COMPETENT PERSON'S REPORT

BAHAMAS PETROLEUM COMPANY PLC

LICENSES HELD BY BAHAMAS OFFSHORE PETROLEUM LIMITED
IN THE COMMONWEALTH OF THE BAHAMAS

As of June 30, 2011

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EXECUTIVE SUMMARY

The Bahamas Petroleum Company PLC (Bahamas Petroleum) contracted Ryder Scott Company (Ryder Scott) to provide a Competent Person's Report assessing Prospective Resource volumes on the Bain, Cooper and Donaldson exploration licenses located offshore, Bahamas.

Ryder Scott has reviewed newly acquired 2D seismic data, older seismic information, available subsurface information and technical reports prepared by other consultants and operating companies concerning the petroleum potential of the Bahamas. Ryder Scott has also incorporated data on known producing fields from both public sources and our own files in this evaluation as potential analogs to accumulations that may be discovered on these license areas.

The Prospective Resource volumes in this report were estimated probabilistically incorporating ranges of values for each key parameter. The resulting volumes are reported below as the Low Estimate, the highest confidence values; the Best Estimate, most likely technical values; and the High Estimate, low confidence values. Note that these Low, Best and High estimates of Stock Tank Oil Originally in Place (STOOIP) and recoverable prospective resource volumes (EUR) have not been adjusted according to the geological chance of success for each area and zone of interest and are therefore reported as "Unrisked" volumes.

Structure	Horizon	Unrisked STOOIP (MMBO) Gross (100%)				Unrisked EUR (MMBO) Gross (100%)				Chance of Success
		Low	Best	High	Mean (2)	Low	Best	High	Mean (2)	
A	Top Cretaceous	78.7	231.4	575.9	286.2	12.9	45.7	146.4	66.9	11%
	Top Albian	190.0	1,087.6	3,258.5	1474.3	33.8	202.8	798.3	337.6	13%
	Top Aptian	664.7	2,234.2	5,836.0	2849.7	115.8	437.3	1,502.8	687.3	31%
B	Top Cretaceous	752.8	2,572.3	7,053.7	3322.5	134.6	527.7	1,610.5	764.0	26%
	Top Albian	479.0	1,904.7	5,433.5	2539.7	93.1	388.1	1,314.6	572.6	23%
	Top Aptian	494.0	2,227.3	6,445.7	2964.6	97.8	415.8	1,702.3	703.3	35%
C	Top Cretaceous	201.8	552.6	1,397.3	696.3	32.8	119.2	363.1	168.4	28%
	Top Albian	312.2	839.8	2,109.7	1057.6	54.2	180.0	537.6	250.9	28%
	Top Aptian	174.7	511.7	1,222.9	628.2	29.0	104.8	314.9	148.0	35%
D	Top Cretaceous	99.4	217.4	517.7	268.2	15.7	46.8	132.0	62.4	9%
	Top Albian	677.9	1,703.5	4,029.8	2103.8	115.4	377.9	1,068.3	506.1	12%
	Top Aptian	0	0	0	0	0	0	0	0	

MMBO = million barrels of oil

(2) In accordance with the PRMS, we have reported the low, best and high estimates for each horizon. As requested by Bahamas Petroleum, we have also included the mean estimates for each horizon.

The geological Chance of Success is an evaluation of the probability of a discovery based on the likelihood of the presence of a functioning Petroleum System. The Chance of Success does not consider whether a discovery will be economically viable.

Volumes in this report are estimates of undiscovered, prospective resources and are subject to significant uncertainty. The volumes may or may not be discovered and, if discovered, may be different from the volumes shown herein. If discovered, the volumes may or may not be economically recoverable.

The volumes in this report should only be considered in the context of this full report.

Ryder Scott reviewed some basic economic evaluation data such as capital expenditures, expected operating expenses, pricing, and the overall economic model pertaining to the operating contract agreements of Bahamas Petroleum. In it is noted that such screening economics at this point are subject to potentially significant changes once a commercial development occurs and a field is placed on production. Our review indicates that the economic parameters utilized by Bahamas Petroleum in its economic models appear to be reasonable. In general, the relative magnitude of the reserve volumes in each structure would indicate that in most cases the unrisked best case volumes would be commercially viable under a single reservoir discovery. The available deep well control demonstrates the presence of multiple reservoir quality zones within each of the three major intervals mapped. There is, therefore, a potential for multi-zone discoveries in any or all of the three major intervals. The high case volumes resulting from a multi-zone discovery should be commercially very attractive.

The results of this study pertain only to the technical aspects of potential oil recovery. These results are, under no circumstance, to be interpreted as our opinion regarding the economic success of the venture. We have not conducted any economic evaluations of these assets and thus we have no opinion and make no warranty or guaranty of any kind on the subject of economic feasibility of this project.

This report considers only prospective reservoirs in the Cretaceous section and only structurally trapped accumulations that may exist in the mapped closures. The report does not address potential stratigraphic traps such as the carbonate buildups of the Golden Lane fields or combination structural / stratigraphic traps such as Poza Rica Field that are known to exist in similar geologic settings onshore and offshore southern Mexico. This report also does not consider potential sub-thrust accumulations such as the Sihil discovery underlying the giant Cantarell Field offshore, Mexico. Additionally, prospective reservoirs known to exist regionally in the shallower Tertiary and deeper Jurassic sections are not considered.

Bahamas Petroleum is currently acquiring 3D seismic data which may allow evaluation of the potential in these additional trap types and prospective reservoir intervals. An updated Competent Person's Report is expected to be completed once the 3D seismic information is available.

INTRODUCTION

In June, 2010, and January, 2011, Bahamas Petroleum acquired 1327 kilometers of 2D seismic data across deep water portions of its Bain, Cooper and Donaldson exploration licenses offshore, Bahamas. This new information indicates the presence of potential structural traps on Bahamas Petroleum acreage. Ryder Scott Company was contracted by Bahamas Petroleum to assess the Prospective Resource volumes that may be present in these potential hydrocarbon accumulations in accordance with the guidelines of the 2007 Petroleum Resources Management System (SPE-PRMS). The U.K. Financial Services Authority, under the U.K. Listing Authority's Issue No. 13, accepts mineral expert's reports that comply with the SPE-PRMS.

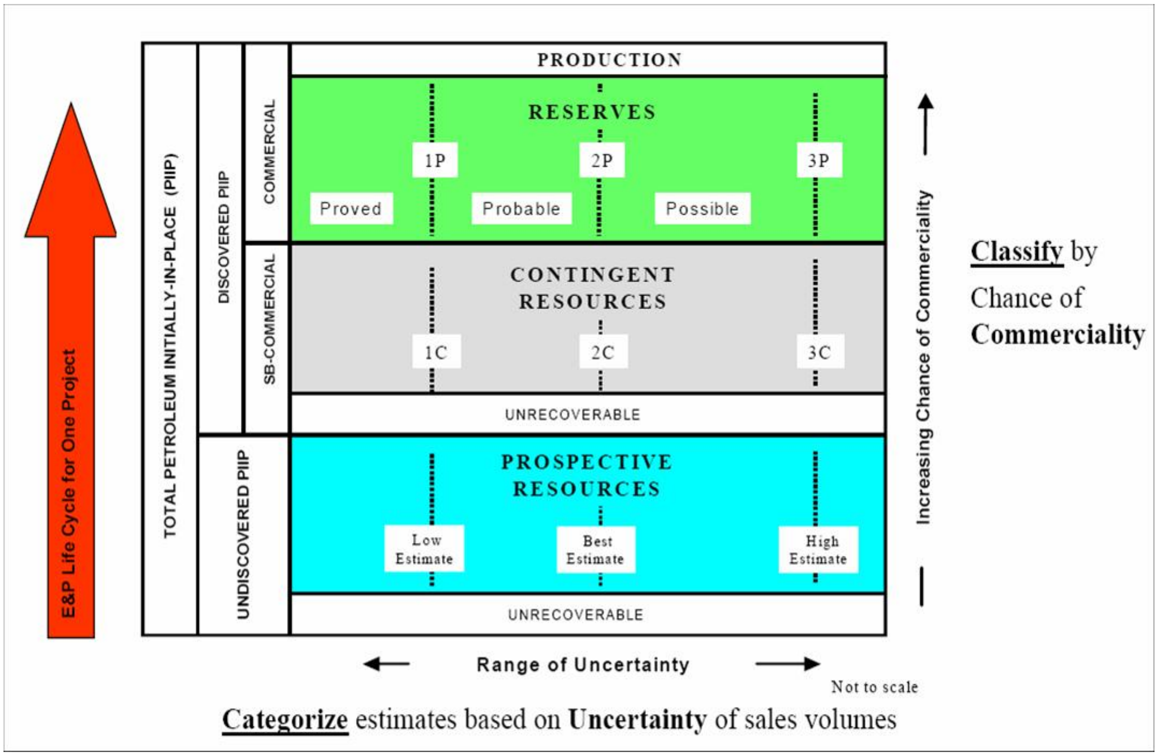
RESOURCE DEFINITIONS

The resource volumes in this report are all undiscovered, i.e. the existence of currently in place, mobile hydrocarbons has not been demonstrated by a well. Based on the PRMS resource classification system shown below, these volumes are classified as "Prospective Resources". Prospective resource volumes are uncertain; that is, there is a range of possible outcomes. The primary focus of this report is to describe the range of potentially recoverable volumes associated with various exploratory leads and prospects identified on the Bain, Cooper and Donaldson exploration licenses. The PRMS directs that Prospective Resource volumes may be estimated deterministically or probabilistically. The least uncertain volume is reported as the "Low Estimate"; the most uncertain as the "High Estimate".

Resource volumes in this report are estimated probabilistically. In keeping with the guidelines in the PRMS, the "Low Estimate" is the P90 volume of the resource distribution derived for each individual lead or prospect. Similarly, the "Best Estimate" is the P50 volume and the "High Estimate" is the P10 volume.

The Low Estimate, Best Estimate and High Estimate are unrisked volumes. These estimates are intended to represent a reasonable range of estimated potentially recoverable volumes. They do not consider the chance that a discovery will occur. This chance is usually described as the "geological chance of success" which is an estimation of the probability that all of the components of a petroleum system (source, trap, seal and migration) are in place.

In this report Ryder Scott provides estimates of the unrisked Low, Best and High estimates and a chance of success (COS) for each lead or prospect. Risked volumes are not provided here. Risked volumes should incorporate an either/or probability of (1 – COS) that the exploration well will be a dry hole and the resource volume is zero.



ASSET OVERVIEW

As of May 31, 2011, the Bahamas Petroleum portfolio consisted of five petroleum exploration licenses covering a total of 15,676 square kilometers (3,873,546 acres) in the territorial waters and maritime Exclusive Economic Zone (EEZ) of The Commonwealth of the Bahamas (Figure 1). Four of the licenses (Bain, Cooper, Donaldson and Eneas) are contiguous and cover the southwest margin of the shallow water Great Bahamas Bank and the adjacent deep water Santaren Channel and Old Bahama Channel. These four licenses are held by Bahamas Offshore Petroleum Limited, a wholly-owned Bahamian subsidiary of Bahamas Petroleum Company PLC.

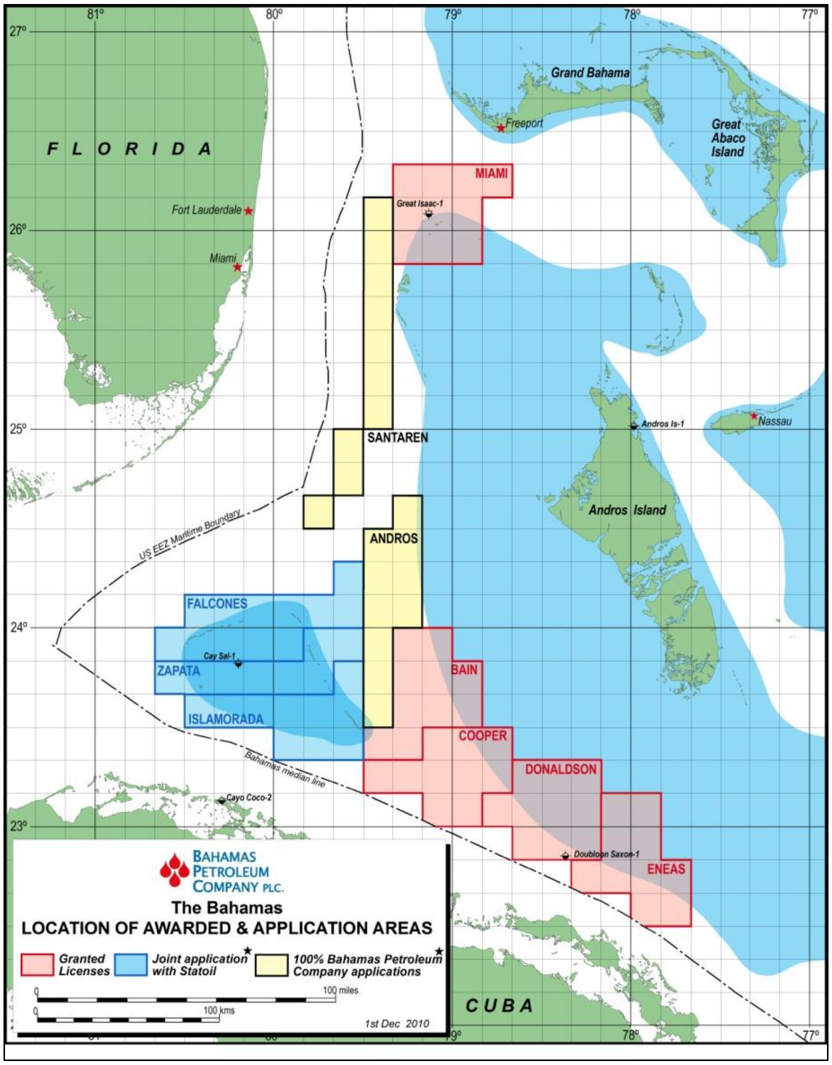


Figure 1 Bahamas Petroleum Company Licenses (provided by Bahamas Petroleum)

No new seismic information was acquired over the Eneas license southeast of Bain, Cooper and Donaldson or the isolated fifth license to the north (Miami). Due to the limited seismic information available on these two licenses, this report does not attempt to quantify prospective resources that may exist in leads identified on these two license areas.

Details of the three licenses discussed in this report are given in Table 1.

Table 1: Assets in this Report

Asset	Holder	Interest	Status	License Expiry Date	License Area
Bain License	Bahamas Offshore Petroleum Limited	100%	Exploration	2015*	775,468 acres 3,138 km^2
Cooper License	Bahamas Offshore Petroleum Limited	100%	Exploration	2015*	777,934 acres 3,148 km^2
Donaldson License	Bahamas Offshore Petroleum Limited	100%	Exploration	2015*	778,855 acres 3,152 km^2

*The current exploration license period expires in April, 2012. Under the terms of the licenses, the Governor General grants the license holder, Bahamas Offshore Petroleum (BOP) and Island Offshore Petroleum (IOP), subsidiaries of Bahamas Petroleum Company Plc, the sole right to undertake exploration in its license areas subject to conditions set forth in the licenses, Petroleum Act and Regulations. If BOP and IOP meet the financial and regulatory provisions of the licenses, the Governor General shall renew the licenses for another 3 years providing the Company commits to drill an exploration well and spud the well before the end of the first renewal year, i.e., by April 26, 2013. The Company advised the Ministry of the Environment in a letter dated in February, 2011, that Bahamas Petroleum has fulfilled the commitments of the current licenses, and that they intend to continue the exploration program into the next extension (through 2015) and that they intend to spud the first well by April 26, 2013.

