

**Competent Person's Report  
on the Oil and Gas Assets of i3 Energy  
as at 31<sup>st</sup> January, 2017**

Prepared for

**i3 Energy North Sea Limited**

19th July, 2017

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- III. Contingent Resources Summary Table
- IV. Production Profiles

19<sup>th</sup> July, 2017

The Directors,  
**i3 Energy North Sea Limited**  
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The Directors  
**W H Ireland Limited**  
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Dear Sirs,

## Introduction

At the request of i3 Energy North Sea Ltd (i3 Energy), Gaffney, Cline & Associates (GCA) has prepared a Competent Person's Report (CPR) on the oil and gas assets of i3 Energy, as at an Effective Date of 31<sup>st</sup> January, 2017. i3 Energy has recently acquired a 100% Operated Interest in UK Licence P.1987 from Dana Petroleum (E&P) Limited (Dana). This Licence covers Block 13/23d in the UK North Sea and contains the Liberator discovery (Figure 1), which i3 Energy intends to develop.

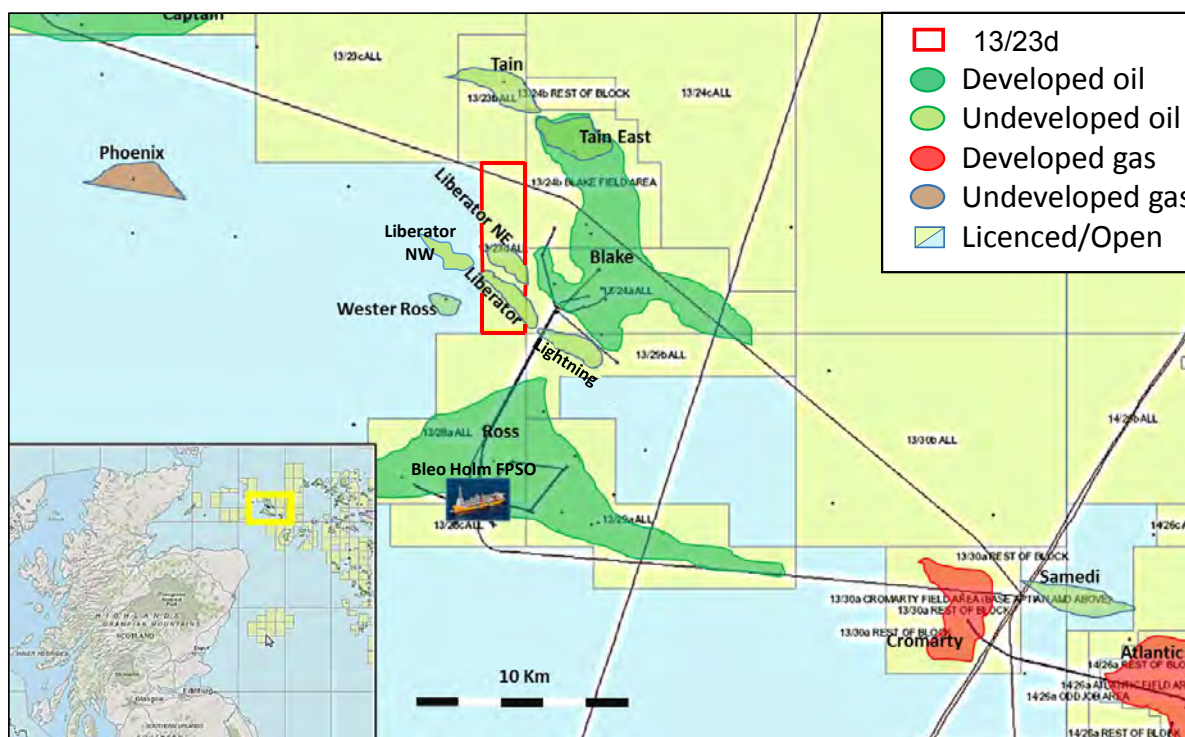
This CPR is in support of a listing on the AIM (formerly the Alternative Investment Market) of the London Stock Exchange, and it has been prepared for that purpose.

In the preparation of this report, GCA has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in March 2007 (see Appendix I). GCA has also followed the requirements of the "AIM Rules – Guidance for Mining and Oil & Gas Companies" dated June, 2009.

This report relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

A glossary of abbreviations used in this report is contained in Appendix II.

Figure 1: Liberator Location Map



Source: modified from i3 Energy

## Summary and Conclusions

### Licence Summary

i3 Energy has recently acquired a 100% Operated Interest in UK licence P.1987 from Dana (Table 1). This licence covers Block 13/23d in which the Liberator discovery and the adjacent Liberator NE structure are located.

Table 1: Summary of Assets as at 31<sup>st</sup> January, 2017

Asset	Operator	Interest (%)	Status	Licence Expiry	Licence Area (km <sup>2</sup> )
Licence P.1987 (Block 13/23d)	i3 Energy	100	Exploration	31 <sup>st</sup> December, 2020 <sup>1</sup>	15

Notes:

1. On approval of a field development plan, a 20-year production licence would be issued.

GCA understands that i3 Energy is also in discussion with the Oil and Gas Authority (OGA) prior to submitting a Field Development Plan (FDP) that would include possible extensions of Liberator to the NW into Block 13/23a (Liberator NW), which is open, and to the SE into Block 13/24a, operated by Repsol Sinopec Resources UK Ltd (Repsol). i3 Energy expects that on approval of the FDP by the OGA, i3 Energy, as the developing party, will be awarded a field development area covering these extensions. This expectation is based on i3 Energy's interpretation, following consultation with the OGA, of the recently published guidelines for Maximising Economic Recovery (MER) in the UK, which seek to ensure hydrocarbon

resources are not left stranded and undeveloped. According to i3 Energy, Repsol has stated that it does not wish to be a party in the development of Liberator, and GCA has seen evidence that i3 Energy has engaged with Repsol in order to obtain access to infra-structure and off-take services that will provide the means to develop the Liberator cluster. Nonetheless, whether the OGA will require Repsol to relinquish the part of Block 13/24a that i3 Energy seeks to obtain, or whether some form of unitization or other commercial arrangement will be required, is not yet clear to GCA. GCA considers there is a risk that this could delay the development, although it understands that i3 Management, following discussions with the OGA, is of the opinion that delays are unlikely.

Volumes are reported herein both within i3 Energy's current acreage and for the larger field development area that i3 Energy expects to be awarded.

## Overview

The data provided to GCA were primarily obtained by i3 Energy from a data room set up by Dana Petroleum specifically for i3 Energy; these data consist of presentation material, screen shots of selected seismic sections and well sections taken from a Kingdom seismic interpretation project. Some limited digital data was made available in the form of top reservoir depth structure grids derived by i3 Energy from the seismic data available in the data room, and well logs from the discovery well 13/23d-8. However, GCA has had no access to the seismic data and therefore has been able to make only very limited checks on the maps provided by i3 Energy and on the interpretations and assumptions made in generating them.

GCA has been able to confirm that the best estimates of STOIP presented by i3 Energy are consistent with the maps provided and the well log data, on the assumption that there is no significant gas cap present. This assumption is supported by the slightly under-saturated nature of the oil, the fact that the Blake field is reported to have only small, local gas caps, each with a different gas-oil contact (GOC), and the absence of any amplitude anomaly over Liberator in the seismic data (which GCA has been unable to check in detail).

GCA has made low and high estimates of STOIP based on plausible assumptions on uncertainty in the top surface maps and, in the low case, assuming that the GOC encountered in the well extends across the entire Liberator structure.

A two-well FDP is currently envisaged by i3 Energy and consists of one horizontal well in the main Liberator structure and a second in the Liberator NE structure. These production wells are proposed to be tied into the subsea Blake production manifold, where the produced fluids would be co-mingled with Blake production and flowed to the Bleo Holm floating production, storage and offloading vessel (FPSO) for processing. The Bleo Holm is a purpose built, double hulled FPSO currently used for processing fluids from the Blake and Ross fields. Oil is stored on board and exported to market via an established fleet of shuttle tankers. Gas not used for fuel or flared is exported via a 6" pipeline to the Frigg system and on to the St Fergus gas terminal. GCA understands that there is adequate ullage at present to handle Liberator production. However, i3 Energy will need to reach an agreement with the partners in the Blake and Ross fields to enable the development to proceed. GCA understands that i3 Energy are in discussions with Repsol, the Operator of the Blake and Ross fields, and communications received by i3 Energy from Repsol indicate that Repsol is receptive to the concept.

GCA understands that the Bleo Holm will need to be "maintained in class" for insurance purposes in 2019, which GCA understands to be in hand, and again in 2024. In GCA's view, there is uncertainty as to whether the FPSO facilities would be available after 2024, although Repsol has indicated its intent to work towards maintaining the vessel in class for as long as is economically justified. Other solutions for production beyond 2024 could be also envisaged.

