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Investigation of different interpolation functions for a newly developed framework for sequential coupling of the reservoir, wells, and surface facilities

Alireza Bigdeli[1], Matheus Lemos Barroso[1], Ivens Da Costa Menezes Lima[1], Fransico Marcondes[1], Kamy Sepehrnoori[2]

[1]*Laboratory of Computation Fluid Dynamics, Block 730, Federal University of Ceará,*
Av. Humberto Monte, s/n, 60455-900, Fortaleza, Ceará, Brazil
alirezabigdeli71@gmail.com, matheuslemosbarroso@gmail.com, ivenscml@yahoo.com.br, marcondes@ufc.br
[2]*Hildebrand Department of Petroleum and Geosystems Engineering, The University of Texas at Austin,*
200 E. Dean Keeton St., C0300, TX 78712-1585, Austin, Texas, USA
kamys@mail.utexas.edu,

Abstract. The development of numerical software which can simultaneously simulate reservoir, well and surface facilities is becoming a remarkable research topic for both academia and industry. Previously, we developed a numerical algorithm for our in-house compositional simulator, UTCOMPRS, to couple the simulator with surface facilities. The information for well and surface facilities is produced by a commercial simulator and included within the UTCOMPRS through two sets of tables named simplified and advanced flow tables. By introducing a new class of flow tables named commercial flow tables, for well modeling, this work presents three main objectives: 1) introducing a newly developed framework for commercial flow tables, 2) introducing a new feature for controlling the injecting well, 3) investigation of different interpolation functions, such as gas-liquid ratio, water-oil ratio, liquid rate, and wellhead pressure for the validation of the newly developed framework with a commercial simulator. Also, we present the results of two case studies. They show that the developed framework was successfully designed and validated. Also, the values of bottom hole pressure, wellhead pressure, water-oil ratio, gas-oil ratio, the pressure of injector, oil, gas, and water rates were in good agreement with both UTCOMPRS and commercial simulators. The outcomes of this research study increase the applicability of our simulator for modeling more complex models through the sequential coupling of the reservoir, well, and surface facilities. Also, these new functions are designed in a way that can be used for our future studies, which are concentrated in application for fully-coupling frameworks.

Keywords: Compositional Simulation, Sequential Coupling, Surface Facilities, Wellhead, Injector.

1 Introduction

Petroleum reservoirs are geological systems in which hydrocarbon fluids are accumulated. From the petrophysical point of view, there are three essential sub-systems; source rocks, reservoir rocks, and cap rocks which generated, transferred, and accumulated the hydrocarbons fluids, respectively. During the production stage of a reservoir, pressure decline analysis should be carried out and monitored carefully due to the withdrawal of hydrocarbon fluids. It is important to know how hydrocarbon fluids are produced and the physics and mechanisms that are involved during the harvest of these natural resources. In porous media, reservoir drives are the main driving force that causes the movement of the reservoir fluids. Additionally, as reported by Ahamad [1], the reservoir's drive has different behavior in terms of ultimate recovery factor, pressure decline rate, gas-oil ratio (GOR), and water productions. Thus, the prediction of reservoir performance, any further development plans, and simulations studies intensively depend on the characteristics of pressure decline analysis.

Compositional simulation of hydrocarbon reservoirs is the most reliable method for pressure decline analysis. Due to interactions of surface and subsurface facilities, the development of simulators that enable the handling of both reservoirs and facilities simultaneously is becoming a remarkable research topic for both academia and industry especially because of an increase of computational power. During the 1970-80s, early numerical packages were developed (Shamir *et al.* [2], Wylie *et al*. [3], Dempsey *et al*. [4], Emanuel and Ranney [5]). Following that, more advanced numerical packages were introduced (Schiozer [6], Trick [7], Byer [8], Barroux [9], Ghorayeb *et al*. [10], Zapata *et al*. [11]). Recently, Cao *et al.* [12] and Bigdeli *et al.* [13] reviewed methodologies of coupling surface and sub-surface simulators. And the works of Seth *et al*. [14], Boogaart [15], Zhou *et al*. [16], Zaydullin *et al*. [17], are examples of more complex and up to dated studies. Brill and Mukherjee [18] noted two important assumptions as follows: In the absence of the flow line, the pressure of the separator can be equal to the wellhead pressure. The separator or wellhead pressures are normally known and can be used as input values for determining the unknown pressures. These two assumptions are particularly important. For example, there is an option in the commercial simulator of the tubing performance table that is fundamentally working under these two assumptions. We used them throughout the course of this report. And the surface facilities' information is generated based on these assumptions.

