Well Construction

• Basics – How Wells are Designed & Constructed
• Minimum Expectations and Best Practices
• Assessing Completion Reliability and Risk
• Key Performance Indicators
Tubular Design and Downhole Equipment

• Casing is run to:
  – prevent “fill” (formation fragments) from entering the wellbore
  – protect fresh water zones from other fluids
  – isolate zones - prevent or channel flow
  – make drilling possible: mud weight has to stay in the “window” between a minimum that will control the pore pressure (and formation heaving) and a maximum that will not fracture the formation.

• Casing is also sometimes used where it is not needed.
Tubular String- 8 Design Factors

- **Tension** – tube must stand its own weight in the running environment. Tubing must stand additional loads when pulling out or setting packers and forces due to temperature and pressure changes.

- **Burst** – maintain integrity with high internal tubing pressures with little or no annular pressure support.

- **Collapse** - maintain integrity with high annulus pressures with little or no internal pressure support.

- **Compression** – tube must stand compressive loads when setting some packers and in highly deviated wells or dog legs.
Tubular String- 8 Design Factors

- **Couplings** – free from leaks, maintain ID clearance, strength through bend areas and in compression and tension loads.

- **Corrosion** - tube must be designed to counter corrosion reactions with flowing fluids over its lifetime. CO2, H2S, acid, cracking, etc.

- **Abrasion/Erosion** – equipment must withstand abrasion and erosion loads over lifetime

- **Stimulation Loads** – The tubular must withstand loads from acids, fracturing or other stimulations
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Shale

\[ P_p = 0.65 \text{ psi/ft} \]
\[ P_f = 0.85 \text{ psi/ft} \]
Since the conductor is often short and rarely cemented, it is not usually regarded as a pressure seal.

Baku – Suggest driving the 28” conductor into place. Drilling in may disturb sediments and aggravate sediment sides???
After the conductor is set, the bore hole is drilled to below the deepest fresh water source. The next smaller casing is run to bottom (maintaining minimum clearances), and this string is cemented. The BOP is commonly mounted on this string.

Baku - Surface or protection string – 20”, usually drilled, but may be driven.
One or more production strings or liners are common for a well, depending on “mud weight window” and things like pipe sticking, reactive shales, and other problem areas.

Baku – Protection string - 13-3/8” – drilling wear can be a problem – how to repair? Production string - 9-5/8”, run to surface, but only partially cemented.
Critical points on liners are the seal at the top and cementing quality along the length.
Liner Hanger Device

12-1/4" Hole
9-5/8" Casing

7" Liner Run and Overlapped into Upper Casing String

8-1/2" Hole

Drilling Out: Stop for Test of Casing Shoe

All Strings Must "Telescope" as the Well is Deepened
Simple gas well wellhead, showing two master valves, a wing valve (leading to a choke unit) and a swab or lubricator access at the top.
This is one type of a well head flange. This unit slips on the top of the casing string and is welded to give a seal.

The port in the side gives access to the annular area when tubing is run and hung off in the “bowl” in the top, inner part.

The top is a flange with a seal groove that bolts to the wellhead or “spool” above.
This is a very simple schematic - usually multiple casing strings and tubing are included – in most cases, there are a minimum of two barriers unless leak potential is very low or there is no potential damage.

Is every string cemented back to surface? – No – most times, it cannot be done in one operation.
Casing Design Intent

• “A” annulus - tubing will collapse before casing bursts.
• “B” annulus – production casing will collapse before surface casing will burst.
• “C” annulus – usually cemented up, but watch any sealed area.
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
1. Tubing and flow area below the tubing
2. “A” annulus – tubing/production liner/production casing
3. “B” annulus – production casing/surface casing annulus
4. “C” annulus – surface casing/conductor
1. **Tubing**
   a. max production pressure
   b. max shut-in pressure
   c. max frac pressure

2. “A” annulus – tubing/production liner/production casing
   a. initial design – pkr fluid & no surf. press.
   b. start-up – temp swing effect on press
   c. change in use to gas lift supply path?
   d. leak?

3. “B” annulus – prod csg/surf. csg annulus
   a. initial design – fluid packed – annular press
   b. leak from high pressure “A” and add temp:
      1. fluid packed
      2. gas over fluid

4. “C” annulus – surface casing/conductor
   a. cemented up or ?
   b. leak?
Special Case:
How does changing the “A” annulus from brine to 2000 psi gas lift supply?

