

INDEPENDENCE TRAIL GAS TRUNKLINE AND CHALLENGES OF ULTRA DEEPWATER AND HARSH ENVIRONMENT PIPELINES

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Abstract

Even as the fossil fuel industry's ability to identify hydrocarbon-bearing sediments beneath the ocean's floor at extreme water depths is improving, the oil and gas transport industry has moved into an increasingly hostile and demanding environment. Consequently, pipe material suppliers and installation contractors are faced with ever more stringent requirements and greater expectations. This paper presents an engineering perspective on the developments that was needed in pipeline manufacturing and offshore installation technology in order to build the Independence Trail Pipeline, the world's deepest offshore gas trunk line and discuss the causes for that necessity.

Introduction

At a record water depth of 7,912 fsw in the Gulf of Mexico, the 138 mile long Independence Trail Pipeline (ITP) is the deepest pipeline ever to be laid. The ITP pushed the industry published capability limits and provided new basis for its future projections developed to support building larger and deeper trunk lines.

ITP initiates from West Delta Block 68 at a water depth of 118 fsw and terminates at Mississippi Canyon Block 920 at a water depth of 7912 fsw (Figure 1.0). At the deep end, a Steel Catenary Riser (SCR) connects the pipeline to the floating production facility (Figure 2.0). The requirements of 1.0 Billion Cubic Feet (BCF) per day gas throughput, Maximum Allowable Operating Pressure (MAOP) of 3640 psi, and the ability to withstand a maximum external pressure of 3516 psi, necessitates an outside pipeline diameter of 24 inches Double Submerged Arc Welded (DSAW) with wall thickness ranging from 0.95-inch to 1.35-inch and a minimum grade of API-5L X-65 material. The pipeline was constructed via Welspun's J-C-O expanded pipe methodology and made from low-carbon, low-sulfur, microalloyed steel plate manufactured by Azovstal and Voest Alpine with thermo-mechanical process control (TMCP) including accelerated cooling.

This paper describes an overall framework of the decision making process for selecting project specifications and other issues associated with typical large capital value deep water trunk lines such as ITP which are characterized by dependent upstream and downstream facilities and must achieve a low level of risk during manufacture, transport and installation and maintain high reliability in operation. Additionally, the paper will clarify the causes for the stringent requirements necessary to achieve targeted safety and reliability factors which ensure high on-line availability and which promote continual utilization of pipelines as the best available and most commercially feasible means for long distance product transport in the offshore arena.

Practicality of Line Pipe Design

The extreme characteristics of ITP led to design challenges that required innovative solutions. These challenges resulted in the need to build upon previous deepwater project experience and to involve experts in various fields to ensure that applicable regulatory requirements and industry accepted standards are met. Additionally, several studies, analyses, laboratory surveys and in-situ tests have been executed in order to determine accurate parameters and design basis conditions.

Design optimization for a long trunk line in deep water requires striking a balance between technical parameters and economic pressures. Selection criteria include outside diameter, wall thickness, operating pressure, grade of steel, weldability issues and installation methodology. Constraints imposed by commercial economics, schedule and world market dynamics narrow down the available solutions. Neither performance excellence nor economic competitiveness can be compromised.

The following sections provide a general description of the main design topics.

Pipeline Route Selection

A preliminary desk-top evaluation of route alternatives was accomplished using publicly available survey information and geotechnical data. This assessment established a preliminary base case route and formed the basis for developing a survey mission plan. The route was chosen with great care to bypass known environmentally sensitive and geotechnically active areas and other zones known to be hazardous. A primary consideration was to reduce the pipeline routing distances in order to limit the environmental footprint of the project and reduce the overall cost. The presence of mud slide areas, rough sea bed terrain, ordnance dumping zones and archaeological sites were taken into account along with technical issues such as the relative ease of installation, and the need to avoid third party pipelines and oil and gas exploration activities in the vicinity also played a major part in the evaluation. To meet regulatory requirements and to protect against disruption from fishing activities and anchors, the pipeline will be buried at 3 ft below seabed for the portion of the route at a water depth at or less than 200 fsw.

C & C Technologies Autonomous Underwater Vehicle (AUV)⁽¹⁾ performed the detailed survey along the preliminary route (Figure 3.0). This system provided exceptionally high data quality, navigational accuracy, speed, survey design flexibility, and digital data delivery, which allowed for almost real time pipeline span assessment. During the detailed survey, both major and minor adjustments were made to the optimize routing. Interpretation of the AUV data allowed large sections of the pipeline route to be finalized. However, a number of areas of concern were also identified. Hence, a reconnaissance visual survey was undertaken using a remotely operated vehicle (ROV) to investigate these areas and allow the route to be finalized.

