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An Integrated Case Study from Seismic to Simulation through Geostatistical Inversion

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Abstract

The field is located in the Persian Gulf and has been producing for the last 30 years with a strong natural aquifer support. The clastic reservoir exhibits highly heterogeneous permeability combined with shale streaks and therefore presents complex flow behavior.

This paper describes the iterative seismic to simulation workflow followed to create a fine scale reservoir static and dynamic simulation model consistent with all available engineering, geologic and geophysical data. The process involved integration of static and dynamic modelling workflows. History matching the production data indicates locations with incorrect information in the static model, which can be corrected and re-exported for the dynamic model in very short time. The integration of static and dynamic modelling is seen as essential for the further commercial development of the field.

A comprehensive integrated study was conducted starting from petrophysical log evaluation and resulting in fine scale reservoir models on a geo-cellular grid. To reduce the uncertainty, a model was created using a geostatistical inversion technique which honoured both geologic and seismic information. The use of high resolution geostatistical inversion provided good and reliable estimates of porosity and lithology away from the wells. The porosity and lithology models were further tested on history matching 92 producing wells for 30 years. The quick match resulted in less uncertainty of porosity and higher confidence in the prediction models.

The history matched model is predicted further to define different potential development scenarios. It is now 3 years since all the data used in the study was acquired and the current field production matches with the model prediction. The models created using geostatistical inversion proved to be robust and predictive for the field development.

Introduction:

This Field is located in the Persian Gulf, 150 kms from Kharg islands. The field was discovered in fifties but production commenced in seventies. 92 wells have produced within 30 years but field currently produces from 65 wells. The national Iranian Oil Company IOOC plans to increase output after completing a static and dynamic modelling study.

The Field is producing from the Ghar formation which consists of more than 80% sands with high porosity.

The producing layer of the Ghar is about 95 metres thick with an anhydrite layer forming a cap. A small gas cap a few metres in height is observed from the logs and well tests.

The field is supported by a very strong aquifer from the west direction, helping the natural flow of oil and precluding any artificial lifting technique. Water cut is drastically increasing in many producing wells and due to low flowing bottom-hole pressure in these wells, most of high water cut wells(>40%) have problem to produce naturally. Therefore they're producing intermittently and need gas kicking to flow.

With the beginning of decline and need of more output, it is useful to have a model which can be used for production prediction.

The permeability information in the field is limited to a few core samples being taken from mostly sands. The heterogeneity of the permeability is very high, ranging from 100mD to 11 Darcies. Hence a main source of uncertainity is permeabilty.

To reduce the uncertainty, a model was created using a geostatistical inversion technique which honoured both geologic and seismic information.

Field Geostatistical Inversion

The geostatistical inversion is a technique that optimally combines well and seismic data to produce 3D rock property models suitable for flow simulation. The method uses an algorithm known as Monte Carlo Markov Chain (MCMC). MCMC is a technique for obtaining a statistically correct random sample from a complex probability distribution, via incremental adjustments similar to those made by an optimisation algorithm (such as conjugate gradients).

In the Geostatistical Inversion a rigorous probability distribution is defined linking the property and lithofacies cubes with the seismic, well logs, histograms and variograms. The histograms and variograms are obtained from log analysis and geological insight, the former giving the likelihood of different values at any given point, the latter giving essentially the "characteristic scale" and texture of the geological features in lateral and vertical directions. Subsequently, sophisticated MCMC methods are used to get a statistically correct set of samples from the overall probability distribution function (pdf), i.e. plausible alternative scenarios for what might exist in the sub-surface.

The output models from the process are both realistically detailed and consistent with the seismic data. Informational synergies within the inversion engine allow hyper-resolution and capture of details beyond the seismic resolution.

These reconstructions are as accurate as conventional seismic inversion. Moreover, they have significant advantages:

- The seismic is interpreted in terms of discrete bodies of lithofacies with sharp edges, where appropriate.
- Fine details (heterogeneity) are included
- Histograms and correlations observed in the wells and/or inferred from rock physics are fully taken into account.

This is because the seismic data provides a measured 3D data set which constrains the geologic modelling process.

At each location for which there is a seismic trace, a synthetic is made from the estimated impedance model and compared to the seismic trace. If the residuals fall below the estimated noise level the model is accepted. Otherwise the model is adjusted until the desired level of match is achieved while still honouring the histograms and variograms and well information.

Once the lithology and impedance volumes have been estimated, other reservoir parameters can be co-simulated using joint probability density functions which relate the desired parameters to the lithology and impedance. This process is also controlled by variograms and the available wells.

Geostatistical Inversion

The main goal of the Geostatistical Inversion was to provide the basis for a static model to be used for the testing of enhanced recovery schemes in a dynamic model. To do this, a Geostatistical Inversion was first used to create lithology and acoustic impedance volumes for the Ghar which were controlled by both the available well control and seismic data. These volumes were then used to co-simulate an effective porosity volume. Both the lithology and porosity volumes were converted to depth and used to build estimates of saturation and permeability.

