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The Effect of Dynamic Data Adjustments in Production System Simulation Models on Oil Production Forecasting Applied To Reservoir Simulation Models

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Abstract
Simulation models of integrated reservoir and production systems are required for a robust production forecast. Traditionally, reservoir and production system models are calibrated against dynamic data to establish future boundary conditions. Herein, we propose probabilistic data assimilation for production system models to improve the quality of production forecasts. We used a benchmark case through a reference model, which represents the real field, and a simulation model for (1) sensitivity analysis of production system parameters; (2) adjustment of production system parameters, based on dynamic production history data, to minimize the gap between data and model using an optimization method; and (3) comparison of production forecast in the simulation model, coupled to history-matched and non-matched production systems, and a reference model. Sensitivity analysis of production system parameters indicated a significant impact of the pressure gradient adjustment parameter. But we verified that there were no unique correlations (multiphase flow and fluid) and absolute roughness in the production tubing that fit overall production history, affecting production forecast. Comparing production curves of simulations, coupled with history-matched and non-matched production system models to the reference model, we show that adequately adjusted models are closer to the real model. It is mainly the case for systems with higher capacity, where production is more dependent on the responses of the production system. The probabilistic calibration approach of production systems before integrating reservoir models to adjust production systems simulation models is simple to perform. It can improve the quality of the forecast of the field.

Keywords: Production System, Reservoir, Adjustment, History Data, Probabilistic

Introduction
Current studies related to oil production, especially in offshore fields, require the integration of reservoir and production systems to properly evaluate the interaction between reservoir, well system (production tubing), and subsea production systems, such as gathering system (flowlines and risers), and surface installations.
Reservoir simulation models integrated with production systems have been frequently used to develop oil fields [1-4].
Several recent methodologies seek to improve coupling between reservoir and production system models to accurately and reliably simulate integrated solutions representing fluid flow through the reservoir to the surface [5].
Production system modeling that reproduces the boundary conditions measured in the actual system deployed in the field is important for more reliable forecasts, considering integrated reservoir systems. However, offshore reservoir production systems can be complex, and the lack of relevant data can generate models inheriting large forecast errors. Additionally, uncertainties in reservoir simulation models and production systems in the early stages of new project implementation can affect decision-making throughout the development of a petroleum field.
For a long time, researchers used dynamic production data to adjust simulation models by reservoir discipline. Historical adjustment involves using observed data to improve the estimation of reservoir properties (attributes) to improve the quality of reservoir simulation models [6]. The goal of the process is to improve the predictability of reservoir models. Reliable and accurate production system responses related to the system head loss regarding the selected multiphase flow correlations, and their influence in reservoir production prediction and optimization, are important [7].
Adjusting reservoir and production system simulation models to improve the prediction of field behavior in future exploration phases is important [8]. To do so,

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they use models of integrated reservoirs and production systems. Production history should be used to adjust reservoir model parameters and production data to adjust the production system model, such as flow correlations, roughness, and, in some cases, a pressure gradient adjustment factor and/or a localized pressure drop applied in the system. They reached this agreement by varying the friction factor inside the tubing. The friction factor had been re-evaluated during the historical period to validate the pressure drop calculation in the wellbore. This practice is widespread in the petroleum industry.

History matching can be a non-linear problem characterized by many local minima. Therefore, premature convergence of any optimization method is an undesirable characteristic in the context of history matching due to the non-uniqueness nature of the problem [7].

The adjustment of the production system simulation model can be initially made by choosing the most appropriate multiphase flow and fluid correlations. In addition, we can adjust the intrinsic physical parameters of the wellbore and the gathering system, following a deterministic approach, in which the simulated results are compared with dynamic data obtained from the production history. But there is the risk of reaching the local minimum against the absolute one and obtaining an incomplete production forecast solution. In this study, we aim to demonstrate that by adjusting the parameters of the production system simulation models as a probabilistic approach. Thus we can improve the quality of the reservoir models simulation results and, consequently, the reliability in the forecast of field production.

Objectives

We aim to develop a methodology for the parameter calibration of the production system model as a probabilistic approach, which is integrated with the reservoir model, and verify the influence of calibration on the forecast and reliability of oilfield production.

Methodology

The purpose of the general methodology, described here, is to evaluate production system parameters, systematize the calibration process of simulation models as a probabilistic approach, and verify the influence of the calibration in production forecast, according to the following steps

Step 1 - Methodology for Sensitivity Analysis of Production System Parameters

1. Select the parameters that will be used in the sensitivity analysis of the production system simulation model. Define the ranges of variation.
2. Generate a production system simulation model for each well by varying the following parameters: fluid correlations, flow correlations, absolute roughness, and pressure gradient adjustment factor (DP/DL).
3. Couple each of these production system simulation models with the reservoir simulation model.
4. Run numerical simulations of the reservoir simulation model for each production system model.
5. Obtain production curves (bottom-hole pressure - BHP, liquid, oil, water flow rates).
6. Select model calibration indicator (objective functions – NQDS), and determine the tolerance range of the functions to be adjusted for NQDS calculation.
7. Define the base case as a comparison parameter.
8. Evaluate the results of the sensitivity analysis with the simulated data by indicators.

Step 2 - Methodology for calibration of production system parameters with dynamic production history data

1. Generate production history (for this study via real case numerical simulation).
2. Obtain production history (Wellhead pressure - WHP, BHP, oil, water, and gas well flow rates, gas lift flow rates).
3. Choose a simulation model for the production system.
4. Select the parameters that will be used in the calibration of the production system simulation model.
5. Select the model calibration indicator (objective functions - NQDS).
6. Select the minimization method to be used for model calibration.
7. Run numerical simulations of each production system model and calculate the value of the objective function.
8. Evaluate the results of the objective function through graphics and indicators.
9. Generate new production system simulation models with the parameter combination defined by the method.
10. Select the production system model (s) calibrated with the historical data.
11. Integrate the calibrated production system model with the reservoir simulation model

Step 3 - Simulation of reservoirs with the coupling of calibrated and uncalibrated production system models and comparison to the reference case (real).

