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Technical Conference Paper

Restoring Wellbore Integrity
a Case Study

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Abstract

The function of a storage cavern wellbore is to allow the safe injection and withdrawal of fluids and gas from the storage cavern. This function cannot be performed safely or effectively unless the integrity of the wellbore is maintained. In addition, the wellbore is the most likely point of failure in the containment of the stored fluids. The wellbore is vulnerable to failure primarily because there are so many potential leak paths that are inherent in the design of a wellbore. This paper will describe the potential leak paths in a wellbore and cite two case histories where pressure-activated sealant technology was utilized to successfully seal the leak paths.

Introduction

An underground storage cavern is essentially and simply a large vessel. The wellbore is the access point to this vessel. It is through the wellbore that fluids are injected and withdrawn. As the access point from the surface to the cavern, the wellbore is also the most vulnerable component of the cavern containment system.

A wellbore consists of the following:

- Tubing – To inject and withdraw fluids.
- Tubing Hangers – To create a seal between the tubing and casing within the wellhead.
- Casing – To isolate the tubing string from the surrounding strata.
- Casing Hangers – To create a seal between the various casing strings within the wellhead.
- Cement – To create a barrier against fluids migrating between the surrounding strata and the casing.
- Packers –To prevent the flow of fluids to the surface between the tubing and casing.
- Downhole Safety Systems – To shut-in flow up the tubing in the event of a catastrophic failure of the containment at the surface.
- Wellhead Valves – To control the flow of fluids from the wellbore.

With age, the integrity of all wellbores will deteriorate. A failure in any one of these components or any activity that compromises the integrity of the wellbore system can result in an uncontrolled flow to the surface. If left uncontrolled, flow up the wellbore represents an ongoing safety hazard and can cause serious or immediate harm or damage to human life and property.[i]

A significant flow of high-pressure fluids to a low-pressure strata results in an underground blowout. A significant flow of high-pressure fluids to the surface results in irreducible casing pressure at the wellhead and the potential for catastrophic failure of wellbore integrity. The worst case consequences of an uncontrolled flow to the surface were discussed at SMRI's Spring 2005 Meeting by Charles Chabannes in his description of the Moss Bluff Cavern Incident.

With over 400 storage facilities and 19,000 injection/withdrawal and observation wells, some fraction of those wells may exhibit uncontrolled flow to the surface. This paper will outline a case study of a leak sealant operations on a cavern storage well that resulted in the re-establishment of wellbore integrity.

Wellbore Leaks – The Problems

Over the life of an oil or gas well, it is possible for a leak to occur in most of the components of the well system. Connection leaks are found in pipelines, umbilical lines, hydraulic lines, control systems, flow hubs, tubing, casing and similar components. Dynamic seal leaks are experienced in SCSSVs, actuators, valves, control systems and similar components. Static seal leaks are seen in pipelines, wellheads, packers, hangers and similar components. Damage to components during installation can result in a variety of leak sources.

Analyzing and repairing leaking well systems is complicated by the lack of access to downhole equipment, the uniqueness of many of the installations and the logistics of delivering a repair solution. Once installed, you can't put you hands on the downhole hardware. The only means of analyzing leaks is through remote diagnostics-often limited to simply taking pressure readings. Further, many of the well systems have little service history, so there is no historical data to assist in diagnostics. Even if the problem is identified, the question is how do you deliver a solution? What are the regulatory issues raised by the leak?

As an engineer evaluates solutions to the problems created by leaks, a first step is an analysis of the problem followed by a review of the options. Traditionally, the solution has been a mechanical workover of the well including replacement of well components. Considerations include availability of a rig, service company availability and coordination, replacement equipment, the cost of all of these factors and the impact of lost production.

What is needed is a method of repairing leaking wellbore equipment and control systems in-situ without the need of mobilizing expensive and risky intervention operations.

Cost-Effective Alternative

As an alternative to a rig workover, a safe, cost-effective sealant process has been developed that is specifically designed to seal leaks in wells and severe environment hydraulic systems.

Pressure Activated Sealant.

The sealant is unique in that a pressure drop through a leak site causes the sealant fluid to polymerize into a flexible solid seal only at the leak site. The sealant reaction is analogous to blood coagulating at a cut. The sealants remain fluid until the sealant is released through a leak site. Only at the point of differential pressure, through the leak site, will the sealant reaction occur. The monomers and polymers in the formula are cross-linked by the polymerizing chemicals. As the reaction proceeds, the polymerized sealant plates out on the edges of the leak site and, simultaneously links across the leak site to seal the leak. The resulting seal is a flexible bond across the leak. The remainder of the sealant will remain fluid and will not clog the well systems.

