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Guidelines for Safe Cable Crossing over a Pipeline

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Abstract

High voltage submarine cables are increasingly being installed in existing and new offshore oil and gas fields for power supply and control purposes. These power cables are both large and with a high submerged weight, which poses a challenge when designing a safe, maintenance free (economical), and fit-for-purpose crossing over a pipeline. Damage to subsea pipeline crossings caused by deterioration of a crossing support, field joint materials and cover components is well known in the industry, particularly with old pipelines.

Crossing cables over an existing pipeline should be avoided whenever economical and practical. However, it is inevitable in some situations to use the existing pipeline (unburied) as the crossing support to a new cable/umbilical. In these situations, crossing the cable/umbilical over the existing pipeline may be a cost-effective and worthy consideration. However, there are no explicit guidelines or criteria in the industry concerning the acceptable practice of design and construction of crossings. The only clear recommendation is relating to pipeline separation distances.

This paper documents a recent case study of damage of a field joint coating at a crossing of an existing pipeline by a 132 kV subsea cable of 191 mm outside diameter. Investigation of the damage on site revealed that it was caused by lateral movement of the cable under the influence of hydrodynamic forces.

Further to investigation and assessment of the damage of the case study presented here, the paper proposes some guidelines for the safe design and construction of cable crossing. Another objective of this paper is to invite further evaluation of the proposed guidelines so that appropriate crossing design requirements can be further developed and standardised.

Keywords: Submarine Cable; Submarine Cable Installation; Crossing Design; Field Joint Coating Damage; On-bottom Stability; Offshore Pipeline.

1 Introduction

Submarine cable crossings are now a common feature of offshore hydrocarbon field development. Instances of cable crossings are consistently increasing with field density and development [Ref. [1]].

Crossings add cost to any new subsea cable installation and should be avoided whenever practical but this should not be at the expense of increasing the length of the cable. The size of the cable, umbilical or pipeline being crossed and their burial condition are important factors in selecting the crossing design concept. Cost, complexity and engineering effort all increase with increasing cable/umbilical/pipeline size. For example, a cable/umbilical/pipeline crossing involving a non-buried large diameter pipeline is considerably more complex compared with a case involving a small, partially buried pipeline. Furthermore, selection of a crossing design concept depends on the construction method, especially when the crossing design involves burial, trenching or rock dumping. In this case, the cost of the construction vessel and equipment will have significant impact on the crossing design and alternative crossing designs may be envisaged.

Deterioration of subsea pipeline crossings is common [Ref. [1]]. Most of the problems associated with this problem are primarily related to the deficiency of the long-term integrity of the crossing support and cover components. Accordingly, it is imperative to ensure that the crossing design is both sound and fit-for-purpose with a maintenance free design life.

This paper describes a case study of recent failure of a field joint coating of crossed pipelines due to installation of a 132 kV submarine cable, along with the subsequent underwater repair. The cause of the damage was assessed and found to be a combination of increased hydrodynamic loads plus excessive lateral cable movement associated with the hydrodynamic forces, resulting in unexpected level of radial and axial loads on the field joint coating of the crossed pipeline as depicted in Figure 1.

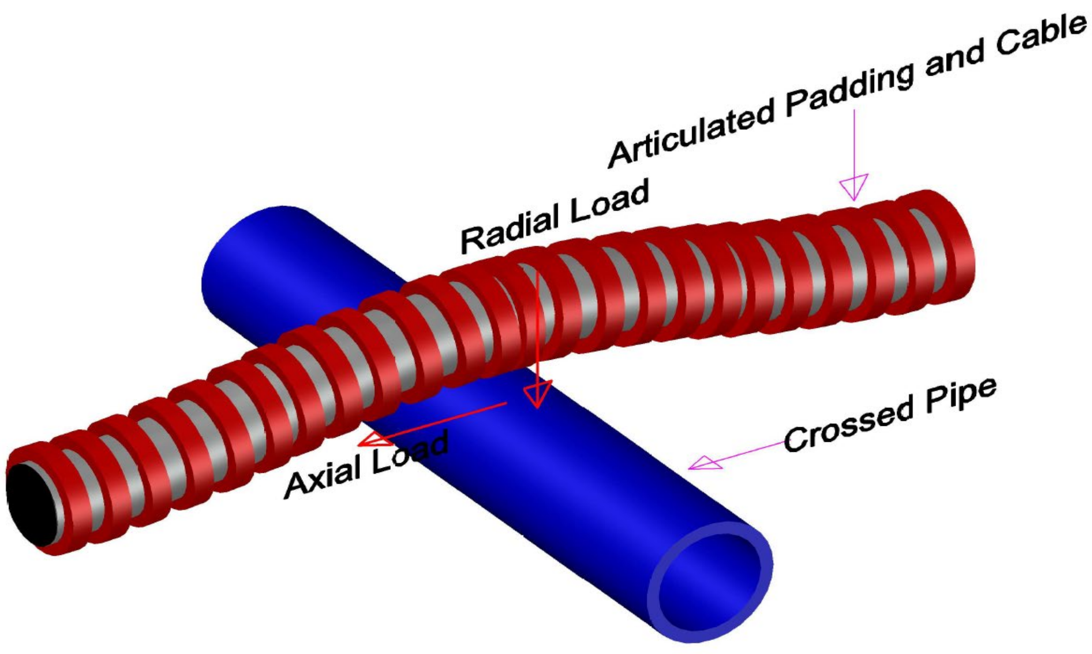

Figure 1: Radial and axial loads applied on the field joint by the cable and articulated padding

An industry accepted standard for the design and construction of cable crossings does not currently exist for the case when the crossed pipeline is used as a support. The paper documents the lessons learned that may be helpful in developing specifications for crossing design and construction in similar scenarios.

2 Crossing Design Concepts

Selection of a crossing concept is normally based on the technical feasibility, cost, safety and environment. The possible crossing methods are as follows:

1. Bury or trench the existing pipeline/umbilical/cable prior to crossing. This will enable the new cable to cross flush with the seafloor or trenched on a pre-defined trench profile.
2. Raise the new crossing pipeline/umbilical/cable above the existing pipeline/umbilical/cable using supports as shown in Figure 2. This will enable the new pipeline/umbilical/cable to be installed without any interference with the existing crossed pipeline. The final separation between the crossed pipeline and the crossing pipeline/umbilical/cable will depend on the settlement of the support over time as shown in Figure 2. Prediction of such settlement is uncertain and typically requires geotechnical sampling for design. Any intervention required to increase the separation during the operation phase is both costly and difficult.

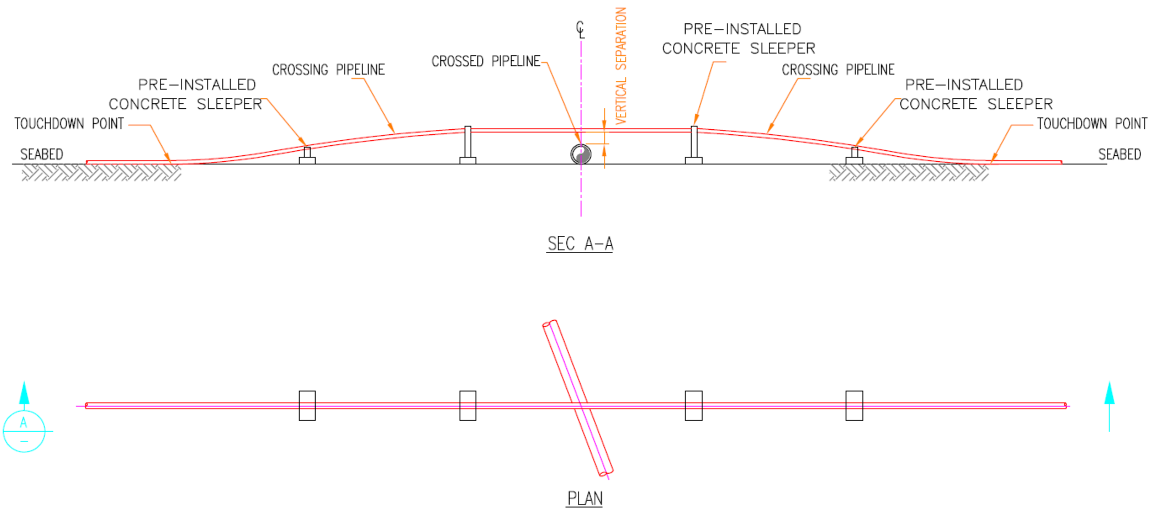

Figure 2: Discrete supports

3. Using the existing crossed pipeline as a support. Provided that:
   - The loads imposed on the crossed pipeline are within the allowable limits.
   - The crossing cable does not bear directly on the crossed pipeline (i.e. the required vertical separation between the crossed and crossing assets are maintained).
   - The integrity of the coating of the crossed and crossing assets are not impaired.
   - The cathodic protection of the crossed and crossing assets are not jeopardised.

- Thermal expansion induced by the operating pressure and temperature of the crossing pipeline can be accommodated by the crossed pipeline without compromising its integrity Ref. [2 , 4, 4 & 5].

Figure 3 and Figure 4 show examples of crossing designs where the existing pipelines are utilised as a support. In Figure 3, the crossing umbilical is laid on the crossed pipeline. The required vertical separation between the crossing umbilical and the crossed pipeline is achieved via a concrete mattress. The weight of the new umbilical and the mattress is partially carried by the crossed pipeline.

Figure 3 shows a situation where the existing (crossed) pipeline is left exposed on the seabed, whereas, the crossing umbilical/cable is excavated and only exposed in the region where it intersects the lay corridor of the crossed pipeline. At the region where the crossing umbilical/cable intersects with the crossed pipeline, a concrete mattress is placed over the top of the crossed pipeline to achieve the required vertical separation between the crossed pipeline and the crossing umbilical/cable. A plastic sleeve is strapped around the crossing umbilical/cable for the protection of the umbilical/cable and its stability and to maintain the allowable curvature of the cable.

In some situations, a covering mattress is required to stop the crossing umbilical/cable from moving laterally on the crossed pipeline under the influence of hydrodynamic forces.

Figure 4 shows a rock cover placed on an existing crossed pipeline with the new pipeline laid on the rock cover. Some designs may subsequently add rock cover over the crossing pipeline. Design of this top rock cover reflects the requirements of secondary stabilisation of the crossing pipeline, upheaval buckling hold down and protection against trawl board or dragging anchor. Design of the rock cover will account for the stability of the rock as well as the potential settlement of the rock.