1. Compare simulated results with previous ones generated with the uncalibrated production system model.
2. Compare both tuned and non-tuned (real) case simulations while varying platform capacity.
3. Evaluate NQDS from the field and simulated data from the well.

Application

Reservoir Models

The proposed methodology in this work utilizes the UNISIM-I-MI benchmark, which is derived from a case study for optimization of management variables of an oil production strategy project [9]. UNISIM-I-MI, derived from UNISIM-I-M, is a field management case in which the production system simulation model is integrated with the reservoir simulation model. This is a synthetic reservoir that simulates an actual Brazilian reservoir in Namorado Filed. It is a black-oil model represented by 36,207 active cells with a production strategy of roughly 23 years and 25 wells, of which 10 are horizontal producers, 4 are vertical producers, and 11 are horizontal injectors. The Namorado Field synthetic reservoir has a total of 2,618 days of production history data. The reservoir model was selected previously by NQDS evaluation and honors history data.

For comparison between the studied scenarios, we used the UNISIM-I-R model, which is a reference case of high geological resolution. UNISIM-I-R is a synthetic model for applications in the development and management phases. It is considered a real case of the benchmark because all dynamic and static data are generated and used to build the simulation models [10].

The boundary conditions applied to the UNISIM-I-MI reservoir simulation model are: Surface installations (Qoil max = 15,500 m^3/day, Qw max = 13,950 m^3/day, Qliq max = 15,500 m^3/day, Qw inj max = 21,700 m^3/day); Producer wells (Qliq max = 2,000 m^3/day, WHP min = 15 kgf/cm², Wcut = 95%, Gas injection rate for gas lift method [11] = 100,000 m^3/day); Injector wells (Qw max = 5,000 m^3/day, BHP max = 350 kgf/cm²).

Production history

We generated a production history of the UNISIM-I-R model with a mixed correlation of pressure drop equations for the production system model wells to generate a history, which would be difficult to model.

Tables A.1 through A.14, available in the appendices, show the parameters provided by the production history of Wells INA1A, INA2, INA3D, IRJS19, PROD005, PROD008, PROD009, PROD010, PROD012, PROD014, PROD021, PROD023A, PROD024A, and PROD025A. These parameters will apply the boundary conditions to calibrate the production system simulation model. The saturation pressure of the fluid is 212 kgf/cm². Observing the BHP values of the production history, some sample points are below the saturation pressure.

Production System model

Fig. 1 shows a schematic of the PROD005 well and data gathering system for the simulation model (producer well number 05 - UNISIM-I-MI database) [12]. Table 1 presents the lengths and input data used in this model. Table 2 shows the variations in submarine layout and target depth for field wells. We created a well and gathering system simulation model for each of the producing wells to adjust with dynamic production history data (Wells INA1A, INA2, INA3D, IRJS19, PROD005, PROD008, PROD009, PROD010, PROD012, PROD014, PROD021, PROD023A, PROD024A, and PROD025A).

The parameters selected to adjust the well and gathering system simulation model were: fluid correlations, multiphase flow correlations, absolute roughness, and the pressure gradient adjustment factor (DP/DL), explained here as the pressure variation divided by length unit.

For the reservoir fluid in the well and gathering system simulator to be representative, the parameters: solubility ratio, formation volume factor, dead oil viscosity, and living oil viscosity are characterized by fluid correlations. Table 3 shows the fluid correlations used in the adjustment [13-20].

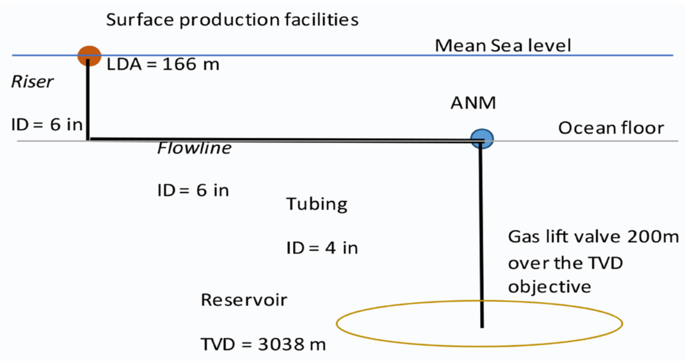

Fig. 1 Schematic of the well and gathering system considered (Adapted from [12]).

Table 1 Production system parameters.

Parameter	Value
Water depth (m)	166
Riser inner diameter (in)	6
Flowline inner diameter (in)	6
Tubing inner diameter (in)	4
Service inner diameter (in)	4
Riser length (m)	166
Surface temperature (C)	20
Riser base temperature (C)	30
WXT temperature (C)	50
Reservoir temperature (C)	80
Reservoir water density	1.01
Injection gas density	0.747
Reservoir gas density	0.747
Oil density (API)	32

Table 2 Variations in subsea layout of production system wells.

Well	TVD gas lift valve - TVD (m)	Flowline length (m)	Reservoir depth - TVD (m)	Tubing length (m)
INA1A	2,796	1,051	2,996	2,830
INA2	2,849	2,585	3,049	2,883
INA3D	2,859	1,391	3,059	2,893
IRJS19	2,803	1,520	3,003	2,837
PROD005	2,838	1,540	3,038	2,873
PROD008	2,861	2,714	3,061	2,895
PROD009	2,876	3,343	3,076	2,910
PROD010	2,871	1,316	3,071	2,905
PROD012	2,786	5,22	2,986	2,820
PROD014	2,807	1,013	3,007	2,841
PROD021	2,863	2,332	3,063	2,897
PRO-D023A	2,973	1,946	3,173	3,007
PRO-D024A	2,921	1,672	3,121	2,955
PRO-D025A	2,898	1,172	3,098	2,932

Table 3 Fluid correlations used in adjustment.

