Basics of Gas Well Deliquification

8th European Gas Well Deliquification Conference
Groningen, 14-16 October 2013
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Short Course Contents & Objectives

- Origin of liquid loading
- Recognise liquid loading
- Model liquid loading
- Importance of liquid loading
- Gas well deliquification
- Select deliquification
Origin of Liquid Loading
Critical Gas Velocity

- Gas wells produce both gas and liquid (condensate and water)
- Multi-phase gas well flow is characterized by different flow regimes
- At high enough gas velocity the liquid is dragged up to surface in the form of liquid film and liquid droplets
- When the gas velocity reduces below the so-called critical velocity the liquids no longer be produced of film or droplets
- Then liquids will accumulate in the wellbore and the liquid fraction increases significantly
Sources of Liquids

- Formation water entering through the perfs
  - Typically saline (up to salt saturated causing salt scaling)
  - WGR ~10-1000 m³/e6 m³ or 2-200 bbl/MMscf

- Water of condensation due to temperature reduction
  - Fresh water, dictated by reservoir pressure and temperature
  - WGR ~5-100 m³/e6 m³ or 1-20 bbl/MMscf

- Gas condensate (heavier hydrocarbon components) due to pressure and temperature reduction
  - CGR ~1-1000 m³/e6 m³ or 0.2-200 bbl/MMscf
Flow Regimes

**ANNULAR MIST**
- Gas phase is continuous
- Pipe wall coated with liquid film
- Pressure gradient determined from gas flow

**CHURN**
- Gas phase is continuous
- Some liquids as droplets in gas
- Liquid affect pressure gradient

**SLUG**
- Gas bubbles expand as they rise into larger bubbles and slugs
- Liquid film around slugs may fall down
- Gas and liquid affect pressure gradient

**BUBBLE**
- Tubing +/- completely filled with liquid
- Free gas as small bubbles
- Liquid contacts wall surface, bubbles reduce density

Decreasing Gas Velocity
- As reservoir pressure ($P_{res}$) declines due to depletion, well production ($Q$) decreases.
- When $Q$ decreases below $Q_{min}$, liquid loading cycle starts and average production drops.

$Q_{min}$ is minimum stable rate, a.k.a. critical rate, a.k.a. liquid loading rate.

$Q_{min} \approx 200e3 \text{ m}^3/\text{d}$
Recognize Liquid Loading
Signs of Liquid Loading

- Production shows accelerated decline
  - Short term – real time data e.g. PI
  - Long term – monthly data e.g. OFM
- Signs of slugging (noise, movement, pressure/rate measurement)
- Intermittent production
- Reduction of LGR
- Reduction of wellhead temperature
- Production and wellhead pressure decline together
- Slow or incomplete pressure buildup
Example (1) - Onset

Well recovers before loading completely

\[ Q_{\text{min}} \approx 160 \times 10^3 \text{ m}^3/\text{d} \]

FTHP = 10 bara
Gas rate (m³/d)

\( Q_{\min} = 40,000 \text{ m}^3/\text{d} \)

\( Q_{\text{meta}} = 12,000 \text{ m}^3/\text{d} \)

Pressure depth graph

Flowing gas gradient unloaded
Flowing gas gradient loaded
Pore pressure
Example (2a) – Bubble Flow

Metastable production or bubble flow: \( Q_{\text{meta}} \approx 50 \times 10^3 \, m^3/d \)

\[ Q_{\text{min}} \approx 190 \times 10^3 \, m^3/d \]
Example (2b) – Bubble Flow (SPE 153073)

Graph showing the monthly average gas rate over the years from 1960 to 2020. The graph highlights the liquid-loading rate and the meta-stable rate. The data includes information such as the cumulative gas and oil production.
Example (3) – Horizontal Well

Well kicked off using batch foam

\[ Q_{\text{min}} \approx 90000 \text{ m}^3/\text{d} \]
Pressure Buildup (PBU)

- Hydrostatic column after shut-in consists of gas column on top and liquid column on bottom.
- Liquid column depends on reservoir, well and production parameters, increases dramatically after liquid loading.
- Liquid column will drain into reservoir i.e. will decrease and ultimately disappear.
- Monitor liquid loading (and water production) via PBU.
Example (4) – Formation Water Breakthrough

