DOME™ STUFFING BOX PACKING

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A wholly-owned subsidiary of
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INTRODUCTION

In 1992 and 1993, Huber began working with problem-solving teams of production supervisors, well attendants, engineers and buyers from major and independent oil companies to find ways to reduce operating costs by improving the performance of stuffing boxes. Huber, which has since become Flow Control Equipment, Inc. (FCE), a wholly-owned subsidiary of Huber, began research in 1993 to support this project.

Most of the stuffing box improvements identified by the focus groups fell into one of six categories shown below:

1. Longer-lasting packing
2. Less demand on the well attendant's time
3. Better lubrication systems
4. Less inventory to support stuffing box maintenance
5. Reliable leak detection and fail-safe options
6. Rapid pay-out for investments in new equipment

Early in the research project, it became apparent that improvements could be achieved in almost every one of the six categories by reducing the coefficient of friction between the stuffing box packing and the polished rod. Rubber, the most widely used packing material, was ideal for its flexibility and memory, but very undesirable for its high coefficient of friction. High coefficients of friction generate heat and result in more frequent stuffing box leaks.

Progress to reduce the coefficient of friction was first reported at the 1994 Southwestern Petroleum Short Course at Texas Tech by Larry Angelo in a paper titled "Metal Film-Coated Stuffing Box Packing". Larry Angelo reported partial success using the Magion™ process to apply a molecular layer of metal over conventional cone rubber packing to reduce the coefficient of friction between the polished rod and stuffing box packing. Since then, Huber and subsequently FCE, has continued to pursue this objective and this paper is the second report on the progress of this research.

The need to evaluate various stuffing box packing materials led to the development of laboratory test equipment shown in Figure 1 which could be used to measure the friction between the polished rod and packing. Tests were conducted on this equipment in non-lubricating environments - the most challenging of all conditions for testing the performance of packing. Metal film-coated rubber was partially successful. Combining PTFE with rubber, which is the subject here, was more successful.

COMBINATION OF RUBBER AND PTFE MATERIALS

The design illustrated in Figures 6, 7 and 8 combines the best properties of PTFE and rubber. The split PTFE seal ring has a low coefficient of friction but no memory of its own, meaning it must have a continuous source of energy to maintain a tight seal as the material wears. Rubber possesses the necessary memory to continuously close the seal ring, eliminating the need for an alternate energy source such as compressed mechanical springs. The flexibility of rubber also compensates for misalignment between the polished rod and stuffing box.

Following numerous trials to determine sizes, shapes, tolerances and an appropriate PTFE to rubber stand-off, the new design evolved to a bowl shape that efficiently converts vertical compression forces - generated as the stuffing box is tightened - into uniform radial forces on the outside of the PTFE seal ring shown in Figure 6. This assures the packing closes and seals around the polished rod and continues to do so as the ring wears. Energy stored by the compressed rubber coupled with the slower erosion of the PTFE ring, ensures a continuous sealing force with fewer adjustments.

Tests have shown that the PTFE split seal ring has a much lower coefficient of friction than can be achieved with rubber compounding used to manufacture conventional packing. The lower coefficient of friction results in less drag on the polished rod and generates less heat. The seal ring stand-off minimizes contact between the rubber and the polished rod.

The bowl shape plus the flexibility of rubber automatically compensate for changes in flow line pressure. As flow line pressure increases, the new design automatically tightens. Conversely, as pressure decreases, the seal relaxes. This capability has been clearly demonstrated in the laboratory and field tests which are discussed later.

LABORATORY TEST EQUIPMENT

Huber designed and built test equipment, shown in Figure 1, that could be operated under controlled laboratory conditions to supplement data collected in the field. This research equipment is capable of measuring polished rod drag, leak rates and stuffing box temperatures under simulated field conditions.

As shown in Figure 1, a prime mover consisting of an electric motor, gear reducer and crank is used to generate linear motion of the polished rod. The stuffing box is attached to a pressure-controlled reservoir that can be loaded with various liquids and gases.

The reservoir is equipped with external heating bands and internal cooling coils to raise or lower the temperature of the reservoir fluid. Stuffing box temperature is measured with a thermocouple installed in the side of the stuffing box. Polished rod temperatures were measured by hand-held contact thermometers.

