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Enabling a Long Distance Tie-back to a Constrained Late Life Asset: Challenges and Solutions

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Abstract
This paper discusses an Australian 40 km subsea wet gas-condensate tie-back development to an existing offshore platform. The case study identified a marginal need for hydrate management, limited to cold season conditions during which the sub-cooling remains less than 3°C. Multiple strategies were considered to enable a low-cost, technically robust development. Optimisation and manipulation of system conditions such as arrival pressure, flowline roughness and gas rate were assessed to understand the potential for a further reduction in hydrate formation risk (through minimisation of sub-cooling). Hydrate kinetics and water hold-up were reviewed to understand the risk of formation versus blockage. The hydrate management premises reviewed ranged from purely risk-based (a tolerance of sub-cooling), thermodynamic or low dose hydrate inhibitor injection and thermal management (insulation).

Ultimately a risk / cost balanced premise was put forward based on seasonal continuous Methanol once-through injection, with injection rates to be further optimised as far as practical based on implementing active in-field seawater temperature measurement into an injection rate algortihm.

The paper demonstrates that the critical enabler for any long distance subsea tie-back is a robust hydrate management strategy, and that justification of a selected premise requires a detailed assessment of the unique field conditions.

Keywords
Long distance tie-backs, hydrate management, LDHI, KHI, techno-economic assessment

Introduction
Long distance subsea tie-backs are required to exploit stranded hydrocarbon reservoirs and extend the production life of existing processing facilities. A critical enabler for any long distance subsea tie-back is a robust hydrate management strategy. A tie-back to an existing offshore operational asset introduces significant brownfield constraints that limit hydrate management options: both in terms of available real estate and infrastructure (e.g. chemical storage) and in terms the need for low cost solutions to support late life economic production.

A case study is discussed in this paper to demonstrate the challenges and potential solutions to enable an approximately 40 km long distance subsea tie-back.

Methodology
The case study concerns an Australian offshore platform in approximately 100m water depth that has depleted the primary reservoir and requires access to a stranded reservoir (40 km distant) to sustain production and extend the life of the asset. The processing platform conditions (dehydrates) and compresses the gas condensate and exports the stream via a 150 km pipeline to shore, connecting to the domestic grid. There is no chemical supply from shore to the platform.

The seawater ambient temperature ranges seasonally from 12°C to 19°C and the tie-back operating pressure ranges with gas rate from 25 to 60 bara targeting a platform arrival pressure of 20 bara. The hydrate formation risk is therefore marginal with a maximum estimated subcooling of approximately 2.5°C at peak rates only during winter (cold) conditions (Figure 1).

The development has a seasonal and marginal hydrate risk. This presents an opportunity to assess a variety of hydrate management techniques.

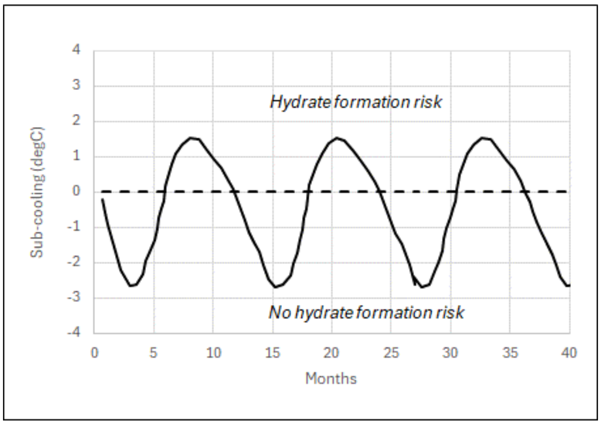

Figure 1. Seasonal subcooling

Do Nothing
For this 'risk-based' strategy, the behavior of hydrate formation versus hydrate blockage is an important distinction. The tie-back flowline exhibits very low water hold-up (<2% hold-up at 40% of the peak gas rate, Figure 2). Any hydrates formed during winter season are therefore likely to be transported rather than accumulate sufficiently to plug the line.

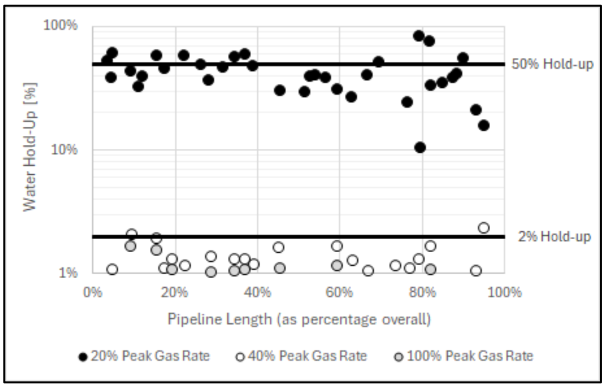

Figure 2. Water hold-up vs. gas rate

This strategy is supported with reference to a Statoil best practice measure [1]: *when the water content at each low point is sufficiently low, typically 10% or less, no hydrate control measures are required during shutdowns*.

