Gas Well Liquids Injection Using Beam Lift Systems

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There are several concepts now available in the industry to pump water downward below a packer in a gas well and allow the gas to flow freely up the casing of a gas well. This reduces the flowing gradient and allows gas flow to occur at a lower flowing bottom hole pressure. Also it eliminates any water disposal problems. This can now be done with ESP systems, PCP systems and also beam lift systems.

In order for these systems to perform, a zone below the gas producing zone must be available where the water can be injected below a packer. According to Enviro-Tech Tools, State Regulatory Commissions are classifying this method as a Class II injection well, and as such they require underground injection control permits.

This paper centers on discussion of some systems using modified beam lift systems to inject water in a gas well to enhance gas production. Systems are reviewed and some field experience is discussed.

The DHI Tool:

The DHI tool is designed to work with a standard beam pump system. This following discussion relies heavily on the manufacturer's description of the tool. The DHI tool is connected to the bottom of a standard tubing pump (see Figure 1). The valves are removed from the plunger and replaced with a plug. The tool replaces the TV and the SV of the pump. The upper body of the tool has five equally spaced inlet cages (Figure 2) constructed internally in the port head valve body. The valve assembly uses five 1 1/4" balls and seats. The upper body is connected to the lower discharge body by a threaded connection. The tool is constructed of 316 steel. Smaller volume pumps may have fewer balls and seats.

An adjustable back pressure valve is threaded into the ID of the lower discharge body connector neck. The valve contains a 1.375" ball and seat, spring, ball/spring guides, adjustable bolt and lock nut.

The back pressure valve acts as a check valve on the up stroke which forces the pump to draw the annulus fluid into the barrel. The normal pressure setting range is from 50-100 psi. The amount of back pressure needed is determined by the ratio of (normal operating casing pressure)/ (injection pressure of the disposal zone). If the injection pressure should be lower than the casing pressure, the casing annulus fluid may flow through the valves as the annulus fluid is lowered when pumping at low spm or when pumped off. Usually the injection pressure is higher than the casing pressure and only enough spring tension in the back pressure valve is needed to minimize spring flutter as fluid is pumped through the valve.

The tubing pump is a chrome ID barrel with a metal plunger. A cup mandrel assembly is attached to the top of the plunger to keep debris from the metal plunger and to retard static tubing fluid slippage.

The plunger has an open top connector cage and a fabricated stainless steel flat bottom plug connected to the lower end. If during shut-in, the gas pressure exceeds the injection zone pressure, the plunger can be lowered and set down on the top of the discharge port in the DHI tool to stop gas from entering the injection zone.

On the upstroke the load consists of the rod load, fluid in the tubing, and any dynamic forces. On the downstroke, a conventional unit carries the rod buoyant weight with any dynamic forces. On the downstroke with the DHI tool, the load stays fairly high since the load is the rods and weight of any fluid in the tubing, dynamic forces, less the force required to inject the fluid down into the disposal zone. Unless the injection pressure is very high, the difference in the up and down stroke loads with the DHI tool is small.

The system used the weight of the fluid in the tubing to supply the necessary injection force instead of the rod string. This eliminates rod stacking. If the injection pressure required is high, sinker bars can be added. Consult the manufacturer for charts for fluid heights and/or sinker bars necessary to inject fluid.

A conventional dynamometer determines if the unit if pumped down. A POC could be used. So far, no gas locking has been detected as a result of the way the device functions.

The manufacturer states that even when some sand is present, the plunger has not hung up due to the fact that the sand is prevented from getting on top of the plunger.

