Optimisation of Well Trajectory and Hydraulic Fracture Design in a Poor Formation Quality Gas-Condensate Reservoir

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The main aim of this project is to determine the optimal well trajectory and hydraulic fracture design that give the maximum sustainable production rates and recovery from a low-quality gas-condensate reservoir in North Africa. Specifically, this will mean quantifying recovery and production potential of the reservoir with different well types: vertical or high angle (horizontal). The backbone of the methodology consisted of constructing high resolution 3-dimensional numerical models followed by evaluation of recovery with a commercial reservoir simulator

This document first describes the nature of the reservoir, the characterisation of the formation, and analysis of the reservoir fluid in question. Next it outlines the inputs into building the model.

The reservoir fluid analysis and the model grid geometry, properties, permeability and porosity values were provided by PetroCeltic International plc, the operator of the field.

Potential well and hydraulic fracture scenarios were simulated with their respective recovery factors compared. A financial model was then constructed to evaluate the commercial value of each options and, hence allow recommending options for implementation. The financial selection criterion is Net Present Value (NPV). This study concludes that the optimal well design, for when there is no high permeability zone and an optimal k_v/k_h ratio of 1, is a hydraulically fractured 2km horizontal well: NPV = 142,247,066 USD, recovery over 20 years = 2,071,570,000 sm^3.

Keywords: Gas-condensate, Poor-quality formation, Hydraulic fracture design, Well trajectory

1. Introduction

The overall objective of this project is to determine the optimal well trajectory and hydraulic fracture design that provides sustainable high production rates and maximum recovery, prerequisites for commercial success, of a low-quality gas-condensate reservoir. This will entail predicting and comparing recovery factors, well types, trajectories, and well spacing with a simulation model.

Specifically, this will mean quantifying recovery and production potential of the reservoir with different well trajectories: vertical or high angle (horizontal). Due to the generally very poor formation matrix quality, except for a high permeability layer (0 - 8 m) in the appraisal area, plus the inclusion of natural fractures, hydraulic fracturing will be essential to attain commercial production rates – whose impact will in turn be analysed.

At the present time, the company is considering a development plan consisting of 2km spaced vertical wells designed to penetrate the upper 50m of the reservoir column. The appraisal well tests show that well productivity is low and therefore hydraulic fracturing is needed. However, further analysis is needed to determine if this is the optimal plan. This provided an opportunity to build a multi-phase flow simulation model, optimise through calibration of model to measurements, and then simulate development options to suit the unique characteristics of this reservoir.

The primary question to answer: What is the best well trajectory and HF design to give sustainable production rates and high recovery factors?

The main uncertainties in the reservoir are the

• Thickness of a high permeability layer at the top of the reservoir which varies from 0 to 8m
• Vertical Transmissibility of the formation i.e. vertical/horizontal permeability ratio

2. Reservoir description

The reservoir was formed during the Ordovician period by the deposition of sands transported by a glacier cutting through a valley. The reservoir structure is a large, low-relief, four-way dip closure, approximately 80 x 50 km in area, with a hydrocarbon column in reaching 100 m overlying an aquifer.

Core samples taken from the appraisal wells show the presence of a high permeability layer of 2 to 8 m in the north-eastern sector of the reservoir. It is believed the high permeability was formed by chemical dissolution (diagenesis) of the cemented sandstones. (*English et al. 2016*).

This project focuses on evaluating the reservoir properties and well designs that influence recovery.

2.1. Sedimentology

The deposition of sediments was turbulent resulting in grains of various sizes, and hence variable formation quality. Mineralisation led to the extensive quartz cementation of much of the pore spaces. This has severely impacted permeabilites in much of the sandstones. As a result, well porductivity is very low.

