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EMERGENCY PIPELINE REPAIR SYSTEM (EPRS)

Effectiveness can be measured by the reduction in downtime of a subject to random 3rd party events.

Authored by:
Nigel Curson, EVP of Technical Excellence
Ali Alani, Europe Director of Asset Integrity
Thomas McIntyre, Mechanical Engineer

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Abstract

This paper presents the typical steps taken to respond to an emergency pipeline damage scenario and the impact on downtime when the operator of the pipeline is not prepared. The industry standard method of preparing for an emergency damage event is an Emergency Pipeline Repair System (EPRS) which provides guidance on the likelihood of each type of damage event occurring, the best practices when assessing the damage and the best repair strategy for the damage pipeline.

The paper focuses primarily on offshore pipelines and follows a hypothetical damage event with each stage of the emergency response and repair explored. The damage event example allowed for investigation of the emergency response and repair process for both an offshore pipeline with and without a comprehensive EPRS in place. For each stage, the tasks carried out when with and without an EPRS are detailed and an estimated time to complete each stage for the two scenarios is given. This allowed for comparison and discussion on the time saving benefits of an EPRS for offshore repair.

A discussion on the uncertainty of the estimated time to complete each stage of the emergency response and repair is given and highlights areas for potential further research. This uncertainty discussion is revisited in the conclusion where a plan to improve the time predictions made for the EPRS model is made.

Two case studies of third-party damage response to subsea pipelines are used as comparative cases to the hypothetical damage event case, the case studies cover a pipeline with a comprehensive EPRS in place and one without allowing for useful comparison and discussion on the accuracy of the estimated times given for each step of the EPRS.

1. Introduction

During a pipeline's life, it is expected that the integrity of the pipeline will reduce due to defects caused by time dependent and randomly occurring hazards. Inspection of the pipeline at regular intervals acts to identify these hazards before failure of the asset and aid in planning assessment and repair. When the pipeline is subjected to any form of interaction, there is risk of mechanical damage to the pipeline. This damage can be severe enough to justify an emergency response to prevent short term failure of the asset or to minimize the economic and environmental consequences as well as the health and safety risk in the case of a leaking or ruptured pipeline. A typical action taken at the beginning of emergency response sees the pipeline's internal pressure reduced to lower the stresses at the damage section, this has been found to be effective in minimizing risk of failure of the asset [1]. By reducing the internal pressure, the volume of product exported is reduced resulting in deferred revenue. It is therefore in the interest of the operator to return the pipeline to normal operations as soon as practical.

The Emergency Pipeline Repair System (EPRS) is a requirement of multiple pipeline safety legislations, codes and standards [1,2,3]. The EPRS aims to provide operators with direction and guidance on returning the pipeline to normal operating conditions as quickly and safely as possible following an emergency damage event and initial response. An EPRS is a management system that is typically documented in procedures, inventory listing and specifications that is shared between all parties involved in the emergency response and repair. The documents acts as a custom tool for a given pipeline or field as the properties of the pipeline and the environment it operates in dictate the content included. For example, the inspection and assessments given in the EPRS for an onshore pipeline will differ to an offshore pipeline as the types of expected damage will differ, another example would be different recommended repair strategies for small diameter pipelines and large diameter pipelines as certain repairs are cost prohibitive or less effective for larger diameter pipelines.

The research carried out in a previous paper on risk based strategy for EPRS development [4] is used to validate the overall time difference estimated between the EPRS and no EPRS case. A Mean Time To Repair (MTTR) table given in the previous paper [4] applies to an offshore emergency response and repair scenario therefore for this paper, the hypothetical damage scenario applies to an offshore pipeline and the timeline for emergency response and repair will be explored. The documented hypothetical emergency response and repair scenario will then be compared with two real life case studies of third-party damage to a pipeline and the subsequent response and repair.

2. Materials and Methods

The aim of this paper is to demonstrate that an EPRS can work to reduce the downtime of a pipeline subject to random third-party events. The EPRS aims to cover tasks that can be done before a damage scenario that speed up the pipelines return to normal service such as contacts for appropriate repair suppliers or procurement of an appropriate repair method prior to damage.

