SPE 107069

Rigless Tubing Repair Using Permanent and Retrievable Patches at Prudhoe Bay, Alaska—Continued Analysis and Current Applications

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This paper was prepared for presentation at the 2007 SPE Production and Operations Symposium held in Oklahoma City, Oklahoma, U.S.A., 31 March–3 April 2007.

Abstract

At Prudhoe Bay, Alaska, non-rig tubing repairs have become a viable alternative to rig workovers (RWO's). They provide an economic remediation for wells with production tubing by “A” annulus communication. Electricline (EL)-set patches can eliminate tubing communication at a significant cost savings. They are particularly attractive in areas where RWO cost is significant, such as offshore, remote, or arctic locations. The advantage of tubing patch repair over a conventional RWO is that there is no need to pull tubing, resulting in the well being returned to service faster. Typical patch deployment costs are less than 5% of the costs for tubing replacement with a RWO. To date, 263 permanent and retrievable tubing patches have been set in 181 wells at Prudhoe Bay.

This paper discusses the history of conventional tubing patches at Prudhoe Bay and recommended pre-patch diagnostics. The paper also provides a systematic approach for the design and deployment of conventional tubing patches.

Introduction

Prudhoe Bay, Alaska, is a mature EOR/waterflood oil field. When mechanical problems with the original completions arise, they have traditionally been repaired with a rig workover. The majority of these wells were completed with 4-1/2” and 5-1/2” L-80 carbon steel production tubing. Significant cost savings are achieved by deploying alternative remediation and may result in additional reserves recovered.

Tubing patches are designed to straddle and eliminate production tubing by “A” annulus communication (Figure 1). They can be installed in producers or injectors to isolate leaks in damaged gaslift mandrels (GLM’s), jewelry, tubing collars, and eroded or corroded tubulars. For the purpose of this paper, only conventional patches will be considered. Additional patch types include gaslift straddles and perforation straddles and have been deployed at Prudhoe Bay, but are not discussed in this paper.

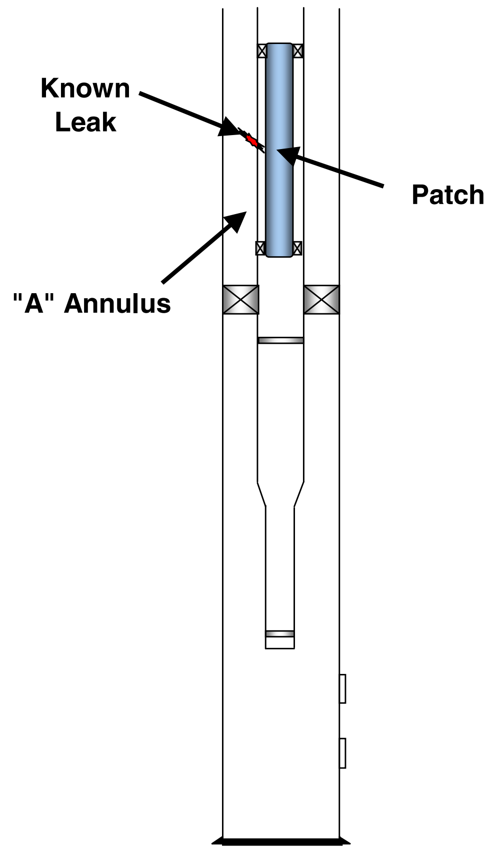

Figure 1. Tubing Patch (not to scale)

Many changes have been made to initial procedures to improve diagnostics and minimize mechanical risk. Patch operation principles, history, annular communication mechanism, diagnostics, candidate selection, patch design, deployment, and retrieval are discussed below.

Patch operation principles. Tubing patches consist of two sealing elements connected by a pipe spacer to straddle and isolate the source of tubing by “A” annulus communication (Figure 2).

