Exploiting Reservoirs with Horizontal Wells: the Mærsk Experience

Danish-based Mærsk Olie og Gas AS transformed prospects in their Dan field by drilling horizontal wells and then hydraulically fracturing them. No operator had previously fractured a horizontal well. Understanding their motivation, following their learning curve, experiencing their taste for innovation is to capture the spirit of the horizontal well revolution sweeping the industry.

When the oil industry recession hit its low in 1987, Mærsk Olie og Gas AS began an experiment designed to ensure its continued growth into a major North Sea oil producer. Mærsk Oil, an A.P. Møller affiliate operating on behalf of a partnership of A.P. Møller, Shell and Texaco, initiated oil production from the Dan field in 1972. Situated 200 kilometers (km) [120 miles] offshore in the southwestern part of the Danish North Sea, the Dan field is an anticlinal structure about 6 km [4 miles] across and contains four producing formations totaling several hundred feet in thickness (above). Total oil in place is estimated to be two billion barrels, but recovery factors are low, around 10 percent. The formations are medium-porosity chalks—18 to 36 percent porosity—with very low permeability, typically less than 1 millidarcy (md).

Mærsk Oil began its Dan field development with a six-wellhead platform, and then

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boosted production with two more six-wellhead platforms, in 1975 and 1976 respectively. The increase was short-lived. Even with the benefit of hydraulic fracturing, the chalk simply would not yield enough oil. Production steadily declined (above).

In an effort to boost production, Mærsk Oil established two more platforms each with 12 wellheads and began drilling into the northwestern half of the anticline, called A block. (The downthrown A block is separated from the southeastern, upthrown B block by a northeast-southwest fault zone.) Deviated up to 60 degrees and hydraulically fractured, these 24 new wells went on stream in 1987, increasing production at first to 30,000 barrels of oil per day (BOPD).

Unfortunately, production declined rapidly, the economic effects being exacerbated by a steadily weakening crude market. Mærsk Oil was thus faced with implementing an altogether bolder scheme.

Back in 1978, Mærsk Oil reservoir engineers had studied the then revolutionary idea of tapping the tight chalk with horizontal drainholes. Recognizing numerous technical problems, the advantages seemed distinctly attractive. A horizontal drainhole could drain thousands of feet of reservoir compared with hundreds of feet drained by a conventional well. Fewer wells would be required, costing less money, and valuable space on platforms could be saved.

Following the lead of Shell researchers in The Hague, The Netherlands and of F.M. Giger at the Institut Français du Pétrole, the engineers compared the productivity index (PI) expected from a horizontal well with that of a conventional, hydraulically fractured well. In the center of the Dan field, such a well would have a PI about twice that of a conventional fractured well, while at the flanks the PI advantage would be marginal. In general, the increased cost of drilling the horizontal well did not seem worthwhile. A fractured horizontal well, on the other hand, looked promising. Several fractures regularly spaced along the well offered a four- to six-fold increase in PI. This seemed particularly inviting outside the gas cap on the reservoir flanks, where induced fractures would not act as a gas conduit into the production stream.

In 1978, however, few horizontal wells had been drilled anywhere, and none had been fractured. Horizontal wells were being drilled to tap naturally fractured reservoirs and were completed either openhole or with uncemented slotted liner. Cementing and perforating conventional liner in a horizontal well, necessary to isolate zones for hydraulic fracturing, was regarded as too difficult. By 1986, though, Mærsk Oil decided that cementing would work and that it was time to attempt the industry’s first horizontal, hydraulically fractured well. The initial commitment was to drill and evaluate three horizontal wells.

The First Three Wells
A period of careful planning covered all aspects of the operation. Wellbore trajectory, wellbore stability, bottomhole assembly (BHA) design, drillstring torque and drag modeling, drilling mud specification, casing and liner selection, cement slurry design, stimulation hardware—these factors all required special attention. The first well, MFB-14, was planned to tap 1000 horizontal feet [300 meters] of the upper Maastrichtian chalk, the most permeable of the Dan field formations. The horizontal section was to be far outside the gas cap on the flanks of the reservoir in the A block. The intended stimulation was acid fracturing (next page).