By covering each stage of the emergency response and repair, the difference in time taken to complete the stage with and without an EPRS is assumed to be added, avoidable downtime of a pipeline from not having a comprehensive EPRS. Measuring the additional downtime can therefore suggest how effective the EPRS is for pipeline response and repair.

This approach was used for a hypothetical offshore pipeline emergency response and repair case as well as for the two real life offshore pipeline case studies in which third party anchor drag events occurred. The overall time difference for the hypothetical damage scenario was validated against the time estimates given in the previous research papers MTTR table [4].

3. Results and Discussion

Following damage to a pipeline, an emergency response is carried out followed by a typical repair process to return it to safe, operable conditions. Emergency response and repair is explored for a hypothetical offshore pipeline subject to 3rd party damage. The typical events and tasks of each stage are documented and time estimates to complete each stage are made based on similar offshore pipeline MTTR estimates from previous projects.

4. Emergency Response

The initial emergency response is typically carried out through three definitive actions: notification of the incident, implementation of the Emergency Response Plan (ERP) and handover to an Emergency Pipeline Repair (EPR) team. The first step involves reporting an incident by a party (company personnel, contractors, SCADA systems etc.) to the control room operator who logs the incident. The next step sees the control room operator report to the on call manager who, using the ERP, classifies the situation type as an emergency, incident or abnormal operation. The ERP is then used to form an emergency response team, inspect the location of the reported incident, close off access to that location in the interest of safety, and then if required, depressurization work of the pipeline is carried out. Once the emergency is under control, the emergency response team hands responsibility to the repair team.

For the proposed hypothetical damage scenario, it is concluded no difference in completion time would occur between a pipeline with and without a comprehensive EPRS as an EPRS does not provide guidance on the initial emergency response and only on the pipeline repair.

5. Mobilization of Repair Team and Contractors

Following discovery of a damage event, typically a pipeline's emergency director would form an incident management team. This team will work to mobilize an inspection team and a dedicated repair team for the damage. Team members for both teams will need to be trained, qualified and competent in their areas of expertise to carry out the work (pipeline inspection and if required, pipeline repair). For offshore pipelines, a sufficiently equipped vessel will need mobilising to travel to and from the damage area with appropriate personnel and equipment. Existing schedules for these vessels and their proximity to the damage event may mean huge delay to the completion of this step.

Contractors may also be needed if the required experience is not found in-house and their schedules may delay the completion of this step. An EPRS provides the pipeline operator with a dedicated plan for incident management including recommended exercises for improving mobilisation of the response to a damage event and, emergency repair organisation requirements such as competencies and required training for a repair. A comprehensive EPRS would have updated contacts for all potential contractors such as inspection and repair vessel owners and specialist repair contractors which should in theory, speed up personnel and equipment mobilisation. For the hypothetical damage scenario, a time difference for this stage would be expected between a pipeline with and without an EPRS. It is estimated that for the two scenarios, the minimum time difference to complete this step is 2 days.

The estimated time difference for this stage carries a high level of uncertainty and is heavily influenced by the operators access to a repair vessel. The wait time for a vessel could be as high as 16 weeks if the vessel is in demand therefore having a comprehensive EPRS that establishes and maintains contacts with multiple vessel suppliers can potentially reduce this wait time.

6. Procedure Preparation

Procedures are necessary when responding to a damage event as they provide well researched guidance on aspects of the inspection, assessment and repair to all parties working on the emergency response. A thorough EPRS covers some of the following procedures: Risk assessment of the pipeline, defect identification requiring repair, emergency repair strategy and a contracting strategy, all of which must be carried out at some point before inspection and repair stages respectively. It is also anticipated that more time is taken to research and write these procedures for offshore pipelines due to the greater difficulty in inspecting and repairing an offshore pipeline compared with onshore. For the hypothetical damage event, a time difference for this stage would also be expected between an offshore pipeline with and without an EPRS. It is estimated that for the two scenarios, the minimum time difference to complete this step would be around 4 weeks.

The estimated time difference for this step also carries a similar level of uncertainty to the previous step. The size of the pipeline and how deep it is offshore will largely contribute to the time taken to establish procedures due to the greater health and safety risk of inspection and repairs for deeper offshore pipelines. Workforce size, in house expertise issues and data sharing difficulties, are also likely to delay the completion of this stage where a comprehensive EPRS is not in place for the damaged pipeline.

