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Design Basis and Parametric Criteria for Offshore Oil and Gas Material Selection and Consideration: A Review

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Abstract
The current deep-water and ultra-deep-water oil and gas production required highly reliable and sustainable materials, in addition to effective management of offshore protective technologies. This study present offshore oil and gas facilities design basis and parametric criteria for materials selections and requirements for the challenging conditions and difficult to access remote sites. The criteria and constraints for selection of material for the corrosive offshore environments are presented using concepts selection, which involves the development of major criteria used in making offshore fields more economically viable. Costs-advantage and technical considerations are the governing criteria for the final selections. Technical requirements concepts should unaffectedly withstand both internal and external forces and loads. Subsea line pipes for the oil and gas transport extend from a take-up point, normally from a platform to the end-point, typically to another platform or to onshore facilities. Offshore Line pipes are rapidly evolving to ensure safe, effective and sustainable transportation with minimal human intervention for inspection maintenance and repair (IMR). The parts of the line pipes discussed in this study include flowlines, pipelines and risers. The

study deduced carbon steel currently in use are very limited with high critical stress greater than actual strength and much below the maximum design stress. Duplex steel though safe but limited in comparison with x65 carbon steels. Super 13Cr clearly show maximum design stress greater than expected limit and the critical membrane stress are well within the limit required.

Introduction

Line pipes inspection monitoring and repair (IMR), surveillance and autonomous intervention (AUVs & AIVs) and fibre optical monitoring and inspections (DTS, DAS & DSS) are due to deep-water challenges. These are especially critical in relation to design for sustaining satisfactory flow assurance and integrity. The several subsea line pipes are classified as shown in figure 1. In this study offshore waters are classified in accordance to NS-ES ISO 13628-1 (2005) as:

- Deep-waters: Water depths range from 610m – 1830m
- Ultra-deep-waters: Water depths range above 1830m

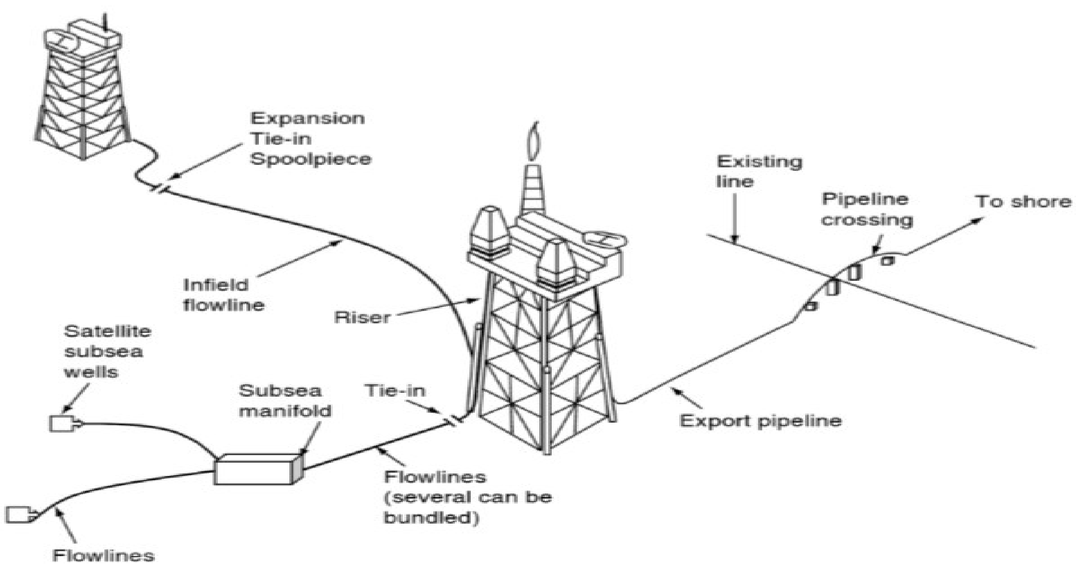


Fig. 1: Offshore line pipes (Langhelle 2011).

Ensuring Integrity of Subsea Line Pipes Materials

For a robust design, corrosion monitoring, corrosion countermeasures, and system inspection are the fundamental basis for ensuring the integrity of subsea line pipes.

The figure below highlighted those activities as explain in literature which are important in integrity assessment and control. This chapter provides design data and parameters from the activities indicated in the figure. The most feasible challenges here is inadequacy of historical, design, fabrication and installation as well as technical reports data. This adds to the complication of performing reliable integrity assessment, as well as material selections.

