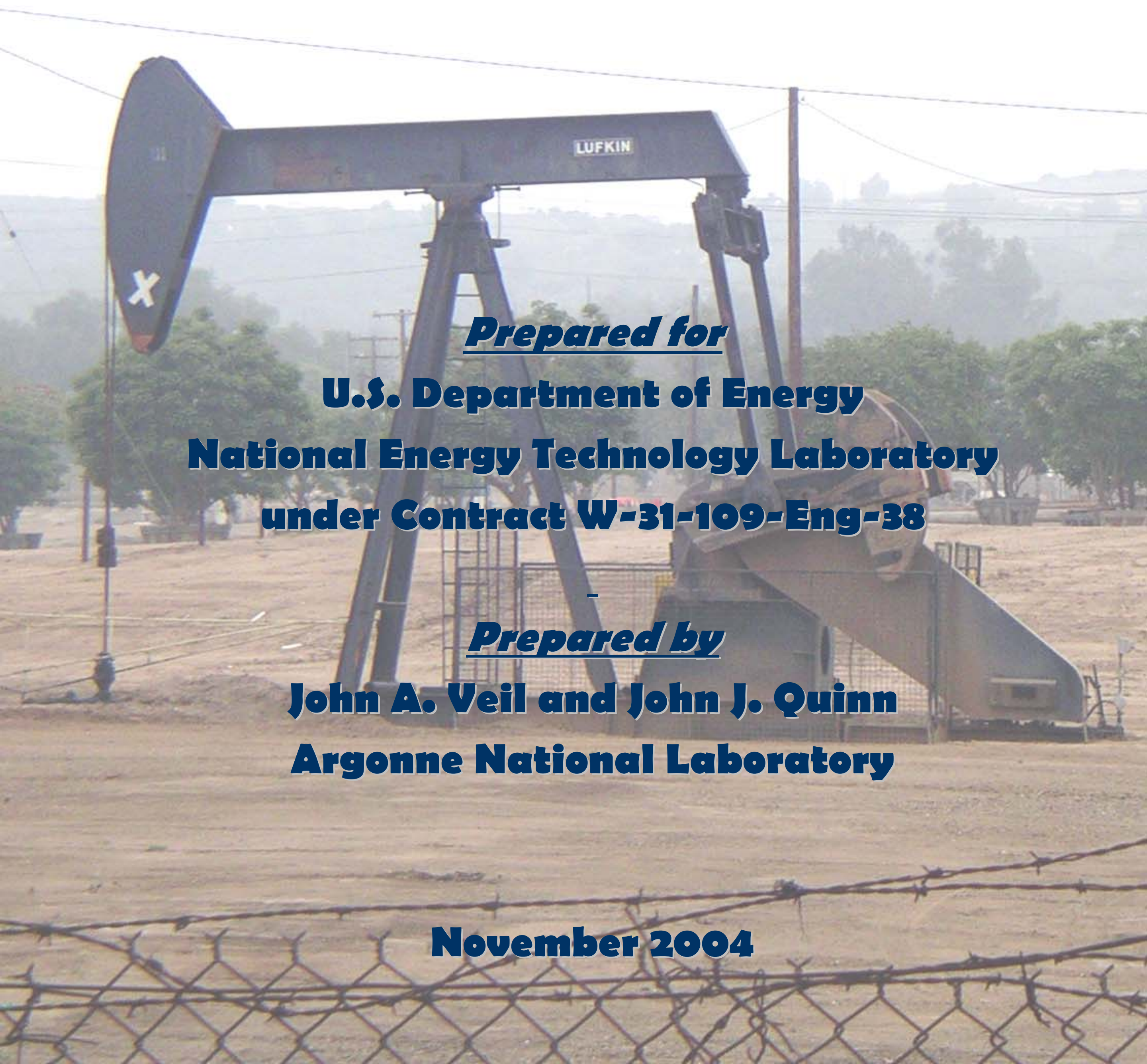
Downhole Separation Technology Performance: Relationship to Geologic Conditions



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Executive Summary

Produced water is underground formation water that is brought to the surface along with oil or gas. It is by far the largest (in volume) by-product or waste stream associated with oil and gas production. Management of produced water presents challenges and costs to operators. If the entire process of lifting, treating, and reinjecting can be avoided, costs and environmental impacts are likely to be reduced. With this idea in mind, during the 1990s, oil and gas industry engineers developed various technologies that separate oil or gas from water inside the well. The oil- or gas-rich stream is produced to the surface, while the water-rich stream is injected to an underground formation without ever being lifted to the surface. These devices are known as downhole oil/water separators (DOWS) and downhole gas/water separators (DGWS).

Two basic types of DOWS have been developed. One type uses hydrocyclones to mechanically separate oil and water, and the other relies on gravity separation that takes place in the well bore. A more detailed description of the technologies, with figures and references, can be found in Veil et al. (1999) and Veil (2001, 2003).

DGWS technologies can be classified into four main categories: bypass tools, modified plunger rod pumps, electric submersible pumps, and progressive cavity pumps. There are tradeoffs among the various types, depending on the depth involved and the specific application. Produced water rates and well depth control which type of DGWS tool is appropriate. A good reference on DGWS technology is a 1999 report prepared by Radian International for the Gas Research Institute (GRI 1999).

DOWS and DGWS technologies received a great deal of attention in the late 1990s. Over the past few years, few installations of either technology have been made. The U.S. Department of Energy asked Argonne National Laboratory to compile a database of as many DOWS and DGWS trials as possible and determine what set of production formation geology and injection formation geology offered the greatest chance for a successful installation. Although the field of geology encompasses many aspects and properties of underground formations, we focused this study on the basic types of rocks (i.e., carbonate, sandstone, or other). The primary reason for this was that the data we used in this analysis had only limited information on other geologic properties.

This report provides data on 59 DOWS trials and 62 DGWS trials from around the world (Tables 1-3) and a qualitative discussion of at least 35 other installations. The data are taken from the literature, vendor Web sites, and material directly provided by operators or vendors. We are aware that there have been other field installations, but data on those installations are either being held privately as proprietary information or are not available for other reasons. Despite not including all worldwide field trials, the data compiled here represent the largest and most complete set of information on downhole separation that is publicly available. We further note that in some columns in the data tables, data are lacking for many trials. Although this lack of data is unfortunate, the large amount of data compiled and reported here is still useful.

The analysis of preferable geologic conditions began by reviewing the conclusions presented at a 2002 meeting of the International Downhole Processing Group, at which downhole separation

experts from around the world presented their latest information. Alhanati et al. (2002) presented an analysis of the effect of geologic conditions on the risk of a DOWS trial. Those authors reviewed records on about 80 installations of hydrocyclone-type DOWS that used electric submersible pumps (ESPs) for pumping. They concluded that installations having both carbonate production and injection formations have the lowest risk of failure, or, conversely, the highest probability of success. Installations having the following production zone/injection zone combinations posed a medium risk: carbonate/consolidated sandstone, consolidated sandstone/carbonate, and consolidated sandstone/consolidated sandstone. Installations with carbonate/unconsolidated sandstone or consolidated sandstone/unconsolidated sandstone conditions posed a medium risk for regular DOWS installations, but a high risk when the injection zone was above the production zone. Finally, any installation that had unconsolidated sandstone as the production zone offered a high risk.

We were unable to examine the data used by Alhanati et al. (2002); therefore, our results are based on an independent effort. Table 5 includes qualitative performance ratings, where possible, for each DOWS installation listed in Table 1 on overall performance, increase in oil production, reduction in water to the surface, and longevity. This ranking scheme has shortcomings, but we were unable to provide a more precise ranking scheme because there were gaps in the available data. Table 2 summarizes DGWS data from GRI (1999). We do not have much information on the trials themselves. GRI included its own performance ranking of success, failure, or economic failure. Table 3 contains information on a few additional DGWS installations not included in GRI (1999). Because the data records are not complete, only an overall performance rating is shown.

Table 6 compares qualitative performance with geologic types for the 59 DOWS installations from Table 1. Overall, about 59% of the trials were rated as good. All three categories in which both the production and injection formations were known showed about the same percentage of good trials (50–58%). Overall, about 31% of the trials were rated as poor. For the three categories in which both the production and injection formations were known, the percentage of poor trials ranged from 28% for sandstone/sandstone to 50% for carbonate/sandstone.

Table 7 compares GRI's qualitative performance with geologic types for 48 DGWS installations. Overall, about 54% of the trials were rated as successes. The carbonate/carbonate, carbonate/sandstone, and sandstone/sandstone categories all showed a high percentage of trials rated as successes (70–100%), but none of the three stood out as a clearly better combination than the others. Overall, about 42% of the trials were rated as failures or economic failures. Nearly half of the trials were in situations in which one or both of the formations were unknown. This subset of trials had the worst overall success rate, with only 30% being rated as successes and 61% being rated as failures or economic failures.

The results from Table 3 are much more straightforward. Twelve of the 14 trials were qualitatively rated good. Five trials had sandstone/sandstone formations, and two others had coal/unknown formations. No information on formations was available for the other seven trials.

Our analysis of about 120 DOWS and DGWS installations from numerous different countries, states, and provinces does not support the theory that the combination of carbonate production and injection formation offers the best chance for a successful DOWS or DGWS installation. On the basis of the data described in this report, it is not possible to predict the performance or likelihood of DOWS or DGWS success solely on the basis of the geology of the production formation or the injection formation. One caveat to this conclusion is that the data sets reviewed by Alhanati and his coauthors were probably much more complete than the data sets presented in this report. We believe that our conclusions are still valid, but we recognize that we did not have the ability to consider many details about the formation properties other than their geology into our ranking scheme. Despite intensive efforts to obtain more complete data sets, we were unsuccessful in that regard.

There are other factors that play a role in the success of DOWS systems. Probably the most important factor is ensuring that the injection formation has good injectivity and that the injection process does not introduce materials that could clog the pores of the injection formation and reduce its injectivity. Another important parameter is good vertical and mechanical separation between the production and injection formations. The candidate well should be located in a formation that has sufficient remaining reserves to allow payback of the investment.

Representatives from companies that have used or have sold DGWS were contacted and asked their opinion on the value of the geologic setting and other factors. A theme that emerged from these discussions was that the DGWS success rate is not dependent on the geology of the source zone or disposal zone, but rather on site-specific properties of the disposal zone at individual wells. In general, disposal zones that are favorable for DGWS have high permeability, high porosity, and are underpressured.