7. Inspection

Inspection allows parties involved in the emergency response to better assess the size and scope of the damage. The time needed for this step depends on the location of the defect with greater time required for defects identified in remote or difficult to reach areas such as subsea pipelines or underground pipelines below major roads. A defect identification guidance procedure could be utilized during inspection of the damage to improve the accuracy of assessment carried out following inspection.

The time to complete the Inspection stage of the hypothetical damage event isn't expected to differ between the EPRS and no EPRS scenarios. This is because the procedures and actions to be taken during inspection of the offshore pipeline should be understood and memorized by the inspection team before deployment. The comprehensiveness of the EPRS could affect the time difference by hours if all queries from the inspection team before and during inspection have been addressed in the EPRS, however, this is difficult to quantify due to high variability in inspection scenarios so isn't explored further in this paper.

8. Defect Assessment, Repair Selection /Design

A defect assessment would be carried out following inspection of the damage area, this assessment will depend on the quality of the input data sourced from the inspection carried out and material test data available. Assessments performed would use well researched techniques and follow industry codes and standards to determine whether the damage is acceptable at present or whether further action is needed such as repair or replacement at the damage area. A comprehensive EPRS, would also provide guidance to the inspection team on required input data for the appropriate defect assessment enabling the pipeline operator to prepare this before contracting the work to an integrity service. The established procedure for assessment would also allow for immediate identification of the appropriate assessment against the appropriate design code thereby reducing the time for the assessment to be carried out. For the hypothetical damage event, a time difference for this stage would be expected between an offshore pipeline with and without an EPRS in place. It is estimated that for the two scenarios, the minimum time difference to complete this step is 6 days as this is roughly the minimum time required to carry out a detailed integrity assessment of the damage such as an FEA study.

The uncertainty in the estimated time difference for this stage is expected to be high. The comprehensiveness of the EPRS is expected to be the biggest contributor to time saved in this stage as a comprehensive EPRS would provide tailored limits on all types of potential defects to the affected pipeline thereby allowing quick comparison and decision making on a repair. A basic EPRS will need the integrity service provider to review and calculate these limits after inspection. Other factors such as personnel expertise, size of workforce and urgency of repair are also expected to affect the time to complete this step between the EPRS and no EPRS scenario.

9. Contractual Times

If a defect assessment of a damaged pipeline concludes a repair is needed for safe, continued operation, pipeline repair suppliers will be contacted to negotiate a purchase of an existing repair option or fabrication of repair equipment for the damage. A contract will need to be written for the pipeline repair supplier. Management and coordination of the repair delivery will also need to be done. A comprehensive EPRS allows for procurement of a repair option or for up to date contacts of repair suppliers prior to the damage event ensuring time is not spent organising and negotiating this. For the hypothetical damage event, a time difference for this stage would be expected between a pipeline with and without an EPRS in place. It is estimated that for the two scenarios, the minimum time difference to complete this step would be 7 days for a unique contract and less for one where both parties had experience establishing a similar contract.

The uncertainty in the estimated time difference for this stage is also expected to be high due to the potential size of the contract requirements. For offshore pipelines, greater assurances are possibly needed on the integrity of a repair to avoid revisiting the repair area and the complexity of the repair option design and fabrication may be greater therefore more discussion may occur before all parties agree to the contract. These factors may delay agreement of the contract for weeks or months.

10. Repair Options

Recommendations made from results of the defect assessment will dictate whether an immediate repair is needed for the pipeline. The repair option recommended will vary based on pipeline sizing, location, safety, efficiency, and purpose. For pipelines with large diameters (D>30"), it may be that a custom sized repair option is needed due to a limited availability of repair options, typically Sleeves or sectional replacement repairs are made for large pipelines. For smaller diameter pipelines, the repair option will likely be cheaper and easier to install. Typical repair options include a temporary leak clamp or dressing followed by a composite wrap. The prioritization of an EPRS from an operator's perspective will likely be influenced by the sizing of the pipeline as downtime is likely to be longer for large diameter pipelines needing custom repairs.

