INTEGRATION OF 2D SEISMIC AND WELL LOG DATA FOR PETROPHYSICAL MODELING AND GAS RESERVE ESTIMATION IN APPRAISAL STATE OF PETROLEUM EXPLORATION

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ABSTRACT

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Three-dimensional (3D) petrophysical modeling is an essential step in quantitative description, static and dynamic evaluation of any hydrocarbon reservoir. This study addresses several important issues of integrating high and low resolution data in regional steps of petroleum exploration. The approach used in this study can constrain stratigraphy and geocellular model by integrating multiple kinds of geophysical data. The specific procedure implemented consists of a broad-band two-dimensional (2D) seismic inversion and stochastic petrophysical modeling. The final high resolution model, which can be used in both static and dynamic evaluation of the reservoir, is utilized for gas in-place estimation in the initial steps of hydrocarbon exploration in Iranian Farour-A oilfield. The results indicate that the application of this methodology on well logging and 2D seismic data provides a detailed description of the reservoir properties, and also leads to better reserve evaluation in comparison with the conventional techniques based on well logs and seismic data.

KEY WORDS: 2D seismic inversion, seismic attributes, well logs, petrophysical evaluation, modeling, stochastic sequential Gaussian simulation, gas in-situ reserve evaluation.

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INTRODUCTION

Structural and geological modeling is a conventional tool in reservoir management for analyzing reservoir heterogeneity that controls fluid storage and flow in porous media. Quantitative description of porous media at pore scale is a necessity in many specific subjects such as rheology (Müller and Saez, 1999), geophysics (Berryman and Wang, 2000), statistical physics (Hilfer, 2000), chemical physics (Spoler and Klapp, 2004), petroleum engineering (Kantzas et al., 1988) and so forth. Regarding the geometrical modeling, both seismic and well logging data provide important information. Sparse well data and lack of direct measurement of reservoir properties make the proper modeling of the reservoirs difficult. Building a geological model of a reservoir is like finishing a puzzle in which most of the pieces are missing. In the first stage of developing an oil and gas field when there is insufficient and sparse amount of well logging data, building a suitable geological model is challenging.

Although, previous conceptual geological models based on sedimentological, stratigraphical and well logging observations are used to understand overall petrophysical characteristics (Anderson, 1989; Fleming, 1998a,b; Stanford and Ashley, 1998; Galloway and Sharp, 1998a,b), an accurate estimation of oil and gas reserve is required to reduce the associated uncertainty on hydrocarbon saturation and other related petrophysical parameters. For example, the geometry of a potential hydrocarbon reservoir must be inferred and interpolated based on some drilling and seismic data between the existing wells and its porosity should be properly characterized to quantify the reserve. The situation gets worse when there are just two wells and some 2D seismic sections.

This study aims at presenting an innovative procedure for spatial representation of lithological properties and geological modeling with the best use of available data in regional steps of hydrocarbon feasibility study. To achieve these goals, the borehole geophysical logs as hard data and the seismic data as soft data are integrated to develop the reservoir model. In reality, any kind of data which are not measured directly or their origins have high degrees of ambiguity are generally treated as soft data. Seismic data have low vertical resolution and they are not expected to show the structure thinner than ten meters, but they can show the geometry and lateral changes in the reservoirs. In contrast, well logging data give priceless but restricted information in the vicinity of the well. While good quality seismic data have ten meters resolution, the information of the thinner scales is accessible by using well logs. The geostatistical modeling of rock properties could help so that hard data at well locations are matched to the reality of the reservoir, while soft data are used to provide information in regions away from the wells. If correlations between soft and hard data near the wells are high, the same degree of confidence away from the wells, where there is no hard data, is applicable.

Taking the foregoing points into account, the following steps proceed to achieve the goals:

1. Incorporating multiple types of geophysical data for generating and visualizing 3D petrophysical models of an oilfield.

2. Distributing continuous petrophysical and geophysical characters by using 2D seismic and well logs data to solve special reservoir problems.

3. Detailed documentation for creating 3D models of petrophysical characterization and reserve evaluation via integrating soft and hard data.

Reservoir engineers can use this modeling procedure to improve their simulations for specific objectives. This procedure was applied to improve the modeling and also to facilitate the study of Farour-A offshore oil field, Persian Gulf, Iran.

