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Intermittent Gas Lift For Liquid Loaded Horizontal Wells In Tight Shale Reservoirs

Daniel Croce, PhD – Colorado School of Mines

SPE-201601-MS and SPE-201153-MS

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Agenda:

1. **Overview of the problem:**
   - Size of the problem
   - Why it happens
2. **Current solutions and The New Idea:**
   - Limitations of current Artificial Lift Systems
   - Layout and operation of the Backsweep
3. **Fundamentals behind it:**
   - Design principles
   - Hypothesis
4. **Results:**
   - Experimental tests
   - Improvements
5. **Conclusions**

The new playground:

Lower drilling costs and time to complete, have driven the number of unconventional wells up (to over 140 M by 2018).

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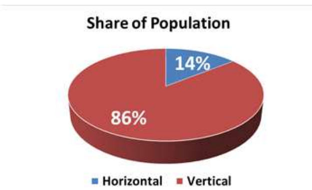
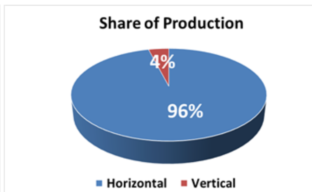
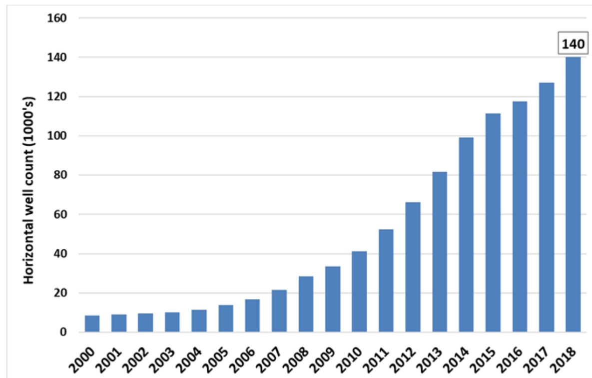
Horizontal Tight Wells in the US

- Permeability within nano-Darcie's
- Tight completions (4" casing - 2 3/8" tubing)
- Quick production decline
- Large water and gas volume fraction
- Presence of solids







Horizontal well count in the US
(US Energy Information Administration / E.I.A, 2020)

The liquid buildup problem:

As the pressure in the vicinities of the well drops, so does the gas velocity. The sheared liquid droplets are no longer dragged to surface, falling to the bottom of the well.

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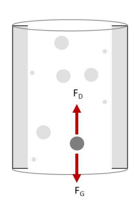
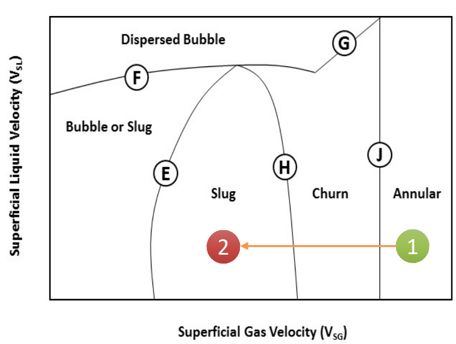
1 **Initial Flow Pattern**

Annular flow



$$F_D > F_G$$

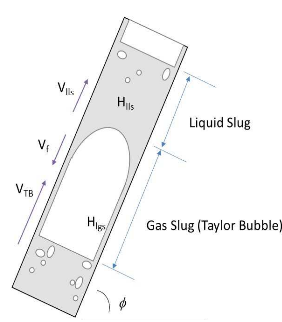
$$v_t = \frac{1.593 \cdot \sigma^{1/4} \cdot (\rho_l - \rho_g)^{1/4}}{\rho_g{}^{1/2}}$$



Flow pattern map for upward vertical pipes (Taitel, 1973)