For pipelines located offshore, the repair option must be suitable for a subsea environment. The materials used for the repair option and processes for installation must be effective under the pressure, temperature and chemical conditions of sea water at depth and installable by divers and/or ROV, meaning the cost and time to fabricate these may be longer. For onshore pipelines, the material and design of the repair option may need to consider resistance to soil loading and be compatible with the CP system for example. These design considerations may add time to the procurement of the repair option.

The safety and efficiency of installing the repair option will influence the chosen repair. For repair options in which qualified welders are needed, the safety of carrying out surface preparation, grinding, and welding to the pipeline must be considered and, the expected time to carry out the welding job, if subsea and carried out by divers, this may take more time to satisfy health and safety concerns. Some repairs require that the pipeline is fully shut down to perform such as isolation and cutout which will likely have a greater cost to the operator than temporary repair solutions.

The purpose of the repair would be vital for the operator when deciding the repair option. If the pipeline has a long remaining design life, a permanent repair will be prioritised while an old pipeline may be retired early due to a repair not being cost effective.

An estimated time to prepare the appropriate repair option for installation reflecting all scenarios would be too simplistic due to the large time differences between certain repair options. A better approach would be to find the average time to complete the repair step for each type of repair. Not enough case studies were reviewed to calculate these time estimates in this study however, for future research, this may be a valuable tool for operators to assess the value of developing a comprehensive, up to date EPRS.

It is expected that a time difference to complete this stage would exist between a pipeline with and without an EPRS. Using the hypothetical damage event, an offshore pipeline with a comprehensive EPRS in place would have had an appropriate repair option designed, fabricated and stored in preparation of the damage event or have contracts in place to order a repair option off the shelf. In contrast, without an EPRS, the design, fabrication and testing of a repair option or management and coordination of an off-the-shelf repair would need to be done after the defect assessment step adding more time before returning to normal operating pressure.

For better comparison with the explored case studies, It is assumed that the chosen repair option is a grouted repair clamp to suit a subsea pipeline suffering denting and lateral dragging along the seabed from 3rd party interaction with the pipeline. Without an EPRS, the expected minimum design, fabrication and testing time for the repair option is 12 working weeks. For a pipeline with a comprehensive EPRS, the repair option would exist in the operator's or supplier's storage facility and can be prepared for installation within 5 days. The time difference between the EPRS and no EPRS scenarios is, therefore, 55 days.

As was briefly discussed, the required time to complete this stage is heavily dependent on the damage scenario and the subsequent required repair, therefore, a high level of uncertainty is predicted.

11. Repair Installation

Following the preparation of the repair option and the strategy for deployment, the installation of the repair is carried out. Like the repair option step, the variability in the tasks carried out and the time to carry out the step are hugely dependent on the damage scenario and the repair option. For a subsea pipeline, installation would be carried out with divers or an ROV, both require a vessel to deploy from that will need to be available when required, if divers need training or the vessel is delayed this adds to the time taken to complete. An onshore buried pipeline will typically be excavated at the damage area, this could be in an urbanized area with high footfall making it more difficult to schedule installation for example. The estimated time to carry out this stage therefore ranges greatly. Other uncontrollable factors that may affect the time taken for this step are personnel skill and availability, installation equipment availability, environment (i.e. unsafe for prolonged exposure) and more. An estimated time to complete this step reflecting previous experience of pipeline repairs is therefore not made in this paper.

For the hypothetical emergency response and repair event however, the repair installation stage is not expected to be completed any quicker for the EPRS case than a pipeline without an EPRS. It is expected that during the repair option stage, the emergency repair team would have written installation procedures and prepared for installation through practice while the repair option was being fabricated or delivered by the repair supplier.

12. Re-commissioning

Following installation of the repair option, the recommissioning process for the pipeline takes place. To recommission the pipeline to operating pressure, it may be required that time is given for the repair to settle such as curing time for a grout filled repair clamp. Inspection and testing to the repair may also be needed to ensure the repair is fitted properly, no hazards remain at the repair area or that the repair will restore the pipelines capacity. Depending on the country the pipeline operates in, results of the repair may need presenting to stakeholders to demonstrate the repair is successful and it is safe to recommission the pipeline. An EPRS is not expected to reduce the time taken for this stage. Therefore, a pipeline with no EPRS in place is assumed not to differ in the days taken when compared with a pipeline with an EPRS.

