USING POLYLINED TUBING IN A WEST TEXAS FIELD TO MITIGATE TUBING FAILURES, A CASE HISTORY

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ABSTRACT

This paper reviews the experiences of one field where use of polyethylene lined tubing began in 2000 in one well and was then extended to other wells in efforts to mitigate high tubing failures. The data contained here in reviews the pre and post tubing failure rates of the about 40 wells, and reviews the salvages of tubing in a few select wells discussing their reduction in lost tubing value per day. The improvement in well failures and the reduction in lost value are very significant offsetting the added material costs and handling problems associated with "polylined" tubing. The paper will also provided notes addressing some of those handling caveats gained from field experiences.

BACKGROUND

During 1994 and 1995 several former water injectors were returned to production as rod pumping oil wells. These wells injected into and then produced from a San Andres field in West Texas. These wells began production at reasonably good rates, but with high water cuts. As time progressed, oil and water production tapered off, operations personnel who had initially operated these wells on hand now had to control the wells by percentage timer or pump off controller. Failures began to occur, some of them experienced multiple stress cracking failures in very short order.

In recent years this field it was discovered that sulfate-reducing and acid producing bacteria existed in the area where the RTP wells exist, on top of that the field's free gas has been determined to contain about 3 mole percent CO_2 and 1.5 mole percent H_2S. Corrosion coupon readings show weight loss coupons yielding losses between 5 and 200 mills per year (mpy) depending upon the severity of the bacteria, and the effectiveness of the chemical treating, though heavy corrosion treating can obtain rates of about 1 mpy. Thus, this field and these wells have been a source of high rod, tubing and pump failures, related mostly to corrosion, but generally with rod wear also a significant contributor.

Given the corrosiveness of this field, additional factors contributed to the failure rate. One was a major change in the chemical program occurring late in 1999, when one vendor left the lease and another came in. The new vendor experienced a "learning curve" about the corrosion they were now confronted by. Another factor was brought about by the business climate, occurring in 1998 the price of oil fell. During this period operators struggled to find less costly means of well repair. New tubing became anathema due to its cost, and used tubing (especially yellow band) became the norm for replacement. Before long, the used tubing market in the Permian Basin dried up and pipe was sought elsewhere. Pipe from the Gulf Coast was obtained, but its true quality may have been in doubt since even that market was drying up also. Thus, it is suspected that the used tubing quality obtained between 2000 and 2001 may have been a contributing factor in a surge in failures experienced after the collapse of the oil prices.

Efforts to curb the tubing failure rate seemed to be fruitless. Adjustments in the chemical program, use of better tubing inspection, controlling the well's run time and such, downsizing lift capacity, and other techniques seemed to fail to reduce the failure rate. Word came one day that other operators were trying polylined tubing and being successful, so authorization was sought to apply a first string of the lined tubing in a well.

Some of these wells failed at a rate of one tubing failure per year, others about one tubing failure every other year. As a group, the well failure rate per well per year for merely tubing failures was 0.6. Field wide, the rate for about 180 wells was 0.46 failure per well per year in 2001. Eventually, 37 of the San Andres wells were equipped with polylined tubing. At the end of 2007, the failure rate of the entire field was 0.14, failures per well per year, including rod, tubing and pump failures. One of the most significant factors contributing to the reduction in failures was the use of polylined tubing; beginning in 1999 (in one well) and then gradually expanded to the current population of 37.

TRACKING TUBING HISTORY

Table 1 is shown below as two sub-tables and a legend, and depicts the tabulated history of the tubing from Well 330. Similar tables were also constructed to tabulate the history of several other wells including Wells 220, 264, 549, and 1557. First a discussion on what the table is trying to capture.

Over the years, various procedures or techniques were used to repair Well 330's tubing string, including hydraulically testing or "hydrotest" and/or electro-magnetic inspection or "scanning." Sometimes tubing string replacement without inspection of the old tubing was utilized. (In the old days, aluminum paint was used to find "the hole".) Using the well file, a table was set up that reconstructed the pulling events such that the quality of the tubing pulled and that run back in could be summarized. Attention was given to the number of joints pulled, and the number replaced.