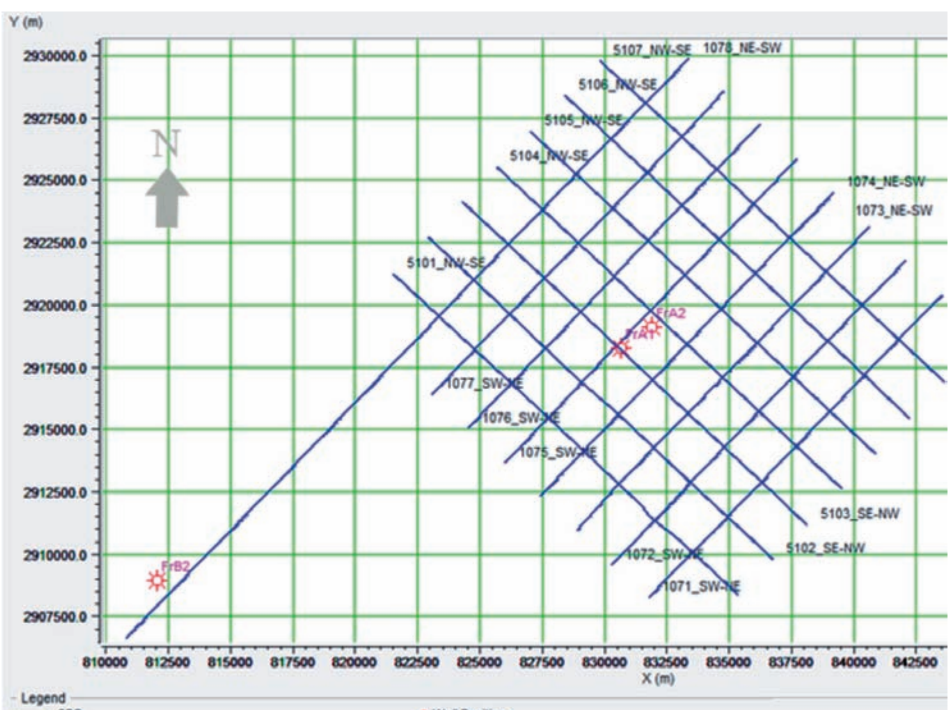

Fig. 1. Farour-A oilfield map; lines are 2D seismic time sections and stars are drilled wells in the region; X- and Y-coordinates are in universal transverse mercator (UTM).

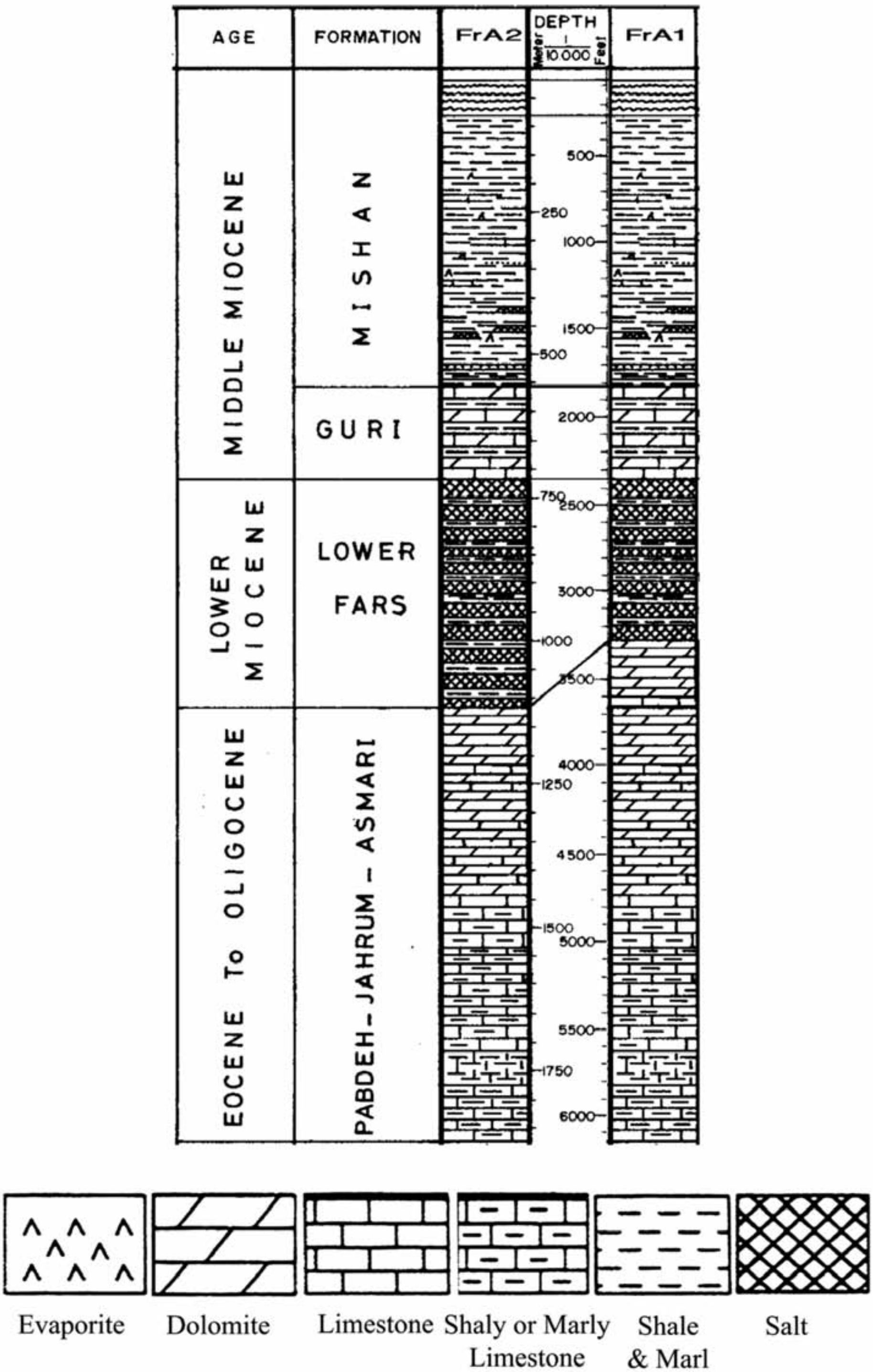

Fig. 2. Geological column in Farour-A drilled wells.