It was decided to go for a long-radius hole, so conventional hardware could fit down the hole. The trajectory was planned to minimize torque and drag, with three kickoff points. The first was to be at 800 feet [240 meters] where angle would be built at
There were two BHA options for steering the hole, a steerable motor or an offset stabilized steerable turbine. The steerable motor was chosen because it could accommodate the high mud flow rate, around 900 gallons per minute, required to clean the deviated and horizontal sections of the well. The steerable motor performed flawlessly except in the lower Danian chalk that overlies the Maastrichtian. Chert stringers in this section deflected the bit from its proper course, causing it to build angle far too fast. The well had to be plugged back and the Danian drilled with a super stiff BHA to keep the hole on track. This increased total drilling time to 68 days, which altogether was 20 more than planned.

Perhaps the most critical planning concerned cementation. Five fractures planned along the 1000-foot horizontal drainhole, would have been impossible to achieve if there were fluid communication through the cement. Research by the Horwell consultancy group, which included a physical simulation of a horizontal cement job, indicated that to prevent channel development the cement slurry must have no free water


The Dan field, divided by a major northeast-southwest trending fault into the downthrown northeastern block A and the upthrown southeastern block B. The field has four producing chalks, in increasing depth: upper Danian, lower Danian, upper Maastrichtian and lower Maastrichtian. The Maastrichtian chalks are the better producers. Conventional wells produce from all four chalks. Horizontal wells produce from the upper Maastrichtian only.

2½ degrees per 100 feet [30 meters] to achieve a deviation of 38 degrees. This angle would carry the well to near the target where the second kickoff would take place. Angle would be built at the same rate to about 70 degrees allowing the well to proceed to the top of the chalk reservoir. At the last kickoff, the well would build to almost horizontal entering the upper Maastrichtian.

Torque and drag modeling indicated that as long as the planned trajectory was followed, standard drillpipe and collars were strong enough to transmit the necessary weight and torque to the bit as deviation increased. The horizontal sections required drill collars in the less-than-50-degree sections of the well to provide weight. In fact, MFB-14 was drilled very close to specifications, and the torque and drag encountered while drilling came within 10 percent of computer-modeled predictions.
and no sedimentation. These requirements were met by Dowell Schlumberger’s latex-based formulations.

It was also considered necessary to maximize space in the annulus to guarantee mud displacement. In MFB-14, a 5½-inch liner was run in the 8½-inch drainhole, with three centralizers on every two joints of liner. (In subsequent horizontal wells, a 7-inch liner was used and satisfactorily cemented.) Another precaution was ensuring that the entire liner could be rotated as well as reciprocated to maximize mud displacement. This required a special liner hanger and centralizers allowing liner movement. With these precautions, cementation in MFB-14 proved satisfactory. This was indicated first by good bond on Cement Evaluation Tool (CET®)/Cement Bond Tool (CBT®) logs and later when the five fractures were created without leakoff.

Evidence that MFB-14 had not gone completely to plan came from Tough Logging Condition (TLC®) logs run on drillpipe throughout the horizontal section, a complex procedure that has become routine on all Maersk Oil's horizontal wells. The logs suggested that after about 330 feet [100 meters], the well trajectory had left the upper Maastrichtian chalk and entered the overlying lower Danian. This is a tighter chalk and known from experience to require propping. Interestingly, the well trajectory was on target. It was the target that was off—formation dip was one degree more than expected (below).

Stimulation plans therefore had to change. The original plan called for acid fracturing using a straddle packer with swab cups as packing elements. This was unsuitable for pumping proppant, so the five zones were perforated and stimulated using a conventional drillstem test string. This required isolating previously stimulated zones with a bridge plug set just beyond the zone to be stimulated. After stimulating the zone and killing the well, the plug was milled and a new plug set farther up the hole for preparation for stimulating the next zone. Each zone therefore required three trips in the hole, rather than the envisaged one, and this extended completion time from the planned 12 days to 40 days. MFB-14 came on stream in July 1987 initially producing 7,500 BOPD on a 90/64-inch choke, triple the rate of the best conventional well.

