Water Control

Today, oil companies produce an average of three barrels of water for each barrel of oil from their depleting reservoirs. Every year more than $40 billion is spent dealing with unwanted water. In many cases, innovative water-control technology can lead to significant cost reduction and improved oil production.

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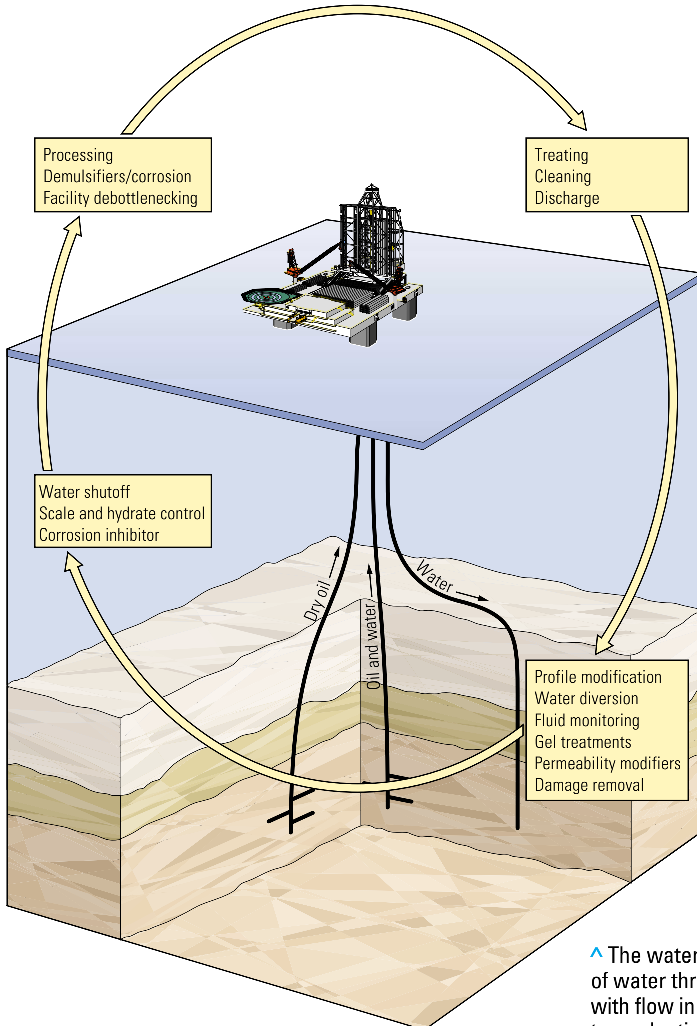
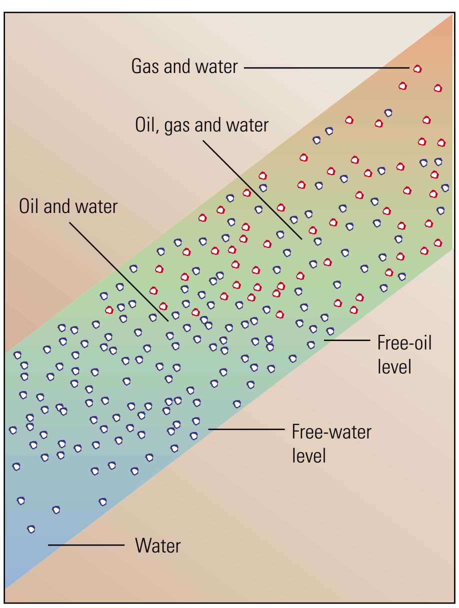
Given the worldwide daily water production of roughly 210 million barrels [33.4 million m^3] of water accompanying every 75 million barrels [11.9 million m^3] of oil, many oil companies could almost be called water companies. Water-handling costs are high—estimates range from 5 to more than 50 cents per barrel of water. In a well producing oil with an 80% water cut, the cost of handling water can be as high as \$4 per barrel of oil produced. In some parts of the North Sea, water production is increasing as fast as reservoir oil rates are declining.

Water affects every stage of oilfield life from exploration—the oil-water contact is a crucial factor for determining oil-in-place—through development, production, and finally to abandonment (below). As oil is produced from a reservoir, water from an underlying aquifer or from injectors eventually will be mixed and produced along with the oil. This movement of water flowing through a reservoir, into production tubing and surface-processing facilities, and eventually extracted for disposal or injected for maintaining reservoir pressure, is called the 'water cycle' (above).



^ The water cycle. The transport of water through the field starts with flow in the reservoir leading to production, and then surface processing. Finally, the water is disposed of at the surface or injected for disposal or pressure maintenance.

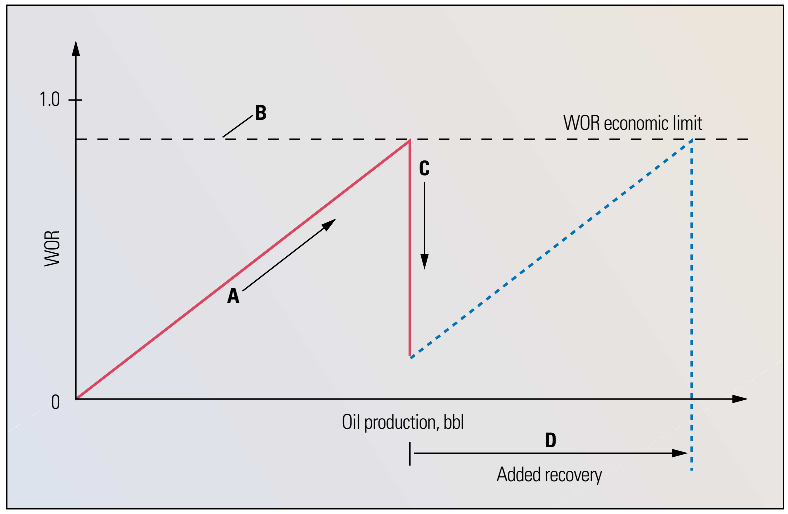


Reservoir containing water, oil and gas. The figure shows the fluid distribution in a typical reservoir before production or injection begins. Above the free-oil level, water saturation will be at its irreducible value. The transition zone between the free-oil and free-water levels is characterized by a gradual increase in water saturation to 100%. In this zone, both oil and water are partially mobile. The thickness of the transition zone depends on factors such as pore size, capillary pressure and wettability. There is a transition zone between the hydrocarbon and water layers where water and oil saturation vary. In general, low-permeability rocks will have thicker transition zones.

Oil producers are looking for economic ways to improve production efficiency, and water-control services are proving to be one of the fastest and least costly routes to reduce operating costs and improve hydrocarbon production simultaneously. The economics of water production throughout the water cycle depend on a number of factors such as total flow rate, production rates, fluid properties like oil gravity and water salinity, and finally the ultimate disposal method for the water produced. Operational expenses, including lifting, separation, filtering, pumping and reinjection, add to the overall costs (below). In addition, water-disposal costs can vary enormously. Reports vary from 10 cents per barrel when the unwanted water is released into the ocean offshore to over $1.50 per barrel when hauled away by trucks on land. Although the potential savings from water control alone are significant, the greatest value comes from the potential increase in oil production and recovery.

Managing the cycle of water production, separation downhole or at the surface, and disposal involves a wide range of oilfield services. These include data acquisition and diagnostics using downhole sensors; production logging and water analysis for detecting water problems; reservoir modeling to characterize flow; and various technologies to eliminate water problems such as downhole separation and injection, chemical and mechanical shutoff, and surface water separation and production facilities.

In this article, we focus on the detection and control of excess water production. First, we review the many ways in which water can enter the wellbore. Then, we describe measurements and analysis to identify these problem types. Finally, we examine treatments and solutions. Case studies demonstrate applications in individual wells, on a field scale and in surface facilities.



^ Water control to increase well productivity and potential reserves. As most wells mature, the water/oil ratio (WOR) increases with production (A) due to increasing amounts of water. Eventually, the cost of handling the water approaches the value of oil being produced and the WOR “economic limit” (B). Water-control methodology and technology reduce the well’s water production (C) enabling continued economic oil production. Water control results in increased economic recovery in the well (D).

		20,000 B/D		50,000 B/D		100,000 B/D		200,000 B/D		Average	
Lifting	Capex/Opex	$0.044	5.28%	$0.044	7.95%	$0.044	9.29%	$0.044	10.25%	**$0.044**	**7.69%**
	Utilities	$0.050	6.38%	$0.054	9.62%	$0.054	11.24%	$0.054	12.40%	**$0.054**	**9.30%**
Separation	Capex/Opex	$0.087	10.36%	$0.046	8.27%	$0.035	7.24%	$0.030	6.82%	**$0.049**	**8.55%**
	Utilities	$0.002	0.30%	$0.003	0.45%	$0.003	0.52%	$0.003	0.58%	**$0.003**	**0.43%**
	Chemical	$0.034	4.09%	$0.034	6.16%	$0.034	7.20%	$0.034	7.94%	**$0.034**	**5.95%**
De-oiling	Capex/Opex	$0.147	17.56%	$0.073	12.99%	$0.056	11.64%	$0.046	10.58%	**$0.081**	**13.92%**
	Chemicals	$0.040	4.81%	$0.041	7.25%	$0.041	8.47%	$0.041	9.34%	**$0.041**	**7.00%**
Filtering	Capex/Opex	$0.147	17.47%	$0.068	12.18%	$0.047	9.85%	$0.030	6.87%	**$0.073**	**12.63%**
	Utilities	$0.012	1.48%	$0.010	1.79%	$0.010	2.09%	$0.010	2.31%	**$0.011**	**1.84%**
Pumping	Capex/Opex	$0.207	24.66%	$0.122	21.89%	$0.091	19.06%	$0.079	18.15%	**$0.125**	**21.61%**
	Utilities	$0.033	3.99%	$0.034	6.01%	$0..034	7.03%	$0.034	7.75%	**$0.034**	**5.81%**
Injecting	Capex/Opex	$0.030	3.62%	$0.030	5.45%	$0.030	6.37%	$0.030	7.02%	**$0.030**	**5.27%**
	Total cost/bbl	**$0.842**	**100%**	**$0.559**	**100%**	**$0.478**	**100%**	**$0.434**	**100%**	**$0.578**	**100%**
	Total chemicals	$0.074	8.90%	$0.075	13.41%	$0.075	15.67%	$0.075	17.28%	**$0.075**	**12.96%**
	Total utilities	$0.102	12.16%	$0.010	17.87%	$0.100	20.88%	$0.100	23.03%	**$0.101**	**17.38%**
	Total wells	$0.074	8.89%	$0.075	13.40%	$0.075	15.66%	$0.075	17.27%	**$0.075**	**12.95%**
	Surface facilities	$0.589	70.05%	$0.309	55.33%	$0.227	47.80%	$0.184	42.41%	**$0.328**	**56.71%**

Surface processing			Wells, producers			Wells, injectors		
Separation	0.0025	kw/bbl	1 Well 7000 ft	$1,000,000.00	Drill and complete	1 Well 7000 ft	$600,000.00	Drill and complete
Lifting	1.92	kw/bbl	Recompletion	300,000	Per completion	Recompletion	200,000	Per completion
Injection	1.2	kw/bbl	Total 1 well	$1,600,000.00	3 Completions	Total 1 well	$1,000,000.00	3 Completions
Cost	$0.028	Per kw-hr	Cost for water	$400,000.00		Total injected	32,850,000	3 Completions
			Total production	1,000,000	bbl @ 90% water cut	**Cost for water injection**	**$0.03**	$/bbl
			Total water	9,000,000	bbl @ 90% water cut			
			Cost for water lift	**$0.04**	$/bbl			

^ Water-cycle cost. The table shows typical estimated water-handling costs per barrel—capital and operating expenses (Capex and Opex), utilities and chemicals—lifting, separation, de-oiling, filtering, pumping and injection for fluid production varying from 20,000 to 200,000 B/D [3181 to 31,810 m^3/d].

Water Sources

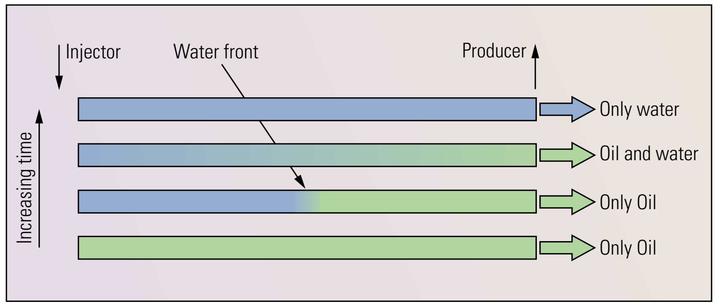
Water is present in every oil field and is the most abundant fluid in the field.[1] No operator wants to produce water, but some waters are better than others. When it comes to producing oil, a key issue is the distinction between sweep, good (or acceptable), and bad (or excess) water.

"Sweep" water—Sweep water comes from either an injection well or an active aquifer that is contributing to the sweeping of oil from the reservoir. The management of this water is a vital part of reservoir management and can be a determining factor in well productivity and the ultimate reserves.[2]

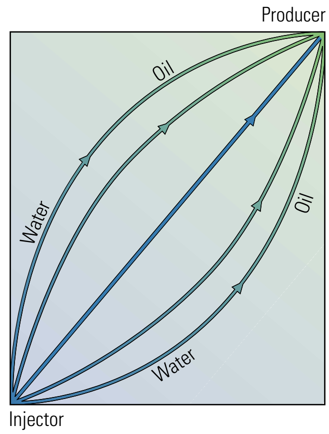
"Good" water—This is water that is produced into the wellbore at a rate below the water/oil ratio (WOR) economic limit (previous page, top).[3] It is an inevitable consequence of water flow through the reservoir, and it cannot be shut off without losing reserves. Good-water production occurs when the flow of oil and water is commingled through the formation matrix. The fractional water flow is dictated by the natural mixing behavior that gradually increases the WOR (top right).

Another form of acceptable water production is caused by converging flow lines into the wellbore (middle right). For example, in one quadrant of a five-spot injection pattern, an injector feeds a producer. Flow from the injector can be characterized by an infinite series of flowlines—the shortest is a straight line from injector to producer and the longest follows the no-flow boundaries from injector to producer. Water breakthrough occurs initially along the shortest flowline, while oil is still produced along slower flowlines. This water must be considered good since it is not possible to shut off selected flowlines while allowing others to produce.

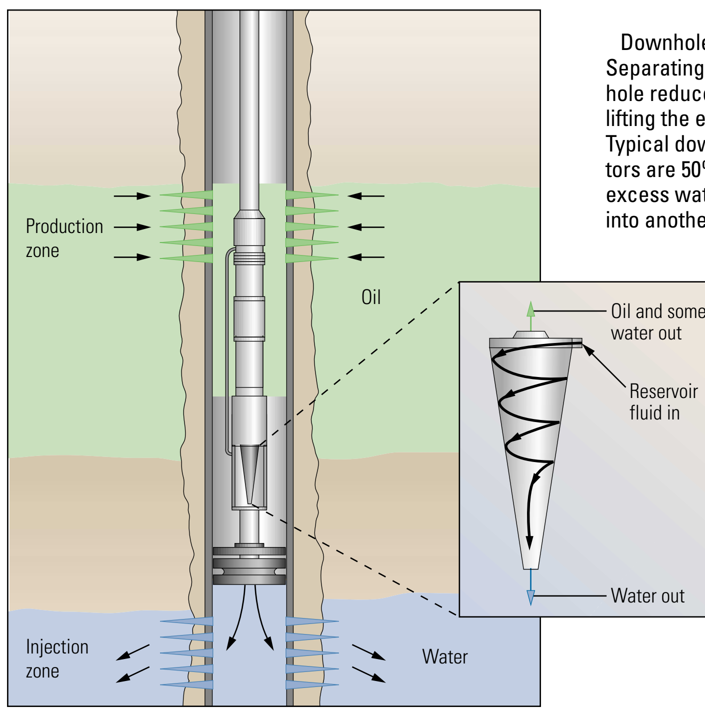
Since good water, by definition, produces oil with it, water management should seek to maximize its production. To minimize associated water costs, the water should be removed as early as possible, ideally with a downhole separator (bottom right). These devices, coupled with electrical submersible pumps, allow up to 50% of the water to be separated and injected downhole to avoid lifting and surface-separation costs.



