OPTIMUS

Inland Technologies Inc

Evaluation of the
Mono-ethylene Glycol [MEG] Concentrator to Recycle MEG
used in Hydrate Prevention

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1 Summary

Inland Technologies has developed a process for recovering and concentrating mono-ethylene glycol (MEG) through use of proprietary equipment called the MEG Concentrator. This technology has been developed and used in recycling airplane de-icer glycols at airports for over 10 years. Given the same chemical group is used in hydrate prevention for offshore gas production, the unit was used successfully in an industry cross over on the Galata gas project in Bulgaria. This paper is a technical review investigating the use of the patented MEG Concentrator in the natural gas industry generally. A number of areas were considered, and Optimus' conclusions are summarised below.

- Inland Technologies' MEG Concentrator is considered to be capable of meeting certain field requirements without major modification and at potentially lower capital and operating costs.
- The main potential applications may be small developments such as Galata, or a host facility with satellite tiebacks. Given the capacity of a single standard unit, new developments in warmer waters may be most appropriate.
- There may also be opportunities for replacement of existing systems.

2 MEG Concentrator Uses

The most significant potential applications for mono-ethylene glycol (MEG) recovery using the Inland Technologies MEG concentrator in the Oil & Gas Industry are:

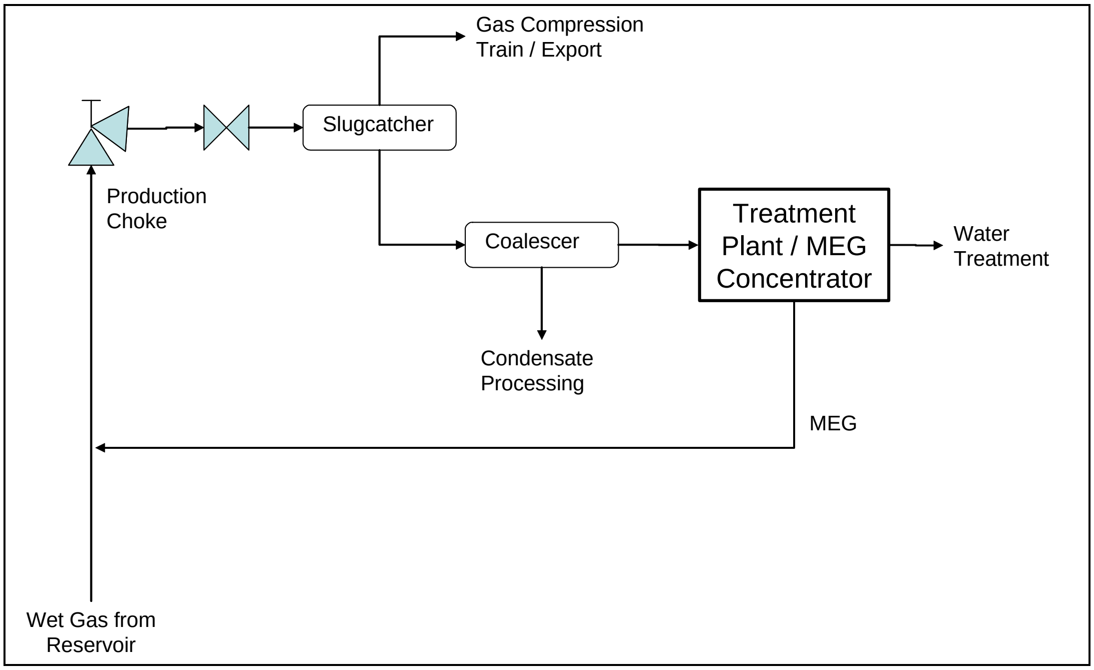
- Hydrate inhibition in subsea tiebacks (from the wellhead choke to the offshore reception facility), and
- Hydrate inhibition in export pipeline (from offshore reception facility to onshore terminal).

The aspects of these applications are reviewed are discussed in this report.

2.1 Hydrate Inhibition in Subsea Tieback

MEG is commonly used to prevent the formation of hydrates (ice-like solids) in subsea flowlines that carry gas or gas/condensate. Generally, there is no problem with hydrate formation if oil is present in the pipeline. The MEG is typically injected at the wellhead choke and flows with the hydrocarbons and water in the flowline. The MEG/water mixture is then separated from the hydrocarbons on the offshore facility. The MEG/water stream is treated to regenerate the MEG, which is recycled (see Figure 2.1). The Inland Technologies MEG Concentrator could perform this treatment.

