FIELD MODEL PREDICTIONS TO DEMONSTRATE THE VALUE OF INTEGRATED GAS CONDENSATE NEAR-WELL SCAL DATA

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ABSTRACT

This paper looks at the issues affecting gas condensate production and how special core analysis (SCAL) data for near-well relative permeability may be used to model productivity in a full field model for evaluating gas condensate reservoir development. Although some aspects of gas condensate reservoir can be studied using standard techniques from dry gas reservoir engineering, it is also important to consider issues such as liquid recovery and change in yield during field life, compositional gradients, and the reduction in well deliverability caused by condensate blockage.

Condensate well deliverability is particularly important as it impacts downstream issues such as the number of wells required, surface gas handling facilities, drilling schedules and income from gas sales contracts. Accurate forecasting of condensate well deliverability usually requires SCAL data to measure relative permeabilities in the near-well region, and to understand high-velocity phenomena such as the improvement in relative permeability at high capillary number.

In this paper we describe the use of Decision Risk Management techniques to quantify the value of SCAL data in terms of its impact on reservoir management decisions. We illustrate these methods by an example of a condensate reservoir where the well productivity affects the number of wells needed for an optimal development.

INTRODUCTION

In many gas reservoirs well productivity has a major impact on development and operational decisions such as the number of wells, whether to fracture wells, the size of surface facilities and the level of gas sales contracts. In gas condensate reservoirs the issue is more complex as liquid build-up around the well (or 'condensate blockage') can cause a significant loss in productivity after the bottom hole pressure falls below the dew point.

The impact of condensate blockage is very sensitive to the gas-oil relative permeabilities in the region around the wellbore. Several laboratory experiments (e.g. reference 1) have demonstrated an increase in mobility for gas-condensate fluids at the high velocities typical of the near-well region, a mechanism that would reduce the negative impact of condensate blockage. There is also some evidence from well test results to suggest that this effect occurs in the field [2].

Calculating Gas-Condensate Well Productivity

Forecasting of condensate well productivity usually requires fine grid numerical simulation to model near-well effects and the improvement in relative permeability at high velocity. However, it is also possible to use 2-phase pseudopressure methods [3] to provide a simpler and faster method of estimating condensate well productivity. Pseudopressure methods have been extended to model high-velocity effects and can also be applied to fractured and horizontal wells [4]. These methods are suitable for rapid calculations to examine sensitivities to different input parameters.

Measurements of Gas-Condensate Well Productivity

The uncertainty in gas-condensate well productivity can be reduced by Special Core Analysis (SCAL) measurements on core samples. Special techniques have been developed for measuring gas-condensate relative permeabilities at conditions typical of the near-well region, and for quantifying the importance of high-velocity effects [1]. These experiments may cost in the region of $100,000, and this cost needs to be justified in terms of a benefit from improved decision making and reservoir management. The Decision Risk Management methods described in the next section offer a way of estimating the value of SCAL data.

Decision Risk Management (DRM)

Reservoir development and management decisions must be taken in the presence of a number of uncertainties. Condensate blockage and its impact on well productivity is just one of the uncertainties. The others include reservoir properties such as the volume of gas in place or the absolute permeability, financial data such as oil and gas prices, and operational parameters such as the time taken to drill a well. Decision Analysis offers a way of selecting the optimum decision, allowing for the presence of uncertainty. It may be possible to reduce some of the uncertainties by additional testing in the field or by measurements in the laboratory. Decision Risk Management can also be used to estimate the value of the information, in terms of its impact on reservoir management decisions.

ESTIMATING THE VALUE OF SCAL DATA

To demonstrate how DRM methods can be used to estimate the value of SCAL data, we consider a rich gas condensate reservoir that is to be developed with either two or three wells. Initial estimates suggest that the first two wells can each produce about 60 MMscf/d at initial pressure, while the third well can produce about 30 MMscf/d. The total production is constrained by facilities limits to a plateau rate of 100 MMscf/d. A high well productivity favours developing the reservoir with two wells, whereas a low productivity will normally require an extra well. The cost of drilling Well 3 is about $43 million.