AVAILABLE DATA

Subsurface

There has been limited exploration activity in the Bahamas with only five deep wells drilled to date; the last in 1986. Table 2 shows the existing deep well control and Figure 2 shows the locations of the wells relative to the Bahamas Petroleum licenses and known producing trends in South Florida and North Cuba.

Table 2: Petroleum Exploration Wells, Onshore Bahamas and Bahamian Waters

Well	Year	Operator	Total Depth	Age @ TD
Andros Island-1	1947	Superior	14,585'	Early Cretaceous
Cay Sal-1	1959	Bahamas California	18,906'	Jurassic/Early Cretaceous
Long Island-1	1970	Bahamas Gulf	17,557'	Jurassic/Early Cretaceous
Great Isaac-1	1971	Bahamas California	17,847'	Jurassic (?)
Doubloon Saxon-1	1986	Tenneco	21,740'	Early Cretaceous

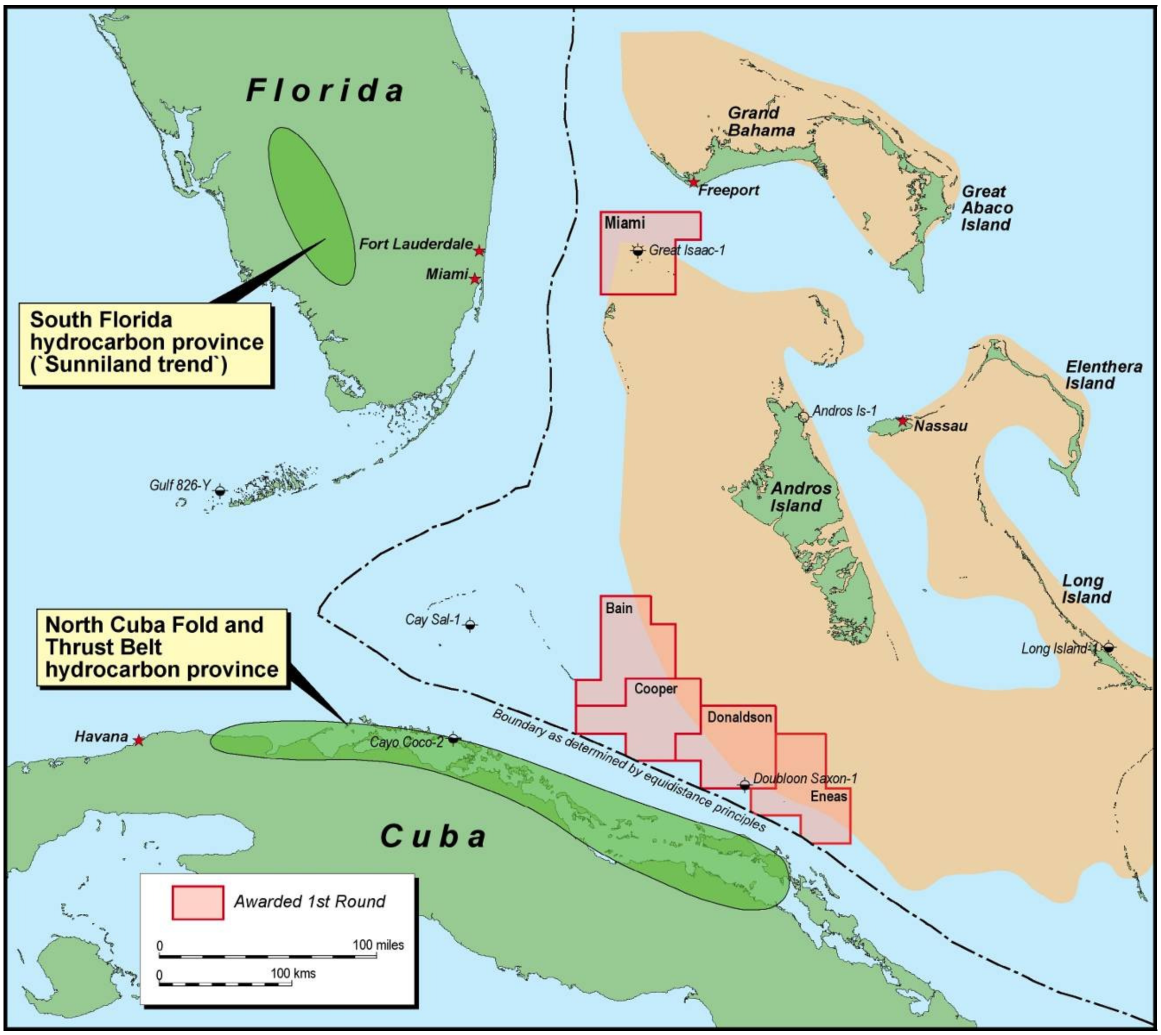


Figure 2 Locations of Deep Exploration Wells (provided by Bahamas Petroleum)

Bahamas Petroleum provided for our review log data for the Cay Sal-1, Doubloon Saxon-1 and Great Isaac-1 wells along with various core and cuttings samples reports. Various reports were also available for the Andros-1, Long Island-1 and Gulf 826-Y wells.

The wells all encountered thick carbonate and evaporite deposits with indications of hydrocarbons as shown in Figure 3. Various potential reservoir facies in limestones and dolomites are demonstrated to be present along with potentially sealing anhydrites and occasional thin salt layers. Due to the large distances and lack of direct seismic ties between wells and sparse paleontological information resulting from extensive dolomitization, correlation of individual reservoir or seal layers between wells is not possible.

A nearly complete modern log suite along with petrographic studies of core and cuttings samples are available for the Doubloon Saxon-1 well drilled in 1986 in the south central part of the Donaldson license. Sonic, density and sidewall neutron porosity logs are also available for the Great Isaac-1 well drilled in 1971. Although this well lies at a considerable distance from the area of interest, the depositional setting at this location relative to the Bahamas Platform during the Cretaceous may be more representative of the deep water, re-worked platform margin depositional system expected in the area of interest than the section evaluated by the Doubloon Saxon-1 well which appears to have penetrated primarily shallow water platform facies. Ryder Scott has used both wells to model the expected character of reservoirs that may occur in the Bain, Cooper and Donaldson license areas.

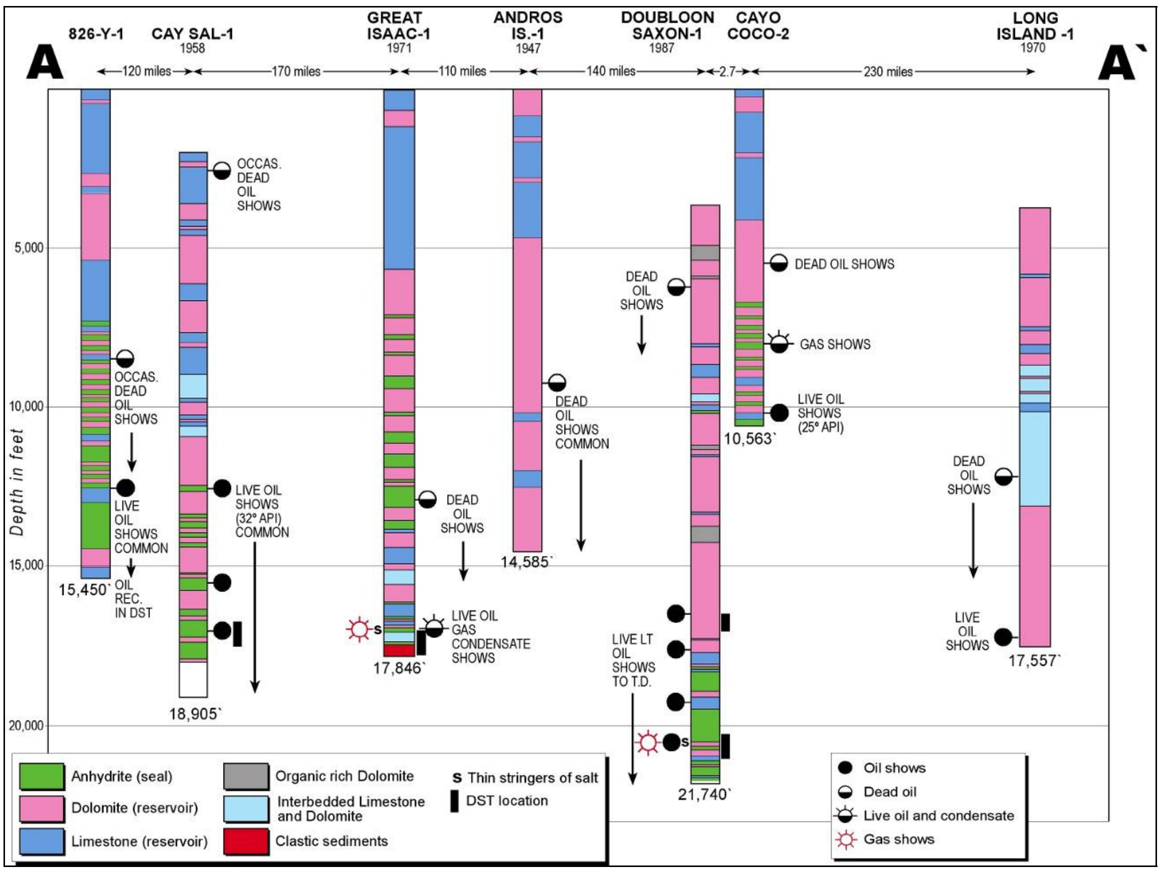


Figure 3 Deep Well Cross Section (provided by Bahamas Petroleum)

Seismic

Over 7500 kilometers of deep water 2D seismic data in Old Bahama Channel, Santaren Channel and the Florida Straits acquired in 1981 and 1982 were available in the form of unmigrated prints from the University of Miami. These data were scanned, vectorized to seismic traces and then post-stack migrated. These data (the "BH" data) form an approximate 10 X 10 km grid in the deep water channels

(1500 to 4000' water depth). These lines were provided to Ryder Scott in the format of an SMT Kingdom Project. The locations of these lines in relation to the existing deep well control and the Bahamas Petroleum Company licenses are shown on Figure 4 in gray.

In June, 2010, Bahamas Petroleum acquired four new 2D lines totaling 200 kilometers to assess the impact of modern data acquisition techniques on data quality. These lines duplicated parts of the pre-existing BH data in order to provide a direct comparison. These lines are included in the SMT project and are shown in green on Figure 4.

Based on the results of the June, 2010, seismic shooting Bahamas Petroleum acquired a moderately spaced grid of 2D seismic data in January, 2011. These new data consist of 27 lines totaling 1127 kilometers. The 23 northeast-southwest oriented lines were acquired at an average spacing of 5 kilometers. The four remaining lines are generally oriented northwest-southeast; three at an approximate average spacing of 25 kilometers. The fourth northwest-southeast line was acquired along the crest of the structural trend. The January, 2011, data are also included in the SMT project provided to Ryder Scott and are shown on Figure 4 in red.

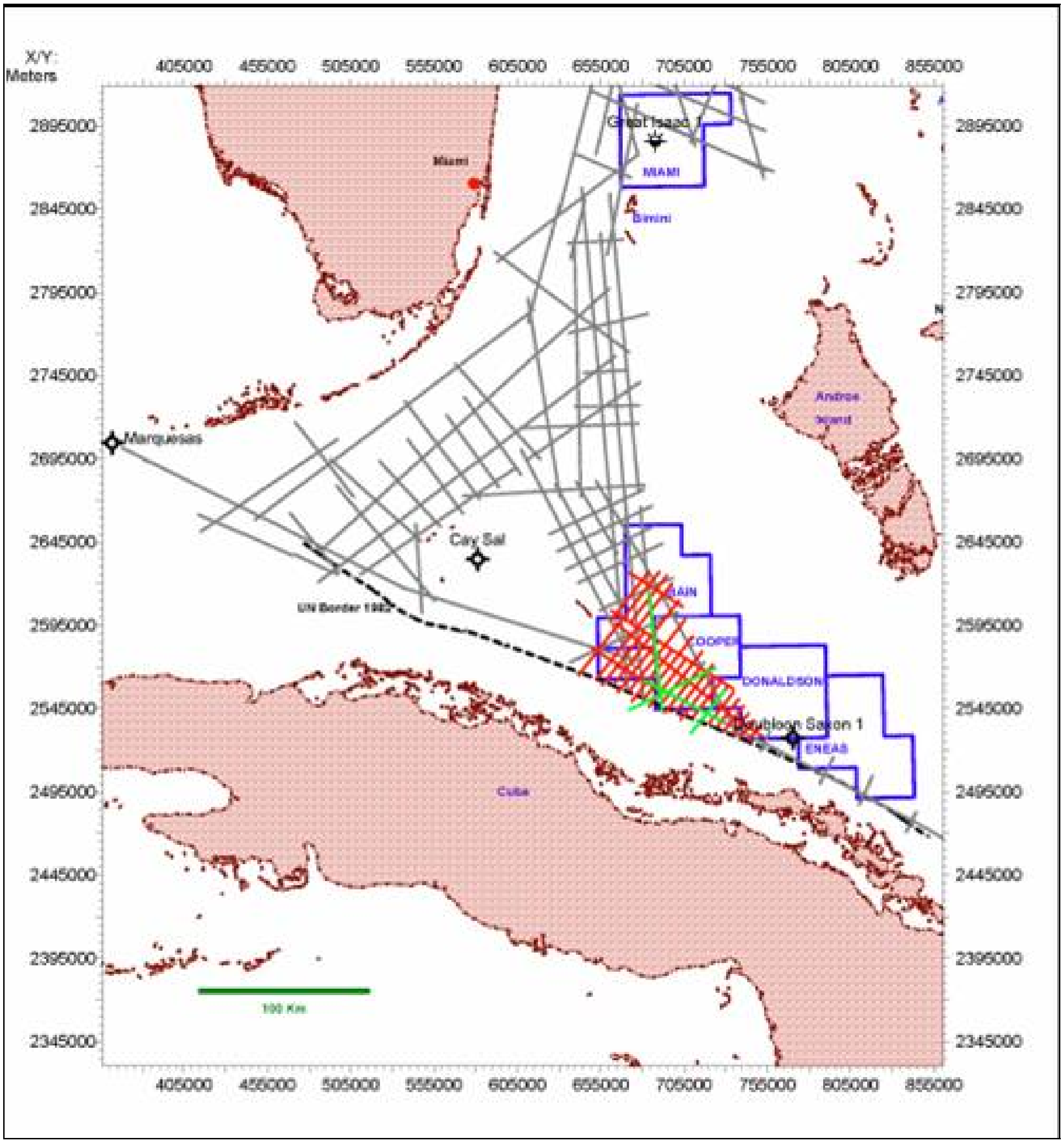


Figure 4 2D Seismic data as of January, 2011

The January, 2011, seismic data set was processed through post stack time migration and interpreted by Jon Kirkpatrick of International Geophysical Consulting (IGC). The final processed data and interpreted time horizons and faults from IGC were provided to Ryder Scott and served as the basis of the structural interpretations discussed in this report. The IGC time horizons that appear to have potential as exploratory targets are as follows:

- A time horizon slightly shallower than the Top Cretaceous which has been named the Near Top Cretaceous
- The Top Cretaceous time horizon
- The Albian time horizon
- The Aptian time horizon

COMMENTS ON SEISMIC DATA QUALITY

Overall, the 2D seismic data acquired in 2010 and 2011 (2010/2011 data set) represents a significant improvement over the BH data with respect to the quality of imaging. Certain data quality issues remain, however, which include distortions due to the significant velocity contrast between materials in the Tertiary section versus those in the Cretaceous and deeper section. Additionally, there appears to be a lingering problem with multiples although this problem is significantly reduced versus what was seen in the BH data set.

