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Going into 2000m+ waters:
Are pipe-in-pipes getting too heavy for installation?

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Introduction

Pipe-in-pipe systems are generally known to provide a robust and efficient solution to flow assurance issues, especially in deepwater. In fact, 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 production lines.

Going into ever deeper waters, from today's "run-of-the-mill" 1500 m to tomorrow's 2500 m, the requirement for thermal insulation will most likely increase. As the procurement and installation costs of the seabed equipment (wells, pipework,…) will increase with depth, there is little chance that insulation requirements will be come less stringent as the profitability of a project will hinge on the ability to make longer tie-backs to a single surface facility (FPSO).

Wet insulation materials cannot provide the required thermal performance, and even less so in deep waters where their conductivity increases. This article discusses the technical issues associated with the use of pipe-in-pipe in deep waters and the present limits to their utilisation. It will show that beyond these water-depths, a change in the pipe materials is required if the conventional installation barges (J-lay, S-lay and reel) are to be employed.

It will be concluded, that the industry must prepare for these technologies that already have a decade-long history in other areas.

Pipe-in-pipes – why are they used?

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 or lower and pressures of 10-20 MPa and above.

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This overall flow assurance strategy is typically 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.

FLOW ASSURANCE – THERMAL REACH

There are generally three temperatures of importance to design a hydrocarbon production system

- 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). For conservativeness this calculation is usually made for some turndown ratio of the wellstream, e.g. 50%. 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 chose 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 cooldown time 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). For conservativeness, it is generally calculated with an empty or gas-filled pipe.

It is then obvious that the efficiency of the insulation applied to the flowline will define how long tie-backs can be.

Taking a typical flowline pipe size of 10" (274 mm OD) the tieback distance in 2000m water depth as a function of insulation value is the following:

