Client

Wintershall Noordzee BV

Project

D12-B to D15-FA-1 Pipeline Detailed Design

Document

Basis of Design

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Revision History

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01	Initial Issue – For Client comments
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Revision Status

Revision	Description	Issue date	Prepared	Checked	Enersea approval	Client approval
01	For Client Comments	03-07-2018	VH	PF	PF	
02	For Client Approval	04-09-2018	VH	PF	PF	

Table of content

1. Introduction

1.1. General

Wintershall is planning to install a satellite platform D12-B in Block D12-A in the Dutch Sector of the North Sea. Export of the gas will be via a 10” pipeline to the D15-FA-1 platform. Platform D12-B will be operated by Wintershall and platform D15-FA-1 is operated by Neptune.

Additionally a future import pipeline (10”) is foreseen at D12-B.

For the new location Wintershall will take over topside E18-A operated by Wintershall, and will reuse this topside for the new location on the North Sea. The existing E18-A topside will be removed from the jacket, and it will be installed on the new D12-B jacket.

The platform will normally be unmanned.

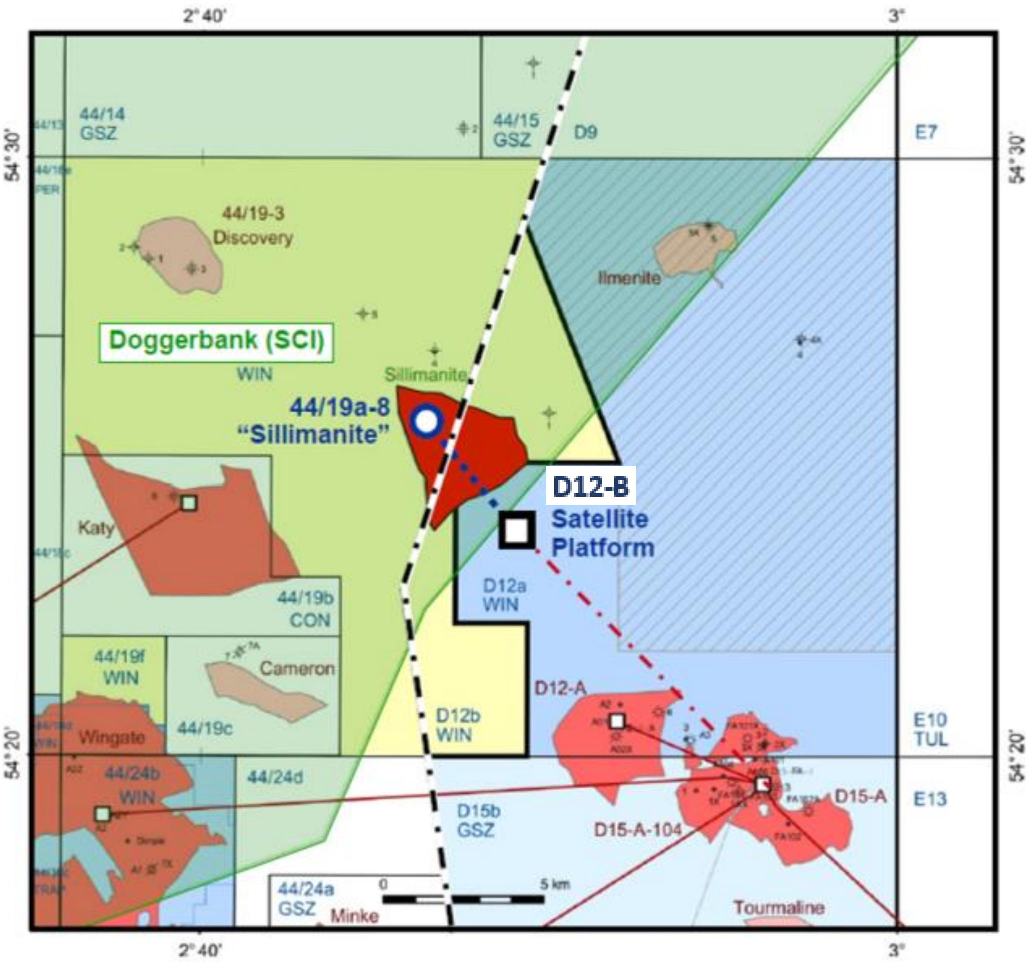

Figure 1-1 Sillimanite field licences & outline

1.2. Purpose Document

The BoD defines the methodology and design data to be used throughout the pipeline design from D12-B to D15-FA. The riser and spool pieces at D15-FA are also part of the scope.

The following engineering items are described in subsequent sections of this BoD report:

- Regulations, Guidelines and Specifications
- Pipeline Routing
- Seabed Geology
- Materials and Corrosion Protection
- Operational and Product Data
- Environmental Data
- Design Philosophy & Criteria

1.3. System of Units

All dimensions and calculations shall be documented using the International System of Units (SI) unless noted otherwise.

1.4. Abbreviations

BoD = Basis of Design

FEA = Finite Element Analysis

LAT = Lowest Astronomical Tide

MTO = Material Take Off

TB = Target Box

TOP = Top of Pipe

VIV = Vortex Induced Vibrations

2. Regulations, Guidelines and Specifications

The codes, regulations, guidelines and specifications used throughout the project are outlined in the following sections.

2.1. Regulations, Codes, Standards and Guidelines

[1] NEN3656:2015 “Eisen voor stalen buisleidingsystemen op zee” December 2015

[2] DNV-OS-F101. “Submarine Pipeline Systems.” October 2010.

[3] DNV-RP-F105. “Free Spanning Pipelines.” February 2006.

[4] DNV RP-F107. “Risk Assessment of Pipeline Protection.” October 2010.

[5] DNV-RP-F109. “On-Bottom Stability Design of Submarine Pipelines.” October 2010.

[6] DNV-RP-F110. “Global Buckling of Submarine Pipelines. Structural Design due to High Temperature/High Pressure.” October 2007.

[7] DNV-RP-C203. “Fatigue Design of Offshore Steel Structures.” April 2010.

[8] DNV-RP-C204. “Design against accidental loads.” November 2014.

[9] 21. American Lifelines Alliance. “Guidelines for the Design of Buried Steel Pipe. ASCE July 2001.

[10] ASME Boiler and Pressure Vessel Code. Section VIII Rules for Construction of Pressure vessels. Division 1. July 2013.

[11] Design of Submarine Pipelines Against Upheaval Buckling OTC 6335 by A.C. Palmer e.a. May 1990

[12] ISO 15589-2. “Petroleum petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems - Part 2: Offshore pipelines” 2nd edition - 2012

2.2. Project Reference Documents

[i] Fugro report GH210-R3, issue 1 “Geotechnical Report Investigation Data, Sillimanite Pipeline Routes, Dutch Sector, North Sea” May 2017

[ii] Fugro report GH210-R1 Vol.3 rev.01 “Report 1 of 2: Sillimanite D12-B Geophysical Site and Route Sur veys, Volume 3 of 3: Route Survey Results” April 2017

[iii] PhysE report “C702 - R 791-17:2017-06, Metocean criteria, volume 1 - design criteria, rev 2F”

[iv] PhysE report “C702 - R 791-17:2017-06, Metocean criteria, volume 2 - operational presentations, rev 2F”

[v] PhysE report “C702 - R 791-17:2017-06, Metocean criteria, volume 3 - supporting Information, rev 2F”

[vi] Wintershall report D12B-ST-BR-0001 rev. 01 “Structural Basis of Design for D12-B platform” December 2017

[vii] Wintershall report D12B-PL-BR-0001 rev. 01 “Sillimanite, Pipeline Basis of Design, D12-B – FEED” De cember 2017

[ix] Wintershall specification “CPE-PL-PS-020-02 – Project specification for pipeline external neoprene coating”

[x] Fugro report P902940/03 (2) “Geotechnical report – Engineering Assessments – Sillimanite- D12-B Jacket site”

[xi] MoM meeting 08.02.2018 “18004-MOM-002_2018.02.08”

[xii] Fugro route survey drawing “GH210_D15_AL_03_5K.dwg”, 30.05.2017, Rev.01

[xiii] Enersea report “17086-20-RPT-01003-01-01_In-place analysis - Jacket and Topsides”, April 2018

[xiv] Enersea report “18004-60-RPT-05001-01-05_Pipeline FEED design”, March 2018

[xv] XYZ Data “D12-B_D15-FA_Sillimanite_Route_0.5m_LAT_2017_Part_1”

[xvi] XYZ Data “D12-B_D15-FA_Sillimanite_Route_0.5m_LAT_2017_Part_2”

[xvii] XYZ Data “D12-B_D15-FA_Sillimanite_Route_0.5m_LAT_2017_Part_3”

[xviii] Alignment Chart KP -0.500 to KP 3.670 “18004-60-DWG-05200-01-01 Alignment sheet - Sheet 1”

[xix] Alignment Chart KP 3.420 to KP 8.260 “18004-60-DWG-05200-02-01 Alignment sheet - Sheet 2”

[xx] Alignment Chart KP 8.010 to KP 11.800 “18004-60-DWG-05200-03-01 Alignment sheet - Sheet 3”

[xxi] Enersea drawing “18004-60-DWG-01002-01-01_D12-B Platform Approach”, March 2018

[xxii] KCI report “GDF-11176-D18-R-L-26002-01 – Riser & Spool piece Detailed Design Report @D15-A” - D15-FA jacket displacements

[xxiii] PhysE report “C423 - R 494-11:2012-01, Metocean Criteria Block D18a, vol. 1 - design criteria, rev 1F”

[xxiv] PhysE report “C423 - R 494-11:2011-11, Metocean Criteria Block 18a, vol. 2 - operational presentations, rev 1D”

[xxv] Email Wintershall (Andrew Telling), 07.08.2018 @12:50hrs; “Thermal Profile”

[xxvi] Email Wintershall (Andrew Telling), 07.08.2018 @13:58hrs; “Thermal Profile”

[xxvii] Email Wintershall (Andrew Telling), 16.08.2018 @13:21hrs; “Sillimanite liquids”

3. Pipeline route data

This chapter deals with the pipeline route data describing the starting and end point of the pipeline, the used coordinate system, pipeline route coordinates and key facilities as well as the route bathymetry and contacts detected along the pipeline route. Based on this info the most optimal pipeline routing will be considered.

3.1. General

The new pipeline (10") to be installed originates at the D12-B platform and terminates at the D15-FA-1 platform via a dedicated riser. The pipeline length is approx. 11.8 km.

As per requirements from ref. [1] the pipeline is to be buried along its entire length with a minimum burial depth TOP of 0.2 m. The final cover height will be determined based on the results of a risk assessment study and the upheaval buckling analysis.

Figure 3-1 shows the intended pipeline approach at the South-East direction of the D15-FA platform. This in order to avoid the scouring spots which are located at the North-West direction of the platform.

One (1) 36" NGT pipeline approaches the platform from the east and lies exposed towards South-East of the platform. Therefore as part of the D12-B to D15-FA-1 pipeline design, a spool piece crossing will be required to avoid any obstruction with the existing 36" NGT pipeline nearby platform D15-FA-1.

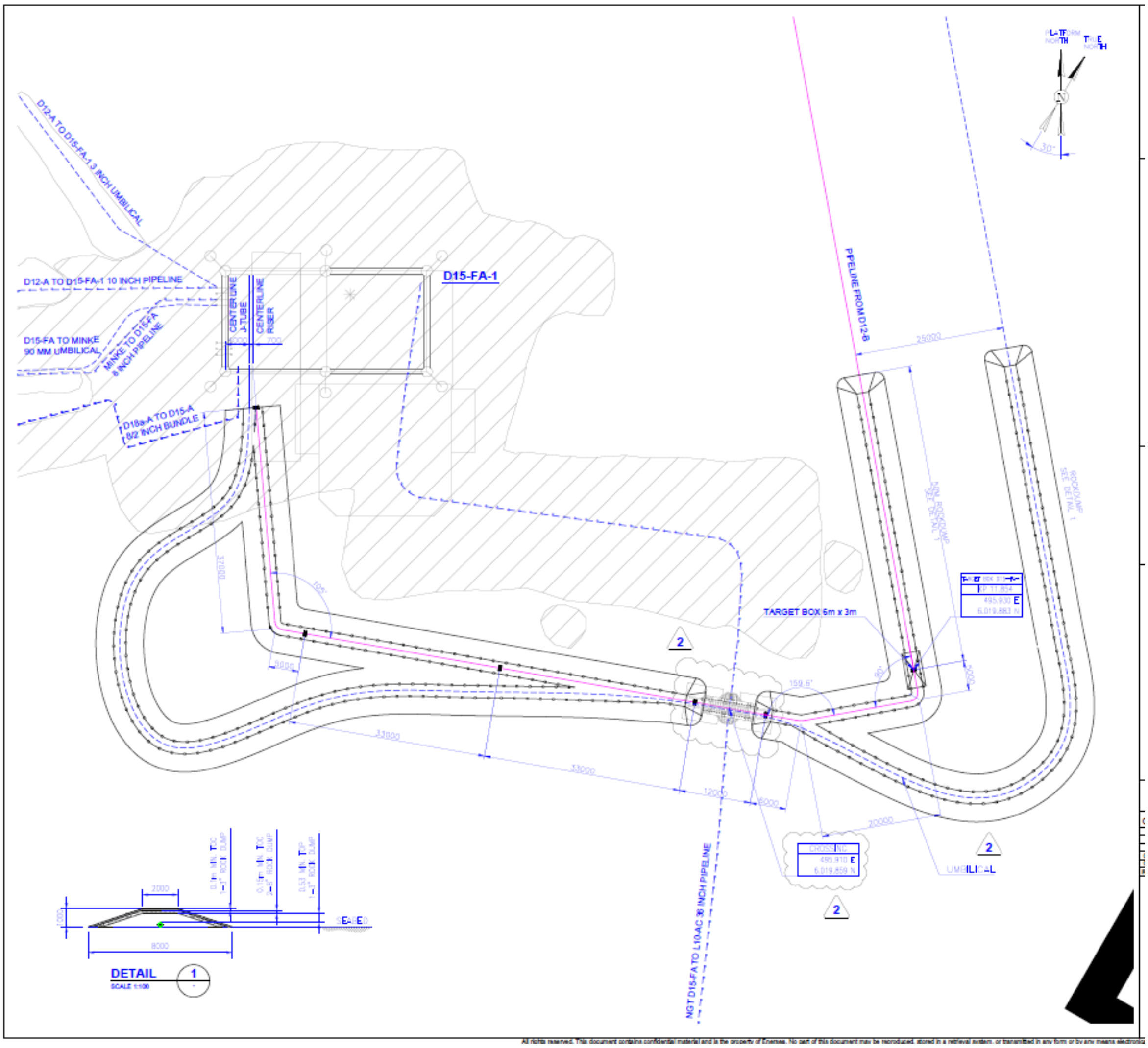

Figure 3-1 Platform approach @ D15-FA-1

The target box location at the D12-B platform which is the start point of the pipeline is already defined and is as per Pipeline FEED design report [xiv]. Reference is made to the D12-B platform approach, see Figure 3-2.

