DUAL INJECTION AND LIFTING SYSTEMS: ROD PUMPS

Lon Stuebinger and Kevin Bowlin, Texaco,
Jonathan Wright, Talisman Energy
Mike Poythress and Brock Watson, Dresser Oil Tools, Div of Dresser Industries, Inc.

Abstract

In 1994 Texaco personnel viewed chemicals as the primary means to reduce water handling costs. They recognized from downhole videos that oil and water remain separated in the tubing-casing annulus. Capitalizing on this revelation of "gravity segregation," they conceptualized a dual-ported, dual plunger rod pump to produce oil and water from the annulus on the upstroke while injecting water on the downstroke.

Texaco and Dresser jointly developed this pump and named it the Dual Action Pumping System (DAPS). In January 1995, the first generation prototype was installed. It verified the technical and economic feasibility of this new technology. It substantially increased production while simultaneously reducing power requirements. A second generation prototype was developed to improve the valve design. It has continued to function without problems since its installation in October 1995. Tests in a Rocky Mountain Oilfield Testing Center well and several Talisman wells have further demonstrated that this will be a unique, new tool for the oil industry.

These papers will both explain how DAPS works and describe some of the early testing results. Work is continuing to improve the performance predictions. Tests have shown it to be an inexpensive technology that can reduce lifting costs and thereby increase and/or accelerate reserves recovery when the right conditions exist. While many potential applications or benefits of DAPS have been identified, these can generally be classified in three categories:

- Increase oil production
- Reduce water handling costs
- Reduce potential investment costs

Introduction

In 1993, many of Texaco's oil fields and wells were rapidly becoming uneconomic to produce because of excessive water production. Texaco's Exploration and Production Technology Division (EPTD) was requested to evaluate ways to manage excessive water production. This was conceived largely as a concerted attempt to use chemicals or cement to shut off excessive water. A surprising new option became apparent.

Part of the process was to conduct a literature search and monitor industry activity in this arena. This monitoring revealed was that it is possible to utilize pumping units for tasks such as downhole injection[1], surface pumping, gas compression, and other purposes. The scope of the study also envisioned improved diagnostic procedures. One of the diagnostic tools evaluated by EPTD was the downhole video. Tapes provided by Halliburton Energy Services[2] showed their tool had potential to qualitatively determine which perforations produce the most oil. With somewhat more difficulty, it appeared that perforations producing excessive amounts of water could also be identified. Texaco ran a downhole video in one of its wells that was equipped with a pumping unit, to test this latter theory.

Downhole Gravity Segregation.

Again, it was noticed from this video that the oil droplets were distinctly separate from the water that was being produced. This is unlike the murky mixture of oil and water typically seen at the surface. In fact, these distinct oil droplets literally squirted into the wellbore with each stroke of the pump. The rising oil droplets looked like the oil in a lava lamp. From this it was recognized that oil and water are typically separated by gravity segregation in the wellbore until they are mixed together by the pump. In retrospect, we realized that there is other evidence of this phenomenon. Consider a conventional rod pump in a high water-cut well that is pumping below the producing perforations. After it has been off production for several days, it may take hours or days before it starts producing oil again. This occurs because the oil has collected at the top of the annulus. The water in the column below the oil must be produced before the interface of the oil and water is lowered to the pump intake. This is shown in **Fig. 1.**

The idea of the Dual Action Pumping System (DAPS) was born by connecting these concepts: 1) the need to reduce excessive water production; 2) the ability of pumping units to inject water; and, 3) the segregated state of water and oil before it goes into the pump. Texaco EPTD collaborated with Dresser and the first generation prototype of DAPS was installed in a Texas field nine months later.

East Texas Field

To prove this visionary concept, the first DAPS prototype was designed and patented (#5,497,832). It used conventional pump parts and a couple of specialty parts that were made in a welder's shop. This pump design incorporated dual intakes to take advantage of the gravity segregation in the casing. Both the upper and lower intakes on this first pump consisted of several sets of valves external to the tubing. These balls and seats were installed in 1 1/4" four piece traveling valve cages, which were mounted to lugs welded to the side of the tubing subs. The upper pump's discharge valve was located at the top of the plunger and installed in a standard open top plunger cage. The discharge on the lower pump consisted of a spring loaded cage with a ball and seat assembly inside. This cage was turned upside down so that the spring resisted the gravity forces on the ball. This kept it on the seat when not discharging.

Texaco's First Test.

Texaco decided to deploy the first test in the East Texas field. The East Texas field has unique field rules with maximum allowable water production rates which made the application attractive. With a 300 barrel per day limit on water, oil production is restricted. Using the Dual Action Pump, it was envisioned that the fluid level in wells could be drawn down without exceeding the 300 barrel limit on the water. It was deemed possible to separate the oil from the water and only lift 18 to 30% of the fluid that the pump was handling. If possible, this would enable us to increase the oil production as we would be withdrawing more fluid from the formation. Since the water was re-injected back into the same reservoir, the water in effect never leaves the reservoir.

