CALCULATION OF HYDROCARBON VOLUME IN PLACE USING 3D SEISMIC SECTION AND WELL LOG DATA: A CASE STUDY OF ICC FIELD

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ABSTRACT

The calculation of hydrocarbon in place of I.C.C field Niger Delta Nigeria was done using the integration of seismic sections and well logs data using the petrel software.

The weighted average of the net pay porosity was found to be 29.53%, water saturation 24.73% and Hydrocarbon saturation to 75.27%. Field G-reservoir probabilistic oil in place reservoir estimation was also carried out by Monte Carlo Simulation using Crystal Ball Software. The oil water contact (OWC) was found at 1740mSS, 1741.5mSS and 1743mSS.The Deterministic oil in place was found to be 324.97mmSB.

The comparison of estimate of the earlier results of 2002 and the current study suggest that there is an increase of 93MMSTB in the P50 estimate of I.C.C field oil in place estimate.

INTRODUCTION

The ICC field is located in the offshore Niger Delta in approximately 90m of water depth. On this straddling structure two vertical exploration wells ICC-1 and –2 were drilled in 1993. The wells encountered one hydrocarbon (Oil)-bearing reservoir called "G Reservoir". The discovered oil was above bubble point pressure, with ~40 API gravity. Due to the decline in production new exploration data were acquired in 2017 for further analysis.

The amount of oil or gas contained in a unit volume of a reservoir is the product of it's porosity and the hydrocarbon saturation. To quantify the hydrocarbon saturation in place of a reservoir, knowledge of the character and extent of such a reservoir is needed. Information required for volume analysis are the thickness, pore space and area extent of the reservoir (Ihianle et al. 2013; Gluyas and Swarbrick,2004). Other input parameters are shale volume, saturation, net to gross and shale volume values (Edward and Santogrossi; 1990).

Almost all the oil and gas produced in the world to day comes from accumulation in the pore spaces of lithologies like sand stones, limestone and dolomite (Etu-Efeotor 1997). The gamma ray log can be use for the reservoir rocks (sand) and the embedding shale differentiation. The resistivity log on the other hand, can be used, as this study for determining the nature of interstitial fluid (Aigbedion and Aigbedion, 2011).

Seismic attributes can be used for both quantitative and qualitative purpose. Quantitative sues include prediction of physical properties such as porosity or lithology. Qualitative uses include detection of stratigraphic and structures features. Then from the

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derives seismic attributes, we can evaluate and estimate subsurface properties of interest using physical theories, statistical methods and geological model, along with well log data.

In reservoir development projects where knowledge of thickness and area of reservoir is vital, the description of the reservoir is achieved through the integration of well legs and three dimensional seismic data (Ellis 1987).

Avseth (2005) said that in seismic reservoir characterization and evaluation, detailed characteristics of reservoir using seismic data are analyzed and described both in quality and quantity. This he said is done by delineating reservoir parameters.

Aigbedion and Iyayi (2007) explained that in an oil prone area like the Niger Delta, even though hydrocarbon are within the subsurface, they cannot impulsively gush to the surface when penetrated by a production well. On the contrary, Stacher (1995) noted that most reservoir hydrocarbons reside in the microscope pore spaces or open fractures of sedimentary rocks (sandstones and lime stones). To produce them, detailed geological and petrophysical knowledge and data are needed to guide the placement of production platforms and well paths. This can consequently help to optimize hydrocarbon recovery and to improve predications of and reservoir performance (Thomas,1995).

Egbai and Aigbegu (2012) used mathematical modeling method of petro-physical parameters to characterize reservoir in kwale of Delta State, Nigeria. They concluded that most reservoirs in the wells are gas bearing zones with hydrocarbon saturation, ranging from 74.18% to 94.64% with high resistivity values.

Reservoir characterization and formation evaluation of some parts of Niger. Delta, using 3-D seismic and well leg Delta was carried out by Abe and Olowokere (2013) in their work, only three reservoirs were delineated across the wells. The results of this analysis with structural interpretation will be reliable and efficient way of carrying out formation evaluation and reservoir characterization. It will also enhanced hydrocarbon exploration for optimal well placement and reserve estimation.

The aim of this study is to compare the 2002 original oil in place(OOIP) with the current estimate for further development due to the new acquisition and reprocessing of seismic data. This study is based on the use of well logs and seismic section to analyze and estimate prospective volume of hydrocarbon in place of ICC field.

GEOLOGY OF THE STUDY AREA

The ICC structure is a well-identified culmination controlled to the North by a major down to basin growth fault and to the west by a prominent fault which is synthetic to the Okono field structure counter-regional fault. Four intra-field growth faults are present across the structure.

The study area is located offshore of the Niger Delta, situated on the Gulf of Guinea along the west coast of Africa (Figure 1). From the Eocene to the present, the delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development. These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2, a sediment volume of 500,000 km^3, and a sediment thickness of over 10 km in the basin depocenter (Ejedawe,1981;Doust and Omatsola,1990,Ayoola,2004). The Niger Delta Province contains one identified petroleum system, named as Tertiary Niger Delta (Akata - Agbada) Petroleum System(Egwebe,2003).