2 **Final Flow Pattern**

Slug flow



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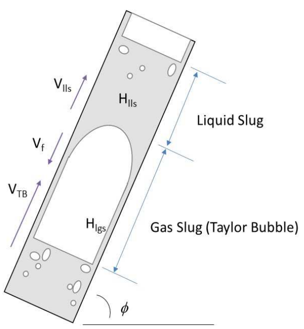
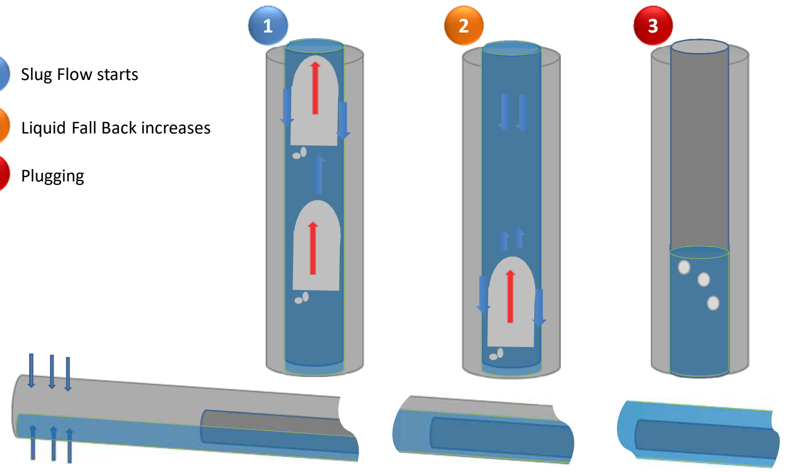
The liquid buildup problem:

Continuous fallback of liquid film and droplets, results in the accumulation or "build up" of liquids. The well flows in slugging pattern, below a profitable rate, eventually not flowing.



Slug Flow Pattern Scheme

1. Slug Flow starts
2. Liquid Fall Back increases
3. Plugging



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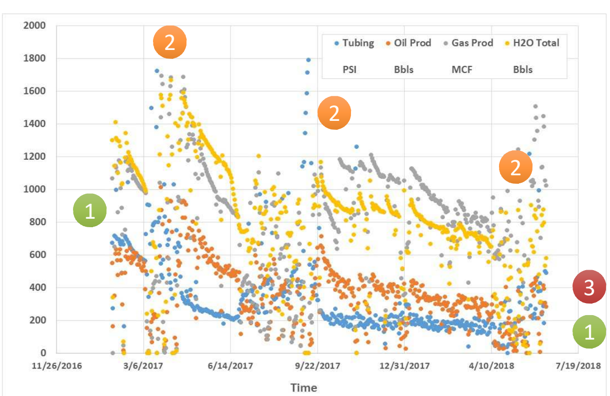
The liquid buildup problem:

The tight nature of the well, results in a quick pressure decline. The lower and discontinuous production, results in the quick abandonment and final P&A.



Gas well production data - Anadarko Basin (Courtesy: Anadarko)

1. Quick pressure Drop (as high as -400 psi in 2 years or 75% of pressure drop)
2. Large/increasing production of water
   - Accumulation of water in the tubing and casing
   - Instable production behind a slugging flow pattern
   - Large cumulative intervention costs
3. Quick decrease in production

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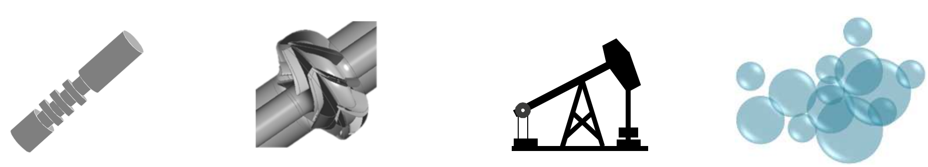
Current Artificial Lift Systems and Their Limitations

A NEW IDEA

Conventional Artificial Lift Systems (ALS):

None of the current artificial lift methods can be continuously and effectively used in horizontal completions.



	Plungers	Electro Submersible Pumps (ESP's)	Sucker Rod Pumps	Soap Sticks
Principle	Sweep liquids with a plunger (pushed by gas)	Kinetic energy is transferred to the fluids building pressure (head)	Progressive cavity pump collects liquids from the bottomhole	The liquid reaches the surface as foam
Limitations	Can't Operate on horizontal wells: **Loss of hydraulic seal**	Can't continuously and reliably handle over 50% of GVF: **Gas locking**	Can't reach the horizontal section: **Excessive friction and wear**	Low efficiency for large liquid rates: **Excessive soap required**

