IN SITU DISPOSAL OF WASTE WATER PRODUCED THROUGH GAS PRODUCTION

Clarence Michael
Enviro-Tech Tools, Inc., Pratt, Kansas

This paper describes field implementation of a newly-developed downhole injection (DHI) tool for same-well-bore, simultaneous-gas-production-and-water-disposal, for water drive oil and gas formations with water coning problems. The method enhances the production rate of water-free gas while minimizing disposal cost and eliminating problems associated with water disposal. (Fig. 1)

Environmental regulations governing the disposal of salt water produced from gas wells have become an economic burden for oil and gas companies, and even more stringent regulations may loom on the horizon. When the DHI tool is used, waste water is never brought to the surface, and thus concerns about contaminating fresh water resources and surface soils, leaks from fragile transport lines, and overflows from storage tanks are eliminated.

Historically, the control of water coning ranges from very limited to non-existent. In new wells where gas/water contacts (GWC) are defined by coring or E-logs, and the gas-to-water ratio pressures are tested, one can be assured if the gas-to-water ratio is greater, the rate of gas pressure drawdown is critical to rapid water coning.

A number of methods have been tried to produce gas, oil, and water simultaneously and independently in a single well [1]. An early method involved drilling and casing down to a lower known-low-pressure formation. The waste water was then simply allowed to flow downward by means of water pressure coupled with the static pressure difference between the production and disposal zones. The water removal rate was limited and the water drive pressure could not be controlled.

Recent papers have been presented [2] and successful field tests reported in water drive wells which appear to control water coning. The method involved dual segregated zone perforations with a tailpipe drainage sink. The zone was perforated in the top portion and near the base, below the oil/water contacts (OWC). An isolation packer was set between the perforations. A downhole progressive cavity (PC) pump was used to lift the water in the tubing, while the formation pressure caused water-free oil to flow up the annulus. However, this method of water coning control does not address either the cost of water disposal or the environmental concerns caused by bringing the water to the surface.

PC and electric submersible pumps (ESP) positioned above an isolation packer to pump water into a disposal zone are being used with varying degrees of success. This type of installation tends to be quite expensive, and small-to-medium water volumes are difficult to regulate. Pump-off control and gassy fluid can be troublesome and may result in damage to the pump.

By contrast, the new DHI tool described in this paper allows for waste water to be pumped down into a lower non-producing zone. Thus the DHI user enjoys simultaneous control of water coning while eliminating both water disposal costs and the environmental problems associated with that disposal. (Figs. 2, 3)

Installations to Date

Several tools are currently being used successfully in Texas, Oklahoma, Kansas, Indiana, and Louisiana. Well depths range from 700 ft. (coal gas) to 8200 ft. Performance data from two installations are shown in Tables 1 and 2.

Well Selection and Preparation Requirements

This concurrent production/disposal method is not appropriate for all wells. A prospective well requires a non-producing zone at a sufficient depth below with proper porosity and permeability and reservoir capacities to accept the waste water. A geological barrier should exist between the production zone and the disposal zone. Casing must be set and cemented deep enough to set an isolation packer.

If the casing is set below the injection zone, the packer is set directly above the injection perforations. In some installations the casing was not set at a depth to cover the intended injection zone, but was set deep enough below the production perforations to set the packer, and water is thus being injected into the open hole. Intervals between the producing zone base to packer set has ranged from 24 ft. to 2000 ft.

Downhole Injection Tool Assembly

The DHI tool and method is designed to be used in conjunction with standard rod/plunger lift pumping tools. The DHI tool is connected at the base of a modified tubing-type pump. The valves are removed from the plunger and a plug is installed at its base. The tool replaces both the traveling valve and standing valves. The upper body of the tool has five equally-spaced inlet cages constructed internally in the port head valve body. The valve assembly contains five 1.25 in. pump balls and seats. The five valves greatly improve volumetric efficiency, minimize turbulence, and allow large-bore, high-volume pumps to be used. The upper body is connected to the lower discharge body by a threaded connection. The tool is constructed of 316 stainless steel.