^ Good and bad water. Good water needs to be produced with oil. It cannot be shut off without shutting off oil. Downhole separation may be a solution. Bad water does not help production, and it depletes pressure.



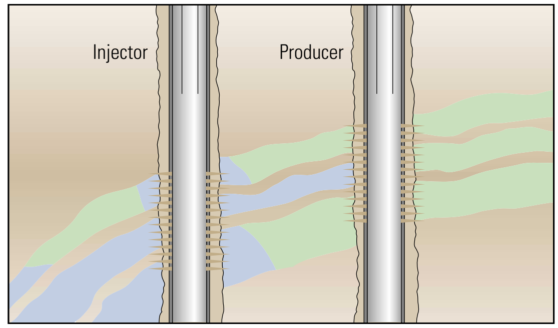
Simulating water flow in a reservoir. FrontSim streamline reservoir simulation software is ideal for demonstrating what happens to fluids flowing in a reservoir. The streamlines represent the flow of water from injector to producer. The simulator requires geological, structural and fluid information. The plot shows one quadrant of a uniform five-spot injection pattern where the water from the most direct streamline is the first to break through to the producer. The water from these streamlines is considered good water because it cannot be shut off without decreasing oil production.



Downhole separator. Separating water downhole reduces the costs of lifting the excess water. Typical downhole separators are 50% efficient. The excess water is injected into another formation.

1. Kuchuk F, Sengul M and Zeybek M: "Oilfield Water: A Vital Resource," *Middle East Well Evaluation Review* 22 (November 22, 1999): 4-13.
2. Kuchuk F, Patra SK, Narasimham JL, Ramanan S and Banerji S: "Water Watching," *Middle East Well Evaluation Review* 22 (November 22, 1999): 14-23; and also Kuchuk F and Sengul M: "The Challenge of Water Control," *Middle East Well Evaluation Review* 22 (November 22, 1999): 24-43.
3. Water/oil ratio (WOR) is the water production rate divided by oil production rate. It ranges from 0 (100% oil) to infinite (100% water). Also commonly used are the terms 'water cut' or 'fractional water flow' defined as water production rate divided by total production rate as a percentage or fraction, respectively. Correspondence between these measures can be easily calculated (for example, a WOR of 1 implies a water cut of 50%). The WOR economic limit is the WOR at which the cost of the water treatment and disposal is equal to the profit from the oil. Production beyond this limit gives a negative cash flow. This can be approximated by the net profit from producing an incremental unit volume of oil divided by the cost of an incremental unit volume of water.

"Bad" water—The remainder of this article deals principally with the problems of excess water. Bad water can be defined as water that is produced into the wellbore and produces no oil or insufficient oil to pay for the cost of handling the water—water that is produced above the WOR economic limit. In individual wells, the source of most bad-water problems can be classified as one of ten basic types. The classification of water problem types presented here is simplistic—many variations and combinations can occur—but it is useful for providing a common terminology.[4]



^ Watered-out layer without crossflow.

Water Problems

The ten basic problem types vary from easy to solve to the most difficult to solve.

Casing, tubing or packer leaks—Leaks through casing, tubing or packers allow water from non-oil-productive zones to enter the production string (below left). Detection of problems and application of solutions are highly dependent on the well configuration. Basic production logs such as fluid density, temperature and spinner may be sufficient to diagnose these problems. In more complex wells, WFL Water Flow Logs or multiphase fluid logging such as the TPHL three-phase fluid holdup log can be valuable. Tools with electrical probes, such as the FlowView tool, can identify small amounts of water in the production flow. Solutions typically include squeezing shutoff fluids and mechanical shutoff using plugs, cement and packers. Patches can also be used. This problem type is a prime candidate for low-cost, inside-casing water shutoff technology.

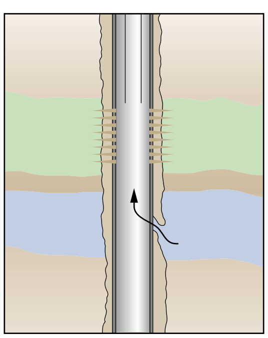
Channel flow behind casing—Failed primary cementing can connect water-bearing zones to the pay zone (below middle). These channels allow water to flow behind casing in the annulus. A secondary cause is the creation of a 'void' behind the casing as sand is produced. Temperature logs or oxygen-activation-based WFL logs can detect this water flow. The main solution is the use of shutoff fluids, which may be either high-strength squeeze cement, resin-based fluids placed in the annulus, or lower strength gel-based fluids placed in the formation to stop flow into the annulus. Placement is critical and typically is achieved with coiled tubing.

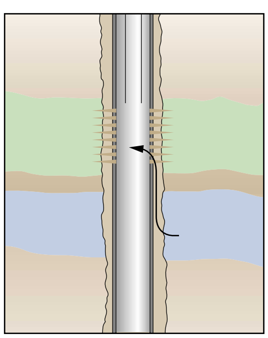
Moving oil-water contact—A uniform oil-water contact moving up into a perforated zone in a well during normal water-driven production can lead to unwanted water production (below right). This happens wherever there is very low vertical permeability. Since the flow area is large and the rate at which the contact rises is low, it can even occur at extremely low intrinsic vertical permeabilities (less than 0.01 mD). In wells with higher vertical permeability ($K_v > 0.01\ K_h$), coning and other problems discussed below are more likely. In fact, this problem type could be considered a subset of coning, but the coning tendency is so low that near-wellbore shutoff is effective. Diagnosis cannot be based solely on known entry of water at the bottom of the well, since other problems also cause this behavior. In a vertical well, this problem can be solved easily by abandoning the well from the bottom using a mechanical system such as a cement plug or bridge plug set on wireline. Retreatment is required if the OWC moves significantly past the top of the plug. In vertical wells, this problem is the first in our classification system that extends beyond the local wellbore environment.

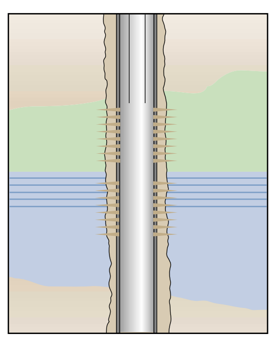
In horizontal wells, any wellbore or near-wellbore solution must extend far enough uphole or downhole from the water-producing interval to minimize horizontal flow of water past the treatment and delay subsequent water breakthrough. Alternatively, a sidetrack can be considered once the WOR becomes economically intolerable.[5]

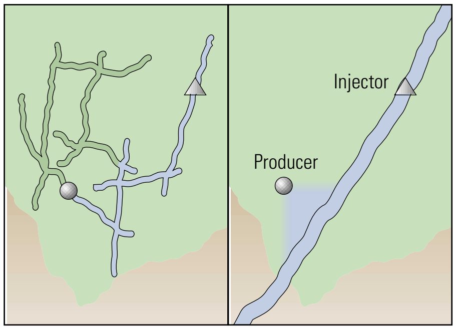
Watered-out layer without crossflow—A common problem with multilayer production occurs when a high-permeability zone with a flow barrier (such as a shale bed) above and below is watered out (above). In this case, the water source may be from an active aquifer or a waterflood injection well. The watered-out layer typically has the highest permeability. In the absence of reservoir crossflow, this problem is easily solved by the application of rigid, shutoff fluids or mechanical shutoff in either the injector or producer. Choosing between placement of a shutoff fluid—typically using coiled tubing—or a mechanical shutoff system depends on knowing which interval is watered out. Effective selective fluids, discussed later, can be used in this case to avoid the cost of logging and selective placement. The absence of crossflow is dependent on the continuity of the permeability barrier.

Horizontal wells that are completed in just one layer are not subject to this type of problem. Water problems in highly inclined wells completed in multiple layers can be treated in the same way as vertical wells.

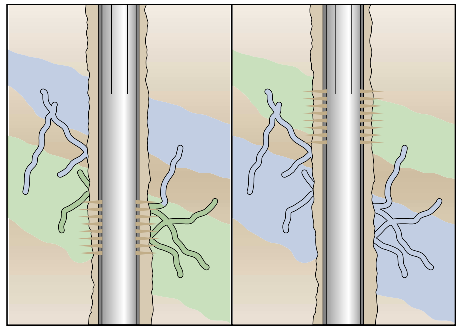

^ Casing, tubing or packer leaks.


^ Flow behind casing.

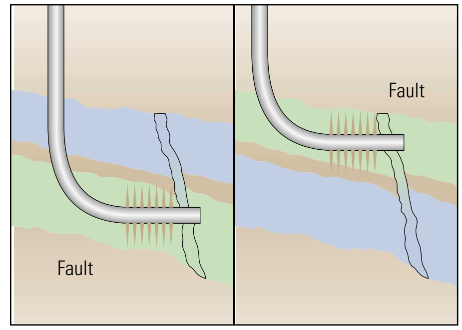

^ Moving oil-water contact.



^ Fractures or faults between an injector and a producer.



^ Fractures or faults from a water layer (vertical well).



^ Fractures or faults from a water layer (horizontal well).

Fractures or faults between injector and producer—In naturally fractured formations under waterflood, injection water can rapidly break through into producing wells (above). This is especially common when the fracture system is extensive or fissured and can be confirmed with the use of interwell tracers and pressure transient testing.[6] Tracer logs also can be used to quantify the fracture volume, which is used for the treatment design. The injection of a flowing gel at the injector can reduce water production without adversely affecting oil production from the formation. When crosslinked flowing gels are used, they can be bullheaded since they have limited penetration in the matrix and so selectively flow in the fractures. Water shutoff is usually the best solution for this problem.

Wells with severe fractures or faults often exhibit extreme loss of drilling fluids. If a conductive fault and associated fractures are expected during drilling, pumping flowing gel into the well may help solve both the drilling problem and the subsequent water production and poor sweep problems—particularly in formations with low matrix permeability.

In horizontal wells, the same problem can exist when the well intersects one or more faults that are conductive or have associated conductive fractures.

Fractures or faults from a water layer—Water can be produced from fractures that intersect a deeper water zone (above middle). These fractures may be treated with a flowing gel; this is particularly successful where the fractures do not contribute to oil production. Treatment volumes must be large enough to shut off the fractures far away from the well.

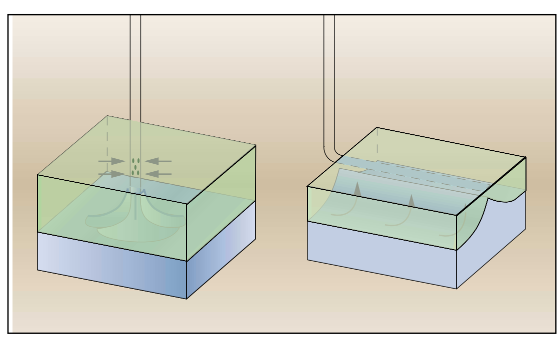
However, the design engineer is faced with three difficulties. First, the treatment volume is difficult to determine because the fracture volume is unknown. Second, the treatment may shut off oil-producing fractures; here, an overflush treatment maintains productivity near the wellbore. Third, if a flowing gel is used, it must be carefully tailored to resist flowback after the treatment. In cases of localized fractures, it may be appropriate to shut them off near the wellbore, especially if the well is cased and cemented. Similarly, a degradation in production is caused when hydraulic fractures penetrate a water layer. However, in such cases the problem and environment are usually better understood and solutions, such as shutoff fluids, are easier to apply.

In many carbonate reservoirs, the fractures are generally steep and tend to occur in clusters that are spaced at large distances from each other—especially in tight dolomitic zones. Thus, the probability of these fractures intersecting a vertical wellbore is low. However, these fractures are often observed in horizontal wells where water production is often through conductive faults or fractures that intersect an aquifer (above right). As discussed above, pumping flowing gel may help address this problem.

Coning or cusping—Coning occurs in a vertical well when there is an OWC near perforations in a formation with a relatively high vertical permeability (below). The maximum rate at which oil can be produced without producing water through a cone, called the critical coning rate, is often too low to be economic. One approach, which is sometimes inappropriately proposed, is to place a layer of gel above the equilibrium OWC. However, this will rarely stop coning and requires a large volume of gel to significantly reduce the WOR. For example, to double the critical coning rate, an effective gel radius of at least 50 feet [15 m] typically is required. However, economically placing gel this deep into the formation is difficult. Smaller volume treatments usually result in rapid water re-breakthrough unless the gel fortuitously connects with shale streaks.

A good alternative to gel placement is to drill one or more lateral drainholes near the top of the formation to take advantage of the greater distance from the OWC and decreased drawdown, both of which reduce the coning effect.

In horizontal wells, this problem may be referred to as duning or cusping. In such wells, it may be possible to at least retard cusping with near-wellbore shutoff that extends sufficiently up- and downhole as in the case of a rising OWC.



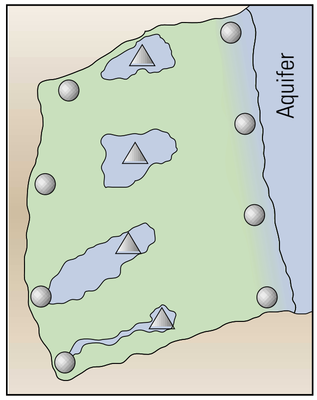
^ Coning or cusping.

4. Elphick J and Seright R: "A Classification of Water Problem Types," presented at the Petroleum Network Education Conference's 3rd Annual International Conference on Reservoir Conformance Profile Modification, Water and Gas Shutoff, Houston, Texas, USA, August 6-8, 1997.
5. Hill D, Neme E, Ehlig-Economides C and Mollinedo M: "Reentry Drilling Gives New Life to Aging Fields," *Oilfield Review* 8, no. 3 (Autumn 1996): 4-17.
6. A fissure is an extensive crack, break or fracture in a rock.

Poor areal sweep—Edge water from an aquifer or injection during waterflooding through a pay zone often leads to poor areal sweep (right). Areal permeability anisotropy typically causes this problem, which is particularly severe in sand channel deposits. The solution is to divert injected water away from the pore space, which has already been swept by water. This requires a large treatment volume or continuous viscous flood, both of which are generally uneconomic. Infill drilling is often successful in improving recovery in this situation, although lateral drainholes may be used to access unswept oil more economically.

Horizontal wells may extend through different permeability and pressure zones within the same layer, causing poor areal sweep. Alternatively, water may break through to one part of the well simply because of horizontal proximity to the water source. In either case, it may be possible to control water by near-wellbore shutoff sufficiently up- and downhole from the water.

Gravity-segregated layer—In a thick reservoir layer with good vertical permeability, gravity segregation—sometimes called water under-run—can result in unwanted water entry into a producing well (below). The water, either from an aquifer or waterflood, slumps downward in the permeable formation and sweeps only the lower part of the reservoir. An unfavorable oil-water mobility ratio can make the problem worse. The problem is further exacerbated in formations with sedimentary textures that become finer upward, since viscous effects along with gravity segregation encourage flow at the bottom of the formation. Any treatment in the injector aimed at shutting off the lower perforations has only a marginal effect in sweeping more oil before gravity segregation again dominates. At the producer there is local coning and, just as for the coning case described earlier, gel treatments are unlikely to provide lasting results. Lateral drainholes may be effective in accessing the unswept oil. Foamed viscous-flood fluids may also improve the vertical sweep.



