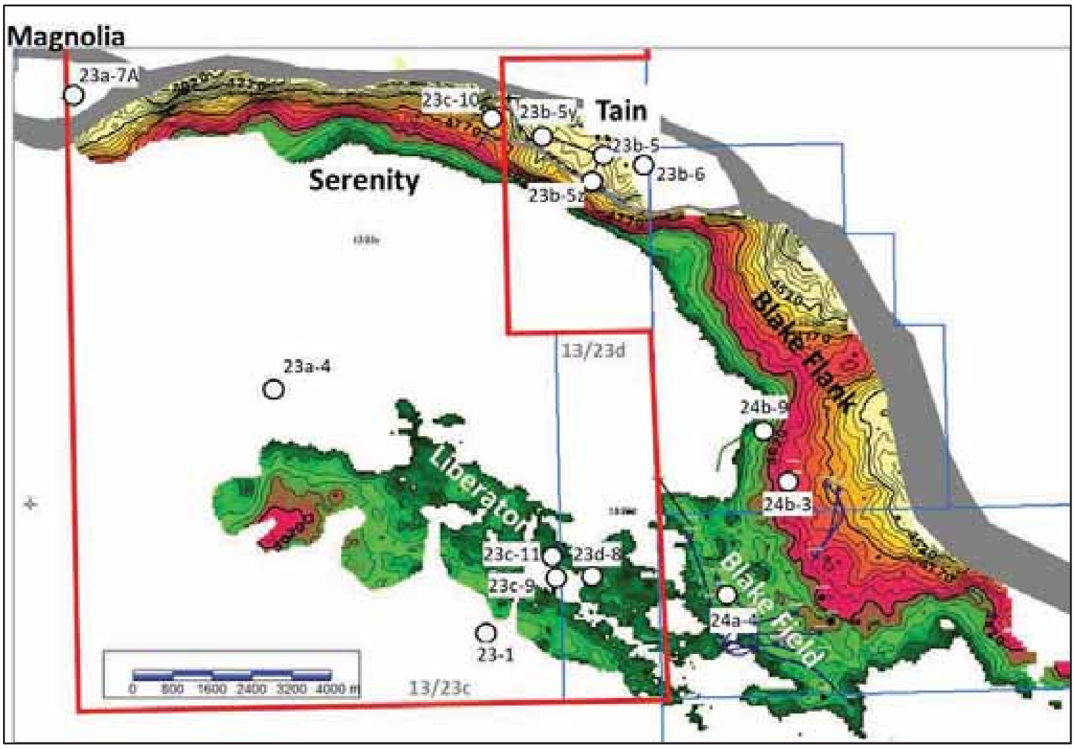
All volumetric calculations are based on independent mapping undertaken by TRACS using data provided to TRACS. The reservoir properties input to the volumetric calculations and the associated volume uncertainty ranges are based on TRACS experience over more than 20 years of performing evaluations, and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

Executive Summary

i3 Energy (i3) commissioned a Competent Person's Report (CPR) to assess the resource potential of the Serenity discovery, found by well 13/23c-10. The well is located 129 km north-east of Aberdeen, in the South Halibut Basin of the Moray Firth Province, within UKCS Block 13/23c, licence P.2358. i3 hold 100% interest in the licence block, which was awarded to i3 Energy in the 30th UK Offshore Licensing Round. The licence also contains an extension of the Liberator discovery in the south of the block. Liberator extends eastwards on to UKCS Block 13/23d, license P.1987, also operated by i3 Energy.

This evaluation builds upon a pre-drill evaluation of the Serenity discovery undertaken by TRACS. The work is now updated with well data from the Serenity discovery well (13/23c-10) drilled in October 2019. STOIIP and resource estimates in this report concern the Serenity discovery only, on block 13/23c.



Location map clipped at the 5270ft depth contour

The report has been prepared to be included in an appendix to the AIM admission document prepared and published in accordance 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").

Block	Licence	Asset	Operator	Interest	Status	Area (km^2)	Expiry
UKCS Block 13/23c	P.2358	Serenity	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.

Development planning is at a preliminary stage, and no economic value or development Risk Factor has been determined. Export could conceptually take advantage of existing infrastructure associated with the ongoing development of the adjacent Tain Field (operated by Repsol Sinopec, RSRUK) or, if sufficient volumes are firmed up by planned appraisal, through a stand-alone FPSO. Since no development or export option has been determined, associated gas has not been considered as sales volumes in this report.

At this stage, the calculated resources have been classified as "Contingent, Development Unclarified". Contingencies include the technical requirement for further appraisal, and non-technical, in the event of a lower in-place volume development, requiring an agreement with the Tain infrastructure owners.

The resultant, unrisked contingent resource volumes are shown below.

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)	
Serenity, Block 13/23c	1C	2.4	-	-	2.4	2.4	-	-	2.4	N/A
	2C	16.2	-	-	16.2	16.2	-	-	16.2	
	3C	115.2	-	-	115.2	115.2	-	-	115.2	

Serenity Resource Summary

Evaluation Summary

The Serenity discovery well penetrated the eastern part of the elongate west-east Serenity prospect and encountered a thin (11 ft) oil-bearing sand interpreted as Captain Sandstone. The Serenity discovery is adjacent to the Tain discovery (drilled in 2005) and the producing Blake field. Based on an evaluation of the available data, i3 Energy believe that Serenity could be a down-dip extension to the Tain oil discoveries and that both Tain and Serenity could share a common OWC with Blake and Liberator as deep as 5270ft. i3 consider the moderate to high seismic amplitudes observed at Top Rødby in Serenity as an indication of oil-filled sands. The trapping mechanism is stratigraphic with pinch-out of Captain sands to the north against the Halibut Horst. To the west, i3 consider that the reservoir sand thickens significantly; on-depositional trend with the 9-km distant Magnolia well (13/23a-7A), which encountered Captain sands approximately 100 ft thick. In order to trap the structure, i3 invoke a stratigraphic closure (channel fairway edge) in this western region since there is no independent structural closure.

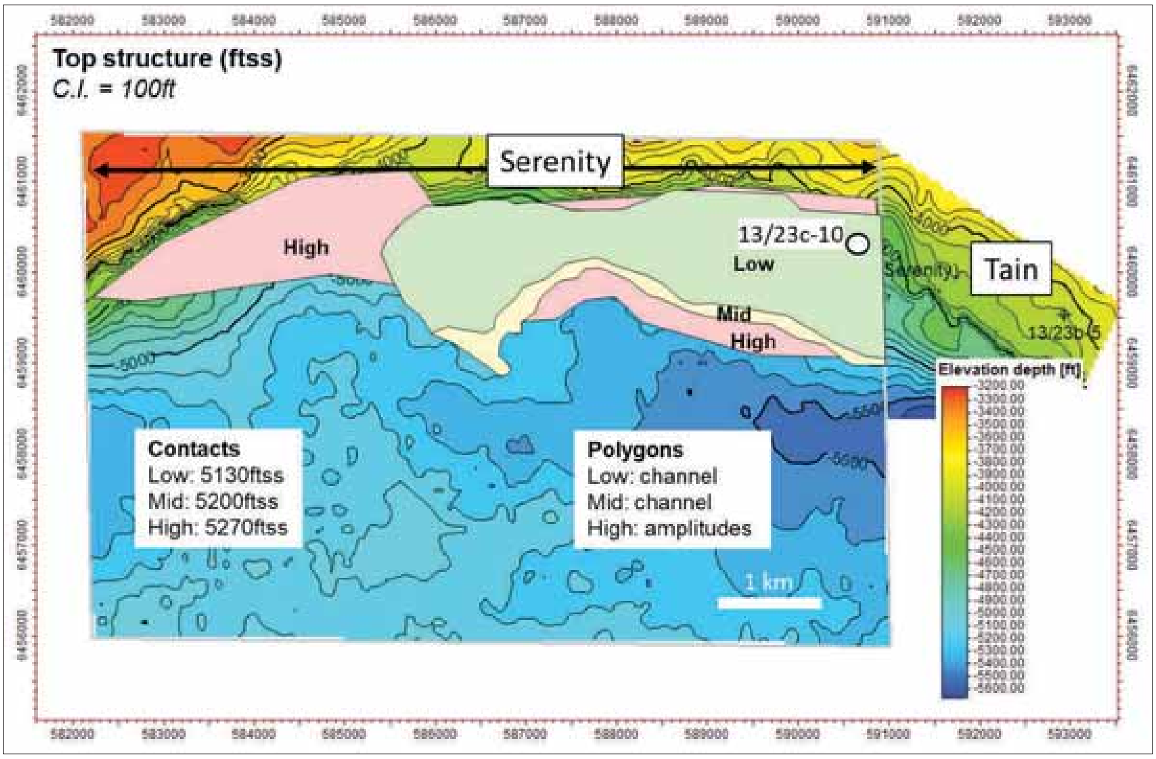
This report deals with 13/23c-10 well results, and what key uncertainties remain post-drill. Based on an integrated assessment, the following uncertainties are considered to have the most significant impact on in-place volumetric estimates:

- Net sand thickness (gross thickness and net-to-gross (N/G)
- Lateral extent and continuity of oil-bearing sand
- Depth of the oil-water-contact (OWC)

A geophysical investigation of well ties, tuning effects and amplitude analysis was undertaken to establish whether an amplitude response seen at Top Rødby is indicative of an oil-filled Captain Sandstone. Based on modelling, TRACS conclude that amplitudes cannot be reliably used as an unequivocal indicator of either fluid fill or net sand thickness. The seismic response is interpreted to be compromised by a 'tuning' effect, which is caused by interference of reflectors and is consistent with stratigraphic thinning at the northern edge of the basin. In the western part of the structure, where stratigraphic closure is required, TRACS consider the possibility of an alternative channel fairway edge with a more easterly position compared to i3. This is based on a change in observed seismic character in the western part of Serenity.

As a result, TRACS' Mid and Low Case STOIIP assumes more limited lateral extent and continuity to the west (channel polygon) and uses net sand thickness assumptions that are guided more by the Serenity well result and seismic character than the Magnolia well data nearly 9km away from the Serenity well. Nevertheless, TRACS consider that other interpretations are credible and adopt the full i3 amplitude polygon and more optimistic net thickness assumptions for high case STOIIP inputs.

TRACS agree that an OWC as deep as 5270 ft tvdss is feasible but that a shallower OWC at 5130 ft tvdss is also possible given the pressure data available and associated uncertainty. TRACS consider a low to high case OWC range from 5130-5270 ft with a mid-point at 5200 ft.



Top structure map with volumetric cases illustrated

Three deterministic STOIIP cases representative of Low-Mid-High cases, were established combining a range of values for those parameters with the greatest impact. The resulting in-place volumes are summarised below.

Case	***OWC (ft tvdss)***	***Polygon***	***GRV (10^6 m3)***	***N/G (fr)***	***Net sand (ft)***	***PHI (fr)***	***So (fr)***	***FVF (v/v)***	***STOIIP (MMstb)***
Low	5130	Serenity channel	100	0.18	11	0.28	0.6	1.17	16
Mid	**5200**	**Serenity channel**	**129**	**0.25**	**16**	**0.32**	**0.75**	**1.15**	**42**
High	5270	Rødby amplitude	207	0.72	50	0.34	0.85	1.13	240

Summary of TRACS STOIIP inputs and results

Case	***TRACS STOIIP (MMstb)***	***i3 Energy STOIIP (MMstb)***	***Case***
Low	16	109	P90
Mid	**42**	**190**	**P50**
High	240	273	P10

Comparison of STOIIP results

The TRACS STOIIP estimates are lower than the i3 Energy volumes and this can be attributed to:

- smaller net sand thickness used by TRACS – driven by seismic character and observations in the Serenity and Tain wells
- use of more limited sand polygon in the TRACS Low and Mid case – driven by seismic character
- use of shallower contact in TRACS' Low and Mid case; all 3 cases generated by i3 Energy use an OWC of -5270 ft tvdss

Subject to funding and potential farm-out activities, i3 Energy anticipate further 2020 appraisal drilling on the Serenity and Liberator accumulations. No firm development plans exist at present, though it is possible that that Serenity could be produced as a phased development across existing infrastructure, initially as a single well tie-back to the Tain development, which has first oil targeted for Q3 2022 via the Bleo Holm FPSO. Should further appraisal of Serenity prove significant additional volumes to the west, it is likely that the production volumes would justify a standalone FPSO development.

Given the uncertainty associated with volumes in place, only a high level assessment of recovery factors was undertaken taking into account information available from Blake and Liberator fields and the results of an i3 preliminary reservoir simulation. The recovery factor range reflects a range of potential recovery mechanisms and number of wells. The Low case is based on the low STOIIP case, assumes a single development well and poor connectivity to aquifer pressure support; hence the single well produces via depletion and solution-gas-drive processes with a recovery factor of 15%. In the Mid case a second phase of development including waterflood is invoked, with 2 further producers and 2 injectors. A moderate areal sweep efficiency of 70% is assumed giving total recovery factor of 39%. In the High case the water flood development includes a further 3 producers and 3 injectors. A higher areal sweep efficiency of 80% is assumed giving total recovery factor of 48%.

Case	STOIIP (MMstb)	Recovery Factor	Recoverable oil (MMstb)
Low	16	15%	2.4
Mid	42	39%	16.2
High	240	48%	115.2

STOIIP and Recovery Factor range

Contents

Figures

Tables

1 Introduction

i3 Energy (i3) have commissioned a Competent Person's Report (CPR) to assess the resource potential of the Serenity discovery in accordance with resource definitions presented in the SPE's 2018 Petroleum Resources Management System ("SPE-PRMS", Appendix A – Summary of 2018 SPE Petroleum Resource Management System Classification). The report has been prepared to be included in an appendix to the AIM admission document prepared and published in accordance 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.

This CPR builds upon a pre-drill evaluation of the Serenity Prospect, prior to discovery, undertaken by TRACS. This work is now updated with well data from the Serenity discovery well (13/23c-10) drilled in October 2019.

1.1 Overview

The Serenity discovery well, 13/23c-10, is located 129 km northeast of Aberdeen in the South Halibut Basin of the Moray Firth Province (Figure 1-1). The Serenity well is situated down-dip and approximately 1.5 km west of the 2005 Tain discovery, which is itself located northwest of the producing Blake field (hosted by the Bleo Holm FPSO).

The well penetrates the eastern part of the elongate west-east Serenity structure in Lower Cretaceous Captain Sands. Based on an evaluation of the available data, i3 Energy believe that Serenity could be a down-dip extension to the Tain oil discoveries and that both Tain and Serenity could share a common oil-water-contact (OWC) with Blake and Liberator as deep as 5270 ft tvdss. The trapping mechanism is stratigraphic with likely pinch-out of Captain sands to the north against the Halibut Horst. To the west, i3 consider that the reservoir sand thickens considerably; on-depositional trend with the Magnolia well (13/23a-7A), which encountered Captain sands more than 100 ft thick. In order to trap the structure, i3 also invoke a stratigraphic closure (channel fairway edge) in this western region since there is no structural closure.

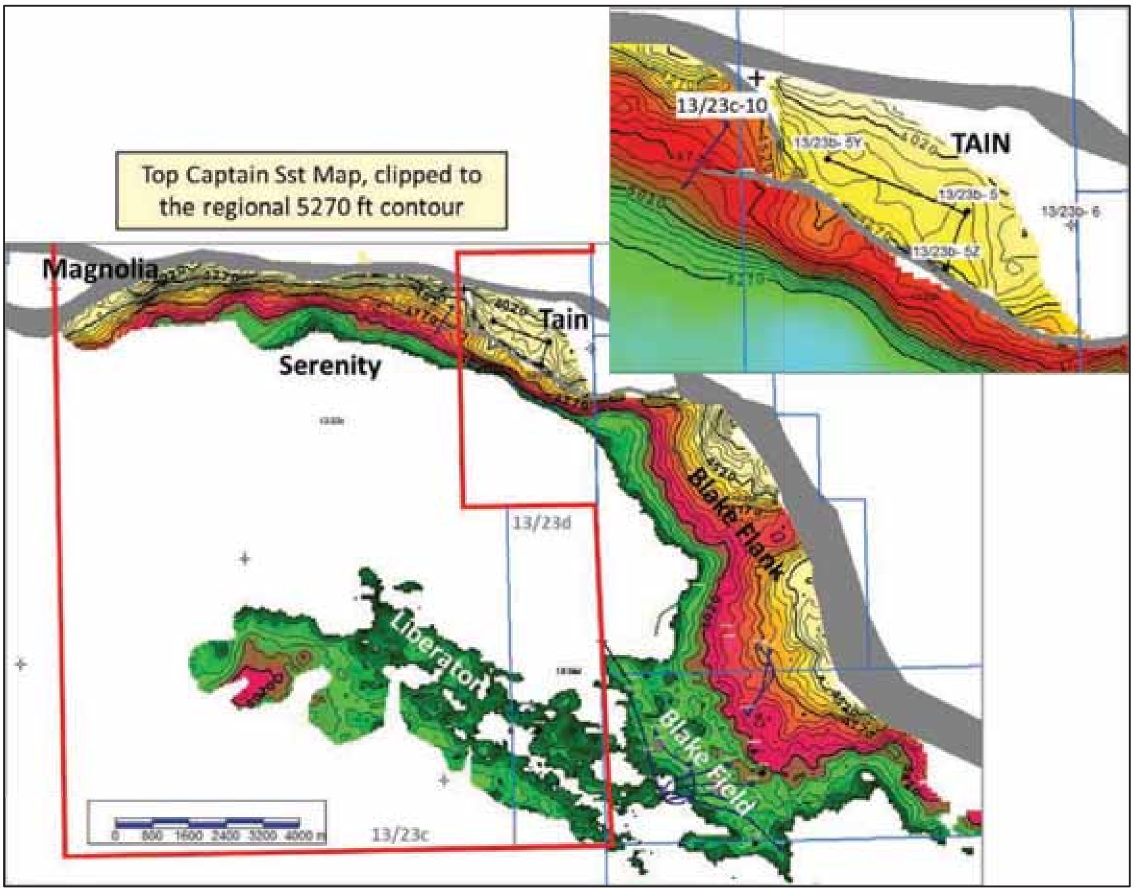


Figure 1-1 Serenity well location map

The Serenity exploration well was drilled in October 2019 at the eastern end of the prospect in a relatively crestal position, encountering a thin (11 ft), but high net-to-gross, oil-bearing sandstone with excellent reservoir quality in the upper part of the Captain Sands, assigned informally by i3 to the K50 sequence stratigraphy interval. Figure 1-2 summarises the key findings. The oil-bearing sand was encountered at a depth of 4729 ft tvdss with an oil-down-to (ODT) at 4747 ft tvdss below a silt-dominated interval containing an oil-bearing, but very thin, sandstone stringer. i3 assign the oil-bearing sand to a K50.3 sub-unit, with the underlying water-bearing sandstones assigned to K50.2.

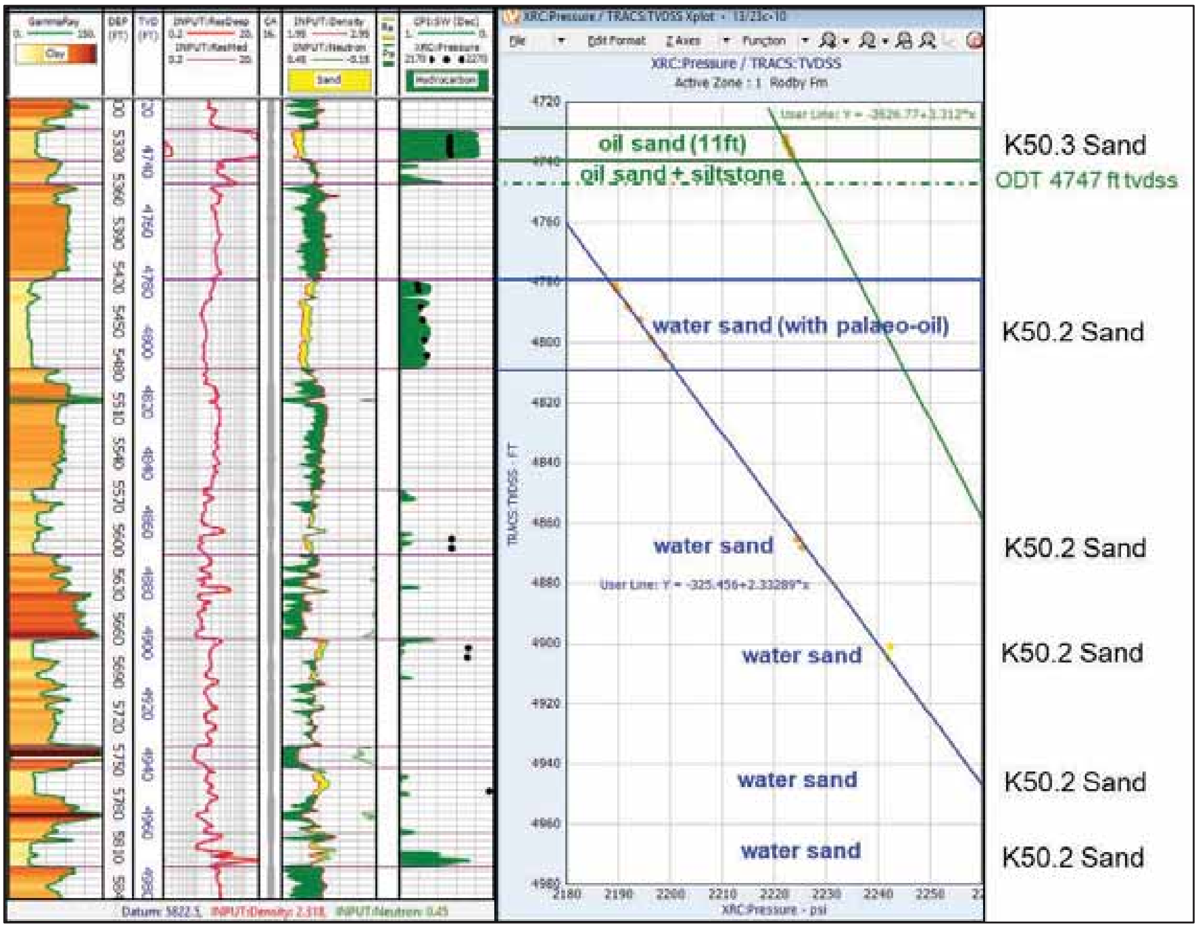


Figure 1-2 Overview of 13/23c-10 (Serenity) well results

MDT pressure data confirms an oil gradient in the K50.3 unit and a common water gradient for all the K50.2 sands. The uppermost K50.2 sand contains residual oil and suggests the existence a palaeo-OWC deeper than the current contact. Palaeo-OWCs are a well-documented phenomenon in the Captain sands, consistent with eastern tilting of the basin during the early Tertiary which resulted in re-migration of hydrocarbons generally in a westerly direction. Basin modelling by i3 Energy is consistent with published literature in this respect.