An adjustable back-pressure (B.P.) valve is thread-connected into the I.D. of the lower discharge body connector neck. The B.P. valve contains a 1.375 in. ball and seat, spring/ball guides, adjustable bolt, and lock nut. The valve cage, guides, and adjustable bolt are constructed of 304 stainless steel and the spring from 316 stainless steel. For severe corrosive environments, Monel is used.

The B.P. valve acts as a check valve on the up-stroke which forces the pump to draw the annulus fluid into the barrel. On the downstroke the inlet valves close, and fluid is forced down through the B.P. valve and packer and into the disposal zone. The barrel is designed so the plunger can be spaced one to two inches above the discharge port hole to allow for full compression on the downstroke. The normal pressure setting range is from 50 PSI to 100 PSI. The amount of back pressure needed is determined by the ratio of the normal operating casing pressure to the injection pressure of the disposal zone.

In the event a low-pressure injection zone is encountered that is substantially lower than the casing PSI, the casing annulus fluid may "U-tube" through the valves as the annulus fluid is lowered when pumping at low strokes-per-minute or when the well is pumped off. In most cases, however, the injection pressure will be higher than the operating casing pressure, and in those cases only enough spring tension against the ball is needed to minimize ball spinning or spring flutter as fluid is pumped through the valve.

The Downhole Pump

A tubing-type, precision, chrome I.D. barrel with a metal or Lubri-Plunger is used with the DHI tool. The plunger has an open-top connector cage and a fabricated stainless steel flat-bottom plug connected to the lower end. In the event a gas well is shut in for a considerable period of time and the shut-in casing pressure exceeds the bottom-hole pressure (BHP) of the injection zone, the plunger can be lowered and set down on the top of the discharge port of the DHI tool to stop gas from "U-tubing" into the disposal formation. The lower barrel full-bore collar is connected directly to the DHI tool. The plunger can be spaced to within a few inches of the discharge port on the down-stroke for more efficient compression of gassy fluids and prevention of gas locking.

In pump efficiency tests where the distance between the production interval and the disposal formation was sufficient to allow gas/water separation, the pump volumes were 100% efficient. The higher the flow rate, the more distance is required for maximum separation. If the producing zone perforations are segregated to allow for water drainage, separation of gas/water in some cases will occur in the formation.

The effect of the DHI tool on the pump jack and rod string has been the subject of continued dynamometer testing and engineering study. There are important similarities and differences between a conventional plunger pump and the DHI tool's pumping methods. On the upstroke, the rod load from either system consists of the weight of the fluid in the tubing, plus the weight of the rod string, plus the positive 'g' forces generated by the rod string as it turns around at the bottom and accelerates upward. The resulting rod load tends to be relatively high.

On the downstroke of a conventional pump, the rods are carrying their own weight (the tubing is holding the fluid column), less the buoyancy of the rods in the fluid, less the negative 'g' forces generated by the rod string as it turns around at the top and accelerates downward. The resulting rod weight tends to be relatively low. The power (peak torque of the reducer) required to lift the fluid is directly proportional to the magnitude of the difference between the upstroke and downstroke rod loads. The transition from high upstroke load to a lower downstroke load also causes a change in rod length which subtracts from effective travel of the plunger, resulting in lower pump efficiencies.

On the DHI tool pump, the downstroke load tends to stay relatively high because the rods are carrying their own weight, plus the weight of the fluid loaded in the tubing ("dead" weight moves with the rods), less the negative 'g' forces generated by the rod string as it turns around at the top and accelerates downward, less the force required to inject the fluid down into the disposal zone. The difference between upstroke and downstroke rod load thus tends to be relatively small unless the pressure in the disposal zone is unusually high or excessive strokes per minute are used. Since this difference is smaller, less power is required and there is less rod length change during the transition. The result is less loss of effective plunger stroke and higher pumping efficiency.