Hydraulic and Flow Assurance aspects

Typically a new project for an offshore gas pipeline starts with a steady-state multiphase flow analysis that comprises a wide range of sensitivity cases incorporating differencing operating pressures, diameters, lengths and simplified sea bed profiles. As soon as an optimum solution that provides an attractive rate of return is found, the detailed design phase is initiated.

At the in-depth design stage, the steady state model of the optimum pipeline configuration is refined using an accurate representation of the gas composition, gas phase envelope, sea bed topography, sea water temperature, pipeline length, wall thickness, external coating, pipeline buried / unburied condition of the sea bed, heat transfer coefficients, and the various anticipated pressures and temperatures of the gas. This steady state multiphase thermodynamic model helps in evaluating the system requirements such as compressor station characteristics and receiving facility requirements and provides a high level classification of the flow (i.e., liquid hold up, gas / condensate phase behavior, slug formation severity and size). However, transient analysis is conducted in order to fine-tune equipment sizing and forecast response under different operational conditions such as start-up, shutdown, line pack, blow down, and leak detection.

Hydrate formation is another important issue in long distance deep water gas pipelines. Hydrates form when water enters the gas stream, normally due to operational disruptions or a leak in regions where the outside pressure is higher than the gas pressure inside the pipeline. ITP is designed to overcome hydrate formation at normal operating conditions by drying the gas to a level that ensures its maintenance outside the hydrate formation envelope. Furthermore, a methanol injection system has been installed on the production facility for the condition of off-spec gas entering the pipeline due to operational disruptions. A leak detection system will be utilized and an action plan to reduce the formation of hydrates in case of a leak has been developed. In addition, methods for locating the hydrate plug and for removing hydrates have been identified.

Deep water pipelines have been remarkably free from external corrosion problems except in very low (e.g., sub-zero) seawater temperatures.⁽²⁾ Despite water depths to 7912 fsw, ITP will not be exposed to unusual seawater temperatures or compositions. Neither is internal corrosion an issue, since the pipeline will transport sweet dry gas with low carbon dioxide (CO₂) partial pressure.

Structural Design

The wall thickness of a steel pipeline is the most relevant factor in the pipeline's capacity to bear the loads imposed during its installation and operation. Wall thickness is also a considerable factor impacting pipeline costs. Large diameter deep water pipelines are designed with wall thicknesses and materials that resist local buckling due to bending, axial tension, and external pressure (since gas pipelines are typically laid air-filled). During installation, this load combination typically occurs at the sag bend region and free spans support points. As a result, the pipe wall is over-sized in the deep water portion for the internally pressurized condition that applies during normal operations.

Should an accidental buckle occur, it would propagate at high speed until it reaches either shallow water or a stronger pipe section or stiffeners, also known as buckle arrestors. Integral-ring type buckle arrestors (Figure 4.0) are used on ITP due to their high efficiency in restraining a propagating buckle. Buckle arrestor spacing influences the length of pipeline that is damaged and hence how much spare line pipe is needed for repairs. Hence, the optimization of the buckle arrestor spacing is best done at the same time as the optimization of the line pipe spacing.⁽²⁾

Clearly the ability of the pipe to withstand external pressure has a significant impact on project economics. Collapse resistance is directly proportional to the compressive yield strength in the circumferential direction and pipe cross sectional ovality. However, the manufacturing process of large diameter pipe, and its expanding stage in particular, introduces cold-working effects which result in an increase in tensile yield strength in the circumferential direction. But, the

effects reduce the compressive yield strength in the circumferential direction of the pipes, thus having a negative impact on the pipe's ability to resist collapse under external pressure. Code specified safety factors for external pressure collapse resistance reflect this reduction. Conversely, thermal aging of pipes due to exposure to moderate temperatures equivalent to a normal coating temperature (392 to 464° F) was found to significantly increase compressive yield compared to the initial state after manufacture. With regard to ovality, the high degree of pipe quality offered by current technology is far more qualified and controlled resulting in a considerable reduction in geometric imperfections. These improvements have resulted in a major reduction in the required wall thickness for collapse resistance.^(3,4,5,6)

In addition to external and internal pressure, the pipeline is subjected to other secondary loads acting during the installation and the operating life. Examples of secondary loads include those caused by differential settlements, by the curvature during installation or on the soil profile where the pipe has been laid, or by mud slide phenomena. Although "secondary" to the definition of the steel wall thickness, these loads can impose the need for costly modifications to the installation of the pipeline and to the configuration that the pipe assumes on the seabed. The definitions of line pipe specifications for both primary and secondary loads are linked together and variations of one parameter will have an impact on the others. The optimization process cannot then be performed for one design aspect in isolation, but must explore the potential for global savings considering the mutual relations among the different cost elements.