This report deals with Serenity discovery and addresses the in place and resource potential on 13/23c block only, together with classification and commercial risking of resources according to SPE-PMRS guidelines. An economic evaluation has not been conducted because of the remaining uncertainty in volumes, and lack of maturity and clarity in defining a development plan. On this basis, the potentially recoverable volumes are defined as Contingent Resource – Development Unclarified.

1.2 Licence history, burdens and current status

i3 Energy hold a 100% interest in the P.2358 licence, Block 13/23c, which was awarded in 30th UK Offshore Licensing Round in May 2018, with one firm well as a drilling commitment. In autumn 2019, i3 Energy embarked on a 3-well drilling campaign that included the Serenity Prospect (13/23c-10) and two further wells on the Liberator structure (13/23b-9 & -11), thus fulfilling the terms of the licence commitment.

The licence will be operated under the UK tax and royalty system. At present there is no royalty charge on production for new fields in the North Sea. Taxation (Corporation Tax and Supplementary Charge) amounts to 40% of profits. The volumes presented in this report are gross working interest resources, however since there are no royalties or working interest partners, all volumes are attributable to i3 Energy.

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 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, though it is possible that that Serenity could be produced as a phased development across existing infrastructure in the initial phase. It is possible that Serenity could be developed initially as a single-well tie-back into the Tain development. Public statements from the partner in the Tain field indicate the Tain project will be moving towards FDP mid-2020 based on a 2 well tie-back, via dedicated pipeline (19 km) to the Bleo Holm FPSO. The Tain operator, Repsol Sinopec Resources UK (RSRUK), issued an environmental statement for the proposed Tain development in March 2020 and first oil is targeted for Q3 2022.

Should further appraisal of Serenity prove significant additional volumes to the west, it is likely that the production volumes would justify a standalone FPSO development.

1.4 Data available

The assessment was carried out using well data from the Serenity discovery (13/23c-10) but also includes material provided for a pre-drill evaluation of the Serenity Prospect together with previous work undertaken on the Liberator accumulation and MDT pressure data from the latest Liberator well (13/23b-11). Relevant data from the previous evaluations include:

- Seismic data and interpretation extending over Serenity prospect together with Liberator, Tain and Blake fields.
- Well data for various exploration wells, including the Tain area.
- A regional dynamic model extending over the Serenity-Tain-Blake-Liberator area.

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 SPE-PRMS. i3 were forthcoming with all requests for further information and clarifications.

1.5 Key uncertainties

Key uncertainties identified for the discovery are listed below and are reflected in the range of input parameter values selected for volumetric estimation. Though the Serenity well was a success, the oil-bearing sand is thin at the well location and the well was drilled in an-up-dip location such that the oil column is represented by a shallow ODT. Significant subsurface uncertainty remains and relies on interpretation and extrapolation of key parameters away from the wellbore.

Subsurface Uncertainties:

- Net sand thickness; gross thickness and net-to-gross (N/G)
- Fluid distribution – Depth of oil-water-contact (OWC)
- Lateral extent and continuity of reservoir sands
- Recovery factor associated with recovery mechanism

Input assumptions for in place and recoverable resources and assessment of uncertainties are documented in further detail in subsequent chapters.

2 Geology Overview

2.1 Wells considered

The Serenity discovery well 13/23c-10 lies in block 13/23c immediately to the west and down-dip of the Tain discovery and 3 km west of the northern part of the Blake Field. A number of exploration and development wells have been considered for their regional stratigraphic context but also as input into understanding of the dynamic regional aquifer pressure history. The location of key offset wells is shown in Figure 2-1.

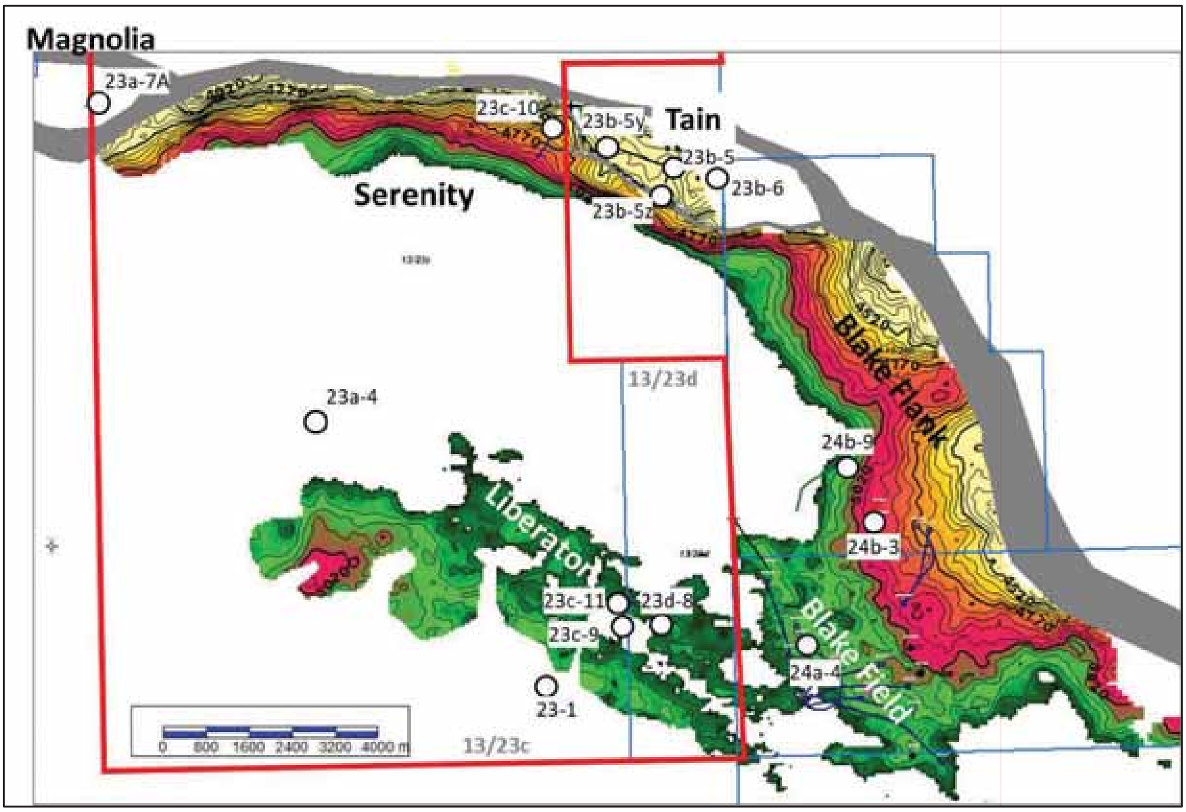


Figure 2-1 Well location map

2.2 Well correlation

A correlation panel across the Serenity discovery area is shown in Figure 2-2. This runs from the 13/23a-7A well in the north (which targeted the Magnolia prospect, dry hole) eastwards across the Serenity well 13/23c-10, Tain wells 13/23b-5y & -5z and then further south to the Blake Field discovery well, 13/24a-4.

The top reservoir sand is clearly observed on logs. The top Captain Sandstone sits approximately 45 feet below the Top Rødby Formation in the Magnolia-Serenity-Tain area but lies at >100 feet below Top Rødby in the Blake-Liberator region. The top sand is generally considered to coincide with the top of the K50 sequence, which spans the Late Aptian to Early Albian age.

From these wells, the Captain Sandstone package in the Serenity-Tain area can be seen to be lithologically heterogeneous with a predominantly interbedded sandstone and shale character. i3 Energy adopt an informal 3-fold subdivision of the K50 Captain sands into K50.1, K50.2, K50.3 based on regional mapping of discrete seismic packages integrated with well data, and the relative sand body positioning with respect to Top Rødby (Figure 2-3). It is not known how much chronostratigraphic data has been used to draw this conclusion as post-well biostratigraphy studies were still ongoing at the time of the evaluation. It is also unclear to what extent biostratigraphy is capable of unambiguously resolving K50 subdivisions. Nevertheless, i3 interpret the Serenity oil sand as belonging to the uppermost K50.3 unit which they correlate with the uppermost thin sands in the Tain area to the east. Some 9 km to the west, the Magnolia well 13/23a-7A comprises an uppermost sand that is thicker and better quality, and interpreted by i3 to represent a thickening of the K50.3 unit to the west.

The Captain Sandstone facies is different in the Blake-Liberator area which has a much better developed 'massive channel' character assigned to the slightly older K50.1 unit, though the Blake Flank area Captain Sands (K50.2) are notably thinner and more heterogeneous.

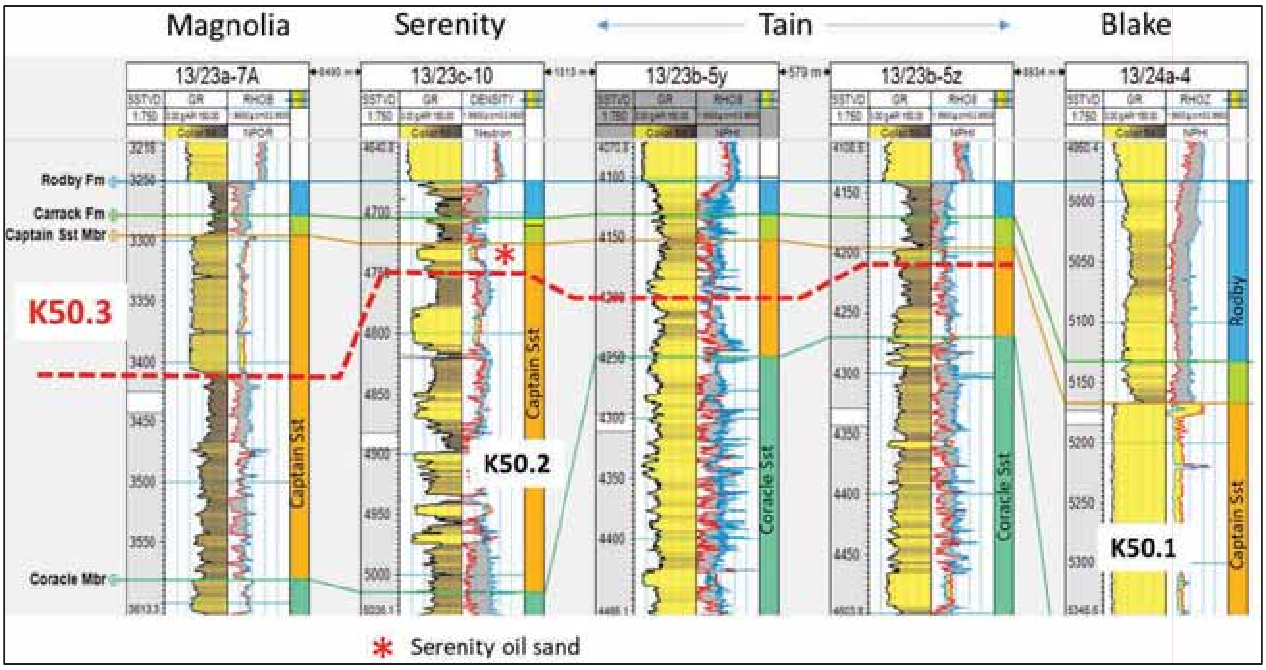


Figure 2-2 Correlation panel, superimposed with i3 interpretation and correlation of the K50.3 sub-unit

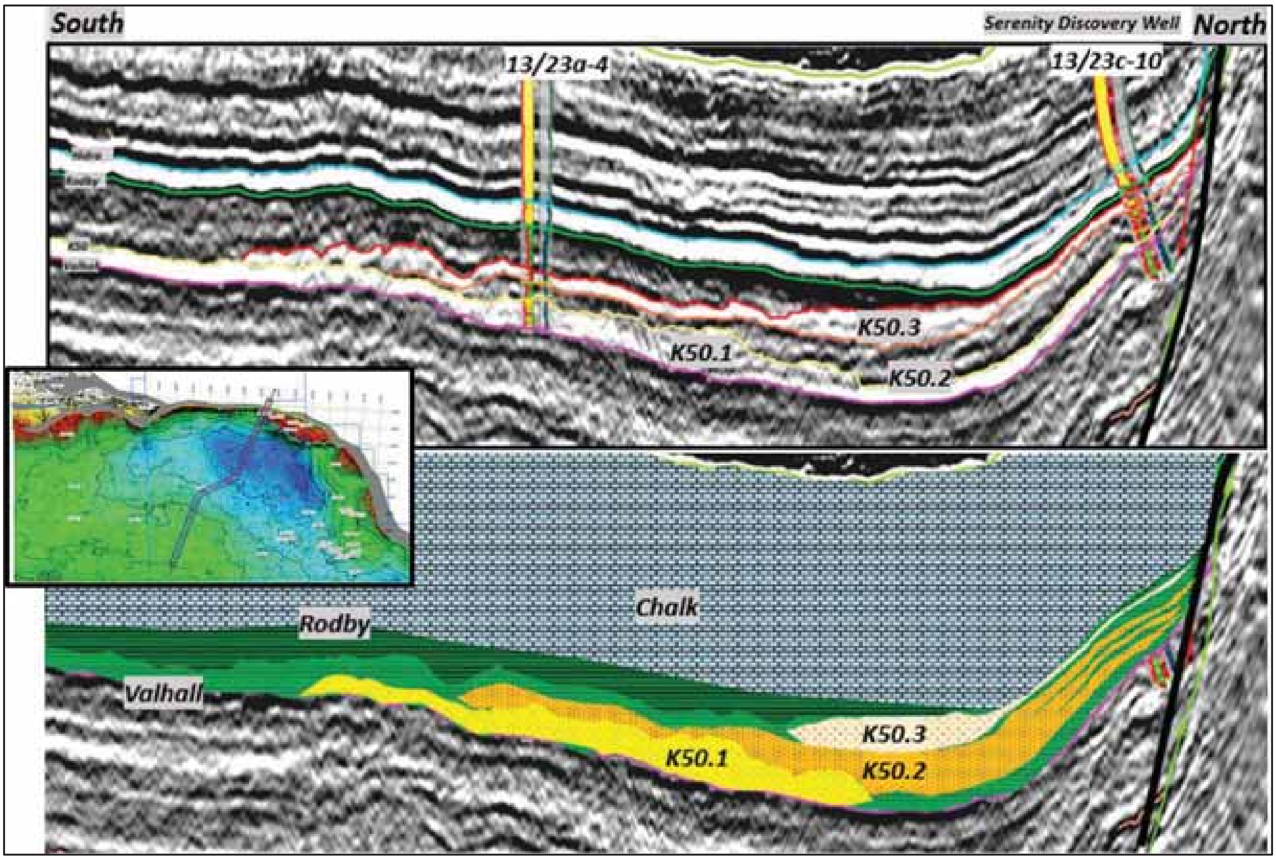


Figure 2-3 i3 regional seismic interpretation, SSW-NNE line

2.3 Reservoir geology

Regional Geological Setting

Early Cretaceous Captain Sands of Aptian to Albian age were laid down in the Inner Moray Firth in a deep marine environment, deposited against a background of hemipelagic shales and marls. The established model comprises a NW-SE oriented axial system of submarine channels located south of the Halibut Horst and extending regionally from the Captain field to the NW through to Goldeneye and beyond in the SE, informally referred to as the Kopervik fairway (Figure 2-4). These channels were capable of distributing thick and amalgamated mass flow sandstones up to hundreds of feet thick into the main Blake field and Liberator areas.

North of the main fairway, facies heterogeneity increases, as is clearly illustrated in the correlation panel in Figure 2-2 for the Serenity-Tain areas. Thinner and potentially more confined turbidite channel deposits become interbedded with shales. The Blake Flank area is notably more heterogeneous than the main Blake field (or "Channel" area). The Captain fairway is known to thin and eventually pinch-out to the north-west in the Tain area (the Tain-6 well contains no sand at the Captain interval; see inset Figure 1-1 for detail of Tain well locations).

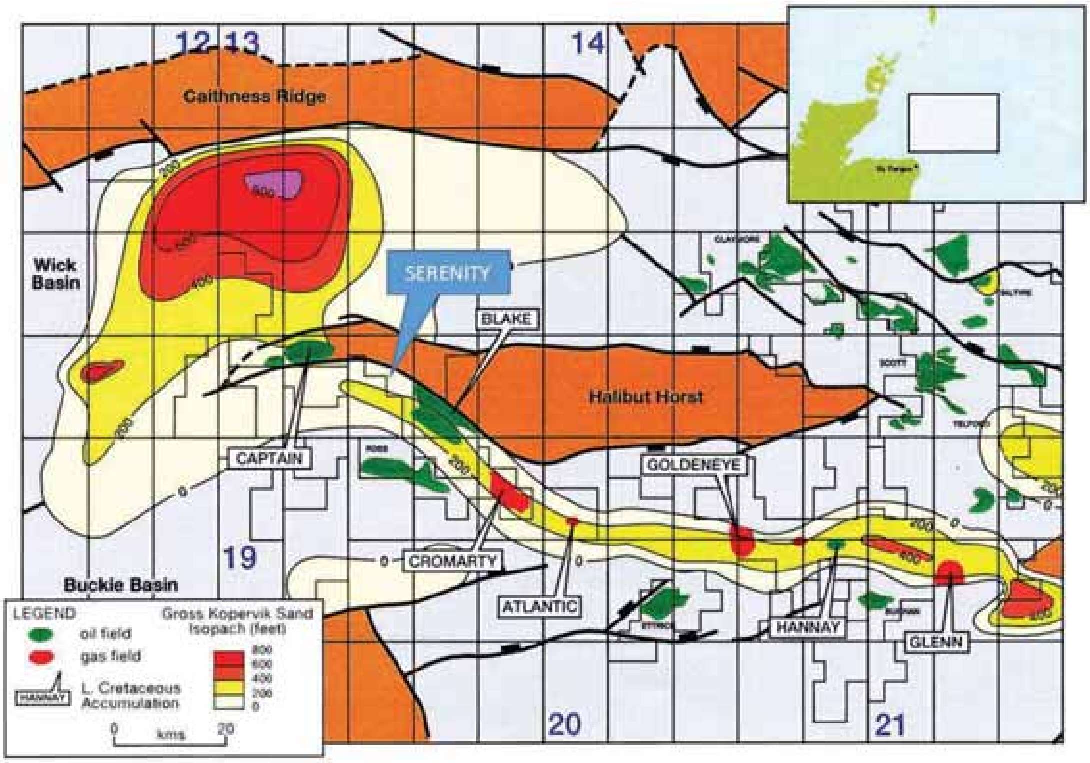


Figure 2-4 The Kopervik sand fairway (from Law *et al* 2000, Petroleum Geoscience vol 6)

Captain Sand-body Architecture

As mentioned, i3 Energy adopt an informal 3-fold subdivision of the K50 Captain sands into K50.1, K50.2, K50.3 based on regional mapping of discrete seismic packages combined with sand body positioning with respect to Top Rødby (Figure 2-5). They interpret the Blake-Liberator sands as older K50.1 deposits characterised by blocky high density turbidite packages, with the Blake flank area assigned to areally offset, but locally overlapping K50.2 sands/shales. The uppermost (youngest) sands within the Serenity-Tain-Magnolia wells area are assigned to the K50.3 unit. According to i3, the thin oil-bearing sand in Serenity discovery well is assigned to K50.3 ("Upper Captain"), whilst the underlying water-bearing sands are interpreted as K50.2.

