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Long-distance step-out - how far can we go?

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Introduction

The conservation of fluid flow and the ability to restart production is a prime concern for the operation of a deepwater hydrocarbon production system.

The last 5-10 years have seen thermal management of the wellstream emerge as the single most used engineering tool for preventing blockages from obstructing the production lines.

It is generally recognized that keeping the well fluids from cooling down will prevent paraffin from depositing on the pipe walls during fluid flow, as well as forestall the formation of gas hydrates that are stable forms of ice occurring when water and small gas molecules (methane, ethane, hydrogen disulfide, etc.) combine at temperatures around 20°C and pressures of 10-20MPa and above.

This overall flow assurance strategy is generally associated with a more specialized treatment of localized elements, such as spools, jumpers, manifolds that are more difficult to insulate efficiently, by injecting chemicals that will prevent the water from combining with the gas molecules.

A main driver for field architects is the distance over which the wellstreams can be transported safely. In this respect, thermal insulation is a key enabling technology, and this paper will show the significant advantages obtained from using the most highly efficient insulation materials. Relationships for maximum tie-back distances will be established and it will be shown that the existing technology for pipe-in-pipe can be used to develop projects on an ambitious scale with no loss to flow assurance security. The synergies with other emerging subsea technologies such as heat tracing and subsea pumps will also be discussed.

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Why use PIPs

For a subsea production system, the flow assurance is generally governed by three temperatures:

- Well head inlet temperature
- Process inlet temperature
- And minimum preservation temperature for shutdown

The sea-bottom temperature is also of importance as it defines the temperature gradient across the insulating materials, but this is usually a constant 4°C for all deepwater projects, except for some very special cases.

The two first temperatures are related to the system in production and define a “temperature budget”, i. e. how many degrees (of temperature) can be lost during the transportation of the fluid from the wellhead to the process facility (e. g. an FPSO). This will give a first value for the minimum insulation to be applied to the flowlines.

The latter temperature is related to the appearance of hydrates –the operator will choose to work with fluids at temperatures above the hydrate appearance temperature and allow himself a margin to take into account contingent cooling in case of a production stop.

Operationally, this margin is defined as a number of hours (“cooldown time”) that the operator requires before having to start up a preservation scheme to replace the hydrate-prone fluids inside the flowlines with inert (“dead”) oil. This duration results from a risk-based analysis and is usually in the 12-24 hour range, depending on flowline volume and topside pumping capacity, but it may go as high as 52 hours (author’s experience).

This cooldown time defines another insulation value which may very well be the driving criterion for insulation, especially if the cooldown is to be calculated with a gas-filled flowline, which will not pack nearly as much energy as a liquid-filled pipeline at typical pressures of 100 bars and less.

A last point that also should be considered is the internal cooling of the fluid. This is related to the expansion of the associated gas as it travels down the flowline (Joule-Thomson effect) and the vaporization of hydrocarbon liquids as the pressure decreases in the flowline. These phenomena are very often (inappropriately) lumped together under the term ‘Joule-Thompson cooling’. They obviously are most present in the parts of the flowline experiencing the largest pressure drops, i.e. the risers. Thermal insulation has no influence on this effect.

In short, the thermal design of a pipeline has to consider:

- thermal losses to the environment in flowing conditions
- preservation time in case of shutdown
- thermal losses due to internal processes

Analytical evaluation

The different elements the thermal budget can be evaluated as follows:

Thermal losses in flowing conditions along the pipeline:

$$T_{out} = T_{sea} + \left(T_{in} - T_{sea}\right)\exp^{\frac{U\pi D}{Q_m Cp_i}x} \qquad (1)$$

Upon a shutdown, the pipe will cool with time according to the following equation:

$$T_{final} = T_{sea} + \left(T_{initial} - T_{sea}\right)\exp^{\frac{U\pi D}{H}t} \qquad (2)$$

In the riser section, internal processes will dominate the temperature evolution – typically 6 to 10°C can be lost due to pressure decrease.

