

Clean out existing well perforations by surging the formation

Surging the formation with a wireline retrievable tool can remove debris from perforations and increase flow channel area, thereby potentially increasing production from the existing wells

J.L. Pearce, Otis Engineering Corp., Dallas, and
Emmet Brieger, Consultant, Nogal, N.M.

ONE IMPORTANT advantage of the now popular tubing conveyed perforating system (TCP) is believed to be its ability to dislodge debris from perforations and to flush out all or part of the surrounding compacted area. This is accomplished by perforating with a differential pressure toward the wellbore. This differential can be very high, approaching formation shut-in pressure.

A new service tool provides a means to surge existing wells that were perforated without high underbalance, in which perforation damage (debris and compaction) is thought to exist. This can be accomplished by suddenly subjecting the existing perforations to high differential pressure much as in the tubing conveyed perforating method.

The basic procedure for surging the formation with the backsurge tool is:

- Set "plug" type valve (backsurge tool) in the tubing.

- Create a differential pressure across this valve.
- Suddenly open the valve, dumping fluid from the casing below the packer into the low pressure section of tubing.

This creates a high differential pressure across the perforations to backsurge and flush the flow channels. The plug is retrieved with a slick wireline. Since it is not necessary to kill the well to unseat the packer and to pull the tubing, the cost is substantially less than reperforating with large guns. The process can be repeated as often as desired.

TCP BACKGROUND

The perforating phase of well completions has undergone scrutiny and change in recent years. It is well documented¹ that shaped charge guns leave the perforations (within the formation stone) filled with gun debris and surrounded with a compacted area of reduced permeability. A finite differential pressure (a variable depending on many factors) is required to dislodge the debris and start flow. Therefore, it is conceivable that perforations that are not subjected to sufficient differential pressure, such as could occur when swabbing, can remain plugged and may never produce.

Downhole flowmeter tests² have shown that many wells only produce from 10% to 20% of the existing perforations. Therefore, it is suspected that many perforations in some wells are indeed still plugged from the original perforating operation. Further, it is also documented³ that the compacted stone surrounding the wellbore can restrict flow. TCP is now being performed on many newly completed wells to ensure ample flow area through perforations.

POST COMPLETION OPERATION

A great number of wells completed in past years did not use TCP methods, some of which are suffering from reduced production rates due possibly to plugged or partially plugged perforations. A slick wireline tool has been designed (and tested) to dislodge the perforation debris and open additional flow area. The wireline tool uses the same principle of differential pressure as TCP to remove the debris from the perforations.

Tool design. The initial tool design took into consideration current downhole wireline tools connected to locking mandrels and set in tubing landing nipples. It was desirable to design a back surge tool that would fit into this family of downhole