Figure 2.1: Simplified typical subsea tieback process



Calculations for a typical Southern North Sea (SNS) field showed that a gas production rate of **42 mmscfd** can be treated by a standard, single Inland Technologies MEG Concentrator with a feed rate of 1m^3 of 20 wt% MEG. [Note: multiple MEG Concentrators can be used].

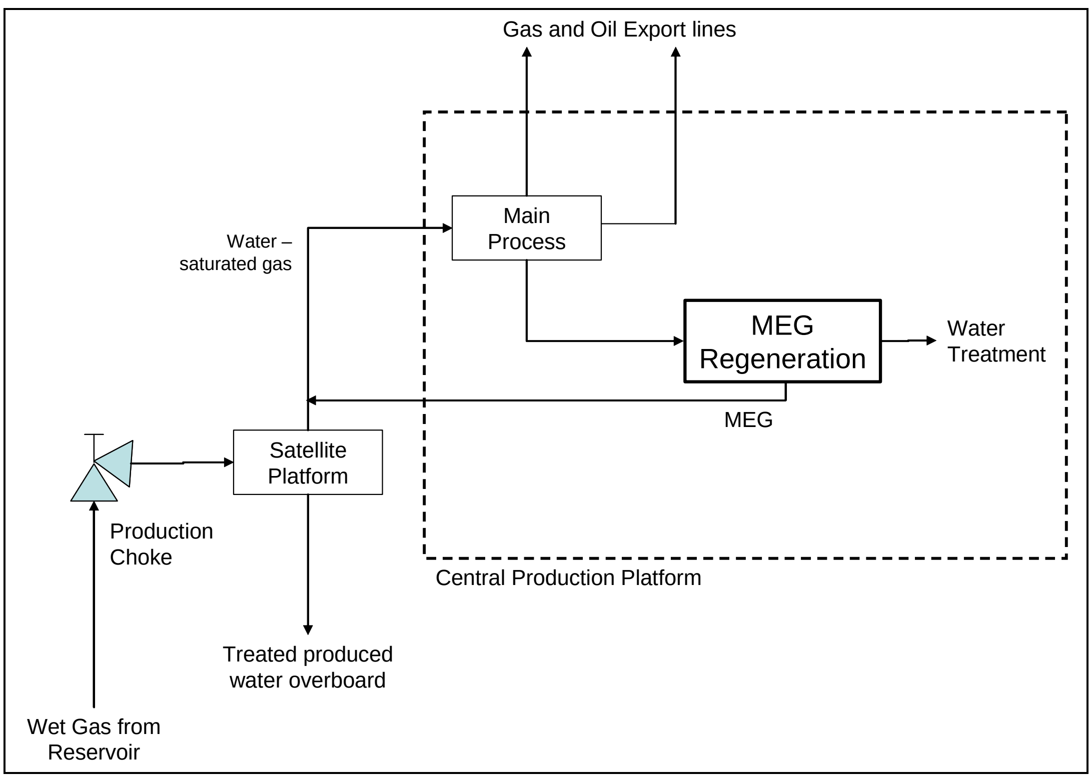
These calculations assumed a gas field with small quantities of condensate, saturated with water at reservoir conditions, where the only water present in the flowline is the saturation water that drops out as the pressure and temperature in the flowline fall. This production rate is affected by field composition, the initial quantity of saturation water present, and the design margin used to calculate the degree of inhibition required. Follow on sections in this paper discuss the aspects of a field that should be evaluated to determine the suitability of the Inland Technologies MEG Concentrator to a particular application.

2.2 Hydrate Inhibition in Export Pipeline [ex. Galata]

MEG is also used to prevent the formation of hydrates (ice-like solids) in export pipelines. The MEG is typically injected at the offshore facility after bulk water removal and flows with the hydrocarbons and condensed water in the pipeline. The MEG/water mixture is then separated from the hydrocarbons at the onshore terminal. The MEG/water stream is treated to regenerate the MEG, which is recycled. The Inland Technologies MEG Concentrator could perform this treatment. For this application, the Concentrator would be situated onshore or at a host platform (see Figure 2.2).