- Reduces the pressure at the shoe (removal of most of the hydrostatic column)
- Backs up (increases) the collapse resistance of the production casing in the “B” annulus.
- Must consider the effect of liquid packed vs. gas cushion.
Tubing:
burst and collapse set by production, stimulation and kill forces.

“A” annulus – select to collapse the tubing before production casing will burst.
Factors:
1. Liner top integrity
2. Is the shoe designed to leak?
3. What back-up force is provided by the tubing?
4. What back-up force is provided by the cement?
Casing collapse in a deep water environment – occurred while running a 7” string at about 7500’ of water. The automatic fill float valve failed and much of the string was only air filled when the pipe began to collapse. 17 joints collapsed in one “run” of the collapse – across couplings!
## Casing Grades

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<th>Minimum Yield</th>
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<td>V-150</td>
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</tr>
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</table>
Casing Design Options – think about running and setting packers.

Mixed weights, same grade

Mixed grades and weights

Monobore: mixed grades, same weight
Running Casing

If casing velocity downward is faster than mud escape up the annulus, then pressure below the casing is raised. Rock may be fractured.
Tubular Joints

- **T&C** – Threaded and Coupled
- **LT&C** – Long Thread and Coupled
- **ST&C** – Short Thread and Coupled
- **Integral** – direct connection using thread cut onto one pipe and a box and thread cut into another.
Threaded and Coupled

Integral Connector

Pin

Coupling or Connection

Box
EU or external upset – strong connection, full opening, clearance problems

IU or internal upset – moderately strong connection, reduced opening, good external clearance

NU or non-upset – weak connection, full opening, good external clearance
Spotting Problems With Connections. What does it take?
1. Initial Thread Inspections
2. Torque/turn indicator – and difference…..
3. Leak testing – effective?

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BP 5-1/2" 20# Deltas
\[ R^2 = 0.7351 \]
Why Cement?

• Completes the isolation step that was started with casing.
  – Pressure isolation
  – Pipe support and protection
    • Exterior corrosion
    • Pressure control
    • Load and force application support
  – Leakoff control – prevents crossflow?
  – Water influx control
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.
Cement Circulation

• Path: Down the casing and up the annulus
• Concerns:
  – Cement density vs. pressure “window” from formation
  – Cement bond between pipe and formation
  – Cement pump time
  – Ability to place the cement over the whole column (fluid loss control, correct volumes, pumpability)
  – Cement strength development
  – The quality and longevity of the seal.
Equivalent Circulating Density

Cement is a viscous, dense fluid. The problems are in effective displacement of the mud and attaining a full column of uncontaminated cement.

16 ppg

18 ppg effective mud weight?

Friction Pressure
The final slurry design has a certain slurry density, usually between 11 and 18 lb/gal, with typical class G or H being about 16.4 lb/gal. More water can be added, but the water will separate as it sets, resulting in channels or weak cement.
Fluid Density Balance – used to get fluid density in lb/gal
General properties of cement slurries before additives. Note that without additives, the class G and H slurries would not be usable for many wells. Correct slurry design is critical for cement success.
Every cement design must take into account the temperature and pressure extremes in the well. Low temp retards the cement set time. High temp accelerates the cement set time.
Geothermal gradient from an Alaska well through the permafrost.
Modifying the Set Time of the Slurry

• Accelerators speed it up.
  – calcium chloride
  – sodium chloride
  – gypsum

• Retarders slow it down
  – lignins, sugars, cellulose
  – some drilling muds
  – sodium chloride

The sodium chloride may be an accelerator or a retarder, depending on amount of salt and other factors.

The effect of mud on the set time of cement is unpredictable.
Cement without a retarder in a hot formation will set up too rapidly; often before the cement has been completely displaced into the annulus. Increasing temperature makes the cement set up more quickly.
Cementing Problems That Must be Addressed in the Design

1. Well Control – remember, until the cement sets, it must control the pore pressure like any other well control fluid.

2. Pumpability – The pump time must be long enough to completely displace the cement from the pipe to the annulus.

3. Fluid Loss Control – If the cement dehydrates, it can also shorten the “set” time.

4. Communication control (avoiding channels)

5. Invasion of natural fractures in the pay by cement.
Well Control

• Working in the slurry density “window”
  – Pore pressure establishes the lower limit of slurry density.
  – Fracturing gradient establishes the upper limit of slurry density.