This paper shows for the first time a new framework that enables our in-house simulator, UTCOMPRS [19], to be compared with commercial simulators by adding a new algorithm. We also present a new feature for injection well control. Different interpolation functions' parameters were investigated, and it was revealed that the wellhead pressure is the best one. Finally, we show the results of two case studies for the newly developed framework.

2 Newly Developed Framework

In this section, some newly developed features for our in-house simulator are presented. During modeling integrated PPS, the well section and pressure drop across the tubing can be treated differently by simulators. In general, there are three approaches as reported by Holmes *et al*. [20]. 1) A homogenous flow model that assumes the same velocities for oil, gas, and water phases, 2) The drift flux models which allow different phases (oil, gas, water) to have different velocities, and 3) a pre-calculated pressure drop table.

The main assumption of this work is based on the third approach. In this way, the pressure drop alongside the tubing is calculated as a function of flow rate, water-oil ratio (WOR), gas-liquid ratio (GLR), or any other desired operational parameters such as a bottom hole (BHP) or wellhead pressures (WHP). The advantage of this approach is the decrease of the computational cost for the well section. Considering the complexity of the numerical modeling of the grid blocks from the reservoir section, the using pre-calculated pressure drop tables is a very efficient tool. Simulators, such as Co-Flow [21], Builder [22], VFP designer^{TM} [23] are examples of commercials simulator which use this technique.

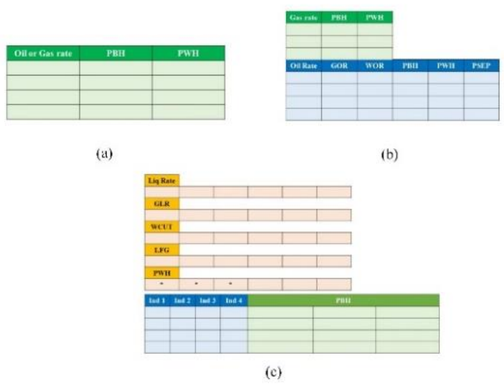

Figure 1. Conceptual schematic of different flow tables that have been developed for UTCOMPRS: a) simplified flow tables, b) advanced flow table, and c) commercial flow tables

To increase the capability and flexibility of our in-house simulator, previously, we reported a framework in which a pre-calculated table can be fed to UTCOMPRS (Bigdeli *et al.* [13]). We developed some numerical packages for reading and comparing the values of the flow table and reported the corresponding results for this option. Two sets of tables named simplified (SFT) and advanced (AFT) flow tables were reported. The SFTs are tables in which only the information of WHP, BHP, and single flow rate of oil or gas are included. They were quite simple tables that were used to investigate the concept of the pre-calculated pressure drop table for UTCOMPRS. Later, we included the AFTs, in which more advanced information, such as WOR, GOR, BHP, WHP, and pressure of separator (PSEP) are included. Both tables were run and tested successfully for UTCOMPRS. However, since those tables were in-house designed tables, they cannot be validated by any other commercial simulators. Hence, to solve this problem, we are presenting the third class of flow tables. Since they are designed in a way that enables our simulator to be compared with commercial simulators, the third generation of tables is named commercial flow tables (CFT). Figures 1 (a-c) show a conceptual schematic of SFT, AFT, and CFT respectively.

