Streamline based reservoir screening for improved automatic production and seismic history matching

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Research Article

Streamline based reservoir screening for improved automatic production and seismic history matching

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A b s t r a c t

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It is becoming more and more common to use assisted history matching methods to find different combinations of reservoir simulation models that agree with production and time lapse seismic data if exists. Models with a large number of cells contain millions of unknown parameters and selecting the correct values can be difficult. In practice not all are important but finding which parts of the reservoir require updating can be difficult. In this work we investigate methods of history matching by focusing on sub-volumes of the parameter space and we use streamlines to help us choose where the model requires change. We identify localities in the reservoir that affect particular wells and we update reservoir properties (net:gross and permeability) within. We control changes using the pilot point method combined with a Neighborhood Algorithm.We first apply these approaches for production history matching of the Nelson field where uncertainty of the shale distribution controls predictions. The field is divided into localities based on the performance of the worst well predictions. We then extend the application to a more complex case including both production and seismic data in history matching.

The localities that require change are sufficiently separate that we can modify them one at a time. We also compare our result with a more *ad hoc* approach where the whole area around the well is modified. We find that, for the wells of interest, the streamline guided approach gives a 70% improvement in the history match from our starting model and around 40% reduction of misfit in prediction. This improvement is twice that of the total area approach. The streamline approach has been applied successfully for seismic and production history matching of Nelson that makes 50% and 35% improvement of well production in history and prediction periods and 10% improvement of seismic map compared to the base simulation model.Reservoir simulation and history matching are crucial for reservoir management especially when developing field management plans. By application of a good updating workflow in the right area of the model through an automatic history matching process we have gained a greater insight into reservoir behavior and have been able to better predict flow from simulation models.

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1. Introduction

History matching is an inverse problem where the aim is to find a set of best reservoir parameters such that simulations can honor the real observations of the reservoir such as well pressure, oil, water and gas rates or time-lapse seismic signatures. This process involves identification and selection of uncertain reservoir parameters which are modified to be consistent with geological information. Simulations are run using updated parameters and the output is compared with observed data through an objective function. Further modifications are then made and the process is repeated until a good match to history is obtained. Due to the number of parameters involved and the limitation of data which leads to non-uniqueness of solutions this process is a time consuming and tedious task.

Over the last four decades or so, researchers have tried to improve the efficiency of the process by automatically minimizing the objective function using different inversion algorithm deterministically or stochastically [7,28,38,42,43,44]. Additionally, researchers have focused more on honoring the geostatistical constraint of the model when we update the reservoir parameters by using parameterisation methods like pilot points with Kriging the gradual deformation method probability perturbation and the Ensemble Kalman Filter [8,12,1319,20]. For some, the aim has been to use assisted tools to find important parts of the reservoir which need updating by using the streamline concepts or other measures of sensitivity such as the adjoint approach [2,6,9,10,25]. These approaches are more reliable compared to the ad hoc methods used for choosing the reservoir regions to be updated such as the region around the wells [35]. Various improvements can be made to each part of automatic history matching loop and which may lead to better predictions with greater efficiency. Because of the complexity of the reservoirs, however, research continues to makes this process accessible in general.

The time-lapse seismic data can be used in the history matching workflow in varying degrees from the qualitative to quantitative [1,3,4,14,15,16,17,18,23,24,26,27,29,31,32,40,41]. Qualitative use of time-lapse data is more useful for late life of a field in order to use data for identifying the upswept part of the reservoir independently from simulation models. A first quantitative application of data would be visual comparison of the output of simulation (pressure and saturation) with seismic data. In this case it is possible to better identify compartmentalization in the field as well as better develop the in-fill well targets. In a semi-quantitative time-lapse seismic study, synthetic 4D seismic will be derived from reservoir simulations and then compared to real data in order to obtain an aeral/volume match in the model as part of history matching. In full quantitative studies, the synthetic 4D seismic can be matched based on real data. In this case we can also identify the heterogeneities in the model by a full volume match in the reservoir, further increasing value. Greater quantitative application increases the value of this data to connect better the reservoir properties and the location of infill wells.

In this study we perform Automatic Production and Seismic History Matching (APSHM) on a North Sea field using the Neighborhood algorithm as the inversion tool and we combine that with a parameterization scheme based on pilot points with Kriging in order to honor the geostatistical distribution of properties in the reservoir [33]. Further, we use streamline simulation as a guide to help us choose the important regions of the reservoir for updating [34]. We also used a suitable parameter updating scheme which dramatically reduces the number of parameters we need to change during the automatic inversion stage and this is very important as it helps reduce the number of simulation runs and saves a lot of CPU time [21,22].

First we introduce the streamline based selection approach and the parameterization scheme used in APSHM in the method section and then we apply this workflow on the Nelson field. At the end we compare results for this approach with a more ad hoc method where we update the reservoir in the vicinity of production wells. Finally time lapse seismic data has been integrated into the workflow and we performed production and seismic history matching. This study shows that optimal parameterization with the help of streamlines gives a better result to match the history of the wells and, further, we also get a good forecast.

2. The General Strategy for History Matching of a Reservoir

In order to have success in solving the history matching inverse problem, an appropriate strategy needs to be considered. This strategy involves understanding and analysing available data such as geological information or fluid flow patterns in the reservoir, studying the sensitivity of the effect of selected parameters on fluid movement, combining different variables in the history matching study in order to keep the geological features and to control the fluid displacement, and finally analyzing the output of simulation and deciding to accept or reject the new reservoir models. Fig.1 shows a complete workflow of history matching of a reservoir from the beginning (which involves choosing the regions to update in the model) to the end.

The first stage in a history matching strategy is likely to be selection of reservoir parameters that needs modifications. Also we need to know where and how this variables need to be updated in the reservoir (Stage 1a and 1b in Fig.1). Generally for any history matching study the reservoir parameters must then be chosen using the available knowledge for the uncertainty of various data in the reservoir, the geological understanding of the reservoir and also change to the fluid movement that can be expected. In this study the guide for choosing the reservoir properties initially is mainly based on the geology of the reservoir and different fluid flow behaviors. As a summary the challenge in Nelson was updating shale volume and distribution by updating three parameters net:gross, horizontal and vertical permeability and multipliers are used to change those variables and a reasonable range for multipliers needs to be chosen based on prior information.

For selecting the updating regions in the reservoir, the idea in this study is that by using streamlines. Streamlines represent the path of fluid displacement in the reservoir; therefore appropriate selection of regions to update can be made. This idea would be suitable for the any active region of the reservoir.

For appropriate updating of the reservoir, various parameter updating schemes have been introduced before (Stage 3 in Fig.1) [22]. By parameter updating, we tried to find the most efficient ways to combine the parameters in the model in order to reduce the number of simulations significantly and make Automatic History Matching (AHM) workable.

As part of using an AHM workflow (Stage 3 in Fig.1) the aim was to reduce the mismatch between observed and modeled data by updating the parameters in the reservoir and applying data analysis (Stage 4 in Fig.1). After analyzing the parameters, and also the reduction of misfit, there were two options. If the results were satisfactory and the parameters converged to a specific value, we went to the final steps of the process (Fig.1 step 5) and by combining the best results; an ensemble of best reservoir models was obtained. Otherwise, the process returned to the beginning of the loop and chose another region for reservoir updating, changing the parameters or modifying the range of the parameters for sampling. In the following sections there is more discussion about the different parts of Fig.1.