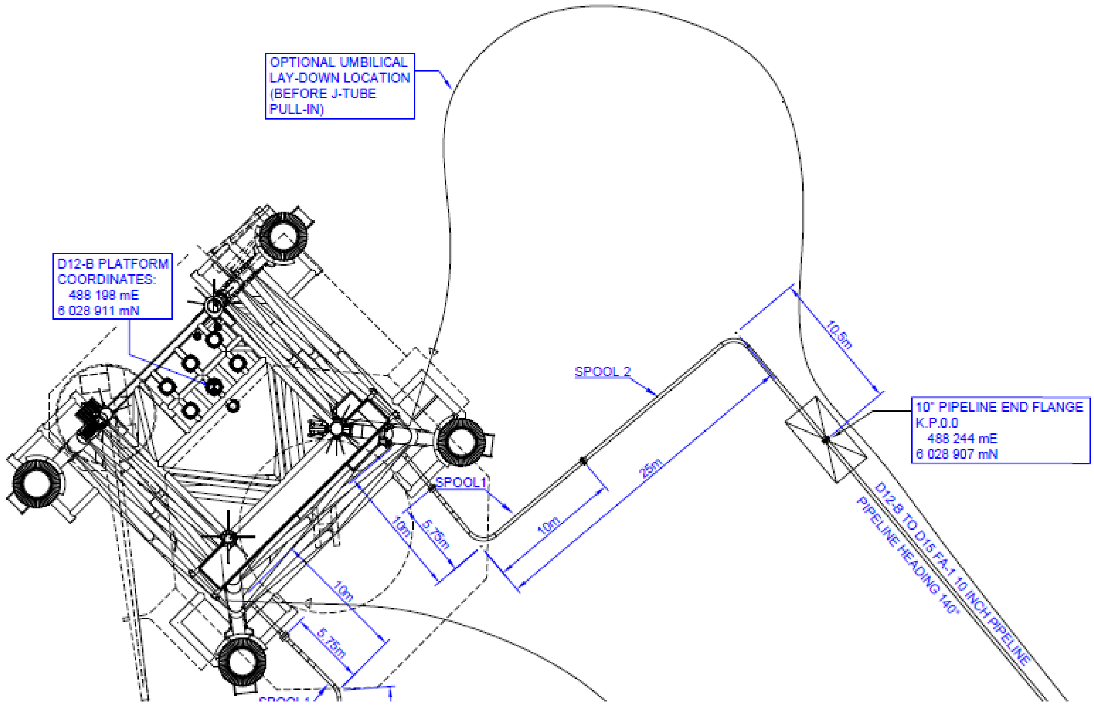

Figure 3-2 Platform approach @ D12-B

3.2. Coordinate system

The parameters of the geodetic system to be used for horizontal positions are taken from ref. [i] and listed in Table 3-1.

Item	Value
Datum	European Datum 1950 (ED50)
Projection	ED50 / UTM zone 31 N
Ellipsoid name	International 1924
Semi major axis	6 378 388 m
Inverse flattening	297.000
Central Meridian	03°00”00’ E
Latitude of Origin	00°00”00’ N
False Northing	0 mN
False Easting	500 000 mE
Scale Factor	0.9996

Table 3-1: Geodetic parameters

The vertical position is given relative to the Lowest Astronomical Tide (LAT).

3.3. Key facility coordinates

The following platform and target box locations have been derived from Ref. [xii], [xiv], [xxi] and are presented in Table 3-2.

ITEM	Northing (m)	Easting (m)
D12-B platform (well E)	6 028 911	488 198
D15-FA-1 platform	6 019 887	495 821
D12-B target box	6 028 907	488 244
D15-FA-1 target box	6 019 883	495.930
Water depth @ D12-B	28.6m LAT	
Water depth @ D15-FA-1	40.0m LAT	

Table 3-2 Key Facility coordinates

3.4. Bathymetry

Figure 3-3 shows the typical bathymetry along the surveyed pipeline route upon which the final route is to be selected; bathymetry data is taken from ref. [ii]

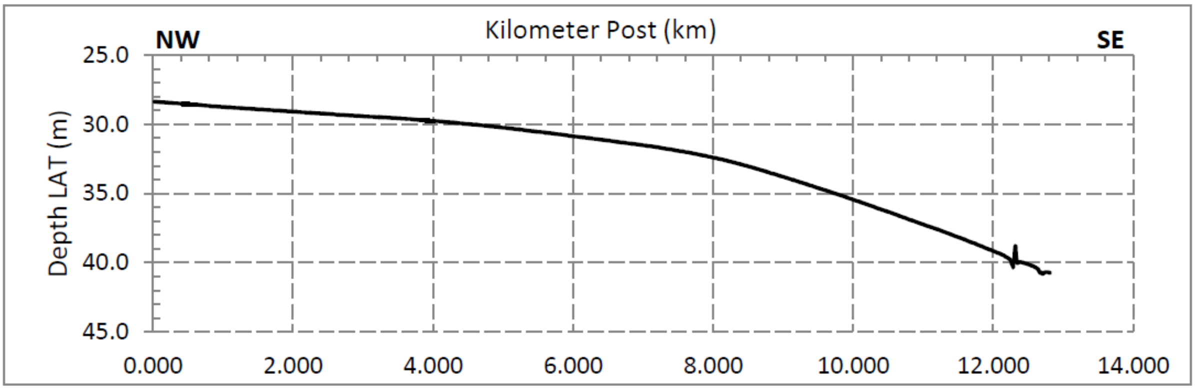

Figure 3-3 Seabed profile along pipeline route from D12-B to D15-FA-1 (D12-B @KP 1.000)

The water depths recorded during survey along the proposed D12-B to D15-FA route ranges between 28.4 m LAT and 40.9 m LAT with the seabed gently deepening to the south east. Local variations in water depths occur due to scouring of up to 1.0 m depth around the D15-FA platform location.

The platform depth at the platform locations are given in Table 3-2.

Location	Water depth LAT [m]	Type of structure	Remarks
D12-B Platform	28.6	Jacket	New wellhead platform
D15-FA Platform	40.0	Jacket	Existing platform

Table Error! No text of specified style in document.-2: Platform water depths

3.5. Side Scan Sonar Contacts & Magnetometer Anomalies

Ref. [ii] describes the seafloor sediments across the D12-B survey area to consist of fine to medium SAND. The seafloor is smooth and featureless and there are no sedimentary structures present that could indicate sediment transport.

The side scan sonar contacts detected along the pipeline route corridor are listed in Table 3-3, whilst Table 3-4 shows the magnetometer anomalies. Data has been taken from Ref. [ii].

Seventeen (17) debris items, two (2) wet stored mattresses and one (1) depression were observed within the survey area.

The sonar contact S_D15_0007 is interpreted as a possible wooden wreck (8.8m x 2.7m x 0.7m). The origin of the remaining debris items is unknown.

No seismic anomalies and no faults were interpreted within the survey area. However, the presence of (especially deeper) faults cannot be fully excluded from SBP data.

No other evidence of hazards, obstructions or anomalies that may present a hazard to pipeline installation was observed within the survey area.

KP	DCC [m]	Easting [m]	Northing [m]	SSS Target ID	Comments/Dimensions (L x W x H)
0.260	32.5	488304	6028647	S_D15_0001	Debris; 3.4 x 1.1 x 0.2
0.461	-357.4	488732	6028745	S_D15_0002	Debris; 1.9 x 1.1 x 0.1
0.648	-267.2	488784	6028544	S_D15_0003	Debris; 6.9 x 2.5 x 0.3 (Debris in 0.3 m deep depression)
1.977	163.7	489314	6027252	S_D15_0004	Debris; 2.0 x 1.5 x 0.7
3.833	33.6	490613	6025920	S_D15_0005	Debris; 1.0 x 0.4 x 0.3
4.366	-67.3	491035	6025578	S_D15_0006	Debris; 3.4 x 0.8 x nmh
5.934	52.2	491957	6024305	S_D15_0007	Wreck; 8.8 x 2.7 x 0.7 Possibly wooden wreck. Also in database Dienst der Hydrografie.
6.643	-254.8	492650	6023962	S_D15_0008	Debris; 3.1 x 1.3 x 0.2
9.815	-28.1	494527	6021396	S_D15_0009	Debris; 0.9 x 0.3 x nmh
9.819	333.4	494254	6021159	S_D15_0010	Debris; 2.0 x 1.0 x 0.4
9.831	-278.6	494729	6021545	S_D15_0011	Depression 3.7 x 1.1 x 0.2 m deep
10.954	-324.6	495490	6020718	S_D15_0012	Debris; 3.0 x 1.8 x 0.3
11.084	72.0	495271	6020363	S_D15_0013	Debris; 3.8 x 1.4 x 0.6 Debris in 0.4 m deep depression
11.168	-37.2	495409	6020369	S_D15_0014	Debris; 1.9 x 0.5 x 0.1
11.452	-13.1	495574	6020137	S_D15_0015	Debris; 2.0 x 1.0 x 0.1
11.601	27.8	495639	6019997	S_D15_0016	Possible debris; 2.1 x 0.7 x nmh
11.755	-33.2	495785	6019919	S_D15_0017	Debris; 1.2 x 0.9 x nmh
11.835	29.7	495789	6019817	S_D15_0018	Debris; 1.3 x 0.5 x 0.2 Debris near platform rock dump
11.836	28.2	495791	6019817	S_D15_0019	Debris; 1.4 x 0.7 x 0.1 Debris near platform rock dump
11.978	-90.6	495973	6019786	S_D15_0020	Wet-stored mattress; 5.4 x 3.1 x nmh
11.983	-95.3	495980	6019785	S_D15_0021	Wet-stored mattress 5.6 x 3.4 x nmh
12.376	32.5	495917	6019217	S_D15_0022	Debris; 4.7 x 0.7 x 0.1

Table 3-3 Identified sidescan sonar contacts

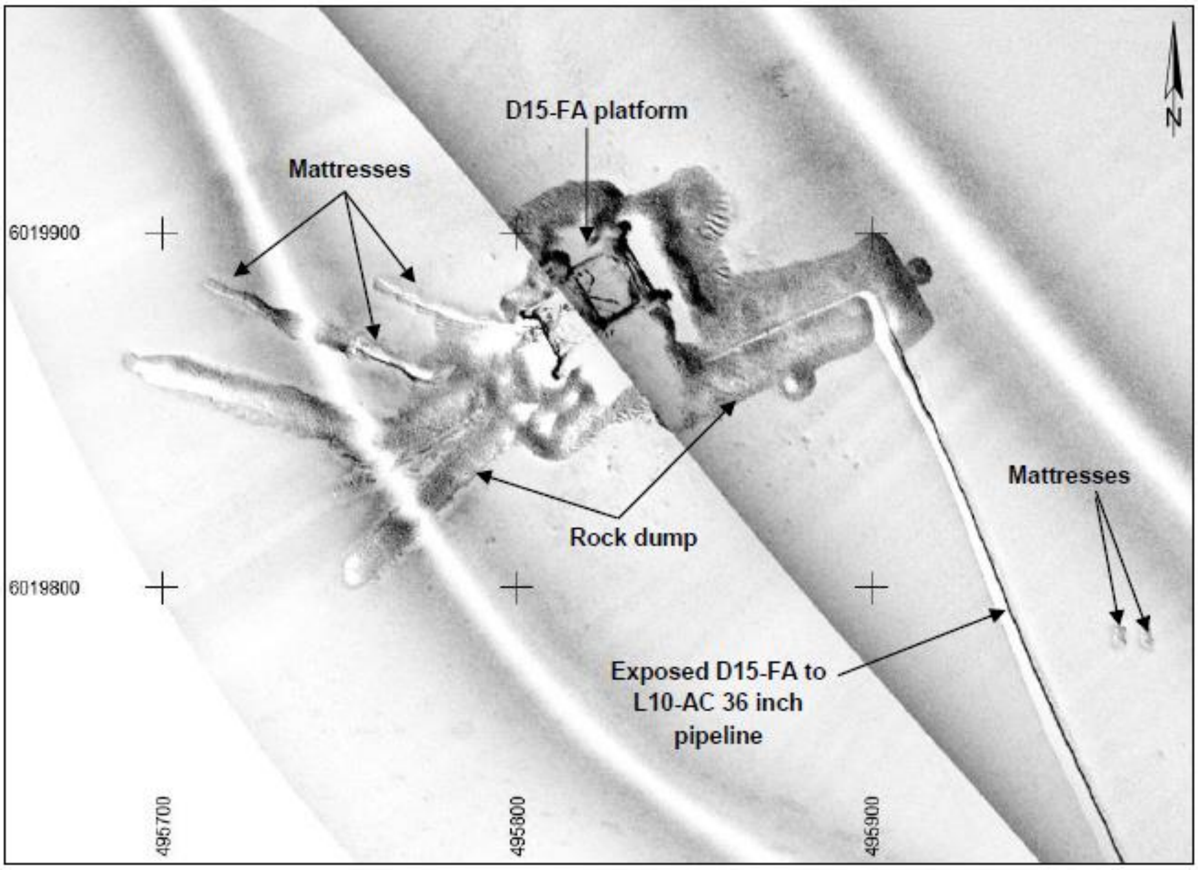

Figure 3-4 SSS record of the D12-B to D15-FA route end at the D15-FA platform area

MAG Target	Easting [m]	Northing [m]	KP	DCC [m]	Ampli-tude [nT]	Monopole / Dipole	Line	Comments
M_D15_01	488493	6028466	0.520	5.5	4.1	Dipole	D15CLm	
M_D15_02	488780	6028124	0.966	7.3	3.6	Dipole	D15CLm	
M_D15_03	490850	6025683	4.167	6.0	11.4	Monopole	D15CLa	Same anomaly as M_D15_04
M_D15_04	490852	6025679	4.171	7.6	10	Monopole	D15CLm	Same anomaly as M_D15_03
M_D15_05	492370	6023893	6.515	3.5	4.6	Monopole	D15CLm	
M_D15_06	492377	6023884	6.527	4.1	5.6	Dipole	D15CLm	
M_D15_07	492931	6023225	7.387	7.8	9.4	Dipole	D15CLa	Same anomaly as M_D15_08
M_D15_08	492935	6023224	7.391	5.1	10.1	Dipole	D15CLm	Same anomaly as M_D15_07
M_D15_09	494442	6021440	9.726	8.3	5.4	Dipole	D15CLa	Same anomaly as M_D15_10
M_D15_10	494448	6021442	9.729	2.7	22.2	Dipole	D15CLm	Same anomaly as M_D15_09
M_D15_11	495808	6019771	11.883	44.7	72.4	Dipole	D15CLa.1	Near platform
M_D15_12	495819	6019765	11.894	40.4	74.7	Dipole	D15CLa.1	Near platform
Infrastructure								
M_D15_13	495706	6019888	11.727	47.2	2.8	Dipole	D15CLa.1	D12-A to D15-FA-1 10 inch pipeline
M_D15_14	495740	6019873	11.761	30.9	43.6	Dipole	D15CLma	D12-A to D15-FA-1 10 inch pipeline
M_D15_15	495754	6019847	11.790	37.0	138.9	Dipole	D15CLma	Wingate to D15-FA-1 12/2 inch bundle
M_D15_16	495742	6019827	11.797	59.1	27.5	Dipole	D15CLa.1	Minke to D15-FA 8/3 inch bundle
M_D15_17	495769	6019825	11.816	39.8	94.1	Dipole	D15CLma	D18a-A to D15-A 8/2 inch bundle
M_D15_18	495755	6019812	11.817	58.9	40.4	Dipole	D15CLa.1	D18a-A to D15-A 8/2 inch bundle
M_D15_19	496032	6019584	12.170	-5.1	656.2	Dipole	D15CLa.1	D15-FA to L10-AC 36 inch pipeline
M_D15_20	496034	6019577	12.177	-2.1	1008.6	Dipole	D15CLma	D15-FA to L10-AC 36 inch pipeline

Table 3-4 Identified magnetometer anomalies

3.6. Cable & Pipeline Crossings

No in/out of use pipeline and/or cable crossings are foreseen along the pipeline route.

4. Design Parameters

This chapter describes the design data to be considered for the pipeline from D12-B to D15-FA. Also the design data for the riser and spool piece at D15-FA platform is defined.

4.1. Pipe Data

The basic line pipe design and riser and spool piece data to be considered in the analysis for the 10" export gas line are presented in Table 4-1 and Table 4-2. Data has been taken from Ref. [xi].