The CFTs consist of two sections. In the upper section, there are a series of ranges of flow conditions information including liquid rate, gas-liquid ratio, water cut, lift gas injection rate (LFG), and WHP (the yellow section). Then based on the value of the flow inside the tubing, these four values (Liq, GLR, WCUT, LFG) are converted into sets of four indices (the blue section) and, based on the fixed values of WHP, a series of BHP values are set in the bottom right side of the table (the green section). The type of information that exists in each type of table will change the corresponding algorithm of the simulation. For the CFTs, we will do as follows. Firstly, the CFT and three types of information are passed as input files into the simulator: 1) initial bottom hole pressure, 2) the fixed value of WHP, and 3) initial value LFG. Once these values are received by the simulator, a reading function is called to obtain the information from the CFT. Then, the initial bottom hole value is passed to the simulator, and oil, water, and gas rates are calculated. Next, based on these rates, the values of liquid rate, GLR, WCUT, and LFG are computed, and this information is used by a comparing function. This function will convert this information, based on the upper side of the table, into four indices (see the yellow part of Fig. 1c) and locate the corresponding row inside the CFT (see the blue part of Fig. 1c). Based on the values of WHP and the range of them in the table, the corresponding columns of bottom holes are located (see the green part of Fig. 1c). A series of bottom hole values (two sets for lower indices, and two sets for high indices) are located. At last, these values are interpolated, and one final BHP is the output of this function. This bottom hole pressure will be checked against the initial guessed bottom hole pressure, and if their difference is less than 103.421 KPa (or 15 psi), according to Emanuel and Ranney [5], the simulation goes to the next time step. If the tolerance is not achieved, the last BHP is used for the next iteration, and all the parameters are calculated again. This process continues until the end of the simulation.

Figure 2 shows an example of CFT to clarify how the values of bottom hole pressures are selected.

```
LIQ
 500.0 2500.0 7500.0
GLR
 500.0 890.0
WCUT
 0.12 0.39 0.47
LFG
 0.0 500.0
WHP
 500.0 4500.0 7320.0
BHP
**iflo  igfr  iwfr  iadd    bhp(1st whp).............bhp(nth whp)
   1     1     1     1      620.1425       4614.5997      7445.50651
   1     1     1     2      620.143789     4614.55643     7445.46524
   1     1     2     1      632.716541     4619.91253     7451.99695
   .     .     .     .
   .     .     .     .
   .     .     .     .
   2     2     2     2      652.970116     4532.33072     7363.72065
   2     2     3     1      652.973856     4532.46361     7366.84968
```

Figure 2. An example of a commercial flow table

Suppose the values of Liq, GLR, WCUT, LFG, and WHP are 1000 m^3/day, 600 m^3/m^3, 0.2, 450 m^3/day, and 550 KPa, respectively. By comparing the upper section of the table, the current values will stand between the indices 1 and 2 for each set of parameters. As a result, the corresponding code for fluid flow inside the tubing will be 1111 and 2222. Now based on the values of PWH, which is 550 KPa, columns number 1 and 2 are located. For the lower indices (1111) we have two bottom hole pressure values: 620.1425 and 4614.5997 KPa. And for the higher indices (2222) we got 652.970116 and 4532.33072 KPa. Now the question is how to interpolate these four values and report the final bottom hole pressure from the above table.

Before we explain how the interpolation functions are working, it is important to have a feature that can control the injection rate for the injector well. This feature will allow us to control the use of CFT more efficiently and increase the accuracy of comparison of our tables with other commercial simulators. One of the advantages of using CFTs is the fluid rates are reported in terms of the volumetric format. Thus, from the surface facilities engineering point of view, this technique can be used for any required surface facility capacities. However, during the simulation run time, sometimes it is necessary to control the injection rate into the reservoir which its producing well is using the CFTs. Hence, a new feature was designed for our simulator that enables the user to control the production. The new feature is designed in a way that puts a restriction on the injection rate, and it is collaborating with the producing well which is operating with the flow table option. In this work, we show the injector pressure limit, in which once the pressure of the injector reaches the specific limit, the injector well's constraint will switch from constant rate injection into constant bottom hole pressure.

