Well Integrity: The Foundation of Everything We Do.

a. Design Best Practices
b. Well Failures and Learnings
c. Well Integrity Testing

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Sand Antonio, TX.

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My first Engineering boss passed this on to me...

• You cannot build a skyscraper on the foundation of an outhouse.

• The foundation we build upon is well integrity.
Well Integrity Management

• Well Integrity is the application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of the well; and the preservation of the formation from outside influences that would have an adverse effect on its capacity to produce. (Well Integrity Management – GOM Dave Porter)
Introduction – what will we cover?

• Design – We can only improve when we learn from the mistakes:
  • Best Practices – Do it right the first time => less problems later.
  • Critical Injection Points – What are typical failure points?
  • Warning Flags – For some failures, you can see them coming!

• Well Failures and how we learn from them:
  • Sources of leaks – are 95% of leaks coming from <5% of places?
  • Age vs. Era – Old doesn’t mean bad if it was done the right way first!
  • Barrier failure vs. Integrity Failure – A tremendous difference!

• Testing and (The Culture of Maintenance):
  • Everyone wants to build, but nobody wants to maintain.
  • A culture of maintenance can only exist in a top=>down driven program.
  • This is where Key Performance Indicators (KPIs) can help
General Well Design Observations

• Wells are **designed** from inside out & bottom to top.
• Wells are **built** from outside in and from top to bottom.
• The formation and produced fluids have the final word in what works & doesn’t.
• Wells are built with multiple barriers to provide isolation between well fluids and environment.
• When a barrier fails, a leak can only form when 1.) a movable fluid exists, 2.) a flow path is created and 3.) a differential pressure exists toward the outside.
Multiple Barriers? Unusual?

• Barriers in a modern car in a front-end crash:
  1. Sacrificial crush zones ahead of the passengers.
  2. Collapsible steering wheel.
  3. Air-bags
  4. Seat belt/shoulder harness

• Avoidance
  • Road design – shoulders and dividers
  • Anti-lock disk brakes
  • Fast response power steering
  • Drivers training/experience
  • Warning systems – approach
  • Autobraking
Well Design:

1. Tubing
2. Production Liner
3. Production Casing
4. Surface Casing
5. Conductor Pipe

Details and Considerations:

1. Max press during production.
2. Max pressure during shut-in.
3. Max pressure during frac.
4. Packer fluid density & height.
5. Changes in well use? Gas lift source in the “A” annulus instead of packer fluid?
6. Effect of leaks
7. Annular pressure at start-up
Casing Design Intent

• A well is actually designed from the inside out and from the bottom to the top.

• “A” annulus - tubing will collapse before casing bursts (designed to fail internally and prevent leaks or spills).

• “B” annulus – production casing will collapse before surface casing will burst (same leak protection intent).

• “C” annulus – usually cemented up, but watch any sealed area.
Sequential Barriers in a Completed Well

Surface: Two barriers are typical.Leaks are easy to spot and fix.

Shallow Depth: Two to four barriers depending on well type, pressure, presence of protected resources (waters) and corrosion potential.

Mid Depth: Two barriers typical, with added protection near corrosive brines. Cement overlaps between casing stings and liners. Special composition cements considered when CO2 or H2S is an issue.

Deep: One to two barriers with open hole completions used in some instances. Tubing and exposed casing at depth may be of specialized alloy if required to meet corrosion potential.
Barrier Failure or Well Integrity Failure

- **Single Barrier Failure** => No Leak Path? => No Well Integrity Failure
- **Unless All Barriers Fail, A Leak Will Not Happen**

Wells are Designed with Multiple Barriers. Number of Barriers Depends on the Hazard Level.

<table>
<thead>
<tr>
<th>ZONE</th>
<th>Hazard to Ground Water If Well Integrity Is Lost</th>
<th>Typical Number of Barriers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Above Surface</td>
<td>Low</td>
<td>1 to 2</td>
</tr>
<tr>
<td>Fresh Water</td>
<td>Low to Moderate</td>
<td>2 to 4</td>
</tr>
<tr>
<td>Mid Depth</td>
<td>Very Low</td>
<td>1 to 2</td>
</tr>
<tr>
<td>Deep</td>
<td>Lowest</td>
<td>1</td>
</tr>
</tbody>
</table>
Well Types

• Vertical or Horizontal
• Oil
• Gas
• HPHT
• Injection
• Disposal
• Acid Gas and other corrosive producers
• Impact of repurposing a well type
Well Use Influence

Barrier type, Number and Construction Method Vary with Well Type.
Well Construction – well integrity is the thread that stitches these activities together.

- Drilling
- Casing
- Cementing
- Downhole (DH) equipment
- Operations Outline
- Abandonment
To Begin – The Ideal Well...

• **Doesn’t Exist.**

• Why?

• All wells should be designed to meet the safety, environmental, and economic goals of a project whose purpose is to produce oil and gas from miles away.

• Mother Nature is anything but consistent.
Wells are drilled in stages with casing strings run and cemented to control formation pressures, to seal off unwanted fluids and to isolate sections of the formation.

16 to 17” Drilled Hole (40.6 to 43.2 cm)

13-3/8” Casing (34 cm)
While the steel casing provides the initial strength, the cement provides the seal between zones. It also supports and protects the casing.

Cement circulated to surface – some fallback is normal.
The deeper parts of the well are drilled and the deeper casing string (the production casing in this example) is run through the upper strings (the surface casing) after the upper casing is cemented and tested to the maximum pressures expected in drilling the lower sections.
At the surface the small amount of cement fallback due to gravity, leakoff and other factors may leave a few feet with poor cement coverage.

Regardless of intent – cement is never perfect. And – it only extends to ground level.
9-5/8” (24.4 cm) cemented, but open area left below 13-3/8” (34.0 cm) overlap.

If the uncemented section is in a permeable formation, any annular pressure in the outside annulus can bleed off to the formation.
If the open lap is cemented sealed with cement or covered with mud or other fluid loss control material, the ability is lost to bleed off the pressure and the outside annulus becomes a sealed pressure chamber.