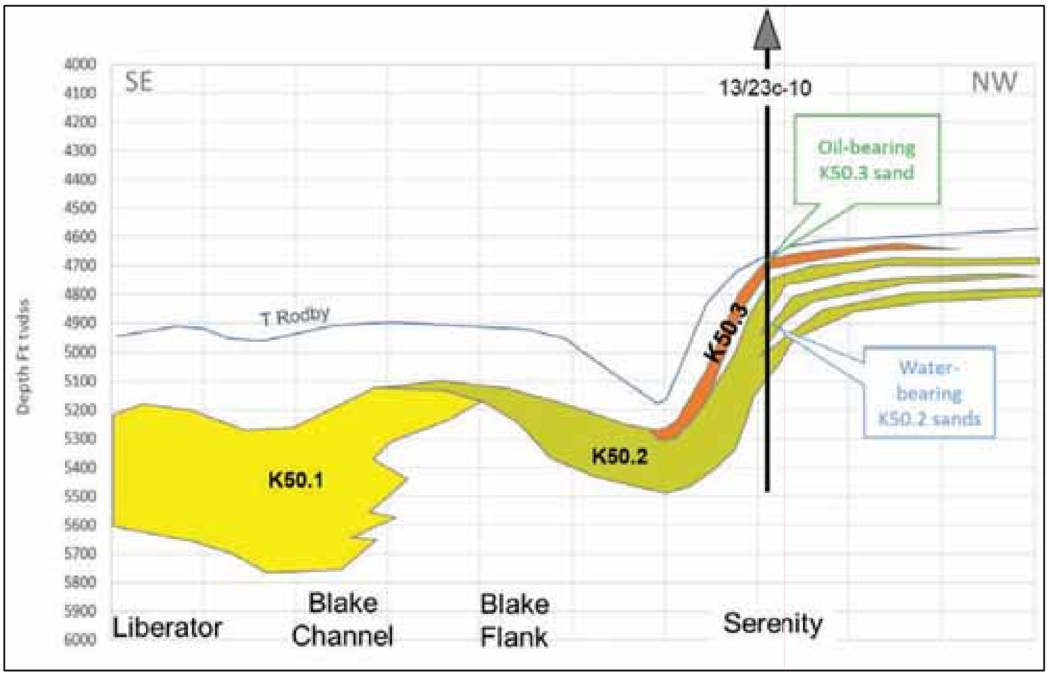


Figure 2-5 Schematic view of i3's Captain sand subdivision into K50.1, K50.2 & K50.3

The sand body architecture model of i3 integrates well and seismic data and is consistent with the regional connectivity story in the Kopervik fairway. The presence of a regionally-connected aquifer along this fairway is well documented in the published literature suggesting at a regional scale, most of the Captain sands communicate via a common regional aquifer. At a more local field level, heterogeneity may nevertheless result in poor communication between sub-units on a production timescale.

TRACS considers the i3 approach to be well-considered and integrated but believe a number of factors reduce the confidence in sandbody mapping and continuity:

- The inherently weak reflectivity contrast between sandstones and shales means that resolving individual channel bodies is challenging seismically.
- Well control is sparse, lithostratigraphic correlation on its own is challenging and biostratigraphic resolution is likely to be limited at the scale of individual Captain sub-units. Furthermore, regional biostratigraphic schemes for this basin tend to be proprietary and not widely published in consistent form.

Though the i3 definition of a contiguous K50.3 oil sand in Serenity and it's extrapolation to Magnolia and Tain may be valid, TRACS consider that the data limitations mean other interpretations are possible.

Regional Dynamic Reservoir Pressure

The well-connected and dynamic nature of the regional Captain Sandstone aquifer is well documented in published literature. For example, as part of the Peterhead CCS project (published 2015), Shell model the approximate regional Captain sand aquifer as extending from Blake field in the west, through Cromarty, Atlantic, Goldeneye and Hannay in the east (Ref 1). According to this study, the resultant aquifer dimensions could be 5-10 km wide and up to 100 km long with average porosities of 25-20% and Darcy permeability. The Captain oil field was the first to come on production in 1997, but Shell exclude this from the aquifer model due to its elevated footwall position on the Halibut Horst fault. Blake came online in 2001, with Hannay following in 2002, Goldeneye in 2004 and Atlantic/Cromarty in 2006. Of the fields along the Captain trend only Blake and Captain had water injection support. At the time of writing, Blake is the only field still online and injects more reservoir barrels than it produces.

i3 Energy have built, and made available to TRACS, their own regional pressure model in order to understand the aquifer pressure evolution over time due to production depletion and then subsequent shut-in of fields along the trend. They believe they can match the regional pressure story with MDT pressure data recorded historically (Tain) and more recently in the Serenity (13/23c-10) and Liberator wells (13/23b-11). The latter wells, drilled between October and December 2019, record oil and water pressures around 50 psi higher than pre-production data in the Captain fairway, which is consistent with Blake injection and recent pressuring-up of the regional aquifer.

Figure 2-6 summarises some of the key MDT pressure data in the Serenity-Tain-Blake-Liberator area and illustrates the highly dynamic nature of the aquifer due to nearby production. The data shown is mostly from Captain sands, though some Coracle (geologically-older) sands were sampled in the Tain wells. Blake well 13/24a-4 was drilled in 1998, around the time of first production from the Captain field and before production start-up in the Goldeneye, Atlantic and Cromarty fields. It therefore represents virgin pressure conditions in the Captain fairway. When pressure data was collected in the Liberator 13/23d-8 well in 2013, the aquifer pressure was depleted by around 70 psi, though by 2013 the Goldeneye field had been offline for 3 years so it's possible that there was already some level of pressure recovery by this point. Moving forward to 2019, the aquifer is inferred to be over-pressured by about 50 psi with respect to virgin conditions, due to net-positive volume replacement caused by Blake injection and cessation of production from other nearby fields. Pressure data from water points in Serenity and the Liberator 13/23c-11 well, drilled back-to-back in 2019, appear to line-up on a common aquifer gradient.

i3 Energy extrapolate the oil and water points in Serenity to derive an intercept at 5270 ft tvdss, consistent with the Blake field free water level and supporting their concept of common regional OWC between Blake, Serenity and Tain. i3 quite reasonably interpret the Tain pressure data to be connected to the dynamic regional aquifer. They go on to infer that in 2005 the Tain oil points intersected the regional contact at 5270 ft, since at that time the regional aquifer pressure would have been depleted and lying between the 1998 Blake data and the 2013 Liberator -8 well trend. TRACS consider this scenario credible as a high case but, due to the uncertainty associated with the pressure data, believe a wider range of OWCs is possible. In short, the OWC position is uncertain due to the following:

- Uncertainty with respect to the oil and water gradients applied, and their resulting intercept. For Serenity, different gradients result in a range in OWC of 5130-5270ft; all gradients used honour the available pressure and PVT data.
- Fundamentally, this is a dynamic pressure system. Estimating OWCs from pressure intercepts assumes the oil and water legs are in equilibrium at any one time, which may not be the case.

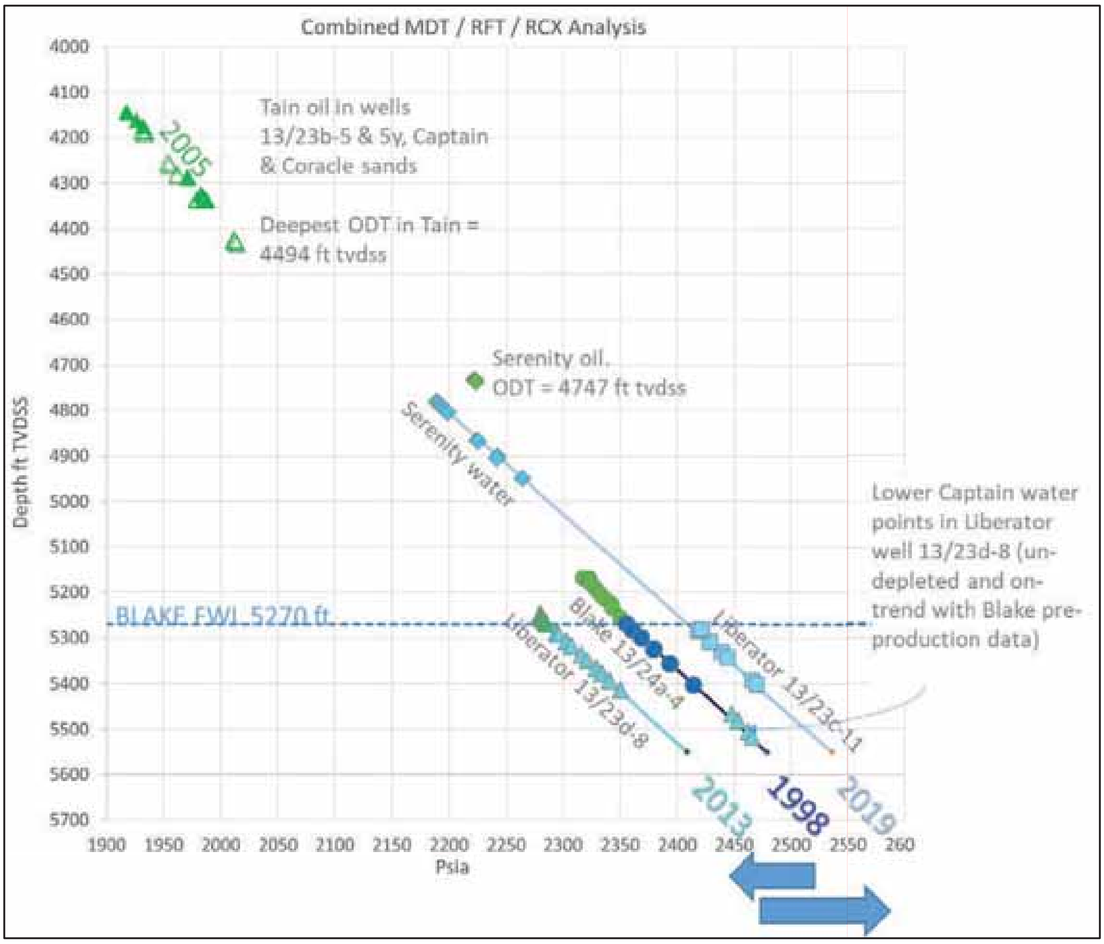


Figure 2-6 Regional pressure data and dynamic aquifer

Further detail on the range in oil and water intercept for Serenity pressure data is given in Section 3.3. The impact on STOIIP of a wider OWC range is addressed in Section 5.

Trapping Mechanism

The Serenity trap appears to be largely if not entirely stratigraphically constrained, with closure to the north defined either by pinch-out (Tain -6 well) or fault closure against the Halibut Horst.

The trap geometry is stratigraphic to the west since there is no structural closure. To the east there is potential for communication through to the Tain licence area, though for the purposes of this evaluation the interpretation does not extend in detail into this area.

For the High case OWC scenario, there is potential for a larger stratigraphic trap with communication and a shared common OWC with the Blake field.

3 Petrophysical Evaluation

The 2019 study from TRACS was based on the wells pre-13/23c-10. The petrophysical input for this audit is to summarise the properties at 13/23c-10 and any regional updates based on the findings at this well. The zone of interest consists of the Captain sands.

3.1 Data availability and quality

The client supplied an Interactive Petrophysics (IP) database which included the Tain and Magnolia wells as well as the new Serenity well (Table 3-1 Wells supplied in the IP project from i3

The database included measured logs, CPI results, formation tops, deviation surveys, pressure data and all interpretation inputs.

Field	Well
Magnolia	13/23a-7A
Tain	13/23b-5
Tain	13/23b-5Z
Tain	13/23b-5Y
Serenity	13/23c-10

Table 3-1 Wells supplied in the IP project from i3

3.2 Petrophysical interpretation

In providing the complete interpretation database the client has made the interpretation inputs completely transparent.

3.2.1 Clay Volume (V_{cl})

V_{cl} has been calculated using both the GR input and the Neutron/Density crossplot methods in all wells. Generally a minimum V_{cl} from the combined outputs has been taken as input going forward. Only V_{cl} from the Neutron/Density has been used in 13/23b-5.

3.2.2 Porosity

Porosity has been calculated using the V_{cl} input and the Neutron/Density porosity calculation. The relevant matrix, clay and fluid inputs are used.

3.2.3 Water saturation

Water saturation has been used using the Archie method in IP of the form:

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

S_w = water saturation (decimal)

R_w = formation water resistivity in ohmm (based on salinity and reservoir temperature)

Phi = porosity calculated from logs (decimal)

R_t = true resistivity in ohmm (usually a Deep resistivity log)

a, m and n are the Archie parameters (m is a cementation exponent and n is a saturation exponent)

In the previous work the Archie a was constantly given the standard value of 1. There was some variation around the value of 2 in the 'm' and 'n' values based on reservoir quality. In this project 'm' and 'n' have remained constant at 2 for all reservoir intervals.

Formation water salinity is ~58k ppm NaCl.

The 13/23c-10 analysis inputs are consistent with the inputs for the Tain and Magnolia wells. The analysis as supplied by i3 is accepted by TRACS and the results have been used for reservoir properties summaries.

The results for the Serenity well 13/23c-10 are shown in Figure 3-1 where the Captain sand is subdivided into individual events by i3. The uppermost sand (K50.3.1) is the oil-bearing sand at the location of the Serenity well. This sand has very good porosity at ~30% with low S_w. The next sand is the K50.2.1 which is water–bearing though the ~20% oil saturation may be an indication of residual oil e.g. from migration. The pressure data for this sand indicates that formation pressure lies on a water gradient in this sand.

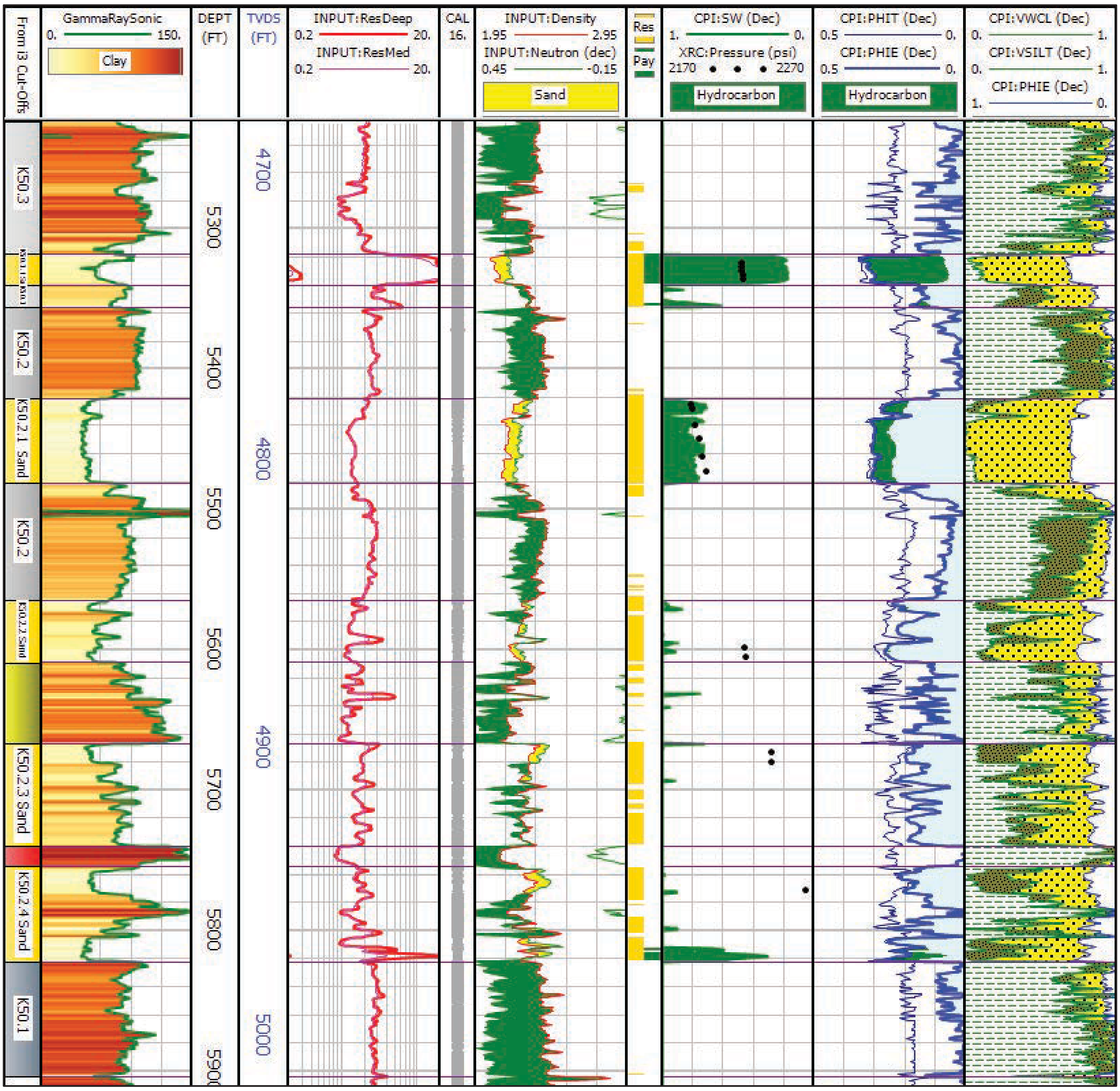


Figure 3-1 Measured logs and analysis results for Serenity well 13/23c-10

3.2.4 Average Properties – All Wells

The reservoir sub-divisions are not present in all wells so the properties for the gross Captain package is captured for all wells (Table 3-2 and Table 3-3). The Captain in the Serenity well will then be broken down by sand unit.

Reservoir Summary									
Well	**Zone**	**Top ft MD**	**Bottom ft MD**	**Top ft tvdss**	**Bottom ft tvdss**	**Gross ft**	**Net ft**	**N/G**	**Av Phi**
13/23a-7A	Captain	3386.00	3678.00	3295.64	3581.04	285.40	186.69	0.65	0.24
13/23c-10	Captain	5310.00	5904.30	4724.93	5014.63	289.73	146.45	0.51	0.21
13/23b-5Y	Captain	5590.00	5930.00	4152.27	4248.49	96.24	43.60	0.45	0.23
13/23b-5Z	Captain	4485.00	4589.00	4195.35	4270.06	74.70	40.39	0.54	0.24
13/23b-5	Captain	4199.00	4283.00	4112.98	4196.67	83.68	24.91	0.30	0.26
All Wells	Captain					165.95	88.41	0.53	0.23

Table 3-2 Net reservoir average properties for the Captain sands

The TVD gross thickness shows variation in package thickness for the Captain sands. The N/G also varies. In the Serenity well the Captain package is thicker than the other wells but the N/G is close to the average for the Captain at 51%. The properties have been calculated where V_{cl}<=0.5 and Porosity>=0.10 consistent with the 2019 work.

Pay Summary										
Well	**Zone Name**	**Top ft MD**	**Bottom ft MD**	**Top ft tvdss**	**Bottom ft tvdss**	**Gross ft**	**Net ft**	**N/G**	**Av Phi**	**Av S_w**
13/23a-7A	Captain	3386.00	3678.00	3295.64	3581.04	285.40	24.93	0.09	0.21	0.64
13/23c-10	Captain	5310.00	5904.30	4724.93	5014.63	289.73	14.98	0.05	0.28	0.29
13/23b-5Y	Captain	5590.00	5930.00	4152.27	4248.49	96.24	26.66	0.28	0.26	0.46
13/23b-5Z	Captain	4485.00	4589.00	4195.35	4270.06	74.70	37.88	0.51	0.25	0.39
13/23b-5	Captain	4199.00	4283.00	4112.98	4196.67	83.68	14.45	0.17	0.28	0.47
All Wells	Captain					165.95	23.78	0.14	0.25	0.44

Table 3-3 Net pay average properties for the Captain sands

Adding a 70% S_w cut-off to define net pay gives a low N/G in the Serenity well but a very low average S_w of 29% indicating better oil saturations than had been observed in the Tain and Magnolia wells.

3.2.5 Average Properties – Serenity Sands

Zooming in to the uppermost reservoir quality sands in the Captain at the Serenity well (Figure 3-2) shows just how good these sands are. The zone naming has been applied by the client and even though there is some uncertainty around exactly which sands can be correlated across the area, this naming has been adopted for convenience. The K50.3.1 sand is the only oil-bearing sand in this Serenity well. It is 10.5 ft thick at this location with 100% net sand and 30% porosity. Mobility from the MDT data are 117 to 448 mD/cP indicating that this also has good permeability. This sand is fairly insensitive to the 70% Sw cut-off with 94% N/G pay and 21% average Sw. The K50.3 interval immediately below is of poorer quality with 36% N/G and 16% porosity. Water is calculated in most of this interval but given the poorer quality there is uncertainty around this. There is some oil calculated at the base of this sand where the Vcl is decreasing and the porosity is increasing so it might still be in the oil leg. The K50.2.1 sand is also 100% net reservoir but has no pay. There is some oil calculated in this sand but it is 79% water on average and the pressure data gives a water gradient.