For a cylindrically homogeneous construction, the U-value is evaluated according to the following equation:

$$U = \frac{\lambda}{R_{ref}\ln\frac{R_{ins} + th_{ins}}{R_{ins}}} \qquad (3)$$

For pipes where different materials are layered on top of each other (typically wet-insulated pipes), the cumulative U-value is obtained by adding the individual U-values of each layer according to the following equation:

$$U^{-1} = \sum_i \frac{1}{U_i} \qquad (4)$$

NOMENCLATURES

T_{in}	°C	inlet temperature of wellstream , typically well head temperature
T_{out}	°C	outlet temperature from pipe, for example at foot of riser
T_{sea}	°C	sea temperature, 4°C
T_{finl}	°C	temperature at start of cooldown
T_{inal}	°C	temperature at the end of coolodown
U	W/(m².K)	overall heat transfer coefficient for the pipe
D	m	pipe diameter
Q_m	kg/s	mass flow rate
Cp	J/(kg.K)	thermal capacity of wellstream
x	m	distance along pipeline
H	J/(m.K)	combined thermal capacity of 1-m section of pipeline and wellstream
t	s	time from onset of cooldown
R_{ref}	m	reference radius for U-value (usually flowline inner or outer surface)
R_{ins}	m	Insulation inner radius
th_{ins}	m	Thickness of insulation
λ	W/(m.K)	Thermal conductivity of insulation

The equations assume homogeneous material properties for the produced fluids and a homogeneous insulation for pipes which is generally sufficient for setting up a first model. More refined modelling can then be used in a later stage of the project to take into account phase changes, multiphase flow etc..

Equation 1 is usually specified for the system operating at reduced capacity, i.e. at a "degraded" flowrate, such as 50% of the nominal flowrate.

The riser thermal behaviour is not treated in these calculations because it is very case specific (the internal cooldown processes depend on the composition), and also because the riser cooldown design criteria can be very different from those of the flowline as gas and water will always be separated by a significant oil interface when the flow has stopped.

As an example, maximum step-outs can then be calculated for different pipe sizes.