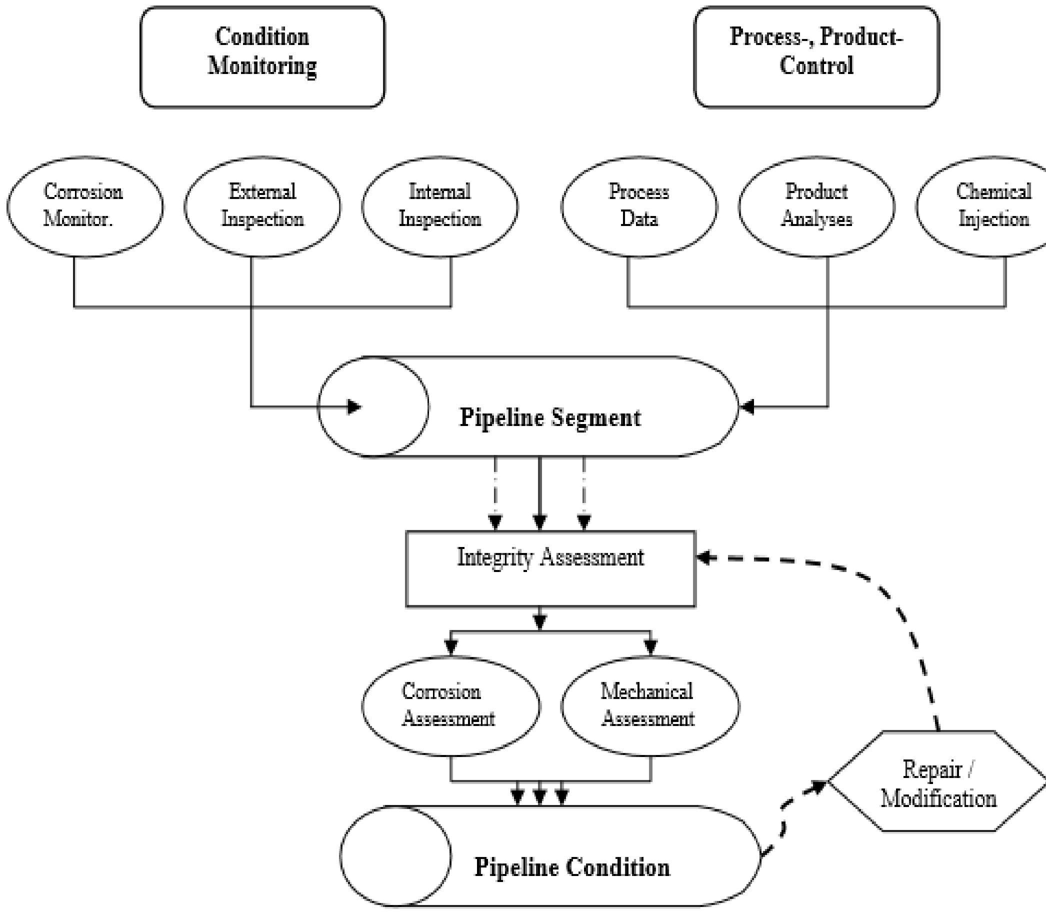


Fig 2: Design activities necessary to control the integrity of subsea line pipes. (DVN 2006)

Literature Review

Low Temperature High Strength Steels

Generally the "design temperatures" for materials qualification is typically 20 ^{O}C below the minimum in-service ambient temperatures. The lowest ambient temperatures on the NCS is about -20 ^{O}C. In the arctic regions the minimum ambient temperatures is about -40 ^{O}C, and "design temperatures" is expected to -60 ^{O}C down.

Strain-based larger deformations for Line Pipes requirement

Generally most current line pipes designs are stress-based with little strain tolerance typically up to 0.5%. Although, larger strain-based design are required for arctic regions, due to frost heave, ice-loads, thaw settlement, iceberg scours (up to 10m deep), landslides, heavy wind etc. Steel production for arctic regions must considered the above mentioned constraints. These constraints combine with low ambient temperatures made the toughest conditions to the offshore structures functionality and lifetime integrity.

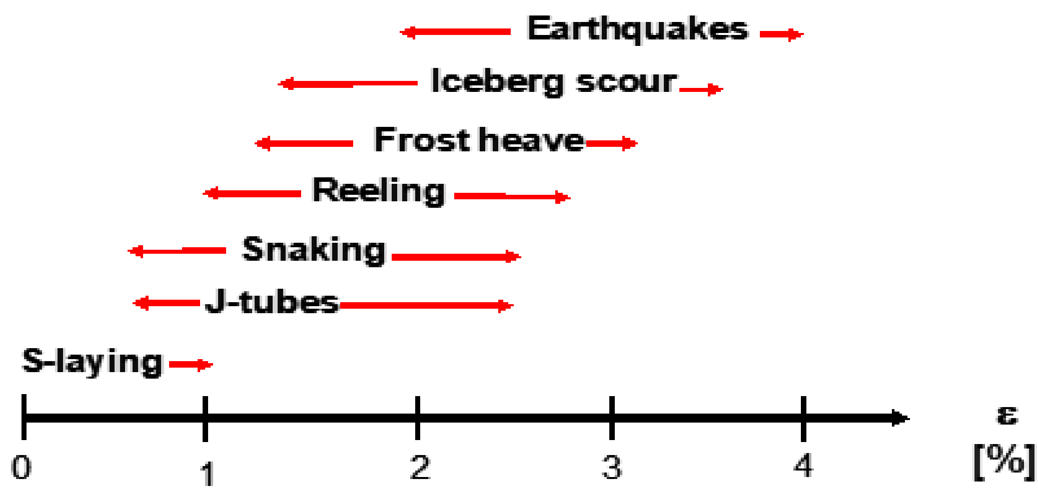


Fig. 3: Range of deformations for line pipes (Thaulow 2006)

Good Quality Welding process

With regard to solid line pipes that needed girth-welding process, it appears as reported that the welding procedures for weldable super 13Cr stainless steels grades often include pre-heating, post-heating and post weld heat treatment (PWHT). The extra reduced carbon super 13Cr stainless steels is softer with considerable high toughness compared to standard martensitic stainless steels grades. The extremely low carbon contents in super 13Cr stainless steels envisages the enhancement of its weldability.

Constraint Based Design and Direct Calculations

There should be a kin interest in brittle fracture phenomena, so as to quantify constraint effect for instance fracture toughness is dependency on material geometry, loading mode and mismatching of materials. The application of constraint corrections such as Q-parameter or T-stress, more precise predictions can be obtained, safety factors can be maintain via introduction of safety conditions. In the figure below the thick line represents material properties (i.e.

fracture toughness) and thin the line is the applied force causing cracking. The structure fracture when the applied force is greater than resistance force of the materials (Thaulow 2006; Thaulow et al., 2004)

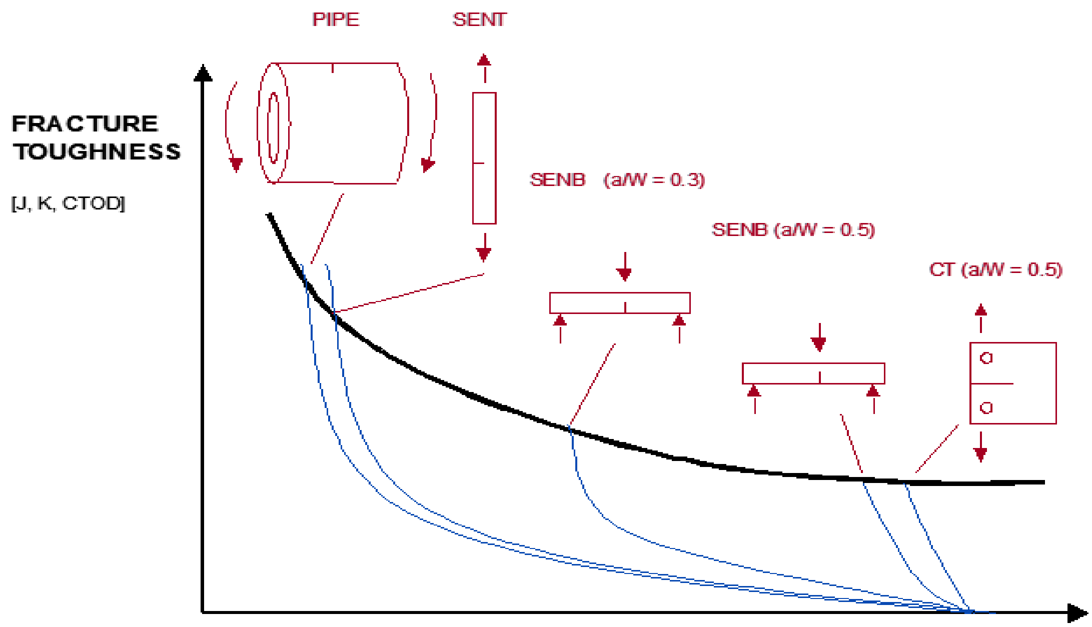


Fig. 4 Schematic representation of fracture toughness as a function of constraint and line pipes geometry also indicated a pipe subjected to bending load. (Thaulow 2006)

