Pseudo Dry Gas System

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

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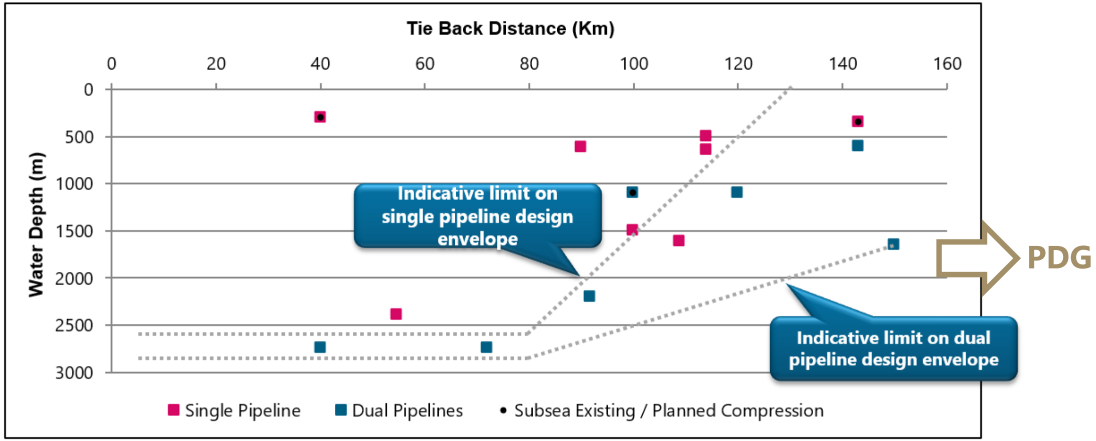
Re-cap

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

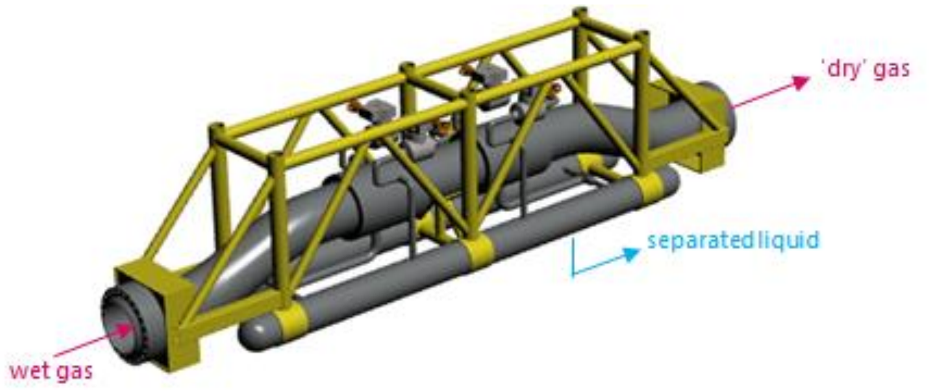
- Demonstrated that tie backs far in excess of the current threshold distance can be achieved.

