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Optimization of the Blueberry Debolt Oil Pools: Significant Production Increases for a Mature Field

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Abstract

The Blueberry Debolt Oil Field of Northeastern British Columbia, discovered in 1956, has over 36 years of production history. It is a complex carbonate reservoir with the oil trapped against the updip termination of a thrust fault. Reservoir quality is extremely variable and controlled by dolomization and fracturing. There is a downdip water leg and early testing indicated the presence of an updip gas cap.

The production performance of the field was difficult to evaluate, in particular, the source of water production. Numerical modelling (simulation) has revealed significant insights into the production mechanisms in the reservoir. The source of water production is better understood and the location of the gas cap better defined. With this information a successful infill drilling program was implemented which has resulted in significant production increases for this very mature property.

The approach utilized and results obtained are described. Successful optimization of this field required integration of geological description, production performance, material balance, well test analysis, numerical simulation, and infill drilling results.

Location

The Blueberry field is located approximately 60 miles northwest of Fort St. John in Northeastern British Columbia. Figure 1(a) shows the general location. There are two pools, which are called the North and South Pools, respectively, as shown in Figure 1(b). The discovery well was drilled in 1956 at d-82-L/94-A-12 (North Pool). Commercial production was obtained from a depth of approximately 2,075 m (6,800 ft.). Production commenced in 1957, following further development drilling. The oil is medium-light with a 36˚ API gravity.

Based on interpretations of DSTs and production tests, early in the life of the reservoir, a gas cap had been interpreted in both the North and South Pools.

Basic Geology

Production is obtained from the Mississippian Debolt formation. Oil is trapped against the updip extreme of a thrust fault related to the Laramide orogeny. The general structure is shown in Figure 2. There is thought to be only a minor amount of roll-over. The leading edge of the thrust fault trends northwest-southeast. Towards the south part of the pool there is a break in the trend of the main thrust. It was thought that there may be a lateral tear, with displacement taken up in two smaller thrusts. It was not clear if this lateral tear was sealing or not.

Lateral faults and/or low permeability are thought to separate the two main South and North Pools. The exact location of the division has not been determined.

Development

South Pool

At the beginning of the study, a total of 15 producers were drilled in the South Pool, including one horizontal well. Overall GOR levels have increased, from 113 m^3/m^3 (635 scf/bbl) initially to 278 m^3/m^3 (1,575 scf/bbl). Such a modest increase indicates some pressure maintenance. Watercuts have increased steadily to 50% at the start of the study. More detailed analysis, on a well by well basis, indicated that the updip wells in the southernmost part had the highest watercuts. The reservoir pressure had dropped from the initial pressure of 19,000 kPa (2,755 psi) to 13,000 kPa (1,885 psi), as shown in Figure 3.

North Pool

In the North Pool, a total of 12 wells had been drilled, of which one was abandoned. In contrast to the South Pool, GORs have risen steadily to 2,300 m^3/m^3 (12,975 scf/bbl). The GORs for individual wells varied considerably. The highest were obtained from

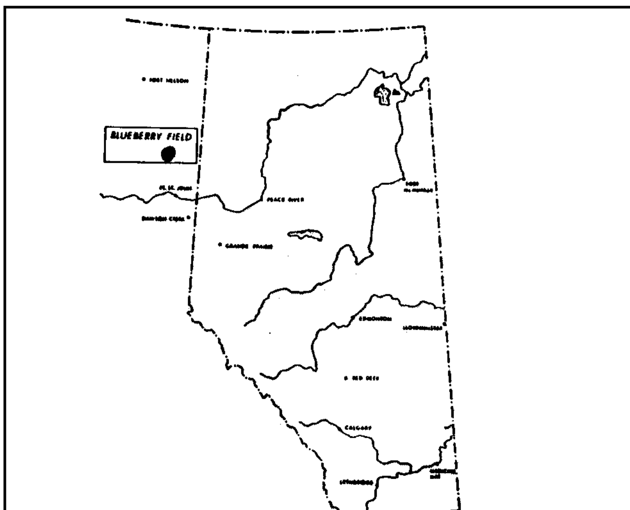


FIGURE 1(a): Location of Blueberry Field.

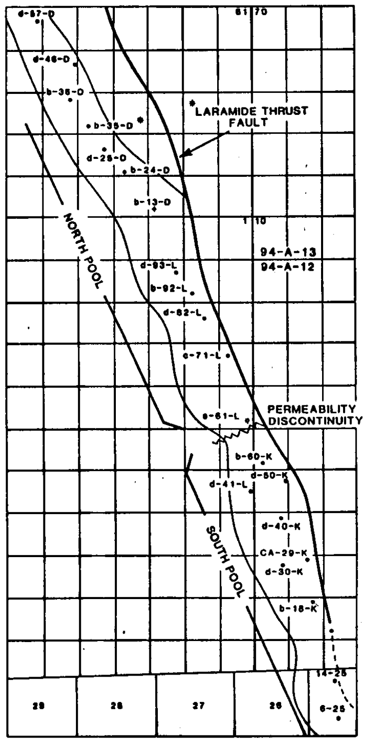


FIGURE 1(B): Outline of north and south reservoirs.

the d-36-D well, which has been shut in. This indicated either a primary gas cap, or a secondary gas cap and solution gas drive.

A gas cap was known to exist in the North Pool; the a-34-D well was put on production for a three month period and produced gas with moderate amounts of condensate.

Water cuts in the North Pool are also dramatically different, remaining low and stable over the complete 37 years of production. Two wells, c-71-L and b-24-D produce more water. This production does not correlate with the structural position of the perforations. The reservoir pressure had dropped from 19,000 kPa (2,755 psi) to 9,000 kPa (1,305 psi), as shown in Figure 4.

Crestal gas injection had been utilized in the a-34-D well during 1964 to 1967. Cumulative injection in the a-34-D well was 21.3 $10^6 m^3$ (0.75 BCF). Early wettability tests indicated that the reservoir was oil-wet. This was a factor in selecting gas re-injection. Subsequent lab tests indicated that waterflooding would be preferable.