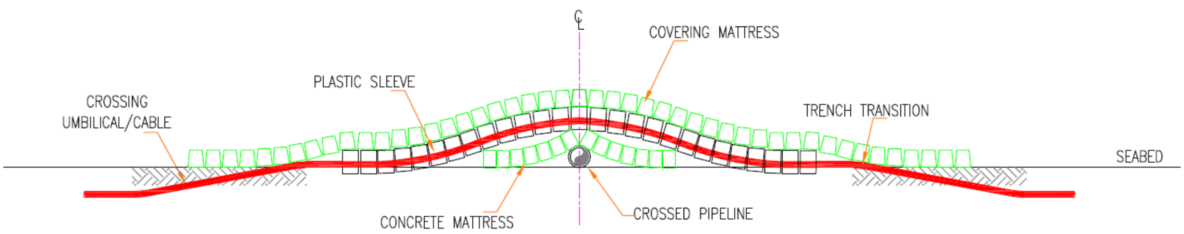

Figure 3: Using the crossed pipeline as a support

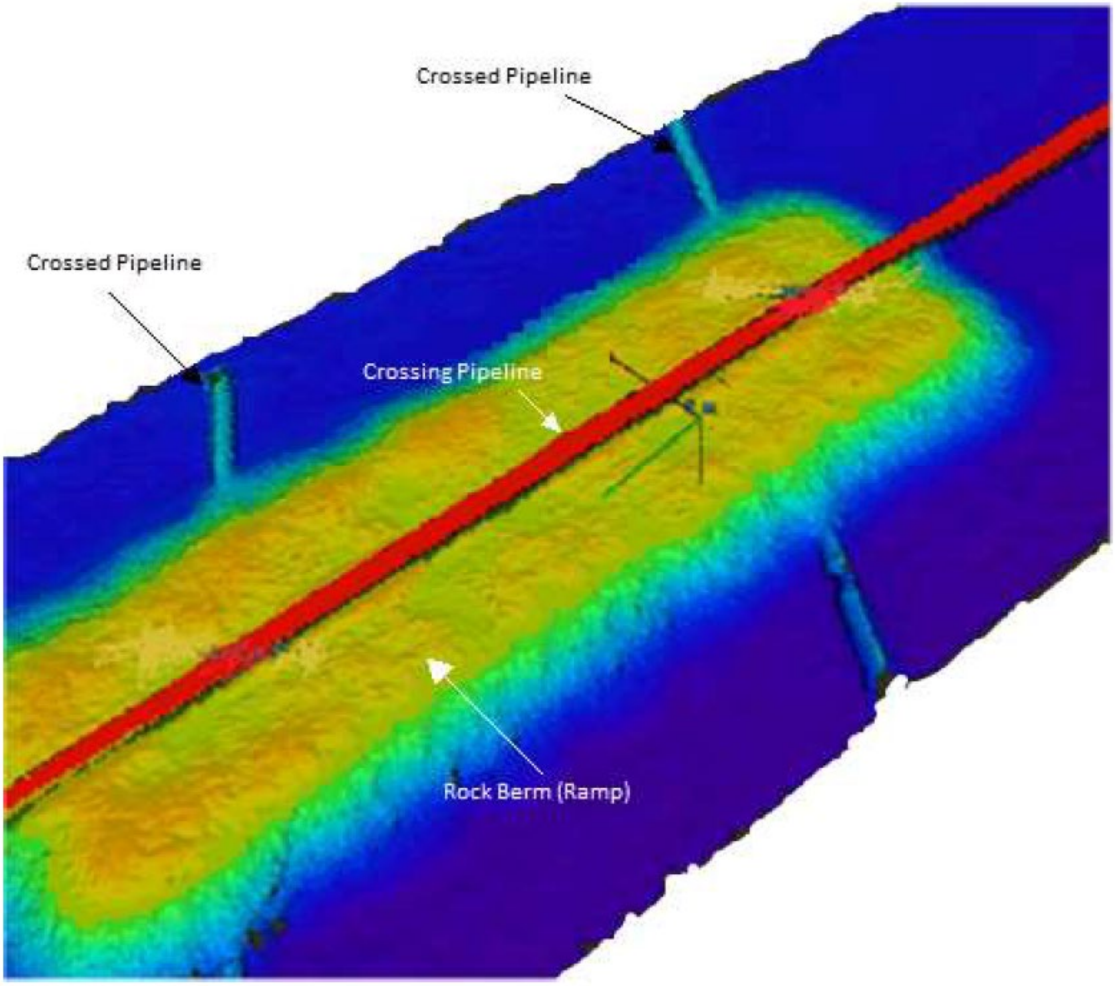

Figure 4: Rock dump concept [Ref. [6]]

It should be noted that the crossing angle shown in Figure 2 is less than 90 degrees. Many pipeline industry sources recommend the included angle between the crossing and crossed pipelines be at a minimum of 30°. This is not based on technical integrity concerns but rather to simplify the construction of the crossing.

For all crossing methods where a third-party pipeline/umbilical/cable needs to cross an existing pipeline/umbilical/cable owned by a different party, a crossing agreement should be prepared by the owner of the crossing pipeline/umbilical/cable and negotiated with the owner of the crossed pipeline/umbilical/cable. The crossing agreement would be divided in two parts: a legal part and a technical part. Owner of the crossing pipeline should include the following, as a minimum:

- Survey of the crossed pipeline/umbilical/cable and the seabed within 200 m of the proposed crossing point for review by the owner of the crossed pipeline.
- The proposed route of the crossing pipeline.
- Drawings, design and detailed schedule relating to the crossing for review by the owner of the crossed assets.
- Crossing installation procedure.

- Permits and approvals complying with all the applicable laws and statutory regulations of the government agencies.

Upon completion of the crossing pipeline/umbilical/cable, the owner of the crossing pipeline should include the following as minimum:

- The post-completion survey at the crossing location.
- A detailed survey of the crossing location within 2-3 years of the crossing installation completion and every 5 years thereafter.

3 Vertical Positive Separation in Codes and Standards

DNVGL-ST-F101 [Ref.[7]] requires that crossing pipelines/cables/umbilicals should be kept separated by a minimum vertical distance of 300 mm.

API-RP-1111 [Ref.[9]] states that "Pipeline crossings should comply with the design, notification, installation, inspection, and as-built records requirements of the regulatory agencies and the owners or operators of the pipelines involved. A minimum separation of 300 mm is required".

ISO 15589-2 [Ref.[11]] states that "A separation of 300 mm is normally adequate, but smaller separation distances may be acceptable if it can be demonstrated that [CP] cathodic protection interference between the lines is insignificant."

In view of the above, when a 300 mm thick mattress or similar protection is placed over the crossed pipeline at the crossing point, then the required positive vertical separation is guaranteed through the design life, provided that the mattress remains correctly in place and does not deteriorate or collapse.

It should be noted that although all the standards and codes require 300 mm of a vertical separation between the crossing and crossed assets, local regulations may require a greater vertical separation.

ICPC (International Cable Protection Committee) recommendation No.3 Issue 10 A [Ref.[11]] states that basic questions should be answered carefully before considering any crossing design. These questions are applicable to the cases where an existing pipeline is crossed by a power cable. The questions are: "Will it require any induced separation to be installed between pipeline and power cable? Will the power cable owner consider artificial separation to be necessary to avoid chafing damage to the power cable?"

Furthermore, ICPC (recommendation No.3 Issue 10 A [Ref.[11]] asks some questions in regards to the cathodic protection of the existing pipeline crossed by a power cable. These questions are "Does the pipeline have cathodic protection? If so, what is the distance between anodes? Are the anode positions accurately known? Can the cable lay be arranged so that the cable is in the mid-50% distance between anodes?"

Cathodic protection systems of the crossing pipeline should be compatible with the existing cathodic protection system on the crossed pipeline and the interaction between the two systems should be evaluated. Based on that, the recommended vertical separation between the crossing and crossed pipelines is important in this regard.

In the case where a high voltage cable crosses over a communication cable, it is imperative to conduct an induced voltage calculation to determine if the induced currents from the crossing power cable may cause damage to the crossed communications cable for the given vertical separation between the top of the communication cable to the bottom of the power cable. If the induced currents from the crossing power cable are found to have damaging effect on the crossed communication cable, the vertical separation between them should be increased. Using articulated padding around the power cable helps to shield some of the induced current.

It is evident from the discussion above that the codes and recommended practices are not explicit in prohibiting installation of a cable crossing at a field joint-coating site of a pipeline when the latter is used as a crossing support.

4 Cable Crossing Design

This section describes the crossing system that was employed for installation of the 132 kV subsea power cable in a congested field of many crossings in a region with no space available on the seabed to install supports.

Figure 5 shows how the crossed pipeline was used as a support. The positive vertical separation between the crossing subsea cable and crossed assets was achieved by the use of articulated padding as shown in Figure 5 and Figure 6.

This system involved offshore application of a specific bend restrictor and articulated padding discs on the new cable prior to installation over the crossed pipeline at the crossing location. Assembly of the system was both quick and efficient, and it was accomplished concurrently with the cable installation.

The articulated padding disc unit is typically made of polyurethane. In this application, it was comprised of two half-shells installed around the bend restrictors at the crossing location. The half-shells were secured by bolting or using pre-cut corrosion resistant banding. The articulated padding outside diameter was 1010 mm, so when the articulated padding was placed over the crossed pipeline at the crossing point, the required separation of 410 mm was maintained over the design life.

The main advantage of this design concept was relinquishing the need for the installation vessel/boat to install a crossing support over the crossing point before installing the new cable over the existing facility/pipeline. Also, installation of the cable at the crossing location did not need to be strictly precise. This allowed the cable to be installed at both a faster rate and reduced cost. This option also allowed post-installation inspection/maintenance on the facility during its operating life, because the new cable can be easily moved (slightly) laterally to allow closer inspection of the crossing and existing pipeline/facility. Another advantage is that the gap between the crossed pipeline and the crossing pipeline/umbilical/cable is not affected by any potential settlement of the crossed pipeline over time. As such, the required vertical separation is guaranteed during the design life. Any intervention to increase the gap or separation during the operation phase was not required.

It should be noted that the design of the articulated passing allowed for relative movement between the articulated padding (discs) and the surface of concrete coated pipeline. This implied that the articulated padding would not always freely rotate when the crossing moves laterally. Rather, the rotation depends upon the complex friction condition of the padding and pipeline, the direction of movement / crossing angle and the loading conditions.

Figure 7 shows deployment of the articulated padding system during the cable installation.