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



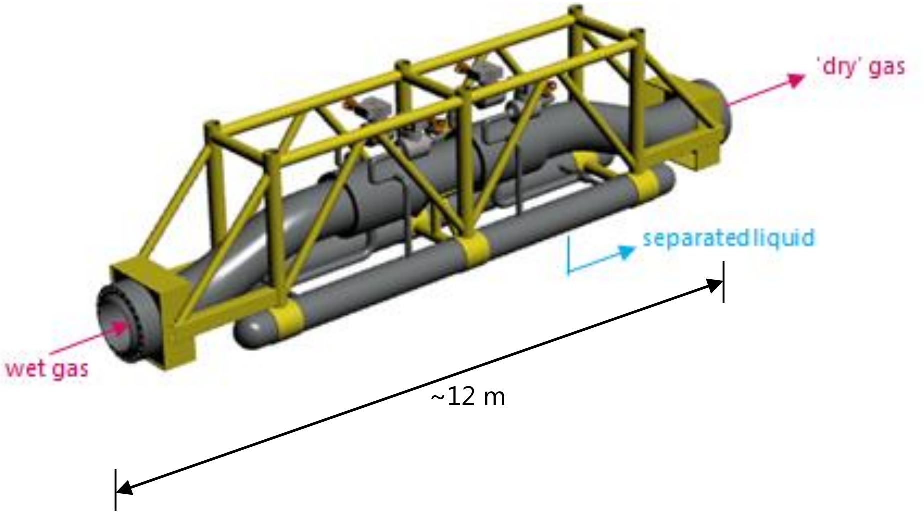
Problem -> Solution

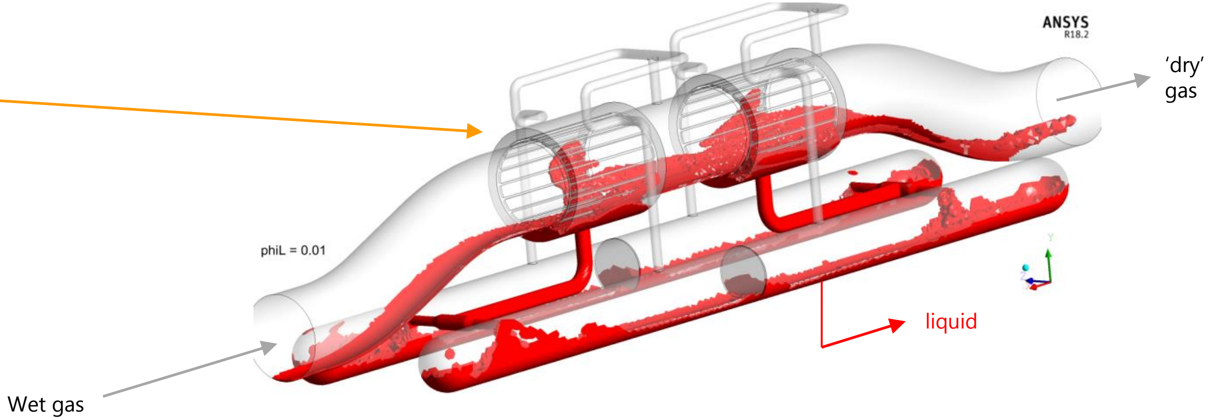
- Common belief that insufficient pressure (energy) at the wells is hindering viability of 'stranded gas' fields….however…
- …typically, the underlying problem is the liquid generated by the gas during transportation
Liquid accumulation = excessive pressure drop = high turn down = reduced gas recovery
- 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

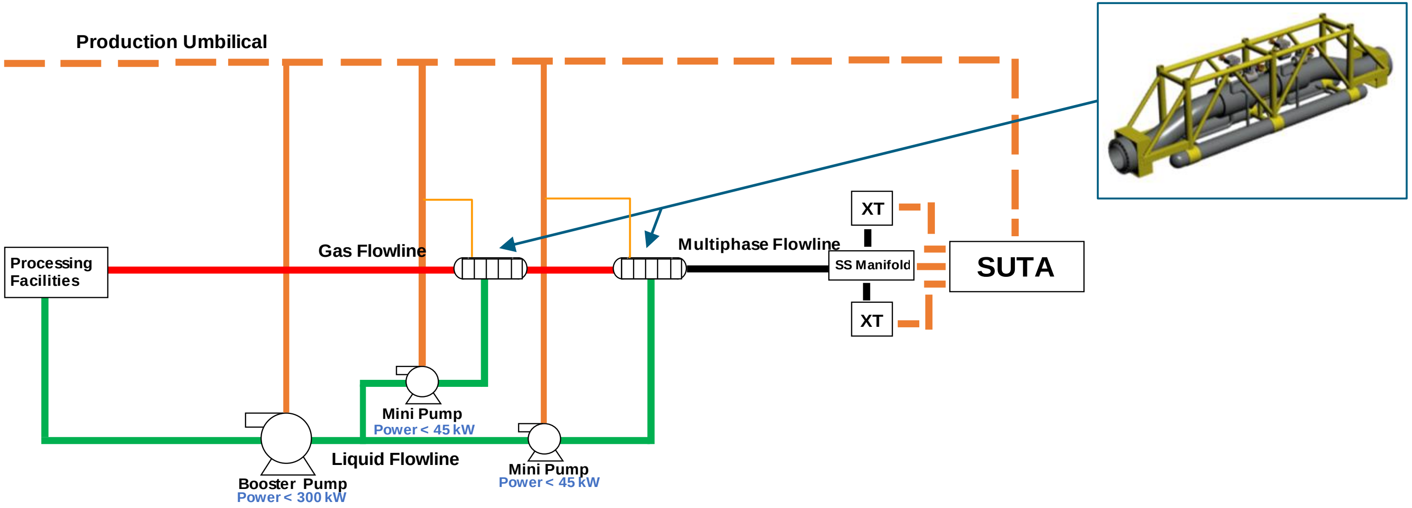
- Compact - Installed as a pipeline in-line structure
- Passive - no moving parts or consumables
- Piggable