3. Method

3.1 History matching workflow

Our history matching method is based on an automatic workflow presented in Fig. 2 where we start with a base model supplied by the operator of the field around which we generate new models as perturbations. First we need to define areas in the reservoir which need improvement (we discuss this in the next section). Then in each area we use the pilot point method with Krigingto control updates [12]. Pilot points are used to directly control where changes are made to properties such as permeability and net:gross. The change at the pilot point becomes the parameter of the inversion scheme. These changes are interpolated laterally using Kriging. The changes are applied uniformly in the vertical direction. In order to reduce the number of unknowns and to spread changes more smoothly, a set of pilot points may be grouped so that changes are applied all in the same way. This approach is often called the master pilot point approach [31,32].

Modifications at the pilot points are initially chosen randomly and a number of new models are generated. We simulate each model by using streamlines which is appropriate for the field we are studying. In other fields finite difference simulation may be required although streamline information may still be obtained. We compare predicted production and seismic data with the observed data using an objective function.

$$M = \sum \frac{(s^{obs} - s^{calc})^2}{\sigma_s^2} + \sum \frac{(Q^{obs} - Q^{calc})^2}{\sigma_Q^2} \qquad (1)$$

The observed 4D seismic in Nelson is phase shifted amplitude (is a type of colored inversion) maps. However the phase shifted amplitude can be considered as pseudo impedance because there is zero crossing trace for interface in both types of data. In each reservoir interval the value of phase shifted amplitude could be equivalent to the impedance value.

Although the outcome of colored inversion is equivalent to impedance but based on the inversion process the unit of product is the same as seismic amplitude. In order to quantitative integration of colored inversion into history matching loop we need some kind of calibration and normalization in order to have a unit (and also order of magnitude) equivalent to the unit of synthetic acoustic impedance data. We previously addressed that[22].

In Nelson for phase shifted amplitude the root mean square of each sample interval was calculated and therefore a 2D map was generated for each reservoir interval and for the time differences. Figure 19 shows as an example map for the top reservoir interval.

Following the strategy used in this study, reservoir properties were updated in the model in order to get a better match to production data from 1990 to 2000.

Predictions of seismic impedances are made by first calculating the saturated bulk and shear moduli for each simulation cell using output from the simulator [21]. From this the p-wave modulus is calculated and upscaled vertically using to give a single value for the reservoir interval [5]. Bulk density is similarly calculated and then the bulk impedance is obtained from:

$$I_{IJ}^{mod} = \sqrt{< \rho^{IJK} >_K / < \left(\kappa_{sat}^{IJK} + 4\mu^{IJK}/3\right)^{-1} >_K} \quad (2)$$

Where “<>K” is the depth average weighted by volume. Seismic attributes were obtained as an equivalent pseudo-impedance property for each bin in the seismic cube. These data were then averaged over each simulator cell to give a value that can be compared to the predicted data using

$$I_{IJ}^{obs} = < I_{ij}^{obs} >_{ij} \quad (3)$$

Where “<>ij” is areally average upscaling from the seismic to the simulator grid.

We also calculate the standard deviation of the observed seismic within each simulation cell as a measure of the variability. A similar misfit is used for production data summing over time series data of oil and water production rates. The production and seismic misfits are added to give a total misfit.

At the end of the loop we use the Neighborhood Algorithm (NA) as a stochastic quasi-global inversion algorithm to select new parameter values automatically. We then iterate through the loop until the objective function is minimized sufficiently.

The NA is a stochastic sampling algorithm introduced by originally for earthquake seismology [33]. Using this algorithm we explore the multidimensional parameter hyperspace using the geometrical constructs known as Voronoi cells. The process is initialized by generating ni models using quasi- or pseudo-random methods. In each iteration that follows the best nr models are selected and their neighborhoods are identified by construction of Voronoi cells in the parameter space. ns new models are generated such that ns:nr models are located within the neighborhoods of the each of the best nr models. One drawback of this algorithm is that for complex misfit surfaces, we require 2nd models initially to properly separate out neighborhoods[33]. To overcome this difficulty we introduce a parameter updating scheme in order to reduce the number of unknowns of the problem which drastically reduces the number of simulation runs. This approach will be discussed later in this paper.

We now have to determine where we should focus our attention for updating. These areas will be those that are known with low uncertainty but also those that have an important effect on the misfit. We address this difficulty by using the streamline guide which will be discussed further later in this section.

3.2 Streamline guide concept

In heterogeneous reservoirs we often see the effect of preferential flow paths, which may be observed in simulators using streamlines. These will appear to be more densely distributed in regions of high flow rate (Fig. 3). Since these regions channel most of the flow, it is reasonable therefore that we should focus on them first to improve the forecast from models. The breakthrough time and the growth of early water cut for a well are more likely to be controlled by the flow properties in these regions. It may be that the permeability of such conduits may be greater or lesser in comparison to the surrounding area or the width of such regions may be incorrect in the model. We apply our initial modifications to the model on these regions. We assume that the simulation model is a reasonable representation of the dominant flow pathways and for the purpose of this work; they will not change with additional realizations or changes to the geological model. This is reasonable in many cases where the model is constrained to seismic data at the larger scale. Fig. 3 also shows that there is a change in the streamline density over time. If this changes too much then we cannot focus on one area. On the other hand, we aim to use the most representative distribution to identify the region we wish to update.

In Nelson we use monthly volumes of water and oil produced to generate either monthly or biannual rates of production, the latter is used for fixing pressures in the streamline simulation approach that we use. We use the data for the first six years of production as a history matching constraint. To reduce the size of the problem, we target the 13 wells with the largest misfit. In Fig. 4 we can see the location of the wells in Nelson indicating the separation and that there is little interaction between wells and various locations of pilot points. The misfit for each well varies over time (e.g. Fig. 5) and we now focus on those time steps with biggest misfit. For each well, we use streamline distributions for the steps within 75% of the maximum time step misfit for that well.

In previous studies the impact of streamline sensitivity from changes to individual cells was considered. In our case we consider a general volume through which a cluster of streamlines passed. We hope to generate a more qualitative understanding therefore [11]. This also allows us to set up a master pilot point such that groups of pilot points are used and properties at each individual location are changed together within the group. In Fig. 6 we see the well in Fig. 4, and show the area that we finally choose for master pilot point locations. This area will cover most of the streamlines around this well. We apply the same procedure to choose pilot point locations for other wells. If we increase the number of targeted wells we should increase the number of pilot points and these will eventually overlap. The separation between pilot points is 5 simulation cells (~500m) in this study and for the cells around the pilot points Kriging with a variogram range of 15 cells (~1500m). Depending on the size of the area that is updated, the numbers of pilot points varybetween 9 and 25 per master pilot point. As an example in Fig. 4 we can see the pilot point locations for two target wells.

3.3 Local Multi-Variable (LMV) approach

All history matching methods require a scheme to search the parameter space using information about misfits from existing models. In general we may have to assume that each parameter that we change interacts with the others when considering their effect on the misfit. In large dimensional problems, this assumption can require that a prohibitively large number of simulations be carried out. In this work we investigate the parameter interactions heuristically to determine whether we can search the parameter space in a more efficient manner.

The LMV updating approach can be applicable for the cases that history matching parameters are dependent but there are local regions in the reservoir where we can update those parameter independently from other localities. In this approach the parameters at every locality will be modified simultaneously (i.e. variables in each updating regions) in order to consider interaction with each other but not with others elsewhere. In this approach very precise locations of the updated regions were needed to make sure that there was negligible interaction. All parameters at each locality were updated and one locality is modified at a time (follow black arrows in Fig.1). The name of LMV comes from the fact that history matching parameter will be updated locality in the reservoir.

