Petro-Elastic Parameters Effects on History Matching Procedures
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Abstract
Rock physics models are the quantitative link between the seismic information and reservoir properties. Thus, several authors have been using this link to develop methodologies aiming to integrate seismic derived information and production history matching. Nevertheless, there are significant uncertainties related to petro-elastic parameters definition and its effects on typical history matching results.

This paper evaluates this problem through the application of two history matching procedures. The empirical allowed range of petro-elastic parameters regarding fluid and rock behavior, such as temperature, salinity and porosity, mineral and dry rock modulus, respectively, are combined to define different data sets. Each set defines petro-elastic models to be coupled to a numerical reservoir model providing synthetic impedance distributions.

These sets of impedance are then used in two different integrated history matching techniques. First, each set is combined with production data defining a global objective function to be minimized and provide a new horizontal permeability distribution resulting in an updated model. Secondly, a constrained inversion procedure is applied to convert impedance into saturation and pressure distributions. These maps indicate the optimization regions and the quantitative seismic information to improve the global objective function accuracy aiming to derive a new permeability distribution. Thus, permeability and bottom-hole pressure from the updated reservoir models are compared to evaluate the several combinations of petro-elastic parameters effects.

The major goals of this paper were to quantify the petro-elastic parameters definition effects on history matching procedures, indicating which of them is more sensitive to their variations. Furthermore, it was possible to assess their individual impact in the history matching results and highlight the importance of a careful definition of these parameters and its coherent integration with fluid flow models. This approach also contributes to quantitative integration aspects of oil reservoir development and management.

Introduction
Simulation models have been used to estimate reservoir behavior. The model is generally built from static geomodels often constrained to log and core data from wells in addition to pre-production seismic. Then they are modified to match static and dynamic well data, including fluid production rates and pressures. Nevertheless, the non-uniqueness of the models can hamper the process due to missing information, particularly regarding to changes in the fluid distributions and pressures between wells.

Several authors have been using seismic derived information in order to face this lack of information. Particularly, time-lapse seismic has been emerging as a valuable tool to improve reservoir characterization and monitoring (Johann 2006, Wu 2005). Nevertheless, there are significant uncertainties related to the quantitative link between reservoir engineering and seismic derived data and their effects on a history matching procedure. The usual approach is to derive synthetic seismic data through the coupling of a Petro-Elastic Model (PEM) and a fluid flow model allowing the assessment of reservoir properties such as densities, porosities and fluid and pressure behavior (Souza, et al. 2010), (Ida 2009), (Gosselin 2003).

The methodology presented by Souza (2010) is an integrated history matching procedure which allows updating fluid flow models regarding seismic derived saturation and pressure maps. The quantitative application of this new information had significantly decreased the usual time necessary for optimization regions definition and improved the objective function minimization accuracy. In other approach, Ida (2009) joined acoustic impedance maps and production data in a global objective function achieving results as good as the former paper.
In this context, this study aims to evaluate the effects of petro-elastic parameters definition on these history matching procedures. Then, it will be possible to evaluate which of them best suits reservoir engineering necessities such as time, human resources, data and computational availability.

**Seismic Attribute definition**

Some authors are used to work with amplitudes differences (Huang, Will, Khan, & Stanley, 1997 and Dadashpour, Landro, & Kleppe, 2008). Nevertheless, the good correlations between Acoustic Impedance (AI) and rock and fluid properties allow a quantitative workflow of this attribute and reservoir properties such as saturations, mass densities, pressure and effective porosity. It is possible to calibrate the reservoir model acoustic response regarding engineering data such as liquid rate, bottom-hole well pressure and material balance (Dong & Oliver, 2001).

**Forward Seismic Modelling**

Significant seismic response variations can be originated by saturation and pressure changes occurring in oil field production periods. An understanding of rock properties is necessary to derive seismic attributes such as P and S velocities and mass density variation from reservoir parameters. Rock physics modeling have been used to estimate seismic attributes variations regarding fluid saturation and pore pressure changes. These models are able to provide the acoustic response of the studied reservoir through the modeling of its elastic rock properties and applying Gassmann equations (Mavko, 1998) for fluid substitution.

