Ekofisk 2/4 VB SSWI

EPCI Contract No.: 089794

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P2052 Pipeline Design Basis

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1. INTRODUCTION

1.1 EKOFISK SOUTH PROJECT

The Ekofisk South Project consists of 2 individual projects in the vicinity of the Ekofisk Complex. The water depth in the area is between 70-74 meters. Ekofisk is located on block 2/4 and has Production license PL018.

The Ekofisk South Project has been identified as an opportunity for increased oil recovery at the field through additional infield drilling and expanded water flood in the southern area of the Ekofisk reservoir. To accommodate this, the Ekofisk South Project consists of:

- A new subsea water injection template 2/4 VB, accommodating up to 8 water Injection wells.
- The water supply to 2/4 VB will be through a new water injection pipeline P2052 connected to the existing 24" P2045 water injection pipeline between 2/7 E and 2/4 K.
- The 2/4 VB Water Injection wells will be controlled through an umbilical U3052 connected to the 2/4 VA Water Injection Template. 2/4 VA is controlled through umbilical U3049 connected to the 2/4 M platform, where the power and control equipment is installed.

The subsea wells will be located approximately 2.5km SE of 2/4 VA in the Ekofisk Field. The facility comprises two piled Hinged Over Subsea Templates (HOST) which will accommodate two water injection manifolds, wellheads and eight horizontal Xmas trees including subsea control modules. Both water injection manifolds will be interconnected and supply four trees each. The subsea facilities will be protected with a free standing protection structure (HPS). Control of the water injection wells will be via umbilical U3052 connected to the 21 4VA manifold which in turn is controlled through umbilical U3049 from 2/4M platform.
Injection water shall be supplied from a tie-in point on the existing 24" WI pipeline from 2/7 E to 2/4 K. The tie-in to the existing 24" WI pipeline will be through the installation of an inline tee in the 24" WI pipeline. The in line tee will be hyperbaric welded to the existing pipeline.
Injection water shall flow from the tie-in point to the 2/4 VB template via the P2052 pipeline, which has an 9,5" ID. In total, the 2/4 VB wells shall be supplied with approximately 100 000 bbl treated seawater/day.

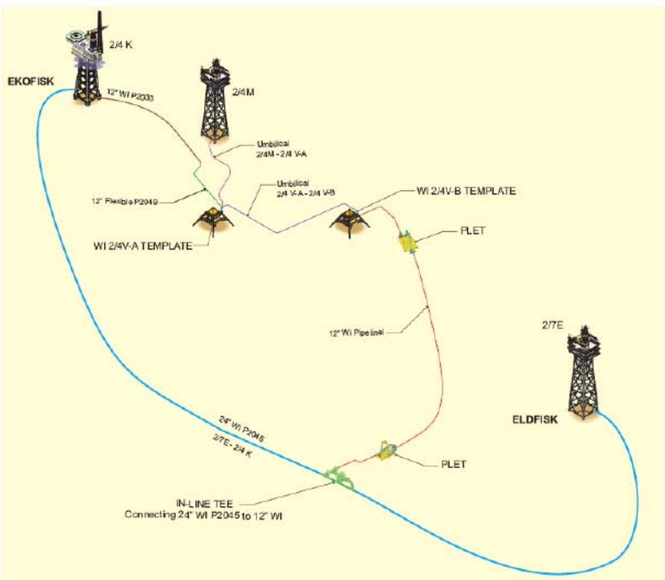

Figure 1.1: Ekofisk 274 V-B SSWI Layout

1.2 SCOPE OF WORK

- Engineer, manufacture and deliver subsea water injection equipment and offshore support services to include templates and piles, wellheads, manifolds, Xmas trees and control modules, ROV pipeline connectors , subsea centre protection structures and electro-hydraulic/fibre optic and services control umbilical U3052.
- Engineer and perform route surveys, debris removal, excavations of existing pipeline at the in-line tee spool tie-in location, concrete coating removal and steel pipe inspection.
- Engineer, procure and fabricate in-line tee spool arrangement for tie-in to the 24" water injection pipeline P2045. Perform installation of in-line tee spool (tie-in) arrangement by removing a section of P2045 and welding in the tie in spool. Install protection structures

1.3 SCOPE OF DOCUMENT

The objective of this document is to summaries all design parameters for design of the P2052 WI line between the ROVCON PLETS.

The main standard for design of the P2052 WI line is DNV-OS-F101, ref. /1/.

1.4 REFERENCES

1.4.1 Standards

Ref.	Doc. Number	Title
/1/	DNV-OS-F101	Submarine Pipeline systems
/2/	DNV-RP-F102	Pipeline Field Joint Coating and Field Repair of Linepipe Coating
/3/	DNV-RP-F105	Recommended Practice, Free Spanning Pipelines
/4/	DNV-RP-F106	Factory Applied External Pipeline Coatings for Corrosion Control
/5/	DNV-RP-F107	Recommended Practice, On Bottom Stability Design of Submarine Pipelines
/6/	DNV-RP-F108	Fracture Control for Pipeline Installation Methods Introducing Cyclic Plastic Strain
/7/	DNV-RP-F109	On-bottom Stability Design of Submarine Pipelines
/8/	DNV-RP-F110	Recommended Practice Global Buckling of Submarine Pipelines, Structural Design due to High Temperature/High Pressure
/9/	DNV-RP-F111	Recommended Practice Interference Between Trawl Gear and Pipelines
/10/	ISO-15589-2	Petroleum and Natural Gas Industries – Cathodic Protection of Pipeline Transportation Systems, Part 2 – Offshore Pipelines
/11/	NORSOK-M-001	Material Selection
/12/	NORSOK-M-501	Surface preparation and protective coating
/13/	NORSOK-M-503	Cathodic Protection
/14/	NORSOK-M-506	CO2 Corrosion Rate Calculation Model
/15/	NORSOK-N-003	Actions and actions effects
/16/	TCD-4061	MetOcean and Geophysical Criteria for Greater Ekofisk Area
/17/	TCD-4650	Material Selection
/18/	TCD-4293	Surface Preparation and Protective Coating
/19/	TCD-5071	Submarine Pipeline Systems
/20/	TCD-6304	Cathodic Protection