13. Emergency Timeline

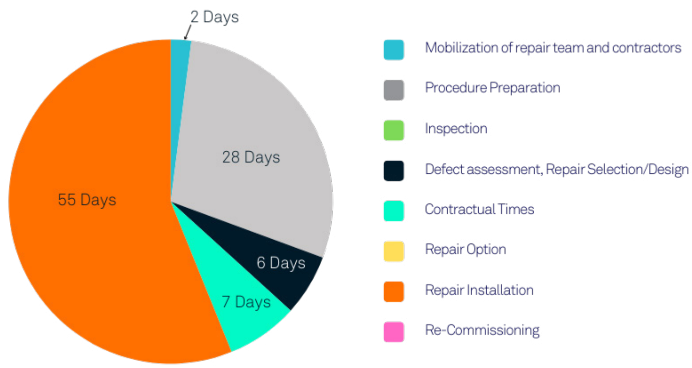

Figure 1: Emergency Response and Repair Scenario: EPRS vs. no EPRS Time Difference

For the hypothetical damage event, the overall minimum estimated time difference for an offshore pipeline emergency response and repair was 98 days as seen in Figure 1, the pipeline is therefore estimated to be at a reduced or shut-down pressure for 98 days longer when a comprehensive EPRS is not in place. A breakdown of each aspect of the project is also given in figure 1. Procurement of the repair equipment is seen to have the greatest impact on the overall time difference between EPRS and no EPRS cases with 56% contribution to the overall time difference. The 98 day minimum time difference specifically reflects the hypothetical damage event of 3rd party anchor dragging damage discussed throughout the paper. It is possible therefore that a lower minimum time difference could be achieved for a different damage scenario. The time saved through an EPRS should always be positive or none as no aspect of the EPRS will hinder the emergency response and repair of the pipeline in an emergency damage event.

These results roughly align with the MTTR estimates given in the work previously published [4] where for a full EPRS case, a large diameter (>20 inch) offshore pipeline is estimated to be repaired within 3 – 6 months whereas for the no EPRS case, repair is estimated to be completed in 8 – 14 months.

Uncertainty in the time estimates is attributed to the high number of contributing variables to the time taken. Variables such as pipeline damage type, pipeline size, offshore or onshore, is the pipeline located remotely or in an urban area are all expected to influence the speed of repair. It is expected that more factors than are listed in the previous steps will delay the repair of a pipeline.

As a next step to the works carried out in this paper, it is proposed that an established model is developed to estimate the repair time of pipelines to emergency damage. The model could work on multiple inputs (offshore or onshore, large diameter or small diameter, high or low operating pressure etc.) to define the pipeline followed by multiple emergency damage scenarios to choose from (mechanical damage from dropped objects, excavation works, rock slides, anchor dragging etc.). Using collected industry research and experience as well as expert advice, each input could have a contributing weighting factor and an estimated repair time can be calculated given each unique combination. This would prove a useful tool for operators interested in assessing the consequence of emergency damage to their pipelines as well as good promotion for the regular maintenance of a comprehensive EPRS.

Real-life case studies were reviewed to assess if the same conclusions could be made on the EPRS reducing downtime of a pipeline in a damage event.

14. Case 1: North East UK 36-inch Diameter Subsea Pipeline

During the summer of 2007, a 36-inch diameter subsea pipeline located off the Northeast coast of the UK was struck and dragged by a third party's anchor [5]. The pipeline was lifted from under the seabed and dragged, causing bending and permanent local and global deformation. Following the steps of a typical emergency response, the following occurred:

14.1 Initial Response

The flow and pressure of the 36 inch subsea pipeline was monitored to determine if any loss of containment had occurred; this was confirmed not to be the case. A 1000m radius exclusion zone was set up around the damaged pipeline, and a guard vessel was stationed to enforce this.

An EPRS existed for the pipeline and was implemented soon after the damage event; the EPRS recommended that the pressure of the pipeline be lowered to stabilize it. The pressure was lowered by 5% and monitored for 48 hours before inspection could take place.

