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Gas Field Deliverability Forecasting: A Coupled Reservoir Simulator and Surface Facilities Model

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Conference Title:
45th Annual Technical Meeting of the Petroleum Society of Canadian Institute of Mining, Metallurgy and Petroleum (CIM)

Conference Location:
Calgary, Canada

Conference Dates:
June 12-15, 1994

Conference Sponsor:
Petroleum Society of Canadian Institute of Mining, Metallurgy and Petroleum (CIM), and
Alberta Oil Sands Technology and Research Authority (AOSTRA)

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This paper is to be presented at the 45th annual technical meeting of the Petroleum Society of CIM organized by the Petroleum Society of CIM, co-sponsored by AOSTRA in Calgary, Canada, June 12-15, 1994. Discussion of this paper is invited and may be presented at the meeting if filed in writing with the technical program chairman prior to the conclusion of the meeting. This paper and any discussion filed will be considered for publication in CIM journals. Publication rights are reserved. This is a pre-print and is subject to correction.

ABSTRACT

This paper describes the procedures used in a joint venture by two software vendors to combine an existing reservoir simulator and an existing surface facilities model into a single forecasting tool. Relatively small changes were made to each program. In the new model, the black oil reservoir simulator provides the formation pressure and water to gas ratio for each well. The surface facilities model then calculates the multiphase flow pressure losses in the wellbore and gathering system, plus the corresponding flow rates for each well. The actual production required from each well to satisfy the pipeline contractual requirements, over each time step, is computed by the surface facilities model and relayed back to the reservoir simulator. The time step is determined dynamically according to the requirements of each program. The performance and results from the coupled model are compared to that of running each model separately for a gas storage field in the U.S.A and for a gas production field with bottom-water. It is shown that running each model separately does not account for all the factors affecting the forecast.

INTRODUCTION

To determine if a gas contract can be satisfied now and in the future, it is necessary to forecast the performance of the gas reservoir, the gas inflow into the sandface, the multiphase pressure losses in the wellbore and gathering system and the field facilities. Surface production models which rigorously model from the sandface to the plant gate are available. However, these surface packages model reservoirs simply, in most cases as tank-type reservoirs. Comprehensive 3 dimensional reservoir simulators are available, but typically only include simple surface networks which don't adequately model multiphase flow in complex gathering systems[1,2,3].

A different approach has been taken in this paper. Two existing commercial models, a 3 dimensional black oil simulator and a multiphase surface facilities model, from different vendors, were coupled into one comprehensive model. This work required only a small fraction of the development time and cost which would have been required to "add on" a surface network to a reservoir simulator. No simplifications of either component were required and each component was supported by experts in that field. Existing data files and documentation were used directly. New developments can be added to either model without adversely affecting the interface.

IMPLEMENTATION

The black oil simulator, IMEX, from the Computer Modelling Group was chosen as the reservoir simulator. FORGAS, from Neotechnology Consultants Ltd. was selected as the surface model. Both models were linked into one executable to save execution time. Two new subroutines were created to pass data between each model. Each routine is responsible for accessing the required data and then converting the data into the acceptable format (e.g. SI to field units). The other model then calls this subroutine whenever it needs the information. The name of each well is used to link the models. A new mainline routine was created which calls each model (as a subroutine) sequentially in a loop. Each model passes a status indicator back to the mainline routine to indicate errors in the data or to inform the mainline routine that the forecast should end.

First, the reservoir simulator reads its input data file and determines the grid block pressure, water to gas ratio and status for each well. A maximum time step length is chosen. To avoid potential problems, the first time step is always chosen to be 1 day in length, which is the minimum time step allowed by the surface model.

Next, the surface model reads its input data file and calls the interface routine to get the static pressure at the midpoint of perforations, water to gas ratio and status for each well common to it and the reservoir simulator. Other wells can produce from the surface model's own tank-type reservoirs when adequate data are not available to model those reservoirs rigorously. The surface model uses either the Rawlins and Schellhardt equation or Laminar-Inertial-Turbulent equation[4] to compute the sandface inflow performance for each well. Multiphase pressure loss correlations such as Aziz, Govier and Fogarasi[5] are used to calculate wellbore pressure losses to compute wellhead deliverability. Multiphase pressure losses in the gathering system are computed using the correlation of Eaton et al[6] and the model of Oliemans[7]. The flow rate for each well is calculated after accounting for contract limitations. The surface model then decides on the actual length for the next time step using the maximum recommended length from the reservoir simulator and its own criteria (e.g. plant anniversary date, time dependent changes in the input data). The contract specifications are used in conjunction with the computed deliverability of the system to calculate the average rate each well will produce from the reservoir over the time step. A summary of calculated pressures and flow rates is then written to an output file.