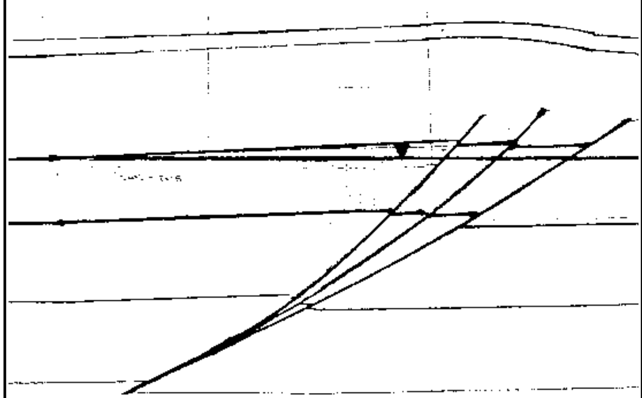


FIGURE 2: Structural cross-section showing thrust faults.

Gas Lift

Both pools were initially developed using gas lift. An unusual method of artificial lift in western Canada, it is well suited to deviated wells. Some wells were eventually converted to beam pumping units. The gas lift is significant in that accurately measuring and calculating gas production is more difficult. The high pressure injected gas must be subtracted from the low pressure gas produced. GOR performance is consequently noisier than is normally encountered.

Completion Practices

Typically wells were completed by perforating and then acidizing. Most of the wells were only drilled into the top of the Debolt and then cased (partial penetrations). This was done to minimize water production.

Reservoir Mechanisms

Two previous engineering studies had been conducted on the pool on substantially different premises. The first was a classic reservoir engineering approach[1]. It included material balance calculations, production performance reviews as well as an extensive review of rock properties. Waterflooding was recommended based on the Craig, Geffen and Morse technique. Immediately following the completion of that study, the price collapse of 1986 occurred.

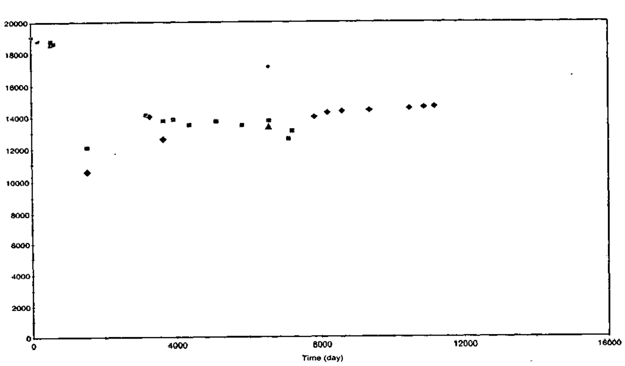


FIGURE 3: South Pool history match data.

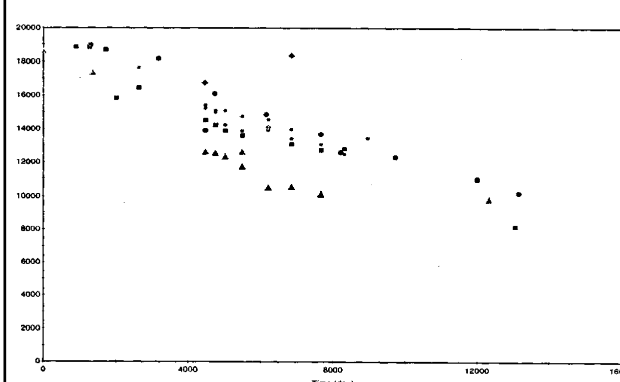


FIGURE 4: North Pool history match data.

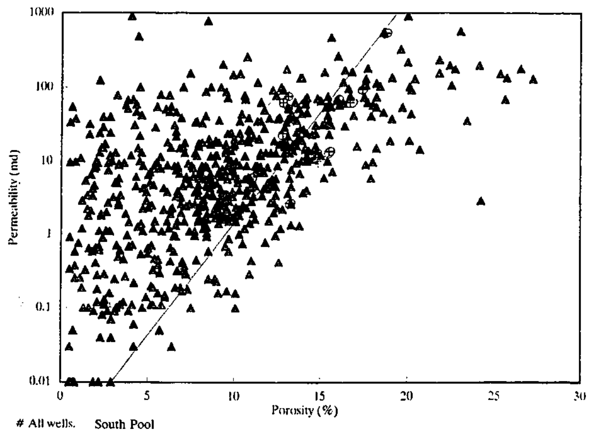


FIGURE 5: Core permeability vs. core porosity.

Consequently, the project was shelved indefinitely.

The second study was based on the fractured reservoir technique developed by Aronofsky, as modified by Aguilera[2]. The essence of this approach is that fluid flow is assumed to occur through the fractures. Oil is transferred to the fracture system by counter-current imbibition. The transfer in Aronofsky's equation takes place on an exponential decline basis and is based on empirical observation. This would allow for the water production from all wells, although some correlation should occur with structure. The analysis used was a hybrid of well test constant pressure terminal solutions (decline curves), matrix to fracture transfer as just described, and a volumetric material balance approach in which the position of the water-oil contact is monitored. The second study was completed in 1990.

Both studies assumed that water was approaching the reservoir from the southwest flank.

Stratigraphy

The Mississippian is a carbonate shale sequence. In the Blueberry area it is overlain unconformably by the Permian Belloy.

The most important reservoir is in the Loomis, which occurs at the base of the upper carbonate member. The carbonate member is commonly 30 to 60 m (100 to 200 ft.) thick. The Loomis subcropped as a post Carboniferous erosional surface.

Below the main reservoir is the Salter, Baril, Wileman (SBW) which consists of micritic limestones and calcareous shales with interbeds of bioclastic limestone. This formation is rarely of reservoir quality.

Further below is the Turner Valley, sometimes referred to as the middle carbonate. It consists of micritic, bioclastic and pelletoid limestones with abundant chert and oolites. Below this are the Elkton, Shunda, Pekisko, and the Banff.

Layering

Previous study indicated that waterflooding would be advantageous. A cross-section was made to determine if any continuous layering was evident. The processed logs, from a recently completed computerized log analysis, were used. No evidence of continuity was found. This was thought to be related, in part, to dolomitization.

Dolomitization

The cause of dolomitization is not known with certainty. Increased dolomitization, as is typically the case, increases reservoir quality. The process, after Majid[3] in the Debolt throughout northeastern British Columbia is thought to be related to four types of development:

1. Early diagenetetic, matrix selective, facies controlled dolomitization
2. Unconformity related dolomitization
3. Fault related dolomitization
4. Hydrothermal dolomitization.

Mechanisms 2 and 3 are though to be quite important in Blueberry.