Where possible, the quality of the tubing was determined from material transfer sheets and from tubing scan summaries. The tubing scans and material transfer sheets usually listed the tubing as new tubing, or yellow, blue, green, and red band tubing. New tubing was assigned a nominal rating of 1.0, yellow band was assigned 0.85, blue was given 0.70, green was assigned 0.50, and red band was assigned 0.0. These ratings were based upon the concept that a new tube had no wall loss, yellow band had 15 % or less of its wall deteriorated, 30 % or less for blue band, 50 % or less for green band, and greater than 50 % was classified as red band. Early in the time frame green band tubing was reused, later it was treated as red and removed from the well. The tubing, both new and used, was assumed to have a market salvage value, a different price for each color or quality rating. Market prices vary from one time to another, the prices used here in are used for illustrative purposes (see Legend for Table 1).

Each time the well was pulled the tubing *quality* was assessed based upon the scan results, if the tubing was merely hydrotested the quality was not assessed but the number of replaced joints could be determined and the quality of the replaced joints could be summed into the previous assessment. If the tubing was replaced without inspection, it was assumed red band, and then the tubing going in was assigned the quality of the tubing delivered to location. After each pull the *value* of the tubing was assessed, then the green and red band were "sold", and the replacement pipe was added into the string as make up tubing and a final installed value was assessed. The value assessment does not consider the cost of rig time, supervision, water hauling, trucking, sucker rod replacement and such.

The well was operated until the next pulling job, if the tubing was scanned its quality and value were reassessed. Then the run-days between tubing services was calculated, and then the value of tubing "deterioration per run-day" was determined. If the well was serviced, but the tubing was not scanned or replaced – and since usually only a few joints were replaced during these jobs - the runtime "clock" was not reset, instead that specific runtime was added to the next pulling job where the tubing was serviced and tubing quality was determined.

THE FIRST INSTALLATION

The first well receiving polylined tubing received a partial string, about half, the lined tubing was placed on bottom. This first well was Well 330. Its tubing failure rate had been about 1.6 failures per year, in fact it suffered eight tubing failures in 5 years. It usually suffered corrosion and rod wear tubing degradation and usually lost between 30 % and 60 % of its string each time it was scanned, which was five times. In each case, the green and red band tubing was laid down, and usually yellow band tubing was used as make up tubing. Two tubing jobs were conducted without scanning shortly after a previous service, and in one case the tubing was merely replaced. In the non-scan cases hydrogen stress cracking was considered the cause of failure. The reader may refer to Table 1 a below to review this well's history.

During the last of these 8 tubing jobs the tubing was replaced with 56 joints of new bare tubing and with 50 joints yellow band polylined tubing, it was put back into service Dec 17, 2000. Just three months later, the tubing failed again, and the scan job for that failure led to the tubing quality rating of 39 yellow band joints, 10 blue, 2 green and 57 red band. All of the bare tubing (previously new) was junked and the yellow band lined tubing was rerun. The disposition of the 12 blue and green lined joints was not recorded. Then the tubing was made up with 69 joints of yellow band polylined tubing and 2 bare joints (installed on top – i.e., the seating nipple was lowered two joints and the supervisor chose to run bare tubing to finish the string).

Well 330 operated with the fully lined tubing until May 12, 2005. That day, the well was recompleted to the San

Angelo and the polylined tubing was moved to another well and installed without inspection. Of that string, the two bare joints were discarded and an estimated 24 joints were replaced due to polyliner that would not drift.

OBSERVATIONS ABOUT WELL 330

Table 1 b, Column 4 shows the estimated relative "Deterioration Rate" in terms of percent change in quality from one installation to the next (%). Column 7 shows the "Deterioration Lost Value" ($/day). Well 330 experienced between 36.8 % tubing degradation and 100% when it was equipped with bare tubing (between the years 1995 and 2000). For the short time it operated with a partially lined tubing string (Late 2000 to February 2001), its degradation rate was estimated at 61.9 %. Then, in 2005, the tubing was removed and at that time its Deterioration Rate was 18.3% (no joints were lost, but 24 joints had problems with the polyliner itself). Meanwhile, its value deteriorated at the rates $7.16/day to $6.28/day, during the 1995 to 2000 time frame, the cost of the deterioration of the tubing with the partially lined string was $20.38/day. But, the cost of deterioration of the lined tubing string was $0.62 per day. This last number was achieved by the significantly longer run life the well experienced with the polylined tubing.