Common Wellbore Failures.

The pressure-activated sealant was originally developed to seal leaks in tubing, casing and other wellbore equipment. The sealant technology has been used in over 1200 operations to cure leaks in the tubing, casing and other wellbore equipment as follows:

- Dynamic Seal Leaks
    - Safety Valves
    - Sliding Sleeves
    - Seal Units
- Static Seal Leaks
    - Wellheads
    - Hangers
    - Packers
- Connection Leaks
    - Tubing
    - Casing
    - Control Lines
- Microannulus Leaks
    - Cement Composition
    - Stress-Thermal/Hydraulic
    - Compaction

Restoration of Mechanical Integrity – Butane Storage Facility

A good example of the benefits of the pressure-activated sealant solution over a traditional rig repair can be seen in an operation performed on a well used to access butane stored in a salt cavern.

Well Background. The subject well is an access well for a butane storage cavern. A wellbore schematic for subject well is shown in Figure 2. A mechanical integrity test was performed in early 2003 and, based on the results of the MIT, it was determined that the well had a leak in a washout area behind the 8 5/8" casing shoe. The washout extended from the shoe to a depth of 1283 feet. The calculated leak rate was 2,331 barrels of nitrogen per year (0.8 liters per minute). Brine weight was 9.9 pounds per gallon.

Considering the condition of the well, a sealant operation was proposed to be performed in conjunction with a conventional workover to inspect the cemented casing, remove the hanger string, conduct a cavern survey and install a refurbished wellhead. At the completion of the entire program, a second mechanical integrity test was performed to determine the results of the entire program.

