Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

By

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and/or the DIC in Petroleum Engineering

September 2014
DECLARATION OF OWN WORK

I declare that this thesis “Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan” is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Abstract

In the South Caspian basin, rapid burial and dewatering of sediments drives hydrodynamic aquifer flow from the basin centre to the basin edge. The flow of water around the ACG field causes tilting of the oil-water contact (OWC) by up to 350m across the structure and asymmetry in the aquifer pressure support. Replicating this behaviour is one of the main challenges when building a reservoir simulation model of the ACG field. Typically, multiple equilibration zones are used to simulate variable OWC depths. However, maintaining a stable tilted OWC whilst accurately capturing the aquifer response to field depletion is particularly difficult with a static representation.

This study provides a method for representing the hydrodynamic aquifer in the ACG full field reservoir model. This is achieved through three stages of modelling. First, the hydrodynamic aquifer is characterised using a basin scale flow simulation. Second, simple analytical and mechanistic models are employed to test the effect of hydrodynamic flow on aquifer pressure support during field depletion. Finally, Carter Tracy aquifers are used to generate hydrodynamic flow in the full field model, and the model performance tested against historical field pressure data.

The geometry of the OWC is found to be very sensitive to aquifer flow direction and rate, with a best fit geometry achieved with aquifer outflow to the northeast of the basin. Flow of the aquifer through a saddle point in the structure is also a major control on OWC depths around the structure. During field depletion, the analytical and mechanistic models predict stronger aquifer support for the south side of the field which faces the source of hydrodynamic flow. This finding is consistent with aquifer sizes predicted from history matched simulation models. The method of using Carter Tracy aquifers in the full field model was successful in replicating the same flow regime as observed in the basin model. By calibrating the initial Carter Tracy aquifer pressures, a good fit to the true OWC is achieved. A good match to historical field pressure data also indicates that the hydrodynamic full field model is capable of replicating aquifer behaviour during production.
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Imperial College supervisor: Professor Alain Gringarten

Abstract

In the South Caspian basin, rapid burial and dewatering of sediments drives hydrodynamic aquifer flow from the basin centre to the basin edge. The flow of water around the ACG field causes tilting of the oil-water contact (OWC) by up to 350m across the structure and asymmetry in the aquifer pressure support. Replicating this behaviour is one of the main challenges when building a reservoir simulation model of the ACG field. Typically, multiple equilibration zones are used to simulate variable OWC depths. However, maintaining a stable tilted OWC whilst accurately capturing the aquifer response to field depletion is particularly difficult with a static representation.

This study provides a method for representing the hydrodynamic aquifer in the ACG full field reservoir model. This is achieved through three stages of modelling. First, the hydrodynamic aquifer is characterised using a basin scale flow simulation. Second, simple analytical and mechanistic models are employed to test the effect of hydrodynamic flow on aquifer pressure support during field depletion. Finally, Carter Tracy aquifers are used to generate hydrodynamic flow in the full field model, and the model performance tested against historical field pressure data.

The geometry of the OWC is found to be very sensitive to aquifer flow direction and rate, with a best fit geometry achieved with aquifer outflow to the northeast of the basin. Flow of the aquifer through a saddle point in the structure is also a major control on OWC depths around the structure. During field depletion, the analytical and mechanistic models predict stronger aquifer support for the south side of the field which faces the source of hydrodynamic flow. This finding is consistent with aquifer sizes predicted from history matched simulation models. The method of using Carter Tracy aquifers in the full field model was successful in replicating the same flow regime as observed in the basin model. By calibrating the initial Carter Tracy aquifer pressures, a good fit to the true OWC is achieved. A good match to historical field pressure data also indicates that the hydrodynamic full field model is capable of replicating aquifer behaviour during production.

Introduction

This study focuses on the ACG field and how to capture its complex hydrodynamic aquifer behaviour in a full field simulation model. Lateral pressure gradients are a common occurrence in many subsurface aquifers. These pressure gradients can be driven from depth by expulsion of water from sediments or from the surface through meteoric recharge. The pressure gradients drive the flow of water through the aquifer leading to them being termed hydrodynamic aquifers. The lateral variation in pressure means hydrocarbon accumulations within them have inclined hydrocarbon water contacts. In the giant Azeri-Chirag-Gunashli (ACG) oil field, offshore Azerbaijan, the oil water contact (OWC) is found up to 350m deeper on the north flank of the structure than the south. This has long been associated with a hydrodynamic aquifer in the South Caspian Basin (Bredehoeft et al 1988). Disequilibrium compaction deep in the basin acts as a source of high pressure fluids which travel up through porous sandstone units to an outflow point hundreds of kilometres away at surface. Other fields in the region also exhibit a similar degree of hydrodynamic tilting; the Shah Deniz gas field has over 200m difference in the gas-water contact depth on either side of the field.

The influence of hydrodynamic aquifers on oil and gas fields has long been known. Hubbert (1953) was the first to explain hydrocarbon-water contact tilts with his theory of hydrodynamics. He showed that, by mapping aquifer overpressure (or potential), you could predict the position and tilt of fluid contacts. Since then, many groups have used his techniques to help explore for hydrocarbons in basins all over the world (Pelissier et al 1980, Green et al 2014, Grosjean et al 2009, Boya et al 2012, Dennis et al 2000 and 2005). Despite this attention from the exploration community, there have been comparatively few studies focussing on modelling producing fields affected by hydrodynamic aquifers; Eisenberg et al (1994) is one of the few examples found by the author.

Using a numerical reservoir simulator to model a field in a hydrodynamic aquifer presents three key challenges:

- The model needs to capture the steady state tilt in the initial fluid contacts.
- It must ensure that the contacts remain stable for the entire length of the model run. Failure to do this will lead to relaxation of the contact and artificial fluid motion even before any production.
- The model must honour the transient behaviour of the aquifer during production.

The first two challenges are addressed by Hsueh et al (1999) who compare methods for establishing and maintaining OWC depth differences in a sector model of the Ghawar field in Saudi Arabia. These methods include alteration of capillary pressure curves; specifying water saturations at initialisation; using separate equilibration zones; and using pseudo water injection and production wells to simulate aquifer flow. None of these methods provide a perfect solution to the problem and
each has a drawback. The first of these methods is non-physical, creating unrealistically large capillary forces; the second two are unstable and lead to fluids relaxing to a flat OWC over time. The pseudo wells method is the most realistic but requires a large number of aquifer cells in the model to avoid interference of the pseudo and real wells.

The final challenge of representing the transient behaviour of the aquifer is arguably the most important. Quantifying the amount, spatial distribution and timing of aquifer encroachment into a field is crucial for planning its future development. Decisions on well placement, whether to provide pressure support and the number and placement of water injectors can all hinge on the performance of the aquifer. The solution for influx of a uniform hydrostatic aquifer into an oil field was presented by Van Everdingen and Hurst as early as 1949. It relies on the assumption that a hydrostatic aquifer has a constant initial pressure at datum across its whole area before field production begins. In contrast, a hydrodynamic aquifer will, by definition, already have a pressure gradient imposed upon it. This leads to an asymmetry in the amount of pressure support.

There is currently no established method for capturing the described hydrodynamic behaviour in a reservoir simulation model. This study aims to develop such a method using the ACG field as an example. This has been achieved in three stages of modelling. Firstly, flow simulation on a basin scale is used to investigate the aquifer flow regime required to generate the overpressure pattern and OWC depths observed in the field. Secondly, simple analytical and 2D simulation models are used to understand the behaviour of a generic hydrodynamic aquifer during field production. Finally, these results are combined to develop a method for simulating the hydrodynamic aquifer in the ACG full field simulation model. This is achieved using two Carter Tracy aquifers, one as a source and one as a sink for aquifer flow. This is an approach adapted from Nagorskiy (2011) who also looked at the ACG field. Through these steps a robust physical representation of the hydrodynamic aquifer system is achieved whilst not compromising the functionality of the full field reservoir model for use as a predictive tool.

**Critical Literature Review**

Prior to Hubbert’s classic 1953 paper on hydrodynamic aquifer theory, early engineers followed the “anticlinal theory” in which oil moves vertically upwards, impelled by buoyancy forces until it reaches a seal. Hubbert (1953) presented a new hydrodynamic theory in which the hydrocarbons move until they reach the point of lowest possible potential. This new theory accounted for lateral variations in aquifer pressure. It also provided an explanation for tilted fluid contacts that had been observed in many onshore fields. Hubbert’s 1953 paper and his later review paper in 1967 provide the basis of hydrodynamic aquifer theory and present a method for mapping aquifer potential and producing fluid contact maps in regions with lateral aquifer pressure variations. Since Hubbert’s papers, most of the work on hydrodynamic aquifers has been concentrated in the exploration domain and focuses on mapping hydrodynamic traps prior to any depletion of the fields. The earlier studies tended to focus on onshore fields where the lateral aquifer flow is driven by meteoric recharge of the aquifer at the surface and flows towards the deeper parts of the basin. Hubbert (1967) describes numerous examples of this type of artesian aquifer.

As the industry moved offshore into deeper basins, a new type of hydrodynamic aquifer was discovered with aquifer flow driven by compaction and dewatering of deep sediments. These burial hydrodynamic aquifers are characterised by water flowing from a deep source to a shallow outflow point. There are now many examples of burial hydrodynamics ranging across most of the hydrocarbon producing regions of the world. A few notable examples are the Gulf of Mexico (Green et al. 2014), the North Sea (Dennis et al. 2000 and Dennis et al. 2005) and the Caspian Sea and Mahakam Delta (Grosjean et al. 2009). Some studies have gone beyond describing hydrodynamic regions and have attempted to understand what controls the amount of till and geometry of fluid contacts. Dennis et al. (2000 and 2005) used glass bead box models to recreate hydrodynamic tilting in the laboratory and compared the results with 2D numerical simulation models. This study also showed that the degree of tilt depends on heterogeneity and structure in the aquifer. Barriers or baffles to flow like faults, low permeability zones or thinning in the aquifer lead to increased tilting and even steps in the hydrocarbon-water contact. These studies also simulated hydrodynamic aquifer flow in 3D full field simulation models using pseudo water injection and production wells. Other studies used similar modelling techniques to predict the position of the hydrocarbon-water contact in real fields (e.g. Boya et al. 2012). Muggridge and Mahmode (2012) used a combination of an analytical model and a 2D simulation model to examine the time it takes for a tilting contact to reach an equilibrium state.

Since the expansion of hydrocarbon exploration into the offshore South Caspian in the 1960’s and 70’s, there have been a number of key studies into hydrodynamics in this basin. With oil-water-contact tilts of up to 350m in some fields, understanding the hydrodynamics is a key part of successful exploration. Bredehoeft et al. (1988) were the first to document regional variation of overpressure in the reservoir units and link this to lateral flow of water through well connected sand bodies. Reynolds (2006) performed a similar study focusing this time on the ACG structure. Tozer and Borthwick (2010) also focussed on the ACG field and used overpressure variations to map oil-water contacts across the structure. Javanshir et al. (2014 in press) provide an updated summary of the pressure data in the South Caspian with data from the Shah Deniz, ACG and other fields. They also fit this data using 3D basin modelling techniques.