The reservoir model then calls the interface routine to retrieve the average production rate for each well and the actual time step taken. The reservoir simulator performs the material balance. If the actual time step is too long, given the predicted flow rates, the reservoir model will subdivide the time step. The reservoir calculations step forward in time until the elapsed period matches the actual time step already completed by the surface model. The maximum length of time step is computed as the previous time step length multiplied by the maximum allowable pressure change (specified by the user) divided by the calculated pressure change over the previous time step.

The surface model recomputes the system deliverability using the revised static grid block pressures and water to gas ratios. The actual time step is chosen and the average production rate of each well is computed and stored to be accessed by the reservoir model when required. This process continues until the last day of forecast, as specified in the input data of the surface model, has been reached.

A potential problem with the procedure used is that the grid block size for the well in the reservoir model may not correspond to the radius of investigation used to compute the deliverability coefficients used by the surface model. To handle this problem, it is recommended that the more rigorous Laminar-Inertial-Turbulent equation using pseudo pressure be used. The laminar coefficient (a) should be adjusted such that the predicted flow rate of the well from the combined model matches the measured flow rate of the well.

The surface model uses only gas rates, and thus cannot handle oil-gas systems. The reservoir model does not handle composition changes in the reservoir and thus cannot be used for gas cycling or gas-condensate reservoirs.

The combined model when dimensioned for 2000 active grid blocks, 255 wells, 666 nodes, 121 field facilities and 3 plants with 10 contracts per plant requires 13 Megabytes of RAM.

The coupling of these two models required 40 man days. An additional 10 man days were utilized to test the model. A total of 4 months elapsed from project start to the end of the initial tests with field data.

APPLICATIONS

GAS STORAGE RESERVOIR

Injection and production from a gas storage reservoir in the north eastern U.S.A. was chosen as one of the test cases to demonstrate the increased accuracy that is obtainable by using the combined model. The storage field is located in a sandstone on an updip stratigraphic pinchout. Structure consists of a uniform dip to the southeast controlling the distribution of gas and water at the reservoir level. The reservoir was modelled as a two layered formation based on the log analysis response. Sedimentary deposition was uniform over the study area allowing for the development of a simple geologic model as input to the reservoir model.

A three dimensional reservoir simulator was required to account for the permeability heterogeneity, layering and varying sand thickness throughout the reservoir. A 77 by 40 by 2 cartesian grid was used. Permeability varied from 1 to 10 millidarcies in the lower portion of the reservoir and from 40 to 200 millidarcies in the upper section. A comprehensive surface model was required to accurately calculate pressure losses in the gathering system and to optimize gathering line and compressor sizing. The location of the 10 injection/production wells plus 4 observation wells is shown in Figure 1.

The combined model was used to evaluate deliverability for the following cases:

1. the base case
2. the addition of 8 production/injection wells
3. the addition of 8 production/injection wells and increasing the diameter of the trunkline from 141.22 mm to 292.76 mm

For all cases, the injection contract rate was specified as 1.27 $10^6 m^3/d$. To prevent going above the original discovery pressure, the maximum wellhead pressure allowed was 14479 kPa. For the base case, the production contract rate was specified as 1.83 $10^6 m^3/d$, whereas for the other 2 cases, this rate was increased to 2.11 $10^6 m^3/d$. In all cases, the wellhead pressure was not allowed to fall below 3447 kPa.

Two injection/production cycles were modelled as follows: 214 days of injection starting April 1, shut in the field for 15 days, 120 days of production starting November 15 and shut in the field for the last 16 days of March. The base case injectivity predicted by the combined model, the surface model using only a tank-type reservoir, and the reservoir model are compared in Figure 2. The base case results for the production cycle are compared in Figure 3. The surface model using only a tank-type representation of the reservoir predicted a higher capability than the combined model because it could not account for the low permeability of the reservoir and the interference between wells. The reservoir model predicted a higher capability than the combined model because gathering system restrictions could not be included. The reservoir model predicted that the required deliverability and injectivity could be reached for all the cases. The surface and combined models predicted that only once the 8 wells were added and the trunkline diameter was increased to 292.76 mm could the target rates be met over the desired period.