Concept Selection Design

Concept selection involves the development of major criteria used in making offshore fields more economically viable. Costs-advantage and technical considerations for the several concepts are the governing criteria for the final selections. Technical requirements in relation to line pipes concepts to unaffectedly withstand both internal and external forces and loads. This according to Langhelle (2011) "provides satisfactory flow assurance" with minimal chances of inner scaling and fouling depositions. This concept enable high rate of hydrocarbons transports that still maintained the necessary strength to contained plasticity. We have discuss in chapter 4 sandwich pipes (SP) and pipe-in-pipe(PIP) the two alternative concepts for the conventional single steel line pipes that uses coatings for insulations. The merits of these systems is the potential of using line pipes materials that has an outstanding thermal properties in addition to structural integrity independently guaranty by the internal and external layers. According to Castello and Estefen (2008) SP concept is advantageous for the potential of having excellent structural strength in addition to adequate flow assurance. They however, added that there still exist some challenges in regards to weight and costs of this systems. There are a well-known challenges for single steel line pipes in relation to weight against lay tensioning capability as well as the required wall thickness that can stand against buckling and collapse in the subsea.

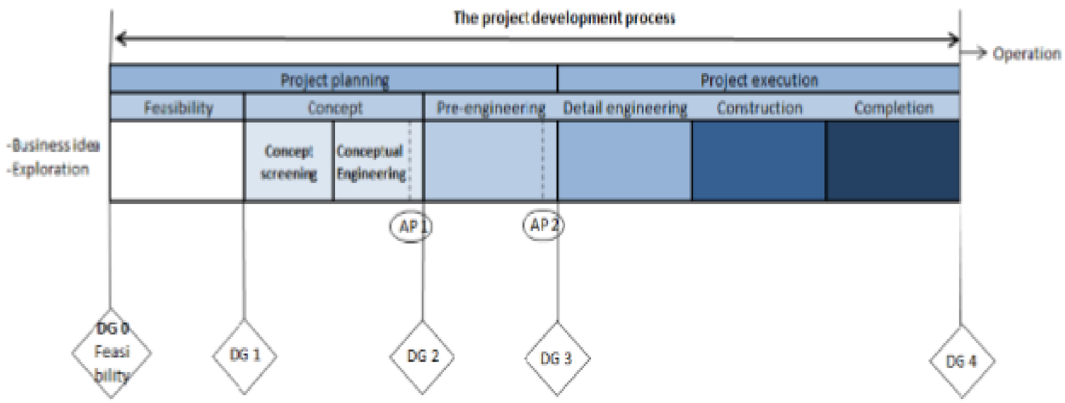


Fig. 5: (a) offshore concept development projects with phases, decision gates (DG) and approval points (AP). (Gordeeva 2013)

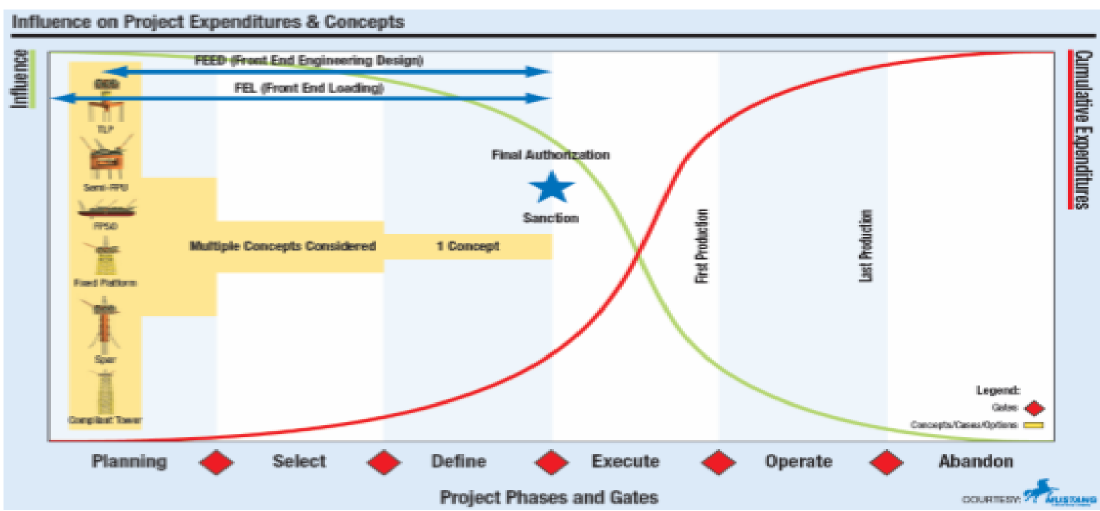


Fig 6: Influence of screening and concept selection on future project expenditures; (Rodriguez et al., 2012)

Flow Assurance and Integrity Design

According to Langhelle (2011) flow assurance is an important concepts in any hydrocarbons transportation systems, where formation and depositions of asphaltenes, hydrates, scaling and waxes creates possible problems. Flow rate reduction and subsequent line pipes blockages can cause non-optimal oil and gas exploitation, with high potentials for localize corrosion and severe economic losses. Many offshore protective measures mentioned in chapter 4 can mitigate or prevent blockages of line pipes materials, chemical inhibitors (glycol, methanol, etc.),pigging (flush out fluids), active heating (electric heater, hot fluids etc.). Also any methods that can generally maintain fluids temperatures until it gets to its final destination as well as the use of insulation coatings barriers. Achieving flow assurance and integrity depends on types of materials to be transported, water depths, concept selection design, changes in deep-waters temperatures and pressures, and specific chemical inhibitors (Langhelle 2011).