Tests of the appraisal wells show that the presence of a high permeability layer at the top of the reservoir in certain areas plays a dominant part in recovery. It is believed the high permeability layer was formed by chemical dissolution of the cemented sandstones freeing up pore space of varying sizes. (*English et al. 2016*). The variation in pore size across the reservoir, can be compared to a collection of capillary tubes with different radii (Dake, 1991), meaning that different sections will have different capillary characteristics.

2.2. Petrophysics

From facies and wireline electrofacies identification for each well, five glacial units were defined, correlated, and mapped, showing a complex infill of valley-like network.

The lithofacies define the petrofacies for the petrophysical properties. The trends porosity and permeability trends for each facies are obtained from core data, supplied by PetroCeltic.

The porosity values were calculated from density log interpretation calibrated to core porosity data.

Though at the wells, the reservoir permeability was calculated from porosity-permeability relationships applicable for each petrofacies from core data. These properties were then mapped in a geological program using Sequential Gaussian Simulation (SGS). The reference permeability data are core plug air permeability measurements made at a 131bar overburden or data corrected to 131bar overburden.

The appraisal well programme reveals very poor reservoir quality in general observed by core data, Figure 1, show that the bulk of the formation has a permeability inferior to 0.1 mD.

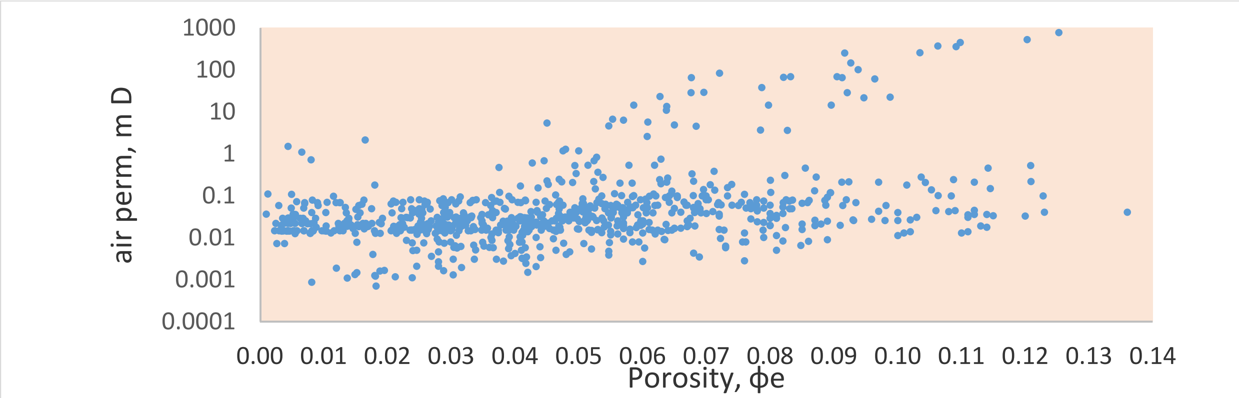

Figure 1 Relationship of permeability to porosity

3. Formation Characterisation for reservoir model

Capillary pressures measured on core samples show that irreducible gas saturations and the transition zone thickness are very sensitive to permeability. For example, in the best quality sandstone formations, we can expect gas saturations exceeding 94%. In poor quality regions, the gas saturation can be less than 50%, Figure 2. To determine the gas saturation and, hence the gas volumes throughout the reservoir, the saturation must be determined from the available data, namely wireline logs and core measurements.

Furthermore, in the dynamic model the fluid distribution is not the same everywhere. The formation is classified into categories where each category has a representative saturation model.

The fluid property tables, and the saturation tables for the in-situ flow modelling were provided. These tables were derived from an Equation of State calibrated to the well fluid data, and were obtained from a recombination of separator oil and gas samples at a reservoir ratio.

