Understanding the Roles of Inflow-Control Devices in Optimizing Horizontal-Well Performance

Zhuoyi Li, SPE, Schlumberger; **Preston Fernandes,** SPE, Chevron; and **D. Zhu,** SPE, Texas A&M University

Summary

An inflow-control device (ICD) is completion hardware that is deployed as part of well completions aimed at distributing the inflow evenly. Even though the detailed structures vary from one design to another, the principle for different ICDs is the same—restrict flow by creating additional pressure drop and therefore adjusting wellbore pressure distribution to achieve an evenly distributed flow profile along a horizontal well. With a more evenly distributed flow profile, one can reduce water or gas coning, prevent sand production, and solve other drawdown-related production problems. In general, ICDs are not adjustable; once installed in the well, the location of the device and the relationship between rate and pressure drop are fixed. This makes the design of a well completion and ICDs extremely critical for production. ICDs can be either beneficial or detrimental to production, depending on the reservoir condition, well structure, and completion design. Realizing that reservoir conditions will change during the life of a well, the impact of an ICD is a function of time. Reservoir heterogeneity and uncertainty can complicate the situation easily. The ICDs sometimes can be overlooked if the design is based only on reservoir flow simulations at initial conditions.

In this paper, we will investigate how and when an ICD should be used. An integrated analysis method of inflow (reservoir) and outflow (wellbore) is used to generate the flow profile of a horizontal well, and additional frictional pressure drop created by ICDs will be considered. Two conditions that result in production problems, wellbore pressure drop and reservoir heterogeneity, will be addressed. The focus will be on when and how an ICD can optimize production. Examples will be used to illustrate that it is critical to understand the reservoir conditions and wellbore dynamics together when designing a well completion with ICDs. The observations from this study show that overdesigned ICDs will not just increase the cost of well completion, but also will impact the well performance negatively. ICDs are not a universal solution of production problems. The application requires a thorough understanding of long-term reservoir behavior and upfront reservoir characterization for implementation.

Introduction

Over the past 30 years, advances in drilling technology have made it possible for horizontal and multilateral wells to become a primary design type to develop reservoirs, especially in unconventional resources. The need for efficient, economic, and environmental friendly production has promoted the development of extended-reach horizontal and multilateral wells that enable greater reservoir contact and lower drawdowns to achieve rates similar to those of conventional wells. However, this increased wellbore length has led to some problems in producing from such a well. Higher pressure drawdown around the heel section as a result of frictional pressure drop of fluid flow in the wellbore causes nonuniform fluid influx along the length of the wellbore and higher production rates at the heel. Longer contact of the reservoir results in higher variation of the reservoir, and heterogeneity becomes a critical influence of reservoir and well performance. Both problems often lead to early breakthrough of water or gas at the higher-drawdown locations (at the heel or at high-permeability zones), which causes a reduction in oil recovery and uneven sweep of the drainage area.

To eliminate these problems, ICDs have been used increasingly in producing wells as a part of well completion to control and optimize individual-well or overall reservoir performance (Alkhelaiwi and Davies 2007; Krinis et al. 2008; Emerick and Portella 2007). The completion with ICDs is often referred to as one kind of intelligent completion, with an inflow-control valve (ICV) as the other commonly used downhole-flow-control means. An intelligent completion can be a well equipped with downhole monitoring systems, downhole-control devices, or both. It has been discussed before that ICVs are more active control and ICDs are passive control (Crow et al. 2006; Birchenko et al. 2008). The purpose of ICDs is to equalize inflow along the length of the wellbore regardless of location and permeability variation. These ICDs enable the entire length of the wellbore to contribute to the total production and thereby optimize hydrocarbon recovery. ICDs are choking devices that balance inflow by adding an additional pressure drop at the sandface. They are designed to apply a specific differential pressure at a certain flow rate.

An ICD is permanent hardware installed upon completion of a well on the basis of initial reservoir conditions and simulation predictions of reservoir performance. It is part of the completion base pipe (liner or casing) with different design of flow path to create additional frictional pressure drop, and therefore to restrict the flow through the path. ICDs should not be mixed with ICVs, which are sliding-sleeve valves installed along the completion. ICVs are positive controls for flow because they are adjustable in terms of how much flow resistance can be provided. On the other hand, ICDs are passive controls to the flow. They are preset and not adjustable (the resistance to flow cannot be changed because there are no adjustable parts). Once installed in the well, the device will function as it is initially throughout the life of the well unless the whole completion string is retrieved. Because there are no moving parts in an ICD, it is a simpler form of flow control and is more reliable than ICVs. Realizing that reservoir condition is dynamic, ICDs have to be reliable even as conditions change in the reservoir. Changes in fluid viscosity, density, and velocity occur with time, and ICDs should be designed to adapt to these conditions without creating an inflow imbalance and a negative effect on production. In general, dynamic conditions of production make ICD selection and design an important factor in determining the productivity from a well. ICDs are developed with different flow-resistance ratings, which signifies the pressure drop attained with the ICD using a reference fluid and flow rate. To avoid detrimental effects to well performance by ICDs, this paper addresses some basic questions as to when ICDs should be deployed and how the additional restriction/pressure drop affects the flow condition of a well.

Methodology of Analysis

Review of ICD Types. There are different ICD types offered in the industry today that use either friction or restriction as their mechanism for creating pressure drop (Coronado et al. 2009; Ouyang 2009). The two most commonly used ICDs are the channel type and

This paper (SPE 124677) was accepted for presentation at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 4–7 October 2009, and revised for publication. Original manuscript received 8 March 2010. Revised manuscript received 9 February 2011. Paper peer approved 8 March 2011.

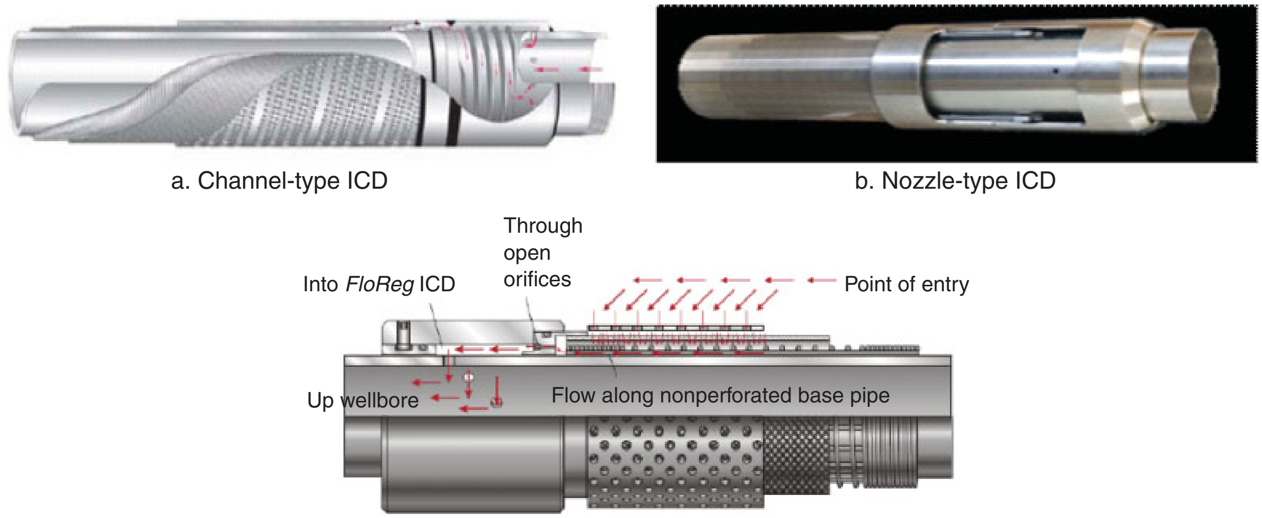


Fig. 1—Common types of ICDs (after Alkhelaiwi and Davies 2007).

the nozzle/orifice type, as shown in **Fig. 1.** There are also variations of channel design and nozzle design. Even with different configurations, the basic operating principles of ICDs are the same.