Property	10" Pipeline D12-B to D15-FA
Product transported	Natural gas
Design life	Min. 30 years
Approx. length	11.8 km
Steel material grade	L360NB
Manufacturing process	HFIW Carbon steel
Pipe outside diameter (")	10" OD
Pipe outside diameter (mm)	273.1 mm
Wall thickness	12.7 mm
Wall thickness tolerance	+5.5% / -5.5 %
Internal corrosion allowance	3 mm
Anti-corrosion coating	Polyethylene
Anti-corrosion coating thickness	2.8 mm
Anti-corrosion coating density	900 kg/m³
Concrete weight coating thickness	N/A
Minimum subsea hot bend radius	1.366 m (5D)

Table 4-1 Pipeline data

Property	10" Riser & Spool @ D15-FA
Product transported	Natural gas
Design life	Min. 30 years
Steel material grade	L360NB
Manufacturing process	HFIW Carbon steel
Pipe outside diameter (")	10" OD
Pipe outside diameter (mm)	273.1 mm
Wall thickness	12.7 mm
Wall thickness tolerance	+5.5% / -5.5 %
Internal corrosion allowance	3 mm
Anti-corrosion coating	Neoprene
Anti-corrosion coating thickness - Inside splash zone	12 mm
Anti-corrosion coating thickness - Outside splash zone	6 mm
Anti-corrosion coating density	1400 kg/m³
Minimum subsea hot bend radius	1.366 m (5D)

Table 4-2 Riser and spool piece data

Steel material properties considered in the design are presented in Table 4-3.

Property	Value
Material	L360NB
Density	7850 kg/m^3
Specified Minimum Yield Strength @20 °C	360 MPa
Specified Minimum Yield Strength @100 °C	304 MPa
Specified Minimum Yield Strength @65 °C	343.2 MPa
Specified Minimum Yield Strength @90 °C	315.2 MPa
Specified Minimum Tensile Strength	460 MPa
Young's modulus	2.07 x 10^{11} Pa
Poisson ratio	0.3
Thermal expansion coefficient	1.17 x 10^{-5} m/m·°C

Table 4-3 Steel material properties

4.2. Process conditions

Table 4-4 presents the pipeline, riser and spool design process parameters considered in the analysis.

Property	10" export gas line
Design pressure	148 barg
Hydrotest pressure	202 barg
Design temperature	20 °C (1)
Ambient (air / surface) temperature	+4 °C
Content oil density	100 kg/m^3

Table 4-4 Process design parameters

(1) Ref. [iii]; maximum sea bed temperature is 17 deg. C.

The liquid hold-up volume in the pipeline is estimated to be approximately 15 [m^3], as provided in [xxvii].

Figure 4-1 shows the operational thermal profile along the pipeline, ref. [xxv].

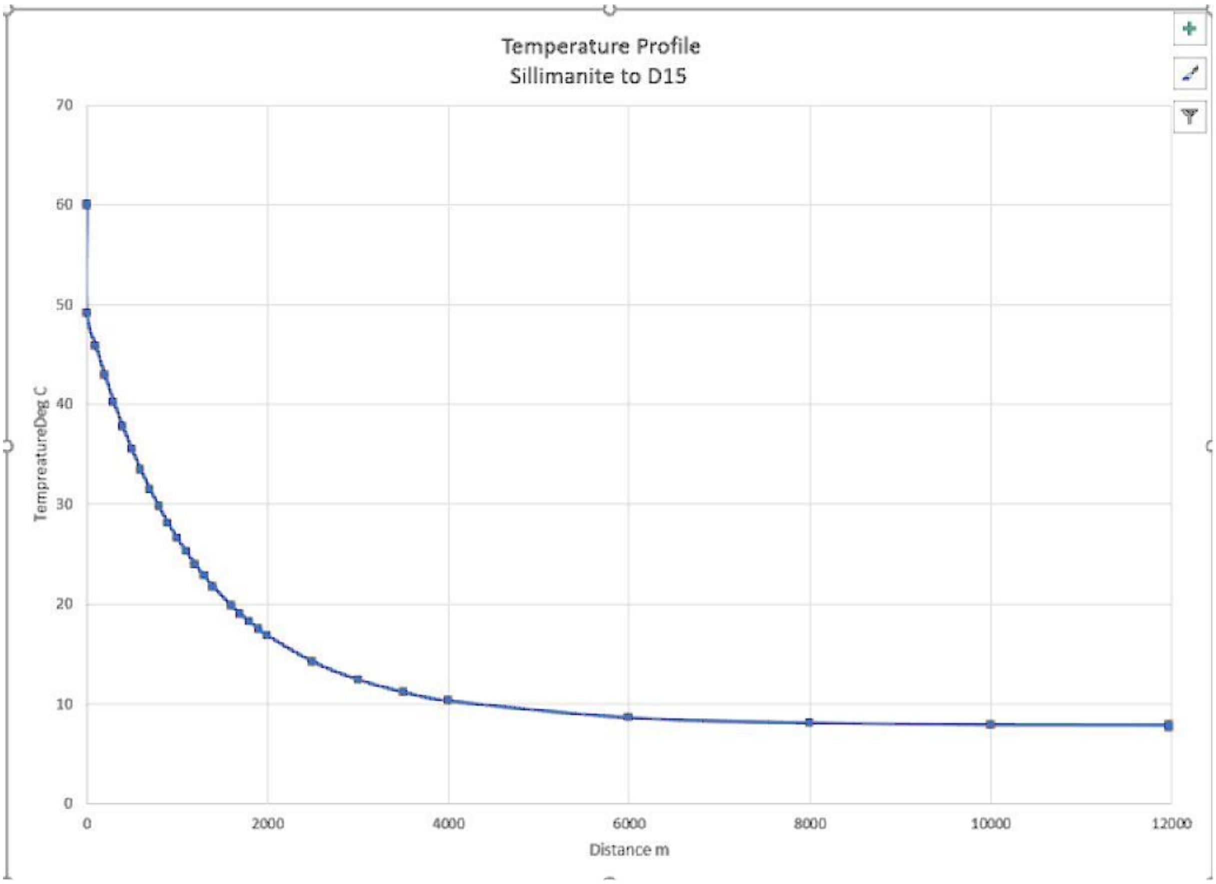

Figure 4-1 Operational thermal profile

4.3. Coating Material Properties

Typical material properties of the coating are given in Table 4-5 (as per WINZ specification; ref. [ix]).

Property	Value
Anti-corrosion coating density	900 kg/m³
Anti-corrosion coating thermal conductivity	0.22 W/m°C
Anti-corrosion coating specific heat capacity	2000 J/kg°C

Table 4-5 Pipe coating material properties

4.4. Flange Properties

Table 4-6 presents the flange classes and main characteristics. The external flange loads will be checked by using the ASME BPVC [10] flange integrity check.

Property	10” export gas line
Flange rating	ANSI/ASME Class 1500
Flange type	RTJ Swivel / Weld Neck
Weld end thickness	12.7 mm

Table 4-6 Flange properties

4.5. D15-FA Riser info

The gas pipeline from D12-B is routed to platform D15-FA and the intended tie-in location will be at leg C2. It is the aim to install a new 10” riser at the location of the current existing 8”/2” riser (D18-A to D15-A), reference is made to Figure 3-1.

4.6. Platform deflections

The D15-FA platform deflections under hydrodynamic loading for 1-year and 100-year environmental design conditions are summarize in Table 4-7 and 4-8. The values are obtained from the jacket in-place analysis report (ref. [xxii]).

1-yr RP displacement waves in (X) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	113	-56	-39
+8.00	109	-31	-19
-8.00	95	-17	-16
-24.00	89	-5	-13
-40.00	71	0	-12

1-yr RP displacement waves in (-X) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-117	-50	-47
+8.00	-93	-28	-26
-8.00	-93	-15	-23
-24.00	-83	-3	-18
-40.00	-80	2	-16

1-yr RP displacement waves in (XY) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	53	84	-35
+8.00	59	73	-17
-8.00	49	76	-13
-24.00	45	76	-11
-40.00	35	69	-10

1-yr RP displacement waves in (-X-Y) direction (243.4 deg)			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-56	-194	-51
+8.00	-41	-135	-29
-8.00	-46	-110	-26
-24.00	-39	-86	-21
-40.00	-43	-69	-19

1-yr RP displacement waves in (Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-5	95	-37
+8.00	10	84	-18
-8.00	3	86	-14
-24.00	3	84	-11
-40.00	-3	76	-10

1-yr RP displacement waves in (-Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	2	-204	-50
+8.00	8	-145	-29
-8.00	0	-120	-25
-24.00	4	-94	-20
-40.00	5	-76	-18

1-yr RP displacement waves in (-X+Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-63	86	-39
+8.00	-39	74	-20
-8.00	-43	77	-16
-24.00	-39	77	-13
-40.00	-40	70	-12

1-yr RP displacement waves in (+X-Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	59	-195	-48
+8.00	56	-133	-26
-8.00	46	-109	-23
-24.00	45	-85	-19
-40.00	31	-68	-16

Y-direction corresponds to platform North

Table 4-7 D15-FA 1 year platform deflections

100-yr RP displacement waves in (X) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	236	-58	-35
+8.00	218	-31	-16
-8.00	197	-17	-13
-24.00	184	-6	-11
-40.00	156	-1	-9

100-yr RP displacement waves in (-X) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-243	-47	-51
+8.00	-203	-27	-29
-8.00	-197	-14	-26
-24.00	-180	-1	-21
-40.00	-167	2	-19

100-yr RP displacement waves in (XY) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	106	214	-29
+8.00	107	173	-11
-8.00	94	167	-8
-24.00	86	156	-7
-40.00	73	140	-6

100-yr RP displacement waves in (-X-Y) direction (243.4 deg)			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-112	-326	-58
+8.00	-92	-237	-35
-8.00	-94	-204	-31
-24.00	-82	-169	-26
-40.00	-83	-143	-23

100-yr RP displacement waves in (Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-9	247	-31
+8.00	11	204	-13
-8.00	4	194	-10
-24.00	2	181	-8
-40.00	-1	161	-7

100-yr RP displacement waves in (-Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	6	-351	-56
+8.00	7	-262	-33
-8.00	-1	-225	-29
-24.00	5	-188	-24
-40.00	-7	-159	-21

100-yr RP displacement waves in (-X+Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	-124	225	-35
+8.00	-87	178	-17
-8.00	-88	171	-14
-24.00	-82	161	-11
-40.00	-77	143	-10

100-yr RP displacement waves in (+X-Y) direction			
Jacket elevation	Δx	Δy	Δz
[m]	[mm]	[mm]	[mm]
+15.80	120	-328	-51
+8.00	104	-236	-29
-8.00	91	-202	-25
-24.00	89	-168	-21
-40.00	69	-141	-18

Y-direction corresponds to platform North

Table 4-8 D15-FA 100 year platform deflections

4.7. Environmental data

4.7.1. D12-B

For the detailed target box to target box design of the pipeline, environmental data has been taken from Ref. [iii] , which is presented in Table 4-9 for 1 and 100 year return periods. Directional data is given in tables 4-10 to 4-13

Property	1-year return period	10-year return period	100-year return period
Wave direction	Omni-directional	Omni-directional	Omni-directional
Maximum wave height (H_{max})	12.0m	14.7m	17.2m
Associated wave period (T_{ass})	10.1s	11.1s	12.1s
Significant wave height (H_s)	6.5m	7.9m	9.3m
Zero crossing period (T_z)	8.3s	9.1s	9.9s
Current direction	Omni-directional	Omni-directional	Omni-directional
Near-surface current speed	0.91m/s	0.98m/s	1.05m/s
Mid-depth current speed	0.91m/s	0.98m/s	1.05m/s
Near-bed current speed	0.62m/s	0.67m/s	0.72m/s
Positive surge & tidal levels (MSL)	3.33	3.51	3.73
Negative surge & tidal levels (MSL)	-0.85	-1.02	-1.24

Table 4-9 Wave and current data

Return Period	Hs	Tz			Tp			Tass			Hmax	Crest Height
		(lower)	(central)	(upper)	(lower)	(central)	(upper)	(lower)	(central)	(upper)		
	(m)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(m)	(m)
1-year												
N	6.2	7.2	8.1	9.6	9.4	10.9	14.3	8.5	9.8	12.9	11.4	7.4
NE	5.0	6.5	7.3	8.6	8.5	9.9	12.8	7.7	8.9	11.5	9.3	6.0
E	5.6	6.8	7.7	9.1	8.9	10.4	13.6	8.0	9.4	12.2	10.4	6.7
SE	4.6	6.2	7.0	8.2	8.1	9.5	12.3	7.3	8.6	11.1	8.6	5.5
S	6.0	7.1	8.0	9.4	9.3	10.8	14.1	8.4	9.7	12.7	11.1	7.1
SW	6.1	7.1	8.0	9.5	9.3	10.8	14.1	8.4	9.7	12.7	11.3	7.3
W	6.5	7.4	8.3	9.8	9.6	11.2	14.6	8.6	10.1	13.1	12.0	7.7
NW	6.3	7.2	8.2	9.6	9.5	11.1	14.4	8.6	10.0	13.0	11.7	7.6
10-years												
N	7.6	8.0	9.0	10.6	10.4	12.2	15.8	9.4	11.0	14.2	14.0	9.0
NE	6.1	7.1	8.0	9.5	9.3	10.8	14.1	8.4	9.7	12.7	11.3	7.3
E	6.9	7.6	8.5	10.1	9.9	11.5	15.0	8.9	10.4	13.5	12.7	8.2
SE	5.7	6.9	7.8	9.2	9.0	10.5	13.7	8.1	9.5	12.3	10.5	6.8
S	7.3	7.8	8.8	10.4	10.2	11.9	15.5	9.2	10.7	14.0	13.6	8.7
SW	7.5	7.9	8.9	10.5	10.3	12.0	15.7	9.3	10.8	14.1	13.8	8.9
W	7.9	8.1	9.1	10.8	10.6	12.3	16.0	9.5	11.1	14.4	14.7	9.5
NW	7.8	8.1	9.1	10.7	10.6	12.3	16.0	9.5	11.1	14.4	14.4	9.3
50-years												
N	8.5	8.4	9.5	11.2	11.0	12.8	16.7	9.9	11.5	15.0	15.7	10.1
NE	6.9	7.6	8.5	10.1	9.9	11.5	15.0	8.9	10.4	13.5	12.7	8.2
E	7.7	8.0	9.0	10.7	10.4	12.2	15.8	9.4	11.0	14.2	14.3	9.2
SE	6.4	7.3	8.2	9.7	9.5	11.1	14.4	8.6	10.0	13.0	11.8	7.6
S	8.2	8.3	9.3	11.0	10.8	12.6	16.4	9.7	11.3	14.8	15.2	9.8
SW	8.4	8.4	9.4	11.1	10.9	12.7	16.5	9.8	11.4	14.9	15.5	10.0
W	8.9	8.6	9.7	11.5	11.3	13.1	17.1	10.2	11.8	15.4	16.4	10.6
NW	8.7	8.5	9.6	11.3	11.1	13.0	16.9	10.0	11.7	15.2	16.1	10.4

