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Development of an artificial neural network model for prediction of bubble point pressure of crude oils

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A B S T R A C T

Bubble point pressure is one of the most important pressure–volume–temperature properties of crude oil, and it plays an important role in reservoir and production engineering calculations. It can be precisely determined experimentally. Although, experimental methods present valid and reliable results, they are expensive, time-consuming, and require much care when taking test samples. Some equations of state and empirical correlations can be used as alternative methods to estimate reservoir fluid properties (e.g., bubble point pressure); however, these methods have a number of limitations. In the present study, a novel numerical model based on artificial neural network (ANN) is proposed for the prediction of bubble point pressure as a function of solution gas–oil ratio, reservoir temperature, oil gravity (API), and gas specific gravity in petroleum systems. The model was developed and evaluated using 760 experimental data sets gathered from oil fields around the world. An optimization process was performed on networks with different structures. Based on the obtained results, a network with one hidden layer and six neurons was observed to be associated with the highest efficiency for predicting bubble point pressure. The obtained ANN model was found to be reliable for the prediction of bubble point pressure of crude oils with solution gas–oil ratios in the range of 8.61–3298.66 SCF/STB, temperatures between 74 and 341.6 °F, oil gravity values of 6–56.8 API and gas gravity values between 0.521 and 3.444. The performance of the developed model was compared against those of several well-known predictive empirical correlations using statistical and graphical error analyses. The results showed that the proposed ANN model outperforms all of the studied empirical correlations significantly and provides predictions in acceptable agreement with experimental data.

1. Introduction

For a hydrocarbon system, bubble point pressure refers to the highest pressure at which the first gas bubble starts leaving oil to form a separate gas phase [1,2]. Bubble point pressure is one of the most important pressure–volume–temperature (PVT) properties of petroleum systems which, together with other properties, plays a significant role in a number of reservoir and production engineering calculations such as mass balance calculations, well and reservoir simulation, flow performance calculations, production facilities design, enhanced oil recovery projects, reservoir future performance forecast, and economic evaluation [3–7].

Bubble point pressure can be obtained in laboratory by conducting constant-composition expansion (CCE) test on reservoir fluid samples [1]. In CCE test that is also called flash evaporation, flash separation, flash expansion or volume-pressure relation, first some reservoir fluid is put in a visual PVT cell at reservoir

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temperature and a pressure higher than initial reservoir pressure. Next, step by step by reducing the pressure at constant temperature, the total hydrocarbon volume is measured and plotted against the pressure; on this plot, the pressure at which plot slop changes is recognized as the bubble point pressure [1]. Although the experimental method provides well-precise and valid results, it is time-intensive and requires much care when taking fluid samples from the oil reservoir [2]. In cases where experimental data is not available, one can use equations of state or empirical correlations to estimate PVT properties. Equations of state are often associated with well-complicated calculations and require a complete set of data on reservoir fluid composition.

During the last seven decades, researchers have presented many empirical correlations for the estimation of PVT properties of crude oils. These correlations enjoy simple calculations and mostly they have been introduced for one or more than one specific geographical locations with given chemical composition and range of other data for reservoir oil. The correlations are developed based on linear, non-linear, and multiple regression as well as graphical techniques. Most of these correlations are developed assuming bubble point pressure as a function of solution gas-oil ratio, reservoir temperature, oil gravity (API) and gas specific gravity.

In 1947, Standing [8] used 105 experimental data sets collected from oil samples taken from different locations across California to propose graphical correlations for the calculation of bubble point pressure, oil formation volume factor (OFVF), and total OFVF. Standing ended up with average errors of 4.8%, 1.17%, and 5% for bubble point pressure, OFVF, and total OFVF, respectively.

In 1958, Lasater [9] used 158 experimental data sets of oil samples taken from Canada, America, and South America to propose a correlation for the prediction of bubble point pressure. The correlation was based on oil samples free from non-hydrocarbon components. Lasater [9] expressed that; the presence of such components might contribute into underestimated bubble point pressure, reporting an average error of 3.8% for his correlation.

In 1980, Vasquez and Beggs [10] investigated 600 experimental data sets collected from oil fields around the world and presented correlations for the calculation of PVT properties such as solution gas oil ratio, saturated and undersaturated OFVF, and undersaturated oil viscosity. Their study showed that separation conditions have a significant effect on gas gravity that is an important correlating parameter in their correlation. Therefore, they suggested adjusting the gas gravity at a separator pressure of 100 psig. Furthermore, they subdivided oil samples into two groups ($API > 30$ and $API \leq 30$).

