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Low-Dosage Hydrate Inhibitors (LDHIs): Reducing Costs in Existing Systems and Designing for the Future

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Abstract

Hydrates remain a significant flow assurance issue in nearly every Deepwater development. Traditional hydrate control methods of insulation and/or thermodynamic chemical inhibition may not provide the desired level of hydrate protection at an economic price. Low-Dosage Hydrate Inhibitors (LDHIs) are a proven technology to control hydrates in numerous applications and are instrumental in reducing the total cost of operations (TCO). In particular, LDHIs offer solutions to existing problems such as unexpected water breakthrough, undersized methanol injection capacity, and high-volume methanol transportation / storage limitations. As an added benefit, it is possible to co-formulate LDHIs with other production chemicals, such as paraffin and corrosion inhibitors, and thus minimize the number of chemical injection lines. While the benefits to existing developments are appreciable, the true potential of this technology lies in the reduced capital expenditures (Cap Ex) required for systems designed specifically for LDHIs. Potential savings include, smaller umbilical line diameters, the elimination of a methanol wash and recovery operation, fewer umbilical lines, smaller / lighter storage capacity, and smaller pumps.

Introduction

Types of Hydrate Inhibitors

Hydrate inhibitors are typically classified into the following groups:

- *Thermodynamic Hydrate Inhibitors* – Traditional hydrate inhibitors, such as methanol (MeOH) and ethylene glycol (MEG), shift the conditions at which hydrates are stable. If enough thermodynamic hydrate inhibitor is injected, hydrates will never form in the system. The difficulty comes

in being able to inject enough. For Deepwater applications, MeOH usage rates are typically on the order of 0.25 – 1 bbl MeOH/bbl water. MEG rates are comparable to MeOH, but the MEG must usually be recovered and recycled to be economical.

- *Kinetic Hydrate Inhibitors* (KHIs) – This type of LDHI works by delaying hydrate nucleation and/or growth for a period of time known as the induction time. Dosage rates are typically a fraction of that required for thermodynamic hydrate inhibitors. KHIs are highly effective in low to moderate subcooling applications. The latest generation of products is even showing promise for high subcooling applications, particularly when supplemented with small amounts of MeOH or MEG. Products are tailored to meet the economic and induction period requirements of a system.
- *Anti-Agglomerant Hydrate Inhibitors* (AAs) – This type of LDHI allows hydrates to form, but keeps the particles small and well-dispersed in the hydrocarbon fluid. Fluid viscosities remain low, allowing the hydrates to transport along with the produced fluids without depositing. AAs are particularly attractive for severe hydrate forming matrixes and are also effective for extended shut-ins.

Why LDHIs Can Lower Costs

As with many paradigm shifts, the switch from thermodynamic hydrate inhibitors to LDHIs is driven by economics. Some of these economic drivers are obvious and readily quantified, such as when the LDHI facilitates higher production rates in a MeOH volume-limited system. Others are more subtle, complex, and/or difficult to quantify, such as the adverse impact of MeOH on topsides processing.

As discussed in detail below, the dramatically lower volumes required for LDHIs compared to MeOH lead to a whole host of potential cost savings. It is not unusual to reduce hydrate inhibitor volume by 90% when switching from a thermodynamic hydrate inhibitor to an LDHI. In some cases, particularly high subcooling Deepwater systems, volume reductions of 95-99% are achievable. Usually, an operator can treat more water in an existing system with an LDHI than MeOH. More extensive cost savings are often realized if a system is designed for LDHI, as the size of key components is reduced.

There are also secondary benefits of LDHIs. For one, simply eliminating MeOH or MEG from the system is often a distinct advantage. In addition, LDHIs are often amenable to

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multifunctional formulation, thus addressing multiple flow assurance issues with a single chemical injection line.

This paper gives examples, including a few case histories, of the potential impact of switching from MeOH to an LDHI.

Reducing Costs in Existing Systems

The majority of LDHI trials and applications are taking place in systems originally designed for either MeOH or MEG use. Many of these applications are previously described in the literature.¹ The motivations for these trials, and the reasons operators choose to expand many of these trials into permanent applications vary. Often, the operator prefers the convenience of LDHIs. In some, the operator finds that the LDHIs simply cost less per barrel water treated than traditional systems. This is particularly true in systems with low water contents where the majority of MeOH is lost to the hydrocarbons, or low subcoolings where a low dosage KHI suffices to control hydrates in the system. Otherwise, LDHIs are typically implemented when the systems begin making appreciable water. Oftentimes the water production rate outstrips the capacity of the system to inject thermodynamic inhibitor or the logistics of transporting, storing, and continually resupplying the thermodynamic inhibitor proves onerous. A discussion of the manner in which LDHIs can lower costs in existing systems is given below. These possible benefits are listed for illustrative purposes only. Results may vary by system.

