Epic

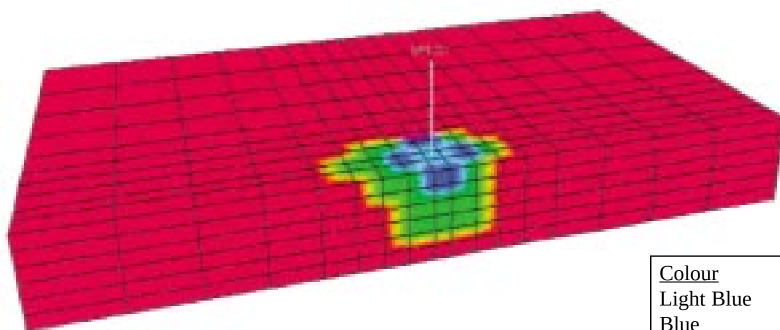
Reservoir Technology

Winter 1998

Epic Consulting Services Ltd. provides innovative and practical solutions in characterizing reservoirs. At the recent Petroleum Society of CIM technical conference, Epic presented a number of papers that have provided insight into a number of issues relating to reservoir management such as modeling cold production, characterizing and modeling of a naturally fractured reservoir and blowdown of a gas cap. A paper that deals with miscible flooding of the Virginia Hills reservoir was presented last year and is being published in the *JCPT* this fall. This newsletter includes the abstract, a brief overview and the conclusions from each of these papers for your enjoyment and learning. If you have any questions or require the full text of any paper, please feel free to contact us at 213-4200.

Modeling Cold Production for Heavy Oil Reservoirs

The term "Cold Production" refers to the use of operating techniques and specialized pumping equipment to aggressively produce heavy oil reservoirs. This encourages the associated production of large quantities of the unconsolidated reservoir sand, creating a modified wormhole geometry that could include "wormholes", dilated zones, or possibly cavities. As well, produced oil in the form of an oil continuous foam resembling chocolate mousse suggests a foamy solution gas drive occurs in situ. This leads to anomalously high oil productivity and recovery because free gas stays entrained in the foam, thereby sustaining reservoir pressure. In a recent paper, the mechanisms that lead to this increased productivity were outlined and the suitable reservoir types conductive to cold production techniques were identified. In this paper, these mechanistic concepts are extended to practical, intuitive modeling techniques that can be applied to existing "black oil" reservoir simulators by appropriate alterations to the input data. Importantly, these techniques have been found to match actual cold production behaviour in applicable Western Canadian conventional heavy oil reservoirs.



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Light Blue	6-10
Blue	4-6
Green	1-4
Red	0

With a history matched model, these techniques can be used to extend the cold production scenario into the future, providing better estimates of ultimate recovery. As well, sensitivities to the process can be investigated, including exploring sensitivities to various reservoir and operating parameters (e.g., reservoir pressure, production rate strategies) and examining the impact of a preceding cold production primary depletion on subsequent secondary and tertiary recovery processes.

Field observations of cold production in some heavy oil reservoirs, in Canada and Venezuela, have resulted in unexpectedly high oil rates and recoveries, as well as low gas-oil ratios which have been the subject of numerous articles in the petroleum literature. A number of studies have been pursued including investigation of laboratory fluid and rock properties, conceptual postulation of mechanisms using actual field behaviour and numerical simulation to model these mechanisms. The two mechanisms within the literature that explain cold production performance of heavy oil reservoirs are fluid and geomechanical effects. The simulation model incorporates both geomechanical and fluid effects to history match an actual field example of cold production. Unlike previous literature, the actual results of

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inside . . .

Simulation of Horizontal Wells to Mitigate Miscible Solvent Gravity Override in a Thick Carbonate Reef

In a recent study for a client, Epic was asked to review the potential for improving recovery in a mature, miscibly flooded carbonate reef. Our assessment was that miscible recovery in the field was significantly limited by poor vertical sweep of the solvent due to gravity override. In the vertically continuous areas of the reef margin, this results in a large bypassed tertiary oil target. The solution to improving recovery was through the use of horizontal solvent injection wells.

Solvent gravity override (Figure 1) occurs when there is sufficient time for injected solvent to segregate, due to gravity differences, prior to its withdrawal and therefore a smaller miscible oil target is swept. Segregation of solvent occurs within a short distance from the wellbore (100-200 m). The flow regime in the reservoir should be viscous dominated as illustrated in Figure 2 in order to maximize vertical sweep. Analytical work showed that to improve recovery, the well spacing (interwell distance in above equation) and/or injection rate of solvent would have to be altered to under 2 ha or 2000 rm^3/d respectively per pattern; both of which were impractical.