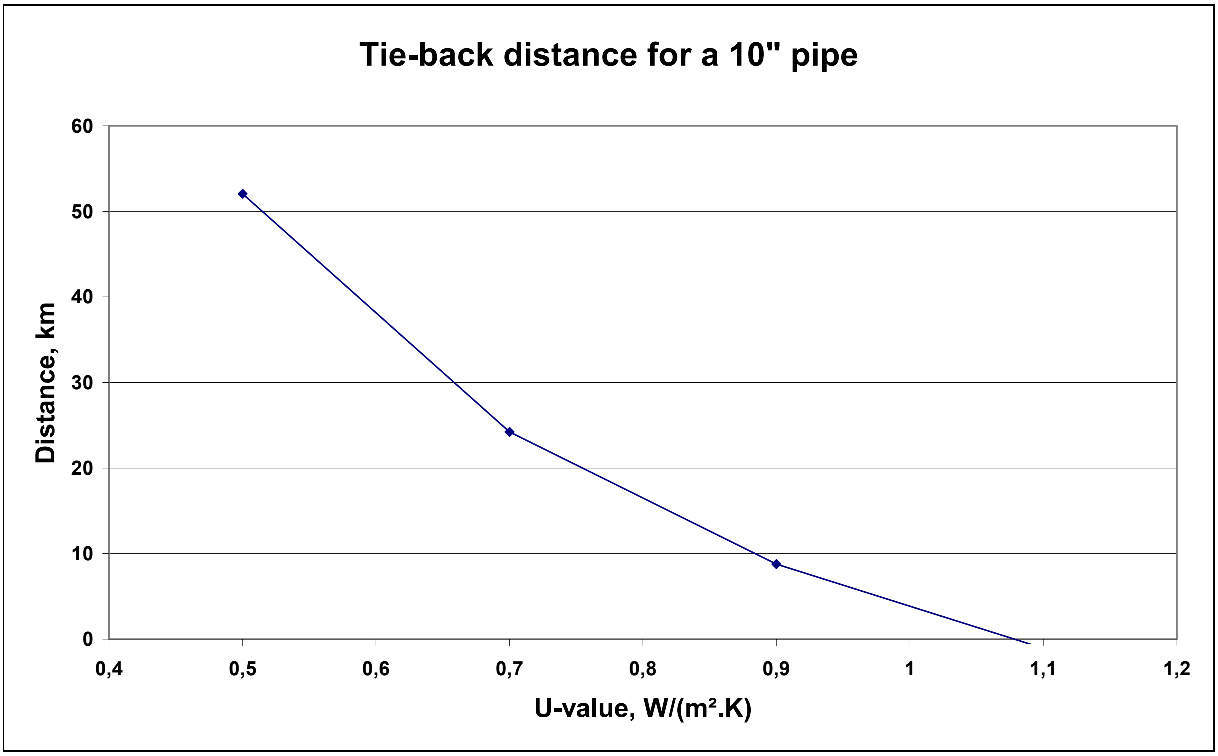

Figure 1: **Allowable tie-back distance calculated for a 10" pipe, 22.2mm WT, SMYS: 450 MPa, Flow: 11,000bbl/day (50% turndown), heat capacity: 2000J/(kg.K), density: 800 kg/m3 Temperatures: Wellhead 60°C, Hydrate appearance: 20°C, Seabed: 4°C Cooldown duration: 24 hours, empty condition. No allowance for Joule-Thomson cooling in riser section**

This figure is of course case-specific, other sets of design conditions (notably on turndown, well-head temperature, cooldown duration and the possibility of including some hydrocarbon thermal mass in the cooldown) will provide different values.

The figure shows that relatively small changes in thermal insulation have a huge influence on the tie-back distance. This is significant for the design of the subsea lay-out of pipelines and the field development architecture. For example, going from a U-value of 0.9 W/(m².K) to 0.7 W/(m².K) increases the tie-back distance from 10 to 25 km, thereby expanding the area that can be “drained” from a central facility (FPSO,…) from 250 km² to 1,800 km².

Weight considerations

The thickness of insulation material employed determines the outer pipe size. As a simple rule, with identical D/t ratios for the different designs, an increase in x% of the outer pipe size leads to a weight increase of 2x%, relative to the most compact solution.

Values for typical insulation references for pipe-in-pipe designed for 2000m are given herebelow.

Insulation reference	**Thermal conductivity**	**Thickness for U=1 W/(m².K) on a 10" pipe / weight increase relative to most compact solution**	**Thickness for U=0.5 W/(m².K) on a 10" pipe / weight increase relative to most compact solution**
Izoflex™[2]	7 mW/(m.K)	7 mm / -	15 mm / -
Aerogel	17 mW/(m.K) (with spacers)	18 mm / +8% (ca 25 kg/m)	39 mm / +9% (+30 kg/m)
PU foam	25 mW/(m.K)	27 mm / +15 % (ca 50 kg/m)	60 mm /+30% (+90 kg/m)

Table 1: Comparison of required insulation thickness for different material references and the influence on pipe-in-pipe linear weight for a water depth of 2000m.

The impact of the additional weight is not negligible, both in terms of direct costs (additional steel, welding and handling) and in terms of installation. For a typical, 40 km project, 25 kg/m translates into an additional 1000 tonnes of steel or 2-3 M$ additional material. For the installation, the additional weight may influence the choice of the lay-barge (and therefore the laying costs) when water depths are close to typical barge hang-off capacities (400-700 tonnes, typ.).