When casing scale or sand flow-back exists, the plunger must be run in the pump barrel using a rod "on/off" tool. In this event, the tubing must be filled from the surface as no annulus fluid can enter the tubing while going in the hole with the tubing string. An affordable low pressure tension shut off unloader sub will be offered in the near future. It is to be run directly on top of the pump barrel. The sub is to be run directly on top of the pump barrel. The sub will let casing fluid displace up the tubing while being run. It will also allow the tubing to be flushed and the static treated tubing fluid to be spotted before the packer is set. The unloader sub will allow tubing to be dry when pulled. Whether the plunger is run in the barrel or on the OD string, the tubing must be clean. It is advisable to run one or two sinker bars with a metal rod stabilizer for plunger alignment. If water is used for the tubing fluid an appropriate amount of corrosion inhibitor must be added.

For installations below 3000', the manufacturer recommends a Lok-Set packer in conjunction with a tubing on/off tool. Above 3000', a standard tension packer with a tubing safety joint is recommended. On both packer types a spring loaded ball and seat snubber cage is connected to the packer mandrel base so as to be double valved through the discharge ports into the injection zone. Both the safety joint and the on/off tool should be positioned at a sufficient distance above the packer in the event the packer becomes sanded in. An advantage of the Lok-Set packer with the snubber cage check below is that the tubing may be pulled for tool and pump maintenance without the charged up fluid from the injection zone "kicking" up the casing.

Caution must be taken when running the tubing string because fluid will not equalize up through the packer. Running too fast will distort the packer elements.

One of several case histories available from the manufacturer and users is mentioned here. A 6000' gas well with 4 1/2" casing and 2 3/8" tubing with a beam system using 3/4" rods and a 1 3/4" pump was one application. Before application, the well would make about 80 bwpd, and less than about 200 mcfd. After application, the well made no water, and over 300 mcfd. Other histories are also encouraging.

Bypass Seating Nipple

This tool is discussed in detail in SPE 24796, "Disposal Tool Technology Extends Gas Well Life and Enhances Profits" by Grubb and Duvall with Oxy, USA. This tool shown installed in Figure 3 and in more detail in Figure 4 is a bypass seating nipple screwed on the end of the tubing with a tubing insert pump above. The completion extends into a packer to allow injection of fluids below the packer to allow the free flow of gas up the annulus, as described above for the DHI tool.

A typical installation might consist of an installation in a well with 5 1/2" casing and 2 3/8" tubing. A beam pump system would be already installed in the well with rods to the pump at tubing depth. The "bypass seating nipple" is made from 2 7/8" stock metal. Figure 4 shows the flow path through the tool and the threads cut on both ends for the 2 7/8's tubing collars. Space for the pump inlet is drilled out of the middle of the seating nipple through about 3/4's of the length of the tool. The bottom 1/4 is not drilled out. making a plugged bottom. A hole is drilled horizontally through the tool as an inlet for the fluid to reach the bottom of the pump. Eight to ten small holes run along the length of the tool concurrent to the pump. These are the bypass holes. A fourteen to twenty foot pup joint of 2 7/8" tubing is run on top of the seating nipple bypass. This allows a space for fluid from the outlet of the pump to flow down beside the pump to the bypass holes in the seating nipple. From there the fluid goes through the bypass holes down to the disposal zone. For larger volumes of water a 3 1/2" tool is made for the 2 7/8" production tubing and the current products are currently distributed by Harbison Fischer.

The tool allows fluid to be pumped into the tubing to a height such that the pressure, carried by the injection zone, is sufficient to inject the salt water into the disposal zone.

Because of less fluid load, the rods are more likely to go into compression. Sinker bars are used to help prevent this.

If the disposal zone is pressured up, stimulation can be done without pulling the tubing. The rod string and pump are pulled, and a standing valve is dropped to seal off the producing formation. Acid can then be pumped down the tubing through the bypass ports to the disposal zone. The standing valve is retrieved, the pump rerun and the well put back on production. One instance was reported where the thin wall between the holes and the intake failed. If the disposal zone is plugged or not taking fluid, the tubing pressure can build and a high pressure shut-down switch is needed.

