DOWNHOLE SEPARATION TECHNOLOGY —PAST, PRESENT AND FUTURE

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ABSTRACT

In the 1990s, a new water management tool, downhole separation technology, was developed. It separates oil and gas from produced water inside the wellbore and injects the produced water into the disposal zone. Based on the different fluid the separators handle, they are categorised as downhole oil-water separators (DOWS) and downhole gas-water separators (DGWS). Two types of separators have been used: hydrocyclone and gravity separators. The authors reviewed the previous 59 DOWS installations and 62 DGWS installations worldwide, and discovered that only about 60% achieved success. Some major issues—including high costs, low reliability and low longevity—have slowed down its industrial adoption. Based on the field experiences, a good candidate well must have a high-quality disposal zone with sustainable permeability. To improve the performance of downhole separation tools, it is crucial to better understand the behaviour of the separator under downhole conditions and the behaviour of the injection zone under the invasion of various impurities in the produced water.

KEY WORDS

Literature review, downhole separation, hydrocyclone.

INTRODUCTION

In mature oil- and gas-field developments, a large amount of produced water is brought to the surface along with oil or gas. The water cut in a mature oil field can exceed 90%. In addition to the natural components in natural water drive, produced water may also contain ground water or sea water injected to maintain reservoir pressure, as well as miscellaneous organic and inorganic solids. Most produced water is more saline than sea water. It may also include chemical additives used in drilling and production operations and in the oil-water separation process.

In offshore environment, the produced water is generally separated, treated and discharged into the ocean. Managing produced water can cost more than several dollars per barrel. Moreover, improper handling of produced water can cause severe pollution. In offshore Australia, the concentration of dispersed oil in produced water discharged into the sea is not to exceed 50 mg/L at any time, and an average less than 30 mg/L during each period of 24 hours. International standards on discharged water are expected to be stricter.

Various technologies were developed to control water production, such as mechanical blocking devices, water shut-off chemicals, dual completion wells, and intelligent completion technology. A relatively new technology, downhole separation technology has been developed to reduce the cost of handling produced water. This technology separates oil and gas from produced water at the bottom of the well and injects some of the produced water into another formation, while the oil and gas are pumped to the surface.

DOWNHOLE OIL-WATER SEPARATION (DOWS)

Although a full DOWS system includes many components, the two primary components are an oil-water separator and at least one downhole injection pump. Two types of separators: hydrocyclone and gravity separators, and three types of pumps: electric submersible pumps (ESP), progressing cavity pumps, and beam pumps have been employed. The individual components of DOWS technology have been proven to work in the field. The challenge is to make separators and pumps work together in the confined space of a 7” or smaller casing in a bottom hole environment.

DOWS with hydrocyclone separator

Hydrocyclones have been used for surface treatment of produced water for the past 25 years. Hydrocyclones have no moving parts and separate substances of different density by centrifugal force. Hydrocyclones can separate liquids from solids or liquids from other liquids. The liquid/liquid type of hydrocyclone is used in DOWS. Figure 1 shows a schematic drawing of a hydrocyclone. Produced fluid is pumped tangentially into the conical portion of a hydrocyclone. Water, the heavier fluid, spins to the outside of the hydrocyclone and moves toward the lower outlet. The lighter fluids, oil and gas, remain in the centre of the hydrocyclone and are carried toward the upper outlet and produced to the surface.

The separation of fluids in a hydrocyclone is not 100% complete: some oil is carried along with the water fraction, and a significant portion of water (typically 10% to 15%) is brought to the surface with oil and gas production. Nevertheless, hydrocyclones can rapidly and effectively separate most of the oil from the water fraction. For example, wells with a water-to-oil ratio in the range of 5–100

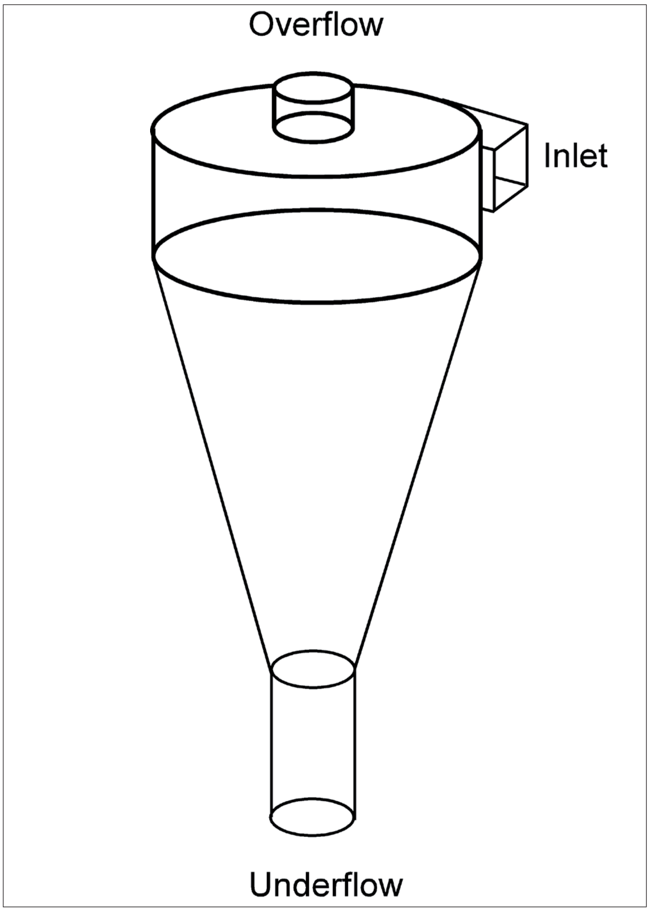

Figure 1. Schematic of a hydrocyclone separator.

can typically achieve water-to-oil ratios between 1.0 and 2.0 with the help of a hydrocyclone-type DOWS.