The first pump was installed on January 20, 1995, on J. M. Dickson #17 in the Woodbine Sand. The existing producing interval was not changed. The well had to be cleaned out in order to expose old perforations that were going to be used for injection. The injection interval was also in the Woodbine beneath an impermeable shale barrier. Surface testing performed as predicted from the IPR curve and the test appeared to be validated. Production values before and after the installation are shown in **Table 1**.

Within a couple of weeks, oil production rates started falling. This indicated that the injection volume was decreasing. The pump was pulled on February 20, 1995 to investigate the problem. When disassembled in the shop, it was noted that the upper pump's discharge valve had a slow leak. The lower pump's discharge valve, in the spring loaded cage, was pitted and also leaked. The pump was repaired, delivered to the well and rerun that same day. Production rates were re-established as before. On April 11, 1995, the production once again began to fall. It was decided that a design change in the lower valve was needed. Engineering departments of both companies began to work on this task. Since the valve had to be re-designed, a goal was also set to streamline the entire lower valve assembly. This was accomplished by eliminating the spring and moving the external valves to the inside of the lower valve assembly.

The pump was left in the hole until the new, and current, lower valve assembly (patent pending) was developed. It was pulled on October 20, 1995. When the pump was torn down, the lower discharge valve was again found to be pitted and leaking. The new lower valve design was then installed on the pump and it was taken back to the well site. Due to packer problems, the well was not put back on production until November 1, 1995. After 18 months, the pump is still pumping satisfactorily and has not required further service.

Prior to installing the Dual Action Pump into this well, the well was producing with a 2 1/4" tubing pump at 9.5 strokes per minute and a 54" stroke. The established production was 3 bopd and 184 bwpd. The Dual Action Pump was installed with a 2 1/4" upper pump and 2 3/4" lower pump. Unit speed was then increased in increments to achieve higher volumes.

Confirming the results.

A second installation of DAPS in the East Texas field had results similar to the original Texaco well. It was run for Chevron in September 1996. Before the pump was installed, the daily production was 7 bopd and 269 bwpd. The unit was running with a 54" stroke at 14 strokes per minute with a 2 1/4" bore pump. Just before the DAPS was installed, the unit was slowed to 8 stokes per minute. Production fell to 2 oil and 148 water. After DAPS was installed, the oil rose to 12 barrels per day and the water dropped to 90. The polish rod stroke remained at a 54" length and 8 spm. The stroke length was increased to 74" to increase the withdrawal rate from the well. This increased the oil to 16 bopd and the water to 114 bpd. In the five months since increasing the stroke length, Chevron's well has averaged 16 barrels of oil and 140 barrels of water per day. The total cost of this project, which included an acid job on the injection formation, was paid out in less than 64 days. Like Texaco, Chevron is currently reviewing well files to determine the next candidates for the Dual Action Pump in East Texas.

Testing DAPS in Canada

Background and Motivation to Test DAPS. Talisman Energy Inc. has approximately 700 vertical and horizontal producing oil wells in their Southeast Saskatchewan operating area of Canada (600 miles East of Calgary, Alberta). Aggressive drilling brings on 50-100 new wells per year. Initial production is often clean oil. The nature of the bottom water drive of the Williston Basin wells, however, is for water cut to increase quickly to about 80%. Then water cut increases gradually to 95% over a number of years.

Typically, the large amounts of new water produced are handled by executing expansions at the processing batteries. Free water knock-out vessels, water disposal pumps, pipelines, and disposal wells are added. This activity is capital intensive and leads to high operating costs for treating and disposal of water volumes. Also, production from exploration and other remote wells is typically trucked at high cost from single well batteries to distant processing batteries until local facilities can be justified.

The costs associated with the activities described above created a strong driver for finding new methods of reducing water production. Talisman was immediately interested upon learning of DAPS from Texaco and Dresser. At the time, field tests conducted by Texaco in the USA matched fairly well with the oil API and gas content seen in Talisman's Parkman field. It is a high watercut pool with 34.4° API oil and solution GOR of 129 scf/bbl. Parkman vertical wells typically produce 300 - 1200 bpd total fluid. It was clear that the system would have to be expanded to higher fluid rates to be of strong interest.

The decision was made to design and test a DAPS system with capability just over 1000 bpd total fluid. The geology of the field required that the disposal zone be located in a formation only 40 feet below the producing zone. It was separated by a chalk seal layer. Both production and disposal zones are fractured Mississipian age carbonate sequences. Porosity and permeability are 12% and 13 mDarcy respectively. Refer to **Figure 2** for a wellbore schematic drawing. As shown, the producing depth is 3420 feet. To install the system, Talisman had to drill out the plug back cement. The producing formation was held back by a $CaCO_3$ pill. The disposal formation was then perforated through casing. A casing packer was installed to isolate the injection formation. To test the DAPS system at 1000 bpd total fluid, the drawdown on the well had to be increased. The DAPS system was designed for higher withdrawals than the original rate of production on the well. Previously, it had been producing with a high fluid level.