## Contingent Resources Summary

Contingent Resources are attributed to the two-well FDP of Liberator and Liberator NE outlined by i3 Energy, as shown in Table 2. Volumes are shown gross and are separated into those lying within Block 13/23d and those lying outside of the Block but within the larger Field Area that i3 Energy expects to be granted consent to produce. Volumes within the Block are 100% attributable to i3 Energy, but i3 Energy currently has no entitlement to volumes outside the Block.

The Contingent Resources estimates are based on production from the first well starting at the beginning of 2018, production from the second well at the beginning of 2020, and the Bleo Holm FPSO being available until the end of 2024. The development plan includes two wells to be drilled, however, GCA has assumed that for the 1C case, the second well (Liberator NE) would not be drilled.

**Table 2: Liberator Development Contingent Resources (Development Pending)  
as at 31<sup>st</sup> January, 2017**

**(a) Within Block 13/23d (i3 Energy Operator with 100% Interest)**

Structure	Oil (MMBbl)			Gas (Bscf)		
	1C	2C	3C	1C	2C	3C
Liberator	2.5	5.8	9.5	8.0	1.5	2.5
Liberator NE	-	2.3	4.2	-	0.6	1.1
<b>Total</b>	<b>2.5</b>	<b>8.1</b>	<b>13.6</b>	<b>8.0</b>	<b>2.1</b>	<b>3.5</b>

**(b) Outside Block 13/23d<sup>2</sup>**

Structure	Oil (MMBbl)			Gas (Bscf)		
	1C	2C	3C	1C	2C	3C
Liberator	0.6	1.5	2.4	2.0	0.4	0.6
Liberator NE	-	0.6	1.0	-	0.1	0.3
<b>Total</b>	<b>0.6</b>	<b>2.1</b>	<b>3.4</b>	<b>2.0</b>	<b>0.5</b>	<b>0.9</b>

Notes:

1. Contingent Resources shown here are 100% of the volumes estimated to be recoverable from the project, in the event that it goes ahead.
2. i3 Energy currently has no entitlement to Contingent Resources outside Block 13/23d; those shown in this table lie in acreage currently operated by Repsol.
3. Gas Contingent Resources are higher in the 1C case than in the 2C and 3C cases because the 1C case assumes a large gas cap is present in Liberator, whereas the 2C and 3C cases assume that the Liberator structure is almost completely oil-filled.
4. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
5. GCA has not estimated any “Chance of Development” or “Risk Factor”: these depend largely on non-technical matters, such as reaching agreement with other parties; GCA does not have all the information that would be required to make a quantitative estimate and therefore considers it would be inappropriate to do so.
6. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
7. Totals may not exactly equal the sum of individual entries due to rounding.

GCA considers the Contingent Resources shown in Table 2 to be in the “Development Pending” sub-class defined by the SPE PRMS. On the assumption that the finance necessary for the development will be raised, the steps that remain before the development can go ahead include:

- Approval of the FDP by the OGA;
- Award of the extended development area to i3 Energy or reaching a form of agreement to proceed on another basis; and
- Reaching agreement with Repsol and the other Ross and Blake partners (of which there are several) for use of the Blake field production facilities.

Once there is reasonable certainty that all of these will be forthcoming, the volumes shown in Table 2 could be reclassified as Reserves, subject to:

- There still being a firm intention to proceed with the project in the form and according to the timing outlined herein;
- Project economics remaining favourable; and
- No new technical or commercial data having become available that would lead to a revision of the estimated volumes.

Contingent Resources are additionally attributed to possible further development of the Liberator area, including production beyond 2024 and a third well, located in Liberator NW. GCA considers these Contingent Resources to be in the “Development Unclassified or On Hold” sub-class defined by the SPE PRMS, as are shown in Table 3.

**Table 3: Contingent Resources (Development Unclarified or On Hold)  
as at 31<sup>st</sup> January, 2017**

**(a) Within Block 13/23d (i3 Energy Operator with 100% Interest)**

Structure	Oil (MMBbl)			Gas (Bscf)		
	1C	2C	3C	1C	2C	3C
Liberator	0.1	0.8	3.0	0.8	0.2	0.8
Liberator NE	-	0.1	0.9	-	0.0	0.2
<b>Total</b>	<b>0.1</b>	<b>0.9</b>	<b>3.9</b>	<b>0.8</b>	<b>0.2</b>	<b>1.0</b>

**(b) Outside Block 13/23d<sup>2</sup>**

Structure	Oil (MMBbl)			Gas (Bscf)		
	1C	2C	3C	1C	2C	3C
Liberator	0.0	0.2	0.8	0.2	0.0	0.2
Liberator NE	-	0.0	0.2	-	0.0	0.1
Liberator NW	-	4.1	8.3	-	1.1	2.2
<b>Total</b>	<b>0.0</b>	<b>4.3</b>	<b>9.3</b>	<b>0.2</b>	<b>1.2</b>	<b>2.5</b>

Notes:

1. Contingent Resources shown here are 100% of the volumes estimated to be recoverable from the project, in the event that it goes ahead.
2. i3 Energy currently has no entitlement to Contingent Resources outside Block 13/23d; those shown in this table lie in acreage currently operated by Repsol, apart from Liberator NW, which is in open acreage.
3. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
4. GCA has not estimated any “Chance of Development” or “Risk Factor”: these depend largely on non-technical matters, such as reaching agreement with other parties; GCA does not have all the information that would be required to make a quantitative estimate and therefore considers it would be inappropriate to do so.
5. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.
6. Totals may not exactly equal the sum of individual entries due to rounding

A summary table of all Contingent Resources is presented in Appendix III.

### Economic Summary

GCA has performed an economic assessment of the FDP outlined by i3 Energy as described herein, i.e. of the Contingent Resources in the Development Pending sub-class as shown in Table 2. This assessment is based upon estimates of costs provided by i3 Energy, including tariff payments that have yet to be agreed, and upon GCA’s understanding of the fiscal terms governing the assets. Further details are given in Section 5 of this report.

GCA’s Brent Crude oil price scenario for the first quarter of 2017, shown in Table 4, has been used as the reference oil price.

**Table 4: Brent Crude Oil Price Scenario**

Year	Price (US\$/Bbl)
2017	58.35
2018	58.36
2019	65.00
2020	70.00
2021 Onwards	+2% p.a.

Reference Pre- and Post-Tax Net Present Values (NPVs) have been attributed to the Contingent Resources (Development Pending) cases, at a discount rate of 10% (NPV10) and are shown in Table 5. NPVs are quoted both at the gross project level and net to i3 Energy's current acreage, and are presented as unrisksed.

**Table 5: Unrisksed NPV10 (US\$ MM) of Potential Future Revenue from Contingent Resources (Development Pending) as at 31<sup>st</sup> January, 2017**

**(a) Gross Project**

	1C	2C	3C
Pre-Tax	73	311	576
Post Tax	48	190	349

**(b) Net to i3 Energy's Current Acreage (Block 13/23d)**

	1C	2C	3C
Pre-Tax	58	249	461
Post Tax	38	152	279

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. Gross Project NPVs reported here are based on 100% of the revenues estimated to be derived from the development project, in the event that it goes ahead, and relate to the extended development area, covering Liberator and Liberator NE, including the parts outside of Block 13/23d.
3. The NPVs reported here are "unrisksed" in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein

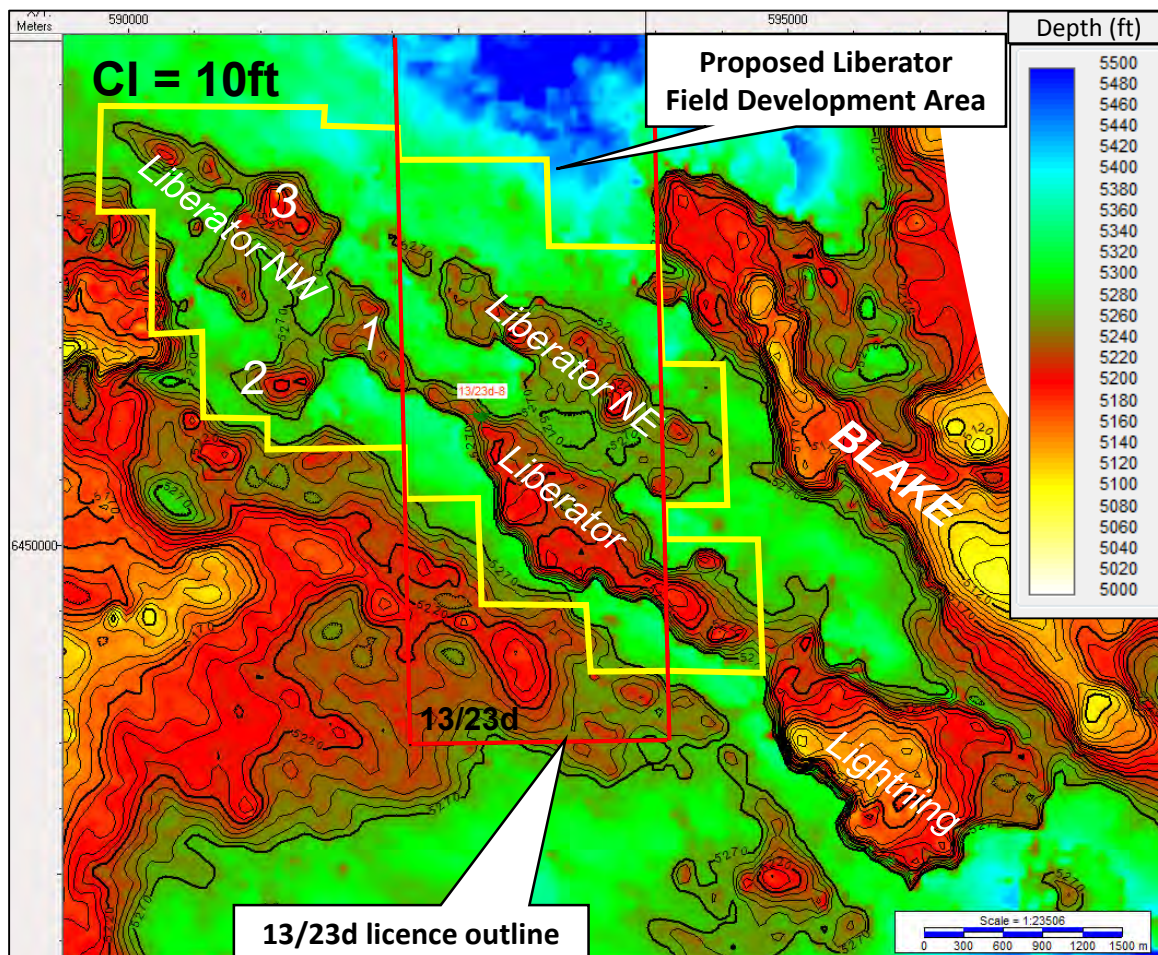
## Discussion

### 1 Background

The Liberator oil discovery is located in the South Halibut Basin of the Moray Firth Province, 120 km north-east of Aberdeen (Figure 1), adjacent to the Blake and Ross fields. Liberator was discovered in 2013 by the 13/23d-8 exploration well, which was drilled by Dana and targeted a four-way dip closed structure located 2.5 km west of the Blake field. The well encountered 19.5 ft of under-saturated, 30°API oil underneath 3.5 ft of gas in the high quality (typically 1 Darcy or more) Captain Sandstone of Albo-Aptian age at a depth of approximately 5,250 ft ss. Liberator appears to have the same original oil-water contact (OWC) as the Blake field, which has been producing from the Captain Sandstone reservoir since 2001.

The top reservoir map provided by i3 Energy (Figure 2) shows Liberator to be a NW-SE oriented, elongated structure, with the discovery well located on the flank near its north-western extremity. The map shows several other structural highs, all of which appear connected within the oil column but separated by saddles where the oil column would be very thin (less than 10 ft). These other highs are Liberator NE, Liberator NW (itself comprising three separate structural culminations), Lightning and Blake.

**Figure 2: Top Reservoir Depth Structure Map (contoured down to OWC at 5,270 ft TVDss)**



Source: i3 Energy

Figure 2 also indicates that the majority of the Liberator and Liberator NE structures lie within Block 13/23d (blue line), but extend to some degree into the Repsol-operated Block 13/24a to the east, while Liberator NW lies almost entirely to the west of Block 13/23d, in open acreage. The Field Development Area that i3 Energy expects to be granted approval to produce from (shown by the yellow outline) encompasses all three structures.

GCA is not aware of any director of i3 Energy having held any previous interest in the asset.

## **1.1 Data Base**

The data provided to GCA were primarily obtained by i3 Energy from a data room set up by Dana specifically for i3 Energy; these data were derived from a Kingdom project and consist of presentation material, screen shots of selected seismic sections and well sections. Some limited digital data was made available in the form of top reservoir depth structure grids and well logs from the discovery well 13/23d-8. There were no seismic data or subsurface models available. GCA understands that i3 Energy has subsequently purchased the seismic data to support implementation of the field development.

i3 Energy has provided a draft Field Development Plan (FDP) in which a two-well conceptual development plan with a tie-back to the Blake field subsea production module and FPSO (Bleo Holm) is outlined.

## **2 Subsurface Evaluation**

### **2.1 Petrophysics**

GCA has reviewed the wireline logs (Figure 3), End of Well Report and other petrophysical data and confirms that the well found an oil-water-contact (OWC) at -5,270 ft ss and 19.5 ft of oil below 3.5 ft of gas within an overall sand package of more than 300 ft. There is a residual oil column of some 30 ft interpreted below the OWC, consistent with that seen in Blake and thought to be caused by tilting of the structure after the hydrocarbons became trapped. This residual oil would not be mobile and is not included in the STOIIIP estimates.

Net-to-gross ratio (NTG) and porosity estimates reported by i3 Energy and used for its volumetric calculations appear reasonable, based on the wireline data from the 13/23d-8 well. However, Blake is reported to have slightly poorer porosity than Liberator, which is reflected in the range of values used. The oil saturation used assumes the development well will be drilled within the transition zone of a larger oil column. i3 Energy's reservoir averages for Liberator are shown in Table 6 below.

Figure 3: CPI of 13/23d-8 Well from the End of Well Report

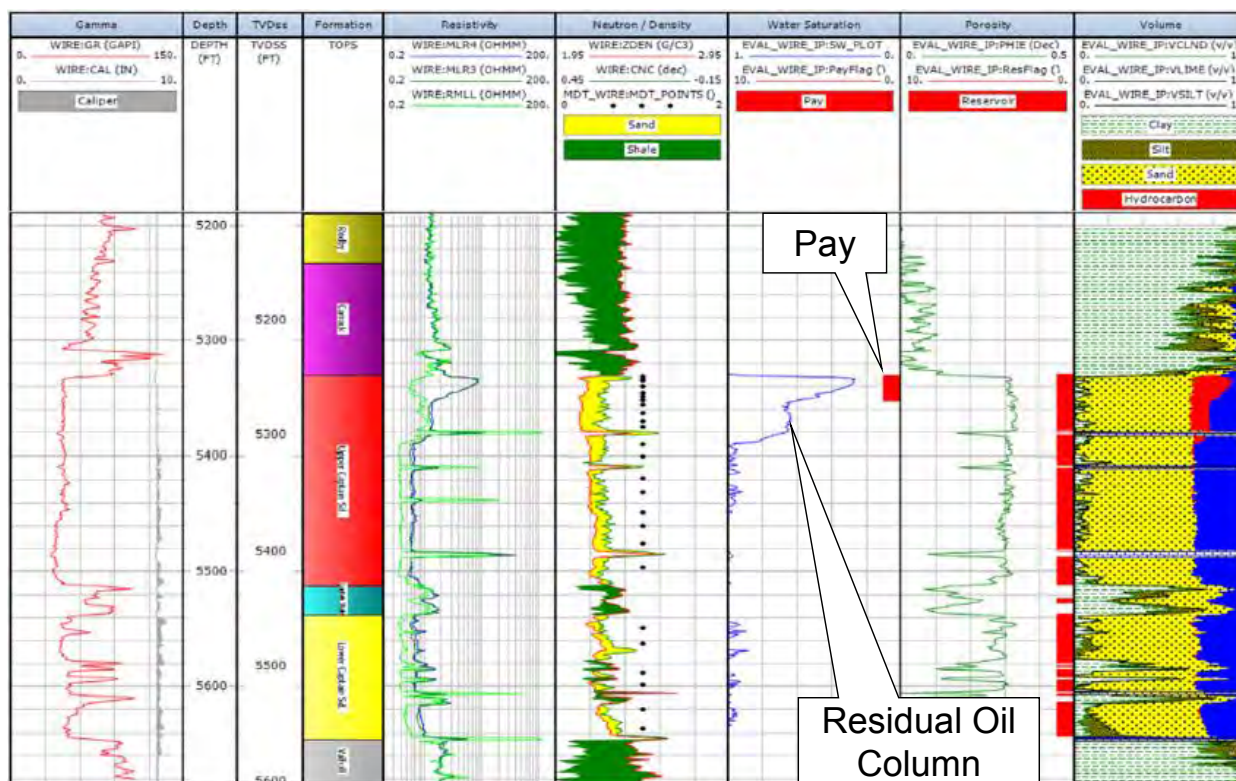


Table 6: Average Reservoir Properties used for STOIP Estimates

Property	Low	Best	High
NTG	0.94	0.96	0.98
Porosity	0.28	0.30	0.31
Oil Saturation	0.74	0.78	0.80