Chapter 1 — Introduction

Background

Produced water is underground formation water that is brought to the surface along with oil or gas. It is by far the largest (in volume) by-product or waste stream associated with oil and gas production. According to the American Petroleum Institute (API), about 18 billion barrels (bbl) of produced water were generated by U.S. onshore operations in 1995 (API 2000). Additional large volumes of produced water are generated at U.S. offshore wells and at thousands of wells in other countries. Khatib and Verbeek (2003) estimate that in 1999 there was an average of 210 million bbl of water produced each day worldwide. This volume represented about 77 billion bbl of produced water for the entire year. Given that worldwide oil production from conventional sources is nearly 80 million barrels per day (bbl/d, or bpd), one may conclude that 3 bbl of water are produced for each 1 bbl of oil worldwide, and that for the United States, one of the most mature petroleum provinces in the world, the ratio is closer to 6 or 7 bbl of water per 1 bbl of oil.

In early 2004, Argonne National Laboratory (Argonne) generated estimates of onshore produced water volumes in the United States for the year 2002 (Veil et al. 2004). Making these estimates was challenging, since many of the states did not have readily available information on volumes. The 2002 total onshore volume estimate of 14 billion bbl was derived directly from the applicable state oil and gas agencies or their Web sites when data were available and extrapolated when data were not available. The estimate does not include produced water from coal-bed methane (CBM) wells or from offshore U.S. production. The actual U.S. total volume of produced water in 2002 was probably much higher than the estimated 14 billion bbl.

Management of produced water presents challenges and costs to operators. The cost of managing produced water after it is already lifted to the surface and separated from the oil or gas product can range from less than $0.01 to more than several dollars per barrel. If the entire process of lifting, treating, and reinjecting can be avoided, costs are likely to be reduced. With this idea in mind, during the 1990s, oil and gas industry engineers developed various technologies to separate oil or gas from water inside the well. The oil- or gas-rich stream is produced to the surface, while the water-rich stream is injected to an underground formation without ever being lifted to the surface. These devices are known as downhole oil/water separators (DOWS) and downhole gas/water separators (DGWS). These technologies are described in Chapter 2.

Scope of Study

Argonne previously studied and described DOWS technology for the U.S. Department of Energy (DOE) through a technology feasibility evaluation (Veil et al. 1999) and prepared several updates on the status of the technology after that (Veil 2001, 2003). These studies pointed out the potential for cost savings resulting from DOWS and DGWS installations. In early 2003, Argonne was contacted by an environmental program manager from DOE's National Energy Technology Laboratory and asked to undertake a study of the geologic conditions under which DOWS and DGWS were most successful. The DOE manager's intention was to have Argonne identify oil and gas formations throughout the United States that had the optimal geologic conditions to increase the prospects of successful DOWS and DGWS installations.

This report describes the data that Argonne compiled on DOWS and DGWS installations. The data do not support any clear trend relating specific geologic conditions to DOWS or DGWS success. Therefore, the intended extrapolation to other U.S. formations was not conducted.

Acknowledgements

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Chapter 2 — Downhole Separation Technology

This chapter describes the various types of tools that are used to separate oil or gas from water inside of wells. The tools are generally designed either for oil/water separation or for gas/water separation and therefore are described separately in the following sections.

DOWS Technology

DOWS technology reduces the quantity of produced water that is handled at the surface by separating it from the oil downhole and simultaneously injecting it underground. A DOWS system includes many components, but the two primary ones are an oil/water separation system and at least one pump to lift oil to the surface and inject the water. Two basic types of DOWS systems have been developed. One type uses hydrocyclones to mechanically separate oil and water, and the other relies on gravity separation that takes place in the well bore. A more detailed description of the technologies, with figures and references, can be found in Veil et al. (1999) and Veil (2001, 2003).

Hydrocyclones use centrifugal force to separate fluids of different specific gravity; they operate without any moving parts. A mixture of oil and water enters the hydrocyclone at a high velocity from the side of a conical chamber. The subsequent swirling action causes the heavier water to move to the outside of the chamber and exit through one end, while the lighter oil remains in the interior of the chamber and exits through a second opening. The water fraction, containing a low concentration of oil (typically less than 500 mg/L), can then be injected, and the oil fraction along with some water is pumped to the surface. Hydrocyclone-type DOWS have been designed with electric submersible pumps (ESPs), progressing cavity pumps, gas lift pumps, and rod pumps.

Gravity separator-type DOWS are designed to allow the oil droplets that enter a well bore through perforations to rise and form a discrete oil layer in the well. Most gravity separator tools are vertically oriented and have two intakes, one in the oil layer and the other in the water layer. This type of DOWS uses rod pumps. As the sucker rods move up and down, the oil is lifted to the surface and the water is injected. Three North Sea-based companies collaborated to develop another class of gravity-separation DOWS that works by allowing gravity separation to occur in the horizontal section of an extended reach well. The downhole conditions allow for rapid separation of oil and water. Oil is lifted to the surface, while water is injected by a hydraulic submersible pump (Almdahl et al. 2000).

DOE has actively promoted DOWS technology. With DOE funding, Argonne conducted an independent evaluation of the technical feasibility, economic viability, and regulatory applicability of DOWS technology in 1999 (Veil et al. 1999). That report provides information on the geology and performance of 37 DOWS installations, representing most of the installations that had been made worldwide through 1998. Some of the key findings from those installations are summarized below:

- More than half of the installations were hydrocyclone-type DOWS (21 compared with 16 gravity-separator-type DOWS).

- Twenty-seven installations were in Canada, and 10 were in the United States.
- Of the 37 DOWS trials described, 27 were in four producing areas: southeast Saskatchewan, east-central Alberta, the central Alberta reef trends, and East Texas.
- Seventeen installations were in 5.5-in. casing, 14 were in 7-in. casing, one was in 8.625-in. casing, and five were unspecified.
- Twenty of the DOWS installations were in wells located in carbonate formations, and 16 were in wells located in sandstone formations. One trial did not specify the lithology.
- The rate of oil production increased in 19 of the trials, decreased in 12, stayed the same in two, and was unspecified in four. The top three performing hydrocyclone-type wells showed oil production increases ranging from 457% to 1,162%, while one well lost all oil production. The top performing well improved from 13 to 164 bbl/d. The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production. The top-performing well in this group improved from 3 to 10 bbl/d.
- All 29 trials for which both pre-installation and post-installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding a 75% reduction.

Argonne later ran a program for two years under which DOE funds were offered to companies to subsidize the cost of installing DOWS systems in exchange for receiving detailed operating data. Only two companies participated in this program. The data from a gravity-separator-type DOWS trial in New Mexico (Veil 2000) and a hydrocyclone-type DOWS trial in Texas (Argonne and ALL-LLC 2001) are available on Argonne's Web site at http://www.ead.anl.gov/project/dsp_topicdetail.cfm?topicid=18.

Several organizations have worked to develop a DOWS unit that separates fluids by using a centrifuge. DOE funded development of a centrifugal DOWS by Oak Ridge National Laboratory (Walker and Cummins 1999), but this technology has not been tested in a full-scale field application. In May 2003, Chachula (2003) reported on a separate research effort that was expected to complete a prototype centrifugal DOWS by the fourth quarter of 2003. As of August 2004, no publicly available papers have been identified describing a centrifugal DOWS field trial.

One of the applications for which DOWS could be used is to improve the water handling and production rate on a fieldwide basis. To date, DOWS have not been used for this purpose. The following examples lead in that direction.

In 1999, DOE awarded a large grant to Venoco, Inc., a Southern California offshore producer, to conduct a pilot application using downhole water separation units attached to electric submersible pumps. The goal was to improve field economics and minimize water disposal in the South Ellwood Field, offshore from Santa Barbara, California. Venoco had hoped to install a DOWS on one of its wells during the first quarter of 2004, but as of summer 2004, the earliest likely installation date is projected to be the second quarter of 2005 (Horner 2004).

Chachula (2003) discusses use of a DOWS as part of a "smart well" system that would control real-time choking, plugging, isolation, and monitoring. He acknowledges that this is an expensive, complex, and unproven technology.

Recent DOWS Activity

DOWS developments and new installations have been mostly stagnant for the past few years. The lack of DOWS sales has translated into changes to the DOWS marketplace. At the time Veil et al. (1999) was released, three companies were actively marketing DOWS tools in the United States: Centrilift (a division of Baker Hughes), REDA Pumps, and Dresser/Axelson. During 2002, only Centrilift continued to actively market the technology, and by 2004, none of these companies were promoting DOWS.

Because of low DOWS sales, Centrilift currently does not actively market its DOWS tools (Voss 2004a). REDA was subsequently taken over by Schlumberger, which reports that REDA's DOWS tool (the Aqwanot™) is no longer being sold because it was not sufficiently reliable. Schlumberger continues proprietary development of downhole separation tools and has looked at separation devices other than hydrocyclones. It anticipates having a field prototype late in 2005 and commercialization in 2006 (Fielder 2004).

During 2000, the author was not able to contact a Dresser/Axelson representative to learn if the company planned to continue marketing DOWS. No recent contact has been made, although none of the persons interviewed by the author while researching this paper mentioned any DOWS activity by Dresser/Axelson.

Texaco was a leader in developing the gravity-separator-type DOWS technology sold by Dresser/Axelson. However, since 1999, Texaco's core group of DOWS researchers has been disbanding (some have retired, and others have been reassigned to different projects). One Texaco well with an installed DOWS system was sold, and the DOWS was removed from the well.

In Canada, Quinn Pumps marketed several DOWS tools in the late 1990s but has not had many installations during recent years. Quinn is still marketing downhole separation systems but has focused more on gas wells rather than oil wells (Prostebby 2003).

One new entry into the DOWS marketplace is READ Well Services, which, in conjunction with Wood Group ESP, developed a two-stage hydrocyclone-type DOWS system and installed it in a well operated by PDVSA in Venezuela in December 2001. The unit is sized to handle 10,000 bbl/d but was operated at 8,000 bbl/d until May 2002, when the ESP component of the unit failed. The water separated in the hydrocyclone could be either injected or sent to the surface via the well annulus. PDVSA and READ tested the system at various water splits (the percentage of water separated in the hydrocyclone). The unit was set to operate at a 60% split, but the tests ranged from 30% to 70% split. In the 50–70% split range, the water fraction contained from 35 to 200 mg/L of oil (Smestad 2003). The DOWS operated for 5 months until various components of the pump and controls (but not the separator) had failed. The DOWS was pulled from the well and has sat on the surface for several years, where it is becoming corroded. Because of the political upheaval in Venezuela during the past few years, no additional work has been done at that location (Smestad 2004).