Steel Catenary Riser (SCR)

The SCR is the pipeline segment which transports natural gas from the floating production facility to the seabed. The SCR is suspended from the surface floating production facility in a catenary shape with a portion resting on the seabed and connected directly into the pipeline. The interface with the floating production unit consists of a hang off structure and a flex joint which absorbs the dynamic moment variations generated by the motion the floating production unit. The interface with the seabed is dynamic, as the touch down point can move both axially and laterally. This interaction with the seabed creates a fatigue sensitive zone which often requires special design, material selection, and fabrication processes.^(7,8,9)

The SCR is typically subjected to a range of changing forces over long periods of time due to ocean currents, water pressure, vessel motions and wave action, and therefore must be designed to minimize fatigue damage. In the deep part of the Gulf of Mexico where the ITP is to be terminated, currents are among the worst in any deep water. An intermittent "loop" current circulates at the region, at speeds exceeding 5.0 feet per second. Furthermore, a continuously changing background current occurring throughout the water column creates variable loads along the SCR's length. These currents cause the SCR to oscillate due to vortex shedding effects which can result in considerable fatigue damage. A remedy is typically achieved by increasing top tension via hang off angle selection and installing helical strakes on the outside of the SCR (Figure 5.0). For the ITP project, the combination of 15 degree hang off angle, 90% strake coverage of the SCR suspended length was chosen. High quality girth welds that qualifies to a fatigue performance such as that of a DOE C S/N classification⁽¹⁰⁾ and minimal stress concentrations (i.e., Stress Concentration Factor (SCF)⁽¹¹⁾ less than 1.2) was found to be sufficient to reduce the fatigue damage to a range that meets the project design requirements.

The SCR is manufactured from pipe sections which meet high tolerance and fracture toughness requirements after field welding. Hence, stricter pipe end tolerances (i.e., out-of-roundness, wall thickness, eccentricity) are specified to reduce misalignment. In addition, pipe ends matching and/or counter bore on the ID of the pipes is required.⁽⁹⁾ For the ITP project, the optimization of

pipe specification to meet the requirements of flow capacity, minimized weight, and prevention of collapse under external pressure resulted in 20-inch outside diameter, Grade API X65, DSAW with a nominal wall thickness of 1.21-inch. However, the wall thickness tolerance does not allow end machining. This meant that the only alternative available to achieve the end tolerances required level of weld misalignment is end sizing with end matching.

Mechanical properties of the pipe joints and weld are confirmed through a steel weldability test per API RP2Z⁽¹³⁾, API 5L⁽¹²⁾ and BS 7910⁽¹⁴⁾ requirements and weld procedure qualification tests per API 1104⁽¹⁵⁾. The fracture toughness property is of particular importance to the fatigue life of the welded joint as it defines the resistance of the joint to failure through fracture once flaw propagation has reached a critical size. The welded joint fracture toughness for high yield strength risers requires careful attention to line pipe properties and the welding processes. Generally, difficulties arise with higher strength steels that tend to have high hardness and low fracture toughness properties.⁽⁹⁾ These require extensive qualification to confirm weldability and provide long term fatigue performance in an offshore environment.

A full scale, 3 month long fatigue test on a resonant bending rig using welded project specific SCR pipe joints and welding procedures is typically performed to qualify and confirm fatigue performance relative to the design curve. The test also provides a platform for the verification of the weld defect acceptance criteria developed based on an Engineering Critical Assessment (ECA)⁽¹⁴⁾ and nondestructive examination (NDE) procedures to be used offshore. An ECA is the application of fracture mechanics analysis methods to the weld to assess the effect of flaws on weld performance. Because these tests are typically carried out at the later stages of the project when the pipe becomes available, success is essential. Any failure will lead to a significant impact on project schedule.

Offshore Installation

The economic performance of ultra-deep water pipeline systems is highly dependent on the installation considerations. A key element for reducing overall cost is the optimization of the pipeline design with the anticipated installation vessel. Offshore pipeline construction is typically conducted by lay barges in one of two types of configurations, either S-lay or J-lay, as shown in the following sketches (Figure 6.0). The installation process induces significant temporary longitudinal stresses in the pipeline during pipe lay due to 1) the tension maintained on the string to prevent buckling, and 2) bending induced by the pipeline profile. The required tension depends on the lay method, water depth, the weight of the pipe and the allowable installation strain. In addition, the lay process subjects the pipe line to linear and angular displacement caused by wind, waving and ocean currents. Hence, strains during installation represent the most severe the line may experience during its service life.

Few vessels are capable of installing the ITP pipeline and SCR in this water depth in either configuration. Allseas Solitaire S-lay vessel (Figure 7.0) was selected for ITP due to the company's long and successful track record in laying large diameter pipeline in deep water. Nevertheless, upgrades to its tensioning system, stinger and abandonment and recovery system were necessary to execute the work (Figure 8.0 & 9.0). Test and qualification trials are planned for the vessel and for the main and ancillary equipment before starting the laying process to ensure that the systems are compatible and that the capacity meets project requirements.