Channel-Type ICD. This type of ICD is one of the earliest types of ICDs that uses surface friction to generate a pressure drop. It uses a number of channels with preset diameters and lengths. The produced fluid flows through a multiple-layered screen into the annulus between the screen and a solid base pipe and then is forced to flow through the channels before getting into the wellbore, as shown in Fig. 1a (Alkhelaiwi and Davies 2007). The design causes the fluid to change directions numerous times, which causes the pressure drop along a longer channel path. This proves advantageous because it generates lower flow velocities, which reduces the chances of erosion and plugging. However, a disadvantage of using friction to generate pressure drop is that the ICD becomes viscosity dependent, which can cause problems in maintaining uniform influx in wells where there is a larger difference between viscosities of the oil and produced water or gas.

Orifice-/Nozzle-Type ICD. These ICDs use fluid constriction to generate a desired pressure drop. Fluid is forced through a preconfigured set of small-diameter nozzles (Fig. 1b) or orifices (Fig. 1c) into the pipe to create a flow resistance. The pressure drop across this ICD occurs instantaneously, which means that it is highly dependent on the fluid density and velocity and not the viscosity. It would be ideal for wells that require a low sensitivity to viscosity. Another advantage of this ICD type is that its simple design allows for the configuration to be changed rather easily should real-time data suggest it. On the contrary, being dependent on fluid velocity makes the ICD highly prone to erosion from sand particles and less resistant to plugging.

Other ICD Types. There are many other designs of channel type/nozzle type/combination of channel and nozzle. One hybrid design uses multiple bulkheads that form chambers and flow slots 180° apart. Fluid flows through each successive chamber and incurs a pressure drop. The mechanical design of different types of ICDs may vary, but the operating principle underlying the devices is the same—using additional frictional pressure drop to redistribute flow along a horizontal wellbore.

Selection of ICDs should be kept simple. With multiple structure types and functions combined together, a more comprehensively designed ICD can theoretically work better. But at downhole with dynamic conditions of fluid type, fluid density and viscosity, and reservoir pressure and temperature, the flow condition is most likely unpredictable when designing the completion. Once one or more sections of an ICD fail (plugging, erosion, or other mechanical causes), there will be a direct impact on the flow of the well. In reality, a sensitivity study is necessary to identify the possible problems during production.

Mathematical Approach. To evaluate the performance of a horizontal well with ICD completion, we use a horizontal-well-flow model with a black-oil reservoir simulator (Eclipse) to calculate the relationship between flow rate and pressure distribution. The wellbore model calculates pressure in a pipe with distributed wall-inflow for two phases. For two-phase flow in the wellbore, pressure drop is calculated by a model presented previously (Yoshioka et al. 2006). The pressure gradient for oil and water two-phase flow is solved from the equation

$$\frac{\mathrm{d}p}{\mathrm{d}x} = -\frac{\rho_m v_m^2 f_m}{R} - \frac{\mathrm{d}\left(\rho_m v_m^2\right)}{\mathrm{d}x} - \rho_m g \sin\theta, \quad \text{(1)}$$

where ρ_m is mixed density of the fluid and v_m is mixed velocity. If we assume no slip between phases, then the mixed velocity can be expressed as

$$v_m = \frac{\rho_o}{\rho_m} v_{so} + \frac{\rho_w}{\rho_m} v_{sw}. \quad \text{(2)}$$

In Eq. 2, v_{sw} and v_{so} represent superficial velocities of water and oil, respectively. The oil/water-mixture viscosity is estimated by a correlation (Jayawardena 2005):

$$\mu_m = \mu_c \left(1 - y_d\right)^{-2.5}, \quad \text{(3)}$$

where the subscript c means continuous phase and d means dispersed phase. y_d is the holdup of the dispersed phase. Eq. 1 is solved for pressure distribution along the pipe. Notice that the velocity is a function of location as the flow from the reservoir continuously joins the wellbore flow. The inflow effect on wellbore pressure drop is considered through the friction factor f_m in Eq. 1. When the flow is liquid/gas multiphase flow, the drift flux model (Ouyang 2000; Yoshioka et al. 2006) is used to calculate slip velocity between gas and liquid phase.

For a given reservoir, a horizontal well is represented in the reservoir by a series of point sources when simulating reservoir flow. Separating from the reservoir simulation, these source grids are linked together to reassemble the horizontal well in the well-flow model. The pressure drop from ICDs is included in the well-flow model, and then as an input skin factor in the reservoir simulation. Such an approach allows flexibility to handle the wellbore-flow problem, which in most cases is a smaller-scale problem compared with the reservoir-flow problem. To evaluate the ICD effect correctly, a well-flow model is essential, and iteration is necessary to achieve the agreement between the reservoir simulation and wellbore flow. The system used in this study is shown in **Fig. 2.** This

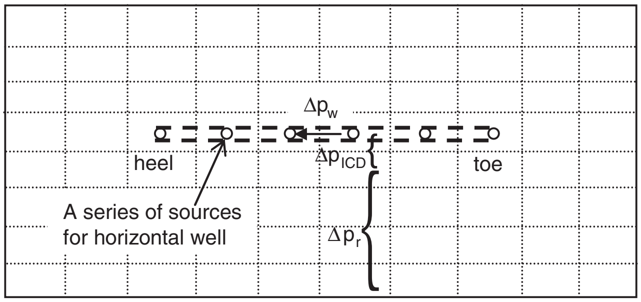


Fig. 2—Physical system for the calculation model.

approach can be used for single-phase or multiphase-flow systems at transient flow condition or stable condition for reservoir flow. The transient effect in wellbore flow is included consecutively at each timestep by updating the flow at the boundary from the reservoir simulation. The wellbore can be located anywhere in the reservoir, fully penetrating or partially completed through the reservoir. The one critical assumption is that in each grid that contains a wellbore, the wellbore has to be parallel to the grid boundary. For nonhorizontal wells, the grid size has to be relatively small to avoid numerical error.

Initially, a wellbore flowing pressure is assumed at the heel of the horizontal well, and the drawdown at the heel grid is defined. Constant well-flow pressure is used as a constraint for the reservoir simulation. When the flow rate at each well grid is calculated as a result of simulation, the well model calculates the pressure distribution in the horizontal wellbore on the basis of the flow distribution from reservoir inflow. This wellbore pressure distribution is then used as the new boundary condition for reservoir-flow simulation. The iteration converges when the assumed wellbore pressure for reservoir flow is confirmed by the wellbore pressure from wellbore-flow model. The flow chart of the calculation is shown in **Fig. 3.**

The pressure drop created by ICDs is considered to be through a positive skin factor (resulting in flow rate decreasing). ICD models are dependent on the specific design of each ICD (Aadnoy and Hareland 2009). To make the problem simple, we will use the channel-type ICD to illustrate the impact of ICDs on well production because the frictional pressure drop of a channel flow can be expressed explicitly as a function of flow rate. Because frictional pressure drop is proportional to squared flow rate (q^2), we have used a general equation for ICD pressure drop (Δp_{ICD}) calculation:

$$\Delta p_{\mathrm{ICD}} = Cq^2\rho_m. \quad (4)$$

In Eq. 4, parameter C is a function of configuration and dimension of the ICD, which may vary with different designs (Coronado et al. 2009). In this study, we assign the pressure drop across the ICD at the heel a defined value with a given flow rate. In general, this value is determined by how much pressure constraint is needed according to the drawdown and wellbore frictional pressure drop. From Eq. 4, we then calculate the parameter C. The value of C is