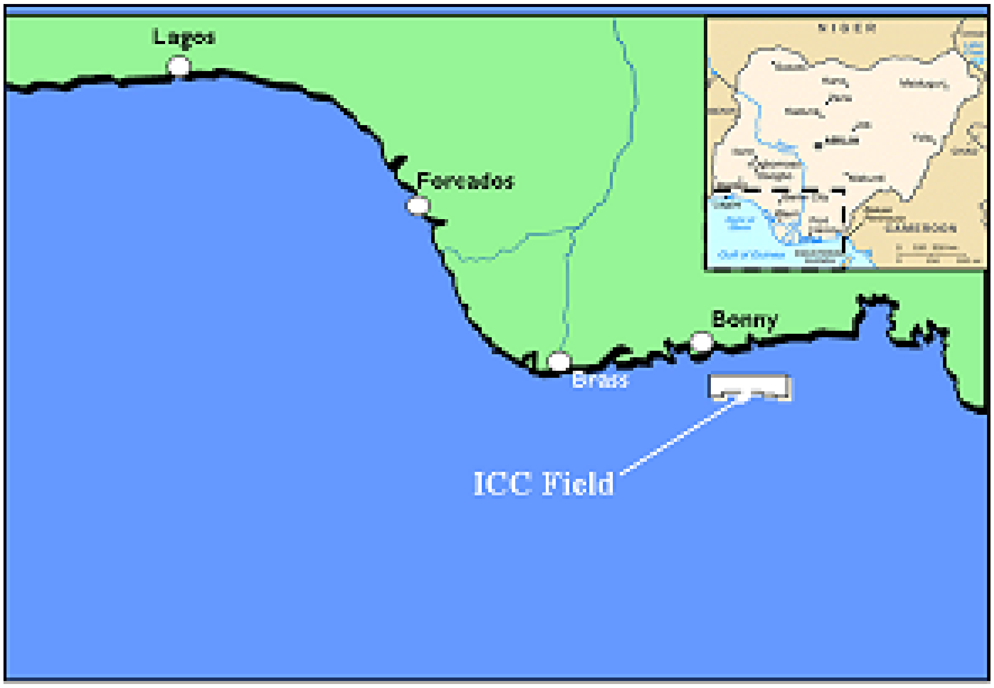

Figure 1.1: ICC FIELD LOCATION MAP

MATERIALS AND METHODS

MATERIALS

The materials used for this study are 3D seismic section, resistivity log, Gamma-ray log, spontaneous potential log, density log and neutron log .

METHODS

In this study, log data were loaded on petrel software to identify the information about the reservoir. The gamma ray logs, which detects radioactive emission of rocks were use to identify lithology i.e to identify between shale and non shale zones. The gamma ray logs were also integrated with the resistivity value than when in water bearing zone. Using the Gamma ray log, the lithology, correlation of equivalent srata across the two or three walls was performed by matching for similarity in the interval of logs from different well.

All the seismic data were loaded on petrel software in SEG-Y format. The data were processed and interpreted to define the structural frameworks of the “ICC” field with a view to identify and correlate the surface boundary along seismic transit from one well to another. The petrel software was the in identification of faults and the marking of horizon. Netpay, porosity, water saturation and net-to-gross of the G reservoir layers has been estimated by applying 70% V-Shale, 15% Porosity and 65% Water Saturation cut-off on the wells CPI data.

HYDROCARBON SATURATON MODELS

Saturation models are models which relate measured resistivity to water saturation from which hydrocarbon content can be determined. Hydrocarbon saturation models like Archie and Waxman-Smits are used to calculate the hydrocarbon saturation fro resistivity log.

ARCHIE MODEL

In 1942, Archie from empirical observation, suggested that the resistivity of brine. Saturated rock, R_0, was related to brine the resistivity, R_W. He established that the ratio of the resistivity of R_O to R_W was a constant for every given rock sample. The names, resistivity formation factor (F) was given to this proportionality constant. Hence, according to Archie,

$$F=\frac{R_0}{R_w} \qquad (1.1)$$

Archie (1942) also showed that there was a strong linear relationship between the logarithms transform of F and porosity () in sand stones i.e F depends only on porosity.

$$F= \frac{1}{\emptyset^m} \quad (1.2)$$

where m, the porosity exponent, takes different values for variety of sandstones and limestone's. Archie estimated to be approximately 2. combining equations gives the well known Archie's equation expressed as the electrical resistivity of water saturated sediments (R_0) as:

$$R_0 = \frac{aR_w}{\emptyset^m} \quad (1.3)$$

where a and m are Archie constants which can be derived empirically, with m commonly called the cementation factors.

