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Estimation of in place hydrocarbon volume in multilayered reservoirs using deterministic and probabilistic approaches

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Abstract

This paper presents the results of the calculation techniques used for estimation of hydrocarbon initially in place for a multilayered gas reservoir located in the Persian Gulf via two methodologies. The porosity, water saturation, and net pay raw datasets for six wells enclosed within the studied area are thoroughly examined and fed to the deterministic and probabilistic calculation algorithms and the results are compared. In order to include the probable effects of the uncertainties associated with reservoir characterization, two distinct methodologies are developed and incorporated in both types of the calculation processes. In the first methodology, total hydrocarbon volume is calculated in one stage, while in another, hydrocarbon volume estimation have been carried out separately in each producing layer; then, summing them to estimate total hydrocarbon volume. The prominent conclusion of this research indicates that the second developed method in both deterministic and probabilistic conditions presents more reliable results for hydrocarbon volume estimation.

Keywords: Estimation, Gas Reservoir, Deterministic, Probabilistic, Monte Carlo Simulation

1. INTRODUCTION

Estimation of hydrocarbon initially in place (HCIIP) is a critical issue for both economic and technological aspects of petroleum industry. By development of computational instruments, it is possible to run sophisticated calculations that were

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previously impossible to be performed. Monte Carlo simulation is a probabilistic technique that requires a huge number of calculations to be fulfilled. This technique has been used for calculating HCIIP of hydrocarbon bearing fields for some years now. In the following, a brief literature review, related to reservoir estimation in oil and gas fields is presented.

In 1988, Garb introduced deterministic and probabilistic techniques as two methodologies for estimation of hydrocarbon reserves (Garb, 1988). In 1991 Caldwell and Heather classified methods used in reservoir evaluation in three principal categories: analogy, volumetric and performance analysis. They stated that these three classes of hydrocarbon reserves evaluation methods can be used for either deterministic or probabilistic analysis, noting that when uncertainty is high, the applicability of probabilistic methods seems to be more viable compared to the deterministic methods (Caldwell and Heather, 1991). Zhang and Srinivasan in 2003 presented a methodology for generating MCMC (Markov Chain Monte Carlo) model of a geological system and described it in mathematical expressions (Zhang and Srinivasan, 2003). In 2009 Z. Komlosi and J. Komlosi used Monte Carlo simulation to estimate the amount of reserves in three oil fields (one anticline-type and the other two lithologic-type) and concluded that “Monte Carlo simulation’s accuracy is determined by the reliability of the geo-technical model, parameters and conditions forecasted” (Komlosi and Komlosi, 2009).

In this paper attempts have been made to estimate deterministically and probabilistically the volume of hydrocarbon (mostly gas at reservoir condition) initially in place for an anticline-type gas-bearing field located in the Persian Gulf by two methodologies. The main reservoir consists of four gas-bearing carbonate type layers (identified in this paper as k1, k2, k3 and k4 layers from top to bottom), separated from each other by non-reservoir type inter-beds. The methodologies are discussed as follows.

2. METHODOLOGY

Volumetric calculation method of original hydrocarbon in place uses static reservoir properties such as area of accumulation, pay thickness, porosity, and initial fluids saturation. Given the often-large uncertainties associated with the limited number of available datasets, statistical methods such as Monte Carlo simulation are often used to quantify the effects of such uncertainties on the volumetric estimates of HCIIP (Murtha, 2001).

Porosity, water saturation, and net pay versus depth values for six wells located in the studied area were the main raw datasets based on which the required input distributions to the probabilistic calculation process were defined. To estimate the volume of hydrocarbon initially in place (at reservoir condition) one can simply use:

$$HCIIP = A \times h \times \varphi \times (1 - S_w) \quad (1)$$

Where: HCIIP is the volume of hydrocarbon initially in place contributed to area A in reservoir cubic meter, A is the studied area in square meter, h is net pay in meter, φ is porosity in fraction, and S_w is water saturation in fraction.

An extensive review of the available suite of logs for the wells located within the project area revealed the fact that each well path has intersected a total of four gas-bearing layers, all separated by non-reservoir type layers in between. For comparative reasons, the associated net pay, porosity, and water saturation profiles of the gas-bearing layers have been incorporated in the probabilistic initially hydrocarbon in place calculation process through the application of the following two methodologies.