The flowchart applied to derive synthetic seismic attributes is depicted in Figure 1. It’s important to note that the forward seismic modeling had been defined accordingly to the fluid flow model parameters. Reservoir properties are taken from simulation runs for each requested time and made as inputs to the PEM deriving the seismic attribute value for each grid cell. Thus, it’s expected a significant coherence among the petro-elastic and fluid models to be coupled.

One of the crucial points of this coherence certainly is related to those parameters necessary to PEM definition which are not necessarily defined in a fluid flow model. The flowchart in the Figure 1 highlights this fact showing that parameters such as salinity, temperature and lithology need to be provided to derive the synthetic seismic data and they are out of scope of the fluid flow model definition.

![Flowchart applied to derive synthetic seismic attributes.](image-url)
Petro-Elastic Model Definition
As this study deals with synthetic seismic data and a complex reservoir model, a suitable PEM was used to calculate AI at each grid cell. The elastic rock properties assumed are presented in Table 1. Aiming to improving the reservoir acoustic sensitivity to pressure variations empirical relations are also applied (Emerick 2007).

Table 1: Petro-elastic parameters (EMERICK, 2007).

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (T)</td>
<td>80°C</td>
</tr>
<tr>
<td>Salinity (S)</td>
<td>55000 PPM</td>
</tr>
<tr>
<td>Mineral density ($\rho_{\text{mineral}}$)</td>
<td>2.645 Kg/m$^3$</td>
</tr>
<tr>
<td>Mineral bulk modulus ($K_{\text{mineral}}$)</td>
<td>350000 Kgf/cm$^2$</td>
</tr>
<tr>
<td>Mineral shear modulus ($\mu_{\text{mineral}}$)</td>
<td>430000 Kgf/cm$^2$</td>
</tr>
<tr>
<td>Water depth (WD)</td>
<td>1000 m</td>
</tr>
<tr>
<td>Overburden gradient ($\nabla_{\text{sobre}}$)</td>
<td>0.226 Kgf/cm$^2$/m</td>
</tr>
<tr>
<td>Sea water gradient ($\nabla_{\text{mar}}$)</td>
<td>0.095 Kgf/cm$^2$/m</td>
</tr>
<tr>
<td>Quartz density ($\rho_{\text{quartz}}$)</td>
<td>2.65 Kg/m$^3$</td>
</tr>
<tr>
<td>Clay density ($\rho_{\text{clay}}$)</td>
<td>2.55 Kg/m$^3$</td>
</tr>
<tr>
<td>Quartz bulk modulus ($K_{\text{quartz}}$)</td>
<td>360 000 Kgf/cm$^2$</td>
</tr>
<tr>
<td>Quartz shear modulus ($\mu_{\text{quartz}}$)</td>
<td>440 000 Kgf/cm$^2$</td>
</tr>
<tr>
<td>Clay bulk modulus ($K_{\text{clay}}$)</td>
<td>250 000 Kgf/cm$^2$</td>
</tr>
<tr>
<td>Clay shear modulus ($\mu_{\text{clay}}$)</td>
<td>90 000 Kgf/cm$^2$</td>
</tr>
</tbody>
</table>

History Matching Procedures
This paper will apply two different history matching techniques, regarding production history, AI distributions and seismic derived water saturation and pressure maps. Both procedures evaluated in this paper follow through similar steps and the main difference between them is the definition of how the seismic derived information can be used in the objective function: saturation and pressure (HM1 procedure) or AI maps (HM2 procedure) (Table 2).

Table 2: Type of seismic derived information on each history matching procedure.