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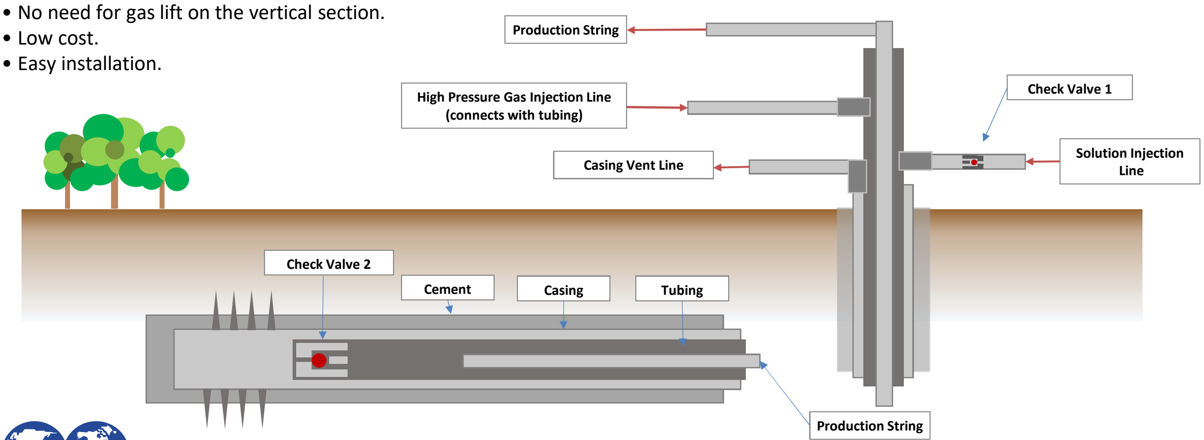
Proposed idea – "Backsweep" big picture:

Use the tubing as a containment chamber.

- No need for gas lift on the vertical section.
- Low cost.
- Easy installation.



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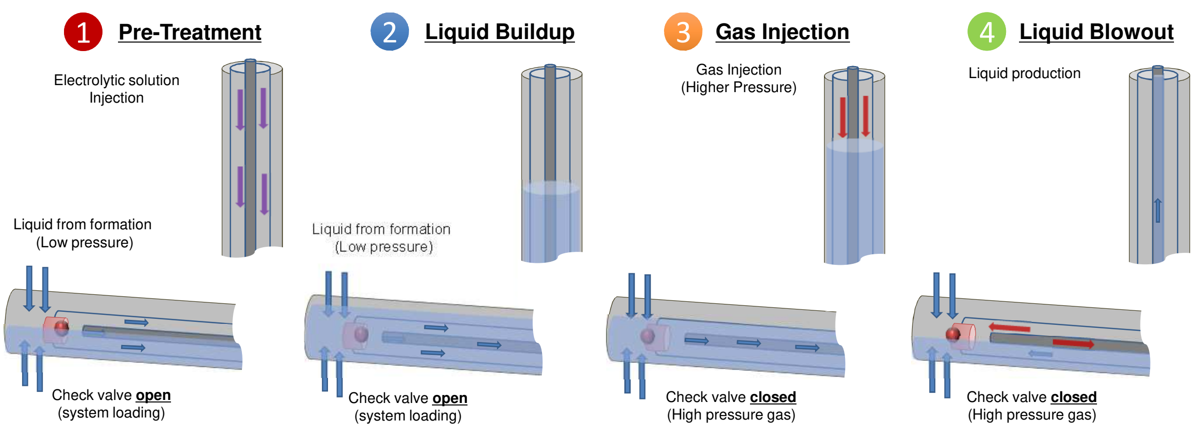
Backsweep – operating cycle:

Produce intermittingly in controlled blowouts.



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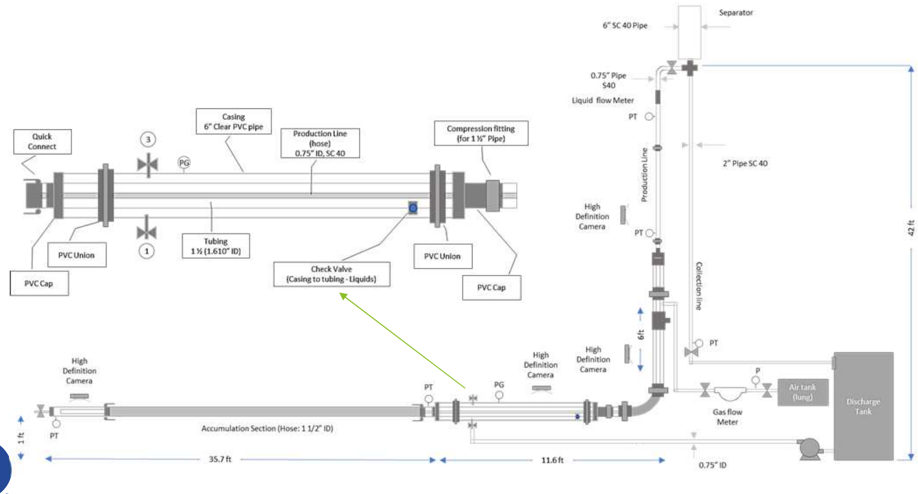
Facility Layout:

The experimental facility at Colorado School of Mines, is about 40 feet tall, and a horizontal capacity 50 of feet.