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)

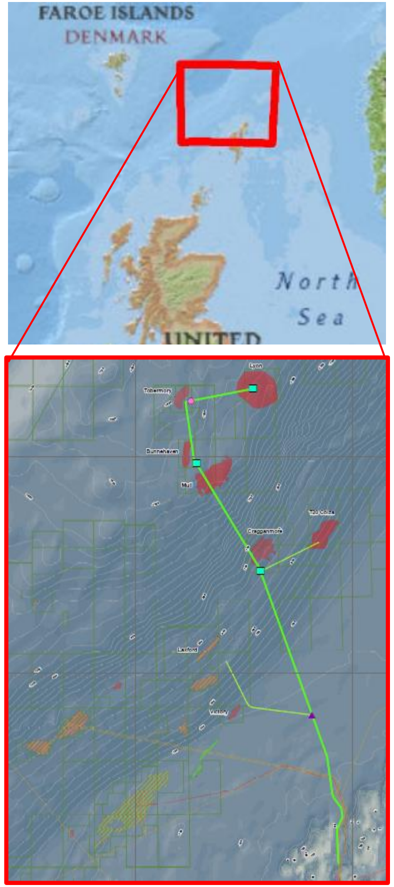
<u>Options assessed:</u>

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

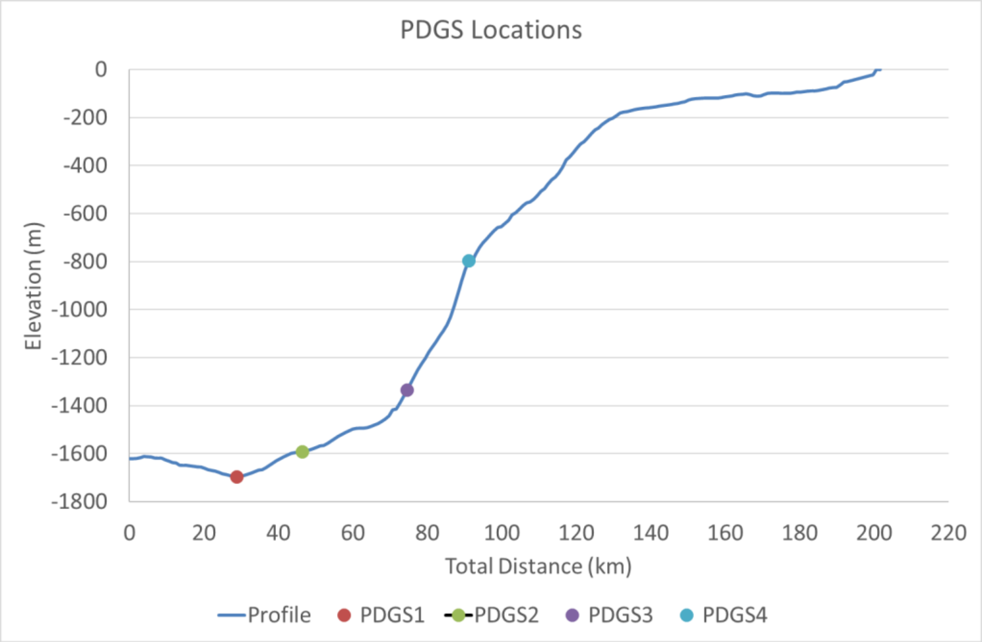
	FPSO, dry gas export	Subsea Tie-back – single flowline	Subsea Tie-back – dual flowlines	WGC - proven (dP=32 bar)	WGC- future (Pr=2)	Pseudo Dry Gas
Optimum line size	2 x 10″ (risers)	1 x 22″	2 x 18″	2 x 18″	2 x 18″	1 x 30″
WHP to deliver 500 MMscfd @ HP	114 bar	168 bar	168 bar	132 bar	84 bar	102 bar
Trunkline pressure drop	No wet gas trunkline	98 bar	98 bar	98 bar (incl. 32 bar WGC)	98 bar (incl. 84 bar WGC)	32 bar
Slug (surge) volume generated from short term turn down and ramp-up 100%->50% to 100% *(100%->25%->100%)*		2421 m^3 *(9208 m^3)*	1034 m^3 *(4416 m^3)*	1034 m^3 *(4416 m^3)*	1034 m^3 *(4416 m^3)*	negligible
Subsea Power	No subsea power demand			7 MW	20 MW	0.5 MW