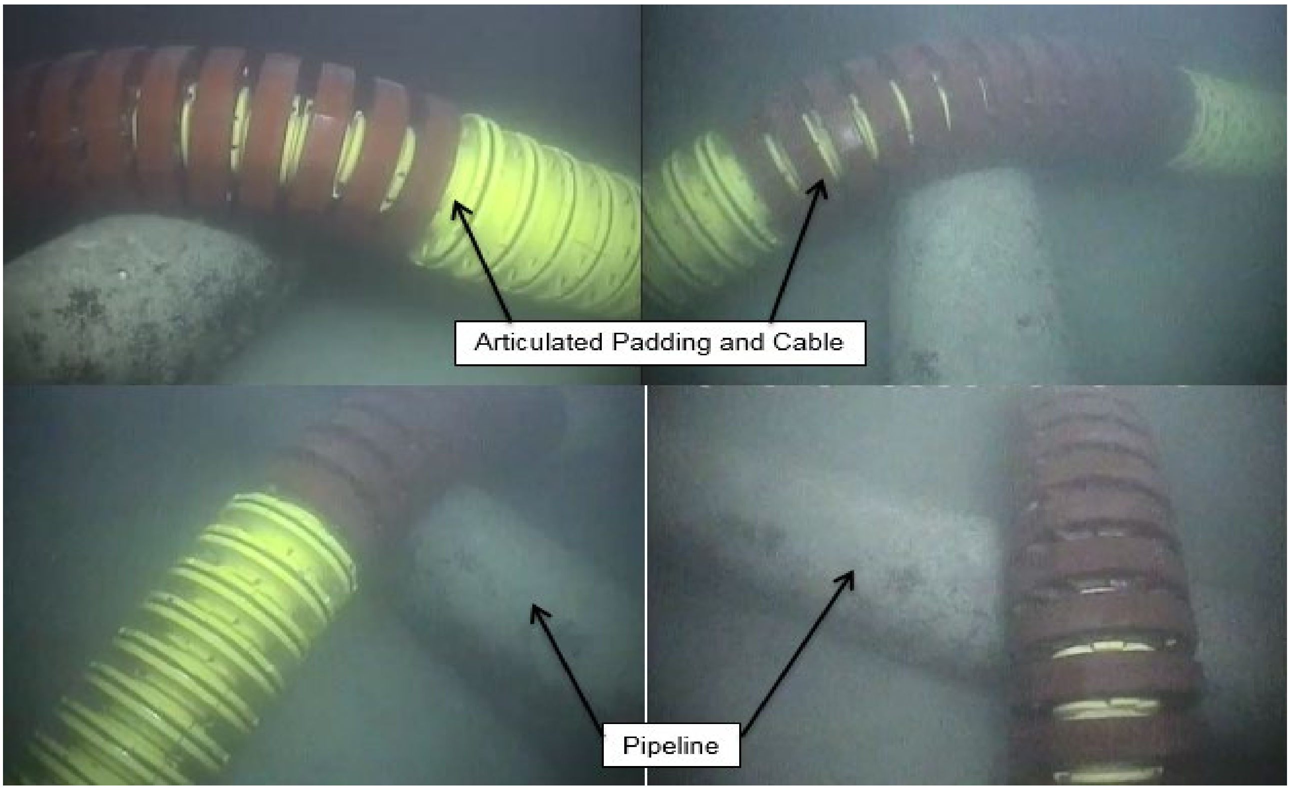

Figure 5: General arrangement of the articulated padding crossing system [Ref.[1]]

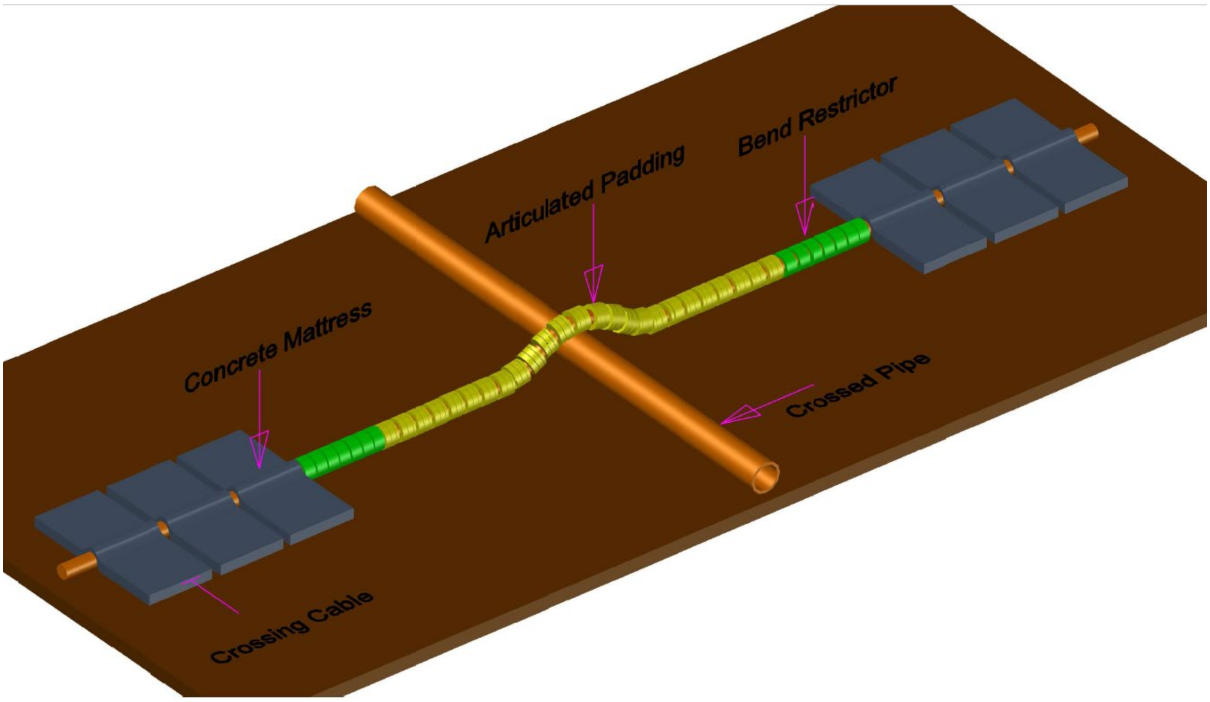

Figure 6: Schematic showing the general arrangement of the articulated padding crossing system.

Figure 7 Deployment of the articulated padding

Figure 8 shows the mock-up trial undertaken on the articulated padding and bend restrictors. The mock-up test was performed to ensure efficiency of the offshore installation procedure during the actual operation.

Figure 8: Mock-up test undertaken at the factory.

5 Design Requirements

The schematic in Figure 9 illustrates elements of the crossing design adopted for the subsea power cable using the articulated padding system and the crossed pipeline as a support. Fitted around the crossing cable, the articulated padding provides the required positive vertical separation and prevents the cable itself from bearing directly on the crossed pipeline. The vertical separation is measured from the top of the crossed pipe to the bottom of the cable's body, as illustrated in Figure 10 . The diameter of the articulated padding is designed and moulded to provide a design vertical separation of 410 mm. The design vertical separation depends on the voltage induced by the cable in the crossed pipeline. The separation is sufficient to ensure that the induced currents from the power cable will not cause any interaction with existing cathodic protection of the crossed pipeline.

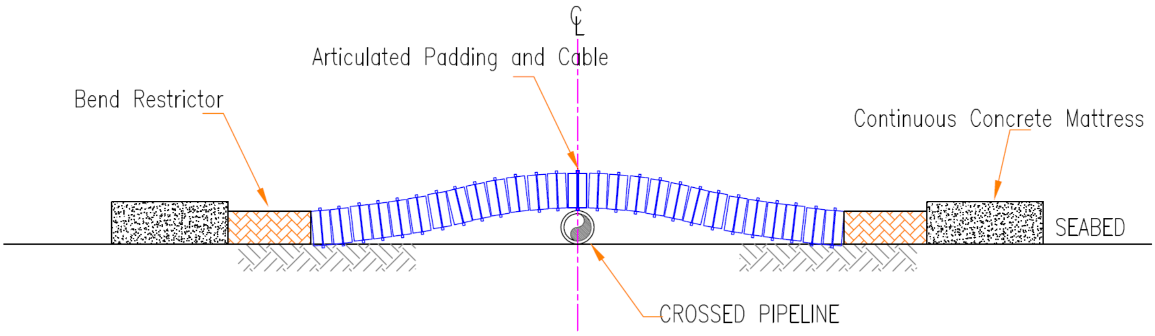

Figure 9: General arrangement of the articulated padding crossing system

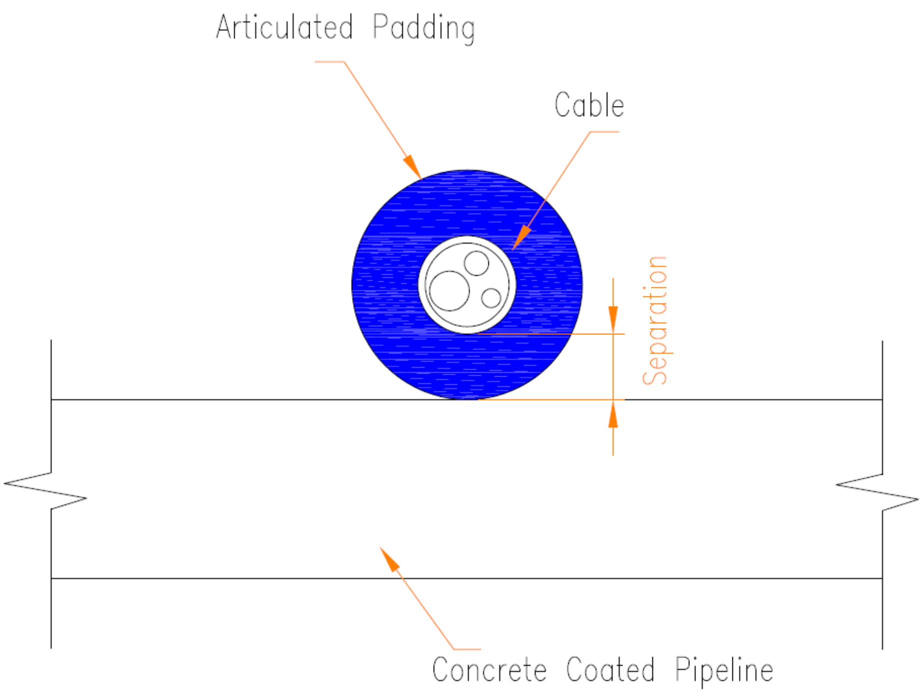

Figure 10: Positive Separation between the crossing cable and the crossed pipeline.