The stuffing box is equipped with a detection system to measure leaks. The system consists of a top seal and two elastomeric seals to ensure no gas escapes to the atmosphere. These seals force any leaking gas into a water trap. The gas displaces the water into a graduated cylinder which can be read directly to determine leak rates.

A bi-directional load cell installed between the prime mover and the polished rod is used to measure polished rod drag on the upstroke and downstroke. Drag is recorded on a single pen strip chart recorder. Wider bands on a recording chart represent greater drag. Narrow bands are lower drag.

LABORATORY TEST CONDITIONS

Each test illustrated by the recording charts in Figures 2, 3 and 4 was conducted using a 1-1/4" diameter "spray-metal" polished rod. Stroke length was 14 inches and reciprocating speed was 20 strokes/minute. Each set of packing was compressed just tight enough to establish a seal on the nitrogen gas cap. Each test had fresh water in the reservoir with a 1 inch nitrogen gas cap. The test condition simulated severe service because no lubrication was provided for the packing. None of the heat exchangers were used during these tests. Temperatures at the stuffing box were the result of heat generated between the polished rod and the packing.

LABORATORY TEST RESULTS

Earlier tests by Angelo on conventional rubber packing and metal film-coated rubber packing are shown in Figures 2 and 3, respectively. Both are displayed as strip chart recordings of polished rod drag vs. time. Both tests were run at a constant pressure of about 50 psi until the packing failed. Stuffing box was tightened as necessary to prevent leaks. Failure was the point at which a leak could not be stopped by tightening the stuffing box. Initially, the packing was tightened just enough so that no leaks occurred.

Conventional packing failed after 10 hours. The metal film-coated packing ran 114 hours before failure. Drag on the conventional packing was 300 pounds for the first 3 hours but increased dramatically to values as high as 1650 pounds before failing. During this period, stuffing box temperatures increased to 203°F.

During the first 50 hours of the metal film-coated packing test in Figure 3, the drag was in the range of 250 pounds. After 50 hours, drag increased slowly until it eventually reached a maximum of 1150 pounds prior to failure. Temperatures of the stuffing box were noticeably lower than temperatures on the conventional packing test.

Failures in both tests had similar distinctive signatures on the recording charts. In each case, failure occurred a few hours after the signature began. In both tests, the rise in temperature correlated with the increase in drag.

Pressure was set higher at 195 psig for the PTFE-rubber test. The strip chart in Figure 4 which shows the drag for the new combination of PTFE and rubber packing is self-explanatory. Drag, which never exceeded 185 pounds, was more consistent throughout the 112-hour test period. Temperatures ran higher than the metal film-coating test only because polished rod temperatures were recorded rather than stuffing box temperatures. Squeaking sounds, that were audible during the initial phase primarily on the downstroke, slowly faded away. The stuffing box was never tightened during the test which accounts for the decline in pressure and drag during the second half of the test. The test was suspended after 112 hours. Examination of the PTFE seal ring and rubber packing showed little to no wear after 112 hours of operation.

FIELD TEST RESULTS

Following the successful test in the laboratory, commercial quantities of the packing were manufactured and the new design was assigned the trade name of Dome™ packing as shown in Figures 6, 7 and 8. Field tests were initiated in August, 1994, on four Huber wells in the Texas Panhandle. Currently, the number of wells included in the field tests has been increased to 10. Operating conditions for all 10 wells are shown in Figure 5.

Major Oil Company
Red Earth Creek
Alberta, Canada

Average service life of cone packing was 10 days. Dome™ packing was installed November 20, 1996, and was still operating as of February 14, 1997. Since the test was started, the stuffing box has been tightened only once on January 5, 1997. The test is still in progress. Based on the 8.6 service life improvement factor, annual savings on replacement packing alone has already exceeded $250 as determined by the economic chart in Figure 9.

Huber
Panhandle Field Texas
Womble 3, 4, 5
Goehnaier 4

All four wells are Brown Dolomite gas wells in the Texas Panhandle Field. Water, which is very corrosive, is pumped to keep gas flowing from the casing-tubing annulus. The produced water contains very fine abrasive carbon solids and no oil. No stuffing box lubricators were used before or after. Average service life of conventional cone packing was 6 weeks and the stuffing boxes had to be tightened every other day. Dome™ packing extended the service life to 30 weeks and the frequency of tightening stuffing boxes to once per week. Average service life improvement factor was 5.0.

