Maximizing reserves recovery using horizontal wells requires management of fluid flow through the reservoir. One increasingly popular approach is to use inflow control devices that slow water and gas encroachment and reduce the amount of bypassed reserves.

Heel-toe effect. Pressure losses along a horizontal wellbore in a homogeneous formation cause the flowing tubing pressure to be lower at the well’s heel than at the toe. In time, and long before oil (green) from sections near the toe arrives at the wellbore, water (blue) or gas (red) is drawn to the heel (top), resulting in an early end to the well’s productive life. Inflow control devices inside sand screen assemblies equalize the pressure drop along the entire length of the wellbore, promoting uniform flow of oil and gas through the formation (bottom) so that the arrivals of water and gas are delayed and simultaneous.
Extended-reach and multilateral horizontal drilling techniques significantly increase wellbore/reservoir contact. This augmented contact allows operators to use less drawdown pressure to achieve production rates equal to those of conventional vertical or deviated wells. The ability to optimize results from these standard configurations through better reservoir fluids management has been greatly enhanced by the development of remotely operated inflow control valves and chokes. These devices enable engineers to adjust flow from individual zones that are over- or underpressured or from those producing water or gas that may be detrimental to overall well productivity.

Long sections drilled horizontally through a single reservoir, however, present a different set of challenges. In homogeneous formations, significant pressure drops occur within the openhole interval as fluids flow from TD toward the heel of the well. The result may be significantly higher drawdown pressures at the heel than at the toe. Known as the heel-toe effect, this differential causes unequal inflow along the well path and leads to water or gas coning at the heel (previous page). A possible consequence of this condition is an early end to the well’s productive life and substantial reserves left unrecovered in the lower section of the well.

Water or gas breakthrough anywhere along the length of the wellbore can also result from reservoir heterogeneity or from differences in distances between the wellbore and fluid contacts. Pressure variations within the reservoir caused by reservoir compartmentalization or by interference from production- and injection-well flow can also lead to early breakthrough.\(^1\) Carbonate reservoirs, because they tend to have a high degree of fracturing and permeability variation, are especially vulnerable to uneven inflow profiles and accelerated water and gas breakthroughs.\(^2\)

Many completions designed for long-reach wells include sand control systems. If these completions do not have isolation devices such as packers, annular flow can lead to severe erosion and plugging of sand screens. In the past such annular flow effects were countered with gravel packs or expandable sand screens. But gravel packs often reduce near-wellbore productivity. Expandable sand screens require complex installation procedures and are prone to collapse later in the well’s life.

In traditional completions the solution to an increase in water or gas cut is to reduce the choke setting at the wellhead. This lowers drawdown pressure, resulting in lower production rates but higher cumulative oil recovery. However, this simple solution generally does not work in wells drilled at high angles.

In wells completed with “intelligent” technology, operators may shut off or reduce flow from offending zones using remotely actuated downhole valves. But horizontal wells designed to optimize reservoir exposure are often poor candidates for such strategies. Extremely long wells often have many zones. The limit on the number of wellhead penetrations available may render it impossible to deploy enough downhole control valves to be effective.\(^1\) Additionally, such completions are expensive, complex and fraught with risk when installed in long, high-angle sections.

As a consequence, operators often choose to produce these multiple-zone wells using isolating devices such as swellable packers. To mitigate crossflow and to promote uniform flow through the reservoir, they have turned to passive inflow control devices (ICDs) in combination with swellable packers. By restraining, or normalizing, flow through high-rate sections, ICDs create higher drawdown pressures and thus higher flow rates along the borehole sections that are more resistant to flow. This corrects uneven flow caused by the heel-toe effect and heterogeneous permeability.

Whether intended for injection or production, ICDs have applications in horizontal and deviated wells and in several types of reservoirs.\(^4\) These devices are usually part of openhole completions that also include sand screens. In addition, ICD completions often use packers to segment the wellbore at points of large permeability contrast. This strategy combats water coning or gas creasing through fractured zones, halts annular flow between compartments and allows for isolation of potential wet zones.