Core Porosity vs. Core Permeability

A plot of all core porosity vs. core permeability is shown in Figure 5. The data shows a tremendous scatter and a triangular distribution. This, in the authors' experience, is often typical of fractured reservoirs. Lower porosity rock is more prone to fracturing than higher porosity rock. The latter can accommodate more deformation by grain rearrangement. The lower line is thought to be representative of the rock's matrix properties.

Fracture Pattern

Clearly, understanding the distribution of fractures is critical. There is some very interesting work in the groundwater literature. Long and Witherspoon[4] have shown that reservoir permeability is controlled by connectivity and not by fracture orientation. This is shown very clearly in Figure 6. This material is discussed in

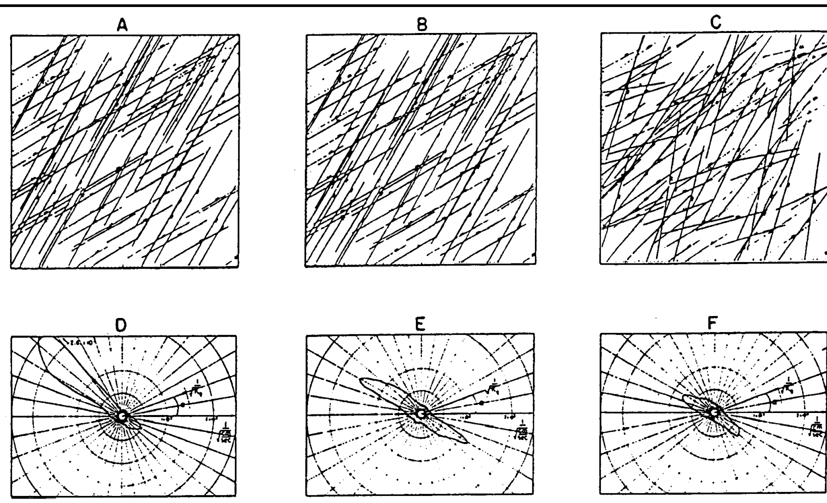


FIGURE 6: Statistical fracture patterns and permeability rosettes.

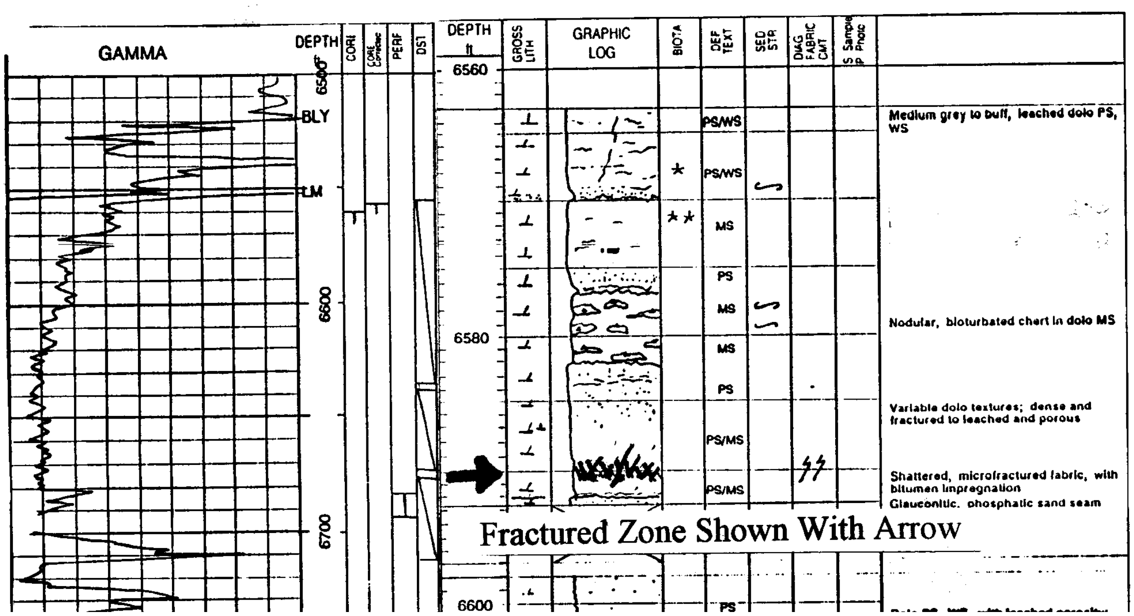


FIGURE 7: Geological description—detailed logging.

more detail by Carlson(5).

The best way to characterize fractures is to be able to look at them directly; i.e., by core examination. A very large study on the Debolt had been purchased(4) and had detailed descriptions of most of the Blueberry wells.

The "sugar cube" visualization of fractures has always been recognized as somewhat oversimplified. However, detailed core descriptions in this area give no indication of any fracture patterns that could be described as remotely similar to a repetitive pattern.

In fact, it seems that fracturing is vertically localized, almost in "beds." This is shown in Figure 7 [from Reference (4)]. Further, the spacing of fractures in these beds is typically on a fine scale, with the micro-fractures normally spaced 2 to 8 cm (0.75 to 3 in.) apart. This does not fit the classic dual continuum approach which has been very fashionable in the petroleum literature.

Characteristic Well Test Response

Perhaps the fashion has been most popular with well test analysis. The logical step at this point was to evaluate what the buildup test responses looked like. Four type curves were available for a-50-K, c-71-L, d-25-D and d-36-D. Two examples are shown in Figures 8 and 9. These wells all look like they have been hydraulically fractured, yet no such treatments were used in this field. This is also consistent with the authors' experience in the central foothills of Alberta and other areas.

Reservoir Development

The natural question is what type of well test response would be obtained from intensely fractured "beds" of limited areal extent? We have called this model "poddy fracture development." Based on the work done by Witherspoon, it would seem likely that the pods may have a significant directional permeability characteristic.

Of course, no analytical model has yet been developed for such a pattern. A reservoir simulator was a logical method of generating type curves. The output from the model would then be input into a well test analysis package, to enable patterns to be identified in a manner consistent with well test interpretation.

Uniform Reservoir

A simulator grid was developed and uniform reservoir properties were assigned. With this simplification the simulator-well test

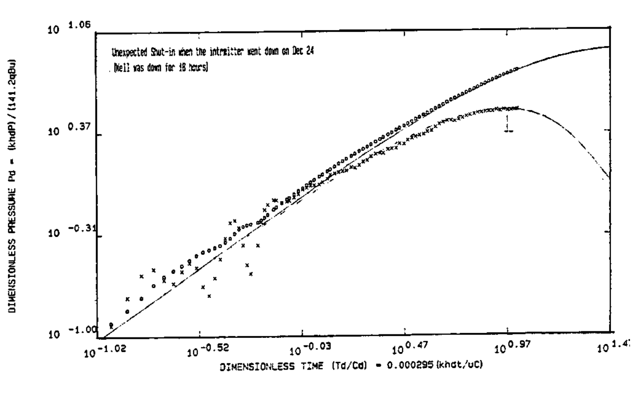


FIGURE 8: Data plotted using Agarwal equivalent time.