As represented by the following equations, the first methodology is based on the assumption that the net pay, porosity, and water saturation profiles of the four productive layers are not independent of each other as it uses a set of three common probability distribution functions to represent the combined net pay, porosity, and water saturation profiles of the four layers. The second methodology assumes that the characteristics of net pay, porosity, and water saturation profiles of the four gas-bearing layers have no similarities; therefore it requires a set of three probability distribution functions to be defined for net pay, porosity, and water saturation of each of the four layers under consideration.

Equation representing the first methodology:

$$HCIP_1 = A \times h \times \sum_{j=1}^6 \alpha_j \times \varphi_j (1 - S_{wj}) \quad (2)$$

Equation representing the second methodology:

$$HCIP_2 = A \times \sum_{i=1}^4 h_i \times \sum_{j=1}^6 \alpha_j \times \varphi_{ji} (1 - S_{wj}) \quad (3)$$

In which α_j is allocated drainage area coefficient determined for each well as successively described. This coefficient is an impact, related to the surface of drainage area. Deterministic estimates of the initial hydrocarbon in place for the worst, most likely, and the best cases are also calculated and compared with their respective P10, P50, and P90 probabilistic values.

2.1. Allocated Drainage Area Calculation Algorithm

With the limited number of available datasets and the lack of information on general reservoir and inter-well geological features, and also the uncertainties associated with the extent of the total project area affected by each well's drainage, a unique procedure was devised and used to calculate per-well allocated drainage area required by the deterministic and probabilistic calculation methods. Figure 1 shows a descriptive and schematic summary of the different steps involved in the above-mentioned per-well allocated drainage area calculation process.

Table 1 shows the values of allocated drainage area coefficient factors as calculated by the above mentioned procedure. Although this process is not a usual method for determining drainage area, the process is used to determine drainage area of each well. This coefficient is not incorporated in simulation process, except as an independent parameter.

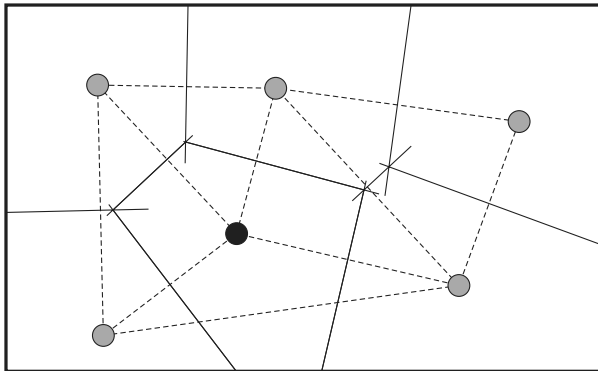
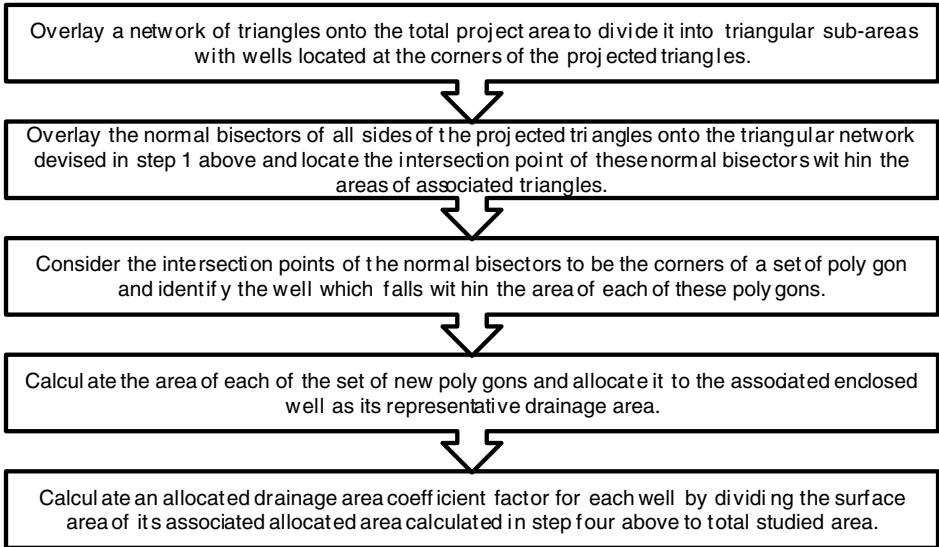


Figure 1. The process of calculating coefficient factor of allocated drainage area of each well in the area under study: a) the algorithm; b) this figure shows the schematic algorithm of contributing allocated area. The 6 dots are well locations and the dashed lines are level one of the above algorithm. Solid lines are bisectors of the second level. One of the polygons described in level 3 is hatched and its corresponding well is in black.