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^{o}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	⇧

Technical Viability

Pseudo Dry Gas

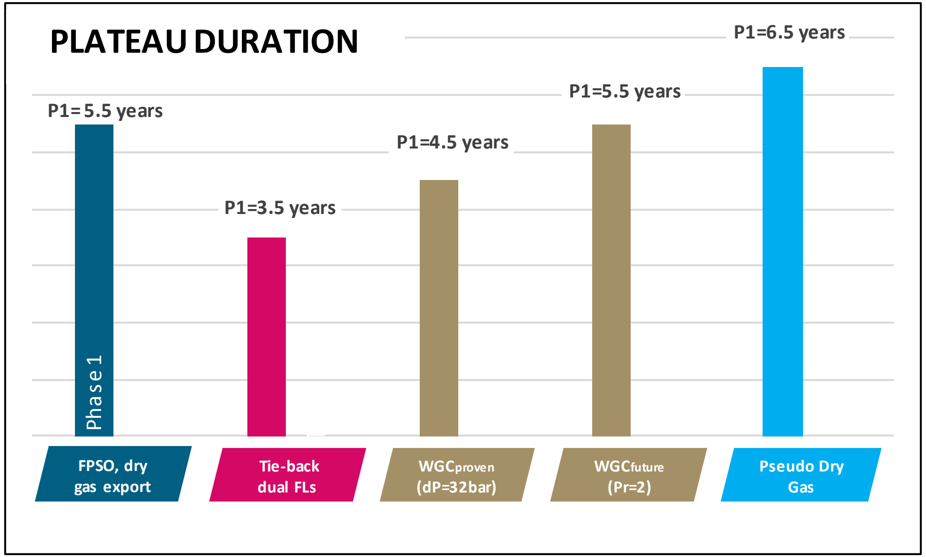


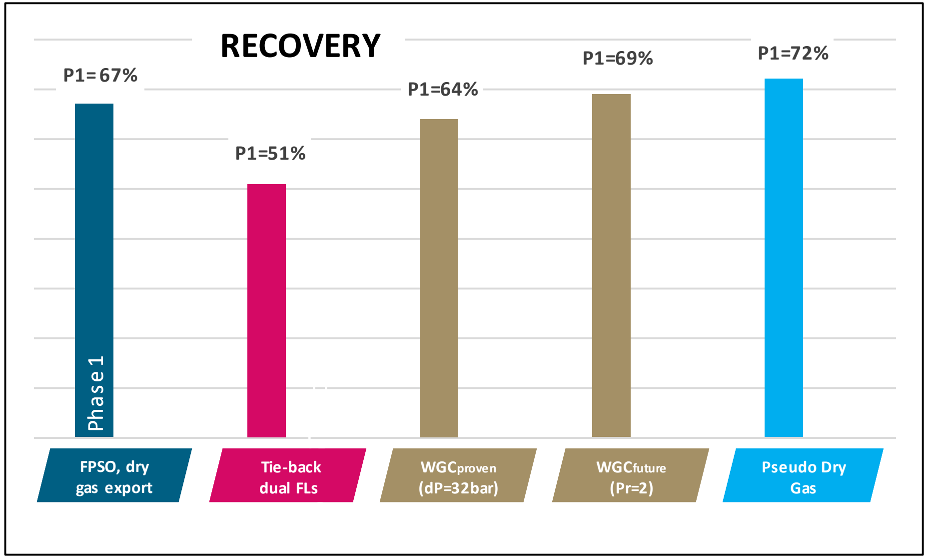
- 4 x units strategically located to manage liquids
- Liquid removal units efficiencies based on experimental work and two independent CFD studies (Strathclyde University & in-house)
- Solution gives near dry-gas performance