All parameters at each locality are updated and one locality is modified at a time. A parameter range refinement step is considered if it appears that there is no convergence or the search is stuck on the limit set initially. After all localities are updated, the final results are amalgamated into a single model.

We generated 10 models by using updated reservoir parameters of each local history matching study. Imagine the abbreviation $\mathrm{Locality}_j^i$ ($j = 1,2,3,4,5,6$) for history matching result of each locality and $i = 1,2,3,..10$ to show best history matched model in terms of misfit value sorted from high misfit to low misfit (lowest is for $i = 10$). Then the final models were generated by combining the updated reservoir parameter such that:

$$\mathrm{LMV}_{\mathrm{Final1}} = (\mathrm{net:gross, horizontalpermeability, verticalpermeability})_{\mathrm{Locality}_1^1} + \ldots + (\mathrm{net:gross, horizontalpermeability, verticalpermeability})_{\mathrm{Locality}_6^1}$$

3. Application

3.1 Nelson field

The Nelson field is an undersaturated oil field located in bocks 22/11, 22/6a and 22/12a in the UK Central North Sea. The first production was in 1994 and 27 production wells were drilled up to 2000. The original oil in place was estimated at 126 million cubic meters of oil and by the end of 2000, 47 million cubic meters had been produced from the field [39]. The production drive is aquifer supported coupled with the water injection from 4 injection wells in the edge of the reservoir.

The reservoir sands in Nelson are turbidities with excellent reservoir quality with average net:gross of 70%, average porosity of 23% and permeability ranging from 200 to 1700 milidarcies. Geologically there are three distinct intervals in Nelson separated mainly by shale. Each interval has a channelized characterization and the amount and distribution of shale within and between the channels are one of our main uncertainties. We therefore vary horizontal and vertical permeability along with net:gross.

3.2. History matching of Nelson

We set well controls using historical liquid rates to maintain the correct voidage and we specified a general limit for bottom hole pressure of the wells to make sure that the bubble point pressure is not reached, as observed. The misfit is calculated based on oil and water production rates. We history matched from 1994 to 2000 and we check the quality of the result by forecasting from 2000 to 2003. We allow permeability and net:gross to vary by an order of magnitude increase or decrease. Net:gross is obviously not allowed to exceed unity.

In this history matching study we focus on updating areas near 13 wells chosen for the study (Fig. 4). Seven wells are completed in the first geological interval only so for these localities and we only update the reservoir properties in that interval. For each of these wells, there are only 3 variables modified so each sub-problem is three dimensional. The other 6 wells that we focus on are completed in both intervals therefore we need to update properties in both geological intervals and each of them is a six dimensional problem. Overall we have a 57 dimensional problem. Each sub-problem is considered in turn. For localities that are three dimensional we used 16 models initially and generate 10 new models per iteration of the NA. A total of 5 iterations are performed. For the six dimensional problems, 128 initial models are generated and 10 iterations are used within which 18 new models are generated. In all cases 2 models per neighborhood in the parameter space (i.e. ns:nr = 2).

We analyze the reduction of oil and water production misfits via history matching for each well in Fig. 7. The reduction of total production misfit ranges from 82% to 95% over all of the wells which is very good. All parameters converge to a better value during updating. Note that a correct parameter range is required otherwise convergence may not occur.

After history matching we select the 10 best parameter combinations from each pilot point location and combine them to generate a set of 10 best models overall. In Fig. 8a and 8b we can see total oil production rate and total water cut of field for one of the best models. In this picture we can see that compared to the base model we have a significant improvement in matching the production profile of field oil rate and water cut.

To better understand how the reservoir parameters change as a result of history matching, we plot the multipliers of each variable over the base reservoir model in Fig. 9. On balance, we increase parameter values in the model although there are regions where decreases are necessary. Typically, we increase the ratio of horizontal permeability versus vertical permeability from 10 to around 13 and this increase leads to more edge drive from the aquifer and less bottom drive. This is better seen in Fig. 10.

In Fig. 11 we can see the total misfit value of the base model and the 10 best models history matching and forecast periods along with the percentage reduction. The history match misfit is around 70% lower for all models but for forecasting the reduction varies from 10 to 40 percent. Overall, model 9 is the best model and we plot the oil rate and water cut for 4 wells in different locations to see the change of production profile (Fig. 12). The forecast period also has a good match.

3.3 Sensitivity of pilot point locations

In order to understand better the importance of guiding the choice of pilot point locations in the reservoir by streamlines we perform a sensitivity analysis. For each well the streamline approach is used to identify a preferential location of the master pilot point and the modified area is offset from the well. This means that roughly three-quarters of the area around the each well is unchanged. In this study we consider the relative impact of changing those other three quarters, each as a pilot point region, separately or together with the streamline guided region. We identify the streamline guided area in Fig. 13 as the black box and the other three regions using the colored arrows with labels A-C for each well. These new pilot point locations are treated in the same way as the streamline guided area such that the dimensionality of the sub-problem is the same.

We choose the three wells in Fig. 13 due to their respective fluid behavior which results from connectivity between wells and to the aquifer. For Well 1, regions 1B and 1C are located between Well 1 and another well and changes there will affect the water displacement from the aquifer. The streamline guided area for Well 2 is also in the edge of the reservoir with an injector nearby. There are two other producers very close and within the box. Although we target a particular well to improve the match, we do not want to degrade the match of other wells in the process. Area 3 is located at the centre of the reservoir and there is no injector close to this well. In contrast to wells 1 and 2, this well is completed in both geological intervals whose different properties add complexity. Three areas for pilot points are chosen in both intervals around this well and each could be representative of different water displacement toward this producer.

Well 1 and 2 history matching cases are three dimensional for the original streamline guided region and so for A, B and C the same dimensionality is considered. We change each of A, B and C properties on their own but also perform history matching modifying them with the region identified from streamlines so that we have six dimensional problems. The reason for combining two areas (or sets of pilot points) is because we want to investigate whether or not there is a local interaction or if changes are spread more widely round the well. For area 3, however, because the pilot point locations are in two intervals we have 6 dimensional history matching cases to begin with. Therefore we only run history matching individually in 3A, 3B and 3C.

Fig. 14 compares the misfit change when updating the alternative areas A, B or C on their own compared to the streamline guided case. The streamline guided result is clearly the best option in all cases. There is some improvement to the target wells when changing the properties in the other areas. In fact, we get different results with less change in the streamline guided region when combined with A, B or C. However, we also found that the misfit of non-targetted wells deteriorated so if these were included in the misfit then very little change to the alternative areas occurs. This sensitivity study for the three wells shows that regardless of the complexity of the history matching problem by the combination of well location and interaction with other parts of reservoir, the optimum location of pilot points around these wells are based on the streamline guide approach.

4. Well Vicinity vs. Streamline Guided Approach

In this paper so far we introduced an updating scheme for history matching of Nelson based guided by streamlines and in the previous sensitivity study we showed that this is an optimal method for choosing the right area of the reservoir to change to reduce the mismatch. On the other hand the alternative and most used method for updating the reservoir is by considering the area in the vicinity of each well, as in Fig. 15. In this case we assume that the region around the well is equally important in order to improve the oil displacement from the aquifer or injector to the producer [11]. The modified region now has the well located in the middle. As above, we use the local multi-variable scheme for each well to improve the same reservoir properties. The only difference here is the location of the pilot points. Again we consider the reduction in the production misfit.