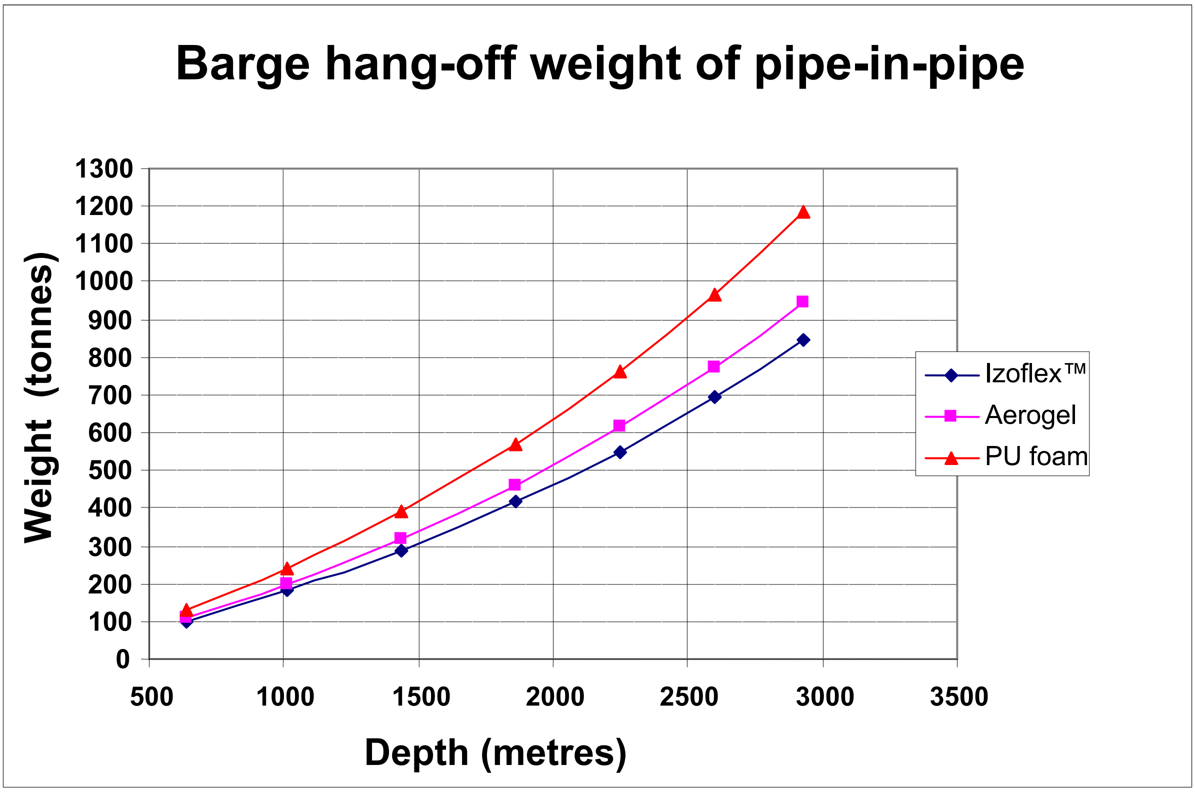

Figure 2: **Pipe-in-pipe hang off weights. Calculated for a 10" flowline, insulated to U=0.5 W/(m².K) Flooded condition.**

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

Another issue linked to the weight is the installation stress: all current pipe installation systems handle the suspended pipe string by holding either the inner or the outer pipe. This pipe will then support the complete weight of the suspended pipe-in-pipe string, i. e. roughly twice the weight of a single string as inner and outer pipes often have similar sections.

The following calculations are all performed with the hypothesis that the pipe-in-pipe is held through the inner pipe. This is justified by the present choice of many barge operators who all use hang-off clamps when pipe string weights approach barge capacity (McDermott with DB50, Saipem with FDS, Acergy with Polaris). These hang-off clamps are forged pipe pieces with protruding teeth that rest on a pedestal when the pipe string is suspended from the barge. The set-up provides a positive security (contrary to friction clamps) in case of barge power loss.