Table 4-10 Independent Directional Extreme Wave Heights and Associated Periods

Direction from (relative to True North) – part 1

Return Period	Hs	Tz			Tp			Tass			Hmax	Crest Height
		(lower)	(central)	(upper)	(lower)	(central)	(upper)	(lower)	(central)	(upper)		
	(m)	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(m)*	*(m)*
100-years												
N	8.9	8.6	9.7	11.5	11.3	13.1	17.1	10.2	11.8	15.4	16.4	10.6
NE	7.2	7.7	8.7	10.3	10.1	11.7	15.3	9.1	10.5	13.8	13.3	8.6
E	8.1	8.2	9.3	10.9	10.8	12.6	16.4	9.7	11.3	14.8	14.9	9.6
SE	6.7	7.5	8.4	9.9	9.7	11.3	14.8	8.7	10.2	13.3	12.3	8.0
S	8.6	8.5	9.5	11.3	11.0	12.8	16.7	9.9	11.5	15.0	15.9	10.3
SW	8.8	8.6	9.6	11.4	11.1	13.0	16.9	10.0	11.7	15.2	16.2	10.5
W	9.3	8.8	9.9	11.7	11.5	13.4	17.4	10.4	12.1	15.7	17.2	11.1
NW	9.1	8.7	9.8	11.6	11.4	13.2	17.2	10.3	11.9	15.5	16.9	10.9
1,000-years												
N	10.1	9.2	10.3	12.2	11.9	13.9	18.1	10.7	12.5	16.3	18.8	12.1
NE	8.2	8.3	9.3	11.0	10.8	12.6	16.4	9.7	11.3	14.8	15.2	9.8
E	9.2	8.8	9.9	11.6	11.5	13.4	17.4	10.4	12.1	15.7	17.1	11.0
SE	7.6	8.0	9.0	10.6	10.4	12.2	15.8	9.4	11.0	14.2	14.1	9.1
S	9.8	9.0	10.2	12.0	11.8	13.8	18.0	10.6	12.4	16.2	18.2	11.7
SW	10.0	9.1	10.3	12.1	11.9	13.9	18.1	10.7	12.5	16.3	18.5	12.0
W	10.6	9.4	10.6	12.5	12.3	14.3	18.7	11.1	12.9	16.8	19.7	12.7
NW	10.4	9.3	10.5	12.4	12.2	14.2	18.5	11.0	12.8	16.7	19.3	12.4
10,000-years												
N	11.4	9.7	11.0	13.0	12.8	14.9	19.4	11.5	13.4	17.5	21.0	13.6
NE	9.2	8.8	9.9	11.6	11.5	13.4	17.4	10.4	12.1	15.7	17.1	11.0
E	10.3	9.3	10.4	12.3	12.1	14.0	18.3	10.9	12.6	16.5	19.1	12.4
SE	8.5	8.4	9.5	11.2	11.0	12.8	16.7	9.9	11.5	15.0	15.8	10.2
S	11.0	9.6	10.8	12.7	12.5	14.6	19.0	11.3	13.1	17.1	20.4	13.2
SW	11.2	9.7	10.9	12.8	12.6	14.7	19.2	11.3	13.2	17.3	20.8	13.4
W	11.9	10.0	11.2	13.2	13.0	15.1	19.7	11.7	13.6	17.7	22.1	14.2
NW	11.7	9.9	11.1	13.1	12.9	15.0	19.5	11.6	13.5	17.6	21.6	14.0

Table 4-11 Independent Directional Extreme Wave Heights and Associated Periods

Direction from (relative to True North) – part 2

Height Above Sea Bed	N	NE	E	SE	S	SW	W	NW	Omni
1 Year	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*
Surface	0.42	0.45	0.64	0.84	0.91	0.55	0.55	0.52	0.91
75% of Water Depth	0.42	0.45	0.64	0.84	0.91	0.55	0.55	0.52	0.91
50% of Water Depth	0.42	0.45	0.64	0.84	0.91	0.55	0.55	0.52	0.91
40% of Water Depth	0.40	0.43	0.62	0.80	0.87	0.54	0.52	0.49	0.87
30% of Water Depth	0.39	0.41	0.60	0.77	0.84	0.52	0.51	0.48	0.84
20% of Water Depth	0.37	0.39	0.56	0.73	0.79	0.48	0.48	0.45	0.79
10% of Water Depth	0.33	0.36	0.52	0.67	0.73	0.45	0.44	0.41	0.73
5% of Water Depth	0.29	0.31	0.44	0.57	0.62	0.38	0.38	0.35	0.62
Near Bed	0.29	0.31	0.44	0.57	0.62	0.38	0.38	0.35	0.62
10 Years									
Surface	0.46	0.48	0.69	0.90	0.98	0.60	0.59	0.56	0.98
75% of Water Depth	0.46	0.48	0.69	0.90	0.98	0.60	0.59	0.56	0.98
50% of Water Depth	0.46	0.48	0.69	0.90	0.98	0.60	0.59	0.56	0.98
40% of Water Depth	0.44	0.47	0.67	0.86	0.94	0.58	0.56	0.53	0.94
30% of Water Depth	0.42	0.45	0.65	0.84	0.91	0.56	0.55	0.52	0.91
20% of Water Depth	0.40	0.42	0.61	0.79	0.86	0.52	0.51	0.48	0.86
10% of Water Depth	0.36	0.39	0.56	0.72	0.79	0.48	0.48	0.45	0.79
5% of Water Depth	0.31	0.33	0.48	0.62	0.67	0.41	0.41	0.38	0.67
Near Bed	0.31	0.33	0.48	0.62	0.67	0.41	0.41	0.38	0.67
50 Years									
Surface	0.48	0.51	0.73	0.95	1.03	0.63	0.62	0.59	1.03
75% of Water Depth	0.48	0.51	0.73	0.95	1.03	0.63	0.62	0.59	1.03
50% of Water Depth	0.48	0.51	0.73	0.95	1.03	0.63	0.62	0.59	1.03
40% of Water Depth	0.46	0.49	0.70	0.91	0.99	0.61	0.59	0.56	0.99
30% of Water Depth	0.44	0.47	0.68	0.88	0.96	0.59	0.58	0.55	0.96
20% of Water Depth	0.42	0.44	0.64	0.83	0.90	0.55	0.54	0.51	0.90
10% of Water Depth	0.38	0.41	0.59	0.76	0.83	0.51	0.50	0.47	0.83
5% of Water Depth	0.33	0.35	0.50	0.65	0.71	0.43	0.43	0.40	0.71
Near Bed	0.33	0.35	0.50	0.65	0.71	0.43	0.43	0.40	0.71

Table 4-12 Profiles of Independent Direction Extreme Total Current Speed (m/s)

Directions are towards – part 1

Height Above Sea Bed	N	NE	E	SE	S	SW	W	NW	Omni
100 Years									
Surface	0.49	0.52	0.74	0.97	1.05	0.64	0.63	0.60	1.05
75% of Water Depth	0.49	0.52	0.74	0.97	1.05	0.64	0.63	0.60	1.05
50% of Water Depth	0.49	0.52	0.74	0.97	1.05	0.64	0.63	0.60	1.05
40% of Water Depth	0.47	0.50	0.71	0.93	1.01	0.62	0.60	0.57	1.01
30% of Water Depth	0.45	0.48	0.69	0.90	0.98	0.60	0.59	0.56	0.98
20% of Water Depth	0.43	0.45	0.65	0.85	0.92	0.56	0.55	0.52	0.92
10% of Water Depth	0.39	0.42	0.60	0.78	0.85	0.52	0.51	0.48	0.85
5% of Water Depth	0.34	0.36	0.51	0.66	0.72	0.44	0.44	0.41	0.72
Near Bed	0.34	0.36	0.51	0.66	0.72	0.44	0.44	0.41	0.72
1,000 Years									
Surface	0.53	0.56	0.80	1.05	1.13	0.69	0.68	0.65	1.13
75% of Water Depth	0.53	0.56	0.80	1.05	1.13	0.69	0.68	0.65	1.13
50% of Water Depth	0.53	0.56	0.80	1.05	1.13	0.69	0.68	0.65	1.13
40% of Water Depth	0.51	0.54	0.77	1.00	1.09	0.67	0.65	0.62	1.09
30% of Water Depth	0.48	0.52	0.75	0.97	1.06	0.65	0.64	0.61	1.06
20% of Water Depth	0.46	0.48	0.70	0.91	0.99	0.61	0.59	0.56	0.99
10% of Water Depth	0.42	0.45	0.65	0.84	0.91	0.56	0.55	0.52	0.91
5% of Water Depth	0.36	0.39	0.55	0.72	0.78	0.47	0.47	0.44	0.78
Near Bed	0.36	0.39	0.55	0.72	0.78	0.47	0.47	0.44	0.78
10,000 Years									
Surface	0.56	0.60	0.85	1.11	1.21	0.74	0.73	0.69	1.21
75% of Water Depth	0.56	0.60	0.85	1.11	1.21	0.74	0.73	0.69	1.21
50% of Water Depth	0.56	0.60	0.85	1.11	1.21	0.74	0.73	0.69	1.21
40% of Water Depth	0.54	0.57	0.82	1.06	1.16	0.71	0.69	0.66	1.16
30% of Water Depth	0.51	0.55	0.80	1.03	1.12	0.69	0.68	0.64	1.12
20% of Water Depth	0.49	0.51	0.75	0.97	1.05	0.64	0.63	0.60	1.05
10% of Water Depth	0.44	0.48	0.69	0.89	0.97	0.60	0.59	0.55	0.97
5% of Water Depth	0.39	0.41	0.59	0.76	0.83	0.50	0.50	0.47	0.83
Near Bed	0.39	0.41	0.59	0.76	0.83	0.50	0.50	0.47	0.83

Table 4-13 Profiles of Independent Direction Extreme Total Current Speed (m/s)

Directions are towards – part 2

4.7.2. D18a

For the detailed riser and spool piece design at D15-FA, environmental data has been taken from Ref. [xxiii], which is presented in Table 4-14 for 1 and 100 year return periods. Directional data is given in tables 4-15 to 4-17.

Property	1-year return period	10-year return period	100-year return period
Wave direction	Omni-directional	Omni-directional	Omni-directional
Maximum wave height (H_{max})	12.7m	15.4m	17.9m
Associated wave period (T_{ass})	10.7s	11.9s	12.7s
Significant wave height (H_s)	6.7m	8.2m	9.5m
Zero crossing period (T_z)	8.5s	9.4s	10.1s
Current direction	Omni-directional	Omni-directional	Omni-directional
Near-surface current speed	0.89m/s	0.96m/s	1.03m/s
Mid-depth current speed	0.89m/s	0.96m/s	1.03m/s
Near-bed current speed	0.50m/s	0.54m/s	0.58m/s
Positive surge & tidal levels (MSL)	3.44m	3.62m	3.84m
Negative surge & tidal levels (MSL)	-0.83m	-1.01m	-1.22m

Table 4-14 Wave and current data

Return Period	Hs	Tz			Tp			Tass			Hmax	Crest Height
		(lower)	(central)	(upper)	(lower)	(central)	(upper)	(lower)	(central)	(upper)		
	(m)	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(s)*	*(m)*	*(m)*
1-year												
N	6.7	7.7	8.5	9.4	10.2	11.9	15.3	9.2	10.7	13.8	12.6	7.9
NE	5.1	6.7	7.4	8.2	8.9	10.4	13.3	8.0	9.4	12.0	9.7	6.1
E	5.6	7.0	7.8	8.6	9.4	10.9	14.0	8.5	9.8	12.6	10.6	6.6
SE	4.5	6.3	7.0	7.7	8.4	9.8	12.6	7.6	8.8	11.3	8.5	5.3
S	5.9	7.2	8.0	8.8	9.6	11.2	14.4	8.6	10.1	13.0	11.1	6.9
SW	6.0	7.3	8.1	8.9	9.7	11.3	14.6	8.7	10.2	13.1	11.3	7.1
W	6.7	7.7	8.5	9.4	10.2	11.9	15.3	9.2	10.7	13.8	12.7	8.0
NW	6.7	7.7	8.5	9.4	10.2	11.9	15.3	9.2	10.7	13.8	12.6	7.9
10-years												
N	8.1	8.4	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.3	9.5
NE	6.2	7.4	8.2	9.1	9.8	11.5	14.8	8.8	10.4	13.3	11.7	7.3
E	6.8	7.7	8.6	9.5	10.3	12.0	15.5	9.3	10.8	14.0	12.9	8.0
SE	5.4	6.9	7.6	8.5	9.1	10.6	13.7	8.2	9.5	12.3	10.3	6.4
S	7.1	7.9	8.8	9.7	10.6	12.3	15.8	9.5	11.1	14.2	13.4	8.4
SW	7.2	7.9	8.8	9.8	10.6	12.3	15.8	9.5	11.1	14.2	13.7	8.5
W	8.2	8.5	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.4	9.6
NW	8.1	8.4	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.3	9.6
50-years												
N	9.0	8.9	9.9	10.9	11.9	13.9	17.8	10.7	12.5	16.0	17.0	10.6
NE	6.9	7.8	8.6	9.6	10.3	12.0	15.5	9.3	10.8	14.0	13.0	8.2
E	7.6	8.2	9.1	10.0	10.9	12.7	16.4	9.8	11.4	14.8	14.3	9.0
SE	6.1	7.3	8.1	9.0	9.7	11.3	14.6	8.7	10.2	13.1	11.4	7.2
S	7.9	8.3	9.2	10.2	11.0	12.9	16.6	9.9	11.6	14.9	15.0	9.4
SW	8.1	8.4	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.2	9.5
W	9.1	8.9	9.9	11.0	11.9	13.9	17.8	10.7	12.5	16.0	17.1	10.7
NW	9.1	8.9	9.9	11.0	11.9	13.9	17.8	10.7	12.5	16.0	17.1	10.7

Table 4-15 Independent Directional Extreme Wave Heights and Associated Periods

Direction from (relative to True North) – part 1

Return Period	Hs	Tz			Tp			Tass			Hmax	Crest Height
		(lower)	(central)	(upper)	(lower)	(central)	(upper)	(lower)	(central)	(upper)		
	(m)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(s)	(m)	(m)
100-years												
N	9.4	9.1	10.1	11.2	12.1	14.1	18.2	10.9	12.7	16.4	17.8	11.1
NE	7.2	7.9	8.8	9.8	10.6	12.3	15.8	9.5	11.1	14.2	13.6	8.5
E	7.9	8.3	9.2	10.2	11.0	12.9	16.6	9.9	11.6	14.9	15.0	9.4
SE	6.3	7.4	8.3	9.1	10.0	11.6	14.9	9.0	10.4	13.4	11.9	7.5
S	8.3	8.5	9.5	10.5	11.4	13.3	17.1	10.3	12.0	15.4	15.6	9.8
SW	8.4	8.6	9.5	10.6	11.4	13.3	17.1	10.3	12.0	15.4	15.9	9.9
W	9.5	9.1	10.1	11.2	12.1	14.1	18.2	10.9	12.7	16.4	17.9	11.2
NW	9.5	9.1	10.1	11.2	12.1	14.1	18.2	10.9	12.7	16.4	17.8	11.1
1,000-years												
N	10.7	9.7	10.8	11.9	13.0	15.1	19.4	11.7	13.6	17.5	20.2	12.7
NE	8.2	8.5	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.5	9.7
E	9.1	8.9	9.9	11.0	11.9	13.9	17.8	10.7	12.5	16.0	17.1	10.7
SE	7.2	7.9	8.8	9.8	10.6	12.3	15.8	9.5	11.1	14.2	13.6	8.5
S	9.5	9.1	10.1	11.2	12.1	14.1	18.2	10.9	12.7	16.4	17.8	11.1
SW	9.6	9.2	10.2	11.3	12.2	14.3	18.4	11.0	12.9	16.6	18.1	11.3
W	10.8	9.7	10.8	12.0	13.0	15.1	19.4	11.7	13.6	17.5	20.4	12.8
NW	10.8	9.7	10.8	12.0	13.0	15.1	19.4	11.7	13.6	17.5	20.3	12.7
10,000-years												
N	12.0	10.3	11.4	12.6	13.7	16.0	20.5	12.3	14.4	18.5	22.6	14.2
NE	9.2	9.0	10.0	11.0	12.0	14.0	18.0	10.8	12.6	16.2	17.4	10.9
E	10.1	9.4	10.5	11.6	12.6	14.7	18.9	11.3	13.2	17.0	19.1	11.9
SE	8.1	8.4	9.4	10.4	11.3	13.2	16.9	10.2	11.9	15.2	15.2	9.5
S	10.6	9.6	10.7	11.9	12.8	15.0	19.3	11.5	13.5	17.4	19.9	12.5
SW	10.8	9.7	10.8	12.0	13.0	15.1	19.4	11.7	13.6	17.5	20.3	12.7
W	12.1	10.3	11.4	12.7	13.7	16.0	20.5	12.3	14.4	18.5	22.8	14.3
NW	12.1	10.3	11.4	12.7	13.7	16.0	20.5	12.3	14.4	18.5	22.7	14.2