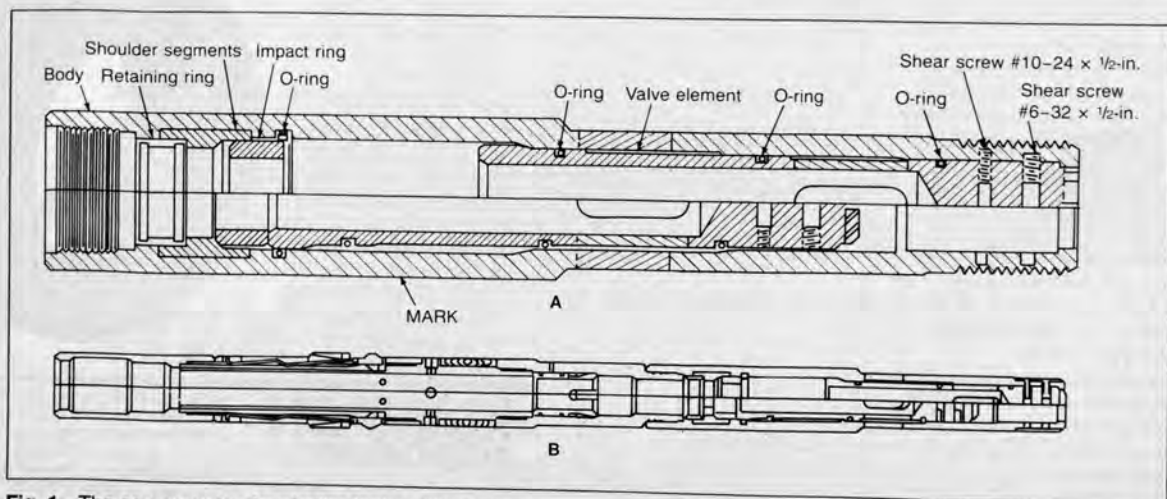


Fig. 1—The components of a wireline tool and its operation.

tools. Fig. 1a illustrates the components of a 2³/₈-in. backsurge tool.

Tool operation. The tool is run on a slick wireline connected to a locking mandrel and equalizing valve (Fig. 1b) and landed in a landing nipple close to the bottom of the tubing string. When pressure across the tool reaches a predetermined value, shear screws will permit a valve in the tool to open instantaneously. The rapid valve opening causes the well to suddenly produce its fluid, thereby flushing out the debris lodged in the perforations. Then the tool is retrieved by wireline and the well placed back on production.

Curves in Fig. 2 illustrate a pressure profile of the pressure surge due to the backsurge tool operation as compared to flowing a well through the tubing string. A much greater instantaneous differential pressure can occur downhole using the surge tool.

Features of the design. The operator determines the pressure at which the valve opens and installs the desired number of shear screws. Up to six #6 and six #10 brass shear screws are normally used in the 2³/₈-in. tool, while eighteen #10 brass screws can be used in the 4¹/₂-in. tool. This permits a maximum of 6,800 psi and 4,900 psi differential pressure for the 2³/₈-in. and 4¹/₂-in. tools, respectively. The sheared screws are retained within the tool and are retrieved with it.

To minimize damage due to the active parts of the tool, a replaceable brass insert is used as a shock-absorbing element. It is designed to be replaced after each use, if damage is significant.

The internal shoulder that stops the motion of the valve element is a three-piece segmented part. It is held in position by a retainer ring, which, in turn, is kept in its position by an equalizing sub. Disassembly is quick and easy, requiring a minimum of tools.

The O-ring glands are sized successively smaller toward the bottom end of the tool. This feature minimizes frictional drag on the valve element. As the valve element moves upward, all three O-rings leave their respective honed bores and face internal diameters that are larger than their free outside diameters. Thus, there is no further O-ring drag on the valve element and it is free to move as rapidly to the open position as possible.

The uppermost O-ring is not used for sealing. It provides a rest for the brass insert to keep it in position. This O-ring also serves as a "catcher" to retain the valve element in place after it shifts to the open position. This feature allows more rapid retrieval of the tool than if the valve were to return to the closed position and prevent hydraulic bypass.

APPLICATION OF BACK SURGE TOOL

Backsurging the perforations can be accomplished on existing wells. Good candidates are:

- Wells that could produce more as indicated by well tests
- Wells completed before TCP was in widespread use
- Wells in which scale problems are known
- Water injection wells.

To relieve pressure above the tool, surface pressure is lowered by opening a wing valve. For many wells, especially oil wells that have a significant hydrostatic head, relieving surface pressure will not establish the desired pressure across the tool. In such cases, fluid above the tool must be removed. A common method for accomplishing this is to run coil tubing into the well and displace the crude oil with pressurized