The coupled model exhibited significant oscillations in the predicted flow rates of several wells. Preliminary investigation seems to suggest that these oscillations are due to the explicit coupling of the surface and reservoir models; however, further research is required to determine the exact cause.

The results from the combined model for each case are compared in Figure 4 and Figure 5. Note that due to the restrictions in the trunkline, there was almost no benefit from the addition of the 8 wells. Only once the trunkline diameter was increased to 292.76 mm could the target rates be met.

GAS PRODUCTION FIELD WITH BOTTOM-WATER

A gas production field with bottom-water was chosen as the second case to test the combined model. The objective was to determine how water coning would affect the deliverability of wells over the 10 year forecast period. This gas reservoir was modelled using a 13 by 14 cartesian grid with 11 layers (Figure 6). Permeability was between 1 and 100 millidarcies. The location of the gas plant and the 5 wells is shown in Figure 6.

The combined model was used to evaluate the following cases:

1. the base case
2. adding compression at the plant at the start of the second year

The predicted water to gas ratios from the combined model for well W-5, the only well affected by water coning, are shown in Figure 7 for each case. The water to gas ratio oscillates until compression is added. Without compression this well is unable to produce against line pressure, and it is shut in for the time step. By the start of the next time step, the water cone has subsided and thus the well can produce versus the back pressure. The production causes more water coning, killing the well for the next time step. This cycle continues until the back pressure on the well is reduced by compression, allowing the well to lift its liquids. The addition of compression substantially increased the water to gas ratio produced by this well.

The total plant deliverabilities for the base case predicted by the combined model, the surface model using only a tank-type reservoir and the reservoir model run independently are compared in Figure 8. The surface model using only a tank-type representation of the reservoir predicted a higher deliverability than the combined model because the tank-type model was unable to predict the pressure gradients in the reservoir. The reservoir model when run alone was able to predict the correct water to gas ratios but was unable to translate this into a decreased wellhead deliverability capability due to the increased gathering system backpressures, and thus predicted the highest well production rates.

The combined model exhibited oscillations during the first and second year. During that time, the maximum wellhead pressure of well W-3 was very close to the current backpressure on the well. The well could not produce and was shut-in for the 3 month time step. Then the reservoir pressure had built up enough so that the well could produce. The water cone had subsided and thus water production did not occur until after the next time step. After more production, the well was no longer capable of delivering against the system back pressure. After being shut-in one time step, well W-3 was once again able to produce. This cycle was repeated until well W-3 was no longer capable of any more production.

When the surface model was run alone, it also showed oscillation because the predicted water to gas ratios in the gathering system changed as well W-3 stopped and restarted production, causing large changes in the backpressures on all the wells, and thus changes in the system deliverability.

For the compression case (see Figure 9), the reservoir model overpredicted the system deliverability because the correct compressor inlet pressure and corresponding pressure loss in the gathering system could not be predicted. Thus the best that could be done was the provision of a wellbore hydraulics table for the wells and an estimate of the wellhead flowing pressure. The increase in water production from well W-5 could not be predicted by the surface model, thus underestimating its wellbore and the overall gathering system pressure losses.

A 486 33 Megahertz IBM PC compatible microcomputer with 8 Megabytes of RAM required 15 minutes to perform a 10 year forecast using the combined model.

DISCUSSION

The combined model is useful for simulating the following situations:

1. gas reservoirs with low permeability. In a gas reservoir with permeability less than 1 md in Alberta, the surface model, when run independently using a tank-type reservoir, predicted production rates 100% larger than those forecasted by the combined model.
2. water coning problems
3. heterogeneous reservoirs

A surface model alone can be used for permeable, homogenous reservoirs without water influx. A reservoir model alone can be used in situations where well flow rates are independent of wellbore, surface and contract limitations. It is important to remember that the combined model should be used only if there are enough data to model the reservoir with a simulator and the surface system adequately.

The advantages of the method used to create the combined model include:

1. much less time and cost was required than to program a surface network from scratch to include in a reservoir simulator or to program a reservoir simulator from scratch to include in a surface model.