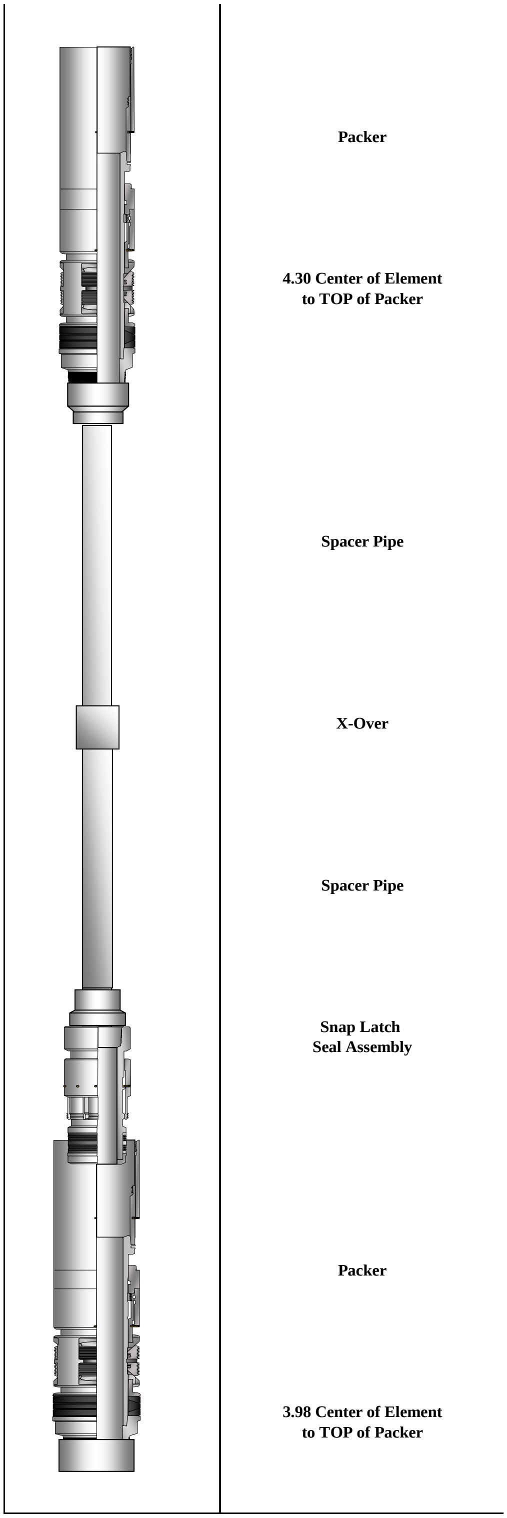

Figure 2: Typical patch configuration

Typically, patches are modular, and can be adapted to special applications such as CT hang offs or extended-length patches[1]. Once set, the patch results in a restriction in the tubing, however, most EL, slickline (SL), coiled tubing (CT), and pumping operations can still be carried out through the tubing patch. Even hydraulic fracturing and CT cement squeeze operations can be performed successfully through patches. These operations may make patch retrievability challenging, if not impossible. Patches are available for most API tubing sizes, and are available in permanent and retrievable models.

Permanent patches. Permanent patches are classified by seal type and can have 1) metal-to-metal primary seals with elastomer secondary seals, or 2) elements that are made of soft metal, either low carbon steel or 300 series stainless steel, with molded rubber on the outside. These are called "soft-set" and provide more effective sealing in corroded tubulars because the seals can conform to tubing irregularities. "Soft-set" patches are run on a pressure-operated setting tool that exerts a pushing force on the top tapered swage and a pulling force on the bottom tapered swage. Both swages are simultaneously driven into the soft metal elements, which expand and seal against the tubing walls. The sealing elements form a metal-to-metal seal, backing up the molded rubber seal.

Retrievable patches. Retrievable patches are deployed in one or two runs. In single-run patch deployment, both packers are set simultaneously with a spacer pipe connecting them to straddle the source of communication. The spacer pipe has a secondary tube through it to the bottom of the assembly to transmit the setting force to the bottom packing element and extrude it to the tubing wall to achieve a seal.

The two-run systems consist of two separate packers and a seal assembly to connect the two with a spacer pipe (Figure 3).

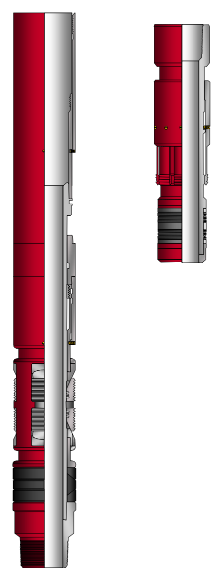

Figure 3: Retrievable two-run packer and seal assembly detail

First, the lower packer is set after rigging up sufficient lubricator to cover the full length of the patch assembly. Next, the second packer is run into the well, and the spacer pipe and seal assembly (stinger) are engaged into the lower packer with a latching mechanism. This engagement is confirmed by pulling tension against the latch. With engagement confirmed, the packer is brought back to neutral weight and the upper packer is set. To pull the upper assembly, the packer is released first, and then the latching mechanism is sheared, disengaging it from the lower packer.

History of patches at Prudhoe Bay, 1986 to 2005

In early field life at Prudhoe Bay, patches were considered short-term repairs. They allowed a well with tubing by "A" annulus communication to be returned to production until a RWO could be scheduled to replace the tubing. The first patches run in the mid 1980's, were set with SL and retrievable. These are still commonly available from many vendors and use tubing stops and packoff sections with stackable patch extension tubes. The SL operation entails multiple runs to set the bottom tubing stop, lower packoff, patch extension tubes, upper packoff, and top hold down stop. Modifications were made so the bottom tubing stop could be set on EL for precise depth control. SL then set the lower packoff, stack up patch extensions for the required length, install the upper packoff and the top hold down stop.

Later patches were permanent and initially had problems with galling when setting. This problem was identified while testing, and the swage and box elements were subsequently coated to address the galling. However, the coated swage and box elements were found to be too slick to grip the tubing walls, and in a surface test, the swage shot across the test yard when the shear ring broke at the end of the setting process. The patch still pressure tested, so a ratchet ring to hold the expander elements was developed.