Lower Operating and Intervention Costs

Lower Chemical Costs. The selling prices of specialty chemical LDHIs are significantly higher than the commodity chemicals MeOH and MEG. Typically, LDHIs are sold for tens of dollars/gallon, whereas MeOH is typically \$0.30 - \$0.90/gal² and MEG is typically \$1.75 - \$3.75/gal.³ Recycling MeOH and MEG tends to lower these prices but necessitates an upfront capital expenditure. It is important to remember that it is the treatment rate *times* the price/gallon that determines the total treatment cost. Thus, for example, a MeOH price of \$0.50/gal and treatment rate of 1 bbl/bbl water combine to give a total treatment cost of \$21/bbl water. An LDHI that controls hydrates at 0.70 gal/bbl water (0.017 bbl/bbl water) and costs \$30/gal* still gives a total treatment cost of \$21/bbl water, and thus is cost equivalent to MeOH in this example.

Lower Transportation Costs. The treatment cost is only a small portion of the total cost to control hydrates. Another contributing cost is the transportation charge to supply hydrate inhibitor to the platform or field. In readily accessible locations, the charge may be nominal. In remote locations, the cost of the transportation may actually exceed the cost of the MeOH itself. For Deepwater platforms, MeOH is typically transported by dedicated supply boats, often necessitating special licenses and permits. High supply costs also apply to remotely located fields on shore. Since transportation costs are typically a fixed \$/gal, LDHI transportation costs can be as much as 99% lower than MeOH transportation costs.

* The price listed here is an example only and should not be used to estimate costs in a real system.

Lower Manpower Costs for Handling Hydrate Inhibitor.

One cost often not accounted for is the manpower time required to handle large quantities of thermodynamic hydrate inhibitor. Each time a supply of MeOH is delivered, operators must handle the transfer from the transportation container to the storage tank. Given the hazards associated with handling this low flash point chemical, this procedure is necessarily disruptive to other platform operations. For systems with recycle and regeneration facilities, there are also manpower requirements for monitoring and maintaining such systems.

No MeOH in Topsides and Downstream Operations.

Some unintended and undesirable side-effects have emerged as the usage of MeOH for Deepwater hydrate control has become more prevalent. In particular, MeOH often adversely affects oil/water separation procedures. This is most simply understood by realizing that MeOH lowers the density of the aqueous phase, reducing the density difference between the hydrocarbon and water phases and thus diminishing one of the driving forces for phase separation. In fact, in high API gravity gas condensate systems with high MeOH demands, it is possible for the aqueous/MeOH phase in the separator to actually float on the gas condensate. MeOH also impacts the hydrocarbon/aqueous interfacial tension. Operational experience suggests that it is particularly difficult to meet overboard water quality specs in systems treated continuously with high volumes of MeOH.

Because of the prolific nature of many Deepwater wells, many operators have sought to debottleneck their topsides processing. As noted above, the presence of MeOH can impede oil/water separation, limiting the effectiveness of processing equipment and topsides chemical treatments. In addition, every barrel of MeOH injected is processed as a barrel of liquid when it returns to the platform *via* the flowline. In many systems, this amounts to hundreds of barrels per day of extra liquid, occupying valuable capacity in both the flowline and topsides processing equipment. Switching to an LDHI not only lowers the volume of liquids that require processing, but in some cases improves oil/water separation (especially in black oil systems). To be fair, it is noted that LDHIs do increase emulsion tendencies in some hydrocarbon systems. In such cases, additional demulsifiers and/or water clarifiers are occasionally necessary.

High concentrations of MeOH, and to a lesser extent MEG, can exacerbate scaling tendencies in oilfield brines.⁴ Additionally, high salinity systems are vulnerable to salt (halide) precipitation if treated with MeOH and MEG. Scaling problems have been noted in both the flowlines and topsides of systems treated continuously with thermodynamic inhibitors. In severely scaling systems, high MeOH concentrations in the vicinity of the MeOH injection mandrel may lead to localized precipitation of scale and plugging of the injection point.