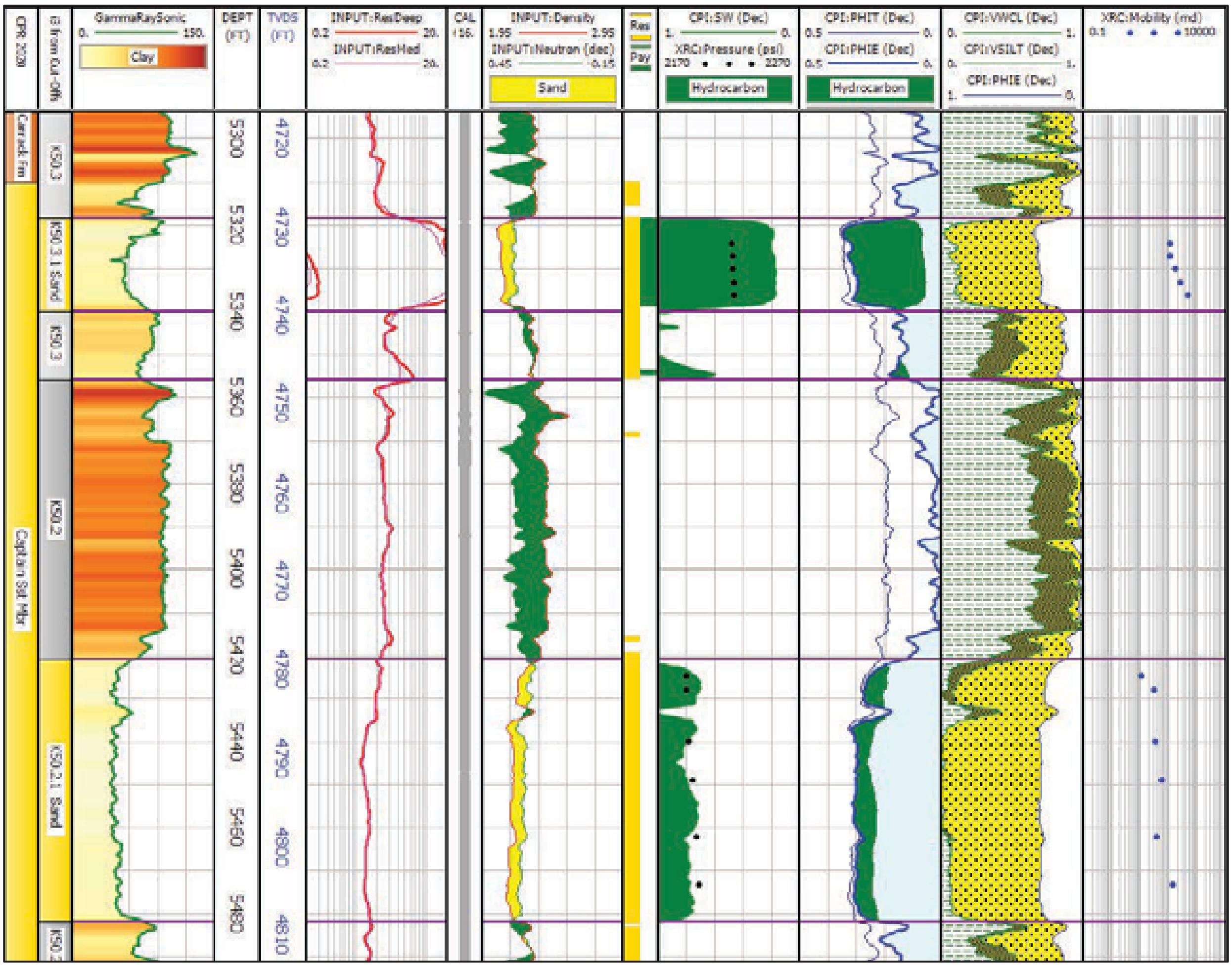


Figure 3-2 Reservoir sands in Serenity Captain

All of the sand intervals have a good-to-high N/G and porosity of 18% or more (Table 3-4). These numbers have been derived using the same cut-offs as the results presented for all wells, i.e. V_{cl}<=0.5, Porosity>=0.1.

Reservoir Summary										
Well	**Zone Name**	**Top ft MD**	**Bottom ft MD**	**Top ft tvdss**	**Bottom ft tvdss**	**Gross ft**	**Net ft**	**N/G**	**Av Phi**	**Av S_w**
13/23c-10	K50.3.1	5205.00	5318.25	4673.91	4728.95	55.04	4.31	0.08	0.19	0.93
13/23c-10	K50.3.1 Sand	5318.25	5340.00	4728.95	4739.51	10.56	10.56	1.00	0.30	0.23
13/23c-10	K50.3	5340.00	5355.75	4739.51	4747.16	7.65	2.73	0.36	0.16	0.81
13/23c-10	K50.2.1	5355.75	5421.00	4747.16	4778.87	31.71	0.00	0.00	---	---
13/23c-10	K50.2.1 Sand	5421.00	5481.75	4778.87	4808.38	29.51	29.45	1.00	0.29	0.79
13/23c-10	K50.2	5481.75	5564.75	4808.38	4848.70	40.32	3.28	0.08	0.19	1.00
13/23c-10	K50.2.2 Sand	5564.75	5609.00	4848.70	4870.20	21.51	18.59	0.86	0.22	0.98
13/23c-10	K50.2.3 Sand	5667.00	5740.25	4898.38	4933.96	35.58	21.80	0.61	0.18	0.99
13/23c-10	K50.2.4 Sand	5755.00	5822.75	4941.12	4974.23	33.11	19.80	0.60	0.20	0.87
13/23c-10	K50.1	5822.75	5904.25	4974.23	5014.65	40.42	0.00	0.00	---	---
13/23c-10	All Zones	5205.00	5904.25	4673.91	5014.65	305.40	110.52	0.36	0.23	0.80

Table 3-4 Serenity Well 13/23c-10 average properties. Serenity oil sand (K50.3) highlighted in green

3.3 Fluid contacts

As mentioned, the saturation calculations for K50.3 in the Serenity well are uncertain given the poor quality. No obvious oil water contact (OWC) is observed in the K50.3.1 Sand so the oil is observed down to (ODT) 4739.6 ft tvdss with a possible deepest indicator of oil at the base of K50.3 (4747 ft tvdss). The pressure data indicates that there is water up to (WUT) 4779.1 ft tvdss with some residual oil calculated. The oil encountered in 13/23c-10 is deeper than encountered in the wells in the wider region and water is encountered above the oil in all other wells (Figure 3-3).

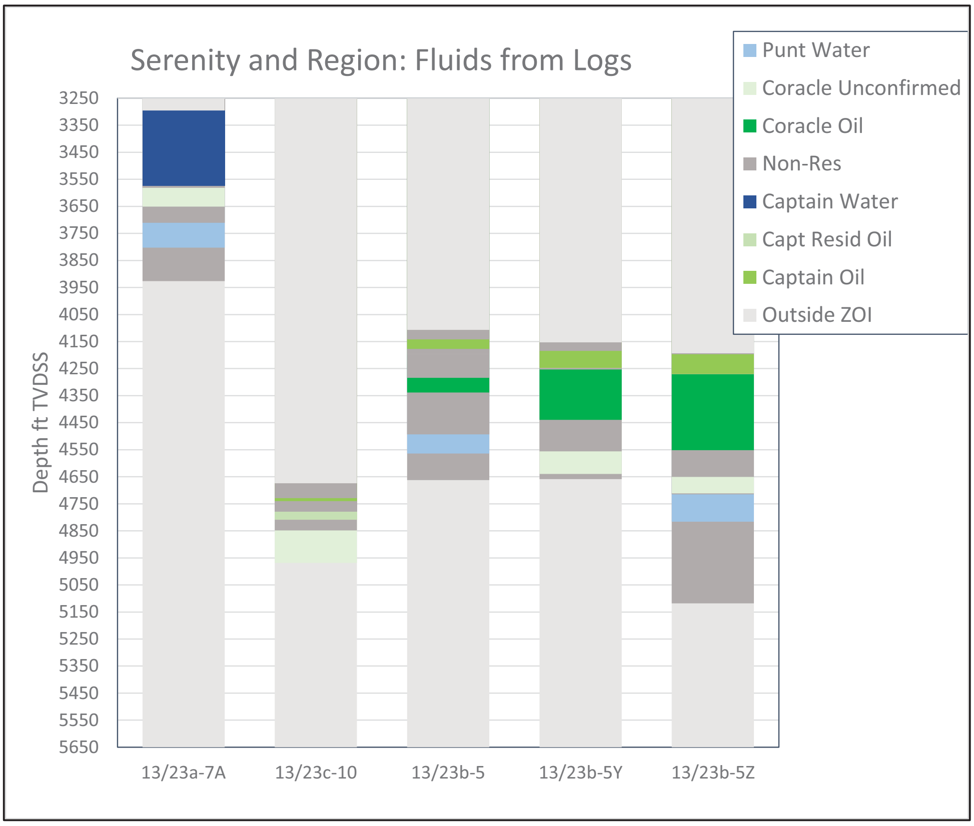


Figure 3-3 Fluid distribution from logs in Serenity region

From logs alone no OWC is identifiable in the Serenity well. There are a lot pressure data available for the region and successful pressure measurements were also taken in this well. Plotting the pressure data with the log analysis (Figure 3-4) illustrates that there appears to be a common water gradient from the K50.2.1 Sand to the K50.2.4 Sand. At first look it appears that the oil-bearing sand is isolated from the general pressure regime given that the formation pressure in the oil leg is so high compared to the measurements in the water leg.

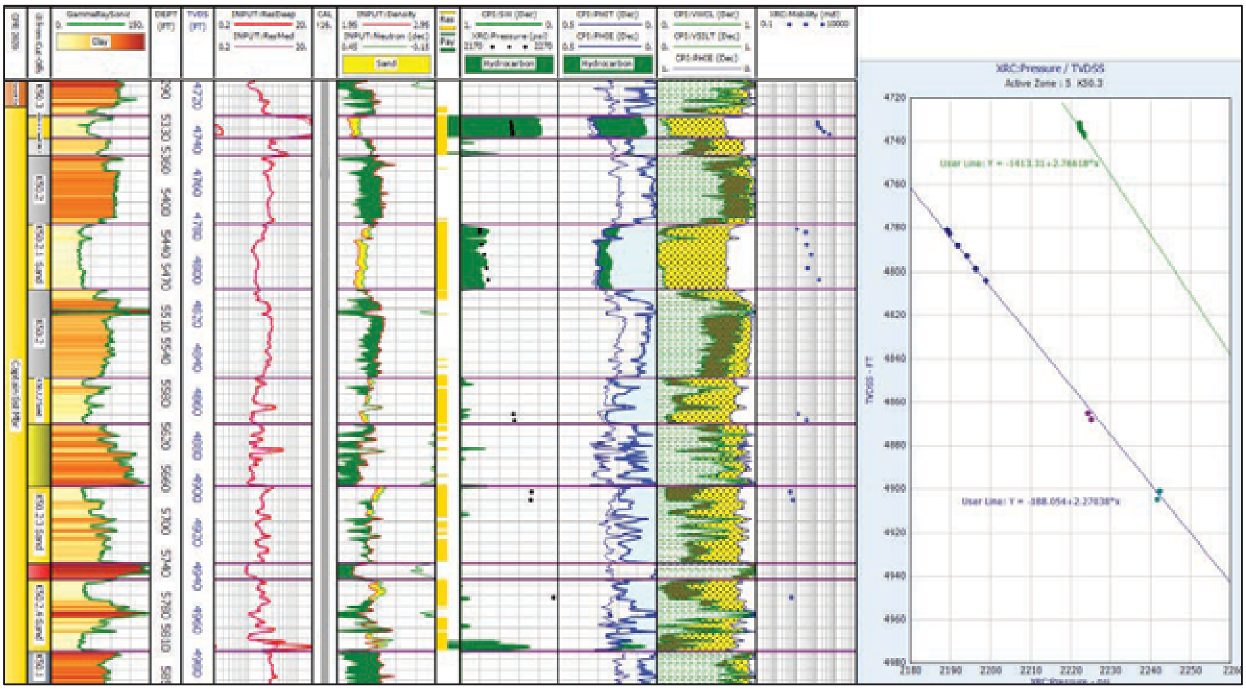


Figure 3-4 Serenity well 13/23c-10 with pressure data

However, given the possible complexity in the picture of sealed and charged sands on the structure (as described in geology Section 2.3), it is possible that a FWL can be derived from this data based on a common aquifer. This would mean the K50.3.1 Sand eventually connects to the aquifer down-dip while the K50.2.1 Sand is not sealed and is actually showing the true aquifer gradient. The distribution of pressure data over time in Figure 3-5 reflects production and injection over time in the area. However with the changing aquifer and oil pressure over time there is uncertainty around deriving FWLs from oil and water gradients since the system is not in equilibrium.

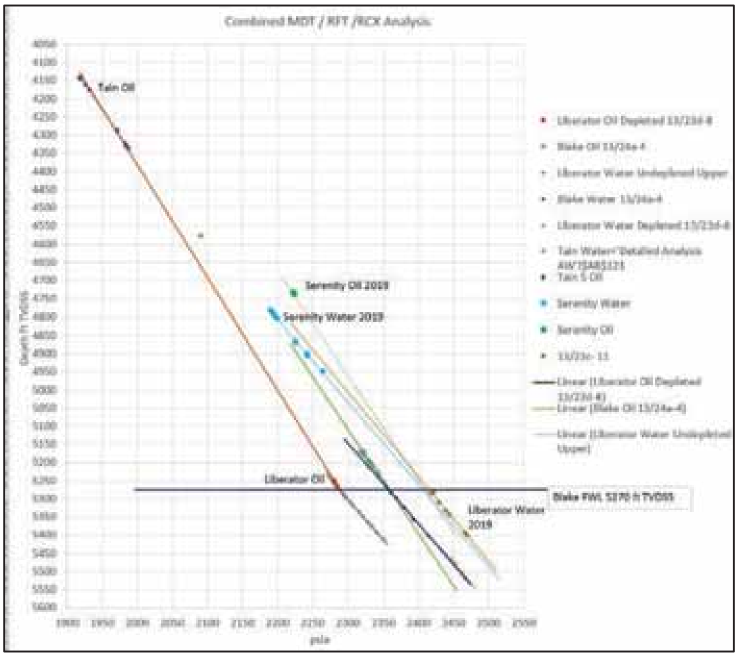


Figure 3-5 Pressure data for wider region

It is possible that the FWL in the Serenity well is at 5270 ft tvdss but there is also uncertainty around the fluid gradients within the well. There is some scatter in the water points (Figure 3-6) so the water line can vary slightly depending which points are included. Zooming in on the measurements in the oil bearing K50.3.1 Sand in the right hand plot of Figure 3-6 shows that there is no single common line through all of the oil points.

Figure 3-6 Serenity well pressure data

From the Serenity pressure data a range of FWLs can be derived around sensible gradients for the fluid densities. The range of calculated FWL is 5128 ft tvdss to 5422 ft tvdss illustrating the uncertainty around the combined pressure data. ODT from logs is a hard data point but FWL is very uncertain so a range is applied in the volumes calculations of between 5130 and 5270 ft tvdss (the 5270ft high case value limited by the regionally mapped OWC shared with Blake and Liberator).

3.4 Conclusions and recommendations

Drilling a well down dip in the Serenity structure would be useful for tagging the OWC in the K50.3.1 Sand. It would be useful to confirm how the thickness of this sand varies away from the reference point of 13/23c-10, especially towards the west.

4 Geophysical Evaluation

TRACS carried out a pre-drill evaluation of Serenity. The evaluation has now been updated with the Serenity well data. As part of those evaluations, TRACS was supplied with a Kingdom project containing the following data:

- well data (various, and now including the Serenity well 13/23c-10)
- Western Geco Q13Ph1 data – 2013 3D seismic data set (‘Q13Ph1’)
- Megamerge 13/22 data – 3D seismic data set (‘Phoenix3D’)
- TGS MF10 PSTM data – 2010 3D seismic data set (‘MF10’)
- Hess 92-13 data – 1992 3D seismic data set (‘AHL’)
- various time, depth and amplitude horizons/grids

The extents of the various surveys are shown in Figure 4-1. For the purposes of this evaluation the focus has been on the Q13Ph1 data over Serenity and Tain, and also the Phoenix3D over the Magnolia well.

Note that for some wells there are minor errors in tophole and location; these are generally in the order of 50 m and do not have a material impact on the analysis or findings.

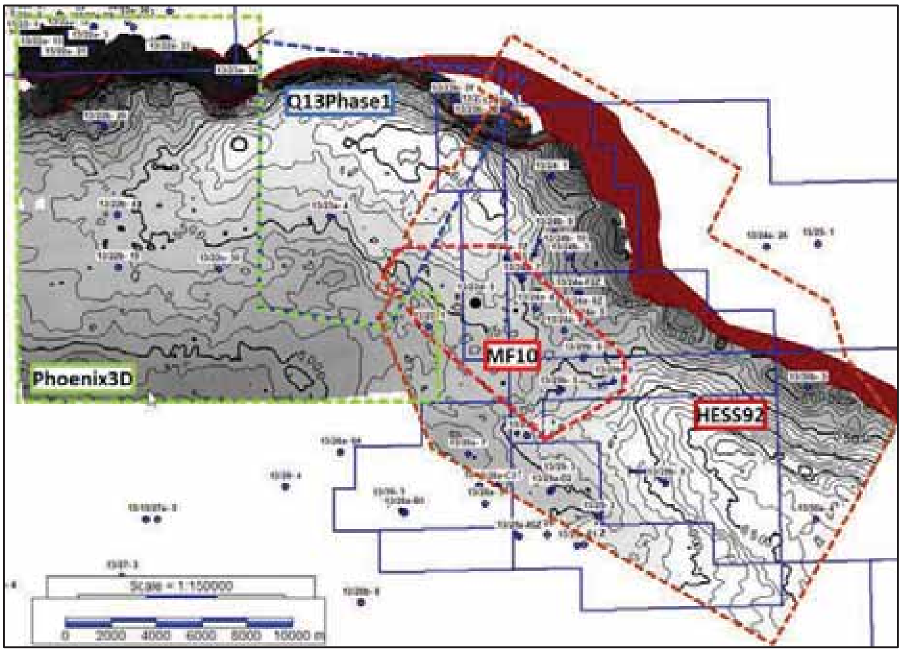


Figure 4-1 Seismic data coverage (supplied by i3 Energy)

The main objectives of the geophysical evaluation were as follows:

- review the seismic interpretation over Serenity in light of the 13/23c-10 well
- review seismic amplitudes as potential indicators of net sand thickness and fluid fill over Serenity
- review seismic facies as potential indicators of sand presence

4.1 Review of horizons

TRACS reviewed the supplied horizon interpretation. Top Rødby is picked on a positive event of moderate to strong amplitude. It is a clear and robust reflector across Serenity. A distinct sequence boundary at the top of the K50 sequence (henceforth ‘*trough*’) is picked on a negative event generally of moderate to strong amplitude. An overview seismic line is shown in Figure 4-2. The strength and character of the *trough* reflector is much more variable than the top Rødby reflector, see below for more details. Both horizons have been validated by TRACS.

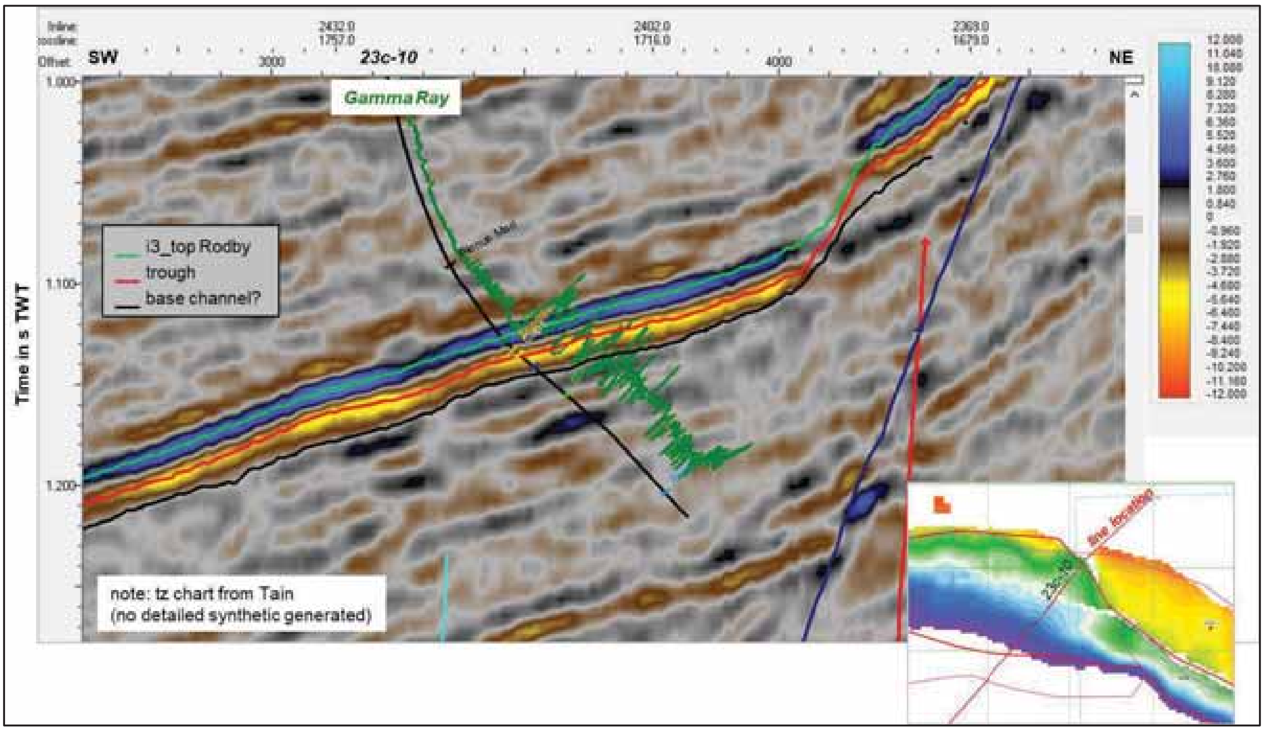


Figure 4-2 Seismic line through Serenity

4.2 Synthetic seismograms and tuning wedges

4.2.1 Synthetics

There was insufficient data to generate a robust synthetic seismogram for the Serenity well.