Archie's, also showed that assuming that hydrocarbon partially saturates the pore, space, he suggested multiply R_0 by a factor called the resistivity index 1, to obtain true resistivity, R_t

$$R_t = 1R_0 \quad (1.4)$$

which led him to propose

$$1= \left(\frac{1}{S_w^n}\right) \quad (1.5)$$

The combination of these equations led to the Archie's equation for water saturation (S_w) in a formation.

$$Sw = \left(\frac{aRw}{\emptyset^m R_t}\right)^{\frac{1}{n}} \tag{1.6}$$

THE WAXMAN- SMITS EQUATION/ MODEL

The Waxman-Smits equation/model is a semi empirical extension of the Archie's equation, taking into account the additional conductivity caused by shale (Egbai, and Aigbegun, 2012). The Waxman-Smit equation/model is mostly used for dispersed shaly sandstones. In case of laminated shaly sandstones, either the Archie or the Waxman-Smit equation /model can be used in combination with specialist software.

It is easier to arrive at the Waxman smits equation by working with conductivities rather than resistivity's. Therefore

$$Ct= \emptyset^m S_w^N C_w \tag{1.7}$$

where C_t = conductivity of the party hydrocarbon- ebaring rock $\frac{1}{Rt}$

C_w= conductivity of brine = $\frac{1}{Rw}$

Again, Waxman-smits began with equation (1.7) but replace (w by an equivalent water conductivity (w + Cw + Ce/Sw), thus taking the additional clay conductivity into account. Due to the fact that the surface to volume ratio for the brine has now changed with this factors, the additional term Sw arises(Evenick, 2008).

The tortuosity factor $\emptyset^m$ acts on this clay conductivity in some way as it acts on the brine conductivity, as a result, the Waxman. Smiths equation foe hydrocarbon bearing shally sandstone becomes.

$$Ct = \emptyset^{\dot{m}^*}\, S_w^n\, (C_w + C_E\,/S_W) \qquad (1.8)$$

or $$Ct = \emptyset^{m^*}\, S_w^{n\,*} (C_w + B.Q_v\,/S_W) \qquad (1.9)$$

(by substituting B. Qv for Ce)

where m = Cementation exponent in the Waxman- Smits equation

n= Saturation exponent of the Waxman- Smits equation

Equation (1.9)is the general form of the Waxman- Smits equation

Equation (1.9) can be written in terms of resistivities rather than conductivities result in

$$Ct = \emptyset^{m^*}\, S_w{}^{-m^*} R_w /\, (1 + R_w B.Q_v\,/S_w) \qquad (1.10)$$

Netpay weighted average porosity and water saturation of the well data was calculated to determine the average field properties. The estimated weighted averages were used for deterministic evaluation of oil in-place. For probabilistic estimates the minimum and maximum input values were estimated by varying the porosity cut-off. The cut-off was varied due to

- Data and interpretation uncertainties discussed above.
- The wells in ICC field are concentrated in the southern and central part of the field and there is very limited data with respect to petrophysical properties of northern one-third part of the field.

The estimated average porosity, average water saturation and net to gross values are shown in the Table-4.5 below:

Table- 1.1: Porosity, water saturation and net to gross estimates.

	Minimum	Most-likely or Deterministic Input	Maximum
	%	%	%
Porosity	28.0	30.0	32.0
Water Saturation	22.0	25.0	28.0
Net to Gross	60.0	66.0	72.0

OIL FORMATION VOLUME FACTOR (FVF)

PVT analysis data is available from ICC-3 G-2.0B, G-2.1 and G-2.2 layer DST samples and ICC-4 G-2.0B production test sample. The FVF values estimated from the data are as follow:

G-2.0A & B 1.2591 rbbl

G-2.1 1.2602 rbbl

G-2.2 1.3013 rbbl

OIL IN-PLACE ESTIMATION

Oil in-place for the ICC Field G reservoir has been estimated using three different techniques. A summary discussion on the techniques used and results is given below:

Deterministic OOIP Estimation

i. Bulk Rock Volume has been estimated from updated top reservoir depth map prepared in 2002 with an oil-water contact (OWC) at 1741.5m SS determined from ICC-7 RCI data

ii. Net pay, average porosity and average water saturation have been estimated using 70% V-Shale, 15% Porosity and 65% Water saturation cut-off.

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iii. Formation volume factor has been estimated from PVT data.

The results of the deterministic evaluation are given in the Table-1.2 below:

Reservoir Layer	Average Netpay Thickness	Average Netpay Porosity	Average Netpay Water Saturation	Net to Gross	Formation Volume Factor	OOIP
	M	%	%	%	rbbl/bbl	MMSTB
G2.0A	1.00	24.87	46.22	39.49	1.2591	8.61
G2.0B	12.60	28.53	24.96	72.40	1.2591	131.93
G2.1	27.21	28.79	24.44	86.67	1.2602	178.16
G2.2	8.45	28.04	19.42	60.82	1.3013	6.27
					Total OOIP	324.97

Table-1.2: Deterministic OOIP estimation results.