The DHI system uses the principles that the weight of the fluid loaded in the tubing supplies the necessary injection force. Thus fluid for disposal zone pressure calculations relates to the depth and specific gravity of tubing fluid necessary to provide the injection force for given injection zone pressure. Calculations are provided for the weight of sinker bars necessary to make up a shortfall in tubing fluid load for wells with unusually high injection pressures and for the use of large bore pumps. (Figs. 4, 5)

The intended injection zone should be thoroughly stimulated and tested. Injection rates and pressures must be known in order to calculate the specific gravity of fluid weight and depth of the tubing fluid needed to minimize rod compression on the downstroke. One must take into account the additional forces generated by the instantaneous flow velocity caused by the intermittent flow rate surges of the pump stroke and the SPM.

In addition to its static pressure, the permeability of an injection zone will add a pressure resistance to the injection flow that increases with the rate of injection. It is important that the test data used to determine the injection zone pressure for applying the DHI tool be correlated to the maximum instantaneous flow of the injection pump. The flow rate of the pump at its mid-stroke is its highest velocity, and this can be calculated using the formula:

$$\text{Max. instantaneous flow (GPM)} = (.0427) \times (\text{stroke length}) \times (\text{SPM}) \times (\text{plunger diam.})^2$$

Fluid pound on a DHI tool pump may not be as pronounced as one might see on a conventional plunger pump. On the downstroke of a conventional rod plunger, the fluid in the barrel must be compressed to the hydrostatic pressure of the tubing fluid column before the plunger traveling valve will open. The DHI pump downstroke compression is that of the injection zone entry pressure. On some installations, a pump-off control may be needed. A dynamometer will effectively detect when the annulus fluid is pumped down.

From pump tests to date, no detection of gas-locking has occurred, because at the end of the upstroke, no gas movement can get through or past the plunger due to the static fluid pressure above the plunger. If the back pressure valve is set properly, along with the greater pressure differential from the injection zone to casing, there will be no flow of gas downward, thereby allowing the inlet valves to close at the top end of the upstroke. If the stroke length is sufficient, the pump will actually compress gas into the disposal zone.

Consideration should be given to the pumping unit power source installation so as to have variable stroke-per-minute adjustments to maintain proper pump-off control.

In wells that have been recently fractured and the swab test indicated moderate concentrations of sand still entering the casing before the DHI assembly was run, no indication of plunger hangup has been detected, since no sand or casing scale can get on top of the plunger from the annulus fluid being pumped. Where there is the possibility of tubing/casing scale or casing annulus trash, the plunger must be run in the pump barrel with a rod on-and-off tool. A tubing unloader sub is run directly on top of the pump barrel. The sub will let casing fluid displace up-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 rod 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 also be added.

Isolation Packers

For installations below 2000 ft., lock-set packers are recommended in conjunction with a tubing on-and-off tool. Above 2000 ft. a standard tension packer with a tubing safety joint may be used. A spring-loaded snubber cage is run below the packers for double valve protection. An advantage of the lock-set packer with the on-and-off tool is that in the event the packer becomes sanded in, tubing can be retrieved and sand washed out for packer removal. For normal pump/tool maintenance, the packer may be left in place when tubing is pulled and fluid will not kick up the annulus. 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.

Another tool available is a drillable cement retainer-type plug to be used as a zone isolation packer. It may be stung in and out of the retainer and has a sliding sleeve shutoff. A safety joint is recommended above the retainer. Tubing can be pulled in tension after stung-in. The retainer may be set with a wire line or tubing mechanical setting tool.

Water Flooding

Water flooding of oil- and gas-drive pools are being accomplished with the DHI tool assembly. After selecting a pumping well to be used as the injection well, a known compatible water-bearing formation above is perforated and the packer is positioned between the source water and the producing formation. By using this method, an existing well becomes the water source, and existing equipment becomes the pump/pressure system. This method is a closed system and eliminates oxidation of the flood formation.

Special Energy Corporation is currently using the DHI tool for a water flood application in Payne County, Oklahoma, to flood the Bartlesville sand. The in-field well selected as the injection well is taking the source water from perforations at 2659-2684 ft. The zone was sand frac'd and swab tested. This water is being pumped into the existing Bartlesville sand perforations from 4522-4558 ft. PBTD is at 4650 ft. The downhole assembly consisted of a lock-set packer, one joint tubing spacer, on-and-off tool, DHI tool with a 2.5 in. x 2.75 in. x 16 ft. tubing pump. At 228 unit with 86 in. stroke is being used, injecting 800 BPD.