<table>
<thead>
<tr>
<th>History Matching Procedure</th>
<th>Seismic Derived Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AI Maps</td>
</tr>
<tr>
<td>2</td>
<td>Saturation and Pressure Maps</td>
</tr>
</tbody>
</table>

Parameterization
Souza (2011)(2007) presented a methodology where error maps obtained from the difference between simulated maps (initial model simulation) and “observed” data (in this synthetic case - real model simulations) cell by cell of the simulation grid defined as follows:

$$\Delta X_i = X_i^{\text{Initial}} - X_i^{\text{Real}}$$  \(1\)

where the subscript $i$ is the cell grid position, $\Delta X$ is the difference of the property calculated inside the cell $i$, $X_i^{\text{Initial}}$ and $X_i^{\text{Real}}$ are its measurements for the initial and real models, respectively.

Two types of regions are considered for the map adjustment: attribute and parameter. This last one is defined as every region where an error measurement is made and its values are incorporated into the objective function. The regions where the modifications are done are defined as attribute regions.

The anomalies which are in the error maps are related to some possible reservoir heterogeneities (Machado, 2009). In order to understand them the following statements are made:
• Positive anomalies in the mapped property indicate the presence of higher water quantities in the initial model than in the real one. Then inserting a fault or reducing the absolute permeability might be necessary to delay the fluid front.
• Negative anomalies point that there is a lack of water in the region. The saturation front needs to be “accelerated” to the anomalies direction. In general this scenario indicates a channel with higher permeability compared with the average of the model.

Objective Function Definition

The objective function used in this paper is defined as follow:

$$OF = W_P \cdot POF + W_M \cdot MOF$$  \hspace{1cm} (2)

where $POF$ is the production and $MOF$ is the maps objective function and $W_P$ and $W_M$ are the respective weights. Risso (2007) introduced this global objective function aiming to consider error provided from properties maps and production data. In this case, the values of $W_P$ and $W_M$ which improve the OF implementation are 0.33 and 0.67, respectively (Machado, 2009).

The POF is determined through an equation that weights each evaluated parameter (oil and water production and bottom-hole pressure) as follow:

$$POF = \sum_{i=1}^{m} w_i \sum_{j=1}^{n} (w_j \cdot \varepsilon_j)$$  \hspace{1cm} (3)

where $m$ represents the number of wells to be adjusted in the same objective function, $w_i$ is the weight of each well, $n$ is the number of adjusted parameters per well, $w_j$ is the weight of each parameter adjusted in the well, $\varepsilon_j$ is the measured error of each adjusted parameter given by:

$$\varepsilon_j = \frac{A_{f,j}^{sim}}{A_{f,j}^{Initial}}$$  \hspace{1cm} (4)

where $A_{f,j}^{sim}$ is called the distance parameter that indicate the difference between the observed and matched parameter and is defined as follow:

$$A_{f,j}^{sim} = \sum_{k=1}^{No} (X_{k,j}^{obs} - X_{k,j}^{sim})$$  \hspace{1cm} (5)

where $X_{k,j}^{obs}$ is the observed data of the parameter $j$ and $X_{k,j}^{sim}$ is the same parameter $j$, however now obtained from a simulation run of the initial model. $No$ is the number of observed data of the parameter $j$, this parameter can be well data and/or map measurements like pressure and saturation. $A_{f,j}^{Initial}$ is obtained when $X_{k,j}^{sim} = X_{k,j}^{Initial}$.

The weights of each well ($w_i$) are proportional to the initial distance parameter ($A_{f,j}$), derived from equation 12 when $X_{k,j}^{sim} = X_{k,j}^{Initial}$. In this paper the maximum weight applied was 0.5 in order to avoid an excessive influence of any particular well to the POF. Similarly, a minimum value of 0.05 was applied avoiding any underestimation.

Firstly it is calculated the ratio between the distance parameter of each well and its maximum value among the selected wells to be matched and it is defined as:

$$z_i = \frac{A_{f,j}^{base}}{\max(A_{f,j}^{base})}$$  \hspace{1cm} (6)

where $i$ is the well index and $j$ is the parameter with higher misfit index. This ratio needs to be normalized in order to derive the weights $w_i$ as follow:

$$w_i = \frac{z_i}{\sum_{i=1}^{np} z_i}$$  \hspace{1cm} (7)

Ida (2009) highlight that an objective function formulated as in equation (3) has the advantages listed below:
• Due to its dimensionless, it is possible to deal with different types of variables and magnitudes;
• Allow a more quantitative comparison between the simulated runs response;
• It is possible to develop an automatic optimization procedure as all variables to be matched can be exported by the simulator.