The workflow followed was straightforward:

1. Edit and condition well logs
2. Define lithology logs
3. Estimate wavelet and tie wells to seismic
4. Interpret seismic for structural model
5. Estimate lithology and impedance volumes
6. Cosimulate porosity volume

While straightforward in principle, the field dataset provided a number of challenges which had to be overcome.

Well Log Quality: The first big problem was that the majority of the wells in the field were drilled in the 1970's and many are missing either sonic or density curves or both. Reliable acoustic impedance curves are an important part of the geostatistical inversion process, so it was necessary to synthesize the missing curves using models derived from wells with the appropriate curves.

The second problem stems from the fact that the field has been producing since 1978 but 3D seismic was only acquired in 2002. Over this time, the OWC depth (TVDSS) was estimated to have moved from approximately 881 m (2890 ft) to 872 m (2861 ft). With the very high porosity associated with the field, a change in reservoir saturation modifies other subsurface parameters like density and velocity sufficiently that it is important that the well logs are corrected for this discrepancy to ensure an accurate tie with the seismic.

Based on testing, the Greenberg and Castagna approximation to Gassmann's equation was used to perform fluid substitution.

An estimate of shear velocity is required to calibrate the computations. One of the more recent wells had a DSI (Dipole Shear Sonic Imager) recorded as part of the well log suite which was used to create a suitable fluid substitution model for the remaining wells.

For the porosity cosimulation step a second set of fluid substituted wells was created in which the entire Ghar section was replaced with the brine filled equivalent.

Lithology Definition: In this field, the Ghar formation has been subdivided into five lithologies: Shale, Tight Sand, Medium Sand, Porous Sand and Carbonate.

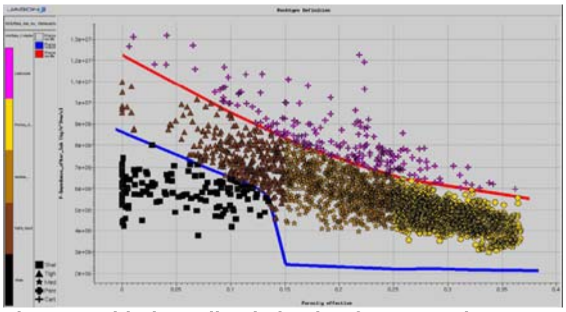

Figure 1: Lithology discrimination from Impedance Vs Porosity Crossplot

Table 1: Porosity Cut-off for Lithology Discrimination

Lithology	Effective Porosity %	
	Min	Max
Shale	Function	
Tight Sand	0	15
Medium Sand	15	25
Porous Sand	25	39
Carbonate	Function	

The shale/sand and sand/carbonate cut-offs were defined by acoustic impedance as a function of effective porosity.

In *Figure 1*, upper red line is the function used to separate carbonates from sands. The position of the line was determined by looking at a similar crossplot coloured by "volume of dolomite" as determined from the petrophysical analysis. The lower blue line shows the function used to separate the shales from the sands. The position of this line was determined using a crossplot coloured by "V clay".

Seismic Quality: The seismic dataset acquired in 2002 is generally of good quality except near the platforms where it is undershot. Seismic should be of good quality to carry out geostatistical inversion.

Since the geostatistical inversion process will interpolate through areas of missing seismic, areas with low quality seismic were removed rather than have them corrupt the inversion process.

The *Figure 2* below shows the extent of the original survey in green and the data used for the inversion in black.

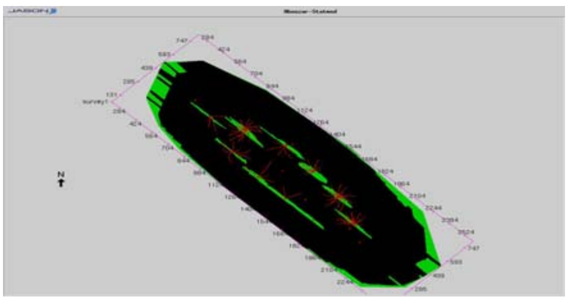

Figure 2: Areas in green indicate removed data

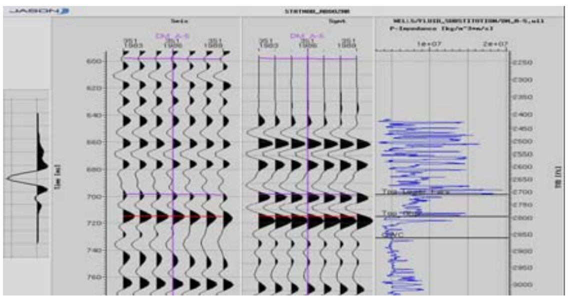

Figure 3: Example of well tie from A-5 well.

Wavelet Estimation: Accurate wavelet estimation is absolutely critical to the success of any seismic inversion because a basic assumption is that the seismic data can be modelled as a convolution of the seismic wavelet with the reflection coefficient series derived from the acoustic impedance of the subsurface.