The work described above focuses on the hydrodynamic aquifer effects prior to any production and depletion of the fields they surround. There has been less work focussing on how dynamic aquifers behave during production and how to model these in reservoir simulators. Hsueh et al. (1999) present a comparison of methods for simulating fields with tilted oil-water-contacts. These methods include alteration of capillary pressure curves, specifying water saturations at initialisation, using separate equilibration zones and using pseudo water injection and production wells to simulate aquifer flow. The study concludes that all of these methods have their advantages and disadvantages but fails to show examples of successful application of these methods on real fields. Eisenberg et al. (1994) is one of the few studies to apply hydrodynamic modelling
techniques to the production of a real field in Papua New Guinea. They use pseudo water injectors and producers to simulate aquifer flow and attempt to history match a 2 year field history with this model. The results show an improved match. However, due to a lack of any seismic data and a significant uncertainty in the subsurface characterisation, it is difficult to fully determine the effectiveness of the modelling technique. Nagorskiy (2011) used Carter Tracy aquifers to simulate aquifer flow in the ACG field and demonstrated the effectiveness of this technique. However, the model presented required non-physical values of aquifer parameters in order to match the historical data.

A very large number of papers have been written and presented on modelling and quantifying aquifer influx into oil fields. A few of these are relevant to the methods used in this study. Van Everdingen and Hurst (1949) provided solutions to the diffusivity equations for radial and linear reservoir geometries for constant terminal pressure and constant terminal rate cases. Their solutions are considered the basis for aquifer influx calculations. Carter and Tracy (1960) provided an approximation to the Van Everdingen and Hurst solution to simplify calculations. Mortada (1955) showed that more complex boundary conditions, like multiple fields sharing the same aquifer could be solved using spatial superposition of solutions. This principle has been neatly illustrated by Hortle et al. (2010) who looked at the spatial variation in aquifer overpressure before and after field production in the Gippsland basin, Australia. This showed that the depletion of hydrocarbon fields significantly changes the regional overpressure pattern and hence the aquifer flow directions.

Introduction to the Azeri-Chirag-Gunashli (ACG) field

The ACG field is made up of three connected sub-fields: the Azeri, Chirag and Gunashli. The field is located in 200m water depth, 75km offshore of the Aspheron Peninsula in the Caspian Sea (Figure 1). It lies on the crest of an anticline 50km in length and 10km in width trending northwest-southeast. The north flank of the structure has a steep dip of up to 40 degrees while the south flank is less steep, dipping at 25-30 degrees. The structure is split into two main segments; the Chirag and Gunashli section to the West and the Azeri section to the East. They are joined by a saddle zone where high stress during compression of the region has led to deformation and degradation of the reservoir units. The field is made up of a series of stacked sandstone reservoirs interrupted by laterally extensive shales all deposited as part of the paleo-Volga delta system. Development has principally focussed on the Pereriv reservoirs. This study focuses on one of the thickest flow sections within
the sequence, the Pereriv B. This contains light oil with a gas cap in the Azeri field only. The oil column is over 1000m thick in some places and fills the entire reservoir thickness meaning water must flow around and not under the OWC.

The westernmost end of Gunashli, known as Shallow Water Gunashli (SWG), is operated by SOCAR and has been in production since 1982. Chirag was brought online by BP and a consortium of partners in 1997 with Azeri following in 2005. The pressure depletion associated with the early production of Shallow Water Gunashli is seen in both the Chirag and Azeri fields showing pressure communication throughout the set of fields (Reynolds 2006). However, production data suggests a restricted flow of fluids through the saddle zone. The field is driven by a combination of compaction, oil expansion, natural water drive and gas cap drive (Azeri only). This is supplemented by water injection in all three fields and gas cap injection in Azeri only. Aquifer support has been observed to be greater in the south flank than the north.

Hydrodynamic Aquifer Theory

The following sections discuss the observed overpressure in the ACG fields and its causes. Overpressure is defined as a pore fluid pressure above the normal hydrostatic pressure for the depth of observation. All overpressure numbers are given at Caspian Sea level datum. By definition, normally pressured formations would have zero overpressure. In order to have hydrodynamic flow of water through an aquifer system, three key elements are required:

- Source of overpressured water: In the South Caspian Basin, rapid sediment deposition rates, have led to disequilibrium compaction and a build-up of overpressure (Bredehoeft et al. 1988).
- Pathway for flow: Without a well-connected pathway of permeable units there is no way for the overpressured water to find a sink. The Pereriv B reservoir unit has been correlated regionally across the basin with over 150 well penetrations. It is considered to be laterally continuous across distances of hundreds of kilometres.
- Outflow point: Without an outflow point, the overpressure in the reservoir units cannot be released and aquifer flow cannot occur. One of the key observations made in the South Caspian Basin is that some of the sand units are at a much lower pressure than the neighbouring shales. These units have an outflow point at surface and can therefore release the overpressure whereas the shales cannot (Bredehoeft et al. 1988, Javanshir et al. 2014). The outflow point for the Pereriv reservoir units is currently unknown. These formations do outcrop onshore close to Baku however it has not been confirmed whether this is the main sink for hydrodynamic flow.

Link between Overpressure and Fluid Contacts

Figure 2 illustrates a simplified oil and gas field in a hydrostatic (left) and hydrodynamic (right) aquifer. In both cases the hydrocarbons are in full communication meaning there is no lateral pressure gradient. This leads to a flat gas oil contact (GOC) and identical hydrocarbon pressure profiles. In the hydrostatic case, the pressure profile in the water leg is also identical on both flanks. In the hydrodynamic case there is a lateral pressure gradient in the water leg in the direction of flow. The difference in pressure in the water leg translates to an offset in the OWC across the two flanks. This effect is illustrated in
the pressure-depth plots in Figure 2. The result is that the free water level tilts downwards in the direction of aquifer flow. For the purpose of this study the free water level and oil water contact are synonymous. This is justified since the capillary transition zone is negligible in the Pereriv B reservoir. Therefore, the main control on OWC is the aquifer pressure and not capillary forces. Hubbert (1953) showed that the amount of tilt can be related to the lateral gradient in aquifer pressure by:

\[
\text{OWC tilt} = \frac{dx_{\text{OWC}}}{dx} = \frac{dp_{\text{aq}}}{dx} \frac{dx}{dx_{\text{W-h}}} \quad \text{(Equation 1)}
\]

\[
\frac{dp}{dx_{\text{W-h}}} = \text{water minus oil vertical pressure gradient}
\]

\[
\frac{dp_{\text{aq}}}{dx} = \text{the aquifer overpressure gradient}
\]

This relationship can also be obtained by considering the isostatic balance of fluid columns. In order for the pressure in the oil leg to be constant, the difference in aquifer pressure must be balanced by the density difference of the two fluids. This means that for a given pressure drop the vertical displacement of the OWC will be smaller for a larger density contrast. This is why hydrodynamic tilting is less pronounced in gas reservoirs than oil reservoirs. Another important implication of this relationship is that the OWC tilt is very sensitive to small pressure gradients in the aquifer. Using ACG fluid gradients of 0.098 Bar/m (water) and 0.068 Bar/m (oil) gives a difference of 0.03 Bar/m which for just a 1 Bar/km lateral aquifer pressure gradient corresponds to a tilt of 33 m/km. By rearranging Darcy’s law and substituting into Equation 1 the tilt can be expressed in terms of the rock permeability \((k)\), aquifer cross sectional area \((A)\) and the flow rate \((Q)\) and viscosity of the aquifer water \((\mu)\).

\[
\frac{dx_{\text{OWC}}}{dx} = -\frac{\mu Q}{k A} \frac{dp}{dx_{\text{W-h}}} \quad \text{(Equation 2)}
\]

This shows that permeability and cross sectional flow area in the aquifer formation greatly impact the OWC tilt. Where flow is constricted or diverted by baffles and barriers like faults and shale bodies or by narrowing of the sand body or lateral variations in rock quality the degree of OWC tilt will increase. Dennis et al. (2000 and 2005) illustrated this using laboratory experiments and 2D simulation models. Where flow is severely restricted by laterally continuous faults or shales, vertical steps in the OWC are observed.

**Pressure and Contacts in ACG**

There are two main hypotheses for offsets in the ACG OWC: reservoir compartmentalisation and a hydrodynamic aquifer. The lack of major sealing faults and the good pressure communication throughout the field during SWG depletion rules out compartmentalisation (Tozer and Borthwick 2010). The hydrodynamic aquifer theory is further supported by the systematic variation in overpressure throughout the Caspian Basin and the observation of similar fluid contact tilting in Shah Deniz and other fields in the region (Javanshir et al. 2014). A map of the interpreted original OWC depths prior to any production is shown in Figure 3. These have been interpreted from a combination of MDT data in exploration and appraisal wells and wireline resistivity logs from early production and injection wells. The overpressure of the water leg extrapolated to South Caspian Sea level datum is also shown. Wells with measurements taken after a period of production are marked as depleted. In Chirag and Gunashli, due to the large degree of depletion in the SWG field, the overpressures have not been shown. Where no pressure data in the water leg was available, the oil pressure was extrapolated down to a known OWC contact depth and this pressure was used for the water leg.

A number of key features are visible on this map. Firstly, there is a clear offset in overpressure and OWC between the north and south flank. The difference is up to 350m and 10.5 Bar with the south indicating a higher pressure and shallower OWC than the north. This offset is measured between two of the earliest wells, GCA4Z on the south flank and GCA2 on the north. The 350m and 10.5 Bar differences are consistent with Equation 1 since the water-oil vertical pressure gradient difference is 0.03 Bar/m. The second feature is variation of overpressure and OWC along the south flank. In Azeri, the contact deepens as you go east towards the nose of the structure. In Chirag and Gunashli the contact appears to deepen as you go west towards the other nose. Along the north flank, the contact appears to remain relatively flat at around 3410m TVDSS.

There are two anomalous regions highlighted in Figure 3. In Southwest Azeri, close to the saddle zone, there is a localised depression in the OWC of around 150m. This has been associated with flow of water through the saddle causing a lowering of the pressure and deepening of the contact in this region (Nagorskii 2011). More recently, it has been suggested that water expelled from mud volcanoes may be the cause. The second anomaly is around the East Azeri nose where a sudden step in the OWC of 150m is accompanied by a 4 Bar change in aquifer overpressure in the space of 2km. It was originally thought that the East Azeri anomaly was caused by faults in this region acting as barriers to flow. However, a lack of geophysical evidence for faulting has brought this into question.
Figure 4: Basin model output of OWC depth, overpressure and flow lines around ACG field. Top: aquifer outflow to the NE. Bottom: aquifer outflow to the NW.