For the purposes of this example we assume that the wells must all be drilled before the start of production. As the well bottom hole pressure falls below the dew point early in field life, condensate blockage has a significant impact early in field life. The value of the SCAL data in this case lies in reducing the uncertainty in condensate blockage and hence in forecasts of well productivity.

The other uncertainties included in the analysis are oil and gas prices, the initial gas in place, the permeability-thickness (*kh*) product for the wells, and the cost to drill a well.

Figure 1 shows the decisions and uncertainties in this example. The two decisions, shown by rectangular boxes on the left-hand side of the figure, are whether to drill a third well and whether to measure SCAL data to minimise the uncertainty in well productivity before taking this decision. The ellipses show the uncertainties – each uncertainty node is represented by three possible outcomes – a 'low', 'base' and 'high' case with probabilities 25%, 50% and 25% respectively. The remaining three boxes show 'values' which can be calculated for each possible combination of the decision and chance nodes. The arrows show that one node influences another. Although the SCAL results do not directly influence condensate blockage, there is an indirect influence as the SCAL data will give information on the reservoir relative permeabilities.

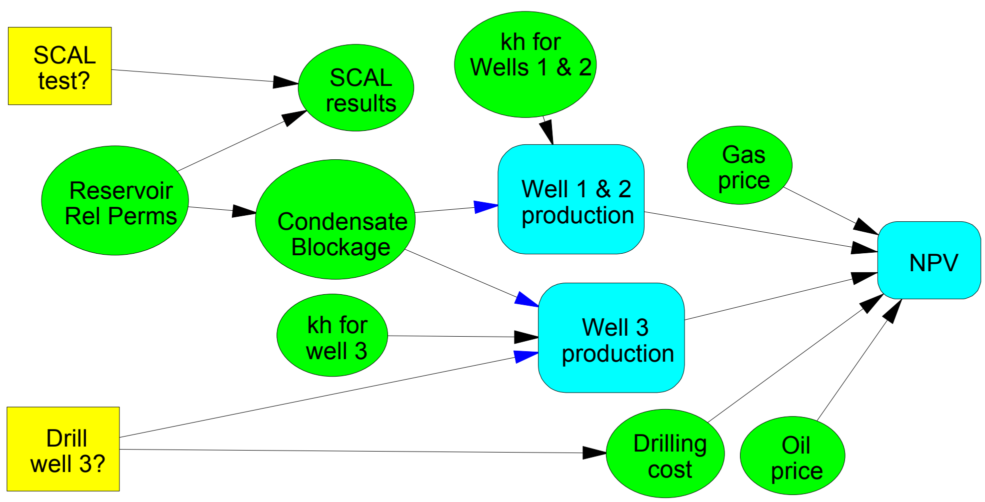

Figure 1. Influence Diagram showing decisions and uncertainties.

Decision Risk Management requires a way of estimating project NPV for each possible combination of the decisions and uncertainties. The NPV is calculated with an Excel cash flow spreadsheet that estimates production and costs every quarter throughout field life. Decision analysis software can be linked to the spreadsheet so that the calculations are carried out automatically.

Estimating Production Profiles for Different Scenarios

The cash flow spreadsheet calculates production profiles from tables of the maximum gas production rate ('capacity') for each well, in terms of the cumulative gas production for the reservoir. The tables for a limited number of base cases can be calculated from full-field simulation models. It is impractical to run simulation models for all possible combinations of the uncertainty nodes, but the simulation profiles can be adjusted analytically to estimate the impact of changes in parameters such as well productivity or gas-in-place.

Well productivity calculations with a pseudopressure technique can be used to estimate a range of possible values for condensate blockage. In this example the worst case assumed no increase in mobility at high velocity, the best case assumed a significant increase in mobility with velocity, and the base case lay between these two extremes.