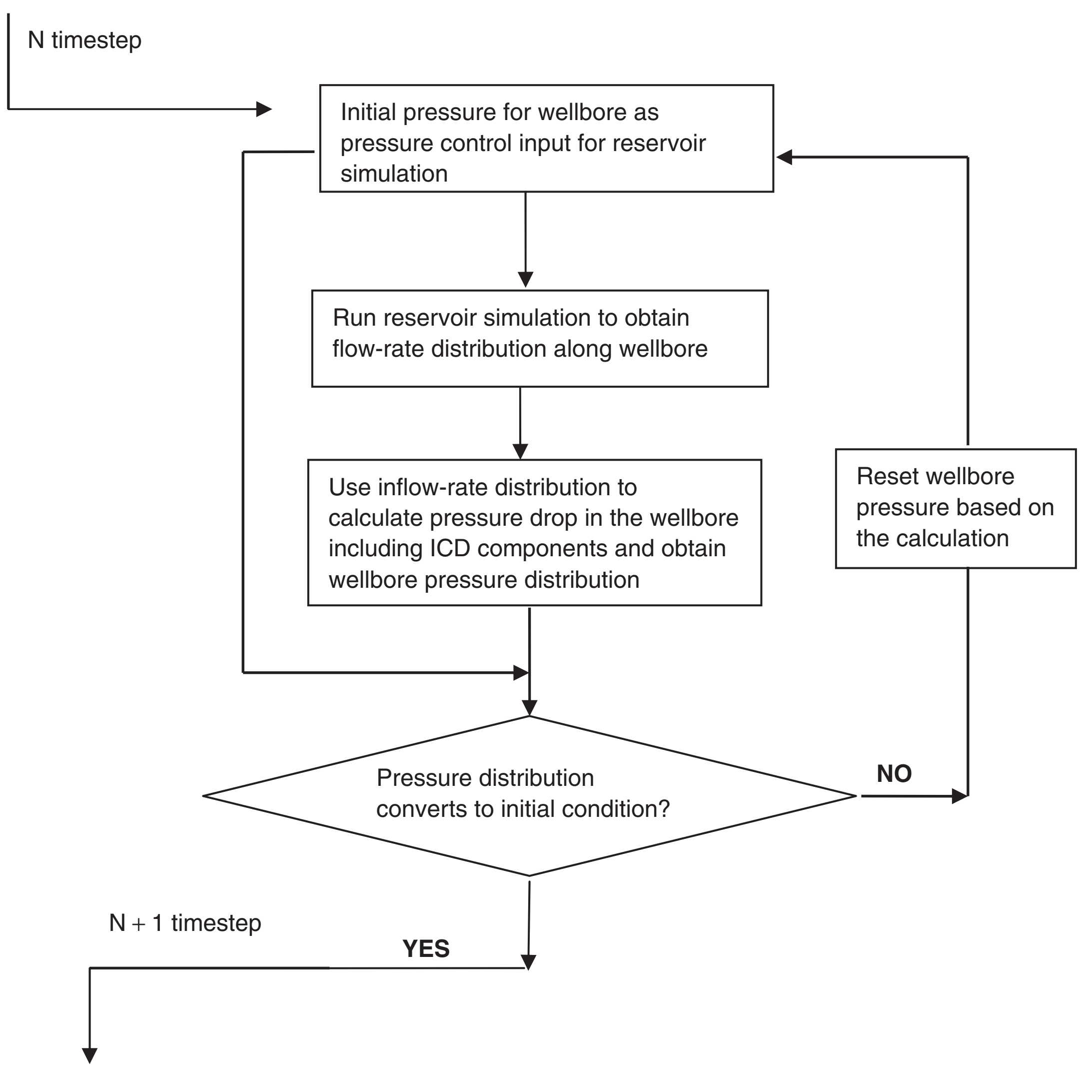


Fig. 3—The procedure to predict horizontal-well performance with ICDs.

TABLE 1—INPUT FOR OIL/WATER CASES			
		Case 1a	Case 1b
Reservoir thickness	ft	100	120
Reservoir dimension	ft × ft	2,000 × 8,000	2,000 × 4,000
Well length	ft	8,000	4,000
Horizontal permeability	md	800	50
Vertical permeability	md	80	5
Average reservoir pressure	psi	2,930	2,950
Well-flow pressure at heel	psi	2,650	2,550
Oil viscosity	cp	2	2
Oil density	lb/ft^3	40	40
Tubing diameter (ID)	In.	4.5	5.5
Water density	lb/ft^3	63	63
Number of ICVs	–	40	20

used throughout the entire wellbore for any location where an ICD is installed. We assume that the same type of ICD is used in one well completion. Thus, pressure drop by each ICD is determined by the flow rate at each location from Eq. 4.

Because the pressure drop through an ICD, Δp_{ICD}, is proportional to the squared flow rate, q^2, flow rate is very sensitive to the pressure drop. A small pressure drop can cause a big change in flow rate. This results in unstable problems when used in the simulation as a part of the boundary condition from the wellbore flow. To avoid a numerical-convergance problem, this additional pressure drop is treated as a skin factor for the reservoir flow. At Location i, a local skin factor from ICD, $s_{\mathrm{ICD},i}$, is calculated until it creates the same pressure drop as the ICD at the location. Then, this skin factor is used in the reservoir flow as an input. From the well model used in horizontal-well simulation (Babu and Odeh 1988), it is easy to show that the local skin factor can be expressed as

$$s_{\mathrm{ICD},i} = \frac{\Delta p_{\mathrm{ICD},i}}{\Delta p_{r,i}} \ln\left(\frac{r_{eq}}{r_w}\right), \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

where r_{eq} is equivalent wellbore radius in the grid that has an ICD installed, r_w is wellbore radius, and $\Delta p_{r,i}$ is the drawdown at the grid.

We use this approach to simulate well performance of horizontal wells with ICD completions. The results include pressure distribution and flow distribution in the reservoir and along the well. The focus of this study is the well-flow behavior, and the impact of ICDs is evaluated by the flow distribution along the well and cumulative production from the well.

Examples and Discussions

As previously discussed, ICDs are used in the field mainly for three production problems—evenly distributing the flow along a horizontal well in high-permeability formation, reducing early breakthrough at the heel for thin oil formations, and delaying water breakthrough at high-permeability locations for heterogeneous formations. We will use three examples in this section to address each problem. A field case will be used to illustrate how ICDs can help to improve production if installed correctly.

Balance Flow Distribution in High-Permeability Formation. When horizontal wells are used in formations with good permeability, reservoir simulation can simply show that the longer the wellbore, the higher the flow rate. This sometimes leads to an overdesigned well length that results in high frictional pressure drop. This high frictional pressure loss can cause two problems—higher drawdown at the heel leading to early breakthrough and higher pressure drop along the wellbore leading to tubing limited production. This is often referred to as the heel/toe problem. Installing ICDs at the heel of a horizontal well in such a case is believed to reduce the unbalanced flow distribution.

For an ICD to work appropriately in such a condition, two conditions have to exist. First, the pressure drop inside the wellbore needs to be at a relevant level to reservoir drawdown; second, the ICDs need to create corresponding pressure at a meaningful level (certain flow rate is required). It has been shown that the ratio of pressure drops in the wellbore to that in the reservoir can be used for evaluation if wellbore flow is the restriction to production (Hill and Zhu 2008). For a horizontal well, if wellbore pressure drop is dominated by frictional pressure drop, then the ratio

$$K = \frac{\Delta p_f}{\Delta p_r} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (6)$$

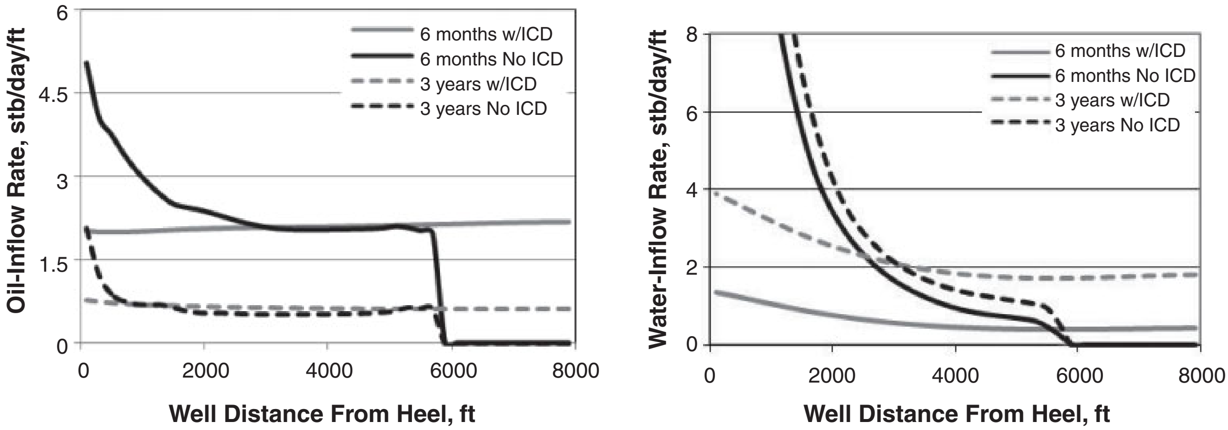
indicates if wellbore pressure drop is a problem for production. K can be large if reservoir permeability is high (small Δp_r), well length is too long, or tubing diameter is too small (large Δp_f). In general, if K is significant, using ICDs or other flow-control devices can balance the flow along the wellbore, improve well performance, and increase recovery. If K is less than 0.1, adding ICDs to the completion for wellbore flow distribution is unnecessary. For each individual well, K should be examined for well structure and completion design.