Solubility ratio (RS)	formation volume factor (Bo)	Dead oil viscosity	Living oil viscosity ($P\leq P_{SAT}$)	Living oil viscosity ($P>P_{SAT}$)
Standing	Standing	Beggs and Robinson	Beggs and Robinson	Vazquez and Beggs
Vazquez and Beggs	Vazquez and Beggs	Glaso	Kartoatmodjo & Schmidt	
Glaso	Glaso	ASTM Method	Petrosky and Farshad	
Lasater				

Multiphase flow correlations are used in the well and gathering system simulator to calculate pressure drop along the current line from the bottom of the well to the production platform. Table 4 shows the different correlations available for each segment that makes up the production system [21-39].

Table 4 Multiphase flow correlations used in production system tuning.

Riser and tubing (vertical flow)	Flowline (horizontal flow)
Aziz, Govier and Fogarasi	Aziz, Govier and Fogarasi
Baxendell and Thomas	Baxendell and Thomas
Beggs and Brill	Beggs and Brill
Beggs, Brill and Palmer	Beggs, Brill and Palmer
Duns and Ros	Dukler
Fancher and Brown	Dukler, Eaton and Flanigan
Gray	Dukler and Minami I
Hagedorn and Brown	Dukler and Minami II
Mukherjee and Brill	Duns and Ros
Orkiszewski	Fancher and Brown
Poettmann and Carpenter	Gray
	Hagedorn and Brown
	Mukherjee and Brill
	Oliemans
	Orkiszewski
	Poettmann and Carpenter

Roughness is an intrinsic physical characteristic of the constituent material of the production system risers, flowlines, and production columns. The values adopted for the variation of the absolute roughness parameter in each of the production system segments are: 0.001, 0.010, 0.017, 0.046, 0.050, 0.100, 0.183 and 0.200.

In addition, a pressure gradient adjustment factor (DP/DL) can be applied to each segment of the well and gathering system simulation model. In general, it is necessary to use the adjustment factor when selecting the multiphase flow correlation that best fits the model since it is not sufficient to fit the simulation results with the field data. The values adopted for the pressure gradient adjustment factor ranged from 0.90 to 1.10 at 0.01 intervals, as normal fine-tuning. We included values of 1.15 and 1.20 to allow hard adjust the well and gathering system model.

Adjustment Indicators

The definitions of fit quality indicators for production data follow the pattern are presented [6]. Equation 1 presents the simple linear deviation.

$$LD = \sum_{1}^{n} (BHP_{sim} - BHP_{hist}) \tag{1}$$

Equation 2 presents the calculation of the quadratic deviation.

$$QD = \sum_{1}^{n} (BHP_{sim} - BHP_{hist})^2 \tag{2}$$

Equation 3 presents the calculation of the acceptable quadratic deviation.

$$AQD = \sum_{1}^{n} (Tol.BHP_{hist} + C)^2 \tag{3}$$

Equation 4 presents the calculation of the normalized quadratic deviation with the signal.

$$NQDS = \frac{LD}{|LD|}\frac{QD}{AQD} \tag{4}$$

Table 5 shows adjustment quality indicators according to NQDS ranges.

Table 5 Quality of models depending on the range of NQDS value.

Quality indicator	NQDS Ranges
excellent	$-1\leq NQDS\leq 1$
very good	$-2\leq NQDS<-1$ e $1<NQDS\leq 2$
good	$-5\leq NQDS<-2$ e $2<NQDS\leq 5$
regular	$-10\leq NQDS<-5$ e $5<NQDS\leq 10$
bad	$NQDS<-10$ e $10<NQDS\leq 20\geq -20$
unsatisfactory	$NQDS<-20$ e $NQDS>20$

The NQDS equation was applied to measure the quality of the adjustment in the production system of the wells for the production history used: tolerance = 5% and C = 0. For the quality indicator calculation of the oil production forecast and UNISIM-R model curves of both field and representative producer well, the NQDS equation used: tolerance = 10% and C = 0.

Selected Minimization Method

Step 2 contains applying the Iterative Discrete Latin Hypercube (IDLHC) method [40] to minimize the misfit between historical and simulated values. This method is capable of selecting good candidate solutions as a probabilistic approach and find the best deterministic candidate.

The IDLHC method was defined with the following settings: the number of samples = 30; iterations = 8; percentage cut = 80%; Minimum ratio between the maximum number of valid levels and number of samples[2] = 4.

Equation 5 presents the global objective function MQD used for minimization, which calculates the mean quadratic deviation.

Equation 5 presents the global objective function MQD used for minimization, which calculates the mean quadratic deviation.

$$MQD = \frac{1}{n}\sum_{1}^{n} (BHP_{sim} - BHP_{hist})^2 \quad (5)$$

Simulators Used

The simulators used in the case studies were CMG IMEX™ 2016 for reservoir simulations and Petrobras' Marlim II for simulations of permanent multiphase flow in well and gathering systems. The explicit coupling form was adopted among the simulators [41].

Scenario Definition

For each of the 14 wells in the field, a well and gathering system simulation model was created using the Marlim II simulator. For each of these models, a series of simulations were performed with varying parameters: fluid correlations, flow correlations, absolute roughness and pressure gradient adjustment factor (DP/DL). For this, the reference model (UNISIM-I-R) and management model (UNISIM-I-MI) were used and coupled with calibrated and non-calibrated production system simulation models. We considered restrictive (original processing capacity of fluids at surface facilities) and less restrictive (processing capacity of fluids at surface facilities increased by 100%) reservoir simulation scenarios, as described below.