Table 4-16 Independent Directional Extreme Wave Heights and Associated Periods

Direction from (relative to True North) – part 2

Height (asb)/ Depth Ratio]	North	Northeast	East	Southeast	South	Southwest	West	Northwest	Omni
1 Year	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*
Surface	0.34	0.29	0.61	0.89	0.66	0.23	0.55	0.54	0.89
75% of Water Depth	0.34	0.29	0.61	0.89	0.66	0.23	0.55	0.54	0.89
50% of Water Depth	0.34	0.29	0.61	0.89	0.66	0.23	0.55	0.54	0.89
40% of Water Depth	0.33	0.28	0.58	0.85	0.63	0.22	0.53	0.52	0.85
30% of Water Depth	0.32	0.27	0.55	0.82	0.61	0.21	0.50	0.49	0.82
20% of Water Depth	0.30	0.26	0.53	0.77	0.58	0.20	0.48	0.47	0.77
10% of Water Depth	0.27	0.23	0.48	0.70	0.53	0.18	0.43	0.43	0.70
5% of Water Depth	0.25	0.21	0.43	0.63	0.48	0.17	0.39	0.39	0.63
Near Bed	0.19	0.17	0.34	0.50	0.37	0.13	0.31	0.31	0.50
10 Years	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*
Surface	0.37	0.31	0.66	0.96	0.71	0.25	0.59	0.58	0.96
75% of Water Depth	0.37	0.31	0.66	0.96	0.71	0.25	0.59	0.58	0.96
50% of Water Depth	0.37	0.31	0.66	0.96	0.71	0.25	0.59	0.58	0.96
40% of Water Depth	0.35	0.30	0.63	0.92	0.68	0.24	0.57	0.56	0.92
30% of Water Depth	0.34	0.29	0.60	0.88	0.66	0.23	0.54	0.53	0.88
20% of Water Depth	0.32	0.28	0.57	0.84	0.63	0.22	0.51	0.50	0.84
10% of Water Depth	0.29	0.25	0.52	0.76	0.57	0.20	0.47	0.47	0.76
5% of Water Depth	0.27	0.23	0.47	0.68	0.51	0.18	0.42	0.42	0.68
Near Bed	0.21	0.18	0.37	0.54	0.40	0.14	0.33	0.33	0.54
50 Years	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*
Surface	0.39	0.33	0.69	1.01	0.75	0.26	0.62	0.61	1.01
75% of Water Depth	0.39	0.33	0.69	1.01	0.75	0.26	0.62	0.61	1.01
50% of Water Depth	0.39	0.33	0.69	1.01	0.75	0.26	0.62	0.61	1.01
40% of Water Depth	0.37	0.32	0.66	0.97	0.72	0.25	0.60	0.59	0.97
30% of Water Depth	0.36	0.31	0.63	0.93	0.69	0.24	0.57	0.56	0.93
20% of Water Depth	0.34	0.29	0.60	0.88	0.66	0.23	0.54	0.53	0.88
10% of Water Depth	0.31	0.26	0.55	0.80	0.60	0.21	0.49	0.49	0.80
5% of Water Depth	0.28	0.24	0.49	0.72	0.54	0.19	0.44	0.44	0.72
Near Bed	0.22	0.19	0.39	0.57	0.42	0.15	0.35	0.35	0.57
100 Years	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*	*m/s*
Surface	0.40	0.34	0.70	1.03	0.77	0.27	0.63	0.62	1.03
75% of Water Depth	0.40	0.34	0.70	1.03	0.77	0.27	0.63	0.62	1.03
50% of Water Depth	0.40	0.34	0.70	1.03	0.77	0.27	0.63	0.62	1.03
40% of Water Depth	0.38	0.33	0.67	0.99	0.73	0.26	0.61	0.60	0.99
30% of Water Depth	0.37	0.32	0.64	0.95	0.70	0.24	0.58	0.57	0.95
20% of Water Depth	0.35	0.30	0.61	0.90	0.67	0.23	0.55	0.54	0.90
10% of Water Depth	0.32	0.27	0.56	0.82	0.61	0.21	0.50	0.50	0.82
5% of Water Depth	0.29	0.24	0.50	0.73	0.55	0.19	0.45	0.45	0.73
Near Bed	0.22	0.19	0.40	0.58	0.43	0.15	0.36	0.36	0.58

Table 4-17 Profiles of Independent Direction Extreme Total Current Speed (m/s)

Directions are towards

Furthermore reference is made to Appendix A, where the (omni-)directional H-T wave scatter diagrams are given, Ref. [xxiv].

4.8. Geotechnical data

The assumed soil properties are listed in Table 4-18, data has been taken from ref. [x] and recommended values as per DNV-RP-F105 (Ref. [3]) based on the soil general description.

Soil type	Applicable area	Submerged Unit Weight (kN/m^3)	Angle of internal friction (°)
Loose fine to medium sand	Pipe on surface	10	34
Loose fine sand	Trench backfill	8.5	28
Rock dump	Crossing / Tie-in	10	40

Table 4-18 Assumed soil geotechnical properties

5. Riser and Spool piece analysis

The purpose of the riser and expansion spool analysis at D15-FA is to determine the combined effect of functional and environmental loads on the structural integrity of the system and to estimate the design loads for the riser clamps and tie-in flanges design. The analysis is divided into two sections; namely a riser and spool stress analysis and a riser fatigue analysis, carried out in accordance with NEN 3656:2015 [1].

5.1. Stress Criteria

Stresses in the riser and tie-in spool pieces at D15-FA will be assessed by using the finite element software ANSYS. The analysis ensures the structural integrity of the riser/spool system by NEN 3656 (Ref. [1])

The analysis will account for the load history of the pipe over the design life by considering the following three load cases:

- Installation
- Hydrotest
- Operational – Nominal
- Operational – Corroded

Considering the design cases listed above the following design loads will be considered when performing the stress analysis, see Table 5-1.

Load	Installation	Hydrotest	Operation
Pressure	N/A	Hydrotest Pressure	Design Pressure
Temperature	Seawater Temperature	Seawater Temperature	Design Temperature
Internal Fluid	Empty	Seawater	Product Filled
Wall Thickness	Nominal	Nominal	Nominal / Fully corroded
Hydrodynamic Loads	1-year wave + 1-year current	1-year wave + 1-year current	100-year wave + 100-year current
Pipeline End Expansion	N/A	Expansion Under Hydrotest Pressure	Expansion under design temperature and pressure

Table 5-1 Design loads

Calculated equivalent stresses for the various design conditions will be checked against the allowable stress values, as per NEN3656 (Ref. [1]), see Table 5-2.

Case	Load Combination As Per NEN3656 Table 3.	Limit Stress	Allowable Equivalent Stress
Installation	LC1	$R_{e(\theta)} / \gamma_m$	327 MPa
Hydrotest	LC4	$0.85\ (R_e + R_{e(\theta)}) / \gamma_m$	556 MPa
Operation (Nominal / Corroded)	LC4	$0.85\ (R_e + R_{e(\theta)}) / \gamma_m$	543 MPa

Table 5-2 Applied stress limits

Where:

Re = specified minimum yield strength at 20ºC (N/mm^2).

$R_{e(\theta)}$ = the yield strength of the material at design temperature.

γ_m = material factor (for steel 1.1).

All design loads applied will be factored as per the requirements of NEN 3656 (Ref. [1]), see Table 5-3.

Loads	Load factors for load combinations (a)								
Load combinations	LC 1	LC 2	LC 3	LC 4	LC 5	LC 6	LC 7a	LC 7b	LC 8
Internal pressure (design pressure)	-	1.25	-	-	-	-	1.0		1.0
Internal pressure (In combination)	-	-	-	1.15	1.15	-	-	1.0	1.15
Internal pressure (max. Incidental pressure)	-	1.10	-	-	-	-	-		1.1
Temperature differences (c g)	1.0	-	1.10	1.10	-	-	1.0	1.0	-
Soil parameters (d)	-	-	(d)	(d)	(d)	-	-	Low	-
Forced deformation (e)	-	-	1.1	1.1	1.1	1.1	-		-
Own weight	1.1	-	1.1	1.1	1.1	1.1	1.0		1.0
(Possible) coating (h)	1.2	-	1.2	1.2	1.2	1.2	1.0	1.2	1.0
Pipe contents (h)	1.1	-	1.1	1.1	1.1	1.1	1.0	1.1	1.0
Installation loads (f)	1.1	-	-	-	-	1.1	-		-
Hydrostatic pressure	1.1	-	1.1	1.1	1.1	1.1	1.0	1.1	
Marine growth (h)	-	-	1.2	1.2	1.1	-	1.0	1.0	1.0
Hydrodynamic forces & platform movements	1.1	-	1.2	1.2	1.1	1.1	1.0	1.2	1.0
(a)	If a load has a favorable influence on the considered case this will not be considered if the load is variable and for a permanent load a multiplication factor of 0.9 is applied.								
(b)	The maximum incidental pressure does not need to be checked separately however must be ascertained by the pressure control system.								
(c)	During calculations of stress variations caused by temperature differences the highest and lowest occurring operation temperature should be considered. The displacements loads and moments exerting on connected equipment and/or structures are to be considered based on the design temperatures i.e. the temperature difference between the installation temperature and the maximum operational temperature.								
(d)	Reference is made to ref. [1] – K.4 to determine load spreading factors								
(e)	Forced deformations can be caused by: settling differences trench roughness execution sacking differences deformations due to prevented thermal expansion distortions in horizontal drilling and bottom-tow installation.								
(f)	Examples of installation loads are those applied during pipelay tie-ins trenching landfalls and HDD etc.								
(g)	Combined with measurements.								
(h)	In the stability check (BC 7b) the most unfavorable combination must be chosen. If necessary divide by the relevant factor.								

Table 5-3 Load factors

A description of the load combinations is shown below;

LC 1: Installation

LC 2: Only internal pressure, operating pressure, incidental pressure

LC 3: External load with zero internal pressure

LC 4: External load with internal pressure and temperature difference

LC 5: Variable load (primarily static load, e.g., temperature changes and pressure)

LC 6: External pressure, external load and internal pressure zero

LC 7a: Incidental load (other than internal pressure)

LC 7b: Incidental load (meteorological)

LC 8: Dynamic loading

5.2. Model description

The riser and spool pieces at D15-FA will be modelled by using ANSYS's dedicated submerged pipe element "PIPE59". This element is a uniaxial element with tension-compression, torsion, and bending capabilities and can account for internal pressure effects. The element is a 3D element with six degrees of freedom, translations in the x, y and z directions and rotations about the x, y and z axes. In addition the element accounts for buoyancy, wave and current loads, and is capable of large deflections and rotations.

Hot bends are modelled by using "PIPE18" elements which are elastic bend pipe elements with similar properties as the straight "PIPE59" elements described previously.

At riser clamp locations pipe nodal translation and/or rotations shall be constrained appropriately based on the physical constraints provided by the clamps (guide clamps / anchor clamps).

To incorporate pipeline end expansion into the spool pieces a representative pipeline length (greater than the anchor length) will be modelled. Note that conservatively seabed undulations are neglected while modelling these pipeline sections as this provides the greatest end expansion into the spool pieces.

Pipe-soil interaction is simulated using three independent non-linear spring elements (COMBIN39) attached to each pipe element. The springs represent the soil frictional resistance in the axial and lateral directions and the soils bearing capacity in the vertical direction. As the spool piece will be rock dumped after the hydrostatic testing, additional non-linear springs representing the uplift resistance of the rockdump / trenched backfill material, are attached to the pipe elements for the "operational" load cases. A detailed description of how the pipe soil interaction will be modelled is provided separately in section 5.3.

5.3. Pipe-soil interaction

The characteristics of the springs, which simulated the pipe-soil interaction, are defined through non-linear force-deflection curves. The force-deflection curves describe the frictional restraint provided by the soil to the pipeline in the axial and lateral direction and the soil's bearing capacity / upwards resistance in the vertical direction. The upcoming sections describe how the force-deflection curves of the springs are generated.

5.3.1. Exposed pipeline – axial soil resistance

The axial soil resistance for a pipeline / spool piece resting on the seabed, per meter pipe-length, is a function of the pipe submerged weight (vertical load) and the axial Coulomb friction coefficient. The axial friction is determined as follows:

$$F_{axial} = \mu_{Coulomb} w_s$$

Where:

- F_{axial} = Peak axial soil resistance [N/m]
- $\mu_{Coulomb}$ = Coulomb friction coefficient [-]
- w_s = Pipe submerged weight [N/m]

The axial restraint will be described through a bi-linear force-displacement relationship, as shown in Figure 5-1. The stiffness of the springs varies along the pipeline route and between load steps to account for variations in the pipe submerged weight and soil conditions.

The axial spring mobilization displacement is assumed to be 1mm.

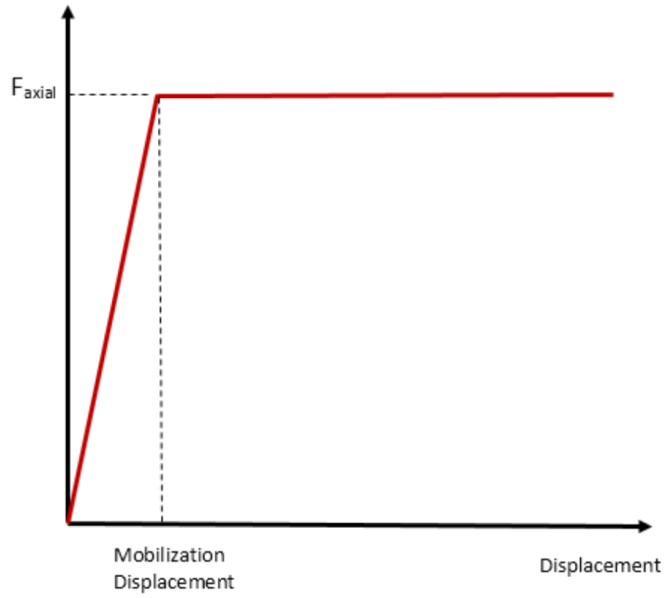

Figure 5-1 Axial resistance Force-Displacement curve

5.3.2. Exposed pipeline – lateral soil resistance

Lateral soil resistance is composed of two parts:

- Coulomb friction.
- Passive soil resistance due to the build-up of soil penetration (and hence a soil berm, as the pipe moves laterally).

To account for both components of resistance, an equivalent friction coefficient shall be used, which is defined as:

$$\mu_{equivalent} = \mu_{Coulomb} + \mu_{passive}$$

Where:

- μ_{eqv} = Equivalent lateral friction coefficient [-]
- $\mu_{Coulomb}$ = Coulomb friction coefficient [-]
- $\mu_{passive}$ = Passive soil resistance coefficient [-]

The passive soil resistance model proposed in DNV's Recommended Practice, DNV-RP-F109 [5] will be used.