What was learned from MFB-14? Except for the problem of chert stringers, drilling had been relatively uneventful. For the next well, computer modeling suggested the drainhole length could be safely extended to 3000 feet [900 meters]; the next well, MFB-15, actually went out 2500 feet [760 meters]. Cementing the liner had gone smoothly, so well in fact that a larger 7-inch liner was chosen for MFB-15.

The main problem was stimulation technique—the time it took and the possibility that not enough sand had got into the fractures. This seemed a likely explanation for the almost immediate drop in MFB-14’s production, to 1,000 BOPD within 2 to 3 months. The production decline was undoubtedly due also to the well entering the less productive Danian—production logs run with coiled tubing showed most of the production coming from the two fractures in the more productive Maastrichtian. To better understand the production decline, downhole pressure and temperature gauges with surface readout were installed on all future horizontal wells (next page, top).

MFB-15 was spudded in January 1988 and directed to the B-block upper Maastrichtian. The horizontal section begins under the gas cap and then goes outside it. To ensure correct placement of the well, a seismic line was shot along the projected well trajectory, and later, during drilling, a pilot hole was first drilled to the 50-percent water saturation level to identify the formation tops. As a third safeguard, the well was planned to go at exactly 90-degree deviation, parallel to and at a fixed height above the 50-percent water saturation depth. Drilling proceeded on schedule and was completed in 52 days (next page, middle).

Stimulation also experienced fewer problems. Seven acid fractures were performed along the 2500-foot drainhole using a straddle packer assembly that reduced the number of trips per fracture to just one and the completion time to 39 days. The well came on stream at 9,000 BOPD. Production declined but not as rapidly as in MFB-14, stabilizing at 2,000 BOPD.

* Mark of Schlumberger
Average well production in the Dan field since 1972, when production began, against average price of crude. The color bands represent the six main stages in the field's development. The sixth stage is the horizontal well development described in the article. The horizontal wells gave the field a new lease on life when conventional wells were considered unattractive.

MFB-13, the third horizontal well, was directed under the gas cap in B block to see if a fractured well here could produce high oil flow without gas coning. Experience in the previous wells suggested that the lower Danian formation, which overlies the Maastrichtian, would close around an acid fracture preventing gas entry. This time, no pilot hole was drilled—an intermediate logging run was used instead just after the well pierced the Maastrichtian. Drilling the 2,600-foot [800-meter] drainage proceeded without incident. The acid fracturing was performed through a new packer assembly that set a retrievable plug just beyond each zone being fractured. This technique isolated each fracture immediately after stimulation, preventing substantial losses of completion fluid experienced in the previous well. MFB-13 came on stream in June 1988 at 4,000 BOPD and has since declined to about 2,500 BOPD.

These first three wells accelerated Maersk Oil along the horizontal well learning curve. The two-year pilot program had proved that in very low permeability formations, such as in the Dan field, fractured horizontal wells were not only possible but economical. Including the platform slot, each well cost 1.4 times a conventional well, yet produced initially three to six times more oil.

But there was still much to learn and perfect. Before drilling more horizontal wells, Maersk Oil had to better understand these wells' performance. More work was needed to perfect the completion hardware and stimulation method. And avoiding the trajectory problem in MFB-14 required a clearer picture of where each drainage hole was headed relative to the reservoir geometry.

Well trajectories for MFB-15, the second Dan field horizontal well, and its pilot hole. To avoid repeating the trajectory complications of MFB-14, the pilot hole was drilled to map the formation tops and find the 50% oil-saturation depth. The well was then plugged back and redrilled to be exactly horizontal and at a fixed distance above the oil-water transition zone.
Well Performance

Although the first three horizontal wells outperformed conventional wells, their production drop-off demanded careful analysis (right). This was particularly true for MFB-15, which was far from the gas cap and looked on paper to be trouble free. Two options were followed simultaneously: conventional semianalytical well test analysis, adapted for fractured horizontal wells; and a full-scale simulation.