• Cement density normally is 16.4 lb/gal
  – Typical light weight cement is 11 to 12 lb/gal
  – Heavier weight cements may be up to 23 lb/gal
Cement Problems and Failures

• Problems?
  – Cement at shoe not strong enough to contain pressure of deeper zones—must repair before drilling ahead.
  – Casing not centralized – leaves mud channel on low size. May leak now or later. Requires squeeze.
  – Casing not moved during cementing – you need to get mud displacement by cement to get a good job.
  – Not enough cement in annulus to function as a barrier.
How far is cement brought up the annulus?

Minimum 200 to 500 ft above the shoe

Is the cement brought to surface? – Unlikely.

Why?
1. Fracture gradient is usually 0.7 psi/ft, cement density is 0.85 psi/ft.
2. Time
3. Cost
4. Not understanding protection need.
Common contaminants and ops that degrade cement bond?

- Slurry contamination – primarily mud during displacement.
- Sulfate effects on mixing slurry and on set cement – use sulfate resistant cement.
- Explosives (perforating) – usually minor effect if there are no channels.

Typically, if a cement job “breaks down” after perforating, acidizing, solvent, or frac, the problem is that an existing mud channel in the cement has been disturbed.
Dehydration of the slurry causes a plug in the annulus.

Since the first objective of a cement displacement is to remove the mud filtercake, the increased fluid loss has to be controlled by the cement slurry.
Fluid loss through wide natural fractures is often very hard to control – requiring particulate and/or flake fluid loss control additives.
Low strength formations (low fracture gradient) pose a special problem.

Created or natural fractures can be a thief zone for whole cement – causing less height in the annulus.

Natural fractures can also act as a fluid loss site for leakoff for water from the cement – the result is dehydration of the cement slurry.
Salt zones can create cavities or washouts.

If a salt water slurry is used, the salt must be checked with pumpability – the salt can be an accelerator or a retarder.
Cement Displacement

• The first part of the cement slurry removes the mud cake – and contaminates the cement. Contaminated cement will not set up.

• Where does the mud contamination come from?
  – Mud system in the annulus
  – Interior pipe walls
  – Open hole – filter cake
  – Washouts and cavities

• Now, what can you do to prevent contamination?
Plugs and Floats

Gelled Mud and Contaminated Cement Ahead of Plug
DOUBLE PLUG CEMENT HEADS
Cement

5 Wiper Plug

Gelled Mud Pushed In Front of Plug

Mud
Float Valve

Float is a Check Valve Pinned Open During Running Allows Casing to Fill with Mud

Displacement of Mud by Cement

Holds Back Pressure, Keeps Cement from Flowing Back
Examples of equipment used on the BHA (bottom hole assembly) during casing running. The float equipment helps prevent backflow of cement after full displacement. The guide shoe helps guide the casing past ledges and doglegs (sudden hole direction changes) during pipe running.
Other Equipment

- Centralizers
- Scratchers

Both help to improve the cement bond and seal between casing and formation.
Use of centralizers improve the ability of the cement to surround the pipe, displacing the mud and creating a channel-free seal. Centralizers also assist running casing in deviated sections.

Area of undisplaced mud – a mud channel remains, requiring squeezing.
Bow spring centralizer. This is a deformable, but very weak centralizer that looses value with increasing string weight and increasing wellbore deviation.
Straight vane casing centralizer. This is a slip-over type that floats between the couplings unless lock rings are added.
Spiral centralizer, assists in decreasing drag and helps centralize casing. It may also help channel cement in a short lived swirl pattern just downstream of the centralizer location. These are usually viewed as highly effective in improving cement isolation.
Squeeze Cementing

- Forces cement slurry, under pressure, through perforations or holes in the casing or liner.....
  
  • Used to permanently block entry of undesirable fluids to the wellbore or to fill channels behind the casing. Water production form watered out zones or leaks are common targets.
  
  • Also used to set “cement packers” to isolate sections of the annulus.
  