Rate Control
Winter seasonal production rates could be turned down to avoid sub-cooling if there is sufficient back-fill from the existing (depleted) primary reservoir.

Credit Hydrate Kinetics
The time-dependent processes of hydrate nucleation and growth are challenging to measure. Behavior is highly system dependent and stochastic, however within the hydrate metastable region, there will be a finite time before hydrates will form. The available time until hydrate formation (the 'survival' time) depends on the system pressure. Required subcooling values of up to 3.6°C for the onset of hydrate formation have been reported in literature, Figure 3, depending on the system [2].

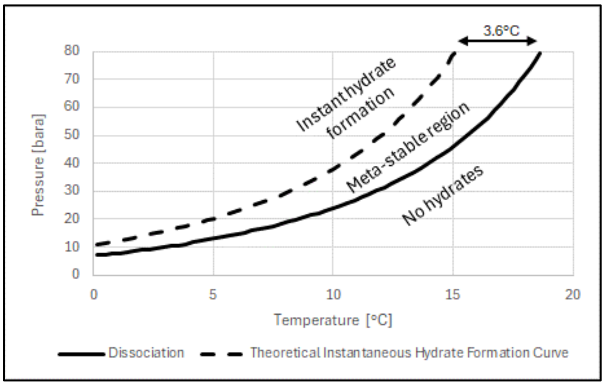

Figure 3. Hydrate meta-stable region

Reduced Pressure Operation
With significant capital and operating expenditure (CAPEX and OPEX) the platform compressor could be re-wheeled to achieve a lower suction pressure (pipeline arrival pressure reduction from 20 bara to 10 bara). The flowline roughness can be reduced by specifying rigid rather than flexible line and with consideration of a low-roughness internal coating.

Insulate and Blowdown (I&B)
Heat retention to avoid sub-cooling over the 40 km length represents a challenge, with a low overall heat transfer coefficient (approaching 3 W/m^{2}K, Figure 4) required. This impacts the flowline installation strategy and introduces complex operating procedures, namely partial depressurization on shutdowns during the winter season.

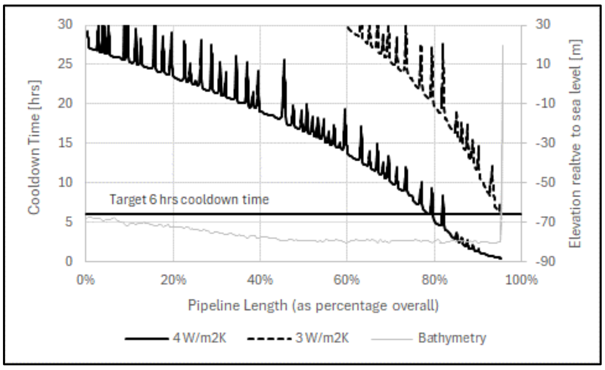

Figure 4. Available cooldown time profile

Thermodynamic Hydrate Inhibitor (THI)
Batch THI injection is required regardless of strategy for cold well start-up. Continuous injection during the winter season requires additional chemical storage on the platform. Higher rates of chemical depletion have a logistics impact in terms of chemical supply from shore. THI regeneration offshore is not an option (insufficient real estate). Selection of Methanol (MeOH) rather than monoethylene glycol (MEG) reduces consumption rates, storage volumes and supply chain costs, however MeOH introduces toxicity and environmental (discharge) concerns. Supplementing insulation with electrical heating

was discounted based on high CAPEX and limited platform real estate.

Low Dose Hydrate Inhibitor (LDHI)

The use of anti-agglomerant (AA) requires a significant condensate phase (typically 10% holdup fraction) to act as a transporting fluid for the resultant hydrate slurry. The development condensate content is insufficient.

Kinetic hydrate inhibitor (KHI) is a low dosage chemical that reduces hydrate formation kinetics by preventing nucleation and hindering crystal growth. They are typically used to promote longer cooldown time (hold-time until hydrate formation). The main challenge for KHIs is chemical qualification, relating to the confidence in hold-times reported and concerns in the repeatability of experimental results in specific field conditions.

Results and Discussion

For the subsea tie-back development five hydrate management premises were shortlisted for techno-economic screening:

1. ‘Do-nothing’: tolerate seasonal subcooling and rely on insufficient water hold-up to form a hydrate blockage.
2. Seasonal THI (MeOH) injection to fully inhibit the produced water at peak gas rates.
3. Seasonal THI (MeOH), but with seasonal gas rate reduction to reduce THI consumption. Back-fill the temporary production shortfall from existing gas wells on the platform.
4. Insulate the flowline to give sufficient cooldown time. Partial depressurisation on shutdown (after cooldown time).
5. Seasonal KHI injection to fully inhibit the produced water.

Each premise was scored against individual weighted screening criteria, as shown in Table 1.