Results

When using Decision Risk Management for this type of problem, it is often more useful to calculate the incremental NPV from comparing two different development options. In this case we consider the incremental NPV from drilling the third well. Figure 2 is a 'Tornado Diagram' which shows the sensitivity of the incremental NPV to changes in the uncertainties. Figure 2 shows that condensate blockage has the largest impact on the incremental NPV; if condensate blockage is low and productivity is high, the incremental NPV is negative, so that it is best not to drill Well 3.

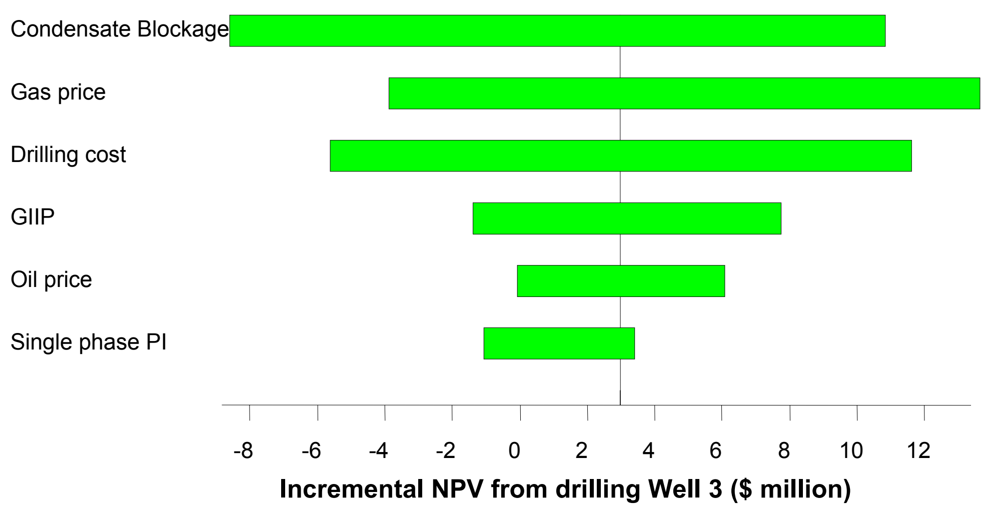

Figure 2. Tornado Diagram showing the sensitivity of the incremental NPV to different parameters.

The value of SCAL data can be estimated by using a 'Decision Tree' to calculate the average NPV resulting from different decisions, taking account of uncertainties. The decision tree in this example is shown in Figure 3 – the squares denote decisions and the circles show uncertainties, and the bold lines represent the optimal decisions. The decision tree has been simplified, so that the circles on the right of the tree represent all possible combinations of the remaining uncertainties – condensate blockage, gas-in-place, oil and gas prices and drilling costs.

If SCAL data have been obtained, additional information is available to guide the decision about drilling Well3. If the SCAL data suggest a high value of relative permeability in the near-well region, the average NPV is higher if Well 3 is not drilled. In the other cases, it is best to drill Well 3. Without SCAL data, drilling Well 3 leads to a higher average NPV.

Figure 3 shows that the average NPV is increased by about $1.2 million by carrying out SCAL measurements, even after allowing for a cost of about $100,000. The value of the SCAL data can be quantified in this case because of its impact on a development decision.