ICDs are also effective in reservoirs where their ability to regulate inflow rates creates a sufficient pressure drop at the toe of the wellbore for the reservoir fluid to flow or lift filtercake and other solids to the surface. This article describes various ICD designs and how they are modeled to suit particular applications. Case histories from Asia, the North Sea and the Middle East illustrate how these passive devices enable operators to increase well life and ultimate recovery.

**Velocity Control**

Inflow control devices are included in the hardware placed at the formation/borehole interface. They use a variety of flow-through configurations including nozzles, tubes and labyrinth helical channels (above). These devices are intended to balance the well’s inflow profile and minimize annular flow at the cost of a limited, additional
All ICDs are permanent well components and are rated by their flow resistance. Essentially, the rating signifies the total amount of pressure drop created across the device with a reference fluid property and flow rate. Nozzle- and orifice-type devices enjoy an advantage over channel ICDs: The nozzle size and therefore the ICD rating can be adjusted easily at the wellsite, before deployment, in response to real-time drilling information. The designs of ICDs are typically based on predrilling reservoir models, and changing the rating of channel- or tube-type ICDs is more difficult, time-consuming and not easily done on location.

### Modeling: Static and Dynamic

Historically, nozzle-type ICDs have been designed using a ratio of the pressure drop at the device inlet as calculated by Bernoulli’s equation to the average formation drawdown pressure derived from Darcy’s equation. When this ratio is close to unity, the ICDs are self-regulating.

The designs based on these assumptions are simple and effective in horizontal wells with relatively high productivity indexes (PIs) and minimal flow restrictions. The same number and size of ICD nozzles are assigned to each joint of tubing from toe to heel. This approach usually improves flow uniformity through the reservoir, counters much of the heel-toe effect and balances flow from heterogeneous zones.

But these goals may be achieved at the cost of overly restricting the flow from high-permeability, high-rate oil zones. Additionally, this method eliminates flexibility for zonal control and does not include the effects of variation in zonal porosity thickness, saturation and oil/water contacts.

For more-precise designs, engineers can turn to modeling using tools such as the Schlumberger ICD Advisor software. Using steady-state systems, the experts model wellbore hydraulics to determine tubing and annulus flow, flow direction and completion-specific flow correlations. Reservoir flow is determined through PI models.

Incorporating data from offset wells, LWD tools, geology and other sources, engineers optimize well designs by determining near-wellbore performance at a specific time. They test various scenarios and completion designs to balance flow, decrease water cut, control gas/oil ratios and, by varying the number of isolation packers per well section, verify the effects of annular compartmentalization (next page, top right). In doing so, they are determining the impact of packer density on production in the presence of ICDs. Finally, they determine the number and sizes of nozzles to be deployed in each compartment.
The advantages of this steady-state modeling are quick designs, high-resolution near-wellbore models and quantification of the upside potential of oil production with decreased water and gas cut. However, this approach delivers only a snapshot in time and cannot predict or quantify the value of delaying water or gas breakthrough. This step requires the investment of considerably more time and effort to perform dynamic simulations, such as using the Petrel software reservoir engineering workflow in conjunction with the Multi-Segmented Well (MSW) model of the ECLIPSE reservoir simulator.

This model treats the well as a series of segments and allows engineers to model independently three-phase flow, liquid-gas holdup and the implications of using ICDs and flow control valves over the life of the well. Each modeled segment can be angled upward or downward and can contain different fluids to account for an undulating well path.

Ideally, dynamic modeling is accomplished using a full-field geologic model. But often this is not practical, even with high-performance, parallel computing hardware, because of the long computational simulation necessary to complete the runs. A more practical solution begins by extracting a sector model from the ECLIPSE full-field simulation model that can extract flux, pressure or no-flux boundary conditions to reduce dynamic simulation time while honoring the geologic heterogeneity and interference from nearby wells.

Reducing the number of geology grid cells offers more-sensitive runs. Furthermore, the sector model can be combined with the full-field model. The area of interest is then modified to refine the grid and upscale from the geologic model, and the well trajectory is loaded. The segmented well with ICDs and packers is then created in the ECLIPSE simulation.