WELL 330 AND FOUR OTHER WELLS

Four other wells were tracked with following the same method as Well 330; these wells are Well 220, 264, 549, and 1557. Their equivalent of Table 1 is not shown, but a set of summary tables are, see Table 2 a-e. These tables show of all of the wells realized an "Order of Magnitude" reduction in the Lost Value per Day of their tubing when fully lined tubing strings were used.

Well 264, between 1995 and 2001, experienced 9 tubing failures, six times it was scanned and two jobs involved only hydrotesting. It was never equipped with only a partial string. Then it operated until 2006 when it experienced a tubing failure and its tubing was scanned. Table 2-a shows the Lost Value per Day to be $11.30/day with bare tubing and $0.62/day with polylined tubing.

Well 220, between 1995 and 2001, experienced 4 tubing failures, one time it was scanned and once the tubing was replaced without inspection, once 21 joints were replaced without inspection, and once half of the tubing was replaced with polylined tubing. In 2002, the bare tubing was replaced with polylined making the whole string lined tubing. Table 2-d shows that the Lost Value per Day to be $9.34/day for the bare tubing, $3.74/day for the partially bare tubing string, and it has not failed with the fully lined tubing string. If it failed February 13, 2008, and it scanned blue band (not unreasonable to assume) the Lost Value per Day would be $2.67/day, and this number declines with each passing day.

Well 549, between 1996 and 1999, experienced 4 tubing failures, three times it was scanned and once the tubing was replaced without inspection. In 2001 the tubing was replaced without inspection and the tubing size was changed from 2 3/8" to 2 7/8". During this job half of the tubing was lined with polyethylene. A workover occurred in 2002 and the bare tubing was replaced with polylined tubing making the entire string polylined. A rod failure occurred in 2005, during that job the tubing had to be pulled because of a few failed liners. It was made up with a few new joints of lined tubing and continues to serve today. Table 2-e shows the Lost Value per Day to be $11.78/day when the tubing was bare and when it was 2 3/8". It operated for over one year with the partial string and then the well was worked over. The Lost Value per Day for that period was $8.64. Since then, it has operated at a Lost Value per Day cost of $2.36 per day, assuming it failed February 13, 2008, and it scanned blue band.

The last of the four study wells, Well 1557, between 1999 and 2001, experienced 4 failures. One was a rod failure where in the tubing was scanned, one was a tubing leak involving a scan job, two tubing failures occurred where the tubing was hydrotested. During the last of these, half of the tubing was replaced with polylined tubing. Almost one year later the tubing failed, it was scanned and made up with a fully lined tubing string. Table 2- b shows the Lost Value per Day to be $22.17 for the time when bare tubing was used, $19.98 when the tubing was partially lined, and if it failed on February 13, 2008 and scanned blue band its Lost Value would be $2.82/day.

These four wells show the cost of tubing deterioration per day reduced in each case by an order of magnitude. Other wells can be show similar improvements.

PERFORMANCE OF POLYLINERS FOR THIRTY SEVEN WELLS

Graph 1 depicts the well failure rate for tubing failures for 37 wells, of which 33 are of the McKnight zone (abbreviated McK). Beginning in 1994 and ending in 2007, all tubing failures experienced by these wells are depicted with a 1. When bare tubing was used, a failure was denoted by a "1". If polylined tubing was installed " ***<u>1</u>"*** depicts the failure. If polylined tubing were installed during a workover a "***<u>WO</u>"*** is depicted. If a partial string of polylined tubing was installed a "***<u>½</u>"*** is depicted, where a "***<u>½</u>"***is followed by another "***<u>½</u>,***, then the partially lined tubing string failed (see Legend for Table 3). Some wells did not exist or were not producing early on, so the years that the well did not exist are grayed out. For each year the population of lined tubing strings are tallied and shown at the bottom of the Table. The failure per well per year statistics for each year are at the bottom of Table 3, and are depicted by Graph 1. Between 1994 and 2001 the average failure rate per well per year was 0.53, peaking at about 0.7 in the years after the price of oil fell, but improving year after year afterwards to a low of 0.05 failure per well. This graph demonstrates that the use of polylined tubing had a significant effect on the tubing failures of many wells equipped with it. It also identifies wells that have had some failures. In each case, however, the number of joints of failed tubing is small, usually due to external corrosion.