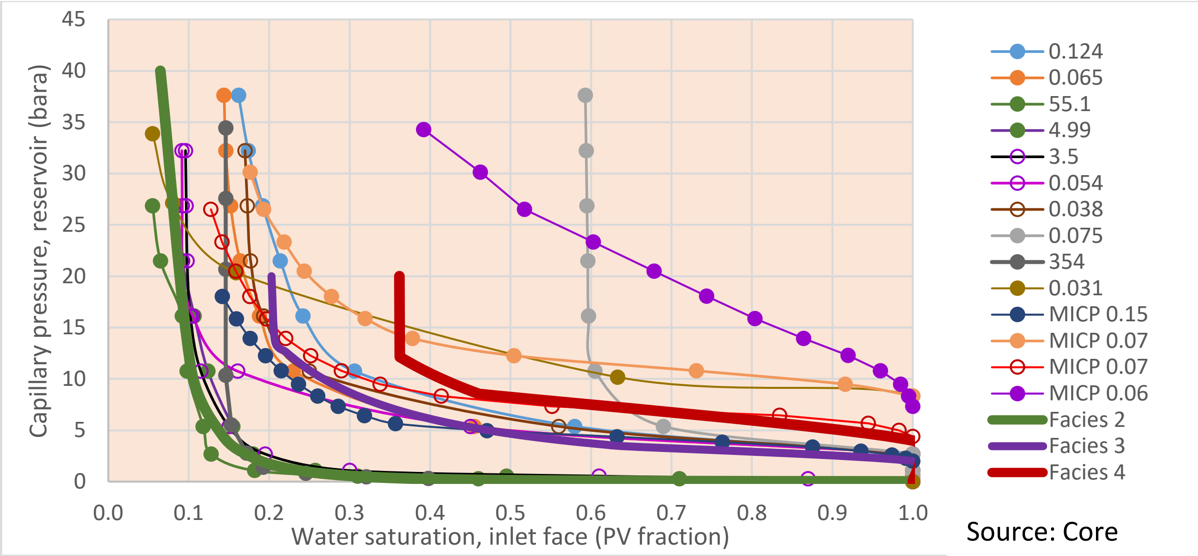

Figure 2 Capillary Pressure Curves – each curve is the capillary pressure curve of a different core

The petrofacies were categorised using permeability as a criterion, Table 1.

Table 1 Saturation regions in simulation model

Category (criterion permeability)		**K range, mD**	
Petrofacies	**Description**	**min**	**max**
1	Fractures	200	2000
2	Best	1	200
3	Mid quality	0.015	1
4	Poor	0.00001	0.015

4. Reservoir Fluid

The reservoir fluid is gas-condensate, meaning that at initial conditions in the reservoir the fluid is gas. However, as the fluid pressure falls in the reservoir during production, we can expect liquid to condense in the formation upon reaching a certain value, the dewpoint, Figure 4. For the subject field, this occurs at 191.9 bar (2783 psia), Table 2, condensate starts to form.

	Pressure	Temperature
Standard	1.01	15.56
Initial	202.5	96

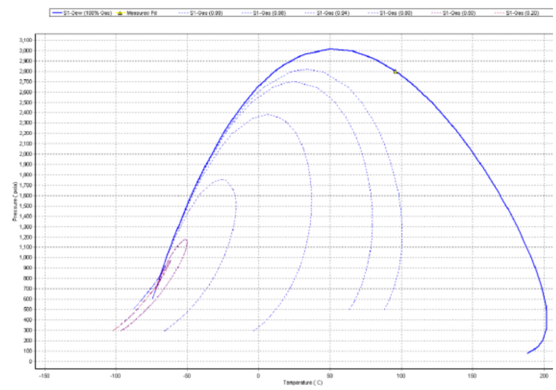

Figure 3 Phase envelope for recombined samples

The PVT report provided the following properties at reservoir conditions determined from Constant Composition Expansion (CCE) test.