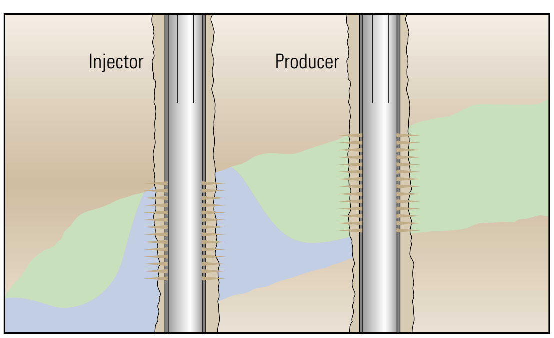
^ Poor areal sweep.

In horizontal wells, gravity segregation can occur when the wellbore is placed near the bottom of the pay zone, or when the local critical coning rate is exceeded.

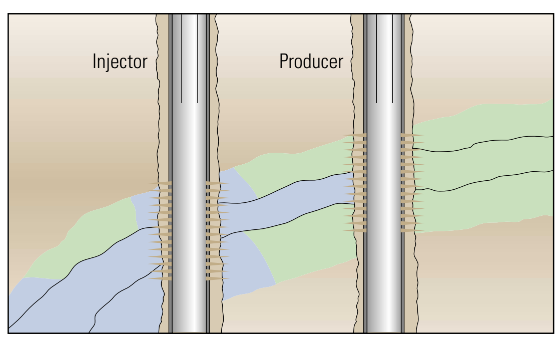
Watered-out layer with crossflow—Water crossflow can occur in high-permeability layers that are not isolated by impermeable barriers (below right). Water production through a highly permeable layer with crossflow is similar to the problem of a watered-out layer without crossflow, but differs in that there is no barrier to stop crossflow in the reservoir. In these cases, attempts to modify either the production or injection profile near the wellbore are doomed to be short-lived because of crossflow away from the wellbore. It is vital to determine if there is crossflow in the reservoir since this alone distinguishes between the two problems. When the problem occurs without crossflow, it can be easily treated. With crossflow, successful treatment is less likely. However, in rare cases, it may be possible to place deep-penetrating gel economically in the permeable thief layer if the thief layer is thin and has high permeability compared with the oil zone. Even under these optimal conditions, careful engineering is required before committing to a treatment. In many cases, a solution is to drill one or more lateral drainholes to access the undrained layers.

Horizontal wells completed in just one layer are not subject to this type of problem. If a highly inclined well is completed in multiple layers, then this problem occurs in the same way as in a vertical well.

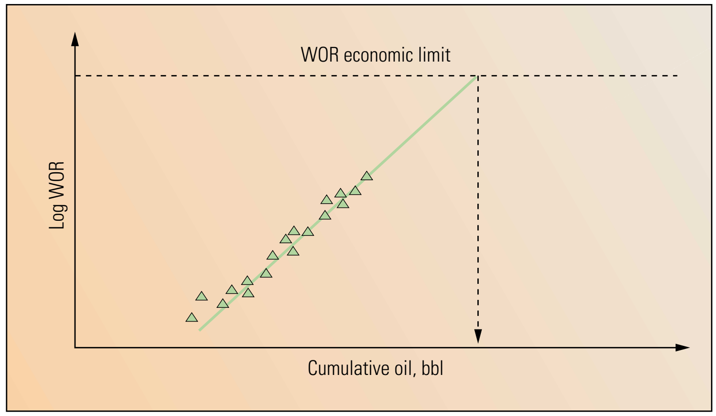
Knowing the specific water-control problem is essential to treating it. The first four problems are relatively easily controlled in or near the wellbore. The next two problems—fractures between injectors and producers, or fractures from a water layer—require placement of deeper penetrating gels into the fractures or faults. The last four problems do not lend themselves to simple and inexpensive near-wellbore solutions, and require completion or production changes as part of the reservoir management strategy. Any operator wishing to achieve effective, low-risk, rapid payout water shutoff should initially concentrate on applying proven technology to the first six problem types.



^ Gravity-segregated layer.



^ Watered-out layer with crossflow.



^ Recovery plot. The recovery plot shows the increasing trend in water/oil ratio with production. If the extrapolated WOR reaches the economic limit when the cumulative oil produced reaches the expected recoverable reserves, then the water being produced is considered good water.

Well Diagnostics for Water Control

In the past, water control was thought of as simply a plug and cement operation, or a gel treatment in a well. The main reason for the industry's failure to consistently control water has been a lack of understanding of the different problems and the consequent application of inappropriate solutions. This is demonstrated by the number of technical papers discussing the treatments and results with little or no reference to the geology, reservoir or water-control problem. The key to water control is diagnostics—to identify the specific water problem at hand. Well diagnostics are used in three ways:

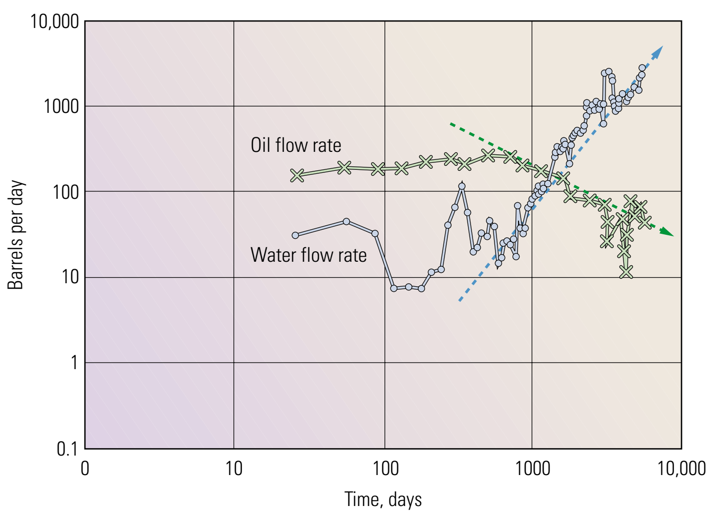
- to screen wells that are suitable candidates for water control
- to determine the water problem so that a suitable water-control method can be selected
- to locate the water entry point in the well so that a treatment can be correctly placed.

When a reliable production history is available, it often contains a wealth of information that can help diagnose water problems. Several different analytical techniques using information, such as water/oil ratios, production data and logging measurements, have been developed to distinguish between the different sources of unacceptable water.

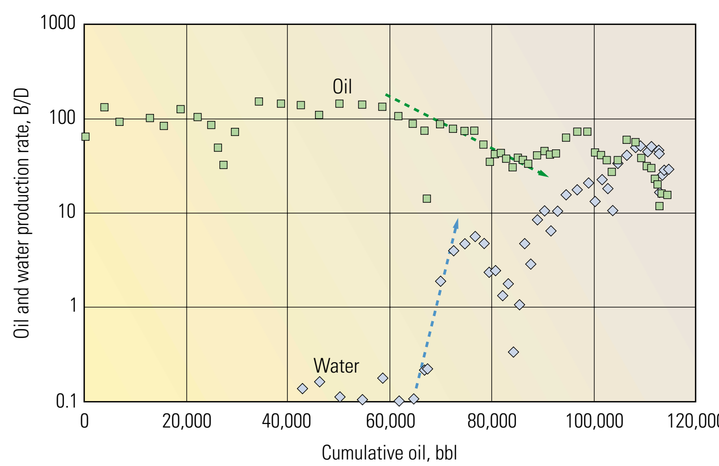
Recovery plot—The recovery plot is a semilog plot of WOR against cumulative oil production (above). The production trend can be extrapolated to the WOR economic limit to determine the oil production that will be achieved if no water-control action is taken. If the extrapolated production is approximately equal to the expected reserves for a well, then the well is producing acceptable water, and no water control is needed. If this value is much less than the expected recoverable reserves, the well is producing unacceptable water and remedial action should be considered if there are sufficient reserves to pay for intervention.

Production history plot—This plot is a log-log plot of oil and water rates against time (below left). Good candidates for water control usually show an increase in water production and a decrease in oil production starting at about the same time.

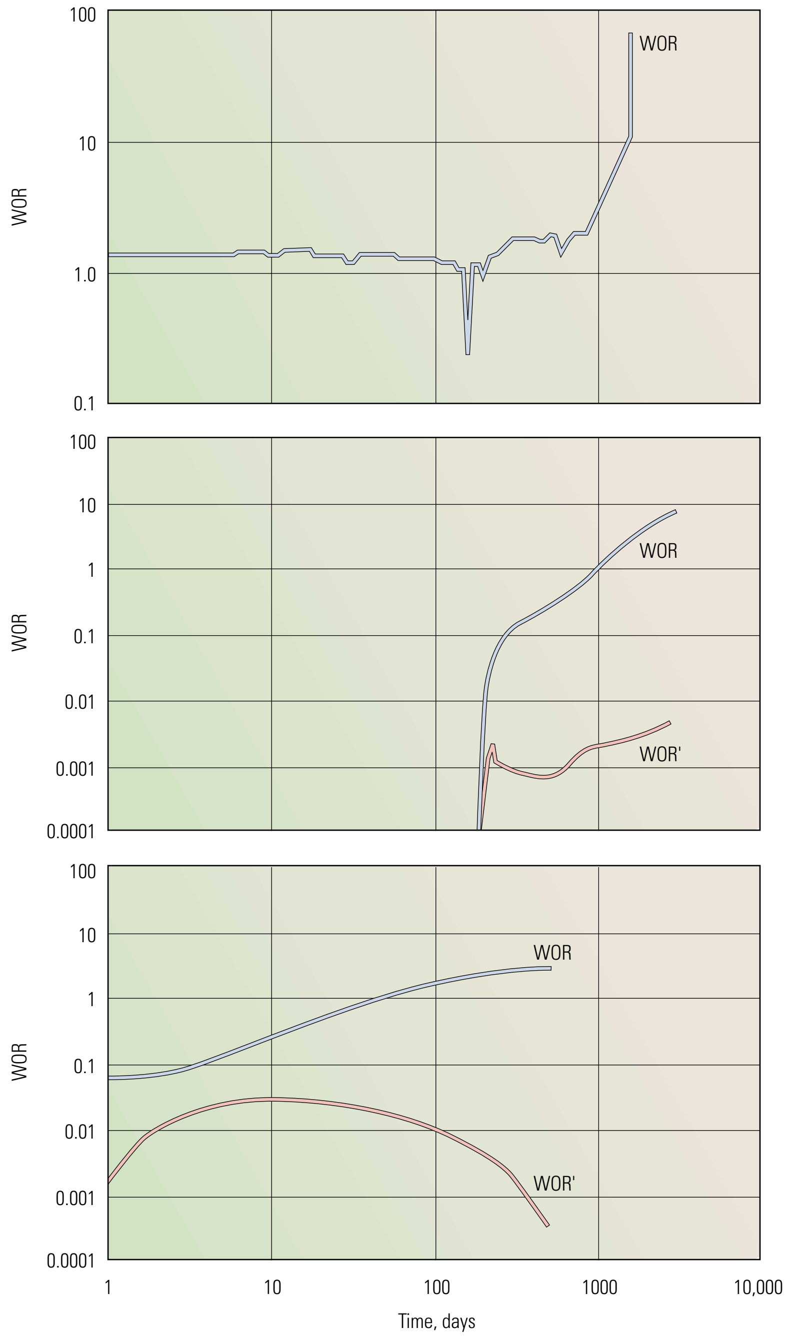
Decline-curve analysis—This is a semilog plot of oil production rate versus cumulative oil (below). A straight-line curve can be expected for normal depletion. An increased decline may indicate a problem other than water, such as severe pressure depletion or damage buildup.



^ Production history plot. A time, days plot of the water and oil flow rates against time can be helpful in identifying water problems. Any sudden simultaneous change indicating increased water with a reduction in oil is a signal that remediation might be needed.



^ Decline curve. Any sudden change in the slope of the usual straight-line decline in oil production rate is a warning that excess water, as well as other problems, may be affecting normal production.

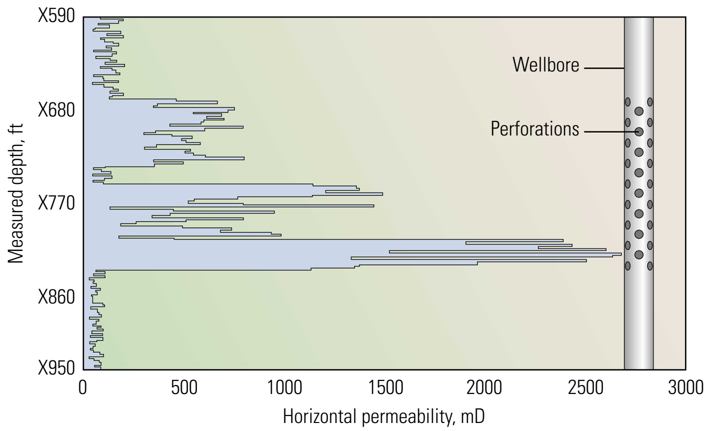


^ Diagnostic-plot profiles characterizing water breakthrough mechanisms. An open flow path *(top)* shows a very rapid increase. This profile indicates flow through a fault, fracture or a channel behind casing, which can occur at any time during the well history. Edgewater flow *(middle)* generally shows a rapid increase at breakthrough followed by a straight-line curve. For multiple layers, the line may have a stair-step shape depending on layer permeability contrasts. A gradual increase *(bottom)* in the WOR indicates the buildup of a water cone early in the well's life. It normally levels off between a WOR of 1 and 10. The slope of WOR decreases. After the water cone stabilizes, the WOR curve begins to look more like that for edge flow. The magnitude of the slope, WOR', is shown in red in the two lower profiles.

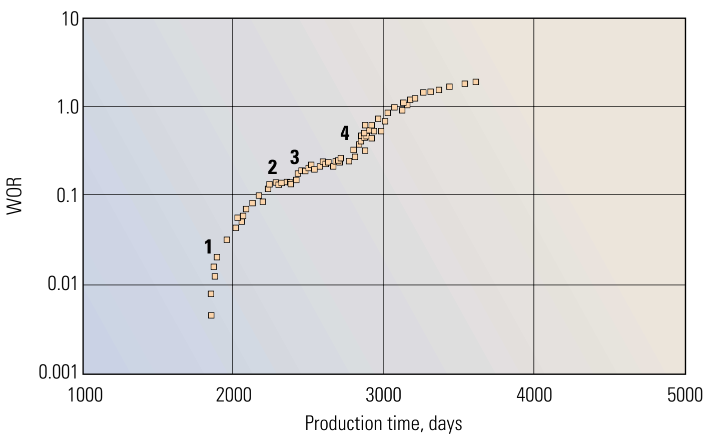
Diagnostic plots—A diagnostic log-log plot of WOR versus time can be used to help determine the specific problem type by making comparisons with known behavior patterns (left). Three basic signatures distinguish between different water breakthrough mechanisms: open flow through faults, fractures, or channel flow behind casing; edgewater flow or a moving OWC; and coning problems.[7] Edgewater flow interpretations have been constructed from numerical simulation and field experience.[8] The time-derivative of the WOR also can be used, but the uncertainty or noisy nature of field measurements generally limits its application. The interpretation engineer can learn to recognize the many variations in these profiles and minimize the problem of nonuniqueness, when combined with other data.