Scenario description

- R - Reference case (UNISIM-I-R)
- R (2X) - Reference case with 100% increased fluid processing capacity at surface facilities
- M2 - Field Management model with unadjusted production system simulation model (UNISIM-I-MI)
- M2 (2X) - Field Management model with unadjusted production system simulation model (UNISIM-I-MI) with 100% increased fluid processing capacity at surface facilities
- M4 - Field Management model with adjusted production system simulation model (UNISIM-I-MI)
- M4 (2X) - Field Management model with adjusted production system simulation model (UNISIM-I-MI) with 100% increased fluid processing capacity at surface facilities

To perform step 1, the production system simulation models were coupled to the reservoir simulation model in the UNISIM-I-MI model. The parameters were varied within the proposed values and new curves were generated and compared with the new curves in the base case (multiphase flow correlations = Beggs and Brill, pressure gradient = 1, Relative roughness = 0.001, RS = Vazquez and Beggs, Bo = Vazquez and Beggs, Dead Oil Viscosity = Glaso, Live Oil Viscosity (P≤PSAT) = Beggs and Robinson, Live Oil Viscosity (P> PSAT) = Vazquez and Beggs).

1. The parameter minimum ratio between maximum number of valid levels and the number of samples was added to the IDLHC method to accelerate the method's convergence, keeping the proportion of combinations by attributes fixed.

To perform step 2, the objective function MQD, defined in equation 5, was minimized through the IDLHC method. Then, calibrated well and gathering system simulation models were created for each well.

To perform step 3, the well and gathering system simulation models were coupled to the reservoir simulation model in the UNISIM-I-MI model, and new production curves were generated. The new production curves were compared with the production curves of the UNISIM-I-R reference model.

Results

Step 1 - Sensitivity Analysis

Figs. 2 to 5 show reservoir simulation results (oil, liquid, and water production, and water injection in the field, respectively) for sensitivity analysis of the most representative well and gathering system parameter, in this case, the pressure gradient adjustment factor. Other factors resulted in inexpressive differences.

Fig. 6 shows the oil production curve for a representative producer well (INA3D), and Fig. 7 shows the water injection curve for a representative injector well (INJ017), for sensitivity analysis of the most representative well and gathering system parameter, in this case, the pressure gradient adjustment factor.

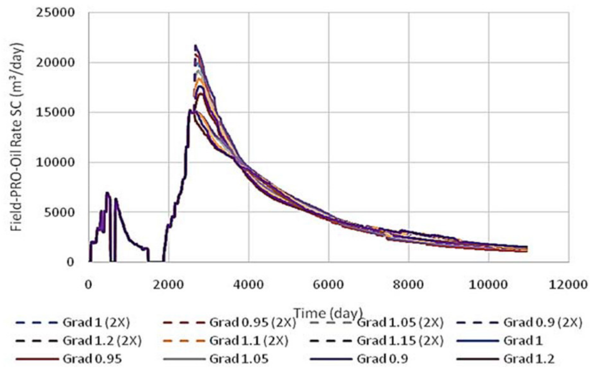

Fig. 2 Sensitivity analysis of field oil production for pressure gradient variable. (2X) 100% increased fluid processing capacity on the surface facilities.

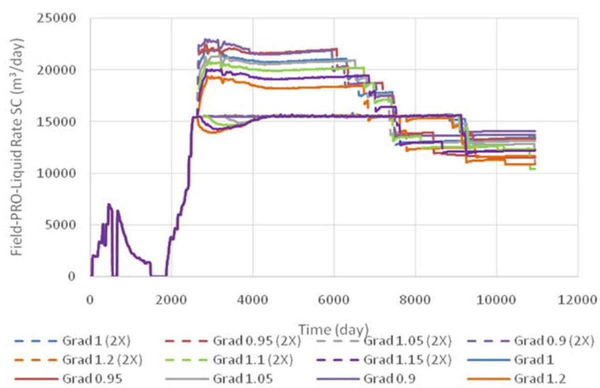

Fig. 3 Sensitivity analysis of field liquid production for pressure gradient variable. (2X) 100% increased fluid processing capacity on the surface facilities.

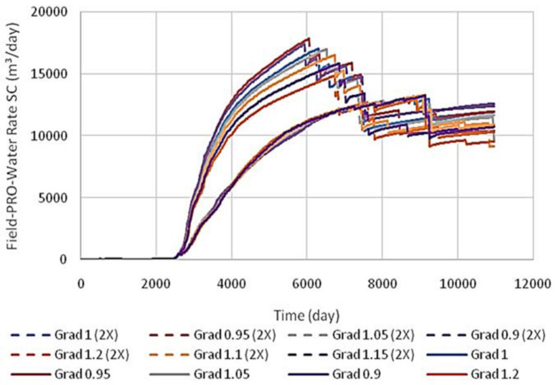

Fig. 4 Sensitivity analysis of field water production for pressure gradient variable. (2X) 100% increased fluid processing capacity on the surface facilities.

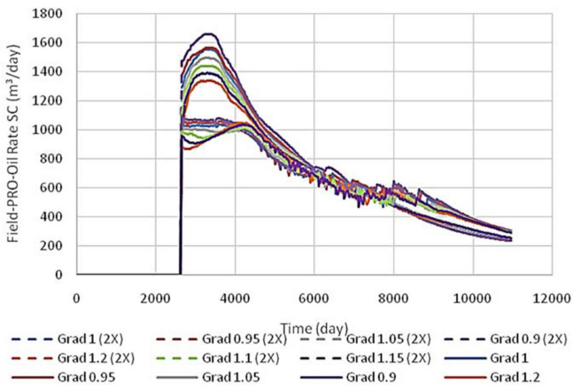

Fig. 6 Oil production sensitivity analysis for pressure gradient variable - well INA3D. (2X) 100% increased fluid processing capacity on the surface facilities.

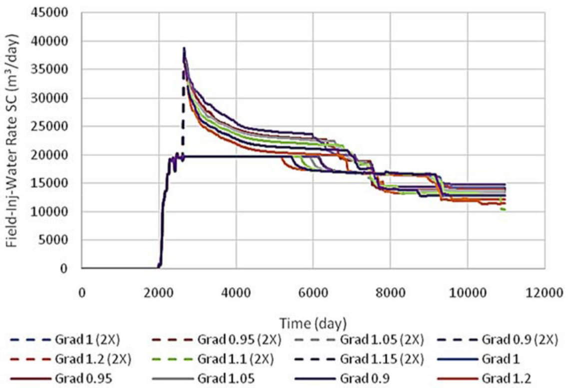

Fig. 5 Sensitivity analysis of field water injection for pressure gradient variable. (2X) 100% increased fluid processing capacity on the surface facilities.