Hydrocyclones used in DOWS tend to be narrow and tall. Hydrocyclones can be smaller than 50 mm in diameter and 1–2 m in length. If a single hydrocyclone does not provide enough capacity to handle the total fluid volume, several hydrocyclones can be installed in parallel. The capacity limits for hydrocyclone-type DOWS with three different types of pumps are listed in Table 1 (Matthews et al, 1996).

DOWS systems can take different configurations. The system illustrated in Figure 2 is referred to as a push-through system. In this design, the injection pump discharge is connected directly to the inlet of the separator. The injection pump provides the pressure required to operate the separator and inject the separated water. In some cases, where the pressure required to inject the water is equal to or higher than the pressure required to lift the oil stream to surface, the injection pump can serve both purposes and only one pump is required. Where injection pressure is low, it is normal practice to use a second pump to lift the oil stream. If two pumps are used, a common motor normally drives both.

Reduced power requirement is the primary justification for using two pumps in a push-through system. Significant power savings can result if the injection pressure is low and the water cut is high. In this situation, the total production volume is pumped only to the pressure required

Table 1. Capacity limits for hydrocyclone-type DOWS.

Pump type	Casing size (inch)	Total volume (bbl/day)	Maximum volume to surface (bbl/day)
Electric submersible pump	5.5	3,800	440
	7.0	10,000	940
Progressive cavity pump	5.5	2,200	450
	7.0	3,800	1,360
Rod pump	5.5 (85% watercut)	1,700	530
	5.5 (97% water cut)	1,200	70
	7.0 (85% watercut)	2,500	790
	7.0 (97% water cut)	1,900	190

for injection, while the production pump boosts only a fraction of the produced fluid to the pressure required to reach the surface. This reduction in power requirement has been used to either install lower horsepower motors—reducing energy requirement and extending motor life—or to increase total draw-down and oil production without an increase in the motor size or energy consumed, as compared to a conventional lift system.

Figure 3 shows a pull-through system. In this configuration, the suction of the injection pump is connected to the water outlet of the separator. The pump draws separated water from the separator and boosts pressure to a level suitable for injection. Unless the well is free flowing (i.e. does not require an artificial lift system to produce to the surface), a second pump is required to lift the oil stream to the surface (Bower et al, 2000).

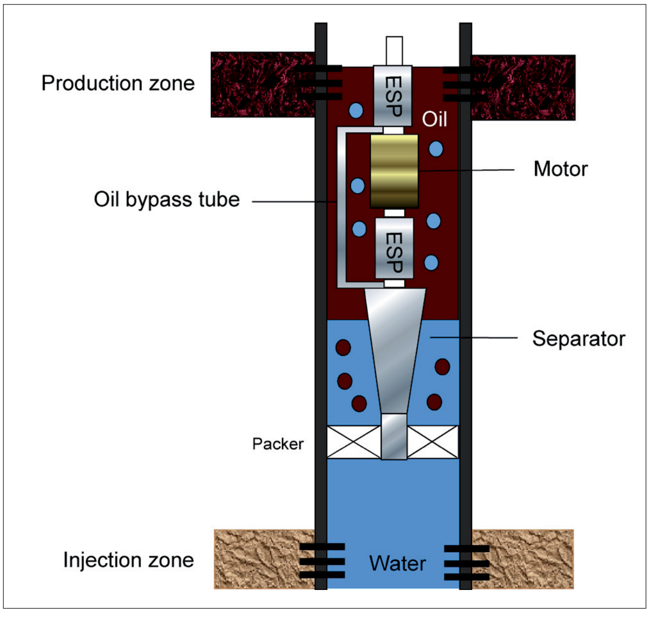

Figure 2. Push-through type DOWS.

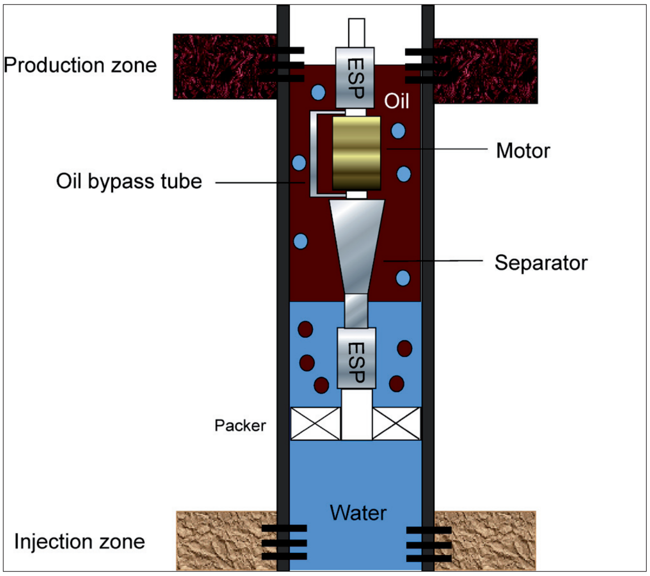

Figure 3. Pull-through type DOWS.

