Topics

Field Operations
- Wellhead operations
- Piping
- Compressor stations
- Pigging

Inlet Receiving
- Separator principles
- Slug catcher configurations

Gas Hydrates
Field Operations
GOSP

Gas-Oil Separation Process (GOSP) for removing gas from high pressure oil well.

Associated gas is almost always saturated with water.

- Either dehydration (usually glycol dehydration, see Chapter 11) or...
- Hydrate inhibitors (see section 8.3) are added to prevent hydrate formation.
Compression station (Booster Station)

Condensed liquids may be stored or returned to the line

Some locations may have dehydration or sweetening facilities

Figure 8.4
Pigging

- Provides a barrier between liquid products using the same pipeline
- Check wall thickness and find damaged sections of lines
- Remove debris such as dirt and wax from lines
- Provide a known volume for calibrating flow meters
- Coat inner pipe walls with inhibitors
- Remove condensed hydrocarbon liquids and water in multiphase pipelines

Courtesy of Girard Industries
Instrumented Pigs

from GmbH
Pig Launcher & Receiver
Inlet Receiving
Gas-Liquid Separators

Final protection for downstream equipment

Either vertical or horizontal

Vessel has four stages of separation:
- Primary Separation
- Gravity Settling
- Coalescing
- Liquid Collecting
Gas-Liquid Separators

A = Inlet Device
B = Gas Gravity Separation
C = Mist Extraction
D = Liquid Gravity Separation
Typical 3-phase Separator

From: Natural Gas Production/Dehydration, J.W. Williams Inc.
Inlet Receiving (Slug Catchers)

Protect plant from large, sudden liquid influxes

Two kinds

- Manifolded piping
  - Good for high pressures, open space
  - Still require liquid storage

- Large vessels
  - Good at lower pressures
  - Combines slug catching and liquid storage

Adequate liquid storage needed in both kinds
Harp Design Slug Catcher

Kimmitt et al., 2001
Harp Design Slug Catcher

“A new approach for sizing finger-type (multiple-pipe) slug catchers”
H. R. Kalat Jari, P. Khomarloo, & K. Ass
Harp Design Slug Catcher

Gas Hydrates
Hydrates: Problems/Issues

Solid hydrate can cause:
- Plugging in pipelines and process equipment
- Freezing of valves/relief valves
- Damage to piping due to solid material flowing at high velocities
- Contained energy, dangerous when they heat up and gas evaporates

Commonly found:
- Oil/gas applications
- Bottom of ocean
- Arctic climates under permafrost
What are gas hydrates?

Ice-like solids which can form well above 32°F.

Natural gases form in one of three structures but most commonly in Structure II.

Hydrate forming gases include: \( N_2, O_2, C_1 \) through \( iC_5, H_2S \) and \( CO_2 \).

Hydrate formation conditions highly dependent upon gas composition.

- Propane content is a major factor.
Hydrates: Structures

- Water molecule 'cage'
- Gas molecule (e.g. methane)

Methane, ethane, carbon dioxide....
Propane, iso-butane, natural gas....
Methane + neo-hexane, methane + cycloheptane....

www.pet.hw.ac.uk
What do they form?

Either of three crystalline structures

<table>
<thead>
<tr>
<th>Waters per unit cell</th>
<th>Structure I</th>
<th>Structure II</th>
<th>Structure H</th>
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<tbody>
<tr>
<td></td>
<td>46</td>
<td>136</td>
<td>34</td>
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<tr>
<td>Small</td>
<td>6</td>
<td>8</td>
<td>3</td>
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<tr>
<td>Large</td>
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<td>2</td>
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<tr>
<td>Cages per unit cell</td>
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<td></td>
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<td></td>
<td>6</td>
<td>8</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2</td>
<td>1</td>
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<tr>
<td>Average cage radius,</td>
<td>39.1</td>
<td>39.0</td>
<td>39</td>
</tr>
<tr>
<td>nm</td>
<td>43.3</td>
<td>46.8</td>
<td>4.1</td>
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<tr>
<td>Gases fitting into</td>
<td>N₂,O₂, C₁,H₂S</td>
<td>N₂,O₂, C₁,H₂S</td>
<td>N₂,O₂, C₁,H₂S</td>
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<tr>
<td>cages</td>
<td></td>
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<tr>
<td>N₂, O₂, C₁, H₂S, C₂</td>
<td></td>
<td>N₂, O₂, C₁, H₂S, C₂, C₃, iC₄, C₄</td>
<td>N₂, O₂, C₁, H₂S, C₂, C₃, iC₄, C₄, iC₅</td>
</tr>
</tbody>
</table>
Hydrate formation in gases
Methane + Propane Hydrate Formation

![Graph showing hydrate formation data](image)

- 100% Methane
- 99.0%
- 97.4%
- 95.2%
- 88.3%
- 36.2%

<table>
<thead>
<tr>
<th>Temperature, °F</th>
<th>Pressure, psia</th>
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</thead>
<tbody>
<tr>
<td>30</td>
<td>10</td>
</tr>
<tr>
<td>35</td>
<td>100</td>
</tr>
<tr>
<td>40</td>
<td>1000</td>
</tr>
<tr>
<td>45</td>
<td>10000</td>
</tr>
<tr>
<td>50</td>
<td>36.2%</td>
</tr>
<tr>
<td>55</td>
<td>95.2%</td>
</tr>
<tr>
<td>60</td>
<td>99.0%</td>
</tr>
</tbody>
</table>

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Hydrate formation in liquids
Ethane hydrate formation conditions

![Graph showing the formation conditions for ethane hydrates with pressure on the y-axis and temperature on the x-axis.]