Step 2 - Model Adjustment

Tables 6 to 10 show the results obtained for the different simulated wells using the IDLHC method to minimize the difference between the simulation results and the dynamic production history data, applying the proposed methodology for the calibration of the well and gathering system simulation models. Table 6 shows the multiphase flow correlation results per well and segment. Table 7 shows the absolute roughness results per well and segment. Table 8 shows the pressure gradient results per well and segment. Table 9 shows the results of fluid correlations per well.

Table 6 Results of multiphase flow correlations for the adjusted model.

Well	Riser Correlation	Flowline Correlation	Column Correlation
INA1A	Poettmann and Carpenter	Hagedorn and Brown	Beggs and Brill and Palmer
INA2	Aziz and Govier and Fogarasi	Dukler and Minami Ii	Beggs and Brill
INA3D	Orkiszewski	Beggs and Brill	Beggs and Brill and Palmer
IRJS19	Orkiszewski	Baxendell and Thomas	Beggs and Brill and Palmer
PROD005	Beggs and Brill	Hagedorn and Brown	Mukherjee and Brill
PROD008	Aziz and Govier and Fogarasi	Dukler and Minami I	Beggs and Brill and Palmer
PROD009	Aziz and Govier and Fogarasi	Oliemans	Beggs and Brill and Palmer
PROD010	Beggs and Brill	Hagedorn and Brown	Beggs and Brill
PROD012	Duns and Ros	Duns and Ros	Beggs and Brill and Palmer
PROD014	Beggs and Brill and Palmer	Hagedorn and Brown	Beggs and Brill and Palmer
PROD021	Poettmann and Carpenter	Dukler	Mukherjee and Brill
PROD023A	Fancher and Brown	Oliemans	Mukherjee and Brill
PROD024A	Beggs and Brill and Palmer	Dukler and Eaton and Flanigan	Mukherjee and Brill
PROD025A	Aziz and Govier and Fogarasi	Oliemans	Beggs and Brill and Palmer

Table 7 Absolute roughness results for the adjusted model.

Well	Riser	Flowline	Column
INA1A	0.100	0.200	0.183
INA2	0.010	0.010	0.183
INA3D	0.017	0.046	0.200
IRJS19	0.183	0.046	0.200
PROD005	0.017	0.100	0.200
PROD008	0.010	0.050	0.010
PROD009	0.010	0.010	0.200
PROD010	0.017	0.001	0.046
PROD012	0.001	0.046	0.001
PROD014	0.017	0.200	0.200
PROD021	0.010	0.046	0.183
PROD023A	0.183	0.200	0.017
PROD024A	0.100	0.200	0.200
PROD025A	0.010	0.010	0.200

Table 8 Pressure gradient adjustment factor (DP/DL) results for the adjusted model.

Well	Riser	Flowline	Column
INA1A	0.99	1.08	1.02
INA2	0.94	0.95	0.93
INA3D	1.20	1.04	0.99
IRJS19	1.05	0.93	0.98
PROD005	0.94	1.01	1.02
PROD008	1.15	1.01	1.02
PROD009	1.10	1.01	0.96
PROD010	1.20	1.00	1.06
PROD012	0.98	1.01	1.15
PROD014	1.10	1.09	0.96
PROD021	1.07	1.07	1.02
PROD023A	0.93	1.04	0.93
PROD024A	0.94	1.04	0.96
PROD025A	1.10	1.01	0.96

Table 9 Fluid correlations result for the adjusted model.

Well	Solubility ratio (RS)	Formation volume ratio (Bo)	Dead oil viscosity	Live oil viscosity ($P \leq P_{SAT}$)	Live oil viscosity ($P > P_{SAT}$)
INA1A	Lasater	Vazquez and Beggs	Beggs and Robinson	Petrosky and Farshad	Vazquez and Beggs
INA2	Lasater	Vazquez and Beggs	Glaso	Kartoatmodjo and Schmidt	Vazquez and Beggs
INA3D	Glaso	Vazquez and Beggs	Beggs and Robinson	Kartoatmodjo and Schmidt	Vazquez and Beggs
IRJS19	Glaso	Glaso	Beggs and Robinson	Petrosky and Farshad	Vazquez and Beggs
PROD005	Glaso	Glaso	Glaso	Petrosky and Farshad	Vazquez and Beggs
PROD008	Glaso	Vazquez and Beggs	ASTM	Petrosky and Farshad	Vazquez and Beggs
PROD009	Lasater	Standing	ASTM	Kartoatmodjo and Schmidt	Vazquez and Beggs
PROD010	Standing	Glaso	Glaso	Beggs and Robinson	Vazquez and Beggs
PROD012	Glaso	Glaso	Glaso	Kartoatmodjo and Schmidt	Vazquez and Beggs
PROD014	Standing	Glaso	Beggs and Robinson	Kartoatmodjo and Schmidt	Vazquez and Beggs
PROD021	Vazquez and Beggs	Glaso	Beggs and Robinson	Kartoatmodjo and Schmidt	Vazquez and Beggs
PROD023A	Glaso	Glaso	ASTM	Petrosky and Farshad	Vazquez and Beggs
PROD024A	Glaso	Vazquez and Beggs	Beggs and Robinson	Petrosky and Farshad	Vazquez and Beggs
PROD025A	Lasater	Standing	ASTM	Kartoatmodjo and Schmidt	Vazquez and Beggs

Table 10 Results provided by the tool in the minimization process for an adopted tolerance of 5% for the adjusted model.