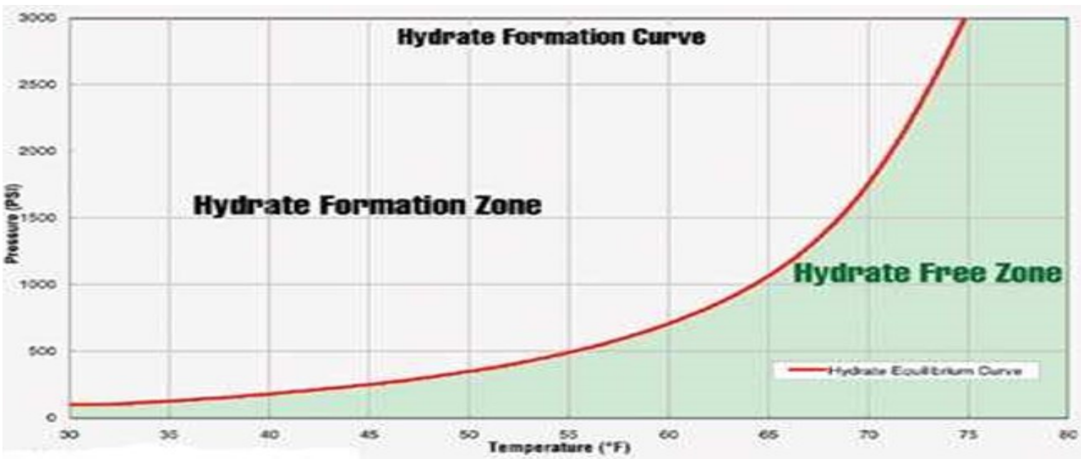


Fig. 7: Hydrate formation zone inhibitors (Langhelle 2011).

Material Selection and Wall Thickness Design

Materials and chemical compositions are important considerations for the development of sustainable oil and gas line pipes. Materials selection should satisfy the required strength, corrosion resistance and fracture toughness in addition to workability and weldability requirements. Conditions are more severe than for shallow waters or onshore, couple with HTHP, residual stresses and strain as well as aggressive chemistry. These factors required a special consideration in the development of both inner and out line pipes materials. Installation and laying process equally influence material selection.

It has been reported that applying higher graded steels such as super 13Cr (lean, medium, and high) in design of line pipes, will ultimately reduce wall thickness due to higher yield strength. This subsequently decreases the weight of materials, making them costs effective as well as feasible pipe laying process. Weight reduction has benefits but is not without challenges, the need for high quality welding, on-bottom instability, extreme environmental forces and loads, the demand to withstand buckling and collapse, the need for corrosion allowance which relate to thickness. The on-bottom instability required measures as anchors, rock dumping, pigging to ensure stability. The design are considered to avoid initiation and propagation of buckling and collapse of line pipes if offsets measures provided (Langhelle 2011; Palmer and King 2008)

Free Spanning Design and Seabed Intervention

Spans occur as a result of seabed depression and obstacles, whose effects is dependent on the height and length of the line pipes. This are the potential agents for overstress and fatigue loading, which are ultimately due to static and dynamic loads. The potential of critical free spans increases with increase seabed undulations, result in high residual stresses and strain. Vortex induced vibration (VIV) with high natural frequencies close to vortex shedding frequency will cause fatigue damages to line pipes materials. The natural vortex frequency is influence by span mass, length, flexural rigidity, axial forces, boundary conditions etc. Long spans in less weight are most likely to be affected by fatigue, vibration equally cause damage to pipe coatings and welds. The magnitude of VIV can be suppressed using shroud and strake as part of line pipes installation. The static and dynamic loads, the drag and lift force, the VIV all causes plasticity in line pipes materials. (Langhelle 2011; Karunakaran 2010 b)

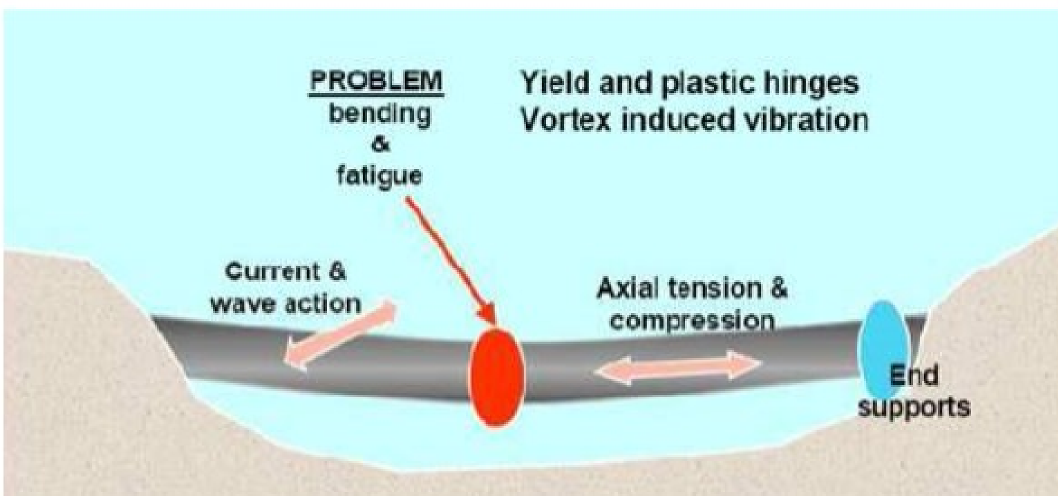


Fig. 8: Span associated problems (Langhelle 2011)

Seabed interventions

Seabed interventions for subsea line pipes inspection monitoring and repair (IMR) are costly and complex at increased water depths, smooth and soft nature of seafloor presents more challenges offshore. Other challenges include mudflows, landslide and subsidence all due to instability of the seafloor. Intervention such as trenching, rock dumping, anchors and other mechanical supports can mitigate these problems. Inadequate awareness and knowledge of these mitigating measures in offshore problematic and field review is required (Langhelle 2011).

Materials and Method

Design Data and Properties

Generally a design basis is developed starting from the selected considerations and appropriate calculations. For the following offshore design basis, the recommended standards and required practices stated below are applied:

- DNV-OS-F101 (2007) Subsea Line Pipes Systems
- DNV-RP-F105 (2006) Free Span Line Pipes Systems
- DNV-RP-F109 (2007) On-bottom Stability for Subsea Line Pipes Systems

Water Depths

Line pipes design are considered in water depths range within 800m, 1400m, 2000, and 3500m.

Coating Design

Line Pipes Coatings Data and Properties

The line pipes in this study apply multiple layer polypropylene (PP) coatings on Fusion Bonded Epoxy (FBE) and PP adhesive, PP form and shield are used for external corrosion and thermal insulation. This satisfy the maximum of U-value of 5.0 W/m2k as required for the line pipes. The following table shows coatings data and design parameters.

Table 1: line pipes coatings data.

