New, Simple Completion Methods for Horizontal Wells Improve Production Performance in High-Permeability Thin Oil Zones

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Summary

Simple alterations to the completion can be used to enhance the performance of long horizontal wells producing from high-permeability formations. Production performance and operational feasibility of the investigated completion methods are compared. The methods should be considered for horizontal wells where frictional pressure losses along the perforated section restrict production performance.

Introduction

Inflow from the reservoir to a horizontal well in high-permeability formations can be severely restricted by the frictional pressure loss along the horizontal well (**Fig. 1**).[1,2] For long horizontal wells with high production rates, considerable pressure loss is experienced along the horizontal part of the well. The liner pressure increases exponentially from the heel end toward the toe end of the well, and the drawdown and influx to the liner decrease accordingly. The effect of a declining drawdown along the well becomes important in high-permeability reservoirs where the pressure loss through the reservoir may be of the same magnitude as the pressure loss along the horizontal wellbore. The upstream part close to the toe of the well contributes less to the production than the downstream part close to the heel, and a severe reduction in well productivity is experienced.

In thin oil zones, the drawdown will often be restricted because of gas and water coning, and maximum production rates may be limited as a result of coning problems rather than lack of downstream transport capacity. By reducing the effect from pressure loss along the wellbore, higher production rates can be maintained without causing gas or water coning problems to become more severe. In this study, optimization of completion design is based on three basic principles: (1) reduction of the frictional pressure loss along the perforated part of the well, (2) redistribution of the frictional pressure loss along the perforated part of the well by changing the flow direction in parts of the liner, and (3) creation of an optimal sandface pressure profile by introducing inflow control along the wellbore.

Three modifications to the horizontal well completion design are discussed. Each modification explores one of these three principles. The "stinger" completion[2] is based on the second optimization principle. Reduced perforation density and the inflow-control liner are based on the first and third principles, respectively. The study also shows how the methods applied in combination have an additive effect and how additional potential for optimization beyond the elimination of frictional pressure losses explores additional drainage area at the end zones of the well.

The Troll field offshore Norway, with PI's in the range of 6 to 12 (std m^3/d)/(100 kPa/m) and production rates restricted by gas and water coning, was expected to be a good candidate for optimized completion methods. Thus, data representing this field were used as input for investigating the different completion methods' production performance. A horizontal well simulator developed in house was used in combination with reservoir simulations to optimize the completion methods. The simulator is designed to handle complex well paths and flow geometries in detail because it is based on a network representation of the wellbore flow paths. The pressure loss calculations for both the continuously perforated liner and the stinger completion were based on experimental data discussed later.

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Enhanced Completion Methods

Stinger Method. The proposed stinger completion method[2] divides a long horizontal well into two shorter well sections where fluid flows in opposite directions. The configuration resembles two horizontal wells producing into a common drain. By inserting an extension of the production tubing, or stinger, into the horizontal section of the well, the drain is moved from the heel end of the well to the stinger inlet located some distance toward the middle of the liner.

Fig. 2 is a schematic layout of a stinger-completed well. Compared with a conventional screen-and-liner completion, a larger average drawdown can be obtained while exposing the formations to the same maximum drawdown. The increased average drawdown along the well caused by the stinger results in higher well productivity. This enhanced well productivity can be used to obtain higher plateau rates or to extend the plateau period. When the maximum well length is limited by frictional pressure losses along the perforated part of the well, the stinger method also increases the feasible well length by the length of the inserted stinger.

The stinger itself may either be an extension of the production tubing or be installed through the tubing. The stinger will rest on the bottom of the liner rather than being centralized because this configuration is simpler and causes less pressure loss through the stinger/liner annulus owing to a more-favorable hydraulic diameter.

Stinger-Method Modeling. Calculations for the stinger completion were based on flow experiments especially designed to study the pressure loss through perforated liners with and without a stinger inserted. With a hydraulic diameter derived particularly for the eccentric stinger annulus, the derived friction factors were consistent with expected values based on previous studies[3] for perforated liner without a stinger.