Results. The system was installed in July 1996. After dealing with startup problems, stable operation was achieved. The production values before and after the system installation are shown in **Table 1.**

As shown, the total well inflow was increased to 1068 bfpd and successful separation was achieved. The quality of separation was verified with the use of a bubble tube. This is a capillary string of 1/4" tubing running from the injection zone to surface. This allowed monitoring of injection pressures and the lifting of disposal water samples to surface. It was known prior to installation that the injection zone back pressure may not be high enough to force sample fluid flow to surface. Upon installation, it was found that the pressure was just enough to obtain samples. However, this was only when the fluctuating injection pressure was at maximum and when there was no particulate buildup in the tube. As such, proper purging of the bubble tube and extended sampling of the disposal water was not possible. However, a few samples were obtained and were shown to have less than 100 ppm of oil in water. This is comparable to the separation efficiency of free water knock-out vessels in this field.

Problems. The main problem encountered on this project was the production of $CaC0_3$ and limestone formation fines after DAPS installation. Original production from this well contained no particulates, as the well had been at stable rates for many years. Preparatory work included introduction of a $CaCO_3$ pill to the producing formation during completion operations and acidization to remove it. Along with increased drawdown on the well, these caused the onset of fines migration and particulate production.

On initial startup, the well never achieved stable production. This was due to rapid buildup of fines, plugging off all valves and the production zone. The system was pulled within days for a thorough acid cleanup of both the production and injection zones. Upon reinstallation, the system started up without problem to yield the results shown earlier. Unfortunately, fines production continues to be a problem on this well, with several acid jobs having been required at two month intervals to date.

The system has been demonstrated to work effectively up to 1068 bpd total fluid. However, the fluid must be free of significant particulates to run for long periods without disposal zone plugging.

Potential Applications of DAPS

Although DAPS is a relatively low cost technology itself, the cost of preparing some wellbores for simultaneous production and injection can be expensive. Economic justification will usually be more dependent on well work costs than on pump costs.

Revenue Generation. Increased production is possible in several ways. Artificial lift constraints are a problem that can sometimes be overcome by DAPS. Applications tested to this point indicate that a pumping unit can sometimes move 30% more fluid with DAPS than it can for a similar conventional application. Another approach is to convert conventional injection wells to DAPS. Injection can be maintained in the deeper zone while moving uphole to a high water cut zone that can not only provide enough water to maintain desired injection but also produce oil. Uneconomic wells may be returned to production in some cases.

DAPS could make it practical to develop waterfloods in small reservoirs underlying a mature flood. Additionally, it may be possible to improve vertical and even horizontal sweep efficiency in multilayer reservoirs by use of DAPS. A demonstration project was proposed to the DOE, but its rejection has delayed proof of this concept.

Expense Reduction. DAPS was originally conceived as a means of reducing water handling costs. However, it is often difficult to justify conversion to DAPS if water is being handled at a cost of around ten cents a barrel or less. Five hundred barrels of water a day at ten cents a barrel is only fifty dollars a day. There are numerous leases where water is being handled at over $.30 a barrel, though. These cases can make expense reduction as significant as revenue generation. Trucking and disposal fees are often two sources of this cost.

Trucking savings were the foremost benefit realized by Talisman. Remote wells often truck production out from single well batteries. These quickly go uneconomic when water production increases. Trucking costs range from $US 0.35/bbl of fluid up to $US 1.50/bbl for distant routes. As such, a DAPS system can often be justified with as short as a two month payout.

Third party processing and water disposal fees were also significant to Talisman. These fees range from $US 0.30/bbl to $US 0.70/bbl of fluid processed when handled by a third party facility. DAPS can be justified with payouts as short as 4 months in these cases, if wellbore and geological conditions are favourable.

Another unique feature demonstrated by DAPS testing is that water production diagnostics (e.g., cased hole logs) are far less important than with chemical water shutoff treatments. The source of the water does not impact the operation of DAPS. DAPS will handle uniform influx of water equally as well as from a thin water stringer. In other words, it is not imperative with DAPS to identify which perforations are producing most of the water. Conversely, water shut off techniques usually require that most of the water is coming from a specific interval that can be plugged.

In spite of the fact that more fluid was being moved, the unit speed was actually reduced in several installations. The ramification of this is that well failure rates could be reduced.

Both Texaco and Talisman found that operating costs are often low enough that it is not possible to justify installation of DAPS for electrical savings alone. Other benefits as detailed above must accompany those savings.

Investment Savings. Wells that are candidates for larger lift equipment, such as submersible pumps, may be candidates for DAPS. The cost of converting to an ESP could justify the investment needed to install DAPS. DAPS will have a much lower operating cost than an ESP.

Another potential investment benefit is the use of DAPS to avoid the cost of installing additional water handling facilities. Overloaded disposal wells or facilities may require investing capital. DAPS might provide the reduction in water volumes needed to continue without further investment. Similarly, the cost of complying with regulations that require pit closures may be reduced by use of DAPS and smaller facilities.

When drilling a number of new wells in an older established field, water handling and disposal facilities in Canada can require expansion ranging from $US 200,000 to $US 750,000. Such expansion usually is accompanied by increased operating costs at the facility. With the availability of DAPS, it is now worthwhile to first analyze the nature of field production and geology. Consideration should be given to the conversion of older, high rate and high watercut wells to DAPS rather than battery expansion. If conditions are right, this could often be done for less overall capital, while reducing water volumes and operating costs. This can be particularly true for small, isolated leases.