Permitting

State underground injection regulatory commissions are classifying the DHI simultaneous production/disposal method as a Class II injection well, and thus a permit is required.

Common commission permit application requirements include:

Casing integrity test from the producing zone to the surface prior to DHI installation, then every five years

Monitoring of injection rates

Monitoring of injection pressure so as not to exceed the frac gradient

In the states where tools have been installed and in Canada the rates and pressures were addressed as follows:

By the use of a downhole positive displacement pump, flow rates are determined by the pump factor x stroke length x strokes per minute. A dynamometer will record pump-off and the SPM can be adjusted.

The injection pressure is determined when testing the injection zone. The dynamometer will record any excessive injection pressure increases. A ball & seat can be installed in the base of the pump plunger, and if the injection pressure exceeds the tubing static fluid weight, the injection pressure will be gauged at the surface. A pressure shutdown control may be used.

The typical time from submitting the application to receiving the permission is four to six weeks.

Advantages of the DHI tool

Simultaneously producing gas while disposing of water by positive mechanical displacement in the same well-bore offers many desirable features for both short- and long-term economic and environmental benefits.

- Prevents contamination of fresh water resources and surface soil
- Eliminates water disposal hauling expenses
- Restores sub-economic and marginal wells back to profitable production
- Maximizes profitability
- Encourages future exploration
- Eliminates environmental problems associated with water disposal

[1] M.D. Swisher and A.K. Wojtanowicz, "In Situ-Segregated Production of Oil and Water - A Production Method with Environmental Merit: Field Application," SPE/EPA Exploration & Production Conference, Houston, Texas, 27-29 March 1995.

[2] M.D. Swisher and A.K. Wojtanowicz, "New Dual Completion Method Eliminates Bottom Water Coning," SPE Annual Technical Conference & Exhibition, Dallas, Texas, 22-25 October 1995.

Average cost for DHI tool installation: $12,500 (not including well preparation)
Salt water disposal cost: $1/barrel
Potential increased gas flow rates are not included in calculations.

Salt Water (Barrels/day)	Monthly Hauling Cost	Payback Time (Months)
75	$2250	5.55
100	$3000	4.16
125	$3750	3.33
150	$4500	2.77
200	$6000	2.08
250	$7500	1.66
300	$9000	1.38

Figure 1 - Payback Times for DHI Tool vs Water Hauling

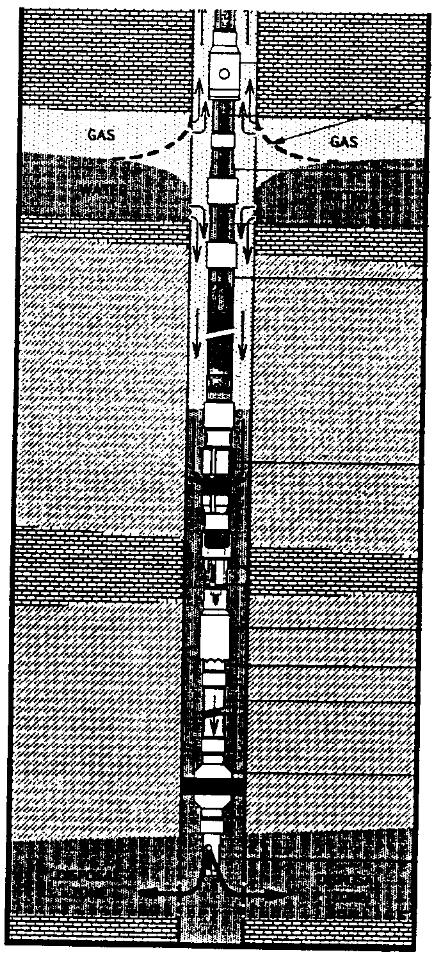

Figure 2 - Simultaneous Gas Production / Disposal Method (water cone down)