Nominal bore (In)	14	20	28
External diameter, (mm)	355.6	508.0	711.2
Surface insulation coatings against outer corrosion	Multiple layer coatings systems: 0.3mm FBE/1300 kg/m^3 ; 2.7mm PP + adhesive/900 kg/m^3 ; PP foam thickness/620 kg/m^3 ; 3.0mm PP shield/890 kg/m^3		
Noncircularity (%)	1.5	1.5	1.0
Wall thicknessTolerance (mm)	1.0		
Note: Maximum of 5.0 w/m^{2}k are used for the line pipes. Abbreviations: PP = Polypropylene; FBE = Fusion bonded epoxy			

(Langhelle 2011)

Table: Line pipes coatings properties

Coatings materials	Density (kg/m³)	Thermal conductivity (W/m²k)	Coatings thickness (mm)
FBE	1300	0.301	0.3
PP Adhseive	900	0.221	2.7
PP Foam	6200	0.148	variable foam
PP Shield	890	0.206	3

Table: line pipes required insulation wall coatings thickness

Water depth	line pipes required insulation coating thickness								
	14"			20"			28"		
	Wall thickness (mm)	Pp foam thickness (mm)	U-value (W/m^2k)	Wall thickness (mm)	Pp foam thickness (mm)	U-value (W/m2k)	Wall thickness (mm)	Pp foam thickness (mm)	U-value (W/m2k)
800	13.3	34	4.89	19.0	31	4.99	26.6	30	4.98
1400	15.1	34	4.97	20.8	32	4.92	27.7	31	4.89
2000	17.8	35	4..95	24.4	33	4.89	32.3	31	4.94
3500	25.3	38	4.95	33.9	35	4,91	45.1	33	4.91

Wall Thickness Design

Line pipes wall thickness design is one of the most important critical considerations, it is the determining factor for important parameters such as: external and internal corrosion resistant, stress influences, bending and buckling resistant, burst and collapse, as well as economic aspect. Line pipes must satisfy the requirements of (DNV 2007): to contain both internal and external pressures, and to avoid the above mentioned failure. The local buckling and propagation buckling of the line pipes materials are given in the following tables. The local buckling and propagation buckling system are calculated using as tabulated.

$$Pe - Pmin \leq \frac{pc(t1)}{\Upsilon m \Upsilon sc}(1) \qquad local\ buckling$$

$$Pe \leq \frac{Ppr}{D\Upsilon m \Upsilon sc}(12) \qquad propagation\ buckling$$

Table wall thickness local and propagation buckling parameters

Water Depth	Local Buckling								
	Carbon Steels			**Duplex Steels**			**Super 13Cr**		
	14"	**20"**	**28"**	**14"**	**20"**	**28"**	**14"**	**20"**	**28"**
800	12.2	17.0	22.7	12.1	16.9	22.6	12.0	16.7	22.4
1400	15.1	21.1	28.1	14.9	20.8	27.7	14.6	20.4	27.3

2000	17.8	25.0	33.0	17.4	24.4	32.3	16.8	23.5	31.4
3500	25.3	35.6	47.7	24.0	33.9	45.1	22.3	31.4	45.6
Propagation Buckling									
800	20.1	34.4	40.1	19.5	33.4	38.9	18.5	31.6	36.9
1400	25.1	43.0	50.2	24.4	41.8	48.7	23.1	39.6	46.2
2000	28.9	49.6	57.9	28.1	48.2	56.2	26.6	45.6	53.3
3500	36.2	62.1	72.4	35.1	60.2	70.3	33.3	57.1	66.6

CRAs Line Pipes Material Data

Table 2: CRAs line pipes chemical compositions

Materials	Chemical compositions (Wt. %)								
	C (Max.)	Cr	Ni	Mo	W	Cu	Ti	N	PRE (Min.)
13CrS (UNS S41525) Supermartensite	0.03	11.5-13.5	4.5-7.0	2.0-3.0	-	-	0.01-0.05	-	
DP8 (UNS S31803) Weldable duplex	0.03	21.0-23.0	4.5-6.5	2.5-3.5	-	-	-	0.08-0.20	34
Dp3w (UNS S39274) Superduplex	0.03	24.0-26.0	6.0-8.0	2.5-3.5	1.5-2.5	0.20-0.80	-	0.24-0.32	40

PRE=% Cr + 3,3(% Mo + 0,5% W) + 16% N Source: (Sagara et al., 2015)

Table 3: CRAs line pipes Materials properties

CRAs	**Tempt. (°C)**	**SMYS (MPa) (Min.)**	**SMTS (MPa) (Min.)**	**Hardness (HV) (Max.)**	**Density (kg/m^3)**	**Young's Modulus (MPa)**	**Poisson's ratio**	**Max. YS/TS ratio**
13CrS (UNS S41525) Supermartensite	25	550-555	620-750	320HV	7850	$2,07x10^5$	0.3	0.93
	100	540	690	-				
DP8 (UNS S31803) Weldable duplex	25	450	640	28HRC				
	100	380-482	565-575	-				
Dp3w (UNS S39274) Superduplex	25	550	800	32HRC				
	100	480	725	-				
X65 Carbon steel	25-100	448-450	530-556					

Source: (Sagara et al., 2015)

The stress strain relation based on Ramberg-Osgood (RO) relationship, are applied to characterize the materials from two points on the stress-strain curve. The harden parameter n, and the RO stress $\sigma_R$are tabulated below.

CRAs	Stress-Strain Points	Stress (Mpa)	Strain E (-)	Harden Parameter (n)	RO Stress, (σ_R) (MPa)
13CrS (UNS S41525) Supermartensite	SMTS (1st point)	550	0.005	30.00	413
	SMTS (2nd point)	620	0.200		
DP8 (UNS S31803) Weldable duplex	SMTS (1st point)	482	0.005	27.08	464
	SMTS (2nd point)	565	0.200		
X65 Carbon steel	SMTS (1st point)	448	0.005	25.24	428
	SMTS (2nd point)	530	0.200		

The three main super martensitic steels with their typical chemical compositions, and corrosion resistance design parameters are given in the tables below:

Table 5.4: Supermartensitic stainless steels grades types and typical chemical composition

Elemental Composition (max)	Supermartensitic Alloy Grades		
	Lean alloy grade 11Cr-2Ni	Medium alloy grade 12Cr-4.5Ni-1.5Mo	High alloy grade 12Cr-6Ni-2.5Mo
C	0.015	0.015	0.015
N	0.012	0.012	0.012
Mn	2.0	2.0	2.0
Mo	0.1	1.0-2.0	2.0-3.0
P	0.030	0.030	0.030
Cr	10.5-11.5	11.0-13.0	11.0-13.0
S	0.002	0.002	0.002
Ni	1.5-2.5	1.5-2.5	1.5-2.5
Cu	0.2-0.6	0.2-0.6	0.2-0.6
Si	0.4	0.4	0.4