Repacking alone (Figure 9) has resulted in annual savings of $40 for each of the four wells included in the study. The well attendant has continued to make daily trips to each location so no savings have resulted from reducing the number of trips to the well site (Figure 10). However, the well attendant estimates an additional savings of $30 per year for each well for the 10 minutes per month (Figure 11) saved on the location. Therefore, total annual savings are estimated to be $70 per well.

This study was extended in January, 1997, to determine if adding lubricators could further improve stuffing box performance. Early indications are that frequency of tightening stuffing boxes has improved from once each week to once every two weeks. This is a strong indication the service life improvement factor of 5.0 will also increase.

All four wells are at the end of 440V single phase electrical power lines in the area. Prior to the installation of Dome™ packing, it was not uncommon for these wells to overload circuit breakers. Less drag on the polished rod, resulting from the lower coefficient of friction, has eliminated electrical overloads. No credit was included in the savings estimate for eliminating this downtime.

Huber West Texas
Monterey University 1 and 2
Monterey University 3 and 4

University 1 and 2 were equipped with Dome™ packing on December 6, 1995. Testing is still in progress. Results are positive and two more wells, University 4 and 5, which are 4,600 ft. completions in the San Andreas formation, have recently been added to the program.

University 1 and 2 are 7,000 ft. wells in the Clear Fork formation in West Texas. Production fluids have moderate amounts of water and iron sulfide. Dome™ packing has not been adjusted on either well since installation 14 months ago. Life expectancy for conventional cone packing was 4 1/2 months and the stuffing box adjustment frequency was once per week. So far, daily drive-by monitoring has continued. Well attendant estimates a savings of 10 minutes per month on the location of each well. Savings from longer packing life is already at break-even. Using the guidelines in Figures 9 and 11, combined annual savings is currently $40 per well and the service life performance factor of 3.1 is still increasing.

Major Oil Company
Kern River California
Well No. 102

Well 102 is a shallow, heavy crude well that cycles between steam injection and production. Immediately after steam injection, production temperatures are 285°F. Temperature decreases to 100°F by the end of the production cycle. The flow line is exposed on the surface. As a result, temperature swings between day and night, especially in the winter, cause flow line pressure to fluctuate between 400 and 1500 psi, respectively.

The well could not be operated because of stuffing box problems. If conventional packing was tight enough to seal at higher pressures, the rods would not fall. If the packing was loose enough for the rods to fall, the stuffing box leaked.

Dome™ packing was installed on January 16, 1996, and the same set of packing is still operating. No leaks have occurred. Operator has stated that the well could not be operated without Dome™ packing. The well attendant currently monitors Well 102 daily on a drive-by basis. Pay-out has been the recovery of 5 BOPD of lost production.

CONCLUSIONS:

The opportunity to achieve an acceptable pay-out and return on the investment in Dome™ packing increases dramatically as the repacking frequency increases. Based on the economic charts in Figures 9, 10 and 11, the wells most likely to benefit most are wells requiring packing changes more frequently than once every 12 weeks.

Reliability and increased well attendant productivity are convincing features of Dome™ packing. If there is a downside, it is not as effective if the polished rod surface is corroded, pitted, scratched or out of around, and it may not be as forgiving to polished rod misalignment.

Based on the three laboratory tests and 30 months of field tests, it has been concluded that the combination of rubber and PTFE has a lower coefficient of friction than conventional rubber cone packing. As a result, it generates less heat especially in non-lubricated conditions and satisfies many of the criteria for stuffing box improvements set forth by the focus groups.

The new packing clearly lasts longer and requires fewer adjustments which were the first two priorities. Because it is virtually self-lubricating, the new design solves the need for a superior lubrication system which is, in reality, just one more stuffing box accessory that requires service and maintenance.

In order to reduce inventory required to support maintenance, the focus groups concluded a lot could be gained by standardizing on a single stuffing box design. Dome™ packing satisfies this fourth objective because it can be retrofitted to any of the popular cone-packed, stuffing boxes. Retrofitting existing stuffing boxes with the new packing will also improve the pay-out and return investment objective.