The quality of the 2010/2011 data set worsens noticeably below the Top Cretaceous horizon making the time picks for the Albian and Aptian horizons somewhat more uncertain than the Near Top Cretaceous and Top Cretaceous horizons. Also, due to the data quality deterioration in the deeper section, there is the potential for additional faulting at the Albian and Aptian horizons that is not recognized in the IGC interpretation.

COMMENTS ON IGC INTERPRETATION

The IGC interpretation made use of the data acquired in 2010 and 2011 as well as certain of the BH lines. In general, the IGC structural interpretation of the key horizons appears reasonable given the limitations of the available data.

The closest well to the lines acquired in 2010/2011 is the Doubloon Saxon-1 which is about 18 kilometers from the nearest line in the 2010/2011 data set. Unfortunately the BH lines which pass close to the Doubloon Saxon-1 are of extremely poor quality making it impossible to tie the Doubloon Saxon-1 into the 2010/2011 data set. However, it is possible to tie the Great Isaac-1 into the 2010/2011 data set through a series of BH lines that are of reasonable quality. This tie is not without potentially significant inaccuracy as the Great Isaac-1 is approximately 260 kilometers from the nearest line in the 2010/2011 data set.

The shallowest potential exploration target, the Near Top Cretaceous, shows prospective target structures which have been identified as Trend A (A), Fold B (B), and Fold C (C) by IGC. These target structures are shown in Figure 5, which is a time map on the Near Top Cretaceous and on Figure 5b, which is the 2D line BPC2011-27. Additional prospective structures D and E have been identified by IGC, however; these prospective structures have apparent vertical relief that is very subtle when compared to prospective structures A, B, and C and are only identifiable on a few 2D lines. Therefore, we believe that prospective structures D and E are more speculative and have significantly less potential than the other prospective structures that have been identified by IGC.

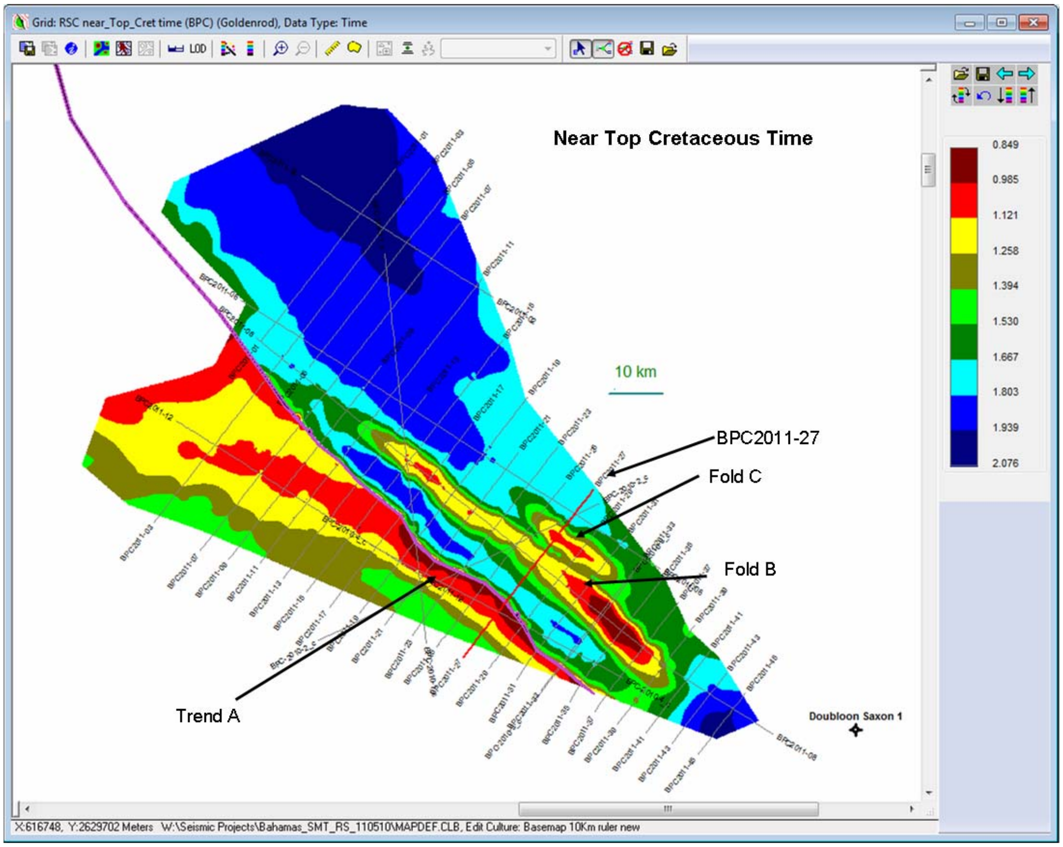


Figure 5 Time Structure Map for Near Top Cretaceous Horizon Showing Location of Line BPC2011-27 and Prospective Structures A, B, and C.

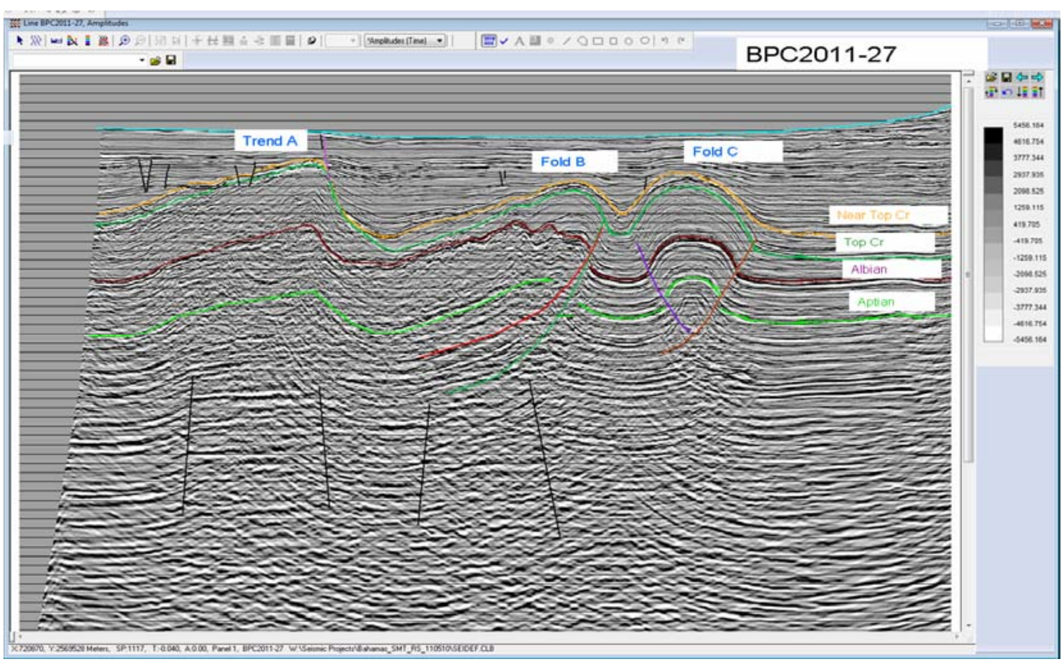


Figure 5b Line BPC2011-27 Showing Prospective Structures A, B, and C and Key Prospective Horizons.

Velocity data are available for the Doubloon Saxon-1 and the Great Isaac-1 wells. The time depth relationships for these two wells are shown in Figure 6.

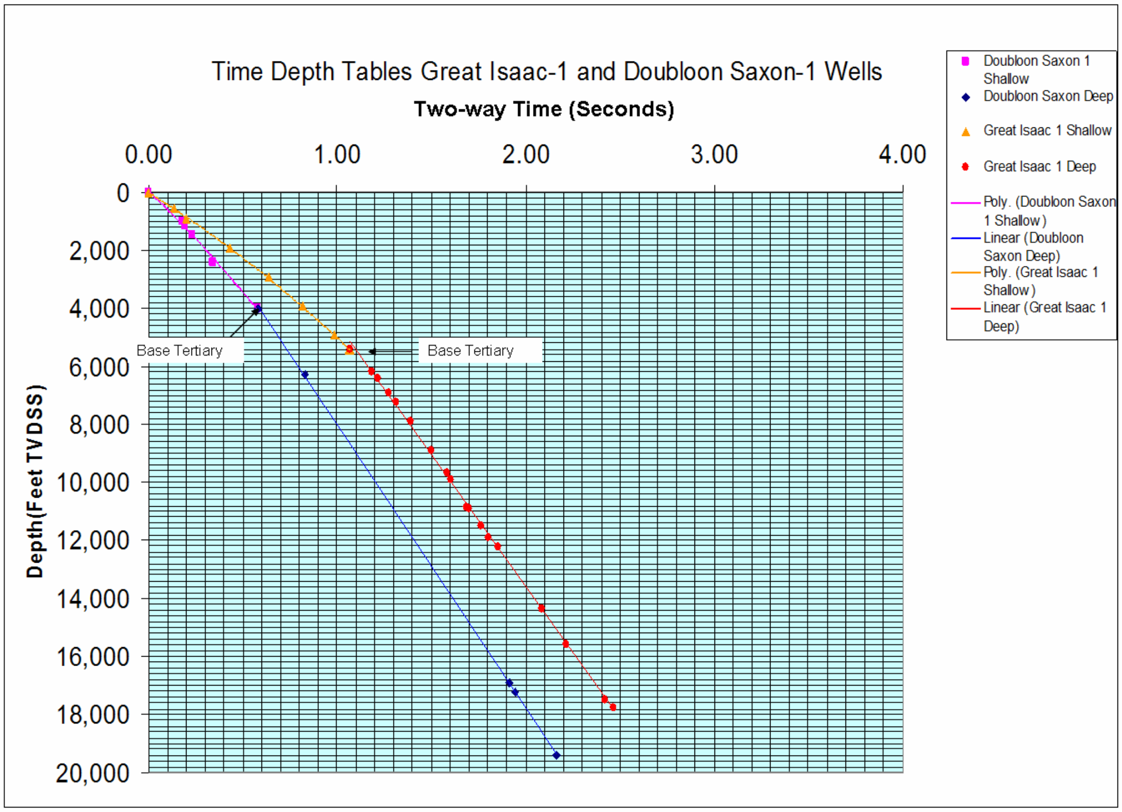


Figure 6 Time-Depth Relationships From TD Tables in IGC SMT Project.

Both wells show a similar linear trend corresponding to approximately 9500 Ft./Sec.(based on two-way time) in the section below the base of the Tertiary. However, there is a marked difference in the time-depth relationship of the two wells in the Tertiary section. In both cases the velocity in the Tertiary section is significantly slower than is the case in the section below the base of the Tertiary; however, the Tertiary velocity in the Great Isaac-1 is significantly slower than is the case for the Doubloon Saxon-1. As can be seen in Figure 7, the thickness of the Tertiary section varies considerably across the area of the prospective structures which means that there is considerable uncertainty in the structural interpretation in depth below the Near Top Cretaceous horizon. This uncertainty is most significant in the case of the Albian and Aptian horizons, particularly in the vicinity of Trend A. In addition to the velocity issue in the Tertiary section, there is also some variation in the depth to the water bottom within the prospective area which could have an impact on depth conversion. In various communications with IGC it is apparent that they are very much aware of the velocity issues.

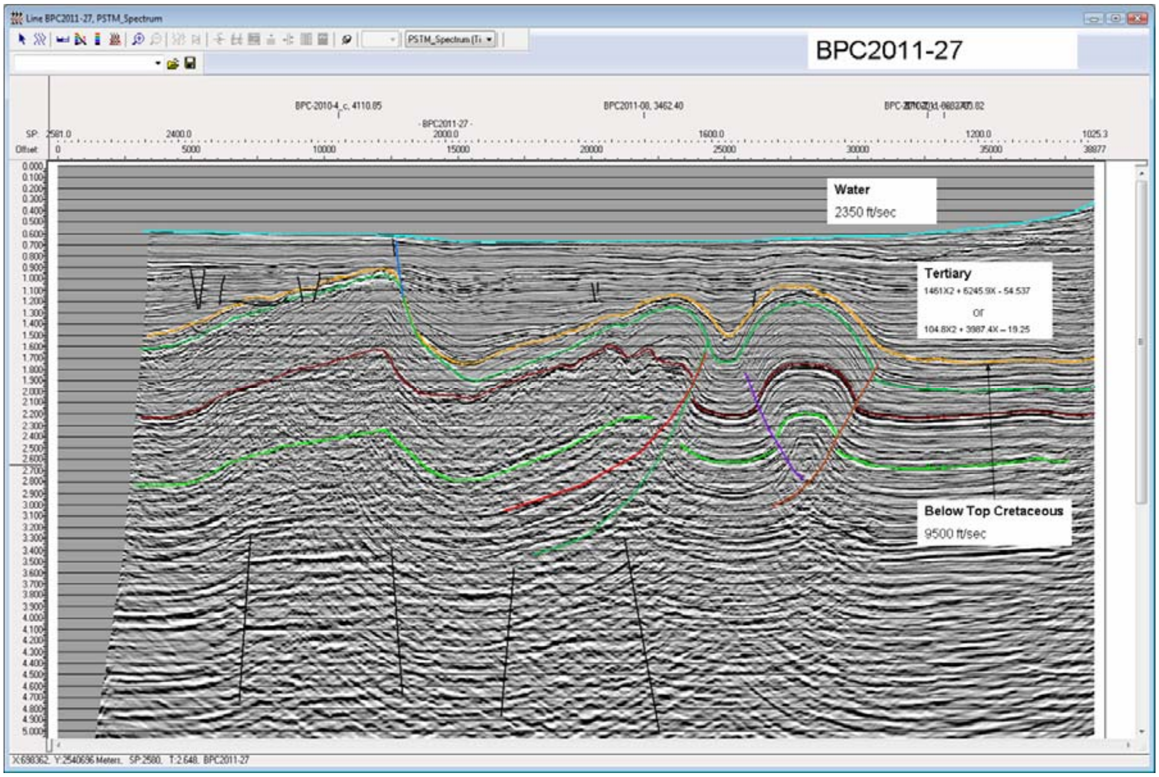


Figure 7 2D Line BPC2011-27 With Expected Velocities and Time/Depth Relationships . Velocities and Time/Depth Relationships Shown are Based on Two-Way Time.