By 1987, many packoff gaslift mandrels (POGLM's) were being installed to provide artificial lift for wells that did not have conventional GLM's and to straddle damaged GLM's. Installation consists of punching the production tubing and then straddling the tubing punches with a POGLM. To date, 72 POGLM's and gaslift straddles have been installed in 35 wells. These are not discussed in this paper; however, subsequent patches run to isolate tubing punches are included.

Permanent patches with a primary metal-to-metal seal and an elastomer backup seal were the next evolution. Half of the fifty permanent patches run were this type. In 1991, "soft-set" permanent patches became more common because of their improved ability to set in corroded tubing.

By 1994, retrievable patches became increasingly popular as it became apparent that patches were not merely a temporary fix, but could provide long-term tubing integrity. Retrievable patches are more expensive and have a smaller internal diameter (ID) than permanent patches, however, their increased flexibility makes up for these disadvantages. By 1996, all patches installed at Prudhoe Bay were retrievable. To date, 263 patches have been run, and of these, 217 (82%) were retrievable.

Tubing by "A" annulus communication mechanism. Initially, the primary cause of tubing by "A" annulus communication at Prudhoe Bay was due to problems associated with gaslifting operations. Sixty percent of the patched wells have had communication problems associated with gaslifting, including damaged GLM's, broken or stuck gaslift valves (GLV's), and tubing punch isolation. As the field matured, failure became increasingly due to corrosion and 28% of the patches were set to isolate tubing holes. Figure 4 describes the most common causes of communication repaired with tubing patches.

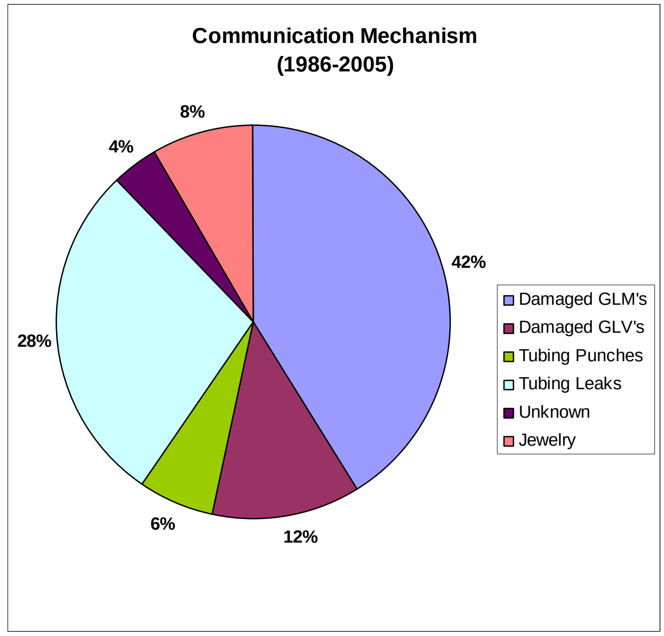

Figure 4. Annular communication mechanism for all patches set from 1986-2005

Gaslift mandrels. The most common source of annular communication is due to damaged sidepocket GLM's resulting in 80 wells requiring patch repair. The majority of these failures were at the lowermost GLM. Premature damage to the GLM can occur when 1) the well is "kicked off" too fast when the "A" annulus is loaded, 2) a GLV is not completely set in the GLM pocket, or 3) a GLV becomes flow cut while loading the "A" annulus. Hydraulic fracturing and CT squeezes were common operations in early Prudhoe Bay history. During these operations, the "A" annulus was fluid packed and pressured up to prevent the packer from unseating due to high tubing pressure. This was done by setting dummy GLV's in all of the GLM's except the lowermost GLM, which was left open. The "A" annulus was then fluid packed, at rates as high as 4 barrels per minute (bpm). It is likely this led to damaged GLM's. Current practice limits the rate pumped through a GLM to 2 bpm.

With the advent of smaller completions (4-1/2" tubing inside of 7" casing, instead of 5-1/2" and 4-1/2" inside of 9-5/8"), smaller, thinner walled GLM's have become necessary to fit inside the smaller casing. These have proven to be even more fragile.

Recently, it has been noted that the pup joints and collars immediately above and below GLM's are also prone to failure. The mechanism has not been determined and this is an area that is being researched.

Gaslift valves. In the past, completions incorporated an equalizing dummy GLV (EDGLV). These are designed to prevent SL toolstrings from being "blown uphole" caused by a pressure differential between the tubing and "A" annulus. To equalize the pressure, the EDGLV's equalizing prong EDGLV is pulled first. Next, a second SL trip is made to pull the EDGLV body.

The latch of an EDGLV is weaker than a conventional DGLV due to the hole bored through the latch for the prong. In early field history, many EDGLV latches were broken during attempted retrieval. EDGLV's are no longer run and it has become convention to avoid pulling the existing EDGLV's. Unfortunately, even if the latch is intact, they are still prone to leak.