Basin Scale Modelling

All the reservoir simulation in the following sections was performed using Halliburton’s Nexus Reservoir Simulation package. The important features of the models are included in the text. Further details of each model can be found in the accompanying Appendices B, C and D. A simulation model was constructed to investigate the flow of water over the whole areal extent of the basin with the aim to determine the direction and volume of aquifer flow required to tilt the ACG OWC. The basin model consists of a coarse one layer grid of the Pereriv B, (250kmx160kmx150m) generated from regional seismic data. A two layer local grid refinement was created around the ACG structure for better resolution. Permeability and porosity were correlated to depth with rock quality decreasing with depth. Other known hydrocarbon accumulations in the region were treated as barriers to aquifer flow by setting zero permeability. Rock and fluid properties were taken from BP’s in-house full field simulation model of ACG. Straight line oil-water relative permeability curves were used for simplicity. The model was initialised with oil only in the ACG region, the remaining cells contain water. The OWC was started flat with a depth of

Figure 3: Map showing OWC depth and overpressures in the Pereriv B reservoir. The best estimate of original oil (green) and gas (red) is also shown. Accompanying MDT data is also shown.
Initially the position of the pseudo-producers was varied to investigate the sensitivity of the system to the aquifer outflow point. Two cases were run, one with outflow to the northwest, towards Baku, and one with the outflow to the northeast. Figure 4 shows the resulting model overpressure and flow-lines. Outflow to the northeast leads to the dominant direction of flow along the anticline axis. This in turn means the OWC tilts along the structure rather than across it. With a northeast outflow point, flow is perpendicular to the anticline axis and the OWC tilt is across structure. This is much closer to the real contact geometry and is therefore the preferred case. To calibrate the model, the pseudo injector BHPs were varied and the model aquifer overpressure measured at the location of the GCA-4Z (south flank) and GCA-2 (north flank) wells. The BHPs were adjusted until the model achieved the observed overpressure difference of 10.5 Bars. Once the correct pressure gradient had been obtained, both the injector and producer BHPs were adjusted by the same amount until the correct oil datum pressure was achieved. Full calibration results can be found in Appendix B.

To test the model sensitivity to flow through the saddle two cases were run: one with unrestricted flow of water through the saddle zone and one with restricted flow, using an adjusted permeability of 5mD in the saddle zone. The difference in overpressure and OWC depth between these runs is shown in Figure 5. Flow through the saddle decreases the pressure and lowers the OWC on the south side and increases the pressure and raises the OWC on the north flank. Since the north flank OWC is generally observed to be flat, it is likely that there is minimal flow through the saddle zone. To try and replicate the abrupt step in OWC and overpressure at the East Azeri nose, cases were run with and without a fault in East Azeri were compared. Figure 5 shows the results. A fully sealing fault was sufficient to cause a 4 Bar drop in overpressure and 150m step in OWC. It should be noted that this is just one way to achieve this pressure drop and does not represent a unique solution.

**Analytical and Mechanistic Models**

This part of the study focusses on understanding the behaviour of a hydrodynamic aquifer during depletion of a field within it. In particular, it aims to quantify whether the hydrodynamics have a strong influence on the influx rates on either side of the field. Is the asymmetry of the aquifer system significant or can the influx be approximated to a hydrostatic aquifer? Van Everdingen and Hurst’s (1949) hydrostatic aquifer influx solutions use the condition that the initial pressure in the aquifer at all distances from the field is constant. This isn’t applicable for a hydrodynamic aquifer since there is already a pressure gradient within it. This problem is very similar to that of multiple oil fields sharing a common aquifer. Pressure interference from other fields must be taken into account when they are in communication across a common aquifer (Mortada 1955). Just as linear solutions to the diffusivity equation can be superposed in time, Mortada (1955) showed that they could be superposed in space to generate solutions to the problem of multi-field interference. This principle of spatial superposition of pressure drops is used here. The pressure drop, \( \Delta p(x,t) \), for a hydrostatic system is added to a constant aquifer pressure gradient to model a hydrodynamic solution (Figure 6).
Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

Figure 6: Schematic showing superposition principle used to model a hydrodynamic aquifer.

Figure 7 shows the key features of the simple model. The aquifer consists of a flat elongate rectangle of rock with uninform properties. At one end is a fixed pressure boundary at high pressure to act as a hydrodynamic source. At the other end is a fixed pressure boundary at low pressure to act as a hydrodynamic sink. Halfway along the aquifer is a linear field, length $L_f$, that stretches the full width of the aquifer. At time $t = t_p$ the pressure in the field is dropped to the field drawdown pressure $p_f$ and is held at this pressure indefinitely. This is therefore a constant terminal pressure problem.

To simplify the problem three assumptions are made. Firstly, before the field starts producing at time $t = t_p$ there is a stable constant flow of water through the aquifer. This implies a constant time-independent pressure gradient in the aquifer ($g_A$). In reality the pressure gradient in the aquifer is unlikely to be time-independent since the source of overpressure will be continually diminishing. However, changes to the aquifer flow pressure gradient will change over geological timescales compared to the hundred year production timescales we are interested in. Secondly, the field does not act as a barrier to aquifer flow. Although this may seem counterintuitive it is a product of modelling one-dimensional flow. In reality the field would act like a barrier but water could flow around it out of the model plane. Thirdly the aquifer is long enough that any pressure disturbance created by the field will not reach the aquifer boundaries. As such, the field can be modelled as an infinite linear aquifer and the constant terminal pressure analytical solution of Miller (1962) can be applied. This is justified due to the wide lateral extent of the Pereriv B formation over hundreds of kilometres.

The pressure drop caused by production in the field ($\Delta p_{\text{field}} = p_i - p$) is calculated using Miller’s constant terminal pressure solution for an infinite linear aquifer. Since this is only defined for positive values of $x$, the system is considered in two halves: an upstream half, facing towards the high pressure boundary and a downstream half facing towards the low pressure boundary. The constant pressure gradient is added to the pressure drop for the upstream half and taken away for the downstream half to create a total pressure drop as a function of $x$ and $t$. 

---

**PLAN VIEW**

**Field**

High Pressure Boundary

Upstream half

$p = p_i + g_A x_{up}$

$p = p_f$

$x_{up}$

Aquifer

$x_{up} = 0$

Field

$p = p_i$

$p = p_f$

$x_{down} = 0$

Field

Aquifer

$x_{down}$

Low Pressure Boundary

Downstream half

---
Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

Figure 8: Mechanistic hydrodynamic simulation model.

\[
\Delta p_{\text{field}}(x,t) = \Delta p_{\text{Darcy}} \left( \frac{x}{2 \sqrt{A \Delta t}} \right) \quad (\text{Miller 1962})
\]

\[
\Delta p_{\text{up}}(x_{\text{up}},t) = \Delta p_{\text{Darcy}} \left( \frac{x_{\text{up}}}{2 \sqrt{A \Delta t}} \right) - g_A x_{\text{up}}
\]

\[
\Delta p_{\text{down}}(x_{\text{down}},t) = \Delta p_{\text{Darcy}} \left( \frac{x_{\text{down}}}{2 \sqrt{A \Delta t}} \right) + g_A x_{\text{down}}
\]

\[
a = \frac{k}{\phi \mu c}
\]

The influx rate into the field \( Q \) for both the upstream and downstream halves of the field are calculated using Darcy’s law. With the pressure derivative evaluated at the field edge \( x_{\text{up,down}} = 0 \). Non-dimensional variables are introduced to generalise the solution.

\[
Q_{\text{up}} = \frac{1}{k h A D} + \frac{2 g_A L}{k h A D} \quad \text{and} \quad Q_{\text{down}} = \frac{1}{k h A D} - \frac{2 g_A L}{k h A D}
\]

\[
Q_D = \frac{Q_{\text{up}} - Q_{\text{down}}}{L_f}
\]

\[
\frac{\Delta Q_{\text{up-down}}}{L_f} = \frac{2 k h g_A}{\mu} \quad \text{(Equation 3)}
\]

This simple model therefore predicts that the difference between the upstream and downstream influx rates will be constant and is directly proportional to the hydrodynamic pressure gradient \( g_A \). The analytical model is an idealised representation of the dynamic aquifer problem. In reality the field will only occupy a fraction of the aquifer width and water will flow around the field. In order to capture this behaviour and test the validity of the analytical model, a 2D mechanistic reservoir simulation model (Figure 8) was developed. This consists of a regular rectangular grid, 1 cell thick, filled with water. The high and low pressure boundaries in the analytical model are replaced with a line of fixed BHP injectors at one end and a line of fixed BHP producers at the other. The field is modelled using a horizontal well across the field of length \( L_f \). The injectors and producers are turned on and the model run until a steady state flow is achieved through the aquifer. The horizontal “field” well is then turned on and held at a constant BHP. The flow of water into the field well from the up and down stream directions was output and the difference between the up and down stream flux was calculated. This difference was normalised for the length of the field well. A transect of pressure through the aquifer was also output.

Two parameters were varied: the length of the field and the pressure gradient in the aquifer. The pressure gradient was controlled by varying the difference between injectors and producer BHPs. The length of the field was varied from 100% to 25% of the aquifer width in increments of 25%. Figure 9 shows the results. The pressure transect through the simulation model at 1.5 years shows good agreement between the analytical and simulation model. As expected from the analytical model the upstream influx rate was found to be higher than the downstream influx rate. The normalised rate difference was found to be directly proportional to the pressure gradient in the aquifer and was independent of field length. This relationship was also found to be consistent with Equation 3 thus validating the analytical model.

Applying Equation 3 to typical values in the ACG field and aquifer system gives an estimated 30-50 Msm3/day difference in aquifer influx rate. This difference suggests that the south (upstream) side of the aquifer will provide more pressure support than the north (downstream) side. This is consistent with current best estimate history matching cases which indicate the southern aquifer approximately twice as strong as the northern aquifer.
Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

Figure 9: Left: Pressure transect for 1.5 years into field production. Right: normalised rate difference versus aquifer pressure gradient for varying field lengths (lengths expressed as percentage of aquifer width).

Full Field Model

The full field reservoir model is an important tool for predicting reservoir behaviour, testing and optimising development strategies and tracking the movement of fluids in the reservoir system. An effective reservoir model should capture the major drive mechanisms and behaviour of the system whilst being simple enough to run within a short enough timeframe and produce stable results. In ACG, one of the main modelling challenges is to capture the tilted oil-water contact in the model. The contacts must be stable throughout the modelling period to avoid anomalous movement of fluids. In addition the model must honour the influx behaviour outlined in the previous section with the south flank (upstream) aquifer influx stronger than the north (downstream). In this section, two questions are addressed. Can the original (pre-production) contacts be modelled with a dynamic aquifer in the full field model in the same way as was done with the basin model? Does a dynamic aquifer description significantly improve the model’s ability to match historical field data?

Hsueh et al. (1999) proposed four methods for modelling a tilted oil-water contact in a reservoir model:

- Adjust the capillary pressure curves to make the observed oil-water contacts stable: this creates a non-physical solution to the problem and means that very large capillary forces are introduced to the system.
- Use equilibration zones to set the OWC around the field in sections: this works if the aquifer isn’t connected across the different equilibration zones. If it is, the pressure differences across adjacent zones will equilibrate over time and the contacts will relax.
- Overwrite the water saturation array on initialisation: this creates large unstable saturation contrasts that quickly equilibrate.
- Use pseudo water injectors and producers to simulate aquifer flow – this is the most physically realistic solution. However, in models with narrow aquifer zones, there are interference effects between the pseudo wells and the actual wells. This method is therefore only possible if a large number of aquifer cells are included in the model.