Well	ID	Iteration	Run	MQD	Samples	NQDS
INA1A	238	8	28	9.09	25	0.0990
INA2	123	5	3	18.82	24	0.1951
INA3D	91	4	1	16.74	23	0.1873
IRJS19	187	7	7	23.78	22	0.3646
PROD005	62	3	2	16.96	10	0.2383
PROD008	127	5	7	19.09	19	0.1848
PROD009	19	1	19	0.01	1	0.0001
PROD010	57	2	27	42.34	16	0.2917
PROD012	172	6	22	30.32	5	0.2059
PROD014	87	3	27	8.3	4	0.0686
PROD021	194	7	14	1.64	3	0.0126
PROD023A	68	3	8	0.55	2	0.0091
PROD024A	118	4	28	14.79	13	0.1728
PROD025A	19	1	19	20.62	7	0.1031

Table 10 shows the results of calculations used to minimize the mean quadratic deviation (MQD) between simulated BHP and BHP from production history to optimize the adjustment process of the well and gathering system simulation models. NQDS value is calculated for each optimum value.

Table 11 shows the number of fluid correlations and multiphase flow correlations, and values for absolute roughness and pressure gradient adjustment factor (DP/DL) evaluated during 8 IDLHC iterations for PROD005 well.

Table 11 Number of fluid correlations and multiphase flow correlations, and values for absolute roughness and pressure gradient adjustment factor (DP/DL) evaluated during IDLHC iterations for PROD005 well.

Parameter / IDLHC Iteration	1	2	3	4	5	6	7	8
Formation volume ratio	3	3	3	3	3	2	2	2
Dead oil viscosity	3	3	3	3	2	1	1	1
Live oil viscosity ($P \leq PSAT$)	3	3	3	3	3	3	3	2
Live oil viscosity ($P > PSAT$)	1	1	1	1	1	1	1	1
Solubility ratio	4	4	3	3	3	3	3	2
Riser Correlation	11	6	4	4	4	3	3	3
Flowline Correlation	16	5	4	4	2	2	2	1
Production Column Correlation	11	3	3	3	3	3	2	2
Absolute Roughness Riser	8	4	4	3	2	2	2	2
Absolute Roughness Flowline	8	6	3	2	2	2	2	2
Absolute Roughness Production Column	8	4	3	3	2	2	2	1
Riser	23	6	4	4	4	3	3	3
Flowline	23	6	4	3	3	3	2	2
Production Column	23	6	4	3	2	2	2	2

Step 3 - Comparison Between Models

Figs. 9 to 12 show comparisons between field yield curves for different simulated scenarios of oil, liquid, and water production, and water injection, respectively.

The NQDS value, considering reservoir simulation curves for the normal constrained oil field production forecast period, in the platform changed from 4 (unadjusted production system) to 3 (adjusted production system with observed dynamic data). Considering modified restrictions in the platform (100% increased fluid processing capacity on the surface facilities), the NQDS value changed from 3 (unadjusted production system) to -1 (adjusted production system with observed dynamic data).

Cumulative oil production from the field, with normal restrictions in the platform, changed from 49.6 MMm³ (unadjusted production system) to 49.3 MMm³ (adjusted production system with observed dynamic data), compared to the reference model, which is 46.1 MMm³. Considering modified restrictions on the platform (100% increased fluid processing capacity on the surface facilities), the cumulative field production values changed from 50.3 MMm³ (unadjusted production system) to 48.0 MMm³ (dynamic data adjusted production system), compared to the reference model, which is 49.0 MMm³.

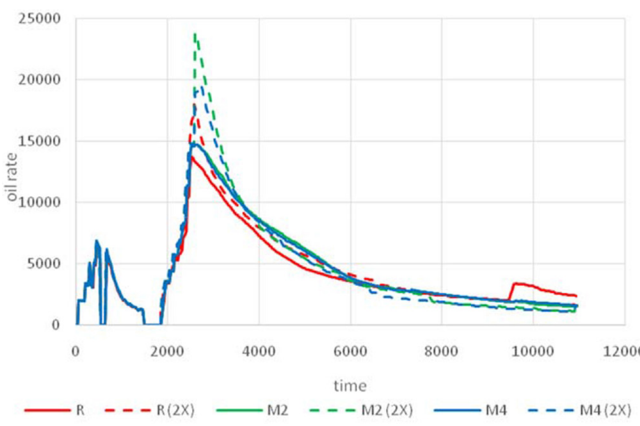

Fig. 9 Field oil production curves with the production system model integrated with the reservoir model. (2X) 100% increased fluid processing capacity on the surface facilities. (M2) reservoir model with unadjusted production system simulation model. (M4) reservoir model with adjusted production system simulation model.

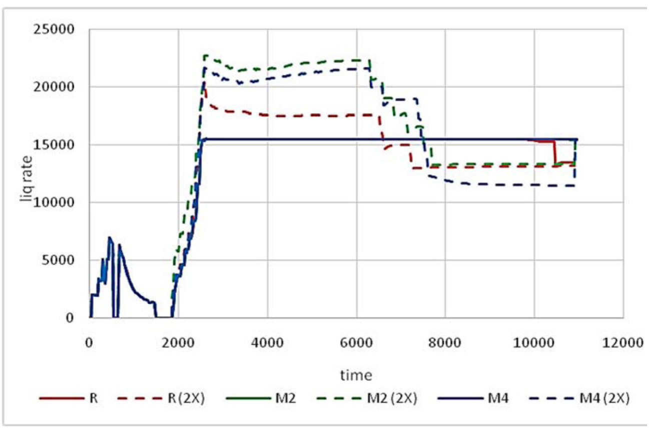

Fig. 10 Field liquid production curves with the production system model integrated with the reservoir model. (2X) 100% increased fluid processing capacity on the surface facilities. (M2) reservoir model with unadjusted production system simulation model. (M4) reservoir model with adjusted production system simulation model.