A review of the offset well synthetics was undertaken as part of the pre-drill evaluation, and summarised here. Prior to generating synthetic seismograms, wavelets were extracted from the data and compared for consistency. The wavelets showed a reasonable match to a Ricker wavelet of 25Hz. The Ricker wavelet was taken forward for use in the synthetics and the forward modelling over Serenity.

Synthetics were generated for the Tain wells and the Magnolia well. Log availability is an issue as 23b-5 is the only well with a sonic log. The TRACS petrophysicist computed synthetic DT logs using the neutron method for all the wells. As a QC, the computed DT log in 23b-5 was compared to the actual DT and the match was excellent. This provided confidence that the computed curves were suitable for generating synthetics and indeed for modelling purposes.

Time-depth data were taken 'as is' from the active time depth charts in Kingdom and are assumed to be adequate.

Two synthetics are shown here, one for Tain (23b-5, Figure 4-3) and one for Magnolia (23a-7A, Figure 4-4); the remaining synthetics are summarised.

The quality of the synthetic in 23b-5 is moderate. There is a good tie point at top Rødby and again at top Punt. In this well the Rødby Formation is 44 ft thick and the Captain Formation is a mainly poor quality with three thin (~2ft) clean sands and a net pay of 15ft. There is interference between the top Rødby and top Captain Formation reflection events; the result is that in this well the top Captain Formation pick falls on a zero crossing. Similarly, there is interference between the subsequent reflection events (tops and bases of minor sands). The result is that in this well the Captain Formation is incorporated within the '*trough*' and the base Captain Formation pick (top Coracle) falls on a zero crossing.

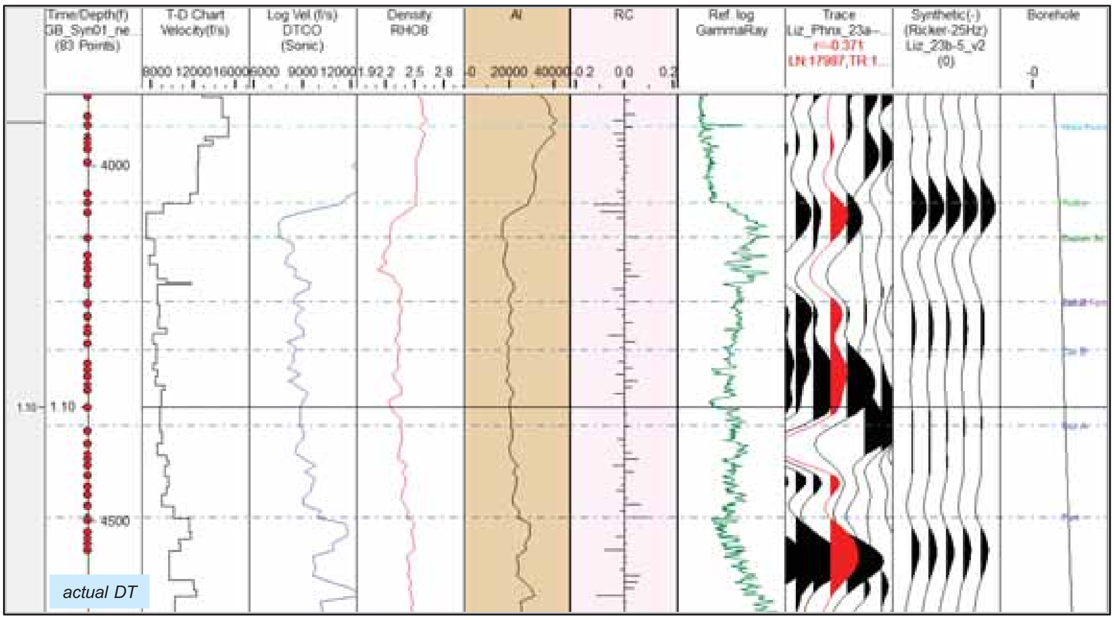


Figure 4-3 Synthetic at 23b-5

The quality of the synthetic in 23a-7A is poor to moderate, partly due to poor Signal-to-Noise Ratio (SNR). There is a reasonable tie point at top Rødby but no robust tie points at deeper levels. In this well the Rødby Formation is 45 ft thick and the Captain Formation consists of a thick clean sand (~115 ft) overlying a thick shaley, poorly-developed interval. There is interference between the top Rødby and top Captain Formation reflection events; the result is that in this well the top Captain Formation pick falls on a zero crossing. Also, in this well the base of the clean sand lies close to the 'trough'.

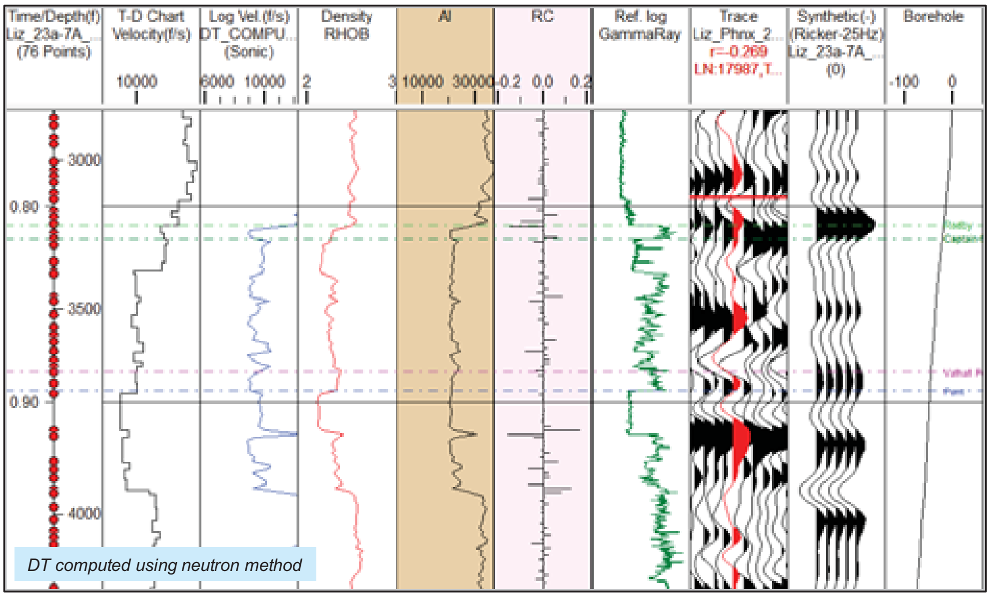


Figure 4-4 Synthetic at 23a-7A

In 23b-5Y there is a good tie point at top Rødby. In this well the Rødby is 49ft thick and overlies a thick Captain Formation of mixed quality. The net sand thickness is ~44ft with net pay of ~27ft. Once again there is interference between various events resulting in top Captain falling somewhere between a zero crossing and a trough. The base of the Captain lies on a zero crossing.

In 23b-5Z there is a good tie point at top Rødby. In this well the Rødby is 46 ft thick and overlies Captain Formation of variable quality. Net sand thickness is ~40 ft with net pay of ~38 ft. In this well top Captain Formation corresponds to the *trough* and base Captain falls on a zero crossing.

Well 23b-6 has no density log and no sonic log over the Level of Interest (LOI). The synthetic seismogram at this well is, therefore, not as reliable as at other wells. The 23b-6 well encountered no sand or hydrocarbons and is thus referred to as the 'mud well'. At this location the Rødby peak has a lower amplitude. Top Captain Formation falls within that peak and base Captain Formation corresponds to a weak trough.

A summary table of the seismic character at the wells is presented below (Table 4-1).

Well	top Rodby	top Capt	base Capt	top sand
23b-5	peak	+ to -	- to +	
23b-5Y	peak	0x to trough	- to +	
23b-5Z	peak	trough	- to +	
23b-6	peak	peak	trough	
23a-7A	peak	+ to -		trough

Table 4-1 Seismic character at wells

4.2.2 Tuning wedges

As part of the pre-drill evaluation, tuning wedges were generated at all the offset wells (examples given in Figure 4-5 and Figure 4-6) using RokDoc 2D. In all cases a Ricker wavelet of 25 Hz was used. All displays are in m TVDss.

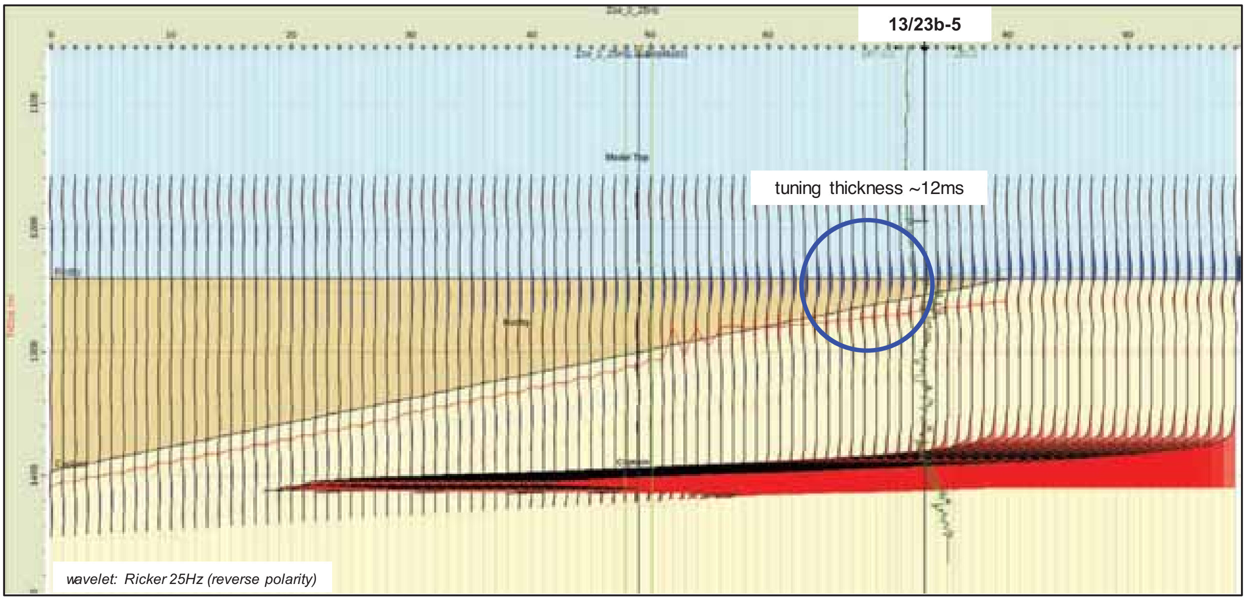


Figure 4-5 Tuning wedge at 23b-5

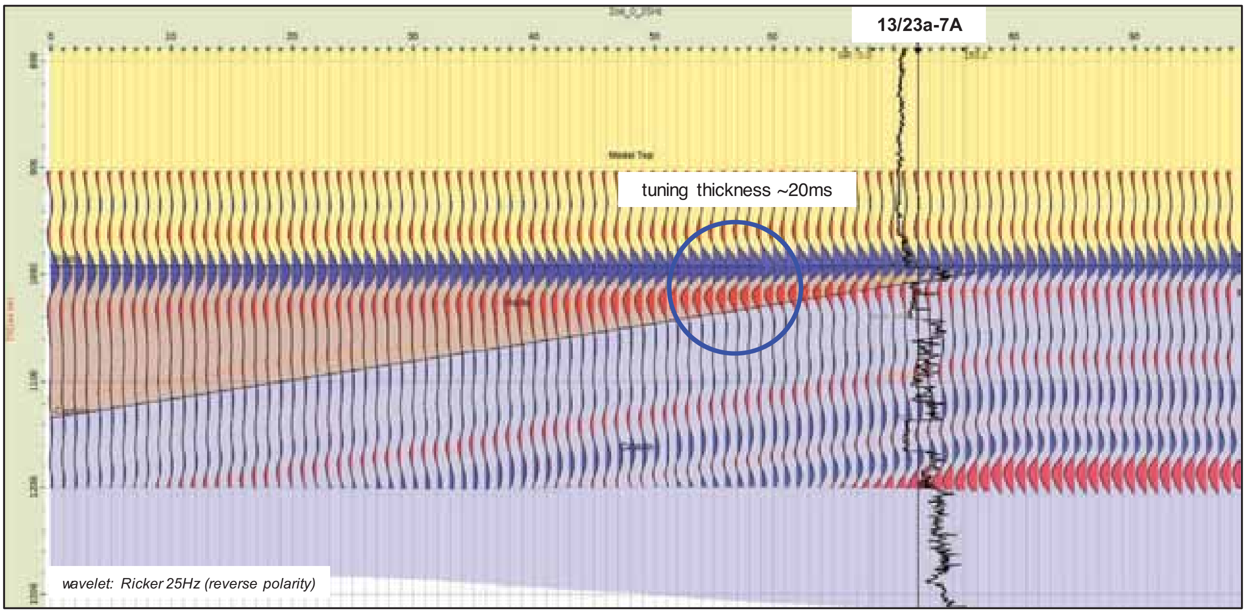


Figure 4-6 Tuning wedge at 23a-7A

In these models tuning occurs between 12-15 ms for the Rødby in Tain, and at ~20ms in Magnolia. A tuning curve was created from the picked horizons (see Figure 4-7). Time thickness is taken between the picked top Rødby horizon and the '*trough*', amplitude corresponds to the RMS amplitude between those horizons. The tuning curve supports the occurrence of tuning at 12-15 ms over Serenity and Tain. The area affected by tuning is relatively large as demonstrated in Figure 4-8. The area affected is shown by the red dashed polygon.

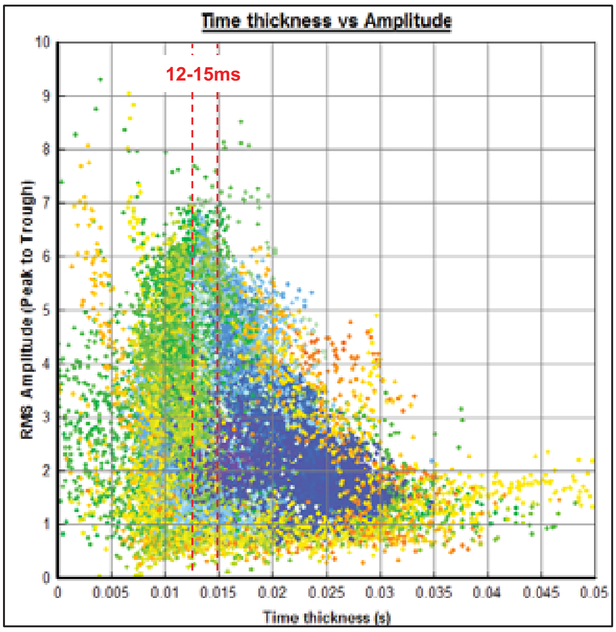


Figure 4-7 Tuning curve over Q13PH1 (Serenity and Tain)

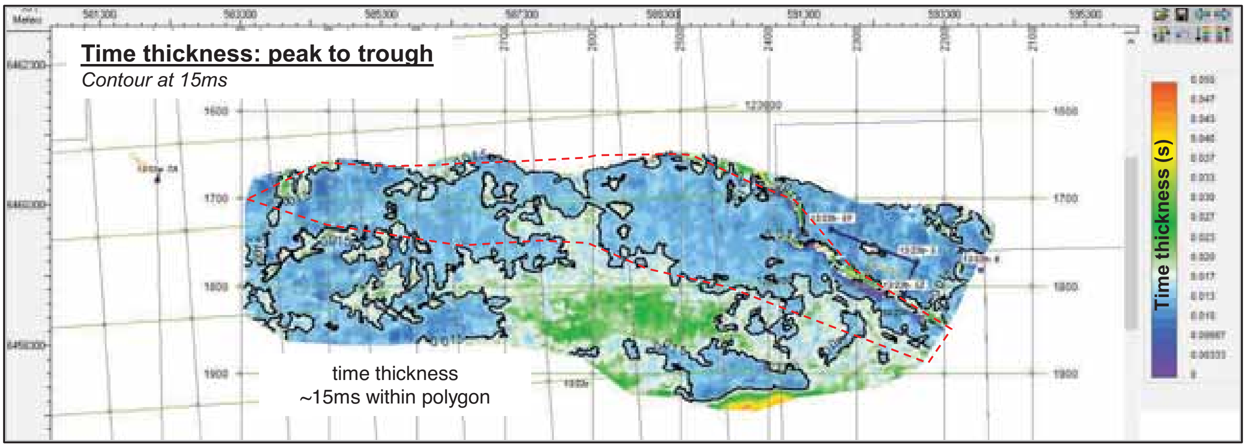


Figure 4-8 Time thickness map of Rødby peak to '*trough*'

4.2.3 Conclusions

The following conclusions can be drawn from the analysis of the synthetics and tuning wedges:

- Top Rødby is a strong peak event with a ΔAI in the order of -35% to -40%
- There is interference between the Rødby and Captain reflecting events
- In places the amplitude at top Rødby is affected by tuning
- Top Rødby peak does not correspond to top Captain or top sand
- In places the amplitude at the *trough* event is affected by tuning
- The *trough* event does not consistently correspond to top Captain, top sand or base Captain

4.3 Amplitude analysis

i3 Energy has used the amplitude at top Rødby as an indicator of the presence of oil filled sand, see Figure 4-9. They propose that there is good conformance with the -5270ss contour which is the Oil Water Contact carried by i3 in all volume cases. TRACS does not agree with this interpretation as top Rødby does not represent top sand or top Captain. Note also that in the western part of Serenity there is no conformance between depth and amplitude, implying some sort of stratigraphic limit. A similar, but slightly different, amplitude response is seen at the level of the *trough* event.

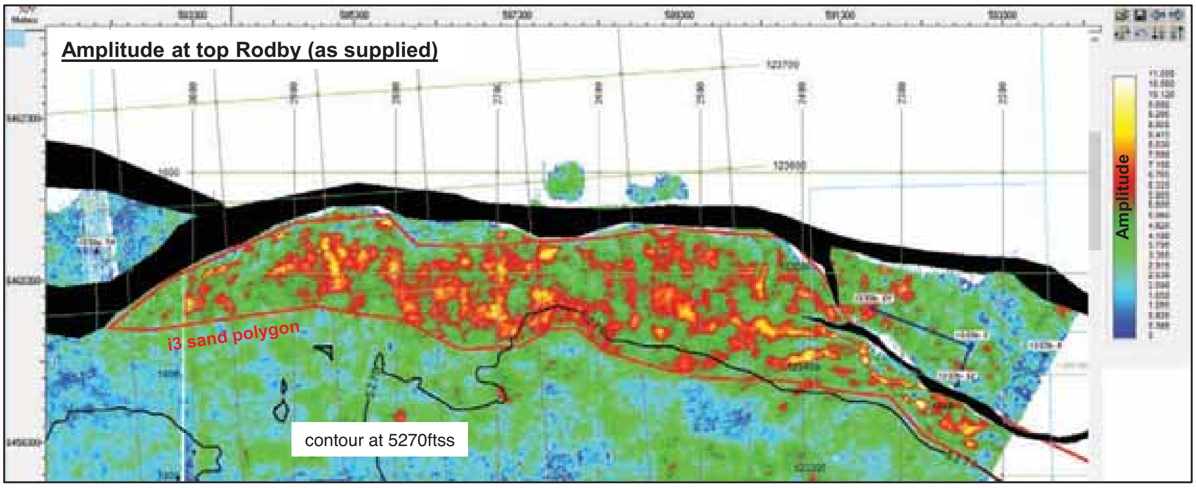


Figure 4-9 Amplitude at top Rødby with contour at -5270ss

Pre-drill, TRACS carried out some 1-D modelling to understand what the seismic response could look like for various sand thicknesses. TRACS has used pseudo-logs based on 23b-5 well data, the only well with a complete log suite. Note also that the Tain structure is closer in depth to Serenity than Magnolia is, another reason for selecting the Tain well as the basis for generating pseudo logs.

The Captain Formation was modelled as follows:

- poor-quality unit overlying clean sand
- clean sand thickness varied from 20ft to 100ft

Two additional cases were tested:

1. poor-quality oil: thick, poor-quality unit
2. thick oil: thick (115ft), clean sand immediately below the Rødby (Magnolia look-alike)

All models assume oil fill. There has been no extensive modelling of e.g. porosity perturbations, alternative sand-shale configurations, variations in cap rock thickness etc. Thumbnails of the 1D models are shown below (Figure 4-10). The results are summarised in two graphs (Figure 4-11).