Consequences of sealing the annulus at the bottom.
The Two Barrier Rule

• Barriers may be the same in some instances.
• Both must be capable of controlling the full well pressure.
• Many barriers are conditional – may need back-up.
Wellhead Cutaway

Multiple barriers and methods of creating other barriers.
Above and Below: Gate valve seals and bar – common in wellheads.

If a valve requires greasing to pass a pressure test, does the maintenance schedule rigid?

Note: open a valve fully (count the turns) and close it fully (also count turns) – throttling flow with a valve will lead to erosion.

Right top: plug valve – common in surface treating “iron”

Right center: dowhole flapper valve.

Right lower: butterfly valve common on tanks.
<table>
<thead>
<tr>
<th>Comparison Considerations</th>
<th>Plug &amp; Perf - Cemented</th>
<th>O.H. - Packer &amp; Sleeve</th>
<th>Csg Sleeve - Cemented</th>
<th>CT Op. Sleeve-Cemented</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advantage</td>
<td>Less expensive, slower</td>
<td>Higher cost, faster</td>
<td>Moderate cost, faster</td>
<td>Higher cost, mod. speed</td>
</tr>
<tr>
<td></td>
<td>Unlimited stages</td>
<td>Stage # usually limited</td>
<td>Stage # limit w/o PNP</td>
<td>Stage # limit w/o PNP</td>
</tr>
<tr>
<td></td>
<td>Refrac easier</td>
<td>Refrac more difficult</td>
<td>Refrac easier (PNP)</td>
<td>Refrac easier (PNP)</td>
</tr>
<tr>
<td></td>
<td>Csg landing not critical</td>
<td>Landing depth critical</td>
<td>Landing depth critical</td>
<td>Landing depth critical</td>
</tr>
<tr>
<td></td>
<td>Frac screensouts rare</td>
<td>Screenouts less rare</td>
<td>Screenouts less rare</td>
<td>Screenouts less rare</td>
</tr>
<tr>
<td></td>
<td>High entry pts /frac stage</td>
<td>Low entry pt/frac stage</td>
<td>Low entry pt/frac stage</td>
<td>Low entry pt/frac stage</td>
</tr>
<tr>
<td></td>
<td>Csg-to-frac time short</td>
<td>Packer set days to weeks</td>
<td>Packer set days to weeks</td>
<td>Csg-to-frac time short</td>
</tr>
<tr>
<td></td>
<td>High frac rate possible</td>
<td>Frac rates limited</td>
<td>High frac rate possible</td>
<td>Frac rates limited</td>
</tr>
<tr>
<td></td>
<td>Cleanout easy (w/ CT)</td>
<td>Cleanout difficult</td>
<td>Cleanout easy (W/CT)</td>
<td>Cleanout easy (W/CT)</td>
</tr>
<tr>
<td></td>
<td>Prop placement ?</td>
<td>Prop placement controlled</td>
<td>Prop placement better</td>
<td>Prop placement best</td>
</tr>
<tr>
<td></td>
<td>Gauge hole not critical</td>
<td>Gauge hole critical</td>
<td>Gauge hole not critical</td>
<td>Gauge hole not critical</td>
</tr>
<tr>
<td></td>
<td>Offers high degree of reliability at low cost.</td>
<td>Ball drop systems most common HMF in Canada</td>
<td></td>
<td>Offers closable frac sleeves.</td>
</tr>
</tbody>
</table>
Potential For Pollution is Reduced by Application of Technology. We learn from our failures............

<table>
<thead>
<tr>
<th>Time Era</th>
<th>Operation Norms - Level of Technology</th>
<th>Era Potential For Pollution</th>
</tr>
</thead>
<tbody>
<tr>
<td>1830 to 1916</td>
<td>Cable Tool drilling, no cement, wells vented</td>
<td>High</td>
</tr>
<tr>
<td>1916 to 1970</td>
<td>Cementing isolation steadily improving.</td>
<td>Moderate</td>
</tr>
<tr>
<td>1930’s</td>
<td>Rotary drilling replace cable tool, BOPs</td>
<td>Moderate &amp; Lower</td>
</tr>
<tr>
<td>1952</td>
<td>Fracs reduce # wells. Better pipe &amp; cement</td>
<td>Lower from Frac aspects</td>
</tr>
<tr>
<td>1960</td>
<td>Gas tight couplings and joint make up</td>
<td>Moderate</td>
</tr>
<tr>
<td>1970</td>
<td>Cement improving, Horizontal Wells introduced</td>
<td>Lower</td>
</tr>
<tr>
<td>1988</td>
<td>Multi-frac, horizontal wells, pad drilling reducing environmental land footprint 90%</td>
<td>Lower</td>
</tr>
<tr>
<td>2005</td>
<td>Well integrity assessment, premium couplings, adding barriers &amp; cementing full strings.</td>
<td>Lower after 2008 to 2010 *(STRONGER Reg Review)</td>
</tr>
<tr>
<td>2008</td>
<td>Chemical toxicity &amp; endocrine disruptors sharply reduced. Real time well integrity needs studied - early warning &amp; avoidance.</td>
<td>Lowest yet, most states caught up with design and inspection requirements.</td>
</tr>
</tbody>
</table>

Cement was first used to isolate wells in 1903. Over 100,000 wells drilled before 1903, most in Northeast US.
What is the value of technology?

Comparison to the Airlines

Causes of Fatal Air Crashes (%) by Decade

Why did weather crashes drop over time?

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Pilot Error</td>
<td>57%</td>
<td>56%</td>
<td>43%</td>
<td>46%</td>
<td>51%</td>
<td>54%</td>
</tr>
<tr>
<td>Other Human Error</td>
<td>2%</td>
<td>9%</td>
<td>9%</td>
<td>6%</td>
<td>9%</td>
<td>5%</td>
</tr>
<tr>
<td>Weather</td>
<td>16%</td>
<td>9%</td>
<td>9%</td>
<td>6%</td>
<td>9%</td>
<td>5%</td>
</tr>
<tr>
<td>Mechanical Failure</td>
<td>21%</td>
<td>19%</td>
<td>20%</td>
<td>20%</td>
<td>18%</td>
<td>24%</td>
</tr>
<tr>
<td>Sabotage</td>
<td>5%</td>
<td>5%</td>
<td>13%</td>
<td>13%</td>
<td>11%</td>
<td>9%</td>
</tr>
<tr>
<td>Other Cause</td>
<td>0</td>
<td>2%</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
<td>0</td>
</tr>
</tbody>
</table>
Why?