Calculations for a typical Northern North Sea (NNS) field showed that a gas export rate of **57 mmscfd** could be achieved using a standard Inland Technologies MEG Concentrator with a feed rate of 1m^3 of 20 wt % MEG. Again, the export rate is sensitive to the design margin assumed. The calculated treatable export rate increases to 87 mmscfd if the design margin is reduced from 5^o C to 2^o C. If the production rates were in the correct range, a series of Inland Concentrators could give a low cost, low energy alternative to conventional still column regenerators.

Figure 2.2: Hydrate inhibition at export pipeline



2.3 Review of Field Factors

The Inland Technologies unit is of appropriate capacity for application to several new fields. However, other factors must be considered.

The Inland Technologies Concentrator is unlikely to be a preferred option for:

- High CO2 fields, as high CO2 contents depress the hydrate formation temperature.
- High H2S fields, as high H2S contents depress the hydrate formation temperature.
- High pressure / high temperature fields, as the produced fluids will be hot, and hydrate inhibition is unlikely to be required.

The Inland Technologies MEG Concentrator **will have** a commercial advantage for:

- Fields with saline formation water that require hydrate inhibition, as it is easier to clean the unit and to remove salt build-up for the MEG Concentrator unit than for a conventional MEG regenerator.

It should be noted that, for the installations identified, the most commonly selected inhibitor appeared to be methanol. This may be because many of these planned fields will be tied back to existing infrastructure and already have methanol facilities in place.

2.4 Alternative Technologies

The most significant hydrate inhibition technologies currently used are MEG injection and methanol injection. The advantage and disadvantages of these alternatives are summarised in Table 2.3 below.

Table 2.3: Advantages and Disadvantages of Alternative Technologies

	Advantages	**Disadvantages**
THI / KHI – proprietary chemicals	• No recovery system required	• Limited suppression at high pressure • Short operating life in pipeline • High operating cost • Toxicity of overboard discharges
Methanol	• Can dissolve hydrate plugs • More effective hydrate inhibition per unit volume injected	• High losses to gas (30-40%) • Difficult to control process • Toxicity
MEG with distillation	• Lower cost than methanol	• Glycol loss to atmosphere
MEG with Inland Technologies Concentrator	• Low capital cost • Low power requirement • More suitable for use with saline fluids • Scalable system	• 60% wt highest practical glycol concentration limit

2.5 Field Evaluation of the MEG Concentrator

This section outlines the factors that comprise an “Ideal Field” for application of the Inland Technologies MEG Concentrator. The factors assume that a single, standard unit will be installed. New tieback to FPSO or Host Platform with no current MEG regeneration or insufficient spare capacity, or replacement of existing facilities due to poor reliability or insufficient capacity.

- Gas field
  - With no initial produced formation water and small quantities of condensate. Condensate to gas ratio (CGR) < 3 bbl/mmscfd
  - Where future production conditions (e.g. formation water) will not require additional hydrate inhibition.
- Fluid production rate that can be treated by a standard unit is sensitive to the minimum expected flowline temperature, i.e. to seawater temperature.

Sea Water Temperature	Indicative Maximum Production Rate
4^{o}C	< 40-60 mmscfd
10^{o}C	< 150 mmscfd

[Note: the equipment is often used in plant applications where three to five units are required]. The advantages of a multiple unit plant are scalability [ramping up or down] and modularity [one unit can be offline while still allowing production to continue].

3 Inland Standard Solution

The Inland standard supply was reviewed with respect to offshore considerations. Where additional flexibility could improve the probability of a successful bid, this has been indicated.

- Physical size: a standard unit can be accommodated in an area approx 12 ft by 26 ft, and maximum 20 ft high (8m x 3.7m x 6.1m max). This area should not be unreasonable for a reception facility. Offshore, the height may require the unit to be located on a higher deck.
- Weight: The standard unit weighs 5.5 te. This should not be an issue.
- Auxiliary requirements:
  - Power: 3 phase, 90 A, 60 Hz. Installed power, maximum of 80 kW. The voltage can be changed at Inland's manufacturing facility. Also, step up transformers can be used if required.
  - Compressed air: minimum 20 psi for instrument air.
  - Water: ~120 litres of clean, industrial water required on start-up only.
- Ambient design temperature of 4 to 40^{o}C. Ambient conditions on many offshore reception facilities may be lower than 4^{o}C. This would require an enclosure, and fire and explosion venting.
- Storage of MEG solution to cover offline periods. Expect 3-4 day shutdown for annual maintenance, which could be covered by normal platform shutdown. Brief shutdown every few weeks for basic maintenance.
- Glycol loss. The current glycol loss is specified as ~1000 mg/L, which is equivalent to <0.01 wt% of glycol in feed.
  - If lower levels are required, a bolt-on reverse osmosis unit may be added.

