Reservoir Modeling of a Deep-Water West African Reservoir: A Fully Integrated, Multi-Scenario Approach

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Introduction

In the early stages of field development, there is a high degree of uncertainty in reservoir description. Creating a range of reservoir models allows proper assessment of reservoir uncertainties in a more rigorous way than using a single base case model. This is crucial in fields with significant geologic and production complexities where new in-fill wells are drilled to accelerate production, increase reserves and maximize oil recovery. This case study demonstrates the application of a decision tree-based methodology to model multiple uncertainties for an off-shore field in West Africa. The goal was to understand which uncertainties have the most significant impact on fluid flow and create several dynamically tested reservoir models to represent them. Models were created quickly over a small sector area. Initial dynamic simulations provided feedback that improved the seismic interpretation and static model construction for subsequent iterations. An integrated team composed of a geophysicist, geomodeler, and simulation engineer were able to produce a set of geologically plausible, dynamically tested full field models.

Background

The subject of this study, the Enyenra field, is part of theTweneboa-Enyenra-Ntomme (TEN) complex of fields. It is located in the Tano sub-basin of the Deep Ivorian Basin between the Romanche and St. Paul fracture zones. Basement-rooted extensional faulting created accommodation space for deepwater deposition. During the Turonian, sediments comprising the Enyenra reservoir were shed from the Tano high and deposited in the lower to middle slope as a series of aggradational levee-confined channel complexes. The reservoir is trapped laterally by stratigraphic pinch-outs and updip by faults or pinch-outs.

Enyenra is located 60 km offshore from Ghana and 25 km west of the Jubilee field in water depths varying from 1400 to 1700 m (Figure 1). From the northernmost to southernmost well, the field extends 24 km and is 300 to 1000 m wide. The Owo-1 discovery well, drilled in 2010, encountered 46 m of oil pay. Eleven wells have been drilled, six of which were completed as producer-injector pairs spaced 2 km apart. Production started in August 2017 and the current production rate is 35 MSTB/day. As of May 2018, the cumulative oil produced is 18 MMSTB and 26 MMSTB of water have been injected. Current recovery factor is 4%. Data used in this study include dual azimuth seismic data from 2014, three cores, well logs, pre-production drill stem tests, interference tests and production data.

Due to the channelized nature of the deposits, there is a high degree of stratigraphic complexity and potential for compartmentalization. Multiple channel complexes have been identified and interpretation of these is complicated by variation in erosion rates, stacking patterns, and sinuosity (Figure 2). Individual reservoir intervals are identified by upward fining successions on gamma ray logs. Reservoir extent and continuity are further validated through integration of seismic interpretations, static reservoir pressures, and interference tests. Reservoir quality is highly variable in and outside the channel axis making the location and description of this boundary critical in modeling (Figure 3). There are also finer-scale heterogeneities observed at the core scale: a range of facies types from traction to muddy debrites to cement with varying porosity-permeability relationships that will exhibit different flow behaviors.

Production from the Enyenra field has had a number of issues. Wells are currently equipped with inflow control devices allowing continued production/injection from different reservoir intervals, but some production allocation issues have been observed. High-pressure water injection created hydraulic fractures in some injectors. In addition, there is a short production history and no evidence of water breakthrough. All of these factors impact the dynamic response of the reservoir during the process of model calibration and history matching.

Methodology

Given the large number of uncertainties, it was important to evaluate them systematically and understand which have the most significant impact on fluid flow. They were divided into geologic, modeling, and dynamic uncertainties and organized in a decision tree with a range of possible values. These possibilities were combined in multiple ways to create a suite of reservoir models (Figure 4).

To quickly build and simulate these models, a subset of the field (15% of the total area) was selected for a sector model study. This area showed a variety of stratigraphic and production complexities, representative of the larger field. Various styles of seismic interpretation were created and multiple models were generated from these using different combinations of geologic and modeling uncertainties. These models were dynamically tested and the simulation engineer, geomodeler and geophysicist jointly analyzed the results in an iterative loop shown in Figure 5. Together, the team learned which factors were of most importance and focused on those for subsequent rounds of testing.