The crossing design was undertaken using the commercial finite element program (ABAQUS Ref.[11]). The objective of the crossing design was to ensure that:

- The crossing cable curvature and effective tension resulting from all loads (weight, buoyancy, residual tension and environmental forces) are within the allowable limits.
- The loads imposed on the crossed pipeline are within the allowable limits.
- Fatigue damage ratio associated with the lateral movement of the cable is within the allowable limits.
- The crossing cable was not designed for absolute stability, meaning that the cable is expected to move laterally under the influence of hydrodynamic loads, so the crossing design ensured that both the cable curvature and effective tension are acceptable without jeopardising the cable integrity under these hydrodynamic loads.
- An abrasion test (see Figure 11) was conducted to ensure that the material loss due to abrasion of the articulated padding will comply with the design life of the cable. Value of the span length between the two cable touchdown points will be such that in-line or cross-flow VIV will not take place as per the criteria given in DNVGL-RP-F105 [Ref. [12]] and Ref.[14]. VIV refers to Vortex induced vibration.
- Finite element dynamic analysis was undertaken on the crossing arrangement shown in Figure 9. Results of the dynamic analysis showed that the predicted lateral movement of the subsea cable was excessive. Further work showed that the movement could be reduced to within acceptable levels by placing a concrete mattresses outside the touchdown points, as shown in Figure 9, ensuring that the limit states listed in Table 1 are satisfied.

Figure 11 Abrasion Test outcome

Visual and side-scan surveys of the crossed pipelines and the seabed within 250 m of the proposed crossing point were conducted in advance so that the crossing design could be verified prior to installation of the cable. The survey focused on the following:

- Providing data for designing appropriate crossing locations and configuration.
- Truthing existing or crossed pipelines burial and seabed levels (i.e. depth of burial of the crossed pipeline as measured from natural sea-bottom to top of pipe).
- Obtaining detailed bathymetry of the crossing site area.
- Examining the physical condition of the crossed assets.
- Establishing an as-laid position of the crossed pipeline.
- Locating the sacrificial anodes in the proximity of the crossing point.

If the crossing design concept uses discrete supports or a ramp as shown in Figure 2, a geotechnical survey is also required at the crossing point to enable characterisation of the soil type and its shear strength parameters. However, this survey is not required if the design is based on articulated padding, since the positive separation is maintained irrespective of the settlement of the crossing configuration.

During the visual survey, the anodes in the proximity of the crossing point were identified as shown in Figure 12. Design of the crossing ensured that any lateral cable movement due to hydrodynamic forces would be away from the existing sacrificial anodes. To ensure that the cathodic protection of the crossed pipeline is not compromised, the cable lay was arranged so that the cable crossing was mid-way between the anodes as per [Ref. [14]].

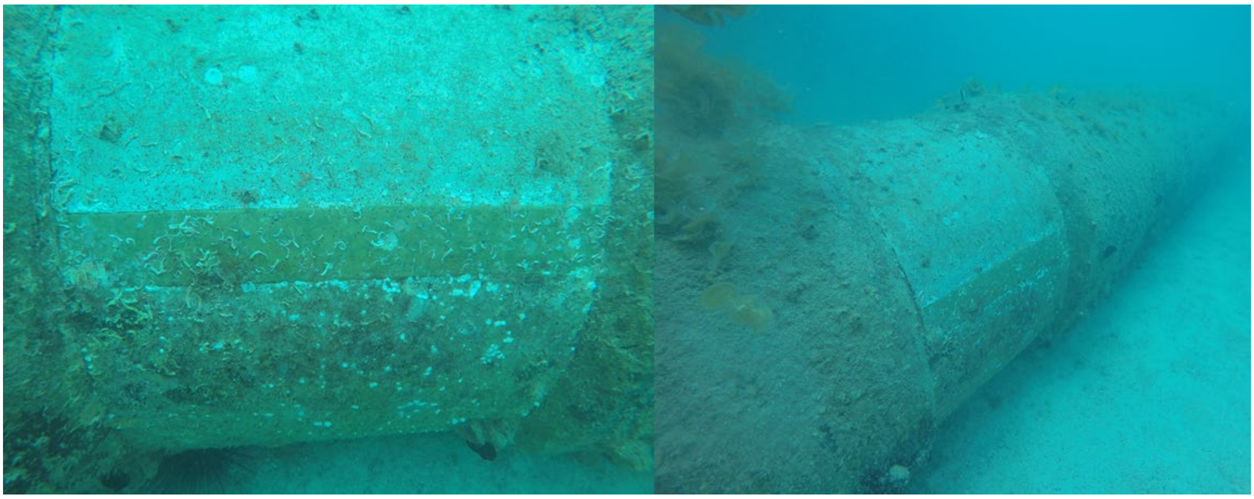

Figure 12: Anodes in the proximity of the crossing point

As part of the crossing design, an induced voltage study was undertaken to:

- Ensure that the shielding around the power cables was sufficient to render the likelihood of electromagnetic interference sufficiently remote from being of practical concern.
- Confirm that the selected positive separation between the crossed pipeline and the crossing cable was sufficient to ensure that the induced current from the crossing cable will not interact or compromise the existing cathodic protection on the pipeline.

6 On-Bottom Design Philosophy

6.1 General

The submarine cable stability was verified in accordance of DNVGL-ST-F101 [Ref. [7]] and DNVGL-RP-F109 [Ref. [15]], although these standards/recommended practices are not applicable to submarine cables, especially with regards to the safety objectives.

The stability analysis at the crossing locations involved assessment of the cable integrity and response at the crossing locations when subjected to hydrodynamic forces. The integrity of the cable was verified in accordance with the limit states provided in DNVGL-ST-F101 [Ref. [7]]. The limit state design approach requires that all established safety objectives are met by:

- Sustaining functional loads.
- Surviving extreme events.
- Mitigating the consequences of failures.

Based on the above, criteria are required to assess whether the risk of a failure event is acceptable or not. As per DNVGL-ST-F101 [Ref. [7]], the acceptance criteria are based on fulfilling acceptable limits for the risks with respect to environment, human safety as well as economics. In DNVGL-ST-F101 [Ref. [7]], the acceptance criteria are based on achieving the required target reliability levels for the applicable limit states. During the stability assessment of the cable, all relevant failure modes formulated in terms of limit states are considered.

6.2 Limit States

The following limit states were considered in the design of the cable at the crossing locations:

a) **<u>Serviceability Limit State</u>**

DNVGL-RP-F109 [Ref. [15]] considers excessive displacement due to the action of the hydrodynamic loads to be a serviceability limit state. In the context of a crossing cable, the serviceability limit state is reached in the following cases:

- Excessive and repeated lateral movement of the cable that could lead to abrasion to the outer sheathing of the cable, as shown in Figure 13. Once the outer sheath is abraded, the galvanized armour will also gradually abrade, and consequently the armour will corrode. Abrasion of the subsea cable takes place due to relative motion of the cable against rough surfaces such as a rocky seabed. [Ref. [16]] explained that cable abrasion over time, associated with the lateral movement, will inevitably lead to cable failure as shown in Figure 14. It is indicated by [Ref. [16]] that abrasion of the outer sheath of the cable could possibly lead to fibre failure and a cable break.
- If the cable moves laterally over the crossed pipeline and became in contact with the anodes of the crossed pipeline.
- If the cable moves laterally over the crossed pipelines and comes into direct contact with the field joint of the pipeline.

Figure 13: Outer sheathing damage and armour exposure due to instability

Figure 14: Example of cable break due to abrasion [Ref.16]

b) Ultimate Limit State (ULS)

The ultimate limit states considered compromise the minimum bend radius and the corresponding tension/compression limits.

c) Accidental Limit State (ALS)

In this context, the accidental limit state is similar to the ultimate limit state, except that the probability of occurrence is much lower.

d) Fatigue Limit State (FLS)

Fatigue damage of the cable may occur due to:

- repeated lateral movement
- Vortex induced vibration (VIV).

6.3 Analysis Methodology

Two approaches are used to assess the on-bottom stability of a subsea cable:

1) Static approach:

This approach uses the traditional force balance method. The purpose of this approach is to determine the cable submerged weight that ensures absolute stability of the submarine cable at the crossing location (i.e. zero displacement of the cable under the hydrodynamic loads). Typically, this approach is implemented when the flow regimes are dominated by a steady current. This approach is primarily used as a screening assessment tool for identifying the locations requiring further optimization.

2) Dynamic approach:

This approach is used to: (a) optimize the results obtained from the static stability approach, by investigating the cable response under the influence of the hydrodynamic forces and (b) to identify the extent of the secondary stabilization based on the response under extreme environmental forces. The acceptance of the dynamic approach is achieved by fulfilling the applicable limit states.

Table 1 presents the environmental return period to be applied for the applicable limit state. The return period in the analyses depends on the limit state being considered.

Table 1: Environmental Return Period

Design Criteria	***Definition***	***Assessment Criteria***	***Return Period (Year)***
Ultimate Limit State	Cable at limit of integrity	Cable minimum bend radius versus effective tension/compression load	100
Serviceability Limit State	Cable at limit of integrity of serviceability	Cable inoperable	100
	Assessment to check the degree of cable stability	Extent of cable displacement	
Accidental Limit State	Cable at limit of integrity	Cable minimum bend radius versus effective tension/compression load	1000
Fatigue limit state	- Cyclic loading may lead to fatigue damage for a cable that is allowed to move laterally along the crossed pipeline. - Cyclic radial loading combined loading may lead to fretting fatigue damage to the articulated padding.	Ensure that the radial and load experienced by the articulated padding are within the allowable limits of the polymer material and within the limits provided by the manufacture. The fatigue damage ensured by the cable are within the allowable fatigue damage ratio.	Ambient metocean condition

7 Field Joint Coating Failure

The 132 kV subsea power cable and the crossing arrangement shown in Figure 15 were installed successfully in 2012. Figure 15 presents a snapshot from the as-built survey undertaken upon completion of the concrete mattress installed to reduce lateral cable movement.