DAPS may be an excellent alternative for waterflooding small reservoirs or conducting pilot floods. Typically, this requires investing in injection pumps, filtration, and injection lines. As an alternative, an operator might be able to provide injection water from a shallower, high water cut interval with DAPS. A "projector" is both a producer and an injector. Projectors could generate revenues from shallower intervals (at a lower lifting cost). They could make a waterflood justifiable at almost no additional expense and a nominal investment.

Environmental Benefits. The benefits of producing less water seem readily apparent. They are worth enumerating, though, because these benefits can become part of the economic justification of DAPS. Trucking and water treating are the more obvious impacts of brine production. Demulsifiers, oxygen scavengers, corrosion inhibitors, and scale inhibitors are just a few of the chemicals that may be necessary when handling water. Sand and diatomaceous earth filters generate solid wastes. As much as eighty per cent or more of the produced water can be injected rather than handled at the surface. (This is a function of well parameters and the pump design.) DAPS reduces the amount of water treating and handling that is necessary. This reduces the need to use and handle chemicals, and thereby reduces the potential for environmental complications.

The use of less energy to handle brine can have both direct and indirect benefits. Fired heaters, used to separate produced water from hydrocarbons, are often a target of environmental monitoring. Use of less heat to provide separation can help alleviate the emissions and potential impacts on flora and fauna. Benefits of reducing energy demand would be realized at power generation facilities.

Brine contamination is becoming an increasingly difficult issue for the oil industry. Reducing the quantity of brine handled at the surface can help alleviate load on facilities. Line leak frequency can be reduced by handling less pressure and rate in surface lines. This, in turn, can reduce the cost of surface damages.

Handling less water at the surface can reduce the footprint of oil operations. Retention time in vessels can be increased. DAPS could lessen the need to use pits. The use of fewer and smaller tanks and vessels could reduce damages to the surface. Trucking brine to a disposal site can be a problem in environmentally sensitive areas.

Application Criteria

While there are numerous applications for DAPS, there are also limitations. The following criteria can be used for initial candidate screening and selection.

Multiple intervals. The most important requirement is the existence of a suitable injection or disposal interval. **Figure 3** provides a conceptual drawing of a typical installation. The injection interval must be deeper than the production perforations by a minimum of about ten feet. Isolation between the two intervals is necessary. The injection zone can be the same formation as the producing zone provided that the perforated intervals are not communicating actively. The pressure required to inject water should not be excessive. The injection pressure gradient of the candidates tested has been low or moderate (less than 0.45 psi per foot of depth). Modeling work, as well as experience from some of our testing, indicates that higher injection gradients can be achieved. The produced water must be compatible with the injection zone. It is usually inadvisable to mix water from carbonate and sandstone reservoirs. However, bacteria and scaling problems caused by oxygen introduced at the surface or by temperature changes should not be as much of a problem. This is attributed to that fact that DAPS does not bring as much water to surface.

Zonal isolation. A common constraint is casing integrity. As with any injection well, the casing (and the cement behind it) must be suitable to set a packer and withstand injection pressure. This is often a "fatal factor" for older wells that have experienced casing leaks and extensive corrosion. It is best to have impermeable strata between the injection and producing zones.

Fluid separation. Another important factor is oil-water separation. The wellbore must be relatively vertical between the location of the upper and lower valves for separation to occur. Although it has been shown from downhole videos that oil rises to the top of the fluid column, it is anticipated that this will not be true in certain situations. Cold, heavy crudes which are approaching 10° API or less may not be good candidates. Wells that produce tight emulsions are not necessarily poor candidates. The emulsion may be a result of mixing in the pump chamber.

Operation and Features

The Dual Action Pumping System is a radical departure from conventional rod pumping, but it consists primarily of off-the-shelf components. Essentially, DAPS consists of 1) an upper pump, 2) a lower pump, 3) valves for injecting water into the disposal zone, and 4) a packer to isolate the production and disposal zone. The upper pump can be either a tubing type or insert type API rod pump. It does not have a standing valve but has the addition of an extra top plunger cage to connect the plunger to the valve rod of the lower pump. The lower pump consists of a tubing pump less both the standing and the traveling valves. The traveling valve has been replaced with a solid valve seat. This prevents communication through the plunger enabling both injection and lift. A stationary valve located between the two pumps acts as the standing valve for the differential displacement of the two pumps to the surface. The lower valves consist of an intake valve and an injection valve. Both valves are made from standard rod pump valve components with the addition of fittings that channel fluid in from the annulus and below the packer through the tubing. The injection valve is a simply a check valve with tubing threads that prevents back flow of water from the injection zone during the lifting cycle. Sinker bars or weight bars are normally placed above the top pump to provide the force necessary to overcome the injection pressure opposing the downward movement of the bottom pump.

Physical Description. A distinguishing feature of DAPS is that it has two sets of intake ports and two plungers (**Fig. 4**). The upper ports, contained on the outside of the pump housing, are the point of entry for all produced oil and some produced water for the upper plunger. The lower ports are contained in a valve assembly and feed the bottom plunger. This valve assembly is the intake point for all water standing in the annulus beneath the producing perforations.