  • The cement plug must remain an effective seal full temperature, highest pressure and in contact with any fluid from the well.
Repair Cementing

• Squeeze Cementing
  – Shutting off watered-out perforation intervals
  – Filling channels behind the pipe
  – Covering pipe annuli that was never cemented
  – Setting cement packers

Partly copied from Arco Alaska presentation.
Treatment Execution

• Execution of squeeze cementing operations in four basic steps:
  – Wellbore preparation
  – Slurry mixing and pumping
  – Squeeze
  – Removal of excess cement
Squeeze Cementing – channel repair

• Objectives
  1. Locate the channel
  2. Perforate into the channel
  3. Inject cement and fill the channel

Problems
  1. locating the channel
  2. squeezing into the channel
Channel Detection

• Cement bond log

• Noise log? - leaks

• Segmented or radial bond log
  – Bond differences
  – Looking for patterns that represent channels

• Block perforate and squeeze techniques
Squeeze Types

• **Hesitation squeeze** – steady application of pressure thought by some to force cement in matrix – may only help build size of dehydrated mass or “node” through fluid loss of liquid from the cement slurry.

• Actually – what may be happening in some cases is that the wellbore is being “restressed” – forming a “stress cage” by solids from mud or cement wedging into and bridging on the formation. This may allow 1 to 5 lb/gal higher fluid gradient weight than initial frac pressure of the formation.
Squeeze Types

• Suicide squeeze – This squeeze perforates two spots – high and low and squeezes from the bottom towards the top. There is a chance, if slurry volumes are too large, of cement spilling out of the upper perforations and sticking the isolation packer or retainer in the well.
Fluid Loss Control

- Excessive fluid loss in the slurry can result in bridging of tubulars by dehydrated cement.
- Slurries with too little fluid loss can result in insufficient buildup of filter cake on the formation (may also be a function of permeability and pressure).
- Fluid loss additives may be required to control fluid loss.
Cement Node Buildup

Node with minimal intrusion into wellbore

Casing

Formation

Primary cement sheath

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Rheology Controls

• Cement slurries have higher viscosity than most workover fluids and this significantly reduces maximum possible pump rate.

• Rheology and stability tests are commonly performed:
  – At surface mixing temperatures, and
  – At bottomhole static temperature BHST (caution – make sure mix water temperature is not higher than bottom hole temp.).

• Slurries must stable to provide good rheology characteristics that are easily reproducible.
Slurry Volume

• Volume of slurry prepared depends on:
  – Length of perforated interval
  – Capacity of liner/casing or channel behind pipe
  – Void areas behind the perforations
  – Force that can be applied to the tubing
  – Configuration of surface mixing / pumping equipment
  – Use of cement plugs, pigs or darts (isolation devices)

• Previous squeeze experience provides best guidelines.
Depth Control – (with CT)

- In cement squeezing, surface equipment not accurate enough to position CT nozzle
- Downhole reference point is generally required
- Methods of setting depth reference
  - Tagging bottom
    - inaccurate in wells with fill, but viable in certain conditions
  - Tagging completion restrictions
    - tubing end locator (TEL) or tubing nipple locators (TNL)
    - commonly used in squeeze cementing
Cement Contamination Problems

• Contamination can result in:
  — Unpredictable slurry characteristics
  — Reduced compressive strength of the set cement
  — Incorrect placement due to change in slurry volume

• To avoid contamination:
  — Spacer fluid should isolate (ahead of/behind cement)
  — Lines should be flushed each time a new fluid is pumped
  — Mechanical separation of cement slurry using CT plugs (darts or pigs)
Reel Manifold Sampling Point and Flush Line

- Circulating pressure sensor
- To reel core and CT through reel isolation valve
- From pump unit
- Reel manifold valves
- Flush line to disposal
- Sample point

Arco
Cement Composition and Vol.

• Low or high fluid loss? Depends on depth
• Volume of cement? – depends on channel size
  – Often try several small squeezes.
  – Pressure?
Squeeze Success?

• Usually about 50% - but conditions make success vary widely.

• Increases when:
  – circulation is possible through the channel,
  – Isolation is used for cement injection,
  – cement blending is pod mix,
  – the operator is experienced.
Cement Packer

• Can isolate the annulus
  – Water control
  – Tubing repair or isolation
  – Stabilizing tubing prior to milling window

• Problems and considerations
  – Floating the cement in the annulus – there are ways!
  – How long a cement column? - 50 to 300+ feet.
  – Cement compositions for packers
Cement Packer

• Perforated annulus at or below point for packer.
• May need to perforate above top of packer when annulus is liquid filled.
• Displace cement from a straddle packer or packer and plug (or retainer) into the annulus.
Cement Placement With and Without Retaining “Platform”

Cement slurry falls through less dense fluids.

Stable cement column placed over the platform.