FAROUR-A OFFSHORE OIL FILED

Seismic and well logging data used in this study are taken from Farour-A offshore oil field located in Persian Gulf in southern part of Iran. The only reservoir with recoverable gas in this region is located in Asmari formation. The locations of Farour-A and Farour-B wells and the top view of 7x8 post stack 2D seismic time sections are shown in Fig. 1. The geological columns near Farour-A wells are shown in Fig. 2. The well named Fr.A1 is located near a graben fault which is caused by a salt dome, but Fr.A2 well is away from this fault surface. The well logs used include: Neutron Porosity Log, Sonic Velocity Log, Bulk Density Log and Deep Resistivity Log (Figs. 3 and 4).

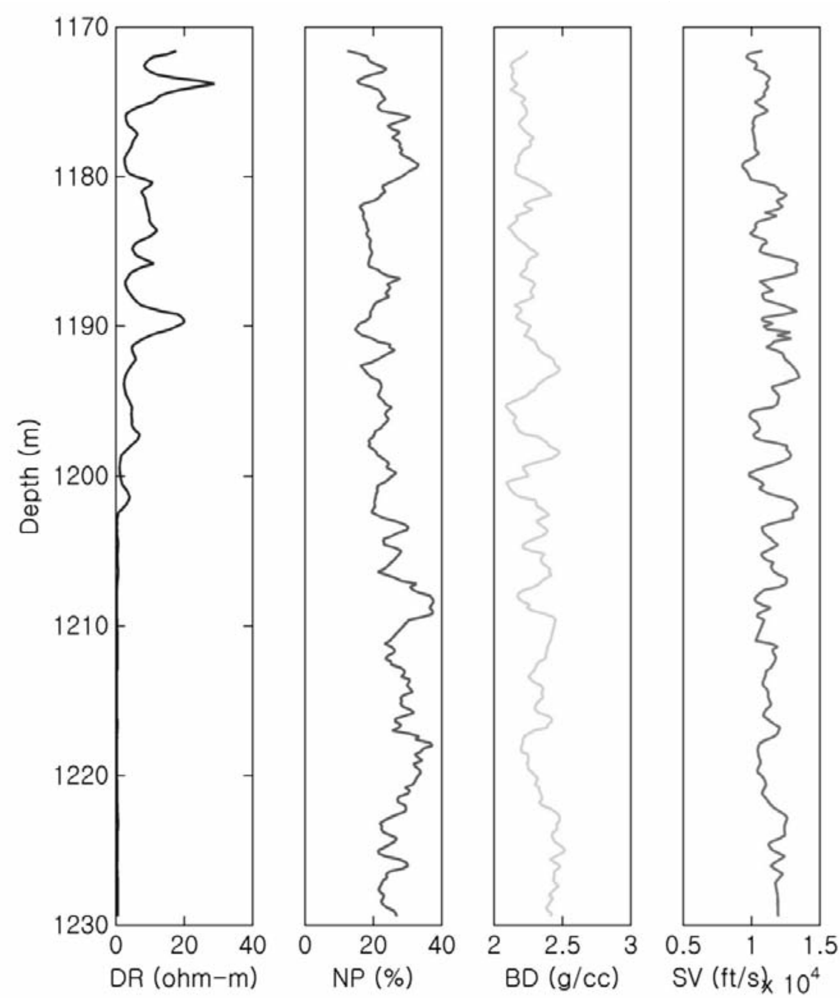

Fig. 3. Deep Resistivity (R_{LLd}), Neutron Porosity (NPHI), Bulk Density (ROHB) and Sonic Velocity (SV) Logs of Asmari formation in Farour-A1 well.

METHODOLOGY

To reduce uncertainties in quantitative and qualitative interpretation of data, the ability of different methods in geophysical survey is widely recognized (e.g. Dannowski and Yaramanci, 1999; Hubbard et al., 2001; Garambois et al., 2002). A common way to combine multiple and diverse geophysical surveys is by deriving the independent subsurface models and joining them to a single integrated model in the target subsurface region. In the current research, linking multiple datasets during the inversion and model generating process was the general procedure.