In SPE 24796, several cases related to the economics of use are presented. One case presented was for a well that was not profitable before installation. In one year more than 2/3's of the well profits were achieved after the installation of the disposal nipple. To date in the paper, the well has made more than $90,00 in earnings and accumulated 119,751 mcf of additional gas reserves salvaged from a well that was a candidate for abandonment.

Down Hole Disposal Tool

This tool was made to reduce water hauling costs in the Amoco Ulysses operations. In this location, water hauling is the second largest expense costing about $65/hr with a 2 hour minimum. This is between .54-.56 cents per barrel depending on the size of the loads.

The tool made allows operation with no water brought to the surface, no hauling cost, no environmental hazard potential, and allows for other wells water to be plumbed into a well with the tool installed. This last advantage could cause some problems if there are surface leaks present. Like the tools mentioned above, gas produces at all times with much less water interference to the flowing gradient.

This particular tool (shown schematically in Figure 5) requires an on/off tool, a joint of pipe for the side string, a one foot blank sub and some welding to assemble the parts. Detailed dimensions included a 1x6' sub at the bottom, a 1x1' blank sub, a 1x4' perforated sub, slotted on the bottom, a 1x10' seating nipple, a 1x6' sub at the top, and a 1 1/4' side string. For this tool, the assembly costs were less than $1000/unit so with 80 bwpd, it would take about 12 days for pay out for just this particular cost. It uses a bypass tube illustrated in Figure 5 and 6. It is somewhat similar to the first version of the bypass nipple that was used by Oxy where they used a section of coiled tubing to bypass the pump (See SPE 24796).

Figure 6 illustrates a typical installation with some additional costs incurred for the installation illustrated as well.

As with the other tools mentioned, you need a cased wellbore with a disposal zone that can be perforated. The gas producing zone is above.

In the Ulysses area, gas flows from the Hugoton formation at about 2700'. The water falls to the top of the perforated sub where the pump intake is located. The water is pumped up the tubing until gravity provides the pressure needed for injection into the Lansing formation at 5200' needing about 600 psi of injection pressure.

One test made was on a well making 80 bwpd and 20 mcfd. The packer was set just above the 5200' deep disposal zone. A downhole disposal tool was installed with a top hold down 1 1/2" pump, 12' long and the pumping unit rods. A pressure gradient test was made to see what injection pressure was needed. The well tested at 3 bwpd at 600 psi. When the test started, there was zero pressure at the surface.

The well was pumped for 2 weeks and reached a high of 43 mcfd with no water production. This particular well was weak and would not produce against the usual line pressure. Fluid levels in the well indicated that the injection pressure determined earlier was being overcome by an equivalent needed level of water in the tubing.