In an S-lay, the pipe is joined in a linear pipe fabrication facility called the firing line. The girth weld is fabricated in a number of stages. The root and hot pass are installed at the first welding stations with the fill and cap passes installed subsequently. At later stations NDE is

conducted on the completed welds, and an anti-corrosion field joint coating is applied. At regular intervals, the vessel moves ahead a distance equivalent to the joint length and a new joint of pipe is introduced at the beginning of the firing line. Once the move has been completed, the firing-line operations continue (Figure 10.0).

It is essential that constant tension is maintained on the pipeline. At the back end of the firing line, the pipe is held by tensioners or caterpillar tracks which clamp the pipe. The tensioners control the movement of the pipe, maintaining a set tension on the pipe string. The pipe is supported aft of the firing line by a "stinger" (Figure 11.0) which extends beyond the stern of the vessel, sloping downwards at a radius optimized to reduce the amount of residual curvature in the pipe. The tension is controlled to ensure a smooth catenary to the touchdown point on the seabed, minimizing free spanning of the pipeline and reducing residual axial tension. If tension is lost, the weight of the pipeline will sag and cause bending stress, creating the potential for a buckle in the vicinity of the touchdown area.

Mechanized welding in combination with automatic ultrasonic testing (AUT) has become the primary method utilized in producing and inspecting circumferential girth welds for deep water pipe line applications. This approach provides for higher production rates, more desirable weld metal and heat affected zone properties, and low defect rates in an assembly-line process. Also, part of the efficiency with automatic welding is achieved through the use of steeper J- and U-shaped bevel designs (Figure 12.) which limit the size of the weld deposit. Experience has shown that mechanized GMAW welding and J-bevel-type joint designs are susceptible to the formation of side-wall lack-of-fusion defects. AUT was found to be especially well suited to detecting and characterizing planar flaws, including side-wall lack of fusions defects.⁽¹⁶⁾

Offshore installation rates are a major cost concern for deep water pipeline installation. The combination of automatic welding, narrow welding groove, AUT inspection, and an alternate flaw acceptance criterion via ECA offers the ability to produce high-quality welds at desirable production rates. However, pipeline ends must be clear of any surface imperfections and inclusions that might interfere with the AUT system. Also, ends must meet tight misalignment requirements to ensure minimum stress concentration factors.⁽¹⁶⁾

Installation of an SCR is an extension of the pipe lay operations. However, it is complex and typically progresses at a far slower rate as it does not allow weld repair and requires a stringent weld defect acceptance criterion. Further, the SCR is installed after the floating production unit is in place. Therefore pre-laying the SCR within a pre-defined corridor within the floating production facility mooring is typically performed if the SCR is installed prior to the floating production facility using S-lay. The hanging of the SCR on the floating production facility involves a complex handover operation between the heavy lift vessel and the floating production unit, where the vessel is working in close proximity to the floating production unit. This situation greatly increases the level of risk associated with this operation.⁽⁹⁾

The unevenness of the sea bottom is always a risk factor. In addition to the operations detailed in the preceding paragraphs, other parameters are of concern in avoiding or limiting the need for remedial work to accommodate physical irregularities. These parameters include the accuracy of the theoretical route profile, the cross section regularity of the laying corridor, the accuracy of the lay barge when laying the pipe within the corridor, and the ability to predict the pipe line configuration on the seabed once laying operations are completed. Extensive remote operational vehicle (ROV) surveying and assisted laying are an essential support for pipe laying in deep waters and difficult seabed areas. Also, the installation of T-piece tie-ins (Figure 13.0) into the pipeline in anticipation of future capacity additions is considered a risky operation due to the time required to execute the task and the stress increase on the pipe during that operation.

Conclusion

Offshore pipeline design, manufacturing and installation technology has been extensively tested over the last decade in some milestone projects. The ITP project has built upon these experiences and further pushed the boundary in water depth for pipelines and SCRs. Enhanced manufacturing and construction practices effectively addressed and reduced a variety of associated risks due to the following factors:

- Advances in the understanding of pipeline and SCR failure mechanics and how they relate to pipeline manufacturing and installation welding processes
- Great achievements in the performance of the material and in manufacturing pipe reducing the chances of failures in the pipe material or seam weld
- Enhancement of offshore installation capability allowing for ability to handle pipe lines safely at extreme water depth and reducing the likelihood of failures in girth welds
- Ability to control the factors that cause defects and degradation in service environment reduced the possibility of failures due to fatigue and corrosion
- Enhancement in testing, inspecting, protecting, and maintaining pipelines reducing the probability of failures due to a variety of causes

The test for the industry is to maintain and improve upon this level of quality while reducing installation and operating costs for deep water projects. The global marketplace for long distance transportation of natural gas is risky and increasingly competitive. In order to succeed, projects must maintain cost effectiveness without sacrificing performance. The engineering and financial successes to be realized on the ITP project prove that the industry is poised to meet the challenge.