Today, in a field of 920 pumping wells, 59 wells have polyliners, of these 38 McKnight wells have polylined tubing, 15 are Judkins wells, and 2 are Tubb wells. Thirty-three McKnight wells are depicted in Table 3, along with 3 Judkins and 1 Tubb. The McKnight and Judkins reservoirs are both considered San Andres reservoirs and the Tubb is consider a Clearfork reservoir. Table 3 does not include every well, but has a significant number of them listed and should be representative of the performance of all of the polylined tubing wells.

<u>PUMP AND ROD FAILURES</u>

None of the data shown depicts the failure of rods and pumps to any specificity. It can be said, that those failures did and do occur. And, when pulled the rods often are severely corroded or eroded. Yet, a review of the wells listed in Table 3 did not show a significant increase in the numbers of failures of those components. And, comparing rod replacement data from the days of bare tubing to the days of polylined tubing, these wells appear to not be incurring higher replacement percentages per job now as compared to before. That said, pump and rod failures man require the removal of the tubing and this should be anticipated.

<u>WHEN POLY LINED TUBING STRINGS FAIL</u>

In sour/corrosive wells, fully lined tubing lasts a very good while, but partially lined tubing seems to experience no improvement in a well's failure rate, though its tubing salvage can be a little better. It seems that in corrosive environments, the energy of the corrosion process may even work harder on the bare tubing since it is prevented from spending its energy on the lined tubing.

If a failure occurs in the polylined tubing, generally it will involve a few externally corroded joints near the bottom, or one or two rod cut joints elsewhere. Of all the polylined tubing installed so far, only a few cases of polyliner failure due to rod abrasion exist, and in these cases only a few joints were removed due to that problem.

Hydrotesting is usually adequate to identify structurally good tubing. If the liner is in tact, and the steel is structurally sound, with no holes, polylined tubing can be rerun at low risk. Damaged polyliners can be found using the hydrotest bars, and if found the joint should be replaced. Usually, the tube can be relined if one accepts the trouble to get that done.

Bare steel sucker rods and fiberglass rods with carbon steel end fittings may experience more severe corrosion due in part to the concentrated unspent energy of the corrosive fluids and due to the erosion effects created by the higher fluid velocities in the tubing/rod annulus compared with unlined tubing of the same nominal diameter. This is especially true in the lined portion of a partially lined string. Sinkerbars have been observed corroded to the diameter of sucker rods in some cases.

Meanwhile, oversized polylined joints have served very well when used as bottom tubing joints (i.e., joint above the seating nipple). For 2 7/8" tubing strings, a 3 ½" joint lined with polyliner have been used in lue of IPC or stainless steel lined, or other forms of blast joints. Occasionally, corrosion ruins the tube, but the lined over sized joints are much less expensive than the alternatives. However, when a well generates sand, and if a bottom hold down pump is used, it is very possible for sand to prevent the removal of the pump without stripping the tubing out. Sometimes the pump must be cut out of the tube with a torch to be salvaged for reuse. But, it has been a better technique for the bottom joint over all than the alternatives. (A crossover collar or such will be required at both ends of the oversized joint.)

Wells completed in zones similar to Clearfork formations, where rod wear is a problem, but where corrosion is mild, can experienced improved tubing run lives (See Table 3, Well 1458). Three wells were so equipped, and due depths and costs received partially lined tubing strings. Runtime did improved, but when pulled for a rod failure or etc., frustrations experienced with "collapsing" polyliner led to its removal. In the field of this study, a large number of wells exist like Well 1458. These wells tend to be large water volume producers and are economically marginal, so caution has slowed their population with polyliners. So, there has been benefit from the use of polyliners, though not to the degree of benefit in the San Andres wells.

Tubing replacement tends to be due primarily to "collapsed" polyliner more than corrosion or rod wear. In a few cases, the liner has been scratched by a "burr", while running in hole with a rod pump leading to a rather tight ball of poly "string" at the seating nipple. In one case, while pulling a pump, the collapsed poly caught a pump on the way out. In this case the well site supervisor mistook the symptom as a paraffin bridge and hot watered down the casing and tubing, resulting in a "glob" of polyethylene.