Stinger-Method Operational Problems. The stinger method does, however, carry some negative side effects that may limit its application in the field. **Fig. 3** illustrates the pressure loss experienced through 10.16-cm-ID stingers from 150 to 300 m long. The typical pressure loss through the stinger will, for the application described later, range between 500 and 1000 kPa. The additional system pressure loss through the stinger itself does not affect the well inflow performance but may restrict production rates in cases with low downstream transport capacity resulting from high water cut or low reservoir pressure. In cases where production of free gas is desirable for the gas-lift effect in the vertical part of the well, a large multiphase pressure loss through the stinger may restrict the possibility of producing this free gas. The presence of the stinger will also prevent production logging and maintenance in the heel part of the well. For these reasons, the stinger was not found to be the optimal solution for the example field case.

Reduced Perforation Density. Because a high density of perforations in continuously perforated liner and screens has been shown to cause a considerable increase in the friction factor, a potential exists to reduce the number of perforations and to design the remaining perforations to cause minimal contribution to the frictional pressure loss along the liner.

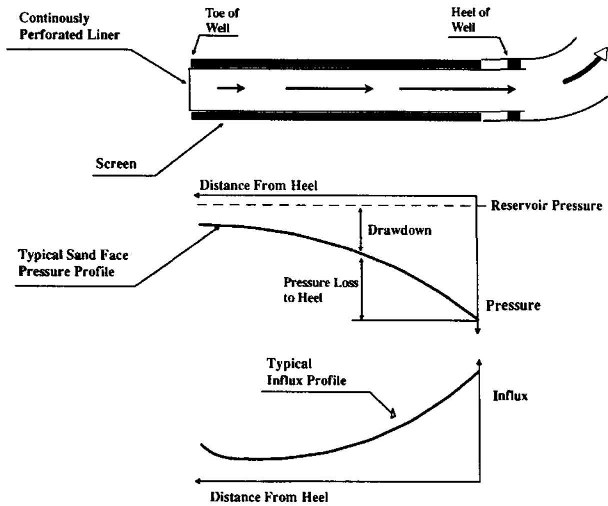

Fig. 1—Typical pressure and influx profile along a conventionally completed horizontal well.

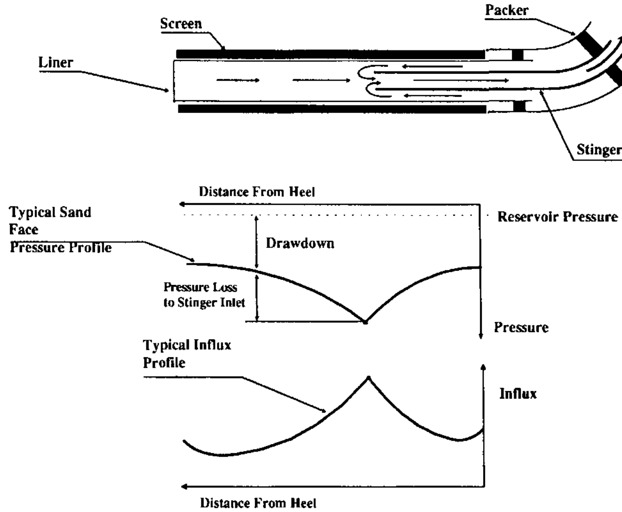

Fig. 2—Typical pressure and influx profile along a stinger-completed well.

We used a perforation density of 590 perforations/m for the conventional prepacked and continuously perforated liner in long-term tests of horizontal wells. The results from flow experiments with continuously perforated liner showed that for actual flow velocities, the friction factors for perforated pipe were from 70% to 40% larger than the corresponding friction factors for smooth pipe. The increase in friction factor is caused by turbulence and drag effects occurring around the high number of perforations used in standard continuously perforated liner. Radial inflow through the perforations had a reducing, but insignificant, effect on the friction factor.