Since production profile logs and simple simulation models confirmed that solvent segregation occurred in the field, a pattern simulation study was undertaken to determine how recovery could be improved. To have confidence in the results of the study, it was considered critical to use the geological and production history data in combination to determine the interwell extent of heterogeneities. This required close integration of geological and engineering information in all phases of the study. Other issues included the impact of selecting a small pattern in a large field and how to initialize the model after 27 years of waterflooding in order to minimize the time spent on history matching.

The forecasts required a large number of cases to determine the optimal horizontal well placement. Sensitivities included WAG ratio, areal location, solvent rate, well length, and vertical placement. Economic considerations included the incremental recovery, the response time, and the costs associated with the surface facilities. Use of the optimal miscible injector would result in an incremental oil recovery of 76 E^3m^3 (4 % of the OOIP in the pattern) over the existing vertical injectors. This was a sig-

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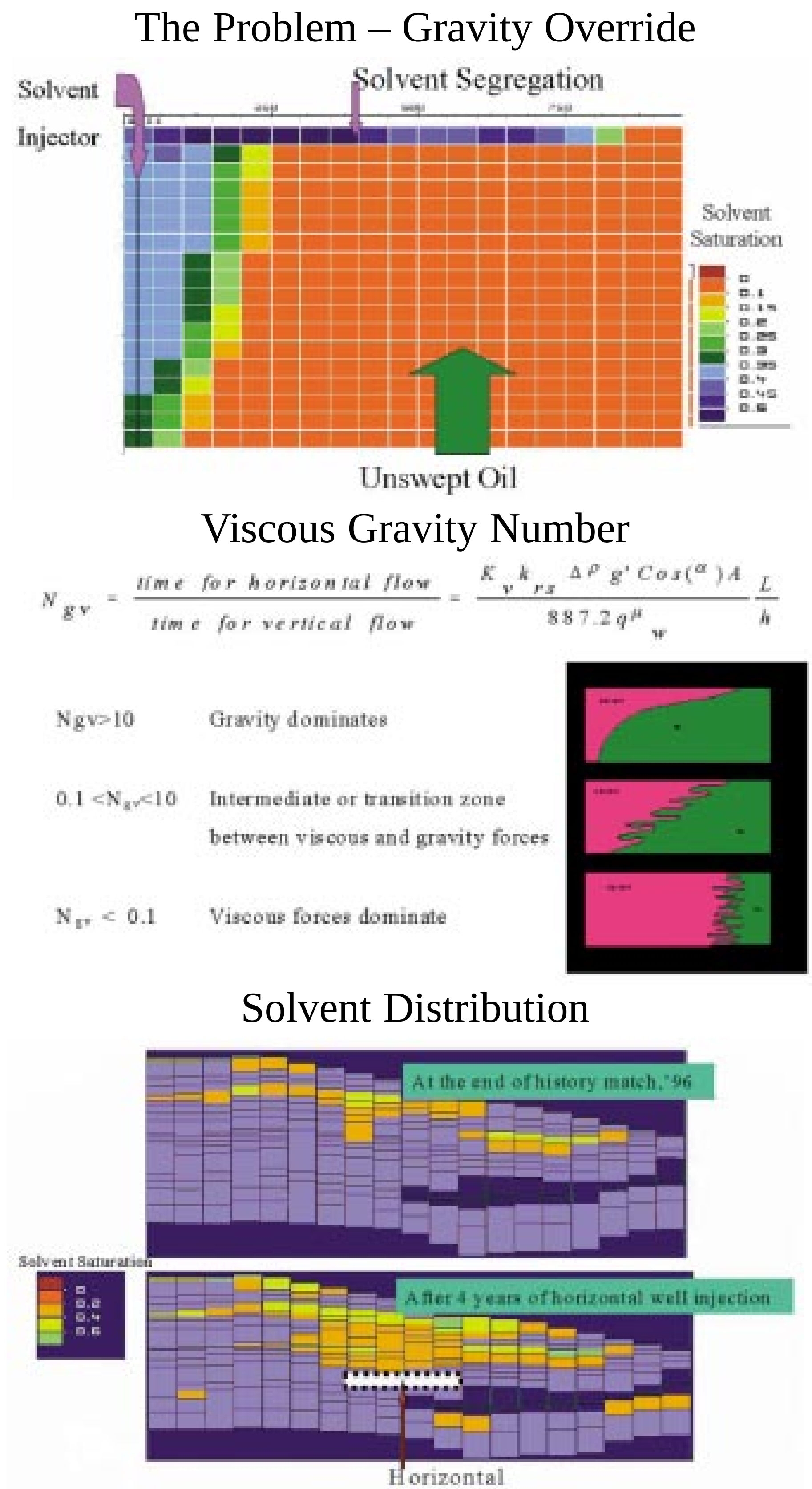