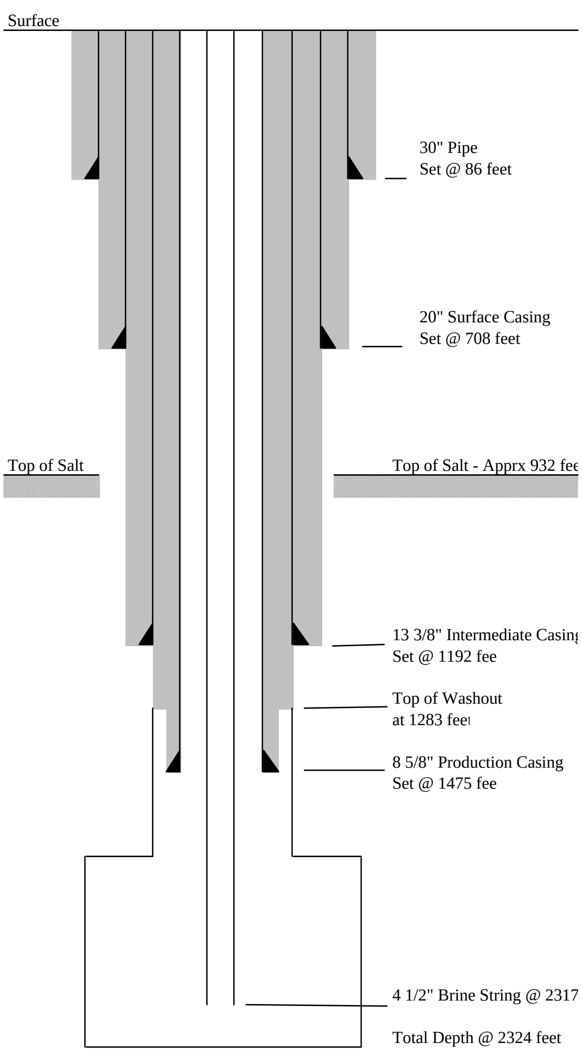

Figure 2 –
Pre-Operation Wellbore Schematic

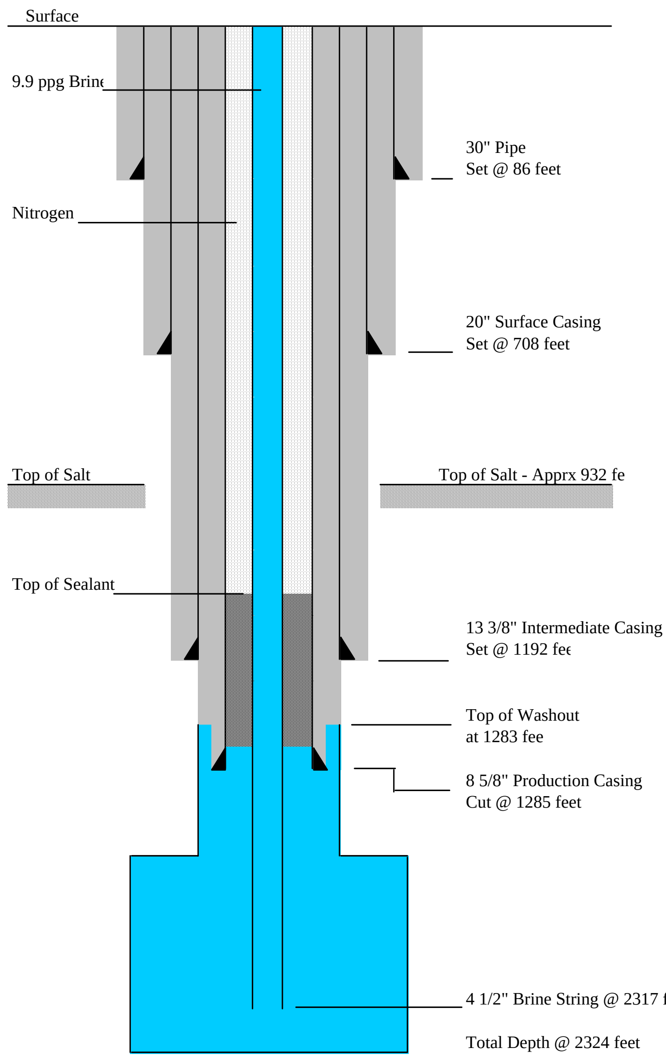

Figure 3 –
Operational Wellbore Schematic

<u>Workover Procedure – Cutting Casing.</u> As originally installed, the production casing was set at a depth of 1475 feet. Over time, a washout had occurred behind the production casing to a depth of 1280 feet. Prior to the sealant treatment, a workover was performed to perforate and cut the casing at 1285 feet (just below the washout location).

Sealant Treatment Procedure. The sealant treatment procedure as implemented was as follows:

1. Verify weight of sealant at 7.7 pounds per gallon so as to float on top of brine.
2. Verify pressures and interface location:
   - 2.1. Production Annulus: 1004 PSI
   - 2.2. Production Tubing: 1004 PSI
   - 2.3. Surface Casing: 0 PSI
   - 2.4. Nitrogen/Brine Interface: 1278 Feet
3. Rig up triplex pump to inject sealant into the annulus.
4. Inject sealant into the annulus.
5. Wait for sealant to fall to brine interface
6. Run electric line density log to determine sealant/nitrogen interface.
7. Inject additional sealant to establish final sealant/nitrogen interface at 1250 feet.
8. Run electric line density log to determine sealant/nitrogen interface.
   - 8.1. Final sealant/nitrogen interface: 1250 Feet
9. Increase nitrogen pressure to push sealant around casing shoe.
10. Increase brine pressure to push sealant up into the annulus leak site.
11. Regulate pressure to maintain seal within leak site.
12. After cure time perform mechanical integrity test.

Mechanical Integrity Test. After the sealant had cured, the nitrogen pressure was increased to move the sealant nitrogen interface below the cemented production casing shoe to a depth of 1320 feet. Once the pressures stabilized, the following parameters were recorded:

1. Nitrogen pressure in the annulus.
2. Brine pressure at the wellhead.
3. Nitrogen/Brine interface level.

The test results are summarized in Figure 5.