Table 2 CCE summary of fluid properties at reservoir conditions

Test ID :	CCE at 96.0 °C	
Test Temperature	96.0	°C
Dew Point Pressure	2783	psia
Compressibility at Pres	275.4	10^-6/psi
Compressibility at Psat	288.6	10^-6/psi
Res. Fluid Density at Pres	0.176	g/cc
Res. Fluid Density at Psat	0.168	g/cc

5. Reservoir Model

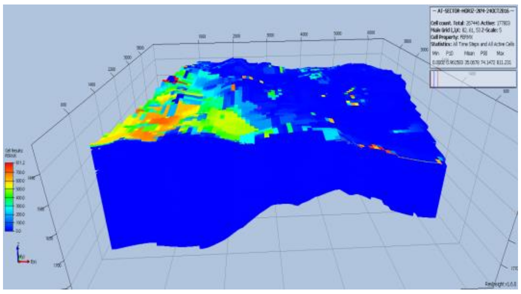

Figure 4 Reservoir section

The section of the reservoir analysed covers 6.1 x 4.5 km with a thickness of about 350M. There are 270,041 grid cells in the model. The cell size is a nominal 75 x 75m to capture the geology in sufficient detail.

6. Simulation Model File Structure

The commercial simulator Eclipse 100 was used to model flow. The grid geometry, properties, permeability and porosity values were generated within Petrel and the resultant data files provided by PetroCeltic.

Two regions were defined, the first containing the high permeability zone,

The production was simulated, setting the maximum rate at 300 000 sm3/day. The well stops producing when the WHP falls to 40 bara.

7. Simulation Modelling

7.1. Impact High permeability zone has on Productivity

The impact of the high permeability zone on well productivity and total recovery was analysed. To match the development plan, an uncased vertical well was drilled to a depth of 1510m, 50m below top of the reservoir column. Log and core data show the exploration well penetrated a 4m high permeability layer. In the model this is incorporated in Region 1.

From that, three cases were looked at to determine the effect of a high permeability layer to recovery – the exclusion of a high permeability layer, and the inclusion of one of varying size, height 2 and 8m.

The principal observation is that a high permeability zone does has an impact, increasing recovery, and the larger the zone, the greater the increase. A 20% increase is seen in the recovery factor from no high permeability zone to an 8m size one.

7.2 Impact Hydraulic Fracturing has on Productivity

A hydraulic fracture of 20m height, 70m half length, 0.5m width, and fracture conductivity of 1000mD was added to the previous well in the model.

The principal observation is that a high permeability zone continues to have an impact on recovery, but the effect is smaller with most of the registered increase coming from the region containing the high permeability zone. A smaller 9% increase is seen in the recovery factor from no high permeability zone to an 8m size one. With no high permeability zone, the addition of a hydraulic fracture, sees a 11.4% increase in the recovery factor; while an 8m high permeability zone sees a very small increase of less than 1%.

7.3 Vertical Transmissibility (kv/kh) Sensitivity

The impact the ratio of vertical against horizontal permeability, k_v/k_h, has on well productivity and total recovery was looked at. Four cases were evaluated ranging from optimal (1), realistic (0.8), poor (0.15) to very pessimistic (0.02).

Additionally, the cases were simulated with and without the inclusion of a zone of high permeability, and the uncased vertical wells were not hydraulically fractured.

The reservoir conditions are identical to those of the previous scenarios, initially without a hydraulic fracture.

The principal observation is that vertical transmissibility only has an impact on recovery when a high permeability zone is present in the reservoir. A 3% decrease is seen in the recovery factor when k_v/k_h is changed from 1 to 0.02 provided there is an 8m high permeability zone.

7.3.1 The Case with Hydraulic fracturing

A hydraulic fracture of 20m height, 70m half length, 0.5m width, and fracture conductivity of 1000mD was added to the previous well to also determine the effect it has on the k_v/k_h ratio. The reservoir conditions are identical to those of the previous scenarios.

The principal observation is that vertical transmissibility has a much greater impact on recovery when the well is hydraulically fractured, though the presence of a region of high permeability does not further increase the sensitivity to vertical transmissibility. A 3% decrease is seen in the recovery factor when k_v/k_h is changed from 1 to 0.02.