- **K15-FK-106**

  - **K15-FK Flowline WH-106**
  - **K15-FK THP WH-106**
  - **K15-FK THP TEMPERATURE WH-106**

  - \( K15FK1.FIC-01-6.PV \) 6Nm\(^3\)/d
  - \( K15FK1.PI-02-6.PV \) barg
  - \( K15FK1.TI-02-6.PV \) °C

  - 15/01/2011 16:44:57.338
  - 01/04/2011 16:44:57.338
  - 5.00 days

  - 0.2
  - 0.4
  - 0.6
  - 0.8
  - 1
  - 1.2
  - 1.4
  - 1.6
  - 1.8

  - 0
  - 2
  - 0
  - 200
  - 0
  - 100

  - 77.2
  - 64.5
  - 0.256

  - **Dry BU**

  - **Wet BU**
Example (5) – Tight Gas with Natural Fractures

- CMS_PW-FI-0580
  0.00000
  T/J DAY
- CMS_PW-PI-0583
  113.07597
  BARG

Dry BU

Wet BU

- WELL A-580 (PW-27) FLOW
- WELL A-580 (PW-27) PRESS

7) FLOW : WELL A-580 (PW-27) PRESS
Example (6) – Large Liner Kick-Off

- GGT1-FR-31
  69505
  Nm³/d
- KOL1-PR-1
  18.119
  BARG
- KOL1-TRC-1
  29.680
  Gr C

KOL-1

Liner Loading & Unloading
Liner Slugging

11/01/2012 00:06:04
15/01/2012 00:07:32
4.00 days
Model Liquid Loading
Translates minimum gas velocity at wellhead into minimum gas rate

Independent of WGR

Water of condensation sufficient to cause liquid loading

Liquid loading initiated by water also in high CGR gas wells

Minimum rate for condensate typically ½ minimum rate for water

$Q_{\text{min}} = \frac{TC \cdot \text{FTHP}^{0.5} \cdot \text{ID}^2}{[(\text{FTHT}+273) \cdot Z]}$

E.g. 5” tubing & 20 bar FTHP
$Q_{\text{min}} = 70,000 \text{ m}^3/\text{d}$
- Takes multi-phase flow regime along entire wellbore into account
- Bottom of lift curve is accepted as most representative minimum stable rate – steady state production left of bottom is possible but unreliable
- Bottom ≠ Turner
- Especially at higher \( Q_{\text{min}} \) (above 50e3 m\(^3\)/d or 2 MMscf/d)

**Q_{\text{min}} – Wellbore Model, Bottomhole Pressure (e.g. Prosper)**

\[ P_{\text{res}} = 50 \text{ bar}, \ A = 10 \]
\[ \text{FTHP} = 10 \text{ bar}, \ ID = 4.291” \]
\[ \text{WGR} = 100, \ CGR = 100 \]
\[ \text{WGR} = 0, \ CGR = 100 \]
\[ \text{WGR} = 0, \ CGR = 0 \]
\( Q_{\text{min}} \) - Tapered String (Liquid Loading = Misnomer)

- \( Q_{\text{min}} \) means instability rather than liquid loading
- Liquid loading can occur at gas rate higher than \( Q_{\text{min}} \)

\[
\begin{align*}
Q_{\text{LL}} &= 50,000 \text{ m}^3/\text{d} \\
Q_{\text{LL}} &= 103,000 \text{ m}^3/\text{d} \\
Q_{\text{LL}} &= 223,000 \text{ m}^3/\text{d}
\end{align*}
\]

- 4" String
- 6" String
- 8" String

\[
\begin{align*}
3000m 4" \quad Q_{\text{min}} &= 61,830 \text{ m}^3/\text{d} \\
2800m 4"+200m 8" \quad Q_{\text{min}} &= 63,990 \text{ m}^3/\text{d} \\
200m 6"+2600m 4"+200m 8" \quad Q_{\text{min}} &= 91,104 \text{ m}^3/\text{d}
\end{align*}
\]
Importance of Liquid Loading
Material Balance