C-FER Technologies is a DOWS 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.

Another company that already sells an industrial oil/water separation device, Gnesys, Inc., is developing a new DOWS tool and hopes to try a pilot test later this year (Janckhe 2004).

DGWS Technology

Several companies have marketed downhole separators for gas wells. Since the difference in specific gravity between natural gas and water is large, separation occurs naturally in the well. The purpose of the DGWS is not so much one of separation of the fluid streams but of disposing the water downhole while allowing gas production. The technology is somewhat different than DOWS technology, for which the fluid separation component is very important.

A good reference on DGWS technology is a 1999 report prepared by Radian International for the Gas Research Institute (GRI 1999). Much of the information in this section is based on that report. DGWS technologies can be classified into four main categories: bypass tools, modified plunger rod pumps, ESPs, and progressive cavity pumps. There are tradeoffs among the various types, depending on the depth involved and the specific application. Produced water rates and well depth control which type of DGWS tool is appropriate.

Bypass tools are installed at the bottom of a rod pump. On the upward pump stroke, water is drawn from the casing-tubing annulus into the pump chamber through a set of valves. On the next downward stroke, these valves close and another set of valves opens, allowing the water to flow into the tubing. Water accumulates in the tubing until it reaches a sufficient hydrostatic head so that it can flow by gravity to a disposal formation. 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/d and a maximum depth in the 6,000- to 8,000-ft range. GRI (1999) identified two vendors of bypass tools: Harbison Fischer and Chriscor, a division of IPEC, Ltd.

Modified plunger rod pump systems incorporate a rod pump, which has its plunger modified to act as a solid assembly, and an extra section of pipe with several sets of valves located below the pump. On the upward pump stroke, the plunger creates a vacuum and draws water into the pump barrel. On the downward stroke, the plunger forces water out of the pump barrel to a disposal zone. 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/d) and depths from 2,000 to 8,000 ft.

GRI (1999) notes that Downhole Injection, Inc. (DHI) is the leading vendor of modified plunger rod pump systems, and Burleson Pump reportedly also offered them.

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 (greater than 800 bbl/d) and can operate at great depths (more than 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. GRI (1999) reported that Centrilift and REDA (now part of Schlumberger) both offered DGWS systems using ESPs at that time. GRI also noted that another company, Petrospec Engineering, Ltd., had introduced an ESP that was deployed on coiled tubing for shallow and low-power-demand applications. Few ESP-type DGWS tools have been installed.

The fourth type of DGWS uses progressive cavity pumps (also referred to as progressing cavity pumps). This type of pump has been used throughout the petroleum industry. 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 (e.g., sand grains or scale) more readily than rod pumps or ESPs. GRI (1999) reported that Weatherford Artificial Lift Systems offered a DGWS system using progressive cavity pumps. The GRI study did not identify any actual applications of progressive cavity pump DGWS systems in use.

GRI (1999) gave summary data on 53 DGWS field tests involving 34 operators in the United States and Canada. Sixty percent of the tests used modified plunger rod pumps, while another 32% used bypass tools. The remaining 8% used ESP systems. Gas production rates were increased in 57% of the tests, but only 47% of the field tests were termed successful, confirming that there is still significant risk. About half of the failures were attributed to water cycling or poor injectivity issues.

Although most DGWS systems are designed for injection to formations below the production formation, some systems have been developed to inject to a formation that lies above the production formation.

Recent DGWS Activity

Kudu Industries Inc. 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 (Roche 2001).

Quinn Pumps (a division of Quinn's Oilfield Supply Ltd.) has two DGWS technologies available (Quinn Pumps Web site [undated]). 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 well bore. 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.

Harbison-Fischer Mfg. Co. manufactures a bypass tool licensed from Oxy USA.

DHI continues to develop and test new DGWS equipment. DHI produces rod pumps, including a reverse flow injection (RFI) system and a progressive cavity RFI system for handling high solids content. It has pilot-tested a downhole three-phase separation system that is intended to separate oil, gas, and water into separate streams. As of August 2004, DHI has not yet conducted a full-scale field test of the three-phase separation system (DHI Web site [undated])

Burleson Pump Company continues to build custom-made plunger pumps for DGWS applications.

Centrilift remains active in DGWS technology and is marketing an ESP called GasPro™, which has a capability for controlling the water disposal rate. Centrilift also has a progressing cavity pump DGWS system (Voss 2004b).

Schlumberger and its REDA Pumps division produce electric submersible pumps and progressing cavity pumps.

An Austrian company, Rohoel-Aufsuchungs AG, has published two recent papers that briefly discuss a device called the subsurface side door, or SSD (Clemens and Burgstaller 2004; Clemens et al. 2004). The lead author of the papers has indicated that the SSD is a simple device that allows opening or closing a portion of the tubing. It is not a bypass tool; it connects the producing and injection formations, which are separated by packers (Clemens 2004). The papers indicate that the field trial in April 2003 was successful and that the company plans a full field application for 2004.

Dual-Completion Wells

This section describes another technology that can be used to control water in an oil well. The technology is known as a dual-completion well or a downhole water sink. Oil production can decline in a well because the oil layer/water layer interface forms a cone around the production perforations, limiting the volume of oil that can be produced. Downhole water sink technology requires that an oil well be drilled through the oil-bearing zone to the underlying water zone. Then the well is completed in both the oil and water zones with the two completions separated by a packer. During production, oil flows into the top completion while water is drained by the lower completion. The water drainage rate is adjusted to the oil production rate so that the water cannot cone upwards and invade the top completion. As a result, the top completion produces mostly oil with minimal water. The water drained by the lower completion can either be produced to the surface for treatment or reinjected in the same well.

Dual completion wells have been tested in field operations (Swisher and Wojtanowicz 1995) and in theoretical studies (Shirman and Wojtanowicz 2000; Wojtanowicz et al. 1999). Swisher (2000) compares the performance of a dual-completion well with the performance of three wells having conventional completions in a north Louisiana field. Although the dual-completion well costs about twice as much to install, it took the same or fewer number of months to reach payout as did the other wells. At payout, it was producing 55 bbl/d of oil, compared with about 16 bbl/d produced by the other three wells. The net monthly earnings at payout for the dual-completion well were nearly \$26,000, compared with \$5,000–8,000 for the other wells. Wojtanowicz and Armenta (2004) provide a recent overview of downhole water sink technology, offering a variety of additional examples from more complicated geologic settings, including gas wells and both horizontal and vertical oil wells.

Chapter 3 — Data on DOWS and DGWS Installations

As noted in Chapter 1, the purpose of this report is to collect data on as many field installations of DOWS and DGWS technologies as possible and then try to develop a correlation between their successful performance and geologic conditions. This chapter provides data on 59 DOWS and 62 DGWS trials from around the world and a qualitative discussion of at least 35 other installations. The data are taken from the literature, vendor Web sites, and materials that were directly provided by operators or vendors. We are aware that there have been other field installations, but data on those installations are either being held privately as proprietary information or are not available for other reasons. Despite the fact that they do not include information on all worldwide field trials, the data compiled here represent the largest and most complete set of information on downhole separation that is publicly available. We further note that data are lacking for many trials in some columns of the data tables. Although this lack of data is unfortunate, the large amount of data that is compiled and reported here is still useful.

The following sections provide general information about the DOWS and DGWS installations. A discussion of the performance of the installations is included in Chapter 4.

DOWS Installations

Table 1 contains information on 59 DOWS installations. Data on 37 of these installations were compiled in the original DOWS database in Veil et al. (1999). Data on 13 of the remaining 22 installations came from data summary tables provided by Centrilift (Voss 2004a). The remaining data were derived from literature published since 1998.

Most of the installations were in North America (34 in Canada and 14 in the United States). Six 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. Two-thirds of the installations used gravity-separation-type DOWS.

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.

DGWS Installations

According to one of the companies that has marketed DGWS technology for several years, about 300 systems have been installed in the United States and Canada through 2003 (DHI 2004). Nevertheless, it was difficult to obtain good data sets on DGWS technology. First of all, very few papers on DGWS technology have been published in the open literature (e.g., Society of Petroleum Engineers [SPE] papers). Second, DGWS vendors and users generally have been reluctant to share the details of their installations. With only a few exceptions, most of the data compiled on DGWS installations came from a single report (GRI 1999). That report provided data for many trials but showed only a limited number of parameters for each trial. In addition, the operators of the wells were not identified. Because of the differences between the GRI data and the other DGWS data, the data are compiled into separate tables: Table 2 has GRI data, and Table 3 has other DGWS data.

Table 2 offers limited data on 48 DGWS installations. GRI (1999) contains information on 53 installations, but for five of them, the information was insufficient. Therefore, these were not included in Table 2. Thirty-four of the installations were in the United States, with Oklahoma (16) and Kansas (11) heading the list. Fourteen installations were in Alberta. More than 60% of the installations (30) used modified plunger rod pump systems. Bypass tools were used in 14 installations, and ESPs were used in 4 installations.

DGWS were installed in 11 wells producing from carbonate formations, 12 wells from sandstone formations, two from clastic formations (combined with sandstone in later analyses), and three from coal. For 20 other installations, the production zone geology was not stated. On the injection side, nine DGWS injected to carbonate formations, 13 injected to sandstone formations, and two injected to clastic formations. No information was available about the remaining 24 installations.

Table 3 shows data on 14 DGWS installations other than those included in Table 2. Eight of these installations were in Alberta, four were in Oklahoma, and there was one each in Kansas and Austria. Five of the installations used bypass tools, and five others used modified plunger rod pump systems. Three used a coil-tubing ESP. The Austrian installation used an SSD device.

DGWS were installed in five wells producing from sandstone formations and two producing from coal. The production zone geology was not stated for the other seven installations. On the injection side, five DGWS injected to sandstone formations; no information was available about the remaining nine installations.

Table 2 shows three installations made into coal-producing formations, and Table 3 shows two others. None of the five data records identify the operator or well number, but the Table 3 installations may be the same wells as two of the Table 2 installations.

We also obtained limited information from three additional sources about multiple DGWS installations. None of these data sets was complete enough to include in Table 3. Voss (2004b) provided a table of 25 Centrilift GASPRO ESP-type DGWS installations from 1993 through 2002. The installations were in Oklahoma, Kansas, Texas, California, and Canada. The table did not provide information on gas and water production before and after DGWS installation, nor did it include any description of production or injection formations.