During this phase, only six months of production data were available. The dynamic models were constrained by daily production and injection rates. The difference between the simulated pressures and observed pressures were compared for the different scenarios from the decision tree.

Results

The sector model testing reduced the number of plausible models resulting in a simplified decision tree, shown in Figure 6. Following are some details on how various branches of the tree were retained or discarded.

Seismic interpretation styles from channel sequence (coarse) to channel scale (fine) were tested along with different variations of channel geometries. Comparisons of predicted versus actual pressures indicated that a fine-scale (channel complex scale) interpretation of four continuous complexes produced the best match (Figure 7).

Environments of deposition such as channel axis, margin and levee, were defined in various ways: using seismic amplitude cutoffs or polygons interpreted on amplitude and thickness maps. History matching showed that 3D amplitude-based cutoffs produced models that were too disconnected, so this branch of the decision tree was discarded from future testing.

Grid resolution was tested early so that simulations could be accelerated using a coarser grid without compromising the desired level of geological realism.

Fine-scale uncertainties were also tested. The layering style of the grid was especially critical for wells located near the channel-levee boundary. There is a large variation in net to gross in this area which impacts how these regions are connected to each other. History matching provided guidance on connecting these regions into a single zone, indicating that layers should follow the base of that zone (curved layers) rather than pinching out as flat layers (Figure 7).

Other fine-scale uncertainties evaluated were the vertical and lateral extents of petrofacies derived from seismic and well data. Testing showed longer correlation lengths, implying greater connectivity, led to better history matches.

The proportion of petrofacies was also a major uncertainty due to limited sampling. Petrofacies were populated using a soft trend based on seismic amplitudes. Vertical proportion curves were implemented to distribute traction facies at the base of channels and shalier facies at the top.

The location of lateral baffles were derived from seismic amplitude extractions showing potential discontinuities in the reservoir. Different global permeability adjustments were applied to the straight and sinuous portions of the channels to account for varying connectivities and predictable contrasts in effective permeability in areas of contrasting depositional architecture. The number and location of these additional baffles were verified by history matching.

In two months of testing, the range of uncertainty was narrowed as several branches of the decision tree were eliminated. Remaining uncertainties such as transmissibility multipliers, petrofacies proportions, and correlation lengths were combined to generate a range of plausible models. From this range, independently derived low, mid, and high case models were selected. This approach is more valuable in the context of uncertainty assessment than creating a single base case model or generating an ensemble of purely stochastic permutations of a single underlying concept.

Conclusion

The benefit of this workflow is to systematically create a range of reservoir models by identifying multiple complexities at different scales and testing them to understand which are the most important for fluid flow. By confining the work to a sector area, the team quickly learned which modifications needed to be made to the static model rather than applying more blunt modifications in the dynamic model. The sector model workflow was employed to make multiple full field models by extending the seismic interpretation and incorporating all wells. These models have been used to optimize locations of infill wells and assess the value of accelerating production. There is greater confidence in the predictability of these models as minimal adjustments to the dynamic model were required to achieve history matches.