3. RESULTS AND DISCUSSION

3.1. Application of t-test for Hypothesis Testing

Next we applied the t-statistical test to all the wells in the project area to check the similarity of porosity and water saturation datasets of their four gas-bearing layers. All

Table 1. Allocated drainage area coefficient factors.

Well No.	1	2	3	4	5	6	Summation of allocated area coefficients
Allocated Area Coefficient (α_j)	0.131	0.241	0.155	0.160	0.196	0.118	1

Table 2. The results of the application of t-test to the porosity and water saturation datasets of four layers of the six wells in the studied area. The cells, upper side of trace, indicate the results of t-test for porosity of each two layers of the well and cells of downside of trace indicate the results of t-test for water saturation of each two layers of the well.

$S_w\phi$	k1	k2	k3	k4	$S_w\phi$	k1	k2	k3	k4
k1		1	0.644	1	k1		0.814	0.757	1
k2	1		1	1	k2	1		0.987	0.992
k3	0.80	1		1	k3	1	1		1
k4	1	1	1		k4	0.318	1	1	
Well 1					Well 2				
$S_w\phi$	k1	k2	k3	k4	$S_w\phi$	k1	k2	k3	k4
k1		1	0.996	1	k1		0.36	0.873	0.998
k2	1		0.657	1	k2	0.899		0.878	0.995
k3	0.996	1		1	k3	1	1		0.999
k4	1	1	1		k4	1	1	1	
Well 3					Well 4				
$S_w\phi$	k1	k2	k3	k4	$S_w\phi$	k1	k2	k3	k4
k1		0.354	1	1	k1		0.991	1	0.967
k2	1		1	0.996	k2	1		0.991	1
k3	1	1		1	k3	1	1		1
k4	1	1	1		k4	0.393	1	1	
Well 5					Well 6				

statistical tests begin with a null and alternative hypothesis. The alpha level is set next and the appropriate statistical test is performed. The p-value is calculated from the test statistics and finally a decision is made on whether the results indicate that the datasets are statistically different or the difference between the datasets is not statistically significant. The results of the application of t-test to the porosity and water saturation datasets of four gas-bearing layers for each of the six wells in the project area are summarized in Table 2.

Table 3 shows the averages of the values listed in Table 2. Based on these calculated average values, we can conclude that the probability of having a confidence level of greater than 95% in similarity of the datasets is approximately less than 44%.

Table 3. Results of the “t” test: the upper trace cells show the statistical indices of t-test of porosity and lower trace cells show the statistical indices of t-test of water saturation.

	Porosity	S _w
Average of t-tests	0.921	0.917
Standard Deviation of t-tests	0.225	0.217
Z for Average of t-tests (Normalized)	0.127	0.153
Probability of the confidence limit in similarity of the datasets being greater than 95%	0.449	0.439

The expected values of the probability of the similarity for both porosity and water saturation datasets are calculated next:

$$EVP \geq 0.95 \times 0.499 - 0.05 \times 0.551 = 0.454 \quad (4)$$

$$EVSW \geq 0.95 \times 0.499 - 0.05 \times 0.551 = 0.445 \quad (5)$$

That EVP stands for “expected value for similarity of porosity datasets”, and EVSW stands for “expected value for similarity of water saturation datasets”. The probabilities of similarity and their expected values shown above indicate that we cannot decide on selecting one of the two previously described methodologies as the sole preferred calculation algorithm that should be used for hydrocarbon initially in place estimation, accordingly both methodologies were incorporated in the deterministic and probabilistic calculation processes.

3.2. Deterministic Calculation of Hydrocarbon Initially in Place

Examination of the profiles of porosity and water saturation raw datasets for the six wells located within the project area revealed that lognormal distribution would be the best type of probability distribution function that can be used to define the characteristics of the above-mentioned datasets. A similar examination of the net pay raw dataset indicated that a combined set of triangular and normal probability distribution functions could be used to define the profiles of the net pay of all gas-bearing layers of the studied wells.

