

Appendix J

Recommendations for Design. Pipe Materials,
Girth Welds, Non-destructive Testing,
Coatings and Cathodic Protection Materials

Memo

Subject Baltic Pipe
To Nina Vendelboe
Copy MIK, SEJ
From Celia Juhl
Re Recommendations for Design. Pipe Materials, Girth Welds, Non-destructive Testing, Coatings and Cathodic Protection.

Introduction and Conclusion

The Baltic pipeline will be designed as a 30" line for transportation of sweet commercial natural gas. A compressor station will be installed onshore on the Danish side, presumably immediately before the pipeline enters the sea.

An extensive literature search has been performed with the aim of assessing modern materials, joining methods, corrosion protecting methods etc. for subsea pipelines and giving recommendations for design of a Baltic pipeline. Also results from research performed by committees, which DONG is a member of, e.g. Pipeline Research Committee International and Gas Research Institute, have been included.

The choice of materials is important because of the large impact on the cost of the pipeline. The choice of corrosion protection is important because the possibilities of monitoring during operation are limited. A relatively conservative corrosion protection design is justified by the limited monitoring possibilities as well as the fact that it is common practice to upgrade the design life of subsea pipeline systems.

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Offshore pipe-laying techniques are principally the same as 20 years ago when DONG laid two pipelines in the North Sea. The pipeline production efficiency however, has improved dramatically through new pipe handling, welding and NDT techniques, improved material qualities and narrow tolerances on e.g. pipe wall thickness and out-of-roundness. These improvements were recognised when DONG laid the South Arne pipeline two years ago.

All three DONG offshore pipelines are made of carbon-manganese (C-Mn) steel pipe covered with a corrosion coating of either coal-tar enamel or asphalt enamel, and a weight coating of concrete. Anode bracelets of either zinc or aluminium are used for cathodic protection of the three pipelines. The three lines have the following characteristics:

- The oldest gas pipeline (138 barg) was made of steel grade X 60 with a diameter of 30" and a wall thickness of 18.7 mm,
- The oil pipeline (95 barg) was made of steel grade X 60 with a diameter of 20" and a wall thickness of 12.7 mm,
- The South Arne pipeline (150 barg) was made of steel grade X 65 with a diameter of 24" and a wall thickness 22 mm.

The specifications for the South Arne pipeline were prepared as project specific specifications in another format than DONG's general specifications. As it is DONG's intention to have general specifications available for new projects, the existing specifications will have to be rewritten.

The South Arne pipeline was certified according to DNV's 1996 guideline [1], and it would be a natural continuation to have the Baltic pipeline certified according to the new DNV 2000 guideline [2]. The DNV 2000 guideline has gone through a considerable revision and extension from 128 to 204 pages. This also calls for new specifications.

From this memo, it may be concluded that the materials and corrosion protection methods that were used for the South Arne pipeline are still applicable. When preparing new specifications, a number of changes should however be considered.

Pipe Materials

The most commonly used and most economic pipe material for gas subsea pipelines is longitudinally welded C-Mn steel.

Reeled steel pipes and multilayer flexible pipes have been used as flow lines and risers because of the advantages: onshore manufacture of long lengths, relatively easy installation from reels, limited field joints required etc. These materials are however limited to relatively small diameter pipelines (maximum 14-16") and they are therefore not applicable for the Baltic pipeline.

The use of glass-fibre reinforced plastic piping (composite tubular) is growing, however the diameter as well as the pressure prohibits its use for the BalticPipe pipeline, besides there would be great problems with applying extra heavy weight coating.

The conditions for offshore linepipes and risers are becoming more and more severe especially in deep-water projects. This has resulted in increased toughness requirements, particularly in the heat affected zone at the weld. This favour the use of seamless pipe, especially for the most stringent demands, however they are costly compared to longitudinally welded pipe. Seamless pipes are available up to steel grade X70, but only in size ranges up to approximately 400 mm OD. They are therefore not applicable for the Baltic pipeline.

Material selection for onshore as well as offshore pipelines is principally governed by internal corrosion and strength considerations. Corrosion occurs when water or water vapour is present. In pipelines with untreated natural gas, water may be present both as formation water and as condensed water. In treated gas however, only condensed water may form and only if the temperature of the gas (e.g. locally) gets lower than the water dew point of the gas. Commercial natural gas contains carbon dioxide (CO₂) and small amounts of hydrogen sulphide (H₂S). Water in combination with carbon dioxide and hydrogen sulphide creates a corrosive environment inside the pipeline (sweet and sour corrosion). The combination of condensed water in commercial natural gas and CO₂ or H₂S creates a more severe corrosion situation than when formation water is (also) present. Observing the water

dew point is therefore very important for the safe use of gas pipelines, and a better way of preventing corrosion than relying on inhibitors.