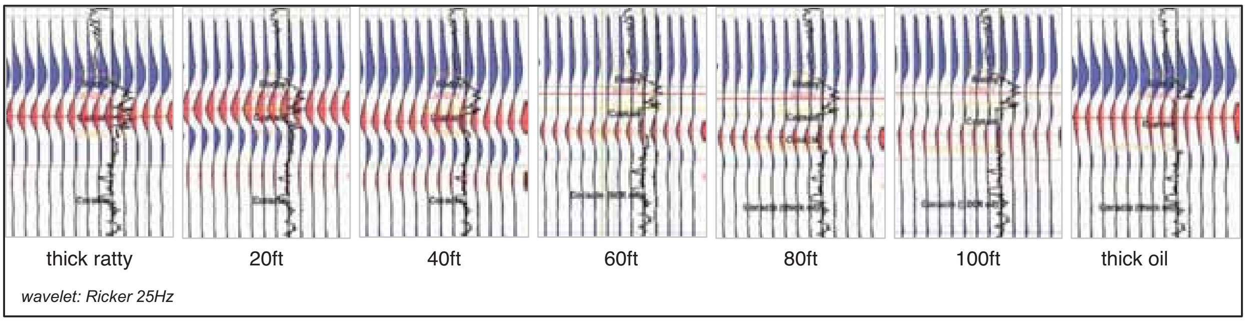


Figure 4-10 1D models showing seismic response for various sand thicknesses

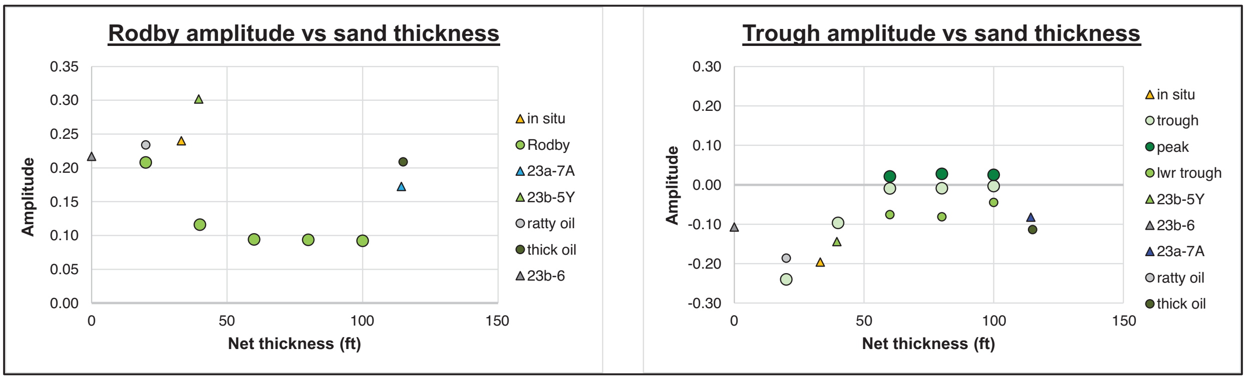


Figure 4-11 Amplitude versus sand thickness at top Rødby and the *trough* event

The left hand plot shows the amplitude at top Rødby versus net sand thickness. It highlights the disparity between reality (wells plotted as triangles) and the models (circles). The models suggest that an increase in thickness of oil filled sand below the Rødby would result in dimming once the Rødby gets above tuning thickness. The graph also highlights that the actual sand-shale configuration could be an important factor. Compare the response of the '100ft sand' and the 'thick oil' case. In the latter case the thick, clean sand lies immediately below the Rødby.

The right hand plot shows the amplitude at the *trough* versus net sand thickness. There is better agreement between the models and reality at 23b-5 and 23b-5Y. Again the models suggest that an increase in thickness of oil filled sand would result in dimming of the *trough* once above tuning thickness. The other observation is that once the sand package gets above ~50ft, the response changes from a trough to a trough-peak-trough, i.e. an extra loop is developed. Again, it is likely that the sand-shale configuration will have an impact on the actual response. Although there is no direct ground truth data available, there are hints around the 23b-5Y well of an extra loop appearing in the thickest part of the channel, as interpreted by TRACS from seismic data (see further).

The graph also suggests that it is not possible to discriminate fluid fill in the case of a thick, clean sand. Compare the response of the 'thick oil' case and actual 'thick water', i.e. 23a-7A (Magnolia) in the blue triangle in Figure 4-11. As discussed previously, TRACS does not support using the *trough* amplitude as an indicator of the presence or nature of sand.

4.3.1 Conclusions

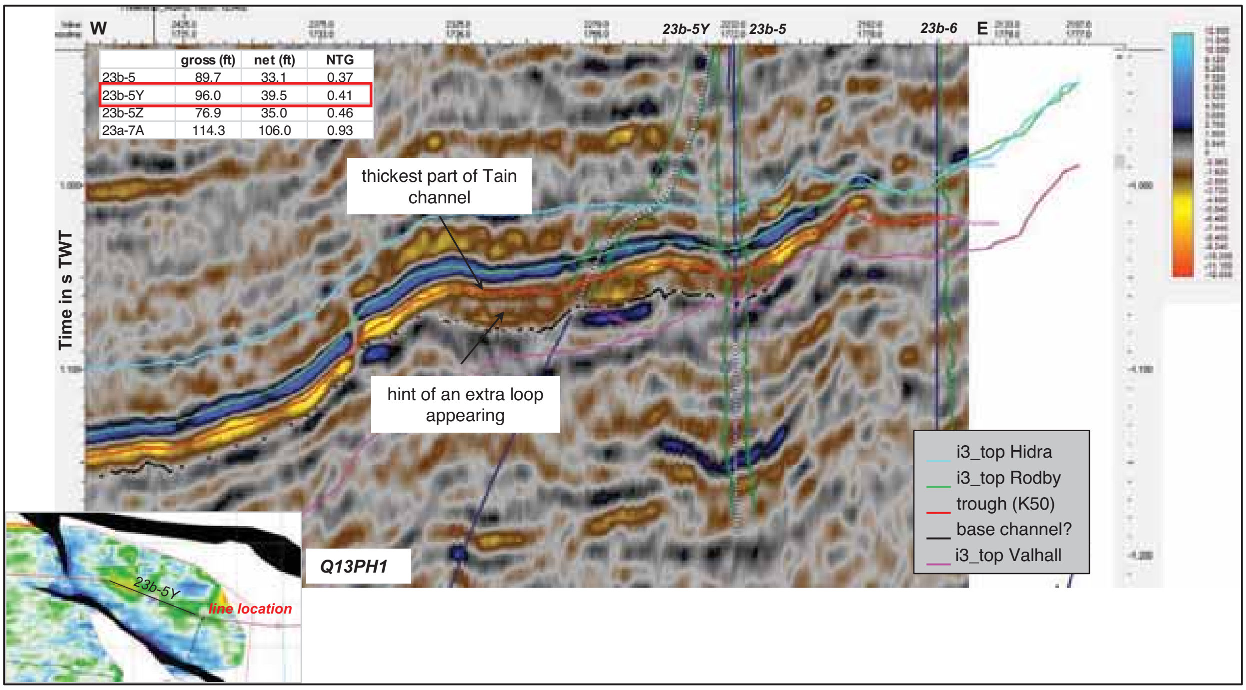
The following conclusions can be drawn from the amplitude analysis:

- Amplitudes at top Rødby cannot reliably be used as an indicator of the presence or nature of Captain sands
- Amplitudes at the *trough* event cannot reliably be used as an indicator of the presence or nature of Captain sands
- Sands with a thickness of ~60ft are likely to generate an additional loop
- It may not be possible to discriminate between thick oil and thick water sands based on amplitude
- At the Serenity well, the amplitudes at both the Rødby and trough events are moderate to high and indicate that the seismic response is tuned at this location.

4.4 Seismic facies analysis

TRACS carried out a seismic facies analysis over Tain and Serenity. It was not possible to generate a seismic facies interpretation over Magnolia because of poor SNR and data quality.

Tain is characterised by a distinct scour feature that can be mapped over a small area around the discovery (Figure 4-12). The thickest part of the mapped channel lies just to the west of the 23b-5Y reservoir section, Figure 4-13. In the thickest part there is indeed a hint of an extra loop appearing. The thickest part is also characterised by dimming at the *trough* event.



	gross (ft)	net (ft)	NTG
23b-5	89.7	33.1	0.37
23b-5Y	96.0	39.5	0.41
23b-5Z	76.9	35.0	0.46
23a-7A	114.3	106.0	0.93

Figure 4-12 Seismic character over Tain

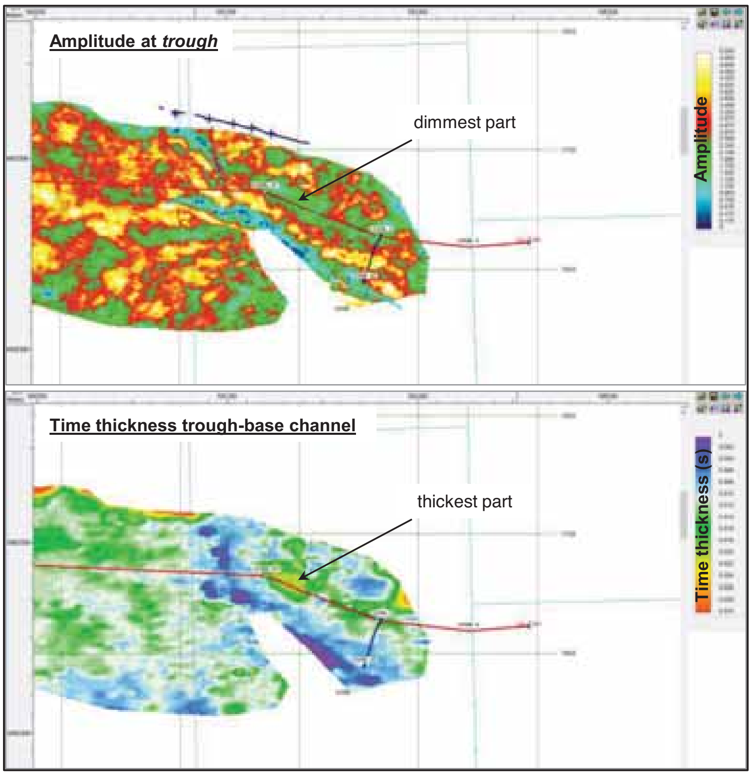


Figure 4-13 Amplitude and time thickness maps over Tain

The base of a channel feature can be mapped across a large part of Serenity (Figure 4-14) but not across the whole of i3's 'Rødby amplitude' area. Inspection of the seismic data suggests that the character and implied thicknesses observed in Tain are not present in Serenity, i.e. there are no thick channel areas with an extra loop. Locally there is minor thickening but not to the same extent as in Tain (Figure 4-15).

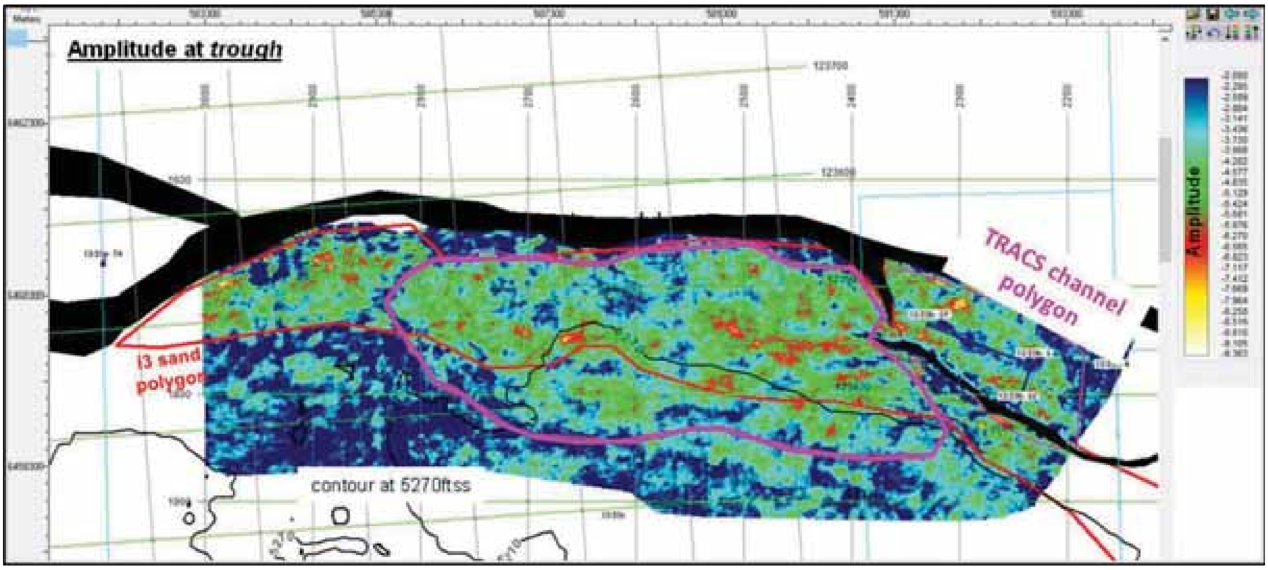


Figure 4-14 Amplitude at *trough* with i3 and TRACS polygons

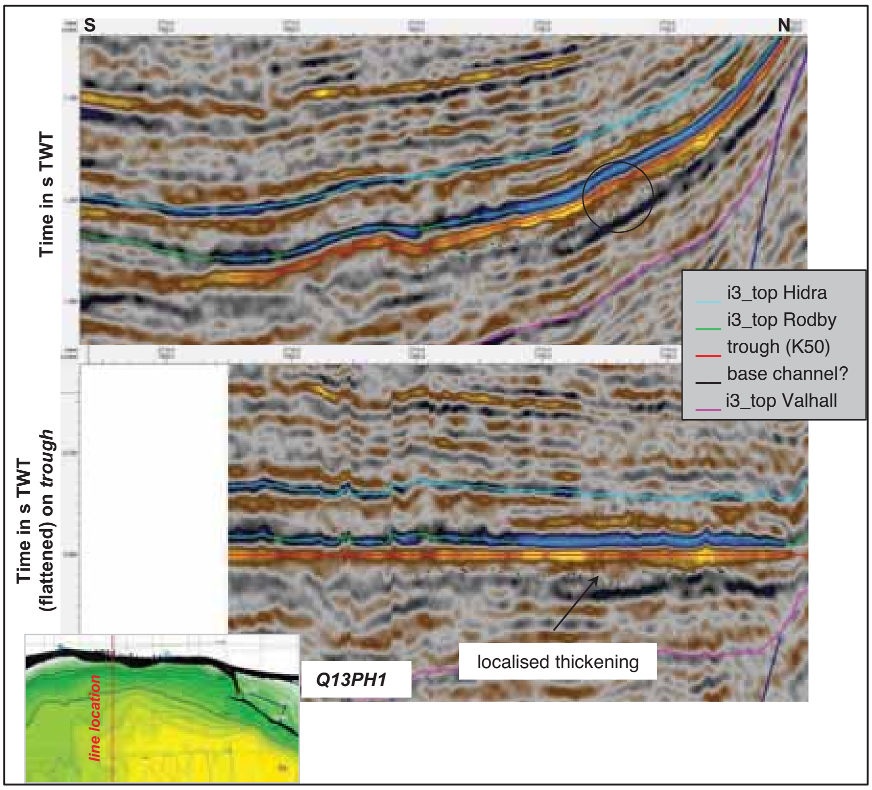


Figure 4-15 Seismic character over the western part of the Serenity area

To the west, closer to Magnolia, the seismic character is different and may correspond to a back-filled channel. Given that there is no structural closure over Serenity, the edge of the mapped TRACS channel could well represent the stratigraphic limit of the sands, thus providing the trapping mechanism to the west.

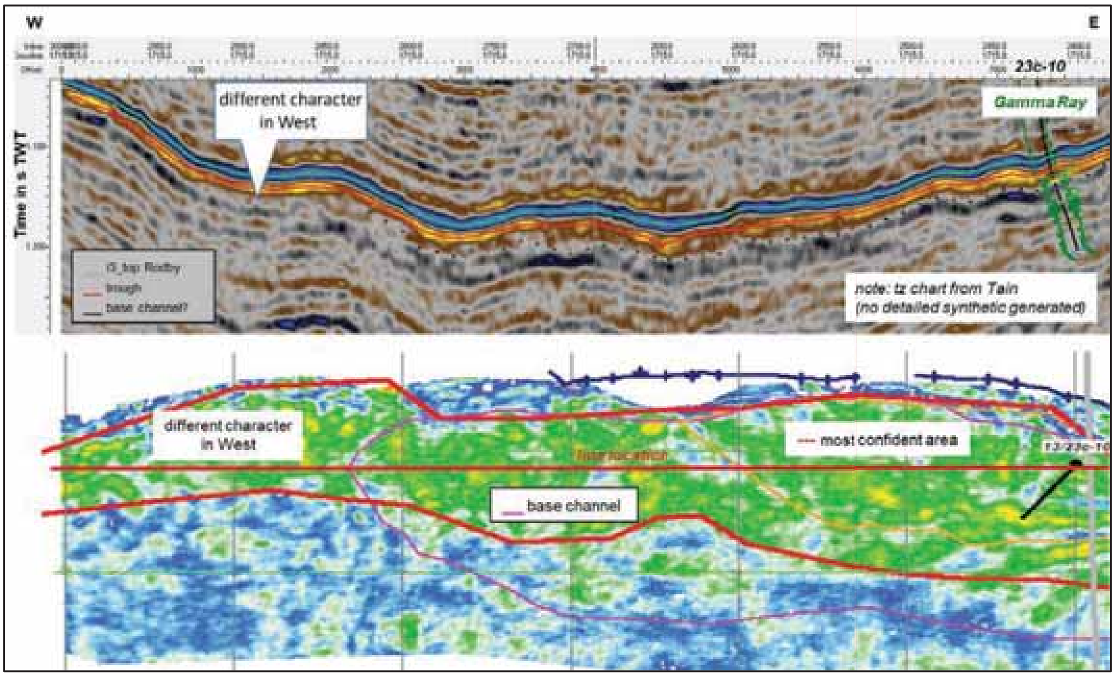


Figure 4-16 Change in seismic character at the far west of Serenity

4.5 Depth conversion

The depth conversion methodology adopted by i3 Energy is a layer-based model incorporating 10 layers using constant interval velocities derived from the Liberator well (23d-8) and additionally 23-1 for the fill within a shallow channel present over the area. The depth conversion method is suitable for use over Serenity.

The supplied top Rødby depth map does not tie the wells in Tain or Magnolia so TRACS tied the map in Petrel. It is not clear exactly how the supplied 'top Serenity' maps have been generated. In numerous places it lies above top Rødby, especially in the west. Clearly this is not possible and so for the purposes of the volume calculations TRACS generated its own top structure map, as described in Section 5.1.

5 In Place Volumes

Because of the high uncertainty in a few key parameters, and the lack of sufficient data to fully define the probability distributions, in-place volumes have been derived using a series of deterministic cases, and no probabilistic evaluation has been carried out.

The key uncertainties on in place volumes are:

- net thickness
- lateral extent of sand
- OWC contact

5.1 Gross Rock Volume (GRV)

A simple slab model was generated in Petrel to allow a range of realisations to be tested quickly and effectively.

Top structure was generated as follows. The top Rødby horizon was tied at the wells and then shifted down by 46 ft (average Rødby Formation thickness in Serenity and surrounding wells) in order to generate a top Captain Formation depth map. Depth uncertainty is not considered to be a major uncertainty for in-place volumes and no variation of top structure was implemented in the volumetric uncertainty analysis.

The oil-bearing Captain Formation (equivalent to the K50.3 sand of i3) is represented by a slab up to 80 ft gross thickness to which different OWCs and lateral sand extent realisations could be applied (see 5.1.1 & 5.1.2). Note that this approach was adopted in order to generate a tool that was flexible enough to handle a wide range of net sand thicknesses (see section 5.2) but avoids hard wiring erroneous thicknesses into the slab model. The seismic character/modelling over Serenity prospect would suggest net sand thickness is no larger than 60ft, see section 4.3.

5.1.1 Contact realisation

The Serenity well encountered a thin oil-bearing sandstone with an ODT of 4747 ft tvdss (Section 3.3). Similarly, the nearby Tain wells (13/23b-5, 5z & 5y) encountered a series of ODTs with the deepest recorded in the -5z well in Coracle sands at 4494 ft tvdss. Based on pressure data and regional mapping, i3 Energy interpret a base case OWC of 5270 ft tvdss, which they believe represents a common OWC between Blake, Tain and Serenity accumulations.

TRACS agree that the OWC as deep as 5270 ft tvdss is feasible but that a shallower OWC at 5130 ft tvdss is plausible given the pressure data available. TRACS consider a low to high case OWC range from 5130-5270 ft. For volumetric purposes, this range is considered a uniform distribution and so the mid case OWC is simply the mid-point at 5200 ft.

Figure 5-1 illustrates schematically the low and high case contact scenarios. Note that both end members honour the existence of a regionally connected aquifer, as supported by regional pressure data.

An ultra-low case scenario, in which the Serenity oil sand represents a completely isolated sand (not connected to the regional aquifer) has not been considered in the volumetrics and is considered extremely unlikely. The key reasons for eliminating this case are as follows:

- Strong evidence for a highly dynamic regional aquifer, injection in the nearby Blake field, combined with current (2019) pressure data from Serenity and Liberator (well 13/23b-11) provide an adequate explanation for why the Serenity oil and water pressures are currently approximately 50 psi over-pressured compared to pre-production pressures in the Captain fairway.
- The presence of an oil-charged sand in Serenity suggests connectivity to a larger hydrocarbon system (the Captain sands in this area are too shallow to be locally charged and require migration from the deeper source area to the east).