Based on the P10, P50, and P90 values extracted from the probability distribution functions (pdf’s) fitted to porosity, saturation, and netpay datasets of each of the four layers of the studied wells, the first and second methodologies were used to calculate the worst, most likely, and the best deterministic values of hydrocarbon initially in place. Tables 4 and 5 show inputs of first and second methodologies for both deterministic and probabilistic processes, and the final results of deterministic process are shown on the Table 6.

Comparing the values of the mean, the standard deviation, and the P90-P10 range is listed in Table 6, we can conclude that for the case of second methodology the data points

Table 4. Input values of the first methodology.

		Well 1	Well 2	Well 3	Well 4	Well 5	Well 6
Porosity value	P10	0.07	0.06	0.07	0.05	0.06	0.06
	P50	0.14	0.12	0.14	0.09	0.10	0.11
	P90	0.26	0.23	0.24	0.15	0.16	0.21
Water Saturation Value	P10	0.03	0.04	0.04	0.11	0.11	0.06
	P50	0.07	0.14	0.09	0.22	0.27	0.11
	P90	0.21	0.54	0.23	0.46	0.65	0.30
Net Pay Value		158.34	210.46	113.23	62.03	89.61	178.16

Table 5. Input values of the second methodology.

		k1	k2	k3	k4
Porosity value	P10	0.05	0.07	0.06	0.08
	P50	0.11	0.14	0.11	0.17
	P90	0.20	0.21	0.17	0.28
Water saturation value	P10	0.07	0.03	0.07	0.02
	P50	0.15	0.05	0.16	0.05
	P90	0.36	0.09	0.30	0.14
Net pay values		23.32	23.77	17.68	93.57

Well 1

		k1	k2	k3	k4
Porosity value	P10	0.07	0.05	0.06	0.08
	P50	0.11	0.09	0.08	0.16
	P90	0.20	0.15	0.15	0.25
Water saturation value	P10	0.12	0.07	0.23	0.04
	P50	0.19	0.12	0.30	0.08
	P90	0.39	0.19	0.41	0.18
Net pay values		12.50	13.41	1.98	85.50

Well 3

		k1	k2	k3	k4
Porosity value	P10	0.05	0.07	0.06	0.06
	P50	0.10	0.11	0.07	0.09
	P90	0.19	0.16	0.09	0.14
Water saturation value	P10	0.08	0.07	0.24	0.20
	P50	0.17	0.11	0.31	0.44
	P90	0.35	0.17	0.37	0.69
Net pay values		30.78	5.79	1.07	51.97

Well 5

		k1	k2	k3	k4
Porosity value	P10	0.05	0.06	0.06	0.06
	P50	0.11	0.13	0.11	0.13
	P90	0.21	0.20	0.18	0.25
Water saturation value	P10	0.07	0.04	0.07	0.04
	P50	0.19	0.07	0.16	0.14
	P90	0.51	0.13	0.31	0.70
Net pay values		36.73	26.37	31.55	115.82

Well 2

		k1	k2	k3	k4
Porosity value	P10	0.06	0.05	0.06	0.06
	P50	0.09	0.09	0.10	0.07
	P90	0.15	0.15	0.16	0.12
Water saturation value	P10	0.10	0.11	0.27	0.40
	P50	0.19	0.17	0.33	0.54
	P90	0.36	0.31	0.45	0.71
Net pay values		27.58	22.25	4.72	7.47

Well 4

		k1	k2	k3	k4
Porosity value	P10	0.07	0.06	0.07	0.06
	P50	0.12	0.11	0.10	0.12
	P90	0.20	0.18	0.15	0.24
Water saturation value	P10	0.06	0.06	0.11	0.05
	P50	0.12	0.10	0.20	0.10
	P90	0.30	0.16	0.39	0.33
Net pay values		29.72	31.24	20.57	96.62

Well 6

Table 6. Deterministic Values of Hydrocarbon Initially in Place.