Conventional GLV's can also be difficult to pull, due to calcium carbonate scaling or adhesion of the GLV packing to the GLM pocket over time. Occasionally, a GLV latch will break while attempting retrieval. To date, 24 wells have been patched as a result of broken latches or GLV's bodies.

Tubing leaks. Communication problems due to erosion and corrosion have increased as the field matures. Twenty-eight percent of the patch repairs are due to tubing leaks. It is more difficult for packers to obtain a good seal in corroded tubing, particularly tubing with a "line of corrosion." Patch failure is typically much higher. Even if the patch is set successfully, a second leak may be present which was not evident during pre-patch diagnostics. Second holes can also develop later. Twenty-six percent of patches have been set to isolate tubing holes.

In some areas of the field, production casing leaks can occur because the cement top was not brought up over the Cretaceous interval, a zone which is very high in chlorides. The high salinity can result in external casing corrosion. Once a hole in the production casing develops, a hole in the tubing sometimes follows. Of the 55 patches set to isolate tubing holes, nine were set in wells with production casing leaks.

Jewelry leaks. Sixteen wells (8%) have had leaking subsurface safety valve nipples, collar leaks, sliding sleeves, packers, and other jewelry. Two patches have been set successfully across varying pipe ID's due to leaks at crossovers.

Tubing punches. As mentioned earlier, 35 wells have had POGLM's or gaslift straddles installed to allow them to be artificially lifted. In time, several of these wells no longer needed gaslift to flow, and when the gaslift straddle or POGLM failed, the tubing punches were isolated with a patch. To date, 12 wells 6%) had tubing punches requiring patch isolation.

Injection well tubing patches. Corrosion in injectors is not common at Prudhoe Bay; however, it is the leading cause of annular communication for injection well patches (73%). To date, nineteen patches have been run in 14 injectors. Patches have lasted as long as 12 years in water and miscible gas injectors.

Chrome completions. Original tubing completions were carbon steel, but approximately 40% of the producers have been recompleted with 13Cr tubing. Twenty three 13Cr completions have been repaired with tubing patches, the majority associated with GLM problems.

Historical patch failure analysis. The number of patches and success rate has varied considerably over the years (Figure 5). The average is 15 patches set per year with an approximate 70% success rate.

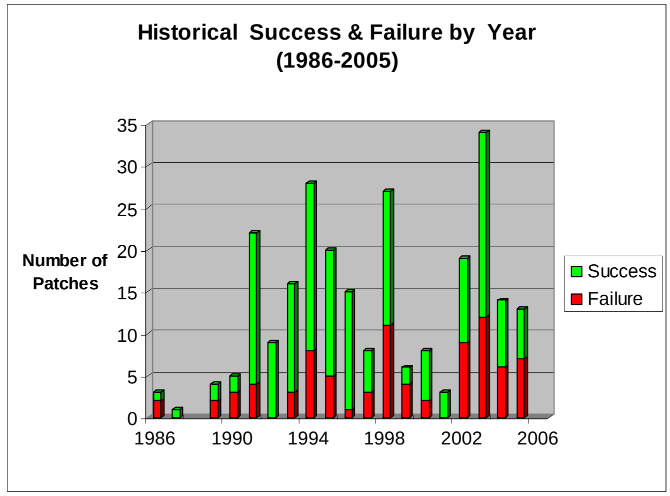

Figure 5. Historical patch success and failure for all patches by year (1986-2005).

Failure mechanism for patches can be divided into patches that fail immediately after setting, and those that are initially successful, but subsequently fail. Since 1986, 263 patches have been run and there have been 189 failures. Eighty patches (45%) have failed immediately.

Immediate failure. The most common reason that patches fail immediately is a leak in the patch (28%) or a second leak (26%) detected by running a post-patch LDL (Figure 6).

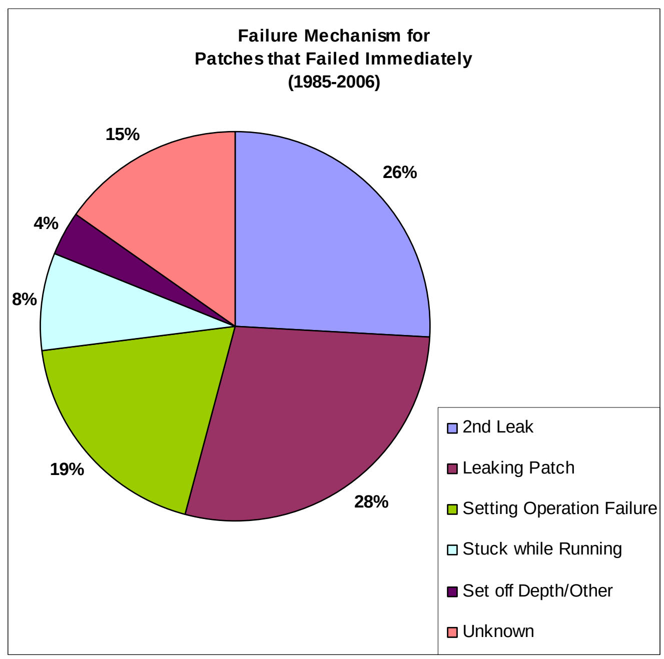

Figure 6. Failure mechanism for patches that failed immediately (1986-2005).