In 1980, Glasø [11] presented correlations to predict bubble point pressure, OFVF, total OFVF, and dead oil viscosity. The correlations were developed on the basis of 45 crude oil samples most of which were collected from North Sea. Glasø [11] further presented a correction method for bubble point pressure in the presence of H_2S, CO_2, and N_2 components and reported average relative errors of 1.28%, −0.43%, and −4.56% for the calculated bubble point pressure, OFVF, and total OFVF values, respectively.

In 1987, Obomanu and Okpobiri [12] developed correlations for the estimation of OFVF and solution gas-oil ratio; the correlation was based on 503 PVT data points collected from 100 Nigerian oil reservoirs across Niger Delta Basin.

In 1988, Al-Marhoun [13] utilized 160 oil samples taken from 69 hydrocarbon systems across Middle Eastern to present correlations for the estimation of bubble point pressure and OFVF. He reported an average absolute relative error of 3.66% for bubble point pressure and 0.88% for OFVF.

Many studies have focused on the comparison between the results of above mentioned empirical correlations and other similar empirical correlations proposed by different authors for different oil fields around the world (e.g. Labedi [14] for Africa oil samples, Macary and El-Batanoney [15] for Gulf of Suez oil samples, Dokla and Osman [16] for United Arab Emirates oil samples, Frashad et al. [17] for Colombian oil samples, Omar and Todd [18] for Malaysian oil samples, Petrosky and Farshad [19] for Gulf of Mexico oil samples, Kartoatmodjo and Schmidt [20] for Middle Eastern, Indonesian, North and Latin American oil samples, Khairy et al. [21] for Egypation oil samples, Dindoruk and Christman [22] for Gulf of Mexico oil samples and Naseri et al. [23] for Iranian oil samples) and experimental data for different types of crude oil [24–29]. All of these studies have indicated that these correlations are not accurate enough to be generalized to estimate PVT properties of crudes with various properties in different geographical locations. On the other hand, these correlations were developed on the basis of multiple linear and nonlinear regression methods, which may not give reliable results.

During the recent past, researchers have used artificial neural networks (ANNs) as a powerful and reliable tool serving data-mining and numerical applications in terms of PVT properties prediction for petroleum systems. The most common neural network and training algorithm are feed forward neural network and back propagation (BP) algorithm, respectively.

For example, in 1997, Gharbi and Elsharkawy [30] proposed neural networks models for the prediction of bubble point pressure and OFVF; being based on solution gas-oil ratio, oil specific gravity, reservoir temperature, and gas relative density, the models were developed for Middle Eastern crude oil samples. They used neural networks with two hidden layers with 4-8-4-2 and 4-6-6-2 structures to determine bubble point pressure and OFVF, respectively. Both models were trained by 498 experimental data sets and tested by 22 test data sets. They reported lower relative errors and standard deviations for their proposed models, as compared to considered correlations for the calculation of bubble point pressure and OFVF.

In 1998, Elsharkawy [5] developed a radial basis function neural network model as a new approach to estimate OFVF, oil viscosity, gas-oil-ratio, undersaturated oil compressibility, saturated oil density, and evolved gas. Input data used were reservoir pressure, temperature, stock tank oil gravity, and separator gas gravity. Input data set which was collected from different oil and gas systems from different oil fields were divided into a training set (with 90 different PVT test data points) and a test set (with 10 test data points). A comparison between the provided accuracy by the model and those of published correlations (when the prediction of crude oil properties is concerned) indicated the model to be of superior accuracy over the published correlations.

In 2001, Osman et al. [6] used a feed forward multilayer back propagation neural network with 4-5-1 structure which was designed on the basis of 803 published data sets from oil fields in Colombia, Gulf of Mexico, Middle Eastern and Malaysia to predict OFVF at bubble point pressure. Their model provided a correlation coefficient of 98.8% and an absolute percent relative error of 1.789% which was the lowest error compared to the proposed correlations by Al-Marhoun [31], Al-Marhoun [13], Standing [8], Vasquez and Beggs [10] and Glasø [11].

In 2006, Malallah et al. [32] followed a new approach, called alternating conditional expectation algorithm to estimate of the bubble point pressure and OFVF. Their model was developed using 5200 data points corresponding to crude oil samples taken from different regions around the world (including oil fields in Africa, Southeast Asia, Middle Eastern, North Sea, and North and South America). Of the total available data points, 5000 data points were randomly taken as training set, with the remaining 200 data points used to test the developed model. With an average absolute relative

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