Errors in the acoustic impedance logs or in the time to depth ties in the seismic can result in phase or frequency artefacts in the wavelet estimation. Such errors in the shape of the extracted wavelet can strongly influence the inversion results and therefore subsequent assessments of the reservoir quality.

In this field, four vertical wells (A-9, A-10, A-12 and A-19) were chosen for their geographic spread over the area. Wavelets were estimated for each well individually to determine the consistency of the data and the final wavelet was estimated from the four wells simultaneously.

The convolution of the wavelet with the estimated reflectivity from a well should produce a synthetic dataset with a close match to the original seismic data as seen in the *Figure3*. Mismatches may indicate problems with the wavelet, the well logs, or the seismic data itself.

Time Depth Conversion: The structure as interpreted is fairly simple with no major faults. Three horizons were interpreted: (starting from the top) Lower_Fars, Ghar and Lower_Asmari.

The Lower Fars and Ghar horizons were well controlled as all of the wells penetrated these zones.

The Lower Asmari horizon was less reliable as only a handful of wells penetrated to this level. In addition, the horizon was distorted in time due to the effects of gas and oil saturation on the velocities.

An initial attempt at time to depth conversion was performed using a datum horizon based on a time to depth crossplot to the top of the Ghar formation and a velocity file derived by interpolating the velocity logs from the wells.

QC’s showed that the velocity file was not reliable, particularly in the gas zone as there was little control and the higher velocities from wells in the oil and wet zones tended to be interpolated up into the gas zone. In addition, the Lower Asmari horizon in time was not very smooth when converted to depth and there were changes in the isopach which caused problems building and interpolating the Ghar layers in the static model.

To create a more useful model, the following workflow is followed:

1. Adjust the time horizons for Lower Fars and Ghar to exactly tie the corresponding well tops in time.
2. Create depth horizons for the GOC (836 m TVDss) and the estimated OWC at the time of seismic acquisition (872 m TVDss).
3. Create base of reservoir zone (Lower_Asmari_est) by shifting a copy of the Ghar datum 75.5 m down and fitting to well tops in depth.
4. Estimate average velocities for gas, oil and wet zones using velocities derived from the time to depth curves for the wells tied to the seismic (gas: 2000 m/s, oil: 2100 m/s, wet: 2700 m/s)
5. Estimate a time horizon for the GOC using the average velocities for the gas zone, the Ghar datum, the GOC depth horizon and the Ghar time horizon.
6. Fit the GOC time horizon to the well tops
7. Estimate a time horizon for the OWC using the average velocities for the oil zone, the GOC in depth, the OWC in depth, and the GOC time horizon.
8. Fit the OWC time horizon to the well tops.
9. Estimate a time horizon for Lower_Asmari_est using the average velocities for the wet zone, the OWC in depth, Lower_Asmari_est, and the OWC time horizon.
10. Fit the Lower_Asmari_est time horizon to the well tops.
11. Run EarthModel builder tool with TDC using the adjusted time horizons and the estimated Ghar datum in depth. Adjust the resultant velocity file based on the GOC, OWC and Lower_Asmari_est in time and depth.

The result was a solid model in time and depth with Lower Fars, Ghar and Lower_Asmari_est horizons which tie the wells in both time and depth. The horizon Lower_Asmari_est is approximately the same as the original Lower Asmari but is much smoother and more closely parallels the Ghar.

The solid model time surfaces from the Earthmodel builder tool with TDC are the solid model used for the Geostatistical Inversion.

Geostatistical Analysis

For each layer of the model, the parameters to be modelled and their statistical properties must be determined. Histograms are used to limit the range of the property. Variograms, both vertical and horizontal, are used to control the spatial distribution of the property.

In general the following process is used:

- Determine the lithologies to be used in the layer.
- Estimate the relative frequency of each of the lithologies.
- Estimate vertical and horizontal indicator variograms for each lithology.
- Estimate a histogram of acoustic impedance for the lithology.
- Estimate the vertical and horizontal variograms for acoustic impedance.
- Estimate joint probability density functions for co-simulation parameters.

The usual source of data for the histograms and variograms is the available well control. During the inversion process, the program estimates its own statistics based on the influence of the seismic and if necessary, the requested variograms and histograms are modified.

In the main Ghar reservoir the key problems to solve are the placement and distribution of the thin impermeable shale bodies and the distribution of the porous sands. The problems are complicated by the fact that different fluids significantly affect the acoustic impedance of the porous sands which in turn affects the seismic response. These effects must be accounted for within the model to ensure that the continuity of the lithology and reservoir properties is not affected.

To solve the fluid problem, the GOC and OWC in time were used to create a fluid mask volume as seen in the *Figure 4* below (water in blue, oil in green and gas in red).

Histograms of acoustic impedance were estimated for the porous sands for each of the fluids. But variograms were estimated based on fluid substituted acoustic impedance logs containing only brine.