Summary

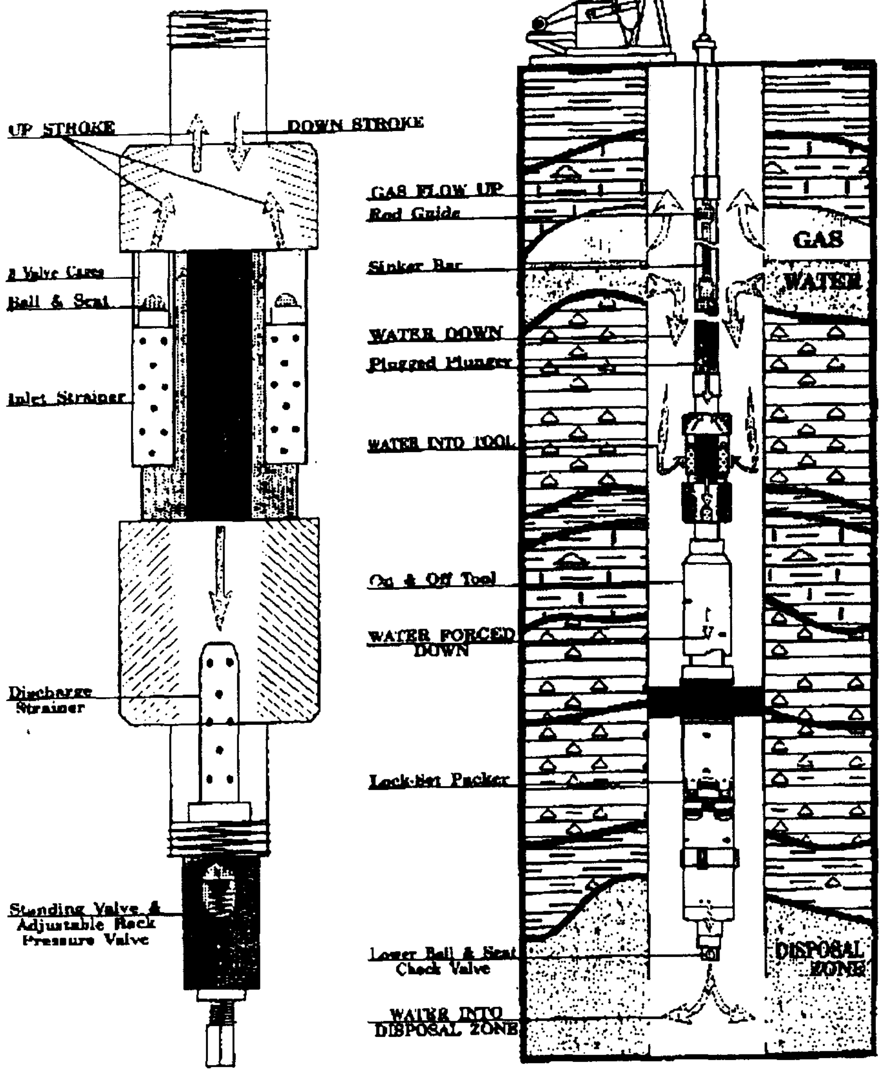
Injection of water in a beam lift well to allow gas to flow has been proven to be economical by several operators. Systems to allow this have been discussed here. You must have a disposal zone that will take the water for disposal and it must take the water at a reasonable pressure for the rates that must be injected. If this injection zone is present below the gas pay, then the systems discussed in this paper may very well be economic.

References:

1. Enviro-Tech Tools Inc. brochure on the DHI (Down Hole Injection) tool.

2. "Disposal Tool Technology Extends Gas Well Life and Enhances Profits" by A. Grubb and D. K. Duvall, Oxy USA Inc., SPE 24796, presented at the 67th annual SPE conference in Washington D. C., Oct. 4-7, 1992.