7.4 Impact Of Fracture Conductivity

The effect of altering the hydraulic fracture conductivity has on well productivity and total recovery was looked at. The model consisted of a shallow vertical well cased above a hydraulic fracture of 20m height, 70m half-length, and 0.5m width, but with the conductivity modified. To avoid crossflow, the well was cased above the hydraulic fracture. So as not to complicate the model further by altering the geometry of sub-cells in the hydraulic fracture’s path, the fracture width remained constant and only the value of the permeability within the hydraulic fracture was altered. Three cases were looked at: optimisitic = 1000 mD.m; realistic = 224 mD.m; and pessimistic = 100 mD.m; but also without a high permeability zone present, and with one of 2m and 8m height.

The principal observation was that changing the fracture conductivity does impact production, the higher the conductivity, the higher the recovery, though this difference is relatively small and is only registered within the first 200 days via an increase in the production rate.

7.5 Hydraulic Fracture Height Comparison

The effect hydraulic fracture height has on well productivity and total recovery was analysed.

The model consisted of a shallow uncased vertical well with a hydraulic fracture of half-length 70m, 0.5m width and fracture conductivity of 1000md.m, but with the height modified. Three cases were looked at for the hydraulic fracture height 20, 40, and 80m; but also without a high permeability zone present, and with one of 2m and 8m height.

The principal observation from the following results is that by increasing the height of the hydraulic fracture, the greater the value of production recovered. A 9.2% increase is seen in the recovery factor when the hydraulic fracture height is increased from 20m to 80m, provided there is no high permeability zone. The difference of recovery factor between HF heights jumps to 23.4% when there is an 8m high permeability zone present.

7.6 Impact of Hydraulic Fracture Length

The effect that hydraulic fracture length has on well productivity and total recovery was also looked at.

The model consisted of a shallow vertical well with a hydraulic fracture of varying height, 0.5m width and fracture conductivity of 1000md.m, but with the half-length modified. Three cases were looked at are HF half-length 70, 100, and 140m; but also without a high permeability zone present, and with one of 2m height.

The principal observation from the following results is that by increasing the half-length of the hydraulic fracture, the greater the value of production recovered.

7.7 Hydraulic Fracture Configuration Comparison

It can be inferred that without a high permeability zone present, the longer the hydraulic fracture half-length is, the more fluid that is recovered. However, when there is a high permeability zone present, the larger the HF height, the more fluid that is recovered.

7.2 Deeper Penetration Wells

The difference in recovery of drilling a deeper well to a depth of 1544m, and the shallow vertical well, at a depth of 1505m, was looked at. The recovery was analysed with and without a high permeability region.

The principal observation is that when hydraulically fractured, drilling deeper does not achieve a significant difference to recovery.

7.3 HORIZONTAL WELLS

7.3.1 Option: 1km Horizontal Well

The first well looked at was a 1km horizontal well passing through region 1 at a depth of around 1478m. Six cases were analysed: the well without HF, with 2 HF, and 4 HF, spaced out along the length of the well; with and without an 8m high permeability zone. The hydraulic fractures are 20m height, 70m half length, 0.5m width, and fracture conductivity of 1000mD.m. The reservoir conditions are identical to those of the previous scenarios. The more hydraulic fractures, the larger the recovery.

7.3.2 Option: 0.5km well

A shorter horizontal well of 0.5km, following the same path passing through region 1 at a depth of around 1478m, was simulated next. Four cases were analysed: the well without HF, and with 2 HF, spaced out along the length of the well; with and without an 8m high permeability zone. The hydraulic fractures are 20m height, 70m half length, 0.5m width, and fracture conductivity of 1000mD.m. Hydraulic fractures see a large increase in recovery.