For 7 wells in the reservoir we plot the reduction of oil and water production misfit in Fig. 16 and compare the results to the reduction for the streamline guided approach. We also compare the trend of the reduction compared to the original value of misfit for base reservoir model. The first observation of Fig. 16 is that for all these areas we have a reasonable decrease in misfit value for the well vicinity approach but the streamline guided approach is twice as good.

After combination of the best models in each region we generate the 10 best reservoir models for the well vicinity approach. We calculate the total production misfit of oil and water for the wells we used in history matching. Fig. 17 shows the production misfit for base reservoir model and for the best 10 models for the streamline guided and well vicinity approaches. Overall the well vicinity approach is fifty percent worse than the streamline guided method (Fig. 17a). Moreover, the forecast is worse if the streamline guide is not used (Fig 17b).

One important issue in history matching is the correlation of forecast versus the history matching misfit. We need to know whether a good history matching model also gives a good forecast. For this purpose we plot the misfit improvement in forecast versus history matching for the best 10 models chosen after matching for both streamline and well vicinity cases in Fig. 18. There are two main observations about this figure. Firstly, there is a broad correlation that better history matching models forecast better albeit with some deviation. The streamline guided models consistently match history and forecasts better than those obtained with the well vicinity approach. An important consideration for the history matching process is how we update the reservoir: are the new properties consistent with our prior geological knowledge? In Fig. 19 we can see the multiplier of parameters for the best model of well vicinity cases which are qualitatively similar to the results for the streamline guided study (Fig. 9). On balance, there are increases to the variables across the model. These changes are very smooth in most of the areas for streamline cases but the well vicinity case results is more localized changes which may be less geologically valid.

Focusing on the area indicated by the arrows in Fig. 19a, the well vicinity and streamline guided updates are quite different. This area which belongs to a production well is supported mainly by a water injector nearby. In the streamline case we observe increasing horizontal permeability which means that we try to increase the movement of water from injector to producer. On the other hand, updating the reservoir in the well vicinity results in increases to the net:gross only which means increasing the volume of oil close to the well and which delays breakthrough for the well by slowing down the front propagation. We can conclude that the streamline guided method is more accurate at selecting areas and then finding appropriate changes to make.

In the area indicated by arrow 2 in Fig. 19a, there is a production well which is supported by the aquifer below the reservoir. In the streamline guided case, by increasing the vertical permeability of the model and decreasing horizontal permeability and net:gross we effectively modify the distribution of shale in this part of the field so that there is more connectivity to the aquifer. In contrast, the well vicinity case we increase all three variables near the well but net:gross and horizontal permeability are slightly decreased to the north west.

5. Production and Seismic History Matching Results

An example of misfit convergence is shown in Fig.20 where the trend of misfits during history matching is plotted for 3 different parts of the reservoir. In this figure, the production misfit is only shown for selected wells (the wells targeted in those areas). The seismic misfit was obtained for the whole reservoir but it was affected only by the region close to the specific well in each case.

A local multi-variable (LMV) approach was used as described before which means that each history matching case consists of seven 3 or 6 dimensional sub-cases. Each sub-case provided us with an updated set of parameters which was then amalgamated to obtain a better fitting model. We then built a set of the final 10 models by including modified reservoir parameter from the 10 best results from the sub-cases.

In this study we have targeted the 13 worst matching wells with one master pilot point per well. These wells make up 84 per cent of the total production misfit. 7 of these wells are completed in the top geological interval so we do not change properties at those locations in the intervals beneath. In this case each history matching problem is three dimensional. The other 6 remaining wells that we focus on are completed in both oil filled intervals where we update properties. The problem is therefore six dimensional for these regions. Overall, the problem is 57 dimensional by using the local multi-variable approach is a combination of 7 three dimensional problems and 6 six dimensional problems. The seismic misfit was obtained for the whole reservoir but it was affected only by the region close to the specific well in each case.

After combination of updated reservoir parameters we again selected the best 10 history matched models (Fig. 21). The history matching result is investigated for its capability to predict the future behavior of the reservoir (i.e. beyond the history matching period to forecast from 2000 up to 2003). For this purpose the well production data between 2000 and 2003 were used to measure the forecast accuracy of the best 10 models from each case. We know that because the history matching is non-unique we do not expect the forecasts to be the same.

From Fig. 21 it is clear that we successfully update the reservoir properties by reduction of misfit with 50% and 30% in history matching and forecasting periods. Fig. 22 shows the time-lapse (4D) signature prediction of the best history matched model. Comparing each model with the base model (Fig. 22b) a general improvement of seismic in the middle of the reservoir was observed.

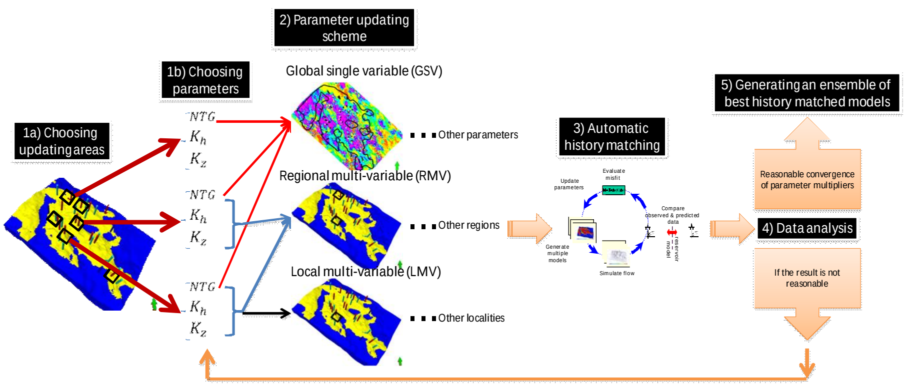

Fig. 1. A general strategy to have success in automated production and seismic history matching.

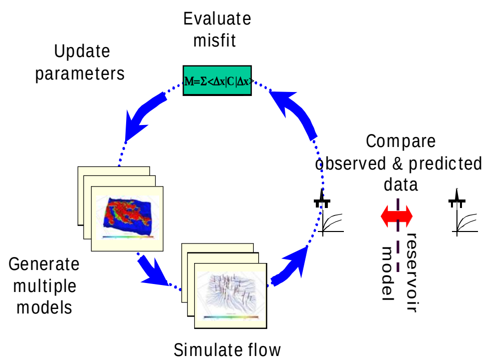

Fig.2. The automatic history matching workflow (details in Stephen et al. 2006; Stephen et al. 2009).

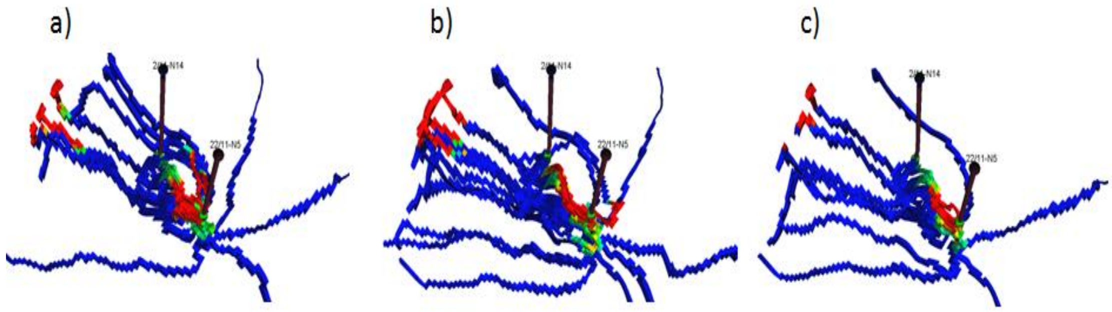

Fig.3.A fraction of streamlines for one production well in Nelson showing a cluster of streamlines for a) July 98, b) Oct 98 and c) Jan 99.