The following equation describes how the maps objective function (MOF) is defined. In this equation \( nRS \) is the number of parameter regions in the saturation error map and \( w^RS_i \) is the saturation weight and \( \epsilon^R_{ij} \) is defined by the Equation 11.

\[
MOF = \sum_{i=1}^{nRS} \left( w^RS_i \cdot \epsilon^R_{ij} \right)
\]  
(8)

The calculation of \( w^RS_i \) is similar to that one of the \( w_i \) described above. It is important to underline that a region defined in one map do not have any influence in the weight of another region, even though the maps could have different parameters on it. Thus, each map has the sum of its weights equal to 1.

The main difference between the procedures applied in this paper is that in HM1 procedure the MOF variable (Equation 9) is time-lapse seismic derived saturation data and in HM2 procedure it has AI variation values.

**Methodology**

The methodology presented on this paper has two main topics. The first one concerns two integrated history matching techniques that allow a quantitative application of seismic derived information into the history matching (Figure 2). The second one regards the use of different PEM input parameters aiming to evaluate the sensitivity of these parameters definition on both history matching procedures (Figure 3).

It is important to highlight the different sets of input and output saturation and pressure data used in this process. They are listed below:
• Observed saturation and pressure;
• Initial estimative of saturation and pressure;
• Estimated saturation and pressure;

As this study deals with synthetic data, the observed properties are obtained from the flux model called “real” which has known behavior that needs to be honored. The flux model named “Initial” (IM) is the one that has to be modified to honor the Real Model (RM) and provide the initial estimative of the evaluated property and is an input of the inversion procedure. Thus, the estimated saturation and pressure are the seismic information regarded into the history matching.

The methodology presented in the Figure 2 is based on the integration of an inversion and two History Matching procedures.

**Inversion Method**

This step comprehends a well pressure matching between the real and initial models. These models also provide production data and PEM inputs.

The initial pressure estimative has reduced uncertainties at the wells position providing a better input for inversion procedure. After defining these data, they are input to the optimization algorithm which derives the estimated saturation and pressure maps to the History Matching.

**History Matching 1**

This technique applies the p-wave acoustic impedance maps directly on the global objective function (Equation 9). These maps difference provide the permeability update regions through the definition of the attribute and parameters regions. Then the objective function values are evaluated and its minimum among several runs determines the end of the process or the re-evaluation of the parameterization step.

**History Matching 2**

Now the estimated saturation and pressure maps are used in the parameterization step to define the attribute and parameter regions. Then the objective function values are evaluated and its minimum among several runs determines the end of the process or the re-evaluation of the parameterization step.

**PEM Parameters Evaluation Step**

On this step different PEM input parameters are input in the integrated workflow (Figure 2) and provides a number of history matching data sets to be evaluated.
Figure 2: Flowchart of the presented methodology.

Figure 3: Flowchart applied to compare different history matching results.
Application/example

Fluid Flow Model
In this paper it is used an adapted data set from the Namorado Field located in the Campos Basin, Brazil. The field has 10 producer and 5 injector wells which the most important change from the original model was the forwardness of the injector wells opening schedule according to producer wells to create advanced water fronts.

The reservoir was discretized with a Cartesian grid with 52 x 30 x 6 number of cells (9,360 total cells with 5,673 active cells) with dimensions of 150 m x 150 m x variable thickness Figure 4, considering a geostatistical interpolation to obtain it. The original volume of oil is 107.63 million m³. The reservoir outline is show in Figure 1 and it can be seen the structural map of the top. The oil density is 28 °API and the fluid model used is the Black-Oil.