7.3.3 Option: 2km well

A horizontal well of 2km, following the same path passing through region 1 at a depth of around 1478m, was considered next. Four cases were analysed: the well without HF, and with 4 HF, spaced out along the length of the well; with and without an 8m high permeability zone. The hydraulic fractures are 20m height, 70m half length, 0.5m width, and fracture conductivity of 1000mD.m. Hydraulic fractures see a large increase in recovery.

7.3.4 Option: Inclined well

A well was then drilled Horizontally inclined from the upper region (1463m) to the lower (1500m), and then hydraulically fractured, with and without an 8m region of high permeability. Hydraulic fractures see a large increase in recovery.

7.4 Vertical & Horizontal Well Comparison

When all the horizontal well options are compared along with a shallow vertical well, the 2km horizontal well comes first, recovering substantially more over 1200 days than the 1km inclined horizontal well, second in total volume produced. When not hydraulically fractured, there is very little to differentiate between all the other cases, though the vertical welcomes out slightly ahead of the 1km and 0.5km options. All the horizontal wells, regardless of dimensions, when hydraulically fractured, not only see an increase in recovery but produce much more gas than a vertical well.

7.5 Optimal Well Spacing

The optimal spacing between two wells was looked at, specifically three cases, where a second identical shallow vertical well with a hydraulic fracture of 20/70/0.5m was added to the model a set distance apart: 0.5, 1, and 2km.

Without a high permeability zone present, the further apart the two wells are, the greater the recovery, which subscribes to the development plan of having wells 2km apart. With a high permeability zone present, the 1km case comes out as the optimal distance between 2 wells. 0.5km appears too short, as while it does show an increase in recovery compared to a single well, it is substantially less than the other two cases.

8 Financial analysis

A financial model was created to calculate net present value (NPV) for possible well trajectories and hydraulic fracture designs. Due to the missing costs, the value attained cannot be considered the true NPV and is only being used for comparative reasons between the options. As the cost of surface plants along with maintenance and administration costs have not been included, the NPV is only to be used for comparative reasons between the options. The preferred scenarios are those with the greatest NPV. A 2km horizontal well along the upper region, with four hydraulic fractures spaced out along the length of the well, gives the greatest NPV, 142,247,066 USD. Figure 5 shows how the net cash flow of the hydraulically fractured 2km horizontal well (grey bar), increases with each year, over the 10-year period, as opposed to all the other cases which decrease. This is because the well manages to maintain maximum production (300,000 sm^3/day) for over 10 years, and with the estimated yearly gas price increase, results in the increasing values of Net Cash Flow.