The top half of DAPS consists of a conventional pump with a plugged plunger oriented downward to inject water. Fluid enters the pump on the upstroke and the traveling valve closes on the downstroke.

A lower valve assembly is placed on the tubing string between the lower pump and the injection packer. Water standing in the annulus above the injection packer enters into the lower pump chamber through the lower valve assembly

Functional Description. The operation of DAPS can be broken into two cycles: the injection cycle and the production or lifting cycle. Since the cycles operate concurrently, they each have an impact on loading of the other cycle.

Injection Cycle. The relatively simple injection cycle is shown in **Figure 4**. On the upstroke, water enters the tubing below the pump through the lower valve assembly. On the downstroke, injection pressure is primarily provided by the fluid column in the tubing and the weight of sinker bars placed immediately above the top pump. Other parameters, depending on well conditions, can also assist in providing injection pressure. The location of the lower valve assembly usually is not critical. It can be situated anywhere below the pump provided that it is placed lower than the producing perforations but above the injection packer. This can range from just a few feet to thousands of feet deeper than the pump itself.

Lifting Cycle. The lifting cycle is more complex. **Figure 4** shows that, on the downstroke, the top valve (normally the "traveling valve" of a conventional pump) closes to carry the weight of the fluid in the tubing. The external valve opens to allow fluid to enter the pump chamber. On the upstroke, the external valve closes off the annulus and the top valve opens. Oil and water are physically being lifted by the lower plunger. They are passed from the larger pump chamber of the lower pump into and through the upper pump chamber. The relationship in size between the two plungers, which are joined by a connecting rod, determines the proportions of fluid lifted and injected.

Environmental Permitting

A new challenge created by DAPS is the matter of underground injection control. Many agencies require operators to annually report rates and pressures. Monitoring and reporting injection pressures and rates is more difficult with this configuration than with a conventional injection well. Direct measurement of injection pressure in a conventional injection or disposal well is a relatively simple matter. With a pump, valve assembly and rods in the tubing, it is not as easy to measure injection rates and pressures below the injection packer with DAPS.

It can be demonstrated that injection rates and pressures can be calculated with reasonable certainty from surface conditions. Injection rates can be calculated from pump displacement, speed and stroke length. Testing at the Rocky Mountain Oilfield Testing Center (RMOTC) demonstrated that maximum injection pressure can be determined from the minimum polish rod load. It is intended that the analysis of quantitative data received from the RMOTC test will be reported to industry in the future. Talisman and Texaco have each met with the respective governing agencies prior to installing DAPS in various states and provinces to discuss the experimental nature of the tests being conducted.

DAPS provides an additional measure of protection for shallow aquifers. In the event that communication starts occurring behind the wellbore, the zone producing water for injection purposes also provides a pressure sink for water trying to migrate out of zone. This would be detected with changes in water cut at the surface.

Canada - Injection Zone Monitoring.

Injection zone monitoring is a subject which requires careful planning. It is always useful to have monitoring systems for troubleshooting. Unfortunately, the unreliable nature of downhole electronic pressure and flow monitoring systems often limits the feasibility of their use. In addition, the high cost of such systems can often cause the project economics to fall below the minimum acceptable hurdle rate.

A bubble tube was used to measure injection zone pressure on the Parkman installation by tying into the disposal water tubing just above the packer. (**Figure 2.**) The system has the advantages of being mechanically more robust than electronic cable. It is also lower in cost and can sample injected water quality. To measure injection pressure, nitrogen is injected at surface from a portable bottle. When the disposal water has been fully displaced to the bottom of the tube, the gage measuring the nitrogen pressure will stop rising. This indicates all water head has been displaced. The flowrate of nitrogen is then cut back to a trickle to eliminate friction effects. The injection zone pressure is then the sum of the surface pressure and the calculated nitrogen head in the bubble tube (usually minimal).

To obtain disposal water samples, the tube is simply blown down to atmosphere. There must be enough disposal zone pressure to overcome the water head required to produce water to surface through the bubble tube. If water flow is achieved, simply purge a full bubble tube volume of water then take a representative disposal water sample. For systems where injection pressure is insufficient to have bubble tube flow reach surface, dual bubble tubes with a simple form of gas lift are being investigated.

If confidence exists regarding separation efficiency and injection pressure expectations, injection zone monitoring costs may not be necessary. Further knowledge is derived from baseline and subsequent dynalog surveys. These give an indirect indication of disposal pressure. If such confidence does not exist, a bubble tube can be used for the first DAPS application until field specific information is gained in disposal zone performance and separation efficiency.

Canadian authorities have generally embraced the DAPS system. It should benefit producers as well as the government by extending economic limits, hence leading to larger ultimate reserves. As such, they have placed fairly minimal requirements on the regulatory approvals process. Depending on the jurisdiction, a letter-type summary of the project intentions and method of disposal zone monitoring (if any) is required when water disposal is deemed to be within the same zone as production. For water disposal to a separate zone, a process similar to the existing one for water disposal wells is required.