1.4.2 Company Documents and Drawings

Ref.	Doc. Number	Title
/21/	089794	EKO 2/4 VB SSWI Project – Subsea and Pipelines Contract
/22/	089794 – Exhibit A	Scope of Work
/23/	089794 – Exhibit E	Specifications, Drawings and Technical Information
/24/	20911040	Geotechnical Report, Field Data Ekofisk WI 2/4VB Jack Up location, Geotechnical Soil Investigation
/25/	BD01-JP-L-00034	Specification for Crossings of Subsea Pipelines and Cables
/26/	BD01-JP-L-00067	Specification for Seamless (reelable) carbon steel linepipe
/27/	BD01-RE-L-30114	Specification for Anode Manufacturing
/28/	EKOV-JP-L-10103	Design Basis Report
/29/	EKOV-JP-L-10105	2/4 VB System Design Feed Report
/30/	EKOV-JP-L-10106	Route Selection Technical Note
/31/	EKOV-JP-L-10107	Material Selection Technical Note
/32/	EKOV-JP-L-10108	Wall Thickness Design Technical Note
/33/	EKOV-JP-L-10109	Cathodic Protection Technical Note
/34/	EKOV-JP-L-10110	On-Bottom Stability Technical Note
/35/	EKOV-JP-L-10111	Installation Analysis Technical Note
/36/	EKOV-JP-L-10112	Freespan Assessment Technical Note
/37/	EKOV-JP-L-10113	Expansion and Upheaval Buckling Technical Note
/38/	EKOV-JP-L-10114	Pipeline Crossing Design Technical Note
/39/	EKOV-JP-L-10116	Seabed Intervention and Protection Design Technical Note
/40/	EKOV-JP-L-10124	PLET Design Technical Note
/41/	EKOV-JP-L-10129	Pipeline and Tie-in Installation and RFO Method Statement
/42/	EKOV-JP-L-00150-001	Overall System Schematic
/43/	EKOV-JP-L-00151-001	Subsea Layout
/44/	EKOV-JP-L-00152-001	P2045 to 2/4 VB Pipeline Route

/45/	EKOV-JP-L-00153-001	Pipeline Approaches to P2045
/46/	EKOV-JP-L-00154-001	Pipeline Approaches to 2/4 VB
/47/	EKOV-JP-L-00155-001	12" Anode General Arrangement Layout and Details
/48/	EKOV-JP-L-00156-001	Pipeline Crossing Layout and Details
/49/	EKOV-JP-L-00163-001	P2045 to 2/4VB Pipeline Alignment Sheet 1
/50/	EKOV-JP-L-00163-002	P2045 to 2/4VB Pipeline Alignment Sheet 2

1.4.3 Subsea 7 Documents and Drawings

Ref.	Doc. Number	Title
/51/	GR-DCE-RPL-015	Guideline Pipeline Design Engineering Plan
/52/	EKOV-SU-L-00222	Liner Design Report
/53/	EKOV-SU-IKM-S-L-0001	Livelink request for subsidence data

1.5 ABBREVIATIONS

3LPP	3 Layer Polypropylene
bbl	Oil Barrel
BSF	Below Seafloor
ECA	Engineering Critical Assessment
FBE	Fusion Bonded Epoxy
FEA	Finite Element Analysis
HAT	Highest Astronomical Tide
HDPE	High Density Polyethylene
ID	Inner Diameter
LAT	Lowest Astronomical Tide
LOFS	Life Of Field Seismic
MSL	Mean Sea Level
N/A	Not Applicable
OD	Outer Diameter
PP	Polypropylene
PU	Polyurethane
SMTS	Specified Minimum Tensile Strength
SMYS	Specified Minimum Yield Strength
SRHM	Subsidence Related Horizontal Movement
SSWI	Subsea Water Injection
TBC	To Be Confirmed
TCD	Technical Company Document
UTM	Universal Transverse Mercator
VIV	Vortex Induced Vibrations
WI	Water Injection
N	North (compass direction)
NE	North East (compass direction)
E	East (compass direction)
SE	South East (compass direction)
S	South (compass direction)
SW	South West (compass direction)
W	West (compass direction)
NW	North West (compass direction)

2. SYSTEM DESCRIPTION

The 2/4 VB facilities are in practical terms an extension of the 2/4 VA facilities, however the pipeline P2052 supplying injection water is tied directly back to the existing 24” subsea pipeline from 2/7 E to 2/4 K (P2045) and not to 2/4 K-2/4 W pipeline, as for 2/4 VA.

The subsea wells will be located approximately 2.5km SE of 2/4 VA in the Ekofisk Field. The facility comprises two piled Hinged Over Subsea Templates which will accommodate two water injection manifolds, wellheads and eight horizontal Xmas tress including subsea control modules. Both water injection manifolds will be interconnected and supply four trees each. The subsea facilities will be protected with a free standing protection structure.

Control of the water injection wells will be via umbilical U3052 connected to the 2/4 VA manifold which in turn is controlled through umbilical U3049 from 2/4M platform.