The ACG model is shown in Figure 10. It has been designed with large aquifer zones on the north and south flanks to assist in modelling the hydrodynamic aquifer. There is communication of the aquifer around the full perimeter of the field. The model incorporates all the members of the Pereriv reservoir units (A-E). All the changes made to the aquifer description in the following section are only applied to the Pereriv B layer, all other layers are left unchanged.

Figure 10: Plan view of top layer of Pereriv B in the full field model. The large regions of aquifer cells are highlighted as are the points of Carter Tracy attachment.
The current model in use does not attempt to replicate the hydrodynamic flow of the aquifer. Instead it relies on only the aquifer cells in the model to provide pressure support. Pore volume and transmissibility multipliers are applied to rows $j = 1$ and $j = 157$ to control the volume and speed of aquifer influx on each flank. This will be referred to as the hydrostatic case. The hydrostatic case is initialised with a specified water saturation to generate the observed OWC geometry. This is done using a non-equilibrium setting in the simulator so that the capillary pressure curves aren’t adjusted automatically. A large number of equilibration regions are used to try to keep the contact stable. This method still suffers from contact relaxation since neighbouring equilibration regions in the aquifer will equilibrate with each other, causing the flow of fluids before the start of production. This is illustrated in Figure 11. The model has been initialised and run for 100yrs without any production and the change in oil saturation over the 100 year period has been output. This shows vertical OWC movement of up to 50m with the raised OWC on the south flank deepening and the lowered OWC on the north flank becoming shallower.

Table 1: Parameters used in the Carter Tracy Analytical Aquifers

<table>
<thead>
<tr>
<th>Property</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability</td>
<td>$k$</td>
<td>200</td>
<td>mD</td>
<td>Aquifer rock quality decreases with depth. Values of 10mD to 3D are seen in the Pereriv B.</td>
</tr>
<tr>
<td>Porosity</td>
<td>$\phi$</td>
<td>20</td>
<td>%</td>
<td>Aquifer rock quality decreases with depth. Values of &gt;5% to 35% seen in ACG</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>$\mu$</td>
<td>0.45</td>
<td>cP</td>
<td>Constrained from fluid samples. Small uncertainty of ±10%</td>
</tr>
<tr>
<td>Total Compressibility</td>
<td>$c_t$</td>
<td>0.0019</td>
<td>Bar$^{-1}$</td>
<td>Constrained from cores data. Rock compressibility can vary by &gt;100% in ACG</td>
</tr>
<tr>
<td>Field Radius</td>
<td>$r_e$</td>
<td>65</td>
<td>km</td>
<td>These two variables play off against each other. They were estimated by considering the field edge as a cirle segment</td>
</tr>
<tr>
<td>Fraction of circle</td>
<td>$s$</td>
<td>0.125</td>
<td></td>
<td>Varies between 20-200m throughout basin based on well log data.</td>
</tr>
<tr>
<td>Thickness</td>
<td>$h$</td>
<td>42</td>
<td>m</td>
<td>Varies between 20-200m throughout basin based on well log data.</td>
</tr>
<tr>
<td>North CT aquifer Pressure</td>
<td>$p_{\text{North @} 2900m}$</td>
<td>318</td>
<td>Bar</td>
<td>These parameters were varied. The values shown are the best fit cases.</td>
</tr>
<tr>
<td>South CT aquifer Pressure</td>
<td>$p_{\text{South @} 2900m}$</td>
<td>338</td>
<td>Bar</td>
<td>These parameters were varied. The values shown are the best fit cases.</td>
</tr>
</tbody>
</table>

New model – Hydrodynamic case

To generate aquifer flow in the ACG model, Nagorskiy (2011) proposed the use of Carter Tracy aquifers, attached to opposite edges of the model, with a pressure offset between them. The Carter and Tracy (1960) technique for calculating aquifer influx is an approximation to the solution of Van Everdingen and Hurst (1949). It is used due to the significant reduction in computation required compared to the full Van Everdingen and Hurst method. The main assumption for the Carter Tracy technique is constant water influx over each finite time interval. The cumulative aquifer influx at a given time step $W(t + \Delta t)$ is related to the influx at the previous time step $W(t)$, the pressure drop at the aquifer boundary $\Delta p(t)$ and the Van Everdingen and Hurst constant terminal rate pressure function $P_d$ and its derivative $(P_d')$.

\[
W(t + \Delta t) = W(t) + \frac{B[(t + \Delta t)]}{P_d(t_d + \Delta t_d)} \Delta p(t_d) \Delta t_d
\]

\[\Delta p(t) = p_{\text{aquifer}} - p(t)_{\text{adjacent cell}}\]

\[B = \frac{2\pi\phi c hr^2 s}{t_c = \frac{k}{c_t \phi \mu r^2}}\]

\[\Delta t_d = t_c \Delta t\]
This relationship shows that the aquifer influx is a function of the pressure drop across the aquifer boundary \( \Delta p(t) = p_{\text{aquifer}} - p(t)_{\text{adjacent cell}} \). The amount and speed of influx for a given pressure drop is governed by the two parameters \( B \) and \( t_c \). In the reservoir simulator, \( p_{\text{aquifer}} \) is specified along with the parameters used to calculate \( B \) and \( t_c \). For the ACG model, infinite Carter Tracy aquifers were used, this is justified given the large lateral extent of the aquifer. To reduce the number of variables in the system, the north and south Carter Tracy aquifer properties were kept the same. The only difference between the two was the initial Carter Tracy aquifer pressure, which was deliberately set higher in the south than the north. Best estimates were chosen for the other aquifer parameters. The values used, their sources and associated uncertainties can be found in Table 1. Initially an attempt was made to model the original OWC prior to any production using the Carter Tracy aquifers to tilt the contact from a flat average starting depth. Carter Tracy aquifers were attached along the full length of the north and south edges of the model. The model was then initialised with just one equilibrium zone meaning it started with a flat OWC contact and a constant overpressure in the aquifer model cells. The northern Carter Tracy aquifer was given an initial pressure less than the aquifer model cells causing it to accept water. The southern Carter Tracy aquifer was given an initial pressure greater than the aquifer model cells causing it to give water. The model was run for 1000 years and the OWC and aquifer overpressure was checked after this period. The Carter Tracy pressures were adjusted until a good fit to the observed OWC and overpressures was found. Figure 12 shows the OWC generated from the best fit case superimposed on the current best estimate of original OWC position.

Three checks were used to ensure that the solution was plausible and in agreement with the results from the basin modelling.

1. Do the aquifer influx rates match the water flow rates around the field in the basin model? In the first 105 yrs of the full field model, the aquifer flux through the model averages 490Mm/yr. The basin model showed aquifer flow velocities of 10-20cm/yr. Over the full field model length of 60km and Pereriv B thickness of 42m the expected hydrodynamic flux is 250-500 Mm/yr. The two are consistent.

2. Do the flow lines of the water match those observed in the basin model? The flow lines in the basin model and the hydrodynamic model.
full field model are shown in Figure 13. For comparison the flow lines for the hydrostatic case are also shown. The basin model and hydrodynamic case match well. In the hydrostatic case the flow lines truncate against the field edge showing that the water is moving from south to north as the contact relaxes.

3. **Is the contact stable?** To test this, the oil saturation for a cell close to the OWC was output and is shown in Figure 12. This shows that the contact moves within the first 200 years and is then stable.

These results show that the complex geometry of the OWC in the ACG field can be matched relatively accurately using the hydrodynamic setup. Even the comparatively complex geometry around the East Azeri nose can be fit well. This approach has the added advantage of not requiring multiple equilibration zones to generate the required geometry. As with the basin model, there are a number of areas where the hydrodynamic model cannot match the observed contact. In particular in Southwest Azeri close to the saddle the modelled contact is over 100m higher than the observed contact.

**Table 2: History match cases run in the full field model**

<table>
<thead>
<tr>
<th>Case</th>
<th>Pore volume and transmissibility multipliers</th>
<th>Carter Tracy analytical aquifers</th>
<th>Equilibration Zones</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrostatic</td>
<td>Applied to rows j=1 and j =157. South larger than North.</td>
<td>None</td>
<td>Multiple zones with varying OWC</td>
</tr>
<tr>
<td>Hydrodynamic</td>
<td>None</td>
<td>Carter Tracy aquifers attached to rows j =1 and j=157. North has low aquifer initial pressure. South has high aquifer initial pressure.</td>
<td>Multiple with constant OWC = 3200m</td>
</tr>
<tr>
<td>No extra aquifer (base case)</td>
<td>None</td>
<td>None</td>
<td>Multiple zones with varying OWC</td>
</tr>
</tbody>
</table>

*N.B. Dynamic aquifer only applied to Pereriv B layer.*

**Comparison of Hydrodynamic and Hydrostatic cases during History Match**

The behaviour of the hydrodynamic and hydrostatic cases was compared over the full production history of the field. As a base case a model was run without any pore volume multipliers or Carter Tracy aquifers. This case relies only on the aquifer cells in the model for aquifer support. Table 2 summarises the key details of each case. In reality it is impractical to initialise the full field model with a flat OWC and then tilt it over prior to production. This is because matching STOIIP becomes very challenging. In addition, when the oil tilts, it leaves a residual oil rim that will impact the movement of fluids close to the OWC. Therefore an adapted method was used for the hydrodynamic case:

- Carter Tracy aquifers were attached to the north and south using the best fit pressures and parameters found in the previous section. This provides the correct amount of aquifer flux through the system to support the tilted contacts.
- The OWC was set to a constant average value of 3200mTVDSS in all the equilibration zones. This ensured that there is a constant pressure at datum in the aquifer upon initialisation.
- The calculated water saturation was overwritten by a specified water saturation array. This was done using a non-equilibrium setting in the simulator so that the capillary pressure curves weren’t adjusted automatically. This meant that the correct contact depths and STOIIP were in the model upon initialisation.
- The model was initialised and run for a 100 year pre-production period to test the stability of the contacts
- The full field production history was simulated and compared to historical pressure and production data.

![Figure 14: Comparison of simulated average reservoir pressure and historical average reservoir pressure from pressure build up analysis.](image)
Simulated average reservoir pressures are compared to historical average reservoir pressures calculated from pressure build up data in Figure 14. The “no extra aquifer” case is consistently low indicating that the aquifer cells alone do not provide enough pressure support. The hydrostatic and hydrodynamic cases are generally a good match to the data indicating that the level of support is correct.