The first example used a waterdrive reservoir to explain the principle of using ICDs to correct the heel/toe problem. A fully penetrated wellbore in a homogeneous reservoir is assumed in this example to isolate the effect of frictional pressure drop on production. The heterogeneity effect will be discussed later.

The reservoir has a strong bottom aquifer with an initial pressure of 3,000 psi, and reservoir boundary is at no-flow condition. There are two cases in Example 1. The significant differences between these two cases are that one has higher permeability and longer wellbore (Case 1a) to represent the high-flow-rate condition (Arfi et al. 2008), and the other has moderate permeability and well length (Case 1b), representing more-general conditions. A fully penetrating wellbore is assumed in both cases to emphasize the benefits of using ICDs, and to separate the partial-penetration effect. Each wellbore is segmented into numerous pieces with a constant length of 200 ft. We assume that each segment has one ICD installed. A summary of the reservoir and well properties is shown in **Table 1.**

The simulation results from the method described earlier include pressure and flow-rate distribution along the well, and cumulative production. For each case, we simulated the well performance with ICDs and without ICDs. Pressure drop through ICDs at the heel is set at 100 psi to calculate the parameter C in Eq. 4 for the high-permeability case (Case 1a).

The unit flow rate [(B/D)/ft) of oil along the wellbore is shown in **Fig. 4a,** and the unit water rate is shown in Fig. 4b. The performance at 6 months and 3 years is plotted. In Fig. 4, the grey-colored data are results with ICDs, and the black is without an ICD. The flow-rate results show that without an ICD, the water



a. Oil unit rate

b. Water unit rate

Fig. 4—Oil- and water-rate distribution for Case 1a (high perm).

rate at the heel is extremely high (Fig. 4b), and a section of the well is not flowing because of high frictional pressure drop in the wellbore (Figs. 4a and 4b). This is a well-understood phenomenon in high-rate long horizontal wells. ICDs improve the flow condition effectively. The oil-flow rate becomes evenly distributed (Fig. 4a), and water production is restricted successfully (Fig. 4b). This improved condition is confirmed by the cumulative production of the well. **Fig. 5** illustrates the cumulative production for oil and water as a function of time. It is clear that water production is delayed and reduced because of ICDs. Oil production is slightly reduced at the beginning of the production because of additional pressure drop added to the flow. In the long term, cumulative production of oil is higher in the case with ICDs than in the case when ICDs are not installed.

This is a good example to show the positive function of ICDs in enhancing horizontal-well performance. The main reasons that ICDs worked in this case are the high permeability in the reservoir that results in a high flow rate at a small drawdown and the relatively long well length that created significant frictional pressure drop. **Fig. 6** shows the flowing pressure distribution. Before installing the ICDs, frictional pressure drop along the well is approximately 265 psi. Compared with the drawdown at the heel (280 psi from Table 1), it gives a K value of 0.93 (Eq. 6), indicating that wellbore pressure drop will be a problem.

Fig. 4 shows a sudden drop in flow rate at approximately 6,000 ft. This instaneous flow-rate drop is because the flow in the reservoir and the wellbore is in two phases; the inflow rate should be oil plus water or gas. If we combine Fig. 4a (oil rate) and Fig. 4b (water rate), then the total rate will be relatively smoother. The larger grid size in simulation also contributes to the local rate change.

In a similar situation, if the permeability of the reservoir reduces and the well length becomes shorter, the picture will change. **Fig. 7** shows the oil and water unit rate distribution along the wellbore for Case 1b (50-md permeability and 4,000-ft-long wellbore). Clearly, the oil rate (Fig. 7a) and water rate (Fig. 7b) are both flat from the heel to the toe, and there is no effect of frictional pressure drop. In such a case, if the reservoir is fairly homogeneous, adding ICDs does not benefit well performance or reservoir recovery. From Fig. 7b, we see that water is restricted somewhat later (after approximately 3 years), but we sacrificed oil production. **Fig. 8** shows that while we are reducing water production after approximately 400 days of production, oil production suffers from early time. A pressure drop of less than 9 psi is observed along the wellbore **(Fig. 9).** Compared with the drawdown of 400 psi (from Table 1), the K value is only approximately 0.02. It is strongly recommended in such a case not to use ICDs for production improvement.

Thin Oil Rim With Gas Cap. A thin oil formation with a gas cap is difficult to produce efficiently. Gas has a much higher mobility than oil, and thus gas easily breaks through to the wellbore and chokes off the oil-flow rate. One common practice to produce such a formation is to control the drawdown to a relatively small value to delay gas breakthrough. ICDs in this situation can help to improve production efficiency, and this has been proved in the Troll field, North Sea (Rahimah et al. 2010). The second example presents a thin oil reservoir with a gas cap above with an initial pressure at 3,200 psi. The reservoir dimension is the same as in Case1b, the formation thickness is 40 ft, and the reservoir boundary is no-flow condition. Similar to Example 1, we use two conditions, one has a higher permeability (200 md) and the other a moderate permeability (100 md). **Table 2** summarizes the data used in this

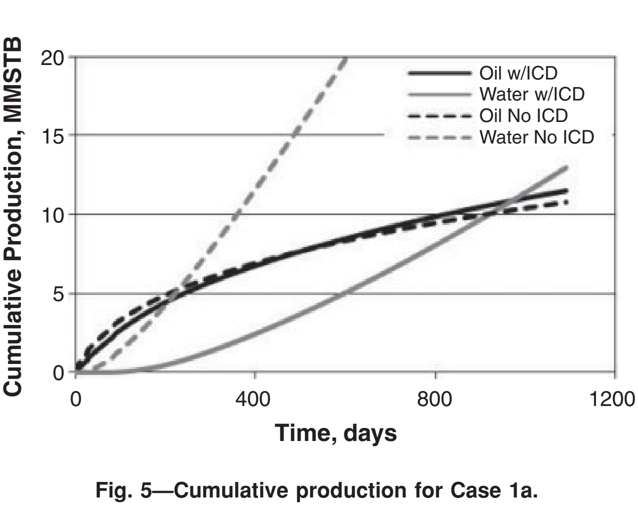


Fig. 5—Cumulative production for Case 1a.

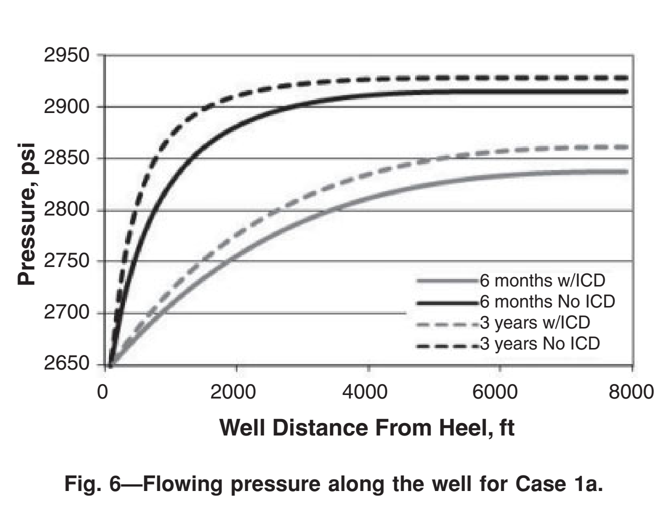


Fig. 6—Flowing pressure along the well for Case 1a.