Injection water shall be supplied from a tie-in point on the existing 24” WI pipeline from 2/7 E to 2/4 K. The tie-in to the existing 24” WI pipeline will be through the installation of an inline tee in the 24” WI pipeline. The inline tee will be hyperbaric welded to the existing pipeline.

Injection water shall flow from the tie-in point to the 2/4 VB template via the p2052 pipeline, which has a 9.5” ID. In total, the 2/4 VB wells shall be supplied with approximately 100 000 bbl treated seawater/day.

This document describes the basis of design of the P2052 pipeline with the ROVCON hubs at the respective PLETS as battery limits.

2.1 DESIGN LIFE

The design life of the system is 25 years, ref /28/.

2.2 BATTERY LIMITS

The battery limits for the design of the P2052 pipeline, as described in this report, are presented in Table 2.1.

System	Start	End
P2052 pipeline	ROVCON hub near Tee	ROVCON hub near template

Table 2.1: Battery limits P2052 WI line

2.3 KP DEFINITION

KP 0 for the P2052 pipeline is defined as the end of the flange on the tie-in spool at the P2045 Tee, increasing towards the 2/4 VB template.

2.4 FIELD LAYOUT

The coordinate system used to present the locations is presented in Table 2.2.

Description	Value
Coordinate system	Universal Transverse Mercator (UTM)
Grid zone	31 N
Central Meridian	3°
International spheroid	1924
European datum	1950

Table 2.2: Definition of coordinate system

The facility locations are presented in Table 2.3.

Facility	UTM (E)	UTM (N)
P2045 Tee location ref00151-001	510933	6261315
P2045 PLET pipeline tie-in ref.00153-001	510962	6261308
Ekofisk 2/4 VB template ref00151-001	514721	6264170
2/4 VB PLET centre ref.00154	514772	6264161

Table 2.3: Facilities locations

2.5 PIPELINE CROSSINGS

A total of 16 pipeline crossings have been identified. 6 Crossings are over existing buried pipelines and 10 crossings are over LOFS cables (to be installed prior to pipelay). The coordinates of the crossings are presented in Table 2.4, ref./48/.

No.	Description	KP	Easting	Northing	Burial depth [m]
1	P2018B 30” Pipeline	0.021	510982	6261315	1.1
2	P2016B 24” Pipeline	0.048	511007	6261325	2.4
3	P2016R 24” Pipeline	0.117	511072	6261349	0.4
4	P2022 20” Pipeline	0.152	511105	6261361	1.5
5	20” Valhall pipeline	0.206	511154	6261379	1.4
6	LOFS cable[1)]	1.455	512326	6261812	TBC
7	LOFS cable[1)]	1.757	512610	6261916	TBC
8	LOFS cable[1)]	2.059	512893	6262021	TBC
9	LOFS cable[1)]	2.361	513176	6262129	TBC
10	LOFS cable[1)]	2.675	513447	6262284	TBC
11	LOFS cable[1)]	3.018	513700	6262516	TBC
12	LOFS cable[1)]	3.390	513940	6262799	TBC
13	LOFS cable[1)]	3.762	514181	6263083	TBC
14	LOFS cable[1)]	4.134	514421	6263367	TBC
15	LOFS cable[1)]	4.562	514643	6263726	TBC
16	GT4 10” pipeline	4.792	514709	6263947	1.8

Note 1) LOFS cables to be installed prior to pipeline installation, final positions to be confirmed afterwards.

Table 2.4: Pipeline crossing locations

2.6 DESIGN CODES:

Design for the WI pipeline will be in accordance to DNV-OS-F101 Submarine Pipeline Systems, company provided Technical Control Documents (TCD) and applicable NORSOK and ISO standards, ref/22/.

2.7 SAFETY ZONES

In line with ref /1/, partial safety factors applied in code checks shall be based on safety classes. The safety classes are determined based on fluid category, location classification and phase (temporary or operational).

The fluid (water) can be classified as category A, typical non-flammable water based fluid, ref/1/. The pipeline is located outside the safety zone of the Ekofisk 2/4A platform, so location class 1 is used for the whole pipeline, ref. /1/. The safety classes, ref /1/ table 2-4, for the P2052 pipeline are presented in Table 2.5.

Pipeline	Safety class	
	Temporary phase	Operational phase
P2052	Low	Low

Table 2.5: Pipeline safety class

2.8 INSTALLATION TOLERANCES

The pipeline installation tolerances are presented in Table 2.6, ref/28/.

	Lateral tolerances	Longitudinal tolerances	Heading tolerances
Normal pipelay	± 10.0m	N/A	N/A
Start-up and laydown	± 1.5m	± 3.0m	± 1.0°
Crossings	± 2.5m	N/A	N/A

Table 2.6: Installation tolerances

2.9 MATERIALS

Linepipe material is carbon manganese steel with a high density polyethylene (HDPE) internal plastic liner. Detailed pipeline material properties are presented in Note 1): Typical value Table 2.7. Steel material grade is DNV SMLS 450 PD, ref/28/. Supplementary requirement P and D is required, ref/26/.

Description	Unit	Value	Value
Material	-	Carbon steel	HDPE
Material grade	-	DNV SMLS 450 PD	Borealis HE 3490 LS H
Density	kg/m^3	7850	960 [1)]
SMYS @20°C	MPa	450	25.0
SMTS @20°C	MPa	535	-
Young's Modulus	MPa	207000	1100 [1)]
Poisson ratio	-	0.3	-
Thermal Expansion coefficient	1/°C	$11.7*10^{-6}$	$120*10^{-6}$ [1)]
Thermal Conductivity	W/m°K	45	0.5 [1)]

Note 1): Typical value

Table 2.7: Pipeline material properties

The HDPE inner liner pipe dimensions are presented in Table 2.8, ref. /52/.