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Facility Layout:

A cyclonic separator was included due to the large gas circulating in the system.

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Facility Layout:

A quick-connect principle was followed to easily and quickly test different tubing sizes and combinations.

In vertical pipelines at slow velocities

SLUG FLOW IN STAGNANT LIQUIDS

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Slug flow in stagnant liquids:

On stagnated liquids, the raise velocity of the Taylor Bubble depends on surface tension, density and the diameter of the pipe.

Froude Number

$$Fr = \frac{u\rho_l^{\,0.5}}{\sqrt{gD(\rho_l - \rho_g)}} = \frac{\text{Inertial Forces}}{\text{Gravity Forces}}$$

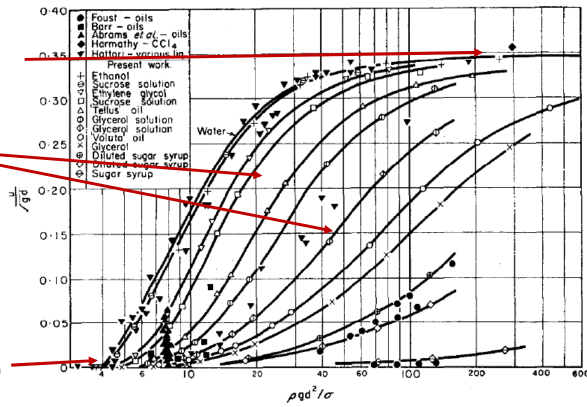
Eotvos Number

$$Eo = \frac{(\rho_l - \rho_g)g}{\frac{\sigma}{L^2}} = \frac{\text{Gravity Forces}}{\text{Surface Tension Forces}}$$

Harmathy $0.35\sqrt{gD}$

Lines of Same Nvis (Viscosities)

Critical Zone (No rise velocity)



Bubble Raise velocity in stagnated liquids
(White and Beardmore, 1969)

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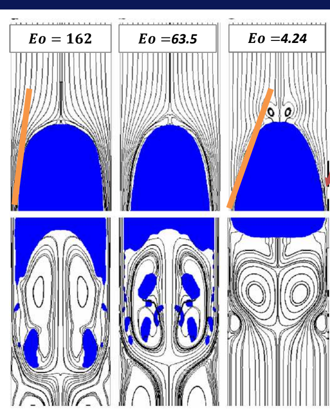
Slug flow in stagnant liquids:

Lower Eotvos number or larger viscosity, results on lesser liquid fallback. The thickness of the liquid film is related to the size and shape of the Taylor Bubble.



– σ +

Constant Nvis (Zheng, 2007)

Restricted Liquid Fallback

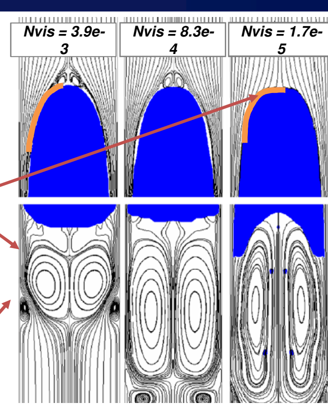
- Thinner liquid film
- Larger conversion angle of the streamlines

Flatter nose curvature

Slower liquid fallback

Reduced shear of the bubble

- Smaller recirculation area
- Reduced detachment of the tail



+ μ –

Constant Eo (Zheng, 2007)

Slug flow of gas in stagnated liquids :

Reduced liquid fallback can be expected from larger liquid viscosities (larger Mo) and lower Eo numbers (smaller ID and larger surface tension).