The passive soil resistance coefficient, for a pipeline resting on a sandy seabed, depends on the pipe penetration depth into the soil and can be determined by the formulation:

- $\mu_{passive} = \frac{F_R}{F_C} = (5\kappa_s - 0.15\kappa_s{}^2)\left(\frac{z_p}{D}\right)^{1.25}$ if $\kappa_s \leq 26.7$
- $\mu_{passive} = \frac{F_R}{F_C} = \kappa_s\left(\frac{z_p}{D}\right)^{1.25}$ if $\kappa_s > 26.7$

Where:

- F_R = Passive resistance force [N/m]
- F_C = Vertical contact force between pipe and soil [N/m]
- D = Pipe outside diameter, including all coatings [m]
- z_p = Total pipe penetration [m]
- κ_s = Soil parameter for sandy soils [-]
- γ'_s = Submerged unit soil weight [N/m^3]

The soil parameter for sand, κ_s, is determined as:

$$\kappa_s = \frac{\gamma'_s D^2}{F_C}$$

The total pipe penetration is taken as the sum of:

- Initial penetration due to self-weight.
- Penetration due to dynamics during laying.
- Penetration due to pipe movement under the action of waves and current.

The pipe static/initial penetration due to self-weight for pipelines resting on sandy soil will be determined using the following formula taken from DNV-RP-F109 [5]:

$$\frac{z_{pi}}{D} = 0.037\kappa_s^{-0.67}$$

Just as for the axial restraint, the lateral soil resistance will be described through a bi-linear force-displacement relationship as presented in Figure 5-1. The friction forces are increased monotonically to a maximum value calculated as the product of the pipe submerged weight (w_s) and the equivalent friction coefficient (μ_{eqv}), at a mobilisation distance of 1mm.

5.3.3. Vertical soil bearing capacity (Downward resistance)

The static vertical soil reaction per unit length can be determined based on bearing capacity formulas for ideal 2-D strip foundations, as per DNV-RP-F105 [3]:

$$R_V = \gamma_{soil} N_q v_{eff} + 0.5 N_\gamma B$$

Where:

- R_V = Vertical soil reaction [N/m]
- N_q & N_γ = Bearing capacity factors [-]
- v_{eff} = Effective penetration [m] (The larger of $v - D/4$ and 0)
- v = Vertical penetration [m]
- B = Contact width for pipe-soil load transfer [m]

The bearing capacity factors are determined as follows:

$$N_q = e^{\pi \tan \varphi_s} \tan^2\left(45 + \frac{\varphi_s}{2}\right)$$

Where:

φ_s = Angle of internal friction [°]

$$N_\gamma = 1.5\left(N_q - 1\right) \tan \varphi_s$$

The contact width for pipe-soil load transfer, B, is given by:

- $B = 2\sqrt{(D - v)v}$ if $v \leq D/2$
- $B = D$ if $v > D/2$

5.3.4. Buried pipeline – axial soil resistance

Soil resistance forces for buried pipeline sections are based on ASCE's "Guidelines for the Design of Buried Steel Pipe" [9].

The maximum axial soil force that can be transmitted to the pipe per unit length is given by:

$$T_u = \pi D \alpha c + \pi D H \gamma'_s \frac{1 + K_0}{2} \tan \delta$$

Where:

- c = Soil cohesion representative of soil backfill material [N/m^2] (c=0 for sand)
- H = Depth to the pipeline centreline [m]
- K_0 = Coefficient of earth pressure at rest [-] $(1 - \sin \varphi_s)$
- α = Adhesion factor [-]
- δ = Interface angle of friction for pipe and soil [°] $(f \varphi_s)$
- f = Coating dependent factor relating the internal friction angle of the soil to the friction angle at the pipe soil interface.

The axial resistance mobilisation displacement, Δ_t, is determined considering the soil type as follows:

- Δ_t = 3mm for dense sand
- Δ_t = 5mm for loose sand
- Δ_t = 8mm for stiff clay
- Δ_t = 10mm for soft sand

5.3.5. Buried pipeline – lateral soil resistance

The maximum lateral force that the soil can transmit per unit pipe length is given by:

$$P_u = N_{ch}cD + N_{qh}\gamma'_s HD$$

Where:

- N_{ch} = Horizontal bearing capacity for clay (0 for c=0).
- N_{qh} = Horizontal bearing capacity factor for sand (0 for $\varphi_s = 0$)

The bearing capacity factors are taken from the

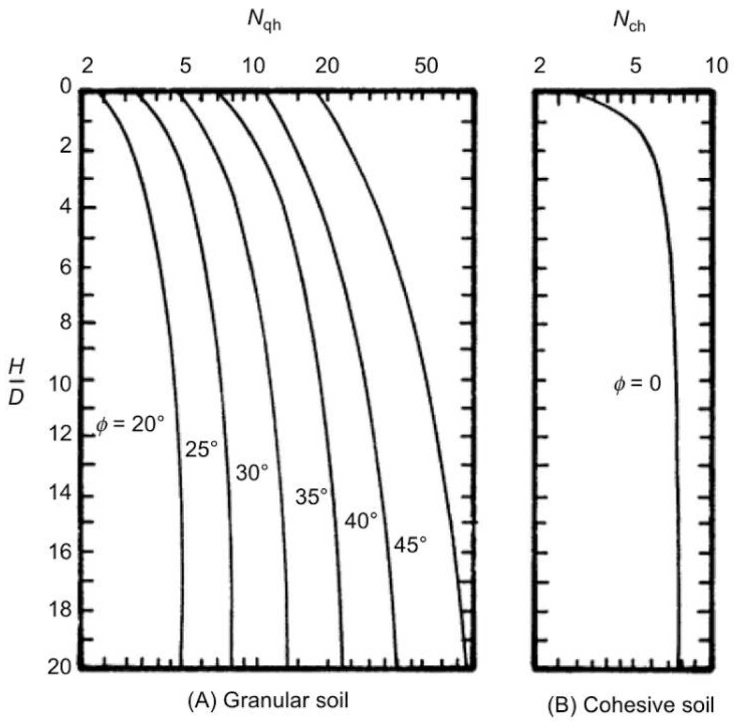

Figure 5-2 Horizontal bearing capacity factors

The lateral soil resistance mobilization displacement;

$$\Delta_p = 0.04\left(H + \frac{D}{2}\right) \leq 0.10D \ to \ 0.15D.$$

5.3.6. Buried pipeline – vertical upward soil resistance

The uplift resistance R_{max} of a pipe in sand consists of two components, viz. a component owing to the weight of the soil above the pipe and a component owing to soil friction as per DNV-RP-F110 [6]. The uplift resistance can therefore be expressed as:

$$R_{max} = \left(1 + f\frac{H}{D}\right)(\gamma'_s HD)$$

The uplift resistance factor, f, is:

- $f = 0.1$ for loose sand (backfill)
- $f = 0.5$ for rockdump

The non-linear force-displacement response of a buried pipe is represented by a tri-linear curve as shown in

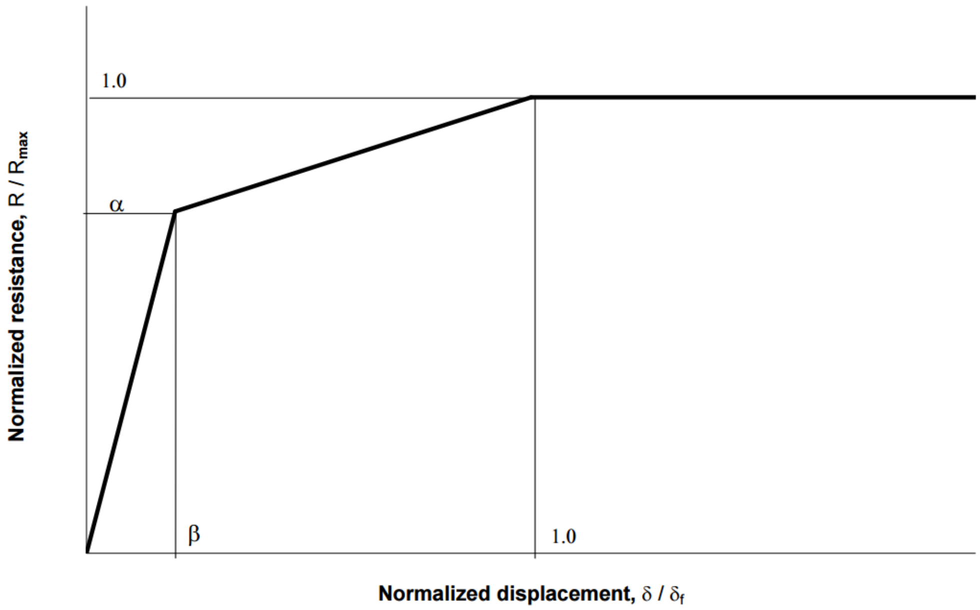

Figure 5-3 Uplift resistance Force-Deflection curve

Where:

- δ_f= Failure displacement (=0.0065H for loose sand backfill) (=20mm for rock dump)
- $\alpha = 0.8$ for loose sand (backfill) and $\alpha = 0.7$ for rock dump
- $\beta = 0.2$

5.4. Fatigue analysis

Fatigue is caused by time varying stresses resulting from applied loads to the riser and parts of the spool piece system which are exposed to hydrodynamic loads. The riser and spool piece section are from approx. LAT +6.000m to seabed level exposed to the environment and hence are subjected to time varying loads. Three sources of time varying loads, and hence fatigue damage to the riser, are identified:

1. Vortex Induced Vibrations (VIV)
2. Direct wave loading
3. Indirect loads resulting from platform deflections

Riser guide clamps will be spaced such that the maximum span length is below the critical span length at which VIV can occur. The methodology for determining the critical span lengths are described in chapter 7 of this re-port.

To assess fatigue damage due to direct and indirect wave loading, platform deflections are applied, and the ex-posed riser section will be subjected to hydrodynamic drag and inertia forces. The drag and inertia forces are determined using the wave induced velocities and accelerations as experienced by the riser section over the lifetime of the pipeline system considering the ”Individual Wave Scatter Diagrams for Fatigue H-T” attached as appendix A.

To estimate the fatigue damage, due to direct and indirect wave loading, a detailed finite element assessment will be carried out considering the same finite element model of the riser spool system as described in Section 5.

In this case the wave scatter diagram will be subdivided into a number of representative blocks, with a single sea-state selected to represent all waves in that block. This reduces the number of required finite element anal-yses. These wave blocks and the 1-year platform deflections as reported in Section 4.6 will be applied to the model and the maximum stress ranges ($\Delta\sigma_{eqv} = 2 \cdot \sigma_{eqv}$) extracted from the riser elements. All other loads (pressure, temperature and current) are neglected as they are time invariant compared to the wave loading. The analyses will account for the directionality of the wave and the number of occurrences of the waves as per the scatter diagrams.

The allowable number of cycles will then be determined (N_p) in relation to the maximum stress range in all riser elements ($\Delta\sigma_{eqv,max}$) for each wave block given by:

$$\log N_p = \log a_n - m_n \log\left(\Delta\sigma_{eqv,max}\left(t/t_{ref}\right)^k\right)$$

Where:

- N_p = Predicted number of cycles of failure for stress range [-]
- $\Delta\sigma_{eqv,max}$ = maximum stress range [N/m^2]
- $\log a_n$ = Constant valid in the range n (see Table 5-4)
- m_n = Constant valid in the range n (see Table 5-4)
- t = Wall thickness [m]
- t_{ref} = Reference wall thickness (32mm)
- k = Thickness component (see Table 5-4)

S-N curve designation	N<=10^6 cycles		N>10^6 cycles		Fatigue limit at 10^7 cycles	Thickness component (k)
	m_1	$\log(a_1)$	m_2	$\log(a_2)$		
F_1	3.0	11.299	5.0	14.832	36.84	0.25

Table 5-4 Fatigue curve parameters (ref. [7])

The total fatigue damage due to direct wave loading and platform deflections is then determined, through summation using the Palmgren-Miner rule at each element in the riser as follows:

$$FD = \sum_{1}^{k} \left(\frac{n_i}{N_i}\right)$$

Where:

- k = Number of stress/wave blocks
- n_i = Number of stress cycles/wave occurrences in stress block i
- N_i = Number of cycles to failure at constant stress range in stress block i

The acceptability of the fatigue damage is then determined by comparison with the allowable fatigue damage (α_{fat}) ratio as given in Ref. [2]:

$$\alpha_{fat} \geq FD$$

Where:

α_{fat} = Allowable damage ratio = 0.1 [2]

6. Wall Thickness Analysis

Several phenomena are to be investigated prior to finalising the selected wall thickness. Elements to be taken into account:

- pressure containment;
- on-bottom stability;
- implosion;
- progressive plastic collapse;
- local buckling;
- bar buckling;

6.1. Pressure containment

6.1.1. Design condition

NEN 3656, states that for every load combination the design resistance (R_d) must be greater than or equal to the loading effect (S_d) or:

$$R_d \geq S_d$$

R_d is defined as:

$$R_d = R_{e(\Theta)} / \gamma_m$$

Where:

$R_{e(\Theta)}$	=	yield strength of the material at design temperature (N/mm^2)
γ_m	=	material factor (1.1 for steel)

For load combination LC2 (internal pressure only), the equation for hoop stress can be expressed as:

$$\sigma_h = \frac{\gamma_p \cdot P_d \cdot (OD - t_{\min})}{2 \cdot t_{\min}}$$

Where:

S_h	=	hoop stress (N/mm^2)
γ_p	=	load factor as per Table 5-3 (-) => 1.25
Pd	=	design pressure (N/mm^2)
OD	=	outside diameter of steel pipe (mm)
t_{min}	=	minimum wall thickness (mm)

The selected wall thickness (t_{nom}) is then determined by:

$$t_{nom} = \left\{ \frac{t_{\min} + CA}{1 - f_{tol}} \right\}$$

Where:

CA = applicable corrosion Allowance (mm)

f_{tol} = fabrication tolerance (%)

Further to this, NEN 3656 specifies additional requirements for bends with a bending radius R_b < 10 OD, to adjust the hoop stress of straight pipe (torus effect).

$$S_h(bi) = \frac{2R_b - \frac{1}{2}OD}{2R_b - OD} \cdot S_h$$ (for inside bend)

$$S_h(bo) = \frac{2R_b + \frac{1}{2}OD}{2R_b + OD} \cdot S_h$$ (for outside bend)

6.1.2. Hydrostatic Testing

The hydrostatic testing of pipeline / riser systems has two objectives:

- verify the strength of the system
- verify that there are no leaks from the system

The test pressure, P_t, will be determined as per as per Section 10.18.3 of NEN 3656 (Ref. [1]).

$$P_{t.\min} = C_p \cdot P_d \cdot \frac{R_e}{R_{ev}}$$

Where:

C_p	=	pressure test coefficient (-) => 1.30 for gas lines; 1.25 for others
P_d	=	design operating pressure (N/mm^2)
R_e	=	minimum yield stress at 20 °C (N/mm^2)
R_{ev}	=	minimum yield stress at design temperature (N/mm^2)

The maximum hydrostatic test pressure is based on the weakest part of the pipeline/riser system to be tested. The pressure shall not exceed, $P_{t,max}$, which is defined by:

$$P_{t.\max} = \frac{2.R_e \cdot t_{\min}}{(OD - t_{\min})}$$

However, the maximum hydrotest pressure should not exceed the mill test pressure, which is given by:

$$P_{T,mill} = 0.9 \cdot \frac{2 \cdot R_e \cdot t_{nom}}{OD} \quad \text{and}$$

$$t_{nom} = \left\{ \frac{t_{\min} + CA}{1 - f_{tol}} \right\}$$

Where:

t_{nom}	=	nominal wall thickness (mm)
t_{min}	=	minimum wall thickness (mm)
CA	=	applicable corrosion Allowance (mm)
f_{tol}	=	fabrication tolerance (%)

6.2. On-bottom Stability

6.2.1. Introduction

The aim of stability analysis is to verify that the submerged weight of the pipeline ensures lateral stability against environmental loading. On-bottom stability analysis is carried out for the following condition only:

- Installation – Flooded

The pipeline is to be laterally stable on the seabed for 1 year return period environmental conditions. During hydrostatic testing and operation, the pipeline will be buried and therefore not subject any to environmental loading.