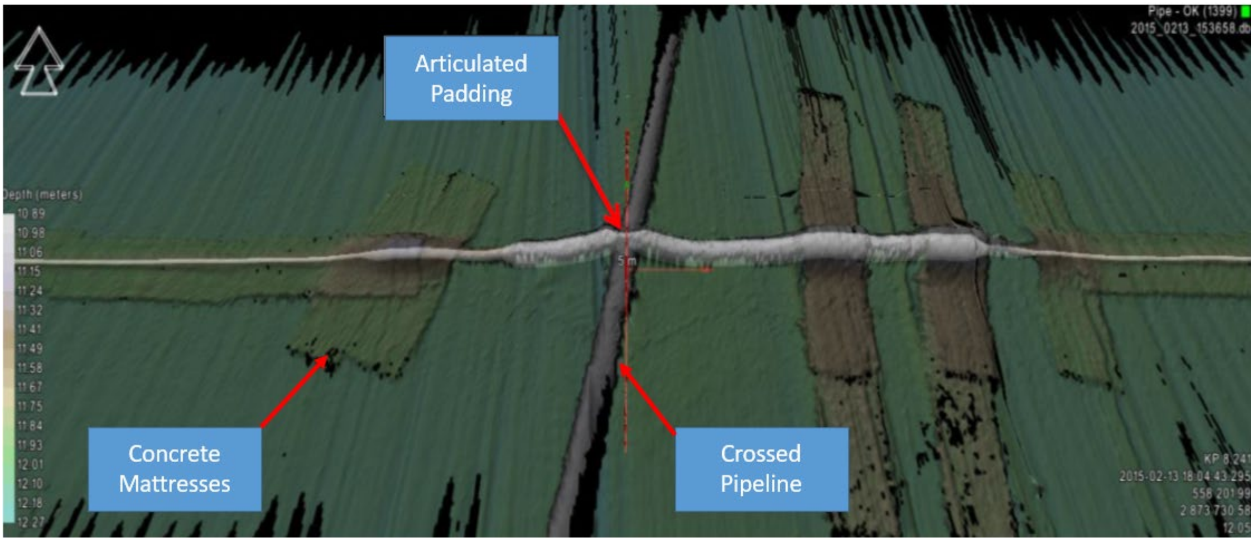

Figure 15: Snapshot from the as-built survey of the 132 kV -0.191 m power cable at the crossing area

Figure 16: ROV Survey at the crossing locations- Note the articulated padding installed on the crossed pipeline away from the field joint

A post-installation survey was undertaken one year after the cable installation. The survey included three dozen crossing locations similar to that shown in Figure 16. Visual inspection revealed that coating damage had occurred in the pipeline field joint at two crossing sites.

Figure 18 and Figure 19 reveal the damage resulting from the lateral movement of the cable and the articulated padding, combined with the contact load exerted by the cable/articulated padding on the field joint coating.

Furthermore, Figure 17 and Figure 18 show damage in the concrete weight coating cutback. This indicates that the cable/padding was moving laterally and the concrete cutback acted as a stopper (to some extent).

Figure 17: Damaged Field Joint Coating-Pipeline # 1. Note that the cable is not yet lifted for the purposes of inspection in this photograph.

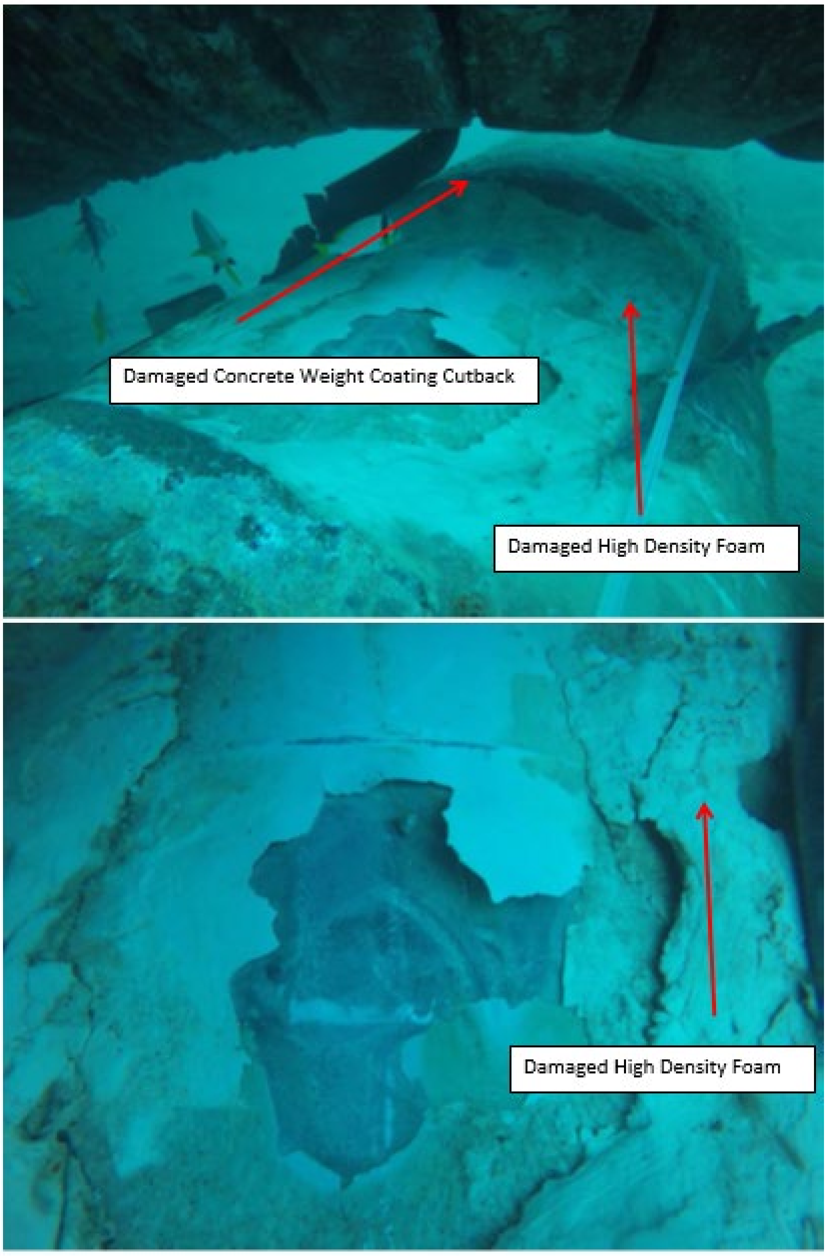

Figure 18: Damaged Field Joint Coating-Pipeline # 1. Note that the cable was lifted for the purposes of inspection in this photograph.

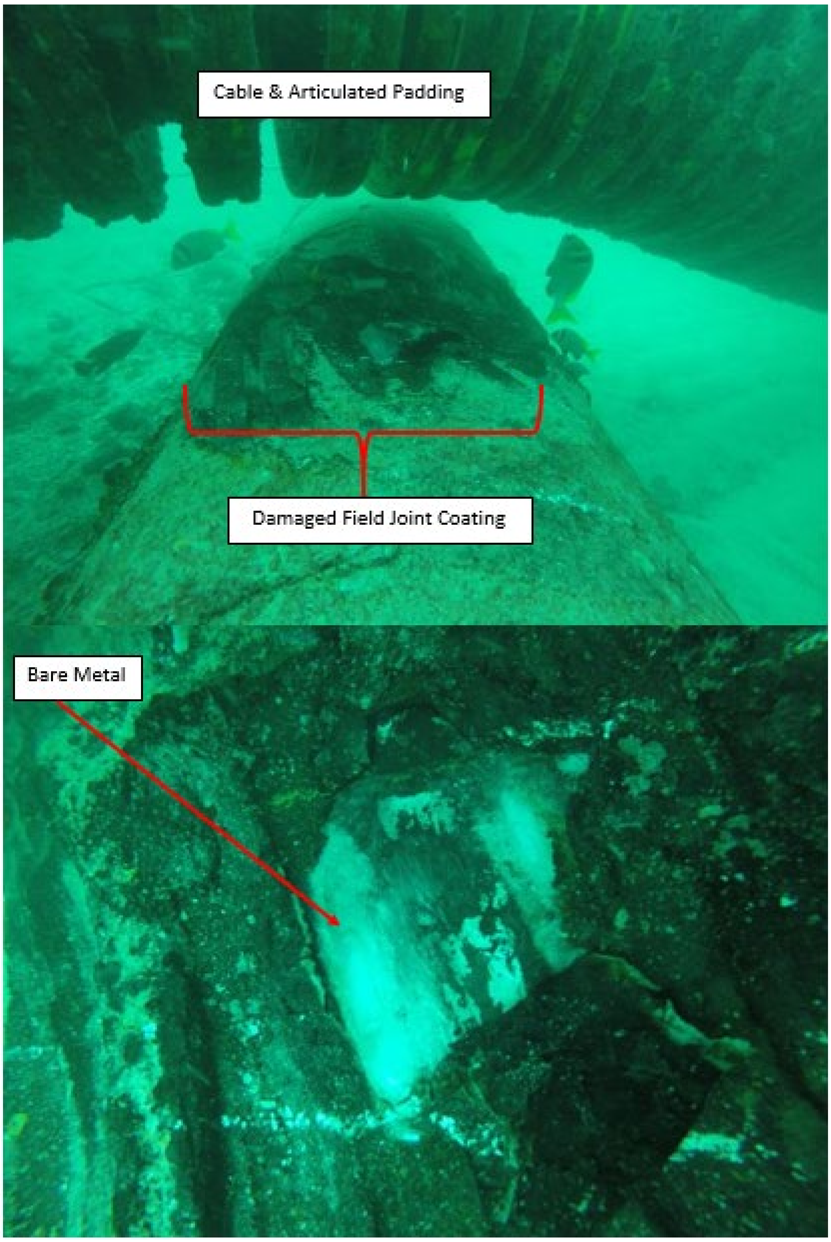

Figure 19: Damaged Field Joint Coating-Pipeline # 2

The damage occurred along the entire width of the field joint coating (approximately 0.8 m), confirming that the damage spread across both sides due to cyclic lateral movement.

8 Root Cause Analysis

The root cause analysis reviewed potential factors in several categories: engineering design, manufacture, installation and environmental aspects.
From the root cause study, it was concluded that the damage of the field joint coating is attributed to the combined effect of installation works, lateral cable movement and repeated dynamic impact.

8.1 Installation

The root cause analysis identified that prior to finalization of the crossing design, a ROV survey was undertaken of the crossed pipelines and the seabed within 250 m of the crossing point. A survey requirement was to ensure that there was no anode at the crossing point. As per the industry practice, the crossing survey focused on the existing pipeline burial depth, detailed bathymetry of the crossing site area seafloor levels and the physical condition of existing pipelines. However, the survey did not identify the location of the pipeline field joints in relation to the design crossing point. The crossing design was finalised based on the results of that survey. The cable installation contractor used the side-scan and visual data from the ROV survey at the proposed crossing location in the Installation procedure.

During the survey, identification of the joint numbers and field joints was not carried out. Locating field joints in relation to the crossing point as part of the pre-lay survey is not a common practice in the cable/pipeline industry. Moreover, the joints in older pipelines may be covered in marine growth which increases the difficulty in identifying them. If pipelay records are not available, identification of the joints would be extremely difficult.

The root cause investigations revealed that the codes and recommended practices are not explicit about prohibiting installation of a crossing at a field joint of a pipeline.