The Sweet Spot
The advantage gained by the ability to quickly incorporate new data into completions was demonstrated in a field offshore Malaysia. Having opted, for economic reasons, to drill two long horizontal wellbores into a target characterized by a thin oil rim with a gas cap and active aquifer, the operator included ResFlow ICDs in the completion design. Because they are nozzle-type devices, it is easy to adjust and optimize them on location in response to new LWD data without costing valuable rig time.

The wells were part of a second-stage development of a mature field; challenges included a stacked sand reservoir with uncertain dips and unconsolidated sands. The company also sought to avoid formation damage during drilling, minimize drilling costs, and maximize production and drainage of remaining reserves while minimizing water cut.

While the horizontal well option was less costly than an alternative plan that included drilling three deviated wells, it was technically more challenging. It required one 2,000-ft [610-m] lateral and one 1,000-ft [305-m] lateral to be placed precisely with respect to fluid contacts and reservoir boundaries (below). This option also required openhole sand screens and passive ICDs to enable production contribution from the entire length of the wellbore.

Rotary steerable systems were used to drill the wells as far from the water contact as possible to delay water production and as close to the overlying shale boundary as possible to capture attic oil. An LWD assembly that included a deep azimuthal resistivity distance-to-boundary tool—

![Well placement. As part of an ongoing field expansion, this small area within a field offshore Malaysia was targeted for development using one 2,000-ft lateral (A) and one 1,000-ft lateral (B). The thin oil rim (green) is bounded by a strong waterdrive (blue) and a gas cap (red). Depth contours are labeled in feet. (Adapted from Maggs et al, reference 7.)](image_url)

<table>
<thead>
<tr>
<th>Oil Rate, bbl/d</th>
<th>Gas Rate, Mcf/d</th>
<th>Water Rate, bbl/d</th>
<th>Water Cut, %</th>
<th>BHP, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open hole</td>
<td>7,759</td>
<td>698</td>
<td>2,411</td>
<td>23.7</td>
</tr>
<tr>
<td>3 x 4 mm, second joint</td>
<td>8,821</td>
<td>798</td>
<td>1,263</td>
<td>12.5</td>
</tr>
<tr>
<td>3 x 4 mm, joint</td>
<td>9,290</td>
<td>837</td>
<td>762</td>
<td>7.6</td>
</tr>
</tbody>
</table>

^Packer density impact. By isolating compartments within heterogeneous formations, it is possible to reduce water cut and sand production considerably while maintaining or, as in this case, increasing oil production. Reservoir engineers first test the model for optimum packer density before determining the number and sizes of ICDs needed for the completion. In this example, installing three 4-mm-diameter nozzles per joint reduced water cut to 7.6% compared with 23.7% in an openhole completion. At the same time production increased from 7,760 to 9,290 bbl/d [1,233 to 1,476 m³/d] without a significant increase in bottomhole pressure (BHP). When the same nozzle configuration was used on every second joint, water cut was reduced to 12.5%.

![Diagram of Well Placement](image_url)
the PeriScope bed boundary mapper—was used to steer a smooth wellbore trajectory.

The longer lateral came online without the assistance of gas lift at 2,300 bbl/d [366 m³/d] of oil and a water cut of about 10%. This level of water production was expected from mobile water in the oil rim and is not associated with breakthrough from the water leg. The second well, drilled updip from the first, required gas lift to clean up and initially produced about 1,900 bbl/d [302 m³/d] with 20% water cut.

Production from both wells compared favorably with that from other deviated wells in the area drilled conventionally through the stacked sands of the field. However, even including costs of the additional technology—rotary steering system, LWD and ResFlow ICDs—the overall project cost was 15% less than it would have been using traditional well construction methods. In addition, increased sweep efficiency gained by well placement and ICDs has increased the asset value by an estimated 100,000 bbl [16,000 m³] of oil.

Critical Components

Besides their ability to enhance drainage efficiency and boost cumulative oil recovery, ICDs offer the industry relatively inexpensive, low-risk components for technology-driven strategies. They can be easily added to development programs that include sand control and horizontal wells.

In the Norwegian sector of the North Sea, engineers at Marathon Petroleum Company (Norway) LLC concluded that the recoverable reserves in the relatively thin oil columns of the Alvheim and Volund fields were directly and consistently linked to the amount of net pay exposed to the wellbore (left). To establish maximum contact, Marathon therefore drilled single-, dual- and trilateral wells with horizontal sections ranging in length from 1,082 to 2,332 m [3,550 to 7,651 ft].