In the inversion process, the acoustic impedance for the porous sands was sampled as a continuous variable, independent of fluid, and then modified based on an estimate of the fluid present at the particular sample. This ensured that lithology changes were not artificially induced at the fluid contacts.

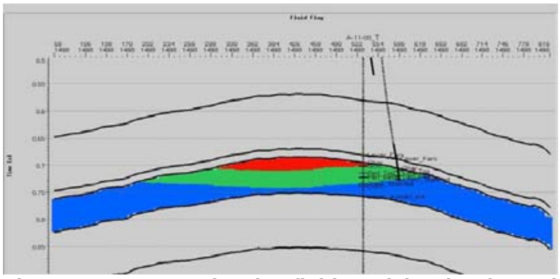

Figure 4: Structure showing fluid mask in Ghar formation.

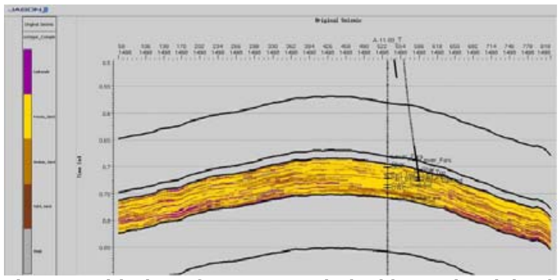

Figure 5:Lithology from geostatistical inversion (Time)

The remaining lithologies and impedances within the Ghar were sampled in the standard way. For the other three layers in the model which acted as a buffer to the Ghar zone, only acoustic impedance was estimated.

The final outputs from the Geostatistical Inversion are stratigraphic horizon files in time of the lithology and acoustic impedance. Examples of these are shown in the *Figure 6 and 7* below.

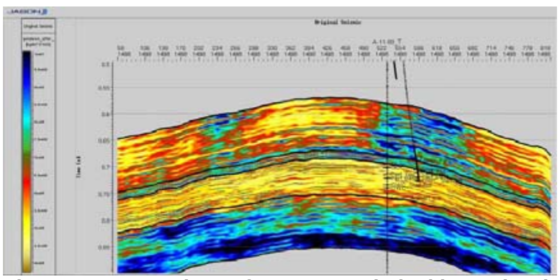

Figure 6:3D Impedance from geostatistical inversion (Time)

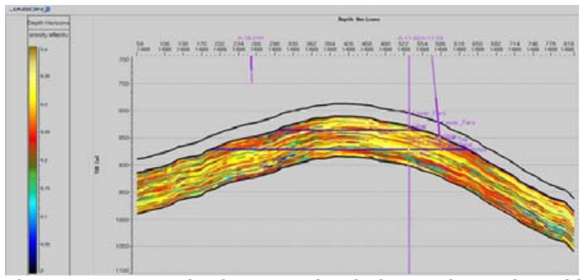

Figure 7:3D Porosity from co-simulation and TDC (Depth)

For porosity co-simulation, joint probability density functions between Acoustic Impedance and Effective Porosity were estimated for each of the lithologies in the Ghar.

To avoid discontinuities across the fluid boundaries, the fluid substitution process used in the inversion was essentially reversed. For samples of porous sands in the oil and gas zones, the impedance in the model was transformed back to the equivalent impedance for brine filled sand and then the porosity was estimated from wet sand to effective porosity quantile-correlation transform.

The output time volumes were then converted to depth volumes using the 3D velocity model.

The process created 3D models of lithofacies and porosity suitable for input into geo-cellular model building. The property models developed tie the well data and also honour the seismic data.

The data were sampled in depth at 1m. The depth models (still on the seismic grid) were transferred into the proprietory geo-cellular model building software for upscaling and output to flow simulation.

This sophisticated inversion scheme is ideal for creating 3D models with accurate prediction of the thin shale barriers in the Ghar reservoir. Such models are essential for proper dynamic performance during history matching and should provide a much more robust base for forecast scenarios than simple layer based modelling.

Geocellular Model

The geostatistical inversion provided 3D lithology and porosity volumes need to populate a reservoir grid. The volumes were sampled at 100m horizontally and 1 m vertically. The depth converted horizons were used to create a corner point grid and mesh of 1 metre thick 80 layers. The seismic derived porosity and lithology were easily brought into the fine scale grid in proprietary geological modelling package. After incorporating well paths and perforations, the model was up-scaled to coarser resolution for the finite difference simulator. Various other reservoir property models were built on the coarse model using lithology indicator. The simulator compatible model was exported for numerical reservoir simulation.

A 3D structural framework of the reservoir is built using the depth horizons as used to build the earthmodel. A corner point grid resolution has the same resolution as seismic resolution used to create the 3D properties. The 3D properties in seismic resolution have to be transferred into a depth grid domain successfully. We used a unique technique of solid model grid and property. The Solid Model is the virtual grid designed to transfer seismic derived 3D properties correctly at the same location in geologic grid. The solid model property retains the stratigraphic zonal information required with the grid. This enables the transfer of trace based 3D properties smoothly at the right location in cell based corner point grid. This technique avoids the potential re-sampling errors caused by using map based upscaling. Porosity and lithology models are resampled to the corner point grid.