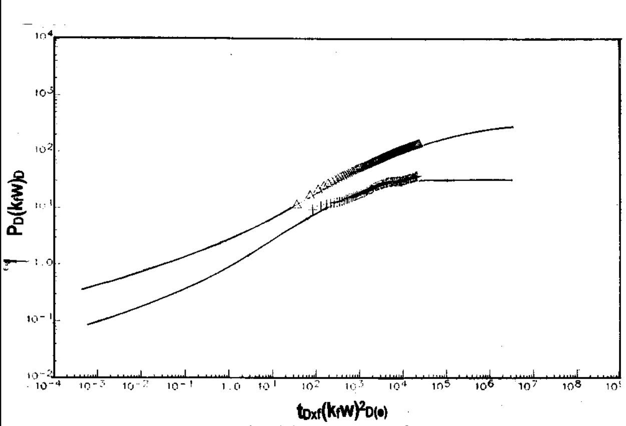


FIGURE 9: Finite conductivity fracture typecurve (Cinco-Ley) pressure buildup plot.

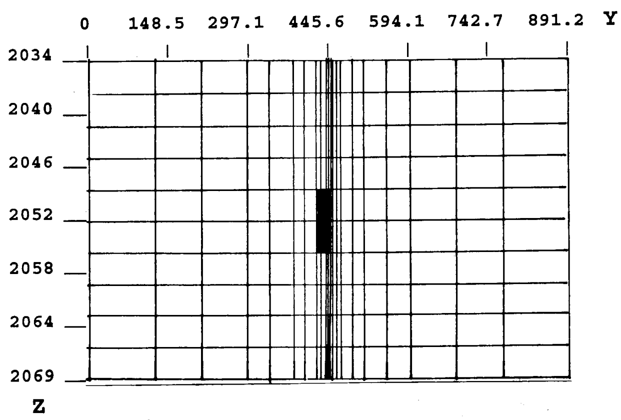


FIGURE 10: Simulation grid will test analysis.

package could be readily tuned and errors evaluated. Some noise was evident and there is some error in derived properties. The type curve overestimated permeability by 13% and the Horner plot underestimated permeability by 17% (a systematic trend?). Overall, such an error would be considered relatively minor in field terms. Note that no wellbore storage has been used.

Next directional permeability was evaluated. For the sake of brevity, these plots are not shown; however, the average permeability was overestimated by 10.2% on the type curve and underestimated by 4.2% on the Horner plot.

Pod Model

A pod model with no directional permeability was developed as shown in Figure 10. Note that the pod does not extend very far laterally. The results are shown in Figures 11 and 12. The results are startling. First, the shape of the curves is very similar to that observed on the actual well tests. Second, reservoir properties calculated are well below the true reservoir properties.

A compound pod was then developed as shown in Figure 13. The results of the well test analysis are shown in Figures 14 and 15. In this case there is considerable apparent "noise" that is related to complex boundaries and changes in pod properties.

Finally, a last quality control run was made with a multi-layered system. Overall, the levels of error were low and the character of the type curves generated followed expectations from analytical solutions.

Concentric Systems

It is often possible to get matches based on concentric reservoir systems. Under this system it always appears that most wells drilled somehow always encountered an area of good reservoir development, a logical conundrum. This is the model suggested some time ago by Adams[6] and more recently by Grant[7]. This poddy nature can also be represented geostatistically. Any well that encounters a pod will have a negative skin.

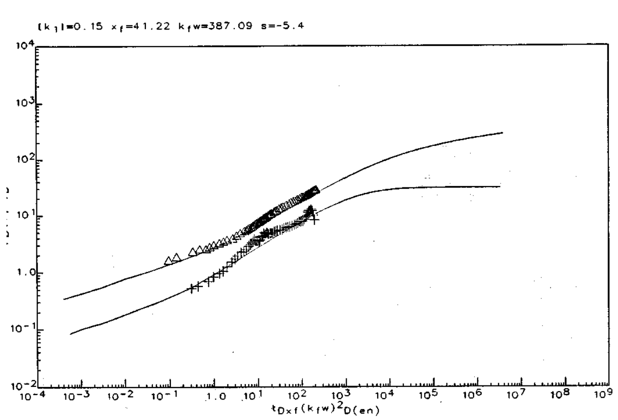
Reservoir Characterization

The pods, as shown in the preceding diagrams, are of limited areal extent. Well test analysis and productivity is very strongly controlled by near well bore conditions/pods. They are also ubiquitously present. The approach used was to assign an average permeability, the pods being of sufficiently small scale that a "salt and pepper" approach can be used on a field scale (areal simulation) basis.

This still leaves an important and unresolved issue—how is the water production explained in the pool?

Water Production

As outlined earlier, the updip wells produced more water than the downdip wells. Well productivity would suggest that the number and quality of pods increase updip and with deformation. In fact, this is not surprising: rocks are rarely uniform. An expecta-

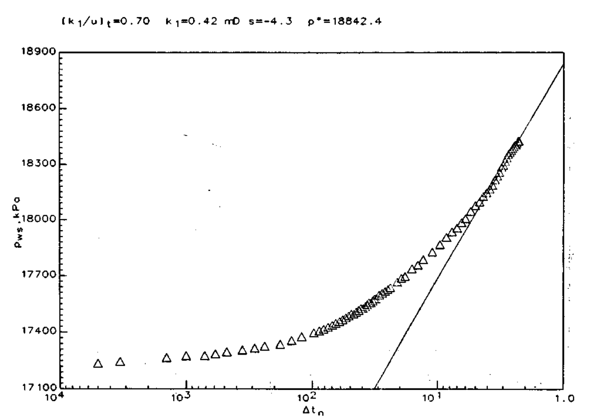


High Permeability Layer

	Parameter	Multiple of Actual
Base Permeability	1.000 mD	
Pod Permeability	100.0 mD	
Average Well Permeability	20.80 mD	
Type Curve Permeability	0.150 mD	0.007 - 0.150
Horner Plot Permeability	0.420 mD	0.020 - 0.420

(hipod.dat)

FIGURE 11: Finite condition fracture typecurve (Cinco-Ley) pressure buildup plot.