In the case study presented here, the cable with the articulated padding was unintentionally laid on the field joint location during the cable installation works, as illustrated in Figure 20.

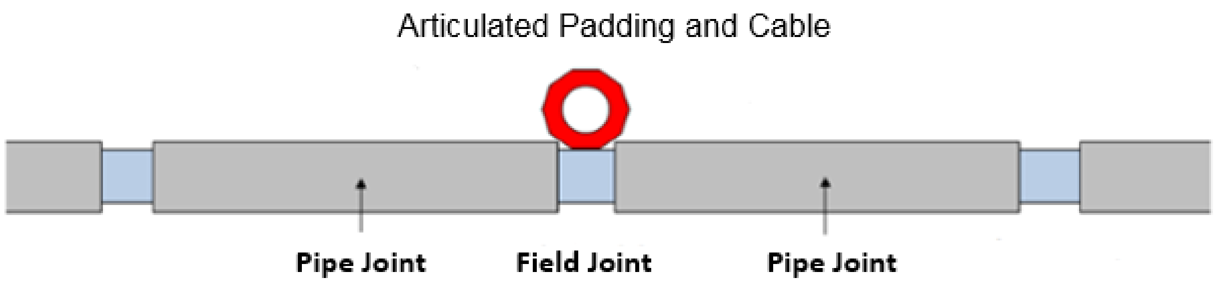

Figure 20: Location of articulated padding in relation to field joint

The investigation also indicated that during the cable installation, it was difficult to identify the field joint due to presence of marine growth. Figure 21 and Figure 22 show images for the first field joint downstream from the damaged field joints for pipeline # 1 and pipeline # 2. From these figures it is evident that the field joints were indeed fully covered with the marine growth. This made it impossible to differentiate between the pipeline and the field joint.

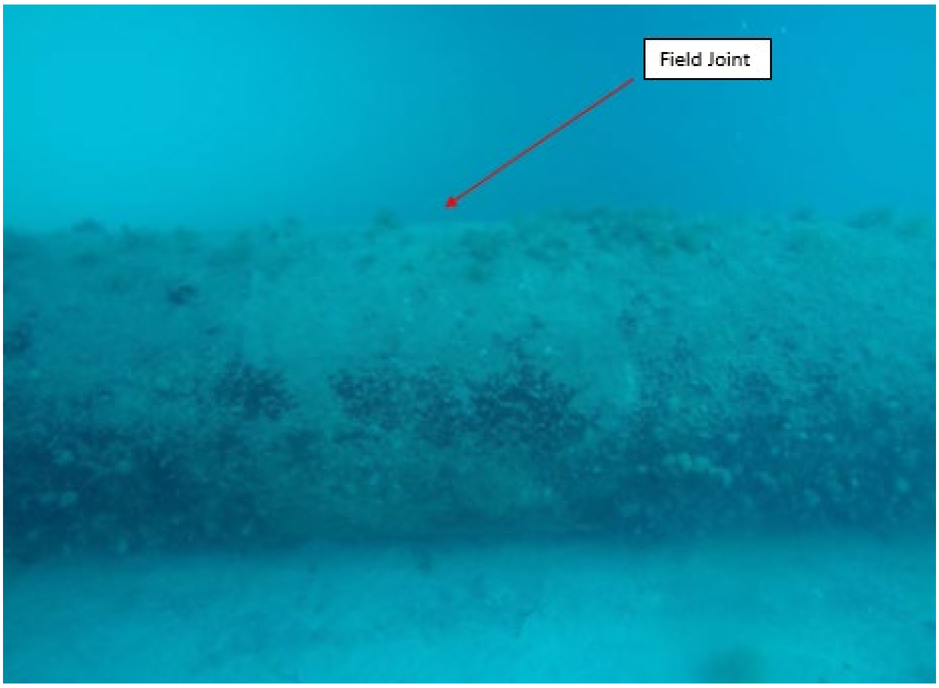

Figure 21: Field joint coating downstream the damaged joint- Pipeline # 1 (note the overgrowth)

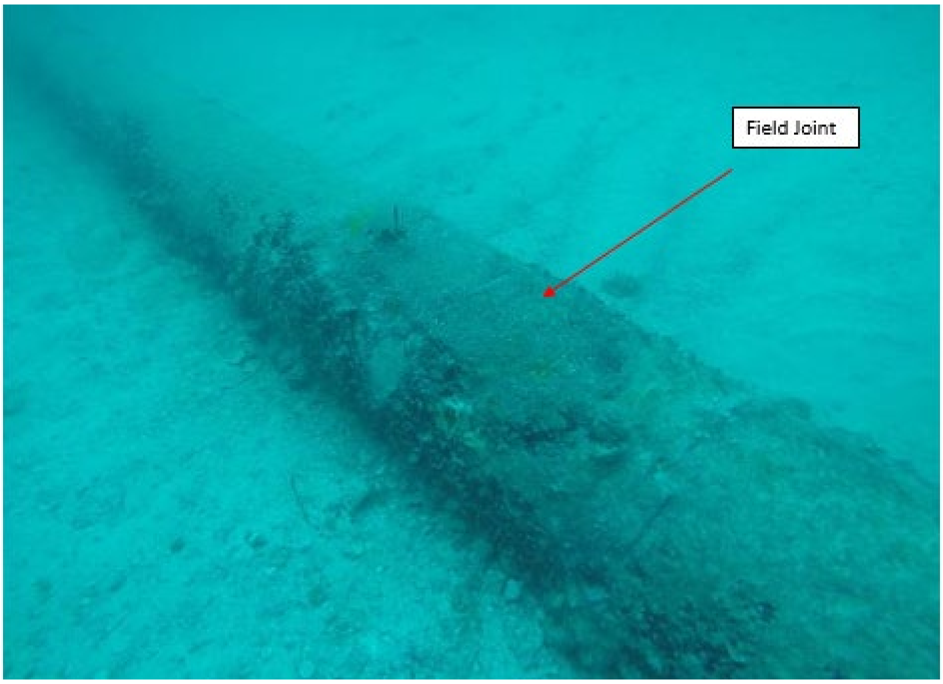

Figure 22: Field Joint downstream of the damaged field joint- Pipeline # 2 (note the overgrowth)

8.2 Lateral Movement

Numerical simulations using ABAQUS [Ref. [11]], were undertaken to estimate the contact loads generated by the articulated padding on the field joint. The finite element model used in the investigation is shown in Figure 23 and the results are provided in Table 2. The radial and axial loads are reported at the crossing point as shown in Figure 1. The lateral displacement presented in Table 2 is for the articulated padding at the crossing location (i.e. for the articulated padding resting on the crossed pipeline).

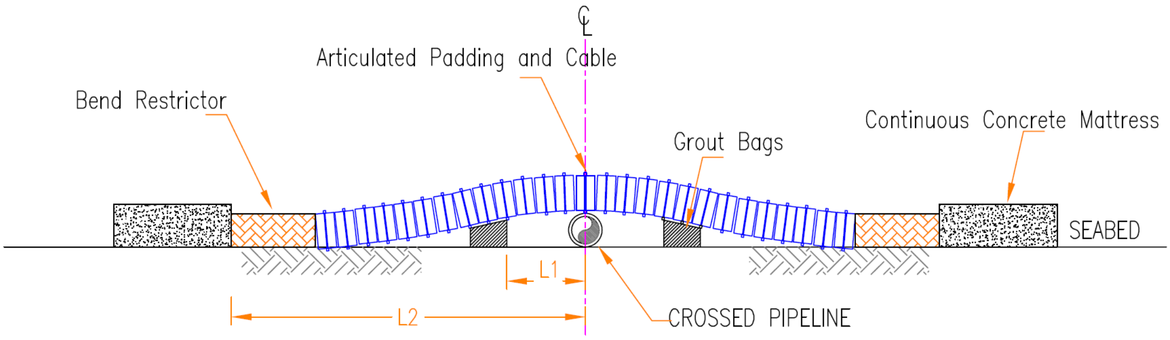

Figure 23: Finite Element model

The main features of the finite model used in the assessment are as follows:

1. The cable, bend restrictor and padding were all specified as separate entities with their own properties and interfaces.
2. The seabed, the crossed pipeline and the grout bag were modelled using an analytical rigid cylindrical surface.
3. The soil at the locations of the damage was dense siliceous carbonate sand with areas of gravel over very weak to moderately weak calcarenite /weak to moderately strong limestone.
4. The contact between the cable/articulated padding/bend restrictor and the seabed was modelled as soft contact. Friction between the cable/articulated padding/bend restrictor and the seabed was assigned to the seabed in the axial and lateral directions. The standard ABAQUS friction model was employed in the analyses. The friction between the articulated padding and the crossed pipeline/grout bag was modelled using a simple Coulomb friction model. The contact between the articulated padding and the crossed pipeline was modelled using contact elements.
5. The interaction between the bend restrictor and articulated padding (disc) was modelled using contact element. The friction between the bend restrictor and the articulated padding (disc) was modelled using a simple Coulomb friction model.
6. The minimum cradle height was 25% of the articulated padding (disc) diameter as highlighted in Figure 24 and Figure 25 to achieve the required pinning of the padding and the cable. Lateral restraint was added to the section of the padding area resting on the cradles.
7. A subroutine was used to generate the time series of water particle velocities at the seabed and at the crossing levels. The subroutine required the surface wave spectral data and a steady current. The time series of water particle velocities at the seabed was generated as follows:
    - A JONSWAP spectrum was generated using the equivalent spectral parameters.
    - Using the mean direction and the wave spreading, the JONSWAP wave spectrum was transformed to a directional spectrum.
    - The directional wave spectrum was transformed to the near seabed velocity spectrum using linear wave theory.

- The velocity spectrum was transformed to a time history of velocity along the cable using the inverse fast Fourier transformation.

8. The articulated padding resting on the cradle was shielded from the external hydrodynamic loads.
9. The directionality of the wave and current in relation to crossing location was considered.
10. The cable crossing was at 90 degrees to the pipeline. This represented the worst-case scenario. It was found that the axial and radial loads reduced as the crossing angle became acute.