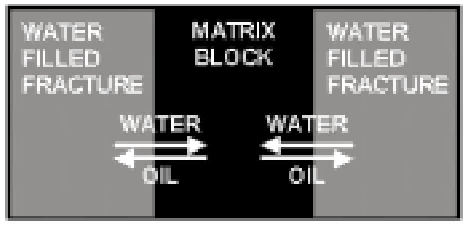
An Integrated Geology-Reservoir Description and Modeling of the Naturally Fractured Spraberry Trend Area Reservoirs

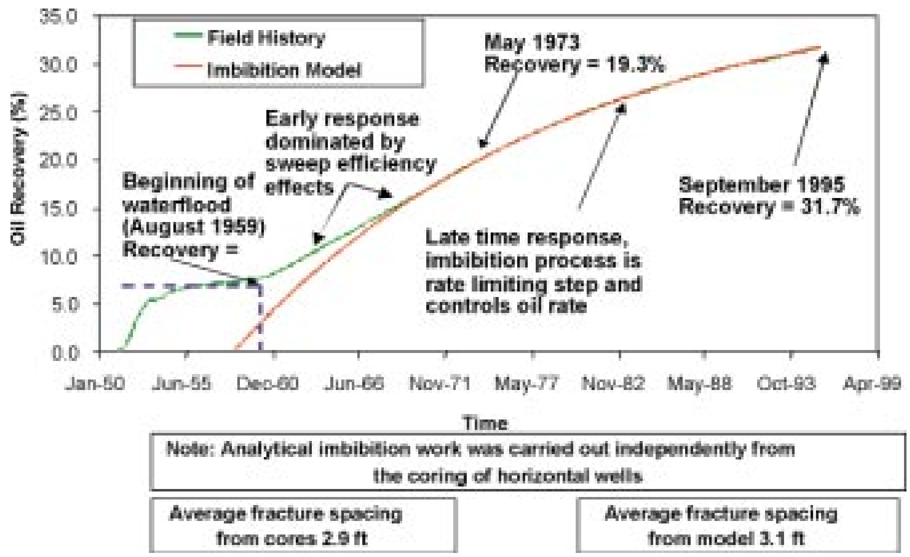
Effective fracture spacing is critical to the design of waterfloods and CO_2 floods in naturally fractured reservoirs. Decline rate data with imbibition data can be combined in a straightforward manner to estimate effective fracture spacing. This paper describes how carefully designed laboratory imbibition experiments were scaled to the field and how these simple observations were used to estimate fracture spacing for a large naturally fractured reservoir. Fracture spacing was also independently estimated by horizontal well cores. There was excellent agreement between the decline rate/imbibition spacing calculations and that obtained from the horizontal well cores.

Understanding the recovery mechanism (imbibition) gives us a tool to narrow down the range of some key parameters. The objective of this paper was to use our understanding of the imbibition process to narrow down the range of uncertainty in reservoir parameters such as fracture spacing and matrix permeability.

The results of the study do not prove conclusively that imbibition is the only driving force at work in E.T. O'Daniel. However, it is revealing how well the imbibition model matches the field decline behaviour, suggesting the dominance of the imbibition mechanism. These results indicate that a relatively weak imbibition process has controlled oil rates for over 25 years of lease production under waterflood operation.

The major conclusions from this analytical study were:





1. Based on the quality of the history match, it can be inferred that imbibition is currently the dominant recovery mechanism in the E.T. O'Daniel lease.
2. Using the imbibition constant predicted by the Aronofsky et. al model and equating it to the Guo and Schechter model, the effective fracture spacing in the E.T. O'Daniel lease is 3.1 ft, on the order of results from horizontal well core data.
3. The relationship between effective fracture spacing is highly sensitive to changes in reservoir parameters such as matrix permeability and porosity. Effort to ensure the relevance of reservoir data should be made before using this type of model for characterization purposes.

(reference: Baker, R.O.; Spenceley, N.K.; Guo, B.; Schechter, D.S.; "Using an Analytical Decline Model to Characterize Naturally Fractured Reservoirs.")

nificant increase and is very encouraging both for redevelopment in the mature flood areas and for expansion to unflooded regions.

As Figures 3 and 4 show, there is a significant change in the distribution of solvent after flooding with a horizontal injector. Note that there is much higher solvent saturation generally and that it is spread through more layers in the horizontal injection case. Solvent distribution has been improved due to both increased solvent velocity and shorter inter-well distance. The vertical sweep has also been improved by placement of the solvent low in the section.