<u>The BPC "Pearl" 3D Survey</u>

Bahamas Petroleum is currently shooting a state of the art 3000 square kilometer 3D survey in the southern license area. Figure 8 shows the outline of the 3D survey in relation to the prospect outlines and the license blocks. The 3D survey operations began in June, 2011, with acquisition expected to be completed in September and processing and initial interpretation completed by the end of the year. Planned processing includes a pre-stack depth migrated (PSDM) volume. The 3D survey will provide a complete seismic coverage of the major "A", "B" and "C" prospects and more rigorous velocity control. We expect the data will:

1) reduce uncertainty related to the shape and extent of the structures,
2) provide improved imaging and allow for mapping of potential deeper Jurassic, subsalt or subthrust structures,
3) provide a tool for seismic facies mapping, including possible identification of reservoir facies not included in this analysis,
4) allow delineation of the lateral continuity of reservoir and / or seal intervals over the structures and
5) allow the integration of seismic attributes into the evaluation.

An updated CPR is expected after the 3D survey information has been evaluated.

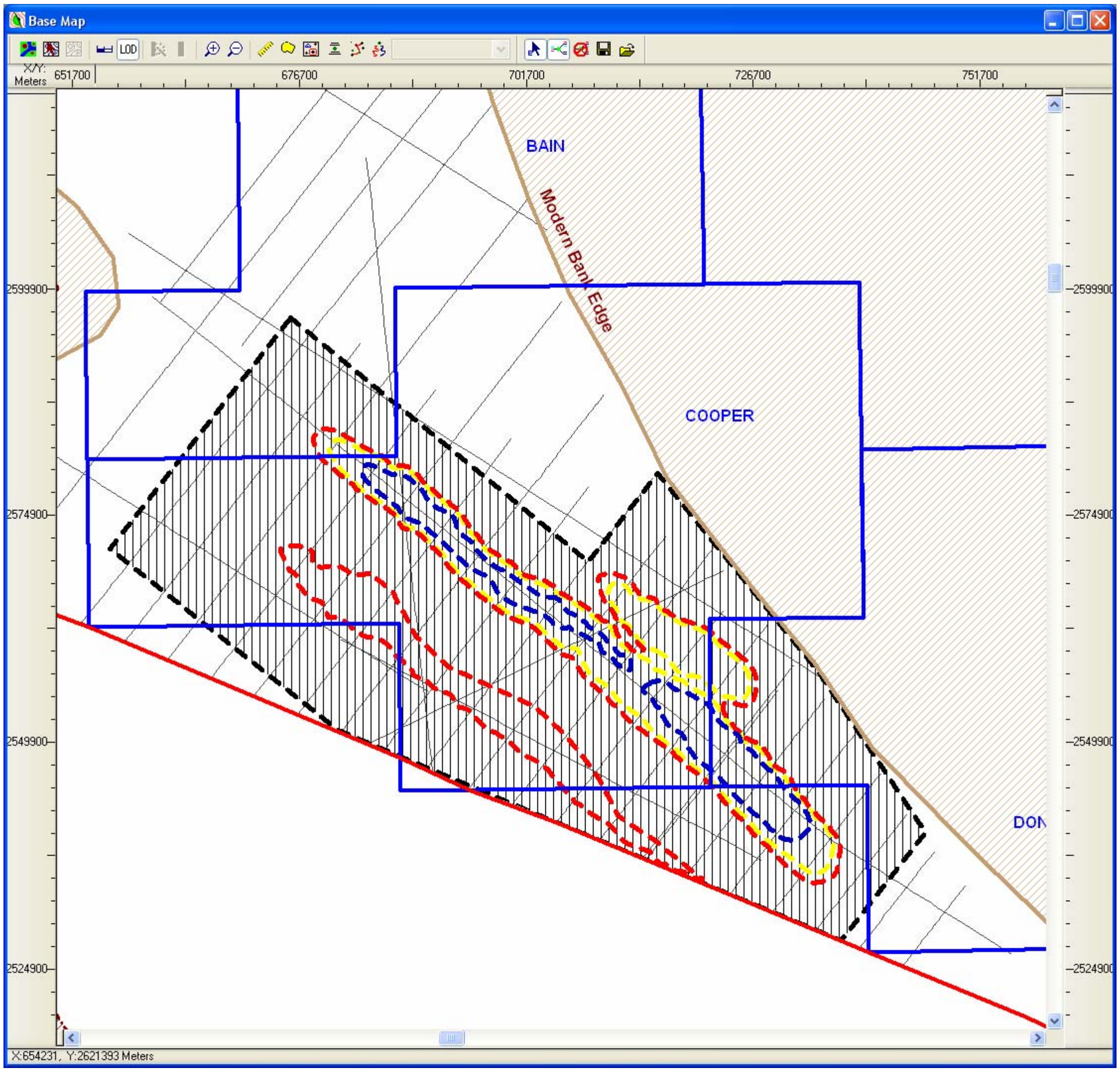


Figure 8 Base map of the Bain, Cooper and Donaldson license blocks showing the Bahamas Petroleum Company prospect outlines. Shaded area defines the 3000 km^2 "Pearl" 3D survey being acquired at the date of this report.

REGIONAL PETROLEUM SYSTEM

Economic hydrocarbon accumulations are dependent on the presence of a working petroleum system. A petroleum system consists of a mature hydrocarbon source of sufficient volume to generate economic quantities of hydrocarbons, reservoirs capable of producing at economic rates, seals in proximity to the reservoirs and structural and / or stratigraphic traps which formed prior to the migration of the hydrocarbons from the source and which have retained their integrity to the present day.

Source

As shown in Figure 3 above, deep exploration wells in and around the Bahamas have encountered numerous shows of hydrocarbons. Commercial oil production has been established along the north coast of Cuba in the vicinity of the Bahamas Petroleum licenses. Studies commissioned by Bahamas Petroleum and other independent studies all conclude that there are active hydrocarbon sources in the Bahamas. In the vicinity of the Bahamas Petroleum licenses it appears that the source is most likely to be deeply buried carbonates and oil prone. Based on a review of the previous studies, hydrocarbon shows in the Doubloon Saxon and Cay Sal wells in the vicinity of the Bahamas Petroleum licenses and established production in Cuba; Ryder Scott Company has assumed that a mature hydrocarbon source of undefined volume is likely to be present.

Figure 9 below is from a presentation from Cupet, the Cuban national oil company, showing established source intervals in western Cuba. The presentation is believed to be part of an informational package provided to potential licensees of Cuban deep water exploration blocks.

Figure 10 is from the same presentation and shows the structural style and proposed oil migration routes in Cuban north coast oil fields.

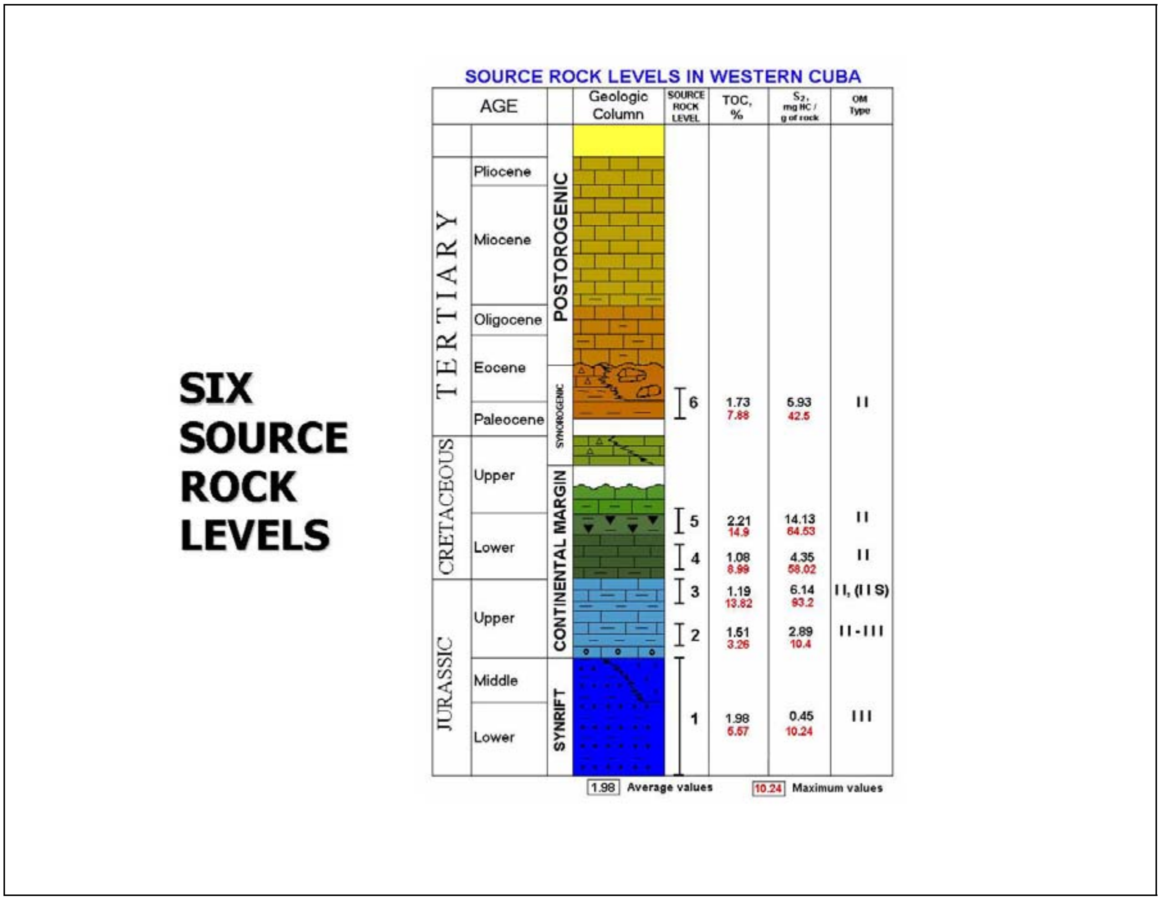


Figure 9 Western Cuba Source Rock Information from Cupet Presentation

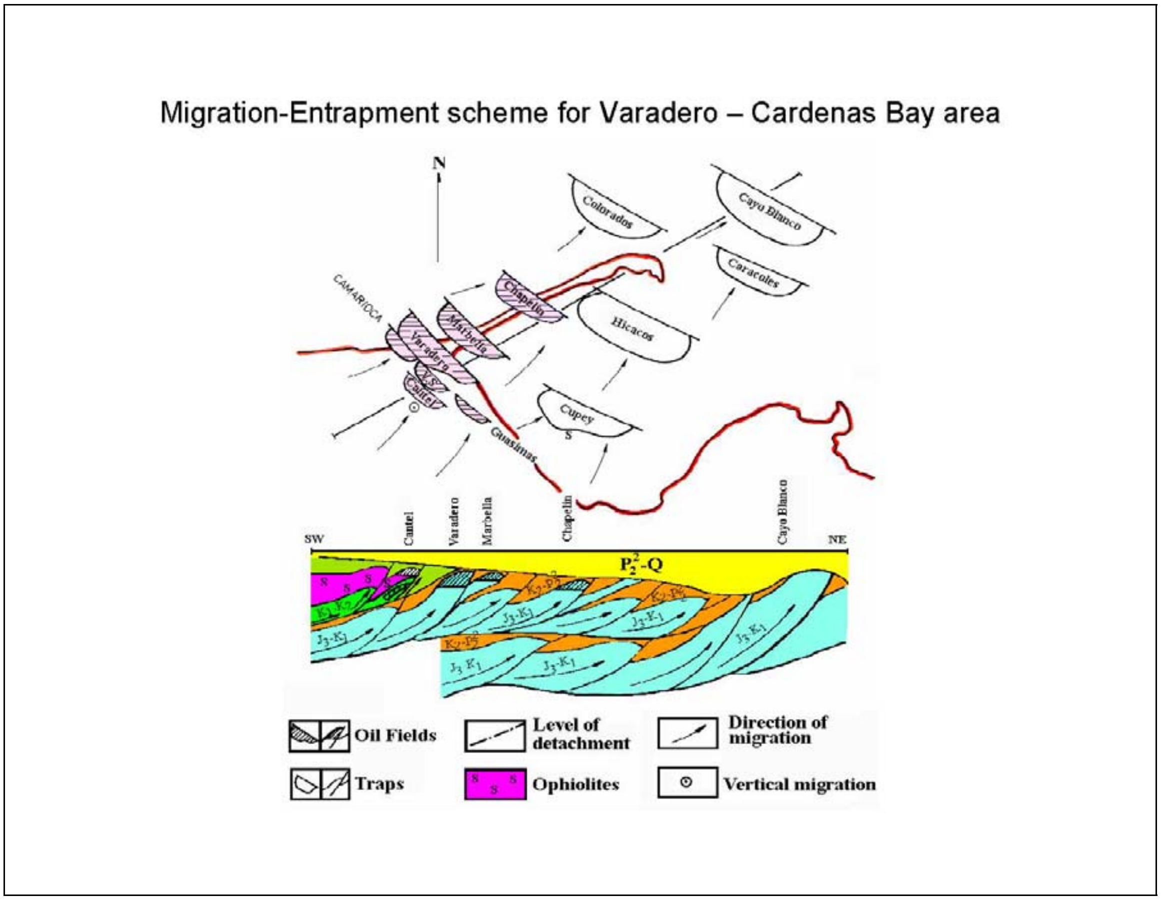


Figure 10 Cuban North Coast Oil Fields from Cupet Presentation

Seismic data on the Bahamas Petroleum licenses indicate the presence of similar migration paths along thrust planes from potential deep source intervals into the Cretaceous reservoirs evaluated in this report. The basal clastic interval penetrated by the Great Isaac well may be of Jurassic age. Jurassic shales and argillaceous carbonates are important source intervals in Cuba, the Sunniland trend and the oil producing regions of southeast Mexico.

The proximity of these fields to the Doubloon Saxon well located on Bahamas Petroleum's Donaldson license is shown in Figure 11.