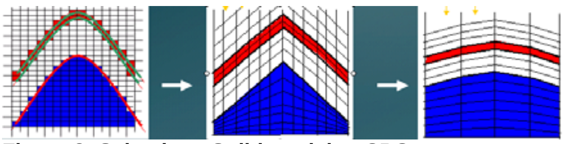

Figure 8: Seismic to Solid model to CPG

Porosity to permeability relation was developed from the core analysis information. Due to the lack of detailed permeability information for different rocks, a simplistic relation was derived. 3D permeability model in different directions are created. The permeability to shales and carbonates were defined separately with the lithology model as an indicator. The coarse grid was designed to retain as much vertical resolution inside the Ghar as possible to capture the thin impermeable layers accurately in the flow simulation. The final Up-scaled cell size was defined as 200x200m laterally and 5 meters vertically in the Lower Fars. Vertical resolution in Ghar reservoir is retained as 1 meters, same as fine model to comprise of fine details. This reduced the number of cells to 1/5th of the fine scale model, reducing the computation time for history matching and prediction runs.

Porosity, water saturation and net to gross models were up-scaled together to coarse model. Permeability models in three directions were also up-scaled to coarse grid. Different upscaling methods were tested during initial runs of simulations to determine the optimum permeability upscaling method. Other 3D properties such as connate water, residual oil saturation, and capillary pressure were all created based on the lithology indicators and the petrophysical parameters for different rocks. The well paths, perforations, skin, well connection factors for all wells were defined. A complete set of up-scaled seismically derived 3D properties and schedule files were exported to finite difference simulator for history matching 30 years of production life.

History Matching Simulation

In 2005, the field is facing water production problem and is in need of reservoir management consideration. A goal of the study is to assist in the implementation of a development plan for the field. As of 2006, not a single injection or artificial lift technology was required. With the strong support of aquifer, production has continued at approximately 165,000 bbl/day. Less reliable permeability information is available from the cored wells. Out of 107 wells, 92 have produced sometime in 30 years and the rest are abandoned, exploratory, delineation and gas producing wells. Only 6 wells are vertical and the rest are deviated or horizontal. It is very important to maintain the integrity of deviated and horizontal well paths. Small changes in KB height and inclination could cause serious problems in matching saturations around the perforations. A small error in the thin reservoir could place the perforations close to waterfront. The objective was to optimize the uncertain permeability model. Following the match, prediction scenarios are planned to derive ultimate recovery plan for the field. The water breakthrough has begun and it is time to restrict the flow further and maintain the reservoir pressure.

A dynamic simulation model was built including static model, PVT table, relative permeability, fluid & rock properties and production schedule data. Static properties with wells were exported from the geological model building package. Any changes required during the history matching phase were implemented in the static model, re-exported and simulated further.

The dynamic model consisted of approximately five hundred thousand cells with 1 meter thickness and 75 layers in the Ghar formation. Initial GOC was at 830m and OWC at 881m as shown in *Figure 16*. 5. Rock types were defined with their respective residual oil, water and gas saturations and capillary pressures.

The permeability of shales is defined 0.01 mD, carbonates 16mD and for sand, it was derived from the core analysis information. Permeability is highly heterogeneous ranging from few millidarcies up to 11 Darcies.

Match:- The initial history match runs on the 3D properties derived from geostatistical inversion gave good match with 75% of the 92 wells in terms of oil rate, pressure and watercut. Geom AH-HA(Geometric – Arithmetic-Harmonic x Harmonic-Arithmetic), permeability upscaling method gave a closer match with the field oil rate, watercut and the pressure match. The method is selected after having sensitivities on other upscaling methods.

In the inversion process, only 42 wells were used instead of 107 wells drilled so far. Due to lack of required well log curves, the limited information provided the uncertainty to the model. It was expected that the wells with no curves would perform badly in the initial history matching of rates. Interestingly it was found that 85% of the wells with no curves were matching oil rates and water cut.

Most of the problematic mismatch wells were horizontal. The horizontal sections are about 1000 metres in some wells and it is difficult to use such wells in inversion. The logs available do not have vertical variations and mostly pass through one layer rock. The oil rates were matched fairly quickly but the vertical permeability was a complete uncertain factor. Sensitivity runs suggested the Kh/Kv ratio of 50. Initially, one single ratio was applied globally. The matching process for horizontal wells involved local permeability modifiers.

Further, local modifications around 8 horizontal wells had to be applied. Permeability in K was changed to suit the water front moving faster than observed. The western area of the field is mostly producing through horizontal wells and also the aquifer flow is from west. With the availability of robust 3D porosity model, 75% of the history matching was easily achieved. The rest had to be modified with local permeability modifiers. The permeability information on the western platforms is not available form the cores. Hence the uncertainty on the permeability model is justifiable. Using a single porosity permeability relation (in case of data unavailability) on the seismic derived porosity model shows much faster history matching. Another uncertainty was with the perforation intervals. The deviated wells were recorded with surveys in seventies and sometime measured from KB or well head. This places the small perforation intervals either 2 to 4 metres higher or deeper, affecting the late or early breakthrough of water from the aquifer.