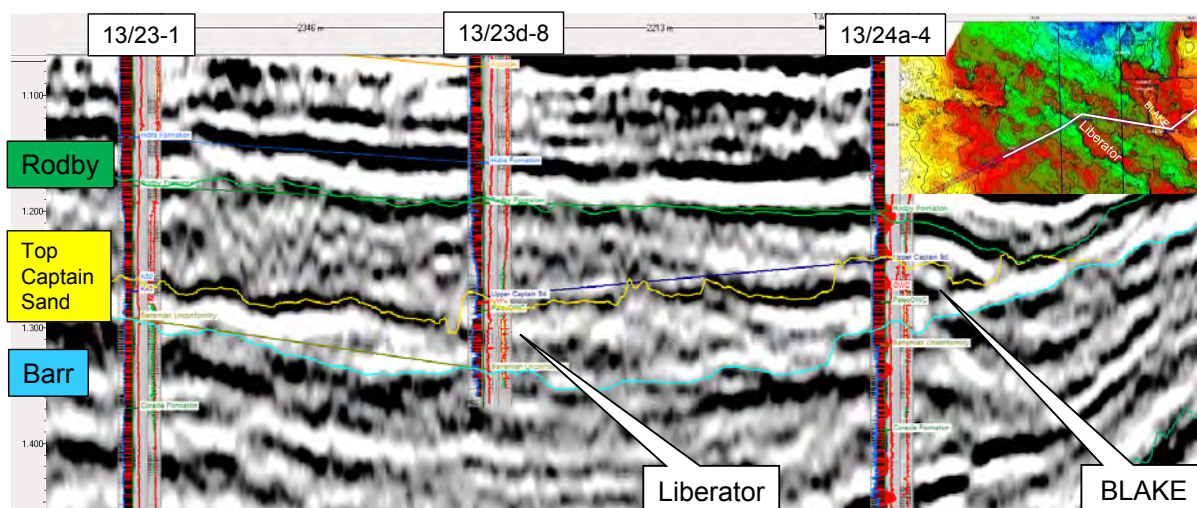
## 2.2 Structure

The structure of the Liberator discovery is much less tightly constrained than its reservoir properties.

The digital maps, comprising a top Captain Sandstone depth structure (K50) grid and a derived height-above-OWC grid were made available to GCA for this audit. These were generated in a data room by the i3 Energy geoscientist, who was already familiar with the asset. Images of several interpreted seismic sections crossing the discovery were made available, along with presentations on the synthetic well-ties to offset wells, an image of the original TWT grid, and a description of the depth conversion process used.

The seismic section in Figure 4 illustrates the correlation with the Blake field.

Figure 4: Seismic TWT section showing the Liberator Discovery Well and the Blake field.



Source: i3 Energy

## 2.3 Subsurface Risks

GCA sees two subsurface risks; firstly demonstration of hydrocarbons in place in the undrilled areas of the structures, which is subject to seismic depth uncertainty and secondly distribution of free gas across Liberator.

### 2.3.1 Depth Conversion.

A good correlation is observed between the well data, synthetics and seismic data. The pre-drill prognosis for the top Captain Sandstone (K50) was 105 ft shallower than actually found, mostly due to the pre-2012 seismic interpretation failing to distinguish between the Carrack and Captain Formations.

Depth conversion is a recognised uncertainty in any structural mapping. The depth conversion used by i3 Energy in the data room was a two-layer approach (average velocity to Top Rodby, followed by an isopach generated from the seismic isochron and the interval velocity of Rodby itself). The Top Rodby surface was tied to the wells in depth then the isochron to K50 was depth converted using interval velocity and hung from below. This was a reasonable approach to take given the time constraints of a data room, and demonstrates clearly the presence of structures.

This workflow ensures good residuals at the wells, but retains uncertainty between wells, depending on how the residual corrections were applied. For example, using the velocity function generated during the data room, there was a mistie of only 7 ft at 13/23d-8 at Top Rodby, which is good but is comparable to the height of connection invoked between the various Liberator structures. The final depth structure map (Figure 2) would vary depending on how the residual corrections were applied.

Further, GCA notes that the structure called Lightning is more closely connected to both Liberator and Blake than Liberator is to any of the adjacent structures, yet Lightning is not considered as contributing resources to the Liberator development.

### 2.3.2 Hydrocarbon Resources

From the data presented, GCA is confident that several structural highs exist and that they are likely to be hydrocarbon bearing, but the connections between them are tenuous and not confidently known, being below reasonable levels of seismic resolution. According to the map presented by i3 Energy (Figure 2), the saddles between Liberator and Liberator NE and between Liberator and each of the extensions in the NW (1, 2 or 3), are less than 10 ft above the OWC.

While Liberator and Blake appear to have a common OWC, and therefore to be part of the same accumulation, the map in Figure 2 suggests that the communication between Liberator and Blake is via Lightning, rather than Liberator NE.

GCA therefore considers that the presence of hydrocarbons in Liberator NE and Liberator NW is not yet proved, and GCA has omitted these structures from the Low case. On the basis of the map presented, however, GCA accepts that it is probable that the discovery made at Liberator extends into Liberator NE and Liberator NW, so volumes therein are included in the Best and High cases.

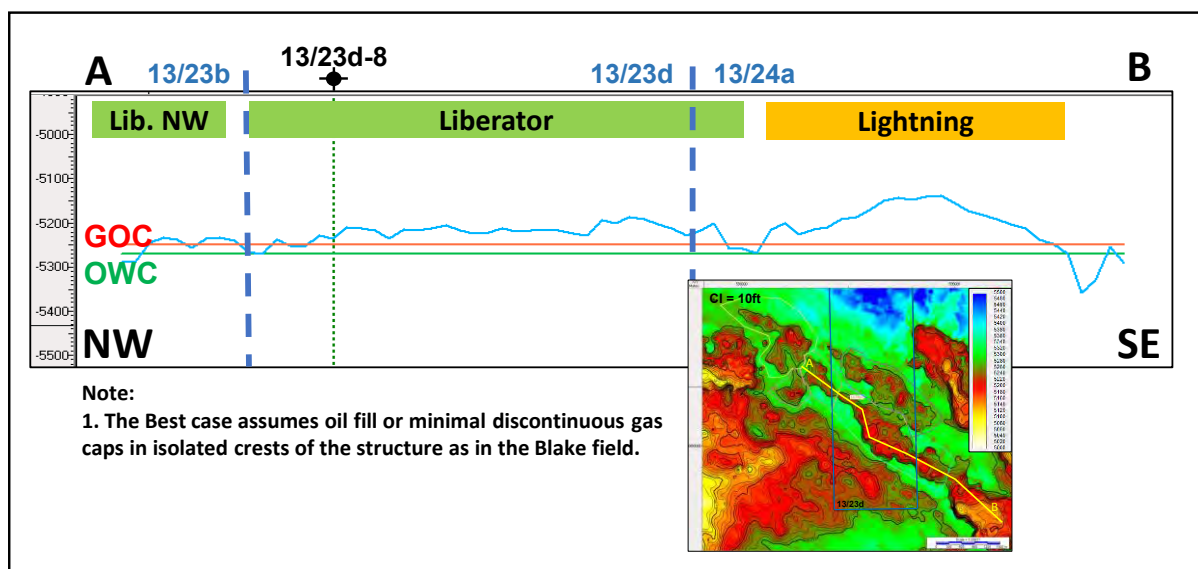
### 2.3.3 Fluid Fill

There is a confirmed 3.5 ft gas leg in the Liberator well. Discontinuous pockets of free gas are reported across the Blake field, even though it does not have a large gas cap or a common shared GOC.

The pressure, volume and temperature (PVT) analysis of the fluid samples obtained indicates that the Liberator oil is slightly under-saturated, which would support that the gas cap is not large. Wireline (MDT) pressure data also indicate a depletion of approximately 70 psi compared to the initial pressure at Blake, which is 12 psi above the measured bubble point. It is possible that the gas is a small isolated gas cap in an inferred closure below the seismic resolution. However, the available structure maps do not show any local closure at the discovery well location (Figure 5), so if the gas in the vicinity of the well 13/23d-8 at Liberator is an isolated pocket, the structure must be more segmented or have more numerous culminations than mapped. Until further wells are drilled, the possibility that gas extends across the whole structure cannot be ruled out.

The presence of a large gas cap would significantly reduce the volume of oil present in the Liberator structure (as indicated by the cross-section in Figure 5), although it would mean that a significant volume of gas would be available for monetisation.

Figure 5: Top Reservoir Structural Cross-Section NW to SE with OWC and Low Case GOC



Additional evidence to support the absence of a large gas cap was provided by i3 Energy in the form of a seismic amplitude map, covering both the Liberator discovery and the Blake field, which shows the absolute seismic amplitude extracted across a vertical window including the Captain sandstone (Figure 6). GCA notes, however, that the window used is over 200 ms thick and includes signal from most of the Lower Cretaceous and may not be an unequivocal indicator of the top Captain Sandstone reservoir response. The seismic insert in Figure 6 hints at an amplitude dimming over Liberator, but this is not reflected in the map or in the logs. Further, the amplitude anomalies identified at Blake and interpreted to support the presence of gas, are not directly coincident with the mapped structural culminations nor are they clearly due to a response at top reservoir.