To date, patch leaks have not been analyzed in detail and could be due to many causes. These include mechanical failure of the patch while setting, patch elements leaking due to wellbore conditions (such as the presence of scale, asphaltines, etc.), elements not sealing due to corroded tubing, seal bore leaks due to the upper assembly not being fully stung in, the patch not fully straddling the leak because pre-patch diagnostics were not clear, and other causes.

Second leaks can be masked by larger leaks during pre-patch diagnostics, particularly if the first leak is large. Occasionally, after revisiting the initial LDL, the 2nd leak can be seen as a very small anomaly that was not noted, due to its small magnitude.

Setting operation has also been a failure cause in the past (19%). Most of these failures occurred when a new patch vendor started supplying patches. This rash of setting tool-related patch failures emphasized the need to ensure that the on-site patch representative understands the equipment and setting procedures thoroughly.

Three failures have been due to setting the patch off depth. This illustrates the importance of obtaining a good tie-in log during pre-patch diagnostics. Proper tie-in procedure must be followed, particularly in the case of permanent patches.

Failure after the patch is initially successful. The most common root causes for patch failures that initially had integrity are 2nd leak failures (38%), leaking patches (30%), and unknown causes (31%) (Figure 7).

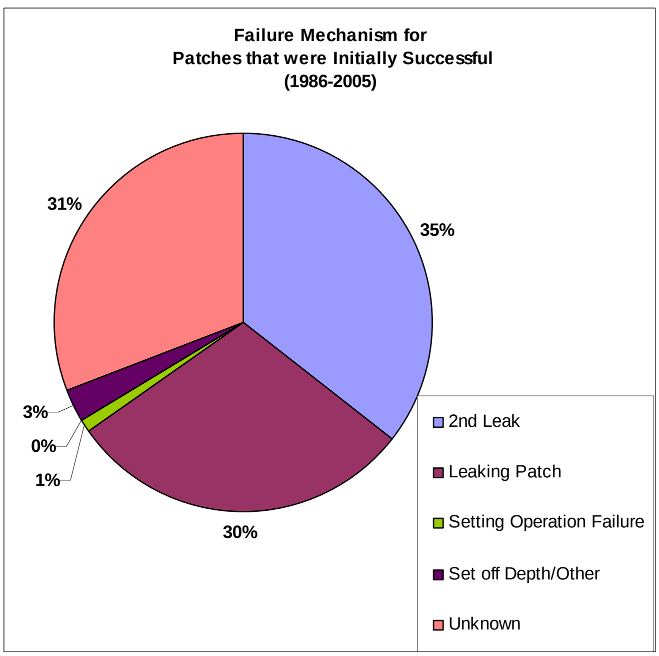

Figure 7. Failure mechanism for patches that were initially successful, but subsequently failed (1986-2005).

Although not verified, it is probable that after initial success, subsequently leaking patches are primarily due to element failure. It is important to note that the higher the number of pressure cycles undergone by the patch, the higher the likelihood that the element will fail due to extrusion. Additional research is being conducted to determine the root cause of the failures that are unknown.

Rarely, patch failure was due to subsequent wireline operations. In one case, an inflatable bridge plug failed while the well was producing and hit the patch, lodging with enough force to cause the patch to lose integrity. In another case, a SL toolstring was pulled up through the patch at an excessive speed and got stuck, resulting in premature patch failure.

Patch life. Patch life has ranged from 1 month to 14 years. Patch survival rate is difficult to calculate due to varying patch installation dates, the number of patches that still have integrity (51), the number of patches pulled for wellwork operations prior to their failure (22 patches), and a patch installation program that continues today. A conservative average patch life of 3.5 years can be obtained by dividing the sum of all of the initially successful patch lives by the number of patches installed. The second phase of this study will focus on a rigorous statistical approach to determine patch survival rates.

Pre-patch diagnostics. Several diagnostic steps must be completed prior to setting a tubing patch. These have evolved over the years as technology has improved.

Tubing by "A" annulus communication. Prudhoe Bay wells which have tubing by "A" annulus communication must be shut-in until the communication is resolved. If the well has live GLV's, they are pulled, dummy GLV's are run, and the "A" annulus is re-pressure tested. If tubing by "A" annulus communication still exists, the liquid leak rate (LLR) is obtained to determine if the leak is large enough to be identified with conventional logging tools. If the well has a tubing tail plug or other downhole plug, a LLR is determined by pumping down the "A" annulus and taking returns up the tubing to surface facilities. If there is no plug in the tubing, the LLR is determined by pumping fluid down the "A" annulus, where it enters the tubing through the leak, into the formation. This typically must be larger than 0.2 bpm for conventional spinner/temperature leak detection logs (LDL's), depending on the wellbore configuration. A commercially available ultrasonic noise detection log has proven that leaks can be accurately pinpointed with LLR's as low as 0.005 gallons per minute[2]. Approximately 30 of these logs have been run at Prudhoe since it was introduced.