- Other:
  - Operator intervention: for saline produced fluids, the Inland Technologies design may be more suitable than a conventional MEG regeneration system, as the plate heat exchanger can be hosed down or back-flushed.
  - Delivery time: 16 weeks
  - Control: Operators may prefer to incorporate control within the DCS, rather than use standalone control panels with integral PLCs.
    - An interface to integrate with DCS would be advantageous.

These conclusions are summarised in Table 3.1 below.

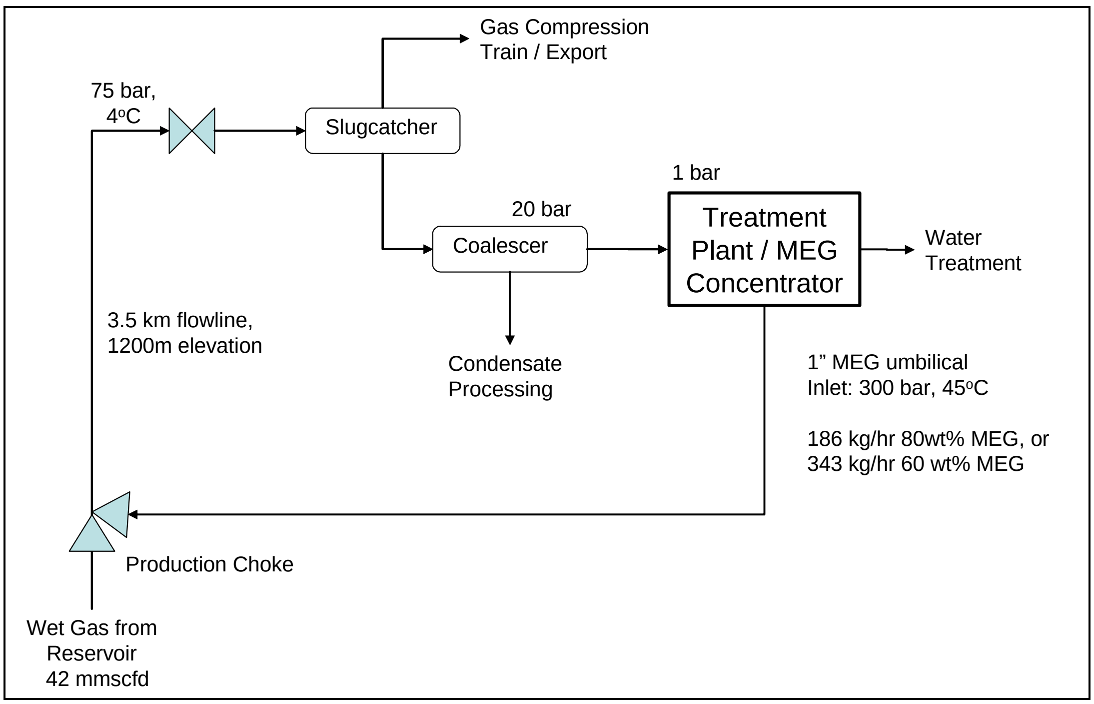
Table 3.1: Technical Evaluation of Inland Standard Solution

Factor	**Assessment**	**Comment**
Area required	✓	8m x 3.7m x 6.1m
Height	✓	May need to place some equipment on higher deck
Weight	✓	5.5 tons
Power supply	✓	Will probably need a step-up transformer
Compressed air	✓	20 psi
Water	✓	120 litres on start up only
Design Temperature	✓	4 to 40º C
Materials	✓	Will be impacted by site and location requirements
MEG storage	✓	Tank holding volume will vary based on site.
Glycol loss	✓	1000 mg/L or less
Design standards	✓	Modifications may be required based on location and operating conditions
Operator intervention	✓	May be suitable for use with saline produced fluids, with operator intervention or if designed with back-flush cycle.
Reliability	✓	Designed for continuous and batch operational modes
Contaminants in feed	✓	May require additional degasser, but this is unlikely.
Built in Control Panel	✓	Option to integrate to DCS would be advantageous

4 Case Study

Hydrate inhibition in a subsea tieback was examined further as a case study. The scenario used was a 3.5 km tieback from subsea wellhead to a central production facility. A typical Southern North Sea (SNS) reservoir was selected. A gas production of 42 mmscfd was assumed, as this was the maximum production that could be handled by a single standard Inland Technologies MEG Concentrator unit. The maximum mass rate of water that would condense in the pipeline (i.e. when cooled to 4^{o}C) was approximately 220 kg/hr. The hydrate formation temperature for the selected reservoir fluids, at choke pressure, was 16^{o}C.