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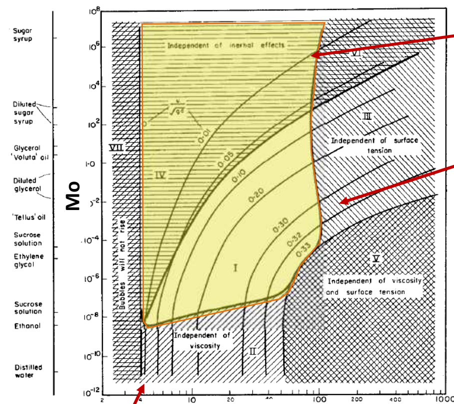
Morton Number

$$Mo = \frac{g\mu^4(\rho_l - \rho_g)}{\sigma^3 \rho_l} = \frac{\text{Viscous Forces}}{\text{Surface Tension Forces}}$$

Eotvos Number

$$Eo = \frac{(\rho_l - \rho_g)g}{\frac{\sigma}{L^2}} = \frac{\text{Gravity Forces}}{\text{Surface Tension Forces}}$$



Lower Fr (0.01)

Larger Fr (0.33)

No raise velocity Eo=4

Variable influence map (White and Beardmore, 1969)

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Why and how

HYPOTHESIS AND SCOPE OF WORK

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Hypothesis:

Previous research suggests that the sweep efficiency of the Backsweep, can be improved by altering the shape of the gas bubble.

if — **Modify the Eo and Nvis of the liquids**

- Modify the ID, surface tension and viscosity.

then — **Change the size and shape of the gas bubble**

- Change the Eo and the Nvis for a larger bubble.

so — **Improve the sweeping efficiency of the Backsweep**

- Larger swept cross-sectional area of the pipe.
- Avoid increasing friction from a lower tubing ID.

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General behavior of the system

RESULTS

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Backsweep operating cycle:

The operating cycle is marked by the start of the gas injection and the arrival of the gas slug to surface..

1 **Pre-Treatment**

Injection of additives

2 **Liquid Buildup**

A certain level of liquids is accumulated in the completion

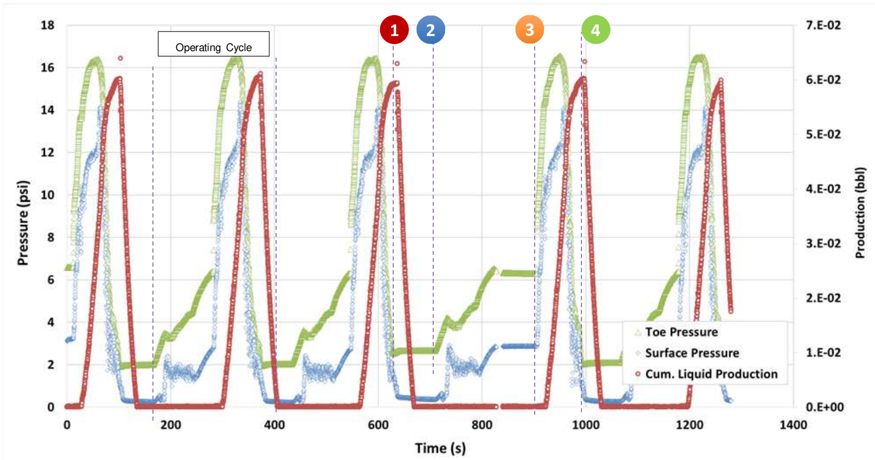
$$HOC = \frac{P_{casing}}{\rho_l g}$$

3 **Gas Injection**

The gas valve is opened

4 **Liquid Blowout**

The gas injection is stopped



Operating cycles of the Backsweep. Water and air. q_g=0.25 cfm, 0.75" ID production string

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Experimental results - video recording:

Water and air. 0.75 in ID production string, qg=0.25 cfm (1.3 ft/s), injection pressure 45 psi.

- 0:05.00 – Gas injection begins
- 0:26.79 – The nose of the gas slug reaches the toe
- 0:57.82 – The first gas slug reaches the separator (discharging sound)

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Characteristics of the Operating Cycle

