PÖYRY

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Peritus

# Cost reduction of subsea gas production systems using emerging hydrate remediation technology

## Presentation Outline

- Introduction
- Gas hydrates in deep water subsea gas production systems
- Mitigation and remediation options
- Costs and risks: CAPEX vs. OPEX
- Light well intervention overview
- Technology gaps and solutions
- Market Status
- LWI Vessels: requirements and availability
- Case studies
- Concluding remarks
- Questions

# Introduction

- Subsea production system
- Proposed gas/LNG field development
- Deep water remote location NW Australia
- Single flowline vs. dual flowlines from each production cluster to host platform
- CAPEX reduction $$$ several hundred million
- Reduced conservatism from better flow assurance analysis
- Reduced CAPEX, risk of higher OPEX
- Accept and manage risk of hydrate blockage

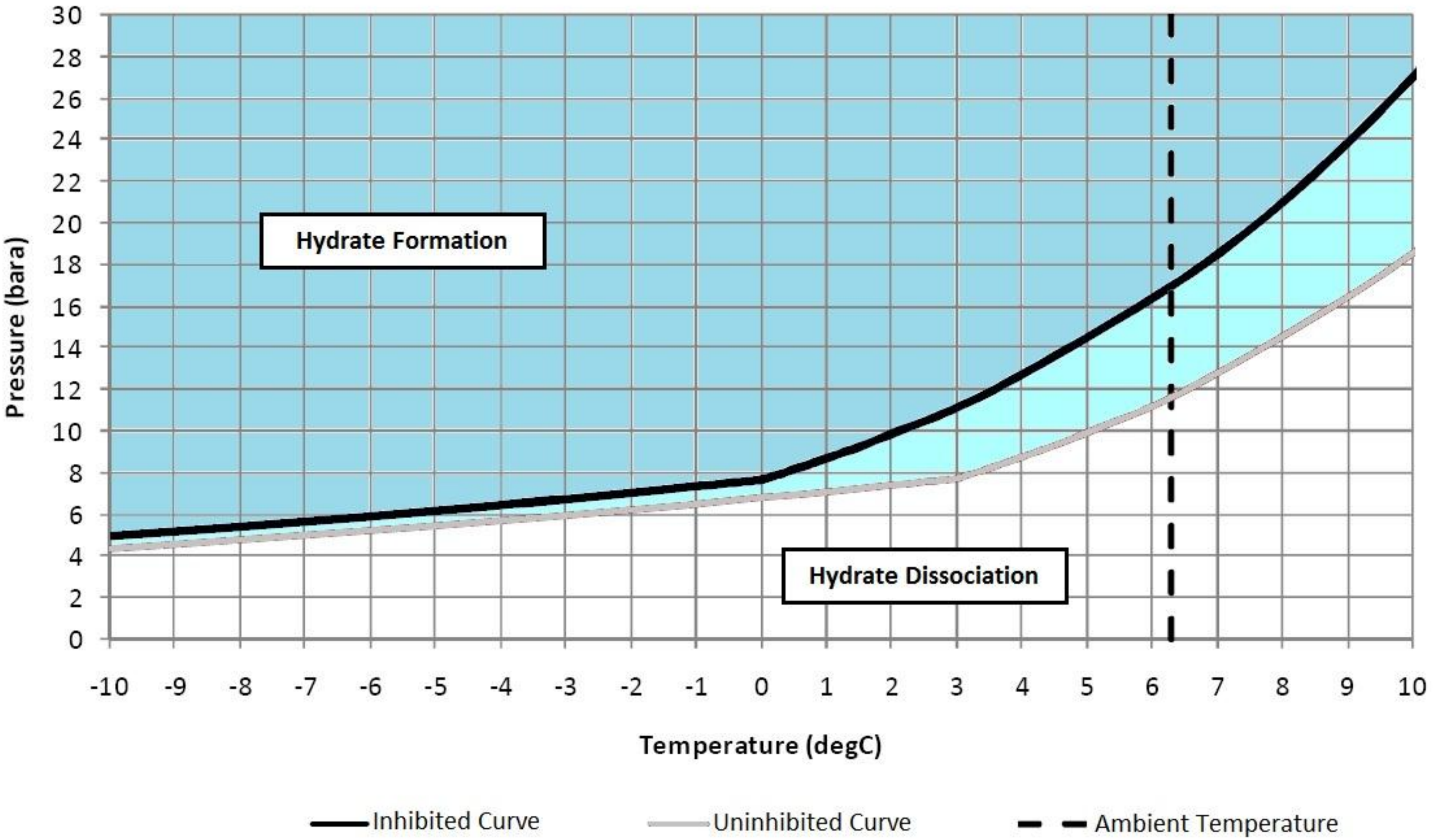
- Fallback plan

•Primary: MODU intervention via well

•Alternative : Offshore Service Vessel and subsea / Light Well Intervention technology

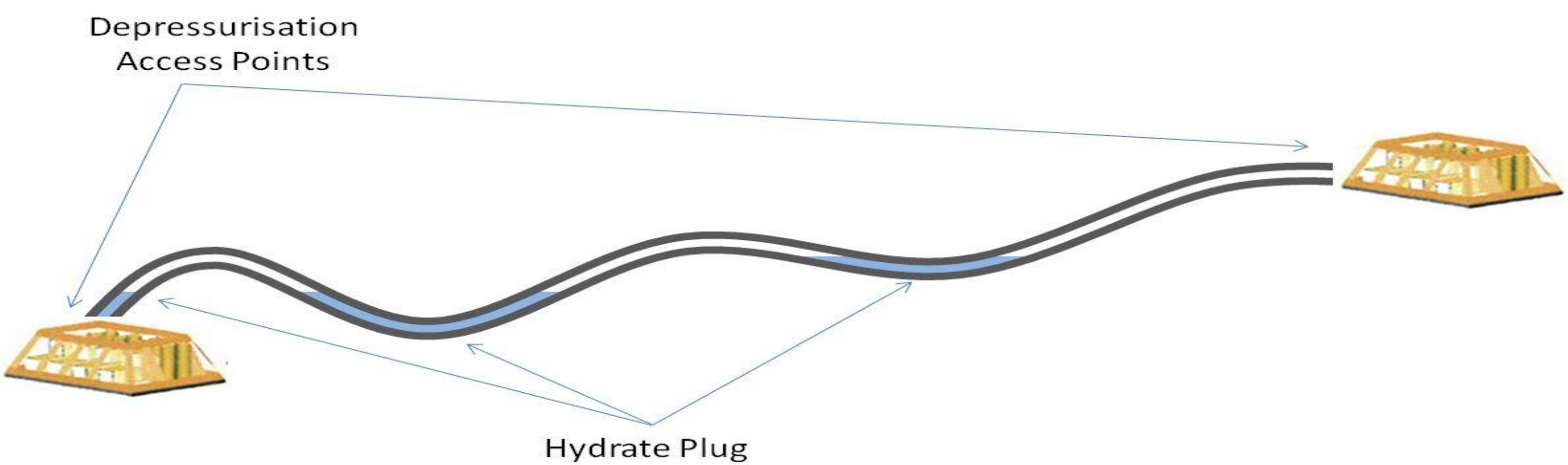
- Feasibility of alternative plan
- Peritus in conjunction with Pöyry in Q3-Q4, 2010