DEFECTIVE LINERS

After submersion into a well, but noticed during a service job, a polyethylene liner may experience a defect near a tubing joint's pins that makes reuse of the tube impossible without replacing the liner. Field descriptions might include, "the poly collapsed", or "the liner was defective", or "it wouldn't drift." This phenomenon seems to occur shortly after a rod string and pump are pulled through a lined tubing string, and before attempts to rerun the pump are made. It may also occur at other inconvenient times too, but this is the pattern observed most by the author.

Two other details have been learned. The liner collapse occurs in only a few joints, but sometimes as much as 10 percent of the tubes in a string can be affected. And, it seems to occur frequently enough that the pulling procedures one plans for a well should anticipate this before a well is serviced.

To alleviate this problem, one should not pull a polylined tubing string unless one has to. Then make sure sufficient makeup lined tubing is readily available. And plan to drift the tubing – each and every joint when going back in the hole. A hydrotest service rig with a test bar and cups that can negotiate a good polyliner can be used to hydrotest and drift for bad liner tubing.

Several possibilities come to mind about how the polyliner becomes defective. One possibility is free gas migrating behind the liner. Or it might be solution CO_2 gas and water that migrates behind the liner. One other possibility could be rod slap which could deform the liner. Another possibility may be due to sharp objects scratching the liner while running the object into a well. It is doubtful that the hydrotesting itself causes the damage, because it can occur before a tubing string is hydrotested. However, hydrotest bars can get stuck in a polyliner and, if pulled too hard, the bar can pull the liner out of the tube.

The author speculates that hydrogen gas forming inside tubing steel grain structure may be a source of the polyliner defects. Hydrogen gas migrates into the tubing steel in the form of a proton, when there it bonds with an electron and forms a hydrogen atom. Then when another hydrogen atom forms they bond together and form a gas molecule. Under "normal" conditions the gas is trapped, but as more gas accumulates pressure rises. Eventually, the pressure becomes great enough to cause stress cracking of hardened steel. This process can happen in a few hours. If so, then during "non-normal" events, such as removing tubing from a well, the hydrogen can then escape in a few hours, or in the time it takes to pull a pump and rerun it. How much gas evolves and at what pressure it exists at is not known for sure, but some have suggested gas pressure as high as 10,000 psi can exist within the steel. Pressure that great, if released, does not require a lot of volume to distort a plastic liner. The phenomenon of gas bubbles of hydrogen have been known to cause blistering of chrome metal layered over brass barrels in sucker rod pumps, it is also known to cause blistering of mild steel and spalling in hardened steel. Thus, if it can blow a bubble in steel, could it not blow a bubble in plastic?

CAVEATS

A short list of caveats for pulling wells with polylined tubing:

- Once installed, don't pull well unless necessary, when pulled expect to address some polyliner problems.
- Hot water with great care, polyethylene has a maximum operating temperature of 160 degrees F. Hot watering at 200+ degrees can damage the polyliner.

- Polyliner defects can occur in about 10 % of all joints when a well is pulled (in a few cases the percentage has been higher). Always plan for makeup joints.
- Hydrotest bars are an effective method of drifting, but the bars can become stuck if the cups and bar are not tested relative to the polyliner diameter.
- Tubing scanning doesn't evaluate the condition of the polyliner, just the steel tubing. But, it will yield important string integrity data should that be desired. As long as the tubing has sufficient structural strength (and no holes) even red band tubing has been rerun in some operations.
- Avoid partially lined stings in sour/acid service, instead line the tubing string from the surface to the seating nipple. Yet, partially lined strings may be okay in high pH wells.
- Don't forget to have the TAC lined
- When excessive sucker rod corrosion exists in wells with polylined tubing, plastic coated steel rods or fiberglass rods with nickel end fittings or end fittings made of 4620 stainless steel will improve the performance. In this case, spay metal couplings will corrode less than T-couplings.

CONCLUSIONS

Polyethylene lined tubing has improved the performance of rod pumped well economics where in the well has serious corrosion and rod wear occurring simultaneously. It has also generated benefits for wells with significant rod wear problems. Wells with a tubing failure rate of about 0.50 or worse have benefited significantly.

Polylined tubing often experiences changes in the liner's integrity caused by well conditions, but anticipating that and planning a few addition steps in the service procedure on can mitigate the problem. Well site supervisors not familiar with this problem can get into a much more expensive situation than necessary as they try to "fight" their way through a pulling job and if this happens the economic benefits of polylined tubing will be lost.