• Weather crashes decline because measurement and prediction methods improved.

• The culture of inspection and maintenance is also important:
  
  Odds of being killed on a single scheduled airline flight:
  
  • 1 in 29 million for the top 30 airlines,
  • 1 in 1.7 million for the 25 worst airlines;

So, **some operators just do a much better job**

One indicator of a Culture of Maintenance is production performance =>
minimum breakdowns, minimum spills, short cycle time to return to production, safe operation performance, and well-trained people.
Metrics, Alarms, Failures & Improvements

• Key Performance Indicators or KPI’s – a quick view......
• Star ★ - areas of importance for inspection
• “Red Flags” – early signs that something is amiss.
• Risk - always present – how to manage it.
• Failure tolerance - ? – why it is needed.
**General Well & Integrity Failure Causes & Estimated Qualitative Failure Frequency by Well Types**

<table>
<thead>
<tr>
<th>Well Type</th>
<th>Typical Failure</th>
<th>Common Cause</th>
<th>Failure Rank Expected</th>
<th>Mitigation Methods</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fireflood</td>
<td>Pipe burn-off, collapse, breaks, severe corrosion</td>
<td>Extremely hot gasses</td>
<td>High rate of pipe failure but low incidence of fire flood use.</td>
<td>Few</td>
</tr>
<tr>
<td>Steam Flood</td>
<td>Connection failure, cement bond failure</td>
<td>Pipe expansion and coupling load cycling</td>
<td>High rate of failure but only localized steam flood use</td>
<td>Designs that allow for cyclic expansion and contraction.</td>
</tr>
<tr>
<td>HPHT (high Press &amp; Temp)</td>
<td>High pressure related pipe failures</td>
<td>Collapse &amp; burst common, erosion failures possible</td>
<td>Moderate to low</td>
<td>HPHT design philosophy, controlled drawdown, fit-for-purpose equipment</td>
</tr>
<tr>
<td>High Compaction Stress</td>
<td>Pipe collapse and shear failure</td>
<td>Subsidence, formation flow (salt)</td>
<td>Moderate in a few geographical locations, rare overall.</td>
<td>Very heavy wall pipe, concentric strings with cement fill.</td>
</tr>
<tr>
<td>Producer in Corrosive Environments</td>
<td>Interior or exterior corrosion</td>
<td>O₂ leaks, CO₂, H₂S, Low pH waters, MIC, microbial induced corrosion hydrogen embrittlement</td>
<td>Moderate - Depends on maintenance – can be the most common damage in industry &amp; most expensive</td>
<td>Eliminate O₂ entry, Corrosion resistant alloys (CRA), corrosion inhibitors – problems sharply reduced with regular maintenance</td>
</tr>
<tr>
<td>High Pressure Injection</td>
<td>Leaks &amp; corrosion, some seismic disturbance potential</td>
<td>Thread leaks, Continuous HP operation &amp; large flow volumes of saline water</td>
<td>Low - Small saltwater leaks. Seismic noted in about 0.01% of UIC Class II wells</td>
<td>Lower if wells properly designed, sighted &amp; operated. Routine pressure testing required.</td>
</tr>
<tr>
<td>(disposal and re-injection wells)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fracturing Old Well</td>
<td>Pipe burst or collapse</td>
<td>Low side corrosion in casing, loss of pipe strength, seep leaks</td>
<td>Moderate risk but infrequent fracturing of old wells lowers threat potential.</td>
<td>Pressure testing required and drift test recommended before running tools or equipment.</td>
</tr>
<tr>
<td>Fracturing New Well</td>
<td>Pipe burst or fracture height growth.</td>
<td>Short duration pressure surge</td>
<td>Very low risk. Frequency of burst failures in new pipe at/or below rated pressure about 0.0005%</td>
<td>Pipe and coupling inspection, adequate cement fill and limit max surface pressure.</td>
</tr>
<tr>
<td>Producing Wells</td>
<td>Leaks &amp; Corrosion</td>
<td>Well pressure drops steadily in producing wells due to depletion and thus the risk is low.</td>
<td>Very low risk</td>
<td>Wider use of gas-tight threaded connections and metal-to-metal would lower risks further</td>
</tr>
</tbody>
</table>
Quality and Inspections.......  
Two Quotes to Remember:

• “Inspection does not improve the quality, nor guarantee quality. Inspection is too late. The quality, good or bad, is already in the product. As Harold F. Dodge said, “You can not inspect quality into a product.” - W. Edwards Deeming

• Quality Is not an act, it is a habit. - Aristotle
Visual Inspections

• You see less than 1% of the well from surface.

• What you can see can suggest a lot about the 99% you cannot see.

• But, to confirm it requires testing........
Do not go **just** by appearances....... 

OR 

Both were good, solid wells.
Can we afford to fail?

“Failure is central to engineering. Every single calculation that an engineer makes is a failure calculation. Successful engineering is all about understanding how things break or fail.”

– Henry Petroski
Risk = Frequency of Occurrence vs. Impact

Risk exists in every action.

What is operationally safe?

Occurrence & impact create a threat level that we can understand & accept or reject based on what we believe: hopefully on assessment of facts.

SPE 166142, Barrier vs. Well Failure, King
The Element of Time – always a factor. When does the warranty run out.....?

Curves such as this describe continuous load / constant use assumptions.
But all operators are not the same.

The difference that a Culture of Maintenance can make is staggering.
What is a Culture of Maintenance?

• Maintenance - the set of actions that minimize deterioration of an asset, and, in some cases, the infrastructure of a development.