Discussion

The work presented here shows that the hydrodynamic behaviour of the ACG field aquifer can be modelled effectively using Carter Tracy aquifers to simulate the flow of water through the aquifer. Using this approach, the original OWC tilt associated with the hydrodynamic aquifer can be captured whilst still maintaining a functional model capable of replicating the production behaviour of the reservoir. A sequence of modelling steps is laid out that can be replicated in other fields of this type. Firstly, the rate and direction of aquifer flow was determined using a coarse basin model of the aquifer driven by pseudo water injectors and producers. This type of model could be easily calibrated to get the desired OWC and overpressure match to real well data by adjusting the BHPs of the pseudo wells and their locations. This flow pattern was then replicated in the full field model using Carter Tracy aquifers as aquifer sources and sinks. Initially the original, pre-production OWC was modelled by tilting a flat OWC with the Carter Tracy aquifers. Once a good match was achieved, a production history matching process was carried out and showed that the hydrodynamic representation performed just as well as the current best fit hydrostatic representation. By starting at the basin scale and working down to match pressure data at the well scale this approach captures the true physical behaviour of the system and honours the regional aquifer properties and observations.

Modelling the original OWC position, prior to any production, at both the basin and field scale, highlighted a number of issues. Firstly, the orientation of the contact tilt is highly dependent on the direction of flow. If the aquifer water flows towards an offtake located onshore in Azerbaijan the dominant direction of aquifer flow is along the trend of the ACG structure. This leads to the OWC tilting downwards along the structure rather than across it as observed. A much better fit is found with an aquifer offtake to the NE. Although it is recognised that this is less geologically plausible, given that the Pereriv B unit deepens to the NE, it is difficult to reconcile the observed across structure OWC tilt with aquifer outflow in the NW. Another observation from the basin modelling was how sensitive the OWC height was to variations in the flow field. Allowing flow through the saddle zone and placing a fault at the East Azeri nose caused OWC height changes of 100m and more.

There is still uncertainty surrounding the ACG structure particularly around the East Azeri nose and the saddle point between Chirag and Azeri where there are a limited number of control points. At East Azeri, faults have typically been used to explain the step in OWC and overpressure over a very short distance. However, a lack of clear evidence for faults in seismic images has led to doubts over their existence. In the full field model a close approximation to the interpreted OWC is achieved with the hydrodynamic representation without the need for faults. Further work is required to fully investigate this region. In West Azeri, close to the saddle zone on the south flank, the observed contact is 150m deeper than predicted by the hydrodynamic model. A number of explanations have been put forward for this. Flow through the saddle may be acting to reduce the pressure in this region and hence lower the OWC. This effect was shown using the basin model (Figure 5) and can lower the contact by over 100m. However, flow through the saddle is inconsistent with the low permeability and high level of rock deformation in this zone. Saddle flow also leads to an equivalent elevation of the OWC by 100m on the north flank. Although well control in this region is low, there has yet to be any clear evidence for a raised contact here. The second explanation for the anomalously deep Southwest Azeri contact is the presence of mud volcanoes. These are common in ACG and one is imaged close to the saddle zone. Water sourced from these volcanoes may have led to incorrect interpretation of the OWC depth. This hypothesis is currently under further investigation.

The simple analytical and mechanistic models developed in this study suggest that ACG should experience a significant difference in influx rates on each flank. The south flank, which faces the deeper part of the basin, where hydrodynamic aquifer flow is driven from, is expected to have stronger aquifer support than the north flank. It should be stressed that the models do not aim to provide an accurate estimate for influx rates but are intended to test whether the hydrodynamic flow has a significant impact on the aquifer influx rates for each flank. In reality, the flow is not completely linear and responds to barriers like faults and oil fields in the aquifer. Lateral variations in the permeability and thickness of the aquifer will also impact the system. More involved models could be developed involving these aspects but for the purposes of this study they are not required. The finding that the south flank should experience stronger influx than the north flank is consistent with aquifer pore volume sizes calibrated during history matching. The best fit model has the size of the southern aquifer twice that of the northern aquifer.

The history match conducted in this study indicated that the hydrodynamic aquifer representation performed similarly to the hydrostatic representation. Both methods have their advantages and choosing between which method to use for future modelling depends on the purpose of the model. The hydrostatic representation, using pore volume multipliers, has the advantage of being quick and easy to implement and calibrate and it captures the contact at Southwest Azeri better. However, it suffers from contact relaxation (Figure 11) as the forces in the system are not in equilibrium and also requires multiple equilibration zones which adds to the complexity of the model. The hydrodynamic method, using Carter Tracy aquifers, is a more accurate physical representation of the system and it requires less equilibration regions whilst still replicating the OWC geometry. Nonetheless, it has problems around the Southwest Azeri region and is harder to calibrate. Although the two representations performed similarly in history matching, this does not mean they will predict the same behaviour in the future.
An important piece of future work is to test the forward prediction of the two cases to look for and understand any divergence in their results.

It is recognised that this study has only used one realisation of the ACG field during modelling. Uncertainty in the characterisation of the field has therefore not been fully assessed. Future work is required to test the effects on changing the field and aquifer properties on the hydrodynamic model performance. Equally a full sensitivity analysis on the Carter Tracy aquifer parameters is required before inclusion in an operational model.

**Conclusion**

Hydrodynamic flow of water through an aquifer causes tilting of oil water contacts in fields contained within it and makes reservoir simulation of these fields challenging. A method for modelling this type of behaviour in reservoir simulators and its application to the Pereriv B reservoir ACG field in the South Caspian Basin is presented here. The method makes use of Carter Tracy aquifers on either side of the model to generate aquifer flow. The Carter Tracy method is calibrated and checked against basin scale simulations, simple analytical and mechanistic models. Its performance during history matching was also compared to the current hydrostatic aquifer representation. A few key conclusions can be taken from this work:

- Basin scale modelling shows that the flow of water in the South Caspian Basin is south to north and roughly perpendicular to the ACG structure. Offtake of water to the northeast, towards Baku, cannot be reconciled with the oil-water contact tilt seen in ACG.
- The OWC geometry is very sensitive to the aquifer flow around the structure. Water flowing through the Azeri-Chirag saddle zone can cause contact changes of up to 100m.
- Simple analytical and mechanistic models suggest that the south, upstream, flank of the ACG field should experience greater aquifer support than the north. This is consistent with current best estimates of aquifer sizes from history matching which suggest that the southern aquifer is twice as strong as the northern one.
- Using Carter Tracy aquifers, a good fit can be achieved to the original OWC prior to any production even around the complex East Azeri nose region. The model fails to match the anomalously deep contact in Southwest Azeri.
- When matching the pressure history of the field the hydrodynamic representation provides a good match and performs similarly and sometimes better than the hydrostatic representation.
- The hydrodynamic method greatly simplifies the model as it requires significantly less equilibration zones compared to the hydrodynamic method.

**Further Work**

The work presented here can be developed in four ways:

- A detailed study into the impact of aquifer flow through the saddle on the OWC in Southwest Azeri would help towards understanding the anomalous OWC depression in this region.
- A full sensitivity analysis on the parameters controlling the Carter Tracy aquifers would be useful to quantify the full range of behaviour of the model within the bounds of parameter uncertainty outlined in Table1.
- A comparison of prediction cases for the hydrodynamic and hydrostatic representations is necessary to understand the differences between the two.
- The hydrodynamic representation can be extended into the other Pereriv reservoirs.

**Nomenclature**

A note on units: all equations in this study are expressed in consistent SI units. In some places in the text, values have been converted to more familiar units (e.g. Bar and mD) for the purpose of illustration.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Quantity</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Cross sectional area of flow</td>
<td>m$^2$</td>
</tr>
<tr>
<td>BHP</td>
<td>Bottom Hole Pressure</td>
<td>Bar</td>
</tr>
<tr>
<td>$c_t$</td>
<td>Total compressibility</td>
<td>Pa$^{-1}$</td>
</tr>
<tr>
<td>dp/dx</td>
<td>Lateral pressure gradient</td>
<td>Pa/m</td>
</tr>
<tr>
<td>dp/dz</td>
<td>Vertical pressure gradient</td>
<td>Pa/m</td>
</tr>
<tr>
<td>dz/dx</td>
<td>OWC tilt</td>
<td>m/m</td>
</tr>
<tr>
<td>$g_A$</td>
<td>Aquifer Pressure gradient</td>
<td>Pa/m</td>
</tr>
<tr>
<td>GOC</td>
<td>Gas oil Contact</td>
<td></td>
</tr>
<tr>
<td>h</td>
<td>Thickness of flow unit</td>
<td>m</td>
</tr>
<tr>
<td>k</td>
<td>Permeability</td>
<td>m$^2$</td>
</tr>
<tr>
<td>L$_f$</td>
<td>Length of field</td>
<td>m</td>
</tr>
<tr>
<td>MDT</td>
<td>Modular Formation Dynamics Tester</td>
<td></td>
</tr>
</tbody>
</table>

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Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan 15
Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

\[
\begin{align*}
\mu & \quad \text{Viscosity} \quad \text{Pa.s} \\
\text{OWC} & \quad \text{Oil Water Contact} \\
\rho & \quad \text{Pressure} \quad \text{Pa} \\
\Delta \rho & \quad \text{Pressure drop} \quad \text{Pa} \\
P_i & \quad \text{Dimensionless pressure function} \\
p_i & \quad \text{Field drawdown pressure} \quad \text{Pa} \\
p_i & \quad \text{Field initial pressure} \quad \text{Pa} \\
Q & \quad \text{Volumetric flow rate} \quad \text{m}^3/\text{s} \\
\Delta Q & \quad \text{Rate difference} \quad \text{m}^3/\text{s} \\
Q_o & \quad \text{Dimensionless flow rate} \\
r_e & \quad \text{Field radius} \quad \text{m} \\
s & \quad \text{Fraction of circle circumference occupied by field edge} \\
\Delta t & \quad \text{Elapsed time or time step} \quad \text{s} \\
t_D & \quad \text{Dimensionless time} \\
W(t) & \quad \text{Cumulative aquifer Influx} \\
x_{\text{up, down}} & \quad \text{Distance from field} \quad \text{m}
\end{align*}
\]

References


Nagorskiy, K.: “Modelling of dynamic aquifer for Pereriv B reservoir of the ACG field,” thesis for MSci in Reservoir Geosciences and Engineering, IFP School, France (Nov. 2011)


Appendix A: Critical Literature Review
## Milestones in the Study of Hydrodynamic Aquifers and the South Caspian Basin