Cement platform

A retainer, mechanical plug, highly gelled mud pill (10 to 20 bbls) or a cement plug may be used as the “platform”.
Tool Selection

• Tool strings should generally be kept to a minimum
  — Connector
    • required on all jobs
  — Check valves
    • cannot be used with reverse circulation of excess cement
  — Depth correlation
    • tubing end or nipple locators are commonly used
  — Plug catcher
    • catch and retrieve plugs ahead/behind cement slurry
  — Nozzles
    • developed to improve the slurry placement
Cementing Nozzle Features

- Pins to retain ball within the nozzle
- Multiple small-diameter radial ports
- Large-diameter port
- Multiple small-diameter radial ports
- Large diameter ports
Monitoring Recording Parameters

Coiled tubing
- Pressure, rate/volume, string weight, depth and tubing OD and tubing cycles.

Pump unit
- Pressure, density and pump rate/volume

Slurry batch mixer
- Monitor density and volume

Other tankage
- Monitor density and volume

Annulus
- Monitor volume and density of all fluids returned and pumped through the annulus.
- Record pressure.
Wellbore Preparation

Filtered seawater or similar at high rate

Choke open

Wellbore clean and packed – establish leakoff rate.
Laying In Cement Slurry

- Slurry pumped at maximum rate
- Choke open
- Nozzle pulled up 50 ft below cement interface
- Wellbore pack fluid
- Spacer/fresh water
- Cement slurry
Placing Thixotropic Slurries

Choke closed, if wellbore not fluid packed, pump slowly down annulus to prevent U-tubing.

Slurry pumped at maximum rate/pressure allowed.

Nozzle placed above thief zone.

Wellbore pack fluid

Cement slurry

Wellbore pack fluid

Highly gelled mud or other “platform” usually needed except in severe fluid loss.
Commencing Squeeze

Low rate continuous pumping or hesitation

Choke back returns monitoring pressure and volumes

Wellbore pack fluid

Spacer/fresh water

Cement slurry

Nozzle pulled up >50 ft above cement interface
Completing Squeeze

Displacement fluid pumped at maximum rate/pressure allowed

Wellbore pack fluid

Spacer/fresh water

Cement slurry

Choke back returns increasing final squeeze pressure

Nozzle moved continuously or frequently
Contaminating Excess Slurry

Contaminant pumped at maximum rate/pressure

Returns choked to maintain pressure on squeezed zone

Contaminated slurry

Nozzle penetrates slurry at a rate which provides a 50% mix of contaminant

Cement slurry
Reverse Circulating Excess Slurry

Fluid pumped at maximum rate/pressure for allowable differential (1500 psi)

Open returns from CT

Wellbore pack fluid

Contaminated slurry

Nozzle penetrates contaminated slurry at a rate which provides a 50% mix of contaminated slurry and pack fluid
Reverse Circulating Live Slurry

Fluid pumped at maximum rate/pressure for allowable differential (1500 psi)

Open returns from CT

Wellbore pack fluid

Nozzle penetrates slurry at a rate which provides a 50% mix

Cement slurry
Wellbore Circulated Clean

Fluid pumped at maximum rate/pressure

Returns choked to maintain pressure on squeezed zone

Wellbore pack fluid

Nozzle reciprocated through treatment zone to TD

Differential pressure maintained against squeezed zone
Wellbore Preparation

- Wellbore preparation operations include
  - Slick-line work, e.g. fitting dummy gas-lift mandrels
  - Pressure test the production tubing annulus
  - Establish hang-up depth or TD using slick line
  - Confirm and correlate depths with CT and flag the tubing
  - Remove fill from rat hole below perforated interval
  - Perform pretreatment perforation wash or acidizing
  - Place a stable platform for cement slurry
  - Ensure wellbore fully loaded with filtered water (or equivalent)
Slurry Mixing and Pumping

• Key points in the slurry mixing and pumping process include
  – Batch mix and shear the slurry
  – Conduct job-site quality control tests
  – Prepare contaminant and spacer fluids as required
  – Confirm CT depth
  – Lay in cement slurry following pumping schedule

• When using thixotropic cements
  – Do not stop pumping while cement is inside the work string
  – Place CT nozzle above thief zone and pump down production tubing/CT annulus while squeezing the cement
  – Overdisplace cement slurries out of the wellbore
Squeeze

• Downhole generation of filter cake aided by performing hesitation type squeezes
  — For example, 10 min at 1000 psi, 15 min at 1500 psi, 20 min at 2000 psi...