	Worst Scenario	Most Likely Scenario	Best Scenario	Average	Standard Deviation	P90-P10 Range
	P10 of porosity, P90 of water saturation and P10 of net pay	P50 of porosity, P50 of water saturation and P50 of net pay	P90 of porosity, P10 of water saturation and p90 of net pay			
First methodology	753,000,000 m ³	4,507,000,000 m ³	13,401,000,000 m ³	6,220,000,000 m ³	6,496,000,000	12,648,000,000 m ³
Second methodology	680,000,000 m ³	4,358,000,000 m ³	11,938,000,000 m ³	5,659,000,000 m ³	5,740,000,000	11,258,000,000 m ³

show less variability as they are closer to their mean when compared to the data points of first methodology case. Also, the P10, P50, and P90 hydrocarbon initially in place values calculated by the second methodology are higher than their respective values resulting from the application of the first methodology. As shown in Table 6, the magnitude of the standard deviation is higher than the magnitude of its associated average and this is a pitfall for deterministic approach used in this study, since it causes the value of Hydrocarbon in Place to become negative at probabilities values close to zero.

3.3. Probabilistic Calculation of Hydrocarbon Initially in Place

To come up with a probability distribution function for the Hydrocarbon Initially in Place the technique of the Monte Carlo Simulation was applied to both first and second methodologies. As explained above through the examination of porosity, water saturation, and net pay raw datasets, the probability distribution functions that could best define the characteristics of these datasets were selected and used as inputs to the probabilistic calculation process.

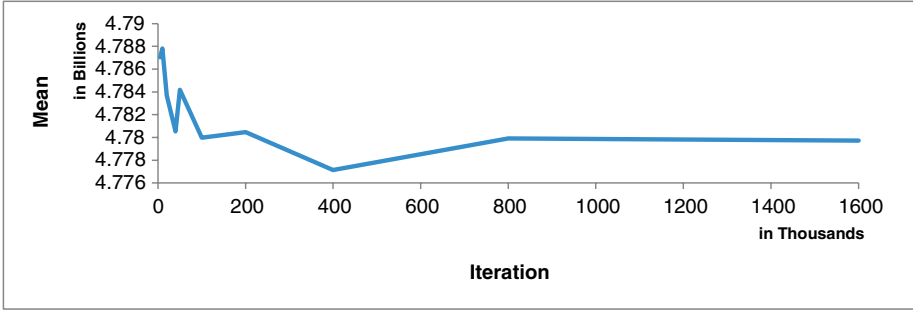
Examination of the raw datasets for porosity and water saturation indicated that these datasets are negatively correlated (Murtha, 1995). Table 7 shows the values of the correlation coefficients that were used for the two cases of first and second methodologies to correlate porosity and water saturation.

3.3.1. Effect of the Variation of Number of Iterations on the Value and Convergence of the P50 Estimate and Standard Deviation

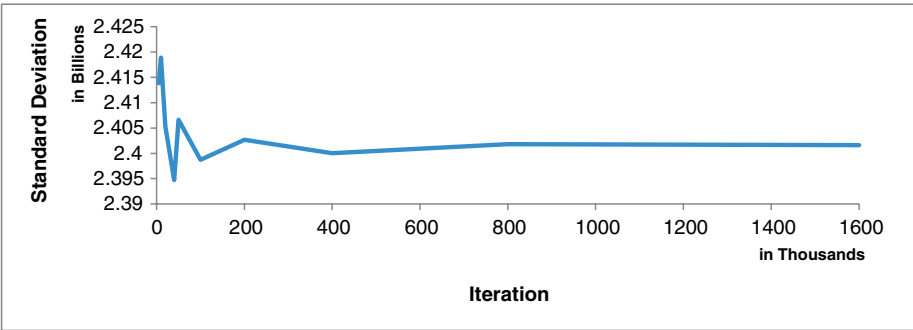
For both cases of first and second methodologies as shown in Figure 2, the minimum required number of Monte Carlo simulation iterations for convergence of mean estimate and standard deviation of the original hydrocarbon in place turned out to be around 800000. The probability distribution functions for the resulting mean and standard deviation of both methodologies turned out to be lognormal.

Table 7. Porosity and water saturation correlation coefficients in each well, also in each layer of each well.