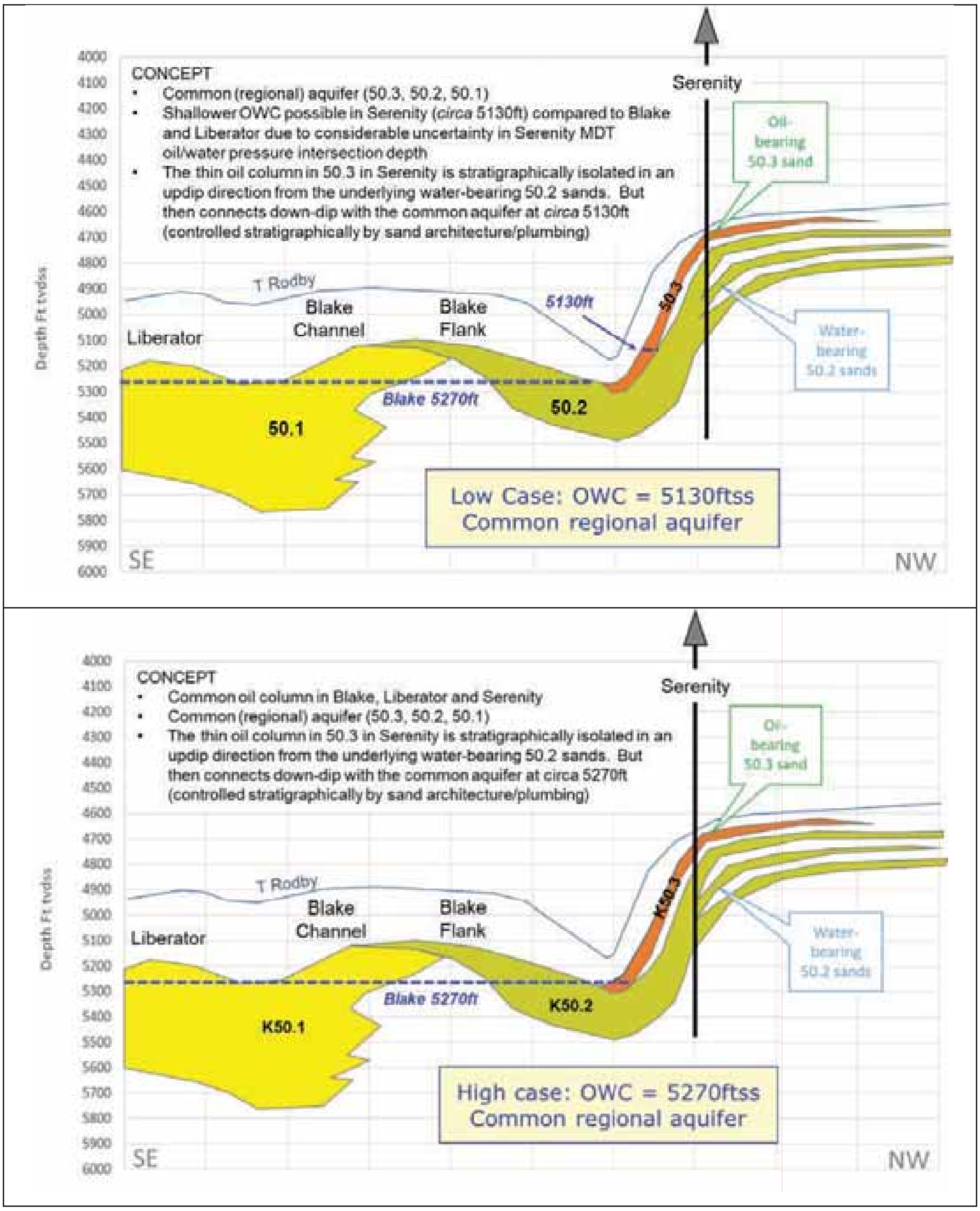


Figure 5-1 TRACS OWC range, schematic view

5.1.2 Lateral sand extents

The main conclusion from the amplitude modelling is that amplitudes cannot be reliably used as an indicator of net sand thickness or fluid fill. In the western part of the structure, TRACS consider the possibility of an alternative channel fairway edge with a more easterly position compared to i3 (Serenity channel polygon).

The following realisations have been selected for the Low-Mid-High cases (and illustrated in Figure 5-2:

- Mid case and Low case: the edge of the Serenity channel (as interpreted by TRACS) is assumed to be the western edge of the sand (4.4)
- High case: uses amplitudes at top Rødby (as suggested by i3)

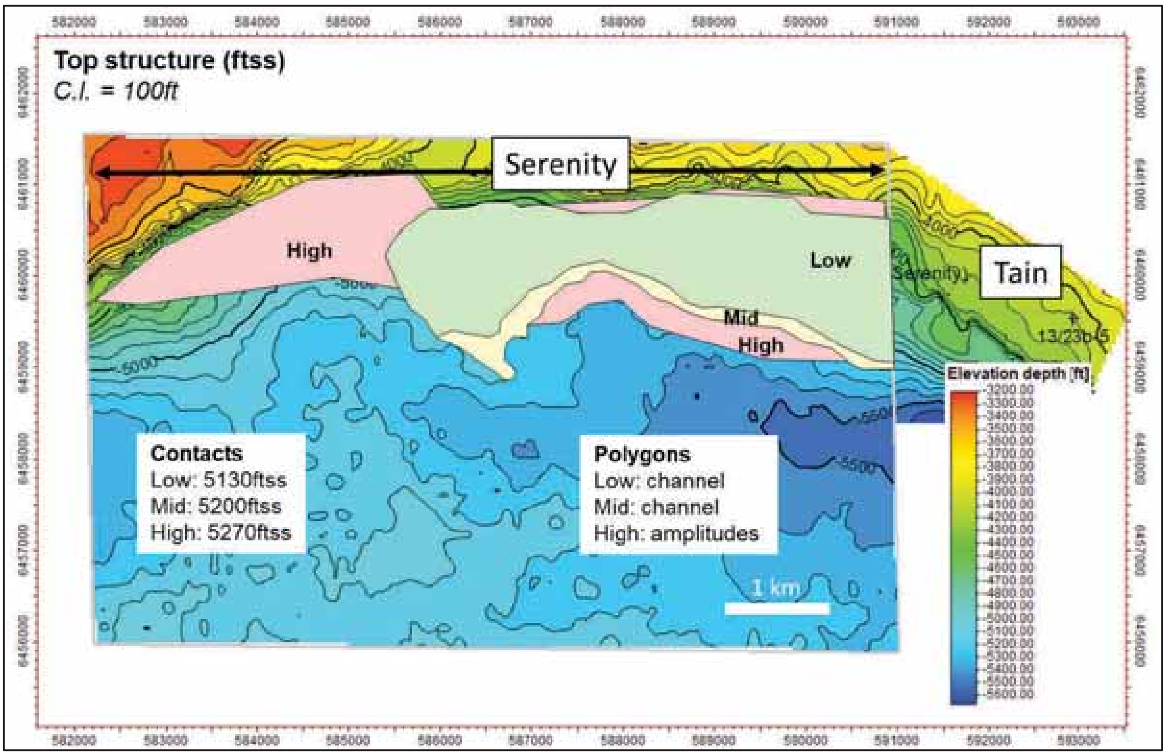


Figure 5-2 Top structure map with volume cases illustrated

5.1.3 Results

The resulting range in GRV is presented in Table 5-1. GRVs are calculated within the license boundary only.

	Gross (slab) thickness ft	*OWC ft tvdss*	*Polygon used*	*GRV (10^6 m^3)*
Low	60	5130	TRACS channel	100
Mid	**65**	**5200**	**TRACS channel**	**129**
High	70	5270	amplitudes	207

Table 5-1 GRV range

5.2 Properties

TRACS has used average properties for populating the entire rock volume. The properties are guided by the petrophysical averages from the Serenity well (K50.3 unit, Table 3-4) and nearby offset wells in Tain, but also take into account the seismic character.

The range in net sand thickness is presented in Table 5-2. Note that the N/G is a derivation of the net sand thickness with gross (slab) thickness. TRACS assumes a much thinner net sand package than i3 Energy in the mid case and this is driven by the Serenity well data and seismic character over the Serenity structure. Though only 11 ft of net sand was encountered in the Serenity well, TRACS mid case of 16 ft allows for the fact that the 13/23c-10 well was drilled in a relatively up-dip position, therefore closer to the likely northern pinch-out edge of the Captain sands. As discussed previously however, no thick channel facies is observed from seismic data in Serenity suggesting that the mid case net sand thickness does not significantly exceed the net sand pay thickness in Serenity well and nearby Tain well 13/23b-5 where the net sand thickness is approximately 14ft (see Section 4.4, Table 3-3).

In the volumetric model the Captain Sandstone is represented by a slab of 60-65-70 ft gross thickness in the low-mid-high case. The seismic character/modelling over Serenity prospect would suggest net sand thickness is no larger than 60 ft. The High case N/G allows for more net sand but the net sand thickness is not allowed to exceed 60ft (above which an extra loop would be expected on seismic data).

	Net Sand Thickness (ft)	***Gross "slab" Thickness (ft)***	***N/G (fr)***
Low	11	60	0.18
Mid	**16**	**65**	**0.25**
High	50	70	0.72
i3 P50	*42*	-	-

Table 5-2 N/G and net sand thickness range

The net pay thickness inputs used by i3 Energy are more optimistic and assume significant thickening of the reservoir to the west towards the Magnolia well (13/23a-7A), which records a net pay thickness of approximately 100 ft (see Figure 5-3). Though possible, TRACS consider this only likely as a High case. The i3 net thickness map is an interpolation of a small number of well data points with large bullseyes around the wells particularly Magnolia, which is nearly 9 km away from 13/23c-10. TRACS Low and Mid cases are guided by the nearest wells (Serenity and Tain) combined with seismic character.

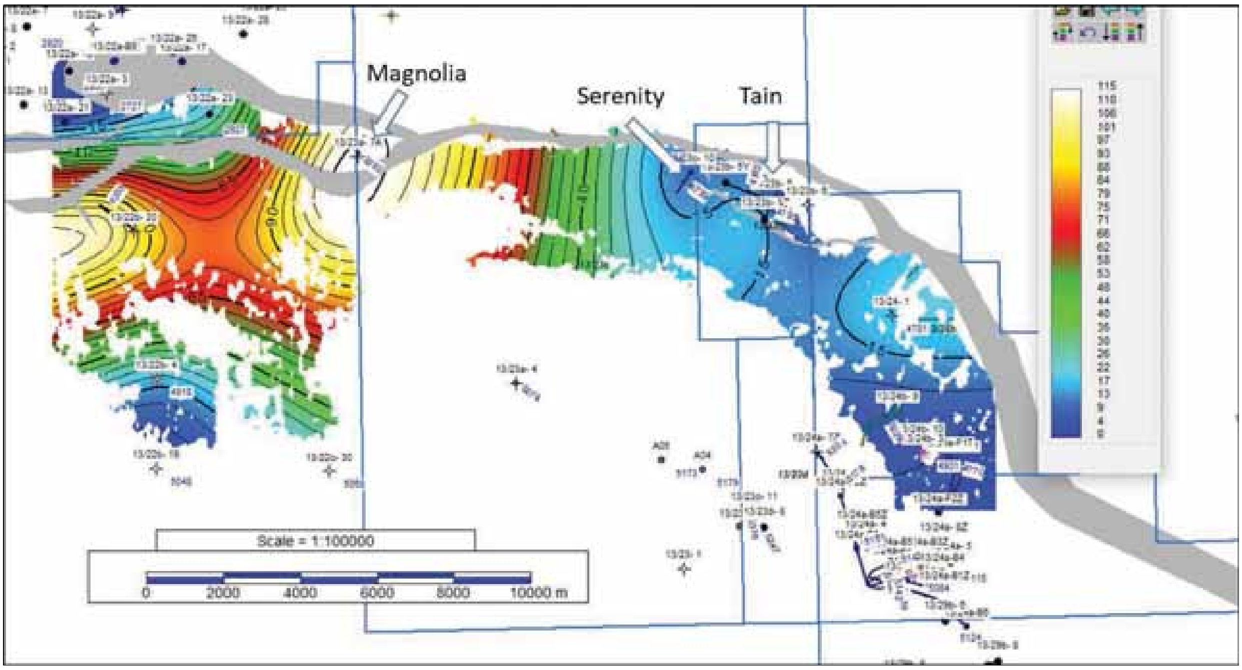


Figure 5-3 i3 Energy view of net sand thickness

Porosity and saturation are guided by the average properties in the wells. Overall, TRACS and i3 property inputs are similar (Table 5-3). The FVF is consistent with the PVT data from Serenity and Tain.

	PHI (fr)	***So (fr)***	***FVF (v/v)***
Low	0.28	0.60	1.17
Mid	**0.32**	**0.75**	**1.15**
High	0.34	0.85	1.13
i3 P50	*0.28*	*0.78*	*1.16*

Table 5-3 Porosity, oil saturation and FVF range

5.3 STOIIP evaluation

The elements described in the previous section were brought together to calculate in place volumes for three deterministic cases (Table 5-4 & Table 5-5).

Case	OWC ft tvdss	Polygon	GRV 10^6 m^3	N/G fr	Net sand ft	PHI fr	S_o fr	FVF v/v	STOIIP MMstb
Low	5130	Serenity channel	100	0.18	11	0.28	0.6	1.17	16
Mid	**5200**	**Serenity channel**	**129**	**0.25**	**16**	**0.32**	**0.75**	**1.15**	**42**
High	5270	Rødby amplitude	207	0.72	50	0.34	0.85	1.13	240

Table 5-4 Summary of TRACS STOIIP inputs and results

Case	*TRACS STOIIP (MMstb)*	*i3 Energy STOIIP (MMstb)*	*Case*
Low	16	109	P90
Mid	**42**	**190**	**P50**
High	240	273	P10

Table 5-5 Comparison of STOIIP results

TRACS STOIIP estimates are lower than the i3 Energy volumes and this can be attributed to:

- smaller net sand thickness used by TRACS – driven by seismic character and observations in the Serenity and Tain wells
- use of more limited sand polygon in TRACS Low and Mid case – driven by seismic character
- use of shallower contact in the TRACS Low and Mid case; all 3 cases generated by i3 Energy use an OWC of -5270ft tvdss

In all cases it is assumed that the fluid fill is 100% oil. Similar to Blake and Liberator, there is a possibility that gas is present locally at the crest. If so, they are likely to be thin gas caps. This is not captured in the in place volume range presented here.

6 Reservoir Engineering

6.1 Data review

Data provided consisted of:

- Formation pressures and limited PVT data from the Serenity discovery well. A single oil sample was acquired at a depth of 5331.3 ft MD. At the time of this review only interim PVT data was available, which included surface densities but no estimate of reservoir conditions saturation pressure or GOR.
- Fluid properties for this review are based on PVT data from Tain, Liberator and Blake fields
- Production history data from Blake including recovery to date, plus Captain field voidage history
- DST (drill stem test) data from well 13/23b-5Z
- The Client's t-Navigator regional dynamic simulation model over the Serenity prospect, Tain, Liberator area and Blake Field.

Based on the measured reservoir fluid properties of the Serenity and Tain discovery wells 13/23c-10 and 13/23b-5Z, the Serenity reservoir fluid is likely to be similar to the Tain and Liberator fluids (Table 6-1). The flashed Serenity fluid samples API is slightly lower than Tain and is expected to be most similar to the Liberator fluid.

	Serenity	**Tain**	**Liberator**	**Blake**	
Oil gravity	31.4	33.8	30.5	30.3	API
GOR		298	341	358	scf/bbl
P_b		1645	2263	2358	psi
B_o (@P_b)		1.142	1.16	1.168	v/v
Oil vis (@P_b)		1.87	1.9	1.89	cP

Table 6-1 Oil properties at initial conditions – Serenity, Tain, Blake & Liberator

The difference in the fluid properties suggests there is uncertainty whether the oil leg is connected between Serenity/Tain and Blake fields. If connection occurs, the oil compositions must vary areally or vertically, as the Serenity and Tain oil zone is located at a much shallower depth than the Blake and Liberator oil zones. This could be explained by the complex charge history combined with the time it takes for the system to equilibrate in the presence of permeability baffles, e.g. faults and stratigraphic baffles.

6.2 Evaluation

To help understand the regional dynamic pressure story and the OWC cases for Serenity, i3's t-Navigator regional dynamic simulation model was reviewed. The pressures in the basin at Serenity and Liberator are sensitive to:

- Injection at Blake, particularly well B7z
- Connectivity of layers at B7z to the measured units in Serenity and Liberator
- Connectivity between Blake basin area and Captain field area to the West.

In i3's reference case model the basin area is open to the west towards Captain field and closed to the South, which configuration results in near normal pressures in the basin. Figure 6-1 shows a variant of the i3 model in which there is poor connectivity to the west and this results in significant pressure movement in the basin, of order 100 psi at Serenity. This variant is not intended as a history match, but it confirms the plausibility of reservoir continuity between Blake and Serenity and provides an explanation for the excess pressures recorded in the MDT pressure data from the 2019 Serenity and Liberator wells.

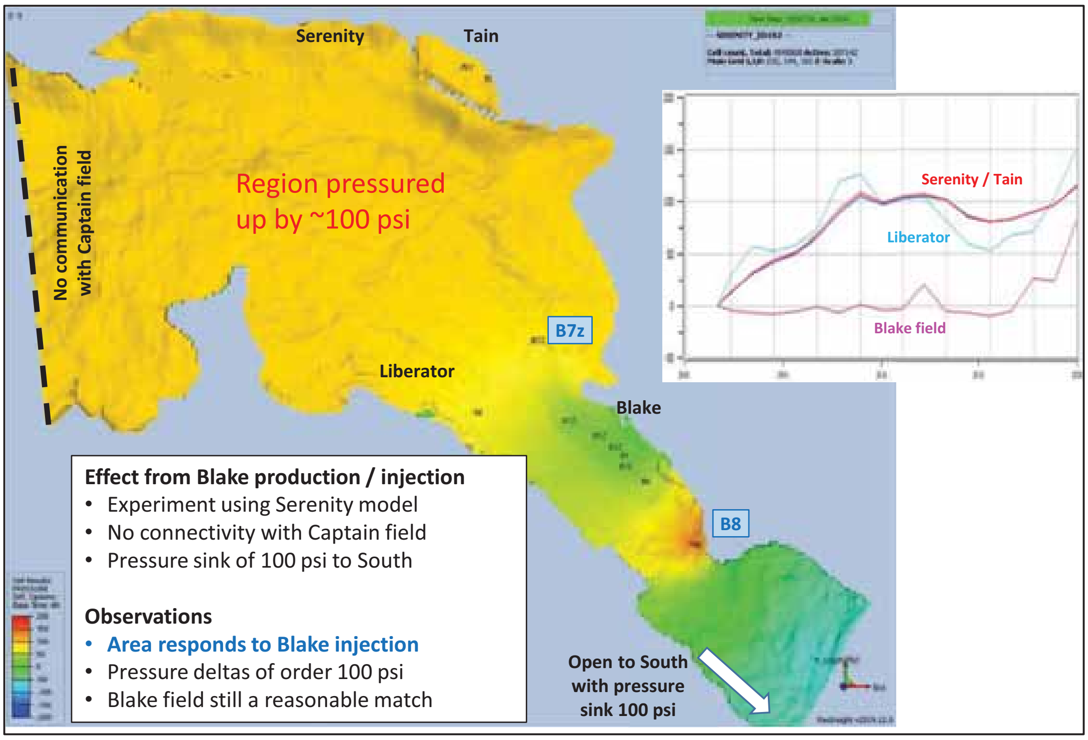


Figure 6-1 Variant of i3 regional model showing example of excess pressures at Serenity

6.3 Depletion / Solution Gas Drive

Given the uncertainty associated with volumes in place, only a high level assessment of recovery factors was undertaken taking into account information available from Blake and Liberator fields and the results of an i3 preliminary reservoir simulation.

Figure 6-2 shows a depletion recovery factor case from an analytical material balance depletion tool, based on the technique outlined by Laurie Dake in "The Practice of Reservoir Engineering", published by Elsevier. [Chapter 3.7 - Volumetric Depletion Fields].

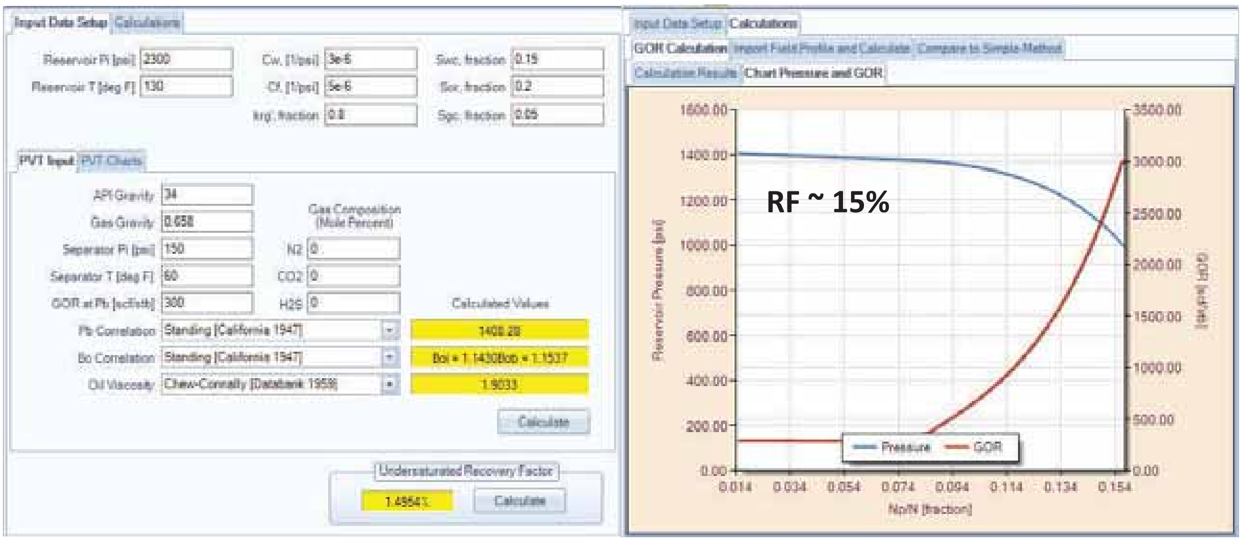


Figure 6-2 Analytical model for depletion recovery factor for low case

6.4 Water Flood Recovery

Figure 6-3 shows cases from an analytical tool for calculation of recovery factor based on the equation developed by the American Petroleum Institute (API) "A Statistical Study of Recovery Efficiency", 1967. The tool shows that the microscopic sweep efficiency in the range 56 – 59 - 62%, which depends on permeability, with cases for 500 – 1000 – 2000 mD, which i3 has viewed as a reasonable uncertainty range and is consistent with published literature from the Captain sand fairway (Ref 1). Rounded numbers to the nearest 5% have been used as a range (55% to 60%) in the recovery factor calculation for development EUR (Section 7.2).