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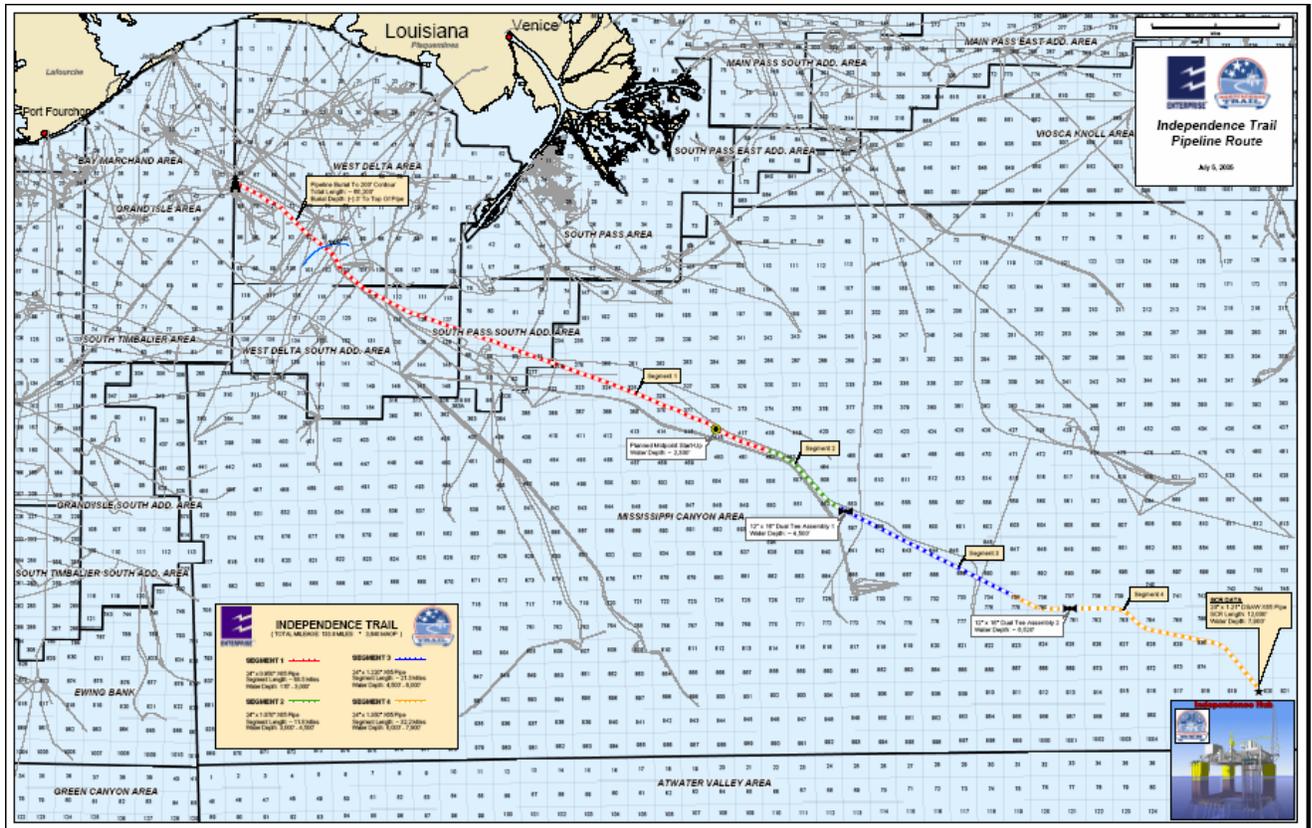