A continuously perforated, 16.8-cm-ID, 800-m-long liner has a total perforation area of 34 m^2. With a 5000-std m^3/d production rate, the velocity through the 10-mm diameter perforations is only $\approx$0.5 to 2.5 mm/s. If access to the whole inflow area of the screen can be maintained regardless of perforation density, the number of perforations may be drastically reduced for horizontal well applications.

Calculations performed to optimize perforation density with respect to pressure loss along the wellbore support the feasibility of reducing the perforation density by a factor of 50. The limiting design criterion was to stay below the field-proven velocity through prepacked screen. By reducing the perforation density and optimizing the shape of the remaining perforations, the friction factor may be reduced to approach the friction factor of smooth pipe, which in this context refers to that of unperforated pipe. The reduced roughness provided by fewer perforations is also expected to extend the horizontal reach for coiled-tubing operations.

The only detected negative effect from reducing the perforation density is a reduced safety factor in case of unsatisfactory perforation cleaning after kill operations. With the earlier perforation density of 590 perforations/m, 98% of the perforation could remain clogged without causing complications. By including a reasonable safety factor, a significant reduction in perforation density is still feasible and is included in the design for the field case presented.

Inflow Control to Liner. To obtain a sandface pressure profile that resembles a frictionless well, a method based on distributing flow restrictions along the liner was investigated. The main objective for this method is to prevent uncontrolled and unevenly distributed inflow of fluids from the reservoir to the liner.[2,4] **Fig. 4** illustrates the configuration, with associated pressure profiles at the sandface and inside the liner. The inflow-control devices pass all fluids from the formation because they form the only communication between the reservoir and the inside of the liner. By adjusting the flow characteristics for the restrictions, effective and stable control of the influx to the liner can be achieved. Because the flow area through the liner is not decreased by this method, the downstream transport capacity will be close to that of a standard completion.

In the field case described below, sand control is a requirement. By use of a prepacked liner that allows inflow over the entire screen regardless of perforation density, perforations can be replaced with two flow restrictions for each liner section. **Fig. 5** shows a schematic of the selected configuration. Each inflow-control device is designed as a labyrinth channel embedded in a sleeve that surrounds the liner at each end of the prepack section. All inflow-control devices along the well have a common design and are equipped with valves to activate up to 10 labyrinth stages, depending on the need for choking along the well. Each inflow-control device is equipped-downstream with a secondary filter to allow killing the well without

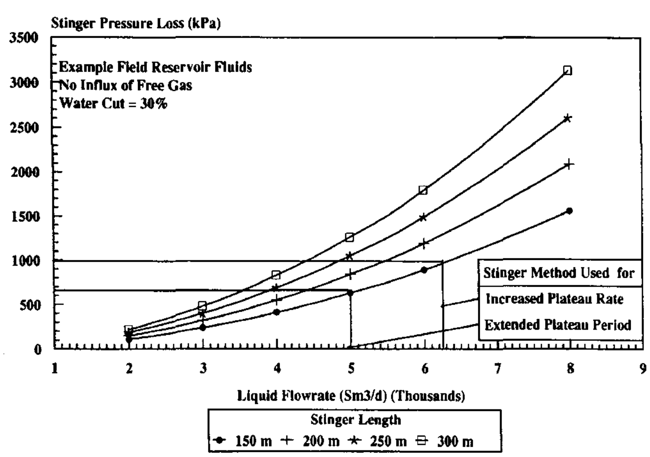

Fig. 3—Pressure loss through a 10.16-cm-ID stinger vs. liquid flow rate with stinger length varied.