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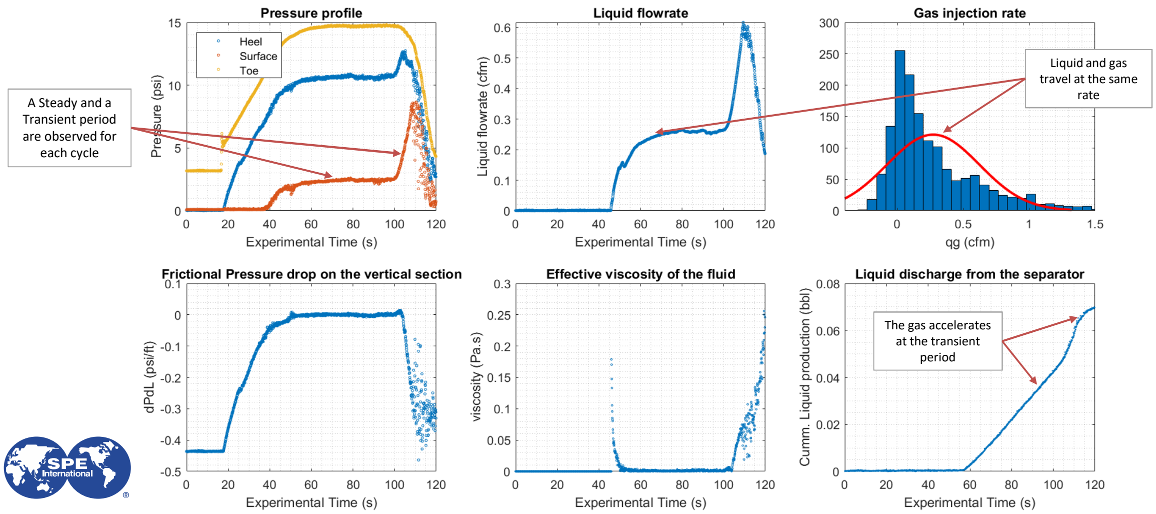

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Effect of the Eo and injected gas rate:

The smaller the Eo and the gas injection rate, the better the removal efficiency.
The optimum gas injection rates were closer below Turner's velocity (vt).

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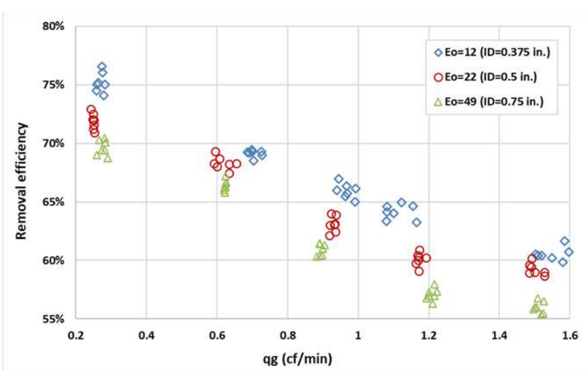

$$Removal\ efficiency = \frac{Volume\ of\ liquid\ removed}{Volume\ of\ liquid\ available}$$

Table 1: Experimental gas velocity compared to Turner's velocity and the Froude numbers for the horizontal and vertical sections inside a 0.75 in. production line.

q_g (cf/min)	V_{sg}/V_t	Fr_h Exp.	Fr_h Exp $/Fr_h$ Theo.	Fr_v Exp	Fr_v Exp $/Fr_v$ Theo.
0.25	0.06	0.19	0.35	0.54	1.69
1	0.23	0.61	1.15	1.93	6.06
5	1.14	3.05	10.1	9.65	30.1
10	2.28	6.11	11.5	19.2	60.3
30	6.85	18.3	34.5	57.6	181

$$Fr_H = 0.54 - \frac{N_{vis}}{0.01443 + 1.886 \cdot N_{vis}}$$ (Moreiras et al. 2014)

$$Eo = \frac{(\rho_l - \rho_g)g}{\frac{\sigma}{L^2}}$$

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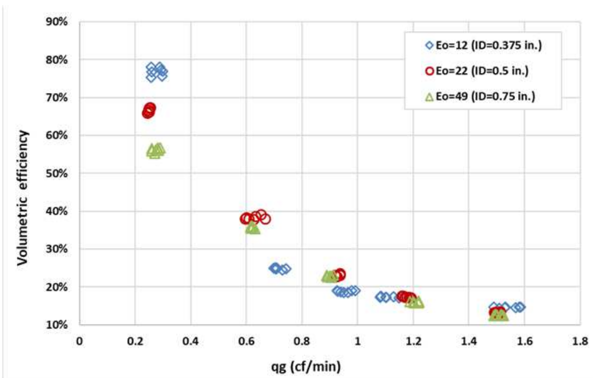
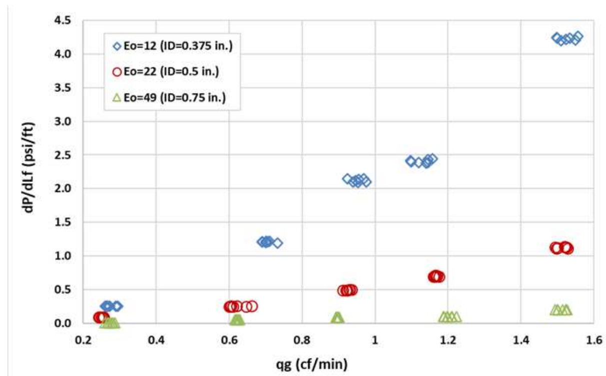
Effect of the Eo and injected gas rate:

Smaller Eo and gas injection rates delivered larger volumetric efficiencies. The ID of the line as a mean to reduce the Eo is limited by the frictional gradient.





$$Volumetric\ efficiency = \frac{Volume\ of\ liquid\ removed}{Volume\ of\ injected\ gas}$$

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Avoiding increases on frictional pressure drop.