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Type Curve Permeability	0.150 mD	0.007 - 0.150
Horner Plot Permeability	0.420 mD	0.020 - 0.420

(hipod.dat)

FIGURE 12: Superposition pressure buildup plot.

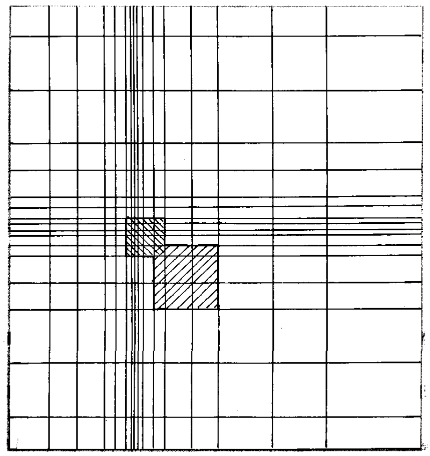


FIGURE 13: Varipod composite pods in simulator grid.

tion of regular fracture development (sugar cubes) is less likely than patchwork development. This suggested localized fractures at the leading edge of the thrust sheet and upward migration of water. There are thus two possible models of water influx, which are contrasted in Figure 16.

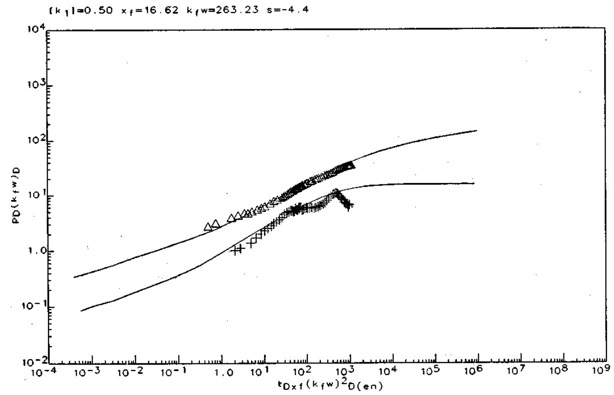
In general, it would be normal to discount the lower permeability of the underlying formations. However, as shown in Figure 16, there are a number of factors that should be considered. These include areal extent, which is very large; short distances, compared to flank encroachment; and the possibility of some vertical fracturing.

Grid Construction

The grid used was therefore developed as shown in cross section in Figure 17. Pore volume is included in front of the fracture plane, as well as below. Analytical aquifers were also set up along the bottom and downdip flank. A transmissibility barrier can easily be used to test the effects of coning vs. edge influx. The South Pool was modelled first.

Coning Sensitivities

Coning sensitivities require a fine grid. A test was therefore made to see if the areal grid was sufficiently fine to analyse the problem in an areal or 3D model. If this was not successful, then a cross-sectional model would have to be implemented as an interim solution.

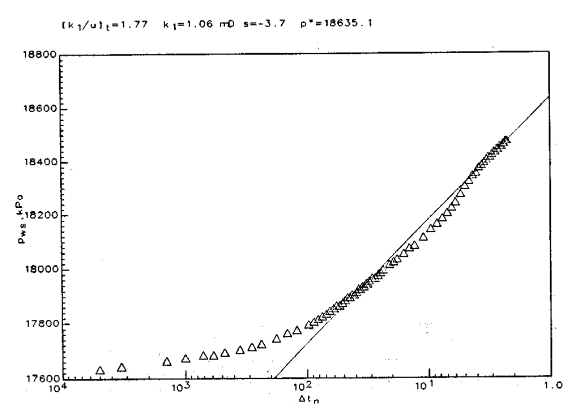


Variable Permeability Layer

	Parameter	Multiple of Actual
Pod Close To Well	50.00 mD	
Distant Pod	25.00 mD	
Average Well Permeability	10.80 mD	
Base Formation Permeability	1.000 mD	
Type Curve Permeability	0.500 mD	0.046 - 0.50
Horner Plot Permeability	1.060 mD	0.098 - 1.06

(Varipod.dat)

FIGURE 14: Finite condition fracture typecurve (Cinco-Ley) pressure buildup plot.



Variable Permeability Layer

	Parameter	Multiple of Actual
Pod Close To Well	50.00 mD	
Distant Pod	25.00 mD	
Average Well Permeability	10.80 mD	
Base Formation Permeability	1.000 mD	
Type Curve Permeability	0.500 mD	0.046 - 0.50
Horner Plot Permeability	1.060 mD	0.098 - 1.06

(Varipod.dat)

FIGURE 15: Superposition pressure buildup plot.

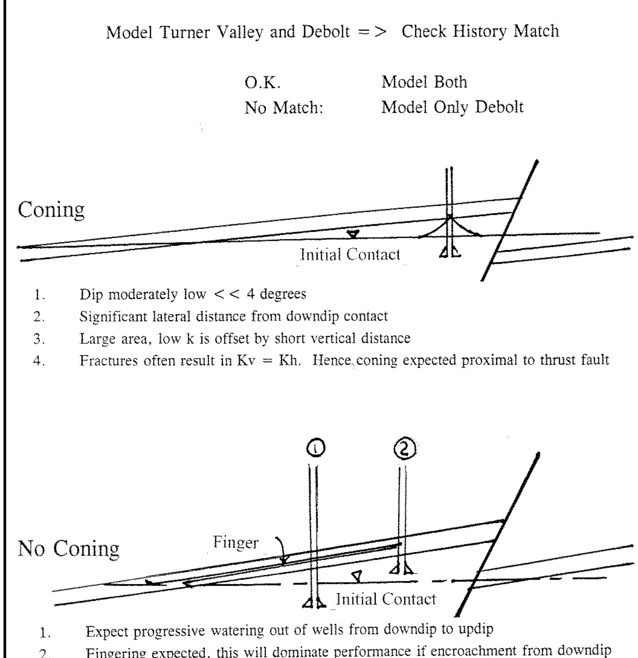


FIGURE 16: Coning vs. edge influx.

