Pseudo Dry Gas System

Economic performance of the novel Pseudo Dry Gas System for long distance tiebacks

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Re-cap

• AOG 2018 – INTECSEA introduced an innovative Pseudo Dry Gas (PDG) separation technology

• Demonstrated that tie backs far in excess of the current threshold distance can be achieved.

• Objective is to make long distance subsea tiebacks, which are typically not economically or even technically feasible, commercially viable.
Problem -> Solution

• Common belief that insufficient pressure (energy) at the wells is hindering viability of ‘stranded gas’ fields....however...

• ...typically, the underlying problem is the liquid generated by the gas during transportation. Liquid accumulation = excessive pressure drop = high turn down = reduced gas recovery

• PDG addresses the root problem – targeted liquid removal at the point of accumulation

• Removing the gravitational pressure loss allows the use of large pipelines (limited only by installation) to negate the frictional pressure drop

• Bulk subsea separation alone is not sufficient – limited by water depth and liquid does not all condense at the inlet of the pipeline
Concept

- Compact - Installed as a pipeline in-line structure
- Passive - no moving parts or consumables
- Piggable
Configuration

- Multiple PDG units are installed in-line and are piggable. Liquids are removed via small diameter pipe and small single phase centrifugal pumps (kW).

- Power, telecommunications cables, hydrate inhibitor such as MEG and other service lines are deployed by means of an umbilical.
Techno-Economic Case Study

- Case study basis data provided by the UK Oil and Gas Authority
- Peer reviewed by North Sea based Operators / Tier 1 contractors

- North Sea (West of Shetland) – known basin of stranded gas fields in 1700 m water depth, with significant geographical spread between fields
- Base case ("Phase 1") potential is approx. 2.5 TCF (full basin ~6.5 TCF (GIIP))
- 200 km subsea trunkline tie-back to onshore terminal
- 500 MMscfd target plateau rate
- Liq. to Gas Ratio 6 bbls/MMscfd (water, cond., MEG)

Options assessed:

- FPSO, dry gas export
- Subsea Tie-back (Wet) – single vs. dual flowlines
- Wet Gas Subsea Compression - proven (dP=32 bar) vs. future (Pr=2)
- Pseudo Dry Gas
## Technical Evaluation Summary

<table>
<thead>
<tr>
<th></th>
<th>FPSO, dry gas export</th>
<th>Subsea Tie-back – single flowline</th>
<th>Subsea Tie-back – dual flowlines</th>
<th>WGC - proven (dP=32 bar)</th>
<th>WGC- future (Pr=2)</th>
<th>Pseudo Dry Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Optimum line size</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1 x 30”</td>
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<tr>
<td></td>
<td>2 x 10” (risers)</td>
<td>1 x 22”</td>
<td>2 x 18”</td>
<td>2 x 18”</td>
<td>2 x 18”</td>
<td></td>
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<tr>
<td><strong>WHP to deliver 500 MMscfd @ HP</strong></td>
<td>114 bar</td>
<td>168 bar</td>
<td>168 bar</td>
<td>132 bar</td>
<td>84 bar</td>
<td>102 bar</td>
</tr>
<tr>
<td><strong>Trunkline pressure drop</strong></td>
<td></td>
<td>98 bar</td>
<td>98 bar</td>
<td>98 bar (incl. 32 bar WGC)</td>
<td>98 bar (incl. 84 bar WGC)</td>
<td>32 bar</td>
</tr>
<tr>
<td></td>
<td>98 bar</td>
<td>98 bar</td>
<td>98 bar</td>
<td>98 bar (incl. 32 bar WGC)</td>
<td>98 bar (incl. 84 bar WGC)</td>
<td></td>
</tr>
<tr>
<td><strong>Slug (surge) volume generated from short term turn down and ramp-up 100%-&gt;50% to 100% (100%-&gt;25%-&gt;100%)</strong></td>
<td>2421 m³ (9208 m³)</td>
<td>1034 m³ (4416 m³)</td>
<td>1034 m³ (4416 m³)</td>
<td>1034 m³ (4416 m³)</td>
<td>negligible</td>
<td></td>
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<td></td>
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<td></td>
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</tr>
<tr>
<td><strong>Subsea Power</strong></td>
<td>No subsea power demand</td>
<td></td>
<td>7 MW</td>
<td>20 MW</td>
<td>0.5 MW</td>
<td></td>
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Technical Viability

- **FPSO, dry gas export**: FPSO located over main reservoir, distant fields cannot be tied-back (insufficient WHP). Riser elevation = 1.6 km, JT expansion in risers gives -23°C.

- **Subsea Tie-back – single flowline**: Not considered technically feasible due to liquid management (excessive / uncontrollable slug volume) – unable to recover the trunkline following shutdown.

- **Subsea Tie-back – dual flowlines**: Liquid management still a challenge, large slug catcher and careful ramp-up control required.

- **WGC - proven (dP=32 bar)**: Compression required within 18 months (e.g. Day 1 install).

- **WGC - future (Pr=2)**: Significant subsea power demand.