• Maintenance extends an asset’s working life, ensuring that it can continue to operate to a design level.

• Culture is acceptance of the need to exercise the required maintenance. It must be firmly rooted in the business plan of the company.
Failures in Age and Era

• Era of construction, the type of well, the location and the practices of that era are often more important than just age.

• The target of exploration is another factor
  • HPHT Wells,
  • Coal bed methane,
  • Tight Gas,
  • Sand Control wells,
  • Deep Water,
  • Shales.

For every new oil and gas source, the technology of well construction and stimulation must be adapted to fit the specifics of the formation.
Pollution potential & risk are functions of technology & maintenance in practice over time.

=> Old well behavior doesn’t necessarily describe new well behavior.

1905 vs. 2015

9 hp., 25 mph and every practical safety device known to man in 1905.

640 hp., 200 mph and every practical safety device known to man in 2015.
The increase in casing collapses in 1990’s, is probably due to increased drilling, more deep drilling, and more deep-water operations.
Cars (and drivers?) getting safer.

Do Oil & Gas Wells Leak?

• Although it is a common accusation, the great majority of wells do not leak.

• If enough protection barriers fail, a most common subsurface leak type is for liquids (overwhelmingly salt water) to leak into the well.

• There are sharp differences between a barrier failure in a multiple barrier well design and an outright well integrity failure that could lead to pollution of water or air.
Barrier and Integrity Failures Study from a population of 330,000 US wells

Things That Keep actual Well Integrity Failures Very Low

1. Pressure inside the wells is lower than outside in hydrostatic of water table.
2. Modern wells are built with multiple barriers.
3. Cement reinforces and protects the casing.
4. Regulations are tighter now than a few years ago.
5. Multi-Fractured horizontal wells replace 5 to 10 vertical wells in many developments. Less pollution potential with fewer water table penetrations.


Proven Another Way - % of Produced Fluids Leaked

<table>
<thead>
<tr>
<th>Area</th>
<th>Number of Wells</th>
<th>Type of Wells</th>
<th>Barrier Failure Freq. Range (w/ containment)</th>
<th>Integrity Failure (leak path – in or out)</th>
</tr>
</thead>
<tbody>
<tr>
<td>US Gulf of Mexico</td>
<td>11,498 (3542 active)</td>
<td>Platform based wells</td>
<td>30% overall first annulus SCP 50% of cases. 90% of strings w/ SCP have less than 1000 psi. 10% are more serious form of SCP (Wojtanowicz, 2012)</td>
<td>0.01% to 0.05% of wells leaked</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.00005% to 0.0003% of prod oil spilled 1980 thru 2009.</td>
<td></td>
</tr>
<tr>
<td>US Gulf of Mexico</td>
<td>4,099</td>
<td>Shoe test failures required repair</td>
<td>12% to 18% require cement repair to continue drilling</td>
<td>0 (all repaired before resuming drilling)</td>
</tr>
<tr>
<td>Norway</td>
<td>406</td>
<td>offshore</td>
<td>18%</td>
<td>0</td>
</tr>
<tr>
<td>GOM/Trinidad</td>
<td>2,120</td>
<td>Sand Control</td>
<td>0.5 to 1%</td>
<td>0% subterranean ~0.0001% via surface erosion potential</td>
</tr>
<tr>
<td>Matagorda Island 623</td>
<td>17</td>
<td>Compaction failures; casing shear &amp; sand fail</td>
<td>80% to 100% - the high number is due to high pressure and formation compaction.</td>
<td>Wells routinely shut-in and repaired prior to restart.</td>
</tr>
<tr>
<td>Sumatera</td>
<td>175</td>
<td>without maintenance</td>
<td>43%</td>
<td>1 to 4%</td>
</tr>
</tbody>
</table>
What are some more common groundwater pollutants?

- UST – Gas & Diesel
- Septic Systems
- Landfills
- Spills
- Fertilizer
- Large Industrial Facilities
- Hazardous Waste Sites
- Animal Feedlots
- Pesticides
- Surface Impoundments
- Storage Tanks – surface
- Urban Runoff
- Salt Water Intrusion
- Mine Drainage
- Agriculture Chem. Facilities
- Pipelines & Sewer
- Shallow Inj. Wells (Class V)
- Salt Storage & Road Salting
- Land application of Waste
- Irrigation Practices

Underground storage tanks (UST) in neighborhood filling stations and convenience stores were made of steel until the mid 1980s. These shallow buried steel tanks corroded in groundwater and are one of the most common sources of pollution.

Oil and Gas Wells Didn’t Make the List.
What are Groundwater Pollutants Today & Where do Oil & Gas Wells Rank?

Used Texas as a Study Case.

Over a million penetrations through the 29 major & minor aquifers in Texas.

Texas is #2 in total Groundwater withdrawals with ~ 80% going to Agriculture & Municipalities.

If the water was really polluted by O&G wells, we'd see it quickly in Municipal & Ag.
Last 12 years of Pollution Reports in Texas – Top 20 Listed - TCEQ & TGPC Database

Number of New Reports Per Year

- Gasoline (from Underground Petroleum Storage Tank)
- SVOC & VOC
- Chlorinated Solvents
- TPH (Total Petro. Hydro. Non-TRC Control)
- Chloronated Mixed Materials
- unidentified metals
- All Benzene & BTEX materials
- Diesel (from Underground Petroleum Storage Tank)
- Unknown
- Toxic Metals (Sb, As, Pb, Hg, Cr, Zn, etc.)
- Waste Oil
- MTBE
- Pesticides & Herbicides
- Nitrate & Nitrite
- PCB
- PAH
- Barium
- Crude Oil (transport)
- Radioactive
- Brominated & other Halogenated

SPE 166142, Barrier vs. Well Failure, King
Producing Wells are less than 1% of total for most years.
Comparing Spills and Seeps

Various sources – data in SPE 166142
Pre-Drill water well sampling & background survey show methane to be nearly ubiquitous in water wells in this region - over 78% of water wells exhibit detectable methane.