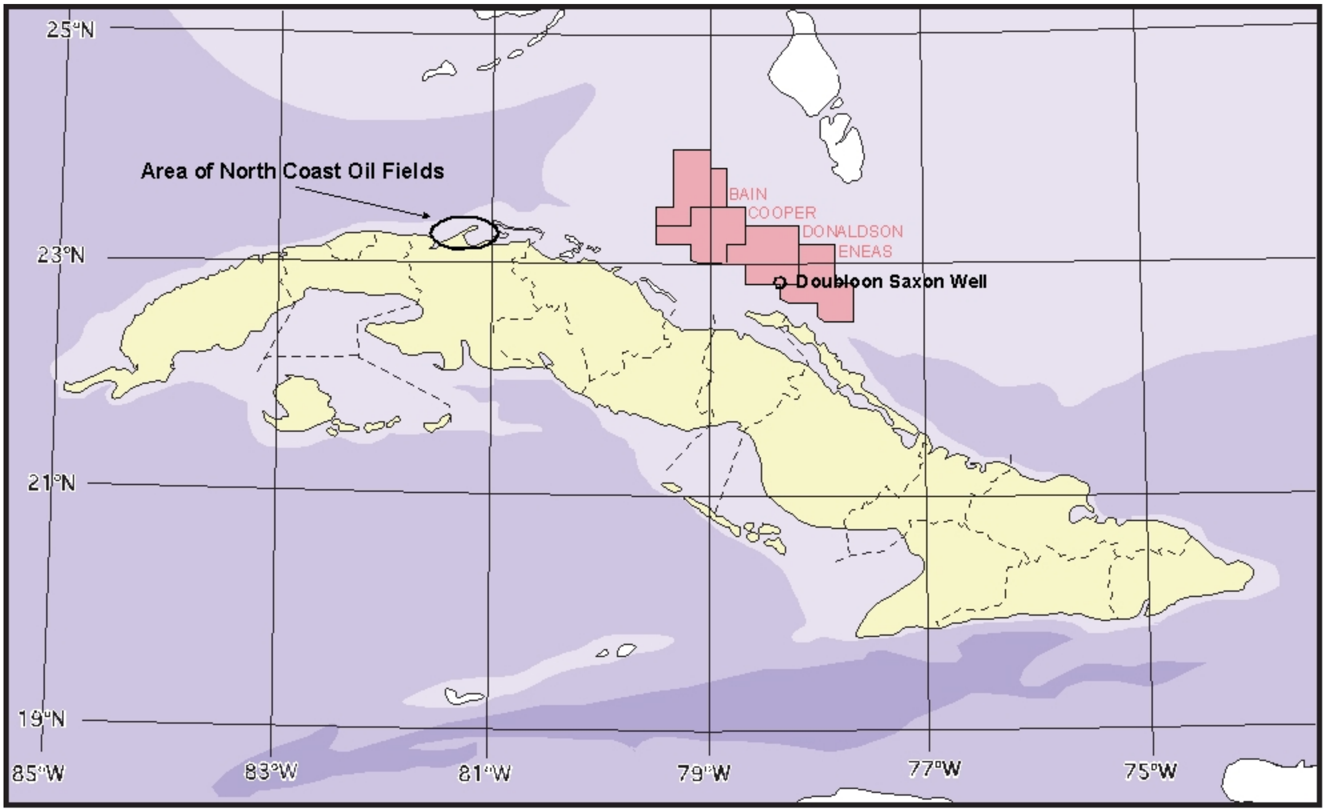


Figure 11 Locations of Cuban North Coast Fields, Bahamas Petroleum Licenses and Doubloon Saxon well

Reservoir and Seal

The Doubloon Saxon-1 well in the south central part of the Donaldson license demonstrates the presence of a significant thickness of limestones and dolomites with varying pore and fracture systems. There is limited permeability information from conventional and rotary sidewall core data. The permeability / porosity relationship in this carbonate system is expected to be complexly related to original depositional fabric, diagenesis and fracturing. Log derived sonic porosity and cross-plot porosity values differ significantly in many intervals and both can differ from porosity observed in thin sections and core data. Log based porosity calculations may be insufficient to predict which systems will be able to provide economic flow rates.

Two drill stem tests (DSTs) were conducted in the Doubloon Saxon, one in open hole and one in cased hole. Although neither test recovered hydrocarbons, the cased hole test demonstrates that some of the reservoir facies are capable of producing hydrocarbons at potentially economic rates.

The open hole test over the interval 20,510' – 20,830' recovered 75 barrels of formation water in the DST string. The cased hole test over the interval 16,468' – 16,498' flowed 222 barrels of formation water in 5 hours and 45 minutes while jetting with nitrogen. This test has been interpreted as indicating potential flow rates ranging from 1400 to 3500 BFPD. However, these rates are based primarily on fluid level rise in the tool while nitrogen was being injected into the well and do not account for the changing fluid density. The reported recovery of 222 barrels in 5 hours and 45 minutes implies a rate of

927 BFPD. It has not been demonstrated that the reservoir could have sustained this rate over a longer test period without the assistance of the injected nitrogen.

Figure 12 shows the interval tested by the cased hole DST. The neutron (blue) and density (red) porosity are displayed on a dolomite matrix in the second track from the right. The photoelectric curve is shown in the same track with values above 5.0 highlighted in orange. Most of the higher porosity values are associated with PE values above 5.0 and may consequently be more indicative of borehole rugosity than formation porosity. Two relatively high porosity zones near 16,470' and 16,560' are associated with higher gamma ray values and may represent true porous intervals containing organic matter. Porosity values from conventional core data measured by Core Lab and from thin section analysis are shown in the rightmost track.

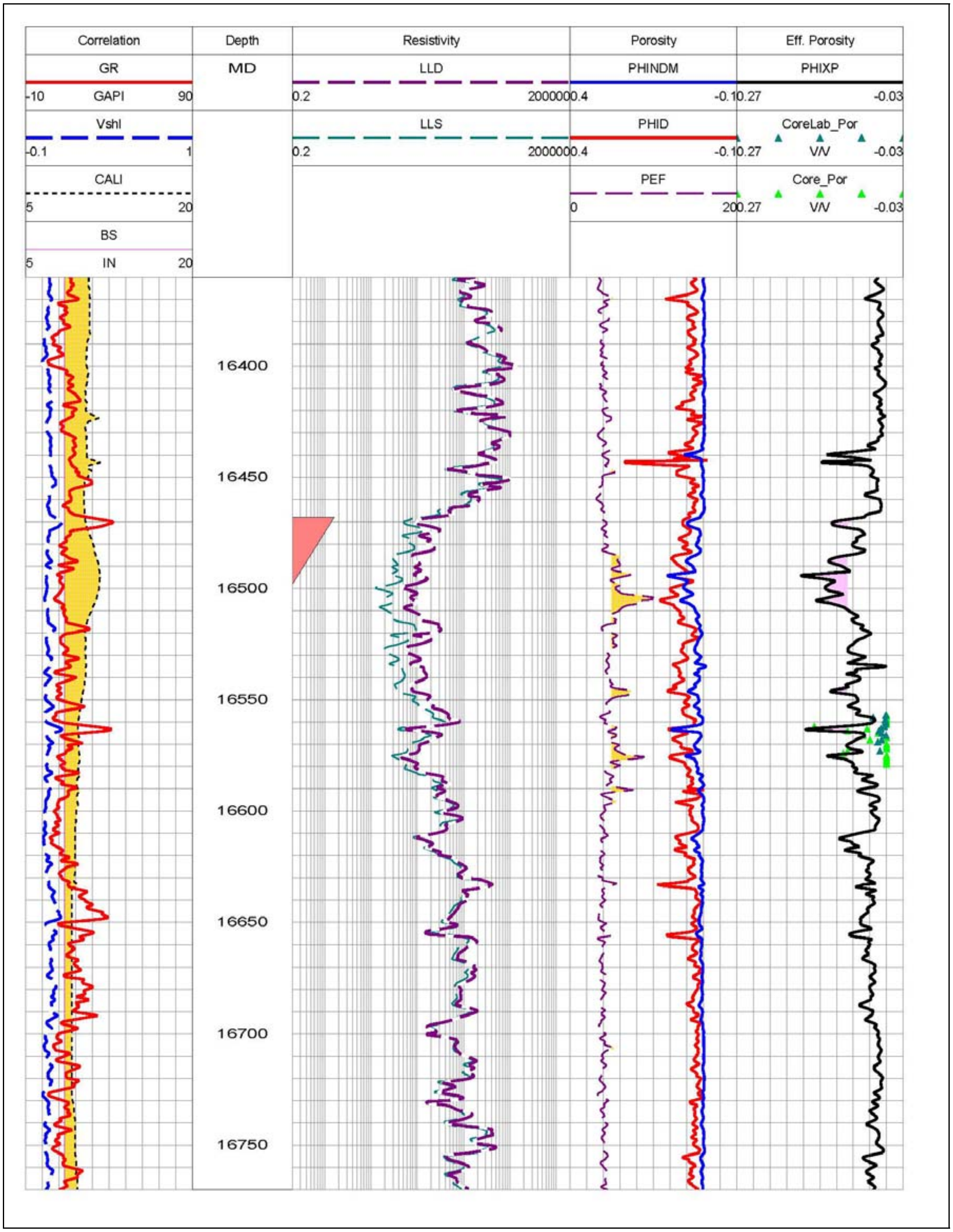


Figure 12 Log of Cased Hole DST Interval in Doubloon Saxon well

Figure 13 shows the distribution of porosity values across the tested interval 16,468' to 16,498' after removing questionable measurements associated with PE values greater than 5.2.

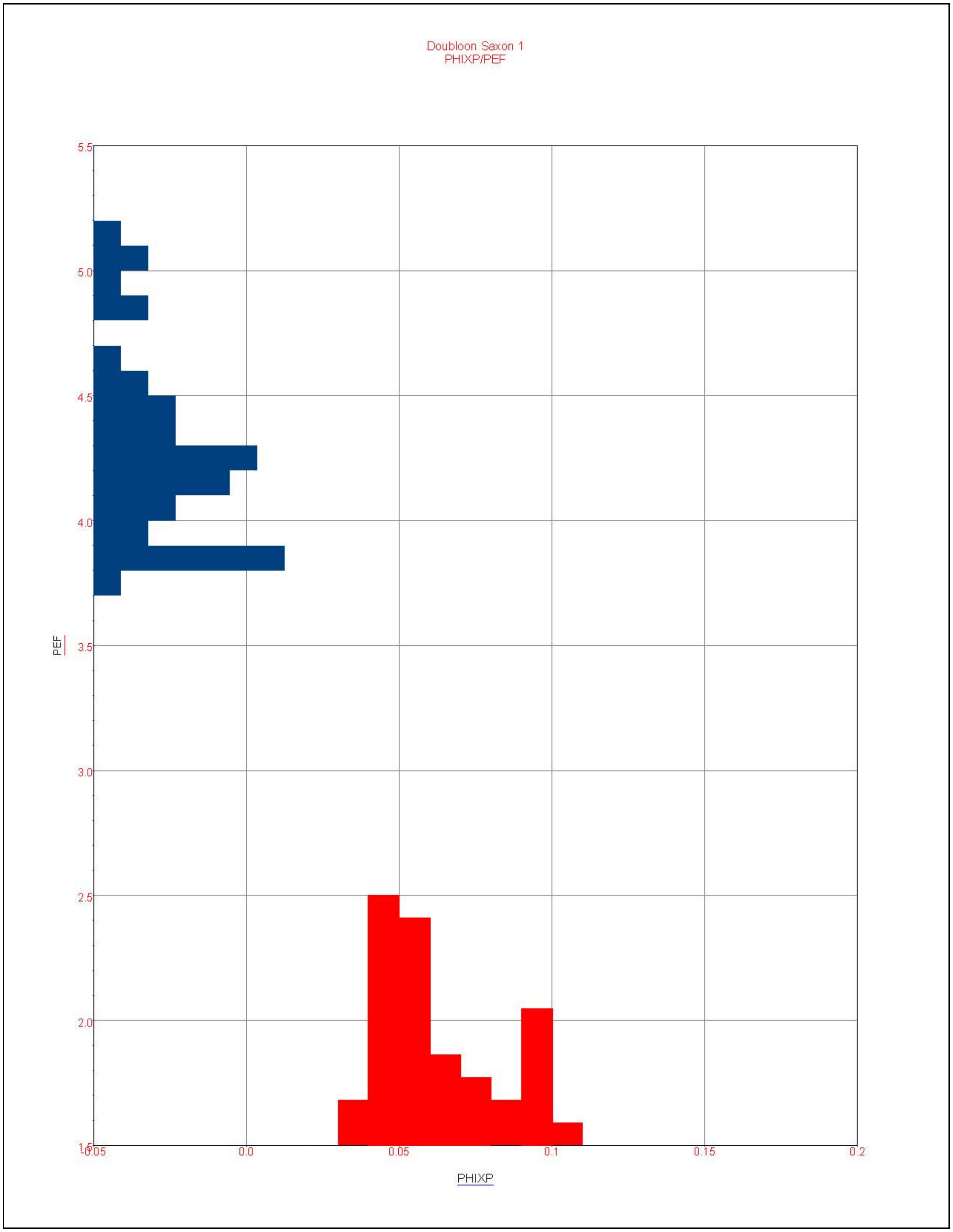


Figure 13 Porosity Distribution across Cased Hole DST Interval (16,468' – 16,498')

The porosity distribution within the tested interval is bimodal. The distribution is dominated by porosity values between 4% and 6% with a secondary peak at 9% representing the high gamma ray interval 16,468' to 16,473'. The limited information from the DST is insufficient to determine which portion of the tested interval contributed to flow.

Figure 14 shows the porosity distribution across the entire reservoir interval potentially tested by the cased hole DST.

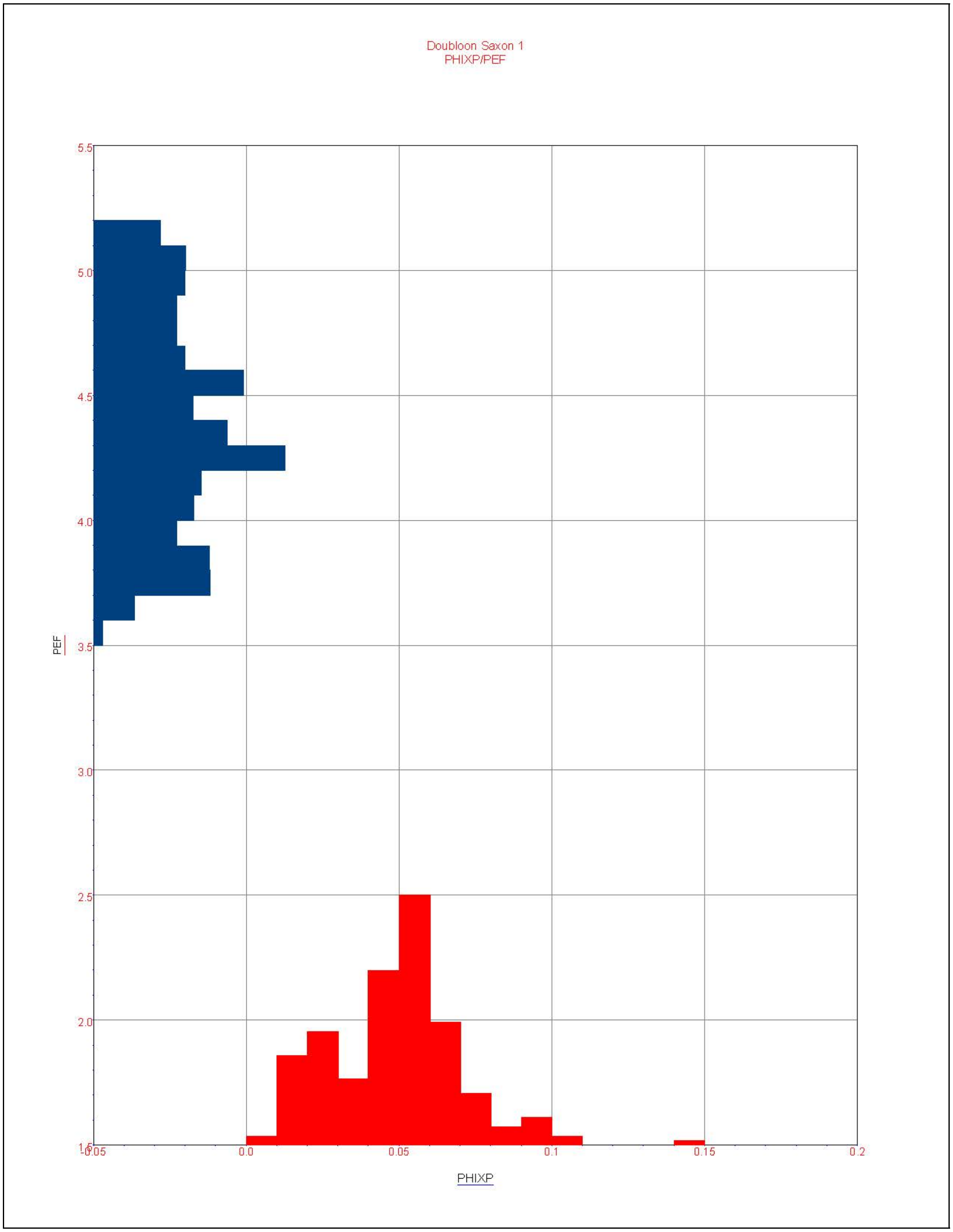


Figure 14 Porosity Distribution across Reservoir 16,468' to 16,620'

The potential reservoir interval displays a tri-modal distribution dominated by values between 4% and 7%.