Early in field life, leak detection diagnostics included downhole video surveys and LDL's with temperature, spinner, density, and casing collar locator logging tools. These LDL's were either logged with the well on production with gaslift, or while pumping fluid into the tubing or the "A" annulus. Calipers became more common by 1993 and video use declined as a patch diagnostic tool. Rarely, noise logs were run.

Downhole cameras. The majority of early leaks were at the lowermost GLM in uncorroded tubing, and downhole videos were a common form of leak detection. Video technology enables the operator to view the wellbore in real-time to make a visual assessment of the leak and the condition of the surrounding tubing. A surface-based optical receiver decodes and sends the signal to surface equipment. Videos can provide extremely accurate leak diagnosis, particularly in jewelry such as GLM's, however, it can be very difficult to obtain a clear picture and the fluid volume required can be significant. Although corrosion damage can often be detected in the leak vicinity, the damage is generally not quantifiable.

At Prudhoe Bay, the EL unit which runs the video camera is a single drum hydraulic unit spooled with a fiber-optic cable. The optical fiber is encapsulated in stainless steel tubing. Outside the tubing is a single electric conductor to power the camera and lights. The cable has a braided guard wire over the conductor and appears identical to 7/32" multi-strand electric line.

Today, it is rare to use the downhole video to diagnose leaks because of the difficulty and cost in ensuring optimum viewing conditions. Often the video is obscured below the depth of the top leak.

Leak detection logs. If the LLR is large enough, a LDL is performed with spinner, temperature, and density tool. A static baseline pass is logged first, followed by pumping passes. A major limitation of current logs is that a large tubing hole will often mask smaller holes, and correspondingly, a shallow hole can mask deeper holes.

Although memory LDL's are less expensive, real-time LDL's are preferred due to the advantages of on-the-fly procedural changes. Repeat passes of anomalies can be important to ensure accurate leak identification. Log presentation should include identifying jewelry so that the log can be used for patch tie-in (Figure 8).

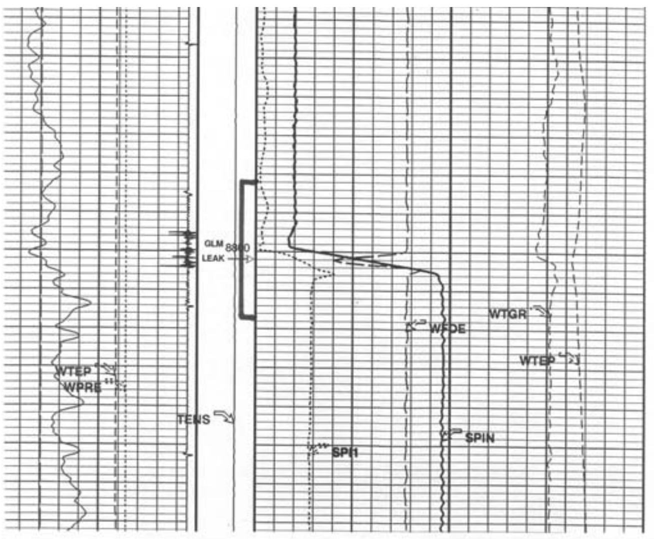

Figure 8. Leak detection log showing leak at gas lift mandrel. Pumping down the "A" annulus taking returns down the tubing into the formation.

Figure 9 shows a GLM leak identified by the ultrasonic noise detection log. Approximately 30 jobs have been performed to date using this new commercially available technology. It is preferable to conventional leak detection logs because of its sharp leak delineation. However, it currently cannot detect leaks larger than 1 bbl per minute.

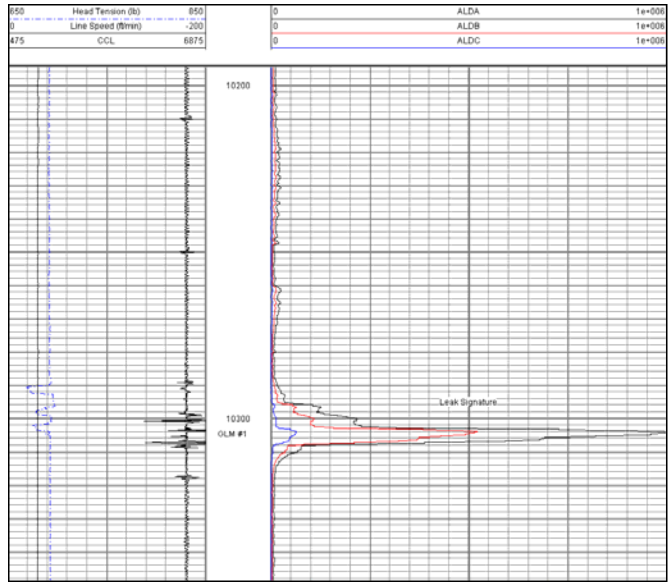

Figure 9. Ultrasonic noise log showing leak at gas lift mandrel. The leak rate ranged from approximately 0.16 to 0.025 gpm.