Table 1. Screening outcomes

Premise	Technically feasible?	CAPEX	OPEX
#1 (Do Nothing)	×	Low	Low
#2 (THI)	✓	Med	Med
#3 (THI, low rate)	✓	Med	Med
#4 (I&B)	×	High	Low
#5 (KHI)	✓	Med	High

The KHI strategy (#5) was not preferred primarily due to:

- The environmental risk (approval for overboard with separated produced water).
- A lack of regional track record and risks associated with an onerous chemical qualification process. A literature search could not determine any operational case studies of LDHI use in the APAC region (to date). Global use case studies were found to be few and far between, with actual field deployment references typically sourced from 10 years or more in the past.

The I&B strategy (#4) was not preferred primarily due to:

- The 40 km step-out represents a limit for wet insulation.
- The high insulation thickness introduces installation risks (risk of cracking) and reduces the spooled length per reel, with potential increased re-spool trips required and cost / schedule impact.

Seasonal tie-back gas rate reduction plus MeOH (#3) is feasible. The key risk is the reliance on remaining reserves from a depleted reservoir. The premise is therefore contingent on increased subsurface confidence.

The ‘do nothing’ scenario (#1) is compelling but ultimately a ‘risk-based’ approach. Up to 2.8°C subcooling must be tolerated for months every year. There is reliance on kinetics to distinguish risk of formation versus blockage. The premise requires multiple stakeholder buy-in, and hence a risk of project recycle was identified by the development operator.

The preferential premise was seasonal MeOH injection to inhibit against peak gas rates (#2), Figure 5. Risks are manageable, relating to additional chemical storage volumes and frequency of refill. Optimisation of the injected volume is possible through detailed assessment of backpressure, pipeline roughness, arrival pressure and also accounting for the salinity in the produced water to suppress the hydrate equilibrium curve.

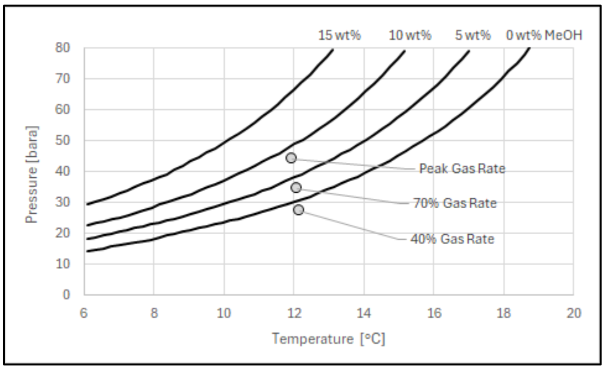

Figure 5. Inhibited hydrate equilibrium curves

Furthermore, it is recognized that flow assurance can err on conservativism, especially with respect to the prevailing ambient sweater temperature. Reported absolute minimum seawater temperatures in Metocean reports may reflect a datum that persisted for just minutes over a long (i.e. 10 year) period. A practical approach to the assessment of persistent seawater temperature is required to recommended strategies that protect the system but are not overly onerous in terms of lifecycle cost and operation. Use of exceedance data (e.g. 95% of the measured temperatures are greater than 13°C – Figure 6) would further reduce the MeOH injection rate and consumption.

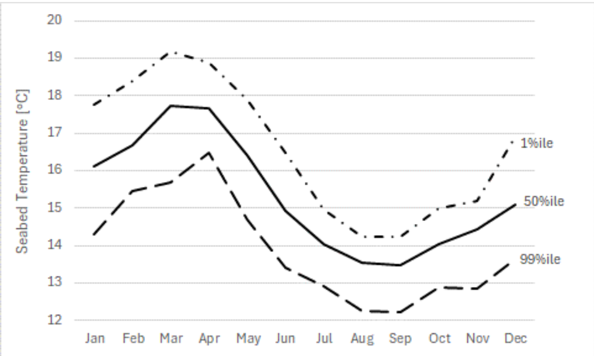

Figure 6. Seasonal seawater temperature by exceedance percentile

Active ambient temperature monitoring and feedback to a MeOH injection rate adjustment algorithm is recommended. This can be achieved using a hydrate advisory tool as part of a digital twin deployment, such as Virtuoso.

Conclusions

The subsea tie-back development was found to be an interesting case study of a marginal need for hydrate management, limited to cold season and <3°C sub-cooling. Multiple strategies were considered ranging from risk-based (reliance on no line blockage) to thermal management (insulation).

Detailed flow assurance modelling and assessment was combined with economic analysis to screen the various premises based on risk and cost impact.

A risk / cost balanced premise was put forward based on seasonal (as required) continuous MeOH once-through injection, with injection rates to be reduced as far as practical based on addressing conservatism in the hydrate equilibrium curve and implementing feedback of actively measured, in-field, seawater temperature.

Responsibility Notice

The authors are the only responsible for the paper content.

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