Acknowledgements

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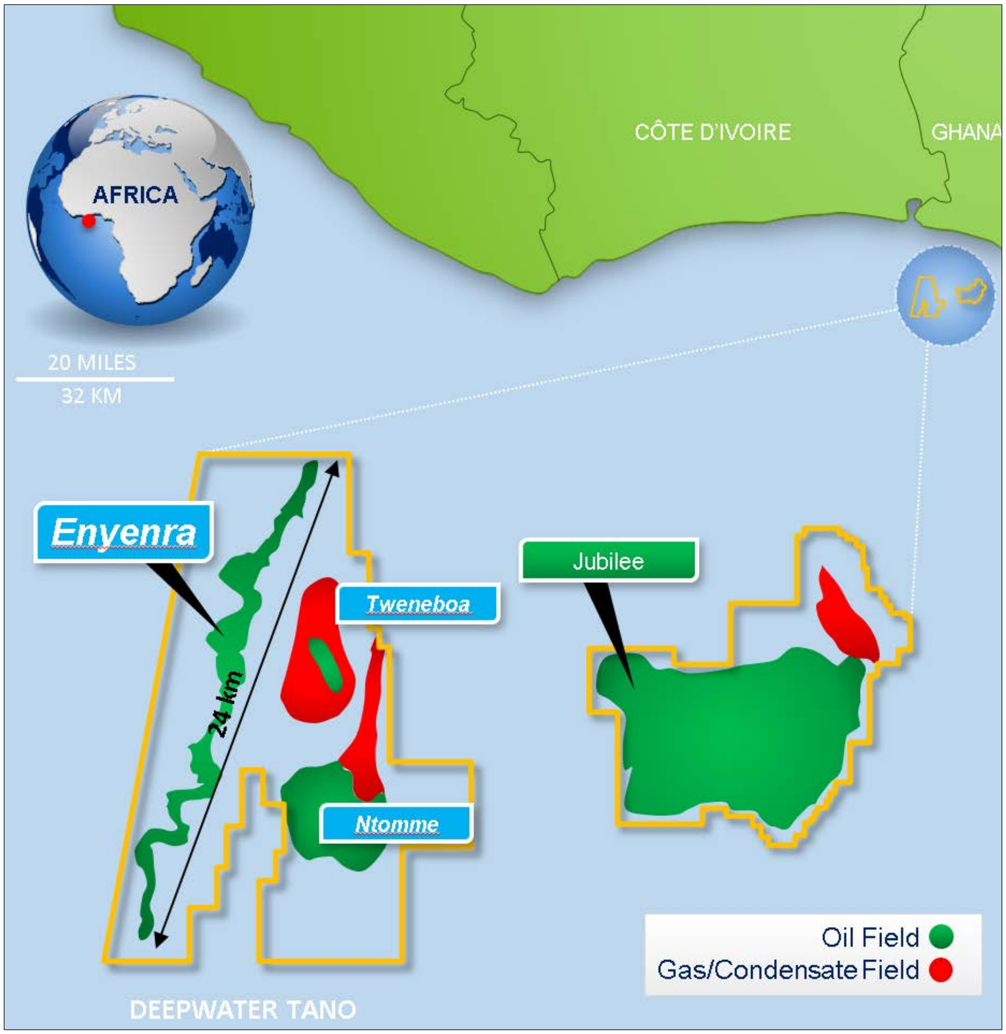

Figure 1. Location map for Enyenra field. The field is located 60 km off the coast of Ghana and 25 km west of the Jubilee field. From the northernmost to southernmost wells, the field extends 24 km and varies in width from 300-1000m.