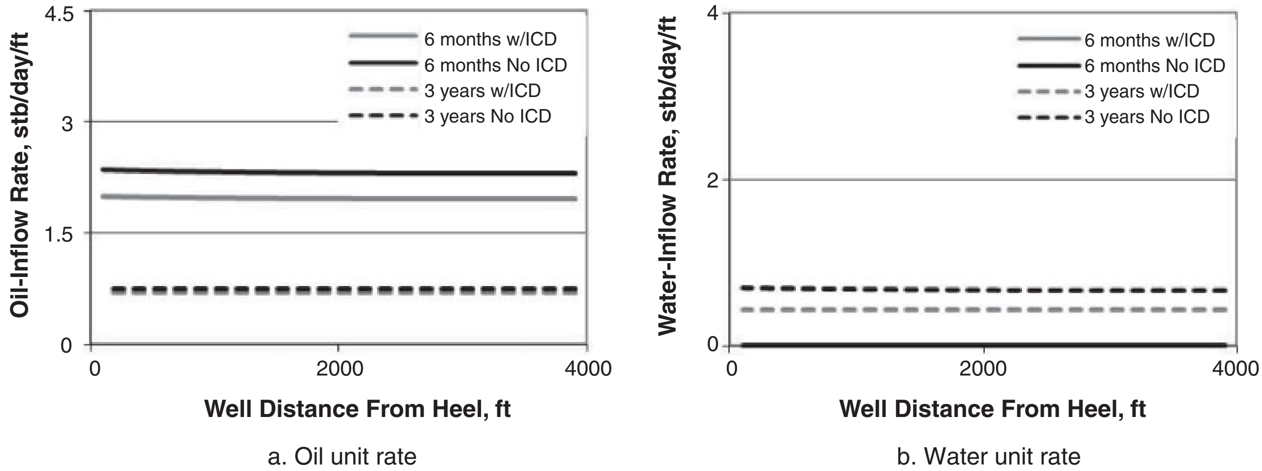


Fig. 7—Oil- and water-rate distribution for Case 1b (low permeability).

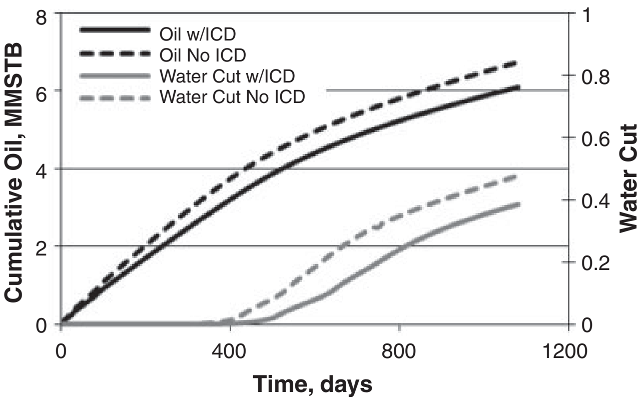


Fig. 8—Cumulative production of oil and water for Case 1b.

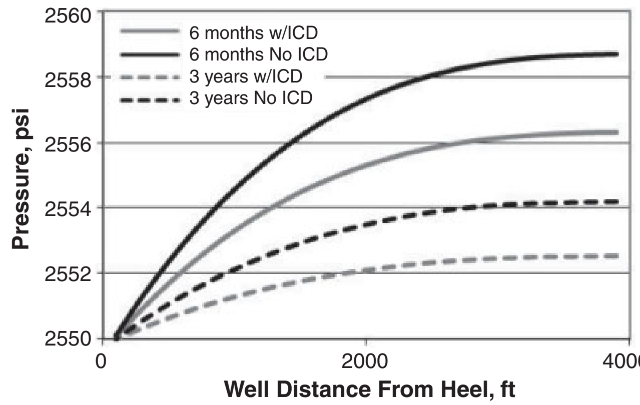


Fig. 9—Flowing pressure distribution for Case 1b.

example. For the high-permeability case, drawdown at the heel is 60 psi, and for the low-permeability case, it is 15 psi. In thin-oil-rim reservoirs, early gas breakthrough and overcapacity gas production are serious problems for production. To produce such a formation, drawdown is usually limited to a low value to avoid gas breakthrough and gas production. It is believed and proved that ICDs can help to improve the performance of horizontal wells in the thin-oil-formation case (Leemhuis et al. 2008; Henriksen et al. 2006). The segments for both cases are 200 ft in length, and each segment has one ICD installed.

The simulation results are presented in the following figures. For the higher-permeability case, Case 2a, the flow-rate distribution of oil and gas is shown in **Fig. 10** (Fig. 10a for oil rate and Fig. 10b for gas rate). Without ICDs (dashed lines), the gas flow dominates the total production, causing low oil-flow rate (Fig. 10a), and a part of the well does not produce at all (Figs. 10a and 10b). High gas-flow rate also causes reduced production because of limitation of surface-facility capacity. This could be a serious problem for offshore wells. Moreover, reducing drawdown could slow down the gas production more, but that will also reduce the oil-flow rate and reduce the economic value of the well.

TABLE 2—INPUT DATA FOR GAS/OIL CASES

		Case 2a	Case 2b
Reservoir thickness	ft	40	40
Well length	ft	4,000	4,000
Horizontal permeability	md	200	100
Vertical permeability	md	20	10
Average reservoir pressure	psi	3,360	3,240
Pressure at heel	psi	3,300	3,225
Oil viscosity	cp	2	2
Oil density	lb/ft^3	40	40
Tubing diameter	in	4	4
Gas viscosity	cp	0.02	0.02

The performance of the well is obviously improved after adding ICDs to the completion. First, the drawdown is more evenly distributed, and the entire wellbore experiences inflow rather than only a part of the wellbore toward the heel. Second, gas-flow rate is greatly reduced and thus the wellbore-limitation problem is relaxed. From Fig. 10a, the oil-flow rate is also reduced because of the additional pressure drop from the ICDs.

Unlike the oil- and water-flow problem (Example 1), for a thin oil formation with a gas cap, the pressure drop, both drawdown and in the wellbore, offers only a very narrow range when designing the well structure and completion. Flow distribution (type of fluids and flow rates) is also very sensitive to pressure drop. In such a case, extreme caution in designing ICDs is encouraged. Overdesigned ICDs will result in low oil production and loss of economic value. The pressure ratio K should be estimated when designing the completion. **Fig. 11** shows the pressure difference between the grid reservoir pressure and the well flowing pressure at the wellbore grid, which is referred to as local drawdown. From the toe to the heel, there is a 55-psi pressure drop at 6 months of production if there is no ICD. Compared with the drawdown of 60 psi at the heel (Table 2), K is 0.9. Without ICDs, the local drawdown varies from 60 psi at the heel to 0 psi at approximately 2,000

