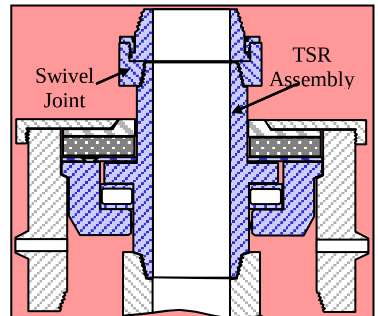
OMEGA TECHNOLOGIES INC.

TUBING SAVER ROTATOR

(TSR, Patented)

Omega Technologies Inc. has developed the innovative Tubing Saver Rotator (patent pending), **TSR**, to substantially reduce the number of failures in pumping wells by 75% to 90% (4 to 10 times the life between failures). A majority of pumping failures is due to the wearing of the rods or rod guides on about 20% of the tubing's circumference (causing tubing splits or "Corrosion due to Wear"). The TSR distributes this wear pattern over the entire tubing's circumference (5 times the area to wear down). This is accomplished by the TSR allowing one person to manually rotate the tubing string about once per month or quarter with a pipe wrench. It consists of a bowl that sits below the wellhead and houses a thrust bearing to hold all the tubing weight (in lieu of slips) on a tubing mandrel with a swivel located between the wellhead and pump tee. The TSR is priced to be roughly the cost of one average tubing failure repair job, which enables **Rate of Returns between 40% and 100%** to be achieved for wells failing more than once every 24 months. Thus, the TSR is an excellent investment for wells with an average or poor run time between failures. This easily and quickly installed mechanism should be the preferred investment before rod guides are installed and the corrosion program changed (see Theory of Tubing Wear).



Tubing Saver Rotator (TSR)
Inside Wellhead

HISTORICAL PERFORMANCE

Several failure mechanisms are present in a pumping well, but are normally related to (1) Wear, (2) Corrosion, (3) Stress on rods, (4) Pump Failure, and (5) Other miscellaneous categories (sand, paraffin, scale, etc.). Wear is the principal culprit in most pumping operations in wells with a proper downhole design and proper installation (see Theory of Tubing and Rod Wear). The TSR theoretically should reduce the number of these failures by 75% to 90%, which corresponds to extending the run time between failures by 300 to 900%. In 25 wells installed with the TSR equipment for 4 years, the run time was improved by 313% (76% reduction) for all failure mechanisms (wear, stress, scale, etc.). These same wells saw the run time between failures due to Wear only (Tubing Splits or Corrosion Hole due to Wear) increase by 484% (83% reduction).

An experiment was performed in a large oil field (1200 rod pumped oil producers) to reduce failures. The worst performing 25 wells were installed with the TSR equipment from 1996 to 1998 with significant improvements (see Table 1 below). The average run time between failures was improved from 1.5 months (8 month average) to 6.1 months per well (48 month average) with further improvement to 9 months per well 1 year after installation. This improvement yielded a **100% Rate of Return (ROR) and a 3-month payout**. In addition, this 76% reduction (4.1 times the life) is for all failure types (not just wear related, but also includes rod parts, stuck pumps, etc.). If one only considered wear related failures, the average run time per well was improved from 3 months to 16 months (an 83% reduction or 6 times the life). Thus, it appears one could assume that the TSR could extend the life between failure repairs by 4 to 6 times. These savings generate around **40% to 100% Rate of Returns** for wells that fail at least once every two years or more often (assuming the TSR cost is equal to one repair cost). Thus, the TSR is applicable for the average well and the problem wells.