1700 well study.
Methane Seepage from Soils

Oil & Gas Seeps are indicators of oil & gas beneath the surface

Many natural seep flows diminished as wells were drilled & produced.

Total: 4.3 Million Wells

Well Density in US & Canada

Sedimentary Basins in US & Canada

Source: IHS / HPDI

Source: NPC Report, 15 Sept 2011

Areas of possible micro and macro seeps of methane to the surface

Source: Kevenvelden 2005, Etiope & Klusman, 2002
Source of methane gas from seeps?

How much? 5 to 10 bcf/day

From Natural Seeps.
Methane Emissions – From Oil & Gas

• **Super Emitters, ~80 to 90+% of emissions in an O&G Producing Area**
  • A small number of potential offenders:
    • Gas Plants
    • Pipelines
    • Compressors

• **Macro Emitters, ~5 to 10+% of emissions**
  • A moderate number of potential emitters
    • Maintenance Operations
    • Valves
    • High bleed controllers

• **Micro Emitters, ~<5 to 10% of emissions**
  • A small number of potential emitters
    • Thread leaks
    • Low bleed controllers
Cement Every Annulus to Surface? May **NOT** be the best plan. – **SURPRISE!**

**Full Annulus Cementing?**

- Most full cement columns require a two-stage cement job – requires perforating or DV tool – may decrease well integrity.
- Careful positioning of cement top in inner annulus allows monitoring of pressure build-up or monitoring type of fluid flow if leaks are seen.
- Repair options increase when open annulus exists including down-squeezes & inner pipe removal.

- Placing end of casing in strong, low permeability formations increases isolation success.
- Placing salt water and fresh water zones behind different casing strings nearly eliminates potential for salt water intrusions behind the pipe.
Open Annulus and Open Shoe. Still a viable completion?

- Full length casing strings
- No open shoes
- Cement to surface on 2 outer strings
- Open annulus preserved on inner csg

- String & Liner Combination
- Multiple open shoes
- Cement short of surface (fallback)
- Trapped annuli

Can accidentally pressure up shallow zones.
Early Warning Signs? - Design

• Extremely long casing strings (especially with very little cement).
• Short overlaps (<200 ft)
• Open shoe wells.
• Limited cement
  • <200 ft. in overlaps
  • Gas charged formations (coal, shale, etc.) that are not covered by cement.
• Poor alloy selection.
• Connections that are not suitable for the well purpose.
• Well designs that lack flexibility to recomplete or repair.
• “Cookie-Cutter” designs in non similar environments.
• High risk well types.
Early Warning Signs? – Re-Design

• Repurposed wells.
  • Producer-to-injector – check alloys and cement
  • Conversion of primary flow wells to high pressure gas lift.
  • Deepened wells – wear in pipe and higher pressures
  • Recompleted to soft sand or soft chalks – subsidence?
Buckling Failure Points (symptoms & causes)

Causes?
Too much dog leg severity (DLS) – drilling too rapidly, Subsidence, etc.

Source: Rassenfoss, S., “Drilling Wells Ever Faster May Not Be the Measure of Success,” SPE JPT
Early Warning Signs? - Drilling

- Record time drilling
- Make-up problems
- High makeup RPM (over 20 rpm)
- No gradual torque shows
- Early leak issues at the threads
- Fast casing running (<3 sec/ft where clearances are close => Surge pressure rises sharply.)
- Casing-to-hole clearances less than ¾” (18 mm) or clearances > ~3” for smaller casing.
Early Warning Signs? - Completion

• Wells that had drilling problems.
• Non centralized wells
• Long periods of rotating drill string
• Poor cement practices.
  • Radial clearances (casing O.D. to hole diameter less than $\frac{3}{4}''$ or more than ~2”)
  • Poor chemical dispersion/flush prior to cement pumping.
  • Poor cement density control (loss of circulation)
  • Poor returns
• Wells that repeatedly failed pressure testing
Cement Specifics – Isolation Critical

Cement Application & Design Failure Issues
• Poor Design Information
• Lack of Centralization
• Low Cement Top
• Poor Cement Blending
• Poor Preflush Design
• Lack of Fluid Loss Control
• Fracture Breakout (Cement)
• Excess Water
• Lack of Pipe Movement

Post-Pumping Issues
• Gas Cut Cement
• Cement Shrinkage & Fallback
• Deterioration by $\text{SO}_4$ or $\text{CO}_2$
• Very High Temperatures
Cementing Statistics

• Primary cementing cost about 5% of well cost.
• About 15% of primary cement jobs require squeezing because a shoe test failed.
• Total cost of cementing when squeezing is required is about 17% of well cost. (12% savings in a five million dollar well is $600,000)
• Typical number of squeezes required to fix a problem in a primary cement job = 3.
• Perforating holes in pipe and squeezing can weaken the pipe and some squeeze operations are suspected of collapsing the pipe.
How Much Cement is Needed for Isolation?  
Every inch of cement is NOT required to be perfect.

Quality of cement is more important than the volume.

Isolation can only be measured with a pressure test.

Bond logs are not always best tool

- ~10% channels missed.
- Instances of false negatives & positives.

Over 10,000 psi can be held with less than 50 ft of cement, but 200 to 300 ft is routinely used.
The Best “Tool” for Evaluating Cement Quality is the Pump Chart

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Filling surface equipment w/ fresh water</td>
</tr>
<tr>
<td>2</td>
<td>Pressure test – two leaks in surface connection &amp; a successful test</td>
</tr>
<tr>
<td>3</td>
<td>Pump spacer to separate mud from cement</td>
</tr>
<tr>
<td>4</td>
<td>Constant density spacer and early batch mixed cement</td>
</tr>
<tr>
<td>5</td>
<td>Shut down to drop bottom plug &amp; switch to on-the-fly cement</td>
</tr>
<tr>
<td>6</td>
<td>Pumping cement – within density guidelines, but barely.</td>
</tr>
<tr>
<td>7</td>
<td>Cement free-fall – heavier cement pushes mud faster than pump in.</td>
</tr>
<tr>
<td>8</td>
<td>Cement density variance – was a special tail-in slurry used?</td>
</tr>
<tr>
<td>9</td>
<td>Shut-down to flush surface lines and drop the solid top plug.</td>
</tr>
<tr>
<td>10</td>
<td>Bottom plug lands, diaphragm ruptures &amp; cement into annulus.</td>
</tr>
<tr>
<td>11</td>
<td>Free-fall make up – more flow in than out - pressures equalizing</td>
</tr>
<tr>
<td>12</td>
<td>Cement lift pressure too low – check return volumes and timing.</td>
</tr>
<tr>
<td>13</td>
<td>Top plug “bumps” (lands in the shoe track) – placement complete.</td>
</tr>
<tr>
<td>14</td>
<td>Hold back pressure on casing if float valve fails. (not in this case).</td>
</tr>
</tbody>
</table>

![Diagram](image-url)
Does Perforating Shatter Cement?