2. existing technology and expertise is used

3. existing input data files and documentation can be used with only minor modifications

CONCLUSIONS

1. Coupling an existing reservoir simulator and an existing surface model requires only a small fraction of the time and cost that would be required in developing the complementary model from scratch. With consistent effort, the process should take less than 4 months.

2. This process can be used to couple any existing reservoir simulator with any surface model which includes sandface inflow performance and wellbore pressure loss calculations.

3. Coupling a reservoir simulator and surface model allows gas forecasts to include many factors which could not be included when running each model independently.

4. The gas storage case illustrated the importance of modelling both the pressure gradients in the reservoir and the pressure losses in the surface pipeline network.

5. The bottom-water drive case showed that it is important to use the coupled model to predict changes in the water/gas ratios. Otherwise the deliverability of the system will be overestimated.

ACKNOWLEDGMENTS

We would like to thank the National Fuel Gas Supply Corporation for allowing us to present their data and the U.S. Department of Energy for providing the simulation results for the gas storage reservoir. We would also like to acknowledge the member companies of the Computer Modelling Group for supporting this research..

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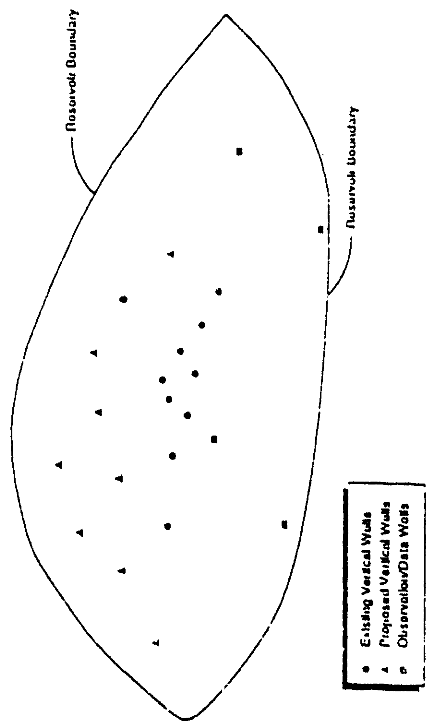