Real Model
The characteristics of the history model consist mainly of two heterogeneities: a fault and a channel, that can been seen in the Figure 5.
Initial Model
This model does not contain the fault and channel, observed in the history model and it is used as the initial guess for the model based optimization technique.

Results and Discussion
The main difference between the history matching procedures is the way how the parameterization step (Figure 2) is done. In the HM2 procedure are applied saturation and pressure maps (Figure 6a and b, respectively) to define the attributes and parameter regions. The evaluation of the two highlighted regions in the saturation map (Figure 6a) indicate that permeability need to be updated on these regions as these trends are not observed in the Initial Model. Note that the pressure map allows the identification of a possible anomaly region (red circle in the Figure 6b).

![Figure 6: Time-lapse seismic derived maps: (a) Saturation and (b) Pressure.](image)

These attribute and parameter regions are defined in the HM1 directly from acoustic impedance variation behavior (Figure 7). Note that it possible to identify the same fluid trends as the ones observed in the seismic derived saturation map (Figure 6a). The main point regarding both methods is that from the AI map is not possible to identify the structure indicated by the pressure map (Figure 6b). The parameterization step is crucial important and it can define if your history match will have successful or not.

![Figure 7: Observed acoustic impedance variation.](image)

The PEM parameters evaluation is separated in two data sets: fluid and rock properties. The effects of salinity and temperature on bulk modulus are widely known (Batizee Wang 1992). Thus, suitable values of these parameters are combined to evaluate their impact on the OF values and the updated fluid flow model behavior.

In order to assess the temperature impact in the OF, it is applied a 10% variation in the measured temperature of the field (88°C) and combined with one single salinity value (Table 3).
Table 3: Temperature and salinity values for the different runs.

<table>
<thead>
<tr>
<th>Procedure</th>
<th>Temperature (°)</th>
<th>Salinity (PPM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TempRun1</td>
<td>88</td>
<td>50000</td>
</tr>
<tr>
<td>TempRun2</td>
<td>79.2</td>
<td>50000</td>
</tr>
<tr>
<td>TempRun3</td>
<td>96.8</td>
<td>50000</td>
</tr>
</tbody>
</table>

These parameters were applied in the HM1 and the derived OF values are in the Figure 8. It’s observed a significant OF variation due to temperature changes, the map objective function value have increased more than 100 % for 96.8° C. Meanwhile the global OF, for 79.2°C, presents 75% of improvement on its accuracy emphasizing the importance of this property to the overall procedure. Moreover, the temperature variation on the PEM definition had shown an impact in the production objective function indicating that this property could be determining in the permeability update during these history matching procedures.

Figure 8: Objective function minimum values for HM1 – Temperature variation.

This temperature definition impact on the production OF can be noted on the Figure 9, where the water rate curves provided by each procedure at producer 01. Significant changes are observed on the curve behavior in a manner this fact certainly could affect the well match.

The procedures to evaluate the salinity effect are listed in Table 4. It had been applied a 10% variation in the measured salinity value (50 000 PPM). It is observed an overall increase of the map OF in relation to the temperature effect (Figure 8: Objective function minimum values for HM1 – Temperature variation, Figure 8). Highlighting that for 55 000 PPM it is observed the least production objective function indicating the influence of this parameter in a production data.

Figure 9: Water rate of the producer 01 for temperature impact evaluation.
Table 4: Procedures for Salinity effect evaluation

<table>
<thead>
<tr>
<th>Procedure</th>
<th>Temperature (°C)</th>
<th>Salinity (PPM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SaltRun1</td>
<td>88</td>
<td>45000</td>
</tr>
<tr>
<td>SaltRun2</td>
<td>88</td>
<td>50000</td>
</tr>
<tr>
<td>SaltRun3</td>
<td>88</td>
<td>55000</td>
</tr>
</tbody>
</table>

Following the same trend shown by the temperature effect, the producer 01 water rate curve (Figure 11) indicates that salinity definition can be important for well match. In accordance with the minimum OF values, the water rate curve that best fits the forecast data is for salinity equals to 55000 PPM. With the same trend the other procedures had shown an increase in the OF values.