DHI Tool



US and Foreign Patents - US 5425416; PCT/US95/00103

Figure 1 - Down Hole Disposal Tool

FIVE VALVE TOOL

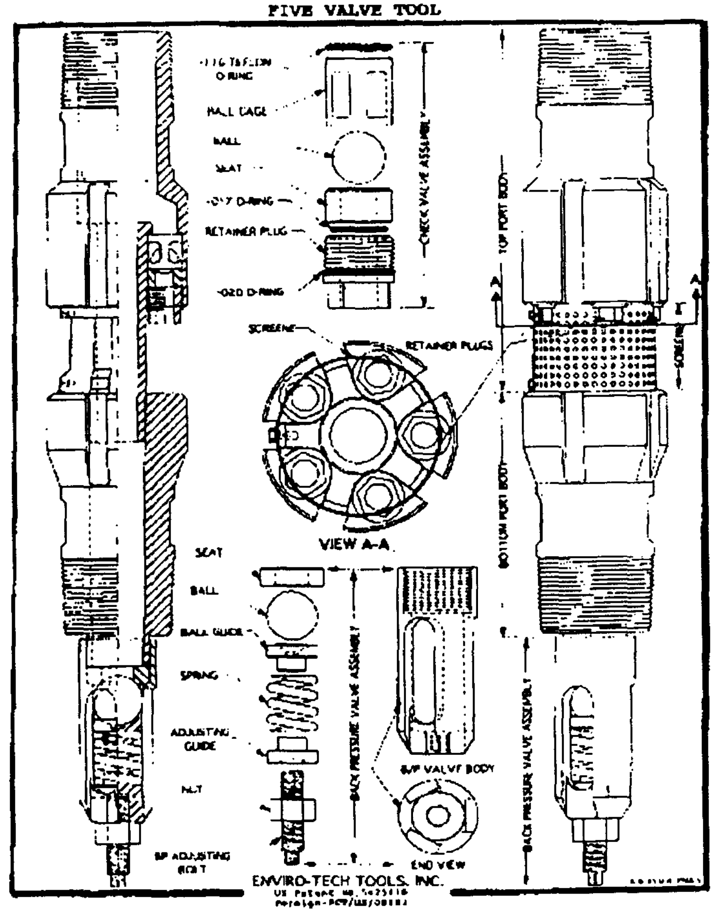


Figure 2 - Internals of DHI Tool

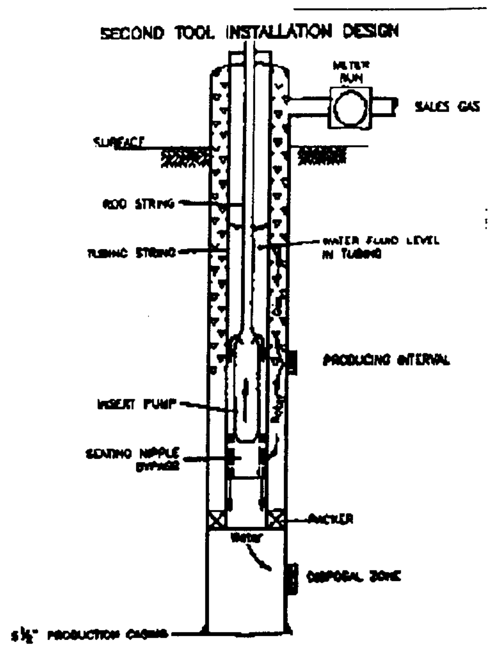


Figure 3 - Bypass Nipple System
(SPE 24796)

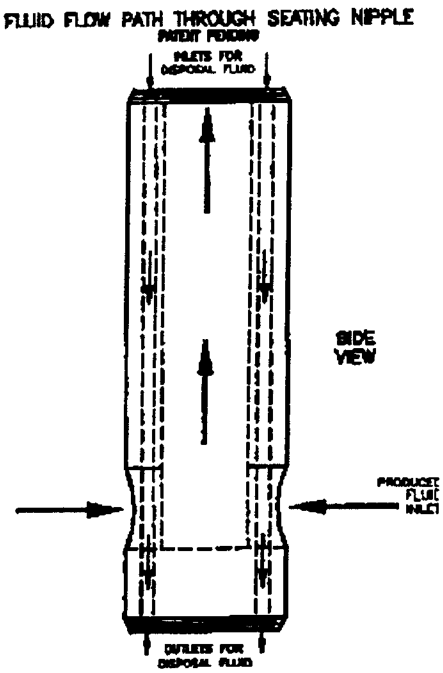
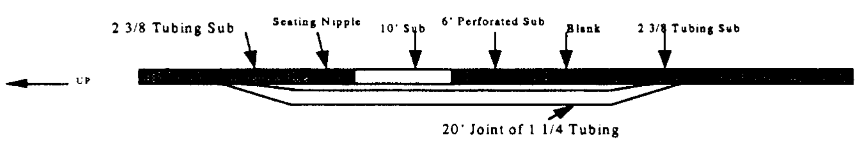


Figure 4 - Bypass Seating Nipple Flow Path
(SPE 24796)