- Unconfined Cement? – Yes

Multiple perforating (3 gun runs, 12 total shots) using 20 g & 23 g. DP charges, 5-1/2” casing cemented inside 8-5/8” casing. Outer 8-5/8” casing cut away for photograph.

10/9/2019

IPEC Well Integrity, George King, GEK Engineering
Early Warning Signs? - Fracturing

• Fracture jobs that sharply applied frac pressure repeatedly.
• Over-pressured fracturing (above ECD adjusted frac gradient).
• 30 or more frac stages (30 is very approximate)
• Single very long casing strings (depends on geology)
Statistics

• Primary cementing cost about 5% of well cost.
• About 15% of primary cement jobs require squeezing
• Total cost of cementing when squeezing is required is about 17% of well cost.
• Typical number of squeezes required to fix a problem in a primary cement job = 3.
Trees – Surface Control Point

Source: API 6A
Wellheads

- Lockdown Screws (LDS)
- Gaslift Valve
- S-Riser
- Bradenhead
- Flutes
- Landing Ring Assembly
- Fluted Landing Ring
- Suck Port
- Wellhead Equipment

IPEC Well Integrity, George King, GEK Engineering
P2-42 Leaking Bradenhead
08-14-02
Crack in the casing immediately below the wellhead. Probably due to a minor defect in the tubular and perhaps compounded by wellhead stress.
Flanges – look closely

Information Sources: Woodco, Joe Anders (BP-Alaska), Danny Pitts (Stress Engineering)
Stud Makeup Requirements

API specifies stud thread engagement should equal the stud diameter.

A good workmanship standard is to have a minimum of 2 threads but no more than 10 threads extending past the nut.

What do you do when the studs are short?

Before

After
Importance of a single bolt in a flange?

The wellhead is the surface pressure control point.

A leak cannot be accepted.

Because of the pressure differential from inside the well to the atmosphere, any leak will likely become a “washout” due to erosion.

There is a safety factor built into every flange, but the best approach is do it right the first time.
Early Warning Signs - Inspection?

• Poor construction methods
• Poor maintenance of surface equipment
• Leak stains
• Poor valve performance
• Valve wear – erosion
• Valves that must be repeatedly greased to pass a pressure test (most are in this group)
Not all of the problems are in the well and few are visible.

Slow flow unable to sweep sludge and biomass out of pipes

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Patrick J. Breen – Marathon)
Eagle Ford MIC

Slow flow unable to sweep sludge and biomass out of pipes

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Eagle Ford MIC

The blister is a combination of the covering and other debris from MIC attack.

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Patrick J. Breen – Marathon)
Eagle Ford MIC

Underneath, there is a characteristic, "stair step" pit.
Corrosion Failures

• Higher than about 5% (mole) CO2
• H2S and mixtures of H2S and CO2
Failures – Older Wells – Risks increase - Sometimes

Wear?

Collapse

Burst – Above cement support

Hydrogen embrittlement – high strength P-110 Coupling

SPE 179120 - Well Integrity - King & Valencia
Compaction, Subsidence & Collapse

- Removal of a load supporting element (gas/oil/water) means the formation matrix must support more load.
- Most severely affected are weak formations UCS (unconfined compressive strength) < ~2000 psi.
- As a formation shrinks – it can increase tension on the cemented casing.

Such events are rare, usually in soft sands and chalks. Particularly rare in onshore wells with hard sandstone or dolomite formations.
What Fails?

Is it related to a barrier failure or a well failure?

Is it prevented by another step such as cementing?

What should happen in a design to prevent it?

Identity of barrier failures in a Norwegian study of 406 wells with 75 reporting a barrier issue. None of the issues created pollution.
Erosion most serious in the upper couplings – just under the wellhead.
Monitoring Check - Erosional wear after Fracturing

Example of wear (by multi-arm caliper measurement) in a joint of 5-1/2” P-110 casing.

Erosion was less than 15 feet below ground level.

The swirl pattern common in these erosion occurrences indicated a fast flow environment with significant instability in the flow path. Common downstream of annular access ports or other flow interruptions for about 8 to 20 pipe diameters.
Erosion below ports in tubinghead

Coupling 1

Coupling 2
Early Warning Signs- Potential Casing Damage

• High Dog Leg Severity
• High rate fracturing with numerous stages
• Very large proppant amount used in the frac
• Tubing-to-annuli leaks developing

• KPI’s
  • Established company workflows to high-grade or optimize hydraulic fracture placement.
Warnings - Production

• Look for changes in the system due to corrosion, embrittlement, erosion.
• Repurposing wells – producer to injector and adding high pressure lift systems.
• Weather effects.
• fluid changes
• Secondary recovery and refracturing
Surface erosion

Small leaks can become big leaks and even bigger problems if not corrected immediately.

A culture of maintenance stops these problems.
Vertical Fractures – where do they stop?

Actual hydraulic fracture in a west Texas carbonate formation at a depth of 4579’.

Width of the fracture is approximately 0.09”.
Fracturing: Level of Risk?

Fracturing Risk: Occurrence vs. Impact. Both are sharply reduced by technology application.