## Natural Gas Hydrates



# Australian Gas Field Study

- Water depth up to 650 msw, ambient ca. 6°C or less
- Multiple production well clusters in various depths
- Tieback distances up to ~20 km
- Uninsulated flowlines
- Flowing gas temperature is below hydrate formation temperature
- Continuous chemical inhibition required
- 2” hot stab ROV access points throughout subsea system
- Single flowline provides large CAPEX saving



# Australian Gas Field Study

Primary remediation plan:

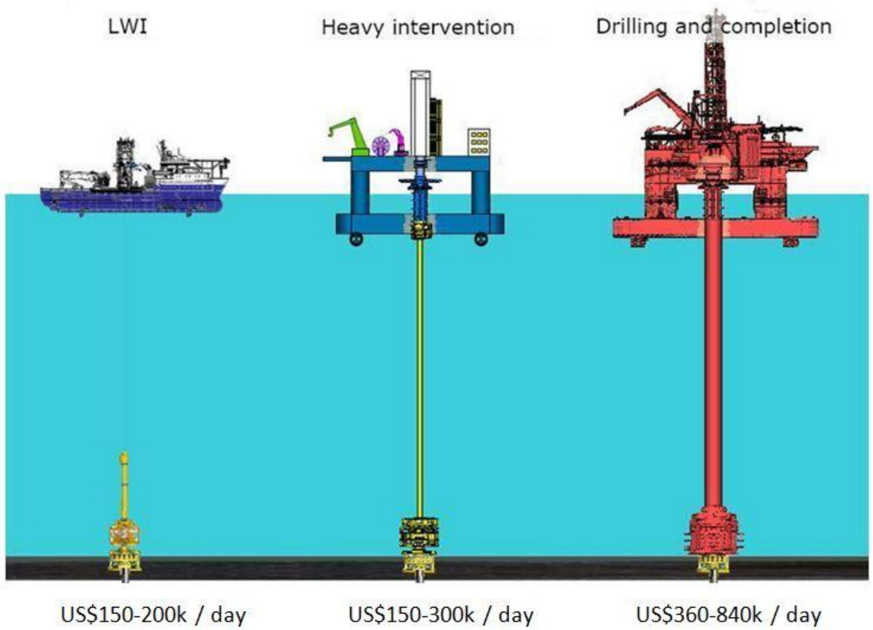
- –MODU connects to wellhead/tree and bleeds off flowline gas pressure.
- –Host facility bleeds off simultaneously.
- –Time delay and cost considerations.

Alternative plan:

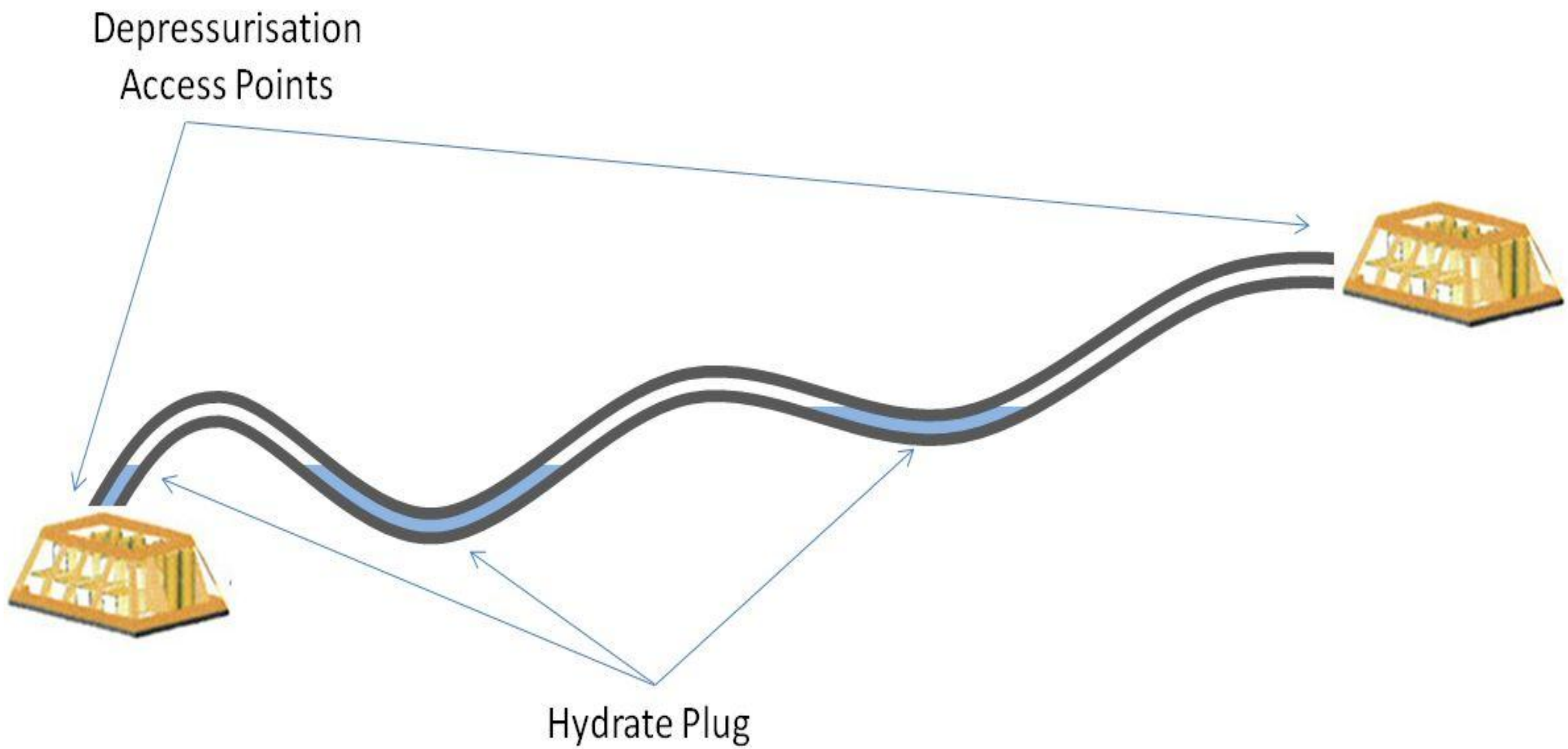
- – Offshore Service Vessel (OSV, DSV etc.) performs same tasks.
- –Technical feasibility/practicality and likely time/availability/cost savings