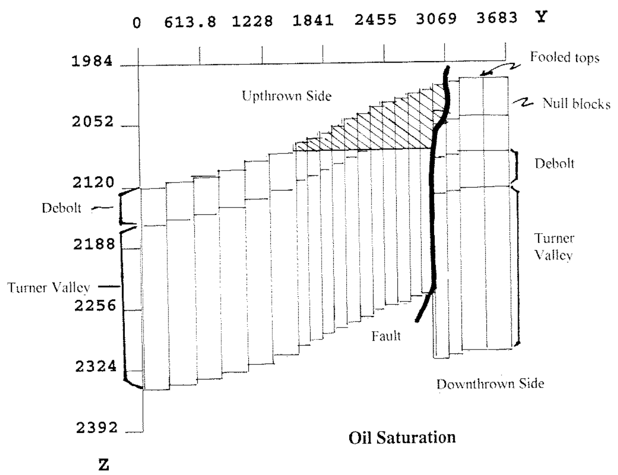


FIGURE 17: Grid sensitivity analysis.

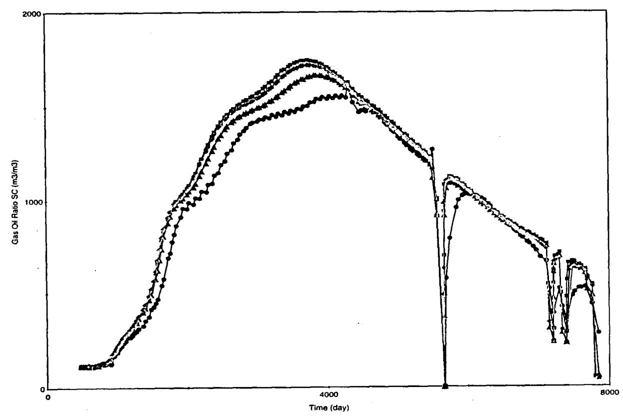


FIGURE 18: Grid sensitivity analysis.

A single well was chosen and sensitivities made with a variety of grids. The GOR and watercut results are shown in Figures 18 and 19. In essence, the areal grid is accurate to about 20%, and definitely correctly predicts trends. This was considered sufficiently accurate in view of the quality of the input data. This level of accuracy is not too far different from detailed grid studies have indicated on water displacement processes done by Carlson[5].

Coning vs. Edge Influx

Figures 20 and 21 show the results from early history matching on two wells. One is located structurally updip and the other is located structurally downdip. It is very obvious that influx is best modelled as vertical coning, rather than as edge influx.

Gas Cap

The model was initialized with what was thought to be the known GOC level. As shown in Figure 22, the model predicted drastically more gas would be produced than actual production which occurred. Such a discrepancy was not a numerical error; a coning sensitivity demonstrated good accuracy. Therefore, it was concluded that a gas cap did not, in fact, exist. This was a very positive discovery for updip development locations. It also demonstrates where simulation can have a distinct advantage over material balance techniques, which typically give multiple solutions of gas cap sizes and aquifer strengths.

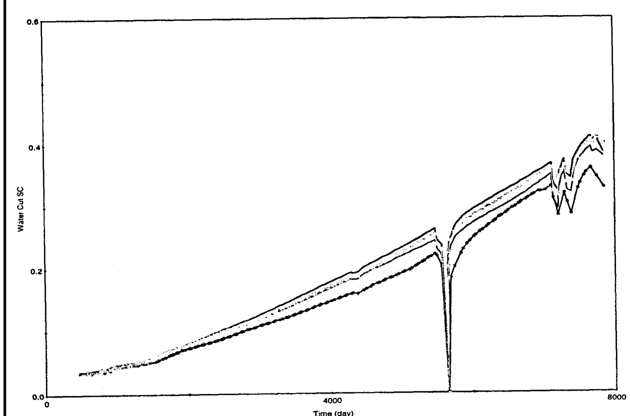


FIGURE 19: Grid sensitivity analysis.

Balance Of History Match—South Pool

History matching for the South Pool, after these discoveries, was remarkably straightforward. A number of sensitivities were run on the location of a lateral fault (at right angles to main thrust fault) with a fairly definite conclusion. A series of minor permeability and porosity corrections, on a well by well basis, were also

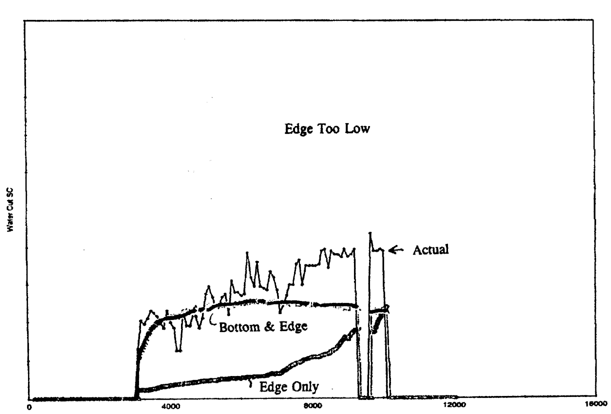


FIGURE 20: Coning analysis structurally high well.

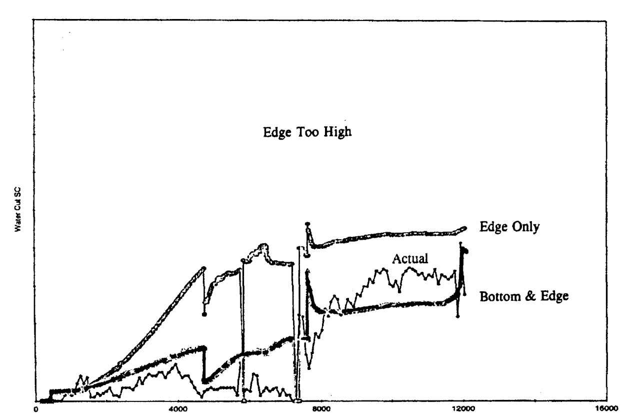


FIGURE 21: Coning analysis structurally low well.

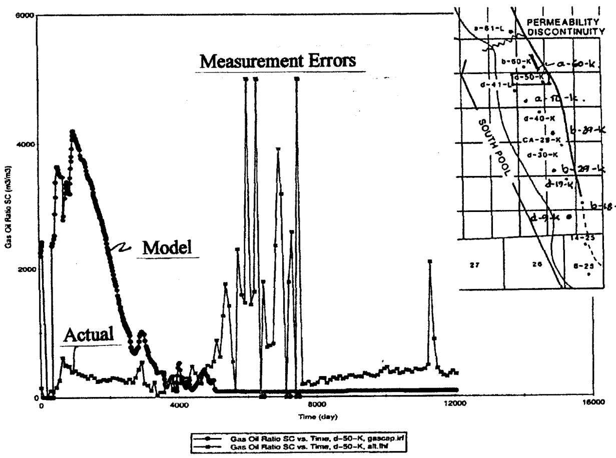


FIGURE 22: Measurement errors.