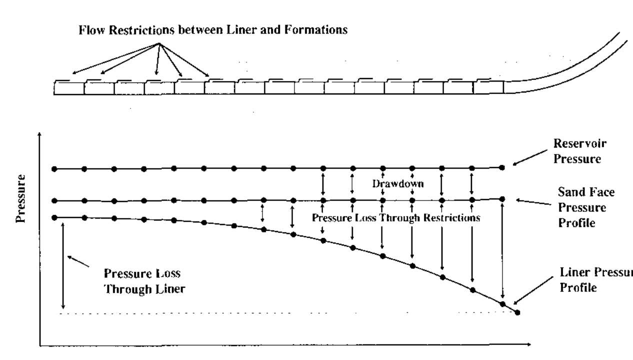

Fig. 4—Schematic of horizontal well with inflow control along the liner.

clogging the flow labyrinths or annular flow area between the sandpack and base pipe.

A prototype liner section was tested in the laboratory to establish flow characteristics for the inflow-control device. The prototype was also tested with respect to clogging by fines, kill properties of the secondary filter, and the feasibility of reopening for production after a kill operation. The tests demonstrated good operational functionality. Owing to the technical feasibility of the design and the large potential for increased productivity, this method will be applied in selected wells for the field case presented. The inflow-control method will also have applications for reservoirs other than the thin oil zones with high permeability. Combined with inflatable casing packers for zonal isolation, any sandface pressure profile may be obtained along wells in highly heterogeneous reservoirs.

Field Example: Troll Oil Province

Norsk Hydro drilled two horizontal wells in the Troll thin oil zone, one in a 22-m oil column and one in a 12-m column; the wells were tested for 11 and 4 months, respectively.[5-7] The results of these tests have improved the understanding of oil production from thin oil zones. Experience from the tests suggests that the combination of a small, limited drawdown and a high liquid rate severely restricted the productivity of long horizontal wells because of frictional pressure losses within the perforated section. The Troll oil province contains thin oil rims between a large gas cap and an active aquifer. The field consists of an easterly tilted fault block where the oil zone is from 22 to 26 m. The producible oil is in high-quality sands with 3000- to 15 000-md permeabilities. Because the oil production is limited by gas coning, a limited available drawdown can be applied.

Reservoir Simulation. A $20 \times 9 \times 24$ block simulation grid was used to model the $1.5 \times 1.5\text{-km}^2$ drainage area of a typical well in the example field. The 22-m oil zone was divided into 15 simulation layers with thicknesses varying between 1.0 and 3.5 m. Average horizontal permeability in the oil zone was 8500 md, and average vertical permeability was 1500 md. The 800-m horizontal well was positioned 3.5 m above the water/oil contact (WOC). The pressure loss calculations within the perforated section of the wells were based on results derived from the flow experiments discussed previously. A 15.24-cm-ID liner was used throughout the simulations.

Simulation Results. Four completion strategies were investigated through the numerical reservoir simulations.

1. Case A: normal completion (continuously perforated liner).
2. Case B: stinger completion (250-m stinger length).
3. Case C: reduced perforation density.
4. Case D: inflow-control liner.

A 250-m-long stinger was found to be optimal for the 800-m-long well. For the liner with reduced perforation density, a 0.025-mm roughness was assumed (close to commercial steel quality). Experimentally obtained friction factors were used for the normal completion. In Case D, a frictionless well was simulated to represent the inflow-control liner because we found that the inflow-control liner

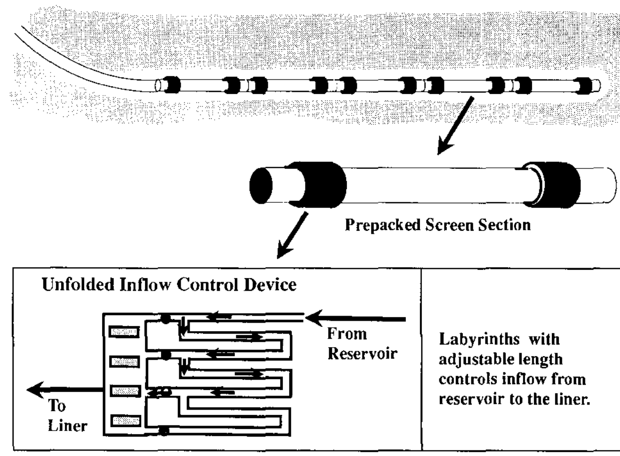

Fig. 5—Inflow-control-liner schematic.

could be adjusted to provide an evenly distributed drawdown along the well throughout the production life.