Well test analysis is complicated by the numerous flow regimes to be expected in a fractured horizontal well (below right). After a very early flow regime dominated by the fractures, oil flows linearly toward the fracture faces. Analysis during this period could reveal fracture size if the formation permeability is known. Gradually, the flow becomes pseudo-radial toward each fracture, and depending on fracture spacing and orientation, the flows may start to interfere with one another. After a time, the interference transforms into a gross linear flow from the far formation toward the well. Analysis during this regime can yield formation permeability because the effective flow width—the distance along the horizontal drainhole from the first fracture to the last—is known. Finally, providing no flow barriers are encountered, pseudo-radial flow toward the whole well may occur. In conventional well test analysis, this regime yields formation permeability, but in low-permeability chalk, the regime takes months or years to appear, and may never materialize.

Guidelines for interpreting well test data were established by Maersk Oil's partner, Shell, and promised in certain cases to even help estimate fracture orientation. But applied to the pressure data, the results looked unreliable. It was later discovered that the fractures in MFB-15 were probably closing with decreasing well pressure. This nullified an important assumption in the analysis, that fracture geometry must be fixed. Another weakness of the test analysis was its inability to deal with gas, not a problem for wells outside the gas cap but definitely a limitation for those beneath it.

Flow regimes predicted by test analysis in fractured horizontal wells. Once the well is allowed to produce, flow is first linear toward the fracture faces. Then, as the volume of formation contributing to flow enlarges, individual flows toward fractures become pseudo-radial and begin to interfere. Flow next becomes linear toward the well. Eventually—and in very low-permeability formations this may take months or years—flow becomes pseudo-radial toward the entire well.

Average production from five of the first six horizontal wells compared with a typical conventional well. Except for the first well, MFB-14, which tapped the wrong chalk unit, the increase in production from a horizontal well pays several times over for the increase in drilling and completion costs.
The second approach used a simulator developed in conjunction with the Franlab consultancy group. Because MFB-15 had not flowed long enough for the flows into adjacent fractures to begin to interfere with each other, it was considered sufficient to investigate the performance of a single fracture. Since it was also assumed that the fractures were symmetric in shape, just one-quarter of one fracture was actually modeled. The results were then multiplied by 28 to obtain total well performance.

Since the fractures were simulated as being infinitely conducting, their orientation relative to the drainhole ceased to be a factor in this attempt to understand MFB-15's performance. The issue of fracture orientation remains a bit of an enigma. The directions of the three horizontal wells cover a 90-degree spread. Thus, if the earth's horizontal stress were roughly uniform within the field area, fracture orientation should vary substantially from one well to the next; it could even be parallel to one well and perpendicular to another. To date, Maersk Oil is still unsure of fracture orientation.

The simulator, as it was initially set up using basic knowledge of reservoir properties, failed to match MFB-15's production history in two crucial ways. It reproduced neither the well's high initial production rate, nor its rapid production decline. The first discrepancy had been noted previously in conventional wells and was thought to be caused by the acid stimulation creating small fractures in the formation near the fracture face, allowing the formation to produce more freely. Grid cells near the fracture face were therefore given higher permeability than the surrounding formation initially, but to simulate closing, progressively less permeability as pressure decreased. The second discrepancy was ascribed to the fracture closing as well pressure declined. A linear decrease in fracture area with pressure was therefore built into the simulator. With these two modifications, the simulator closely matched MFB-15's production history. The simulator was later refined to allow initial fracture size and formation permeability to be chosen individually for each fracture. These parameters were then adjusted to match flowmeter logs that showed the net flow from each fracture (below).

The main lesson learned from the simulation was that, where appropriate, fractures should be propped to prevent closure. This was advisable under the gas cap, but should certainly be done outside it, the case for one of the next horizontal wells drilled—MFA-17. Nine hydraulic fractures in this well took 8.1 million lb of sand, with the largest taking over 2 million lb. The operation was carried out with the largest stimulation vessel the North Sea could offer, but it still took four round-trips to bring material to the platform. Production has not declined as rapidly as in MFB-15, and it is certain that the fractures have remained open.