3 The different interpolation functions

As was discussed earlier, different values of bottom hole pressure are obtained from the table. One can select different formulations, such as linear, bilinear, or quadratic interpolation functions. However, based on the notations of Stackel and Brown [24], and Emmanual and Rammny [5], we decided to use a linear interpolation function. Eq. (1) demonstrate the relationship between a dependent (Y) and independent (X) variables for two given values (up and down) and a linear interpolated point between them.

$$\frac{Y_m - Y_d}{X_m - X_d} = \frac{Y_u - Y_d}{X_u - X_d} \tag{1}$$

The objective here is to find the middle value, Y_m, that exists between up and down values. Inserting Eq. (1) into Eq. (2) will give the general form of the equation used to interpolate different parameters.

$$Y_m = Y_d + \left[\left(\frac{Y_u - Y_d}{X_u - X_d} \right) \times \left(X_m - X_d \right) \right] \tag{2}$$

For our purpose, which is to evaluate the bottom hole pressure, we consider the dependent variable Y as the bottom hole pressure and set different parameters for independent values X. This is done because the CFT is a multidimensional table, which means that one can choose any parameter to be the reference from which to interpolate from.

4 Results and Discussion

In this section, we show the results of two case studies in which the wellhead pressure was set at different levels. In all cases, one CFT was generated for each test. Cases1 and 2 showed an actable range of accuracy for the newly developed framework. It is also worth mentioning that the reservoir models used here were previously compared with GEM from CMG which is a commercial simulator for the producer, operating under a constant bottom hole pressure option in the studies reported by Farias *et al.* [25]. The reservoir used for all case studies refers to a quarter of five-spot configuration and it was discretized using a 2D areal grid. Among the four parameters (WCUT, LGR, Liq rate, and WHP), implemented in Eq (2), the WHP was the one that produced the best results.

4.1 Case 1

Here, the result of the first case study is presented. To decrease the uncertainties, it was assumed a homogeneous and isotropic reservoir. Detailed information of the reservoir, well and fluid properties for the case 1 & 2 can be found in Tab 1, 2 and 3.

Table 1. Reservoir properties of the validation case

Reservoir Parameters	Value	Reservoir Parameters	Value
Number of grid blocks	8 x 8 x 1	Permeability in Z Direction	4.93×10^{-15} m2
Grid Block Size in the X- and Y-directions	60.09 m	Formation Compressibility	4×10^{-6}
Grid Block Size in the Z direction	243 m	Initial reservoir Pressure	31026.41kPa
Porosity	0.35	Reservoir Temperature	76.66 °C
Permeability in X- and Y- directions	9.87×10^{-15} m2	Simulation Run Time	10000 days

Table 2. Wellbore properties and operational conditions

Wellbore Parameters	Value	Wellbore Parameters	Value
Tubing Diameter	0.134112 m	Initial reservoir pressure	10342.14 KPa
Bottom Hole Temperature	76.66 °C	Injection type	Gas Injection
Wellhead temperature	26.6 °C	Injector limit (activated)	11721.09 KPa
Tubing length	762 m	WHP (Case 1 & 2)	8273.709, 4136.85 kPa

Table 3. Initial and injection fluid components of the validation case

Reservoir components	C1	C3	C6	C10	C15	C20
Initial Concentration	0.50	0.03	0.07	0.20	0.15	0.05
Injection concentration	0.7	0.2	0.05	0.04	0.005	0.005

The injection pressure limit, and wellhead pressure for the producer, were set at 11,721.09 KPa (1.700 psi) and 8273.70 KPa (1200 psi), respectively. The coupling point was set at the bottom hole, and the injection fluid is gas. The required commercial flow table was generated and used to both simulators. Also, simulation run time was set at 10,000 days. Figures 3(a-h) show the results of these studies. The curves are oil, gas, water rates, GOR, WOR, the pressure of injector, WHP, and BHP. Although the bottom hole pressure was set free to receive different bottom hole values from the table, during the simulation, both simulators (UTCOMPRS and GEM) operated under a constant bottom hole pressure. This is because the fluid variation inside the tubing was not intensive for this case.