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TABLE 1 A											
Well 330											
Date	Failure	Job	Service Remarks	Tubing Conditon						Total	Grade
Rig Up				new	yellow	blue	green	red	oth	Jts	
1	2	3	4	5	6	7	8	9	10	11	12
4/27/1995	OTH	Run	USP, change to tubing Pump		106					106	l-80
5/25/1995	Tbg	Pull	HYD, RPM jt#82 split (stress cracking)		104			2		106	l-80
		Run	changed 2 jts (vs rep: 1 jt)		108					108	l-80
2/19/1996	Tbg	Pull	TIN, HYD, 2 jts split (marks from tong)		17	49	39	1	2	108	l-80
		Run			57	49				106	l-80/j-55
2/29/1996	Tbg	Pull	HYT, RPM, collar split (manuf. Defect)					1	105	106	l-80/j-55
		Run			1				105	106	l-80/j-55
6/25/1997	Tbg	Pull	TIN, RPM, 2 7/8 ceramic bottom joint		0	10	61	35		106	l-80/j-55
		Run	failure caused from sinker bar ware	81	1	10	14			106	j-55
3/16/1998	Oth	Pull	ACD						106	106	j-55
		Run							106	106	j-55
11/18/1998	Tbg	Pull	TIN, HYD, RPMtubing body split (rod ware)		0	2	77	23	4	106	j-55
		Run			5	56	41		4	106	j-55
10/11/1999	Tbg	Pull	RTB, DSP, tubing assumed bad (w & c)					106		106	j-55
		Run			105					105	j-55
6/8/2000	Tbg	Pull	TIN, RIN, RPM, tubing leak due to rod ware			2	5	98		105	j-55
		Run	RTB, HYD, SWB		108					108	j-55
12/17/2000	Tbg	Pull	TIN, RIN, RPM, tubing leak due to corrosion		1	2	7	90	8	108	j-55
		Run	(prob. Main reason)	57	50					107	j-55/poly
1/10/2001	Rod		RIN, RPM, pin break (inprop.tong set.)							107	j-55/poly
										107	j-55/poly
2/10/2001	Tbg	Pull	TIN, RIN, HYD, tubing leak (corrosion and		39	10	2	57		108	j-55/poly
		Run	RPM rod ware), 2 top joints bare		110					110	poly
5/12/2005	WO	Pull	TIN, WO, tubing moved to another well		86	24				110	poly

TABLE 1 B						
Well 330	Run (days)				String	Deterioration
Date	Tbg pull to	String	Deterioration Rate		Value	Lost Value
Rig Up	Tbg pull	Quality	[%]	[%/d]	($)	($/day)
1	2	3	4	500.0%	6	7
4/27/1995					$10,785	
5/25/1995	28					
		85.000				
2/19/1996	298	63.194	36.8	0.124	$7,064	$12.49
		78.066			$9,118	
2/29/1996						
6/25/1997	492	35.377	64.6	0.131	$5,105	$8.16
		90.425			$12,460	
3/16/1998	Oth					
11/18/1998	511	37.642	62.4	0.122	$4,917	$14.76
		60.330			$6,381	
10/11/1999	327	0.000	100.0	0.306	$4,040	$7.16
		85.000			$10,683	
6/8/2000	241	3.714	96.3	0.400	$4,124	$27.22
		85.000			$10,988	
12/17/2000	192	5.324	94.7	0.493	$4,023	$36.28
		92.991			$12,808	
1/10/2001	Rod					
2/10/2001	289	38.102	61.9	0.214	$6,919	$20.38
		85.000			$11,192	
5/12/2005	1318	81.727	18.3	0.014	$10,375	$0.62

Legend for Table 1

RPM	Routine Pump Maintenance	OTH	Other	String Quality Rating		String Value per Ft	
USP	Upsize Pump	TIN	Tubing Inspection	red	0	2 7/8"	
FIS	Fish and Hang on	SWB	Swabbing	green	0.5	red	$1.21
HYD	Hydrotest Tubing	ACD	Acidize	blue	0.7	green	$1.61
DSP	Downsize Pump	RIN	Rod Inspection	yellow	0.85	blue	$2.15
RTB	Replace Tubing	LST	Long Stroking	new	1	yellow	$3.23
DAJ	Dump Acid Job	WBC	Wellbore clean out			new	$4.30
WO	Workover	HTW	Hot Water			2 3/8"	
						red	$0.92
						green	$1.30
						blue	$1.74
						yellow	$2.60
						new	$3.47