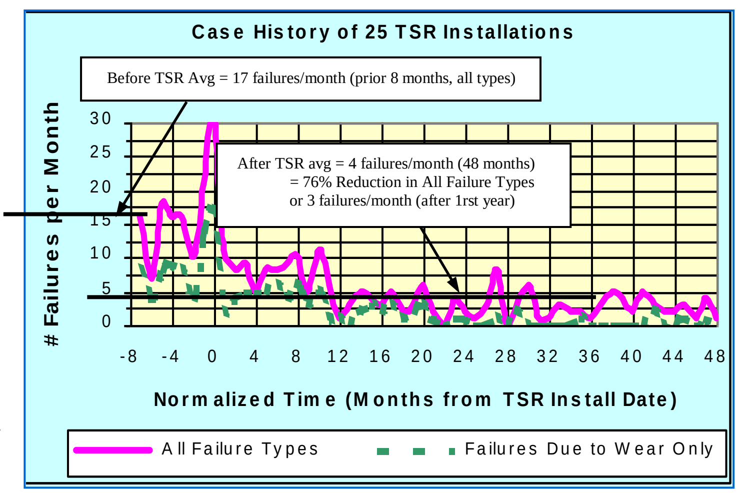
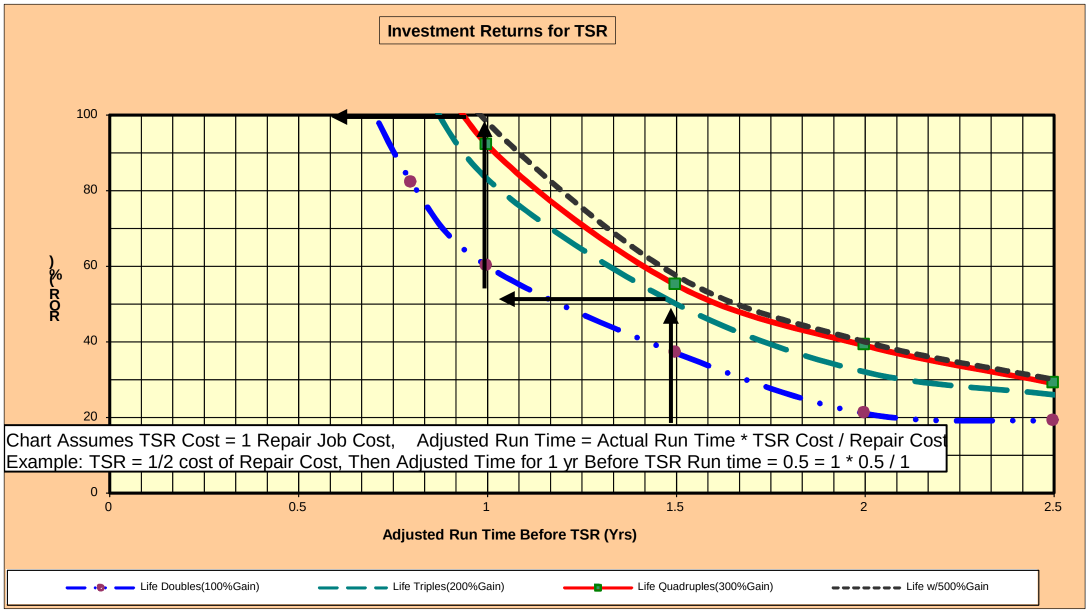


TABLE 1: Case History of 25 Wells installed with the TSR for 4 years

	All Failures Types (#Repairs/yr)	Run Time for all Failure Types (Months)	Wear related failures (#Repairs/yr)	Run Time for Wear related failures only (months)
Before TSR	203	1.5	108	2.8
After TSR	49	6.1	18	16.2
Improvement	313 %	313 %	484 %	484 %
Reduction	76 %	76 %	83 %	83 %

ECONOMICS OF INSTALLATION

The Omega Technologies Inc. TSR is economical to install on pumping oil wells with run times between failures of 2 years or less and even marginal wells. A chart is given below to demonstrate the Investment Rate of Return on a Tubing Saver Rotator installation. This chart does not credit the revenue lost when a well is shut-in awaiting repair, which should improve the RORs. The curves on the chart reflect potential investment returns if the time between repairs is improved by 100% to 500%. Case Histories suggest possible use of the 300% Gain Curve when all failure types are used and then the 500% Gain Curve if only wear failures are considered (see HISTORICAL PERFORMANCE section).



To use the chart, one needs to know the average run time between failures based on proper documentation of their failure types and mechanisms. The 500% Gain Curve could be used for wells utilizing wear only failure rates. The Tripling Life curve may be used if only the Life for All Failure types is known (Case Histories suggest the Quadrupling Curve). It is highly recommended that failure causes be documented and recorded for each well to help in proper well analysis. An operator should rely on his or her own experience in determining applicability of TSR installation.