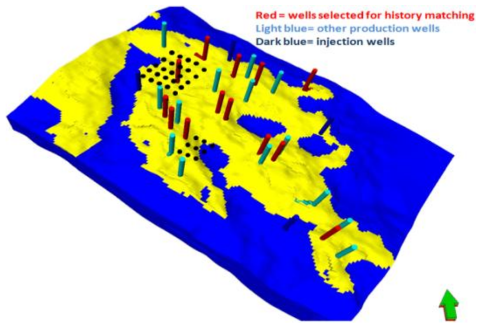

Fig.4.Location of wells selected for history matching and other production and injection wells in reservoir. The black dots are two example master pilot points for two wells.

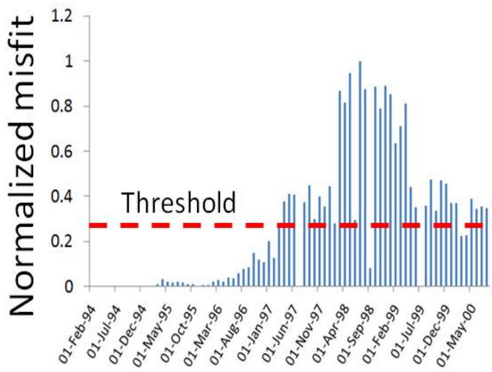

Fig.5.The normalized misfit value for an example well as it varies over time. A threshold of 25% of the maximum is used as a threshold for investigating streamline distributions.

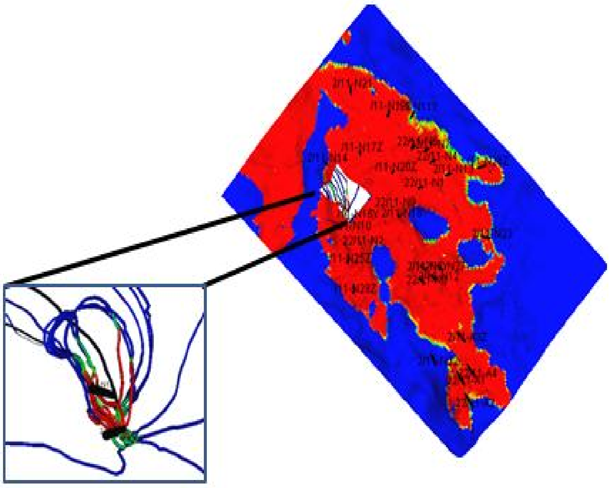

Fig.6.An example location of the master pilot point near a well chosen by streamlines

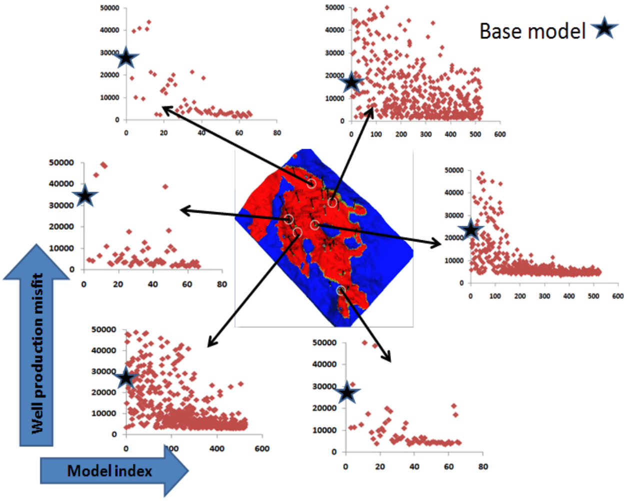

Fig.7.Well water production misfit versus model index for 6 wells in different part of the reservoir, the blue star shows the misfit value of base model.

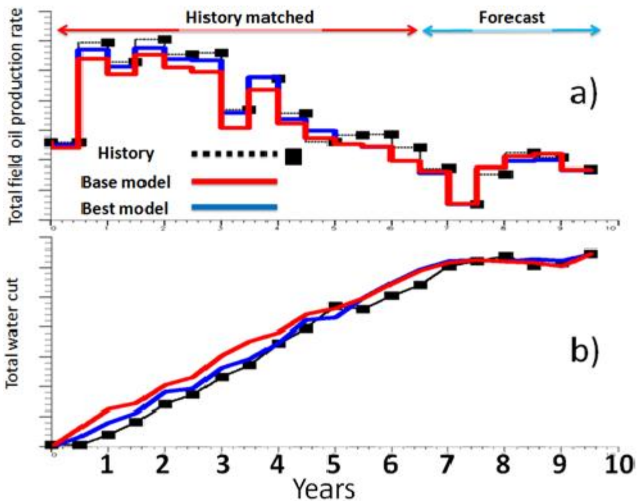

Fig.8.(a) Total field oil production rates (b) and water cut for the best model compared to historical data and the base case model.

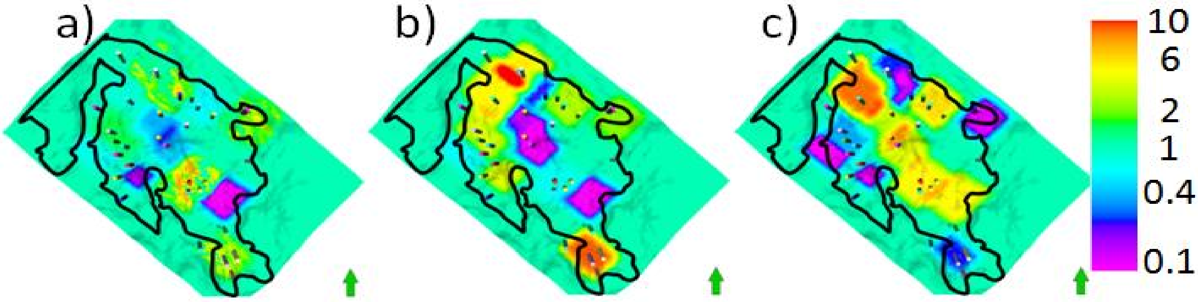

Fig.9.Multipliers of parameter for the best reservoir model over the base model for a) net:gross, b) horizontal permeability and c) vertical permeability.

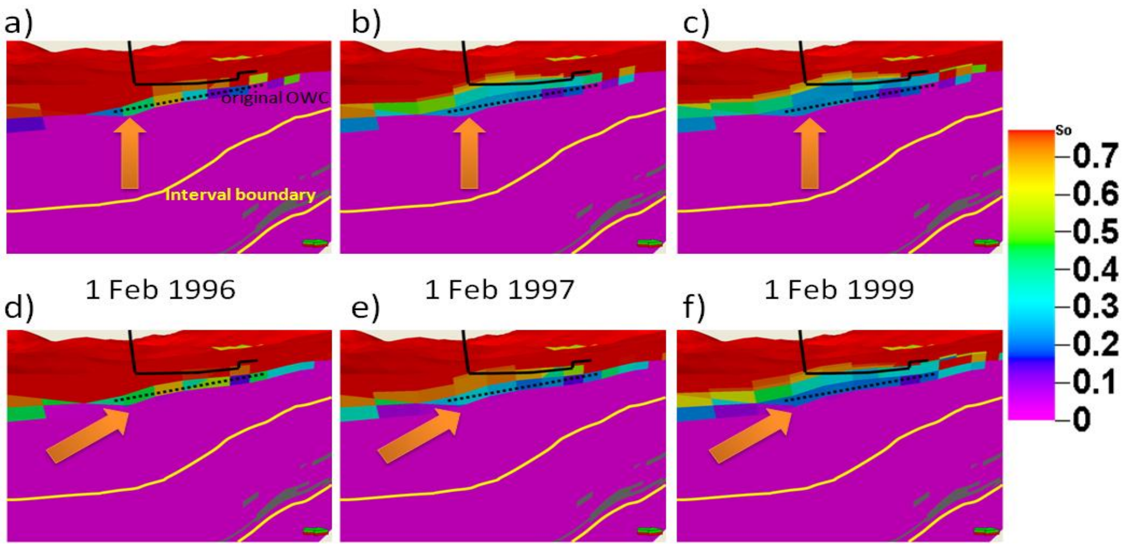

Fig. 10.Cross section of water movement near a well for the base model (a to c) and one of best models after history matching (d to f) in different time steps. The arrow shows the water discplacement from the aquifer toward the well. Because this is a 3D view the water oil contact does not look horizontal.