6.2.2. Hydrodynamic loads

Hydrodynamic loads arise from the relative motions between pipe and seawater. They consist of drag, lift and inertia forces.

The drag force F_D is given by:

$$F_D = C_D \cdot OD_{tot} \cdot \frac{1}{2} \cdot \rho \cdot V \cdot |V|$$

Where:

C_D	=	drag force coefficient (-)
OD_{tot}	=	total diameter of coated pipe (m)
ρ	=	mass density of surrounding fluid (kg/m^3)
V	=	velocity of the fluid normal to the pipe axis (m/s)

The lift force F_L is calculated by the following equation:

$$F_L = C_L \cdot OD_{tot} \cdot \frac{1}{2} \cdot \rho \cdot V^2$$

Where:

C_L	=	lift force coefficient (-)

The inertia force F_I is determined by the following equation:

$$F_I = \rho \cdot C_I \cdot \frac{\pi}{4} \cdot OD_{tot}^{\ 2} \cdot a$$

Where:

C_I	=	inertia force coefficient (-)
a	=	Fluid particle acceleration (m/s^2)

The recommended values of hydrodynamic coefficients for the on-bottom stability design as a function of the embedment of the pipeline are listed in Table 6-1.

Coefficient	Pipe embedment		
	0%	**10%**	**20%**
Drag	0.70	0.63	0.53
Lift	0.90	0.90	0.81
Inertia	3.29	2.80	2.30

Table 6-1 Overview hydrodynamic coefficients

The wave induced water particle velocities and accelerations will be determined using the appropriate wave theory for the design wave height, period and water depth. Phase shifts between horizontal and vertical water particle velocities will be considered.

6.2.3. Stability check

The stability of the pipelines is checked using the following relationship:

$$W_s > f_s \cdot \left(\frac{F_D + F_I}{f_w} + F_L \right) - \frac{F_P}{f_w}$$

Where:

W_s	=	pipeline submerged weight (N/m)
f_s	=	safety factor (-) => 1.1
F_D	=	drag force (N/m)
F_L	=	lift force (N/m)
f_w	=	friction factor (-)
F_I	=	inertia force (N/m)
F_P	=	passive soil resistance (N/m)

A safety factor (f_s) of 1.1 will be implemented. The above equation assumes absolute stability criteria. Note that the actual F_p is limited to the maximum of the combined drag and inertia forces.

The passive soil resistance is derived from:

$$F_p = 0.5 \cdot \rho_{soil} \cdot \varepsilon^2 \cdot K_p$$

Where:

ρ_{soil}	=	submerged soil density (kg/m^3)
ε	=	embedment of pipeline (m)
K_P	=	coefficient of passive soil resistance (-)

and K_P is calculated from :

$$K_P = \frac{1+\sin(\phi)}{1-\sin(\phi)} = \tan^2 \cdot \left(45 + \frac{\phi}{2} \right)$$

Where:

ϕ	=	angle of internal friction (°)

6.3. Implosion

6.3.1. External overpressure

The collapse pressure p_c causing implosion (radial instability) can be determined using:

$$(P_c - P_e) \cdot (P_c{}^2 - P_p{}^2) = P_c \cdot P_e \cdot P_p \cdot 2 \cdot \delta_0 \cdot \frac{D_g}{t}$$

Where:

D_g	=	nominal diameter of pipe (mm)
P_c	=	critical external pressure for collapse (N/mm2)
P_e	=	critical external pressure for elastic deformation (N/mm^2)
P_p	=	critical external pressure for plastic deformation (N/mm^2)
P_L	=	allowable external pressure (N/mm^2)
δ_0	=	initial deformation (mm)
t	=	nominal wall thickness (mm)

$$D_g = \frac{1}{2} \cdot \{OD_{nom} - (OD_{nom} - 2 \cdot t_{min})\}$$

The critical external pressure for plastic deformation is calculated from:

$$P_p = \frac{2 \cdot R_e \cdot t}{D_{nom}}$$

The critical external pressure for elastic deformation is calculated from:

$$P_e = \frac{2 \cdot E}{1 - \nu^2} \cdot (\frac{t}{D_{nom}})^3$$

Where:

ν	=	Poisson's ratio for elastic deformation (-) => 0.3

As a part of this the initial deformation is derived from:

$$\delta_0 = \frac{D_{\max} - D_{\min}}{D_{\max} + D_{\min}}$$

Where:

D_{max}	=	largest diameter of the ovalized pipe cross section
D_{min}	=	smallest diameter of the ovalized pipe cross section

The maximum allowable external pressure is defined as:

$$\gamma_{g,p} \cdot P_L \leq \frac{\gamma_M \cdot P_c}{\gamma_{m,p}}$$

Where:

$\gamma_{g,p}$	=	load factor (-) => 1.05
γ_M	=	model factor (-) => 0.93
$\gamma_{m,p}$	=	material factor (-) => 1.45

6.3.2. Bending moment

In case of a bending moment on the pipe, the moment which will cause buckling is calculated from the plastic moment of the pipe section.

$$M_c = D_{nom}{}^2 \cdot t \cdot R_e$$

The maximum allowable bending moment is defined as:

$$\gamma_{g,M} \cdot M_L \leq \frac{\gamma_M \cdot M_c}{\gamma_{m,M}}$$

Where:

$\gamma_{g,M}$	=	load factor (-) => 1.1
γ_M	=	model factor (-) => 1.0
$\gamma_{m,M}$	=	material factor (-) => 1.3
M_L	=	allowable bending moment for buckling (Nm)
M_c	=	critical bending moment for buckling (Nm)

6.3.3. Combined external pressure and bending moment

When external pressure exists in combination with a bending moment besides the checks above the condition for combined stresses as shown below shall be fulfilled.

$$\frac{\gamma_{g,p} \cdot P_L}{P_c / \gamma_{m,p}} + \left(\frac{\gamma_{g,m} \cdot M_L}{M_c / \gamma_{m,M}} \right)^n \leq \gamma_M$$

Where:

$$n = 1 + 300 \cdot \frac{t}{D_{nom}}$$

Where:

$\gamma_{g,p}$	=	load factor for pressure (-) => 1.05
$\gamma_{g,m}$	=	load factor for bending (-) => 1.55
γ_M	=	model factor (-) => 0.93
$\gamma_{m,p}$	=	material factor for pressure (-) => 1.25
$\gamma_{m,M}$	=	material factor for bending (-) =>1.15
M_L	=	allowable bending moment for buckling (Nm)
M_c	=	critical bending moment for buckling (Nm)

6.4. Progressive plastic collapse

Progressive plastic deformation load cycle will lead to extreme deformation, collapse and cracks initiation through the wall.

The condition for avoiding buckle propagation is:

$$\varepsilon_{\max} = \alpha \cdot \Delta T \leq \left[\frac{R_{ev}}{E} \cdot \sqrt{1 - \frac{3}{4}\left(\frac{\sigma_h}{R_{ev}} \right)^2} + \frac{R_e}{E} \sqrt{0.9 - \frac{3}{4}\left(\frac{\sigma_h}{R_e} \right)^2} \right]$$

Where:

α	=	coefficient of linear thermal expansion (m/ m/ ° C)
ΔT	=	temperature differential [° C] (design – installation)

Parameters have to be factored as defined in section 6.

6.5. Local buckling

In accordance with NEN 3656, if OD / t < 55, an assessment on local buckling can generally be omitted. For this project the OD / t ratio is 273.1 / 12.7 = 21.5, which is well below 55; hence local buckling will not be investigated further.

6.6. Bar buckling

In a free span the pipeline will be susceptible to bar buckling. Bar buckling may occur due to an effective axial compressive force (N) in the pipeline. The compressive force in an axially restrained pipeline is based on the longitudinal stress:

$$N = A \cdot (\nu \cdot S_h - \gamma_t \cdot E \cdot \alpha \cdot \Delta T)$$

Where:

A	=	cross sectional area of steel (mm^2)
ν	=	Poisson's ratio for elastic deformation (-) => 0.3
S_h	=	factored hoop stress (N/mm^2)
γ_t	=	load factor as given in Table 5-3 (-)
α	=	coefficient of thermal expansion (m/m/°C)
ΔT	=	pipeline temperature differential (° C) (design – installation)

The factored hoop stress (S_h) is calculated from:

$$S_h = \gamma_P \cdot \sigma_h$$

and

$$\sigma_h = \frac{P_d \cdot (OD - t_{\min})}{2 \cdot t_{\min}}$$

Where:

P_d	=	design pressure (N/mm^2)
t_{min}	=	minimum pipe wall thickness (mm)
OD	=	outside diameter of steel pipe (mm)
γ_P	=	load factor as given in Table 5-3 (-)

The buckling length is based on the Euler buckling load definition, defined in Ref. [3]. Bar buckling is avoided if the span length fulfils:

$$L \le \sqrt{4 \cdot \pi^2 \frac{E \cdot I}{|N|}}$$

Where:

L	=	allowable span length (mm)
I	=	moment of inertia (mm^4)

7. Free Span analysis

Spanning of a pipeline on the seabed causes forces and stresses in the pipe. The criterion for accepting a pipeline configuration is that the pipe should not be subjected to over-stressing, nor to excessive dynamic loading because of resonant oscillations of the pipe caused by the vortex shedding phenomenon during installation, testing and throughout its operating life.

The pipeline span assessment includes the following items:

- Static span analysis
- Dynamic span analysis.

The static analysis concerns the determination of the pipe stresses under functional- and static environmental loads for a given span length.

The dynamic span analysis is based on criteria for prevention of vortex induced vibrations (VIV) as outlined in NEN 3656 considering both current- and wave induced velocities.

In addition, operational limits of the trenching equipment, limits the span gap (distance between the pipe and the seabed).

Although the pipeline will be buried below the seabed prior to its operation, the pipeline must be checked for spanning for the period between installation and burial.

In the analysis, along with the seabed topography, both functional and environmental loads are taken into consideration to check pipeline structural integrity under the considered load cases.

7.1. Static span

Combining hoop, longitudinal and bending stresses in the pipeline, which shall satisfy criteria for equivalent stresses, gives the maximum allowable static span lengths. Checks are to be made for the installation, hydro test and operational load case.

The maximum bending moment is calculated from the (vector) combination of the pipelines' own weight and hydrodynamic forces for the maximum wave condition:

$$q = \sqrt{\gamma_W{}^2 \cdot W_S{}^2 + \gamma_H{}^2 \cdot (F_D + F_I)^2}$$

Where:

γ_W	=	load factor as per Table 5-3 (-)
γ_H	=	load factor as per Table 5-3 (-)

End fixity of an actual span is commonly assumed between fixed - fixed and fixed – pinned and the bending moment (M) calculated from:

$$M = \frac{q \cdot L^2}{10}$$

Where:

L	=	Maximum allowable span length [m]

The maximum allowable bending moment (M_{all}) is given by:

$$M_{all} = \frac{2 \cdot I \cdot \sigma_b}{OD}$$

Where:

I	=	moment of inertia (m^4)
OD	=	pipeline outside diameter (m)
s_b	=	maximum allowable bending stress

The maximum allowable static span can then be determined by:

$$L\max = \sqrt{\frac{20 \cdot \sigma_b \cdot I}{OD \cdot q}}$$

The maximum allowable span length follows from the condition that the equivalent stress (S_e) from the load combination satisfies the following conditions:

For the operational and hydrotest cases:

$$S_e \leq 0.85 \times (R_e + R_{ev}) / \gamma_m$$

For the installation case:

$$S_e \leq R_e / \gamma_m$$

Where:

R_e	=	minimum yield stress at 20 °C (N/mm^2)
R_{ev}	=	minimum yield stress at design temperature (N/mm^2)
γ_m	=	material factor (-) => 1.1

7.1.1. Load cases

The maximum static span will be determined for the load cases, and considering the environmental load return periods, as detailed in Table 7-1:

Condition	Wave Height Return Period	Current velocity Return Period
Installation	$H_{max,1yr}$	1 yr
Hydrotest	$H_{max,1yr}$	1 yr
Operational,1	$H_{max,100yr}$	10 yr
Operational,2	$H_{max,10yr}$	100 yr

Table 7-1 Load Cases for Span Assessment

7.2. Dynamic span

Flow of water particles induced by currents and waves perpendicular to a spanning pipeline or riser span can lead to vortices being shed. This will disrupt the flow around the pipe and thereby potentially cause periodic loads on the pipeline or riser, also known as Vortex Induced Vibration (VIV).

The natural frequency of a span being close to the vortex shedding frequency can result in a resonant oscillation, possibly resulting in fatigue failure of the pipeline or riser.

The oscillations of the span may occur in two directions:

- in line with the flow (parallel to the flow direction of the water particles)
- in cross flow direction (perpendicular to the flow direction of the water particles)

When assessing VIV, the span should be confirmed to be within acceptable limits set by either avoidance of VIV or an acceptable fatigue life for both the installation and operational condition.

Relevant dimensionless parameters governing the VIV phenomenon are the reduced velocity (V_r) and stability parameter (K_s).

The reduced velocity (V_r) parameter is defined by:

$$V_r = \frac{V_s}{f_{n \cdot OD_{tot}}}$$

Where,

V_s	=	water particle velocity due to current and significant wave (m/s)
f_n	=	1^{st} natural frequency of the pipe span (1/s)
OD_{tot}		total outside diameter of the pipe (m)

The 1st natural frequency can be calculated from:

$$f_n = \frac{a}{2\pi} \cdot \sqrt{\frac{E \cdot I}{m_e \cdot L^4}}$$

Where,

a	=	frequency factor (-) => 15.4 for a fixed-pinned beam, which is used for the pipe
E	=	Young's modulus (N/m^2)
I	=	moment of inertia (m^4)
L	=	length of span in pipeline / riser (m)

The stability parameter (K_s) is defined by:

$$K_s = \frac{2 \cdot m_e \cdot \delta}{\rho_{sw} \cdot OD_{tot}^2}$$

Where,

m_e	=	effective mass of pipe (kg/m)
ρ_{sw}	=	density seawater (kg/m^3)
δ	=	logarithmic decrement of damping (-) => δ = 0.126 for steel

The effective mass of the pipe can be calculated as:

$$m_e = m + \pi/4 \cdot C_M \cdot \rho_{sw} \cdot OD_{tot}{}^2$$

Where,

m	=	Pipeline / riser mass (kg/m)
Cm	=	added mass coefficient (-)

NEN 3656 states that In-line oscillations will occur if $K_s \le 1.8$ and cross flow oscillations will occur if $K_s \le 16$.

7.2.1. In-line VIV

NEN 3656 furthermore states that in-line oscillations of the span occur if the reduced velocity is within the range of: $1.0 \le Vr \le 3.5$

Vortices around a spanning pipe occur in a relatively steady state environment. The wave induced velocity varies from a maximum at t=0, to zero at t=1/4*Twave. Furthermore, the system does not respond instantaneously to the applied forcing. To ignore the wave induced velocity in assessing the allowable dynamic span length would be too optimistic, to account for the maximum induced value would be too conservative, therefore reference is made to DNV-RP-F105. “Free Spanning Pipelines.” (ref. [3]).

According to Ref. [3], fatigue damage due to in-line VIV can be neglected if the current flow velocity ratio α, as defined by the equation below is smaller than 0.8.

$$\alpha = \frac{v_{cur}}{v_{cur} + v_{wave}}$$

Where,

v_{cur}	=	Particle velocity due to current [m/s]
v_{wave}	=	Particle velocity due to waves [m/s]

7.2.2. Cross-flow VIV

The occurrence of cross flow oscillations depends on the magnitude of the Reynolds number, Re, and the reduced velocity as given in Figure 7-1.