14.2 Initial Inspection

A Survey vessel was diverted from planned works to perform a survey of the damaged pipeline using side scan sonar and a remotely operated vehicle (ROV). The survey found that the pipeline and its coating had been damaged by the anchor. The scan also identified lateral movement of the pipeline by approximately 4 to 5 m. Anchor scars were clearly visible on the side scan survey and widespread damage to the concrete was observed by the video ROV.

Due to the extent of the damage, further detailed inspection by divers was needed. The operator's EPRS did not cover guidance or procedures for detailed inspection of an anchor drag damage area, so an engineering assessment was carried out to determine the safe and effective actions required to inspect the pipeline. With a comprehensive EPRS, the engineering assessment would not have been needed potentially saving the operator downtime on the pipeline.

14.3 Detailed Inspection
The detailed inspection required that the damaged area be excavated to improve the visual survey of the pipeline; a mechanical coating removal tool was used to remove the concrete weight coating and coal tar corrosion coating from the pipeline to expose bare steel, this work was carefully performed over several days. Once complete, a close visual inspection of the pipeline could take place where it was found no gouges existed in the damaged area, all welds were sound and free from defects and no cracks were detected in the pipe wall. 2 plain dents matching the flukes of the anchor were found around 9 o'clock however with the deepest of these being 31mm.

14.4 Defect Assessment
The defect assessments carried out utilizing the detailed inspection data found the fatigue strength of the damaged pipeline to be lower than the design life of the pipeline. Initially, a PDAM [6] fatigue assessment found the remaining life of the 31mm dent on a seam weld to be 17 years with a high proportion of this consumed during the single depressurisation cycle. A repair was, therefore, decided.

14.5 Repair Strategy
The operator's existing repair planning included a subsea hydraulic repair clamp in storage. This was found to be not fit for purpose as the repair clamp would not fit on the pipeline due to its lateral curvature. To solve this an alternative repair strategy, a complex mitred sleeve, was designed, fabricated and tested before installation at the damage area. A comprehensive EPRS would have identified the threat of excessive curvature to the pipeline, which could have been accounted for in the repair strategy design.

14.5 Case 1 Repair Time
The emergency response and repair of the 36-inch diameter subsea pipeline was carried out within 9 weeks of identification of the damage. The pipeline returned to normal operation once the repair had been installed and grout had cured. A table summarizing the timeline of this project is given in Table 1.

EPRS Stage	Time Taken to Complete (Days)
Emergency Response	2
Repair Team Mobilization	2
Procedure Preparation	1
Inspection	5
Defect Assessment	5
Contractual Times	2
Repair Option	30
Repair Installation	3
Recommissioning	2

Table 1: Case 1 Summary of Time Taken for Emergency Response and Repair

15. Case 2: Shallow Water 38-inch Subsea Pipeline

15.1 Initial Discovery

A 38-inch diameter subsea pipeline was discovered to have two potential dents during a caliper pig run carried out during the summer of 2022. The coordinates of the dents were checked and found to be coincident with pipeline displacement, which was first recorded in 2015 through ROV inspection. There was also a reported area of concrete weight coating (CWC) loss at the same location leading to further verification of the caliper and MagneScan inspection where it was discovered two more dents existed near the previously reported dents.

15.2 Response

Following the initial discovery of the dents and CWC loss, the operations team reviewed the pipeline defect assessment reports provided as part of the EPRS for the affected pipeline. The reports recommended that the pipeline's internal pressure be reduced to a maximum of 80% of the maximum pressure the pipeline experienced during or since the time the damage occurred. This was actioned before further inspection could take place.

As a result of the Dent verification tasks, it was decided by the Operator that a detailed inspection was needed with divers performing a close visual inspection (CVI). The diver inspection started by locating and verifying the girth weld closest to the damage area followed by high-pressure water jet cleaning of the pipeline to remove marine growth at the locations of the two suspected dents. A 2nd campaign was taken to clear the entire pipeline section at the CWC loss area where it was discovered that an additional 3 dents to the pipeline existed. The overall findings of the detailed inspection with divers were 5 dents, 3 upstream and 2 downstream with gouging/metal loss associated with each dent and 1 case found on the girth weld.