The potential seal for this reservoir is an overlying 350' thick dolomite interval with porosity generally between 1% and 3%. If this porosity distribution is considered characteristic of carbonate facies that may act as a seal, then it may be reasonable to assume that the lower limit of productive porosity is on the order of 3%.

The log of the Doubloon-Saxon-1 well across the open hole DST interval is shown in Figure 15. The neutron and density porosity values are again presented on a dolomite matrix. The light blue shaded areas between neutron values near zero and negative density porosity values highlight the presence of anhydrite.

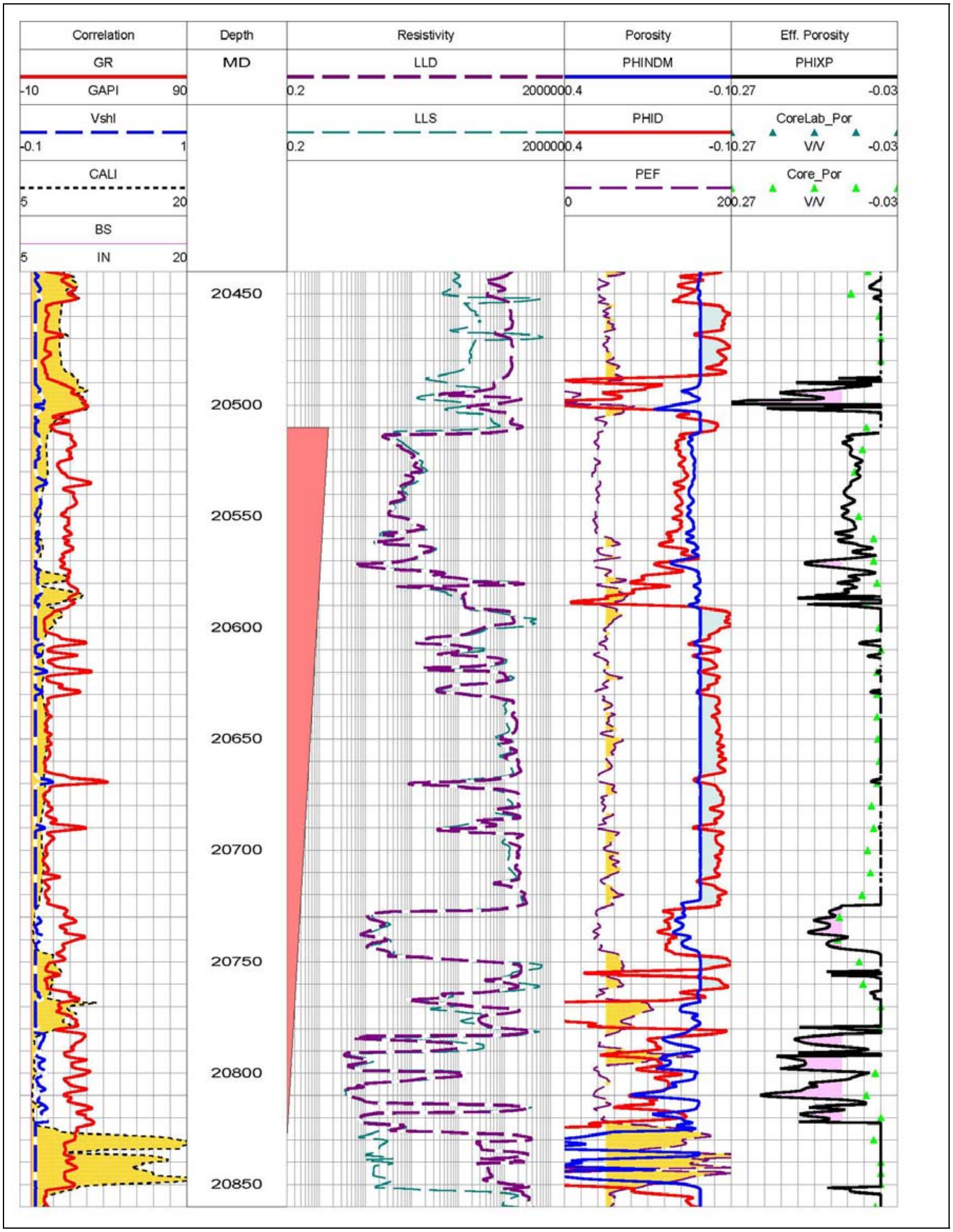


Figure 15 Log of Doubloon-Saxon well across Open Hole DST interval 20,520'- 20,830'

The tested interval consists of multiple, porous dolomite stringers interbedded with anhydrite and thin beds of salt. There is limited information about the results of this test. After the nitrogen cushion was bled off, the tool was left open for 18 hours with no flow to the surface. After a one hour pressure buildup, the packer was unseated and the test string pulled into the casing. Approximately 75 barrels of salt water with a chloride concentration of 122,000 ppm was reversed out with no sign of hydrocarbons.

The porosity distribution across the tested interval is shown in Figure 16.

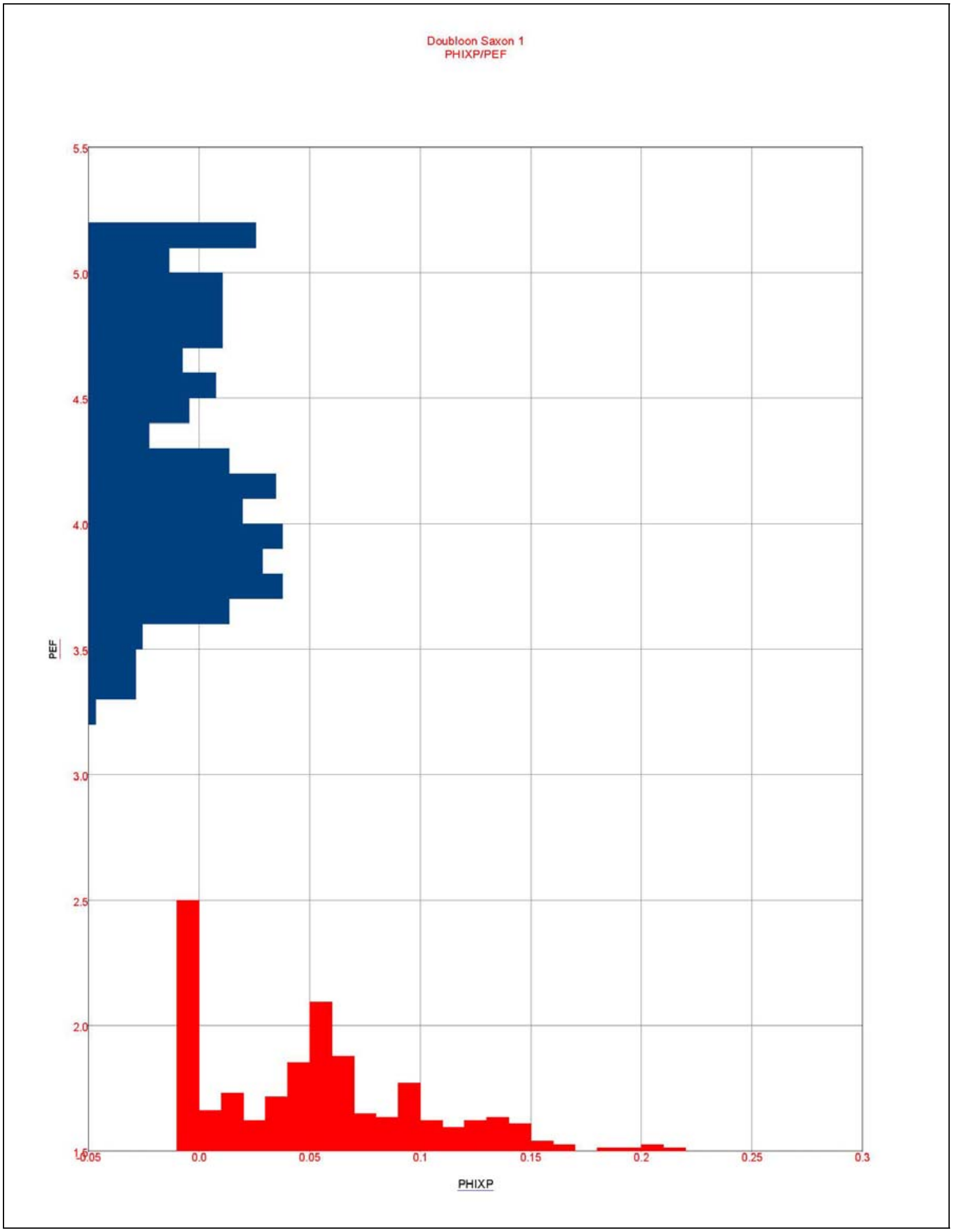


Figure 16 Porosity Distribution in Doubloon-Saxon, Open Hole DST interval 20,510' - 20,830'

Low apparent porosity values from -1% to 2% represent the potentially sealing, interbedded anhydrite and salt intervals. Most of the borehole rugosity observed in the interval is associated with salt beds. The porous dolomite stringers are characterized by slightly elevated gamma ray values and are dominated by porosity values ranging from 3% to 7%. The light green triangles in the rightmost track represent porosity estimates from thin sections of cuttings. The cuttings analysis corroborates the presence of porosity values approaching 9% in the interval 20,725' to 20,745'.

The Great Isaac well was not tested in the Cretaceous carbonate section as all porous zones were water bearing. In contrast to the Doubloon Saxon, the three available porosity curves; sonic, density and sidewall neutron, all indicate similar porosity values when corrected to the same lithology and correspond well with available core porosity values. This may be an indication of a less complex pore system.

In the Gulf of Campeche, offshore Mexico, high rates of production have been established from Cretaceous carbonates in a similar depositional setting to that expected in the area of interest.

Field	Reservoir	Porosity	Reservoir Depth	I.P. Test Rate
Abkatun	Pal.-Up. K Breccia	13	11,200'	8500 BOPD
	Mid. K Dolomite	8		
	Lwr. K Dolomite	9		
Bacab	Pal.-Up. K Breccia	12	10,500'	1978 BOPD
Batab	Pal.-Up. K Breccia	9	11,800'	12,300 BOPD
	Jur. Fract. Dolomite	5	15,600'	5718 BOPD
Caan	Pal.-Up. K Breccia	9	11,700'	5439 BOPD
Chuc	Pal.-Up. K Breccia	12	11,500'	
	Lwr. K Frac.Dolo	6	13,200'	37,200 BOPD
Ek	Pal.-Up. K Breccia	9	10,100'	
Ku	Eocene Calcarenite	19	9700'	2866 BOPD
	Pal.-Up. K Breccia	8		2021 BOPD
	Mid. K Dolomite	5		
	Lwr. K Frac.Dolo	5		
Maloob	Pal.-Up. K Breccia	9	10,150'	5840 BOPD
Pol	Pal.-Up. K Breccia	10	12,200'	6250 BOPD
	Mid. K Frac.Dolo	6		9000 BOPD
	Jur. Frac.Dolo	4	13,600'	3900 BOPD
Uech	Jur. Frac.Dolo	15	16,400'	9000 BOPD

Adapted from AAPG Memoir 54 – Giant Oil and Gas Fields of the Decade 1978 to 1988

Based on the similarities between the reservoir descriptions in these fields and the lithologies observed in the Doubloon Saxon and Great Isaac wells, it appears reasonable that the expected reservoirs in the prospect areas should be able to produce at sufficient rates to allow an economic development.

In the Doubloon Saxon well porous dolomites are interbedded with low porosity limes and dolomitic mudstones from at least 5500'. Below 17,300' to well total depth at 21,740' porous dolomites are interbedded with anhydrite, low porosity dolomitic limes and minor salt layers. In the Great Isaac well significant thicknesses of anhydrite are present from 5100' to the base of the carbonate section at 17,570'. Minor salt layers are observed in the Great Isaac below 16,150'. Both wells demonstrate the presence of multiple reservoir / seal pairs.

Traps

Large structural traps consisting of anticlines with four-way dip closure were indicated on the Bahamas Petroleum licenses on the mid-80's vintage 2D seismic lines. Tenneco attempted to test one of these features with the Doubloon Saxon well in 1986. Seismic acquisition and resolution issues related to the transition from deep water in the Old Bahama Channel to very shallow water on the Bahamas Platform make it difficult to determine if the well was located in a crestal structural position on the older data.

Bahamas Petroleum acquired new 2D data in June, 2010 duplicating some of the older lines. This new data also indicated the potential for large structural traps on the licenses.

In January, 2011, Bahamas Petroleum acquired a grid of 2D seismic across the Bain, Cooper and Donaldson licenses. Ryder Scott reviewed the time horizons interpreted by International Geophysical Consultants and converted them to depth using the time-depth relationship from the Doubloon Saxon well. Figure 17 shows the relative locations and sizes of the four identified prospective structures at the Top Cretaceous horizon. Appendix A contains more detailed maps for each of the structures at each of the three mapped horizons: Top Cretaceous, Top Albian and Top Aptian.

Figure 17 Identified Prospective Structures at Top Cretaceous

ESTIMATION OF UNRISKED PROSPECTIVE VOLUMES

Unrisked prospective resource volumes in this report are estimated probabilistically through Monte Carlo simulation using Crystal Ball software. The general equation (in SI units) for stock tank oil originally in place (STOOIP) is:

STOOIP bbls = 7758 bbls/ac-ft * A * H * NTG * Phi * (1-Sw) / Boi

Where:

A is productive area
H is gross reservoir thickness
NTG is Net to Gross Ratio
Phi is Porosity
Sw is Water Saturation
Boi is volume of oil at reservoir conditions / volume of oil at standard conditions (formation volume factor)

A potential range of values and the expected shape of the distribution of those values are determined for each of the six parameters listed above. Dependencies between the various parameters are evaluated and incorporated into the Monte Carlo simulation. The result is given as a distribution of potential outcomes; in this case, a distribution of prospective STOOIP. Derivations of the distribution for each parameter are discussed below.

Prospective Resources are defined (SPE-PRMS) as: "Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations."

The potentially recoverable volume (EUR) is calculated from the STOOIP by applying a recovery factor (RF) such that:

EUR bbls = STOOIP * RF

The recovery factor is dependent on the character of the hydrocarbons in the reservoir, reservoir heterogeneity, drive mechanism, development program applied and the economics of the development.

The range of potential recovery factors and the shape of the distribution will be described below.