DOWS with gravity separator

Oil and water exist as separate fractions downhole. Emulsions are typically formed when oil and water are mixed by pumping. The gravity separator type of DOWS takes advantage of the gravity separation of oil and water that occurs in the casing/tubing annulus. The dual action pumping system (DAPS), which is the most commonly used type of gravity separator, is constructed by modifying a rod pump to contain two separate pump chambers and inlets, and adding an injection valve and packer.

Figure 4 is a schematic drawing of the DAPS developed by Texaco in 1994. The upper inlet is located at an elevation near the oil/water interface, so that a mixture of oil and water enters the upper pump and is brought to the surface on the upstroke. The lower inlet is located below the oil/water interface, so that primarily water enters the lower pump and is subsequently injected during the downstroke. Proper sizing of the two pump chambers is critical in preventing oil from being disposed of to the injection zone. If the working fluid level drops below the upper inlet, no fluids will be pumped to the surface, and both water and oil will be injected into the injection formation.

The sucker rod strings of conventional rod pumps are designed to tolerate a tension strain but not a compression strain. The force required to inject water into a formation can place an undue compression strain on sucker rods, so sinker bar weights are often added above the top pump on a DAPS to overcome the injection pressure.

DAPS have been installed in more than a dozen wells. DAPS are most commonly used on wells with 4.5" casing. Because of size constraints, the largest DAPS that will work in that size casing can pump about 1,000 bbl/day. Another limitation is that DAPS cannot effectively handle gas and solids. Moreover, DAPS require enough vertical space between the injection and production zones for sufficient gravity separation.

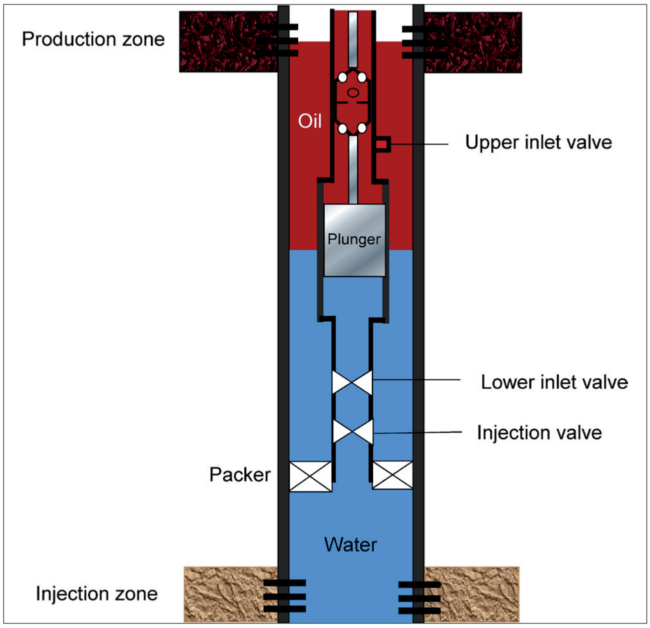

Figure 4. DAPS schematic.

Previous DOWS installations

A total of 59 DOWS trials worldwide were identified from literature. Some of the general trends are discussed in this section.

COSTS

Two-thirds of the installations used hydrocyclone-type DOWS. A hydrocyclone DOWS system can cost between US$90,000 and US$250,000—excluding the cost of a workover to install the equipment, which can add another US$100,000 or more. Hydrocyclone DOWS systems are from two to three times the cost of a comparable conventional ESP. Gravity separation DOWS systems are considerably less expensive, and range between US$15,000 and US$25,000, plus the cost of an installation workover. The total cost of a DOWS application ranges from US$120,000 to US$300,000.

The cost-benefit analysis of an offshore DOWS system can be quite different from that of an onshore system. Many onshore fields have very high water handling and disposal costs. In these cases, the cost of a DOWS system can be justified purely by lifting and handling less water, particularly if the installed cost of the system is low. For offshore cases, operating costs associated with water handling are not likely to be so high. Given the required investment for offshore DOWS installation, incremental oil production is almost mandatory for justification.

GEOGRAPHICAL LOCATION

Among the total 59 applications worldwide, most of the DOWS installations were in North America with 34 in Canada and 14 in the United States. Six installations were in Latin America, two were in Europe, two were in Asia, and one was in the Middle East. All trials were at onshore facilities, except for one trial in China.