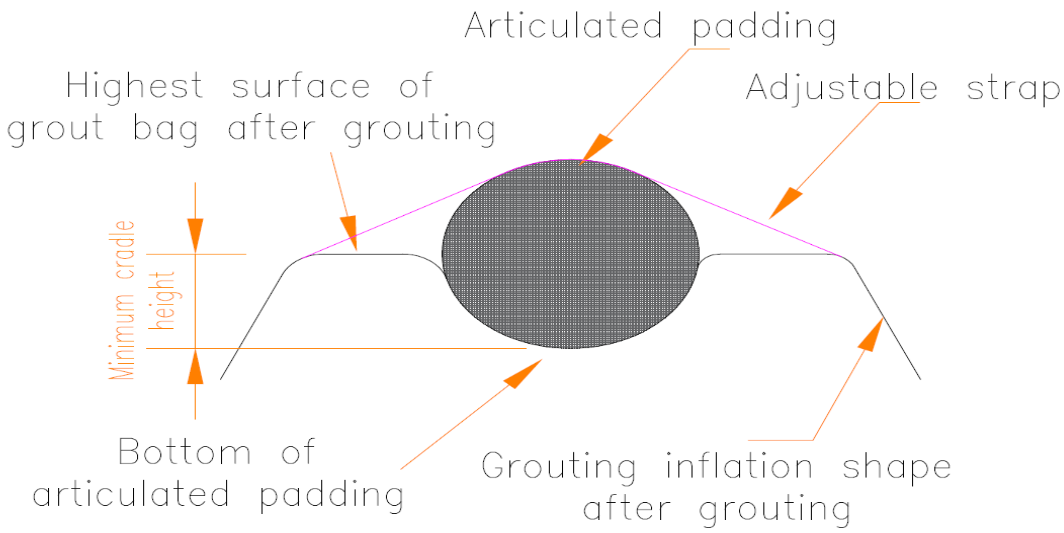

Figure 24: Minimum height of the cradle

Figure 25: Mock-up trial for the cradle support

Table 2: Crossing analysis results

Case Number	L1	L2	Grout bag type	Maximum radial force (kN)	Maximum axial force (kN)	Maximum lateral displacement (m)
1	No grout bags	7.5	No grout bags	55	6	0.65
2	2	7.5	Vertical support only	49	2.5	0.65
3	2	7.5	Cradle type	12	1	0.15
4	1.5	7.5	Cradle type	10.8	0.6	0.09

<u>Notes:</u>

1- The residual lay tension used in the simulation was 6 kN and it was applied before the grout bags were installed under free span.
2- The water depth was 22 m.
3- The maximum wave height and maximum wave period used in the simulation were 8.3 m and 8.6 s, respectively.
4- The steady current at the sea surface was 1.25 m/s.
5- The vertical support provides only vertical restraint, and that the lateral restraint is ignored. Therefore, the lateral displacement for case-1 and case-2 are the same.

The finite element analysis clearly showed that reducing the free span from 7.5 m to 2 m (L2 and L1 respectively in Figure 23), by adding a vertical support, reduced the radial and axial loads. Adding cradle type bags with further horizontal restraint greatly reduced these loads. Also, it can be seen that for cases 3 and 4 with cradle type support, reducing L1 from 2 m to 1.5 m lowers the radial/axial forces and the lateral displacement at the centre of the crossing.

Based on the dynamic simulations undertaken, the following results were determined.

- Increasing the free span length generates significantly larger lateral movement across the crossed pipeline.
- Increasing the lateral displacement can significantly increase dynamic radial loads. As such, it must be considered as a contributing factor.
- There is a strong link between radial/axial load, support placement, type of support and lateral movement of the cable at the crossing.
- Providing cradle type grout bags (vertical & lateral restraint) each side of the crossing will reduce the lateral movement, because the cradle type grout bags provide additional restraint to the articulated padding/cable. Furthermore, the articulated padding sections resting on the

cradle are shielded from the external hydrodynamic loads. This can be demonstrated by Figure 24 and Figure 25.

- The advantage of vertically constraining the crossing close to the asset is to reduce the radial and axial reaction forces exerted on the load bearing of the articulated padding. This is in part because the self-mass of the entire crossing, bend restrictor, articulated padding and cable in free span acting at the contact surfaces is reduced. The vertical reaction load is directly proportional to free span length.
- The advantage of horizontally constraining the crossing close to the asset is that both the axial and radial loads are reduced through the significant reduction in the lateral displacement.

The sea state used in the assessment is shown in notes 3 and 4 of Table 2. This data is used during the design stage.

The actual sea state for the duration when the damage of the field joint coating occurred was reviewed. It was concluded that the actual sea state in this period did not exceed the sea state used in the original design. Dynamic analyses were undertaken based on the actual sea state and it was found that the radial and axial loads were 39.1 kN and 1.7 kN, respectively, producing a maximum lateral displacement of 0.32 m for the articulated padding at the crossing.

The damage of the field joint occurred at a less onerous sea state than was originally designed.

8.3 Repeated dynamic impact loads

Dynamic loads due to rolling or sliding of the articulated padding across the rough surface of the round pipeline are difficult to quantify, because of the complexity of the lateral motion and involvement of many unknown force components. However, the damaged concrete at the cutback area shown in Figure 26 appears to have resulted from significant rolling and sliding loads.

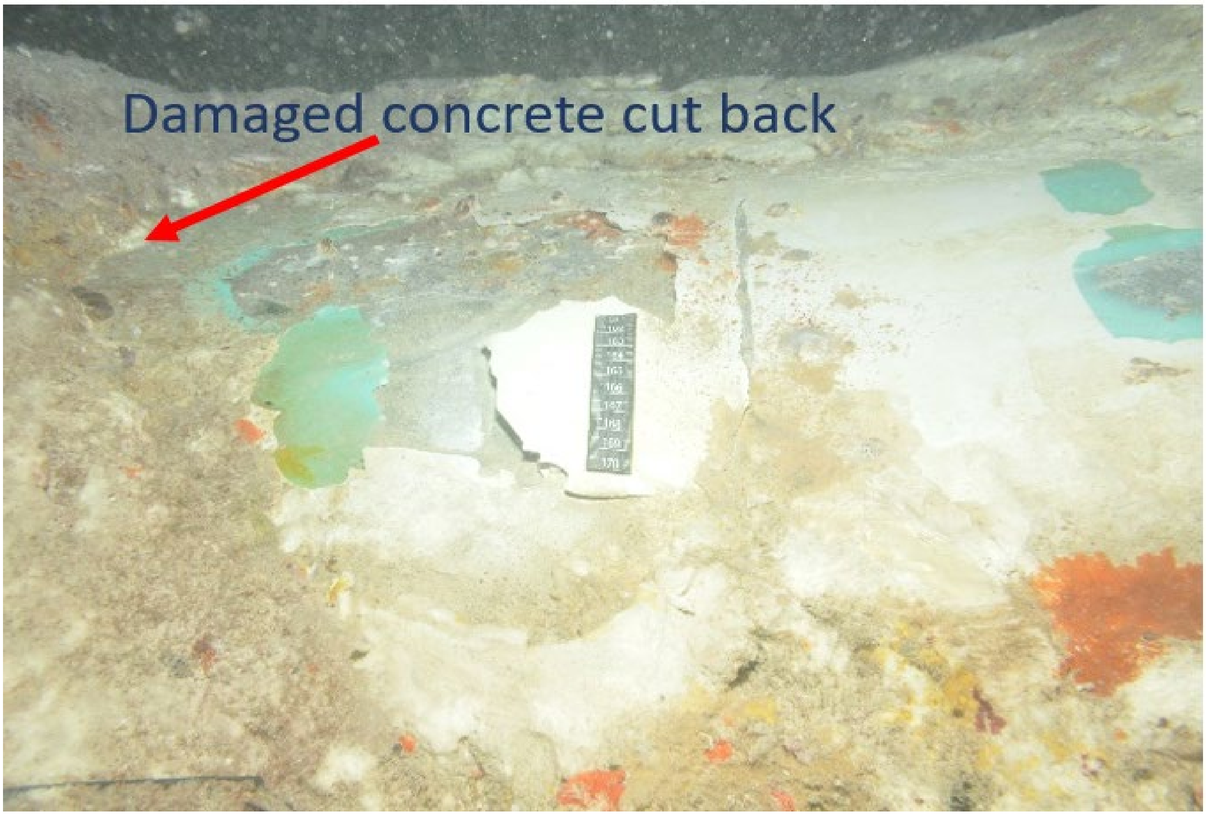

Figure 26: Damaged concrete cut back

9 Rectification

A mitigation measure was implemented to repair the field joint coating and prevent future damage at the site.

The finite element simulations undertaken demonstrated that if the cable free span length and lateral movement are reduced by adding vertical and horizontal constraints as close as possible to the pipeline, the global reaction forces due to self-weight and environmental factors (waves and current) will be reduced. Accordingly, it was decided to install two large cradle grout bags (Figure 27) to prevent contact between the pipeline field joint and the cable. The distance between the crossed pipeline and the edge of the grout bag and the edge (X in Figure 27 and L1 in Figure 23) was set to 2 m.

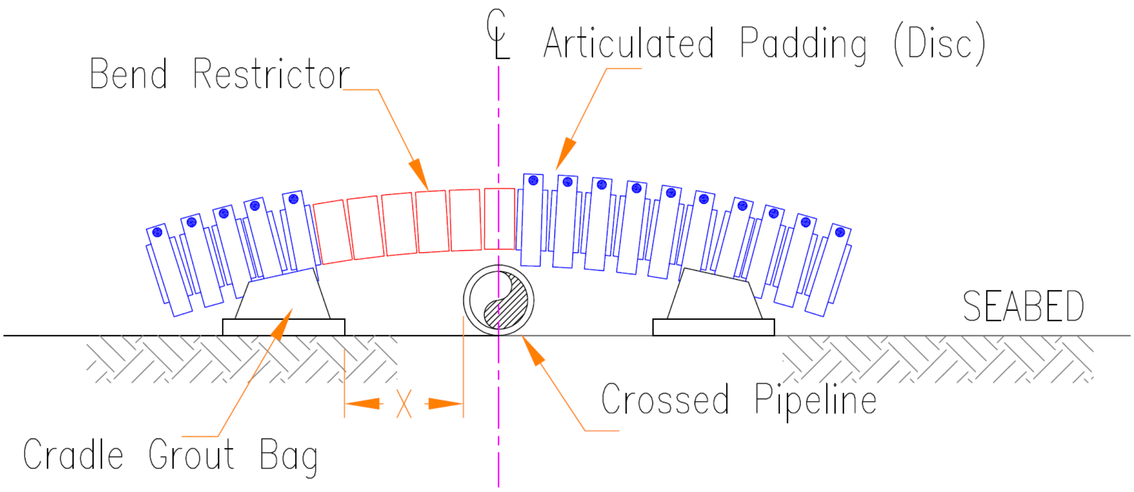

Figure 27: Installation of cradle grout bags.