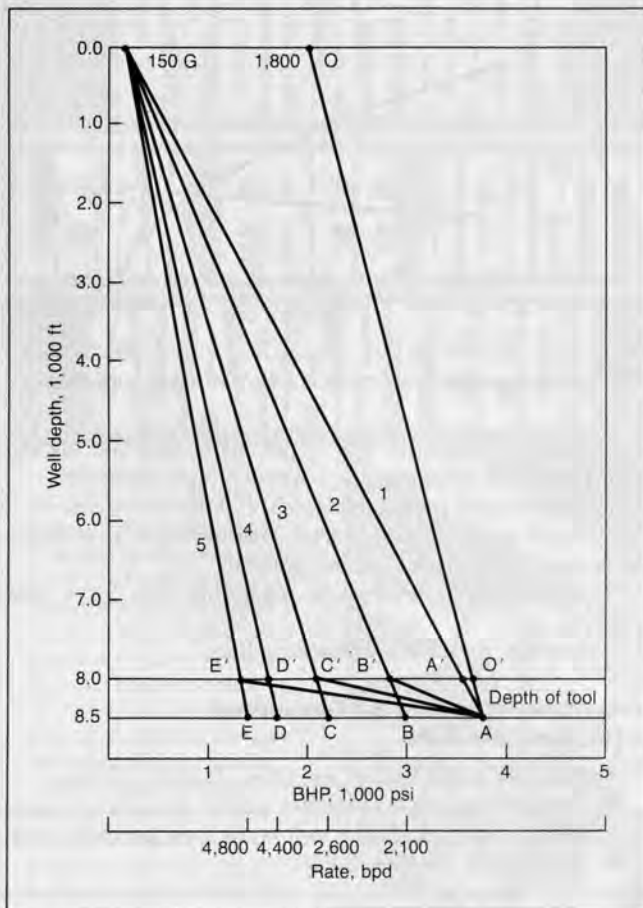


Fig. 2—Pressure profile indicated a much greater instantaneous differential pressure caused by using backsurge tool

nitrogen. Another method would be to run the tool into the well to just above its landing nipple and stop. Fluid above the tool is then pumped back into the formation by injecting pressurized nitrogen into the tubing at the wellhead. Once a sufficient column of crude oil has been displaced, nitrogen injection would stop and the tool would be landed and the job carried out as outlined previously. Although it is not normal practice to pump well fluids back into the formation, the procedure does save the expense of a coil tubing unit.

Procedure for using the backsurge tool varies with the type of the formation:

Formations with Sufficient Pressure.

- Allow formation to build approaching maximum practical shut-in pressure.
- Run tool in the well and lock in landing nipple, remove wireline.
- Open wing valve and bleed down pressure at surface—back surge tool opens at preset pressure differential.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on line.

Formations with Lower Pressure.

- Allow formation to build to maximum practical shut-in pressure.
- Run tool in the well and lock in landing nipple.

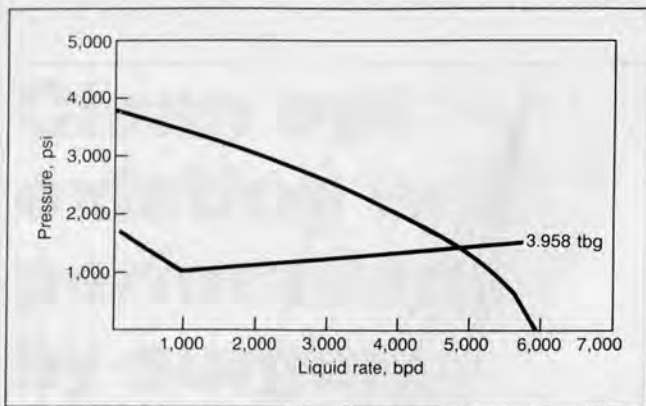


Fig. 3—Inflow performance curve and a 4 1/2-in. tubing outflow curve.

- Run coil tubing in well to just above tool and displace well fluids with nitrogen.
- Remove coil tubing from well.
- Open wing valve and bleed down pressure at surface—back surge tool opens at preset pressure.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on line.

Alternate Procedure for Formations with lower pressure.

- Run tool in the well to just above landing nipple.
- Connect pressurized nitrogen source to wellhead, pump nitrogen into well, displacing well fluids back into formation.
- Lock tool in landing nipple.