CASING SIZE

Among 40 hydrocyclone-type DOWS, 15 installations were in 5.5" casing, one was in 6.625" casing, 17 were in 7" casing, one was in 8.625" casing, four were in 9.625" casing, and two were unspecified. Among the 19 gravity separator type DOWS, 10 were in 5.5" casing, three were in 7" casing, and six were unspecified.

VOLUME OF OIL PRODUCED

The volume of oil production increased in 31 of the trials, decreased in 17 of the trials, stayed the same in eight trials, and was unspecified in three trials. For the 40 hydrocyclone type DOWS, 19 trials showed an increase in oil production, 11 trials showed a decrease, eight trials showed unchanged production, and two did not specify oil production. For the 19 gravity separator type DOWS, 12 trials showed an increase in oil production, six trials showed a decrease, and one did not specify oil production. The top three performing wells with hydrocyclone showed oil production increases ranging from 457% to 1,162%, while one well lost all oil production. The top three gravity separator type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production. Based on the change in oil production, the successful rate is only about 53%.

Incremental oil production can be achieved in a number of ways, most of which are made possible by the reduction in loading on existing water handling and injection systems with the help of DOWS systems. For example, if a well is not operating at maximum recommended draw-down because the water handling facilities are fully loaded, installation of DOWS systems will allow increased draw-down and incremental production. On the other hand, if a well is already being produced at maximum rates, the reduction in water to the surface can allow shut-in wells to be returned to production. Either way, incremental oil is generated.

LITHOLOGY

It was believed that the produced sand from sandstone can clog the water disposal zone, which causes the DOWS fail to reduce water production. Therefore it is necessary to investigate if the failures of DOWS are related to the geology environment where they are installed. DOWS were installed in 24 wells producing from carbonate formations, and in 30 wells producing from sandstone formations. Information on production zone geology was not available for five other installations. On the injection side, 19 DOWS injected to carbonate formations and 32 injected to sandstone formations. No information was available for eight of the installations. Based on the statistics in Table 2, the success rates for carbonate/carbonate and sandstone/sandstone combinations are very close: 58% versus 57%.

Table 2. DOWS performance and geology environment.

Geology of producing formation and injection formation	Trials rated good	Trials rated poor	Total number of trials	Trials rated good (%)	Trials rated poor (%)
Carbonate and carbonate	11	8	19	58	42
Carbonate and sandstone	2	2	4	50	50
Carbonate and unknown	1	0	1	100	0
Sandstone and sandstone	16	12	28	57	43
At least one is sandstone	1	1	2	50	50
Unknown and unknown	4	1	5	80	20
Total	35	24	59	59	41

There is no clear relationship between a successful DOWS application and formation geological combinations (Veil and Quinn, 2005).

Experiences with problems

The problems encountered during DOWS applications are either due to the hardware or the formation conditions (Ogunsina and Wiggins, 2005).

INJECTIVITY DECLINE

For DOWS technology to function properly, the injection zone must have sufficient permeability and porosity to accept brine at a pressure within the capability of the pump. Several installations by Texaco, Pinnacle and Alliance suffered from low injectivity of the receiving zone. Inappropriate fluids contacted sensitive sands and damaged part of the permeability. Particles in the produced water clogged the injection zone.

In fact, injectivity decline caused by the various contaminants in the water phase widely exists in water flooding operations. This phenomenon is referred to as formation damage which can lead to serious loss in productivity or injectivity. A field case is the offshore Siri Field in the southern Persian Gulf (Moghadasi et al, 2004). Water injection into the Siri Field was started in 1984 with 9,100 bbl/day; however, the injectivity decreased progressively, until it was stopped in 1990 when the water injection rate dropped to only 2,200 bbl/day, as shown in Figure 5.

Five wells in the Gulf of Mexico demonstrated even faster decline (Sharma et al, 2000); one example is given in Figure 6. The water injection rate declined from 7,000 bbl/day to less than 1,000 bbl/day in just 200 days. For both cases, suspended particles in the injected water were identified as the cause of injectivity decline.

Injectivity declines vary from case to case, depending on different reservoir properties. High porosity and high permeability tend to sustain the injectivity longer. Even though formation damage has been studied for years, and many models have been established, it is still a challenging job to predict the decline accurately. How to maintain the injectivity of the injection zone is the most challenging issue facing DOWS applications.

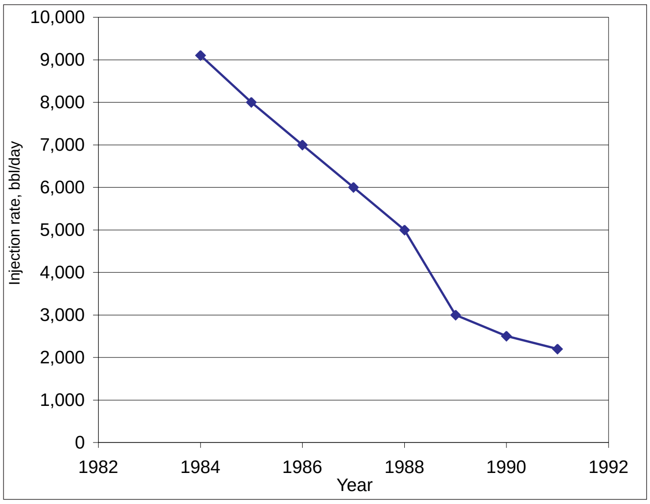

Figure 5. Water injection history of a well in the Siri oil field.