**Potential Outcomes**

- **Transport and Storage**
  - 1 Spill of clean water - fresh or low salt
  - 2 Spill of conc. biocide (Glutaraldehyde - 50%)
  - 3 Spill of dry additives - toxic but recoverable
  - 4 Spill of 150 gal diesel - wrek - 20% recoverable
  - 5 Spill of diesel refueler - ~4700 gal, 20% recoverable
  - 6 Spill of frac water - no additives, 5000 gal
  - 7 Spill frac tank, water w/ biodeg biocide (<50 ppm)
  - 8 Spill < 10 gal diesel fuel while refueling
  - 9 Spill frac tank frac flowback, <20,000 gal, no toxics

- **Surface Well Events**
  - 10 Frac ruptures surf csg, loss of 500 gal frac water
  - 11 Tbk pulls out of pkr - no losses outside well
  - 12 Cement channel - 1/4" diam. Well < 2000 ft deep
  - 13 Cement channel - 1/4" diam. Well > 2000 ft deep
  - 14 Intersects other well in pay, no leak or pollution
  - 15 Intersects properly abandoned well, no leak
  - 16 Intersects improperly abandoned well, 500 gal lost
  - 17 Frac to surface thru rock layers, well depth >2000 ft
  - 18 Earthquake from frac of Mm > 5.0 (Richter)
  - 19 Frac intersects a natural seep & increases seep rate
  - 20 Air Emissions (SOx, NOx, particulates) >= normal

**Desired Outcome (Target is 99.9%)**

- 21 No spills or measurable pollution
Weather Related

Warmer weather – but expanding gas cools things very rapidly, especially at restrictions.

Collapse caused by ice – water inside a near-surface annulus.
Pipe wall deterioration – Multiple causes

Failures like this may have multiple causes.

Even corrosion of the steel wall is rare, more common corrosion attacks are localized pitting, embrittlement, abrasion or erosion-assisted corrosion and corrosion attacks at the 6’oclock position in horizontal lines.
This example of a 13-3/8” casing from an Alaska well burst when a gas leak from a gas-lift source in the tubing-by-production casing annulus leaked through a buttress thread connection and pressured up the production casing-by-surface casing annulus, creating a trapped annulus.

The nearly liquid filled annulus, already pressure up by the leaked gas, was further stressed as the well was brought on, raising pressure rapidly.

The original cement job top (1980’s vintage) was thirteen feet (13’) below the surface.

The casing burst just above the cement top and before the inner casing could collapse.

Failure to bring cement to surface on a surface casing:
1. Decreases casing support by the cement.
2. Increases potential for oxygen corrosion or and/or bacterial induced corrosion
Corrosion Trench

The cause is water condensate from the flowing gas stream as temperature and pressure decline during production. The water adsorbs CO2 can and runs down the low side of the tubing.
Salt – Changes Well Integrity Radically.

# 1970’s Industry Study of Failures

<table>
<thead>
<tr>
<th>Method</th>
<th>% of Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion (all types)</td>
<td>33%</td>
</tr>
<tr>
<td>Fatigue</td>
<td>18%</td>
</tr>
<tr>
<td>Brittle Fracture</td>
<td>9%</td>
</tr>
<tr>
<td>Mechanical Damage</td>
<td>14%</td>
</tr>
<tr>
<td>Fab./Welding Defects</td>
<td>16%</td>
</tr>
<tr>
<td>Other</td>
<td>10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cause</th>
<th>% of Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Corrosion</td>
<td>28%</td>
</tr>
<tr>
<td>H₂S Corrosion</td>
<td>18%</td>
</tr>
<tr>
<td>Corrosion at weld</td>
<td>18%</td>
</tr>
<tr>
<td>Pitting</td>
<td>12%</td>
</tr>
<tr>
<td>Erosion Corrosion</td>
<td>9%</td>
</tr>
<tr>
<td>Galvanic</td>
<td>6%</td>
</tr>
<tr>
<td>Crevice</td>
<td>3%</td>
</tr>
<tr>
<td>Impingement</td>
<td>3%</td>
</tr>
<tr>
<td>Stress Corrosion</td>
<td>3%</td>
</tr>
</tbody>
</table>

In 2019, the problems are the same, but quality control and inspections have reduced fabrication defects.
EAGLE FORD MIC

Slow flow unable to sweep sludge and biomass out of pipes

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Patrick J. Breen – Marathon)
Slow flow unable to sweep sludge and biomass out of pipes

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Patrick J. Breen – Marathon)
Eagle Ford Gathering Lines

SPE Presentation: Microbial Corrosion (MIC) in the Eagle Ford Shale (Thanks to Patrick J. Breen – Marathon)

Left: a “blister” that is debris covering a bacteria colony.
Center: the pit in the pipe wall under the “blister” – note the “stair-step” sides.
Right: a pit through the gathering line wall.
This type of damage occurred within six months of gathering line construction.
Some Corrosion Control Best Practices

1. Maintain high pH (pH >7 minimizes acid reactions)
2. Control gas breakout (turbulence disturbs protective layers and inhibitor films)
3. Use passive metals (e.g., Carpenter 20, Hasteloy, Monel, etc. – but match alloy to case)
4. Remove Oxygen (Close tank hatches, pump intake leaks and use nitrogen blankets)
5. Control velocities (too low allows bacteria growth, too high disturbs inhibitor films and layers)
6. Lower chlorides (low pH and high salt concentration can be very corrosive)
7. Bacteria control (continuous & batch treating may work, but survey and remove sessile colonies)
8. Acid/brine use considerations and alternatives
9. Control bacteria in waters used for any purpose
10. Inhibitor injection – match inhibitor to the need
11. Coatings may work in initial construction but watch erosion and wireline cuts.
Corrosion – management strategy

- Adopt a corrosion management strategy.
- Be aware of corrosion and erosion causes.
- Completion planning must reflect corrosion potential over well’s life.
- Develop maintenance programs, measure corrosion.
- Know the corrosion specialists.
- Ensure inhibitors are compatible with materials and the reservoir!
- If tubing corrosion is suspected, DO NOT bullhead fluids in the perforations or the formation.

corrosion in tubing exacerbated by abrasion from wireline operators.