The Marathon team realized that to fully exploit the benefits of the correlation of recoverable reserves to net feet of reservoir contact, it was important that the entire length of the completions contribute to production. Early in the project they decided to use both ResFlow nozzle-type ICDs and helical-type ICDs in all production wells—a total of 10 wells at Alvheim and 1 at Volund.

As a result of this technology-based approach and the favorable geology, Marathon has increased its booked reserves at Alvheim from 147 million to 201 million bbl [23 million to 32 million m³] of oil and from 196 to 269 Bcf [5.5 billion to 7.6 billion m³] of gas.

The fields have been in production less than two years, and the completions include numerous technologies, making it difficult to attribute specific results to a single methodology. However, overall water production at the Alvheim floating, production, storage and offloading (FPSO) facility is less than originally expected. A good example is the 24/6-B-1CH well, which has a 13-m [43-ft] oil column and an active aquifer. The well has been produced at higher rates than originally planned without significant onset of, or increase in, water production (left). Both these outcomes, though their causes are inconclusive, suggest ICD success in maintaining an even flow profile.

When one completion planned as a single lateral evolved to a trilateral, engineers also learned a valuable lesson concerning planning for the use of ICDs and multilateral installations. Because the actual completion departed from the original plan, the flow rate was different than predicted. The ICDs chosen for these installations were of a design type that could not be readily changed, and thus optimized, on location. The result was gas and water coning earlier than expected in both laterals.
Recently, a different operator expanded on the application of ICD completions, not to counter the effects of uneven inflow profiles but to counter uneven pressure profiles. In one horizontal well extending more than 5,200 ft [1,600 m] through a high-permeability reservoir in a large Middle East field, the pressure differential between heel and toe was 200 psi [1.4 MPa] with the higher pressure at the heel.6

An initial production log confirmed what was expected given the pressure profile: A downward crossflow of fluids from heel to toe was detected during a shut-in logging pass. In addition, production logging measurements acquired while the well was flowing showed water moving downward from the heel and oil flowing to the surface. Logs also indicated production was coming from only the first 10% of the lateral.7

Based on the results of static modeling, the operator recompleted the well with 22 ResFlow ICDs and, to segment the well, seven swellable packers on the production string. Logs acquired after recompletion indicated that crossflow had been eliminated and production was coming from the entire lateral. Water cut was reduced from 30% to less than 10%, and the actual inflow profile matched that predicted by the static ICD model (above right).8

### A Clean Start

Predictably, it has been observed that the difference in pressure drops between the heel and toe caused by friction losses in an openhole horizontal well increases with wellbore length. This disparity can lead to the filtercake being preferentially lifted from the wellbore wall at the heel and to poor inflow performance caused by correspondingly higher skin at the toe.

Studies have shown that in relatively high-permeability environments, the best cleanup results—removal of filtercake after drilling or completion—are obtained through proper chemical treatment and extended flowback with high rates.1 In 2006 Saudi Aramco completed two test wells equipped with ICD systems, one in a sandstone formation and the other in carbonate rock. In the sandstone there were concerns over water and gas coning through high-permeability streaks, and the operator sought to decrease the impact of the heel-toe effect to improve cleanup and sweep efficiency. The 5½-in. openhole completion included 5½-in. screens with ResFlow ICD nozzles on every joint of tubing. For compartmentalization and better inflow control, small, swellable elastomer packers were placed on every second joint. The horizontal section was 2,540 ft [775 m] long.

The well was produced at 6,000 to 7,000 bbl/d [953 to 1,113 m³/d] for 4 months. A production log was then acquired. The log data, as well as the inability to get the tool within 650 ft [198 m] of TD because of solids-laden mud filling the toe of the wellbore, indicated the well had not cleaned up despite the prolonged flow period.