Pipe dimension	Before swageling	After swagelining [1)]
Outer diameter (mm)	350	282.7 [1)]
Wall thickness (mm)	12.12	13.64

Note 1): The after swagelining properties are based on 323.9mm OD and 20.6mm WT.

Table 2.8: HDPE inner liner dimensions

The pipeline will be coated with 3mm 3LPP anti-corrosion coating. Field joint coating is PIH 3LPP hot applied tape wrap system. Details of the anti-corrosion coating are presented in Table 2.9.

Coating layer	coating density [kg/m^3]	Coating thickness [mm]
FBE	1450	0.3
Adhesive	900	0.3
PP	900	2.4
3LPP (total)	955	3.0

Table 2.9: Pipeline coating properties

2.10 CORROSION ALLOWANCE AND CATHODIC PROTECTION

The pipeline is fabricated with a HDPE inner liner, so internal corrosion to the inside of the steel pipeline is assumed to be 0mm.

The pipeline will be protected against corrosion by a combination of coating and sacrificial anodes. The anodes will be a bracelet type of AlZnIn alloy. The cathodic protection system will be designed per following codes and standards: ref/4/, /10/, /13/ and /20/.

3. DESIGN DATA

Design data of the internal fluid is presented in Table 3.1, ref./28/. The system test pressure is defined as 1.15*Design pressure, ref. /41/.

Description	**Unit**	**Value**
Fluid type	Injection Water	-
Fluid density	1025	kg/m^3
Design pressure (@ 35.8m)	414	barg
System test pressure (@35.8m) (1.15*Design pressure)	476	barg
Normal operating pressure at wellhead	290	barg
Maximum design temperature	12	°C
Minimum design temperature	3	°C
Maximum flowrate through Tee at P2045	280,000	bbl/day
Maximum flowrate through template 2/4 VB	80,000	bbl/day

Table 3.1: Pipeline operational data

The allowable fatigue damage ratio (α_{fat}) is 0.33 based on safety class low and table 5-9 ref/1/. The split in fatigue damage ratio between the different phases is presented in Table 3.2.

Phase	**Split**	**Allowable fatigue damage**
Installation	10%	0.033
As-laid	80%	0.264
Operation	10%	0.033
Total	100%	0.33

Table 3.2: Allowable pipeline fatigue damage (VALUES TBC)

The pipeline will be rock dumped prior to operation.

4. ENVIRONMENTAL DATA

Environmental data is provided in ref. /16/**Error! Reference source not found.**. All data in this section comes from ref **Error! Reference source not found.** unless noted otherwise.

4.1 WATER DEPTH

The minimum and maximum water depths are presented in Table 4.1. The seabed is essentially level throughout the route with the seabed slope typically in the region of 0.1° and shoals very gently towards the proposed 2/4VB template.

Description	**Value**
Minimum water depth relative to LAT	70.2m
Maximum water depth relative to LAT	73.1m

Table 4.1: Minimum and maximum water depths

4.2 SEAWATER LEVEL VARIATIONS

Tidal variations are presented in Table 4.2.

Water level	**Value [m]**
HAT – LAT	1.33m
MWL – LAT	0.67m

Table 4.2: Tidal variations

Total sea level extremes excluding subsidence are presented in Table 4.3Note 1: Relative to MWL
Table 4.3. Maximum vertical displacement due to subsidence is 6.114m, ref /53/.

	Return period [years]				
	1	**10**	**100**	**1000**	**10000**
Total sea level[1] [m]	1.03	1.29	1.55	1.82	2.08
Total sea level tide removed[1] [m]	0.77	0.99	1.2	1.42	1.63

Note 1: Relative to MWL
Table 4.3: Sealevel return periods

4.3 SEAWATER PROPERTIES

Seawater properties are presented in Table 4.4.

Parameter	**Unit**	**Value**
Density	kg/m^3	1025
Temperature at sea level (max / min)	°C	20.0 / 2.6
Temperature at seabed (max / min)	°C	11.6 / 3.5
Kinematic viscosity [1)]	m^2/s	$1.51*10^{-6}$
Thermal conductivity [1)]	W/m*K	0.6
Resistivity [2)]	Ohm*m	0.33

Note 1: Industry standard value.
Note 2: Resisitivity at minimum seawater temperature, ref /10/.
Table 4.4: Seawater properties

4.4 MARINE GROWTH

The pipeline is located between 56-59°N and below 40m water depth. The marine growth is assumed at 50mm, ref/15/.

The thickness of marine growth may be assumed to increase linearly to the presented value over a period of 2 years after pipeline installation, ref /15/.

The roughness height is taken as 20mm, ref /15/. The dry weight of the marine growth is assumed to be $13kN/m^3$, ref /15/.

4.5 FIELD SUBSIDENCE

The Ekofisk field is subject to vertical subsidence of the seabed and associated with the vertical subsidence, there is a horizontal movement of the seabed within the subsidence bowl radially towards the field centre. The Subsidence Related Horizontal Movement (SRHM) is zero at the centre of the bowl, attains a maximum value at some distance from the centre and then decays to zero at the edge of the bowl. A plot of the subsidence for the P2052 WI line is shown in Figure 4.1. The subsidence data is based on ref. /53/.