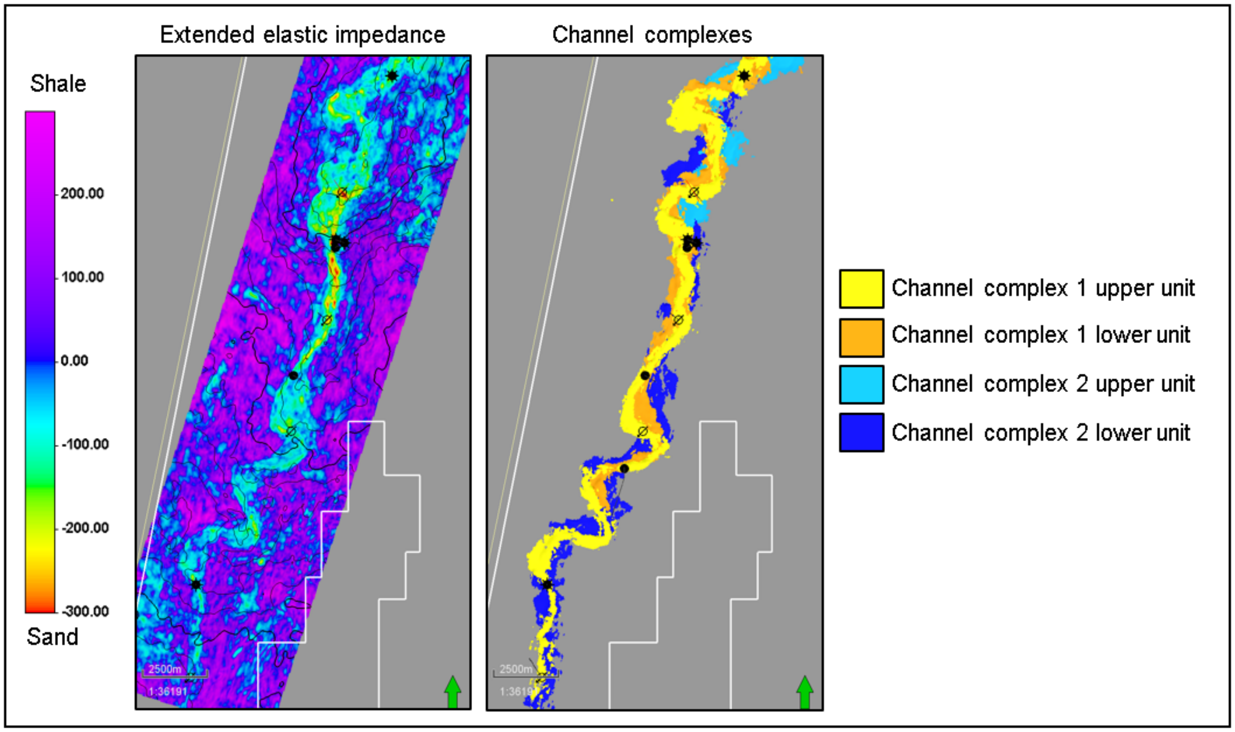

Figure 2: Sum of negative amplitudes extracted from an extended elastic impedance volume showing possible sand distribution. Four channel complexes were identified on seismic data and verified with static pressure data.