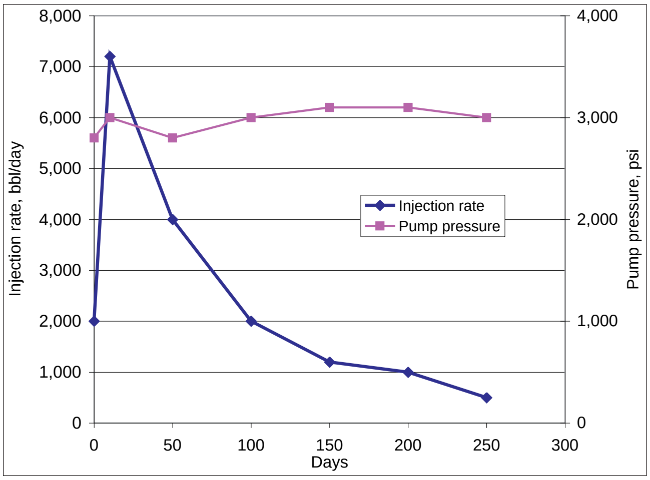

Figure 6. Water injection history of well A09 in the Gulf of Mexico.

SOLIDS PLUGGING

Excessive sands not only damage the injection zone, they also result in premature mechanical failure of the separator, pumps, or bypass tubing. In at least two cases, solids production was so excessive that the entire pump/separator assembly was packed with solids when inspected at the surface. In one case the solids were formation solids, and in the second case the solids were iron sulfide scale.

ISOLATION PROBLEMS

To protect the producing reservoir, the injection zone must be adequately isolated by an integral confining zone and sound cement behind production casing. If isolation is not sufficient, the separated water can migrate into the producing zone and then short-circuit into the producing perforations. The result will be recycling of the produced water, with oil production rates dropping to nearly zero. Crestar and Chevron reported these problems during their applications.

MECHANICAL/CORROSION PROBLEMS

It is a big challenge to fit the separator inside a well. In particular, channels to bypass oil flow around the pump and motor assembly must be fitted into a very small cross-section, and are exposed to very high flow rates. This creates risks of erosion/corrosion. Additionally, because these flow bypass channels are normally formed from thin walled tubing and often attached to the outside of the pump assembly, there is a high potential of damage to these tubes in the course of installation, especially when the well is deviated. Talisman and Texaco both reported that trials were cancelled because of corrosion problems with their DAPS tools.

How to select a good candidate well for DOWS

It is attractive to reduce produced water handling and disposal costs, and possibly produce more oil through installation of a DOWS; however, not all wells are good candidates for a cost-effective DOWS installation. Several authors have indicated the criteria they have used in selecting candidate wells for installations of hydrocyclone-type DOWS systems.

Matthews et al (1996) described the selection criteria used to site three hydrocyclone-type DOWS systems in the Alliance Field in east-central Alberta, Canada. From a production standpoint, wells had to have a water-to-oil ratio of eight or higher and productivity of greater than 1,260 bbl/day. The reservoir had to contain sufficient incremental reserves and provide a suitable disposal zone. The casing had to be at least 5.5” in diameter, and the wellbore had to have good mechanical integrity and a minimum separation of about 24 m (80 ft) between the production zone and disposal zone. The wellbore had to be already open below the production zone so that additional drilling would not be necessary.

Peats and Schrenkel (1997) described the selection criteria used to site a hydrocyclone-type DOWS in the Swan Hills Unit One Field in Alberta, Canada. Only wells having a water cut of 94% (a water-to-oil ratio of about 16) were considered. Since a DOWS sized to fit in a 5.5” casing would be very long and costly, a well with 7” casing was preferable to maximise the rate of production and allow for better clearance. Wells with a history of asphaltene and scale problems or wells with high gas-to-oil ratios were avoided.

Stuebinger et al (1997) identified several screening criteria for DAPS. The most important is the availability of a suitable injection zone that is isolated from and at least 3 m (10 ft) deeper than the production zone. The pressure required to inject water cannot be excessive. The injection pressure gradient must be less than 0.45 psi per foot of depth. The chemistry of the produced water must be compatible with the injection zone; it is usually inadvisable to mix water from carbonate and sandstone formations. As with all other types of DOWS, the casing must be in sufficiently good condition to withstand setting of a packer and the pressures needed for injection. To promote proper gravity separation of oil and water, the wellbore should be as vertical as possible between the upper and lower intakes. Wells producing cold, heavy crude oil with an API gravity of 10° or less may not be good candidates for gravity separation. An API gravity of 15° may be a more appropriate cut off for gravity separation type DOWS.

To sum up, a good candidate well for DOWS application should meet the following requirements.