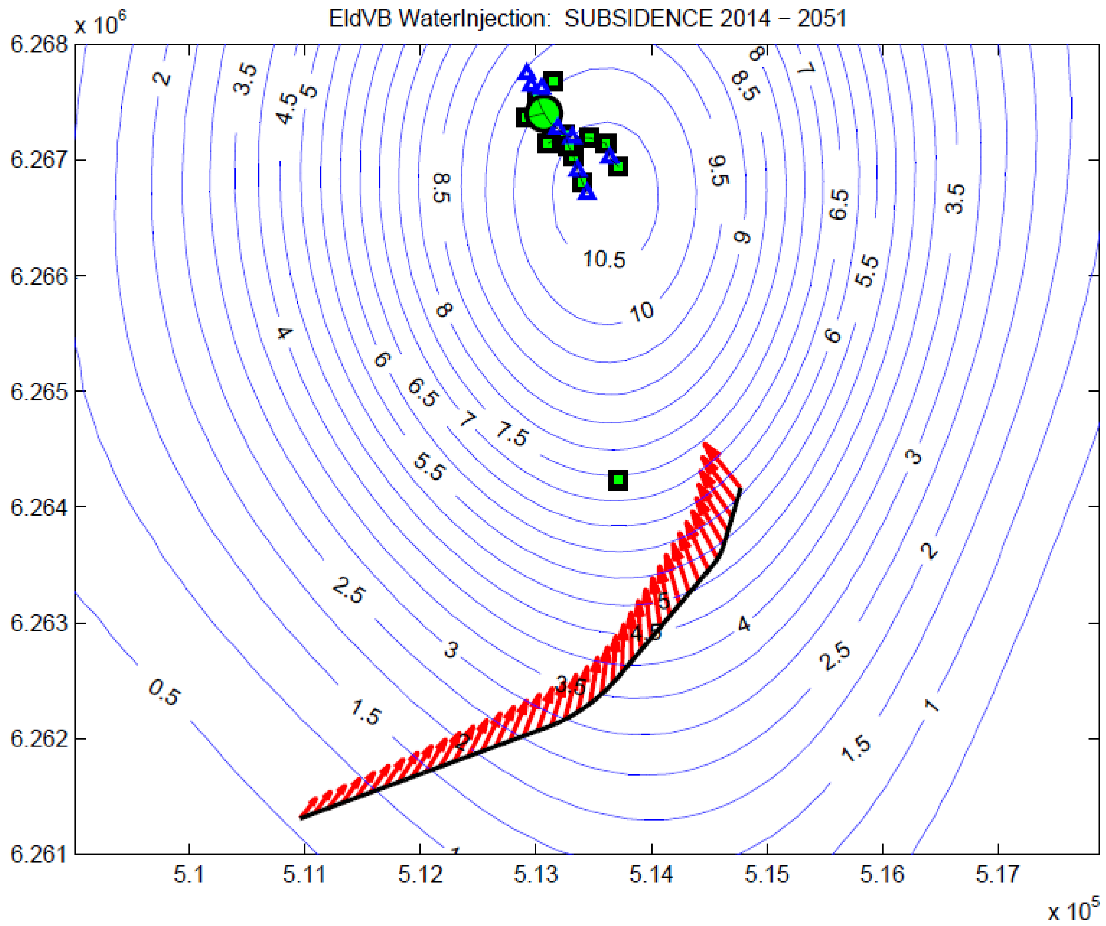

Figure 4.1: Plot of subsidence data for P2052 WI line

4.6 METOCEAN DATA

4.6.1 All Year Waves

The omni-directional wave extremes and their corresponding return periods for all year conditions are presented in Table 4.5.

Description	Unit	Return period				
		1	10	100	1000	10000
Significant wave height Hs	m	9.59	11.74	13.79	15.78	17.71
Zero crossing period T_{m02}	s	9.91	10.94	11.87	12.74	13.55
Average period T_{m01}	s	10.70	11.82	12.85	13.82	14.73
Peak period T_p	s	13.02	14.32	15.51	16.61	17.65
Individual wave height H_{max}	m	17.30	21.28	25.19	29.07	32.96
Associated wave period T_{Hmax}	s	12.44	13.49	14.39	15.16	15.86
Crest (SWL)	m	10.58	13.13	15.70	18.34	21.09

Crest (LAT)	m	11.54	14.18	16.84	19.57	22.42

Table 4.5: Omni-directional extreme values

The extreme directional significant wave heights and their corresponding return period are presented in Table 4.6, the corresponding zero-crossing and peak wave period are presented in Table 4.7 and Table 4.8.

H_s [m]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	9.59	7.39	4.82	6.50	6.11	6.19	7.63	8.18	8.99
10	11.74	9.43	6.43	8.18	7.41	7.77	9.60	10.31	11.35
100	13.79	11.36	7.87	9.66	8.54	9.18	11.42	12.27	13.54
1000	15.78	13.20	9.20	11.02	9.55	10.49	13.14	14.12	15.62
10000	17.71	14.97	10.46	12.29	10.48	11.72	14.76	15.88	17.60

Table 4.6: Directional extreme values for significant wave height

T_z [s]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	9.91	8.78	7.31	8.29	8.07	8.12	8.91	9.20	9.61
10	10.94	9.83	8.25	9.20	8.79	8.98	9.92	10.26	10.76
100	11.87	10.76	9.04	9.95	9.38	9.71	10.79	11.19	11.76
1000	12.74	11.61	9.72	10.60	9.89	10.35	11.58	12.02	12.67
10000	13.55	12.39	10.34	11.19	10.34	10.93	12.30	12.78	13.50

Table 4.7: Directional extreme values for zero-crossing periods for corresponding extreme significant wave height

T_p [s]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	13.02	11.60	9.81	11.01	10.74	10.79	11.77	12.13	12.64
10	14.32	12.92	10.96	12.12	11.62	11.85	13.03	13.46	14.09
100	15.51	14.09	11.92	13.06	12.36	12.76	14.13	14.63	15.36
1000	16.61	15.17	12.78	13.89	12.99	13.57	15.13	15.69	16.52
10000	17.65	16.17	13.55	14.64	13.56	14.31	16.05	16.67	17.59

Table 4.8: Directional extreme values for peak periods for corresponding extreme significant wave height

A scatter table based on 25years of wave measurements is presented in Table 4.9.