REMOVAL OF “PROTECTIVE” FILM
Conclusions - Specific Takeaways

• Problem types may be common to an area or technique. Problems in drilling are reliable precursors to problems with well integrity.
  • Dog Leg Severity (DLS)
  • Poor cementing practices
  • Cutting corners on any part of well construction.

• Production issues on older wells (prior to refracturing) must be examined.
  • Corrosion, hydrogen embrittlement, erosion, etc.

• Recurring problems demand a closer look at the what, why, when and how of failures.
Critical Issues – early warnings

1. “Drilling incidents are often leading indicators of well integrity problems”.
2. Initial well and completion design are factors in the ability to stimulate or re-stimulate.
3. Critical factors in cementing include:
   • Landing points of critical upper completion casing strings to provide a high strength “shoe”,
   • Centralization of the pipe,
   • Pre-cementing preparation of the drilled hole,
   • Quality of cements during mixing and pumping,
   • Minimize gas flow, fluid loss & equivalent circulating density in cement placement.
   • Final cement top position that seals off all annular gas charged formations and protects against leaks,
   • Sufficient cement overlap between nested casing strings,
4. High pressure, high temperature and cyclic applications of high pressures can produce cracks in some single-barrier cement sheaths. This can be offset by cement and additive selection.
Gas Storage Well – Recompleted from a producing well. Look at Records......

- Initial drill 10-5/8” hole from surface to 2767’ – lost circulation twice while drilling. (1953)
- Opened 10-5/8” hole to 16” from surface to 990’.
- Ran and cemented 11-3/4” (42 lb/ft) Youngstown (H-40) T&C casing at 990’ with 600 sx Diamix 1:1 followed by 100 sx of neat cement.
- Lost circulation with 114 ft3 (20 bbls) of cement slurry to displace. TOC 260 ft below surface.
- Cemented twice around top of casing – 75 sx, then 60 sx neat cement.
- Cleaned out to 2567’- drilled 10-5/8” hole to 2925’. Twisted off drill collar – fished 2 days and washed over & recovered drill collar.
- Drilled 10-5/8” hole 2925’ to 3073’ Twisted off 11 joints DP and 2 drill collars – fished and recovered.
  - Drilled 10-5/8” hole to 4530
  - Drilled 8-5/8” hole to 4948
- Lost 893’ of DP, drill collar and tools – fished for 7 hours – no recovery.
- Plugged back to 3967’ – set cement plug, set whipstock at 3860’
- Drilled off whipstock with 7-7/8” bit to 3929’ at 3.5 degrees deviation.
  - Opened hole to 8-1/2”– opened to 10-5/8” to 8585’
  - Ran mixed string of 7” casing, (26lb/ft J-55, 23 lb/ft N-80, 26lb/ft N-80, 29 lb/ft N-80) to 8585’
- Cemented with 600 sx cement (came 1724’ up the annulus, creating 6861’ of open hole to the bottom of the 990’ shoe of the 11-3/4” surface string.
  - Drilled out with 6” bit to 8749’, reamed, ran 189’ 5-12” flushed joint liner (slotted) (1954)
Sustained Annular Pressure
(SPE 119869 case history – gas storage)

Fig. 1—Sustained casing pressure observed before this study.

Fig. 10—Cement sheath bond log.

Fig. 11—SCP not observed after implementing solutions from this study.

Rotation
Thin or Light Mud
Good Centralization
Plugs Ahead & Behind
Optimized Shoe Track Length
Enhanced Modeling & Sensitivities Run
Verification Testing
LCM Fluid Design
If you relate the trapped volumes and the initial compression factors back to well operation:

- An annulus with more low pressure gas will compress slower than one with small gas volume.

- An annulus with a gas volume that is already highly compressed will experience a faster pressure rise.
A split in the side of 5-1/2” casing. Cause was unknown – mechanical damage (thinning by drill string abrasion) was suspected.
Annular Pressure and Integrity

• The causes of annular pressure
• What defines well integrity?
• Rate of heat transfer – loss and gain
• Leaks – self equalizing and one-way.
• Remediation,
• Monitoring,
• Prevention.
Parts of a Well

Conductor pipe – not cemented, keeps the loose soil and rock out of the cellar area.

Cellar

Surface casing

Production Casing

Casing shoe (shows a seal – either packer or cement fill)

Outside Annulus (also called B annulus) – nothing flowing if no leaks

A annulus or IA access valve

B annulus or OA access valve

Inside Annulus (also called A annulus)

Gas Lift Valves

Production Packer

Tubing - Produced Fluid Flow Path

Cement locations are not shown in this drawing although cement is used.
Pressure Integrity Tests

• PIT or leakoff test used to evaluate isolation created by a cement job. The formation immediately below the shoe is open to the test.

• Procedure – BOP is closed and fluid slowly pumped into well. At a set pressure, injection is stopped & pressure is monitored for a time to check for leaks, then pressure is released.

• Drilling can progress is the test shows no leaks that cannot be explained by the permeability of the formation.
Pressure Integrity Tests

Too slow a rate will not properly describe the safe pressure.
Sequential Fracs – Barnett, Western Parker Co.

$W/X_f = 2$
Examine cement isolation (PNP)

Figure 5—DTS temperature map of multi-stage hydraulic fracture stimulation (8 stages) in a horizontal well completed using cemented plug and perf systems limited entry (CPnP). Warm colors represent high temperature while cooler colors symbolize relatively lower temperatures. In this well the expected “stair-step” pattern is broken in all but one of the stages. The DTS indicates that during the stimulation of stages 4 and 5 communication occurs all the way to stage 1 (red ovals).
## Well Integrity is in Every Step

<table>
<thead>
<tr>
<th><strong>Design</strong></th>
<th><strong>Application</strong></th>
<th><strong>Stimulation</strong></th>
<th><strong>Production</strong></th>
<th><strong>Maintenance</strong></th>
<th><strong>P&amp;A</strong></th>
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<tbody>
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<td>Information</td>
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<td>Design</td>
<td>Economics</td>
<td>Commitment</td>
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