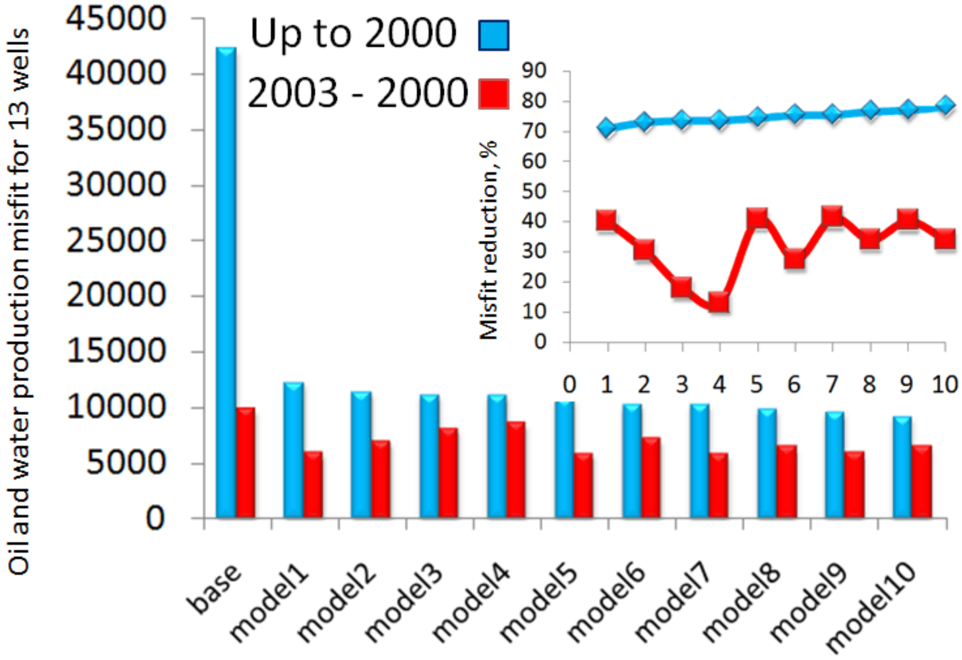

Fig. 11.Oil and water misfit reduction for best 10 models in history and forecast period.

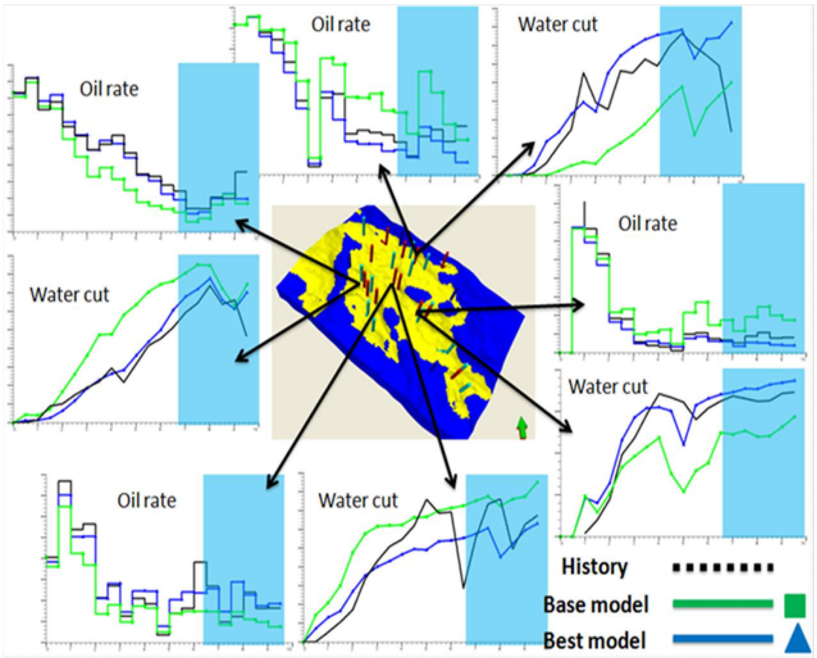

Fig. 12. Oil rate and water cut of 4 different wells in history and forecast (light blue) period.

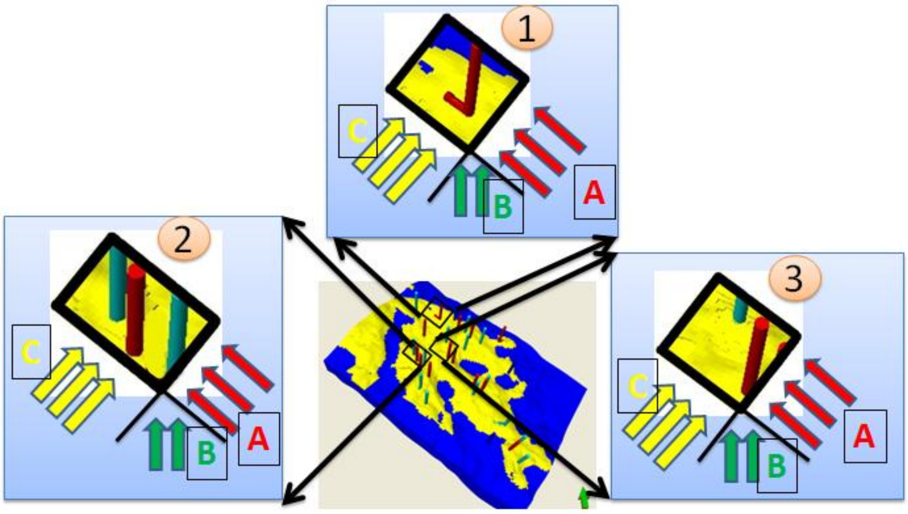

Fig. 13.Three wells and associated areas in the reservoir chosen for a sensitivity study of the streamline guided approach. Black boxes indicate regions suggested for updating by streamlines while A, B and C regions are alternatives considered for each of the three wells.