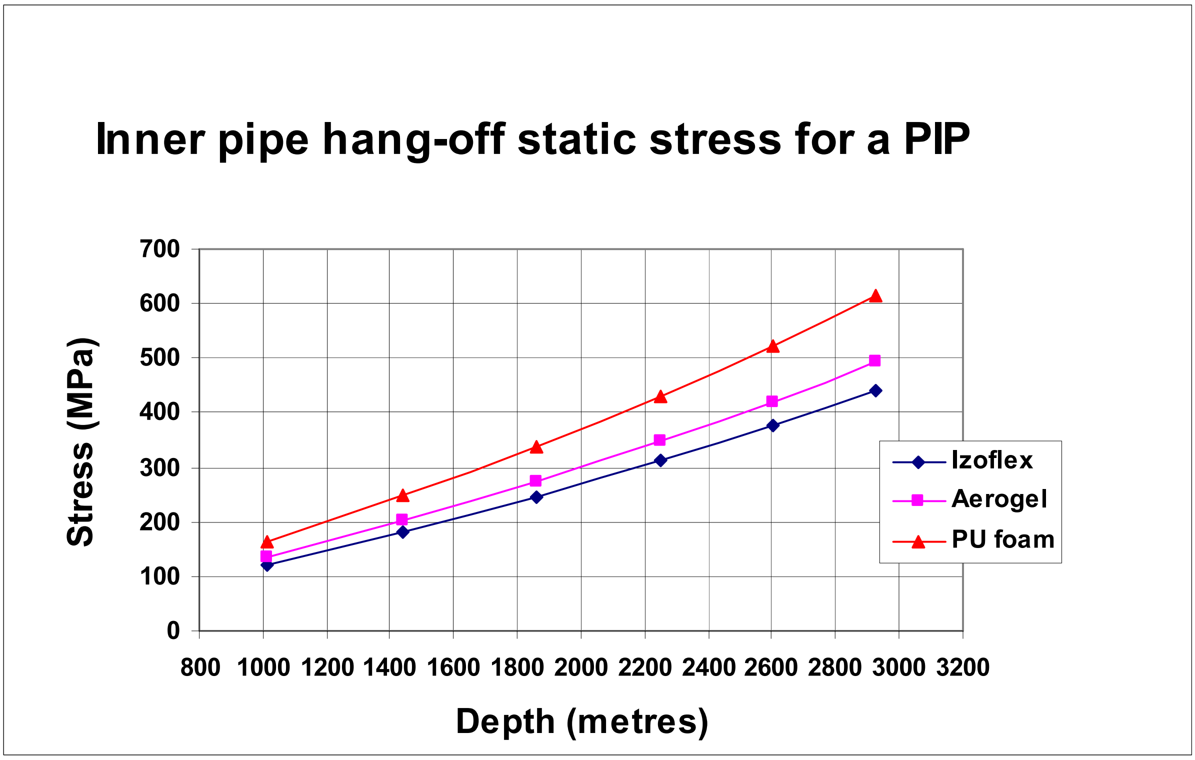


Figure 3: **Pipe-in-pipe hang off stress. 10" flowline, insulated with Izoflex to U=0.5 W/(m².K) Flooded condition.**

Depending on installation criteria, with a typical seamless steel pipe grade X65, the maximum allowable installation stress is around 360 MPa (80% of SMYS). Therefore, at a water depth around 2500 m the total weight will exceed steel stress capacity. This limit would occur at even smaller smaller water depths if a less efficient insulation material had been selected.

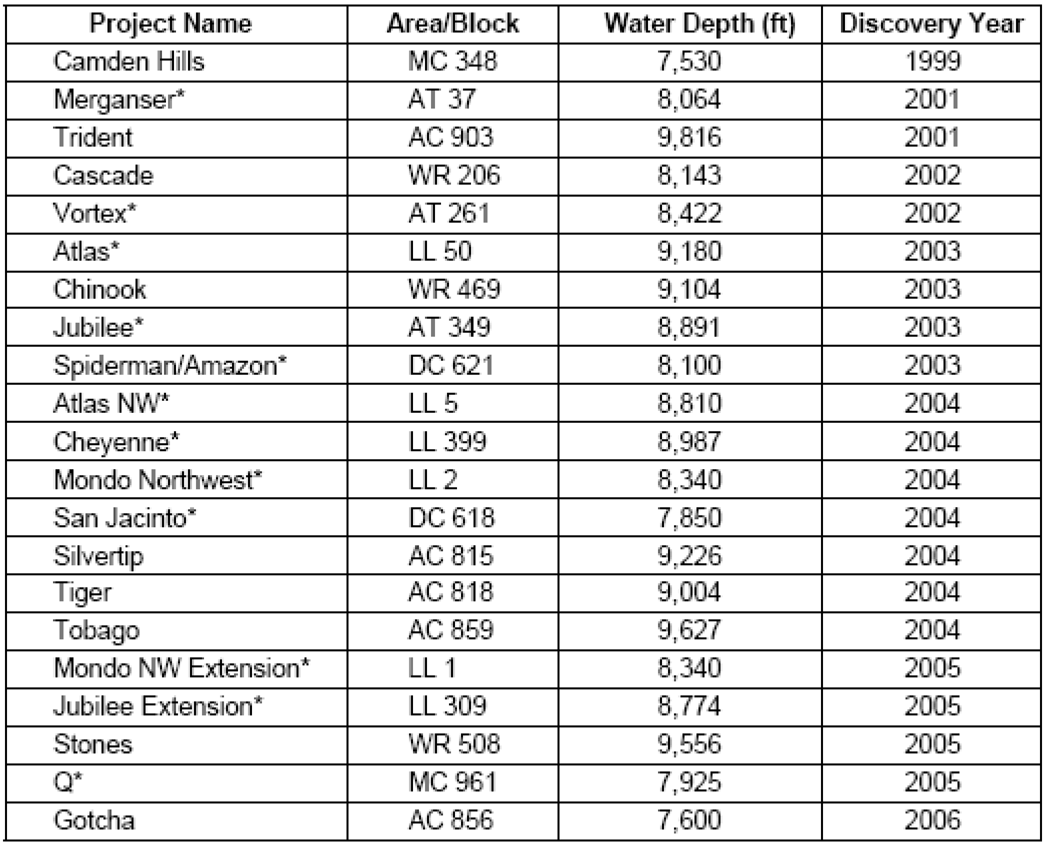
The depth limits calculated above are of course project-dependent, actual inner pipe design pressures will result in different inner pipe wall thicknesses which will provide some variability on the depth limit: heavier wall inner pipes will increase the weight carrying capacity of the system, although the advantage is partially offset by the increased weight. In general, depending on the actual system design, it has been established that in water-depths between 2000 and 2500 m the present pipe-in-pipe design and laying methods will hit limits that will require some innovation to circumvent.