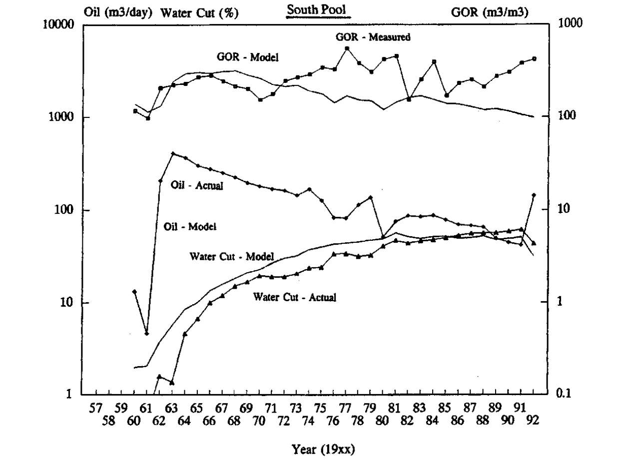


FIGURE 23: South Pool history match plot.

implemented. These changes were within normal tolerances.

The final history match for the South Pool is shown in Figure 23. Overall, an excellent history match was derived. The GORs seem to fall off somewhat: this issue will be returned to later. Recall that the pressure history indicates that the reservoir pressure is actually increasing with natural water influx. This would normally lower GORs.

North Pool

After completing the South Pool match with little difficulty, the study was then switched to the North Pool. A fast history match was confidently expected, based on the rapid completion of the South Pool.

Initialization identified that the location of the water-oil contact was limited by the spill point on the structure at the northern extreme of the North Pool.

Water Influx

The North Pool proved to be very difficult to match. First, turning the aquifer on and off did not give a good history match. After a considerable number of runs it was decided to put all of the history match plots on a large sheet of paper and compare various runs on the wall. It was immediately obvious that the effect of water support diminished further north. Best results were obtained with some aquifer influx in the south part and no influx in the north part.

On the surface there was no possible reasonable explanation for this behaviour. Upon reviewing one of the overview papers, it was discovered that Law[8] had mapped fingers of Middle Carbonate (Turner Valley) extending to the northeast, as shown in Figure 24. Due to partial penetrations, it was not possible to know this with any certainty. It was postulated that such a finger existed under the Blueberry field and provided water influx only in the South Pool and the southern extreme of the North Pool. A deeper well may yet prove (or disprove) this hypothesis.

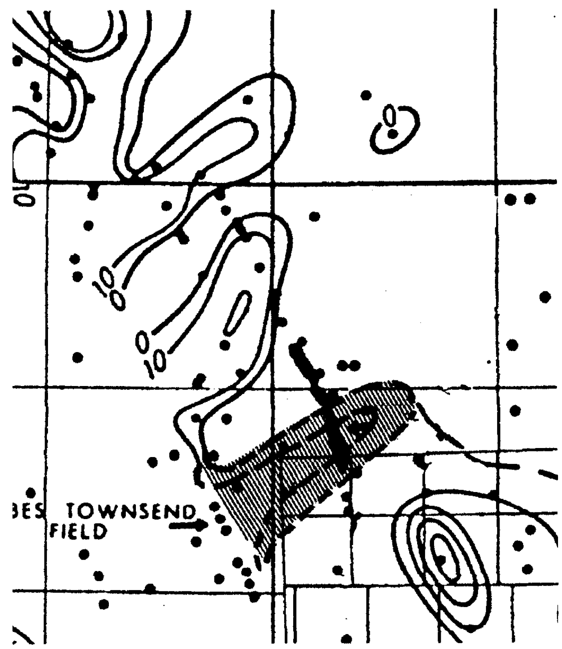


FIGURE 24: Location of porous permeable Turner Valley—probable source of pressure recharge.

Balance Of History Match—North Pool

A number of lateral faults were introduced in finishing the history match for the North Pool. It would appear to be much less continuous than the South Pool. The final history match is shown in Figure 25. Note that for the North Pool the model GORs are higher than actual. The water cuts are low and follow the trend reasonably well.

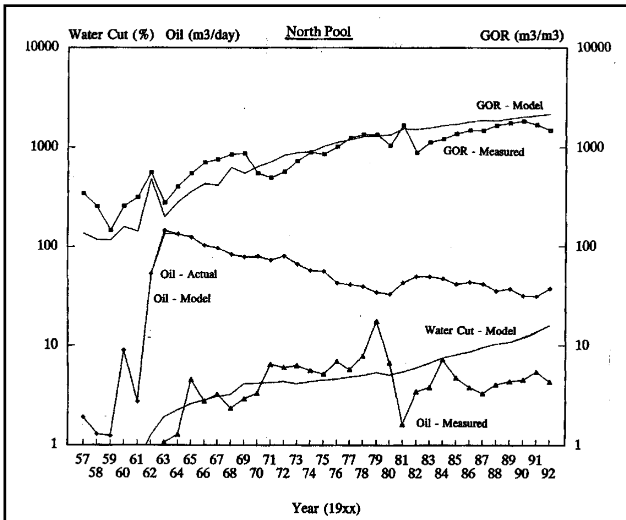


FIGURE 25: North Pool history match plot.

If the history match from the South and North Pools are combined, as shown in Figure 26, a better match is obtained. Recall

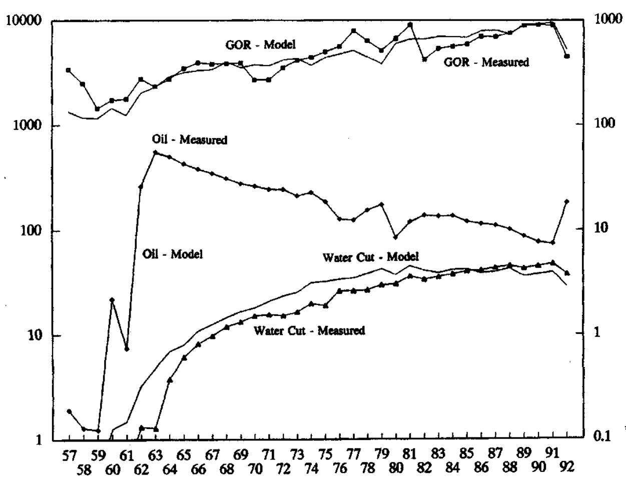


FIGURE 26: North and South Pools history match plot.

that gas allocation is difficult in this field due to the use of gas lift. On a field scale, total gas sales are well known via continuous pipeline measurement.