<table>
<thead>
<tr>
<th>Reference</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulletin of Aapg, AIME, Vol. 204</td>
<td>1955</td>
<td>A Practical Method for Treating Oilfield Interference in Water-Drive Reservoirs</td>
<td>M. Mortada</td>
<td>Demonstrated how spatial superposition of solutions to the diffusivity equation could be used to model pressure interference of multiple fields sharing an aquifer.</td>
</tr>
<tr>
<td>AAPG</td>
<td>1967</td>
<td>Application of Hydrodynamics to oil exploration</td>
<td>M.K. Hubbert</td>
<td>Review paper of different hydrocarbon regions affected by hydrodynamic aquifer activity. Main focus is on US fields.</td>
</tr>
<tr>
<td>AAPG Bulletin Vol. 72</td>
<td>1988</td>
<td>Lateral Fluid Flow in a Compacting Sand-Shale Sequence: South Caspian Basin</td>
<td>J.D. Bredehoeft et al</td>
<td>First to document the overpressure regime in South Caspian Basin and attribute it to a hydrodynamic aquifer.</td>
</tr>
<tr>
<td>SPE 28750</td>
<td>1994</td>
<td>Reservoir Management in a Hydrodynamic Environment, Igfu-Hedinia Area, Southern Highlands, Papua New Guinea</td>
<td>L.I. Eisenberg et al</td>
<td>Attempt to simulate production and history match pressure data in a field with hydrodynamic aquifer. Modelling was done with pseudo wells.</td>
</tr>
<tr>
<td>SPE 53373</td>
<td>1999</td>
<td>A review of different methods in initializing and history matching a reservoir with tilted oil-water-contact</td>
<td>P.T. Hsueh et al</td>
<td>Compared four methods to run a model with a tilted OWC: 1) Capillary pressure corrections 2) Specify initial water saturations 3) Different aquifer equilibration regions 4) Use pseudo injection and production wells in aquifer to simulate aquifer flow.</td>
</tr>
<tr>
<td>Norwegian Petroleum Society</td>
<td>2000</td>
<td>Hydrodynamic activity and tilted oil-water contacts</td>
<td>H. Dennis et al</td>
<td>Used laboratory experiments, 2D and 3D simulation models to show sensitivity of OWC tilt to aquifer heterogeneity.</td>
</tr>
<tr>
<td>Petroleum Geology Conference</td>
<td>2005</td>
<td>Tilted oil-water contacts: modelling the effects of aquifer heterogeneity</td>
<td>H. Dennis et al</td>
<td>3D reservoir simulations using pseudo wells in aquifer to simulate flow. Emphasises effects of heterogeneity on OWC geometry. All simulation is pre-production.</td>
</tr>
<tr>
<td>SPE 101175</td>
<td>2006</td>
<td>The Geological Use of Pressure Data: Examples from the Development of the Giant ACG Oil Field, Azerbaijan</td>
<td>A.D. Reynolds</td>
<td>Looked at spatial and temporal variations in ACG pressure data and concludes that reservoir is well connected.</td>
</tr>
<tr>
<td>Iptc 13962</td>
<td>2009</td>
<td>Burial Hydrodynamics and Subtle Hydrocarbon Trap Evaluation: From the Mahakam Delta to the South Caspian Sea</td>
<td>Y. Grosjean et al</td>
<td>Described a number of offshore regions affected by burial driven hydrodynamics including the South Caspian.</td>
</tr>
<tr>
<td>Geological Society Special Publication 347</td>
<td>2010</td>
<td>Variation in fluid contacts in the Azeri field, Azerbaijan: sealing faults or hydrodynamic aquifer?</td>
<td>R.S.J. Tozer &amp; A.M. Borthwick</td>
<td>Describes aquifer pressure pattern in Azeri part of ACG field and shows this is related to a hydrodynamic aquifer rather than reservoir compartmentalisation.</td>
</tr>
<tr>
<td>Msci Thesis IFP School, France</td>
<td>2011</td>
<td>Modelling of dynamic aquifer for Pereriv B reservoir of the ACG field</td>
<td>K. Nagorskiy</td>
<td>Developed a method using Carter Tracy aquifers to generate hydrodynamic flow in the ACG reservoir model.</td>
</tr>
<tr>
<td>SPE 153507</td>
<td>2012</td>
<td>Predicting water in the crest of a giant gas field: Ormen Lange hydrodynamic aquifer model</td>
<td>M. Boya Ferrero et al</td>
<td>Used isopotential mapping of aquifer to predict tilted OWC position. Uses 2D and 3D simulation to determine initial OWC position and gets good fit to well data.</td>
</tr>
</tbody>
</table>
American Institute for Mining Engineers (AIME), Petroleum Transactions – SPE 949305-G (1949)

The Application of the Laplace Transformation to Flow Problems in Reservoirs

Authors: A.F. Van Everdingen, W. Hurst

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This is a classic paper which presents constant terminal pressure and constant terminal rate solutions for radial and linear flow into a reservoir from an aquifer. It also shows how superposition can be used to determine aquifer influx for a multi-rate or multi-pressure history.

Objective of the paper:
To present the solutions for aquifer influx for a field with constant terminal production rate and constant terminal field pressure. To present a method for superposing constant pressure and constant rate solutions to calculate aquifer influx for multi-rate and multi-pressure histories.

Methodology used:
The authors solve the radial and linear diffusivity equation using Laplace transforms for the below boundary conditions:
- **Constant terminal rate** – the field and aquifer start at a constant initial pressure at time $t=0$. The field produces at a constant rate and the pressure history with time is calculated.
- **Constant terminal pressure** – the field and aquifer start at a constant initial pressure. At time $t=0$ the field pressure is reduced to a constant production pressure. The water influx into the field is calculated as a function of time.

The authors also show that multi-rate and multi-pressure histories can be calculated by superposition of multiple constant terminal pressure or constant terminal rate solutions.

Conclusion reached:
- Tables of all the above solutions are presented in the paper.
**Bulletin of the American Association of Petroleum Geologists Vol. 37, No.8 (1953)**

Entrapment of Petroleum under Hydrodynamic conditions

**Authors:** Hubbert, M.K.

**Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics:** (*)

First to recognise the effects of aquifer flow on tilting OWC. Develops a mathematical theory for hydrodynamic traps by considering fluid potential.

**Objective of the paper:**
To explore and outline the theory of hydrodynamic aquifer traps.

**Methodology used:**
Hubbert uses a fluid potential argument based on the fact that hydrocarbon fluids in the subsurface will migrate to the point of lowest possible potential. In hydrodynamic aquifers the aquifer potential varies laterally which leads to tilted isopotential surfaces and hence tilted OWC.

Hubbert also conducted a set of experiments using sandboxes to measure tilt under hydrodynamic flow conditions and compare this to calculated tilt.

**Conclusion reached:**
- Hydrodynamic aquifers will cause OWC to tilt and can lead to trapping of hydrocarbons in traps without structural closure
- Tilt can be estimated using the equation:

\[
\tan \theta = \frac{dz}{dx} = \frac{\rho_w}{\rho_w - \rho_o} \frac{dh}{dx}
\]

\[
\frac{dz}{dx} = \text{the change in contact height with depth}
\]

\[
\theta = \text{contact angle}
\]

\[
\frac{dh}{dx} = \text{the slope of the potentiometric surface of the water in x – direction}
\]

- Tilt observed in sandbox experiments closely matches calculated tilt from the above equations,

A Practical Method for Treating Oilfield Interference in Water-Drive Reservoirs

**Authors:** Mohamed Mortada

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)

Shows how spatial superposition can be used to model pressure interferences in aquifers containing multiple fields.

**Objective of the paper:**
Develop an analytical method for calculating interference of fields sharing a common aquifer.

**Methodology used:**
Solutions to the constant diffusivity equation for radial fields are superposed in space and time to model the pressure interference caused by two fields sharing an aquifer.

**Conclusion reached:**
- This method can be extended to many fields in one aquifer with complex production histories.
SPE 1626-G (1960)

An Improved Method for Calculating Water Influx

Authors: R.D. Carter, G.W. Tracy

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This paper presents an approximation to the solutions of Van Everdingen and Hurst for aquifer influx into an oil field. The solution is computationally easier and is hence used in most numerical reservoir simulators.

Objective of the paper:
To present an approximation to the aquifer influx solutions of Van Everdingen and Hurst that allows faster computation of aquifer influx into oil fields.

Methodology used:
The authors discretise the continuous solutions of Van Everdingen and Hurst and use Laplace transformations to express the cumulative water influx in terms of the constant terminal rate solution (pD) and its derivative.

Conclusion reached:
- The approximation matches the results of Van Everdingen and Hurst
- The approximation significantly reduces computation time
- The discrete time steps used must be chosen carefully to get an accurate solution.
Simulation of a Hydrodynamic Aquifer in the ACG Field, Azerbaijan

Journal of the Institute of Petroleum Engineers, Volume 48, Number 467 (1962)

Theory of Unsteady-State Influx of Water in Linear Reservoirs

Authors: Frank G. Miller

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This paper extends the work of Van Everdingen and Hurst to present analytical solutions for aquifer influx for infinite and finite linear aquifers.

Objective of the paper:
To present analytical solutions for aquifer influx in infinite and finite linear aquifers.

Methodology used:
The author presents solutions to the linear diffusivity equation for constant terminal rate and pressure boundary conditions for finite and infinite linear aquifers.

Conclusion reached:
- Equations and plots of the above solutions are presented in the paper.
Proceedings of the 7th World Petroleum Congress, 1b, 59-75 (1967)

Application of Hydrodynamics to Oil Exploration

Authors: Hubbert, M.K.

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*) Review of the hydrodynamic theory originally presented in Hubbert (1953). Summarises the different regions and fields where hydrodynamic tilting of contacts has been observed.

Objective of the paper: Review paper of hydrodynamic aquifer theory.

Methodology used: Same methodology as Hubbert (1953) applied to real field cases.

Conclusion reached:
- Hydrodynamic aquifers are found in many hydrocarbon provinces.
- Understanding and quantifying tilt is key to successful exploration.

Lateral Fluid Flow in a Compacting Sand-Shale Sequence: South Caspian Basin

Authors: John D. Bredehoeft, Rashid D. Djevanshir, Kenneth R. Belitz

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This was the first study to document the presence of lateral aquifer flow in South Caspian sand bodies.

Objective of the paper:
To interpret the pressure data available and develop a basin compaction model that explains the data.

Methodology used:
Pore pressure vs depth data was available for a number of wells across the basin. A compaction model of the sands and shales was developed to try and explain the pressure distributions.

Conclusion reached:
- The shales are higher pressure than the sand units
- The sand units are acting as drains
- There is lateral flow in the sands from deep to shallow in the South Caspian Basin
- Modelling suggests average permeability of the sands of 1 to 30mD.
SPE 28750 (1994)

Reservoir Management in a Hydrodynamic Environment, Iagifu-Hedinia Area, Southern Highlands, Papua New Guinea

Authors: L.I. Eisenberg, M.V. Langston, R.E. Fitzmorris

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)

This study models the effect of a hydrodynamic aquifer of a field both prior to production and during production. As such it is one of the first to look at the transient behaviour of a hydrodynamic aquifer.

Objective of the paper:
Understand and model the hydrodynamic aquifer and its effect on the pressure in a series of interconnected reservoirs in Papua New Guinea

Methodology used:
The study uses a 3D reservoir simulation to model the hydrodynamic aquifer. Pseudo water injector and producer wells are used to generate flow. The model is initiated with flat OWC and allowed to tilt over geological timescales. The model is then history matched for a two year production period.