Source: (Lange andRogne2004;)

These alloys have been developed to meet the designed requirements that increased stress corrosion cracking SCC resistance in sour service. The main alloying designed targeted for SCC resistance are giving in the table below (Lange and Rogne 2004). Adequate low temperature toughness is desired, minimized ferrite content to meet required toughness. Ferrite forming chemicals Cr, Mo, and Si should counterbalanced austenite stabilizers (i.e Ni). C and N are made the lowest to ensure optimum weldability via reduction of hardness (Drugli et al.; 1999). A sample phenomena is shown in the following Cr and Ni equavalents (wt %):

"Creq = Cr + 1.37 Mo + 1.5 Si + 2 Nb + 3 Ti (1)
Nieq = Ni + 22 C + 14.2 N + 0.31 Mn + Cu (2)"

Table 5.5: super martensitic alloy design to meet required targeted corrosion resistance

Environmental parameters	Supermartensitic Alloy Grades		
	Lean grade 11Cr2Ni	Medium grade 12Cr4.5Ni1.5Mo	High grade 12Cr6Ni2.5Mo
T	20-100°c	20-100°c	20-100°c
pH	3.5-4.5	3.5-4.5	3.5-4.5
$P(H_2S)$	-	0.005 bar	20 bar
$P(CO_2)$	10 bar	20 bar	20 bar
CL^-	600-100,000ppm	600-100,000 ppm	600-100,000 ppm

(Lange and Rogne 2004)

Results and Discussions

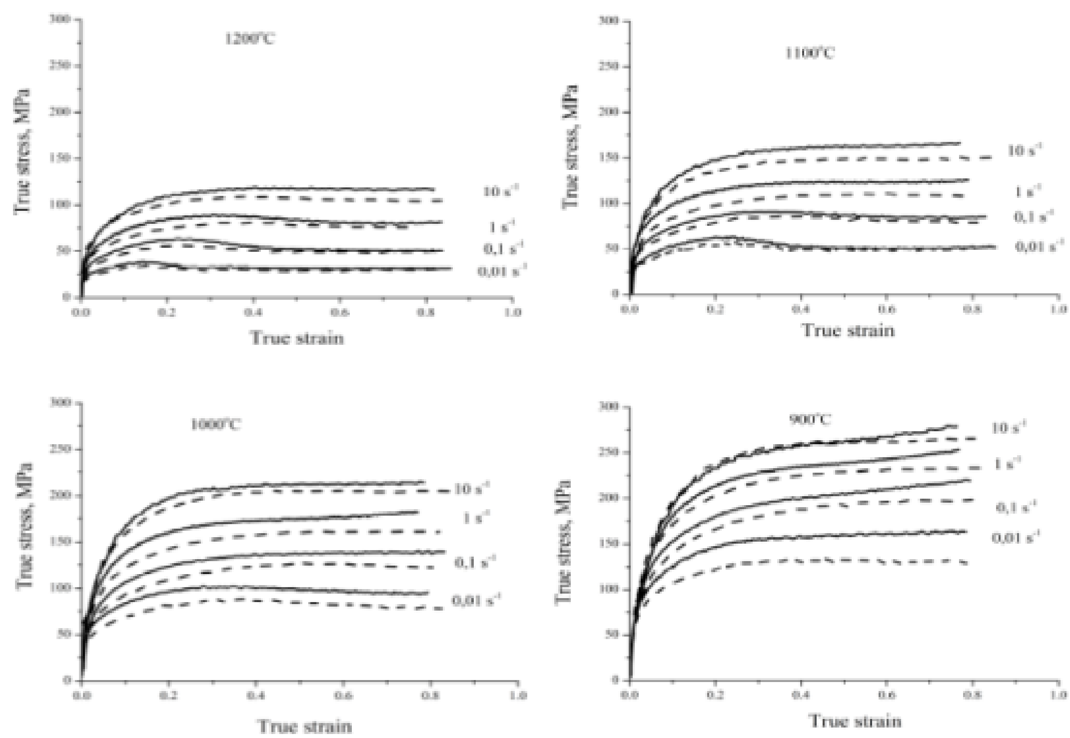
The general design criterion of offshore projects is the conservative utilization of line pipes material up to 70-80% of the yield strength during the life cycle. This phenomena is connected with Specific Minimum Yield Strength (SMYS) and /or actual yield strength (YS). These approaches have been used in the industry, the presume maximum allowance defect in all cases is (2x50mm) lower limit. However, the defects extends by 1mm during installation, giving rise to (3x50mm) and other possible defects accumulation can give (3x60mm). The table below show the operational engineering critical assessment performed on carbon, duplex and supermaertensitic 13Cr steels.

Materials	SMYS	Max. design stress (MPa)	Actual YS (MPa)	CTOD fracture toughness (mm)	Defect size (ax2c) (mm)	Critical memebrane stress (MPa)
X65 carbon steel	450	338	556	0.7	3x60	564
Duplex steel	450	338	630	0.03	3x60	419
Super 13Cr steel	550	413	648	0.02	3x60	371

From the table we can see that carbon streel is very limited with high critical stress greater than actual strength and much below the maximum design stress. Duplex steel though considered safe but limited in comparison with x65 carbon steels. Super 13Cr clearly show maximum design stress greater than expected limit and the critical membrane stress are well within the limit to initiate hydrogen induced cracking.

Stress-Strain Deformations Relationship

The stress-strain relationship of martensitic and supermaertensitic stainless steels was investigated by Ahmed et al., (2016), based on compression test via Gleeble-3800 thermomechanical simulator with temperature range from 900-1200 ^{O}C and strain rates of 0.01-10s^{-1}. The flow stress ($\sigma_{s)}$ of supermartenstic exceeds that of martensitic for same zone of deformations, σ_s increases with increasing zener Holloman parameter, but is not more than 15 MPa. The activation energy values for martensitic and supermaertensitic are 432 kJ/mol and 440 kJ/mol respectively. A critical deformation that can initiate dynamic recrystallization for supermaertensitic is lower than martensitic steels. The stress-strain curves of the studied was plotted in terms of true stress (σs) to true strain (ε) as shown below.



Fiq 9: (a) stress-strain curves for supermartensitic steels and martensitic steels from compression test via Gleeble-3800 thermomechanical simulator by (Ahmed et al., 2016).