In selecting type of pipe material for onshore as well as offshore pipelines, it is necessary to take upset conditions, where water is formed in the pipeline, into consideration. If the Baltic pipeline will be fed from the aquifer storage in Stenlille, an upset condition could be that a dehydration unit in Stenlille does not work properly.

Another situation could be a glycol carry-over from a dehydration unit and transportation of glycol into the pipeline. At the lower temperatures prevailing in the line, glycol, being hygroscopic, will attract water from the gas phase. Hence, the carry-over may result in an aqueous phase that, in the presence of H₂S, could create a hydrogen-related problem, leading to cracking.

For sour service, special C-Mn steels that pass standard tests for sour service are supplied. Steel pipes for sour service are at least 10% more expensive than pipes for sweet service and not necessary for the Baltic pipeline as it is possible to keep the water dew point sufficiently low.

Offshore pipelines are designed to considerably higher pressure than pipelines onshore and the laying stresses are much larger. Consequently, either higher strength steel or larger wall thickness must be used. The material grades for offshore pipelines today typically lie between grade X 60 and grade X 70 with grade X 60 and X 65 as the most commonly used. X70 has only been used on a few offshore pipelines and only for sweet service.

For reasons associated with ease of Welding, strength levels are usually kept as low as practical, however the higher the pressure in the line, the higher the strength may have to be to limit the thickness and thereby keep the material and welding cost at an economic level.

Traditionally the American API 5L standard [4] has been used as reference when line pipe is specified. The problem in referring to the API 5L for more demanding use such as offshore or sour service is that very many supplementary requirements are necessary, which often result in conflicting requirements. The South Arne pipe specification was based on the API 5L, and modified to include requirements for sour service.

For offshore use (sweet or sour), both ISO 3183-3 [5] and prEN 10208-3 [6] apply. The two standards are basically the same, but the EN standard is still in the preliminary state. The DNV 2000 guideline refers to ISO 3183-3. In addition, the DNV guideline includes some supplementary requirements regarding manufacture and testing. The GL rules refer to EN 10208-2 [7] as well as API 5L and DIN 17172 [8]. None of these standards qualify the pipe for offshore or sour service and therefore the GL rules have a large number of supplementary requirements. GL's choice of pipe standard may be explained by the lack of a standard for demanding purposes at the time when the GL rules were published.

It is recommended to use the ISO 3183 standard as reference for a general DONG offshore specification.

Girth Welds and Non-destructive Testing

Offshore pipelines are subject to high longitudinal strains during laying. With high laying stresses, thick wall pipe, integrity becoming a major issue, sophisticated materials etc, girth weld quality and non-destructive inspection becomes very important.

Neither the DNV guideline, nor the GL rules refer to any welding standard, but set their own requirements. The Syd Arne pipeline was welded according to the British standard BS 4514 [9], which is a recognised standard. To be consequent, DONG should refer to the DNV guideline.

In conventional lay barge operations, non-destructive inspection is the most critical activity controlling productivity. Traditionally, radiography has been the principal inspection method and ultrasonic inspection has only been used as backup to assist with interpretation of uncertain features on the radiograph. Radiography is however recognised to have some inherent limitations for the detection of inclined planar defects as well as giving hazardous radiation.

Radiographic inspection has provided a valuable tool for the assessment and control of welds. Engineering critical assessment of girth welds in buried pipelines has however shown, that the absence of problems is largely because of low longitudinal stresses in onshore pipelines, rather than the success of radiography in removal of defects.

Offshore pipelines are welded by use of mechanised welding systems, which are more likely to produce planar types of defects than shielded metal arc welding, which is mainly used onshore. Therefore, the integrity of girth welds for offshore projects should not rely on past inspection experience with manual welding of pipelines. Although the incident of girth weld failures from undetected defects is low, such incidents have occurred.

Automated ultrasonic techniques (AUT) using digitised recording systems are taking over onshore as well as offshore. The mechanised test operates with a large number of simultaneously working probes. It is fast, provides instant results and there is no radiation. Direct recording is provided, and it can optimise and monitor consistency of sensitivity. It can, by use of supplementary data-processing facilities make such recording objective according to pre-set criteria.

Because AUT is, contrary to radiography, capable of quantifying through-thickness extent of defects, indications can be sentenced against acceptance criteria with defect height as a parameter. This allows for an approach in which only the really critical defects are repaired, instead of repairing uncritical defects in the Good Workmanship approach.