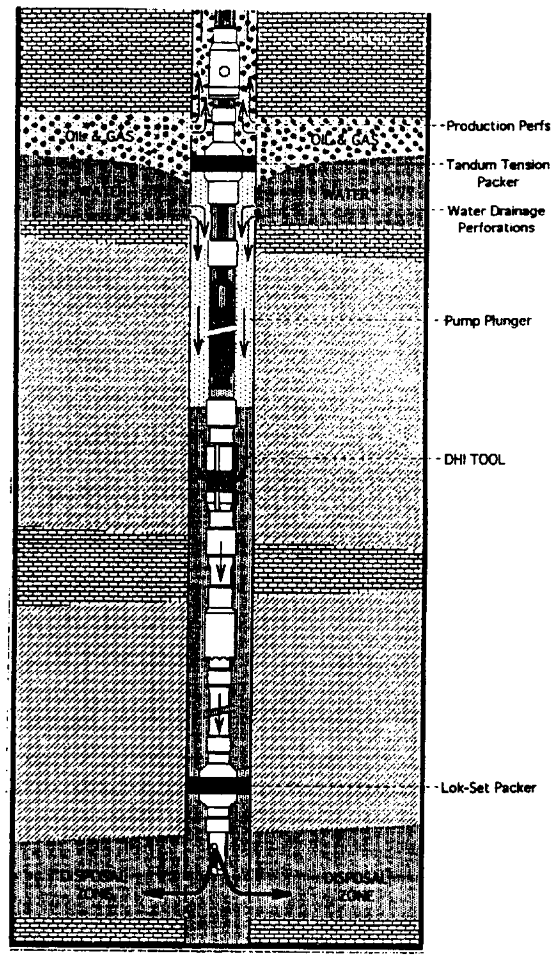

Figure 3 - Simultaneous Gas and Oil Production / Disposal Method (water cone down)

Table 1

DHI PERFORMANCE DATA
SEWARD COUNTY, KS

Casing:	4 1/2"	Tubing:	2 3/8"
Rods:	3/4"	Pump Size:	1 3/4"

Production: Chase Group (2606-2684')
Disposal Depth: Lansing/Kansas City (4668-78) (4694-4707)

The folowing production data was supplied by the operator from the pumper's daily gauge reports. The tool was operational on October 19, 1993 at 1:45 P.M. On the morning of October 23, it was selling 186,000 CFGPD.

BEFORE INSTALLATION

The last three months of production is used as daily "before" production rates.

DATE	MMcf/month	WATER	DAYS	Mcf/day
8/93	2,916	66	31	94,064
9/93	2,630	66	26	101,153
10/93	2,462	66	21	117,238

Total MMcf 8,008 over 78 days = 102.7 Mcf/day

AFTER INSTALLATION

DATE	MMcf/month	WATER	DAYS	Mcf/day
11/93	3,457	0	26	132,961
12/93	4,055	0	31	130,806
01/94	3,593	0	25	143,720
02/94	3,887	0	28	138,810

Total MMcf of 14,992 over 110 days = 136.3 Mcf/day

MONTHLY AND ANNUAL GROSS INCOME GAIN
(Gross before taxes and operations)

Before:	102.7 Mcf/day X $1.75 X 30.5 DAYS =	$5,479
	Water disposal cost	-2,013
	Monthly gross income	$3,466
After:	136.3 Mcf/day $1.75 X 30.5	$7,274
	Water disposal cost	0
	Monthly gross income	$7,274
Monthly Gross Gain		$3,808
Estimated Annual Gross Gain		$45,696

MINIMUM TUBING FLUID LOAD (Ft. above the plunger)