<u>Area</u>

The area for each lead or prospect was determined primarily from the structural interpretation of the January, 2011, seismic data by International Geophysical Consulting. The interpretation was reviewed by Ryder Scott in Bahamas Petroleum's offices in Boulder, Colorado on May 9, 2011. As discussed above, Ryder Scott received the seismic time horizon interpretations from IGC in a Seismic MicroTechnologies project, converted the major map horizons to depth and loaded these depth grids into Petrel (geostatic modeling software) to evaluate the prospective structures.

The area to the lowest closing contour is used as the maximum area, the area related to 50% structural fill is considered likeliest and the area related to 30% structural fill is considered the minimum productive area. This distribution is admittedly arbitrary but in keeping with standard industry practice. This method results in a large range of potentially productive area between P10 and P90. This large range is intended to recognize not only the potential change in area due to fill but also potential changes due to velocity changes, facies changes on structure and the potential presence of long oil /

water transition zones. The 3D seismic data being acquired at the date of this report may provide velocity and seismic facies data sufficient to narrow the range of uncertainty.

Due to limited information on hydrocarbon source volume and lack of nearby applicable analogs a triangular distribution of these areas was used.

Gross Thickness, Net to Gross and Porosity

Ryder Scott has chosen to use observed distributions of these properties in the Doubloon Saxon and Great Isaac wells to estimate the ranges of these properties.

Ryder Scott chose twenty-one intervals within the Doubloon Saxon and seventeen intervals within the Great Isaac as potential analogs for reservoirs that might be encountered on the Bain, Cooper and Donaldson licenses. These intervals were selected based on vertically associated occurrences of neutron-density crossplot porosity in excess of 4% in which the log readings were deemed reliable by inspection of caliper, photoelectric, neutron and density log responses.

The net to gross and porosity distributions within these intervals are dependent on the method of porosity determination and the porosity cutoff chosen. The log data provided for the Doubloon Saxon included a sonic log above 11,668' and neutron and density curves from 5490' to 21,680'. The log data provided for the Great Isaac included sonic, sidewall neutron and density information across the entire interval of interest. The data also included a significant number of petrographic porosity estimations made from thin sections of well cuttings. The sonic response, corrected to the lithology indicated by the neutron-density crossplot, generally indicated lower porosity than the neutron-density crossplot in the Doubloon Saxon while all three curves are in relative agreement in the Great Isaac. The petrographic estimates were generally lower than either the sonic or the neutron-density values. There are several potential explanations for these disparities including a higher probability of preserving smaller pores in the cuttings. Industry has commonly considered the sonic porosity to represent connected porosity and the higher neutron-density response to represent the presence of non-connected vugs. However, a recent paper by Weger et al (AAPG, October 2009) argues that the acoustic response in carbonates is more complex.

With the data currently available in the Bahamas it is not possible to determine which, if any, of the porosity log responses accurately depicts the storage capacity of the reservoirs that may be encountered.

Due to the uncertainty in the porosity determination and the lack of permeability information it is also difficult to determine the productive porosity cutoff. Ryder Scott has chosen to determine the net to gross ratio and average porosity for each interval by applying porosity cutoffs of 4%, 6% and 8% to both the neutron-density crossplot porosity and the sonic porosity. This range of cutoff values appears reasonable based on Ryder Scott's experience with matrix porosity dominated carbonate reservoirs. Intensively fractured dolomite breccias with porosity of 3 to 5% are the main reservoir in Cantarell Field. Cases with resulting net to gross ratios of less than 10% were discarded as unlikely to be economic in this environment.

Both the Doubloon Saxon and Great Isaac wells exhibit multiple potential reservoir intervals within the large gross intervals described by the mapped Top Cretaceous, Top Albian and Top Aptian horizons. A probability exists therefore that more than one hydrocarbon bearing reservoir may be developed in each of the major zones. To recognize this, Ryder Scott assigned a discrete distribution to describe the potential for multiple reservoirs. In 70% of the realizations for each mapped horizon on each structure, a single reservoir is developed; in 20%, two reservoirs are developed and in 10%, three reservoirs are developed.

Figures 18, 19 and 20 show the resulting distributions for Gross Thickness, Average Porosity and Net to Gross.

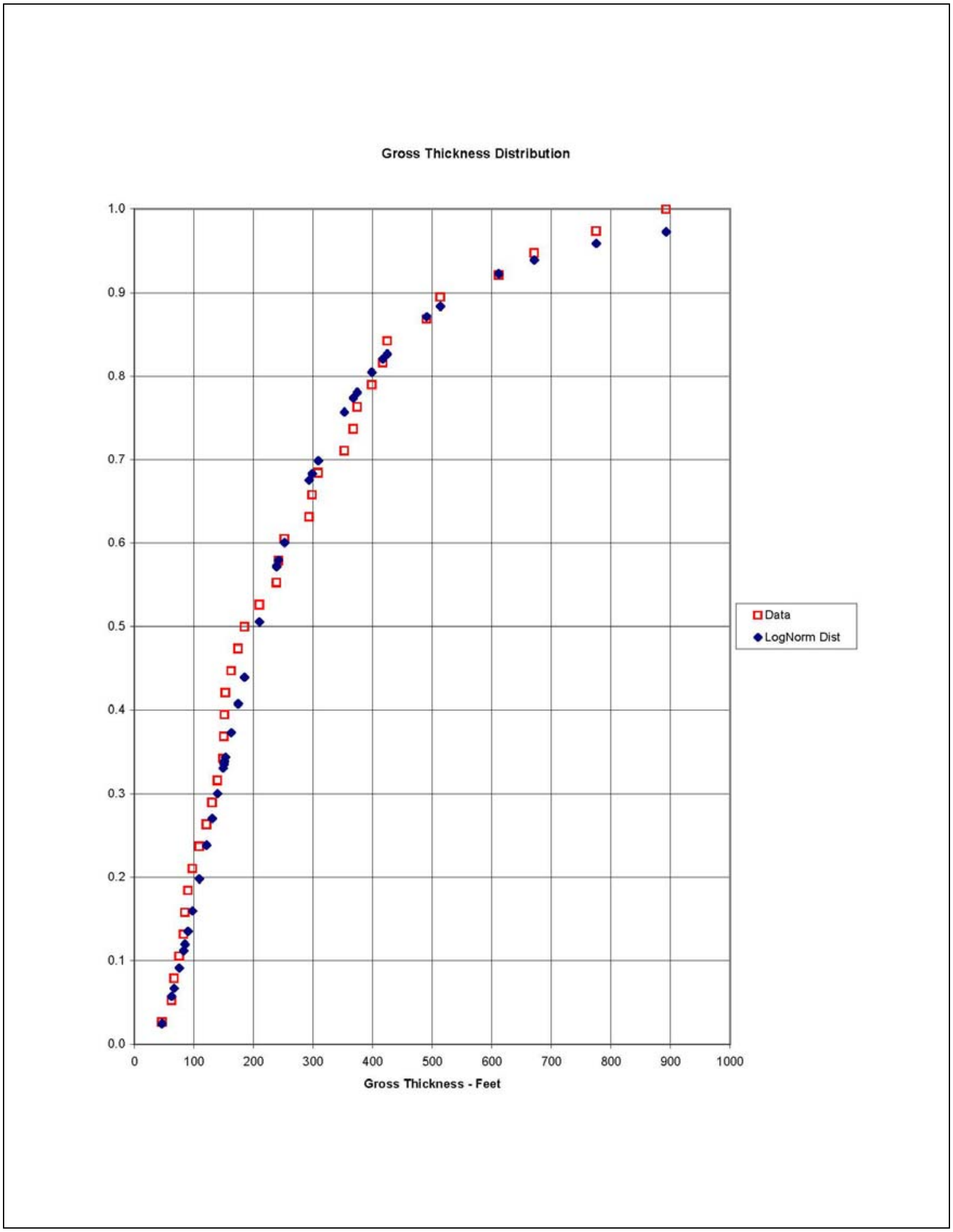


Figure 18 Reservoir Gross Thickness observed in Doubloon Saxon and Great Isaac wells and Log Normal Distribution Used

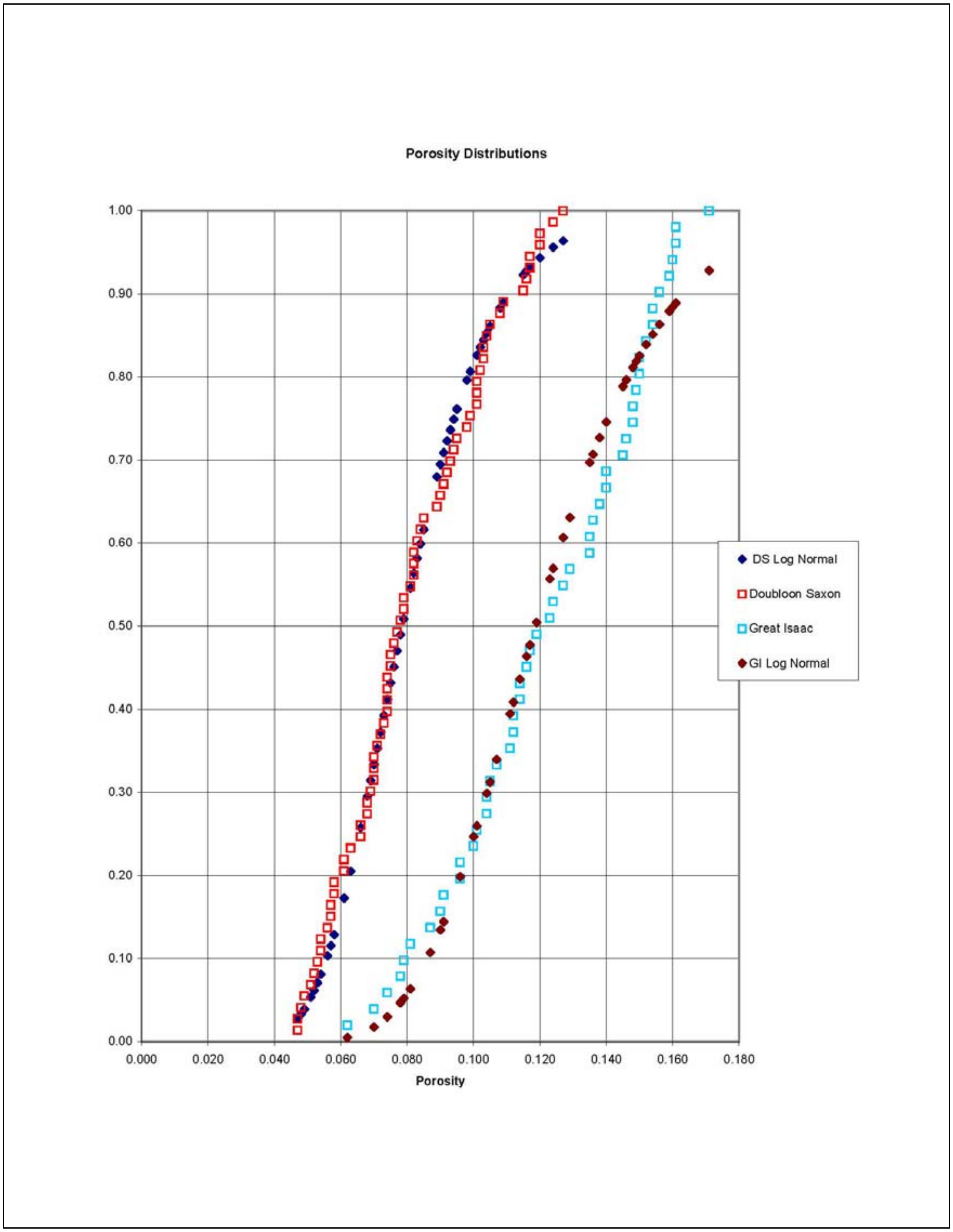


Figure 19 Observed Porosity Values in Doubloon Saxon and Great Isaac wells and Log Normal Distributions Used

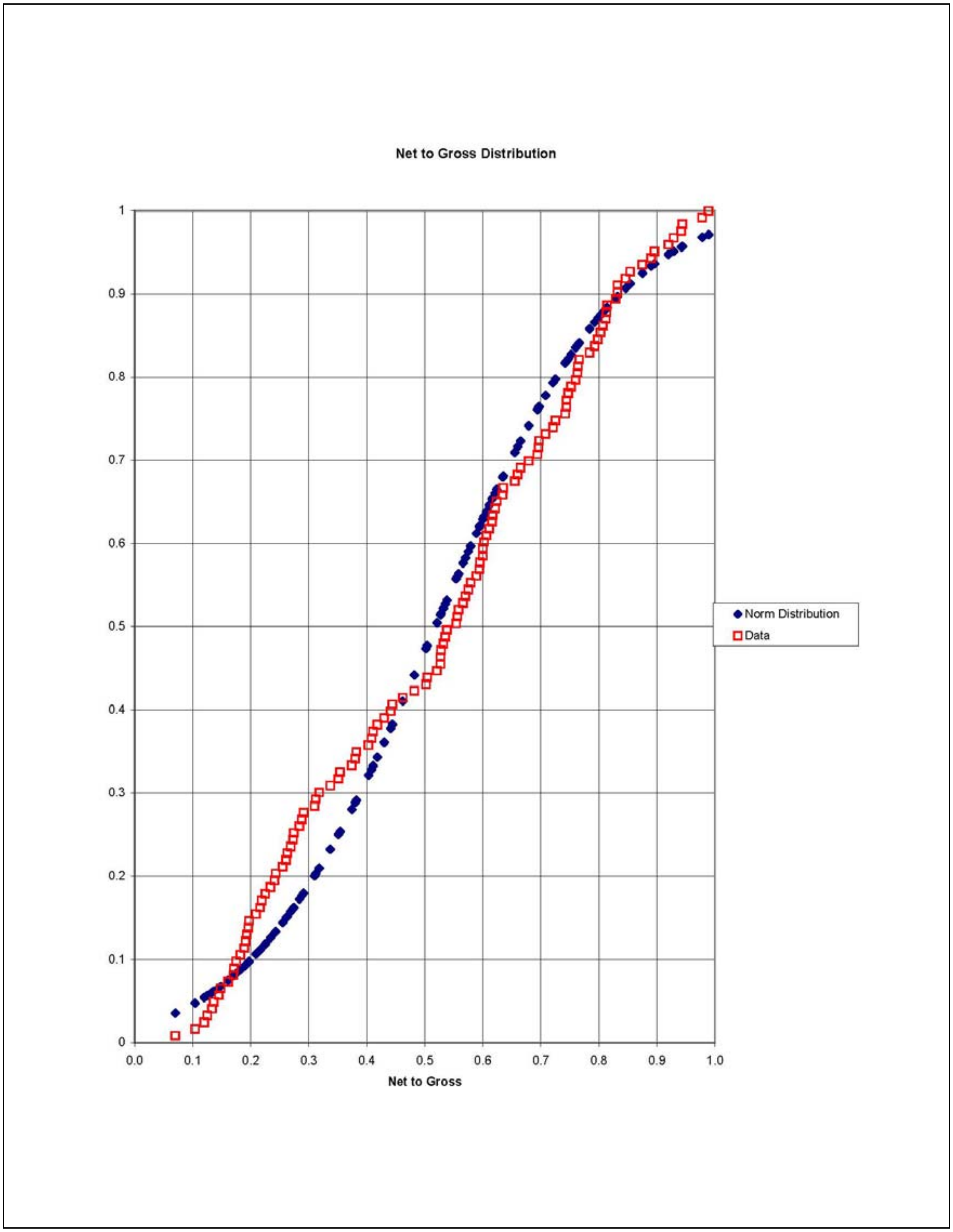


Figure 20 Net to Gross Ratio Distribution of "Reservoir" Intervals in Doubloon Saxon and Great Isaac wells and Normal Distribution

Log normal distributions appear to be appropriate for Gross Thickness and Porosity values while the Net to Gross Ratio appears to be normally distributed.