The actual cost for AUT can be lower than for radiography due to reduced personnel requirements and lower priced consumables. As wall thickness increases, the exposure time for radiographic examination increases together with cost – on an exponential basis. Similarly, consumable costs increase as a function of pipe diameter for radiographic testing.

AUT is not specifically addressed in the GL rules. The DNV 2000 guideline has a chapter dedicated the subject. South Arne girth welds were tested by AUT. This was decided very late in the project. It is recommended to start the process as early as possible for the Baltic pipeline.

Coatings

The external surface of the Baltic pipeline will be provided with an anti-corrosion coating as well as a concrete weight coating, and the internal surface with a flow coating. The properties and quality of all coatings are important, because they must remain intact throughout the lifetime of the pipeline, as rehabilitation is not possible.

The primary objective of applying an external anti-corrosion coating is to reduce the current requirements for cathodic protection. With a properly applied coating, the current requirements for coated sections is very close to zero, which means that only coating damages drain current from the anodes. In addition to reducing the sacrificial anode weight, other benefits from coatings are a high initial current density on the exposed steel, favouring the formation of a high quality calcareous (calcium and magnesium products) layer, and improved current density and potential distribution.

The temperature is an important factor in choosing type of coating. The Baltic pipeline is expected to operate within a temperature range of 0 °C to 50 °C. The 50 °C is a consequence of installing a compressor station at landfall.

Internal flow-coating

Pipes for onshore use have been coated internally with epoxy for more than 40 years. The main purpose has been to increase flow by reducing the surface roughness, but a number of other benefits have been achieved such as corrosion protection during storage and construction and more rapid drying after hydrostatic testing. This means savings on commissioning costs as well as on operating costs. The coating is very thin (60-100 m μ m) and does not protect against corrosion during operation. The weld joints are not coated, as this would only have a marginal effect on the flow. Coating of weld joints is however possible. Epoxy has been used internally on offshore pipelines for about 10 years. The South Arne pipeline was internally coated and so should the pipes for the Baltic pipeline.

Corrosion protecting coatings on the internal surface are generally avoided if possible, owing to difficulties in control of application and inspection. They are also susceptible to local erosion and damage from pigs, and bare spots can accelerate localised corrosion in service.

Internal flow-coating has traditionally been specified with reference to an American recommendation API RP 5L2 [10], and so was the specification for the Syd Arne pipeline. The latest edition is however from 1987, and does not take the development in the paint industry into account. Some years ago, Statoil, DONG and other gas companies with long pipelines experienced the formation of a white powder from constituents in the paint when a specific epoxy paint was used under certain pressure and temperature conditions. The problem arose because the paint manufacturers change the composition of the paint from time to time. In order to avoid the problem, DONG included some additional requirements in the general specification [11] and these requirements were transferred to the specification for the Syd Arne project [12].

Two flow-coating standards are under preparation, one within the framework of ISO [13] and the other within CEN [14]. The white powder problem is addressed in the preliminary ISO standard by a paragraph with the wording: It [the paint] shall not contain any substances, which will be released from the paint film after it has cured.

It is recommended to discuss whether it would be acceptable to refer to the preliminary ISO standard if the standard is attached to the specification as an annex. This would reduce the number of special DONG requirements.

External corrosion coating

To minimise the risk of external corrosion, anti-corrosion coatings are routinely applied to protect subsea pipelines. The coating forms a barrier between the steel and the seawater however, all coatings have defects, which can allow ingress of the corrosive environment to the underlying steel. The application of a good coating will reduce the required cathodic protection demand.

Offshore pipelines operating at ambient temperatures have traditionally been coated with hot applied coal tar or asphalt (bitumen) enamel coatings and they are probably the cheapest of the available coatings. They are applied over chlorinated rubber primers, reinforced with non-woven glass fibre wraps and applied in a thickness of at least 6-7 mm. The rough surface of these coatings normally eliminates the risk of slippage between coating and concrete due to tensioning. The experience with asphalt and coal tar based thick film coatings is mainly good on offshore submerged pipelines, where a high quality concrete weight coating offers an effective shield against mechanical damage. The majority of oil and gas pipelines in the North Sea are coated with bitumen enamel and the rest mainly with coal tar enamel.

Detailed requirements for the manufacturing of asphalt and coal tar coatings for offshore use are provided in a DNV recommendation [15], which adheres mainly to a BS standard [16]. Also a preliminary European standard prEN 10300 [17] exists. Different grades of asphalt and coal tar coatings are available for different temperature ranges.