The flow rate was then increased to 9,000 to 10,000 bbl/d [1,430 to 1,590 m³/d] for 4 h and the well was logged again. The new data indicated an improved flow profile and the tool was able to travel an additional 350 ft [106 m]. Four hours later, the logging tool was run again, this time to within 50 ft [15 m] of TD (below). The rate was reduced to the original 6,000 to 7,000 bbl/d and data from the final logging run indicated a permanent change had been made to the inflow profile.

![Inflow profile from production log measurements. After installation of ICDs and swellable packers, production logging tools were run to acquire an inflow profile along the length of the well at low, medium and high flow rates. The inflow profile shown was obtained with the well flowing at the medium rate. Crossflow evident in earlier logs has been eliminated and flow contribution is evident from the entire lateral. The actual inflow profile (green) was very close to the simulated one (red). (Adapted from Krinis et al, reference 8.)](image)

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Winter 2009/2010
Table 1. Comparison of different scenarios for Zone 1, Zone 2, and Zone 3 with varying characteristics.

<table>
<thead>
<tr>
<th>Zone 1</th>
<th>Standard Screen</th>
<th>ICD with Same Nozzle Size, 1.2 cm/joint in All Zones</th>
<th>ICD with Different Configuration</th>
<th>Target Rate, m³/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>800 to 1,800 mD</td>
<td>5,800</td>
<td>4,604</td>
<td>3,570</td>
<td>3,500</td>
</tr>
<tr>
<td>Zone 2</td>
<td>748</td>
<td>1,233</td>
<td>820</td>
<td>800</td>
</tr>
<tr>
<td>200 to 500 mD</td>
<td></td>
<td></td>
<td>0.7 cm/joint</td>
<td></td>
</tr>
<tr>
<td>Zone 3</td>
<td>961</td>
<td>1,677</td>
<td>3,128</td>
<td>3,200</td>
</tr>
<tr>
<td>100 to 2,000 mD</td>
<td></td>
<td></td>
<td>2.2 cm/joint</td>
<td></td>
</tr>
<tr>
<td>Total injection rate, m³/d</td>
<td>7,509</td>
<td>7,514</td>
<td>7,518</td>
<td>7,500</td>
</tr>
</tbody>
</table>

Engineers suspected that the higher rates required to clean up the entire production interval had exacerbated the heel-toe effect in the traditional openhole completions. Modelers matched the production log data to a static reservoir simulation and replaced the ICD completion in the simulation with a standard screen completion. They then increased the rate in the standard screen completion to 15,000 bbl/d [2,400 m³/d].

That simulation indicated an extreme heel-toe effect: The toe was contributing only 25% as much production as the heel. By contrast, simulations with ICD completions with 15,000-bbl/d rates showed better balance of the inflow, including the balancing effect or cleanup efficiency at the wellbore. Just as they do with inflow control, ICDs address these challenges by balancing fluid outflow along the entire length of the injection wellbore. If the well has a high-permeability streak, the ICD self-regulating feature prevents a significant increase of local injection rate. This ability to automatically control fluid mobility results in better water distribution and pressure support and thus enhanced areal and vertical sweep of oil reserves in all zones. It also delays water breakthrough, and because ICDs can control injection pressure and rate, there is minimal risk of near-wellbore fracturing. These capabilities matched the management goals of the Statofel team planning the 2004 development of the Urd field—a satellite producing to the Norne FPSO vessel in the North Sea. Placed in production in 2005, the Urd oil field contains two heterogeneous structures: Sval and Stær, which are 4 and 9 km [2.5 and 5.6 mi], respectively, from the main field. The field was developed using three subsea templates and pipelines for oil production, water injection and gas lift. Management goals for the ICD injection system included

- optimizing injection projects must consider permeability contrasts, heel-toe effect, formation damage, creation of thief zones and injectivity changes at the wellbore.
- Just as they do with inflow control, ICDs redress these challenges by balancing fluid outflow along the entire length of the injection wellbore. If the well has a high-permeability streak, the ICD self-regulating feature prevents a significant increase of local injection rate. This ability to automatically control fluid mobility results in better water distribution and pressure support and thus enhanced areal and vertical sweep of oil reserves in all zones. It also delays water breakthrough, and because ICDs can control injection pressure and rate, there is minimal risk of near-wellbore fracturing.