Of course, if the inner X65 pipe could be made out of X100 grade steel, the depth limit would be pushed out to 3000m. However, X100 steels, although being developed and tested for onshore applications for the last 20 years, do still seem to have some significant technical hurdles to overcome before they are readily accepted for offshore applications and construction methods. The concerns are mostly linked with sour service requirements combined with the need for weldability (development of the welding wires and processes that will ensure overmatching welds). Steel grades are increasing, but the movement is slow-paced as it requires the concurrent efforts of both Operators, Contractors, Welding Companies and Pipe Manufacturers.

Is this a real issue for operators?

Looking at official published data, it is clear that the industry is going into deeper waters. There are already numerous oil finds that will have to be developed in the years to come. As an example, we can look at the Gulf of Mexico where there is much publicly available data.

This region of the world represents less than 25% of world total oil output of 6 million boepd, and the this total is expected to rise to 9 million boepd by 2010 (World Oil, Gulf Publishing Company, Sept. 2007, p.69). This provides a clear picture that technological solutions will have to evolve to solve tomorrow's production challenges.



Project Name	Area/Block	Water Depth (ft)	Discovery Year
Camden Hills	MC 348	7,530	1999
Merganser*	AT 37	8,064	2001
Trident	AC 903	9,816	2001
Cascade	WR 206	8,143	2002
Vortex*	AT 261	8,422	2002
Atlas*	LL 50	9,180	2003
Chinook	WR 469	9,104	2003
Jubilee*	AT 349	8,891	2003
Spiderman/Amazon*	DC 621	8,100	2003
Atlas NW*	LL 5	8,810	2004
Cheyenne*	LL 399	8,987	2004
Mondo Northwest*	LL 2	8,340	2004
San Jacinto*	DC 618	7,850	2004
Silvertip	AC 815	9,226	2004
Tiger	AC 818	9,004	2004
Tobago	AC 859	9,627	2004
Mondo NW Extension*	LL 1	8,340	2005
Jubilee Extension*	LL 309	8,774	2005
Stones	WR 508	9,556	2005
Q*	MC 961	7,925	2005
Gotcha	AC 856	7,600	2006

Table 2: Deepwater discoveries in water depths greater than 2286 m (7500 ft) in the US Gulf of Mexico.
Source: US Minerals Management Service, OCS Report MMS 2007-021.