Material Balance

\[
G_p = OGIP \frac{(P_i/Z - P_{res}/Z)}{(P_i/Z)}
\]

\[
UR = OGIP \frac{(P_i/Z - P_{min}/Z)}{(P_i/Z)}
\]

\[
RF = \frac{(P_i/Z - P_{min}/Z)}{(P_i/Z)}
\]

\[
\Delta G_p = 505e6 \text{ m}^3
\]

\[
P_i/Z = 200 \text{ bara}
\]

\[
P_{res}/Z = 117 \text{ bara}
\]

\[
P_{min}/Z = 83 \text{ bara}
\]

\[
D = 15e6 \text{ m}^3/\text{bara}
\]

Tank model
- Straight line material balance determines incremental production as reservoir pressure declines
- Not representative for tight gas well
- Better represented by two-tank or multi-tank model
Determine incremental reserves based on reduction of minimum achievable reservoir pressure ($P_{\text{min}}$)

- Material Balance – “Single Tank”
  - $Q_{\text{min}} = 0.15$ mln m$^3$/d
    - $(P/Z)_{ab} = 28$ bar
    - UR = 1.66 Bcm
  - $Q_{\text{min}} = 0.3$ mln m$^3$/d
    - $(P/Z)_{ab} = 34$ bar
    - UR = 1.62 Bcm
Impact of LL and GWD on Ultimate Recovery

Assumes Vertical Well

Recovery Factor (%)

(K.H (mD.m))

(A=10,000) (A=1000) (A=100) (A=10)

Tight Prolific

4-1/2" Tubing, 20 bara FTHP
2-3/8" Tubing, 20 bara FTHP
2-3/8" Tubing, 2 bara FTHP

(Improve KH) Deliquification
GWD Very Important for Tight Gas Reservoirs

Reservoir Quality

GWD
Compression
HorWell Stimulation
Primary Depletion

Recovery Factor

Tight Poor Moderate Prolific

0% 100%
Gas Well Deliquification
Gas Well Deliquification

- Increase gas rate above $Q_{\text{min}}$
  - Compression, stimulation, gas lift, intermittent production
- Reduce $Q_{\text{min}}$
  - Compression, velocity string, foam, plunger
- Remove liquid
  - Downhole pump, heater
Life-Cycle GWD Strategy

Early Life
- Casing Flow
- Tubing Flow
- Intermittent Production

Mid-Life
- Compression
- Velocity String
- Foamer
- Plunger

Late Life
- More Compression
- Gas Lift
- Downhole Pump
Deliquification Techniques

- Intermittent production
- Compression
- Stimulation or water shut-off
- Velocity string
- Continuous foam
- Plunger lift
- Gas lift
- Downhole pump
Intermittent Production
Natural Cycle

- (1) & (5) Stable production: both gas & liquids produced to surface
- (2) Liquid loading: liquids no longer produced to surface, gas production declines as liquid column builds
- (3) Meta-stable production: gas produced to surface, liquids injected downhole
- (4) No production: no gas production, liquids injected downhole, pressure recovery
(1) & (5) Stable production: both gas & liquids produced to surface

(2) Liquid loading: liquids no longer produced to surface, gas production declines as liquid column builds

(3) Meta-stable production: gas produced to surface, liquids injected downhole

(4) No production: no gas production, liquids injected downhole, pressure recovery
**IP – Field Example (1)**

- **Flowrate (E3m³/d)**
- **Date**
  - 04/28/2007
  - 11/14/2007
  - 06/01/2008
  - 12/18/2008
  - 07/06/2009
  - 01/22/2010
  - 08/10/2010
  - 02/26/2011

- **OJP #1 Production (LL then Cycled Effectively)**
  - **Avg Daily Production**
  - **Avg Monthly Production**

**Q_{min} \approx 12e3 m^3/d**

**Metastable production is sub-optimum !!!**

**Continuous Flow**

**Cycling**
IP – Field Example (2)
Start-up of Automated Intermittent Cycles

Increase in daily average water and gas production
Reservoir pressure at onset of liquid loading is unchanged for fast tank.

Reservoir pressure at onset of liquid loading is higher for slow tank, difference controlled by inflow and crossflow parameters.