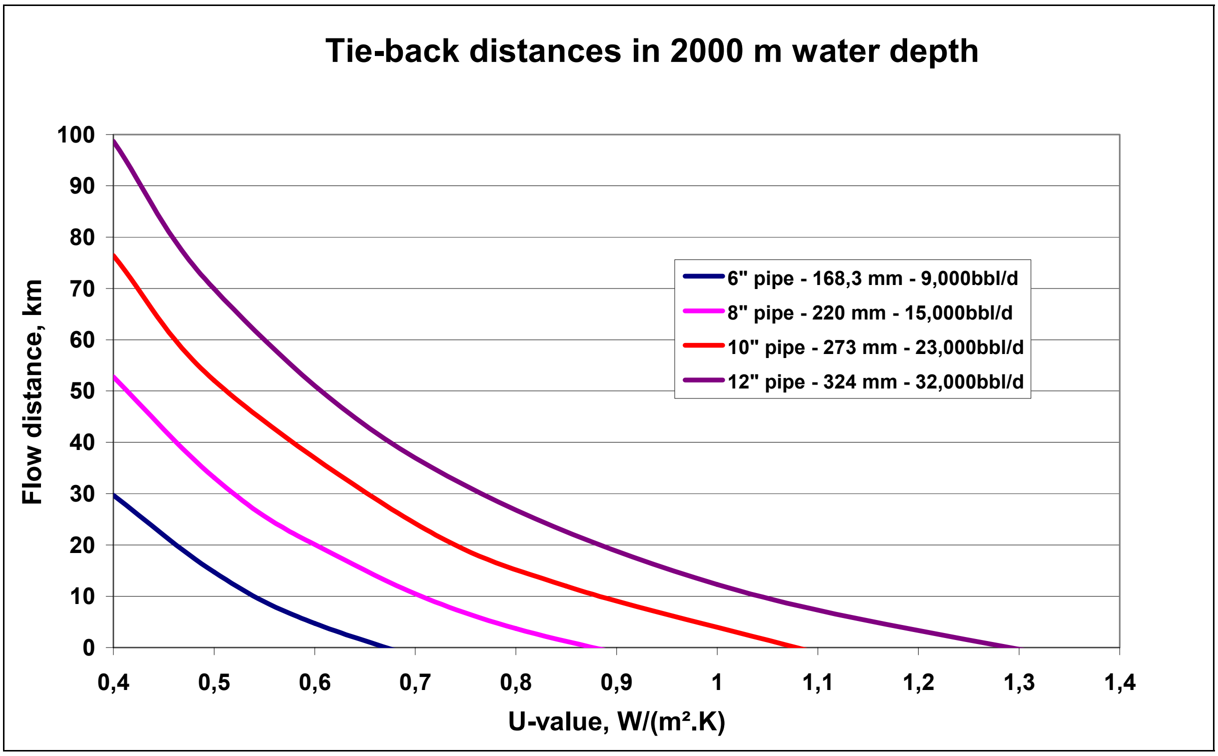

Figure 1: Tie-back distances (wellhead to riser foot) as a function of U-values. Nominal production rates when pipes are flowing at 1 m/s are indicated.

Calculation hypotheses:
Inner pipe: X65, D/t=12.8 (700 bar)
Wellhead, hydrate and seawater temperatures: 60°C, 20°C, 4°C
Flowrate: 50% turndown
Cooldown time: 24 hours, with an empty pipe
Wellstream density and heat capacity: 800 kg/m^3, 2000 J/(kg.K)

The preliminary inspection of the graph shows that from a thermal point of view, with the range of U-values chosen here, the "thermal reach" of an oil production system can be extended significantly beyond the 20-30 km often seen in today's subsea field development architecture. It is noteworthy that these U-values are realistically achievable: in particular ITP has achieved U-values significantly better than 1 W/(m².K) over the last few years, i.e. Tchibéli, 0.55 W/(m².K), Camisea, 0.35 W/(m².K) and Rosa 0.6 W/(m².K).

The long tie-backs presented in the graph are achieved with no reduction of operational security compared with current operational practice (it is even rather conservative), as they have been calculated for the combination of: 50% turndown rate and 24-hour cooldown time with an empty pipe – no benefit has been drawn from added thermal capacity incurred by production fluids in the pipe.

Sensitivity to design hypotheses.

In order to assess the robustness of the thermally insulated solutions, the sensitivity of the tie-back length to variations of the input parameters has been assessed:

The following parameter variations have explored:

- Increased minimum flowrate, from 50% to 60% of nominal flowrate
- Increased well head temperature, from 60°C to 65°C
- Decreased hydrate temperature, from 20°C to 19°C
- Decreased cooldown time, from 24 hours 23 hours
- Allowance for some fluids in flowline during cooldown: 100 kg/m3 @ 2000 J/(kg.K)

The different parameters influence the tie-back length in different ways, as explained in the table below:

Parameter	**Flowrate**	**Wellhead temperature**	**Hydrate temp**	**Cooldown time**	**Gas-fill**
Parameter change over base case	Increase from 50% to 60%	Increase from 60°C to 65°C	Decrease from 20°C to 19°C	Decrease from 24 hours to 23 hours	Include fluids thermal mass for cooldown: 100 kg/m^3 and 2000J/(kg.K)
Influence on tie-back	+20% of tie-back length	+12.1 km*D/U	+9.2 km*D/U	+1.9 km	+5.3km
Comment	Proportional to flowrate	Depends on surface/volume ratio	Depends on surface/volume ratio	Independent of diameter and U-value	Independent of diameter and U-value
Comparison with base cases	a) +20 km b) + 6 km	a) +9.8 km b) + 5.1 km	a) +7.4 km b) + 3.9 km	a) + 1.9 km b) + 1.9 km	a) +5.3 km b) + 5.3 km

Table 1: Influence of parameter variations on tie-back lengths.
The base cases are: a) 12” OD pipe, U=0.4 W/(m².K), tie-back distance: 99 km
b) 6” OD pipe, U=0.4 W/(m².K) tie-back distance: 30 km
all other hypotheses as per figure 1 above.

The D/U multiplier which appears in two of the above columns provides a measure of the amount of heat enclosed in the flowline (proportional to D²) divided by the heat loss (proportional to U*D). It shows that increasing the tie-back distances by adapting input parameters is more difficult for smaller pipes with a less favourable surface-to-volume ratio. The sensitivity of the system to parameter variations (or combinations thereof) can then be deduced by simple manipulations on the base case results, without re-running calculations on the complete system.