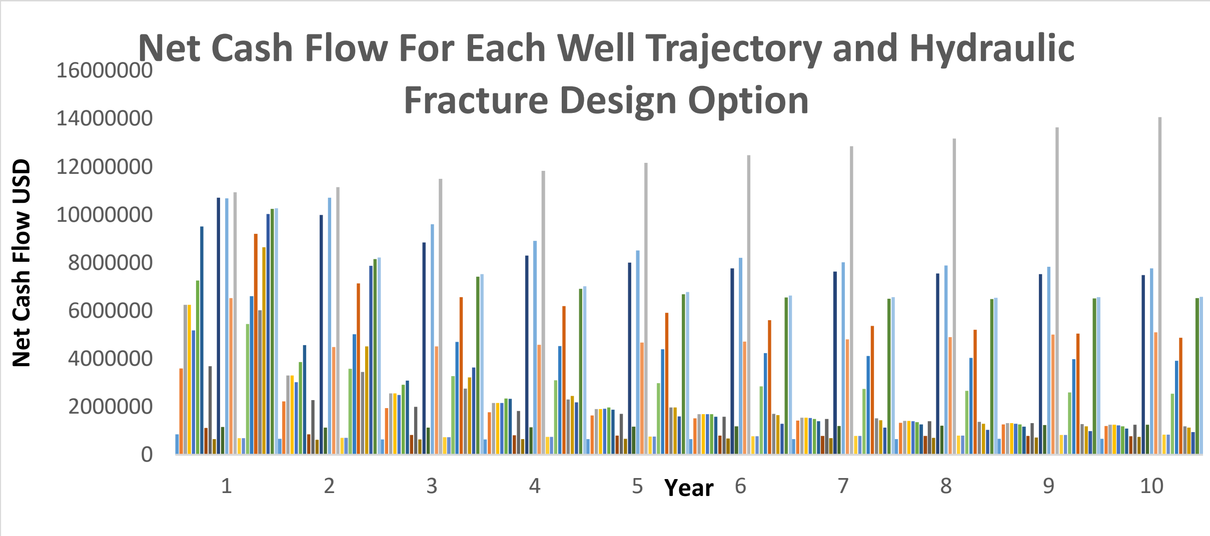

Figure 5 Net Cash Flow bar graph for each well type

9 Conclusion

The main objective of this project was to determine the optimal well trajectory and hydraulic fracture design for a low-quality gas-condensate reservoir to sustain high production rates that maximise recovery and to assess whether the current development plan would be sufficient.

The simulation results reveal that a shallow vertical well cannot produce commercial quantities of gas and is also seen to be insensitive to change in the vertical transmissibility, unless a high permeability zone is present.

A hydraulic fracture gives a notable boost in recovery from the well, which in turn increases depending on the size of the high permeability zone. With a HF, the recovery is very sensitive to the k_v/k_h ratio. A poor ratio results in a lower recovery factor as less fluid can flow vertically.

Altering the fracture conductivity does impact on the recovery, but not enough to warrant concern over the uncertainty, even with the presence of high permeability zone.

Increasing the height of the hydraulic fracture, also sees a significant increase in the recovery, which gets larger still with the increasing size of the high permeability zone. The same effect is seen when the HF's half-length is altered. To the point where it can be concluded that the longer the hydraulic fracture half length, the higher the recovery, especially when there is no high permeability zone. It should be noted however that when there is a high permeability zone present, it is the HF height which has the greater influence on recovery.

Despite, the initial assumptions, drilling deeper does not have the desired effect of increasing production. An increase is registered when there is no HF, which has already been determined to be necessary, and depending on the size of the high permeability zone, more condensate is produced. The addition of a hydraulic fracture sees virtually no difference in the recovery, nor the CGR, of a deep well to that of a shallow well.

While the impact of condensate deposition in the formation should always be considered, the evaluation of the conditions here found that it is not an immediate issue as the formation of condensate, once the reservoir pressures falls below the dewpoint, reduces the gas permeability (and hence the gas productivity) by a maximum of 5% - a value considered insignificant.

Due to their extra coverage, simulation predicts that drilling horizontally will see greatly increased production values and this is the case when the wells are hydraulically fractured, with substantial returns being made compared to a vertical well.

When considering drilling more than one well, and there is no high permeability zone, the further away two wells are, in this case the max distance is 2km, the higher the recovery will be. However, when there is a high permeability zone the optimal distance between wells is seen to be 1km. This is an unexpected outcome: generally, the more homogeneous and poor quality the formation, the wider the spacing required to maximise recovery.

From the financial model, the most lucrative system, based on its NPV, is a hydraulically fractured 2km horizontal well, assuming there is no high permeability zone and an optimal k_v/k_h ratio of 1. Though based on the increased recovery factors of the well options when there is an 8m high permeability zone present, the extra revenue brought about from production sales would still not be enough to change the outcome reached. Therefore, the ideal system for this reservoir, based on the cases tested, is a hydraulically fractured 2km horizontal well.

It would be valuable evaluating separate wells each producing from the high and low permeability zones, instead of production from both zones simultaneously.

The production rate limit could be altered, changing the plateau length, to see the effect this would have on the recovery of the different well types.

More work is needed in optimising hydraulic fracture dimensions for the given reservoir conditions.

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