Figure 6: Amplitude Extraction and Associated Extraction Window in Red

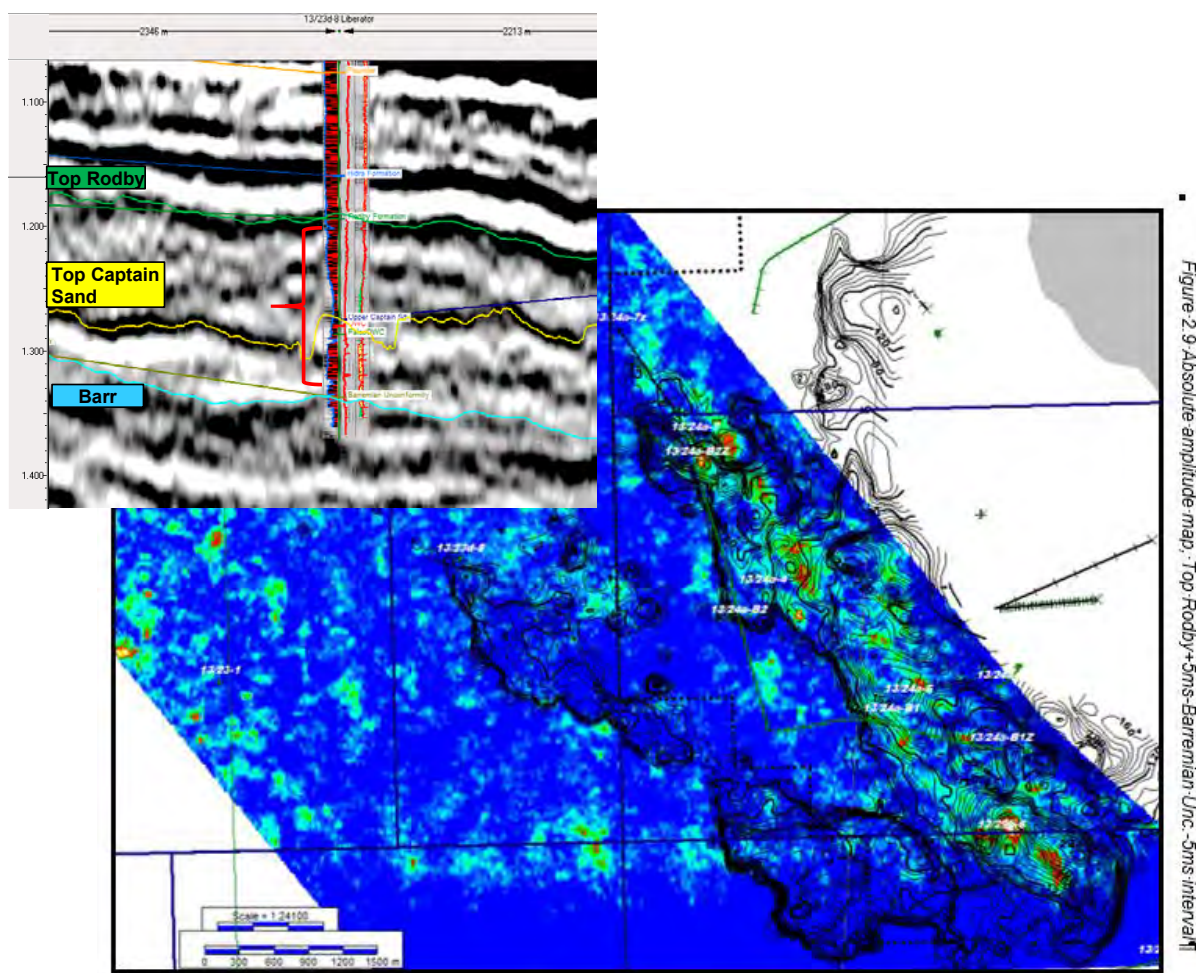


Figure 2.9 Absolute amplitude map, Top Rodby+5ms-Barremian Unc. 5ms interval

Source: i3 Energy

### 3 Hydrocarbon Volumes Initially in Place

GCA has confirmed that the Gross Rock Volumes (GRVs) estimated for Liberator and Liberator NE by i3 Energy are consistent with the grids supplied. Only one case was provided by i3 Energy, and has been taken as the Best (mid) case. GCA has made High and Low GRV estimates to account for the uncertainties discussed above.

In this assessment, the basis for estimating GRV in the Low, Best and High cases for Liberator, Liberator NE and the Liberator NW extensions is:

- **Low Case:** 19.5 ft oil leg across the structure with a GOC at 5,250 ft ss, the depth at which it was measured in the 13/23d-8 well, supporting a large gas column; no hydrocarbons present in Liberator NE and Liberator NW as there is sufficient structural uncertainty that these could be isolated closures;
- **Best Case:** no significant gas cap, all structures fully oil-filled down to the OWC at 5,270 ft ss;

- **High Case:** same as the Best case but assuming that the top reservoir is 10 ft shallower across all three areas.

Low, Best and High STOIP and GIIP estimates were then made by GCA by combining the GRV estimates with the average reservoir petrophysical parameters shown in Table 6, using a deterministic approach. These STOIP and GIIP volumes are tabulated below in Table 7.

**Table 7: Estimates of STOIP and GIIP in the Liberator Accumulations**

Structure	STOIP (MMBbl)			GIIP (Bscf)		
	Low	Best	High	Low	Best	High
Liberator	12.1	25.8	35.2	16.2	6.7	9.2
Liberator NE	-	9.8	16.3	-	2.5	4.2
Liberator NW	-	13.7	21.8	-	3.6	5.7
<b>Total</b>	<b>12.1</b>	<b>49.3</b>	<b>73.3</b>	<b>16.2</b>	<b>12.8</b>	<b>19.1</b>

Notes:

1. Volumes shown here include volumes outside of Block 13/23d.
2. The GIIP in the Low case assumes a large gas cap with a GOC at 5,250 ft ss exists.
3. All GIIP estimates included solution gas.

## 4 Development Plan

i3 Energy has proposed a development plan involving the drilling of two horizontal wells, one in Liberator and one in Liberator NE, as shown schematically in Figure 7. Both wells are proposed to be tied back to the Blake sub-sea manifold, where the produced fluids would be co-mingled with Blake production and flowed to the Bleo Holm FPSO for processing.

The Bleo Holm is a purpose built, double hulled FPSO currently used for processing fluids from the Blake and Ross fields. Oil is stored on board (the storage capacity is 117,200 tonnes) and exported to market via an established fleet of shuttle tankers. Gas not used for fuel or flared is exported via a 6" pipeline to the Frigg system and on to the St Fergus gas terminal. Produced water is treated and discharged overboard. GCA has seen communications suggesting that there is adequate ullage at present to handle Liberator production.

GCA understands that the Bleo Holm will need to be "maintained in class" for insurance purposes in 2019, which GCA understands to be in hand, and again in 2024, which has yet to be planned. The increasing age of the vessel makes each re-classification potentially more challenging and a view on the economic justification for re-classification in 2024 may have to be taken nearer the time. Hence, in GCA's view, there remains an uncertainty as to whether the FPSO facilities would be available after 2024, although Repsol has indicated its intent to work towards maintaining the vessel in class for as long as is economically justified. This should not be read as implying that production will necessarily cease at end 2024: even if the Bleo Holm is retired at that date, other solutions for continuing production could be considered, including a replacement FPSO of a smaller size. However, it is only in the High case that production from the initial two-well Liberator development on its own would support the cost of an FPSO, so the economic viability of continued production for a significant period beyond 2024 would depend on continued production from Blake and/or from other potential developments in the area that may have been developed by that date.

The horizontal section of the Liberator well would be placed 40 ft above the OWC; that of the Liberator NE well slightly closer to the OWC as there is less structural relief. A pilot-hole would be drilled to optimize the placement of each horizontal section, and GCA understands that i3 Energy has purchased the seismic data, which will be an additional help in placing the wells and reduce the risk of missing the target. It is planned to complete the wells with “Equalizer” type screens and inflow-control (ICD) to provide equal flow distribution along the horizontal sections of low drawdown wells; giving the potential to defer water and gas coning and optimise production.

**Figure 7: Schematic Illustration of Proposed Two-Well Development**



Source: i3 Energy

#### 4.1 Recoverable Volumes

i3 Energy believes that the Liberator accumulations are connected to a large and active aquifer, and consequently that a high recovery factor, approaching the 62.5% reported for the Blake field, can be achieved with no water injection. I3 Energy have assumed a 43% recovery factor for the most likely case; in GCA’s opinion there are sufficient uncertainties related to reservoir, fluid fill and aquifer support that this represents a high case value.