Conclusion reached:
- Hydrodynamic modelling using pseudo wells can improve the history match.
- Pressure history could be matched by adjusting the volume of the upstream and downstream aquifers

The main difficulty with modelling hydrodynamics is balancing the flux of water out of the system. This was found to be particularly difficult with injection wells where the injected water channelled out of the system via the aquifer exit point.
SPE 53373 (1999)

A Review of Different Methods in Initializing and History Matching a Reservoir Model with Tilted Oil-Water-Contact

Authors: Hsueh, P.T., Pham, T.R. and Bu-Hulaigah, E.H

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
Outlines the advantages and disadvantages of four different initialisation methods each aimed at recreating a tilted oil-water-contact in a numerical reservoir simulation model.

Objective of the paper:
To assess and compare different initialisation methods for modelling a tilted oil-water—contact.

Methodology used:
Numerical simulation study: Four initialisation methods were implemented on a segment model of a giant Saudi oil field with a tilted OWC and the resultant behaviour compared.

1. Use capillary pressure corrections to artificially change OWC height.
2. Specify water saturations consistent with a tilted contact on model initialisation
3. Use different equilibration regions for each side of the contact
4. Use pseudo injection and production wells in aquifer to simulate aquifer flow.

Conclusion reached:
Conclusions for each method used were:
1. Gravitationally stable but can lead to unrealistic fluid movements. Not physically justifiable.
2. Easy to implement but can lead to instability in fluid movement due to large imposed saturation contrasts
3. Simple to apply and works well. If equilibrium regions are in contact in the aquifer then the system reverts back to a flat OWC equilibrium.
4. Most physically accurate but tilt is sensitive to aquifer permeability and thickness so becomes difficult to history match.
Hydrodynamic activity and tilted oil-water contacts in the North Sea

Authors: Hugh Dennis, John Baillie, Torleif Holt, Dag Wessel-Berg.

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This is an excellent integrated study of hydrodynamic aquifer behaviour. It uses results from sandbox modelling to verify the results of simple 2D simulation models of hydrodynamic aquifers. It then uses 3D simulation models to simulate the OWC tilt in the Pierce field. The study is also one of the first to investigate the effects of aquifer heterogeneities on the OWC tilt.

Objective of the paper:
Verify the Hubbert tilt equations using sandbox and 2D simulation models. Model the OWC in the Pierce field in the North Sea using 3D simulation models. Investigate the effects of heterogeneity in the aquifer.

Methodology used:
- Experimental – anticline shaped sandboxes filled with glass beads are used to measure tilt in an OWC at varying water flow rates.
- 2D modelling – a 2D numerical simulation replica model of the sandbox experiments was used to test the validity of the numerical simulation techniques
- 3D modelling – a 3D model of the Pierce field was constructed and dynamic aquifer flow simulated using pseudo water injectors and producers in the aquifer.
- Heterogeneity sensitivity – the effects of faults, low transmissibility regions and vertical variations in permeability were investigated in both the 2D and 3D models

N.B. The modelling is all pre-production.

Conclusion reached:
- Observed experimental OWC tilts match those calculated using Hubbert’s tilt equation
- 2D simulation models match the results of the experimental sandbox models
- A stable tilted OWC was successfully modelled in the Pierce field 3D model but has yet to be verified with well penetrations.
- In 2D faults and low perm regions acted to increase the tilt of the OWC. In 3D this effect was less pronounced due to the ability for the water to channel around obstructions.
Tilted-oil-water contacts: modelling the effects of aquifer heterogeneity

Authors: H Dennis, P Bergmo, T Holt

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This paper shows the effects of aquifer heterogeneity on the geometry of the oil water contact in the presence of a flowing aquifer.

Objective of the paper:
Test the sensitivity of the OWC geometry to different structural and geological heterogeneities.

Methodology used:
This study uses a simple 3D simulation model of an anticline filled with oil and generates hydrodynamic tilt using pseudo water injector and producer wells. 36 geological realisations were run with crestal thinning, faulting, channeling, diagentic variations and stratigraphic pinch outs. The geometry of the OWC was observed for each case.

N.B. The modelling is all pre-production.

Conclusion reached:
- Hydrodynamically affected OWC are rarely planar due to the effects of heterogeneities
- Where the aquifer flow area is decreased the tilt in the OWC increased.
- Where the permeability in the aquifer is reduced the tilt in the OWC increased.
- Faults cause discreet steps in OWC
SPE 101175 (2006)

The Geological Use of Pressure Data: Examples from the Development of the Gant ACG Oil Field, Azerbaijan

Authors: A.D. Reynolds

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This study summarises the pressure history of the field and the geological implications of this data.

Objective of the paper:
To summarise and interpret the field wide pressure patterns seen during the first 10 years of production of ACG.

Methodology used:
Two types of pressure data are analysed:
- Pressure vs depth data taken from well RFT measurements
- Pressure build up data

These are analysed in three ways:
- Pressure vs depth – to determine layering, flow along wells and contact depths
- Pressure vs time – to determine levels of depletion
- Pressure vs lateral distance – to infer geological boundaries (e.g faults)

Conclusion reached:
- There is field wide communication of pressure
- There is a dynamic pressure gradient in the aquifer
- There is vertical layering causing breaks in pressure vs depth trends
- The field has been depleted by production of the neighbouring Shallow Water Gunashli field. The amount of depletion is shown to vary with distance away from this field.
IPTC 13962 (2009)

Burial Hydrodynamics and Subtle Hydrocarbon Trap Evaluation: From the Mahakam Delta to the South Caspian Sea

Authors: Yves Grosjean, Parick Zaugg, Jean-Michel Gaulier

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This paper summarises data from a collection of Total fields to show the importance of hydrodynamic trapping driven by sediment burial.

Objective of the paper:
To summarise the evidence from fields in the Mahakam Delta basin, South Caspian basin and the North Sea of hydrocarbon traps affected by burial hydrodynamics.

Methodology used:
The paper uses pore pressure data in shales and sandstone units. These are plotted as pressure vs depth for wells as well as being spatially plotted in terms of water potential.

Conclusion reached:
- Wherever you have rapid burial of sediments you will get lateral overpressure variations and flow of water from deep to shallow.
- Where you have well connected sandstones without major faulting or geological barriers you will get drainage of pressure in these units leading to differential pressure between sandstones and shales.
- This flow leads to hydrodynamic tilting of contacts.
- These observations have been observed in Total assets in Mahakam Delta, South Caspian Sea and the North Sea.
Variation in fluid contacts in the Azeri field, Azerbaijan: sealing fault or hydrodynamic aquifer?

**Authors:** R.S.J. Tozer, A.M. Borthwick

**Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics:** (*)

This investigates the hydrodynamics of the ACG field which is the subject of this study.

**Objective of the paper:**
To determine whether a hydrodynamic aquifer can explain the difference in OWC across the ACG field.

**Methodology used:**
The study uses pressure-depth data to look at the regional variation in overpressure in the aquifer around the field. They also look at the pressure in the oil leg to determine whether compartmentalisation may be causing OWC differences. By plotting a plane through the overpressure points the authors produce a map of expected OWC. The authors compare the results with interpretation from 4D seismic.

**Conclusion reached:**
- ACG has good communication in the oil leg and is therefore not compartmentalised.
- There is a systematic decrease in aquifer overpressure towards the North of the field.
- Both these pieces of information, combined with the rapid regional compaction and dewatering in the deep South Caspian basin, point towards a hydrodynamic aquifer.
- Aquifer overpressure decreases laterally by 3.5 Bar/km to the North
Moelling of dynamic aquifer for Pereriv B reservoir of the ACG field

Authors: Kyril Nagorskiy

Objective of the paper:
Develop a method for modelling hydrodynamic flow in a full field model of the ACG field Azerbaijan.

Methodology used:
Compares pore volume multipliers, saturation overwrite and Carter Tracy methods for simulating tilt and performs history matching using these methods.

Conclusion reached:
- Carter Tracy provides the best solution
- A better match can be achieved using Carter Tracy aquifers
SPE 153507 (2012)

Predicting water in the crest of a giant gas field: Ormen Lange Hydrodynamic Aquifer Model

Authors: Boya Ferrero, Maria Jesus, Price, Simon Paul, Hognestad, Jon

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
Good example of where hydrodynamic aquifer modelling is applied to a real field and predictions are validated with an appraisal well. Shows how the timing of hydrodynamic activity can lead to residual hydrocarbons.

Objective of the paper:
Understand and model the OWC pattern in Ormen Lange gas field (offshore Norway).

Methodology used:
The study uses 2D and 3D numerical reservoir simulation models to test whether a hydrodynamic aquifer can explain the presence of water in the crest of the structure. The timing of hydrodynamic behaviour is phased to try and recreate the presence of residual gas. The results were tested with an appraisal well.

N.B. The modelling is all pre-production.

Conclusion reached:
- Hydrodynamic aquifers can explain crestal water as an alternative to perched water.
- Phasing of hydrodynamics can lead to residual hydrocarbons as the water displaces hydrocarbon during tilting.
Hydrodynamic aquifer or reservoir compartmentalisation?

Authors: Ann Muggeridge and Hisham Mahmode

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)

This study analyses the time taken for a flat OWC to reach a stable tilt with a hydrodynamic aquifer.

Objective of the paper:
To use an analytical expression to estimate how long it takes for a tilted OWC to reach equilibrium and test this against 2D simulation models. To test the sensitivity of this to different geological and fluid properties. To assess when lateral pressure gradients in the oil leg can be attributed to compartmentalisation or when they are due to transient behaviour in the hydrodynamic aquifer.

Methodology used:
The paper uses an analytical expression for the time taken for two immiscible fluids to reach a stable contact. Based on this equation the time taken for a flat OWC to reach a stable tilt in a hydrodynamic aquifer is calculated. This is compared with 2D simulation models. The effects of faults, barriers, different geological and fluid properties is then tested using this model.

Conclusion reached:
- Typical oil fields will take 100k.y to reach an equilibrium tilted contact
- When the hydrodynamic system changes a transient period takes place as the OWC adjusts.
- During this period the pressure in the oil leg will vary laterally.
- Therefore lateral variations in the oil leg can be attributed to the transient hydrostatic behaviour and doesn’t have to be due to reservoir compartmentalisation.

Validation of lateral fluid flow in an overpressured sand-shale sequence during development of Azeri-Chirag-Gunashli oil field and Shah Deniz gas field: South Caspian Basin, Azerbaijan

Authors: Rashid J. Javanshir, Gregory W. Riley, Stephan J. Duppenbecker, Nazim Abdullayev

Contribution to the understanding of hydrodynamic aquifer modelling and South Caspian Basin hydrodynamics: (*)
This is the most up to date and thorough study of the pressure data from both the ACG and Shah Deniz fields. It also includes 3D regional basin modelling of the South Caspian.

Objective of the paper:
To describe and explain the pressure variations in the Shah Deniz and ACG fields. To fit this data using a regional 3D basin model.

Methodology used:
The pressure data in different sandstone and shale units is plotted and compared. A 3D regional basin model was constructed that reconstructed geological processes and was used to output pressure in the basin through time.