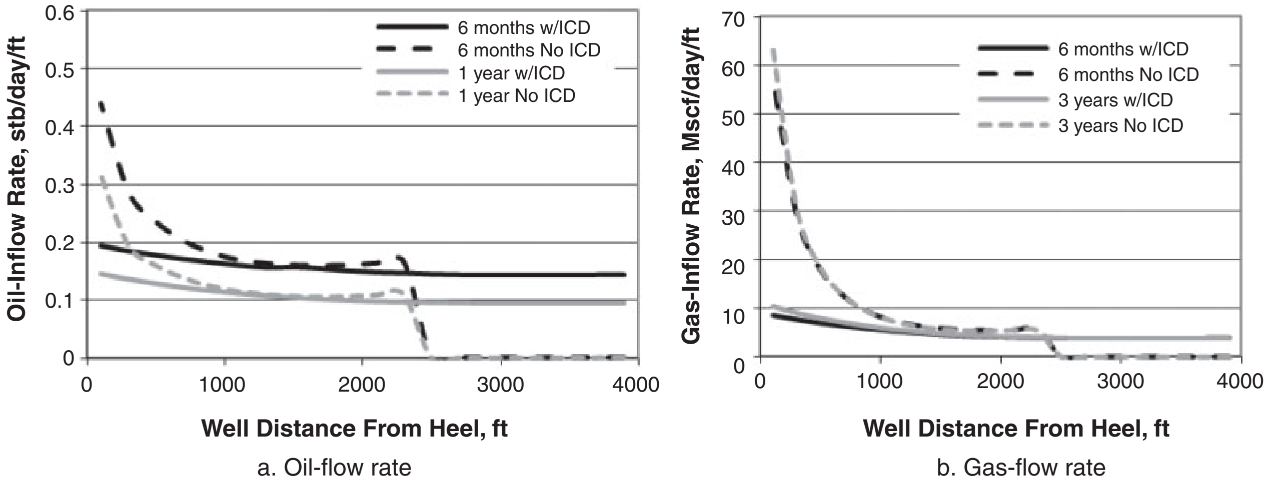


Fig. 10—Flow rate for Case 2a (oil/gas flow at high permeability).

ft from the heel, and the rest of the well is not flowing. The ICDs are designed so that at the heel, Δp_{ICD} is 40 psi. ICDs changed the flow condition, and the local drawdown in this case is now more uniformly distributed along the wellbore. Although the drawdown is significantly reduced, resulting in oil-production reduction, the ICDs also reduce the gas rate dramatically. We can obtain higher oil cumulative production in a reasonable time frame compared with the case without ICDs. **Fig. 12** shows that the cumulative production of oil is higher after approximately 200 days if ICDs are deployed, which balances the production and improves the well performance. But for short time, oil production is higher in the case of no ICDs. An economic analysis is necessary to prove the benefit of ICDs.

For the case of a thin oil zone with a gas gap, we also examined the effect of permeability on the completion design. For Case 2b, we reduced the permeability from 200 to 100 md. To delay gas breakthrough, the drawdown is set to be 15 psi. The flow rates for oil and gas are shown in **Fig. 13.** With a much lower flow rate for both oil and gas, the wellbore pressure drop decreased, and the well is able to produce along the entire length. The pressure drop along the wellbore is shown in **Fig. 14.** The frictional pressure drop along the well is less than 1 psi. Obviously wellbore pressure drop does not play an important role in production. An ICD of 26 psi/(400 B/D) is attempted in this case to choke back the gas inflow toward the heel. This not only reduced gas rate, but also oil rate. **Fig. 15** shows that while gas rate is restricted, oil production also suffered. By the end of 3 years of production, the cumulative oil production is still lower in the case with ICDs than in the case without ICDs.

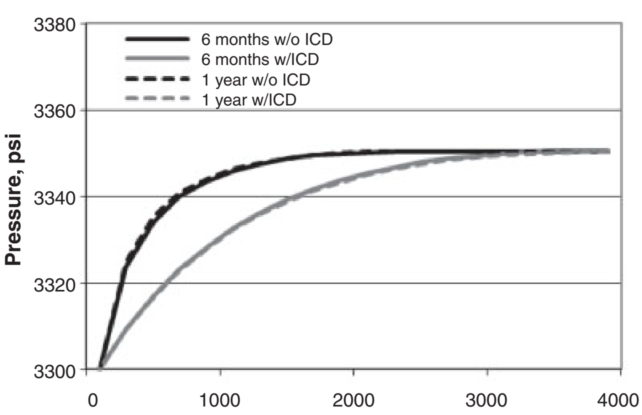


Fig. 11—Flowing pressure distribution along the wellbore for Case 2a.

Heterogeneous Reservoirs. For heterogeneous reservoirs, sometimes ICDs are designed in well completions to control higher inflow at local higher-permeability zones such as channels and natural fractures. One of the production problems in the heterogeneous reservoir is that these high-permeability locations will more than likely start producing water earlier than other locations, and ICDs can choke back the local flow rate. This example illustrates the function of ICDs in a reservoir that has five high-permeability zones along a 5,000-ft horizontal wellbore, as shown in **Fig. 16.** The input data are given in **Table 3.** The reservoir boundaries are surrounded by a strong aquifer. The main concern in such an application is to determine the locations of high-permeability zones before designing and installing the completion. ICDs can function correctly only when installed at the desired locations. One of the reliable methods of locating high-permeability zones is a downhole image log, which can be costly to run. If the distribution of permeability along the wellbore is not identified, sometimes ICDs are evenly designed along the wellbore, and there is a good chance that ICDs will be misplaced. This example shows the oil- and water-flow rate for three different scenarios, the completion without ICDs, with ICDs at the correct location, and with ICDs at a distance away from the high-permeability zones. The operation pressures at the well heel for these cases are the same. Five ICDs are used in this example, each has a length of 20 ft. Three different scenarios were examined, production without ICDs, with ICDs at the high-permeability locations, and with the ICDs installed 180 ft away from the high-permeability zones.

Fig. 17 shows the oil-production-rate history (Fig. 17a) and cumulative oil production (Fig. 17b) for 3 years of production, and **Fig. 18** shows the water history. From Fig. 17 we conclude that with the restriction of ICDs, the oil rate is slightly lower than the rate without ICDs. If the ICDs are misplaced 180 ft away

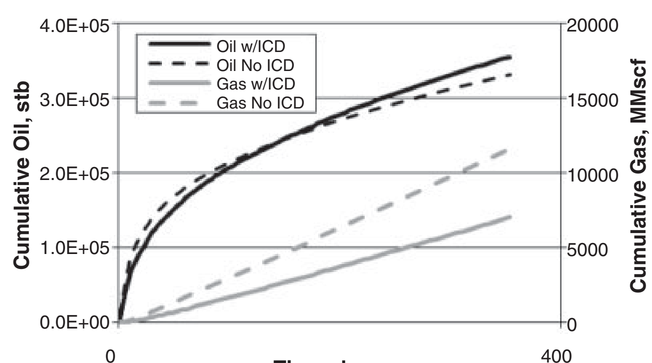
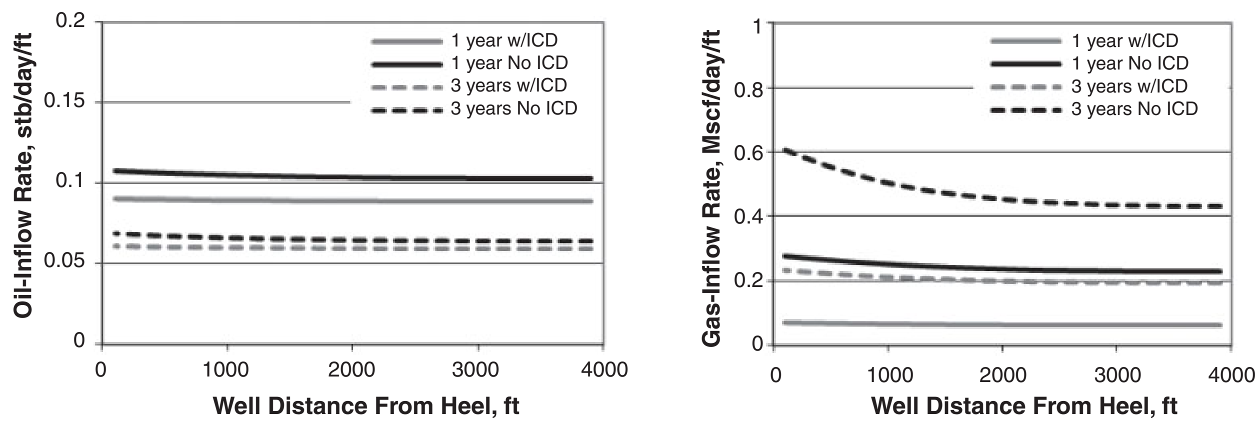


Fig. 12—Cumulative production of oil and gas for Case 2a.



a. Oil-flow rate

b. Gas-flow rate

Fig. 13—Flow-rate distribution for Case 2b (oil/gas at low permeability).