Case	PDG (bar)	Dry Gas (bar)
500 MMscfd SoL	102	100
250 MMscfd SoL	-	-
125 MMscfd SoL	-	81
500 MMscfd EoL	72	70
250 MMscfd EoL	48	47
125 MMscfd EoL	-	38

Recovery Assessment – Phase 1

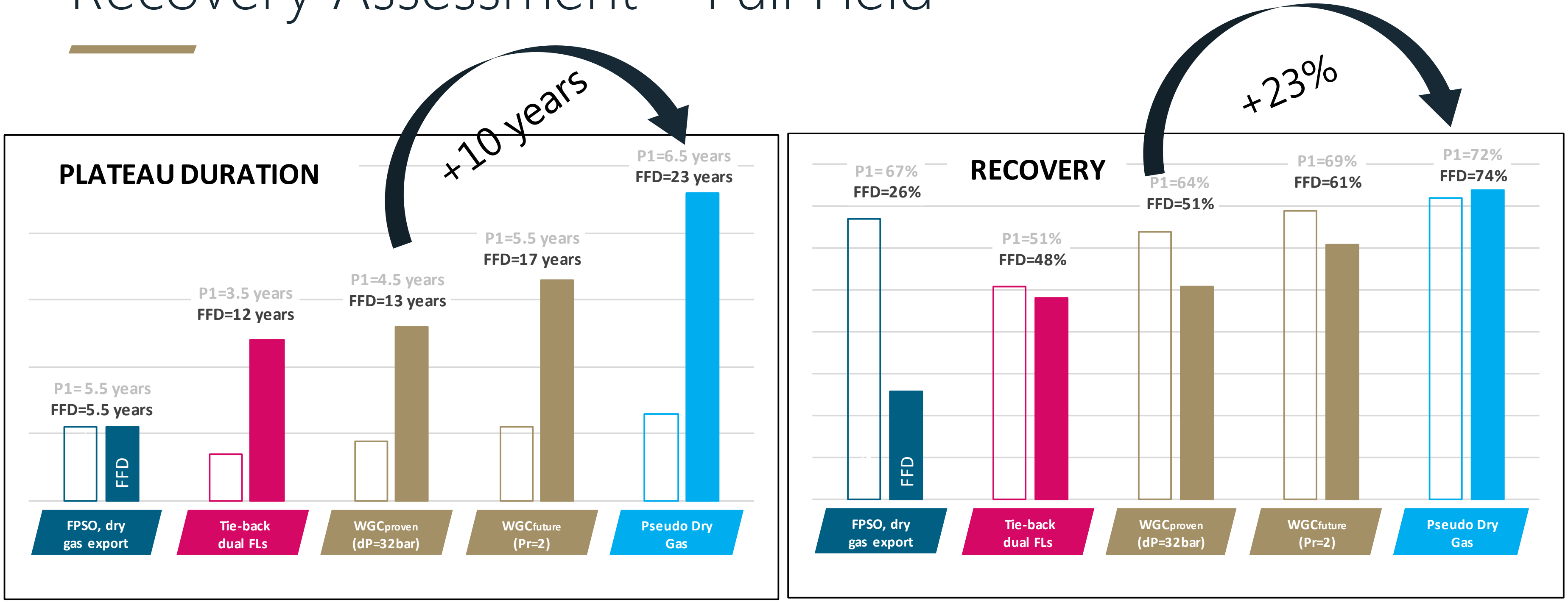
- Integrated production modelling to assess plateau duration and total recovery for base case (Phase 1) development