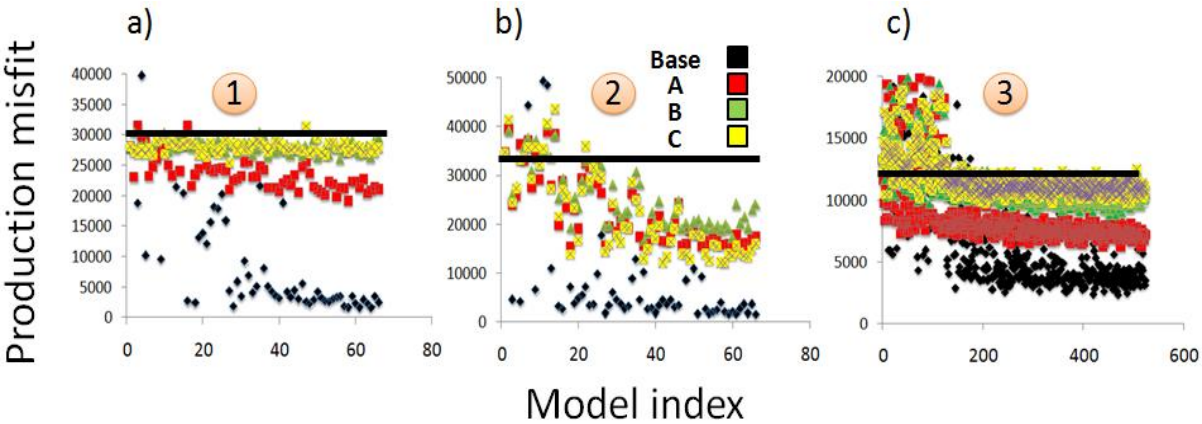

Fig. 14.Reduction of production misfit value using new location of master pilot point compared to the original case using streamline guide approach for 3 areas a) 1, b) 2 and c) 3. The colour coding is consistent with the colours of A-C in Fig. 13.

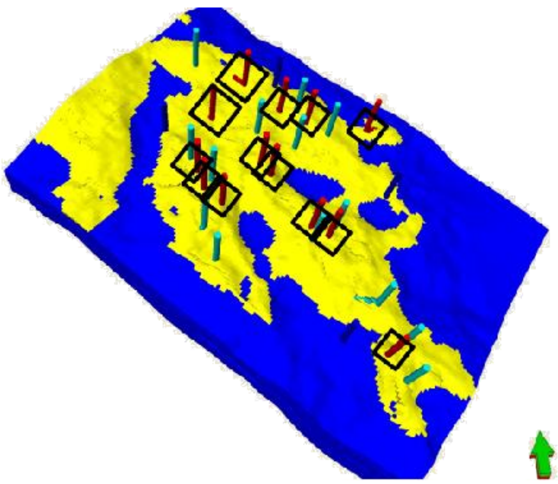

Fig. 15.Location of master pilot points in black box in the vicinity of each well.

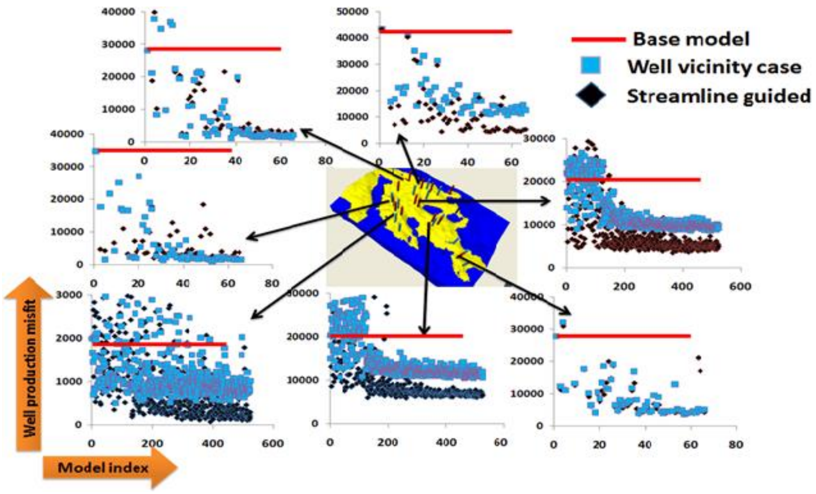

Fig. 16.Well production misfit through history matching for well vicinity and streamline case in different locations in the reservoir.

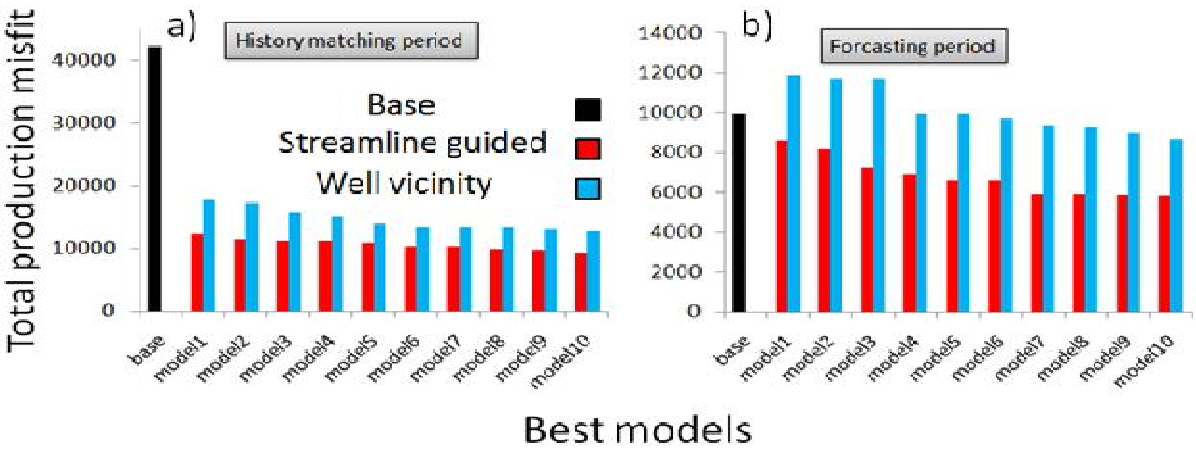

Fig. 17. Total production misfit value of the wells used in (a) history matching in matching period and (b) forecast period.

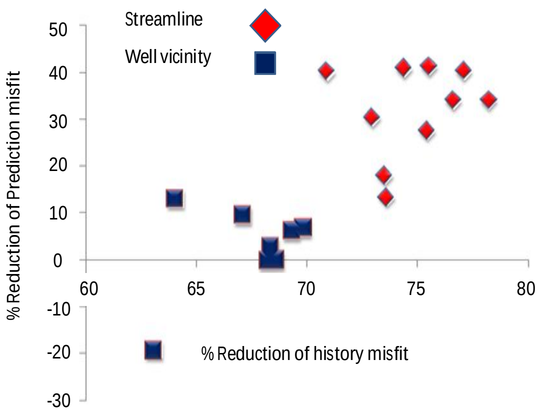

Fig. 18.Cross plotting of misfit reduction in matching and forecast period for best10 models of well vicinity and streamline cases.

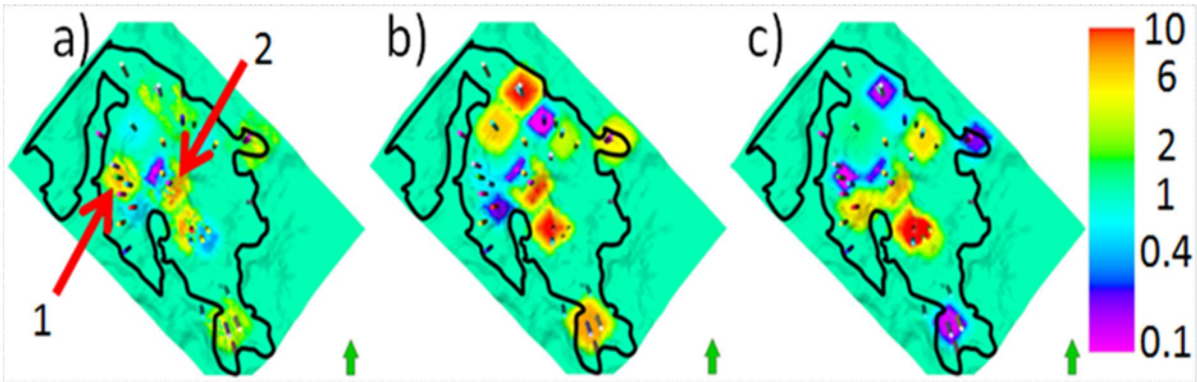

Fig. 19. Multipliers of parameter for the best reservoir model over the base model for a) net:gross, b) horizontal permeability. and c) vertical permeability.