Yu (2004) reported that EnCana Corp. had installed DGWS systems in 10 wells. All were located in southern Alberta, and all had production from the upper Viking formation (sandstone) and injection into the lower Viking formation (sandstone). No quantitative performance data were included.

DHI (undated) has tested DGWS technology in more than 30 wells in the United States and Canada in a variety of geologic basins ranging from 900 to 6,800 ft in depth. Examples of the

DHI experiences are listed in Table 4. Details on geology, success rate, and equipment type were not included in DHI (undated).

Chapter 4 — Performance and Relationship to Geologic Conditions

A main goal of this report is to identify trends and correlations between the performances and probabilities of success of DOWS and DGWS technologies and the geologic conditions in the production or injection formations.

Previous Analysis

As a starting point, we looked at the conclusions presented at a 2002 meeting of the International Downhole Processing Group, at which downhole separation experts from around the world presented their latest information. Alhanati et al. (2002) presented an analysis of the effect of geologic conditions on the risk of a DOWS trial. Those authors have been involved in developing some of the hydrocyclone-type DOWS technologies and have followed DOWS developments for many years. They reviewed records on about 80 installations of hydrocyclone-type DOWS that used ESPs for pumping. The installations represented 33 wells in 26 fields from 18 different producers.

They concluded that installations having both carbonate production and injection formations have the lowest risk of failure, or, conversely, the highest probability of success. Installations having the following production zone/injection zone combinations posed a medium risk: carbonate/consolidated sandstone, consolidated sandstone/carbonate, and consolidated sandstone/consolidated sandstone. Installations with carbonate/unconsolidated sandstone or consolidated sandstone/unconsolidated sandstone conditions posed a medium risk for regular DOWS installations but a high risk when the injection zone was above the production zone. Finally, any installation that had unconsolidated sandstone as the production zone offered a high risk.

Alhanati et al. (2002) does not provide a specific description of how the authors categorized trials into low, medium, or high risk. It does include summary data on mean time to failure, percentage increase in oil production, and percentage decrease in water produced to the surface. Within each of the risk categories, the report does distinguish between weak and strong trials. Weak trials are those that failed in less than 1 month. Surprisingly, about 41% of the trials in the low-risk category failed in less than 1 month, although most of the failures were related to activities not specific to DOWS technology. The low-risk trials clearly stood out in terms of better mean time to failure, positive impact on oil production, and reduction in water to the surface. The medium- and high-risk trials were more difficult to segregate, and the primary factors were the mean time to failure and the number of trials experiencing injectivity problems.

The conclusions of Alhanati et al. (2002) seemed logical, in that sandstone formations are more likely than carbonate formations to produce solids that will subsequently plug an injection zone. Unconsolidated sandstone formations are more likely to produce sand grains and other solids than are consolidated sandstones. Carbonate formations can also contribute small $CaSO_4$ or $CaCO_3$ scale particulates that can plug injection zones but, in general, sandstone formations will generate more solids. Although we assumed that the Alhanati et al. (2002) conclusions were accurate because the researchers used a large data set and had a long history of experience working with DOWS technology, we still proceeded to independently collect as much data on

DOWS and DGWS trials as possible. The logical place to start was to contact C-FER Technologies (Alhanati's organization) to see if we could examine the data that those researchers used to reach their conclusions. We were advised that C-FER's data were proprietary and could not be shared with us. We were further advised that C-FER itself had a difficult time compiling DOWS data because many of the original records had been archived, key people had left their positions, and both operator and vendor companies had merged (Zahacy 2004). In the absence of the original data used by C-FER, we proceeded to collect data from other sources.

<u>Results</u>

Table 5 includes qualitative performance ratings, where possible, for each DOWS installation listed in Table 1 on overall performance, increase in oil production, reduction in water to the surface, and longevity of the installation. The following criteria were used to make the qualitative ratings:

- Increase in oil: good (>20%), neutral (0–20%), and poor (0%),
- Reduction in water: good (>30%) and neutral (0–30%), and
- Longevity: good (>3 months) and neutral (0–3 months).

The overall rating was a subjective, qualitative evaluation of the three specific ratings. This ranking scheme has shortcomings, but we were unable to provide a more precise ranking scheme because there were gaps in the available data. Because few of the records in Table 1 had both start and end dates, it was often difficult to determine the longevity of an installation or its mean time to failure. Another complicating factor is that most of the data records we obtained express "before-DOWS performance" and "after-DOWS performance" in terms of a single number. We evaluated a few detailed data sets (Veil 2000; Argonne and ALL-LLC 2001) and found that oil and water production vary significantly over time and also vary as the mechanical features of the pumping system (e.g., pump rates, pressures) are tweaked by the operators. Many of the installations included in Table 1 were at least partially experimental in nature so that the operators and vendors could determine how well the technology performed under different conditions. We were unable to determine how representative of long-term operation the single-number performance values were.

Table 2 summarizes DGWS data from GRI (1999). We do not have much information on the trials themselves. GRI included its own performance ranking of success, failure, or economic failure. GRI (1999) notes that a ranking of success is generally associated with mechanical or technical success, an increase in gas production, or a decreased cost compared to handling water at the surface. GRI further notes that an increase in gas production is not the only criterion considered and that not all successful installations showed an increase in gas production. It reports that failures were associated with difficulty in injecting the water, low gas rates, or poor well bore conditions.

Table 3 contains information on a few additional DGWS installations not included in GRI (1999). Because the data records are not complete, only an overall performance rating is shown. The data records in Table 3 are generally less complete than those in Table 1, so it was even more difficult to assign a meaningful performance ranking. In about half of the installations, the wells in which the DGWS were installed were shut in before the installation. Any increase in gas production could be viewed as a positive trial. For all other installations in Table 3, the gas production increased following installation, so all trials were rated as good except for two that were considered uneconomical by the operators. These were given a ranking of neutral, because they were achieving DGWS goals but had low gas production attributed to various factors.

Table 6 compares qualitative performance with geologic types for the 59 DOWS installations from Table 1. Overall, about 59% of the trials were rated as good. All three categories in which both the production and injection formations were known showed about the same percentage of good trials (50–58%). Overall, about 31% of the trials were rated as poor. For the three categories in which both the production and injection formations were known, the percentage of poor trials ranged from 28% for sandstone/sandstone to 50% for carbonate/sandstone.

The results from Table 2 installations are tallied in Table 7, which compares GRI's qualitative performance with geologic types for 48 DGWS installations. Overall, about 54% of the trials were rated as successes. Note that this is a similar percentage to that shown in Table 6 for the DOWS trials. The carbonate/carbonate, carbonate/sandstone, and sandstone/sandstone categories all showed a high percentage of trials that were successes (70–100%), but none of the three stood out as being a clearly better combination than the others. Overall, about 42% of the trials were rated as failures or economic failures. Nearly half of the trials were in situations in which either one or both of the formations were unknown. This subset of trials had the worst overall success rate, with only 30% being rated successes and 61% being rated as failures or economic failures.

The results from Table 3 are much more straightforward; no additional tabulation is necessary. Twelve of the 14 trials were qualitatively rated as being good. Five trials had sandstone/sandstone formations, and two others had coal/unknown formations. No information on formations was available for the other seven trials.

The previous chapter mentioned additional but incomplete data on Centrilift and EnCana installations. Voss (2004b) noted that out of 25 Centrilift DGWS installations, 20 met or exceeded economic and performance criteria, four met pumping expectations but did not produce economical gas volumes, and only one failed. The failed installation was determined to be undersized and unable to meet pumping performance. Voss does not include information on the geology of the production or injection formations, so no correlations were possible for this set of installations.

Yu (2004) noted that his company's 10 DGWS trials worked to some degree. The results were very site specific. Successful performance depended more on the ability of the injection formation to take the water (i.e., injectivity) than on any particular type of geology. He further noted that trials could have problems with sand. This is not surprising, given that all trials had both sandstone production and injection formations.

Chapter 5 — Conclusions

Is There a Relationship between DOWS and DGWS Success and Geologic Conditions?

Alhanati et al. (2002) draws clear conclusions on the relationship between DOWS performance and geologic conditions. In particular, the paper suggests that the combination of carbonate production and carbonate injection formations offers the lowest risk and, therefore, the highest chance of DOWS success. Unfortunately, the researchers did not make their raw data available for others to review.

An independent analysis of about 120 DOWS and DGWS installations in numerous countries, states, and provinces does not show the same relationship. On the basis of the data described in this report, it is not possible to predict the performance or likelihood of DOWS or DGWS success solely on the basis of the geology of the production or injection formation. One caveat to this conclusion is that the data sets reviewed by Alhanati and his coauthors were probably much more complete than the data sets presented in this report. We believe that our conclusions are still valid but recognize that we limited our analysis solely to rock type and did not consider a wide range of geologic properties in our ranking scheme. Despite intensive efforts to obtain more complete data sets, we were unsuccessful in that regard.

What Factors Should Be Considered in Siting DOWS or DGWS Installations?

Other factors can play a role in the success of DOWS systems. Veil et al. (1999) reviews some characteristics of good candidate wells.

- Probably the most important factor is that the injection formation has good injectivity. A step rate injection test can be performed to determine at what pressure and rate the disposal zone takes water and at what point the injection zone clogs or fractures.

- A related factor is that the injection process should not introduce materials that could clog the pores of the injection formation and reduce its injectivity. Several factors are relevant to clogging. Solid particles could come from the production formation, from proppants used in hydraulic fracturing, or from chemical precipitates or biological slimes created by interactions between the water from production formations and the water from injection formations. Small amounts of oil in the produced water can potentially serve to block pores because of capillarity effects. It may be important to include a pretreatment process that produces a water stream that is extremely low in colloidal oil content (globules 5 to 50 μm in size).

- Another important parameter is good vertical and mechanical separation between the production and injection formations.

- The candidate well should be located in a reservoir that has sufficient remaining reserves to allow payback of the investment.

Representatives from companies that have used or have sold DGWS technologies were contacted and asked their opinion on the value of the geologic setting and other factors (Yu 2004; White 2004; Tortensen 2004; Prostebby 2004). A theme that emerged from these discussions was that the DGWS success rate is not dependent on the geology of the source zone or disposal zone but rather on site-specific properties of the disposal zone at individual wells. In general, a high-permeability, high-porosity, fractured, and underpressured disposal zone is favorable for DGWS technology.

Why Haven't DOWS and DGWS Technologies Been Used More Often?