Probabilistic OOIP Estimation:

ICC Field G reservoir probabilistic oil in-place estimation has been carried by Monte Carlo Simulation using Crystal Ball Software. The assumptions for input parameters are as follow:

i. Bulk Rock Volume (BRV) has been estimated from updated top reservoir depth map prepared in 2002 with oil-water contact (OWC) at 1740m SS, 1741.5m SS and 1743m SS due to wireline logs based OWC uncertainty.

ii. Netpay, average porosity and average water saturation ranges have been estimated using different cut-offs to take into account the potential properties variation in the vast un-appraised / developed area of the field.

iii. Formation volume factor has been estimated from PVT data.

Triangular distributions of the input parameters have been used. The ranges used for the estimation are given in the Table-1.3 below:

Table-1.3: Probabilistic OOIP estimation input parameters.

Property	Units	Minimum	Mostlikely	Maximum
Bulk Rock Volume	acre-ft	355522.31	368836.37	373340.18
Avg. Net to Gross	%	60.0	66.0	72.0
Avg. Porosity	%	28.0	30.0	32.0
Avg. Water Saturation	%	22.0	25.0	28.0
Formation Volume Factor	rbbl/bbl	1.2591	1.2602	1.3013

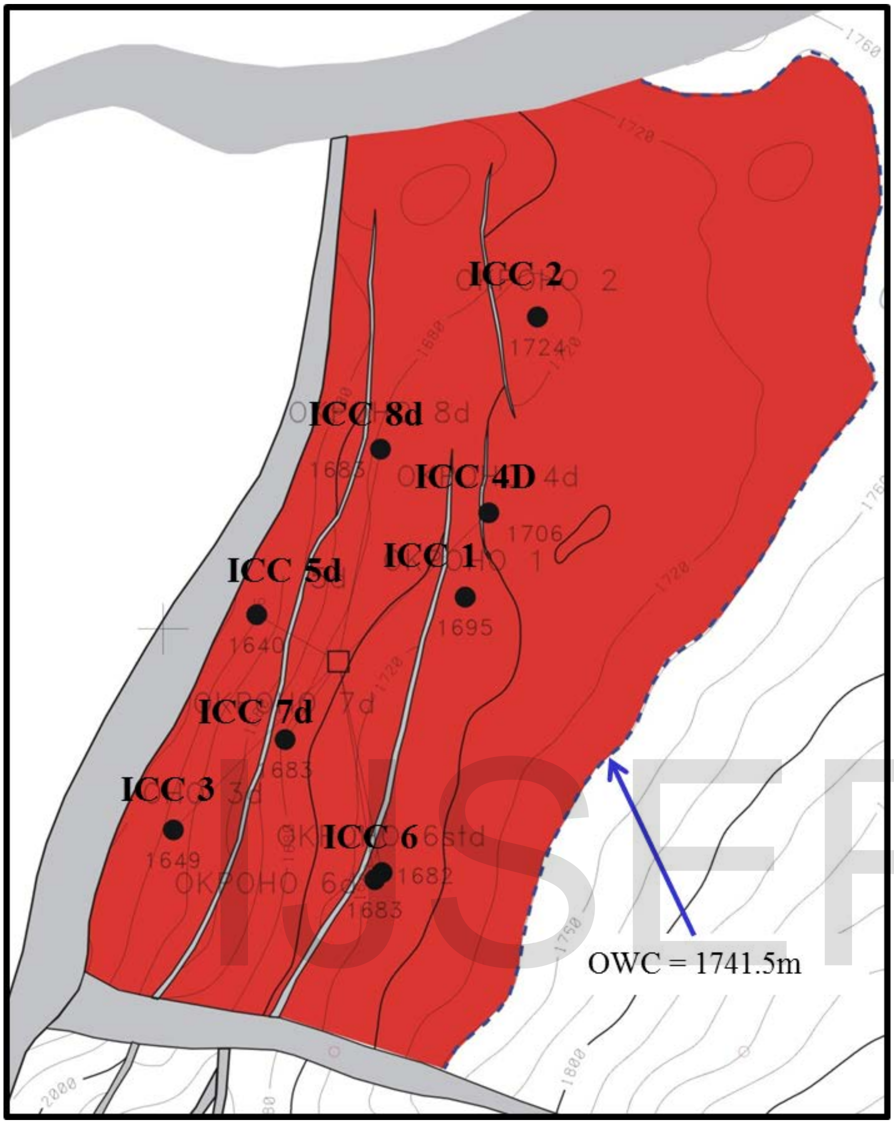

Figure 1.2 : ICC top G reservoir depth map

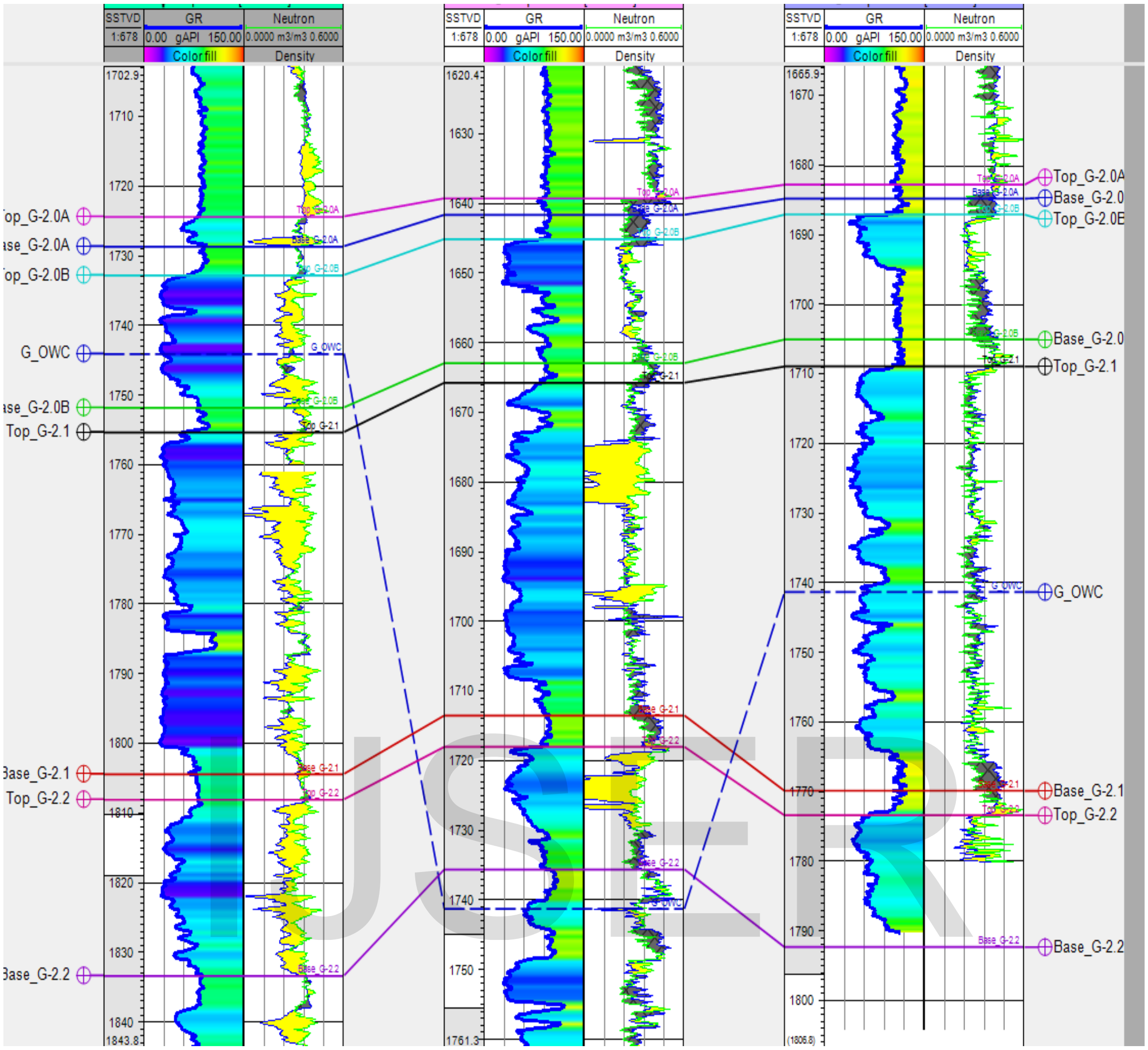

Figure 1.3:Well correllation

The Monte Carlo Simulation OOIP results are given in Table-1.4 below and PDF is shown in Fig. 1.4:

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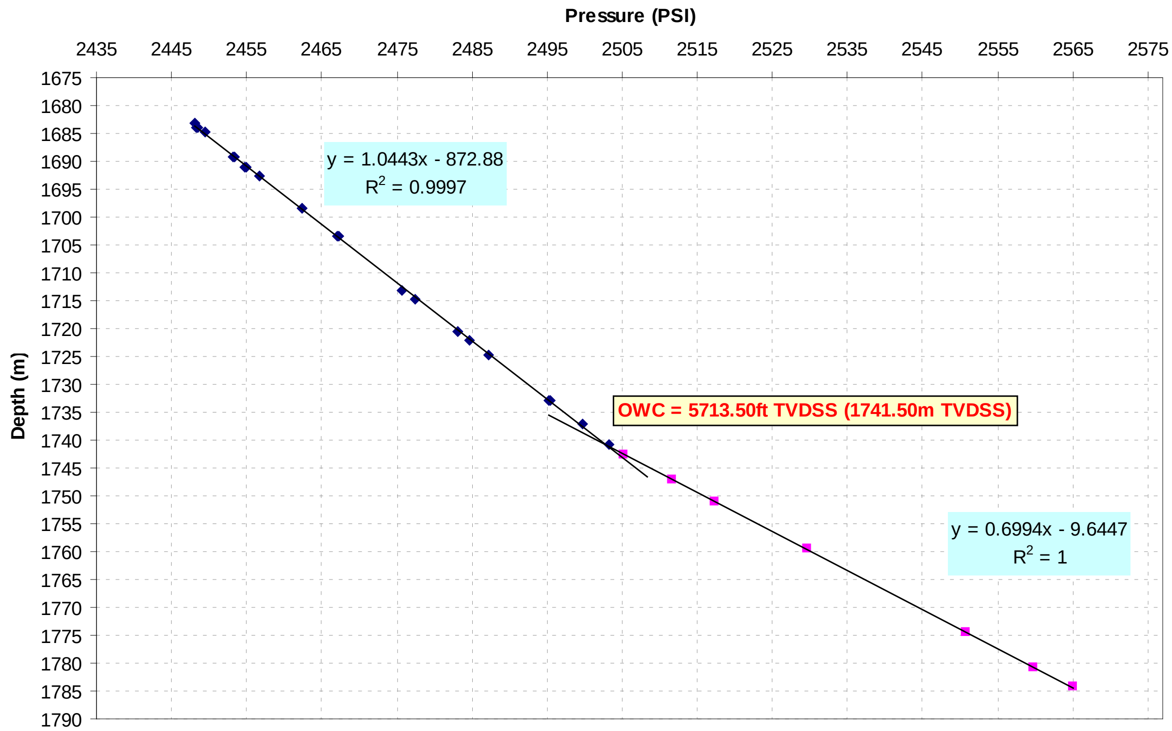

Figure 1.4 : ICC field Pressure plot

Table-1.4: Probabilistic OOIP estimation results.

	P90	P50	P10	Mean
OOIP (MMSTB)	306.90	327.96	351.06	328.80

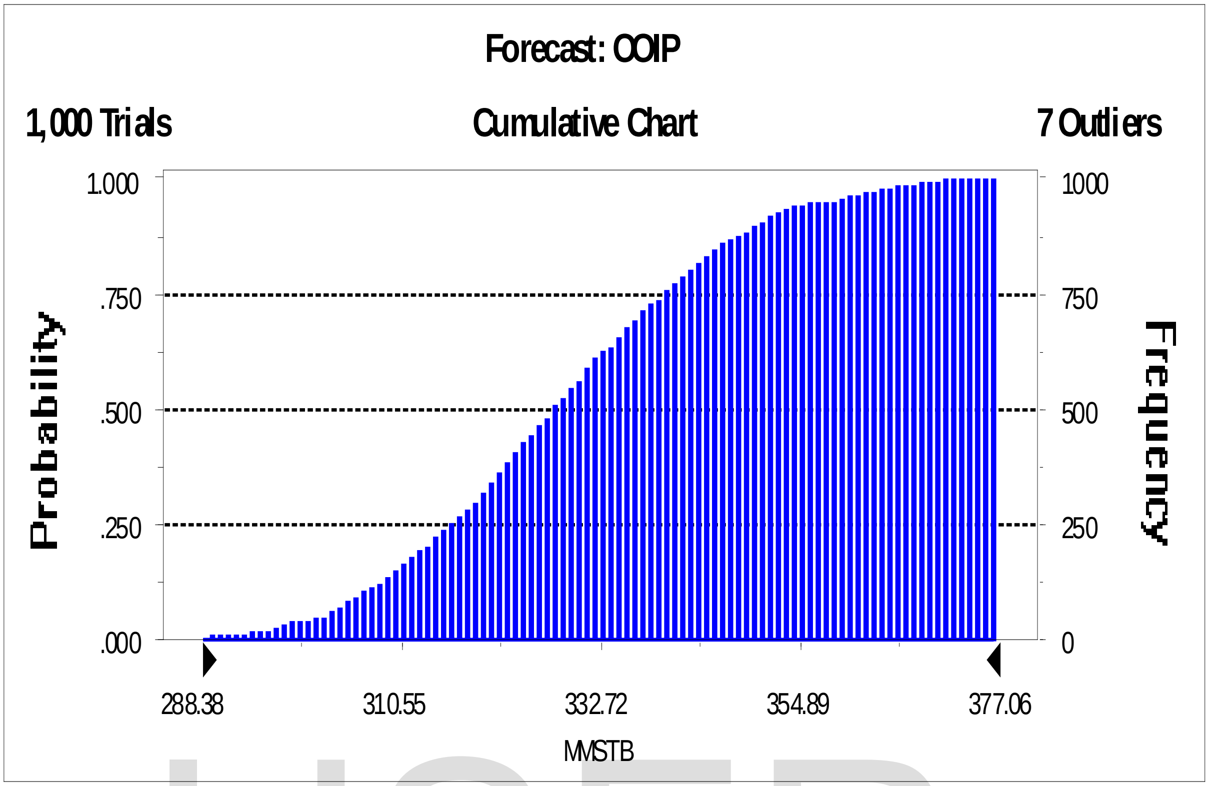

Figure-1.5: ICC Field Probabilistic OOIP estimates PDF diagram

3D Static Modelling OOIP Estimation:

A 3D Static Model has been prepared for the field using Petrel software. The available studies and data has been utilised to prepare the model. A summary of the workflow is given below:

Step-1: Model is comprised of three bounding faults and four intra-field faults.