Figure 4.1 – Typical Process Schematic



4.1 Options Examined

Two cases were evaluated:

1. A conventional design comprises injection of 80 wt% MEG in water solution at the choke, with the MEG being recovered by a distillation column with heat recovery. A high-level design was performed for the selected case.

2. This design comprises injection of 60 wt% MEG in water solution at the choke, with the MEG being recovered by an Inland Technologies MEG Concentrator. A high-level design was performed for the selected case.

4.2 Comparison of Estimated Costs

For high level estimating, it is acceptable to base an equipment cost estimate on the weight of the equipment. This method factors the cost of basic materials, fabrication, associated piping & instrumentation etc., delivery, installation etc. for an offshore facility.
The cost of a conventional MEG regeneration system (column with reboiler) and the Inland Technologies Concentrator were calculated using this method, to provide comparative figures.

Table 4.1: Comparison of Estimated Costs [2007 estimates only]

	Typical Conventional MEG regeneration system	**Inland Technologies MEG Concentrator**
Installed Cost (using estimation method based on weight)	£6.4M	£2M
Mobilisation & Lease Cost (Galata) – excludes installation and commissioning costs	n/a	US$100,000 mobilisation US$120,000/yr lease

There appears to be significant potential for the Inland Technologies MEG Concentrator to undercut the cost of a conventional regeneration system.

4.3 Comparison of Other Factors

Other relevant results from the Case Study are summarised in Table 4.2, below.

Table 4.2: Comparison of Other Factors

	Typical Conventional MEG regeneration system	**Inland Technologies MEG Concentrator**
MEG injection pump power (1” injection line)	1.9 kW	3.6 kW
MEG regeneration system - power	200 kW	80 kW
- Equivalent reduction in CO_2 emissions [1]	-	480 te/yr
- Equivalent saving in fuel gas	-	70 kSm^3/yr
Glycol loss (as % of recycled mass)	Typically 500-1000 ppm (<0.01 wt% MEG in feed)	Typically 100 to 1000 mg/L distillate (<0.01 wt% MEG in feed)
Flow assurance	No concerns	No concerns

[1] To put this into context, 500 kte of CO_2 was a typical emission for an UK offshore platform in 2005.

5 Conclusions

1. Mono-Ethylene Glycol (MEG) is a widely used hydrate inhibitor in the worldwide oil & gas industry. It is a lower cost alternative to methanol, but lacks some of the properties associated with methanol, the main one being that it cannot dissolve hydrates once they have formed, only prevent the formation in the first place.
2. Inland Technologies has a proven method of concentrating MEG that could be used in place of conventional reboiler and still technology. This process has limitations in that it can only concentrate a solution to approximately 60 wt%, where a conventional still column can achieve 98%+ wt% MEG. The units supplied by Inland Technologies to date have been limited in throughput to a feed stream of 1 m3/hr of feed at c.20wt% concentration. However, the multiple units are sometimes operated up to ~ 5m3/hr.
3. Two operating fields in the North Sea have been considered and found that if the Inland Technologies MEG Concentrator had been considered for glycol regeneration on these facilities, they would have been capable of meeting the field requirements.
4. There are modifications that may be required to the current standard package to allow it to operate on an offshore Oil & Gas installation. None of these are considered to be major issues for Inland Technologies to adopt within their existing package design.
5. The North Sea is a mature oil field in cold waters. In less mature fields, where there is no existing infrastructure dictating hydrate inhibitor use, or regeneration technology to be used, the opportunities to introduce a new concept for regeneration will be greater. In fields located in warmer waters, the concentration of MEG required to avoid hydrates will be lower, and the MEG recirculation rate will be lower, increasing the suitability of the standard Inland Technologies unit.