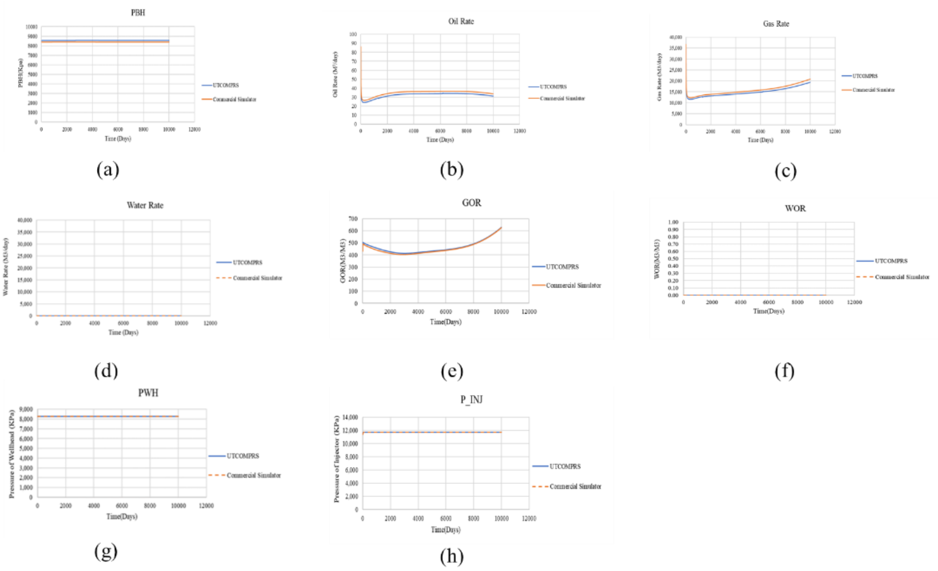

Figure 3a-h. Results of case 1: a) BHP, b) oil rate, c) gas rate, d) water rate, e) gas-oil ratio, f) water-oil ratio, g) WHP and h) pressure of the injector

Some interesting findings can be observed in Fig. 3. First of all, the selection of pressure of wellhead from the lower index as the interpolation function seems a good choice (see Fig 3-a). Second, all curves show a very good agreement between UTCOMPRS and the commercial simulator. The limit pressure of the injector well was reached almost at the very beginning of the simulation (1.33 days) and the switching option from constant injection rate into constant bottom hole pressure was activated successfully (see Fig 3-h).

4.2 Case 2

The second case is the same 2D reservoir, with the same injection and initial fluid composition, the same injection pressure limit, but the difference is the value of the wellhead pressure. It was decreased to half of the one in case 1, which is 4136.85 KPa (600 psi). Figures 4 (a-h) show the results for this case.