1. A compactable injection zone—the injection zone needs to have sustainable permeability for long-term water disposal, which is the most import requirement for DOWS applications. The injection zone should also be compactable with the injected water, which means the chemical properties of the injected water will not cause severe permeability damage. Due to the uncertain separation efficiencies for various DOWS systems, and the different solids specifications from various production zones, there is no clear criteria for cut-off permeability; however, formations that produce no or little sand are favourable.
2. Production requirement—the oil should have a gravity of 15°API or higher. The total production should be less than 1,200 bbl/day for a gravity-type DOWS, or higher flow rates for a hydrocyclone-type DOWS with water cut of at least 90%.
3. Well requirement—the well has to be straight or slightly deviated. The casing has to be at least 5.5" in diameter, and the wellbore has to have good mechanical integrity and a minimum separation of about 24 m (80 ft) between the production zone and disposal zone. There is no connection between production zone and injection zone.

DOWNHOLE GAS-WATER SEPARATION (DGWS)

DGWS technologies can be classified into two main categories: gravity separation and hydrocyclone separation. The majority of downhole gas-water separation was achieved by allowing gas and water to naturally separate in the tubing-casing annulus. The separated gas flows to surface, and the separated water is injected with bypass tools, modified plunger rod pumps, ESPs, and progressive cavity pumps. A few hydrocyclone-type separators were also developed, but no field installations have been reported.

DGWS systems

The simplest DGWS device is a bypass tool in which the bottom end of an insert sucker rod pump is seated. The pumping action acts to load the tubing with water from the casing tubing annulus. When the hydrostatic head in the tubing is great enough, the water drains into the disposal zone below the producing perforations and packer. Gas flows up the tubing-casing annulus. The pump provides no pressure for water injection; water flows solely by gravity. Bypass tools are appropriate for water volumes from 25 to 250 bbl/day and a maximum depth in the 1,829–2,438 m (6,000–8,000 ft) range.

A second type of rod-pump-operated DOWS uses a modified plunger pump, as seen in Figure 7. This system

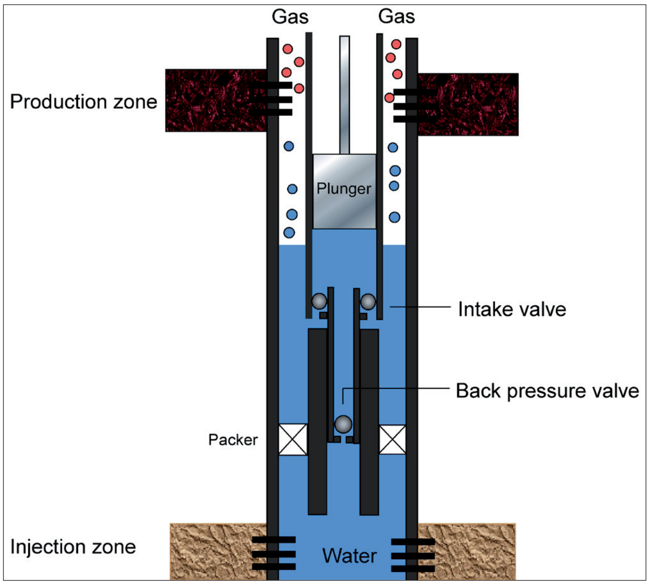

Figure 7. DGWS with modified plunger pump.

consists of a short section of pipe with one to five ball-and-seat intake valves and an optional back-pressure valve, run below a tubing pump in which the travelling valve has been removed from the plunger. On the upstroke the solid plunger creates a lower pressure area in the barrel, allowing the ball-and-seat valves to open and water to enter. On the downstroke, the plunger moves the fluid down and out of the barrel and into a disposal zone below the packer. This type of DGWS can generate higher pressure than the bypass tool, which is useful for injecting into a wider range of injection zones. Modified plunger rod pump systems are better suited for moderate to high water volumes (250 to 800 bbl/day) and depths from 610 to 2,438 m (2,000 to 8,000 ft).

ESPs are commonly used in the petroleum industry to lift fluids to the surface. In a DGWS application, they can be configured to discharge downward to a lower injection zone. A packer is used to isolate the producing and injection zones. ESPs can handle much higher flow rates (above 800 bbl/day) and can operate at great depths (more than 1,829 m or 6,000 ft). They do require a substantial supply of electricity that is not always available in the field. ESPs are available from many suppliers. Centrilift and REDA (now part of Schlumberger) both offered DGWS systems using ESPs in 1990s.

The fourth type of DGWS uses progressive cavity pumps. For DGWS applications, the pump is configured to discharge downward to an injection zone, or the pump rotor can be designed to turn in a reversed direction. In an alternate configuration, the progressive cavity pump can be used with a bypass tool. Then the pump would push water into the tubing, and the water would flow by gravity to the injection formation. Progressive cavity pumps can handle solids (sand grains or scale) more readily than rod pumps or ESPs. Weatherford offered a DGWS system using progressive cavity pumps.

C-FER Technologies developed two types of hydrocyclone gas-water separators. One type uses a one-stage hydrocyclone to separate water and gas, and a centrifugal pump to inject the separated water. The other type uses two stages of hydrocyclone: the first hydrocyclone separates gas and liquid, and the second stage separates oil from liquid.