The solubility of MeOH in crude oil results in a finite volume of MeOH contaminating downstream operations. This can be particularly troublesome during periods of high MeOH usage, such as restarting Deepwater platforms after a hurricane evacuation. Recently in the Gulf of Mexico, a few refineries instituted discounts for crude oil containing MeOH because the MeOH creates a variety of difficulties in crude processing. In particular, MeOH adversely affects the performance of the

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wastewater biotreaters. Typical specifications are on the order of <50 - 200 ppm MeOH in the crude oil. Platforms with such MeOH specs face the added expense of monitoring the MeOH content of their crude oil. This is performed on site and/or onshore. There are costs associated with both the monitoring operations and testing services. In addition, if the crude does not meet these specifications, the operator is forced to either accept the discounted rate or wash the crude offshore with an available water source (either seawater or MeOH-free produced water). Crude washing is also an inherent component of MeOH recovery facilities. The washing process leads to its own difficulties, particularly if the topsides equipment is not designed for such operations, if care is not taken to exclude contaminants from the washing operations, and/or if the wash water is not compatible with the produced brine. Depending on the source water, other processing chemicals are often required, including biocides, scale inhibitors, corrosion inhibitors, and/or oxygen scavengers.

Some LDHIs are formulated in MeOH, primarily because it is a low cost, low viscosity solvent. However, since the volumes used are so much smaller than a traditional MeOH treatment, the resulting absorption of MeOH into the oil phase is often below the detectable limit. In addition, if necessary, the majority of LDHIs can be applied in a non-MeOH solvent.

Lower Pump Maintenance. Pumping high volumes of MeOH or MEG takes its toll on pump equipment. Reducing the volume of chemical pumped 1 to 2 orders of magnitude generally allows the application of a smaller pump and reduces the required maintenance.

No Intervention During Shut-in. In systems which have reached their limit of thermodynamic hydrate inhibitor injection, shut-ins often necessitate some type of intervention to mitigate the hydrate risk posed by higher subcoolings. This intervention is typically displacement of fluids or blowdown. Because LDHIs can treat higher water volumes for a given line size, such intervention is often avoided for systems treated continuously or for planned shut-ins of intermittently treated systems. This is particularly true of AA-type LDHIs which tend to show good performance even during extended shut-ins. KHI products will provide a finite amount of “no touch time,” but eventually require intervention if the shut-in time exceeds the induction time under system conditions.

Lower HS&E Risk. Both MeOH and MEG are toxic to humans. MeOH also poses an explosion hazard due to its low flash point (52 °F/11 °C). Large volumes, toxicity, and a low flash point combine to make MeOH an HS&E concern. Of particular concern are the transfer operations. Though some LDHIs are supplied in either MeOH or MEG, the appreciable reduction in volume mitigates the risk. The difference in HS&E risk between, for instance, a 1000 bbl MeOH tank and a 30 bbl LDHI tank is unfortunately difficult to quantify.

One of the often-cited concerns about the AA-type anti-agglomerants is the impact on overboard water toxicity. In fact, the AAs have appreciable oil solubility. Operational experience suggests that, in most applications, the residual concentration in the overboard water is below detection limits and has negligible effect on the measured aquatic toxicity. In the few cases where measurable quantities of AA remain in the aqueous phase, water clarifiers are available to drive the

residual AA into the oil phase, rendering a dischargeable water phase.

Accelerate and Maximize Production

Accelerate Oil and Gas Production. In systems which are limited in their thermodynamic inhibitor injection capabilities, LDHIs allow higher water production rates. This translates to simplified planned shut-in procedures and enables faster restarts for systems requiring intermittent hydrate control. Both applications afford accelerated production.

Delay Water-Related Curtailment. Systems requiring continuous hydrate inhibitor are vulnerable to high water production rates. If water production exceeds the capacity to treat the water for hydrates, wells are sometimes curtailed to mitigate the risk of hydrate plugging. A switch to an LDHI allows higher produced water rates, thus delaying curtailment due to produced water.

Improve Operational Flexibility. Having operational flexibility in terms of chemical injection for flow assurance helps protect against the unexpected. For instance, occasionally, despite the best efforts of the flow assurance and design teams, a system develops unforeseen problems that require chemical treatment. In such systems, there are often insufficient chemical injection lines to treat the problems. If the system requires continuous MeOH treatment, the MeOH injection requirements take up a large part of the total chemical injection capabilities.