The two Huber production superintendents involved in the Texas field tests have concluded that retrofitting older cone stuffing boxes such as the DPSB™ shown in Figure 7 is acceptable, but future stuffing box purchases should be limited to the newer Big Stuff™ models shown in Figures 12 and 13. The threaded cap on this new generation of stuffing boxes provides more uniform compression on the packing and is easier to adjust than the bolts on the older cone-packed models.

Dome™ packing has no direct impact on leak detection and fail-safe systems except the same fail-safe systems currently used on cone stuffing boxes can also be used with Dome™ packing. The focus groups preferred leak detection systems that alerted well attendants of a leak before shutting a well down over fail safe systems that shut wells down without any warning. However, neither system was a desirable substitute for stuffing box reliability and performance.

ACKNOWLEDGMENTS

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REFERENCES

1. Angelo, Larry: "Metal Film-Coated Stuffing Box Packing", Technical Paper presented at the 1994 Texas Tech Southwestern Petroleum Short Course.

TEST APPARATUS

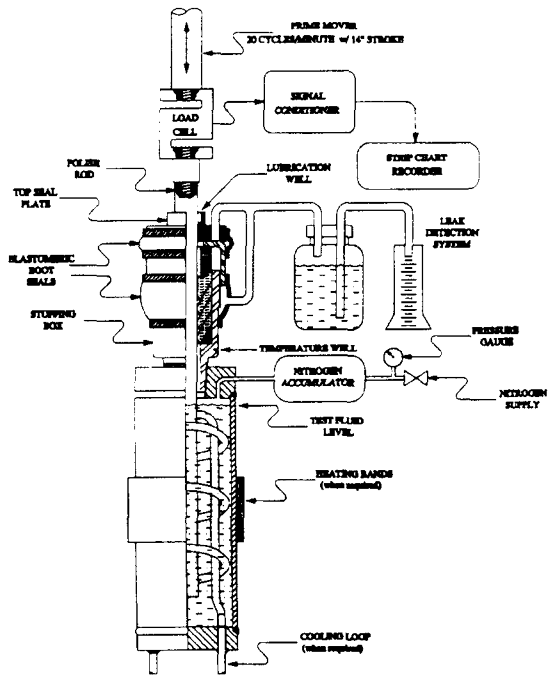

Figure 1

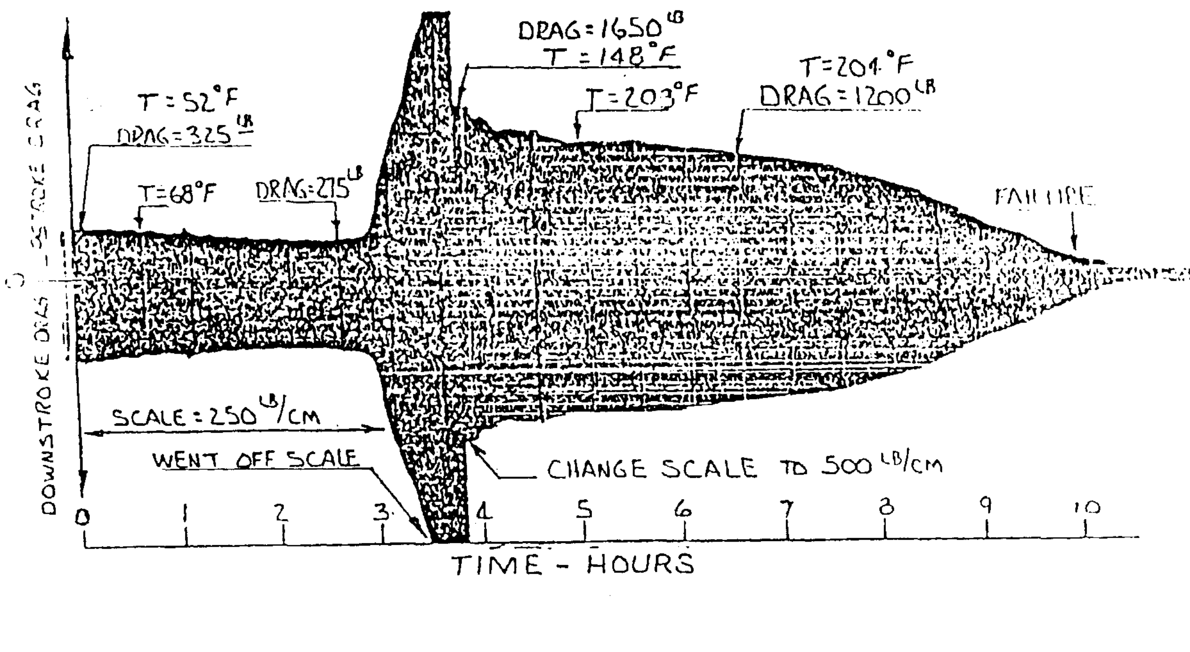

Figure 2

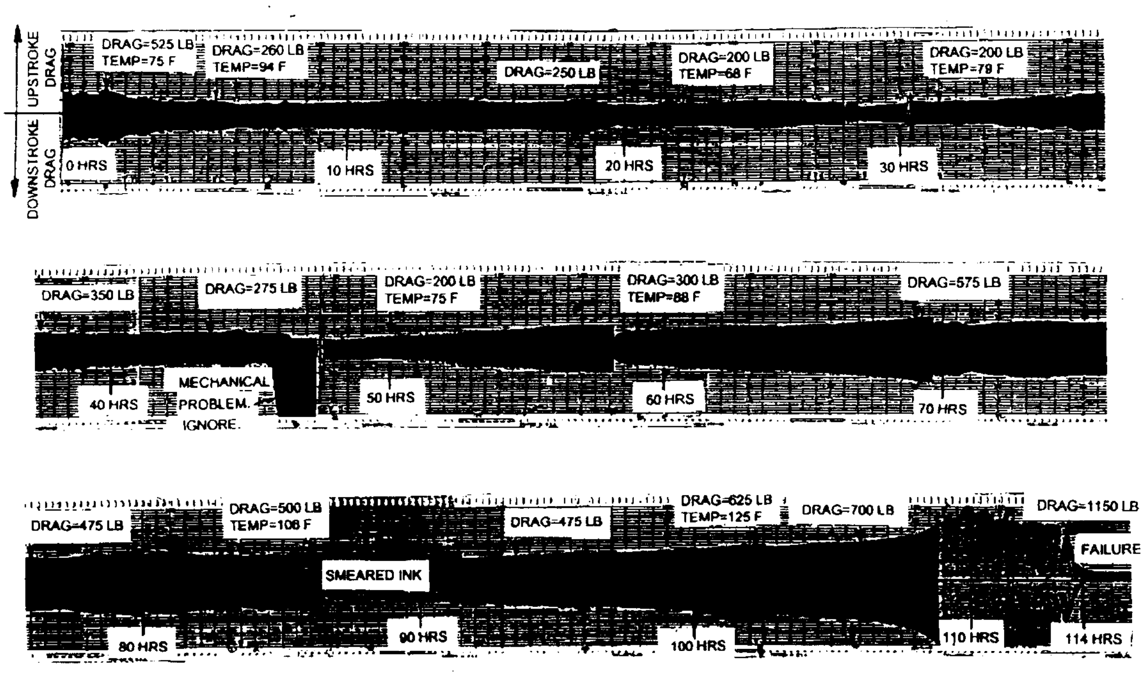

Figure 3

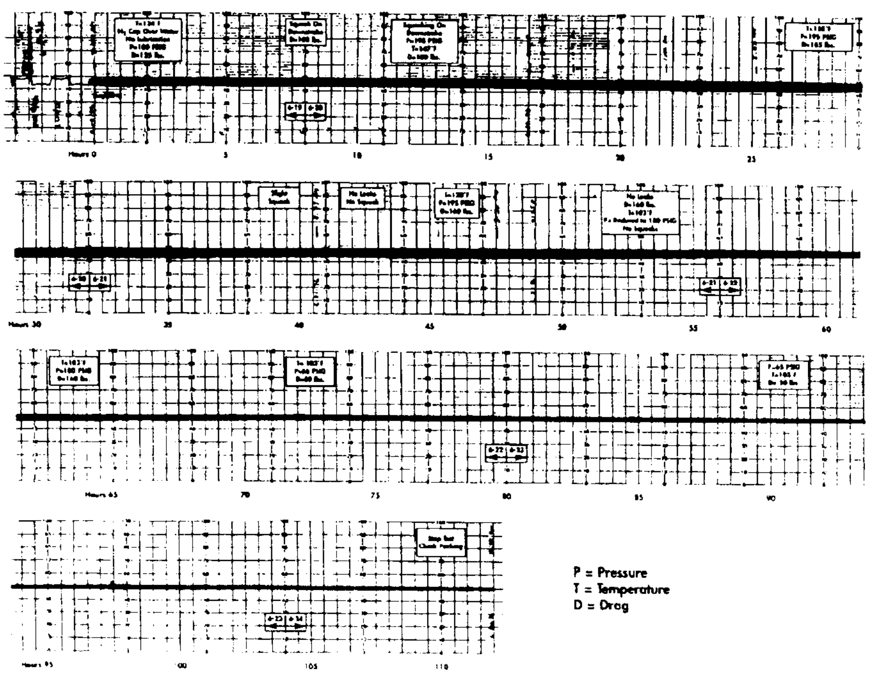

Figure 4

SUMMARY OF DOME™ PACKING
FIELD TESTS

Test No.	Co. Name	Well Name & Number	Well Depth FT	Stroke Length Inches	PR Size Inches	SPM	BOPD	BWPD	Flow Line Pressure PSI	Prod. Temp °F	Test Duration Mos.	Avg. Serv. Life Imprv. Factor	Time Saved on Location Min. Per Mo	Total Annual Savings
1	Major Oil Co.	Red Earth Creek Alberta, Canada	5000	231	1¼	13	128	673	260	140	3	8.6*	10*	$250*
2	Huber	Womble 3	3300	74	1¼	13	0	230	105	100	30	5.0	10	70
3	Huber	Womble 4	3300	74	1¼	13	0	230	100	100	30	5.0	10	70
4	Huber	Womble 5	3300	74	1¼	13	0	230	100	100	30	5.0	10	70
5	Huber	Goehnaier 4	3300	74	1¼	13	0	230	100	100	30	5.0	10	70
6	Huber	Monterey University 1	7000	144	1½	8	38	225	30	180	14	3.1*	10*	40*
7	Huber	Monterey University 2	6900	144	1½	5	18	80	30	180	14	3.1*	10*	40*
8	Huber	Monterey University 4	4900	144	1½	8	100	100	30	140	1	-	-	IC
9	Huber	Monterey University 5	4900	144	1½	8	100	100	30	140	1	-	-	IC
10	Major Oil Co.	Well No. 102 Kern River, California	587	27	1⅛	8	5	12	400-1500	100-280	13	N/A	N/A	9,000

- No stuffing box lubricators were used in any of the cone packing or Dome™ packing field tests.
- Savings are estimated based on $10 per set cone packing; $90 per set Dome™ packing; $15 per hour labor rate, and ½ hour to change packing.
- IC - Incomplete data. Tests are still in progress.
- N/A - Well could not be operated on conventional packing. Therefore, service life and time on location before Dome™ packing could not be determined.

* Test still in progress, minimum estimated annual savings.