Literature search

Locate service providers and establish capabilities



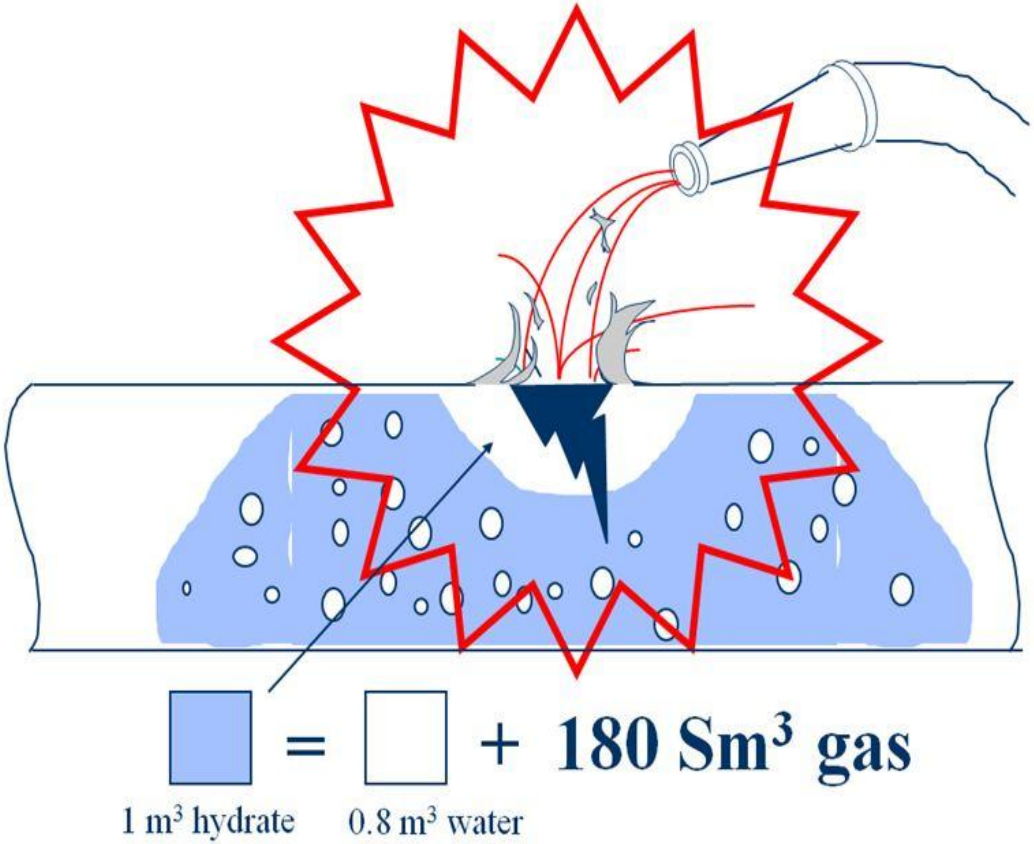
- Likelihood of multiple plugs forming due to topography.



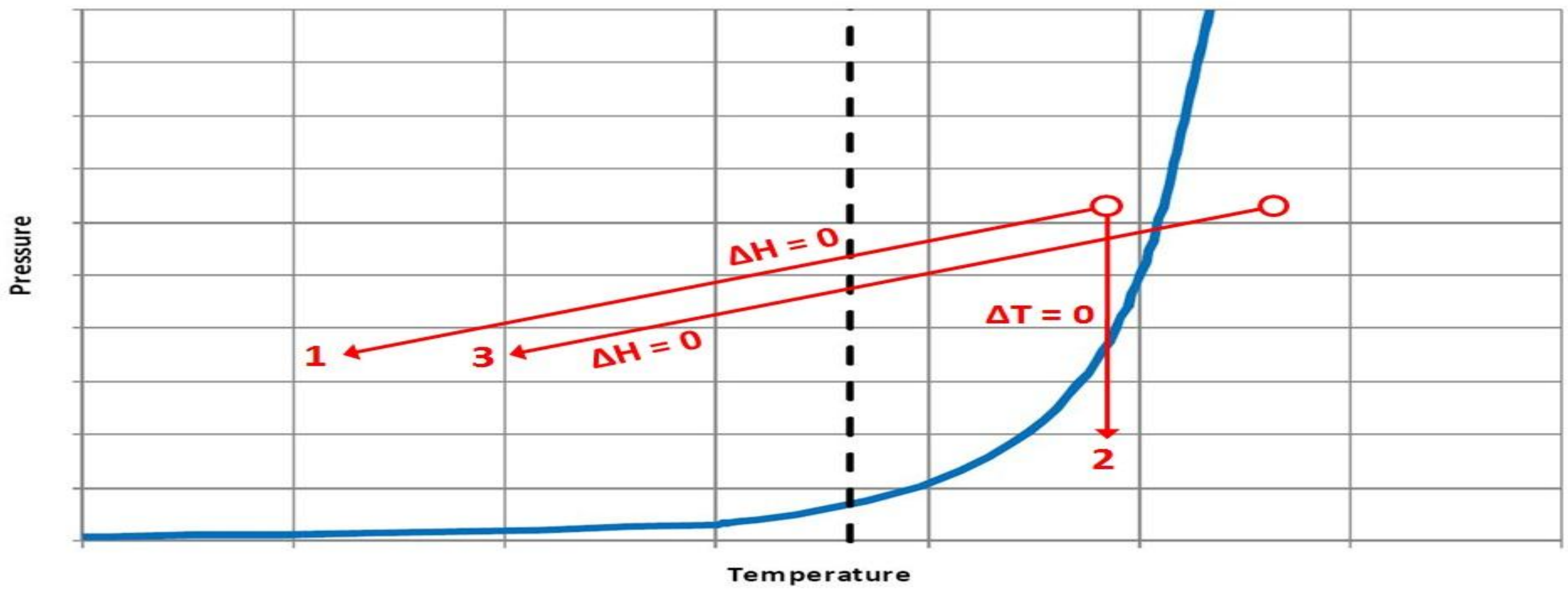
- Multiple plugs
- Projectile risk (momentum)
- Rapid depressurisation – excessive cooling, more hydrate forms
- Pipe wall overpressure failure
- Liquid head pressure remaining after gas vented
- Incompatibility with downstream LNG facilities (e.g. methanol)
- Pigging challenges: length