Slow tank gas volume left at elevated pressure represents gas volume available for intermittent production.
Production Forecast ($V_{\text{fast}}/V_{\text{slow}}=0.10$, $A/R=0.20$)

- $P_i = 350$ bara
- OGIP = $500 \times 10^6$ m$^3$
- $V_{\text{fast}}/V_{\text{slow}} = 0.10$
- $A = 20$ bar$^2/$(e3m$^3$/d)
- $R = 100$ bar$^2/$(e3m$^3$/d)
Close to 100% uptime in first stage of liquid loading

Fig. 12 – Percentage of time since onset of liquid loading that the well is producing.
Compression
# Twin-Screw Pumps

<table>
<thead>
<tr>
<th><strong>Bornemann SLM Series</strong></th>
<th><strong>Bornemann</strong></th>
<th><strong>Leistritz MPS Series</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Single-Well</strong></td>
<td><strong>Well-Cluster Pump</strong></td>
<td><strong>Single-Well Pump</strong></td>
</tr>
<tr>
<td><strong>Applications:</strong></td>
<td><strong>Application:</strong></td>
<td><strong>Applications:</strong></td>
</tr>
<tr>
<td>✓ Penn West (Canada) - Red Earth Field</td>
<td>✓ Mobil (Canada)</td>
<td>✓ Talisman Energy (Canada)</td>
</tr>
<tr>
<td>✓ ExxonMobil (Germany) – Lastrup Field</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>8-1,100 Mscf/day (227-31,000 m3/day)</strong></td>
<td><strong>up to 15,000 Mscf/day (425,000 m3/day)</strong></td>
<td><strong>160-2,400 Mscf/day (4,500-68,000 m3/day)</strong></td>
</tr>
<tr>
<td><strong>16 bar (232 psi) Boost</strong></td>
<td><strong>up to 50 bar (700 psi) Boost</strong></td>
<td><strong>10-20 bar (150-300 psi) Boost</strong></td>
</tr>
<tr>
<td><strong>8-90 kW (10-120 hp)</strong></td>
<td></td>
<td><strong>20-350 hp (15-260 kW)</strong></td>
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</tbody>
</table>

*At $P_{wellhead} = 10$ bar (150 psig)
Velocity String
Gas Well Deliquification Modelling – Velocity String

- Deliquification changes outflow a.k.a. lift curve
- Lift curves for deliquification can be easily modelled in case of compression and velocity string
- Lift curves for other cases are less straightforward e.g. foam and plunger
TID-305 Velocity String Example (1)

TID305

<table>
<thead>
<tr>
<th>7” Casing</th>
<th>3-1/2” Tubing</th>
<th>2” CT</th>
</tr>
</thead>
<tbody>
<tr>
<td>50000</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>40000</td>
<td>50</td>
<td>50</td>
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<tr>
<td>30000</td>
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<td>50</td>
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<tr>
<td>20000</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>10000</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>0</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>0</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>21207</td>
<td>12520</td>
<td>28120</td>
</tr>
</tbody>
</table>

CT Installed

- TID3-FR-305 28120. NM3/D
- TID3-PR-305 12.520 BARG
- TID3-TR-305 21.207 GR C

- NATGAS

01/07/2000 00:00:00 123.00 days 01/11/2000 00:00:00
Champlin 149-B2 Velocity String Example (2)

Average rate for 90 days prior to installation: 246 mcfd
Average for last 30 days: 327 mcfd

Paid out in 3 months

Total Cost: $20,121

7” Casing  2-3/8” Tubing  1-1/4” CT

CT Installed

MCFD  Tubing PSI  Casing PSI  Line PSI  Projection

Paid out in 3 months
Champlin 222-C2 Velocity String Example (3)

Average rate for 90 days prior to installation: 911 mcfd
Average rate for last 30 days: 539 mcfd

Gross Cost: $19905

5-1/2” Casing  2-3/8” Tubing  1-1/4” CT

CT Installed

Average rate for 90 days prior to installation: 911 mcfd
Average rate for last 30 days: 539 mcfd
(Continuous) Foam
Soaping

- Introduce a surfactant at bottom of tubing to induce foaming
- Soap sticks, backside, capillary string injection
- Less effective with condensate
Continuous Foam Lift

- Continuous injection of surfactant (solution) via 1/4” capillary string or backside
- Reduces minimum rate by ≥ 30%
- Surfactant concentration 1,000-10,000 ppm
Continuous Foam – Field Example (1)