Two possible approaches for using the potential for improved well performance have been investigated: a long-term gain obtained by extending the oil plateau production rate and a short-term gain obtained by increasing the initial well-production rates. Compared with the conventional completion method for a given production rate, the maximum drawdown is reduced when the alternative completion methods are used. The gas cone advances toward the well at a reduced pace so that the first gas breakthrough occurs later in the production life.

Fig. 6 illustrates the flow behavior with respect to oil production rate vs. time. In all cases, the wells were controlled by a specified liquid production rate of 5000 std m^3/d until the first gas breakthrough occurred. Then, the liquid rate was consecutively reduced by 5% at each new gas breakthrough to make the gas cone retreat slightly. With the normal completion, the gas breakthrough occurred after 180 days of production, while the stinger completion and reduced perforation density delayed the breakthrough until 291 and 343 days, respectively. The limiting case for potential gain was 565 days, represented by a well with an inflow-control liner adjusted to maintain a flat sandface pressure profile. The gain in cumulative oil production after 2 years was 6% when a stinger completion was used, while the inflow-control liner increased the cumulative production by 14%. No appreciable difference in producing water cuts was observed between the cases. This can be attributed to the closeness of the well to the WOC (3.5 m).

The increased available well potential obtained by implementing the alternative completion methods was also formulated as a production strategy for increased initial rates. Each case had its initial liquid production rate level specified so that the first gas breakthrough occurred at approximately the same time (160 to 180 days). **Fig. 7** illustrates this as oil production rate vs. time. The reference

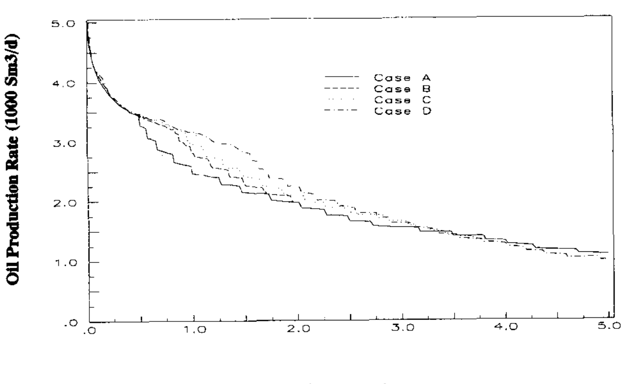

Fig. 6—Field example, extended plateau period; oil production rate vs. time.

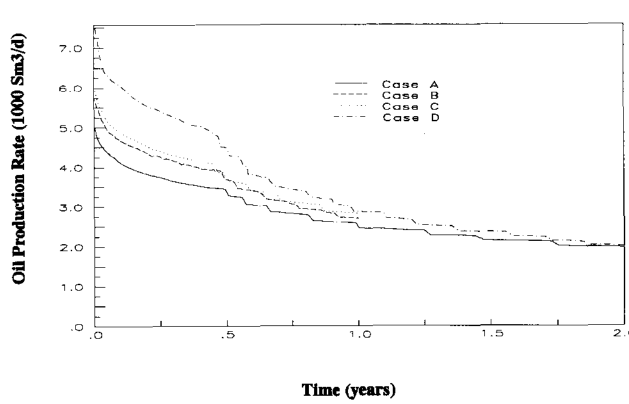

Fig. 7—Field example, increased plateau rate; oil production rate vs. time.