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- optimizing injection pressure support and sweep efficiency for all zones
- delaying water breakthrough in high-permeability connected zones
- avoiding fractures that may dominate water distribution.

The Stør structure was completed with one injector containing ICDs and two horizontal oil producers containing intelligent technology for control of three zones. The reservoir is divided into two segments; the injector and producer are located in Segment 1 and the second oil producer in Segment 2.

The injector is a vertical well drilled through the Not, Ile, Tlj and Åre 2 Formations and provides sweep and pressure support for two horizontal producers. About 250 m [820 ft] deep, the injection well is an openhole completion with ResiInject injection control devices, sand screens and a pack of resin-coated gravel to prevent annular flow.

Engineers from Reslink and Statofel designed the system. They modeled injection rates expected for three zones using different completion techniques: standard screens alone, ICDs of the same nozzle size and number of nozzles per joint, and different numbers of ICDs per joint (left). The team chose to use the same nozzle configuration along the entire wellbore instead of specific ICD nozzle sizes and numbers for each zone. This choice reflected the fact that while different designs in each zone achieved target injection rates, simulations supported maximum injection rates in the upper zones.

These simulations were run to evaluate the economics of using ICD injectors on Stør and to select the nozzle design. Two static near-wellbore simulations were used to compare water distribution: The first was based on injection into the matrix, including its permeability variations, and the second considered injection into a fractured zone.

In the first case, the upper, high-permeability zone received an uneven share of the injected water. However, with ICDs, peak outflow was reduced by 50% and zones with lower permeability received more water. For the second static model, a 12-m [39-ft], 20-D layer was added to

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17. Fram and Sims, reference 16.
simulate a fracture. When ICDs were included in the model, the fracture experienced a water-injection rate increase of only about 10%; there was a 10-fold jump when only a standard screen was used in the same model.

A third evaluation used a full-field reservoir model to estimate the effect of the improved water distribution. This evaluation included an injection well equipped with ICDs in scenarios similar to those analyzed by the near-wellbore simulator in the first two cases.

The simulations concluded that given a high-permeability channel, the use of ICDs increased cumulative oil production by 10% over that achieved with use of a standard screen alone. They also showed that with no high-permeability zone present the ICDs would improve cumulative oil production by 1% and that the most likely case was somewhere between the two (right).

In 2008, based on the success of this water-injection project, Statoil installed another injection well equipped with ResInject ICDs in the Svala structure. The well has performed according to objectives.

**Control of the Future**

The success of ICDs is now drawing the attention of producers concerned with inefficient flow from long laterals. Among these are heavy oil producers. For more than 15 years, steam-assisted gravity drainage (SAGD) has been the process of choice for development of fields producing heavy oil. Despite this history, the process is not well understood. It may be that the current steam distribution in horizontal injection wells designed to heat and drive oil to deeper production wells is less than optimal, particularly in heterogeneous reservoirs.

Besides the common difficulties associated with creating uniform flow through any reservoir, two-phase water systems (liquid and vapor) used in SAGD wells add to the difficulty of control. In addition to single-phase-flow concerns relating to fluid-velocity profiles and pressure drops associated with piping configurations, many other factors including flow-regime effects, water holdup, phase splitting, droplet size, slugging and other variables are introduced in two-phase flow.

Typically, SAGD injection liners are slotted along the entire section—a configuration that does little to optimize steam distribution. To fight the heel-toe effect, many operators today use dual steam conduits in horizontal steam injectors—one landed near the heel of the well and a second near the toe.

In an effort to better understand SAGD production and find more efficient solutions to its challenges, Chevron has constructed a surface horizontal steam-injection facility at its Kern River field near Bakersfield, California, USA. Researchers there are focusing on evaluation and deployment of equipment for accurate and reliable steam placement along laterals in horizontal injection wells to improve recovery.

Their proliferation in recent years is testimony to the effectiveness of ICDs. Use of ICDs has allowed operators to realize full value from the ability to drill long laterals, thereby exposing large volumes of the reservoir to the wellbore. In fact it can be argued that inefficient drainage owing to uneven flow through the reservoir threatened to impose economic limits on wellbore length that were far short of the technical limits. Today's lengths are measured in kilometers rather than in meters, as they were less than a decade ago. —RvF