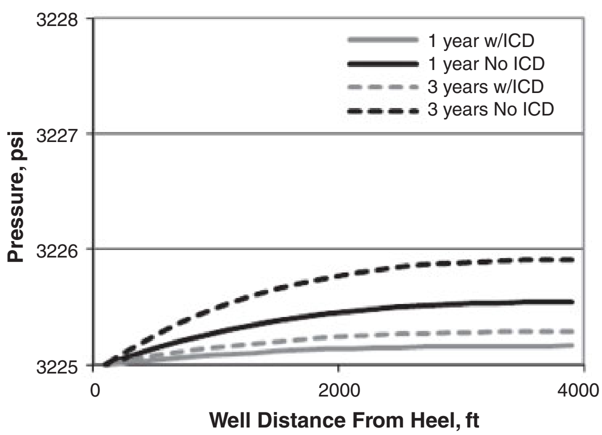


Fig. 14—Well flowing pressure for Case 2b.

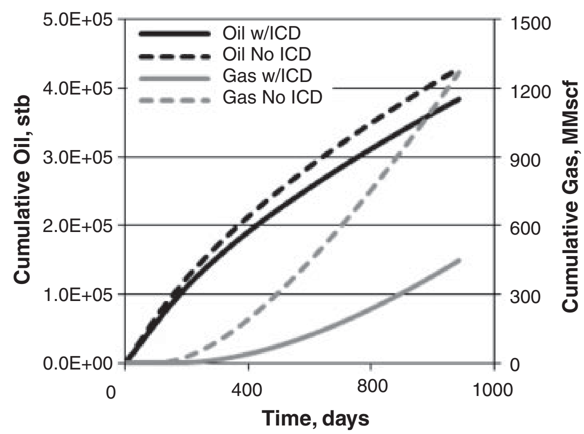


Fig. 15—Cumulative production for Case 2b.

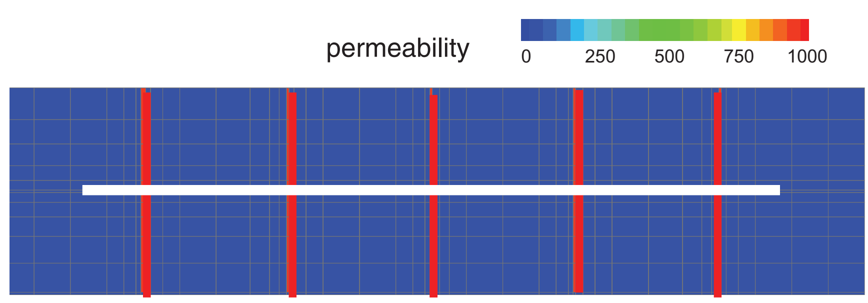
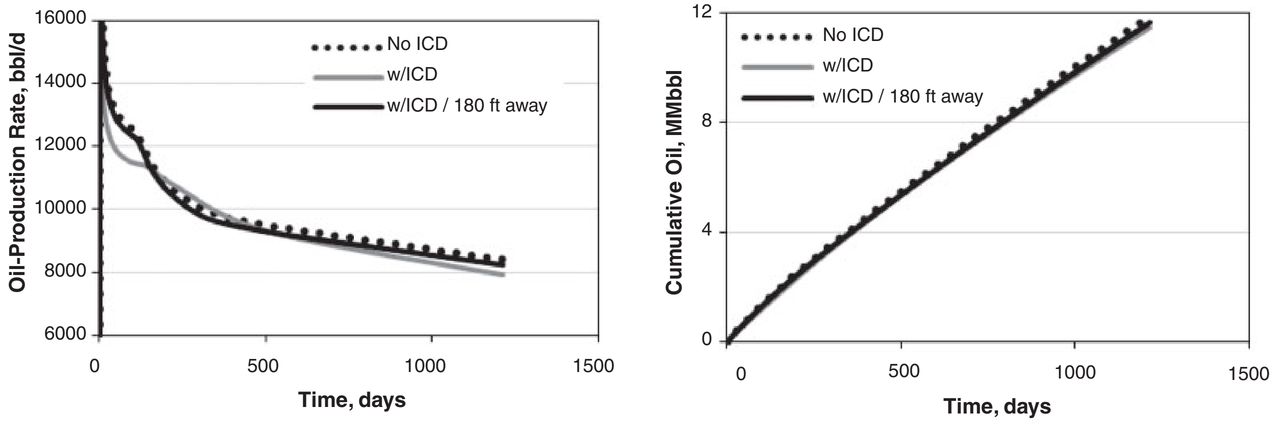


Fig. 16—Schematic of heterogeneous example.

TABLE 3—INPUT DATA FOR HETEROGENEOUS-RESERVOIR CASE

Drainage dimension	ft × ft	6,000 × 2,000
Formation thickness	ft	120
Well length	ft	5,000
Well heel location	ft	500
Well toe location	ft	6,500
Fracture locations	ft	1,000, 2,000, 3,000, 4,000, 5,000
Permeability, $k_x(=k_y=10k_z)$		
Matrix	md	50
High perm (facture)	md	1,000
Number of ICDs		5
Length of ICD section	ft	20
Location of ICDs	Ft	1,000, 2,000, 3,000, 4,000, 5,000



a. Oil unit rate b. Cumulative oil production

Fig. 17—Oil-production for Case 3 (heterogeneous reservoir).

from the high-permeability zones, their effect on production rate is negligible. This is because the restriction of ICDs depends on the flow rate; when installed in a low-permeability zone, the flow rate is low, and restriction is also small. For all three cases, the cumulative oil production shows no significant change. But Fig. 18 shows that correctly placed ICDs can reduce water production successfully, proving the value of ICDs to improve well performance. Notice that if the ICDs are installed 180 ft away from the high-permeability locations, they have no effect on water-breakthrough control at all. Such misplaced ICDs cause an increase in cost and risk, but do not bring any benefit to production.

Keep in mind that reservoir pressure changes as production goes on, and this will change the flow condition in the wellbore. ICDs are designed on the basis of a condition at a certain time. The effect should be studied for the life of the well. It is difficult to retrieve or adjust ICDs once installed, and the impact will always be in the wellbore. Economic evaluation and priority of development are the key components in designing well configurations and completions.

Conclusions

The functions of ICDs in optimizing well-production performance for horizontal oil wells have been studied in this paper. Two reservoir-drive mechanisms are considered in this paper, bottom water drive and gas-cap drive in thin formations. A mathematical approach is developed to predict well performance of horizontal wells. The pressure drop by ICDs is included as a local skin factor. The results of the study lead to the following conclusions:

1. ICDs can be used to improve well performance and increase recovery. Three production problems can be corrected by ICDs—the heel/toe problem, heterogeneous permeability distribution, and thin oil formations.
2. ICDs can function correctly for the heel/toe problem only when the pressure ratio of wellbore fraction to reservoir drawdown is high, and a high-permeability reservoir with long wellbore length can result in this condition. ICDs help to balance the flow condition and enhance the production. If the frictional pressure drop is not significant compared with drawdown, installing ICDs could cause more impact on restricting oil production than on delaying water breakthrough.
3. For a thin oil formation with a gas cap or water aquifer, ICDs can always help to reduce gas/water coning and increase oil production. It is one of the most effective ways to improve well performance.
4. For a heterogeneous formation, using ICDs may help delay water breakthrough. But if permeability distribution is not indentified correctly before completion design and installation, a misplaced ICD has insignificant impact on the well-flow condition with increased completion cost and risk. An ICD is not a universal solution for improving production performance. The application requires a thorough understanding of long-term reservoir behavior and upfront reservoir characterization. Because of the inflexibility of the hardware, ICDs have a limited response to changing downhole conditions. Deployment should be made with caution.
5. The methodology with numerical simulation presented in this paper can help to design well completions with ICDs, and therefore improve well and reservoir performance efficiently.