Once the leak point has been determined, stop counts are performed to pinpoint the leak within 5' to 10'. EL-set patch length is determined by lubricator length and fishing considerations, and is limited to about 35' at Prudhoe Bay. If the tubing leak is at a GLM, the dummy GLV will be replaced with a dummy GLV equipped with extended packing stacks to prior to running a patch. In some cases, this repairs the communication.

Tubing caliper survey. A SL-conveyed memory digital multi-finger caliper survey is obtained to provide detailed tubing surface condition. High-resolution digital data is recorded, followed by a detailed computer analysis. Field data plots and preliminary field interpretation is generally available within two hours of logging. A tabulated joint damage report (Figure 10), color log plots and 3-D data on CD are available within less than one day after completing logging operations. Due to the statistical nature of caliper surveys, calipers do not always detect holes identified by LDL's.

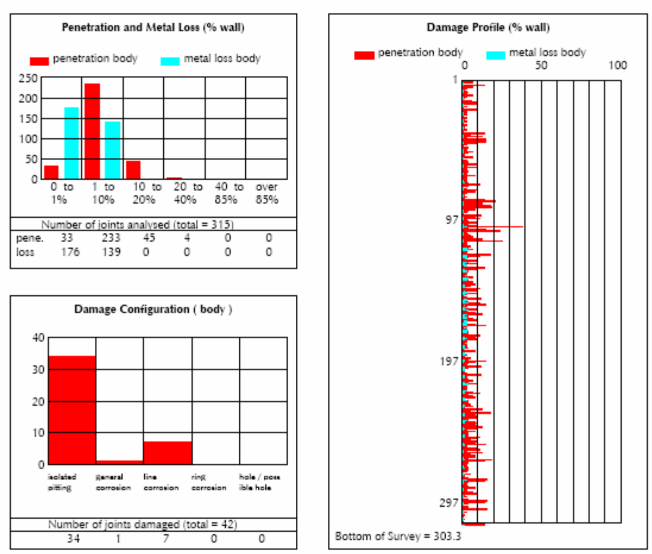

Figure 10. Multi-Finger caliper tabulated joint damage report.

The development of digital caliper data and 3D visualization software allows an engineer, to quickly and accurately understand the details of localized tubing damage. Detailed 3D visualization has vastly improved setting depth location determination (Figures 11-12)[3].

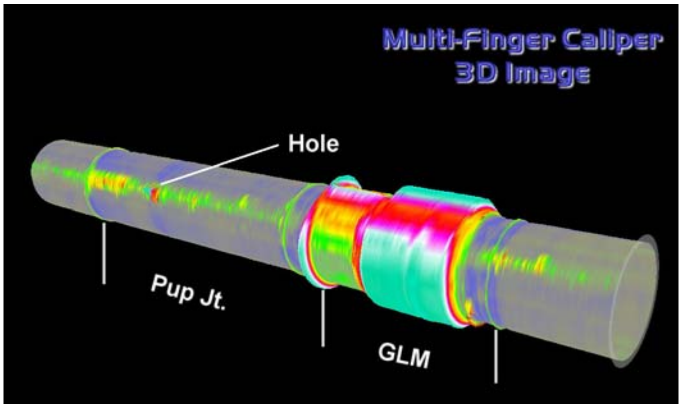

Figure 11. Caliper Survey showing hole in pup joint below GLM.

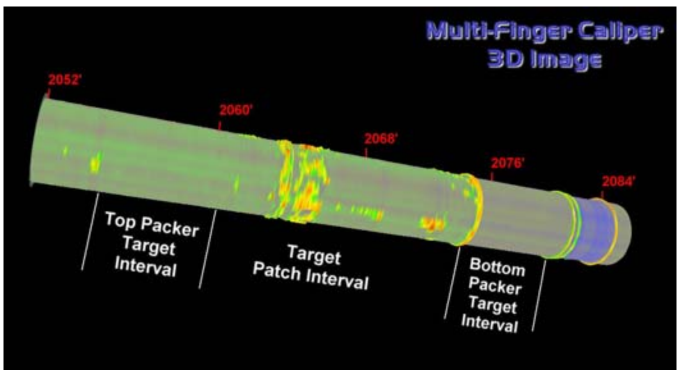

Figure 12. Caliper survey showing target patch location.