The usefulness of WOR diagnostic plots in determining multilayer water encroachment is illustrated by an example in a field operated by a major North Sea operating company. A medium-size reservoir with a moderate-to-high energy shoreface structure had been heavily bioturbated, giving rise to substantial permeability variations (next page, top). No significant shale barriers were present, and the 360-ft [110-m] thick reservoir from X590 to X950 ft [X180 to X290 m] gently dipped into an aquifer. The edges of the reservoir were bounded by sealing faults and truncated by an unconformity. A vertical well was perforated across 165 ft [50 m] in the middle of this unit. No OWC or gas-oil contacts (GOC) were present in the reservoir.

The WOR-diagnostic plot generated from monthly well-test data shows the effect of the permeability variation in the reservoir strata (next page, bottom). The plot illustrates watering-out of high-permeability layers, which contribute to crossflow in the reservoir. The ratio of breakthrough times (1800:2400:2800) gives an indication



^ Horizontal permeability variations in a North Sea reservoir. Significant permeability variation results in effective layer isolation, thereby encouraging preferential flow along high-permeability layers. The well is perforated in the middle section of the reservoir.



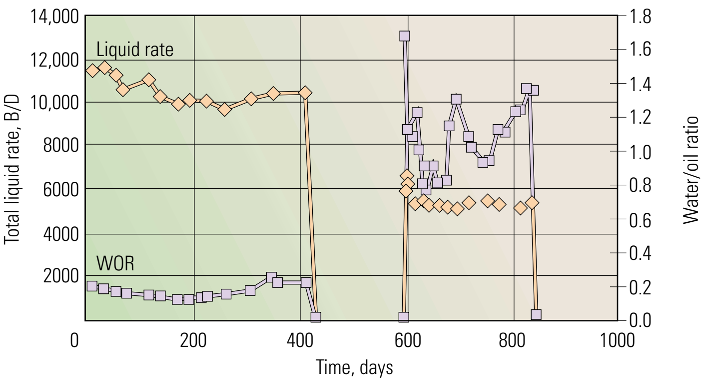
^ Diagnostic plot from monthly well-test data. The plot shows how aquifer water breaks through at about 1800 days (point 1) with a sharp increase in WOR corresponding to a sudden water saturation change at the flood front. This breakthrough is most likely to be from the highest permeability layer. The WOR gradually rises until 2100 days as normal for edgewater flow. The water inflow stabilizes from point 2 indicating that the layer is virtually watered out, leading to a constant WOR. This value suggests that the first layer to break through contributes approximately 14% of the total permeability-height product—the key formation factor determining the flow rate. At 2400 days (point 3), the breakthrough of water is seen through the interbedded high-permeability layers. The curve appears to be less steep at this breakthrough because the WOR is starting at a higher value. At the end of this period, the WOR is approximately 0.24, suggesting that 10% of the permeability-height product comes from the second layer, which has watered out. The last distinctive increase (point 4) represents final breakthrough of the remaining high-permeability layers.

of the permeability ratios in these layers. The cumulative oil produced and the relative permeability-height products of the layers might be used to estimate the remaining reserves in the lower permeability parts of the formation from X590 to X670 ft [X204 m].

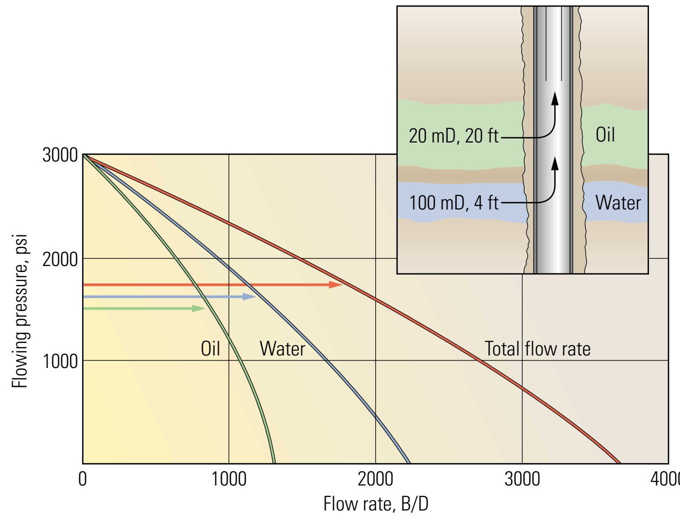
The observed WOR response shows that layers with higher permeabilities have watered out. Although there is no direct evidence of vertical connection between these layers, an understanding of the depositional environment and the impact of bioturbation can help resolve this issue. Some communication between the high-permeability layers is likely, as well as possible vertical communication within the remaining low-permeability zone. Any near-wellbore attempt to control water from the high-permeability layers will depend on vertical isolation over a large areal extent between the remaining reserves above X670 ft and the watered-out layers below. This can be confirmed with MDT Modular Formation Dynamics Tester measurements of layer pressures, vertical interference testing, shale correlations and production logs.

Shut-in and choke-back analysis—The production history of most wells includes periods of choke-back or shut-in. Analysis of the fluctuating WOR can provide valuable clues to the problem type. Water-entry problems, such as coning or a single fracture intersecting a deeper water layer will lead to a lower WOR during choke-back or after shut-in. Conversely, fractures or a fault intersecting an overlying water layer has the opposite effect. Such systems are not stable over geologic time but certainly can be induced during production.

7. Chan KS: "Water Control Diagnostic Plots," paper SPE 30775, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 22-25, 1995.
8. Yortsos YC, Youngmin C, Zhengming Y and Shah PC: "Analysis and Interpretation of Water/Oil Ratio in Waterfloods," *SPE Journal* 4, no. 4 (December 1999): 413-424.



^ Production rates during choke-back. Production data during the choke-back period in a Middle Eastern well show that choking back the production rate 50% results in a dramatic increase in the WOR.



^ Multilayer NODAL analysis. The modeled well *(insert)* used for the NODAL analysis has two layers, each with a different thickness and permeability. The multilayer analysis shows the individual and total flow rates of the oil and water layers as they are produced together at different pressures.

One well from the Middle East showed a production rate of 7000 bbl [1112 m^3] of water per day and 400 bbl [64 m^3] of oil per day after each shut-in (above). These rates reversed after a few days of production. Production data suggest that the apparent cause was a conductive fault connecting the oil reservoir to a shallower watered-out reservoir. In wells with the water source at a higher pressure than the oil, choking back the well causes the WOR to increase. The choke-back test offers a useful diagnostic method to distinguish between these two problems.

When production history data are of low quality, a short-term production choke-back test can be performed with several different choke sizes. The pressure should be monitored along with WOR from a separator or, preferably, a three-phase flowmeter, to accurately determine changes in the WOR with drawdown pressure. This can be performed only if the well has sufficient wellhead pressure to flow at several rates and so should be done early in the life of the well.

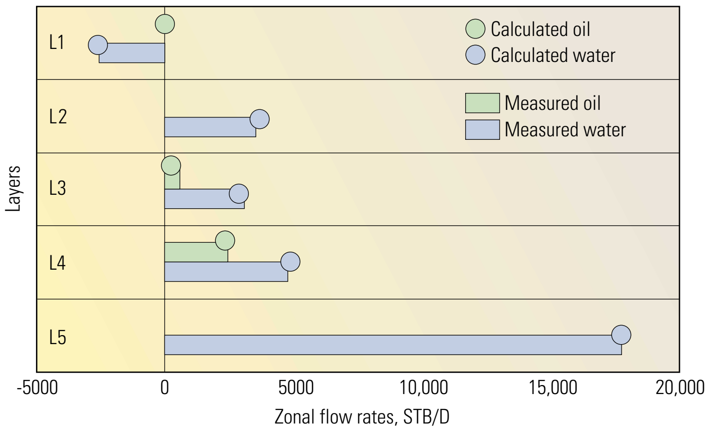
NODAL analysis—The design of a production system depends on the combined performance of the reservoir and the downhole tubing or reservoir "plumbing" system (above right).[9] The amount of oil, gas and water flowing into a well from the reservoir depends on the pressure drop in the piping system, and the pressure drop in the piping system depends on the amount of each fluid flowing through it. The deliverability of a well often can be severely diminished by inadequate performance or design of just one component in the system. An analysis of a flowing wellbore and the associated piping, known as NODAL analysis, is frequently used to evaluate the effect of each component in a flowing production system from the bottom of a well to the separator.

NODAL analysis is also used to determine the location of excessive flow resistance, which results in severe pressure losses in tubing systems. The effect of changing any component in the system on production rates can be determined.[10] For example, a commonly held belief is that choking back a well that produces water will reduce the water cut. This is certainly the case for conventional coning. In other cases, it depends on the problem type as well as the reservoir pressures. For example, if a well is shut in for an extended period of time, the WOR (measured when the well is put on line again) will depend on the water problem and pressures involved.

A 35° inclined North Sea black-oil producer is perforated and producing from five different layers. Each layer is known to be isolated from the others by impermeable shale barriers with no crossflow between them. A nearby injector and an aquifer provide pressure support. The well produced 29,000 B/D [4608 m^3/d] with a water cut of 90%. A recent production log in this well shows significant shut-in crossflow from lower layers into the upper—possibly a thief—layer. NODAL analysis was performed to match the PLT Production Logging Tool analysis for both shut-in and flowing conditions, thereby providing confidence in any prediction of anticipated additional oil production obtained from various water shut-off treatments (next page, top).

Although NODAL analysis is a standard methodology for modeling wellbore response, there are two important considerations in its use in this application. First was the need to calibrate the computed flow responses in the face of aggressive shut-in crossflow, and second, a relatively high number of separate layers were involved. The analysis included six steps.

9. Elphick J: "NODAL Analysis Shows Increased Oil Production Following Water Shutoff," presented at the Petroleum Network Education Conference's 2nd Annual International Conference on Reservoir Conformance Profile Modification, Water and Gas Shutoff, Houston, Texas, USA, August 19-21, 1996.
10. Beggs HD: *Production Optimization Using NODAL Analysis*. Tulsa, Oklahoma, USA: OGCI Publications, Oil & Gas Consultants International, Inc., 1991.
11. A switch angle determines when primarily vertical multiphase correlations should be replaced by primarily horizontal ones. Is important to note that there are no multiphase-flow pressure-drop correlations in the public domain suitable for all inclination angles.

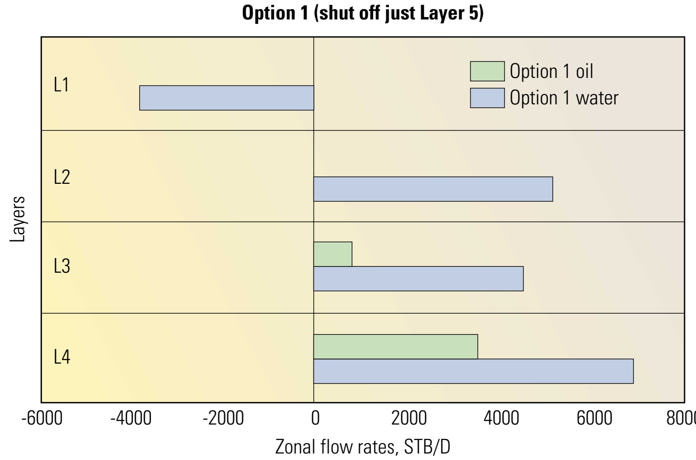


^ Matching NODAL analysis with production measurements. The blue bars represent water flow while the green bars are oil flow measured by production logging tools. The circles represent the results of the NODAL analysis. Layers 2 and 5 are fully watered out. Layer 1 is taking on water and some oil, as indicated by the negative flow rates, because it has lower in-situ reservoir pressure than the flowing wellbore pressure.

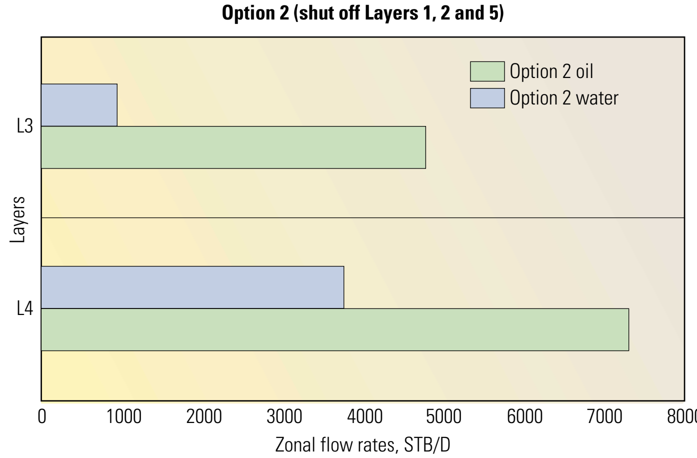
- *Model construction*—Basic model construction required a detailed deviation survey, pressure-volume-temperature (PVT) properties, characteristics of the reservoir in the near-wellbore region for each layer and perforation locations.
- *Geology*—Geological information about the depositional environment around the well was necessary to estimate the degree and lateral extent of impermeable barriers. The well exhibited good lateral extent of such barriers. Elsewhere in the field, variation in depositional environment caused uncertainty in the continuity of permeability barriers, degrading confidence in the sustainability of the localized shutoff treatments.
- *Layer pressures*—Individual layer pressures were obtained from shut-in data. Formation skin damage factors were initially assumed to be zero.
- *Correlation selection*—A multiphase flow correlation comparison was conducted on the basic system to determine the degree of variation exhibited by the models and the impact of correlation parameters, such as switch angles.[11] This step involves matching well-test data.
- *Shut-in crossflow*—First, the shut-in crossflow exhibited by the PLT tool measurements was modeled, enabling skin damage for each layer to be evaluated. The process required a trial and error approach, in which rough estimates (from earlier tests) of each layer's production index were sequentially adjusted to match the data. Well histories were also consulted to determine if any skin due to drilling or operational considerations could be expected. In this example, none was expected.
- *Flowing crossflow*—The process was repeated for flowing conditions and several rates were analyzed. Shutting in all but one net-producing layer at a time can speed up processing. The production index and non-Darcy skin factors of each layer were then adjusted to match the data. The final calibrated model provided a good match to all the data.