On Petrobras P-34 FPSO, Campos Basin, Brazil

# External heating?



Thermodynamic process



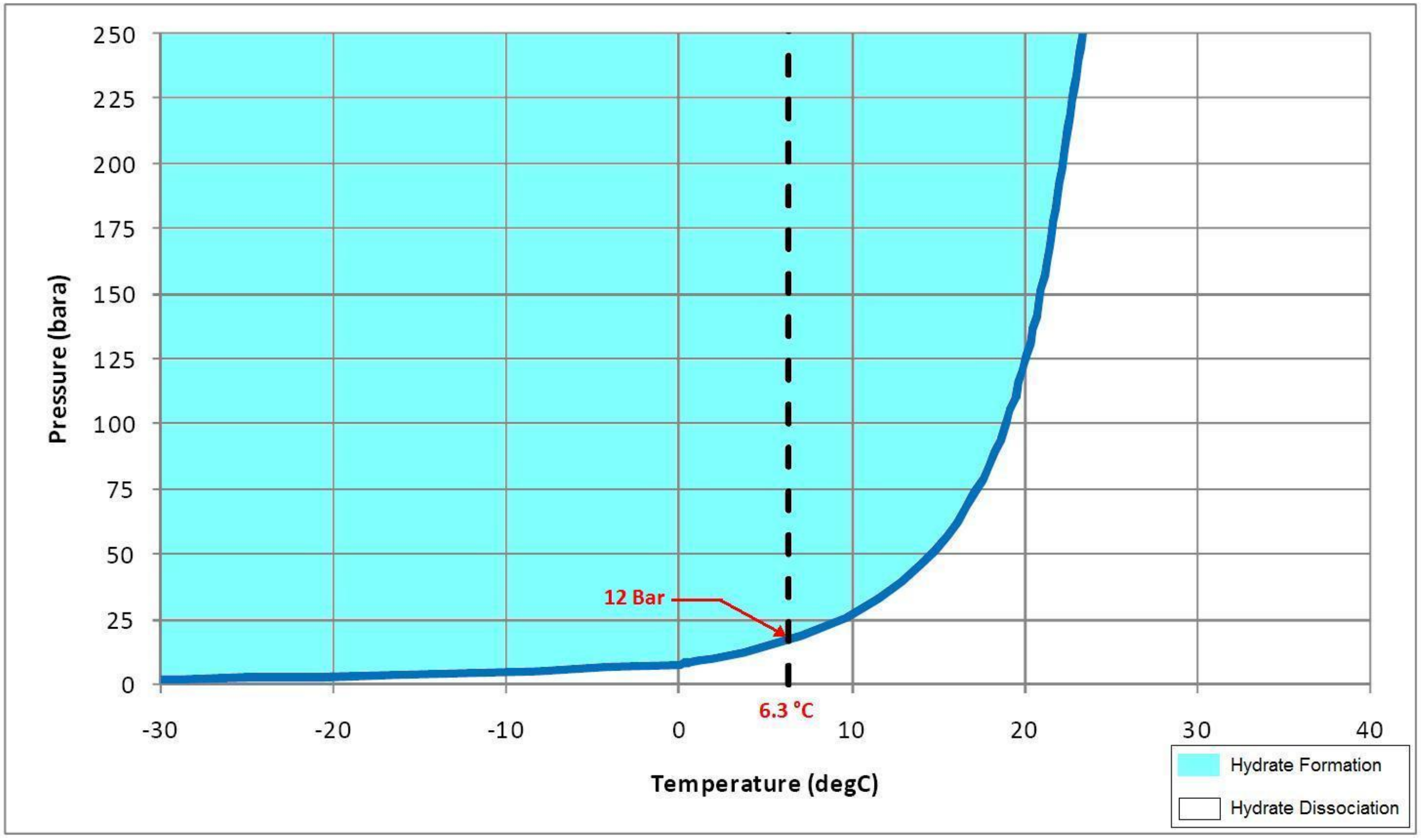

**Depressurisation effects on hydrate formation:**

1 – Uncontrolled rapid isenthalpic expansion

2 – Controlled gradual expansion, similar to pipeline depressurisation

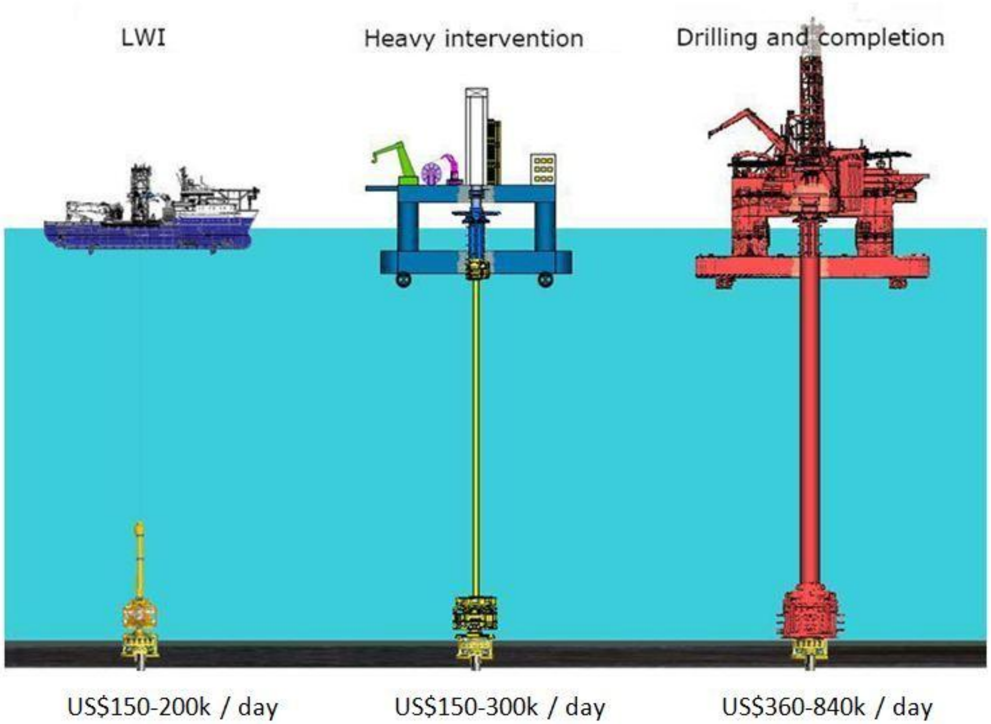
3 – Uncontrolled rapid isenthalpic expansion initiating hydrate formation