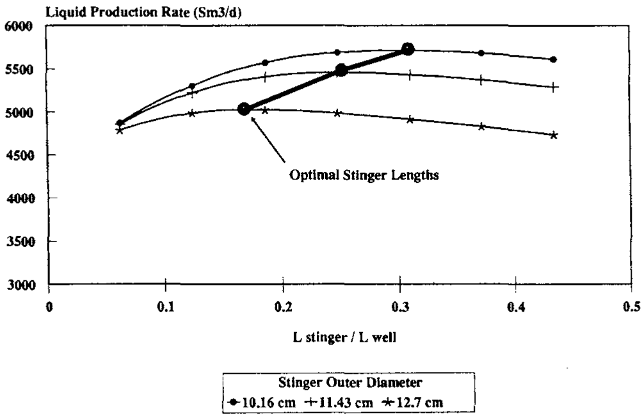

Fig. 8—Liquid production vs. stinger length; stinger OD varied.

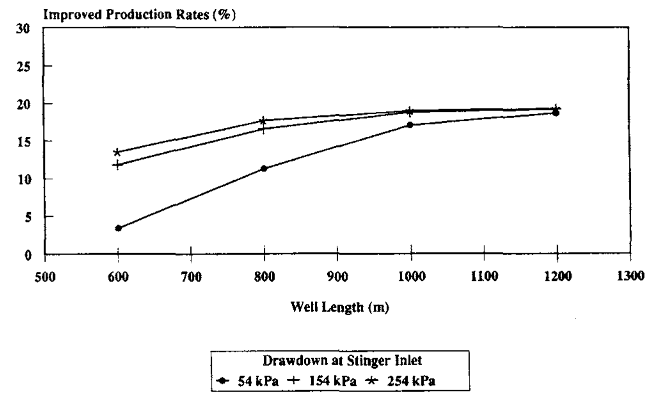

Fig. 9—Improved production with stinger completion vs. conventional completion; well length and drawdown varied.

case was the conventional 15.24-cm-ID perforated liner completion with an initial liquid production rate of 5000 std m^3/d. By inserting a stinger, the well could sustain a 15% higher liquid production rate before gas breakthrough. This was increased to 20% by converting from a perforated to a smooth liner. The limiting case for increased initial rate was, as before, the inflow-control liner, which produced at a liquid rate 50% higher than that of the base case. After 1 year of production, the stinger case had produced 11% more oil than the base case, while the frictionless case had produced 34% more oil.

The simulation results suggested that no extra recovery could be expected from the application of the alternative completion methods, but rather an acceleration of oil production. Because these calculations did not account for interference between wells or global reservoir effects, a full-field simulation should also be performed to quantify the production performance of each completion strategy.

Sensitivity Calculations

Stinger Design Optimization. On the basis of input data from the reservoir simulations, the horizontal wellbore simulator was used to support pressure loss calculations and to perform sensitivity calculations for the various completion alternatives. The PI's for each gridblock interfacing the wellbore were obtained from the reservoir simulator at gas breakthrough (after 160 to 180 days of production). The base case in the sensitivity calculations is the continuously perforated, 15.24-cm-ID, 800-m-long liner with a 250-m stinger.

Dimensionless stinger length is defined as stinger length divided by the length of the horizontal section. The dimensionless stinger length was 0.275 and independent of both well length and drawdown. **Fig. 8** shows the influence of stinger outer diameter on optimal stinger length and production rates. Additional well productivity is gained when the stinger diameter is decreased, which reduces the pressure loss within the stinger part of the liner. The downstream transport capacity is, however, reduced owing to a large pressure loss through a small-diameter stinger.

Fig. 9 shows the potential for improved production rates by introducing an optimal length stinger in 15.24-cm-ID continuously perforated liners of different lengths. As the well length increases, the benefit from use of the stinger completion method becomes less dependent on the magnitude of the drawdown. The potential increase in production approaches 19% for a 1200-m-long well. Also note that with respect to reduced productivity from frictional pressure losses, the benefit from the stinger method is independent of drawdown for a well drilled to its full feasible length.