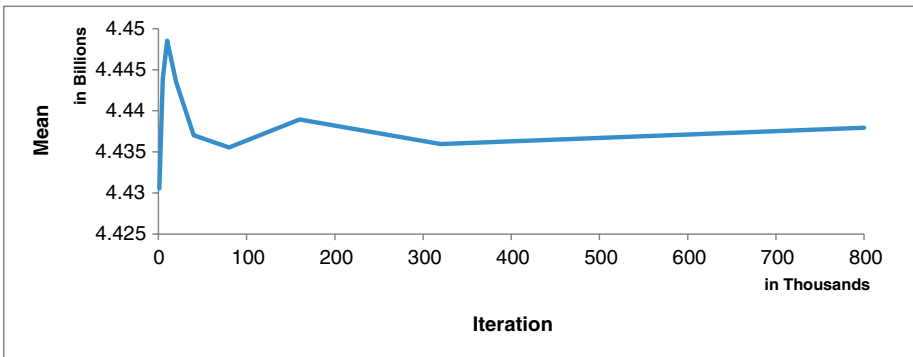
Simulation zone	Correlation Coefficient	Simulation zone	Correlation Coefficient	Simulation zone	Correlation Coefficient
Well 1	-0.766	Well 1	K1	Well 4	K1
Well 2	-0.661		K2		K2
Well 3	-0.762		K3		K3
Well 4	-0.248		K4		K4
Well 5	-0.313	Well 2	K1	Well 5	K1
Well 6	-0.668		K2		K2
			K3		K3
			K4		K4
		Well 3	K1	Well 6	K1
			K2		K2
			K3		K3
			K4		K4



(a)

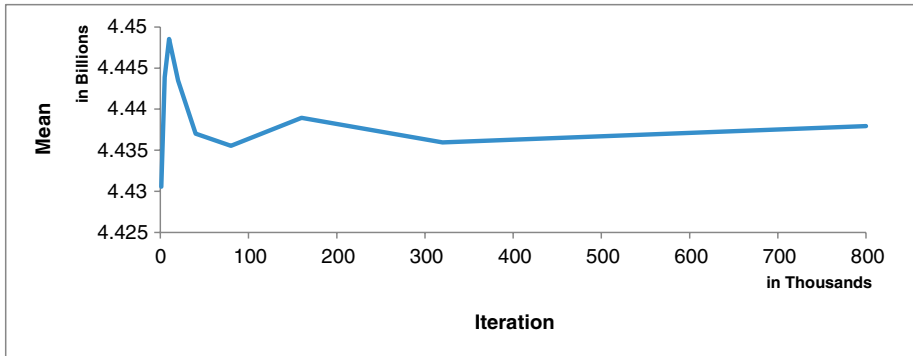


(b)



(c)

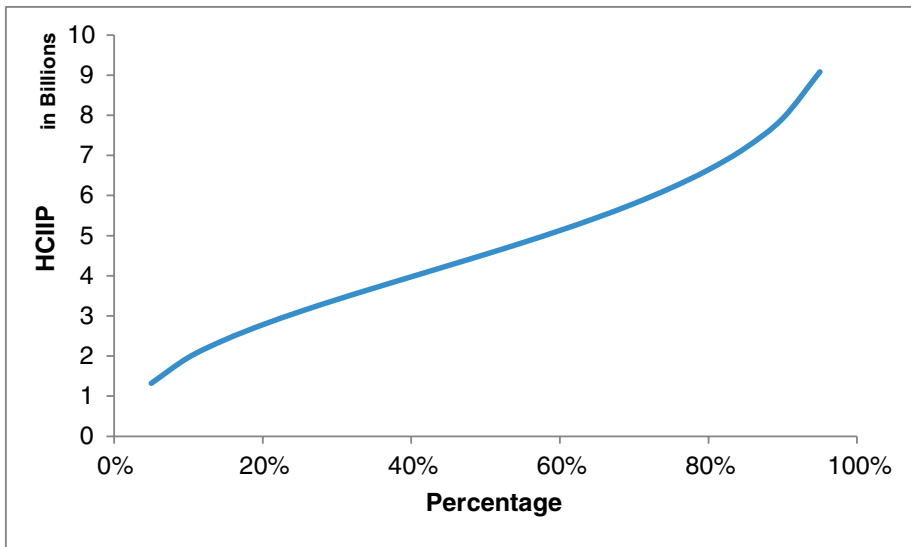
Figure 2. (Continued)



(c)