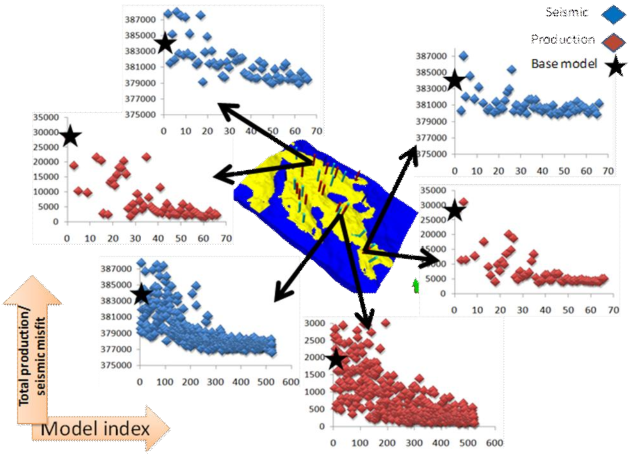

Fig.20.Misfit reduction for seismic and liquid production rate for each well for 3 different areas of the reservoir.

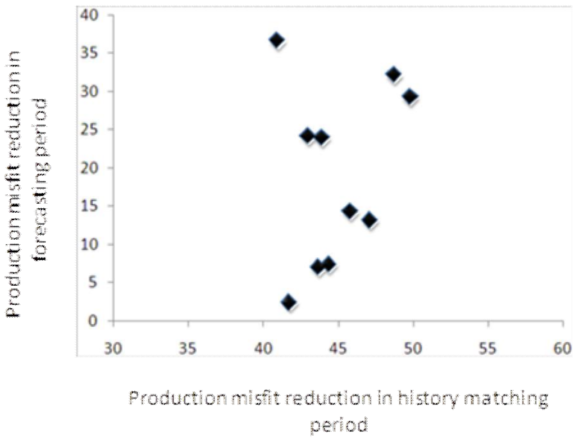

Fig.21. Reduction of total production misfit in forecasting versus matching periods for different history matching studies.

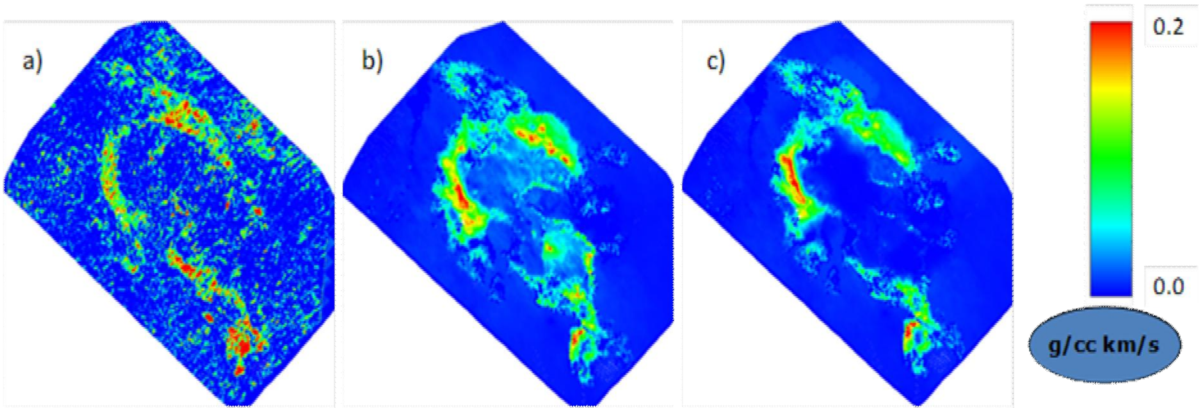

Fig.22.a) observed seismic data, b) synthetic seismic for base simulation model and c) synthetic seismic of best history matched model.

6. Discussion

In this paper we showed how we can define identify the best regions in the reservoir for updating using streamlines as a guide. We found this method very useful in the Nelson field though there could be some fields where the approach requires more care in application. One case might be where we choose to update near a producer and then a new well is drilled during the history matching period. In this case the density of streamlines will be change because of the impact of the new well. We would therefore need to history match in stages, perhaps focusing on the initial well configuration and then making further modifications once the new well is in place.

As an extension to this, we may consider that instead of focusing on the time steps with high misfit only, we could give equal importance to each time step. Then, from the beginning for each time step, we could map the streamlines towards the production wells and add pilot points to control changes to these streamlines. We would update the reservoir parameters successively for each time step by carrying updates onwards in time. If the new model can match the production profile of the well we can continue with this model otherwise we need to map the streamlines onto the new time step and by choosing new pilot point we update the reservoir through history matching.

Another case where the approach may require care is in a mature field with high well density. Finding the location to change may be problematic. On the one hand, this case may be easier to history match if the well separation is less than the correlation length of the permeability field. In this case we propose that smaller regions be considered for updating (i.e. single pilot points with appropriate Kriging parameters, including the variogram range). In this case the dimensionality of the history matching problem will increase. An alternative inversion routine would be preferable and so a Genetic Algorithm may be more appropriate.

In this study, we used a parameterization and updating scheme for better history matching called local multi-variable and applied that for a history matching study of Nelson using a number of wells. The results confirmed the usefulness of this scheme and we improved the match of the wells and also the forecast for the following three years. Comparing to other work in this area for updating the reservoir our method is more applicable for big reservoirs because it reduces the number of unknowns, saving CPU time. In most of the approaches presented previously, the whole simulation model is chosen for updating which increase the CPU drastically.

In order to investigate the optimum method of choosing the pilot point locations we carried out a sensitivity study for three wells and we found that our streamline guide approach is the optimum way of choosing the area of the reservoir for updating. Also we compare the history matching result with a case which we put our pilot point in the vicinity of each well and we found that the streamline guided history matching is more applicable and useful for the Nelson.

We applied the method for production and seismic history matching of Nelson field. This is a more complicated study because seismic data covers the whole area of the reservoir and updating reservoir parameters makes change in the synthetic seismic response. We had success to improve the match between real and synthetic seismic data as long as well production data.

7. Conclusions

The general conclusions of this paper are:

i.The well vicinity approach for updating can be used to reduce the misfit in history matching but forecasts are not so good.

ii. By using streamlines as a guide to identify the optimal area to update reduces the misfit in the history and forecast periods.

iii. Overall, the better the match, to history the better the forecast indicating a distinct correlation.

iv. Geological concepts are better preserved using the streamline guide rather than the well vicinity approach.

v. The streamline guided approach works very well in a local multi-variable method.

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Nomenclature

Q	Production rate, water or oil, m3/day
OBS	Observed production data
CAL	Calculated production data
σ_Q	Standard deviation of observed data, m3/day
n_i	The initial sample NA needs for its initialization
n_s	Total number of models NA generate for each new step
nr	The best model chosen after each step of NA for generation of Voronei cells

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