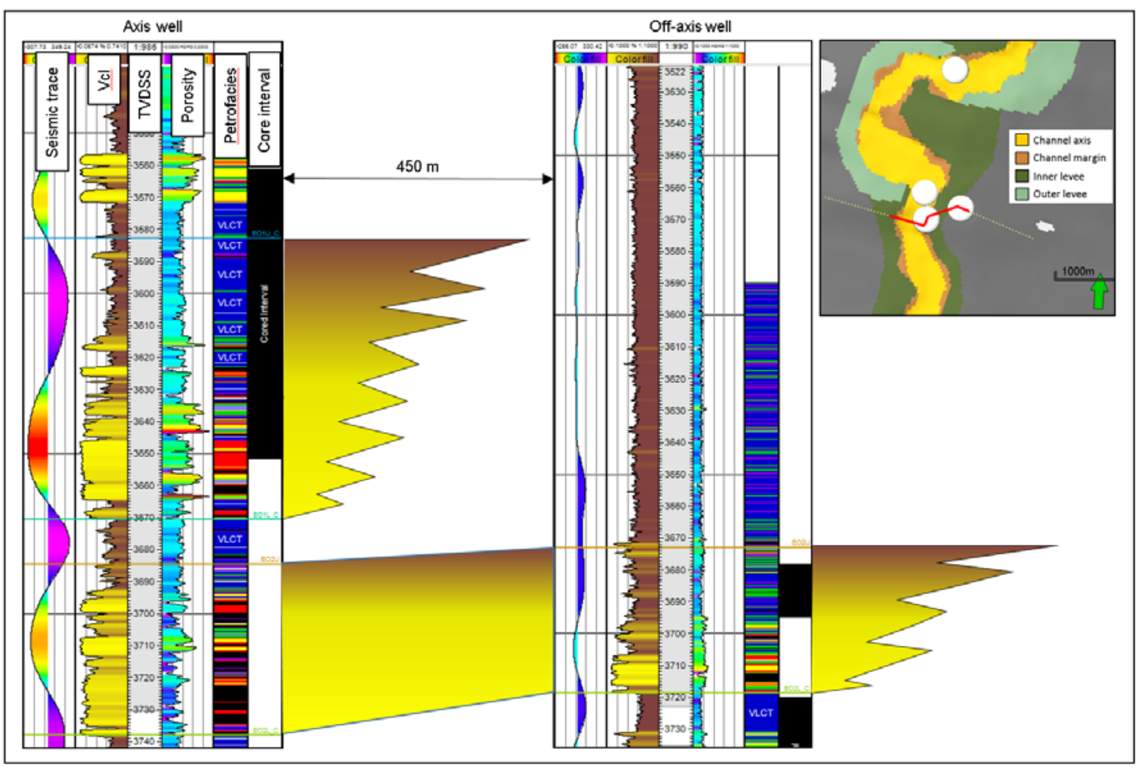

Figure 3. Wells inside and outside the channel axis show a highly variable net to gross.

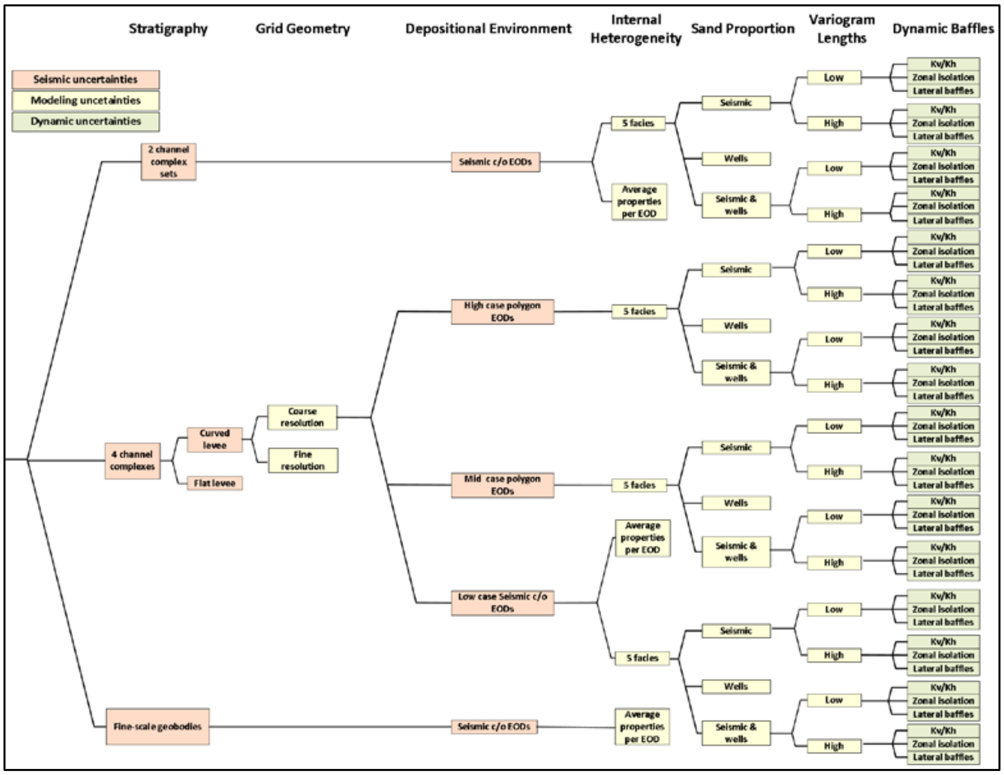

Figure 4. Decision tree illustrating the seismic, modeling, and dynamic uncertainties considered in model construction.