At 4 instances we found that the wells had well log curves used in inversion but had mismatch with rates and water cut. Investigation suggested increase in porosity around a well. This was immediately implemented in the Petrophysics section, porosity increased by 7-10% and then fed back into inversion. Further, a geostatistical run is made with an output of new porosity model.

The geological modelling package replaces an old porosity model with the new model and a complete chain of different models are updated with new information. As an end product, a new simulation model is output in few minutes. Modelling package's capability of storing the ancestors and descendants information makes it very easy to update models when new information is added to the model input. Updateability feature also enables the property changes, local modifications and the resultant properties are changed and exported almost immediately.

The 3D porosity model required not a single modification in order to match pressure, production rates and volumes. The volume is very reliable and robust. Had the permeability information been widely spread, history matching would have been even faster. It is believed that the 3D model created by geostatistics is very reliable in fore prediction. The wells away from the control wells were influenced by seismic information and 85% of these wells matched history without manual intervention.

The following charts show the match for field with 92 producing wells. The match at the very beginning of field's production is questionable due to the problems in production allocation in seventies.

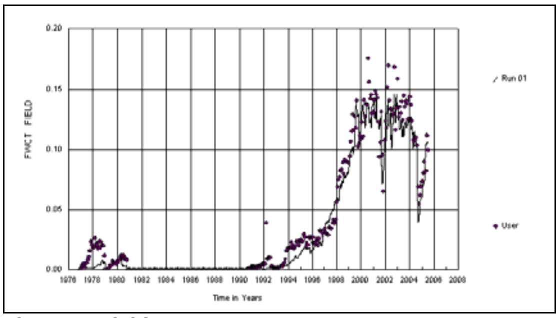
Figure 9: Field Water Cut

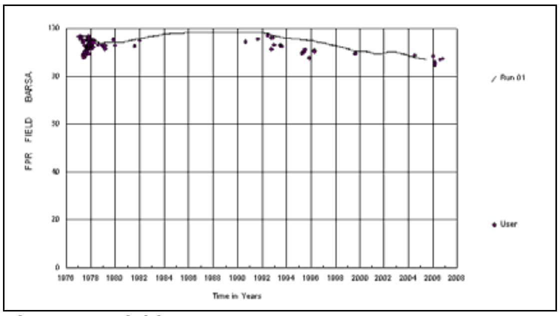
Figure 10: Field Pressure

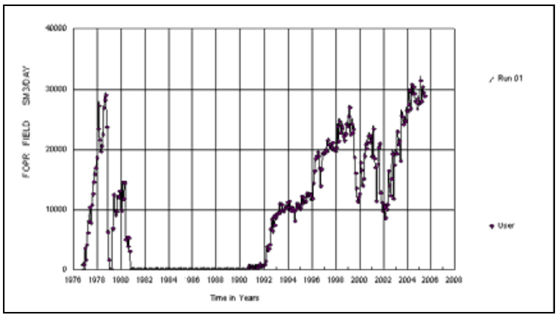
Figure 11: Field Oil Rate

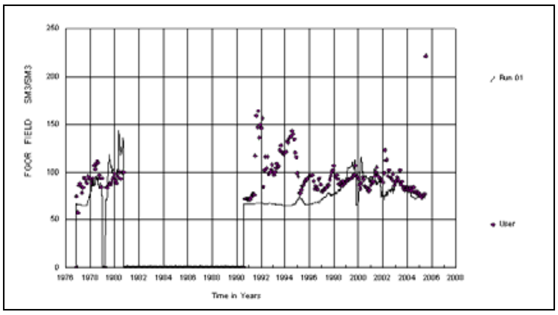
Figure 12: Field Gas Oil Ratio

Prediction Simulation

The achieved history match is considered to be the best achievable with available data, making static and dynamic model quite robust and reliable for prediction scenarios.

The increase in production and effective reservoir management was the ultimate aim of the field study.
Prediction runs were planned for four potential scenarios.

Water Flooding	Infill Drilling
Gas Injection	Gas Lift optimisation

Water Flooding: The water flooding from west periphery does not seem to increase oil production for field due to naturally present strong aquifer. The oil rates increase from eastern platforms but the western platforms water out, resulting in only 2% added recovery compared to base case standard decline run.

Gas Injection: Re-injecting the produced gas into the gas cap was another option. This would help in maintaining the cap by not allowing oil to form residual saturation in this region. It was observed that the recovery is less than the base case. Higher gas cut was observed in some of the wells. Different injection rates did not show much recovery improvement.