- **H-L**
- **H-V**
- **L-W-V**
- **Ice-V**

Temperature, K
Pressure, kPa
Predicting Hydrate Formation

Two factors in hydrate formation:

Thermodynamics

- Equilibrium formation temperature and pressure
  - PREDICTABLE

Kinetics

- Initiation and rate of growth
  - UNPREDICTABLE
Methods for Predicting Equilibrium Formation Temperature and Pressure

Gas gravity curve (Katz, 1945)

- Advantages
  - Quick & simple
- Disadvantages
  - Poor accuracy
  - Valid for pure water only

Statistical Mechanics (van der Waals and Plateeuw, 1959)

- Advantages
  - Most accurate
  - Handles salts, MeOH, EG
- Disadvantages
  - Complex & requires computer for calculations
Hydrate forming conditions

Figure 8.12

Below 1000 psia:

\[
t\left[^{\circ}F\right] = -16.5 - \frac{6.83}{\gamma_g^2} + 13.8 \ln(P[\text{psia}])
\]
Avoid hydrate complications

If prediction shows that the plant or pipeline will be operating within the hydrate formation region, what can you do??

- Change operating conditions so you are outside the hydrate formation region
- Dehydrate the gas
- Add hydrate inhibitors
Chemical inhibitors for hydrates

Advantages

- Used properly, they work

Disadvantages

- Cost
- Determining proper dose
- Injection site may be at a remote location
  - Transportation to site and possible dealing with hazardous materials
- Possible interaction with other additives (such as corrosion inhibitors)
- Possible problems with downstream processes
Classes of chemical hydrate inhibitors

Antiagglomerates (AA)
- Prevent small particles from grouping into larger particles

Kinetic
- Interfere with construction of cages

Thermodynamic
- Freezing point depression
- Mainly methanol and ethylene glycol (antifreeze)
Hammerschmidt equation (1939)

Estimate the concentration of hydrate inhibitor in the water phase to decrease the hydrate forming temperature a specified amount

\[
(\Delta T)_F = \frac{2335 \ W_i}{M_i (1 - W_i)} \quad \Rightarrow \quad W_i = \frac{(\Delta T)_F \ M_i}{(\Delta T)_F \ M_i + 2335}
\]

where:
- \(\Delta T\) is the hydrate depression temperature difference
- \(M_i\) is the molecular weight of the inhibitor
- \(W_i\) is the mass fraction inhibitor in the free water phase

Example – what concentration methanol (32 mol wt) will provide 20°F subcooling into the hydrate region?

\[
W_i = \frac{(\Delta T)_F \ M_i}{(\Delta T)_F \ M_i + 2335} = \frac{(20)(32)}{(20)(32) + 2335} = 0.215 \quad \Rightarrow \quad 21.5 \text{ wt%}
\]
Nelson & Bucklin equation (1983)

Estimate the concentration of hydrate inhibitor in the water phase to decrease the hydrate forming temperature a specified amount

\[(\Delta T)_c = -129.6 \ln(x_w)\]

where: \(\Delta T\) is the hydrate depression temperature difference
\(x_w\) is the mole fraction water in the free water phase

Example – what concentration of methanol (32 mol wt) will provide a 20°F subcooling into the hydrate region?

\[x_w = \exp\left[\frac{(\Delta T)_c}{-129.6}\right] = \exp\left[\frac{20}{-129.6}\right] = 0.8570\]

\[W_{MeOH} = \frac{x_{MeOH}M_{MeOH}}{x_wM_w + x_{MeOH}M_{MeOH}} = \frac{(1-0.8570)(32)}{(0.8570)(18) + (1-0.8570)(32)} = 0.229 \Rightarrow 22.9 \text{ wt%}\]
Kinetics of hydrate formation

Hydrate onset is stochastic and unpredictable

Subcooling always occurs
  - Usually can operate 2 to 4°F into hydrate region without problem

Factors affecting onset and kinetics:
  - Amount of subcooling
  - Presence of liquid water
  - Presence of nucleation sites, e.g., scale, wax, asphaltenes
  - Flow rates
  - Presence of other hydrocarbon phases
  - “History” of water phase
Effect of Memory on Hydrate Formation Rate
How To Prevent Hydrate Formation

Operate outside of hydrate region

- Advantages
  - Good where practical
- Disadvantages
  - Frequently impractical
  - Heating systems are expensive and must be robust
  - Lowering pressures likely requires recompression