The calibrated NODAL analysis model was then used to determine the estimated incremental production for two different shutoff options. The first option would completely shut off all production from the lowest layer, Layer 5 (below). This option leaves Layers 1 to 4 open, and the net result is an increase in oil production from 2966 to 4294 BOPD [471 to 682 m^3/d]. Water production would decrease from 26,510 to 12,742 BWPD [4212 to 2025 m^3/d]. The second option would involve sealing off the nonhydrocarbon-producing Layers 1, 2 and 5, and producing from Layers 3 and 4. This option results in oil production increasing to 4613 BOPD [733 m^3/d], which is only about 300 BPD [47 m^3/d] more than option 1. The

Option 1 (shut off just Layer 5)



Option 2 (shut off Layers 1, 2 and 5)

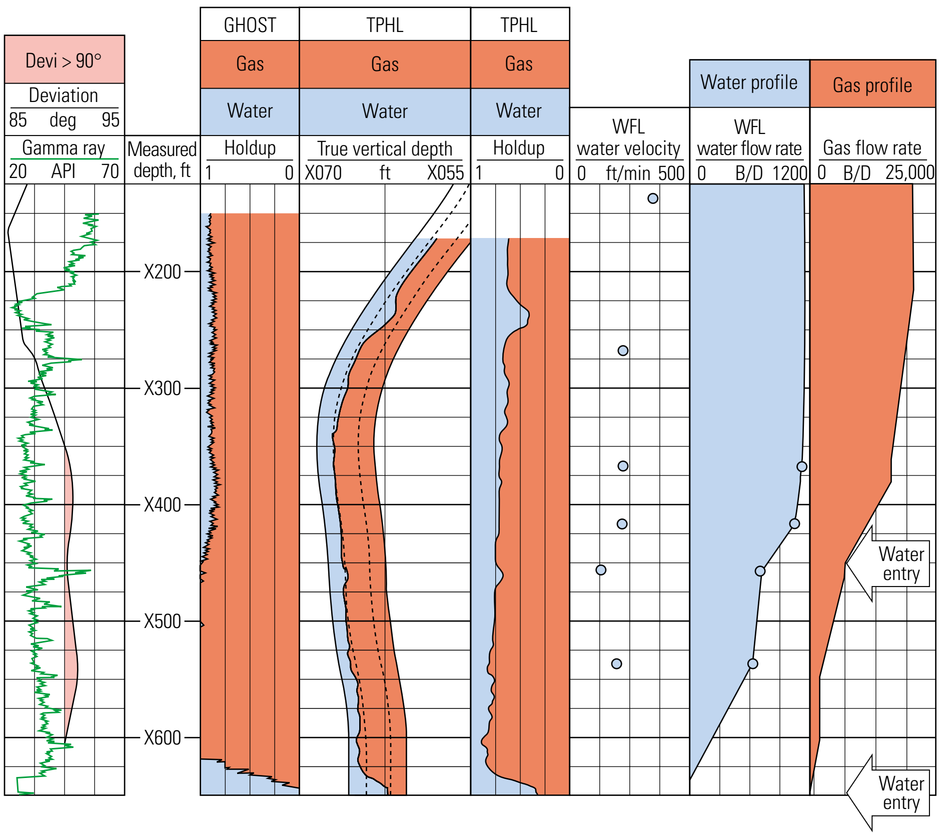


NODAL analysis to predict benefits of water control. The two options proposed for this well were to either simply shut off Layer 5 with a plug and produce from the upper layers, or shut off Layers 1, 2 and 5, leaving Layers 3 and 4 to produce. The first option *(top)* would produce an expected net increase in production of 1328 BOPD [211 m^3/d], whereas the second choice *(bottom)* predicts a net increase in production of 1647 BOPD [262 m^3/d]. The second option is more expensive and probably requires setting a plug to isolate Layer 5 and cementing Layers 1 and 2. The operator chose option 1.

difference between current performance and that predicted from shutting in one or more layers was used as the basis for justifying the treatments.

The production log data showed that water was being produced from all but one of the upper layers. Most of the unwanted water came from the lowest layer. Because of reduced formation pressures, the uppermost layer was stealing a small quantity of the oil and water being produced below. As expected, the liquid volumes entering this thief zone decreased as production increased. At the expected high production rates such losses were considered tolerable. The operator decided on option 1, setting a plug just below Layer 4, completely isolating Layer 5.

Production logs—Accurate production logs, such as those from the PS PLATFORM Production Services measurements can show water entry into the wellbore.[12] This tool can determine flow and holdup for each fluid phase in vertical, deviated and horizontal wellbores.[13] The addition of new optical and electrical sensors incorporating local probe measurements and phase-velocity measurements have resulted in major improvements in the diagnosis in both complex and simple wells with three-phase flow. Such advances in reliable and accurate production logging, particularly in deviated wells with high water cuts, represent a major step forward in identifying and understanding water-problem types.

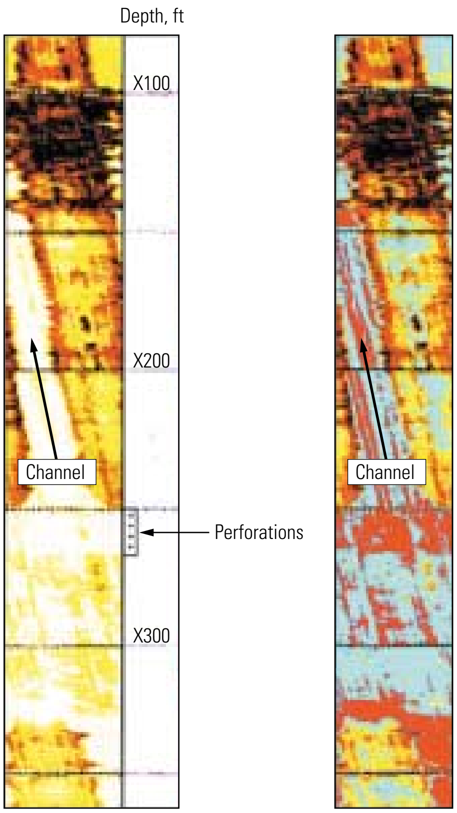


^ Downhole flow profile. Track 1 contains gamma ray (green) and wellbore deviation (solid black) from openhole logs. The measured depth is shown in track 2. In track 3, gas (red) and water holdup (blue) measured by the GHOST Gas Holdup Optical Sensor Tool clearly identify water entering the horizontal section of the wellbore at X450 ft and X640 ft. Track 4 shows gas (red) and water (blue) contributions across the entire wellbore and annulus, which is plotted against the wellbore trajectory profile. These independent phase holdups are derived from the TPHL three-phase holdup log. Increasing water in the profile can be seen as the wellbore turns more vertical above X350. Track 5 shows TPHL gas (red) and water (blue) holdup logs. The WFL Water Flow Log water-velocity measurements (blue circles) are shown in Track 6. Track 7 contains a water flow-rate profile computed from the TPHL holdup and WFL velocity. Track 8 contains the gas flow-rate profile computed using GHOST holdup data.

For example, an operator drilled a horizontal well in the Gulf of Mexico through a small gas sand that was producing excessive water after a short time on production. In this well, the most likely source of the unacceptable water was thought to be edge water from the lower aquifer. If the edge water was entering at the heel of the well, then a cost-effective solution would be to run coiled tubing into the well and cement the portion around the heel, leaving the coiled tubing in place to allow production from the toe of the well. This would delay further water production until the water advanced past the cement plug. However, if water was coming from the toe of the well, then it was possible to cement the lower portion of the well using coiled tubing and a packer in the screen. A final scenario, water entering from the middle of the well, would make it difficult to isolate the water entry and continue production from the toe and heel. The operator needed to know the exact entry point of the water production to take proper remedial action.

The logging program included the basic PS PLATFORM tool string along with the GHOST Gas Holdup Optical Sensor Tool and the RSTPro Reservoir Saturation Tool run on coiled tubing. The GHOST, FloView holdups and spinner-derived fluid velocity represent fluids inside the completion screen, while the TPHL log and WFL measurements respond to flow both inside and outside the screen (left).

The WFL water velocity measurements are combined with the GHOST and TPHL holdup measurements to calculate the water flow-rate profile. In this example, more than 50% of the water production is coming from the toe of the well, flowing behind the screen and in the openhole gravel-pack annulus. The GHOST measurement also identified additional water entering midway along the horizontal wellbore at X450 ft [X137 m]. Since most of the gas is coming from the toe of the well, the operator decided to continue production without further intervention.



^ A channel that produces water. The image of the cement in the annulus behind casing helped to identify a water channel. The USI UltraSonic Imager tool images—amplitude (track 1) and transit time (track 2)—confirm that a large open channel exists in the cement annulus behind the casing just above the perforations.

Through-casing imaging tools, such as the USI UltraSonic Imager tool can help evaluate the quality of the cement job in a well and identify flow channels behind casing. For example, in a well in New Mexico that was producing only water, the existence of a channel above the perforations was confirmed (above). The well began producing oil after a cement squeeze and is currently flowing 50 BOPD [8 m^3/d] and no water.

12. Lenn C, Kuchuk F, Rounce J and Hook P: "Horizontal Well Performance Evaluation and Fluid Entry Mechanisms," paper SPE 49089, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 28-30, 1998.
13. Akhnoukh R, Leighton J, Bigno Y, Bouroumeau-Fuseau P, Quin E, Catala G, Silipigno L, Hemmingway J, Horkowitz J, Hervé X, Whittaker C, Kusaka K, Markel D and Martin A: "Keeping Producing Wells Healthy," *Oilfield Review* 11, no. 1 (Spring 1999): 30-47.
14. Hegeman P and Pelissier-Combescure J: "Production Logging for Reservoir Testing," *Oilfield Review* 9, no. 2 (Spring 1997): 16-20.
15. AL Shahri AM, AL Ubaidan AA, Kibsgaard P and Kuchuk F: "Monitoring Areal and Vertical Sweep and Reservoir Pressure in the Ghawar Field using Multiprobe Wireline Formation Tester," paper SPE 48956, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27-30, 1998.

Special Diagnostics for Vertical Communication

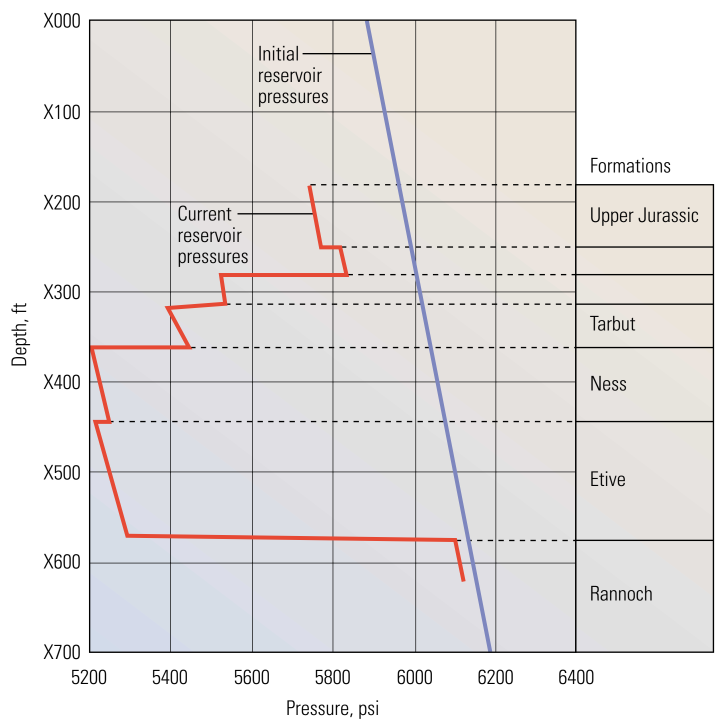
Water crossflow has two clearly defined forms. In addition to crossflow in the reservoir, which has already been discussed, crossflow also occurs inside the wellbore. Both kinds of crossflow are interdependent and deserve careful consideration.

A potential for wellbore crossflow exists whenever the wellbore penetrates multiple layers at different pressures. The pressure difference is maintained only when and where there is continuous isolation between each layer. This implies that reservoir crossflow and wellbore crossflow are mutually exclusive for any pair of layers. Some reservoirs, for example those with stacked sand channels, have local shale barriers extending hundreds of meters. However, such reservoirs may contain globally distant vertical connections that lead to crossflow and pressure communication even though they exhibit local isolation with transient pressure variations between layers during a choke-back test. This gives a mixture of the watered-out layer problems with and without crossflow.

Identifying the presence of crossflow in the formation is critical. Watered-out layers without crossflow can be easily treated at the wellbore, while there are no simple solutions if the layers are not isolated by impermeable barriers. Additionally, watered-out layers without crossflow will be subject to crossflow within the wellbore during shut-in. Several diagnostic methods are useful in determining vertical communication.

Multirate tests—With little additional effort, a production log can be turned into a multirate production log, or 'multilayer test,' by measuring the production rate of each layer at several different producing pressures with station measurements positioned between each layer. This helps determine the productivity index and average reservoir pressure for each layer.[14] In this way, crossflow potential can be assessed using NODAL analysis.

Wireline-conveyed formation testers—Wireline formation pressure measurements, such as those from the MDT tool or the RFT Repeat Formation Tester tool can show if the layers are in pressure communication.[15] If layers have different pressures and are not in wellbore communication, then they are isolated (below). If they show the same pressure, they may be in communication or they may have simply been produced (and injected) at similar rates, giving the same pressure.



^ Pressure measurements showing layer isolation. Pressure measurements, such as those from the MDT tool, can be used in in-fill wells to establish the pressure in each layer after a period of production in the field. When pressure differences exist between layers due to differential depletion, they show that the layers are isolated from each other by vertical permeability barriers.

Vertical interference test—A vertical interference test performed with the MDT tool will show effective vertical permeability near the wellbore. Vertical permeability can be determined from the change in formation pressure measured by a pressure probe, as formation fluid is pumped from the formation by a second (sampling) probe located about 2.3 ft [0.7 m] farther along the wellbore face.[16]

Shale correlations—Log correlations can demonstrate whether extensive shale barriers exist across a field. Excellent shale correlations from well to well suggest that reservoir layers are isolated by impermeable rock and that crossflow is unlikely.

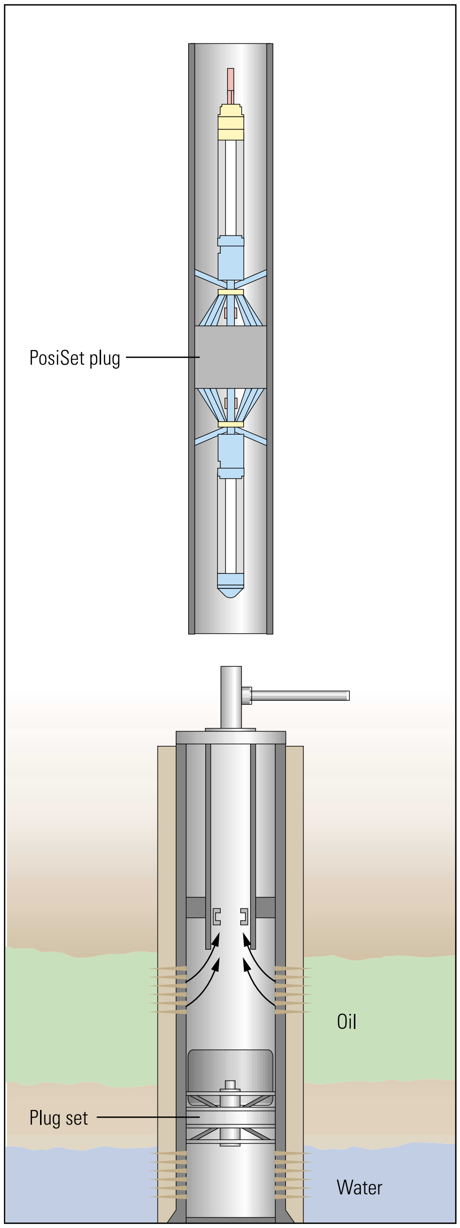
Spinner survey during shut-in—A production log (spinner) may detect wellbore crossflow during well shut-in, a clear sign of a pressure difference between isolated layers.

Choke-back test—Choke-back tests or production data can provide a useful diagnosis of vertical communication through the detection of pressure differences.