After significant product development, chemical service companies have managed to develop corrosion inhibitors (CI) that are soluble in and may be applied by co-injection with MeOH. MeOH-soluble scale inhibitors (SI) have recently been developed and MEG-compatible scale inhibitors are available. However, traditional oil soluble products like paraffin inhibitors (PI) and asphaltene inhibitors (AI) are catastrophically incompatible with MeOH and often immiscible with MEG. Reliance on MeOH for hydrate control often limits an operator's options for flow assurance control.

Many LDHIs are amenable to formulating multifunctional or “combination” products. AA's in particular have appreciable oil solubility, thus opening up the possibilities of AA/PI and AA/AI products. Currently, the following products are commercially available and field-proven: AA/CI, AA/PI, and AA/PI/CI. Development work for AA/AI and AA/SI products is nearing completion. KHI/CI products are also commercially available. KHI/SI products are also feasible. The latest generation of KHI products are soluble in aromatic solvents, affording the possibility of KHI/PI and KHI/AI products as well. Not every pair of products is compatible. For instance, several CIs are known to interfere with AAs and/or KHIs. But, the LDHIs are in general more flexible than either MeOH or MEG when it comes to formulating multifunctional products.

Multifunctional products in turn allow adaptation to changing or unexpected conditions. A single chemical injection line can be adapted to handle 2 or more flow assurance issues.

Increase Ultimate Recovery

In systems requiring continuous hydrate inhibitor treatment, the aforementioned benefits of LDHIs can, in some cases, extend the life of the well. This is particularly true of gas condensate wells that load up when not produced at a sufficiently high rate.

Examples and Case Histories

Operating Subsea System Example. The potential benefits of LDHIs are examined by considering the case of an existing subsea system with a 0.5" ID chemical injection line in 2000 ft of water. Furthermore, assume the required MeOH dosage rate is 0.41 bbl MeOH/bbl water, while the corresponding LDHI rate is 0.012 bbl LDHI/bbl water. Maximum pump discharge pressure is limited to 8000 psig while the pressure at the injection point is 3800 psig. Under these conditions, the maximum amount of water that can be treated with MeOH is roughly 100 – 240 bwpd, depending on the tieback distance (see Figure 1). The LDHI on the other hand can treat 1000 – 7000 bwpd, depending on the tieback distance. This difference results purely from the pressure drop through the umbilical. Note that the MeOH is in turbulent flow while the LDHI is in laminar flow. Thus as the water cut increases, a system relying on MeOH will be forced to consider other options for hydrate control, possibly necessitating the curtailment of gas production. This example illustrates that an LDHI can allow higher water production in an existing system with limited MeOH injection capability.

DVA Case History. Such situations have been encountered in numerous field applications. The authors previously reviewed a TLP which exceeded its capacity to treat for hydrates with MeOH (at 4 and 11% water cuts) in two dry tree (DVA) wells.^{1b} The high volumes of MeOH needed exceed the capacity of their capillary strings, forcing the operator to adopt their emergency shut-down (ESD) procedure for planned shut-ins. This involves shutting in the well and bullheading 98 bbl of diesel into the tubing. On restart, MeOH is injected at its maximum rate on the hope that the well warms to above the hydrate temperature before the hydrates have time to form. Switching to an LDHI for the planned shut-ins and restarts proved trouble-free and was adopted as a standard operating procedure. Because the procedure is simpler and less time consuming, the operator estimates 7500 bbl of accelerated oil production per planned shut-in.

Subsea Case History. More recently, Shell reported a successful LDHI implementation in their Popeye subsea well.^{1a} In this case, one of the subsea wells began watering out. The water production quickly outstripped the system's capability to inject MeOH. The system required 250 bpd MeOH, but the injection system was only capable of delivering a maximum of 175 bpd. This led to partial hydrate blockages and forced the operator to curtail production while searching for ways to increase MeOH injection. Accordingly, an anti-agglomerant LDHI was implemented at 0.35 gal/bbl water (0.8% of the water volume). A total of 12.5 bpd LDHI was required to treat the 1500 bwpd, giving a 95% reduction in chemical usage compared with MeOH. Results of the application are illustrated in Figure 2. After proving the LDHI's efficacy, the well was opened up, affording an

additional 20 mmscfd in gas production. Over the 10 months remaining life of the well, an additional 11 bcf of gas was recovered while lowering the total cost of operations. Shell estimates an \$8 MM net present value (NPV) improvement due to implementation of the LDHI.