GCA accepts that the high permeability (typically 1 Darcy or more) Captain Sands are widespread in the area. However, the degree to which this volume will actively contribute to pressure support at Liberator is unknown. Additionally, as already mentioned, wireline (MDT) pressure data acquired in the Liberator discovery well indicated a depletion of approximately 70 psi in reservoir pressure compared to the initial pressure at Blake, almost certainly due to production from Blake. Although this has occurred following a period of reduced or no water injection in Blake, it indicates that the aquifer may not be as large and active as expected.

GCA also accepts that the Blake field is a good analogue for Liberator in many respects. However, Blake is a larger reservoir with multiple offtake points and a thicker oil column (averaging some 80 ft with a maximum of about 120 ft compared to an average of 40-50 ft with a maximum of 70 ft in Liberator). Therefore, even with water injection, it would be prudent to expect a lower recovery factor at Liberator than at Blake, as also recognised by i3 Energy.

Without water injection, there is a risk of an even lower recovery factor if the aquifer is not as active as expected.

GCA has, therefore, applied the recovery factors shown in Table 8 for the Liberator accumulations.

**Table 8: Recovery Factor Estimates for the Liberator Accumulations**

Structure	Oil Recovery Factor (%)		
	Low	Best	High
Liberator	26	32	45
Liberator NE	-	31	39
Liberator NW	-	30	38

These recovery factors have been applied deterministically to the Low, Best and High estimates of STOIP shown in Table 7 to obtain the estimates of ultimate recovery from the Liberator accumulations under natural depletion shown in Table 9. In the Low case, a gas recovery factor of approximately 70% is assumed; in the other cases, where the gas is all solution gas, the same recovery factor is applied as for oil.

**Table 9: Estimated Ultimate Recovery (EUR) under Natural Depletion as at 31<sup>st</sup> January, 2017**

Structure	Oil (MMBbl)			Gas (Bscf)		
	Low	Best	High	Low	Best	High
Liberator	3.2	8.3	15.7	11.1	2.2	4.1
Liberator NE	-	3.0	6.3	-	0.8	1.6
Liberator NW	-	4.1	8.3	-	1.1	2.2
<b>Total</b>	<b>3.2</b>	<b>15.4</b>	<b>30.3</b>	<b>11.1</b>	<b>4.0</b>	<b>7.9</b>

**Notes:**

1. EUR is 100% of the volume estimated to be recoverable from the structure, in the event that it is developed under natural depletion, including volumes outside of Block 13/23d.
2. The volumes reported here have not been subject to any economic limit test, and may include volumes that would be uneconomic to produce or will not be developed.

## 4.2 Production Profiles

For the purpose of estimating recoverable volumes from the specific development plan proposed by i3 Energy, and corresponding NPVs, GCA has generated Low, Best and High case production profiles (shown in Appendix IV) matching the EURs shown in Table 9, under the following assumptions:

- Liberator well drilled in 2017, with first production at the beginning of 2018;
- Liberator NE well drilled in 2019, with first production at the beginning of 2020;
- No production from Liberator NW (it is assumed that a third well would be needed to effectively drain the Liberator NW area);
- Initial oil production rates similar to those proposed by i3 Energy (slightly lower for Liberator NE); and

- Decline rate adjusted to match the EUR in each case.

Uptime of 86% is reported for the Bleo Holm FPSO and i3 Energy has assumed 85% uptime in the future; GCA accepts this as a reasonable estimate.

Note that not all of the EUR for Liberator and Liberator NE will be achieved by the end of 2024, when the FPSO will require insurance re-certification, though a substantial portion of it would be recovered by that date, with 1.1 MMBbl remaining beyond that date in the Best case.

Best and High case gas profiles have been generated by applying a constant GOR of 260 scf/stb. In the Low case, where it is assumed that a significant gas cap exists, a gas production profile corresponding to blow-down of the gas cap has been generated. No deduction has been made for fuel and flare although it is unclear for how long the Blake and Ross gas will be sufficient to satisfy the fuel requirements of the FPSO.

### **4.3 Costs**

i3 Energy has provided estimates of the capital and operating expenditure (CAPEX and OPEX) associated with the proposed development. Key items include:

- US\$33 MM to drill each of the horizontal wells (including 24% contingency);
- US\$8 MM to tie-in flowlines and umbilical and insurance and management costs (including 24% contingency);
- US\$2 MM annual Fixed OPEX; and
- US\$6.6/Bbl processing, transportation and sales tariffs.

GCA has reviewed the CAPEX estimates presented and accepts them to be reasonable. GCA understands that i3 Energy is in negotiation with various service providers, and is close to entering into agreements for drilling and completion services at more favourable rates than those assumed herein, which would provide additional contingency. On the other hand, until agreements are in place with the operator of Blake to provide access to the Blake field facilities, there is still a high degree of uncertainty with the OPEX, which may take the form of a tariff and/or a share of operating costs. This OPEX uncertainty is reflected through an additional 50% contingency assumed in the economic evaluation and NPV determination. However, GCA considers that the figures proposed are in line with current industry expectations.

### **4.4 Contingent Resources**

Production from the Liberator and Liberator NE wells up to the earlier of the economic limit (see Section 5) or end 2024 in the Low, Best and High cases gives the 1C, 2C and 3C Contingent Resources associated with i3 Energy's proposed two-well development shown in Table 2. Production from these two wells after end 2024, and production from Liberator NW, which would probably require an additional well, are also considered as Contingent Resources, but in the Development Unclassified or On Hold sub-class as shown in Table 3.

## **5 Economic Assessment**

GCA has carried out an economic assessment of the FDP outlined by i3 Energy as described above. This assessment included an Economic Limit Test (ELT) and an evaluation of the potential project Net Present Value (NPV) using the Low, Best and High Estimate production profiles and costs described above.

The economic limit is defined as the production rate beyond which the net operating cash flows are negative; this is the point in time that defines the end of the project's economic life.

Reference Post-Tax NPVs have been calculated from projected cash flows at a discount rate of 10% (NPV10). No adjustments have been made for cash balances, inventories, indebtedness or other balance sheet effects, other than those stated herein. NPVs are quoted both at the gross project level (i.e. 100% interest in the project) and net to i3 Energy, and are presented unrisks, i.e. under the assumption that the development plan will go ahead in the form envisaged.

It should be clearly understood that the NPV of future revenue potential of a petroleum property, such as those discussed in this report, does not represent a GCA opinion as to the market value of that property, nor any interest therein. In assessing a likely market value, it may be necessary to take into account a number of additional factors including: reserves risk (i.e. that reserves and resources may not be realised within the anticipated timeframe for their exploitation); operational risk (e.g. costs may exceed those assumed); perceptions of economic and sovereign risk; other benefits, encumbrances or charges that may pertain to a particular interest and the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs presented herein.

GCA's assessment is based upon GCA's understanding of the fiscal and contractual terms governing this asset, and the various economic and commercial assumptions described herein.

## 5.1 Contract and Fiscal Terms

This assessment has been based upon GCA's understanding of the UK taxation that will govern this asset as included in the model provided by the client and indicated by recent announcements from the UK Oil and Gas Authority (Table 10).

**Table 10: UKCS Taxation Terms**

Description	Value
Corporate Income Tax	30%
Supplementary Charge	10%
Investment Allowance (Deducted for Supplementary Charge)	62.5% of CAPEX

## 5.2 Costs

Estimates of CAPEX and OPEX have been provided by i3 Energy. These include estimates made by i3 Energy and/or by outside contractors for well costs and assumptions related to tariffs for use of the Blake field facilities. GCA has seen evidence that i3 Energy has begun discussions with Respol, the Blake field operator.

The Low Case development has assumed a one well development of the Liberator main accumulation only.

Costs have been escalated at 2% p.a. from 2018 onwards.

### **5.3 Oil and Gas Prices**

GCA's Brent Crude oil price scenario for the first quarter of 2017, shown in Table 4, has been used as the reference oil price.

The gas price used is based on Brent and follows the historic average ratio of the Brent price in US\$/Bbl to the UK National Balancing Point (NBP) gas price in US\$/Mscf of approximately 10:1.

### **5.4 Results**

In all three cases (Low/1C, Best/2C and High/3C), production was found to remain economic until at least the end of 2024, when the FPSO will require re-certification once the insurance expires. For the purpose of this economic evaluation, production is assumed to stop at that date. While the economic limits for the three cases were found to occur at the end of 2026, 2031 and 2037 respectively, it should be noted that the assumed tariff arrangement for OPEX may not continue indefinitely, as production from Blake and Ross declines, although other sources of production in the area could potentially become available to replace it.

The resulting Reference Pre- and Post-Tax NPVs at a discount rate of 10% (NPV10) and are shown in Table 5.

### **5.5 Economic Sensitivities**

The sensitivity of the unrisked NPVs to different discount rates (7.5% and 12.5%) is shown in Table 11. The sensitivity of the unrisked NPVs at 10% discount rate for the 2C case to variation in oil and gas prices ( $\pm$ US\$10/Bbl) and variation in CAPEX and OPEX ( $\pm$ 20%) is presented in Table 12.