TABLE 1—Well input data

Liquid rate (oil + water), bpd	QL	=	4800
Gas liquid ratio, scf/bbl	GLR	=	1000
API oil gravity	API	=	25
Specific gravity of gas (air = 1.0)	SGG	=	0.7
Specific gravity of water	SGW	=	1.0
Percent water cut	WCUT	=	0
Flowing wellhead temperature, °F	TSUR	=	125
Flowing bottomhole temperature, °F	TBOT	=	195
Measured depth of the well, ft	DEPTH	=	8500
Flowing pressure (wellhead or bottomhole), psi	PREF	=	150
Tubing ID, in. (for casing flow use tubing OD)	DIA	=	3.958
Casing ID, in. (for tubing flow use zero)	DICAS	=	0
Kinetic energy term multiplier (use 1)	XKEN	=	1.0
Elevation term multiplier (ratio of tvd/md)	ELEV	=	1.0
Friction term multiplier (use 1)	FRICT	=	1.0
Sign (+ 1. for gas wells, HIGAS = 0 for oil wells)	SIGN	=	1.0
(HIGAS = 1 for gas wells, HIGAS = 0 for oil wells)	HIGAS	=	0

- Allow formation to build to maximum practical shut-in pressure.
- Open wing valve and bleed down pressure at surface.
- Tool opens at preset pressure differential.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on-line.

If the backsurgings is performed, the operator will be able to get maximum potential from each well. And the method is quick and relatively inexpensive, providing good potential for early payout.

ÉDITIONS TECHNIP ÉDITIONS TECHNIP ÉDITIONS

PUBLICATIONS IN ENGLISH AND FRENCH

WORLD ENERGY HORIZONS

14th Congress of the World Energy Conference, Conservation and Studies Committee, Montreal, September, 1989.

J.R. FRISCH

1 vol., hardback, 170 x 240, 392 p. FF 420

NATURAL GAS IN THE WORLD OUTLOOK TO 2000

ATG

1 vol., hardback, 148 x 210, 200 p. FF 250

SEISMIC METHODS

M. LAVERGNE

1 vol., hardback, 170 x 240, 192 p. FF 340

ACOUSTICS OF POROUS MEDIA

T. BOURBIE - O. COUSSY - B. ZINSZNER

1 vol., hardback, 170 x 240, 352 p. FF 620

THERMAL METHODS OF OIL RECOVERY

J. BURGER - P. SOURIEAU - M. COMBARNOUS

1 vol., hardback, 170 x 240, 448 p. FF 567

PHENOMENES D'INTERFACE. AGENTS DE SURFACE.

Principes et modes d'action

sous la direction de J. BRIANT

1 vol., hardback, 170 x 240, 364 p. FF 350

TECHNIQUES D'EXPLOITATION PETROLIERE LE GISEMENT

R. COSSE

1 vol., hardback, 170 x 240, 344 p. FF 340

DYNAMIQUE ET METHODES D'ETUDE DES BASSINS SEDIMENTAIRES

Association des Sédimentologistes Français

1 vol., paperback, 210 x 270, 468 p. FF 240

ETUDE DE LA CROUTE TERRESTRE PAR SISMIQUE PROFONDE

1. Profil Nord de la France

2 vol., paperback, 210 x 297, 288 p. FF 580

SPECIFICATIONS DES PRODUITS MINERAUX POUR FLUIDES DE FORAGE

1 vol., paperback, 170 x 240, 120 p. FF 240

FREE CATALOG ON REQUEST



ÉDITIONS TECHNIP ÉDITIONS
27, RUE GINOUX 75737 PARIS CEDEX 15 FRANCE
Telex 200375 F • Tel: (33-1) 45 77 11 08 • Fax (33-1) 45 75 37 11

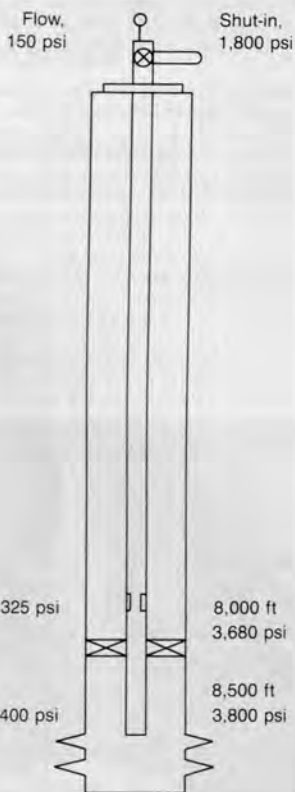
TABLE 2—Flowing bottomhole pressure (fbhp) vs. depth

Flowing pressure psig	Depth ft	Slug velocity ft/s
160	82	58.7
300	1,175	31.7
450	2,272	20.8
550	2,977	16.8
700	4,005	12.9
850	5,004	10.4
1,000	5,980	8.7
1,100	6,618	7.8
1,300	7,851	6.4
1,325	8,000	6.3
1,412	8,500	—
		*29.2

*Average from all points.