Figure 1 Schematic of Storage Reservoir

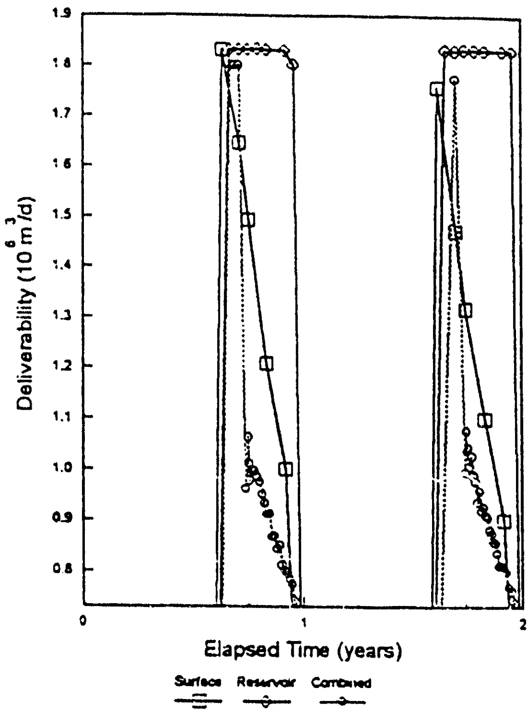

Figure 3 Storage Reservoir Base Case Deliverability

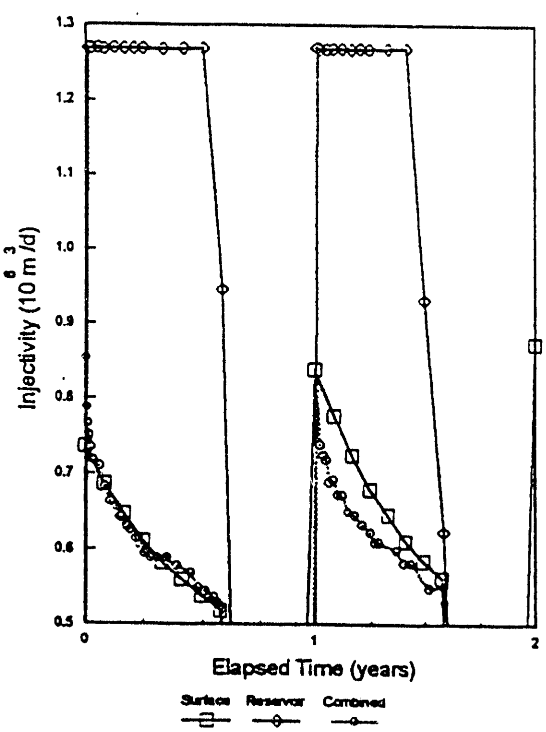

Figure 2 Storage Reservoir Base Case Injectivity

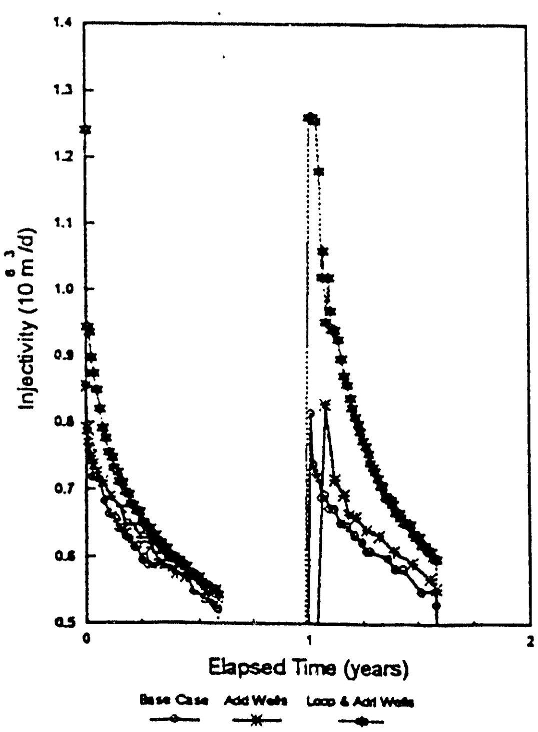

Figure 4 Storage Reservoir Injectivity Predicted by the Combined Model

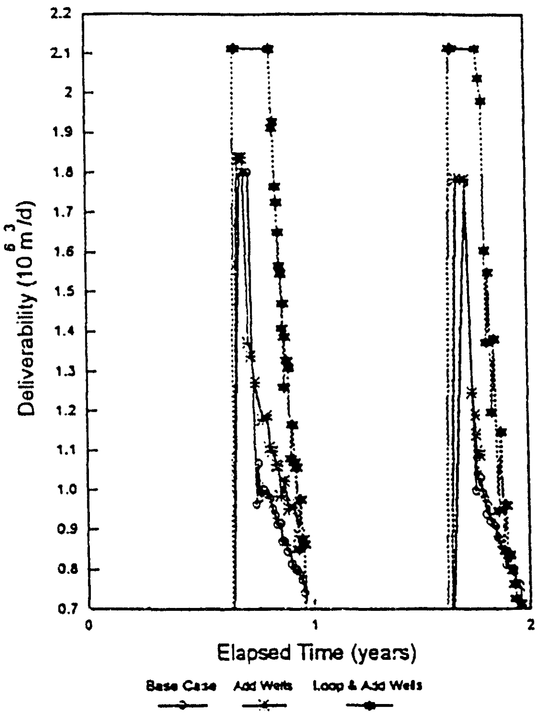

Figure 5 Storage Reservoir Deliverability Predicted by the Combined Model