Hs \ Tp	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-3	13-14	14-15	15-16	16-17	17-18	18-19	19-20	>20	Sum
0-1	0.003	0.020	0.051	0.042	0.018	0.014	0.014	0.013	0.009	0.005	0.004	0.002	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.20
1-2	0.000	0.001	0.025	0.088	0.110	0.061	0.028	0.021	0.019	0.013	0.006	0.004	0.003	0.002	0.001	0.001	0.000	0.000	0.000	0.38
2-3	0	0	0.000	0.005	0.043	0.082	0.046	0.018	0.011	0.010	0.007	0.003	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.23
3-4	0	0	0	0.000	0.002	0.022	0.044	0.024	0.008	0.004	0.003	0.002	0.001	0.000	0.000	0.000	0.000	0	0	0.11
4-5	0	0	0	0	0.000	0.001	0.012	0.020	0.009	0.003	0.001	0.001	0.001	0.000	0.000	0.000	0	0	0	0.05
5-6	0	0	0	0	0	0	0.001	0.006	0.007	0.003	0.001	0.000	0.001	0.000	0.000	0.000	0	0	0	0.02
6-7	0	0	0	0	0	0	0.000	0.001	0.002	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0	0	0	0.01
7-8	0	0	0	0	0	0	0	0.000	0.000	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0	0	0	0.00
8-9	0	0	0	0	0	0	0	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0.00
9-10	0	0	0	0	0	0	0	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0.00
10-11	0	0	0	0	0	0	0	0	0	0	0.000	0.000	0.000	0	0.000	0.000	0	0	0	0.00
11-12	0	0	0	0	0	0	0	0	0	0	0	0	0.000	0	0.000	0	0	0	0	0.00
12-13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
13-14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000	0	0	0	0.00
Sum	0.003	0.021	0.076	0.135	0.173	0.180	0.145	0.103	0.066	0.041	0.025	0.013	0.009	0.005	0.002	0.001	0.001	0.000	0.000	1.00

Table 4.9: Scatter Table, Hs (m) vs Tp (s)

4.6.2 Summer Waves

The omni-directional wave extremes and their corresponding return periods for all year conditions are presented in Table 4.10.

Description	Unit	Return period				
		1	10	100	1000	10000
Significant wave height Hs	m	5.17	6.06	6.43	7.28	7.63
Zero crossing period T_{m02}	s	7.52	8.04	8.26	8.72	8.91
Average period T_{m01}	s	8.11	8.68	8.90	9.41	9.61
Peak period T_p	s	10.07	10.70	10.96	11.53	11.77
Individual wave height H_{max}	m	9.45	11.10	11.80	13.41	14.10
Associated wave period T_{Hmax}	s	9.77	10.41	10.67	11.23	11.46
Crest (SWL)	m	5.71	6.74	7.18	8.19	8.63
Crest (LAT)	m	6.50	7.57	8.02	9.07	9.52

Table 4.10: Omni-directional extreme values for summer period

The extreme directional significant wave heights and their corresponding return period are presented in Table 4.11, the corresponding zero-crossing and peak wave period are presented in Table 4.12 and Table 4.13.

H_s [m]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	5.17	4.20	2.79	3.28	2.88	3.30	4.09	3.73	4.80
10	6.06	4.90	3.87	4.39	3.68	4.22	5.06	4.57	5.74
100	6.43	5.19	4.33	4.86	4.01	4.61	5.46	4.91	6.12
1000	7.28	5.82	5.38	5.92	4.76	5.52	6.37	5.68	6.98
10000	7.63	6.08	5.83	6.37	5.08	5.90	6.75	6.00	7.34

Table 4.11: Directional extreme summer values for significant wave height

T_z [s]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	7.52	6.91	5.93	6.29	6.00	6.30	6.84	6.60	7.30
10	8.04	7.36	6.70	7.04	6.56	6.93	7.46	7.15	7.86
100	8.26	7.53	7.00	7.33	6.79	7.18	7.70	7.36	8.08
1000	8.72	7.91	7.65	7.97	7.27	7.73	8.22	7.83	8.56
10000	8.91	8.06	7.91	8.22	7.47	7.95	8.43	8.01	8.75

Table 4.12: Directional extreme summer values for zero-crossing periods for corresponding extreme significant wave height

T_p [s]	Chart directional sector								
Return period	omni	N	NE	E	SE	S	SW	W	NW
1	10.07	9.34	8.19	8.61	8.27	8.62	9.26	8.97	9.79
10	10.70	9.87	9.08	9.49	8.93	9.36	9.99	9.62	10.47
100	10.96	10.08	9.44	9.84	9.19	9.65	10.28	9.88	10.74
1000	11.53	10.53	10.22	10.60	9.76	10.32	10.92	10.43	11.33
10000	11.77	10.71	10.54	10.92	10.00	10.59	11.18	10.66	11.57

Table 4.13: Directional extreme summer values for peak periods for corresponding extreme significant wave height

The parameters required for making a weibull distribution of the current speeds are presented in Table 4.14.