Figure 1. Independence Trail Pipeline Route

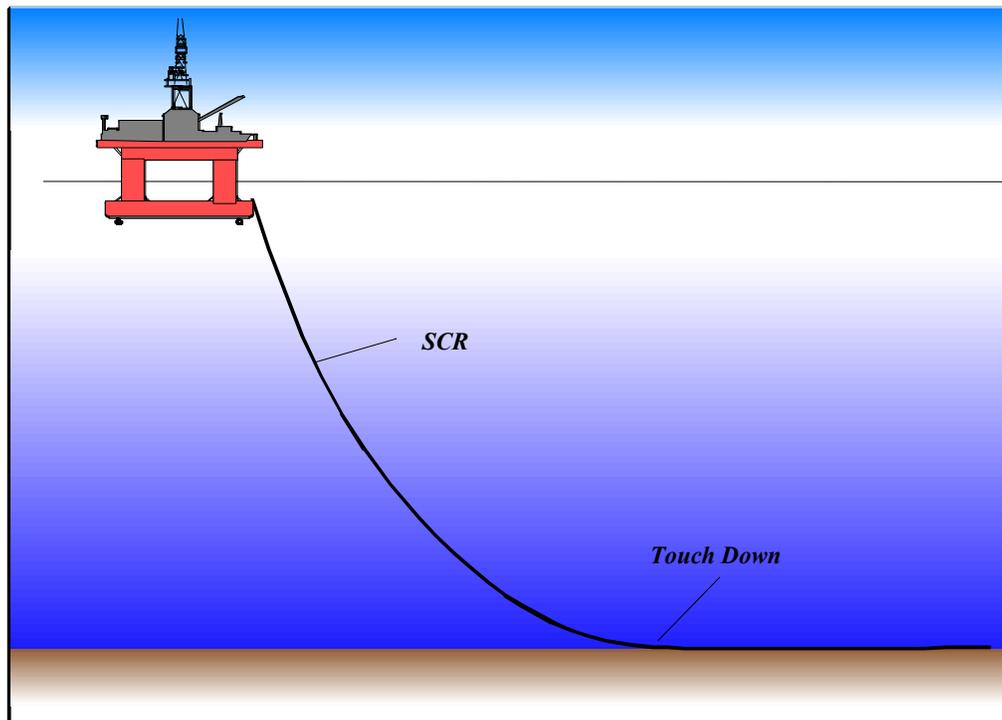


Figure 2. Steel Catenary Riser (SCR) Configuration



Figure 3. C & C's Survey AUV

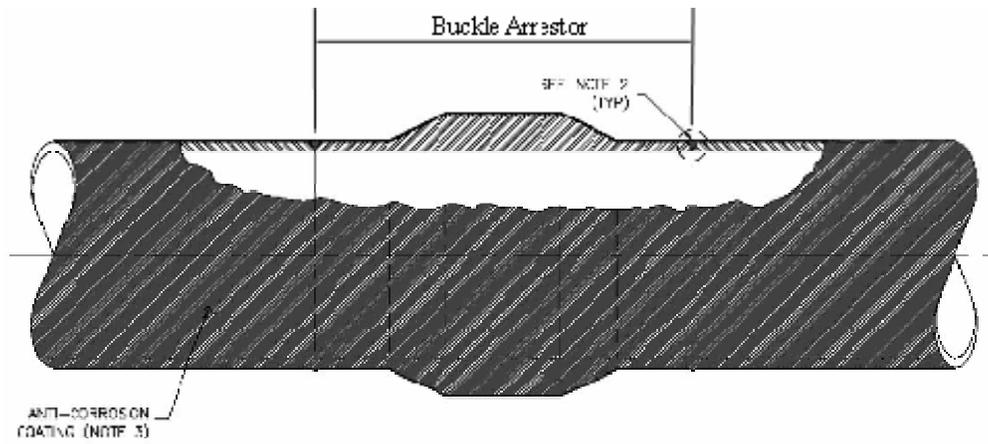


Figure 4. Integral Buckle Arrestor Make-up



Figure 5. Installation of Helical Strakes on SCR

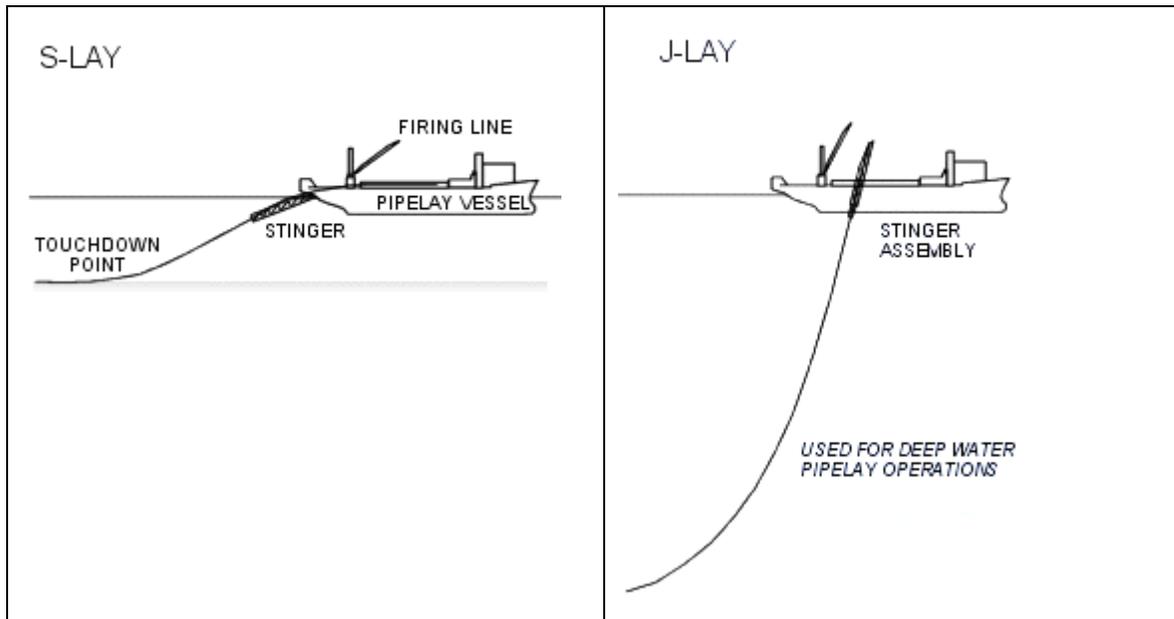


Figure 6. S- and J-Lay Schematics



Figure 7. Allseas Vessel Solitaire (Prior to Upgrades)