Run Time is defined as the periode of time
between two failures of the same kind in chronological order in days

TABLE 2

Well	WR 264		Table 2 a	
Notes	Inspect Date	Run Days	Lost Value	Loss/Day
	10/26/1994	199	$4,536	$22.79
	12/13/1994	48	$3,316	$69.08
Bare	5/1/1996	505	$5,382	$10.66
	4/29/1998	728	$5,190	$7.13
	6/26/2000	789	$4,486	$5.69
	6/4/2001	343	$6,594	$19.22
Avg		2612	$29,504	$11.30
Full Poly*	9/11/2006	1925	$1,210	$0.63

*actual after scan, tubing still in use today

Well	WR 1557		Table 2 b	
Notes	Inspect Date	Run Days	Lost Value	Loss/Day
	11/20/1999	609	$7,837	$12.87
	8/23/2000	274	$6,823	$24.90
Bare	8/20/2001	362	$12,939	$35.74
Avg		1245	$27,599	$22.17
Partial	7/17/2002	331	$6,615	$19.98
Full Poly*	2/13/2008	2035	$5,731	$2.82

*assumes blue band salvaged today,
tubing still in use

Well	WR 330		Table 2 c	
Notes	Inspect Date	Run Days	Lost Value	Loss/Day
	2/19/1996	298	$3,721	$12.49
	6/25/1997	492	$4,013	$8.16
Bare	11/18/1998	511	$7,543	$14.76
	10/11/1999	327	$2,340	$7.16
	6/8/2000	241	$6,559	$27.22
	12/17/2000	192	$6,966	$36.28
Avg		2061	$31,142	$15.11
Partial	2/10/2001	289	$5,889	$20.38
Full Poly*	5/12/2005	1318	$816	$0.62

*assumed blue band when removed

Well	WR 220		Table 2 d	
Notes	Inspect Date	Run Days	Lost Value	Loss/Day
	6/1/1998	928	$3,273	$3.53
	2/24/2000	633	$5,155	$8.14
Bare	12/3/2000	283	$4,710	$16.64
	5/28/2001	176	$5,722	$32.51
Avg		2020	$18,860	$9.34
Partial	8/5/2002	434	$1,625	$3.74
Full Poly*	2/13/2008	2016	$5,392	$2.67

*assumes blue band salvaged today,
tubing still in use

Well	WR 549		Table 2 e	
Notes	Inspect Date	Run Days	Lost Value	Loss/Day
2 3/8"	5/21/1997	302	$4,659	$15.43
	3/10/1999	658	$2,549	$3.87
	12/29/1999	294	$4,354	$14.81
	3/25/2001	452	$8,543	$18.90
Avg		1706	$20,105	$11.78
2 7/8" Partial	5/30/2002	431	$3,722	$8.64
Full Poly	8/3/2005	1161	$2,194	$1.89
*	2/13/2008	922	$2,722	$2.95
Avg		2083	$4,916	$2.36