IMPROVING THE LIQUID REMOVAL EFFICIENCY

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Surface tension of the substances:

Xanthan gum solutions at nearly 250 times lower concentration, achieve the same impact on surface tension that sucrose and sodium chloride.

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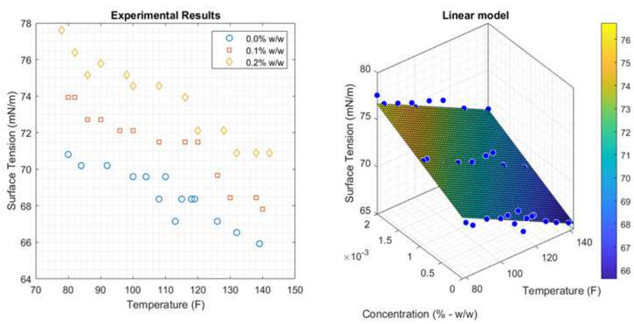
	Nature	Density (kg/m³)	Impact on viscosity	Impact on surface tension
Xanthan gum	Polymeric	1500	High	High
Sucrose	Monosacharide	2160	Low	Medium
Sodium chloride	Ionic	1590	Medium	Low

$$\sigma(T, C) = a + bT + c * C$$

(T, in (°F); C in w/w)

	a	b	c	R^2	Adj R2
Xanthan gum	78.7	-0.092	2585	0.96	**0.96**
Sucrose	78.2	-0.089	14.2	0.94	**0.94**
Sodium Chloride	79.1	-0.093	46.3	0.98	**0.98**



Surface tension measurements and regression models for the xanthan gum solutions.

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Viscosity models:

Xanthan gum use is limited by its large impact on viscosity.

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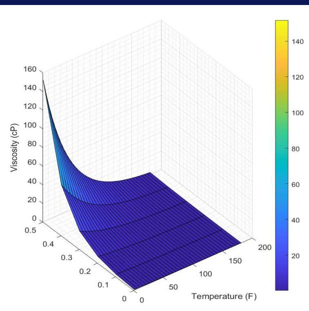
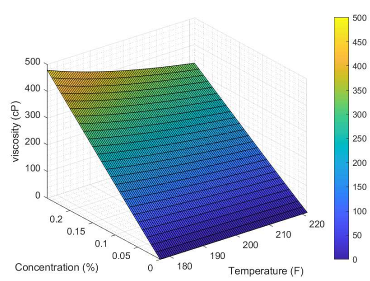


Viscosity of water and sucrose
(Data from Tellis, 2007)

$$\mu_{sucrose} = (a \cdot exp(b \cdot C)) \cdot exp((c \cdot C + d) \cdot T)$$

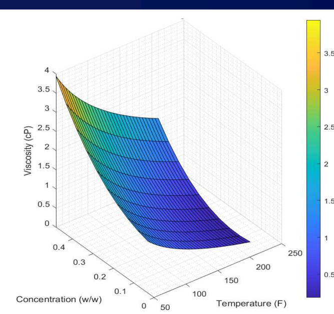
a=0.9076; b=10.2834; c=0.028



Viscosity of water and xanthan gum
(Data from Zhang, 1994)

$$\mu_{xanthan\ gum} = a \cdot exp(b/T) \cdot C^\wedge(d + e \cdot T)$$

a=363; b=494; c=0.9862; e=0.0001



Viscosity of water and sodium chloride
(Data from Ozbek, 1997)

$$\mu_{sodium\ chloride} = (a * C + b) \cdot ln(T) + c * exp(d * C)$$

a=-1.6853; b=-0.7445; c=4.231; e=1.7964

*(T, in (°F); C in w/w)