15.3 Fitness for Service Assessment

Once the diver survey report was finalized, the operations team contracted a level 1 and 2 Fitness For Service (FFS) assessment to be carried out based on the inspection findings. These assessments concluded that gouges were not associated with other damage were not predicted to fail at the reduced operating pressure assumed to be 110 bar, however, the dent associated with a weld where the weld is itself gouged cannot be assessed by any industry recommended method. It was recommended that gouges be dressed and repair using custombuilt grouted repair clamps be carried out or a level 3 FEA assessment be carried out to determine whether the pipeline was safe enough not to need the gouges dressed and the repair be made with the clamps covering them.

15.4 FE Analysis

FE analysis work carried out for the damaged pipeline assessed the global and local stresses as well as the plastic strain. This process saw the progress of the work presented weekly to the operator and SME's where feedback was given, changes to the analysis throughout this stage following advice and recommendations on the modelling and analysis of the damage added time to the completion of this step. The complexity of the damage meant that the modelling process couldn't be straightforward and that multiple complex simulations were needed. This was also found to delay completion of this step. The findings of the assessment concluded that the pipeline would still require repair with the custom grouted clamps and that the gouges would need dressing. This analysis was carried out over 3 months.

15.5 Repair Preparation

Following the results of the FEA assessments, at the end of July 2023, the repair team were mobilized and tasked with preparing the custom grouted repair clamps for installation during a shut-down window planned for October 2023. It was recommended that Non-Destructive Testing (NDT) be carried out to the pipeline and dressing work to remove all gouges recorded at the damage area. 3 NDT campaigns took place between June 2023 to October 2023.

The first campaign, completed in June 2023, used Time of Flight Diffraction (ToFD), thickness mapping (T-Scan), Alternating Current Field Measurement (ACFM) and Magnetic Particle Inspection (MPI) and confirmed no surface breaking indications or subsurface indications.

The second campaign, completed end of August 2023, used Phased Array UT and ToFD inspection techniques to confirm no internal or external surface-breaking indications existed at the gouges.

The third campaign was carried out in October 2023 following dressing work to the gouges and found no surface breaking indications existed at the locations of the dressed gouges.

Technical Queries on pre-installation activities were given by the repair team and were addressed between August and October 2023. Recommendations on internal pressures and need for grinding were included in these. Fifteen high-level Technical Queries were provided by the repair team and answered by the integrity service contractor within 7 weeks.

Preparation for dressing the gouges started in February 2023, a mockup of the works to be carried out was set up and performed in a testing facility over 6 days helping the repair team and divers assess the practicality and risk associated with the grinding work. The actual campaign took place during a yearly shutdown window in late October 2023 and was successful in removing all gouges from the damage area including at each dent.The campaign took 2 days to complete followed by 1 day of NDT.

15.6 Repair Installation

All repair pre-installation tasks could not be completed before the planned shutdown, so the repair has been delayed by 12 months for the next planned shutdown in September 2024.

15.7 Case 2 Repair Time

The timeline for the shallow water 38-inch diameter subsea pipelines emergency response and repair will therefore be 25 months. A table summarizing the timeline of this project is given in Table 2.

EPRS Stage	Time Taken to Complete (Days)
Emergency Response	35
Repair Team Mobilization	2
Procedure Preparation	3
Inspection	14
Defect Assessment	104
Contractual Times	3
Procedure Preparation	3

Repair Option	~420[1]
Repair Installation	TBC
Recommissioning	TBC

Table 2: Case 2 Summary of Time Taken for Emergency Response and Repair

16. Conclusion

This paper has presented the typical progression of an emergency response and repair process for a damaged pipeline, with afocus on the time taken to carry out each step. By exploring a hypothetical repair scenario as well as two real life case studies, the difference between emergency response and repair with a comprehensive EPRS and without one could be studied.

The following conclusions were made based on the results of this study:

The EPRS aims to prepare an operator for quick mobilization of a repair in the case of an emergency damage event. Based on results of the offshore pipeline hypothetical damage event explored in this paper, it can be seen this aim is achieved with an estimated time difference of 98 extra days of downtime when no EPRS was in place. This time difference is largely attributed to the contract establishment for access to vessels and repair materials, defect assessment guidance and repair preparation steps that when prepared before the damage event through an EPRS, reduce the completion time of each step of the emergency response and repair process respectively.