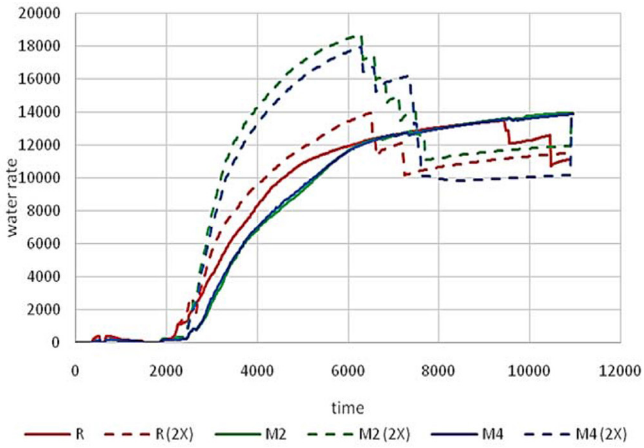

Fig. 11 Field water production curves with the production system model integrated with the reservoir model. (2X) 100% increased fluid processing capacity on the surface facilities. (M2) reservoir model with unadjusted production system simulation model. (M4) reservoir model with adjusted production system simulation model.

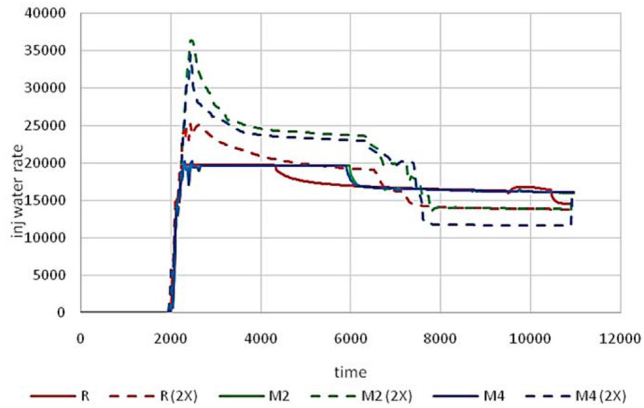

Fig. 12 Field water injection curves with the production system model integrated with the reservoir model. (2X) 100% increased fluid processing capacity on the surface facilities. (M2) reservoir model with unadjusted production system simulation model. (M4) reservoir model with adjusted production system simulation model.

Fig. 13 shows comparisons between oil production from the field for different simulated scenarios for modified restrictions on the platform (100% increased fluid processing capacity on the surface facilities), including a combination of parameters for deterministic approach (best value) and 5 aleatory runs into the good quality limit of models on the NQDS (range of value 5) for probabilistic approach. Cumulative oil production from the field varied between 48.2 to 49.9 MMm^3.

NQDS value considering reservoir simulation curves for a representative well (PROD005) of the field in the oil production forecast period, with normal constraints in the platform, changed from 91 (unadjusted production system) to -4 (adjusted production system with observed dynamic data). Considering modified restrictions in the platform (100% increased fluid processing capacity on the surface facilities), the NQDS value changed from 35 (unadjusted production system) to 2 (adjusted production system with observed dynamic data).

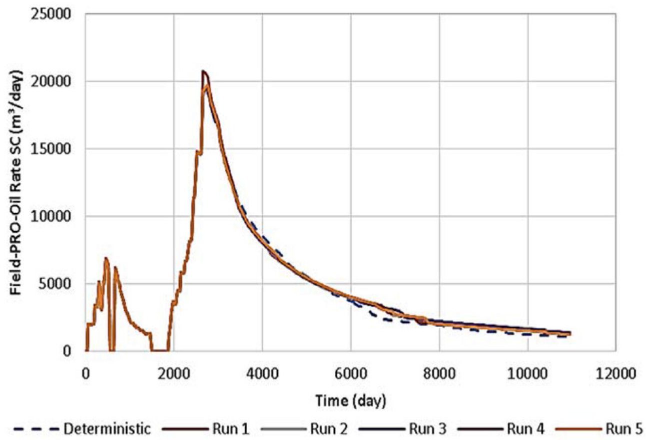

Fig. 13 Field oil production curves with the adjusted production system model integrated with the reservoir model (100% increased fluid processing capacity on the surface facilities) for deterministic approach (best value) and 5 aleatory runs above the good quality limit of models on the NQDS (range of value 5) for probabilistic approach.

Discussion

Step 1 - Sensitivity Analysis

The proposed methodology enabled us to analyze the influence of the production system parameters on the reservoir simulation results.

Bottom-hole pressure and water and oil flow rates were more sensitive to variations in the production system pressure gradient adjustment factor, which led to more evident variations in the cumulative field production with relation to the other analyzed parameters. It is compatible with the common sense of using the pressure gradient adjustment factor to adjust the production system model but verified for this case. Good to mention that other parameters had a minor impact.

The bottom-hole pressure and water flow at older ages in the production forecast period, when the water cut is above 70%, are more sensitive to variations in multiphase flow correlations, fluid correlations, and absolute roughness in the production tubing when compared to oil and gas flows. This is due to the greater participation of the gravitational portion in the equation governing the pressure drop in the system (long vertical production columns). This analysis would suggest considering only the pressure gradient adjustment factor to adjust the production system model. But it is unable to capture combinatorial effects.

Analyzing the results presented, we observe that the total liquid flow is limited due to restrictions in the surface facilities. Thus, small variations in the oil, water, and gas rates of the field are evidenced. With the 100% increase in liquid handling capacity of surface facilities, the operation encounters no restrictions. This allows the wells to operate near their full production potentials. Thus, greater variations in the production of oil, water, and gas from the field and producing wells are evidenced, as well as the increased capacity of the injector wells. In these cases, calibration is more important.

Platform boundary conditions, imposed by limitations on surface facilities, are important and may determine the need to calibrate, or not, production system simulation models.

Step 2 - Model Adjustment

The study was proposed initially to obtain the best fit of production history and model forecast, a common practice in the industry, but considering all adjustment parameters. All 14 wells studied showed values very near 0 for MQD, with excellent fit quality (range from -1 to 1) for NQDS. Additionally, we obtained good convergence to the IDLHC method by minimizing the difference between simulated BHP and observed dynamic BHP from production history. The minimum value generally occurs from number 150 of the MQD calculation run (ID).