Candidate selection. Potential patch candidates are evaluated by combining LDL and caliper information. Job reports from previous wellwork operations (including gaslifting) can give clues to help with leak identification. It is important to determine if the tubing condition warrants setting a patch. It is desirable to set the packer elements and slips where the tubing has less than 20% wall loss, to ensure a good seal. Ideal candidates include wells with areas of corrosion that can be straddled by a patch which is no longer than 30-35' and have fairly good condition tubing below the proposed patch. After determining that the tubing can be repaired with a conventional patch, risk-weighted economics are performed.

Patch design considerations. Patch type, length, future operations, and retrieval must be considered prior to setting a patch.

Retrievable versus permanent. The two types of permanent patches that have been used at Prudhoe Bay are those with metal-to-metal seals and "soft set" which have an elastomer seal to back up the metal-to-metal seal. Metal-to-metal patches are the least expensive patch type. A "soft set" seal may be required if the tubing surface is non-uniform a

Retrievable patches cost more and have a smaller internal diameter, but can be pulled to allow perforating with larger guns, gaslifting below the patch, and CT drilling.

Patch retrieval. Retrievable patches can usually be retrieved with slickline or braided line using conventional fishing tools, weight bar, oil jars, and spang jars. Patch retrieval has not generally been a problem at Prudhoe Bay although often braided line is required. Rarely, CT has been used. Often the patch elements are stripped off at nipple profiles and other restrictions and must be fished out separately. It is important to allow a recommended minimum "element relaxing time" of approximately 45 minutes prior to starting out of the hole after the patch has been released. Pumping cold fluid to shrink the elements has also been used occasionally with success. Fishing neck erosion and corrosion (Figure 13) can occur. requiring the need to set a releasable spear for fishing, however, generally fishing operations are successful.

Figure 13. Corroded tubing patches

Patch Choice. Several vendors' permanent and retrievable patches have been used successfully. Packer choice should be based on specifications required (such as ID, OD, temperature, and pressure rating) and if available, historical reliability and retrievability in the geographical area. Packer pressure rating is reduced when packers are set in a straddle configuration. Historically, single set patches have been much more successful and are used when possible.

Length. Once the decision has been made to run a patch, a thorough analysis of the LDL and the caliper log is completed to refine the packer setting depths and length. The packers should be set in the best tubing possible and should be kept as short as possible. When rerunning a patch, it is desirable to straddle the area where the first patch slips were set. There is also evidence that corrosion and erosion occur at higher rates immediately above the patch, so it is advantageous to straddle the old patch, when running subsequent patches.

GLM's have short pup joints above and below the mandrel. At Prudhoe Bay, both pup joints are straddled when patching a GLM's, because the pups and associated collars are often the source of leaks.

Spacer pipe. Typically, the production engineer wants the largest spacer pipe possible to minimize ID restriction of the patch. At Prudhoe Bay, 3.5" collared jointed pipe is deployed in 5-1/2" tubing, and either 3-1/2" flush joint, or 2-7/8" collared pipe in 4-1/2" tubing. In 3-1/2" tubing, 2-3/8" spacer pipe is used.

Pre-patch operations. Prior to installing the patch, it is important for SL to run a patch dummy to approximately 200' below the lower packer setting depth to ensure tight spots are not encountered in the tubing.. The dummy patch assembly should be run in the hole at the same speed the patch will be run (typically 50-100 foot per minute). If the patch dummy run is made at faster speeds, the SL toolstring may sit down when going through tight spots, closing the spangs. This can allow the patch dummy to "fall through" tight spots unnoticed. EL will not have this same capability, and the patch may get stuck.

The wellbore should be free of debris. If the caliper indicates tubing buildup, the well should be brushed, scraped, or acidized so a better patch seal can be obtained. String shot has occasionally been used prior to patch setting operations to ensure an optimum seal. Since 1986, five patches have become stuck due to tight spots which were not noted in the pre-patch slickline drift.

Future studies. A significant amount of data was collected for this study and additional analysis is planned. Most importantly, historical data will be analyzed to determine if initial success rate, can be increased. This work will focus on improving pre-patch diagnostics to eliminate 2nd holes and preventing mechanical issues that result in patches that immediately fail.

Conclusions

1. Over 263 permanent and retrievable tubing patches have been set in wells at Prudhoe Bay with an overall 70% success rate.
2. Gaslift operations are the main failure mechanism for wells repaired with patches.
3. The two main root causes for patches that fail immediately are patch leaks and 2nd leaks detected after the patch has been set.
4. Patch lifetime can exceed 14 years and is highly dependent on wellbore conditions.
5. Thorough pre-patch diagnostics, including the use of 3D viewing software for digital multi-armed tubing calipers, can increase patch success rate.

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Acknowledgments

The authors thank the management of BP Exploration and our Prudhoe Bay partners for permission to publish this work. The opinions stated here and the techniques and/or conclusions are those of the author(s) and are not necessarily shared by Prudhoe Bay Unit Working Interest Owners.

Special recognition is made to Curtis Blount, Conoco-Phillips, for his contributions to the success of the Prudhoe Bay patch program.