Conclusion reached:
- High net-to-gross units (Pereriv and Balakhany) are lower in pressure than surrounding shales. This is because they are connected to a low pressure sink.
- The high net to gross units are laterally connected across the whole basin.
- Low net-to-gross units (Pereriv and Balakhany) are higher in pressure than surrounding shales. This is because they are not laterally connected to an outlet so maintain high overpressures.
- Overpressure gradients across the Shah Deniz structure are 3.6 Bar/km.
Appendix B: Basin Simulation Model Further Details, Methods and Results

### Base grid

<table>
<thead>
<tr>
<th>NX</th>
<th>176</th>
<th>DX</th>
<th>1500m</th>
</tr>
</thead>
<tbody>
<tr>
<td>NY</td>
<td>127</td>
<td>DY</td>
<td>1500m</td>
</tr>
<tr>
<td>NZ</td>
<td>1</td>
<td>DZ</td>
<td>20-280m</td>
</tr>
</tbody>
</table>

### Relative Permeability

| Sor | 0.3 |
| Swc | 0.112 |
| Krwe | 1 |
| Kroe | 1 |

### Local Grid Refinement

<table>
<thead>
<tr>
<th>NX</th>
<th>148</th>
<th>DX</th>
<th>375m</th>
</tr>
</thead>
<tbody>
<tr>
<td>NY</td>
<td>100</td>
<td>DY</td>
<td>375m</td>
</tr>
<tr>
<td>NZ</td>
<td>2</td>
<td>DZ</td>
<td>50-160m</td>
</tr>
</tbody>
</table>

### Water Properties

| Compressibility | 0.000046 Bar^{-1} |
| Viscosity       | 0.45cP |
| FVF             | 1.025 rb/stb |
| Density         | 1001 kg/m$^3$ |

### ACG field Initialisation

| Fluids              | Oil + Water |
| Datum Pressure      | 3133mTVDSCS |
| Datum Depth         | 280 Bar |
| Datum Depth         | 2900 mTVDSCS |

### Rock Compressibility

| 1.45E-04 | Bar^{-1} @339 Bar |

### Pseudo well details

| Radius | 1m |
| Control | BHP only |
| Number of Injectors | 15 |
| Number of producers | 15 |
Basin Model Calibration Results:
Injector and producer BHPs were varied until a good match was found to the overpressure difference between flanks and the datum pressure in the oil.

Table B2: Results of basin model calibration

<table>
<thead>
<tr>
<th></th>
<th>Case</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>Expected</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Producer datum BHP</strong></td>
<td>Bar</td>
<td>276</td>
<td>276</td>
<td>276</td>
<td>276</td>
<td>276</td>
<td>309</td>
<td>0</td>
</tr>
<tr>
<td><strong>Injector datum BHP</strong></td>
<td>Bar</td>
<td>376</td>
<td>576</td>
<td>776</td>
<td>976</td>
<td>1076</td>
<td>1015</td>
<td>0</td>
</tr>
<tr>
<td><strong>Injector BHP minus Producer BHP</strong></td>
<td>Bar</td>
<td>100</td>
<td>300</td>
<td>500</td>
<td>700</td>
<td>800</td>
<td>706</td>
<td>0</td>
</tr>
<tr>
<td><strong>Steady state inj/prod rate</strong></td>
<td>STM3/d</td>
<td>2852</td>
<td>8298</td>
<td>13798</td>
<td>19350</td>
<td>22081</td>
<td>19550</td>
<td>0</td>
</tr>
<tr>
<td><strong>Mean Aquifer Velocity</strong></td>
<td>cm/yr</td>
<td>2.95</td>
<td>8.61</td>
<td>14.3</td>
<td>19.9</td>
<td>22.932</td>
<td>20</td>
<td>&gt;10</td>
</tr>
<tr>
<td><strong>Oil Pressure at Datum</strong></td>
<td>Bar</td>
<td>284</td>
<td>290.6</td>
<td>297</td>
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<tr>
<td><strong>GCA4 Aquifer Overpressure</strong></td>
<td>Bar</td>
<td>-4.8</td>
<td>2.55</td>
<td>9.64</td>
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<td><strong>GCA2 Aquifer Overpressure</strong></td>
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<td>-7.06</td>
<td>-2.67</td>
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<td><strong>GCA6Z Aquifer Overpressure</strong></td>
<td>Bar</td>
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<td>1.27</td>
<td>7.6</td>
<td>13.99</td>
<td>17.26</td>
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<td>46.3</td>
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<td><strong>Difference GCA4 - GCA2</strong></td>
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<td>5.22</td>
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<td>11.7306</td>
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<td>10.5</td>
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<td><strong>Difference GCA4 - GCA6Z</strong></td>
<td>Bar</td>
<td>0.28</td>
<td>1.28</td>
<td>2.04</td>
<td>3.01</td>
<td>3.2</td>
<td>2.82</td>
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Figure B2: Basin model calibration. Overpressure difference across N and S flank versus pseudo well BHP difference.
Appendix C: Simple Analytical Model Derivation.

Fig 1. Schematic of hydrodynamic analytical model (also in text).

Definitions: (all equations are defined in SI units)

\[
\Delta p_{field} = \text{pressure change caused by field drawdown} = p_i - p
\]

\[p_i = \text{pressure at field prior to production}\]

\[p_f = \text{drawdown pressure in field}\]

\[\Delta p_a = p_i - p_f\]

\[x_{up,down} = \text{distance from field in up or down stream direction}\]

\[g_A = \text{hydrodynamic pressure gradient in aquifer}\]

\[a = \frac{k}{\phi \mu c}\]

\[\Delta t = \text{time since start of field production}\]

\[L_f = \text{field length}\]

\[Q = \text{Volumetric flow rate}\]

\[Q_{up} = \text{flow rate into the field from the upstream side}, Q_{down} = \text{flow rate into the field from the downstream side}\]

Assumptions:

- Flow is in 1 dimension and therefore linear solutions to the diffusivity equations can be used
- The flow in the aquifer prior to production is assumed to be steady state. Thus the pressure gradient in the aquifer \[\frac{\Delta p_{aquifer}}{dx}\] is constant throughout the aquifer and time independent. This gradient is labelled \(g_A\)
- The aquifer is long enough to be modelled as infinite

The total pressure change \(\Delta p_{total}(x, \Delta t)\) is calculated by superposing the pressure change due to drawdown in the field \(\Delta p_{field}\) and the pressure change due to the aquifer pressure gradient. The pressure change due to field drawdown is modelled using the solution of Miller (1962) to the diffusivity equation. The boundary conditions and solution is outlined below:

\[
\Delta p_{field}(x, t) = \Delta p_0 \text{erfc}(\frac{x}{2\sqrt{\Delta t}}) \quad \text{Miller (1962)}
\]

Initial condition: \(\Delta p_{field}(x, \Delta t = 0) = 0\) for all \(x \geq 0\)

Outer condition: \(\Delta p_{field}(x = \infty, \Delta t) = 0\) for all \(\Delta t\)

Inner Condition: \(\Delta p_{field}(x = 0, \Delta t) = \Delta p_0\) for \(x = 0\)
In the upstream direction, the aquifer pressure before production is given by:

\[ p_{up}(x, t) = p_i + g \alpha x_{up} \]
\[ \Delta p_{up} = -g \alpha x_{up} \]

In the downstream direction, the aquifer pressure before production is given by:

\[ p_{down}(x, t) = p_i - g \alpha x_{down} \]
\[ \Delta p_{down} = g \alpha x_{down} \]

Adding the pressure drawdown of the field to the hydrodynamic aquifer gradient gives expressions for the total pressure drop in the upstream and downstream directions. These can then be rearranged to get the pressure as a function of \( x_{up} \) and \( x_{down} \).

\[ \Delta p_{up}(x_{up}, \Delta t) = \Delta p_i e^{-f c \left( \frac{x_{up}}{2 \sqrt{\alpha \Delta t}} \right)} - g \alpha x_{up} \]
\[ p_{up}(x_{up}, \Delta t) = p_i + g \alpha x_{up} - \Delta p_i e^{-f c \left( \frac{x_{up}}{2 \sqrt{\alpha \Delta t}} \right)} \]
\[ \Delta p_{Down}(x_{down}, \Delta t) = \Delta p_i e^{-f c \left( \frac{x_{down}}{2 \sqrt{\alpha \Delta t}} \right)} + g \alpha x_{down} \]
\[ p_{down}(x_{down}, \Delta t) = p_i - g \alpha x_{down} - \Delta p_i e^{-f c \left( \frac{x_{down}}{2 \sqrt{\alpha \Delta t}} \right)} \]

To get the rate of water influx into the well from both the upstream and downstream direction Darcy’s law is applied:

\[ Q = -\frac{k A}{\mu} \left( \frac{d p}{d x} \right)_{x=0} \]

where A is the cross sectional area of the field edge: \( A = h L_f \)

Since we are interested in the rate into the well we will consider \(-Q\). The rate into the field from the upstream and downstream directions is:

\[ Q_{up} = \frac{k h L_f}{\mu} \left( \frac{d p_{up}}{d x_{up}} \right)_{x_{up}=0} \]
\[ Q_{down} = \frac{k h L_f}{\mu} \left( \frac{d p_{down}}{d x_{down}} \right)_{x_{down}=0} \]

Differentiating the equations for \( p_{up}(x_{up}, \Delta t) \) and \( p_{down}(x_{down}, \Delta t) \) and substituting into Darcy’s law gives:

\[ Q_{up} = \frac{k h L_f}{\mu} \left( \frac{1}{\sqrt{\pi \alpha \Delta t}} \right) + \frac{k h L_f}{\mu} g \alpha \]
\[ Q_{down} = \frac{k h L_f}{\mu} \left( \frac{1}{\sqrt{\pi \alpha \Delta t}} \right) - \frac{k h L_f}{\mu} g \alpha \]

The difference in influx rate between the upstream and downstream directions is given by:

\[ \Delta Q_{up-down} = Q_{up} - Q_{down} = \frac{2k h L_f}{\mu} g \alpha \]

Introducing dimensionless variables generalises the solution:

\[ Q_D = \frac{Q \mu}{k h \Delta p_0} = \text{dimensionless rate} \]
\[ (Q_{up})_D = \frac{1}{\sqrt{\pi \alpha \Delta t_D}} + \frac{g A L_f}{\Delta p_0} \]
\[ (Q_{down})_D = \frac{1}{\sqrt{\pi \alpha \Delta t_D}} - \frac{g A L_f}{\Delta p_0} \]
\[ (\Delta Q_{up-down})_D = \frac{2g A L_f}{\Delta p_0} \]

\[ \Delta t_D = \frac{k \Delta t}{\Phi \mu L_f} \]

Dimensionless time
Appendix D: Mechanistic Model Parameters

Table D1: Mechanistic model parameters

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<th>Base grid</th>
<th>Water Properties</th>
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<td>NY 50</td>
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<td>NZ 1</td>
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<td>Density 1001 kg/m³</td>
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<td>KZ 10mD</td>
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<td>Number of producers</td>
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