It is also important to note that the tie-back distance is quite sensitive to the well-head temperature, so it may be worth considering, in some instances, the use of insulated production tubing in the wells, so as to extend the insulated pipe length well below the mudline. This could be of particular importance for relatively cold reservoirs that are lying close to the seabed.

Implications for subsea developm’ts and field architectures

There are several implications to the results developed above. The most immediate is that greater areas can be drained from a single production facility (i.e. FPSO), for example, increasing the tieback length from 20 to 50 km increases the reachable area from 400 to 2500km² - equivalent to 100 offshore blocks in the Gulf of Mexico.

The other implications are less obvious but are also of importance for field development architects. The first concerns brownfield developments, i.e. tie-backs to existing facilities. If the chosen flow assurance strategy is to displace the live oil after a certain cooldown time with dead oil from the production facility, the prevailing way to develop such a field is to install new pumping equipment on the production facility so that both the “new” production pipelines and the “old” ones can be treated within 24 hours from a production stop. With thermal insulation in the range of 0.5 W/(m².K), production stops of 36-48 hours are acceptable, meaning that the live oil in the “new” pipelines can be displaced after the “old” ones have been treated. This saves the cost of the new pumping equipment and significantly reduces the payload on the production facility (which may even not be available).

Another new type of field architecture that is made possible with the long step-outs is the tie-back to the beach or at least shallower waters. It is then possible to place the processing equipment on land or at least on a fixed platform, which induces significant savings relative to a deepwater FPSO with its associated risers, anchoring systems etc. Of course, even if the long-distance step-out is possible from a thermal point of view it does not solve all associated flow issues. In particular, the pressure head along the pipeline may reduce the well flowrates and will certainly impact the eventual abandonment pressure of the wells. There are therefore synergies with other technologies that should be considered, in particular with subsea pressure boosting that could be installed close to the wellheads, which would improve on flowrates. Significant progress has been made in the last few years in this area, with the current record for subsea power distribution standing at 67 km for the Troll platform and 120 km being planned for the future subsea boosting modules that will be installed on Ormen Lange, both in the Norwegian sector of the North Sea.

How do we reach these low U-values?

The practical question is then how the low U-values can be obtained. While from a theoretical point of view, any U-value can be obtained with any insulation material by simply piling it on in thick enough layers, there are practical limitations. Inspection of Eq. (3) also shows that the insulation’s efficiency is ever-decreasing at is applied on increasing diameters; therefore, the more efficient insulation materials will provide significantly more compact designs. In view of this, the practically achievable U-values have been evaluated for a range of materials with the limitation that the insulation thickness should not exceed

Thermal conductivity values for typical insulation references for pipe-in-pipe designed for 2000m are given herebelow.

Insulation reference	**Thermal conductivity**
Izoflex™[2]	6 mW/(m.K)
Aerogel	17 mW/(m.K) (with spacers)
PU foam	27 mW/(m.K)

Table 2: Comparison of installed thermal conductivity for different material references used in PIPs.

These values can then be used to calculate the U-values, referenced to inner diameter. These values are most usefully compared to the tie-back distances that were previously calculated.