Sector	Occurrence (%)	Weibull parameters		
		Scale (m)	Shape	Location (m)
Omni	100	0.960	1.215	0.470
N	26.9	1.280	1.537	0.285
NE	2.5	0.758	1.056	0.523
E	4.3	0.852	1.094	0.442
SE	5.7	0.700	1.153	0.540
S	8.3	0.663	1.059	0.618
SW	12.6	1.020	1.230	0.434
W	11.7	1.028	1.315	0.370
NW	27.9	1.278	1.355	0.235

Table 4.14: Weibull distribution parameters for directional summer waves

The extreme directional significant wave heights and their corresponding return period are presented in table, the corresponding zero-crossing and peak period are presented in table and table respectively.

4.6.3 Current

Extreme current speeds and their corresponding return periods are presented in Table 4.15. The current profile may be considered constant up to 3m above seabed, for the lower 3m a logarithmic profile as per ref/3/ may be considered. The parameters required for making a Weibull distribution of the current speeds are presented in Table 4.16.

Current (cm/s)	Chart Directional Sector								
Return period	Omni	N	NE	E	SE	S	SW	W	NW
1	56	48	42	40	37	40	40	45	54
5	65	54	45	48	43	44	43	51	64
10	69	56	47	51	45	46	45	53	69
50	79	61	50	58	51	49	48	59	79
100	83	63	51	61	53	51	49	61	83
1000	112	75	59	82	67	61	58	75	112

Table 4.15: Current speed return periods

Sector	Occurrence (%)	Weibull parameters		
		Scale (m)	Shape	Location (m)
Omni	100	8.283	1.269	5.778
N	13.5	14.349	1.747	1.937
NE	21.5	14.004	2.061	2.811
E	6.7	5.668	1.073	5.134
SE	5.0	9.493	1.416	0.000
S	15.4	10.509	1.668	3.264
SW	24.9	11.018	1.810	3.975
W	7.7	12.877	1.582	0.000
NW	5.4	9.348	1.130	2.401

Table 4.16: Weibull distribution parameters for directional current speed

5. GEOTECHNICAL DATA

Geotechnical data for the 2/4 VB drill site is provided in ref /24/. A summary of the soil conditions is presented in Table 5.1. The soil conditions for the pipeline route are assumed to be equal to the drill site location.

Layer	Depth range of soil units [m BSF]		Soil description
	Top	Base	
I	0.0	0.3-0.5	Medium dense to dense silty fine SAND with many fine coarse gravel-sized shells and shell fragments
II	0.3-0.5	23.5-24.0	Dense to very dense silty fine SAND with pockets and partings of black organic matter and few thin to thick beds of stiff to hard clay
III	23.5-24.0	44.8	very stiff to very hard slightly sandy CLAY with pockets and partings of silt few thin to thick beds of fine sand
IV	44.8	45.3 [1)]	Very dense SAND

Note 1: End of borehole.

Table 5.1: Soil data

For pipe-soil interaction, only the top sand layer is relevant as the pipeline is unlikely to penetrate below this layer. A pipeline soil interaction report will be made, which will describe all the soil parameters required for the pipeline design.

6. DESIGN METHODOLOGY

The following design activities will be performed for the P2052 WI pipeline:

- Wall thickness design
- Routing and layout
- Installation analysis
- Weld link details and reelability
- On-bottom stability
- Pre-lay seabed intervention design
- Post-lay seabed intervention design
- Preparation of alignment sheets
- As-laid confirmation analysis

Trawl gear interaction and dropped objects analysis will not be formed, since the pipeline will be covered by rocks during the operational phase.

6.1 WALL THICKNESS

The wall thickness will be designed according ref/1/. The design shall take into account the following:

- Pressure containment
- Collapse under hydrostatic pressure
- Buckle initiation and propagation
- Combined loading check
- Manufacturing tolerances
- Corrosion allowances
- Installation and stability requirements
- Maximum and minimum water depth along the route

6.2 ROUTING AND LAYOUT

Pipeline routing shall take into account the following considerations:

- Imposed limitations by construction and other support vessels
- Practicable route curve radii, taking into account: soil conditions, lay tensions and water depth
- Optimum approaches to selected tie-in points
- Minimisation of pipeline length
- Existing pipelines, umbilicals, cables, wells and subsea structures
- Freespans
- Effect of SHRM
- Dropped objects
- Trawl gear impacts
- Pipeline start-up and laydown constraints
- Avoidance of seabed obstructions

6.3 INSTALLATION ANALYSIS

Installation of the pipeline will be performed by one of Subsea7s pipeline reeling vessels. Detailed installation analysis will be performed for the dedicated pipelay vessel. Static and dynamic analysis taking into account the environmental conditions will be performed

The installation analysis will also check the curve stability during laying.

6.4 ECA, WELD LINK DETAILS AND REELABILITY

An Engineering Critical Assessment (ECA) will be performed for the pipelines to determine allowable flaw sizes and weld defects. The analysis will be performed in accordance with the requirements of DNV-OS-F101, ref /1/ and DNV-RP-108, ref. /6/.

The software CRACKWISE will be used for the fracture mechanics analyses. The acceptable weld defect sizes will be determined for pipeline system installation and operation.

Detailed finite element analysis (FEA) of the reeling process of the pipelines using *Seven Navica* reel-lay vessel will be performed using ANSYS.

The stresses and strains within the pipelines and initial straightening curvature are determined from the results of the FEA analysis. Further FEA will be performed to accurately model geometrical and material property variations (mismatches) of the pipelines and estimate the cross-sectional ovalisation. The geometric mismatch and yield strength mismatch will be taken into account in the analysis. The weld material and weld links will also be modelled.