Un-inhibited conditions



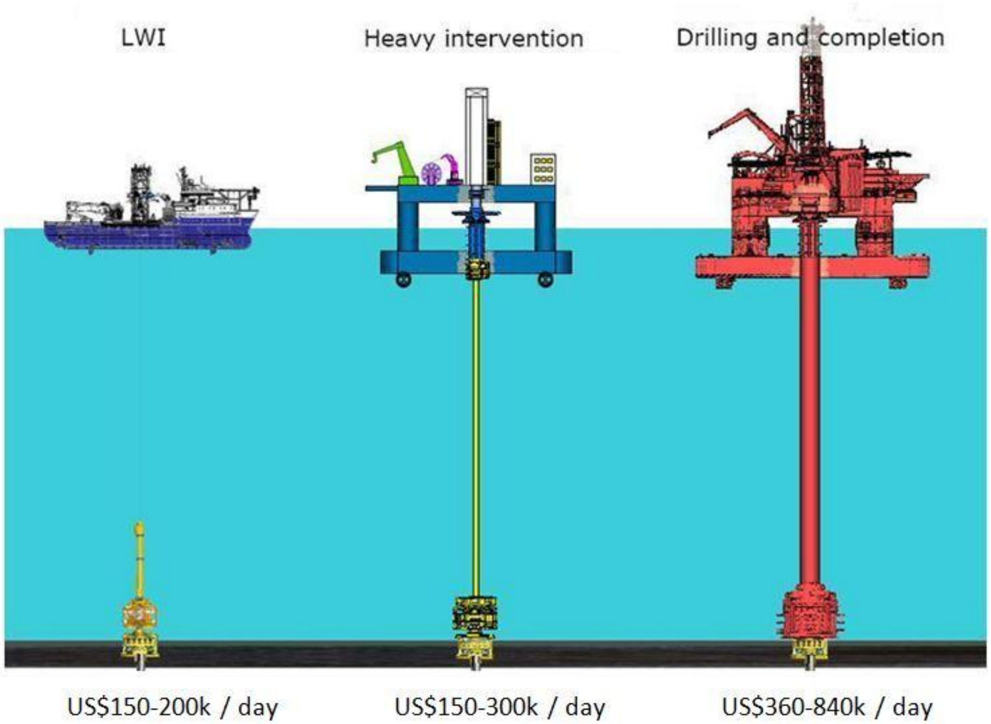
## Light Well Intervention (LWI) Overview

- “Rigless” downhole interventions
- Started in mid-1980s
- Lower cost vessels
- Wireline and/or coiled tubing through open water
- Lubricator package on tree
- Umbilical connects well to surface, very limited ability to circulate fluids
- Tools run downhole, no produced fluids aboard vessel



# Light Well Intervention (LWI) Overview

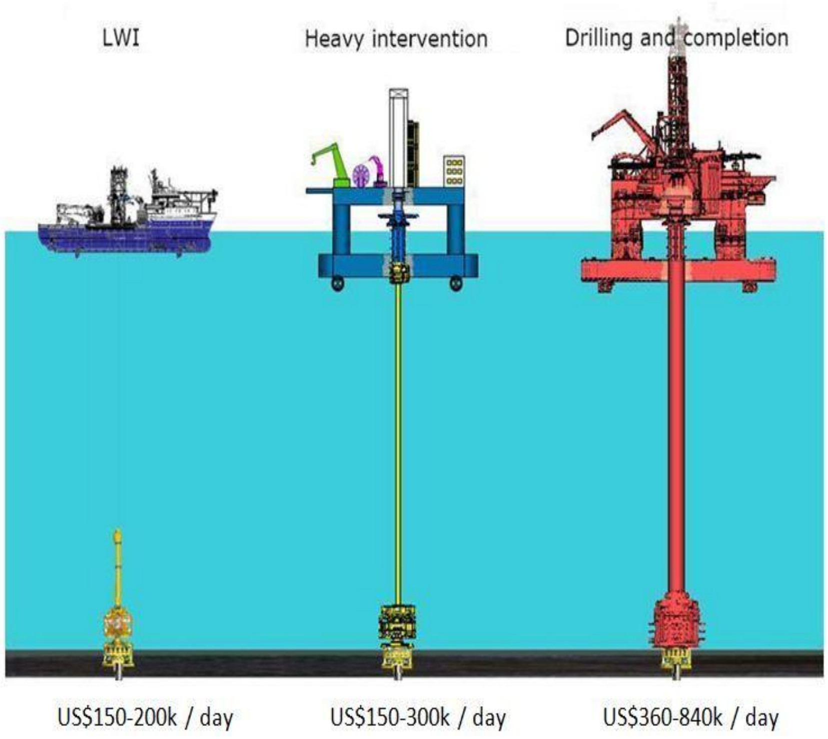
- Well abandonment by LWI, significant pumping capabilities via external flexible pipes/hoses
- LWI and well abandonment still avoid live HCs on vessel
- OSVs being built and classed with more “well-related” construction and intervention tasks inc. well testing in mind
- Liquid hydrostatic holdup-pumping or lifting required