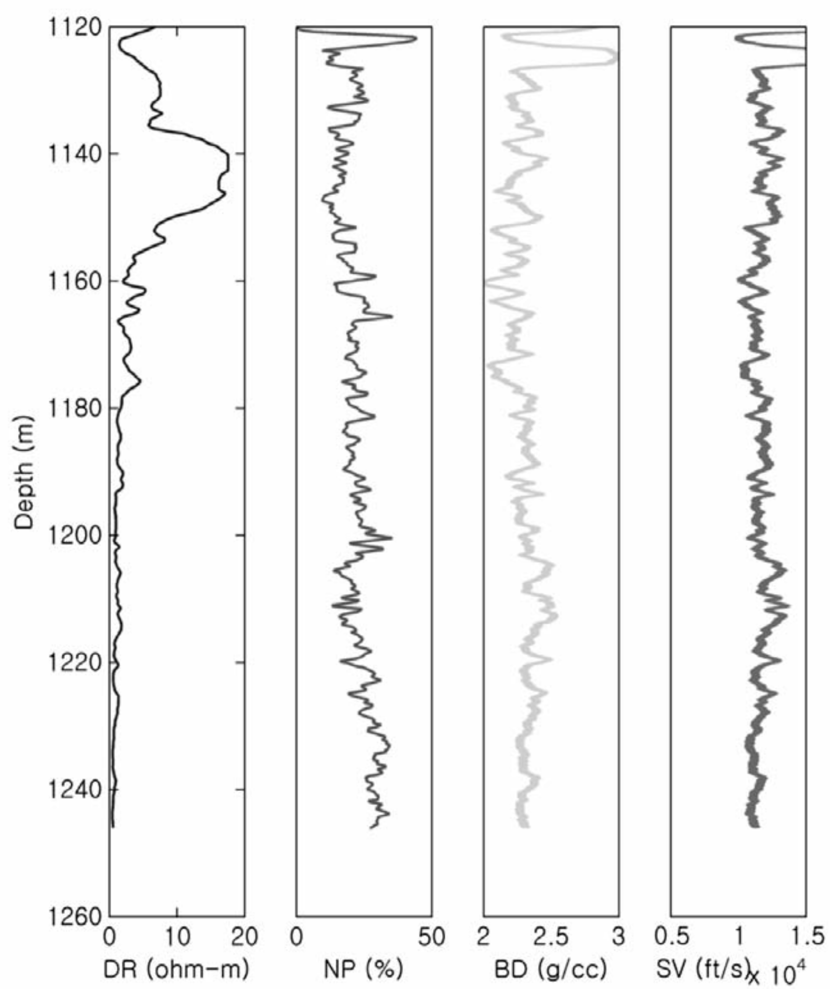

Fig. 4. Deep Resistivity (R_{LLd}), Neutron Porosity (NPHI), Bulk Density (ROHB) and Sonic Velocity (SV) Logs of Asmari formation in Farour-A2 well.

Collection, preparation and interpretation of data, extraction of specific petrophysical characters, model creation and analysis of modeling results are the major phases of the research. Fig. 5 (Nikravesh, 2007) illustrates the schematic diagram of the reservoir data mining when we deal with different kinds of data in petroleum industry. The Nikravesh's technique was considered as the optimal procedure to compensate inadequacy of data in the regional phase of petroleum exploration. Fig. 6 shows the modeling procedure in which seismic and well logging data are used as input for constructing a geological model in two steps of seismic inversion and stochastic petrophysical modeling. In the first step, seismic and well logging data are engaged to broad-band acoustic impedance extraction, and then by incorporating it with other seismic attributes, porosity is estimated as a final output. In the second step, the evaluated porosity and well logging data were used to make a geological model, and this model is used for reserve calculation. More details of the method are explained in the following section.

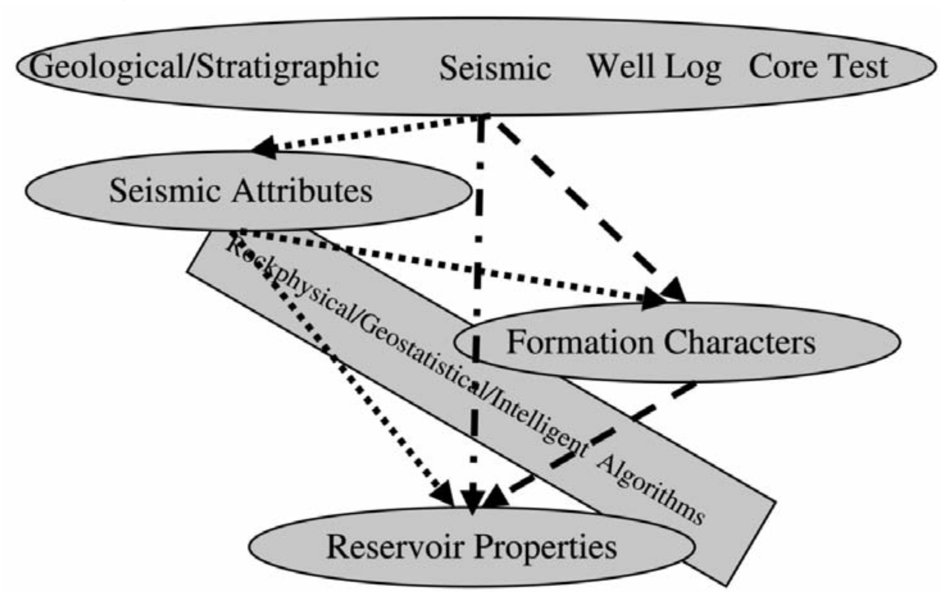

Fig. 5. The schematic procedure of reservoir data mining (Nikravesh, 2007).