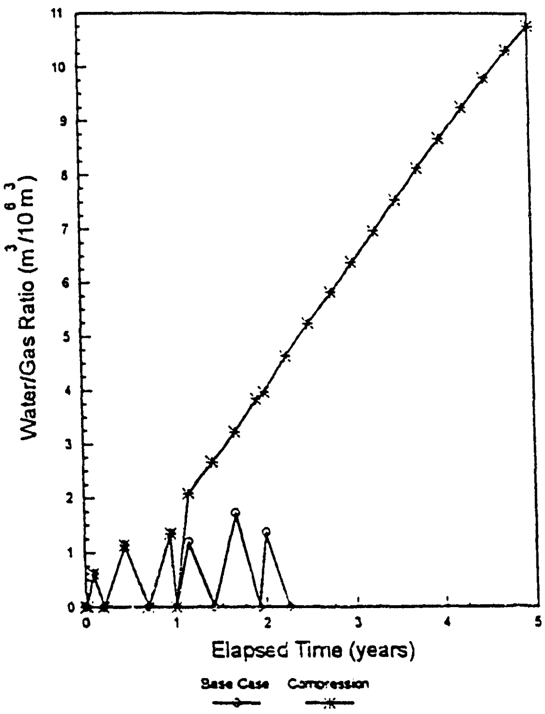

Figure 7 Water to Gas Ratio Predicted for Well W-5 by Combined Model

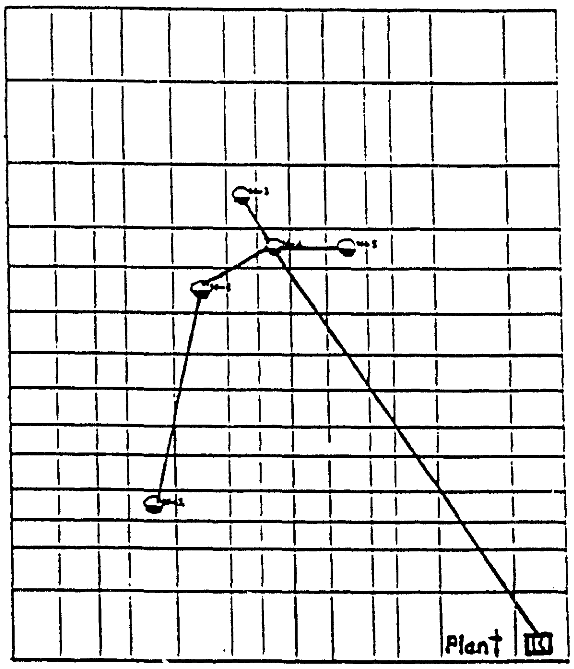

Figure 6 Schematic of Bottom-Water Reservoir

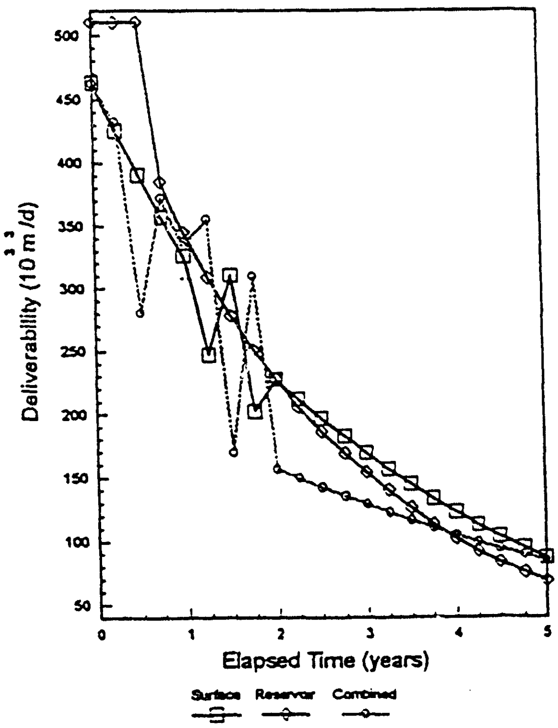

Figure 8 Bottom-Water Base Case Deliverability

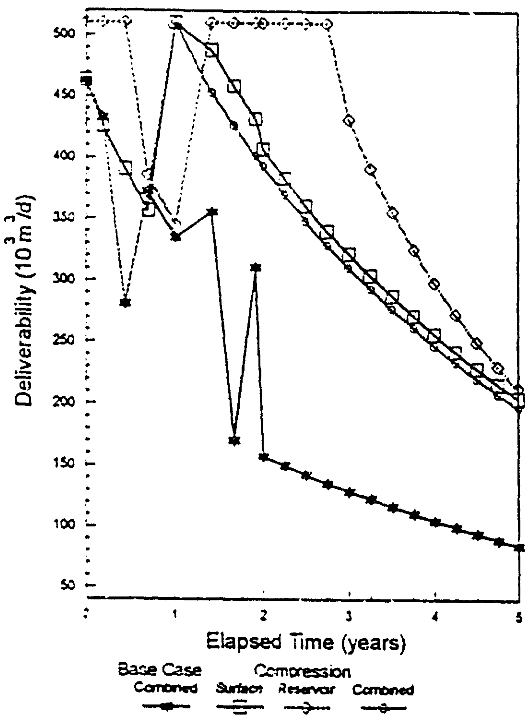

Figure 9 **Bottom-Water Compression Case Deliverability**

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