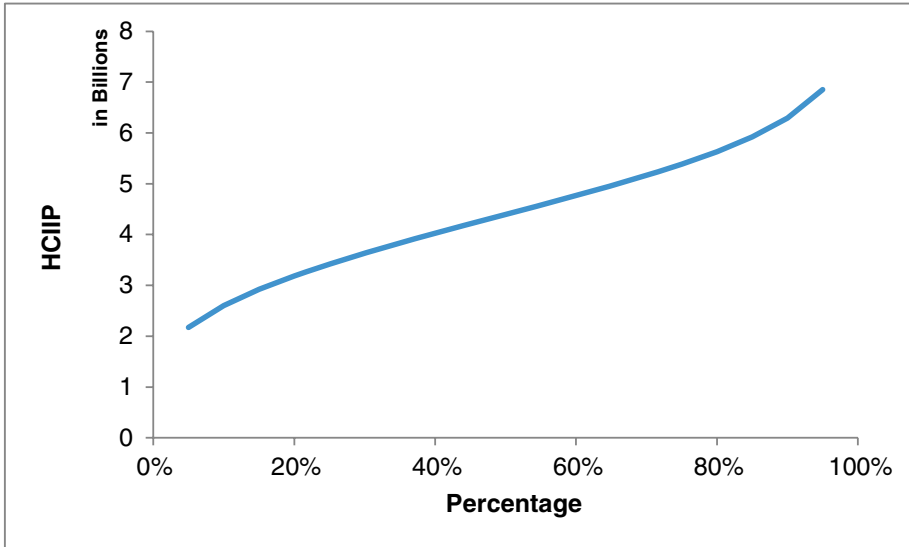
Figure 2. Effect of the variation of number of iterations on the value of the: a) mean and its convergence in the first method; b) standard deviation and its convergence in first method c) value of the mean and its convergence in second method d) standard deviation and its convergence in second method.

Cumulative Distribution Functions (CDF) of the probabilistic calculation of HCIIP using Monte Carlo simulation technique are shown in Figure 3.



(a)

Figure 3. (Continued)



(b)

Figure 3. Cumulative Distribution Function (CDF) of HCIIP resulted from probabilistic process: a) first methodology, b) second methodology.

3.3.2. Sensitivity Analysis

The tornado chart depicting the sensitivity of the first methodology's estimated HCIIP to the inputs of the probabilistic calculation process is shown in Figure 4. Based on the examination of structure of the formulation used for the first methodology one can expect HCIIP to have an exceptional sensitivity to net pay compared to other input parameters. The tornado chart for the case of second methodology (Figure 4a-b) identifies h4 as the input parameter to which HCIIP shows an exceptional sensitivity.

4. SUMMARY

Two methodologies were defined and used for deterministic and probabilistic calculation of hydrocarbon initially in place. The available raw datasets for porosity, water saturation and net pay of six wells located in the studied area were examined thoroughly and the probability distribution functions that could best define the characteristics of these datasets were defined and fed as inputs to both approaches. The profiles of the raw datasets for porosity and water saturation were tested for any correlations that might exist between the two and the associated correlation coefficients were calculated and incorporated into the probabilistic calculation technique. The t-statistical test was applied to all the wells in the studied area to examine the inter-dependency of porosity and water saturation datasets of their four gas-bearing layers to verify or nullify the existence of inter-dependency between these two datasets.