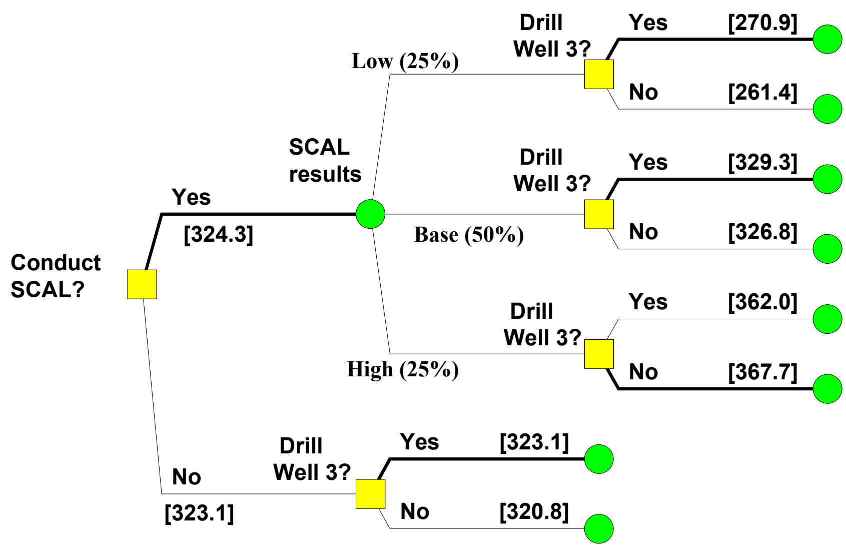

Figure 3. Simplified Decision Tree for SCAL tests and drilling Well 3. Figures show project NPV in $ million.

This analysis does not assume an exact correlation between the results of SCAL data and the impact of condensate blockage in the field. We have used an 'accuracy' of 80% for these calculations – for example, if the SCAL data show a high relative permeability, then there is an 80% chance that the well productivity will also be high. The value of the SCAL data increases with its accuracy – in this example, changing the accuracy from 80% to 100% increases the value of the data from $1.2 million to $1.7 million, while reducing the accuracy to 50% means that its value is marginal at $0.1 million.

An alternative way of analyzing the decision about drilling Well 3 is to use incremental economics. Figure 4 shows a cumulative probability plot for the **incremental** NPV for two strategies

(1) Do not measure SCAL data and always drill Well3.
(2) Measure SCAL data and drill Well 3 unless high relative permeabilities are found.

The incremental NPV is found by comparing with a base case, which is never to drill Well 3. Figure 4 shows the probability that the incremental NPV is less than a certain value, and gives an indication of the range of possible results. The vertical lines show the average values of the incremental NPV for the two strategies. Figure 4 shows that the strategy with SCAL data has both a higher average incremental NPV (£3.5 million compared with £2.3 million), and a lower chance of making a loss (25% compared with 44%)

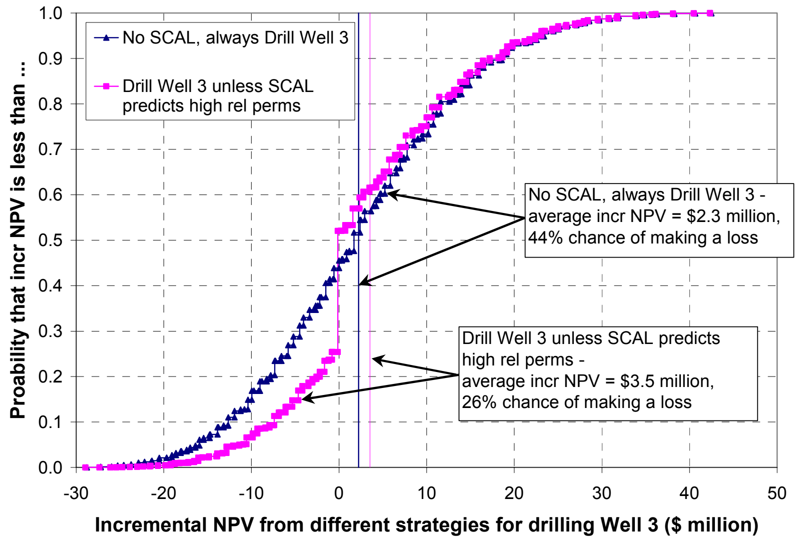

Figure 4. Cumulative probability distribution for incremental NPV from different strategies for drilling Well 3.

OTHER APLICATIONS

We have used the techniques in this paper to examine a range of other development and operational decisions for gas condensate reservoirs, such as whether to fracture a well, when to plugback a well and re-complete in a different reservoir, and the setting of gas sales contracts. The same methods can also be used to estimate the value of other types of data, such as SCAL data for oil reservoirs under water influx, 4-D seismic or well testing.

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