*actual after scan, tubing still in use today

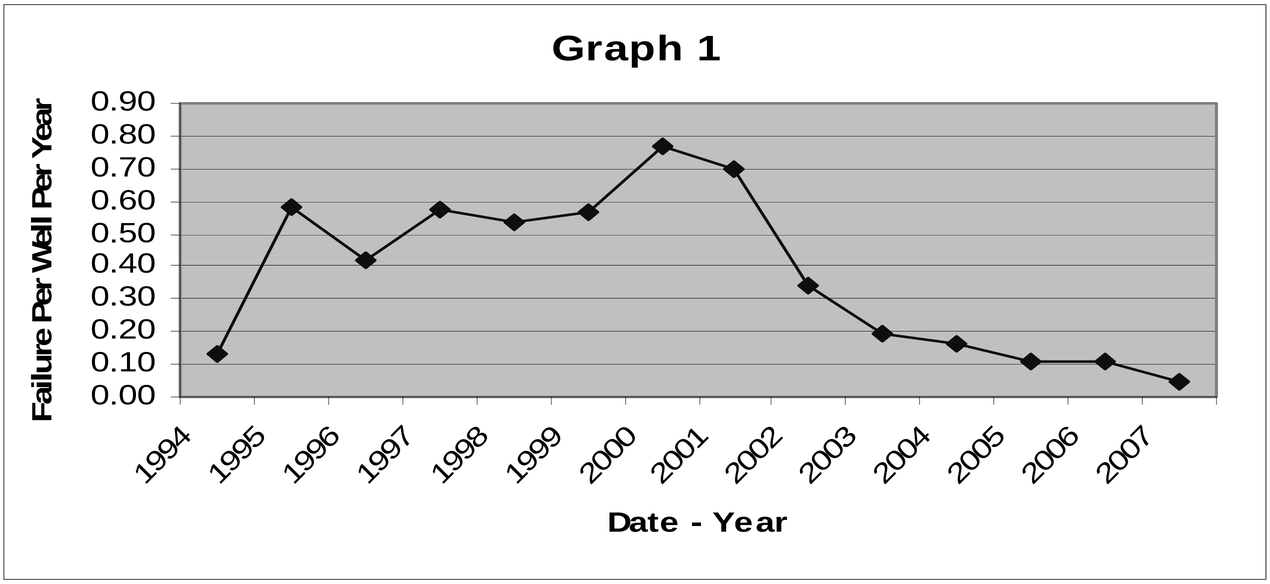
Table 3

Polyethylene Line Tubing Failure Tracking

Well No.	Zone	Btry	Year														
			1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Totals
272	Jdk	316									WO	1	1				2
492	Jdk	316											WO	3	1		4
950	Jdk	316							WO			1					1
104	Mck	353	RTP			WO					1			1	1	1	4
147	Mck	290	1		1		1				1						4
216	Mck	316		1		1	1		1	1							5
217	Mck	316		2	1	1		1	1	1							7
220	Mck	316					1		2	1/2	1/2						5
252	Mck	316						1	1	1	1		1				5
254	Mck	316			1	1			1	1							4
264	Mck	316		2	1		1		1	1					1		6
275	Mck	316					1	2	1		1						5
330	Mck	316		1	1	1	1	1	1/2, 1/2	1				ended 5 23-05	1		9
389	Mck	316		RTP	1			1		1		1					4
390	Mck	316		1			1		1		1	1					5
511	Mck	316				1	1	1	1		1					1	6
515	Mck	11					TF	TA				WO	1				1
517	Mck	316		1		1	1	1		1							5
519	Mck	316		1		1			1	1							4
545	Mck	316		WO		1			1		1						3
549	Mck	316		1	1	1		2		1							6
697	Mck	67	1				2		1		WO	1	1				6
842	Mck	353				1	1		2	1							5
858	Mck	11		1		1		2		1		1					6
888	Mck	11		1	1	1	1	1	1	1	1						8
924	Mck	11									RTP		1				1
1304	Mck	67			1	1	1			1		1/2	1/2				6
1388	Mck	290							WO	2							2
1531	Mck	11				NW	WO		1	1	1						3
1533	Mck	353				NW	1	1		1							3
1557	Mck	11					NW	1	1	1/2	1/2						4
1558	Mck	11					NW	1	2	1							4
1559	Mck	11					NW		1	1							2
1568	Mck	353					NW			1	1						2
1597	Mck	353								New							0
1598	Mck	11								New							0
1458	Tubb	290		2	1	2	1	1	1		1	1/2			ended 5/8/06		10
Failure Per Year			2	14	10	15	16	17	23	23	12	7	6	4	4	2	157
Wells Count Per Year			15	24	24	26	30	30	30	33	35	36	37	36	37	37	

All Wells Eventually Equipped w/ Poly

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
F/W/Y	0.13	0.58	0.42	0.58	0.53	0.57	0.77	0.70	0.34	0.19	0.16	0.11	0.11	0.05



Legend for Table 3

New	New Well
NW	Polyliner installation year, w/o failure since
WO	Work Over - polylined tubing
2	Failure tally for two failures, the second of which received the polyliner
1/2	Indicates well partially equipped with polyliner, and subsequently equipped with supplement liner material after a failure
1	Failure tally for year and indicator of polyliner installation
1	Failure after equipped with polyliner
1	Tubing failure
NW	New Well - Bare tubing
RTP	Return to Production - Bare Tubing
TA	Temporarily Abandoned
WO	Work Over - Bare Tubing
	Well not active