Over the large range of gross interval thickness considered, the net to gross ratio is inversely dependent on the gross thickness.

As the porosity cutoff is lowered, the calculated net to gross ratio in an interval tends to increase and the calculated average porosity value tends to decrease However, the major control on porosity is the original depositional fabric and subsequent diagenesis. Other than the "artificial" dependency created by varying cutoffs there does not appear to be a relationship between net to gross and porosity. The net to gross ratio and porosity are treated as independent variables in Ryder Scott's analysis.

The Florida Geological Survey published detailed descriptions of the South Florida Sunniland trend fields in Information Circular 111 published in 1997. Average reservoir porosity information was included for each of the 14 fields described. Ryder Scott was not able to locate any published reservoir information on Cuban fields. Readily available published reservoir information is available for major Texas oil reservoirs in the Atlas of Major Texas Oil Reservoirs published by the Bureau of Economic Geology in 1983. Several South Texas and West Texas reservoirs described in this volume have similar depositional and diagenetic histories to those anticipated in the Bahamas. These reservoirs have been compiled into a potential analog field data base included in this report as Appendix B.

Figure 21 below compares the porosity distribution of the selected intervals in the Doubloon Saxon and Great Isaac wells with the distribution of reservoir average porosity values reported for the Florida Sunniland and Texas analog fields.

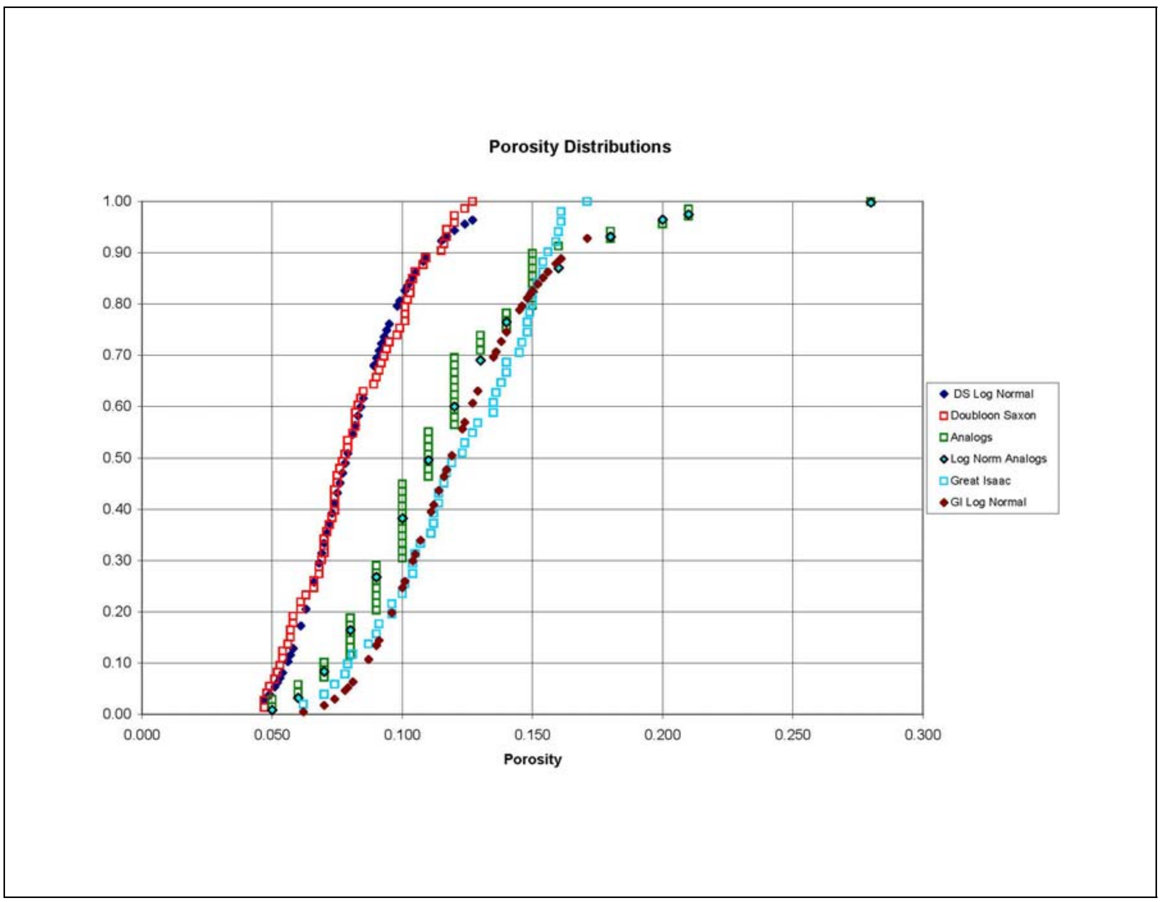


Figure 21 Porosity Distributions in Doubloon Saxon, Great Isaac and Proposed Analog Fields

The observed porosity distributions in Doubloon Saxon and Great Isaac appear to encompass the reported values in the Florida and Texas fields as well as those of the Mexican fields described above and in AAPG Memoir 54. Both the Doubloon Saxon and Great Isaac distributions have been used in evaluating the prospective resources in this report.

Water Saturation

No productive reservoirs have been penetrated to date in the Bahamas. The Florida Geological Survey report only gives saturation values for two reservoirs in the Sunniland.

In the Handbook of Log Evaluation Techniques for Carbonate Reservoirs published by the American Association of Petroleum Geologists in 1985, Asquith presents the table shown below relating the bulk volume water (BVW = Porosity x Water Saturation) and carbonate grain size and porosity type.

Grain Size	**millimeters**	**BVW**
Coarse	1.0 to .5	.02 to .025
Medium	.5 to .25	.025 to .035
Fine	.25 to .125	.035 to .05
Very Fine	.125 to .0625	.05 to .07
Silt	< .0625	.07 to .09
Carbonate Porosity Type		**BVW**
Vuggy		.005 to .015
Vuggy & intercrystalline		.015 to .025
Intercrystalline		.025 to .04
Chalky		.05

Figure 22 shows a crossplot of reported reservoir porosity against water saturation values for the analog fields discussed above. Based on the table above the reservoirs are grouped by BVW as a proxy for the dominant porosity type. The water saturation distribution used in the volumetric calculation is calculated from the porosity distribution using the equations shown after randomly selecting a rock type.

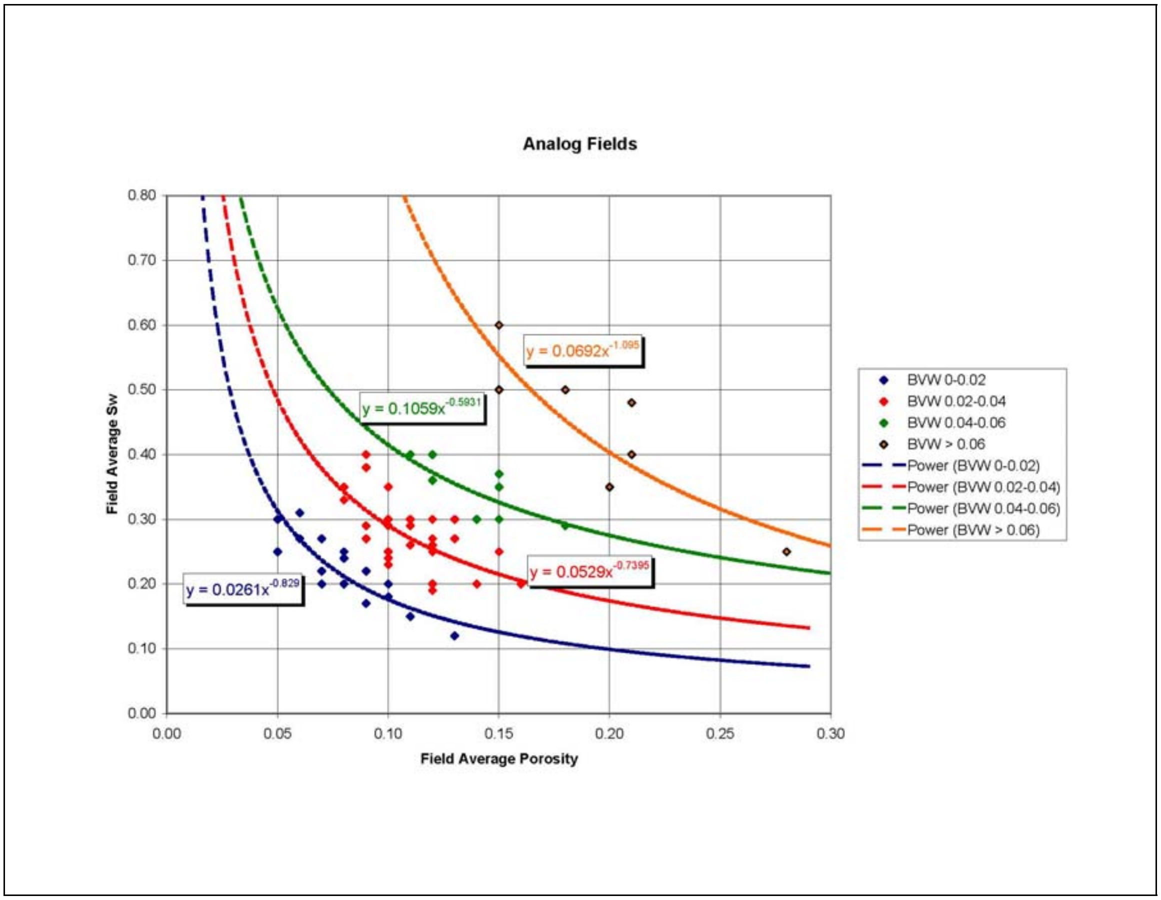


Figure 22 Analog Field Porosity - Water Saturation Relationship

<u>Formation Volume Factor</u>

The Oil Formation Volume Factor (Boi), a dimensionless factor, measures the reduction in the volume of crude oil from reservoir to surface conditions. Mathematically, it is the volume of oil at reservoir conditions / volume of oil at standard conditions. The general equations below are for a single phase assumption.

Boi = Vrb/Vstb

Where:
Boi - Formation Volume Factor (rb/stb)
Vrb - Volume of oil at reservoir conditions (rb)
Vstb - Volume of produced oil under stock tank conditions (stb)

Standing Correlation - Below Bubble Point Pressure
Boi = 0.972 + 0.000147 F 1.175

Where:
F = Rso (Sg/So) 0.5 + 1.25 T
Rso – Solution Gas oil Ratio (GOR) (scf/stb)
Sg - Gas Gravity
So - Oil Gravity
T - Temperature (deg.F)

So = 141.5/(131.5 + API)
Rso = Sg(p/(18*10^Yg))^1.204
Yg = 0.00091 T – 0.0125 API

Correlations - Above Bubble Point Pressure
Bo = Bob exp[co (pb - p)]

Where:
Bob = Formation volume factor at bubble point (rb/stb)
co - Oil Compressibility (1/psi)
pb - Bubble Point Pressure (psi)
p - Reservoir Pressure (psi)

T = Depth * .01 degF/ft + 50
p = Depth * .465 + 15

Thus, from the GOR, API gravity, temperature and pressure conditions, the Boi for each reservoir can be calculated.

API was obtained from 4 classes of Oil:

Mature: This is from potential analogs in West Texas (25% chance of occurrence)
Immature: This is from Florida Sunniland and Cuba North Coast (45% chance of occurrence)
Mexico 1: This is from group A Campeche Area offshore fields (15% chance of occurrence)
Mexico 2: This is from group B Campeche Area offshore fields (15% chance of occurrence)

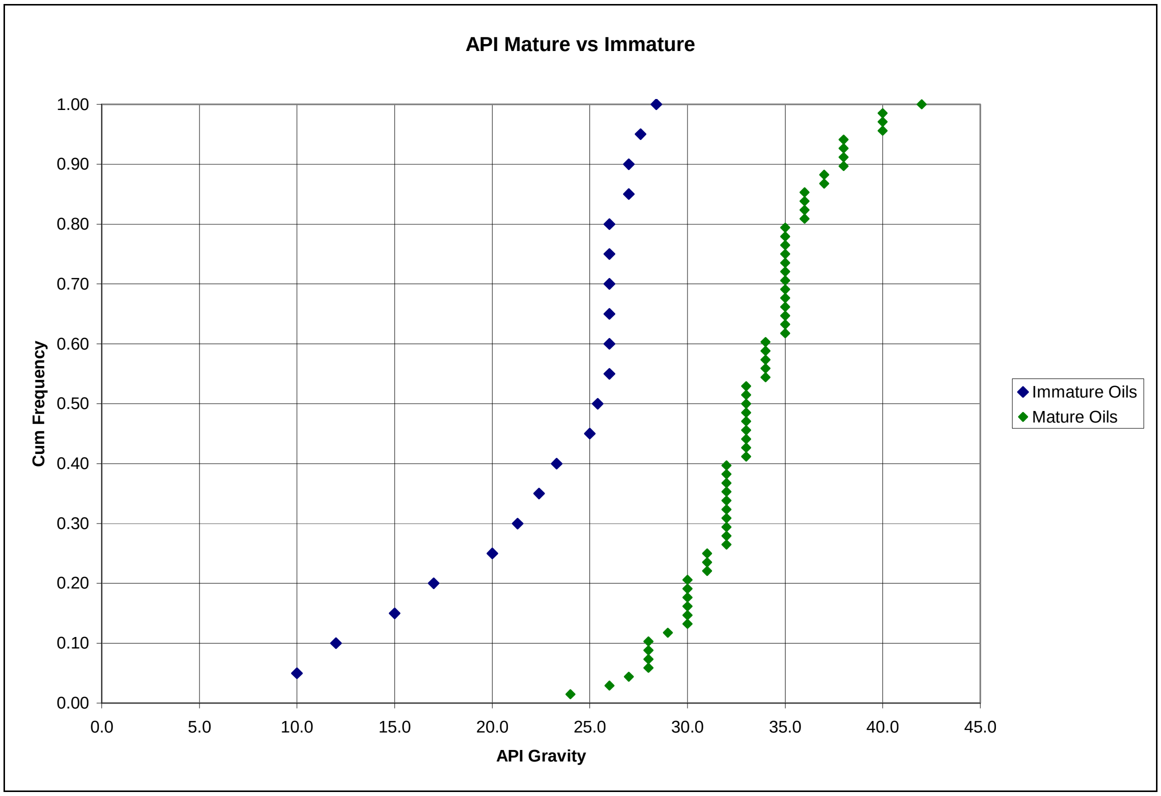


Figure 23 Reported Oil API Gravity ranges from analog fields.

<u>Recovery Factor (RF)</u>

Recovery Factor, the percentage of oil in place in a reservoir that ultimately can be produced commercially was obtained from a distribution of the 2P (proved plus probable) recovery factors estimated for producing fields in the Campeche area offshore, Mexico.