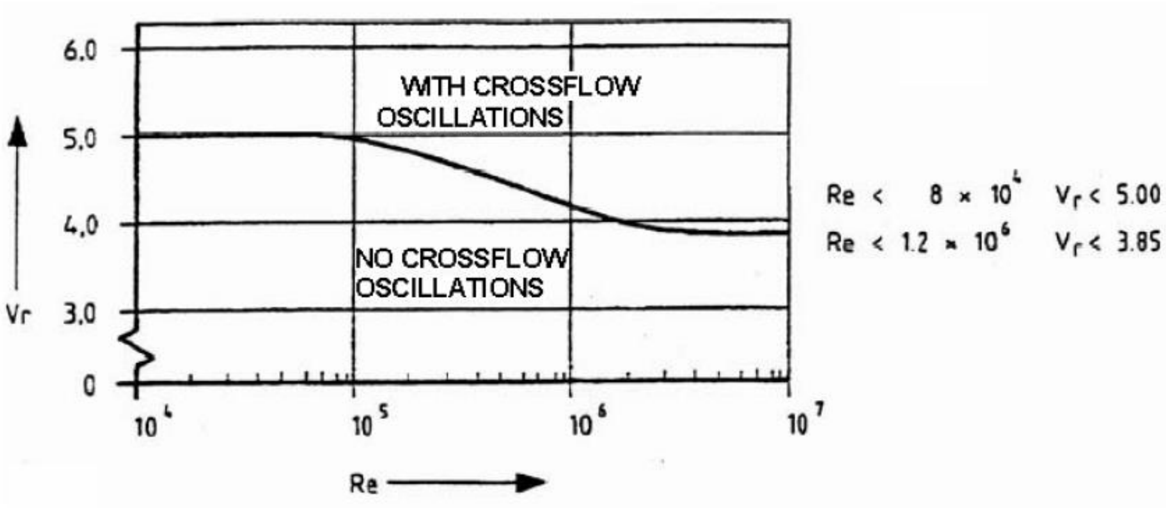

Figure 7-1 Reduced velocity for cross flow oscillations

$$\mathrm{Re} = \frac{\mathrm{v} \cdot OD_{tot}}{\nu}$$

Where,

v	=	particle velocity (m/s)
OD_{tot}	=	pipeline outside diameter (m)
n	=	Kinematic viscosity water (m^2/s) => 1,307 x 10^{-6} (@10 °C)

8. Bottom roughness

8.1. General

To ensure the structural integrity of the pipeline bundle over its entire design life finite element analyses will be carried out using industry proven software like Ansys or RFEM.

The analysis will assess the interaction between the pipeline and the supporting soil along the entire pipeline route and will be carried out in accordance with the requirements of NEN 3656 (Ref. [1]). The analysis will determine the number of spans exceeding the allowable span length and the subsequent pre-sweeping requirements. The design loads at the tie-in locations will be determined and in addition the analysis will assess the upheaval buckling response of the pipeline system under operating conditions.

The analysis will account for the load history of the pipelines over the design life by considering the following load cases:

- Installation (empty);
- Installation (flooded);
- Pipeline operation - nominal (nominal wall thickness content filling maximum operating pressure and temperature);
- Pipeline operation - corroded (corroded wall thickness content filling maximum operating pressure and temperature).

The pipeline will be modelled by uniaxial elements with tension-compression torsion and bending capabilities and can account for internal pressure effects. The element is a 3D element with six degrees of freedom translations in the x y and z directions and rotations about the x y and z axes. In addition the element needs to account for buoyancy wave and current loads and to be capable of large deflections and rotations.

The pipeline is to be modelled with a maximum element length of 0.5 – 1.0 m and accounts for all curvatures in the horizontal plane and undulations in the vertical plane. Pipe-soil interaction is simulated using three independent non-linear spring elements attached to each pipe element. The springs represent the soil frictional resistance in the axial and lateral directions and the soils bearing capacity in the vertical direction.

For sections of the pipeline which are buried additional vertical non-linear springs representing the uplift resistance of the trench backfill material will be attached to the pipe elements.

Seabed roughness will be simulated by displacing the vertical springs representing the soil bearing capacity to the correct depth based on the bathymetric data and allowing the pipe to move and rest on the vertical springs.

When the depth of the pipeline at a certain point is less than the depth of the seabed a "free span" is identified. Similar succeeding joints indicate a larger span. The length of the free span is determined by subtracting the coordinates of the beginning of the span from the coordinates of the span end.

At pipeline termination points an additional axial spring will be attached to the pipeline ends to incorporate the structural response of the subsea tie-in spool/riser and supporting piping.

8.2. Pipe-soil interaction

The characteristics of the springs which simulate the pipe-soil interaction are defined through non-linear force deflection curves. These force-deflection curves describe the frictional restraint provided by the soil to the pipeline in the axial lateral direction and the soils bearing capacity /upwards resistance in the vertical direction.

2 situations can be distinguished:

- exposed pipeline
  - axial soil resistance;
  - lateral soil resistance;
  - vertical bearing capacity (downward resistance);

- buried pipeline
  - axial soil resistance;
  - lateral soil resistance;
  - vertical bearing capacity (downward resistance);
  - vertical upward soil resistance;

Table 8-1 gives an overview of the calculation basis of the mentioned soil resistances/capacities.

Direction	Exposed pipeline	Buried pipeline
Axial	Function of pipe submerged weight and axial Coulomb friction coefficient	Function of pipe diameter, burial depth and effective unit soil weight.
Lateral	Combination of Coulomb friction part and passive soil resistance due to build-up of soil penetration (ref. [5])	Based on horizontal bearing capacity factor (ref. [9]
Vertical bearing	Based on bearing capacity formulas for ideal 2-D strip foundations ref. [3]	Based on bearing capacity formulas for ideal 2-D strip foundations ref. [3]
Vertical upward	N/A	As per ref. [6] based on burial depth pipe diameter and submerged soil weight

Table 8-1 Overview soil resistance/capacity calculation basis

9. Upheaval Buckling

Buried pipelines exposed to compressive effective axial forces may get unstable beyond its anchor point and move vertically out of the seabed if the cover has insufficient resistance. An out-of-straightness configuration will result in forces acting on the cover perpendicular to the pipeline. In case these vertical forces exceed the cover resistance the pipeline will buckle upwards.

The relation between minimum required cover height and the imperfection height (out-of-straightness) will be established in accordance with ref. [11].

Parameters used in the assessment of upheaval buckling are the dimensionless imperfection length parameter (Φ_L):

$$\Phi_L = L \cdot \sqrt{\frac{N_e}{EI}}$$

Where:

L	=	exposure length (m)
N_e	=	effective axial compressive force (N)
EI	=	bending stiffness (N m^2)

And the dimensionless maximum download parameter (Φ_w):

$$\Phi_w = \frac{w \cdot E \cdot I}{\Delta_{calc} \cdot N_e^{\,2}}$$

Where:

w	=	required download [N/m]
Δ_{calc}	=	imperfection height [m]

Depending on the Φ_L value the required download is derived from Φ_w in accordance with:

$$\Phi_w = 0.0646 \quad \text{for} \quad \Phi_L < 4.49$$

$$\Phi_w = \frac{5.68}{\phi_L^{\,2}} - \frac{88.35}{\phi_L^{\,4}} \quad \text{for} \quad 4.49 < \Phi_L < 8.06$$

$$\Phi_w = \frac{9.6}{\phi_L^{\,2}} - \frac{343}{\phi_L^{\,4}} \quad \text{for} \quad \Phi_L > 8.06$$

In cohesionless soils the uplift resistance (q) due to the cover of the pipe can be calculated from:

$$q = \gamma \cdot H \cdot OD \cdot \left(1 + f \cdot \frac{H}{OD}\right)$$

Where:

γ	=	effective under water weight of soil (N/m^3)
H	=	depth of cover (m)
OD	=	outside diameter of pipe (m)
f	=	uplift coefficient 0.5 for dense material 0.1 for loose material

The calculated required download (w) shall be smaller than the actual combination of the submerged weight and uplift resistance of the pipeline.

The simplified method from Reference [11] is conservative in that it does not model a number of mitigating factors such as:

- The finite axial stiffness of the pipeline which determines how rapidly the axial force diminishes as the pipeline moves upwards
- The pipeline resistance to axial movement through the soil determines how far the pipeline can slide towards a developing buckle.

Both the above factors may cause progressive upheaval buckling predicted by the analysis method in Reference [11] not to occur.

Further the sinusoidal imperfection profile assumed in the model is envisaged to yield conservative download requirements.

The results will be presented as a maximum imperfection length with respect to the cover depth and the imperfection height.

10. Cathodic Protection

As per NEN 3656 the cathodic protection system of the pipeline bundle will be designed as per ref. [12]. The characteristics of a typical anode element are given in Table 10-1.

Item	Value
Type	Half Shell Bracelet
Material	Aluminium
Cable connections	2 x @ 10" pipeline

Table 10-1 Typical anode characteristics

The cathodic protection will be designed to prevent external corrosion of the pipeline. The mass and spacing of the anodes will be such that the following criteria are met:

- Total anode mass to meet the mean and final current demand over the design life of the pipeline.
- Anode current output to meet the required current output at the end of the design life.
- Anode separation not to exceed a value of 300 m.

The pipeline will be divided in to sections where changes in conditions, such as water depth, operating temperature or burial, can give rise to variations in design current density.

From the pipeline dimensions and the coating selected, the mean current demand, I_{cm}, and the final demand, I_{cf}, shall be calculated separately as per the following:

$$I_c = A_c \cdot f_c \cdot i_c$$

Where:

I_c = the current demand for a specific pipeline section calculated for mean and final conditions (A)

A_c = the total surface area for a specific pipeline section (m^2)

f_c = the coating breakdown factor determined for mean and final conditions (-)

i_c = the current density, selected for mean and final conditions (A/m^2)

For pipelines fully buried, a design current density (mean and final) of 20 mA/m^2 should be used irrespective of seawater temperature, oxygen content or depth as per Section 7.4.3 of Ref. [12].

The coating breakdown factors for mean and final conditions, f_c, taking into consideration the deign life of the pipeline, are calculated as follows.

The mean coating breakdown factor, $\overline{f_c}$, is determined by:

$$\overline{f_c} = f_i + (0.5\Delta f \cdot t_{dl})$$

And the mean coating breakdown factor, f_f , is determined by

$$f_f = f_i + (\Delta f \cdot t_{dl})$$

Where:

f_i = the initial coating breakdown factor at the start of pipeline operation (-)

Δf = the average yearly increase in the coating breakdown factor (-)

t_{dl} = the design life (yrs)

The initial coating breakdown factor and average yearly increase in breakdown factor are dependent on the anti-corrosion coating and field joint coating material. Values for various coating are taken from [12] and reported in Table 10-2.

Factory-applied coating type	Field joint coating type	f_i	Δf
Fusion-bonded epoxy (FBE)	Heat-shrinkable sleeves (HSS[a])	0,080	0,003 5
	FBE	0,060	0,003 0
Three-layer coating systems including epoxy, adhesive and polyethylene (3LPE)	HSS[a]	0,009	0,000 6
	FBE	0,008	0,005
	Multilayer coating including epoxy and PE (e.g. moulded, HSS[a] or flame spray)	0,007	0,000 5
Three-layer coating systems including epoxy, adhesive and polypropylene (3LPP)	HSS[a]	0,007	0,000 3
	FBE	0,006	0,000 2
	Multilayer coating including epoxy and PP (e.g. HSS[a], hot tapes, moulding or flame spray)	0,005	0,000 2
Heat insulation multilayer coating systems including epoxy, adhesive and/or PE, PP or PU	Thick multilayer coating systems including epoxy, adhesive and/or PE, PP, PU, HSS[a] or a combination of these products.	0,002	0,000 1
Thick coatings: elastomeric materials (e.g. polychloroprene or EPDM) or glassfibre-reinforced resins	Thick elastomeric materials or glassfibre-reinforced resins	0,002	0,000 1
Flexible pipelines	Not applicable (mechanical couplings)	0,002	0,000 1

[a] HSS can be used with or without primer.

Table 10-2 Coating breakdown factors [12]

Having established the mean current demand the total required mass of anode material for a specific pipeline section is determined as follows:

$$m = I_{cm} \cdot t_{dl} \cdot \frac{8760}{\mu \cdot \varepsilon}$$

Where:

m = the total net anode mass, for the specific pipeline section (kg)

I_{cm} = the mean current demand for the specific pipeline section (A)

μ = is the utilization factor (-) = 0.8 for bracelet anodes as per Section 8.4 of Ref. [12].

ε = the electrochemical capacity of the anode material per kilogram (A/h)

The electrochemical capacity of the anode material is dependent on the surface temperature of the anode and its burial status. The applicable values are taken from Section 8.3 of Ref. [12] and reported in Table 10-3.

Having determined the total net anode mass required to meet the current demand, the minimum number of anodes required in a specific pipeline section, will be determined as follows:

$$n = \frac{m}{m_a}$$

Where:

n = the number of anodes to be installed on the specific pipeline section (-)

m_a = the individual net anode mass (kg)

The minimum number of anodes, n, shall be determined considering the maximum allowable anode spacing of 300m as reported in Section 8.1 of Ref. [12].

Anode type	Anode surface temperature[a]	Immersed in seawater		Buried in seawater sediments[d]	
		Potential	Electrochemical capacity	Potential	Electrochemical capacity
		Ag/AgCl/ seawater	ε	Ag/AgCl/ seawater	ε
	°C	mV	A·h/kg	mV	A·h/kg
Aluminium	< 30	− 1 050	2 000	− 1 000	1 500
	60	− 1 050	1 500	− 1 000	800
	80[b]	− 1 000	900	− 1 000	400
Zinc	< 30	− 1 030	780	− 980	750
	> 30 to 50[c]			− 980	580

Electrochemical capacity for a given alloy is a function of temperature and anode current density. Reference is made to Annex A for guidance on CP design for variations in anode current densities.

For non-buried pipelines, the anode surface temperature should be taken as the external pipeline temperature and not the internal fluid temperature. For buried pipelines, the anode surface temperature shall be taken as the internal fluid temperature.

[a] For anode surface temperatures between the limits stated, the electrochemical capacity shall be interpolated.

[b] For aluminium anodes, the anode surface temperature shall not exceed 80 °C unless the performance has been demonstrated in tests and has been documented.

[c] For zinc anodes, the anode surface temperature shall not exceed 50 °C unless satisfactory performance has been demonstrated in tests and has been documented.

[d] Pipelines which are rock-dumped shall be considered as buried in seawater sediments.

Table 10-3 Design values for galvanic anodes [12]

To provide the required current, the actual anode current output shall be greater than or equal to the required current output:

$$I_{af} \geq I_f$$

Where:

I_{af} = the actual end-of-life individual current output (A)

I_f = the required end-of-life individual anode current output (A)

The required end-of-life individual anode current output, I_f, shall be calculated from the following:

$$I_f = \frac{I_{cf}}{n}$$

Where:

I_{cf} = the total current demand for the protection of the specific pipeline section at the end of life (A)

For a given anode size and mass, the actual individual anode current output at the end of life, I_{af}, is calculated from the below equation:

$$I_{af} = \frac{E_c - E_a}{R_a}$$

Where:

E_c = the design protection potential (V)

E_a = the design closed-circuit potential of the anode (V)

R_a = the total circuit resistance, which is assumed to be equivalent to the anode resistance (ohms)

The anode resistance, R_a, shall be calculated as follows:

$$R_a = 0.315 \frac{\rho}{\sqrt{A}}$$

Where:

ρ = the environmental resistivity (ohm.m)

A = the exposed surface area of the anode (m^2)

For determining the end-of-design-life anode-to-seawater resistance, the anodes shall be assumed to be consumed to an extent given by their utilization factor. The approximate anode dimensions (exposed surface area) corresponding to this degree of wastage shall be used in the anode resistance formula for R_a.

APPENDIX A (Omni-)Directional H-T Wave Scatter Diagrams

(10 pages)