**Table 11: Sensitivity to Discount Rate of Unrisked NPV (US\$ MM) of Potential Future Revenue from Contingent Resources (Development Pending) as at 31<sup>st</sup> January, 2017**

**(a) Gross Project**

Case	1C			2C			3C		
	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Pre-Tax	80	73	67	339	311	286	633	576	525
Post-Tax	52	48	43	208	190	175	384	349	318

**(b) Net to i3 Energy's Current Acreage (Block 13/23d)**

Case	1C			2C			3C		
	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Pre-Tax	64	58	54	271	249	229	506	461	420
Post-Tax	42	38	35	167	152	140	307	279	255

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. Gross Project NPVs reported here are based on 100% of the revenues estimated to be derived from the development project, in the event that it goes ahead, and relate to the extended development area, covering Liberator and Liberator NE, including the parts outside of Block 13/23d.
3. The NPVs reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein

**Table 12: Sensitivity to Costs and Commodity Prices of Unrisked NPV10 (US\$ MM) of Potential Future Revenue from 2C Contingent Resources (Development Pending) as at 31<sup>st</sup> January, 2017**

**(a) Gross Project**

	Base	Oil Price		CAPEX		OPEX	
		-US\$10/Bbl	+US\$10/Bbl	-20%	+20%	-20%	+20%
Pre-Tax	311	238	384	329	293	331	291
Post-Tax	190	147	234	200	181	202	178

**(b) Net to i3 Energy's Current Acreage (Block 13/23d)**

	Base	Oil Price		CAPEX		OPEX	
		-US\$10/Bbl	+US\$10/Bbl	-20%	+20%	-20%	+20%
Pre-Tax	249	191	307	263	235	265	233
Post-Tax	152	117	187	160	144	162	143

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. Gross Project NPVs reported here are based on 100% of the revenues estimated to be derived from the development project, in the event that it goes ahead, and relate to the extended development area, covering Liberator and Liberator NE, including the parts outside of Block 13/23d.
3. The NPVs reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest therein

## Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client and where relevant, available public domain sources, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of the data room sourced data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil volumes are reported in millions ( $10^6$ ) of barrels at stock tank conditions (MMstb). Natural gas volumes have been quoted in billions ( $10^9$ ) of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60°F.

GCA prepared an independent assessment of the reserves and resources based on data and interpretations provided by i3 Energy.

### Definition of Reserves and Resources

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have

been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts).

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

It must be appreciated that the Contingent Resources reported herein are unrisks in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

GCA has not undertaken a site visit and inspection because there are no assets to visit. As such, GCA is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GCA is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

### **Use of Net Present Values**

It should be clearly understood that the NPVs contained herein do not represent a GCA opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Reserves or Resources may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs presented herein.

## Qualifications

GCA is an independent international energy advisory group of more than 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with i3 Energy Ltd. Furthermore, the management, directors and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

The team was led by Mr. Jonathan Westbury, Senior Commercial Business Advisor, who has 40 years of industry experience. He holds a B.Sc. (Hons) in Applied Geology (Dundee University, UK, 1976). He is a Fellow of the Geological Society, a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, and of the American Association of Petroleum Geologists.

The ultimate signatory of the report is Dr John Barker, Technical Director, Reservoir Engineering, who has 32 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

GCA confirms that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in this CPR since the effective date of 31<sup>st</sup> January, 2017.

Yours sincerely,

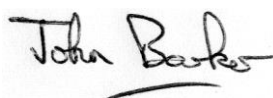
**Gaffney, Cline & Associates**



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Project Manager

Jonathan Westbury, Senior Commercial Business Advisor



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Reviewed by

John Barker, Technical Director – Reservoir Engineering

## **Appendix I Glossary**

## GLOSSARY

### Standard Oil Industry Terms and Abbreviations

API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
B	Billion (10 <sup>9</sup> )
Bbl	Barrels
/Bbl	Per barrel
Bscf	Billion standard cubic feet
CAPEX	Capital expenditure
ELT	Economic limit test
EUR	Estimated ultimate recovery
°F	Degrees Fahrenheit
FDP	Field development plan
FPSO	Floating production, storage and offloading vessel
ft	Foot/feet
GBP	Pounds Sterling
GIIP	Gas initially in place
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
km	Kilometres
m	Metres
M	Thousand
MBbl	Thousands of barrels
Mscf	Thousand standard cubic feet
MDT	Modular dynamic tester (a wireline logging tool)
MM	Million
MMBbl	Millions of barrels
MMscf	Million standard cubic feet
ms	Milliseconds
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
psi	Pounds per square inch
PVT	Pressure volume temperature
RF	Recovery factor
scf	Standard cubic feet
ss	Subsea
stb	Stock tank barrel
STOIP	Stock tank oil initially in place
TVD	True vertical depth

TVDss	True vertical depth subsea
TWT	Two-way time
UKCS	United Kingdom Continental Shelf
US\$	United States Dollar
WI	Working interest
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
1Q	First quarter (of year)

## **Appendix II**

### **Abbreviated form of SPE PRMS**

**Petroleum Resources Management System**

**Definitions and Guidelines <sup>(1)</sup>**

**March 2007**

**Preamble**

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:  
[www.spe.org/specma/binary/files/6859916Petroleum\\_Resources\\_Management\\_System\\_2007.pdf](http://www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf)

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<sup>1</sup> These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

## **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.***

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

### **On Production**

*The development project is currently producing and selling petroleum to market.*

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

### **Approved for Development**

*All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.*

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

### **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.*

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

## **Proved Reserves**

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

- (1) the area delineated by drilling and defined by fluid contacts, if any, and
- (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

## **Probable Reserves**

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

## **Possible Reserves**

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

## **Probable and Possible Reserves**

*(See above for separate criteria for Probable Reserves and Possible Reserves.)*

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally

higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

### **Developed Reserves**

*Developed Reserves are expected quantities to be recovered from existing wells and facilities.*

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

#### **Developed Producing Reserves**

*Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.*

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

#### **Developed Non-Producing Reserves**

*Developed Non-Producing Reserves include shut-in and behind-pipe Reserves*

Shut-in Reserves are expected to be recovered from:

- (1) completion intervals which are open at the time of the estimate but which have not yet started producing,
- (2) wells which were shut-in for market conditions or pipeline connections, or
- (3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

### **Undeveloped Reserves**

*Undeveloped Reserves are quantities expected to be recovered through future investments:*

- (1) from new wells on undrilled acreage in known accumulations,
- (2) from deepening existing wells to a different (but known) reservoir,
- (3) from infill wells that will increase recovery, or
- (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
  - (a) recomplete an existing well or
  - (b) install production or transportation facilities for primary or improved recovery projects.

## **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.***

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

### **Development Pending**

*A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.*

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

### **Development Unclassified or 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.*

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

### **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.*

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

## **PROSPECTIVE RESOURCES**

***Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.***

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

### **Prospect**

*A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.*

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

### **Lead**

*A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.*

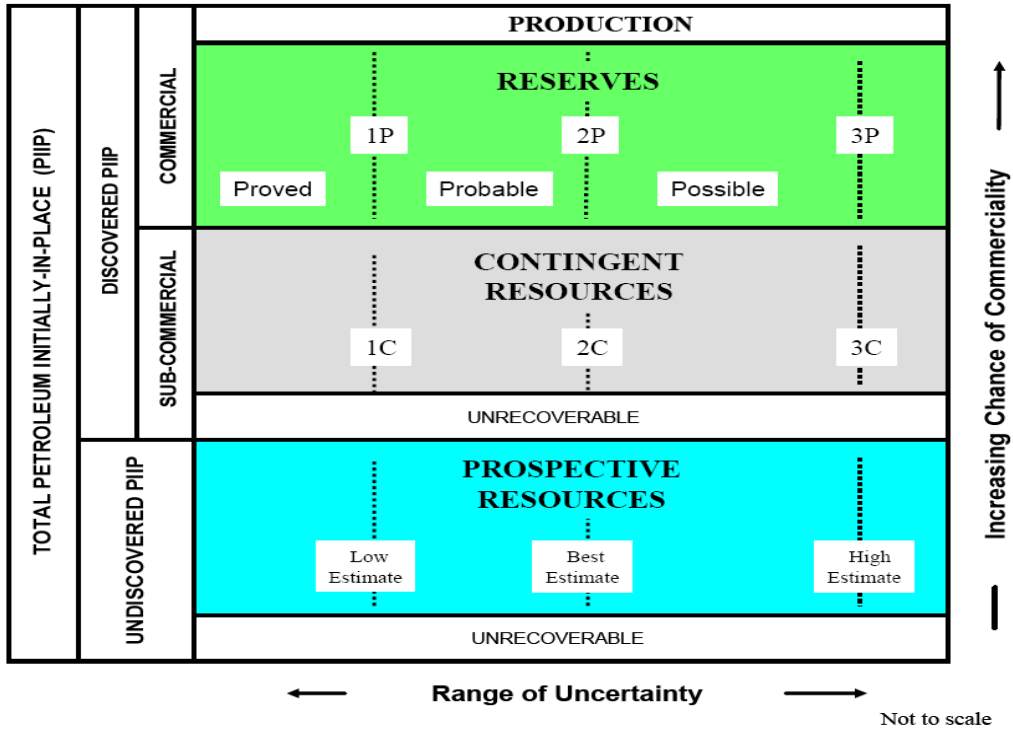
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