Nomenclature

f_m = friction coefficient, dimensionless
g = gravity constant, L/sec^2
K = ratio of wellbore pressure drop/drawdown pressure, dimensionless

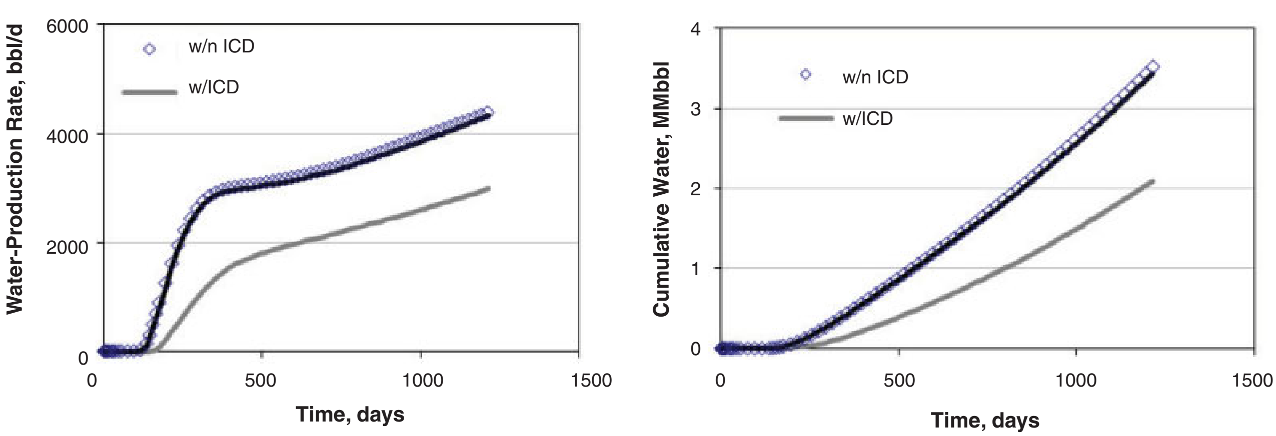


Fig. 18—Water-production rate along the well for Case 3.

p = wellbore pressure in horizontal segments, psi
q = total inflow rate, B/D
r_{grid} = grid effective radius, ft
r_w = wellbore radius, ft
R = tubing radius, in.
s_{ICD} = homeostatic skin factor for ICD
v_m = fluid mixture velocity, ft/sec
v_{so} = oil superficial velocity, ft/sec
v_{sw} = water superficial velocity, ft/sec
x = distance, ft
y_d = holdup of discontinues phase, dimensionless
Δp_{ICD} = pressure drop caused by ICD, psi
Δp_r = drawdown pressure, psi
θ = wellbore-deviation angle, degrees
μ_c = viscosity of continuous phase, cp
μ_m = fluid mixture viscosity, cp
ρ_m = fluid mixture density, lbm/ft^3
ρ_o = oil density, lbm/ft^3
ρ_w = water density, lbm/ft^3

References

Aadnoy, B.S. and Hareland, G. 2009. Analysis of Inflow Control Devices. Paper SPE 122824 presented at the Offshore Europe, Aberdeen, 8–11 September. http://dx.doi.org/10.2118/122824-MS.

Alkhelaiwi, F.T. and Davies, D.R. 2007. Inflow Control Devices: Application and Value Quantification of a Developing Technology. Paper SPE 108700 presented at the International Oil Conference Exhibition in Mexico, Veracruz, Mexico, 27–30 June. http://dx.doi.org/10.2118/108700-MS.

Arfi, S.A.A., Keshka, A.A.-S., Salem, S.E.-A., et al. 2008. Inflow Control Device an Innovative Completion Solution from "Extended Wellbore to Extended Well Life Cycle". Paper IPTC 12486 presented at the International Petroleum Technology Conference, Kuala Lumpur, 3–5 December. http://dx.doi.org/10.2523/12486-MS.

Babu, D.K. and Odeh, A.S. 1988. Productivity of a Horizontal Well Appendices A and B. Paper SPE 18334 presented at the SPE Annual Technical Conference and Exhibition, Houston, 2–5 October. http://dx.doi.org/10.2118/18334-MS.

Birchenko, V.M., Al-Khelaiwi, F.T., Konopczynski, M.R., and Davies, D.R. 2008. Advanced Wells: How To Make a Choice Between Passive and Active Inflow-Control Completions. Paper SPE 115742 presented at the SPE Annual Technical Conference and Exhibition, Denver, 21–24 September. http://dx.doi.org/10.2118/115742-MS.

Coronado, M.P., Garcia, L., Russell, R., Garcia, G.A., and Peterson, E.R. 2009. New Inflow Control Device Reduces Fluid Viscosity Sensitivity and Maintains Erosion Resistance. Paper OTC 19811 presented at the Offshore Technology Conference, Houston, 4–7 May. http://dx.doi.org/10.4043/19811-MS.

Crow, S.L., Coronado, M.P., and Mody, R.K. 2006. Means for Passive Inflow Control Upon Gas Breakthrough. Paper SPE 102208 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 24–27 September. http://dx.doi.org/10.2118/102208-MS.

Henriksen, K.H., Gule, E.I. , and Augustine, J. 2006. Case Study: The Application of Inflow Control Devices in the Troll Oil Field. Paper SPE 100308 presented at the SPE Europec/EAGE Annual Conference and Exhibition, Vienna, Austria, 12–15 June. http://dx.doi.org/10.2118/100308-MS.

Hill, A.D. and Zhu, D. 2008. The Relative Importance of Wellbore Pressure Drop and Formation Damage in Horizontal Wells. *SPE Prod & Oper* **23** (2): 232–240. SPE-100207-PA. http://dx.doi.org/10.2118/100207-PA.

Jayawardena, S.S. 2005. New Model for Dispersed Multi-Layer Oil-Water Flow. Presented at the Engineering Technology Conference on Energy (IETC 2005), Houston, 5–7 February.

Krinis, D., Dawood, N.J., and Soremi, A. 2008. Horizontal Well Performance Optimization using Linearized Inflow Control Device. Paper SPE 117213 presented at the Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 3–6 November. http://dx.doi.org/10.2118/117213-MS.

Leemhuis, A.P., Nennie, E.D., Belfroid, S.P.C., Alberts, G.J.N., Peters, E., and Joosten, G.J.P. 2008. Gas Coning Control for Smart Wells Using a Dynamic Coupled Well-Reservoir Simulator. Paper SPE 112234 presented at the Intelligent Energy Conference and Exhibition, Amsterdam, 25–27 February. http://dx.doi.org/10.2118/112234-MS.

Ouyang, L.-B. 2009. Practical Consideration of an Inflow-Control Device Application for Reducing Water Production. Paper SPE 124154 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, 4–7 October. http://dx.doi.org/10.2118/124154-MS.

Rahimah, A.K., GordonGoh, K.F., Azrul, N.M., Asyikin, A.N., Leung, E., and Johan, A.M. 2010. Horizontal Well Optimization With Inflow Control Devices (ICDs) Application in Heterogeneous and Dipping Gas-Capped Oil Reservoirs. Paper SPE 133336 presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, 19–22 September. http://dx.doi.org/10.2118/133336-MS.

Yoshioka, K., Zhu, D., Hill, A.D., Dawkrajai, P. , and Lake, L.W. 2006. Detection of Water or Gas Entries in Horizontal Wells From Temperature Profiles. Paper SPE 100209 presented at the SPE Europec/EAGE Annual Conference and Exhibition, Vienna, Austria, 12–15 June. http://dx.doi.org/10.2118/100209-MS.

Zhuoyi Li is a software engineer at Schlumberger. His research interests include reservoir flow simulation and production logging interpretation. He holds an MS degree from Tsinghua University and a PhD degree from Texas A&M University. **Ding Zhu** is an associate professor in the Petroleum Engineering Department at Texas A&M University. Her research areas are production engineering, well stimulation, and complex well performance. She holds MS and PhD degrees in petroleum engineering, both from the University of Texas at Austin. Zhu is the author of more than 100 technical papers and a coauthor of the book *Multilateral Wells*. She has been a committee member and chairperson for many conferences and events with Society of Petroleum Engineers and is currently a technical editor for *SPE Production and Operations Journal*.