Seismic inversion and petrophysical evaluation

Seismic traces which are currently substituted for seismic inversion data were primarily introduced in 1970s (Lindseth, 1979). Because seismic data were band limited, extracted acoustic impedance was band limited too. So, due to the lack of low and high frequency ranges in seismic data, trends were omitted from

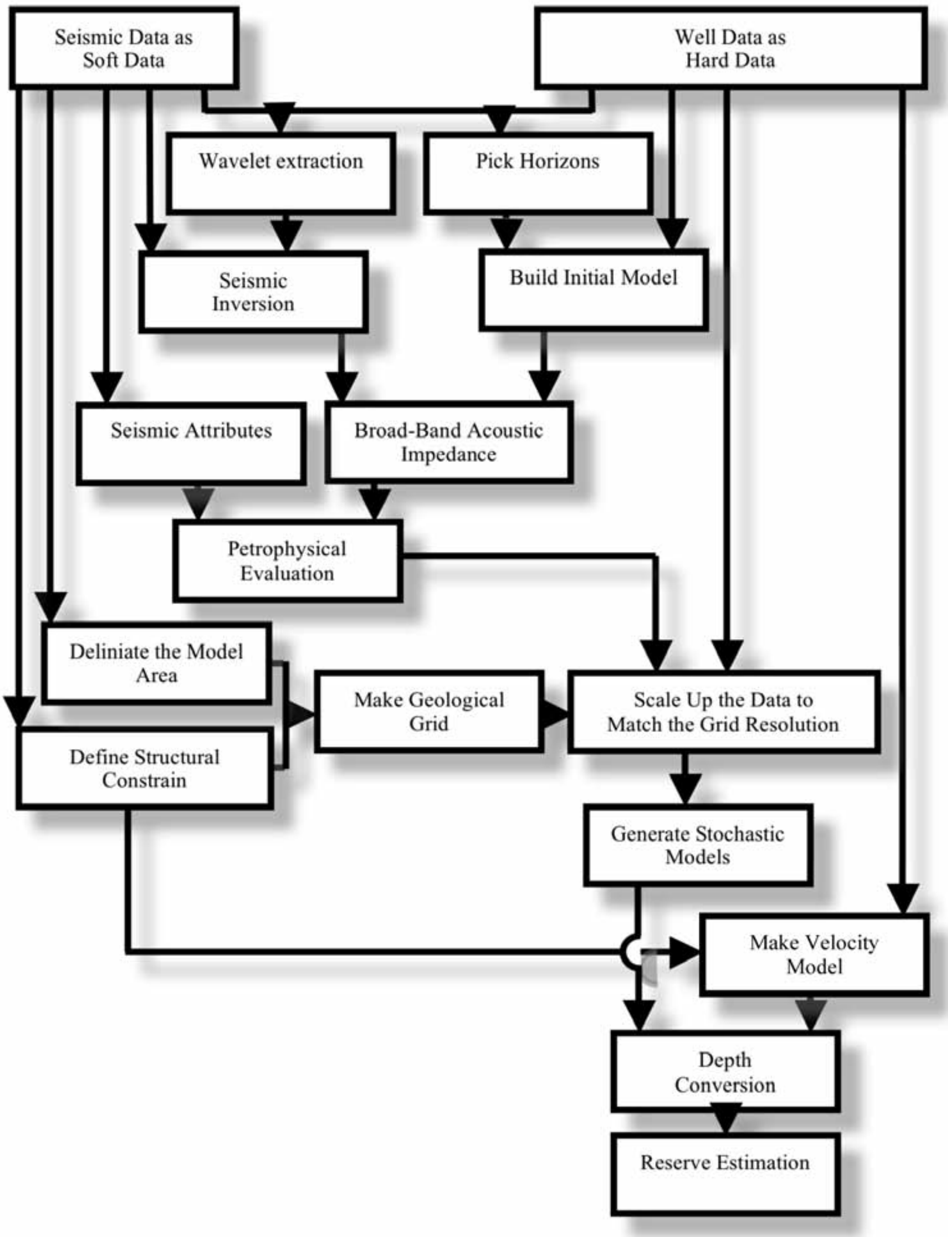

Fig. 6. Flow diagram in integration of hard and soft data and geological modeling for reserve estimation.

the final output. Lindseth (1979) presented a methodology in which low frequency ranges were back to the model from well logging data by using an initial base model. Later, many algorithms like Sparse-Spike (Oldenburg, 1983) and Model-Base (Hampson and Russell, 1990), which had their own advantages and disadvantages, were presented. An important utility of such inversion approach is that the inherent ambiguity of each dataset is covered by additional constrains provided by other datasets. The procedure to extract petrophysical properties from seismic data is as follows (Fig. 6):

1. Picking horizons (by using the available check shot): Horizons which show the top and the base of the formations are picked on seismic data. These horizons are used for correlating seismic data to well logging data and matching depth domain to time domain.

2. Wavelet extraction: For correlation of seismic data to well logging data, it is essential to build a synthetic trace at well locations. A trace, which is dependent on rock velocity and density, is made by convolution of a wavelet to acoustic impedance variation.

3. Building initial model: This model is made by using the picked horizons and well logging data, and supports the final model with low frequency.

4. Inversion to acoustic impedance: Based on the integration of an initial model and the seismic inversion output, broad-band acoustic impedance will be the final output of inversion.

5. Petrophysical evaluation from seismic attributes and acoustic impedance: In the last step, based on the best configuration of seismic attributes and inversion results, the petrophysical evaluation can be done. By finding the relationship between these seismic features and petrophysical properties at well locations, it is possible to estimate these properties away from the wells. The relationship of seismic attributes and porosity that are used in this process are shown in cross plots of Fig. 7.

Petrophysical modeling

Following structural modeling, petrophysical modeling of the reservoir is very important. Main procedures of petrophysical modeling are described below and schematically shown in Fig. 6.

1. Scaling up the data to match the grid resolution: using the arithmetic mean for scaling up the evaluated petrophysical data, the mean value of petrophysical properties near any cells is assigned to the nearest cell.