### **Play**

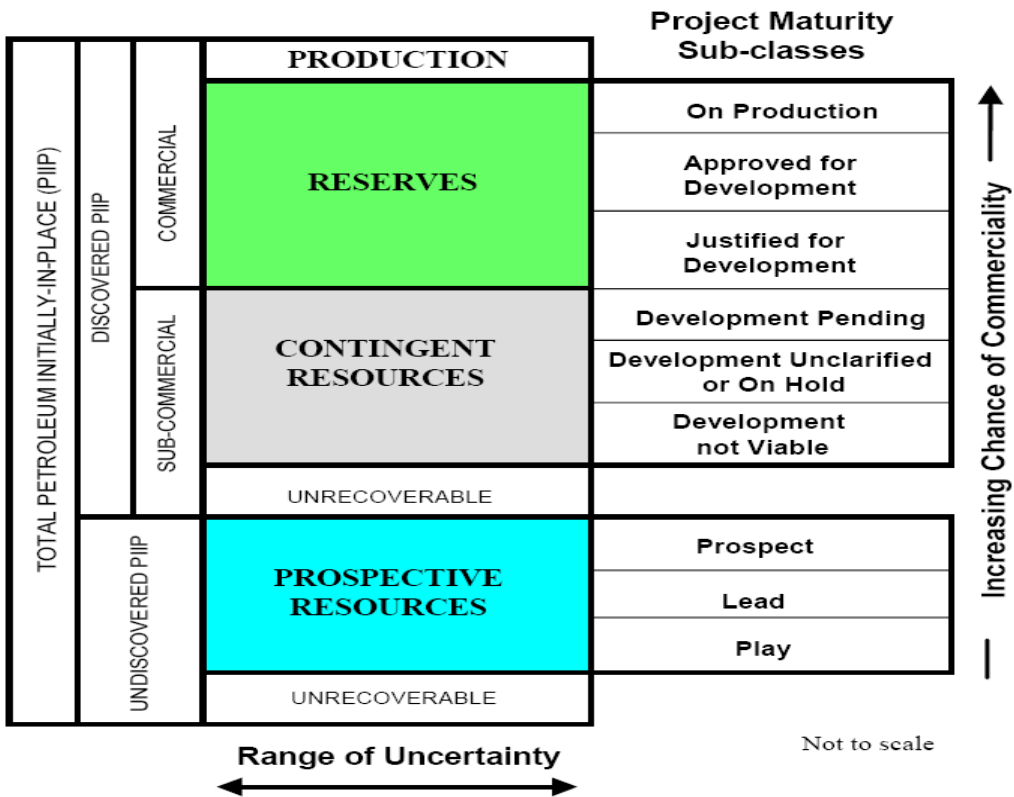
*A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.*

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

### RESOURCES CLASSIFICATION



### PROJECT MATURITY



## **Appendix III Contingent Resources Summary Table**

**Table AIII.1: Contingent Resources Summary Table**

Licence Block	Development Status	Structure Oil (MMBbl)	Gross			Net to i3 Energy			Operator
			1C	2C	3C	1C	2C	3C	
13/23d	Pending	Liberator	2.5	5.8	9.5	2.5	5.8	9.5	i3 Energy
		Liberator NE	-	2.3	4.2	-	2.3	4.2	
	Liberator	0.1	0.8	3.1	0.1	0.8	3.1		
	Liberator NE	-	0.1	0.9	-	0.1	0.9		
13/24a	Pending	Liberator	0.6	1.5	2.4	-	-	-	Repsol Sinopec Resources UK Ltd
		Liberator NE	-	0.6	1.0	-	-	-	
	Liberator	0.0	0.2	0.8	-	-	-		
	Liberator NE	-	0.0	0.2	-	-	-		
13/23a	Unclassified	Liberator NW	-	4.1	8.3	-	-	-	None
		<b>Total Oil</b>	<b>3.1</b>	<b>15.4</b>	<b>30.3</b>	<b>2.5</b>	<b>9.0</b>	<b>17.6</b>	
13/23d	Pending	<b>Gas (Bscf)</b>	<b>1C</b>	<b>2C</b>	<b>3C</b>	<b>1C</b>	<b>2C</b>	<b>3C</b>	i3 Energy
		Liberator	8.0	1.5	2.5	8.0	1.5	2.5	
		Liberator NE	-	0.6	1.1	-	0.6	1.1	
		Liberator	0.8	0.2	0.8	0.8	0.2	0.8	
		Liberator NE	-	0.0	0.2	-	0.0	0.2	
		Liberator	2.0	0.4	0.6	-	-	-	
		Liberator NE	-	0.1	0.3	-	-	-	
13/24a	Unclassified	Liberator	0.2	0.0	0.2	-	-	-	Repsol Sinopec Resources UK Ltd
		Liberator NE	-	0.0	0.1	-	-	-	
		Liberator NW	-	1.1	2.2	-	-	-	
		<b>Total Gas</b>	<b>11.1</b>	<b>4.0</b>	<b>7.9</b>	<b>8.8</b>	<b>2.3</b>	<b>4.6</b>	

Notes:

1. Contingent Resources have been estimated by GCA based on data and interpretations provided by i3 Energy.
2. Gross Contingent Resources are 100% of the Contingent Resources attributed to the Licence Block.
3. Contingent Resources are volumes estimated to be recoverable from a development project, in the event that it goes ahead; the volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the project may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
4. GCA has not estimated any “Chance of Development” or “Risk Factor”: these depend largely on non-technical matters, such as reaching agreement with other parties; GCA does not have all the information that would be required to make a quantitative estimate and therefore considers it would be inappropriate to do so.
5. Gas Contingent Resources are higher in the 1C case than in the 2C and 3C cases because the 1C case assumes a large gas cap is present in Liberator, whereas the 2C and 3C cases assume that the Liberator structure is almost completely oil-filled.
6. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.

## **Appendix IV Production Profiles**

**Table AIV.1: Production Profiles (Liberator and Liberator NE)**

Year	Low		Best		High	
	Oil (MMbbl)	Gas (Bscf)	Oil (MMbbl)	Gas (Bscf)	Oil (MMbbl)	Gas (Bscf)
2018	1.26	1.88	2.19	0.57	2.86	0.74
2019	0.75	2.31	1.60	0.42	2.32	0.60
2020	0.46	1.94	2.61	0.68	3.78	0.98
2021	0.28	1.50	1.62	0.42	2.86	0.74
2022	0.17	1.09	1.04	0.27	2.19	0.57
2023	0.10	0.77	0.68	0.18	1.69	0.44
2024	0.06	0.53	0.46	0.12	1.31	0.34
2025	<i>0.04</i>	<i>0.36</i>	<i>0.32</i>	<i>0.08</i>	<i>1.02</i>	<i>0.27</i>
2026	<i>0.02</i>	<i>0.24</i>	<i>0.22</i>	<i>0.06</i>	<i>0.80</i>	<i>0.21</i>
2027	<i>0.01</i>	<i>0.16</i>	<i>0.16</i>	<i>0.04</i>	<i>0.63</i>	<i>0.16</i>
2028	<i>0.01</i>	<i>0.10</i>	<i>0.11</i>	<i>0.03</i>	<i>0.50</i>	<i>0.13</i>
2029	<i>0.00</i>	<i>0.07</i>	<i>0.08</i>	<i>0.02</i>	<i>0.39</i>	<i>0.10</i>
2030	-	-	<i>0.06</i>	<i>0.02</i>	<i>0.31</i>	<i>0.08</i>
2031	-	-	<i>0.04</i>	<i>0.01</i>	<i>0.25</i>	<i>0.06</i>
2032	-	-	<i>0.03</i>	<i>0.01</i>	<i>0.20</i>	<i>0.05</i>
2033	-	-	<i>0.02</i>	<i>0.01</i>	<i>0.16</i>	<i>0.04</i>
2034	-	-	<i>0.02</i>	<i>0.00</i>	<i>0.13</i>	<i>0.03</i>

Note:

1. All volumes shown are currently classified as Contingent Resources.
2. Volumes up to and including 2024 are classified as Development Pending, while those after 2024 (shown in italics) and are classified as "Development Unclassified or On Hold".
3. Volumes reported here are 100% of the volumes estimated to be recovered from the development project, in the event that it goes ahead, and relate to the whole Liberator and Liberator NE structures including the parts outside of Block 13/23d.