- **Pseudo Dry Gas**: Solution gives near dry gas performance, solves liquids management issues.
- 4 x units strategically located to manage liquids
- Liquid removal units efficiencies based on experimental work and two independent CFD studies (Strathclyde University & in-house)
- Solution gives near dry-gas performance

<table>
<thead>
<tr>
<th>Case</th>
<th>PDG (bar)</th>
<th>Dry Gas (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 MMscfd SoL</td>
<td>102</td>
<td>100</td>
</tr>
<tr>
<td>250 MMscfd SoL</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>125 MMscfd SoL</td>
<td>-</td>
<td>81</td>
</tr>
<tr>
<td>500 MMscfd EoL</td>
<td>72</td>
<td>70</td>
</tr>
<tr>
<td>250 MMscfd EoL</td>
<td>48</td>
<td>47</td>
</tr>
<tr>
<td>125 MMscfd EoL</td>
<td>-</td>
<td>38</td>
</tr>
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</table>
Recovery Assessment – Phase 1

• Integrated production modelling to assess plateau duration and total recovery for base case (Phase 1) development

- PDGS significantly reduces the back pressure on the wells versus other options – by up to 65 bar, therefore gives significant additional duration on plateau, resulting in a recovery improvement over other options.
Recovery Assessment – Full Field

- PDGS significantly reduces the back pressure on the wells versus other options – by up to 65 bar, therefore gives significant additional duration on plateau, resulting in a recovery improvement over other options

- Results are confirmed and accentuated when the full field development is assessed

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<th>Phase</th>
<th>Recovery</th>
<th>PLATEAU DURATION</th>
<th>RECOVERY</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>FPSO, dry gas export</td>
<td>P1=5.5 years FFD=5.5 years</td>
<td>P1=67% FFD=26%</td>
</tr>
<tr>
<td></td>
<td>Tie-back dual FLs</td>
<td>P1=3.5 years FFD=12 years</td>
<td>P1=51% FFD=48%</td>
</tr>
<tr>
<td></td>
<td>WGCproven (dP=32bar)</td>
<td>P1=4.5 years FFD=13 years</td>
<td>P1=51% FFD=51%</td>
</tr>
<tr>
<td></td>
<td>WGCfuture (Pr=2)</td>
<td>P1=5.5 years FFD=17 years</td>
<td>P1=64% FFD=61%</td>
</tr>
<tr>
<td></td>
<td>Pseudo Dry Gas</td>
<td>P1=6.5 years FFD=23 years</td>
<td>P1=69% FFD=61%</td>
</tr>
<tr>
<td></td>
<td>FPSO, dry gas export</td>
<td>P1=5.5 years FFD=5.5 years</td>
<td>P1=72% FFD=74%</td>
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CO₂ Assessment

- Full development (reservoir to market) annual average power demand:
  - FPSO > 23 MW
  - WGC (PR=2) > 15 MW
  - WGC (proven) > 10 MW

- Subsea tie-back and PDG are relatively low power solutions, hence have lower emissions

- CO₂ tax of $40/Te fed into economic assessment
Economic Assessment (Phase 1)

- Life of Field ~15 years
- Discount rate 10%
- Standard gas/oil pricing / tariff assumptions
- PDG provides best Net Present Value (significant upside +34% over next best option)
- Cost is marginally higher than wet subsea tie-back (dual flowline) option [within 10%]
- CAPEX for new onshore plant included for all cases except FPSO.
Summary

- PDG addresses the root cause of gas reserves remaining stranded – management of the liquids generated

- The case study compares PDG to the current best available design solutions for stranded gas fields:
  - PDG significantly reduces the back pressure on the wells – up to 65 bar
  - PDG provides significant operational advantages during turndown, ramp-up, shutdown and restart
  - PDG provides the best gas recovery / longest time on plateau for both base case and full field development
  - PDG gives the lowest produced CO\textsubscript{2} emissions

**KEY TAKE AWAY:** PDG is a compelling development option for long, deep subsea tie-backs. Removing liquids from the pipeline along the route results in a significant reduction in both hydrostatic and frictional pressure drop without the use of large amounts of power
Development Plan

2017 - Initiation
Pseudo Dry Gas incepted as an idea
First funding gained for engineering definition and CFD studies

2018 – Engineering Definition
All related hardware & power systems at TRL 5-7
Liquid removal at TRL2
OGTC joint study on known stranded gas fields.
A number of Operators and tier 1 contractors joined the project

2019 to 2020 – Prototype (Flow Loop)
First Prototype tests completed
Liquid removal to TRL4
Work with OGTC to identify pilot test
Operator / contractor collaboration opportunities

2021 - 2022
Install fully functioning pilot

2018 / 19
• Kicked off a techno-economic study for the Oil and Gas Technology Centre (OGTC) to assess the potential benefits of the PDG technology; within their portfolio of subsea initiatives (marginal, long distance, deep water)
• Testing of a prototype in lab conditions (Cranfield University (UK))
• Open to work with other Operators/ Organisations
  • Proof of concept studies
  • Invitations to participate in peer reviews
Thank you – any questions?

- APAC focal point

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Back-up
‘Pseudo-dry’ e.g. liquids not completely removed, and will accumulate over very long time periods (start of life):

- At 50% turndown ~8 months to equilibrium
- At 25% turndown ~5 years to equilibrium

- Accumulated liquids are drained on shutdown (pumped-off).
  - Accumulated liquid in trunkline is reduced to 12% of the equilibrium volume at 50% turndown using pumps (2.5 days to drain)
  - Subsequent restart to 500 MMscfd – simulations record no surge volume onshore

- Rare scenarios (prolonged (months) turndown in early field life can be managed.
Economic Assessment (Phase 1 Only)

- PDG consistently the best economic outcome with respect to:
  - Internal Rate of Return
  - Discounted Profitability Index
  - Value Investment Ratio

- Time until NPV positive:
  - FPSO = 7 years
  - WGC = 6 years
  - Subsea tie-back / PDG = 5 years