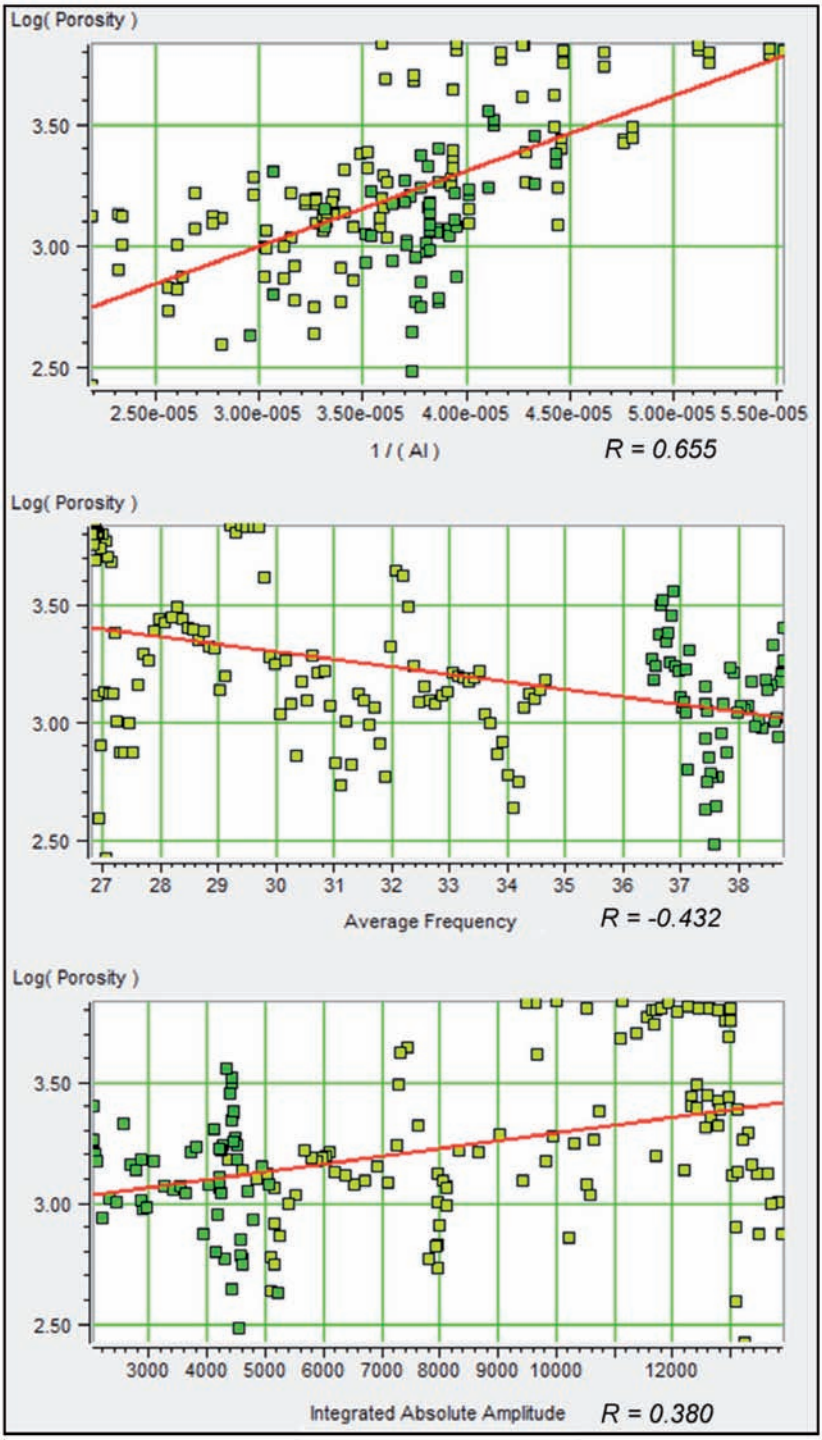

Fig. 7. Cross plots showing the relationships between seismic attributes and logarithm of porosity.

2. Generating stochastic models: characterizing reservoir requires integration of different qualities and quantities of data in a consistent manner to show the reservoir properties at unmeasured locations.

In regional steps of petroleum exploration with a few drilled wells and 2D seismic sections, reservoir characterization is geo-statistically different from the situation in which many exploratory wells and 3D seismic data are available. Applying geostatistical methods and building 3D spatial variations of petrophysical properties are necessary for reservoir characterization. This technique enables us to propagate reservoir properties in a manner that is statistically coherent and consistent. They have the capability to show trends and variability of properties for describing reservoir parameters. The Sequential Gaussian Simulation (SGS) was used for this purpose. It was typically used to distribute continuous properties such as porosity. There are many versions of SGS such as SGS with the trend, collocated co-Kriging, and external drift. The SGS as a stochastic method of interpolation based on Kriging is as follows:

A. Random selection of an unvalued grid node.

B. Estimation of the value using Gaussian uncertainty at an unmeasured location by Kriging and using the measured grid node.

C. Drawing a random number from the defined distribution by step (B) and assigning this simulated value to the grid node.