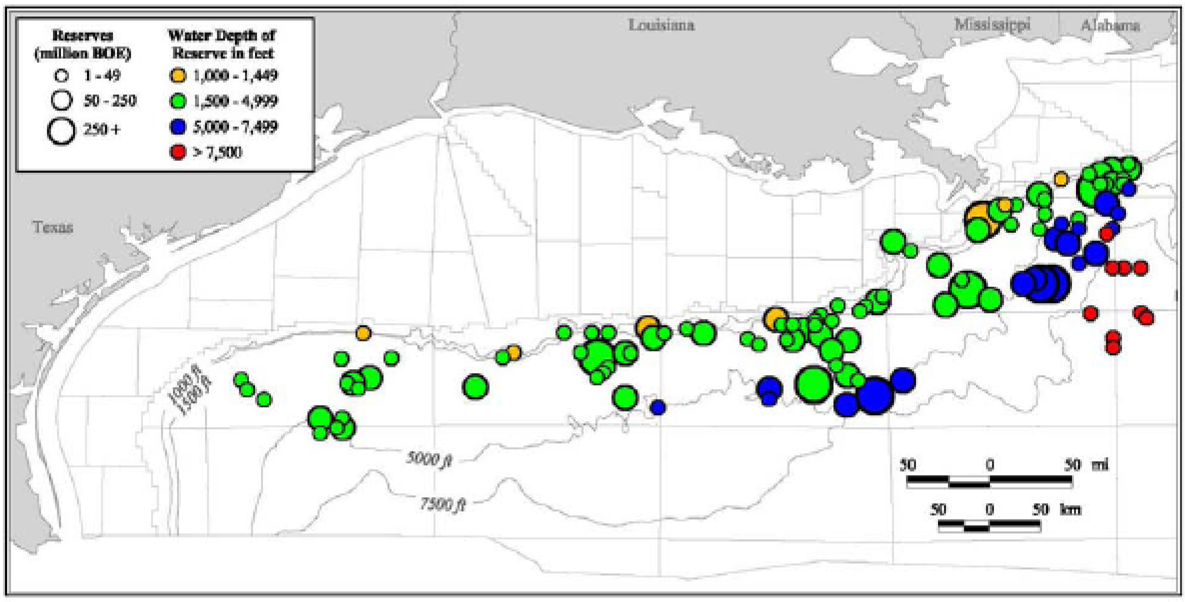


Figure 4: Estimated volume of proved deepwater fields.
Source: US Minerals Management Service, OCS Report MMS 2007-021.

There are also oilfinds similar water depths in other geographical regions such as Brazil, West Africa and Egypt by all major oil companies such as Petrobras (Carioca, 2140m), Total (Manjeriçao, 2000m), BP (Cordelia, 2300m, Terra 2320m), etc.

Possible solutions to the weight problem

The issue of weight is linked to the need for flow assurance; if pipe-in-pipes were not needed, 3000 m waterdepths would be readily attainable. Therefore, a vigilant eye should be kept on alternative technical solutions which will obviate the need for thermal insulation, such as subsea separation or slurry flow of non-agglomerating gas hydrates.

However, these solutions come with their own set of problems and probably do not eliminate all requirements for thermal insulation as there will be significant pieces of equipment that cannot be economically located at every wellhead. Rather they will be located at some sub-sea collection centre(s), and all inflowing liquids will need some kind of flow assurance to prevent the formation of hydrates etc, between the wellheads and the collection centre, i.e. thermal insulation.

Accordingly, at least for the time being, there seems to be no escaping future requirements for thermal insulation in ultra-deep waters. Also, given the central importance of the flowlines to the overall project viability, evolutions to meet future needs will be evolutionary, with well-tried technologies, not revolutionary.

Any changes to Pipe-in-pipe design will therefore most likely focus on the outer pipe, because it represents a significant part of the weight (~50%) while not in direct contact with the wellstream. Manufacturing and welding procedures for the flowline itself can then be left unchanged.

There are two significant ways to make the outer pipe lighter: change the steel for a higher-grade alloy or use another material such as composite reinforced materials (i.e. glass or carbon fiber).

Investigating the possible weight gains by replacing an X65 material with a higher grade material does not provide significant gains as the outer pipe failure mode is dominated by a geometrical buckling (ovalisation). This failure mode is only slightly dependent on yield stress.

An alternative with potential for deeper waters is to replace outer pipe steel with composite materials. Given the advantageous specific tensile stresses and elastic modulus, there are significant weight gains to be made. This is shown in the following table which compares the main mechanical properties of steel with those of a unidirectional fibre-reinforced composite material.

The comparison of the materials is particularly interesting on a performance/submerged weight basis. This is reported as “specific values”.

The numbers show that the composite materials can provide significantly better performance than steel if the stress loads are predominant in one direction. Their main limitation comes from the lower strain at break limit which translates into higher safety factors. Carbon composites will generally be more costly than their steel equivalents, whereas glass reinforced composites may compete on a more equal footing.

Material	**Density, kg/m^3**	**Elastic modulus, GPa**	**Specific modulus in water, MPa/(kg/m^3)**	**Stress limit, MPa**	**Specific stress limit in water, MPa/(kg/m^3)**
Steel, X65	7,800	210	31	450	0.07
Glass Fiber Composite	2,000	50	50	800	0.8
Carbon Fiber Composite	1,700	150	210	1000	1.4

Table 3: Comparison steel and composite materials for subsea applications. Specific values are obtained by dividing the original value by ($\rho_{material}$-ρ_{water}).