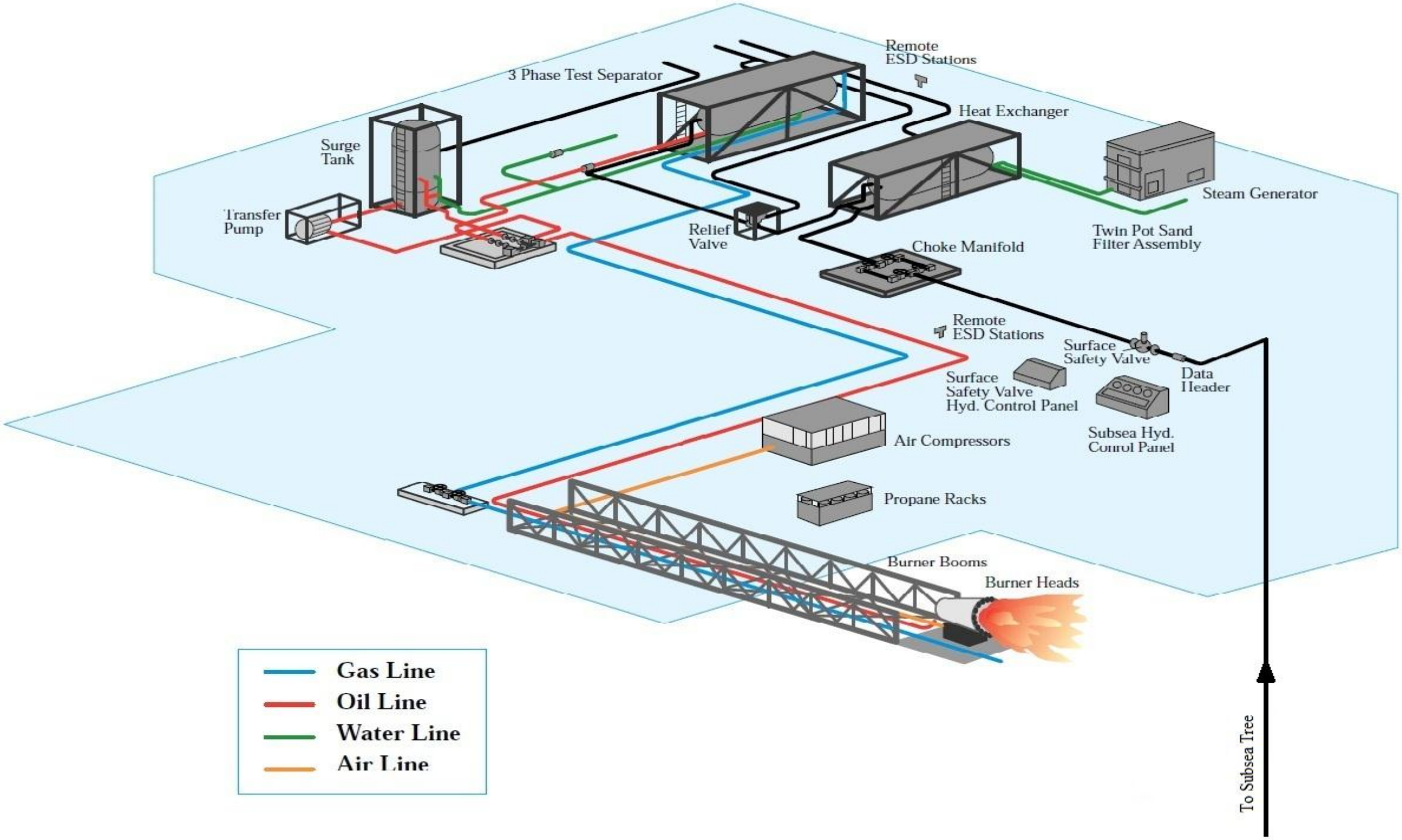
Four apparent technology gaps:

- Handling and disposal of HCs
- Conduits for gas and liquids from flowline to vessel
- Liquid lifting
- Limited number of vessels available suitable for HCs

All have solutions from other segments of offshore industry



## ↗ Well test spread vs. "bleed off package"



# Market status: LWI vs. subsea remote intervention

LWI contractors focussed on “true” LWI

Significant LWI frame agreements

Subsea construction/IMR contractors (non-LWI) in GoM have deep water hydrate remediation experience - not widely reported

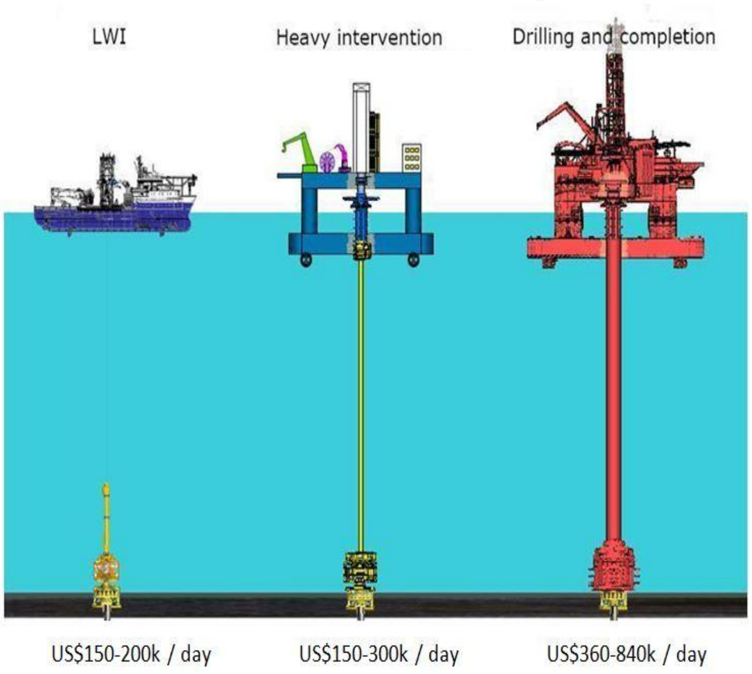
Evolving business area requiring increased interactions between:

- “well drilling and completions”
- “subsea construction and remote intervention”
- “vessel owners and charterers”

LWI market still embryonic

Scope for growth

No single provider actively offering turnkey <u>hydrate remediation</u> services



# Vessels: requirements and availability

GoM contractors' advice based on deep water hydrate remediation jobs:

- Min. DP Class 2 vessel
- Length ~100 m
- Deck area ~1000 sq.m
- Dual work class ROVs
- AHC crane ~20 Te rated w/wire for water depth
- Working moonpool preferred
- Safety Case for Australia
- Classification Society approval of mods. and proposed tasks
- (Class notation situation currently evolving)
- Well test/bleed-off spread and flare boom
- Two CT unit for large (~2") CT
- Subsea deployment frames, pumps, valves etc.