D. Including a new grid node to the model and repeating from step (A) until there is no unvalued grid node.

The key concept of geostatistical reservoir modeling is Kriging. This method makes data pairs in a given direction. One can estimate or simulate the data around or at the vicinity of the data pairs through the relationship of the data pairs.

Reserve calculation

Reserve calculation is very important to show the economic conditions of the oilfield. The following equation (Ahmed, 2000) describes the relationship between various dependent parameters in the gas reserve estimation.

$$G = 43{,}450\, Ah\phi(1 - S_{wi})/B_{gi} \quad , \tag{1}$$

where G is the gas in-place in scf, A is the area in acres, h is the net pay in meter, ϕ is the porosity and S_{wi} is the water saturation, both in fraction, while B_{gi} is the gas expansion factor in ft^3/scf. Porosity and water saturation are petrophysical properties, which are distributed across the field and are determined by geostatistical methods. The net volume is defined by the space between horizons and oil/gas water contact and the gas expansion factor depends on the pressure and gas type of the reservoir. Reserve estimation is important because its value persuades a company whether to invest in a field or not and understand what would be the profit if they invest.

RESULTS AND DISCUSSION

Petrophysical evaluation and geological modeling were the two main phases of this research. In the first phase, by using model base inversion, broad-band acoustic impedance was extracted for all seismic time sections and was integrated with other seismic attributes for porosity and water saturation evaluation. Selecting proper seismic attributes for porosity evaluation was done with step-wise regression by cross validation error criteria. So, selecting two seismic features would be optimal, but more seismic attributes would decrease the resolution of the final result when the cross validation error increases (Russell, 2004). Thus, acoustic impedance and average frequency attributes were selected for porosity evaluation. The results of the three kinds of radial basis function (RBF), multi layer feed forward (MLFN), and probabilistic neural networks (PNN) were investigated for the best estimation of porosity from selected seismic attributes. They showed that PNN was the best estimator of porosity from the selected seismic attributes, where the root mean square error (RMSE) was at minimum and correlation coefficient was at maximum for the validation data (Table 1). The up-scaled values by the best estimation of porosity from all seismic time sections are shown in Fig. 8. Unfortunately, water saturation was poorly estimated through this methodology due to data inadequacy. The output showed low resolution, forcing us to deploy a conventional procedure for water saturation modeling by using well-log data.

Table 1. Results of different ANNs methods for prediction of porosity.

Type of ANN	RMSE	Correlation Coefficient
RBFN	7.28	0.60
MLFN	6.53	0.68
PNN	6.11	0.74

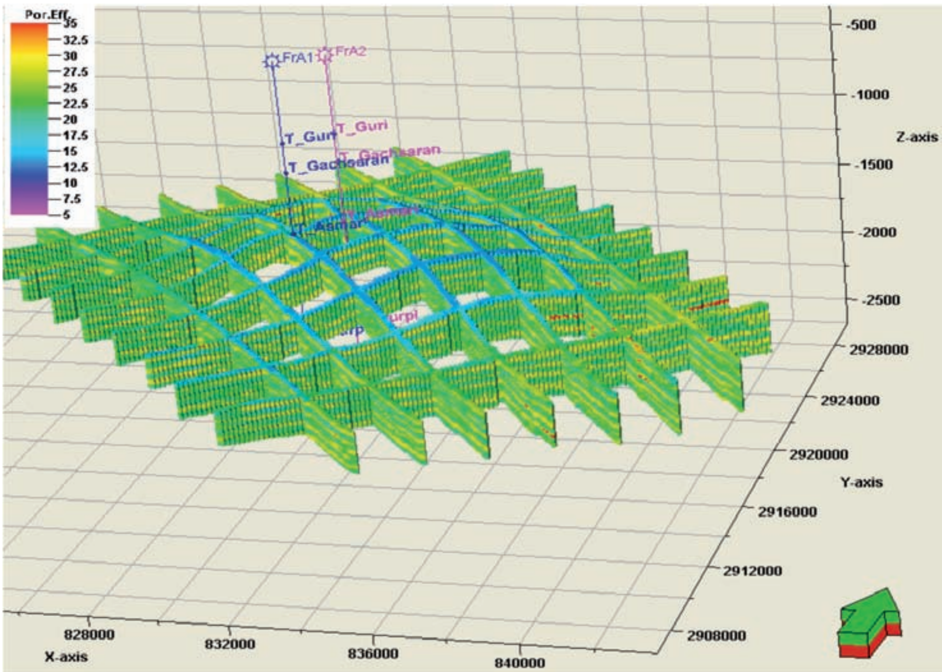

Fig. 8. Up-scaled value by the best estimation of porosity from all seismic time sections.

The porosity model for Asmari formation using 2D seismic and well logging data along with stochastic method of SGS with the trend is shown in Fig. 9. Water saturation model using well logging data is illustrated in Fig. 10. Water saturation increases gradually with depth and the values of 0.8 is the cut off for water saturation where gas water contact is assigned. Net volume is the space between the top of Asmari formation horizon and gas water contact. By using these models, gas in-place for 124 meters gas column of Asmari formation was evaluated to be 46.72 Billion cubic meters in surface condition (bcms). This evaluation is 1.2 (bcms) greater than the previously available constructed homogenous reservoir model based on the well data provided by Iranian offshore oil company. This increase is due to more accurate evaluation in porosity distribution through the reservoir. In spite of increase in accuracy, uncertainty of evaluation exists due to the porosity estimation from seismic attributes.