The chart assumes that the cost of the TSR is the same as one repair job. If the repair cost is different than the TSR cost, then one needs to use a normalized:

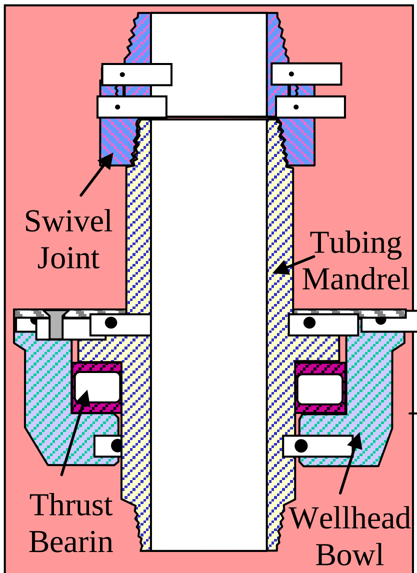
"Adjusted Run Time" = (Actual Run Time) * (TSR Cost) / (Repair Cost per job).

Example 1: A well is failing every 2 yrs (with undiagnosed failures). The operator can buy a TSR for 75% of the cost of one repair job. Using the Life Triples Curve and an "Adjusted Run Time" of 1.5 years, a 49% ROR is anticipated.

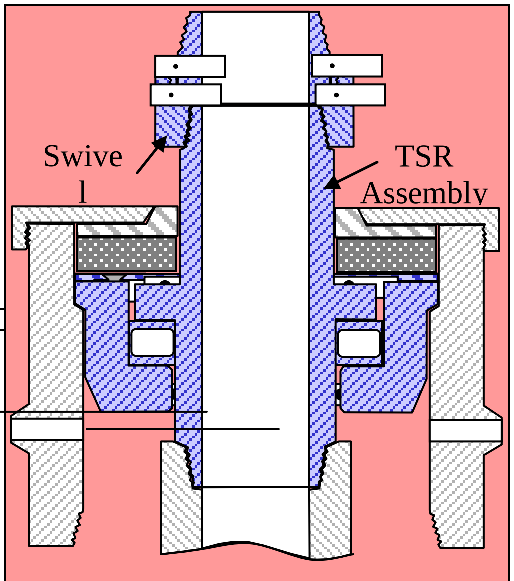
The "Adjusted Run Time" = 1.5 years = 2 yrs * (1 Repair Cost * 75%) / (1 Repair Cost).

Example 2: A well has wear related failures occurring about once every 12 months. The TSR will cost about the same as one repair job. The Chart implies a possible 99% ROR (For 500% Gain) with a TSR investment and installation.

INSTALLATION



Tubing Saver Rotator (TSR)



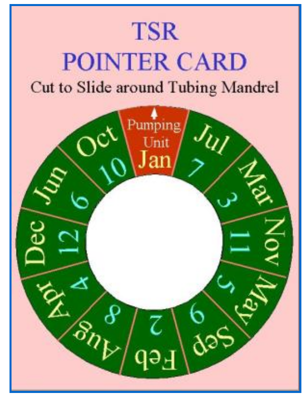
Tubing Saver Rotator (TSR) Inside Wellhead

The TSR is one unit installed during a pulling job (see drawing). The Rig will have a pin end sticking up and a pin end sticking down on the TSR Tubing Mandrel. The Rig should:

1. Make up the bottom pin end to the Tubing.
2. Lower the Mandrel and Bowl into the wellhead until it seats on shoulder within wellhead.
3. Pack off wellhead with normal rubber and plate.
4. Attach the Swivel (one can leave on Pump Tee on future pulls).
5. Make up the Pump Tee.
6. Install 6' or 12' pony rod immediately above pump (longer than stroke length). Add or remove another pony above pump on future pulls.

USEAGE

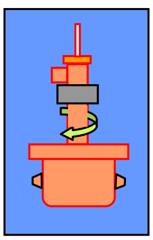
The Mandrel is designed to be stronger than J-55 tubing while maintaining a Rockwell Hardness of C22 or lower (To minimize H2S stress cracking). Different metallurgy may be available for high strength or severe corrosive situations. The TSR is designed to be turned easily with one person using a pipe wrench. The pumper or treater procedure may:



1. Ensure Safe Operation when turning rotator by inspecting area and using proper safety precautions.
2. Grab hold of the bottom part of the swivel or on the tubing mandrel.
3. Rotate the Tubing Clockwise. Then pump chemical inhibitors (if applicable)
4. A "Pointer" is made up on the swivel or mandrel to guide rotation of the TSR. Commonly, this pointer is rotated relative to a laminated "Pointer Card" that a person could carry. One Part of the Round Card has an area to point at the Pumping Unit. Months or Numbers are then marked on the card to show relative position at which the pointer should be set on after rotation. If the Date were January, then the "Pointer" would be pointing at the Pumping Unit, while April would have the pointer aligned about 240^{o} clockwise from the Pumping Unit (the eight o' clock position).
5. Once a person turns a few wells, then they will know where to turn the "Pointer" on the Swivel without rechecking the Card or an operator may prefer to have the person <u>rotate ¼ turn every time</u>.
6. This method allows one to check to see if the rotator is being turned by anyone with a card (supervision check).
7. If the wellhead leaks, then the operator can tighten down the dognut or replace the rubber element without a rig.

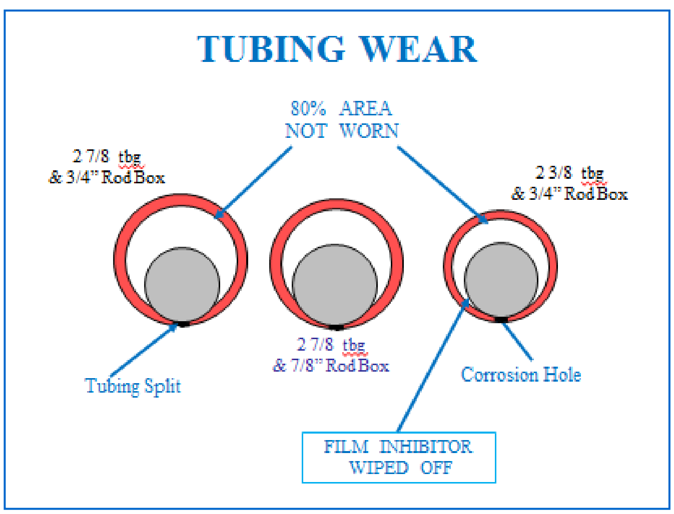
It is recommended to have the tubing rotated immediately before doing a batch chemical treatment down the casing. This will allow inhibitor to coat the clean area that was previously wiped off due to wear from rods or rod guides. If the tubing is rotated after a batch job, then part of the tubing will not have an inhibitor film. The automatic rotators wipe off inhibitor over 100% of the circumference and therefore do not benefit failures due to corrosion holes like manual rotation may.

REPAIR



Repair of the TSR mandrel assembly is easily accomplished if ever needed with replacing only three O-Rings in the TSR Bowl assembly. The top two O-Rings can be changed by removing the Bowl Plate and inserting new O-Rings. The bottom O-Ring will require a rig to pull the TSR from the well as will replacement of the thrust bearing. Failure of the O-Rings is not critical and may only allow fluids to enter into the bearing housing area and thereby lead to future corrosion of some of the elements (Bearing, bowl, and mandrel). Typically, O-Ring failure should not immediately hurt the rotation of the tubing or allow fluids to exit the wellhead since the wellhead fluids are usually sealed with the top rubber element When the tubing is to be pulled, one should inspect the rotator for any potential repairs.

THEORY OF TUBING AND ROD WEAR



The action of reciprocating or rotating the rods within a pumping well causes wear of the rod string against the tubing (Figure shows relative sizes of rod boxes in 2-3/8 & 2-7/8 in. tubing with contact area shown and two failure mechanisms). The deviations of a hole will severely increase the sideways force that increases the friction (drag) between the rods and tubing. However, even <u>"straight holes"</u> will have significant wear because (1) the tubing or rods will lay to the side of the hole (very little room between rod couplings and tubing) and (2) the buckling action of the rods due to the downstroke or whipping action of the rotating rods. This leads to failures in "crooked holes" to sometimes be in the order of months (with new tubing), to several years in "perfectly" straight holes. This **wear** action is very important, because it is often the actual culprit of several types of failures: (1) tubing splits, (2) corrosion holes & pits, (3) rod box failure, and (4) rod body failure. Proper diagnosis and documentation of these problems is important to improve the run time of pumping wells. The mechanisms of these failures related to wear are:

- A "tubing split" is often accomplished by the tubing being worn thin and smooth on one side (usually a straight path being 20% of the circumferential area and the length of the pump stroke) until the pressure in the tubing blows a hole in the tubing. The picture on the right shows a thin smooth section on the right half of the tubing with a split at the top{a rod box would fit nicely in the worn area with 80% of the area not worn at all}. The TSR spreads this wear over the entire circumference to extend run times by potentially 500%.