Step-2: Facies modelling based on petrofacies estimated by applying cut-offs to logs and CPI data. Modelling of the facies was carried using proportion curve technique.

Step-3: Porosity modelling was carried out using petrophysical evaluation based porosity estimates and modelling was conditioned to the modelled facies.

Step-4: Water Saturation modelling was carried out using petrophysical evaluation based water saturation estimates and modelling was conditioned to the modelled facies.

Step-5: Permeability was predicted using available core data analysis. Three realisation of the permeability were prepared in the model and modelling was conditioned to the modelled facies.

Step-6: Net to Gross Estimation: 3D model net to gross was estimated by applying shale facies cut-off and 15 percent porosity cut-off.

The oil in-place estimated from the 3D model is given in the Table- 1.5 below:

Table- 1.5: 3D Modelling OOIP estimation results.

	Bulk Volume	Net Volume	Pore Volume	HCPV Oil	STOIIP
Unit	10E6 m^3	10E6 m^3	10E6 rm^3	rm^3	MMSTB
G2.0A	70783865.95	33758856.00	7241507.00	3604803.00	18.01
G2.0B	168096880.36	149544350.00	42295747.00	29094522.00	145.34
G2.1	181852172.67	172597823.00	50180546.00	36981910.00	184.58
G2.2	12788039.29	11822450.00	3607249.00	2260320.00	10.93
				Total OOIP	358.81

DISCUSSION OF RESULTS AND CONCLUSION

The review of the input data used for the 2002 evaluation and the current evaluation suggests that the upward revision of the OOIP of the ICC Field can be attributed to the following factors:

1. **Better Structure Definition**:

ICC seismic data acquired and processed during 2001 was of poor quality. Following the initial review of the seismic data in 2001, it was recommended that 3D data should be re-processed using advanced seismic processing techniques. The data was re-processed in year 2017 and the processing included conventional data processing and PSDM processing. The re-processing led to improvement in the seismic data quality. The VSP data, from the seven exploration and development wells drilled in the field, was one of the key factors in the improvement of the seismic data processing quality.

The PSDM processing led to better definition of structural configuration and faults. This improvement in seismic data quality resulted in approximately 96 acre-ft increase in the bulk rock volume (BRV) estimate for the field. The 2002 estimate of BRV was 257.86 acre-ft compared to current estimate of 351.47 acre-ft (Fig. 4.4).

2. **Acquisition of Reservoir Characterisation Data from Development Wells:**

The 2002 estimates were based on ICC-1, -2 and –3 wells which are situated at edges of the field with either thin HC column or relatively poor reservoir quality. During the last years five wells, namely ICC-4, -5, -6, -7 and -8 were drilled in the field, which encountered thick HC column and better reservoir quality. This additional data acquisition led to improvement in the reservoir properties estimation especially the netpay thickness estimates (Fig. 1.6). The results of the seismic lithology study carried out were also a contributing factor to the higher net to gross estimates as the study suggested that thick reservoir quality sand encountered in the wells are probably present across the entire field.

CONCLUSION

A summary of estimates of the oil in-place for the ICC Field from the different methods described above is given in Table 1.6 below:

Table-1.6: ICC Field OOIP estimates summary

	P1 (P90)	P1+P2 (P50)	P1+P2+P3 (P10)
	MMSTB	MMSTB	MMSTB
Deterministic Estimate		324.97	
Probabilistic Estimate	306.90	327.96	351.06
3DModelling Estimate			358.85

The previous estimation of the oil in-place for the field (deterministic estimate) was carried out initially during early 2002, which was later revised after the ICC-3D well. The estimates details are shown in the Table-5.2 below:

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Table 1.7: ICC Field 2002 OOIP estimates summary

OOIP Evaluation
After Okpoho 1 and 2 wells

LEVEL	G.B.V MM m3	N.P.V MM m3	O.H.I.P MMRCBO	Bo Rb/Stb	O.H.I.P. MMSTBO
G2.0.A	Not Evaluated				
G2.0.B	127,01	30,75	130,66	1,313	**99,51**
G2.1.A	135,64	33,10	135,95	1,313	**103,54**
G2.1.B	Water bearing				
G2.2	Water bearing				
TOTAL	262,66				203,05