Net Injection pressure / PSI	Specific Gravity of the Fluid 0.70	0.75	0.80	0.90	1.00	1.05	1.10	1.20	1.25	1.30	1.35
1	3	3	3	3	2	2	2	2	2	2	2
2	7	6	6	5	5	4	4	4	4	4	3
3	10	9	9	8	7	7	6	6	6	5	5
4	13	12	12	10	9	9	8	8	7	7	7
5	16	15	14	13	12	11	10	10	9	9	9
6	20	18	17	15	14	13	13	12	11	11	10
7	23	22	20	18	16	15	15	13	13	12	12
8	26	25	23	21	18	18	17	15	15	14	14
9	30	28	26	23	21	20	19	17	17	16	15
10	33	31	29	26	23	22	21	19	18	18	17
20	66	62	58	51	46	44	42	38	37	36	34
30	99	92	87	77	69	66	63	58	55	53	51
40	132	123	115	103	92	88	84	77	74	71	68
50	165	154	144	128	115	110	105	96	92	89	85
60	198	185	173	154	138	132	126	115	111	107	103
70	231	215	202	179	162	154	147	135	129	124	120
80	264	246	231	205	185	176	168	154	148	142	137
90	297	277	260	231	208	198	189	173	166	160	154
100	330	308	288	256	231	220	210	192	185	178	171
200	659	615	577	513	462	440	420	385	369	355	342
300	989	923	865	769	692	659	629	577	554	533	513
400	1319	1231	1154	1026	923	879	839	769	738	710	684
500	1648	1538	1442	1282	1154	1099	1049	962	923	888	855
600	1978	1846	1731	1538	1385	1319	1259	1154	1108	1065	1026
700	2308	2154	2019	1795	1615	1538	1469	1346	1292	1243	1197
800	2637	2462	2308	2051	1846	1758	1678	1538	1477	1420	1368
900	2967	2769	2596	2308	2077	1978	1888	1731	1662	1598	1538
1000	3297	3077	2885	2564	2308	2198	2098	1923	1846	1775	1709
2000	6593	6154	5769	5128	4615	4396	4196	3846	3692	3550	3419
3000	9890	9231	8654	7692	6923	6593	6294	5769	5538	5325	5128
4000	13187	12308	11538	10256	9231	8791	8392	7692	7385	7101	6838
5000	16484	15385	14423	12821	11538	10989	10490	9615	9231	8876	8547
6000	19780	18462	17308	15385	13846	13187	12587	11538	11077	10651	10256
7000	23077	21538	20192	17949	16154	15385	14685	13462	12923	12426	11966
8000	26374	24615	23077	20513	18462	17582	16783	15385	14769	14201	13675
10000	32967	30769	28846	25641	23077	21978	20979	19231	18462	17751	17094

Figure 4 - The enviro-tech tool pumps the fluid into the injection zone on the downstroke. This chart gives the depth of fluid above the plunger that is necessary to provide the downstroke force so that the rod string will not go into compression. If the required tubing fluid depth from the chart is greater than the depth of the well, the shortfall will have to be made up by the use of sinker bars at the bottom of the rod string. Refer to the "NET SINKER WT. REQUIRED" chart on the reverse side to determine net sinker bar weight needed.

NET SINKER WT. REQUIRED (Lb.)

Tube Fluid Depth Shortfall / Ft	Pump Plunger Diameter (inches) 1.060	1.250	1.500	1.750	2.000	2.250	2.500	2.750	3.750	4.750
1	0.4	0.5	0.8	1.0	1.4	1.7	2.1	2.6	4.8	7.7
2	0.8	1.1	1.5	2.1	2.7	3.4	4.3	5.1	9.6	15.4
3	1.1	1.6	2.3	3.1	4.1	5.2	6.4	7.7	14.4	23.0
4	1.5	2.1	3.1	4.2	5.4	6.9	8.5	10.3	19.1	30.7
5	1.9	2.7	3.8	5.2	6.8	8.6	10.6	12.9	23.9	38.4
6	2.3	3.2	4.6	6.3	8.2	10.3	12.8	15.4	28.7	46.1
7	2.7	3.7	5.4	7.3	9.5	12.1	14.9	18.0	33.5	53.8
8	3.1	4.3	6.1	8.3	10.9	13.8	17.0	20.6	38.3	61.4
9	3.4	4.8	6.9	9.4	12.3	15.5	19.1	23.2	43.1	69.1
10	3.8	5.3	7.7	10.4	13.6	17.2	21.3	25.7	47.9	76.8
20	8	11	15	21	27	34	43	51	96	154
30	11	16	23	31	41	52	64	77	144	230
40	15	21	31	42	54	69	85	103	191	307
50	19	27	38	52	68	86	106	129	239	384
60	23	32	46	63	82	103	128	154	287	461
70	27	37	54	73	95	121	149	180	335	538
80	31	43	61	83	109	138	170	206	383	614
90	34	48	69	94	123	155	191	232	431	691
100	38	53	77	104	136	172	213	257	479	768
200	76	106	153	208	272	345	425	515	957	1536
300	115	160	230	313	408	517	638	772	1436	2304
400	153	213	306	417	545	689	851	1030	1914	3072
500	191	266	383	521	681	861	1064	1287	2393	3839
600	229	319	459	625	817	1034	1276	1544	2872	4607
700	268	372	536	730	953	1206	1489	1802	3350	5375
800	306	425	613	834	1089	1378	1702	2059	3829	6143
900	344	479	689	938	1225	1551	1914	2316	4307	6911
1000	382	532	766	1042	1361	1723	2127	2574	4786	7679
2000	765	1064	1532	2085	2723	3446	4254	5148	9572	15358