Many of the early trials were made in poorly chosen candidate wells. Companies often offered wells near the end of their useful lives for trials rather than wells that had a good chance of success. In some cases, equipment suppliers designed and installed systems on the basis of formation data supplied by operators. The data were not always accurate, and the systems failed because they were designed for conditions other than those actually present in the formation.

In many of the DOWS and DGWS installations, individual components of the system that were not unique to DOWS or DGWS technologies failed prematurely. For example, a cable may have been crimped during installation, a bolt may not have been fastened tightly, pump motors may have shorted out, or seals might have leaked. These types of problems have plagued many DOWS and DGWS installations, and in the past few years, operators have been reluctant to make new DOWS or DGWS installations.

What Is the Value of This Report?

This report was not able to meet the goal outlined by the DOE project manager (i.e., determining the geologic conditions that most favor DOWS and DGWS success and identifying the fields and formations throughout the United States that have that preferred geology). In order to make that type of analysis, detailed information on the geological properties of the formations (e.g., injectivity, permeability, extent of fracturing, vertical separation between production and injection formations, fracture pressure) and more accurate information on the longevity of successful operation of the technology and the reasons for failure or termination of the trials would be needed. Those data either do not exist or have not been made available for the purposes of this analysis.

In spite of these shortcomings, the report is valuable because it contains the most complete publicly available set of data on DOWS and DGWS installations. The data tables and list of references contained herein represent a useful resource for other researchers and scholars.

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Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Field	State/ Province	Type of DOWS	Pre-DOWS Oil (bpd)	Pre-DOWS Water (bpd)	Post-DOWS Oil (bpd)	Post-DOWS Water (bpd)	% Increase in Oil	% Decrease in Water	Casing Size (in.)	Production Formation	Injection Formation
Imperial Redwater #1-26	Redwater	Alberta	Aqwanot™	19	1,780	24	59	26	97	7	Devonian D-3	Devonian D-3
Pinnacle-Alliance (originally PanCanadian) 7C2	Alliance	Alberta	Aqwanot™	44	380	100	95	127	75	5.5	Ellerslie-Dina	Dina
Pinnacle-Alliance (originally PanCanadian) 06D	Alliance	Alberta	Aqwanot™	25	820	100	160	300	80	5.5	Ellerslie-Dina	Dina
Pinnacle-Alliance (originally PanCanadian) 07C	Alliance	Alberta	Aqwanot™	38	1,200	37	220	-3	82	5.5	Ellerslie-Dina	Dina
Texaco Dickson #17	East Texas	Texas	DAPS	3	184	10	126	233	32	7	Woodbine	
PanCanadian 00/11C-05	Provost	Alberta	Aqwanot™	21	690	17		-19		5.5	Dina	
PanCanadian 00/11A2-05	Provost	Alberta	Aqwanot™	34	979	14		-59		7	Dina	
PanCanadian 00/16-05	Provost	Alberta	Aqwanot™	9.4	546	16		70		5.5	Dina	
Texaco SU 1040	Levelland	Texas	DAPS									
Talisman Energy 4-27-9-33W1	Parkman	Saskatch-ewan	Aqwanot™	6	629	39	21	550	97	7		
PanCanadian 00/02-09	Bashaw	Alberta	Aqwanot™	13	428	164	239	1162	44	5.5	Nisku D-2	Nisku D-3
Talisman Energy Tidewater Parkman 4-27	Parkman	Saskatch-ewan	DAPS	16	252	33	139	106	45	5.5	Tilston	Lower Tilston
Anderson 08-17	Swan Hills Unit #1	Alberta	Aqwanot™	176	3,648	264	264	50	93	7	Beaverhill Lake	Beaverhill Lake
Texaco Salem #85-40	Salem	Illinois	DAPS	6	655	6	150	0	77	5.5	Salem	Devonian
Chevron Fee 153X	Rangely	Colorado	Aqwanot™	45	1,400	32	500	-29	64	7	Weber Zone 1&3	Weber Zone 5

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Lithology	Injectivity (bpd/psi)	Injection Pressure Differential (psi)	Prod. and Inj. Formation Separation (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information
Imperial Redwater #1-26	Carbonate/ carbonate				Jul-94	Jan-95	Scale problems.	Gray (1998)
Pinnacle-Alliance (originally PanCanadian) 7C2	Sandstone/ sandstone	20	0	43	Jul-95			Matthews et al. (1996)
Pinnacle-Alliance (originally PanCanadian) 06D	Sandstone/ sandstone	2	0	73	Aug-95			Matthews et al. (1996)
Pinnacle-Alliance (originally PanCanadian) 07C	Sandstone/ sandstone	20	0	60	Sep-95			Matthews et al. (1996)
Texaco Dickson #17	Sandstone/ sandstone				Oct-95		Shut in.	Elphingstone (1998)
PanCanadian 00/11C-05	Sandstone/ sandstone				Dec-95		Problems with sand plugging.	Florence (1998)
PanCanadian 00/11A2-05	Sandstone/ sandstone				Dec-95		Problems with sand plugging.	Florence (1998)
PanCanadian 00/16-05	Sandstone/ sandstone				Jan-96		Problems with sand plugging.	Florence (1998)
Texaco SU 1040	Sandstone				Feb-96		Pulled early.	Elphingstone (1998)
Talisman Energy 4-27-9-33W1	Carbonate/ carbonate				May-96			Naylor (1998)
PanCanadian 00/02-09	Carbonate/ carbonate			104	May-96		Problems with H_2S and scale.	Florence (1998)
Talisman Energy Tidewater Parkman 4-27	Carbonate/ carbonate	6	0		Jul-96	May-97	Corrosion problems to pump and tubing.	Wright (1998)
Anderson 08-17	Carbonate/ carbonate	21	0	23	Jul-96		Problems with well bore and scale formation.	Peats (1998)
Texaco Salem #85-40	Carbonate/ unknown			1,137	Aug-96	Apr-97	Pumps damaged by corrosion.	Murphy (1998)
Chevron Fee 153X	Sandstone/ sandstone		0	30	Aug-96		May have been recycling water? Undersized pump.	Hild (1997)

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Field	State/ Province	Type of DOWS	Pre-DOWS Oil (bpd)	Pre-DOWS Water (bpd)	Post-DOWS Oil (bpd)	Post-DOWS Water (bpd)	% Increase in Oil	% Decrease in Water	Casing Size (in.)	Production Formation	Injection Formation
Talisman Energy Creelman 3c7-12/dB	Creelman	Saskatch-ewan	Aqwanot™	113	2,516	277	126	145	95	7	Alida	Alida
Chevron Shepard #65	East Texas	Texas	DAPS	7	269	16.5	127	136	53	5.5	Woodbine	Woodbine
Richland Parkman 1-17	Parkman	Saskatch-ewan	DAPS	20	220	15	190	-25	14	5.5	Tilston	Souris River
Texaco RMOTC 77 Ax20	RMOTC	Wyoming	DAPS	5	190	10	38	100	80	5.5	2nd Wall Creek	3rd Wall Creek
Talisman Energy Hayter	Chatwin	Alberta	DAPS	25	250	32	25	28	90			
Talisman Energy Handsworth 4dB-16/1d6	Hands-worth	Saskatch-ewan	Hydro-Sep	88	1,700	50	189	-43	89	7	Alida	Blairmore
Talisman Energy South Sturgeon	Grande Prairie	Alberta	DAPS	27	932	26	179	-4	81			
Petro-Canada E4-10-16	Bellshill Lake	Alberta	Q-Sep-G	30	470	38	61	27	87	7	Basal Quartz	Basal Quartz
Chevron PNB 14-20	Drayton Valley	Alberta	DAPS	75	517	84	14	12	97	5.5	Nisku D2	Nisku D3
Wascana B7-27	South Success	Saskatch-ewan	Aqwanot™	76	2,450	0	380	-100	84	7	Upper Rosary	Lower Rosary
PT Caltex Pacific 5E83	Minas	Indonesia	Aqwanot™	631	7,060	14	1,153	-98	84	7		
Petro-Canada Utik 13-21	Utikuma	Alberta	DAPS	8	451	10	63	25	86	5.5	Keg River	Keg River
Marathon Etah #7	Garland	Wyoming	Hydro-Sep	70	4,000	78	320	11	92	8.625	Madison	Madison

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Lithology	Injectivity (bpd/psi)	Injection Pressure Differential (psi)	Prod. and Inj. Formation Separation (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information
Talisman Energy Creelman 3c7-12/dB	Carbonate/ carbonate		0		Aug-96			Sobie and Matthews (1997)
Chevron Shepard #65	Sandstone/ sandstone		0	71	Sep-96		Unit is currently due for a workover but has functioned well.	Noonan (1998); Roberts (1998)
Richland Parkman 1-17	Carbonate/ carbonate	13	40	151	Jan-97		Immediately after installation, well produced 35 bpd oil and 160 bpd water.	Scharrer (1998)
Texaco RMOTC 77 Ax20	Sandstone/ sandstone			240	Feb-97	Mar-97	Injection zone damaged during a workover.	Stuebinger (1998)
Talisman Energy Hayter	Sandstone				Feb-97			Wright (1998)
Talisman Energy Handsworth 4dB-16/1d6	Carbonate/ sandstone	34	-412	1,284	Apr-97			Sobie and Matthews (1997)
Talisman Energy South Sturgeon	Carbonate/ carbonate				May-97			Wright (1998)
Petro-Canada E4-10-16	Sandstone/ sandstone		100	81	May-97	Nov-97	Worked very well; sold lease.	McIntosh (1998)
Chevron PNB 14-20	Carbonate/ carbonate				May-97	Aug-97	Well was very unstable and gassy; DAPS worked well.	Lockyer (1998)
Wascana B7-27	Sandstone/ sandstone	Very high		12	May-97	Nov-97	Produced sand damaged the hydrocyclone	Briffet (1998)
PT Caltex Pacific 5E83	Sandstone/ sandstone				May-97	Jun-97	Packer leak.	Voss (2004a)
Petro-Canada Utik 13-21	Sandstone/ sandstone			46	Jun-97	Oct-97	After two days, DAPS stopped working. DAPS was set above the fluid level.	Krug (1998)
Marathon Etah #7	Carbonate/ carbonate	20	300	48	Jun-97		Did not install check valve.	Kintzele (1997)