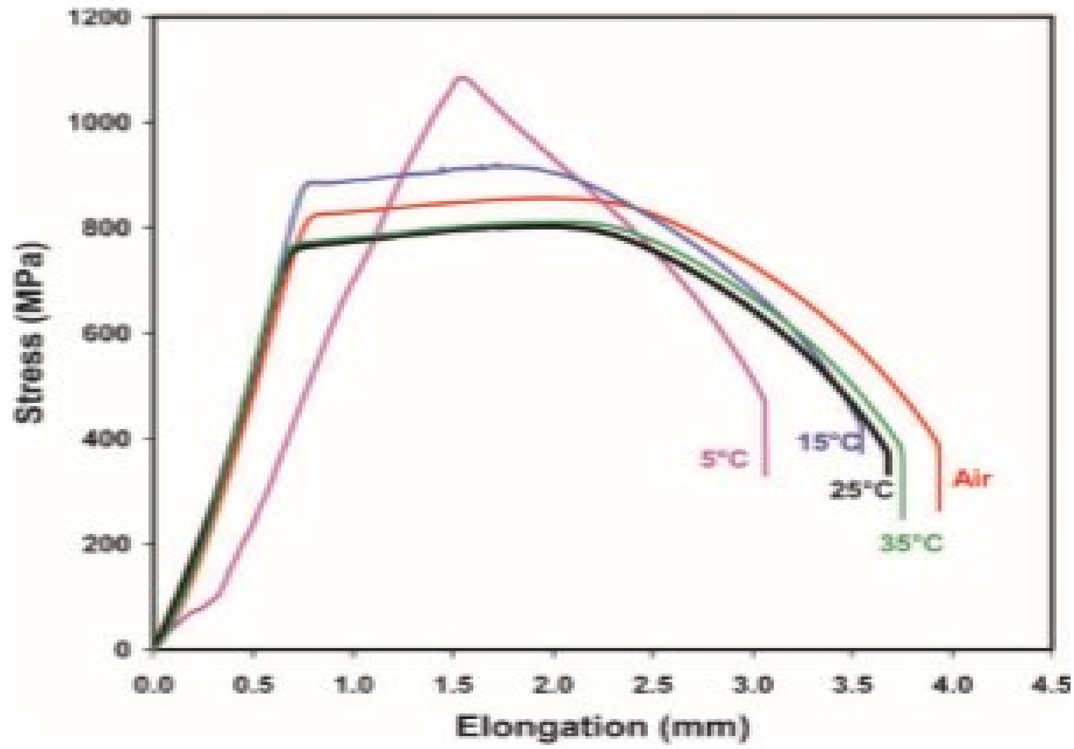


Fig 10: Stress versus elongation curves of supermaertensitic obtain from slow strain rate testsby (Salazar et al., 2017)

Environmental Data

The Arctic Environmental Challenges

The arctic regions is characterised by additional harsh requirements to competence and technological advancement for the implementation of new materials. Fundamental arctic challenges lies in severity, risky, remoteness, and demanding soil conditions. Particular arctic environmental conditions that has to be considered for the execution of new materials includes (Gordeeva 2013):

- Extremely low arctic temperatures (min. ambient temperatures on the NCS is about -20 ^{O}C &the arctic regions min. ambient temperatures is about -40 ^{O}C, and “design temperatures” is expected to -40 &-60 ^{O}C respectively).
- Extremely high external pressures
- Frost heave
- Ice-loads
- Thaw settlement
- Iceberg scours
- Landslides

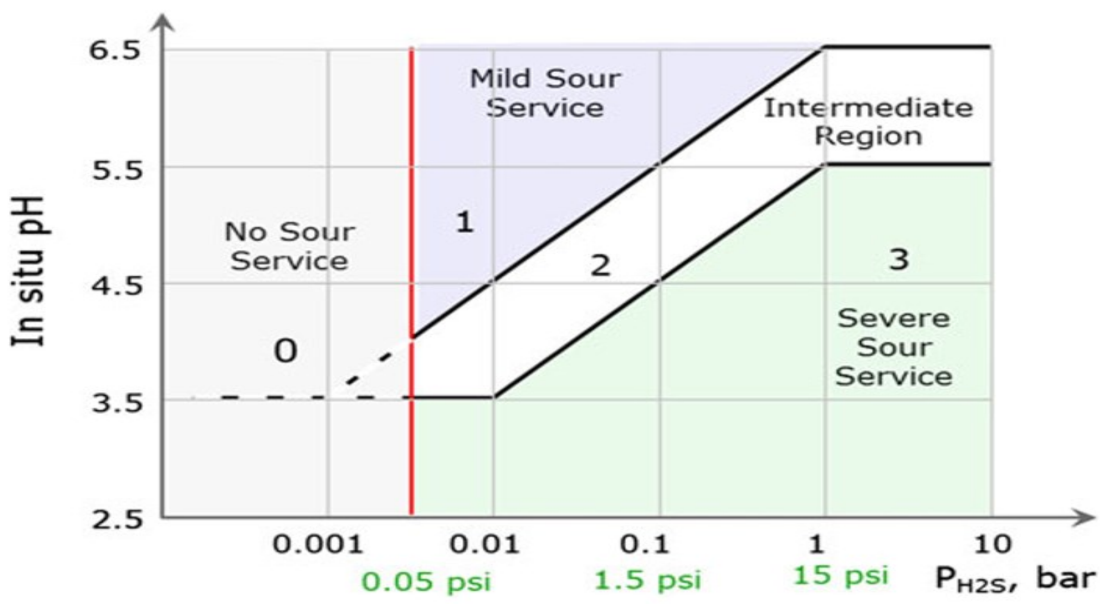
- Heavy wind
- Fog and darkness
- Mudflows
- Polar low