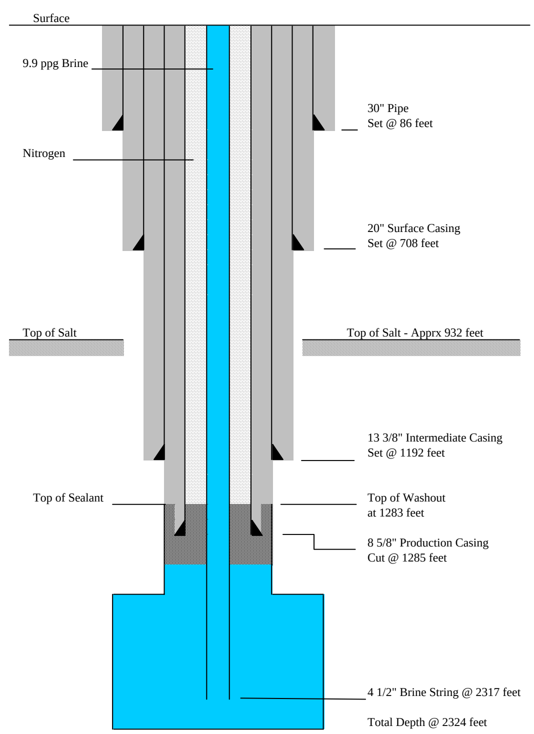

Figure 5 – MIT Summary

	TEST START	*TEST END*	*CHANGE*
Date	7/7/05	7/8/05	
Time	1215	1231	24.25 Hrs
Wellhead Brine Pressure (psig)	309.83	310.38	0.55 Psi
Wellhead Nitrogen Pressure (psig)	956.52	956.76	0.24 Psi
Nitrogen/Seal-Tite Interface Depth (ft)	1320.0	1319.5	0.50’
Average Wellbore Temperature (°F)	90.02	89.47	-0.55 °F
Test Period - Calculated Leak Rate (bbls)		-0.00159	bbls
Annual Calculated Leak Rate (bbls/yr)		-0.57	bbls/yr
Minimum Detectable Leak Rate (bbls/yr)		23.67	bbls/yr

Conclusion. As evidenced by the Mechanical Integrity Test results, the integrity of the wellbore was re-established by sealing the leak occurring up the annulus behind the production casing.

Casing Leak

Well Background. A production well was experiencing a leak from the production casing to an outer annulus. To evaluate the leak, sea water was pumped into both inner and outer annuli, the production casing was pressurized and leak rates at different pressures were recorded. Based on the diagnostics, the leak rates were as follows:

Pressure – Production Casing	**Leak Rate**
500 psi	400 ml/min
750 psi	500 ml/min
1000 psi	800 ml/min

Based on diagnostics, the leak appeared to be a connection leak in a cross-over at a depth of 1180 feet.

Sealant Treatment Procedure. The sealant treatment procedure as implemented was as follows:

1. Vent outer annulus to storage tank.
2. Inject sealant into production casing annulus at low pressure displacing the annular fluid (sea water) through the leak site and into the outer annulus.
3. Follow sealant with hydraulic fluid to displace sealant to leak site.
4. When sealant is calculated to have reached leak site, increase injection pressure to 1000 psi.
5. Inject oil into production annulus at 1000 psi and take returns from outer annulus.
6. Increase pressure to 1200 psi for two hours.
7. After two hours, no returns evidenced from outer annulus. Injection rate has decreased significantly.
8. Increase pressure to 1500 psi. After one hour, no returns on outer annulus and no further injection of hydraulic fluid. Pressure stable at 1500 psi.
9. Increase pressure on production annulus to 2200 psi, shut-in and monitor overnight. No returns on outer annulus and no further injection of hydraulic fluid.

Conclusion. After the sealant treatment the well was returned to production with no pressure on the production annulus or outer annulus.

Risk / Economic Benefits

In the final analysis, what actions should be taken to address the problem of leaks in wellbores is a function of the benefits of maintaining a well with a leak versus the costs and risks of attempting to eliminate the leak.

Risk Benefits.

A major impediment to curing leaks is that the risks associated with curing the problem may be greater than the risks of ignoring the problem. A conventional rig workover is a risky operation. In contrast, the described sealant process can be performed using only two technicians and very little equipment. No rig is needed. Thus, wellbore leaks can be eliminated and the risks of injury to personnel or damage to equipment and the environment are reduced.

Economic Benefits.

Typical expenditures for downhole leak workovers on similar wells have been in the range of \$500,000 to \$1,500,000. Using the described pressure-activated sealant technology, the total cost is approximately \$45,000 - roughly a 90% reduction.

Conclusions

Based on the described laboratory testing and field sealant operations, the use of a pressure-activated sealant technology to seal wellbore leaks and restore wellbore integrity is a safe and cost-effective alternative to a conventional rig workover. The benefits of the sealant technology significantly lower the cost/benefit threshold of maintaining wellbore integrity.

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[i] Proposed Rules, Federal Register, November 9, 2001