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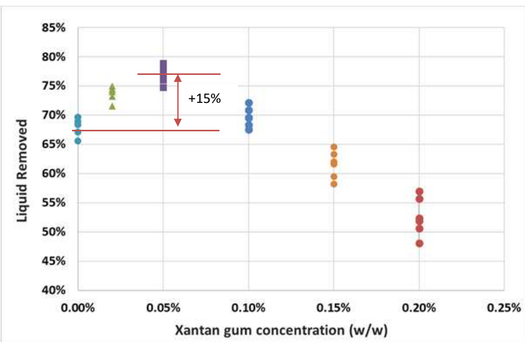
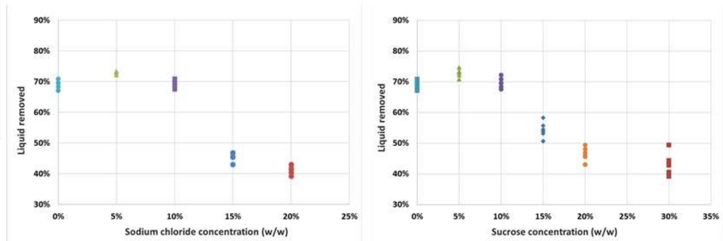
Effect of the Eo and Nvis:

Increasing the surface tension does improve the removal efficiency. Xanthan Gum's large impact at low concentration puts it as the best candidate.



Xanthan Gum concentration effects

C % (w/w)	Liquid removal vs. pure water	Eo	Nvis	Mo
0.00%	1	49.4	1.22E-04	2.62E-08
0.02%	1.08	48.7	3.52E-03	1.77E-02
0.05%	1.15	48.2	8.95E-03	7.20E-01
0.10%	1.06	47.3	1.63E-02	7.43E+00
0.15%	0.86	46.5	2.73E-02	5.62E+01



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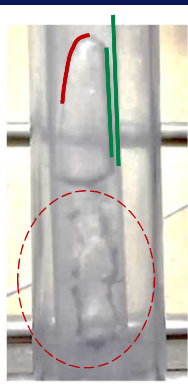
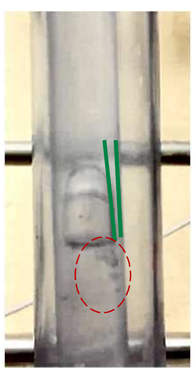
Effect of the Eo and Nvis:

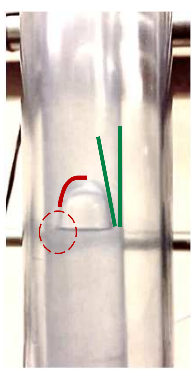
The change in shape of the Taylor bubble, is related to the liquid removal efficiency of the Backsweep.



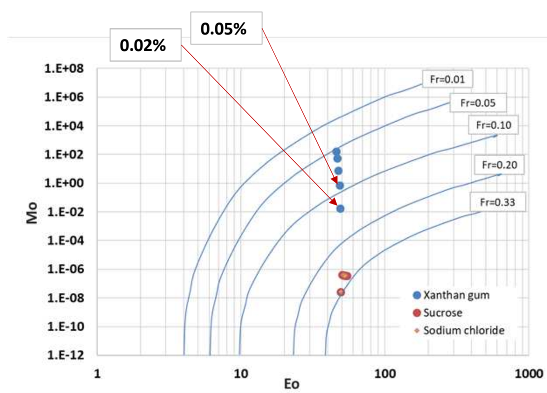
0.0% w/w;
Eo = 49.4;
Nvis = 1.22E^4



0.02% w/w;
Eo = 48.7;
Nvis = 3.52E-3



0.05% w/w;
Eo = 48.2;
Nvis = 8.95E-3



Variable influence map

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Conclusions and Next Steps

- At experimental level, the "Backsweep" successfully removed nearly 75% of the stagnant liquid volume.
  - Nearly 80% of the removed liquid volume came from the first liquid slug.
  - It is not needed to reach the toe of the well.
  - The operation can be automated to the stagnant liquid level.

- Larger removal and volumetric efficiencies were obtained for smaller Eo and gas flowrates.
  - Optimum gas rates are below 1/10 of that defined by Taylor's critical velocity.
  - The Eo can be reduced through the ID of the production line or by increasing the surface tension.

- Next Steps:
  - Present the **comprehensive model** for dimensioning and operating the Backsweep **(ATCE'21 / SPE-205962-MS)**
  - Test the isolating valve designed developed at Colorado School of Mines.

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Thanks!

- Thanks to the SPE.
- Thanks to Colorado School of Mines.
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