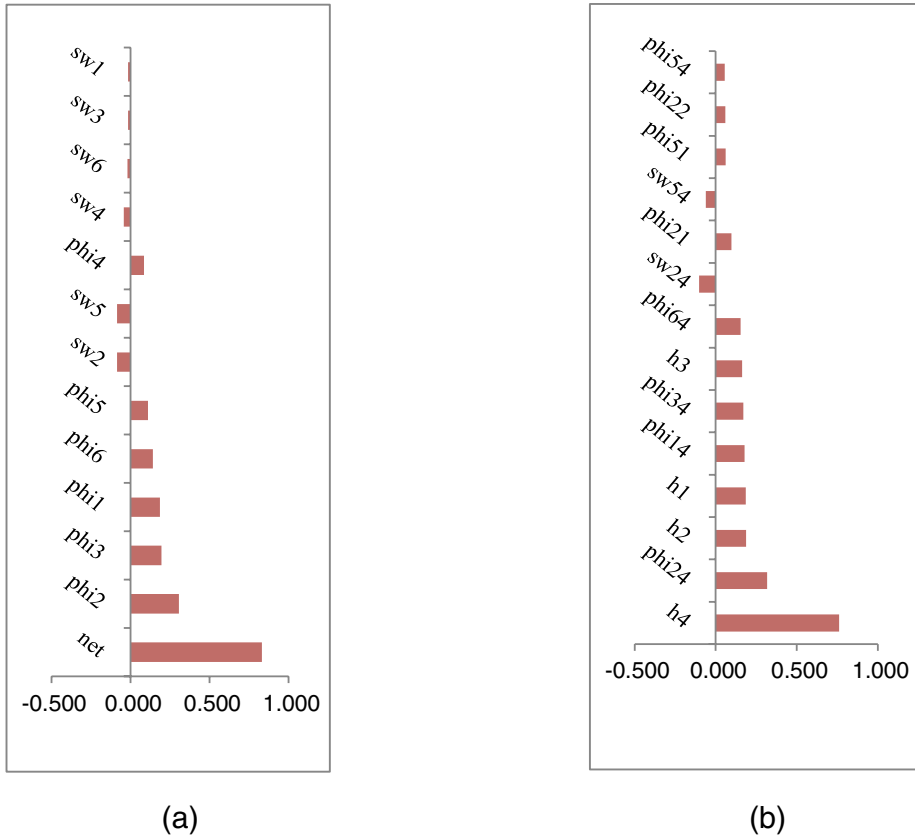


Figure 4. Tornado Chart a) First Methodology: The parameter sw_i shows the sensitivity of the estimated value to the water saturation of the well i ($i = 1, 2, 3, 4, 5,$ and 6). Also the parameter phi_i shows the sensitivity of the estimated value to the porosity of the well i ($i = 1, 2, 3, 4, 5, 6$). Also the parameter net shows the sensitivity of the estimated value to the net pay. b) Second Methodology: The parameter sw_{ij} shows the sensitivity of the estimated value to the water saturation of j th layer of the well i ($i = 1, 2, 3, 4, 5,$ and 6). Also the parameter phi_{ij} shows the sensitivity of the estimated value to the porosity of the j th layer of the well i ($i = 1, 2, 3, 4, 5, 6$). Also the parameter h_i shows the sensitivity of the estimated value the net pay of each layer. Parameters, affecting less than 0.05, are not included here.

A summary of the results and findings of above-mentioned tests, calculation processes, and analysis is shown in Figure 5. In general the values of P90-P10 ranges, standard deviations, and the average estimated HCIIP for the case of deterministic calculation techniques are higher than their respective values for the probabilistic techniques. For both cases of probabilistic and deterministic calculation of estimated Hydrocarbon Initially in Place, comparative study of the outcomes of the two incorporated methodologies indicates that higher variability of HCIIP values should

be expected if the first methodology (which assumes all four layers as one statistical society) is selected as the preferred calculation method.

5. CONCLUSION

As a best practice, both deterministic and probabilistic calculation techniques should be considered for addressing reservoir-related uncertainties and also for gaining a broader view of the magnitude of initial hydrocarbon in place through the comparative analysis of the outcomes of the two sets of calculations.

- The usefulness of t-test as a methodology selection tool turned out to be questionable for this study.
- Comparative study of the results of two methodologies for both approaches suggests that second methodology should be selected as the preferred evaluation algorithm for this case study.
- Deterministic approach is not a viable technique to be used for this study as the values of standard deviation for both methodologies are higher than those of their respective average values in both methodologies of probabilistic approach.
- Another recommended best practice for initial hydrocarbon in place calculation is to perform a thorough examination of all the given datasets for existence of any type of correlations that might exist among the same.
- Availability of per-well estimated drainage area datasets, which could be used to define probability distribution functions for allocated well drainage areas, could have been helpful in obtaining a more meaningful estimate for the amount of initial hydrocarbon in place obtained through the probabilistic calculation techniques.
- The representative values for estimated Hydrocarbon initially in Place of the studied area evaluated in this study are: proved reserve (P10 of second methodology of probabilistic approach) is 2,604,000,000 m³, probable reserve (P50 of 2nd methodology of probabilistic approach) is 4,397,000,000 m³ and possible reserve (P90 of 2nd methodology of probabilistic approach) is 6,292,000,000 m³. Definitions are based on the definitions presented by Demirmen, 2007

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