Typical well data

SITP = 1,800 psi
 FTP = 150 psi
 SBHP = 3,800 psi
 FBHP = 1,400 psi
 PI = 1 to 5
 RATE = 4,800 bpd
 GR = 25° API
 GOR = 1,000/1
 TBG = 4½-in. OD
 TVD of well = 8,500 ft
 TVD of tool = 8,000 ft
 St. GR = 0.235 psi/ft
 Fl. GR = 0.148 psi/ft
 V = 29.2 ft/sec.*
 T = 8,000 ft/29.2 ft/sec
 T = 274 sec. or 4.6 min.



*Average from program

Fig. 4—Typical well data of the example well and surging procedure: Build well pressure to static condition. Run in backsurge tool and land with a 2,355-psi differential pressure. Bleed down tubing pressure above backsurge tool. Backsurge tool will shear when tubing pressure above is reduced (3,680 - 2,355) = 1,235 psi.

COMPUTER ANALYSIS

To illustrate the possible effect of "surge pressure" using the back surge tool as compared to the pressure differential generated by flowing the well at a high rate, the following data were used for an example:

Static bottomhole pressure, psi	3,800
Test liquid rate (oil and water), bpd	4,000
Flowing bottomhole pressure at test liquid rate, psi	2,000
Tubing OD, in.	4½

Reservoir inflow performance was calculated using Vogel's equation and the flowing bottomhole pressure required for various production rates through 4½-in. OD tubing was calculated using the generalized correlation of Hagedorn and

HYDRATIGHT LEAK FREE JOINTS GUARANTEED!

Whatever your industry, oil, gas, petrochemical, power generation, when it comes to leak free joints no professional company can give you a guarantee. However, Hydra-Tight Limited provide a unique service which gets a lot closer than most.

Combined with Flexitallic Limited, an associate company and respected experts in the field of gasket sealing technology, Hydra-Tight Limited offer an unrivalled range of products for sale or hire, plus on site services for controlled bolt tightening and in situ on site machining - worldwide.

So for a full package to solve your jointing problems topside or subsea one call to Hydra-Tight Limited will introduce you to a complete solution.

Hydra-Tight offer full on-site services and a wide product range available for both sale or hire.

Hydraulic bolt tensioners, Hydraulic torque wrenches, Torque Multipliers, Hydraulic Nut Splitters, Hydraulic Flange Spreaders and Pulling Equipment, Stud Bolts together with Ultrasonic bolt stress monitoring are all complemented by CAD, full technical support and a worldwide agent/group network.



HYDRATIGHT

A Division of T&N plc

HEAD OFFICE, HYDRA-TIGHT LIMITED, ARGYLE HOUSE, BENTLEY MILL WAY, WALSHALL, ENGLAND WS2 0LB. TELEPHONE: WALSHALL (0922) 645945. TELEX: 339994. TELEFAX: (0922) 646652.

ABERDEEN OFFICE, WELLHEADS INDUSTRIAL ESTATE, DYCE, ABERDEEN, SCOTLAND AB2 0GA. TELEPHONE: ABERDEEN (0224) 770739. TELEX: 739380. TELEFAX: (0224) 724175.

Brown. Inflow and outflow curves were plotted as in Fig. 3, from which it can be seen that the maximum production rate through 4 1/2-in. OD tubing (the intersection of the inflow and outflow curves) is 4,800 bpd.