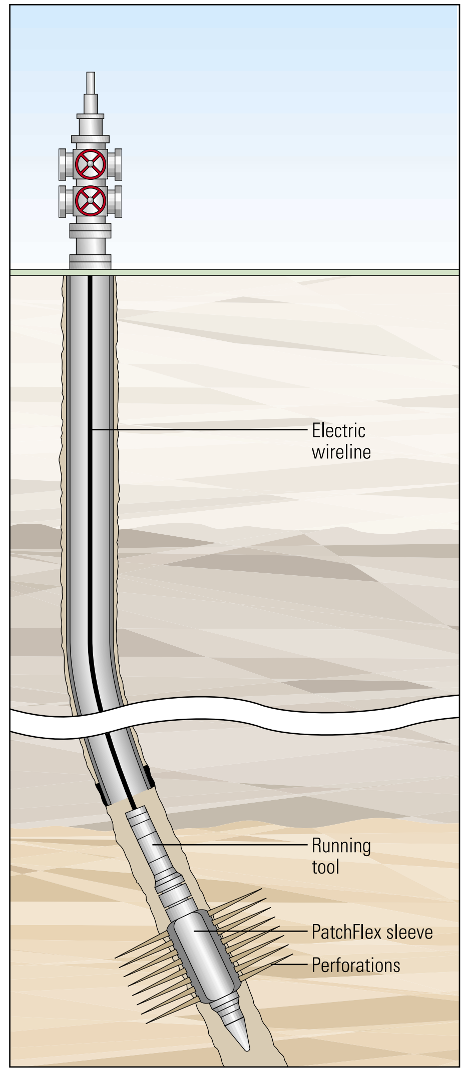
Water-Control Solutions

Each problem type has solution options that range from the simple and relatively inexpensive mechanical and chemical solutions, to the more complex and expensive reworked completion solutions. Multiple water-control problems are common, and often a combination of solutions may be required. Today, in addition to the traditional solutions described above, there are new, innovative and cost-effective solutions for water-control problems.

Mechanical solutions—In many near-wellbore problems, such as casing leaks, flow behind casing, rising bottom water and watered-out layers without crossflow, mechanical or inflatable plugs are often the solution of choice. The PosiSet mechanical plugback tool can be deployed on coiled tubing or wireline, and is a field-proven technology that ensures reliable wellbore shutoff in cased- and openhole environments (right).



^ **PosiSET mechanical plugback tool application. The PosiSET through-tubing plug is used for near-wellbore water shutoff. The wireline- or coiled tubing-deployed plug uses a positive anchoring system with upper and lower slip-anchors *(top)* that isolate water-producing layers in both open and cased holes *(bottom)*.**



^ **The PatchFlex sleeve. A flexible composite cylinder made of carbon fiber, thermosetting resins and a rubber skin, the PatchFlex sleeve is built around an inflatable setting element that is attached to a running tool and run into a well on a wireline. When the sleeve is positioned opposite the area to be treated, a pump within the running tool inflates the sleeve using well fluid. The resins are then heated until fully polymerized. The inflatable setting element is then deflated and extracted to leave a hard, pressure-resistant sleeve that fits snugly, even in damaged or corroded casing.**

When the wellbore must be kept open to levels deeper than the point of water entry, a through-tubing patch may be the answer. For example, a new coiled tubing- or wireline-deployed, inside-casing patch called the PatchFlex sleeve has been used successfully in many applications worldwide (far right). It is particularly well suited to through-tubing water or gas shutoff, injection-profile modifications and zonal isolation. The inflatable sleeves are custom-built to match the length of the perforated intervals and can withstand wellbore crossflow pressures. Once set, the sleeve becomes a composite liner inside the casing that is millable using through-tubing techniques if a subsequent squeeze operation is desired, or it can be reperforated later to allow reentry to the zones. The only disadvantage of the composite liner is a reduction of less than 1 in. [2.5 cm] in the wellbore diameter. However, other mechanical patch remedies take up even more of the available casing inner diameter.

Shell UK Exploration and Production reduced water cut in a North Sea well from 85% to 10% by using a PatchFlex sleeve to isolate the water-producing intervals. The PS PLATFORM logging tool quantified fluid contributions from each producing zone. Two 4-ft [1.2-m] perforated intervals were identified as producing most of the unwanted water. The RST readings confirmed the high water saturation in the water-producing intervals. In addition, the RST saturation analysis identified two more unperforated oil zones below the other producing zones. A traditional bridge plug could shut off the water-producing zone, but would also block the new oil zones beneath. Using PatchFlex technology, Shell shut off the water-producing zones and produced the new oil zones below them.

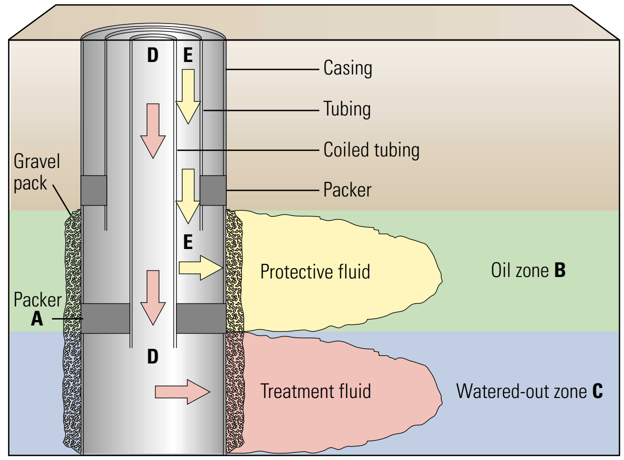
Chemical solutions—Chemical treatments require accurate fluid placement. Coiled tubing with inflatable packers can help place most treatment fluids in the target zone without risk to oil zones. Coiled tubing dual injection is a process of pumping protective fluid down the coiled tubing to the casing annulus and delivering the treatment fluid through the coiled tubing (right).

SqueezeCRETE cement is another key weapon in the armory of water-control solutions.[17] Its low fluid loss and capability to penetrate microfractures narrower than 160 microns make it ideal for remedial treatment of tubing leaks caused by flow behind pipe. Once set, this cement shows high compressive strength, low permeability and high resistance to chemical attack. SqueezeCRETE treatment is often used with common cement for shutting off perforations when the problem is watered-out layers, or rising bottom water or OWCs. Other applications include sealing gravel packs, casing leaks or channels behind casing.

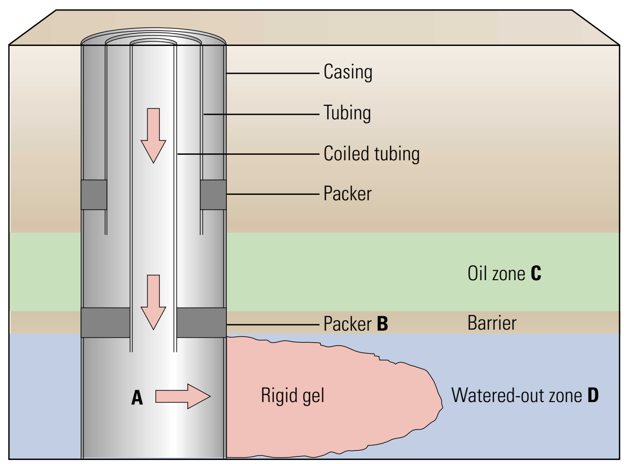
Rigid gels are highly effective for near-wellbore shutoff of excess water (right). Unlike cement, gels can be squeezed into the target formation to give complete shutoff of that zone or to reach shale barriers. They have an operational advantage over cement treatments because they can be jetted rather than drilled out of the wellbore. Typically based on cross-linked polymers, products like MaraSEAL and OrganoSEAL-R systems can be easily mixed and have a long working life. They can be bullheaded into the formation to treat specific water problems such as flow behind casing and watered-out layers without crossflow, or selectively placed in the water zone using coiled tubing and a packer.[18]

Another solution is a flowing gel that can be injected into small faults or fractures, but only penetrates formations with permeabilities greater than 5 darcies. Large volumes (1000 to 10,000 bbl) [159 to 1589 m^3] of these inexpensive fluids often successfully shut off extensive fracture systems surrounding waterflood injector or producing wells.[19] Like rigid gels, products such as Marcit and OrganoSEAL-F systems are cross-linked polymers that are simple to mix, have a long (up to three days) working time before becoming rigid, and can be pumped through completion screens.

Smart or selective fluids in the form of polymers and surfactants are being developed for formation matrix treatments near the wellbore. These treatments, called relative permeability modifiers, produce a permanent gel-like material



^ Coiled tubing dual injection. In water-control problems where the treatment fluid placement is critical, a coiled tubing-conveyed inflatable packer (A) can be used to provide wellbore isolation between the oil (B) and watered-out (C) zones. In this gravel-pack example, a treatment fluid (D) to stop unwanted water entry is pumped through the coiled tubing into the lower watered-out zone and a protective fluid (E) is simultaneously pumped through the annulus into the oil-producing zone.



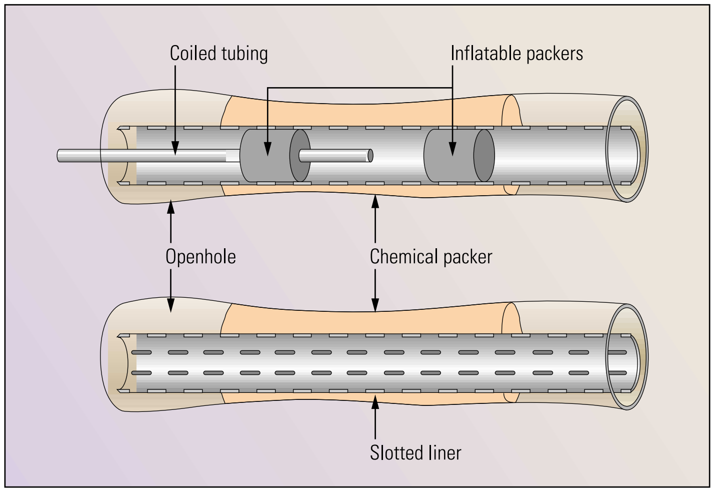
^ Rigid-gel application using coiled tubing. Pumping a rigid gel (A) into the watered-out zone can shut off water entry from a layer without crossflow. A coiled tubing inflatable packer (B) isolates the oil-producing zone (C) from the watered-out zone (D).

16. Crombie A, Halford F, Hashem M, McNeal R, Thomas EC, Melbourne G and Mullins OC: "Innovations in Wireline Fluid Sampling," *Oilfield Review* 10, no. 3 (Autumn 1998): 26-41.
17. Boisnault JM, Guillot D, Bourahla A, Tirlia T, Dahl T, Holmes C, Raiturkar AM, Maroy P, Moffett C, Mejía GP, Martínez IR, Revil P and Roemer R: "Concrete Developments in Cementing Technology," *Oilfield Review* 11, no. 1 (Spring 1999): 16-29.
18. These gels will not penetrate formations with permeability less than 25 mD.
19. O'Brien W, Stratton JJ and Lane RH: "Mechanistic Reservoir Modeling Improves Fissure Treatment Gel Design in Horizontal Injectors, Idd El Shargi North Dome Field, Qatar," paper SPE 56743, presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, October 3-6, 1999.

to stop flow in water layers, but retain fluid behavior in oil layers to allow production to continue. In some applications, they offer the potential of performing a selective treatment simply by using a low-cost bullheading method of placement.

Treatments for water problems in horizontal wells are most effective when the treatment zone is isolated from the remainder of the wellbore. In cased holes, and to some extent in openholes, this is achieved mechanically with inflatable packers. However, when a screen or liner has been run but left uncemented, such mechanical devices are not effective in isolating the open annular space behind the pipe. Developed for such situations, the Annular Chemical Packer (ACP) achieves zonal isolation using coiled tubing-deployed packers or bridge plugs (right).[20] The objective of the ACP is to achieve full circumferential coverage over a relatively small length while leaving the liner free of material that might obstruct fluid flow or tool passage through the section. A low-viscosity, cement-based fluid is pumped through coiled tubing and a straddle-packer assembly and placed through the small slots in the pipe. Once placed, the fluid immediately develops high gel strength to prevent slumping and ensures complete annular filling and isolation.

Completion solutions—Alternative completions, such as multilateral wells, sidetracks, coiled-tubing isolation and dual completions, can solve difficult water problems such as rising OWCs, coning, incomplete areal sweep and gravity segregation.[21] For example, coproducing water is a preferred strategy for coning in high-value wells. It involves perforating the water leg and using dual completions (below).

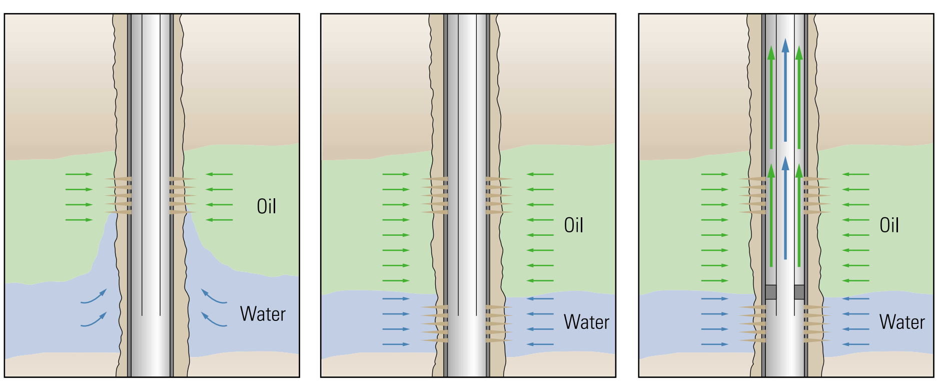


^ Annular Chemical Packer. ACP technology involves placement of a cement-based fluid into the annular space between an uncemented slotted liner and the formation. The fluid is conveyed to the treatment zone using coiled tubing and injected between an inflatable packer assembly to fill the annulus over a selected interval. It is designed to set in this position forming a permanent, impermeable high-strength plug, fully isolating the volume of the annulus.

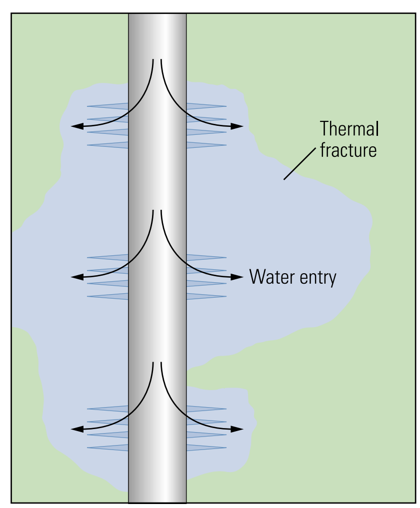
Injector Problems

Injectors can induce problems if the injection water is not properly filtered, because it may contain particles large enough to cause matrix plugging. Or, if it is not treated properly with production chemicals such as bactericide and oxygen scavengers, damage can build up. Both of these can increase injection pressure until a fracture is initiated. Initially short, these fractures will grow in length and height to maintain injectivity as the fracture faces become plugged.[22] When induced fractures extend vertically over several layers, the operator no longer has control over the vertical sweep. It is difficult to regain control of the injection profile.