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Field	State/ Province	Type of DOWS	Pre-DOWS Oil (bpd)	Pre-DOWS Water (bpd)	Post-DOWS Oil (bpd)	Post-DOWS Water (bpd)	% Increase in Oil	% Decrease in Water	Casing Size (in.)	Production Formation	Injection Formation
Texaco Ingram	East Texas	Texas	DAPS	15		26	150	73		7	Woodbine	
Gulf Canada 02/12-01	Fenn-Big Valley	Alberta	Aqwanot™	21	1,038	117	217	457	79	7	Nisku D-2	Nisku D-3
Tristar	Sylvan Lake	Alberta	DAPS	35	403		57		86			
Talisman Energy 7d9-6/1-6-10-7w2m	Hands-worth	Saskatch-ewan	Subsep	94	1,560	133	586	41	62	7		
Crestar Energy Ranchman Sylvan Lake 00/08	Sylvan Lake	Alberta	DAPS	25	315	2	54	-92	83	5.5	Pekisko	Pekisko
Talisman Energy Handsworth 2d5-13/1c7	Hands-worth	Saskatch-ewan	Aqwanot™	63	1,260	38	63	-40	95	7	Alida	Blairmore
Shell International Eldingen 58	Eldingen	Germany	Aqwanot™	10	470	31	168	210	64	6.625	Top Lias Alpha	Top Lias Alpha
Tri-Link Resources Bender 9-30	Bender	Saskatch-ewan	Progressing cavity version of hydrocyclone-type DOWS	35	976	35	227	0	77	5.5	Tilston	Souris Valley
PanCanadian 00/07-09 Bashaw	Bashaw	Alberta	Hydro-Sep	19	352	62	250	226	29	5.5	Nisku D-2	Nisku D-3
Southward 11-13	Carlile	Saskatch-ewan	DAPS	24.5	458	16		-35		5.5	Tilston	Souris River
Pioneer Resources 5b-25-040-03	David, Dina	Alberta	Subsep	53	2,994	80	150	51	95	5.5		
Astra VM-097	La Ventana	Argentina	SubSep	57	2,463	41	567	-28	77	5.5	Barrancas	Rio Blanco

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Lithology	Injectivity (bpd/psi)	Injection Pressure Differential (psi)	Prod. and Inj. Formation Separation (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information
Texaco Ingram	Sandstone/ sandstone				Jul-97			Elphingstone (1998)
Gulf Canada 02/12-01	Carbonate/ carbonate	23	0	148	Jul-97			Peats (1998)
Tristar	Carbonate/ carbonate				Jul-97		Company out of business; disposition of well is unknown.	Poythress (1998)
Talisman Energy 7d9-6/1-6-10-7w2m	Carbonate/ sandstone				Jul-97	Dec-97	Injection zone sanded up.	Voss (2004a)
Crestar Energy Ranchman Sylvan Lake 00/08	Carbonate/ carbonate		24	Crestar Energy Ranchman Sylvan Lake 00/08	Aug-97	Mar-98	Water is recycling; separation of zones is only 24 feet in a fractured carbonate.	Grenier (1998)
Talisman Energy Handsworth 2d5-13/1c7	Carbonate/ carbonate	43			Aug-97		Capillary tube got creased.	Sobie and Matthews (1997)
Shell International Eldingen 58	Sandstone/ sandstone			89	Sep-97	Mar-00		Verbeek et al. (1998)
Tri-Link Resources Bender 9-30	Carbonate/ carbonate		87	76	Oct-97	Mar-98	Pulled DOWS because of failure in transfer tube.	Browning (1998)
PanCanadian 00/07-09 Bashaw	Carbonate/ carbonate			133	Nov-97			Florence (1998)
Southward 11-13	Carbonate/ carbonate				Jan-98	Mar-98	Residence time in separation chamber was too short; oil lost into disposal zone.	Poythress (1998)
Pioneer Resources 5b-25-040-03	Sandstone/ sandstone				Apr-98		Injection zone sanded up.	Voss (2004a)
Astra VM-097	Sandstone/ sandstone				Apr-98	Nov-98	Injection zone sanded up.	Scaramuzza et al. (2001)

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Field	State/ Province	Type of DOWS	Pre-DOWS Oil (bpd)	Pre-DOWS Water (bpd)	Post-DOWS Oil (bpd)	Post-DOWS Water (bpd)	% Increase in Oil	% Decrease in Water	Casing Size (in.)	Production Formation	Injection Formation
Chevron HSA #1107	Wickett	Texas	Hydro-Sep								Wichita-Albany	Wichita-Albany
PanCanadian 4C-33-40-1W4	Hayter	Alberta	Aqwanot^{TM}	28	1,387	25	352	-11	75	7		
Marathon Colony Fee 16		Wyoming	Subsep	86	7,692	47	567	-45	93	7		
Elf LaqSup 90	LaqSup	France	Subsep	19	961	31	16	63	98	9.625	Lower Senonien	
Spirit Energy	Van	Texas	Aqwanot^{TM}	62	3,402	71	167	15	95	5.5		
Marathon IHU-12	Indian Hills	New Mexico	Aqwanot^{TM}	560	7,440	560	560	0	92	7		
Texaco Bilbrey 30 -Fed. No. 5	Lost Tank Delaware	New Mexico	TAPS	17	173	7	70	-59	60	5.5	Lower Cherry Canyon	Bell Canyon
Astra VI-284	Vizca-cheras	Argentina	Subsep	18	1,052	18	265	0	75	5.5	Papagayos	Barrancas
Astra VI-261	Vizca-cheras	Argentina	Subsep	51	1,408	51	117	0	92	5.5	Papagayos	Barrancas
Phillips XJ30-2	Xijiang platform	China	Subsep	1,903	6,747	2,200	1,800	16	73	9.625		
PDO Y-276	Yibal	Oman	Aqwanot^{TM}	462	3,840	708	954	53	75	9.625		
Repsol/YPF Amo C-1	Tivacuno	Ecuador	Subsep	636	8,964	275	2,800	-57	69	9.625		
EnCana 13W4	Schneider Lake	Alberta	Subsep	118	668	118	118	0	82	7		
PDVSA	La Victoria	Venezuela	Read	300	8,000	800	3,700	167	54			
EnCana 21W4	Wayne Rosedale	Canada	Subsep	57	2,295	57	138	0	94	5.5		
Astra VI-122	Vizca-cheras	Argentina	Subsep	38	1,972	38	254	0	87	5.5		

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Lithology	Injectivity (bpd/psi)	Injection Pressure Differential (psi)	Prod. and Inj. Formation Separation (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information
Chevron HSA #1107	Carbonate/ carbonate				Jul-98		Permit assigned, waiting on tools.	Noonan (1998); Roberts (1998)
PanCanadian 4C-33-40-1W4	Sandstone/ sandstone				Aug-98			Voss (2004a)
Marathon Colony Fee 16	Carbonate/ sandstone				Sep-98	Jan-00	Motor burned up.	Voss (2004a)
Elf LaqSup 90	Carbonate/ sandstone				Oct-98	May-01	Test concluded.	Chapuis et al. (1999)
Spirit Energy	Sandstone/ sandstone				Oct-98		Injection zone sanded up.	Voss (2004a)
Marathon IHU-12	Sandstone/ sandstone				Oct-98		Casing failure.	Voss (2004a)
Texaco Bilbrey 30 -Fed. No. 5	Sandstone/ sandstone			480	Jan-99	Aug-99	Well sold; DOWS pulled.	Veil (2000)
Astra VI-284	Sandstone/ sandstone				Feb-99	Nov-00		Scaramuzza et al. (2001)
Astra VI-261	Sandstone/ sandstone				Jul-99	Oct-00	Motor burned up.	Scaramuzza et al. (2001)
Phillips XJ30-2	Sandstone/ sandstone				Sep-00	Oct-00	Water recirculation.	Voss (2004a)
PDO Y-276	Unknown				Feb-01	Mar-01	Motor drive failed.	Verbeek and Wittfeld (2004)
Repsol/YPF Amo C-1	Unknown				Apr-01	Apr-02	Motor burned up.	Voss (2004a)
EnCana 13W4	Unknown				May-01	Dec-03		Voss (2004a)
PDVSA	Unknown				Dec-01	May-02	Failure of cable, pump, and pressure gauges.	Bangash and Reyna (2003); Smestad (2004)
EnCana 21W4	Unknown				Jun-02	Dec-03		Voss (2004a)
Astra VI-122	Sandstone/ sandstone				Oct-02	May-03		Voss (2004a)

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Field	State/ Province	Type of DOWS	Pre-DOWS Oil (bpd)	Pre-DOWS Water (bpd)	Post-DOWS Oil (bpd)	Post-DOWS Water (bpd)	% Increase in Oil	% Decrease in Water	Casing Size (in.)	Production Formation	Injection Formation
Renaissance Energy	Provost	Alberta	Q-Sep-G	13	252	18	60	38	76		Dina	Dina
Rennaissance Energy	Webb South	Saskatch-ewan	Q-Sep-G	50	441	37	69	-26	84		Roseray	Roseray
Santa Fe Energy Jones Canyon 4-#2	Indian Basin	New Mexico	Aqwanot[TM]	100	3,000					7	Cisco-Canyon	Devonian & Montoya

Table 1 - Data on DOWS Installations (Note that data for each installation spans two sheets)

Operator and Well Name	Lithology	Injectivity (bpd/psi)	Injection Pressure Differential (psi)	Prod. and Inj. Formation Separation (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information
Renaissance Energy	Sandstone/ sandstone						Injection zone plugged.	Quinn Pumps website
Rennaissance Energy	Sandstone/ sandstone						Plugged with sand.	Quinn Pumps website
Santa Fe Energy Jones Canyon 4-#2	Carbonate/ carbonate		212	2,300			Permitted.	Rogers (1997)

Table 2 - DGWS Installation Data from GRI (1999)