Use this chart to calculate sinker bar weights needed if the depth of tubing fluid required from chart #1 is greater than the depth of the well itself. The tube depth shortfall is defined as follows:

Formula: Tube Fluid Depth Shortfall = (Required Tube Fluid Depth) - (Total Depth of Well) (This number must be "positive" in order to be a shortfall)

FORMULA: Corrected Net Sinker Bar Weight = (Chart Weight) / (Specific Gravity)

For a margin of safety we recommend that you add an extra 10% to the weight from the chart.

Table 2

DHI PERFORMANCE DATA
TEXAS COUNTY, OK

Casing size: 4 1/2" Tubing: 2 3/8"
Rods: 3/4" Pump size: 1 3/4"

Production Depth: Upper Morrow (6120-26)
Disposal Depth: Lower Morrrow (6215-40)

The following production data was supplied by the operator from the pumper's daily gauge reports. The tool was operational on Feb. 25, 1994, at 4:30 p.m.

BEFORE INSTALLATION

DATE:	MMcf/MO	WATER	Mcf/day
10/93	6,854	80 bbl/day	221,096
11/93	4,907	80 bbl/day	163,366
12/93	6,594	80 bbl/day	212,064

Total MMcf of 18,355 over 92 days = 199.5 Mcf/day

"Before" production rates are taken from the 10th and 12th
Total MMcf of 13,448 over 61 days = 220 Mcf/day
Prior production rates are taken from the 10th & 12th months = 13,448 - 61 days = 220,459 per day.

AFTER INSTALLATION

DATE:	WATER	Mcf/day	DATE	WATER	Mcf/day
2/26	0	25	3/12	0	* 313
2/27	0	150	3/13	0	* 313
2/28	0	200	3/14	0	* 313
3/01	0	210	3/15	0	* 313
3/02	0	(down) 200	3/16	0	* 313
3/03	0	(down) 271	3/17	0	* 313
3/04	0	(down) 244	3/18	0	* 313
3/05	0	(down) 249	3/19	0	318
3/06	0	327	3/20	0	309
3/07	0	345	3/21	0	(down) 140
3/08	0	(down) 232	3/22	0	335
3/09	0	302	3/23	0	343
3/10	0	351	3/24	0	351
3/11	0	328			

*Pumper averaged from 3/12-3/18

Note: For much of this period, the pumper was not using a sufficiently fast stroke to utilize the tool optimally. This problem was corrected on 3/21. Therefore, for purposes of these calculations, the average of the last three days are used.

Total MMcf of 1029 over 3 days = 343 Mcf/day

MONTHLY AND ANNUAL GROSS INCOME GAIN
(Before taxes and operations)

Before:	220 Mcf/day X $1.75 X 30.5 DAYS	$11,742
	Water disposal cost	-2,440
	Monthly Gross income	$ 9,302
After:	343 Mcf/day X $1.75 X 30.5	$18,307
	Water disposal cost	- 0
	Monthly gross income	$18,307
	MONTHLY GROSS GAIN	$ 9,002
	ESTIMATED YEARLY GROSS GAIN =	$108,060