Fleet of suitable vessels is growing, expected to attract a price premium
Availability of these in APAC is not good

# Case Studies of Hydrate Remediation

# Case Studies of Hydrates in Gas Systems

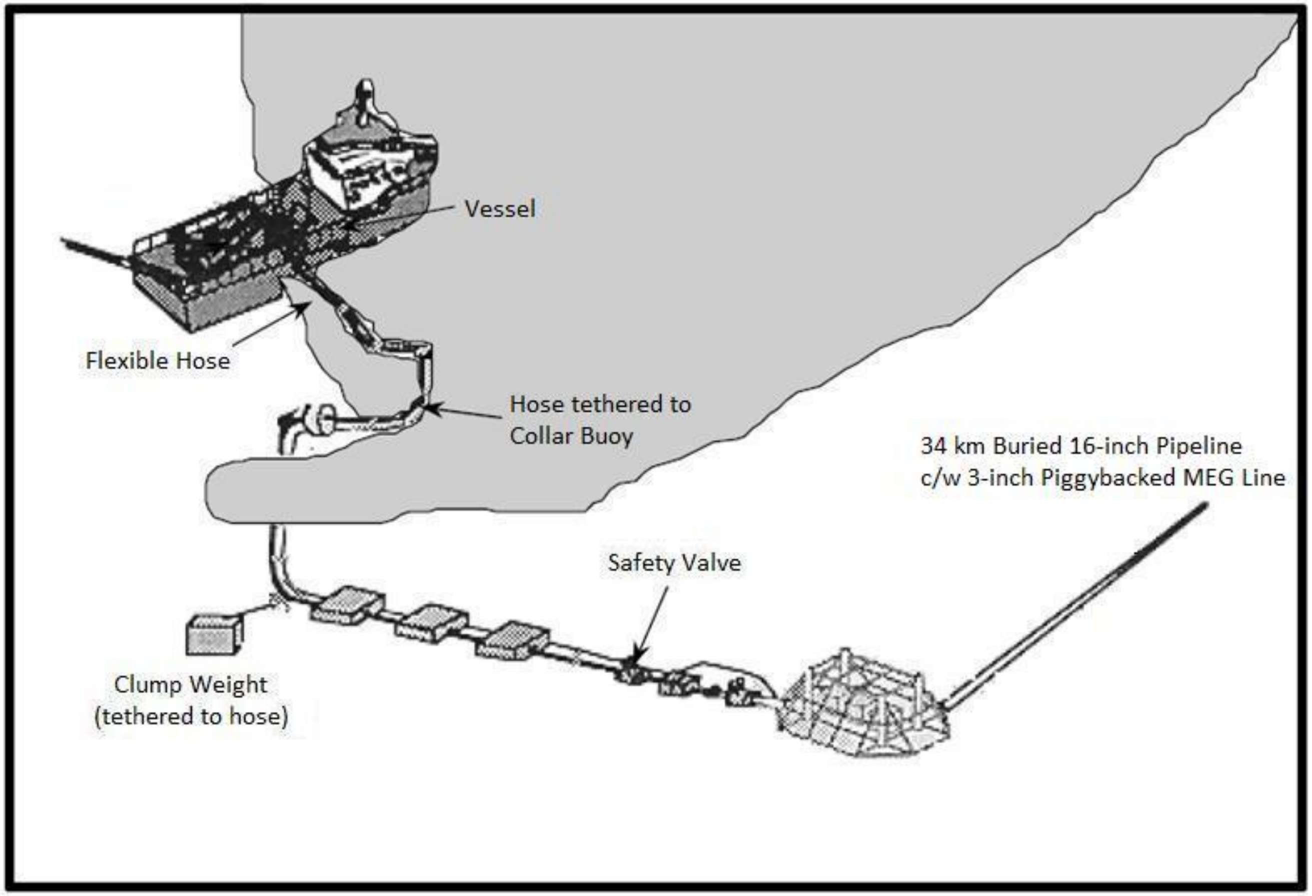
Public domain literature not extensive:

- ARCO Orwell gas field, North Sea, shallow water, 33msw, 1996
- BP Whittle and Wollaston gas fields, North Sea, shallow water, 40msw, 2005
- Exxon Mobil Mica gas production flowline, GoM, 1300msw, 2004
- Statoil Tommeliten experiments by SINTEF, Norway, shallow water 75m, 1994/95

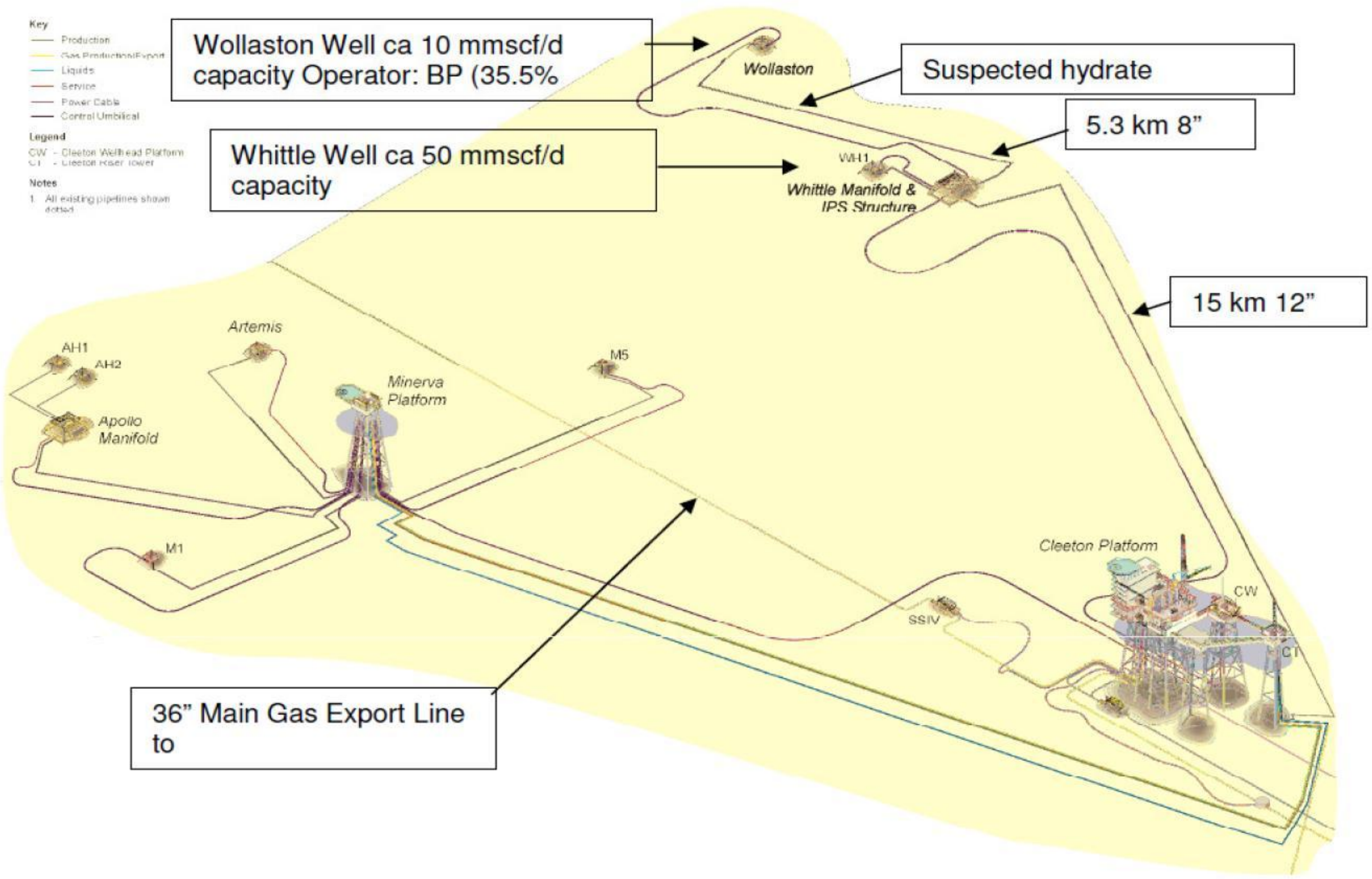
Found GoM contractors have done unreported hydrate remediations from OSVs, including equipment for liquid lifting in deep water