State/ Province/ Country	Type of DGWS	Pre-DGWS Gas (mcfd)	Pre-DGWS Water (bpd)	Post-DGWS Gas (mcfd)	Post-DGWS Water Injected (bpd)	% Increase in Gas	Production Formation	Lithology	Injection Formation	Lithology	GRI's Qualitative Measure of Performance
Alberta	Bypass seating nipple, Harbison Fischer	Shut in	Shut in	175			Lower Cretaceous	Clastics	Lower Cretaceous	Clastics	Success
Alberta	Bypass seating nipple, Harbison Fischer	Shut in	Shut in	150			Lower Cretaceous	Clastics	Lower Cretaceous	Clastics	Success
OK	Bypass seating nipple, Harbison Fischer	125	130	200	130	60	Cottage Grove	Sandstone	Wabaunesee/ Lower Council Grove	Sandstone	Success
OK	Bypass seating nipple, Harbison Fischer	Shut in	250 (before shut in)	220	250		Council Grove (Wolfcampian)	Shallow shelf carbonate	Lower Council Grove	Shallow shelf carbonate	Success
OK	Bypass seating nipple, Harbison Fischer	0	250	160	250		Council Grove (Wolfcampian)	Shallow shelf carbonate	Lower Council Grove	Shallow shelf carbonate	Success
OK	Bypass seating nipple, Harbison Fischer	Shut in	Shut in	90	250		Council Grove (Wolfcampian)	Shallow shelf carbonate	Lower Council Grove	Shallow shelf carbonate	Success
OK	Bypass seating nipple, Harbison Fischer	50	15	18	300	-64	Council Grove (Wolfcampian)	Shallow shelf carbonate	Lower Council Grove	Shallow shelf carbonate	Failure
TX	Bypass seating nipple, Harbison Fischer	140	70	100	70	-29	Council Grove (Wolfcampian)	Shallow shelf carbonate	Lower Council Grove	Shallow shelf carbonate	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	706	143		Manneville	Sands	Manneville	Sands	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	353	142		Manneville	Sands	Manneville	Sands	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	353	238		Manneville	Sands	Manneville	Sands	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	282	87		Manneville	Sands	Manneville	Sands	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	194	244		Manneville	Sands	Manneville	Sands	Success
Alberta	Downhole water injection tool (Chriscor)	Shut in	Shut in	141	71		Manneville	Sands	Manneville	Sands	Success
OK	Electric submersible pump (Centrilift and Reda)	200	1,500	200	10,000	0					Economic failure
OK	Electric submersible pump (Centrilift and Reda)	120	1,500	120	1,500	0	Morrow	Sandstone			Economic failure

State/ Province/ Country	Type of DGWS	Pre-DGWS Gas (mcfd)	Pre-DGWS Water (bpd)	Post-DGWS Gas (mcfd)	Post-DGWS Water Injected (bpd)	% Increase in Gas	Production Formation	Lithology	Injection Formation	Lithology	GRI's Qualitative Measure of Performance
Alberta	Electric submersible pump (Petrospec coiled tubing)	Shut in	Shut in	100	NA						Success
Alberta	Electric submersible pump (Petrospec coiled tubing)	350	220	990	200	183					Success
OK	Modified plunger rod pump (DHI)			50	290		Mulky	Coal	Burgess	Sandstone	Failure
OK	Modified plunger rod pump (DHI)	Shut in	Shut in	24	140		Mulky	Coal	Burgess	Sandstone	Success
OK	Modified plunger rod pump (DHI)	Shut in	Shut in	20	50		Mulky	Coal	Burgess	Sandstone	Failure
KS	Modified plunger rod pump (DHI)	New well	450	175	250		Viola	Dolomite	Arbuckle	Dolomite	Success
KS	Modified plunger rod pump (DHI)	102	66	160	100	57	Chase (Upper Wolfcampian)	Dolomite/limestone	Chester and Morrow	Sandstone	Success
KS	Modified plunger rod pump (DHI)	133	50	160	90	20	Chase (Upper Wolfcampian)	Dolomite/limestone	Council Grove (Wolfcampian)	Shallow shelf carbonate	Success
KS	Modified plunger rod pump (DHI)	NA	125	103	135		Chase (Upper Wolfcampian)	Dolomite/limestone	Council Grove (Wolfcampian)	Shallow shelf carbonate	Failure
KS	Modified plunger rod pump (DHI)	Shut in	50	60	50		Chase (Upper Wolfcampian)	Dolomite/limestone	Council Grove (Wolfcampian)	Shallow shelf carbonate	Success
OK	Modified plunger rod pump (DHI)	100	70	NA	NA		Osage	Fractured carbonate	not stated		Failure
Alberta	Modified plunger rod pump (DHI)	1,100	NA	800	60	-27					Success
Alberta	Modified plunger rod pump (DHI)	131	26	350	150	167					Unknown
Alberta	Modified plunger rod pump (DHI)	220	116	270	128	23					Unknown
Alberta	Modified plunger rod pump (DHI)	1,043	182	800	135	-23					Economic failure
KS	Modified plunger rod pump (DHI)	428	144	500	530	17					Failure
KS	Modified plunger rod pump (DHI)	Shut in	Shut in	148	250						Failure
KS	Modified plunger rod pump (DHI)	45	80	30	125	-33					Failure
KS	Modified plunger rod pump (DHI)	100	384	110	285	10					Success
LA	Modified plunger rod pump (DHI)	175	250	200	200	14					Failure
MI	Modified plunger rod pump (DHI)	50	350	9	289	-82					Economic failure
NE	Modified plunger rod pump (DHI)	150	300	120	365	-20					Success
OK	Modified plunger rod pump (DHI)	200	250	165	250	-18					Failure
TX	Modified plunger rod pump (DHI)	250	80	530	144	112					Failure

State/ Province/ Country	Type of DGWS	Pre-DGWS Gas (mcfd)	Pre-DGWS Water (bpd)	Post-DGWS Gas (mcfd)	Post-DGWS Water Injected (bpd)	% Increase in Gas	Production Formation	Lithology	Injection Formation	Lithology	GRI's Qualitative Measure of Performance
TX	Modified plunger rod pump (DHI)	350	250	750	300	114					Success
OK	Modified plunger rod pump (DHI)	200	80	343	200	72	Probably Chase				Failure
TX	Modified plunger rod pump (DHI)	250	300	100	300	-60	Probably Chase				Success
KS	Modified plunger rod pump (DHI)	40	60	0	112	-100	Probably Council Grove				Failure
OK	Modified plunger rod pump (DHI)	400	200	100	286	-75	Carmichael sand member of Topeka Limestone Group	Sands	Tonkawa sand member of Douglas Group	Sands	Failure
OK	Modified plunger rod pump (DHI)	300	500	125	640	-58	Morrow	Sandstone			Failure
KS	Modified plunger rod pump (DHI)	352	50	200	100	-43	Not stated	Sandstone			Economic failure
OK	Modified plunger rod pump (DHI)	120	40	226	260	88	Upper Prue (aka Lagonda)	Sandstone	Lower Prue	Sandstone	Success

Table 3 - Data on DGWS Installations Other Than GRI (1999)

Operator and Well Name	Field	State/ Province Country	Type of DGWS	Pre-DGWS Gas (mcfd)	Pre-DGWS Water (bpd)	Post-DGWS Gas (mcfd)	Post-DGWS Water Injected (bpd)	Post-DGWS Water to Surface (bpd)	% Increase in Gas	Casing Size (in.)	Production Formation	Lithology	Injection Formation	Lithology	Injection Pressure Differen-tial (psi)	Prod. and Inj. Forma-tion Separa-tion (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information	Qualitative Measure of Performance
Olympia et al. Bittern 10-24-046-22W4		Alberta	Bypass tool	565	440	777	195		38			Glauconitic sandstone		Basal quartz sandstone	222	403	Feb-96	Feb-96	Bypass pump became unseated after a few days	Nichol and Marsh (1997)	Good
PanCanadian Countess 100/5-27-17 16 W4M	Countess	Alberta	Downhole water injection tool (Chriscor and Kudu)	Shut in	Shut in	>1,000	315	0			Upper Bow Island	Clastic sandstone	Lower Bow Island	Clastic sandstone			Jan-01		Some initial injectivity problems	Roche (2001)	Good
Ferintosh 14-29	Ferintosh	Alberta	Downhole water injection tool (Chriscor and Kudu)	0		200	300	0		5.5	Ellerslie	Sandstone	Ellerslie	Sandstone	400	82	Oct-02	Continuing	Corrosion problems due to 5% CO2 in the gas	Powell (2004)	Good
Ferintosh 06-32	Ferintosh	Alberta	Downhole water injection tool (Chriscor and Kudu)	0		250	75	0		4.5	Ellerslie	Sandstone	Ellerslie	Sandstone	0	75	Mar-03	Continuing	Corrosion problems due to 5% CO2 in the gas	Powell (2004)	Good
RAAG Friedburg 5	Molasse Basin	Austria	Subsurface side door (not specified but believed to be a bypass tool)	3,500	880	3,500	880	90	0	7	Upper Puchkirchen Sands	Stacked turbidite clastics	Lower Puchkirchen Sands	Stacked turbidite clastics		1,300	Apr-03	2003		Clemens and Burgstaller (2004)	Good
		OK	Modified plunger rod pump (DHI)	Shut in	Shut in	50	70			4.5	Shallow coal beds	Coal	Depleted Mississippian oil zone		400	79			This may be the same as one of the coal seam trials found in Table 2	Phelps (2002)	Good
		OK	Modified plunger rod pump (DHI)	Shut in	Shut in	65	68			4.5	Shallow coal beds	Coal	Depleted Mississippian oil zone		955	366			This may be the same as one of the coal seam trials found in Table 2	Phelps (2002)	Good
Addison Energy 6-18-59-14W5	Windfall	Alberta	Downhole water injection tool (Chriscor)			529 (peak)	75	0			Notikewan		Pekisko				Jul-00	2003 or later	Saved $160K in water disposal costs, earned $545K from additional recovered gas as of 2003	Hill (2003)	Good
Anadarko Milhon B3		KS	Modified plunger rod pump (DHI)	98	50	172	160	0	76								Nov-99			DHI (undated)	Good
OKIE Crude Carbonex #1		OK	Modified plunger rod pump (DHI)	49	2	128	128	0	161		The Dutcher, Spiro, Foster, Wapanueka producing zones in the Huntoon Formation		Deeper Huntoon Formation				Mar-02			DHI (undated)	Good
XTO Energy Teel 1-22		OK	Modified plunger rod pump (DHI)	225	39	258	43	0	15								Apr-01			DHI (undated)	Good

Table 3 - Data on DGWS Installations Other Than GRI (1999)