For the riser multiphase flow correlation, (Aziz, Govier and Fogarasi) occurs in 29% of cases, followed by (Beggs, Brill and Palmer), (Beggs and Brill), (Orkiszewski) and (Poettmann and Carpenter), each with 14.0 % of occurrence. For the flowline, (Hagedorn and Brown) occurs in 29% of cases, followed by (Oliemans) in 21% of cases and (Baxendell and Thomas), (Beggs and Brill), (Dukler), (Dukler, Eaton and Flanigan), (Dukler and Minami I), (Dukler and Minami II), (Duns and Ros), each occurring in 7% of the cases observed. For the production tubing, (Beggs, Brill and Palmer) occurs in 57% of cases, followed by (Mukherjee and Brill) in 29% of cases and (Beggs and Brill) in 7% of cases.

For the production tubing, the absolute roughness of 0.2 occurs in 50% of cases, followed by 0.183, which occurs in 21% of the cases. For the flowline, absolute roughness of 0.2 and 0.046 occurs in 29% of cases, followed by 0.01, which occurs in 21% of cases. For the riser, the absolute roughness of 0.01 occurred in 36% of the cases, followed by 0.017, which occurred in 29% of the cases.

For the production tubing, the pressure gradient adjustment factor with a value of 0.96 and 1.02 occurs in 29% of cases. For the flowline, the factor 1.01 occurs in 36% of cases, followed by 1.04 in 21% of cases. For the riser, the factor of 0.94 and 1.1 occurs in 21% of the cases.

Glaso's correlation was selected in 50% of cases for both solubility ratio (RS) and oil formation factor (Bo), followed by Standing in 14% of cases. The Beggs & Robinson correlation occurs in 43% of cases for dead oil viscosity, followed by the ASTM and Glaso method, both with 29% of cases.

For living oil viscosity (P≤ PSAT), the Kartoatmodjo and Schmidt correlation occurred in 50% of cases, followed by the Petrosky and Farshad correlation in 43% of cases. The Vazquez & Beggs correlation occurs in all cases for living oil viscosity (P>PSAT).

These results showed no unique multiphase flow correlations, fluid correlations, and absolute roughness in the production tubing that fits the overall production history. Other combinations of these parameters could be able to represent the production system models if considering the good to the excellent fit quality of the models. It is critical, especially for short periods of production history, when the number of parameters is higher than observed data, and several combinations are feasible.

Fig.8 shows that, in 49% of all AQM evaluations, several parameter combinations fitted production history with a good quality limit of models on the NQDS range of value 5 for PROD005. It shows that this minimization problem had several local minima, which suggests considering more than one parameter value as an option to adjust the production system model to avoid local minima. This behavior was not captured by sensibility analysis, and thus it justified a probabilistic approach for production system history matching.

Table 11 shows the iterative evolution of IDLHC method, reducing the number of fluid correlations and multiphase flow correlations, and values for absolute roughness and pressure gradient adjustment factor (DP/DL) evaluated in IDLHC iterations for the PROD005 well. Again, there was more than one parameter value possible for almost all parameters, which is adequate to avoid local minima.

Another observation was related to great adjustments in pressure gradient adjustment factor in some wells, above 1.10. This parameter should operate as a fine-tuning of the other parameters representing the multiphase flow physics, indicating modeling problems.

Step 3 - Comparison between Models

In the original case, the total production of the field was restricted due to constraints on the surface facilities, which causes a low influence on oil production NQDS results between the calibrated and uncalibrated (4 to 3) well and gathering system simulation models. This is mainly due to operational constraints on surface facilities, which restrict the maximum production potential of wells and justify few impacts of adjustment.

We tested a less restrictive case by doubling the platform processing capacity, generating greater influence from adjustments to production system models and showing greater variation in NQDS results (3 to -1). The adjustment had a relevant impact on the field total production due to minor restrictions in well potential.

The quality of the field production forecasting depends on how well and gathering system parameters of the production system model, coupled to the reservoir model, were calibrated. But this calibration is less important for more restrictive systems.

We observed that the production curves and bottom-hole pressure of the well in the reservoir model, with the production system properly adjusted and coupled to it using production history information from an early time in the project life, approaches the respective curves to the reference model. In your study, the reservoir model is a possible scenario for the real model, and differences in terms of inter-well properties and well productivity could not be adequately captured in reservoir data assimilation. The next studies include evaluating reservoir model uncertainties together with production system uncertainties.

Comparing the NQDS values of a representative well with the field values shows a greater difference of this parameter. Because, during a simulation run, there is a natural adjustment in the field mass and total energy balance when compared individually to each well. Changes in boundary conditions in the bottom hole due to calibrated well and gathering system models affect the dynamic flow behavior differently inside the reservoir.

Conclusions

There is a common sense in the petroleum industry for using pressure gradient adjustment factor to adjust tubular elements in the production system model, verified for a benchmark case using sensibility analysis.

However, we observed that production system history matching could be a minimization problem with several local minima, which suggests considering more than one parameter value as an option to adjust the production system model to avoid local minima. This behavior is not captured by sensibility analysis, and thus it justifies a probabilistic approach for production system history matching.

Several parameters were selected to adjust the production system simulation model (fluid correlation, multiphase flow correlation, absolute roughness) and the pressure gradient adjustment factor (DP/DL) were adequate for minimizing the relative error between production history BHP and simulated BHP. These results showed that there were no unique correlations and values that fit the overall production history. Combinations of these parameters could be able to represent the production system models. It is critical, especially for short periods of production history when the number of parameters is higher than observed data.

The quality of the field production forecasting depends on how well and gathering system parameters of the production system model, coupled to the reservoir model, were calibrated. But this calibration is less important for more restrictive systems.

Using production history information to adjust the production system simulation model to forecast production from an early time in the project life contributes to reducing uncertainties in the reservoir and production system simulation model, increasing reliability in production forecasting.

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