With Table 1 input data, a pressure versus depth traverse was computed using the generalized correlation of Hagedorn and Brown. Flowing pressures and depths, shown in Table 2, were selected from the printout and plotted (E, E', G) as in Fig. 2. The well diagram, Fig. 4, also illustrates the wellbore with the backsurge tool installed at 8,000 ft. The tool is shear pinned to surge the formation with a differential pressure of 2,355 psi.

Therefore, when the tubing pressure above the backsurge tool is reduced to 1,325 psi, the valve in the tool moves rapidly, imposing a 2,335-psi differential to the formation, causing an instantaneous surging action shown as curve 5 (points A, E', G). Flowing curves were also plotted in Fig. 2 as curves 1 through 4. The difference between the flowing curves 1,2,3 and 4 is a time factor(s). By using the backsurge tool, the differential pressure surge to the formation is instantaneous. By opening up the tubing and flowing the well, curve 1 will progress to curve 4 and impose a differential pressure to the formation, but it may require minutes, hours, days or weeks for this to occur depending on the flow characteristics of formation.

To determine maximum drawdown using the backsurge tool most effectively for flowing wells, the following is recommended:

- Determine maximum production from well, Fig. 4.
- Use a flowing gradient program and plot depth vs. pressure.

- Select the fbhp at maximum production at proposed location of the back surge tool.

- Set shear pin value in back surge tool to shear at a differential pressure to give the selected fbhp.

FIELD TEST DATA

A field test of the 4 1/2-in. backsurge tool was performed on a well that had similar data to the above computer model. The well was producing 1,300 bpd. The backsurge tool was set to operate at approximately 1,500 psi, which is illustrated in Fig. 2 as flowing curve A, C', G. After surging the well one time, production increased to 1,780 bpd, a 37% improvement.

ACKNOWLEDGMENT

The authors thank Otis Engineering Corp. for permission to publish this article, and a special thanks to Karen Bybee and Ken Belanus for helping evaluate surge pressures in wellbores.

LITERATURE CITED

- Maier, L.F. and Nelner, S.H., "Jet-vac differential pressure perforating," *Journal of Canadian Petroleum Technology*, Oct.-Dec. 1972.
- Suman, G.U., Jr., "How to avoid poorly designed or plugged perforations that impair productivity and prevent effective sand control," *World Oil*, Jan. 1975.
- Walker T., "Completing gas wells with controlled pressure technique—in Kansas and Oklahoma," API Prod. Division Mid-Continent Dist. Mtg. Preprint No. 851-39A.
- Colle, E., "Increase production with underbalanced perforation," *Petroleum Engr.*, July 1988.
- Bowler, G. V. and Suparman, D., "Tubing conveyed perforation (TCP): operating experience (An approach to better gas zone evaluation and completion)," 7th SPE Offshore South East Asia Conf. (Singapore), Preprints, 1988.
- King, G.E., Anderson, A. and Bingham, M., "A field study of underbalance pressures necessary to obtain clean perforations using tubing—conveyed perforating," 60th Annual SPE of AIME Tech. Conf. Preprint, 1985.
- Tarig, Syed M., "Evaluation of flow characteristics of perforations including nonlinear effects with the finite element method," SPE Production Engineering, May 1987.

KLEPO® THREAD PROTECTORS FOR RELIABILITY & SAFETY...

■ REVOLUTIONARY TYPE

KLEPO offers a revolutionary type of casing and tubing pin-and protector which has proven to be very reliable, safe and durable. The working principle of the Klepo Protector, based on pressurization by rig air (5-9 Bar), justifies the use on all Standard, as well as Premium thread forms.

The Absence of any moving parts or any other mechanisms, guarantees a long and maintenance-free lifecycle and a very dependable device. Also the rugged buffer in the bottom of the protector, and the fact that only the inside of the protector inflates, guarantees excellent protection of your pin seal ends.

The Protector is designed to provide a 360 degree grip, with greater, evenly divided holding power.

This construction guarantees that the outside of the protector does not change in any way, but that only the inside inflates to provide a better grip on the pin.