DOWN HOLE DISPOSAL TOOL



2 3/8" MILLED COLLARS ARE NEED TO GET THE TOOL IN 5.5 " CASING
THE FIRST AND LAST SUB ARE SLOTTED 4" X 1/2"
A JOINT OF 1 1/4 TUBING IS CUT ON A BEVEL TO FACILITATE WELDING AND SLOTTED TO MATCH THE SLOTS IN THE 2 3/8 SUBS
THE PARTS ARE ASSEMBLED IN THE MANNER SHOWN AND THE 1 1/4 TUBING IS WELDED TO THE SLOTS IN THE SUB
ALL THE COLLARS ARE WELDED SO THEY WILL NOT TIGHTEN AND CHANGE THE LENGTH OF THE TOOL
A PACKER IS SET 2 OR 3 JOINTS BELOW THE ON OFF TOOL TO ISOLATE THE BOTTOM ZONE THAT WE ARE DISPOSING INTO 2 OR 3 JOINTS ARE PUT ABOVE THE ON OFF TOOL BELOW THE DISPOSAL TOOL TO LET THE TUBING LINE UP IN THE CENTER OF THE HOLE
THE SEATING NIPPLE IS SET AT THE BOTTOM PERFORATIONSTHAT YOU ARE PRODUCING FROM

Figure 5 - Disposal Tool Details

Down Hole Disposal Project
Deepening an Existing Chase Well
Hugoton Field, Kansas

Total Estimated Cost $40,000

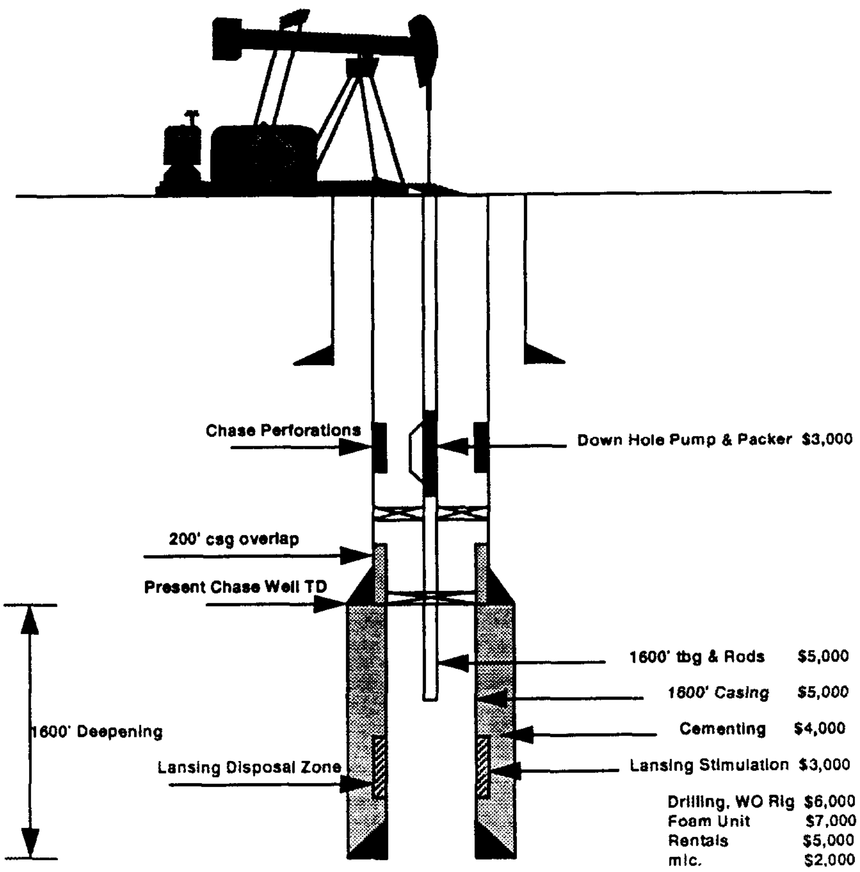


Figure 6 - Disposal Tool Installation