LEVEL (G2.0.B) O.W.C. 1743.6 mss
LEVEL (G2.1.A) O.W.C.1739.0 mss

OOIP Evaluation
After Okpoho 3 Dir. well

LEVEL	G.B.V MM m3	N.P.V MM m3	O.H.I.P MMRCBO	Bo (*) Rb/Stb	OOIP MMSTBO
G2.0.A	23,798	2,3	7,76	1,313	**5,91**
G2.0.B	119,263	28,5	106,94	1,313	**81,45**
G2.1(A+B)	161,429	41,3	171,54	1,313	**130,65**
G2.2	13,546	4,5	22,74	1,313	**17,32**
TOTAL	318,036				235,33

AVERAGE O.W.C. 1740 mss
(*) Provisional

The comparison of the estimates of 2002 and the current study suggests that there is an increase of 93 MMSTB in the P50 estimate of the ICC Field oil in-place estimate (Table-1.8).

Table-1.8: ICC Field 2002 and OOIP estimates comparison in this study.

	P1 (P90)	P1+P2 (P50)	P1+P2+P3 (P10)
	MMSTB	MMSTB	MMSTB
2002Post ICC-3 estimate.	235.33	235.33	235.33
Probabilistic Estimate	306.90	327.96	351.06
Increase in OOIP	71.57	92.63	115.73

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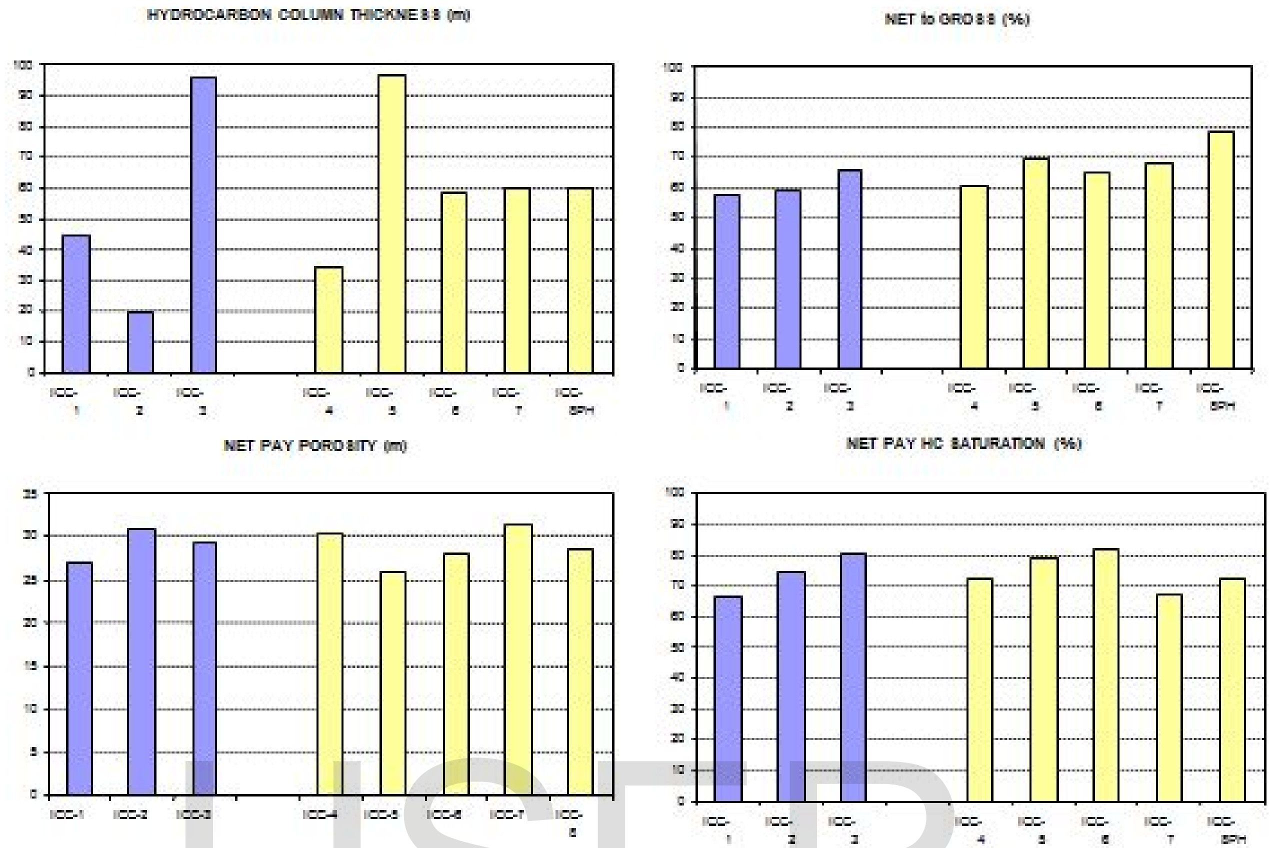

Figure-1.6: ICC Field 2002 and OOIP input parameters data comparison plots

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