Health and safety restrictions can be expected to result in the continuing decline in the use of coal tar and asphalt enamels. Especially coal tar has some adverse effects. The carcinogenic nature of some coal tar components has resulted in restrictions of varying severity on the use in some countries [18]. Coal tar dust contains polycyclic aromatic hydrocarbons (PAHs), which are considered cancer-causing, capable of producing skin tumors, and volatile components of coal tar are known to be toxic when ingested, absorbed through the skin, or inhaled. There are strong warnings about protection from vapours of hot tar. Asphalt enamel is currently being used to an increasing extent offshore as a substitute for coal tar because it contains lower levels of carcinogens, however the same restrictions with regard to rigorous fume extraction apply during its use.

Asphalt enamel coating has some limitations in terms of flexibility at very low temperatures. Asphalt coatings are however still adequate if applied to a properly blast-cleaned pipe surface and handled carefully in pipe laying.

There has been a demand for a higher performance asphalt coating, which has led to the development of second-generation asphalt products where asphalt is blended with e.g. polyurethanes, epoxies and synthetic rubbers. Phønix together with Shell has developed a rubber-modified product Bituseal, which is said to have increased adhesion, flexibility, temperature stability (-20 °C to 80 °C) and better low temperature properties [19]. According to experience and tests performed, it should be possible to reduce the coating thickness from 6 mm, as is normal for coal tar and bitumen enamel, to 4 mm. Additionally the number of reinforcing wraps has been reduced from 1-2 inner, and 1 outer wrap to 1 specially developed outer wrap. This keeps the price comparable with the traditional asphalt coatings. However, the product has not been used for any offshore pipelines, and it could be argued that this is too little experience.

During the laying operation, very large shear stresses are imposed at the interfaces between the different components of the coating system by the weight of the steel pipes. The lack of friction between the concrete weight coating and the modern smooth synthetic types of anti-corrosion coating such as fusion bonded epoxy (FBE) and polyethylene (PE) have given problems, especially because

relatively small movements may fracture connections to sacrificial anodes. Both FBE and PE have however performed satisfactorily in recent years. The disadvantage is that they are relatively expensive compared to asphalt.

FBE coatings are typically applied in layers of the order of 500 μm . A thin coat of fibre-reinforced concrete is necessary to ensure good adhesion to the main concrete cover to avoid slippage, and to prevent damage by the sprayed concrete.

PE is normally applied in a total thickness of 2.0 mm, including primer and adhesive. The surface of PE must be specially treated to have a sufficiently rough surface to avoid slippage.

For the South Arne project, specifications for asphalt and PE coating were prepared. The PE specification required chromate washing of the steel surface to promote coating adhesion and avoid cathodic disbonding. It is however very likely that surface pre-treatment chemicals incorporating hexavalent chromium will disappear from the line pipe coating industry as health and safety legislation covering the handling and disposal of these materials becomes more stringent. As cathodic disbonding is not a big issue on offshore pipelines, it is recommended to omit chromate washing. The DNV coating recommendation [9] does not include chromate washing.

Asphalt enamel coating was chosen for the Syd Arne pipeline for economical reasons, however environmental considerations were also made. The environmental influence of the finished pipe coating with the weight coating applied was taken to be minimal. The same reasons apply today and asphalt is recommended for the Baltic pipeline.

External field coating

After jointing, the gap between the two concrete jackets is in many cases filled with marine mastic over a primary corrosion protection, e.g. primers, tapes or sleeves. The corrosion protection is installed on top of a weld bead, which is still hot due to the residual heat of the welding.

Coal tar and asphalt coated pipes are usually field coated by mounting a steel mould into which a rapid setting hot mastic solution of coal tar, respectively asphalt is poured. The mastics are modified coal tar or asphalt, reinforced with sand or fibres.

Different types of shrink sleeves and tapes have been used, but generally the performance has been disappointing. Polyurethane foam coating, with or without addition of iron ore for increased density, has been tried. The performance seems to have been satisfying together with fusion bonded epoxy coating. Their performance together with other types of pipe coating is not known.

Field joint coatings for modern coating systems are demanding with regard to surface preparation, application and curing time. This generates some logistics problems and costs for lay barge operation. Also the progressive movement of a pipeline onto the stinger poses problems for maintaining process control and quality in coating application because of possible damage resulting from the pipeline being laid so quickly after application of the joint coating.