Designing for the Future

While the impact of LDHIs on existing systems is impressive, more dramatic effects are seen when systems are designed specifically to employ LDHIs. Here, the smaller volumes and ability to make multifunctional products truly come into play in lowering capital expenditures. Benefits are derived from smaller diameter umbilicals/capillaries, fewer chemical injection lines, smaller storage tanks, less storage weight, and smaller pumps. The impacts are explored with a series of Design Examples.

Design Example 1

The following assumptions are used to compare MeOH and LDHI for a subsea tieback:

- 25 mile tieback in 2000 ft of water
- gas condensate requiring continuous hydrate inhibitor injection to treat up to 860 BWPd at >30 °F subcooling
- 8000 psig pump discharge pressure and 3800 psig WHP
- 14 day hydrate inhibitor storage required

Based on these assumptions and operating experience, a typical MeOH treatment rate is 0.41 bbl/bbl water, while the corresponding LDHI anti-agglomerant treatment rate is 0.012 bbl/bbl water.

Results of the calculations are given in Table 1. The LDHI injection rate is roughly 97% lower than the MeOH injection rate. To treat this system at the maximum expected water production rate would require 350 bpd MeOH and a 1" ID chemical injection line. The chemical injection line ID is estimated by calculating the pressure drop of the MeOH through the line at 350 bpd and iterating the line ID until the flow could be achieved using the assumptions given. A 14 day supply of chemical requires 4900 bbls of storage for a total of 1,400,000 lbs of inhibitor.

In contrast, the corresponding LDHI rate is 10 bpd and requires a 0.375" ID chemical injection line. A 14 day supply of chemical is equivalent to 146 bbl and weighs 44,000 lbs. Using "rule of thumb" estimates for the umbilical, pump, storage tank, and weight allowance, we estimate the potential CAPEX savings to be on the order of \$5-10 MM for the system as described. This does not include any infrastructure improvements necessary to supplying the 4900 bbl MeOH per week.

Figure 3 shows a sensitivity analysis of the chemical injection line size as a function of tieback distance. As expected, the required ID increases with increasing tieback distance. Note that it is possible to supply an LDHI via a 0.5" line 50 miles out, while a MeOH application would necessitate a line exceeding 1.1" ID.

Design Example 2

The following assumptions are used to compare MeOH and LDHI for a dry tree (DVA) system:

- wells in 5000 ft of water with the SCSSV 3000 ft below the mudline
- black oil requiring hydrate inhibitor only for shut-ins and restarts >30 °F subcooling
- 10,000 psig pump discharge pressure and 8000 psig at the SCSSV

Based on these assumptions and operating experience, a typical MeOH treatment rate is 0.35 bbl/bbl water, while the corresponding LDHI anti-agglomerant treatment rate is 0.015 bbl/bbl water.

The LDHI injection rate is roughly 96% lower than the MeOH injection rate. Table 2 shows the maximum water production that is treatable with each of these chemicals as a function of chemical injection capillary ID. For this exercise, three standard size capillaries are assumed: 0.25", 0.375", and 0.50" ID. Given these size lines, MeOH may treat a maximum of 120-750 bwpd. Given these restrictions, MeOH injection for planned shut-ins and restarts is limited to low water cuts. As the water cut increases, the operator is forced to switch to alternative methods, such as displacing the tubing fluids with each shut-in. In contrast, the LDHI could treat a maximum of 2200 – 13,000 bwpd with the same size lines. Thus, designing for an LDHI allows for smaller ID capillaries while simultaneously designing the system to treat higher water volumes.