Predictions

Predictions were made for both the North and South Pools. These are shown in Figures 27 and 28. Both show substantial increases in production are possible.

Results Achieved

The South Pool was prioritized. Figure 29 is a recent plot of the production performance. Oil production has remained constant, based on some of the programs suggested by the simulation study. Note that field implementation has not been as quick as input in the simulator. All optimization opportunities have not been implemented as yet, so further upside may yet be reached.

Wells Drilled

To date, a total of five wells have been drilled based on study results. Note that some slight modifications have been made:

c-08-K/94-A-12
c-39-K/94-A-12

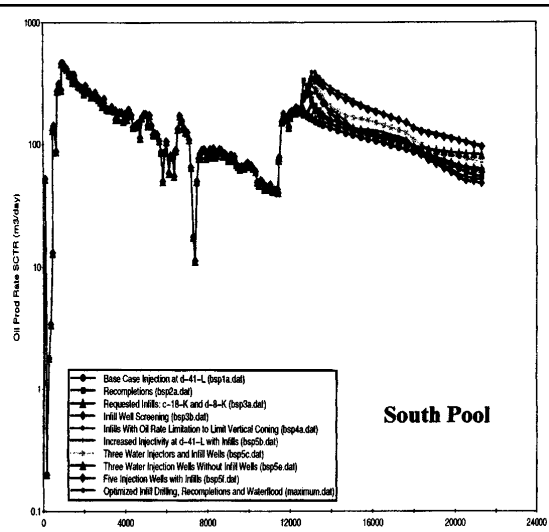


FIGURE 27: South Pool predictions.

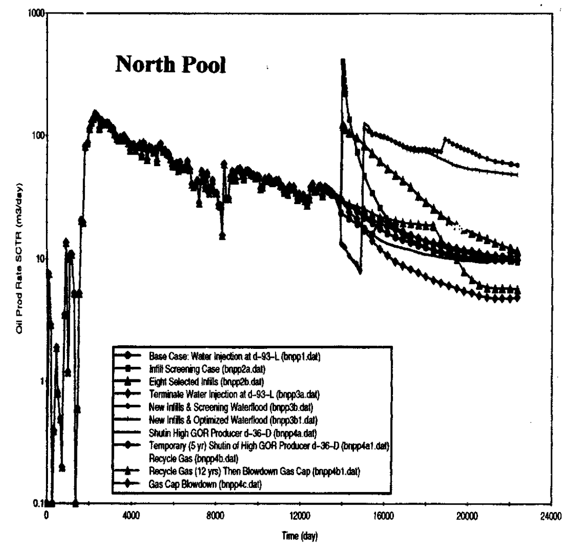


FIGURE 28: North Pool predictions..

b-49-K/94-A-12
c-a60-K/94-A-12
d-a19-K/94-A-12
c-50-K/94-A-12

Results have been a mixture of better than expected and less than expected. This is not surprising and represents the process used in tuning wells for predictions. An average tuning factor is used. Permeability in a simulator is typically based on log analysis, which is derived from core permeability vs. core porosity air permeability data. Adjustment for liquid permeability is never exactly constant. Also, there is considerable scatter (typically an order of magnitude) in permeability, for even a good quality core permeability vs. core porosity relation. Precise tuning factors cannot be determined in advance.

Injection has commenced in d-41-L, d-30-K and d-40-K to augment the natural water drive. Further injection is contemplated in an additional location.

Summary

In general terms, the simulator seems to have correctly predicted the total fluid increases. Well results indicate that water saturations and hence water cuts were higher than expected. Although the simulation is clearly not exact, it was critical in developing an improved understanding of reservoir mechanisms. Substantial improvements were obtained with this new understanding.

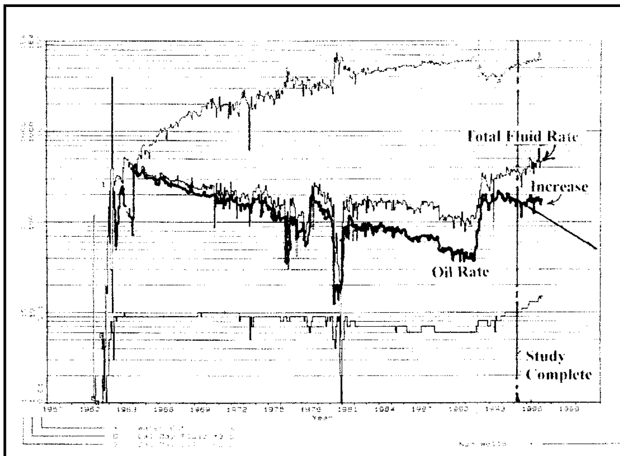


FIGURE 29: South Pool production history and infill building reate increases.

Conclusions

1. Production analysis and geology played a large role in improving the understanding of this reservoir. In this case, the Turner Valley, which was incapable of supporting economic well production, exerted considerable influence on the production mechanisms in the South Pool. Development geology should always be linked with an understanding of flow mechanisms in the reservoir.
2. In this case, reservoir simulation contributed greatly to the understanding of the reservoir. Simulation demonstrated that there was no initial gas cap in the South Pool. Also, water influx was identified as vertical.
3. This reservoir is another example of the "general rule" that water influx must ultimately be sourced horizontally, in this case the Middle Carbonate (there is not enough compressibility in water to support substantial vertical contact movements).
5. The use of grid refinement and simulation for buildup tests is demonstrated.
6. A new view of fractured reservoirs is demonstrated, which has been termed "poddy reservoir development." This model seems to explain well test analysis and reservoir performance.
7. Production optimization was achieved by drilling further updip, without the fear of producing gas. Also, the natural production mechanisms favour development in the South over the North Pool. The natural water influx is being augmented on the downdip portions of the South Pool.
8. A number of successful wells have been drilled, in part based on the results of this study. This is an example of where significant production improvement can be achieved for a mature reservoir.
9. Several surprises have occurred with further development subsequent to completing the study. There have been many different approaches used to analyse this reservoir. Production optimization is a continuous process. Although the work described has enabled significant optimization, it is likely that future improvements will be made.

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