External weight coating

The weight coating consists of a concrete coating that encloses the pipe and the anti-corrosion coating. The chief function is to add sufficient weight to the pipeline to achieve the required negative buoyancy. The weight coating must also have resistance to damage during laying and trenching

operations, from natural environmental hazards and from the effects of human hazards, such as fishing trawls and trailing cables.

When a pipeline is immersed in seawater, the concrete gains weight by water absorption. It is desirable to keep the water absorption as low as possible, because it can have a significant effect on submerged weight.

No standards cover weight coating and therefore both the DNV guideline and the GL rules set requirements.

Cathodic Protection

External corrosion protection (CP) involves both coating and cathodic protection using sacrificial anode bracelets. The anodes are mounted on top of the corrosion coating, but before application of the concrete coating. Until relatively few years ago, zinc was the most common sacrificial material used for cathodic protection of subsea pipelines, however now aluminium is usually chosen.

Design of the cathodic protection system for an offshore pipeline is described in the DNV recommendation RP-B401 [20]. A good quality of pipe coating leads to less corrosion of the anodes and less risk of maintenance and repair of the anodes, which would be very costly or impractical. It is normal practice to apply the same anode design life as for the pipeline to be protected. The DNV recommendation RP-B401 however states that the operator should also consider the likelihood of the design life of the object being extended. The design life for the CP system on Statoil's Zeepipe pipeline (and probably other newer pipelines) is 50 years [21].

Cathodic disbondment, where a coating loosens due to the reaction with hydroxide ions formed by cathodic protection, is very important to onshore pipelines, however it is less relevant for offshore pipelines. The reason is that zinc and aluminium sacrificial anodes are used for offshore lines. These have a low driving potential, in contrast to the impressed current anodes on onshore pipelines. Overprotection is thus practically impossible on offshore pipelines. Besides, nearly all offshore lines above a certain diameter have a concrete weight coating on top of the corrosion coating which prevents mechanical damage to the corrosion coating. Disbonding has not been reported to be a problem for offshore pipelines.

Pure zinc and zinc with additions of aluminium and cadmium have been used in seawater as anode materials. In pure zinc, the amount of cadmium as impurity is restricted to max. 0.003%. In zinc with cadmium addition, the content is in the range 0.025 to 0.07%.

For the last ten years, mainly aluminium anodes have been used offshore. There are three groups of aluminium alloys, all containing zinc in varying amounts together with tin, mercury or indium as activator. Some commercial anode alloys have additional alloying elements present such as silicon, bismuth, manganese, magnesium or titanium.

Due to environmental restrictions the aluminium-zinc-indium anode alloys are generally the most frequently used. There are many individual specifications of this generic alloy, however, the zinc content is usually in the range 2.5 and 5.0% and the indium content around 0.02. Residual impurities, such as iron and copper are kept to a minimum.

The South Arne project specification for sacrificial aluminium anodes does not adhere to any standard regarding fabrication and testing. This is not acceptable as standards exist, e.g. regarding fabrication : NACE RP-0492 [22]. Regarding testing, the NACE TM-0190 [23] is applicable. This

document e.g. reduces the ability of manufacturers to “cook” their test results by testing at high current densities.

According to [24], an anode spacing of 1 per 8 joints was recommended on the South Arne pipeline, and this is in agreement with normal practice in the North Sea [25]. Because of the cost of manufacturing and handling pipe joints with anodes is higher than for pipe joints without anodes, Statoil is now fitting two anodes on one pipe thus reducing the number of pipes with anodes. This could be considered for the Baltic pipeline. On the old gas pipeline, a spacing of 1 per 10 was used, which was conservative for that time.

Two High Voltage Direct Current (HVDC) cables cross the Baltic Sea, the KONTEK cable and the BALTIC cable. The KONTEK cable links Denmark and Germany and the BALTIC cable links Sweden and Germany. HVDC links are often based on a single conductor cable (monopolar links) where the current passes the cable and returns via earth electrodes through the ground. The returning current affects the electric gradient field in the ground, and this may cause severe corrosion on pipelines onshore as well as offshore. Corrosion may occur either at holidays in the coating or as extra consumption of anodes. Installing insulation couplings can eliminate problems, and this was done on the transmission system on Sjælland in 1993, after the KONTEK link was established. The Baltic pipeline will be affected onshore as well as offshore by both the two HVDC links, and the problem should be analysed before construction. Balslev A/S has experience in modelling potentials from similar work in the North Sea.

A CP-survey should be considered performed prior to hydrostatic pressure test in order to avoid hydrogen damage in case the pipeline has been mechanically damaged (refer to the 45 Mio. DKr burst of the DORAS oil pipeline during hydrotesting).

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