Optimal Sandface Pressure: Inflow Control. The Troll case study indicated a 50% increase in the plateau rate for a frictionless well compared with a standard completion well. Inflow control was simulated to design a flow system with a constant pressure with respect to location along the well sandface. The well will behave as a frictionless well in the reservoir. The productivity profile at gas breakthrough from the reservoir simulation was used as input for the inhouse horizontal wellbore simulator. A configuration with flow restrictions connecting the liner and reservoir was used, and a flat sandface pressure profile was obtained by adjusting the restriction lengths. The total liquid flow rate was matched to the 7500-std-m^3/d flow rate obtained from the reservoir simulations with a frictionless well. **Fig. 10** shows the liner, sandface, and reservoir pressures for the 800-m, 15.24-cm-ID liner equipped with flow restrictions.

The constant drawdown along the well was initially thought to be the ideal case. During the study, however, we observed that a concave pressure profile would provide an even higher well productivity. The increased drainage area at the ends of the well results in higher productivities at these locations than at the middle sections of the well. The reservoir simulations showed that the productivities at the end sections of the well initially were 15% higher than at the middle section and 45% higher at gas breakthrough.

Fig. 11 shows the pressure profiles for both the continuously perforated liner and the frictionless well. Each pressure profile gave approximately the same production time before gas breakthrough

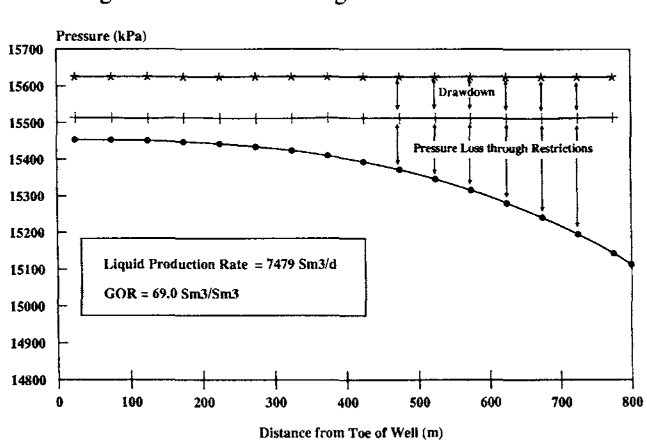

Fig. 10—Pressure profiles for liner with flow restrictions; flat sandface pressure profile.

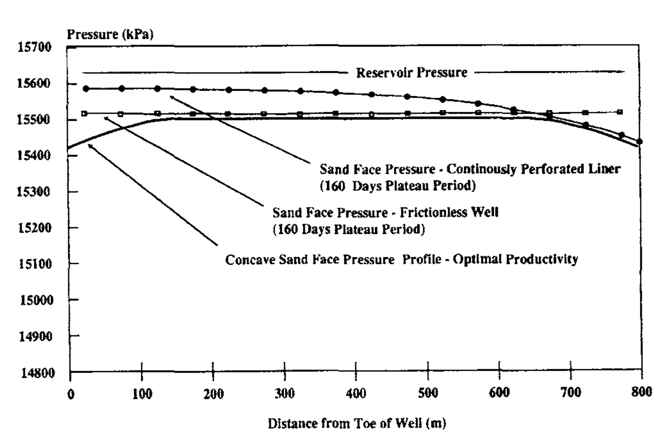

Fig. 11—Optimal sandface pressure profile.

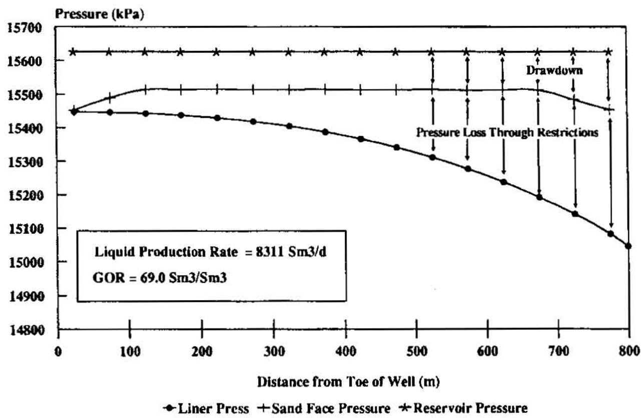

Fig. 12—Pressure profiles for liner with flow restrictions; concave sandface pressure profile.