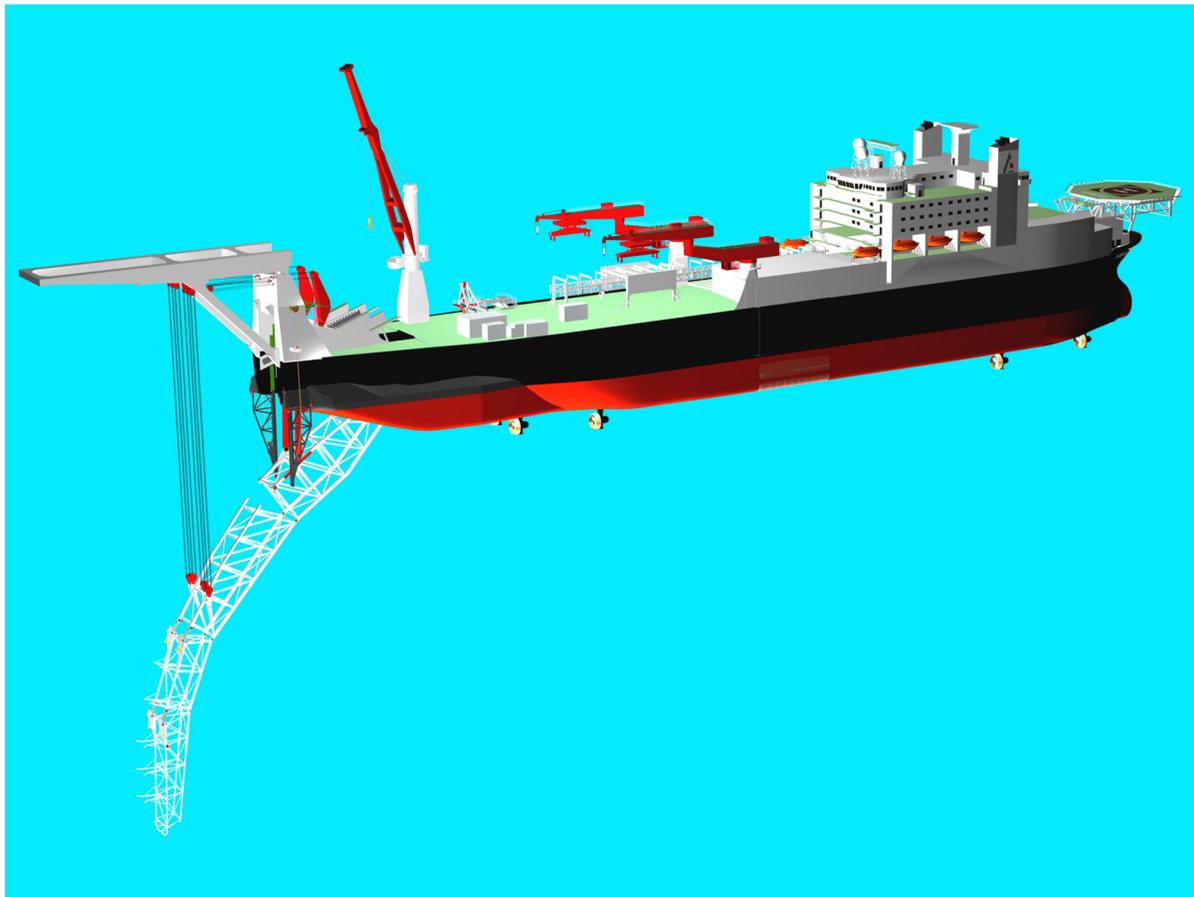


Figure 8. Allseas Vessel Solitaire (after Upgrades)