This would imply recovery factors ranging from 45 – 47 - 50% for a high case with 80% macroscopic sweep efficiency, which would be a high case where there are sufficient producers and injectors to sweep most of the drainage area excepting limited areas around the periphery of the field and up-dip attic volumes.

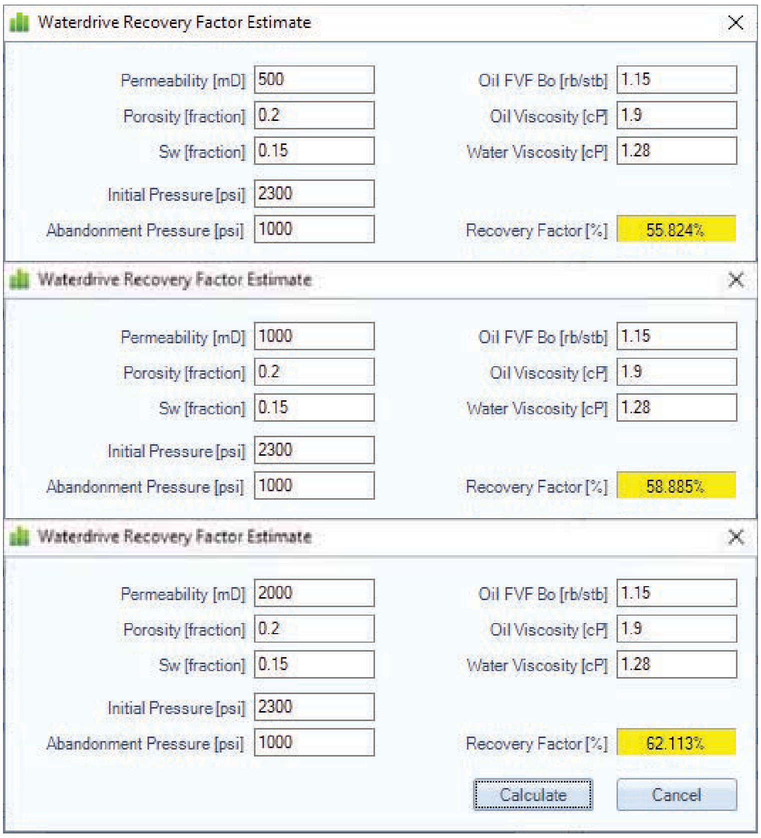


Figure 6-3 Analytical model cases for water flood recovery factor (microscopic sweep) for mid/high cases

7 Appraisal and Development Plans

7.1 Overview

The Serenity discovery well lies in block 13/23c immediately to the west and down-dip of the Tain discovery and 3 km west of the northern part of the producing Blake Field. The 13/23c-10 discovery encountered an ODT in thin (11 ft), but high-quality sandstones in a near-crestal location. TRACS consider that significant subsurface uncertainty remains, principally the position of the OWC and net sand thickness and continuity across the structure. Further appraisal is required in order to narrow the range of potential resources and understand reservoir development, particularly in the west of the Serenity structure.

i3 Energy currently anticipate a 2020/21 appraisal programme that will 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.

7.2 Development options

Detailed development strategy, options and economics have not been evaluated as part of this resource audit.

No firm development plans exist at present, though it is reasonable that Serenity could be produced as a phased development across existing infrastructure. For this review a notional development phasing is assumed as follows:

1. Serenity could be developed initially as a single well tie-back into the proposed Tain development, though no decision will be made on this development option until further appraisal has taken place. Public statements from the partner in the Tain field indicate the Tain project will be moving towards FDP mid-2020 based on a 2 well tie-back, via dedicated pipeline (19 km) to the Bleo Holm FPSO. The Tain operator, Repsol Sinopec Resources UK (RSRUK), issued an environmental statement for the proposed Tain development in March 2020 and first oil is targeted for Q3 2022.
2. Contingent on further appraisal of Serenity, there may be an economic case for further development by a water flood with up to 3 further producers and 3 injectors. In the mid and high cases there production volumes would justify a standalone FPSO development.

The following figures show schematics of the Serenity development in the deterministic low, mid and high cases.

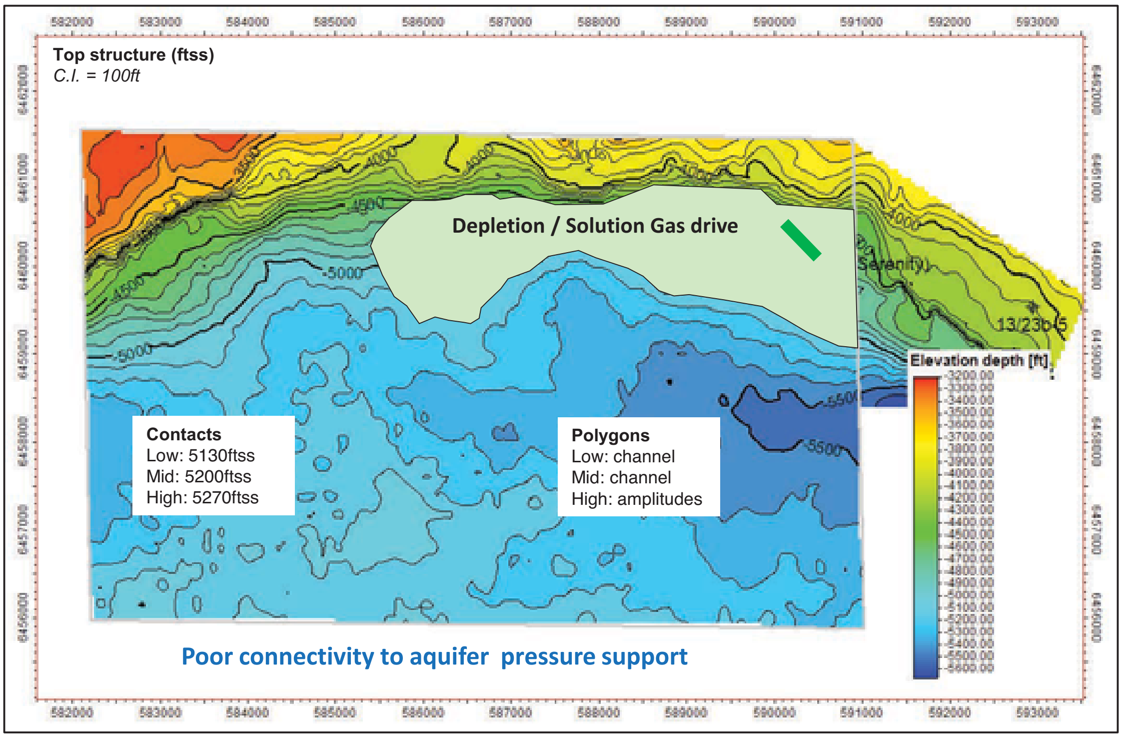


Figure 7-1 Notional single well tie-back development in the deterministic low case

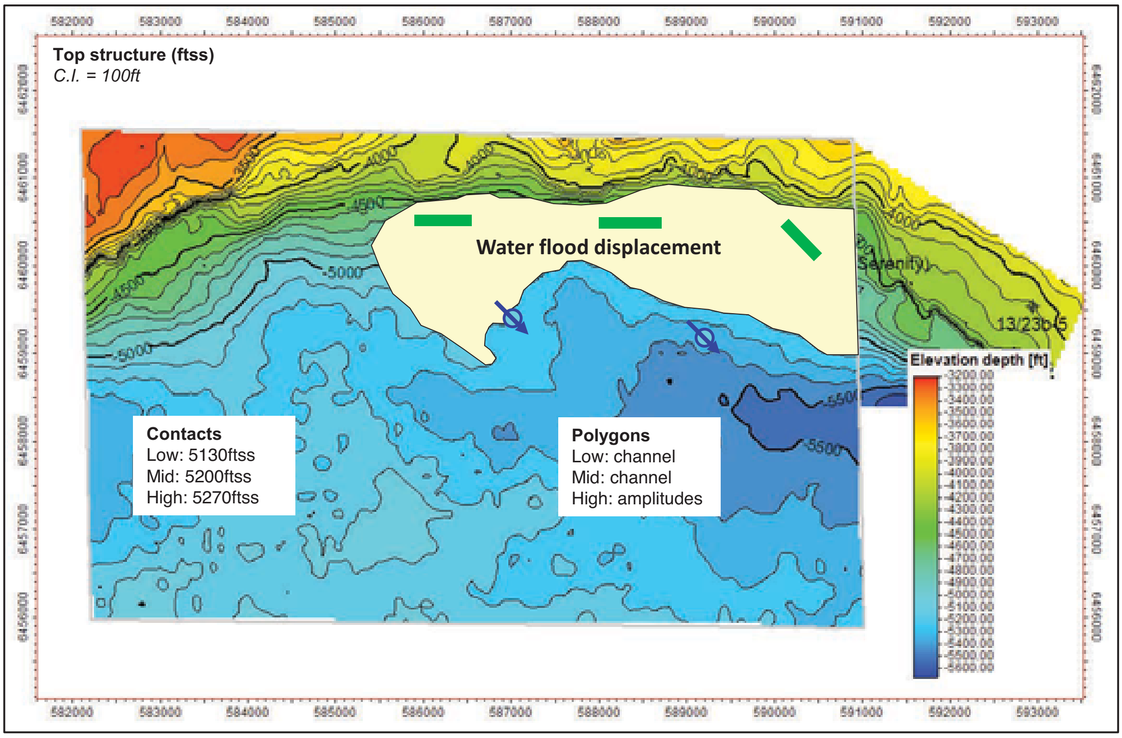


Figure 7-2 Notional water flood development in the deterministic mid case

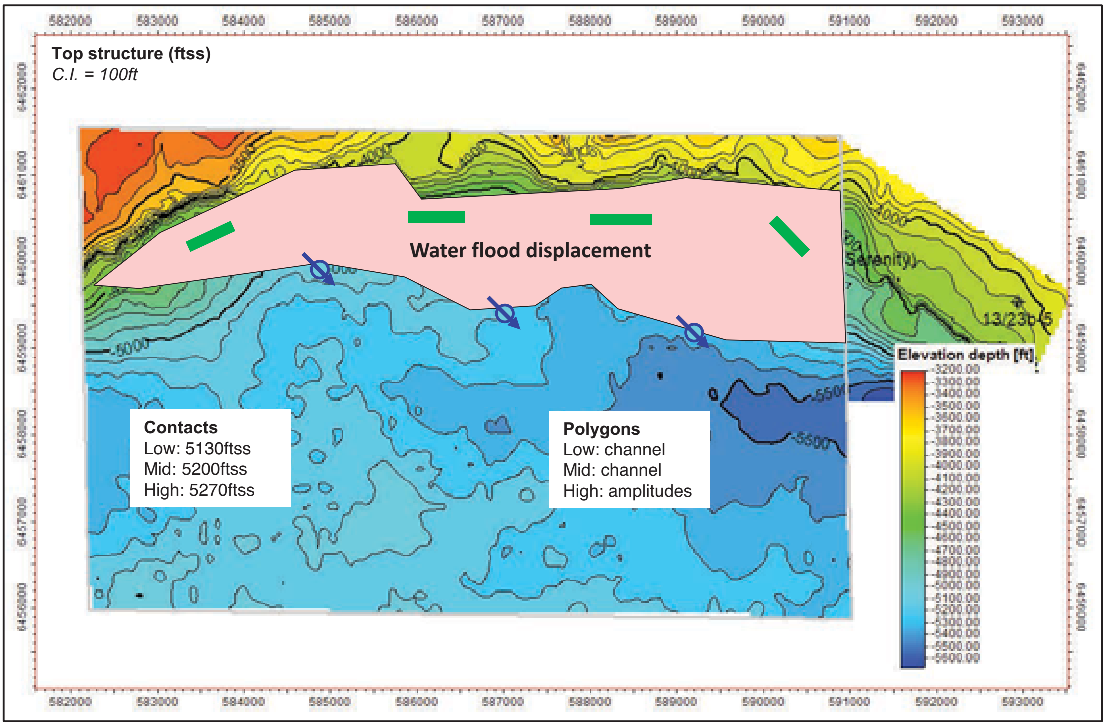


Figure 7-3 Notional water flood development in the deterministic high case

7.2.1 Phase 1 Single Well Tie-Back

Recovery factors have been defined for a single well tie back project in the deterministic cases.

- The low case is based on the low volumetric case, assumes poor connectivity to aquifer pressure support, and has only the preliminary development well. Figure 7-1 shows the location of the drainage area and development well. The preliminary well produces via a depletion and solution gas drive process. The recovery factor of 15% is based on the analytical model with the Liberator / Tain fluid properties (Boi ~ 1.13 – 1.17 rb/stb, GOR 300 – 340 scf/stb).

- The mid and high cases may produce via natural water drive, but with poor areal sweep efficiency from a single drainage point in the polygon. Areal sweep is assumed 30% in the mid case and 25% in the high case, which also result in a recovery factor of ~ 15% for these cases.

Table 7-1 shows the deterministic cases with recovery processes and resulting CR for a phase 1 single well tie-back development.

Phase 1 Case	STOIIP MMstb	Aquifer strength	Recovery Process	Micro sweep	Phase 1 (CR Development Unclarified)			
					#wells	Drainage	RF pct	Incr. CR
Low	16	Weak	Depl/SGD	15%	1p	100%	15%	2.4
Mid	42	Moderate	Nat. WD	55%	1p	30%	15%	6.5
High	240	Strong	Nat. WD	60%	1p	25%	15%	36.0

Table 7-1 Deterministic cases recovery for a phase 1 single well tie-back development

7.2.2 Phase 2 Standalone Water Flood

Recovery factors have been defined for standalone water flood project in the deterministic cases.

- In the low case the depletion of the preliminary well will be evidence for low STOIIP and poor connectivity to the aquifer, in which case there would be no further development.
- In the mid case there is a further water flood development with further 2 producers and 2 injectors. Figure 7-2 shows the location of the drainage area and development wells. A moderate areal sweep efficiency of 70% is assumed. In addition a microscopic sweep efficiency of 55% is used (low end of the range from the work shown in Section 6.4). This gives a total recovery factor of 39%.
- In the high case there is a further water flood development with further 3 producers and 3 injectors. Figure 7-3 shows the location of the drainage area and development wells. A higher areal sweep efficiency of 80% is assumed. A microscopic sweep efficiency of 60% is assumed in the high case (high case from range from Section 6.4) giving a total recovery factor of 48%.

Table 7-2 shows the deterministic cases with recovery processes and resulting CR for a phase 2 standalone water flood development.

Phase 2 Case	STOIIP MMstb	Aquifer strength	Recovery Process	Micro sweep	Phase 2 (CR Development Unclarified)			
					#wells	Drainage	RF pct	Incr. CR
Low	16	Weak	-	-	-	-	15%	0.0
Mid	42	Moderate	Water flood	55%	+2p, 2i	70%	39%	9.7
High	240	Strong	Water flood	60%	+3p, 3i	80%	48%	79.2

Table 7-2 Deterministic cases recovery for a phase 2 water flood development

7.3 Summary Development Recovery

Table 7-3 shows a summary of Serenity CR projects and recovery.

Summary CR Case	STOIIP MMstb	Phase 1 (Unclarified)		Phase 2 (Unclarified)		Total all phases	
		#wells	Incr CR	#wells	Incr CR	Total CR	RF pct
Low	16	1p	2.4	-	-	2.4	15%
Mid	42	1p	6.5	2p, 2i	9.7	16.2	39%
High	240	1p	36.0	3p, 3i	79.2	115.2	48%

Table 7-3 Summary Serenity recovery by phase and total CR

8 Resource Estimation

The primary objective of the resource assessment has been to evaluate the Contingent resources of Serenity discovery, providing a range of STOIIP and associated range of recovery factors to arrive at a range of recoverable resources.

8.1 Classification

The Serenity discovery has resources defined for two development phases in the Contingent Resource, Development Unclarified categories. The development phases are presented in 7.2.

Note that development planning is at a preliminary stage and no economic value has been determined. A Risk Factor reflecting the chance of development has not been evaluated for the Serenity project because of the preliminary nature of the analysis.

Development	Project Description	Resource Category
Phase 1	Single well tie-back into the Tain development	CR Development Unclarified, non-Technical contingency
Phase 2	Water flood with up to 3 additional producers and 3 injectors, standalone FPSO development	CR Development Unclarified, non-Technical and Technical contingency

Table 8-1 Serenity discovery – Contingent resource summary

8.2 Contingent Resources

Table 8-2 shows a summary of the unrisked contingent resources described in section 7. Estimates of contingent resources are prepared in accordance with reserves definitions presented in the SPE's Petroleum Resources Management System ("SPE-PRMS" summary in Appendix A – Summary of 2018 SPE Petroleum Resource Management System Classification).

i3 Energy Working Interest 100%, Unrisked									
Asset	Resource Category	Company Share Gross Resources				Company Share Net Resources			
		Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (MMscf)	NGL (MMbbl)	BOE (MMbbl)
Serenity, Block 13/23c	1C	2.4	-	-	2.4	2.4	-	-	2.4
	2C	16.2	-	-	16.2	16.2	-	-	16.2
	3C	115.2	-	-	115.2	115.2	-	-	115.2

Table 8-2 Serenity Discovery – Contingent Resource summary

9 References

Ref 1 Shell UK Limited. Peterhead CCS Project: Static Model Reports (Doc No PCCS-05-PTD-ZG-0580-00001), March 2015

10 Glossary of Terms

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

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

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 Unclarified	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

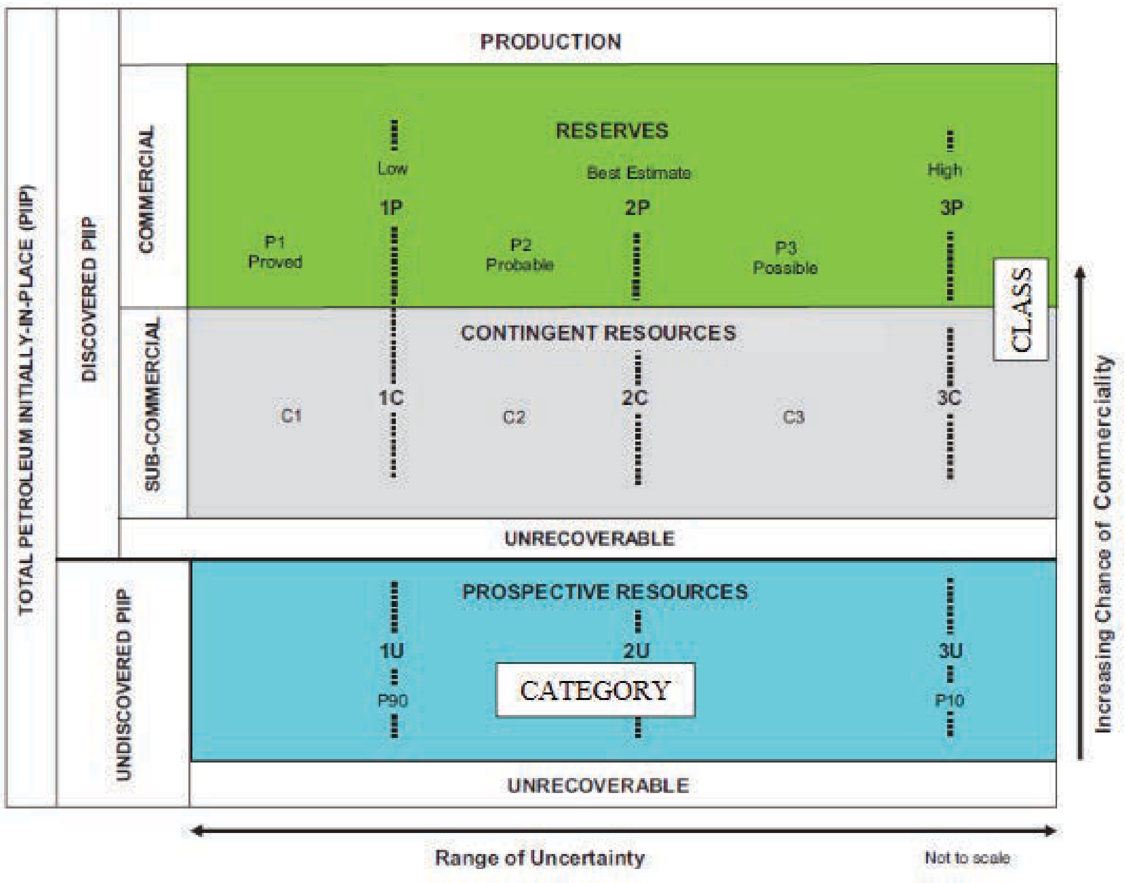


Figure A 1 SPE PRMS Petroleum Resources Classification Framework