The regulatory bodies have generally requested brief progress reports bi-annually so they can learn along with the producers. These reports include calculated approximations of the volume of water injected to the disposal zone.

Modeling DAPS

An all-inclusive design program for this system is not available. Currently available commercial design software utilize a numerical solution of the damped wave equation, calculation of rod buckling tendency, and a constant downstroke pump load (e.g., NABLA's SROD$$). These, coupled with a spreadsheet, are sufficient to design a system. Other software packages are being utilized. The software package must include a means to enter a downhole load acting at the pump on the downstroke. This is needed to model the injection forces acting up on the lower plunger. The process using these tools is iterative but fairly straightforward.

The upstroke surface loading (e.g., unit torque, structure loading, rod loads, etc.) is determined in a conventional manner using the lower plunger size. The lower plunger provides the work to produce and inject. The upper plunger only provides a moving seal. Although the loads are dictated by the lower pump, the surface rate is based on the difference in two pump areas. The pump intake pressure must reflect the total flow rate from the perforations (both production and injection). The injection rate is calculated directly from the lower plunger size.

On the downstroke, sufficient force from the fluid load in the tubing and annulus and buoyant weight of the rod string is needed to overcome the injection forces without buckling the rod string. The traveling valve is closed and the side intake valve between the pumps is open on the downstroke. Therefore, a portion of the hydrostatic load in the tubing and annulus acts on the lower plunger. The force required to inject water downhole is counteracting these forces underneath the plunger. This upward force imposed on the lower plunger is modeled by calculating a force balance of these loads at the lower plunger. The load is entered into SROD$$ as a pump friction only acting on the downstroke. Within the program, this load acts as an upward constant force on the downstroke of the cycle. This enables the model to more accurately predict sucker rod buckling during the injection cycle.

Expanding the Envelope.

Currently there are relatively few wells with DAPS installations. The focus has been to determine where DAPS can be used. Follow-ups to the original tests are now (in the first half of 1997) being designed.

Tool Limitations. The widest application for DAPS systems in Canada is for vertical wells with 5.5" casing. It is common to see total fluid rates over 1500 bpd. Due to physical size constraints, the largest system available in 5.5" casing is 2" x 2.25." For typical pumpjack stroke and speeds, this limits withdrawals to about 1000 bpd. If a lower-profile, side intake mandrel (ie the upper port) can be developed, separation efficiency can be tested at higher rates by using larger pumps -- potentially up to 2.75" or 3.25" in size.

An injection valve assembly has been designed for 4 1/2" casing applications. This has not been tested at this time. Resolution of this limitation will open the door for numerous follow-ups to the East Texas well tests.

Deep Wells. Talisman Energy has just begun testing DAPS in a deep well approximately 400 miles Northwest of Calgary, Alberta. The production zone is a carbonate formation at a depth of 8400 ft. The disposal zone is at 8550 ft. The specific gravity of the water is 1.1, and the oil is 36° API. Initial results demonstrate successful separation and operation as shown in **Table 1**. Note that this well has only been running since April 1997. At the time of writing this paper, the system is in the process of being sped up to optimized rates. The expected "optimized" results are also shown in **Table 1**.

Heavy Oil. Talisman Energy is currently testing a DAPS system approximately 250 miles northeast of Calgary, Alberta. One goal is to extend the service envelope to include heavy oil fields. The producing zone is the Dina sand at a depth of 2300 ft. The disposal zone is at 2360 ft, and is separated from the producing zone by a seal layer of rock. Production is from a consolidated sandstone, but produced fluids are free of particulates. The produced water specific gravity is 1.05 with 17.5° API oil.

The system has only been running since April 1997, and was started up at low rates as a precaution. The preliminary results demonstrate successful separation and operation. This is evidenced by an excellent match with the well inflow performance curve. The pumpjack is currently being sped up to approach an optimal pumped off condition. The "future optimized" data is shown in **Table 1.** Based on successful results to date, it represents the expected condition when a pumped off condition is realized.

Monitoring. A baseline dynomometer survey a few days after startup is usually useful for comparison to surveys done later, especially if problems are encountered. It can be used for the usual diagnostics, as well as giving an indication of whether the disposal zone pressure is increasing over time. Testing at RMOTC and other wells discussed above is providing excellent quantitative data that will be used for this purpose. This testing may provide a means to quantify injection pressure beneath the packer. It may also yield a means to identify equipment failures when they occur. Pump failures can be detected by use of production data and dynomometer data. This information will be discussed in a future paper.

Optimizing fluid levels in DAPS wells is a challenge that will be evaluated. DAPS will not develop a fluid pound in the same manner as a conventional well. If the upper pump is "starved," all produced liquids will be injected by the lower plunger. When the working fluid level falls below the upper intake, the lifting cycle is "starved," while the lower valve assembly will continue feeding the injection cycle. Consequently, the produced oil would be injected along with all the water if this occurs. Accordingly, DAPS should not be used to completely pump off a well.

Other Challenges. Still other problems must be resolved. Wells with poor injectivity need to be tested to determine whether DAPS can economically overcome high injection gradients. Even the issue of accounting for a well that is both producing and injecting presents a challenge that may test a company's accounting system.