** Recovered 5 BOPD for 360 days of lost production at an incremental income of $5 per bbl.

Figure 5

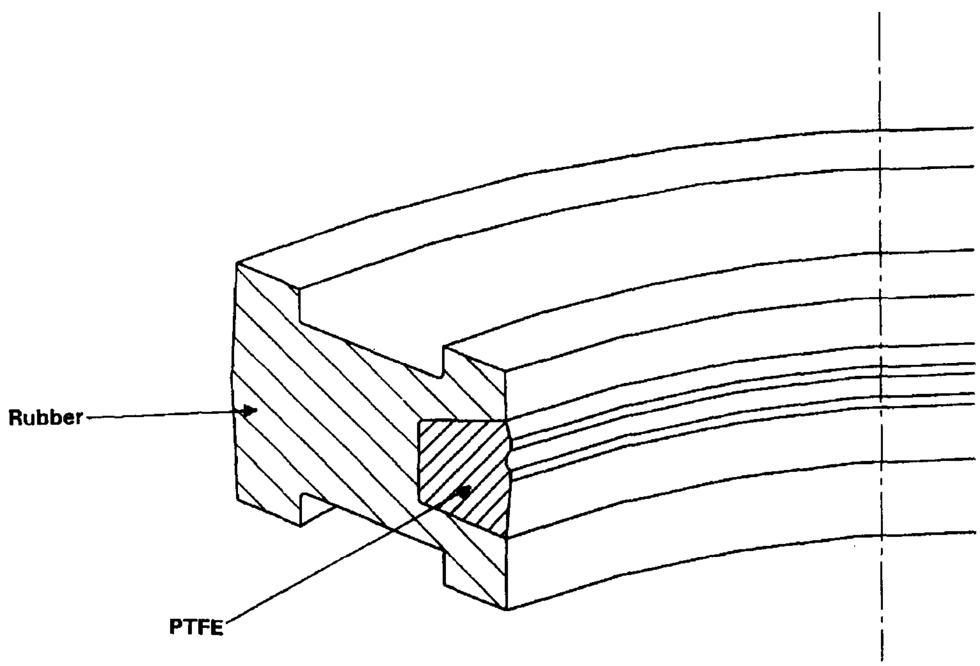

Figure 6

Typical Installation

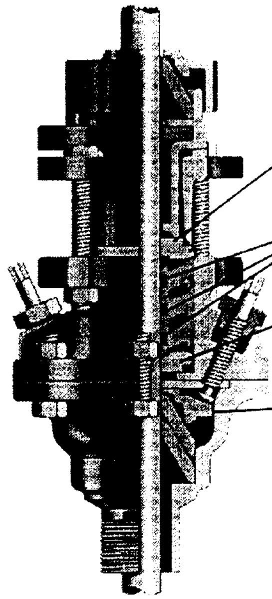

Figure 7

DOME™ Packing and Conversion Kit

Figure 8