Although the composite materials provide much more advantageous specific values than steel, the body of knowledge on their behaviour subsea is much smaller than for steel. There are also specific concerns to be addressed, most notably as concerns aging and impact resistance. The application of composite materials to pipe-in-pipe construction shows that the depth limit for pipe in pipes can be pushed out beyond the 3000 m mark.

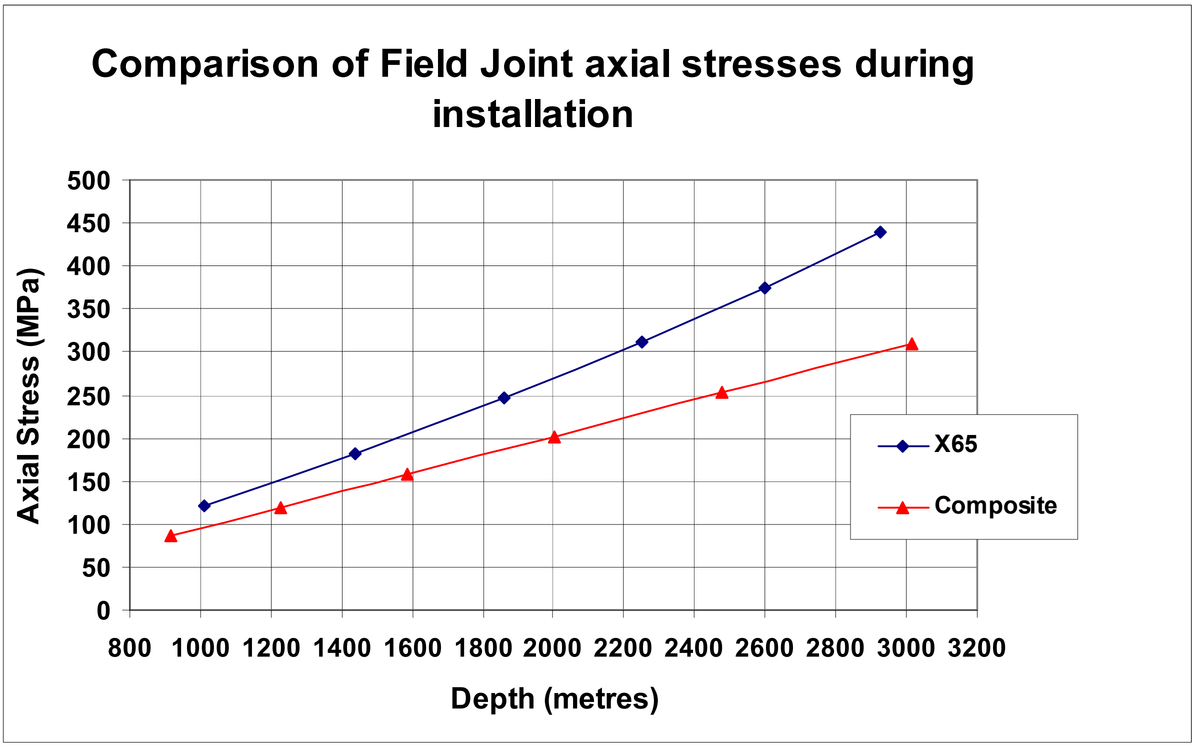


Figure 5: **Pipe-in-pipe hang off axial stresses. Calculated for a 10" X65 inner pipe, insulated with Izoflex and two different outer pipe constructions. Flooded condition.**

There are of course significant challenges to overcome before qualifying such a system, but for installation with a J-lay ship, the advantage is that there is no change to the installation method as performed today.

Conclusion

There are real and significant challenges in providing highly insulated pipelines for the ultradeep waters. Today’s solutions can be used “as is” to water depths around 2200-2400m, if sufficiently large installation vessels, capable of handling the hang-off weights are employed. However, beyond this water-depth, where oil-companies already drill and make development plans, there are no highly insulated solutions with U-values below 1 W/(m²·K). If the installation methods are not changed to decrease hang-off stresses during the installation process, new materials are required to reduce the weight of pipe-in-pipe strings. Higher grade steels may be a solution but their development requires the implication of numerous actors and is a historically slow and gradual process that may or may not keep pace with the requirements of the Oil and Gas industry; the alternative consists in making the outer pipe of the pipe in pipe string lighter by replacing steel with composite. Given the specific strength of composite materials, pipe-in-pipes for 3000m waterdepth are possible, and should be installable with little change to existing lay-barges, but a significant qualification effort is required, with buy-in from the operators.

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.