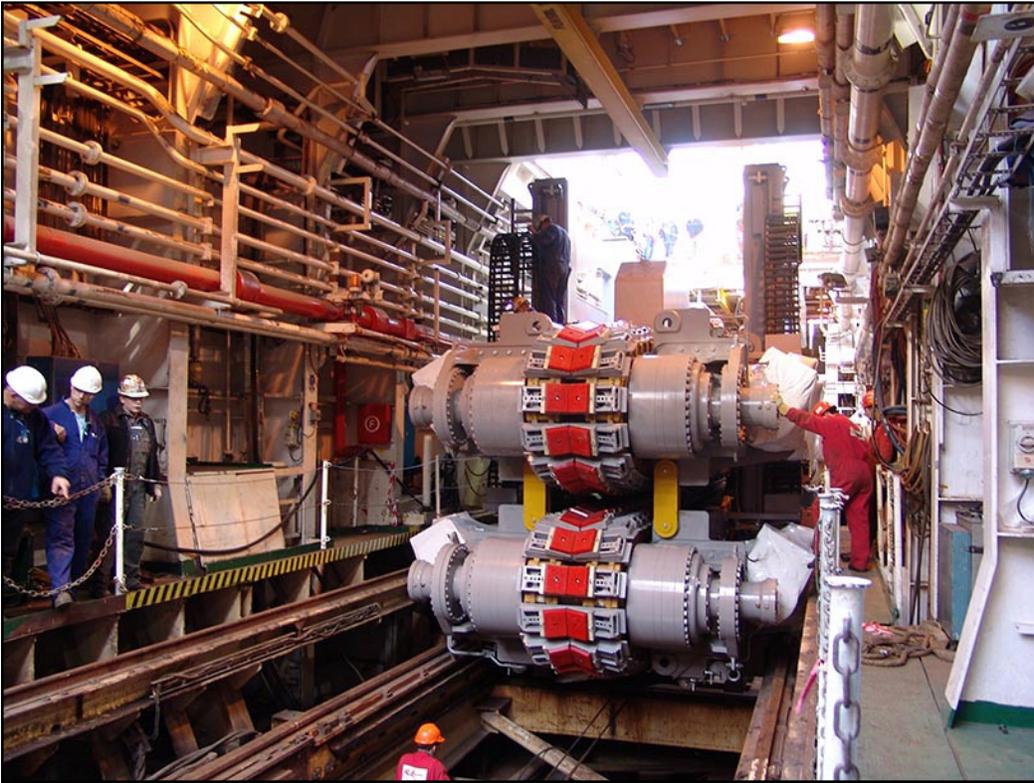


Figure 9. One of Solitaire's New Tensioners



Figure 10. S-lay Welding & NDE Firing Line



Figure 11. S-lay Stinger

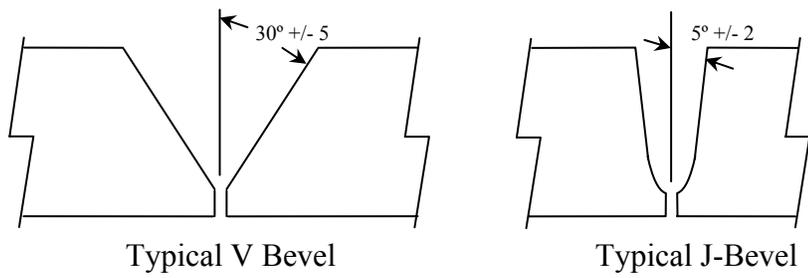


Figure 12. Typical Girth Weld Joint Designs

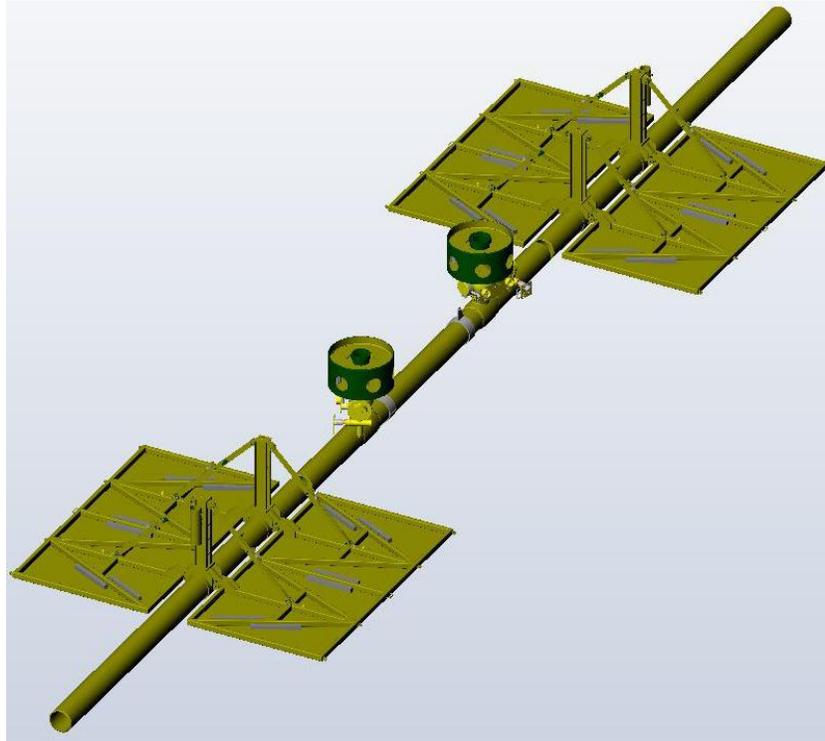


Figure 13. Dual Tee in-line Structure