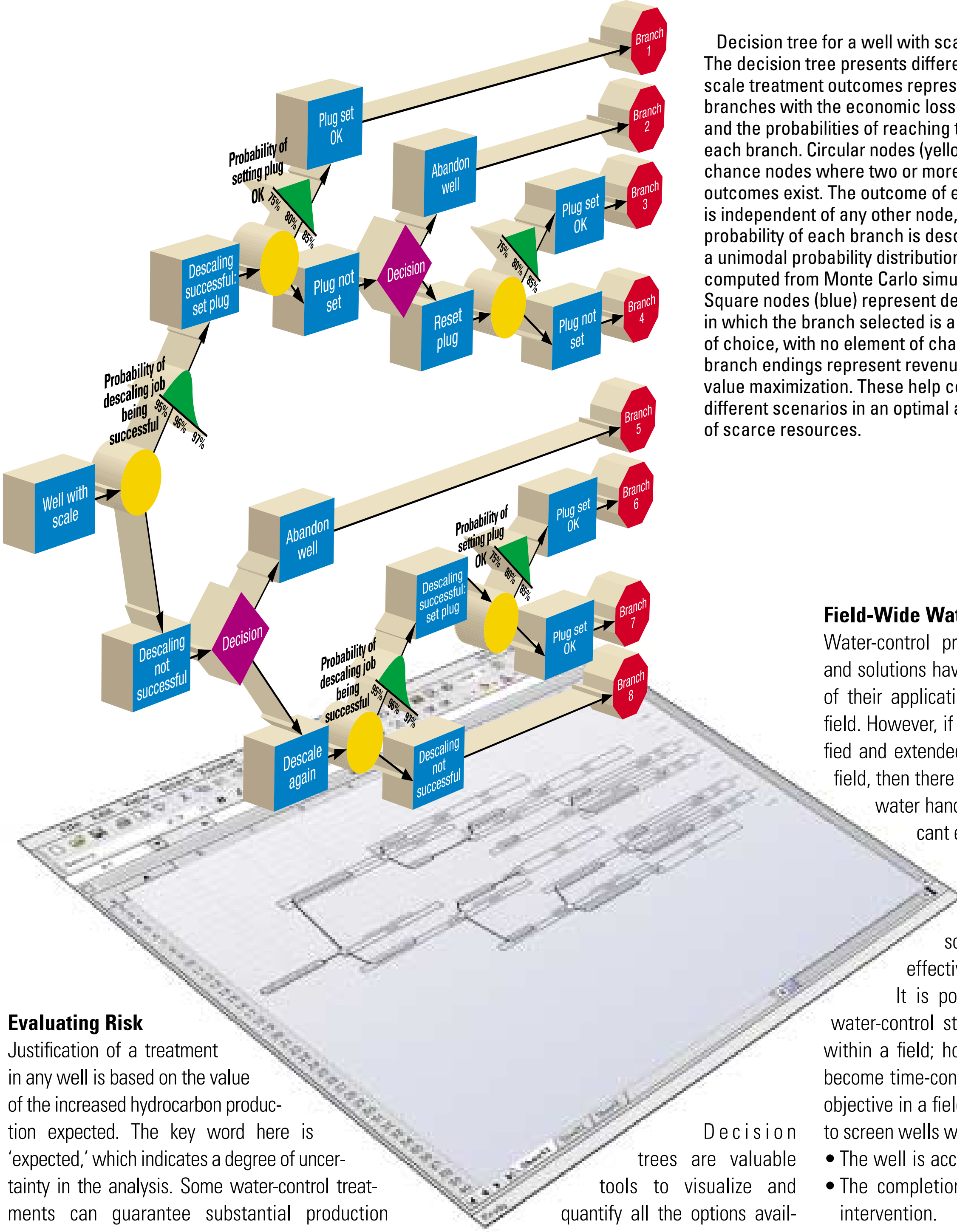
Thermal fracturing, often encountered offshore, is caused by the stress reduction in the injection zone from cool-down. The zone with the highest injectivity cools down first and then fractures—taking even more injection fluid and causing poor vertical sweep (below). In these cases, it is difficult to avoid thermal fracturing. The best strategy may be to ensure that all zones are fractured, either thermally or hydraulically, to ensure a more even injection profile. Sometimes if a high-permeability layer is adjacent to a low-permeability layer, the thermal fracture can break into the high-permeability zone, taking all the injection water and leaving the low-permeability zone unswept.



^ Fighting water with dual drains. One solution to water-coning problems *(left)* is to perforate the water leg of the formation and coproduce *(middle)* the water to eliminate the water cone. This low-cost approach may increase the water cut, but improves the sweep efficiency and long-term reserve potential. Alternatively, the water and oil can be produced separately through the tubing and annulus *(right)*.



^ Thermal fracturing in an injector well. Fractures can be initiated in injector wells through pressure and thermal stress induced by cold-water entry. As a result, the vertical sweep profile is compromised.



Decision tree for a well with scale. The decision tree presents different possible scale treatment outcomes represented by branches with the economic losses or profits and the probabilities of reaching the end of each branch. Circular nodes (yellow) represent chance nodes where two or more possible outcomes exist. The outcome of each branch is independent of any other node, and the probability of each branch is described by a unimodal probability distribution (green) computed from Monte Carlo simulations. Square nodes (blue) represent decisions in which the branch selected is a matter of choice, with no element of chance. The branch endings represent revenues—called value maximization. These help compare different scenarios in an optimal allocation of scarce resources.

Evaluating Risk

Justification of a treatment in any well is based on the value of the increased hydrocarbon production expected. The key word here is 'expected,' which indicates a degree of uncertainty in the analysis. Some water-control treatments can guarantee substantial production increase. In such circumstances, the primary element of uncertainty is the job success itself. When the incremental production is relatively small (or was based on several assumptions) not only does job-risk come into play, but also the prediction itself becomes a key risk. Therefore, the value of a water-control treatment to the operator needs to be quantified. An analysis incorporating the multifaceted components of risk can be undertaken using the methods of quantitative risk analysis (QRA).

Decision trees are valuable tools to visualize and quantify all the options available to a decision-maker and the probability of their outcomes. As an illustration, PrecisionTree, provided by Palisade Corporation, is a decision-analysis program used with the Excel spreadsheet program. The software can be coupled to Monte Carlo methods, furnishing a 'risked decision tree' to analyze water-control options for specific wells (above).

20. Elphick J, Fletcher P and Crabtree M: "Techniques for Zonal Isolation in Horizontal Wells," presented at the Production Engineering Association Meeting, Reading, England, November 4-5, 1998.
21. Hill et al, reference 5.
22. Injectivity is a measure of how much liquid can be pumped in a well (or zone) with a given difference between the injection fluid pressure and formation pressure.

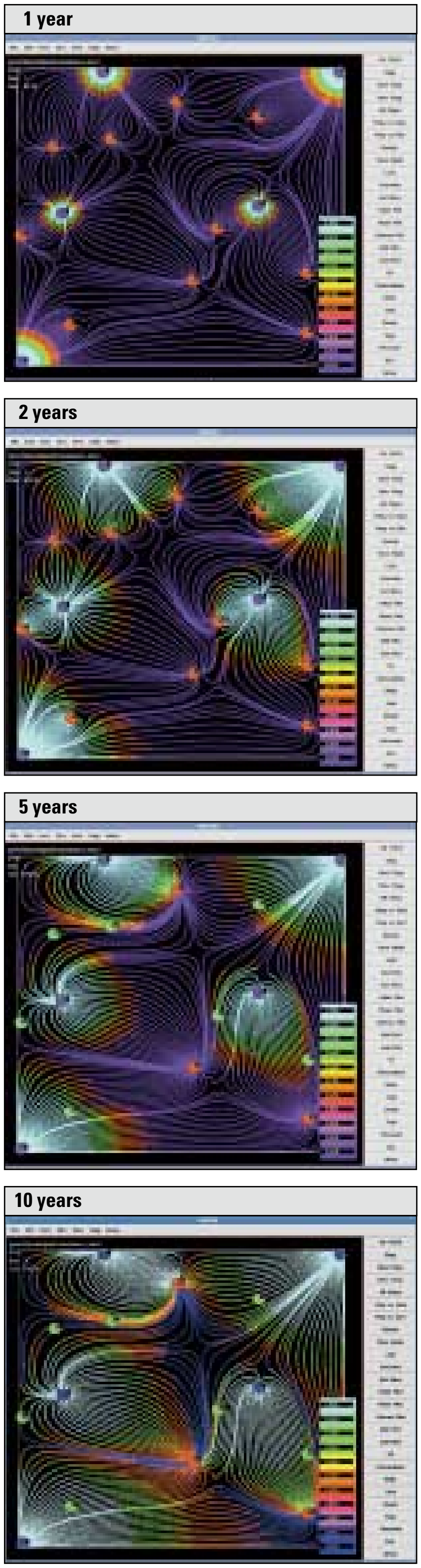
Field-Wide Water Control

Water-control problems, diagnostic techniques and solutions have been discussed in the context of their application to individual wells within a field. However, if diagnostic techniques are modified and extended to large number of wells in a field, then there is greater reduction in total field water handling and, in many cases, significant enhancement in total field hydrocarbon production. By combining the correct diagnosis with the application of proven solutions, water control can be an effective reservoir management tool.

It is possible to apply individual well water-control strategies to a number of wells within a field; however, in large fields, this can become time-consuming and inefficient. The first objective in a field-wide water-control program is to screen wells with the following characteristics:

- The well is accessible for intervention.
- The completion is robust enough to tolerate intervention.
- There is economic value to reducing water production from that well.
- The well has a water-control problem that can be treated economically with acceptable risk.

Field-wide water-control strategies often are different from those applied on a well-by-well basis. For example, completion designs that have worked effectively on single wells may need to be modified for field-wide improvements. In one case, a South American operator was producing from a layered reservoir with distinct flow units separated



^ Streamline simulation. History-matched FrontSim water-flow streamline simulations can be used to show well interactions and detail the exact fraction of water that flows between the injector and producer wells. In this example with 10 producers (red circles) and 5 injectors (blue circles), the model helps visualize where injection water is going at 1, 2, 5 and 10 years. Unswept regions (blue) are clearly visible near the center of the reservoir.

by shales. The operator perforated all layers and ignored the variable pressures across the different layers. Eventually, water appeared at several layers in different wells, and the subsequent pressure depletion caused decreased oil production in the remaining layers. Originally, the operator simply shut off water in the offending layers where the local geology was favorable, but field production continued to decline because of increased occurrence of water breakthrough and possible crossflow through discontinuities in the shale barriers. Using a field-wide water-control strategy, the operator moved away from commingled to single-layer production in each well, so that the crossflow could not occur and full effective drawdown on the low oil-pressure layers was achieved. This means fewer wells were draining each layer, but the field was being swept more efficiently.

Field-wide considerations also include the collective influence of inflow performance of many wells. Local and regional geology—in terms of structure and heterogeneity—influence fluid movement. For example, the hydraulic relationships between producers and aquifers or injector wells should be considered (left). Current and future completion strategies also are important factors in the analysis. Clearly, a lengthy scoping, or screening, study is not required every time a field-wide water-control project is undertaken. Nor should a scoping study simply be a sifting mechanism for finding treatable wells. The study must fit the problem, and the operator's extensive knowledge can often help augment and expedite the study.

Every water-control scoping study uses engineering diagnostic tools to identify which wells have high value and can be effectively treated at low risk. The scoping study consists of two phases, the diagnostic phase and the solutions phase. The diagnostic phase uses the operator's regional expert knowledge and experience coupled with Schlumberger engineering and software to profile the nature and cause of the problem. Wells are initially screened to select a focus area within the field, then again to identify wells that might benefit from some type of intervention, and finally to choose wells that are of sufficient value to justify treatment.

WaterCASE software-based methodology screens candidate wells on the basis of existing data such as production histories, existing production logs, reservoir characterization from both numerical and analytical models and offset treatment data and experience (next page). One recent study provided by Schlumberger in the North Sea illustrates the results of the screening process. Here a field contained nearly 100 wells with water cuts ranging from 20% to 90%, and a field average of 60%. The scoping study made the following determinations:

- 15 wells are subsea, requiring a rig for intervention, and 6 have production tree or 'fish-in-hole' problems, making intervention difficult.
- Of the remaining 85 wells, 20 have corroded tubulars, increasing intervention risk.
- Of the remaining wells, 25 have significant potential for additional productivity if the water cut is reduced.
- Of these 25 wells, 15 have solvable problems consisting of casing leaks, flow behind pipe, bottom water, high-permeability layers without crossflow, or fractures from injector to producer.

The results identify primary candidate wells to take through to the second phase of the intervention process—developing a solutions plan.

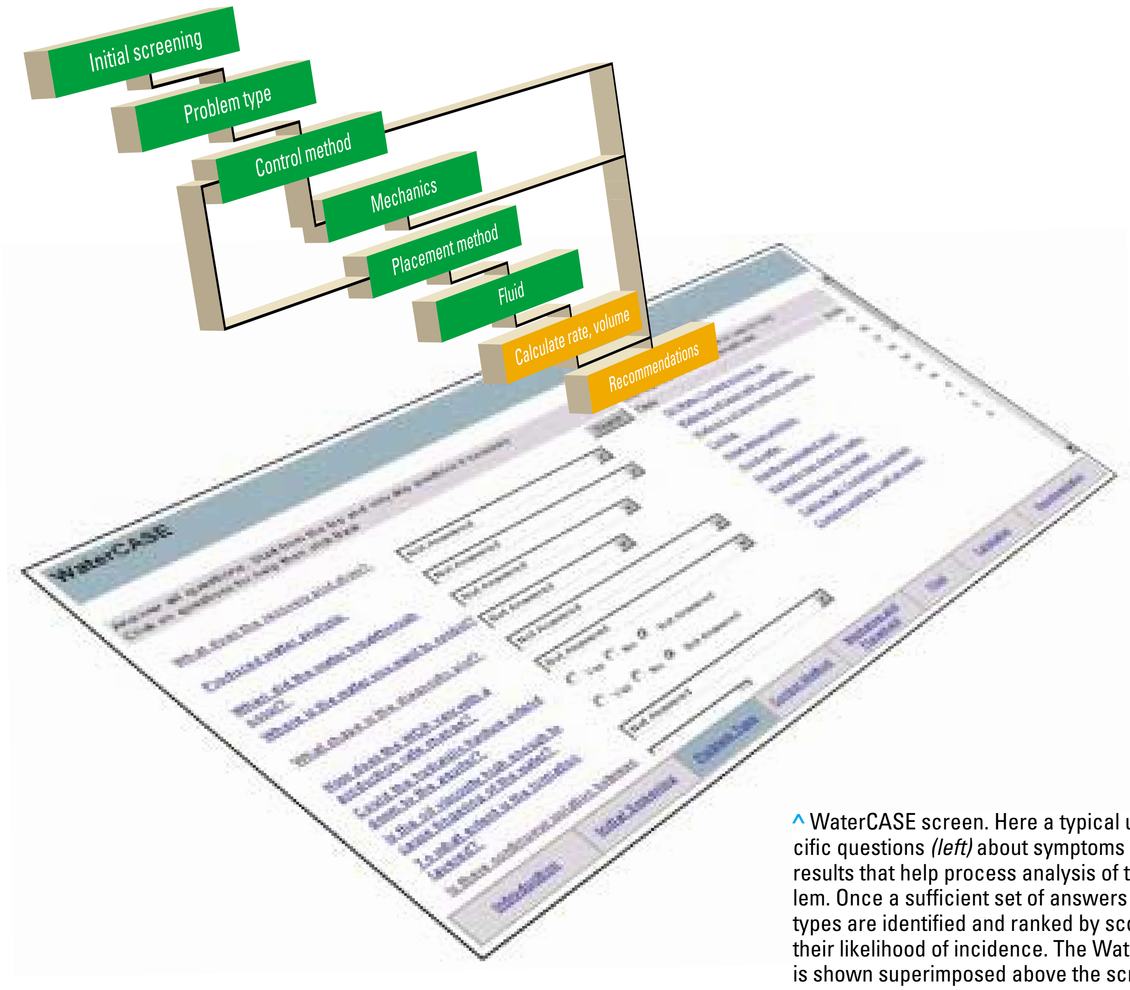
In this phase, a spectrum of solutions including mechanical, fluid and completion options is developed. The solutions spectrum is ranked by risk, cost and benefit using Schlumberger quantitative risk analysis (QRA). Solutions range from 'quick hit and rapid pay' to longer duration, 'higher cost with higher pay' solutions. Schlumberger works jointly with the operator's asset team to identify the most cost-effective, lowest risk and highest value treatment option for each well. The chosen solution for each candidate well is fully engineered for final submission and peer review prior to execution.

To maximize field-wide cost reductions, surface-related water-control services *(page 50)* should be included in the overall screening process. An integrated solution is often a combination of borehole, reservoir-scale and surface systems. Surface facilities may contribute up to 25% reduction in overall water-handling costs.