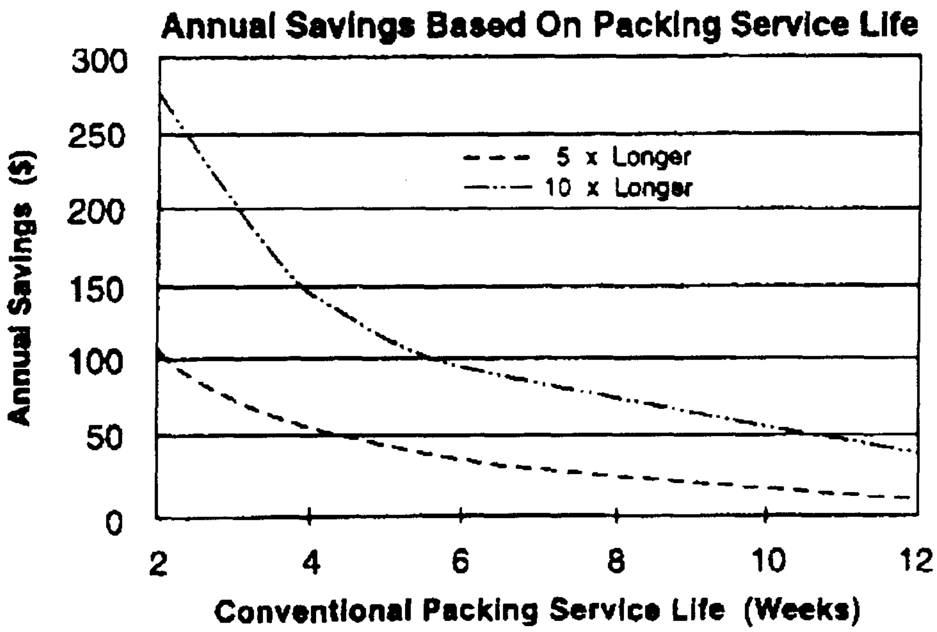

Figure 9

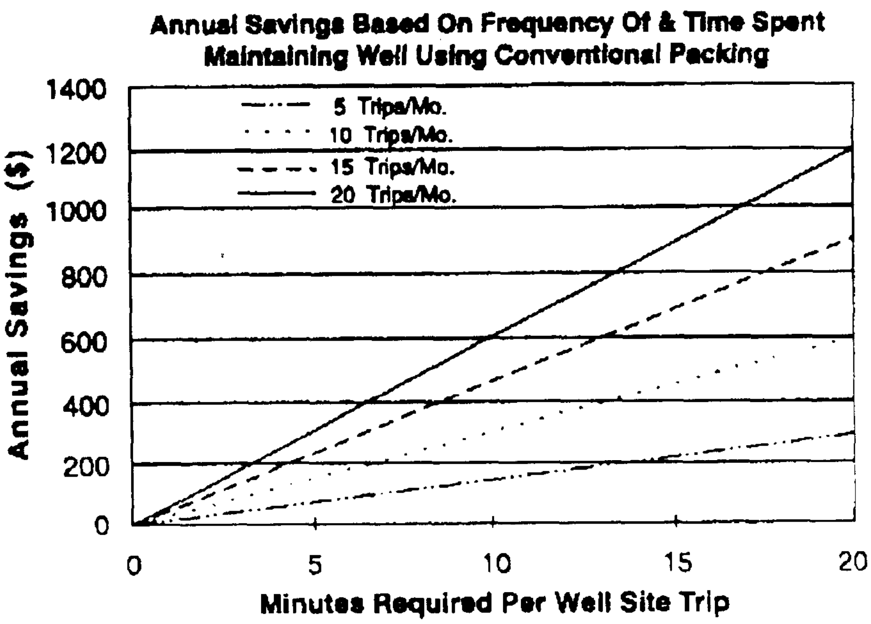

Figure 10

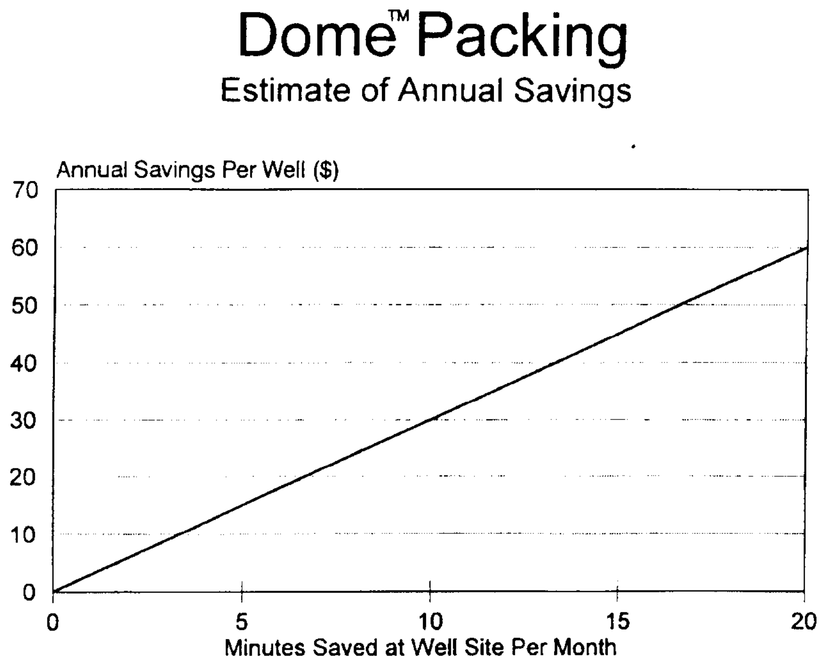

Figure 11

BIG STUFF™

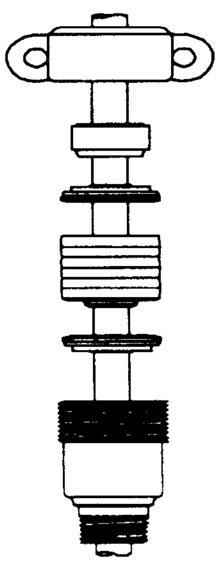

Figure 12

DOUBLE PACKED BIG STUFF™

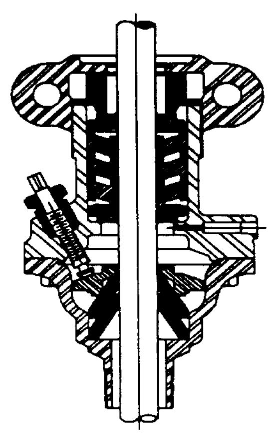

Figure 13