Infill Drilling: Few un-swept locations were identified on existing western platforms. Additional 5 new infill locations were proposed with their respective prediction rate results for next 35 years. The wells were based on the higher porosity sand locations from fine model. The recovery is expected to be 3% higher with the infill locations.

Gas Lift Optimisation: None of the above except infill drilling showed significant recovery addition as expected. The nature of reservoir with high aquifer support and high permeability discouraged the heavy usage of water injection or gas injection. More sensitivity was performed on gas lift optimisation with the aim of lifting heavier column and allowing water to be produced. Currently wells are shut with 40% water cut, but with gas lift it is recommended to let the wells produce with more than 80% water and re-inject the same from western periphery. The current produced gas in the field is sufficient to be used for gas lift option in each well. All the existing wells were allowed in simulation to produce with gas lift of incremental value 20,000sm^3. The model assigns 20,000sm^3 gas for lifting and checks if the oil rate increases by adding 20,000sm^3 more gas to the lifting amount. If no rate change is observed, the simulator uses the least value, which is 20,000sm^3 of gas. The wells be controlled by THP and shut with 90% water cut limits. Additional 13 infill wells were also proposed along with gas lift optimisation. This showed significance boost to the production and recovery from un-swept areas.

The resultant recovery observed with gas lift optimisation is 43% compared to 34% from the base case scenario. The current historical recovery is 15%. The recovery of 43% can even be increased further with the movement of perforation zones higher and advance EOR techniques.

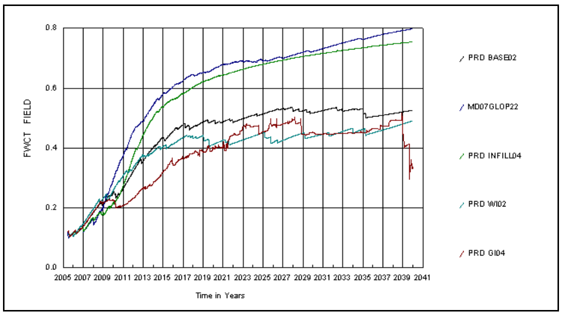

Figure 13: Prediction-Field Water Cut

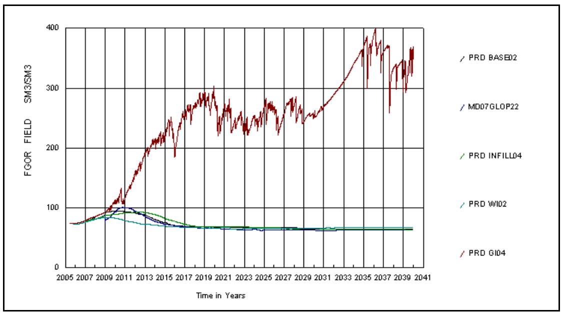

Figure 14: Prediction-Field Gas Oil Ratio

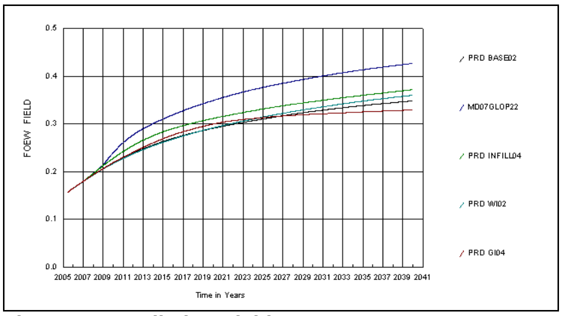

Figure 15: Prediction-Field Recovery

Gas lift optimisation with infill drilling was selected to be the optimum scenario for the development. Basic economics showed significant increase in addition recovery and revenues.

Integration: The project is fully integrated. The packages used can be used back and forth and updated very quickly with new information.

Figure 17 shows the workflow if new changes are required in history matching process or the model needs to be updated with new log when a new well is drilled.

After the initial ground work of Petrophysics log conditioning, geostatistical inversion, geo-cellular model and dynamic model building, it is very fast to run through the iteration when new information needs to be added to the project. During the history matching process if it is concluded that a particular well need more local porosity, then a fix is made directly into the porosity well log curve and then an entire process is run up to history matching as shown in the *Figure 17* in less than two days time. Decision to go back to fix log curve is only taken after few sensitivities are run on dynamic modelling parameters. It is not always that the models are fixed from the input data. Most of the times, fixes are done in history match model and the changes are not applied at the static model or well log stage. With the integrated approach it is very convenient in the future to look into the well related complications faced with the new wells. New detailed information can make a model up to date and provide with more certainty.

During the study, there were instances where history matching suggested structural or property anomaly. When it was realised, root cause was traced back to the log and fixed immediately. This was input into the inversion and the output model was ready in 4 hours. Geocellular model only needs to change with the first input 3D porosity and lithology model and rest is updated with updateability feature of the geological modelling package. The static model is ready in 8 hours for dynamic simulation.

Result: It was recommended that gas lift be implemented on the field along with 13 infill locations. Increase of water handling capacity and let the wells produce 90% water. Same water can be used to re-inject from western platforms. This may give additional 2-3 % recovery. Moving perforations higher would provide recovery higher than 43% obtainable with gas lift.