Field-Wide Problems

Eventually most oil fields are under a waterdrive either from waterflood or a natural aquifer. Any attempt to significantly increase the recovery factor must increase at least one of the components of the recovery factor: displacement efficiency, areal-sweep efficiency or vertical-sweep efficiency. The first, displacement efficiency, can be improved only by reducing the residual oil saturation with a surfactant, miscible flood or water-alternating-gas scheme. Water control improves areal- or vertical-sweep efficiency.

Any analysis of water sweep at a field scale requires an understanding of the geology and proper reservoir characterization. Reservoir characterization, particularly heterogeneity, is poorly understood early in the life of the field, but gradually improves as dynamic production data become available.



^ WaterCASE screen. Here a typical user interface asks specific questions *(left)* about symptoms and diagnostic test results that help process analysis of the water-control problem. Once a sufficient set of answers is completed, problem types are identified and ranked by score *(right)* according to their likelihood of incidence. The WaterCASE logical structure is shown superimposed above the screen display.

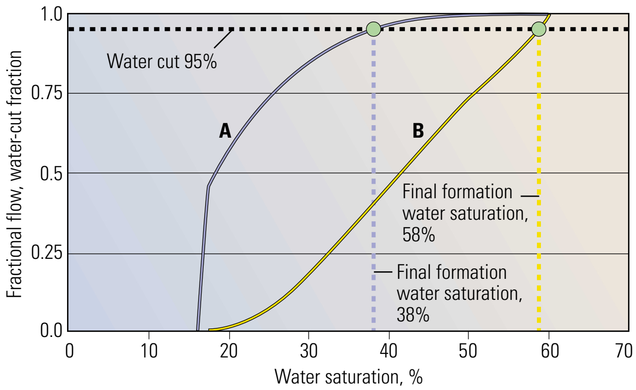
In calm depositional environments such as shallow marine, continuous shales are often present, providing good vertical isolation between layers, and making vertical sweep improvement practical. Any problem with watered-out layers without crossflow is easily corrected at the wellbore, and in this environment, this problem dominates the more difficult problem of watered-out layers with crossflow.

Eolian sands, often thick with good vertical permeability, pose different problems for water control. They can exhibit gravity fluid segregation, causing unwanted water entry into producing wells.

Fluvial and deltaic depositional environments typically create sand channels. These may vary from well-stacked sands with good horizontal and vertical continuity to isolated channels with poor communication. Since various problem types can occur in this setting, good sand characterization is important.

Carbonate reservoirs have their own challenges, including frequent natural fractures leading to water entry from a water layer, or through fractures connecting injectors and producing wells. Additionally, large dissolution channels from underground water flow, sometimes several meters across, can create superhighways to flow, often with premature water breakthrough. These may be considered subsets of fracture-induced water problems. Shutting off this type of channel is extremely difficult.

Many operators are reluctant to proactively control water prior to breakthrough, so most action is remedial. Proactive water control would include choking back zones with higher permeability to create a more uniform sweep, but this would mean sacrificing early cash flow for an uncertain return due to incomplete knowledge of heterogeneity. However, the production (and injection) profile can be improved through selective stimulation of zones with lower permeability. This is a



< Fractional-flow prediction. The two fractional-flow plots show how a multilayer reservoir might perform under different assumptions. The two curves show a large difference in the final formation water-saturation value at the same water-cut flow rate. Assuming that reservoir layers water out according to their flow capacity, Curve A shows a substantial amount of oil still remaining in the formation. Assuming layers water out from bottom to top, Curve B shows nearly all the oil is recovered.

particularly attractive option because of the capability of using coiled tubing to precisely place small hydraulic fractures. The improvement in horizontal drilling techniques, including multilaterals and coiled tubing, also is allowing a greater range of viable solutions for complex reservoir problems. However, the predominantly reactive mode for water control, and hence sweep improvement, is likely to continue until more precise early reservoir characterization is achieved.

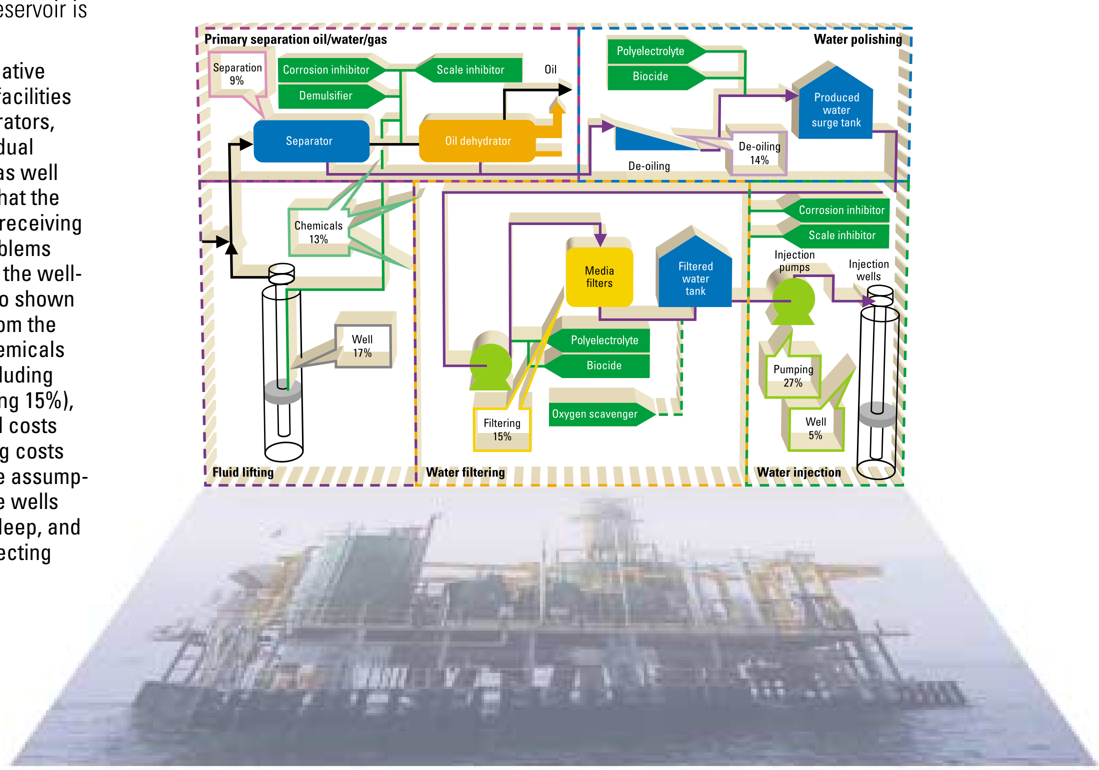
Based on knowledge—or even a rough estimate—of the reservoir volume and the fractional-flow curve, the expected recovery can be estimated assuming production continues to a given water cut. By comparing the expected recovery with the ultimate recovery indicated by the WOR semilog plots, one can use field-wide diagnostics to estimate how well the reservoir is being swept. If the WOR is less than the fractional-flow curve indicates, then there is bypassed oil (above).[23] If the oil production is accelerated, then it must account for its time-delayed value when calculating net present value—the value of the oil as it is produced minus its value when it would have been produced. If the oil is incremental, then the water-control operation can assume all the value to help justify the costs of operation. Incremental oil is often more valuable than accelerated oil.

Surface Facilities

Surface facilities separate water from oil and process it to an acceptable specification suitable for disposal to the environment or for reinjection (below). Gas is sent to a gas-processing plant or simply flared, while the oil is processed in a 'water-polishing' stage in which water is removed from the oil down to the 0.5 to 1.0% level, depending on delivery requirements. Water is reinjected for both disposal and pressure maintenance. In a typical water-treatment facility for injection purposes, all water streams from each stage of separation are further de-oiled to a level compatible with discharge to the environment or receiving formation, typically between 10 and 40 ppm. This includes filtering through a 10- to 50-micron filter to remove solids, making the water more compatible with the formation prior to reinjection.

Chemical treatments including emulsion breakers, biocides, polyelectrolytes and oxygen scavengers are added to the water to condition it for reinjection, and corrosion inhibitors and antiscale chemicals are added to protect tubulars and downhole equipment. When water is produced at high rates, chemical additives constitute up to 20% of the surface water-handling costs. Surface equipment and facilities account for the remaining 80%.

In practice, surface solutions start downhole. Partial downhole oil-water separation in the wellbore can eliminate some of the costs of lifting water. An alternative to simultaneous downhole separation and reinjection is downhole segregated production whereby water and hydrocarbons are produced separately—avoiding the need for surface separation capability. Finally, chemical treatments, such as emulsion breakers, antiscale and corrosion inhibitors injected downhole can prepare fluids for efficient surface treatment.[24]



> Typical surface water facilities and relative costs. The surface water-management facilities include primary oil, water and gas separators, water-polishing systems to remove residual oil from the water, solids-filter systems as well as chemical treatments. These ensure that the reinjected water is compatible with the receiving formation and does not cause other problems such as scale deposits and corrosion in the wellbore system, and reservoir damage. Also shown are typical relative water-cycle costs from the producing well (lifting costs of 17%), chemicals 13%, removal and processing costs (including separation 9%, de-oiling 14%, and filtering 15%), pumping 27% and finally reinjection well costs 5%. Estimates of average water-handling costs of 50 cents per barrel were based on the assumption that the fields were onshore and the wells were 6000 to 8000 feet [1828 to 2438 m] deep, and producing 1000 BOPD [159 m^3/d] and injecting 5000 BWPD [795 m^3/d].

Well pad factory concept—Existing separation technologies and multiphase pumping are readily available for commercial use as a "well pad factory." Oil, water and gas are separated close to the wellhead area and the unwanted water and gas are reinjected for pressure maintenance or disposal with multiphase pumps.

Conventional surface facilities—Conventional gravity-separation facilities can be designed for specific production profiles. With best practices and technologies, surface facilities can provide substantial savings in the water-removal chain (right). For example, centrifugal separation performed by Framo Engineering—technology derived from multiphase pumping practices—could soon provide important operational and capital savings by reducing the amount and size of equipment, and chemical-injection costs. Centrifugal separation could be extended to the well pad factory. Other specific water-conditioning technologies used to reduce the concentration of water in oil to extremely low levels include water polishing, which can reduce the water content down to the 40 ppm level; ultrapolishing systems that reduce the water down to the 5 ppm level; and fine solids removal to filter debris such as sand down to 2-micron particle size.

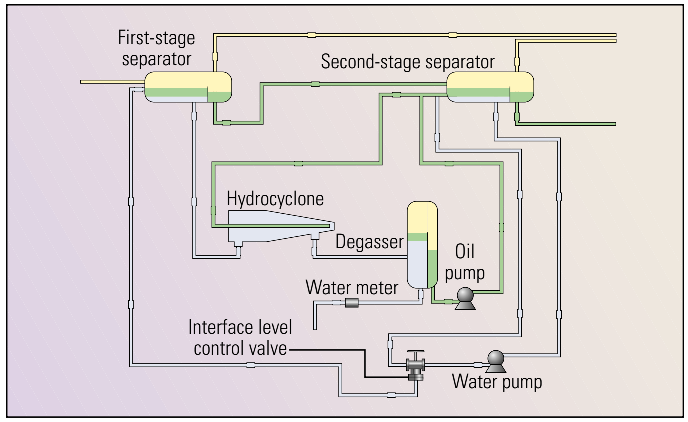
As worldwide daily water production increases, surface facilities, which were not originally designed to handle large volumes of water, are being retrofitted with equipment that can handle higher water fractions economically. Today, some reservoirs are being produced cost-effectively with over 95% water cut. In well-known reservoirs, such improvements in water-handling services at surface facilities are unlocking additional recoverable reserves.

The LASMO Plc Apertura project in the Dación field in Venezuela is an example of a water-control strategy used to improve the economics of field-wide oil production by reducing the bottlenecks in the water-handling capabilities of surface facilities. Managed by the LASMO-Schlumberger alliance, the project, which began in April 1998, consists of three phases:

- Complete an intensive upgrading and debottlenecking of surface facilities to increase processing capacity 50%, from 20,000 B/D [3178 m^3/d] at 50% water cut to 80,000 B/D [12,712 m^3/d] at 60% water cut, increasing oil production from 10,000 to 30,000 BOPD [1589 to 4767 m^3/d].

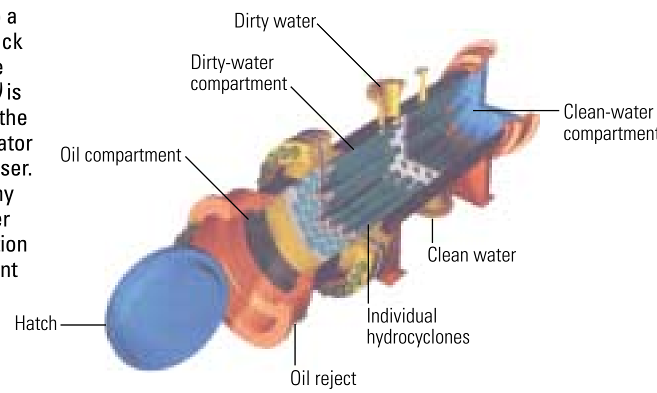
23. Dake LP: "The Practice of Reservoir Engineering," in *Developments of Petroleum Science* 36. Oxford, England: Elsevier, 1994: 445-450.
24. Crabtree M, Eslinger D, Fletcher P, Miller M, Johnson A and King G: "Fighting Scale—Removal and Prevention," *Oilfield Review* 11, no. 3 (Autumn 1999): 30-45.

Flow path for removal of oil-contaminated water



^ Surface water polishing. Oil is removed from produced water prior to disposal into a river or sea, or injection back into the reservoir *(top)*. The hydrocyclone unit *(bottom)* is positioned downstream of the water outlets on the separator and upstream of the degasser. Its function is to remove any entrained oil from the water and return it to the separation process before water is sent to the degasser.

Hydrocyclone cross section



- Install new production facilities with processing capacity of 360,000 B/D [57,204 m^3/d] at 75% water cut, reaching a 90,000 BOPD [14,300 m^3/d] oil-processing capacity.
- Retrofit the water-handling module in the future to boost the mature-field water-handling capacity to cope with up to 90% water cut, allowing an economic final production phase of up to 600,000 B/D [95,340 m^3/d] and 30,000 BOPD.

In this particular field-wide redevelopment project, water-control services and management have unlocked reserves by doubling the crude-oil recovery factor from 14% to nearly 35%.

A Look at the Future

The goals of reducing the costs of excess produced water and unlocking additional recoverable reserves from mature fields appear difficult, but some quick victories are within reach. Understanding water-flow problems and their solutions is now a key component of today's reservoir engineering.

Making the best of what we have is the first step in water control, requiring a detailed understanding of the assets, resources, activities and costs associated with handling produced water. Opportunities may then become apparent to reduce the costs of traditional practices and materials (chemicals) and identify where future potential cost increases can be controlled. Technical innovation will enable larger gross volumes to be handled with existing facilities. The total production system, from reservoir to custody transfer point for oil and final resting place for water, must be considered. In many operator and service companies, research and development programs are currently targeted at developing appropriate tools to manage this wave of produced water.

Finally, an integrated approach to water control in every well from reservoir to disposal (or back to reservoir for pressure maintenance) will bring immediate and long-term cost-savings. Integrated water management services is envisioned as the key to reservoir production optimization by providing the means for producing additional recoverable reserves. While water-control services will provide the bulk of progress, a downhole factory—built on the well pad factory concept—will minimize produced water-handling costs, and optimized facilities processes could turn waste into a commodity, which will further enhance the recovery factor. Nevertheless, the real money comes from the potential increase in oil production. —RH