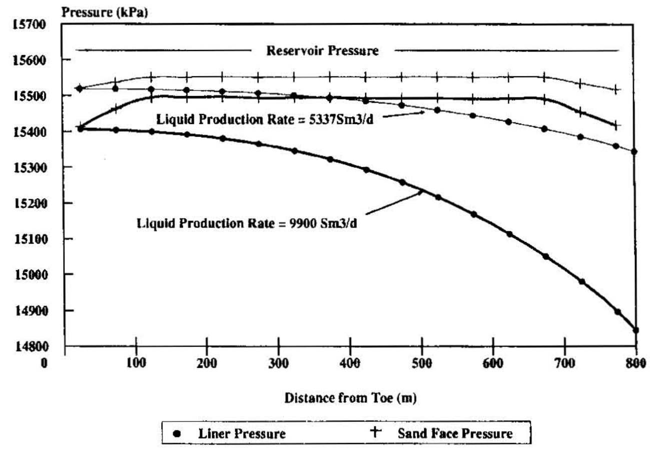

Fig. 13—Inflow control, concave sandface pressure profile; variations in drawdown.

(160 to 180 days), but the magnitude of the maximum drawdown varied significantly between simulated cases. This indicates that the gas cone is pulled down more easily at the center of the well than at the end zones. The normal completion benefits somewhat from the favorable location of the maximum drawdown at the end zone of the well. However, although a higher maximum drawdown can be applied for the normal completion, it has a smaller average drawdown and a lower total productivity compared with the frictionless well.

The positive qualities for both the standard and frictionless completions may be combined to enhance well productivity further. The inflow-control liner can be adjusted to provide a concave pressure profile (**Fig. 12**). Maximum drawdown at the ends of the liner is of the same magnitude as maximum drawdown for the conventional continuously perforated liner with a flow rate that results in 160 days of production before gas breakthrough. The middle section of the liner had equivalent drawdown to that of a frictionless well with a production rate resulting in 160 days of production before gas breakthrough. The calculated liquid plateau production rate for this configuration was 8311 std m^3/d, a 66% improvement over that of the continuously perforated liner in the base case. Thus, an additional 16% improvement was gained beyond the frictionless case by exploring the well-end contributions. **Fig. 13** shows pressure profiles for this same configuration as the heel pressure is varied between 14 850 and 15 350 MPa. Observe that the shape of the sandface pressure profile remains undistorted as the heel pressure is varied. This indicates a stable system response for production rate variations.

Conclusions

Three approaches for well optimization to overcome the reduction in well productivity from pressure loss along the wellbore have been investigated. The potential for increased well productivity from reducing the wellbore friction effects was found to be significant for all methods investigated. The inflow-control liner was found to have the largest potential with respect to both increased well productivity and practical feasibility.

By replacing the perforations along a horizontal well with a limited number of flow restrictions, the influx along the liner may be controlled to create a flat sandface pressure profile along the well. Thus, the well will behave as a frictionless well in the reservoir and respond accordingly. The performance of an inflow-control-liner completed well indicated a potential 50% increase in plateau rate or a 214% increase in the plateau period.

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SI Metric Conversion Factors

bar	× 1.0*	E+02 = kPa
bbl	× 1.589 873	E−01 = m^3
ft	× 3.048*	E−01 = m
ft^2	× 9.290 304*	E−02 = m^2
ft^3	× 2.831 685	E−02 = m^3
in.	× 2.54*	E+00 = cm
psi	× 6.894 757	E+00 = kPa
sq mile	× 2.589 988	E+00 = km^2

*Conversion factor is exact.

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