Both the design and the permitting process must be streamlined. Nabla Corporation is working with Texaco to improve modeling predictions. Agencies in the several states and provinces where tests have been performed have indicated willingness to learn more about the potential of DAPS.

Not every installation of DAPS to the time this paper was submitted is reported. While most systems have actually exceeded our expectations, a few have not been as successful as those described. Two wells, identified as DAPS candidates, experienced casing failures during wellwork prior to installing DAPS. Another experienced casing failure about a week after the wellwork. Oil production increased only slightly in another (but the surface water was reduced dramatically). Some installation problems arose in others, but Dresser personnel have gained valuable experience to prevent a similar recurrence.

Future Developments.

It has been shown that the DAPS system can be applied to improve the economics of mature fields. It can reduce the capital expenditure associated with water handling for newly drilled locations. Any reservoir engineer will say that the extension of the economic limit for a well or field results directly in incremental reserves being recovered. This benefits industry, royalty owners, and governments alike. The challenge now is to continue to extend this technology to applications with higher rates, lift from greater depth, and lower API gravity oil. As demonstrated, projects are currently underway to achieve this.

The commitment of the authors' companies to better manage water production has led to the conclusion that a whole new class of artificial lift lies in the future. Industry has a term for this class of new technologies: Dual Injection and Lifting Systems (DIALS). The Centre for Engineering Research (CFER)[3] has developed a line of products such as their "Aqwanot" that utilize hydrocyclones to separate water and oil downhole. DAPS utilizes gravity segregation to selectively lift oil and some water to surface while injecting the remaining water. Encouraged by the success of DAPS, Texaco has other DIALS technologies in various stages of development. Each of these systems utilize the same, key principle that led to the invention of DAPS -- downhole gravity segregation of water and oil.

Each installation of the DAPS technology has opened our eyes to exciting, new potential. For example, anything less than a 20° API crude was considered an unlikely candidate a year ago. Talisman's test, as well as other evidence, gives reason to believe that DAPS could work in some fields with 13° API crudes. The RMOTC test has demonstrated the feasibility of waterflooding a water-sensitive zone with water from a shallower oil reservoir.

Conclusions.

The degree of successful application of DAPS systems to achieve the benefits detailed in this paper rests solely on the technical and communication skills of the teams involved in the exploitation and production of oilfields. No longer can the attitude of "we'll find the oil, then Operations can worry about producing it" exist. Geologists need to interact with exploitation and production engineers. They need to consider factors like remote distances to well locations, trucking costs, drilling to disposal depth, and battery capacity when planning drilling locations. Does it make sense to consider DAPS? Does a suitable disposal zone exist? At least one location has been drilled by Talisman Energy to date which would not have been previously deemed a viable exploration target due to high water cut and remote trucking costs. The plan incorporated a DAPS system from inception, which rendered the target economic.

Acknowledgments.

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Table 1
DAPS Production Comparisons

	Test	Surface Oil Prod. bopd	Surface Water Prod. bwpd	Water to Disposal. bwpd	Fluid Level, ft From Surface
Before DAPS	E. Texas	3	184	0	834
After DAPS		10	126	392	1131
Before DAPS	Parkman	14.5	221	0	312
After DAPS		35	151	882	561
Before DAPS	Deep test	27	932	0	3085
After DAPS		28	179	851	2900
Optimized		33	209	993	4080
Before DAPS	Heavy Oil	25	250	0	1400
After DAPS		32	25	265	1495
Optimized		38	38	400	1900

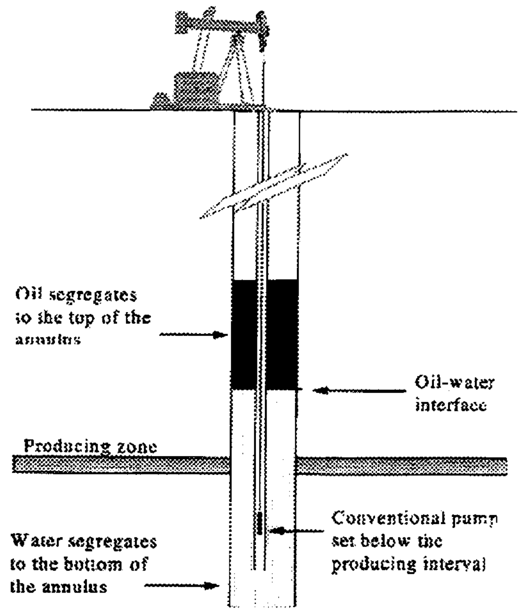

Figure 1 - The well in this example has a conventional pump set beneath the producing perforations. If it stops producing for several days and then is put on production, it will produce only water for hours or days--demonstrating gravity segregation.