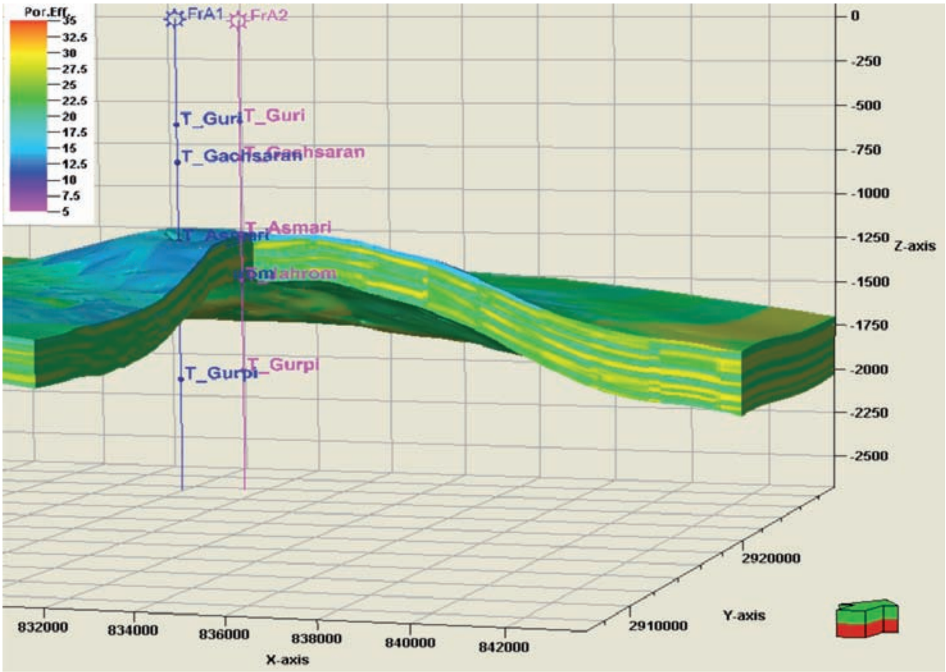

Fig. 9. The prepared porosity model using the new described method.

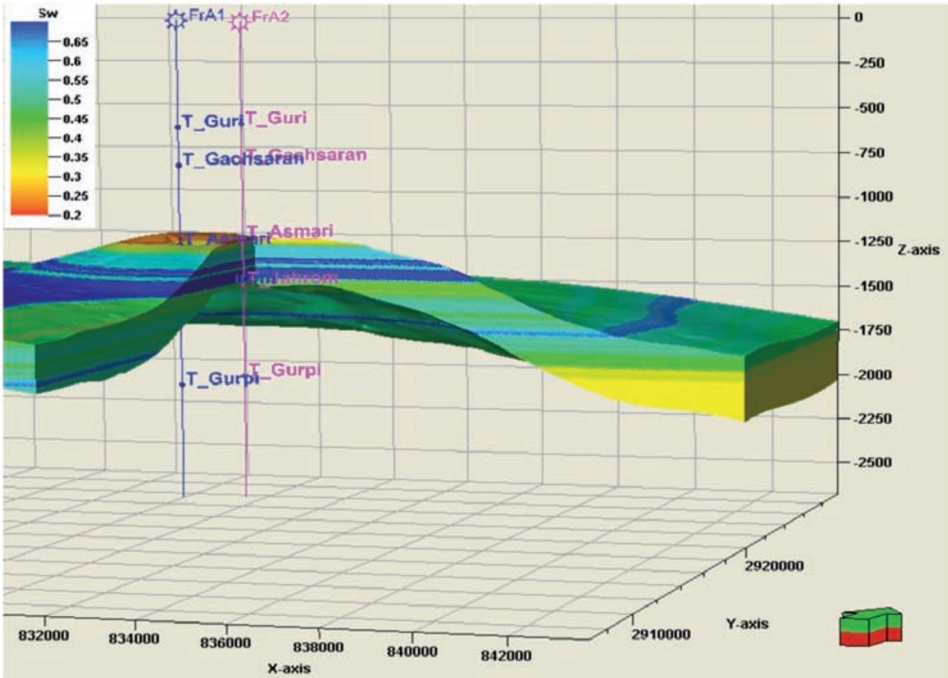

Fig. 10. The acquired water saturation model in this research.

CONCLUSION

In this study, new approaches of optimal integration in various geophysical datasets incorporating of SGS modeling were examined and by using the minimum available data, the best possible geological model was constructed. Important issues in creating precise geological and petrophysical models involve proper incorporating of multiple kinds of data with different vertical and horizontal resolution. So, using innovative solutions through integration of well logging and seismic data, the researchers constructed the models and used them for accurate gas in-place estimation. The obtained results indicate that the value of gas in-place within the Asmari reservoir is about 46.72 billion cubic meters in surface condition (bcms) that is 1.2 (bcms) greater than the previous estimation by Iranian offshore oil company. This is due to more accurate evaluation in petrophysical parameters distribution throughout the modeled reservoir. In addition, this methodology, which uses broad-band seismic inversion and stochastic petrophysical modeling, provided a powerful tool for accurate reserve estimation. Future works include dynamic reservoir modeling with fluid and flow parameters.

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