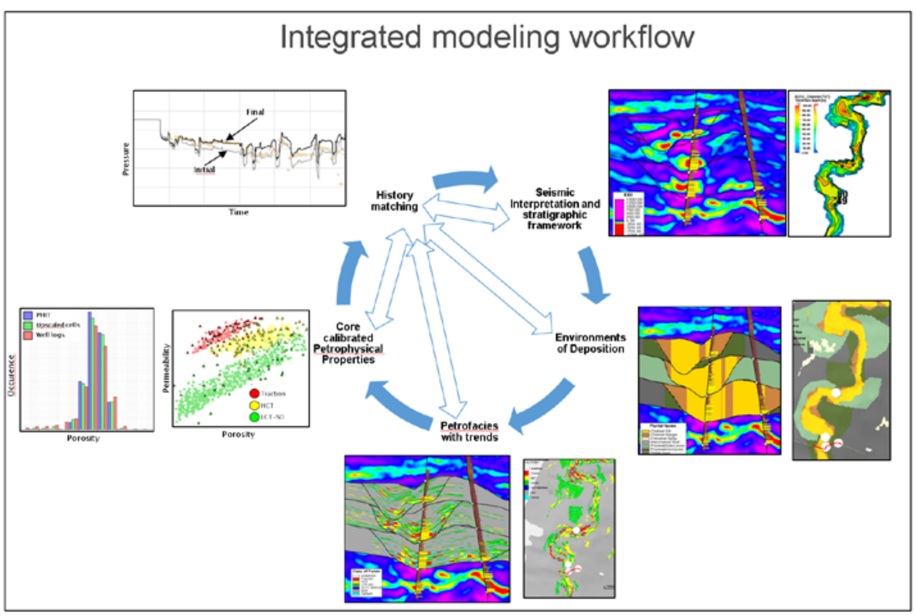

Figure 5. Integrated modeling workflow illustrating the loop from seismic interpretation to static modeling to dynamic simulation and the feedback provided by history matching to update the seismic interpretation and static model.