Sour Environment Requirements

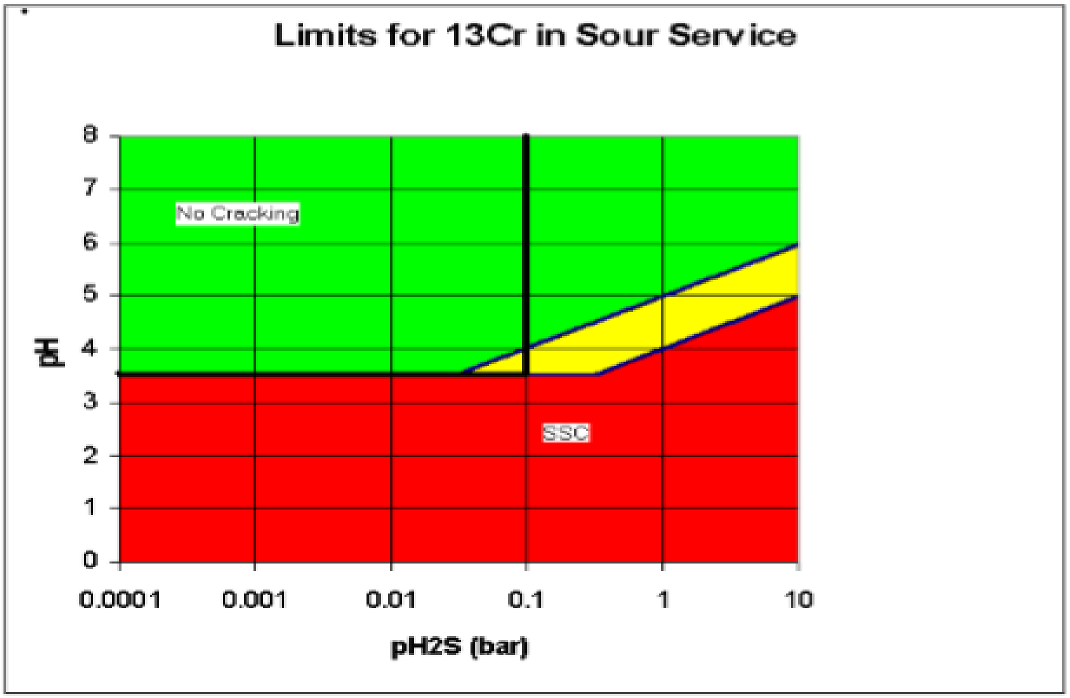
NACE MR0175/ISO 15156 recommendations and requirements for the selection of materials for sour environments, part 2 of NACE MR-01-75 document presents two selection options in regard to low carbon alloy steels in sour in-service:

The First option: Considers the partial pressure of H_2S as the determining parameter. For the partial pressure of H2S ≥0.3 kPa (0.05 psi) then SSCC resistance steels should be used. Max. Double tempering heat treatment at temperature range 648-691 and a hardness 23 HRC. The utilization of API 5CT/ISO11960 grades shall be based on the material requirements such as chemical composition, mechanical properties and to some extent in-service temperatures.

The second option: Enables user qualification and selection of materials resistance to particular SSCC or some specific range of sour in-service environments. The partial pressure of H_2S and the in situ pH are used to defining different regions of severity. If requirements for mechanical properties are satisfied based on the region applications, selection can be considered. Low alloy steels recommended to be tested and qualify for the conditions under considerations. The figure below indicate user qualification (Perez 2013).



(a)



(b)

Fig. 11: The regions of in-service severity regarding SSC of low alloy steels and carbon (NACE 2009)

ISO 15156-3 specification of H2S content of 0.1bar (1.5 psi) and a minimum PH of 3.5 for supermartensitic steels in sour service for general materials. The general consensus is that API 13Cr L80 can handle considerable high H2S as in the figure below. SSCC susceptibility is within the red portion, resistance is in green while yellow required further decisions, and ISO15156-3 is indicated by black thick lines. Super 13Cr have merit over the other CRAs via austenite and tempering, the austenizing and tempering temperature are 980 ^{O}C and 710 ^{O}C respectively. NACE Standard MR-01-75 desired double tempering for all martensitic steels used in sour in-service (Cerruti S.)

Sweet Environment Requirements

There is no standard industrial approach or guidelines in the selection of materials for CO_2 in-service, unlike H_2S cracking for instance in ISO 15156 recommendations. Different conceptual relationships between in-service variables and the inclination to sweet corrosion have been presumed, ranging from the simplest general principle based on experience on CO2 partial pressure to approximate complex predictable models.The several models are either based majorly on empirical laboratory correlated data or based on a field data, while few other models are based on the mechanisms of distinct chemical and transport reactions. Many of such models have frequently been utilized and most were successful in their presumption, but difficult to say which better. (Perez 2013) is.Croletand Bonis (2010) predicted rules for downhole CO_2 corrosion as shown in the table below.

Table 6: Prediction rules for downhole CO_2 corrosion

Expected corrosion	PCO2 max (bar)	In situ HAc (mM)
Condensed water		
Low/acceptable	<5	<1
High/unacceptable	>5	>1
Reservoir water		
Low/acceptable	-	<0.1
High/unacceptable	-	>0.1

Source: (Crolet and Bonis 2010)

Design Criteria

Line pipes materials parameters are based on safe class DNV (2007) class location:

- Class 1 location: Zone of less frequent human activities.
- Low safety class: Low risk to human life and negligible environmental and economic effects.

Table 7: design parameters.

Factors	Class	Value
Line pipes resistance factor, γ_m(external forces)	Serviceability Limit State, ultimate limit state, and Accidental damage Limit State –(SLS/ULS/ALS)	1.15
Safety class resistance factor, γ_{SC} (pressure containment)	Low	1.046
Line pipes strength factor, α_U	Normal	0.96
Line pipes fabrication factor, α_{fab}(max)	UingOing and Expansion (UOE) forming methods	0.85
Temperature de-rating	-	-
Load effect factor, γ_C	Line pipes resting on uneven seafloor	1.07

(DNV 2007)

Conclusions and Recommendations

The materials selections for this study had satisfied the required strength, corrosion resistance and fracture toughness in addition to workability and weldability requirements. These factors required a special consideration in the development of both inner and outline pipes materials. Installation and laying process equally influence material selection. Solid line pipes are compared to composite and flexible pipes, for wide applicability in offshore due to outstanding strength that withstand all external forces, and are relatively cost-advantage. Single solid line pipes are advantage for larger diameter when compared to sandwich (SP) and pipe-in-pipe (PIP) that are limited at ultra-deep waters and weight. Additionally single solid line pipes steels have a considerable simple construction design with a familiar behaviours during installations and laying, and are economically viable. Many environmental and technical challenges affect line pipes design and installation operations. Design due to extreme low arctic temperatures, high external forces such as: frost heave, ice-loads, thaw settlement, iceberg scours (up to 10m deep), landslides, heavy wind, and mudflows, in addition to the demand to withstand buckling and collapse. The need for corrosion allowance which relate to thickness. The on-bottom instability required measures as anchors, rock dumping, pigging to ensure stability. Limitation in the availability of pipe laying platform is escalating prices, adequate thermal insulation to achieve satisfactory flow assurance at alternate warm and cold zone are equally a challenge. The use of high graded alloys steels (super 13Cr) has the potential to enhance line pipes layability, decrease wall thickness to minimize collapse and reduce weight. An overall costs-advantage is the most possible outcome of super 13Cr stainless steels.

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