■ EASY OPERATION

Air can be inserted into, or released from the air chamber through the air inlet/release valve, flush mounted in the casting. Installation on the pin-end is achieved by pushing the protector on the pin-end, putting the airgun to the valve and introducing normal tool-air, which will inflate the inside of the protector, creating an instant strong grip on the pin-end thread.

■ IMPROVED SAFETY

Handling and using Klepo Protectors on the pipe-rack rig floor does not create any safety hazards to your personnel. When attaching or detaching the protector to or from the pipe, all required manual action takes place at the outside of the protector body.

■ NO NEED FOR INSIDE MANUAL ACTION WITH KLEPO PROTECTORS!

■ IMPROVED ECONOMICS

The Klepo Protector virtually eliminates "jump-offs" and therefore does not cause interruption of your job and possible damage to the threads and/or steel ends.

■ NO REPAIR COSTS FOR KLEPO THREAD PROTECTORS!

Maintenance is restricted to an absolute minimum (air-valve replacement).

■ CONFIRMED PERFORMANCE

Oil companies, rig operators and service companies using Klepo Protectors, have confirmed the advantages and characteristics.

■ KLEPO HEAVY DUTY HD & HDH THREAD PROTECTOR

The special bottom of the "KLEPO HD" protector is made from a different and nearly indestructible material. It has the ideal structure to protect the expensive seal c.g. pipe-ends and it forms one solid protector body. The "KLEPO HDH" protector is made of a material which is very suitable for tropical conditions.

We are able to deliver the KLEPO HD & HDH from stock, up to 2 weeks maximum delivery time.

KLEPO HD Protectors are manufactured in bright yellow/black. KLEPO HDH Protectors are manufactured in red.

The linings and loll pipe systems are made from stainless steel. The valves are made from brass, with a stainless steel spring and a viton rubber seal.

■ BETTER MATERIALS

Klepo Protectors are manufactured in Polyurethane (Rohmax R 280K) with the following characteristics:

- Hardness: 78 Shore
- Yield strength (Din 53505): 24 N/mm²
- Abrasion (Din 53504): 0.090 g
- Temperature range (Din 53516): -25°C/+42°C (other temp. ranges on request)

KLEPO THREAD PROTECTOR KEY FACTS:

- RELIABILITY AND SAFETY
- SPECIAL MATERIALS FOR HIGH TEMPERATURES
- SPECIAL MATERIALS FOR ROUGH HANDLING
- DOWN-TIME, THEREFORE MONEY SAVING
- NO MOVING PARTS, NO DEFORMATION
- FIRM ATTACHMENT TO ALL THREAD TYPES
- ADEQUATE PROTECTION OF THREADS AND SEAL-ENDS
- EASY TO INSTALL, EASY TO RELEASE
- NO REPAIRS, MINIMUM MAINTENANCE

SIZE RANGE KLEPO THREAD PROTECTORS		
2 1/2"*	7"	14"
2 1/2"*	7 1/2"	16"
3 1/2"*	8 1/2"	18 1/2"
4"	9 1/2"	20"
4 1/2"	10 1/2"	24 1/2"
5"	11 1/2"	26"
5 1/2"	12 1/2"	30"
6 1/2"	13 1/2"	

* In HDH conversion only available on request

MATERIAL SPECIFICATION HD PROTECTOR

The HD PROTECTOR is specially developed for rough conditions

Hardness Body/Buffer	78/85 Shore
Yield strength	24.28 N/mm ²
Abrasion	0.090 g/1000 ft
Temperature range	-25°C/+42°C

MATERIAL SPECIFICATION HDH PROTECTOR

The HDH PROTECTOR is specially developed for the Far East, Middle East and Africa as well as South America.

Hardness Body	78 Shore
Yield strength	28 N/mm ²
Abrasion	0.211 g
Temperature range	+18°C/+55°C



See us in Composite Catalog on pages 2242-2243.

KLEPO MAIN OFFICE: Holland Telephone: (31)110 435 17 00* Telefax: (31)110 435 76 45 Telex: 24827 KLEPO NL
KLEPO USA OFFICE: Houston Telephone: 713 464 0770 Telefax: 713 461 6711