As a comparison, the final model was rerun with homogeneous permeability to test the impact of the detailed geological / petrophysical work and interwell heterogeneity determined through history matching. The history match for this case, although poorer on a number of parameters, actually provided a reasonably close match on cumulative volumes of oil, water and solvent. However, the incremental production forecast in a homogeneous case would have been 122 E^3m^3, an overstatement of the expected recovery by 60 %! The lower recovery predicted by the heterogeneous case reflects the poorer sweep and increased solvent to recovery requirements likely to occur as hotstreaks impact the response.

The results of this study encouraged the client to drill a horizontal solvent injector. The interwell geology, based on log data, was remarkably similar to that represented in the model with 598m of net reservoir rock in the horizontal leg at 7% average porosity. Initial response in the offset producers has been quite encouraging and within 15 % of the predictions.

(reference: Chugh, S.; Baker, R.; Cooper,L.; Spence, S.; "Simulation of Horizontal Wells to Mitigate Solvent Gravity Override in the Virginia Hills Margin", presented at 48th annual Technical Meeting of Petroleum Society in Calgary, Alberta, Canada, June 9 – 11, 1997.)

Gas Cap Blowdown of the Virginia Hills Belloy Reservoir

Concurrent gas and oil production from Virginia Hills Belloy Shunda Unit #1 was considered. A full field simulation study was used to evaluate the impact of initiating early blowdown of the gas cap. An excellent match of production, pressure and two-phase interface movements was achieved.

The model predicts that early blowdown and delayed blowdown cases achieved comparable ultimate oil and gas recoveries. The paper discusses the role of a well-established water fence between the gas cap and oil leg, unique reservoir characteristics and reservoir management strategy.

With the field maturing, a simulation study was commissioned to determine the ultimate recovery and whether oil and gas recovery would be impacted by early blowdown of the gas cap. With the existing gas plant approaching turndown and economic limits, decommissioning the plant in 1999 would be followed by capital expenditures to re-inject the sour gas and eventual blowdown of the gas cap. Early blowdown would conserve capital and make efficient use of existing resources. In addition, concurrent production (early blowdown) would result in a reduction of the operating life by 12 years, and thereby also reduce associated expenses.

The major conclusions from this simulation study were:

1 The simulation model achieved a successful history match of the production, pressure, and two-phase interface movement. The model was also used to successfully identify bypassed oil, which resulted in the drilling of a successful horizontal well.
2 Ultimate oil and gas recovery in the early blowdown case is virtually the same as in the delayed blowdown case.
3 Monitoring of liquid influx and its effect on gas cap pressure is possible through pressure transient analyses
4 The existing water fence, reactivation of high GOR interface wells, drawdown of the producers, and maintenance of the voidage replacement ratio all contribute to the result that ultimate recovery is not adversely impacted by early blowdown

(reference: Kuppe. F.; Chugh, S. and Kyles, J.D.; “Gas Cap Blowdown of the Virginia Hills Belloy Reservoir” presented at the 49th Annual Technical Meeting of Petroleum Society in Calgary, Alberta, Canada, June 8 – 10, 1998.)

(Continued from page 1)

the history match have been shown.

The major conclusions from this simulation study were:

1. Foamy oil behaviour can be matched with geomechanical and fluid effects.
2. Transmissibility enhancements provide a realistic method to model “wormhole” growth. The transmissibility (permeability enhancements) grew larger as pressure decreased (i.e., as pressure drop increased), representative of the mechanism and effect of actual reservoir “wormhole” growth.
3. A suppressed gas relative permeability was important. It also helped to abate pressure decline and to keep the system compressibility higher.
4. Consistent with the regional description, an aquifer was required to match the water production, which could not be matched through other mechanisms.
5. Taken together, the transmissibility enhancements (simulating wormhole growth) and suppressed gas relative permeability were shown to effectively match historical cold production behaviour (some authors have matched one to two variables; however, we tried to achieve a match of reservoir pressure, drawdown pressure, GOR and watercuts). To our knowledge this is the first demonstration of any such cold production match documented in the petroleum literature.
6. Findings presented can be applied to full field simulation models to investigate various configurations of forecasting and production strategies.

(reference: Denbina, E.S.; Baker, R.O.; Gegunde, G.G.; Klesken, A.J.; Sodero, S.F.; “Modeling Cold Production for Heavy Oil Reservoirs” presented at 49th Annual Technical Meeting for the Petroleum Society in Calgary, Alberta, Canada June 8 – 10, 1998 SPE 39623,1998., Chugh, S.; Baker, R.; Telesford A.; Zhang E.; “Mainstream Options for Heavy Oil, Part 1 – Cold Production”, SPE 97-99)

Epic’s Capabilities Include:

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- ***Horizontal Wells***
- ***Coal Bed Methane***

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