- 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

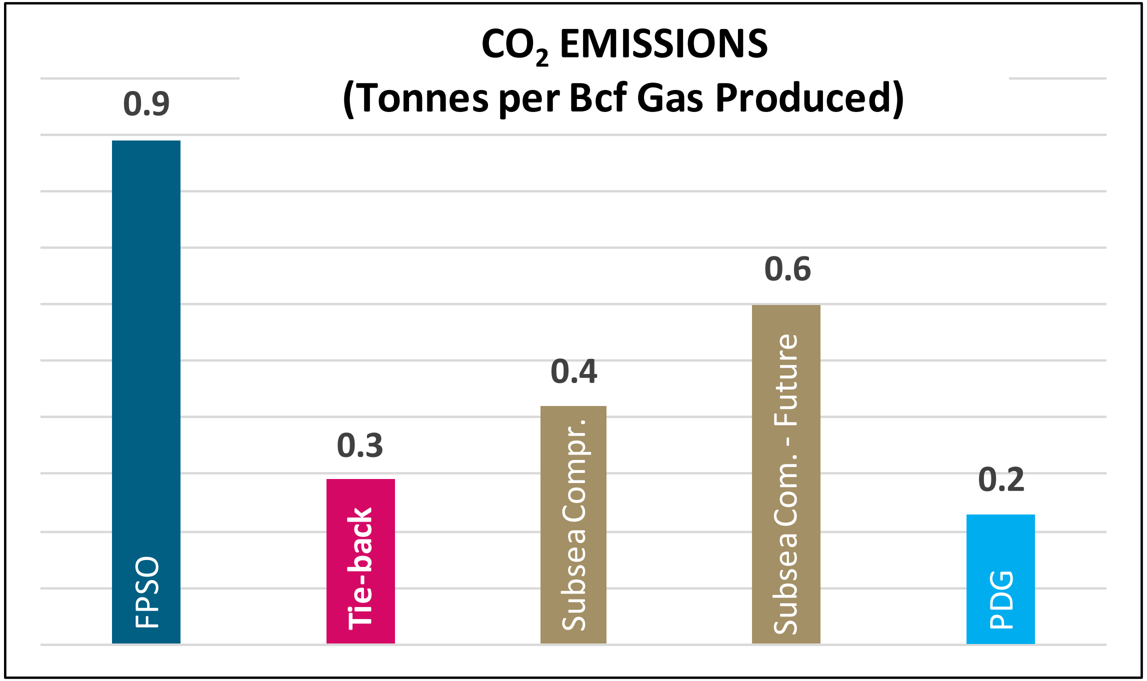
Recovery Assessment – Full Field



- 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 <u>and accentuated</u> when the full field development is assessed**