- "Corrosion hole or pitting" occurs because (a)"poor chemical selection or application" or (b) when inhibitor is wiped off from friction wear, allowing corrosion to take place. This "wiping off of inhibitor" is accomplished by (1) internal wear from rods or rod guides, or (2) externally by tubing expansion (unanchored). Analyze to determine if (1) corrosion is occurring around entire circumference (poor chemical treatment or selection), or (2) pitting along an area wiped free of inhibitors (corrosion due to wear). This corrosion wear is indicated roughly by a straight line of pitting along an area of wear (similar to a "tubing split" without pattern being smooth). This wear area is usually (a) 20% of the circumference for internal wear with no rod guides (30% with certain rod guides), or (c) 20% of external tubing circumference from movement (pumping without tubing anchor).

The Figure on the left shows severe pitting along the width of a rod box (tubing was wetted for enhancement), which also was thinner above and along the pitting area (indicating wear wiping off inhibitor since the rest of tubing has very minor corrosion). The Figure below shows tubing with external wear with pitting along 20% of the tubing's circumference (I.D. is the same but O.D. is worn along a straight line indicating tubing wear against casing (unanchored tubing). This "Corrosion Due to Wear" mechanism will **not normally** be solved by (a) installing rod guides and/or (b) redesigning the chemical program (if 80% of area is unpitted, then the problem is not normally due to chemical type or treatment method). Intermittent rotation with a TSR spreads out the corrosion area to reduce the frequency of corrosion failures (5 times more metal to corrode around the circumference since the old wiped off area should be coated with inhibitor after the tubing is turned). Whereas automatic, continuous tubing rotation has the potential to wipe off the inhibitor with every stroke, therefore not recommended if "Corrosion due to Wear" failures occur. This "Corrosion due to Wear" failure mechanism (absent in some "failure literature") is a common occurrence since many wells are treated with inhibitors to minimize corrosion rates. Unfortunately, many "unsuccessful" chemical programs may actually be adequate, but the wiping off of inhibitors by wear causes corrosion holes and lead to unsuccessful attempts to modify the chemical program.

- A "rod box failure due to wear" will often have one side of the box worn down until the box fails. Rod guides, which are continuously replaced, may temporarily correct this at the expense of increasing rod stresses and the circumferential area for corrosion (certain rod guides may wipe off inhibitor from a larger area). One solution is to install Spray Metal Alloy boxes, which are less corrosive and "smoother" (reduces friction and wear) and are very hard to wear down. With less friction and tubing rotation, the service life may be substantially improved.

- A "rod body failure due to wear" will often have one side of the rod body worn down until the body fails due to tension, particularly in deviated wells. This is often temporarily corrected or delayed by Rod Guides. This is not as big a problem in relatively straight wells because most wear occurs at the rod box site.

Thus, if the pumping well is properly designed, the prevalent failure mechanism will normally be Wear or Corrosion Due to Wear (often 40 to 80% of the failures). This failure mechanism can be delayed by 400% to 900% by rotating the tubing. Less run time improvement may be expected from the use of the more expensive continuous rotating heads since they could be wiping off the corrosion inhibitors and thereby not helping the "Corrosion Due to Wear" failure mechanism.

SUMMARY

Omega Technologies Inc. provides a Tubing Saver Rotator, patent pending, (TSR) that provides an economical way to substantially reduce the repair costs of pumping wells. By lowering operating costs and reducing production downtime, the economics of each well may be significantly improved, which extends reserve life. The TSR is designed to potentially be a high Rate of Return Investment (40% to 100% for wells failing more often then every 2 years) with minimal complications in the use of the TSR. Even marginal wells can afford the TSR and keep reaping the benefits of lower operating costs and increased yearly production with the proper usage of the TSR. The actual documentation of failure types and causes is recommended to enable proper selection of techniques to improve pumping performances in the oil and gas industry.

Update: September 18, 2018 by Omega Technologies Inc. | P.O. Box 822, Seabrook, TX 77586 | (713) 582-5678 | sales@omega1technologies.com | FAX: (267) 295-7971 | Website:\\www.omega1technologies.com