Dry the gas - avoid free liquid water

- Advantages
  - Safest
- Disadvantages
  - Frequently impractical
  - Dehydration expensive, CAPEX & OPEX
  - CO$_2$, NO$_x$, BTEX emissions

Add equilibrium inhibitors

- Alters temperature and pressure of hydrate formation

Add Low Dosage Inhibitors (LDI)

- Alters rate of formation (kinetic inhibitors) or prevents agglomeration
Effect of Methanol on Hydrate Formation Conditions

Temperature, °F

Pressure, psia

Wt % Methanol

74  65  50  35  20  10  0

-100 -80 -60 -40 -20  0  20  40  60  80

10000

1000

100

Temperature, °F

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Rate of hydrate formation in presence of kinetic inhibitors

Effect of Kinetic Inhibitors on Hydrate Formation

85% C₁ + 10 CO₂ + 5% C₃, No Salt

No Inhibitor

PVP

PVCap

VC-713

IQ-1

T = 40°F

ΔT = 18°F

P = 600 psia

ΔP = 425 psi

Inhibitor Conc. = 0.5 wt%
# Comparison of kinds of inhibitors

<table>
<thead>
<tr>
<th></th>
<th>Equilibrium</th>
<th>Low Dosage</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>MeOH</td>
<td>EG</td>
</tr>
<tr>
<td><strong>Applicability</strong></td>
<td>Universal</td>
<td>Universal</td>
</tr>
<tr>
<td><strong>Time Dependence</strong></td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td><strong>Unit Cost</strong></td>
<td>Cheap</td>
<td>Cheap</td>
</tr>
<tr>
<td><strong>Amount Needed</strong></td>
<td>20 to 50 Wt%</td>
<td>20 to 50 Wt%</td>
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<tr>
<td><strong>Compatibility</strong></td>
<td>????</td>
<td>????</td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td>Toxic</td>
<td>Toxic, Oil &amp; Grease</td>
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<tr>
<td><strong>Volatility</strong></td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td><strong>Processing Issues</strong></td>
<td>Recovery?</td>
<td>Recovery?</td>
</tr>
</tbody>
</table>
Using Inhibitors

Factors determining injection rate:

- Maximum subcooling (include brine effect)
  - Determines inhibitor concentration
- Amount of free and condensing water present
  - Determines injection rate for treating water
- Hydrocarbon flow rate
  - If gas phase present, must include vapor losses for MeOH
  - If condensed hydrocarbon phase present, must include inhibitor losses
Summary – How Can Hydrates Be Prevented

When practical, operate outside of hydrate region or avoid free water in system.

Add equilibrium inhibitors, MeOH or EG
  - Many costs associated with this option and it may not be available in future.

Add LDI, KI at low subcooling, AA at higher subcooling
  - Emerging and attractive technology, but need to verify effectiveness

No matter which option is chosen, remember hydrate inhibitors must be compatible with other inhibitors.
How To Remove Hydrates

Onboard/onshore process equipment
- Shut-in, depressurization and warm-up

Well and pipeline plugs
- Learn what happened prior to plugging and possible cause
- Locate plug by altering line pressure
- Determine best route, MeOH injection, heating, depressurization
  - Beware of JT cooling, safety issues.
- Decide restart procedure, including removal of water
Is there anything good about hydrates?

Very large potential source of $C_1$ from $C_1$-hydrates on ocean floor

Inexhaustible source of research projects for graduate students
Summary
Summary

Field Operations
- Initial gas, oil, & water separations at the well site
- May have field compression to get gas to the processing location

Gas Gathering System
- Need to design for multiphase flow
- Pigging very common

Inlet Receiving
- Final protection for downstream equipment
- Need to have volume to contain & bleed off slugs of liquids

Gas Hydrates
- Try to prevent either by thermodynamic or kinetic inhibitors
Approximate operating Ranges of mist eliminators

Courtesy of ACS Industries
Droplet capture efficiency

THEORETICAL EFFICIENCY VS. VELOCITY FOR VARIOUS DROPLET SIZES (WATER IN AIR AT AMBIENT CONDITIONS FOR TYPICAL MESH PADS AND PLATE-PAK™ UNITS WITH LIGHT LIQUID LOAD)

Courtesty of ACS Industries

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Gas wells with condensate tank & fired separators

Figure 8.2
Booster station

Courtesy of Wind River Environmental Group
Automated Ball Launcher

From Kimmitt, et al., 2001
Inlet Receivers with Pigs
Inlet receivers (slug catchers)

Figure 8.18
Multiple Slug Catcher

Liquid volume 500 bbls, nominal gas rate 206MMscfd

Kimmitt et al., 2001
Gas Well with Separator and Tankage
Gas Wells and Metering

Courtesy of the Williams Companies
Como Ball Receiver
G-Line Pig Receiver
H-Line Pig Receiver
Inlet Facilities
Remote automated pig launcher
Smart pig removed from receiver

Figure 8.9

Smart pig being removed from pig receiver. The pig uses magnetic flux to detect corrosion and mechanical damage in pipeline wall. (Courtesy of ROSEN Group)
Aerial view of slug catcher

Courtesy of The Williams Companies