CO_2 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



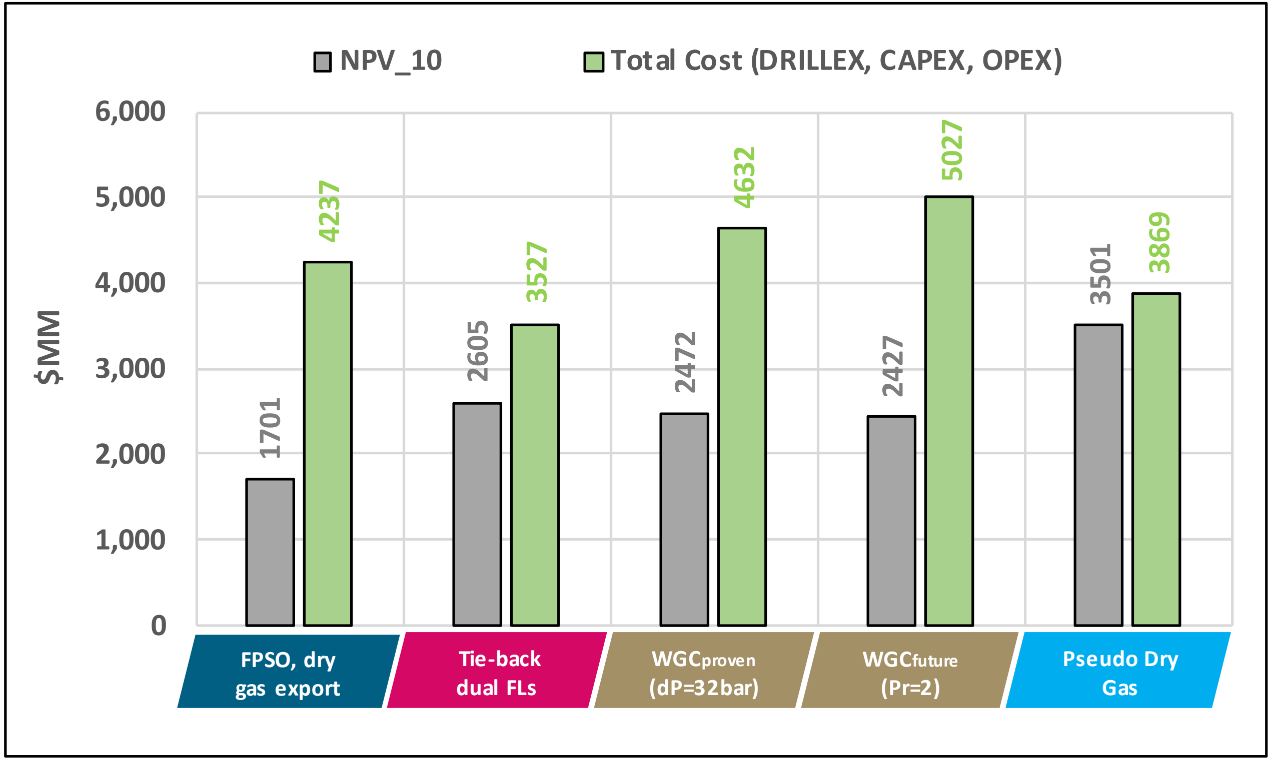
Economic Assessment (Phase 1)

- 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_2 emissions

	FPSO, dry gas export	Tie-back dual FLs	WGCproven (dP=32bar)	WGCfuture (Pr=2)	Pseudo Dry Gas
Revenue / Recovery	3	5	4	2	✓ 1
NPV, IRR, DPI, VIR	5	2	3	4	✓ 1
CO2 Emissions / Tax	5	2	3	4	✓ 1
Total Cost (DRILLEX, CAPEX, OPEX)	3	✓ 1	4	5	2

- **<u>KEY TAKE AWAY</u>: 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

TRL 1

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

TRL 2

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

TRL 4

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

TRL 6

2021 - 2022
Install fully functioning pilot

<u>2018 / 19</u>

- 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?

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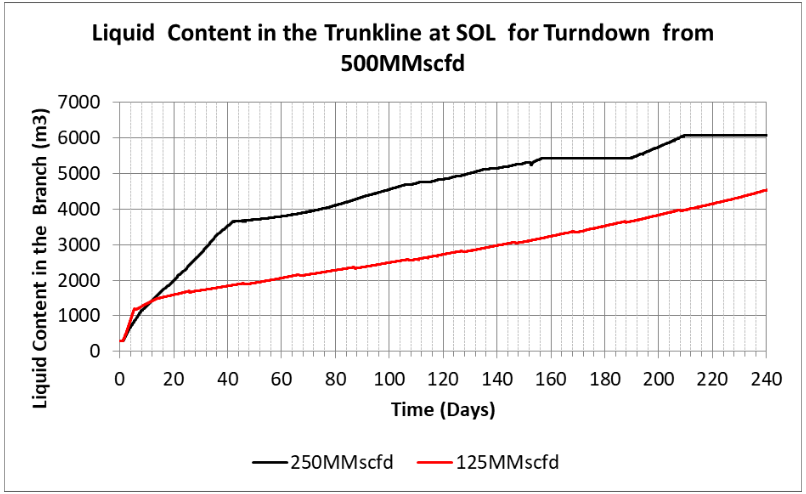
Back-up

Technical Viability

Pseudo Dry Gas

- '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