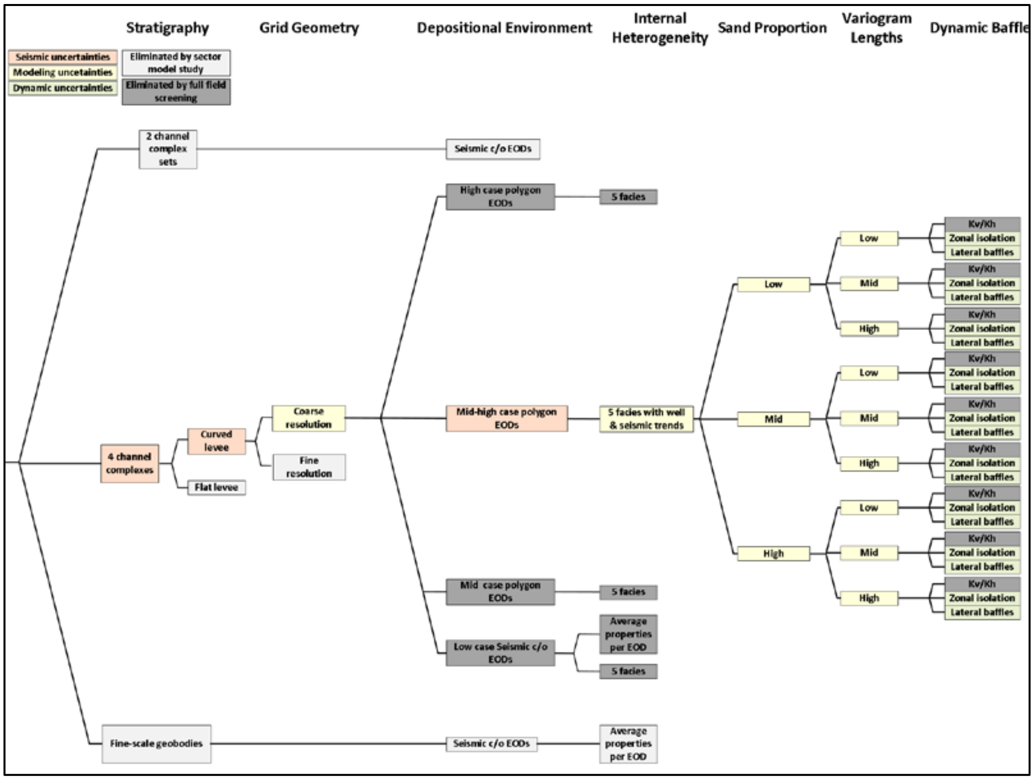

Figure 6. Simplified decision tree after testing in sector area.

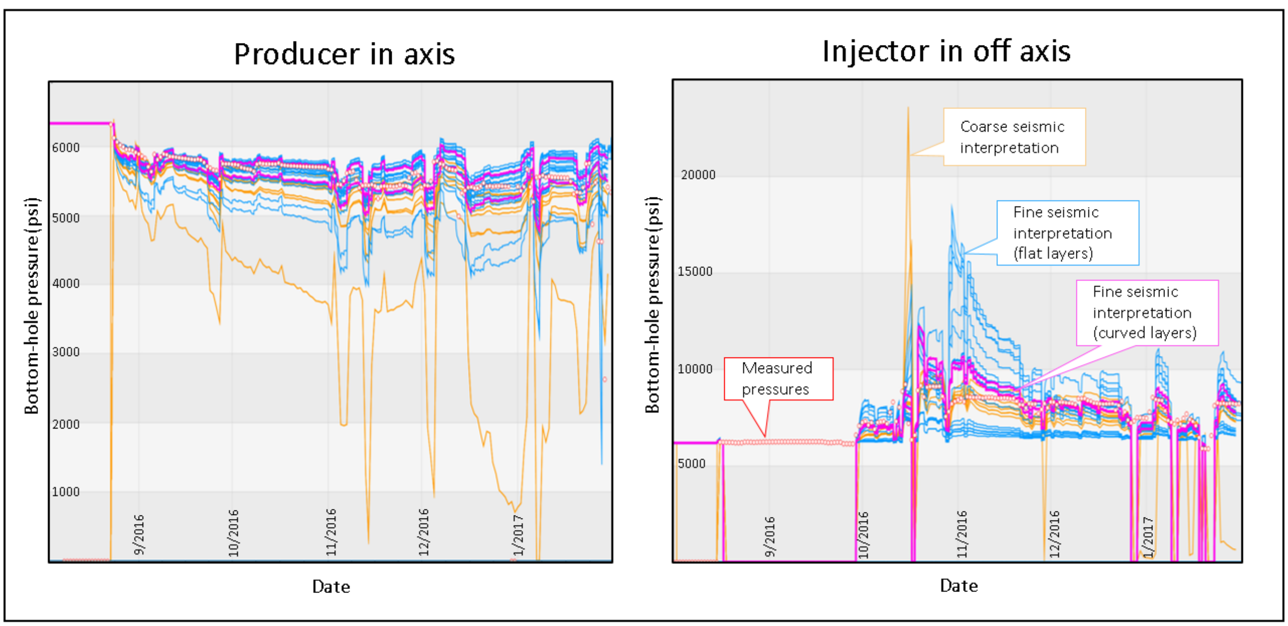

Figure 7. Comparison of actual bottom hole pressures (red circles) and simulated pressures for various scenarios (colored lines) over six months. These results indicated that the coarse-scale seismic interpretation (yellow lines) produced pressures that were too low, suggesting the models were too disconnected. Using curved layers in the fine scale seismic interpretation (pink lines) produced a better match between modeled and actual pressures.