Design Example 3

Golczynski and Niesen⁵ recently presented work discussing the volumes and injection rates of MeOH required to startup ultra-deepwater wells under a variety of scenarios. Their model system included the following assumptions:

- 3 – 15 mile tieback in 7000 ft of water
- black oil requiring hydrate inhibitor only for shut-ins and restarts at a rate of 0.40 – 0.60 bbl MeOH/bbl water
- 5000 psia pump discharge pressure and 2800 psia shut-in pressure
- total production rate from 2 wells in the range of 5000 – 30,000 bopd

Under these conditions, the authors note the appreciable role delivery of MeOH plays in the ability to start up the system. For instance, in the case of a 15 mile tieback, 6.5 gpm MeOH is delivered through a 0.75" ID line. This is acceptable for a 2% water cut system, but at a 25% water cut, this would limit the system startup rate to <2000 bopd, requiring in excess of 24 hrs warmup time for the five common insulation options considered. A 1.5" ID line allows 40 gpm, which is sufficient to start the system up at 9800 bopd and 25% water cut.

For comparison, assume an LDHI dosage rate of 0.015 bbl/bbl water. That same 0.75" ID line would be sufficient to deliver enough LDHI to start the wells up at their maximum rate (30,000 bopd) at a water cut in excess of 30%. Considered another way, if the target is start-up at 9800 bopd and 25% water cut, the 1.5" ID MeOH line could be replaced by a 0.5" ID LDHI line.

Systems Under Development

The potential advantages of LDHIs to capital expenditures caught the attention of the oil and gas community. Because LDHIs are relatively new technology, only a handful of

systems designed specifically for LDHI use have come on-line to date. Most notable of these is ETAP (Eastern Trough Area Project), operated by BP, which was designed specifically to "utilize innovative Threshold Hydrate Inhibitor [i.e., a KHI] removing the requirements for costly methanol recovery facilities."⁶ Phillips and Grainger¹ⁿ cite an estimated savings of \$40MM due to the design for LDHI rather than MeOH.

The authors are involved in a dozen projects to design systems specifically to use LDHIs, both KHIs and AAs, in locations around the globe, including the Gulf of Mexico, North Sea, West Africa, and Southeast Asia. Another ten systems are being designed for MeOH or MEG, but are configured such that LDHIs could be used if desired. BP recently reported they are investigating LDHIs as an alternative to MeOH for their upcoming deepwater projects in the Gulf of Mexico, such as Thunder Horse.⁷ The article cites, "Potential cost savings run into tens of millions of dollars."

Conclusions

A summary of the potential economic impact associated with LDHI use is shown in Table 3. Based on the numerous field applications to date, LDHIs are proven alternatives to traditional hydrate control chemistries such as MeOH and MEG. As noted in the case histories and design examples, the true value of LDHIs extends far beyond the \$/bbl water treatment cost. LDHIs can provide significant reductions in TCO for existing systems using MeOH or MEG. LDHIs have the biggest economic impact when designed into systems, often affording multi-million dollar reductions in capital expenditures.

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Nomenclature

The following abbreviations and acronyms are used throughout the text:

AA	anti-agglomerant hydrate inhibitor
AI	asphaltene inhibitor
bbl	barrel (42 US gallons = 0.159 m ³)
bopd	barrels of oil per day
bpd	barrels per day
bwpd	barrels of water per day
CI	corrosion inhibitor
DVA	direct vertical access (i.e., dry tree, platform wells)
ESD	emergency shut-down
ft	feet = .305 m
gal	US gallon = 3.78 liters
gpm	gallons per minute
hrs	hours
HS&E	health safety and environmental
ID	inner diameter
"	inch = 2.54 cm
KHI	kinetic hydrate inhibitor
LDHI	low-dosage hydrate inhibitor
MEG	ethylene glycol
MeOH	methanol
MM	million

NPV	net present value
PI	paraffin inhibitor
ppm	parts per million
psia	pounds per square inch (absolute) = 0.069 bars
psig	pounds per square inch (guage)
SCSSV	surface controlled sub-surface safety valve
SI	scale inhibitor
TCO	total cost of operations
WHP	wellhead pressure

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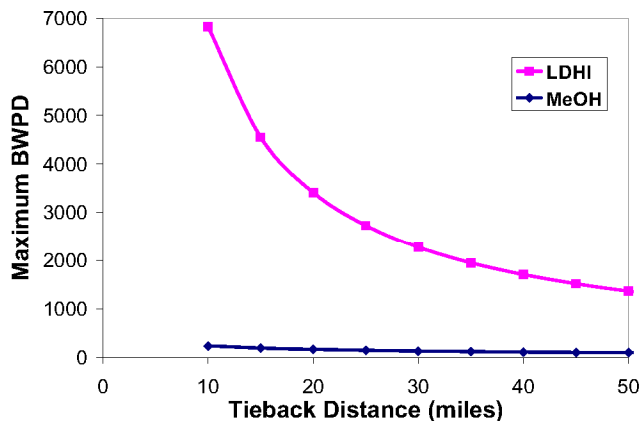