• As fracture pressure exceeded
  — Filter cake prevents formation from fracturing
Removal of Excess Cement

• Efficient removal of excess cement
  — Critical to timely completion of job

• Achieved using several methods:
  — Reverse circulation of live cement
  — Circulation of contaminated cement
  — Reverse circulation of contaminated cement
Reverse Circulation of Live Cement

• Reverse circulation of live cement slurry can be performed if
  — Designed slurry thickening time (including safety factor) allows for completion of the reversing phase
  — CT penetration rate controlled to effectively dilute the slurry as it is removed
  — Maximum density of reversed fluid is 10 lb/gal
  — Reversing is continued until clean returns observed at surface
Rev. Circulation of Contaminated Cement

• Contamination of excess cement is often necessary to:

  ― Extend slurry thickening time
    • allows cleanout operations to be completed safely

  ― Allow cleanout operations to be delayed until cement nodes have increased compressive strength
Typical Cement Slurry Contaminant Composition

• **TYPICAL CEMENT SLURRY CONTAMINANT COMPOSITION**

  • **Borax/Bentonite**
  • 10 to 20 lb/bbl  Bentonite
  • 20 lb/bbl  Borax
  • 3 gal  Cement Retarder
  • **Bio-Polymer Gel**
  • 1.5 lb/bbl  Biozan gel
Circulation of Contaminated Cement

• Conventional circulation used when:
  — Operating conditions cannot safely support reverse circulation of excess slurry

• Example:
  — Operations performed through 1-1/4-in. work strings cannot employ reverse circulation techniques
  — Reason: excessive friction pressure encountered
Evaluation of Squeeze

• Methods used to evaluate depend on treatment objectives

• Initial step in evaluation process
  – Confirm condition of wellbore in the treatment zone

• If wellbore is obstructed
  – Drilling/under-reaming may be required

• Additional check
  – Ensure the rat hole is debris or cement free
Monitoring
Regulations
KPIs and Best Practices
Cement Displacement

• The first part of the cement slurry is contaminated by cement. Contaminated cement will not set up.

• Where does the mud contamination come from?
  – Mud system in the annulus
  – Interior pipe walls
  – Open hole – filter cake
  – Washouts and cavities

• Now, what can you do to prevent contamination?
Basic Mud Cake Removal

• Physical – scratchers, rotation, reciprocation
• Chemical – dispersants, sweeps, solvents
Mechanical removal devices such as scratchers and scrapers require pipe movement, which is frequently not possible in high torque and drag instances. They also introduce easily breakable parts into the wellbore.
Chemical Flush Basics

1. Base fluid condition
2. Dispersant
3. Sweep
4. Spacer
5. Cement

A properly designed flush focuses on time of contact, fluid mixing, lift of solids and avoidance of cement contamination.
Displacement and Pill Design

- must be designed to obtain effective mud displacement & water wetting of casing. Keys:
  - disperse and thin the drilling fluid
  - lift out debris and junk
  - water wet pipe
  - remove debris (mud cake, pipe dope, scale, etc.)
  - effectively displace the mud
  - allow uncontaminated cement to reach the desired height.

Source: Wellcert
Brines for Mud Displacement

1. A thinning base fluid flush.
2. An effective brine transition system must further thin and strip the mud and create wellbore displacement.
3. A carrier spacer must sweep out the solids and clean any coating from the pipe or rock that could cause damage problems.
4. A separation spacer must do the final cleaning and separate the residual mud from the brine.
5. The brine must sweep the spacer out. At this point the well should be clean. Fluid loss may be high!
## Cleaning and Transition Spacers

9-5/8” casing in 12-1/4” hole, annular area = 0.3 ft²

<table>
<thead>
<tr>
<th>Spacer Type</th>
<th>Function</th>
<th>Minimum Coverage</th>
<th>WBM</th>
<th>OBM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Fluid</td>
<td>Thin &amp; mud condition</td>
<td>250 to 500 ft</td>
<td>Water</td>
<td>Base oil</td>
</tr>
<tr>
<td>Transition</td>
<td>Mud to spacer, cuttings removal</td>
<td>500 to 1000’</td>
<td>Viscous pill</td>
<td>Viscous Pill</td>
</tr>
<tr>
<td>Wash</td>
<td>Clean pipe</td>
<td>500 to 1500’</td>
<td>Water+ WBM disp. surfactant</td>
<td>Oil + OBM disp. surfactant</td>
</tr>
<tr>
<td>Separation</td>
<td>Separate WS from brine, solids removal</td>
<td>500 to 1000’</td>
<td>Viscous pill</td>
<td>Pill?</td>
</tr>
<tr>
<td>Completion Fluid</td>
<td>Completion fluid</td>
<td>Fill</td>
<td>Completion Fluid</td>
<td>Completion Fluid</td>
</tr>
</tbody>
</table>
### Brine Flush Contact Times