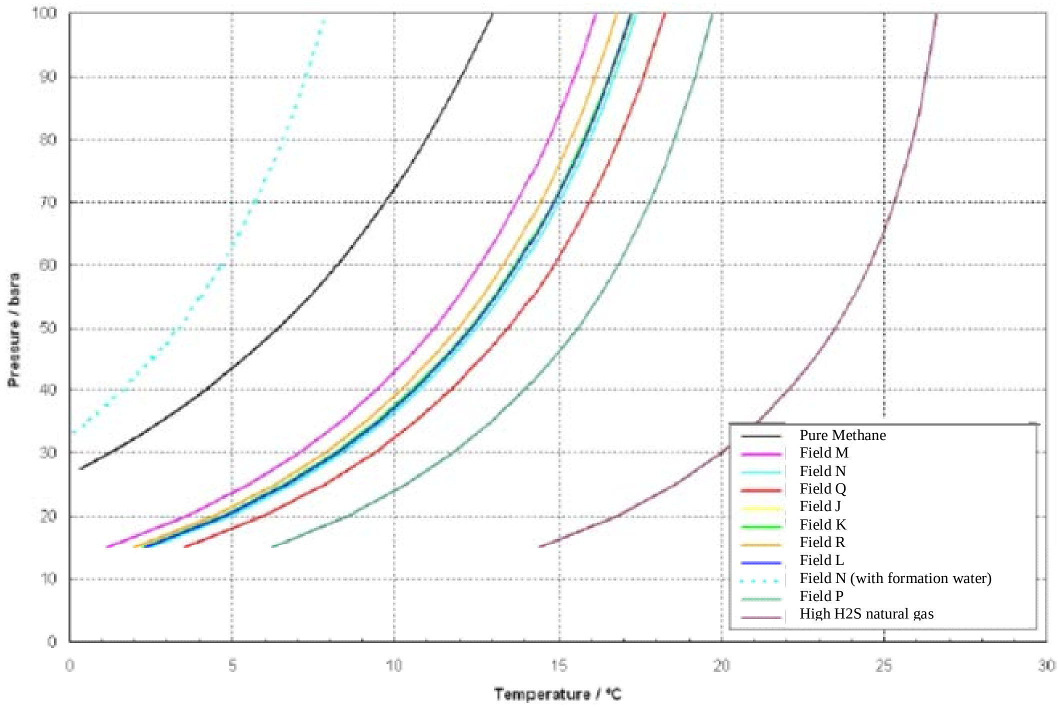
Attachment A – Technical Aspects of Hydrate Inhibition

A.1 Hydrate Formation in Hydrocarbon Streams

Hydrates are ice-like solids that can form in streams containing methane and water. They are frozen lattice-like substances, officially called methane hydrate, and can cause blockage of flowlines. Once formed, hydrate plugs are difficult to remove. It is therefore preferable to prevent formation.

The hydrate formation curve is dependent upon a number of factors:

- **Composition**. The presence of heavier hydrocarbons, such as ethane, propane, butane increases the hydrate formation temperature at a given pressure, i.e. the severity of hydrate conditions tends to increase with gas gravity. The presence of significant amounts of CO2 or H2S has a similar effect.
- **Presence of Salts**. The presence of salts, e.g. in formation water, will depress the hydrate formation temperature, reducing the severity of hydrate conditions.
- **Addition of Inhibitor**. The presence of certain chemicals will depress the hydrate formation temperature. The most commonly used inhibitors are the glycols and methanol, as these are easily recovered with the aqueous phase, regenerated and recycled. The most popular inhibitor is MEG, which offers lower cost, lower viscosity, and lower stability in liquid hydrocarbons. The exceptions are at cryogenic temperatures (below -25^{o}C), where methanol is usually preferred because the high viscosity of glycol makes effective separation difficult; and for saline produced fluids.
- Experience in the Southern North Sea (which is among the most severe operating experience, due to low sea water temperatures) indicates that hydrate inhibition was most frequently required during early field life. Once formation water production became significant, the associated salts may eliminate the need for additional hydrate inhibition. This is reinforced by the lower production pressures, which reduce the hydrate formation temperature. The overall effect is that few mature fields in the SNS now require hydrate inhibition.



This figure shows the effect of composition on the hydrate formation curve. It is clear that the hydrate formation temperature is highly field specific. The figure also clearly illustrates the effect of formation water salts. At 100 bar, the hydrate formation temperature for Field N is 17^{o}C. However, with formation water present, this is reduced to 8^{o}C.

As fields with produced formation water do not generally require hydrate inhibition, this study only considers gas/condensate fields where the only water present in the system is water that was saturated at reservoir conditions, but dropped out as the flowline pressure decreased.