Simulation results for MFB-15. The well's high initial production rate was closely matched by assuming that permeability near the fracture faces was increased due to minifracturing during stimulation. The subsequent rapid decline in flow was matched by assuming that these minifractures as well as the hydraulic fractures themselves closed up as bottomhole pressure declined. The pressure distribution shown comes from a simulation in which individual fracture character was tuned to match flowmeter data.
Selective Completion
The greatest challenge faced drilling the second series of horizontal wells was improving the completion/stimulation hardware. There were at least three forces urging improvement:
• to decrease completion time and consequently overall well cost—Maersk Oil stuck to the ideal that stimulating each zone had to be done in only one trip
• to reduce losses of expensive completion fluids and improve well control between stimulating different zones
• to be able to selectively open and close individual fractures once the well was producing.
It was clear that selective completions would be the key to a horizontal well development of the Dan field. Each horizontal well with multiple fractures had to be viewed as several conventional wells rolled into one, each part requiring individual control. This appeared especially true when considering a water injection scheme. Whether the injection was from horizontal wells or existing vertical ones, breakthrough to individual fractures would be unpredictable. To stop water production, it was mandatory to be able to close off producing well fractures at will.

Much thought, discussion and experimentation with Baker Oil Tools recently resulted in radically new completion hardware that permits one-trip stimulation for acid fracturing and leaves hardware downhole that allows selective opening and closing of individual zones. Further development is underway to provide one-trip perforation and stimulation when using sand.

The hardware left in place downhole comprises any number of “downhole assemblies,” one per zone (below). Each assembly consists of a retrievable packer, a sliding sleeve that can be opened and closed with coiled tubing, a section of 4½-inch tubing as long as the zone and a seal assembly that seats into the retrievable packer of the next assembly. The deepest assembly seats into a “sump packer” set at the end of the hole with drillpipe, and production tubing seats into the topmost assembly’s retrievable packer.

Downhole assemblies are carried sequentially into the hole on a “service assembly” that comprises a retrievable packer, a length of 2½-inch tubing, a circulating port and tubing-conveyed perforating guns (next page). The service assembly with downhole assembly riding piggyback are run to perforating depth, the service assembly packer is set, and the guns fired. The guns retract automatically into the service assembly, and stimulation commences. After stimulation, the service assembly packer is unseated to establish circulation. The service assembly is then lowered to stab the downhole assembly into the previous zone’s downhole assembly packer or, if it is the first zone to be completed, into the sump packer. Finally, the downhole assembly packer is seated and the service assembly pulled from the hole. The process is repeated for each zone. When all zones are completed, coiled tubing is used to wash debris from the sliding sleeves and then open or close them as required.

Maersk Oil used this technique successfully on two of the second set of three horizontal wells drilled in the Dan field. Both were completed and stimulated with one trip in the hole per zone; one well was acid fractured, the other matrix acidized. Even these pilot runs resulted in savings in time and completion fluid costs. The huge sand fracturing operation in MFA-17 was completed with two trips per zone. The downhole assemblies are susceptible to damage by large sand flows; further development is required to protect the...
The service assembly (left) used to carry downhole assemblies into the well (below, left). The service assembly comprises from left: a retrievable packer, a length of 2 7/8-inch tubing, a circulating port and tubing-conveyed perforating (TCP) guns that retract inside the tubing after firing.

With the guns positioned opposite the zone to be treated, the service assembly's packer is set to permit isolated perforating and stimulating. The downhole assembly is then set in place and the service assembly is released and retrieved for carrying the next downhole assembly into the well.

Selective Completion

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- to reduce losses of expensive completion fluids and improve well control between stimulating different zones
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It was clear that selective completions would be the key to a horizontal well development program in the Dan field. Each horizontal well with multiple fractures had to be viewed as several conventional wells rolled into one, each part requiring individual control. This appeared especially true when considering a water injection scheme. Whether the injection was from horizontal wells or existing vertical ones, breakthrough to individual fractures would be unpredictable. To stop water production, it was mandatory to be able to close off producing wells at will.

- Radically new completion hardware used in the second series of three horizontal wells in the Dan field to achieve selective zone isolation for stimulation and production. The basic component is the downhole assembly, comprising from left to right: a retrievable packer, a sliding sleeve, a length of 2 7/8-inch tubing as long as required to cover the zones, and a seal assembly. In the completed well, as many assemblies as zones are in place, each one seated into the assembly below it (above, right). The deepest assembly seats into a sump packer; production tubing seats into the top packer.