## ARCO Orwell, 1996

**Figure 8**



## ↗ BP Whittle and Wollaston, 2005



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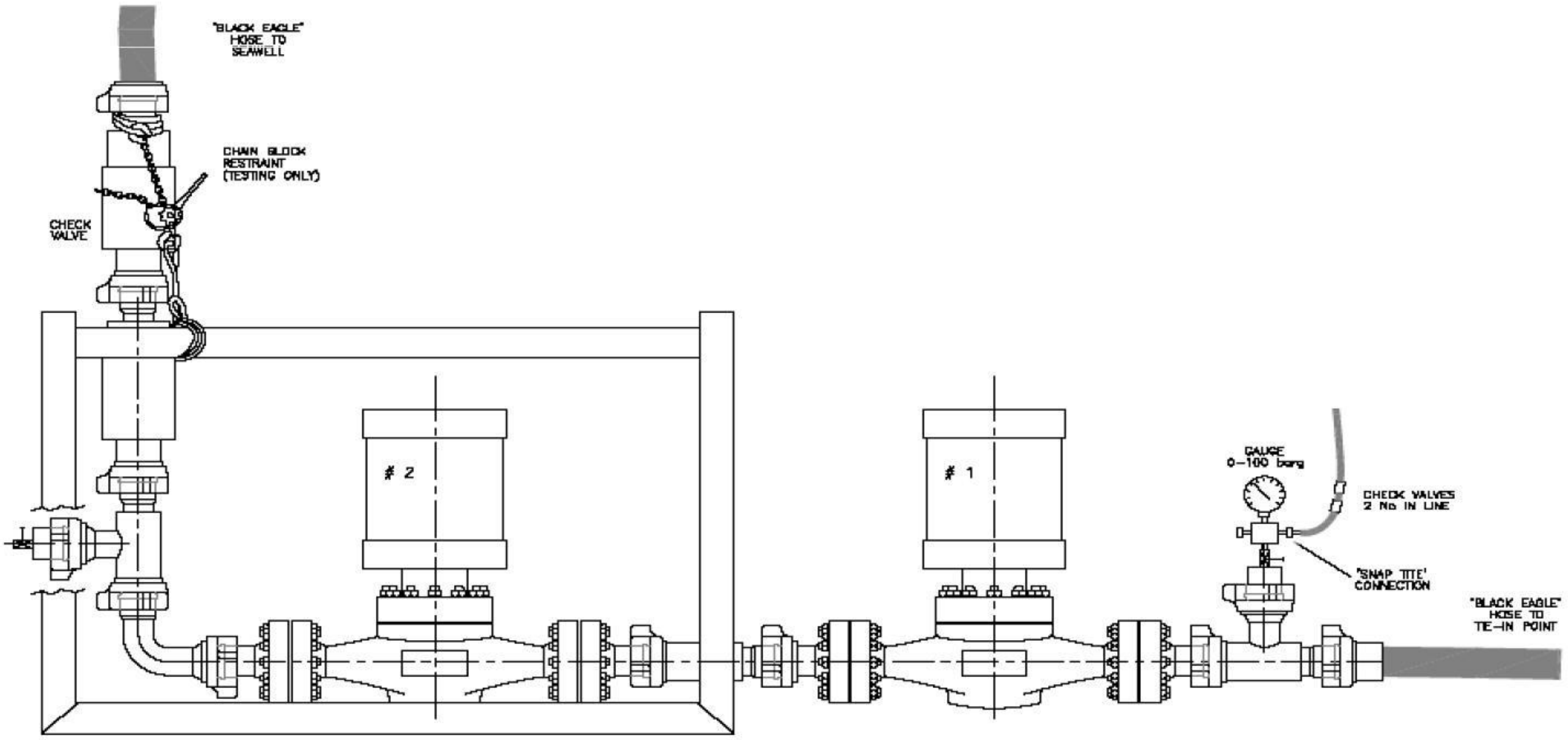

ExxonMobil Mica, 2004

↗ Statoil Tommeliten Gamma 1994-95

Exxon Mobil Mica

Gas production flowline, GoM, 47km, 8”, deep water 1325 m

Did not require any intervention vessel, but some key learnings were interesting:

- Blockage occurred during an ESD
- Cause was under-inhibition because of a change in flowline operation, from LP to HP
- DSD to platform using cross over to other (oil) flowline
- Required 60 days
- Some porosity of hydrate plug, would have been quicker if they supplemented depressurisation with methanol injection

Statoil Tommeliten, Norway, 11km 6” flowline, shallow water 75 m

Numerous (19) experiments performed by SINTEF to learn:

- Hydrates are formed quickly and easily both subsea and topside
- Plugs typically porous and permeable
- JT cooling on low pressure side during depressurisation causes hydrate growth
- Both methanol and depressurisation are effective

# Conclusions

1. The necessary elements of equipment and technology for hydrate remediation from an OSV all exist
2. To achieve a full working system will require a combination of LWI technology and subsea construction/intervention technology
3. The first "prize" is elimination of dual flowlines in subsea gas field tiebacks
4. A significant further prize if operator or consortium was to develop a working contingency system in advance of a hydrate blockage incident happening . This could entail a commercial arrangement for a service provider to engineer the necessary vessel, equipment, techniques, and approvals ahead of time, and maintain in a state of readiness.
5. An OSV would then be able to perform hydrate remediation more quickly and cost-effectively than a MODU
6. The provision of pressure access points for ROV connection of downlines at trees, manifolds and tees is strongly supported as it makes access much easier than by using an LWI package onto the wellbore

↗ Questions?

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