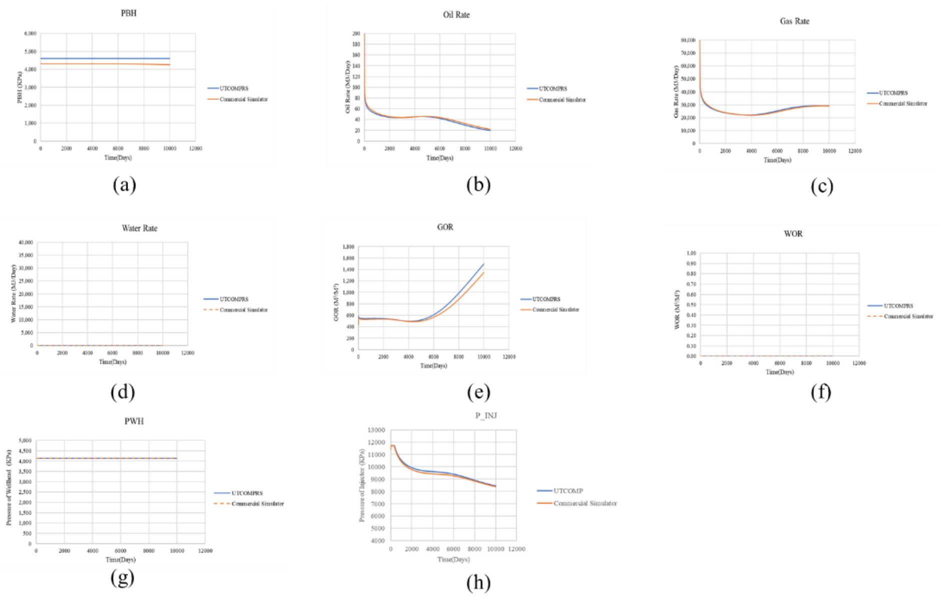

Figure 4 (a-h). Results of case 2: a) BHP, b) oil rate, c) gas rate, d) water rate, e) gas-oil ratio, f) water-oil ratio, g) pressure of wellhead, h) pressure of the injector

Compared to case 1, this case shows more information about the newly developed framework. As can be seen from Figs. 4 b and c, the change of surface facilities condition (pressure of the wellhead), changed the profile of the production remarkably. This shows the importance of the coupling of surface facilities equipment with conventional reservoir simulation. Also, this finding is in association with our previous findings regarding the importance of surface facilities that were working with SFT and AFT. The second additional information of the second case study is the pressure of the injector. As can be seen from Fig. 4h, the limit of injector pressure is activated on the first day of the simulation. However, after almost 300 days of simulation, the pressure of injectors decreases below the threshold, so the activation switch is turned off, and the injectors go back to the constraint of constant injection rate. Since the simulators are injecting gas with different pressure values (see Fig. 4h), the values of the GOR is changing after almost 4000 days (see Fig 4e). This is the time that the change of GOR is sensed by the producing well. Also, it is worth mentioning that the difference between the values of bottom hole pressure for this case was bigger compared to case 2 (see Fig. 4a). The difference of bottom hole pressures of the simulators was 163.4 KPa (23.7 psi) and 293.7 KPa (42.6 psi) for cases 1 and 2, respectively. The pressure of wellhead set at the fixed values for both case studies (see Fig. 3g and 4g). Finally compared to case 1, the change of GOR was sharper for the second case studies (see Figs 4e and 3e).

5 Conclusions

The main three objectives of this work were accomplished: 1) to introduce a newly developed framework for commercial flow tables, 2) to introduce a new feature for injector well control option and 3) the investigation of different interpolation parameters, such as GLR, WOR, Liq, and WHP for the validation of the newly developed framework with a commercial simulator. Also, two case studies were presented and their results were compared to the commercial simulator. The key findings of this work are summarized as follows: A new option for CFT was included in the input files of UTCOMPRS. Both reading and comparing algorithms for CFT were implemented successfully. Different interpolation parameters were checked and the pressure of wellhead from the lower index seems a better candidate. A new feature was added to the simulator to control the pressure limit of the injector well. The different values between bottom hole pressures of UTCMOPRS and commercial simulator could be caused by the 1) method of searching in the tables, 2) method of converting flow conditions into indexes, or 3) convergence criteria for the simulators. Currently, CFT enables the simulator to compute liquid rate, GLR, WCUT, LFG, and based on them to report BHP as a function of WHP.

The general outcome of this study shows the comparability of the new framework that was designed for our in-house simulator UTCOMPRS with the one from a commercial simulator.

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