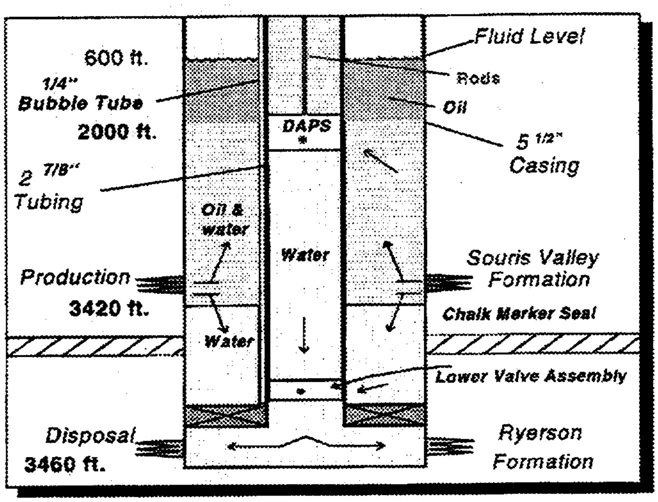

Figure 2 - Talisman Energy installed DAPS in the Parkman Field in Canada--more than doubling production. Both the injection and the lifting pumps are placed much shallower than the injection valve assembly.

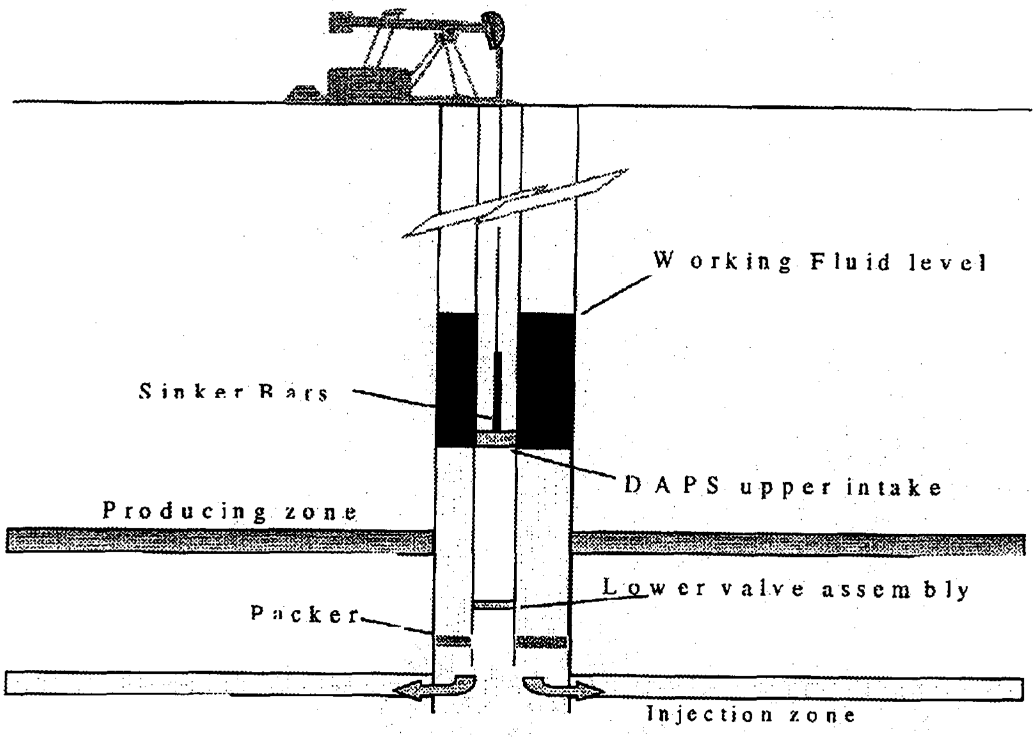

Figure 3 - DAPS requires an injection zone to function. Two separate reservoirs are shown, but one continuous reservoir with 10" between producing and injection perforations could work.

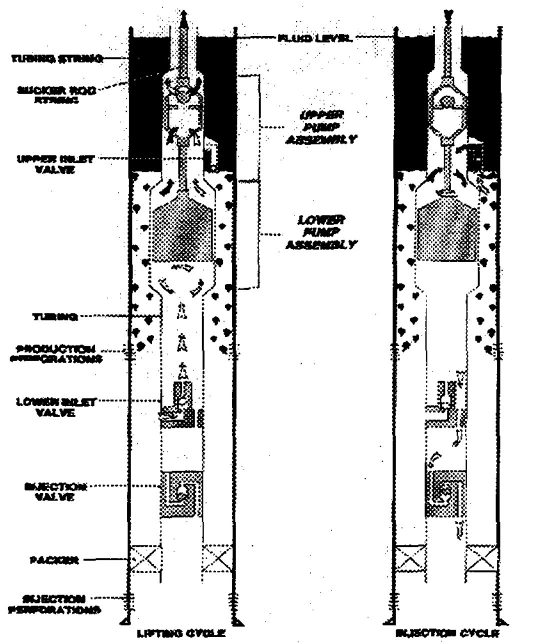

Figure 4 - Schematics of the lifting and injection cycles of DAPS (Patent #5,497,832) show how it selectively lifts oil and some water but injects only water. The two valves comprising the Lower Valve Assembly (patent pending) are shown separately as the "Lower Valve Inlet" and the "Injection Vālve." There can be significant vertical separation between the pumps and the Lower Valve Assembly.