Figure 1: Operating Subsea System Example - LDHI Allows Treatment of Higher Water Production Rate for a Given Chemical Injection Line Size

Table 1: Design Example 1 – Potential Impact of LDHI on Subsea System Design

	MeOH	LDHI
Dosage Rate (vol% of water)	41%	1.2%
Injection Rate (bpd)	350	10
Umbilical ID (inch)	1	0.375
14 Day Supply Volume (bbl)	4900	146
14 Day Supply Weight (lbs)	1.4 MM	44,000

Table 2: Design Example 2 - Potential Impact of LDHI on Dry Tree (DVA) System Design

	MeOH	LDHI
Dosage Rate (vol% of water)	35%	1.5%
Maximum BWP @:		
0.25" ID capillary	120	2200
0.375" ID capillary	350	5800
0.5" ID capillary	750	13,000

Table 3: Potential LDHI Impact on New and Existing Designs

LOWER CAPITAL COSTS

- Smaller diameter umbilicals
- Fewer chemical injection lines
- Smaller storage tanks
- Less storage weight
- Smaller pumps

LOWER OPERATING AND INTERVENTION COSTS

- Lower chemical costs
- Lower transportation costs
- Lower manpower costs handling hydrate inhibitor
- No MeOH in topsides and downstream operations
 - No MeOH penalties
 - No manpower/testing fees for monitoring MeOH content in crude oil
 - Improved oil/water separation
 - Less liquid to process
- Lower pump maintenance
- No intervention during shut-in
- Lower HS&E risk
 - Lower volumes of hazardous chemicals
 - Less explosion hazard
 - Less handling of high flashpoint chemicals

ACCELERATE AND MAXIMIZE PRODUCTION

- Accelerate oil and gas production
- Delay water-related curtailment
- Improve operational flexibility

INCREASE ULTIMATE RECOVERY

- Extend life of well

These possible benefits are shown for illustrative purposes only. Results may vary from system to system.

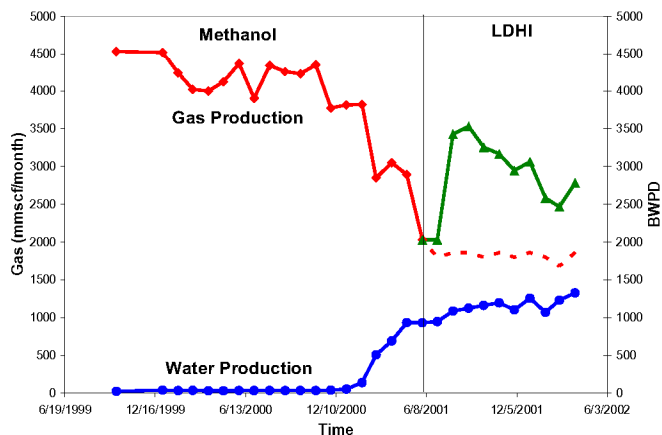


Figure 2: Case History – LDHI Allows Additional Gas Production in Methanol-Limited System (Deepwater Gulf of Mexico)

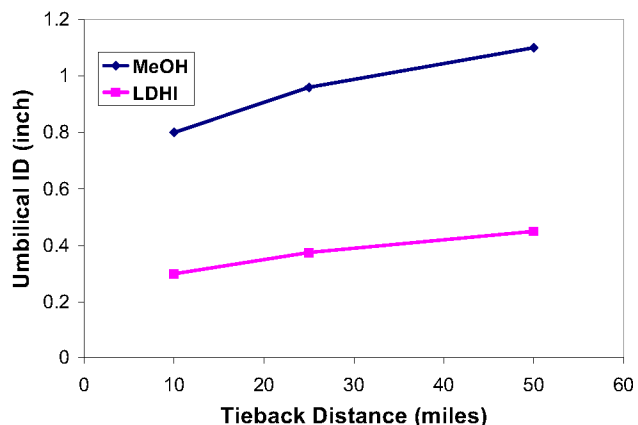


Figure 3: Design Example 1 - LDHI Allows Use of Smaller ID Chemical Injection Lines for a Given Water Production