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The hardware left in place downhole consists of number of "downhole assemblies," one per zone (below). Each assembly consists of a retrievable packer, a sliding sleeve that can be opened and closed with coiled tubing, a section of 4 1/2-inch tubing as long as the zone and a seal assembly that seats into the retrievable packer of the next assembly. The deepest assembly seats into a "sump packer" that act at the end of the hole with drillpipe, and production tubing seats into the topmost assembly’s retrievable packer.

Downhole assemblies are carried sequentially into the hole on a "service assembly" that comprises a retrievable packer, a length of 2 7/8-inch tubing, a circulating port and tubing-conveyed perforating gun (TCP) that retread inside the tubing after setting. With the guns positioned opposite the zone to be treated, the service assembly’s packer is set to permit isolated perforating and stimulating. The downhole assembly is then set in place and the service assembly is released and retrieved for carrying the next downhole assembly into the well.

The service assembly (left) used to carry downhole assemblies into the well (far left). The service assembly comprises from left: a retrievable packer, a length of 2 7/8-inch tubing, a circulating port and tubing-conveyed perforating (TCP) gun that retread inside the tubing after setting. With the guns positioned opposite the zone to be treated, the service assembly’s packer is set to permit isolated perforating and stimulating. The downhole assembly is then set in place and the service assembly is released and retrieved for carrying the next downhole assembly into the well.

sliding sleeves and other parts of the assemblies from sand erosion.

Today, horizontal development of the Dan field continues at full pace (above). Last year saw the completion of MFA-13, MFA-16 and MFA-17. At least seven more horizontal wells will be drilled this year and next. Meanwhile, Mærsk Oil is applying its horizontal technology to three other fields in Danish waters: the gas-bearing Tyra field and the oil-bearing Valdemar and Kraka fields.

For each problem solved in this odyssey, though, fresh problems are always on the horizon. First, there is the never-ending quest to speed up any offshore operation to cut costs. Much progress has been made in reducing drilling, logging, completion and stimulation times. The next opportunity is to perform as much workover as possible with coiled tubing.

The second problem today concerns matrix acidization. The first well to be matrix acidized in the Dan field was MFA-16, which is situated under the gas cap. Experience in this well suggests that the acid seeks out one permeable entry into the formation and little else gets cleaned. All types of diverters have been tried, but the acid continues to bypass the majority of the zone being acidized. Inflatable packer tools on coiled tubing may be a solution.

A third problem is ensuring that a horizontal well sticks to reservoir pay, particularly in thin or faulted producing zones. Well trajectory can be controlled satisfactorily. The uncertainty is knowing structure and stratigraphy near the wellbore. For example, a fault unexpectedly caused the horizontal Valdemar-I drainage well to suddenly exit the field's thin producing formation. Measurement-while-drilling (MWD) data and micro-paleostratigraphy on cuttings helped pull the well back to the producing formation (next page). Later, after a check-shot survey was run, it was possible to trace the well trajectory on a seismic section and observe its intersection with a fault. A check-shot measurement performed while drilling would place the well's location on the section in real time, revolutionizing the ability to optimize hole trajectory.

A final challenge is in reservoir planning, deciding on horizontal well spacings and the role of conventional wells in injection programs—in short, generating the reservoir engineering expertise the industry has acquired over decades in conventional field development.

Horizontal wells will continue to revolutionize a certain segment of the oilfield. Much as happened in just a few years, Mærsk Oil looks forward to the innovations of the future.

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Tracking well trajectory in Valdemar-1, the first horizontal well in the oil-bearing Valdemar field, situated northwest of the Dan field. The well unexpectedly met a fault and exited the target B1 formation, entering the Barremian shales. This was recognized in real time from MWD data and micropaleostratigraphy analysis of cuttings—the shale zone is clearly seen between 2250 and 3000 feet from logs run after drilling.

The well was redirected down to reenter the B1 formation. The events could also be seen on a seismic section, but only after a check-shot survey was run to fix the well trajectory in two-way time. A check-shot survey while drilling might revolutionize the ability to remedy this situation.