Figure 10: Objective function minimum values for HM1 – Salinity variation.

Figure 11: Water rate of the producer 01 for salinity effect evaluation.
In order to evaluate the rock property influences it is applied changes in the original porosity model from the fluid flow model, this had been made through a set of porosity multipliers directly on the numerical reservoir model. The Table 5 list these multipliers accordingly to their respectively procedure. The Figure 12 presents the OF values and as expected the porosity have a major influence on the history matching OF. All procedures have been showing an increase of the global OF indicating that the porosity multipliers had changed the AI maps to values more inaccurate in relation to the reference ones. The first procedure called PorRun1 is presenting a significant increase in the production OF. Consequently, the producer 01 water rate curve also presents the porosity changes effect that could be determining to the well match. The PorRun2 procedure (0.8 multiplier) has the least production OF.

Table 5: Procedures for Porosity effect evaluation

<table>
<thead>
<tr>
<th>Procedure</th>
<th>Original Porosity multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>PorRun1</td>
<td>0.7</td>
</tr>
<tr>
<td>PorRun2</td>
<td>0.8</td>
</tr>
<tr>
<td>PorRun3</td>
<td>0.98</td>
</tr>
</tbody>
</table>

Figure 12: Objective function minimum values for HM1 – Porosity variation

Figure 13: Water rate of the producer 01 for porosity effect evaluation.
The quality of the maps used on HM1 and HM2 procedures is crucial for the parameterization step. Nevertheless, as described above, this quality can be affected by salinity, temperature and porosity. The Figure 14, 15 and 16 are showing the AI variation map provided by the updated fluid flow model obtained from the procedure TempRun3, SaltRun2 and PorRun2, respectively. These maps highlight the importance of this parameters definition for maps derivation because it is possible to observe that they differ among each other and the fluid trends can be hard to identify depending of the set of PEM parameters that is used. The region delimited by the black circle on these maps shows the influence of temperature, salinity and porosity on them as is observed AI variation changes for each procedure.

Figure 14: AI variation derived from the PorRun2 updated model.

These maps approach is fundamental for the comparison between HM1 and HM2 as both depend on the AI distribution. The fact that HM2 requires the saturation and pressure maps derived from AI variations from Real and Initial Models (Figure 2) indicates that it will be affected by fluid and rock properties on the PEM definition. The joined interpretation of these maps allows an improved estmative of permeability regions update. This fact is an important improvement of HM2 in relation to HM1. Furthermore, the use of saturation and pressure maps allows the application of constraints provided by fluid flow data during the inversion method. It is also possible to do an iterative process, using the saturation and pressure provided by the updated model as a new input to the inversion method. The Figure 17 presents the water saturation variation that is the initial guess to the inversion method, in the Figure 6a is the saturation estimated through this process. Thus, the application of this new saturation input map could valuable to the inversion method accuracy, regarding that it is used an optimization algorithm based on gradient.

Figure 15: AI variation derived from the SaltRun2 updated model.
Conclusions

This paper presented a multidisciplinary methodology aiming to evaluate the effect of fluid and rock properties on two history matching procedures.

It is important to highlight that PEM parameters definition can significantly affect traditional history matching indicators such as the objective and production curves. The results suggest that is necessary to be careful to define these properties in a coupling between a PEM and a flow model.

Certainly the impact of these PEM parameters on AI variation distribution can hamper history matching results due to different definitions of the attribute and parameter regions.

In spite of the fact that, traditionally, acoustic impedance has been used on history matching procedures (HM1) certainly the application of seismic derived saturation and pressure maps can be more fruitfull (HM2). The pressure map provides...
important complementary information, not only in the parameterization step identifying anomalies, but also in the improvement of the objective function accuracy.

One of the major contributions of this paper is to collaborate with integration aspects between time-lapse seismic derived attributes and reservoir simulation data yielding a more reliable model for prediction.

References


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