The inspecting diver confirmed location of the grout bag via the locating transponder unit. This installation location was recorded during the rectification by the survey team. Figure 28 shows that the bags were inflated with concrete, and air bags were used to lift the cable off the grout bags. The discs were then installed around the bend restrictor are removed and seafloor excavated underneath the crossed pipeline to facilitate repair of the field joint coating. Also, some of the concrete mattresses installed originally at the touch down points were removed to ease lifting the cable using the air bags. Once the cradle grout bags were inflated and in place, then the divers used the adjustable straps and tighten the cradle up onto the discs. Then the concrete mattresses were returned to their locations at the touch down points.

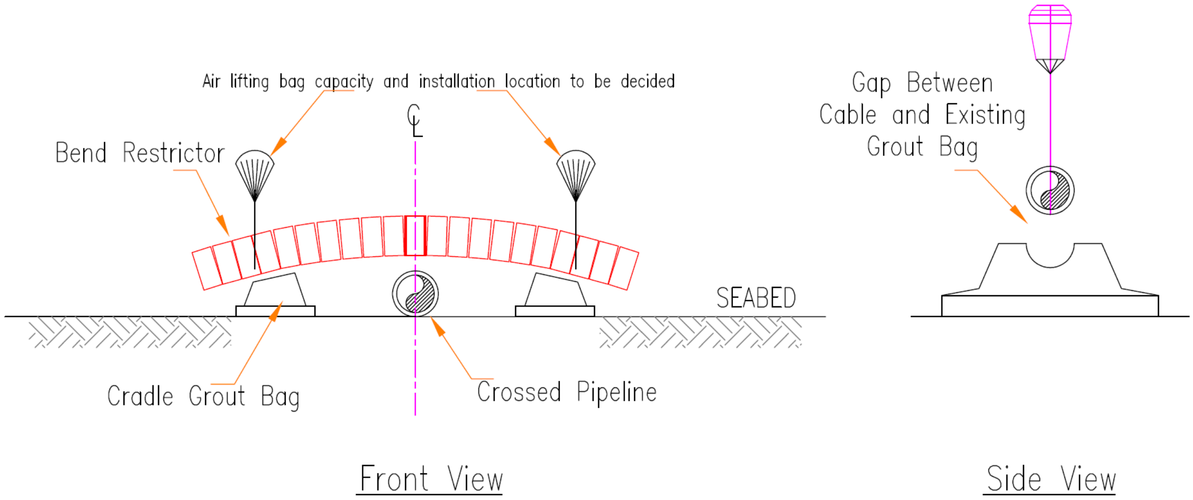

Figure 28: Lifting of subsea cable

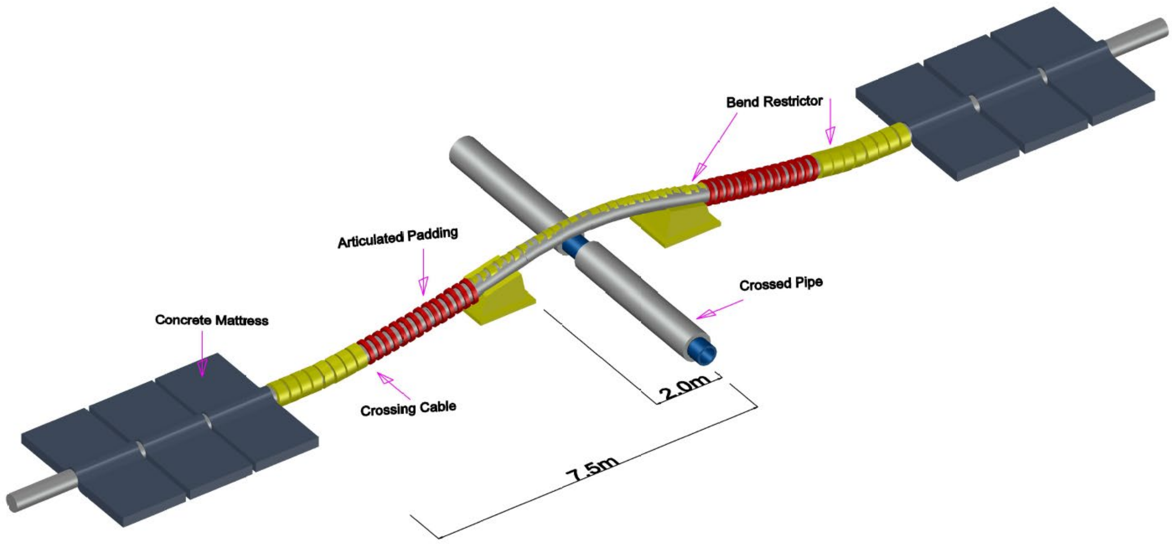

Figure 29: Final Position

Figure 29 shows a schematic of the situation after the repair was completed, the air bags removed and the cable supported by the grout cradle bags. The required vertical distance of 410 mm from the bottom of the cable to the top of the field joint was achieved by the design-specific grout bag.

Figure 30: Actual Footage showing air bags lifting the cable

Figure 30 shows photos of the air bags lifting the cable where the articulated padding system was lifted. The right-hand side photo shows the field joint after repair.

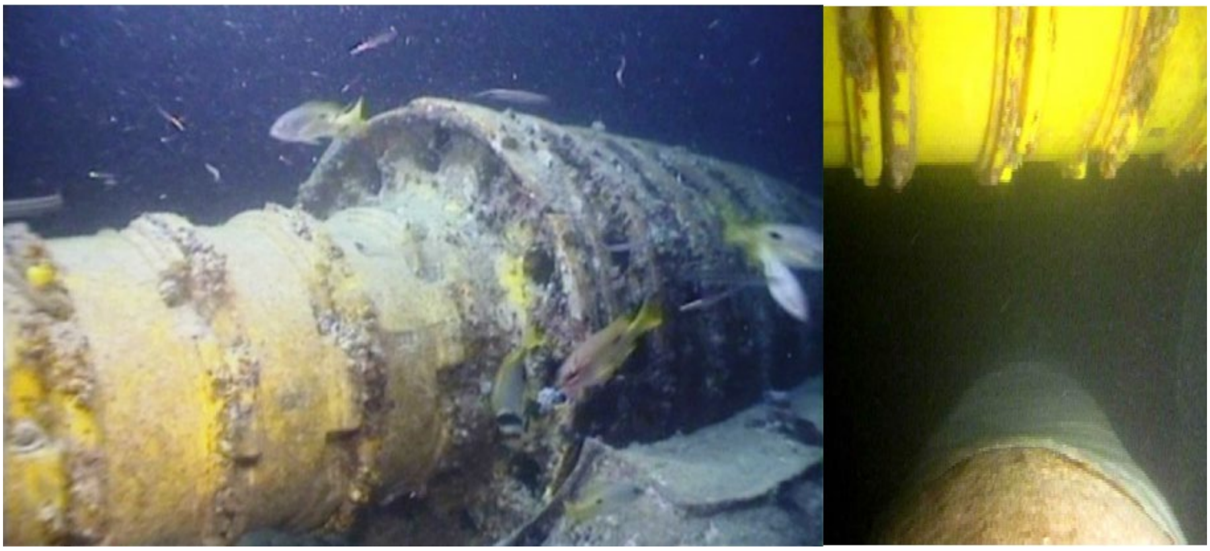

Figure 31: Photo showing the as-built vertical separation and cradle grout bag support.

The right-hand side the photo of Figure 31 shows the as-built vertical separation between the bottom of the cable/bend restrictor and the top of the field joint. The left-hand side photo of Figure 31 shows the cable/bend restrictor sitting on the cradle grout bag. It can be seen from the same figure that the bend restrictor prevents the cable from sagging at the crossing point.

The option of shifting the cable away from the field joint was investigated but this option was found to be unfeasible due to the cost of relocating numerous mattresses installed at the cable touch down point plus the risk to the exposed section of the cable in the crossing exclusion zone.

10 Operational Experience

A recent ROV survey was performed at the crossing locations where the rectification was made to document the experience and the performance of the articulated padding, bend restrictor and the cradle grout bag under the functional and environmental loadings. The ROV survey was undertaken six years after the rectification.

Figure 32: ROV survey for the cable and the bend restrictor

Figure 33: ROV survey for the cable and the cradle support.

It is evident from Figure 32 that the bend restrictor is intact and still preventing the cable from sagging at the crossing point and the vertical separation between the bottom of the bend restrictor to the top of the crossed pipeline is maintained.

Figure 33 demonstrates that the discs rest on the cradle and the discs are restrained by the cradle. There is no sign that the discs broke through the cradle. Furthermore, there is no sign of damage of the cradle.

The ROV survey also covered the mattresses at the touchdown point to investigate if the cable was washed away from the mattresses. This is shown in Figure 34.

Figure 34: ROV survey showing the mattresses at the touch point.

11 Conclusions

The paper describes a case study of failure at the field joint coating of a pipeline crossed by a 132 KV submarine cable. The damage occurred due to the lateral instability of the cable and the associated the lateral movement under the influence of the hydrodynamic forces. The investigation showed that the hydrodynamic stability of the crossing cable or line is an issue of practical significance to system integrity and it should be considered during design. The investigation and video survey provide evidence that increased free span – defined as the distance from the crossing asset to the first vertical support – will lead to a larger lateral movement. It is important during the assessment of the lateral stability of a cable/pipeline at the crossing location to study the interaction between the free span and lateral movement.

The crossing analysis performed established that there is a strong link between radial/axial loads, vertical and horizontal support placement and lateral movement of the crossing.

The coating at the field joint was damaged due to the high radial and axial loads combined with the high residual lay tension. The radial and axial loads were the result of the interactions between the free span and the lateral movement.

It was found that industry accepted standards concerning the design and construction of submarine cable crossings do not provide guidance for the case in which the crossed pipeline is used as a support. Nor do the industry standards consider the consequences of field joints being near to the crossing.

The analysis and discussion presented here provide the following guidelines for designers and practitioners in the case that the articulated padding will be used without grout bags:

- Locate field joints in the vicinity of the crossing during surveys
- Undertake dynamic analysis of the crossing line to identify the extent of its lateral movement
- Ensure that the crossing location is an adequate distance from field joints.
- Obtain the installation pipe tally sheet that contains the coordinates of the field joints of the existing/crossed pipeline

If it is impossible to obtain the required information, then the cradle type support can be utilised in conjunction with an articulated padding system to ensure that the radial load and axial load experienced by the padding is kept to a minimum value below the bearing capacity of the field joint coating.

It is further recommended that the industry should consider revising the relevant codes and practices to emphasise the potential risks of installing a crossing near a field joint and to recommend undertaking dynamic analysis of the crossing line.

The findings and conclusions provided above can serve as preliminary guidelines towards developing an industry standard /specification for the design and construction of submarine cable crossings when the crossed pipeline is used as a support.

12 References

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