Previous DGWS installations

Compared with DOWS data, DGWS data are relatively incomplete. Among the 62 of the DGWS installations worldwide, 39 of the installations were in the United States, with Oklahoma (20) and Kansas (12) heading the list; 22 installations were in Alberta, Canada. Thirty-five of the installations (57%) used modified plunger rod pump systems. Bypass tools were used in 19 installations, and ESPs were used in seven installations.

Table 3 again attempts to relate success or failure of applications to geology conditions. It can be seen the sandstone/sandstone combination gains higher success rate (94%) than that for carbonate/carbonate combination (70%); however, the authors are not confident enough to draw the conclusion. Data in Table 3 also show that the overall success rate for DGWS applications is only 61%, which is similar to that for DOWS applications (59%).

For water production rates less than 50 bbl/day, conventional surface disposal is most cost effective. Bypass tool systems are more cost effective in the 25–250 bbl/day range, up to a maximum depth of about 2,438 m (8,000 ft). A modified plunger system was shown to be most cost effective for 250–800 bbl/day over about the same depth range. For high water rates (above 800 bbl/day) and depths below 1,829 m (6,000 ft), ESP systems are typically more cost effective. Our study also determined that a DGWS system stands the best chance of success when it is installed in a well with: well cemented casing; minimal sand production; soft water (minimal scaling); water production of at least 25–50 bbl/day; disposal costs above US$25–$50/day; and, a low pressure, high injectivity disposal zone below the production zone. These criteria are similar to those for DOWS.

RECENT ACTIVITIES IN DOWNHOLE SEPARATION TECHNOLOGY

DOWS developments and new installations have been mostly stagnant for the past few years. The lack of DOWS sales has changed the DOWS market. In 1998, three companies were actively marketting DOWS tools in the United States: Centrilift, REDA Pumps, and Dresser/Axelson. During 2002, only Centrilift continued to market this technology. By 2004, none of these companies were promoting DOWS.

Because of low DOWS sales, Centrilift does not actively market its DOWS tools anymore. REDA was subsequently taken over by Schlumberger, which reports that REDA's DOWS tool Aqwanot is no longer being marketted because it was not sufficiently reliable.

Table 3. DGWS performance and geology environment.

Geology of producing formation and injection formation	Trials rated good	Trials rated poor	Total number of trials	Trials rated good (%)	Trials rated poor (%)
Carbonate and carbonate	7	3	10	70	30
Carbonate and sandstone	1	0	1	100	0
Coal and sandstone	3	2	5	60	40
Sandstone and sandstone	15	1	16	94	6
Sandstone and unknown	0	3	3	0	100
Unknown and unknown	12	15	25	48	52
Total	38	24	62	61	39

Texaco was a leader in developing the gravity-type DOWS sold by Dresser/Axelson; however, since 1999, Texaco's DOWS team has been disbanding. One Texaco well with an installed DOWS was sold, and the DOWS was removed from the well.

Kudu Industries provides a downhole water injection tool that relies on a progressing cavity pump and a Chriscor downhole injection tool. Chriscor Downhole Tools is now a division of Kudu Industries. The Chriscor tool is installed with a beam pump or a progressive cavity pump and has a bypass area that allows the water in the tubing string to move downward.

In Canada, Quinn Pumps marketed several DOWS tools in the late 1990s but has not made many installations during recent years. Quinn is still marketing downhole separation systems but has focussed more on gas wells rather than oil wells. Quinn Pumps has two DGWS technologies available. One is the Q-Sep Gas T, which pumps water off a gas well and directly injects the water into a disposal zone in the same wellbore. The Q-Sep Gas R, which is coupled with a Chriscor injection tool, pumps the water upward, where it flows by gravity to the injection zone.

Centrilift developed and installed an ESP-DGWS tool called GasPro in 2002, which has the ability to control the water disposal rate. Centrilift also has a progressing cavity pump DGWS system. But these tools are no longer being sold.

C-FER Technologies is a developer rather than a vendor. C-FER played an active role in developing the original hydrocyclone-type DOWS systems and continues to develop new DOWS technologies, such as the gas-lift DOWS. C-FER is also engaged in developing hydrocyclone-type DGWS to handle high gas flow rates.

What resulted in so few installations recently? Downhole separation technology is theoretically feasible, but technically immature. Even though some applications gained benefits, the overall success rate is only 60%. High cost and low reliability have slowed down the acceptance of this relatively new technology.

It is common sense that deploying more downhole tools leads to more risks and failures. Downhole separation systems generally combine two pumps, one motor and one separator. Multiple components inevitably brought more problems. Moreover, downhole separation is a very complicated process. The downhole environment can be very different from well to well. Water cut, pressure, temperature, and the related fluid properties all affect the efficiencies of the separators and pumps; however, the in-depth knowledge of these effects has not been fully understood. As a result, the system optimisation is indeed a trial-and-error process. It is unlikely that a system with so many unknowns can function properly. It is also unlikely that one design can suit many wells.