Operator and Well Name	Field	State/ Province Country	Type of DGWS	Pre-DGWS Gas (mcfd)	Pre-DGWS Water (bpd)	Post-DGWS Gas (mcfd)	Post-DGWS Water Injected (bpd)	Post-DGWS Water to Surface (bpd)	% Increase in Gas	Casing Size (in.)	Production Formation	Lithology	Injection Formation	Lithology	Injection Pressure Differen-tial (psi)	Prod. and Inj. Forma-tion Separa-tion (ft)	Trial Starting Date	Trial Ending Date	Comments	Source of Information	Qualitative Measure of Performance
Amoco Canada 15-8-77-8W4		Alberta	Electric submersible pump (Petrospec coiled tubing)	Shut in	Shut in	1100	315	0		4.5			Lower Clearwater				Jul-98	Oct-98	Payout in one month	Chalifoux and Young (1999)	Good
Amoco Canada 06-9-77-8W4		Alberta	Electric submersible pump (Petrospec coiled tubing)	Shut in	Shut in	128	89	0		4.5							Aug-98	Nov-98	Low gas rate due to low position in reservoir, formation damage, and depletion	Chalifoux and Young (1999)	Neutral (uneconomic)
Amoco Canada 9-14-77-9W4		Alberta	Electric submersible pump (Petrospec coiled tubing)	Shut in	Shut in	250	252	0		4.5							Aug-98	Nov-98	Low gas rate due to low position in reservoir, formation damage, and depletion	Chalifoux and Young (1999)	Neutral (uneconomic)

Table 4 — Examples of DGWS Installations Made by DHI

State	Basin Name	Type of Gas
Michigan	Michigan Basin	Tight/fractured shale/CBM
Ohio	Appalachian Basin	Tight/fractured shale/CBM
Indiana	Illinois Basin	Fractured shale/CBM
Illinois	Illinois Basin	Fractured shale/CBM
Oklahoma	Cherokee Basin	CBM
	Anadarko Basin	Tight
Texas	Permian Basin	Tight
	Fort Worth Basin	Fractured shale
	East Texas/Arkla Basin	Tight
	Gulf Coast Basin	Tight/fractured shale
Kansas	Anadarko Basin	Tight
Nebraska	Denver Basin	Tight/fractured shale/CBM (Niobrara)
Colorado	Piceance Basin	Tight/fractured shale
Utah	Uinta Basin	Fractured shale
	Paradox Basin	Fractured shale
New Mexico	San Juan Basin	CBM

Source: DHI undated

Table 5 - Data on DOWS Performance and Qualitative Ranking*

Lithology	Pre-DOWS Oil (bpd)	Post-DOWS Oil (bpd)	% Increase in Oil	Oil Rating*	Pre-DOWS Water (bpd)	Post-DOWS Water (bpd)	% Decrease in Water	Water Rating*	Trial Starting Date	Trial Ending Date	Longevity Rating*	Overall Performance Rating
Carbonate/ carbonate	19	24	26	Good	1,780	59	97	Good	Jul-94	Jan-95	Good	Good
Sandstone/ sandstone	44	100	127	Good	380	95	75	Good	Jul-95			Good
Sandstone/ sandstone	25	100	300	Good	820	160	80	Good	Aug-95			Good
Sandstone/ sandstone	38	37	-3	Poor	1,200	220	82	Good	Sep-95			Neutral
Sandstone/ sandstone	3	10	233	Good	184	126	32	Good	Oct-95			Good
Sandstone/ sandstone	21	17	-19	Poor	690				Dec-95			Poor
Sandstone/ sandstone	34	14	-59	Poor	979				Dec-95			Poor
Sandstone/ sandstone	9.4	16	70	Good	546				Jan-96			Neutral
Sandstone									Feb-96			Poor
Carbonate/ carbonate	13	164	1162	Good	428	239	44	Good	May-96			Good
Carbonate/ carbonate	6	39	550	Good	629	21	97	Good	May-96			Good
Carbonate/ carbonate	16	33	106	Good	252	139	45	Good	Jul-96	May-97	Good	Good
Carbonate/ carbonate	176	264	50	Good	3,648	264	93	Good	Jul-96			Good
Carbonate/ carbonate	113	277	145	Good	2,516	126	95	Good	Aug-96			Good
Carbonate/ unknown	6	6	0	Neutral	655	150	77	Good	Aug-96	Apr-97	Good	Good
Sandstone/ sandstone	45	32	-29	Poor	1,400	500	64	Good	Aug-96			Poor
Sandstone/ sandstone	7	16.5	136	Good	269	127	53	Good	Sep-96			Good
Carbonate/ carbonate	20	15	-25	Poor	220	190	14	Neutral	Jan-97			Poor
Sandstone	25	32	28	Good	250	25	90	Good	Feb-97			Good
Sandstone/ sandstone	5	10	100	Good	190	38	80	Good	Feb-97	Mar-97	Neutral	Good
Carbonate/ sandstone	88	50	-43	Poor	1,700	189	89	Good	Apr-97			Poor
Carbonate/ carbonate	75	84	12	Neutral	517	14	97	Good	May-97	Aug-97	Neutral	Good
Carbonate/ carbonate	27	26	-4	Poor	932	179	81	Good	May-97			Neutral
Sandstone/ sandstone	30	38	27	Good	470	61	87	Good	May-97	Nov-97	Good	Good
Sandstone/ sandstone	631	14	-98	Poor	7,060	1,153	84	Good	May-97	Jun-97	Neutral	Poor
Sandstone/ sandstone	76	0	-100	Poor	2,450	380	84	Good	May-97	Nov-97	Good	Poor
Carbonate/ carbonate	70	78	11	Neutral	4,000	320	92	Good	Jun-97			Good
Sandstone/ sandstone	8	10	25	Good	451	63	86	Good	Jun-97	Oct-97	Good	Good
Carbonate/ carbonate	21	117	457	Good	1,038	217	79	Good	Jul-97			Good
Carbonate/ carbonate	35				403	57	86	Good	Jul-97			Neutral
Carbonate/ sandstone	94	133	41	Good	1,560	586	62	Good	Jul-97	Dec-97	Good	Good
Sandstone/ sandstone	15	26	73	Good		150			Jul-97			Neutral

Table 5 - Data on DOWS Performance and Qualitative Ranking*

Lithology	Pre-DOWS Oil (bpd)	Post-DOWS Oil (bpd)	% Increase in Oil	Oil Rating*	Pre-DOWS Water (bpd)	Post-DOWS Water (bpd)	% Decrease in Water	Water Rating*	Trial Starting Date	Trial Ending Date	Longevity Rating*	Overall Performance Rating
Carbonate/ carbonate	63	38	-40	Poor	1,260	63	95	Good	Aug-97			Poor
Carbonate/ carbonate	25	2	-92	Poor	315	54	83	Good	Aug-97	Mar-98	Good	Poor
Sandstone/ sandstone	10	31	210	Good	470	168	64	Good	Sep-97	Mar-00	Good	Good
Carbonate/ carbonate	35	35	0	Neutral	976	227	77	Good	Oct-97	Mar-98	Good	Good
Carbonate/ carbonate	19	62	226	Good	352	250	29	Neutral	Nov-97			Good
Carbonate/ carbonate	24.5	16	-35	Poor	458				Jan-98	Mar-98	Neutral	Poor
Sandstone/ sandstone	53	80	51	Good	2,994	150	95	Good	Apr-98			Good
Sandstone/ sandstone	57	41	-28	Poor	2,463	567	77	Good	Apr-98	Nov-98	Good	Poor
Carbonate/ carbonate									Jul-98			Poor
Sandstone/ sandstone	28	25	-11	Poor	1,387	352	75	Good	Aug-98			Neutral
Carbonate/ sandstone	86	47	-45	Poor	7,692	567	93	Good	Sep-98	Jan-00	Good	Poor
Carbonate/ sandstone	19	31	63	Good	961	16	98	Good	Oct-98	May-01	Good	Good
Sandstone/ sandstone	62	71	15	Neutral	3,402	167	95	Good	Oct-98			Good
Sandstone/ sandstone	560	560	0	Neutral	7,440	560	92	Good	Oct-98			Good
Sandstone/ sandstone	17	7	-59	Poor	173	70	60	Good	Jan-99	Aug-99	Good	Poor
Sandstone/ sandstone	18	18	0	Neutral	1,052	265	75	Good	Feb-99	Nov-00	Good	Good
Sandstone/ sandstone	51	51	0	Neutral	1,408	117	92	Good	Jul-99	Oct-00	Good	Good
Sandstone/ sandstone	1,903	2,200	16	Neutral	6,747	1,800	73	Good	Sep-00	Oct-00	Neutral	Good
Unknown	462	708	53	Good	3,840	954	75	Good	Feb-01	Mar-01	Neutral	Good
Unknown	636	275	-57	Poor	8,964	2,800	69	Good	Apr-01	Apr-02	Neutral	Poor
Unknown	118	118	0	Neutral	668	118	82	Good	May-01	Dec-03	Good	Good
Unknown	300	800	167	Good	8,000	3,700	54	Good	Dec-01	May-02	Good	Good
Unknown	57	57	0	Neutral	2,295	138	94	Good	Jun-02	Dec-03	Good	Good
Sandstone/ sandstone	38	38	0	Neutral	1,972	254	87	Good	Oct-02	May-03	Good	Good
Carbonate/ carbonate	100				3,000							Poor
Sandstone/ sandstone	13	18	38	Good	252	60	76	Good				Good
Sandstone/ sandstone	50	37	-26	Poor	441	69	84	Good				Poor

* Qualitative ratings are:

Rating	Oil	Water	Longevity
Good	>20%	>30%	>3 months
Neutral	0-20%	0-30%	0-3 months
Poor	<0%		

Table 6 — Comparison of Performance and Geologic Conditions for 59 DOWS Trials Contained in Table 1

Geology of Producing Formation/Injection Formation	# Trials Rated Good	# Trials Rated Neutral	# Trials Rated Poor	Total # of Trials	% Trials Rated Good	% Trials Rated Poor
Carbonate/carbonate	11	2	6	19	58	32
Carbonate/sandstone	2	0	2	4	50	50
Carbonate/unknown	1	0	0	1	100	0
Sandstone/sandstone	16	4	8	28	57	28
Don't know both, but at least one is sandstone	1	0	1	2	100	50
Unknown	4	0	1	5	80	20
Totals	35	6	18	59	59	31

Table 7 — Comparison of Performance and Geologic Conditions for 48 DGWS Trials Contained in Table 2

Geology of Producing Formation/ Injection Formation	# Trials Rated Success	# Trials Rated Failure	# Trials Rated Economic Failure	# Trials Rated Unknown	Total # of Trials	% Trials Rated Success	% Trials Rated Failure or Economic Failure
Carbonate/ carbonate	7	3	0	0	10	70	30
Carbonate/ sandstone	1	0	0	0	1	100	0
Coal/ sandstone	1	2	0	0	3	33	67
Sandstone/ sandstone	10	1	0	0	11	91	9
Sandstone/ unknown	0	1	2	0	3	0	100
Unknown/ unknown	7	8	3	2	20	35	55
Totals	26	15	5	2	48	54	42