Start Soap Injection
Rate $14.1 \times 10^3$ m$_3$/d
Declining Casing Pressure

With Soap Performance
Continuous production for 7 weeks at high rate.
Estimated up-lift: $5 \times 10^3$ m$_3$/d
On-time increased from 50 to 100%

Forward Plan
Reduce soap injection rate
Continuous Foam – Field Example (2)

3-1/2” Casing  1-1/4” CT

CT  Foam

Gas Rate (MCF/D)
Continuous Foam – Solutions to Retain SSSV

Actuated Manual

Onshore

Offshore

Control line fluid and Surfactant

FV=SSSV

Control line fluid

REN-LMGV

FV=SSSV

KW

SV

FWV

UMGV=SSV

LMGV

Surfactant
Plunger
1. Plunger at surface, well open: gas is produced, liquid accumulates on top of standing valve

2. Well shut in: plunger drops to bottom

3. Plunger on bottom with liquid slug on top: casing pressure builds up

4. Well open: casing gas expansion plus reservoir gas push plunger plus liquid to surface

5. Plunger at surface, well open: gas is produced, liquid accumulates
**WYK-32 Plunger Lift**

- **WYK-32**
- **Open up**
- **Flow period**
- **Plunger rise**
- **Shut-in period**
- **Shut in**
- **Plunger falls**
- **Plunger arrives**

**CALCULATED FLOW**

FLOWLINE TO WELLHEAD PRESSURE

TEMPERATURE

Target velocity up = 150-300 m/min

1200 m AHD in 6 min = 200 m/min
Field Examples
Plunger Design and Material Selection

- Plunger design
  - Barstock plungers are commonly used due to low cost and low maintenance.
  - Viper plungers are used for wax wells (spiral design)
  - In low production wells, padded plungers are used to provide better seal

- Material Selection
  - Lubricator – rated for 5000 psi and cold temp spec
Plunger Materials
Gas Lift
Intermittent Gas Lift using Concentric Coiled Tubing

1. Dry Gas Bubble Flow
2a. Lift Gas CT
2b. Lift Gas CTxCT Annulus
3. Wet & Dry Gas Flow

Movie #10
Downhole Pump
Pulse Pump or Balance Pump

- Hydraulically actuated down-hole pump system in a pulsing manner.
- Simple DH reciprocating pump – no reversing mechanism required.
- Closed power-fluid system with only one string for single acting.
- Simple surface equipment.
- For deep well with 4.5” casing, the pump have to run through the casing or 3.5” tubing.
- Pump capacity is lower rate ~ 20 BPD for deep well and small casing.
Select Deliquification
One Tool Does Not Solve All Problems
Selection Impacted by Well Parameters

- **LGR (WGR and CGR)**
  - Plunger lift has limited liquid capacity (slug size & cycle time)
  - Gas lift is designed to handle large liquid volumes

- **Solids**
  - Downhole pump requires screen / filter to handle solids
  - Gas lift does not depend on solids

- **Completion geometry**
  - Plunger deployment depth and effectiveness dictated by ID profile
  - Compression does not depend on completion geometry

- **Well geometry**
  - Plunger cannot be deployed beyond 50-60 degrees deviation
  - Velocity string can be installed down long horizontals
Selection Impacted by Operating Parameters

- Installation cost
  - Downhole pump requires significant investment in well and surface equipment
  - Plunger lift is characterised by low installation cost

- Reliability
  - Downhole pump has limited reliability
  - Velocity string has excellent reliability

- Operating cost
  - Plunger lift increases number of interventions and is often not compatible with offshore production operations
  - Velocity string does not require additional interventions
Make GWD Part of Initial Well & Facility Design

- Consider future deliquification when designing new well and surface facilities
- Select tubing size that is robust against low productivity scenario
- Adopt monobore to avoid liner loading & to allow use of plunger
- Include actuated (flow wing) valve and wellhead P/T gauge upstream of flowing wing valve for intermittent production
- Provide well profile to hang off velocity string
- Provide wellhead / Xmas tree access for continuous foam, gas lift and/or pump hydraulics
- Provide flowline / manifold access for mobile compression
- Plan for power for compression
- Plan for gas lift flowlines for gas lift
- .....................