The hypothetical case explored also highlights the importance in time saved from having a viable repair option ready for mobilisation following fitness for service assessment of the damage. Using the hypothetical emergency response and repair scenario detailed in this paper, for the repair method stage, it was estimated that 55 days worth of downtime could be saved by procuring a repair clamp prior to mechanical damage of the offshore pipeline as this was found to be the average time given by repair suppliers for design, fabrication and testing of this type of repair. A comprehensive EPRS would identify the most likely damage scenario and recommend an ideal repair for the damage, allowing the operator to source or design the repair in preparation.

The first case study found that for the 36-inch subsea pipeline, the EPRS in place was not comprehensive enough. The dedicated repair option in storage would not fit over the damaged area due to the excessive curvature of the pipeline caused by the anchor dragging. A new mitred repair clamp was designed, fabricated and tested within 5 weeks, enabling the operator to return to normal service within 9 weeks of discovery of the damage. Using today's prices for LNG, this would be in the range of $100 to $200 million in deferred revenue.

The first case study demonstrates the uncertainty in the estimated times for each stage of the explored hypothetical emergency response and repair scenario. Based on that scenario, the estimated time for the 36 inch subsea pipeline to return to service would be higher. This therefore highlights areas for improvement of the time estimation aspect for each stage of emergency repair.

[1] The high number of days to complete the Repair Option stage is due to this figure being the time between the completion of the defect assessment stage up to the repair installation stage. This figure would be much smaller had installation not been delayed until the next planned shutdown.

Factors such as qualifications and experience of personnel, the number of working personnel, the hours worked by all involved, the level of access to equipment (long or short lead times, schedules etc.) and more are not considered in the scenario explored but are expected to affect the completion time.

The second case study found that for the 38-inch subsea pipeline, the EPRS was comprehensive, but the emergency response and repair were still slow to complete compared with the hypothetical case. The overall downtime of the pipeline is expected to be 25 months before returning to regular service. Using today's prices for LNG, this is estimated to be over $500 million in deferred revenue.

The second case study highlights how an EPRS cannot guarantee a quicer return to normal service as the overall time taken to repair is much higher than both the hypothetical scenario and case 1. The main attributing factors to this were found to be factors that are not affected by the EPRS however, such as culture and hierarchy associated with decision making. The number of stakeholders involved in the approval process was suspected to have slowed decisions made which led to the missed repair during the planned shutdown window. Multiple SME's also meant no single authoritative body in relation to damage assessment and the decision to repair which has led to repeat assessments and research work. These challenges should be captured in an updated EPRS model to ensure its effectiveness.

This paper primarily covers offshore emergency response and repair scenarios to demonstrate and emphasize the time saving aspects of an EPRS due to the requirement for specialist inspection and repair equipment for offshore repair. A hypothetical anchor drag event as well as two real life anchor dragging events were covered to demonstrate this. The philosophy of an EPRS and the time saving advantages of a comprehensive EPRS, as demonstrated through this paper, are expected to also apply to onshore pipelines albeit with different time estimates for each step. Following this paper, similar research could be carried out to explore the time saved with an EPRS for onshore pipelines.

The EPRS allows reduction in the consequence of failure of a pipeline in terms of downtime and associated losses. Once a full EPRS is in place, the operator may wish to update their pipeline risk assessment to take advantage of the potential risk reduction. Risk assessment methodologies typically capture the benefits of an EPRS system or emergency responses, as an example API RP 580/581[7,8] suggests the use of a Management System Factor to capture emergency response and other tools to ensure readiness. A comprehensive EPRS could allow the reduction of the management factor applied.

It is proposed that following on from this paper, a model is developed for estimating the downtime of a pipeline during an emergency damage scenario. This model could cover pipeline characteristics (offshore or onshore, large diameter or small diameter, located remotely or in an urban area etc.) and different damage scenarios (dropped object, landslide, anchor dragging etc.) to provide an estimated repair time based on available case studies and colleted industry research and expertise. This could help all parties involved in emergency response and repair to improve on the efficiency of each stage of the EPRS and encourage operators to maintain a comprehensive EPRS for these time saving benefits.

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About Penspen

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CONTACT OUR ASSET INTEGRITY TEAM

Email: contact@penspen.com | Website: www.penspen.com