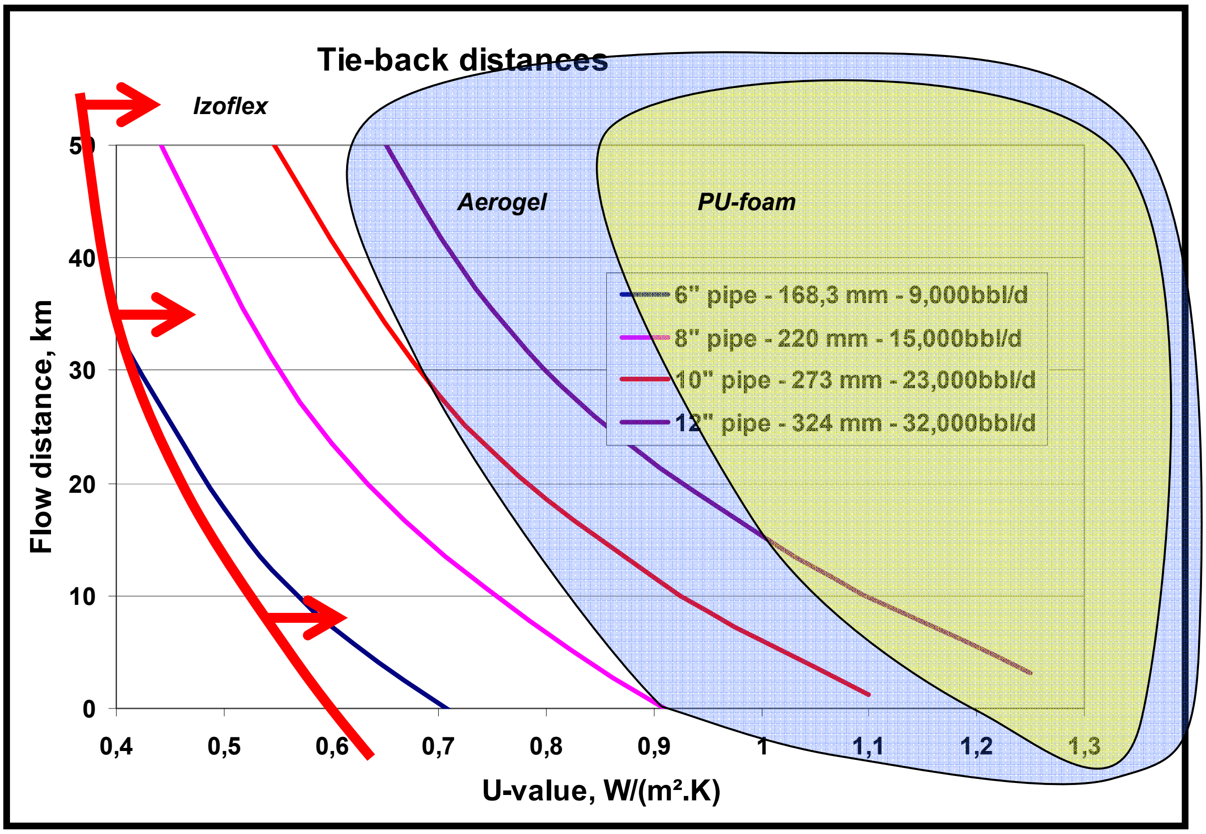

Figure 2: Tie-back distances (wellhead to riser foot) as a function of U-values. All conditions as per Figure 1. Three areas have been identified for PU-foam, Aerogel and Izoflex, in order of increasing size, corresponding to achievable U-values, referenced to ID. Insulation thickness is limited to 25% of pipe diameter (e.g. 81 mm on 12" pipe, 42 mm on 6" pipe).

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[2] Izoflex™ is an ITP trademark material developed for use in pipe insulation.

The graph shows that the long tie-backs necessarily require the use of the most efficient insulation materials. It is also worth noting that the use of the most efficient insulation material provides the most flexibility in design, as the addition of just two mm to the insulation thickness has a significant impact of around 0.1 W/(m².K) for a typical insulation thickness of 10 mm.

Conclusions

The above discussions show that, from a thermal point of view, it is quite possible to extend tie-backs over much longer distances than what is currently done in the industry. The thermal insulation of pipelines is thus an enabling technology because it allows considering the field development architectures in a different way, especially as concerns long tie-backs to shallower waters or even to the shore.

There are interesting synergies with presently developed subsea pressure boosting systems that allow even longer step-outs because of the higher flowrates that can be reached; this requires field architects to look into the details of subsea equipment utilized and in particular to combine the best available technologies and insulation materials, so that fields can be developed in an economic and safe manner.

ITP descriptive brief

ITP is the leading designer and manufacturer of highly insulated pipelines for the offshore industry. ITP has developed and pioneered innovating insulated pipe concepts for High Pressure/High Temperature flowlines, for subsea transfer of LNG and holds several industry breakthroughs, such as the most highly insulated oil pipeline (Tchibéli, U=0.55 W/(m².K)), the most highly insulated subsea LPG pipeline (Camisea, U=0.35 W/(m².K)). ITP holds several patents and is the sole user of the Izoflex material.