Value: A Robust and highly reliable static & dynamic model is available. Model can be easily updated in short time with new information.

30 years of history matched model with little modifications and higher reliability of volumetric and prediction model.

Model predicted achievability of 43% recovery with Gas lift Optimisation.

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Nomenclature

MCMC = Monte Carlo Markov Chain
TDC = Time Depth Conversion
PDF = Probability Distribution Function
Kh = Horizontal Permeability
Kv = Vertical Permeability
THP = Tubing Head Pressure
EOR = Enhance Oil Recovery

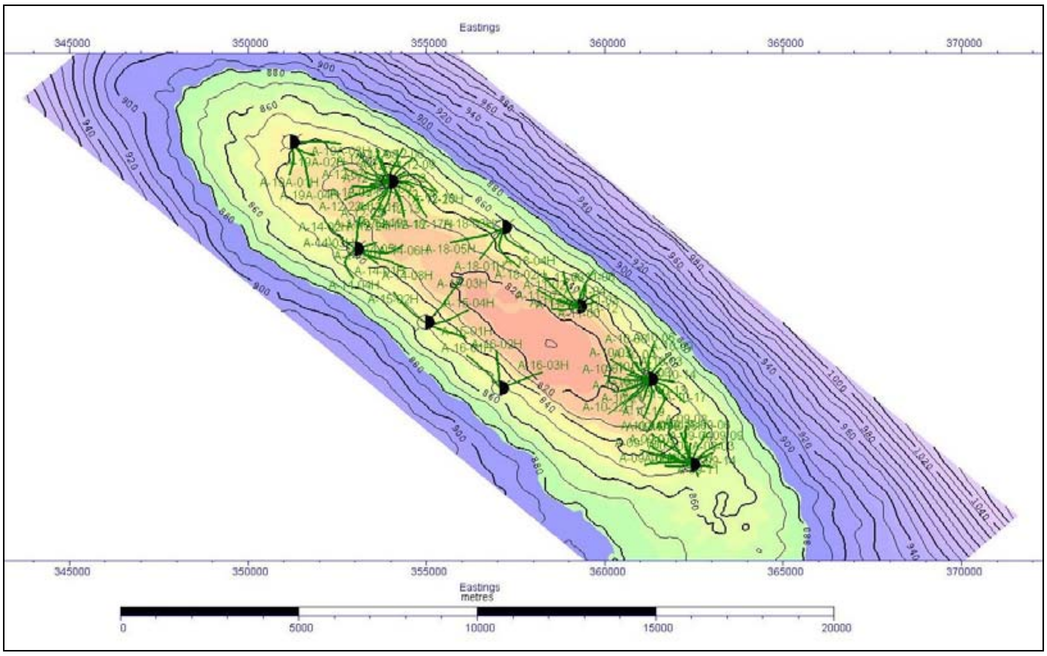

Figure 16: Field Map (Aquifer: Blue)

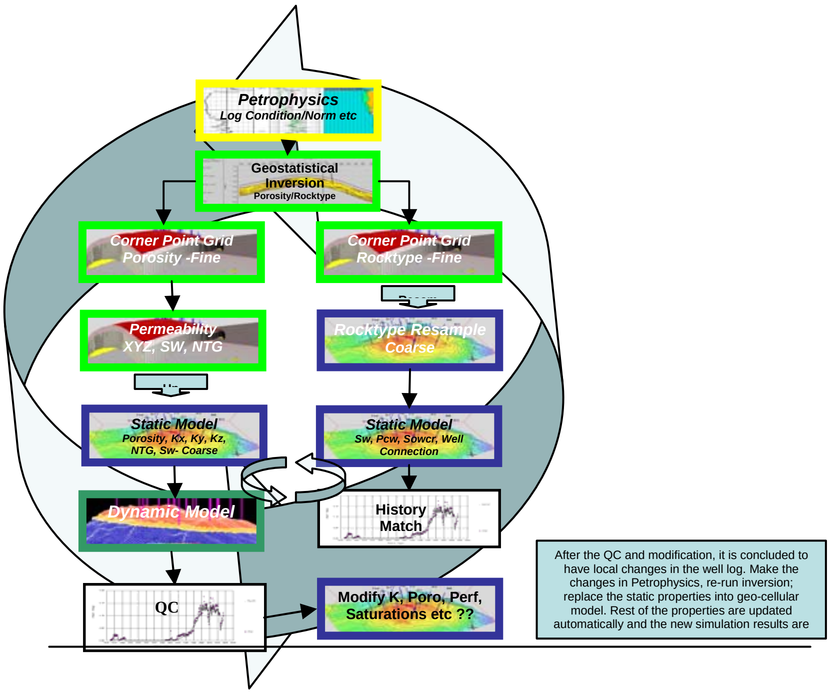

Figure 17: Brief Integrated modelling workflow