9-5/8” casing in 12-1/4” hole, annular area = 0.3 ft$^2$

<table>
<thead>
<tr>
<th>For Pump Rate, bpm</th>
<th>Annular Velocity, ft/min</th>
<th>Barrels Pumped</th>
<th>Column Length, ft</th>
<th>Contact Time, minutes on one foot.</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>150</td>
<td>200</td>
<td>3743</td>
<td>25</td>
</tr>
<tr>
<td>10</td>
<td>187</td>
<td>400</td>
<td>7486</td>
<td>40</td>
</tr>
<tr>
<td>12</td>
<td>225</td>
<td>400</td>
<td>7486</td>
<td>33</td>
</tr>
</tbody>
</table>
Removal of the Mud Cake

• Part of the mud cake does not contribute to the fluid loss control. Removing these particles from the completion cleans the well.

• Approximately 80% of the outer layer of the cake can be removed in some muds without affecting fluid loss.

• Removal by velocity is often very effective. Even more effective with a dispersant.

300 ft/min or 92 m/min
Flow profile in a well with decentralized pipe. Note that most of the flow comes along the top of the pipe. This affects cleanup and residence time of the fluid on the wellbore. The lower section of the wellbore may remain buried in cuttings and never have contact with any of the circulated fluids.

Centralizing the pipe and rotating the pipe (reciprocating too) help!
How can you tell if the entire hole is being circulated?

- Displacement marker sweeps.
  - Dye, grain, colored beads, etc.
  - Time their travel – compare to calculated sweep.

Marker arrival at near expected time, hole sweep is near ideal.

Fast marker arrival at surface, entire hole is not being swept – expect channels in the cement.
Displacement of the annulus to displace fluids and mud cake depends partly on velocity.

The annulus changes as casing replaces the drill string. As the annular space decreases – velocity for any rate increases in the smaller area and the back pressure on the bottom hole may also increase – rates may have to decrease to avoid high ECD’s (equivalent circulating densities).

Circulating down the casing and up the small annulus can produce very high friction pressure and raised BHP.
Cement Displacement in the Pipe

• The Two-Plug displacement system
  – Patented and used since about 1915
DOUBLE PLUG CEMENT HEADS
A single wiper plug dropping tool, showing “bail” release mechanism.
The Two Plug System – Helps isolate the cement from the mud and the displacement fluid.

The top plug is solid and the bottom plug is hollow and has a diaphragm that ruptures when the bottom plug hits the float collar.

If the plugs are accidentally reversed, the cement will be trapped in the casing. The plugs are color coded to help prevent switching or help diagnose the problem when a plug is drilled out.
Every time a plug sweeps through the casing, a small amount of mud and other debris is pushed ahead of the plug. The contaminated cement in this area will not set or will set very slowly.

For this reason, a float collar, set a joint above the shoe will keep the contaminated cement at the end of the displacement inside the casing – not at the shoe.

<table>
<thead>
<tr>
<th>Mud Sheath Thickness (inch)</th>
<th>5 1/2 inch Casing</th>
<th>7 inch Casing</th>
<th>9 5/8 inch Casing</th>
<th>13 3/8 inch Casing</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/16</td>
<td>51 ft.</td>
<td>40 ft.</td>
<td>28 ft.</td>
<td>20 ft.</td>
</tr>
<tr>
<td>1/32</td>
<td>25 ft.</td>
<td>20 ft.</td>
<td>12 ft.</td>
<td>10 ft.</td>
</tr>
<tr>
<td>1/64</td>
<td>13 ft.</td>
<td>10 ft.</td>
<td>7 ft.</td>
<td>5 ft.</td>
</tr>
</tbody>
</table>
5 Wiper Plug

Gelled Mud Pushed In Front of Plug
A float valve allows fill of the casing from the hole as the casing is run, but it must close after the cement has been pumped to prevent U-Tubing.