Above all, most of the DOWS and DGWS systems were installed in wells with poor integrity. The installations were mostly trials in nature, thus the wells with minor importance but many problems were selected. The common problems for aged wells include bad cement, sand production, and low liquid supply. These problems can fail downhole separation and injection processes. In other words, these wells were not producing properly even under mature production technologies, thus it is unlikely that they can be saved by downhole separation technology.

POTENTIAL OF DOWNHOLE SEPARATION TECHNOLOGY

Like other fields in the world, Australia's offshore gas fields are producing a large amount of water. The production data of Barrow Island in 2005 are listed in Table 4. The water production from Barrow Island in 2005 averaged about 50,000 bbl/day. Chevron's Thevenard Island asset is producing a similar amount of water (DoIR, 2006).

Unlike other fields in the world, offshore Australia is more environmentally sensitive. Produced water from Woodside's Enfield project and Chevron's Thevenard Island has to be injected back into the reservoir rather than dumped overboard. If downhole separation technology is employed, not only the energy to lift the produced water is saved, the environment issue is also solved.

It is an appealing idea to apply DGWS technology to the gas fields in Australia's North West Shelf; however, the available downhole separation technology is neither mature nor applicable to Australia's gas fields. The developed DGWS system separates gas and water in the tubing-casing annulus, which indicates the gas flow rate is very low. The gas fields in Australia can produce several million scf of gas per day. Gas at this flow rate cannot be separated in the annulus by gravity.

Table 4. Production data of Barrow Island in 2005.

Date	Oil production (bbl)	Water production (bbl)	Gas production (km^3)
Jan. 2005	233,415	1,544,428	3,949
Feb. 2005	214,885	1,443,964	3,513
Mar. 2005	235,309	1,593,138	3,881
Apr. 2005	215,583	1,512,236	3,684
May. 2005	218,219	1,519,784	3,724
Jun. 2005	221,521	1,560,341	3,836
Jul. 2005	233,063	1,609,510	4,169
Aug. 2005	224,641	1,571,406	4,025
Sep. 2005	213,281	1,658,554	3,691
Oct. 2005	222,647	1,526,533	4,013
Nov. 2005	210,696	1,448,040	4,055
Dec. 2005	215,690	1,566,292	4,196
Annual total	2,658,950	18,385,636	46,737

Researchers at Commonwealth Scientific Industrial Research Organisation (CSIRO) and Curtin University of Technology are developing a novel systematic solution for the gas wells in North West Shelf. This project is divided into three aspects to tackle the problems encountered in previous installations. First, a prototype separator was designed and is being tested in CSIRO's fluid mechanics laboratory. As discussed earlier, optimisation of the separation process is not well understood. To improve the separation efficiency, a CFD (computational fluid dynamics) simulation package is used to study the separator's behaviours under various conditions. With the test data from the prototype separator and the simulation results from CFD, separator designs can be customised for wells with unique characteristics. Last but not least, the choice of candidate wells is crucial for a successful application. As discovered earlier, it is important to study the effect of the damage caused by the impurities in the produced water, and hence be able to predict the reactions from the injection zone. Based on the results, candidate wells can be selected more scientifically to reduce the risk.

Nevertheless, reducing water production is not the only benefit of downhole separation technology. The main function of an offshore platform is to separate oil and gas from water. If a downhole separator is successfully deployed, the produced gas will contain a very minor amount of water. To eliminate the risk of hydrate formation, a subsea dehydration unit may be required to remove nearly all of the water content in the produced gas. Then the dry gas can flow directly to shore through subsea pipelines. If this blueprint comes true, a platform is no longer necessary. Because this subsea system could save the high costs in platform construction and operation, many small deepwater reservoirs that are not economical to be developed with a platform may become economical. Downhole separation technology may hold the key to a new era of offshore development.

CONCLUSIONS

Downhole separation technology allows oil, gas and water to be separated downhole and produced water to be disposed underground. It can reduce water production and save energy from lifting produced water to surface. Downhole separation technology is theoretically feasible, but technically immature. Based on the review, only 60% of the worldwide applications were successful. The industrial adoption of downhole separation technology has been stagnant due to this low reliability. As a result, most service companies have abandoned downhole separation tools.

The most recognised problem from the previous applications is the injectivity decline during injection of separated water. The impurities in the injected water clogged the formation and caused the whole process to fail. In addition, separators and pumps have different characteristics under different downhole environments.

The separation processes under various conditions and related fluid properties are not well understood. Lastly, downhole separation technology makes the well structure much more complicated than conventional completions, which naturally introduces more mechanical failures from the pumps, motors, or separators.

All in all, most failures can be attributed to the lack of thorough understanding of the separation and injection processes. Downhole separation technology has great potential in gas well dewatering and deepwater reservoir development. The researchers at CSIRO and Curtin University are working together to revitalise this young technology and unlock the door to a new era of offshore development.

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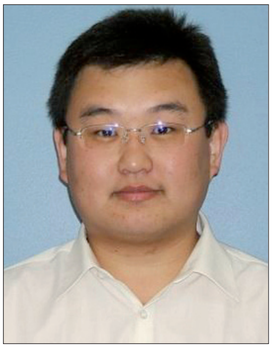
Authors' biographies next page.

THE AUTHORS



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APPEA