The peak strain at the field joints will be verified against the allowable strain criterion in accordance with DNV-OS-F101 ref /1/.

6.5 ON-BOTTOM STABILITY

The pipeline will be rocked dumped after installation. On-bottom stability during temporary phases (empty, flooded, hydrotest), as well as post rockdumped phase will be performed in accordance with ref /7/. Curve stability during pipeline installation will be checked in the installation analysis.

The pipeline on-bottom stability shall take into account the wave and current loads during all phases of the project.

6.6 PRE-LAY INTERVENTION DESIGN

The pre-lay intervention design consists of a crossing design and freespan analysis.

The pipeline route crosses several existing pipelines and cables, see section 2.5. Crossing design shall be in accordance with ref /19/. Base case for the crossing design is protection by concrete mattress installation. The minimum separation is 0.3m according Company requirements, ref//28/.

Free span analysis has to be performed in according ref /19/. The maximum allowable static span length for the pipelines will be determined according DNV-RP-F105, ref /3/, for the following conditions:

- After installation (empty)
- Flooded (prior to hydrostatic testing)
- During hydrostatic testing (flooded)
- Operational for the exposed area

Dynamic span analysis to determine the maximum allowable pipelines free span lengths due to Vortex Induced Vibration (VIV), will be performed in accordance with DNV-RP-F105, ref /3/, if required. The analysis will use significant wave height and associated period to calculate wave induced water particle velocities and accelerations. Effect of particle velocity increase adjacent to the platform will be taken into account. The dynamic span analysis will be performed with the DNV approved software FATFREE.

6.7 ON-BOTTOM ROUGHNESS

The on-bottom roughness analysis will be performed using SAGE software for assessment of pipelines under following conditions:

- After installation (empty and flooded);
- During hydrotest;
- During operation (with product);

The pre-lay span correction will be based on the on-bottom roughness (seabed roughness and stress code compliance) check for all load conditions (empty, flooded, hydrotest and operational).

The output from the analysis will include displacements, axial forces (effective axial force and true pipe wall force), bending moments, bending stresses, longitudinal stresses, equivalent stresses, and longitudinal strains. For each load condition, the analysis output results will be used to perform limit state checks in accordance with DNV-OS-F101 Ref. /1/.

6.8 POST-LAY INTERVENTION DESIGN

Post-lay intervention design consists of the following:

- Pipeline expansion analysis
- Crossing protection design
- Upheaval buckling design
- Subsidence analysis

6.8.1 Crossing protection design

The pipeline will be rockdumped over the full length. Protection design will done in accordance with ref /19/, note that crossing protection design is not in CONTRACTORS scope of work.

6.8.2 Pipeline expansion analysis

Changes to the pipeline temperature and pressure relative to the installation conditions alters the effective axial force within the pipeline, resulting in expansion at the ends of the pipeline.

Expansion analysis will be performed with in-house developed sheet.

6.8.3 Subsidence analysis

The Ekofisk field is subject to vertical subsidence of the seabed and associated with the vertical subsidence, there is a horizontal movement of the seabed within the subsidence bowl radially towards the field centre. The Subsidence Related Horizontal Movement (SRHM) is zero at the centre of the bowl, attains a maximum value at some distance from the centre and then decays to zero at the edge of the bowl. The SRHM will be transmitted to the pipeline through seabed friction. This has the effect of inducing compressive and tensile forces in the pipeline, additional to those due to operational conditions and environmental forces.

The pipeline and seabed will be modelled using finite element (FE) software and analyses will be performed to simulate the behaviour of the pipeline under the effects of functional and environmental loads. The SHRM data will be incorporated in the FE analyses and sensitivity cases will be run for a range of friction coefficients to determine the envelope of pipeline behaviour and check for compliance with the design code ref /1/.

6.8.4 Upheaval buckling

Due to temperature and pressure driven build up of axial force and seabed undulation, backfilled or rock dump protected pipelines may develop upheaval buckling tendencies. If the amount of down force generated by pipeline protective cover is not sufficient to resist generated upheaval force, the pipeline may start upwards movement and eventually, in extreme cases, break out of the protective cover.

The pipelines will be rock dumped along the whole route. The required rock cover will be assessed against upheaval buckling tendencies of the pipeline.

Predictive UHB analysis will be based on establishing balance between uplift force and required download force generated by rock cover. The assessment will be carried out using the seabed profile along the route. Safety factor will be applied to uplift force and required rock cover to ensure robustness of the assessment.

6.9 ASSESSMENT OF PIPE-SOIL INTERACTION AND RELEVANT PARAMETERS

Detailed geotechnical engineering, based on the soil parameters and geotechnical data provided by the Company, ref /24/, will be performed during detailed design to assess pipelines embedment and soil resistance to pipe axial and lateral movements. The following aspects of pipe-soil interaction will be considered:

- Initial embedment of pipelines due to self weight, factored to account for load concentration and cycling during installation;
- Peak and residual axial friction (resistance) for initial embedment and during lateral movement (reduced embedment during lateral excursions);
- Lateral friction for breakout and residual resistance and interaction with soil berms generated at maximum lateral excursion.
- Pipe resistance and interaction for the rock dump cover.

A range of values will be derived for pipelines subject to upper and lower bound soil parameters for empty, flooded and operational cases as applicable. Consideration will also be given to drained response for axial friction in the long term condition, if applicable.

6.10 CATHODIC PROTECTION

The pipeline will be protected against corrosion by a combination of coating and sacrificial anodes. The anodes will be a bracelet type of AlZnIn alloy.

The amount of anodes and anode spacing required will be calculated using in-house developed calculation sheets, see also Section 2.10.